Advanced Metering Infrastructure Technical Conference Report

MPSC Staff

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Dan Scripps, Chair

Katherine Peretick, Commissioner

Shaquila Myers, Commissioner

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Executive Summary

The Michigan Public Service Commission's order in Case No. U-22065 directed Staff to convene a technical conference and subsequently file a report in the same docket providing recommendations to guide the future implementation of Advanced Metering Infrastructure (AMI). The conference was held on July 14th, 2026, and consisted of presentations from DTE, Consumers, ICF, Mission: data, and a panel moderated by MEIBC. The conference provided information on DTE Energy's and Consumers Energy's plans for future AMI, the projected capabilities of AMI 2.0, and Distributed Energy Resources (DERs) integration and utilization.

This report is organized by the questions asked by the Commission in its U-22065 order and provides summaries of relevant sections of the conference presentations. This is followed by discussion from Staff including analysis of what was presented and relevant past examples related to AMI. Staff then provides its recommendations to the Commission regarding the future of AMI. These recommendations are stated in Staff's discussion and listed in the conclusion of the report.

1 | Introduction

The Michigan Public Service Commission's (MPSC or the Commission) order in Case No. U-21585 adopted the Administrative Law Judge's (ALJ) recommendation of convening a technical conference on the future of Advanced Metering Infrastructure (AMI) implementation.[1] This recommendation by the ALJ was based on the testimony of Energy Michigan; the Foundry Association of Michigan; and Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively, MEIU), recommending that the Commission open a separate proceeding to investigate Consumers Energy's (Consumers) next-generation AMI investments.[2] The testimony outlined Consumers' history with AMI, including the initial benefits claimed by the Company as well as three main issues that the Company has faced regarding its initial AMI investment.[3] The first issue is the obsolescence of cellular technology that the Company's meters rely on, requiring the Company to replace or upgrade 620,000 3G meters to 4G CatM1 meters.[4] The second issue brought up by MEIU is the Company's failure to provide a sufficient business case to the Commission, citing the proposal for decision from Case No. U-21389 in which the ALJ states, "the current NPV for advanced metering is negative $60 million, far less than the company's original project of a positive NPV of approximately $40 million."[5] The third issue described by MEIU is the meter battery contamination issue which resulted in 20,672 customers receiving estimated bills for more than two consecutive months as well as violations to rules regarding new service installation.[6] The order in Case No. U-21585 states, "The Commission intends for the technical conference to include focused discussion and be open to all rate-regulated utilities as well as other interested persons, including the Staff."[7]

On April 30th, 2026, the Commission opened a new docket, Case No. U-22065, and issued an order providing further information about the technical conference. This order directed Staff to convene the technical conference within 90 days and submit a report into the same docket no later than August 31st, 2026, summarizing the contents of the technical conference and offering recommendations to guide the future implementation of AMI. The order provided a list of questions to serve as the primary areas of focus for the conference:

- What benefits of AMI 1.0 have been realized?
- What other benefits are possible with AMI 1.0 that have not been leveraged?
- What benefits of AMI 1.0 did we expect that were never fully realized, and what were the impacts or lost opportunities as a result?

- What barriers were encountered relating to the deployment of AMI 1.0 that frustrated attempts to realize the full expected benefits?

- How does AMI 2.0 help achieve benefits that were not realized with AMI 1.0?

- What benefits does AMI 2.0 provide that are not possible with AMI 1.0 or any other method or technology?

- What data is currently being leveraged for DER integration, and where does that data come from?

- Is there data from other sources beyond AMI devices, such as customer-owned inverters, smart appliances, or data aggregators, that a utility could use rather than collecting that same data with AMI devices?

- What is the projected lifecycle of AMI 2.0 in years? Please explain what would lead the company to replace the infrastructure before the end of its lifecycle.

- What of the company's existing infrastructure supporting AMI 1.0 is interoperable with AMI 2.0? What infrastructure would need to be replaced? Can AMI 1.0 and AMI 2.0 meters exist in the same network?

- How can AMI 1.0 or AMI 2.0 be used to support customer-side resources that could be used to serve load more broadly?

Staff held a technical conference on July 14 that consisted of presentations from DTE, Consumers, ICF, Mission:data, and a panel moderated by the Michigan Energy Innovation Business Council (MEIBC). The following discussion is grouped according to the questions posed by the Commission in Case No. U-22065 and includes a summary of what was presented at the conference that relates to the questions relevant to that section, followed by Staff's takeaways from what was presented, and finally, Staff's recommendations to the Commission.

[1] Case No. U-21585-0396, Pg. 98.
[2] Case No. U-21585-0213, Witness Sherman, Pg. 49-50.
[3] Case No. U-21585-0213, Witness Sherman, Pg. 50-60.
[4] Case No. U-20147-0093, Pg. 95.
[5] Case No. U-21389-0386, Pg. 75.
[6] Case No. U-21458-0004, Pg. 25.
[7] Case No. U-21585-0396, Pg. 99.

2 | Conference Summary and Discussion

MPSC Commissioner Peretick's Opening Remarks

Commissioner Peretick opened the technical conference by discussing the opportunity and obligation that we have in Michigan to thoughtfully assess our path forward with next generation AMI 2.0 technology given the magnitude of the investment. She stated that a successful implementation goes beyond simply installing the meters. AMI 2.0 technology needs to fully utilize the capabilities the meters provide to improve reliability and resiliency, support DERs, and lower cost over the long term in order to *truly* deliver value to customers. Commissioner Peretick stressed the importance of a clear strategy for how the technology will be used and closed her remarks with the following: "If Michigan moves forward with AMI 2.0 it should be because we've demonstrated that not only the technology is promising but that we have a prudent, efficient plan to fully leverage its capabilities on behalf of customers."

Results of AMI 1.0 implementations

What benefits of AMI 1.0 have been realized? What other benefits are possible with AMI 1.0 that have not been leveraged? What benefits of AMI 1.0 did we expect that were never fully realized, and what were the impacts or lost opportunities as a result? What barriers were encountered relating to the deployment of AMI 1.0 that frustrated attempts to realize the full expected benefits?

Conference Summary

DTE's presentation explained what AMI 1.0 was able to provide for the Company. This included billing and revenue protection which reduced estimated bills and allowed the Company to recover unbilled revenue due to tamper and theft. It included remote connect and disconnect capabilities and automated meter reads which allowed the Company to reduce truck rolls. Additionally, DTE stated that proactive outage and usage alerts keep customers informed, reduces field visits, and allows crews to be dispatched before a customer calls. The Company also listed some unrealized capabilities of AMI 1.0. These included the identification of high-risk transformers, the use of voltage data to map meter-to-transformer connections for maintenance and restoration, the continuous tracking of customer electric status, the monitoring of incorrect meter installations, the use of voltage, phase, and device data to detect hazards like broken conductors, and the tracking of load control device health to reduce high failure rates.

Similar to DTE, Consumers Energy's presentation explained the core capabilities delivered by AMI 1.0 including automated meter reading, billing accuracy, remote connect/disconnect capabilities, detection of unauthorized use, and outage detection. Consumers then explained capabilities of AMI 1.0 that it had the ability to enable after deployment, including the use of heat data to detect overload conditions, detection of high or low voltage conditions, and detection of level 2 electric vehicle (EV) charging. The limitations of AMI 1.0 provided by Consumers include the inability for near-real-time grid visibility due to 24-hour data batches, limited real-time communication and scalability due to legacy IT systems, and the risk of obsolescence.

The panel, moderated by MEIBC, discussed challenges encountered by utilities implementing AMI 1.0 such as customer disruption during AMI 1.0 installation, challenges around managing the data collected from AMI 1.0, and the lack of consideration given to things like information technology and change management in initial utility applications for AMI 1.0.

Staff Discussion and Takeaways

Both utilities listed the core capabilities that AMI 1.0 has delivered. DTE discussed AMI 1.0 capabilities that it has not leveraged, while Consumers did not discuss untapped AMI 1.0 capabilities. Neither utility discussed significant issues experienced related to AMI 1.0. For example, DTE has struggled to receive power outage notifications from most of its meters during crucial times. In 2022, the Company reported to the Commission that in cases when more than 100,000 customers lose power, the power outage notification rate has dropped to 30%[8], yet DTE claims a core benefit of AMI 1.0 is proactive notifications and outage visibility. Additionally, as discussed by MEIU in its testimony in Case No. U-21585, Consumers experienced meter issues that resulted in 20,672 customers receiving consecutive estimated bills for more than two months from 2020 to 2023, despite the core AMI benefit of billing accuracy Consumers presented on. These estimated bills were a result of a battery contamination issue preventing meters from reporting usage, 3G meters still being installed after the 3G communication network was retired, and insufficient manual meter reading to read meters that could no longer communicate remotely. The Company cited the battery contamination issue from the meter manufacturer, a lack of meter inventory, and supply-chain issues as contributing factors to these estimated reads. Another area that was not addressed in the presentations was the benefits that were expected with AMI 1.0 that were never fully realized. The concern brought forth by MEIU in Case No. U-21585 on Consumers' negative $40 million net present value is the result of significant expected benefits that were not fully materialized.

A full understanding of the impacts and lost opportunities from initial AMI implementations will be important when considering plans and investments for next-generation AMI technology. AMI 1.0 has delivered many of the expected benefits, as the utilities shared in their presentations, however, it has also fallen short of expectations in other areas. In Consumers' initial request for recovery of AMI 1.0, it listed direct load control and demand response programs as benefits enabled by

[8] Case No. U-21305-0003, Pg. 94.

AMI.[9] These programs have only seen low levels of adoption by customers despite the significant incremental cost to implement them. Consumers reported in 2022 that only 4.8% of customers participated in its air conditioning peak cycling program, 6% participated in its peak time of use program, and 2.4% participated in its smart thermostat program.[10] Similarly, in Consumers' 2010 rate case, it listed net metering as a benefit, however, Consumers reported in its most recent smart grid metrics report that only 0.7% of its customers were participating in net metering at the end of 2025, 16 years after this was claimed as a benefit.[11][12] Additionally, as discussed by MEIU in Case No. U-21585, Consumers Energy's implementation of AMI, which was originally expected to deliver long-term net benefits, resulted in a negative $60 million net present value. The issues each Company experienced with AMI 1.0 discussed above highlight the potential uncertainty that can come with the adoption of a new technology. It will be important to understand how the Companies have dealt with issues they have experienced and how they have learned from the lost opportunities with AMI 1.0 when evaluating plans for future AMI implementation.

Capabilities of AMI 2.0

How does AMI 2.0 help achieve benefits that were not realized with AMI 1.0? What benefits does AMI 2.0 provide that are not possible with AMI 1.0 or any other method or technology?

Conference Summary

In its presentation, DTE shared the capabilities of AMI 2.0. It explained that AMI 2.0 will retain the existing capabilities of AMI 1.0, such as remote billing and remote connect/disconnect. There are also capabilities of AMI 1.0 that are enhanced with AMI 2.0 such as power status notifications, active temperature monitoring, and theft detection. AMI 2.0 additionally provides capabilities such as location awareness, hazard detection, transformer load and voltage monitoring, more precise knowledge of data from DERs, and management of DERs. DTE then explained the limitations of AMI 1.0 meters related to outage detection. The Company explains that due to the mesh network that its meters rely on, the severity of an outage significantly affects the number of meters that are able to send power outage notifications to the Company. DTE stated that with AMI 2.0, the meters continue to communicate for a longer period of time after an outage, which maintains the mesh network briefly and increases the number of power outage notifications.

Consumers presented on the benefits of AMI 2.0 and explained the capabilities of distributed intelligence. The capabilities were separated into three categories: grid reliability, operational improvements, and DER integration. Grid reliability benefits include real time outage/restoration verification, voltage sag/swell monitoring, and

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[9] Case No. U-15645-0002, Witness Preketes, Pg. 29.
[10] Case No. U-21389-0011, Witness Coker, Pg. 9.
[11] Case No. U-16191-0002, Witness Trumble, Pg. 23.
[12] Case No. U-17990-0449, Pg. 11.

enhanced hot socket and micro-arc detection. Operational improvements include fault location detection and wire-down risk assessment, location awareness, and real-time transformer load monitoring and management. For DER integration, benefits include non-intrusive load monitoring and disaggregation, reverse power flow detection, and prevention of overloads caused by localized DER concentrations. As mentioned above, Consumers also presented on the limitations of AMI 1.0 which were that 24-hour data batches prevent near-real-time grid visibility, legacy IT systems limit real-time communication and scalability, and the risk of obsolescence.

The MEIBC panel also discussed benefits of AMI 2.0 including the ability to distinguish phase and transformer association to particular meters, the ability to guide utilities to the location of the cause of an outage, and the enablement of more customer insights via load disaggregation.

Staff Discussion and Takeaways

Both utilities presented on the benefits AMI 2.0 is expected to provide and the limitations of AMI 1.0 technology, although not all of the benefits presented were new or were a limitation of AMI 1.0. For example, DTE's list of next-gen AMI features shows that location awareness will help resolve the unregistered meters issue, when in fact unregistered meters are not caused by a limitation of the current AMI technology but are a result of human-error. DTE previously shared with Staff that unregistered meters are caused by errors while performing routine work activities such as meter exchanges and meter installations at new construction.[13] Although this capability of AMI 2.0 may help resolve the unregistered meters issue, a complete overhaul of DTE's metering infrastructure is not necessary to resolve the issue, which should be able to be resolved with process improvements and training. This highlights the importance of reviewing each claimed benefit of new AMI technology and considering whether or not it can be achieved with either AMI 1.0 or lower cost alternatives. Additionally, both DTE and Consumers included outage detection or improved restoration as a benefit of next-gen AMI. Both DTE and Consumers claimed these as a benefit in their first requests for recovery of AMI 1.0.[14][15] As DTE stated in its presentation, the current limitation of outage detection is, in part, due to its mesh network. While DTE claims that AMI 2.0 can increase the number of power outage notifications, as Staff stated above, this original expected benefit of AMI has not been fully realized, and it is unclear how much of an improvement could be expected with next generation technology. An understanding of the magnitude of the incremental benefit that AMI 2.0 can provide will be important when assessing the impact of this claim and therefore, the reasonableness of an investment in next generation AMI.

Staff believes that it will be necessary for utilities to explain, demonstrate, and quantify the benefit of each of the claimed capabilities of future AMI investments

[13] Case No. U-21860-0349, Exhibit S-22.4, Pg. 14.
[14]Case No U-16472-0001, Witness Sitkauskas, Pg. 8.
[15] Case No. U-15645-0002, Witness Preketes, Pg. 28.

when seeking recovery of investment or approval, and to specifically be able to distinguish what is possible with AMI 2.0 that is not possible with AMI 1.0 (rather than what was simply not implemented with AMI 1.0). Staff recommends that the Commission require utilities to provide justification and quantification for each benefit it claims as part of next-generation AMI including the assumptions that support the expected quantified benefits. Additionally, Staff recommends that the Commission require utilities to provide an analysis of alternative technology or solutions that can achieve the benefits claimed by AMI 2.0.

DER Integration and Alternative Data Sources

What data is currently being leveraged for DER integration, and where does that data come from? How can AMI 1.0 or AMI 2.0 be used to support customer-side resources that could be used to serve load more broadly? Is there data from other sources beyond AMI devices, such as customer-owned inverters, smart appliances, or data aggregators, that a utility could use rather than collecting that same data with AMI devices?

Conference Summary

In its presentation, DTE addressed DER integration and compares current data sources to AMI 2.0 data sources. DTE listed the current data sources for DER integration and their limitations. Its current data sources include customer-owned solar inverters and batteries, smart-device and demand response platforms, customer-authorized data sharing, and vendor-specific online portals. DTE then listed the data that AMI 2.0 would be able to collect and what that data would enable. DTE stated that AMI 2.0 provides direct measurement of customer usage and generation at regular intervals and supports consistent, territory-wide sourcing of measurement for forecasting, outage alerts, remote service, flexible rates, and DERMs integration.

In Consumers' presentation, it provided four areas that will become more important as DER integration increases: visibility, reverse power flow, masking, and integration. Consumers currently uses AMI 1.0 data to detect DERs that may be operating without an interconnection agreement and works with customers to guide them through the interconnection process. Consumers also uses AMI voltage data to understand how solar interconnection impacts circuits and to validate proposed DER capacity and compatibility with circuits. The Company then listed the things that AMI 1.0 does not provide, such as real-time telemetry, DER control through meters, and DERMs functionality. In addition, Consumers provided key considerations for utility integration of customer-owned DERs. These considerations include cybersecurity, data quality, communications reliability, measurement and verification, interoperability and standards, ownership and responsibility, and device lifecycle and support. Consumers stated that the costs, benefits, and implementation approaches are still being explored across the industry, therefore, pilots and collaboration are an important construct that should be embraced.

In its presentation, ICF highlighted three barriers to DER integration and utilization. The first barrier discussed was variability and uncertainty resulting from limited real-time data beyond the substation. The second was that data comes from multiple sources, each with different protocols, security, and ownership. The last barrier was the lack of observability and clarity around DER grid services, which creates uncertainty that inhibits DERs from being treated as reliable system resources. ICF then discussed two data layers driving DER integration, the grid analysis layer and the measurement layer, and listed the different data sources for each layer. For the grid analysis layer, data comes from study/power flow tools, standards and methods, hosting capacity analysis, and public data. For the measurement layer, ICF listed substations, line and field sensors, AMI meters, smart inverters, and edge DERMS as data sources. ICF stated that AMI provides secure, dependable, and accessible data to the utility. This includes system-wide coverage, standardized intervals, and no access issues. ICF stated that a holistic approach to DER integration involves utilizing both AMI data and data from other data sources listed in the measurement layer above. ICF listed what AMI 2.0 can provide to support customer-side resources: situational awareness and visibility, enhanced grid services, model accuracy and interconnection, and advanced analytics and customer insight.

In its presentation, Mission:data discussed device-level metering and stated that it is complementary to utility meter data, but not a substitute for it. Pros and cons of device-level metering were then listed, with the pros being that inverters and EV chargers typically have ANSI C12-compliant metering, device-level metering can be used for wholesale market operations, and solar inverter data can help expand wholesale market participation. For the cons, Mission:data stated that device-level metering is not ubiquitous, data is only available from customers that choose to have these devices, it is not used for utility billing, and incentives can be misaligned when the utility meter has different usage patterns than individual devices.

Staff Discussion and Takeaways

As DERs such as rooftop solar, battery storage, electric vehicles, and demand response become more prevalent, utilities have expressed that existing AMI 1.0 systems do not provide the level of visibility and operational functionality needed to effectively manage an increasingly dynamic distribution system. During the technical conference, utilities explained that AMI 2.0 can provide more granular and timely data on customer load, voltage conditions, and power flows, enabling utilities to better identify emerging constraints, improve hosting capacity analyses, support distribution management and DER management systems, and verify DER performance. These capabilities may become increasingly valuable as utilities seek to integrate larger volumes of DERs, support virtual power plant programs, and leverage non-wires alternatives to traditional infrastructure investments.

While AMI 2.0 may offer potential enhanced capabilities, utilities may not require such investments if existing operational objectives can be achieved using current AMI infrastructure, targeted monitoring equipment, and traditional distribution planning tools. Many Michigan utilities continue to manage DER interconnections, perform hosting capacity analyses, and operate demand response programs using AMI 1.0 data supplemented by supervisory control and data acquisition (SCADA) systems, advanced metering analytics, and circuit-level monitoring. Additionally, utilities have increasingly sought approval for investments in a distributed energy resource management system (DERMs) which allows for the utility to monitor and control DERs and would enhance their ability to manage DERs on the distribution system without requiring a full transition to AMI 2.0. As a result, the incremental benefits of AMI 2.0 remain uncertain unless the utility can clearly demonstrate specific use cases, operational requirements, or customer benefits that cannot be achieved through existing systems and planned investments. It remains unclear how the various proposed investments including AMI 2.0, DERMs, advanced monitoring equipment, and other grid modernization initiatives will function as an integrated solution. Several of these investments appear to provide overlapping capabilities, making it difficult to assess whether the proposed expenditures are complementary, duplicative, or necessary to achieve the utility's stated DER integration objectives. Staff recommends that the Commission require utilities to provide specific use cases and customer benefits for DER-related next-gen AMI capabilities and identify areas of functional overlap between next-gen AMI investments and other DER investments if seeking recovery for next-gen AMI.

Longevity of Next Generation AMI

What is the projected lifecycle of AMI 2.0 in years? Please explain what would lead the company to replace the infrastructure before the end of its lifecycle.

Conference Summary

In its presentation, DTE stated that AMI 2.0 is a layered infrastructure of technologies, so there is not one expected lifecycle for the entire AMI system. DTE provided the expected lifecycle for each component of the AMI 2.0 system. For smart meters, the typical lifecycle is 15 to 20 years, for the field area network, it is 10 to 15 years, for the headend system, it is 7 to 10 years, for the meter data management system/analytics platform, it is 5 to 8 years, and for the backhaul/security infrastructure, it is 5 to 10 years.

Consumers did not provide an expected lifecycle of AMI 2.0 in its presentation, nor did it explain what would lead it to replace AMI 2.0 before the end of its lifecycle. Consumers did, however, provide that its current meters rely on the 4G LTE communications network, which it expects to be retired in the mid-2030s.

Staff Discussion and Takeaways

Based on the information DTE provided regarding the projected lifecycle of its AMI 2.0 system components, by the time its meters reach the end of their expected useful life, the field area network would have to be replaced once, the head-end system would have to be replaced twice, the meter data management system and analytics platforms could have to be replaced four times, and the backhaul/security infrastructure could also have to be replaced four times. This shows that the lifecycle of next-generation AMI will be dependent on multiple system components, not just the meters themselves. This is not dissimilar to what was seen with AMI 1.0 implementation with the retirement of the 3G cellular communications network. Just four years after completing the deployment of its AMI 1.0 meters, Consumers had to replace 620,000 3G meters from 2021 to 2023.[16] Additionally, DTE installed 1,800 FARs in 2025 and 2026 in an effort to increase the low power outage notification rate from its meters discussed earlier.[17] It will be important for utilities to provide a holistic view regarding plans for each component of the entire AMI system over the lifespan of the meter, including obsolescence of communications networks or other supporting components in order to properly evaluate next generation investments. Staff recommends that the Commission require utilities to provide justification for each AMI network component, as well as information about the useful life and any obsolescence concerns for each component when seeking recovery of next generation AMI investments.

Interoperability between AMI 1.0 and AMI 2.0

What of the company's existing infrastructure supporting AMI 1.0 is interoperable with AMI 2.0? What infrastructure would need to be replaced? Can AMI 1.0 and AMI 2.0 meters exist in the same network?

Conference Summary

In DTE's presentation, it stated that AMI 1.0 and AMI 2.0 will have to co-exist during a multi-year transition. The Company stated that this will require operating two head-end systems simultaneously and potentially operating dual or overlay network architecture. DTE also stated that the reuse of enterprise backbone and backhaul will be enabled to avoid degrading the AMI 1.0 mesh network performance during that transition.

In Consumers' presentation, it stated that its current backend systems and meter data management system will require upgrades and reconfiguration to support the continued use of AMI 1.0 data along with AMI 2.0 data. It also stated that its head-end system is not compatible with AMI 2.0 and will need to be replaced. Consumers stated that its plan is to avoid reactive replacement, prove value before deployment, and protect reliability and affordability during the transition.

Staff Discussion and Takeaways

Because AMI 1.0 and AMI 2.0 systems will have to be operated simultaneously during the transition, utilities must prioritize cost and reliability during the transition phase. Both DTE and Consumers stated that the transition phase will take place over multiple years and that they will have to operate separate systems simultaneously.

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[16] Case No. U-20147-0093, Pg. 95.
[17] Case No. U-21860-0349, Witness Hansen, Pg. 6-7.

Staff is concerned at the possibility that this could significantly disrupt operations and affect reliability over that transition phase. It will be important for utilities to demonstrate that they can operate both systems simultaneously while maintaining the same level of communication and performance with their meters as they did before the transition.

Staff is similarly concerned about the costs of this transition phase. Due to the multiple hardware and software components required to support the continued use of AMI 1.0 meters during the transition phase, there is an especially high risk of unnecessary costs being passed onto customers. Additionally, Staff is concerned about the risk of stranded assets. For example, DTE has recently been installing additional field area routers (FARs) to improve the power outage notification rate of AMI 1.0 meters, but it has not been confirmed if these FARs will be compatible with AMI 2.0.[18] Utilities considering a transition to AMI 2.0 should carefully consider these stranded costs in its analyses of available solutions and provide detailed plans to minimize costs to customers, should they pursue a new technology. It will be important for utilities to review how other utilities have handled transitions and learn from the experiences of those utilities. Staff recommends that the Commission require utilities to identify any stranded assets in their cost benefit analysis between next generation AMI technology and alternative solutions. Staff additionally recommends the Commission require utilities to provide plans to minimize costs, stranded assets, and disruption without sacrificing reliability, should they seek recovery for next-generation AMI investments.

Additional Discussion and Takeaways

One of the claimed capabilities of AMI 2.0 is distributed intelligence, which is the ability to run applications on the meter itself, enabled by the inclusion of a computer on the meter. Staff has concerns with this ability for the meter to run applications. One concern is the potential obsolescence of the computer before the end of the expected useful life of the meter. Staff is concerned that 15 to 20 years after the installation of a meter with distributed intelligence, the computer installed on the meter, or the applications that it can run, will not be as useful as when the meter was first installed. Staff is also concerned about the potential for applications running on the meter to increase security risks or crash the computer running on the meter. Additionally, with the ability for the meter to collect real-time data, Staff is concerned about the large volume of data this will produce, and the ability for utilities to collect, process, and store it. As discussed in the MEIBC panel, utilities have struggled to manage the data provided by AMI 1.0 implementations. Lastly, Staff is concerned about the cost of adding a computer to each of millions of meters and whether or not the benefits outweigh that cost. Due to these concerns, Staff believes it will be especially important for utilities claiming distributed intelligence as a benefit to be able to validate the usefulness and reliability of this new technology and be able to

[18] *Ibid.*

meaningfully distinguish that usefulness from the AMI technology that is already in place.

Another capability that AMI 2.0 claims to provide is improved restoration operations and communication through things like fault location and real-time outage and restoration verification. Staff is concerned that this is only a surface-level solution for poor reliability performance. In the Commission's order addressing the audit of Consumers performed by the Liberty Consulting Group (Liberty), while discussing Liberty's recommendation to, "[r]estate EDIIP reliability and safety program, measure, and activity scopes to optimize scope and expenditures assuming an extended period to reach second quarter SAIDI performance," the Commission states,

> The Commission is not yet convinced that a slower pace in spending in certain areas will result in delayed reliability goals, if the company appropriately considers alternative routes to achieve improved reliability. As noted in the comments, tradeoffs between capital and operations and maintenance (O&M) spending, including tree trimming, must be fully evaluated, and requests for rate recovery must include evidence of the analysis performed which supports the plans proposed by the company.[19]

While utilities claim that AMI 2.0 will improve outage detection, to the extent that there is an incremental cost in the technology and the infrastructure required to support it, this claimed benefit should be tempered by the notion that avoidance of outages altogether is preferable to quicker notification of outages. A more prudent use of ratepayer funds is in direct improvements to reliability, especially when considering issues utilities have encountered in fully realizing the capabilities of AMI 1.0 and inability of the Commission to compel utilities to fully leverage a technology's capabilities.

In its current rate case, Case No. U-22046, DTE states that its current AMI system vendor has been shifting its investments, workforce, and development efforts towards more modern AMI solutions, therefore, the software and hardware that manages communication between the meters and the utility is facing increasing obsolescence risk, requiring a transition to new metering technology. Consumers had to replace 620,000 3G meters due to the retirement of the 3G cellular network and is facing a similar situation with the potential retirement of the 4G network that would make the Company's 4G meters unable to communicate, of which it has 1.18 million.[20] In its initial recovery request for AMI 1.0 in 2008, Consumers stated it, "seeks to implement AMI in a manner that allows for future "smart grid" development, while mitigating the potential for the technological obsolescence of key AMI components."[21] The possibility that Consumers may have to replace over a million meters due to the obsolescence of cellular communications networks highlights the

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[19] Case No. U-21305-0029, Pg. 18.
[20] Case No. U-20147-0093, Pg. 95-96.
[21] Case No. U-15645-0002, Witness Preketes, Pg. 33.

risk associated with overreliance on a particular technology and how Consumers fell short of what it initially sought to do. These examples show the potential for utilities' chosen technology to become obsolete and the importance for careful planning around the potential for technology obsolescence. Threats of obsolescence for current AMI solutions appear to be forcing the hand of the Commission to approve investments in AMI 2.0 regardless of the cost or the ability to deliver on the claimed benefits. Staff recommends that the Commission require utilities to provide evidence that a vendor is retiring technology essential to its current AMI network when requesting recovery for an AMI transition due to that retirement.

Both DTE and Consumers are currently planning approaches to replace their current metering infrastructure. In DTE's current rate case, Case No. U-22046, it is already requesting recovery for costs to support its next-gen AMI transition, stating that it would use the requested costs over the next couple of years to conduct pilots, vendor sourcing, and deploy its next-gen AMI headend system.[22] DTE also included its plan to transition to next-gen AMI in its 2026 Distribution System Plan Report.[23] Neither of these filings, however, include specific information about what a full implementation of next-generation AMI will look like such as the total cost, a transition timeline, the implementation of claimed benefits, or the expected useful life of the new system. Due in part to these reasons, Staff has not recommended that DTE receive recovery of its AMI 2.0 expenditures in Case No. U-22046. Consumers, in its Case No. U-21870 rate case, stated that its cellular network provider informed the Company that it expects to maintain the 4G LTE network into the mid-to-late 2030s, and therefore, the Company is evaluating its metering technology, vendors, and software; and is working to define an approach for eventually replacing 4G meters.[24] Staff recommends that the Commission require utilities to provide a roadmap for its AMI infrastructure plans for at least the expected useful life of the chosen meter technology before granting recovery for the investment. This roadmap should include the timing of the purchase and replacement of all hardware and software that will be a part of the metering infrastructure. Staff also recommends that the Commission require utilities seeking recovery for a next-gen AMI transition to provide a cost-benefit analysis comprising all software and hardware components that make up the next-gen AMI system. Along with the cost benefit analysis, utilities should provide how each cost and benefit was calculated, what assumptions were made, and support for those assumptions.

[22] Case No. U-22046-0004, Witness Rademacher, Pg. 140.
[23] Case No. U-22104-0001, Pg. 299.
[24] Case No. U-21870-0009, Witness Partlan, Pg. 128.

3 | Conclusion and Recommendations

Like Commissioner Peretick stated in her opening remarks, Staff believes that requests for next generation AMI technology implementation should only be made once the utility can demonstrate how the technology can improve reliability and resiliency of the grid, support DERs, and lower costs over the long term. Staff agrees with Commissioner Peretick that clear and thoughtful plans are paramount to a successful implementation and finds it important that the technology be able to deliver benefits to the average ratepayer. Staff makes the following recommendations to allow for thoughtful consideration of any utility requests for approval of AMI 2.0 investments:

Recommendations

1. Staff recommends that the Commission require utilities to provide justification and quantification for each benefit it claims as part of next-generation AMI including the assumptions that support the expected quantified benefits.
2. Staff recommends that the Commission require utilities to provide an analysis of alternative technology or solutions to achieve the benefits claimed by AMI 2.0.
3. Staff recommends that the Commission require utilities to provide specific use cases and customer benefits for DER-related next-gen AMI capabilities and identify areas of functional overlap between next-gen AMI investments and other DER investments.
4. Staff recommends that the Commission require utilities to provide justification for each AMI network component, as well as information about the useful life and any obsolescence concerns for each component.
5. Staff recommends that the Commission require utilities to provide plans to minimize costs and stranded assets while transitioning to next-generation AMI.
6. Staff recommends that the Commission require utilities to provide evidence that a vendor is retiring technology essential to the AMI network when requesting recovery for an AMI transition due to that retirement.
7. Staff recommends that the Commission require utilities to provide a roadmap for AMI infrastructure plans for at least the expected useful life of the chosen meter technology. This roadmap should include the timing of the purchase and replacement of all hardware and software that will be a part of the metering infrastructure.
8. Staff recommends that the Commission require utilities to provide a cost-benefit analysis comprising all software and hardware components that make up the next-gen AMI system. Along with the cost benefit analysis, utilities should provide how each calculation was made, what assumptions were made, and support for those assumptions.

People with disabilities may request this material in an alternate format by emailing LARA-MPSC-ADA-Requests@Michigan.gov or calling 1-517-284-8090.

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

Appendices

Appendix I – Advanced Metering Infrastructure Technical Conference Presentation

Advanced Metering Infrastructure Technical Conference

MPSC Staff

July 14th, 2026

Orders

- In Case No. U-21585, the Commission ordered a future technical conference focused the future of AMI implementation.
- The order in Case No. U-22065 directed Staff to convene the technical conference within 90 days of the order.

Outcome

- The Commission directed Staff to submit a report in the U-22065 docket by August 31st, 2026, summarizing the contents of the conference and providing recommendations to guide the future implementation of AMI.

Reminders

- Please ensure you are muted to reduce interruptions.
- Please be respectful of other's opinions and perspectives.
- There will be time reserved for questions and comments at the end of the conference.
  - Anyone is welcome to submit comments to the docket for this conference which is Case No. U-22065.

Opening Remarks

Katherine Peretick

Commissioner

Michigan Public Service Commission

AMI 2.0 Technical Conference

Case No. U-22065

July 14, 2026

Executive Summary

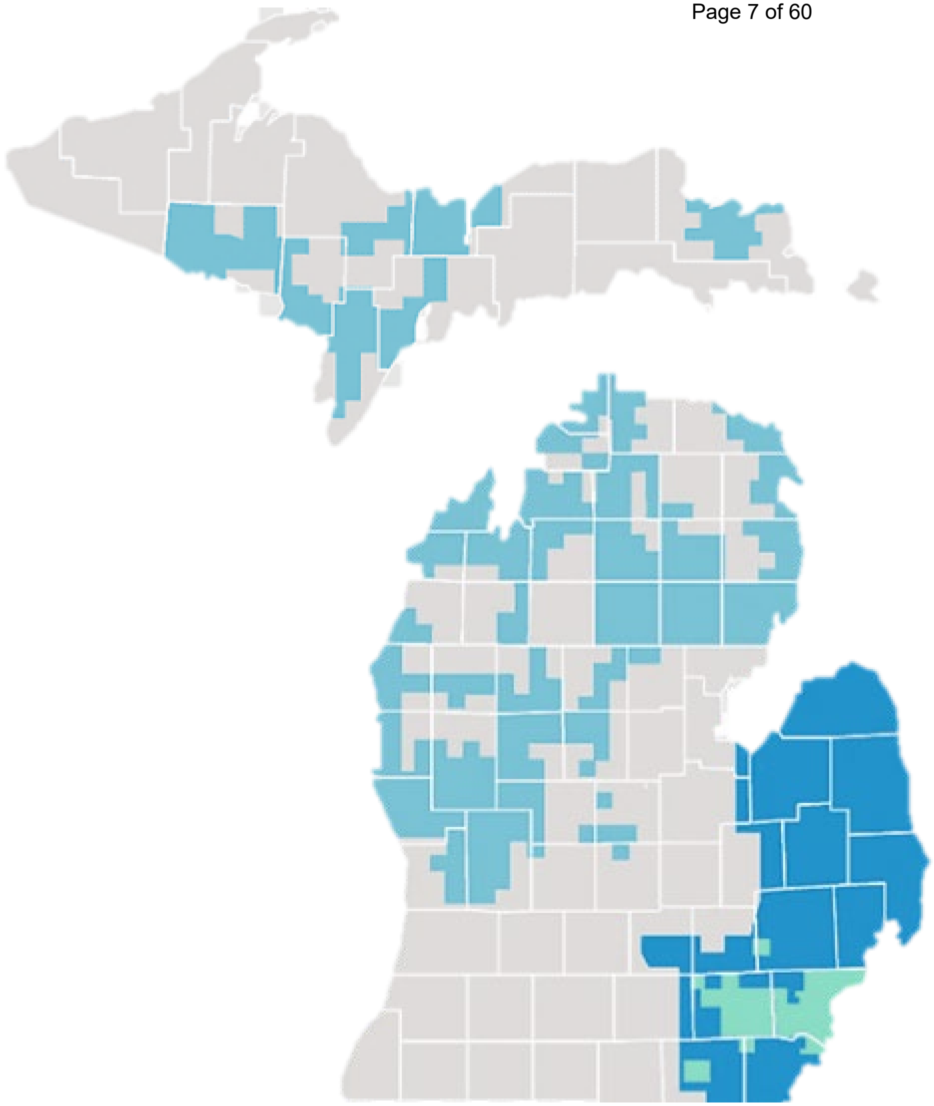
- **DTE Electric and today's AMI footprint:** DTE Electric serves 2.3 million customers across 7,600 square miles via ~2.6 million AMI meters and ~7,200 field area routers; ~20% of meters can no longer take firmware updates and Itron support ends after 2030
- **AMI 1.0 value delivered:** the 2008–2018 rollout drove billing accuracy, remote connect/disconnect, proactive notifications, and outage visibility, with gains across customer experience, operations, reliability, safety, and revenue protection
- **Benefits left untapped:** batch data feeds and aged Itron OpenWay architecture left grid-intelligence uses—transformer risk modeling, phase mapping, hazard detection, and load-control monitoring—largely unrealized
- **What AMI 2.0 adds:** in-meter distributed intelligence enables smarter restoration, transformer-level load management, proactive hazard detection, DER and dynamic-rate enablement, and a storm-resilient communication network architecture
- **Why now:** AMI 1.0 obsolescence coincides with accelerating electrification-driven load growth of 3–3.5% annually, making next-generation grid visibility, real-time control, and DER integration capabilities a strategic necessity
- **Transition approach:** a phased Sustain–Prepare–Activate roadmap reuses backhaul and enterprise IT, runs AMI 1.0 and 2.0 in parallel with dual head-ends, and manages 5–20 year layered lifecycles to avoid stranded costs

DTE Overview

Company snapshot, infrastructure footprint, and service territory

Total Electric Customers: 2.3 Million
Communities Served: 450
Electric Service Territory: 7,600 Square Miles

Electric Distribution Lines: 44,000 Miles
Distribution Substations: 700



DTE Electric service area
DTE Gas service area
Overlapping gas & electric service area

DTE

*Values are approximate

DTE Electric assesses customers' power status using a combination of technologies

AMI meters, Field Area Routers, Cellular Network and applications at DTE Data Management Systems

Sensors — **Communication Network** — **Processing**

~7,200 Field Area Routers (FARs) act as collectors, aggregating data for transfer to central systems

Backhaul infrastructure
(e.g., cellular networks, fiber) processes FAR data in the field and delivers it to DTE's systems

Backend Data Processing
Outage Management System
Data Lake
Customer Billing system, etc.

AMI Meters

The legacy AMI meter population is aging
~20% can no longer receive firmware updates today, and over 20% will be more than 20 years old by 2030. Itron will not guarantee meter hardware availability past 2030.

AMI Mesh

Field Area Routers
Mesh upgrades in 2024–2026 strengthened meter communications and set the foundation for next-generation AMI.

Headend System

Headend system (HES) compatibility
All next-generation meters require a new HES. The legacy Itron OpenWay Collection Engine (~2008) is no longer deployed, making the gap with modern metering capabilities more evident.

Customer, operational, reliability, safety, and revenue outcomes from the 2008–2018 deployment

Billing & Revenue Protection

Automated meter reads reduced estimated bills for 90%+ accuracy, while tamper and theft analytics recover unbilled revenue and protect paying customers.

Operational Efficiency

Remote connect/disconnect and automated reads remove routine truck rolls, lowering cost per customer and freeing crews for higher-value work.

Customer Experience & Safety

Proactive outage and usage alerts keep customers informed, while fewer field visits reduce safety exposure — proved especially valuable during COVID-related restrictions

Reliability & Outage Response

Last-gasp signals map outages in real time so crews dispatch before customers call, with meter-by-meter restoration supporting SAIDI and SAIFI goals.

Deployment Scale & Realized Outcomes

2.6M	75K	7,200	90%+	16
Mesh smart meters deployed	Cellular smart meters in service	Field area routers in the network	Reduction in estimated bills	Years of reliable operational service

D

Lessons from AMI 1.0 Implementation

Untapped capabilities and their impact on grid operations

Grid Intelligence & Modeling

Power Quality

Identify high-risk transformers and replace them before they cause service interruptions

Electric Grid Phase Modeling

Use voltage data to map meter-to-transformer connections more accurately for maintenance and restoration

Customer & Service Quality

Customer Excellence Program

Pinpoint circuits with frequent outages to fix electrical or vegetation issues (in progress)

Electrical Service State Awareness

Ensure AMI continuously tracks customers' electrical status with reliable reporting

Meter-Service Accuracy Detection

Catch incorrect meter installations and verify that all connected systems reflect meter changes (in progress)

Safety & Operations

Hazard Detection

Combine voltage, phase, and device data to detect hazards like broken conductors (FLISR in progress)

Load Control

Track load control device health via AMI to reduce high failure rates

Limitations in realization of advanced use cases

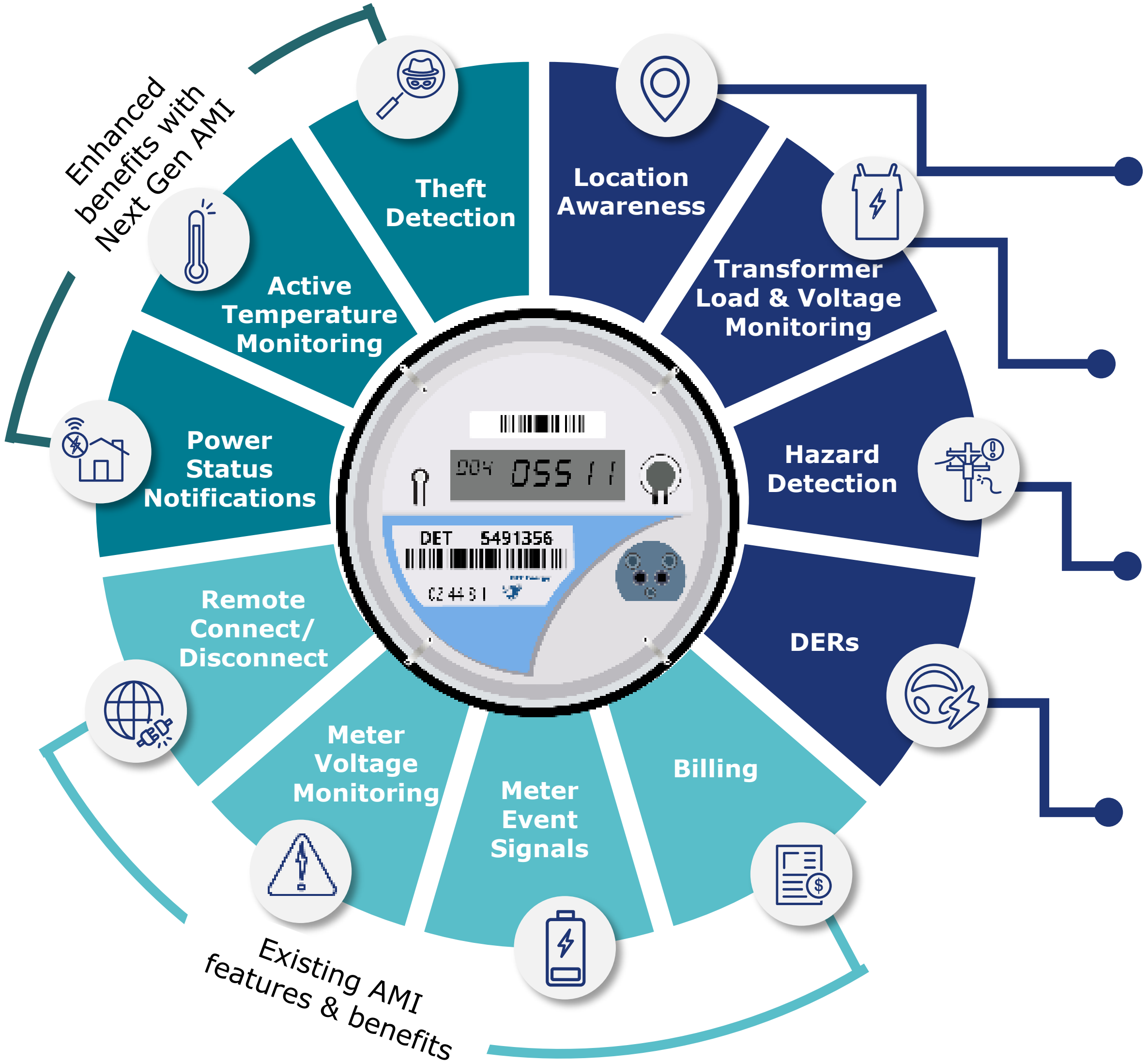
Data Quality and Timeliness: AMI 1.0 data is received through batch feeds several times per day, which is insufficiently timely for real-time or near real-time operational decision-making

AMI 1.0 Architecture: The current DTE's Itron OpenWay architecture has aged and no longer aligns with current grid control, outage communications expectations and operational requirements

Data Processing: Data processing and AI capabilities have advanced significantly since the implementation of AMI 1.0, resulting in a lag in fully leveraging available data

Obsolescence risk: Vendor indications that meter hardware may become unavailable after 2030 introduce uncertainty for mid-term planning and investment decisions

Next Gen AMI embeds intelligence in meters to enable customer-level power insights



Smarter Restoration: Self-mapping, fault location, and nested outage identification enable faster, more accurate restoration and help resolve unregistered meter issues

Load Management at the Edge: Real-time monitoring at the transformer level helps prevent overloads and reduce equipment failure

Proactive Hazard Detection: Detects hazards such as broken conductors through continuous voltage and grid-edge monitoring, improving public and employee safety

DER & Dynamic Rate Enablement: Supports FERC 2222* compliance while enabling local load control, dynamic rate optimization, and grid stabilization

DTE — Next Gen AMI features | Existing AMI features w/ Next Gen upgrades | Existing AMI features

*FERC Order No. 2222, issued by the Federal Energy Regulatory Commission (FERC) in September 2020, is a landmark regulation designed to integrate distributed energy resources (DERs) into the organized wholesale electricity markets run by regional transmission organizations (RTOs) and independent system operators (ISOs)

AMI 2.0 Outage Communication Improvements

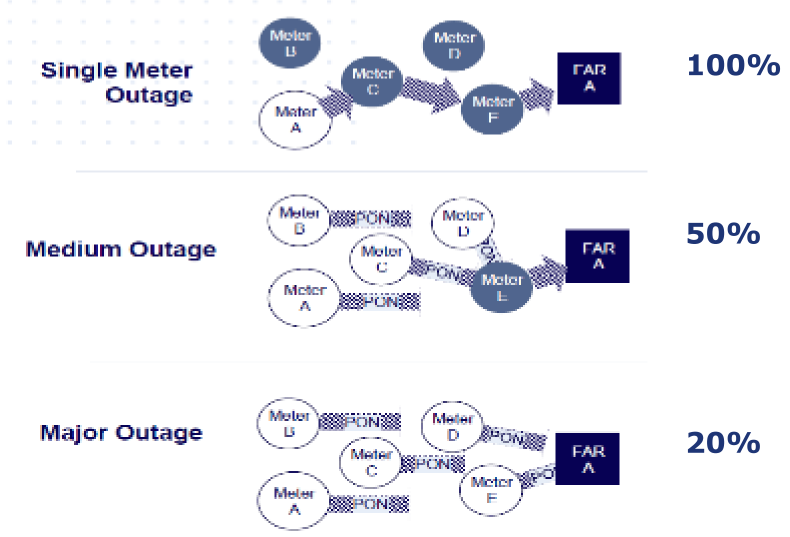
How persistent mesh networking overcomes AMI 1.0 outage detection limitations

AMI 1.0 PON Communication

Each meter independently sends a Power Outage Notification (PON) to the Field Area Router (FAR) with no awareness of the power conditions of other meters

AMI 1.0 Outage Type Dependency

PON success rates vary significantly depending on the type of outage, limiting the reliability of AMI 1.0 outage detection



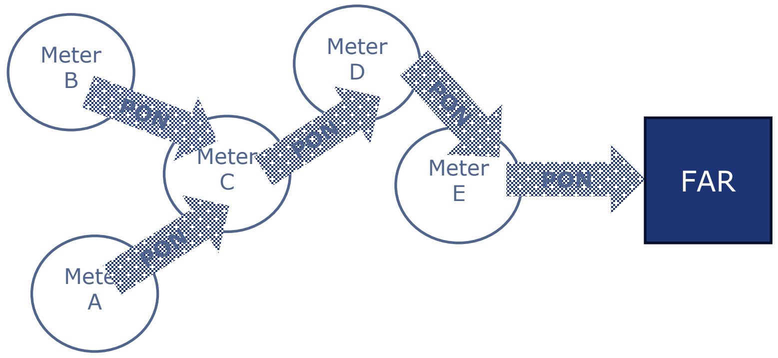
AMI 2.0 Persistent Mesh Network

AMI 2.0 meters persist the meter mesh during the ‘Extended Last Gasp’ period allowing meters to detect power conditions of other meters and relay that information

Outage Type Independence

AMI 2.0 technology significantly removes outage type variability, delivering 90%+ performance even in large-scale outage scenarios

Major Outage 100%



DTE

Drivers for Next-Gen AMI with Distributed Intelligence

Focus on boosting load capacity & optimizing existing infrastructure using real-time edge data

Electrification Surge

Growing Demand

Electrification and EVs will grow power demand by 3.5% every year

Real-Time Grid Control

Next-gen AMI enables real-time remote control of grid power flows and selective load control at the consumer level

Reliability and Cost Effectiveness Paradox

Modernization Challenge

Grid modernization is essential for reliability and operability, but rate pressures challenge it

Expanded Capabilities

Next-gen AMI visibility expands existing grid capabilities and improves cost effectiveness*, helping customers manage usage

Aging AMI Technology

Aging Meter Fleet

The average age of meters in DTE Electric's service territory is 11 years. ~400k meters no longer accepting over the air updates. The vendor does not guarantee meter availability beyond 2030

OpenWay Architecture

The current OpenWay architecture does not support grid-edge intelligence and is no longer actively deployed.

Addressing the Challenge

- Analyze alternatives to build a value-focused business case
- Stage the deployment and retirement to protect operations and affordability by phasing meter/network upgrades while aligning AMI 1.0 sunset with useful-life economics to avoid stranded costs
- Defend the expanded real-time cyberattack surface with stronger controls and monitoring

DTE

* by allowing more effective utilization of existing distribution assets through grid edge-level near real-time load control

DER Integration: AMI 2.0 vs. Current Data Sources

AMI 2.0 serves as a core building block within the broader energy management ecosystem, helping integrate customer-owned resources into grid operations

Current Data Sources

Available Sources

- Data from customer-owned solar inverters and batteries
- Smart-device and demand response platforms (e.g., OpenADR protocol)
- Customer-authorized data sharing (Green Button / Connect My Data)
- Vendor-specific online portals and connections to energy devices

Key Limitations

- Requires customer consent, security safeguards, and clear data-handling rules
- Each vendor requires a custom technical connection, adding complexity
- Limited access to advanced capabilities
- Cannot support real-time decisions or grid reliability improvements

AMI 2.0 – Based Data

Direct Measurement

Meters directly measure how much energy a customer uses and generates at regular intervals

Single Source of Truth

Provides consistent, territory-wide usage data as the primary system of record

Flexible Rates & Forecasting

Supports time-of-use rate plans and better demand forecasting

Outage Alerts & Remote Service

Automatic outage alerts and remote connect/disconnect simplify customer experience

DERMS Integration

Integrates with DERMS (energy management software) to assess the combined impact of solar, batteries, and other customer-owned devices

Note: AMI 2.0-based data is preferable because it provides direct consistent measurement across the entire service territory without relying on customer consent or vendor-specific integrations. It delivers consistent, high-frequency interval data as a single source of truth, enabling real-time grid visibility, DERMS integration, and reliability improvements that current customer- and vendor-sourced data cannot support.

The Next-Gen AMI Roadmap includes three segments

Sustain segment will run in parallel throughout the implementation until all AMI 1.0 meters are retired

PREPARE…

ACTIVATE…

Existing AMI Reliability

Intent: Keep the system safe and reliable while managing obsolescence. Non-discretionary spend to continue existing AMI operations, including failed meters/FARs, vendor lifecycle risks, and system remediation.

Key Actions:

- Replace failed, obsolete, and high-risk meters
- Address vendor lifecycle, firmware, and system remediation
- Maintain FARs field operations, spares, and support

Foundational Readiness

Intent: Reduce uncertainty and enable informed decisions before deployment. Avoid rework and bridge existing AMI sustainment to Next Gen AMI activation—creating optionality before major capital commitments.

Key Actions:

- Perform additional market intelligence gathering and vendor RFIs
- Conduct technical evaluations and limited lab / field pilots
- Define solution architecture, integrations, and cybersecurity

Develop and Deploy Next Gen AMI

Intent: Scale delivery once decisions are made and readiness thresholds are met. Decision-gated approach and ramp to large-scale deployment aligned with asset replacement cycles and DSP objectives.

Key Actions:

- Deploy backend systems (HES, MDMS, analytics, integrations)
- Build and scale communications network infrastructure
- Procure and install meters at mass-deployment scale

AMI 1.0 and AMI 2.0 Network Coexistence

AMI 1.0 and AMI 2.0 meters shall coexist during a multi-year transition, coexistence means parallel operations

Dual Head-End Systems

Parallel Operations

Dual head-ends are required during the multi-year transition period to support both AMI 1.0 and AMI 2.0 simultaneously

Network Architecture

Potentially dual/overlay networks with careful network hardening to maintain reliability

Integration & Backhaul

Enterprise Backbone

DTE integration backbone (ESB), OMS/ADMS, analytics/data lake flows, and operational portals can be retained

FCN/Backhaul Reuse

Existing FCN/backhaul can be leveraged, especially for pilots and phased rollout

Mesh Performance

AMI 1.0 Protection

Must avoid degrading AMI 1.0 mesh performance during transition to preserve existing operational capabilities

Performance Safeguards

Network hardening ensures existing meter operations remain stable throughout the migration process

Legacy meters are incompatible with next-generation meters; coexistence requires careful planning of dual infrastructure and phased rollout

The Next-Generation AMI Journey

A phased transition that protects the benefits AMI 1.0 already delivers, captures more value from the existing investment, and prepares the grid for future electrification needs such as DER growth

Preserve *today's value*

Maintain the customer and operational benefits AMI 1.0 delivered as field equipment approaches end of useful life, ensuring continuity for ratepayers during the transition.

- Accurate, on-time billing
- Remote service connect / disconnect
- Real-time outage visibility

Enhance *what works*

Improve the capabilities customers already receive, capturing more value from the existing investment without rebuilding from scratch.

- AMI mesh and communication upgrades
- Voltage and power-quality monitoring
- Restoration intelligence and crew dispatch

Enable *what's next*

Unlock new capabilities not feasible at scale with AMI 1.0, positioning DTE to meet Michigan's electrification needs, DER, and grid-edge needs.

- Distributed energy resource (DER) integration
- Meter-to-transformer location awareness
- Transformer analytics and grid-edge optimization

Why this journey matters for customers

This phased approach protects the benefits customers already funded under AMI 1.0, captures additional value from the existing investment as it ages, and prepares the grid to serve future electrification, reliability, and clean-energy needs without asking customers to pay twice for capabilities they already receive.

AMI 2.0 Projected Lifecycle

AMI 2.0 is best understood as layered lifecycles across meters, networks, and software

AMI 2.0 Component	Typical Lifecycle	Notes
Smart Meters (Gen 4/5)	15-20 years	Driven by hardware durability, accuracy standards, and regulatory depreciation
Field Area Network	10-15 years	Radios, collectors, and FARs often refreshed mid-cycle
Head-End System (HES)	7-10 years	Software/Hardware lifecycle; upgraded or replaced multiple times
MDMS/Analytics Platforms	5-8 years	High churn due to cybersecurity, analytics, and regulatory needs
Backhaul/Security Infra	5-10 years	Driven by cyber standards, encryption, and vendor support windows

DTE is taking a measured approach that leverages insights from early adopters to ensure future emerging technology investments are prudent, cost-effective, and structured to mitigate the risk of rapid technological obsolescence

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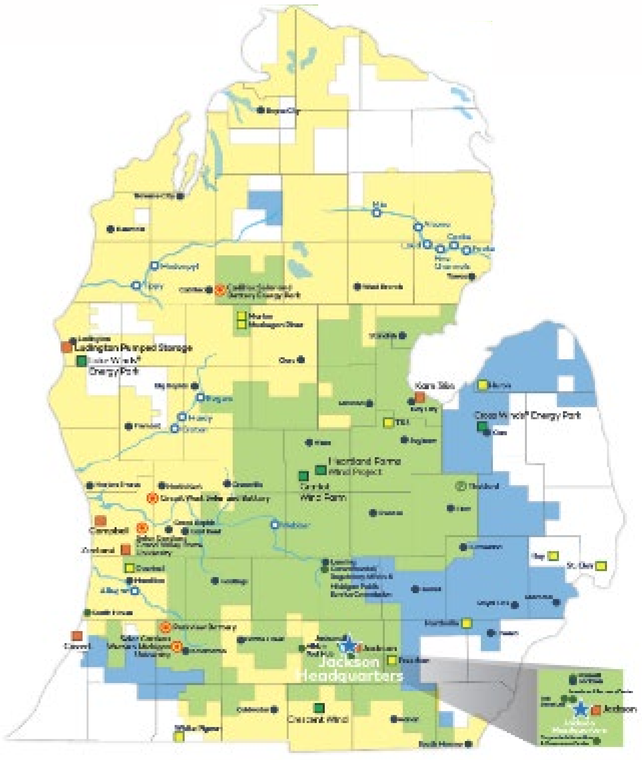
AMI Technical Conference (U-22065)

July 14, 2026

Consumers Energy
Count on Us®

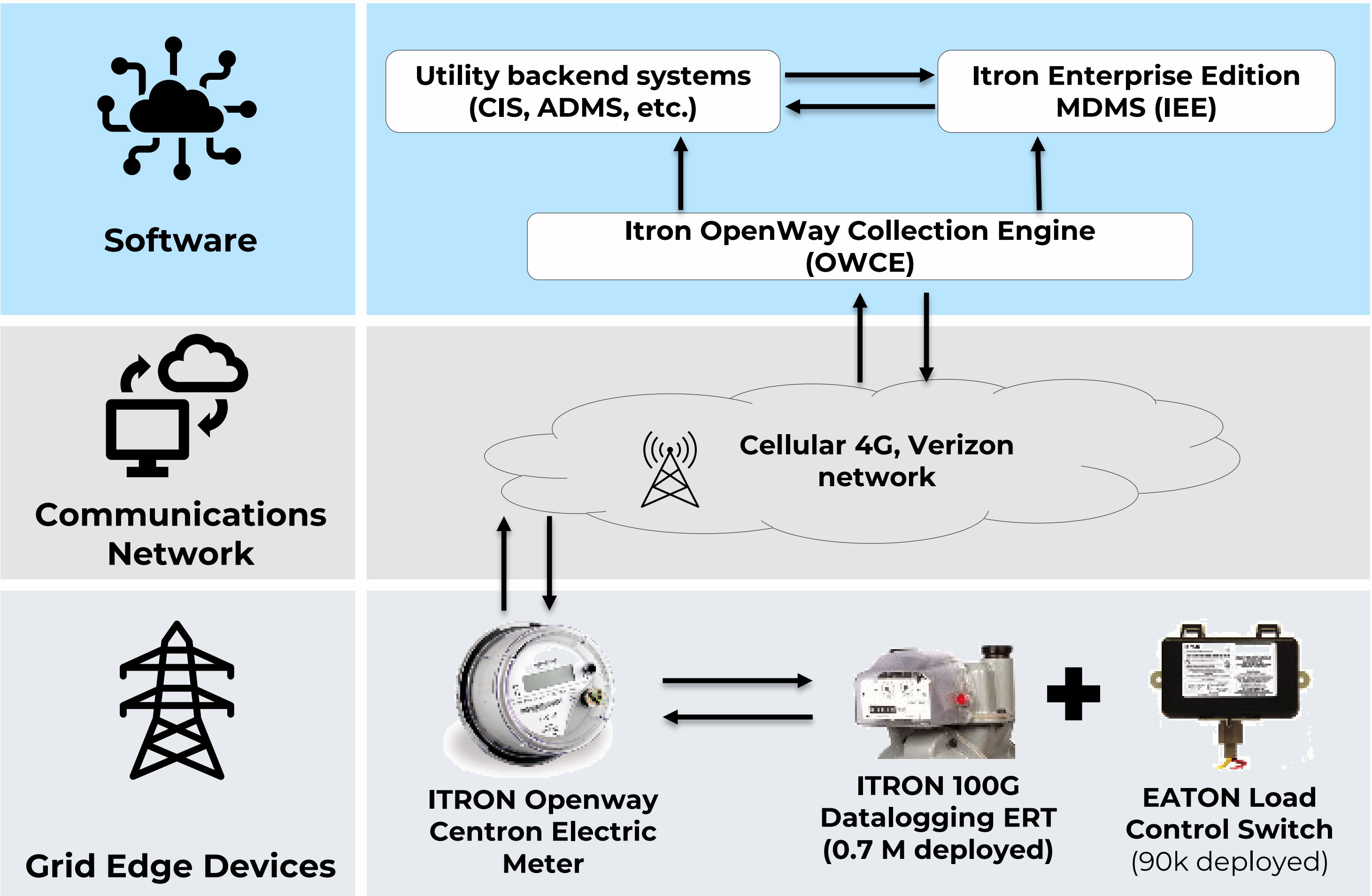
Electric AMI 1.0 Background & Current State

Consumers Energy serves 1.8M Electric and 1.8M Gas customers in Michigan



Electric service territory
Combination service territory
Natural Gas service territory

Upgraded 1.8M electric meters between 2012-2017



Core Capabilities And Benefits Delivered By AMI 1.0

BILLING ACCURACY & REVENUE ASSURANCE

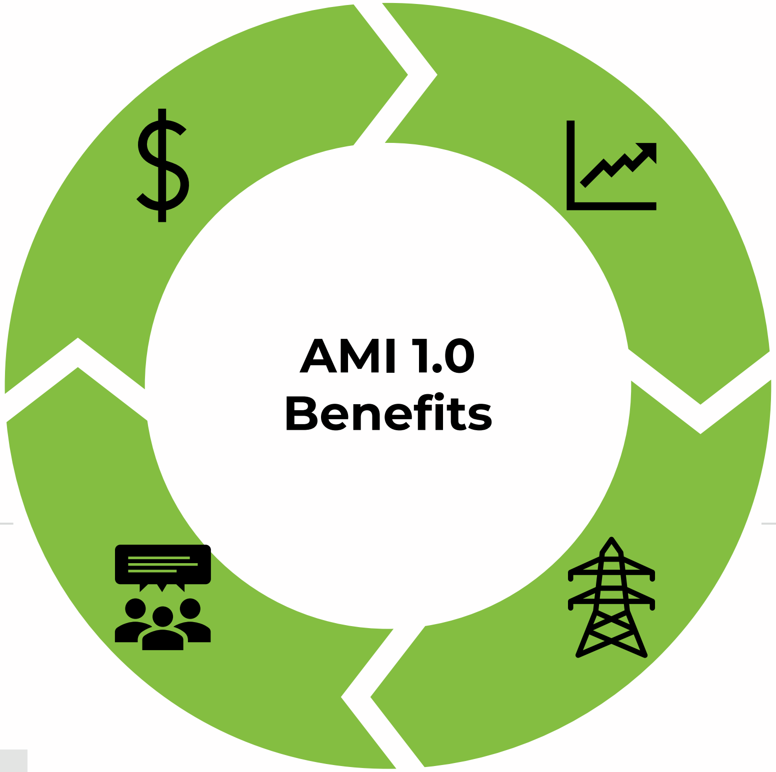
Automated cellular meter reads, remote connects/disconnects, and faster collections that translated directly into billing accuracy and reduced uncollectible accounts expense.

99%+ meter reads and 92% ↓ manual connects / disconnects

REVENUE PROTECTION & THEFT DETECTION

Detection of unauthorized use through AMI events and analytics.

1,300+ confirmed theft cases and $1.6M unauthorized usage



CUSTOMER EXPERIENCE & PROGRAMS

Customer programs: select due-dates, time of use rates, and energy usage dashboard

~600k customers are participating in Select Due Date program

OUTAGE DETECTION

Meter last gasp identifies customer outage before call, improves outage prediction and provides restoration time supporting reliability goals.

SAIDI reduction of ~10 mins

Additional Benefits and Limitations Of AMI 1.0 Realized

01. Heat Detection & Proactive Response

- Use AMI temperature / environmental data to detect overload conditions
- Enable proactive repairs based on abnormal operating conditions

02. High / Low Voltage Detection

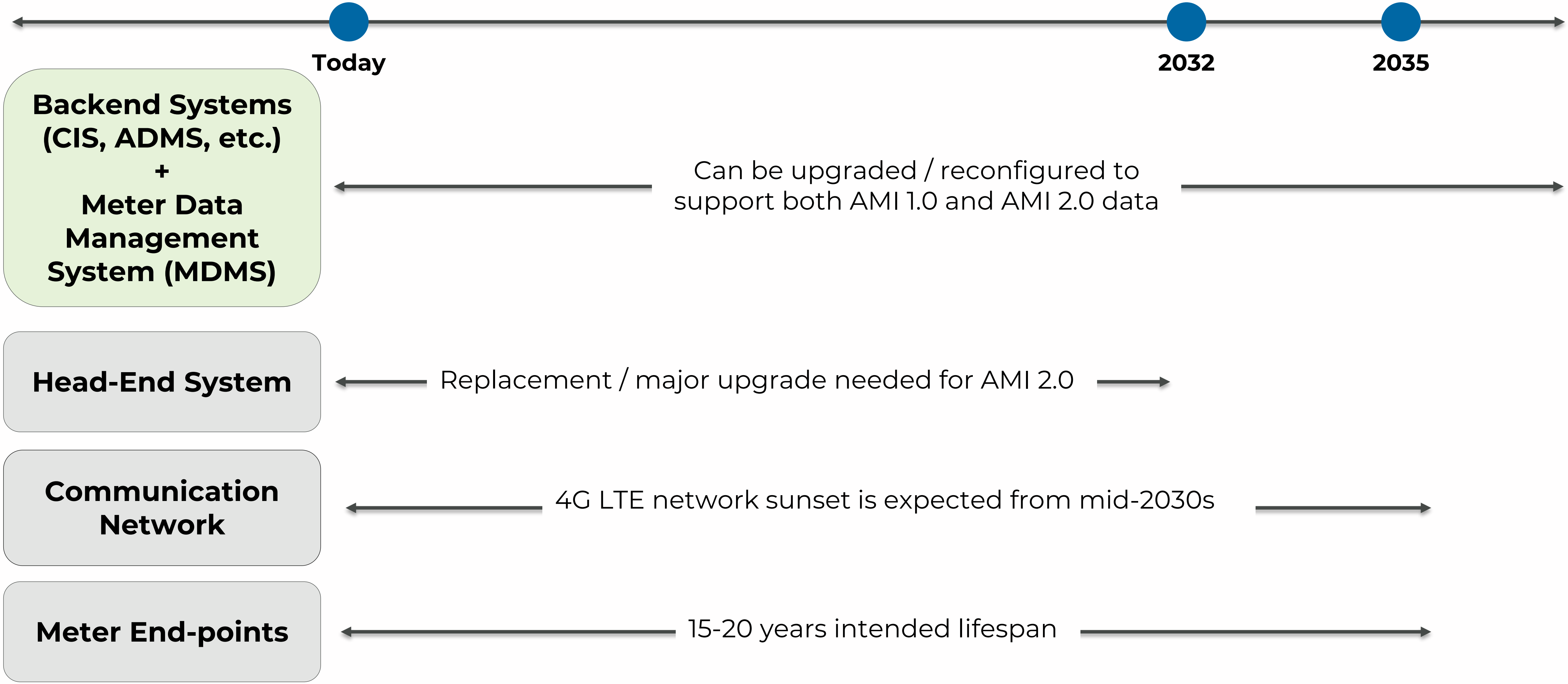
- Detect meters outside ±5% voltage bands
- Geographic view to support voltage compliance
- Trigger investigations before customer complaints

03. Level 2 (5kW+) EV Charging Detection

- Enable targeted managed-charging outreach and off-peak charging programs
- Identified ~27k (out of ~51k) grid-impacting EVs
- Drove 80%+ off-peak charging participation

Limitations of AMI 1.0:

- **Batch data processing:** 24-hour data dumps with hourly-average data prevents near-real-time grid visibility and decision-making for control
- **Infrastructure constraints:** Legacy IT systems with centralized analytics limit real-time communication and scalability, constraining AMI's ability to support evolving grid demands
- **Obsolescence risk:** Meter hardware has a limited lifespan of 15 - 20 years and is nearing end-of-life


Today
2032
2035
Backend Systems (CIS, ADMS, etc.) + Meter Data Management System (MDMS)
Can be upgraded / reconfigured to support both AMI 1.0 and AMI 2.0 data
Head-End System
Replacement / major upgrade needed for AMI 2.0
Communication Network
4G LTE network sunset is expected from mid-2030s
Meter End-points
15-20 years intended lifespan

A Phased Transition To Enable Tomorrow's Grid

1 PRESERVE Today

2 VALIDATE The Future

Validate AMI 2.0 in a production-like environment with limited endpoints

- RFP-driven vendor selection
- Validate select use cases
- Confirm interoperability, cybersecurity controls, solution architecture, and data quality

3 DEPLOY At Scale

Scale AMI 2.0 over a multi-year run-way while, retiring AMI 1.0 in a value-focused, affordability-aligned sequence

- Enterprise integration (CIS, ADMS, GIS, MDMS, etc.)
- Coexistence of AMI 1.0 and 2.0 during transition
- Activate edge apps, DER orchestration, FERC 2222 readiness
- Align retirement with useful-life economics to avoid stranded costs

Guiding principles for the transition:

Modernize Responsibly: Transition from legacy infrastructure while preserving reliability, affordability, and existing asset value.

Future-Proof the Platform: Deploy a flexible, interoperable foundation adapting to evolving technology, regulatory, and customer needs.

Enable Grid Intelligence: Unlock near real-time visibility and control to improve reliability, planning, and DER integration.

Enhanced capabilities vs AMI 1.0

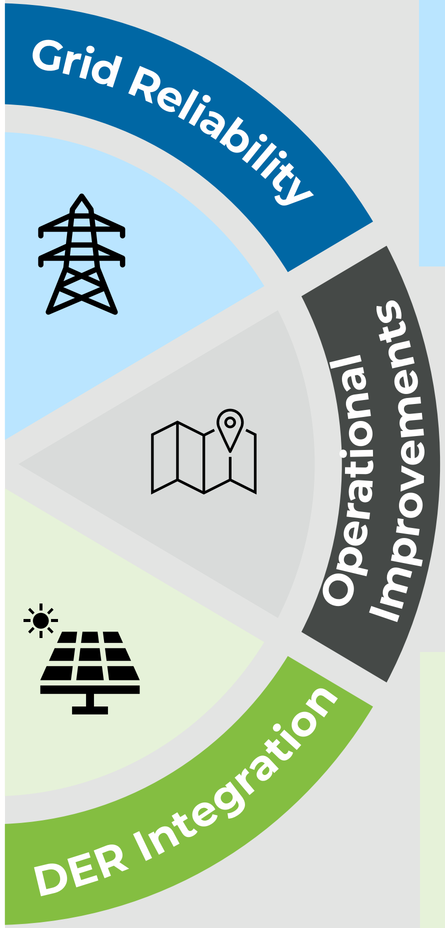
AMI 1.0		AMI 2.0
1 ***Interval Reads***	→	***Real-time + Event-driven Grid Sensing***

Enhanced customer safety: Near real-time voltage / current waveform analysis and execution of protocols based on event-driven alarms

2 ***Reactive, Centralized Analytics***	→	***Proactive, Edge Intelligence***

Faster anomaly detection and reduced latency with localized decision support

Additional use cases to improve customer experience

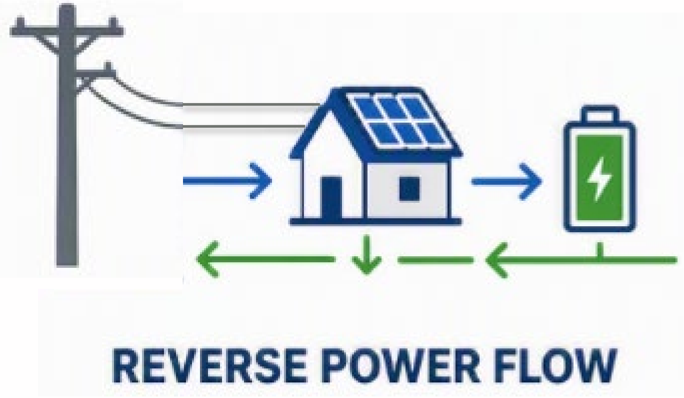


- Real-time outage/restoration verification with three-phase outage detection for partial outages
- Voltage sag/swell monitoring
- Enhanced hot socket and micro-arc detection

- Detect fault location and wire-down risk assessment including high-impedance and neutral faults analysis
- Real-time transformer load monitoring and management
- Network mapping of meter to transformer to phase and circuit

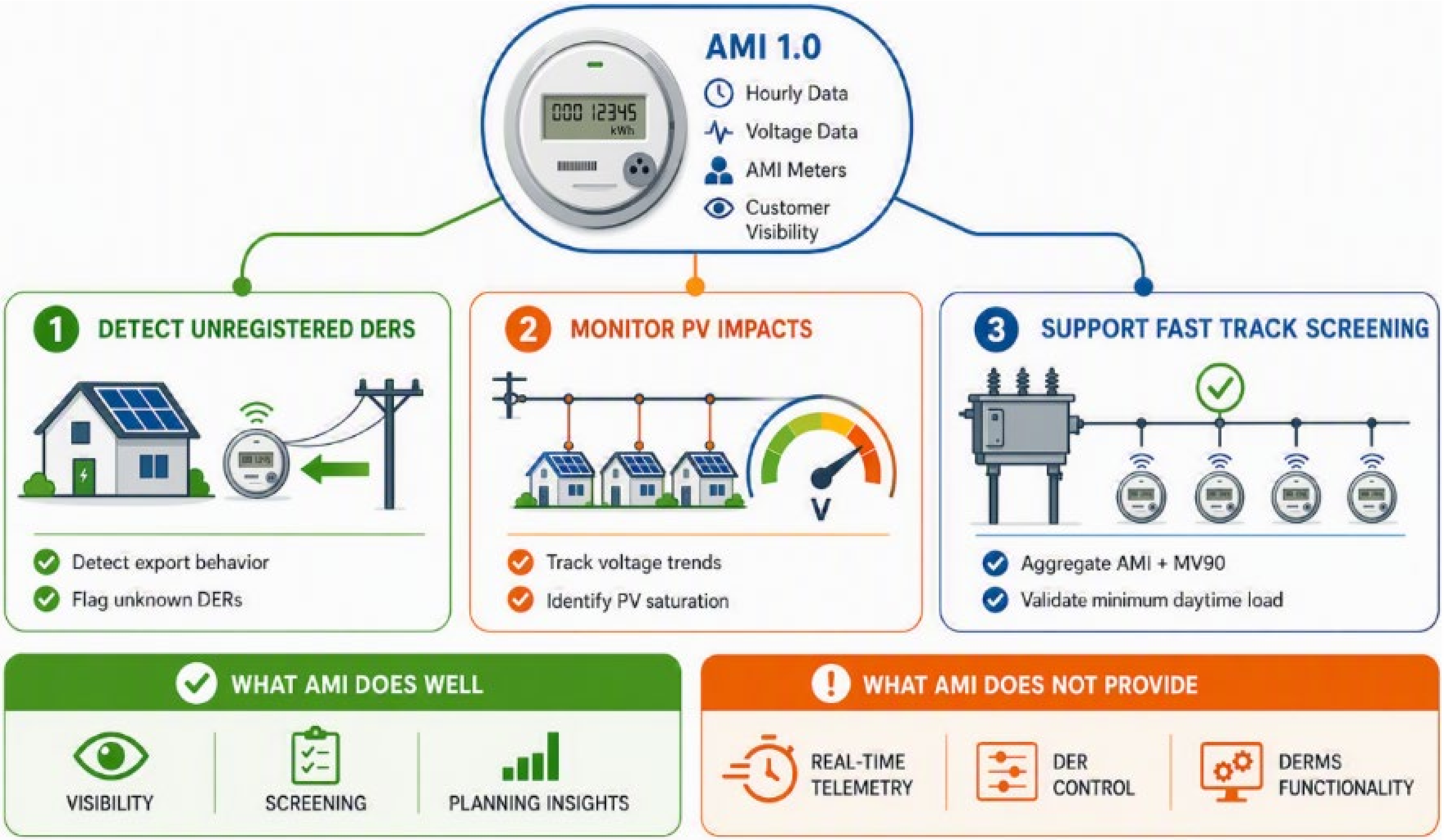
- Non-intrusive load monitoring and load disaggregation
- Detect reverse power flow
- Prevent overloads caused by localized DER concentrations

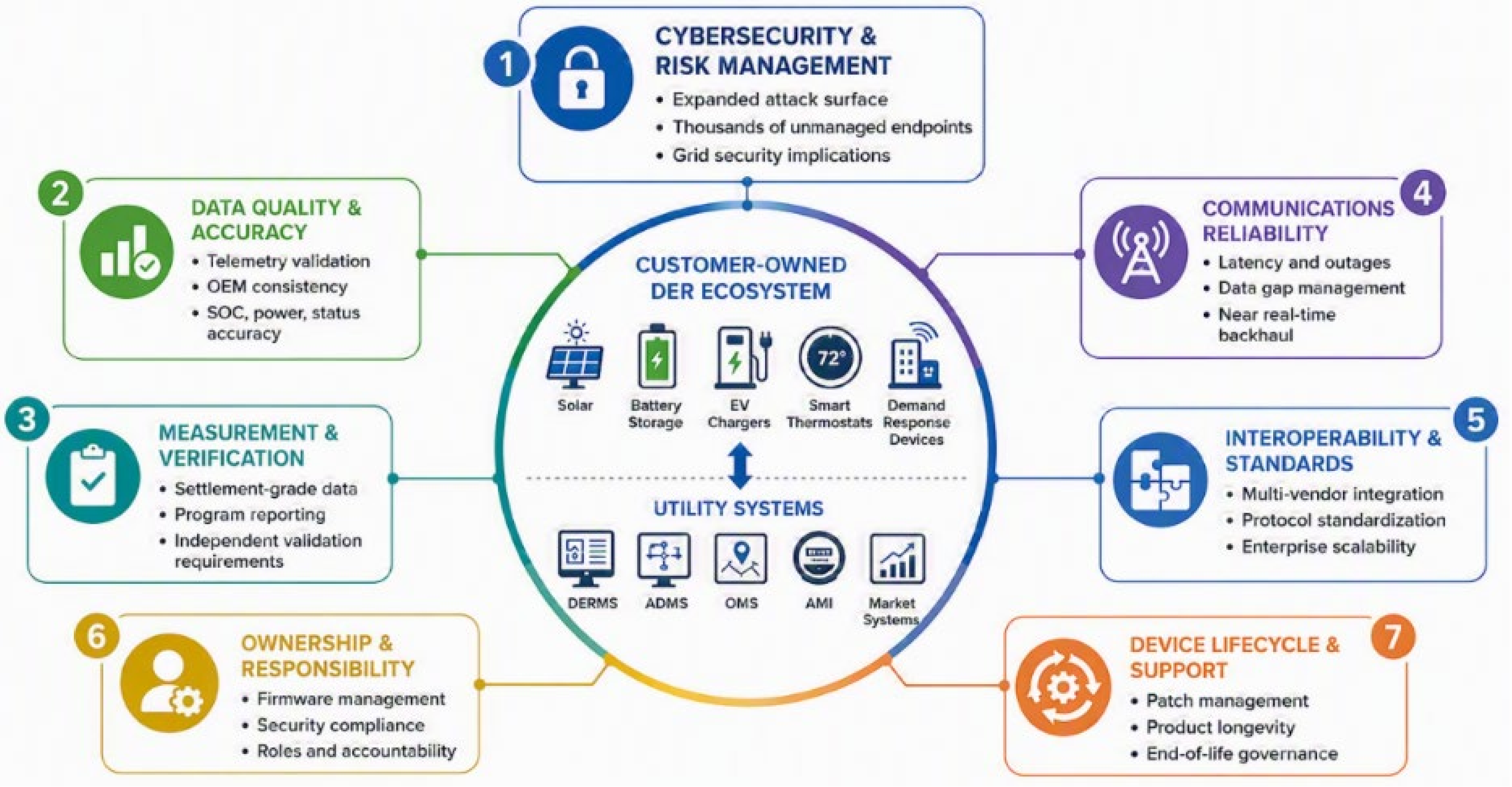

VISIBILITY


REVERSE POWER FLOW


MASKING


INTEGRATION


AMI 1.0
Hourly Data
Voltage Data
AMI Meters
Customer Visibility
000 12345
kWh
1 DETECT UNREGISTERED DERS
Detect export behavior
Flag unknown DERs
2 MONITOR PV IMPACTS
V
Track voltage trends
Identify PV saturation
3 SUPPORT FAST TRACK SCREENING
Aggregate AMI + MV90
Validate minimum daytime load
WHAT AMI DOES WELL
VISIBILITY
SCREENING
PLANNING INSIGHTS
WHAT AMI DOES NOT PROVIDE
REAL-TIME TELEMETRY
DER CONTROL
DERMS FUNCTIONALITY


1
CYBERSECURITY & RISK MANAGEMENT
• Expanded attack surface
• Thousands of unmanaged endpoints
• Grid security implications
2
DATA QUALITY & ACCURACY
• Telemetry validation
• OEM consistency
• SOC, power, status accuracy
3
MEASUREMENT & VERIFICATION
• Settlement-grade data
• Program reporting
• Independent validation requirements
4
COMMUNICATIONS RELIABILITY
• Latency and outages
• Data gap management
• Near real-time backhaul
5
INTEROPERABILITY & STANDARDS
• Multi-vendor integration
• Protocol standardization
• Enterprise scalability
6
OWNERSHIP & RESPONSIBILITY
• Firmware management
• Security compliance
• Roles and accountability
7
DEVICE LIFECYCLE & SUPPORT
• Patch management
• Product longevity
• End-of-life governance
CUSTOMER-OWNED DER ECOSYSTEM
Solar
Battery Storage
EV Chargers
72°
Smart Thermostats
Demand Response Devices
UTILITY SYSTEMS
DERMS
ADMS
OMS
AMI
Market Systems

Using AMI and other data to facilitate DER integration

MPSC Advanced Metering Infrastructure Technical Conference

Darren Murtaugh
Director, Electric Distribution Strategy

07/14/2026

Today's agenda

1. Michigan Docket U-21585
2. Framing Grid Evolution & DER Integration
3. Barriers and Grid Needs
4. Benefits of AMI 2.0
5. Data Strategy

Michigan's AMI fleets are at a re-investment decision point

- 1st generation smart meters in service for over a decade.
- As grid becomes more dynamic with adoption of customer technologies and changing load patterns, Michigan needs to ask:
  - *What data is currently being leveraged*
  - *What capabilities should AMI's next generation deliver?*
  - *How will those capabilities enhance grid reliability and efficiency?*

~1.8M
Consumers Energy electric smart meters (Itron); ~$750M program

3M+
DTE Electric advanced meters (Itron) — ~99.7% of customers

15-20 yrs
Typical AMI service life — fleets now well into second half

THE DOCKET

Mar 2025
U-21585 order directs a technical conference on next-generation AMI and DER functionality

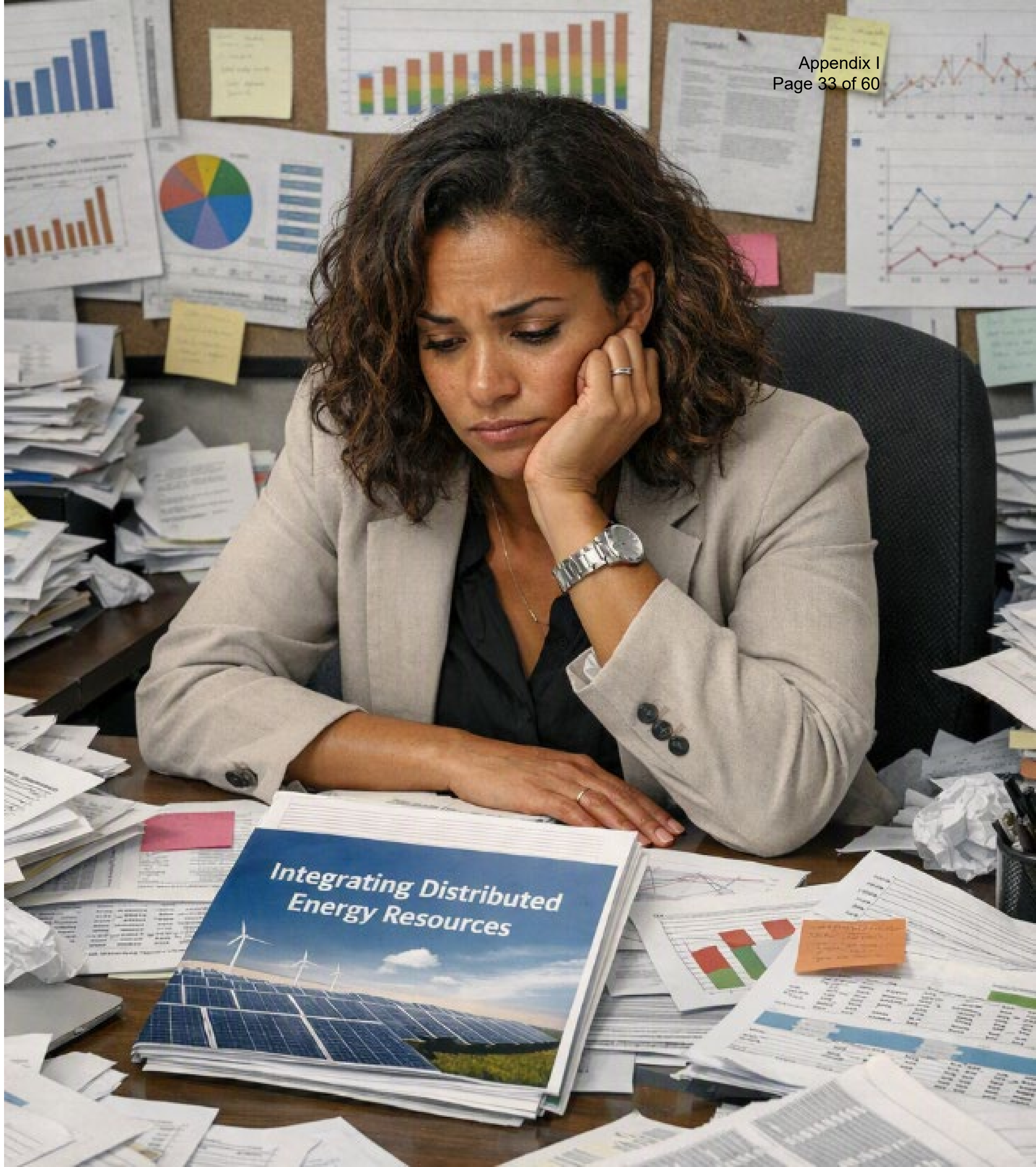
Apr 30, 2026
U-22065 opened (3–0); conference to be held within 90 days

July 2026
Technical conference — this presentation

Aug 31, 2026
Staff report with recommendations due in the docket

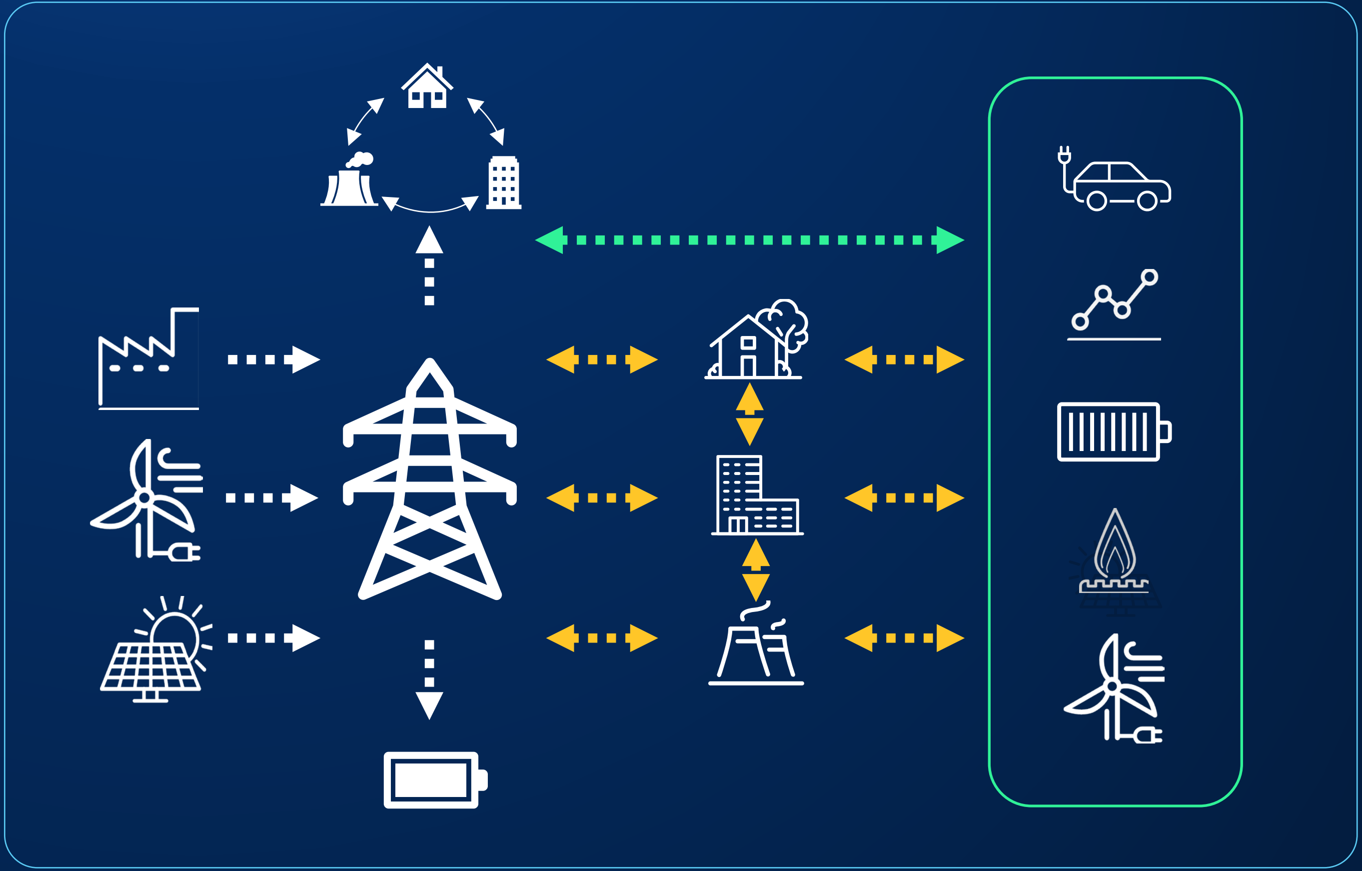
Coordinated with Michigan's VPP / customer-side-resources workgroup

A solid plan for how to use it will turn access into outcomes.



From one to many

From many to many



This has implications for:

- DER integration & electrification
- Grid modernization
- Reliability & resiliency
- Utility program design
- DER value contribution
- Affordability

ICF

Addressing the need for reliability of DER Distribution Grid Services

Customer technology adoption

Building electrification, rooftop solar, energy storage, electric vehicles and flexible loads

Changing load shapes

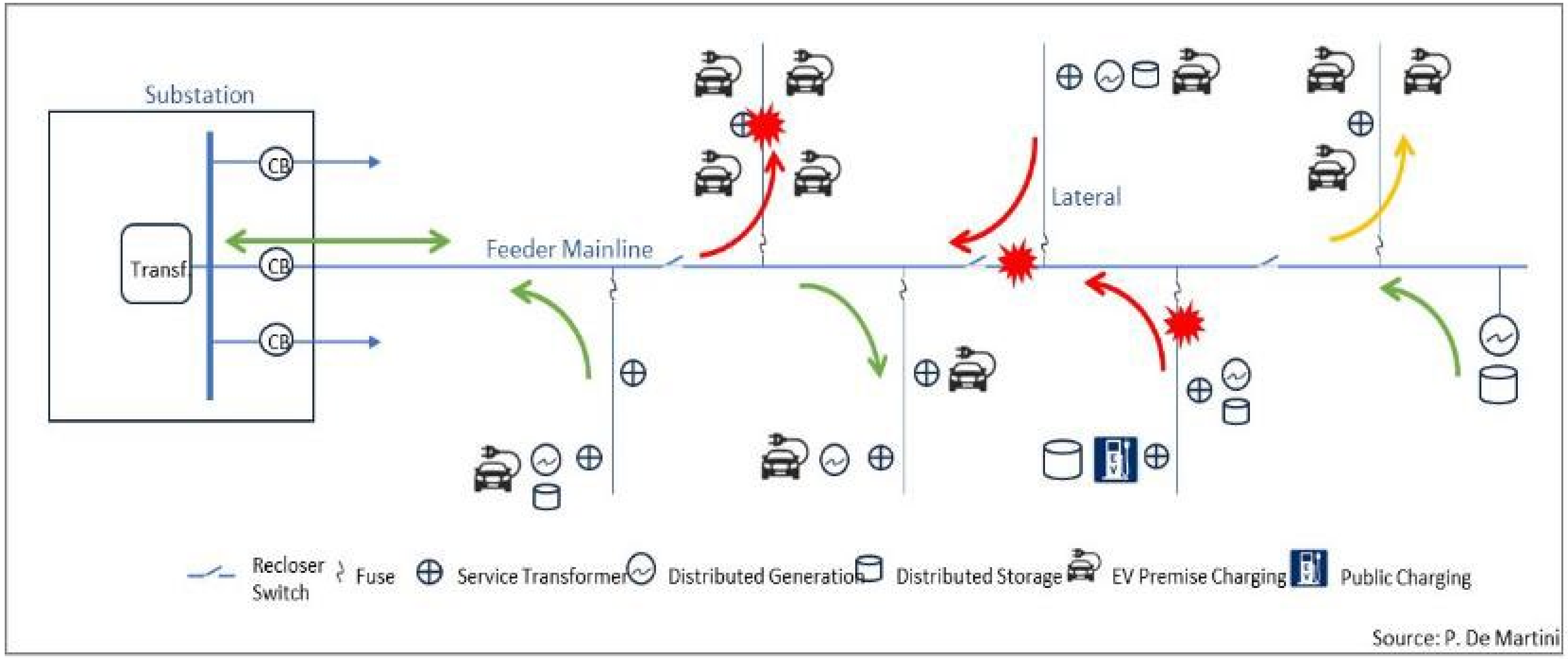
New peaks, steeper ramps and midday troughs, less predictable

Two-way power flow

Exports reverse one-way design assumptions

Automated switching

Dynamic, self-reconfiguring network operations and voltage management



Source: DOE/ICF/Newport draft paper on DER Accreditation

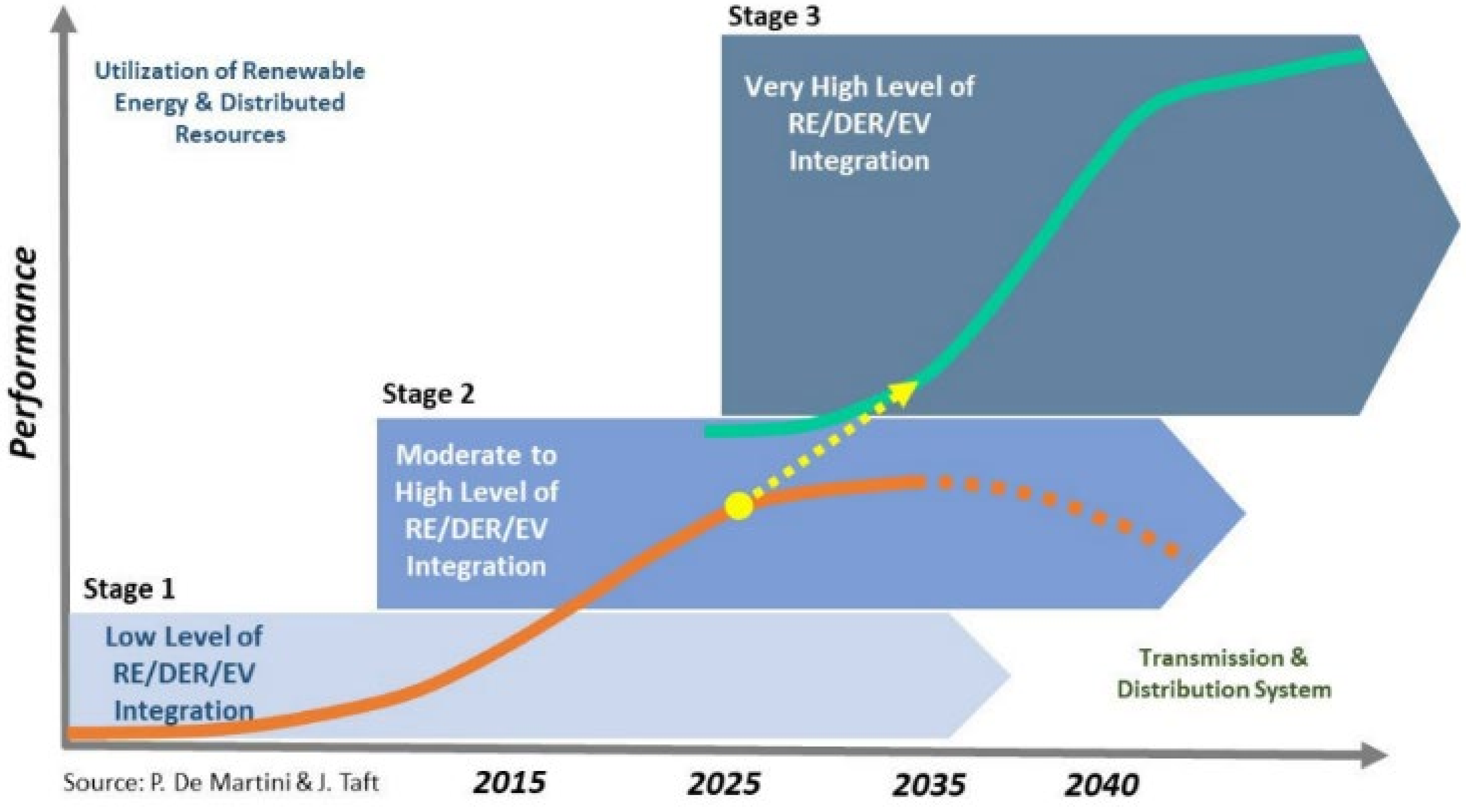
Distribution system evolution is a transformation

Core requirements

Safety
Non-negotiable for crews and customers

Reliability & resiliency
Keep the lights on through disruption

Affordability
Manage cost as the system evolves



Source: P. De Martini & J. Taft

Barriers between DER integration and utilization

01

Grid needs

Hosting-capacity, model accuracy, managing variability and uncertainty, limited real-time visibility beyond the substation. Behind-the-meter solar + storage mask true load and degrade forecasts.

02

Data integration & interoperability

Data originates from various sources: AMI, SCADA, GIS, CIS, ADMS, DERMS and customer devices — each with different protocols, security, data models and ownership. Poor integration limits visibility and situational awareness.

03

Grid services

Lack of observability and clarity around DER grid services creates uncertainty that inhibits DERs from being treated as reliable, dispatchable system resources.

AMI 1.0: benefits realized vs. left on the table

Realized

- Avoided manual reads and truck rolls
- Remote connect / disconnect
- Outage detection ("last gasp" + ping)
- Accurate billing & interval data
- Customer usage portals

Unrealized

- Real-time grid visibility
- DER situational awareness
- System-wide voltage / CVR optimization
- Masked-load & behind-the-meter detection
- DER-aware operations

WHY THE GAP: bandwidth-limited RF mesh delivering next-day data · siloed IT systems · weak OMS/ADMS/DERMS integration · limited communication and data resolution

(1) Modeling Layer determines what grid can host

GRID ANALYSIS LAYER	
Study/powerflow tools	CYME · Synergi Electric · Milsoft WindMil
Standards & methods	EPRI hosting-capacity (DRIVE) · IEEE 1547 · 3002/3007
Hosting capacity analysis	MI maps published — currently capped at 2 MW
Interconnection queue	Where new DER is projected to interconnect on each feeder
Public data	NOAA weather → variability & forecasts

(2) Measurement Layer senses what's happening

MEASUREMENT LAYER	
SCADA & substation	Feeder telemetry · MV-90 interval data
Line & field sensors	Sentient · S&C · G&W · Gridware · Edge Zero
AMI meters	Endpoint sensors: V, I, temp at every service point
Smart inverters/devices	IEEE 2030.5 · SunSpec Modbus · OpenADR · CTA-2045
Edge DERMS	Local processing of device-level data

Emerging DER Data Sources

Smart inverters deliver real-time data on generation, voltage support, and system response for DER integration.

Aggregators and virtual power plants collect data from distributed assets enabling coordinated control and load management.

Edge DERMS offer localized processing for rapid grid response without centralized infrastructure dependency.

Smart appliances and EV chargers generate detailed usage data revealing customer behavior and demand flexibility.

DECISION FACTORS: data access/ownership · accuracy · latency · communication medium · control capability · reliability & availability

AMI vs Alternative Data Sources

AMI offers consistent data collection across all customers providing a reliable baseline for system monitoring and analysis.

AMI delivers billing-grade accuracy and standardized measurement intervals trusted for operational and regulatory needs.

DER data provide higher resolution and lower latency for timely and precise system insights.

Enhanced grid optimization and advanced control strategies when combining AMI and alternative data sources

How AMI 2.0 supports customer-side resources to serve load

1

Situational awareness and visibility

Detect masked load and behind-the-meter flexibility in an increasingly dynamic operating environment.

2

Enhanced grid services

Support bulk and retail markets, hosting-capacity headroom, and VPP participation.

3

Model accuracy and interconnection

Better forecasts and load allocation; less conservative margins; streamlined DER interconnection.

4

Advanced analytics & customer insight

Load disaggregation, dynamic pricing and demand-response engagement.

AMI 2.0: Enabling a digital platform for the future's grid

Digital platform capabilities enable quantifiable benefits

- Enhanced grid situational awareness (distributed intelligence)
- Advanced sensing and analytics
- Integrated edge computing and communications
- DER/electrification integration

Societal benefits		Customer benefits			
Reduced outage time	Wildfire risk reduction	Operational cost reduction	Distribution cost avoided or deferred	Flexible connection – speed to power	Avoided energy procurement

Together, these AMI 2.0 capabilities create the digital foundation required to enable the modern grid in support of reliability and affordability.

Source: Modified from SCE's Application for Approval of Advanced Metering Infrastructure 2.0 Program, filed March 26, 2026

Five moves to leverage AMI data for improved DER Integration

1

Define the intended outcome, and be specific about what is needed to overcome barriers; position metering as an enhancement for visibility & integration.

2

Derive data specification

Determine what data quantities, resolution, latency, and frequency of update are needed.

3

Choose communication pathway(s)

Separate from the billing network; consider the bandwidth, dependability, and security needed.

4

Create data management plan

Have a plan for how the data will be managed, organized, stored, including retention plan and cybersecurity.

5

Stand up operations

Have a plan for how the data will be used. Prepare people, processes, and systems integration plans MS/ADMS/ DERMS.

Thank you! And please keep in touch.

Darren Murtaugh

Director, Electric Distribution Strategy
503-502-6862
Darren.Murtaugh@icf.com

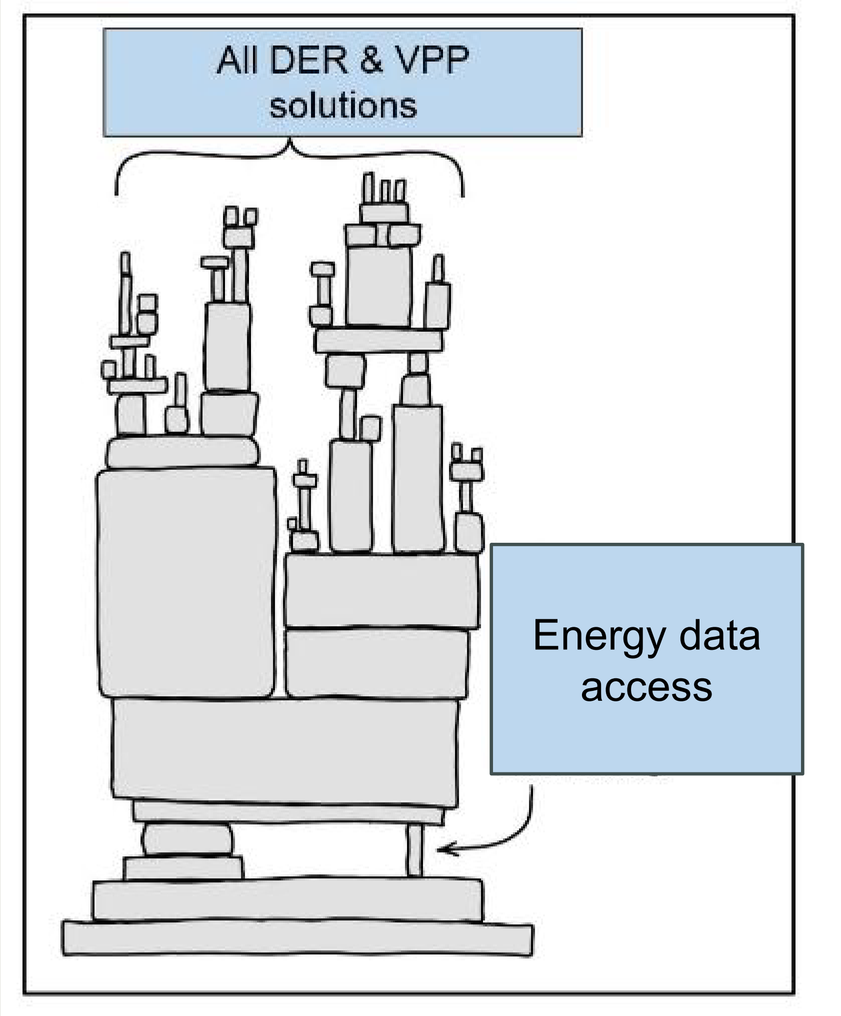
About ICF

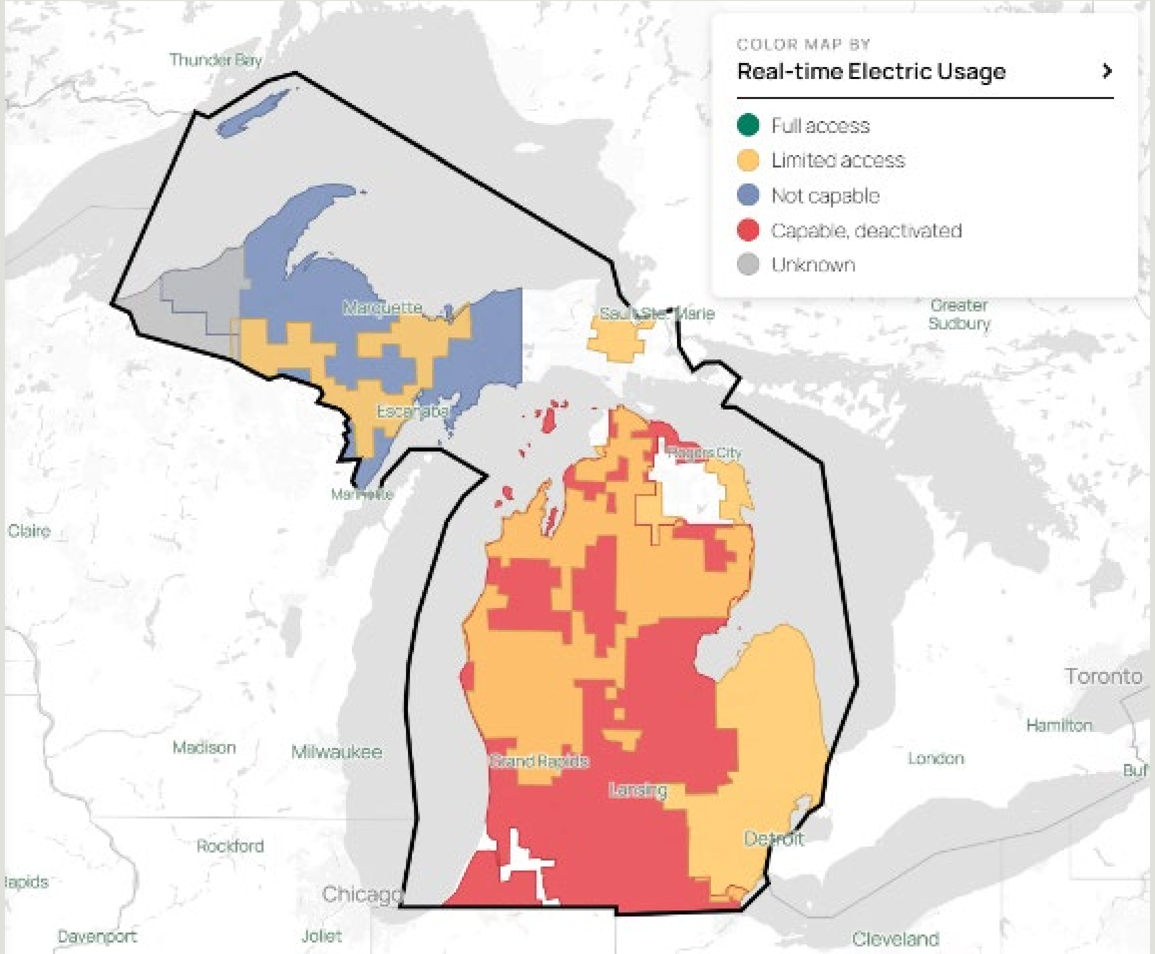
About ICF ICF (NASDAQ:ICFI) is a global consulting and technology services company with approximately 9,000 employees, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future.

10 Minute Break

Agenda:

1. Regional developments AMI v2.0
2. Device-level metering pros/cons
3. AMI v1.0 vs. AMI v2.0 comparison
4. Model policies for real-time usage data





Mission:data Coalition Introduction

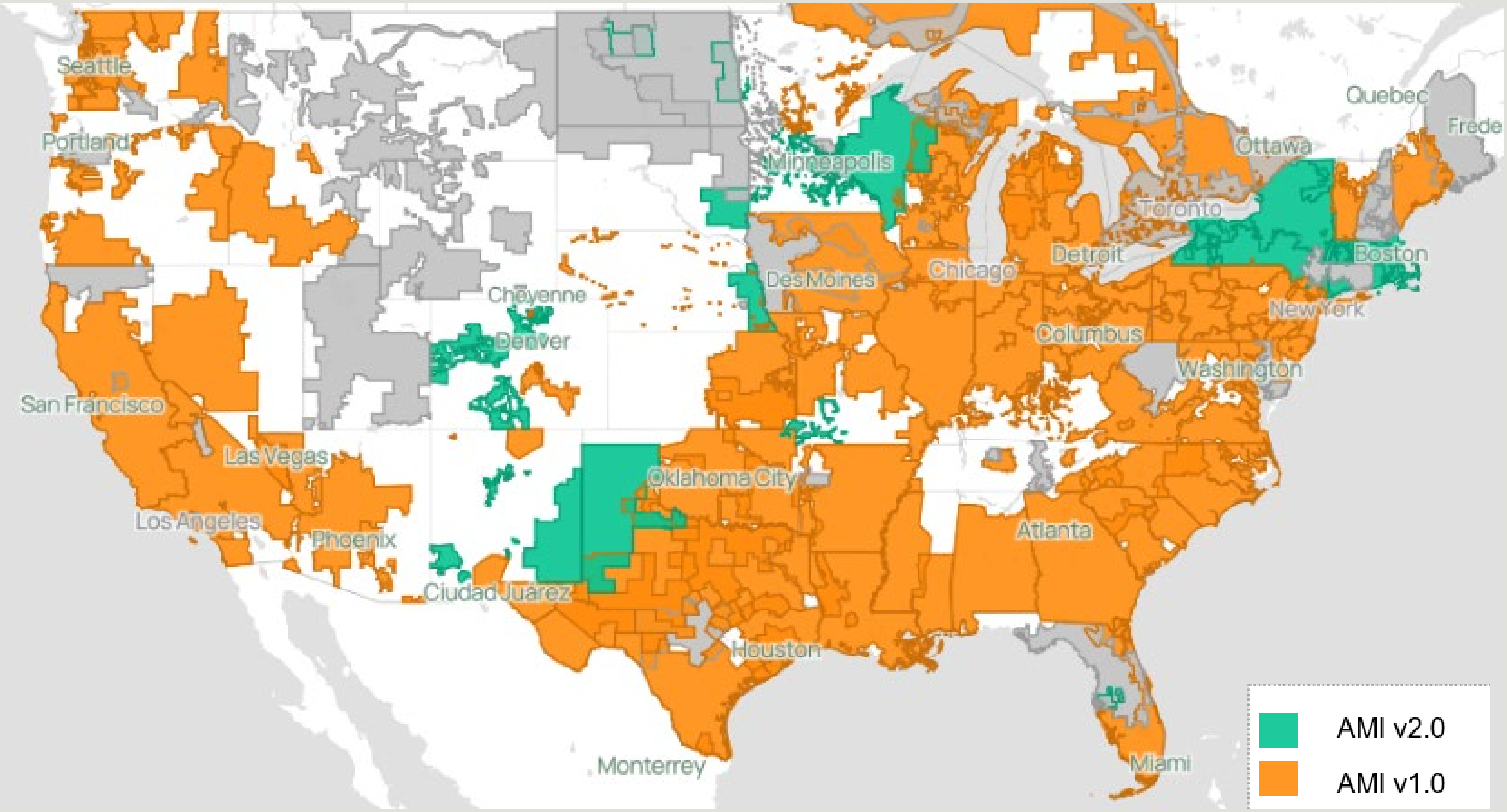
THE MISSION

Mission:data advocates for customer-friendly energy data access policies throughout the country in order to deliver benefits for consumers and enable an innovative, vibrant market for energy management services.

PRINCIPLES

All consumers should have easy access to the best available information about their energy use (including both “backhaul” information through the utility website and real-time information directly from smart meters) and the ability to easily share that data with energy management service providers of their choice.

[Green Button Explorer]



Current AMI v2.0 Applications:

<u>ComEd Illinois</u>

Grid Modernization Plan Docket 26-0047

$984 million

<u>San Diego Gas and Electric</u>

SDGE AMI 2.0 A. 25-12-012

$825 million

<u>Southern California Edison</u>

SCE AMI 2.0 A. 26-03-030

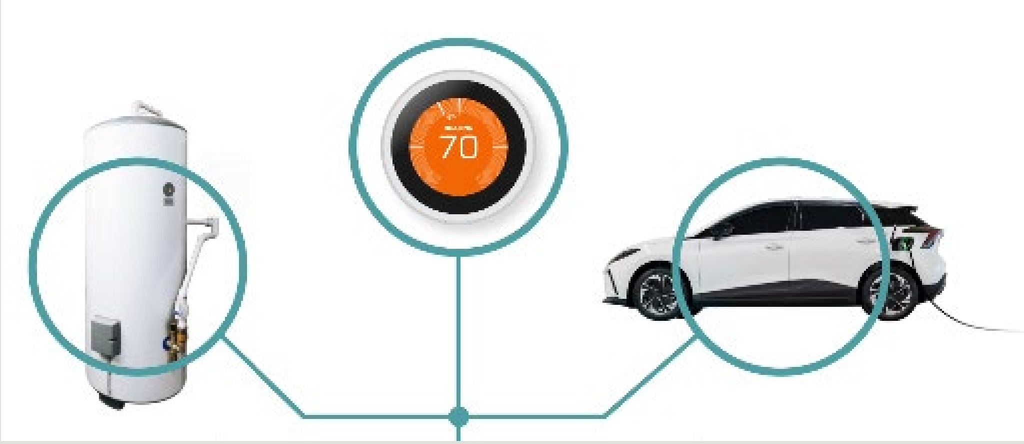
$1.865 billion

<u>Rhode Island Energy</u>

Advanced Metering Functionality Business Case 22-49-EL, 25-19-EL

$188 million

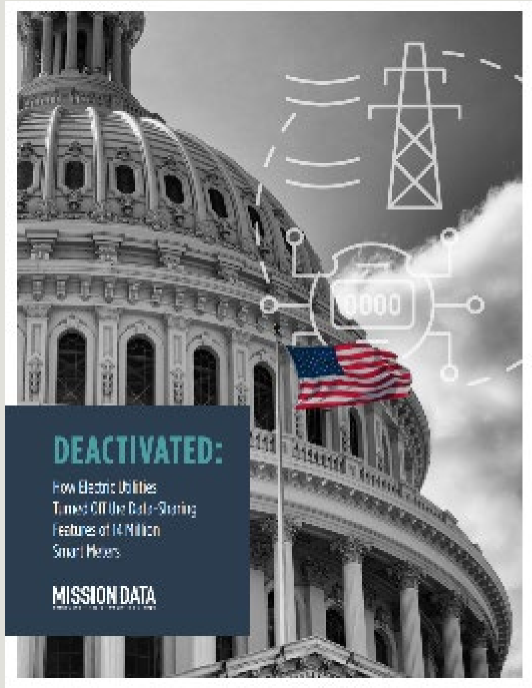
Device-level metering



Complementary to, not a substitute for, access to utility meter data

Pros	Cons
• Inverters & EV chargers typically have ANSI C12-compliant metering built in • Can be used for wholesale market operations and settlement (depends on rules) • Solar inverter data can help avoid double-counting concerns and expand wholesale market participation	• Not ubiquitous • Solar installers typically install a whole-home meter anyway • Incentives are misaligned when the utility meter (i.e. whole premise) has different usage patterns than individual device(s) • Multiple DERs at a single premise should be reconciled with a utility meter • Not used in any way for utility billing*

Real-Time Data Access Comparison



AMI v1.0	AMI v2.0
• Real-time kW/kWh data broadcast every 5-7 seconds • ZigBee Smart Energy Profile 1.1b (2.4GHz, ~100 ft range) • Customer must buy dedicated ZigBee device • Device "pairing" has been a friction point • **Exclusive tying & restrictions exist** – e.g., DTE customers must buy Zigbee device from unregulated affiliate • Tens of millions of ZigBee-capable meters have been deactivated	• Real-time kW/kWh data transmitted over Wi-Fi every ~1 second • Possible protocols include IEEE 2030.5, Matter or E-BUS* • Third party applications can be loaded onto meters, potentially doing disaggregation and sending this info to Wi-Fi devices or the cloud • Exclusive tying is still a risk without proper regulation for applications and cloud networks

Regulators will need to decide on a protocol given (i) device support nationwide, (ii) user experience matters, (iii) level(s) of interoperability

Real-Time Data Model Policies

Topic	Detail
Applicability	• Applies to all customers with AMI v2.0
Data Ownership	• Meter data belongs to customer • Customers may share their data as they choose without limitation
Utility Obligation	• Utility may not charge fees for sharing real-time data • Data sharing must be convenient and secure • Data must be available at all times • The same mechanism used to grant third party access may be used to revoke access
Fair Competition	• Must have fair competition between authorized third parties, the utility and the utility's regulated or unregulated affiliates • Prohibited from discriminating against authorized third parties, degrading real-time data services or favoring utility offerings or utilities' affiliates offerings • Equal opportunity to discover and enroll in competitive services • Provide 90 notice to data recipients for any data formatting changes • Web-based tracking for technical issues

Real-Time Data Model Policy

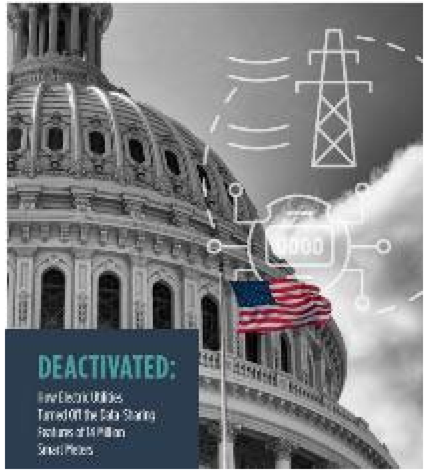
Topic	Detail
Real-Time Data Protocol	• Must support nationally recognized real-time usage data broadcast protocol • Following customer authorization, real-time data will be delivered within 90 seconds
Registration of Authorized Third Parties	• Open, non-discriminatory registration process for authorized third parties • Contact information and a federal tax identification number • Agreement to rules • Third party must not be disqualified as a customer data recipient by the Commission • Adoption of and compliance with Department of Energy's ("DataGuard").
Proof of Capability	• Utility shall complete end-to-end testing demonstrating that customers can share their real-time data over Wi-Fi with any authorized third party • At minimum, 15 residential and 15 non-residential customers shall be randomly selected to test. • Testing shall be based upon ordinary conditions like testing at the customer's home or business • Testing results shall be submitted to the Commission

Real-Time Data Model Policy

Topic	Detail
Limitation of Liability	• Utilities shall have no liability for the misuse of data after it has been securely transmitted
Terms and Conditions	• There shall be no additional terms and conditions
Support	• Utilities are responsible for ensuring that meter's Wi-Fi functionality operate correctly
Customer Complaint	• Utilities can report third parties to the Commission in writing and provide the same notice to the third party • Utilities are not expected to monitor third parties • Only the Commission may suspend a third party's access

Thank you!

Real-Time Data Model Policy:
https://www.missiondata.io/s/Model-policy-real-time-usage-data.pdf



katherine@missiondata.io

https://www.missiondata.io/reports

Appendix: Wholesale Market Reporting Requirements

PJM Requirements

- 60-minute usage data
- Customer Name
- Premise Address
- Account number
- Peak Load Contribution (PLC)
- Transmission Zone
- Line losses

MISO Requirements

- 5-minute usage data
- Customer name
- Customer email address
- Customer telephone number
- Premise address
- Account number
- Meter number
- Local Balancing Authority (LBA)
- Load Serving Entity (LSE)
- Commercial Price Node (CPNode)
- Elemental Pricing Node (EPNode)

Details: https://explorer.missiondata.io/?display=utilities%3AgbStatus&selection=rto%3Arto_003

Panel Discussion

Moderator

- **Jared Deluccia**, Regulatory Analyst, Michigan Energy Innovation Business Council

Panelists

- **Kelly Crandall**, Vice President of Regulatory and Policy, UtilityAPI
- **Darleen DeRosa**, Vice President of Regulatory Affairs, Bidgely
- **Jonathan Staab**, Head of Product Management, Landis + Gyr

The Evolving Case for a Connected Grid Edge

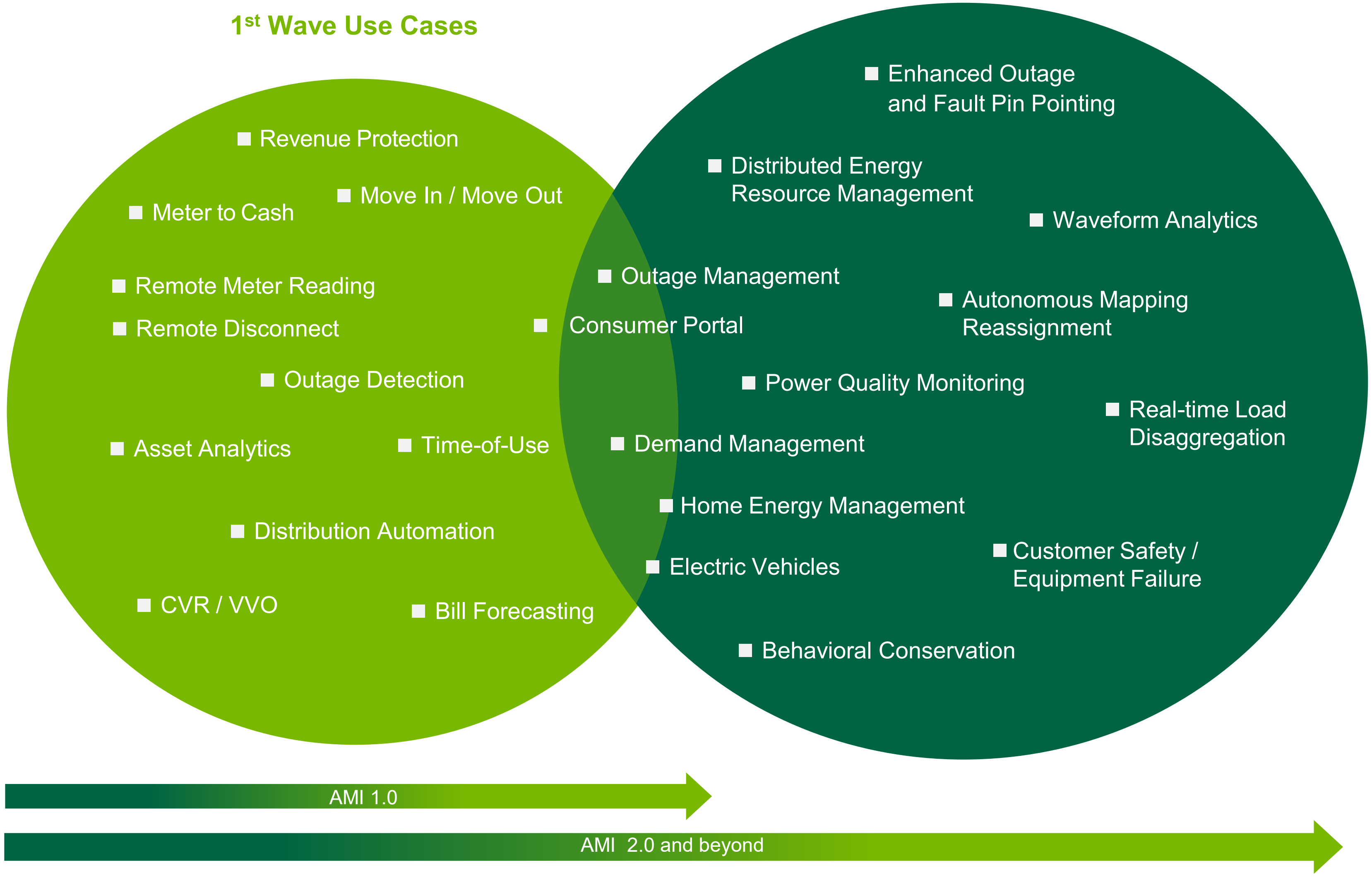
An intelligent, connected grid sensing platform, paired with an advanced network and real-time cloud integration, will enable all 1st and 2nd waves use cases and benefits for utilities *and* their customers.

Meter-to-Cash & Utility Operations

1st Wave Use Cases

Real-time Grid Management & Consumer Engagement

2nd Wave Use Cases



Questions and Comments

Next Steps

- As ordered in Case No. U-22065, Staff will submit a report in the docket by August 31st, 2026, summarizing the contents of the conference and providing recommendations to guide the future implementation of AMI.
- Anyone is welcome to submit comments to the docket for this conference which is Case No. U-22065.
- The recording of this conference will be posted to the MPSC website.

Contact me: hansenh5@michigan.gov

Thank you!