Electric Distribution Planning Stakeholder Process

MPSC Staff Report

April 1, 2020

Contents

Executive Summary

Consumers Energy ("the Company") appreciates the opportunity to provide its comments on this draft report from the MPSC Staff and looks forward to continued collaboration as it develops its 2021 Electric Distribution Infrastructure Investment Plan. The Company's comments are inserted in the detailed "Summary and Recommendations" section beginning on page 27; the Company is not repeating its comments on recommendations in this Executive Summary section.

This report represents the Michigan Public Service Commission's (MPSC or Commission) Staff's review, summary, and corresponding recommendations following a public stakeholder process held throughout 2019 that addressed the on-going issues and challenges of utility electric distribution planning in Michigan. The stakeholder participation was significant. The stakeholder responses were varied and added value to the process. This report is intended to inform the Commissioners about the distribution planning process and dialogue that has taken place, 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. 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:

<u>Distribution Planning Objectives</u>

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 way past the end of expected life and utility investments must consider the vast ratepayer resources needed to assure reliable service during all types of weather. Staff believes this 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 to be included in a forthcoming Commission order:

- 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 (NWA) – A portfolio of DER, such as distributed generation, energy storage, energy efficiency (or energy waste management), demand response, combined heat and power, and grid software and controls, used to defer, mitigate, or eliminate the need for traditional utility infrastructure investments.

- Locational Value Assessment – Locational value assessment is intended to quantify the benefits and costs of DER, which are often locational in nature.

Benefit-Cost Analysis (BCA)

Staff recommendation:

- BCA sensitivities be required for all distribution investments using rate-payer funds. If the Commission elects to require only one BCA sensitivity, Staff recommends the Utility Cost test. If the Commission elects to require more than one sensitivity, Staff also recommends the Regulatory Test (also known as the Resource Value Test).
- BCA analyses be conducted for platform components individually and bundled with the modular applications that it enables.
- At least one discount rate sensitivity for all conducted BCAs be required where a low-risk discount rate ranging from 0-3% is selected by the Commission to reflect the regulatory viewpoint.
- 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.
- The Commission clearly relay its ranking of non-monetized benefits, including safety and system planning, so that utilities can use this ranking, if needed, when examining non-monetized benefits in BCAs.
- Require a “grid modernization” scenario be analyzed for all distribution investments,

- Require reporting of BCAs for distribution planning related utility investments in rate cases with clear definition of all BCA assumptions.
- Report actual investment benefits and costs in rate cases after project implementation consistent with the original BCA methodology used for project justification to monitor performance over time.

<u>Hosting Capacity Analysis</u>

<u>Staff recommendation:</u> Staff recommends that the following be adopted for the HCA pilots requested by the Commission:

- Adopt the "interconnection of DER" as the use-case for HCA
- Adopt a phased implementation approach for the HCA pilots where phased implementation ranges from a base-level approach like a zonal go/no-go map to a more detailed map with feeder voltage levels information. This will 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.
- 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

<u>Non-Wires Alternatives</u>

<u>Staff recommendation:</u> Staff agrees that the questions presented in Paul DeMartini's October 16 stakeholder presentation[3] should be asked by the Commission and answered by the utilities prior to refining and implementing 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?

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".

Staff believes that NWA is a topic that merges with the work of the MI Power Grid Energy Programs and Technology Pilots workgroup,[4] 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 AEE August 14, 2019 stakeholder presentation[5] be explored by the workgroup. 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[6] 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: Instead of providing a definition of resiliency, Staff recommends the Commission identify the events that have the potential to effect electrical system resiliency. Once we identify the events that we are most concerned about when we think about resiliency, then metrics should be identified.

The Commission should provide guidance to be used for the MI Power Grid Integration of Resource/Transmission/Distribution Planning workgroup[7] 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.

Standardized Components for Future Utilities' Distribution Plans

Staff recommendation: The Commission support the joint utility proposal that was presented at the October 16, 2019 stakeholder session, and outlined in the presentation, where utilities agree to standardized components for upcoming distribution plans, as well as areas in their plans that will likely differ based on company specific circumstances.[8]

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.[9]

Michigan Infrastructure Council

Staff recommendation: The utilities should reference the Michigan Infrastructure Council as they develop their utility distribution plans. As referenced in the Commission November 2018 order,[10] utilities should coordinate distribution planning efforts with the Michigan Infrastructure Council efforts in order to benefit all MI residents through more efficient and effective planning.

The Role of Energy Efficiency with Distribution Planning

Staff recommendation: The Commission direct the utilities to include an assessment of energy efficiency resource options in their forthcoming electric distribution plans.

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 vision becomes the roadmap for results. As the utilities' proposed at the October 16 stakeholder session,[11] a long-term strategic vision and plan should be a featured component of every utility distribution plan going forward.

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 refresh 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 a two-year refresh schedule so that the plans remain updated and relevant to changing technologies and priorities.

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 in Case No. U-17990[12] and DTE Electric Company in Case No. U-18014,[13] 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 raised and 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 Energy Company (Case No. U-17990)[14] and DTE Electric Company (Case No. U-18014)[15] 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 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, refresh 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,[16] DTE Electric Company filed their first five-year distribution plan on January 31, 2018[17] and Consumers Energy Company filed their first five-year distribution plan on March 1, 2018.[18]

Two additional orders followed from the Commission (April 2018, order[19] requiring Indiana Michigan Power Company 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[20] 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 Electric Company and Consumers Energy Company 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,[21] 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[22] 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, Indiana Michigan Power Company filed their initial distribution plan for 2019-2023 in the U-20147 docket on April 3, 2019.[23]

On September 11, 2019,[24] 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 Electric Company and Consumers Energy Company. This aligns with the June 30, 2021 deadline already established for the filing of Indiana Michigan Power Company's next distribution plan.

Summary of Distribution Planning Commission Orders			
Order Date	**Case Number**	**Description**	**Link**
1/31/2017	U-18014	This Commission Order 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 Electric Company.	1/31/17 Order
2/28/2017	U-17990	This Commission Order 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 Energy Company.	2/28/17 Order
10/11/2017	U-18014 & U-17990	This Commission Order provides guidance on the submission of the utilities' final five-year distribution plans and proceedings.	10/11/17 Order
11/21/2018	U-20147	This Commission Order 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
4/18/2018	U-20147	This Commission Order confirms the determination to remove Consumers Energy Company's March 1, 2018 filing in Case No. U-17990 and U-20147.	4/18/18 Order
4/12/2018	U-20147	This Commission Order opens this docket and provides other requirements for Consumer's Energy Company, DTE Electric Company and Indiana Michigan Power Company	4/12/18 Order
9/11/2019	U-20147	This Commission Order sets forth additional guidance and requirements for the Commission Staff; extends/sets the date for DTE Electric Company, Consumers Energy Company, and Indiana Michigan Power Company 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. As referenced in the Commission's October 2017 order as well as the April 2018 order that opened the U-20147 docket, stakeholder input into the distribution planning process was encouraged. More particularly, the Commission invited stakeholder comments addressing "expectations for the next set of distribution plans".[25]

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 (MiEIBC), Michigan Municipal Association for Utility Issues, Environmental Law & Policy Center, 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, MiEIBC, Indiana Michigan Power Company, Consumers Energy Company, DTE Energy Company, 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, Indiana Michigan Power Company 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 & Fall of 2019 and maintained stakeholder communications through the Commission's email listserv messaging tool.

Stakeholder meetings: utility and other stakeholder presentations

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 MPSC's webpage.[26] 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 Chair 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. Ryan Katofsky of the Advanced Energy Economy (AEE) 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. Indiana Michigan Power Company, Consumers Energy Company, and DTE Electric Company all presented information on proposed HCA and NWA pilots. Indiana Michigan Power Company included candidate locations for NWA. Consumers Energy Company provided an overview of their proposed solar zone / HCA pilot. DTE Energy 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. 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 Energy Company, DTE Electric Company and Indiana Michigan Power Company 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. MiEIBC moderated a panel that addressed "Third-Party Uses of Hosting Capacity Analysis". Newport Consulting's Paul De Martini (consultant to the U.S. Department of Energy) 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 Energy Company, DTE Electric Company, and Indiana Michigan Power Company 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.

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[27]

MiEIBC and AEE combined comments addressing the August 14 content that was presented and discussed[28]

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[29]

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

MiEIBC and AEE combined comments addressing the September 18 content that was presented and discussed[30]

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

ABATE addressed the October 16 content that was presented and discussed[31]

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[32]

Indiana Michigan Power Company reply comments in response to written comments filed on September 11 and October 4 by stakeholders regarding I&M's distribution planning issues[33]

Consumers Energy Company comments in response to discussions on issues related to distribution planning in the Electric Distribution Planning stakeholder workgroup[34]

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[35]

Significant Issues

Benefit-cost analysis

Two 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 Energy's 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 DO) 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. One 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 Indiana Michigan's Power Company's August 14, 2019 HCA pilot presentation, one stakeholder did not support the utility's claim that the absence of 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 hosting capacity 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 Energy Company's 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 Energy 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 Energy Company jointly presented on the costs associated with a 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 Energy Company 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. 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 Indiana Michigan Power Company'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 Energy Company's 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 Energy Company 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 from Newport Consulting, consultant to the U.S. Department of Energy, presented a customer-centric approach to NWA on slide 3 of his presentation entitled "NWA Framework: Evaluation, Sourcing Options, and Relative Risks".[36] 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 Energy 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.[37] DTE Energy 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. Indiana Michigan Power 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,[38] 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".[39]) 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 process protocols, inclusion of probabilistic DER and load growth scenarios for improved modeling etc., 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 Energy Company 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".[40] 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 Energy Company, 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,[41] 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.[42] 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: A) differences among utility systems where each utility may emphasize different strategic areas, and B) company preferences that necessitate different levels of content detail narrative flows in respective reports.

Coordination with Michigan Infrastructure Council

During the June 27, 2019 stakeholder session, the Michigan Infrastructure Council efforts were flagged as being relevant and important to Michigan utility distribution planning processes. Reference was made to the Commission's acknowledgement of the Michigan Infrastructure Council in their November 2018 order in the U-20147 docket. DTE Energy specifically spoke about their active role with the Michigan Infrastructure Council. No further discussions were conducted about alignment of future Michigan utility distribution plans with the Michigan Infrastructure Council 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.[43] 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".[44] 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.

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".[45] 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 with Distribution Planning

DER are defined differently by various organizations and entities. At times energy efficiency (or energy waste management) is included in the definition of DER, and other times it is not. The key issue is not if energy efficiency is included in the DER definition, but instead that energy efficiency is recognized as a key resource consideration when utilities engage in distribution planning. Energy efficiency can impact distribution system needs both from broad scale "baseload" types of energy efficiency as well as from enhanced energy efficiency targeted at specific time periods and/or geographic locations. The distribution resource planning process should fully consider energy efficiency as a resource.

The Michigan stakeholder process that explored distribution planning did not particularly feature an energy efficiency focus, but the concept of energy efficiency as a resource and the relationship of energy efficiency practices with distribution planning should not be overlooked.[46] Most utilities are not currently using energy efficiency in distribution system planning, but several states are pursuing new approaches to using efficiency to displace traditional distribution infrastructure upgrades and integrate more renewables into the grid.[47] The role of energy efficiency with distribution system planning is likely to be included in the Michigan discussion going forward.

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:[48]

> "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"[49] in relationship to the Commission's stated objectives. Slide 2 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 lieu 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. An important consideration to "cost effectiveness and affordability" is resource diversity. Both HCA and NWA are directly tied to how accessible the distribution system can be to emerging technologies such as DER. HCA and NWA may serve as key components to resource diversity on the distribution system over time.

<u>Staff recommendation:</u> 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 Commission should also confirm Staff's assumption that an important consideration to "cost effectiveness and affordability" is resource diversity. 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. Staff believes this 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.

Consumers Energy comments: The Company agrees that these four objectives continue to be appropriate for distribution planning, and that safety should be the top priority in planning, followed by reliability and resiliency. The Company requests that Staff provide clarification around the assertion that cost effectiveness and affordability is tied to "resource diversity" – namely, how is Staff defining "resource diversity" in this case? Resource diversity is often understood to refer to an electric supply consideration, i.e. maintaining geographic diversity and fuel diversity of a generation fleet, and the Company is not familiar with its use as a distribution term. In the context of this paragraph, it appears that Staff is connecting a concept of resource diversity to addressing the tension between the large number of distribution assets past their lifespan and the costs associated with replacing all of those assets. If that is Staff's intent, Staff should clarify the connection and explain why resource diversity, in Staff's understanding, would address this problem.

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.[50] 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, technical entities, consultants and other interested participants.

Consumers Energy comments: The Company appreciates Staff reinforcing that aggregate stakeholders not become the lead actor in developing distribution plans. While stakeholders can add value to the distribution planning by bringing their ideas to collaborative workgroup meetings, it is the utility that must evaluate and select the most appropriate investments for its distribution system.

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

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 – A portfolio of DER, such as distributed generation, energy storage, energy efficiency (or energy waste management), demand response, combined heat and power, and grid software and controls, used to defer, mitigate, or eliminate the need for traditional utility infrastructure investments.

Locational Value Assessment – Locational value assessment is intended to quantify the benefits and costs of DER, which are often locational in nature.[51]

Benefit-Cost Analysis

In U-17990[52] and U-18014,[53] the Commission ordered DTE Electric and Consumers Energy to include benefit cost analysis (BCA) that considers benefits as well as both capital and O&M costs in their respective five-year distribution investment and maintenance plan. Clearly, the Commission recognizes the usefulness of BCA when making five-year distribution investment and maintenance plans. However, outside of requiring BCA, the Commission did not provide any further guidance.

One main motivation of having a required BCA methodology is "to provide interested parties a consistent and transparent methodology to calculate the benefits and costs of potential projects and investments."[54] The ability to compare investments within an utility and across utilities greatly increases consistency and transparency when evaluating investments. The output of a BCA, such as the benefit-cost ratio, provides a readily understandable metric regarding the value of specific utility investments that can benefit utilities, stakeholders, Staff, and the Commission when examining investment options.

The BCA methodology impacts the study scope and findings. 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)."[55] Several BCA methodologies are commonly employed, many originally developed by the California Standard Practice Manual.[56] See Table 1 below for a summary of BCA tests.

Table 1: Types of Benefit Cost Analysis Tests[57]

BCA Test	Focus	Analyzed Cost and Benefits:
Total Resource Cost Test	Utility and Participating Customers	Utility and participating customers (may include quantifiable non-energy benefits)
Utility/Program Cost Test	Utility	Utility; Those affecting revenue requirement (only include environmental costs and benefits paid by the utility)

Participant Cost Test	Participating Customers	Participating customers
Ratepayer Impact Measure	Rate impacts to all customers	Those affecting utility rates (includes lost revenue)
Societal Cost Test	Society	Those experienced by society (includes non-monetary benefits)
Resource Value Test	Regulator	Utility plus those associated with achieving policy goals

BCA is a specific type of cost effectiveness test and is distinct from the least-cost, best fit framework, which some stakeholders promoted. ICF summarized the three main methodologies for evaluating grid expenditures. These are: (1) least-cost, best-fit, (2) BCA, and (3) opt-in (no regulatory justification).[58] Stakeholders acknowledged the less strenuous analysis required for the least-cost, best-fit framework, which minimizes costs for the desired function or outcome and does not monetize benefits.[59] It is commonly used for platform components and traditional expenditures such as replacing aging infrastructure and maintaining reliability.[60]

Though some stakeholders believe least-cost, best-fit should be used for all or only warranted applications, Staff supports Tim Woolf's recommendation to apply multiple cost-effectiveness tests. For applications where the least-cost, best-fit approach is used, Woolf recommends the Utility Cost test be conducted as a sensitivity to determine the impact on customer bills.[61] Specifically, he recommends two sensitivities be conducted, the Utility Cost test, which provides the best indication of impacts on customer bills, and the Resource Value Test[62] (also known as the Regulatory Test), which provides the best indication of achieving regulatory goals.

In U-18368, the Commission provided guidance regarding the type of BCA it wished to see. "…[I]f ratepayer funding is proposed as a funding source, the Commission expects a detailed cost-benefit analysis to be included, with any benefits specifically concentrated on those to ratepayers as utility customers, not as a part of society in general."[63] Though this order pertained to alternative fuel vehicle pilot programs, the language sheds light on the Commission's view of BCA. The Commission requested BCA tests that focus on utility customers (i.e. the Utility Cost test) and clearly did not want a BCA focused on societal impacts (i.e. the Societal Cost Test). As such, Staff recommends that the utilities be required to conduct at least one BCA sensitivity (the Utility Cost test) for all utility distribution investments using rate-payer funds. Should the Commission desire another BCA sensitivity, Staff recommends the Regulatory Test.

Consumers Energy comments: The Company disagrees with Staff's conclusion that a BCA should be required for "all utility distribution investments using ratepayer funds," for several reasons. First, the referenced presentation from Tim Woolf of Synapse Economics clearly supported the position that many distribution investments can be properly justified through a least-cost-best-fit approach, with the observation that this approach is recommended by the U.S. Department of Energy for expenditures necessary to maintain reliability among other purposes. While Mr. Woolf did suggest that utilities could use a utility cost test as a "check" on their least-cost-benefit-analysis, the Company would not interpret that suggestion to imply a requirement to perform a utility cost test for all distribution investments; such a *de facto* requirement for a utility cost test BCA in all cases would make the guidance regarding least-cost-best-fit obsolete.

Second, the referenced Commission Order in Case No. U-18368 is not applicable to something as broad as "all utility distribution investments." Case No. U-18368 concerned a proposal for a specific and discrete pilot program. In its Order, the Commission required that, if the utility was going to use ratepayer funding to execute a pilot, then the utility would need to show a detailed BCA for that pilot. This requirement makes sense when applied to a) a specific single investment that b) due to its experimental nature could have conceivably *not* been put into rate base. The Company argues that it is not appropriate to expand this narrow requirement in that case to apply to the entirety of a utility's distribution investments, which consist of hundreds or thousands of individual projects performing types of work that, by their nature, are understood to be put into rate base.

Third, a significant amount of the Company's "distribution investments using ratepayer funds" consist of emergent customer- or outage-driven work for which there is no meaningful alternative. In the Company's recently filed rate case in Case No. U-20697, well over 40% of the Company's distribution investments are in its emergent New Business, Demand Failures, and Asset Relocation programs.

Finally, during the distribution planning workgroup meetings in the second half of 2019, it was clear that each utility has its own particular means of assessing costs and benefits. Requiring any particular methodology to be use for *all* distribution investments would limit each utility's ability to make its own business decisions to manage its own system. As was discussed during the workgroup meetings, it is better to agree on definitions of costs and benefits while still allowing each utility flexibility over methodology.

In any case, Staff would need to specify a level of detail intended by the recommendation to require a BCA for *all* distribution investments. In its recently filed Case No. U-20697, the Company provided a list of over 1,300 planned distribution projects covering the 2021 calendar year. Out of those, the Company provided additional business case information for over 100 larger projects, consisting of hundreds of pages of documentation. No utility could reasonably provide even that level of analysis for five years of projects; specific projects are not known that far in advance, and even if a utility could provide a list of all its planned projects for the next five years with a thorough BCA of each project, the information would be exceptionally voluminous.

Though the Utility Cost test, Total Resource Cost test, and Societal Cost test are increasingly used for grid modernization, DERs, and other energy initiatives, these tests were developed for energy efficiency applications.[64] There are notable differences in the benefits and costs associated with energy efficiency and DER applications like distributed generation and energy storage, which may increasingly enter the distribution system. The National Standard Practice Manual (NSPM), developed to update and replace the California Standard Practice Manual,[65] describes the benefit and cost differences across four categories: energy efficiency, demand response, distributed generation, and distributed storage. Though the "NSPM should serve as a foundation for assessing the cost-effectiveness of DERS", there are DER specific considerations that are "beyond the scope of this NSPM, [that] should be addressed by each jurisdiction as they develop cost-effectiveness practices for DER."[66] Currently, a NSPM for BCA of DER is under development for release in June 2020.[67] Commission guidance regarding BCA is needed at this point. However, future information on the best approaches to BCA, such as the forthcoming NSPM guide, may help inform future revisions to Commission BCA guidance.

The discount rate can significantly impact BCA findings. By using a discount rate, benefits and costs occurring in different time periods can be compared by expressing their value in present terms."[68] 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."[69] For example, the present value of a program benefit of $5 billion occurring 30 years in the future can vary drastically based on the discount rate employed 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."[70]

Though the utility weighted average cost of capital (WACC) is widely used in BCA,[71] including in Michigan, other discount rates can and should be considered.[72,73] The discount rate reflects a time preference[74,75] and "should be based on the regulatory perspective, which may be different from the utility investor perspective."[76] "The regulatory perspective should account for many factors, [such as]: low-cost, safe, reliable service; intergenerational equity; [and] other regulatory policy goals."[77] Because of these considerations, a regulatory perspective leads to a lower discount rate since lower discount rate values future benefits more highly.[78] For example, investor-owned utility 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%.[79]

Discount rate sensitivities can be conducted to see the impact of different discount rates. Woolf recommends using the WACC as a high discount rate sensitivity and a low-risk or societal discount rate as the low discount rate sensitivity.[80] Given that distribution planning and grid modernization investments focus on long-term transformation of the electric system and not necessarily immediate benefits, a discount rate lower than the WACC is warranted. The use of the same discount rate across utility resource cost-effectiveness analyses make results comparable and allows more direct comparison across resource types.[81] As such, Commission definition of the discount rate sensitivities to be used is necessary to ensure the regulatory goals for Michigan are reflected when making reasonable and prudent utility investments. Staff recommends that the Commission select a low-risk discount rate anywhere between 0-3% to be required as a discount rate sensitivity for all required BCAs.

How investments are examined within BCA can also impact findings. The analysis of an individual utility investment, such as a platform, versus bundled investments, such as a platform with applications, may alter the cost effectiveness findings of the BCA. In some cases, the platform alone is not cost-effective but once examined with other modular applications that it enables, the total bundled cost may be cost-effective.[82] It is important to analyze distribution platforms not only as individual platform investments, but also bundled with enabled modular applications.

The inclusion of non-monetized impacts in BCA is challenging, but not insurmountable. Consumers Energy, DTE, and I&M all acknowledged the difficulties they face when trying to value non-monetized impacts such as the value of a life. As such, non-monetized impacts are typically largely excluded from the utilities' cost-effectiveness evaluations. In a review of twenty-one recent grid modernization plans, Lawrence Berkeley National Lab found three areas where all plans failed to provide monetized benefits. Non-monetized areas were safety, system planning, and customer satisfaction.[83]

Though stakeholders agreed with the inherent challenges of valuing certain metrics, they also emphasized the need to include non-monetized impacts when analyzing project benefits and costs. Some critics of BCA object to putting a price on things, believing that it degrades them, "as if the value of life could or should be monetized."[84] However, the purpose of BCA "is not to monetize values, but rather to provide a ranking of choices expressed in monetary terms…Market values…need not represent 'mere commodities' but instead represent choices."[85] This distinction allows metrics related to the non-monetized impacts that have monetary value to be used as proxies.

In the stakeholder discussions, the value of a human life was an example that presented challenges to all utilities, as their infrastructure has safety implications. Though it is impossible to place a monetary value on a human life, there are monetized metrics related to human life that may serve as proxies in a BCA. One example is median lifetime earnings values for which there is ample data. The BCA is a tool to rank possible solutions based on the present value of each solution's costs and benefits. Though imperfect, using proxies for previously non-monetized areas in BCA allow important areas such as safety and system planning to be factored into the selection of distribution projects in a more consistent and quantitative manner. Every effort should be made to define benefits or proxies so they can be monetized. However, if this is too difficult, efforts should still be made to quantify the non-monetized benefits through a point system to assign value to non-monetized benefits, a weighting system to assign priorities to non-monetized benefits, or multi-attribute decision-making techniques.[86]

The Commission expressed its interest in non-monetized benefits of utility investments in the past. Regarding alternative fuel related pilots, the Commission said it was considering issues such as load management, safe installation, future program design, and inclusion of new technology.[87] Though the Commission's interest in non-monetized benefits like safety and system planning have been expressed, the Commission has not ranked the non-monetized benefits by order of importance. Such a ranking may be helpful to utilities that opt to quantify non-monetized benefits through ranking or weighting systems.

Staff recommends BCA analyses for utility distribution investments using ratepayer funds be included in the rate case to allow an iterative review and improvement of BCA requirements in Michigan. In Consumers Energy Company 2016-2017 rate case U-17990, the Commission declined to approve detailed BCA in the next rate case as it found the information duplicative of the Company's BCA requirement in the five-year distribution plan filing.[88] However, "rate cases are the mechanism to validate the prudency of investment portfolios."[89] By including the BCA with all assumptions detailed in rate cases, utilities, stakeholders, Staff, and the Commission can review the prudency of utility investments and review the conducted BCAs. Since "[l]eading states still continue to evolve their BCA frameworks,"[90] Michigan likely will be no different. It will need to evolve its BCA guidance over time. The iterative review of the employed BCAs in rate cases provides the Commission opportunity to improve and tailor its BCA guidance given up-to-date best practices and stakeholder input at a more frequent interval than every five years. Given the importance of BCA in the selection and implementation of electric infrastructure, the more rapidly the Commission can improve BCA guidance to be impactful for Michigan, the more rapidly Michigan's electrical system can modernize to meet regulatory goals. Lastly, the energy landscape is rapidly changing with emerging technologies and changing prices. A BCA conducted with prices and technologies from even a few years prior may be dated and inaccurate. BCA analyses of investments before such investments are made are necessary to provide the considered and deliberate investment choices needed in modernizing Michigan's electrical system.

Consumers Energy comments: Given that the purpose of this collaborative workgroup process has been to provide guidance regarding five-year distribution plans, the Company submits that changes to rate case requirements are outside the scope of the workgroup's purpose. Notwithstanding that concern, as noted above, in its recently filed Case No. U-20697, the Company did provide detailed business case information for larger distribution projects, which the Company believes will help Staff and intervenors better assess the prudence of the Company's planned investments. If the Commission creates any future requirements about providing BCAs for distribution investments in rate cases, then a reasonable level of required detail must be set. In Case No. U-20697, the Company listed over 1,300 individual distribution projects, and provided detailed business case information for over 100 larger ones, and that level of detail alone resulted in hundreds of pages of additional documentation. It would be unduly burdensome to require that level of analysis for every proposed project, and would produce a voluminous amount of documentation to include in a filing. Furthermore, over 40% of the Company's proposed 2021 distribution investment in Case No. U-20697 is dedicated to connecting new customers (New Business), relocating assets in response to customer needs (Asset Relocations), and responding to outages (Demand Failures). For this spending, there are no projects to analyze, and no real option to not do the work.

If the Commission ultimately does require more defined BCAs in rate cases, it should set a project cost threshold of $500,000 before a BCA is needed, or else it should allow utility to perform higher-level BCAs, for example for broader investment programs.

Notwithstanding any future changes to rate case requirements, the Company asserts that a rate case is the only venue in which project-level BCAs *could* be presented. Over the five-year horizon of a distribution plan, most specific projects will not yet be known. In a distribution plan, a utility could a) discuss BCA methodology that informs project selection for future years and/or b) present a high-level BCA for spending programs, showing impacts to costs along with delivered benefits for each given program.

In addition to the required BCA sensitivities, Staff recommends the utilities provide the range of options investigated, each of their BCA findings, and the final selected option. It is not enough to examine only the business-as-usual scenario and provide the BCA. The selected option must be compared with other possible solutions. Given that utilities, stakeholders, and the Commission are all learning in regard to grid modernization, one of the solutions should be a "grid modernization" scenario where it focuses on the "flexibility needed to adapt to the whole range of new technologies in the grid".[91]

Consumers Energy comments: For many projects, there is no meaningful alternative to the project other than to simply do nothing. For example, the Company invests to replace deteriorated poles on its LVD circuits; currently, the only choice is to a) replace a pole or b) not replace it and continue to use the deteriorated asset. As noted above, if a BCA is required for every distribution project, the result would be voluminous, even more so if each BCA was required to consider multiple alternatives when few alternatives actually exist.

The Company submits that what Staff contemplates with a grid modernization "scenario" is unclear. As discussed in the workgroups, the Company has a detailed multi-year grid modernization plan that includes a variety of investments in new technologies and capabilities, and the Company will present a BCA of this grid modernization plan, as it outlined on multiple occasions during workgroup meetings. The Company considers this grid modernization plan to be a course of action that 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, assuming "grid modernization" is defined to refer to the investment in new technologies and capabilities. Many traditional distribution investments do not even have a theoretical grid modernization alternative; for other projects, grid modernization-style solutions like NWAs may still be nascent and clearly not yet feasible to address the issue at hand.

Utilities should be required to report the benefits and costs after project approval and implementation in rate cases to monitor performance over time. In the end, it is not the projected benefits and costs that matter, but the actual benefits arising from the implemented project in a timely manner. As such, it is imperative that utilities provide data on benefits and costs after project implementation consistent with the original BCA methodology used for project justification to monitor performance over time. The touted benefits that convinced regulators of reasonable and prudent spending can only be confirmed through actual data after project implementation

Consumers Energy comments: Tracking and reporting all actual costs and benefits of all distribution investments would represent a significant new regulatory requirement, and further discussion would be needed regarding what this would look like in practice. Furthermore, tracking "actual" benefits can be difficult and error-prone, because it is difficult to truly prove cause and effect. For example, outages on a circuit could fall following the completion of a project, but that improvement could be partially due to fewer weather challenges. Conversely, the performance of a circuit could worsen following a project due to some other unforeseen challenge. In either case, separating what actually caused an improvement or a decline can be difficult. Therefore, the Company submits that this should not be a requirement.

As Consumers Energy noted, "Michigan's actions should be considered and deliberate as the State has a great opportunity to modernize the electric distribution grid and move towards greater integration with electric supply, but innovation should be well-thought out, reasonable, and prudent."[92] To proceed with grid modernization in Michigan absent Commission guidance on BCA will allow Michigan utility system changes to develop in an ad hoc fashion, with each utility deciding its own methods of benefit cost evaluation which some stakeholders critiqued as overly qualitative and opaque. Given the current lack of Commission guidance on the BCA methodologies to employ, Michigan utilities have utilized disparate methodologies and ranking systems, some of which are developed in-house.[93, 94, 95]

For modernization of the electric grid to move forward in a thoughtful, reasonable, and prudent method, consistent BCA sensitivities should be required for utility investments, one that is guided by an overarching vision of a modernized Michigan electric grid that cannot be provided by utilities and their investors alone. As such, it is imperative the Commission provide guidance on BCA methods and discount rate sensitivities to better ensure that Michigan electric grid investments proceed in a thoughtful, reasonable, and prudent fashion that meets regulatory goals.

Staff recommendation:

- BCA sensitivities be required for all distribution investments using rate-payer funds. If the Commission elects to require only one BCA sensitivity, Staff recommends the Utility Cost test. If the Commission elects to require more than one sensitivity, Staff also recommends the Regulatory Test (also known as the Resource Value Test),
- BCA analyses be conducted for platform components individually and bundled with the modular applications that it enables,
- At least one discount rate sensitivity for all conducted BCAs be required where a low-risk discount rate ranging from 0-3% is selected by the Commission to reflect the regulatory viewpoint,
- 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.
- The Commission clearly relay its ranking of non-monetized benefits, including safety and system planning, so that utilities can use this ranking, if needed, when examining non-monetized benefits in BCAs.
- Require a "grid modernization" scenario be analyzed for all distribution investments,
- Require reporting of BCAs for distribution planning related utility investments in rate cases with clear definition of all BCA assumptions, and
- Report actual investment benefits and costs in rate cases after project implementation consistent with the original BCA methodology used for project justification to monitor performance over time.

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 as well as the discussion are provided with this framing. Though some of the considerations pertain to system HCA, Staff recommendations presented here pertain only to the HCA pilots directed by the Commission. Recommendations regarding system-wide HCA cannot be made at this time and will depend on the pilot findings.

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.

Though an HCA use-case can be recommended, a recommendation on how to 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 Energy, 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.[96] 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 Energy's 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.[97] 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 the use-case for hosting capacity analyses. However, 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 directed to replace aging infrastructure to maintain safety and reliability. Currently 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.[98] 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%. 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. For the pilots, utilities should select locations that can maximize usage of the HCA data where a larger number of potential DER's may be integrated.

While customers can interconnect DER without participating in the DR program, it may not be economic for most residential customers. In lieu of these points, 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. As such, Staff recommends the utilities 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 to provide detailed technical information about a point of interconnection,[99] if such reports are ever required, 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 is likely to determine 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 option for utilities to incrementally increase the amount of publicly available hosting capacity information at no additional cost to customers.

<u>Staff recommendation:</u> Staff recommends that the following be adopted for the HCA pilots requested by the Commission:

- Adopt a the "interconnection of DER" as the use-case for HCA
- Adopt a phased implementation approach for the HCA pilots where phased implementation ranges from a base-level approach like a zonal go/no-go map to a more detailed map with feeder voltage levels information. This will 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.

- 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.

Consumers Energy comments: The Company appreciates Staff's recognition that full-system HCAs are not needed immediately, and that a better use of utility resources is to focus on more limited pilots. The Company also appreciates Staff's recognition that each utility's system is different, and that HCA pilots may therefore be different. In their final report, Staff should 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.

The Company requests clarification on Staff's recommendation that a phase-in approach "ranges from a base-level approach like a zonal go/no-go map to a more detailed map with feeder voltage levels information," with the clarification making it clearer what Staff anticipates in a phase-in approach. The Company's understanding is that a utility pilot should either a) provide high-level hosting capacity information about a broader part of its system or b) more detailed hosting capacity information about a narrower part of its system. The Company submits that Staff should accept this interpretation.

The Company also requests Staff clarification regarding expected implementation timelines of phase-in pilots: should utilities be executing their pilots in 2020 and demonstrating results in their 2021 distribution plan filings, or should they be designing pilots and presenting their designs in their 2021 filings, with execution to follow? The Company notes that if new expenses must be incurred to conduct pilots, execution may be reliant on approval of costs in a rate case, and the Company should, in such a case, be allowed to outline a pilot for future execution.

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. 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 NWA.[100] See p. 8 of this report.

Once these questions are answered, a focus on the perimeters 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". DTE Energy 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.

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.

Consumers Energy comments: The Company is generally in agreement with Staff's recommendations related to NWAs. The Company respectfully disagrees with Staff's inclusion of "new business" in this discussion. The Company has a distribution capital investment program called "New Business," with a significant amount of investment in that program dedicated to the interconnection of new customers, which could not be addressed through NWAs.

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, Ryan Katofsky from Advanced Energy Economy (AEE) 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 (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"[101] where they explore adjustments to cost of service regulation as utilities experience a more service-oriented future. Slide 6 of the presentation[102] 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[103] 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

On September 11, 2019, the Commission issued the Statewide Energy Assessment (SEA) report[104] and corresponding order that accepted and adopted the report.[105] 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 integrated resource plans
- 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 discussion presentations coupled reliability and resiliency together.[106] 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.[107] A "reliable" grid is viewed as a grid that is resistant to a disruptive event. Reliability can be measured through specific, standardized 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,[108] U-16065,[109] and U-16066[110]). 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.[111]

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.[112] 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.[113] 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.[114] 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.

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.[115] This will be further explored by the MI Power Grid Security and Reliability Standards Workgroup,[116] 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

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

The Role of Energy Efficiency with Distribution Planning

The concept of energy efficiency as a resource is relevant to the distribution level. Energy efficiency may delay or avoid the need for new distribution infrastructure, and also reduce demand and energy needs at individual homes and businesses. The MI Power Grid Interconnection Workgroup will likely be developing a definition of DER that may or may not include energy efficiency. The most important point, however, is that energy efficiency becomes a key consideration for electric distribution planning because of the DER/energy efficiency nexus, and the value that energy efficiency as a resource brings to reducing load – both from broad scale 'baseload' types of energy efficiency as well as from enhanced energy efficiency measures targeted at specific time periods and/or geographic locations. The role of energy efficiency as a resource is clearly a distribution planning consideration.

Staff recommendation: The Commission direct the utilities to include an assessment of energy efficiency resource options in their forthcoming electric distribution plans.

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 HCA's 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' second slide 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.

<u>Staff recommendation:</u> 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.

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 perimeters 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. 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 Michigan Infrastructure Council, 3) the role of energy efficiency 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[117] that the next round of electric distribution plans for Consumers Energy Company and DTE Electric Company will be June 30, 2021 (the Commission had previously directed Indiana Michigan Power Company 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 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 a two-year refresh schedule so that the plans remained updated and relevant to changing technologies and priorities.

Consumers Energy comments: In delaying the filing date of the Company's next distribution plan to June 2021, the Commission acted to synchronize the Company's distribution plan filing with its next integrated resource plan. The Company believes there is great value in continuing to further align distribution planning and resource planning. Since the Company expects to continue filing integrated resource plans on a minimum three-year cycle, the Company believes that distribution plans should also be filed every three years, on a schedule that better facilitates alignment of the two plans.

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.

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