STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to establish a workgroup to investigate appropriate financial incentives and penalties to address outages and distribution performance moving forward.	Case No. U-21400

At the August 6, 2026 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Shaquila Myers, Commissioner

ORDER

Background

In the April 24, 2023 order in this case (April 24 order), the Commission established the Financial Incentives and Disincentives workgroup as part of the MI Power Grid Initiative. April 24 order, p. 12. The April 24 order outlined the initial focus of the workgroup as:

> developing metrics relating to reliability including, but not limited to, SAIDI [system average interruption duration index] (including and excluding MEDs [major event days]), SAIFI [system average interruption frequency index], CEMI [customers experiencing multiple interruptions], CAIDI [customer average interruption duration index], and resilience, including, but not limited to, downed wire response and the frequency and duration of outages during extreme weather, [using] the recently updated Service Quality [and Reliability Standards for Electric Distribution Systems (SQRS)] rules as a baseline.

Id. In addition to developing metrics around reliability and safety, the Commission stated that "the workgroup shall also consider challenges around the readiness of utility distribution grids to effectively accommodate and leverage the increasing and further anticipated growth of distributed generation [(DG)], EVs [electric vehicles], and other DERs [distributed energy resources].” *Id*.

In the March 13, 2025 order in this case (March 13 order), the Commission identified the following potential focus areas for feedback and consideration for future application of financial incentives and disincentives, otherwise referred to as “reliability-plus”:

- DER interconnection;
- Customer data access and hosting capacity;
- DER aggregation and non-wires alternatives (NWAs);
- 4.8 kilovolt (kV) distribution system conversions; and
- Advanced metering infrastructure (AMI) utilization/grid modernization.

The Commission also attached to the March 13 order the Reliability-Plus Framework Discussion Paper (Discussion Paper) that contained additional detail on these topics and questions for which the Commission was soliciting feedback. Specifically, the Commission sought input on whether the five proposed topic areas are the appropriate areas of focus, feedback on the proposed discussion items included under each of the proposed topic areas to guide the work of the Financial Incentives and Disincentives workgroup, feedback on proposed metrics contained in the Discussion Paper, suggestions on timing for this additional work on these reliability-plus elements, and any other related issues. The Commission invited initial comments from interested persons on the topics listed above that were due no later than 5:00 p.m. (Eastern time (ET)) on May 16, 2025, and reply comments that were due no later than 5:00 p.m. (ET) on June 27, 2025.

The Association of Businesses Advocating Tariff Equity (ABATE); the City of Ann Arbor (Ann Arbor); Consumers Energy Company (Consumers) and DTE Electric Company (DTE Electric) (jointly, the Companies); the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively, the Clean Energy Organizations or CEOs); Michigan Electric and Gas Association (MEGA); and Michigan Energy Innovation Business Council and Advanced Energy United (MEIBC/United) filed initial comments on May 16, 2025. The CEOs, Consumers, DTE Electric, and MEIBC/United filed reply comments on June 27, 2025.

Initial Comments

1. Association of Businesses Advocating Tariff Equity

ABATE notes that there are three levels of performance mechanisms in the Discussion Paper: (1) reporting metrics, (2) scorecards, and (3) performance incentive mechanisms (PIMs), and provided "enumerated Discussion Items on various potential Reported Metrics, Scorecards and/or PIMs in each of the five proposed focus areas." ABATE's May 16, 2025 initial comments, p. 2. ABATE asserts that "until the Commission gains sufficient experience with applying financial incentives and disincentives in the context of reliability performance[,] the Commission should be very cautious in pursuing additional issues to which it may apply financial incentives and disincentives. There are lessons to be learned from first applying these measures to reliability performance alone." *Id*., pp. 2-3. ABATE contends that because there is no urgent need to establish financial incentives and disincentives for the five potential areas, any work in these areas should be limited to the development of reporting metrics and scorecards.

In addition, ABATE asserts that it is unclear whether the Commission can apply financial incentives to these additional areas. Citing statutory and case law, ABATE argues that:

> [i]t does not appear that DER interconnection, customer data access and hosting capacity, DER aggregation and non-wires alternatives, 4.8 kilovolt distribution system conversions, and advanced metering infrastructure utilization/grid modernization fall within or are akin to "standards for service outages, distribution facility upgrades, repairs and maintenance, telephone service, billing service,

> operational reliability, and public and worker safety," as set out in [MCL 460.10p(5)].

ABATE's May 16, 2025 initial comments, p. 4. ABATE notes that the April 24 order, the February 27, 2025 order in this case (February 27 order), and the March 13 order also describe these issues as outside of the core issue of distribution reliability and safety.

Next, ABATE argues that applying financial incentives and disincentives to these potential areas raises a number of concerns. First, ABATE asserts that the "potential PIM would only benefit a narrow group – small customers and developers seeking to interconnect new DERs smaller than 150 kWac [kilowatt alternating current] in size – rather than ratepayers as a whole." ABATE's May 16, 2025 initial comments, p. 5. Second, ABATE expresses concern regarding a shared savings mechanism for utility NWA projects that utilize customer-sited DERs. ABATE avers that:

> [t]he case-by-case pursuit of NWA projects involving aggregated DERs as an alternative to new distribution infrastructure is appropriate when it provides a lower cost solution with the same level of reliability that would have been provided by that new distribution infrastructure. However, a utility's pursuit of such NWA projects should be part of that utility's normal course of business with respect to planning its system to provide reliable electric service at [the] lowest reasonable cost. A utility's failure to do so is a matter of imprudence and can be dealt with when identified by disallowing recovery of the utility costs that could have been avoided by pursuing the NWA project instead of new distribution infrastructure.

Id., p. 6.

Third, regarding discussion topics for future DER capacity PIMs, ABATE states that "[t]he proposal appears to essentially treat aggregated DER programs somewhat similar to Demand Response ('DR') programs and Energy Waste Reduction ('EWR') programs with respect to providing capacity." *Id.*, p. 7. ABATE disputes this treatment, asserting that aggregated DER programs are not quite the same as DR and EWR programs because DER programs inject an amount of net power into the distribution system, and possibly the transmission system, and this can present delivery challenges not found with DR and EWR. Accordingly, ABATE recommends more study on this issue.

Fourth, ABATE addresses the discussion topic of flexible interconnection in locations where the 4.8 kV system is limiting/slowing interconnection of DG. ABATE states that "[f]lexible interconnections should only be permitted where they do not introduce reliability risks of their own and are cost effective compared with pursuing the distribution upgrades that would otherwise be necessary to allow interconnection. Regardless, this is not something that needs a PIM." *Id*., p. 8. Fifth, regarding a future PIM for outage response and notification, ABATE argues that "[t]his is a fundamental component of basic, good utility service and should already be encompassed by the Commission's existing service quality and reliability standards. To the extent a utility does not meet those standards it should be subject to penalty." *Id*. Sixth, ABATE states that, at this time, the Commission's efforts should be focused on developing reporting metrics and scorecards, rather than implementing of time-of-day (TOD) and specialty rates.

2. City of Ann Arbor

As an initial matter, Ann Arbor reiterates its position from previous comments that a utility should not receive a financial incentive unless it meets all criteria in the Commission's SQRS. In addition, Ann Arbor requests clarification as to whether the topics in the Discussion Paper were intended to include battery storage.

Regarding the development of a DER interconnection scorecard, Ann Arbor states that it "supports tracking DER interconnection timelines to encourage progress as proposed in the Discussion Paper. It is reasonable to require utilities to measure and report annual average DER interconnection timelines and to create a scorecard where each utility's performance would be publicly reported." Ann Arbor's May 16, 2025 initial comments, p. 2. Ann Arbor also supports the requirement that utilities track and publicly report costs and timelines for interconnection studies. However, Ann Arbor contends that "[t]his reporting requirement should not be focused on any particular size DER projects, but should be tracked for all projects that require an interconnection study." *Id*., p. 3. Ann Arbor requests that the Commission require the utility to provide transparency as to why each project requires an interconnection study and the reasons that a particular project causes delays in the interconnection study and completion process.

Regarding the plan for a future DER interconnection PIM, Ann Arbor asserts that one calendar year is a reasonable amount of time for a utility to gather information to develop a performance baseline. Ann Arbor contends that if an interconnection timeline exceeds the amount of time under the Commission's rules, the utility should not earn an incentive. Similarly, Ann Arbor argues that:

> an interconnection timeline PIM should be asymmetrical, such that there would be a penalty for not meeting a target even if a utility's performance improved from its baseline, and incentives would only start once a utility exceeds the target. For example, if the target for Level 2 is 30 days and a utility's baseline is 45 days, that utility would receive a penalty for achieving a 31-day average because it failed to meet the target, despite improving from its baseline. The utility would be eligible for an incentive if it exceeds the 30-day target (i.e., 29 days or less), but not if it just meets the target because the target should be the expectation.

Id., p. 4.

In response to the topic of developing reporting metrics on flexible interconnection, Ann Arbor states that "[i]t is unclear to date how DTE [Electric] plans to allow export-limited or other interconnections." *Id*. Accordingly, Ann Arbor suggests that a preliminary baseline could be the number of communications to customers about the availability of an export-limited interconnection to reduce costs or interconnection timelines. Ann Arbor also contends that "[t]here should also be a disincentive if there are no technological solutions that are acceptable to DTE [Electric] as a demonstration of export limitations or a long delay at evaluation of customer-suggested technological solutions to assure limited export." *Id*., pp. 4-5. Ann Arbor notes that it supports reporting metrics for new load energization timelines but states that batteries and microgrids should be added to this conversation.

Ann Arbor agrees that DER integration is an appropriate area of focus for the reliability-plus initiative. According to Ann Arbor, it "wants to ensure that the interconnection of both solar and energy storage resources (i.e., batteries) are included in this discussion not only because they provide resiliency benefits, but also because they should be part of the conversation surrounding solutions for growing capacity demand and the long timeline for needed system upgrades." *Id*., p. 5.

Regarding hosting capacity analysis (HCA) reporting metrics, Ann Arbor supports "the recommended reporting metrics and stresses the importance of more frequent updates to hosting capacity maps, as well as the public availability of such maps. The City also recommends that such maps identify areas of anticipated load growth where the utility would be open to collaborating on a pilot battery program or microgrids to help manage the strained capacity." *Id*., p. 6. Similarly, Ann Arbor expresses support for data access metrics and additional metrics that would allow customers to access their data in a timely manner. In addition, Ann Arbor asserts that access to aggregated customer data is missing from the discussion about customer data access and hosting capacity. Ann Arbor notes that, "[b]efore providing aggregated customer data, DTE [Electric] requires consent from each tenant in buildings in which there are 14 or fewer tenants. This requirement is burdensome and goes much further than necessary to protect customers' privacy interests and ensure individual customer data is protected." *Id*., p. 7. Ann Arbor recommends that aggregated customer data be available without obtaining customer consent for each tenant for buildings with five or more tenants.

Pursuant to the discussion about developing a DER-capacity scorecard, Ann Arbor "requests clarification as to whether 'managed EV charging' includes vehicle-to-grid capability, and if not, to consider its inclusion in determining system-level peak capacity." *Id*., p. 8.

In response to the discussion on developing a future shared savings mechanism for NWAs, Ann Arbor asserts that its Sustainable Energy Utility, otherwise known as A2SEU, is able to facilitate customer-sited DERs within the City's boundaries with no up-front costs to customers. Ann Arbor states that "[i]t would be happy to collaborate with DTE [Electric] on a pilot regarding deployment of NWAs in which the A2SEU facilitates DERs in a particular area to achieve cost savings that could be shared." *Id*. In addition, Ann Arbor avers that it would welcome the opportunity to discuss the acquisition of DER capacity through cooperations with A2SEU.

Regarding the tracking of DER integration costs, Ann Arbor "supports the recommended initial set of items to track under the DER integration cost metric, but it does not believe the tracking of such costs should be the basis of a performance incentive." *Id*., p. 9. For the tracking of 4.8 kV conversion projects, Ann Arbor agrees with annual reporting on the current progress of conversion projects versus planned projects. Regarding the mapping of 4.8 kV conversion projects, Ann Arbor recommends:

> mapping not only planned upgrades and the timing of such projects, but also mapping the locations of additional capacity that will result from conversion projects. This would allow for better alignment between future development projects and future grid capacity. It would also allow local governments to align land-use planning with areas of increasing and available utility capacity.

Id., p. 10.

In response to the discussion on understanding current limits on hosting capacity and the impact on DERs/EVs, Ann Arbor notes that it supports the proposed reporting metrics. Ann Arbor also "believes it is important that utilities are transparent about the costs of system upgrades in areas with limited hosting capacity. Understanding the interplay of costs and demand, specific to grid locations, will lead to better prioritization and sequencing of timelines for grid upgrades and DER interconnections, as well as NWAs." *Id*., p. 11.

Regarding potential DER-based solutions on feeders waiting for upgrades, Ann Arbor "supports the exploration of flexible interconnection and investment in load relief projects with customer-sited DER in locations awaiting 4.8kV conversion." *Id*. Ann Arbor agrees that the Michigan Environmental Justice Screen (MiEJScreen) tool should be used to determine the location of these projects; however, Ann Arbor recommends that other factors be considered too. Furthermore, Ann Arbor contends that activities related to 4.8 kV distribution system conversion are an appropriate area of focus for the reliability-plus initiative.

Next, Ann Arbor states that it supports the proposed metrics for the outage response and notification scorecard so long as the data is tracked with the goal of improving the utilities' power restoration accuracy and timeliness, first estimate accuracy, and outage notification delivery. However, Ann Arbor objects to "the development of financial incentives for improved utilization of AMI because customers are already paying a significant cost for AMI infrastructure in their rates; utilities should not be awarded [sic: rewarded] for merely maximizing the use of its rate-funded investments." *Id*., p. 12.

Regarding a future PIM for outage response and notification, Ann Arbor contends that it should be omitted or made asymmetrical so that there is no incentive but instead a penalty if a utility fails to meet a target. Ann Arbor explains that:

> [r]atepayers are already funding AMI infrastructure and paying the rate of return on equity for that infrastructure in part because they were told it would improve their reliability and allow for faster outage response. Ratepayers should not have to pay an additional amount to incentivize a utility to efficiently use rate-funded investments to provide accurate and timely notice of outages and power restoration

> timelines because that was the core reason given for the purchase of the AMI infrastructure in the first place.

Id., p. 13.

Finally, Ann Arbor asserts that AMI utilization and grid modernization are appropriate focus areas for the reliability-plus initiative so long as the metrics are designed in a manner that penalizes the utilities for failing to meet certain targets. However, Ann Arbor "does not support the use of metrics in these categories as the basis for awarding incentives to utilities. Ratepayers are already funding investments in AMI infrastructure and grid modernization and pay a rate of return on those investments. There is no reason ratepayers should have to pay any additional amount if investment in such infrastructure proves successful." *Id*., p. 14.

3. Consumers Energy Company and DTE Electric Company

The Companies assert that because of the breadth of topics in the reliability-plus initiative, it was difficult to deeply and meaningfully engage. They state that "full consideration has not been given yet to where the five focus areas fall in terms of their relative priority for limited utility resources," and, therefore, the Companies "do not necessarily agree that all of the focus areas considered in the Discussion Paper warrant prioritization by utilities and the Commission, particularly for focus areas that mainly provide benefits to individual stakeholders rather than to utility customers generally." Companies' May 16, 2025 initial comments, p. 4. Although the Companies support tracking metrics, they contend that there must "be a common understanding of the intended goals and outcomes of the Reliablity [sic] Plus process and the topic areas" in order to determine the metrics to be tracked. *Id*. Accordingly, the Companies assert that the five topic areas should be better defined to determine which metrics are appropriate to track.

The Companies also argue that, although penalties are relevant to reliability, "as the conversation evolves into newer areas such as NWAs, circuit conversions, and how customers access and utilize individual and system data, the basis for any adverse financial outcomes is far less clear." *Id*., p. 6. Therefore, the Companies assert that any PIMs for the reliability-plus initiative should be only structured as incentives. Furthermore, the Companies request that the cost to achieve the target is commensurate with the value it provides to customers and that the cost associated with tracking and reporting the metrics should be appropriately recovered by the utilities.

Regarding the discussion about DER integration, the Companies agree with the Discussion Paper that it is premature to develop target performance levels for this metric. Rather, the Companies assert that developing reporting metrics is more appropriate at this time. *See*, *id*., pp. 6-8. The Companies also note that Rule 92 of the Commission's Interconnection and Distributed Generation Standards, Mich Admin Code, R 460.992 (Interconnection rules) requires an annual report of all interconnection activity. The Companies recommend "the use of a workgroup format for developing the proper scope of the R 460.992 annual report and recommend that the Commission direct Staff [Commission Staff] to establish a workgroup that includes the stakeholders filing comments related to the DER Interconnection Discussion Items in this proceeding." Companies' May 16, 2025 initial comments, p. 8 (footnote omitted). The Companies contend that the workgroup can address the questions under Discussion Item #1.1 in the Discussion Paper.

The Companies also express concern regarding the flexible interconnection concepts set forth in the Discussion Paper. They assert that "utilities already have the tools necessary to engage in limited use of 'flexible interconnections' where the circumstances warrant it" and that "[t]he Commission should not pursue a blanket goal to promote 'flexible interconnection' to the greatest extent possible . . . ." *Id*., p. 11. The Companies contend that flexible interconnections should follow a two-step process to ensure system safety and avoid adverse system impacts and should also be considered on a case-by-case basis.

The Companies acknowledge that hosting capacity maps provide transparency about the grid; however, they assert that "hosting capacity maps are informational only, and do not replace the need for a formal interconnection review." *Id.*, p. 12. The Companies note that the Commission directed the completion of a Grid Integration Study in Case No. U-21251, and the Companies believe that "[t]he comment-and-feedback process [in this case] presents an opportunity to build on the discussions contained within the Grid Integration Study and the questions reintroduced by the Discussion Paper." Companies' May 16, 2025 initial comments, p. 13.

In the Companies' opinion, customer data access is not appropriate for reliability-plus incentives and disincentives. The Companies contend that each company "provide[s] web accessible platforms for customers or their representatives to access actual energy usage data." *Id.* They argue that greater utilization of these platforms provides more value for customers.

Regarding DER aggregation, the Companies assert that "aggregation should not be included in the Reliability Plus process absent a tangible policy goal that might be addressable through the use of aggregated DERs and demand response ('DR'), and only after careful consideration (e.g. through a workgroup focused specifically on this issue)." *Id.*, pp. 14-15. In addition, the Companies note that the Federal Energy Regulatory Commission (FERC) and Midcontinent Independent System Operator, Inc. (MISO) are working on issues that affect DER aggregation and any work ordered by the Commission must be consistent with FERC's and MISO's adopted processes.

Next, the Companies argue that it is premature to discuss a metric that includes system level peak capacity potential from EWR; DR plus DER technologies, including solar plus storage;

managed EV charging; and new microgrid projects. They state that "[a] combination of these technologies and interventions likely has a role to play in managing the system, however the specific problem or objective that this metric would track is unclear, and the specific role of these technologies in addressing such an objective requires additional exploration." *Id*., p. 15. The Companies assert that there are existing processes to manage supply side resources, and, therefore, they recommend that the Staff conduct an analysis to understand any unaddressed capacity concerns.

Regarding NWAs and the consideration of reporting metrics and scorecards, the Companies state that "there are open questions to be explored regarding how to value an NWA, considering both the cost to develop the project and the expected cost savings that would be generated." *Id*., p. 17. In addition, the Companies agree with the Discussion Paper that the next step is to identify potential pilot NWA projects, and they express interest in working with interested persons to determine specific NWAs to test.

In response to the topic of 4.8 kV distribution system conversion, the Companies state that, "[g]iven the extensive record of discussion and review of DTE Electric's 4.8 kV conversion program, it is not evident what would be achieved with additional tracking of projects." *Id*., p. 19. The Companies also assert that 4.8 kV conversion is not appropriate as a standalone topic and that any discussion items that relate to hosting capacity, NWAs, or interconnections should be directed to those topic areas to be addressed holistically.

The Companies contend that any discussion about how the utilities can better utilize AMI data should consider the utilities' significant progress in the use of AMI data and capabilities to improve timely and accurate outage restoration estimates. However, the Companies acknowledge that they are still in the early stages of implementing major new systems for using AMI data and "will need additional time to assess what is working and where improvements can be made to these new systems in order to better understand their potential and their limits." *Id*., pp. 21-22. In addition, the Companies assert that AMI technology is not sufficient—on its own—to provide solutions for delivering accurate outage restoration estimates to customers each time; other data is needed to fill in the gaps. Accordingly, the Companies argue "that it is too early to determine target levels for these metrics and that the Commission needs to allow the Companies to collect more data and gather more experience with these new systems before attempting to move toward a Scorecard level of performance mechanism for this topic." *Id*., p. 22. Similarly, the Companies state that it is premature to consider the implementation of any PIM-level performance mechanism. They recommend establishing a workgroup to address these issues.

Finally, the Companies request that the Commission not adopt any performance mechanism for customer adoption of AMI-enabled specialty rates. The Companies:

> view customer adoption of time-of-day and other specialty rates as a primarily market-driven issue where enrollment is determined by third-party choices that the Companies do not control. It would never be appropriate to penalize utilities for the choices of their customers, especially when customers are choosing rate options that the Commission itself determines to make available in each utility's tariffs.

Id., p. 23. Furthermore, the Companies believe that it would not be beneficial to the relationship between the utilities and their customers. However, the Companies assert that, if the Commission determines that a performance mechanism is warranted, "the Commission should only consider an incentive-only approach where utilities could adopt customer-education initiatives and other marketing strategies meant to inform customers of the benefits of certain rate options and receive rewards for successful enrollments." *Id*.

4. The Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar

The CEOs agree with the three levels of performance mechanisms set forth in the Discussion Paper: metrics, scorecards, and PIMs. However, the CEOs contend that, "[w]hen considering performance incentives and disincentives, it is critical to differentiate performance from compliance." CEOs' May 16, 2025 initial comments, p. 2. The CEOs note that in the Discussion Paper, it states that the utilities' distribution system plans describe major strategic investments for the next 5-10 years. In addition, the CEOs note that in the Discussion Paper, it states that "*[d]eveloping additional metrics and scorecards in this framework can track utility performance towards established goals and complement existing review and approval processes for Michigan utilities' distribution plans and rate cases*." CEOs' May 16, 2025 initial comments, p. 2 (quoting Exhibit A to the March 13 order, p. 2) (emphasis added by the CEOs). The CEOs aver that:

> [h]ere, "distribution system plans" refer to the distribution grid plans which certain electric utilities in the state were required to file under docket [no.] U-20147. In the September 26, 2024 order in that case, the Commission found that the utilities had generally complied with the requirements of the order opening that docket—that is to say, the utilities agreed to a set of minimum requirements which were also approved by the Commission. These requirements relate to reliability, outages, costs, affordability, energy equity, and safety. The purpose of the performance incentives is not to incentivize compliance with these requirements, but to "track utility performance towards established goals and complement existing [. . .] processes."

CEOs' May 16, 2025 initial comments, p. 2 (quoting Exhibit A to the March 13 order, p. 2) (alteration added by the CEOs). Accordingly, the CEOs assert that it is important to evaluate each proposed PIM, scorecard, and metric to determine how it relates to existing requirements. The CEOs argue that "it is critical that PIMs go beyond the minimum requirements—utilities should not be provided extra incentive simply to meet existing standards." CEOs' May 16, 2025 initial comments, p. 3.

In addition, the CEOs state that there are two other factors that should be considered in the development of PIMs: (1) "incentives should consider the utility's overall risk profile, and the opportunity to receive an incentive should result in a meaningful reduction in the utility's return on equity ('ROE')" and (2) "the structure of the incentives must be based on a thorough benefit-cost analysis ('BCA') to ensure that incentive dollars are awarded for meaningful improvements to the tracked metrics, and that utilities are actually being rewarded for improved performance, and not just increased spending." *Id*.

Regarding the development of a DER interconnection scorecard, the CEOs assert that the utilities should provide the Financial Incentives and Disincentives workgroup with detailed data on interconnection timelines to date. The CEOs state that, "[o]nce this data has been provided[,] it should be used to set a target that strikes a balance between achievable and aspirational." *Id*., p. 4. Additionally, the CEOs aver that when setting the initial target, the Financial Incentives and Disincentives workgroup should also create a timeline for the development of more stringent requirements.

The CEOs state that the utilities should already have the data available for establishing a PIM. Furthermore, the CEOs "agree that a symmetrical incentive and disincentive should be adopted. [The CEOs] also advocate for a deadband between the incentive and disincentive; a utility should strive to interconnect customers' DERs in a reasonable time, and should only receive an incentive if it consistently exceeds the performance threshold." *Id*., p. 5. In addition, the CEOs assert that the PIM should be regularly adjusted to account for changes in actual performance and that the amount should be based on a thorough BCA.

The CEOs provide a detailed background and context for flexible interconnection. The CEOs believe that the specific metrics in the Discussion Paper for flexible interconnection are good starting points but request that the Commission add the metric of cost, i.e., what is the cost of a system upgrade that customers are required to pay for. The CEOs note that "many proposed DER projects may be cancelled or modified after learning of the need to pay for a distribution system upgrade; the quantity, type, and size of projects which fall into this category must also be tracked to inform the [flexible interconnection] metrics, scorecards, and PIM, with a performance metric related to reducing the number of projects which are cancelled or reduced in scope." *Id.*, p. 7. Furthermore, the CEOs recommend that a future metric for tracking should be the difference in kilowatt-hours between the potential generation based on a DER's nameplate and the actual generation.

Regarding the development of proactive reporting metrics for new load energization timelines, the CEOs note that the Discussion Paper specifically identifies EVs and building electrification as new load energization. However, the CEOs state that the Discussion Paper fails to mention data centers. The CEOs assert that, "[r]ecognizing how closely load energization timelines are connected to [flexible interconnection], we encourage the [Financial Incentives and Disincentives workgroup] to actively coordinate the two areas when identifying metrics to track." CEOs' May 16, 2025 initial comments, p. 8. In addition, although the Discussion Paper recommends tracking individual DER interconnection steps separately, the CEOs propose that each step in the energization process should also be tracked. Furthermore, the CEOs request that utilities collect data about customers who request load energization but then withdraw or modify their requests because of long timelines or high costs. Finally, the CEOs state that "while the Discussion Paper indicates that metrics should be differentiated by load category, meta-analysis should focus on ensuring that improvement in timelines for certain categories does not negatively impact others, to ensure that improvements for one load type do not come at the expense of delays for other types of load." CEOs' May 16, 2025 initial comments, p. 9.

The CEOs note that the Discussion Paper sets forth a list of three potential metrics for HCA reporting. The CEOs state that "the proposed metrics are a good start, focusing on the level of detail and frequency of updates to data in the HCA. Additional metrics around the quality and accuracy of data should also be provided." CEOs' May 16, 2025 initial comments, p. 9. The CEOs cite a 2022 National Renewable Energy Laboratory and Interstate Renewable Energy Council report that highlights the importance of, and best practices for obtaining data quality and validation.

Regarding data access metrics, the CEOs note that the Discussion Paper provided two potential metrics for the usage of existing web portals and that the Discussion Paper requests the recommendation of any additional metrics. The CEOs state that they:

> agree that establishing tracking metrics related to customer data access and web portals (such as Consumers Energy's Green Button solution) is critical for ensuring customers and authorized third parties can securely, easily and reliably access customer data. This data is required for integrating and utilizing DERs, including scoping the technical and financial viability of customer DER solutions, enrolling customers in demand flexibility programs, and ultimately operating these programs. Moreover, the ability to securely, easily and reliably access customer interval usage data is a foundational benefit of installing advanced metering infrastructure ("AMI"), tying this category to several others.

CEOs' May 16, 2025 initial comments, p. 10 (footnote omitted). The CEOs recommend several additional metrics that address timing of various access steps and that include solutions for granting third-party data access. *See*, *id*., p. 11.

The CEOs disagree with the two-step process that identifies the capacity potential of DERs, along with the application of targets by technology type. The CEOs argue that "[t]his process both ignores significant additional benefits that DERs can provide, and dilutes these potential impacts by seeking to disaggregate benefits by the type of DER rather than by the type of benefit. Rather than setting targets by the type of DER, targets should be set by the type of benefit." *Id*., p. 11. However, the CEOs agree with the Discussion Paper that the integrated resource plan (IRP) process is the appropriate forum for setting targets but only if the targets are derived from a robust BCA.

In response to the request in the Discussion Paper that commenters provide recommendations on NWA frameworks, mechanisms for identifying ideal locations for NWAs, shared savings mechanisms for NWAs, and potential pilot projects, the CEOs assert that they are strongly in favor of NWAs, but believe that the questions in the Discussion Paper do not accurately reflect the status of NWA deployment in Michigan. The CEOs state that:

> utilities in the state are well beyond the stage of identifying locations or conducting pilot projects for NWAs (which the Discussion Paper asks about). Instead, the focus should be on crafting a PIM that incentivizes expansion of utilities' existing NWA pilots, with a roadmap to creating permanent NWA programs. Therefore, [the CEOs] suggest that the [Financial Incentives and Disincentives] workgroup request the utilities to provide detailed data from the completed and ongoing pilots, including details on the capital expenditures successfully deferred or avoided by the NWA pilots, as a next step.

CEOs' May 16, 2025 initial comments, p. 13. The CEOs note that New York has developed a successful NWA process that includes shareholder incentives and cost recovery mechanisms that the Financial Incentives and Disincentives workgroup should consider when developing shared savings mechanisms that encourage the deployment of NWA projects that use customer-sited DERs.

The CEOs recommend that the Financial Incentives and Disincentives workgroup address whether the proposed PIM applies to utility-owned front-of-the-meter DERs, customer-owned behind-the-meter DERs, or both. The CEOs recommend that "the PIM should only apply to [behind-the-meter], as the utilities' cost of service regulatory construct already sufficiently incentivizes utilities to invest in [front-of-the-meter] DERs." *Id*., p. 14. Moreover, the CEOs request that, in addition to system-level capacity targets, local targets should be considered too. In addition, the CEOs recommend "symmetrical incentives with deadbands. Questions related to thresholds, initial incentives, and cost-effectiveness should all be determined through the process of a robust BCA." *Id*.

Regarding the metrics for costs of infrastructure, the CEOs state that although cost tracking is important, it is not appropriate for a PIM. The CEOs contend that "the 'right' level of expense should be determined through a BCA, and the process of developing the BCA is the right place to determine which categories of costs need to be tracked." *Id*.

Next, the CEOs assert that it is unclear why a separate category is necessary for metrics, scorecards, and PIMs for 4.8 kV conversion. The CEOs explain that "[t]he conversions are already covered in the distribution grid plans, and where the existence of a 4.8kV circuit affects other categories, such information should be tracked within those categories." *Id*., p. 15. In addition, the CEOs argue that it is not prudent to separately track hosting capacity and interconnection timelines based on the distribution voltage.

The CEOs note that several utilities already manage outage maps that include estimated restoration times. According to the CEOs, the Financial Incentives and Disincentives workgroup should better "understand how accurate these maps are, how quickly they are updated, and how residents are currently using them. This would be the starting point for developing metrics and targets." *Id*.

Finally, the CEOs note that the Discussion Paper recommends that the Financial Incentives and Disincentives workgroup should review current participation in the TOD and specialty rates that utilize AMI and asks how adoption would be tracked, whether a target should be established, and whether a PIM is appropriate. The CEOs state that "tracking adoption should be a straightforward task for utilities, and that the [Financial Incentives and Disincentives] workgroup should be provided with this data. A more critical task, however, would be to analyze the impacts on individual ratepayers of moving to TOD and specialty rates." *Id*., p. 16. Additionally, the CEOs recommend the development of two metrics: (1) track the share of customers on the most affordable rate given their usage patterns and (2) track the result of utility outreach to support customer affordability. The CEOs state that "[t]wo PIMs could be developed in this area, the first incentivizing utilities to move customers to more affordable rates, and the second incentivizing outreach that results in reduced monthly billing for customers negatively impacted by a change in rate." *Id*., pp. 16-17.

5. Michigan Electric and Gas Association

As an initial matter, MEGA notes that in a footnote on page 2 of the June 6, 2024 order in this case (June 6 order), the Commission stated that the straw proposal initially focused on metrics and methods for Consumers and DTE Electric and that, in the future, the Financial Incentives and Disincentives workgroup would discuss applicability to other investor-owned utilities. MEGA also notes that it provided comments on the straw proposal on July 12, 2024; and, in the February 27 order, the Commission did not apply the PIM requirements to MEGA's members. MEGA states that it:

> offers comments on the proposed Reliability Plus framework with the understanding that, in a similar fashion to the PIM, "the workgroup expects to discuss applicability to other investor-owned utilities through future engagement and review of comments." Therefore, these comments are provided as offering a smaller utility perspective, while not endorsing the applicability of any reliability-plus metrics to its member utilities.

MEGA's May 16, 2025 initial comments, p. 3 (quoting the June 6 order, p. 2, n. 1).

MEGA also asserts that prior to the establishment of any metric, scorecard, or PIM, the five focus areas proposed should have clearly defined policy goals. Through this approach, MEGA states that “it may [become] apparent the ultimate policy goal is not something for which the utility should or is ultimately responsible.” MEGA’s May 16, 2025 initial comments, p. 4. Furthermore, MEGA recommends that after the Commission determines the metrics to be measured, the Financial Incentives and Disincentives workgroup should be directed to consider the availability and quality of data for benchmarking before the scorecard or PIM are established. In addition, MEGA “encourages the usage of thresholds for determining whether a utility needs to comply with future metrics.” *Id*., p. 5.

Next, MEGA expresses concern about any additional reporting that may be required to measure and score performance. MEGA explains that “[t]he incremental nature of each new reporting requirement over the years increases the difficulty of Association members in assigning these costs to business units and requesting recovery. Oftentimes, because of the small nature of the addition, they are just absorbed into existing operations and the same staff hours are asked to perform multiple tasks.” *Id*., p. 6. MEGA requests that the Commission consider a workgroup or technical conference to review whether the current reporting requirements could be improved for efficiency and to reduce the complexity of some of the filings, if possible.

Regarding DER interconnection, MEGA recommends “[a] clear articulable goal for the need for DER interconnect data” and the “measure[ment] of interconnect times to create benchmarking, but asserts that it is premature to establish a scorecard or PIM.” *Id*., p. 8. MEGA also asserts that its members have varying systems for DER interconnection requests and did not contemplate reporting requirements when they established their tariffs. Accordingly, MEGA requests that utilities be allowed to easily amend their tariffs if costs increase. In addition, MEGA requests that the Commission consider that interconnection times are not always absolute and that "[u]tilities responsible for a metric may be beholden to forces outside their control for contract work on such a small scale, making it difficult to measure the utilities' performance." *Id*., p. 8.

Finally, in response to customer data access, hosting capacity access, AMI utilization, and grid modernization items in the Discussion Paper, MEGA states that its members do not have AMI infrastructure that can report in meaningful increments for customer use. Furthermore, MEGA asserts that "members are not experiencing the level of EV adoption other utilities may be. Some members are seeking waivers from Transportation Electrification Plan submissions for this very reason." *Id*., p. 9.

6. Michigan Energy Innovation Business Council and Advanced Energy United

Regarding the topic of DER interconnection in the Discussion Paper, MEIBC/United state that the Commission's Interconnection rules provide the maximum timelines for interconnection. MEIBC/United assert that, thus, "it is unnecessary to spend an extended time period collecting data and measuring the current timelines for the interconnection of DERs [because] Michigan's utilities have been implementing the new interconnection procedures using the new timelines since at least August 2023." MEIBC/United's May 16, 2025 initial comments, p. 3. However, MEIBC/United recommend that the Commission require each utility to report on its average monthly DER interconnection timelines for the steps controlled by the utility for each level of the project. In any event, MEIBC/United contend that because the information for measuring timelines is already available, "the financial incentives and disincentives ('FID') workgroup could then meet in the near-term to establish an interim target for DER interconnection timelines. Although Michigan EIBC/United agree that Level 1 and 2 projects should be the simplest and fastest to review, [they] do not believe that the targets should be limited to only Level 1 and 2 projects." *Id*., p. 4.

MEIBC/United support the Discussion Paper's proposal to track the costs and timelines for interconnection studies. According to MEIBC/United, "[m]onthly reports such as those required by the Hawaii Public Utilities Commission would provide significant new data and information relevant both to interconnection customers and to the development of future financial incentives/disincentives." *Id*., p. 5. MEIBC/United also state that it is important to understand the costs and timelines for DER projects of all sizes.

Regarding a DER interconnection PIM, MEIBC/United reiterate that because performance data is already available, the Financial Incentives and Disincentives workgroup can develop a scorecard and PIM for interconnection performance. MEIBC/United state that the PIM should be "symmetrical, meaning that the utility has the ability to earn either a reward or a penalty and the scale of the reward and penalty are equivalent to one another." *Id*., p. 6. MEIBC/United also contend that the PIM should be thoughtfully designed to ensure that it aligns with public policy goals, creates customer benefits, and results in appropriate earning opportunities for utilities. *See*, *id*., pp. 7-8.

Next, MEIBC/United support the establishment of flexible interconnection policies to ensure that customers are able to interconnect DERs without significant upfront costs while waiting for distribution system upgrades. MEIBC/United state that these issues could be addressed in a technical workgroup. In addition, MEIBC/United contend that reporting metrics that include the number of DG customers that require system upgrades do "not entail a goal or target other than simply reporting facts around the need for upgrades to facilitate interconnection. Thus, such reporting is not appropriate for a metric." *Id*., p. 9. Instead, MEIBC/United recommend that the

Commission create a reporting requirement, on a circuit level, that tracks the number of DG projects filed, the number of projects that will need upgrades, the number of projects that change size or leave the queue, and the number of projects the utility offered a flexible interconnection solution. Furthermore, MEIBC/United argue that "[t]he Commission should also consider requiring the reporting of the difference between the cumulative nameplate generation at a given site and the actual generation allowed to be exported by a customer under a flexible interconnection agreement." *Id*., p. 10.

Regarding proactive reporting metrics for new load energization timelines, MEIBC/United assert that reporting, itself, is not an activity that should be rewarded or penalized. MEIBC/United state that "[a]lso, as noted above, Michigan EIBC/United are concerned that when faced with significant costs and long timelines to energize loads, customers may not move forward with a given project. It would be helpful to track those projects that request energization and then how and why either the project changes or does not move forward." *Id*., p. 11.

MEIBC/United state that: (1) they support the focus on DER interconnection timelines, costs, and flexible interconnection/energization; (2) there is already significant data available to be leveraged/analyzed to develop appropriate PIMs; (3) the Financial Incentives and Disincentives workgroup should quickly institute PIMs for interconnection timelines for projects of all sizes; and (4) the Commission should consider an additional reporting requirement associated with the cost of interconnection. *See*, *id*., pp. 12-13.

In response to the Discussion Paper's suggestion that utilities publicly report areas where the hosting capacity tools can be improved, MEIBC/United assert that these are simple data points that are already available for each utility's online hosting capacity map. MEIBC/United contend that "[t]hese do not represent metrics that move the needle in any significant manner – they are simply facts that can be determined very quickly with a simple online search." *Id*., p. 14. MEIBC/United argue that for a hosting-capacity or load-carrying-capacity map to be the most useful, it must be updated when there are major changes to a circuit and improved to allow for greater granularity. Accordingly, MEIBC/United recommend that the Commission "create a scorecard and PIMs that reward real-time updates to combined hosting capacity and load-carrying capacity maps with sufficient granularity to enable DER and EV deployment." *Id*., p. 16.

MEIBC/United state that the proposed data reporting and metrics for customer data access can be improved and refined. Specifically, MEIBC/United explain that "improving access to customer usage data is needed to determine what value can be provided through investments in advanced energy technologies and services. Likewise, improving the accessibility of these data allows for more efficient, economical, and cleaner energy solutions to participate in the marketplace, whether provided by a utility, a utility contractor/agent, or a third party." *Id*., p. 17. However, MEIBC/United request that the Commission strike an appropriate balance between access to customer data usage and customer privacy. MEIBC/United believe that it would be beneficial for the Commission:

> to collect information on whether Green Button Download My Data is enabled for each utility and the number and percentage of eligible customers using this functionality. Additionally, Michigan EIBC/United suggest that the Commission consider establishing a more robust foundation of requirements that would create an effective data-sharing ecosystem, which could potentially be assessed through a set of metrics or scorecard. Should the Commission find it appropriate, penalties could be assessed for failure to meet foundational requirements. At the same time, this set of requirements should be distinguished from activities which could represent excellent performance and potentially justify a financial incentive.

Id., p. 18. MEIBC/United suggest certain requirements to achieve the Commission's objectives around increased data access and sharing. *See*, *id*., pp. 18-23.

Next, MEIBC/United note that the Discussion Paper provides a two-step process for developing a scorecard for DER aggregation: (1) reporting system-level peak capacity from EWR, DR, and DERs; and (2) establishing aggregate capacity targets for each utility. Although aggregate capacity targets could be developed using the utilities' IRPs, MEIBC/United contend that the Commission should consider how the development of aggregate targets for each utility will interact with and consider third-party aggregation of DERs. MEIBC/United assert that, "[w]hile there are significant opportunities, benefits, and cost-savings associated with third-party DER aggregation, it will be important to ensure that any incentives provided to utilities do not require or otherwise encourage DER aggregation by utilities." MEIBC/United's May 16, 2025 initial comments, p. 24. According to MEIBC/United, the Commission should encourage utilities to work with cost-effective third-party aggregators to develop appropriate and effective programs to incentivize DER deployment and aggregation that will maximize benefits to the grid. In addition, to determine capacity potential from DERs to reduce system peak demand, MEIBC/United recommend utilizing advanced load forecasting.

Regarding the development of future shared savings mechanism for NWA projects, MEIBC/United recommend a simple method for developing a mechanism. MEIBC/United explain that:

> the total cost of the NWA and the projected cost of the avoided capital expenditures (including carrying costs) could be compared, and the incentive could be set as a share of the difference. The major benefit of an NWA is that it provides for the deferral of larger capital projects, which can save the utility and its customers money, while providing the utility an earnings opportunity for NWA solutions. Under these approaches the NWA shared-savings mechanism would rely on a prepaid multi-year service expense that would be amortized over time as a regulatory asset with the utility return applied to the yearly unamortized balance.

Id., pp. 26-27. If pilot projects must be identified, MEIBC/United state that this topic may not be ready for a PIM and may be better suited for the measurement and development of metrics.

MEIBC/United note that the Discussion Paper states that a future PIM would reward or penalize performance for enrollment relative to the established system-level capacity targets. MEIBC/United assert that "it will be important to carefully consider the role of third-party aggregators when developing a future PIM to ensure that such a PIM does not require or encourage utility[ ]ownership and operation of DERs as well as grid-edge distributed energy resource management systems ('DERMS') or disadvantage third-party aggregation of DERs." *Id*., p. 28. However, MEIBC/United caution the Commission that to the extent a PIM is adopted to improve the interconnection process or that increases the number of DERs on the utility's system, the Commission should be careful not to provide a second incentive or penalty for the same activity.

MEIBC/United state that a PIM should be symmetrical to incentivize the increase in cumulative DER capacity. In addition, MEIBC/United assert that "[t]he metrics and thresholds for this PIM should be focused on both the calculated cumulative capacity of DERs on the distribution system as well as the improvements that the utility has actively engaged in to facilitate the adoption in DERs." *Id*., p. 29. MEIBC/United argue that the incentive amount for a PIM should be enough to incentivize the utility to make changes but should be based on a percentage of base revenue. Furthermore, MEIBC/United assert that "the use of 'deadbands' around a baseline level of performance, where a utility would not be penalized or rewarded, can help ensure that incentives or penalties are properly applied." *Id*. According to MEIBC/United, the exact performance levels associated with the deadband and the maximum penalties and rewards may be determined and aligned through the use of a BCA.

MEIBC/United argue that it is critical to determine the cost-effectiveness of the DER capacity acquired through utility programs or a proposed PIM because it will assist in determining reasonable DER capacity goals and the penalties and rewards for the PIM. MEIBC/United note that Michigan has been developing a unified BCA tool that can be applied to various types of DER technologies that will be ready for use in 2026. MEIBC/United contend that the BCA "can be performed at the portfolio-level to analyze the cost-effectiveness of a combination of different DER programs rather than looking at individual DER programs in a silo. This is important to note, as a PIM incentivizing increased DER capacity would be targeting various forms of DERs rather than one DER type." *Id*., p. 30.

In addition, MEIBC/United assert that "[i]t is important to recognize that as DER integration grows, especially if DER aggregation is effectively utilized, utilities will also benefit from deployment of those DERs and reduction of other system costs. As such, with any tracking of the costs associated with DER integration, it will be critical to also track the reduction in costs (i.e., the benefits)." *Id*., p. 31. MEIBC/United request that the Commission direct the utilities to also track deferred distribution system infrastructure costs and cost savings achieved by third-party administration of DER aggregation programs.

Regarding DER aggregation and NWAs, MEIBC/United state that these issues are new to Michigan utilities and, therefore, it may not be appropriate to establish scorecards and PIMs at this time. In MEIBC/United's opinion, "[i]t may be more appropriate to establish metrics and targets in the near-term and revisit the development of PIMs in the future." *Id*., p. 32.

MEIBC/United agree with the Discussion Paper that it would be beneficial to customers considering DER projects if utilities were required to report on conversion projects and to provide a map showing the timing of planned upgrades. However, MEIBC/United contend that it would "be critical for these data to be updated more than once per year because, in a similar manner to hosting capacity data, the data will quickly become outdated and inaccurate in the absence of the frequent (i.e., at least monthly) updates." *Id*., p. 33. MEIBC/United assert that utilities should investigate methods to present the data and projections to customers in conjunction with hosting-capacity and load-carrying-capacity maps to determine whether and how a planned DER project may develop most cost-effectively. In addition, MEIBC/United state that the utilities should "track and report estimated increased load carrying capacity associated with any line conversions. This, along with updates on the current conversion projects and planned projects, will help customers choose an optimal location and adequate size of DER projects that will be located on a prospectively converted 4.8kV line." *Id*.

MEIBC/United assert that it is unclear in the Discussion Paper what is meant by requiring reporting of the number 4.8 kV feeders where hosting capacity is below 75% for both DG and EVs. MEIBC/United state that "hosting capacity is a more nuanced measurement that takes into account the impact of a potential DER on a variety of system factors such as power quality, voltage, etc." *Id*., p. 34. MEIBC/United recommend that this measurement be more detailed to provide a meaningful metric. Additionally, MEIBC/United argue that "it would be useful for utilities to report on the number of interconnection requests requiring system upgrades to interconnect DERs and the timeline for each step of those interconnection applications (e.g., not simply a single metric of the 'length of delays' as that is not sufficiently specific)." *Id*.

Regarding utility operational considerations for implementing flexible interconnection and NWA projects on the 4.8 kV distribution system, MEIBC/United contend that "it is critically important to not exceed any voltage or load limitations that the utility has set for a specific line. One way that this can be accomplished is through limited export agreements, which is a simple form of flexible interconnection." *Id*., p. 35. MEIBC/United state that an alternative would be for the utility to install infrastructure in congested areas of the distribution system as a temporary remedy and to ensure that if additional DERs are interconnected, the voltage of the system will not drop or change. Furthermore, MEIBC/United suggest that utilities could "consider expanding the available pool of customer-owned technologies that can be used to avoid service upgrades." *Id*., p. 36. MEIBC/United also assert that issues related to interconnection to the 4.8 kV distribution system are appropriate for consideration in the reliability-plus initiative but with the added focus on hosting capacity and flexible interconnection/energization.

MEIBC/United support the use of metrics to track outage restoration accuracy and timeliness and the proposal to set targets for these metrics. However, MEIBC/United recommend a symmetrical PIM and request that the Commission include additional metrics. MEIBC/United state that:

> [a] metric or threshold that could be used to measure the performance of the utility regarding outage response is the percentage of customers that are restored from [an] outage within a certain number of hours during normal conditions. Regarding notification of an outage, a metric or threshold that could be used is the percentage of customers that receive a notification of an outage, via the internet or in-person, within a certain number of minutes of the outage. If the utility falls below a certain percentage it can receive a penalty, however, if it exceeds the percentage it has the ability to earn a reward.

Id., pp. 39-40. MEIBC/United also reiterate the argument about setting the incentive/disincentive level that was discussed above. For a PIM related to outage response and notification, MEIBC/United request that the metric or threshold that determines a penalty or reward be well-defined and standardized for all utilities.

Regarding measuring the implementation of TOD rates for AMI systems, MEIBC/United assert that:

> the Commission could track the percentage of total residential customers that participate in time-of-day rates as well as peak demand and load curve comparisons associated with the time-of-day rates. The peak demand information would entail understanding the peak load contribution for the relevant RTO [regional transmission operator] capacity as well as the coincident peak demand and non-

> coincident peak demands for time-of-day rate customers as compared to non time-of-day rate customers. It is also informative to understand the average 8760 load curve for time-of-day rate customers as compared to non time-of-day rate customers. These data would be helpful to inform how attractive time-of-day rates are and whether these rates are effectively impacting load.

Id., p. 41. MEIBC/United state that for TOD rates and programs that are implemented with AMI systems, the Commission could consider performance targets aimed at total rate class enrollment targets and a specific level of peak load reduction. Furthermore, MEIBC/United contend that "a shared-savings mechanism would be beneficial to improve AMI and time-of-day rate adoption and reduce peak demand. The specific incentive structure should be explored further by the Commission and could take into account some of the facets of the shared-savings mechanism as discussed above related to NWAs." *Id*., p. 42.

Although MEIBC/United support the focus on issues related to AMI utilization and grid modernization through the reliability-plus initiative, they assert that outage response notification and TOD rates are too limited in scope and should be expanded to include other uses of AMI. MEIBC/United state that "[a] narrow lens on next generation AMI risks diminishing the importance of new, meter-based functionalities that can facilitate DER adoption and integration, decarbonization, and grid resiliency, among other beneficial outcomes." *Id*., p. 43. Moreover, MEIBC/United "recommend that the Commission consider systematic data access for third-parties when evaluating the use of AMI. Customers should be able to readily share data with third-parties, including aggregators and other entities, who can facilitate DER deployment or otherwise reduce costs." *Id*., p. 44.

Finally, MEIBC/United recommend that the Commission consider additional metrics, scorecards, and PIMs related to the utilization of AMI to improve DER integration, EV-managed charging, vehicle-to-grid capabilities, reliability, and resiliency. MEIBC/United assert that "AMI could also facilitate expansion of time-of-use rates. The [Financial Incentives and Disincentives] workgroup could, for example, consider the value in incentivizing the implementation of day-ahead real time pricing, which could further alleviate constraints on the grid." *Id*.

Reply Comments

1. Consumers Energy Company

Consumers contends that, while it may be appropriate to adopt initial reported metrics, it is premature for the Commission to approve performance mechanisms for the five reliability-plus topics. Consumers reiterates that DER interconnection should be limited to reported metrics because the Interconnection rules were recently approved and "[i]t will take time for the Company to establish meaningful experience related to its new procedures and how those procedures impact performance under the Interconnection Rules." Consumers' June 27, 2025 reply comments, p. 3. Consumers contends that it is unclear what objective will be achieved by applying a PIM to DER interconnections.

In response to Ann Arbor's proposed target timelines for DER interconnection, Consumers argues that these timelines are shorter than those approved by the Commission in 2023, are unreasonable, and should be rejected. Additionally, Consumers asserts that "[r]equiring justification for each study would be inconsistent with the Interconnection Rules. Nevertheless, the Company does collect data on delays beyond the rule-defined timelines and is open to discussing a mechanism for reporting this information to the Commission." Consumers' June 27, 2025 reply comments, p. 3. Consumers continues to urge caution regarding the consideration of flexible interconnection concepts.

In response to MEIBC/United's comments regarding customer data access and HCA, Consumers notes that it "is currently developing its 'Phase II' hosting capacity analysis, which was first described in the Company's 2021 Electric Distribution Infrastructure Investment Plan. The forthcoming publication of the Phase II analysis will obviate a number of issues raised by MEIBC[/United]." Consumers' June 27, 2025 reply comments, pp. 4-5. However, Consumers contends that anything beyond the Phase II analysis will require additional time and further financial and human resources. In addition, Consumers states that it is not necessary for the Commission to create financial incentives/disincentives for improving hosting capacity. Rather, Consumers asserts that "the Commission could simply provide guidance through an Order about what utilities should do in the area and allow utilities to recover the costs of doing so." *Id*., p. 5. If the Commission implements financial incentives/disincentives, Consumers requests that the Commission allow the utilities to recover costs commensurate with responding to those incentives.

Consumers disputes the relevance of MEIBC/United's suggestion to update the HCA process to account for circuit-specific DER forecasts and other circuit factors, such as customer density, type of area served, and customer demographics. Consumers contends that "[h]osting capacity analysis is a technical simulation that determines the amount of generation or load that the system can accommodate, which is not dependent on these types of customer factors." *Id*. Furthermore, Consumers objects to MEIBC/United's recommendation to develop an incentive for making real-time updates to combined hosting-capacity and load-carrying-capacity maps. Consumers states that it "is not aware of any utilities who are currently providing such updates or any industry-standard tools that can support real-time updates to combined analysis maps." *Id*., p. 6.

Consumers also expresses concern regarding Ann Arbor's suggestion that maps identify areas of anticipated load growth. Consumers explains that "[i]nterconnection studies are necessarily based on current grid status and known projects. Future projections can easily be wrong, especially when made at a granular level, which could easily lead to misleading or inaccurate hosting capacity maps." *Id*.

Consumers continues to argue that NWAs are not fully developed to be ready solutions for distribution grid issues and, therefore, are not appropriate for shared savings mechanisms or other incentives. Consumers "also maintains that a discussion of DER aggregation metrics, scorecards, and PIMs is premature, and that the utility role in aggregating demand response ('DR') or DERs requires additional discussion. However, the Company agrees with MEIBC[/United]'s statements on page 24 of the May 16 comments regarding the need for advanced load forecasting capabilities." *Id*.

Regarding 4.8 kV distribution system conversion, Consumers asserts that "[i]t is unclear if any commenters are suggesting that the Company be incentivized or penalized based on the conversion of a large amount of 4.8 kV / 8.32 kV Wye to increase hosting capacity on those lines. The 4.8 kV / 8.32 kV Wye system provides 173% of the phase-to-phase voltage compared to the 4.8 kV Delta and is not a constraint in continuing to meet customer capacity needs." *Id*., p. 7. Accordingly, Consumers argues that it would be premature to base a PIM on conversion.

Consumers objects to MEIBC/United's recommendation to track the percentage of total residential customers that participate in TOD rates and the peak demand and load curve comparisons associated with TOD rates and to consider performance targets for total class enrollment. Consumers contends that:

> [t]hese measures are not necessary as the Commission ordered the utility to move residential customers to mandatory time of use rates in Case No. U-18322. The Company subsequently developed and piloted a summer time-of-use rate and moved all residential customers, other than those that voluntarily elected to pay an opt out fee, to a summer time-of-use rate. Currently, 99% of residential customers are on a time-of-use rate.

Id., pp. 7-8.

2. DTE Electric Company

DTE Electric reiterates that the scope of the focus areas in the Discussion Paper should be reduced and clarified. DTE Electric states that "[w]hile there may be additional topics to consider within Reliability Plus, or different ways to capture data, it is critical that the totality of potential metrics, scorecards, and performance incentive mechanisms within Reliability Plus be appropriately prioritized both on a standalone basis and in relation to the existing work being done on the same topics and by the same experts." DTE Electric's June 27, 2025 reply comments, p. 3. In addition, DTE Electric contends that the financial resources required for additional reporting, to achieve targets, and to fund incentives should be balanced with the system-wide benefits that are provided to customers. Furthermore, DTE Electric asserts that "the cost to achieve must be recoverable in its entirety. However, considering affordability, it's critical that even with an ability to recover costs, Reliability Plus must be prioritized amongst the many other investments needed to maintain and improve general utility service for all customers, system reliability, resiliency, safety, and efficiency." *Id*., p. 4. Accordingly, DTE Electric recommends that the Commission focus on two tangible issues for the reliability-plus initiative: NWA pilots and an exploration of the availability and use of hosting capacity information and how hosting capacity maps can benefit all customers.

In response to MEIBC/United's comments about interconnection, DTE Electric states that:

> the Company's procedures are still pending resolution in a contested case at the time of these comments. Said differently, the Company does not yet have an approved implementation mechanism for the interconnection rules and does not possess "18-19 months" of "readily available data" under its new procedures. Also pending is the finalization of the annual interconnection report scope and format, which is the first step in determining if there are any remaining gaps.

Id., p. 5 (quoting MEIBC/United's May 16, 2025 initial comments, p. 6). In addition, DTE Electric asserts that MEIBC/United's [initial] comments do not identify an actual gap related to an outcome of interest. Furthermore, DTE Electric argues that there is not a thorough understanding of the actual gaps and risks of change associated with flexible interconnection and, therefore, it is premature to set specific targets and PIMs.

Next, DTE Electric contends that the achievement of metrics must be within the utility's control. According to DTE Electric, "[m]etrics that are partially outside of the utility's control, such as total interconnection timelines, or completely outside of the utility's control, such as whether third-party aggregators can develop cost effective programs, provide limited or no value in measuring utility performance." *Id*., p. 6.

Responding to MEIBC/United's proposed concept for PIMs, DTE Electric states that:

> a PIM would be appropriate if it incentivized a utility behavior that, all else equal, may reduce utility earnings. The Company observes that a natural extension of the concept is that there should be no role for penalties if PIMs are meant to replace potentially forgone earnings opportunities. Further, there may be no role for PIMs at all within topics that primarily benefit individual customers. Some topic areas, such as deployment of specific non-wire alternative projects, could reduce the need for utility capital in certain situations but, from a systematic point of view, require further knowledge building (recommended above as a focus of Reliability Plus).

Id., p. 7.

DTE Electric also disputes Ann Arbor's claim that a utility should not earn incentives if the utility fails to meet all of standards in the SQRS rules. DTE Electric asserts that "[t]he extent to which [Mich Admin Code,] R 460.741(1) applies a limitation on incentives related to reliability metrics was extensively discussed during the prior phase of this proceeding. However, the plain language of the rule makes clear that it is inarguably inapplicable to Reliability Plus." DTE Electric's June 27, 2025 reply comments, p. 8.

Furthermore, DTE Electric argues that the CEOs and MEIBC/United provide no basis for the recommended penalties. DTE Electric explains that "[b]oth organizations discuss symmetric design from the perspective that any targets set within this proceeding are minimum standards to be met. To the extent there are minimum standards (timelines from the interconnection rules, for example) these are already within the Commission's purview and have prescribed remedies." *Id*. In addition, DTE Electric contends that for focus areas such as customer data access, there is no minimum below which a utility should be penalized.

Finally, DTE Electric agrees with ABATE that development of financial incentives is premature. According to DTE Electric, "based on the Discussion Paper, there is no area where the need is so urgent that an incentive mechanism needs to be applied in the near term." *Id*., p. 9.

3. The Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar

In response to the Companies' concerns regarding PIMs for the reliability-plus topics, the CEOs note that the establishment of metrics and incentives will be a lengthy process and that there will be ample time to address the Companies' concerns. The CEOs agree with the Companies' requests for workgroups; however, the CEOs request that the "workgroups must be narrowly crafted with deadlines and clear objectives and deliverables in order to ensure that workgroups make the best use of participants' contributions and address specific questions raised in the process of developing performance metrics." CEOs' June 27, 2025 reply comments, p. 3.

The CEOs object to the Companies' claim that because every interconnection is not necessarily beneficial to other customers, DER interconnection issues should be excluded from a performance-based mechanism. The CEOs assert that "[t]here is an extensive body of research covering the wide-scale benefits of DERs, documenting benefits to resilience, costs, decarbonization, health, and more. As we advocated in our initial comments, it is important to conduct a thorough BCA to determine the appropriate structure and amount of any performance mechanism." *Id*., p. 4 (footnotes omitted). In addition, the CEOs dispute the Companies' claim that DER interconnection should be excluded from the reliability-plus initiative because of cost shifting. The CEOs state that Michigan law supports the growth of DERs and that when aggregated and coordinated as virtual power plants (VPPs), DERs provide measurable grid value.

The CEOs argue that the Companies too narrowly define flexible interconnection. According to the CEOs, "in addition to being 'programmed to curtail output before exceeding a […] threshold,' DERs can also be programmed with fixed or scheduled limits, or be directly managed by utilities with day-ahead or real-time limits." *Id*., p. 5 (quoting Exhibit A to the March 13 order, p. 5) (alteration added by the CEOs). The CEOs also assert that the Companies too narrowly define the situations in which flexible interconnection can be implemented. In the CEOs' opinion, flexible interconnection "can also be used to defer or eliminate the need for distribution system upgrades, and allow DERs to be connected at their full capacity in locations where constraints only exist for a few hours per year." CEOs' June 27, 2025 reply comments, p. 5.

Furthermore, the CEOs object to the Companies' claim that flexible interconnection is only suitable for certain larger projects. The CEOs state that:

> [t]his claim is problematic for several reasons. First, as the Companies note earlier, the process they describe with export-limited systems is already permitted by the Interconnection Rules in [Mich Admin Code,] R 460.980(4), but the rules do not require SCADA [supervisory control and data acquisition] for such systems. Second, there are several methods of implementing [flexible interconnection] that do not require SCADA, including the method the Companies are discussing which utilizes fixed export limits. Third, even where it is required, SCADA is not needed to "ensure [a] project remains compliant," but instead to allow monitoring and control where real-time [flexible interconnection] is being implemented.

Id., p. 6 (quoting Companies' May 16, 2025 initial comments, p. 11). The CEOs also contend that the Companies overstate the safety risks of flexible interconnection.

The CEOs reiterate the importance of improving HCA and request greater transparency and granularity. *See*, CEOs' June 27, 2025 reply comments, pp. 7-8. Accordingly, "[t]o support continuous improvement and ensure that hosting capacity maps serve as effective planning tools, [the CEOs] recommend incorporating hosting capacity into the Commission's performance metrics framework." *See*, *id*., p. 8.

In response to the Companies' claim that PIMs are premature for DER aggregation and NWAs, the CEOs state that "[w]hile it is true on the surface that individual adoption of DERs is a customer choice, this argument belies the fact that customers seeking to interconnect have no choice but to deal with their utility, and that the Companies have significant power to make the process smooth, clear, and transparent; or to obstruct, obfuscate, and delay." *Id*., pp. 8-9. Accordingly, the CEOs assert that it is important that the Commission adopt carefully considered metrics to ensure that the Companies prioritize the role of partner in the process. The CEOs also suggest implementing a DER aggregation PIM that has established targets tied to reductions in peak load attributable to multi-technology VPPs.

The CEOs dispute the Companies' claim that NWAs are all custom projects and should be treated as pilot projects. The CEOs argue that NWAs are not any more custom than wires-based solutions and assert that "it is well past time to begin developing a roadmap to permanent NWA programs . . . ." *Id*., p. 11.

In response to the Companies' argument that utilities should not be driving customers toward particular rate options—specifically AMI-enabled rates—the CEOs reiterate that there is an exception to this argument. The CEOs explain that "[b]ecause customer affordability is a key directive of the Commission, a PIM which incentivizes the Companies to move customers to a more affordable rate is entirely appropriate." *Id*. The CEOs reiterate their two recommendations for this issue set forth in their initial comments.

4. Michigan Energy Innovation Business Council and Advanced Energy United

MEIBC/United agree with MEGA that it would be helpful for the Commission to clearly establish goals for future metrics, scorecards, and PIMs. However, MEIBC/United state that "a singular goal does not need to be established to begin the process of data collection and metrics establishment. Development of scorecards and PIM[s] can be accomplished in parallel with the development of specific goals to guide those scorecards and PIM[s]." MEIBC/United's June 27, 2025 reply comments, pp. 2-3. MEIBC/United also contend that utilities are a major driver of adoption of reliability-plus technologies and that these utilities can impact the degree of customer adoption and general perception. Moreover, MEIBC/United disagree with MEGA's request that the Commission only consider interconnection timing data after the Commission approves each utility's interconnection procedures. MEIBC/United state that because the utilities have been using the Interconnection rules since March 2024, such a delay is unnecessary. *See*, MEIBC/United's June 27, 2025 reply comments, p. 4.

MEIBC/United disagree with ABATE's request that the Commission wait to apply financial incentives/disincentives to any of the reliability-plus focus areas until the Commission has more experience with these focus areas. MEIBC/United "believe that the performance incentives envisioned within the Discussion Paper are a reasonable approach to entice utilities to achieve improvements in areas that, if left unresolved, could lead to reliability and customer access concerns." *Id*., p. 5.

MEIBC/United object to the Companies' claim that the five focus areas of the reliability-plus initiative will require extensive work and resources to achieve the outcomes. MEIBC/United "find it hard to believe that, given the appropriate financial incentives and disincentives, the state's two largest utilities could not find the 'time, workforce, and financial resources' to ensure improvements to their processes to the benefit of customers [and the] grid." *Id*., pp. 5-6 (quoting the Companies' May 16, 2025 initial comments, p. 4). MEIBC/United also dispute the Companies' argument that only financial incentives should be used for the reliability-plus initiative. MEIBC/United note that the Commission has chosen to focus on both incentives and penalties in the context of reliability and should do the same for the reliability-plus initiative.

In response to the Companies' claim that they have not had time to implement the interconnection procedures or collect data, MEIBC/United contend that the revised procedures were filed with the Commission in August 2023 and that the utilities have been using the procedures since that time. MEIBC/United state that "[i]f there are any specific procedures impacting the timing of DER interconnections that have changed (either due to the statutory change or Commission Order), those can be specifically examined by the Financial Incentives and Disincentives workgroup and additional data can be collected specifically on those issues." MEIBC/United's June 27, 2025 reply comments, p. 7.

Regarding the Companies' request that flexible interconnections follow a two-step process and be considered on a case-by-case basis, MEIBC/United note that they somewhat agree with the Companies. However, MEIBC/United:

> support a broader set of use-cases for which flexible interconnection practices can be applied. Specifically on this matter, the Discussion Paper generally supports a potential broader use of flexible interconnection, stating that "reporting metrics on customer delays from system upgrades and areas of the distribution system with declining hosting capacity can provide insight on when flexible interconnection processes may be useful."

MEIBC/United's June 27, 2025 reply comments, p. 8 (quoting Exhibit A to the March 13 order, p. 5).

MEIBC/United dispute the Companies' claim that the Discussion Paper acknowledges that adopting a scorecard level mechanism for DER interconnections is premature. MEIBC/United assert that "the Discussion Paper explicitly focuses on the development of a DER Interconnection Scorecard as discussion item #1.1 within the DER Interconnection topic, and even provides example reference points for the [Commission] to consider when establishing target performance for a potential scorecard." MEIBC/United's June 27, 2025 reply comments, p. 9 (quoting Exhibit A to the March 13 order, pp. 3-4).

In response to the Companies' argument that customer data access is not an appropriate topic for performance-based ratemaking, MEIBC/United contend that it is simply a potential reporting metric and an area for improvement. According to MEIBC/United:

> "[h]ow utilities can improve the data available to customers" is entirely within the utilities' purview to address and has a broader scope for the development of a performance based ratemaking structure of some kind, as the utilities can be incentivized to improve data available to customers. "Encouraging more customers to access their data" is a reasonable tactic for how the utilities can improve data available to customers, however, this should not be misconstrued as the goal of the Discussion Paper, as the utilities' have stated.

MEIBC/United's June 27, 2025 reply comments, p. 9.

MEIBC/United disagree with the Companies that the reliability-plus initiative should be limited to pilot NWA projects. MEIBC/United assert that "[d]ue to the existence of a number of NWA pilot projects, it may be worthwhile to leverage the knowledge gained from these projects to establish a PIM, and consider the expanded use of NWA projects outside of the current pilot project context." *Id*., p. 10.

In addition, MEIBC/United dispute the Companies' claim that they need additional time and experience to gather information about AMI utilization. MEIBC/United argue "that it is unnecessary to collect more data and gather more experience before moving toward a PIM on the grounds that the Companies seemingly have collected enough data related to this topic to determine that improvements have been made over the last several years." *Id*., p. 11.

Responding to Ann Arbor's request that the utilities have a reasonable time to collect information and establish a performance baseline for DER interconnection, MEIBC/United reiterate that enough data exists for the Commission to develop metrics, scorecards, and PIMs. *See*, *id*. However, MEIBC/United agree with Ann Arbor that it would be helpful to "collect[] information on what export-limited interconnection options currently exist and are offered by the utilities [because it] would be incredibly useful to further the development of a performance based ratemaking mechanism." *Id*., p. 12.

MEIBC/United also agree with Ann Arbor that hosting capacity maps should identify areas of anticipated load growth so that a utility could collaborate with third parties on battery pilots or microgrid projects to alleviate strained capacity. *See*, *id*.

Regarding the development of a PIM for DER interconnections, MEIBC/United support the CEOs' recommendation that PIMs be regularly adjusted to account for changes in actual performance. MEIBC/United contend that this will "ensure that the utility continues to improve performance overtime [sic]." *Id*., p. 13. MEIBC/United also generally agree with the CEOs' recommended approaches for flexible interconnection, customer data access and hosting capacity, and DER aggregation and NWAs. *See*, *id*., pp. 13-14.

<u>Discussion</u>

The Commission appreciates all the comments provided by the parties in this docket. The Commission has reviewed the initial and reply comments and, to facilitate discussion on these issues, has developed a straw proposal, attached to this order as Exhibit A, to refine the initial focus areas of the reliability-plus initiative; to solicit feedback on updated metrics, scorecards, and PIMs for the reliability-plus initiative; and to outline next steps for this proceeding.

The Commission invites interested persons to comment on the straw proposal. Of particular interest to the Commission is reaction to the candidate metrics, and where included, the proposed target performance identified for each metric, and the potential incentive/disincentive mechanisms to be applied to each metric for each focus area. In addition, the Commission is interested in any alternative metrics or approaches to those identified in the straw proposal. Written and electronic initial comments on the straw proposal are due no later than 5:00 p.m. (ET) on October 1, 2026. Written and electronic reply comments must be received no later than 5:00 p.m. (ET) on November 5, 2026. The written and electronic comments should be paginated and reference Case No. U-21400. Written comments should be mailed to: Executive Secretary, Michigan Public Service Commission, P.O. Box 30221, Lansing, MI 48909. Comments submitted in electronic format may be filed via the Commission's E-docket website, or for those persons without an E-dockets account, via e-mail to LARA-MPSC-Edockets@michigan.gov. Any person requiring assistance prior to filing may contact the Staff at (517) 284-8090 or by e-mail at LARA-MPSC-Edockets@michigan.gov. All comments submitted to the Commission in this matter will be filed in Case No. U-21400 and will become public information available on the Commission's website and subject to disclosure.

THEREFORE, IT IS ORDERED that interested persons may file comments in Case No. U-21400 regarding the straw proposal attached to this order as Exhibit A. Comments must be received no later than 5:00 p.m. (Eastern time) on October 1, 2026. Reply comments must be received no later than 5:00 p.m. (Eastern time) on November 5, 2026.

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 LARA-MPSC-Edockets@michigan.gov and to the Michigan Department of Attorney General - Public Service Division at sheac1@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

Katherine L. Peretick, Commissioner

Shaquila Myers, Commissioner

By its action of August 6, 2026.

Lisa Felice, Executive Secretary

Phase 2 Reliability-Plus Framework Straw Proposal

Background

In the April 24, 2023 order initiating this docket (April 24 order), the Commission noted that beyond the initial focus on the reliability and safety of utility distribution systems, a further goal was to "consider challenges around the readiness of utility distribution grids to effectively accommodate and leverage the increasing and further anticipated growth of distributed generation, [electric vehicles], and other [distributed energy resources (DERs)]." April 24 order, p. 12. Subsequently, in a March 13, 2025, order in this case (March 13 order), the Commission requested comments and reply comments on the *Financial Incentives and Disincentives Workgroup Reliability-Plus Framework Discussion Paper* (Discussion Paper). The Discussion Paper identified the following focus areas for further comment and discussion, including feedback on potential metrics, scorecards, and performance incentive mechanisms (PIMs) in each focus area:

1) Distributed Energy Resource (DER) Interconnection
2) Data Access and Hosting Capacity
3) DER Aggregation and Non-Wires Alternatives
4) 4.8kV Conversions
5) Advanced Metering Infrastructure (AMI) Utilization and Grid Modernization

On May 16, 2025, interested parties filed initial comments on the Discussion Paper. Reply comments followed on June 27, 2025.

Purpose of the Phase 2 Straw Proposal

After reviewing responses to the Discussion Paper, the MPSC staff developed this Phase 2 Straw Proposal (Straw Proposal) to refine the initial focus areas and recommend updated metrics, scorecards, and PIMs for the Reliability-Plus Framework. Similar to the straw request further comments from the Financial Incentives and Disincentives (FID) workgroup proposal for reliability metrics issued earlier in this proceeding, the Commission will take this feedback into consideration in final decisions on the framework.

Reliability-Plus Framework Connections with Key MPSC Dockets

While a central focus of the Commission's work, concerns over the affordability of energy services have grown in recent years. In addition, managing load growth has also emerged as a priority issue in Michigan and elsewhere. The following section briefly summarizes the key linkages between this framework and the MPSC's current priority initiatives relating to electricity affordability and managing load growth.

Electricity Affordability and Efficient Use of the Distribution System

The recommendations in this Straw Proposal encourage more efficient use of the distribution grid, maximize the value of existing investments, and support cost-effective additions of DERs, including aggregated DERs and virtual power plants (VPPs). Done well, these actions can defer or avoid costly infrastructure additions and reduce upward pressure on rates. The framework also supports the MPSC's recent guidance to review and maximize the value from existing AMI investments.

DER Deployment and Virtual Power Plants

The Reliability-Plus Framework also directly complements the Commission's emerging focus on VPPs and the expanded use of DERs that make up VPPs. According to the U.S. Department of Energy's (DOE) September 2023 "Pathways to Commercial Liftoff: Virtual Power Plants" report, VPPs are "aggregations of distributed energy resources (DERs) such as rooftop solar with behind-the-meter (BTM) batteries, electric vehicles (EVs) and chargers, electric water heaters, smart buildings and their controls, and flexible commercial and industrial (C&I) loads that can balance electricity demand and supply and provide utility-scale and utility-grade grid services like a traditional power plant." The performance incentive and disincentive mechanism recommended in this proposal recognizes the ability of VPPs to reduce the need for conventional peaking infrastructure and encourages utilities to successfully integrate these resources into grid operations and provides accountability if utility progress falls below Commission-established targets.

Distribution System Plans, IRPs, and Data Center Requests

The Reliability-Plus Framework is also connected to the MPSC's oversight of utility distribution system plans (DSPs) and Integrated Resource Plans (IRPs). DTE Electric Co. (DTE Electric) filed its distribution system plan in April 2026, and Consumers Energy's (Consumers) filing is expected in October 2026. These plans are required to address grid modernization efforts, including DER integration, non-wires alternatives, and distribution management systems. The metrics and scorecards developed through this workgroup will provide important benchmarks for evaluating utility performance against commitments made in those filings. The DSP filings will also provide updated data—on hosting capacity, load growth projections, and planned infrastructure—that should inform the calibration of targets under this framework.

The IRP process provides an important connection point. New IRPs will soon be filed by Consumers, DTE Electric, and other utilities and are required to model aggregated distributed generation (DG), DERs, and VPPs as selectable resources. The recommended shared savings mechanisms tied to cost-effective DER deployment and VPP development utilizes these results in setting targets for implementing these demand-side resources.

The rapid growth in data center load requests in Michigan presents a distinct but related challenge. In the absence of additional regulatory approaches, these new loads could potentially trigger costly additions in traditional generation and transmission capacity. By leveraging resources that are either already on the system of are relatively quick to deploy, VPPs can meet at least a portion of these demands for new capacity and mitigate cost pressures and also allow for faster interconnection timelines that would not be possible relying on traditional generation or transmission solutions alone. However, traditional cost-of-service regulation discourages utilities from pursuing this resource at the scale required by new loads. This Straw Proposal recommends new metrics and an incentive/disincentive mechanism to accelerate deployment of DERs and develop VPP resources.

Focus Area 1: DER Interconnection

The DER interconnection process plays a critical role in enabling customers to connect generation and flexible resources to the distribution grid efficiently while maintaining safe and reliable operations. This Straw Proposal continues to prioritize improving interconnection timelines and transparency beyond the minimum levels required in interconnection standards and recommends establishing a performance incentive mechanism for DER Interconnection through the FID workgroup. The 2025 Annual Interconnection Reports recently filed by Michigan utilities provide important baseline information on interconnection performance under the updated Michigan Interconnection and Distributed Generation rules (MIXDG rules). In addition to a PIM for interconnection, the proposal encourages tracking metrics for interconnection of flexible loads as this resource can improve efficient use of the distribution system. As electrification increases, particularly from electric vehicles, managed charging represents a key resource to align new load with off-peak periods, improve utilization of existing system capacity, and mitigate upward pressure on rates.

Key Updates on DER Interconnection Focus Area

2025 Annual Interconnection Reports filed by Consumers and DTE Electric

In March 2026, in Case No. U-20890, DTE Electric and Consumers filed their first Annual Interconnection Reports, which covered calendar year 2025. The utilities reported the following trends on interconnection:

- **Customer requests to interconnect DERs are increasing.** In 2025, Consumers received 2,798 DER interconnection applications and approved 2,685 (96%) to proceed with interconnection. DTE Electric received 3,699 applications and approved 3,476 (94%) to continue with interconnection. Combined, Michigan's two largest utilities processed over 6,400 applications in a single year, the vast majority for solar and solar-plus-storage projects.

- **A significant share of interconnection requests currently require multiple reviews, adding delay and cost to the process.** The "once-through" approval rate refers to the proportion of applications approved on the first submission, as opposed to those applications that require multiple attempts prior to gaining approval to interconnect. For Level 1 solar projects, representing smaller projects of up to 20 kilowatts (kW) alternating current (AC) using certified inverters, DTE Electric's reported once-through rate was 63%, and 47% for similar-sized solar plus storage projects. Consumers reported a 46% once-through approval rate for Level 1 solar-only projects and only 17% for solar-plus-storage projects. For larger projects, once-through rates were even lower, DTE Electric and Consumers reported that the most common reasons applications are rejected include deficiencies in one-line diagrams, site plans, and equipment specifications. Overall, these high rejection rates suggest opportunities to improve application guidance and review processes.

- **Interconnection timelines provide a baseline for further review.**

The following table summarizes interconnection timelines for Consumers and DTE Electric.

Table 1: Comparison of Average Interconnection Timelines for Solar Only Projects (days)[1]

Project Size	Consumers	DTE Electric
Level 1	67	64
Level 2[2]	151	111
Level 3[3]	178	165
Level 4[4]	417	N/A
Level 5[5]	N/A	N/A

[1] Table One compares Average Time from Receipt of Complete Application to Authorization to Operate in Parallel (Days). Both utilities also reported project statistics for solar and storage projects, which indicated lower application volumes but longer interconnection timelines for Level 1 projects.

[2] Level 2 projects are defined as certified projects between 20-150kWac.

[3] Level 3 projects are defined as projects of up to 150kWac that are not certified, or projects between 150-550kW.

[4] Level 4 projects are defined as projects between 550kWac-1 megawatt (MW)ac.

[5] Level 5 projects are defined as projects larger than 1MWac.

Compliance with MIXDG Deadlines. On April 25, 2023, the MPSC's Michigan's MIXDG rules became effective. The rules outline how projects owned by customers or developers connect to the utility system, a standardized process and schedule, reporting, and rules to ensure interconnection is done safely. Each utility also filed interconnection procedures and forms, which were approved by the Commission.

Both utilities reported high compliance rates with meeting MIXDG utility timelines. Consumers reported 51 missed utility deadlines out of approximately 19,700 opportunities (0.26%), while DTE Electric reported missing 42 out of 23,246 deadlines (0.18%). Reasons stated for missing deadlines include significant growth in application volume, project complexity, and updates to application software systems.

DER Interconnection Recommendations

Faster interconnections allow customers to realize the benefits of DERs sooner while providing greater certainty and reducing project costs. Improving interconnection performance can also reduce utility backlogs, increase transparency, support economic development, and contribute to Michigan's clean energy objectives. To continue improving timely DER interconnection, this Straw Proposal recommends several further actions described below.

1. **Implement DER Interconnection Timeline PIM for Level 1, 2, and 3 Projects**

   This proposal recommends setting an initial PIM for Level 1, 2, and 3 projects (DERs ≤550kW) focusing on the timelines for utilities to complete steps in the interconnection process under their control.

   The MIXDG rules establish timelines for reviewing DER interconnection requests and include a provision for the MPSC to impose penalties under R 460.656.

   DER Interconnection Penalty – The MPSC would annually review the number of instances that a utility fails to meet interconnection review timeframes established in the MIXDG. Utilities currently report this information in the Annual Interconnection Report.[6] After reviewing the circumstances for violations of the MIXDG rules, the MPSC would determine if the utility should incur a penalty.

   DER Interconnection Incentive - This proposal recommends establishing a two-tiered financial incentive for interconnection of Level 1, 2, and 3 DER projects. The MPSC would measure interconnection performance using the average timeline from "Receipt of Complete Application to Authorization to

[6] See Part 5a. of Annual Interconnection Report.

Operate in Parallel (Days)," included in the MPSC's Annual Interconnection Report.[7]

This proposal recommends setting initial targets for the top tier of performance at 10 days on average for Level 1 and Level 2 projects, with the lower tier incentive set at 20 days average interconnecting time. While the Commission acknowledges that both targets represent a significant improvement over current performance, 2025 average interconnection timelines for projects of up to 25kW of exporting capacity at a peer utility (Commonwealth Edison) in Illinois were approximately 5.5 days (and less than 15 days for projects of up to 5 MW of nameplate capacity), suggesting that this level of performance is well within the ability of similarly situated utilities to meet.

This proposal further recommends setting initial targets for Level 3 projects at 20 days for the highest tier of incentive, with a reduced incentive available at 30 days average interconnection time. Again, the Commission notes this represents a significant improvement over the current average timelines for Level 3 projects of 165 and 178 days for DTE Electric and Consumers, respectively.[8]

Incentive and penalty amounts – This proposal encourages comments on recommended levels for potential incentives and penalties under this PIM.

Continuous improvement – While the primary focus of this recommendation is to establish initial interconnection PIMs for Level 1, 2, and 3 projects, the Commission is also interested in how opportunities for continuous improvement should be structured at the point utilities meet the initial timelines that trigger incentives. For example, the PIM used by Commonwealth Edison includes a symmetrical PIM aimed at incentivizing continuous improvement in interconnection timelines. The Commission seeks comment on whether a similar structure should be adopted in Michigan, or whether there are other opportunities to drive continuous improvement.

2. **Scorecard for DER Interconnection Timelines for Projects >550kW**

[7] See Part 4 of Annual Interconnection Report.

[8] As noted above, this is still longer than the current average timeline for Commonweath Edison to process applications for projects of up to 5MW, and the lower incentive tier is approximately equal to the average timeline of 32.4 days for Commonwealth Edison to process applications for projects of between 5-10MW of nameplate capacity.

This Straw Proposal recommends a target for average interconnection timelines for Level 4 and 5 projects with no incentive or disincentive at this time. DTE Electric and Consumers reported few projects larger than 550kWac, with Consumers reporting an average of 417 days to approve interconnection of Level 4 projects. (DTE Electric did not have any Level 4 projects reported, and neither utility reported any Level 5 projects.)

This straw proposal recommends an initial target of 75 days, which interested parties should discuss in their comments.

3. **Implement Flexible Interconnections through Interconnection Technical Workgroup (ITWG)**

   In Case No. U-21480, the MPSC directed staff to convene an Interconnection Technical Workgroup (ITWG). In 2025, the ITWG developed an Annual Interconnection and Distributed Generation Report Template (Annual Interconnection Report) and finalized the reporting process in November 2025.[9] Utilities filed their first annual reports on March 31, 2026. Given the ITWG's progress developing this comprehensive set of reporting metrics, this proposal recommends continuing with the current reporting metrics for distributed generation and storage. In addition, the Discussion Paper solicited comments on the topic of flexible interconnections. Comments broadly supported this concept but indicated that the implementation details require further discussion. During the comment period on the Discussion Paper, MPSC staff clarified that the scope of the ITWG would include flexible interconnection for distributed generation and storage. The ITWG currently plans to discuss this topic in upcoming meetings. Given this existing workgroup that plans to convene the appropriate technical experts, this proposal recommends the ITWG continue developing further actions to implement flexible interconnection for MI utilities, including additional recommendations on new metrics for tracking flexible interconnection. The ITWG can also consider metrics associated with load energization timelines.

4. **Implement Flexible Interconnections through Interconnection Technical Workgroup (ITWG)**

   The Discussion Paper solicited comments on the topic of flexible interconnections. Comments broadly supported this concept but indicated that the implementation details require further discussion. During the comment period on the Discussion Paper, MPSC staff clarified that the scope of the ITWG would include flexible

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[9] See https://www.michigan.gov/mpsc/commission/workgroups/interconnection-technical-workgroup for further information on the ITWG. The annual report template is available online at: https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/interconnection-technical-workgroup/Annual-Report-Template-FINAL-111025.docx?rev=b0377772c94e400cbf4baf9dee9d36e5&hash=A07F188F4F4846C266562035B6DFFEBD.

interconnection for distributed generation and storage. The ITWG currently plans to discuss this topic in upcoming meetings in 2026. Given this existing workgroup that plans to convene the appropriate technical experts, this proposal recommends the ITWG continue developing further actions to implement flexible interconnection for MI utilities.

Focus Area 2: Data Access and Hosting Capacity

Providing customers with access to timely and transparent information on the distribution system and energy use improves opportunities to leverage DERs to minimize costs and efficiently operate the distribution grid. For these reasons, the Discussion Paper included this focus area as a priority and requested feedback on reporting metrics to assess the effectiveness of utility data access platforms and hosting capacity maps.

Key Updates on Data Access and Hosting Capacity Focus Area

After issuing the Discussion Paper, interested parties submitted comments and provided a range of views on data access reporting metrics. In addition, the MPSC issued an order in July 2025 in Case No. U-20147 (July 2025 order), which directed improvements to Consumers and DTE Electric hosting capacity maps by October 1, 2025. Consistent with the July 2025 order, DTE Electric and Consumers updated their hosting capacity maps, and MPSC staff reviewed the revised versions in preparing this Straw Proposal. Finally, DTE Electric filed an updated Distribution System Plan in April 2026, and Consumers' next DSP is expected in the fall of 2026. Further steps on this topic area are outlined below.

Data Access and Hosting Capacity Recommendations

After reviewing comments on the Discussion Paper and updated hosting capacity maps, this proposal seeks comment in the following area related to Data Access and Hosting Capacity Maps:

As noted above, in the July 2025 order the MPSC directed Consumers and DTE Electric to update their respective hosting capacity maps by October 1, 2025, start updating the maps on a quarterly basis, and provide monthly updates for any feeder that has more than 500 kW of generation since the last quarterly update.[10] This order also provided guidance on hosting capacity maps in future distribution system plan filings.[11]

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[10] See July 2025 order at p. 32.

[11] See *Id.*, Exhibit A – "Distribution System Planning Staff Proposal" at p. 9.

The 2026 distribution system plan filings for Consumers and DTE Electric will provide another opportunity to review progress with their hosting capacity maps. Finally, the DER Interconnection PIM will encourage overall improvements with the interconnection process, including enhancements to hosting capacity maps.

The Commission seeks comment on opportunities to maximize the usefulness of the hosting capacity maps developed by Consumers and DTE Electric. Further, the Commission seeks comment on whether performance-based regulatory mechanisms are needed to further objectives around data access and hosting capacity information, or whether traditional regulatory tools are sufficient. The Commission acknowledges that other issues around data access were raised in comments and intends to take further action on issues including Green Button Connect implementation and other data access metrics as part of utility DSPs and in other proceedings as appropriate.

Focus Area 3: DER Aggregation and Non-Wires Alternatives (NWAs)

There has been a significant amount of focus recently on opportunities connected with VPPs. According to the DOE VPP Liftoff report noted above, “VPPs enroll DER owners – including residential, commercial, and industrial electricity consumers – in a variety of participation models that offer rewards for contributing to efficient grid operations.” Notably, VPPs can serve multiple purposes, including supporting overall resource adequacy, reducing the need for peaking infrastructure, and addressing localized issues in a way that avoids or mitigates the need for expensive grid upgrades.

In recent directives, the Commission has prioritized actions for Michigan’s utilities to implement VPPs. To further these directives and the technical discussions to implement VPPs in other proceedings, this straw proposal recommends a VPP PIM to support and encourage cost-effective VPPs that can address load growth and improve affordability of distribution system costs. The straw proposal describes a draft structure for the VPP PIM for further review by this FID workgroup.

Key Updates on DER Aggregation and Non-Wires Alternatives (NWAs)

In December 2025, the MPSC updated the planning parameters and filing requirements for future IRP filings and required utilities to treat demand-side resources as a selectable resource. This requirement should allow utilities to develop and propose resource plans with demand- and supply-side options optimized on a more equal basis. The new requirements provide greater transparency on the treatment of VPPs and demand-side resources, which can support setting future targets for acquiring VPPs similar to supply-side resources.

In addition, the Commission has also previously outlined requirements for addressing VPPs and NWAs as part of DSPs and will consider the DSPs submitted by DTE Electric (April 2026) and Consumers (expected in October 2026).

Finally, In Consumers' recent rate case decision (Case No. U-21870), the Commission discussed its expectations on treatment of VPPs in upcoming plans and noted further Commission-led efforts to support implementing VPPs. As discussed more fully below, the Commission held an AMI technical conference on July 14, 2026, which included presentations from utilities and third parties on AMI and DER integration and utilization

The Commission further notes that a necessary precondition in unlocking the full value of VPPs and other forms of aggregated DERs is the level of DERs on the system that can be aggregated.

DER Aggregation and Non-Wires Alternatives (NWAs) Recommendations

The straw proposal recommends developing a VPP PIM to complement the technical and operational discussions on VPPs in other proceedings and Commission-led efforts. The discussion below outlines a proposed structure for the VPP PIM and builds on the current mechanism used for EWR Programs and the Benefit-Cost Analysis tool developed in Case No. U-20898.

VPP Performance Incentive Mechanism

Michigan's EWR program provides a well-established and applicable model for a VPP PIM and/or a PIM focused on DER deployment. Under the EWR framework, utilities earn a performance incentive by demonstrating that energy efficiency programs deliver net benefits to customers, with shareholder earnings tied to the value created above program costs. This same incentive structure — encouraging utilities for achieving verified net benefits — is well suited to DER deployment and VPP programs, which can similarly reduce the need for conventional infrastructure investment and deliver system-wide cost savings.

The key design elements of the EWR shared savings mechanism can translate to aggregated DER programs. Under EWR, the incentive is calculated as a percentage of the net present value of verified net benefits. A utility that exceeds its savings targets earns an incentive payment; a utility that falls short faces a penalty.

For DER aggregation and VPP programs, a parallel structure would reward utilities for demonstrating that aggregated resources deliver net system benefits — including avoided generation, transmission, and distribution capacity costs — relative to the cost of acquiring and operating those resources.

The benefit-cost analysis tool developed in Case No. U-20898 can provide the appropriate analytical foundation for this PIM and ensure that net benefit determinations apply a

Commission-approved methodology, use utility-specific avoided cost data, and account for the full range of system benefits including deferred infrastructure investment, improved reliability, and avoided energy costs.

The proposed VPP PIM structure would include:

- VPP and DER deployment targets established in the utility's IRP;
- 15% shared savings for implementing Commission-approved VPP or DER deployment target;
    - Consider scaling this sharing % linearly to 20% up to 110% of target if VPPs and/or DERs remain cost-effective, similar to the tiered incentive mechanisms used in the EWR context.
- Apply a penalty for failure to implement a minimum threshold of VPP or DER deployment target;
    - consider 80% of Commission-approved VPP or DER deployment target as an initial penalty threshold;
- Utilize BCA tool to estimate avoided costs, including distribution investment deferral.

FID workgroup participants are encouraged to comment on this proposed structure and potential alternatives to consider on setting DER deployment and VPP targets, incentive sharing rates, and any modifications to the U-20898 BCA methodology needed for VPP or DER program evaluation. In addition, recognizing that VPPs and aggregated DERs can address different challenges in different ways, the Commission is also seeking comment on whether different PIMs are needed for VPPs and aggregated DERs that serve as NWAs versus those focused on resource adequacy or peak reduction.

Focus Area 4: 4.8 kV Conversion

The March 2025 Discussion Paper highlighted this topic and solicited feedback from interested parties. Comments generally supported treating this focus area as a subset of the topics of DER interconnection, flexible connections, and NWA/load relief initiatives. In addition, the MPSC provided further guidance on this topic in DTE's last rate case order and directives in the DTE Electric's Liberty Audit Order. The MPSC will continue to review this topic in DTE Electric's DSP and related proceedings.

For these reasons, this straw proposal recommends removing this focus area from the Reliability-Plus effort and instead addressing concerns in other proceedings.

Focus Area 5: AMI Utilization and Grid Modernization

The Discussion Paper included AMI Utilization and Grid Modernization as focus areas for the Reliability-Plus Framework recognizing the significant investments in AMI by several Michigan utilities and ongoing efforts to implement distribution system plans. A core element of this framework is maximizing the value of these investments and opportunities to leverage new customer technologies to lower cost and improve distribution system operations.

Interested parties provided a range of feedback on the proposed elements under these topic areas. Based on review of this feedback and recent events discussed below, this straw proposal recommends establishing tracking metrics for grid utilization and a scorecard for outage response metrics. In the future, the MPSC could consider performance incentive mechanisms for grid utilization and outage response.

Key Updates on AMI Utilization and Grid Modernization Focus Area

Michigan AMI Technical Conference (Case No. U-22065)

On April 30, 2026, the Commission issued an order in Case No. U-22065 directing Staff to convene a technical conference on the future implementation of advanced metering infrastructure (AMI), which was held on July 14, 2026. The technical conference focused on the technical aspects of planning for AMI investments, current and future utilization of AMI for DER deployment and integration, next-generation AMI functionality, improving AMI business cases, ensuring AMI investments are maximizing value for customers, and developing an AMI strategy that's consistent across other cases. Staff must submit a report by August 31, 2026, summarizing the conference and recommending guidelines for future AMI implementation. The Commission explicitly directed this conference to coordinate closely with forthcoming work on VPPs. In addition, the discussions in this proceeding may inform further metrics on AMI utilization.

Summary of Utility Reporting in Case No. U-21388

Case No. U-21388 is the Commission's primary docket for addressing the reliability and resilience of Michigan's electric power system. The Commission opened this proceeding in April 2023 following a series of severe storms. It has generated a series of utility reports and Commission orders directly relevant to the outage restoration metrics recommended in this straw proposal. The following summarizes key findings from utility reports filed in that docket and subsequent Commission directives.

- **July 2024 Utility Reports on Customer Communication Protocols and AMI Utilization.** Pursuant to the Commission's December 21, 2023, order in U-21388, DTE Electric and Consumers each filed reports by July 1, 2024, describing their customer communication protocols, strategies, and timelines during outage events. The reports also described initial steps taken to develop internal processes to use AMI data to confirm individual customer service restoration and to improve the accuracy of outage maps and estimated restoration times. No comments were filed in response to the reports. These reports represent the utilities' own assessment of their restoration communication capabilities and identify opportunities to leverage AMI investments to improve the customer experience during outages—directly relevant to the AMI utilization metrics addressed elsewhere in this proposal.

Recent Developments with Grid Utilization Metrics

A March 2026 Brattle Group study, *The Untapped Grid*, provides important context for the grid utilization metrics included in this straw proposal. The study found that new load growth can put downward pressure on rates if utilities integrate loads when and where the electric system has spare capacity. The study identifies three pathways to improve utilization: adding load where existing headroom already exists; adding flexible load that can shift to off-peak hours; and deploying DERs (batteries, EV managed charging, HVAC controls, smart panels) to reduce existing peak demand and create new headroom. All three pathways are relevant to Michigan's distribution systems and address new load growth. The report recommends establishing grid utilization metrics as a first step to understanding and improving system utilization.

In April 2026, Virginia enacted legislation (HB 434, Chapter 611) that provides another useful model for how Michigan could structure grid utilization metrics. Under HB 434, major Virginia utilities must petition the State Corporation Commission by October 15, 2026, for approval of electric grid utilization metrics.

The legislation specifies a minimum set of metrics that include:

(i) the ratio of distribution system peak load to total distribution electric grid capacity;
(ii) the ratio of current electric load delivered to total potential deliverable electric load over the distribution system;
(iii) the percentage of kilowatt-hours lost during the distribution process;
(iv) an analysis of constrained circuits; and
(v) an evaluation of distribution system performance at system peaks.

The legislation directed the Virginia State Corporation Commission to include a timeline for each utility to improve utilization and to describe how the metrics may inform future cost recovery decisions. Virginia also requires the Commission to analyze each utility's potential to increase grid utilization through NWAs, including energy storage, customer-owned resources, utility-contracted DERs, virtual power plants, and flexible interconnection. This statutory framework informs the recommendations on grid utilization metrics in this straw proposal, which are described further below.

AMI Utilization and Grid Modernization Recommendations

1. **Add Distribution Grid Utilization Metrics and Reporting to Inform Future PIM Development**

The Discussion Paper suggested tracking metrics related to customer adoption of time-based rates as measures of maximizing the value of AMI investments and improving system efficiency. Recent national research and legislative developments provide strong support for expanding and deepening this approach.

Building on the Brattle framework and the Virginia model, this proposal recommends tracking the following metrics at the system aggregate, substation, and feeder levels of the distribution system:

- peak utilization (peak demand (MW) / capacity limit (MW)); and
- capacity factor (energy usage (MWh) / capacity limit (MW) x hours in period (h))

Utilities should also report on overall distribution system losses, constrained circuits, and distribution system conditions during peak demand. These recommendations track the initial metrics required by Virginia's legislation.

Comments on this topic can address the preferred period of reporting these metrics starting with annual and monthly values and expanding over time as additional data becomes available.

After establishing a baseline based on data submitted by utilities and others, the MPSC should consider setting utility-specific improvement targets, consistent with the Virginia HB 434 model, and evaluate opportunities to use these metrics to inform future cost recovery decisions for distribution capital investments and potentially other PIMs.

The Commission encourages comments on these elements of program design, as well as on overall issues related to increasing grid utilization and leveraging performance-based regulatory mechanisms to encourage more efficient use of existing grid assets.

2. Restructure Demand Response PIMs to Focus on Performance
   Since demand response (DR) programs provide utilities with operational tools to improve distribution system utilization, metrics should also demonstrate how DR contributes to (or could contribute to) reducing peak demand, relieving distribution system constraints, and increasing utilization of existing infrastructure. DR performance metrics alongside grid utilization metrics will assess if utilities are effectively using customer flexibility to maximize the value of AMI investments, improve system efficiency, and the possibility to avoid or defer unnecessary distribution capital investments. This should also support a restructured approach to DR incentives tied to DR performance, as opposed to the current approach tied to a utility's level of spending on DR programs.

In addition, utilities should report DR performance and recommend the following metrics:

- enrolled demand response capacity (MW);
- verified peak demand reductions achieved through DR events (MW);
- percentage of constrained feeders or substations supported by DR resources;
- frequency and effectiveness of DR event dispatch during system and local peak conditions; and
- customer participation and event performance rates for DR programs.

The Commission seeks comment on the identified reporting elements and associated metrics, as well as on opportunities to restructure the DR PIMs to reflect actual DR performance.

3. Implement Scorecard for Outage Restoration Metrics
MPSC Staff reviewed the feedback from interested parties, including concerns raised by utilities on this topic. Given the importance of maximizing customer value from existing investments and improving outage response performance, this proposal recommends continuing with tracking outage response metrics and setting targets based on utilities' prior submissions with their proposed goals for outage response. After further tracking utility progress towards these targets, the MPSC can determine if a performance incentive or penalty mechanism is warranted.

CONCLUSION

In addition to the specific recommendations around proposed PIMs and metrics, the Commission is also seeking holistic comments on how the individual proposals fit together, and the extent to which the proposals represent a symmetrical approach to performance-based mechanisms, both when considering the Focus Areas associated with Phase 2 of the Reliability-Plus framework, as well as in concert with the PIMs contained in Phase 1. Finally, the Commission seeks comments on whether the recommendations are likely to lead to both energy cost savings for customers and improved grid performance.

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

STATE OF MICHIGAN)

Case No. U-21400

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on August 6, 2026 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 J. Brown

Brianna Brown

Subscribed and sworn to before me
this 6th day of August 2026.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2030

GEMOTION DISTRIBUTION SERVICE LIST

kabraham@mpower.org	Abraham,Katie - MMEA
mkuchera@AEPENERGY.COM	AEP Energy
mfurmanski@algerdelta.com	Alger Delta Cooperative
akellen@wppienergy.org	Alger Delta Cooperative
kd@alpenapower.com	Alpena Power
dgreen@alpenapower.com	Alpena Power
VSTRetailReg@VistraCorp.com	Ambit Midwest, LLC
kerdmann@atcllc.com	American Transmission Company
acotter@atcllc.com	American Transmission Company
john.calhoun@ardentnaturalgas.com	Ardent Natural Gas, LLC
awebster@baycitymi.gov	Bay City Electric Light & Power
sara.anderson@bayfieldelectric.com	Bayfield Electric
rbishop@BISHOPENERGY.COM	Bishop Energy
braukerL@MICHIGAN.GOV	Brauker, Linda
cherie.fuller@bp.com	BP Energy Retail Company, LLC
christine.hughey@bp.com	BP Energy Retail Company LLC
greg.bass@calpinesolutions.com	Calpine Energy Solutions
lachappelle@varnumlaw.com	Chappelle, Laura
manderson@wpsci.com	Cherryland Electric
mengels@wpsci.com	Cherryland Electric
cdrys@wpsci.com	Cherryland Electric
ljohnson@wpsci.com	Cherryland Electric
rjohnson@cherrylandelectric.coop	Cherryland Electric Cooperative
frucheyb@DTEENERGY.COM	Citizens Gas Fuel Company
crystalfallsmgr@HOTMAIL.COM	City of Crystal Falls
gpirkola@escanaba.org	City of Escanaba
jolson@gladstonemi.gov	City of Gladstone
kmaynard@cityofmarshall.com	City of Marshall
tdavlin@portland-michigan.org	City of Portland
cwilson@cloverland.com	Cloverland Electric
mheise@cloverland.com	Cloverland Electric
todd.mortimer@CMSENERGY.COM	CMS Energy
Kenneth.Johnston@cmsenergy.com	Consumers Energy
Yong.Keyes@cmsenergy.com	Consumers Energy
chibuzo.obikwelu@cmsenergy.com	Consumers Energy
sarah.jorgensen@cmsenergy.com	Consumers Energy Company
Michael.torrey@cmsenergy.com	Consumers Energy Company
CANDACE.GONZALES@cmsenergy.com	Consumers Energy Company
mpsc.filings@CMSENERGY.COM	Consumers Energy Company
mpsc.filings@CMSENERGY.COM	Consumers Energy Company
david.fein@CONSTELLATION.COM	Constellation Energy
kate.stanley@CONSTELLATION.COM	Constellation Energy
kate.fleche@CONSTELLATION.COM	Constellation New Energy

GEMOTION DISTRIBUTION SERVICE LIST

choicecompliance@constellation.com	Constellation New Energy Inc
lpage@dickinsonwright.com	Dickinson Wright
shaundillon@dillonenergy.com	Dillon Energy Services
info@dillonpower.com	Dillon Power, LLC
Neal.fitch@nrg.com	Direct Energy
Kara.briggs@nrg.com	Direct Energy
Ryan.harwell@nrg.com	Direct Energy
bryce.mckenney@nrg.com	Direct Energy
stephen.lindeman@dteenergy.com	DTE Energy
karl.lievense@dteenergy.com	DTE Energy
konstantin.korolyov@dteenergy.com	DTE Energy
mpscfilings@DTEENERGY.COM	DTE Energy
joyce.leslie@dteenergy.com	DTE Energy
karen.vucinaj@dteenergy.com	DTE Energy
customerservice@eligoenergy.com	Eligo Energy MI, LLC
regulatory@eligoenergy.com	Eligo Energy MI, LLC
frank.travaglione@vistracorp.com	Energy Harbor
rfawaz@energyintl.com	Energy International Power Marketing d/b/a PowerOne
sejackinchuk@varnumlaw.com	Energy Michigan
michael.reiss@engie.com	Engie Gas & Power LLC
customercare@plymouthenergy.com	ENGIE Gas & Power f/k/a Plymouth Energy
VSTRetailReg@VistraCorp.com	Everyday Energy, LLC d/b/a Energy Rewards
felicel@MICHIGAN.GOV	Felice, Lisa
bgorman@FIRSTENERGYCORP.COM	First Energy
phil@allendaleheating.com	Forner, Phil
dburks@glenergy.com	Great Lakes Energy
manderson@wpsci.com	Great Lakes Energy
mengels@wpsci.com	Great Lakes Energy
cdrys@wpsci.com	Great Lakes Energy
ljohnson@wpsci.com	Great Lakes Energy
slamp@glenergy.com	Great Lakes Energy Cooperative
sculver@glenergy.com	Great Lakes Energy Cooperative
johnm@gogreenlightenergy.com	Greenlight Energy Inc.
lrgustafson@CMSENERGY.COM	Gustafson, Lisa
jhammel@hillsdalebpu.com	Hillsdale Board of Public Utilities
coneill@homeworks.org	HomeWorks Tri-County Electric Cooperative
psimmer@HOMEWORKS.ORG	HomeWorks Tri-County Electric Cooperative
bmcbride@aep.com	Indiana Michigan Power
mgobrien@aep.com	Indiana Michigan Power Company
dan@megautilities.org	Integrys Group
daustin@IGSENERGY.COM	Interstate Gas Supply Inc
michael.nugent@igs.com	Interstate Gas Supply d/b/a IGS Energy
general@itctransco.com	ITC Holdings
cmarshall@itctransco.com	ITC Holdings
apascaris@itctransco.com	ITC Holdings

GEMOTION DISTRIBUTION SERVICE LIST

vanesetti@justenergy.com	Just Energy of Michigan Corporation
igoodman@commerceenergy.com	Just Energy Solutions
krichel@DLIB.INFO	Krichel, Thomas
dbodine@LIBERTYPOWERCORP.COM	Liberty Power
ham557@GMAIL.COM	Lowell S.
tjlundgren@varnumlaw.com	Lundgren, Timothy
tcarpenter@mblp.org	Marquette Board of Light & Power
regulatory@medianenergy.com	Median Energy Corporation
suzy@megautilities.org	MEGA
dan@megautilities.org	MEGA
mmann@USGANDE.COM	Michigan Gas & Electric
VSTRetailReg@VistraCorp.com	Michigan Gas & Electric (US Gas & Electric)
shannon.burzycki@wecenergygroup.com	Michigan Gas Utilities Corporation
mrzwiers@INTEGRYSGROUP.COM	Michigan Gas Utilities/Upper Penn Power/Wisconsin
kabraham@mpower.org	Michigan Public Power Agency
info@michigannaturalgasllc.com	Michigan Natural Gas, LLC
JHDillavou@midamericanenergyservices.com	MidAmerican Energy Services, LLC
JCAltmayer@midamericanenergyservices.com	MidAmerican Energy Services, LLC
LMLann@midamericanenergyservices.com	MidAmerican Energy Services, LLC
manderson@wpsci.com	Midwest Energy
mengels@wpsci.com	Midwest Energy
cdrys@wpsci.com	Midwest Energy
ljohnson@wpsci.com	Midwest Energy
dave.allen@TEAMMIDWEST.COM	Midwest Energy Cooperative
terry.rubenthaler@teammidwest.com	Midwest Energy Cooperative
kerri.wade@teammidwest.com	Midwest Energy Cooperative
Marie-Rose.Gatete@teammidwest.com	Midwest Energy Cooperative
meghan.tarver@teammidwest.com	Midwest Energy Cooperative
d.motley@COMCAST.NET	Motley, Doug
rarchiba@FOSTEROIL.COM	My Choice Energy
customerservice@nordicenergy-us.com	Nordic Energy Services, LLC
regulatory@nordicenergy-us.com	Nordic Energy Services, LLC
karl.j.hoesly@xcelenergy.com	Northern States Power
sarah.m.frazee@xcelenergy.com	Northern States Xcel
kbeattie@ntherm.com	nTherm, LLC
daho@ontorea.com	Ontonagon County Rural
esoumis@ontorea.com	Ontonagon County Rural Electric
regulatory@indraenergy.com	PALMco Energy MI, LLC d/b/a Indra Energy
mpauley@GRANGERNET.COM	Pauley, Marc
mmpeck@fischerfranklin.com	Peck, Matthew
bschlansker@PREMIERENERGYLLC.COM	Premier Energy Marketing LLC
manderson@wpsci.com	Presque Isle

GEMOTION DISTRIBUTION SERVICE LIST

mengels@wpsci.com	Presque Isle
cdrys@wpsci.com	Presque Isle
ljohnson@wpsci.com	Presque Isle
MVanschoten@pieg.com	Presque Isle Electric & Gas Cooperative, INC
aberg@pieg.com	Presque Isle Electric & Gas Cooperative, INC
yesterdae@getprovision.com	Provision Power & Gas, LLC
johnbistranin@realgy.com	Realgy Corp.
BusinessOffice@REALGY.COM	Realgy Energy Services
akeilson@genieretail.com	Residents Energy LLC
btrombino@rpaenergy.com	RPA Energy d/b/a Green Choice Energy
mvorabouth@ses4energy.com	Santana Energy
rabaey@SES4ENERGY.COM	Santana Energy
ttynes@ses4energy.com	Santanna Natural Gas Corporation
trish.mcfadin@southstarenergy.com	SouthStar d/b/a Grand Rapids Energy
kejoseph@sparkenergy.com	Spark Energy Gas, LP
cborr@WPSCI.COM	Spartan Renewable Energy, Inc. (Wolverine Power Marketing Corp)
jbelec@stephenson-mi.org	Stephenson Utilities Department
kay8643990@YAHOO.COM	Superior Energy Company
legal@symmetryenergy.com	Symmetry Energy Solutions, LLC
regulatory@texasretailenergy.com	Texas Retail Energy, LLC
agilbert@cleanskyenergy.com	Tital Gas, LLC d/b/a CleanSkyEnergy
bessenmacher@tecmi.coop	Thumb Electric Cooperative
president@tomorrowenergy.com	Tomorrow Energy Corporation
manderson@wpsci.com	Tri-County Electric
mengels@wpsci.com	Tri-County Electric
cdrys@wpsci.com	Tri-County Electric
ljohnson@wpsci.com	Tri-County Electric
mlindsay@uetllc.com	United Energy Trading d/b/a Kratos Gas & Power
colleen.sipiorski@wecenergygroup.com	Upper Michigan Energy Resources Corporation
djmier@integrysgroup.com	Upper Michigan Energy Resources Corporation
James.Beyer@wecenergygroup.com	Upper Michigan Energy Resources Corporation
Richard.Stasik@wecenergygroup.com	Upper Michigan Energy Resources Corporation
nbell@uppco.com	Upper Peninsula Power Company
jformol@uppco.com	Upper Peninsula Power Company
ghaehnel@uppco.com	Upper Peninsula Power Company
estocking@uppco.com	Upper Peninsula Power Company
manager@villageofbaraga.org	Village of Baraga
Villagemanager@villageofclinton.org	Village of Clinton
VSTRetailReg@VistraCorp.com	Viridian Energy PA, LLC
jeinstein@volunteerenergy.com	Volunteer Energy Services
leew@WVPA.COM	Wabash Valley Power
melissa.schauer@wecenergygroup.com	We Energies
andrew.miller1@wecenergygroup.com	We Energies
melissa.schauer@wecenergygroup.com	Wisconsin Public Service

GEMOTION DISTRIBUTION SERVICE LIST

andrew.miller1@wecenergygroup.com	Wisconsin Public Service
tking@WPSCI.COM	Wolverine Power
jbaumann@wpsci.com	Wolverine Power
cborr@wpsci.com	Wolverine Power
ddecouer@wpsci.com	Wolverine Power
bvalice@wpsci.com	Wolverine Power
Amanda@misostates.org	Wood, Amanda
Deborah.e.erwin@xcelenergy.com	Xcel Energy
Michelle.Schlosser@xcelenergy.com	Xcel Energy
bryce.mckenney@nrg.com	Xoom Energy Michigan, LLC d/b/a Xoom Energy