S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to review the response of **ALPENA POWER COMPANY, CONSUMERS ENERGY COMPANY, DTE ELECTRIC COMPANY, INDIANA MICHIGAN POWER COMPANY, NORTHERN STATES POWER COMPANY, UPPER MICHIGAN ENERGY RESOURCES CORPORATION, AND UPPER PENINSULA POWER COMPANY** to recent storm damage in their service territories.	)	Case No. U-21122
In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters.	)	Case No. U-20147
In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to integrated resource and distribution plans.	)	Case No. U-20633

At the March 3, 2022 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Tremaine L. Phillips, Commissioner
Hon. Katherine L. Peretick, Commissioner

ORDER

I. BACKGROUND

Beginning on August 10, 2021, a series of severe thunderstorms hit Michigan's Upper and Lower Peninsulas (August 2021 storms). Wind gusts reached over 70 miles per hour (mph), causing widespread destruction to trees and utility poles. As a result, almost 1 million Michigan utility customers lost electric service. An estimated 372,000 customers of Consumers Energy Company (Consumers), 500,000 customers of DTE Electric Company (DTE Electric), and 20,000 customers of Indiana Michigan Power Company (I&M) lost electric power to their homes and businesses for varying lengths of time. Several other utilities reported thousands of customers with outages.[1] Reports indicate that Consumers and DTE Electric had approximately 8,000 and 3,100 downed wire calls, respectively, while I&M had approximately 340 downed wire calls. Outages lasted anywhere from a few hours to more than one week.

On August 20, 2021, Governor Gretchen Whitmer issued a letter to the Commission, calling on the Commission to:

- Prevent recovery of outage credit costs and other relief efforts in upcoming utility rate cases;
- Expedite the promulgation of updated technical standards for electricity service and utility service quality rules as much as possible;
- Consider requiring utilities to increase emergency preparedness planning around extreme weather, to add reporting requirements that add transparency around their efforts to improve system reliability, and to carefully review the recently filed utility distribution plans to gauge whether the proposed actions and investments are sufficient; and

[1] More than 72,000 customers of Great Lakes Energy Cooperative lost power, as well as about 30,000 customers spread over five other electric cooperatives.

- Convene a technical conference on emergency preparedness, planning, and storm response.[2]

As a result, on August 25, 2021, the Commission issued an order in Case Nos. U-21122 *et al*. directing investor-owned utilities (IOUs) regulated by the Commission to file a report and soliciting written comments from utilities and other stakeholders (August 25 order). As noted in the August 25 order, "[t]he Commission's focus is on the issues of reliability, resilience, and readiness for these extreme events." August 25 order, p. 3. The Commission reiterates that "[r]atepayers have a right to expect the utilities to anticipate extreme weather events, to provide a hardened grid that can withstand extreme weather, and to be prepared to restore power expediently when the grid fails." *Id*. The Commission is committed to implementing improvements in these areas.

In the August 25 order, the Commission also stated:

> Weather-related events are not uncommon in Michigan, and the August 2021 storms cannot be dismissed as unique or unlikely to ever reoccur. In fact, the pace of climate change dictates that such events will likely only become more frequent and planning must be responsive to this reality. As part of responding to the effects of climate change on the incidence of extreme weather, the Commission has ramped up efforts to examine the reliability and resilience of the distribution system and the impacts of aging infrastructure, and to implement the changes that are required to reduce the potential for death and injury and the possibility of larger and lengthier power outages.

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[2] The letter is available at: https://content.govdelivery.com/attachments/MIEOG/2021/08/20/file_attachments/1912083/Utility%20Letter_Outages_MPSC.pdf (accessed February 23, 2022). At the same time, Governor Whitmer issued a letter to the Presidents of I&M and of the parent companies of Consumers and DTE Electric, calling on these three utilities to automatically credit customers who experienced outages while also expanding the amount of credits paid, and to announce additional investments and redirect existing resources to improve reliability through tree trimming and grid hardening without financing these investments through ratepayers. *See*, https://content.govdelivery.com/attachments/MIEOG/2021/08/20/file_attachments/1912081/Utility%20Outage%20Letter%20to%20CEOs.pdf (accessed February 23, 2022).

Id., p. 4. The Commission also provided an overview of several of its efforts to address these issues including prior investigations into weather-related events and service quality issues, the review of distribution planning as part of the 2019 Statewide Energy Assessment (SEA), the launch of the MI Power Grid effort in October 2019, which includes an examination of grid optimization, various workgroups and rulemakings, and efforts to update tree trimming and vegetation management standards. *See*, August 25 order, pp. 3-7.

Notwithstanding those efforts, the Commission acknowledged that, despite the efforts to date, "the August 2021 storms show that the Commission and the utilities must do more and must do it faster" and that "the Commission needs more data on what is being done, more transparency around planning, and more engagement in how best to prepare and harden Michigan's distribution system to absorb the impact of extreme weather on a regular basis." *Id*., p. 7. Therefore, in the August 25 order, the Commission directed IOUs regulated by the Commission to file a report in Case No. U-21122 including the following information:

1. A summary of the utility's ongoing vegetation management and grid hardening efforts, including miles trimmed, dollars spent, and all other metrics and milestones included in the utility's annual reporting requirements.

2. Details on how current efforts outlined above have contributed to reliability performance, including – to the extent data is available – a comparison of like circuits that have been recently trimmed/hardened with those that have not. Information should include changes, if any, to System Average Interruption Duration Index (SAIDI), system average interruption frequency index (SAIFI), and customer average interruption duration index (CAIDI) as a result of those efforts.

3. A ranked breakdown of the top 10% worst performing circuits in the year 2021 to date in terms of frequency of outages, and the top 10% worst performing circuits in the year 2021 to date in terms of duration of outages, and provide a map illustrating where those circuits are located within the service territory. Include any planned investments in reliability/resiliency on the circuits and note whether these circuits are primarily back lot-constructed overhead, front lot-constructed overhead, or underground circuits. In

providing this information, utilities should include the name of the circuit, as well as the zip code(s) and name(s) of the municipality covered by the circuit

4. Using data from the beginning of 2020 to the present, a map of the top ten zip codes with both the highest and lowest SAIFI, and the top ten zip codes where most future tree trimming and other reliability/resiliency improvement efforts are planned.

5. A summary of efforts contained in currently filed distribution plans to address outages and system reliability. For Consumers and DTE Electric, this summary shall include information on metrics and financial incentives or penalties as required in the utility's most recent rate case.

6. Plans and/or actions taken following the August 2021 storms addressing outage credits, including plans and/or actions to make the credits automatic, expand the outage credit amounts and/or expand eligibility, as well as any other compensation or customer-focused efforts utilized during the restoration period.

7. A summary of restoration efforts during the August 2021 storms, including the total cost of the outage events (for example, materials costs, overtime pay, mutual assistance, community support, advertisements, etc.), details of customer communications efforts, and opportunities for improvement in storm response and customer communication. This information should include a description of efforts made to proactively communicate with and support vulnerable customers, if any.

Id., pp. 8-9.

To assist the Commission's understanding of the costs and benefits associated with moving established overhead electrical lines underground, the Commission also directed the IOUs to include the following in the reports:

1. A breakdown of the total cost to move a typical overhead back lot-constructed line and overhead front lot-constructed line underground, including a high, low, and average cost estimate depending on the varying circumstances encountered.

2. The difference in cost of maintenance of an overhead back lot, overhead front lot, and underground electric line, on an average annual basis.

3. The average measured reliability of an underground line compared to a comparable back lot and front lot overhead electrical line.

4. A comparison of the average rate and severity of safety incidents that occur both to the public as well as to utility workers associated with underground lines, overhead front lot lines, and overhead back lot lines.

Id., p. 9. Recognizing that some of this information may already exist in other places, the Commission found that assembling this information in one filing will further the important goals around transparency for the Commission, the Commission Staff (Staff), stakeholders, and particularly for utility customers.

In response to this directive, on October 1, 2021, Consumers, DTE Electric, and I&M filed their respective reports. On October 29, 2021, Upper Peninsula Power Company (UPPCo) filed its report, and on November 1, 2021, Alpena Power Company (Alpena); Northern States Power Company, a Wisconsin corporation (NSP-W); and Upper Michigan Energy Resources Corporation (UMERC) each filed a report. The individual reports are addressed more fully below.

Noting its concern that the planning processes used by both utilities and the Commission rely heavily on historical data and may not be sufficient in an era of increasingly severe weather exacerbated by climate change, the Commission also requested utilities and other stakeholders to provide comments on whether the planning processes based on historical data are sufficiently robust to plan for the realities of a future that may look very different from what has been historically experienced. In response, the Commission received numerous comments, which are more fully discussed below.

The Commission also announced in the August 25 order that it would be hosting a one-day Technical Conference on Emergency Preparedness, Distribution Reliability, and Storm Response (Technical Conference) to be held in person on October 22, 2021.

On September 24, 2021, the Commission issued an order amending its in-person plans for the Technical Conference to a virtual event that would allow participation through video/teleconference only (September 24 order). The September 24 order also announced that October 22, 2021, would be Day 1 of the Technical Conference, and that a date for Day 2 of the Technical Conference was forthcoming. On October 4, 2021, the Commission issued a notice including how to participate in Day 1 of the Technical Conference and announcing that Day 2 of the Technical Conference would take place on November 5, 2021. Subsequently, the Commission issued notices of the agendas for each day of the Technical Conference. The Commission also developed a webpage for information pertaining to the Technical Conference, including links to recordings of both sessions.[3]

On October 22, 2021, the Commission convened Day 1 of the Technical Conference. Day 1 of the Technical Conference covered topics ranging from power outage data and reliability in Michigan to the future of electric reliability and resilience. Day 1 panel discussions included a panel of representatives from the utility companies discussing the current status of the Michigan utilities and a panel relating to customer and community-based experiences. On November 5, 2021, Day 2 of the Technical Conference was held and included topics such as whether Michigan is meeting existing standards, modeling the future grid, performance-based regulation (PBR), and addressing reliability and storm response. An additional panel discussion was held on Day 2 regarding new technologies and grid modernization.

II. UTILITY REPORTS

A. Consumers Energy Company's Report

On October 1, 2021, Consumers filed its report responding to the August 25 order (Consumers' report).

[3] *See*, https://www.michigan.gov/mpsc/commission/workgroups/mpsc-technical-conference-on-emergency-preparedness-distribution-reliability-and-storm-response.

1. Summary of the Utility's Ongoing Vegetation Management and Grid Hardening Efforts

Consumers indicates that it has experienced an increased amount of observed wind gusts in its territory which have caused "a corresponding increase in the amount of electrical outage incidents." Consumers' report, p. 2. Consumers avers that the increased incident rate, even at comparable wind levels, demonstrates the deterioration of its system and, around 2017, the company started increasing its investments in the reliability spending program. The company states that even though wind gusts have increased in frequency and severity over the past 10 years, the trends indicate that "the Company's increased investment in its Reliability program has led to a declining trend for all-in SAIDI" and that its "historical reliability investment has resulted in an overall reduced duration of storm outage time (SAIDI) despite an increasing number of outage incidents." *Id*., pp. 2-3.

Consumers further states that its grid hardening efforts are spread across many capital investment areas and that "[m]ost capital investments in the distribution system have some effect of hardening the grid, because they replace old assets with new components that are built to the most up-to-date standards." *Id*., p. 3. The company notes that its proactive efforts on grid hardening include a few key capital investment areas in the Low Voltage Distribution (LVD) system and the High Voltage Distribution (HVD) system. With respect to the LVD system, Consumers states that this includes the "LVD Lines Reliability sub-program, including the targeted circuit improvements, pole replacements, and circuit exit enhancement investments categories; the LVD Lines Repetitive Outage sub-program; and the LVD Lines Rehabilitation sub-program, particularly the security assessment repairs investment category," and provides a summary of its investments in these areas in Figure 2. *Id*., pp. 3-4. For the HVD system, the company indicates that its "specific grid hardening efforts include the HVD Lines Reliability, HVD Lines Rehabilitation, HVD Substation Reliability, HVD Substations Rehabilitation, LVD

Substation Reliability, and LVD Substations Rehabilitation sub-programs," and Consumers included a summary of the investments in Figure 3. *Id*., pp. 5-6.

Consumers indicates that, over the past five years, it "has focused on clearing more miles of the LVD system of trees and brush while maintaining its clearing cycle on the HVD system, completing the mileage authorized in rate cases each year to demonstrate its commitment to improving system reliability to its customers." *Id*., p. 7. Citing its recent general electric rate case proceedings, the company indicates the increases in approved line clearing expenses are part of its five-year plan to reduce the LVD clearing cycle from a 14-year cycle to a seven-year clearing cycle and "[m]oving the LVD system from its current state to an effective seven-year cycle will greatly increase reliability to customers by reducing the frequency of outages caused by weather events." *Id*. Consumers also provides Figure 4 which "shows the history of line clearing expense and miles cleared since 2018 and related metrics." *Id*. In addition, the company indicates that its clearing specifications "are consistent with other utilities' clearing specifications across the Great Lakes and Mid-Atlantic regions of the country." *Id*., p. 8.

2. How Current Efforts Have Contributed to Reliability Performance

Consumers states that it compares how assets perform after receiving an investment versus how they performed before the investment to measure the effectiveness of how hardening investments contribute to reliability in its LVD lines system. The company indicates that:

> LVD circuits are divided into multiple protective zones, which are portions of the primary circuit between two protective devices, such as fuses and reclosers. LVD circuits leave LVD substations and branch out in multiple directions, meaning customers on one part of the circuit may experience significantly different reliability compared to customers on another part. The Company approaches poorly performing circuits by studying the circuit at a zonal level and determining which zones are experiencing the majority of the incidents on the circuit. The Company then targets these zones for improvements. By approaching LVD investment on a zonal basis, the Company can more surgically target its investments, focusing on where the greatest needs are from a reliability benefit perspective.

Id., pp. 8-9. Consumers notes that, since investments are made on a zonal basis, it also measures reliability benefits on a zonal basis and summarizes the benefits from investments in Figure 5. *See*, *id*., p. 9. The company states that, "after zones receive investment, the number of outages in those zones decreases dramatically in the following years." *Id*. Consumers indicates that it can be difficult to quantify impacts to SAIDI, SAIFI, and CAIDI because they are systemwide measurements of reliability, but avers that its "data clearly shows that investments in the system deliver clear local benefits to customers, and as the Company continues to increase its investment levels to cover more of the system, then systemwide benefits will accumulate." *Id*.

With regard to its HVD lines system, Consumers states that it "has assessed the performance of lines that have been recently hardened against a sample of those that have not" and has reflected its analysis in Figure 6. *Id*., p. 10. The company avers that the data reflects that "after an HVD line is rebuilt or rehabilitated, it can be expected to experience few, if any, outages in subsequent years, while comparable lines that have not been rebuilt or rehabilitated continue to experience outages at a much higher frequency." *Id*., p. 11.

Consumers states that, while substations experience failures needing to be addressed, it did not include substation investments in its before and after analysis because substation outages generally do not produce widespread customer interruptions. The company indicates that its 2021 Electric Distribution Infrastructure Investment Plan (EDIIP) "explains how each LVD voltage class responds differently to tree contact, and why each voltage class should be cleared on a different cycle (as explained in the EDIIP, averaging these class clearing cycles results in the 'effective' seven-year cycle for the entire LVD system)." *Id*. Consumers evaluates the impact of LVD line clearing by looking at "the number of tree-caused faults per mile on the circuit for three years prior to clearing and 10 years after clearing. Because each voltage class is different in this regard, the

Company has aggregated data for 8.32-kV [kilovolt] circuits, 12.47-kV circuits, and 24.9-kV circuits." *Id*.; *see also*, *id*., pp. 12-13 (Figures 7-9). Consumers avers that the data demonstrates "that line performance improves following line clearing and stays improved for several years thereafter, before declining again as it gets closer to the time when the next clearing cycle is needed." *Id*., p. 13.

3. Ranked Breakdown of the Top 10% Worst Performing Circuits in 2021 to Date

Consumers states that 10% of its LVD system is equal to 203 circuits. The company provides a detailed table at pages 14-86 of its report reflecting its "10% worst performing LVD circuits for SAIFI (i.e. 'in terms of frequency of outages') and the 10% worst performing LVD circuits for CAIDI (i.e. 'in terms of duration of outages')." *Id*., p. 14. Consumers notes that its data includes major event days (MEDs) "and the interruptions may have been caused by outages on the LVD, HVD, Substations, or Transmission system" but that it "does not have the data to indicate if the circuits are primarily back lot-constructed overhead or front lot-constructed overhead." *Id*. Consumers also provides maps (Figures 10 and 11) reflecting the circuits listed in the table for both SAIFI and CAIDI performance. *Id*., pp. 86-88.

4. Maps of the Top Ten Zip Codes with both the Highest and Lowest System Average Interruption Frequency Index, and the Top Ten Zip Codes Where the Most Future Tree Trimming and Other Reliability and Resiliency Improvement Efforts are Planned

Consumers indicates that its Figure 12 on page 89 of its report "represents the 10 ZIP codes with the lowest, or best, performing SAIFI ('top') and the 10 ZIP codes with the highest, or worst, performing SAIFI ('bottom')" and that it selected zip codes which "include at least 100 customers to filter out potential outliers." *Id*., p. 88. Figures 13 and 14 list the zip codes, location, and SAIFI included in Figure 12. *See*, *id*., pp. 89-90.

Consumers also provides a map (Figure 15) documenting the 10 zip codes with the most planned LVD lines, LVD forestry, and substation improvements planned from September 2021 through the end of 2022, and that Figure 16 lists the zip codes, location, and total spending. *See*, *id*., pp. 91-92.

The company indicates that it has identified levels of HVD investment by county rather than zip code because "[i]nvestments in HVD lines and substations are not easily represented by ZIP code." *Id*., p. 92. In Figure 17, the company reflects the levels of HVD investment for large HVD substation and HVD line projects planned from September 2021 through the end of 2022, and that the specific projects are shown in the maps contained in Figures 18 to 23. *Id*., pp. 92-99.

5. A Summary of Efforts Contained in Currently Filed Distribution Plans to Address Outages and System Reliability

Consumers indicates that many of its recent filings with the Commission have listed five objectives for the company's electric distribution system. The company notes that all five objectives inform distribution planning and investments, and the objectives are:

> • **Safety and Security:** Improving overall safety and security for customers and employees;
> • **Reliability:** Improving system reliability under normal operating conditions and resiliency under extreme conditions;
> • **System Cost:** Delivering the objectives above at an optimal, long-term system cost for all customers;
> • **Sustainability:** Continuing to look for opportunities to explore sustainable options and reduce system waste; and
> • **Control:** Providing customers with the data, technology, and tools to take greater control over their energy supply and consumption.

Id., p. 100 (emphasis in original).

Consumers indicates that, since its first EDIIP filing in 2018, it has increased the investments in its electric distribution system, with an emphasis on reliability improvements, and has proposed to continue increasing investments over the next five years in the 2021 EDIIP. The company states that its 2021 EDIIP "is a result of a planning process designed to prioritize and sequence investments to meet system needs and deliver benefits to customers" and was developed using "a multi-faceted approach to identifying and prioritizing projects to maximize customer benefits and ensure that customer benefits are equitable throughout Michigan." *Id*. Consumers notes that it has continued investing in grid modernization and has developed a Grid Modernization Roadmap, with a longer-term vision of the grid. The company avers that its "longer-term vision is increasingly important as the Company's Integrated Resource Plan process has, since 2018, pointed to a future with considerably more decentralized energy resources, such as solar, as part of the Company's electric supply mix." *Id*., p. 101. Consumers states that is also developing other grid-related capabilities.

The company indicates that it plans to invest "between $708 million and $865 million per year in capital projects on the electric distribution system" and "plans Operating and Maintenance ('O&M') spending between $221 million and $308 million per year" from 2021 to 2025 and summarizes the planned spending in Figure 24. *Id*., pp. 101-102.

Consumers indicates that its 2021 EDIIP has metrics, which are included in Figure 25, to track its distribution performance against the five objectives and that it "regularly tracks and reports performance against [Commission]-defined performance standards for electric power reliability and service quality through annual filings and through periodic updates with [Commission] Staff." *Id*., pp. 102-104. The company further notes that the 2021 EDIIP includes a proposal for PBR which focuses the reliability metrics of "on two reliability metrics: SAIDI and CEMI-5 (Customers Experiencing Multiple Interruptions ('CEMI'))." *Id*., p. 104. Consumers avers that PBR structures must be designed carefully and "should not be imposed in haste, but intentionally and incrementally." *Id*., p. 105. The company notes that its proposal for these metrics outlines a phased-in approach, with PBR incentives and disincentives as depicted in Figure 26. *Id*., p. 106.

Further explaining its PBR proposal, Consumers indicates that it proposed the target for SAIDI performance be set at the trailing five-year average of actual performance and the CEMI-5 performance be set at 5% of all customers. The company states that its proposal includes a deadband, at which no incentive or disincentive is applied, which should "start at one standard deviation below the target (i.e. point 3 in Figure 26) and end at 1.6 standard deviations above the target (i.e. point 4 in Figure 26)" and that "[t]he maximum incentive level (point 6) is set at 1.6 standard deviations below the target, and the maximum penalty level (point 7) is set at two standard deviations above the target." *Id*., p. 107. Consumers further describes its proposed incentives and disincentives, as included in the 2021 EDIIP, including a summary in Figure 28 on page 109. *See*, *id*., pp. 108-110.

6. Plans and/or Actions Taken Following the August 2021 Storms Addressing Outage Credits

Consumers indicates that it took several steps to address the outages following the August 2021 storms including that the company:

> • Proactively issued $25 credits to customers with consecutive and non-consecutive 120+ hour outages over the course of the storm restoration;
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> • Issued all requested outage duration credits from customers in the seven most highly impacted counties without investigation; and
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> • Issued all requested outage duration credits from remaining counties with confirmation that power was lost during this event for any time duration.

Id., p. 110. The company further details the timeline and amount of credits issued, as well as noting that "[a] technology/process redesign project has been scheduled for 2022 planning and subsequent implementation" which will identify a customer's duration outage credit eligibility proactively, automatically issue any appropriate bill credits, and send appropriate communication to the affected customer. *Id*., p. 111.

7. Summary of Restoration Efforts During the August 2021 Storms

Consumers estimates that its costs from the August 2021 storms, specifically from August 8 through August 10, were approximately $70.5 million. *See*, *id*., p. 112. With regard to customer communications, the company indicates that it shifted its communications beginning August 10, 2021, to "protecting the safety of customers and employees while giving people information to help them navigate outages following the large storm system" and that "[r]ed banners were immediately placed at the top of the Company's website to represent the situation and encourage customers to visit the Company's Outage Center for information or details on how to report outages." *Id*., pp. 112-113. Consumers avers that its communications efforts were "timely, transparent, and thoughtful" and utilized "web banners, email, media relations, social media, digital and radio advertising, and direct contact with customers through community activations." *Id*., p. 113. The company notes that whenever there are storm-related power outages, it places downed wire safety messages in counties with downed wires which, in this instance, ran from August 10 to August 18, 2021. The company indicates that its website saw a significant increase in visitors, the media relations team engaged in 20 interviews, and its social media messages reached numerous customers including replies to direct messages from customers on Facebook and Twitter.

Consumers indicates that its efforts included providing a generator to the Quincy Water & Sewer Department, which experienced a failure in its stand-by generator, allowing the department to continue to provide safe drinking water. The company states that it "gave people water and ice, free ice cream cones, free admission to Binder Park Zoo, or gift cards for a water park" working with community-based partners and even "worked on helping secure a generator for a senior apartment complex in Adrian so they could keep their elevator working, as well as providing several residents with water and ice." *Id*., p. 114. Consumers states that on August 18, 2021, there were still 1,487 customers without power and that $150 gift cards were sent to each of these customers who were located in St. Joseph County, Branch County, and Hillsdale County.

Consumers indicates that it has conducted an After-Action Review (AAR) to review its response to the August 2021 storms. Noting that the AAR was not finalized at the time of filing the instant report, the company states that some lessons have already been identified including:

> 1. Resourcing Storm Roles – The Company will adjust its Incident Command System ("ICS") storm response to include 24/7 on-call coverage for all ICS storm roles. The Company will also develop additional needed storm roles to allow for all Company employees to contribute to responding to catastrophic storm events. This will ensure all resources are ready whenever a storm hits;
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> 2. Damage Assessment Process – The Company will redesign the damage assessment process which records the extent, type, and severity of damage by substation and circuit. New technology will be used to create visual representations of where the damage is located on the circuit;
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> 3. Increase capacity to onboard additional Electric Line Crews ("Crews" in this section) – In the August catastrophic storm, the Company acquired and utilized more Crews than it ever had before. At the peak of the storm event there were 573 Crews on the system conducting restoration; each Crew consists of three to five people on the Crew. The Company will investigate training additional Field Leaders that organize and lead Crews throughout the storm event. With an expanded pool of Field Leaders, the Company is confident that additional Crews can be safely onboarded provided Mutual Assistance organizations can release Crews to Consumers Energy;
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> 4. Wire Down Response – The August catastrophic storm caused 665 wire downs that had emergency officials standing by for relief. On average, the Company relieved these emergency officials in just under six hours, below the standard of four hours or less. Since 2019, the Company has applied new strategies to improve its overall wire down response, responding to issues raised during [Commission] Staff-led workgroups. However, in a storm of this size, the Company was unable to meet the wire down relief metric. A problem-solving team has been formed to review new technologies and processes that can improve this metric. The Company's investment in Advanced Distribution Management System ("ADMS") is expected to have new capabilities that will aid in improving this metric;
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> 5. Securing alternate lodging – Given the locations where heavy damage occurred (mainly more rural areas of the state with declared states of emergency) lodging accommodations quickly became over booked, both by customers impacted by outages and by the record number of field resources the Company utilized, resulting in poor experiences for Crews that assisted the Company. Some Crews had to drive two hours or more to find accommodations after working a 16-hour shift for multiple days in a row. In other cases, Crews slept in their vehicles because there simply was no place for them to be housed. The Company appreciates local

> Emergency Managers who partnered with the Company to provide assistance. The Fort Custer facility in Augusta provided bunks, and Glen Oaks Community College in Centreville allowed the Company to use dorm space, all in an effort to securing lodging for Crews. Contracts are being developed with outside vendors to supply additional lodging beyond what has been traditionally used during storm, and the Company is developing other new approaches to ensure all resources that come to work for Consumers Energy will have a bed at the end of their shift;
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> 6. Resource Management Tracking System – The Company uses an in-house developed software to manage all people that respond to storms. This includes all office personnel and field resources, including Crews. Bringing on more resources than ever before highlighted the need for an updated resource management tracking system. The Company will investigate building enhancements to its current product and/or will conduct "requests for information" including demonstrations from vendors in the marketplace that offer products designed for a utility;
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> 7. Work Order Management – During the August catastrophic storm, the Company experienced nearly 11,000 hazards on the system ranging from wire downs, broken crossarms, trees on lines, and broken poles. In addition to these hazards, 7,200 outages were experienced. These all generate work orders in the Company's systems that are dispatched to Crews and the Field Leaders that supervise Crews. With this high volume of orders, it became challenging for those conducting restoration to routinely indicate that orders were complete as the work itself was completed. The Company's investment in ADMS will aid in this problem. The newer ADMS system will provide order consolidation, allowing fewer orders to be dispatched to Crews and Field Leaders. This lower order volume will allow field resources to focus on safely restoring power and less on work order management in their device.

Id., pp. 118-19.

8. Overhead to Underground Comparison

Consumers further responds to the Commission's inquiry regarding the comparison of overhead versus underground circuits.

a. Breakdown of Total Cost to Move a Typical Overhead Back Lot-Constructed Line and Overhead Front Lot-Constructed Line Underground

Consumers states that it "does not have a cost comparison for back lot-constructed vs. front-lot constructed overhead because there is not a substantial difference for overhead to underground construction based on this type of location." *Id*., p. 120. Noting that cost can vary significantly depending on several factors, the company indicates that urban settings are typically more expensive than rural settings. In Figure 29, the company indicates that costs to move a rural overhead to underground would range from $277,000 to $974,000 per mile, while in an urban setting the cost would range from $757,000 to $1,926,000 per mile, and notes that "these costs assume direct buried underground and do not include the cost of Metro underground infrastructure (i.e. cement encased duct banks, vaults, and manholes)." *Id*.

b. The Difference in Costs of Maintenance of an Overhead Back Lot, Overhead Front Lot, and Underground Electric Line on an Average Annual Basis

Again, noting that it has not historically tracked back lot versus front lot maintenance, Consumers states that its Figure 30 "represents the difference in cost to maintain overhead and underground electric lines on an annual basis, using the actual costs incurred in the three years from 2018 through 2020" and lists a cost to maintain per mile of $5,600 for overhead and $2,100 for underground. *Id*., pp. 120-121. The company further states that this does not include capital replacements of deteriorated equipment or Metro system underground maintenance and that overhead cost could increase to about $10,000 due to planned increases in forestry spending.

c. Average Measured Reliability of an Underground Line Compared to a Comparable Back Lot and Front Lot Overhead Electrical Line

Consumers presents a 10-year evaluation of outage rates for overhead and underground LVD primary circuits, excluding MEDs, again noting it does not have data differentiating front lot and back lot overhead lines. Figures 31 and 32 indicate an average failure rate of 0.054 for underground circuits and 0.233 for overhead circuits. *Id*., p. 122. The company also indicates that the "[f]ailure rates for underground are based on equipment codes and outage comments for underground cable, underground hardware, underground equipment, subsurface transformers, and sub metro failure." *Id*., p. 121.

d. Comparison of the Average Rate and Severity of Safety Incidents Relating to the Public and Utility Workers Associated with Underground Lines, Overhead Front Lot Lines, and Overhead Back Lot Lines

Consumers provides the average annual electrical related incidents for both its employees and the public using data from 2018 through August 2021. Figure 33 indicates that there was an average of one employee injury per year pertaining to both overhead and underground work. *Id*., p. 123. Regarding public safety incidents, Figure 34 lists the annual average of 0.5 fatalities, 2.67 serious injuries, and 5.0 minor incidents relating to overhead lines, and annual average of 0.0 fatalities, 0.25 serious injuries, and 2.5 minor incidents relating to underground lines. *Id*.

B. DTE Electric Company's Report

On October 1, 2021, DTE Electric filed its report in response to the August 25 order (DTE Electric report). DTE Electric states that the August 2021 storms caused outages for more than 500,000 of its customers. The company further indicates that from June 20 to September 29, 2021, it "experienced 12 storm events that, taken together, were unprecedented in the Company's history in terms of storm magnitude, interval, and customer impact." DTE Electric report, p. 1. In addition to the high number and intensity of storms, the company contends that there were only 4.6 days on average between each storm event. DTE Electric contends:

> In order to restore power to as many customers as possible, as quickly as possible, DTE [Electric] follows standard industry practice where crews first make quick temporary fixes in lieu of more time-consuming permanent repairs, then follow up in subsequent weeks to fully repair the system and make temporary patches permanent. The short window between this summer's storms prevented DTE [Electric] from performing necessary follow-up work to bring the system back to normal state, which led to increased vulnerability.

Id., p. 3.

DTE Electric states that, in addition to these storms, the National Weather Service confirmed six tornados in DTE Electric's service territory: "[w]hen compared to major storms the areas affected by tornadoes are relatively small, but with wind speeds of up to 120 mph the damage to poles and wires caused by tornadoes can be devestating [sic]." *Id*. The company further states that the August 2021 storm was a "four-day weather event," including extreme wind gusts and lightning, "which for safety reasons, requires overhead line crews and damage assessment teams to suspend restoration efforts." *Id*., pp. 3-4.

DTE Electric contends that it immediately deployed secure first teams to identify and secure downed wires after declaring a catastrophic storm on August 9, 2021. This was followed by damage assessment teams who worked 16-hour shifts around the clock. The company indicates that it brought in 1,513 additional line workers to assist the company's approximate 800 line workers. Overall, the company avers that the storm response cost $158 million. *See*, *id*., p. 5.

In addition to the above, DTE Electric indicates that it launched a Storm Crisis ICS on August 17, 2021, based on a model developed by the Federal Emergency Management Agency. The company acknowledges:

> that there are opportunities to improve the storm response and communication to impacted customers and communities, [and] this ICS team has three main goals: (1) to improve the reliability of the most impacted communities, (2) to improve the accuracy of the outage-related communications sent to customers, and (3) to improve and build lasting relationships with impacted communities.

Id., p. 6. DTE Electric states that the ICS identified communities with substandard reliability performance and has "identified and prioritized the scope of the improvement work, including maintenance tree trimming (trimming trees along the entire line of the circuit), spot trimming (targeting trimming in areas where trees are most impacting the power lines), sectionalizing, pole top maintenance and other reliability work" with a goal of completing reliability work in each identified community by the first quarter of 2022. *Id*. Further, the company indicates significant system and process changes are required to ensure all outage information and updates are vetted and confirmed before they are published. The company also notes that it has deployed a communication process with all stakeholders to share information regarding reliability improvements and to gather feedback.

DTE Electric next responds to the specific topics as set forth in the August 25 order.

1. Summary of the Utility's Ongoing Vegetation Management and Grid Hardening Efforts

DTE Electric states that trees are a leading factor in reliability performance and, historically, have been responsible for two-thirds of the outage minutes and half of overall outages. The company indicates that it launched the Enhanced Tree Trimming Program (ETTP) in 2016, recognizing the need to increase its tree trimming efforts. The goal of the ETTP is to trim and/or remove trees to maintain circuit clearance for a five-year cycle of growth. To further implement this program, the company proposed and was approved for the Tree Trim Surge in Case No. U-20162. *Id*., p. 7; *see also*, May 2, 2019 order in Case No. U-20162. The Tree Trim Surge proposed achieving the five-year cycle in the ETTP specifications by the end of 2025. The company contends that, since approval of the Tree Trim Surge, it "has made significant progress: by the end of 2021, 72% of the system will be on-cycle, including 89% of the city of Detroit." DTE Electric report, p. 8. Further, DTE Electric avers that circuits that are on the five-year cycle have fewer outage events, fewer customers affected, shorter outages, and fewer downed wires than compared to circuits which are not yet on the five-year cycle. DTE Electric also indicates that, in light of the 2021 severe storms, it proposed $70 million in additional funding for tree trimming in Case No. U-21128, which it states will allow it "to increase the number of miles trimmed in 2021 through 2023, with the intention of completing the Tree Trim Surge earlier than previously proposed." DTE Electric report, p. 8.

The company also indicates that "[t]he 4.8kV hardening program improves the safety and reliability of one of the oldest parts of DTE [Electric]'s distribution system, which includes Detroit and its surrounding communities." *Id*., p. 9. DTE Electric states that this program began in 2018 when the company hardened 105 miles of circuits and that it "was designed to bring significant improvements to safety and reliability to this area, as measured by reductions in wiredowns and improvements in All-Weather reliability performance and reliability performance excluding major event days." *Id*. The company describes the scope of the 4.8kV hardening program as "testing all poles and replacing as needed, replacing wooden crossarms with fiberglass crossarms, trimming trees to support construction, removing any service lines to abandoned properties, and performing any work as dictated by field conditions." *Id*. DTE Electric indicates that the current planned program ends in 2026 at which time 45 substations and over 2,200 miles of overhead lines will have been hardened.

DTE Electric states that it established its Customer Excellence program in 2019 "to provide rapid solutions to areas in which small pockets of customers experience poor reliability. These customers are identified as experiencing four sustained outages (SAIFI > 4.0) or nine momentary outages (MAIFI [momentary average interruption frequency index] > 9.0) on a 12-month rolling basis." *Id*., p. 10. The company indicates that circuits are selected for this program based on DTE Electric's rolling 12-month reliability data and a field patrol of a selected circuit is conducted to understand the conditions of the equipment and trees. DTE Electric adds that:

> After patrol, the scope of work is developed for both tree-related and equipment-related problems identified. In addition to the tree trimming and defective equipment replacements, the scope of work also includes checking operating equipment to ensure it is functioning properly, conducting fault studies to ensure fuses are properly sized, and installing additional equipment, such as reclosing devices and animal guards, to prevent future outages.

Id. Historically, the solutions have cost between $60,000 and $80,000 per circuit; however, the company avers that the circuits to be addressed in the rest of 2021 and 2022 may have additional costs due to increased scope and equipment.

2. How Current Efforts Have Contributed to Reliability Performance

The company again notes that the ETTP has provided benefits in terms of improved reliability and safety as circuits that have been trimmed "have fewer outage events, fewer customers interrupted, shorter outage duration and fewer wiredowns compared to circuits that have not been trimmed in the ETTP." *Id*., p. 11. DTE Electric provides a chart (Figure 4) comparing the performance of ETTP circuits and a control group pertaining to outage events, customers interrupted, and minutes of interruption. *See*, *id*., pp. 11-12.

With respect to the 4.8kV hardening program, DTE Electric indicates that it has measured effectiveness using three metrics: (1) an all-weather SAIFI, (2) SAIDI excluding MEDs, and (3) unaudited down wire events. The company also states that it has added two additional metrics for the purpose of an analysis on storm effectiveness: (1) all-weather SAIDI and (2) all-weather CAIDI. DTE Electric presents charts (Figure 5) showing performance of circuits hardened by the program versus a control group (circuits not yet hardened by the program) and concludes that, "[f]or all metrics shown, circuits that have been hardened are showing significant improvements, both in an absolute measurement, and when compared to the control group." *Id*., p. 13.

DTE Electric states that it measures the effectiveness of its Customer Excellence program through improvements in SAIFI and MAIFI. The company contends that "[t]he most recent analysis of circuits addressed by the Customer Excellence program is a 42% absolute improvement in SAIFI and a 36% reduction in MAIFI. In both instances, the control group, which is a set of circuits served from the same substation, experience small increases in reliability events." *Id*., p. 14; *see also*, Figures 6 and 7.

3. Ranked Breakdown of the Top 10% Worst Performing Circuits in 2021 to Date

DTE Electric states that its distribution system includes 3,239 circuits and that it has attached two lists of 324 circuits, contained in Exhibit A to its report, which represent "the top 10% worst performing circuits from both the SAIFI and SAIDI metrics as of September 6th, 2021" and are "ranked based on circuit-level SAIDI or SAIFI based on the experience of the customers on that circuit, rather than from system-level performance." *Id*., p. 16. The company notes that the information provided is fluid and rankings can change with each outage on the system. The company includes maps in Figure 8 on page 16, depicting the location of the circuits identified in Exhibit A. DTE Electric further states that its Exhibit A also lists the most recent and the next planned tree trimming, planned reliability work on each circuit, and projects and programs aimed at improving resiliency of the system.

4. Maps of the Top Ten Zip Codes with both the Highest and Lowest System Average Interruption Frequency Index, and the Top Ten Zip Codes Where the Most Future Tree Trimming and Other Reliability and Resiliency Improvement Efforts are Planned

DTE Electric provides a table with the highest and lowest SAIFI, attached to the report as Exhibit B, and notes that these will change over time. The company also provides a map of the zip codes (Figure 9) and a table listing the planned work in the highest and lowest SAIFI zip codes. DTE Electric notes that it has not tracked data where most future tree trimming or reliability improvements are planned because the work spans zip codes; however, the company provides Figures 10 and 11, which depict the locations for much of the planned work. Moreover, DTE Electric notes that "Figures 10 and 11 have not been updated with the additional $70 million investment in tree trim and pole top maintenance" requested in Case No. U-21128 "but the Company expects to publish an updated version of Figures 10 and 11 for 2022." *Id*., p. 19.

5. A Summary of Efforts Contained in Currently Filed Distribution Plans to Address Outages and System Reliability

DTE Electric states that its final Distribution Grid Plan (DGP) was filed on September 30, 2021, and "provides a detailed description of DTE[Electric]'s strategic investments to improve reliability for [its] customers. The entire portfolio of strategic investments was developed using the grid modernization process described in the DGP, and informed using three scenarios, one of which anticipates increased frequency and intensity of severe weather." *Id*., p. 22. The company indicates that the strategic investments were categorized into the following four pillars: (1) infrastructure resilience and hardening, (2) tree trimming, (3) infrastructure redesign and modernization, and (4) technology and automation. At pages 22-23, DTE Electric provides a table describing these four pillars and identifying the projects and programs which are expected to create reliability improvements.

The company also indicates that the DGP describes its proposed approach to PBR. DTE Electric indicates that the DGP proposes additional reporting and transparency through a PBR report which would "include new metrics and expanded context and discussion of metric performance" as well as "two reliability metrics which are appropriate for incentives/penalties and includes a discussion on the key considerations in incentive design and the role of the chosen metrics." DTE Electric report, p. 23. The company further explains the proposed metrics include SAIDI (excluding MEDs), which "captures the overall system condition and is a widely utilized reliability metric," and CEMI, which "more closely reflects the customer experience" and "will be developed and proposed following the finalization of the service standards and outage credit discussions with stakeholders." *Id*., pp. 23-24.

6. Plans and/or Actions Taken Following the August 2021 Storms Addressing Outage Credits

DTE Electric states that to address customer concerns from the August 2021 storms, it has "focused on service recovery, which includes improving communications during outages, targeting error free customer communication, and proactively processing reliability credits." *Id*., p. 24. The company notes that all eligible customers, based upon the Commission's criteria, should receive a reliability credit on their bills by the beginning of December 2021, at the latest. In addition, DTE Electric states that it also issued a discretionary customer courtesy credit to acknowledge the hardships customers experienced from the August 2021 storms to help mitigate some costs associated with the extended outage.

DTE Electric estimates "a tentative $1.2 million cost and 6-month development and implementation plan for the process and system modifications necessary to fully automate reliability credits." *Id*., p. 25. The company notes, however, that this cost and timeline will continue to be evaluated.

7. Summary of Restoration Efforts During the August 2021 Storms

DTE Electric states that it experienced four storms in August, including one of the largest in company history. The company indicates that the first of the August storms affected nearly 500,000 customers, required the assistance of 367 out-of-state crews and 1,547 out-of-state line workers, and cost the company approximately $158 million. *Id*., pp. 25-26. DTE Electric indicates that it began communicating weather warnings to customers, including safety instructions and procedures for reporting down wires, on social media platforms and banners on the DTE Energy Outage Center as early as August 9, 2021, and that the "messages were updated throughout the week as weather progressed and restoration began." *Id*., p. 26.

With respect to advance preparations, the company indicates that it constantly monitors weather forecasts and began securing additional line workers to enable the fastest possible response to hazards and outages. DTE Electric states that its advance preparation "allowed for better overall management of crew resources and provided more resources to sooner address hazards and customer outages as the weather came through [its] service area" and that additional line workers came "from Canada, Connecticut, Illinois, Indiana, Kentucky, New York, Ohio, Pennsylvania and Michigan." *Id*., p. 27. The company notes that progress after the August 9 storm was delayed because of waves of additional storms and hazardous weather, which did not allow crews to continue damage assessments out of concern for the safety of employees. Due to the continued hazardous weather, DTE Electric notes that it took approximately 48 hours on average to provide restoration estimates to customers as opposed to approximately 8.5 hours for later storms.

The company states that it received feedback from customers that power restoration estimates were incorrect and through this process the company has identified gaps involving people, the company's processes, and technology that include: "(1) field restoration work was closed-out or cancelled in [the company's] outage management system before customers were completely restored, and (2) notifications were triggered based on crews being assigned to work in the field, rather than engaging with the customer's meter to confirm power status." *Id*., p. 28. DTE Electric states that it has implemented measures to mitigate the sharing of inaccurate information and is finalizing a plan to prevent similar mishaps from occurring in the future. The company contends that it immediately executed several measures including: (1) the suspension of customer notifications until the company could ensure notifications were accurate, (2) the reinforcement of company expectations to all DTE Electric employees who were working on the storm restoration process and provided access to a tool to "ping" meters to verify the restoration of power, and (3) several technology changes utilizing advanced metering infrastructure (AMI). Specifically, the company states that it "used AMI voltage reads throughout the storm to verify restoration was complete, and also used the information to understand which customers were still having power issues on circuits with more damage." *Id*., p. 29. The real-time outage map updates were discontinued because the data verification involved "manual components" which took "longer than automatic updates," and the company also "reduced the cadence to five times per day in order to verify the AMI information across multiple systems." *Id*. DTE Electric adds that a longer-term process is underway to address the cause of incorrect information being distributed to customers.

The company also indicates that it engaged in community outreach to the communities that were most impacted and/or vulnerable. DTE Electric states that it “activated and deployed team members to over 30 affected communities across the region to hand out over 27,000 bags of ice, 140,000 water bottles, and 15,000 essential supplies, such as phone chargers and flashlights.” *Id*., pp. 29-30. DTE Electric asserts that company employees accompanied the teams to assist in answering questions about the storm restoration process and to assist customers in applying for the reliability credit. The company also states that food vouchers were also distributed in the vulnerable communities in southwest Detroit and the company sponsored “open pool days in Dearborn, Imlay City and Ann Arbor.” *Id*., p. 30.

8. Overhead to Underground Comparison

DTE Electric states that it has “received a lot of feedback from customers and other stakeholders who are interested in understanding the role of relocating overhead lines to underground, to mitigate impacts from wind and trees, building resiliency.” *Id*. The company indicates that it has, therefore, “been investigating the costs and benefits of undergrounding and is responding to the impacts of the storms and customer feedback by increasing [its] focus and investment in Strategic Undergrounding.” *Id*., pp. 30-31. DTE Electric notes that it has the Appoline DC 1346 strategic undergrounding pilot project underway and is considering additional pilot programs “to study best practices that reduce costs and evaluate the overall total cost of ownership for underground infrastructure as compared to overhead infrastructure.” *Id*., p. 31. The company explains that the Appoline DC 1346 pilot began in late 2018, and covers about 60 residential customers in the City of Detroit with a scope of installing “a looped URD [underground residential distribution] system with approximately 1,300 feet of primary, six transformers, and underground services to residences. When the underground equipment is completed and functional, the overhead infrastructure will be removed.” *Id*.

a. Breakdown of Total Cost to Move a Typical Overhead Back Lot-Constructed Line and Overhead Front Lot-Constructed Line Underground

DTE Electric states that, based on the pilot, the current cost per line mile is $3 million to move an established overhead lateral electrical line to underground. However, the company believes that through incorporating lessons learned in the pilot, industry benchmarking, more cost efficiencies, and a large scope with economies of scale, costs could be reduced approximately 20% to 30%. Pertaining to the Commission's specific request, the company indicates that it "does not have enough current pilot experience or understanding of costs from any established large-scale undergrounding programs to be able to identify a range of high/low/average costs but will continue to develop the program cost standards through pilot work and benchmarking." *Id*., p. 32. More specifically, DTE Electric contends that:

> A key factor in determining the cost of undergrounding an overhead circuit is which specific section or sections of a circuit configuration is rebuilt underground. Circuit configuration is typically comprised of the feeder, which is from the substation to the first sectionalizing point; the backbone, which is the three phase portion of the circuit from the first sectionalizing point to the connection point of the outermost lateral; and laterals, which are the single phase primary voltage portion of the circuit supplying customers. The backbone and feeder portions of a circuit are the costliest to convert to underground because the construction requires trenching in active streets to place concrete incased conduit at approximately three or more times the cost of similar work on laterals.
>
> In addition to the feeder, backbone, and laterals, the final connection to a customer is the service, sometimes called a service drop. Services are the secondary voltage (typically 120V [volt]/240V) conductors connected to customers' homes. In areas with overhead laterals, the service wires run above ground from an overhead asset to customers' homes, and for URD areas, the service conductors run from equipment at ground level to customers' homes.

Id.

The company further notes that another important consideration is the timing of the conversion of an overhead line to underground and whether it is a solution to a specific reliability issue or part of a 4.8kV substation and circuit conversion project. In addition, DTE Electric states that it has received Commission approval "to require any new, relocated or upgraded service to be placed underground" and with "customer interest in underground electrical infrastructure, the Company is exploring extending this concept to proactively underground existing service drops under some circumstances." *Id*., p. 33; *see also*, December 11, 2015 order in Case No. U-17767, Attachment B. The company indicates that its current cost of relocating an existing overhead line to underground is about $2,400 per house and that upcoming pilots can help it understand the benefits and costs associated with undergrounding services.

b. The Difference in Costs of Maintenance of an Overhead Back Lot, Overhead Front Lot, and Underground Electric Line on an Average Annual Basis

DTE Electric reiterates that it is evaluating the difference in maintenance costs based on varying circuit configurations. With respect to overhead line maintenance, the company notes that "costs are driven largely by tree trim and pole and pole top hardware (Pole/PTMM)" and that, depending varying factors "[t]he cost for Pole/PTMM can range between $20,000 and $25,000 per overhead line mile" and "[t]ree trim costs can range between $15,000 and $75,000 per mile depending on tree density and accessibility." DTE Electric report, p. 33.

DTE Electric further contends that it "has invested between $0.5 million and $1.0 million per year over the last three years for manhole inspections and between $27,000 and $37,000 for primary switch cabinet inspections per year." *Id*., p. 34. In addition, the company states that circuits with underground services still require Pole/PTMM inspections and tree trimming as they often have overhead feeder and/or backbone. Through piloting, the company indicates its analysis thus far shows that moving rear lot overhead laterals to front lot underground locations "shows potential to provide significant reliability improvements, and potential avoided emergent capital and O&M of over $250,000 and $400,000, respectively. Additionally, it would eliminate over 20 wire-downs per year vs. a historic three-average [sic]." *Id*.

c. Average Measured Reliability of an Underground Line Compared to a Comparable Back Lot and Front Lot Overhead Electrical Line

The company presents a table on page 35 comparing all-weather reliability metrics of customers served by overhead and underground from 2018 to September 2021 utilizing the CAIDI, SAIDI, and SAIFI metrics. In general, the company's data reflects a reduction in each index for underground circuits. *See*, *id*., pp. 34-35.

d. Comparison of the Average Rate and Severity of Safety Incidents Relating to the Public and Utility Workers Associated with Underground Lines, Overhead Front Lot Lines, and Overhead Back Lot Lines

DTE Electric indicates that it does not track or maintain the data requested and, instead, provides benchmarking by the Edison Electric Institute. *See*, *id*., pp. 35-36.

C. Indiana Michigan Power Company Report

On October 1, 2021, I&M filed a report in response to the August 25 order (I&M report).[4] I&M indicates that, at the peak, it had about 20,900 customer outages following the August 2021 storms. The company states that the restoration spanned six days but that it "managed the process in such a way as to minimize most of its customers' outage durations." I&M report, p. 2. The company states it experienced unprecedented flooding at one of its substations requiring utilization of a mobile substation. The company asserts that, "[a]s a result of [its] efforts and organization, 70.4% of customers were restored within 24 hours; 94.3% within 48 hours; and 99.7% within 72 hours." *Id*., p. 3. I&M notes that two customers served by a wire through a wooded area experienced an 89-hour outage as "[t]rees brought down the wire and restoration required a tree crew to clear the trees followed by a line crew to repair the wire." *Id*. I&M states that its internal personnel of 80 line and 25 assessment personnel were assisted by "44 line and 19 assessment

[4] While the I&M report is not paginated, the Commission references page numbers in natural order beginning with the first page of the report.

personnel from sister American Electric Power (AEP) companies. Also called into action were 210 base load line personnel and 375 line and 34 assessment personnel from off [the] AEP system. Additionally, I&M had 136 forestry full-time employees working the restoration effort." *Id*.

1. Summary of the Utility's Ongoing Vegetation Management and Grid Hardening Efforts

I&M provides a summary of its completed vegetation management and grid hardening work in Tables 1.2 and 1.3, along with additional details regarding its grid hardening efforts in Table 1.3. *See*, *id*., p. 4. The company contends that it prioritizes vegetation management through evaluation of circuit performance and input from field personnel and notes that, in 2021, it has increased funding for vegetation management by approximately $1 million in comparison to previous years. I&M highlights its Reliability and Asset Renewal Projects, stating that these projects are "developed to replace aging infrastructure and harden the distribution system to make it more resilient." *Id*., p. 5. The company indicates that it has various distribution projects, and is in the process of deploying AMI. I&M indicates that AMI will allow for "improved system monitoring, enhanced distribution system performance, and improved management of and response to outages, which improves the customer experience through improved data, information, and analytics." *Id*. Similarly, the company notes it is "installing Distribution Automation Circuit Reconfiguration (DACR), which consists of creating smart circuit ties coupled with technology that isolate an outage condition and automatically reconfigure the power supply to minimize the duration customers are affected." *Id*. In addition, the company states that it utilizes supervisory control and data acquisition systems, distribution line sensors, smart reclosers, and smart circuit tie program upgrades. I&M describes each of these measures as providing additional data and monitoring of the company's systems.

Overall, the company notes that its grid hardening strategy "involves the utilization of best practices, techniques, and design standards to reduce the vulnerability of [its] operated portion of the electric power grid" and that the "current I&M design standards are more robust than historical standards and call for the use of poles with stronger structure strength." *Id*., p. 6. I&M also provides SAIDI performance data, both excluding MEDs (Figure 1.1) and including MEDs (Figure 1.2). *See*, *id*., p. 7.

2. How Current Efforts Have Contributed to Reliability Performance

I&M provides a listing in Table 2.1 of its distribution circuits that were cleared in 2020, including a circuit-to-circuit assessment "to compare each circuit against itself, before and after it was cleared." *Id*. The company indicates that it breaks the system into segments smaller than the circuit level, which allows it to "harden more problematic areas and on the whole, provide a greater benefit to the system." *Id*., p. 8. The company indicates that this causes some circuits to have hardening every year, albeit on small portions of the circuit.

3. Ranked Breakdown of the Top 10% Worst Performing Circuits in 2021 to Date

Noting that it "prioritizes planning, reliability efforts, restoration prioritization, and funding on a circuit and sub-circuit basis" rather than based on zip code, I&M provides a list of its top 10% worst performing circuits and corresponding zip codes by SAIFI in Table 3.1 and by CAIDI in Table 3.2. *Id*., p. 9. The company also provides maps depicting its top 10% worst performing circuits by SAIFI (Figure 3.1) and CAIDI (Figure 3.2).

4. Maps of the Top Ten Zip Codes with both the Highest and Lowest System Average Interruption Frequency Index, and the Top Ten Zip Codes Where the Most Future Tree Trimming and Other Reliability and Resiliency Improvement Efforts are Planned

I&M provides a map of the zip codes with the highest and lowest SAIFI in Figure 4.1, as well as tables listing the same (Tables 4.1 and 4.2). *See*, *id*., p. 12. The company notes that, based on its approved cyclical vegetation clearing approach, "I&M will clear all lines in all zip codes in a given five-year time span." *Id*., p. 13. The company again notes that it does not categorize its work according to zip code explaining that the company's "Vegetation Management Plan is managed at the circuit based level which cross zip code boundaries." *Id*.

5. A Summary of Efforts Contained in Currently Filed Distribution Plans to Address Outages and System Reliability

I&M states that it "plans to spend in excess of $65,000,000 over the next five (5) years in operations & maintenance costs for vegetation management practices." *Id*. The company notes that the costs are broken down by year in Table 5.1, which also includes costs by year for asset renewal, combined projects, inspection programs, and grid modernization.

6. Plans and/or Actions Taken Following the August 2021 Storms Addressing Outage Credits

I&M states that it is providing outage credits in compliance with Mich Admin Code, R 460.745 through R 460.747 of the Commission's Service Quality and Reliability Standards for Electric Distribution Systems. The company notes that, in anticipation of rules changes, it "is evaluating and planning for back office system process and billing software changes to update outage credit amounts, calculation methodologies, and for providing automatic billing credits to eligible customers." I&M report, p. 13.

7. A Summary of Restoration Efforts During the August 2021 Storms

I&M states that it was alerted on August 9, 2021, to the potential of a cluster of severe storms and, accordingly, immediately began to send its crews and business partners to its Michigan service territory. The company again notes that the majority of its outages were relating to the flooded substation. By August 10, 2021, the company states it had requested external resources and by August 11, 2021, "had secured 140 full time employees (FTE's) from affiliate companies that were in route from Ohio Power and Appalachian Power, along with a host of contract FTE's from those utilities." *Id*., p. 14. Further, the company indicates it "secured an additional 130

FTE's from Public Service Corporation of Oklahoma (PSO)" in anticipation of additional storms predicted for August 12, 2021. *Id*.

I&M states its actual costs in response to the August 2021 storms for labor, materials, lodging, meals, and miscellaneous expenses totaled approximately $3.3 million. The company notes that it "expects other expenditures to materialize, ultimately bringing the total to approximately $3,700,000" and outlines these costs in Table 7.1. *Id*.

The company contends that it utilized five communications channels following the August 2021 storms including email, text, social media, One Voices, and media interviews. I&M states that it was primarily providing customers with its estimated time of restoration and providing information regarding the challenges in restoring power due to the extent of damages and continuing weather conditions. The company states that it sent media alerts to news outlets in Fort Wayne, South Bend, and Elkhart, Indiana, and Southwest Michigan; posted more than 135 messages to social media; and sent 150,000 combined emails and texts. I&M concludes that, "[i]n total, more than 560,000 instances of communication efforts were executed during and following restoration efforts" and that it "conducted media interviews with four different stations and engaged social media through 135 individual posts, with the public engaging over 4,400 times." *Id*., p. 15.

With respect to vulnerable customers, the company states that its "Liaison Officer maintained a priority customer list throughout the storm, keeping in constant contact with Distribution Operations during the storm restoration effort." *Id*. In addition, I&M states that its "Liaison Officer uses a multi-faceted approach, depending on the situation, by incorporating individual calls, outage notifications via text/email, and feedback loops through [the company's] Contact

Center" and that its customer services team worked to prioritize activities around critical customers. *Id*.

8. Overhead to Underground Comparison

   a. Breakdown of Total Cost to Move a Typical Overhead Back Lot-Constructed Line and Overhead Front Lot-Constructed Line Underground

I&M estimates that the cost to convert a typical overhead front lot-constructed single-phase line with 135 services to underground is approximately $1,070,000 per mile, and approximately $640,000 per mile for an overhead back lot-constructed single-phase line with 70 services. For the single-phase line in residential developments, I&M states that it made the following assumptions:

- All conductor installation is by directional bore and in a conduit sleeve
- Estimates do not include cost to convert customer owned meter socket and electrical panel, if necessary
- Estimates do not include cost to maintain existing streetlighting
- Estimates do not include cost to repair landscaping including grass, gardens, structures and fencing
- Estimates do not include cost to secure additional easements

Id., p. 16. The company further estimates a cost of $3,122,000 per mile to convert a typical overhead three-phase line with the following assumptions:

- All conductor installation is by directional bore and in a conduit sleeve
- Estimates do not include any work to convert service wire from source to meter location
- Estimates do not include cost to convert customer owned meter socket and electrical panel if necessary
- Estimates do not include cost to maintain existing streetlighting
- Estimates do not include cost to repair landscaping including grass, gardens, structures and fencing
- Estimates do not include cost to secure additional easements
- Estimates do not include cost to construct concrete transformer pads
- Estimates do not include any sectionalizing or other coordination equipment
- Estimates do not include any concrete structures or encasement
- I&M does not install delta padmount transformation - This would require further accommodations

Id.

b. The Difference in Costs of Maintenance of an Overhead Back Lot, Overhead Front Lot, and Underground Electric Line on an Average Annual Basis

I&M states that its data does not "differentiate maintenance costs according to front lot, back lot, or underground construction" but notes that back lot maintenance is more expensive than front lot due to "access issues requiring increased time and special equipment or manual procedures." *Id*., p. 17. In addition, the company avers that underground lines will generally be less expensive to maintain but they "tend to have a useful life of approximately half of that of overhead lines and therefore require replacement more often than overhead lines." *Id*.

c. Average Measured Reliability of an Underground Line Compared to a Comparable Back Lot and Front Lot Overhead Electrical Line

I&M provides Tables A.1 and A.2, which illustrate the reliability metrics of underground versus overhead electrical lines at page 17 of the I&M report.

d. Comparison of the Average Rate and Severity of Safety Incidents Relating to the Public and Utility Workers Associated with Underground Lines, Overhead Front Lot Lines, and Overhead Back Lot Lines

I&M indicates that it "did not have any electrical contact incidents with overhead or underground electrical lines in Michigan between [January 1, 2020] and [August 31, 2021] that resulted in injury to utility workers, or any member of the public." *Id*., p. 18.

D. Upper Peninsula Power Company's Report

On October 29, 2021, UPPCo filed its report in response to the August 25 order (UPPCo report).

1. Summary of the Utility's Ongoing Vegetation Management and Grid Hardening Efforts

UPPCo states that it currently has 103 line clearance project areas within its service territory and that it has attached its line clearance cycle maps and metrics for 2019, 2020, and 2021, to its report as Attachments 1(a), 1(b), 1(c), and 2. The company notes that it "executes its vegetation management program through a six-year project area cycle, whereby each distinct line clearance project is trimmed and brushed at least once every six years. A project area may be cleared ahead of its originally intended cycle if vegetation growth or observed outages warrant such action." UPPCo report, p. 2. UPPCo explains that its current line clearance plan requires vegetation management for 2,232 miles of overhead primary line over each six-year period, or approximately 372 miles each year, which does "not include additional required trimming or brushing work on customer service extensions, secondary line segments, or special tree requests." *Id*. The company also indicates that its program is continuously evolving in response to factors such as diseased tree species requiring additional tree removals, as well as stronger, more frequent storms requiring additional right-of-way (ROW) tree removal to aid in the prevention of line segment failures.

2. How Current Efforts Have Contributed to Reliability Performance

UPPCo contends that its "line-clearance program is a systematic and methodical process intended to clear pre-defined areas within each district of the Company's distribution system footprint at regular intervals, thereby driving cost-efficiency into the process" and that "it is difficult to derive correlation between the immediate impact of line clearance on system reliability from one year to the next when compared to the localized and random nature of the more extreme storm events that have been observed in recent years." *Id*., p. 3. Nevertheless, the company avers that the total SAIDI minutes for combined weather and tree-related outages declined from 81% for calendar years 2018 to 2019, down to 60% for calendar years 2020 to 2021 as of the filing date.

3. Ranked Breakdown of the Top 10% Worst Performing Circuits in 2021 to Date

The company states that it has approximately 100 circuits and, as such, provides the top 10 worst SAIDI and SAIFI circuits as Attachment 3, and provides maps of those circuits as Attachment 4. In addition, UPPCo states that its:

> service territory is primarily rural with an average of 12 customers per mile. As a result of this unique circumstance, each circuit is a mixture of 3-phase, single-phase, overhead, and underground construction that may be within a road ROW or outside of the road ROW. UPPCO puts emphasis on reliability projects that can reroute a line from outside of the road ROW to within the road ROW to improve accessibility, reduced line clearance requirements, and improve the Company's ability to patrol the system and locate outage causes and boundaries more efficiently.

Id., p. 4. UPPCo adds that it has regularly invested in the 10 worst circuits as fully described in Attachment 5. The company notes that it has also completed "many smaller scale projects that improve system reliability and resiliency based on routine system inspections and other activities, such as danger and reject pole replacements, line relocations, shared facilities attachments, and overhead line to underground conversions, among others." *Id*., pp. 4-5.

4. Maps of the Top Ten Zip Codes with both the Highest and Lowest System Average Interruption Frequency Index, and the Top Ten Zip Codes Where the Most Future Tree Trimming and Other Reliability and Resiliency Improvement Efforts are Planned

The company states that its outage management system does not track outages by zip code. UPPCo refers again to its Attachments 3 and 4, which include a list of its top 10 worst SAIDI and SAIFI circuits and map with the location of those circuits. UPPCo further notes that its line-clearance program does not "uniformly correspond to zip codes" because its "distribution system circuits generally cover a specific geographic region which may not correspond to a specific set of zip codes, but rather a circuit will loosely cover a city, township or a portion thereof." *Id*., p. 5. The company also adds that the geographic areas on its line-clearance map in Attachment 1 "often do not cover the entirety of one complete circuit, and therefore the any [sic] particular circuit may not be completely cleared within the same year of UPPCO's six-year line clearance schedule." *Id*.

5. A Summary of Efforts Contained in Currently Filed Distribution Plans to Address Outages and System Reliability

UPPCo states that it is not required to file a distribution plan with the Commission like other Michigan utilities. The company notes, however, that in Case No. U-20276, UPPCo's last general rate case, it "provided significant detail related to its plan to improve distribution reliability, which outlines the decision criterion utilized by the Company to prioritize reliability driven distribution system investments." *Id*., p. 6. UPPCo adds that it "regularly evaluates the merits of significant reliability-driven projects to its distribution system and will look to expand these efforts in the coming years as a means to provide increased reliability and resiliency of its distribution system to the benefit of its customers." *Id*.

6. Plans and/or Actions Taken Following the August 2021 Storms Addressing Outage Credits

UPPCo states that, unlike the Lower Peninsula, its customers did not have similar severe weather events in August 2021 which caused significant outages. More specifically, the company states that it did not have any outages equating to a catastrophic event as defined by the Commission and, as a result, has not been required to pay outage credits to any customers in 2021 as of the date of filing.

7. A Summary of Restoration Efforts During the August 2021 Storms

Noting again that it did not experience any catastrophic event days in August 2021, UPPCo states that its response to the outages that did occur was its typical storm response plan. The company adds that:

> Due to the mild nature of the storms experienced in the UPPCO service territory in relation the catastrophic events observed elsewhere throughout the state, there was not an immediate need to put forth any abnormal, widespread customer communications or any other activity tied to big storm events that have long restoration times. UPPCO is prepared to issue these types of widespread customer communications in the future, should the situation present itself.

Id., p. 7.

8. Overhead to Underground Comparison

   a. Breakdown of Total Cost to Move a Typical Overhead Back Lot-Constructed Line and Overhead Front Lot-Constructed Line Underground

The company states that its records do not distinguish overhead front lot-constructed lines from overhead back lot-constructed lines but "more typically refers to these types of line installations as within ROW and outside ROW." *Id*., p. 8. UPPCo indicates that:

> Based on 2020 pricing and actual jobs completed, the cost to re-build an overhead 3-phase line to underground is about $62/ft [feet] and about $23/ft for 1-phase. These cost estimates consider standard design practices, including risers and junction enclosures, and account for up to 50% boring and 50% plowing, 25kV jacketed cable for 1-phase (1/0), and 3-phase (4/0), with the bored sections in conduit. UPPCO notes that these cost estimates do not include any necessary permits, line clearance, conversion of individual customer services from overhead to underground, easements, outside engineering or consultants, or unusual construction, such as a vacuum truck or rock boring. These extraneous factors are dependent upon the configuration, topography, and geology of the site in question, and may cause the economics of one specific underground project to vary greatly from another.

Id.

   b. The Difference in Costs of Maintenance of an Overhead Back Lot, Overhead Front Lot, and Underground Electric Line on an Average Annual Basis

UPPCo states that its system includes about 4,500 electric line miles of which approximately 76% "are configured as overhead conductor while the remaining 24% of the total line miles are underground." *Id*., p. 9. The company lists 2019 maintenance costs of $7.1 million and 2020 costs of $6.2 million and notes that "the cost to maintain underground was 23% of the cost to maintain overhead per foot of system installed during this period." *Id*.

   c. Average Measured Reliability of an Underground Line Compared to a Comparable Back Lot and Front Lot Overhead Electrical Line

The company indicates that outages associated with underground lines for calendar years 2020 and 2021 year to date, only accounted for 0.5% of the total SAIDI minutes. Further, "UPPCO sees significant value and opportunity to increase the reliability of its distribution network by strategically targeting specific circuits for underground conversion, yielding both a decrease in maintenance expenses and increased reliability and resiliency of the system." *Id*.

d. Comparison of the Average Rate and Severity of Safety Incidents Relating to the Public and Utility Workers Associated with Underground Lines, Overhead Front Lot Lines, and Overhead Back Lot Lines

UPPCo contends that, in general, it has very few safety events related to its lines regardless of whether they are overhead or underground. The company further notes that from 2020 to the date of filing in 2021, "human-caused events . . . accounted for only 3.2% of total outage events: 1.6% are attributable to vehicle accidents, 0.9% to human error, and the remaining 0.7% are caused by 'dig-ins'. In addition, UPPCO is rarely called upon to respond to downed wire situations." *Id*., p. 10.

In conclusion, the company states that even though the August 2021 storms in its service territory were less severe than experienced in other parts of the state, it nevertheless "responded quickly and efficiently to the localized storm events to restore service to its affected customers." *Id*. Further, UPPCo notes that it has "a fair amount of extreme weather within its service territory" and, therefore, "distribution projects that are intended to bolster the reliability of the distribution system are prioritized within the Company's planning processes." *Id*., pp. 10-11.

E. Alpena Power Company Report

On November 1, 2021, Alpena filed a report in response to the August 25 order (Alpena report).[5] Alpena indicates that its service territory experienced two severe storms between August 9 to 14, 2021, but notes that "while they were significant in severity neither reached the magnitude of Catastrophic Events defined as 10% or more customers losing service." Alpena

[5] While the Alpena report is not paginated, the Commission references page numbers in natural order beginning with the first page of the report.

report, p. 4. Alpena states that the August 9 storm caused 737 customer outages with an average outage duration of 100 minutes, while the August 11 storm caused 694 customer outages with an average outage duration of 197 minutes. The company indicates that its restoration efforts were completed by its own crews and local tree trimming contractors.

1. Summary of the Utility's Ongoing Vegetation Management and Grid Hardening Efforts

Alpena states that its vegetation management consists of cycle-based trimming and spot trimming to improve circuit performance or upon customer request. The company notes that cycle-based trimming "is the preferred and most cost-effective method to directly affect safety and reliability. Alpena has determined that a 5-year trimming cycle is optimal to provide the level of safety and service reliability expected by Alpena's Customers." *Id*., p. 6. Alpena summarizes its vegetation management from 2017 to September 2021, including costs and miles trimmed in Table 1 and tree-related outage information in Table 2. *See*, *id*., pp. 6-7. The company indicates that tree-related outages were mostly consistent through the years, but avers that recent increases may be "due to a combination of forest health issues, such as the Emerald Ash Borer and Oak Wilt, and weather events." *Id*., p. 7. Alpena states that, in 2020, it decided to increase trimming to address tree-related outages, which included increasing the vegetation management budgets.

Alpena describes its approach to grid hardening as a three-pronged approach including "periodic testing and inspections, replacement of aged assets that are reaching the end of their expected design lives and grid modernization upgrades." *Id*. The company states that its testing and inspection program includes varying weekly, monthly, and annual testing and lists its total maintenance expenses in Table 3. *See*, *id*., p. 8. Alpena gives examples of its recent replacement of aging assets including substation transformer replacements, substation circuit breaker or recloser replacements, and distribution pole replacements. The company states that the goal of its "grid modernization program is to increase both reliability and resiliency of the grid by implementing projects that; [sic] target areas where a single failure can cause a significant customer outage and implement redundancy, enhance contingency capacity . . . and expand Supervisory Control and Data Acquisition." *Id*., pp. 8-9. Alpena provides specific examples of projects and notes that "[t]he combination of aged asset replacement and grid modernization make up a majority of Alpena's capital expense" which are listed in Table 4. *Id*., p. 9.

2. How Current Efforts Have Contributed to Reliability Performance

Alpena provides its SAIFI data without major storms included (Table 5), SAIFI data with major storms included (Table 6), SAIDI data without major storms included (Table 7), SAIDI data with major storms included (Table 8), CAIDI data without major storms included (Table 9), and CAIDI data with major storms included (Table 10) at pages 10 to 15 of its report. The company avers that the data provided demonstrates that "[g]rid hardening efforts such as vegetation management have the most immediate impact on reliability indexes such as SAIFI and SAIDI" and that "[o]ther efforts such as periodic inspections and testing, aged equipment replacement and system upgrades have longer term effects on system reliability." *Id*., p. 16.

3. Ranked Breakdown of the Top 10% Worst Performing Circuits in 2021 to Date

Alpena also provides its 10% worst performing circuits of its 38 circuits based on its SAIFI data without major storms included (Table 11), SAIFI data with major storms included (Table 12), SAIDI data without major storms included (Table 13), SAIDI data with major storms included (Table 14), CAIDI data without major storms included (Table 15), and CAIDI data with major storms included (Table 16) at pages 16 to 17 of its report. Alpena presents a map depicting the circuits in Figure 2 and the company notes that "[t]he circuits with the poorest reliability performance are rural, front lot constructed overhead lines where a majority of the outages are vegetation and weather related." *Id*., p. 18. In addition, Alpena provides a summary of planned investments in Table 17. *See*, *id*., p. 19.

4. Maps of the Top Ten Zip Codes with both the Highest and Lowest System Average Interruption Frequency Index, and the Top Ten Zip Codes Where the Most Future Tree Trimming and Other Reliability and Resiliency Improvement Efforts are Planned

Alpena states that it serves a total of nine zip codes but that the majority of its customers are located in the 49707 zip code. The company notes that "[d]ue to its size and the relatively few zip codes served compared to circuit numbers Alpena does not track reliability metrics or projects by zip code." *Id*., p. 20. Nevertheless, the company provides a map of the zip codes served (Figure 3) and a table including the customer count by circuit and zip code (Table 18).

5. A Summary of Efforts Contained in Currently Filed Distribution Plans to Address Outages and System Reliability

The company responds indicating that it "does not currently file a distribution system plan." *Id*., p. 22.

6. Plans and/or Actions Taken Following the August 2021 Storms Addressing Outage Credits

The company indicates that due to the August 11, 2021 storm, "17 of Alpena's customers were without power for more than 16 hours with the final 2 customers being restored just over 24 hours after they lost power." *Id*. The company further indicates that it did not receive requests for bill credits "and therefore did not take any action to change procedures from what is outlined in the current Service Quality and Reliability Standards for Electric Distribution Systems." *Id*.

7. A Summary of Restoration Efforts During the August 2021 Storms

The company indicates that as a result of the storm on August 9, 2021, there were a total of 737 customer outages with 73,648 outage minutes. Alpena states that all restoration work was completed with Alpena crews and lists the total cost of the August 9, 2021 outage in Table 19 on page 23. With respect to the August 11, 2021 storm, the company states that there were 694 customer outages and illustrates the outage restoration in Figure 4 on page 24 of its report. Alpena further indicates that the longest outage duration from the August 11, 2021 storm included "13 customers in [a] rural subdivision that received extensive tree damage" and the company includes pictures of the damage at pages 25 to 27 of the report. *Id*., p. 24. The company again provides a table with the total cost of the August 11, 2021 outage in Table 20 on page 28.

In addition to the above, Alpena states that it "is in the process of implementing an outage management system which will increase customer communications through on-line outage mapping and an integrated voice response system. The system is expected to be on-line in Q2 2022." *Id*., p. 28.

8. Overhead to Underground Comparison

    a. Breakdown of Total Cost to Move a Typical Overhead Back Lot-Constructed Line and Overhead Front Lot-Constructed Line Underground

Alpena indicates that it has already converted many areas from overhead front lot-construction to underground construction and indicates that the conversion, on average costs $9.43 to $35.30 per foot (Table 21). *Id*., p. 29. The company indicates that "[t]he large range of costs is due to many factors including but not limited to; [sic] ground conditions (wetlands, rock, etc.), customer density, vegetation density and obstacles to construction (roadways, driveways, other utilities, etc.)." *Id*., pp. 28-29.

    b. The Difference in Costs of Maintenance of an Overhead Back Lot, Overhead Front Lot, and Underground Electric Line on an Average Annual Basis

The company states that it "does not track the differences in cost of maintenance of an overhead back lot, overhead front lot and underground electric line, on an average annual basis." *Id*., p. 29.

    c. Average Measured Reliability of an Underground Line Compared to a Comparable Back Lot and Front Lot Overhead Electrical Line

Alpena states that it "does not have any circuits that are primarily underground construction, instead the underground makes up a portion of many circuits typically in subdivisions, commercial areas or rural areas with repetitive outage issues." *Id*. The company also notes that the urban areas in its service territory typically have back lot-construction while the more rural areas typically have front lot-construction. Alpena provides the average SAIFI data from 2017 to September 2021 of its circuits noting the typical construction type in Tables 22 and 23. *See*, *id*., pp. 30-31.

d. Comparison of the Average Rate and Severity of Safety Incidents Relating to the Public and Utility Workers Associated with Underground Lines, Overhead Front Lot Lines, and Overhead Back Lot Lines

The company indicates that it "did not have any electrical contact incidents with overhead or underground electrical lines between [January 1, 2017, and September 30, 2021] that resulted in injury to utility workers, or any member of the public." *Id*., p. 32.

F. Northern States Power Company's Report

NSP-W filed a report on November 1, 2021, in response to the August 25 order (NSP-W report).

1. Summary of the Utility's Ongoing Vegetation Management and Grid Hardening Efforts

NSP-W states that it "has worked to develop grid hardening guidelines which lead to greater resilience of the distribution system" and that "the purpose of grid hardening is to ensure that if the system were to fail, it will fail in a manner that minimizes damage to the system leading to reduced outage times and fewer impacted customers." NSP-W report, p. 1. Nevertheless, the company contends that even with the grid hardening efforts extreme weather conditions will still have some effect on the customers and the system.

NSP-W notes that its Michigan service territory is located in a heavily wooded area "and consists of smaller conductors (i.e., wires) that have weakened over time due to repeated damage from vegetation landing on them. Because of this deterioration, the conductors have a higher susceptibility to breakage. Older, smaller poles are also more likely to fail when a tree lands on the line." *Id*., p. 2. The company adds that many outages occur on distribution taps rather than on the mainline feeder. According to the company, "[s]ince the majority of storm-related outages occur beyond the distribution taps, focusing efforts only on substation and feeder improvements, will not resolve all of the reliability issues" and that "it is necessary for NSP-W to focus efforts on distribution taps in addition to other capital asset health investments, like pole replacements." *Id*.

The company indicates that it regularly conducts maintenance on its system, including vegetation management, which consists "of several activities, including routine cycle maintenance on circuit-based projects occurring throughout the year on a targeted 4-year rotation, as well as non-cycle-based activities such as customer request response, storm and emergency response, and supplemental patrols when needed." *Id*., p. 3. NSP-W adds that vegetation management work varies from year to year but, on average, the company spends $370,000 per year on vegetation management in its Michigan service territory.

NSP-W states that with tree damage being a leading contributor to longer outages, it is essential for the company to rebuild areas of its system to address reliability concerns, including the relocation of lines to avoid vegetation damage. NSP-W notes that "[i]n 2021, about 75% of the $4,000,000 total capital forecast was focused on grid hardening efforts." *Id*.

2. How Current Efforts Have Contributed to Reliability Performance

The company provides a graph (Figure 1) to show the vegetation reliability from August 2020 through July 2021. NSP-W avers that the data demonstrates improved performance following cycle maintenance work. The company states that its analysis on the root cause of vegetation outages indicates that over 90% of outages in Michigan were not preventable (Figure 2). In other words, the company contends that, "if tree trimming were performed the day before, the event still would have occurred. These events are typically healthy tree and branch failures from vegetation outside the typical work zone." *Id*., p. 4.

NSP-W also provides its annual SAIDI and SAIFI data, both including and excluding MEDs (Figures 3 and 4). The company states even though the data in Figures 3 and 4 seems "to reflect a positive trend in reliability results for NSP-W Michigan customers, performance for both SAIDI and SAIFI show that [the] system is still prone to poor results relative to the average NSP-W System customer and the average utility customer." *Id*., p. 6.

3. Ranked Breakdown of the Top 10% Worst Performing Circuits in 2021 to Date

NSP-W provides Figures 5 and 6, which sort the 29 circuits serving customers by SAIDI (Figure 5) and SAIFI (Figure 6) as well as maps illustrating the location of each circuit (Attachment A). The company indicates that the majority of the outage minutes for the top 10% worst performing SAIDI feeders can be primarily attributed to storms, while the top 10% worst performing SAIFI feeders can be attributed to varying factors including the storms, "transmission system related outages, and vegetation related outages." *Id*., p. 6.

4. Maps of the Top Ten Zip Codes with both the Highest and Lowest System Average Interruption Frequency Index, and the Top Ten Zip Codes Where the Most Future Tree Trimming and Other Reliability and Resiliency Improvement Efforts are Planned

The company indicates that its 29 circuits serving Michigan span across six zip codes as illustrated in Attachment A to the report. However, NSP-W states that it does not track SAIFI data by zip code, but it provides Figure 7 which "uses data from January 2020 through August 2021 to demonstrate the SAIFI for all circuits and the zip codes served by each." *Id*., p. 9.

5. A Summary of Efforts Contained in Currently Filed Distribution Plans to Address Outages and System Reliability

NSP-W lists projects which will help improve the reliability of its system as follows:

• The Company has recently constructed the Penokee Range substation, which is a 12.5kV source, and is in the process of converting the 4kV system served from

> Ironwood substation. The new Penokee Range substation and conversion was prioritized because of the age and condition of the 4kV switchgear for which parts are no longer available for maintenance, arc flash concerns with the switchgear design, and the deterioration of the building housing the switchgear. This project improves reliability with a new substation, 12.5kV distribution, improved feeder ties with adjacent substations, and elimination of the 4kV substations at Ironwood and Northside.
>
> • Extending Bessemer Feeder BES021 five miles to connect with Great Lakes feeder GLA021 and rebuild GLA021 from single-phase to three-phase resolves the risk of an extended outage of the Great Lakes distribution if the substation transformer were to fail.
>
> • The Township Feeder Rebuild project will relocate portions of the feeder line that runs east of the Township substation from heavily vegetated right-of-way to road right-of-way and upgrade the conductor size. This project is being coordinated with [the] pole replacement program.

Id., p. 10. The company avers that these projects will have benefits including "increased reliability and capacity, in addition to reducing the risk from severely degraded wires and poles that are susceptible to vegetation-related outages." *Id*.

6. Plans and/or Actions Taken Following the August 2021 Storms Addressing Outage Credits

NSP-W indicates that it "is committed to providing safe and reliable service to Michigan customers" but that it "does not currently take specific actions to address outage credits during storm events, is unaware of any customer request for such credits, and does not have plans to make automatic outage credits." *Id*., pp. 10-11.

7. A Summary of Restoration Efforts During the August 2021 Storms

The company states that its service area was only slightly impacted by the August 2021 storms and that earlier storms in July had greater impacts. NSP-W indicates that its total costs from the summer storms was approximately $100,000, with the majority of expenses relating to the July 2021 storms. The company indicates that over 90% of customers were restored within 24 hours and that restoration efforts included "internal personnel from the Xcel Energy Distribution, Transmission, Vegetation, Civil, Electric Meter, Design, and Supply Chain organizations" and that "numerous contract crews were mobilized for the restoration effort." *Id*., p. 11.

NSP-W notes that it proactively made social media posts regarding safety and how to report outages as well as provided information to the Ironwood Daily Globe regarding outages and restoration efforts.

8. Overhead to Underground Comparison

   a. Breakdown of Total Cost to Move a Typical Overhead Back Lot-Constructed Line and Overhead Front Lot-Constructed Line Underground

NSP-W provides a table (Figure 8) listing the cost per foot to move typical overhead lines to underground. The company notes that "[i]t is highly likely that existing easements for overhead lines do not include provisions for underground construction. Prescriptive rights are not applicable to a change from overhead to underground." *Id*., p. 13. Therefore, NSP-W provides potential easement costs in Figure 9.

   b. The Difference in Costs of Maintenance of an Overhead Back Lot, Overhead Front Lot, and Underground Electric Line on an Average Annual Basis

The company indicates that, other than vegetation management, once an overhead line is constructed no other maintenance is generally performed on that line and that costs for performing vegetation management vary greatly. NSP-W estimates that costs for vegetation management for an average overhead front lot is approximately $6,000 per mile while average overhead backlot work is about $12,000 per mile. *See*, *id*. The company also indicates that reactive maintenance is performed on overhead and underground lines "when they reach their end of life and begin to cause performance and reliability issues." *Id*., p. 14. NSP-W states that overall annual maintenance costs are difficult to quantify but, "all factors considered, underground lines are more costly to maintain than overhead." *Id*.

c. Average Measured Reliability of an Underground Line Compared to a Comparable Back Lot and Front Lot Overhead Electrical Line

NSP-W states that it does not track the measured reliability of underground lines as compared to overhead lines, nor does its data distinguish between front lot or back lot overhead lines. Given that the company primarily operates overhead feeders, it avers that "[a] comparison of average measured reliability of an underground to an overhead line is not practical due to the small amount of underground in the system." *Id*., p. 14.

d. Comparison of the Average Rate and Severity of Safety Incidents Relating to the Public and Utility Workers Associated with Underground Lines, Overhead Front Lot Lines, and Overhead Back Lot Lines

The company states that, "[i]n the state of Michigan, there have been no injuries to NSP-W utility workers or contractors (minors, first aids or recordables) in 2021" and that there is "no record of any injuries to the public in Michigan in 2021." *Id*., p. 15.

G. Upper Michigan Energy Resources Corporation's Report

On November 1, 2021, UMERC filed its report in response to the August 25 order (UMERC report).[6]

1. Summary of the Utility's Ongoing Vegetation Management and Grid Hardening Efforts

UMERC provides two tables summarizing its line clearance projects for 2020 and 2021, with 2021 data being presented through September 2021.

2. How Current Efforts Have Contributed to Reliability Performance

UMERC states that "[d]ue to the numerous factors that influence reliability performance, it is difficult to draw a direct correlation relative to how the Company's line clearance projects in 2020

[6] While the UMERC report is not paginated, the Commission references page numbers in natural order beginning with the first page of the report.

contributed to 2021 reliability performance." *Id*., p. 3. The company further indicates that it does tree trimming by project area and not by municipality or feeder and, therefore, cannot provide improvements in SAIDI or SAIFI as a result of its efforts. However, UMERC provides a table demonstrating the change in customers interrupted (CI) and customer minutes of interruption (CMI). The company notes that while the project areas that had trimming saw an increase in CAIDI scores, so did those that were not trimmed. UMERC notes that its data shows "CMI increased in areas without trimming work and decreased in areas with trimming work. CI decreased in areas both with and without trimming work," which the company avers illustrates "that many factors influence reliability performance." *Id*.

3. Ranked Breakdown of the Top 10% Worst Performing Circuits in 2021 to Date

UMERC provides its top 10% worst performing circuits in Table 1, noting that "[t]he ranking by duration is shown in the SAIDI rank column and the ranking by frequency is shown in the SAIFI rank column." *Id*., p. 4. The company also provides maps illustrating the SAIDI rankings (Figure 1) and SAIFI rankings (Figure 2). *See*, *id*., pp. 5-6. The construction type, zip codes, and municipalities containing the top 10% worst performing circuits are provided in Table 2. *See*, *id*., pp. 6-7.

With respect to planned improvements, UMERC states that it has planned the following:

> • On WSM1, there is a planned project to create a 3-phase tie between WSM1 and LOL2. This project will extend approximately 11 miles of 3-phase primary conductor, with construction planned for 2022 through 2024. This tie will allow bridging to occur at the tail ends of WSM1 and LOL2, which will allow greater operational flexibility for maintenance on these circuits, as well as the capability to restore customers faster in an outage event.
>
> • On the PWR62 circuit, there is an on-going voltage conversion and rebuild project. In 2021, an approximately 2 mile section of primary conductor is being rebuilt to 24.9kV 3-phase. The second part of this project is planned to be constructed in 2022; converting and rebuilding an approximately 2 mile section of primary conductor from 13.8kV delta to 24.9kV grounded wye operation. This project will also be creating a 3-phase loop within the PWR62 circuit.

• On the LOL3 circuit, there is a planned project to be completed by the end of 2021 to replace the underground LOL3 feeder exit. As part of this project, the LOL2 underground feeder exit will also be replaced.

Id., p. 7.

4. Maps of the Top Ten Zip Codes with both the Highest and Lowest System Average Interruption Frequency Index, and the Top Ten Zip Codes Where the Most Future Tree Trimming and Other Reliability and Resiliency Improvement Efforts are Planned

UMERC provides a map (Figure 3) depicting the top 10 municipalities in its service area that have the highest and the lowest SAIFI scores based upon company data from January 1, 2020, through August 31, 2021. The company notes that it "does not have the requested data available for zip codes nor a map of the future trimming projects." *Id*., p. 8.

5. A Summary of Efforts Contained in Currently Filed Distribution Plans to Address Outages and System Reliability

UMERC states this question is not applicable to it and that "no response will be provided." *Id*., p. 9.

6. Plans and/or Actions Taken Following the August 2021 Storms Addressing Outage Credits

UMERC indicates that, while it plans to actively participate in this docket, it "did not experience any significant storm related outages during the month of August, 2021. As a result, UMERC has not initiated any specific plans or actions related to outage credits." *Id*., p. 10.

7. A Summary of Restoration Efforts During the August 2021 Storms

UMERC again notes that it "did not experience any significant storm related outages during the month of August, 2021" and, therefore, did not require mutual assistance, community support, or additional advertising as a result of the August 2021 storms. The company nevertheless provides its weather-related expenses for August 2021. *Id*., p. 11.

8. Overhead to Underground Comparison

a. Breakdown of Total Cost to Move a Typical Overhead Back Lot-Constructed Line and Overhead Front Lot-Constructed Line Underground

UMERC provides projected cost breakdowns for two projects converting front lot-constructed overhead to underground which, as of the date of filing, were expected to be completed in 2021. Further, the company states that it cannot provide meaningful high, low, and average cost estimates "given the varying degrees of field conditions and the limited number of such projects that UMERC performs given the uniqueness of its service territory. UMERC has not had a back-lot constructed overhead to underground project." *Id*., p. 12.

b. The Difference in Costs of Maintenance of an Overhead Back Lot, Overhead Front Lot, and Underground Electric Line on an Average Annual Basis

UMERC indicates that:

> From January 1 to August 31, 2021 overhead system maintenance expense was $942,631 while underground system maintenance was $80,222. Annualized overhead maintenance was $1,413,947 and annualized underground maintenance was $120,333. On a per mile basis, annualized overhead maintenance was $627 per mile while annualized underground maintenance was $137 per mile.

Id., p. 13. The company also notes that its overhead expenses are not broken down between back lot and front lot.

c. Average Measured Reliability of an Underground Line Compared to a Comparable Back Lot and Front Lot Overhead Electrical Line

UMERC states that "an underground line is roughly two times more reliable than an overhead line of the same length" based upon its analysis of 2013 to 2018 historical reliability data. *Id*., p. 14.

d. Comparison of the Average Rate and Severity of Safety Incidents Relating to the Public and Utility Workers Associated with Underground Lines, Overhead Front Lot Lines, and Overhead Back Lot Lines

As of the date of filing, UMERC indicates that its 2021 safety incidents are as follows:

• Seven safety incidents involving the Company's underground facilities. Four were dig-ins to underground lines and three involved vehicles striking pad mount equipment. All safety incidents involved third parties; no injuries were reported.

• Six safety incidents involving UMERC's overhead facilities. One involved a contractor making contact with an overhead service; the remaining five involved vehicles striking poles or down guys. No injuries were reported in any of the safety incidents. The Company does not keep track of overhead incidents on a front lot versus back lot basis.

• Zero employee incidents involving either underground or overhead facilities.

Id., p. 15. The company further states that these safety incidents are "indicative of the quantity and severity of safety incidents that UMERC has experienced in previous years." *Id*.

III. <u>COMMENTS</u>

The Commission has reviewed each of the comments and suggestions filed in this docket and expresses its gratitude to all that took the time to file comments and suggestions for the Technical Conference. The comments and suggestions are summarized as follows.

A. Public Comment

The Commission received numerous individual comments from utility customers and other interested persons. Many of the concerns noted in these comments include the frequency of power outages and concerns about the duration of outages, including costs incurred by utility customers from loss of food, medications, and lodging. Several commenters also note that, despite rate increases and having some of the highest rates in the United States (U.S.), outages are still common occurrences. Local officials file similar comments, passing along the concerns of their constituents as well as listing varying concerns pertaining to tree trimming and the inaccuracy of information shared by utilities.

Numerous individuals also recommend the implementation of programs to target health and safety issues as well as energy waste reduction (EWR) resources. Specifically, commenters indicate that such resources should be directed to communities in most need and with the highest energy burdens. Several commenters also suggest topics or panel topics pertaining to the Technical Conference. Additional comments are summarized below.

B. Utility Comments

1. Consumers Energy Company's Comments

On September 24, 2021, Consumers filed comments in response to the August 25 order (Consumers' comments). Consumers first notes that the terms "reliability" and "resilience" are related, but not identical terms. Consumers avers that reliability can be measured through industry standard SAIDI, SAIFI, and CAIDI metrics "which effectively measure how often and how long customers are without power." Consumers' comments, p. 2. Noting that a consensus has not been reached regarding the definition of resilience, the company defines it "as the ability of the system to withstand a major event (particularly, in this context, a large storm) and the ability of the system to recover from a major event when damage occurs, minimizing the needed restoration and repair time." *Id*.

Consumers states that it has observed that wind speeds have increased in severity in Michigan. The company notes that "[w]ind gusts are particularly damaging to the electric system, given the often-violent nature of gusts. The gustiest year in the past decade was 2019, with 2020 as the second gustiest, while 2017 was also severe." *Id*., p. 3. Further, Consumers contends that the rate of electric outages increases when wind gusts exceed 45 mph which "is indicative of system deterioration--at any given level of adverse weather, the system is less resilient to these conditions than it was in the past." *Id*., p. 4 (footnote omitted). The company notes that while ice and lightning can also be damaging, these weather hazards are less frequent and, as illustrated in Figures 3 and 4, the majority of MEDs from 2011 through 2020 involved high winds. *Id*., pp. 5-6.

Consumers further contends that it does not solely rely on historical data in its current planning processes. Rather, the company states that it:

> utilizes its Reliability Analytics Engine to analyze historical outage minutes across the grid, identify trends, and assess zones with the greatest potential reliability improvement opportunities by considering the consistency of outages, outage rate, customer impact, and current year outages. Beyond this, the Company's investments in the grid are also based on real-time inspections, real-time testing, forecasted load growth (particularly for Capacity investments), and projected system benefit (particularly for Grid Modernization investments). In this way, both the experienced and projected outages on a given zone are included in the ranking of low voltage distribution ("LVD") zones to target investment to maximize SAIDI reduction.

Id., pp. 6-7. The company explains that, in its most recent electric rate cases, it "has compared the overall size of the distribution system to what proportion of the system can be hardened in the year of analysis" which allows it "to identify the worst performing parts of its system each year and allows for prioritization of projects that specifically address that poor performance." *Id*., p. 7.

Consumers references its 2018 through 2021 EDIIPs, noting that it has set forth plans to increase investments and harden more of the system. The company alleges that "[i]ncreased investment will allow the Company to incorporate projections of future, potentially worsening, weather as the climate changes – the Company will be able to address system deterioration while also considering how more severe weather may impact the system and prioritizing investments to address vulnerabilities." *Id*., p. 8. While noting that its investment planning is a reactive approach, Consumers claims that it still produces prudent investments which are proven to overcome and mitigate observed events.

The company also contends that it has developed its reliability standards over several decades but recently highlighted several updates to design standards in the 2018 EDIIP. After detailing some standards, Consumers states that while its:

> use of more robust design standards over time leads to increased resilience, there are tradeoffs to consider in instituting even stricter standards. The higher cost of enhanced standards would mean either (a) that the Company can address less of its system over a given period, assuming total investment stays the same, or (b) that increased investment is needed in order to continue addressing similarly sized sections of the electric system going forward. Recent rates of investment have only allowed the Company to address a small percentage of the distribution system each year; in order to address system deterioration and make needed investments to harden the system against worsening weather due to climate change, investment levels will need to be ramped up.

Id., p. 10.

The company states that investments result in overall system resilience because present day standards are more resilient than prior standards and the replacement of old assets, with higher failure rates, can result in an increase in both reliability and resilience. *See*, *id*., pp. 10-11. Consumers also contends that investments in grid modernization add resilience to the system because "[n]ew data gathering equipment and software tools provide greater insight to grid operators allowing them to monitor current grid conditions and take appropriate actions as conditions change . . . as well as expediting service restoration through automated means where possible." *Id*., p. 11.

Consumers indicates that investing in line clearing also boosts reliability and resilience and avers that it is the "most important action for reducing outages, particularly those related to high winds." *Id*., p. 12. The company summarizes its line clearing ramp up at Figure 6 and claims "[t]his is a cost-effective way to increase spending on line clearing over a period of a few years, allowing the Company to secure the needed line clearing workforce and effectively plan where to best target the new spending." *Id*.

Consumers states that forecasting is of utmost importance if utilities "are to plan investments for the realities of a future that may look very different from what has been historically experienced." *Id*., p. 13. Noting that forecasting of weather is difficult and can result in either over- or under-planning for an event, the company contends that it has been improving its weather forecasting including deploying the "Outage Prediction model produced by IBM, which allows current weather patterns, past outage history, and machine learning to determine the approximate number of customers that will potentially be impacted by a storm." *Id*. In addition to predicting specific weather events, the company notes the difficulty in forecasting impacts of climate change.

> While climate change is expected to result in higher frequency of storms in the future, indicating a need for further hardening of the system, these climate projections do not yet indicate specific locations on the system where wind is more likely to become more severe, limiting the ability to geotarget specific hardening investments. The Company is committed to studying best practices and leveraging industry research to learn how to do more geotargeting in the future. In the meantime, the Company will continue to ramp up its investments in reliability and resilience, as well as its line clearing activity, in order to harden more of the system in advance of worsening climate conditions.

Id., p. 14.

2. DTE Electric Company's Comments

DTE Electric filed its comments in response to the August 25 order on September 24, 2021 (DTE Electric's comments). The company references the filing of its 2021 DGP, which it states outlines DTE Electric's "short-term strategy and long-term vision for improving [its] electric grid." DTE Electric's comments, p. 1. DTE Electric states that it has adapted its grid planning process to face "evolving customer preferences, technological advances, changing regulations and policy, and a changing climate." *Id*. The company indicates that its grid planning methodology includes two components: (1) foundational distribution planning and (2) strategic planning. DTE Electric explains that foundational planning looks at reliability metrics like SAIDI, along with other factors, to prioritize distribution projects while strategic planning has a longer-term view.

DTE Electric states that, in its DGP, it "has adopted scenario-based planning to provide insight into potential future outcomes and to inform [the company's] investment strategy" and that it has "developed three distinct scenarios to identify and analyze the relevant trends likely to affect [its] business over the next 15 years." *Id*., p. 2. The company adds that one scenario includes increased catastrophic (CAT) storms to evaluate potential effects on DTE Electric's infrastructure and to project needed resilience investments to mitigate customer outages. DTE Electric notes that considering this scenario, it can account for "the realities of a future that may look different from what has been historically experienced," while also remaining flexible "given the inherent difficulty in predicting weather far into the future." *Id*.

Turning to its five-year plan, DTE Electric indicates that it plans significant investments in projects and programs to improve reliability performance including tree trimming, 4.8kV hardening, and PTMM. The company avers that "[t]hese reliability programs will upgrade large areas of the system over the next 5-years by reducing tree-related outages and replacing aging overhead equipment with stronger poles, fiberglass crossarms, and polymer insulators which all have increased strength in the face of inclement weather." *Id*., p. 3. DTE Electric indicates that its "longer-term plan also addresses reliability and resiliency by fundamentally rebuilding the grid through programs such as the 4.8kV conversion program and subtransmission rebuild and redesign program. These programs will continue to fully rebuild circuits to [the] latest, more reliable and resilient standard, while also adding needed capacity." *Id*.

In conclusion, DTE Electric states that its utilization of scenarios in its planning methodology allows consideration "of a future that may look very different from what has been historically experienced." *Id*.

3. Indiana Michigan Power Company's Comments

On September 24, 2021, I&M filed comments with its responses to the August 25 order (I&M's comments). I&M states that while it does not "currently develop climate change models or long horizon weather forecasting models, it does consider the impacts of increased and/or more extreme weather events in distribution planning process." I&M's comments, p. 1. Noting that its current Five-Year Distribution Plan utilizes design standards that are more robust than historical standards, the company contends that the more robust design standard "in turn, improves resiliency and lessens the likelihood of a weather event causing broken poles leading to outages." *Id*. I&M indicates that its grid modernization programs will also enable a more rapid restoration of service.

I&M additionally states that, as a transmission owner, it "has experienced how extreme weather can affect transmission system equipment and operations on a number of notable and documented events over the past 15 years, such as polar vortices and derechos." *Id*., p. 2. While the company adheres to the National Electrical Safety Code standards, it states that "no standard exists today to look at a local area's ability to withstand specific weather events. This type of analysis would need to consider multiple lines taken out of service at the same time, which is well beyond the NERC requirements." *Id*.

The company concludes that it "strives to meet the needs of its distribution and transmission systems related to increased instances of extreme weather" and "looks forward to working collaboratively with the Commission to evaluate forward-looking, long-term criteria to plan future investments and upgrades to the Company's distribution and transmission systems targeted at addressing the increase in extreme weather." *Id*.

4. Northern States Power Company's Comments

NSP-W filed comments on September 24, 2021, in response to the August 25 order (NSP-W's comments). The company states that its priorities for the electric distribution system include "reliability, safety, and customer focus," which it contends support its recently proposed capital investments. NSP-W's comments, p. 2. NSP-W explains that it makes capital investments in distribution "to improve the safety and reliability of the system, to improve system functionality, and to modernize the distribution system" and that it "also maintains safe and reliable service by making significant investments to support capacity needs due to increased loads from existing or new customers and to relocate existing facilities in response to road construction projects." *Id*. The company adds that it is making forward-looking investments to increase safe and reliable service for its current customers but also is laying groundwork for the future needs of the grid. NSP-W contends that additional spending, above historical levels, is needed to "meet the requirements to improve [the company's] system integrity, ensure employee and public safety, and to fulfill customers' reliability expectations." *Id*.

The company notes that its data shows that average outage times for NSP-W's Michigan customers exceed the average outage time per customer in its Wisconsin jurisdiction. NSP-W contends, therefore, that its "Michigan service territory is in need of additional capital investments to storm harden the system and to improve safety and reliability." *Id*., p. 3. Noting that "with the advent of social media, customers share their knowledge and frustration when they have an outage" and "are becoming less accepting of outages caused by storms," the company states that it is working to improve the resilience of its distribution system. *Id*.

NSP-W indicates that even though it is working to harden the grid, extreme weather conditions will still have an impact on its system, especially regarding older infrastructure and heavily wooded areas, such as in its Michigan service territory. Going forward, the company states that "it is necessary to focus efforts not only on substation and feeders, but also on distribution taps and a more robust pole replacement program." *Id*.

The company concludes that "is not appropriate to rely solely on historical storm outage data for utility planning purposes, but rather to utilize a balance of historical storm outage data and grid hardening efforts" and that "[s]torms are extremely unpredictable, therefore, the Company is proposing to continue grid hardening [its] distribution system so that [it is] able to withstand the storms, improve reliability and improve SAIDI and SAIFI results." *Id*., p. 4.

5. Upper Michigan Energy Resources Corporation's Comments

On September 24, 2021, UMERC filed comments responding to the August 25 order (UMERC's comments). The company states that "[o]f paramount importance in UMERC's infrastructure planning is to ensure the safe, reliable and resilient operation of its electric distribution system. UMERC's electric distribution system is designed to perform reliably under many conditions and to be able to recover from disruptive events." UMERC's comments, p. 1. The company notes that "[w]ith the advent of social media, customers share their knowledge and frustration when they have an outage" and "are becoming less accepting of outages caused by storms." *Id*., p. 2. Therefore, UMERC contends that it is working to "develop grid hardening guidelines, which lead to greater resilience of the distribution system." *Id*.

The company indicates that it conducts regular assessments and risk analysis of its distribution infrastructure which, is "based, in part, on historical data is vitally important in distribution infrastructure planning and is sufficiently robust for planning purposes. Incorporating historical trend information in the forward-looking long term planning process safeguards a reliable and resilient distribution system." *Id*. UMERC states that its service territory has older facilities and heavily wooded areas, which makes it more prone to being impacted by significant weather events even though it is implementing various grid hardening efforts.

UMERC notes that it "recognizes that it is not adequate to rely exclusively on historical storm outage data for distribution system planning purposes, but rather to utilize a balanced approach that includes historical storm outage data along with grid hardening and resilience improvement objectives to plan distribution system work." *Id*. Further, the company states that capital investments greater than its recent historical investments will be necessary to continue to improve the resiliency of its distribution system.

C. Commission Staff's Comments

On October 4, 2021, the Staff filed comments in response to the August 25 order (Staff's comments).[7] The Staff requests that the deadline be extended to March 31, 2022, for filing formal comments in response to the August 25 order, given that the reports from IOUs are to be filed after the comment deadline, "and that the Commission is hosting a technical conference over two sessions (October 22, 2021, and November 5, 2021) which will provide further information relevant to the state of electric distribution systems and utility plans relative to these systems that would be useful to review when answering these questions." Staff's comments, p. 6.

D. Michigan Department of Attorney General's Comments

On September 17, 2021, the Michigan Department of Attorney General (Attorney General) filed comments in response to the August 25 order (Attorney General's September 17 comments).[8] With her comments, the Attorney General provides the National Association of State Utility Consumer Advocates (NASUCA) 2019 resolution. The Attorney General avers that the NASUCA resolution is especially relevant given the recent increases in outages due to extreme weather:

[7] While the Staff's comments are not paginated, the Commission references page numbers in natural order beginning with the first page of the comments.

[8] While the Attorney General's comments are not paginated, the Commission references page numbers in natural order beginning with the first page of the comments.

"The Attorney General is concerned that an extended electric outage during an extreme heat wave or cold snap could endanger lives." Attorney General's September 17 comments, p. 1. Therefore, she recommends that the Commission "consider implementing a plan now to address such a situation that could occur in the future as we experience more of these extreme weather events." *Id*. The Attorney General also notes her interest "in discussing more metrics and benchmarking of storm outage events and restoration times to ensure that customers are getting the best service possible for electric rates they are paying every month," as well as implementing additional performance-based measures and requiring reductions in annual outages "to ensure that the money being spent on tree trimming and other distribution upgrades are having the desired impact." *Id*.

In addition, the Attorney General submitted comments on September 24, 2021 (Attorney General's September 24 comments). Noting that the August 2021 storms were intense, the Attorney General states that gathering data is of utmost importance in determining the true causes of outages. She contends that the information requested by the Commission is a "good start" but will be "insufficient to determine the root causes of power outages" and:

> [u]ntil the utilities provide additional critical information on specific causes and effect, specific circuits affected, and granular information on the specific causes of power outages by area, tree density, etc., it is not possible to define appropriate solutions that maximize the effectives of any required spending to fix those real problems.

Attorney General's September 24 comments, p. 2. The Attorney General further contends that the evaluation of additional data will assist in creating solutions to prevent and minimize outages. She agrees that "it is worthwhile to explore the possibility of burying all power lines underground" but contends that "[t]he benefits, challenges, and costs of this option need to be thoroughly evaluated, including the long-term cumulative impact on customer bills and the impact on customer affordability of large increases in electric bills." *Id*., pp. 2-3.

The Attorney General notes that "[p]redicting future events is fraught with pitfalls, particularly when trying to anticipate weather events." *Id*., p. 3. She continues that:

> [b]ecause climate change is a reality, however, it is critical to assess whether recent extreme weather conditions are cyclical events or long-term weather trends. It makes sense to do the outmost within customer affordability limits to strengthen the electric distribution infrastructure, once we better understand what the root causes of the power outages are and how they can best be resolved.

Id.

E. Great Lakes Renewable Energy Association's Comments

On September 17, 2021, the Great Lakes Renewable Energy Association (GLREA) filed comments in response to the August 25 order (GLREA's comments).[9] GLREA avers "that ratepayers for DTE Energy [Company] and Consumers Energy are paying the highest rates in the upper Midwest and are receiving some of the worst service in the country with Michigan ranked the fourth worse [s]tate for [g]rid reliability." GLREA's comments, p. 1. GLREA indicates that these companies have received substantial rate increases in recent years with a poor reliability record and, because they operate as state-sponsored monopolies, ratepayers have no choice but to pay a substantial amount of money for unreliable service. GLREA states that ratepayers' options are further limited by the cap placed on distributed generation, limiting the ability to take control of energy needs by installing solar energy systems.

GLREA suggests building resiliency into the grid by: (1) increasing the ability of residential ratepayers to install behind the meter solar; (2) utilizing micro-grids to reduce the geographical size of outages; (3) accelerating solar and battery storage on the grid to be used during outages;

[9] GLREA filed initial comments and revised comments on the same date. For purposes of this order, the Commission references only GLREA's revised comments. In addition, while the GLREA's comments are not paginated, the Commission references page numbers in natural order beginning with the first page of the comments.

(4) addressing the economic impacts of power outages "on ***low and moderate income rate-payers and Black, Indigenous, People of Color communities*** and the disproportionate number and length of outages in these communities;" and (5) changing the way utilities are compensated including moving to PBR metrics. *Id*., p. 3 (emphasis in original).

F. 5 Lakes Energy, LLC's Comments

On September 23, 2021, 5 Lakes Energy, LLC (5 Lakes) filed its comments in response to the August 25 order (5 Lakes's comments).[10] 5 Lakes begins by indicating that, "[e]ven if the Commission and the utilities it regulates pursue aggressive programs to address electricity distribution reliability assuming worsening climate conditions, it will be many years before those programs have full effect." 5 Lakes's comments, p. 1. 5 Lakes states that the Commission should enable community resilience when there are large-scale and prolonged outages and that local governments should be included in the development of future distribution system and outage planning. 5 Lakes contends that with large-scale and prolonged outages other support systems, like water and sewer services, telecommunications, and gas delivery, can fail in correlating events. Therefore, 5 Lakes states the Commission should consider scenarios with cross-system effects and dependencies.

5 Lakes indicates that the Commission should consider all potential causes of outages, recommending "that planning be based on a series of 'design conditions', each of which reflects the combined weather conditions that occur together and cause large-scale or prolonged outages," which "could be specified based on major outages experienced in the last decade and the frequency or parameters of those conditions forecasted based on changing climate projections."

[10] While 5 Lakes's comments are not paginated, the Commission references page numbers in natural order beginning with the first page of the comments.

Id., p. 2. 5 Lakes avers that systematic biases in the load and resource and sales forecasts submitted by the utilities will lead to adverse results. Specifically, 5 Lakes states that "if load is under-projected in a rate case then fixed and embedded costs allocated to the under-projected load will lead to excessive rates." *Id*.

5 Lakes states that, in addition to recognizing weather trends, "the Commission should note that the variability from year-to-year is large enough that a short-run average over 3-5 years is likely to be an uncertain predictor of weather in even the next year" and "therefore recommend[s] that the Commission make use of trended weather as the normal practice in its cases rather than using short-term or long-term averages." *Id*., pp. 2-3. 5 Lakes further contends that it is necessary for the Commission "to consider the correlated effects of weather on load, generation, and transmission when developing resource plans and especially when assessing system resource adequacy" and that it is key that "analyses account for the full correlated effects of weather on the whole system." *Id*., p. 3. Therefore, 5 Lakes recommends that the Commission should require "that utility planning account for weather holistically, using more sophisticated models than the simple temperature-based normalization or forecasts that are currently used" and "that forecasting renewable generation, capacity availability, transmission capacity, and load be done on a coherent basis that reflects the physics-based correlation of these aspects of power and gas systems." *Id*.

In conclusion, 5 Lakes states that:

> reliability and outage consequences should be approached by considering outage risks conditioned on weather and then considering the likelihood of weather conditions that cause outages or resource inadequacy. It will then be possible to focus risk analysis and planning on the specific adverse conditions that are most challenging to the utility and its customers and develop plans or programs around those design conditions.

Id.

G. Association of Businesses Advocating Tariff Equity's Comments

On September 24, 2021, the Association of Businesses Advocating Tariff Equity (ABATE) filed comments in response to the August 25 order (ABATE's comments). ABATE states that the Commission's question regarding "the appropriateness of using historical weather data in utility planning" inappropriately "omits a bigger question regarding the most cost-effective ways to reduce the impact of increasingly common severe weather events on the electric grid." ABATE's comments, p. 1. ABATE states that a new approach to distribution planning is necessary and the current processes using historical weather data "are not sufficiently robust and fall far short of the rigor required." *Id*., p. 2.

ABATE notes that the first consideration is to determine the appropriate balance to reduce storm impact while not causing extreme rate increases through "considering both the most cost-effective ways to reduce storm impact and how storm impact reduction compares to other spending priorities." *Id*., p. 3. ABATE avers that there are three categories of storm impact reduction: resilience, restoration, and independence. For resilience, ABATE states that utilities can trim trees, harden the grid, and have grid redundancy or flexibility. ABATE indicates that utilities can call in mutual aid crews to help with restoration and that this could be done earlier. For independence, ABATE claims that while this category is "largely limited today, this may change in the future, with implications for grid investment." *Id*.

ABATE contends that it is likely that tree trimming is the most cost-effective resilience approach and notes its endorsement of a reduction in tree trimming cycles, if reasonable and prudent. For grid hardening, ABATE avers that there is no research that shows presumptive replacements of equipment provide reliability benefits exceeding the cost; therefore, "these distribution grid programs are unlikely to represent a cost-effective approach to storm impact reduction." *Id*., p. 6. ABATE also claims that the undergrounding of overhead lines does "not deliver reliability-related benefits in excess of costs." *Id*. ABATE notes that, in addition to the cost, faults in underground lines take longer to find and repair and have shorter useful lifespans than overhead lines. ABATE contends that the largest problem with utilizing costly back-ties to interconnect nearby circuits is that storm damage is typically widespread and "[i]f there are no energized circuits nearby from which to secure back-up electric supply through re-routing, the capability clearly becomes much less valuable in reducing storm impact." *Id*., p. 7. ABATE alleges that calling in mutual aid crews sooner can also reduce storm impacts on customers. With respect to grid independence, ABATE states that customer independence is an important consideration and, given declining prices in photovoltaic solar and battery storage, "more customers are likely to become independent of the grid during emergencies." *Id*., p. 8. ABATE contends that pilots and formal research are necessary to best determine the cost-effectiveness of storm impact reduction measures.

Continuing, ABATE claims that Michigan ratepayers can only support a limited rate increase, and as a result, "[d]ifficult decisions and trade-offs regarding spending priorities will therefore be necessary and unavoidable." *Id*., p. 9. ABATE further indicates that utilities alone should not be making these decisions and that the Commission and stakeholders must participate in the planning processes. ABATE avers that the utilities' proposed capital investment increases "are not justified by favorable cost-benefit analyses or technical rationale. Instead, the investments are justified by promises of reliability improvements not demonstrated through pilot results or research." *Id*., p. 10.

ABATE contends that the current distribution planning process changes Michigan regulatory policy as it reduces the risk of cost disallowances for utilities and shifts risk from shareholders to customers. ABATE claims that "[t]he Commission should carefully consider the ratepayer protections and utility burdens that have been weakened under the new distribution planning process and should take whatever corrective actions the Commission deems appropriate, including a more detailed and stakeholder involved planning process." *Id*., p. 11. ABATE alleges that:

> The current construct of distribution planning with no discovery, and forward test years with relatively inadequate discovery periods ill-suited to the dynamics and complexities of modern distribution investment and operations, puts stakeholders at a distinct evidential disadvantage. Combined with inherent information and expertise asymmetry it is clear stakeholders and ratepayers are inequitably handicapped under the current planning and ratemaking processes.

Id., p. 12.

ABATE further argues that stakeholders are contending with missing data points such as the lack of benefit/cost analyses, which it contends is inexcusable. Without this information, ABATE states that it is not able to "translate the reliability improvements a utility projects from its plan or components into economic benefits to the community served by the utility." *Id*., p. 13. ABATE states that "[a]n accurate estimate of the economic impact of service outages to Michigan's economy is essential to crafting a plan to reduce storm impact. Without it, ratepayers and the Commission cannot be sure if customers and the utility are investing too much or too little." *Id*.

ABATE recommends that the Commission should improve the distribution planning process and, that prior to amending the process, the Commission should set forth guidelines for consideration by utilities, stakeholders, and the Staff. Some factors that ABATE recommends for the guidelines include process steps, transparency, benefit/cost analysis, risk-informed decision-making, decision rights, process administration, and mandates. *See*, *id*., pp. 14-16. ABATE also recommends that the Commission appoint the Staff to secure missing datapoints including "researching both the cost effectiveness of various storm impact reduction measures and the value of reliability improvements." *Id*., p. 16. Additionally, ABATE contends that missing data points include cost and benefits and the economic impact of electric interruptions of varying extents and durations. ABATE explains that the "Staff should be tasked with overseeing both of these research projects to reduce bias." *Id*., p. 17. ABATE concludes that "the Commission should implement the recommendations provided [in its comments] to ensure a thorough and informative distribution system planning process to avoid unnecessary rate increases while advancing State policies." *Id*.

H. Initiative on Climate Risk and Resilience Law's Comments

On September 24, 2021, the Initiative on Climate Risk and Resilience Law (ICRRL) and two of its member organizations, Columbia Law School's Sabin Center for Climate Change Law and the Institute for Policy Integrity at New York University School of Law (collectively, the ICRRL group) filed comments in response to the August 25 order (ICRRL group's comments). The ICRRL group notes its concern that the utility planning processes rely too heavily on historical data which does not reflect climate change as a reality. The ICRRL group states that "[t]here is broad agreement among scientists that climate change is and will continue to increase the frequency and severity of extreme weather events, which . . . pose a major risk to utility infrastructure." ICRRL group's comments, p. 2 (footnote omitted). While noting that utilities have had to address weather-related issues, the ICRRL group states that climate change is a new issue which presents a fundamentally different problem because it is "likely to affect utility systems in multiple, compounding, and synergistic, ways, both because individual climate impacts may affect multiple parts of the system and because multiple impacts may occur simultaneously." *Id*. (footnote omitted).

The ICRRL group contends that utility planning will need to be modified to incorporate climate change risks and resiliency to address potential causes of failure. The ICRRL group recommends that the Commission "require electric utilities under its jurisdiction to regularly assess their climate-related vulnerabilities and identify measures to make their systems resilient to climate impacts." *Id*., p. 3. The ICRRL group contends that planning based on historical data is insufficient and to the detriment of ratepayers because it fails to recognize changing weather patterns and will increase the potential for weather-related electricity outages. The ICRRL group states that:

> basing electric system planning solely on historic [sic] weather data is likely to result in utility assets being designed, installed, or operated in ways (and locations) that make them vulnerable to climate change-amplified weather and environmental shifts. This will, in turn, impair utilities' ability to deliver reliable electricity services and increase the costs faced by customers. Given the long-lived nature of many utility assets, failing to plan for future climate impacts is likely to cause utilities to incur avoidable costs, possibly in the form of retrofits or early retirement of assets, both of which ultimately burden customers.

Id., p. 4.

The ICRRL group references the *Climate Risk in the Electricity Sector: Legal Obligations to Advance Climate Resilience Planning by Electric Utilities* (Resilience Planning Paper) which it attached to its comments to recommend that the Commission adopt a two-stage planning process including:

> 1. a climate vulnerability assessment, which uses forward-looking climate projections . . . to identify where and under what conditions assets and systems are at risk from the impacts of climate change; and
>
> 2. a climate resilience plan, which evaluates measures to reduce the risk to vulnerable assets and systems.

ICRRL group's comments, p. 5. The ICRRL group indicates that these efforts can take a number of forms but, "[i]n developing climate resilience plans, electric utilities match risks to responsive measures, compare the expected net effects of those measures and, on that basis, determine whether, when, and how to invest." *Id*. Reiterating the importance of resilience planning, the

ICRRL group states that grid hardening projects have long lead times that must be accounted for now to improve reliability in the future.

The ICRRL group states that there are limited examples of utilities that are already engaged in resilience planning and that there is additional guidance available in published reports. According to the ICRRL group, "[t]hose reports generally recommend that electric utilities take a long-range, 50-plus year view and plan for the impacts of climate change over the anticipated useful life of existing assets and new assets under development," and that "electric utilities should not necessarily limit their review solely to assets they own or operate, particularly where their ability to deliver reliable electricity services depends on facilities owned or operated by third-parties, such as generators." *Id*., p. 6. The ICRRL group notes that some utilities are concerned about utilizing climate projections because the data is too uncertain but states:

> [h]owever, using well-established modeling techniques, scientists can project likely future conditions based on historic [sic] and anticipated future emissions. While most models produce coarse-resolution projections (e.g., showing conditions within a grid cell that may be 60 square miles or more in size), those projections can be refined through downscaling to estimate climate impacts at finer geographic scales (e.g., in increments of one square mile or less). Probability distributions can be attached to the projections, enabling an assessment of the relative likelihood of different climate outcomes, and thus providing decision-useful information that electric utilities can employ in planning.

Id., p. 7. In conclusion, the ICRRL group urges the Commission to "take steps to ensure that electric utilities better prepare for the impacts of climate change, including by engaging in climate resilience planning." *Id*., p. 8.

I. International Transmission Company and Michigan Electric Transmission Company

On September 24, 2021, the International Transmission Company d/b/a ITC*Transmission* and Michigan Electric Transmission Company (collectively, the ITC companies) filed joint comments (ITC companies' comments). The ITC companies note that, as independent transmission companies, they "are uniquely positioned to comment on the challenges associated with the system-wide planning, coordination, and integration that must occur to ensure the reliability and resiliency of the electric system given the increasing prevalence of extreme weather events." ITC companies' comments, p. 1. The ITC companies state that they have participated in the transmission planning process for the Midcontinent Independent System Operator, Inc. (MISO) market and advocate for longer-term planning "because it will allow the industry to analyze the best available information to plan for the future. In addition, given the long-lead time and other difficulties associated with transmission development, long term planning is crucial to the reliability of the grid." *Id*., p. 2.

The ITC companies state that:

> although individual systems must be planned and built to withstand extreme weather events and ensure reliability as the generation mix changes, it is imperative for there to be robust collaboration and coordination amongst all stakeholders as we move toward an uncertain future because despite the industry's best planning efforts, there will be unexpected events that require reliance on other systems.

Id. The ITC companies aver that it would be dangerous for a single state to handle issues surrounding climate change on its own "because it could jeopardize not only electric delivery for the customers within its borders but also for electric customers in broad regions." *Id*. The ITC companies also state that they "have significant experience and a proven track record regarding storm preparedness and restoration" and that they "are available and willing to be a resource on storm preparedness for the Commission and other stakeholders as needed." *Id*., p. 3. In conclusion, the ITC companies indicate that they:

> believe that forward-looking, long-term planning is crucial for transmission infrastructure and also believe that it will be beneficial to the planning of the entire electric grid. Long-term planning enables collaboration among all stakeholders because the anticipated electrical solutions are known. In other words, it is easier to create and fit the puzzle pieces together if all stakeholders have an understanding of where we are headed in the long-term.

Id.

J. Advanced Energy Economy and the Michigan Energy Innovation Business Council

On September 24, 2021, Advanced Energy Economy and the Michigan Energy Innovation Business Council (collectively, AEE/MEIBC) filed joint comments in response to the August 25 order (AEE/MEIBC's comments). AEE/MEIBC begins by noting that "the two largest storms in DTE Electric's 135-year history have occurred within the past four years," and therefore, it shares "the Commission's concern that there is a need to examine utility planning processes and improve upon existing methods to prepare for a future that may look very different than the past, which includes increasingly frequent and severe weather events." AEE/MEIBC's comments, p. 1. Continuing, AEE/MEIBC avers that the extreme weather over the past 18 months has put an unprecedented strain on the country's energy system. Therefore, AEE/MEIBC recommends that the Commission direct utilities to use an updated climate model, such as the U.S. Department of Energy's Argonne National Lab's (ANL's) Regional Climate Model, "as an input to create a more robust planning process that accurately assesses future climate trends." *Id*. AEE/MEIBC explains that ANL's Regional Climate Model "can provide a spatial resolution down to the neighborhood level to estimate future weather in a region" and "can also combine topographical data to estimate the risk of flooding in a region at the neighborhood level and assess the likelihood of extreme weather events for a timeline out to 2050." *Id*., pp. 1-2. AEE/MEIBC indicates that the data provided by such modeling could support or even replace historical weather data in the planning processes of distribution and transmission. AEE/MEIBC notes that utilities in New York and California have already added this model to their planning processes and that the Commission should "consider how Michigan utilities can incorporate this powerful tool into distribution and integrated resource planning processes." *Id*., p. 2.

In addition, AEE/MEIBC encourages "the Commission to continue pursuing improvements to utility use of demand response as a tool to mitigate the impacts of such extreme weather events whenever they occur." *Id*., p. 3. Referencing the October 29, 2020 order in Case Nos. U-20628 *et al*., AEE/MEIBC indicates that the Commission "identified important steps that Michigan utilities can take to foster the development of flexible demand resources, including using automatic controls and partnerships with third-party vendors to facilitate customer response." AEE/MEIBC's comments, p. 3 (footnote omitted). AEE/MEIBC contends that these efforts should be "implemented in conjunction with improved forecasting and planning to ensure that better information leads to specific utility action" and that EWR "coupled with load management during extreme weather emergencies offers significant potential to realize flexible load resources that can help maintain a reliable, resilient distribution system." *Id*.

K. Urbint's Comments

On September 30, 2021, Urbint filed comments in response to the August 25 order (Urbint's comments). Urbint comments that:

> • It is essential that planning for capital investments are based on quantitative frameworks that accurately reflect current and future conditions of an infrastructure system's environment. While such a framework must incorporate historical weather data and risk profiles of each threat to the system, it should also incorporate a growing margin of tolerance to accommodate future conditions.
>
> • There is an opportunity for utility capital and operational planning to be more dynamic. To accommodate a changing environment, long-term plans should be adjusted on an annual basis as new information related to weather and other environmental conditions that can improve long-term forecasting becomes available. On a more granular level, operations and maintenance work should be driven by risk-based prioritization models that incorporate situational, environmental conditions of the system. Combining annual and real-time

approaches for capital and O&M investments, respectively, would optimize resilience across the investment spectrum.

> • Machine learning (ML), a form of artificial intelligence, has the capability of understanding changing patterns more acutely than traditional probabilistic modeling approaches. Urbint respectfully requests that the Commission explores the incorporation of ML within capital planning and system operation and maintenance.

Urbint's comments, p. 1.

L. Citizens Utility Board of Michigan's Comments

On October 1, 2021, the Citizens Utility Board of Michigan (CUB) filed initial comments (CUB's initial comments). CUB avers that "recent widespread power outages are a concrete example of the trend that has been captured by reliability metrics for years—Michigan utilities are generally well below peer utilities in nearby states and across the United States on most measures of reliability." CUB's initial comments, p. 1 (footnote omitted). CUB further states that investments in the grid must be planned in advance, and as a result, the effects of investment will not be seen for years. CUB also notes its support for the Attorney General's comments and more specifically responds to the Commission's questions pertaining to Case No. U-20147. *See*, *id.*, pp. 2-10.

On October 21, 2021, CUB filed supplemental comments (CUB's supplemental comments). CUB states that "[a]ll outage statistics, including SAIDI, CAIDI, SAIFI, and the economic cost for the underlying outages should be reported by the grid component class whose failure caused the outage" including "power supply, transmission, transmission substation, subtransmission lines, distribution substation, primary distribution lines, line transformers, secondary lines, and customer services." CUB's supplemental comments, p. 1. CUB avers that a "breakdown of outage statistics by location in the grid would go far toward guiding investment programs to where they would be most cost-effective." *Id*. CUB states that it would be useful for the statistics to also be broken down by the cause of the outage.

In addition, CUB indicates that the use of statistics of outage frequency and worst circuits has only minimal value because "[p]roblems with recurring outages are likely caused by more local issues in circuit branches and often limited to the tails of those branches, so that persistently bad customer experiences may not be adequately targeted by circuit statistics." *Id*., p. 2. CUB, therefore, recommends utilizing a more customer-centric approach. CUB notes that AMI enables utilities to "identify and report on individual customers that experience frequent outages, identify clusters of customers who have the same outages and therefore likely have a common cause, identify larger clusters that may be associated with particularly brittle sections of the grid, and target those for remediation." *Id*. Therefore, CUB avers that "[m]apping of outage frequency using spatial statistical methods should be an essential part of utility accountability for targeting investments." *Id*.

CUB also indicates that the data can be combined with geographical data of social demographics to "help steer investments toward low-income and marginalized communities that experience disproportionately worse reliability." *Id*. Therefore, CUB recommends "the presentation of outage statistics by census tract in order to both provide a basis for broader geographical analysis and for social equity analysis" and "overlay mapping of recent and planned investments and tree trimming [which] will contribute toward more equitable utility efforts." *Id*. CUB states that maps by zip code illustrate this approach but could be improved.

M. Soulardarity's Comments

On October 4, 2021, Soulardarity and the Abrams Environmental Law Clinic (jointly, Soulardarity) filed comments in response to the August 25 order (Soulardarity's comments).

Soulardarity indicates that the impacts of the August 2021 storms demonstrate the clear need to improve the distribution grid, "especially in environmental justice communities." Soulardarity's comments, p. 1. Soulardarity contends that the credit provided to ratepayers was insufficient to cover expenses including spoilage of food and loss of medication from lack of refrigeration. Soulardarity adds that:

> Electricity powers medical devices that help keep some customers alive. Lack of necessary heating or cooling stresses bodies, harms health, and contributes to mortality. Electricity is also necessary for security, as outages can leave customers without their security systems or lighting at night. Customers' ability to work can be disrupted by not being able to rely on elevators in apartment buildings or having to wait for public transportation without streetlights. Low-income customers cannot easily afford to solve these problems by replacing wasted food and medicine, operating their own gasoline-powered generators, or staying in hotels that have power.

Id., p. 2. Soulardarity contends that these effects highlight the need for prioritization of "grid improvements in low-income and BIPOC [Black, Indigenous, and people of color] communities that suffer disproportionately from outages and downed wire incidents and do not have the resources to adapt when the power goes out." *Id*. Soulardarity further states that ratepayers who are not having their infrastructure upgraded should not be required to pay for undergrounding of lines in other areas.

IV. DISCUSSION

The Commission again notes its appreciation for the participation in this docket of a large number of interested parties, including the filing of comments and attendance at the Technical Conference. The participation and input provided is invaluable as the Commission continues to address the challenging topics of emergency preparedness, distribution reliability, and storm response in an era of increasingly severe weather exacerbated by climate change.

The Commission first acknowledges the many comments filed and presentations at the Technical Conference pertaining to planning for climate change. On August 20, 2020, the Commission issued an order in Case No. U-20633 (August 20 order) directing the Staff to hold a series of stakeholder sessions to research best practices in several areas relating to the integration of resource, transmission, and distribution planning, including "[i]dentifying potential revisions to the Commission-approved IRP [integrated resource plan] modeling parameters or the filing requirements to better accommodate transmission alternatives in IRPs in preparation for the next formal review of the Michigan IRP Planning Parameters expected to take place in 2022." August 20 order, pp. 3-4. In that regard, the second of five planned stakeholder meetings commenced on January 31, 2022, and included a discussion on climate change. In that discussion, the Staff proposed that the impacts of climate change be analyzed in two ways: (1) analyzing the overall effect of climate change on "normal" weather to heating and cooling degree days and (2) analyzing the impact of extreme weather. The Staff stated that the impact of the overall effect of climate change can be integrated into the utility load and demand forecasts and profiles as well as the impact to renewable resource generation, while the impact of extreme weather fits better into a risk assessment where correlated variables tie together in a stochastic model. Given this discussion, the Commission finds that the appropriate venue for continued discussion on planning for climate change is the ongoing MI Power Grid stakeholder proceedings where additional and more robust discussion can occur on this topic. Therefore, the Commission directs the Staff to consider pertinent comments and presentations, as filed in Case No. U-21122, as part of the ongoing stakeholder proceedings in the MI Power Grid initiative in Case No. U-20633. The

Commission also encourages those interested in participating in the ongoing discussions relating to planning for climate change to join the stakeholder process in Case No. U-20633.[11]

The Commission also finds that it would be beneficial to have a dedicated and publicly accessible set of resources on the topics of distribution system reliability, customer outages, and storm response. Therefore, the Commission directs the Staff to develop a webpage within the Commission's existing website that is dedicated to distribution system reliability, customer outages, and storm response to be completed in early 2023. The Commission envisions this webpage to be a resource for ratepayers and interested persons that will display the latest information related to distribution reliability. To achieve this goal, the Commission will consolidate some data already filed by the utilities in several different dockets and may require the filing of additional data by the utilities. To further inform this process, the Commission directs the Staff to work with the utilities to hold meetings and collaborate in the development of a reporting template for the filing of additional information pertaining to distribution system reliability, customer outages, and storm response. The Commission finds that the reporting template shall be finalized and filed by the Staff in Case No. U-21122 no later than November 18, 2022. The information to be included in the template with respect to distribution reliability will include annual reliability performance as reported in Case Nos. U-12270, U-16065, and U-16066; reliability metrics that have been proposed in utility distribution plans in Case No. U-20147; and other data or metrics currently reported to public utilities commissions in states that are collecting

[11] For more information, including details on past and future stakeholder meetings, and to sign up for updates, interested individuals can visit the Commission's dedicated webpage available at: https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/optimizing-investments-performance/phase-iii-integrated-resource-plan-mirpp-filing-requirements-demand-response-study-energy-waste-red (accessed February 24, 2022).

and/or incentivizing distribution reliability performance, including the Minnesota Public Utilities Commission.[12] The template should also contain data on outages per month and per storm, including number of outages and restoration times, and monthly tree trimming data including miles trimmed and dollars spent. Specifically relating to storms, the Commission would like to see information for individual events relating to storm type, number of customers interrupted, storm duration and restoration in days, dollars spent per event, dollars paid in outage credits per event, and mutual aid requested and the associated mutual aid costs per event.[13] After reviewing the utility reports filed in Case No. U-21122, the Commission finds that the granularity of data by zip code is especially useful, and that future data should contain the ability to be aggregated by circuit, zip code, and census tract or block.

In addition, the Commission notes its agreement with the comments that weather trends should be examined in future rate cases in addition to the short-term and long-term weather averages currently presented. In that regard, the Commission will consider this suggestion, along with other comments filed in Case No. U-18238, wherein the Commission continues to consider the reopening of the rate case filing requirements for a complete revision. *See*, September 24,

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[12] *See*, *In the Matter of a Commission Investigation to Identify Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operation*, Docket No. E-002/I-17-401, Order Establishing Performance Metrics (September 18, 2019) available here: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B0082456D-0000-CA1F-9241-23A4FFF7C2FB%7D&documentTitle=20199-155917-01 (accessed February 24, 2022).

[13] For example, see the SEA Final Report approved by the Commission on September 11, 2019, in Case No. U-20464, at page 53. The SEA Final Report appears in Case No. U-20464 as filing # U-20464-0063 and is also available here: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000005XrEbAAK (accessed February 24, 2022).

2021 order in Case No. U-18238. The Commission may also consider weather trend analyses included in filing requirements for future IRPs and distribution plans.

Finally, the Commission recognizes the Staff's request for an extension of time to file comments in response to the August 25 order relating to "the final distribution plan filed by Consumers on June 30, 2021, and the draft distribution plans filed by DTE Electric on August 2, 2021, and I&M on July 30, 2021, in Case No. U-20147" as well as the six-related questions posed by the Commission. August 25 order, pp. 9-10. The Commission concludes that the Staff's request is reasonable, and as such, extends the deadline for comments to be filed in Case No. U-20147 to May 27, 2022. The Commission will accept additional comments from all interested persons until this extended deadline. Any person may submit written comments in response to the distribution plans and questions posed in the August 25 order. The comments should reference Case No. U-20147 and should be received no later than 5:00 p.m. (Eastern time) on May 27, 2022. Address mailed comments to: Executive Secretary, Michigan Public Service Commission, P.O. Box 30221, Lansing, MI 48909. Electronic comments may be e-mailed to mpscedockets@michigan.gov. If you require assistance prior to filing, contact the Staff at (517) 284-8090 or by e-mail at mpscedockets@michigan.gov. All information submitted to the Commission in this matter will become public information available on the Commission's website and subject to disclosure; and all comments will be filed in Case No. U-20147.

Furthermore, the Commission will address the filed distribution plans, comments, and related issues such as PBR, after the expiration of the extended comment period.

THEREFORE, IT IS ORDERED that:

A. The Commission Staff shall consider the comments and presentations pertaining to climate change, as filed in Case No. U-21122, as part of the ongoing stakeholder proceedings in the MI Power Grid initiative in Case No. U-20633.

B. The Commission Staff shall develop a webpage within the Commission's existing website, dedicated to distribution system reliability, customer outages, and storm response, to be completed in early 2023.

C. The Commission Staff shall work with utilities to hold meetings and collaborate in the development of a reporting template for the filing of additional information pertaining to distribution system reliability, customer outages, and storm response. The reporting template shall be finalized and filed by the Commission Staff in Case No. U-21122 no later than 5:00 p.m. (Eastern time) on November 18, 2022.

D. The deadline as set forth in the August 25, 2021 order in Case Nos. U-21122 *et al*. to file comments on distribution plans and related questions in Case No. U-20147 is extended to May 27, 2022. Any person may submit comments in response to the distribution plans filed and the questions listed in the August 25, 2021 order regarding the distribution plans. The comments must reference Case No. U-20147 and should be received no later than 5:00 p.m. (Eastern time) on May 27, 2022.

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

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Tremaine L. Phillips, Commissioner

Katherine L. Peretick, Commissioner

By its action of March 3, 2022.

Lisa Felice, Executive Secretary

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

STATE OF MICHIGAN)

Case No. U-21122 *et al.*

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on March 3, 2022 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 3rd day of March 2022.

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

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