

**COMMENTS OF THE**  
**MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL**  
**AND**  
**ADVANCED ENERGY UNITED**  
**Case No. U-21400**

**Introduction**

On March 13, 2025, the Michigan Public Service Commission (“Commission” or “MPSC”) issued an Order in Case No. U-21400 identifying areas of potential focus for the future application of utility financial incentives and disincentives (also referred to as Performance Incentive Mechanisms or “PIMs”). The proposed focus areas discussed within that Order were as follows: 1) distributed energy resource (“DER”) interconnection, 2) customer data access and hosting capacity, 3) DER aggregation and non-wires alternatives, 4) 4.8 kilovolt distribution system conversions, and 5) advanced metering infrastructure (“AMI”) utilization/grid modernization. The Michigan Energy Innovation Business Council (“Michigan EIBC”<sup>1</sup>) and Advanced Energy United (“United,”<sup>2</sup> collectively “Michigan EIBC/United”) offered comments and reply comments in that docket. On August 6, 2026, the Commission issued an Order in Case No. U-21400 with a new straw proposal, called the “Phase 2 Straw Proposal,” which recommends specific actions and PIMs. Michigan EIBC/United comment below on the proposals in the Phase 2 Straw Proposal.

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<sup>1</sup> The Michigan Energy Innovation Business Council is a trade organization tasked with growing Michigan’s advanced energy economy by fostering opportunities for innovation and business growth and offering a unified voice in creating a business-friendly environment for the advanced energy industry in Michigan.

<sup>2</sup> Advanced Energy United is a national business association representing leading companies in the advanced energy industry. United supports a broad portfolio of technologies, products, and services that enhance U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure, and affordable.

Overall, Michigan EIBC/United recommend that the Commission treat these metrics, scorecards, and PIMs as dynamic and establish a process to review, revise, and update these items on an annual or semi-annual basis.

### **Focus Area 1: DER Interconnection**

Michigan EIBC/United support the Phase 2 Straw Proposal's goal to improve interconnection timelines and transparency beyond the minimum requirements in the Michigan Interconnection and Distributed Generation Standards ("MIXDG rules").

#### *Proposed PIM*

The Phase 2 Straw Proposal recommends setting an initial PIM for Level 1, 2, and 3 projects related to the timelines to complete utility-controlled interconnection steps. This proposal includes both an incentive and a penalty. Michigan EIBC/United provide the following comments on these proposals:

- **DER Interconnection Penalty:** The Phase 2 Straw Proposal suggests that the Commission would review the number of times and reasons that a utility failed to meet the interconnection review timelines established in the MIXDG rules and would "determine if the utility should incur a penalty." Michigan EIBC/United believe that this proposal needs to be clarified and strengthened. From the utility's perspective, in terms of dedicating resources and ensuring compliance, it should be more clear when and if a penalty will be imposed. From the customer and installer's perspective, any deviation from the MIXDG rules, resulting in a delay in energization of a project (causing additional time, costs, and lost benefits), should incur a penalty. **Michigan EIBC/United recommend that the Commission clarify the parameters around this penalty to establish clearly that violation of the timelines established in the MIXDG rules more than a certain number of times (e.g., 5 times) in a given year for each Level will be assessed a penalty. As**

discussed below, this should be established by the creation of a symmetrical PIM whereby the utility has the ability to earn either a reward or a penalty and the scale of the reward and penalty are similar to one another.

- DER Interconnection Incentive: The Phase 2 Straw Proposal recommends a two-tiered incentive with the top tier set at 10 days on average for Level 1 and 2 projects (and 20 days for Level 3 projects) and lower tier set at 20 days for Level 1 and 2 projects (and 30 days for Level 3 projects). Although the MIXDG rules clearly spell out the timelines for review, given both the very low once-through approval rate (even for Level 1 projects) and very slow average interconnection timelines (especially in comparison to peer utilities, as noted in the Phase 2 Straw Proposal), it will be valuable to establish an incentive to guide utility improvement efforts. **Michigan EIBC/United strongly support this proposal.** The proposed tiers, although they would represent a significant improvement for Michigan’s interconnection timelines, still do not match those of peer utilities (e.g., Commonwealth Edison in Illinois as noted in the Phase 2 Straw Proposal) or expert guidance including that from the United States Department of Energy (“DOE”), which suggests that projects <50 kW in size (i.e., Level 1 and some Level 2 projects) should be approved within a matter of days (and within 1 day by 2030).<sup>3</sup> Despite that, given the current average timelines, if Michigan’s utilities were to achieve the timelines proposed in the Phase 2 Straw Proposal and achieve the incentives, it would represent a significant improvement for customers wishing to interconnect DERs.

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<sup>3</sup> U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, “Distributed Energy Resource Interconnection Roadmap,” January 16, 2025, available at <https://www.osti.gov/servlets/purl/2997033>.

Overall, an optimal interconnection timeline 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 similar to one another. Illinois, for instance, established in statute a requirement that potential incentives and penalties be symmetrical. (See 220 ILCS 5/16-108.18(e)(2)(B)) As another example, the Hawaii Public Utilities Commission has approved and currently utilizes an Interconnection Approval Time PIM that consists of both potential rewards and penalties for the utilities, specific thresholds for which a utility will gain a reward or a penalty, and a tiered list to determine the exact size of the reward or penalty depending on utility performance. As a result of this PIM being instituted, Hawaii's three utilities experienced a significant decrease in the "adjusted average number of business days to interconnect customer systems within the utility's control"<sup>4</sup> and each of the utilities received a corresponding PIM in both 2021 and 2022. Utilizing the aforementioned structure for the DER Interconnection PIM will help to incentivize a utility to decrease the amount of time it takes to approve an interconnection while disincentivizing the utility from dropping below a set interconnection approval time threshold, which, initially, is at least as stringent as the timelines established in the MIXDG rules.

PIMs must be thoughtfully designed and implemented to ensure that they align with public policy goals, produce customer benefits, and provide meaningful but appropriate earnings opportunities within the broader utility business model. PIMs are particularly effective when they target outcomes that, if achieved, would reduce a utility's earnings opportunity under the traditional cost-of-service model. This may be the case for the development of a PIM that incentivizes interconnection of customer-owned DERs, which do not result in any return on equity for the utility and may decrease electricity sales for the utility. As such, it may be appropriate to provide a relatively robust initial incentive, but only for the types of timelines

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<sup>4</sup> HI PUC Order No. 40462, December 26, 2023.

envisioned by the top tier of the Phase 2 Straw Proposal. The incentive amount can be expressed through various forms, but a reward designed around a percentage of base revenue rather than a direct return on equity basis point reward avoids incentivizing the utility to increase its rate base as a means to increase its reward. Furthermore, 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.<sup>5</sup> However, given that the current average interconnection timelines are unacceptably long, the deadband and any incentives should be established so as not to reward or encourage simply maintaining the current timelines.

In setting the level of any incentive, it will be particularly important to consider the total cost of meeting any metric (not just an interconnection metric) when conducting a benefit-cost analysis (“BCA”) of that incentive. Specifically, costs should include not just the cost to the utility to attain a target (which is recovered from ratepayers), but also the cost to ratepayers incurred in paying the reward. A failure to take a holistic approach could result in customers paying a program implementation cost and paying to reward a utility an amount that, when combined, exceeds the benefit of the program.

#### *Scorecard for DER Interconnection Timelines for Projects > 550 kW*

The Phase 2 Straw Proposal recommends a target of 75 days for the processing of Level 4 and 5 interconnection applications. Consumers Energy reported an average of 417 days to approve interconnection of Level 4 projects (DTE Electric did not report any Level 4 or 5 projects). **Michigan EIBC/United support establishing an initial target of 75 days for the processing of Level 4 and 5 projects.** It is important, in conjunction with the establishment of this target, that the Commission also establish new reporting requirements to better understand why these applications take the utilities so long

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<sup>5</sup> Goldenberg, C., Cross-Call, D., Billimoria, S., and Tully, O., RMI, “PIMs for Progress,” 2020, available at <https://rmi.org/insight/pims-for-progress/>, p. 25.

to process (i.e., more than a year) and are so costly to review. Monthly reports would provide significant new data and information relevant both to interconnection customers and to the development of future financial incentives/disincentives. For example, this could be a monthly report with the following data and information: new Level 4 and 5 interconnection applications submitted, existing Level 4 and 5 interconnection applications that are currently in process, the status of existing Level 4 and 5 interconnection applications, how long each interconnection application has been in the queue, cost incurred to date to process each application, etc.

Subsequently, once these data are collected, it is critical that a PIM is established for Level 4 and 5 projects in a similar manner to that proposed for Level 1, 2, and 3 projects. Specifically, the initial target and reporting requirements could be established and maintained for two years after which the data could be examined and a PIM could be established. It is important to establish those timelines and milestones now to ensure that there is subsequent improvement in the timelines for the processing of Level 4 and 5 applications.

#### *Flexible Interconnection*

The Phase 2 Straw Proposal recommends that the Interconnection Technical Workgroup (“ITWG”) continue its plans to discuss flexible interconnection issues in upcoming meetings, including discussion of additional recommendations for new metrics for tracking flexible interconnection and load energization timelines. **Michigan EIBC/United remain interested in these issues and support continued discussions through the ITWG. However, Michigan EIBC/United also recommend that the Commission update its reporting requirements to gather more data to understand the challenges associated with flexible interconnection and load energization timelines.**

Specifically, it would be helpful to create a reporting requirement that tracks the number of distributed generation (“DG”) projects that are filed, the number of projects that receive a notification that upgrades will be needed, the number of projects that either change the project size or drop out of the queue, and the number projects for which the utility offered a flexible interconnection solution to accomplish interconnection. To help identify specific constrained circuits, such information should be provided on a circuit level. The Commission should also consider requiring 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. This difference in capacity would demonstrate the actual ability to utilize flexible interconnection policies and could be used, in the future, as a metric to create a related PIM. Finally, developers of projects often seek interconnection cost estimates from the utilities to determine whether a project is financially feasible. On occasion, utility estimates can later change, sometimes substantially, thus jeopardizing the financing for a project. The Commission should consider requiring utilities to report the following information: all projects where interconnection cost estimates changed by more than 10%, the reason for the interconnection cost change, whether a flexible interconnection or other solution was offered and implemented to mitigate the cost change, whether the project proceeded with interconnection, and the circuit(s) involved in the interconnection application. Such information may lead to an appropriate future flexible interconnection PIM.

With respect to load energization timelines, Michigan EIBC/United strongly support the institution of flexible energization policies to ensure that new loads from DERs, like EV charging stations, are able to be connected to the grid and energized in a transparent and stepwise manner. This is particularly important for the electrification of fleets and the installation of direct current fast chargers (“DCFC”), which can involve necessary distribution grid upgrades that can be significantly impactful and costly. As in the case of DG projects, 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. Therefore, it would be helpful to track specific projects that request energization and how and why the specific project changes scope or does not move forward with energization. The Commission should also consider as a reporting requirement the difference between the cumulative nameplate load at a given site and the actual capacity provided to a customer under a flexible energization agreement on a circuit level basis. This difference in capacity would demonstrate the actual implementation of flexible energization policies and could be used, in the future, as a metric to create a related PIM.

### *Other Issues*

According to the Phase 2 Straw Proposal, the “once-through” approval rate<sup>6</sup> for Level 1 solar projects was 63% for DTE Electric and 46% for Consumers Energy. This once-through approval rate dropped even further to 47% for Level 1 solar-plus-storage projects for DTE Electric and 17% for Consumers Energy. These rates are incredibly low and suggest a strong need, as the Phase 2 Straw Proposal notes, for improved education, application guidance, and review processes. Specifically, according to Michigan EIBC/United members, applications are often returned to customers multiple times with required changes provided in a “piecemeal” manner during the initial review period. In other words, instead of all of the necessary changes being identified during the first round of review, these changes are identified one at a time with long periods in between responses (often up to the entire allowable time period under the MIXDG rules). This piecemeal approach to changes is not allowed under the MIXDG rules. Instead, as outlined in R460.936, “If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list

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<sup>6</sup> 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.

of *all* deficiencies with the notification.”<sup>7</sup> (emphasis added). **Michigan EIBC/United therefore recommend that the Commission take action to improve communication, education, and application guidance to ensure a more transparent and expeditious interconnection application process and ensure that the MIXDG rules are being followed.**

## **Focus Area 2: Data Access and Hosting Capacity**

As noted by the Phase 2 Straw Proposal, Consumers Energy and DTE Electric were ordered to update their 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.<sup>8</sup> In the Phase 2 Straw Proposal, the Commission seeks guidance on several issues as described below.

### *Usefulness of Hosting Capacity Maps*

**In its Phase 2 Straw Proposal, the Commission points to the DER Interconnection PIM as a sufficient method to improve hosting capacity maps going forward. Michigan EIBC/United do not agree.** As described below, the DER Interconnection PIM may improve the timeliness of interconnection application processing if utilities choose to pursue it. However, hosting capacity maps assist customers *prior* to an application being filed with the utility, as hosting capacity maps are used by developers to scope a project and determine a proper site location on the grid. As such, improvements to the timelines for application processing will not result in improved hosting capacity maps, but improved hosting capacity maps may very well result in improved interconnection timelines. **Instead, Michigan EIBC/United recommend that**

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<sup>7</sup> MIXDG Rules, R460.936, available at <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/interconnection-std/MIXDG-Updated-Rules.pdf?rev=e0aba826a2414cea810b29a27ae9c814&hash=FCD2FD051E0ABE7C4E8A504C4F6BB31E>, p. 16. metrics

<sup>8</sup> Commission Order in Case No. U-20147, July 2025, p. 32.

**the Commission establish enhanced metrics to track improvements in hosting capacity maps to ensure that future maps are updated regularly, provide clear and sufficiently detailed information about available capacity and grid constraints, and help developers and customers identify viable locations for projects.**

The DER Interconnection PIM outlined in the Phase 2 Straw Proposal addresses only a narrow part of the broader issues regarding the need to develop enhanced hosting capacity metrics. The proposed DER Interconnection PIM provides process and speed-to-interconnection incentives; however, hosting capacity issues arise upstream of the interconnection process. The DER Interconnection PIM only becomes effective after an application is in queue; it does not improve or remedy pre-application information issues that are caused by deficient hosting capacity maps. A utility could feasibly improve average interconnection timelines while still providing hosting capacity maps that lack appropriate data granularity and/or are not detailed enough to reveal local constraints. In effect, the DER Interconnection PIM would reward faster processing without addressing the real-world issue of first identifying viable interconnection locations on the grid.

The Phase 2 Straw Proposal notes prior hosting capacity map directives from the July 2025 Order and states that future Distribution System Plans (“DSP”) will provide opportunities to review progress. While this is an important step in improving the usefulness of hosting capacity maps, it also means that any obligations to improve hosting capacity maps may be handled through less timely proceedings within the DSP process. In Michigan, utilities file DSPs every 3 years. This filing cadence creates an incredibly long lag time between implementation and evaluation of mandated practices. Customers and developers should not be expected to knowingly engage with and make decisions based on possibly insufficient and outdated data.

**Michigan EIBC/United maintain that the current utility hosting capacity maps and load-carrying capacity maps are inadequate and do not provide sufficient data to facilitate efficient adoption of distributed generation, distribution-connected projects, and EV charging station deployment in Michigan.** Because the current hosting capacity maps are a “snapshot” of a single point in time updated only periodically, and the interconnection queue is first-come, first-served, a circuit that looks open on the map may already be claimed by one or more projects further ahead in the queue. The maps also lack locational granularity and do not provide appropriate information to determine if a project could (or could not) be interconnected at a certain location given that the maps are modeled based on a fixed project size (e.g., 2 MW). Additionally, the maps lack the granularity needed to determine the upstream effects of placing a project at a specific site. The hosting capacity map may show available capacity while, in reality, local transformer limitations would require costly upgrades before any project comes online. The Commission should specify that utility hosting capacity maps reflect queue-adjusted available capacity (accounting for active higher-queued applications) and model 3-phase distribution feeder capacity up to 5 MW+. Maps should explicitly display substation transformer headroom, reverse power flow constraints, and 3-phase line capacity to prevent developers from filing applications on feeders that appear open but are thermally or operationally constrained. Persistent deficiencies in hosting capacity maps create uncertainty, high project cost volatility, and lost opportunity for distributed resource projects at all levels. **Michigan EIBC/United recommend that the Commission establish enhanced metrics and a scorecard that rewards real-time updates to combined hosting capacity and load-carrying capacity maps with sufficient granularity to enable DER and EV deployment.**

### **Focus Area 3: DER Aggregation and Non-Wires Alternatives (“NWAs”)**

As noted by the Phase 2 Straw Proposal, there are multiple dockets where opportunities connected with Virtual Power Plants (“VPPs”) are being explored, including Consumers’ and DTE Electric’s current IRPs.

This follows Commission directives from December 2025 requiring the inclusion of VPPs in IRP modeling, as well as the Commission’s Order in Consumers Energy’s 2025 general electric rate case (Case No. U-21870) wherein the Commission indicated its expectation for increased VPP implementation. VPPs can serve multiple demand and supply-side purposes. The Phase 2 Straw Proposal refers to VPPs as “demand-side resources” while subsequently recognizing that “...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.”<sup>9</sup>

The Phase 2 Straw Proposal purports to propose a VPP PIM to “support and encourage cost-effective VPPs that can address load growth and improve affordability of distribution system costs.”<sup>10</sup> This proposed VPP PIM builds on the shared savings mechanism used for EWR programs, whereby utilities earn an incentive (up to a certain maximum) for demonstrating that EWR programs deliver net benefits to customers “with shareholder earnings tied to the value created above program costs.”<sup>11</sup> The EWR incentive is calculated as a percentage of the net present value of verified net benefits. A utility can earn an incentive if it exceeds its savings targets, but if it falls short, it faces a penalty. As for DER aggregation and VPP programs, the Phase 2 Straw Proposal states that “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.”<sup>12</sup>

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<sup>9</sup> Commission Order in Case No. U-21400, August 2026, pp. 48 and 55.

<sup>10</sup> *Id.*, p. 55.

<sup>11</sup> *Id.*, p. 56.

<sup>12</sup> *Ibid.*

More specifically, the Phase 2 Straw Proposal recommends a VPP PIM whereby the “deployment targets” would be established in the utility’s IRP. The utility would receive 15% shared savings for implementing 100% of those approved deployment targets (and potentially up to 20% shared savings for meeting up to 110% of the deployment target) and a penalty (potentially for falling below 80% of the deployment target). The new BCA tool developed in Case No. U-20898 would be used to estimate benefits including avoided costs from distribution investment deferrals.<sup>13</sup>

Michigan EIBC/United strongly support the expanded use of VPPs to achieve load reduction and meet other system needs as well as the general concept of using a well-designed, ambitious PIM to incentivize VPP development. However, despite statements in the Phase 2 Straw Proposal that it proposes a VPP PIM to “support and encourage cost-effective VPPs that can address load growth and improve affordability of distribution system costs,” the proposed VPP PIM only appears to focus on peak load reduction and wholly lacks any assessment of actual benefits, including broader benefits to the distribution system.<sup>14</sup> **Michigan EIBC/United do not agree that a utility should be provided with an incentive simply for achieving the VPP deployment targets approved by the Commission in an IRP without consideration of benefits beyond peak load reduction and the verification of specific benefits associated with VPP use.** First, PIMs should be designed to only provide utilities with incentives to go above and beyond what they typically would do (i.e., to go beyond the targets they are already planning to cost-effectively meet as determined during the IRP).<sup>15</sup> Second, Michigan EIBC/United argue that a well-designed PIM should reflect the variety of supply and demand-side benefits that VPPs can provide. Finally, the PIM should also

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<sup>13</sup> *Id.*, p. 57.

<sup>14</sup> *Id.*, p. 55.

<sup>15</sup> Rocky Mountain Institute, “PIMs for Progress”, available at [https://rmi.org/app/uploads/2020/07/rmi\\_pims\\_for\\_progress.pdf](https://rmi.org/app/uploads/2020/07/rmi_pims_for_progress.pdf), p. 69.

be designed to incentivize VPPs that incorporate a wide variety of DERs. Michigan EIBC/United discuss each of these issues below.

As the VPP PIM is currently proposed in the Phase 2 Straw Proposal, the utilities would be incentivized for meeting deployment targets set by the IRP. Using the IRP deployment targets alone as the threshold for receiving an incentive is not sufficient. As required by the Commission in the IRP Filing Requirements and Planning Parameters, the utilities are already required to model VPPs in their current IRPs, establishing cost-effective deployment targets. Subsequent spending toward a Commission-approved IRP Proposed Course of Action (“PCA”) is presumed reasonable and prudent.<sup>16</sup> As such, there is no reason to further incentivize the utilities to meet targets that they establish themselves and already receive pre-approval for spending to meet through the IRP process. Furthermore, VPPs are not just a futuristic idea - they are already being implemented in Michigan and across the country, saving utilities and ratepayers money in the process.<sup>17, 18, 19, 20</sup> Thus, Michigan EIBC/United caution against providing incentives for goals that the utility should already be expected to achieve and for a solution that is already implementable and is saving utilities and ratepayers money across the country. If a VPP PIM is established based on deployment targets (which, as described below, may not be the most effective metric when used by itself), to achieve such an incentive,

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<sup>16</sup> Commission Order in Case No. U-21867, December 2025, p. 128.

<sup>17</sup> Green Mountain Power, “GMP’s Growing Stored Energy Network Delivers \$6M in Savings During July Heat Wave and Provides Lasting Year-Round Benefits for Customers,” July 28, 2026, available at <https://greenmountainpower.com/news/gmps-growing-stored-energy-network-delivers-6m-in-savings-during-july-heat-wave/>.

<sup>18</sup> Rocky Mountain Power, “2024 Utah Energy Efficiency and Peak Reduction Annual Report,” May 27, 2025, available at <https://pscdocs.utah.gov/electric/25docs/2503536/339923RdctdRMPDSM2024EnrgyEfencyPkLdRdctnRprt5-27-2025.pdf>, p. 14.

<sup>19</sup> Commission Order in Case No. U-21653, September 2026.

<sup>20</sup> Commission Order in Case No. U-21867, December 2025, p. 128.

the utilities should be expected to reach deployment targets that are more ambitious than simply achieving the IRP deployment targets. As stated by the Washington Utilities and Transportation Commission, PIMs are designed to “[...] achievable but ambitious performance targets” and “[encourage] performance improvements beyond business-as-usual practices.”<sup>21</sup>

Furthermore, Michigan EIBC/United express concerns with the lack of clarity on how the currently proposed VPP PIM would be directly tied to ratepayer benefits and would reflect the variety of supply and demand-side benefits that VPPs can provide. As is stated in the Phase 2 Straw Proposal, “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.”<sup>22</sup> Michigan EIBC/United support the tracking of these benefits. However, there doesn’t appear to be a direct tie between the tracking of these benefits with the proposed VPP PIM. As proposed, the PIM will be based on “VPP and DER deployment targets established in the utility’s IRP,” which Michigan EIBC/United read as meeting a certain MW deployment target.<sup>23</sup> Meeting deployment targets is a step in the right direction, but is an incomplete way of accurately capturing the benefits provided. The VPP PIM should more clearly set metrics related to the benefits being measured, such as those mentioned in the previous quote regarding the BCA tool, and all other relevant benefits that a technology agnostic VPP can provide. As the Regulatory Assistance Project states, “While

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<sup>21</sup> Washington Utilities and Transportation Commission, “Performance Incentive Mechanisms (PIMs),” available at <https://www.utc.wa.gov/regulated-industries/utilities/energy/performance-based-regulation-pbr/performance-incentive-mechanisms-pims>.

<sup>22</sup> Commission Order in Case No. U-21400, August 2026, pp. 56-57.

<sup>23</sup> *Id.*, p. 57.

there is no perfect answer for structuring metrics, the best practice is that outputs and outcomes that directly impact ratepayers, stakeholders and society at large, such as energy efficiency savings, affordable bills and emissions reductions, are ultimately the most important criteria to track.”<sup>24</sup> In other words, when establishing a VPP PIM, the metrics used to set the PIM need to be much more closely aligned to the actual outcomes being sought. **Michigan EIBC/United encourage the exploration of a VPP PIM that contains tiered incentives based on benefits that a group of aggregated DERs can provide.** So, for example, if a group of DERs provided both quantifiable benefits in distribution upgrade deferrals and ancillary services, it would receive a higher incentive than if it just provided quantifiable benefits in one of these benefit categories.

Finally, Michigan EIBC/United argue that the current proposal should be expanded upon to ensure that a diversity of DERs are utilized in VPPs. VPPs are as strong as their components. While simpler forms of VPPs, such as solely thermostat DR programs, are a good start and can help achieve goals such as peak load reduction, which in turn can lead to avoided generation capacity, use of these technologies only captures a portion of the benefits that a fully technology agnostic VPP can provide. Such a VPP can, for example, provide increased opportunities to avoid distribution capacity upgrades and provide ancillary services, a benefit that Rocky Mountain Power’s WattSmart Batteries program successfully provides in the form of frequency regulation.<sup>25, 26</sup> As described by the DOE’s “Pathways to Commercial Liftoff: Virtual

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<sup>24</sup> Regulatory Assistance Project, “Improving Utility Performance Incentives in the United States,” October 2023, available at <https://www.raponline.org/wp-content/uploads/2023/10/rap-improving-utility-performance-incentives-in-the-united-states-2023-october.pdf>.

<sup>25</sup> EnergyHub, “Building trustworthy virtual power plants: The VPP Maturity Model,” 2026, available at [https://415845.fs1.hubspotusercontent-na1.net/hubfs/415845/EH\\_WP-Building%20trustworthy%20VPPs\\_4.7.27.pdf](https://415845.fs1.hubspotusercontent-na1.net/hubfs/415845/EH_WP-Building%20trustworthy%20VPPs_4.7.27.pdf), p. 10.

<sup>26</sup> Rocky Mountain Power, “2024 Utah Energy Efficiency and Peak Reduction Annual Report,” May 27, 2025, available at <https://pscdocs.utah.gov/electric/25docs/2503536/339923RdctdRMPDSM2024EnrgyEfencyPkLdRdctnRprt5-27-2025.pdf>, pp. 14-15.

Power Plants” report, and which is quoted in the Phase 2 Straw Proposal, “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.”<sup>27</sup> Michigan EIBC/United has previously advocated for this diversity of technologies to be utilized in VPP configurations, and similarly believe that any future VPP PIM should promote a technology-neutral approach.<sup>28, 29</sup> Another avenue to ensure diversity of DERs is to include third-party-owned, front-of-the-meter (“FTM”) dispatchable distribution-connected resources (such as standalone storage or solar-plus-storage systems) in VPPs. Third-party-owned FTM distribution-connected assets offer highly controllable, multi-hour capacity relief for constrained feeders and substations and should be fully eligible under utility VPP shared-savings mechanisms.

It is especially important, as part of this technology-neutral approach, that any future VPP PIM incentivizes deployment of customer-owned behind-the-meter (“BTM”) and third-party-owned distribution-connected FTM resources. As noted by the Phase 2 Straw Proposal, “...traditional cost-of-service regulation discourages utilities from pursuing this resource at the scale required by new loads” and that as a result, a PIM is needed “...to accelerate deployment of DERs and develop VPP resources.”<sup>30</sup> This quote highlights an issue that must be addressed by the VPP PIM -- that utilities are generally not incentivized to foster the

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<sup>27</sup> Commission Order in Case No. U-21400, August 2026, p. 48.

<sup>28</sup> Comments from Michigan EIBC/Advanced Energy United in Case No. U-21653, July 2026, p. 4.

<sup>29</sup> Direct Testimony and Exhibits of William D. Kenworthy and Laura Sherman on behalf of the Michigan Energy Innovation Business Council, Institute for Energy Innovation, the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Case No. U-22058, June 2026, p. 101.

<sup>30</sup> Commission Order in Case No. U-21400, August 2026, p. 49.

increased adoption of resources not owned by the utility such as customer-owned DERs and third-party-owned distribution-connected resources, primarily because the utility does not earn a return on these assets. Given this, a VPP PIM needs to incorporate an incentive for use of these resources (e.g., through collaboration with third-party aggregators) that goes beyond existing DR programs and incorporates other technologies.

Separately from the VPP PIM as proposed, the Phase 2 Straw Proposal mentions that “[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.”<sup>31</sup> Michigan EIBC/United fully advocates for the expanded utilization of NWAs, but have multiple recommendations on how this could meaningfully be done. A VPP PIM, if properly structured to include additional benefits in a tiered manner (e.g., distribution deferral and ancillary benefits), may not need to be separate from an NWA PIM to capture the benefits of aggregated BTM resources. However, a separate NWA PIM may be needed to capture the benefits provided by third-party-owned FTM resources (to the extent that those resources are not incorporated into VPPs). However this is accomplished, it is clear that NWAs are already cost-saving solutions that have been and are continuing to be being implemented across the country.<sup>32, 33, 34</sup>

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<sup>31</sup> *Id.*, p. 57.

<sup>32</sup> UtilityDive, “BQDM program demonstrates benefits of non-traditional utility investments,” March 2019, available at <https://www.utilitydive.com/news/bqdm-program-demonstrates-benefits-of-non-traditional-utility-investments/550110/>.

<sup>33</sup> Joint Utilities of New York, “Non-Wires Alternatives (NWA) Opportunities and Solicitations,” available at <https://jointutilitiesofny.org/nwa-opportunities>.

<sup>34</sup> National Grid, “NWA Opportunities,” available at <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/Opportunities>.

Michigan utilities have already implemented NWA solutions and continue to explore them as well.<sup>35, 36</sup>

Given this, incentivizing the utilities to utilize NWAs when they are already a viable, cost-effective solution should be done carefully. Any VPP PIM which includes use of a VPP as an NWA, should ensure that the incentives for the NWA attributes incentivize a “stretch goal.” It is likely that further analysis needs to be done first to determine what that goal should be. Specifically, the Commission and the utilities need to conduct a robust analysis to determine specifically which areas on the distribution system lend themselves to NWA solutions.

Overall, the VPP PIM and any NWA PIM should not just incentivize the right set of benefits, but it should distribute incentives related to achievement of these benefits fairly. Because DER aggregation and FTM distribution-connected projects can lead to grid benefits such as peak reduction and avoided distribution system upgrades, and thus avoided costs, which would otherwise be borne by the utility customers, customers should be allowed to receive some portion of the incentive established by the VPP and NWA PIM. For example, the total cost of the VPP used as an 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. For example, in 2017, the New York Public Service Commission issued an Order that approved an NWA shared savings incentive for Con Edison. The Order provides for a shareholder incentive that is based on a percentage of the difference between the net present benefits of the NWA (determined using New York’s benefit-cost analysis framework) and the traditional “wires” solution that it replaces in order to encourage Con Edison to pursue more cost-effective solutions. For this mechanism, if Con Edison

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<sup>35</sup> Consumers Energy, “Five-Year Distribution Planning Stakeholder Meeting #2,” August 2019, available at [https://www.michigan.gov/-/media/Project/Websites/mpsc/workgroups/elec-dist-planning/Aug\\_14\\_Presentations.pdf?rev=e0263cf57e974a1d8af6f7b1fbbeb322](https://www.michigan.gov/-/media/Project/Websites/mpsc/workgroups/elec-dist-planning/Aug_14_Presentations.pdf?rev=e0263cf57e974a1d8af6f7b1fbbeb322).

<sup>36</sup> DTE, “DTE Electric Non-Wires Alternative Pilot Phase II,” available at [https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR\\_Collaborative/2026/DTE-NWA-Phase-II-MPSC-Presentation.pdf?utm](https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2026/DTE-NWA-Phase-II-MPSC-Presentation.pdf?utm).

chooses to pursue an NWA, cost overruns and underruns are shared between Con Edison and its customers, which effectively increases or decreases the utility's incentives. In other words, if the utility reduces costs significantly, it can share the savings of the net present benefits of the VPP. However, if there are cost overruns in implementing the VPP, the incentive can diminish to \$0, thus incentivizing the utility to pursue cost-effective solutions.<sup>37</sup>

### **Focus Area 5: AMI Utilization and Grid Modernization**

The Phase 2 Straw Proposal recommends establishing tracking metrics for grid utilization and a scorecard for outage response metrics, which could lead to future PIMs. **Michigan EIBC/United support movement toward greater transparency represented by the proposed AMI Utilization and Grid Modernization metrics. Michigan EIBC/United further request that Staff set an accelerated reporting schedule for these metrics that provides a current and actionable view of each utility's distribution grid infrastructure.** The reporting metrics should be detailed enough for stakeholders to determine where capacity and constraints exist and how these aspects of the system affect customers.

#### *Distribution Grid Metrics and Reporting*

The Phase 2 Straw Proposal recommends tracking peak utilization (i.e., peak demand/capacity limit) and capacity factor (i.e., energy usage/capacity limit x hours in period) at the system, substation, and feeder levels. The proposal also recommends reporting on overall distribution system losses, constrained circuits, and distribution system conditions during peak demand. **Michigan EIBC/United support these proposed distribution grid metrics.**

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<sup>37</sup> New York Public Service Commission, Commission Order in Case No. 15-E-0229, available at <https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=175182&MatterSeq=47911&utm>.

Additionally, the Commission should clarify how each utility is required to calculate the reported metrics. Calculations such as capacity limits can be constrained by many operational considerations (e.g., equipment age, transformer load, voltage disruptions, etc.). Transparent calculation definitions will improve the usefulness of the reported data. If the utility does not clearly identify the assumptions and constraints underlying its calculations, stakeholders cannot determine whether it is accurately reporting things such as available headroom, or whether an upgrade is necessary and appropriately sized, for example. A lack of clarity would also limit the Commission's ability to assess whether the utility is using existing infrastructure efficiently and applying standards consistently. Consistent and transparent reporting will help the Commission and stakeholders better understand how the distribution system is being used, where constraints exist, and where additional investment or alternative solutions may be needed.

The Phase 2 Straw Proposal seeks feedback on the timing of this reporting, recommending annual reporting with monthly values, with data expanding over time as it becomes available. **Michigan EIBC/United request that Staff set an accelerated reporting schedule of these metrics that ultimately provides a current, actionable view of each utility's distribution grid infrastructure.** Existing annual reporting shows broad trends but falls short of the frequency needed to support timely review of interconnection requests, new load, DERs, DR, or proposed grid investments. It is important to build a foundation for further transparency and accountability measures; however, the Commission should avoid setting a reporting frequency that is so infrequent that the process becomes a mere exercise in data collection. **Instead, Michigan EIBC/United recommend that the Commission require utilities to:**

- report information in a consistent format from year to year;
- provide historical comparisons so that stakeholders can determine whether conditions are improving or worsening;
- identify significant constraints and explain their general causes and expected duration;

- provide information at a level of detail that is useful for evaluating specific areas of the distribution system;
- make nonconfidential information available in a reasonably accessible and usable format; and
- explain any missing, estimated, or incomplete information.

The Phase 2 Straw Proposal recommends considering utility-specific improvement targets after establishing baseline data on grid metrics. **Michigan EIBC/United support the Commission’s consideration of future utility-specific improvement targets.** Reporting elements related to future improvement targets should include clear definitions, standardized calculation methodologies, reliable baseline data, and information stakeholders can independently evaluate. Utilities should explain how they define and measure concepts such as peak utilization, capacity limits, system losses, capacity factor, constrained circuits, interconnection timelines, DR performance, and outage-restoration results. Reporting should also identify relevant conditions and limitations, including weather, system configuration, emergency operating limits, and the distinction between projected, enrolled, available, and verified performance. Without these standards, improvement targets may not measure meaningful improvements in system or customer outcomes.

**Michigan EIBC/United further recommend requiring reporting that is frequent and granular enough to support operational accountability and informed planning (e.g., on a monthly basis).**

Annual or high-level summary data may not reveal short-duration constraints, recurring operational issues, delayed interconnections, or the realized benefits of DER, DR, and other grid investments. To the extent practicable, utilities should provide historical and interval-level information at an appropriate feeder or circuit level, while protecting customer privacy and addressing legitimate confidentiality concerns. The information should also be reconciled with hosting capacity maps, interconnection queues, distribution

system plans, integrated resource plans, capital-investment proposals, and outage data. Improvement targets should therefore focus on verified outcomes rather than compliance with reporting requirements, program enrollment, projected benefits, or spending alone. Any associated performance incentives or penalties should be based on these verifiable measures and should include appropriate baselines, deadbands, quality controls, and stakeholder review.

**Finally, Michigan EIBC/United recommend that the Commission establish a stakeholder process, including technical assistance where appropriate, to develop consistent definitions, reporting formats, and data quality standards before using these metrics to establish financial incentives or penalties.** Stakeholders should have a meaningful opportunity to understand and evaluate the information before using it to make decisions affecting customers.

#### *Restructure DR PIMs*

The Phase 2 Straw Proposal recommends a restructured approach to DR incentives tied to DR performance (as opposed to the current approach, which is tied to a utility's level of spending on DR programs). **Michigan EIBC/United support restructuring DR PIMs around verified performance rather than utility spending.**

The Phase 2 Straw Proposal recommends reporting of new metrics associated with DR performance, including enrolled DR capacity, verified peak demand reductions achieved through DR events, percentage of constrained feeders or substations supported by DR resources, frequency and effectiveness of DR event dispatch during peak conditions, and customer participation and event performance for DR programs. The proposal's proposed metrics provide a strong foundation for assessing DR performance and utilization.

Future data collection should continue to clearly demonstrate the value delivered to both customers and the grid through DR performance.

A DR incentive should be based on performance relative to an approved baseline or target, with a deadband and a cap where appropriate. It should include appropriate baselines and deadbands, be supported by a Commission-approved BCA, and be limited to benefits that are verified and not already rewarded through an interconnection, VPP, NWA, AMI, or other performance mechanism. The Commission should identify which mechanism receives credit for a benefit and should not deny compensation merely because a resource participates in multiple programs, so long as the same benefit is not rewarded twice. This framework would align DR incentives with actual customer and grid benefits rather than compliance, spending, or enrollment alone.

#### *Scorecard for Outage Restoration Metrics*

The Phase 2 Straw Proposal recommends continuing to track outage response metrics and setting targets based on each utility's performance and proposed goals and states that this may lead to a future PIM. As communicated in previous comments in this docket, **Michigan EIBC/United aver that further data collection should occur within, and not postpone, a date-certain PIM implementation process. At a minimum, the Commission should establish a date-certain schedule and framework for adopting an Outage Restoration PIM.** While outage restoration data collection is valuable, monitoring data alone does not incentivize improved customer restoration. Without meaningful performance incentives, scorecard data remains informational and does not drive accountability. The Commission should implement financial incentives tied to restoration performance. Since customers cannot choose their utility, utility decisions on staffing, preparedness, communications, infrastructure, and restoration directly impact customer

experience. A PIM can help align utility and customer interests and promote timely, effective outage restoration.

The January 2025 Lawrence Berkeley National Lab report (“LBNL Report”), “Bridging the Gap on Data, Metrics, and Analyses for Grid Resilience to Weather Events,” supports moving beyond information-only reporting. The report states that performance metrics are designed to measure “progress (or lack thereof) toward a resilience objective” and notes that regulators may “link metrics to financial incentives or penalties, or both.”<sup>38</sup> While collecting outage restoration data is important for benchmarking, monitoring without consequences does not meaningfully incentivize utilities to improve customer restoration outcomes.

The Commission should establish a date-certain schedule and framework for adopting an Outage Restoration PIM, including standardized definitions, reporting requirements, Commission-approved targets, and meaningful performance-based rewards and penalties. A framework based solely on utility-specific goals may produce inconsistent standards and make it difficult to compare performance over time or across utilities. The LBNL Report explains that standardized outage data allows utilities and regulators to compare performance “both within a utility and across utilities.”<sup>39</sup> It further recommends measuring service impacts at a granular level and consistently tracking interruption causes. A Commission-approved framework is necessary to ensure that scorecard information can be used for consistent accountability.

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<sup>38</sup> Lawrence Berkeley National Lab, “Bridging the Gap on Data, Metrics, and Analyses for Grid Resilience to Weather Events,” available at [https://eta-publications.lbl.gov/sites/default/files/2025-04/bridging\\_the\\_gap\\_resilience\\_data\\_metrics\\_and\\_analysis\\_revised\\_final\\_040325.pdf](https://eta-publications.lbl.gov/sites/default/files/2025-04/bridging_the_gap_resilience_data_metrics_and_analysis_revised_final_040325.pdf), pp. 15 and 49.

<sup>39</sup> *Id.*, p. 50.

The LBNL Report identifies outage restoration timing as a core performance category for evaluating utility response, including “resourcing,” “timing,” “efficiency,” and “effectiveness.”<sup>40</sup> It also highlights customer-focused measures, such as the time to restore service to specified percentages of affected customers and the percentage restored within a set number of hours. These measures provide a strong foundation for an Outage Restoration PIM because they focus on customer outcomes rather than utility activities or inputs. Therefore, a PIM should use a balanced set of metrics, including restoration to specified percentages of affected customers, restoration within defined time periods, and customer-exposure measures, as appropriate. As outlined in the LBNL Report, those customer-focused restoration metrics could include:

- Time to restore 50%, 90%, and 100% of affected customers. These measures capture restoration progress throughout an event and avoid relying only on the time required to restore the final customer.
- Time from peak customers interrupted to 95% restoration. This directly measures how quickly the utility restores service to nearly all affected customers and can be adjusted for event severity.
- Percentage of customers restored within specified time periods—for example, within 8, 24, 48, and 72 hours. This provides a straightforward customer outcome and highlights prolonged outages.
- Customer interruption exposure metrics. These measure the number of customers experiencing outages exceeding specified durations and help ensure that long-duration outages are not obscured by system averages.
- Customers Experiencing Multiple Interruptions (“CEMI”) or a comparable customer-specific measure. This can identify the percentage of customers experiencing repeated or prolonged interruptions and provide a more granular view of customer impacts.

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<sup>40</sup> *Id.*, p. 62.

- Outage notification performance. The PIM should consider the time to initial notification, the frequency and accuracy of estimated restoration-time updates, and compliance with defined communication intervals.

A symmetrical PIM is particularly appropriate for outage response and notification metrics. As described above, Michigan customers cannot choose their electric utility and must manage the consequences of utility investment decisions and service disruptions. A PIM aligns utility and customer interests by providing direct financial incentives for timely and effective restoration and by ensuring accountability when performance falls below approved standards. The LBNL Report also notes that customer interruption costs and avoided restoration costs are key measures of the benefits from resilience investments and improved performance. Faster, more effective restoration delivers measurable benefits for customers and the electric system, justifying action beyond continued measurement.

For these reasons, the Commission should move beyond an information-only scorecard and establish a defined path toward an Outage Restoration PIM. The Commission should adopt a date-certain schedule to develop and approve the mechanism, establish standardized customer-focused metrics and targets, and implement meaningful, symmetrical rewards and penalties tied to measurable restoration performance. Such a framework will provide transparent and consistent accountability while producing measurable improvements in outage restoration and customer experience.