Demand Response Aggregation Staff Report and Recommendations

Case No. U-20348

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MPSC Staff

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Definitions

AEMA: Advanced Energy Management Alliance
AES: Alternative Electric Suppliers
ARC: Aggregator of Retail Customers
BPM: MISO Business Practice Manual
CONE: Cost of New Entry for Generation
CP Node: MISO Commercial Pricing Node
CSP: Curtailment Service Provider
DER: Distributed Energy Resource
DR: Demand Response
EDC: Electric Distribution Companies
EER: Energy Efficiency Resources
ESR: Electric Storage Resources
FERC: Federal Energy Regulatory Commission
IRP: Integrated Resource Plan
ISO: Independent System Operator
LBA: Load Balancing Authority
LMR: Load Modifying Resource
LRZ: Local Resource Zone
LSE: Load Serving Entity
MP: Market Participant
MECT: MISO Module E Capacity Tracking Tool
MEGA: Michigan Electric and Gas Association
MIRECS: Michigan Renewable Energy Certification System
MISO: Midcontinent Independent System Operator
MPSC: Michigan Public Service Commission
NOPR: FERC Notice of Proposed Rulemaking
OMS: Organization of MISO States
PLC: Peak Load Contribution
PRA: MISO Planning Resource Auction
RERRA: Relevant Electric Retail Rate Authority
RTO: Regional Transmission Organization
ZRC: Zonal Resource Credit

Executive Summary

The Michigan Public Service Commission (MPSC or Commission) issued an order in Case No. U-20348, seeking to review the process for demand response (DR) aggregation for Alternative Electric Supplier (AES or suppliers) customers. DR aggregation typically involves a third-party aggregator that contracts with customers for DR curtailment services or load reduction where ultimately that combined DR load is offered or sold into the wholesale market. The Commission Staff (Staff) was directed to work with parties to examine issues related to who should be responsible for bidding DR resources into the wholesale market, how to adequately track DR, how aggregated DR might affect capacity requirement allocations to load serving entities (LSEs) and address any appropriate reporting requirements related to DR aggregation.

To examine these issues, Staff held three stakeholder meetings that drew participation from Michigan utilities, AESs, third-party DR aggregators, the Midcontinent Independent System Operator (MISO), PJM and other special interest groups and was directed to detail its findings and recommendations as a result of the stakeholder process in a final report. Stakeholders took the opportunity to participate throughout the process and have provided final comments that have been attached as an appendix to this final report.

In this report, Staff includes the following recommendations:

1) Staff recommends that the Commission allow the direct participation of third-party aggregators in the capacity, energy and ancillary services markets on behalf of DR resources aggregated from Michigan-based AES load, aligning with FERC-approved RTO tariffs and processes, effectively removing a barrier to allowing third-party aggregators to fully utilize registered DR resources.
2) Staff recommends continuing to allow forward ZRC contracts, which may include aggregated DR resources, to qualify for Michigan's forward capacity demonstration requirement. In addition, Staff will endeavor to open up lines of communication with third-party aggregators operating in Michigan to better understand their product offerings. Staff will combine information from DR aggregators operating in this state with other information obtained in Michigan capacity demonstration filings to monitor the use of aggregated DR for meeting Michigan's forward capacity requirements.
3) Staff recommends that the Commission direct Staff and the Michigan regulated utilities to work with MISO on developing proposed changes to the MISO process, wherein MISO would provide the amount of dispatched aggregated DR at the time of the MISO peak to be utilized by the utilities in the calculation of peak load contributions (PLCs).
4) Staff recommends an update to Michigan's capacity demonstration requirements to include a requirement for LSEs to comply with Staff auditing of all prompt-year ZRC transfers in the MISO market for ZRC contracts submitted in previous Michigan capacity demonstrations.

5) Due to lack of support and specific concerns expressed related to resource planning and distribution operations, Staff recommends maintaining the status quo relative to banning DR aggregation for bundled retail load.
6) Because the aggregated DR market and framework is still under development, Staff recommends that aggregated Energy Efficiency Resources (EERs), aggregated storage, and aggregated Distributed Energy Resources (DERs) not be accepted as capacity resources in any Michigan four-year forward capacity demonstration, unless they have been qualified by MISO and appropriate documentation is provided. Additionally, Staff recommends that the Commission direct the Staff and the Michigan regulated utilities to continue to work with MISO on any tariff provisions that may be proposed related to third-party aggregated resources in the market, to ensure that the impact of those resources on PLCs is captured appropriately and that communication protocols are put in place to ensure that entities calculating the PLCs will be provided with data reflecting adjustments appropriate due to dispatched resources at the time of the MISO peak.

Background

On September 15, 2017, the Commission order in Case No. U-18369, established a framework for review and approval of utility DR programs and affirmed that AESs may offer DR programs to their customers through entities that assist retail customers with the strategies or technology to reduce their electric usage (commonly known as third-party aggregators, Curtailment Service Providers (CSPs) or Aggregators of Retail Customers (ARCs)),[1] as long as the AES is the entity that bids the DR into the wholesale market. This determination was made in the context of finding that the Commission will continue to review DR programs offered by AESs as part of the capacity demonstration process required by Section 6w of Public Act 341.

Additionally, in Case No. U-18197, the Commission further clarified that under certain circumstances, a supplier can use DR capacity resources from another supplier's customers to meet its forward capacity demonstration obligations. In other words, the Commission authorized third-party aggregation for customers being served by AESs, allowing third-party entities to combine load reductions of multiple customers into one resource and then an AES may bid the aggregated resource into the wholesale market.

On November 21, 2018 the Commission issued an order in Case No. U-20348, seeking to establish a process for DR aggregation for AES customers that: (1) aligns with federal requirements and policy directions (on fundamental jurisdictional questions as well as technical specifications for qualifying DR resources under the RTO's tariff); (2) ensures proper tracking, particularly to avoid double counting in the state's capacity demonstration programs or other gaps that could ultimately affect electric reliability; (3) identifies any unnecessary barriers to third-party aggregation to make it scalable; and (4) works through issues in a collaborative manner, including any state and federal jurisdictional questions, to provide a template for scaling up aggregation that may also accommodate other applications.

The Commission directed the Staff to work with third-party DR aggregators, AESs, customers of AESs, regulated utilities, the Midcontinent Independent System Operator (MISO), and other stakeholders on issues related to:

1) Whether the ability to aggregate demand response for customers of Michigan alternative electric suppliers for bidding into wholesale markets should be limited to suppliers only;
2) How to adequately track demand response resources being used for capacity demonstration purposes;

[1] For the purpose of this report, all third-party aggregators will be referred to as ARCs, recognizing that the terms ARC and CSP were used interchangeably throughout this process but have a slight definitional variation within MISO and PJM.

3) The appropriate treatment of aggregated demand response outside the capacity demonstration framework that may affect capacity requirement allocations to LSEs, such as aggregated DR for capacity, ancillary services, and/or energy; and
4) What are appropriate reporting requirements related to DR and aggregation, and whether the capacity demonstration filing requirements need revision.

To examine these outstanding issues, Staff held three stakeholder meetings that drew participation from Michigan utilities, AESs, third party DR aggregators, MISO, PJM and other special interest groups. Staff also examined the status of DR aggregation in Michigan over the 2017-2019 time-period and identified barriers and other issues within this report.

The recommendations in this report are Staff's alone and should not be considered endorsed by all participating stakeholders. Stakeholder discussions were held providing a common understanding of the issues with an eye towards achieving consensus; however, consensus was not achieved on all fronts. The stakeholder feedback is summarized on an aggregated basis. Not all parties provided feedback to every question. Staff greatly appreciates the participation and contributions made by each of the stakeholders throughout the process.

Overview of DR Stakeholder Engagement Activities

Pursuant to the Commission's direction in Case No. U-20348, Staff commenced a stakeholder process to examine DR aggregation issues identified by the Commission in its November 21, 2018 order. All stakeholder meetings were held in the Lake Michigan Hearing Room at the MPSC office in Lansing, MI.

The first stakeholder meeting was held on February 13, 2019. There were 12 organizations represented in person, while 59 stakeholders participated via phone and/or Skype.[2] Staff provided background information and an overview of the Commission's Order in Case No. U-20348 and provided an overview of the current capacity demonstration process and requirements pursuant to Section 6w of PA 341 and Case No. U-20154. This meeting also included presentations from MISO, Voltus, and Advanced Energy Management Alliance (AEMA). MISO presented an overview of its current DR registration process and how DR may participate in its capacity, energy and ancillary services markets. Voltus, a third-party DR aggregator in Michigan, provided an overview of its aggregated DR currently within MISO. AEMA, a trade association representing DR aggregators, presented on the current DR opportunities and offerings within Michigan and the

[2] In addition to Staff, the following entities were represented at the first stakeholder meeting: Consumers Energy, DTE Energy, Energy Michigan, Voltus, AEMA, Wolverine Power Marketing Cooperative, Constellation, DN VGL, US Steel, Walmart, 5 Lakes Energy, AEP/Indiana Michigan Power Company, NextEnergy, MISO, ABATE and the Michigan Electric Cooperative Association. 42 other individuals representing various organizations, participated via phone and/or Skype.

region. Representatives from DTE Energy Company (DTE) and Consumers Energy participated in a panel discussion with Staff and the audience regarding their experience with aggregated DR in Michigan and issues related to customers' PLC calculations. To wrap up this meeting, Staff posed several questions to the audience related to state vs. federal jurisdiction, tracking aggregated DR, the effects of aggregated DR on an LSE capacity demonstration, and what would be acceptable reporting requirements for Michigan's four-year forward capacity demonstrations. Specific questions related to these topics were circulated to stakeholders after the February 13th meeting. Staff received written feedback from seven different stakeholders. A recording of this meeting is available on the MPSC website.[3]

The second stakeholder meeting was held on March 12, 2019. There were 10 organizations represented in person, while 31 stakeholders participated via phone and or Skype.[4] Staff provided an overview of the agenda and topics discussed during the February 13th meeting and walked through the written responses received after the first meeting. Staff explored and facilitated discussion on the Indiana and Pennsylvania state models. Potential elements for what topics and recommendations would be included in the Staff report were also discussed. To wrap up this meeting, Staff proposed several additional questions to the stakeholders related to the following topics:

- The pros and cons of the Indiana model versus the Pennsylvania model;
    - The Indiana model specifies that participation in RTO demand response programs should be done through the retail customers LSE. Utilities are encouraged to work with ARCs and CSPs under tariffs designed to participate in RTO DR programs. In this model, aggregators acquire and aggregate customers while the LSE registers that DR with the RTO.
    - The Pennsylvania model was created via legislation in 2008 and includes both energy efficiency and peak reduction components. The Pennsylvania model requires Electric Distribution Companies (EDCs) to competitively bid all contracts with a Pennsylvania registration conservation service provider. These entities provide consultation, design, administration and management services to the EDC. The Pennsylvania model essentially requires that unaffiliated, independent companies provide DR services to the utility.
- MISO's DR registration processes versus PJM's DR processes;

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[3] https://www.michigan.gov/mpsc/0,4639,7-159-91243-489901--,00.html

[4] In addition to Staff, the following entities were represented at the second stakeholder meeting: Consumers Energy, DTE Energy, Energy Michigan, AEMA, Wolverine Power Marketing Cooperative, DN VGL, US Steel, 5 Lakes Energy, AEP/Indiana Michigan Power Company, ABATE, the Michigan Gas and Electric Association and the Michigan Electric Cooperative Association. 24 other individuals representing various organizations, participated via phone and/or Skype.

- Whether MISO Business Practice Manual (BPM) changes or tariff revisions related to DR or PLC calculations are warranted;
- Whether the MPSC should implement a voluntary registration process for ARCs serving in Michigan;
- Stakeholder thoughts on whether the MPSC should consider pursuing a Michigan four-year forward capacity tracking tool;
- Whether the ability to aggregate DR for AES customers should be limited to AESs only;
- What would need to happen for stakeholders to feel comfortable with lifting the ban on DR aggregation for all retail customers in Michigan.

Specific questions related to these topics were circulated to stakeholders after the March 12th meeting. Staff received feedback from six different stakeholders. A recording of this meeting is available on the MPSC website.[5]

The final stakeholder meeting was held on May 3, 2019. There were 10 entities represented in person, while 39 stakeholders participated via phone and or Skype.[6] Staff provided an overview of the agenda and topics discussed during the March 12th meeting and walked through feedback received after the second meeting. Based on the feedback received from stakeholders, Staff invited PJM to present on its resource adequacy construct, DR registration process, and DR participation in its markets. Consumers Energy presented on its current DR programs and discussed the current challenges with aggregation and additional concerns that Michigan would be faced with if ARCs are granted unrestricted access to all retail customers. AEMA presented on leveraging a utility-aggregator partnership model in lieu of lifting the ban on DR aggregation of all retail customers. Prior to this stakeholder meeting, Staff circulated a draft Staff report outline for stakeholders to review. A brief discussion of the draft outline took place and Staff outlined next steps for stakeholders to participate with comments. Staff offered to accept proposed redlines and comments on the draft outline through May 15, 2019 and offered to circulate a revised draft outline to stakeholders in mid-May that included draft Staff recommendations on whether to lift the ban on aggregated DR in Michigan and the potential implications for aggregated EERs and aggregated energy storage. Staff also offered to accept additional comments and materials from any stakeholder to be attached to this report as an appendix for inclusion with the final report and reiterated Staff's intention to recommend the Commission

[5] https://www.michigan.gov/mpsc/0,4639,7-159-91243-489901--,00.html

[6] In addition to Staff, the following entities were represented at the third stakeholder meeting: Consumers Energy, DTE Energy, Energy Michigan, AEMA, Wolverine Power Marketing Cooperative, Direct Energy, US Steel, AEP/Indiana Michigan Power Company, ABATE, PJM, the Michigan Gas and Electric Association and the Michigan Electric Cooperative Association. 31 other individuals representing various organizations, participated via phone and/or Skype.

accept additional comments from stakeholders in the docket. Due to technical difficulties, there is no recording available for the May 3, 2019 meeting.

Interested stakeholders were presented with significant opportunity for participation, through listserv messages, stakeholder meetings and written feedback. Staff has reviewed and taken into consideration, the proposed changes to the draft Staff report outline received from four different stakeholders and has included as Appendix A, finalized comments of those stakeholders who requested that they be attached to the final report.

Aggregated DR Participation in Michigan

MISO's tariff and BPM outline the requirements and process for aggregated DR registration and participation in its markets. ARCs may submit a DR registration for aggregated Michigan AES load to MISO. MISO reviews and sends the DR registration information to the utility/EDC for verification that the customer accounts are served by AESs, verification that the resource is not participating in DR with any other supplier and for verification that the load reduction amount is feasible. The utility/EDC provides feedback to MISO if reason exists to reject the aggregated DR registration. Following review by the utility/EDC, MISO submits the aggregated DR registration information to the Relevant Electric Retail Rate Authority (RERRA), in Michigan's case, this would be the MPSC. The RERRA has 10 business days to review the information. If the registration is approved by these entities, MISO will finalize the registration and assign the appropriate capacity credit. If the registration is rejected by any one of these entities, the registration moves back to the ARC for revisions or withdrawal from the registration process. The AESs do not receive any notice or information when any of its customers sign a contract with an ARC nor do they receive any notice or information when any of its customers are included in part of an aggregated DR registration at MISO.

Currently, there is approximately 2,000 MW[7] of retail choice load, or AES load, in Michigan that would be allowed to participate in aggregated DR programs. Staff discovered that some of Michigan's AES customers either are participating in, or have expressed interest in participating in aggregated DR. [8] Michigan currently does not have any regulatory oversight of third-party DR aggregators, ARCs, or the services they offer to their customers. The approved Michigan capacity demonstration process and requirements contain specific provisions for any LSE utilizing new or existing DR resources, however these provisions do not address the scenario in which an AES customer executes a contract with an ARC whom is not subject to the capacity demonstration requirements or any other reporting requirements. Likewise, once a ZRC is created by MISO as part of its resource adequacy construct, it may be sold via a forward ZRC contract that does not

[7] https://www.michigan.gov/mpsc/0,4639,7-159-16377_17111_17999-68257--,00.html

[8] The allowable peak reduction would not exceed each retail customer's actual peak load during MISO's peak hour in the previous planning year, which would likely be less than 2,000 MW.

specify the originating source of the ZRC or even whether it is a supply-side resource or a demand-side resource. In fact, because ZRCs are created by MISO in the prompt-year, forward ZRCs don't actually exist and could be sourced from existing resources or potentially new resources that have not yet been developed or put into service. This creates transparency challenges in forward capacity demonstrations as further discussed later in this report.

Staff's review and audit of AES capacity demonstrations and contracts filed in early 2018 for planning year 2018/19 did not indicate that any AES load was participating in DR Aggregation with an ARC at that time. Likewise, Staff did not find evidence of any LSE procuring aggregated DR on a four-year forward basis and including those resources within its capacity demonstration. However, Staff did become aware of aggregated DR in Local Resource Zone (LRZ) 7 during its review of capacity demonstrations filed in 2019 in Case No. U-20154 for planning year 2022/23. During the auditing process of LSE prompt-year ZRC transfers in the MISO Module E Capacity Tracking Tool (MECT), Staff observed ZRC transfers of aggregated DR to AESs. The transfers observed were for the prompt-year, planning year 2019/20, because MISO's capacity construct is an annual prompt-year construct as opposed to a four-year forward construct employed in Michigan's capacity demonstrations. Forward ZRC contracts were the likely vehicle for procuring the aggregated DR resources. Although Staff observed the prompt-year transfer of aggregated DR resources to AESs for planning year 2019/20, Staff's review of the AES forward contracts did not reveal any aggregated DR resources. Forward ZRC contracts typically specify the zone from which the ZRCs will be sourced, however, they do not specify whether those ZRCs will come from supply-side or demand-side resources. Additionally, capacity demonstrations required in 2019 for planning year 2022/23 also did not indicate that any AES customer load was participating in DR aggregation with an ARC. This will not be determined until Staff reviews LSE prompt-year ZRC transfers in the MISO MECT in 2022.

Discussion and Recommendations

a. Who should be allowed to bid DR into the RTO market?

The September 15, 2017 Commission order in Case No. U-18369, affirmed that AESs may offer DR programs to their customers through third-party aggregators, ARCs or CSPs, as long as an AES is the entity that bids the DR into the wholesale market. The Commission directed Staff to discuss whether the ability to aggregate DR for customers of Michigan AESs for bidding into RTO markets should be limited to AESs, or be extended to non-AES third parties such as ARCs.

Stakeholder Discussion and Feedback

Most stakeholders agreed that the MPSC can prohibit direct participation of retail customers. However, DR aggregators, large customers, and electric choice representatives support allowing ARCs to represent and participate in the markets on behalf of aggregated DR resources for Michigan's AES load, and regulated utilities support a limitation of ARCs not being allowed to bid in the market on behalf of aggregated DR resources for Michigan's AES load.

Staff Recommendation

MISO allows ARCs to register aggregated demand response resources and offer those resources in its market with approval by the RERRA.[9] PJM also allows CSPs to register aggregated demand response resources and offer those resources in its market.[10] The Commission has ordered in Case No. U-18369 that DR aggregation should be permitted for AES load. (9/15/17 Order, p.10). Voltus has already aggregated DR resources from Michigan AES customers and registered it in the MISO market for planning years 2018/19 and 2019/20. Removing the previously approved limitation of requiring an AES to bid the DR resource into the market would provide direct access to the market for those aggregated DR resources, effectively removing a barrier. Limiting the participation of aggregated AES load in RTO markets to AESs as opposed to ARCs or CSPs does not solve technical or transparency related issues as will be discussed further in this report, primarily because AESs are not involved in the registration or dispatch of third-party aggregated DR products, nor are they privy to such information.

Staff recommends that the Commission allow the direct participation of third-party aggregators in the capacity, energy and ancillary services markets on behalf of DR resources aggregated from Michigan-based AES load. This recommendation aligns with FERC-approved RTO tariffs and processes, effectively removing a barrier to allowing third-party aggregators to fully utilize registered DR resources.

b. How do we adequately track aggregated DR?

The Commission directed Staff to discuss how to adequately track DR resources being used for capacity demonstration purposes under MCL 460.6w.

DR contracts are executed directly with the customer by the ARC. The MPSC, the EDC and the AES are not currently privy to this information. Pursuant to Section 9.5 of MISO's BPM 001 and as discussed earlier in this report, MISO will notify the MPSC and the utility/EDC of every new aggregated customer and provide the designated Market Participant (MP), the MW amount, the load balancing authority (LBA) and Commercial Pricing (CP) Node information. Staff posed the question to stakeholders asking whether or not the information provided by MISO is sufficient enough to allow the MPSC to track demand response resources and ensure that cross-subsidization and double counting is not occurring.

[9] https://www.misoenergy.org/legal/business-practice-manuals/
[10] https://www.pjm.com/-/media/documents/manuals/m11.ashx

Stakeholder Discussion and Feedback

There were no stakeholders that disagree that the MPSC should track aggregated demand response, or at least have the ability to obtain the appropriate information from whoever necessary, for capacity demonstration purposes. However, there was general disagreement about whether it is the MPSC's responsibility to ensure double counting doesn't occur and what information, specifically, the MPSC and/or AES would need from the ARC.

For new aggregated demand response resources that have not already been registered in the MISO market, stakeholders have suggested that forward ZRC contracts coupled with signed affidavits from the officer of the company should be deemed sufficient for capacity demonstration purposes. This treatment is consistent with the treatment for supply-side ZRC contracts and the documentation provisions are already covered in the existing capacity demonstration requirements.

ZRCs are fungible products that could be traded many times and do not typically specify the specific supply-side or demand-side resource generating the ZRCs. By not specifying the source of the ZRCs, parties are able to fulfill the delivery requirements in the actual planning year with any available ZRCs; allowing significant optionality and adaptability to adjust to changes to supply-side or demand-side portfolios. ZRC contracts that have been reviewed by Staff typically contain significant financial penalties for non-delivery.

Because ZRC contracts usually intentionally do not specify the source of the ZRCs, there is no way to track any supply-side or demand-side resources included in forward ZRC contracts for capacity demonstrations. Even though the specific sources of these ZRCs cannot be tracked, Staff would be able to calculate the total amount of ZRCs in forward ZRC contracts as part of capacity demonstrations compared to the total amount of registered aggregated DR in the prompt-year MISO market (that Staff obtains as the RERRA) coupled with Staff's projection of the amount of existing undemonstrated supply-side resources in Zone 7 as reported in Staffs annual report on the capacity demonstration results.[11] This gives Staff the ability to determine whether enough ZRCs already exist in the prompt-year market to cover the total amount of ZRCs submitted in capacity demonstrations via forward ZRC contracts.

New aggregated DR resources that have not yet been registered in the prompt-year MISO market would not have been verified by the EDC as AES load and the MW amount would not yet have been compared to the customer's previous PLC to determine if the claimed load reduction is feasible. Even if a contract between a customer and an ARC

[11] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000004PmgNAAS

was supplied as part of the demonstration, the resource would not have been verified by the utility/EDC, the RERRA or MISO for the planning year the LSE is demonstrating for. Attempting to track resources that have not been verified by the EDC or qualified by MISO may prove to be extremely difficult, if at all possible. In addition, because ZRC contracts currently do not specify the source of the ZRCs, new aggregated DR resources that have not been reviewed or verified in any way, could be included in forward ZRC contracts without the relevant parties knowing. Even if a process was developed for the MPSC to verify and qualify forward aggregated DR resources, if the resources are included in demonstrations via forward ZRC contracts, the lack of transparency regarding the source of those ZRCs would preclude the MPSC from being able to track them.

Further, Staff inquired about whether the MPSC should track DR resources that have been procured out of state and if so, how would that would be accomplished and differ for the prompt-year and a four year forward capacity demonstration. Because there is currently no locational requirement and DR is converted into a ZRC just like any other planning resource which MISO uses to serve all load, most stakeholders agreed that the MPSC would not need to track DR sourced from load in another state. The zonal location already included in forward ZRC contracts provides enough information for Staff to be able to track in-state versus out-of-state resources.

Finally, Staff discussed the possibility of developing a Michigan Forward Capacity Tracking Tool similar to MISO's MECT to allow Staff to track ZRCs on a four-year forward basis. Feasibility of developing such a tool was discussed with APX, the company that developed and runs the Michigan Renewable Energy Certification System (MIRECS)[12] and determined that it would be possible. In order to track forward aggregated DR resources in a Michigan Forward Capacity Tracking Tool, the review of customer contracts between ARCs and customers would be required, along with verification from the EDC that the load is in fact AES load and that the claimed MW amount is equal to or less than the previous year's PLC. Along with transparency issues that would still exist stemming from the ability to use forward ZRC contracts, other impeding factors such as cost, lack of stakeholder support, and the potentially limited reduction to vulnerability of reliability issues compared to which already exists, Staff recommends not pursuing a Michigan Forward Capacity Tracking Tool at this time.

It is unclear if the Commission has the authority to require participation in a registration process for DR aggregators, so Staff considered developing a voluntary registration process for DR aggregators. This would allow for direct lines of communication between

[12] MIRECS was established to collect, issue and track Credits from facilities eligible under Michigan's *Clean, Renewable, and Efficient Energy Act, 2008 PA295, 2016 PA342, MCL 460.1001 et seq*.

Staff and DR aggregators operating in Michigan. Staff would have access to information related to aggregated DR of Michigan customers, however because this process would be voluntary, some aggregators may not willingly participate. While Staff does not recommend pursuing any formal or informal registration process for DR aggregators in Michigan at this time, the concept could be revisited in the future if the amount of aggregated DR resources in Michigan grows significantly.

Staff Recommendation

Because ZRC contracts are consistent with current RTO and bilateral market practices, Staff does not recommend the disqualification of forward ZRC contracts in capacity demonstrations, even though the source of those ZRCs are not specified or trackable. To date, ZRC contracts have been a relatively small percentage of the total resources submitted in capacity demonstrations, limiting the scope of potential reliability impact. For planning year 2022/23, approximately 6% of Michigan's capacity obligations were met using ZRC contracts. In addition, Staff will endeavor to open up lines of communication with aggregators operating in Michigan to better understand their product offerings and any potential impacts the use of these products may have on PLCs going forward.

c. How does aggregated DR affect capacity requirement allocations to LSE's outside the capacity demonstration framework?

The Commission directed Staff to discuss the appropriate treatment of aggregated DR outside the capacity demonstration framework that may affect capacity requirement allocations to LSEs, such as aggregated DR for capacity, ancillary services and/or energy.

Stakeholder Discussion and Feedback

MISO's capacity requirement in the prompt-year is based upon the PLC. Michigan capacity demonstration requirements adopt MISO's prompt-year PLC as the forward capacity requirement as well. MISO's PLC is based upon the customer's actual load during the single hour of MISO's coincident peak in the previous year. So, if an aggregated DR resource is dispatched at the time of the MISO peak, it would effectively reduce that customer's PLC in the following year, reducing the capacity requirement for that particular customer's AES in the following planning year, even though that AES may not even be aware of the aggregated DR resource. At the same time, the same load reduction would be available on the supply-side in the aggregated DR resource, effectively allowing the same load reduction to be counted twice.

When an aggregated DR resource is registered at MISO, the EDC and the RERRA are notified of the aggregated DR resource in the prompt-year shortly before MISO's annual Planning Resource Auction (PRA). In most cases, the AES is not, however it is possible that the ARC could inform the AES and/or sell the capacity directly to an AES via ZRC contract. For an aggregated DR resource that is four years forward, only the customer and the ARC are aware of the resource because MISO does not register resources on a forward basis; therefore, there is no process for the EDC and the RERRA to receive notification.

When an aggregated DR resource is dispatched, either by MISO or by the ARC, only the customer and the ARC have first-hand information regarding any dispatched customer load reductions. The EDC, RERRA and the AESs are not aware of dispatch information.

Currently, the EDC provides PLCs to AESs and MISO each year based upon the actual load of the AES customers during MISO's coincident peak hour in the previous year. The AES and the EDC are encouraged to work out any differences between the two parties related to the calculations of the PLC. An LSE may challenge the PLC under the dispute resolution procedures pursuant to the MISO tariff. However, neither the AES nor the EDC have the dispatch data to adjust the PLC for any dispatched load reductions happening during the previous peak as outlined in MISO's tariff.[13] When MISO calls a load reduction, the MP, the ARC in this case, is notified to reduce load accordingly. The MP then decides which customers to call upon to reduce load and tracks that reduction accordingly. The MP is not obligated to inform the AES or the EDC which customers were dispatched. However, MISO should have this information as well as whether the dispatch occurred on peak. If the EDC is unable to adjust the PLC for any load reductions happening during the previous peak, a single load reduction could be counted twice; on the load side in the reduced (unadjusted) PLC and on the supply side as an aggregated resource; potentially creating a reliability problem.

At the February 13, 2019 DR aggregation stakeholder meeting, MISO presented an overview of DR participation in its market. At the May 3, 2019 DR aggregation stakeholder meeting, PJM presented an overview of DR participation in its market.

In MISO, aggregated DR registered as a Load Modifying Resource (LMR) would only participate as a capacity product and would not participate in the energy or ancillary services market. Aggregated DR registered as Demand Response Resource (DRR) Type 1 and DRR Type 2 could participate in the energy and ancillary services market. Lastly, aggregated DR registered as Emergency Demand Response (EDR) would only be dispatched in emergencies when a certain strike price is reached. MISO noted that its tariff allows DR resources to dual register as LMRs, DRRs or EDRs when they qualify to do so. In PJM, aggregated DR can participate as either Emergency DR or Economic DR. Emergency DR can participate in either the capacity or energy markets, while Economic DR participates in the energy or ancillary services market. PJM has procedures to align its

[13] https://cdn.misoenergy.org/Module%20E-1108026.pdf

various DR products with system needs and has a robust review process to ensure double counting does not occur.

The bulk of the discussion was spent on the capacity market products as opposed to the energy and ancillary services products. However, Staff notes that aggregated DR dispatched in the energy and ancillary services market could result in the similar impacts to future PLCs, or capacity requirements, because the future PLCs are based upon the actual load at the time of the MISO peak. Dispatched aggregated DR for economic or reliability purposes would reduce future capacity requirements of the customer's AES if dispatched at the time of the MISO peak because the actual load at the time of the MISO peak is used to set those capacity requirements going forward.

While the dispatch of aggregated DR in the energy and ancillary services market could have impacts on future capacity requirements, stakeholders did not discuss any reasons to prohibit aggregated AES load from participation in the energy and ancillary services market. Staff notes, however, that discussions with ARCs in Michigan should continue to take place to understand how the aggregated AES load would participate in the market and to continue to monitor for potential unintended consequences or other impacts.

Similar issues may exist with aggregated energy efficiency, aggregated storage, and aggregated DER products. Staff is unaware of aggregated energy efficiency or aggregated storage specifically in Michigan as of the date of this report. However, the state reliability mechanism provisions in PA 341 Section 6w effectively created a four-year forward bilateral capacity market in Michigan, making Michigan a more attractive market than any other MISO state for capacity resources, including aggregated capacity resources. The development of those resources in Michigan may not be far off, given the incentive provided by the four-year forward capacity construct. Therefore, Staff recommends that the Commission direct the Staff and the Michigan regulated utilities to continue to work with MISO on any tariff provisions that may be proposed related to third-party aggregated resources in the market, to ensure that the impact of those resources on PLCs is captured appropriately and that communication protocols are put in place to ensure that entities calculating the PLCs will be provided with data reflecting adjustments appropriate due to dispatched resources at the time of the MISO peak.

Staff Recommendation

Staff does not believe that the EDCs should have the responsibility to adjust PLCs, the capacity requirements, of their competitors (i.e. the AESs). Ideally, Staff would recommend that MISO assign and adjust PLCs for AESs, however, that would require a tariff change and Federal Energy Regulatory Commission (FERC) approval and would take time and significant support from MISO and its stakeholders.

Therefore, Staff recommends that the Commission direct Staff and the Michigan regulated utilities to work with MISO on developing proposed changes to the MISO process, wherein MISO would measure or calculate amounts of dispatched aggregated DR at the time of the MISO peak. This dispatched aggregated data would then be provided to the Michigan utilities/EDCs, giving them the ability to adjust the appropriate PLCs, or capacity requirements going forward, as outlined in the current tariff.[14]

Staff also recommends that the Commission allow ARC-registered DR resources comprised of Michigan-based AES load to fully participate in RTO markets, including the energy and ancillary services market, aligning with FERC-approved RTO tariffs, and removing a barrier to market participation.

Staff recommends that the Commission direct the Staff and the Michigan regulated utilities to continue to work with MISO on any tariff provisions that may be proposed related to third-party aggregated resources in the market, to ensure that the impact of those resources on PLCs is captured appropriately and that communication protocols are put in place to ensure that entities calculating the PLCs will be provided with data reflecting adjustments appropriate due to dispatched resources at the time of the MISO peak.

d. Acceptable Reporting Requirements for Capacity Demonstrations?

The Commission directed Staff to discuss what are the appropriate reporting requirements related to DR aggregation, and whether the capacity demonstration filing requirements approved in Case No. U-20154 need revision.

Stakeholder Discussion and Feedback

Through the capacity demonstration process, LSEs are able to show that they have enough resources to cover their capacity commitment. The MPSC has a process for determining the availability and certainty of resources combined with adequate documentation from utilities and their partners. This process is outlined in the Capacity Demonstration Process and Requirements approved in Case No. U-20154.[15]

Staff Recommendation

In addition to the recommendations made in the capacity demonstration Staff Report filed on March 28, 2019 in Case No. U-20154, Staff recommends that as an auditing measure, the capacity demonstration filing requirements be updated to require that prompt-year ZRC transfer documentation be provided for any LSE that utilized ZRC contracts in previous capacity demonstrations. Also, because the market rules and framework is still under development, Staff recommends that aggregated EERs, aggregated storage, and aggregated DERs not be accepted as capacity resources in any Michigan four-year forward

[14] Ibid. (Sec. 69A 1.2)

[15] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000002SQygAAG

capacity demonstration, unless they have been qualified by MISO and appropriate documentation (such as MISO MECT screen shots showing the ZRC credit), along with an affidavit from the officer affirming that the resource will be maintained four years forward, is provided with the demonstration.

The updated filing requirements are attached as Appendix B to this report.

e. Discussion related to the proposal to lift the ban on aggregated DR

At the February 13, 2019 stakeholder meeting, both Voltus and AEMA suggested that allowing aggregation of non-AES customers would increase the amount of DR resources in the state and participation by Michigan businesses will reduce business costs and encourage growth.

On December 2, 2010 in Case No. U-16020, the Commission ordered that Michigan retail electric customers (either individually or through aggregators) of Commission jurisdictional electric utilities are prohibited from bidding DR resources into regional transmission operator wholesale markets. The March 29, 2016 order in this case continued the ban for retail electric customers of Commission jurisdictional electric utilities. However, the Commission Order in the DTE Energy Certificate of Need case, U-18419, discussed that in order to reduce barriers to market-based DR and in anticipation of evolving FERC policy, the Commission could consider removing the current ban on third parties enrolling the EDC bundled customers in non-utility demand response programs and bidding that resource into the wholesale market. The Commission also discussed they are monitoring FERC proceedings as FERC revisits, and perhaps limits, its policy with respect to states' ability to ban DR aggregation. The Commission directed the Staff's DR Workgroup to begin to evaluate coordination and communication issues among aggregators, customers, the Commission, utilities, and MISO, that may need to be addressed if third party DR aggregation is permitted in the future. The DR Workgroup was directed to consider models in other states, such as Indiana.

Finally the Order in Case No. U-20348 directed Staff to work with stakeholders to align with federal requirements for DR, ensure proper tracking of DR, identify barriers to third-party aggregation, and work through issues in a collaborative manner providing a template for scaling up aggregation which may also accommodate other applications. Staff also notes that on May 16, 2019 the FERC issued an Order[16] prohibiting states from limiting the access of non-aggregated energy storage resources connected to distribution systems to wholesale markets.

[16] https://www.ferc.gov/whats-new/comm-meet/2019/051619/E-1.pdf

During the March 12th and May 3rd stakeholder meetings, Staff explored the concept of lifting the current ban on DR aggregation with stakeholders and included specific questions in feedback requests. In these feedback requests, stakeholders asked staff to analyze DR aggregation models in other states, particularly, Indiana and Pennsylvania.

The Indiana model specifies that participation in RTO demand response programs should be done through the retail customer's LSE. Utilities are encouraged to work with ARCs and CSPs under tariffs designed to participate in RTO DR programs. In this model, aggregators acquire and aggregate customers while the LSE registers that DR with the RTO.[17]

The Pennsylvania model was created via legislation in 2008 and also includes both and energy efficiency and peak reduction components. The Pennsylvania model requires EDCs to competitively bid all contracts with a Pennsylvania registered conservation service provider. These entities provide consultation, design, administration and management services to the EDC. The Pennsylvania model essentially requires that unaffiliated, independent companies provide DR services to the utility.

Stakeholder feedback was mixed in regards to these models. Some were receptive to the utility-aggregator partnership model and saw it as a way to increase customer interest in DR programs and leverage the expertise of aggregators and increase the state's DR portfolio. Stakeholders primarily preferred the Indiana model, which would retain the utility's visibility for resource adequacy purposes and be a more moderate step towards aggregation of DR customers. Others were concerned that these models would not fit well in Michigan, as the state already has well-established utility DR programs and these models would add administrative costs and may be too restrictive. The Pennsylvania model in particular was built for a fully deregulated state and would likely require legislation to implement in Michigan.

While the Indiana and Pennsylvania models were suggested as a way to expand DR aggregation in Michigan, Staff also asked stakeholders if they had any other suggestions for changes that would make them comfortable with lifting the ban on DR aggregation for all customers in Michigan. Stakeholder feedback was very polarized on this topic. Those supportive of removing the ban advised that the state take intermediate steps such as utility-aggregator partnership models, an ARC registration process, MISO BPM improvements, codifying metering procedures and other ways to retain MPSC oversight, visibility, and control. These stakeholders think removal of the ban would help the state expand its DR capabilities and would help set up a model for energy efficiency, and distributed energy resource aggregation. Those opposed to removing the ban cautioned against the increased uncertainty surrounding resource planning, cross-subsidization concerns, and operational impacts. These stakeholders think removal of the ban would

[17] In Indiana, the LSEs are all regulated utilities.

aggravate problems with MISO procedures and capacity planning, make it more difficult to develop non-wires alternatives, and interfere with well-established utility DR programs.

At the May 3, 2019 stakeholder meeting, the topic of potentially lifting the current ban on DR aggregation was the subject of presentations by Consumers Energy and AEMA. Consumers Energy presented an overview of its existing DR programs and future plans to increase DR programs included in its Integrated Resource Plan (IRP) that was based upon Michigan's DR potential included in a DR potential study. Lifting the ban on DR aggregation could hamper Consumers Energy's efforts to fully realize the DR expansion plans in its as well as project any remaining DR potential without transparency into the details of its customers participation with ARCs. In addition, Consumers Energy noted the following:

- The ARC business model requires an LSE to continue to plan to meet all customer load;
- Uncertainty around impacts to distribution non-wires alternatives;
- Operational challenges related to load forecast accuracy and distribution system stability if called upon without communicating through the LSE;
- Decreased availability of "Negawatts." A negawatt represents a unit of energy that has been saved as a direct result of energy conservation measures or through the use of energy-efficient products.

Following the presentation by Consumers Energy, brief statements of agreement were made by DTE Electric and the Michigan Electric and Gas Association.

AEMA's presentation recognized the planning and operational challenges the utilities are facing and presented methods to utilize ARCs to maximize cost-effective DR participation to drive system-wide savings without overturning the current ban on DR aggregation. AEMA presented two options for consideration; an Indiana-style tariff (I&M Indiana's D.R.S.1 tariff) or bilateral contracts ranging from DR services provided by an aggregator to a utility to full turnkey DR program management provided by the aggregator.

AEMA's presentation includes the following description of the I&M tariff in Indiana:

- Tariff allows qualified DR providers to recruit C&I customers to participate in wholesale capacity program, but enrollment must happen through utility;
- Enables I&M to account for DR in their system planning and exercise control, while leveraging capabilities of DR providers;
- Compensation is higher of average wholesale capacity price for last four years or 35% of Net Cost of New Entry (CONE);
- Tariff is compatible with ban on ARCs, as utilities enroll customers in the market, not the ARC. ARCs bear underperformance risk, not customers; and
- Won the "Program Pacesetters" award from the Peak Load Management Alliance.

AEMA's presentation also includes the following information regarding bilateral contracts for aggregation services:

- Competitively solicit for DR resources through 3rd party service providers to drive competitive outcomes;
- Can contract for DR capacity to meet wholesale (e.g., MISO capacity credit) and retail (e.g., peak shaving) needs;
- Utility receives full oversight of DR resources and pre-determined quantity of dispatchable demand; can white-label 3rd party's platform if desired
- Contract terms can be determined based on unique circumstances / needs and tailored to utility service area; and
- Utility should receive incentives for procuring DR when it has higher net benefits to all customers than traditional infrastructure.

Staff Recommendation

There were no verbal statements made during the May 3rd meeting suggesting that the current ban on DR aggregation should be lifted. Staff agrees with the Michigan utilities/EDCs that allowing aggregation of bundled retail load would introduce additional uncertainty and complexity into the integrated resource planning process, the distribution planning process, provide operational challenges that would need to be worked through and could result in fluctuating costs to ratepayers if not implemented in a controlled, transparent manner. Given the lack of support expressed for lifting the current ban on DR aggregation, Staff does not recommend lifting the ban at this time. In the meantime, should the Commission wish to explore expanding DR opportunities for bundled customers utilizing ARCs, the utilities could be encouraged to develop an ARC-utility collaboration model and/or directed to present proposals in IRP cases, rate cases, or DR reconciliation cases.

f. Implications for aggregated energy efficiency resources (EERs) and aggregated storage resources.

Staff is aware that FERC ruled in EL17-75 that states may not impose restrictions or bans on aggregated energy efficiency products in wholesale markets. The Organization of MISO States (OMS) argued that the opt-out provisions in Order 719 should be applied to EERs and unsuccessfully filed a comment and a protest in this docket. Michigan joined in these filings but did not file separately.

In December 2017 (EL17-75), FERC issued a Declaratory Order finding that FERC has exclusive jurisdiction over the participation of EERs in wholesale markets. FERC also found that the RERRA cannot bar, restrict, or otherwise condition the participation of EER in wholesale markets unless FERC expressly gives the RERRA such authority. FERC clarified that Order 719 does not allow the RERRA the ability to exercise an opt-out with respect to EERs. FERC granted the Kentucky PSC (KY PSC) the ability to restrict wholesale EER participation. This is because when the KY PSC approved the integration of their utilities into PJM, a condition of their integration was that the KY PSC retained the right to review any demand-side management programs that are offered by PJM to Kentucky retail customers. FERC previously approved this agreement in 2004 and confirmed that its decision stands. Any other RERRA that wishes to restrict EER aggregation would need to specifically make that request before FERC and successfully make the case that restricting wholesale EER participation in their state is just and reasonable.

In MISO's recent planning year 2019/2020 PRA, MISO reports 313 ZRCs of energy efficiency cleared in the auction.[18] MISO's report does not indicate the zonal locations of those energy efficiency resources and it is unknown whether they were located in Michigan or elsewhere in MISO. The MISO tariff defines an EER as a planning resource consisting of installed measures on retail customer facilities that achieves a permanent reduction in electric energy usage while maintaining a comparable quality of service. MISO's tariff further provides that "an EER can annually qualify as a Planning Resource for ZRCs for up to four (4) Planning Years immediately following the EERs initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year."[19]

MISO's tariff defines Electric Storage Resources (ESR) as:

> "a Resource capable of receiving Energy from the Transmission System and storing it for later injection of Energy back to the Transmission System. This definition includes all technologies and/or storage mediums, including but not limited to, batteries, flywheels, compressed air, and pumped-hydro. The location of an ESR may be at any point of grid interconnection, on either the Transmission System or a local distribution system. An ESR must: (1) be capable of injecting and withdrawing a minimum of 0.1 MW; (2) be capable of complying with the Transmission Provider's Setpoint Instructions; (3) have the appropriate metering equipment installed; and (4) be physically located within the MISO Balancing Authority Area. The State of Charge shall be managed by the Market Participant operating the ESR."

In Order 841 (RM16-23, February 2018), FERC required RTOs/ISOs to revise their tariffs to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary services markets. FERC directed the RTOs/ISOs to develop a participation model that ensures a storage resource is eligible to provide all the services it is technically capable of providing. FERC declined to implement electric storage aggregation reforms at

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18 https://cdn.misoenergy.org/20190508%20RASC%20Item%2003a%20PRA%20Detailed%20Results341844.pdf, p. 21.

19 MISO Tariff Section 69A.3.2, Energy Efficiency Resources, 32.0.0.

this time and instead concluded that more information is needed before it makes a final decision. On May 16, 2019, per Order 841-A, FERC clarified that states would not be granted opt out authority for non-aggregated energy storage resources connected to the distribution system. In response to Order 841, MISO filed its Electric Storage Resource participation model at FERC in December 2018 (ER19-465). FERC asked for additional detail on certain aspects of MISO's and other RTOs' filings in April 2019. MISO filed their response on May 1, 2019 and the docket continues to await FERC action. OMS has filed a doc-less intervention in the docket but has not made comments.

As such, as part of Order 841, FERC issued a Notice of Proposed Rulemaking (NOPR) in RM18-9 to gather additional information on potential Distributed Energy Resource (DER) aggregation reforms. This is a continuation of the NOPR FERC previously issued in RM16-23, which specifically addressed electric storage participation and DER aggregation. In these NOPRs, FERC specifically asks whether Order 719, and state authority to restrict DR aggregation, should be applied to DERs. FERC's proposal lists electric storage resources as a type of DER which opens up the possibility that state regulators may not be able to restrict their aggregation. While the Technical Conference concluded in June 2018, FERC has not yet made a decision on DER participation.

OMS is very active in this docket and has filed three sets of comments to date. Regarding aggregation of DERs, OMS sees jurisdictional parallels between DERs and DR, and consequently advocated that DER aggregation be treated similar to DR per Order 719. OMS argues that the RERRA should be able to restrict aggregation of DERs. The MPSC joined in these comments and did not file separately. OMS and MISO have jointly hosted a series of DER workshops to educate and facilitate conversation among stakeholders. OMS continues to track this issue, has listed DERs as a strategic priority in both 2018 and 2019, and has an OMS staff workgroup dedicated to this issue.

Unlike demand response resources, EERs are not likely to present the same operational and day-to-day planning complexity that might interfere with a utility's day-to-day operations as load reduction is more consistent and less volatile.

In its declaratory order EL17-75, FERC stated that "although in Order 719 and Order 745, the Commission granted RERRA's an opt-out from allowing resources to participated as wholesale demand response, we find that the Commission was not obligated to do so." FERC found that the incidental effects from EER participation on the retail markets are not substantial and do not present the same operational and day-to-day planning complexity that could interfere with an LSE's operations. FERC recommended that any such impacts be addressed through the RTO tariff and not through a broad prohibition on EER participation in wholesale markets.

While FERC has not addressed DER aggregation to date, Staff sees similar operational, planning, tracking, and jurisdictional concerns between DR and DER aggregation. DER aggregation could have a widespread impact on EDCs and would involve complex interactions between aggregators, LSEs, the EDC, and the RTO. The MPSC is an active participant in OMS and through that organization, is on record before FERC.

Staff Recommendation

While Staff recognizes that a DR aggregation model could form a workable framework for EER or DER aggregation, this issue is being addressed in ongoing proceedings and as such, Staff is not making any specific recommendations at this time.

As previously discussed, because the market and framework are still under development, Staff recommends that aggregated EERs, aggregated storage, and aggregated DERs not be accepted as capacity resources in any Michigan four-year forward capacity demonstration, unless they have been qualified by MISO and appropriate documentation (such as MISO MECT screen shots showing the ZRC credit), along with an affidavit from the officer affirming that the resource will be maintained four years forward, is provided with the demonstration.

Conclusion

The Commission has established the importance of addressing DR aggregation by creating dockets U-16020, U-18369 and U-20348. Staff is hopeful that the DR aggregation stakeholder process, correlating staff report and attached stakeholder comments identifies workable solutions for the several important issues that had been left unaddressed. Staff would again like to thank all of the stakeholders for their robust participation and meaningful feedback which ultimately helped guide Staff's recommendations.

Staff will continue to monitor the market and framework development process going forward and is committed to working with all relevant parties to address the operational complexities of DR aggregation and to achieve the goals and recommendations as outlined in this report.

Appendix A

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Advanced Energy Management Alliance's Feedback for Michigan Public Service Commission Staff's Report in Case U-20348 on Demand Response Aggregation

The Advanced Energy Management Alliance ("AEMA") is pleased to provide the feedback to Michigan Public Service Commission ("MPSC" or "Commission") Staff for inclusion in the Staff's Report that is to be submitted to the Commission on May 30, 2019. AEMA would like to thank MPSC Staff for their facilitation of three meetings on the subject of Demand Response ("DR") Aggregation and allowing AEMA to present on two occasions, and thanks other stakeholders for their participation and discussion throughout the process.

Below, AEMA has consolidated the responses previously submitted following the first and second meetings held on this topic. Additionally, in response to Staff's recommendation on Item 5e in the Draft Outline for the Staff Report to not lift the ban on DR Aggregation, we offer a suggested change. Currently, the Staff's recommendation states:

> "Staff does not recommend lifting the ban at this time. Should the Commission wish to explore increasing DR opportunities for bundled customers utilizing ARCs, the utilities could be encouraged to develop an ARC-utility collaboration model and/or directed to present proposals in IRP cases, rate cases, or DR reconciliation cases."

AEMA believes that there is by now a robust record demonstrating that ARCs can add value to DR programs and customers. The question at hand is how best to leverage their benefits to drive the most value for all customers, not whether those benefits exist.

While AEMA supports Staff's recommendation not to lift the ban at this time, the Commission should take concrete steps to expand customer access to DR opportunities through ARCs. AEMA therefore recommends the following amendments to Staff's proposal:

> "Staff does not recommend lifting the ban at this time.-However,-given the benefits that ARCs can provide to customers, the Commission should direct utilities to develop an ARC-utility collaboration model(s), if they don't already

> have one in place, and present proposals for such models in their IRP cases, rate cases, or DR reconciliation cases, or describe how they are currently partnering with ARCs to deliver DR opportunities to customers today."

AEMA's Responses to Feedback Request following Meeting #1

State vs. federal jurisdictional questions

1) *Per FERC Order 745, it is clear that the Relevant Electric Retail Regulatory Authority (RERRA) may prohibit 3rd party Demand Response (DR) aggregation in their jurisdiction. However, it is unclear whether the MPSC can partially permit aggregation and also place restrictions on multiple Alternative Electric Supplier (AES) aggregation and who is able to register the aggregated DR at MISO.*

AEMA believes that the RERRA has the authority to designate authorized aggregators of DR for wholesale markets. This can be partial or unlimited. AEMA believes that FERC Order 719 (not FERC Order 745) governs this issue. In FERC Order 719-B, the FERC stated:

> 16. We do not agree with APPA Petitioners that Order No. 719-A's regulatory language restricts the relevant electric retail regulatory authority's ability to determine and enforce qualifications for ARCs. We have stated previously that neither the intent nor the effect of this proceeding is to undermine or require changes to existing retail aggregation programs, or to interfere with the relevant electric retail regulatory authority's role in determining the qualifications and requirements for ARCs within its jurisdiction. We leave it to each relevant electric retail regulatory authority to set and enforce qualifications and requirements for aggregation of demand response within its jurisdiction.[1]

This language appears to give the RERRA wide discretion on approaches to aggregation—from precluding any aggregation, to permitting only the retail supplier to aggregate, to allowing any party to aggregate (relying on the RTO assure qualifications.) AEMA notes the latter model is by far the most common in most RTOs. This works in part because the usual model effectively results in the aggregator paying the customer for the demand resource rather than the customer paying the aggregator as occurs with retail energy suppliers. While AMEA would acknowledge that the Supreme Court's subsequent ruling in Order 745 could be construed to support a future FERC Order reclaiming jurisdiction over aggregation, at this time Order 719 would appear at a minimum to enable delegation of such authority to the RERRA.

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[1] Order 719-B, para. 16 https://ferc.gov/whats-new/comm-meet/2009/121709/E-7.pdf?csrt=6605182290398018427

Do the MPSC's Orders in Case Nos. U-16020, U-18369 or U-20348 raise any jurisdictional questions in your mind?

a. Example: Does the MPSC have the authority to prohibit aggregation across multiple AESs?

AEMA believes that the MPSC has the authority to allow or prohibit aggregation across multiple AESs. Strictly speaking, for wholesale market participation in MISO there should be no prohibition on an aggregators ability to aggregate across multiple AESs.

However, MI has introduced a 4 year forward Capacity Demonstration rule. This rule creates a new administrative requirement to track resources, including DR resources, that are designated for Capacity Demonstration commitment. A tracking mechanism maintained by each utility for its own customers would be simple to administer but could unnecessarily limit DR participation. Ideally, a tracking tool that would jointly track all Michigan DR resources—and perhaps other resources as well—would be established in the state.

i. *Aggregators would be able to operate within an individual AES's customer base (all customers in AES1).*

ii. Aggregators would not be able to aggregate some customers from AES1 and some from AES2 and comingle the use of the demand response resources.

b. Example: Would the MPSC be able to permit the aggregation of AES customers, with only this strict condition that the AES is the entity that registers the aggregated DR with MISO?

Rules that required that only the customer's AES have the right to register DR with MISO could create barriers for DR and for customer flexibility to manage costs as a DR participant. While we think it unlikely, an AES could decline to register DR enabled by a DR aggregator in favor of the AES's own alternate sources of Capacity.

The MPSC's order in U-18197 clearly permits an AES to utilize capacity derived from another AES customer's DR activity.

Tracking aggregated DR

2) *Per MISO's Business Practice Manual (BPM) 1 Sec. 9.5, MISO will notify the MPSC of every new aggregated customer and provide who is the market participant, the MW amount, the load balancing area (LBA), and Commercial Pricing (CP) Node information.*
    a) *Is this information sufficient to allow the MPSC to track demand response resources and ensure that cross-subsidization and double counting are not occurring?*

The information is adequate for tracking. It is suggested that customer identification include the Customer Name, Host distribution company and distribution account number. The MPSC indicates concern about tracking resources offered for Capacity Demonstration purposes. Such DR resources may not necessarily be registered with MISO at the time of the Demonstration. Lack of such a demonstration should not be reason for rejecting a resource offered in a Demonstration.

b) *How would the MPSC be able to track DR that has been procured out of state for use in Michigan? Would it be necessary for the MPSC to track DR in other states?*

AEMA suggests that DR derived from other state resources for the purpose of meeting Capacity Demonstrations have the same identification requirements as in-state DR. This can be supplemented with a Certification by a company officer that DR participation is allowed under the origination state's laws and that the enabling contracts are available for review by the MPSC. AEMA suggests that a centralized registration system as suggested above, can be used to track these resources and identify duplicate customers.

To the extent that DR is proposed from DR that is not yet registered with MISO, AEMA is supportive of criteria that could include certification and collateral requirements for proposed DR that is not fully contracted.

c) *Would your answers for the prompt-year and a four-year forward capacity demonstration differ? How so?*

AEMA does not see a need for tracking of prompt year resources by the MPSC. MISO does this currently through MECT. However, the MPSC may wish to monitor the prompt year DR supplied compared to the four year forward commitment.

The effects of aggregated DR on an LSE's capacity requirement

3) *A Load Serving Entity (LSE's) capacity requirement is determined by their historical Peak Load Contribution (PLC).*
   a) *What potential problems does aggregation of DR resources across multiple AESs' have on the PLC calculation?*

Aggregating DR resources across multiple AESs could introduce problems with the PLC calculation if there is no reporting feedback on the observed load reduction from participating customers to the AES serving the customers' load or to the PSC.

   b) *Example: An aggregator procures DR from AES1. The aggregator sells this DR into the market, where it is procured by AES2 to meet their capacity requirement. If this DR is dispatched on the MISO peak, AES1's PLC is reduced by xMW, even though that DR has been sold to AES2. The next year, AES1 would have a lower* *capacity requirement and AES2 would still have the same capacity requirement as the previous year.*

i) Is this accurate?

Yes, without a mechanism for reporting DR performance, this is correct.

ii) If so, is this a problem and what can be done to fix it?

AEMA suggests that to solve this issue, a tracking mechanism be established with reporting deadlines for AES or aggregator representing DR resources to report the "add-back" to the observed metered load to be able to reconstitute each AESs' peak load. Perhaps this could best be accomplished through MISO providing performance data from DR dispatched coincident with the MISO system peak to the MPSC.

Acceptable reporting requirements for Capacity Demonstration

4) Through the Capacity Demonstration process, electric distribution companies (EDCs) and/or LSEs are able to show that they have enough resources to cover their capacity commitment. For supply side resources, the MPSC has a process for determining the availability and certainty of resources combined with adequate documentation from utilities and their partners.

a) What procedures would be appropriate to apply to demand side resources, particularly aggregated demand response that could be spread across multiple service territories and multiple AES customers?

i) Example: An AES submits a four year forward ZRC contract for aggregated DR.

(1) Should that ZRC contract be treated any differently than if it was a ZRC contract four years forward with a supply-side generation owner? How so?

No, the ZRC contract for aggregated DR should not be treated any differently than supply-side generation. As mentioned in the response to 2a above, DR resources procured four years in advance should not need to be registered with MISO.

b) What information would be sufficient to ensure capacity exists for the commitment period?

AEMA believes the information required to be submitted to MISO for registration purposes should be largely sufficient to ensure the capacity exists. If any additional information should be required, perhaps a preliminary curtailment plan that details how each DR resource intends to achieve the load reduction capacity being used for Capacity Demonstration purposes.

Other markets with forward capacity requirements ensure that DR capacity, esp. “planned” capacity that relies on enrolling new, future customers in the market, shows up by requiring a combination of:

- Credit cover or financial assurance for planned, unproven MW;
- “Sell-Offer” plans, detailing how a participant plans to enroll enough customers to meet their forward obligation. Some markets, such as ISO-NE, require quarterly updates on these plans so that any potential risks can be identified early;
- Qualification audits a few months prior to the delivery year to demonstrate that a participant isn’t short on their obligation (this would be done simply by registering customers with MISO, prior to the PRA); or
- Shortfall penalties on any MW shortfall.

Together, these requirements have been sufficient to ensure that participants’ forward DR commitments “show up” for the delivery year. In PJM, annual DR shortfalls, i.e., the amount of MW that participants fail to deliver based on their commitments, are generally less than 1%. Said differently, participants in PJM deliver 99% of their forward obligations to the market.

AEMA believes with sufficient reporting requirements and proper incentives, Michigan need not worry about forward DR obligations not being met. If even 5% of DR MW didn’t show up—much worse than what we see in PJM—this would likely only be a few MW, and participants would have the costs of that shortfall internalized. Those MW could easily be picked up in the PRA.

c) *What entity would be best to supply this information?*

The Aggregator or AES (if providing aggregation services) providing the capacity would best be able to supply this information, as they will have documentation to support the curtailment methods each DR resource plans to utilized to realize the curtailment, and the amount of load expected to be realized through implementing these methods.

d) *Should a four year forward ZRC contract for aggregated DR (aggregated AES customer load) be considered an acceptable resource if submitted as part of a capacity demonstration on behalf of a utility, municipality or cooperative? Why or why not?*

Yes, it should be to be an acceptable resource if submitted as part of a capacity demonstration. ZRCs do not include a designation of what type of resource is providing the capacity, so a forward contract that utilizes aggregated DR should not be discriminated against compared to any other supply-side resource forward ZRC contract.

5) *Voltus and AEMA both suggested in the February 13, 2019 stakeholder meeting that the MPSC should not limit DR aggregation to only AES customers. What are your initial thoughts on that?*

AEMA believes that allowing non-AES customers to aggregate to provide DR can help reliably meet Michigan's capacity needs in a cost-effective manner. Allowing non-AES customers to provide these services will increase the addressable DR market that should help reduce capacity costs within the state.

To be clear, AEMA is not advocating for the ability to aggregate regulated customers directly in the MISO market. Rather, AEMA believes that utilities should work with DR Aggregators to maximize the amount of cost-effective DR within their footprint. This would ensure MI does not strand any in-state capacity resources by failing to provide customers with sufficient DR opportunities.

6) *Do you have any other recommendations you would like to suggest?*

7) *Do you have any additional topics you would like to discuss for our next DR aggregation stakeholder meeting on March 12th?*

AEMA would like to further discuss allowing DR Aggregators to aggregate non-AES customers, within the constructs of Michigan's existing ban on ARCs, as well as whether licensing or other similar requirements could or should be applicable to allow Aggregators to operate in Michigan.

8) *Are you opposed to having your written response included with the MPSC Staff report that is due to the Commission on May 30th?*

No, AEMA welcomes having our written response included with the MPSC Staff report to the Commission.

AEMA's Responses to Feedback Request following Meeting #2

Indiana model (*See slides 17-20*):

1) *Do you have any immediate feedback on the pros and cons of this model?*
   AEMA supports the Indiana Model for use with non-AES customers.

2) *Is this model worth exploring?*

AEMA supports the Indiana Model for use with non-AES customers. It would provide an approach that provides customers with a choice of participation levels and flexibility while also preserving utility oversight and control of demand response within their territories.

Pennsylvania model (*See slide 21*):

3) *Do you have any immediate feedback on the pros and cons of this model?*

The Pennsylvania model has some useful features. It does not result in creation of capacity resources qualified as demand resources in PJM. Most participants are already qualified DR capacity resources. The program is designed to reduce PA's peak demand by incenting curtailment outside of the RTO framework. It could serve a similar purpose in Michigan though without a capacity-like payment it is less clear what the customer interest would be. Because PA PSC wanted to avoid paying utilities to set up programs that might not be in place for long periods and because the Commission wanted to avoid situations where regulated utilities competed directly with non-franchised aggregators to support programs, the PSC required that only unaffiliated, independent companies could provide the specified services to utilities. This principle should be considered when designing a program, regardless of the ultimate structure. For example, should Michigan decide to implement the Indiana model for non-AES customers, care should be taken that programs are available to non-affiliated aggregators and assure that any utility or utility affiliate participation must be on a comparable basis.

4) *Is this model worth exploring?*

AEMA characterizes the Pennsylvania model as a "peak shaving" model. As such, its value is partly dependent on how peak shaving activity is recognized in load forecasts. If peak shaving of 100MW in Year 0 results in a reduced load forecast or reliability obligation in Year 1, it is likely of value. In PJM, peak shaving impacts are averaged over multiple years in the load forecasting model such that a 100MW reduction in Year 0 might only have a 4MW impact in reliability obligations in Year 1. The impact of peak shaving in Michigan or MISO should be considered in this context. We also note that peak shaving by itself is unlikely to attract much interest from ARCs without some sort of capacity payment. Thus, the Pennsylvania approach has some value as a supplement to a robust capacity program but might not garner interest if pursued as a stand-alone approach. However, peak-shaving programs can complement capacity programs by driving additional net benefits for the state and additional opportunities for customers to monetize their flexibility, again while giving utilities full control and visibility into the resource.

Regarding MISO vs. PJM processes (*See slides 22-23*):

As an initial matter, AEMA offers clarifying comments on two statements regarding PJM in the process comparison.

- **Aggregated economic DR must be served by same EDC and LSE with same pricing point.**
  In PJM, an aggregated economic resource can be created from multiple locations to reach the 100kW minimum size for an economic registration. Such an aggregation must meet the criteria described. However, virtually

all (if not all – we don't know of any exceptions) economic registrations are greater than 100kW. A more appropriate statement might read:

  - **Economic DR registrations are compensated at the TO zone average energy price. Aggregations of locations necessary to meet the 100kW minimum size, must have the same EDC and LSE.**

- **Aggregated emergency DR must be served by same EDC and in same TO zone.**
  As above, an aggregation of small emergency resources created to meet a 100kW minimum must be served by the same EDC and within the same TO zone. However, Emergency resources are aggregated at the zonal level and individual registrations are allowed to be less than 100kW. As a result, the common EDC requirement is essentially moot. We'd suggest that this read:
  - **Aggregated emergency DR must be in the same TO Zone.**

5) *Does the PJM process outlined above have any pros or cons as compared to the current MISO process*?

Pros for PJM:

- PJM allows for the EDC and LSE to affirm RERRA eligibility. This eliminates this role for the RERRA. MISO would have to change this.
- The ARC is not required to identify the RERRA.
- Separate LBA approval is not required (LBAs are not used in PJM)
- PJM checks for duplicate registrations, centralizing this function.

Cons For PJM:

- Registration details. These details address compliance with EPA rules where generators are used, and data on curtailment approaches.

6) *While this discussion is focused on a Michigan specific process to track and verify aggregated DR, would you support supplementing the MISO process with some of the aspects of PJM's registration process?*

AEMA would support a central or coordinated tracking process for MISO Zone 4 demand response. This would allow for DR in one territory to provide capacity in another territory. It would potentially simplify the tracking and review processes for Michigan utilities by avoiding duplicate systems.

7) *Would you support adopting some of these PJM procedures into a Michigan specific process?*

Michigan has implemented a Capacity Demonstration construct which has similarities to PJM's Reliability Pricing Model (RPM) with a 3-year forward procurement. The comparison slides do not address PJM's treatment of demand resources offered in RPM and MISO does not have a comparable structure. PJM's Manual 18 Attachment C describes treatment of DR Plans for resources not yet registered with PJM to offer into the RPM. A similar mechanism would be important to facilitating growing use of DR in meeting Capacity Demonstration needs. If Michigan was to recognize only currently registered DR as eligible for Capacity Demonstration, growth would be challenged by the lack of revenue to justify current participation and registration in order to meet a forward Capacity Demonstration requirement.

AEMA believes that a mechanism to recognize planned DR resources that may not necessarily be under contract or registered with MISO is critical. (In the context of this document, "Planned" DR resources are those that the ARC is confident that it can bring to market but does not yet have under contract. The concept of a Planned DR resource is essential for growth of DR as discussed below.) A key element of PJM's construct is an Officer Certification representing that the provider has a reasonable expectation that DR proposed for a future delivery year can be delivered, and credit requirements for planned MW along with financial penalties if ARCs are unable to bring the planned MW to market.

8) *Would you like to further discuss the IN/PA models or explore aspects of the PJM process?*

AEMA believes that the Indiana and Pennsylvania models and the PJM process all have attributes that can be instrumental components of a robust DR model in Michigan. AEMA and its members have a tremendous amount of experience with and understanding of each of these programs. AEMA is open to such discussions and will participate productively if such discussions move forward.

Other:

9) *Are MISO BPM or tariff revisions warranted to ensure that retail peak load contributions are increased to reflect any relevant load reductions?*

AEMA does not believe any MISO BPM or tariff revisions are necessary. Based upon the response provided for question 11, AEMA believes that as long as the DR event response add-back data is provided to the appropriate EDC's resource planning team, either by MISO or by the ARC representing the resource, that will ensure that that the retail peak load contributions are reconstituted.

10) *Are MISO BPM or tariff revisions warranted to ensure that retail peak load contributions are not double counting the same resource on both the supply side and demand side of the resource adequacy equation? If so, what specific BPM or tariff revisions would you suggest?*

Based on our read of the MISO tariff, in Sections 69.A.1.2.1 and 69.A.1.2(c), it appears as though MISO has the proper rules in place to ensure that retail peak load contributions are not double counting the same resource on both the supply side and demand side of the resource adequacy equation. Specifically, the tariff requires that load reductions during a peak hour that would set a customer or LSE's capacity obligation, and for which that customer/LSE is being compensated by MISO for capacity credit, be added back to the customer/LSE's usage in that hour.

11) *What if a change was made to the MISO tariff such that the PLC was determined to be the highest load for that particular customer for MISO's top twelve peak hours of the previous year? Would this reduce or possibly eliminate the need to make PLC adjustments to account for load reductions?*

AEMA believes that the MISO tariff appropriately leaves the determination of retail customer PLCs to the RERRA or EDC. The Tariff excerpt provided at the 1st stakeholder session supports this. While MISO can allocate overall requirements for reliability supply to EDCs under FERC authority, MISO does not have the authority to determine allocation of such obligations to retail customers. As a result, Michigan could unilaterally implement a PLC allocation for retail customers of its own design. Presumably this already occurs in the context of the Capacity Commitment process.

AEMA also believes that MISO has the ability if not the requirement to notify EDCs and their load planners of any curtailments resulting from MISO dispatch reported to MISO by an aggregator.

Use of the top 12 peak hours (presumably from different days) for allocation could have the result of undervaluing temperature sensitive loads and overvaluing more stable loads by inclusion of relatively cool and lower load days. AEMA would suggest the top five days or use of MISO's wholesale allocation approach.

AEMA recommends that MISO find a way to provide EDCs with curtailments by customers and use this information to "add back" any metered load on any allocation day. Such an add back, if applied, should not result in an increase in PLC year over year. Alternatively, entities authorized to provide DR resources to MISO could be required to report curtailments to the respective EDC.

12) *Should the MPSC develop a voluntary registration process with reporting requirements for ARCs in Michigan? Why or why not? (See slide 31)*

As stated in the response above to question 11, the reporting requirements for customer curtailments observed and reported to MISO could either be provided to EDCs either by MISO or an ARC. AEMA does not have a strong opinion on whether the MPSC should develop a voluntary registration process with reporting requirements. However, absent MISO process changes to ensure the data is provided to the appropriate resource planning groups at each EDC, AEMA would support development and implementation of a voluntary registration for ARCs.

13) *Is legislation necessary to outline a more formal process for registering or licensing ARC's?*

AEMA is not aware of any provisions that would preclude the Michigan Commission from acting to create a more formal process.

14) *What recommendations do you have about what type of information should be included in an ARC registration at the MPSC?*

AEMA recommends the following registration requirements should the MPSC decide to develop a voluntary ARC registration within Michigan:

- Entity name and certification that entity is registered with the State of Michigan to do business
- DUNS and Federal EIN
- Entity tax information (financial statements or other methods to affirm solvency) (submitted to MPSC under seal of confidentiality)
- Proof of MISO ARC registration in good standing (or documentation showing intent to register or in process of registering as an ARC at MISO)
- Statement of management qualifications to participate in DR programs
- Statement of commitment to act in good faith when executing DR programs.

15) *Should the MPSC pursue a Michigan 4-year forward Capacity Tracking Tool that would accommodate the tracking of all capacity resources, including aggregated DR, aggregated energy efficiency and aggregated storage resources, on a 4-year forward basis? Why or why not?*

AEMA thinks that the MPSC should pursue a 4-year forward Capacity Tracking Tool that would accommodate aggregations of the resource types noted. Outside of the prompt year, forward years should allow for individual resources comprising the aggregation to remain undefined, as long as some level of certainty that an entity will be able to deliver the capacity in the applicable delivery year is provided (Officer certification as used in PJM, for example). This will allow flexibility in building out customer or project portfolios, without being locked into any one specific customer or project site.

16) *At this point in time, do you have any recommended changes to the MPSC's capacity demonstration requirements adopted in U-20154, specifically for forward ZRC contracts?*

AEMA believes that a mechanism to recognize planned DR resources that may not necessarily be under contract or registered with MISO is critical. PJM has such a mechanism, though we cannot recommend the specific terms for Michigan use. This is because PJM's current rules were established after DR had become well established and the majority of DR resources were already registered. This means that added growth is incremental under the current terms. Michigan faces the challenge of growing DR from a near zero level which suggests that a flexible framework for forward demonstration of DR should be considered. A key element of PJM's construct is an Officer Certification representing that the provider has a reasonable expectation that DR proposed for a future delivery year can be delivered.

17) *The Commission Order in [U-20348](U-20348) asks us to answer whether the ability to aggregate DR for customers of Michigan AESs for bidding into RTO markets should be limited to AESs, or be extended to non-AES third parties such as CSPs. Based upon the feedback received to date, Staff recommends that we allow CSPs to bid aggregated DR into RTO markets to be consistent with MISO and PJM practices. Do you disagree with this recommendation? If so, please explain.*

AEMA is supportive of Staff's recommendation that CSPs be allowed to bid aggregated DR into RTO markets. CSPs, such as several of AEMA's members, have extensive experience in delivering reliable DR resources to wholesale and retail markets.

18) *What would need to happen to make your company comfortable with lifting the ban on DR aggregation for all customers in Michigan?*

DR is a powerful tool that allows consumers to participate in the energy market, empowering them to control their energy consumption and costs. AEMA and its member companies strongly believe that utilities should maximize cost-effective DR opportunities for their regulated customers that take advantage of wholesale markets. Utility-aggregator partnership models, in which utilities leverage the benefits of 3rd party aggregators but retain ownership, visibility, and control over their DR customers, can accomplish these goals and help maximize DR resources while maintaining consistency with utilities' vertically-integrated nature.

AEMA is supportive of the Commission pursuing additional conversations on DR aggregation, in line with the Commission's March 29, 2016 Order in U-16020, in which it identified four outstanding concerns related to the aggregation of DR directly in the wholesale market. These concerns include a) operational issues for Michigan's jurisdictional utilities, b) lack of Commission oversight of 3rd party aggregators, c) double-counting of customers in multiple DR resources/programs, and d) cross-subsidization. While AEMA believes that concerns b) and c) have been reasonably addressed to date, AEMA believes that further discussion on the other topics would be fruitful. Particularly given an impending FERC ruling on the DER Aggregation NOPR, in which opt-out authority for states remains an open question, AEMA supports conversations about how to maximize benefits from DR and DER aggregations in wholesale markets for all customers.

DR Aggregation Stakeholder Meeting #1

Homework Assignment

Send responses to Erik Hanser hansere@michigan.gov and Heather Cantin cantinh@michigan.gov

The due date for responses is February 28th.

State vs. federal jurisdictional questions

1) Per FERC Order 745, it is clear that the Relevant Electric Retail Regulatory Authority (RERRA) may prohibit 3rd party Demand Response (DR) aggregation in their jurisdiction. However, it is unclear whether the MPSC can partially permit aggregation and also place restrictions on multiple Alternative Electric Supplier (AES) aggregation and who is able to register the aggregated DR at MISO.

   Do the MPSC's Orders in Case Nos. U-16020, U-18369 or U-20348 raise any jurisdictional questions in your mind?

   a. Example: Does the MPSC have the authority to prohibit aggregation across multiple AESs?
      i. Aggregators would be able to operate within an individual AES's customer base (all customers in AES_1).
      ii. Aggregators would not be able to aggregate some customers from AES_1 and some from AES_2 and comingle the use of the demand response resources.
   b. Example: Would the MPSC be able to permit the aggregation of AES customers, with only this strict condition that the AES is the entity that registers the aggregated DR with MISO?

Consumers Energy Comment:
The MPSC has the authority to prohibit retail electric customers from bidding demand response directly into the MISO market, either individually or through aggregators. A state's ability to prohibit direct participation of retail customers in wholesale demand response markets is within its authority to regulate retail electric service. See 18 CFR 35.28(g)(1)(iii). Because of concerns related to (i) tracking demand response resources, (ii) determining and meeting capacity demonstration requirements, (iii) maintaining accurate capacity planning, and (iv) coordinating electric operations (among others), Consumers Energy does not believe that the MPSC should permit an aggregator to bid demand response directly into the MISO market. Please see additional discussion in response to Staff's other requests.

Tracking aggregated DR

2) Per MISO's Business Practice Manual (BPM) 1 Sec. 9.5, MISO will notify the MPSC of every new aggregated customer and provide who is the market participant, the MW amount, the load balancing area (LBA), and Commercial Pricing (CP) Node information.
    a. Is this information sufficient to allow the MPSC to track demand response resources and ensure that cross-subsidization and double counting are not occurring?

    Consumers Energy Comment:
    No, customer account information, including addresses must be provided in order to cross-reference registrations. In addition, the current registration process involves the ARC acting as the "market participant" for the purposes of DR registration, but not for market bidding. Therefore, the registration will only depict the participant as the ARC, and will not include the LSE information. Including the LSE will aid MPSC and LSEs in capacity demonstrations. Requiring the bidding AES to also register the DR with the RTO can improve the Commission's ability to track and verify DR resources.

    b. How would the MPSC be able to track DR that has been procured out of state for use in Michigan? Would it be necessary for the MPSC to track DR in other states?
    c. Would your answers for the prompt-year and a four-year forward capacity demonstration differ? How so?

    Consumers Energy Comment: Please see associated comments at Item 4.

The effects of aggregated DR on an LSE's capacity requirement

3) A Load Serving Entity (LSE's) capacity requirement is determined by their historical Peak Load Contribution (PLC).

Consumers Energy Comment:
This is not true for utilities. Consumers Energy, as an EDC, receives the remainder of Planning Reserve Margin Requirements (PRMR) not attributed to AES entities in the Peak Load Contribution (PLC) process. The capacity obligation calculation, for utilities, is EDC Forecasted Peak Load informed by reserve margin (PRM %) and MISO Transmission Losses, creating the EDC's PRMR. Each AES has a corresponding % of the peak, based upon the account values contributing to the peak. The remainder is then attributed to Consumers' PRMR.

a. What potential problems does aggregation of DR resources across multiple AESs' have on the PLC calculation?

Consumers Energy Comment:
As explained in detail below, aggregating DR across multiple AESs requires exceptional tracking mechanisms for dispatch events, including customer-level performance data. Each AES must increase their PLC by the amount of DR dispatched on behalf of their customers. Aggregators would have to supply each AES with customer-level dispatch data to satisfy this adjustment.

b. Example: An aggregator procures DR from AES_1. The aggregator sells this DR into the market, where it is procured by AES_2 to meet their capacity requirement. If this DR is dispatched on the MISO peak, AES_1's PLC is reduced by xMW, even though that DR has been sold to AES_2. The next year, AES_1 would have a lower capacity requirement and AES_2 would still have the same capacity requirement as the previous year.

i. Is this accurate?

Consumers Energy Comment:
Yes, this is accurate under today's process

ii. If so, is this a problem and what can be done to fix it?

Consumers Energy Comment:
Yes, this is a problem. AES1 would have to increase its PLC, based upon the dispatch event, in order to have an accurate PLC and subsequent contribution to the capacity requirement. However, AES1 currently would not have data for the dispatch event as it is only communicated from MISO to the aggregator. The aggregator is responsible for customer-level dispatch and performance but lacks meter-level data for verification, leaving AES1 without customer-level dispatch data to amend the PLC.

Consumers Energy Comment:
As outlined above, ARCs acting as market participants for DR registration limits the ability of both AES entities and the utilities to accurately forecast and adjust PLC, and corresponding PRMR. If PLC for AES load is not adjusted for DR dispatch events, the load attributed to the AES during the utilities' PRMR would be lower, thus placing a larger percentage of the resource capacity burden on the utilities during forecasting.

Acceptable reporting requirements for Capacity Demonstration

4) Through the Capacity Demonstration process, electric distribution companies (EDCs) and/or LSEs are able to show that they have enough resources to cover their capacity commitment. For supply side resources, the MPSC has a process for determining the availability and certainty of resources combined with adequate documentation from utilities and their partners.

   a. What procedures would be appropriate to apply to demand side resources, particularly aggregated demand response that could be spread across multiple service territories and multiple AES customers?
      i. Example: An AES submits a four year forward ZRC contract for aggregated DR.
         1. Should that ZRC contract be treated any differently than if it was a ZRC contract four years forward with a supply-side generation owner? How so?
   b. What information would be sufficient to ensure capacity exists for the commitment period?
   c. What entity would be best to supply this information?
   d. Should a four year forward ZRC contract for aggregated DR (aggregated AES customer load) be considered an acceptable resource if submitted as part of a capacity demonstration on behalf of a utility, municipality or cooperative? Why or why not?

Consumers Energy Comment:
MISO has a robust process for registering DR as capacity, where capacity is registered and verified on an annual basis. ZRC contracts would be valid for the current and forthcoming Planning Year.
In order to validate DR commitments beyond the prompt year and the MISO capacity process, DR performance must be evaluated. For utilities, this performance validation occurs annually, through the established DR reconciliation process. There is currently no requirement for ARCs to complete this validation step for their DR resources; thereby limiting the confidence in those resources during 4 year planning.

5) Voltus and AEMA both suggested in the February 13, 2019 stakeholder meeting that the MPSC should not limit DR aggregation to only AES customers. What are your initial thoughts on that?

Consumers Energy Comment:

Current registration, dispatch, and tracking processes, between the wholesale market and the aggregator, exclude the AES and the utility under proposed expansion. Aggregated DR load and its subsequent dispatch are managed independent of the load serving entities, interfering with peak load calculations, and resulting in inaccurate capacity evaluations.

Allowing aggregators access to utility customers redistributes the benefits associated with demand response, reducing the financial beneficiaries to the ARC and the DR participants, primarily commercial and industrial customers. Benefits and revenue sharing are limited by contract terms between these parties. Alternately, utility-based DR programs distribute the benefit of reduced system load, and potential capacity payments across all utility customers.

In addition, allowing third party aggregation limits the MPSC's visibility into the state's capacity resources. Currently, Voltus (and other aggregators) are registering DR directly with MISO, prior to any communication with the AES. The MPSC loses control over state demand response programs, their monetary benefits, and their performance, by allowing aggregators unrestricted access to the wholesale market.

As more distributed generation (DG) is connected to the system, the utility is best positioned to manage demand response in a manner that provides both resource adequacy and electric distribution system benefits.

Demand response is growing as a 'non-wires alternative' to manage distribution system issues such as voltage control, frequency regulation and to defer or avoid infrastructure upgrades and investments. Having this integrated view, and leveraging DR to solve for both supply and grid needs, increases efficiency and ultimately provides the customer with a more holistic solution. Aggregators do not have holistic planning in mind, nor the ability to manage or mitigate impacts of their DR resources on the system.

The Company has developed a pilot project to investigate opportunities to use energy efficiency and demand response to avoid or defer distribution system and provide cost savings for customers. This pilot will inform how the Company expands the use of demand response for integrated system planning, ensuring resource adequacy, targeting high load growth areas, reducing infrastructure constraints and aligning with intermittent/variable distributed generation.

The increasingly dynamic nature of the electric grid, combined with growing penetration of DG resources, requires a new level of flexibility and holistic planning across the entire electric system to maximize efficiency and value to customers. The utility is uniquely positioned to maximize value of demand response as it has a comprehensive view of total system performance, in real-time and for long-term, and can therefore deploy resources to solve for multiple system needs and operational objectives.

6) Do you have any other recommendations you would like to suggest? No.

7) Do you have any additional topics you would like to discuss for our next DR aggregation stakeholder meeting on March 12th? No.

8) Are you opposed to having your written response included with the MPSC Staff report that is due to the Commission on May 30th?

While the Company does not oppose the inclusion of its comments in the MPSC Staff report, the Company believes that there may be value in providing an opportunity for the filing of comments subsequent to the completion of the workgroup meetings and prior to the completion of the MPSC Staff report. This would allow all information presented in the workgroups to be fully considered.

DR Aggregation Stakeholder Meeting #2

Feedback Request

Thank you for participating in the MPSC Staff's DR aggregation stakeholder activities. Following the second stakeholder meeting, held on March 12, Staff requests the following feedback. All responses are voluntary and will be kept confidential unless a statement is provided that the information may be quoted in the Staff report or included as an appendix to the Staff report which will be posted in Case No. U-20348 by May 30, 2019. Please provide your responses to Heather Cantin (cantinh@michigan.gov) and Erik Hanser (hansere@michigan.gov) by April 10, 2019. The next stakeholder meeting is scheduled for May 3, 2019 at 1:00 p.m.

Indiana model (See slides 17-20):

1) Do you have any immediate feedback on the pros and cons of this model?

Indiana's demand response model reflects and appreciates the inherent resource adequacy risks of allowing third-party aggregators to directly participate in wholesale markets. Indiana's extensive review of its state demand response model determined that direct retail demand response participation in wholesale markets was not in the public interest. The Indiana Utility Regulatory Commission ("IURC") found that direct customer participation creates significant uncertainty around capacity needs and cost effectiveness in Integrated Resource Planning processes. Specifically, "excluding potential cost-effective resource solutions from the IRP portfolio is counter to the coherent and comprehensive planning process required under Indiana law."

The IURC recognized that direct retail participation through third party Aggregators of Retail Customers ("ARCs") creates significant financial risks for the utility's remaining customers. The IURC reasoned that, "to the extent that a customer directly participates, that curtailable load can no longer be netted from the utility's forecast, so the utility will need to procure more resources than would otherwise be the case at the expense of all customers." Recently, the Louisiana Public Service Commission expressed these same concerns around demand response aggregation by third parties, finding that third-party aggregators should be prohibited from soliciting retail customers to participate in wholesale markets.

The Indiana model encourages joint partnerships between utilities and Curtailment Service Providers to provide opportunities for customers that may be underserved by the utilities. When Indiana enacted its demand response program in 2010, utility demand response programs were less common. Limited options were available for customers seeking the benefits of demand response.

2) Is this model worth exploring?

No. The Indiana model is not a model that should be mirrored in Michigan. Cumulative enrollment forecast for residential demand response is expected to increase from 55 MW in 2018, to 133 MW by 2022.[1] Not only have utility programs for demand response expanded since the creation of the Indiana model, but aggregators (ARCs/CSPs) are not expected to serve or expand services for residential customers.

Similarly, the Company offers tariff-based rate programs for business customers. In addition to interruptible Tariff rates, business customers are eligible to enroll in both emergency and economic demand response programs. The Company works with business customers to set up demand reduction plans at their

[1] U-20165, Ennis testimony at p. 13

facilities that will be implemented when a demand response event is called (when electricity demand and costs are at their highest). Further, although there has not been a need for the Company to contract with a third-party to offer demand response programs, the Company has the ability to work with third parties in providing demand response. Accordingly, there is no need for the MPSC to adopt the Indiana model.

Pennsylvania model (See slide 21):

3) Do you have any immediate feedback on the pros and cons of this model?

Pennsylvania's model mandates accountability for third-party ARCs. All ARCs are required to be registered in the State, providing the Electric Distribution Company ("EDC") with data pertaining to dispatch events. Nonetheless, as noted below, this process should not be considered a prudent substitute for the comprehensive and robust Integrated Resource Planning process that is mandatory under Michigan law.

4) Is this model worth exploring?

The Pennsylvania model for demand response aggregation should not be considered. Pennsylvania's regulatory framework is significantly different than Michigan. Electric service in Pennsylvania is deregulated – there is no long-term, integrated resource planning process in place. Rather, Pennsylvania depends on market price signals to address state resource adequacy needs.

Regarding MISO vs. PJM processes (See slides 22-23):

5) Does the PJM process outlined above have any pros or cons as compared to the current MISO process?

The PJM registration process requires more detailed and granular information to register as an aggregator of retail customers than MISO. Because PJM manages registration and notifications to EDCs, the Relevant Electric Retail Regulatory Authority ("RERRA") is not necessarily part of this process. Alternatively, MISO's rules and procedures around state notifications provide the RERRA (such as the MPSC) with awareness of registered participants in MISO's wholesale markets. This RERRA oversight remains a beneficial difference between MISO and PJM.

6) While this discussion is focused on a Michigan specific process to track and verify aggregated DR, would you support supplementing the MISO process with some of the aspects of PJM's registration process?

Because the MPSC has jurisdictional authority to prohibit direct participation of retail customers (either individually or through an aggregator) in wholesale demand response markets, and MISO's registration processes understand that the MPSC maintains the right to reject the registration of an entity or resource, MISO's registration process does not need to be supplemented with aspects of PJM's registration processes.

7) Would you support adopting some of these PJM procedures into a Michigan specific process?

As noted above, PJM's procedures are not necessary for a Michigan specific process.

8) Would you like to further discuss the IN/PA models or explore aspects of the PJM process?

As noted above, additional discussions around current demand response programs and offerings would be beneficial. However, none of the alternative state models or market processes presented reasonably balance the MPSC's resource adequacy objectives with the need to protect retail customers from unreasonable cost shifting.

Other:

9) Are MISO BPM or tariff revisions warranted to ensure that retail peak load contributions are increased to reflect any relevant load reductions?

Yes. While the tariff[2] provides for adjustments for any load reductions achieved and for which capacity credits are earned, there is no standard processes defined in the business practice manuals to establish how and when those adjustments are to be made.

10) Are MISO BPM or tariff revisions warranted to ensure that retail peak load contributions are not double counting the same resource on both the supply side and demand side of the resource adequacy equation? If so, what specific BPM or tariff revisions would you suggest?

Section 3.2 of BPM 11 addresses demand and energy forecasts. The demand forecast is required to be adjusted for load reductions achieved and for which capacity credits are earned. Generally the demand forecasts are submitted by November 1, prior to the start of the Planning Year. Section 4.2.9 of BPM 11 addresses Demand Resource Registration Process. Demand Resources can be renewed as late as February 1 prior to the start of the Planning Year. Thus these two sections need to be coordinated to address what happens in the instance where a Demand Resource reduced demand and earned capacity credits so that the appropriate demand forecast for both the electric distribution utility and the load serving entity are adjusted prior to the Planning Resource Auction that occurs in late March prior to the planning year.

11) What if a change was made to the MISO tariff such that the PLC was determined to be the highest load for that particular customer for MISO's top twelve peak hours of the previous year? Would this reduce or possibly eliminate the need to make PLC adjustments to account for load reductions?

No. Such a revision may change the magnitude of the adjustment but it would not eliminate the issue. Furthermore, such a redefinition would reduce the capacity credit available to the demand resource which is likely inconsistent with FERC Orders. If the intent is to attempt to mimic the ELCC test for wind powered electric generating facilities, the test is associated with the eight days of the previous year that had the highest or peak hourly demand. This test was designed due to the intermittent nature of the fuel source. In the case of demand resources there is some intermittency involved, but the intermittency should be far less than the intermittency experienced with wind. As a result a test similar to a GVTC test or perhaps an ELCC test used for hydro or solar powered facilities may be more appropriate. Nevertheless, the test method would not eliminate the need to adjust demand forecasts for the amount of load reduction achieved and for which capacity credit is earned.

12) Should the MPSC develop a voluntary registration process with reporting requirements for ARCs in Michigan? Why or why not? (See slide 31)

[2] 69A.1.2.1 Page 31.0.0

While reporting requirements for ARCs in Michigan may be valuable, a voluntary registration process is not expected to remedy the issues presented herein. In order for the electric distribution companies and the load serving entities in the State to accurately plan for and adjust to demand response resources, the data received must be expanded, standardized, and provided consistently. A voluntary program does not create the reliable data availability that is necessary. Additionally, if ARCs were not the market participant, registering in the wholesale market, the required data would come directly to the AES or other Load Serving Entity ("LSE"). The need for registration could be eliminated if the aggregated load was registered through the AES, thus creating the information pathway from the wholesale market to the regulated energy supplier.

13) Is legislation necessary to outline a more formal process for registering or licensing ARC's?

Consumers Energy continues to recommend that the Commission prohibit ARCs from bidding demand response directly into the MISO wholesale market on behalf of Michigan retail customers. Permitting ARCs to bid demand response directly into the MISO market disrupts electric providers' capacity planning, causes concerns with the accuracy of the capacity demonstration process, and results in customers not participating in wholesale demand response markets being required to pay for savings realized by retail customer who do participate in wholesale demand response markets. While Consumers Energy agrees that a formal process for registering or licensing ARCs is preferable to a voluntary one for purposes of obtaining the information necessary for tracking and verifying any aggregated demand response, such a formal process will not solve the significant capacity planning, electric operations, and subsidization concerns that will exist if the Commission permits ARCs to bid directly into the MISO market.

14) What recommendations do you have about what type of information should be included in an ARC registration at the MPSC?

As outlined above in Items 12 and 13, improving data collection does not resolve the issues associated with aggregated demand response, and its impacts to system operations and capacity planning. Not only would additional information be required of the ARCs, but this information must be disseminated to the EDC and LSE for those resources. Information is not limited to registered demand response resources. Data regarding specific customer dispatch events is necessary not only to ensure performance and reliability of demand response, but also to ensure accurate capacity forecasts.
At a minimum, the following would be required to limit inaccuracies:

- Customer account information, as currently required at MISO registration
- Verified Peak Load Contribution of customer
- Dispatch events, to include customer account information, time of dispatch and load reduction per event
    - Dispatch/event data for demand response registered by ARC/CSP is not visible at customer-level, preventing EDCs from adjusting PLC and thus negatively impacting the resource adequacy calculations

      Example: Aggregator (ARC) registers a demand response resource with MISO for 5 MW. Currently, AES and utilities do not receive any customer-level dispatch data, meaning this 5 MW does not get assigned to individual meters. Therefore, no adjustment to PLC is made. If the AES has a total PLC of 25 MW (based on prior year), and the ARC has 5 MW of demand response dispatched (in the current year), then next year's PLC for the AES (based on meter data) would show 20 MW. If the Planning Reserve Margin Requirement ("PRMR") for the utility is the "leftover" after removing transmission losses and PLC from the AESs, then the utility would now be responsible for the extra 5 MW, because it would only be subtracting 20 MW, not 25 MW for that AES. This shifts the capacity burden onto the utilities, unless the ARC communicates

customer-level data to both the AES and utility, enabling them to adjust upward the PLC. Presumably this is exacerbated as ARC-based demand response expands.
The MISO Portal Demand Response Tool allows for review of data related to events, it is still unclear how the tracking and adjustment process would work. As the Demand Response Product is a MISO Settled Item, a BPM for calculation on and adjustment of PLC events should be given by MISO working with the affected Market Participants, as outlined in Items 9-11 above. Currently, no single entity is responsible for tracking and verifying demand response.

15) Should the MPSC pursue a Michigan 4-year forward Capacity Tracking Tool that would accommodate the tracking of all capacity resources, including aggregated DR, aggregated energy efficiency and aggregated storage resources, on a 4-year forward basis? Why or why not?

No. The MPSC already possesses this information in a standard format through the State Reliability Mechanism ("SRM") capacity demonstration requirements. By compiling the information collected through the SRM capacity demonstration, the MPSC Staff can identify capacity needs and understand the capacity position of both the Lower Peninsula and Upper Peninsula. Creating and maintaining any additional systems or tools has the potential to increase reporting complexity, create confusion with MISO reporting requirements, and add unnecessary cost.

16) At this point in time, do you have any recommended changes to the MPSC's capacity demonstration requirements adopted in U-20154, specifically for forward ZRC contracts?

No.

17) The Commission order in U-20348 asks us to answer whether the ability to aggregate DR for customers of Michigan AESs for bidding into RTO markets should be limited to AESs, or be extended to non-AES third parties such as CSPs. Based upon the feedback received to date, Staff recommends that we allow CSPs to bid aggregated DR into RTO markets to be consistent with MISO and PJM practices. Do you disagree with this recommendation? If so, please explain.

As discussed throughout these responses, Consumers Energy does not agree that the Commission should permit ARCs to bid demand response directly into the MISO wholesale market on behalf of Michigan retail customers. Permitting ARCs to bid demand response directly into the MISO market raises several concerns, which include the following:

- The MPSC would be limited in its ability to verify performance of the aggregated demand response resources and consider them in the capacity demonstration process.
- Electric providers would be less able to incorporate ARC demand response participation into capacity demonstrations and resource plans.
- Consumers Energy and DTE Electric already have demand response programs in Michigan, and Consumers Energy has proposed significant increases in demand response as part of its Integrated Resource Plan. Permitting ARCs to bid demand response directly into MISO jeopardizes the Company's ability to reach its demand response targets.
- The limited ability to track and plan for the ARCs' demand response resources devalues the benefits of demand response to all customers.
- Customers that do not participate in wholesale demand response markets pay for the savings realized by retail customers who participate in wholesale demand response markets.

18) What would need to happen to make your company comfortable with lifting the ban on DR aggregation for all customers in Michigan?

Fundamentally, third party aggregators are only focused on “economic demand response,” where program participants are paid to reduce load when economic conditions exist in the market, where the value of that load reduction outweighs the cost paid to the program participant. The difference between the market price and the price paid to the program participant becomes the profit margin available to the aggregator. When these events occur, the only customers who benefit from this arrangement are the program participant and the aggregator. All other energy consumers end up paying the higher market price which the aggregator bid into the market.

The utility demand response model must focus on both emergency and economic events. Specifically, for economic events, the utility is able to request that economic demand response program participants reduce load, and the utility pays the participant for this load reduction. However, this reduced load enables the utility to purchase lower priced power in the market, either to meet capacity needs or margin reserve. The emergency demand response program is in place to ensure reliability of the grid during MISO declared emergency events. Third party aggregators assume no responsibility for emergency events. This is a significant benefit provided only by the utility demand response program. For this reason, ARCs are unable to provide grid stabilization, and are competing with utilities’ ability to provide this benefit.

Lifting the ban on demand response aggregation for utility customers is also contrary to the 10% cap on retail electric choice in Michigan. In creating the electric choice cap in 2008, and reaffirming it in 2016, the Michigan Legislature determined that Michigan utilities should provide electric generation service to 90% of their retail markets. This provision of electric generation service includes both energy and capacity service, and demand response is treated as a capacity resource by MISO. Permitting demand response aggregators to bid demand response into the MISO market on behalf of utilities’ retail customers would circumvent the electric choice cap by displacing a portion of the market which the Legislature has deemed should be served by utilities.

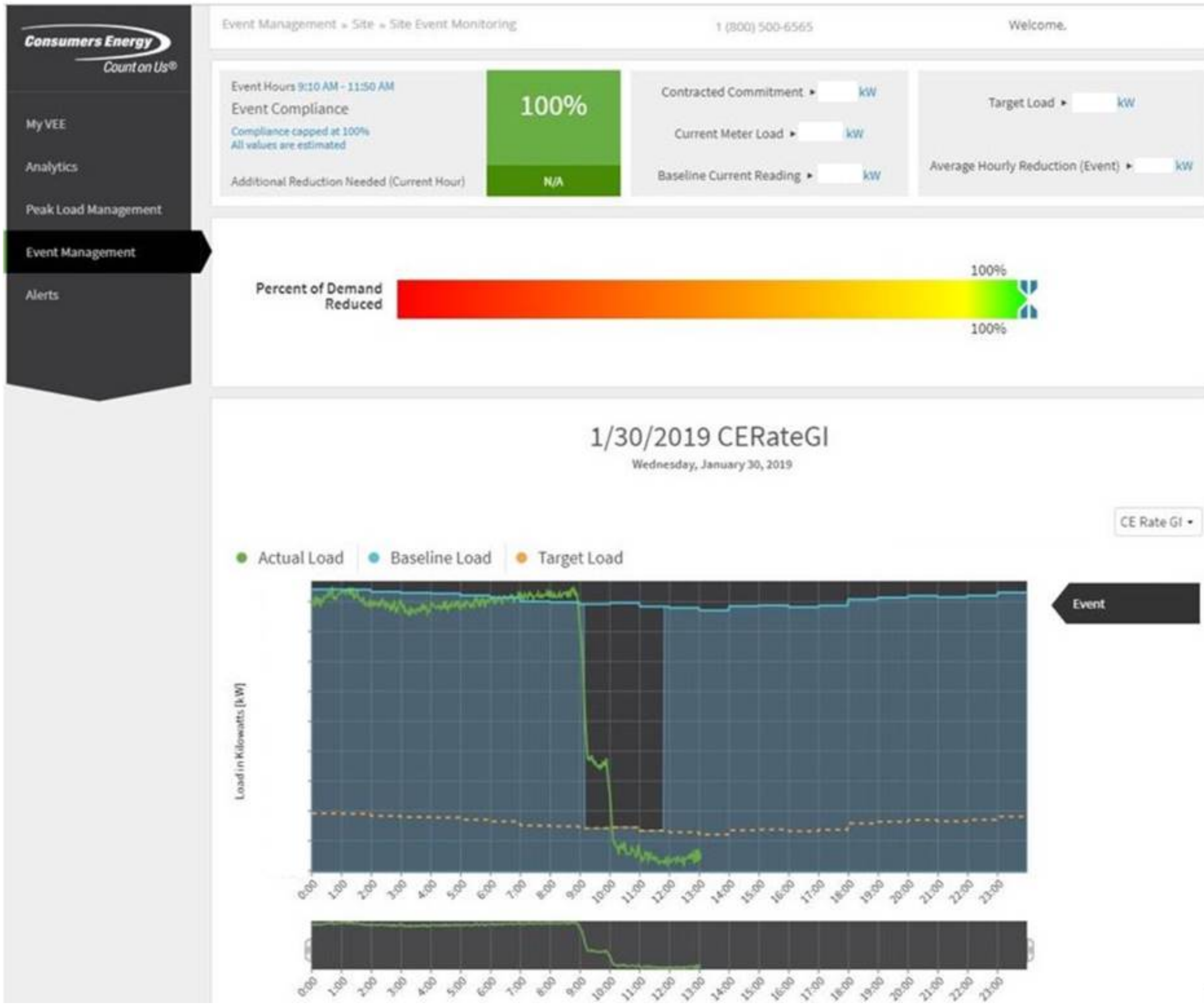
Consumers Energy believes that operating an efficient and effective demand response program is a prudent investment that will support the company in achieving the triple bottom line of People, Planet, and Prosperity. Electric supply and demand fluctuate throughout every day and in the event that supply is not sufficient enough to meet demand, a grid disruption occurs. A grid disruption or emergency can be caused by extreme weather, wholesale price spikes, or unexpected system issues that occur within the entire MISO service territory, which means the customers’ participation is not limited to the grid conditions of their utility. In order to respond to these fluctuating operating scenarios, Consumers Energy dispatches capacity and generation resources that comprise a utility demand response resource.

Demand response allows Consumers Energy to better manage the supply and demand on the electric grid. As temperatures fluctuate seasonally, the amount of electric demand also fluctuates. During the majority of the year, electric demand is lower than the available electric capacity. However, in the summer months when electric demand is highest, there may not be enough capacity available to meet the demand needs. In this scenario, demand response is initiated as one of the ways to reduce electric demand to meet available supply during the demand response season. This is achieved by notifying program participants of a demand response event, which triggers their response to follow established curtailment plans to reduce their demand by a predetermined amount until the event concludes. There are two primary demand response programs offered to customers; Emergency and Economic demand response. The image below outlines key characteristics of the two programs:

EMERGENCY EVENT	**$25/kW Capacity Payment** ▪ One-time payment for standing by and being on-call for an event. ▪ Represents largest portion of total payments.	**$0.05/kWh Energy Payments** ▪ Compensation is for every hour of each event dispatch, based on your dispatch performance. ▪ Smaller portion of total payments.
ECONOMIC EVENT	No annual capacity payment	**$0.30/kWh Energy Payments** ▪ Compensation for every hour of the event dispatch, based on your dispatch performance. ▪ Higher payment than for Emergency events.

In order to acquire customers into the emergency demand response programs the Company has provided two primary benefits to participants to incentivize their participation, while providing prudent investment for all customer classes. First, participants receive financial incentives for being enrolled into the emergency program. This portion is paid whether or not an emergency demand response event occurs. Secondly, participants will receive a financial incentive paid on their actual event performance. Relative to the economic demand response program, participants are not incented for their capacity, but are compensated at a higher level for their demand curtailment because these events are triggered by financial modeling for the participating customers and not grid reliability for all customers. This program is most similar to the offerings by the demand response aggregation companies. As part of the program, participants receive access to an energy dashboard that details near real-time energy consumption data that is leveraged to effectively manage their facilities during demand response events. These dashboards show baseline load curves, actual load, and target load graphs as well as event compliance, actual curtailment percent, and the contracted demand reduction commitment. With a single screen customers are able to successfully monitor their commitments that provides them financial incentives and supports prudent utility investment for the benefit of all customers (see below for a redacted image that customers are able to utilize for their operation during the demand response season). Additionally, the same operating system allows the utility to monitor, manage, and document customer performance, individually or as a portfolio, for effective and reliable performance in alignment with the Energy Supply department of the utility. This single point of contact from a customer perspective creates a consistent and positive customer experience that is efficient and reliable for MISO and the utility.

In addition to the actual event monitoring and reconciliation, Consumers Energy acknowledges that energy can be curtailed in a variety of ways across all industries, including manufacturing, education, healthcare, government, and other commercial sectors. Therefore, the development of curtailment plans that accurately depict available demand reduction and responsiveness of each participating facility are essential to the delivery of the demand response program. Curtailment plans might include shutting down a production line, adjusting temperatures, or reducing lighting, for example. Consumers Energy employs and utilizes Certified Energy Managers to work with customers to develop a curtailment plan that suits the needs of participants and can be executed if and when demand response events occur.



Consumers Energy believes that emergency and economic demand response are valuable programs that are able to provide value to all customers when appropriately designed and executed. We have developed a set of tools that informs and aids customers before, during, and after events with visual keys and compliance reports. To further ensure the success of customers and the demand response program, the Company is actively partnering with customers to create curtailment plans with professional engineers and Certified Energy Managers. We believe that when our customers are supported and successful, then all parties are best represented for the benefit of all Michiganders.

Demand Response Aggregation

U-20348 Stakeholder Workgroup

May 3, 2019

Consumers Energy
Count on Us®

Overview

- Consumers Energy Existing and Planned Demand Response programs
- Demand response potential and role in system planning
- Customer protection and DR performance
- Demand response and capacity markets
- Wholesale markets and rates
- Q & A

Consumers Energy Existing Demand Response Programs

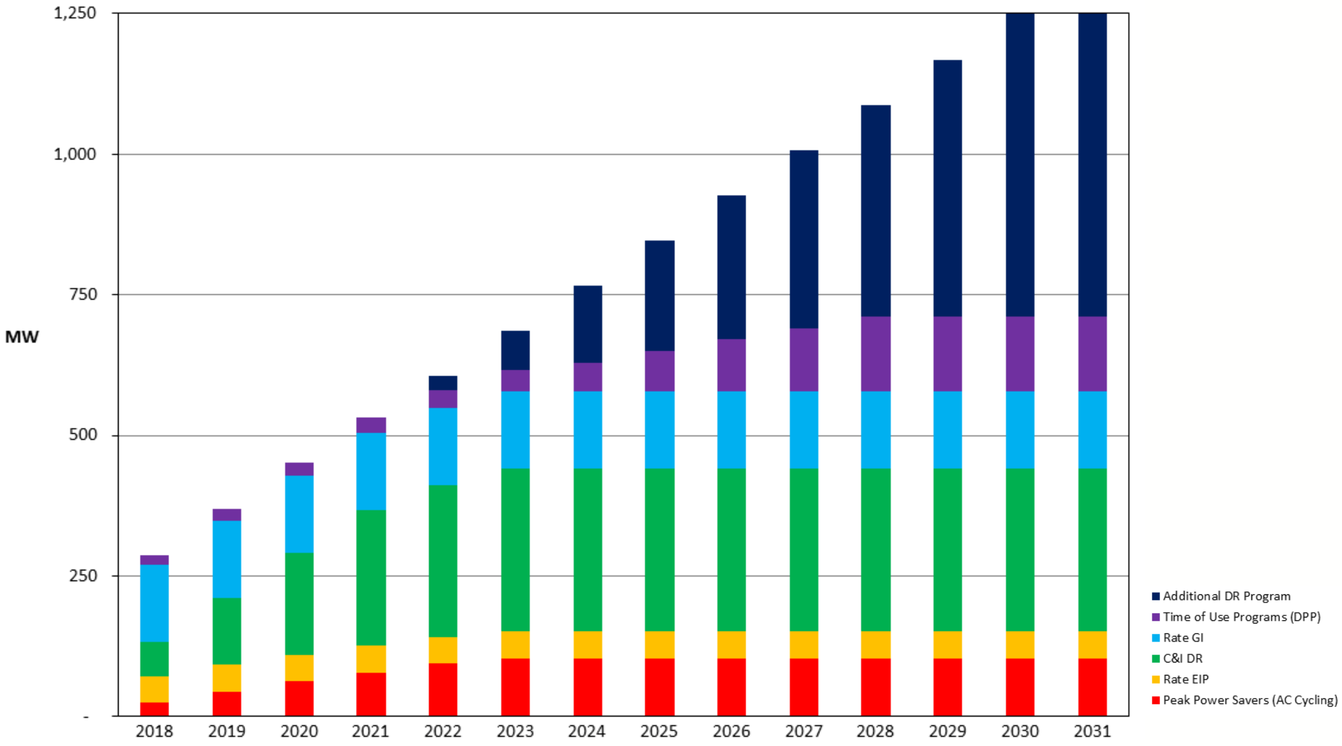
- Demand Response (DR) Programs:
  - Residential Air Conditioning Peak Cycling Program
  - Residential Dynamic Peak Pricing Program
  - Commercial and Industrial Emergency DR
  - Commercial and Industrial Economic DR
  - General Interruptible (Rate GI)
  - Energy Intensive Program (Rate EIP)

- Customer Participation:
  - Tariff rate programs open to all qualifying customers
  - Commercial and Industrial customers have options for Emergency only, Economic only or both.

- Commercial and Industrial Participants must curtail 100kW or more to qualify for DR program

Demand response potential and system planning

- Consumers Energy has filed an Integrated Resource Plan with the Michigan Public Service Commission (U-20165) with planned Demand Response program expansion through existing and new cost effective programs which is currently under review
- State Energy Legislation (MCL 460.6t) requires review of all DR resources through the IRP process and the DR potential studies to determine Least Cost Options for resource planning
- ARC's provide no opportunity for cost, transparency in cost, impact, control or timing in this process should retail customer participation occur



Customer protection and DR performance

- Consumers Energy is currently tracking and reporting Demand Response program capacity, cost, performance and planning to the MPSC in the following annual cases:
  - Capacity Demonstration
  - Demand Response Reconciliation
  - Power Supply Cost Recovery

- Consumers has annual reporting requirements to the Midcontinent Independent System Operator for program capacity, performance and planning as the Demand Response programs are Load Modifying Resources (LMRs) and used as such in the Planning Reserve Auction (PRA) process. MISO's Module E process and the OMS Survey are additional tools to monitor capacity provided by the Company.

- Rate Case filings and the Company's Integrated Resource Plan provide the Commission with additional opportunity to review the performance of the Demand Response programs.

- The Company is focused on ensuring the cost effective generation to all of its retail utility customers, not just those that could take advantage of an aggregation program

Demand response and capacity markets

The ARC business model requires a Load Serving Entity (LSE) to continue to plan to meet all customer load

- LSE Customers Pay for Capacity Portfolio
- ARC Customers Receive an Incentive for willingness to reduce usage
- ARC Sells ZRCs to pay customer incentive

The ARC and ARC customer monetize the ZRCs which are paid for by other customers of the LSE

Demand response and capacity markets example

If ARCs are granted unrestricted access to Utility Retail Customers:

LSE portfolio has average cost of \$100k/MW-Yr	ARC pays customers average of \$25k/MW-Yr	ARC sells ZRCs to other market participants for \$50k/MW-Yr	LSE portfolio still has average cost of \$100k/MW-Yr

LSE customers pay \$100k / MW-Yr so that the ARC can resell that capacity for \$50k / MW-Yr. The ARC and ARC Customer each gain \$25k / MW-Yr

If ARCs required to partner with Load Serving Entities (Current Construct):

LSE portfolio has average cost of \$100k/MW-Yr	ARC pays customers average of \$25k/MW-Yr	ARC sells ZRCs to LSE for \$50k / MW-Yr	LSE portfolio has average cost of \$75k/MW-Yr

All LSE customers benefit from the low cost DR resources. The ARC and ARC customer still gain \$25k / MW-Yr

Additional Concerns if ARCs granted unrestricted access to Retail Customers

- Uncertainty around impacts to distribution non-wires alternatives (NWA).
- Operational challenges related to load forecast accuracy and distribution system stability if called upon without communicating through the LSE
- Difficulty identifying the DR potential remaining for inclusion in IRP
- Decreased availability of “Negawatts”

Conclusion

Allowing ARCs unrestricted access to Michigan's Retail Customers means:

- Fewer retail customer protections
- Less regulatory oversight
- Incomplete realization of the DR value stream
- Higher cost per MW to deliver DR
- Lost opportunity to use DR for distribution system planning
- Reliance on DR for long-term planning will be more challenging

Taken together this means less DR in Michigan and less value to Michigan electric customers

Questions and Answers

May 29, 2019

Comments of DTE Electric on Staff's outline of its draft DR Aggregation report issued on May 16th, 2019 in Case No. U-20348.

Background

On November 21, 2018 the Michigan Public Service Commission (MPSC or Commission) issued an Order in Case No. U-20438 to review issues relating to demand response (DR) aggregation for electric customers served by Alternative Electric Suppliers (AESs). In response to that Order, the Commission Staff (Staff) held meetings on February 13, 2019, March 12, 2019, and May 3, 2019. At the conclusion of the February and March meetings, Staff provided a set of questions; DTE Electric Company's (DTE or Company) written responses to those questions are included with this submission as Exhibit-1 and Exhibit-2, respectively.

The Commission's Order opening this docket directed the Staff to file a report including its recommendations regarding DR aggregation for load served by AESs by May 30, 2019. At the end of the March meeting mentioned above, Staff requested input on the appropriateness of the Commission allowing third-party aggregation of DR capacity from bundled utility load.

Bundled Load DR

In response to Staff's inquiry, DTE submitted the comments included with this document as Exhibit-2. In those comments, the Company explained that the detrimental effects of allowing third-parties to aggregate bundled load DR include, but are not limited to: DR load receiving a double benefit for interruptions and the resulting cross-subsidization issues; increased difficulty in long-term planning; and operational conflicts between DR dispatch in wholesale markets (by MISO) and the need to utilize it for distribution load relief (see pgs. 5 – 7). Staff stated in its May 17th report outline that it agreed with the Company's conclusions and recommended that the Commission not allow third-party aggregation of bundled utility load (see Staff outline, subsection 5e).

In addition to the discussion of the problems that would be created were third-parties allowed to aggregate bundled load DR, DTE's comments detailed its existing and future DR capabilities, which established the fact that DTE is a leader in this sector of the utility industry (see pgs. 7 – 11). Since DTE's bundled load customers are already eligible to select best in class DR programs they have little or nothing to gain through the introduction of third-party aggregation. That lack of benefit combined with the fact that various problems will arise if third-parties are allowed to aggregate bundled load makes clear that enabling third-party aggregation of bundled load does not make sense. DTE Electric supports Staff's recommendation that third-parties should not be allowed to aggregate the demand response capability of bundled utility load.

Choice Load DR

In section 4a of its report outline, Staff recommends that the Commission allow ARCs to bid the DR capability of Choice load directly into the wholesale market. DTE Electric believes that this recommendation is problematic for three reasons.

First, Staff notes in section 4a(i) that Voltus has already registered choice load DR in the MISO market. That fact was confirmed when the Company validated the accounts from its service territory that Voltus registered with MISO, because the registration documentation provided to DTE by MISO listed Voltus as the Market Participant. Voltus, an aggregator, being the MISO Market Participant for electric choice load DR appears to be contrary to the directive in the Commission's Order in Case No. U-18369 that required the customers' AES to perform that function.

Second, in that same section of its outline, Staff states that maintaining the current requirement that the AES be the MISO Market Participant that bids its customers' DR into the market would not "solve technical or transparency related issues. . . primarily because they are not involved in the dispatch of third-party aggregated demand response products." This claim is incorrect. If the AES were the Market Participant for its customers' DR, then by the definition of the term Market Participant, the AES would be bidding that capability into MISO and relaying any subsequent dispatch information. This bidding and dispatch data are needed by the Commission to perform its annual resource adequacy assessment for the state.

Requiring AESs to act as their customers' Market Participant ensures the AESs will have their customers' DR information. Under the provisions of section 6w of PA 341 AESs have a requirement to submit annual capacity demonstration to the MPSC, while aggregators do not. In their capacity demonstrations to the MPSC the AESs would include their customers' DR information. Therefore, requiring the AESs to act as their customers' DR Market Participant will ensure that the Commission is provided with all of the information necessary to assess resource adequacy in the State of Michigan.

Finally, as mentioned above, Staff noted there will be "technical or transparency issues" if third party aggregators are allowed to act as Market Participants for choice load DR. Section four of Staff's outline describes those issues at great length, but that outline does not provide any definitive solutions to those problems. It is the Company's position that 1) the requirement that AESs act as the Market Participant for its customers' DR will provide the Commission with the data necessary to ensure resource adequacy if that requirement is followed; and 2) the issues detailed by Staff that will arise if that requirement is lifted should be resolved prior to and not after the requirement is eliminated.

DR Aggregation Stakeholder Meeting #1
Homework Assignment
Send responses to Erik Hanser hansere@michigan.gov and Heather Cantin cantinh@michigan.gov
The due date for responses is February 28th.

State vs. federal jurisdictional questions

1) Per FERC Order 745, it is clear that the Relevant Electric Retail Regulatory Authority (RERRA) may prohibit 3rd party Demand Response (DR) aggregation in their jurisdiction. However, it is unclear whether the MPSC can partially permit aggregation and also place restrictions on multiple Alternative Electric Supplier (AES) aggregation and who is able to register the aggregated DR at MISO.

Do the MPSC's Orders in Case Nos. U-16020, U-18369 or U-20348 raise any jurisdictional questions in your mind?

a. Example: Does the MPSC have the authority to prohibit aggregation across multiple AESs?

i. Aggregators would be able to operate within an individual AES's customer base (all customers in AES_1).

ii. Aggregators would not be able to aggregate some customers from AES_1 and some from AES_2 and comingle the use of the demand response resources.

b. Example: Would the MPSC be able to permit the aggregation of AES customers, with only this strict condition that the AES is the entity that registers the aggregated DR with MISO?

In its March 29, 2016 order in Case No. U-16020, the Commission upheld a prohibition on retail electric customers (either individually or indirectly through aggregators) from bidding demand response resources into the regional transmission operator wholesale markets. The Commission based its decision in part on the United States Supreme Court decision, *FERC v. Elec. Power Supply Ass'n*, which confirmed the states' ability to prohibit participation in the wholesale demand response market. The March 29th order was appealed, and the decision was upheld by the Michigan Court of Appeals on February 8, 2018. See *In re Detroit Edison Co*., Dkt. No. 332605 (Mich App 2018). In upholding the decision, the Court found that the "[Commission's] power to regulate service and conditions of service as set out in MCL 460.6(1) is sufficient authority for the [Commission] to determine that retail electric customers or aggregators should be prohibited from participating in wholesale markets." The Commission is the relevant electric retail regulatory authority in Michigan and it is "vested with complete power and jurisdiction to regulate all public utilities," and has "the power and jurisdiction to regulate all rates, fares, fees, charges, services, rules, conditions of service, and all other matters pertaining to the formation, operation, or direction of public utilities." MCL 460.6(1).

In light of the 2018 Court of Appeals decision, MCL 460.6(1), and various other statutory provisions that grant the Commission the authority to regulate retail rates, as well as other aspects of the provision of electric utility service, it is clear that the Commission's jurisdiction authorizes it to prohibit retail customers from offering DR resources into the wholesale markets.

Tracking aggregated DR

2) Per MISO's Business Practice Manual (BPM) 1 Sec. 9.5, MISO will notify the MPSC of every new aggregated customer and provide who is the market participant, the MW amount, the load balancing area (LBA), and Commercial Pricing (CP) Node information.

a. Is this information sufficient to allow the MPSC to track demand response resources and ensure that cross-subsidization and double counting are not occurring?

   The customer's account number alone cannot be used to validate the demand response and prevent double counting. From time to time, a customer's account number with the utility may change although the site and the customer remain the same. This may happen due to a legal name change for the customer, to provide a new or different service to the customer, or to establish different billing due to metering changes at the site. The account number along with the site address would prevent double counting.

b. How would the MPSC be able to track DR that has been procured out of state for use in Michigan? Would it be necessary for the MPSC to track DR in other states?

c. Would your answers for the prompt-year and a four-year forward capacity demonstration differ? How so?

DTE

The effects of aggregated DR on an LSE's capacity requirement

3) A Load Serving Entity (LSE's) capacity requirement is determined by their historical Peak Load Contribution (PLC).

a. What potential problems does aggregation of DR resources across multiple AESs' have on the PLC calculation?

ARC Registration Data

In order to get DR aggregation right, the data provided in the initial registration needs to be correct and complete. When reviewing a potential ARC registration, the utility validates the following information:

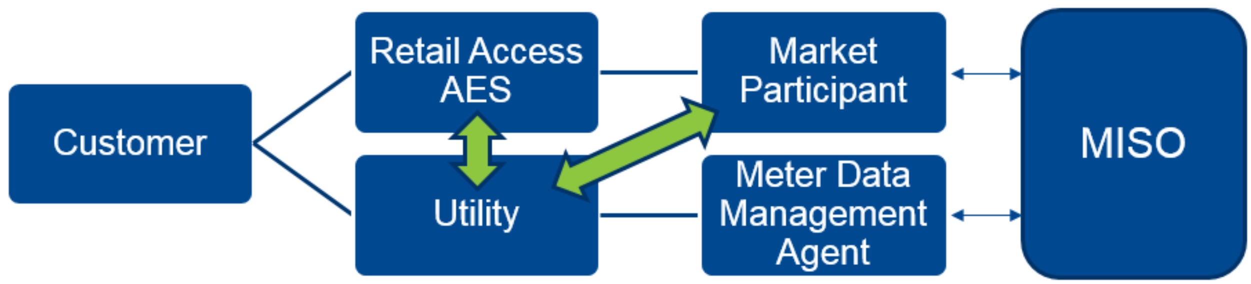
- Account number is correct and active
- Energy of the account is supplied by an alternative electric supplier (AES)
- Site address for the account
- Meter number with the account and
- Peak load contribution (PLC) for the PY 2019-20 is less than the total MW for the LMR number

In the most recent ARC registration received from MISO, the basic data on over half of the sites provided was invalid. DTE was unable to validate to the account number, city or state that had been provided by the aggregator.

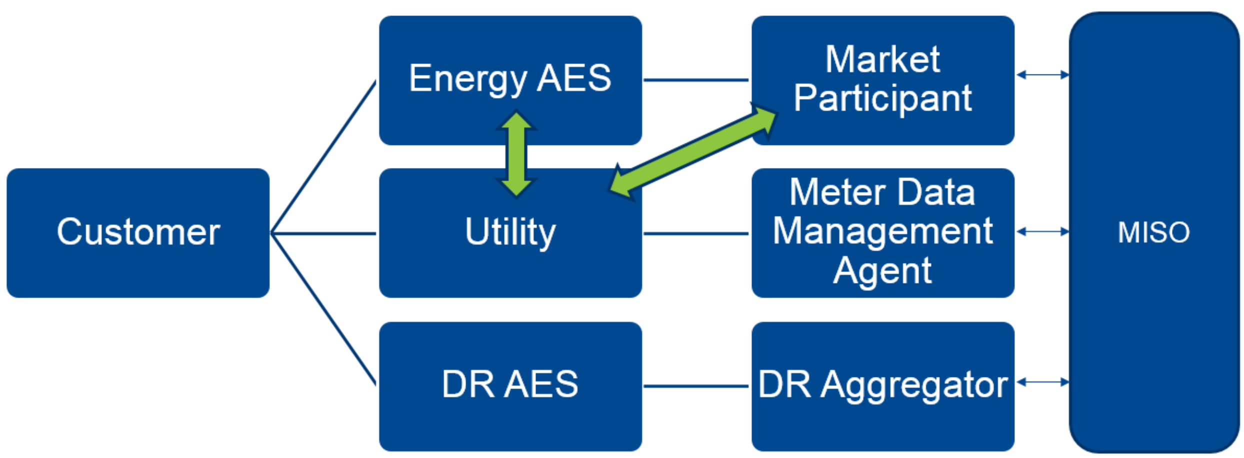
Secondly, the MW in the ARC registration is provided at the LMR level, which aggregates several sites together. In the validation, the utility can only validate if the sum of the PLC for the sites is greater than the demand response for all sites. For example, if there are 10 sites for one LMR, the 10 individual PLC values for each site should be greater than the one demand response value given for the 10 sites. The utility cannot validate the demand response on a site basis. In turn, the utility cannot add the demand response at the meter level based upon the ARC registration, which is required by the MISO tariff for the peak load contribution calculation.

Relationships and Communication

In the current retail access set up, there is a one to one relationship between the customer, the Retail Access AES and the MISO market participant, with the AES and the market participant usually being the same entity. The utility is the meter data management agent supplying the hourly usage to MISO and has a contractual relationship (shown with the green arrows) with both the Retail Access AES and the market participant.



With aggregated demand response, there is now a one to many relationship for the customer to the MISO Market with the Retail Access AES market participant providing access to the transmission lines and the demand response aggregator providing gathering services. Although the customer has a one to many relationship with MISO, zero relationship currently exists between the retail access AES and/or the utility and the demand response aggregator.



The relationships can become more complex as customers may switch retail access suppliers from time to time. In establishing the relationships and communication paths to make aggregated demand response work, it will be key to establish flexible paths that can change as the parties involved with a customer change.

b. Example: An aggregator procures DR from AES_1. The aggregator sells this DR into the market, where it is procured by AES_2 to meet their capacity requirement. If this DR is dispatched on the MISO peak, AES_1's PLC is reduced by xMW, even though that DR has been sold to AES_2. The next year, AES_1 would have a lower capacity requirement and AES_2 would still have the same capacity requirement as the previous year.

i. Is this accurate?

In the current state, this is an accurate depiction of what would happen given the lack of a communication and validation process, assuming AES1 is the current AES serving the customer. AES1 would have a lower capacity requirement since the demand response would be missing and AES2's capacity requirement would be unchanged.

However, per the MISO tariff, the DR dispatched by the customer at the time of the MISO peak must be added to the customer's PLC, which would roll up to the PLC of AES currently serving the customer.

If the customer is being served by AES1, then the PLC would be increased by the DR, assuming a communication process is established, and in turn increase the capacity requirement for AES1. AES2's capacity requirement would be unchanged.

If the customer switched retailers from AES1 to AES2 by the time of the PLC calculation, the PLC for the customer would increase by the DR and increase the capacity requirement for AES2. Only if the customer moves to AES2, would it affect the capacity requirement for AES2.

If the customer switched retailers from AES1 to AES3 by the time of the PLC calculation, the PLC for the customer would increase by the DR and increase the capacity requirement for AES3. AES2's capacity requirement would be unchanged.

ii. If so, is this a problem and what can be done to fix it?

Currently, if aggregated demand response resources are called upon at the time of the MISO coincident peak, the communication is between MISO and the DR aggregator, who is the MISO market participant. There is zero communication or validation to the utility or the alternative energy supplier about the demand response being requested or implemented. There two options to remedy this. One, the utility could add the average customer site demand response to the customer's usage, essentially assuming everyone was utilizing their full demand response at the time of the MISO peak each year. This would be simple, but may lead to an overstatement of the capacity need for the next four years. Also, the customer's AES would not have the data to independently validate the PLC calculation since they do not receive a copy of the ARC registration.

Alternatively, a communication and validation process could be established to communicate the demand response utilized at the MISO peak. This information would need to be shared with the utility calculating the peak load contribution and the alternative electric supplier (AES) that currently serves the customer. Each AES must have the same information to independently validate the peak load contribution calculation. If multiple suppliers are involved, the communication paths would need to be set up to ensure each AES received their own accounts. This will be tricky as customers can switch retailers anytime meaning that a customer may retail switch from AES1 at the time of the MISO peak to AES2 at the time the PLC calculation starts in November. To add the demand response back to the peak load contribution, the demand response amount utilized at the MISO peak must be provided at the meter level, by October 1st for the following planning year.

With either process, the goal of the peak load contribution is to ensure there is enough capacity to serve Michigan's customers for the next four years. With the recent polar vortex in January 2019, Michigan customers were asked to voluntarily reduce their energy usage. This is a reminder of how critical it is to get the peak load contribution calculation correct to provide affordable and reliable power to Michigan's customers.

Acceptable reporting requirements for Capacity Demonstration

4) Through the Capacity Demonstration process, electric distribution companies (EDCs) and/or LSEs are able to show that they have enough resources to cover their capacity commitment. For supply side resources, the MPSC has a process for determining the availability and certainty of resources combined with adequate documentation from utilities and their partners.

a. What procedures would be appropriate to apply to demand side resources, particularly aggregated demand response that could be spread across multiple service territories and multiple AES customers? i. Example: An AES submits a four year forward ZRC contract for aggregated DR. 1. Should that ZRC contract be treated any differently than if it was a ZRC contract four years forward with a supply-side generation owner? How so?

DTE believes demand response resources should show a firm commitment either through a contract or other means that ensures a high level of confidence that the resource will be there in the future. This is important to ensure future resource planning meets the reliability needs of customers in the State of Michigan.

b. What information would be sufficient to ensure capacity exists for the commitment period?

c. What entity would be best to supply this information?

c. Should a four year forward ZRC contract for aggregated DR (aggregated AES customer load) be considered an acceptable resource if submitted as part of a capacity demonstration on behalf of a utility, municipality or cooperative? Why or why not?

Yes, assuming the contract had the similar commitment terms as other forward ZRC agreements.

DTE

5) Voltus and AEMA both suggested in the February 13, 2019 stakeholder meeting that the MPSC should not limit DR aggregation to only AES customers. What are your initial thoughts on that?
The MPSC should limit third party aggregation to AES customers. The utilities already have DR programs that are subject to regulation by the MPSC, allowing third party aggregators to interfere with those programs will cause a litany of problems that will impact reliability, rates, and cost recovery.

6) Do you have any other recommendations you would like to suggest?

7) Do you have any additional topics you would like to discuss for our next DR aggregation stakeholder meeting on March 12th?

8) Are you opposed to having your written response included with the MPSC Staff report that is due to the Commission on May 30th?
We would appreciate a chance to revise the comments after the meeting on 3/12/19 before considering them as final and suitable for inclusion in the Staff's report.

DR Aggregation Stakeholder Meeting #2
Feedback Request

Thank you for participating in the MPSC Staff's DR aggregation stakeholder activities. Following the second stakeholder meeting, held on March 12, Staff requests the following feedback. All responses are voluntary and will be kept confidential unless a statement is provided that the information may be quoted in the Staff report or included as an appendix to the Staff report which will be posted in Case No. U-20348 by May 30, 2019. Please provide your responses to Heather Cantin (cantinh@michigan.gov) and Erik Hanser (hansere@michigan.gov) by April 10, 2019. The next stakeholder meeting is scheduled for May 3, 2019 at 1:00 p.m.

Indiana model (See slides 17-20):

1) Do you have any immediate feedback on the pros and cons of this model?

The Indiana model allows aggregators to interact with bundled retail customers yet the utility is the Market Participant, which is very important because 1) the utility is aware of the DR resources, and 2) it effectively maintains control of those resources. Despite the outsized claims that some 3rd party aggregators make about their abilities to deliver value, DTE Electric can provide the same types of services and as such there is no reason to allow a third party into the process to complicate matters.

2) Is this model worth exploring?

No. Utilities are better positioned to provide demand response programs to their customers directly, without unnecessary assistance or complications from introducing an ARC into the process.

Additionally, as detailed in the response to question #18, DTE Electric already has a very successful set of DR programs.

Pennsylvania model (See slide 21):

3) Do you have any immediate feedback on the pros and cons of this model?

4) Is this model worth exploring?

No. The Pennsylvania Act requires the EDC to have a conservation service provider (CSP) provide all the consultation, design, administration and management services, essentially prohibiting individual companies from having their own demand response programs tailored for their customers.

As detailed in the response to question #18, DTE Electric already has a very successful set of DR programs.

Regarding MISO vs. PJM processes (See slides 22-23):

5) Does the PJM process outlined above have any pros or cons as compared to the current MISO process?

In PJM the RTO owns the validation process and ensures that PLC values are calculated correctly, while that process is not yet completely defined in MISO.

In order to get DR aggregation right, the data provided in the initial registration needs to be correct and complete. When reviewing a potential ARC registration, the utility validates the following information:

- Account number is correct and active
- Energy of the account is supplied by an alternative electric supplier (AES)
- Site address for the account
- Meter number with the account and
- Peak load contribution (PLC) for the PY 2019-20 is less than the total MW for the LMR number

In the most recent ARC registration received from MISO, DTE would have been only able to validate one of the 47 sites initially submitted by the aggregator. On the second submittal, the basic data on over half of the 47 sites provided remained invalid. Upon the third submittal by the aggregator, all sites were either validated or withdrawn from consideration. It is highly concerning that an aggregator would need to submit this basic information at least three times in order to have it validated and raises concerns in regards to their data systems and if the requirements in the MISO market are robust enough.

6) While this discussion is focused on a Michigan specific process to track and verify aggregated DR, would you support supplementing the MISO process with some of the aspects of PJM's registration process?

Please see the response to question #5.

7) Would you support adopting some of these PJM procedures into a Michigan specific process?
Please see the response to question #5.
8) Would you like to further discuss the IN/PA models or explore aspects of the PJM process?

No, given the success of the Company's DR programs DTE does not think discussing the programs from other jurisdictions is necessary or productive.

Other:

9) Are MISO BPM or tariff revisions warranted to ensure that retail peak load contributions are increased to reflect any relevant load reductions?

In module E-1 of the current MISO tariff, it clearly states that it is the responsibility of the EDC to calculate the peak load contribution (PLC) and any load reductions and capacity credits at the time of the MISO peak must be added to the peak demand.

Preferred and Daily Peak Load Default Methods, Section A

The method submitted by an EDC must describe in detail the procedures and data used to determine the assignment of the EDC's forecast Coincident Peak Demand to its retail customers, including those served by LSEs providing service within the EDC's area.

Preferred and Daily Peak Load Default Methods, Section B

....Retail customer peak demands should be increased to reflect any load reductions achieved and for which capacity credits are earned, either through retail programs or participation in wholesale markets (e.g. LMRs)....

The current MISO Tariff lacks the requirement of MISO or the LSEs in the EDC's service area to provide the required validations or data to the EDC to perform this function for load reductions achieved from participation in the wholesale market.

10) Are MISO BPM or tariff revisions warranted to ensure that retail peak load contributions are not double counting the same resource on both the supply side and demand side of the resource adequacy equation? If so, what specific BPM or tariff revisions would you suggest?

No.

11) What if a change was made to the MISO tariff such that the PLC was determined to be the highest load for that particular customer for MISO's top twelve peak hours of the previous year? Would this reduce or possibly eliminate the need to make PLC adjustments to account for load reductions?

To better understand the variance in usage for this method, I pulled MISO's top 12 hours for summer 2018 for those customers included in the March 2019 ARC registration. This sample included 75 meters, with the overall retail access program having 4,664 meters as of 4/1/2019. This sample is 1.6% of our total meters. Only five of the 75 meters had a peak usage that was the same as the MISO peak for 2018.

Peak usage (MW)	Minimum usage (MW)	Variance (MW)	Average Percent Variance
159. 6	65.9	93.7	28%

The total demand response registered for the customers is 38.7 MW.

The EDC was not informed of any demand response that occurred during the summer of 2018. Therefore, the assumption is the variance of 93.7 MW in the table above is due to changes in usage, without the impact of demand response. Given there is on average 28% variance across MISO's top 12 hours for each meter without demand response running, it would be difficult to be comfortable that this method would accurately assess the capacity needs for the upcoming summer.

Additionally, the usage at the time of the 2018 MISO Peak for the sampled meters totaled 118.6MW for the meters, which is 14% of the retail access contribution to the 2018 MISO Peak usage. If MISO top 12-hour methodology was implemented, the usage for these meters would have been 41 MW higher at 159.6 MW for the upcoming plan year. Applying this methodology to all retail access usage, it would result in an additional 291 MW of usage that would need to be resourced. Applying the MISO top 12-hour methodology leads to an overstatement of usage and in turn capacity needs, which may result in new generation needs and ultimately higher costs for Michigan families and businesses.

Thirdly, a change to the PLC methodology would result in a change to the PLC calculation process along with the forecasting process. There is little correlation between the MISO coincident peak and DTE Energy's service area peak. This would require forecasting to be done on 12 different MISO hours to apply the correct forecasting factor for each individual meter based upon its MISO peak hour. The calculation tools would need to be updated to reflect the 12 hours and to provide the transparency to the Alternative Energy Suppliers of the hour used, since they review the PLC calculations. MISO would need to approve the changes to the forecasting and PLC calculation in order to implement. Lastly, there would be billing system upgrades that would be needed to incorporate this additional complexity in the PLC calculation.

Finally, there is nothing in this proposal that would prevent a customer from running their demand response from June to September. This demand response would be excluded and missed under the MISO top 12 methodology, which may lead to reliability impacts for the following summer. Moving to the MISO top 12 methodology does nothing to mitigate the complication of ensuring demand response is included appropriately into the peak load contribution, may lead to an overstatement of capacity needs and would require changes to the PLC forecasting and calculation process.

12) Should the MPSC develop a voluntary registration process with reporting requirements for ARCs in Michigan? Why or why not? (See slide 31)

13) Is legislation necessary to outline a more formal process for registering or licensing ARC's?

14) What recommendations do you have about what type of information should be included in an ARC registration at the MPSC?

As a minimum, any direct ARC or retail customer participation in a RTO market centered on Michigan retail load should require provisions similar to those used for retail choice suppliers in Michigan. These are not limited to, but would include the following-:

- Registration with the responsible electric distribution company (EDC)
- Establishing some level of credit with the Commission
- Providing continuous information to the EDC about the identity of the customers and the amount of load available for a demand response reduction
- Metering verification

It would be expected that the EDC should receive some level of compensation for the use of metering and any other support/verification that would be required of the EDC.

15) Should the MPSC pursue a Michigan 4-year forward Capacity Tracking Tool that would accommodate the tracking of all capacity resources, including aggregated DR, aggregated energy efficiency and aggregated storage resources, on a 4-year forward basis? Why or why not?

16) At this point in time, do you have any recommended changes to the MPSC's capacity demonstration requirements adopted in U-20154, specifically for forward ZRC contracts?

17) The Commission order in U-20348 asks us to answer whether the ability to aggregate DR for customers of Michigan AESs for bidding into RTO markets should be limited to AESs, or be extended to non-AES third parties such as CSPs. Based upon the feedback received to date, Staff recommends that we allow CSPs to bid aggregated DR into RTO markets to be consistent with MISO and PJM practices. Do you disagree with this recommendation? If so, please explain.

- Providing ARCs with this opportunity would create cross subsidization and cost recovery issues and primarily benefit the participating customer and aggregator – but not the broader customer base.
  - 3rd party DR aggregation results in participating retail customers receiving a "double-payment" for a load reduction by getting compensated both through wholesale (energy/capacity payments from MISO) and retail rates (utility bill reduction). For example, if a customer had curtailable load and was dispatched to use it as a DR resource, the customer's metered energy consumption would go down AND it would receive payment for its energy output
  - MISO allocates the cost of the payments to DR resources to the load in the zones to which the DR provided benefits. Put differently, the payments to DR resources used in Michigan will be paid for by non-participating utility customers. Following this approach would result in an unfair subsidization of DR resources through nonparticipating customers
  - When an event is called, either by the Company or by MISO, customers who are on a DR rate and curtail load as expected benefit directly from lower energy expenses during the event, but all bundled customers benefit from the reduced expenses. The Company's cost-based tariffs fairly allocate the cost savings amongst participants and the rest of the Company's customers. Conversely if an ARC were to bid DR into the market, then only the participating customer and the ARC will benefit.
  - The Company's cost-based rates are designed based on its historic bundled load. Allowing third parties to aggregate DR (about which the Company would have no knowledge), would result in the Company's rates being calculated at too low a level (in the short run) and it would cause cost shifts to other customers in the long run.

- It would also negatively affect the utilities' ability to forecast capacity needs and consider demand response in their long-term resource planning.
  - Third party DR aggregation will make it more difficult for the utility to forecast capacity needs and plan for the future accordingly. One benefit of the 10% choice cap is that it provides the utilities with the degree of stability in their sales levels that is necessary to 1) undertake long-term resource planning, and 2) have the resultant financial stability necessary to make the long-term investments needed to serve the state's energy needs. Allowing 3rd party aggregators to bid the DR capability of utilities' bundled retail customers into the wholesale market would diminish that benefit.
  - The participation of 3rd party aggregators raises risks around the potential to double-count DR capacity unless the gaps in the processes for tracking it between ARC, utilities, AES, and MISO are addressed. As an example, without proper safeguards, it is possible that a customer could be on one of DTE's interruptible tariffs and then contract with an ARC to bid that same capability into MISO.
  - In addition, if the DR load normally served by DTE switches back and forth between ARCs and the utility, it will be difficult for DTE to use that resource to cover its resource planning requirements.
  - This could in fact lead to a situation where the Company may be forced to invest in some other alternative (e.g., generation) given the uncertainty in the level of DR resources for which it can take credit.

- Allowing ARCs to directly bid DR into wholesale markets would also have adverse operational impacts.
  - <u>Operational conflicts between generation capacity and distribution load relief:</u> There is a lack of clarity, and it is yet to be discussed and determined, around whether aggregated DR resources should be controlled by MISO for generation capacity relief or by the LDC for emergency local load relief. This lack of clarity in operational priority and processes for aggregated DR resources could cause operational conflicts, particularly when the system is in stressed conditions. In addition, if aggregated DR resources are deployed by MISO, it could cause under-utilization of the DR resources since they cannot be utilized for emergency local load relief.
    - For example, if one of the Company's distribution substations is overloaded, DTE can activate local DR resources to relieve that overload. If those same DR resources were instead bid into MISO by an aggregator the Company may instead need to shed firm load.
    - It is unlikely that an aggregator would dispatch its DR in that situation, because doing so would likely be uneconomic. Aggregators are in business to make money, and unlike an LDC, they aren't responsible for maintaining the reliability of the distribution system.
  - <u>Distribution Planning and Operations Impacts:</u> From distribution planning and operational perspectives, managing aggregated DR resources among multiple third

parties, including planning load forecasts and real time tracking on the quantity and timing of the DR resources, will require substantial resources and investments by the LDCs to ensure that an adequate infrastructure to support peak demand and reliable operations of the distribution systems exists.

- Interconnection Study Impacts: Lastly, aggregated DR resources have not been considered in utility interconnection studies
  - If the DR is dispatched by MISO, as opposed to being controlled by DTE Electric with a clear view of its distribution system, then the loss of that load may require real-time adjustments on distributed generation operations as well as system upgrades to avoid voltage and power quality issues;
  - However, this is not currently factored in the interconnection studies or any required grid upgrades to incorporate distributed generation because the Company does have control of those resources.

- Aside from the issues referenced above, there are several other concerns to consider.
  - DTE Electric agrees with Consumers Energy that allowing third party aggregation for utility customers runs counter to the 10% cap established by the Customer Choice and Electricity Reliability Act. The Act reserves 90% of an electric utility's retail market for the provision of service by the utility. This provision of electric generation service includes both energy and capacity service, and demand response can participate in both. Allowing third parties to bid demand response into the MISO market on behalf of a utility's retail customers would erode a portion of the market that the statute preserved for utilities.
  - The MPSC has the authority to prohibit retail customers from participating in wholesale DR markets, but that does not mean that, once it lifts that ban, it necessarily has authority to regulate that activity.

18) What would need to happen to make your company comfortable with lifting the ban on DR aggregation for all customers in Michigan?

DTE Electric does not believe there is any reason to allow 3rd parties to aggregate bundled load because, as discussed at length below, DTE has well developed DR programs and capabilities and is already providing its customers with excellent DR services. The Company's comments in response to question #17 have detailed the problems and risks that will arise should the Commission allow third parties to interfere with the demand response programs that DTE offers to its bundled retail customers. We do not believe that the issues raised are addressable in a manner other than continuing to maintain the current ban on DR aggregation of bundled load.

The paragraphs below detail the Company's DR programs, which demonstrate the fact that DTE is a leader in DR programs and capability. The success of the Company's DR efforts illustrates the point that realizing the DR potential in the state is not contingent on having third-party aggregators directly participate in the market.

DTE has an established demand response portfolio. It ranked number 11 (out of 411 utilities) in 2017 for potential peak demand (MW) savings through utility DR programs, and number two (out of 126 utilities) in the Midcontinent Independent Service Operator (MISO) territory. DTE Electric is ranked first in both Zone 7 in MISO and in the State of Michigan. This information corresponds to the most updated data published by the United States Energy Information Administration (EIA)[1].

The existing demand response portfolio consists of both dispatchable and non-dispatchable programs that are available to residential, commercial and industrial customers and are focused on reducing peak energy consumption. A dispatchable program is one in which an action is taken in response to requests or "calls" from a utility. The dispatch may be communicated directly to connected devices such as a control switch on an air conditioning unit or to designated energy managers, who modify their operations. Often, there are non-performance penalties or other conditions designed to increase customer compliance. A non-dispatchable program is one in which voluntary actions are taken by the customer to reduce or shift demand from peak to non-peak periods.

The residential and commercial dispatchable programs consist of two direct load control programs. The first program is referred to as the Interruptible Air Conditioning (IAC) program under the Tariff D1.1 Interruptible Space Conditioning Service Rate. The second program is referred to as the Interruptible Hot Water Heating Service Rate under the Tariff D5. Customers who opt to participate in the interruptible space conditioning rate and the interruptible water heating rate elect to have one or both appliance types separately metered. Under these programs, the Company installs a direct load control device on the unit, allowing DTE Electric to cycle the appliance by remote control on selected days. In exchange for allowing the Company to install a direct load control device on the customer's air conditioning unit or water heating unit, the customer pays a discounted energy charge for the energy consumed by those appliances.

For the IAC program, the Company is currently upgrading the existing one-way radio control units with the new two-way ZigBee enabled switches that leverage the Company's Advanced Metering Infrastructure (AMI) network. These two-way switches will better position the program as both a capacity and economic resource in the MISO market. The Company is expecting to finalize the upgrade of an estimated total of 275,000 units by 2023.

Commercial customers have an additional option to take service under the interruptible general service tariff (Tariff D3.3). Under this tariff, customers have a lower $/kWh charge than the traditional general service rate in exchange for accepting the risk of interruption.

Industrial customers have the option to take service under the interruptible primary service rate (D8), or to put a portion of their load on one of the other three interruptible riders (Rider 1.1, Rider 1.2 and Rider 10). Similar to the commercial offering, customers who opt to put either all, or a portion, of their load on an interruptible tariff, pay a lower overall rate compared to standard industrial tariff rates.

[1] See 2017 data at https://www.eia.gov/electricity/data/eia861/

Under tariff D8, customers may be ordered to interrupt only when the Company issues an order to maintain system integrity or prevent a capacity deficiency. Customers who do not interrupt within one hour following a notice are subject to fees and/or penalties.

Rider 1.1 applies to customers who operate electric furnaces for metal melting or for the reduction of metallic ores. Rider 1.2 applies to customers who use electric heat in a manufacturing process, or who use electricity in an anodizing, plating or coating process. In both riders, the customers are subject to immediate interruption on short-term notice to maintain system integrity but will be provided advanced notice of probable interruption and the estimated duration whenever possible. Under Rider 10, customers may contract for no less than 50,000 kW of interruptible service at a single location. The Company notifies the customer as to the total amount of load to be curtailed, which will be stated as a percentage of the total supplied load for the immediately preceding hour. In addition, the Company offers the Capacity Release Rider (Rider 12) where industrial customers are provided a capacity payment in the form of a bill credit by subscribing at least 50% of their facility to interruption instead of receiving a reduced overall cost. No customers are currently taking service under this rate.

In total, DTE's dispatchable demand response programs provide the Company with 709 MWs. The Company registers these resources with MISO which help meet capacity requirements for the peak period. These programs and the MWs of capacity that they provide also assist with the Company with generation planning. The makeup of the 709 MWs is available in Table 1.

Table 1

Program	**Enrollment**[2]	**MW (UCAP**[3]**)**
R10 Interruptible Supply Rider	61	336
D1.1 Interruptible Space Conditioning	274,492	158
D8 Interruptible Primary Supply Rate	166	98
R1.2 Process Heat Rider	196	81
D3.3 Interruptible General Service	128	23
R1.1 Metal Melting Rider	17	7
D5 Interruptible Water Heating	51,031	6
Total	**326,091**	**709**

In addition to the current programs that make up the dispatchable demand response portfolio, DTE Electric is conducting additional demand response pilots encompassing residential, commercial, and industrial customers. These pilots include a Bring Your Own Device (BYOD) program, a

[2] Number of customers taking service under tariff as of 12/31/2018
[3] UCAP values are used by MISO for their resource adequacy requirements.

Programmable Controllable Thermostat Program, a building automation program and an electric vehicle charging program. Based on the results of these pilots and of utility benchmarking efforts, the Company expects to identify other alternative DR programs that may become economic and technically viable alternatives to generation capacity, have an appropriate level of customer adoption potential, and are cost-effective for customers. While the Company intends to learn as much as possible through benchmarking of other pilots and programs and leverage the knowledge of vendors who have experience in implementing demand response programs, it is considered best practice to conduct actual internal pilots before launching a new full-scale program. These pilots seek to identify how our unique customer base will react to specific marketing efforts, program design features, and other characteristics that are dependent on DTE Electric's unique combination of systems, equipment, tariffs, programs, and processes. Demand response pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as well as to assess customer appetite for such programs. If a pilot program is selected to be rolled out on a larger scale, the Company puts together the necessary planning, marketing, and implementation processes to have a successful rollout of the program. This approach helps the Company reduce the ensuing ramp-up time necessary to quickly and cost-effectively run those programs when capacity and reliability needs emerge.

One current pilot that the Company is deeming successful is the BYOD pilot. In the BYOD Program, the Company enrolls residential customers who already have a Wi-Fi enabled smart thermostat installed in their residence. In this program, customers' thermostats are configured to allow the Company to send a control signal during BYOD events which raises the thermostat's set-point by four degrees during an event. The Company started a marketing campaign with the goal to enroll 5,000 customers within the 2018-2021 period (three-year period). As of the end of February 2019, there were 4,554 customers already enrolled in the BYOD program. Resulting from the early success of the BYOD program, the Company plans to expand the program to a total of 25,000 customers by the end of 2020, as well as continuing to test customer engagement during BYOD events.

In the building automation pilot, the Company partnered with NextEnergy (a facility space that incorporates an auditorium, meeting spaces, laboratories, microgrid and other areas) and Enbala (a cloud-based platform provider) to implement a pilot encompassing multiple system assets at NextEnergy's commercial customer facility. The goal of the pilot was to specifically assess the performance of the Enbala's Symphony technology and the communication tool and platform during DR events. The Company was able to use a two-way communication tool and platform to select and manage specific customer assets for load controlling without a full facility shut-off or interruption. The pilot included various customer assets including chilled and chiller water pumps, air handler units (AHU), load bank (microgrid), a generator, and an electric vehicle charger that were all interconnected through Enbala's Virtual Power Plant software. The Company is assessing the applicability of a similar pilot(s) at a different location do the success recognized in the building automation pilot.

DTE anticipates growing its demand response portfolio to 864 MWs through a combination of current programs and pilot programs. Some of the ways that The Company plans to grow its portfolio include updating the legacy switches in the IAC program and increasing the number of

MWs in the interruptible primary supply rate and interruptible supply rider. The increases in the interruptible primary supply rate and interruptible supply rider is based on feedback from customers desiring more interruptible load. In addition, DTE Electric anticipates that some of the pilots currently being evaluated will become programs and part of the DR portfolio in the future. For example, based on the positive feedback from the 2017 Statewide Demand Response Market Assessment conducted by Public Sector Consultants and Navigant and commissioned by the MPSC, DTE Electric plans to begin marketing the Rider 12 tariff in the second quarter of 2019. Even though enrollment in this tariff and demand reduction is dependent on customer reception, the Company anticipates that Rider 12 could be registered as an additional resource into the MISO Capacity Auction.

DTE's commitment to demand response is evident by the size of the current portfolio as well as the continued commitment to pilot new demand response technology. DTE is always benchmarking against other utilities as well as evaluating various demand response programs from across the country to make sure we can provide our customers with programs that fit their wants and needs. By allowing ARCs to aggregate demand response for utility customers, the efforts put forth by DTE to build a successful demand response portfolio will be lost for everyone at the expense of a select few.

ENERGY MI
P.O. Box 14336, Lansing, MI 48901
Telephone 517/482-6237

Date: May 13, 2019

To: Heather Cantin
Erik Hansen
Michigan Public Service Commission
7109 W. Saginaw Highway
P.O. Box 30221
Lansing, MI 48909

Subject: Energy Michigan's Submission of Comments for Inclusion in Staff Report in DR Aggregation Case No. U-20348

Dear Heather and Erik:

At the May 3 meeting of the DR Aggregation group, you stated that the Staff would include any comments by parties in an appendix to the upcoming Staff report.

Energy Michigan's comments for inclusion in the report are attached.

Sincerely,

Alexander J. Zakem
For Energy Michigan, Inc.

Energy Michigan
DR Aggregation – Principles and Comments
for Staff Report
13 May 2019

I. Energy Michigan – Principles

A. DR Can Expand Resources: Energy MI has favored more DR because it expands the quantity of resources in the market and provides more flexibility and opportunity for customers to save energy costs.

In U-18197, Energy MI requested that AESs be allowed to use DR aggregation to meet their forward capacity demonstration obligations, and the MPSC approved this.

B. Separate Wholesale from Retail: MISO and PJM use DR as capacity and also as an operating function, depending on the type of DR that a retail customer or aggregator registers. The retail customer or aggregator participates directly in the wholesale market, which has been approved by the FERC, unless prohibited by the PUC

Similar to that for utilities and AESs, the MPSC may need to quantify the total amount of DR resources within Michigan, the same as it quantifies supply resources and interruptible resources, from reports to the MPSC. For protection of retail customers, ARCs should be registered with and approved by the MPSC, the similar to AESs. And, the MPSC should establish guidelines or standards for communication of basic information from ARCs to customers regarding DR.

Rules for participation of DR have been set by MISO and PJM. A customer or aggregator choosing to participate should have the responsibility directly to MISO/PJM for qualifying and operating the DR resource.

Avoiding Competitive Conflict: Local utilities, which are competitors of AESs, should not have any approval or customer-information rights regarding participation in DR of retail customers of other LSEs through ARCs or AESs, other than information necessary for distribution services.

C. Use Demand Response as Capacity in Michigan: Procedures for implementing DR can be complicated, because DR can be used as an operating tool by the RTO. "Capacity" is the simplest, as it would be called upon only in emergency conditions. DR can offer other aspects at a price – energy, operating reserve, ramp. How all this works is a MISO issue, not a Michigan issue. Consequently, Energy MI previous comments in this proceeding have focused on two aspects:

1. *DR participation as capacity in the wholesale market:* Remove the restrictions on DR aggregation and let the RTO and the customer/aggregator contract directly in the wholesale market.

2. *DR used in demonstrating capacity in Michigan:* Treat a ZRC created from a DR resource the same as a ZRC created from a supply resource. Showings, affidavits, etc. should be very similar.

II. Energy Michigan – General Comments

A. Learn from Others' Experiences – Demand Response ("DR") is not new to MISO. The 2018 Planning Reserve Auction cleared 6,964 MW of Demand Resources, which MISO noted included aggregators. Therefore, much is in place already regarding DR, and Michigan does not have to "reinvent the wheel," but rather research and adopt the processes that are working well now.

B. Use DR as a Planning Resource – To the extent possible, MISO treats a Demand Response Resource just like any other Planning Resource, which will eventually be converted into ZRCs. The concept is that the load that is being reduced when MISO dispatches DR does not "belong" to the LSE that serves the customers forming the DR but rather "belongs" as a resource to the owner of the DR resource, who may be an ARC.

C. Follow the three principles that MISO uses:

1. *ARC Responsibility to MISO* – The ARC is responsible to MISO for the qualification, accounting, and tracking of DR. The Electric Distribution Company ("EDC") and the MPSC have no responsibility directly to MISO for the DR, although the EDC may have provided customer data that the ARC needs. Similarly, Load Serving Entities ("LSEs") have no responsibility for the DR.

   Note: In its February 13, 2019, presentation, MISO asserts that several parties may be involved in "approving" or "rejecting" the ARC's proposed resource (see pages 4-5). Parties involved could be the MPSC, the Local Balancing Authority (Consumers Energy or DTE Electric), the LSE (AES or utility), and/or the Electric Distribution Company (Consumers Energy or DTE Electric or other). Energy Michigan believes that none of these parties should be involved in "approving" or "rejecting." The ARC has the responsibility to demonstrate the validity of its resource to MISO, and MISO has the responsibility for due diligence.

Further, in Michigan, Consumers Energy, DTE Electric, other utilities and cooperatives, and various AESs are all in competition with one another for power supply service to retail customers. No competitor should have authority of approval or rejection of any other competitor's proposals, nor should any competitor have the ability to assess the operational capabilities of another competitor's customer.

In Michigan, the local regulated utility is both a competitor and the EDC. In its EDC function, it would be able to "confirm" – and <u>should be limited to confirming</u> – two pieces of information to MISO:

i. that a customer listed by the ARC actually exists;

ii. that the customer's PLC is equal to or greater than the amount of load reduction that the ARC is claiming for that customer.

2. *Customer Responsibility to ARC* – A retail customer participating in DR is <u>responsible to the ARC (or to MISO if the customer is enrolling directly with MISO), not to the customer's LSE</u>. Therefore, if a customer switches LSEs, the DR obligation does not get transferred to the new LSE, but rather stays with the creator of the ZRC, who is the ARC/customer, just as a generating resource's commitment to MISO stays with the owner of the resource regardless if the ZRC is sold.

3. *Peak Accounting Solved* – The issue of accounting for DR in the determination of a supplier's PRMR is already solved in the MISO tariff. Because DR is treated as any other Planning Resource that has been dispatched, the <u>effect of the DR that has been called upon</u> during the hour of the MISO annual peak is added back into the load of the customer's LSE for the purpose of determining the next year's PRMR for the LSE.

MISO Module E-1, Section 69A.1.1.b:
"The supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (e.g. the Coincident Peak Demand hour) <u>augmented to include the normal Demand from forecasted Demand Resources</u>, whether registered or not registered with the Transmission Provider. "

An example can illustrate the situation. Suppose an AES has a PRMR forecast of 100 MW. The AES is then responsible for the cost of 100 MW of resources, priced at the Auction Clearing Price ("ACP"), no matter where those resources come from. MISO requires 100 MW of resources, for which it will pay the ACP

An Aggregator of Retail Customers ("ARC") has enrolled 15 MW worth of DR from the AES's customers. MISO will pay the ARC 15 MW at the ACP.

Suppose at the time of the MISO peak, MISO dispatches the 15 MW of DR. To serve the 100 MW of load at the peak – where "serving" means matching supply and load – MISO needs 100 MW of resources. Of the 100, 85 MW will come from supply resources and 15 MW will come from demand resources, all paid at the ACP.

While the metered AES peak is 85 MW, it is 85 MW only because 15 MW are being used as a DR resource. Consequently, for the purpose of determining next year's PRMR for the AES, Section 69A.1.1.b says to augment the AES's PRMR "to include the normal Demand from forecasted Demand Resources," which is the 15 MW of DR. Thus, next year's PRMR for the AES is 85 + 15 = 100 MW.

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February 28, 2019

BY ELECTRONIC MAIL

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

Re: MPSC Case No. U-20348: In the Matter on the Commission's Own Motion, to Address Outstanding Issues Regarding Demand Response Aggregation for Alternative Electric Supplier Load.

Dear Ms. Kale:

Enclosed please find ***Comments of the Association of Businesses Advocating Tariff Equity*** as it relates to the first Demand Response Aggregation Stakeholder Meeting that Staff convened on February 13, 2019.

Respectfully,

CLARK HILL

/s/ Stephen A. Campbell

Stephen A. Campbell

SAC/lkd
Enclosures

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to address outstanding issues regarding demand response aggregation for alternative electric supplier load.	)))))	Case No. U-20348

COMMENTS OF THE ASSOCIATION OF
<u>BUSINESSES ADVOCATING TARIFF EQUITY</u>

The Association of Businesses Advocating Tariff Equity ("ABATE"), by its attorneys, Clark Hill PLC, hereby provides its Comments in response to the Michigan Public Service Commission ("Commission") Staff ("Staff")'s February 14, 2019 request for comments emerging from the first demand response ("DR") aggregation stakeholder meeting that Staff convened on February 13, 2019.

While ABATE's comments here do not necessarily address all the technical implementation details of DR aggregation implicated by many of Staff's questions, ABATE's lack of comment on those issues should not be taken as an acquiescence to other entities' comments thereon, and ABATE reserves the right to comment on said issues in the future. In these comments ABATE is responding only to questions 1, 4, 5, 6, and 8 in order to register ABATE's position regarding important policy questions that impact DR aggregation and the provision of DR generally in Michigan. These five questions are included below followed immediately by ABATE's responses.

<u>**QUESTION NO. 1:**</u>

Per FERC Order 745, it is clear that the Relevant Electric Retail Regulatory Authority (RERRA) may prohibit 3rd party Demand Response (DR) aggregation in their jurisdiction. However, it is unclear whether the MPSC can partially permit aggregation and also place restrictions on multiple Alternative Electric Supplier (AES) aggregation and who is able to register the aggregated DR at MISO.

Do the MPSC's Orders in Case Nos. U-16020, U-18369 or U-20348 raise any jurisdictional questions in your mind?

a. Example: Does the MPSC have the authority to prohibit aggregation across multiple AESs?

i. Aggregators would be able to operate within an individual AES's customer base (all customers in AES1).

ii. Aggregators would not be able to aggregate some customers from AES1 and some from AES2 and comingle the use of the demand response resources.

b. Example: Would the MPSC be able to permit the aggregation of AES customers, with only this strict condition that the AES is the entity that registers the aggregated DR with MISO?

<u>**ABATE's RESPONSE:**</u>

Under the Federal Power Act ("FPA"), the Federal Energy Regulatory Commission ("FERC") is authorized to regulate "the sale of electric energy at wholesale in interstate commerce," including both wholesale electricity rates and any rule or practice "affecting" such rates. *FERC v Electric Power Supply Ass'n*, 136 SCt 760, 766 (2016); see also 16 USC 824(b), 824e(a). Thus "the FPA obligates FERC to oversee all prices for those interstate transactions and all rules and practices affecting such prices." *Id*. at 767. The statute provides that "all rules and regulations affecting or pertaining to" rates and charges made, demanded, or received by any public utility for or in connection with interstate transmissions or wholesale sales must be "just and reasonable." *Id*.; see also 16 USC 824d(a). If "any rate [or] charge," or "any rule, regulation, practice, or contract affecting such rate [or] charge[,]" does not meet that standard, it is within FERC's jurisdiction to determine what is "just and reasonable" and impose the same by order. *Id*.; see also 16 USC 824e(a). Contrarily, FERC may not regulate "either within-state wholesale sales" or "retail sales of electricity." *Id*. at 768; see also 16 USC 824(b)(1).

The FPA therefore "delegates responsibility to FERC to regulate the interstate wholesale market for electricity–both wholesale rates and the panoply of rules and practices affecting them." *Id*. at 773. This means that "FERC has the authority–and indeed, the duty–to ensure that rules or practices 'affecting' wholesale rates are just and reasonable," which has been interpreted to extend FERC's "jurisdiction to rules or practices that '*directly* affect the [wholesale] rate.'" *Id*. (citation omitted). As explained in *FERC*, the "rules governing wholesale demand response programs meet that standard with room to spare." *Id*. at 774. In other words, FERC may set the rules for demand response which address transactions occurring on the wholesale market. *Id*. at 776. As the *FERC* decision further explained:

> [W]holesale market operators employ demand response bids in competitive auctions that balance wholesale supply and demand and thereby set wholesale prices . . . The operators accept such bids if and only if they bring down the wholesale rate by displacing higher-priced generation. And when that occurs (most often in peak periods), the easing of pressure on the grid, and the avoidance of service problems, further contributes to lower charges . . . Wholesale demand response, in short, is all about reducing wholesale rates; so too, then, the rules and practices that determine how those programs operate. *Id*. at 774.

The question and examples posed by Staff appear to implicate the rules and practices which determine how wholesale demand response programs operate. Specifically, they involve aggregators' direct interactions with MISO when those interactions pertain to interstate wholesale rates, as opposed to the Commission's authority to set and approve retail rates (meaning the authority "to establish the amount of money a consumer will hand over in exchange for power”). *Id*. at 777. In other words, the question seems to contemplate the Commission establishing “rules and practices” or regulations which directly affect or pertain to rates and charges connected to wholesale sales. Such action would extend into FERC’s jurisdiction and would exceed the Commission’s authority under the FPA.

Indeed, this action contrasts with the authority discussed in *FERC* and quoted in the Commission’s November 21, 2018 Order in Case No. U-20348, which permitted “any State regulator to prohibit its consumers from making demand response bids in the wholesale market.” *Id*. at 779. This permissive, voluntary exercise of authority and discretion (FERC “claim[ed] the ability to negate such state decisions”) essentially provided a veto giving “States the means to block whatever ‘effective’ increases in retail rates demand response programs might be thought to produce.” *Id*. at 779-80. Thus while states were permitted to “retain the last word” regarding consumers’ ability to make demand response bids into wholesale markets in the first place, such authority was premised on the states’ authority to regulate retail rates. The examples posed by Staff concern regulatory activities which are far more granular and do not appear to implicate the retail rate-setting that served as the basis for the states’ initial authority to prohibit consumers’ wholesale demand response bids. Such state regulation would therefore likely overstep the states’ jurisdictional authority as set forth in the FPA and federal law.

Furthermore, the Commission “possesses no common-law powers but is a creature of the Legislature, and all of its authority must be conferred by clear and unmistakable language in specific statutory enactments, because doubtful power does not exist.” *Midland Cogeneration Venture Ltd P’ship v Pub Serv Comm’n*, 199 Mich App 286, 295–96 (1993) (*citing Union Carbide Corp v Pub Serv Comm’n*, 431 Mich 135, 146–62 (1988)). The PSC cannot expand its authority beyond that provided by statute under the guise of its rule making authority. *York v*

Detroit, 438 Mich 744, 767 (1991). There is a long line of authority that an agency's powers cannot be extended by inference and, indeed, the inference is that it was intended that no other or greater power was given than the power specified. *Eikhoff v Detroit Charter Comm'n*, 176 Mich 535, 540 (1913).

Thus when the powers of an administrative agency are specifically conferred, as they are with the Commission, they cannot be extended by inference. *Maxwell v DEQ*, 264 Mich App 567, 570 (2004) (citation omitted). To partially permit and otherwise restrict DR aggregation, the Commission must identify the specific state statutory enactment providing it the power to do so.[1] It does not appear there is any statute which clearly and unmistakably authorizes the Commission to partially permit aggregation or restrict aggregation across multiple AESs. Commission authority to limit the entities able to register aggregated DR at MISO to only AESs also appears

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[1] It is important to note that time and time again, the Michigan Supreme Court has held that "the broad language of § 6 serves as an outline of the PSC's jurisdiction, not a grant of specific powers." *Consumers Power Co v Pub Serv Comm'n*, 460 Mich 148, 160 (1999); see also *Union Carbide*, 431 Mich at 147 ("Although its language is broad, § 6 merely serves as an outline of the commission's jurisdiction, not as a grant of specific authority or powers"); *Midland Cogeneration*, 199 Mich App at 302 (holding that "the broad language of § 6 . . . provides no support for the PSC's conditions, because the statute merely serves as an outline of the PSC's jurisdiction, not as a grant of specific authority or powers"); *Att'y Gen v PSC*, 189 Mich App 138, 145 (1991) ("Although broadly stated, § 6(1) is not a grant of specific power. It is merely an outline of the PSC's jurisdiction"); *Detroit Edison Co v Richmond Twp*, 150 Mich App 40, 49 (1986) (recognizing that § 6(1) "has been determined by the Supreme Court to be merely an outline of the commission's jurisdiction and not a grant of specific powers to the commission").

It is also important to note that MCL 460.6(1) vests the Commission with the jurisdiction to regulate *utility* behavior, rather than *customer* behavior. See e.g. *Mason Co Civic Research Council v Mason Co*, 343 Mich 313, 326-27 (1955) ("The principle has been repeatedly recognized that an express grant of power to administrative officers, boards or commissions, is subject to a strict interpretation"); *Taylor v Michigan Pub Utilities Comm'n*, 217 Mich 400, 402-03 (1922) ("Where a statute creates and regulates, and prescribes the mode and names the parties granted right to invoke its provisions that mode must be followed and none other, and such parties only may act"); *Omne Fin, Inc v Shacks, Inc*, 460 Mich 305, 311 (1999) ("[N]othing may be read into a statute that is not within the manifest intent of the Legislature as derived from the act itself").

to lack a clear and unmistakable statutory grounding. As such, these actions are beyond the Commission's authority as conferred by the Michigan Legislature.

QUESTION NO. 4(a):

Through the Capacity Demonstration process, electric distribution companies (EDCs) and/or LSEs are able to show that they have enough resources to cover their capacity commitment. For supply side resources, the MPSC has a process for determining the availability and certainty of resources combined with adequate documentation from utilities and their partners.

a. *What procedures would be appropriate to apply to demand side resources, particularly aggregated demand response that could be spread across multiple service territories and multiple AES customers?*

   i. *Example: An AES submits a four year forward ZRC contract for aggregated DR.*

      1. *Should that ZRC contract be treated any differently than if it was a ZRC contract four years forward with a supply-side generation owner? How so?*

ABATE's RESPONSE:

To create a level playing field for demand-side and supply-side resources in Michigan, it is important to ensure that the procedures that are employed in the forward capacity demonstration process are no more onerous or burdensome for DR resources relative to forward contracts with generation resources. Specifically, the submission of an executed and legally binding four-year forward contract with a DR resource, with reasonable provisions to address resource non-performance, should be deemed sufficient to comply with the capacity demonstration process, in the same manner as a forward purchased power contract can be used to demonstrate compliance with the requirements of this process. If needed, the Commission can adopt a standard form forward contract between an AES or aggregator of retail customers ("ARC") and a DR customer to ensure that any such contract provides adequate information regarding the DR resource and that the contract contains appropriate non-performance provisions.

QUESTION NO. 4(b):

What information would be sufficient to ensure capacity exists for the commitment period?

ABATE's RESPONSE:

As explained above, the Commission should not impose capacity demonstration requirements on DR resources that are more burdensome than the requirements imposed on supply-side resources. Therefore, a legally binding four-year forward contract with a DR resource that contains reasonable non-performance provisions should be sufficient to ensure that DR capacity will be available during the commitment period. The Commission can also take steps to ensure that any information that must currently be entered into MISO's Module E Capacity Tracking Tool in the case of DR resources (e.g., the entity registering the DR customer as a resource, the identity of the DR customer, the amount of capacity reduction, and where the customer is located) is also reported to the Commission. This will ensure that the Commission has the same information that MISO uses to validate a capacity resource. Again, to avoid creating unnecessary hurdles for the deployment of DR resources in Michigan, the Commission should refrain from imposing any DR reporting requirements that are in excess of the requirements already imposed by MISO.

QUESTION NO. 4(c):

What entity would be best to supply this information?

ABATE's RESPONSE:

The entity that registers the DR resource with the Regional Transmission Organization ("RTO") (such as the AES or ARC) should be responsible for supplying the forward contract information and MISO Module E Capacity Tracking Tool data to the Commission for any DR resource that it uses to comply with the four-year forward capacity requirements under Michigan law. The AES or ARC that employs the DR resource will be a counterparty to the forward DR contract and will be responsible for submitting the Capacity Tracking Tool data for the resource to MISO. Therefore, they are in the best position to provide the same information to the Commission as well.

QUESTION NO. 4(d):

Should a four year forward ZRC contract for aggregated DR (aggregated AES customer load) be considered an acceptable resource if submitted as part of a capacity demonstration on behalf of a utility, municipality or cooperative? Why or why not?

ABATE's RESPONSE:

A four-year ZRC contract for DR resources in general, including but not limited to aggregated DR, should be considered an acceptable capacity resource in Michigan. In order to promote robust DR participation in Michigan, it is vital that DR be considered as a capacity resource on an equal footing with generation supply options as utilities plan to meet their capacity requirements on a four-year forward basis as required by Michigan law. Therefore, a valid, legally enforceable four-year forward contract with a DR resource should be given equal weight as a purchased power contract for generation supply in a utility's capacity planning process. Such a DR contract could specify the consequences for non-performance of a DR resource over the term of the contract to ensure the customer's compliance with its contractual obligations, in the same manner as the supplier default provisions in purchased power contracts serve to ensure delivery of power supplies on a forward basis.

If utilities are permitted to comply with Michigan's statutory capacity procurement requirements by contracting for generation capacity on a forward basis through purchased power contracts while the same option is precluded for DR forward procurement, DR resources would be placed at a distinct disadvantage relative to supply-side resources. This would stifle the expansion of DR resources in Michigan simply due to the imposition of unnecessary regulatory obstacles. The Commission should reject this result as a matter of policy.

As discussed during the February 13, 2019 Staff workshop, DR is a cost-effective alternative to generation supply that can reduce the overall cost of supplying capacity to meet system demand in Michigan. In addition, DR is a green resource that can provide incremental capacity to Michigan without any harmful environmental impacts. Expanding the utilization of DR resources can therefore provide an array of valuable operational, planning, economic, and environmental benefits to Michigan. At the operational level, fast response DR resources can reduce system requirements to maintain spinning and operating reserves. From a system planning perspective, DR resources allow utilities to avoid or defer the construction of incremental generation resources or the purchase of incremental power by reducing the amount of firm load that the utility is required to serve. In general, the system cost of expanding the availability of DR resources is less than the cost of incremental generation.

Therefore, encouraging the expansion of DR will reduce the overall cost of meeting system demand. Moreover, DR resources that can be interrupted for economic reasons allow the utility to reduce its net fuel and purchased power costs, which in turn reduces the cost of service for all customers on the utility's system. Finally, DR provides an emissions-free, green resource that utilities can use to meet system power requirements without increasing their carbon footprint or increasing their other environmental emissions.

In order to fully capture these diverse system benefits of DR, and to expand the potential for DR adoption, the Commission should ensure that its policies provide an equal and fair opportunity for DR to compete with supply-side generation resources in providing capacity to meet customer demand in Michigan. For the reasons discussed above, such policies should include permitting all load serving entities to demonstrate compliance with their forward capacity procurement requirements using four-year forward contracts with DR resources generally and with aggregated DR specifically. It should be noted that the ability to use DR resources to demonstrate compliance with Michigan's capacity procurement requirements should not be limited to utilities, municipalities, and cooperatives. In addition to these entities, an AES should be able to contract with DR resources on a forward basis as part of its capacity demonstration under Michigan law.

QUESTION NO. 5:

Voltus and AEMA both suggested in the February 13, 2019 stakeholder meeting that the MPSC should not limit DR aggregation only to AES customers. What are your initial thoughts on that?

ABATE's RESPONSE:

ABATE strongly supports allowing both AES customers and bundled retail utility customers to participate in DR programs administered by RTOs. As noted above, DR provides a diverse array of operational, economic, reliability, planning, and environmental benefits. As a case in point, DTE Energy recently requested that all of its customers provide voluntary DR to safeguard system reliability during the extreme cold weather event that occurred in late January 2019.[2] This request underscores the value and viability of DR across customer classes in preserving system reliability during extreme weather events and other high demand periods. Moreover, several studies have established that there is significant, untapped, cost-effective DR potential in Michigan.[3] This highlights the fact that Michigan is currently failing to realize the

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[2] DTE Energy News Room, *DTE Energy Asks Customers to Reduce Energy Usage*, January 30, 2019 (http://newsroom.dteenergy.com/index.php?s=26817&item=137234#sthash.0dG8DJYV.dpbs).

[3] See, e.g. Michigan Agency for Energy, *Michigan Capacity Resource Assessment*, January 31, 2017, p 19 ("The demand response programs become increasingly important when the system is stressed due to high demand and/or unexpected plant outages") (https://www.michigan.gov/documents/energy/Michigan_EGEAS_Report__01_31_2017_550217_7.pdf);
Applied Energy Group, *State of Michigan Demand Response Potential Study*, September 29, 2017, p 57 ("By as early as 2023, the state expects that utilities will need to acquire new capacity and, at that time, demand response could play a major role in filling those needs") (https://www.michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf);
Demand Side Analytics, LLC and Optimal Energy, Inc., *Economic Potential for Peak Demand Reduction in Michigan*, February 16, 2017, p 36 ("[I]t is important that policies in the state recognize and enable opportunities to secure strategic demand reductions to ensure capacity requirements are met in the most cost-effective way possible") (http://info.aee.net/hubfs/PDF/Peak-Demand-Reduction-Potential-for-Michigan021717.pdf?t=1487398737782).
ABATE's citation of these documents should not be considered an endorsement of the entirety of their content. Their inclusion here is simply meant to reinforce the point that numerous entities have recognized the true potential for utilizing DR in Michigan is both valuable and has yet to be fully realized.

full benefits of DR. For these reasons, Michigan should make every effort to remove any regulatory and legal obstacles that hinder the participation of DR resources in Michigan.

One prominent such obstacle that should be removed is the prohibition on retail customers that take bundled electric service from participating in RTO capacity or ancillary service markets as DR resources, either individually or through a DR aggregator. This restriction unnecessarily limits the scope of DR in Michigan and denies the benefits of cost-effective, green DR resources to Michigan simply because the customers who could provide such resources happen to take their power supply from a bundled utility rather than an AES. Moreover, this artificial barrier to the expansion of DR hinders Michigan's efforts to meet energy conservation and environmental goals. Therefore, this barrier should be removed as expeditiously as possible.

In an similar vein, ABATE urges the Commission to clarify that retail electricity customers in Michigan will be permitted to offer their DR resources into RTO markets through third-party ARCs and not only through their AES in the case of competitive supply customers. Such a policy would facilitate the expansion of DR opportunities in Michigan and promote competition in the provision of DR services by encouraging new, third-party DR service providers to enter the market.

QUESTION NO. 6:

Do you have any other recommendations you would like to suggest?

ABATE's RESPONSE:

ABATE recognizes that the Commission's prior orders restricted bundled utility customers from directly bidding DR resources into RTO markets. However, the Commission's prior orders do not prevent the utilities in Michigan from allowing large industrial customers to bid into RTO markets through a utility tariff mechanism that establishes the terms and conditions for such participation. Such tariffs can provide a vehicle for establishing the terms and conditions for bundled retail customer DR participation in RTO markets in a manner that adequately addresses the operational, oversight, double-counting, and cross-subsidization concerns that the Commission previously noted in reaching its decision to restrict bundled retail customer participation in RTO markets as a DR resource. The details of the terms and conditions for the provision of such DR could be addressed before the Commission in a formal proceeding to ensure that all of the Commission's concerns regarding bundled retail customer DR participation in RTO markets are comprehensively resolved.

ABATE notes that Northern Indiana Public Service Company ("NIPSCO") has established DR resource riders in its Indiana tariffs that address issues such as operational reliability, performance requirements, utility fees, and other matters associated with DR participation in RTO markets.[4] Indeed, some of the participants in the February 13, 2019 stakeholder meeting indirectly referenced this Indiana tariff in discussing the use of the "Indiana model" as a guide for facilitating the participation of Michigan's bundled retail DR resources in RTO markets. ABATE agrees with these stakeholder observations and believes that a similar tariff rider approach can and should be used in Michigan to ensure that the potential of this valuable DR resource is realized without compromising the Commission's ability to regulate the terms and conditions of such service.

However this is not the preferred approach by ABATE as it adds extra cost and administrative burden of requiring the local utility to play an intermediary role between the retail customer and the RTO. ABATE urges the Commission to reconsider its position and to permit

[4] Northern Indiana Public Service Company, Rider 781, Demand Response Resource Type 1 (DRR 1) – Energy Only and Rider 782, Emergency Demand Response Resource (EDR) – Energy Only (https://www.nipsco.com/about-us/rates-tariffs/electric-service-tariff).

bundled retail customers to directly, or through an ARC, bid into the RTO markets in order to maximize the opportunities for the provision of cost-effective DR in Michigan.

QUESTION NO. 8:

Are you opposed to having your written response included with the MPSC Staff report that is due to the Commission on May 30th?

ABATE's RESPONSE:

ABATE requests that its written responses to these questions be included in Staff's May 30, 2019 report to the Commission in order to provide the Commission with an opportunity to consider ABATE's position on DR issues as it formulates its policies in this area.

CONCLUSION

ABATE appreciates the opportunity to submit these comments. We urge the Commission to move expeditiously to expand DR service offerings and opportunities for both bundled and unbundled large industrial customers in Michigan, as described in these comments. This can be accomplished by facilitating DR aggregation for bundled and unbundled retail customer loads, as well as by removing the regulatory and legal obstacles to retail customer participation in RTO markets as a DR resource, either through their electric utility in the case of bundled electricity customers or through an AES or a third-party ARC in the case of retail customers that take competitive power supply.

Respectfully submitted,

CLARK HILL PLC

By: ______________________________

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Dated: February 28, 2019

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April 10, 2019

BY ELECTRONIC MAIL

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

Re: MPSC Case No. U-20348: In the Matter on the Commission's Own Motion, to Address Outstanding Issues Regarding Demand Response Aggregation for Alternative Electric Supplier Load.

Dear Ms. Kale:

Enclosed please find ***Comments of the Association of Businesses Advocating Tariff Equity*** as it relates to the first Demand Response Aggregation Stakeholder Meeting that Staff convened on March 12, 2019.

Respectfully,

CLARK HILL

/s/ Stephen A. Campbell

Stephen A. Campbell

SAC/lkd
Enclosures

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to address outstanding issues regarding demand response aggregation for alternative electric supplier load.	)))))	Case No. U-20348

COMMENTS OF THE ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

The Association of Businesses Advocating Tariff Equity ("ABATE"), by its attorneys, Clark Hill PLC, hereby provides its Comments in response to the Michigan Public Service Commission Staff ("Staff")'s March 12, 2019 request for comments emerging from the second demand response ("DR") aggregation stakeholder meeting that Staff convened on that same date.

While ABATE's comments do not necessarily address certain technical implementation details of DR aggregation implicated by many of Staff's questions, ABATE's lack of comment on those issues should not be taken as an acquiescence to other entities' comments thereon, and ABATE reserves the right to comment on said issues in the future. In these comments ABATE is responding only to questions 1–4, 8, and 15–18 in order to register ABATE's position regarding important policy questions that impact DR aggregation and the provision of DR generally in Michigan. These questions are included below followed immediately by ABATE's responses.

QUESTION NO. 1:

Indiana Model: Do you have any immediate feedback on the pros and cons of this model?

ABATE's RESPONSE:

ABATE's preferred approach is to allow both bundled customers and competitive supply customers to directly, or through a third-party Competitive Service Provider ("CSP") or Aggregator of Retail Customers ("ARC"), bid into the Regional Transmission Organization ("RTO") markets in order to maximize the opportunities for the provision of cost-effective DR in Michigan. This approach has the advantage of eliminating the extra cost and administrative burden of requiring the local utility to play an intermediary role between the retail customer and the RTO. Therefore, we urge the Michigan Public Service Commission ("Commission") to reconsider its position on this issue and to allow bundled and competitive supply customers to directly bid their DR resources into RTO markets.

In the absence of direct customer DR participation in the RTO markets, ABATE supports allowing Michigan bundled utility customers to bid into RTO markets through a tariff schedule offered by their local utility that establishes the terms and conditions for such participation. This "Indiana model" is consistent with the approach implemented by Northern Indiana Public Service Company ("NIPSCO") in its DR resources riders in its Indiana tariffs. Those tariffs address issues such as operational reliability, performance requirements, utility fees, and other matters associated with DR participation in RTO markets.[1]

[1] Northern Indiana Public Service Company, Rider 781, Demand Response Resource Type 1 (DRR 1) – Energy Only and Rider 782, Emergency Demand Response Resource (EDR) – Energy Only (https://www.nipsco.com/about-us/rates-tariffs/electric-service-tariff).

Adopting utility DR tariffs in Michigan would give the Commission the ability to regulate the terms and conditions for bundled retail customer DR participation in RTO markets. Specifically, a utility tariff for DR would allow the Commission to establish terms and conditions that adequately address any concerns that the Commission may have in areas such as the impact of DR on utility operations, regulatory oversight of DR resources, double-counting of DR resources, or cost cross-subsidization concerns associated with DR resources. A utility tariff mechanism for DR would also ensure that the terms and conditions associated with DR service are fully vetted before the Commission in a formal proceeding to ensure that all of the Commission's concerns regarding bundled retail customer DR participation in RTO markets are comprehensively resolved.

Importantly, DR tariffs in Michigan should not artificially restrict customer participation in the RTO markets for DR to a limited set of demand response products or options. In order to maximize the benefits of DR for Michigan, the DR tariffs should be designed to ensure that retail customers are able to participate in the full range of demand response products and options offered by the RTO, as those products and services evolve over time. Moreover, DR tariffs in Michigan should not add any unnecessary costs or fees for customers who wish to offer their DR resources into RTO DR programs. Any fees that the utilities charge to customers under such DR tariffs should be limited to those fees that are required to cover the utility's cost of administering these programs. Any utility tariff charges in excess of administrative costs would only serve as a barrier to customer participation in the DR markets as a DR resource.

QUESTION NO. 2:

Indiana model: Is this model worth exploring?

ABATE's RESPONSE:

For the reasons set forth in our response to Question No. 1 above, ABATE supports further investigation and implementation of the Indiana model if the Commission declines to reverse its prohibition on direct bundled utility customer DR participation in RTO markets.

QUESTION NO. 3:

Pennsylvania Model: Do you have any immediate feedback on the pros and cons of this model?

ABATE's RESPONSE:

As ABATE understands it, Pennsylvania Act 129 of 2008 ("Act 129") contains provisions that required Pennsylvania utilities to established peak demand reduction programs in order to meet specific percentage peak demand reduction targets mandated by the legislation. Act 129 also required utilities in Pennsylvania to contract with state-registered CSPs to provide these peak demand reduction programs on a utility-specific basis.

Based on this reading of Act 129, ABATE understands the "Pennsylvania model" to be one that would require Michigan utilities to contract with registered, third-party CSPs or ARCs to provide DR programs to their customers, with the intent to achieve specific peak demand reduction targets on a utility-specific basis. Applied in the context of bundled customer DR participation in RTO markets in Michigan, the Pennsylvania model implies a construct under which Michigan utilities would contract with CSPs and ARCs who would offer the DR resources of bundled utility customers into RTO markets.

ABATE believes that the Pennsylvania model has merit in that it would allow bundled retail customers to directly contract with CSPs and ARCs to bid their DR resources into RTO markets. This has the advantage of eliminating the intermediary role of the utility in the process by avoiding the need for a local utility tariff to govern bundled utility customer participation in the RTO markets for DR. At the same, it would give the Commission the ability to oversee the design of CSP DR programs for customer participation in the RTO markets by subjecting the DR contracts that Michigan utilities would execute with DR providers and ARCs to regulatory review and approval.

However, ABATE is opposed to implementing the Pennsylvania model to the extent that it would lead to imposing hard megawatt caps on bundled utility customer participation in the RTO markets for the purpose of achieving specific peak demand reduction goals as set forth in Act 129. Instead, the program should allow all cost-effective DR resources to bid into the RTO markets in order to maximize the benefits of DR resources for Michigan. In addition, the implementation of DR contracts between the local utility and third-party CSPs or ARCs should not restrict the continued implementation of other forms of DR programs that Michigan utilities currently provide directly to retail customers through their tariffs, such as interruptible load programs.

QUESTION NO. 4:

Pennsylvania model: Is this model worth exploring?

ABATE's RESPONSE:

ABATE believes there is merit to further exploring the Pennsylvania model for the reasons set forth in our response to Question No. 3 above, if the Commission declines to reverse its prohibition on direct bundled utility customer DR participation in RTO markets. As we noted in our response to Question No. 3, pursuit of the Pennsylvania model should not lead to the imposition of hard megawatt caps on bundled utility customer participation in RTO markets as a DR resource, nor should it restrict the operation of existing utility interruptible or other DR programs.

QUESTION NO. 8:

Would you like to further discuss the IN/PA models or explore aspects of the PJM process?

ABATE's RESPONSE:

ABATE supports further discussion of the Indiana and Pennsylvania models for the reasons set forth in our responses to Question Nos. 1 and 3 above.

QUESTION NO. 15:

Should the MPSC pursue a Michigan 4-year forward Capacity Tracking Tool that would accommodate the tracking of all capacity resources, including aggregated DR, aggregated energy efficiency and aggregated storage resources, on a 4-year forward basis? Why or why not?

ABATE's RESPONSE:

In order to maximize the benefits of cost-effective DR for Michigan customers, the Commission should refrain from creating unnecessary administrative burdens on the participation of DR resources in the Michigan market. The creation of a forward Capacity Tracking Tool for Michigan DR and other capacity resources would add another layer of administrative complexity that is not needed to allow the Commission to exercise effective oversight of DR in Michigan.

In lieu of creating such a Capacity Tracking Tool, the Commission can require utilities, AESs, CSPs, and ARCs to submit to the Commission the same information that must currently be entered into MISO's Module E Capacity Tracking Tool in the case of DR resources (e.g., the entity registering the DR customer as a resource, the identity of the DR customer, the amount of capacity reduction and where the customer is located). This will ensure that the Commission has the same information that MISO uses to validate a capacity resource. In addition, the Commission can require utilities, AESs, CSPs, and ARCs to submit legally binding four-year forward contracts with their DR resources that contain reasonable non-performance provisions to ensure that DR resources will be available during their contractually designated commitment periods. This information should be sufficient to allow the Commission to accurately track the provision of DR in Michigan and to monitor for any potential double-counting of DR resources, without burdening the DR market with unnecessarily complex reporting or tracking requirements.

QUESTION NO. 16:

At this point in time, do you have any recommended changes to the MPSC's capacity demonstration requirements adopted in U-20154, specifically for forward ZRC contracts?

ABATE's RESPONSE:

The Commission should refrain from creating excessive and complex reporting or capacity demonstration requirements for DR resources in order to minimize the regulatory impediments to the use of DR in Michigan. Moreover, in order to level the playing field between demand-side and supply-side resources, the Commission should ensure that the procedures that are employed in the forward capacity demonstration process are no more onerous or burdensome for DR resources relative to forward contracts with generation resources. For these reasons, ABATE does not recommend any changes to the Commission's capacity demonstration requirements for forward ZRC contracts beyond requiring utilities, AESs, CSPs, and ARCs to submit MISO Module E Capacity Tracking Tool information and four-year forward contract information to the Commission, as discussed in our response to Question No. 15 above.

<u>QUESTION NO. 17:</u>

The Commission's order in U-20348 asks us to answer whether the ability to aggregate DR for customers of Michigan AESs for bidding into RTO markets should be limited to AESs, or be extended to non-AES third parties such as CSPs. Based upon the feedback received to date, Staff recommends that we allow CSPs to bid aggregated DR into RTO markets to be consistent with MISO and PJM practices. Do you disagree with this recommendation? If so, please explain.

<u>ABATE's RESPONSE:</u>

ABATE strongly supports this recommendation. Bundled retail electricity customers in Michigan should be permitted to offer their DR resources into RTO markets through CSPs and/or ARCs and not only through their AES in the case of competitive supply customers. Such a policy would represent an important step forward in facilitating the expansion of DR opportunities in Michigan. Adopting such a policy would also promote competition in the provision of DR services by encouraging new, third-party DR service providers to enter the market. Moreover, such action would not compromise the Commission's ability to exercise oversight of the DR market in Michigan. The Commission's oversight of the DR market can be effectively exercised by adopting appropriate DR reporting requirements, as described in ABATE's response to Question No. 15 above.

QUESTION NO. 18:

What would need to happen to make your company comfortable with lifting the ban on DR aggregation for all customers in Michigan?

ABATE's RESPONSE:

ABATE strongly supports the immediate lifting of the ban on DR aggregation for all customers in Michigan. ABATE also strongly supports the immediate and complete lifting of the Commission's ban on direct participation by bundled utility customers in the RTO DR markets. These restrictions unnecessarily limit the scope of DR in Michigan and deny the benefits of cost-effective, green DR resources to Michigan simply because the customers who could provide such resources happen to take their power supply from a bundled utility rather than an AES. Moreover, this artificial barrier to the expansion of DR hinders Michigan's efforts to meet energy conservation and environmental goals. Therefore, there is no sound policy reason to continue these artificial regulatory impediments to the expansion of DR in Michigan, as they needlessly prevent Michigan customers from reaping the full environmental and cost reduction benefits of DR resources.

Finally, as ABATE explained in detail in our February 28, 2019 response to Question No. 1 of the Staff's first set of questions in this proceeding, it does not appear there is any statute which clearly and unmistakably authorizes the Commission to only partially permit DR aggregation. The Commission's authority for limiting the entities able to register aggregated DR resources at MISO to only AESs also appears to lack a clear and unmistakable statutory grounding. As such, these actions are beyond the Commission's authority as conferred by the Michigan Legislature.

For these reasons, the Commission's ban on DR aggregation and its ban on direct customer participation in RTO DR markets by bundled utility customers should be removed as expeditiously as possible.

CONCLUSION

ABATE appreciates the opportunity to submit these comments. We urge the Commission to move expeditiously to expand DR service offerings and opportunities for both bundled and unbundled customers in Michigan, as described in these comments. This can be accomplished by facilitating DR aggregation for bundled and unbundled retail customer loads, as well as by removing the regulatory and legal obstacles to full retail customer participation in RTO markets as a DR resource, either through their electric utility or through an AES or a third-party CSP or ARC.

Respectfully submitted,

CLARK HILL PLC

By: ______________________________

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May 15, 2019

BY ELECTRONIC MAIL

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

Re: MPSC Case No. U-20348: In the Matter on the Commission's Own Motion, to Address Outstanding Issues Regarding Demand Response Aggregation for Alternative Electric Supplier Load.

Dear Ms. Kale:

Enclosed please find ***Comments of the Association of Businesses Advocating Tariff Equity*** as it relates to the first Demand Response Aggregation Stakeholder Meeting that Staff convened on May 3, 2019.

Respectfully,

CLARK HILL

/s/ Stephen A. Campbell

Stephen A. Campbell

SAC/lkd
Enclosures

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to address outstanding issues regarding demand response aggregation for alternative electric supplier load.	)))))	Case No. U-20348

COMMENTS OF THE ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

The Association of Businesses Advocating Tariff Equity ("ABATE"), by its attorneys, Clark Hill PLC, hereby provides its Comments in response to the Michigan Public Service Commission Staff ("Staff")'s April 26, 2019 outline of the Staff's demand response ("DR") aggregation report to the Michigan Public Service Commission ("Commission").

While ABATE's comments do not necessarily address certain technical implementation details of DR aggregation that are discussed in Section 4(c) of the Staff's outline, ABATE's lack of comment on those issues should not be taken as an acquiescence to other entities' comments thereon, and ABATE reserves the right to comment on said issues in the future. In these comments ABATE focuses on the Staff's policy recommendations contained in Sections 4(a) and 4(b) of its report outline in order to register ABATE's position regarding important policy questions that impact DR aggregation and the provision of DR generally in Michigan.

<u>SECTION 4(A)</u>

In this section of its report outline, Staff proposes to make the following recommendation to the Commission:

"***Should the Commission continue to allow DR aggregation for Michigan based choice load, Staff recommends that the Commission allow the direct participation of ARCs or CSPs in the market on behalf of the aggregated DR resources."***

ABATE strongly supports this recommendation. As ABATE explained in its prior comments in this proceeding, both competitive and bundled retail electricity customers in Michigan should be permitted to offer their DR resources into Regional Transmission Organization ("RTO") markets either directly or through third-party Competitive Service Providers ("CSPs") and/or Aggregators of Retail Customers ("ARCs") and not only through their Alternative Electricity Supplier ("AES") in the case of competitive supply customers. Allowing direct participation in the DR market by ARCs and CSPs as proposed by the Staff would represent an important step forward in facilitating the expansion of DR opportunities in Michigan. Adopting such a policy would promote competition in the provision of DR services by removing a significant regulatory barrier to the entry of new, third-party DR service providers into the Michigan market. Moreover, such action would not compromise the Commission's ability to exercise oversight of the DR market in Michigan. The Commission's oversight of the DR market can be effectively exercised by adopting appropriate DR reporting requirements, as described by ABATE in its prior comments in this proceeding.

However, we believe that the Staff's proposal regarding customer access to the DR markets does not go far enough because it does not address the ability of bundled retail electricity customers to offer their DR resources into the RTO markets, either directly, through a CSP/ARC or through an alternative approach such as a utility DR tariff. This important issue should be squarely addressed in Staff's report with a recommendation that the Commission remove the current restriction on bundled utility customer participation in RTO DR markets.

As discussed in ABATE's prior comments in this proceeding, the current restriction on bundled customer participation in RTO DR markets is discriminatory and unnecessarily hinders the ability of Michigan to realize the full benefits of cost-effective DR and to achieve its emissions reduction and energy conservation goals. ABATE's preferred approach to remedy this problem is to allow both bundled customers and competitive supply customers to directly, or through CSPs or ARCs, bid into the RTO markets in order to maximize the opportunities for the provision of cost-effective DR in Michigan. This approach has the advantage of eliminating the extra cost and administrative burden of requiring the local utility to play an intermediary role between the retail customer and the RTO. Therefore, we urge Staff to prepare a final report to the Commission that recommends that bundled utility customers be allowed to directly bid their DR resources into RTO markets.

In the absence of direct customer DR participation in the RTO markets, ABATE supports allowing Michigan bundled utility customers to bid into RTO markets through a tariff schedule offered by their local utility that establishes the terms and conditions for such participation. As ABATE explained in its prior comments in this proceeding, this approach is consistent with the "Indiana model" implemented by Northern Indiana Public Service Company ("NIPSCO") in its DR resources riders in its Indiana tariffs.[1]

[1] Northern Indiana Public Service Company, Rider 781, Demand Response Resource Type 1 (DRR 1) – Energy Only and Rider 782, Emergency Demand Response Resource (EDR) – Energy Only (https://www.nipsco.com/about-us/rates-tariffs/electric-service-tariff).

However, DR tariffs in Michigan should not artificially restrict customer participation in the RTO markets for DR to a limited set of demand response products or options. In order to maximize the benefits of DR for Michigan, the DR tariffs should be designed to ensure that retail customers are able to participate in the full range of demand response products and options offered by the RTO, as those products and services evolve over time. Moreover, DR tariffs in Michigan should not add any unnecessary costs or fees for customers who wish to offer their DR resources into RTO DR programs. Any fees that the utilities charge to customers under such DR tariffs should be limited to those fees that are required to cover the utility's cost of administering these programs. Any utility tariff charges in excess of administrative costs would only serve as a barrier to customer participation in the DR markets as a DR resource.

As ABATE discussed in its April 10, 2019 comments in this proceeding, ABATE also supports pursuit of the "Pennsylvania model" as an alternative approach that would facilitate bundled utility customer participation in RTO DR markets. The Pennsylvania model would require Michigan utilities to contract with registered, third-party CSPs or ARCs to provide DR programs to their customers, with the intent to achieve specific peak demand reduction targets on a utility-specific basis. ABATE believes that the Pennsylvania model has merit in that it would allow bundled retail customers to directly contract with CSPs and ARCs to bid their DR resources into RTO markets. However, ABATE is opposed to implementing the Pennsylvania model to the extent that it would lead to imposing hard megawatt caps on bundled utility customer participation in the RTO markets for the purpose of achieving specific peak demand reduction goals as set forth in Pennsylvania Act 129. Instead, the program should allow all cost-effective DR resources to bid into the RTO markets in order to maximize the benefits of DR resources for Michigan. In addition, the implementation of DR contracts between the local utility and third-party CSPs or ARCs should not restrict the continued implementation of other forms of DR programs that Michigan utilities currently provide directly to retail customers through their tariffs, such as interruptible load programs.

For the reasons set forth above, ABATE strongly urges the Staff to include in its report to the Commission a recommendation to allow bundled utility customers to participate in RTO DR markets, either directly or through a CSP/ARC. In the alternative, we urge the Staff to recommend that the Commission initiate proceedings to pursue implementation of the Indiana or Pennsylvania models for DR participation in order to expeditiously provide opportunities for bundled retail customers to participate in RTO DR markets, albeit with some involvement by their local utility in an intermediary role.

SECTION 4(B)

In this section of its report outline, Staff proposes to make the following recommendations to the Commission:

"Staff recommends that extra supporting documentation for new aggregated DR resources not be required."

"Staff does not recommend the disqualification of forward ZRC contracts in capacity demonstrations."

"Staff does not recommend pursuing a Michigan Forward Capacity Tracking Tool at this time."

ABATE supports each of these recommendations and we urge the Staff to incorporate them into its final report. As ABATE explained in its April 10, 2019 comments in this proceeding, the Commission should refrain from creating unnecessary administrative burdens on the participation of DR resources in the Michigan market. Minimizing the regulatory and administrative costs of DR participation would help to ensure that the benefits of cost-effective DR in Michigan can be maximized. The creation of a forward Capacity Tracking Tool for Michigan DR and other capacity resources would add another layer of administrative complexity that is not needed to allow the Commission to exercise effective oversight of DR in Michigan. Therefore, it would not be appropriate to implement such a Tracking Tool.

As discussed in our prior comments, the Commission can adequately track DR resources by requiring utilities, AESs, CSPs, and ARCs to submit to the Commission the same information that must currently be entered into MISO's Module E Capacity Tracking Tool in the case of DR resources. The Commission can also require these entities to submit legally binding four-year forward contracts with their DR resources that contain reasonable non-performance provisions to ensure that DR resources will be available during their contractually designated commitment periods. This information would allow the Commission to adequately track DR resources and to monitor for any double-counting or other concerns without creating unnecessary administrative burdens that would add costs to the market and potentially hinder DR participation by customers.

For these reasons, ABATE agrees with the recommendations set forth in Section 4(b) of the Staff's report outline. We urge the Staff to incorporate these recommendations into its final report to the Commission.

OTHER COMMENTS:

ABATE supports the Staff's plan to recommend that the Commission solicit written comments from stakeholders on the final Staff report that will be issued in this docket. This recommendation would give ABATE and other interested parties an important opportunity to provide feedback directly to the Commission on the significant policy issues that Staff intends to address in its final report.

CONCLUSION

ABATE appreciates the opportunity to submit these comments. We urge the Staff to submit a final DR aggregation report to the Commission that is consistent with the recommendations set forth in our comments above along with those previously submitted in this proceeding.

Respectfully submitted,

CLARK HILL PLC

By: ________________________________

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Dated: May 15, 2019

Appendix B

CAPACITY DEMONSTRATION PROCESS AND REQUIREMENTS FOR PLANNING YEAR 2023/24

Capacity Demonstration Process

Commission issued final order on Michigan Forward Locational Requirements for 2022/23 & 2023/24 (Case No. U-18444)	June 28, 2018#
Commission issues orders in cases to assign AES capacity obligations to utilities and impose SRM charges from U-18441 demonstrations; Commission also opens docket (U-20154) for 2022/23 demonstration	September 1, 2018*
Commission Staff issues memo in 2022/23 capacity demonstration docket with updated capacity obligations based upon latest MISO LOLE report	November 1, 2018*
Utilities file capacity demonstrations in same docket	December 3, 2018*
AESs, Cooperatives, Municipalities file capacity demonstrations in same docket	February 11, 2019*
Commission Staff issues memo regarding sufficiency of capacity demonstrations in docket	March 28, 2019*
Commission Order on capacity demonstration, possibly opening new contested case(s) to impose SRM charges	April, 2019*
Commission issues orders in cases to assign AES capacity obligations to utilities and impose SRM charges from 2022/23 demonstrations; Commission also opens docket for 2023/24 demonstration	September 1, 2019*
Commission opens docket for contested case to set the Michigan Forward Locational Requirements for 2024/25 & 2025/26	October, 2019#
Commission Staff issues memo in 2023/24 capacity demonstration docket with updated capacity obligations based upon latest MISO LOLE report	November 1, 2019*
Utilities file capacity demonstrations in same docket	December 1, 2019*
AESs, Cooperatives, Municipalities file capacity demonstrations in same docket	February 11, 2020*
Commission Staff issues memo regarding sufficiency of capacity demonstrations in docket	March, 2020*
Commission Order on capacity demonstration, possibly opening new contested case(s) to impose SRM charges	April, 2020*
Commission issues final order on Michigan Forward Locational Requirements for 2024/25 & 2025/26	July, 2020#

*Capacity demonstration process (repeats annually)
#Determine incremental capacity need (repeats every two years)

The Michigan Public Service Commission (MPSC or Commission) will open a docket in 2019 for planning year 2023/24 capacity demonstrations. The Commission order opening the capacity demonstration docket will provide requirements for load serving entities (LSE) to follow in making demonstrations and include the capacity obligations to be applicable for the demonstration year.

The capacity demonstration obligations will be determined in a consistent and transparent manner, based upon the most recently published Loss of Load Expectation (LOLE) study by the Midcontinent Independent System Operator (MISO).

The capacity demonstrations filed in this docket shall include four years of load obligations and owned or contracted resources, similar to the requests that the Commission has made in previous years. The capacity demonstration for year four will be used to determine if the LSE has met its capacity obligations, while the data filed for years one through three will be used for informational purposes only. Each LSE's applicable capacity obligation will be based upon its most recent Planning Reserve Margin Requirement (PRMR), as specified by MISO, and adopted by the Commission.

For the purposes of the capacity demonstrations for the Michigan State Reliability Mechanism (SRM), MCL 460.6w(8), the total capacity obligation to meet for a given LSE shall be the LSEs' PRMR. The PRMR includes a LSE's MISO Coincident Peak Demand adjusted for internal demand response programs netted against load, plus transmission losses and planning reserve margin (PRM) UCAP (unforced capacity) percentage. For LSEs provided a peak load contribution (PLC) value from their Energy Distribution Company (EDC), their capacity obligation to meet shall be their PLC, if it already includes transmission losses, and PRM UCAP percent adjustments.

The applicable MISO PRM UCAP percentages reported in the MISO 2019-2020 LOLE Study are as follows:

Planning Year	2023/24
PRM UCAP	8.1%

The PRM UCAP percentages will be updated annually, or as released by MISO in future LOLE Studies. The PRM UCAP percentages applicable for each demonstration year will be included in the order that opens the capacity demonstration docket and will be updated by MPSC Staff memo to the docket if applicable PRMR updates are published by MISO subsequent to the Commission Order.

The PLC determination for Retail Open Access (ROA) customers should be made through a cooperative process which is consistent with current MISO rules for dispute resolution. These PLC determinations will ultimately drive the total amount of capacity obligation that an Alternative Electric Supplier (AES) will be required to meet in its annual demonstration before the Commission.

Forward Locational Requirement Methodology[1]

The process used to determine the forward locational requirements is as follows:

1. Use the methodology from Staff's August 1, 2017 report and MISO's comments in Case No. U-18197 to project the Local Resource Zone's (LRZ) Locational Clearing Requirement (LCR) six years forward using the data provided in the 2018-2019 MISO LOLE Study Report.[2]
    a. Extrapolate/Interpolate the Peak Demand and Local Reliability Requirement (LRR) UCAP per-unit of LRZ Peak Demand to find values for the needed year (not necessary in this iteration because 2023/24 values were included in the MISO LOLE Study Report).
    b. Determine the LRZ's LRR by multiplying the zone's peak demand by the LRR UCAP per-unit of LRZ Peak Demand percentage.
    c. Calculate the forward LCR by subtracting the Capacity Import Limit (held constant from the prompt year) from the LRR.

[1] The September 13, 2018 Order in Case No. U-18444 granted a stay to the effect of the June 28, 2018 order in the same case establishing an individual forward locational requirement.
[2] https://www.misoenergy.org/api/documents/getbymediaid/80578.

2. Analyze previously filed confidential and public LSE resource data to project any changes to the amount of existing resources in the zone six years forward.
3. Subtract the projected existing resources in the zone from the zone's LCR to determine the forward locational incremental need.
4. Divided the forward locational incremental need by the zone's Peak Demand. This percent is the forward locational requirement for each LSE for the two year period.
5. Split this percentage evenly to determine the annual percentage applicable to each of the two planning years; 2022/23 and 2023/24.
6. The forward locational requirement applicable to each LSE is the annual percentage multiplied by its respective prompt year peak demand applicable for the demonstration.

Zonal Locational Requirements for Planning Years 2022/23 and 2023/24:[3]

MISO Zone 2					
Planning Year	Peak Demand (MW) {A}	LRR UCAP per-unit of LRZ Peak Demand {B}	LRR (MW) {C}={A}*{B}	Capacity Import Limit (MW) {D}	LCR (MW) {E}={C}-{D}
2023/24	13,054	118.7%	15,495	2,317	13,178

MISO Zone 7					
Planning Year	Peak Demand (MW) {A}	LRR UCAP per-unit of LRZ Peak Demand {B}	LRR (MW) {C}={A}*{B}	Capacity Import Limit (MW) {D}	LCR (MW) {E}={C}-{D}
2023/24	21,384	115.3%	24,656	3,785	20,871

The zonal locational requirements for future planning years 2024/25 and beyond will be addressed in a future filing as determined by the Commission.

Zone 7 Incremental Need and Forward Locational Requirement

The total projected resources in Zone 7 in 2023/24 is based on the capacity demonstration filings in Case No. U-18197 which covered planning years 2017/18 through 2021/22. Adjustments were made to remove behind the meter generation (btmg) not in the MISO Resource Adequacy Construct, reported retirements, zonal resource credit (ZRC) purchases, resources located outside of the zone, and any double counted units. The resulting total projected resources in Zone 7 for 2023/24 is 19,734 MW or 1,137 MW less than the projected MISO LCR in 2023/24[4]. This forward incremental need represents 5.3% of the projected Zone 7 peak demand. Splitting this need evenly between the 2022/23 and 2023/24 planning years results in a forward locational requirement for each LSE in Zone 7 of 2.7% of its

[3] The source for the data in columns {A} through {E} is the MISO 2018 – 2019 LOLE Study Report, https://www.misoenergy.org/api/documents/getbymediaid/80578.

[4] The total projected resources has been updated to include the publicly announced retirements of Karn 1 & 2 as directed by the Commission in its June 28, 2018 order in Case No. U-18444, https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000023GMHAA2.

prompt year PLC to be met with Zone 7 resources in 2022/23, and 5.3% in 2023/24. The percentage requirements were rounded to the nearest tenth of a percent.

Planning Year	Applicable PLC	Forward Locational Requirement
2022/23	Determined January, 2019	2.7%
2023/24	Determined January, 2020	5.3%

The forward locational requirements for Zone 7 for planning years 2024/25 and beyond will be re-evaluated going forward based upon future directives set by Commission Order.

Zone 2 Forward Locational Requirement

Unlike Zone 7, which is entirely located in the Lower Peninsula of Michigan, Zone 2 includes the Upper Peninsula of Michigan and a large portion of eastern Wisconsin. The MPSC does not have the same level of detail regarding the generation sited in Wisconsin as it does for generation sited in Michigan. Without making any assumptions regarding the future retirement of Zone 2 resources, the 2017-2018 MISO Planning Resource Auction Results show the Total Offers Submitted in Zone 2 of 15,149 ZRCs, which exceeds the projected Zone 2 LCR (13,178 MW) in 2023/24 by 15%. Utilizing the same method as applied to Zone 7 results in an incremental need of zero for Zone 2. Based upon the current surplus of existing resources in Zone 2, the forward locational requirement for LSEs in Zone 2 is zero for planning years 2022/23 and 2023/24. Although the current forward locational requirement is zero for LSEs in Zone 2, the adequacy of resources in Zone 2 will continue to be monitored. The PRMR capacity obligations still apply to LSEs in Zone 2 on a four-year forward basis as required by MCL 460.6w. The forward locational requirements for Zone 2 are not subject to biennial reevaluation unless the Commission directs otherwise in a future order.

Zone 1 Forward Locational Requirement

The individual forward locational requirement for LRZ 1 is zero and is not subject to biennial reevaluation unless the Commission directs otherwise in a future order. The PRMR capacity obligations still apply to LSEs in Zone 1 on a four-year forward basis as required by MCL 460.6w.

Resource Demonstrations

The minimum acceptable support for all resources submitted as part of a capacity demonstration include:

1) Documentation supporting the MISO zonal location of the resource, and;
2) The minimum acceptable support based upon the type of resource that is outlined in the sections below.

Existing generation (owned)

The minimum acceptable support for existing generation that is included in a capacity demonstration include:

1) An affidavit from an officer of the company claiming ownership of the unit(s), including a commitment of the unit(s) to LSE load in the applicable Michigan zone four years forward,
2) A copy of the existing ZRC qualification of the unit(s) from the MISO Module E Capacity Tracking Tool, and;
3) If there are retail tariffs or customer contracts associated with the resources, copies should be provided.

Existing demand response or energy efficiency resources (that have not been netted against load)

The minimum acceptable support for existing demand response resources or energy efficiency resources that have not already been netted against load include:

1) An affidavit from an officer of the company outlining the resource(s), including a commitment to maintain at least that same level of resources four years forward,
2) A copy of the existing ZRC qualification of the resource(s) from the MISO Module E Capacity Tracking Tool, and;
3) If there are retail tariffs or customer contracts associated with the resources, copies should be provided.

New or upgraded generation (owned)

The minimum acceptable support for proposed new generation include:

1) An affidavit from an officer of the company outlining the detailed plans for the new generation including milestones such as planned in-service date, expected regulatory approval date(s), planned date to enter the MISO generator interconnection queue, expected date for MISO generator interconnection agreement, construction timeline, etc.,
2) Documentation supporting the expected ZRC qualification from MISO for the new unit(s), and;
3) If there are retail tariffs or customer contracts associated with the resources, copies should be provided.

For new generation submitted as part of a capacity demonstration, the Commission finds that all of the above data be updated and submitted on an annual basis with each subsequent capacity demonstration until the unit(s) are in service.

New demand response or energy efficiency resources (that have not been netted against load)

The minimum acceptable support for new demand response resources or energy efficiency resources that have not already been netted against load included in a capacity demonstration include:

1) An affidavit from an officer of the company outlining the plans for the resource(s), including a commitment to achieve and/or maintain at least that same level of resources four years forward,
2) Evidence that the customer's distribution utility has been notified of specific customers participating in the resource,
3) Specific plans to have the resource(s) qualified by the independent system operator, and;
4) If there are retail tariffs or customer contracts associated with the resources, copies should be provided.

For new demand response or energy efficiency resources submitted as part of a capacity demonstration, the Commission finds that all of the above data be updated and submitted on an annual basis with each subsequent capacity demonstration until the resource(s) are in service. Final qualification / approval from the independent system operator should be submitted in a subsequent demonstration.

Existing generation (capacity contract)

The minimum acceptable support for capacity contracts with existing generation include:

1) An affidavit from an officer of the company including a copy of the contract that specifies the unit(s) or pool of generation that is the source of the contract, including the location of the unit(s) or pool. The affidavit should include a commitment to maintain the contracted amount four years forward regardless of any early out clauses in the contract, and;
2) A copy of the existing ZRC qualification of the unit(s) or pool from the MISO Module E Capacity Tracking Tool that the LSE obtains from the asset owner and includes with the demonstration filing.

Forward ZRC contracts

The minimum acceptable support for forward ZRC contracts include an affidavit from an officer of the company including a copy of the contract that specifies the zonal location of the ZRCs. The affidavit should include a commitment to maintain the contracted amount four years forward regardless of any early-out clauses in the contract. A forward ZRC contract that does not specify the zonal location of the ZRCs will be deemed insufficient towards meeting any portion of a locational requirement, unless the LSE provides other alternative support for the location of the ZRCs.

Any LSE that utilized a ZRC contract as part of their previous capacity demonstrations must provide prompt-year ZRC transfer documentation (MECT Module E screenshot) or provide Staff with the ability to confidentially review ZRC transfers in person at the Commission office.

Resources submitted in an LSE capacity demonstration to meet forward locational requirements must be located within the same LRZ as the LSE. Evidence demonstrating that a resource located outside of the LSE's zone would count towards meeting the LCR of the LSE's zone should be provided by the demonstrating LSE if applicable. Existing contracts with resources outside of an LSE's zone will count towards meeting forward locational requirements if they are for a period of at least twenty years and the contracts were entered into prior to MISO's implementation of local resource zones on June 1, 2013.

Aggregated EERs, Aggregated Storage, Aggregated DERs

The minimum acceptable support for aggregated energy efficiency resources (EERs), aggregated storage, and aggregated distributed energy resources (DERs) include:

1) An affidavit from an officer of the company outlining the resource(s), including a commitment to achieve and/or maintain at least that same level of resource(s) four years forward,
2) Documentation from MISO showing ZRC credit in the prompt-year for the resource(s), such as a MISO MECT screenshot, and;
3) If there are retail tariffs or customer contracts associated with the resource(s), copies should be provided.

PRA Purchases

The amount of ZRCs planned to be purchased in the MISO Planning Resource Auction (PRA) that will be deemed prudent in an approved capacity demonstration will be limited to the following percentage of the LSE's total PRMR requirement.

Planning Year	2022/23	2023/24
PRA Purchases (%)	5%	5%

Utilization of the MISO PRA in interim years

A capacity demonstration filed by an LSE that includes a plan to purchase ZRCs in the PRA four years in the future in excess of the allowable amounts outlined above, will not constitute a demonstration that the LSE owns or has contracted resources to meet its future capacity obligations, unless those ZRCs are tied to specific identified resources that are committed to be offered in the PRA, by contract, on behalf of the LSE for the applicable planning year.

Once the Commission has determined that the capacity demonstration made by an LSE is deemed to be sufficient, it shall not be re-litigated or "trued-up" in the interim years. If, subsequent to its initial satisfactory capacity demonstration, an LSE experiences an unforeseen significant outage at one of its generation assets, or has an unforeseen variation in its total load obligations, these matters will be settled in the PRA. The LSE's initial capacity demonstration will not be re-examined to reconcile projected interim year load obligations or generating resource capacity ratings with actual values that are experienced in that interim year.

Additional Considerations for Capacity Demonstrations

Other types of documentation submitted as part of a capacity demonstration will be evaluated on a case by case basis. Because some of the documentation that is required to be filed in these proceedings is commercially sensitive, competitive information, it shall continue to be treated in a confidential manner, as has been done in the past. The Staff shall file a memo in the docket as directed by the Commission, outlining its findings from the demonstration filings, including a listing of any entities whose demonstration, in Staff's opinion, did not completely pass muster.

In the case where a demonstration filing does not pass Staff's muster, Staff would recommend that the Commission open a contested case docket, whereby the LSE in question could attempt to prove that its capacity demonstration should be deemed acceptable. The outcome of that case would be a Commission order potentially authorizing SRM capacity charges to ROA customer load as well as a respective increase in capacity obligations assigned to the incumbent utility as the Provider of Last Resort for capacity service. Any contested demonstration cases will be opened as soon as practicable following the issuance of the Staff memo and be completed within six months.

If an LSE has met the capacity demonstration requirements, no contested case will be opened, and no further action will be taken regarding any capacity demonstration that has been deemed sufficient by Staff and accepted by the Commission.

Capacity Demonstrations for LSEs in PJM service territory

PJM Interconnection LLC (PJM) has a mandatory forward capacity market for LSEs in its service territory. LSEs in the PJM service territory meet their Independent System Operator capacity obligations either through participation in PJM's Reliability Pricing Model (RPM) Base Residual Auction (BRA) or through PJM's Fixed Resource Requirement (FRR) capacity plan. The PJM capacity market is a three year forward market with the calendar aligned slightly differently than what exists with the MISO capacity market. PJM's tariff requires FRR entities (those that self-supply capacity as Indiana Michigan Power has done since the inception of the RPM construct in 2007) to prove capacity for the 2022/23 delivery year (June 2022 through May 2023) in April 2019. The BRA will be completed in May 2019 for the 2022/23 delivery year, and in May 2020 for the 2023/24 delivery year.

The timing of PJM LSEs capacity demonstrations to the Commission will remain the same as those expected of MISO LSEs, however, PJM LSEs will be allowed to file an amended capacity demonstration two weeks after the completion of the PJM RPM BRA if the LSE participates in the BRA. The capacity demonstration should include the FRR capacity plan and/or BRA results. Meeting PJM's capacity obligations, including any applicable Percentage Internal Resources Required for the delivery year will constitute a satisfactory demonstration, and the demonstrating LSE should provide evidence that it has met PJM's capacity obligations.

Demonstration Format

In addition to all of the items outlined above, the following forms shall also be utilized by the LSE in filing its demonstration.

Case No:
Utility: ________________
Date: ________________
Exhibit 1: Peak Demand Bundled Service

Utility Bundled Service Peak Demand for Michigan MISO LRZ 7

Actual and Forecast (MW) - Excluding Transmission Losses

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line		Sample Calc.	**PY 2016-17**	**PY 2017-18**	**PY 2018-19**	**PY 2019-20**	**PY 2020-21**	**PY 2021-22**	**PY 2022-23**
			Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)								
1	Service Territory	12,345							
2	Choice, Coincident to Service Territory	1,234							
3	Bundled (line 1 - line 2)	11,111	0	0	0	0	0	0	0
	Coincident to MISO Sys.Peak Demand (MW)								
4	Service Territory	12,098							
5	Choice, Coincident to Service Territory	1,209							
6	Bundled (line 4 - line 5)	10,889	0	0	0	0	0	0	0

Utility Bundled Service Peak Demand for Michigan MISO LRZ 2

Actual and Forecast (MW) - Excluding Transmission Losses

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line		Sample Calc.	**PY 2016-17**	**PY 2017-18**	**PY 2018-19**	**PY 2019-20**	**PY 2020-21**	**PY 2021-22**	**PY 2022-23**
			Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)								
1	Service Territory	12,345							
2	Choice, Coincident to Service Territory	1,234							
3	Bundled (line 1 - line 2)	11,111	0	0	0	0	0	0	0
	Coincident to MISO Sys.Peak Demand (MW)								
4	Service Territory	12,098							
5	Choice, Coincident to Service Territory	1,209							
6	Bundled (line 4 - line 5)	10,889	0	0	0	0	0	0	0

Utility Bundled Service Peak Demand for Michigan MISO LRZ 1

Actual and Forecast (MW) - Excluding Transmission Losses

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line		Sample Calc.	**PY 2016-17**	**PY 2017-18**	**PY 2018-19**	**PY 2019-20**	**PY 2020-21**	**PY 2021-22**	**PY 2022-23**
			Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)								
1	Service Territory	12,345							
2	Choice, Coincident to Service Territory	1,234							
3	Bundled (line 1 - line 2)	11,111	0	0	0	0	0	0	0
	Coincident to MISO Sys.Peak Demand (MW)								
4	Service Territory	12,098							
5	Choice, Coincident to Service Territory	1,209							
6	Bundled (line 4 - line 5)	10,889	0	0	0	0	0	0	0

Utility Bundled Service Peak Demand for Michigan PJM

Actual and Forecast (MW) - Excluding Transmission Losses

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line		Sample Calc.	**PY 2016-17**	**PY 2017-18**	**PY 2018-19**	**PY 2019-20**	**PY 2020-21**	**PY 2021-22**	**PY 2022-23**
			Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)								
1	Service Territory	12,345							
2	Choice, Coincident to Service Territory	1,234							
3	Bundled (line 1 - line 2)	11,111	0	0	0	0	0	0	0
	Coincident to PJM Sys.Peak Demand (MW)								
4	Service Territory	12,098							
5	Choice, Coincident to Service Territory	1,209							
6	Bundled (line 4 - line 5)	10,889	0	0	0	0	0	0	0

* Totals carry to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a known change in electric service provider.
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.

Case No:
Utility: ______________
Date: ______________
Exhibit 2: Planning Resources

Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC)

	(a)		(b)	(c)	(d)	(e)
Line		Sample Calc.	**PY 2019-2020**	**PY 2020-2021**	**PY 2021-2022**	**PY 2022-2023**
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	11,111	-	-	-	-
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	11				
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	11,100	-	-	-	-
4	Load Diversity Factor coincident to MISO, %.	98.00%				
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	10,878	-	-	-	-
6	Transmission Losses, %	2.80%				
7	Planning Reserve Margin % UCAP Basis	7.10%	7.90%	8.00%	8.00%	8.10%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	11,977	-	-	-	-
9	Company Owned, In-State, Non-Intermittent, ZRC	8,890	-	-	-	-
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	120	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	660	-	-	-	-
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	100	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	20	-	-	-	-
14	Company Owned, Out-of-State, Intermittent, ZRC	40	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	60	-	-	-	-
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	80	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	9,970	-	-	-	-
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 4)	-	-	-	-	-
19	PPA, In-State, Non-Intermittent, ZRC	100	-	-	-	-
20	PPA, Out-of-State, Non-Intermittent, ZRC	200	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	26	-	-	-	-
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	6	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	1,200	-	-	-	-
24	PPA, Out-of-State, Intermittent, ZRC	40	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	60	-	-	-	-
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-
27	Other Forward Capacity Contract, ZRC - In-State	200	-	-	-	-
28	Other Forward Capacity Contract, ZRC - Out-of-State	100	-	-	-	-
29	Total PPA, ZRC (sum of lines 19-28)	1,932	-	-	-	-
30	Net Load Switching (from Ex. 5)	-	-	-	-	-
31	Planned Auction Purchases (from Ex. 5)	75	-	-	-	-
32	Total Planning Resources, ZRC (line 17 + line 18 + line 29 + line 30 + line 31)	11,977	-	-	-	-
33	UCAP Surplus/(Shortfall), MW (line 32 - line 8)	0	-	-	-	-

Case No:
Utility: ______________
Date: ______________
Exhibit 3: DR Program Resources

Demand Response - Capacity Resources

(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM $_{UCAP}$	(e) Total ZRC per Program Name
PY 2019-UCAP				-
				-
				-
				-
				-
				-
				-
				-
				-
Total Demand Response - Capacity Resources PY 2019-2020 (ZRC)				-
PY 2020-UCAP				-
				-
				-
				-
				-
				-
				-
				-
				-
Total Demand Response - Capacity Resources PY 2020-2021 (ZRC)				-
PY 2021-UCAP				-
				-
				-
				-
				-
				-
				-
				-
				-
Total Demand Response - Capacity Resources PY 2021-2022 (ZRC)				-
PY 2022-UCAP				-
				-
				-
				-
				-
				-
				-
				-
				-
Total Demand Response - Capacity Resources PY 2022-2023 (ZRC)				-

Case No:
Utility: ____________________
Date: ____________________
Exhibit 4: Electric Generation List

Company Owned Electric Generation Resources

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Fuel or	Location of Resource:	Located in	If outside of MI, Contracted	Intermittent		P.A. 295	ICAP MW (ZRC)				UCAP MW (ZRC)			
Line	Electric Generation Unit Name	Renewable Type	LRZ 1, LRZ 2, LRZ 7, PJM, Other	Michigan (Y/N)	Trans Service (Y/N)	Resource (Y/N)	BTMG (Y/N)	Resource (Y/N)	2019	2020	2021	2022	2019	2020	2021	2022
1																
2																
3																
4																
5																
6																
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64																
65								Company Owned, In-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-
66								Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-
67								Company Owned, In-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
68								Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
69								Company Owned, In-State, Intermittent, ZRC	-	-	-	-	-	-	-	-
70								Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-	-	-
71								Company Owned, In-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
72								Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
73								Total Company Owned Generation, ZRC (sum of lines 1-64)	-	-	-	-	-	-	-	-
								CHECK	-	-	-	-	-	-	-	-

Case No:
Utility: ______________
Date: ______________
Exhibit 5: PPA Resource List

Generation Resources Under Contract (PPA, Forward ZRC), Load Switching, and Auction Purchases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(n)	(o)	(p)	(q)
		Fuel or	Specify:	Located in	Intermittent	PA 295	BTMG	PURPA	Other Bilateral	Load	Auction	ICAP MW Contracted (ZRC)				UCAP MW Contracted (ZRC)			
Line	**Electric Generator Name**	**Renewable Type**	**LRZ 1, LRZ 2, LRZ 7, PJM, Other**	**Michigan Y/N**	**Resource Y/N**	**Y/N**	**Y/N**	**Y/N**	**PPA Y/N**	**Switching Y/N**	**Purchase Y/N**	**2019**	**2020**	**2021**	**2022**	**2019**	**2020**	**2021**	**2022**
1																			
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64																			
65											PPA, In-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-
66											PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-
67											PPA, In-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
68											PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
69											PPA, In-State, Intermittent, ZRC	-	-	-	-	-	-	-	-
70											PPA, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-	-	-
71											PPA, In-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
72											PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
73											Other Forward Capacity Contract, ZRC - In-State	-	-	-	-	-	-	-	-
74											Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-	-	-	-	-
75											Net Load Switching, ZRC	-	-	-	-	-	-	-	-
76											Planned PRA Purchases, ZRC	-	-	-	-	-	-	-	-
77											Total PPA, ZRC (sum of lines 1-64)	-	-	-	-	-	-	-	-
											CHECK	-	-	-	-	-	-	-	-

Case No:
Utility: ________________
Date: ________________
Exhibit 1: PRMR by Zone

Total Planning Reserve Margin Requirement (PRMR) for Michigan by Zone

Actual and Forecast (MW)

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Sample Calc.	**PY 2016-17**	**PY 2017-18**	**PY 2018-19**	**PY 2019-20**	**PY 2020-21**	**PY 2021-22**	**PY 2022-23**
			Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast
	Zone								
1	MISO LRZ 1	0							
2	MISO LRZ 2	100							
3	MISO LRZ 7	50							
4	PJM	0							
5	Total	150	0	0	0	0	0	0	0

* Totals carry to Exhibit 2.
* PRMR is synonymous with Peak Load Contribution (PLC) and should include transmission losses and planning reserve margin percentage.
* Provide actual values where available.
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.

Case No:
Utility: _______________
Date: _______________
Exhibit 2: Planning Resources

Planning Reserve Margin Requirements and Planning Resources (ZRC)

Line	(a)	Sample Calc.	(b) PY 2019-2020	(c) PY 2020-2021	(d) PY 2021-2022	(e) PY 2022-2023
1	Total Planning Reserve Margin Requirement, UCAP MW	150	0	0	0	0
2	Company Owned, In-State, Non-Intermittent, ZRC	80	-	-	-	-
3	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-
4	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-
5	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-
6	Company Owned, In-State, Intermittent, ZRC	-	-	-	-	-
7	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-	-
8	Company Owned, In-State, Intermittent (BTMG), ZRC	-	-	-	-	-
9	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-
10	Total Company Owned Generation, ZRC (sum of lines 2-9) (from Ex. 4)	80	-	-	-	-
11	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	10	-	-	-	-
12	PPA, In-State, Non-Intermittent, ZRC	-	-	-	-	-
13	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-
14	PPA, In-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-
15	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-
16	PPA, In-State, Intermittent, ZRC	-	-	-	-	-
17	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-	-
18	PPA, In-State, Intermittent (BTMG), ZRC	-	-	-	-	-
19	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-
20	Other Forward Capacity Contract, ZRC - In-State	15	-	-	-	-
21	Other Forward Capacity Contract, ZRC - Out-of-State	50	-	-	-	-
22	Total PPA, ZRC (sum of lines 12-21) (from Ex. 5)	65	-	-	-	-
23	Net Load Switching (from Ex. 5)	(10)	-	-	-	-
24	Planned Auction Purchases (from Ex. 5)	5	-	-	-	-
25	Total Planning Resources, ZRC (line 10 + line 11 + line 22 + line 23 + line 24)	150	-	-	-	-
26	UCAP Surplus/(Shortfall), MW (line 25 - line 1)	0	0	0	0	0

Case No:
Utility: ______________
Date: ______________
Exhibit 3: DR Program Resources

Demand Response - Capacity Resources

(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM $_{UCAP}$	(e) Total ZRC per Program Name
PY 2019-UCAP				-
				-
				-
				-
				-
				-
				-
				-
				-
Total Demand Response - Capacity Resources PY 2019-2020 (ZRC)				-
PY 2020-UCAP				-
				-
				-
				-
				-
				-
				-
				-
				-
Total Demand Response - Capacity Resources PY 2020-2021 (ZRC)				-
PY 2021-UCAP				-
				-
				-
				-
				-
				-
				-
				-
				-
Total Demand Response - Capacity Resources PY 2021-2022 (ZRC)				-
PY 2022-UCAP				-
				-
				-
				-
				-
				-
				-
				-
				-
Total Demand Response - Capacity Resources PY 2022-2023 (ZRC)				-

Case No:
Utility: ____________
Date: ____________
Exhibit 4: Electric Generation List

Company Owned Electric Generation Resources

Line	(a) Electric Generation Unit Name	(b) Fuel or Renewable Type	(c) Location of Resource: LRZ 1, LRZ 2, LRZ 7, PJM, Other	(d) Located in Michigan (Y/N)	(e) If outside of MI, Contracted Trans Service (Y/N)	(f) Intermittent Resource (Y/N)	(g) BTMG (Y/N)	(h) P.A. 295 Resource (Y/N)	(i) ICAP MW (ZRC) 2019	(j) ICAP MW (ZRC) 2020	(k) ICAP MW (ZRC) 2021	(l) ICAP MW (ZRC) 2022	(m) UCAP MW (ZRC) 2019	(n) UCAP MW (ZRC) 2020	(o) UCAP MW (ZRC) 2021	(p) UCAP MW (ZRC) 2022
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65								Company Owned, In-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-
66								Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-
67								Company Owned, In-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
68								Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
69								Company Owned, In-State, Intermittent, ZRC	-	-	-	-	-	-	-	-
70								Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-	-	-
71								Company Owned, In-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
72								Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-
73								Total Company Owned Generation, ZRC (sum of lines 1-64)	-	-	-	-	-	-	-	-
								CHECK	-	-	-	-	-	-	-	-

Case No:
Utility: ______________
Date: ______________
Exhibit 5: PPA Resource List

Generation Resources Under Contract (PPA, Forward ZRC), Load Switching, and Auction Purchases

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Specify: LRZ 1, LRZ 2, LRZ 7, PJM, Other	(d) Located in Michigan Y/N	(e) Intermittent Resource Y/N	(f) PA 295 Y/N	(g) BTMG Y/N	(h) PURPA Y/N	(i) Other Bilateral Contract Y/N	(j) Load Switching Y/N	(k) Auction Purchase Y/N	(l) ICAP MW Contracted (ZRC) 2019	(m) ICAP MW Contracted (ZRC) 2020	(n) ICAP MW Contracted (ZRC) 2021	(o) ICAP MW Contracted (ZRC) 2022	(p) UCAP MW Contracted (ZRC) 2019	(q) UCAP MW Contracted (ZRC) 2020	(r) UCAP MW Contracted (ZRC) 2021	(s) UCAP MW Contracted (ZRC) 2022
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65	PPA, In-State, Non-Intermittent, ZRC											-	-	-	-	-	-	-	-
66	PPA, Out-of-State, Non-Intermittent, ZRC											-	-	-	-	-	-	-	-
67	PPA, In-State, Non-Intermittent (BTMG), ZRC											-	-	-	-	-	-	-	-
68	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC											-	-	-	-	-	-	-	-
69	PPA, In-State, Intermittent, ZRC											-	-	-	-	-	-	-	-
70	PPA, Out-of-State, Intermittent, ZRC											-	-	-	-	-	-	-	-
71	PPA, In-State, Intermittent (BTMG), ZRC											-	-	-	-	-	-	-	-
72	PPA, Out-of-State, Intermittent (BTMG), ZRC											-	-	-	-	-	-	-	-
73	Other Forward Capacity Contract, ZRC - In-State											-	-	-	-	-	-	-	-
74	Other Forward Capacity Contract, ZRC - Out-of-State											-	-	-	-	-	-	-	-
75	Net Load Switching, ZRC											-	-	-	-	-	-	-	-
76	Planned PRA Purchases, ZRC											-	-	-	-	-	-	-	-
77	Total Resources, ZRC (sum of lines 1-64)											-	-	-	-	-	-	-	-
	CHECK											-	-	-	-	-	-	-	-