Grid Integration Study Report

In Compliance with Senate Resolution 143

June 30, 2023

Dan Scripps, Chair
Katherine Peretick, Commissioner

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Executive Summary

Planning for Michigan's rapidly evolving energy future is becoming increasingly more important and challenging. Utilities are projecting additional demands on the distribution system as electric vehicle (EV) charging infrastructure, building electrification, marijuana grow operations, and other sources of electrification will result in significant new sources of load over the next decade. In addition, customers have increasing choices for installing their own energy resources such as solar photovoltaic (PV) and energy storage systems. In response, the Michigan Public Service Commission (MPSC or Commission) has requested that investor-owned utilities (IOUs) include an analysis of their distribution system capacity to allow new resources such as EV chargers to connect to the grid in their five-year distribution plans. The current electricity system was primarily designed to support a 20th century economy and technologies, and the exploration of how energy will be injected onto the grid and withdrawn from it in the coming years will drive a transparent and cost-effective path towards grid modernization. Ultimately, this work will result in a comprehensive analysis of these important issues in what will be known as a bi-directional hosting capacity analysis.

On September 29, 2020, the Michigan Senate adopted Senate Resolution 143 (SR 143) which encouraged the MPSC to undertake a study on reliability, interconnection, and related grid integration issues for distributed energy, including an analysis of the potential growth of customer-owned distributed generation (DG) systems, changes to system design and operations, and potential system benefits, costs, and other impacts to the grid. SR 143 focuses on where grid reliability issues are likely to be impacted by specific technological components utilized through the grid.

SR 143 coincides with the MPSC's multi-year MI Power Grid efforts, wherein the Distribution System Data Access (DSDA) workgroup includes an expanded scope to analyze the potential impacts on the distribution system from accommodating additional EVs as well as distributed energy resources (DERs). The workgroup explores the utility distribution system and the additional interconnection of emerging technologies such as DGs and EVs. The workgroup investigates the current system and seeks to bring transparency to hosting capacity, which provides information regarding where projects can be more easily or cost-effectively connected utilizing existing grid capacity. In this workgroup, Staff conducted several stakeholder meetings which were composed of many individual subject matter experts, utilities, and other stakeholders. The stakeholder sessions synthesized information and guidance to understand project interconnection issues and the system-wide impacts of integrating DG and EV infrastructure to increase the adoption and lower administrative costs for contractors, developers, site hosts, and customers. The sessions explored the benefits for Michigan regulators, utilities, transmission owners, and DER project developers of having publicly accessible, bi-directional mapping and grid integration tools to prepare for the increased energy demands and DG technologies.

The Grid Integration Study addresses the potential grid impacts from interconnecting additional DERs and EVs including, but not limited to, the topic areas of growth of DERs and EVs, changes to system design and operations, and system benefits, costs, and other impacts. A set of Grid Integration Study recommendations addresses these potential concerns and next steps related to the integration of additional DERs to the distribution grid.

Introduction

Michigan's Energy Transition– The MI Power Grid Initiative

On October 17, 2019, the MPSC launched MI Power Grid in collaboration with Governor Whitmer. MI Power Grid is a customer-focused, multi-year stakeholder initiative intended to ensure safe, reliable, affordable, and accessible energy resources for the state's clean energy future. The initiative is designed to maximize the benefits of the transition to clean, distributed energy resources (DERs) for Michigan residents and businesses. MI Power Grid encompasses outreach, education, and changes to utility regulation by focusing on three core areas: customer engagement; integrating new technologies; and optimizing grid performance and investments. The MPSC maintains a dedicated website for the initiative at www.michigan.gov/mipowergrid.

MI Power Grid seeks to engage a variety of stakeholders, including utilities, energy technology companies, customers, consumer advocates, state agencies, and others, in discussions about how Michigan should best adapt to the changing energy industry.

On July 7, 2022, the Commission initiated the DSDA Workgroup in Case No. U-21251 which recognized customer-owned DG and EVs as being staples to decarbonization and to reducing emissions as outlined in the MI Healthy Climate Plan. The workgroup was tasked with the following objectives:

- Identify the impacts of increased distributed energy on the grid at both grid-wide and location-specific levels, as well as the measurable effects of generation and electric vehicles on grid reliability in other states.
- Model and project the scale of expansion for DG systems and EVs in Michigan
- Assess both the need for and impact of new technologies on both sides of the meter.
- Investigate the costs and benefits of the expansion of DG systems and EVs.
- Coordinate with utilities to analyze circuit-level distribution data and demonstrate hosting capacity throughout the state.

Electric Utility Distribution Plans

The MPSC opened Case No. U-20147[1] on April 12, 2018, which directed DTE Electric Company (DTE Electric), Consumers Energy Company (Consumers Energy), and Indiana Michigan Power Company (I&M) to submit draft five-year investment and maintenance distribution plans evaluating the utilities' aging electric distribution systems and ensuring that such systems are safe, reliable, and resilient. Prior to this order, such investments were only being evaluated over a 12-month period addressed in general rate cases. In contrast, distribution plans allow for further evaluation and planning well into the future and interested parties are given the opportunity to

[1] https://mi-psc.force.com/s/case/500t0000009gHerAAE/in-the-matter-on-the-commissions-own-motion-to-open-a-docket-for-certain-regulated-electric-utilities-to-file-their-distribution-investment-and-maintenance-plans-and-for-other-related-uncontested-matters

comment on the submissions. Since the docket was opened, DTE Electric, Consumers Energy, and I&M have filed distribution plans from 2018 through 2022. On August 20, 2020[2], the Commission issued an order and found that increased visibility into distribution system capabilities and limitations was paramount to the development of DERs. This order emphasized the following overarching objectives that Michigan's electric distribution system must adhere to:

1. **Safety:** as the top priority and reduction of risk to customers and utility workers;
2. **Reliability and Resiliency**: with metrics to include system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI), repetitive outages on particular circuits, overall performance during major outage events, cybersecurity and physical security;
3. **Cost Effectiveness and Affordability**: with processes and analyses for identifying and prioritizing cost-effective investments and alternatives, including the ability to optimally integrate new technologies such as DG to meet customer needs as well as provide additional options for grid improvements;
4. **Accessibility**: with the expectation that Michigan's distribution system infrastructure and planning is well designed to accommodate changes in customer load patterns, as well as optimize integration of customer DER and utility assets.

The Commission stated its expectation that future utility distribution plans include decisions and investments that reflect these objectives and also account for an accelerated pace of technological change.

The Commission emphasized that increased visibility into distribution system capabilities and limitations was paramount to the future development of DERs. The Commission further noted that DER hosting capacity analysis ties directly to the accessibility objective for Michigan's distribution system and that hosting capacity analysis (HCA) will become increasingly important with additional DER deployment (August 20 Order Case No. U-20147 p. 41). Thus, the Commission implemented an approach to make information publicly accessible as new data and findings become available through interconnection studies, system monitoring, and analyses of the electric distribution system. The Commission outlined base-level zonal go/no-go maps as first iterations of utility hosting capacity analyses to be published along with the distribution plans filed in 2021.

In 2021, the Interstate Renewable Energy Council (IREC) published a report[3] describing HCA and considerations of key elements. One early consideration is how the hosting capacity analysis will be used by stakeholders. Options are to 1) use HCA as a tool by developers to guide interconnection site selection and system sizing, 2) use by utilities as a step in an interconnection screen, 3) use by utilities to supplement

[2] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000DcfWRAAZ
[3] *"Key Decisions for Hosting Capacity Analyses"*, https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/

internal distribution planning efforts, and 4) use to assist in analysis of locational value. In Michigan, the initial use is to support interconnection site selection by DER project developers, although several utilities expect that in the future, they will use the analysis to support in-house distribution planning and operations.

Michigan Senate Resolution No. 143 of 2020

On September 29, 2020, the Michigan Senate adopted SR 143 to address potential grid reliability concerns due to expected DG growth on the distribution system. It encouraged the MPSC to "study the potential opportunity to integrate customer-owned generation resources into the electric grid", and requested that the Commission coordinate with electric utilities and other parties on distribution circuit-level data collection, modeling, and analysis to examine and monitor the capacity for, and constraints to, interconnecting additional DERs. SR 143 also directed the Commission to assess technology and operation options to mitigate reliability impacts and maximize customer and system benefits.[4]

U.S. Department of Energy State Technical Assistance to Public Utility Commissions

In the second half of 2021, the MPSC applied for, and received notice of its acceptance to receive technical assistance from the National Labs through the U.S Department of Energy's (DOE's) Technical Assistance to State Public Utilities Commissions initiative. Through this initiative, the Commission requested assistance in the exploration of the development of a publicly accessible bi-directional grid integration mapping tool[5] for the state of Michigan. Moreover, the development of this bi-directional mapping resource assists Michigan regulators, utilities, transmission owners, and developers in adequately preparing and planning for the integration of future distributed generation technologies and emergent energy demands from vehicle electrification and other new sources of electricity load.

In order to meet the objectives of the MI Power Grid DSDA Workgroup, respond to the encouragement to conduct a grid integration study issued by the MI Senate in SR 143, and best leverage the DOE technical assistance to explore the creation of a bi-directional grid integration mapping tool, a process was designed which addresses the study in two parts:

> **Part 1**: High level study on reliability, interconnection, and related grid integration issues for distributed energy that would also satisfy the grid integration study encouraged by SR 143.
>
> **Part 2**: Conduct utility specific or statewide analysis of capacity for and constraints to interconnecting additional DERs and serving emergent sources of new load, with a goal of being able to create utility-specific or statewide bi-directional capacity analysis maps. This resource would be accessible to

[4] https://www.legislature.mi.gov/documents/2019-2020/resolutionadopted/Senate/htm/2020-SAR-0143.htm

[5] A bi-directional grid integration mapping tool would include a map showing where there is existing capacity to support additional DG on the distribution system, as well as existing capacity to support additional new load such as the addition of new high-speed EV charging stations.

public/third-party service providers to assist in identifying areas which could accommodate additional DERs/load, or which could benefit from technological or operational solutions to mitigate cost and reliability impacts on the distribution system. Such an analysis could also require detailed forecasts from utilities of projected DER adoption, EV penetration, or the emergence of other sources of new load on the distribution system at a granular level.

Distribution System Data Access Workgroup and Tasks

Stakeholder Meetings

Stakeholder engagement is a priority of the DSDA Workgroup. Interactions with and feedback from stakeholders including utility companies, DG developers, municipalities, and EV charging companies have helped lay the foundation for the Grid Integration Study. DSDA Workgroup stakeholder communication began in July 2022 shortly after the formation of the workgroup in the July 7 Order in Case No. U-21251. The DSDA Workgroup webpage is available on the MPSC website under the pathway: MPSC > Commission Activities > Workgroups > MI Power Grid > Distribution System Data Access. The webpage tracks workgroup activities and contains the slide decks, agendas, recordings, and meeting notes for stakeholder engagement events. Also available on the DSDA webpage is a sign-up link for stakeholders to receive additional, regular updates via DSDA Listserv email communications.

August 16, 2022- DG Stakeholder Community Listening Session on HCA

The first DSDA stakeholder engagement activity began in August 2022 when the workgroup hosted two three-hour stakeholder sessions to discuss opportunities and barriers relating to the integration of DG and EVs, respectively. The August 16th meeting had 93 attendees and focused on DG with DTE Electric, Consumers Energy, and ITC Transmission Company (ITC) presenting examples of their hosting capacity maps. NREL presenters then gave an overview of hosting capacity best practices, followed by a moderated panel discussion of industry developers and municipality representatives, and an open-forum question and answer (Q&A) session to end each meeting. Representatives from the City of Ann Arbor, and developers from SunPower and Harvest Solar participated in the August 16th panel. Topics of discussion included the need for access to granular data on hosting capacity and greenhouse gas inventories, data for land-use and zoning decisions, and other energy system data to assist in accurately sizing energy storage systems. Panelists emphasized the importance of microgrids and DG systems for the future of electricity in Michigan and underlined the need for further study of DG consumer trends. The MPSC also encouraged stakeholders to reflect on these sessions with written feedback.

August 22, 2022- EV Stakeholder Community Listening Session on HCA

The August 22nd meeting had 71 attendees and focused on Evs. DTE Electric, Consumers Energy, and ITC presented examples of their hosting capacity maps. The

August 22nd panel featured representatives from Oakland County government, as well as developers from Flo and Dunamis Clean Energy Partners, LLC. The panelists spoke to the need for equitable access to hosting capacity data that is "digestible" for the average person. Additionally, granular and accessible hosting capacity data for EV charging would allow community planners to efficiently design networks of EV corridors. Panelists also explained the valuable insights on environmental justice that would arise if utility hosting capacity maps were to include a layer that filtered for socioeconomic and climate-related variables such as: income, race, air quality, asthma rates, and more. Panelists concluded by noting the importance of leveraging federal funding and grant opportunities to finance the installation and upgrade costs of EV chargers.

At the conclusion of the panel sessions, the MPSC proposed a list of questions to the stakeholder audience for consideration and open discussion:

- How can access to bi-directional hosting capacity maps reduce customer acquisition, project siting, or other administrative costs that limit increased adoption and deployment of DG systems and EV infrastructure in Michigan?
- What data would be helpful for DG and EV stakeholders, and what are the differences between the data requested to site DG projects and the data requested to site EV charging infrastructure? In what format and at what level of granularity is this data of use to these stakeholders?
- In what frequency should this information be refreshed and updated?
- How might customer-owned energy storage resources augment both DG and EV hosting capacity?
- Are there examples of utilities nationally that have an ideal platform and process for making hosting capacity data publicly available to third parties?

Any answers to these questions, either verbal or written, including all relevant links provided to external resources by audience participants, are available in the meeting notes in the appendix.

The dialogue and feedback from the August stakeholder panels helped facilitate individual follow-up sessions in late September and early October 2022 with each utility company. In these meetings, the MPSC and NREL proposed a list of questions on hosting capacity maps and data requirements for DTE Electric, Consumers Energy, and I&M.

Utility Discussion on Hosting Capacity Analysis Best Practices and Improvements

The MPSC met with DTE Electric, Consumers Energy, and I&M in September and October 2022 to discuss how to enhance existing or pending publicly available utility hosting capacity maps thereby increasing accessibility and usability of these resources for utility customers and third parties. The MPSC proposed the following list of additional questions to facilitate discussions:

1. What data would utilities be comfortable with providing to DER and EV developers? What data should not be made available under any circumstances?

2. In what format and at what level of granularity can you provide data to stakeholders? How can this data be made more accessible and exportable for stakeholders?

3. How can the hosting capacity maps *interact* with interconnection request processes?

4. How can bi-directional hosting capacity map help reduce utility interconnection costs and achieve renewables/ decarbonization goals?

5. What additional improvements are already in development to be incorporated into the existing hosting capacity maps?

6. What other features/considerations would utilities like to include in a bi-directional hosting capacity map?

7. Are there specific DER and EV growth/projection curves that the utilities can share for impact studies? Is there value in comparing projections from utilities and non-utilities stakeholders?

8. What are the primary data sharing-, security-, and privacy-concerns to sharing hosting capacity data? What are the concerns with making this data more exportable? What are the concerns with sharing more granular data?

9. NREL's proposed bi-directional hosting capacity methodology can benefit from transformer level data. Will aggregated data (on a transformer level) suffice to be shown on the map while the methodology still uses granular consumer data?

The meetings held with DTE Electric, Consumers Energy, and I&M helped frame the November 18, 2022, stakeholder session, and the Commission asked utilities to consider their responses to these questions in preparation to discuss the utilities and stakeholder's perspective on HCA.

September 28, 2022 – DTE Electric

DTE Electric shared concerns with publicly sharing substation names, locations, load profiles, and specific customer information on a hosting capacity map due to concerns with grid security. The existing hosting capacity go/no-go map that is available is done without substation details and allows people to know how much DG can be installed and where with little to no system upgrades. DTE Electric was comfortable with sharing the same limited level of loading data and had security concerns with substation name, location, specific customer information, etc. DTE

Electric requested the reason, rationale, and benefits to customers of more granular hosting capacity data and instead suggested that specific use cases for temporal capacity should be discussed. They also suggested that studies to develop specific cost estimates may be warranted in lieu of more granular hosting capacity data. DTE Electric has concerns that producing a more granular hosting capacity map may provide more information than customers want, though acknowledges that more information upfront reduces the need to study every use case.

DTE Electric acknowledged that it would be possible to study individual customer advanced metering infrastructure (AMI) data, though suggested this would come at a high cost and that data would quickly become outdated. Every utility must deal with customers coming and going, upgrades, and changing loads. As a result, reconciling data granularity with accuracy amid a changing system can be difficult. DTE Electric requested additional information regarding which specific improvements are the most beneficial keeping in mind the cost to the customer and the societal benefits. For instance, keeping separate maps of EV charging and storage would be less complicated than combining them into a bi-directional hosting capacity map. DTE Electric questioned how bi-directional hosting capacity maps may reduce interconnection costs and assist in achieving decarbonization goals. In order to establish a timeline, DTE Electric recommends having a clear understanding of improvements and requests additional discussion for implementation.

October 3, 2022 - Consumers Energy

Consumers Energy described its HCA map as being rudimentary and limited to three-phase wires only. In the next version, Consumers Energy is committed to producing a better, more granular map. Currently, Consumers Energy is working on models with color coded lines that represent the various parts of the electrical grid. Consumers Energy has also expressed a willingness to look at aggregating customer data in order to achieve better data granularity without divulging sensitive individual level customer data. Consumers Energy advised it would be burdensome to have a whole system of temporal data. However, Consumers Energy pledged to investigate certain areas where it could be incorporated for particular use cases and circuits.

To deal with prioritization, Consumers Energy expressed the need to further understand where developers are looking to interconnect. Consumers Energy has an interconnection process which directs customers to the HCA map before the interconnection application. This reduces unsuccessful requests and saves customers time by allowing customers to evaluate if an address can support interconnections without significant upgrades. Consumers Energy will then assist the customer regarding the interconnection and potential system upgrade costs for each specific site.

Consumers Energy advised that there are complications to understanding if bi-directional capacity maps would assist in achieving decarbonization goals. For example, when charging a battery, the impact of the added load on the system is easy to assess, but the impact of discharging the energy from the battery back to the grid is more difficult to assess. Consumers Energy believes batteries are complex and should be thought of as supply-side resources versus load. HCA provides a high-level overview of the system; however, it is necessary for additional studies to occur based on location and for inquiries to be analyzed individually to determine if or what upgrades to the distribution system might be necessary for interconnection.

In order to better understand DER and EV projections, integrated resource plans (IRPs) can be used. Consumers Energy intends to update projections in the next IRP; however, Consumers Energy is also interested in seeing other third-party projections. To better understand these projections, it is necessary to address the cost and charging availability barriers that prevent some people from purchasing EVs. Consumers Energy does not currently have demand rates for fast chargers and debates continue on the merits of demand charges versus societal benefits.

Registrations for license plate data captured includes the identification of EVs and plug-in hybrids and captures data by zip code. Consumers Energy has a concern regarding customer privacy by revealing load patterns and complying with the Commission's recent order on privacy. A transformer has an average of three customers attached and on a long secondary there could be up to 12 customers per transformer. Although NREL suggests bi-directional hosting capacity methodology can benefit from transformer level data, Consumers Energy expressed a desire to investigate use cases to better understand the need.

October 3, 2022 - Indiana Michigan Power Company

I&M has completed a proof-of-concept HCA map on multiple individual circuits using the Electric Power Research Institute (EPRI) Drive and CYME, which is a software tool used for analyzing transmission, distribution, and industrial power systems. EPRI Drive has no end date and is utilized for the conversion process whereas CYME is used to build distribution models. I&M advised they need a better understanding of the relationship and difference between CYME and EPRI Drive on how to automate, add protections, and other details associated with HCA. Once obtained it will be helpful in facilitating discussions with customers and stakeholders.

Currently, I&M's HCA has 95% deployment with distribution supervisory control and data acquisition (DSCADA) and is working towards 100% in the coming years. I&M is likely to start HCA with three-phase, but also has interest in including single and double phase taps in its HCA in the future. Although I&M is still early in the development and deployment process there is an understanding of possible privacy and security concerns. I&M states that customer privacy and security are important but need to evaluate the role each play. At this time, they claim many requests from developers seem reasonable, but granularity and details in requests might cause some concern. This would be an area to thoroughly investigate. Due to a desire to achieve more granular data, NREL offered assistance since they have developed a similar HCA tool. I&M anticipates updates to data on HCAs to be automated and more frequent going forward. However, I&M is still researching the accuracy of results displayed in the HCA map due to distribution system data constantly and rapidly changing.

I&M foresees HCA as having an impact on reducing or streamlining DER developer pre-application inquiries, DER informal screening applications, EV charging developer inquiries, and distribution planning inquiries. HCA will also provide a tool to efficiently answer load capacity questions for potential customers. Load hosting capacity could be used as a siting tool for EV charging infrastructure and traditional HCA would be used as a siting tool for DG. The future of I&M's HCA includes regular analysis of the entire distribution system published to the interactive visualization tool, accessible to internal stakeholders, an evaluation of constraints of external use, analysis based on 8,760 hourly load data[6], and a view of existing and approved DERs on each circuit. AMI data is a key to providing 8,760 hourly load data and I&M is currently deploying AMI meters. I&M is proactively working on best practices from other operating companies and states. Developers were interested in looking at load profiles due to solar and EVs having different times for peak, and it also assists with storage deployment.

November 18, 2022 - Utility and Stakeholder HCA Discussion

On November 18, 2022, the workgroup held a third stakeholder engagement meeting that consisted of MPSC Staff, NREL, utility companies, EV charging companies, DG developers, and automotive companies. There were 38 attendees in total. The purpose of the November stakeholder conversation was to "reach consensus on what the appropriate foundational or minimum standards should be" regarding guiding topics and questions on hosting capacity. The full list of questions as proposed to stakeholders is below, with highlights on the discussion of each topic:

What is the clearly stated value proposition(s) for ratepayers that would justify the additional cost and investment to develop and maintain more robust utility-provided capacity maps and data?

- Both EV and DG stakeholders commented on the importance of up-front information to allow for more transparent customer communication and proactive developer planning.

Noting the potential tension between the additional costs necessary to further develop and improve existing capacity maps, the wants and needs of stakeholders, and the ultimate cost and benefits to ratepayers, can we reach consensus on what foundational or minimum standards should be adopted regarding the following?

Granularity of Data - At what level of data granularity (single-phase v. three-phase, transformer level v. substation level, etc.) provides the best balance among third-party expectations and needs, utility data availability, and ratepayer benefits/ costs.

- EV charging developers and utilities agreed that demonstrating where single-phase and three-phase distribution exists on the hosting capacity map would be a valuable addition that gives insight into where grid upgrades would be the most expensive.

[6] 8,760 hourly load data is used in analyses to simulate load and energy generation for all 8,760 hours in a 12-month period.

- Utilities also stated that transformer-level data is too granular and would not provide valuable information for hosting capacity evaluation because the analysis required is overly complex and prone to error.

Data Refresh Rates - How often should the data be updated/ refreshed (once a quarter, once a year, bimonthly, etc.) given third-party expectations and needs, utility capabilities and costs, and ratepayer benefits/costs.

- Utilities stated that they are currently doing annual updates and the work is primarily manual, but increasing automation in data refresh rates is in the pipeline. EV stakeholders pointed out that seasonal fluctuations and high EV growth in certain areas could lead to massive usage fluctuations from large quantities of fast chargers.

Temporal Data - Should utilities strive to make available capacity data that is temporal as well as spatial, thereby allowing third parties to know where and when there is excess hosting/load capacity? What are the limitations (data availability, costs, etc.) for being able to produce such data? At what level of granularity should this temporal data be offered (on-peak v. off-peak, seasonal, etc.)?

- Utility representatives noted that temporal data, especially hourly and daily data, is highly variable and has high associated costs. Additionally, utilities expressed customer privacy concerns that may arise from the use of transformer-level data for dynamic hosting capacity tracking.

Exportability/ Usability of Data - How should this data best be made available and exportable (comma-separated value (CSV) file, Shapefile, etc.) so to allow for further analysis and data integration by third parties independent of the utility's website or platform?

- Developers explained their goal of utilizing data from hosting capacity maps for programmatic solutions and expressed a preference for data availability through the form of application programming interfaces (APIs). The second preference among developers for data availability was via CSV file, though utility representatives explained that the data from hosting capacity maps was not currently exportable and there were no immediate plans to make it exportable.

Need for Integration Between Hosting Capacity and Load Capacity Maps - What are the benefits of integrating hosting capacity and load capacity maps and data when compared to the ultimate costs and feasibility of this integration? What additional analysis can be performed from the integration of hosting and load capacity data?

- NREL and MPSC agreed that load hosting capacity and generation capacity maps are different tools, but it would be useful to compare those separate maps. I&M explained that they are currently working on creating a tool where hosting capacity and generation maps are two separate layers that can be toggled on and off in the geographic information system (GIS) software. NREL noted that as an initial step, ensuring accessibility to both tools and clear distinction between the two seemed to be an important request from users.

Additional Information or Data - Are there any additional data or information that is currently not being made available via the existing hosting capacity maps or that has not yet been discussed, but should be made available during the next iteration of these resources?

- Multiple participants expressed, and MPSC agreed, that revising the vocabulary and appearance of “go/no-go” for hosting capacity maps is necessary to send proper signals to customers. This also includes modelling the coloration of these maps after other companies such as Southern California Edison (SCE), and marking areas with limited hosting capacity as “constrained” rather than unavailable.

April 7, 2023 – Hosting Capacity Analysis Tool by Coultech and NREL Interconnection Automation Technology Session

On April 7, 2023, the workgroup held a fourth and final stakeholder session. The purpose of this stakeholder session was learning about the technologies that Coultech and NREL are developing to assist with the expansion of DG, EVs, and the coordination between hosting capacity maps and interconnection. Coultech and NREL provided a presentation prior to opening up the session for discussion and Q&As.

Grid Impacts of Integrating Additional DERs

Projected Growth of DERs and EVs Associated with Infrastructure

The Commission has determined the definition of DER to mean “A source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system.”[7]

In an August 20, 2020 Order, the Commission made the following comments regarding definitions:

> "The Commission agrees with the Staff’s definitions of DER, HCA, NWAs, and locational value assessment. While the Staff’s definition of DER does not include demand-side resources, EWR [energy waste reduction] and DR [demand response] are included in the Staff’s definition of NWAs, and the Staff’s DER definition is in-line with Institute of Electric and Electronic Engineers (IEEE) 1547-2018 and matches the Commission’s proposed interconnection rules." (p. 41)

[7] In the August 20 Order, the Commission agreed with Staff’s recommendation to use this definition as stated in the MPSC Staff Report of April 1, 2020 “*Electric Distribution Planning Stakeholder Process*” (p32).

To date, the predominant types of DERs installed in Michigan have been solar PV and energy storage systems.

Michigan's Distributed Generation Program

The DG and legacy net metering programs (collectively DG program) enable Michigan's utility and alternative electric supplier customers to install on-site renewable energy electric generation projects to meet some or all of their electric energy needs and reduce their electric bills.

DG projects are grouped into three size categories with differing billing, metering, and interconnection requirements. Project size is limited such that the annual generation does not exceed the customer's annual electricity consumption. Customers reduce electricity purchases from the utility by using their generated electricity "behind the meter" and receive a credit for excess generation.

The Level 1 DG program for projects 20 kilowatt (kW) and smaller. The Level 1 DG program is available to any customer meeting the generator size requirements (20 kW and under) and using an Underwriters Laboratory (UL) 1741 certified inverter. Typically, residential customers would fit within this size level.

The Level 2 DG program for projects over 20 kW and as large as 150 kW. The Level 2 DG program is available to any customer meeting the generator size requirements. Typically, these customers would be commercial, small industrial, or institutional customers.

The Level 3 program is Limited to Methane Digesters over 150 kW and as large as 550 kW.

Michigan Public Act (PA) 342 of 2016 allows utilities to cap participation in their DG programs at 1% of average annual peak load, with suballocations of 0.5% of average peak load for Level 1 systems of up to 20 kW, 0.25% of average peak load for Level 2 systems of greater than 20 kW and as large as 150 kW, and 0.25% of average peak load for Level 3 systems of greater than 150 kW and as large as 550 kW. However, two Michigan utilities have voluntarily agreed to allow enrollments above the 1% minimum participation level. Consumers Energy agreed to increase its program cap up to 4% and Upper Peninsula Power Company (UPPCO) increased its program cap to 4.5%. Two Michigan Utilities have reached their DG Level 1 allocation. I&M announced its intention to stop accepting applications on May 12, 2023, in Case No. U-15787,[8] and DTE Electric reached its Level 1 allocation and intends to allow customers to continue to enroll into the DG program through 2023.

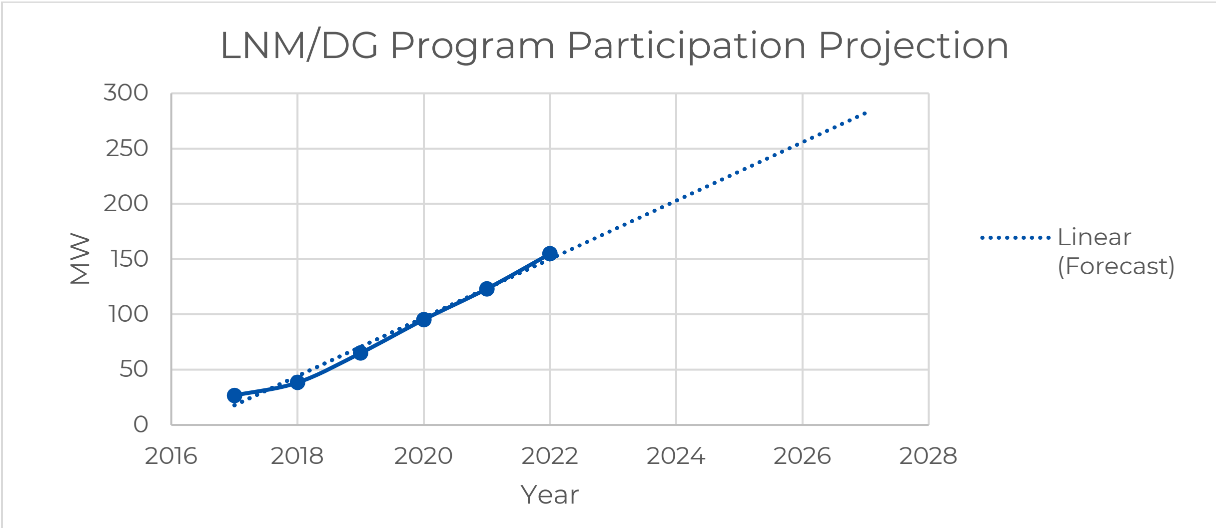
[8] https://mi-psc.force.com/s/case/500t0000008efMtAAI/in-the-matter-on-the-commissions-own-motion-to-promulgate-rules-governing-interconnection-and-net-metering

Utility	Case No.	Beginning DG Program Enrollment	Program Cap (% of Average Peak Load)
Alpena Power Company	U-21045	January 1, 2022	1%
Consumers Energy	U-20697	January 1, 2021	4%*
DTE Electric	U-20836	May 9, 2019	1%
I&M	U-20359	February 1, 2020	1% Level 1 Program closed as of May 15, 2023
NSP	U-21097	January 1, 2023	1%
UMERC	n/a	n/a	n/a
UPPCO	U-20995	May 24, 2019	4.5%*
* Voluntarily increased above the statutory cap by the utility			

The data used in this report is from U.S. Energy Information Administration (EIA) form 861M, which is updated annually. The data contain the cumulative installation count and capacity of generators that are net metered, by technology, state, and sector. Storage systems that are paired with net-metered PV are also captured.

The DG program has seen consistent growth and continued interest in the program as shown in Figure 1. Given the increased interest in clean generation and increasing efficiency of the technology, this trend is likely to continue as customers are becoming more interested in being energy independent. While this projection of the DG program does not include any effects of the new tax credits or any potential policy changes, Staff notes that these changes in the industry may result in an uptick of customer installations. Given the continued interest in the DG program, it will be imperative to develop policies and hosting capacity maps that will allow customers and utilities to better site and plan for the potential DG adoption.

Figure 1: Legacy Net Metering and Distributed Generation Projection



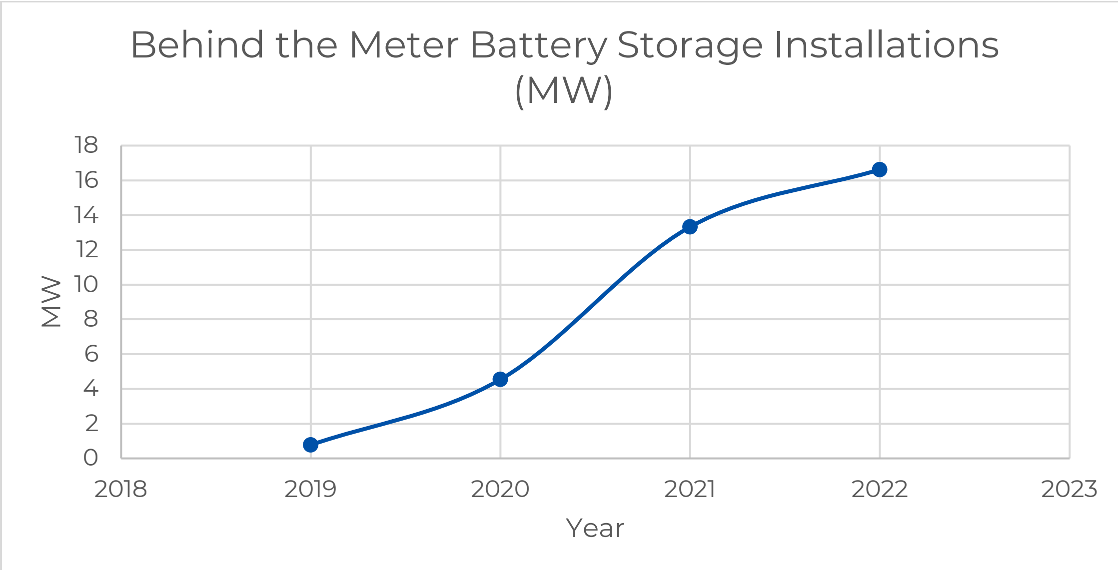
As shown in Table 1 below, there has been considerable growth in both residential and commercial DG installations, while industrial installations have remained steady. Industrial customers generally have many more options for optimizing load, including special rates and larger demand response (DR) programs and benefits. Additionally, because of the size limitation many industrial customers that choose to install solar do so outside of the DG program as the size limitations of the DG program are generally too small.

Table 1: Legacy Net Metering and Distributed Generation Participation Capacity by Customer Class

	Residential Capacity (MW)	Commercial Capacity (MW)	Industrial Capacity (MW)	Total Capacity (MW)
2017	16.156	10.158	0.35	26.664
2018	25.57	11.98	0.745	38.295
2019	46.989	17.157	0.879	65.025
2020	66.894	27.206	1.169	95.269
2021	87.465	34.408	1.288	123.161
2022	113.463	40.153	1.164	154.78

With the implementation of the DG program and customers looking to utilize more solar generation, the interest in behind the meter energy storage has continued to rise. Because the data for energy storage is relatively new, it is not available by sector. Figure 2 below shows the current capacity of battery installations participating in the DG program. Battery storage adds a substantial additional cost to a solar installation. The inflow/outflow structure of the DG program incentivizes the use of battery storage to allow participants to maximize the onsite use of energy given the disparity in inflow/outflow costs. Staff expects that the decreasing costs of storage coupled with the customer benefits that can be captured from utilizing storage in the DG program will lead to the continued growth in the number of energy storage systems.

Figure 2: Behind the Meter Battery Storage Installations



Photovoltaic Systems

DER technologies have continued to evolve as higher penetration of DG have increased throughout the country. In an effort to address issues that have arisen with increased DER deployments and ensure these systems can provide additional benefit to the grid, IEEE 1547-2018 has been established to allow the DERs to provide grid benefits such as Volt/VAR support, frequency, and voltage ride through. These ride-through capabilities are a necessary response during transmission faults that are quickly cleared to prevent massive tripping of DERs, especially inverter-based generation resources.

DER capabilities can help to support voltage in normal grid conditions and can also mitigate distribution voltage disturbances by providing active (Watts) and reactive (VAR) power. While voltage support capabilities are included in DERs certified to IEEE 1547-2018, the functionality tends to work best when the majority of the DERs are participating.[9] This participation proves difficult to achieve, as currently installed DERs typically do not have the capability of providing voltage support and the function reduces the real output of the DERs resulting in (minor) financial disincentives for participating customers.

DERs certified to IEEE 1547-2018 can also provide Volt/Watt support. This function helps to prevent high and low voltages outside of acceptable ranges. This capability faces similar challenges to the Volt/VAR capability but is amplified by the fact that it can result in curtailment of individual DERs for issues that are the result of failed

[9] Incorporating Updated Standards IEEE 1547 (nrel.gov)

distribution system equipment or other factors outside of the DER owner's control.[10] Currently, tariffs for Michigan net metering and DG customers do not specifically provide compensation for voltage regulation. Existing tariffs incentivize maximum real power output of DERs, especially outputs that offset the customers' simultaneous load.

DERs compliant with IEEE 1547-2018 are only now becoming widely available. According to an IREC survey of inverter manufacturers, most manufacturers are projected to have commercially available IEEE 1547-2018 compliant DERs in the March to August 2023 timeframe.[11] The MPSC's Interconnection and Distributed Generation (MIXDG) rules provide for the use of IEEE 1547-2018 inverters when they are commercially available.

Changing Load Patterns - Electric Vehicles

The increasing deployment of EVs and electric vehicle service equipment (EVSE) has opened another avenue of inquiry related to DER interactions with changing load patterns. Electrification of the transportation sector is discussed in the MI Future Mobility Plan published in November 2022 and is viewed as a key element of Michigan's overall energy transition.

Utility Electric Vehicle Pilots - Annual Reports

The Commission has approved EV pilots for Consumers Energy, DTE Electric, and I&M. Since their inception, the pilots have evolved and expanded in reach and scope. Annually, each company files an EV pilot program progress report. The number and data below are from the most recent reports filed in June 2022.

Consumers Energy

The Commission approved Consumers Energy's PowerMIDrive program in Case No. U-20134. It began as a three-year voluntary pilot. Later it was extended up to a total of five years. The Commission authorized a sister pilot, PowerMIFleet, in Case No. U-20697. In Case No. U-21224, the residential pilot graduated to a permanent residential program.

In 2021, Consumers Energy set a goal of having one million EVs in the Company's service territory by 2030. This is in support of the State of Michigan's aim to deploy two million EVs in Michigan by 2030. The company sees PowerMIDrive, with its residential and public infrastructure focus, as critical to meeting these goals. According to 2021 Michigan Secretary of State data, approximately 15,000 EV drivers reside in Consumers Energy's electric service territory currently. More than 1,600 residential customers are enrolled in the PowerMIDrive program.

One of the pilot's goals was to implement best practices for utilizing EVs as an electric grid benefit for all electric customers while monitoring grid infrastructure. Residential load profile data has demonstrated time-of-use (TOU) rate efficacy continues, with

[10] Incorporating Updated Standards IEEE 1547 (nrel.gov)
[11] https://thesolarfoundation.org/blog/regulatory-engagement/new-research-sheds-light-on-when-key-smart-inverters-will-be-available/, accessed March 4, 2023.

approximately 87.9% of residential charging avoiding the on-peak hours of 2PM – 7PM. Furthermore, new techniques that were discovered using AMI monitoring for Bring Your Own Charger (BYOC) program achieved 79.3% super off-peak (11PM-6AM) charging, which is almost twice that of other techniques. Most charging continued to occur overnight in the residential sector, and 81.6% of charging across all categories (residential, public Level 2, and Direct Current Fast Charger (DCFC)) avoided the on-peak hours of 2PM – 7PM.

As of April 30, 2022, PowerMIDrive has received a total of 1,642 residential rebate applications. Of the total applicant pool, 924 applicants have been approved to receive the $500 home charger rebate and over 181 applicants have been approved to receive the $200 FleetCarma incentive option. The BYOC has brought in 537 new participants. The addition of AMI technology has dramatically improved program participation and increased customer engagement.

PowerMIDrive's public charging rebate component is designed to help seed public EV supply equipment investment to improve charging infrastructure accessibility through Consumers Energy's service territory, and to learn about Level 2 installation and usage across different use cases (e.g., general public, workplace, multi-dwelling units (MDU)). The company accomplished the program goal of achieving 200 public Level 2 rebates paid. Of the 200, 168 are general public locations, 20 are at workplaces, and 12 were completed at MDUs.

PowerMIDrive's DCFC rebate component was designed to help create the start of a network of fast charging infrastructure, primarily along four-lane highways throughout the company's electric service territory. Consumers Energy has 37 operational DCFC sites. Utilization of the DCFC sites has increased more than sixfold in over a year, growing from approximately 3,000 sessions to over 18,000 sessions.

To proactively understand how areas of EV clustering could impact existing electric infrastructure, Consumers Energy collaborated with its Low Voltage Distribution Planning and Electric GIS teams to identify and track residential transformers on the electric grid supporting multiple homes with EV supply equipment. The intent of this effort is to proactively monitor load where areas of EV clustering have been identified to understand potential impacts to electric supply infrastructure.

DTE Electric

The Commission approved DTE Electric's first EV pilot, Charging Forward, in Case No. U-20162. Subsequently, DTE Electric received approval for its second EV pilot, Charging Forward eFleets (eFleets), in Case No. U-20935. Charging Forward and eFleets' primary goals include maximizing pilot participation at a minimum cost, testing new technologies, ensuring new load associated with EVs benefit all utility customers, reducing barriers to adoption, minimizing distribution system investments, and helping Michigan achieve its Healthy Climate Plan. Charging Forward and eFleets are making progress toward achieving all goals.

First, Charging Forward is maximizing participation at a minimum cost by deploying a make-ready model, leveraging other sources of available funding, and continually refining pilot design to accommodate additional make-ready rebates with the same budget. Second, DTE Electric is aggressively testing new technologies to efficiently integrate the load with the grid through its battery-powered fast charging, DR, wireless charging, and residential off-peak charging pilots. Finally, Charging Forward is reducing barriers to adoption (through education and outreach) and minimizing distribution system investments through an Engineering Initial Estimate process.

Charging Forward has approved commercial charging rebates for 1,009 Level 2 ports and 78 fast chargers and has a robust waitlist from which it is prioritizing and approving any additional applications. Based on the 1,688 installed chargers, 4.4 Gigawatt-hours (GWh) have been consumed to date; the equivalent of approximately 14.2 million electric miles driven, 3,200 metric tons of carbon emissions eliminated, and 406,000 gallons of gasoline avoided. In Michigan, 2021 EV sales more than tripled from the prior year. In the DTE Electric footprint, the trend held as sales were 11% higher than the previous three years combined. According to the company's data, there are approximately 31,500 EVs in Michigan. Approximately 21,200 (67%) of them were in DTE Electric's service territory. DTE Electric is projecting that EVs will be 10% of vehicles on the road and 22% of new sales in Michigan by 2030.

To date, DTE Electric has about 3,400 customers participating with its Charging Forward program. From their charging data analysis, the company has seen 88% of consumption falling outside the critical peak hours of 3PM-7PM. This is an aggregate percentage across both residential and commercial chargers. They expect this trend to continue as more customers come onboard.

Charging Forward has received applications for more chargers than it has budget to approve and is accepting only waitlist applications moving forward. Because the waitlists are so large and remaining funds are limited, the team has also implemented a prioritization process to score applications and approve them in order of priority based on four factors (site host vertical, location, equity, and circuit capacity).

Charging Forward's rebated make-ready model leverages other funding by design (since the site host funds, owns, and operates the charging stations); but another important goal of Charging Forward is to leverage all available funding sources. Since the launch, 33 approved Charging Forward sites will also receive a combined $1.3 million in funding from the Volkswagen settlement funds that the Michigan Department of Environment, Great Lakes, and Energy (EGLE) is managing (Charge Up Michigan). There is another potential $4.8 million in funding currently going through the Charge Up Michigan evaluation process, and DTE Electric will continue to work closely with state agencies as the process for National Electric Vehicle Investment (NEVI) funding distribution becomes clearer. Charging Forward currently has 21 commercial Level 2 chargers qualified ranging from 7.2- 12 kW and 20 DCFC chargers qualified ranging from 50-350 kW.

Indiana Michigan Power Company

In Case No. U-20359, the Commission approved I&M's IM Plugged In EV pilot program. The pilot program consists of several elements that each play in encouraging plug-in EV adoption in a way that optimizes the overall electric system. The elements include: 1) residential and small commercial EV charging; 2) Multi-unit dwelling (MUD) EV charging; 3) commercial and industrial fleet workplace EV charging; 4) interstate corridor EV charging; and 5) EV education and technical development.

The IM Plugged In pilot program is available to residential and small commercial customers under I&M's tariffs. This program offers a $500 incentive to participating residential and small commercial customers within its service territory with a proof of a qualifying EV purchase on or after the approved date of the program, subject to the IM Plugged In spending cap. As of October 21, 2022, there were a total of 34 approved residential applications. There have been no small commercial program, MUD, or interstate corridor chargers built to date.

Electric Vehicles in Electric Distribution Plans

The MPSC established Case No. U-20147 for utilities to file five-year electricity distribution investment and maintenance plans to support evaluations of distribution system investments to ensure safety, reliability, and resiliency. In the most recent electric distribution plans submitted by Consumers Energy, DTE Electric, and I&M in 2021, the impact of Evs in each territory was briefly described as outlined below.

Consumers Energy

Consumers Energy's 2021 electric distribution plan assumes EV growth starts from a relatively low base. During the five-year time frame covered by the distribution plan, EV growth is not expected to drive major distribution grid investments due to EV charging demand. EV growth, as modeled by the company in its IRP base case, is expected to accelerate in the second half of the 2020s and into the 2030s.

The utility's PowerMIDrive program"has 'ound sufficient distribution capacity to accommodate EV charging loads from deployment of charging stations near cities with easy highway access. No reliability issues have been experienced, with the utility finding that about 90% of EV charging occurs during off-peak hours in customers' homes, which has limited distribution grid impact.

Additional EV penetration may pose grid challenges. Electrification of fleet vehicles could impact the company's overall load profile, creating a need to plan for increased load at single concentrated points rather than over a neighborhood. Should EV penetration increase, some neighborhoods may experience grid issues. As such, this may be an area for greater exploration in future distribution grid plans. Future distribution plans will need to increasingly:

- Account for Evs beyond the 5-year span of the distribution grid plan;
- Identify neighborhood EV clusters in advance to identify areas of potential overload to maintain reliability; and
- Identify measures to control timing of customer EV charging to properly balance the grid.

DTE Electric

DTE Electric anticipates it will be able to support the residential and commercial EV demand and growth in the next five years. However, if EV uptake occurs more quickly than expected and is not uniformly distributed, circuit level load could exceed equipment capacities (Final 2021 DTE Electric Distribution Grid Plan, p. 463). DTE Electric is developing an AMI-based tool to assess loading on service transformers to improve situational awareness of customer facing “grid edge” distribution assets and to better integrate EV grid impacts (DTE Electric DGP, p.481). The company will also determine current and probable distribution design orders or standards violations resulting from EV growth to inform development of upgraded and new standards (DTE Electric DGP, p. 482).

Both DTE Electric residential and commercial customers participating in customer focus groups expected increased electricity use over the next ten years, especially from EV adoption based on focus group discussions (DTE Electric DGP, p. 15). DTE Electric notes accommodating customer adoption of renewable generation, storage, and Evs will require significant grid control improvements, such as switching device controls and DER asset coordination. Integrating DER technologies, like Evs, will require active management and control to maintain reliable grid operations. The company has invested in remotely controlled devices like pole top switches, line breakers, and reclosers in subtransmission and 13.2 kilovolt (kV) systems to enable these capabilities (DTE Electric DGP, p. 50).

Distribution forecasting will require changes to account for demand and load shifting with DERs and Evs. Current DERs and EV impacts in load forecasts are analyzed at the generation system-level and not at a circuit/substation level (DTE Electric DGP, p. 58). Distribution planners must also estimate the charging patterns and locations of Evs on substations and circuits (DTE Electric DGP, p. 479). DTE Electric is working on the development of DER and EV propensity forecasting tools that will use external factors and demographics to predict customer adoption (DTE Electric DGP, p. 428).

Lastly, the electrification scenario examined in the DTE Grid Modernization Study 2021-2035, conducted by ICF, focuses on vehicle and residential heating electrification. It assumes residential and corporate customers adopt Evs and major cities partially electrify their bus fleet, as well as substantial uptake of residential heat pumps. The scenario presents significant electric load growth. The supply resources to meet the projected load under the electrification scenario is not within the study scope and will be covered in the company’s IRP (DTE Grid Modernization Study, p. 15-16).

Indiana Michigan Power

American Electric Power developed an in-house EV forecasting model for all its utility operating companies, including I&M, based on residential customer EV adoption, as well as commercial fleets for light, medium, and heavy-duty vehicles. The EV forecast uses EV registration data at the zip code level to show current EV adoption trends. This data will be integrated into I&M’s DER adoption and growth forecast to help plan for EV expansion.

Currently, Evs and associated charging are not a critical factor in I&M's medium and long-term distribution grid plan. At the end of 2020, there were under 700 plug-in Evs registered in I&M's service territory. Of those, 300 were battery electric vehicles. I&M plans to seek opportunities to increase incentive deployments to increase plug-in electric vehicles (PEV) adoption to charge off peak to drive down overall system cost including direct outreach to drive program enrollment, PEV incentive payments to residential customers charging off peak, and state policy to improve dealership incentives to stock and sell PEVs in service territory.

Electric Vehicles in Integrated Resource Planning

IRP filings required by the 2016 PA 341 are made by utilities to ensure reliable electric service over a 20-year period, with specific requirements for 5-, 10-, and 15-year projections. Utilities must submit these plans at least every five years.

Evs have historically been included in utility IRP filings as a modifier to the Company's load. Consumer's Energy,[12] DTE Electric,[13] and I&M[14] have all included potential EV load increases as part of their most recent IRP filings. These plans demonstrate some visibility into adoption in each utility's service territory through registration by customers. The utilities model these known trends forward using US-centric EV projections released by entities such as the EIA or the EPRI. However, the rapid changes in adoption, infrastructure, and regulatory requirements have so far prevented utilities from using a single strategy to model EV load, as IRP plans are often filed years apart. Because of this, EV forecasts within IRP modeling may not have accurately reflected forecasted load.

On October 27, 2022, the Commission approved revised Michigan IRP Parameters in Case No. U-21219 and revised Filing Requirements for IRPs in Case No. U-18461.[15] These new requirements detail specific EV modeling requirements within planning scenarios and also require detailed EV, DER, and electrification assumptions used in utility forecasting. The new requirements will hopefully bring long-term planning objectives in line with distribution planning for Evs and provide a basis on which to plan for future system modifications.

Power System Impacts

Interactions between DER systems and the grid typically occur at the local distribution level. In areas of high DER deployment, interactions from an "orchestrated response" of aggregated DERs may become apparent at the subtransmission or transmission level. Current technical standards such as IEEE Std 1547-2018 and IEEE Std 2800 specify required performance capabilities during normal and abnormal grid conditions at the distribution level (for all types of DERs) and the subtransmission/transmission level (for inverter-based resources), respectively. Once

[12] Case No. U-21090
[13] Case No. U-21193
[14] Case No. U-21189
[15] MPSC Approves Updates to Michigan's Integrated Resource Planning Parameters and Filing Requirements, October 27, 2022.

adopted by a jurisdiction, these voluntary standards can supplement the existing body of performance requirements with which all interconnections must comply.

Distribution Level Considerations

The *High-Penetration PV Integration Handbook for Distribution Engineers,*[16] a 2016 publication that was sponsored by the DOE contains explanations and mitigation strategies for many common concerns with grid integration of DERs. The publication is focused on PV systems, but also could apply to other inverter-based resources such as energy storage. The report describes concerns with respect to overload and voltage-related impacts, reverse power flow impacts, system protection impacts, and circuit configuration impacts. The report also presents a model-based study guide for assessing impacts to be used by utility engineers. Of special note is an appendix that gives criteria for evaluating PV generation impacts.

Transmission Level Considerations

DERs directly impact distribution grids and are often not accurately included in transmission level planning/operational activities, especially at low adoption levels. However, the rapid growth in DERs has created interests in transmission planning. A 2018 article published by NREL studied impacts of distributed solar PVs using a synthetic integrated T&D transmission and distribution (T&D) model.[17] The study highlighted how the core characteristics of solar PV, including inherent variability and unpredictability, can impact transmission network operations. A detailed model of T&D networks, including end-use equipment of geographically dispersed consumer loads and distributed PV (DPV) connected to the secondary distribution networks, showcased how a lack of generation forecasting can increase the Area Control Error (ACE) at the transmission level for high PV penetration levels. ACE is the difference between scheduled and actual electrical generation.

Similarly, wide scale EV adoption will necessitate assessment of and possible modification to the U.S. electric power generation and distribution systems. In a 2019 report, the Grid Integration Tech Team (GITT) and Integrated Systems Analysis Tech Team (ISATT) of the U.S. Driving Research and Innovation for Vehicle Efficiency and Energy Sustainability (DRIVE) Partnership examined a range of EV market penetration scenarios (low, medium, and high) and associated changes to the U.S. electric power system in terms of energy generation and generation capacity.[18] This report highlighted that even though high adoption of light-duty vehicles poses potential challenges for distribution networks, transmission constraints must also be assessed in a parallel manner to account for the expensive and time-consuming nature of transmission expansions.

System Benefits/ Costs to Integrate Additional DERs and Evs

Strategic planning of location, taking into account distribution system characteristics, and selection of DER type based on their operating attributes is key to maximizing

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[16] https://www.nrel.gov/docs/fy16osti/63114.pdf
[17] https://www.nrel.gov/docs/fy17osti/68995.pdf
[18]https://www.energy.gov/eere/vehicles/articles/summary-report-evs-scale-and-us-electric-power-system-2019

the benefits to the distribution system and reducing integration costs. Hosting capacity maps can assist DER developers with improving project siting by providing available capacity at locations throughout a utility's distribution system. Consumers Energy and DTE Electric have their first iteration of hosting capacity maps available.

The MPSC recently revised its MIXDG rules. Incorporating IEEE 1547-2018, aligning the MIXDG rules more closely with the Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (FERC SGIP), and addressing energy storage were some of the significant updates made. Alignment with the FERC SGIP provides benefits to both utilities and DER developers through a new pre-application report process.[19] DER developers may fill out a pre-application report request form to receive detailed information about the utility's distribution system at the location of a proposed DER project. This step is expected to reduce speculative interconnection applications and provide interconnection information to DER developers without the need to file a complete interconnection application.

DERs, such as solar PV, reduce grid congestion when customers self-consume the power they generate and export excess solar PV generation to the distribution system. DERs may also reduce fuel costs associated with running other generators that would have been incurred without the exported solar generation. This results in less power generated at a large generation plant located far away from the customer, also reducing costs associated with T&D line losses. In the case of a residential customer, the power would have been transmitted through the high voltage transmission system, then lower voltage segments of the distribution system, and finally reach the customer at residential service voltages. Any solar PV generation not consumed by the customer is exported to the distribution system and likely to be delivered to another customer located in close proximity, potentially freeing up space on other parts of the distribution system. Reducing the amount of electricity generated by a large generation plant results in less fuel usage and lower T&D line losses. For electricity which must travel from a large generation plant through the T&D system to reach a residential customer, line losses can be as high as 10% of all electricity generated.[20]

In some cases, DERs, including solar, Evs, and batteries, can provide the opportunity for customers to have electricity in the event of power outages due to storms, extreme weather, or equipment failures. DERs with islanding capability allow for power to be distributed even though the resource is disconnected or no longer receiving power from the main grid. For example, a customer with a solar PV project and a battery, proper wiring, appropriate project sizing in comparison to the customer's household

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[19] https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.901a%20to%20R%20460.1026.pdf – R 460. 930 (Rule 30) and R 460.932 (Rule 32)

[20] See Consumers Energy's Retail Open Access Secondary Rate, Sheet E-21.01, Real Power Losses https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/consumers/Consumers_14_current.pdf?rev=93630c7a03c542008c80fc45276e5b94&hash=D7E34CCE6F3A0EC8B277321D8855B6F9 and DTE Electric's Retail Access Service Rider – Rider EC2, Sheet E-18.01, Real Power Losses https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/dte/dtee1cur.pdf?rev=23c310086e58436ca669815350d3afdb&hash=698A1ACE4376154B6E50744DFA09C604

load, and a throw-over switch, will be able to serve their own electricity needs during a grid outage. This capability can be beneficial to customers by separating from the distribution grid during an outage and maintaining uninterrupted power. Customers having that source of back-up power benefit directly, but eventually it may also benefit the system more broadly by allowing the utility to focus its restoration efforts on customers with no backup power.

In addition, Evs have the ability to provide system benefits including but not limited to efficiency, reliability, and resiliency. New EV load, when incentivized to primarily occur during off-peak hours, improves the efficiency of the grid by utilizing existing grid assets at times when they are underutilized, such as throughout the night when electricity usage is less than during the day. Improving the utilization of grid assets also leads to lower customer rates because the costs of those grid assets are spread over increased electricity sales. Managed charging can be accomplished through special tariffs for customers allowing the utility to manage the customer's EV charging which balances grid conditions with customer needs. V2X can allow Evs to supply back-up power to a customer or back to the grid to meet critical loads for resilience. Vehicle to grid (V2G) technology can provide grid ancillary services supporting reliability or exporting to the grid during periods of high demand. V2G can supply power to the grid similarly to a DER. DERs may also be used to defer distribution system upgrades and can be studied as part of a non-wires alternative (NWA) solution. The MPSC's August 20, 2020 Order in Case No. U-20147 defines NWAs as "a[n] electricity grid investment or project that uses distribution solutions such as DERs, energy waste reduction (EWR), DR, and grid software and controls, to defer or replace the need for distribution system upgrades."

The highest value opportunities for NWAs are where large capital Investments are needed on the distribution system in areas with low load growth. [21] Low load growth means fewer kilowatt hours (kWh) over which to spread the upgrade cost. Applicable upgrades could include substations, poles, and wires. If there is only a small amount of load growth that leads to a required circuit, substation, or wire upgrade, this will result in upgrade costs spread over few additional kWh. If instead of this upgrade an NWA was used to offset the low load growth, this additional cost could be avoided.

As part of the MI Power Grid[22] initiative, the distribution planning workgroup process culminated in a MPSC Staff report *Electric Distribution Planning Stakeholder Process*, issued April 1, 2020. [23] NWAs were considered by stakeholders. The report recommended that utility distribution system plans include "a detailed description of the portion of their capital plans that are avoidable or deferable by NWAs." Utility

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[21] Natalie Mims Frick, Snuller Price, Lisa Schwartz, Nichole Hanus, and Ben Shapiro, et al. 2021. Locational Value of Distributed Energy Resources, Berkeley, CA: Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf

[22] On October 17, 2019, the Michigan Public Service Commission launched MI Power Grid in collaboration with Governor Whitmer. MI Power Grid is a customer-focused, multi-year stakeholder initiative intended to ensure safe, reliable, affordable, and accessible energy resources for the state's clean energy future. The initiative is designed to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses.

[23] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/elec-dist-planning/Distribution_Planning_Report_Final.pdf?rev=4462c73a8bfb4eb9a0efef68e5d92bed&hash=19398456481310E9785156995989D7ED

distribution plans filed to date describe current pilots as including EWR and DR. Incorporation of energy storage, distributed generation, and Evs will occur in future pilot projects.

As the need for more dynamic distribution system data increases, utilities are deploying DSCADA at more substations and installing more line sensors throughout their distribution systems. DSCADA and line sensors provide the utility with load data. Having access to dynamic load data is helpful during the pre-application report process or when the utility is analyzing an interconnection application because the utility will know the substation's and line section's minimum load. This allows the utility to check for reverse power flow, or backfeed at the substation. Backfeed occurs when power flows in the reverse direction and may present unanticipated hazards to electrical grid equipment and service personnel. Detailed utility distribution data provides protection to equipment and operations. These distribution system enhancements add additional cost, and the utility considers strategic locations for future deployment as part of distribution planning.

As DER penetration increases, the need for distribution system upgrades will grow. At some point in the future, regulators will grapple with the situation where a single residential solar project may trigger costly upgrades on some part of the distribution system. There could be additional costs to interconnection customers if an affected system study is needed due to another distribution system potentially being impacted by the project. Midcontinent Independent System Operator (MISO) recently addressed this matter and developed an affected system study process with associated cost information. MISO released a November 4, 2022 draft Distributed Energy Resources Affected System Studies Business Practices white paper[24] which proposes an affected system study where DER net injection exceeds 5 megawatts (MWs) with an initial deposit amount of $60,000 just to complete the study. Under Michigan statute, interconnection customers also pay the cost of any upgrades. One potential mitigation option is for the interconnecting customer to install energy storage on-site and eliminate any outflow to the distribution system. This is a solution relied upon by Hawaiian utilities when solar penetration reached levels where expensive system upgrades were required.

Emerging Practices

Cost-Share Tariff

A 2021 report by Synapse Energy Economics, Inc.,[25]prepared for the Minnesota Public Utility Commission, noted datasets across several utilities, as shown in table 3 below, to assist in the development of Xcel's hosting capacity analysis and distribution grid data security.

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[24]https://cdn.misoenergy.org/20221114%20IPWG%20Item%2004a%20DRAFT%20MISO%20DER%20Affected%20Systems%20Study%20Business%20Practices%20Whitepaper%20Rev%201626905.pdf

[25] Hosting Capacity Analysis and Distribution Grid Data Security, https://www.synapse-energy.com/sites/default/files/Hosting_Capacity_Analysis_and_Distribution_Grid_Data_Security_21-016.pdf

Table 2: Hosting Capacity Map Comparision Across Advanced Utilities

Hosting Capacity Map System Data	States with Advanced Practices						
	California	D.C., DE, MD, NJ	Hawaii	Mass.	Minnesota	Nevada	New York
Solar PV HCA Availability	✓	✓	✓	✓	✓	✓	✓
Load HCA Availability	✓					✓	*
HCA Refresh Date	✓		✓	✓	✓	✓	✓
Substation Name	✓			✓	✓	✓	
Substation Location	✓				✓	✓	✓
Substation Bank Capacity	✓			✓			✓
Substation Peak Load	✓					✓	✓
Substation Load Profile	✓					✓	
Substation DG Connected/In Queue	✓				✓		✓
Substation Total DG	✓						✓
Feeder ID	✓	✓		✓		✓	✓
Circuit map layout (Feeder location)	✓	✓		✓		✓	✓
Heat map layout (No Feeder location)			✓		✓		
Feeder Capacity	✓			✓			
Feeder Peak Load	✓			✓		✓	
Feeder Load Profile	✓					✓	
Feeder DG Connected/In Queue	✓			✓	✓	✓	✓
Feeder Total DG							✓
DG Connected/In Queue Refresh Date	N/A			N/A	✓	N/A	✓
Nominal Voltage	✓			✓	✓	✓	✓
HCA Criteria Violations	✓				✓	✓	✓
Distance from feeder to substation						✓	
Impedance Data						✓	
Customer Type Breakdown	✓						

✓ Indicates the data is present in the current public facing hosting capacity map.

** Indicates the data will be included in a future version of the hosting capacity map.*

"N/A" for the DG Connected/In Queue Refresh Date field indicates the same refresh rate as the rest of HCA data

The Minnesota Public Utilities Commission recently approved a tariff for Xcel Energy which includes a cost-sharing approach to interconnection costs. The newly approved Cost Share Program, for which customers will be eligible starting January 3, 2023, will require customers with projects up to 40 kW to pay a single fee of $200, which will cover all upgrade costs up to $15,000 per project.

Tariff Section 6.2 shall be modified as follows:

> A mandatory cost sharing fee of $200 is applicable to every application subject to these Cost Sharing provisions. Payment of this fee is a prerequisite to the application being Deemed Complete under MN DIP 1.5.2. This fee is non-refundable and in addition to the applicable MN DIP processing fee associated with each application. The fee is subject to

> change annually on January 1 based on a filing with the Public Utilities Commission made on or before September 30.[26]

Minimum Level of Service

An emerging concept is "minimum level of service" for a residential electricity customer. Consumers Energy's residential rate schedules were recently modified to include language providing for electric vehicle charging up to 9.6 kW.

> Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.
>
> Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.[27]

Whether a minimum level of service to residential customers should include the provision of Level 2 EV charging and potential integration of a DER such as solar PV needs further exploration. A program similar to the Xcel Minnesota Cost Share Program could be implemented to build up a fund to pay for interconnection costs and distribution upgrades. The scope and magnitude of these costs are unknown, and it is possible that a situation could arise where it is simply not possible to interconnect additional EVs and DERs without extensive distribution upgrades. Distribution grid modeling incorporating EV and DER forecasting may indicate that expected adoption of EVs and DERs can be accommodated with reasonable distribution upgrades and on-site mitigation measures like adding energy storage. Some distribution utilities are actively upgrading their distribution grids to be ready for EVs and increased electrification which will provide for a minimum level of service.

For some customers, taking advantage of even a minimum level of service may require customers to upgrades to the customer's electrical service panel to accommodate increased EV load and other DERs. The appropriate service panel upgrade size would vary between customers. Certain customer service panel sizes are outdated due to high-usage electric appliances becoming more prevalent over time. As customer loads increased throughout the years as new electric appliances became the norm, new-build service panel sizes have evolved to larger sizes. Service panel upgrades are the responsibility of the customer and can be a significant cost.

[26] Minnesota Public Utilities Commission's December 19, 2022 Order in Docket Number 18-714
[27] Consumers Energy's Residential Summer On-Peak Basic Rate, https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/consumers/Consumers_14_current_D.pdf?rev=8a0c0ce82f144d36b343989030598ae3&hash=7B7F32A5B734FF038C087681461A8F02 Fifth Revised Sheet No. D-14.00

A program to give customers the option to pay for service panel upgrade costs over time on their utility bill, also referred to as on-bill financing, could be a helpful option. In addition, there are federal funding opportunities available to be leveraged to assist with costly upgrades:

- 26 USC 25C: Energy efficient home improvement credit[28]
- High Efficiency Electric Home Rebate Act (HEERA)[29]
- Smart Grid Investment Matching Grant Programs through the Grid Resilience and Innovation Partnership[30]

There is also concern that smart inverters could be vulnerable, or a vector targeted through a cyberattack, as such inverters will possess the ability to communicate with the utility and access the internet. These communication features enable the utility to more effectively utilize the benefits of smart inverters to manage the distribution system, but the increased interconnectedness also creates more vulnerabilities. Several initiatives have begun to develop standards and reduce the concern around increased communication associated with DERs. The DOE has a cybersecurity workgroup defining cybersecurity best practices and supporting their inclusion into national standards. Additionally, National Association of State Energy Officials (NASEO) and National Association of Regulatory Utility Commissioners (NARUC) have put together an advisory team called the Cybersecurity Advisory Team for State Solar (CATSS). This project seeks to develop actionable solar cybersecurity strategies and roadmaps, as well as create stronger public-private partnerships and intra- and interstate cooperation for greater consumer and utility solar cybersecurity.

[28] 26 USC 25C: Energy efficient home improvement credit (house.gov)
[29] Home Energy Rebate Programs | Department of Energy
[30] Smart Grid Investment Grant Program: Overview: Recovery Act | SmartGrid.gov

Changes to System Design and Operation to Accommodate Additional DERs and EVs

Equity Issues in Distribution System Planning

The MPSC has increasingly focused on the importance of considering and addressing issues related to diversity, equity, and inclusion, not only within its own organization, but also within the utility services it regulates. The Commission expects energy equity information and data to become more accessible, transparent, and formalized as utilities, stakeholders, customers, and the Commission Staff increase their focus and devote further resources to this area. In Case No. U-20836, the Commission tasked the Energy Affordability and Accessibility Collaborative (EAAC) to define equity and related terms for utility regulation purposes within Michigan. The collaborative will also explore the data and metrics required to better assess equity issues. In addition, the Commission requested DTE Electric "include future analyses, like overlay maps, charts, graphs, and other displays, that provide a visual or data informed understanding of more holistic impacts of electric infrastructure investments on customer communities" in future rate cases.

A five-year forward distribution planning process is still relatively new to Michigan, with only two sets of distribution plans submitted by three of Michigan's IOUs. As energy equity and related terms have formalized definitions, metrics, and expected data, as defined by the EAAC, and as Michigan utilities begin conducting more holistic analyses of the impacts of electric infrastructure investments on customers and communities, future distribution plans will likely provide improved understanding of the near- and long-term equity impacts of proposed distribution system investments. In addition, past and current investment trends and their equity impacts will be increasingly clear, allowing utilities and the Commission to better address discrepancies and plan for a more equitable energy future for Michigan.

Utility Interconnection Policies and Procedures

The MPSC recently adopted updated interconnection and distributed generation rules. Utilities must comply with these rules and if they cannot, they must seek a waiver for a specific rule or rules. Notable additions and updates to the new rules include, but are not limited to:

- **Informal and formal mediation processes** - These new processes should help resolve disputes between developers or applicants and the electric utility.
- **Updated fees** - These are fees and initial fee caps for various steps in the interconnection process, which may be adjusted at a later date.
- **Pre-application reports** - These reports contain detailed information about the utility's distribution system at the location of a proposed DER project, which should reduce speculative interconnection applications and provide interconnection information to DER developers without the need to file a complete interconnection application.

- **Non-export track** - A study track that evaluates interconnection applications for DERs that will not inject electric energy into an electric utility's distribution system.
- **Fast track review** - An initial review and supplemental review. These reviews use screens to determine whether a DER can interconnect to a particular point on a distribution system. This type of analysis is generally quicker than going through a full interconnection study, which for these rules is called the study track.
- **Study track** - A system impact study and facilities study, essentially a full interconnection study. A system impact study must identify and describe the electric system impacts that would result if the proposed DER was interconnected without electric system modifications. A facilities study must specify and estimate the cost of the required equipment, engineering, procurement, and construction work, including overheads, needed to interconnect the DER, and an estimated timeline for the completion of construction.
- **Modifications to an interconnection application or DER -** These rules govern the process for modifying an "in flight" interconnection application or an installed DER.

The updated interconnection rules, like the previous iteration of the rules, allows the utility to file interconnection procedures. Interconnection procedures are the requirements that govern project interconnection adopted by each electric utility and approved by the Commission. Electric utilities need to file applications for approval of interconnection procedures and forms within 120 calendar days of the effective date of the rules.

The Commission shall issue its order approving, rejecting, or modifying an electric utility's proposed interconnection procedures and forms within 360 calendar days of the electric utility filing an application for approval of interconnection procedures and forms. If the Commission finds the procedures and forms proposed by the electric utility to be inadequate or unacceptable, the Commission may either adopt procedures and forms proposed by another party in the proceeding or modify and accept the procedures and forms proposed by the electric utility.

Two or more electric utilities may file a joint application proposing interconnection procedures for use by the joint applicants. The proposed interconnection procedures must ensure compliance with these rules.

Notable items the proposed interconnection procedures must address include, but are not limited to:

- All necessary applications, forms, and relevant template agreements;
- A schedule of all applicable fixed fees and fee caps;
- Voltage ranges for high voltage distribution and low voltage distribution;
- Required initial and supplemental review screens;

- The process for conducting system impact studies and facilities studies on DERs when there is an affected system issue;
- Testing and certification requirements of DER telecommunications, cybersecurity, data exchange, and remote-control operation;
- Parallel operation requirements;
- A method to estimate the expected annual kWh output of the generator or generators;
- For electric utilities that are member-regulated electric cooperatives, a procedure for fairly processing applications in instances in which the number of applications exceed the capacity of the electric cooperative to timely meet the deadlines in these rules; and
- The procedure for performing a material modification review to determine if a modification is material.

Incentives & Time of Use Rates

DG Tariffs

As discussed in Section 4 of the report, the DG program tariff caps may be voluntarily increased when a utility's program becomes full or in I&M's case, the utility may choose to close the program to new participants. With the legislative cap on DG programs and a desire from customers to participate, it is necessary to further investigate additional tariffs to accommodate those customers. Proposals for addressing the issue have been provided in rate cases. For example, in DTE Electric's rate case, Case No. U-20836,[31] a successor tariff was recommended by intervenors to go into effect once the cap on the DG program is reached. A successor tariff would not be an extension of the DG program that was implemented pursuant to PA 342, rather, it would be a tariff for a post-cap DG program and could be developed and vetted through a stakeholder process to ensure all parties have the opportunity to provide input. Other states have alternative approaches for designing credit structures for DG customers. Massachusetts allows for projects of different sizes to be eligible for different portions of the retail rate. Full kWh retail rate was available to small DG installations and larger installations received supply kWh rate and transmission kWh rate. New Hampshire implemented the residential credit as the sum of the supply kWh rate, the transmission kWh rate, and 25% of the distribution kWh rate. In Texas, a municipal utility approached gross solar generation under a buy-all/credit-all structure which determined a value of solar (VOS) flat kWh rate and included wholesale energy market value, generation capacity savings, transmission, and distribution capacity savings, reduction in line loses, fuel price hedge value, and environmental benefits. [32]

[31] https://mi-psc.force.com/s/case/500t000000WH1HKAA1/in-the-matter-of-the-application-of-dte-electric-company-for-authority-to-increase-its-rates-amend-its-rate-schedules-and-rules-governing-the-distribution-and-supply-of-electric-energy-and-for-miscellaneous-accounting-authority
[32] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000000x83dAAA

Shortly after Texas initiated their VOS structure, Minnesota legislation was passed to allow IOUs to apply for a VOS[33] tariff as an alternative to net metering, which quantifies the value of DPV. The program takes into account energy and its delivery, generation capacity, transmission capacity, T&D line losses, and environmental issues for values of DPV. Key aspects of the methodologies used by Minnesota's utilities are:

- A standard PV rating convention;
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin;
- Requirements for calculating the electricity losses of the T&D systems;
- Methods for performing technical calculations for avoided energy, effective generation capacity, and effective distribution capacity;
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.); and
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review.

New York implemented value of distributed energy resources (VDER)[34], which credits larger DG and certain kinds of energy storage installation. The value-based structure is applied to hourly exports on the grid and the credit elements are time varying. The following structure is applied to hourly exports to the grid:

- Hourly wholesale energy market value;
- Generation capacity value with alternative structures depending on capability of technology;
- A general delivery avoided cost value and a location-specific adder for projects in areas with identified constraints;
- Environmental value for eligible technologies; and
- A community credit for community DG for projects that have a particular policy importance.

Due to differences between Michigan's DG program and implemented elsewhere, there is an opportunity to consider DG programs employed in other states.

EV Tariffs

The Commission has directed DTE Electric and Consumers Energy to transition their residential EV pilots into permanent programs. In Case No. U-20836, DTE Electric was directed to submit a full-scale, well developed, permanent Charging Forward proposal in its next rate case. In a settlement agreement filed in Case No. U-21224, the parties agreed to transition the residential segment of the PowerMIDrive pilot into a

[33] https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwj8gMWujpj-AhVHHjQIHQ3RDWYQFnoECA0QAQ&url=https%3A%2F%2Fmn.gov%2Fcommerce-stat%2Fpdfs%2Fvos-methodology.pdf&usg=AOvVaw3FaYAbHXw885c7fnrJINsz
[34] See New York State Energy Research and Development Authority. (n.d.). The Value Stack. https://www.nyserda.ny.gov/allprograms/programs/ny-sun/contractors/value-of-distributed-energy-resource.

permanent program. In the next rate case proceedings for each DTE Electric and Consumers Energy, tariffs for residential EV programs may need to be updated to reflect the transition from pilots.

DCFC EV chargers which charge EVs place significant demands on the distribution grid while charging takes place. High demand charges, if applied to DCFC chargers, could negatively impact EV adoption. The Commission has approved demand charge holidays for Consumers Energy, DTE Electric, UPPCO, and Alpena Power Company, which allows DCFC chargers to be on rates without demand charges for five years. When demand charge holidays expire, customers could experience significantly higher rates to charge at DCFC stations.

To minimize the potential for suddenly high rates, when passed on to EV charging customers that could discourage EV adoption, a successor tariff could be developed with increases gradually phased in. SCE established a temporary EV rate to eliminate demand charges through 2024. With demand charges phasing back in, charging stations that have low utilization may charge very high rates to the few customers utilizing those particular charging stations. SCE proposed to extend the demand charge holiday for two years while a more sustainable, long-term successor tariff is investigated.[35] Pacific Gas and Electric Company (PG&E) took a different approach for commercial EV customers. Instead of conventional demand charges, PG&E received approval for a subscription charge with a time varying energy charge where a customer subscribes to a specific level of their estimated monthly peak kW demand.[36] Alabama Power offers an Economic Development Incentive rider, which discounts the customers base rate 110% of their estimated marginal cost of serving incremental load with a maximum discount on their base rate, which declines over a predictable multi-year period.[37]

Consumers Energy and DTE Electric have adopted special economic development rates geared towards commercial and industrial customers. Case No. U-21160[38] approved Consumers Energy's Large Economic Development Rate (Rate LED) to offer a competitive rate based on the marginal cost of serving new load. It allows a competitive rate on incremental electric load with a minimum of 35 MW for a minimum contract term of 15 years. Case No. U-21163[39] approved DTE Electric's D13 XL High Load Factor Rate to provide customers with competitively priced energy consistent with cost of service-based rates. It is limited to new and existing customers adding incremental electric load of a minimum of 50 MW and a minimum contract term of 15 years. While new DCFC load is expected to be lower than the thresholds in recently approved economic development rates and the load may differ substantially than the load specified in the economic development tariffs in Michigan, exploring the feasibility of similar rates for DCFC chargers following the expiration of demand charge holidays could be considered.

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[35] 215783846.PDF (ca.gov)
[36] 318552527.PDF (ca.gov)
[37] EDI.pdf (alabamapower.com)
[38] Case: U-21160 (force.com)
[39] Case: U-21163 (force.com)

It is important to structure rates for DCFC chargers to promote the efficient use of the grid so as to minimize the grid investments necessary to accommodate the new load. TOU rates better reflect system costs by providing meaningful price signals to encourage off-peak charging and are predictable and easily communicated. TOU rates could be investigated for DCFC charging following the expiration of demand charge holidays to offset additional grid investment, provide price signals to customers to efficiently utilize the grid, and continue supporting expanded adoption of EVs in Michigan.

Hosting Capacity for Increased Access to Distribution System Data

As noted above in the August 20, 2020, order in MPSC Case No. U-20147, the Commission recognized the importance of increased visibility into the distribution system capabilities and limitations in guiding DER development efficiently and to inform planning decisions. Hosting capacity maps are considered an important step in this evolution.

In the September 8, 2022, order in MPSC Case No. U-20147, the Commission noted that "Michigan utility distribution grids are not well positioned as necessary for growth of EVs and other DERs. Greater information on the loading of distribution feeders and the available hosting capacity on those lines can help identify additional opportunities to improve distribution performance." (p. 67). This echoes the intent that future iterations of HCA maps should include "integrating DER" as an additional use case (discussed in MPSC Staff Report of April 1, 2020 p.14). These three use cases for HCA were discussed in a 2021 report prepared for the Minnesota PUC by Synapse Energy Economics, Inc. (Synapse)[40].

Table 3 shows a summary of use cases discussed.

Table 3: Hosting Capacity Use Cases, Objectives, and Capabilities

Use Case	Objective	Capability
Development Guide	Support market-driven DER deployment	Identify areas with potentially lower interconnection costs
Technical Screens	Improve interconnection screening processes	Augment or replace rules of thumb; determine need for more detailed study
Distribution Planning Tool	Enable greater DER integration	Identify potential future constraints and support proactive upgrades

[40] https://www.synapse-energy.com/sites/default/files/Hosting_Capacity_Analysis_and_Distribution_Grid_Data_Security_21-016.pdf

Michigan Utilities' Existing Hosting Capacity Analysis and Tools

The initial version of the HCA pilots are intended to address the use case for "streamlined interconnection of DER and improved utility distribution mapping capabilities" (discussed in [MPSC Staff Report of April 1, 2020] p.7). The Commission directed Consumers Energy and DTE Electric to develop HCA maps that includes an initial base-level zonal go/no go map to be refined with updated analyses over a two-year period. The Commission directed I&M to monitor the HCA activities of Consumers Energy and DTE Electric and leverage its planning expertise to contribute to the effort (p. 41-42).

In response, Consumers Energy developed a hosting capacity map geared towards locational insight for distribution generation, specifically PV, integration. The high-level analysis, available online, makes three assumptions:[41]

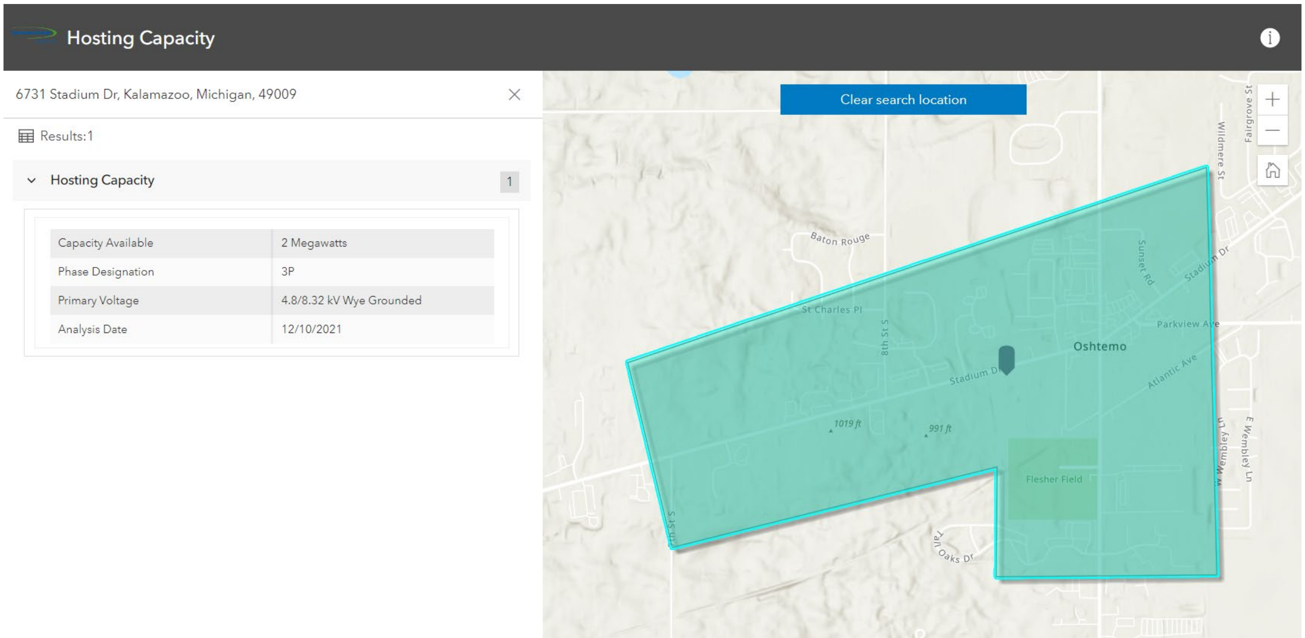
- Generation resource is $\leq$ 2 MW;
- Connection will be three-phase grounded wye; and
- Point of interconnect will be within 0.25 miles of existing infrastructure.

Consumers Energy's Customer Energy Management team assists developers or customers who are looking to install DCFC or Level 2 charging infrastructure. A project coordinator will handle the request and discuss the projects scoping, project details, ensuring legal permissions were received to install and maintain the service, schedule installation, and enter the construction period of the project. Consumers Energy will work with the customer in optimizing the service given the state and national goals for electrification. If the project area is rural and underserved, Consumers Energy recognizes that additional technology solutions should be explored as EV adoption continues.

Phase two of Consumers Energy's HCA intends to leverage EPRI's DRIVE Tool, study go/no go zones, improve criteria, and have a higher resolution for all circuits and zones. The added publicly available data and granularity of data around the type of assets for interconnection will assist in improving the success rate of developer applications for interconnection from Consumers Energy perspective. The complexity to expand Consumers Energy's HCA map will require ongoing maintenance and support from their staff. Consumers Energy's current users select a mapped area indicated by a shaded polygon to learn the capacity available, primary voltage, and date of the analysis.

[41] Consumers Energy. (nd). Hosting Capacity. Retrieved on February 9, 2023, from: https://cms.maps.arcgis.com/apps/instant/lookup/index.html?appid=b90ff63b338043b7bcae43dd685a419d.

Figure 3: Consumer's Energy Hosting Capacity Map[42] (Phase 1, Zonal)



DTE Electric also developed an online hosting capacity map that identifies areas of its service territory where primary voltage interconnection may be more available, and where acceptable customer power quality and reliability can be maintained without infrastructure upgrades. This map focuses on solar PV integration but is not limited to it. It assumes only:[43]

- Interconnections < 2 MW;
- Overhead sections displayed;
- Certain sections displayed;
- Three-phase sections displayed and connected in delta or wye grounded; and
- Distribution voltages are shown (4.8 kV delta, 8.3 kV wye grounded, and 13.2 kV wye grounded).

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42 https://cms.maps.arcgis.com/apps/instant/lookup/index.html?appid=b90ff63b338043b7bcae43dd685a419d&find=6731%2520Stadium%2520Dr%252C%2520Kalamazoo%252C%2520Michigan%252C%252049009

43 DTE. (nd). DTE Hosting Capacity. Retrieved on February 9, 2023, from: https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=64e9f4e0f82c42e7b7ed847273ec2764.

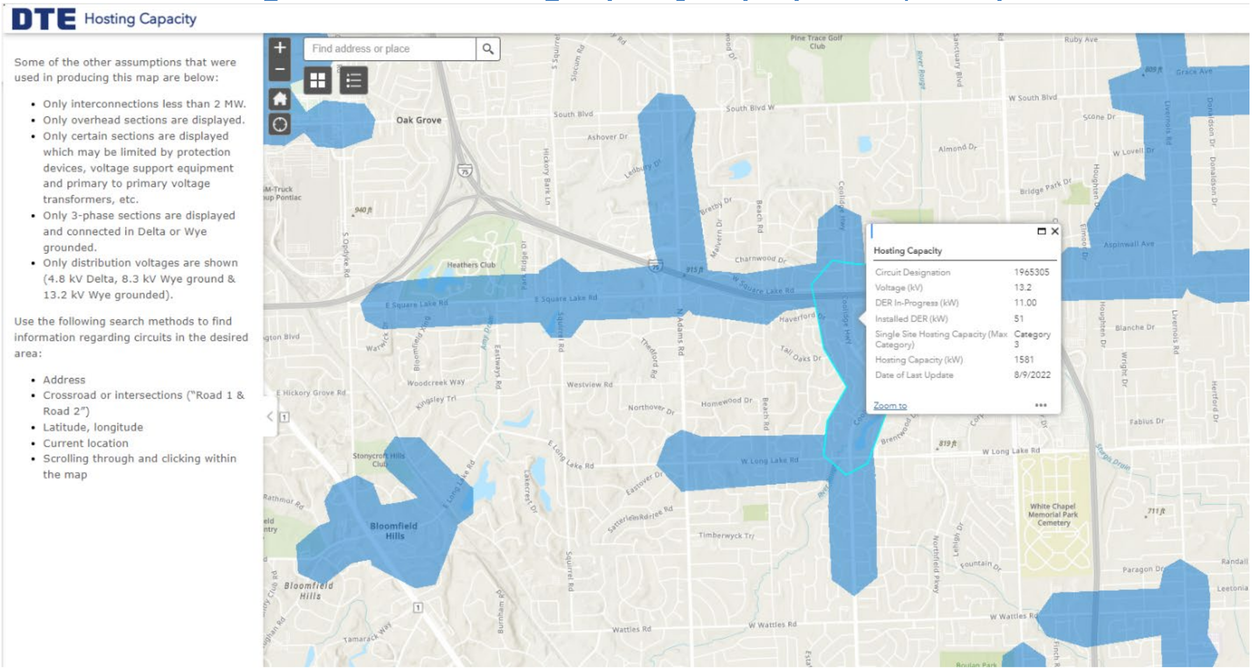
DTE Electric provides public data to inform customers and developers or the potential requirements for a specific site or size availability and it reduces the requests that are received during interconnection or service planning process. The information provided assists developers in completing projects and improving experiences. For mapped areas, DTE Electric hosting capacity map users will see the following information:

- Circuit Designation
- Primary Voltage
- DER In-Progress
- Installed DER
- Single Site Hosting Capacity Max
- Hosting Capacity
- Date of Last Update

DTE Electric has an internal process when a developer or customer is looking to install a DCFC or Level 2 charging infrastructure, which involves the marketing department and distribution planning. The customer has the option to submit a request through the corporate portal and apply for various incentive programs including residential, commercial, fleet, and municipal opportunities. The application is evaluated, and the service planning or make-ready process begins. The customer can also approach the service planning department to request new or increased service. During this process, DTE Electric supports internal and external development efforts while highlighting existing or available capacity when evaluating such projects. DTE Electric works with developers to find most effective ways to service projects and ensure the distribution system has sufficient capacity for long-term utilization and development. In some cases, service improvements are necessary, but DTE Electric has mechanisms for planning long-term development and regional coordination with municipalities.

DTE Electric's current hosting capacity expenses include engineering work, and information technology (IT) infrastructure programming and testing. There are plans to automate data feeds and reduce the required work to perform data updates. When automation is implemented, refreshing the data on the existing hosting capacity map will only have minor costs to maintain the system and perform quality control and validation. Increasing and improving data refresh rates initially will require significant investment by DTE Electric to rearchitect the planning process and allow system updates more frequently than yearly. Automating interfaces is critical to decrease DTE Electric's ongoing costs specifically for administrative personnel. DTE Electric is evaluating the overall investment for area improvements, which includes increasing modeling accuracy. Although DTE Electric has the tools available, they require significantly more data than included in the current modeling methods.

Figure 4: DTE's Hosting Capacity Map[44] (Phase 1, Zonal)



I&M is actively improving distribution system modeling capabilities, which includes publishing and regularly updating the hosting capacity map. Enhanced modeling will support a more complex analysis, provide forecasts for distribution planning, and allow load capacity and EV charging inquiries to be responded to more efficiently. I&M's Economic and Business Development team assist with internal modeling to answer questions from existing or perspective customers regarding load capacity. Moreover, it is projected to increase efficiencies in studying and modeling large DER interconnection applications due to the increased system complexities and DER penetrations. Therefore, I&M's enhanced modeling will enable more accessible avenues for customers and developers to identify locations for DER interconnection and reduce pre-application inquiries.

As requested by the MPSC, ITC completed a Michigan Lower Peninsula-specific hosting capacity study in September of 2021.[45] This analysis studied 225 points of interconnection with a focus on substations greater than 100 kV and three or more transmission line interconnections. The study analyzed interconnections up to 1000 MW for 120 kV, 138 kV and 230 kV stations, and 3,500 MW for 345 kV stations. The study identified several locations that could host new capacity, and the costs identified were for major system upgrades exclusive of directly assigned interconnection facilities.

Hosting Capacity In Other Jurisdictions

In the September 8, 2022, order in MPSC Case No. U-20147, the Commission recognized that "Michigan utility distribution grids are not well positioned as

[44] https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=64e9f4e0f82c42e7b7ed847273ec2764
https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=64e9f4e0f82c42e7b7ed847273ec2764
c/commission/news-releases/2021/10/14/mpsc-welcomes-results-of-itc-michigan-study-on-lowest-cost-areas-for-new-clean-energy-sites

necessary for growth of EVs and other DERs." (p. 67). And while the hosting capacity maps from Michigan utilities are expected to improve in future years, the Commission found it appropriate to examine Michigan utilities' HCA go/no-go maps for improvements, as informed by distribution system data and hosting capacity maps of utilities in other jurisdictions (p. 67). In that same order, the Commission pointed to hosting capacity maps available from the following utilities as having made real progress in providing hosting capacity data. Also, stakeholders recommended reviewing the hosting capacity maps provided by SCE (accessed March 15, 2023).

National Grid – Rhode Island
The National Grid-Rhode Island maps include a distribution asset map, a heat map, and a hosting capacity map displaying annual distribution circuit loading. The distribution assets map denotes substations, three-phase overhead and underground, and single-or two-phase section of circuit. When selected, each feeder reveals specific information:

- Feeder ID
- Planning Area, Substation, and Operating Voltage
- Summer Rating
- Loading information for 10 years in the future

The heat map shows distribution assets with circuits color coded by percent loading. In addition to providing insight to DER developers, the heat map identifies where additional capacity exists and can accommodate electrification and EVs. Known transportation vehicle fleet locations are also shown.

The hosting capacity map shows, at a feeder level, how much DER is connected, how much is in the queue, and local hosting capacity.

Potomac Electric Power Company (Pepco)
The Pepco hosting capacity maps show distribution feeders with color coding illustrating the range of available hosting capacity in kW. Feeder voltage, maximum aggregate capacity for large DERs, in kW, is provided for both the feeder and substation.

New York
New York has standardized and improved data sharing through an Integrated Energy Data Resource (IEDR) platform. It offers data to support DER development, and new and innovative clean energy business models by providing system data and customer data.

Puerto Rico- LUMA
Luma Energy's hosting capacity dashboard provides guidance to developers and customers to understand the impacts of connecting DG to the system. The dashboard

illustrates existing DG, DG penetration, hosting capacity, incremental hosting capacity, and voltage class.

Hawaiian Electric Company, Inc.
Hawaiian Electric's maps are referred to as Locational Value Maps and indicate the approximate amount of DG currently on the primary system with color-coded polygons. A viewer exploring the maps will be able to determine the percent of remaining space for solar on the primary circuit, available remaining KW for solar, and the DG on the primary circuit compared to 15% of peak electricity demand.

Dominion Energy, Inc. – North Carolina and Virginia
Dominion Energy's website includes separate hosting capacity maps for utility-scale generation and residential projects. The utility-scale hosting capacity map shows distribution lines which are color-coded to represent hosting capacity in size ranges up to 24 MW. The residential map shows distribution transformers serving residential customers and the markers are color-coded according to the hosting capacity available limited by that transformer and upline distribution lines and equipment.

Southern California Edison
A fairly mature example of HCA is published by SCE and the maps are referred to as Integration Capacity Analyses. IREC calls the Integration Capacity Analyses a "revolutionary leap forward in grid transparency."[46] Some of the information provided includes the amount of solar PV which can be interconnected on a specific line section, how much capacity is in the interconnection queue, breakdown of customer type by circuit, the substation the circuit connects to, maximum and minimum load information for circuits and substations which can also be downloaded. The Integration Capacity Analyses also provides the ability for developers to search for interconnection sites with capacity available.

[46] https://irecusa.org/blog/regulatory-engagement/what-grid-transparency-looks-like/

Figure 5: SCE Hosting Capacity Map (service territory level)

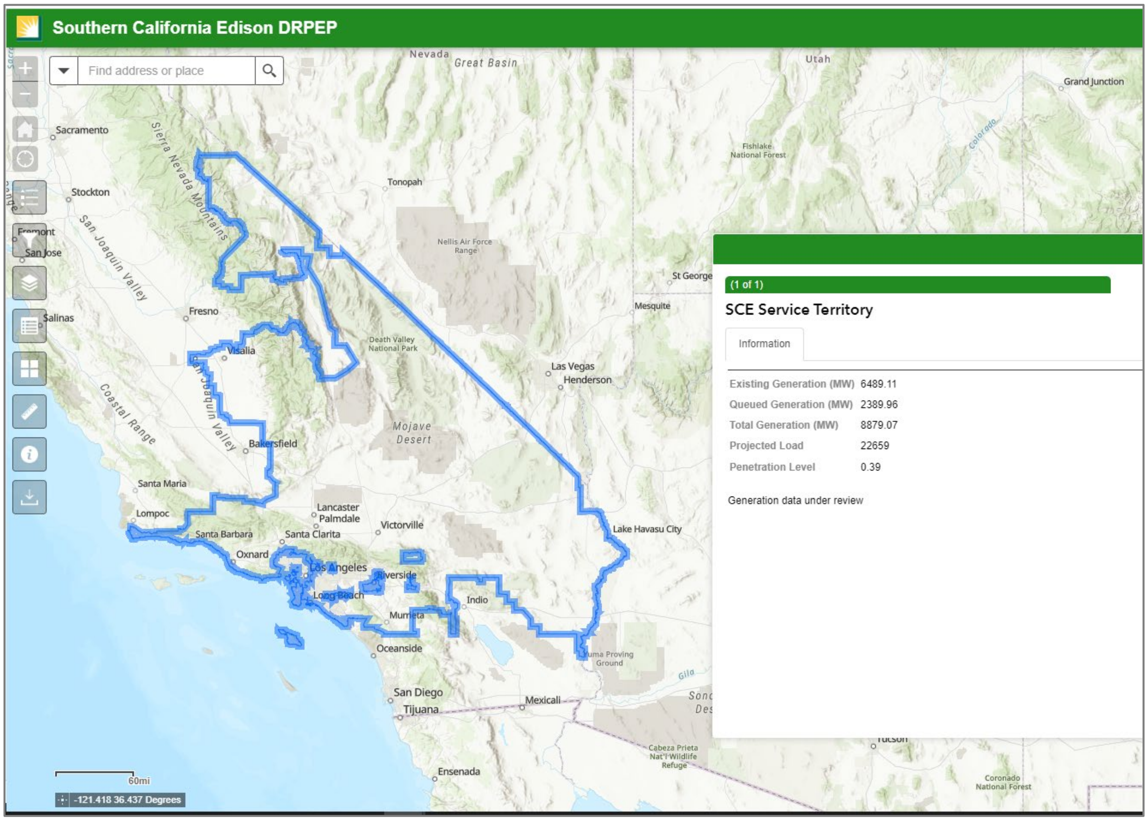


Figure 6: SCE Hosting Capacity Map (substation level)

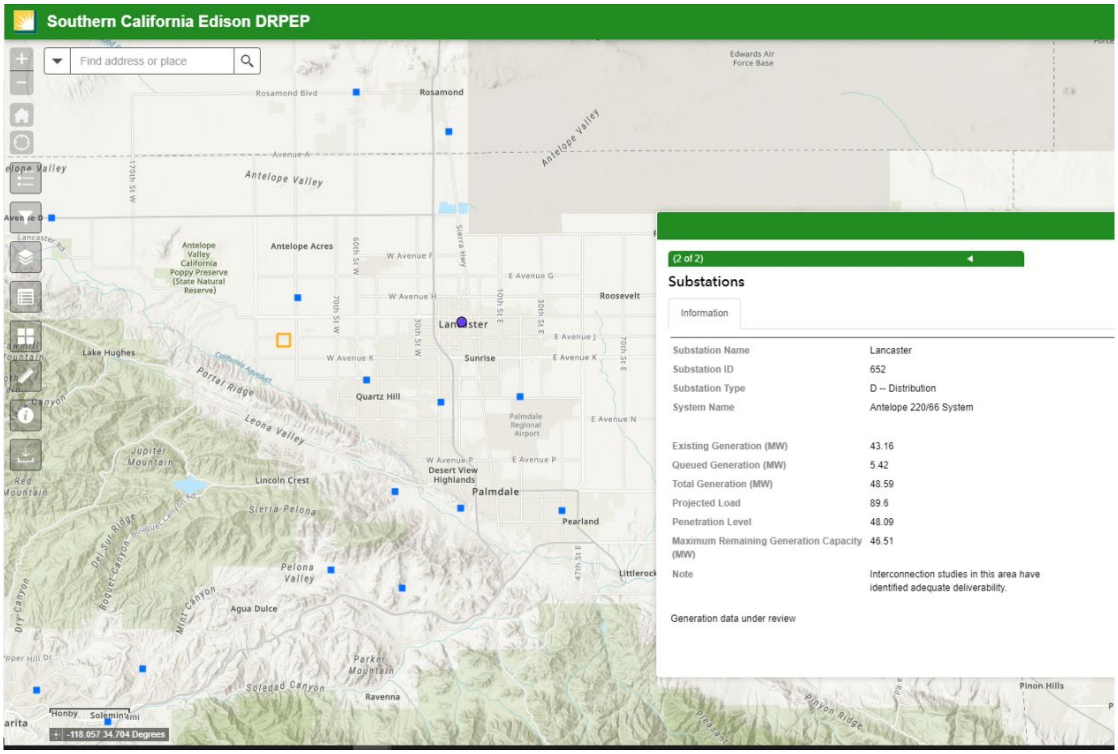
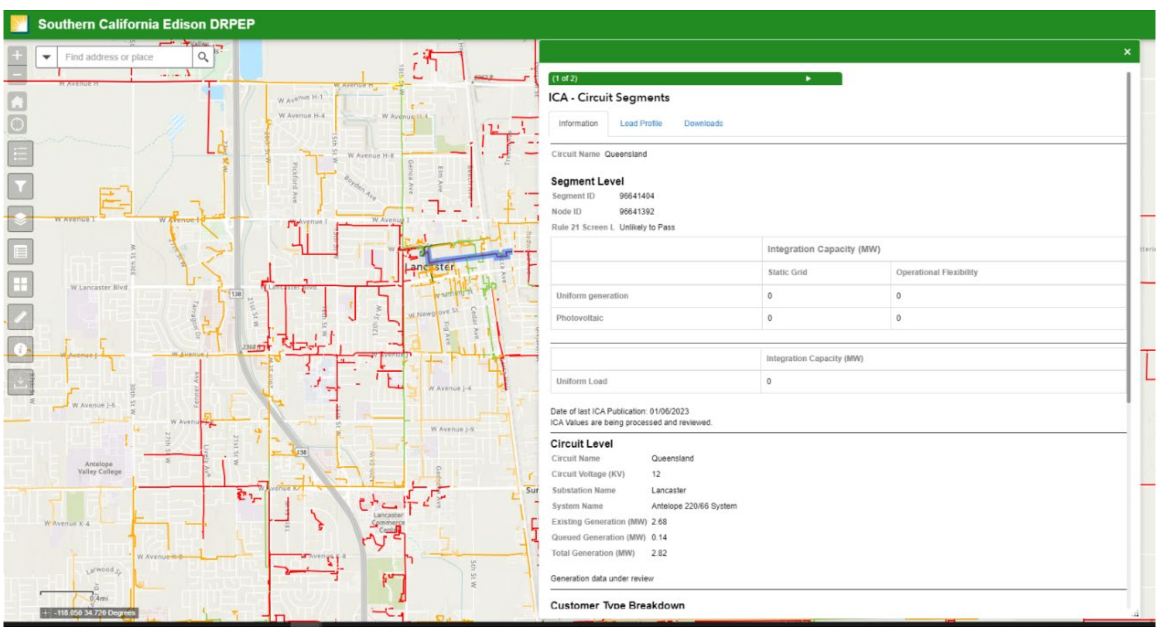


Figure 7: SCE Hosting Capacity Map (circuit level – page 1)



At the feeder and line section level, the map shows color-coded lines. Clickable line sections and nodes will show pop-up quick display window. Displayed (and downloadable) data includes circuit number, voltage, percent of customers, existing generation, queued generation, a yearly load profile, line segment name, the minimum value of uniform interconnection capacity value, the minimum value of uniform interconnection load value, and the PV interconnection capacity value at 12:00 p.m.

Figure 8: SCE Hosting Capacity Map (circuit level – page 2)

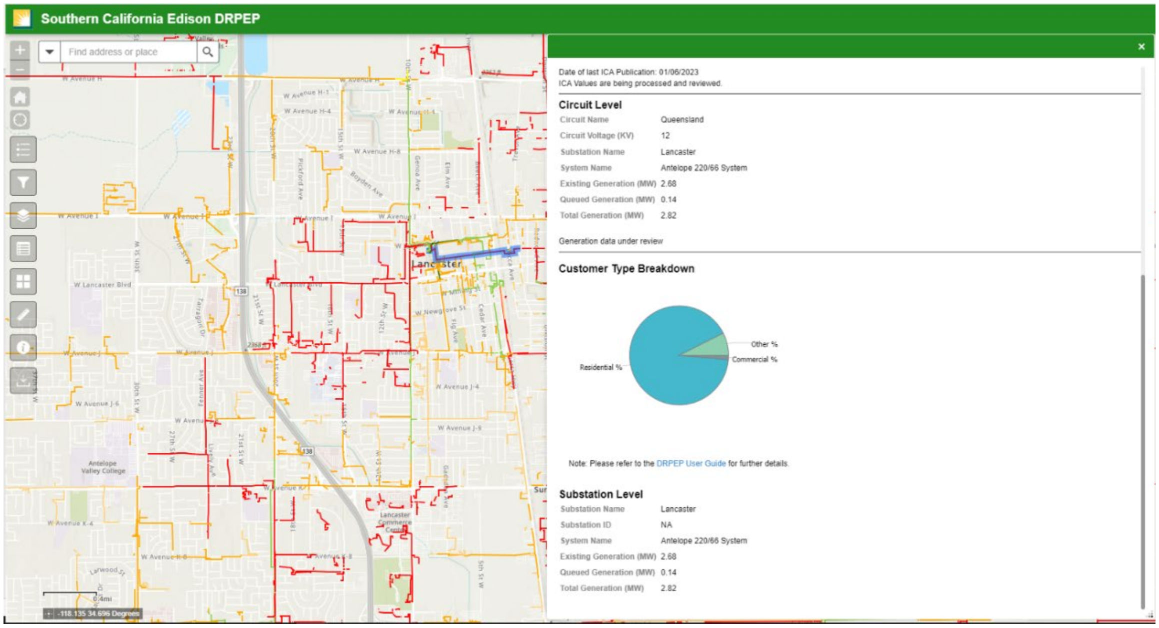


Figure 9: SCE Hosting Capacity Map (circuit level loading)

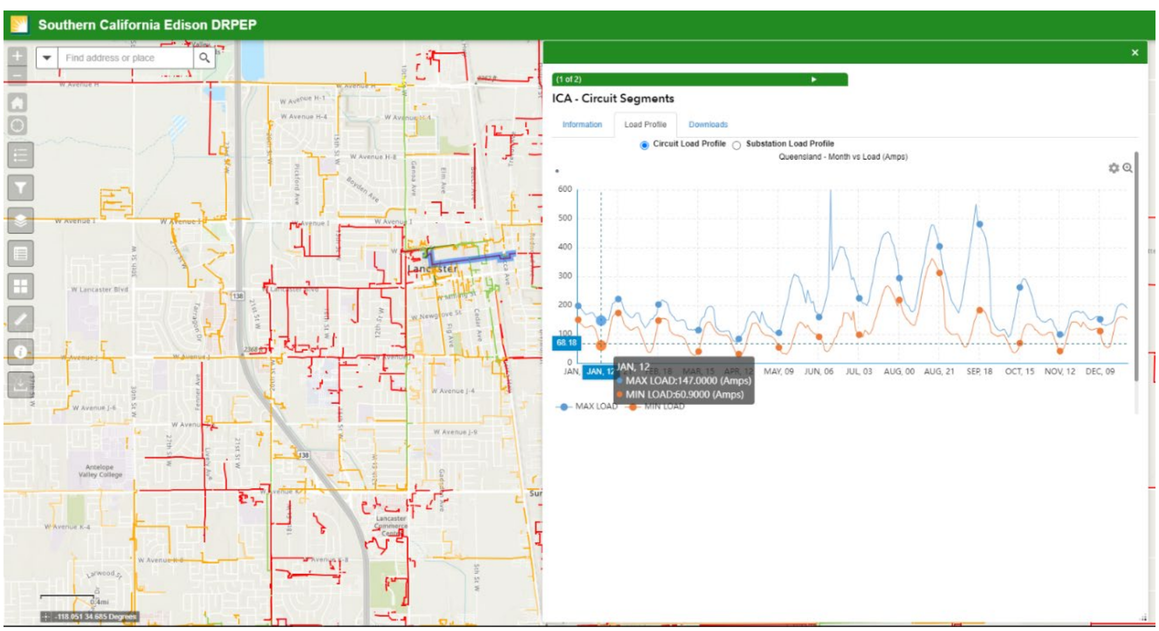


Figure 10: SCE Hosting Capacity Map (data download options)

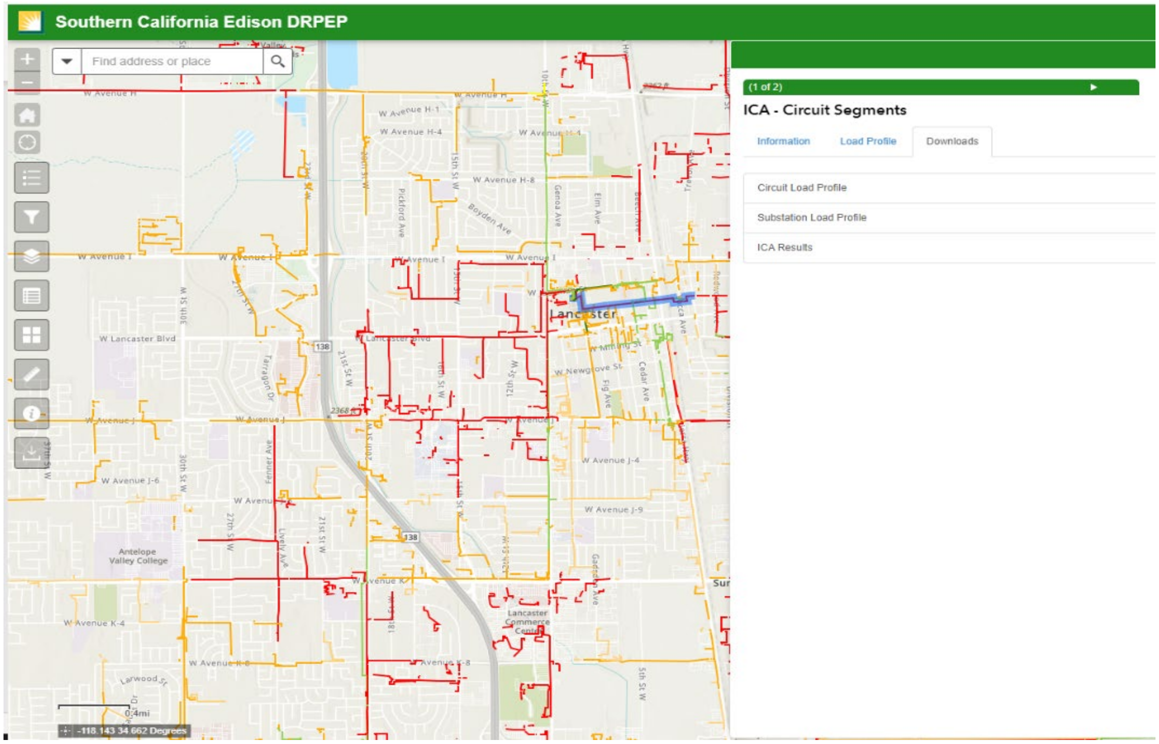
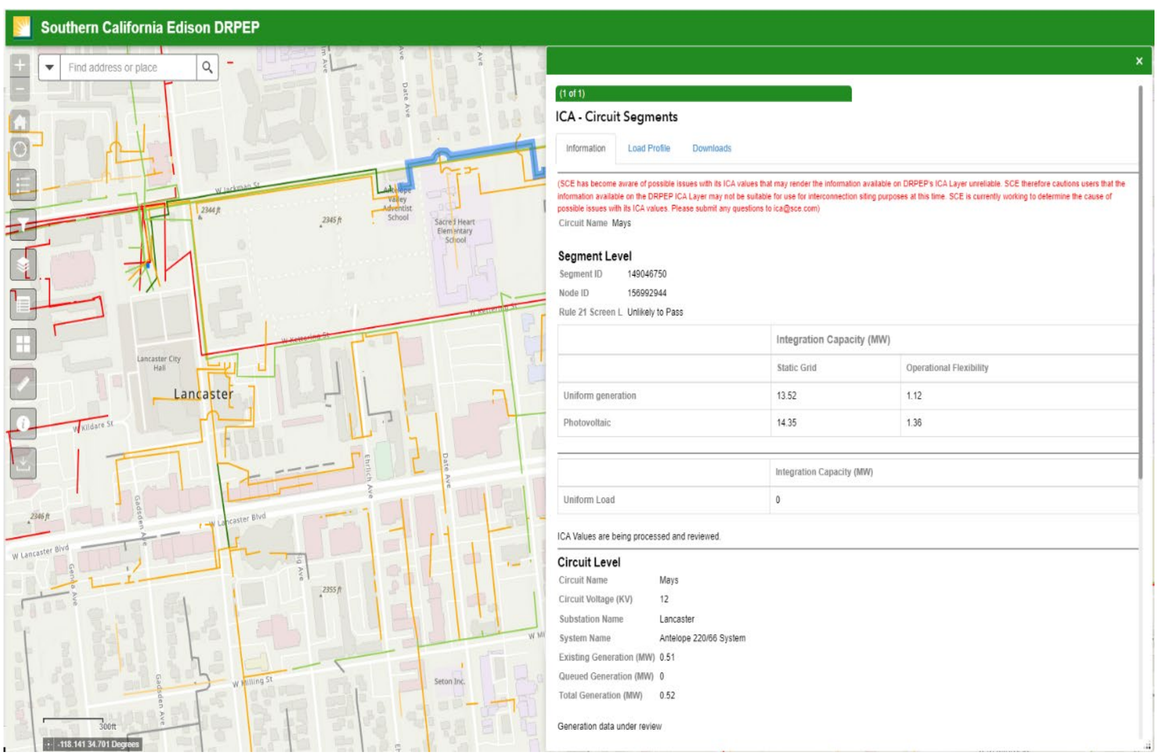


Figure 11: SCE Hosting Capacity Map (data quality/analysis alerts)



A Potential Approach for Bi-Directional Hosting Capacity Analysis

Hosting capacity is defined as the estimate of the maximum amount of DERs that can be connected to the grid without compromising the power quality and reliability and requiring any controls or infrastructure upgrades. The term 'bi-directional' refers to the hosting capacity analysis in two directions – load and generation. Bi-directional hosting capacity will determine the maximum amounts of DERs, such as PVs and EVs, that can be accommodated in each network location. Often, hosting capacities are studied separately on the generation (such as PV) or load (such as EVs) dimension. The following narrative gives a brief explanation of PV and EV hosting capacity methodologies and then follows with a discussion of how these can be merged to provide a bi-directional hosting capacity.

The bi-directional hosting capacity is based on a stochastic approach to PV hosting capacity analysis which is particularly useful for DPV scenarios (as often seen by Michigan utilities). This approach widens the range of nodal hosting capacity with a consideration to the impacts of local or nodal grid constraints (such as the size of spot loads at the connecting nodes) coupled with other DPV deployment scenarios, such as being near or far from the feeder head.[47] This methodology considers a novel approach to generate DPV deployment scenarios for realistic and robust planning activities. The approach can explicitly account for different spatial distributions of PV units as well as their size relative to corresponding loads co-located with these PV units. DPV scenarios, as seen by Michigan utilities, can be reflected by many PV deployment samples or paths and can aid the utilities' integration planning studies.

In the DPV scenario generation, the concept of PV unit(s) placement is considered to capture the importance of spatial distribution, a major driver of system impact of PV integration. This entails a load-relative bound on consumers' PV capacity in terms of the ratio between PV and load sizes. This methodology also explicitly ensures consistency among PV scenarios belonging to the same deployment sample. Finally, the sensitivity of the grid impact from the PV to load size ratio and PV unit placement can be internally reported for the utilities' record (if not published for public).

The PV deployment scenario generation method aims to provide (i) a sequence of PV scenarios that are consistent in the order of penetration levels and (ii) diversified PV deployment pathways to grid integration targets. This method can design each deployment pathway or sample as a succession of PV unit batch deployment in which higher penetration scenarios must have all PV plants deployed in lower penetration scenarios.

A key factor that affects how much impact a PV deployment would have on the distribution grid is the location of the PV units. Previously published work by NREL had found that voltage and thermal impacts of PV scenarios depend on the

[47] Sedzro, Kwami Senam A., Emmanuel, Michael, and Abraham, Sherin Ann. Generating Sequential PV Deployment Scenarios for High Renewable Distribution Grid Planning," Presented at the 2022 IEEE International Conference on Power System Technology (POWERCON 2022), 12-14 September 2022, Pullman, Kuala Lumpur, Malaysia. Online: https://www.nrel.gov/docs/fy22osti/81434.pdf

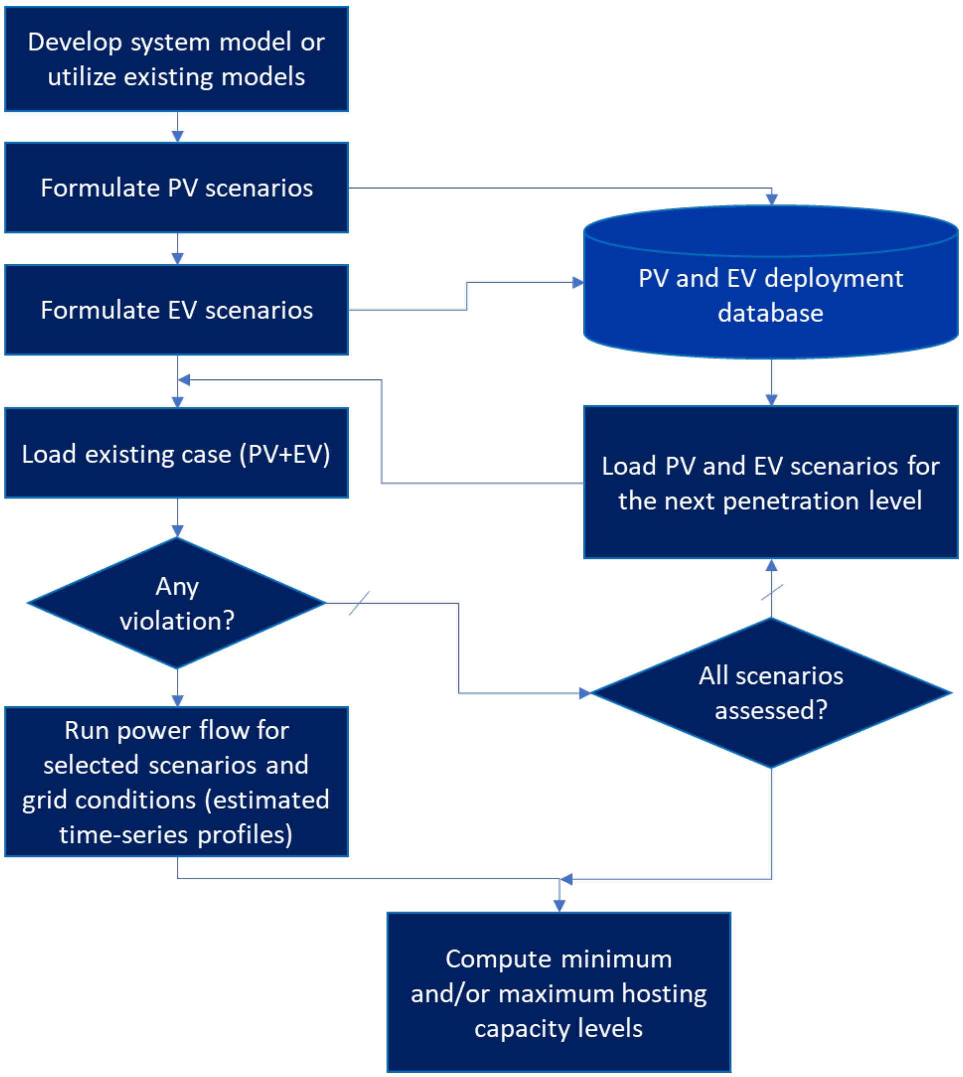
placement of the PV units, whether they are clustered close to the substation or at the tail end of the feeder.[48] To account for the importance of location, three placement categories can be considered: namely, close to substation, far from substation, and random. In the close and far placement categories, equal-length search segments are defined to find out possible locations for PV deployment. To generate the DPV scenarios, the PV candidate locations are randomly and sequentially drawn from one search segment at a time. The PV candidate search ends when the target PV penetration is reached. In the random placement category, however, only one search segment is formed, which covers all candidate buses. From this unique search segment, candidates are drawn, and a PV capacity is assigned to each candidate bus. These scenarios ensure grid impacts are assessed in a holistic manner and interdependent PV placements (such as neighbors being fed by the same service transformer) are studied for the hosting capacity. This spatial distribution methodology can be equally applied for DERs such as EV loads with considerations for residential, commercial, and public charging stations.

Flow-chart of Proposed Framework

A bi-directional hosting capacity can merge the PV and EV hosting capacity methodologies and assist DER developers in general. The following flow-chart describes a simple schematic to compute hosting capacity levels for PVs and EVs in a co-dependent manner. Often hosting capacity considers only a certain time point throughout the year reflecting peak load or peak generation capacity. This bi-directional methodology considers the time-varying nature of PV generation and typical EV charging behaviors to determine dynamic hosting capacity which provides a range of acceptable adoption levels for PV and EVs.

[48] A. K. Jain, K. Horowitz, F. Ding, K. S. Sedzro, B. Palmintier, B. Mather, and Himanshu Jain. "Dynamic hosting capacity analysis for distributed photovoltaic resources—Framework and case study." Applied Energy 280 (2020): 115633.

Figure 12: Flow Chart of Proposed Bi-directional HCA Framework



A bi-directional hosting capacity approach can help Michigan utilities provide useful information to DER developers in general. This proposed approach considers PV scenarios first, as PV as a technology is ahead of EV adoption. A bi-directional approach to hosting capacity can also platform an advanced tool that provides an assessment of co-located energy storage sizing. Energy storage was a part of the discussion among MI utilities and other stakeholders and there is a need to understand how energy storage can impact hosting capacity levels. Ideally, hosting capacity for solar PV-plus-storage is higher than PV only installations. Similar effect can be seen in EV hosting capacity levels. With a bi-directional hosting capacity analysis, co-located energy storage (with either PV or EV) can demonstrate possibly wider accommodations for either technology, helping developers in making an informed decision, at least from a grid-consideration perspective.

Integrating Bi-Directional HCA Capability into Michigan Utilities Hosting Capacity Maps

Utilities serving in the state have different levels of hosting capacity maps accessible to the public. These maps consider PV (generation) technology and can include more information on EV loading capacity. Regardless of underlying approach, data on PV and EV load hosting capacity need to be available for developers to make informed decisions about new projects. Methodologies such as the one described in previous section could pave a way to update Michigan utilities' hosting capacity maps with a 360° look covering both generation and load axes.

DTE Electric's hosting capacity maps as seen in Figure 4, provides hosting capacity in terms of remaining capacity to add DERs in a given circuit. A bi-directional hosting capacity can help break it down further in terms of generation and load capacity. This hosting capacity map shows that DTE Electric is running power flow simulations with their grid data in the background to compute the 'hosting capacity (kW)' value. Bi-directional hosting capacity may require adding more scenarios to simulate along with the power flow calculations to upgrade this map with load hosting capacity for EV charging events. These power flow calculations should consider including 'DER in-progress' as installed capacity to capture a near-future scenario in the hosting capacity map (if not already).

Consumers Energy's hosting capacity map (Figure 3) could also provide a breakdown in a similar fashion with remaining generation, loading hosting capacity and DERs in progress. For both DTE Electric's and Consumers Energy's maps, the proposed approach in the previous section could provide a spatial distribution of DERs as well as nodal capacity at circuit segments. This way utilities and developers could realize the impact of DERs with a view of projected PV and EV scenarios across the whole feeder/substation rather than the circuit segment in question.

The bi-directional hosting capacity maps can be aided further with advanced visualization and data handling techniques. Specifically, the following elements could improve the usability of these hosting capacity maps:

- Include color grading for developers to identify circuits with higher capacity. This can be in two parts – one for generation, the other for load.
- Include DERs in-progress with markers of appropriate sizes. These markers would be helpful in showcasing which areas are getting more interconnection requests.
- Address voltage levels in the circuit topology landing page. Voltage levels provide an additional parameter for developers to gauge the circuit's capacity (lower voltage levels such as 4.8 kV circuits usually have more grid-constrained scenarios for future looking DER interconnections, compared to higher voltage levels such as 13.2 kV).

- Use downloading features for highlighted data/circuit segments.

Data Privacy and Security Concerns

The MI Power Grid Customer Education and Participation Workgroup incorporated the data access and privacy topic to understand how to best facilitate access to customer data while also maintaining customer privacy. Aggregated and anonymized datasets are ways to keep customer identification anonymous. Utilities have the ability to share datasets based on aggregate load and usage from circuit data; however, anonymized datasets are beneficial so sharing can be completed without customer consent due to the difficulty of re-identifying a customer.

Although there are concerns that the hosting capacity maps may be too granular and reveal individual customer load, there are protections in place in order to maintain customers' privacy. Consumers Energy has a dedicated team to define and enforce policies, standards, laws, and regulations related to data retention and security. All data is encrypted and continuously monitored for anomalous activity. DTE Electric maintains customer data and the cybersecurity team protects digital infrastructure and sensitive information in order to minimize the impact of any incident or breach.

Increased Use and Deployment of Distribution System Technologies and Controls

DERs such as solar PV utilize an inverter to convert the generated power from direct current to alternating current. Grid-tied inverters, which serve local loads and export any excess power to the distribution system, match the local grid voltage and frequency. In 2014, the IEEE 1547a standard was issued which provided requirements for voltage ride-through and frequency ride-through.[49] Inverter voltage and frequency ride-through capabilities keep the DER online and operating within utility-specified limits during voltage or frequency deviations on the larger distribution system rather than tripping the DER offline. If enough DER capacity trips offline, the grid can become stressed. Inverters with ride-through capabilities are referred to as smart or advanced inverters.

Energy Storage

There are two main categories storage: short-duration and long-duration. Short-duration storage is typically defined as a technology that has a discharge duration of under eight hours and includes technologies, like flywheels and most lithium-ion batteries. Long duration storage is typically defined as having discharge duration over eight hours, and include technologies like pumped hydro, many flow batteries, and compressed air energy storage. Short duration storage can be used for grid reliability such as voltage support, frequency regulation, and shorter periods of arbitrage, while longer duration storage can be used for load shifting, intermittent generation integration, and longer durations of arbitrage.

[49] Horowitz, Kelsey, Zac Peterson, Michael Coddington, Fei Ding, Ben Sigrin, Danish Saleem, Sara E. Baldwin, et al. 2019. An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72102. https://www.nrel.gov/docs/fy19osti/72102.pdf

- Pumped Hydroelectric: Electricity is used to pump water up to a reservoir at a higher elevation. When water is released from the upper reservoir, it flows down to the lower reservoir through a turbine to generate electricity.
- Compressed Air: Electricity is used to compress air at up to high pressure for storage in a pressure vessel, which is often an underground cavern. When electricity demand is high, the pressurized air is released to expand through a turbine to generate electricity.
- Flywheels: Electricity is used to accelerate a large, low-friction spinning mass (a flywheel) through which the energy is conserved as kinetic rotational energy. When the energy is needed, the spinning force of the flywheel is used to turn a generator.
- Batteries: Like common consumer electronic rechargeable batteries, grid-scale batteries can store electricity in chemical form via a process of oxidation and reduction moving electrons from one electrode to another through an electrolyte, producing or consuming a current as needed. These systems can use lithium ion, lead acid, lithium iron phosphate or other battery technologies.
- Thermal Energy Storage: Electricity can be used to produce or remove thermal energy, or heat, which can be stored until it is needed. For example, electricity can be used to produce chilled water or ice during times of low demand and later used for cooling during periods of peak electricity consumption.

Interest in energy storage use on the grid has risen because of its ability to support different generation types, and for its use cases for grid stability. Given the clean energy goals of the state and utilities, energy storage will be required due to the increasing penetration of renewable generation needed to meet those goals. Additionally, energy storage can be used to defer distribution system investment or to support different distribution and transmission system needs. Energy storage can be paired with renewable energy resources or can be installed as a standalone resource. Given the flexibility that energy storage provides, Michigan utilities have begun utilizing modeling in integrated resources plans to aid in the evaluation of energy storage for large-scale installations.

On August 11, 2021, the Commission issued an order in Case No. U-21032 encouraging Michigan investor- owned electric utilities to propose pilot programs in upcoming rate cases that meet the criteria outlined in the order and the proposed definition and objective criteria for utility pilots. Michigan utilities are using the criteria from the order in Case No. U-21032 to begin testing and piloting several use cases for energy storage which include both NWAs and grid reliability. Additionally, Michigan utilities have proposed several other programs including DR and outage management programs.

MI Power Grid: New Technologies and Business Models

As part of the MI Power Grid Initiative, the New Technologies and Business Models Workgroup explored expanding new opportunities and options related to technologies and business models to control costs. Technologies that were explored include EVs, batteries, heat pumps, behind-the-meter and community solar, storage, combined heat and power, and microgrids at distribution and utility scale. Alternative business and ownership models were evaluated based on integrating new technologies. MPSC Staff released a report with recommendations regarding new technologies and business models. Barriers were identified which may limit the adoption of DERs and EVs. Barriers to increased adoption include several that are not related to grid integration and are therefore not covered in detail in this report. Further consideration of those barriers may be warranted. These include, but are not limited to:

- Current inability to use one meter for multiple technologies on customer premises such as a solar panel and an EV each requiring separate metering;
- Limited multi-family dwelling access to onsite generation due to a lack of utility submetering policies or regulations;
- Market competitiveness issues with utility ownership of behind the meter solar or storage;
- Lack of clarity and issues presented by utility ownership of DERs; and
- Premise definition in MPSC Technical Standards for Electric Service and impact on microgrids limiting the ability of a microgrid to serve multiple customers or customers accessing generation not on their own premises unless supplied by a utility.

While many of the aforementioned barriers are outside of the scope of the Grid Integration Study, the New Technologies and Business Models report provides a useful resource outlining additional barriers that could be addressed to further facilitate the expansion of DERs and EVs in Michigan through ongoing stakeholder engagement and technical expertise. Further work is needed to develop actionable solutions to these barriers. The Commission is currently in the process of collecting and evaluating stakeholder comments related to some of these barriers. Legislative action may be helpful to address certain barriers as discussed in the report; however, going forward, the Commission will continue to evaluate and work through issues within its jurisdiction.

Recommendations and Conclusions

Recommendation 1 – Data Availability and Improving Map Capabilities

While meetings with utilities and other stakeholders have created a greater understanding of the needs of developers and the current capabilities of the utilities to support hosting capacity maps and data beneficial to the efficient integration of DG and the continued development of EV chargers in Michigan, additional improvements are still necessary to improve the quality of the utility hosting capacity maps. As such, the Commission will endeavor to continue to negotiate mutually beneficial improvements with utilities and other stakeholders. Specific improvements to consider include:

- Substation level statistics such as the average minimum load, the average loading as a percentage of rated capability, and the minimum and maximum load for each day or time period specified;
- The ability for the data to be exported or downloaded; and
- Data displayed on GIS interactive maps.

To ameliorate concerns regarding data privacy and security, a data-sharing methodology should be further explored for use by Michigan utilities. Hosting capacity maps made publicly available by utilities such as SCE, Dominion Energy, and others as shared in this report include additional detailed data promoting the efficient integrations of DG beyond what has been shared by Michigan utilities to date. Additional progress to efficiently integrate DG will be facilitated by developing and adhering to a data-sharing methodology, and further exploration is recommended to address data and privacy concerns for Michigan utilities and customers while allowing for beneficial sharing of information that enables further market and solutions development.

Recommendation 2 – Revising Capacity Map Visualizations and Vocabulary

It is necessary to revise the vocabulary and appearance of go/no-go decision pointers for publicly accessible hosting capacity maps to send proper signals to customers and developers. Providing additional hosting capacity information would lead to interconnection applications being less speculative. Areas with limited hosting capacity should be marked as "constrained" on circuit maps and different constraint levels should have clear identifiers such as gradient coloration of the maps should show the different constraint level (e.g., green, yellow, orange, and red for high, moderate, low, and no available hosting/load capacity, respectively). This would further enhance the visualization and utilization of the hosting capacity maps and provide necessary information to stakeholders while not stifling the further adoption and integration of DERs and EV infrastructure. From a planning perspective, this would also aid developers exploring investments in advanced control technologies such as managed charging or co-located solar PV and storage to make sure a new EVSE or PV installation operates within local grid constraints. Improving existing hosting capacity maps or publishing new ones should have a feedback process in place with stakeholder input to provide guidance on appropriate levels of data granularity and attribute types shown on the hosting capacity maps.

Recommendation 3 – Minimum Level of Electric Service

To further enhance the adoption of residential DERs and EVs, exploration of a minimum level of electric service made available to all residential customers which would assure that the distribution system could accommodate DERs and EVs should be explored. The adoption of DERs and EVs may require customer service panel upgrades for older residential homes based on customer need. It is recommended that the need for service panel upgrades be considered to incorporate increased adoption of DERs and EVs.

Residential service panel upgrades could be costly and may require commensurate upgrades on the utility side of the meter. In order to ensure equitable access to DERs and EVs, it is necessary to leverage federal programs and other funding sources to assist in service panel upgrades and distribution system upgrades. As provided previously in the report, the following opportunities should be further explored:

- 26 USC 25C: Energy efficient home improvement credit[50]
- High Efficiency Electric Home Rebate Act (HEERA)[51]
- Smart Grid Investment Matching Grant Programs through the Grid Resilience and Innovation Partnership[52]

Recommendation 4 – Automate Hosting Capacity Analysis Toolkit

To create an accurate and timely representation of grid capacity it is necessary to update HCA maps more frequently than once a year. Michigan utilities should consider streamlining or automating the updates to the hosting capacity analysis in a similar manner as being explored by I&M and the interconnection process as presented to the Distribution Data Access Work Group by NREL's demonstration of PRECISE tool. Utilities should investigate the costs and best practices for automatic hosting capacity maps and to what extent such automations would assist with minimizing the utilities' costs to complete interconnection studies and how such automations could improve the frequency of updates to hosting capacity maps. Piloting the automation of these tools would allow Michigan utilities to explore the expanded use of the tools to support distribution planning while also facilitating the expansion of DERs and EVs.

Recommendation 5 – Hosting Capacity Tools for Load and Distributed Generation

To enhance existing or pending publicly available hosting capacity maps, utilities in future iterations should ensure customers and third parties have maps that allow visualization of remaining capacity considering both load and distribution generation. The expansion provides increased accessibility and useability for a range of stakeholders to assist in identifying areas to accommodate DERs and emerging technologies as EVs and energy storage.

Recommendation 6 – Develop Successor DG and DCFC Tariffs

When DG programs become fully subscribed, successor tariffs are desirable to address the influx of customers wanting to participate. The Commission recognizes that rate design for DG and DCFC EV charging could influence further integration of DERs and high-speed EV charging stations and that rate design can be a powerful tool to assist the efficient integration of DERs and EVs. As such, the Commission recently directed DTE Electric to file the options available to customers with DG

[50] 26 USC 25C: Energy efficient home improvement credit (house.gov)
[51] Home Energy Rebate Programs | Department of Energy
[52] Smart Grid Investment Grant Program: Overview: Recovery Act | SmartGrid.gov

systems, including options under Public Utility Regulatory Policies Act (PURPA) and the existing self-supply tariff, should DTE Electric decide to cap participation in its current DG program consistent with MCL 360.1173(3). The Commission similarly directed I&M to file the options available to customers wishing to interconnect DG systems should I&M decide to continue to cap participation in its DG program as allowed by statute. In addition, a number of utilities already offer EV pilot programs with associated charging tariffs. The Commission intends to work with utilities and other stakeholders in developing additional tariff options for DERs and DCFC charging. These additional tariff options should comply with statutory requirements, reflect cost of service principles, and promote efficient utilization of the existing electric grid.

As technologies and customer loads shift over time, the electricity grid will continuously evolve to meet the demands placed upon it. To reduce the customer costs of the evolving grid, enabling informed decision making using transparent data is paramount. The Commission stands ready to implement any further directives from the Legislature regarding the integration of DERs and EVs into the electric grid.

Appendices

A. DG Stakeholder Session (August 16, 2022)

Recording | Presentation | Notes

The initial session focused on DG and began with opening remarks by Commissioner Tremaine Phillips. Followed by a utility hosting capacity presentation and Q&A by Andrew Galczyk from DTE Electric, Kyle Desser from Consumers Energy, and Kwafo Adarkwa and John Kopinski from ITC. Shibani Ghosh, Michael Ingram, and David Narang, all from NREL, provided information on bi-direction hosting capacity. A panel comprised of Alex Sherman from SunPower, Ken Zebarah from Harvest Solar, and Missy Stults from City of Ann Arbor and moderator by Laura Sherman from Michigan EIBC discussed DER stakeholder data needs. A final guided discussion ensued from all participants. Closing remarks and next steps were provided by Commissioner Tremaine Phillips.

Agenda Items		
2:00	Welcome & Opening Remarks	MPSC Commissioner **Tremaine Phillips**
2:10	Utility Hosting Capacity Presentations and Q/A	**Andrew Galczyk**, DTE Electric **Kyle Desser**, Consumers Energy **Kwafo Adarkwa**, ITC **John Kopinski**, ITC
3:05	Bi-directional Hosting Capacity	**Shibani Ghosh**, NREL **Michael Ingram**, NREL **David Narang**, NREL
3:35	Break	
3:45	Panel Discussion: DER Stakeholder Data Needs	Moderator: **Laura Sherman**, Michigan EIBC Panelists: **Alex Sherman**, SunPower **Ken Zebarah**, Harvest Solar **Missy Stults**, City of Ann Arbor
4:15	Guided Discussion and Stakeholder Listening Session	All participants
4:55	Next Steps and Closing Remarks	MPSC Commissioner **Tremaine Phillips**
5:00	Adjourn	

B. EV Stakeholder Session (August 22, 2022)

Recording | Presentation | Notes

The second session focus was EV and incorporating into hosting capacity maps. Commissioner Tremaine Phillips provided opening remarks to level set the conversation that would develop. Next, Andrew Galczyk from DTE Electric, Kyle Desser and Jeff Myron from Consumers Energy, and Kwafo Adarkwa and John Kopinski from ITC provided a utility hosting capacity presentation and Q&A. Shibani Ghosh, Michael Ingram, and David Narang, all from NREL, provided information on bi-direction hosting capacity in regards to EVs. A panel comprised of Cory Bullis from

FLO, Kimathi Boothe from Dunamis Clean Energy Partners, and Erin Quatell from Oakland Country and moderated by Laura Sherman from Michigan EIBC discussed specific DER stakeholder data needs for EVs. A final guided discussion ensued from all participants. Closing remarks and next steps were provided by Commissioner Tremaine Phillips.

Agenda Items		
2:00	Welcome & Opening Remarks	Commissioner **Tremaine Phillips**
2:10	Utility Hosting Capacity Presentations and Q/A	**Andrew Galczyk**, DTE Electric **Kyle Desser**, Consumers Energy **Jeff Myrom**, Consumers Energy **John Kopinski**, ITC **Kwafo Adarkwa**, ITC
3:05	Bi-directional Hosting Capacity	**Shibani Ghosh**, NREL **Michael Ingram**, NREL **David Narang**, NREL
3:35	Break	
3:45	Panel Discussion: DER Stakeholder Data Needs	Moderator: **Laura Sherman**, Michigan EIBC Panelists: **Cory Bullis**, FLO **Kimathi Boothe**, Dunamis Clean Energy Partners **Erin Quetell**, Oakland County
4:15	Guided Discussion and Stakeholder Listening Session	All participants
4:55	Next Steps and Closing Remarks	MPSC Commissioner **Tremaine Phillips**

C. Hosting Capacity Stakeholder Conversation (November 18, 2022)

Notes

The third session did not have an outlined agenda, rather open dialogue on hosting capacity; however, the MPSC provided guiding topics and questions which consisted of the following.

1. What is the clearly stated value proposition/ propositions for ratepayers that would justify the additional cost and investment to develop and maintain more robust utility-provided capacity maps and data?
2. Noting the potential tension among the additional costs necessary to further develop and improve upon existing capacity maps, the wants and needs from stakeholders, and the ultimate cost and benefits to ratepayers, can we reach consensus on what the appropriate foundational or minimum standards should be adopted in regards to the following:
    a) **Granularity of Data** - At what level of data granularity (single-phase v. three phase, transformer level v. substation level, etc.) provides the best balance among third-party expectations and needs, utility data availability, and ratepayer benefits/ costs?

b) **Data Refresh Rates** - How often should the data be updated/ refreshed (once a quarter, once a year, bimonthly, etc.) given third-party expectations and needs, utility capabilities and costs, and ratepayer benefits/ costs?
c) **Temporal Data** - Should utilities strive to make available capacity data that is temporal as well as spatial, thereby allowing third parties to know where and when there is excess hosting / load capacity? What are the limitations (data availability, costs, etc.) for being able to produce such data? At what level of granularity should this temporal data be offered (on-peak v. off-peak, seasonal, etc.)?
d) **Exportability/ Usability of Data** - How should this data best be made available and exportable (CSV file, Shapefile, etc.) so to allow for further analysis and data integration by third parties independent of the utility's website or platform?
e) **Need for Integration Between Hosting Capacity and Load Capacity Maps** - What are the benefits of integrating hosting capacity and load capacity maps and data when compared to the ultimate costs and feasibility of this integration? What additional analysis can be performed from the integration of hosting and load capacity data?
f) **Additional Information or Data** - Are there any additional data or information that is currently not being made available via the existing hosting capacity maps or that has not yet been discussed, but should be made available during the next iteration of these resources?

D. HCA Technologies Session (April 7, 2023)

The fourth and final stakeholder session evaluated technologies from Coultech and NREL. The session began with welcome and opening comments from Commissioner Tremaine Phillips. Following a demonstration of Coultech's technology and an open Q&A to the participant. NREL then presented their PRECISE technology and held a Q&A after. The session closed with statements and next steps from Commissioner Tremaine Phillips.

Agenda Items		
1:00-1:05 5 min	Welcome & Opening Comments	Commissioner Tremaine Phillips
1:05-1:45 40 min	Coultech Technology Demonstration & Q&A	Luke Ackerknecht, Coultech Phil Stahlfeld, Coultech
1:45-2:25 40 min	PRECISE Technology Demonstration & Q&A	Adarsh Nagarajan, NREL Killian McKenna, NREL
2:25-2:30 5 min	Closing Statements & Next Steps	Commissioner Tremaine Phillips

E. Acronym List

ACE	Area Control Error
AMI	Advanced Metering Infrastructure
API	Application Programming Interfaces
BYOC	Bring Your Own Charger
CATSS	Cybersecurity Advisory Team for State Solar
Consumers Energy	Consumers Energy Company
CSV	Comma-Separated Value
DCFC	Direct Current Fast Charger
DER	Distributed Energy Resource
DG	Distributed Generation
DOE	U.S. Department of Energy
DPV	Distributed Photovoltaics
DRIVE	Driving Research and Innovation for Vehicle Efficiency and Energy Sustainability
DSCADA	Distribution Supervisory Control and Data Acquisition
DSDA	Distribution System Data Access
DTE Electric	DTE Energy Company
DTE Electric DGP	DTE Electric Distribution Grid Plan
EAAC	Energy Affordability and Accessibility Collaborative
EGLE	Michigan Department of Environment, Great Lakes, and Energy
EIA	U.S Energy Information Administration
EPRI	Electric Power Research Institute
EV	Electric Vehicle
EVSE	Electric Vehicle Service Equipment
EWR	Energy Waste Reduction
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System

GITT	Grid Integration Tech Team
GWh	Gigawatt-hours
HCA	Hosting Capacity Analysis
HEERA	High Efficiency Electric Home Rebate Act
I&M	Indiana Michigan Power Company
IEDR	Integrated Energy Data Resource
IEEE	Institute of Electric and Electronic Engineers
IOU	Investor-Owned Utility
IREC	Interstate Renewable Energy Council
IRP	Integrated Resource Plan
ISATT	Integrated System Transmission Company
IT	Information Technology
ITC	International Transmission Company
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hours
MISO	Midcontinent Independent System Operator
MIXDG	Interconnection and Distributed Generation
MPSC	Michigan Public Service Commission
MUD	Multi-unit Dwelling
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Officials
NEVI	National Electric Vehicle Investment
NREL	National Renewable Energy Laboratory
NSP	Northern States Power Company
NWA	Non-Wire Alternative
PA	Public Act

PEV	Plug-in Electric Vehicles
PG&E	Pacific Gas and Electric Company
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaics
Q&A	Question and Answer
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Frequency Duration Index
SCE	Southern California Edison
SGIP	Small Generator Interconnection Procedures
SR 143	Senate Resolution 143
T&D	Transmission and Distribution
TOU	Time of Use
UL	Underwriters Laboratory
UMERC	Upper Michigan Energy Resources Company
UPPCO	Upper Peninsula Power Company
V2G	Vehicle to Grid