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June 6, 2019

Via Facsimile and Overnight Mail
Ms. Terri Lemoine Bordelon
Louisiana Public Service Commission
Records and Recording Division
Galvez Building, 12th Floor
602 N. Fifth Street
Baton Rouge, Louisiana 70802

In Re: Rulemaking to Determine Need for Rate Schedules and Programs Offering Demand Response Products, Development of Such Rate Schedules and Program, Determination of Customer Participation in Such Program, Allocation and Recovery of Program Costs, and Whether Such Programs Shall be Mandatory or Voluntary for Utilities as set Forth in Sec. 3 of the rule Adopted in General Order Dated March 7, 2019 in Docket No. R-34948

LPSC Docket No. R-35136

Dear Ms. Bordelon:

The Advanced Energy Management Alliance ("AEMA") hereby submits the attached responses to Staff's Request for Information pertaining to the consideration of developing DR tariffs and programs.

Please find an original and three (3) copies enclosed. Please file these comments into the record in accordance with the Commission's fax filing procedures. I have enclosed a check in the mail for $25.00 to cover the fax filing fee.

Thank you for your consideration.

Sincerely,

Katherine Hamilton

Katherine Hamilton
Executive Director
Advanced Energy Management Alliance

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF LOUISIANA

DOCKET NO. R-35136

LOUISIANA PUBLIC SERVICE COMMISSION, EX PARTE

In Re: Rulemaking to Determine Need for Rate Schedules and Programs Offering Demand Response Products, Development of Such Rate Schedules and Program, Determination of Customer Participation in Such Program, Allocation and Recovery of Program Costs, and Whether Such Programs Shall be Mandatory or Voluntary for Utilities as set Forth in Sec. 3 of the rule Adopted in General Order Dated March 7, 2019 in Docket No. R-34948

Advanced Energy Management Alliance response to Staff's Request for Information pertaining to the development of DR tariffs and programs

I. Introduction

Advanced Energy Management Alliance ("AEMA")[1] respectfully submits the following responses to Staff's request for information pertaining to the development of DR tariffs and programs. AEMA is a trade association under Section 501(c)(6) of the Federal tax code whose members include national distributed energy resource companies and advanced energy management service and technology providers, including demand response ("DR") providers, as well as some of the nation's largest demand response and distributed energy resources. AEMA members support the beneficial incorporation of distributed energy resources ("DER" or "DERs"), including advanced energy management solutions, into utility planning processes and wholesale markets as a means to achieving electricity cost savings for consumers, contributing to system reliability and resiliency, and ensuring balanced price formation. This filing represents the collective consensus of AEMA as an organization, although it does not necessarily represent the individual positions of the full diversity of AEMA member companies.

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[1] For additional information, see AEMA website: http://aem-alliance.org

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Executive Summary

AEMA appreciates the opportunity to comment on this docket and Staff's and the Consultants' thoroughness in its request for information. Through managing and participating in dozens of DR programs across North America and globally, AEMA member companies are extremely knowledgeable in DR program design. We have distilled that experience down to the examples, lessons, and best practices that we believe are most relevant for Louisiana's utilities and their customers.

Our top-level recommendations are immediately below, and are followed by additional detail as well as answers to the Commission's questions.

1. Successful DR programs provide utilities with a reliable, long-term product that reduces their need to build generation, and also unlocks additional value from customers.
   a. In the MISO portion of Louisiana, utilities should design a program and/or open tariff[2] that aligns with MISO's LMR product for emergency capacity and also captures demand savings during the hours that drive the highest system costs.
   b. In the SPP portion of Louisiana, utilities should design a peak-shaving program or open tariff that reduces each utility's peak demand and therefore each utility's capacity obligation to SPP and also drives demand savings.

[2] We differentiate throughout these comments between an open tariff for DR and a DR program. Open tariff refers to a tariff with identical terms for all customers and no single entity responsible for delivering a contracted number of MW. DR Program refers to a program in which the utility contracts with a 3rd Party DR Provider(s) to deliver a certain number of pre-determined MW.

2. There is a large potential for DR in Louisiana. The MISO portion of the state likely has DR capacity potential close to 10% of its peak load, based on the amount of DR registered across MISO for the 2019/2020 delivery year and Louisiana's large commercial and industrial customer base. The SPP portion of the state likely has DR potential closer to 5% of peak load in the region based on differences in how programs must be designed in SPP relative to MISO to drive capacity savings. The Commission should direct its utilities to develop DR programs that aim to achieve these MW benchmarks.

3. Programs or open tariffs that provide utilities with a long-term planning resource that reduces their need to build new generation should be valued based on the long-term avoided costs of capacity. Programs that provide demand savings during peak periods should be compensated for their avoided transmission, distribution, and energy costs as well. Programs and tariffs should be cost-effective and reduce the energy bills of both participating and non-participating customers; DR programs for commercial and industrial customers tend to be highly cost-effective[3].

4. To maximize customer participation, program reliability, and cost efficiency, the Commission should require utilities to partner with a 3rd-party DR Provider or Providers to help build and manage their programs, but allow utilities the flexibility to decide the optimal partnership model.
    a. Utilities can either qualify one or multiple DR Provider(s) to manage customer participation in an open tariff, or can bilaterally contract with a DR Provider via RFP for a contracted amount of MW in a DR program.
    b. AEMA recognizes that certain large industrials with highly sophisticated energy managers may prefer to participate in an interruptible tariff directly with their utility, and that utilities already have experience managing such tariffs for their largest industrials. As such, we do not oppose that option, although the largest industrials should not be precluded from participating through a 3rd Party Provider if they desire.

We expand on these recommendations below.

[3] See *Table 3: Avoided costs used to evaluate DSM program cost-effectiveness across MISO states*, in response to Staff's Request for Information Question No. 11.

“Straw Man” Recommendations for DR Program Design

AEMA recommends the following basic program designs for Louisiana utilities’ medium and large commercial and industrial customers, which can be customized and tailored to suit each utility’s needs. Theses program designs are modeled after successful utility programs in other states, including regulated states such as Missouri and Indiana, and aim to maximize system value while being mindful of customers’ capabilities.

We provide different design recommendations for MISO vs. SPP utilities. Because of the existence of a capacity market in MISO, utilities have the opportunity to earn capacity value for their programs by qualifying them for MISO-accredited capacity. In SPP, there is no such capacity market; as such, utilities drive capacity savings by dispatching their DR programs to reduce their actual and/or forecasted peaks. This creates some differences in program design.

MISO utilities

AEMA recommends that Louisiana utilities in MISO develop a program or tariff to provide emergency capacity as well as demand savings during peak periods. It should include the following two components.

- A capacity product for use in system emergencies. This product:
    - Should provide utilities with a long-term planning resource to offset the need to build new generation (e.g., 5+ year contract durations)
    - Should align with MISO’s LMR product, which requires summer availability for up to 5 dispatches of 4 hours in length
    - Should be valued similarly to generation based on the long-term avoided cost of capacity
    - Should penalize non-performance to ensure reliability. Penalties should be set somewhere between 100-150% of program payments to prevent against free riding
    - Should be tested annually to ensue on-going capabilities to respond. Tests should not be for more than 1 hour

- A peak-shaving product to drive demand savings. This product:
    - Should be designed to lower a utility’s actual/forecasted peak demand
    - Should be dispatched during clearly-defined peak demand conditions, for example, when system demand reached 98% of the forecasted annual peak. The actual % should result in dispatches in the top approximately 10-20 peak demand hours of the year, which should yield high savings to all ratepayers without unnecessarily fatiguing customers
    - Should be valued based on avoided costs, which includes avoided transmission and distribution costs from reduced peak load and avoided energy costs
    - Should be “pay for performance” so that if a customer doesn’t perform during a dispatch, it doesn’t get paid, but should not involve penalties
    - Should provide customers with a $/MWh payment to compensate for their energy reductions

Reliability and peak-shaving products complement each other by ensuring that programs are available during emergencies and also create real demand savings during the hours that drive the greatest amount of total system costs. Designing a program/tariff that captures both value streams, with appropriate dispatch triggers and limitations to ensure it is only dispatched when truly needed, helps maximize benefits for all customers while being mindful of participating customers' limited capabilities to respond to multiple dispatches.

SPP utilities

AEMA recommends that SPP utilities develop a program or tariff to drive peak demand savings that lowers their capacity obligations to SPP. It should include the following design, similar to the peak-shaving program for MISO utilities but with a couple modifications based on SPP's resource adequacy construct and the fact that it will be relied upon to drive capacity savings.

- A peak-shaving program to drive demand savings. This program:
  - Should be designed to lower a utility's actual/forecasted summer season peak demand
  - Should be dispatched frequently enough to reduce the utility's peak demand without unnecessarily asking customers to curtail. Utilities should determine how many MW they can cost-effectively shave from the peak, and dispatch the program any time they reach a certain MW threshold of peak usage
  - Should be valued based on a full scope of avoided costs, which includes avoided generation, transmission, and distribution costs from reduced peak load, and avoided energy costs
  - Because SPP utilities will rely on it to drive reductions in their capacity obligations, this program should involve penalties to ensure reliable performance
  - Should provide customers with a $/MWh payment to compensate for their energy reductions

The role of 3rd Party DR Providers as Program Administrators

Benefits of 3rd Party DR Providers

As noted by AEMA in previous filings to the Commission[4] and by the Regulatory Assistance Project in a report on DER aggregation commissioned by the Arkansas Public Service Commission[5], 3rd Party DR providers add significant value to DR programs by enhancing reliability, creating economies of scale, and reducing participants' net costs. While the largest industrial customers may be able to participate directly in an interruptible tariff themselves and

[4] *Original Comments on Staff's Report and Recommendation for Advanced Energy Management Alliance (AEMA). Louisiana Public Service Commission Docket No. R-34948, filed December 13, 2018, page 6.*

[5] J. Migden-Ostrander, J. Shenot, C. Kadoch, M. Dupuy, and C. Linvill. "Enabling Third-Party Aggregation of Distributed Energy Resources: Report to the Public Service Commission of Arkansas." Regulatory Assistance Project, February 2018. Available at https://www.raponline.org/wp-content/uploads/2018/04/enabling_third_party_aggregation_distributed_energy_resources2.pdf

should have the option to do so, all other C&I customers benefit from participating through a 3rd Party DR Provider that can aggregate their capabilities together and shield them from penalties. Customers value the experience and expertise that 3rd Party DR Providers bring to programs and, in markets where they are able to participate in programs directly, through a utility, or through a 3rd Party Provider, about 85% of customers (by MW) choose to participate through a 3rd Party.[6]

In addition to the value that 3rd Party Providers bring to customers, 3rd Party Providers also enable utilities to develop efficient and reliable programs with high degrees of customer satisfaction. This is particularly true for utilities that lack a high degree of existing knowledge and system capabilities to build and manage a program. In particular, leveraging a 3rd Party DR Provider(s) as a Program Administrator(s) [7] for new programs leads to:

- **Lower costs.** Program Administrators reduce operational costs by taking on the responsibility for marketing programs to customers and managing their participation. Recruiting customers into programs takes time to educate them and develop effective Energy Reduction Plans that suit their capabilities; oftentimes, customers do not believe they have the flexibility to participate in DR programs when first asked, but discover they have flexibility after speaking with a DR Provider that has worked with similar customers in the past. 3rd Party Providers bring an extensive amount of experience that helps lower overall development costs. Not only can a 3rd Party Provider leverage its existing relationships with national accounts and existing customers that have locations in-state, but it can quickly profile sites to understand their likely curtailment capabilities on a process- or even asset-specific basis. This enables a 3rd Party Provider to recruit customers into programs with lower costs and greater speed than many utilities could on their own.

- **Enhanced customer experience.** 3rd Party DR Providers have dedicated years of time and money in processes and technology platforms that enhance customers' experience in programs. 3rd Party Providers will periodically survey customers to understand their satisfaction or pain points in programs and work with them, and the utility, to continuously improve them. 3rd Party Providers will also assign Account Managers to customers to ensure they have a readily available point of contact. During and after events, they will work with customers to ensure they understand their obligations, sometimes picking up the phone to walk them through their curtailment plans, and will send post-event reports so that customers can easily understand their performance.

- **Improved readiness and reliability.** Taken together, the service and expertise that 3rd Party Providers bring to programs results in improved customer readiness and improved reliability. Recent LMR dispatches from MISO have revealed that readiness among

[6] *2019 Demand Response Operations Markets Activity Report: May 2019*. PJM, May 10, 2019. See figure 14, "Preliminary DY 19/20 Confirmed Load Management DR Registrations Owner/Company Type," page 15. Available at https://www.pjm.com/-/media/markets-ops/dsr/2019-demand-response-activity-report.ashx?la=en.

[7] We use the term "Program Administrator" to refer to a 3rd Party DR Provider's role in managing customer participation in a tariff or managing the end-to-end DR program lifecycle for a utility. This is similar to how utilities will often contract with 3rd party Program Administrators for their EE and residential DR programs.

customers participating in some interruptible programs could improve[8]. As emergency conditions continue to materialize on MISO's system and LMRs are increasingly relied upon, ensuring that customers are ready and reliable should be a priority. 3rd Party DR Providers are experts at developing, implementing, and managing DR resources and will help ensure successful tariffs in Louisiana.

Partnership options between 3rd Party DR Providers and utilities

AEMA recommends that the Louisiana Commission direct its utilities to partner with 3rd-party DR Providers to manage customer participation in their programs or tariffs. This is similar to the approach taken by the Missouri Public Service Commission after a review of models to advance DR in its state, and which led to filing of new or updated DR programs by its utilities[9]. Utilities should have the flexibility to choose whether to do this through one of the two following options:

- Qualify one or multiple DR Provider(s) to serve customers in an open tariff. This model:
    - Mimics open market competition by enabling multiple DR Provider(s) to compete for customers' DR capabilities
    - Maximizes DR in a market by allowing DR Provider(s) to qualify as much DR capacity under the tariff and customers are willing to provide; utilities can cap this at a certain, reasonably high amount if necessary
    - Provides the utility and Commission with an ability to establish qualification and registration criteria for DR Providers
    - Is similar to I&M Power in Indiana's award-winning tariff

- Issue an RFP for a single DR Provider to act as a Program Administrator. This model:
    - Delivers a competitively-priced DR resource to the utility
    - Enables the utility to contract for a set number of MW that can be input annually to its resource planning exercises
    - Provides a high degree of control over the relationship with the DR Provider and flexibility in how the utility chooses to leverage its services to implement the program
    - Is similar to the approach of many vertically-integrated utilities for managing C&I DR programs, including Ameren Missouri, Tampa Electric Company, Tennessee Valley Authority, Montana-Dakota Utilities, and Consumers Energy.

These two options allow utilities to choose the best model for their needs, while ensuring that customers have access to the benefits of 3rd Party DR Providers. While it may be appropriate for the largest industrial customers (e.g., those with >10 MW peak demand) to participate directly with their utility under a special interruptible tariff, both customers and utilities will benefit from leveraging DR Providers to manage a wide range of C&I customers in a new DR program.

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[8] *Midcontinent Independent System Operator, Inc. Filing to Implement Demand Resource Testing*. Docket No. ER19-650-000 filed 21 December, 2018. Prepared Direct Testimony of Timothy Aliff, Page 12.
[9] *"Response To Staff Report Regarding Distributed Energy Resources."* Missouri Public Service Commission, Docket EW-2017-0245. Filed April 18, 2018.

Additional comments on timing and performance incentives

Recommended timeline for final rulemaking

AEMA continues to believe the Commission's original target to have this rulemaking completed by September 2019, although ambitious, can be achieved with thoughtful but expeditious action. To that end, AEMA recommends the following process to ensure new tariffs/programs are developed in time for the Summer 2020 peak season. Following the June 26th Technical Conference, Staff could:

- Issue a request for a second round of comments, to further discuss and narrow in on certain key issues from the technical conference, due mid-July
- If necessary, convene a second technical conference to be held the first week in August
- Issue a draft report with recommendations to the Commission by late August
- Request comments on the draft report by mid-September
- Issue a final report with recommendations to the Commission by October (a very minor delay from the original timeline)

AEMA recommends that the conclusion of this rulemaking be a directive for utilities to develop a new program or open tariff for DR and qualify/contract for a 3rd-party Program Administrator(s) within 3-6 months of the Final Order, for a Summer 2020 program start date.

Performance incentives for utility demand savings

Just like demand-side resources should be valued and treated similarly to supply-side resources, utilities should also be allowed to earn a modest return on demand-side resources. As part of this proceeding, the Commission should consider whether utilities should be eligible for earnings opportunities if they achieve certain demand savings targets. This is similar to how Missouri utilities are incentivized under the Missouri Energy Efficiency Investment Act (MEEIA)[10], which has led to the development of robust DR programs and which AEMA believes would provide a good model for the LPSC.

Review and analysis of North American DR Programs

Emergency/Reliability programs

Based on our review of utility emergency DR programs across the Midwest and our experience managing such programs for utilities across North America, we offer the following recommendations and observations about program design for MISO utilities. For additional detail, please see *Table 1.*

[10] Missouri's Code of State Regulations, *4 CSR 240-20.093 Demand-Side Programs Investment Mechanisms, Section (2)(D)*, explaining that it is the state's policy to 1) Provide the electric utility with timely recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs; 2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and 3) Provide timely earnings opportunities associated with cost-effective measurable and/or verifiable energy and demand savings.

- Reliability tariffs should provide utilities with capacity they can dispatch during system emergencies. In MISO, reliability programs should provide utilities with MISO-accredited capacity by aligning with the LMR product requirements, similar to NIPSCO's tariff and Ameren's program.
- In order to provide utilities with a valuable planning resource, utilities should ask customers (or Program Administrators) to sign multi-year contracts to participate in the tariff. NIPSCO, Ameren, and Vectren all provide multi-year contract options of 3 to 12 years.
- DR resources should be compensated accordingly based on the utility's long-term avoided cost of capacity. While Ameren and NIPSCO achieve this with their programs, Vectren's tariff fails to do so, meaning that cost-effective DR resources are left on the table and that DR is disadvantaged relative to supply-side resources.
- Penalties are a crucial component to reliability tariffs, in which customers act as one of the last lines of defenses against blackouts and must perform when dispatched. Setting penalties between 100-150% of payments under the tariff creates a strong incentive to respond reliably and prevents against free-riders. Customers that are unable or unwilling to bear that risk must have the opportunity to participate through a Program Administrator that can take on their performance risk by building an aggregated portfolio of customers. While NIPSCO's penalties are appropriate, Vectren's penalties are far too harsh and likely act as significant deterrents to participation, particularly as its tariff does not allow customers to participate through a DR Provider.
- Both NIPSCO's and Ameren's tariffs provide utilities with additional value by providing peak-shaving or economic call options in addition to emergency capacity. Tariffs should compensate accordingly for this additional value. Economic dispatches should always be optional and allow customers to buy-through at real-time energy prices if they are unable to curtail.

Table 1: Selected Midwest Emergency DR Programs

Utility	DR program/tariff	Program purpose	Availability	Contract length	Compensation	Penalties	3rd-Party participation
Ameren (MO[11])	Business Demand Response	Long-term emergency capacity + Peak-shaving	Requires 40 hours of availability with 1-hour notice	3 years	Based on competitive solicitation for DR capacity	Subject to MISO penalties	3rd party DR Provider acts as Program Administrator for all aspects of the program
NIPSCO (IN)[12]	Rider 775	Long-term emergency capacity + Economic curtailment	Requires 20 hours of availability with varying lead-time options, and optional availability for up to 380 additional hours	1, 3, 7, 10, or 12 years	For multi-year products, $6.00 to $9.50/kW-month – similar to the long-run cost of new capacity	Subject to MISO penalties	N/A
Vectren (IN)[13]	Rider IC – Interruptible Contract Rider	Long-term emergency capacity + Economic curtailment	Requires 250 hours of availability with 10-minute notice	Minimum 5 years	$3.50/kW-month - well below the long-run cost of new capacity	Up to 1,000% revenue	N/A

Peak-shaving programs

Based on our review of utility peak-shaving DR programs across the Midwest and our experience managing such programs for utilities across North America, we offer the following recommendations and observations about program design for MISO and SPP utilities. For additional detail, please see *Table 2*.

- For SPP utilities that lack access to a regional capacity market, peak-shaving programs provide capacity value by reducing the amount of capacity utilities need to have on-hand

[11] *In the Matter of Union Electric Company d/b/a Ameren Missouri's 3rd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA*, Missouri Public Service Commission Docket No. EO-2018-0211, *Order approving stipulation and agreement and granting waivers*, Appendix J, pages 53-58 (filed December 5, 2018).

[12] *Rider 775, Interruptible Industrial Service Rider*. Northern Indiana Public Service Company, effective date 9/29/2016. Available at https://www.nipsco.com/our-company/about-us/regulatory-information/electric-rates.

[13] *Rider IC, Interruptible Contract Rider*. Vectren Energy Delivery of Indiana, Inc. (Vectren South), effective date May 3, 2011. Available at https://www.vectren.com/assets/downloads/rates/in-south-electric-tariff.pdf

to meet SPP’s resource adequacy requirements. KCP&L operates a program like this in Missouri.

- For MISO utilities, peak-shaving programs complement capacity programs by reducing demand during the hours that typically drives the greatest transmission, distribution, and energy costs on a system. Ameren runs a program that provides a peak-shaving resource in addition to an emergency product.
- Peak-shaving programs should dispatch resources when a utility’s peak reaches a certain % of its forecasted peak demand, and should consider whether it’s appropriate to limit dispatches to a targeted amount of hours (e.g. 10-20 hours). This should be based on an analysis of the utility’s load duration curve. Setting the dispatch at a specific percentage of utility peak allows utilities to plan their system in a capital efficient manner by enabling them to avoid building expensive infrastructure that is only needed for a few hours per year.
- Ameren’s, Con Edison’s, and Pennsylvania’s peak-shaving programs are all designed to meet utility’s peak-shaving needs and are aligned with customers’ capabilities. Their compensation is tied closely to each utility’s true avoided costs, helping to maximize participation while ensuring cost-effectiveness. KCP&L’s program, generally, would be improved if it had a more defined dispatch trigger and/or availability that was more aligned to its system needs, and valued its resources at their true avoided costs.
- Peak-shaving programs are less dependent on the wholesale market design than reliability programs, and Ameren, Con Edison, and Pennsylvania’s program designs could all be easily adapted for Louisiana’s SPP utilities despite being located in different RTOs. All these programs either allow or require a 3rd party DR Provider(s) to act as Program Administrators.

Table 2: Selected Peak-Shaving programs across the US

Utility/ State	**Program/ tariff**	**Relationship to emergency DR product**	**Dispatch trigger**	**Annual availability**	**Compensation**	**Cost-Effectiveness**	**3rd party participation**
Ameren (MO)	Business Demand Response	Bundled as part of emergency capacity product	Load forecasts exceeds a % of forecasted system peak	40 hours/year	Competitive bid through RFP for bilateral contract	1.81 (TRC)	Yes
Con Edison (NY)	Commercial System Relief Program	Layered on top of emergency capacity product	Load forecast exceeds 92% of forecasted system peak	4-hr windows each weekday, May through September	$18/kW-month, except for Staten Island and Westchester, which is $6/kW-month	1.57 (TRC)	Yes
Pennsylvania	Act 129 Utility Programs	Layered on top of emergency capacity product	Load forecast exceeds 96% of forecasted system peak	24 hours/year, which was found to maximize cost-effectiveness	Competitive bid through RFP for one or multiple contracts	1.34-1.63 (TRC)	Yes
KPCL (MO)	Curtailable Electric Demand Rider	Requires emergency availability, despite lack of SPP capacity market	Utility discretion	160 hours/year	$2.62 to $3.34/kW-month	13.56 (TRC)	Yes

Responses to specific Staff questions

While we have summarized key learnings and recommendations above, we also provide the following responses to Staff's list of information requests. We have limited our responses to questions that are not answered by our above comments, or to areas where we feel additional context and color is necessary.

1. *Please provide your definition of demand response ("DR"), and what types of programs you consider to be included within the umbrella of DR programs.*

   According to FERC, Demand Response is defined as "changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."

   We believe this is an appropriate definition. Our comments herein refer to dispatchable programs that provide monetary incentives for customers to reduce their consumption from the grid at critical times.

5. *Please describe the avenues for DR participation in MISO and the SPP. What limitations, if any, currently exist that prevent or limit LPSC-jurisdictional customers from participating in the DR programs in MISO and/or SPP?*

   The primary difference between MISO and SPP is the existence of a capacity market in MISO. MISO's capacity market enables the development of DR programs because utilities can register their DR resources as capacity resources, helping to offset their capacity obligations. Entergy Louisiana's existing interruptible tariffs are designed in this manner and align with MISO's Load Modifying Resource ("LMR") program, which provides emergency capacity to MISO.

   In SPP, DR programs deliver the most value by reducing the peak demand that sets utilities' capacity obligation with SPP. KCP&L's program in Missouri is generally designed to be dispatched during peak periods, although it has design flaws, discussed above, that limit customer participation.

   MISO's and SPP's DR products that enable participation in the energy and ancillary service markets are generally much more challenging for customers than MISO's emergency product. In states that have tariffs that align with MISO's rules for economic and ancillary service DR, actual participation is either non-existent or extremely limited. While these types of programs can add value to some customers, they should not be the PSC's top priority.

7. *Is there a set of principles that should guide the development of retail DR programs in LPSC-jurisdictional areas? Please describe those principles and their importance to the development of DR programs.*

We have listed a set of principles above (pages 3-4) that we believe would serve as an effective straw-man for a C&I-focused program or open tariff for each Louisiana utility. Those principles have been developed based on an understanding of Louisiana's needs, a review of DR programs across North America, and AEMA members' own experiences.

AEMA, in collaboration with a group of large industrials in Minnesota represented by Stoel Rives, also compiled a set of 16 best practices that should be considered when developing new utility DR programs, which we jointly presented at a series of DR workshops hosted by Xcel Energy. While some of the commentary around those best practices is specific to Minnesota, we believe that the general principles apply to any program, and are consistent with our recommendations herein. Please see Attachment A for more information.

8. *Should any DR programs recommended by this proceeding be limited to certain size Customers or certain customer classes? Please describe any suggested limitations and the reasons for excluding some size customers or customer classes.*

   No. AEMA's experience is that successful programs work for all commercial and industrial customer sizes over a certain size threshold (i.e. > 50 kW of load reduction capability), and should be available to all such customers. In markets such as PJM, about 90% of customers that comprise 35% of the total program capacity are less than 1 MW in size, so any program must work for smaller customers.

   Of course, it is generally appropriate to different programs between mass market (residential/small commercial) and mid-size/large C&I customers, as the two tend to have different needs and capabilities.

9. *Should the LPSC consider DR programs only for emergency events and price spikes, or should it also consider other types of DR programs designed to lower costs during non-emergency times?*

   As noted above, AEMA recommends that the LPSC direct each utility to develop a program/tariff that at a minimum avoids the need to build new generation. For MISO utilities, this means developing an emergency program that can be accredited for wholesale capacity value; for SPP utilities, this means developing a peak-shaving program that can reduce utilities' resource adequacy obligation to SPP. Adding a peak-shaving component to an emergency programs can drive customer savings during the hours that drive the greatest amount of system costs. As noted above, there are successful models for how to do this and AEMA would be glad to discuss this further at an upcoming technical conference.

10. *How should interruptible tariffs be designed in order to incentivize economically efficient behavior and penalize non-compliance?*

Programs will be economically efficient as long as they are cost-effective and prevent cross-subsidization between customer classes (e.g., mass market to medium/large C&I). Programs that penalize underperformance during reliability events between 100%-150% of potential payments effectively prevent free-riding and helps ensure reliability, which should be a primary focus.

11. *How can the benefits that interruptible customers bring be measured, and how should those benefits be allocated?*

DR programs are typically evaluated for cost-effectiveness based on their avoided generation, transmission, and distribution costs.

The table below highlights the avoided cost figures used to evaluate DR programs across a few Midwestern states. While the numbers will vary by utility, the table demonstrates that all three avoided costs are commonly considered as benefit for utility programs. The most important element is that the avoided generation costs for multi-year DR programs should be based on a utility's long-run avoided costs of capacity.

For an extended discussion on the topic, Ameren Missouri's Surrebuttal Testimony of Matt Michels in File No. EO-2018-0211 explains Ameren's methodology with regards to its avoided capacity, transmission, and distribution costs, and includes references to other third-party reports and industry standards.

Table 3: Avoided costs used to evaluate DSM program cost-effectiveness across MISO states

	NSP (Xcel) Minnesota[14]	Wisconsin (state-wide)[15]	MidAmerican Energy (Iowa)[16]	NIPSCO (Indiana)[17]	Ameren (Missouri)[18]
Avoided G costs ($/MW-yr)	$63.00	$130.26	$119.47	$122.92	49.80
Avoided T costs ($/MW-yr)	$3.10	-	$16.77	$2.42	6.40

[14] Ryan Hledik et al., *The Potential for Load Flexibility at Northern States Power Service Territory,* prepared for Xcel Energy by The Brattle Group, at 56 ("Table 10 - Summary of avoided costs/value streams in 2023").
[15] These figures represent the entire state-wide portfolio of Wisconsin's DSM programs, which do not include avoided transmission and distribution costs but include $15/ton of avoided emissions benefits. *Focus on Energy Calendar Year 2017 Evaluation Report, Volume 1*, prepared by Cadmus et al., May 22, 2018.
[16] These figures represent MidAmerican's non-residential load management program. MidAmerican Energy Company's Application for Energy Efficiency and Demand Response Plan 2019-2023, Iowa Utilities Board Docket No. EEP-2018-002, exhibit 12 (3 of 4) at 23 (filed July 9, 2018).
[17] These figures are based on programs for large and extra-large customers. Northern Indiana Public Service Company 2016 Integrated Resource Plan, at 83, 91 (Nov. 1, 2016), https://www.nipsco.com/docs/defaultsource/about-nipsco-docs/2016-irp.pdf.
[18] These figures are from Ameren's recently approved MEEIA Cycle 3 filing for new DSM programs, averaged across a 10-year lifespan. *In the Matter of Union Electric Company d/b/a Ameren Missouri's 3rd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA*, Missouri Public Service Commission Docket No. EO-2018-0211, *Order approving stipulation and agreement and granting waivers*, Appendix C (filed December 5, 2018).

Avoided D costs ($/MW-yr)	$8.00	-	$35.83	$46.32	18.60
Total	*$74.10*	*$130.26*	*$180.15*	*$171.66*	*$74.80*
DSM cost-effectiveness (TRC)	2.42[19]	4.07	4.37	1.24 - 2.22	1.81

14. *What protections are needed to make certain that wholesale and retail DR programs do not overlap or double count DR benefits?*

    MISO's rules already address this and prevent against double-counting. MISO's tariff ensures that any load reductions from a retail DR dispatch during the coincident hour that set's a utility's capacity obligation to MISO gets added back to Peak Load Contribution equation for that customer and utility.

15. *Should DR tariffs and programs be generic or should each individual utility develop their own DR alternatives?*

    Utilities should have the flexibility to decide whether an open tariff model or bilateral program is best suited to their needs, provided that the open tariff model doesn't require utilities to incur unnecessary costs by duplicating capabilities that could be competitively procured from a 3rd party DR Provider.

    While providing this flexibility in partnering with 3rd parties, the Commission should ensure that programs adhere to the common principles outlined above, as this will help create the most beneficial and effective programs possible.

16. *How can the administrative costs associated with DR programs be estimated/measured, and how should those costs be recovered?*

    While cost recovery and allocation is not AEMA's area of expertise, Ameren Missouri's recent MEEIA settlement may offer detail that is relevant for Staff and Louisiana utilities. In particular, AEMA recommends looking at Ameren Missouri's administrative costs for their DR programs, which were filed as part of the Order approving their settlement[20].

17. *What, if any obstacles, including technological obstacles, could prevent or delay implementation of effective DR programs?*

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19 *INITIAL FILING--2018 CIP STATUS REPORT - CORRECTED FILING*, Xcel Energy, Page 158. Docket No. 16-115.07, filed 1 April, 2019.

20 *In the Matter of Union Electric Company d/b/a Ameren Missouri's 3rd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA*, Missouri Public Service Commission Docket No. EO-2018-0211, *Order approving stipulation and agreement and granting waivers*, Appendix A (filed December 5, 2018).

There need not be any barriers to the implementation of effective DR programs in Louisiana. However, consistent action and continued leadership from Staff and the Commission will be essential to keep this docket moving forward.

A word of caution comes from Minnesota, where Xcel Energy was required by the Commission to develop programs to bring at least 400 MW of new DR onto its system by 2023, as part of its settlement for its 2015 IRP. While Xcel convened a series of workshops that ran from 2017-2019 to gather input from stakeholders, it has yet to produce any concrete plans for new programs, and is now at risk of failing to implement programs in time to meet their 2023 deadline. While there has been occasional inquiries from the Minnesota Commission on Xcel's plans, there has been little direction or pressure to advance the development of these programs. This culminated in Xcel proposing to delay implementation as part of its recent IRP.

A more positive example comes from Missouri. Here, the Commission and its Staff convened a series of two technical conferences and a couple rounds of comment to discuss emerging issues in DER regulations, including DR programs and DR aggregation. This started in the fall of 2017, and led to a Staff report containing recommendations on DR program development to the Commission by April 2018. Shortly thereafter, the Commission accepted Staff's recommendations and Ameren filed for approval for new programs, which it received from the Commission by December 2018.

As noted previously, leveraging a 3rd Party DR Provider(s) as a Program Administrator(s) can help utilities more quickly develop and scale programs, by reducing the technological, systems, and administrative burden on utilities and helping to enroll customers in new programs. This can help resolve any utility concerns about the time required to develop new programs.

18. *How should DR participation incentives be designed? For example, upfront, one-time payments, monthly payments, reduced prices, after the fact rebates, etc.*

In the case of a customer that is directly participating in an open tariff without a 3rd Party DR Provider, the customer should have the option to be paid either through a credit on their bill or a direct payment. If a customer is participating through a Program Administrator ("PA" - i.e., a 3rd Party DR Provider that was selected via RFP to run the program), the PA should be able to receive the payment directly; it would then be responsible for paying the customer. This is essential to facilitate the participation of 3rd Party DR Providers, as otherwise, the customer would have to pay the 3rd Party which adds an unnecessary and problematic administrative barrier. Payments should be made monthly to program participants.

19. *Are there any DR programs that should be mandatory, e.g., time-of —use rates?*

The Commission should mandate that its utilities offer dispatchable DR programs to its medium and large C&I customers that reduce the utilities' need to build generation. Dispatchable DR programs should be voluntary for customers to participate in; however, if they choose to participate, then customers are taking on an obligation to curtail load when dispatched. If they underperform, they (or their Program Administrator) should be subject to financial penalties.

20. *What types of educational outreach will be needed to effectively implement DR programs?*

Educational outreach is critical to effectively implement DR programs, particularly for the C&I customers that don't typically have access to interruptible programs (like the largest industrial customers). As noted earlier, this is a key area in which 3rd Party DR Providers bring expertise and add value to the implementation of programs. Many times when AEMA members approach customers to participate in programs, customers think they do not have the flexibility to reduce load, so a lot of education is necessary to help them understand their capabilities and the value of the program.

21. *What is a reasonable timeline to complete this DR rulemaking proceeding?*

As noted above, AEMA believes that Staff could issue a final report with recommendations to the Commission by October, with a 3-6 month deadline for utilities to implement programs following the Commission's Order.

22. *What types of communications systems will be needed to implement DR programs, including, any direct control programs? Are those systems available today, or will they need to be constructed, and at what cost?*

There are many different options for communications protocols in a DR program, but for traditional DR programs, there is minimal need for sophisticated communications. Many utilities dispatch their tariffs/programs using email and automated phone calls. Utilities should not need to construct costly systems, and if they do, they should be directed to leverage 3rd Party DR Providers to take advantage of the private investments that have already been made into communications systems and platforms.

23. *Please provide your estimate of the potential levels of DR resources available in Louisiana and the potential benefits of those resources*

Over 11.4 GW of dispatchable DR resources cleared in the most recent MISO PRA[21], equal to more than 9% of MISO's peak load. Assuming this figure is representative of the potential within Louisiana, we would estimate that there is greater than 1 GW of emergency/capacity-based DR within Louisiana[22]. While the benefits from these programs will differ by utility based on each utility's long-term avoided generation, transmission, and distribution costs, the benefits are likely to total in the billions of dollars.

[21] 2019/2020 Planning Resource Auction (PRA) Results, posted April 12, 2019 by MISO. Available at https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf

[22] A benchmark of utilities' emergency-based DR programs throughout MISO supports this estimate; both Duke Indiana and NIPSCO have DR penetrations ranging from 10-16%. For more benchmarking analysis, see *Advanced Energy Management Alliance comments on Entergy Louisiana's data assumptions in docket l-34694,* filed 6/19/2018, starting on page 12.

Generally, the potential for emergency DR programs is higher than for peak-shaving programs because emergency programs provide value simply by being available whereas peak-shaving programs need to be actually dispatched to drive demand savings.

As with emergency programs, the potential for peak shaving programs depends, among other things, on how many hours of dispatch will be required under the program and the compensation that will be available. However, assuming about 10-20 hours of dispatches, which is common for utility peak-shaving programs, and compensation based on the full scope of long-term avoided costs, peak-shaving program potential can typically reach about 5% of a utility's peak demand[23].

AEMA recommends that the Commission direct its MISO and SPP utilities to develop programs to achieve 9% emergency DR penetration and 5% peak demand reduction savings, respectively.

24. *Should the Commission conduct annual reviews to determine the effectiveness and benefits of any DR programs adopted, and how should such reviews be structured?*

If utilities are required to get approval for program cost-effectiveness upfront, then annual filings are likely not necessary except to understand the amount of enrollment (both MW and numbers of customers) in the program.

At a minimum, programs/tariffs should be approved for at least 5 years. This will not only provide utilities with a longer-term resource they can use in their planning exercises, but will ensure stability in the market for customers that may need to invest in equipment or change their operations to participate in programs. A longer-term time horizon is also essential for Program Administrators, who want to invest in a program that allows them to recover their investment costs.

25. *How should DR resources be accounted for in capacity planning, both in the RTO planning processes, and in the Integrated Resource Plans and Certification proceedings of the Commission?*

If a utility bilaterally contracts for DR capacity, it can simply build the contracted amount into its IRP modeling. If utility qualifies a Program Administrator(s) to manage customer participation, but doesn't set or require annual targets, then it should work with the PA to estimate how much customer participation it should expect in each year, and use those estimates in its IRP modeling.

In the case of MISO, customers should be registered annually in the LMR product to ensure utilities receive capacity accreditation for their resources.

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[23] The Pennsylvania Act 129 peak-shaving programs estimated program potential between 5% and 10%, depending on whether the dispatch notification was issued day-ahead or day-of. *DR Potential Study Report for Pennsylvania.* Prepared by the Statewide Evaluation Team for the Pennsylvania Public Utility Commission, February 25, 2015. See "Table 6 5: Phase III Achievable Potential Estimates by EDC and DR Product Type (MW/year)", page 61.

APPENDIX A

As noted in AEMA's response to Question 7 of Staff's Request for Information, the following recommendations were jointly presented by AEMA and the Minnesota Large Industrials to an Xcel Energy-hosted workshop in Minnesota, intended to gather stakeholder input on DR program design in furtherance of the Minnesota Commission's mandate for Xcel to develop 400 incremental MW of DR by 2023[1].

RECOMMENDATIONS ON BEST PRACTICES IN DR PROGRAM DESIGN

Demand Response programs are successful when they work for customers, utilities, and all ratepayers. The following document explains 16 best practices that are essential elements of DR programs and help drive program success. These practices ensure that programs:

A. Are dispatchable and reliable;
B. Are aligned with utility needs;
C. Match the capabilities and interests of customers;
D. Allow qualified 3rd party aggregators to participate; and
E. Are in the public interest and encourage participation.

These best practices are drawn from AEMA's experience managing DR programs throughout North America and globally, and Minnesota industrial customers' experience participating in DR programs in Minnesota and in other areas of the country. Together, we believe that Xcel's DR programs should adhere to these best practices in order to maximize cost-effective customer participation. To supplement these best practices, we provide sample tariff language as examples of how Xcel could incorporate these principles into its own programs.

A. DR programs should be dispatchable and reliable

DR programs deliver the most value to a utility when they are dispatchable. Dispatchable programs provide utilities with a firm resource that they can use to balance their system and incorporate into their planning exercises. DR resources are most often dispatched during extreme conditions when the stability of the grid is threatened; utilities must therefore have a high degree of confidence that they will deliver their expected capacity.

DR has a strong history of reliability on this front. In fact, based on recent data from NERC's 2017 State of Reliability report, DR outperformed generation by 1.1% to 6.4% when comparing DR's performance to generators' average Equivalent Forced Outage Rates (EFOR's) from 2014-2016[2]. DR performance in PJM,

[1] For additional detail, go to https://trello.com/b/vqrVwhQ3/xcel-energy-demand-response-workgroup. These recommendations were presented at Meeting 7 and is the 10th attachment, added May 22 at 12:27.
[2] Data from Appendix C and D of NERC's 2017 State of Reliability report, available at https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

one of the largest DR markets in the world, has averaged 122% from the 2009/2010 to 2017/2018 delivery years.[3]

Proper program design is essential for a reliable DR program. In order to ensure that their programs are reliable and will respond when needed, utilities should:

1. *Require demand resources to curtail load when dispatched to maintain system reliability*. Program participants (either customers or an aggregator) should be compensated and/or penalized for their curtailment performance accordingly; and
2. *Require annual resource testing to ensure customers' on-going capabilities to respond.* The testing requirement should balance the needs of the utility to ensure system reliability with the needs of the customers to continue sustainable business operations. A DR test should not be executed in a year when an actual curtailment event had already been dispatched.

B. DR programs should be aligned with utility needs

DR programs should also meet clearly defined utility needs. DR programs provide resource diversity to utilities and can eliminate the need for utilities to invest in new power plants, and can allow a utility to defer or avoid network investments in transmission and/or distribution capacity by actively managing local or regional load pockets. By managing or reducing demand in the hours of highest need or areas of greatest congestion, DR programs provide significant cost savings to consumers. Offering multiple types of DR products can provide multiple benefits to the utility such as emergency dispatch, quick response economic dispatch, and scheduled economic dispatch.

In order to ensure alignment between program design and utility needs, programs should:

3. *Clearly define and describe the needs they are intended to target and include multiple product offerings in order to best tap into DR's potential*; and
4. *Have clearly articulated dispatch criteria*, such as:
    - System emergencies for capacity programs;
    - Operations at a certain percentage of forecasted peak load for peak-shaving programs;
    - Defined local conditions for non-wires alternative programs; and/or
    - Energy price thresholds for economic dispatches.

C. DR programs should match the capabilities and interests of customers.

DR programs should be designed with customers in mind. Customers require clearly defined participation options in order to evaluate the costs and benefits of participating in programs. Tariffs should provide customers with multiple participation options, so that those with more dispatch flexibility can offer greater value to the utility and earn greater revenue. NIPSCO's C&I DR tariff[4] is a good example of this.

In order to ensure alignment between program design and customer needs, programs should:

5. *Clearly explain participation terms,* such as*:*
    - Maximum annual dispatch limits;

[3] Data from PJM's 2017/2018 Load Management Performance Report, available at https://www.pjm.com/-/media/markets-ops/dsr/2017-2018-dsr-activity-report.ashx?la=en. Average performance was calculated using actual event performance for years in which mandatory events occurred, and test performance in all other years
[4] https://www.nipsco.com/docs/default-source/electric-tariffs-10-01-2016/rider-775.pdf

- Maximum dispatches per day and week;
- Maximum length of dispatch; and
- Minimum lead/notice time for curtailments.

6. *Provide stable compensation to participants* by allowing them to lock in capacity prices for the duration of multi-year contracts
7. *Provide customers with buy-through options for economic dispatches;*
8. *Provide multiple product options to suit different customer needs, such as varying capacity and time commitments, varying commitments for response times, and seasonal flexibility given Minnesota's cold climate* (e.g., a summer only option would correspond with system peak demand while avoiding interruption to must-run operations needed to avoid freezing during winter months); and
9. *Offer customers enhanced compensation for more availability, quick response capability/commitment, flexibility, and contract certainty*

D. DR programs should allow for 3rd party providers to recruit and communicate with customers.

Aggregators provide value-added services to customers and utilities that help maximize customer participation in a program.

Many customers can provide some DR capacity, but not every customer's capabilities perfectly fit a DR program's requirements. Aggregators can address this mismatch by playing "Tetris" with customers' capabilities in portfolios to meet the needs of the program. For example, a program might require 100 hours of availability, but there may be five different customers that can only respond for 20 hours. Aggregators can combine those five customers to create a portfolio capable of responding for 100 hours, enabling them to participate when otherwise they would be unable to do so.

Additionally, customers are often reluctant to expose themselves to out-of-pocket penalties if they are unable to curtail their load when required (because they are meeting a production deadline, for example). Aggregators build portfolios of assets so that when one customer under-performs, it gets balanced out by the over-performance of another customer, and the portfolio as a whole is still able to meet (or exceed) the program's requirements. As a result, aggregators are able to shield customers from penalties, and bear all performance risk themselves, while finding other ways to incentivize customers (through contract structures, for example). In fact, this "penalty shielding" will become increasingly valuable to customers as DR's role in markets expands and dispatches become more frequent.

Together, these services help explain why, in the largest DR markets, aggregators provide more than 80% of all MW enrolled in DR programs, across all rate classes. Therefore, in order to maximize customer participation, programs should:

10. *Allow the utility to qualify/certify/license 3rd party aggregators* to participate in their DR programs;
11. *Allow 3rd party aggregators to recruit customers into the utility's program* and communicate with those customers regarding dispatch orders and other program issues; and
12. *Assess program performance at the aggregator portfolio level*, rather than the individual site or customer level.

E. DR programs should be in the public interest, compensate customers for all system benefits, and encourage customer participation.

DR programs should drive value for all customers by delivering more benefits to the public than they cost to operate. Programs should clearly measure the benefits they provide to a system. For example, a program that provides system capacity while also reducing peak demand can help avoid generation, transmission, distribution, and energy costs throughout the market. It can also reduce carbon emissions and provide option value for future investment decisions.

Accounting for the full stack of quantifiable benefits helps ensure that programs are cost-effective. Programs can then compensate customers based on the sum of their benefits. A program that provides customers with fair and robust payments will maximize participation while driving net savings for everyone. DR programs also drive economic benefits that may be harder to quantify, such as providing economic development to a region and improving system resiliency.

In order to ensure programs maximize participation while remaining in the public interest, programs should:

13. *Transparently determine compensation based on each quantifiable value stream;*
14. *Establish cost-effectiveness thresholds based on the sum of avoided costs and benefits* that a program delivers;
15. *Compensate as close to the cost-effectiveness threshold (minus administrative costs) as possible to maximize DR potential and net benefits to customers*; and
16. *Create an incentive for customer participation when considering the whole program design (including any impact the allocation of program costs among customer classes may have).*

III. Conclusion

AEMA believes that the best practices outlined above help maximize cost-effective savings and customer participation in utility DR programs. AEMA recommends that any utility tariff or program should abide by these best practices

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About AEMA:

The Advanced Energy Management Alliance (AEMA) is an association of providers and supporters of distributed energy resources, including demand response, united to overcome barriers to nationwide use of flexible demand-side resources for an environmentally preferable and more reliable grid. AEMA advocates policies that empower and compensate customers to manage their energy usage and make the electric grid more efficient, more reliable, more environmentally friendly, and less expensive. For additional information, visit the AEMA website: www.aem-alliance.org.