Smart Rate Design for Distributed Energy Resources

Comments on Draft Report

Introduction

The Michigan Energy Innovation Business Council and Advanced Energy Economy (collectively Michigan EIBC/AEE) appreciate the opportunity to provide comments on the draft report entitled "Smart Rate Design for Distributed Energy Resources" ("Draft" or "Draft Report"). We appreciate the Michigan Public Service Commission's ("MPSC" or "Commission") attention to these issues and the Regulatory Assistance Project's ("RAP") efforts in compiling this draft report. As outlined below, we are especially concerned that this Draft Report, although required by Michigan Senate Resolution 142, is removed in its analysis from current law and the legislative context in Michigan. Failure to place this report in that context not only will create confusion, but also, may fail to respond appropriately to the initial context in which it was requested.

Overall

Michigan EIBC/AEE are concerned that the Draft Report does not reflect the legislative context in Michigan, the current state of rate design, or the current level of DER deployment. As described below, the report was written in response to Michigan Senate Resolution 142, which itself was a response to a long-standing legislative discussion about the current statutory limit on distributed generation (DG) systems. However, because the report describes rate design options that are best suited for states with high DG penetration levels, it appears to address a future state with no limits on DG deployment. Currently, DG in Michigan is limited by a legislative cap, making concerns about integrating high levels of DG (and more broadly, distributed energy resources, or DER[1]) largely hypothetical. In addition, it is unclear from the report which of these rate design changes could currently be implemented by the MPSC without need for legislative action.

[1] We use the terms DG and DER somewhat interchangeably in these comments, since the rate designs being discussed generally apply to DG, even though the effort under which this report was prepared is looking more broadly at DERs.

In 2016, the Michigan legislature required the MPSC to develop a cost-of-service based tariff to replace net metering while still retaining the 1% cap on the aggregate capacity of DG systems. Any discussion of future rate designs in Michigan needs to fully explain where it is situated relative to this cap. The report should make clear its assumptions about the penetration of DG systems and the rate of adoption of DG systems (and thereby, assumptions about the current statutory cap). It is unclear, if the current 1% cap is retained, whether there is any reason to consider different rate design options. In fact, the Draft Report indicates that the inflow/outflow tariff does not produce cost shifting and seems to suggest that the recommended rate design options are for a future state with much higher penetration levels. Any presentation of rate design options should clearly explain their relationship to the existing inflow/outflow tariff. The final report should clearly state that the report is relevant only to a future scenario under which DG penetration reaches a much higher level without a statutory limit.

The Commission additionally indicated in an Order in Case No. U-20697 issued December 17, 2020, and corrected via an Errata issued December 30, 2020, that "In the first quarter of 2021, the Commission Staff shall initiate a work group to examine the costs and benefits of distributed energy resources, including solar, in the context of how customers use the grid now and in the future, as described in this order." It is our understanding that this Draft Report represents the output of that "work group" to examine the costs and benefits of DERs. Although the Draft Report does briefly touch on the costs and benefits of DERs, we submit that it is largely focused on future rate design options. Specifically, as outlined in more detail below, the Draft Report does not fully describe the benefits of DERs or the quantification of those benefits in a rate design context. To be responsive to the Order in Case No. U-20697, Michigan EIBC/AEE believe that the final report should include more details on the quantification of the benefits of DERs.

With respect to the specific rate design recommendations made in the Draft Report, we appreciate that the proposed rate design pathways leverage AMI data to enable time-varying rates that address time-specific capacity constraints and can lessen the need for new capacity additions for generation, transmission, and distribution. As described in detail below, while we generally support incorporating the distinction between customer-specific "site infrastructure" and the shared costs of the grid into rate design, these concepts and cost categories need to be carefully defined. However, as in the case of the general description of benefits, specific values for environmental externalities are not provided for all of the rate design recommendations. As a result, those rate designs that provide credits for the value of wholesale energy only will undercompensate customers with DER systems for the emissions-free energy or energy waste reduction associated with those systems. In addition, in the recommended rate designs, the value of DER to the distribution system remains largely unaccounted for. While the Advanced Residential Rate Design pathway discusses a marginal cost or credit associated with the time varying value of generation, transmission, and distribution, it is not clear to what extent the rate will credit DER for generation, transmission, or distribution capacity. Some DERs, especially when paired with energy storage, can provide firm capacity to the system. It is important that the proposed rate designs fully account for these benefits of DERs.

Finally, we note that the Draft Report provides a detailed review of rate design principles and constructs, but the three pathways presented provide relatively high-level recommendations with limited qualitative assessments of the pros and cons of the different options. We suggest that RAP elaborate on the three suggested pathways and provide a qualitative assessment of their pros/cons and potential fit for Michigan, including how a fair and orderly transition would be made from the current rate design system. Any such qualitative assessment, as noted above, should include consideration of existing statutory limitations on DG market development.

Detailed Comments

Introduction

On page 4, the Draft Report describes the development of the inflow/outflow model by the MPSC. However, it is important to situate the change to the inflow/outflow model as a requirement by the legislature. In Michigan Public Act 341, Section 6a, the legislature stipulated that,

> "Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting <u>equitable cost of service</u> for utility revenue requirements for customers who participate in a net metering

> program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295,…"

It is important to reference this law because the Commission did not institute the inflow/outflow model of their own discretion and did not implement it without legislative direction. The inflow/outflow model was designed to be cost-of-service based and, as noted in the Draft Report, eliminates cost shifting from DER customers to non-participating customers.

Similarly, the MPSC did not create the Distributed Energy Resources Rate Design working group without legislative direction as suggested on page 4. Instead, Michigan Senate Resolution 142 was adopted on September 29, 2020 "to encourage the Michigan Public Service Commission to undertake a study into alternative and innovative rate design options for Michigan's electric customers." This should be clarified in the final report.

Background and Regulatory Context in Michigan

On page 8, the Draft Report describes the creation of the DG program in Public Acts 341 and 342. It is important that the Report notes here, as described above, that those Acts also retained the 1% cap on the aggregate capacity of DG systems.

On page 9, the Draft Report suggests that utilities that have "approached" their cap have lifted it. In both the case of UPPCo and Consumers Energy, the utilities have agreed to increase their caps only *after* the cap was reached and customers were put on waiting lists for variable amounts of time. It is also important to note that although UPPCo's now 3% cap is binding, having been agreed to in a settlement agreement, Consumers' DG cap was increased to 2% in an entirely voluntary manner and could be lowered at the discretion of the utility.

On page 13, Figure 3, the Draft Report shows the impact of "high" levels of solar penetration in Hawaii. It is critical, as described above, that readers understand what "high" means in this context. In other words, it is important to understand what the DG penetration was in June 2006, June 2012, and June 2017, leading to the noted changes in system load in Figure 3. Such context would be incredibly useful to policymakers in Michigan as they consider how future rate design needs to evolve. Similarly, throughout the rest of this section, the authors appear to assume that DERs will increase in penetration in Michigan in a manner similar to other states with already high levels of DER penetration. That might be true eventually *but only if* the 1% cap on DG systems is removed statutorily. If the authors are assuming a future in Michigan with increased DG penetration beyond the 1% cap, that needs to be explicitly stated.

Ratemaking Practices and Perspectives on Costs and Benefits

On page 22, the Draft Report suggests that "higher penetrations" of intermittent resources may require investments in technologies to smooth load, including energy storage. As above, it would be very helpful to understand what "higher" means in this context. Additionally, it would be helpful for the authors to provide more detail on whether this is primarily an issue with utility-scale resources or with customer-sited resources and at what penetrations of each type of resource.

Figure 8 on page 23 lists a number of benefits from DERs. Two primary participant benefits appear to be missing – bill reductions (reduced electricity costs) and provision of back-up power (increased reliability). If those benefits are included as sub-benefits of the others listed, that should be clarified, and if they are missing, they should be added.

On page 25, the Draft Report indicates that the full benefits of DERs are often not accurately quantified in the Total Resource Cost test. It would be valuable to understand what those benefits are and how they might be quantified. The authors suggest that all of the non-energy benefits should be accounted for, but do not list what those are or indicate how they can be quantified.

On page 30, the Draft Report discusses the issues around using both embedded and marginal costs. Throughout this section, it would help to provide grounding for Michigan policymakers and stakeholders if the authors situate this information in the Michigan context. In other words, it would be helpful to understand how the MPSC conducts cost allocation and the history of those decisions. Rather than a simple discussion of what has been done in "many jurisdictions," this report should describe specifically what has been done in Michigan.

Overarching Program Parameters

On page 35, the Draft Report suggests that Michigan is similar to other states that have put in place "net metering" caps. However, even with full net metering in place, most states have determined that a 1% cap is far too low and cost shift does not become a concern until higher penetration levels with full net metering. In Michigan, due to the 2016 legislation and change to DG tariffs, Michigan does not have net metering for investor-owned utilities, nor does Michigan have a "net metering" cap. Instead, although other states do have caps on net metering programs, Michigan is one of the only states (if not the only state) with a cap on a DG tariff program that was established to replace net metering and avoid cost shifting. This must be clarified and revised in the final report.

Reforms to Consider and Evaluation of Potential Pathways for DER Rate Design

Overall, it is unclear how the authors developed the "potential pathways" or under what circumstances each might be recommended. As recommendations to policymakers, the tradeoffs/benefits between these pathways and the current system need to be clear. As described above, it also needs to be clear at what level of DG penetration the authors recommend considering these future rate design options.

More specifically, Michigan EIBC/AEE are supportive of the use of AMI data in the proposed rate designs to enable time-varying rates that address time-specific capacity constraints and lessen the need for new capacity additions for generation, transmission, and distribution. It is also beneficial that customer charges are reformed to better reflect the actual fixed costs of serving individual customers. For the smallest customers in multiple-unit dwellings, there may be virtually no customer-specific infrastructure beyond the meter installed. Larger homes in sparsely populated areas are likely to require more infrastructure to serve them. Customer charges that reflect this reality improve alignment with cost causation and likely result in bill relief for customers that are likely in the greatest need.

The report briefly discusses the distinction between "site infrastructure" and "shared infrastructure," and how these concepts can be integrated into rate design. While we agree that accurately incorporating these distinctions can improve the alignment of rate design with cost causation, we urge the Commission to approach this issue with sufficient analysis and stakeholder review. This issue has been controversial in other states,[2] as the distinction essentially separates a customer's bill into two cost categories, one that can be easily reduced by onsite DER and customer behavior and another category that is much more difficult to influence. To accurately account for site-specific costs, the Commission first needs to create a clear definition for them. We recommend that any definition depend on whether the distribution facility was installed to serve a specific customer or multiple customers. Infrastructure installed to serve a specific customer represents a utility's sunk costs for serving that customer. If the customer's load were to diminish or disappear altogether (along with associated cost recovery through rates), the cost to serve that customer would shift to other customers. However, if those customer-specific costs were collected through a charge that is difficult to bypass, it would prevent shifting these costs to other customers.

Shared costs, on the other hand, can be reduced by reductions in load or injections of power into the system. Reductions in load and power injections free up capacity that can be used to serve other customers. Investments in these shared system resources, if they are underutilized by one customer, can be easily used by another. Reducing strain on these shared resources when capacity is tight should be encouraged, and rates should provide some benefit to customers in exchange for their support of system capacity. If shared costs are improperly assigned to rate elements meant to recover site infrastructure, then customers will not see bill reductions commensurate with their beneficial actions that support the system.

If the Commission were to adopt a rate design that depends on separate allocations for site-infrastructure and shared infrastructure costs, it should develop a clear methodology for determining this allocation that reflects the individual vs. shared usage of these facilities as closely as possible. The report provides service lines, secondary networks, and line transformers as examples of costs that could be considered as site-infrastructure. While service lines largely serve specific customers, line transformers and secondary networks may more frequently serve multiple customers. Indeed, in dense urban areas, secondary networks can be highly shared. A

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[2] See for example, NY PSC Proceeding 15-E-0751. "In the Matter of the Value of Distributed Energy Resources." Available at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751.

study that examines the actual use and deployment of these distribution facilities would be necessary to determine what fraction of these secondary voltage system costs categories should be allocated to site-infrastructure costs.

We also maintain that the per kWh fees for exports in the Advanced Residential Rate Design Pathway, which are designed to recover shared infrastructure costs, are unjustified. So long as those power exports are mixing with other customer's loads on shared infrastructure, those injections will only serve to decrease capacity usage and therefore a potential driver of new costs. Because DG has already undergone an interconnection process that screens for the potential of exports to result in costs on the system (and customers are required to pay for any necessary upgrades), there are no identifiable system costs for exports that should be recovered in rates, other than those that would already be recovered through the site infrastructure-related charges.

Michigan EIBC/AEE are also concerned about how costs might be allocated between site infrastructure and customer charges if the "basic customer method" referenced in the Gradual Evolution Pathway is employed in the Advanced Residential Rate Design Pathway. The basic customer method tiers customer charges based on the greater site-infrastructure costs of serving single-family homes and customers with high demand. Absent the site-infrastructure costs, non-demand related customer-specific costs, such as metering, customer service, and billing, are relatively similar among all residential customers. It is not clear why the Advanced Residential Rate Design Pathway would tier residential customer charges (to reflect differences in site-infrastructure costs) *and* recoup site-infrastructure costs through a specific non-coincident peak demand charge. This appears to be double recovery of the same costs. We would prefer that all demand-related site infrastructure costs be recovered in the non-coincident peak demand charge, which is at least controllable to a degree, rather than be lumped into the customer charge, which sends no signals to modify behavior at all.

Conclusion

Michigan EIBC/AEE thank the Commission for its work to date on the subject of rate designs for DERs, and appreciate the opportunity to comment on the Draft Report. We respectfully request that the Commission consider these comments as it works with RAP to prepare the final report. The final report should better reflect the Michigan context in which it will be considered and include the important details on rate design options that are discussed above. The final report should also acknowledge the significant, collaborative legislative and regulatory work that need to occur before rate design changes can be implemented. Michigan EIBC/AEE look forward to participating in this work, with the goal, under an open market without a statutory cap, of developing rate designs that support increased customer adoption of DERs to help Michigan achieve its important clean energy policy goals and benefit customers and the electricity system as a whole.