MI POWER GRID

Making the Most of Michigan's Energy Future

Electric Distribution Planning Stakeholder Process

MPSC Staff Report

April 1, 2020

MPSC

Michigan Public Service Commission

Contents

Executive Summary

On October 17, 2019 the Michigan Public Service Commission (MPSC or Commission) launched MI Power Grid in collaboration with Governor Whitmer. MI Power Grid is a customer-focused, multi-year stakeholder initiative intended to ensure safe, reliable, affordable, and accessible energy resources for the state's clean energy future. The initiative is designed to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses. MI Power Grid encompasses outreach, education, and changes to utility regulation by focusing on three core areas: customer engagement; integrating new technologies; and optimizing grid performance and investments. The MPSC maintains a dedicated website for the initiative at www.michigan.gov/mipowergrid.

MI Power Grid seeks to engage a variety of stakeholders, including utilities, energy technology companies, customers, consumer advocates, state agencies, and others, in discussions about how Michigan should best adapt to the changing energy industry. Stakeholder groups are formed and led by MPSC Staff. This report represents the MPSC Staff's review, summary, and corresponding recommendations following a public stakeholder process held throughout 2019 that addressed on-going issues and challenges of utility electric distribution planning in Michigan. Significant stakeholder participation offered robust perspectives and added substantial value to the process. This report intends to inform the Commissioners about the distribution planning process and subsequent dialogue, followed by Staff recommendations regarding key issues that the Commission may consider going forward. This report, however, 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. This report does not represent the Commissioners' individual or collective perspectives on distribution planning.

The stakeholder process consisted of five public forums held between June and November 2019. Multiple topics were discussed throughout the process. Michigan utility representatives along with experts from across the country presented information at the stakeholder sessions. Stakeholders participated in the discussions and additionally submitted comments into the U-20147 docket in response to issues addressed at the stakeholder sessions.

Summarized comments from the U-20147 docket throughout this Staff report have not been attributed to any particular individual or organization. For specific stakeholder comments, please reference the U-20147 docket.[1]

In this report, Staff has provided summaries and recommendations regarding the following issues:

Distribution Planning Objectives

The Commission established four primary objectives in their October 11, 2017 order in both U-17990 and U-18014 dockets:[2] 1) Safety, 2) Reliability and Resiliency, 3) Cost Effectiveness and Affordability, and 4) Accessibility.

Staff recommendation

The Commission should reiterate the importance of these four objectives in a subsequent order in the U-20147 docket, and also provide confirmation with Staff's assumption that "Safety" is the first priority – both for customers and the utility employees – with the second priority being "Reliability and Resiliency". The utility electric infrastructure in Michigan has many assets that are operating beyond their expected useful life and utility investments must consider the vast ratepayer resources needed to assure reliable service during all types of weather. (However, Staff acknowledges that asset age is not always a justification for replacement. Field equipment routinely operates reliably decades beyond the depreciable lives used in utility accounting.)

The Commission should also confirm Staff's assumption that resource diversity as identified in the State Energy Assessment[3] is correlated to the Commission's fourth objective of "accessibility".

Staff believes the additional emphasis on Commission stated objectives and subsequent priorities will provide clarification for utilities and stakeholders as utility distribution plans continue to be developed and submitted to the Commission.

Definitions

Staff recommendation

For purposes of referencing distribution planning terms going forward, Staff suggests the following definitions for inclusion in a forthcoming Commission order:

- Distributed Energy Resource (DER) – 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 (HCA) – Amount of distributed energy resources (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 distributed energy resources (DER), which are often locational and time varying in nature. (Note: Very little discussion around locational value occurred at the stakeholder meetings and perhaps is a subject that warrants future discussion with stakeholders.)

Benefit-Cost Analysis (BCA)

Staff recommendation

Staff recommends an uncontested stakeholder process to propose specific BCA criteria for Commission consideration and adoption. The stakeholder process should consider:

- One main BCA test and up to two sensitivities required for future distribution plans from the list of BCA tests below:
    - 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 Energy Company (Consumers), DTE Electric Company (DTE), and Indiana Michigan Power Company (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. This allows utilities time to implement and analyze the BCA pilot process. 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.

Hosting Capacity Analysis (HCA)

Staff recommendation

Staff recommends that the following be adopted by utilities for the HCA pilots requested by the Commission:

- 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:

    - Perform base-level approach with a zonal go/no-go map.
    - 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.
    - As interconnection studies are conducted and HCA data for a specific interconnection location is determined, make this information publicly available.
- Staff proposes that Indiana Michigan continue to monitor the HCA activities of Consumers and DTE 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.

Non-Wires Alternatives

Staff recommendation

Staff agrees that the questions presented in Paul DeMartini's October 16 stakeholder presentation[4] should be asked by the Commission and answered by the utilities prior to refining and implementing additional NWA pilots:

- 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?

Additionally, staff suggests that this question also be asked by the Commission and answered by the utilities prior to refining and implementing additional NWA pilots:

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

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 non-wires alternative pilot proposals.

The Commission should encourage the utilities to explore additional opportunities for NWA to provide distribution solutions for the "system expansion" portion of their capital plans, as well as other opportunities that may exist such as "new business", "reliability and resilience", or "voltage and reactive power".

Staff believes that NWA is a topic that merges with the work of the MI Power Grid Energy Programs and Technology Pilots workgroup,[5] and some of the forthcoming clarifications and recommendations from this workgroup will be directly applicable to specific NWA pilots.

Alternative Regulatory Approaches

Staff recommendation

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 Advanced Energy Economy (AEE) August 14, 2019 stakeholder presentation.[6] 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.

Pilot Programs

Staff recommendation

In their on-going work, the Energy Programs and Technology Pilots workgroup[7] should take into consideration the important stakeholder comments that were included in the U-20147 docket as well as the discussions that took place during the distribution planning stakeholder sessions of 2019.

Resiliency

Staff recommendation

The Commission should provide guidance to be used for the MI Power Grid Integration of Resource/Transmission/Distribution Planning workgroup[8] regarding which methodologies to explore as a best fit for Michigan to enable Staff, stakeholders and utilities to further examine ways to improve the resiliency of the Michigan electric grid.

Instead of providing a definition of resiliency, Staff recommends the Commission identify the events that have the potential to effect electrical system resiliency that the Commission finds most compelling. Once these events are identified, the proper metrics can be determined.

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.

Standardized Components for Future Utilities' Distribution Plans

Staff recommendation

The Commission should support the joint utility proposal from the October 16, 2019 stakeholder session. The utilities agreed to standardized components for upcoming distribution plans, as well as areas in their plans that will likely differ based on company unique circumstances.[9]

Staff recommends that the utilities should view System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) in total, as outlined with quartiles, and by cause for the same period. Additionally, Staff recommends that utilities use the (Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Duration (CELID) metrics to directly measure the current unacceptable levels set by the Commission in the Service Quality and Reliability Standards for Electric Distribution Systems, R 460.722.[10]

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.

Michigan Infrastructure Council (MIC)

Staff recommendation

The utilities should reference the MIC as they develop their utility distribution plans. As referenced in the Commission November 2018 order in Case Number U-20147,[11] utilities should coordinate distribution planning efforts with the MIC efforts in order to benefit all Michigan residents through more efficient and effective planning.

The Role of Energy Efficiency (EWR) with Distribution Planning

Staff recommendation

The Commission directs the utilities to include an assessment of energy efficiency options in their forthcoming electric distribution plans, including an evaluation of energy efficiency in utilities' forecasts and NWA analyses. (Energy efficiency, per MI legislative language, is referred to as energy waste reduction (EWR). For the remainder of this report, EE will be referred to as EWR.)

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

Staff recommendation

Staff suggests that the utilities' articulation of "vision" be emphasized every step of the way for future iterations of distribution plans. Such a vision becomes the roadmap for results. As the utilities' proposed at the October 16 stakeholder session,[12] a long-term strategic vision and plan should be a featured component of every utility distribution plan going forward. Staff recommends that the utilities include measurable goals and objectives as a component of their long-term strategic vision and plan.

Next Steps

Staff recommendation

The Commission should provide additional direction and clarification through their orders regarding these important issues prior to the utilities submitting their next electric distribution plans on June 30, 2021. Additionally, the Commission may choose to clarify how often the refreshed distribution plans should be submitted by the utilities. Utility distribution plans typically project needed improvements over a five-year period, with portions of the plans addressing a longer-term view of distribution investment. Staff recommends that utilities align its distribution planning refresh with its integrated resource plan (IRP) filings such that investments in both plans can be considered in their respective cases simultaneously.

Introduction

This report is a response to the Michigan Public Service Commission's (MPSC or Commission) focus on the elevated role of stakeholder participation with utility distribution planning. Following the submittal of the draft five-year distribution plans from Consumers Energy Company (Consumers) in Case No. U-17990[13] and DTE Electric Company (DTE) in Case No. U-18014,[14] the Commission emphasized a more participatory stakeholder process going forward with future electric distribution planning in Michigan. This report summarizes the stakeholder participation process and subsequent issues discussed throughout the 2019 stakeholder forums that were held at the Commission's Lansing, MI facility. Stakeholders are generally referred to as interested parties outside of the utility companies and the Commission. Stakeholders include, but are not limited to, representatives from government and non-government agencies, technical entities, consultants, and other interested participants.

Initially in 2017, the Commission issued two rate case orders requiring Consumers (Case No. U-17990)[15] and DTE (Case No. U-18014)[16] to each develop and submit a five-year electric distribution investment and maintenance plan to the Commission. As indicated in the Background section below, requirements for Indiana Michigan Power Company's (I&M) distribution planning process followed.

The Commission's orders in the U-17990 and U-18014 cases outlined specific planning criteria to be included in the utilities first five-year distribution plans. The overall intent was to create transparency and visibility into electric distribution planning processes for the Commission, Commission Staff, and all interested parties. The distribution plans were intended to provide a more thorough overview of the utilities anticipated needs, priorities, and planned investments beyond the projected test-year timeframe typically reviewed in a general rate case.

The following background section of this report provides the details of what occurred following the Commission's original orders in the U-17990 and U-18014 dockets. NOTE: The utility distribution planning effort was originally referred to as "Five-Year Distribution Planning". That title was subsequently changed to "Electric Distribution Planning" to more broadly include the process of utilities filing five-year distribution plans with implications of planning and investments exceeding five years, refreshed distribution plans being submitted sooner than five years, and the input of stakeholders throughout the planning process.

Background

Following utility draft plan submittals, stakeholder workshops, and a clarifying order from the Commission in October of 2017,[17] DTE filed their first five-year distribution plan on January 31, 2018[18] and Consumers filed their first five-year distribution plan on March 1, 2018.[19]

Two additional orders followed from the Commission (April 2018, order[20] requiring I&M to provide their five-year electric distribution investment and maintenance plan (Case No. U-18370), and an April 2018 order establishing a new docket, Case No. U-20147[21] to act as a single repository for future distribution plans). The Commission encouraged stakeholders to file additional comments and directed Staff to host a technical conference to address stakeholder's concerns outlined in comments submitted to the docket. The technical conference took place on August 7, 2018.

Staff then filed an analysis of the DTE and Consumers initial five-year electric distribution investment and maintenance plans, including a summary of stakeholder input. The Staff report was filed in the U-20147 docket on September 4, 2018,[22] and included recommendations for the Commission to consider going forward.

Subsequently, the Commission issued an order in the U-20147 docket on November 21, 2018[23] in response to Staff's report and additional stakeholder comments, while providing more clarifications for the utility distribution process going forward. More particularly, the Commission order encouraged further discussions relating to dynamic system load forecasting, hosting capacity, NWA, and BCA.

Following a draft plan, the November 21, 2018 order from the Commission, and comments and responses filed by stakeholders, I&M filed their initial distribution plan for 2019-2023 in the U-20147 docket on April 3, 2019.[24]

On September 11, 2019,[25] the Commission issued an order that included important clarifications for the distribution planning process going forward. This order directed Staff to file this report providing an overview of the distribution planning stakeholder sessions in U-20147 (summarizing the stakeholder workgroup process including discussions on the value of resilience, as well as provide recommendations to be used as guidance for the next round of distribution investment and maintenance plans). The Commission order also extended the distribution plan filing deadline to June 30, 2021 for DTE and Consumers. This aligns with the June 30, 2021 deadline already established for the filing of I&M's next distribution plan. Please see Table 1 below for a summary of Commission orders addressing distribution planning.

Table 1: Summary of Distribution Planning Commission Orders

Order Date	Case Number	Description	Link
1/31/2017	U-18014	Authorizes the utility to increase its rates for the sale and distribution of electric energy, on a jurisdictional basis, and authorizes other relief, and sets deadline for draft and final distribution and maintenance plans for DTE.	1/31/17 Order

2/28/2017	U-17990	Authorizes the utility to increase its rates for the sale and distribution of electric energy, on a jurisdictional basis, and for other relief, and sets deadline for draft and final distribution and maintenance plans for Consumers.	2/28/17 Order
10/11/2017	U-18014 & U-17990	Provides guidance on the submission of the utilities' final five-year distribution plans and proceedings.	10/11/17 Order
11/21/2018	U-20147	Follows the August 7, 2018 technical conference, summarizes the Staff's report and subsequent comments, and sets forth future guidance and next steps.	11/21/18 Order
4/12/2018	U-20147	Opens this docket and provides other requirements for Consumer's, DTE, and I&M.	4/12/18 Order
4/18/2018	U-20147	Confirms the determination to remove Consumers' March 1, 2018 filing in Case No. U-17990 and U-20147.	4/18/18 Order
9/11/2019	U-20147	Sets forth additional guidance and requirements for the Commission Staff; extends/sets the date for DTE, Consumers, and I&M to separately file their next distribution investment and maintenance plans by June 30, 2021.	9/11/19 Order

Stakeholder process

As the distribution planning process evolved, the emphasis on stakeholder participation increased. Both the October 2017 order and the April 2018 order that opened the U-20147 docket, encouraged stakeholder input into the distribution planning process. More particularly, the Commission invited stakeholder comments addressing "expectations for the next set of distribution plans".[26]

Stakeholder input from several organizations were submitted to the docket in April and May of 2018 and summarized in the corresponding Staff report. Stakeholders included the Association of Businesses Advocating Tariff Equity (ABATE), Michigan Energy Innovation Business Council (Michigan EIBC), Michigan Municipal Association for Utility Issues, Environmental Law & Policy Center (ELPC), Natural Resources Defense Council (NRDC), Residential Customer Group (RCG) and one Michigan utility customer.

In the Fall of 2018, additional stakeholder and utility comments from ABATE, Michigan EIBC, I&M, Consumers, DTE, Opus One Solutions, Michigan Electric and Gas Association (MEGA), Vote Solar and one Michigan utility customer were filed in response to the draft distribution planning framework which was outlined in the Staff report.

Subsequently, I&M filed their initial draft distribution five-year plan and their final plan, which generated additional stakeholder comments that were filed in the docket.

In 2019, the Commission assigned the Smart Grid Section Staff to shepherd the distribution planning process going forward, emphasizing the stakeholder input portion of the process. The Smart Grid Section Staff set up a stakeholder session agenda for the Summer and Fall of 2019 and maintained stakeholder communications through the Commission's email listserv messaging tool.

Stakeholder Meetings: Utility and Other Stakeholder Presentations

Five stakeholder meetings took place in 2019 on the following dates: June 27, August 14, September 18, October 16 and November 19. All materials for the sessions including agendas, presentations, and recordings of the sessions are available on the Commission's webpage.[27] All sessions featured substantial discussion and contributions from utility Staff, MPSC Staff, national experts, and a variety of other stakeholders.

The *June 27 session* featured an MPSC Staff overview of the U-20147 docket, the Commission's dedicated web page to distribution planning, and the role of the listserv for communications. On behalf of the utilities, the Electric Power Research Institute (EPRI) presented on "Modern Distribution Planning", followed by ICF's presentation entitled "Key Learnings from Integrated Distribution Planning". The EPRI and ICF representatives proceeded to address load and DER forecasting, hosting capacity, NWA and BCA topics. At the end of the session, Commission Chairman Sally Talberg addressed the integration of these topics into the Michigan distribution planning stakeholder process.

The *August 14 session* featured a BCA presentation from Tim Woolf of Synapse Energy Economics (work supported by the U.S. Department of Energy for Lawrence Berkeley National Laboratory). Traditional benefit-cost analyses tests were discussed as well as the different types of grid modernization expenditures. A review of BCA from 21 recent grid modernization plans was presented. The topic on non-monetized benefits was also discussed. On behalf of ABATE, Wired Group consultants Paul Alvarez and Dennis Stephens provided an overview of maximizing grid planning for the customer, including delineation of grid spending and customer value, technical and financial aspects of grid planning, evaluation methods of distribution investments, BCA, risk-informed decision support and performance measurement. AEE's Ryan Katofsky covered the topic of regulatory innovations in the treatment of operating expenses, with a focus on how the utility business and business model is changing and how service alternatives can increasingly replace traditional capital investments. New regulatory options presented include a DER adder, prepaid contract, NWA shared savings, modified clawback, and pay-as-you-go options. MPSC Staff reviewed pilot program highlights. I&M, Consumers, and DTE all presented information on proposed HCA and NWA pilots. I&M included candidate locations for NWA. Consumers provided an overview of their proposed solar zone / HCA pilot. DTE referenced the EPRI assessment of DTE's investment plan and the U.S. Department of Energy (DOE) DSPx framework.

The *September 18 session* featured a presentation from Yochi Zakai on behalf of the Interstate Renewable Energy Council (IREC) featuring HCA information including definitions of and recommendations for use cases, and some key responses to utility pilot proposals. IREC recommended HCA process steps, including choosing methodologies. Curt Volkmann, on behalf of GridLab, presented "Tying It All Together – A Vision for Integrated Distribution Planning". As described in the section below entitled "Significant Issues" (under "Other Issues"), GridLab's presentation included material on load forecasting including DER forecasting. GridLab also provided thoughts on proposed utility pilots for HCA and NWA. Much of the remaining day's session featured Joseph Eto, Staff Scientist and Engineer at the Lawrence Berkeley National Laboratory, addressing "Reliability and Resilience Metrics, and Reliability Value-Based Planning", "Michigan Utility Reliability Reports", and "Resiliency in Michigan – What Matters and How Should It Be Valued?". Highlights of Joseph Eto's resiliency information are featured below in the "Significant Issues" section under "Resiliency".

The *October 16 session* featured a discussion from Consumers, DTE and I&M regarding the treatment of consistent data across all three utilities in future distribution planning reports. Additionally, all three utility companies addressed the topic of BCA. Michigan EIBC moderated a panel that addressed "Third-Party Uses of Hosting Capacity Analysis". Newport Consulting's Paul DeMartini (DOE consultant) provided consecutive presentations entitled "DSPx: Distribution Planning Relationship with Grid Modernization and Cost Effective Framework" and "Non-Wires Alternatives Analysis, Sourcing Options, and Relative Risks". University of Michigan Professor Johanna Mathieu presented "DER Coordination as a Non-Wires Solution: Opportunities and Challenges in Michigan".

The *final session held on November 19* featured follow-up presentations from Consumers, DTE, and I&M addressing "HCA Information: Levels of Detail and Costs" and "NWA: Qualified Projects and Percentage of Totals". The discussions were a continuation of information presented at the October 16 session from Paul De Martini. MPSC Staff led discussions addressing definitions for HCA and NWA. The utilities provided responses to stakeholder docket comments, and then MPSC Staff provided a proposed timeframe going forward regarding the Staff report that will summarize the stakeholder process.

Stakeholder and Utility Comments

Stakeholder and utility comments were submitted by March 5, 2020 following the circulation of Staff's draft version of this report. A summary of those comments is featured in the Appendix chapter of this report, with hotlinks to the web posted complete comments.

Docket Filings

On September 11, 2019, the following comments were filed in the docket:

ABATE's comments summarizing their presentation topics from the August 14 session[28]

Michigan EIBC and AEE combined comments addressing the August 14 content that was presented and discussed[29]

The Environmental Law and Policy Center, Natural Resources Defense Council and Vote Solar combined comments addressing the utilities' preliminary hosting capacity and non-wires alternative pilot plans[30]

On October 4, 2019, the following comment was filed in the docket:

Michigan EIBC and AEE combined comments addressing the September 18 content that was presented and discussed[31]

On November 18, 2019, the following comment was filed in the docket:

ABATE addressed the October 16 content that was presented and discussed[32]

On December 16, 2019, the following comments were filed in the docket:

International Transmission Company (ITC) and Michigan Electric Transmission Company (METC) combined comments addressing transparency and communication in the distribution planning process[33]

I&M reply comments in response to written comments filed on September 11 and October 4 by stakeholders regarding I&M's distribution planning issues[34]

Consumers comments in response to discussions on issues related to distribution planning in the Electric Distribution Planning stakeholder workgroup[35]

Environmental Law and Policy Center and Vote Solar combined comments providing additional resources useful to distribution planning as well as addressing additional issues from the stakeholder process[36]

Significant Issues

Benefit-Cost Analysis

Stakeholders supported using a BCA approach for developing an analytical framework to adequately compare the costs and benefits of all potential resources against each other in proposed distribution system plans, including the evaluation of all supply side and demand side resources as appropriate. Stakeholders stated that a comprehensive BCA framework should guide utility decision-making with respect to distribution system investments.

A stakeholder emphasized the direct correlation between BCA with a transparent and engaged stakeholder process as well as the capital budgeting process.

A stakeholder claimed that variations of benefit-cost analyses have led to inaccurate results and poor investment decisions in other states. Subsequently, the suggestion was that the Commission issue rulings on the development and use of BCAs in Michigan distribution planning and capital budgeting processes. Such rulings would require a BCA for all discretionary investments in utility distribution plans, a definition of how costs should be estimated in BCAs, and a definition of how benefits should be estimated in BCAs. Additionally, the stakeholder recommended that the Commission should clearly define how "costs" are calculated in BCAs and include carrying charges, as well as clearly define how "benefits" are calculated suggesting that operational savings be calculated on variable costs avoided and not fully loaded costs.

Further, the suggestion was that BCA should be used for every distribution investment deemed not to be in the normal, routine course of business. There was disagreement with the utility approach of having qualitative approaches serving as substitutes for a BCA. There was opposition to utilities claiming that some types of benefits are difficult to estimate and therefore a BCA should not be applied. There was a suggestion that a risk-informed decision support approach serve as a BCA, with this approach being desirable in situations where benefits are difficult to estimate.

DOE DSPx method of "least cost, best fit" for cost analysis was challenged with the claim that utilities often liberally interpret what is considered as "necessary" investments. An example was cited of an investment situation considered necessary by the utility as justified to meet a National Electric Reliability Council (NERC) Critical Infrastructure Protection (CIP) standard, when the CIP standard did not directly require that particular investment. Utility proprietary communication networks deemed by a utility as necessary were also questioned due to the availability of third-party service providers to provide the service.

There was opposition to scoring matrices approaches that utilities sometimes use to prioritize investments with a stakeholder claiming that these approaches do not translate outputs into economic risk reduction value.

A stakeholder suggested that the Commission address the rate case timing issue that can result in operating benefits not reaching the customer, and recommended that reliability benefits should be expressed in terms of system-wide SAIDI and SAIFI improvements, and societal benefits should not be included in BCAs.

There was expressed opposition to Consumers' presentation on BCA at the October 16, 2019 stakeholder session indicating that the stakeholder's preferred BCA methods were not adhered to. There was also expressed opposition to DTE and I&M's benefit-cost analyses which included a qualitative instead of quantitative analysis to benefit estimations.

There was some agreement with Paul De Martini's October 16, 2019 explanation of the DOE DSPx distribution planning process addressing BCA in terms of supporting a transparent and engaged stakeholder process and capital budgeting process, which includes defining grid objectives ahead of the planning process. There was also some opposition to the DSPx process including alleged bias from the core DOE team and the absence of residential or business customer advocates on the core team. In general, the stakeholder cautioned the Commission not to accept all aspects of the DSPx initiative.

An additional stakeholder comment suggested that the Michigan distribution planning process should not be biased towards investor owned utilities (IOU's) desired outcomes, and instead focus on customers' desired outcomes.

Hosting Capacity Analysis

Overall, stakeholders support HCA as a very important exercise in a utility's distribution system planning process. A stakeholder recommended that HCA be robust, publicly available, and should include information for the interconnection process so that the public and utilities can assess points in the system that can accommodate DER. Another stakeholder recommended that the utilities perform a system wide HCA even if it lacks a high level of spatial or data accuracy, suggesting that any attempt at an HCA will give the Commission and stakeholders more valuable information than a geographically limited pilot would.

If the utilities do proceed with a geographically limited pilot, it was recommended by a stakeholder that each utility explain how the pilot will be used and describe how the results feed into a system-wide HCA. There was stakeholder support for DTE's phased approach that prioritizes areas with a more robust and updated distribution system that can handle DER additions to conduct HCA and a recommendation that other utilities follow their lead. DTE's phased approach suggests that HCA can be completed with increasing levels of detail added over time. There was a recommendation that the utilities decide upon a common set of selection criteria and use-cases, exercise a consistent approach, identify the source of information to be used, include the planned HCA in their next round of distribution plans, and develop a timeline for the publication of the results in the form of publicly available online maps that contain downloadable data.

Responding to I&M's August 14, 2019 HCA pilot presentation, one stakeholder did not support the utility's claim that the absence of advanced metering infrastructure (AMI) deployment should keep I&M from pursuing HCA. While AMI can give more accurate data and improve HCA output, the stakeholder suggested that HCA be done in phases and each company use what level of detail they currently have.

At the December 16, 2019 stakeholder session, I&M commented that performing an HCA on its entire Michigan grid would be burdensome, costly, and an inefficient use of funds at this time. The currently low level of customer interest in DER does not warrant the company's investment and labor necessary to conduct such an analysis. For customers that are interested in DER, I&M stated it would be more beneficial to assess the capability of the distribution system specific to the customer's project.

Responding to Consumers' August 14, 2019 HCA presentation, one stakeholder recommended the Company pursue a formal HCA as suggested by the Commission. (In previous orders, the

Commission has suggested an exploration into cost effective options for utilities to provide HCAs.). The stakeholder did not see Consumers' "Solar Zone" pilot as a substitute to a true HCA.

A stakeholder agreed with DTE's approach to HCA presented at the August 14, 2019 stakeholder meeting. The stakeholder noted 1) DTE acknowledged that HCA can be performed with more detail over time; 2) DTE discussed the level of detail they are currently using; 3) DTE discussed the criteria it is developing and will use in order to select a "target geographic area" for a hosting capacity pilot; 4) DTE identified the tool it will use to analyze its hosting capacity pilot; and 5) DTE prepared questions it expects answered through its HCA pilot.

After discussions and presentations at the September 18, 2019 stakeholder meeting, one stakeholder agreed with IREC's proposal that it is important to define the use cases for HCA before determining the criteria for implementation, developing methodology, and gathering data in order to get the most value out of the HCA and to successfully accomplish its objectives. The stakeholder recommended the Commission focus on process improvements and benefits for interconnection customers as the initial use case for HCA. HCA can streamline the interconnection process and accelerate DER deployment by saving developers and utilities time and money, giving local communities more choice, and enabling commercial and industrial customers to meet their demand for renewable energy. Despite Consumers' and DTE's comments that HCA projects would not be beneficial in Michigan because of low DER penetration, the stakeholder stated that the need for HCA is higher because of low DER penetration. It is the stakeholder's belief that establishing an interconnection use case would help to identify the benefits of an HCA and define a scope and detail that would be consistent with the expected benefits.

A phased approach was recommended for the implementation of HCA as needs become greater. In phase one, the suggestion was that utilities publish publicly available maps including the location of feeder lines and basic system data in a pop-up box. The information on each feeder and substation including data fields suggested by the stakeholder should be available on the map and able to download in spreadsheet format. The stakeholder suggested that phase 2 involve performing an analysis of the available hosting capacity at each node on the distribution system and publishing the results in a map and spreadsheet format along with the information published in phase one. The stakeholder also believed that, in order to maintain relevance and usefulness, the data used in the HCA will require regular updates. The HCA can be updated more frequently (monthly) for feeders where system conditions change and less frequently for the rest of the system (annually).

At the November 19, 2019 stakeholder meeting, DTE and Consumers jointly presented on the costs associated with HCAs. In response, stakeholders commented that they believe the estimates of $0.5-1M at the lowest end and $40M at the highest end are too expensive and beyond the costs utilities in other states, such as Dominion Energy in Virginia and Xcel Energy in Minnesota, have experienced. Utilities were encouraged to consult subject matter experts and utilities who have previously conducted HCA to improve their cost estimates.

On December 16, 2019, Consumers filed comments stating that the need for HCA is unnecessary at this time and in the near future because DER volume is very low. The company claimed that an HCA process is very expensive and only benefits DER developers. The company also stated that a phased approach is not prudent (nor is it a pilot) because a phased approach does not test a concept; instead it asks utilities to put data in the public domain and assumes it is useful.

Non-Wires Alternatives

Stakeholder input suggested the Commission should continue to allow utilities to pursue NWA pilot studies of their choice, if they are beneficial and will result in large scale changes. Additional input from stakeholders suggested that utilities should go beyond pilots and incorporate NWA analysis as part of their general distribution system planning process. As a first step, utilities should explain and provide, as part of their distribution plans, the portion of their capital plans that are deferrable/avoidable using NWAs[37]. NWA cannot be considered a reliability solution until certain criteria are defined such as cost, deployment timeline, and performance parameters. The Commission, stakeholders, and utilities agree that NWA do not represent a one-size-fits-all solution. Data and results from NWA pilot programs should enable the utilities to learn what is appropriate for their system.

Regarding NWA pilots, one stakeholder recommended utilities 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. There was a stakeholder suggestion that the Company explain how they will identify areas for NWA and why those areas are desirable so that the Commission can work to develop appropriate uniform NWA standards. Another stakeholder recommendation was to have the utilities investigate their ability to obtain and incorporate customer or third-party resources in future NWA pilot proposals.

Commenting on I&M's utility pilot proposal presented at the August 14, 2019 stakeholder meeting, one stakeholder encouraged I&M to expand the scope of its NWA to include customer and third-party owned assets. The assumption is that this will allow for increased innovation at a lower cost.

Commenting on Consumers' utility pilot proposal presented at the August 14, 2019 stakeholder meeting, one stakeholder suggested that the projects described as NWA focusing on maintaining reliability may instead be characterized as utility demand side management programs. They recommended Consumers pursue options for targeted NWA as part of a group of options for using load as a resource to meet grid needs. They also recommended the solar zone pilot include BCA to better understand the value of the approach.

Commenting on DTE's utility pilot proposal presented at the August 14, 2019 stakeholder meeting, a stakeholder recommended expanding the types of methods for achieving load relief and power quality support. This would include using targeted procurements as opposed to DSM programs and considers DER assets not owned by the utility.

At October 16, 2019 stakeholder session, Paul DeMartini presented a customer-centric approach to NWA on slide 3 of his presentation entitled "NWA Framework: Evaluation, Sourcing Options, and Relative Risks".[38] Here he asked the questions pertinent to all utilities, regulators and stakeholders regarding NWA as explained on p. 8 of this report.

On slide 5 of Paul DeMartini's same presentation was an illustration of utility capital expenditure investments. The pie chart showed several categories of a utility transmission and distribution capital plan investment categories such as "replacement", "emergency", "information technology", "new business" etc. Relevant to the NWA discussion, the slide stated that "to-date NWAs nationally have focused on "system expansion" projects driven by load growth and/or increasing hosting capacity". From aggregated national examples, the pie chart indicated that 9% of the capital expenditures investments represent this "system expansion" category.

This 9% national example of transmission and distribution investments categorized as "system expansion" investment sparked a conversation regarding the potential percentage of distribution investments with Michigan utilities where non-wires alternative could be considered. At the November 19, 2019 stakeholder session, the utilities responded to the 9% "systems expansion" slide that Paul DeMartini presented at the October 16 stakeholder session.

Consumers indicated the same 9% potential distribution capital investment applicable to "load-growth capacity projects" and added that NWA are further limited by suitability criteria such as load relief needed, deferrable cost, lead time and customer mix.[39] DTE indicated that 6% of their typical distribution investment portfolio is dedicated to "load relief", and added that not all projects in the load relief category are good candidates for NWA due to other drivers/benefits, amount of overload, timeline of the need and economics/costs. I&M presented an overview of their distribution investment planning process indicating that NWA are considered, however they did not provide a direct comparison of their company's "system expansion" plans to the national information that indicated a 9% system expansion exists that might be appropriate for NWA.

Regulatory Innovations

As presented in the August 14, 2019 stakeholder session,[40] AEE recommended that the Commission consider regulatory models that provide win-win outcomes for consumers and utilities. (It should be noted that PA 341 6a(13) directly addresses considerations of incentives for demand side resources "are not disfavored when compared to utility supply-side investments".[41]) They commented that the current cost-of-service regulatory model encourages capital investment and contrasts with most other sectors of the economy that buy services instead of making capital investments. AEE identified several regulatory options other states are using for piloting services that replace capital investments. Mechanisms such as capitalization of a service contract and the use of regulatory assets allow utilities to place service assets in their rate base and amortize them. Other mechanisms require changes in regulations and are designed to provide financial incentives to utilities that align their earnings opportunities with their ability to generate cost savings using services. These mechanisms include DER incentive adder, capitalization of a prepaid contract, NWA shared savings, modified clawback mechanism, and pay-as-you-go.

AEE elaborated that a DER incentive adder mechanism provides a direct return on services procured by utilities where these services are treated as pass through operations and maintenance costs and cannot be included in the rate base.

Capitalization of a prepaid contract uses a prepaid asset which treats expense like a physical asset by placing it into rate base, amortizing it, and recovering it over time.

NWA shared savings was explained as being similar to a prepaid contract. NWA shared savings is based on a prepaid service that the utility recovers as a regulatory asset, however, an additional earnings incentive is provided on top of earnings from capitalizing the prepaid contract to compensate for lower earnings when service costs less than the traditional capital solutions.

Modified clawback mechanism was explained as an adjustment to net capital plant reconciliation which is used in some states with multi-year rate plans to reclaim the unspent portion of a capital budget, plus associated earnings, if a utility does not spend its full capital budget.

AEE indicated that with the pay-as-you-go mechanism, the utility prepays service expenditure for one year at a time and places the prepayment into the rate base as a regulatory asset. With regulatory approval, the utility amortizes regulatory assets over a period greater than one year to build year on year while being amortized at the same time. Additionally, the utility receives a variable shared savings incentive proportional to the cost savings provided by the service option.

Transparent and Engaged Stakeholder Process

There were several comments suggesting that stakeholders themselves play a more central role with many aspects of the distribution planning process. Although many content topics were addressed such as data access protocols, inclusion of probabilistic DER, and load growth scenarios for improved modeling, the central theme was there should be an emphasis on a more engaged stakeholder process.

One stakeholder suggested that the distribution planning process should provide meaningful and useful data for stakeholders, regulators, and customers to support efforts to create and operate an up to date distribution system. The stakeholder recommended that the Commission establish data access protocols allowing third parties to readily access data going forward, subject to appropriate grid security. The claim is that greater access to the distribution system and customer data would allow customers and third-party providers to provide products and services to utilities to meet grid needs. This would increase the number of competitors in the market and decrease costs for consumers which also allows for innovation. The stakeholder suggested three other types of information be included: probabilistic DER and load growth scenarios, publicly available HCA, and improved consideration of line losses.

The stakeholder additionally stated that a broader range of probabilistic DER and load growth scenarios would allow modeling to be better done. Michigan has low DER penetration with a unique opportunity to anticipate future change and plans. Load forecasts should include more detailed projections of DER potential and expected customer adoption on different parts of the system, and the resulting effects on load profiles. Load and DER forecasting should include development of multiple DER scenarios and use probabilistic planning methods to provide understanding of risks and opportunities as well as be shared with the public.

The stakeholder believes publicly available HCA maps will allow DER providers and customers to provide services to support the grid. Municipalities and communities will also be able to assess if proposed DER will work in their communities.

The stakeholder suggested that improved consideration of line losses in distribution system planning will drive decisions to upgrade or not upgrade conductor sizing. They noted the wide range in cost of re-conductoring per mile and accurate accounting of line losses as an important cost consideration. All these points were raised while suggesting that a more inclusive stakeholder participation framework be utilized to explore these topics.

Two stakeholders believe a transparent distribution planning process is necessary. One stated that detailed information regarding components of the distribution plans should be shared with stakeholders so they can provide input and contribute to the development of the best solution. Another stakeholder recommended a stakeholder engaged nine-step process to distribution planning: 1) Stakeholders identify and prioritize distribution plan goals or outcomes. 2) Stakeholders define distribution performance metrics, targets, timeframes, and reporting requirements for desired outcomes. 3) Utilities collect and publish distribution planning inputs. 4) Utilities propose a list of recommended distribution projects. 5) Stakeholders identify potential alternative and/or additional projects. 6) Potential projects are evaluated using one of three methods based on the nature of each project. The methods include non-discretionary, discretionary with readily quantified benefits, and discretionary with difficult to quantify benefits. 7) Stakeholders select projects and determine capital budgets. 8) Utility implements selected projects and procures selected NWA through competitive solicitation. 9) Performance is measured using metrics and targets that were established in Step 2. The stakeholders also recommended annual exception reports be filed if the utility has any changes from the approved distribution plan.

In opposition to these stakeholder suggestions, on December 16, 2019, I&M filed a comment stating that adoption of the nine-step process would require statutory amendment and/or legislative action. I&M also stated that the process would impact efficiency, and increase labor and time required to complete a distribution plan.

In additional opposition to these stakeholder suggestions, Consumers filed comments on December 16, 2019, stating that a stakeholder engaged distribution planning process would be an "intrusion into utility business practice and of questionable legality".[42] The Company believes that the utility is responsible for making decisions regarding the management and improvement of their distribution system as well as justifying their decisions in regulatory proceedings. While the utility and stakeholders can have discussions in workgroups such as this, the Company believes it would be unreasonable to give third parties a role in the actual decision making.

Pilot Programs

Although specific pilot program content is addressed elsewhere in this report (NWA and HCA), it is important to note that the stand-alone topic of "pilot programs" was also addressed by stakeholders with their comments.

One stakeholder suggested the Commission needs to provide utilities with more detailed guidance of where pilots are necessary and what problems need to be resolved. The recommendation was that the Commission establish a clear and forward-thinking framework for utility pilots to guide the next set of programs that 1) is cost limited and supports a cost recovery mechanism for current utility pilot programs, 2) is publicly accessible, 3) improves rate design to better align end user pricing with generation, transmission, and distribution variable costs from a time and location aspect, and 4) sets a timeframe for distribution planning matters to appropriately align with state policy objectives.

Stakeholders also recommended that the Commission guard against falling into a cycle in which pilot programs are constantly testing ideas while producing no large-scale implementations and urged the Commission to connect programs to an improvement plan that will result in significant change. The recommendation was for a process that requires the utility to identify and communicate potential barriers to deployment up front and create accountability with expectations that projects become solutions for the whole energy system. (The Commission's MI Power Grid initiative has a current workgroup entitled "Energy Programs and Technology Pilots" that will be addressing these types of issues throughout 2020.)

Resiliency

Resiliency represents a key concern for the MPSC, utilities and other stakeholders as emphasized by the Commission's previous orders in the U-20147 docket. Resiliency and reliability were topics of discussion at the September 18, 2019 stakeholder meeting. The discussion was very robust and enlightening and according to Consumers, created more questions than answers.

The September 18 session featured Lawrence Berkeley National Lab's Joseph Eto delivering a focused presentation on the delineation of "reliability" vs. "resiliency", broken down by characteristics such as common features, metrics and actions intended for making improvements. Reliability vs. resiliency was also discussed in terms of "decision making" including which entities are involved in decision making and factors affecting decision making. Grid Modernization Lab Consortium resilience metrics were presented and discussed. It appears as if additional discussion is necessary to determine how resiliency should be defined and how it will fit into future distribution planning.

Additionally, details of the Michigan 2013 ice storm and some of the corresponding statistics regarding the storm restoration timeline and customer impacts were presented as well as a discussion about value-based reliability planning. Mr. Eto also reviewed the Interruption Cost Estimate (ICE) calculator and discussed its use with estimating customer interruption costs.

Other Issues

Standardized Components for Future Utilities Distribution Plans

In the Commission's November 2018 order in U-20147,[43] they stated that "the Commission recommends that utilities, stakeholders, and the Staff discuss, as a part of a future workshop, elements where it would be most useful to have information presented in a consistent manner among utilities".

This discussion took place at the October 16, 2019 session.[44] The utilities are in general agreement that standardized components for upcoming distribution plans consist of A) distribution plan outlines, B) historical system performance, C) projects and program details, D) long-term strategic vision and plan, and E) supporting components. Additionally, here are the areas where the utilities agree that distribution plans will not necessarily follow identical formats: 1) differences among utility systems where each utility may emphasize different strategic areas, and 2) company preferences that necessitate different levels of content detail narrative flows in respective reports.

Coordination with Michigan Infrastructure Council (MIC)

During the June 27, 2019 stakeholder session, the MIC efforts were flagged as being relevant and important to Michigan utility distribution planning processes. Reference was made to the Commission's acknowledgement of the MIC in their November 2018 order in the U-20147 docket. DTE specifically spoke about their active role with the MIC. No further discussions were conducted about alignment of future Michigan utility distribution plans with the MIC efforts.

Dynamic System Load Forecasting

During the June 27, 2019 stakeholder session, dynamic system load forecasting was referenced as being highlighted in the Commission's November 2018 order in the U-20147 docket. At that same session, on behalf of the utilities, ICF presented "Load and DER Forecasting" in the context of integrated distribution planning.[45] ICF stated that load forecasting is a foundational component of the distribution planning process and stressed the importance of load forecasts to support utility investment decisions. ICF provided a graphic of conventional load forecasting to emerging load and DER forecasting (understanding the geospatial and temporal qualities of future DER).

At the September 18, 2019 stakeholder session, GridLab's presentation included a discussion of typical load forecasting today compared to integrated distribution planning that includes load and DER forecasting. This discussion integrated related topics such as HCA, NWA and grid modernization.

Locational Value

At the September 18, 2019 stakeholder session Curt Volkmann, from GridLab, explained that one of the capabilities of Integrated Distribution Planning is the "Disclosure of Grid Needs and Locational Value".[46] Although discussions at the stakeholder sessions did not focus on locational value, MPSC Staff remains interested in how locational value is being approached by utilities and regulators in other states. Additional stakeholder input suggested Staff and Commission make DER valuation and compensation (including locational, temporal, and other valuation) a more explicit part of the distribution planning process going forward.[47]

In a comment filed on December 16, 2019, a stakeholder directed MPSC Staff to a process set by the Future Energy Jobs Act in 2016 by the State of Illinois. The act encourages investment in DER's in many ways, one mechanism being a rebate to distributed generation owners which is intended to replace net metering of distribution charges. The stakeholder referenced a report released by the Pacific Northwest National Laboratory in October 2018, "Illinois Distributed Generation Rebate- Preliminary Stakeholder Input and Calculation Considerations".[48] This report was a result of the Illinois Commerce Commission's workshops, facilitated by the Pacific Northwest National Laboratory, which explored the challenges in determining locational value and compensating distributed resources for that value.

The Role of Energy Efficiency (EWR) with Distribution Planning

DER is defined differently by various organizations and entities. At times EWR is included in the definition of DER, and other times it is not. Staff proposes a definition of DER that includes generation and storage connected at distribution voltage as discussed in the definition section of this report. The key issue is not whether EWR is included in the DER definition, but instead that EWR is recognized as a key resource consideration when utilities engage in distribution planning. EWR can impact distribution system needs both from broad scale "baseload" types of EWR as well as from enhanced EWR targeted at specific time periods and/or geographic locations. The distribution resource planning process should fully consider EWR as a resource.

The Michigan stakeholder process that explored distribution planning did not particularly feature an EWR focus, but the concept of EWR as a resource and the relationship of EWR practices with distribution planning should not be overlooked.[49] Most utilities are not currently using EWR in distribution system planning, but several states are pursuing new approaches to using EWR to displace traditional distribution infrastructure upgrades and integrate more renewables into the grid.[50] The role of EWR with distribution system planning is likely to be included in the Michigan discussion going forward. Additional stakeholder input suggested EWR plans should be reflected in load forecasts, as well as in NWA/project selection.[51]

Summary and Recommendations

The stakeholder process allowed Michigan utilities to respond to the Commission's orders in the U-20147 docket as well as the previous U-17990 and U-18014 dockets. The distribution planning topics that the utilities addressed include dynamic system load forecasting, BCA methodologies, potential HCA and NWA pilot programs, and distribution system resiliency and reliability investments. Additionally, throughout the five public stakeholder sessions and through the docket filings in U-20147, other interested parties were able to share their concerns, perspectives, ideas, and responses to the utility supplied information, including suggestions for alternative regulatory approaches from the Commission.

Distribution Planning Objectives

National consultants advised MPSC Staff during the stakeholder process of the importance of Commission defined objectives to the Michigan utility distribution planning process to help set the stage and define expectations of the utilities. MPSC Staff found value with this advice and consequently revisited the October 11, 2017 order in both U-17990 and U-18014 dockets where the Commission's addressed distribution planning objectives. More particularly, this order states:[52]

> "The Commission's objectives for the electric distribution system relate directly to its mission to ensure safe, reliable, and accessible energy at reasonable rates. Specifically, the Commission is focused on the following overarching objectives:
>
> 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 to third-parties or inclement weather, older facilities designed without up-to-date safety protections, and potentially unsafe work practices while maintaining equipment.
> 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 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."

It is worth noting the synergy of slide 2 in Paul DeMartini's October 16, 2019 stakeholder presentation "DSPx: Planning for Grid Modernization & C-E/Prioritization Framework"[53] in relationship to the Commission's stated objectives. This slide illustrates the scope of grid modernization with overlapping circles representing objectives labeled "reliability and resilience", "DER integration and utilization", "safety and operational efficiency" with "customer needs" as the key objective binding everything together.

Staff underscores the importance of these Commission stated objectives in light of the substantial distribution system investments that are presently being proposed by Michigan utilities. All the sub-topics addressed in this distribution planning stakeholder process are directly correlated to the Commission's stated objectives. Dynamic system load forecasting directly correlates to how best the utilities can provide system updates that are sensitive to these four objectives. BCA processes are especially important to cost effectiveness and affordability.

While not directly included in these objectives, resource diversity is an additional important consideration. The State Energy Assessment (SEA) addressed this topic in great detail.[54]

Resource diversity is a topic primarily affiliated with energy supply issues and reflected in utility IRPs. From a distribution perspective however, resource diversity is worth acknowledging here because of the growing trend of DER integration at the distribution level. Essentially, there is a relationship with DER integration on the distribution system with total resource diversity. HCA and NWA are tools discussed in this stakeholder distribution planning process that can accommodate DER's on the distribution system. As previously noted in the October 11, 2017 Commission order in U-17990 and U-18014, while addressing "accessibility" the Commission stated "As technologies and customer preferences evolve, planning for the distribution system should optimize integration of customer and utility resources where possible". As such, resource diversity as emphasized in the State Energy Assessment appears to have a correlation to the Commission's stated objective of "accessibility".

Staff recommendation

The Commission reiterates the importance of these four objectives in a subsequent order in the U-20147 docket, and also provides confirmation with Staff's assumption that "Safety" is the first priority – both for customers and the utility employees – with the second priority being "Reliability and Resiliency". The utility electric infrastructure in Michigan has many assets that are operating way past the end of expected life and utility investments must consider the vast ratepayer resources needed to assure the lights stay on during all types of weather. (However, Staff acknowledges that asset age is not always a justification for replacement. Field equipment routinely operates reliably decades beyond the depreciable lives used in utility accounting.)

The Commission should also confirm Staff's assumption that resource diversity as identified in the State Energy Assessment is correlated to the Commission's fourth objective of "accessibility".

Staff believes the additional emphasis on Commission stated objectives and subsequent priorities will provide clarification for utilities and stakeholders as utility distribution plans continue to be developed and submitted to the Commission.

Following the circulation of Staff's draft version of this report multiple stakeholders suggested that with the introduction of MI Power Grid, new objectives should be added beyond what the Commission stated in their October 11, 2017 order. Their comments state that the 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, incorporation of emerging technologies. Those comments can be reviewed in the Appendix to this report. Staff recommends that the Commission revisit the four objectives that they originally stated in the October 11, 2017 order in light of advancement of the

MI Power Grid initiative. Any Commission directed revised electric distribution planning objectives can be addressed in subsequent orders in the U-20147 docket.

Definitions

Definitions of terms are important to assuring that all parties are referencing terms from the same perspective. Stakeholders commented on suggested definitions, presenters provided some suggested definitions, and Staff hosted a conversation at the November 19, 2019 session regarding potential definitions to be considered for HCA and NWA.[55] During this discussion, multiple definitions of HCA and NWA were examined to explore common themes in each of the definitions. There was a stakeholder recommendation that the Commission define "stakeholder" to include investor owned utility. Additionally, there was a recommendation that stakeholders define performance metrics, targets, timeframes, and reporting requirements early in the distribution planning process. These proposed definitions are all in the context of an argument advocating aggregate stakeholders control the state's electric distribution planning process instead of the utility that is responsible for the grid investment (see previous discussion in this report under "Significant Issues", "Transparent and Engaged Stakeholder Process"). Staff believes that aggregate stakeholders are very important to the electric distribution process, as evidenced by the continued stakeholder engagement process that this report summarizes. However, Staff does not support the suggestion that aggregate stakeholders replace utilities as the lead actors proposing Michigan electric distribution investment plans. As outlined in the "Introduction" section of this report, stakeholders are generally referred to as interested parties outside of the utility companies and the Commission, and include but are not limited to representatives from government and non-government agencies, DER developers, technical entities, consultants and other interested participants. Stakeholders bring varied interests and abilities to the distribution planning process.

Subsequent to the stakeholder process, Staff determined that the definition of DER would also provide value to future electric distribution planning discussions. Although there is no industry-wide standardized definition for DER, Staff has adopted a definition used for draft Interconnection/Distributed Generation/Legally Enforceable Obligation Standards. These standards are currently under development by MPSC Staff through the following MI Power Grid workgroups: Interconnection Standards & Worker Safety, Distributed Generation & Legacy Net Metering Rules, and PURPA/Legally Enforceable Obligation. Staff recommends the use of consistent definitions across all Commission initiatives to maintain a high level of clarity and understanding among utilities, Staff, and stakeholders. Consequently, adoption of this definition for DER has an impact on other definitions such as NWA that reference DERs. The definition recommendations below attempt to provide clarity and be inclusive to the multitude of technologies available now and into the future.

Staff recommendation

For purposes of referencing distribution planning terms going forward, Staff suggests the following definitions to be included in a forthcoming Commission order:

- 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.[56] (Note: Very little discussion around locational value occurred at the stakeholder meeting and perhaps is a subject that warrants future discussion with stakeholders.)

Benefit-Cost Analysis

Purpose of Benefit Cost Analysis

BCA is a tool to rank possible solutions based on the present value of each solution's costs and benefits. BCA is one of three specific cost effectiveness methodologies used to evaluate grid expenditures. The other two methodologies are opt-in (no regulatory justification) and least-cost, best-fit.[57] 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."[58] The output of a BCA, such as the benefit-cost ratio, provides a readily understandable metric on the value of utility investments when examining investment options.

The BCA "analyzes costs and benefits from a particular point of view, which may range from broad and societal (public perspective) to narrow and focused (private perspective)."[59] The three main aspects impacting a particular view is the selection of: the type of BCA test, the non-energy benefits included, and the discount rate. Each is discussed briefly below.

BCA Test Impacts on the Analysis View

The selected BCA test impacts the benefits and costs included in the analysis. The Utility Cost test, Total Resource Cost test, and Societal Cost test are increasingly used for grid modernization, DERs, and other energy initiatives.[60] However, there are several BCA methodologies that are commonly employed.[61] These are the: Participant Cost Test (participating customers focus), Ratepayer Impact Measure (rate impacts to all customers focus), Resource Value or Regulatory Test (regulator focus), Societal Cost test (Society focus), Total Resource Cost test (utility and participating customer focus), and Utility Cost test (utility focus).[62] Stakeholders and Staff in this process expressed interest in all BCA tests except the Participant Cost Test.

The selected BCA test can impact implemented utility programs. For decades, states have used BCA tests for utility EWR programs.[63] Of nineteen states reviewed, thirteen use either the Total Resource Cost Test or the Society Cost Test for their primary test,[64] recognizing the non-energy benefits from utility demand-side EWR programs. When cost-effectiveness tests did not account for non-energy benefits, innovative programs with additional non-energy benefits were less likely to be implemented.[65] In accordance with state legislation, Michigan uses the Utility Cost Test for EWR.

Non-Energy Benefits & Costs Impact the Analysis View

The BCA "provide[s] a ranking of choices expressed in monetary terms…Market values…need not represent 'mere commodities' but instead represent choices."[66] Monetized metrics related to non-energy and non-monetized impacts can be used as proxies. Proxies can be "a percentage adder applied to monetized benefits, a savings multiplier (e.g., $/MWh), a customer adder ($/customer), or a measure multiplier ($/measure)."[67] Hard to quantify benefits or costs may also be included through a point system assigning value to non-monetized benefits, a weighting system assigning priorities to non-monetized benefits, or multi-attribute decision-making techniques.[68] Though imperfect, proxies allow previously non-monetized but important areas be considered in a consistent and quantitative manner when selecting utility projects. Although proxies allow for non-monetized areas to be considered in a quantitative manner, some may argue that proxies are imperfect because the weighting system, value or multi-attribute decision-making techniques used can be manipulated to favor certain decisions and can lead to gaming if not established and applied consistently.

Discount Rate Impacts on the Analysis View

In BCA, the discount rate reflects a time preference[69,70] and "should be based on the regulatory perspective, which may be different from the utility investor perspective."[71] "The regulatory perspective should account for many factors, [such as]: low-cost, safe, reliable service; intergenerational equity; [and] other regulatory policy goals."[72] Because of this, a regulatory perspective leads to a lower discount rate which values future benefits more highly.[73] For example, investor-owned utility weighted average cost of capital (WACC) ranges from 5% to 8%, a low-risk discount rate ranges from 0-3%, and a societal discount rate ranges from <0% to 3%.[74] Though the utility WACC is widely used,[75] including in Michigan, other discount rates can and should be considered when conducting BCAs.[76,77]

The discount rate significantly impacts BCA findings. It allows comparison of benefits and costs in different time periods by expressing their values in present terms.[78] The "choice of the discount rate can determine whether [a] policy is considered, on economic efficiency grounds, to offer society positive or negative net benefits."[79] The present value of a program benefit varies drastically based on the discount rate used in the BCA. A $5 billion benefit "30 years in the future discounted at 1 percent is $3.71 billion, at 3 percent it is worth $2.06 billion, at 7 percent it is worth $657 million, and at 10 percent it is worth only $287 million."[80]

BCA Sensitivities

Given the significant impacts of the BCA test and discount rate selection on BCA results, sensitivities should be conducted where the BCA test and discount rates are varied. Such sensitivities will clearly demonstrate how results are impacted by the selected BCA test and the discount rate. As the BCA test impacts which non-energy and non-monetized costs and benefit are included, this also explores how these areas impact the findings.

Investments for Benefit Cost Analysis

There was stakeholder and Staff disagreement on the distribution projects that should undergo BCA. This should be further explored. However, there was general agreement that distribution platforms, which are technologies that enable other additional functionalities like AMI, should be analyzed not only as individual investments, but also bundled with the functionalities and modular applications they enable. In some cases, the platform alone is not cost-effective, but it is cost-effective when bundled with enabled applications.[81] For example, AMI provides direct benefits arise through decreased meter reading costs, theft, and tampering. However, AMI also enables volt/volt-ampere reactive optimization, better integration of DERs and NWAs, and a host of other customer-centric benefits that, once included in the BCA, increases the benefit cost ratio of the bundled investment.

A Need for Benefit Cost Analysis Guidance in Michigan

Lack of Commission guidance on BCA has resulted in disparate benefit and cost methodologies at Michigan utilities, many developed in-house.[82, 83, 84] In U-17990[85] and U-18014,[86] the Commission ordered DTE and Consumers to include BCAs considering benefits, capital costs, and O&M 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.

Staff recommends a stakeholder process to explore and propose specific BCA criteria for Commission consideration and adoption. Since "[l]eading states still continue to evolve their BCA frameworks,"[87] Michigan likely will evolve its BCA guidance over time. Staff recommends an iterative review of adopted criteria to improve Commission BCA guidance with current best practices and values. Staff recommends initiating the BCA stakeholder process immediately after the next distribution investment and maintenance plans are filed. Given utility apprehension regarding adopting true BCAs, the stakeholder process could discuss and determine the details of piloting more comprehensive BCAs for select distribution projects. Assuming Commission support of the pilot, stakeholders can reconvene one year after the BCA pilot approval by the Commission. The pilot results and any need for refinements can be revisited in the second BCA stakeholder process to generate refined BCA guidance for Commission consideration and adoption for the third set of distribution investment and maintenance plans.

Staff Recommendation

Staff recommends an uncontested stakeholder process to propose specific BCA criteria for Commission consideration and adoption. The stakeholder process should consider:

- One main BCA test and up to two sensitivities required for future distribution plans from the list of BCA tests below:
  - 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, 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.

Hosting Capacity Analysis

In this stakeholder process, HCA was discussed in the context of the Commission request for Consumers, DTE, and I&M to conduct HCA pilots. Staff and stakeholder comments are provided with this framing.

A key stakeholder recommendation was to define the HCA use-case. There is recognition that energy resources and energy delivery processes are changing. Analysis of Michigan's energy delivery system will help determine where DER can more easily be incorporated into the system and what parts of the system will need improvements and updates to accommodate DER. Specifically, stakeholders suggested the Commission identify "interconnection of DER" as the use-case for the HCA pilots. An additional use-case suggestion is the recognition that HCA inherently increases the utility's ability to map distribution assets. This benefit is synergistic with other distribution system modernization activities such as advanced distribution management.

Though an HCA use-case can be recommended, a universal recommendation on how to specifically conduct HCA for all Michigan utilities is not possible at this time. The HCA roll-out for each utility will be different due to utility specific dynamics and challenges. For example, I&M, unlike DTE and Consumers, does not have AMI meters installed in their customer territory at this time. Though it reduces the utility's data options when conducting an HCA, other non-AMI data may be used instead.[88] DTE has a mesh network in the thumb area which is sensitive to distribution system changes. System modifications require an extensive engineering review. A minor change on a particular feeder could impact the distribution system, potentially back-feeding to the sub-station and posing a safety risk. Consumers' system differs from DTE's as it is much more rural. All of these variables will impact the methods employed in an HCA pilot.

Stakeholders acknowledged the potential high cost of conducting HCAs, while also noting that some jurisdictions have conducted them at lower cost than current estimates by Michigan utilities. At the October 16 stakeholder session, a robust conversation took place with a panel presentation addressing "Third-Party Uses of Hosting Capacity Analyses" including the circumstances that municipalities and developers face regarding siting DER and interconnecting into the distribution system. All parties discussed the possibilities of utilizing lower cost, less detailed forms of HCAs that could help guide municipalities and developers with their preliminary DER plans. This led to an extended conversation at the November 19 stakeholder session where the utilities discussed scenarios including "levels" of potential HCAs.[89] DTE presented the following options: A) area-based assessment, B) feeder-based qualitive assessment, C) feeder-based model assessment and D) feeder-based model assessment with verification. Concurrent feedback from stakeholders was that other states have engaged in HCAs at far lower costs than what the Michigan utilities have discussed, even considering the lower level "area-based assessment" type of HCA.

Staff agrees with the stakeholder suggestion that the Commission identify "integrating DER" as a use-case for hosting capacity analyses and also include the ability to map distribution assets. Staff recommends phased implementation of HCA pilots in recognition that a full-level HCA implementation requires significant time and resource investment at a time when investments need to be balanced with replacing aging infrastructure to maintain safety and reliability. Additionally, under PA342 of 2016, the Distributed Generation program requires utilities to offer the program until 1% of the utility's in-state peak load is reached. 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.[90] Currently, only one utility has reached the minimum required participation level for non-methane digester projects and opted to double the size of its Distributed Generation program to 2%. As of the end of 2018, Consumers Energy and DTE Electric reported 1,887 and 2,612 Distributed Generation program customers, respectively. Indiana Michigan reported 100 customers participating in the program. While not all projects interconnecting with a utility distribution system are participating in the Distributed Generation program, these participation numbers likely provide at least some insight in the level of interest in DER projects in a utility's service territory.

At this time, Staff does not believe it is prudent to make a significant investment in a highly detailed, system-wide HCA. Instead, Staff recommends that Consumers and DTE 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. Due to I&M's low level of DER penetration and the lack of advanced meters on its system, Staff proposes that the company continue to monitor the HCA activities of Consumers and DTE and not be required to undertake any HCA analysis related to its distribution system. This should be revisited in the next electric distribution planning filing after the 2021 filing.

Staff finds value in smaller scale, high-level HCA that would help map utility systems for greater utility transparency that will be beneficial for distribution planning. Staff finds merit in the stakeholder concern that smaller scale, high-level hosting capacity analyses may be obtained at lower costs than what the Michigan utilities have preliminarily indicated. This is an issue that will require more focus with the Commission, utilities, and stakeholders. While each utility's distribution system has unique 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.

Staff recognizes that HCA's can be resource and time intensive. However, there may be opportunities to reduce utility costs elsewhere through providing such information. The information provided by a phased implementation HCA may reduce the number of pre-application reports, which are intended to provide detailed technical information about a point of interconnection,[91] if such reports become part of the interconnection process, by providing basic system information through the HCA. This may reduce costs associated with interconnection requests. The MI Power Grid Interconnection Standards and Worker Safety Workgroup discussed pre-application reports in its stakeholder meetings. HCA information and new interconnection rules, currently being developed by the Interconnection Standards and Worker Safety workgroup, could make the process of connecting DERs to the distribution system easier, faster and more predictable than it is today.

During the interconnection process for projects which require studies, the utility routinely determines the hosting capacity for each project's particular interconnection location. Such studies are funded by the interconnecting customer. Staff recommends that utilities make this limited and location-specific hosting capacity information publicly available. This is an opportunity for utilities to incrementally increase the amount of publicly available hosting capacity information at no additional cost to customers.

Staff recommends that utilities accomplish the HCA activities as recommended above within the next two years, while making resulting information available publicly throughout the two-year period. A detailed status update should be provided in the electric distribution plans filed in 2021.

Staff recommendation

Staff recommends that the following be adopted by utilities for the HCA pilots requested by the Commission:

- 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:
    - Perform base-level approach with a zonal go/no-go map.
    - 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.
    - 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 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.

Non-Wires Alternatives

Throughout the Commission orders in U-17990, U-18014 and U-20147, the Commission has been clear about their preference for an examination of NWA as utilities plan for near-future distribution investments. In this changing distribution planning environment, it is possible that NWA can provide another path to resource diversity, however the details and variables of implementing NWA are complex and should be thoroughly considered. 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.

Central to this topic is the need to examine what NWA are capable of solving. Additional stakeholder input suggested utilities should provide, as a part of their distribution system plans, a detailed description of the portion of their capital plans that are avoidable or deferable by NWAs. The multiple questions about applicability of NWA that Paul DeMartini presented in his October 16 stakeholder presentation (and repeated in the Significant Issues section of this report) should be seriously contemplated before utility NWA are pursued.

Staff recommendation

Staff agrees that the questions presented in Paul DeMartini's October 16 stakeholder presentation should be asked by the Commission and answered by the utilities prior to refining and implementing additional NWA pilots.[92] See p. iv of this report.

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.

The Commission may want to encourage the utilities to explore additional opportunities for NWA to provide distribution solutions for the "system expansion" portion of their capital plans, as well as other opportunities that may exist such as "new business", "reliability and resilience", or "voltage and reactive power". DTE addressed this at the November 19, 2019 stakeholder forum. The Company provided an analysis that showed the possibility of addressing 6% of "load relief" with NWA including key considerations/limitations that may reduce that 6% opportunity. Staff believes that this represents a restricted perspective of the potential solutions that NWA could present.

Staff agrees with the stakeholder suggestion that a utility should provide, as a part of its distribution system plans, a detailed description of the portion of their capital plans that are avoidable or deferable by NWAs. There is a significant synergy with the topic of NWA and the process of refining utility pilot programs going forward. Staff believes that this is a topic that merges with the work of the MI Power Grid Energy Programs and Technology Pilots workgroup, and some of the forthcoming clarifications and recommendations from this workgroup will be directly applicable to specific NWA pilots.

Alternative Regulatory Approaches

The assumption that the electric distribution system planning process is changing implies many variables. These variables that effect the electric distribution system include an increased emphasis on "grid modernization" including accommodating DER at the distribution level, changing utility business models, changing customer demands and preferences for service, third-party service providers, and a revised look at the regulatory tools addressing distribution utilities. At the August 14, 2019 stakeholder session, AEE's Ryan Katofsky provided the presentation "Regulatory Innovations in the Treatment of Operating Expenses" where alternative regulatory approaches were suggested to accommodate the differing approaches in electric distribution planning that have been discussed in the U-20147 docket and during this stakeholder process.

The AEE presentation addressed the prevailing utility business model; a model that features investment in capital that earns a return, and management of operating expenses to minimize pass-through costs. However, emerging options that require different regulatory treatment include mechanisms that allow the utilities to earn on outputs (performance incentive mechanisms) (PIM's), performance based regulation (PBR), and new services based on the utility serving as a platform (as with the State of New York developments). Additionally, utilities can earn on inputs other than capital investments (when the utility procures services in lieu of capital expenditures).

AEE referenced a paper that they published entitled "Utility Earnings in a Service-Oriented World"[93] where they explore adjustments to cost of service regulation as utilities experience a more service-oriented future. Slide 6 of the presentation[94] continues to explore new regulatory options including DER adder, prepaid contract, NWA shared savings, modified clawback and pay as you go. In conclusion, AEE suggests that regulators have multiple options to choose from and can tailor the options to meet state policy goals.

Staff recommendation

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 August 14, 2019 stakeholder presentation along with AEE'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.

Pilot Programs

The Commission has emphasized the need for pilot programs to enable utilities to explore HCA and NWA solutions. However, what resulted from the comments and discussions with utilities was a suggested emphasis on more detailed Commission guidance as to what application(s) necessitate utility pilots and what problems need to be resolved by these pilot programs.

Many of the additional comments in the U-20147 distribution planning docket addressing pilot program perimeters, controls, metrics and transparency and accountability regarding the pilot program results are expected to be addressed with the MI Power Grid Energy Programs and Technology Pilots stakeholder workgroup that is currently underway at the MPSC.

Staff recommendation

In their on-going work, the Energy Programs and Technology Pilots workgroup[95] should take into consideration the important stakeholder comments that were included in the U-20147 docket and 2019 distribution planning stakeholder sessions.

Resiliency

On September 11, 2019, the Commission issued the Statewide Energy Assessment (SEA) report[96] and corresponding order that accepted and adopted the report.[97] Electric grid resilience was a recurring theme of the SEA report recommendations aimed at mitigating risk and ensuring safety of the electric system. Several recommendations from the SEA included a focus on resiliency. Resiliency is a theme that has appeared in the following Commission topics or procedures:

- Recommendations regarding Service Quality and Reliability Standards for Electric Distribution Systems and Technical Standards for Electric Service
- Alignment of utility five-year distribution plans with IRPs
- Relationship to a changing generation fleet
- Developing a methodology to evaluate the benefits of resilience improvements, and
- Consideration of alternatives to transmission projects that may provide cost, reliability and resiliency benefits

Staff attempted to broach the broad topic of electric grid resiliency through discussions in several distribution planning meetings. Staff found that the idea of reliability and resilience were often used interchangeably and simultaneously. Several presentations coupled reliability and resiliency together.[98] However, there was an underlying understanding among stakeholders and utilities that reliability and resiliency also have inherent differences, but these differences were not fully vetted and accepted by all.[99] A "reliable" grid is viewed as a grid that is resistant to a disruptive event. Reliability can be measured through specific, standardized Institute of Electrical and Electronics Engineers (IEEE) metrics including SAIDI, SAIFI, and CAIDI. These metrics are designed to measure local reliability as an average over a period of time. Utility companies currently report reliability metrics to the Commission on an annual basis. (Case Numbers U-12270,[100] U-16065,[101] and U-16066[102]). However, the idea of resiliency is addressed differently among various stakeholders and utilities. For instance, some stakeholders and utilities view resilience as the time it takes to respond to any event no matter the geographic size, number of customers impacted or duration. Other stakeholders and utilities view resilience as the ability to recover from events that are more likely classified as major event days. Another key attribute to resiliency is that, unlike reliability, resilience events have no actuarial basis to establish likelihood of occurrence and therefore make it difficult to assess risk to exposure.[103]

Both reliability and resilience events involve similar failures on the electric grid, such as wire down, broken poles, transformer failures, etc. Therefore, under one view of resilience, any investment that mitigates the risk of failure can be classified as both a reliability and resilience investment. Under the other view, it is presumed that a system is first reliable.[104] A grid that cannot withstand the localized failures is inherently more likely to experience extraordinary events, events that are widespread, spanning a larger geographic area and are more likely catastrophic in nature. Once the electric grid is considered reliable, then further investments that mitigate the risk of extraordinary events can be considered investments in system resiliency.

Many stakeholders and utilities agree that there is a need to define resiliency. However, a clear definition of resiliency may not be what matters the most because there is such a huge variation with the interpretation of resiliency. 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.[105] 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 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.

It should be noted that current metrics for reliability can sometimes mask extreme circumstances due to the use of aggregate data over a large region/utility service territory. Any of these metrics could be applied using a more granular approach, such as substation or circuit view, if the Commission so desires.

In an effort to understand how different investments, specifically DERs, may impact and potentially improve resiliency, some utilities are engaging in pilot activities.[106] Information from these pilot programs can help to quantify potential costs and benefits related to both reliability and resiliency. However, 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.

Staff recommendation

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.

Other Issue Recommendations

Standardized Components for Future Utilities' Distribution Plans

Staff recommendation

Staff supports the joint utility proposal that was presented at the October 16, 2019 stakeholder session and outlined in the presentation where utilities agree about standardized components for upcoming distribution plans as well as areas in their plans that will likely differ based on company specific circumstances. A general adherence to standardized components for future utilities distribution plans make it easier for Staff, Commissioners, stakeholders and the general public to comprehend and compare the utility plans.

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 and CELID metrics to directly measure the current unacceptable levels set by the Commission in the Service Quality and Reliability Standards for Electric Distribution Systems, R 460.722.[107] This will be further explored by the MI Power Grid Security and Reliability Standards Workgroup,[108] 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.

Michigan Infrastructure Council (MIC)

Staff recommendation

The utilities reference the MIC as they develop their utility distribution plans. As referenced in the Commission November 2018 order, utilities should coordinate distribution planning efforts with the MIC efforts in order to benefit all Michigan residents through more efficient and effective planning.

The Role of Energy Efficiency (EWR) with Distribution Planning

The concept of EWR as a resource is relevant to electric distribution. EWR may delay or avoid the need for new distribution infrastructure, and also reduce demand and energy needs at individual homes and businesses. In the "Definitions" section of this report, the recommended definition for DER includes generators and energy storage technologies as sources of electric power connected to a distribution system. The companion definition for NWA however includes reference to EWR.

EWR is a key consideration for electric distribution planning because of the DER/NWA/EWR nexus, and the value that EWR brings to reducing load – both from broad scale 'baseload' types of EWR as well as from enhanced EWR measures targeted at specific time periods and/or geographic locations. The role of EWR as a resource is clearly a distribution planning consideration.

Staff recommendation

The Commission directs 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.

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

Several of the topics addressed throughout the stakeholder process (and emphasized in previous Commission orders) represent a focus on a changing and diversified grid and the corresponding tools that can help manage grid demands such as DER and NWA. When considering diversified approaches to distribution planning, it is important to remain clear about the big picture of the backbone and functionality of the distribution grid. Traditional utility investment dollars addressing the installation, replacement and maintenance of core grid components far exceeds proposed pilot investment dollars designed to explore electricity delivery alternatives. As Michigan utilities continue to develop and submit their distribution plans, a holistic view of how enhanced technology and practices merge with a more traditional poles and wires system is imperative.

Additionally, the grid of the future needs to be an advanced, highly efficient grid. An advanced, highly efficient grid requires an engineering vision directing those investments. Utilities, the Commission and all the other stakeholders will need to concentrate on the vision that will subsequently drive distribution planning and implementation decisions. This "vision" was a topic of the October 16, 2019 stakeholder session as evidenced in the presentation by the joint utilities entitled "Standard Distribution Plan Components". The utilities' Slide 2 referenced a standard component of all forthcoming utility distribution plans addressing "long-term strategic vision and plan". The third slide states "beyond 2025, utilities will provide a long-term strategic vision and plan over the next 10 and 15 years", which is further elaborated on slide seven to include an emphasis on a "vision of advanced distribution planning processes".

At the same October 16 session, Paul DeMartini incorporated the necessity of "vision" in his presentation overview of the DSPx process , where on slide nine entitled "Architecture Manages Complexity", he focuses on the importance of engineering issues to determine the scale and scope of dynamic resources needed to accomplish policy objectives for grid modernization.

While referencing utility vision, the Commission emphasized the need for a longer-term outlook for distribution plans in their September 19, 2019 order in the U-20147 docket. "The initial round of distribution plans covered a five-year period, although consideration was given to longer-term system needs and strategies during the planning discussions. Moreover, utilities have planning models and capital investment strategies looking out over a longer-term horizon than five years. Using a planning horizon beyond five years can help ensure near-term investments will provide long-term ratepayer value and will be adaptive to emerging energy technologies that may alter the way energy is produced, delivered, and used in the future. Therefore, the Commission directs DTE, Consumers, and I&M to continue to develop detailed distribution plans over a five-year period, but also include in the plan their vision and high-level investment strategies 10 and 15 years out. This approach is consistent with the planning horizons used in IRPs."[109]

Staff recommendation

Staff suggests that the 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 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.

Conclusions and Next Steps

Conclusions

Utilities have provided significant insight into their thoughts on the next round of electric distribution plans. Stakeholders have participated in the process and provided their responses to utility supplied information as well as provided additional perspectives and suggestions. Staff has attempted to summarize the information that has been discussed throughout the 2019 stakeholder process. Following the discussion of significant issues in this report, Staff provides summaries and recommendations regarding several significant issues.

Staff revisits the Commission's established objectives driving electric distribution planning. Staff suggests that "Safety" serve as the primary objective, with "Reliability and Resiliency" as a strong second objective. "Cost Effectiveness and Affordability" (and the related topic of resource diversity) along with "Accessibility" are important objectives applicable to electric distribution planning as well. These objectives should be at the forefront of all forthcoming utility electric distribution plans.

Staff recommends that the Commission establish some definitions that will provide reference points for all parties as we proceed to receive and review future utility electric distribution plans. A significant analysis of BCA is offered by Staff with recommendations of the parameters that should apply to future utility supplied BCAs. HCA and NWA are explored with Staff recommendations provided regarding future HCA and NWA pilot programs. The over-arching topic of "pilot programs" was addressed and Staff recommended that MI Power Grid Energy Programs and Technology Pilots workgroup pick up where this Staff report leaves off with respect to the development of pilots. The important topic of resiliency is addressed with Staff recommendations on how resiliency events should be defined and considered in future electric distribution plans.

The remaining topics that Staff provided recommendations to the Commission are 1) the concept of standardized components for future utility electric distribution plans, 2) the significance of electric distribution plans correlating with the work of the MIC, 3) the role of EWR with electric distribution planning, and 4) the importance of the utilities' "vision" for future grid planning.

Next Steps

The Commission has established in their September 11, 2019 order in U-20147[110] that the next round of electric distribution plans for Consumers and DTE will be June 30, 2021 (the Commission had previously directed I&M to file their next distribution plan on June 30, 2021). The purpose of this 2019 stakeholder process was to thoroughly explore with the utilities and other stakeholders the many relevant issues related to electric distribution planning such maintaining a safe electric power grid, the role of resilience, load forecasting, BCA, potential pilots that explore DER and other grid technologies, the relationship with interconnection standards and reliability standards, HCA, NWA, plus other important topics.

The Commission is encouraged to provide additional direction and clarification through their orders regarding these important issues prior to the utilities submitting their next electric distribution plans. Additionally, the Commission may choose to clarify how often the refresh distribution plans should be submitted by the utilities. Utility distribution plans typically address needed improvements over a five-year period, with portions of the plans addressing a longer-term view of distribution investment. Staff recommends that utilities align its distribution planning refresh with its IRP filings such that investments in both plans can be considered in their respective cases simultaneously.

Staff expects that a strong stakeholder process will continue, with Commission-led dialogue regarding future utility distribution plans, BCA, pilot projects, interconnection standards, reliability standards, and incentive/disincentive regulatory approaches applied to such distribution investments.

[1] Michigan Public Service Commission. Case Number U-20147. Retrieved on February 4, 2020 from: https://mi-psc.force.com/s/case/500t0000009gHerAAE/in-the-matter-on-the-commissions-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

[2] Michigan Public Service Commission. (2017, October 11). *Order in Case Numbers U-17990 and U-18014.* Retrieved from https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001URMSAA4

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Appendix

On February 19, 2020, Staff circulated a draft report which generated stakeholder comments. Staff categorized stakeholder comments into topics. Some comments, however, expanded beyond a single category.

Areas where there was considerable agreement with stakeholder comments and the staff recommendations in this report are not reflected in the appendix. The appendix is intended to reflect stakeholder comments that differ from staff recommendations.

Distribution Planning Objectives

ACEEE

Endorses the four primary objectives but recommends adding a fifth objective to cover the issue of environmental sustainability/environmental protection, and clearly indicating its importance.

Recommends energy efficiency be included in definition of DER.

DTE

Supports the four general objectives but believes the utility must maintain discretion in interpreting what they mean and how to pursue them.

Would like to request the removal of "potentially unsafe work practices" from the *reference*. However, that portion of the Staff report is a direct extraction from a Commission order. Staff was reiterating what the Commission said.

Would like to clarify that "Accessibility" does not mean the distribution system can always accommodate services to new or expanding customers without causing major network upgrades. Experience has shown that it is not possible to avoid major network upgrades for interconnection of any new or expanding customers in all cases.

ELPC/Vote Solar

We recommend that the Commission reset or add to the objectives of the distribution planning process to ensure that those objectives align with Mi Power Grid. The additional objectives include Customer Engagement, Integrating Emerging Technologies, and Optimizing Grid Investments and Performance.

Recommend that the Commission draw a distinction between the basic service obligations of all electric utilities to provide reliable, accessible, affordable electric service as provided by law and rule-and the incremental objectives of a long-term distribution planning process- and emphasize those incremental objectives.

Recommended that Staff's reference to resource diversity be removed because it is more relevant in forums that consider tying together resource, transmission, and distribution planning.

Do not support prioritizing objectives, especially given that most choices in the utilities' distribution system planning process involve co-optimizing several objectives.

I&M

In the staff recommendations, a misunderstanding underlies the suggested need for "vast ratepayer resources" to assure reliability or a condition for investments "using ratepayer funds". This concept should be corrected as I&M funds its business using a combination of revenue received from payment for service to customers and the equity and debt capital provided by investors and creditors. Customers pay for energy service at regulated rates and do not provide specific project financing.

Michigan EIBC and AEE Institute

These objectives only represent the baseline threshold for what modern distribution system planning should include. MI Power Grid aims to be more forward looking and incorporates new objectives such as customer engagement, connecting distribution planning with transmission planning, DER and renewable integration, incorporation of emerging technologies, etc.

Holistic Reexamination of Electric Utility Distribution Planning Processes

ELPC/Vote Solar

Mi Power Grid initiative is the gateway to clean, distributed energy resources for Michigan and this distribution planning process needs to advance Mi Power Grid's objective and not the objectives established two years ago at the initiation of this distribution planning process.

Michigan EIBC and AEE Institute

Changes to the distribution planning process should align with the overarching objectives of MI Power Grid and present a more forward-looking approach.

It is important to move beyond traditional utility investments to a more holistic view of how new technologies and practices combine with traditional solutions.

Benefit Cost Analysis

ABATE

Recommend their risk-informed decision support process.

Suggest there is a limitation on the use of the least cost/best fit approach to distribution planning.

Carrying charges must be included in the definition of BCA cost.

Despite the DSPx credentials, certain unsupported fundamental perspectives from which almost all DOE grid modernization work originates should be rejected.

Consumers

Disagrees with Staff's conclusion that a BCA should be required for all utility distribution investments using ratepayer funds because 1) the Company does not believe Tim Woolf's presentation implied a requirement to perform a utility cost test for all distribution investments, 2) they do not believe the Commission Order in U-18368 is applicable to something as broad as "all utility distribution investments", 3) a significant amount of the Company's distribution investments using ratepayer funds consist of outage driven work for which there is no meaningful alternative, and 4) requiring a specific methodology to be used for all distribution investments would limit each utility's ability to make its own business decisions to manage its own system. It is better to agree on definitions of costs and benefits while still allowing each utility flexibility over methodology.

If BCA's were required for all distribution investments, utilities would need to specify the level of detail intended because the information from each program would be voluminous.

Need clarity of grid modernization "scenario". Consumers has a detailed multi-year grid modernization plan that includes a variety of investments in new technologies and capabilities. This will be pursued in parallel to other traditional investments, not one scenario among many potential investment routes. If Staff's intention is that every proposed distribution investment will also be compared against a grid modernization alternative, then this is not possible. Many traditional distribution investments do not have a grid modernization alternative.

Consumers does not recommend the requirement of tracking and reporting all actual costs and benefits of all distribution investments. It would represent a significant regulatory requirement.

CUB

Improving the distribution grid will require a large monetary investment and the MPSC is responsible for ensuring that ratepayers are receiving benefits from their rate increases that outweigh the costs.

Regarding distribution upgrades that pass the BCA, recommends ensuring utilities are making the investments that are most beneficial to system reliability.

DTE

Does not feel it is possible or feasible for utilities to perform BCA on all their electric utility investments. It is the Company's responsibility to prioritize and manage its distribution investments. DTE developed a GPM (Global Prioritization Model) to effectively prioritize strategic capital investments and maximize customer benefits.

The "utility cost" and "regulatory tests" are financially based analyses and rely on quantifying investment benefits into dollar values. Safety, system planning, customer satisfaction, reliability, and major event risk are non-monetized by nature, so these tests are not appropriate. DTE also does not believe it is beneficial or possible to compare investments across different utilities as each utility has its unique system conditions, service territory, and customer base.

Needs clarification on "BCA sensitivities".

Believes BCA may be more appropriate for discretionary categories of investments that are not tied to the core objectives of safety, reliability, and resiliency. Additionally, the discussion of discount rate is not necessary since discount rate is more relevant to discretionary categories of investments.

Seeks clarification on what is meant by "grid modernization" scenario.

Does not support the requirement that the utility provide the range of options investigated, each of their BCA findings, and the final selected options for individual projects and programs. This would be very costly and time consuming.

ELPC/Vote Solar

Support application of both "Utility Cost Test" and the "Regulatory Test".

Although the National Standard Practice Manual (NSPM) for BCA of DER is not completed, it could be incorporated by the Commission by reference in any orders considered during its pendency.

Suggest that the "Resource Value Test" be required to all investments. And should be broadly defined to include all applicable regulatory regimes.

ESA

Staff's proposal that requires projects to pass a cost effectiveness test disregards the fact that the current BCA framework may not capture all the benefits that should be included in a cost effectiveness test for energy storage. Can the current BCA methodology be evaluated for whether it effectively captures the entire range of benefits to ratepayers?

GridLab

Provides examples of other characteristic of good grid mod benefit/cost analysis to consider.

Questions why Utility Cost test is preferred.

Would like clear definition and examples for "platform" and "modular applications" in the Staff recommendation that BCA analyses be conducted for platform components individually and bundled with the modular applications that it enables.

In the Staff recommendation of traditionally non-monetized benefits, especially those related to safety and system planning, be required to be included in BCAs using related monetized proxies or through other quantitative methods, GridLab questions what "system planning benefits" are.

Needs clarity on "grid modernization scenario" and questions if it is relevant for all distribution investments.

Comments that a Societal Cost Test would include benefits as greenhouse gas reductions, economic impacts from improved reliability, low income customer benefits, etc.

I&M

Objects to the overly broad and burdensome "requirements" to apply BCA sensitivities for all distribution investments and presumably all platform components. Many distribution investments are non-discretionary and necessary to provide safe and reliable power to customers.

Disagrees that a "grid modernization" scenario is necessary for all distribution investments. Performing a plethora of BCAs will require significant internal and external resources and increase cost of service. I&M currently uses the Project Value Ranking (PVR) tool to help with prioritization and costing of distribution projects, including grid modernization.

Objects to any monetization of the "safety" value of a project, specifically any attempt to monetize that value of a human life.

The proposal to require reporting of BCAs for distribution planning related to utility investments in rate cases requires more explanation and discussion. It is unclear whether Staff is proposing a new and additional BCA or the BCA from the most recent distribution plan filing.

Overreliance on BCAs could diminish other valid considerations in customer needs, safety, technology, and the four primary objectives of distribution planning. The goal of distribution planning and a BCA exercise should be to evaluate options for discretionary work and inform the decision-making process, not determine it.

The recommendations around BCA contemplate Staff and stakeholder review and likely disputes any proposed changes that could be contentious and significant in regulatory proceedings with a possible formal Commission decision to follow. This could result in a significant and impractical timeline between creating a distribution plan and meeting the objectives of the regulatory process.

MEGA

Applying BCA sensitivities to "all" distribution investments would be unwieldly for the utility and staff. MEGA suggests that the BCA application be for set types of projects, such as grid modernization initiatives, or targeted reliability or resilience investments.

The requirement to do grid modernization analysis for all distribution investments is impractical. There are many distribution investments that have nothing to do with grid modernization.

Regarding the recommended requirement of reporting actual benefits and costs after project implementation to monitor performance over time, MEGA recommends that any type of after-the-fact evaluation should be limited to grid modernization projects, with a projected cost and/or timeline threshold, and with some specific guidance from the Commission about expected outcomes. Additionally, it is recommended that inserting incentives for high performance in these areas that meet a set threshold would be valuable.

Michigan EIBC and AEE Institute

The Regulatory Test accounts for the state's regulatory goals and captures a wider range of non-monetized benefits in BCA calculations. As MI Power Grid aims to maximize the benefits of a transition to clean and distributed energy resources, how well a particular investment aligns with that goal should be part of the equation.

Regarding the Staff recommendation to require reporting of BCAs for distribution planning related utility investments in rate cases with clear definition of all BCA assumptions, Michigan EIBC and AEE Institute recommend filings provide sufficient detail so that stakeholders understand how utilities arrived at their results.

Recommend that if further development of BCA methodology is necessary, it is done by a non-contested case to allow for maximum stakeholder participation.

Suggests engaging stakeholders in the process of utilities providing the range of options investigated. This would help uncover options that the utility may not be aware of.

Believe it is not sufficient for a "grid modernization" scenario to be one of the solutions for the utility to consider. NWA should be considered with every distribution system planning BCA to assess and find the right solution for a problem. Nonspecific “grid modernization” scenario makes this less concrete, less futuristic, and more of a box checking exercise.

MI-MAUI

BCA must include costs imposed on local governments, public lands and rights of way and communities.

Concerned that the use of “Utility Cost” as the boundary of BCA since it considers only costs and benefits borne by the utility and ratepayers.

When all costs and benefits are not borne by the distribution utility, it is not appropriate to discount cash flows using only the utilities WACC.

Hosting Capacity Analysis

ABATE

In Michigan, as in most states, DER adoption is not yet high enough to justify large distribution investments.

Modify or remove the implication that IOU limitations on DER hosting capacity/NWAs should be taken at face value.

ACEEE

Recommends that the Commission clarify that any analysis of hosting capacity should include an assessment of the potential for energy efficiency and demand response to improve the local hosting capacity in any area examined with HCA. The objective should be to optimize the amount of local renewables, not maximize.

Consumers

Recommend staff make clear that each utility must have wide flexibility in designing a pilot that will be most beneficial to its own system and provide its own best lessons learned.

Requests clarification on what Staff anticipates in a phased-in approach. The Company’s interpretation is that a utility pilot should either provide high level hosting capacity information about a broad part of its system or more detailed hosting capacity information about a narrower part of its system. Consumers requests Staff accept this interpretation.

Requests clarification regarding expected implementation timelines of phased-in pilots. Should utilities execute their pilots in 2020 and show results in 2021 distribution plan filing or should they be designing and presenting their plans in the 2021 filing with execution to follow? If new expenses must be incurred, execution may be reliant on approval of costs in a rate case.

ELPC/Vote Solar

The utilities should initiate a phased, system wide implementation of HCA starting with providing distribution system data in a map and spreadsheet format and cleaning up their GIS model, before working with stakeholders to select an HCA methodology.
Strongly disagree with Staff's statement "It does not make economic sense to invest significant resources into a project that will only benefit a relatively small amount of installations while all ratepayers are paying for it." Instead they believe deployment will continue to steadily increase in the future, consistent with Michigan's policy goals and technological improvements.

They suggest the current economics of HCA implementation are irrelevant. The financial attractiveness of distributed generation for all customers will continue to evolve.
Suggest that HCA gets split into its own docket.

GridLab

Suggests utilities can apply the same HCA tool/methodology to both rural and urban feeders.

I&M

The report fails to recognize that I&M is a much smaller utility than the other utilities required, to date, to file distribution plans in terms of customers and urban centers in the service territory. It would be very burdensome and costly for I&M to perform HCA for its entire Michigan grid. Currently the Company has a process in place that responds to customer requests for hosting capacity information as needed.

Believes the draft report should avoid proposing requirements and instead recommend 1) allowing the larger Michigan utilities to gain additional experience in this area which will help better inform the costs, benefits and need for HCA for the smaller utilities in Michigan, 2) continue HCA research regarding measures in nearby states and analysis of other industry organizations such as Electric Power Research Institute (EPRI).

MEGA

Regarding the recommendation that the Commission adopt "interconnection of DER" as a use case in HCA, MEGA comments that DER is not defined as it would be applied here. It would be helpful to make clear if it includes demand response, electric vehicles or storage on the load side of the equation. It would be simpler to just apply generating DER.

Recommends there be threshold of interest set that would trigger investigation of an HCA given the significant investment of time and resources that will be required.

Michigan EIBC and AEE Institute

Regarding the Staff recommendation to adopt "interconnection of DER" as a use case for HCA, Michigan EIBC and AEE Institute note that this use case is not a substitute for having robust, timely DER interconnection processes

Suggests there could also be a "Distribution System Planning" use case where HCA is used to help the utility and third parties understand where on the system DER deployment may be constrained and where DER deployment would be most beneficial. It would be more forward looking and help the utilities identify appropriate investments consistent with the future needs and capabilities of a modern grid.

Regarding the Staff recommendation to adopt a phased implementation approach for HCA pilots, Michigan EIBC and AEE Institute suggests this does not need to occur using pilots. They recommend the Commission encourage utilities to update their distribution systems models and data to be accurate for use in an analysis that matches the "interconnection of DER" use case.

Recommend the Commission examine HCA best practices and methods for cost reduction with input from utilities and other stakeholders. Also recommend the Commission issue an RFI to determine actual cost estimates for different phases of HCA. If RFIs are done by utilities, the Commission should closely review the request to ensure that utility requests are aligned with the use case and are reasonable.

Recommend the downloadable map and spreadsheet include line segment-level information including the remaining capacity on a given line segment and application information.

Believes it is not reasonable to assert that we are not at a point where we can move forward with phased implementation of system wide HCA, especially if this is conducted on a set timeline with full implementation at a reasonable time in the future. The Commission cannot make this assertion without gaining more information on actual costs aside from utility assertions.

Regarding the Distributed Generation program requirements, Michigan EIBC and AEE Institute believe that what Staff stated in the report represents a misunderstanding of the value of distribution system data and HCA. (Their comments on this topic are rather lengthy. For a full reference to their complete comments, please check the Michigan EIBC/AEE hotlink.)

Regarding the Distributed Generation program requirements, they comment on the misunderstanding of HCA in relation to the DG gap. Additionally, they claim that small rooftop solar isn't the main use case for HCA. (Their comments on this topic are rather lengthy. For a full reference to their complete comments, please check the Michigan EIBC/AEE hotlink.)

Regarding Staff's statement "While customers can interconnect DER without participating in the DG program, it may not be economic for most residential customers", Michigan EIBC and AEE Institute disagree and state that economics are irrelevant. They state that unless a user is off-grid, there is no statutory or regulatory guarantee that they will be granted interconnection for a DER outside of the DER program. (Their comments on this topic are rather lengthy. For a full reference to their complete comments, please check the Michigan EIBC/AEE hotlink.)

Non-Wires Alternatives

ACEEE

Recommends that the Commission specify that any NWA analysis include examination of the potential for energy efficiency as well as demand response to contribute to an NWA solution.

Consumers

Disagrees with Staff's inclusion of "new business". Company has a program called New Business with a significant amount of investment dedicated to the interconnection of new customers, which cannot be addressed through NWAs.

DTE

DTEE is already engaging customer and third-party support in the planning and execution of the NWA pilots, and plans to continue to integrate that support in NWA solutions as they evolve in the future. DTEE would like to highlight that for customer and third-party support to work effectively, DTEE needs to retain oversight capability of the NWA solution resources pertaining to DTEE's distribution system and utility customers.

ELPC/Vote Solar

The utilities should incorporate NWA analysis into their broader distribution investment selection and prioritization processes.

The Company recommends that the Commission direct the utilities to incorporate NWA analysis more directly into their distribution system project prioritization and selection process.

As a part of their distribution system plans, the utilities should be required to identify projects that are avoidable or deferrable and provide, for those projects: the type of service required (for example capacity, reliability, etc); where applicable, the need in MW or MWh; the anticipated cost; the anticipated time frame (year, month(s), and hour(s)). The utilities should then describe their efforts to meet these deferrable opportunities with NWA solicitations or NWA projects.

They don't support addressing NWAs in Energy Programs and Technology Pilots workgroup because utilities have already deployed several NWA pilots.

The utilities should move beyond NWA pilots (which may independently provide value) and integrate NWA analysis into their distribution investment selection and prioritization practices going forward. The utilities should identify, as a part of their next distribution plans, a set of NWA screening criteria and a list of distribution system projects that are avoidable or deferrable with NWAs, and for those projects, provide the type of grid service required; the need in MW or MWh; the anticipated cost; and the anticipated time frame (in years, months and hours). The utilities should also describe their efforts to meet these deferral opportunities with NWA solicitations or NWA projects.

ESA

Energy storage serves as a cost-effective alternative for a traditional distribution investment

Energy storage can enhance resilience of the distribution system at times of increasing extreme weather events.

GridLab

Questions if Staff has any recommendations related to the growing importance of more sophisticated load and DER forecasting, and the need for utilities to make this a priority in the near term.

I&M

There is a balance between creating a framework to support and evaluate pilots and ensuring sufficient flexibility is retained to allow utilities to respond to changes in customer needs, interests, and available technologies and services.

Michigan EIBC and AEE Institute

Recommends Staff and the Commission answer the outlined questions now as part of this report and then incorporate the answers into an evaluation of NWA as part of the regulator utility distribution system planning process. NWAs should be considered a standard option.

Recommends the Commission lay out standard metric and reporting methodologies across utilities.

Would like to see NWAs discussed within the context of utility incentives/disincentives within MI Power Grid. Utilities need to have the necessary financial motivations and opportunities to evaluate all possible solutions on a level playing field.

Suggests there should be a distribution system planning specific roadmap for the HCA and NWA pilots already undertaken by the utilities, or at least the Commission should establish a procedural timeline for evaluation.

Alternative Regulatory Approaches

ABATE

Staff's recommendations do not go far enough in addressing the fundamental challenges related to electricity distribution regulation, ratemaking, capabilities, risks, and IOU investment.

Current ratemaking and stakeholder processes were not designed for today's electric distribution grid or business challenges.

Paying incentives to IOUs to address capital bias is an affront to the regulatory compact.

Consumers

Changes to rate case requirements are outside the scope of the workgroup's purpose. If the Commission does require more defined BCAs in rate cases, it should set a project cost threshold of $500,000 before a BCA is needed or it should allow a utility to perform a higher-level BCA for broader investment programs. Notwithstanding any future changes to rate case requirements, the Company believes a rate case is the only venue in which project level BCAs could be presented. With a 5-year distribution plan, specific projects will not yet be known.

DTE

The Company does not believe it would be possible to provide the requested reporting of BCAs for distribution planning related utility investments in rate cases with clear definitions of all BCA assumptions. Some of the benefits cannot be measured or calculated. DTE includes the GPM results in its rate case filings and expects to continue in future.

ESA

Develop utility programs that allow behind the meter storage to provide services that receive compensation for them. These programs are not incentive programs which provide grants or rebates, they are compensating customers for services provided to the system.

Encouraging NWA solutions should include new rules to memorialize best practices for competitive procurement.

I&M

Staff and the Commission should include reconsideration of the traditional regulatory model's emphasis on setting rates based on usage. Specifically, the need to change the methodology of determining a reasonable fixed charge for customers.

Michigan EIBC and AEE Institute

Suggests "accommodation" of DER should not be the main objective. The goal should be "integration", which implies DERs are able to contribute to meeting grid needs.

Stakeholder Involvement

ABATE

The Commission should establish a formal proceeding to develop a transparent, stakeholder engaged distribution planning and capital budgeting process to be employed in the development of Michigan IOUs future distribution plans and capital budgets. Such participation must extend beyond workshops, webcasts, and "input".

Multiple questions are proposed to be addressed in a formal stakeholder engagement process including "What is the most cost-effective mix for risk mitigation spending?".

Elements needing definition include process steps, limitations to participant roles, stakeholder sign-offs, dispute resolution, BCA guidelines, timelines, frequency, and other parameters.

Multiple IOU comments mischaracterized and overstated the implication of ABATE's recommended distribution planning process.

I&M

The report expresses the need for guidance and seems to characterize the document or future MPSC order as advisory in nature. Many of Staff's recommendations are characterized as if they are to become regulatory requirements. There needs to be more analysis of the means by which recommendations in the Draft Report become regulatory requirements and whether statutory revisions or formal administrative rulemaking and/or development of guidelines under the Administrative Procedures Act are needed.

I&M recognizes the Commission's role in overseeing Company decisions and for distribution planning it agrees with and shares the Commission's four objectives. However, I&M has clear "line of sight" in day to day operations and planning systems and is in the best position to leverage existing utility infrastructure to control costs, manage related security and consumer privacy issues, and ensure continued focus on reliability of distribution system operation and the introduction of new technologies and other functionality.

I&M has distinct service area characteristics that should be considered in evaluating distribution planning such as low levels of DER, smaller, more rural service area, limited number of customers to bear new regulatory costs, and the absence of AMI.

Distribution planning is a continual process that requires flexibility and discretion to respond to changing facts and circumstances. It is too early in the process to consider measures that may increase administrative and cost burdens that will limit these.

Suggests the need for an interim cost recovery mechanism such as an adjustment clause should the Commission adopt new regulatory requirements from the recommendations that result in significant compliance expenses.

Proposes that Staff decline to propose specific new regulatory requirements at this time and instead support the continuation of stakeholder dialogue, allowing the utilities flexibility to determine how and when to incorporate knowledge gained through the process in their distribution plans.

Michigan EIBC and AEE Institute

Believes there should be conclusions and recommendations provided related to the importance of a transparent and engaged stakeholder process.

Reference the MI Power Grid goal to ensure "timely and fair grid access and appropriate information exchange to support customer-oriented solutions and reliable system operations". They state that the Staff report provides few recommendations that would create more transparency to the planning process. They further state that a core element of modern distribution system planning processes should be to provide information to customers, regulators, and third parties.

MI-MAUI

Municipal governments should have specific and reserved representation in distribution system planning processes.

Electric distribution plans should incorporate input from local officials and plans about community reliability and resilience needs.

Utilities should engage municipal officials in planning from the beginning as well as in actual project implementation.

Pilot Programs (General)

ELPC/Vote Solar

The utility should explain what it hopes to learn from the pilot, why the utility cannot achieve the desired learning by reviewing other utilities' experiences, why a pilot Is necessary before system wide implementation, and how it will track and report the performance of its pilot.

I&M

Suggests Staff recommend that the broad topic of pilot programs be removed from the distribution planning process to avoid duplication with the MI Power Grid Energy Programs and Technology Pilots workgroup.

Reliability

ABATE

The reliability of Michigan IOU's has barely budged despite dramatic grid investment growth in excess of flat to falling energy and demand.

Distribution planning process needs must be considered in the context of ratebase growth pressure and lack of correlation to reliability improvements.

Staff's reference to assets operating "way past useful life" are unreliable or unsafe and should be removed from the report.

IOU's sometimes justify zero book value asset replacement through claimed improvements in reliability or safety. These claims must be backed by historical equipment failure rate data to merit serious consideration.

All multi-billion grid modernization efforts (or the enhanced cost recovery approved and/or being debated in many states are required to make the grid more reliable or to prepare for an onslaught of DER) should be rejected.

The DOE's "Cost of Interruption" estimates were not scientifically developed and should not be employed in benefit cost analysis.

CUB

Recommends Staff engage independent analyses of distribution improvement projects from qualified third-party sources. These analyses should rank projects to determine which ones generate the greatest return of SAIDI, SAIFI, CAIDI improvements versus capital requirements and time to determine prudency.

Resiliency

MI-MAUI

Concerned that any planning process that seeks to maximize reliability and resilience of only one component of the system will cost more, create duplication of or gaps in investment and ultimately prove to be less effective than a systems approach.

Standardized Components for Future Utilities' Distribution Plans

DTE

Recommends the Commission utilize orders and regulatory proceedings rather than administrative rulemaking on the reporting of reliability indices

An Energy Waste Reduction assessment of energy efficiency resource options is filed in the utility's IRP. Filing a separate assessment in the distribution planning report would be redundant. 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. A more appropriate solution would be to discuss EWR within the context of NWA solutions.

ELPC/Vote Solar

Recommend that utilities historical performance be broken out on a more granular basis (feeder) and overlayed with geographic and demographic to enable an equity and environmental justice lens.

I&M

Urges continued recognition of the flexibility to deviate as necessary. For example, in response to Staff's recommendation on SAIDI, SAIFI, and CAIDI, I&M does not analyze by quartiles, but does analyze by cause with SAIDI and SAIFI, and uses CAIDI as a reference.

MEGA

Believes the approach to distribution planning seems to have become increasingly prescriptive. Adopting an approach that establishes a strict plan discourages deviation even when different management decisions would result in the best use resources could result in unintended and undesirable consequences. Flexibility in distribution plans will allow for the best decision making at the right time.

Michigan EIBC and AEE Institute

Commission guidance should include concrete steps to increase transparency in distribution systems planning. Specifically, recommend the Commission include consideration of HCA and dynamic system load forecasting as standard components in the next set of utility distribution system plans to facilitate discussion and enable nonutility stakeholders to make investments that support grid needs.

The Commission should move away from HCAs and NWAs in the context of pilots and fully consider phased system-wide implementation. These should not only be considered “emerging pilot programs” but integrated as permanent components in future utility plans.

To achieve the objectives, utilities will need to make investment that are consistent with emerging needs. There is little to no mention of advanced forecasts or growth scenarios int his report.

The Commission should take the first steps in building a customer-centric, bottom-up distribution planning process. Recommend the Commission require utilities to take the following steps in their next set of plans or provide a timeline for implementation of these steps: 1) Require utilities to enhance their approach to load and DER forecasting, 2) Require utilities to evaluate how the existing system would meet future needs through an engineering assessment and determine the capacity for DERs through a hosting capacity analysis, and 3) Development of a competitive solicitation framework to source DER-based solutions at the lowest cost, including NWAs and other approaches.

Items crucial to forward-looking distribution system planning are missing from the Executive Summary of the Distribution Report. These topics include the importance of stakeholder involvement/transparency in distribution system planning including for the crafting of metrics/objectives, and dynamic load forecasting.

Locational Value

ELPC/Vote Solar

Regarding transitioning to a successor framework for compensating distributed energy resources, a power outflow study that would allow for a precise valuation of distributed generation benefits was referenced in Case Number U-20162 Order at 171-182 (May 2, 2019).

One component of the value of DERs is avoided distribution system capacity cost and Michigan utilities have not quantified that value on an aggregate or locational basis. A more rigorously locational quantification of value can inform distribution planning.

Suggestion that Michigan might benefit from the Minnesota process exploring how to compensate distributed energy resources for locational value.

The Role of Energy Efficiency with Distribution Planning

I&M

There needs to be a high concentration of cost-effective energy efficiency opportunities in any given local area for the impact to distribution system planning to be meaningful enough to warrant consideration. Energy efficiency measures will need to reduce usage during local distribution system equipment peak use time periods to have meaningful impact on equipment sizing and specification. Assessment, customer acceptance and participation would be challenging.

Grid Vision

ABATE

Grid "Visions" need to be quantified.

I&M

Does not support the proposal that the vision "be emphasized every step of the way". Strategic vision should be a guide rather than a plan component to be interpreted and evaluated over and over as plans are implemented.

MEGA

The context for the safe, reliable, and affordable components continues to change as technology changes. It would be helpful to have a more expansive discussion and description for what a utility vision for distribution planning would look like.

Michigan EIBC and AEE Institute

Would like "long-term" defined.

Staff and the Commission should provide more detail on what this "vision" is and how the utilities can effectively move from traditional distribution planning to a more forward looking vision that actively incorporates NWA, non-traditional technologies, HCA, dynamic load forecasting, etc.. It is the Commission's role to help set the vision and the utilities' role to formulate their plans in a manner that allows them to achieve that shared vision.

Filing Requirements

ELPC/Vote Solar

In the conclusion they would like to change "The Commission is encouraged to provide additional direction and clarification" to "The Commission is encouraged to provide additional filing requirements"… "in order to ensure that the plans are an improvement on the utilities' first set of distribution plans, to ensure that the plans advance the objectives of the Mi Power Grid initiative, and to ensure that the plans inform and improve the rate case process in Michigan."

I&M

Objects to the draft report resulting in additional base rate case filing requirements being imposed upon utilities outside of the usual process for such requirements.