

# Demand Response Aggregation Stakeholder Meeting

Michigan Public Service Commission

May 3, 2019



# Meeting Agenda

- Staff overview of the March 12<sup>th</sup> stakeholder meeting
- Staff review of written participant feedback
- PJM Presentation: DR opportunities in PJM
- Consumers Energy: Overview of current DR aggregation challenges
- AEMA
- Status of Staff Report
- Questions, discussion and next steps

# March 12<sup>th</sup> Stakeholder Meeting

- Overview and discussion to the responses received to Staff's first feedback request surrounding issues related to:
  - State vs. jurisdictional issues
  - Tracking aggregated demand response
  - Effects of aggregated demand response on capacity demonstrations
  - What acceptable reporting requirements would be for capacity demonstrations
  - Demand response aggregation limited to AES customers only
- Explored the Indiana Utility Regulatory Commission's demand response model, NIPSCO's demand response tariff, Pennsylvania's Energy Efficiency and Conservation Program and compared the MISO vs. PJM demand response registration process.

# March 12<sup>th</sup> Stakeholder Meeting

- Potential Elements for a Staff proposal
  - Michigan capacity obligations
  - PLC issue
  - ZRC contracts
  - Overview of Commission directed questions
- Second feedback request circulated March 13th

# Summary of Feedback Request #2

# Indiana Model

## Pros

- Works well in IN
- Retains EDC visibility for resource adequacy purposes
- Gives regulator a more comfortable way to allow aggregation

## Cons

- Administrative costs
- Customers may prefer direct participation
- Doesn't match up well with MI large amount of current DR
- Over-regulating aggregation

## Worth exploring?

- Maybe. An option if MPSC continues to restrict participation

## Pros

- Requires that unaffiliated, independent companies could provide services to utility
- Allows customers to interact directly with CSPs/ARCs

## Cons

- Legislation required
- Not a substitute for IRP and other DR programs
- More about peak shaving
- Built for a fully deregulated state

## Worth exploring?

- Probably not. Maybe just for broad ideas and what works.

# PJM process

## Pros

- PJM thoroughly vets registrations
- Ensures PLC values are calculated correctly.
- Eliminates the role of the RERRA.
- Requires more information from CSPs

## Cons

- Eliminates the role of the RERRA.
- Requires more information from CSPs

## Worth exploring?

- Yes. PJM procedures are more detailed and could provide insight into improving the MISO process.



# Do you support adopting PJM procedures?

## At MISO?

- Broad support
- MISO process needs to be supplemented for tracking purposes
- MISO process needs to be more centralized, not rely on EDC/RERRA for PLC mechanics
- Avoids duplicate systems at state level

## At state level?

- Some support
- Need a process to recognize DR programs not yet registered at MISO
  - MI is 4 years forward, MISO is 1 year forward
- ARC affidavit is key to success/needed in capacity dem. process

**Conditional support:** Only if MPSC continues to allow AES customer aggregation

# Specific MISO BPM/Tariff changes

- Are MISO BPM or tariff revisions warranted to ensure that retail peak load contributions are increased to reflect any relevant load reductions?
  - Tariff is OK: Module E-1 Sec 69A
    - states the EDC must calculate the PLC of any load reductions at MISO peak and add that back to peak demand.
    - *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) augmented to include the normal Demand from forecasted Demand Resources, whether registered or not registered with the Transmission Provider.*
    - *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.*
    - *....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)....*

## **BPM needs work**

- Tariff sets the ‘who and what’ but BPM neglects the ‘how’.
- BPM doesn’t specify how the EDC is supposed to get the data from LSE in its territory to perform PLC calculations.
  - EDC needs DR peak load data from the RTO, LSE, or the ARC to comply with the tariff.

## **Suggested BPM details**

- ARC’s provision of evidence of performance to MISO
- MISO’s verification of that evidence
- ARC’s role to provide MISO’s approval to the EDC
- EDC’s augmentation of the customer’s load at MISO peak

# Change PLC calculation to 12 peaks?

## Pros

- Top 5 days may work better

## Cons

- Tough to do, PLC tied to everything in MISO resource adequacy construct
- Wouldn't eliminate the need to adjust forecasts
- Would reduce DR capacity credit.
- Undervalues temperature sensitive loads/  
overvalues more stable loads

# ARC Voluntary Registration Process in MI

- Should the MPSC develop a voluntary registration process with reporting requirements for ARCs in Michigan? Why or why not?
- Some support if MISO changes are not implemented
  - Others prefer to all be done through RTO
- Voluntary process may not address issues
  - Need consistent reporting and data gathering
- Mandatory process would probably require legislation

# Type of info for MI ARC Registration

- Broad support for making similar to what is required for an AES
  - Line of credit/affirmation of solvency
  - Proof of MISO ARC registration
  - Identity and amount of load aggregated
  - Metering verification
  - Qualifications to aggregate DR
  - Commitment to act in good faith

# MI 4-year forward Tracking Tool

(for agg. DR and/or all capacity resources)

## Pros

- Would allow more flexibility to build a portfolio
- Could work with RTO to get data
  - Don't overlap what RTO already does

## Cons

- Unnecessary administrative burdens
- Cost
- MPSC can require binding 4-year forward contracts instead
  - And/or submit all info to MPSC that is submitted to MISO

# Changes to Capacity Demonstration

- Need a way to recognize planned DR resources not yet under contract or registered with MISO
  - Affidavits to provide level of certainty
- Demand side requirements shouldn't be more onerous than supply side.
- Remove individual LCR to ensure state requirements aren't more strict than MISO requirements
  - Aggregated DR exacerbates the problem.



# Who can bid aggregated DR into RTO markets?

*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.*

# Staff recommendation: ARCs can bid aggregated DR into RTO markets

## **Agreement**

- This is the status quo
- Consistent with RTO rules
- Would expand DR in MI
- MPSC can retain oversight with minor additions to capacity dem. process
- MPSC doesn't have authority to limit DR registration to AES

## **Disagreement**

- Limits visibility and ability to plan for ARC DR.
- Incumbent utilities already have DR programs in place
- Double counting under current MISO procedures
- Risks are not addressable except through a ban on ARC registration.

# Expanding DR aggregation to non- AES customers

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

# Expanding DR aggregation to non-AES customers

## Support

- Intermediate steps can be taken vs. full aggregation
  - Utility-aggregator partnership models
  - Other ways to retain MPSC oversight, visibility, and control
- Customers may prefer to work with an ARC who can customize to their needs
- Would help meet EWR/enviro. goals
- Sets a model for DR, EE, and storage aggregation

## Oppose

- Cross-subsidization is a major concern
  - Benefits accrue to ARC and participating customer
  - No benefit for non-participating customers
- Adverse operational impacts
  - Who controls the DR? MISO or the LDC?
  - Due to ARC business model, system loses out on reliability benefits
- FRR entities need to be able to include aggregated DR in their capacity plan
- Runs counter to MI's 10% choice law

# Expanding DR aggregation to non-AES customers

## Other Ideas

- Any MPSC requirements must be limited to regulated utilities (not munis/coops)
- ARC registration process
- Procedures regarding DR customer information and meter data
- Beef up MISO process
  - More clear peak load forecast procedure
- Utility DR affiliate may be needed to ensure no preferential treatment

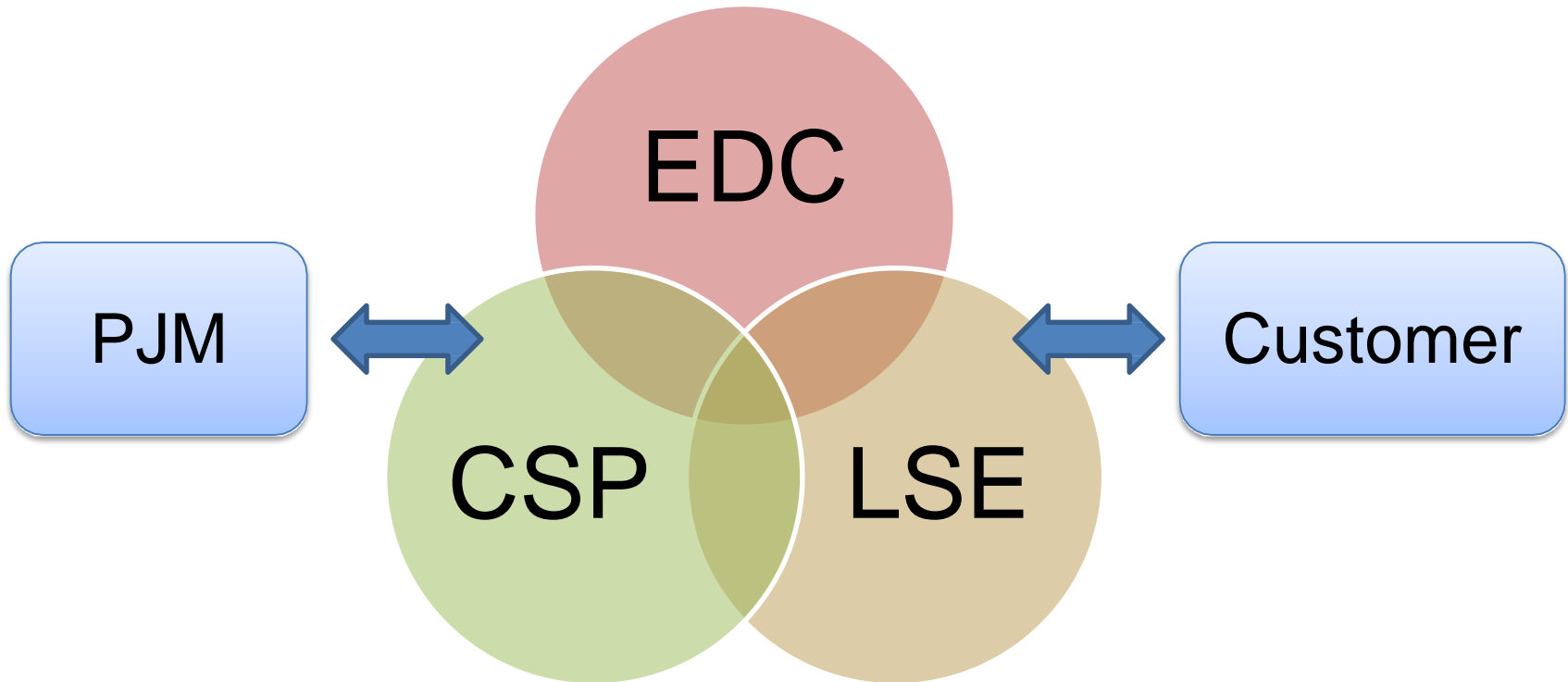
## Oppose

- Harder for incumbent to forecast capacity needs
- Already have broad swath of incumbent utility programs with high participation
- Utility= single point of contact for customer, and MISO
  - Good for reliability and efficiency
- Would aggravate problems with MISO procedures

# Demand Response opportunities in PJM wholesale market

May 3, 2019  
Pete Langbein

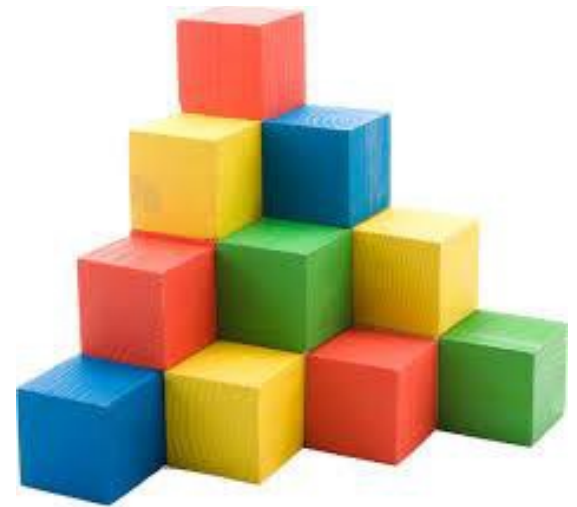
*Electric Distribution Company –  
distribute electricity to the customer*



*Curtailment Service Provide –  
provide DR services to customer*

*Load Serving Entity – provide  
electricity for the customer*

- Wholesale market provides building blocks for participation
- DR participation in wholesale market is guided by Relevant Electric Retail Regulatory Authority (RERRA)





- Allow participation into the markets
  - Size
  - market requirements (annual capacity)
- Portfolio management for compliance
- But ensure:
  - Alignment of market offers, prices and resource parameters
  - LSE/EDC review process
  - Dispatch granularity to meet grid needs

Balance grid management/dispatch and aggregation participation needs

# Demand Response and Energy Efficiency Opportunities in PJM Wholesale Market

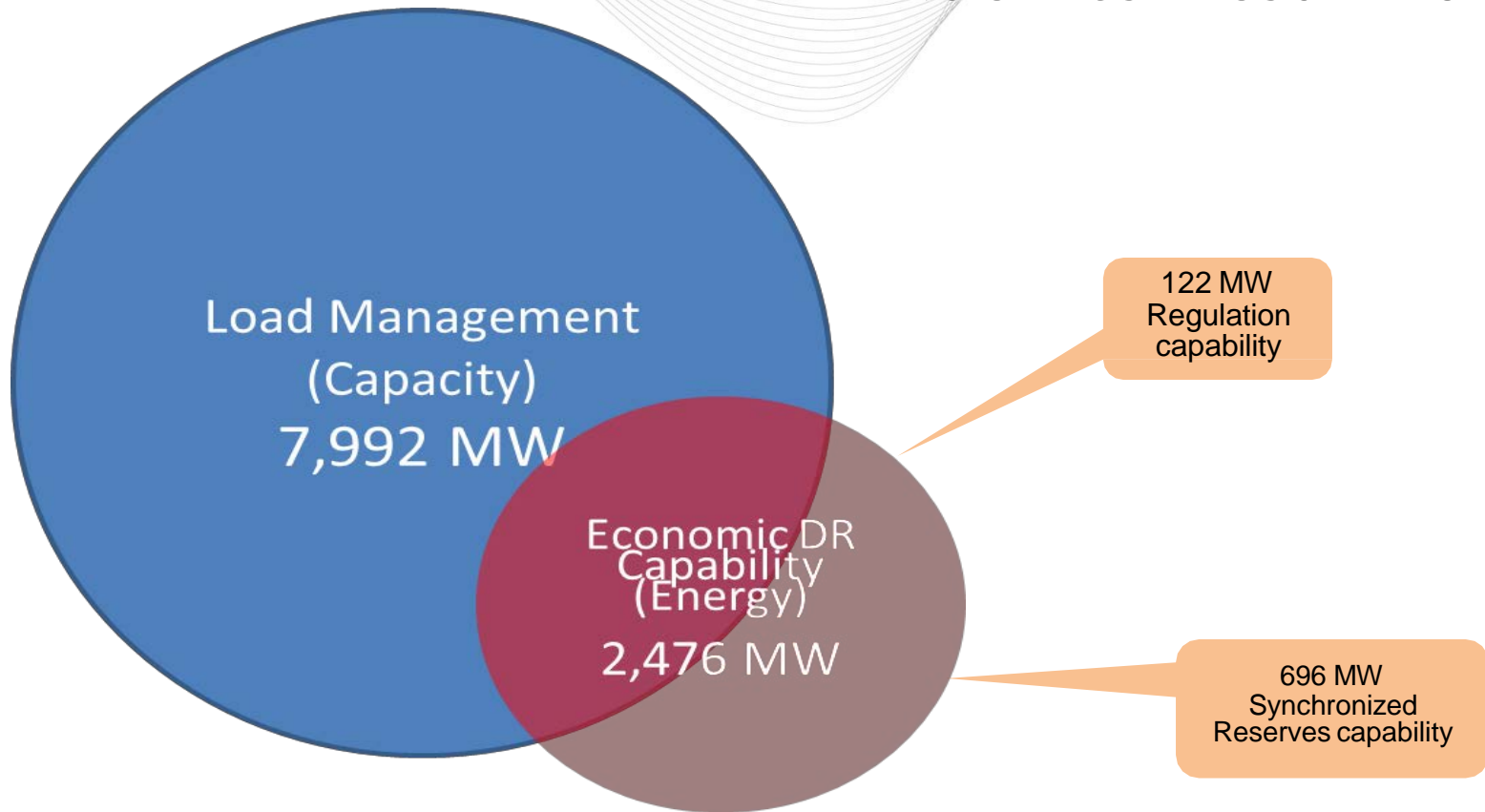
Wholesale Service/Market	Demand Response	Price Responsive Demand (PRD)	Energy Efficiency
Capacity	Yes	Yes	Yes
Energy	Yes		
Day Ahead Scheduling Reserves (30 min)	Yes		
Synchronized Reserves (10 min)	Yes		
Regulation	Yes		

*Emergency DR (Load Management)* is indicated for Capacity, Energy, and Day Ahead Scheduling Reserves (30 min).

*Economic DR* is indicated for Day Ahead Scheduling Reserves (30 min), Synchronized Reserves (10 min), and Regulation.

New Peak Shaving Adjustment to PJM long term forecast recently filed at FERC

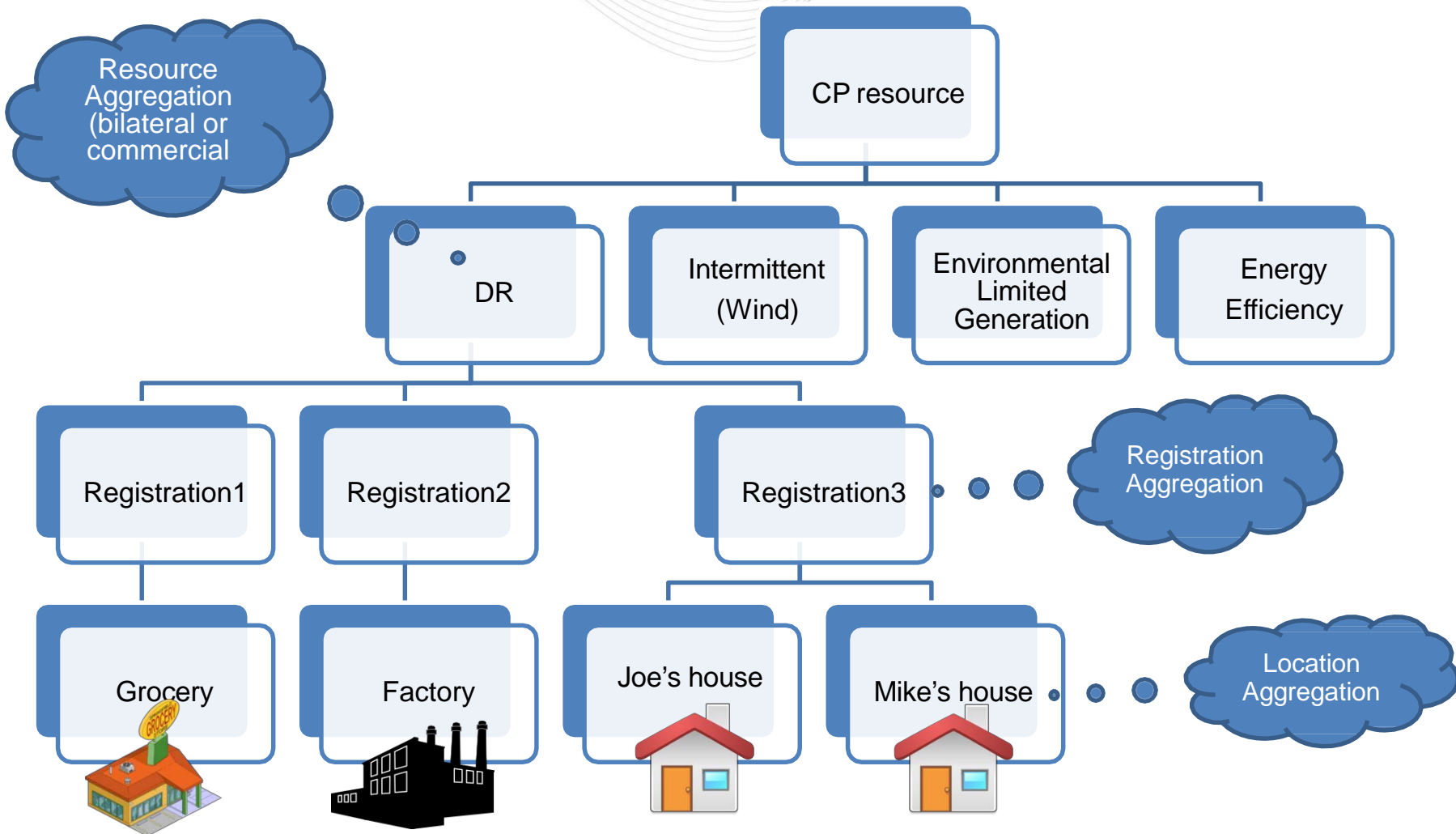
# Demand Response Capability ~ 4% of Peak Load in 2018/19



Represents over 2 million end use customers (~19,000 C&I) across PJM

- Offer in auction up to 3 years in advance
- Load must be reduced within 30 minutes unless qualify for exception (60, 120 minutes)
  - Safety, potential damage, generation startup
- Load reductions should be available
  - June through Oct & May: 10am to 10pm
  - Nov through April: 6am to 9pm
- Load reduction based on summer peak load and winter peak load.
- Hourly Penalty if load is not reduced (~\$3,500 MWh)
- Paid for energy up to offer price.
- Required to test for 1 hour if not dispatched
- Hourly metering

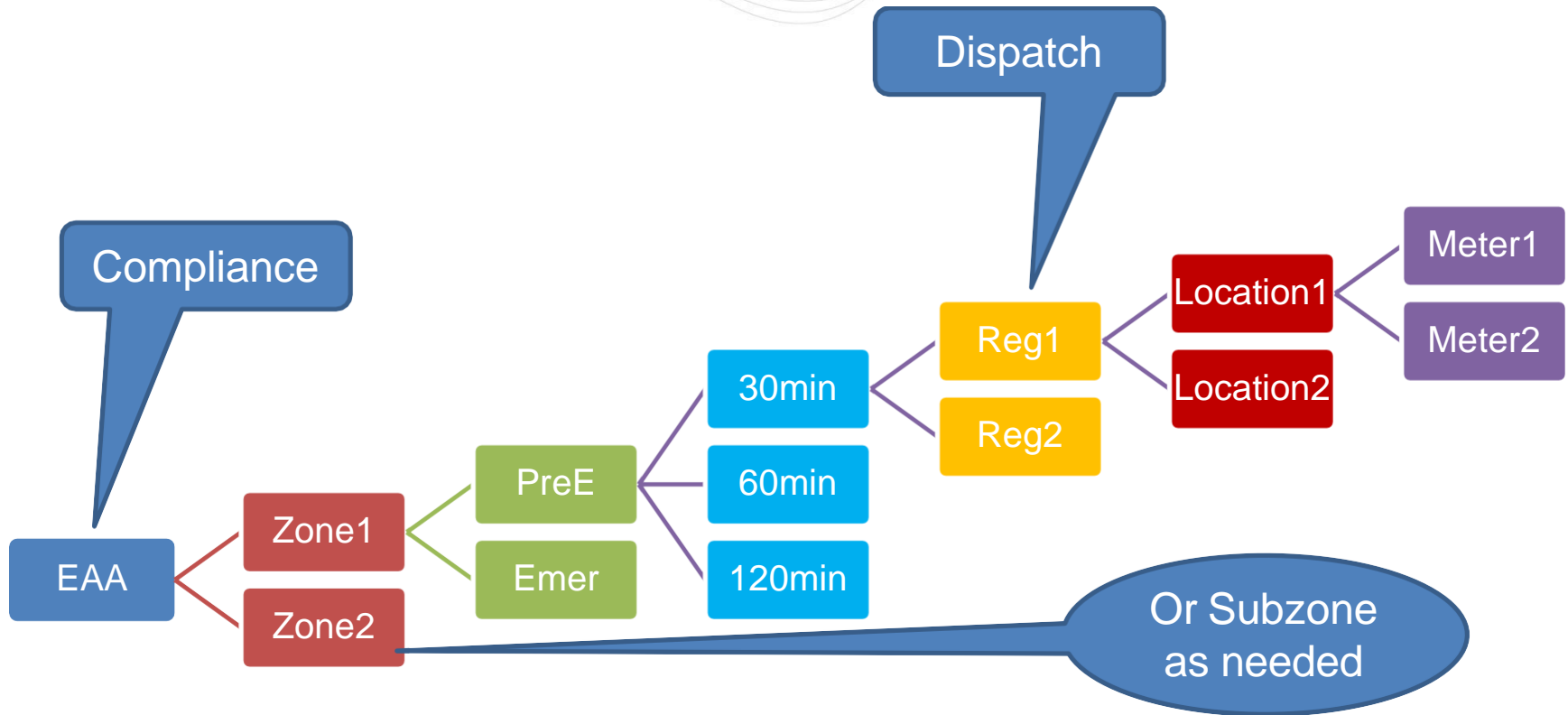
- Location = EDC account number, typically a premise or single building with an address
- Registration = CSP contract with locations to participate in specific market for a period of time for a certain amount. Includes one or more locations
- RPM/FRR resource – represent RPM/FRR capacity commitment for certain for period of time. Includes one of more registrations.
- EAA = Emergency Action Area. Represents location of CP issue (may be multiple zones)
- Subzone = collection of zip codes. All registrations with locations in zip code are included in subzone



- Capacity market aggregation
  - Size
    - Look at RPM resource for 100kw min and seasonal capability
      - Link registrations to the resource (avoid aggregation of locations on a registration which reduces dispatch granularity)
  - Geographic location
    - Smaller of Zone or LDA
  - EDC
  - Energy Pricing point – typically zone or aggregate
  - Capacity Market attributes
    - Type – Emergency/Pre-emergency
    - Lead time – 30/60/120 minute
    - Product – in transition with CP

Ensure aggregation allows registration dispatch flexibility

# Aggregation for Performance is based on registration(s) dispatched and system condition



Allows CSP portfolio aggregation and dispatch flexibility



- Energy – dispatched when economic to participate based on offer and availability.
  - Hourly metering
  - Day ahead and/or real time energy market
  - Customer baseline (“CBL”) to determine reduction
  - Payment based on Locational Marginal Price
- Synchronized Reserves – must reduce load within 10 minutes during reserve shortage
  - 1 minute metering
- Regulation – real time load change (increase and decrease) based on real time system conditions
  - Real time telemetry required

- **Size**
  - May include Locations <100 kw with ability to put 1 >100kw to enable participation on the same registration
- **Geographic location**
  - All locations must have the same Zone, EDC and Pricing Point
- **LSE – when applicable**
- **Market Offer and Dispatch**
  - Registration or Dispatch Group (optional)
- **Compliance**
  - Registration compliance based on sum of load data from associated locations
  - Dispatch Group based on aggregate registration load reductions

Multiple registration in same zone with same pricing point may be aggregated to “Dispatch Group” based on offer parameters

- Participation aggregation
  - Same as energy except:
    - Location based on smaller of transmission zone and SR area
- Market Offer and Dispatch
  - SR area (MAD, non-MAD, RTO)
- Compliance
  - measured across the RTO based on what was dispatched

- **Participation aggregation**
  - If regulation only (no energy market participation) then:
    - May include Locations <100 kw with ability to put 1 >100kw to enable participation on the same registration
    - All Locations must have same Zone and EDC
- **Market Offer**
  - Registration or Dispatch Group (optional)
    - Required to be <10 MW
- **Dispatch**
  - Fleet which is made up of 1 or more Dispatch Groups (optional) or Registrations
    - Required to be <10 MW
- **Compliance**
  - Measured based Registration, Dispatch Group (optional) or Performance Group (optional)
    - Required to be <10 MW

- Participation – allow small locations to meet size threshold
- Geographic Location – dispatch flexibility
- EDC/LSE – data review process (avoid duplicates)
- Pricing Point – all underlying locations receive same market prices
- Offer parameters – same offer parameters (price, MWs, lead time, min down time, etc.) or can be represented in offer curve
- Portfolio management for compliance/settlements

- If RERRA receives FERC approval on order, ordinance or resolution to qualify or prohibit EE participation then:
  - PJM will post reference to all RERRA evidence approved by FERC, applicable EDC(s) and Deliver Years and/or auctions
  - PJM will adjust granularity of EE M&V plan and EE Post-Installation M&V report to facilitate necessary EDC review
  - PJM will send list of EE Providers with EE M&V plan (30 days prior to auction) and EE Post-installation M&V report (15 days prior to start of Delivery Year) to EDC to review for RERRA compliance
  - EDC will review EE Provider list and provide approval in 5 business days

- PJM to send list of EE providers with EE identified in KY to EDC for approval
  - PJM will only allow EE Provider to participate in future auctions or Delivery Year based on EDC approval.
  - EDC will review list of EE providers and ensure they are allowed to deliver EE in KY based on RERRA



# Demand Response Aggregation

U-20348 Stakeholder Workgroup

May 3, 2019





## 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

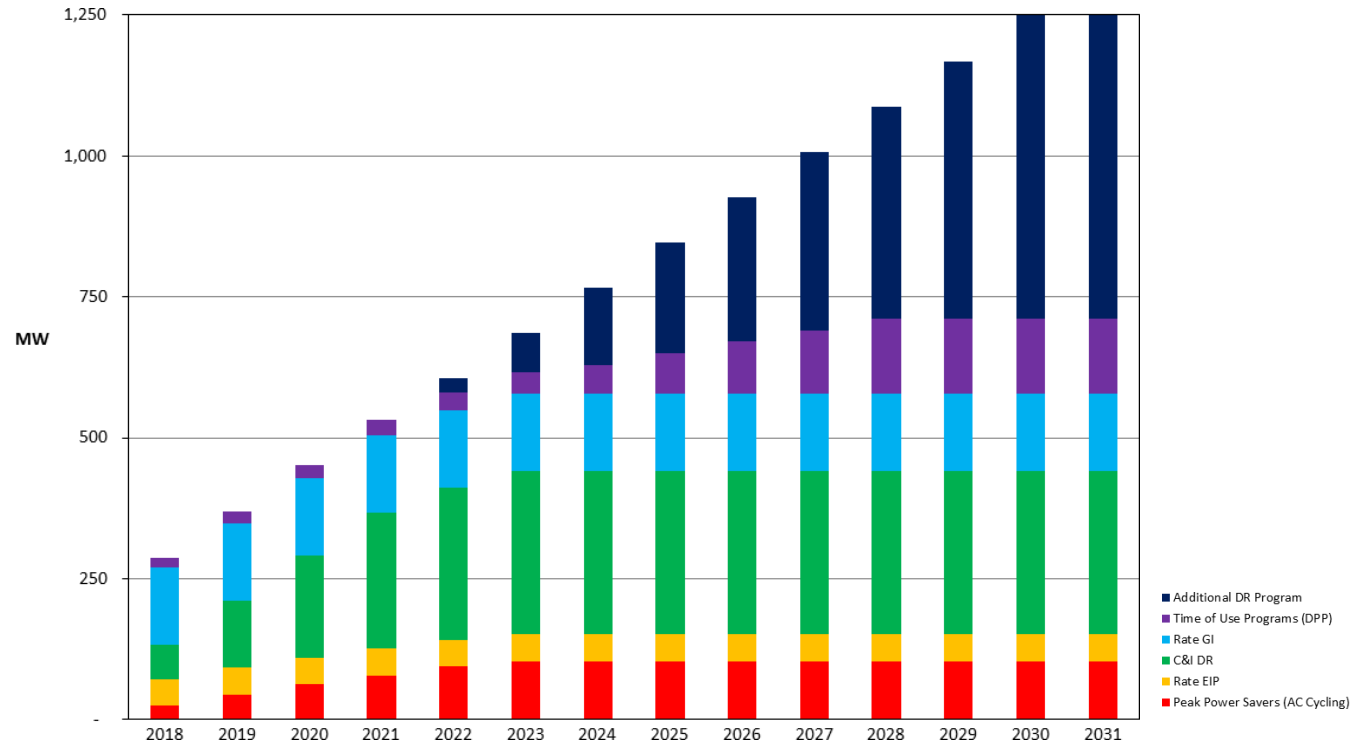
# Consumers Energy Existing Demand Response Programs

- 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 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 lowest cost of 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

# Advanced Energy Management Alliance

## Leveraging Utility-Aggregator Partnership Models

May 3, 2019

Michigan PSC Staff Stakeholder Meeting

# Executive summary

- Michigan's existing ARC ban does not need to be overturned in order to leverage benefits of 3<sup>rd</sup> party DR providers; Michigan utilities are doing this today
- Goal should be to develop a model that maximizes reliable, cost-effective customer participation through ARC-utility collaboration while maintaining utility control/visibility over customers
- Options include bilateral contracting or an open utility tariff
- MISO's evolving markets pose both risks and opportunities for customers participating in DR programs today; ARCs can help customers & utilities adapt to these changes

# How have MISO states addressed ARC participation for regulated utilities?

In the last year, multiple states have encouraged/directed utilities to work with 3<sup>rd</sup> Party DR Providers, without overturning state bans on ARCs:

- Missouri PSC:

“Authorizing unregulated ARCs to take control over aspects of electrical service would prevent the Commission from regulating the service these entities seek to provide. Additionally, the Commission would continue to regulate the utilities to which aggregating customers subscribed, but would have no control over the manner in which the aggregators conducted business. Based on Staff’s research an approach in line with the Indiana Model appears to mitigate these issues. Therefore, Staff recommends the Commission encourage the electric utilities to submit tariffs similar to the Indiana Model.”<sup>1</sup>

- Louisiana PSC:

“LSE’s are encouraged to work together with third party demand response agents who work with the utility to aggregate DR load, if such efforts are prudent and cost efficient, to encourage and implement the demand response programs and to take advantage of the demand response benefits offered by the RTO markets. However, those programs must be developed and implemented under the regulatory authority of the Commission; the Commission will determine the effectiveness of those programs, and how the benefits should be shared by retail customers.”<sup>2</sup>



1. Missouri PSC Staff Report on DERs, Apr. 5, 2018, File No. EW-2017-0245
2. Louisiana PSC General Order, Mar. 9, 2019, Docket No. R-34948

# Goal should be to maximize cost-effective DR participation to drive system-wide savings

- Utilities can leverage benefits of 3<sup>rd</sup> party DR Providers to maximize participation while retaining planning control, insight, and jurisdiction over their customers.
- Two different models:
  - Indiana-style tariff (e.g., I&M Indiana's D.R.S.1 tariff)
  - Bilateral contracts:

DR services  
provided by  
aggregator to  
utility



Full turnkey  
program  
management  
provided by  
aggregator

- Model should suit the needs, capabilities of utility & customers and can be adapted accordingly.

# Benefits of 3<sup>rd</sup> Party DR Providers

- Significant private capital investments in advanced technology that provides real-time resource visibility; supplements utility capabilities while being efficient with ratepayer dollars.
- Expertise in discovering and maximizing customer flexibility; harness potential from a diverse pool of C&I customers, not just the largest, to lower costs for all customers; provide market interface.
- Portfolio aggregation enables reliable performance while shielding individual customers from out-of-pocket penalties that serve as barrier to entry; can also play “tetris” with limited duration customers who may not be able to participate individually.

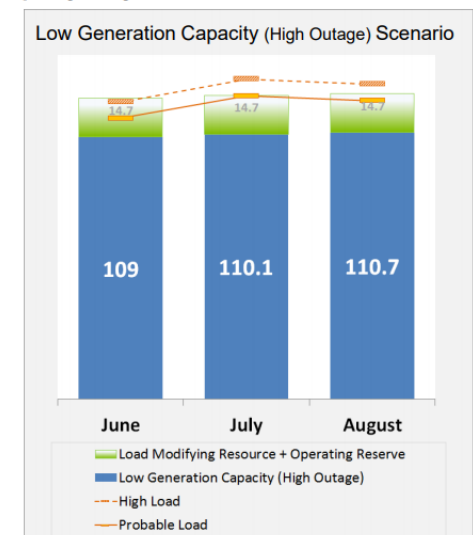
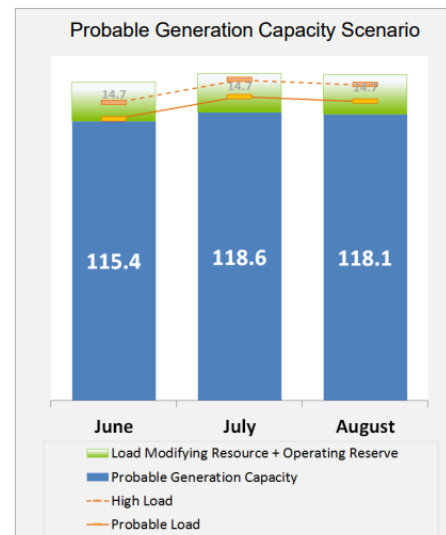
# MISO's evolving market will create new challenges & opportunities for utilities

- How do we protect customer participation as MISO dispatches become more frequent?
- How do we enable customers to harness their flexibility to drive additional system savings?
- What are the potential implications of a forthcoming FERC ruling on DER Aggregations?

70% Chance of LMR Activation for 2019 Summer Season

Utilization of load modifying resources are likely to be needed in the upcoming Summer season

Summer Resource Adequacy Projections





# APPENDIX



# Potential Models: 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 CONE (cost of new generation);
- 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.

# Potential Models: Bilateral contracts

- Competitively solicit for DR resources through 3<sup>rd</sup> 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 3<sup>rd</sup> 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.

# Questions?

To learn more about Advanced Energy Management Alliance, visit our website.

[www.aem-alliance.org](http://www.aem-alliance.org)

# Status of Staff Report

# Questions, Discussion and Next Steps

# Questions & Discussion

- Aggregated energy efficiency and energy storage resources
- Suggested changes to the report?
- Topics that Staff has not considered?

# Next Steps

- **May 15<sup>th</sup>** - Comments/redline changes to Staff report outline circulated on April 26<sup>th</sup> due
- **May 24<sup>th</sup>** - Written finalized comments wishing to be attached as an appendix to Staff's report due
- **May 30<sup>th</sup>** – Staff report to be filed to the docket.
- Staff will recommend that the Commission issue a notice to allow stakeholders an additional opportunity to comment on the final draft of the Staff report directly in the docket.
- Redline changes and comments should be sent to Heather Cantin and Erik Hanser.

[Cantinh@michigan.gov](mailto:Cantinh@michigan.gov) and [Hansere@michigan.gov](mailto:Hansere@michigan.gov)

## Questions?

If you wish to subscribe to the MPSC DR Aggregation listserv, you may do so by accessing our [DR Aggregation Workgroup website](#).