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September 11, 2019

Ms. Kavita Kale,
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, Michigan 48917

Re: Distribution System Planning stakeholder meeting on August 14, 2019

Dear Commissioners and Staff,

The Michigan Energy Innovation Business Council (Michigan EIBC) and the Advanced Energy Economy Institute (AEE Institute) respectfully submit these comments in Case No. U-20147. AEE Institute and Michigan EIBC (also referred to here as "we" or "our") appreciate the Commission's continued attention to distribution system planning and grid modernization. We offer the following comments regarding discussions at the distribution system planning stakeholder meeting that was held on August 14, 2019.

If there are any questions or concerns related to these comments, feel free to contact us directly.

Regards,

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I. Enhancements to the Distribution System Planning Process

A. The Development of a Benefit-Cost Analysis (BCA)

We would like to voice our strong support for the overall approach to BCA that was articulated by Tim Woolf from Synapse Energy Economics, in his presentation at the August 14 workshop.[1] A comprehensive BCA framework should guide utility decision-making with respect to distribution system investments. Before embarking on any major distribution system investment, a sound business case should be required of all utilities. As such, AEE Institute and Michigan EIBC reiterate our strong support for the development of an analytical framework to adequately compare the costs and benefits of all potential resources against each other in proposed distribution system plans. We continue to encourage the Commission to work with stakeholders to develop a comprehensive BCA framework that includes evaluation of all supply-side and demand-side resources, as appropriate. Such a framework would allow utilities to compare traditional solutions with distributed energy resource (DER) solutions, including the potential for a mix or portfolio of such solutions.

A sound BCA should include hard-to-quantify values. Simply because a cost or benefit is hard to quantify does not mean that its value is zero. As stated by Synapse Energy's Tim Woolf at the August 14, 2019 stakeholder session, these hard-to-quantify costs and benefits can also be considered using a binary system or point system. This allows for consideration of these factors, even if they are not included as monetized values subsequent to application of the BCA framework.

B. Regulatory Innovations in the Treatment of Operating Expenses

To further ensure that net benefits accrue to customers, we recommend that the Commission consider regulatory models that provide win-win outcomes for consumers and utilities. In the current cost-of-service regulatory model, which has served the sector and customers well for many years, capital investments are a primary driver of returns to utility shareholders. In contrast, operating costs (such as fuel, labor, maintenance, and service expenses) are generally passed through to customers in electric rates without the utility making any direct profits on them, although utilities remain incented to manage operating costs to reduce overall cost to customers, and also to manage profits between regulatory rate reviews.

This cost-of-service model that incentivizes capital investment stands in sharp contrast to the trend in virtually every other sector of the economy to procure services in lieu of making capital investments. Although examples are many, cloud computing (used in lieu of purchasing software and servers) is a prime example. Because many new technologies today are offered only as a service, utilities may be discouraged from using them even if they provide net benefits to customers. This is because services that can improve the utilization of existing investments or defer or replace new capital investments will have the effect of reducing opportunities for utilities to generate earnings. Realizing that both customers and utilities stand to benefit from equalizing the

[1] Synapse Energy Economics (2019) Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments. https://www.michigan.gov/documents/mpsc/Aug_14_Presentations_663481_7.pdf accessed 09/05/2019

earnings opportunities between traditional capital solutions and service solutions that reduce capital investment needs, several state commissions have explored or implemented mechanisms to compensate for the bias toward capital investments that is inherent in cost-of-service regulation.

We have identified several different regulatory options that states are using or piloting for services that replace capital investments. Some of these mechanisms, such as capitalization of a service contract or the use of regulatory assets are available today without the need for changes in regulation. These mechanisms allow utilities to place "service assets" in their rate base and amortize them like capital investments. Other regulatory mechanisms require changes in regulations (but not accounting rules) and are designed to provide financial incentives to utilities that better align their earnings opportunities with their ability to generate cost savings through the use of services. These include:

- **DER Incentive Adder ("DER Adder")** – This option provides a direct return on services procured by utilities where these services are treated as pass-through O&M costs and therefore not included in the rate base. In this case, the utility receives 4% of the total cost of the periodic payments for the service solution as an incentive to compensate for the utility's avoided earnings. This option was piloted in California.

- **Capitalization of a prepaid contract ("Prepaid Option" or "Prepaid Contract")** – This option employs a prepaid asset, a commonly used form of cost recovery for utilities, which treats an expense similar to a physical asset by placing it into the rate base, amortizing it, and recovering it over time. In this case, a service payment would be pre-paid for a number of years and would be amortized over the length of the contract. The utility would collect its yearly carrying costs, including return for the investors' equity, based on any unamortized balances.

- **Non-Wires Alternative Shared Savings ("NWA Option")** – This option functions similarly to the Prepaid Contract because it is based on a prepaid service that the utility recovers as a regulatory asset. However, an additional earnings incentive is provided on top of earnings from capitalizing the prepaid contract to compensate for lower earnings when the service costs less than the traditional capital solution. Specifically, the utility shares in 30% of the present value of the total savings when compared to the traditional solution. The shared savings are applied in equivalent increments on a yearly basis for the length of the service prepayment. This option is in use in New York state.

- **Modified Clawback Mechanism ("Modified Clawback")** – This option is an adjustment to the net capital plant reconciliation, or "clawback," mechanism, which is used in some states with multi-year rate plans to reclaim the unspent portion of a capital budget, plus the associated earnings, in the event that a utility does not spend its full capital budget.[2] The

[2] While this option may not apply at present in Michigan, where utilities generally file annual rate plans, we include it here because the Commission may want to consider multi-year rat plans as part of broader reforms connected to integrated distribution planning and performance-based regulation.

Modified Clawback Mechanism leaves intact any portion of the revenue requirements associate with the unspent portion of the capital budget, provided that the utility can demonstrate that it used a service-based solution instead to meet the need. The utility thus gets to keep all the revenue associated with that planned investment until the end of the rate plan period, after which the amount of the unspent capital is removed from the rate base and the cost of the service contract is added the revenue requirements.

- **Pay-as-you-Go ("PayGo")** – This option combines a number of features from the mechanisms outlined above. Under PayGo, the utility prepays a service expenditure for one year at a time and places the prepayment into the rate base as a regulatory asset. With authorization from the state utility commission, the utility would amortize these regulatory assets over a period greater than one year. Thus, the regulatory asset would build year-on-year while simultaneously being amortized. In addition to these earnings from rate base, the utility receives a variable shared savings incentive proportional to the cost savings provided by the service option. For example, if the all-in costs of the service solution are 25% less than the traditional solution, the utility would receive 25% of the total savings.

Some of these options such as prepaid contracts and NWA shared savings options are already in use and can be implemented in Michigan without threatening utility earnings and financial health. Based on detailed modeling as described in a report published by AEE Institute it is possible, under a range of circumstances, to achieve cost savings for customers when there is a service option available that is more cost effective than a traditional capital investment.[3] This indicates it would be beneficial to investigate these options – and perhaps others – in Michigan in greater detail and refine them for more widespread implementation.

C. Transparency in Distribution Planning - A Need for Broader Access to Grid and Customer Data

A key element of modern distribution planning is accessible information, whether shared during the planning process or afterwards. Many distribution systems are currently "black boxes" in which market participants have limited transparency. The planning process should provide meaningful and useful data for stakeholders, regulators, and customers to support utility efforts to design and operate a modern distribution system. By requiring utilities to make certain distribution system information available during the planning process, DER providers and other stakeholders can scrutinize utility plans and technology assumptions and can bring forward potential solutions to anticipated grid needs that the utility might not consider. When coupled with the aforementioned BCA framework and regulatory treatment options for services, this will surface the best options for utility distribution system investments and solutions to grid needs – ultimately providing cost savings for utilities and customers and aiding in the achieving of state energy policy objectives.

[3] For a more in-depth discussion of these regulatory mechanisms, see Advanced Energy Economy Institute, "Utility Earnings in a Service-Oriented World: Optimizing Incentives for Capital- and Service- Based Solutions", Jan. 30, 2018.

Similarly, there is good reason for the Commission to establish data access protocols that allow third-parties to readily access data on an ongoing basis, subject to appropriate grid security and customer privacy protections. Greater access to distribution system and customer data would allow customers and third-party providers to provide products and services to utilities to meet grid needs. This increases the number of competitors in the market and decreases costs for consumers. It also enables the development of non-wires alternatives and opens the door for innovation.[4] In addition to broader access to grid data, the specific information should include:

1. Probabilistic DER and load growth scenarios

The distribution planning process would benefit from consideration of a broader range of probabilistic DER and load growth scenarios. Michigan's DER penetration is relatively low, providing the state a unique window to anticipate future changes and plan accordingly. In a world where demand is becoming more controllable and dynamic, and DER market growth adds greater uncertainty to future utility loads, modeling is best done through probabilistic DER and load growth scenarios.

Load forecasting is a complex process that underpins a utility's investment plans. It is critical both to identifying local system needs and ultimately, to informing transmission and generation planning. While this is not expected to change, the relationship between distribution system planning and bulk system planning is changing. The expected growth in DERs necessitates enhancements to current approaches. Forecasts should include more granular projections of DER potential and expected customer adoption on different parts of the system, and the resulting effect on load profiles. By addressing this in a proactive manner, Michigan can be ready for the changes coming to its energy system.

Load and DER forecasting should include the development of multiple DER scenarios and use probabilistic planning methods to provide a robust understanding of risks and opportunities. This will help the utility, the Commission, and stakeholders in Michigan understand what the future looks like and what investments will be needed.

Load and DER forecasts should be shared with the public, as they will benefit from stakeholder input for building scenario and forecast assumptions. For example, utilities may not have full, up-to-date information about DER costs and performance. Stakeholder input may also help with the development of macroeconomic and broad assumptions. Then, assumptions should be shared between different planning activities being undertaken by the Commission and various planning bodies.

2. Publicly Available Hosting Capacity Analysis (HCA)

We applaud the Commission's emphasis on hosting capacity analysis. However, these analyses should be robust and publicly available. Utilities should identify and communicate hosting capacity

[4] These steps are adapted from Advanced Energy Economy's issue brief: "Distribution System Planning: Proactively Planning for More Distributed Assets at the Grid Edge", June 29, 2019. https://info.aee.net/hubfs/Distribution%20System%20Planning%20FINAL%20-%2007-03-2018.pdf

information in a manner to allow the public to assess the ability of the system to accommodate DER at potential points of interconnection. Publicly available hosting capacity maps will allow DER providers and customers to provide services to support the grid. In addition, this information will allow municipalities and communities to assess the viability of proposed DERs in their communities.

Many states and utilities are already providing publicly available HCA. One example is Minnesota, where the PUC opened an electric utility grid modernization proceeding [5] in 2015 with a focus on distribution planning. As part of this proceeding, the Commission required hosting capacity analysis. Since then, the primary utility - Xcel Energy - has published the second iteration of its hosting capacity analysis, safely giving the public insight into the results of 1,047 feeder models analyzing the ability of the grid to accommodate DERs without compromising reliability or quality of service.[6]

3. Improved consideration of line losses

Today, most line losses are averaged over time and smoothed in terms of value, but line loss is proportional to the square of load. Improving how losses are treated in distribution system planning is key to driving decisions to upgrade or not to upgrade conductor sizing. Since distribution system re-conductoring costs range from about $150,000 to $500,000 per mile, accurate accounting of line losses is an important cost consideration.

II. Additional Guidance on Pilots from the Commission is Needed

AEE Institute and Michigan EIBC support the development of pilot programs which allow utilities to test promising technologies and business models while gaining familiarity and expertise. As such, it is reasonable for Michigan's utilities to test various NWA and HCA opportunities using pilot programs. As noted by the Commission in its November 21, 2018 Order in U-20147, "The Commission believes that robust evaluation of alternatives, whether "wires" or "non-wires," is important to ensuring long-term cost-effectiveness, prioritization of investments, and solutions that can adapt to changing distribution grid needs going forward. … Again, the Commission sees a tremendous opportunity to inform policy and technical issues through pilot applications and encourages the development of additional NWAs by utilities. The sharing of experiences and lessons learned related to NWAs in Michigan and in other jurisdictions should be instructive to the next iteration of distribution plans."

However, as we note in Section III below, there are a number of improvements and expansions that could be made to the pilot programs currently being undertaken by Michigan's utilities that would

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[5] Case No. 15-556. In the Matter of a Commission Inquiry into Grid Modernization (2015). https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=eDocketsResult&docketYear=15&docketNumber=556#

[6] Fresh Energy (2017). Location, Location, Location (on the Grid). https://fresh-energy.org/location-location-location-on-the-grid/ accessed 09/05/2019

better inform and improve the next iteration of distribution plans. In order to move toward the goals of more modernized distribution grid planning, AEE Institute and Michigan EIBC recommend that the Commission provide utilities with more detailed guidance to help steer these pilots toward gaps in capabilities that need to be resolved. In order to achieve the Commission's vision and policy goals, the Commission should establish a comprehensive framework for utility pilots to guide the next chapter of programs. As we suggested in comments submitted to the Commission[7] regarding the proposed Staff framework for the utility 5-year distribution system plans, there are a number of opportunities for the Commission to establish a clear framework to guide further exploration. The development of additional direction can help focus efforts on the ultimate objectives and improve process efficiency. Similarly, it is critical that the Commission establish a clear, forward-looking framework for the next iteration of utility distribution system plans.

A. Cost-Recovery and Limitations

We support the cost-recovery mechanism in place for the current utility pilot programs. We recognize that these incentives allow utilities to move away from investment on capital expenditure in physical assets and focus on innovative solutions. However, we recommend that the Commission adopt a cost-limit for pilots. The value of this upper limit should allow utilities to receive a reasonable return on investment but minimize the financial impact on ratepayers.

B. Publicly Accessible Data from Pilot Programs

One of the main benefits of pilot projects is the data that they produce. Because these programs are funded with customer dollars, as much data as possible should be made publicly available, while respecting the needs of utilities and participating third parties to keep certain details confidential. Nevertheless, making as much data as possible public can help speed the scaleup of successful projects in Michigan and other states.

C. Improving rate designs to support distribution system needs

In order to take full advantage of DERs, the Commission should undertake efforts to improve rate designs that better align end user pricing with generation, transmission and distribution variable costs from a time and location aspect. For example, dynamic daily rate designs could be part of the pilots.

D. Time frame for distribution planning matters

The time frame over which distribution planning is optimized can determine the economic solution. For example, a five-year planning time horizon can produce a different answer than a ten-year horizon. The Commission should address this issue with additional guidance so that the planning time horizon is properly aligned with broader state policy objectives.

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[7] Case No. U-20147. Filing No.0019. Comments on behalf of Michigan Energy Innovation Business Council and Advanced Energy Economy Institute. Filed 10/5/2018. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000002zMiXAAU

Furthermore, in considering non-wires solutions, utilities should make available the information on system needs with sufficient lead time so that solution providers can put forward effective solutions that can be considered on a level playing field with traditional solutions.

III. Comments on Utility Pilot Proposals

A. Indiana Michigan Power

We agree broadly with the framing that was provided by I&M with respect to how customers and technology are driving changes to the utility business. This establishes the need to explore new opportunities and business models to take advantage of new technology and to engage customers and third parties in new ways to meet grid needs and changing customer expectations.

With respect to the specific NWAs being piloted within I&M territory, we note that the utility is currently only looking at utility-owned assets. We would strongly encourage I&M to expand the scope of its NWAs to include customer and third-party-owned assets. Consistent with the theme of innovation that I&M articulated in its presentation, this approach is likely to be more successful at unlocking innovation and providing novel solutions at potentially lower cost. Innovation is as much about technology as it is about novel business concepts and we see the potential for multi-sided transactions (utility, customer, third-party) to play an integral part of pilot programs and of the future of the utility business model.

B. Consumers Energy

Among the pilots covered by Consumers Energy in its presentation were several they described as NWAs, where the utility is focused on maintaining reliability. They identified specific substations and were using targeted energy efficiency and demand response to achieve peak load reductions. While we applaud this approach, we would characterize these projects more as utility demand side management (DSM) programs versus true NWAs. The latter are better described as targeted solicitations by utilities to achieve load reductions that can avoid or defer specific capital investments. DSM programs, while they can be geotargeted, are more commonly associated with broader system load and energy reductions. We would thus encourage Consumers Energy to pursue options for targeted NWAs as part of a portfolio of options for using load as a resource to meet grid needs.

With respect to the hosting capacity analysis pilot presented by Consumers Energy, we are glad to see the utility developing these capabilities. Other states have significant experience with HCA and Consumers Energy should take full advantage of those learnings. As the utility notes, DER penetration is currently low, but there is value in utility developing HCA capabilities to lower barriers to DER adoption and encourage DER deployment in locations with higher grid value.

We are also intrigued by the Solar Zone pilot concept, in terms of its potential to lower interconnection costs and system upgrades needed to interconnect DER. We look forward to staying abreast of progress and would recommend that the pilot include a BCA to better understand the value of this approach.

C. DTE

In addition to describing the distribution system planning tool and models that it is investing in, DTE described several NWA pilots, including geotargeted load relief. As the structure of these NWAs appear similar to those described by I&M and Consumers Energy, we would thus offer the same recommendations to DTE with respect to expanding the types of procurement methods for achieving the load relief and power quality support it is looking to demonstrate with these pilots. This includes using targeted procurements vs. DSM programs and considering non-utility owned DER assets.

IV. Moving Beyond Pilots

AEE Institute and Michigan EIBC are concerned that continued use of pilot programs, while valuable, may lead to "pilot-itis" or "pilot fatigue," and a lack of at-scale deployments. Pilot-itis is a term that describes the utility tendency to pursue "pilot after pilot" without resulting in any large-scale changes that would promote innovation and implementation. Pilot and demonstration projects are truly meaningful only if they create system-wide applications so that all consumers can benefit from the programs they funded. AEE Institute and Michigan EIBC respectfully recommend that the Commission guard against falling into a cycle in which pilot programs are constantly testing ideas while producing no large-scale implementations. Innovation can get bogged down by a continuous loop of pilot testing, which negatively impacts consumers and the realization of policy objectives. We urge the Commission to connect these programs to a real roadmap for innovation at scale so that they can result in meaningful change. We recommend a deliberate process and regulatory accountability that includes:

- Requiring utilities to identify and communicate barriers to large-scale deployment upfront: During the project design phase, utilities should include all technical and economic elements in the pilot that are necessary for scaling. Although many parameters may be unknown, a business case for deployment at scale must be constructed so that demonstration teams can prepare for the transition.
- The creation of accountability: The Commission can set consistent expectations that projects should become solutions for the whole energy system. These expectations can be supported by a "procedural timeline for evaluation of the project results and for the utility to make a follow-up proposal detailing whether and how to scale up the project."[8]

[8] Rocky Mountain Institute (2017). The Role of Pilots and Demonstrations in Reinventing the Utility Business Model. https://rmi.org/insight/pathways-for-innovation/ accessed 09/05/2019

V. Conclusion

AEE Institute and Michigan EIBC applaud the Commission for taking steps towards ensuring greater transparency and value for ratepayers in utility distribution planning and we appreciate the opportunity to provide these comments on the utility pilot proposals. We look forward to working with the Commission and stakeholders on these important issues.