IN THE MATTER OF CONSIDERATION OF CERTAIN STANDARDS TO PROMOTE UTILITY DEMAND RESPONSE PURSUANT TO THE INFRASTRUCTURE INVESTMENT AND JOBS ACT	STATE OF NORTH CAROLINA UTILITIES COMMISSION NCUC DOCKET NO. E-100, SUB 189

COMMENTS OF CPOWER ENERGY MANAGEMENT

Pursuant to the North Carolina Utilities Commission's ("Commission") Order Allowing Comments dated November 10, 2022, Enerwise Global Technologies, LLC, d/b/a CPower Energy Management ("CPower") submits the following comments.

I. Summary

CPower takes no position on whether current demand response and demand flexibility standards comply with the new PURPA standard related to demand response practices.[1] The generic language of the federal statute appears to give the Commission ample discretion to make any required finding it deems appropriate, including a determination that its current programs comply.

CPower is submitting these comments because Dominion Energy North Carolina's (Dominion) current tariff-based demand response opportunities do not serve the public interest. This is so because they do not leverage important potential to derive value from demand side flexibility. Specifically, while Dominion has tariffs that have time varying pricing components, such tariffs do not correspond with how Dominion's PJM wholesale capacity obligations are incurred. Dominion's retail electric tariffs do not provide customers with any incentive or mechanism to manage a major component of wholesale power costs. In addition, North Carolina currently prohibits retail customer participation in wholesale demand response. Without any sort of price signal or incentive or program available to customers that

[1] 16 US Code, §2621(d)(20).

is based upon how wholesale capacity obligations are incurred by Dominion, customers' capacity obligation will continue to increase unchecked, and the associated costs of such increasing capacity obligations will be passed on to customers through bundled service rates.

CPower respectfully suggests that the deficiencies in Dominion's tariffs could be remedied by permitting demand response aggregators to work in cooperation with Dominion under the regulatory supervision and jurisdiction of the Commission. As discussed herein, this can be done in a way that will not adversely impact customer rates, will not create cost-shifting or other negative consequences, and will not negatively impact Dominion or its resource planning activities. Pursuing this approach will not only address a shortcoming in Dominion's current tariffs, but could also increase demand side flexibility in North Carolina and provide important benefits to improve reliability and reduce rates.

II. Demand Response and Wholesale Power Costs Drivers

Bundled service rates paid by customers include both retail and wholesale power cost components. The total wholesale power cost is comprised of several components, including energy supply, capacity, transmission service, ancillary services, and certain other charges. Based upon the average price of wholesale power in PJM for 2021, of the total price of power, energy represented 61.1%, transmission represented 19.6%, capacity represented 16.8%, and ancillary services represented 1.3%.[2] These wholesale power cost components can vary significantly from year to year. In 2020 for example, energy represented 48.8%, transmission represented 26.9%, capacity represented 21.2%, and ancillary services represented 1.3% of total wholesale power costs.[3]

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[2] Monitoring Analytics, LLC, State of the Market Report for PJM, 2021, Volume 1, March 10, 2022, at P 18. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol1.pdf
[3] *Id.*

Wholesale energy and capacity are the major components of total wholesale power costs that can be meaningfully impacted by customer participation in demand response.[4] While wholesale energy represents the larger portion of wholesale power costs, demand response approaches addressing capacity obligations and costs is the overwhelmingly dominant form of demand response in the PJM market, representing more than 90% of all demand response activity.[5] While both approaches are beneficial, demand response as a capacity resource remains the most common and most valuable[6] form of demand response participation.

Of the various Dominion tariffs identified in the Commission's Order, all of them are more or less correlated with wholesale energy costs. While this represents a nominal demand response opportunity, Dominion's tariffs miss the boat completely on the overwhelmingly more important demand response opportunity. None of the tariffs bears any relation whatsoever to wholesale capacity cost causation.

Moreover, North Carolina is the only state in PJM that does not participate in wholesale demand response programs at all.[7] North Carolina is an outlier in the PJM market, and unfortunately not in a good way. Indiana, Kentucky, Tennessee, Virginia, and West Virginia – like North Carolina, all traditionally regulated states in PJM - have all created various regulatory vehicles for participation in PJM demand response.[8]

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[4] There are opportunities to participate in ancillary services utilizing demand response in PJM. These comments, however are focused on capacity and energy as representing the vast majority of the demand response value proposition.

[5] PJM 2022 Demand Response Operations Markets Activity Report: January 2023, January 10, 2023, https://www.pjm.com/-/media/markets-ops/dsr/2022-demand-response-activity-report.ashx

[6] For example, demand response participation in the 2022/2023 PJM Base Residual Auction reduced PJM wholesale power costs by over $750 Million. Without demand response, wholesale capacity prices would have been 19.2% higher; Monitoring Analytics, Analysis of the 2022/2023 RPM Base Residual Auction Revised, Revised January 13, 2022; https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf

[7] *See* supra Note 5, at P 3-4. PJM lists demand response registrations by state and utility. North Carolina is the only state not listed as having any PJM demand response registrations.

[8] *Id.*

North Carolina not only does not participate in wholesale demand response at all, but the Dominion retail tariffs promoting retail demand response do not address the dominant use case for demand response to address capacity costs. North Carolina is unfortunately missing out on a vitally important mechanism that could help bring down electricity costs for customers.

III. Disconnect Between Dominion Tariffs and Dominion's Wholesale Capacity Obligation

As one example, under Dominion Schedule 10, customers are charged for demand[9] on the basis of each customer's individual *non-coincident monthly peak load*. By contrast, Dominion, as the PJM load serving entity supplying its own retail customers, incurs its PJM capacity obligation on the basis of the *PJM system annual coincident peak*.[10] This is to say that the quantity of capacity that Dominion must procure and deliver to PJM for each delivery year is based upon the demand level of Dominion customers occurring at the time of PJM's system coincident peak. Meanwhile, customers are charged for demand under Schedule 10 based upon the customer's own peak, which will quite often be very different than the 5 coincident peak load hours used annually to determine the PJM system coincident peak. What this means in the present context is that while customers have an incentive to flatten load if they can under Dominion's tariff, customers lack any incentive or price signal whatsoever to reduce load at times when it would reduce the cost of the wholesale capacity cost component of the bundled rates charged by Dominion.

Many customers have substantial demand side flexibility, but simply may not be able to shift load every day because they have limited control over when daily peaks occur. A restaurant, for example,

[9] Demand, as referred to in Dominion's tariffs, measured in kW, is generally equivalent to capacity in the PJM market, and is also measured in kW.
[10] PJM allocates responsibility for wholesale capacity obligations on the basis of each load serving entity's Obligation Peak Load (OPL). The OPL is the total of the Peak Load Contribution (PLC) for all of the LSE based upon an average of the 5 distinct hourly load values representing the zonal weather-normalized PJM system coincident summer peak load in the year preceding the relevant PJM electric delivery year. *See* PJM Manual 18: PJM Capacity Market, Revision 54, Section 7.4, *inter alia*.

may be nearly empty in the afternoon when PJM system coincident peaks typically occur,[11] but will incur its non-coincident peaks in the evenings during dinner time. Such customers may have limited ability to address their own non-coincident peaks that occur every day to flatten the load, but could make the demand side flexibility they do have (e.g. cycling air conditioning/heating) available during periods of grid stress or high PJM system coincident peak demand. Unfortunately, customers such as this hypothetical restaurant and many, many other customers cannot effectively manage their own Dominion demand charges and have absolutely no incentive to manage wholesale capacity costs using demand response.

To be clear, CPower is not suggesting that a utility such as Dominion charging for demand on the basis of a customer's non-coincident peak serves no legitimate purpose. Indeed, charging for demand on the basis of a non-coincident peak does follows cost causation principles for collecting distribution system costs, and further works ensure revenue stability and sufficiency to the utility for its supply costs. CPower is not suggesting that non-coincident peak demand charges are *per se* problematic. Rather, CPower is suggesting that the current Dominion tariffs have a gap as it relates to managing wholesale capacity costs. What CPower is saying is that non-coincident demand charges are simply not conducive to demand response and are utterly ineffective at addressing wholesale capacity costs because they are not related to how such costs are incurred.

IV. Wholesale vs. Retail Demand Response in North Carolina

In 2010, North Carolina banned participation in wholesale demand response out of concern to preserve the Commission's regulatory jurisdiction.[12] While the Commission prohibited wholesale

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[11] In the last 5 years, from 2018-2022, all of the PJM system coincident peak load billing determinant hours occurred between 2:00pm and 6:00pm EPT during the summer. https://www.pjm.com/-/media/planning/res-adeq/load-forecast/summer-2021-peaks-and-5cps.ashx

[12] *Order Opting Out of Retail Customer Participation in Wholesale Demand Response Programs*, NCUC Docket No. E-22, Sub 418, March 10, 2010.

demand response participation, it was “mindful of the significant role demand response can play in reducing peak demand, postponing the need for additional electric generating capacity, and, ultimately reducing costs for all consumers.”[13] In lieu of wholesale demand response participation, the Commission directed Dominion to file retail demand response programs.

While Dominion has tariffs in place with some demand response components, as discussed above, the tariffs are not geared toward addressing the most impactful and meaningful benefits of demand response for North Carolina customers. Regardless of the disposition of the present docket, North Carolina should re-evaluate its policy adopted 13 years ago. The Commission’s 2010 Order was adopted when wholesale demand response and indeed the PJM capacity market was in its infancy. The PJM capacity market had only been operational for just over two PJM delivery years when North Carolina considered and adopted its Order. Since that time, both wholesale demand response participation and the PJM capacity market have evolved and improved. Now with the benefit of experience in numerous states across PJM, including both regulated and deregulated states, it is time to take a closer look at how wholesale demand response opportunities can serve the public interest.

V. Wholesale Demand Response Consistent with North Carolina Regulatory Model

What has not changed since 2010 was approved is the Commission’s legitimate priority to preserve jurisdiction over retail electric service. Fortunately, there are participation models that can fully preserve and respect the Commission’s jurisdiction. These models have the advantage of leveraging the technological advances and market knowledge of non-utility demand response aggregators, while at the same time providing the Commission a means to regulate the practices of demand response aggregators that it deems appropriate.

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[13] *Id.* at P 4.

CPower recently published a whitepaper on the authority of state regulatory commissions to regulate demand response aggregators and enable wholesale demand response participation by retail customers. The paper was written for Midwestern state regulators, although the approaches discussed work well in the PJM context. Indeed, most of the best practices discussed in the whitepaper were introduced in the context of the PJM market. A copy of this whitepaper is included with this filing as Appendix A.

There are at least four models to consider, all of which preserve retail regulatory jurisdiction:

- Under the "DR Feed In Tariff" model, the utility creates a tariff to pay demand response aggregators and/or retail customers for demand response that is registered directly with PJM. Under this model, the capacity purchased is applied directly toward the utility's capacity resource plan. The utility, in this case Dominion, has full knowledge of the demand response activity and the customers involved. The tariff not only includes the pricing and other terms and conditions, but further passes any performance responsibility to the aggregator or customer without performance risk to the utility.
- Under the "DR PPA with Utilities" model, the utility is a purchaser of capacity from demand response aggregators on a bilateral basis. It is similar to the DR Feed In Tariff in that the utility acquires the capacity rights to the demand response resources from its customers. However, rather than a tariff that includes the terms and conditions, the contract between the utility and the demand response aggregator establishes the terms and conditions applicable to aggregators and customers. The procurement would typically occur through a tender or competitive solicitation, but could also occur through bilateral negotiations.
- Under the "ARC-Facilitated DR Program Administration" model, the demand response aggregator serves as a vendor to the utility. One advantage of this approach compared to

the utility itself operating the program is that the demand response aggregator has the flexibility to contract with more customers and more diverse demand response resources than the utility can due to the utility's non-discrimination obligation.

- The "Conditional Opt In" model is appropriate where a regulator wishes to impose regulatory requirements upon demand response aggregator or customer participation in the wholesale market, but does not want to obligate the utility to purchase the demand response capacity that is developed. The regulatory standards imposed under the Conditional Opt In model will nevertheless ensure that the utility has all of the relevant information it needs to ensure proper resource planning, and also set standards for aggregator business activities.

VI. Conclusion

CPower acknowledges that the Commission's determination of compliance with the new PURPA standard does not require it to adopt the models discussed in the preceding section. As is stated at the beginning of these comments, there is adequate discretion under the language for the Commission to make a finding of compliance with the PURPA standards. Beyond the disposition of this proceeding from a PURPA compliance perspective, the Commission should nevertheless take the further step to evaluate and consider modernizing its approaches to demand response policy.

CPower fully respects and honors the Commission's policy to safeguard its retail regulatory jurisdiction. That said, the 2010 Order has become obsolete. It is simply not necessary to have a blanket prohibition on wholesale demand response participation in order to protect the Commission's jurisdiction.

Maintaining a blanket prohibition does not serve the public interest. As discussed in this paper, today North Carolina customers and utilities are missing out on important opportunities to reduce rates and derive value from demand side flexibility. Experience over the last decade has demonstrated that there are proven structures that both protect state regulatory jurisdiction and enable customers to participate in wholesale demand response and for both customers and utilties to derive benefits from such participation.

CPower stands ready to assist the Commission and Dominion and work with customers and other interested stakeholders to explore the potential and consider appropriate models going forward. CPower respectfully requests that as part of its disposition of the instant proceeding, the Commission direct an evaluation to explore ways in which demand response policies and be modernized and improved with the assistance of demand response aggregator participation in the wholesale market.

Respectfully submitted,

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<u>Certificate of Service</u>

I certify that on this 19th day of January, 2023, a copy of the foregoing filing has been served this day upon the parties of record in this proceeding by electronic mail.

Kenneth D. Schisler

Appendix A

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Regulating Demand Response and Aggregators in the Midwest While Safeguarding Local Jurisdiction:

A Guide for State Regulatory Commissions, Electric Cooperatives and Municipal Electric Utilities

by Peter Dotson-Westphalen and Kenneth D. Schisler

CPower

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Introduction

This whitepaper addresses the long-standing reluctance of Midwestern state regulatory commissions, electric cooperatives and municipal electric utilities to permit Aggregators of Retail Customers ("ARCs") to provide demand response ("DR") services in Regional Transmission Organization/ Independent System Operator ("RTO/ISO") markets and utility programs. State utility regulators and the boards or councils that typically self-regulate electric cooperatives[1] and municipal electric utilities have long been concerned about whether they possess the authority to regulate ARCs. These entities are collectively referred to by the Federal Energy Regulatory Commission ("FERC") as the Relevant Electric Retail Regulatory Authority, and more commonly are referred to by the acronym "RERRA," which will be utilized here throughout.

RERRAs have a legitimate responsibility to ensure that ARC activities do not interfere or conflict with regulated utility service and are consistent with the regulatory model and policies of the state or jurisdiction the RERRAs regulate. This whitepaper approaches the question of RERRA jurisdiction head on and provides a framework for RERRA regulation of ARCs. This analysis will also correct inaccurate assertions that allowing ARC participation will bypass retail regulation.

The intent here is that Midwestern RERRAs will feel empowered to adopt policies to leverage ARCs in a way that is fully compatible with state and local policies of utility regulation and good utility practice. As experts in demand-side flexibility and customer-facing energy management, ARCs work with utilities and customers to increase the efficiency and reliability of the grid and enhance resource planning and can promote competitiveness and economic well-being across the Midwest through advanced technologies and innovations.

1. For ease of reference in this whitepaper, the terms "utility" and "customer" used throughout this whitepaper are meant to include electric cooperatives and members of electric cooperatives, respectively.

Executive Summary

ARCs represent DR and other Distributed Energy Resources ("DER") participation in most wholesale electricity markets in North America and throughout the world. ARCs operate in states and regions served by all models of utility regulation, including traditional rate-of-return regulation of investor-owned utilities, cooperatives and municipal utilities, and areas where retail supply competition is permitted for some or all customers.

However, ARCs are not as prevalent in the Midwestern United States in the Midcontinent Independent System Operator, Inc. ("MISO") and Southwest Power Pool ("SPP") market regions. This whitepaper discusses the reasons for this distinction, which are as much historical as regulatory, and details how RERRAs in the Midwest can leverage the efficiency and reliability benefits and technology innovation that ARCs bring to electricity markets, while at the same time safeguarding and respecting state commission regulatory jurisdiction and the self-regulation policies of municipal utilities and electric cooperatives.

A typical concern of regulators and cooperative and municipal utility leaders with respect to ARCs involves whether and to what extent ARCs may be regulated by state and local regulators. Another concern is whether ARC activities, if permitted to operate in a utility territory, will conflict with utility resource planning activities or otherwise interfere with rate regulation and unfairly shift costs to other customers. All of these are legitimate questions that are explored in this whitepaper to demonstrate how ARCs may cooperate with utilities in ways that promote efficiency, resiliency and innovation and support a clean-energy future.

RERRAs have several avenues available to regulate ARCs that provide services to retail customers and the relationship between ARCs and electric utilities subject to RERRA jurisdiction. This paper discusses how RERRA regulatory jurisdiction is accommodated and supported under federal law and regulation, as well as the basis for state and local regulation of ARCs. It also provides a helpful framework for how Midwestern RERRAs can facilitate the benefits that ARCs offer by increasing DR participation, while also addressing RERRAs' primary concerns.

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Resource Adequacy and Preparing for the Future Grid

The grid-supply mix is changing — and at an increasingly rapid pace — as intermittent energy resources become more common and energy consumption patterns shift more dramatically.

ARCs can play an important role in developing portfolios of DR resources that meet resource adequacy requirements. When there is not adequate supply to meet system needs, this can lead to high clearing prices in capacity markets as well as threaten grid operators' ability to maintain reliability. This was clearly evident in MISO's 2022/23 Planning Resource Auction, in which the North and Central regions were 1.23 GW short of meeting the Planning Reserve Margin Requirements established for the auction.[2] This shortfall resulted in prices in these regions clearing at the Cost of New Entry, the administratively set price of how much it would cost to build a new generator. For utilities and customers exposed to these high prices, the auction results came as a shock. It can take several years to have new generation facilities sited, interconnected and approved to operate in the market. By contrast, ARCs all over the world have demonstrated the ability to develop significant DR resource portfolios that meet resource adequacy needs very quickly — often in a matter of months.

The need for fast-acting, flexible resources to help grid operators maintain system balance will become increasingly important and valuable as intermittent supply resources more frequently replace traditional generation. ARC-enabled DR, particularly where automation is enabled, is able to respond quickly and reliably, and can provide cost-effective ancillary services to RTOs/ISOs.

Additionally, RERRAs located in RTO/ISO regions must prepare for the implementation of wholesale market participation models that include DER aggregations pursuant to FERC Order 2222,[3] which requires each RTO/ISO to develop a wholesale market participation model that allows DER and DR aggregations to provide and be compensated for wholesale market services. DR is often cited as the largest potential DER on the grid.[4] It is also the easiest DER to develop and integrate into the grid. Enabling ARC DR participation now, in advance of the implementation of the wholesale DER model, can provide Midwestern RERRAs and utilities with a valuable on-ramp to gain experience with ARCs and DERs. Increasing ARC participation in the Midwest will also have the added benefits of assisting in meeting reliability needs and reducing costs.

2. See, MISO 2022/23 Planning Resource Auction (PRA) Results (April 14, 2022), available at: https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf.

3. Order No. 2222, 172 FERC ¶ 61,247 (2020); Codified at 18 C.F.R. §35.28(g) (12) (2022).

4. See, Brattle Group, The National Potential for Load Flexibility: Value and Market Potential through 2030, (2019), p.18, available at: https://www.brattle.com/wp-content/uploads/2021/05/16639_national_potential_for_load_flexibility_-_final.pdf

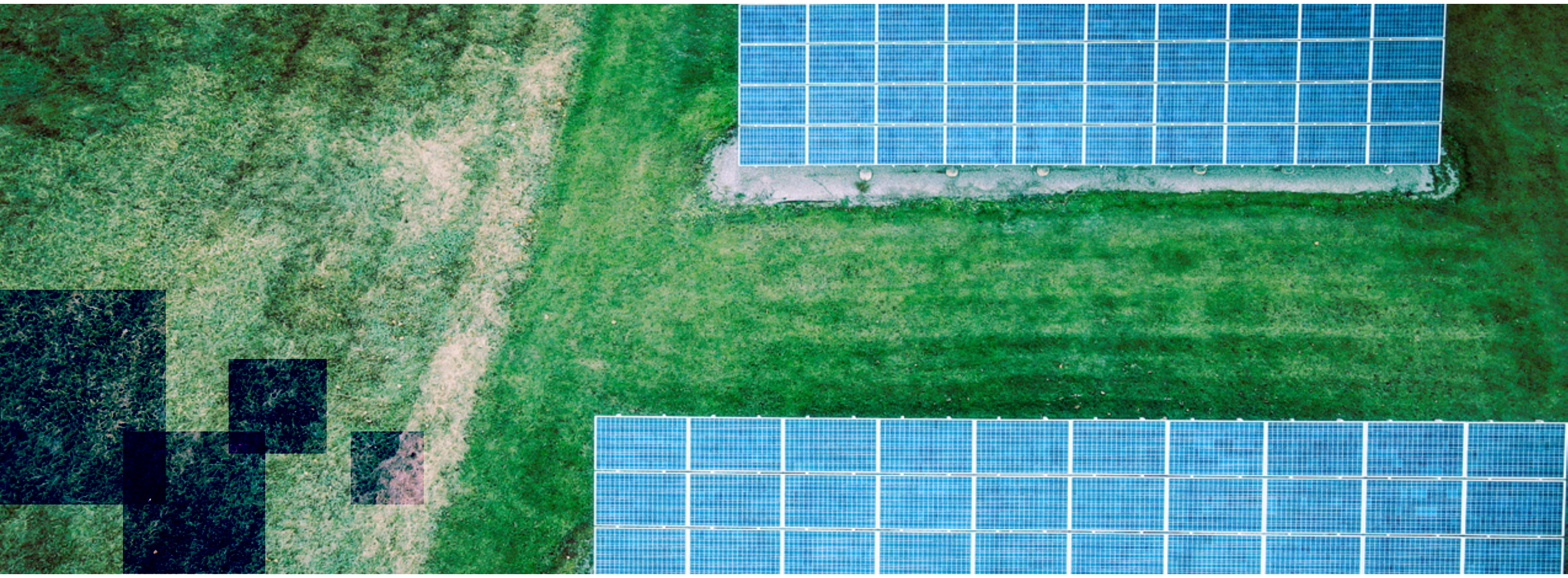
Changing Models for Harnessing Flexibility Through Load Management

Conventional mass market utility load management applications rely on assets such as binary, on/off air conditioning control switches, thermostats and pool pump controls. These typically homogeneous approaches can serve many customers but provide little flexibility for customers to customize participation based upon lifestyle, schedules or preferences.

Furthermore, some traditional utility load control programs are becoming obsolete and are unable to meet the grid's need for greater flexibility. Ironically, the pace at which utility load management programs are becoming obsolete is accelerating as customer appliances are becoming smarter and more advanced. As an example, central air conditioning systems widely sold in the market to residential customers today have variable speed modes of operations that "learn" to operate through artificial intelligence and change modes to optimize energy efficiency. Conventional utility load control programs that only cycle power on and off do not work very well with this newer innovation — and can potentially void warranties of customers' appliances. Though the smart appliances themselves can be efficiently and reliably controlled remotely through digital communications, they are not designed to have the power cut off repeatedly as a load control strategy — they are smarter than that.

Even if participation in a utility load control program does not void customer warranties, externally operated on/off load control switches override advanced features that dynamically operate units to optimize performance and efficiency. Increasingly, customers with these advanced appliances cannot be served by utility load control programs, but they can be served by ARCs who can have custom integrations with manufacturers and can digitally control appliances in a way they are designed to be controlled.

Traditional programs designed for commercial and industrial customers also face challenges and are not able to develop the latent DR potential that exists. Commercial and industrial interruptible load management programs under utility tariffs have standard rules around availability, duration, number of dispatches and penalties for non-performance. The standard rules may work for some businesses, but not all. For example, while a car wash and a grocery store use energy very differently, they typically must adapt to the same standard tariff framework. While some businesses can adapt to the standard framework, those that cannot are often left without options.



Consider the requirements for participation as a DR capacity resource in the MISO market as a Load Modifying Resource ("LMR"). Customers participating as LMRs must be available to be called upon at least 16 times per year[5] for at least four consecutive hours during each event.[6] Though some customers can meet these requirements, not all can do so. A customer that has significant load flexibility capabilities but cannot meet all the MISO requirements would likely not enroll in the utility program and expose itself to penalties for non-performance. On the other hand, ARCs can harness the load flexibility of customers even if they are unsuitable for the utility program. This is because RTO/ISO rules permit performance aggregation, in which overperformance by some customers is netted against underperformance of others.[7] ARCs can build portfolios of customers with diverse capabilities in order to meet the requirements rather than requiring each customer to meet every requirement.

While the rules vary from region to region, performance aggregation is a feature of every RTO/ISO market and managing portfolios to optimize performance is a core competency and value proposition of ARCs. ARCs have aggregation capabilities that are superior to regulated utilities because ARCs can customize participation arrangements and terms for customers, but utilities are legally prevented from doing so. The flexibility that ARCs possess enables them to not only serve more diverse customers, but also to perform consistently at a very high level of reliability under widely varying conditions.

Also, utility load management programs, whether designed for residential, commercial or industrial customers, must operate as a one-size-fits-all to avoid customer cross-subsidization and free ridership as well as ensure non-discriminatory service to customers. Public utilities, by virtue of being a monopoly service provider, face regulatory challenges administering programs that meet the diversity of dynamic energy management options available to customers. Most utilities have only one or a very small number of utility load management options, if they have an option at all.

To be clear, there are successful utility demand-side programs, and utilities are working with technology providers to continue to develop innovative load-management applications. There is, however, an emerging reality that utility DR programs alone cannot suit the diversity of today's technologies and customer preferences. Nor will they be able to meet the increasingly complex future for the grid.

5. While LMR availability and testing requirements have increased in recent years, following FERC's recent acceptance of MISO's proposed changes to move from an annual to seasonal capacity market, beginning with the 2023-24 MISO Planning Year LMRs must be available for at least 16 events per year if they participate in all four seasons. See, Midcontinent Indep. Sys. Operator, Inc., 180 FERC ¶ 61,141 (2022); see also, MISO, FERC Electric Tariff, Module E-1, § 69A.3.5 (42.0.0).

6. id.

7. See, Section 6.2, MISO, Manual No. 26, Business Practices Manual – Demand Response, Rev. 9 (October 1, 2022).

ARCs Operating Under All Regulatory Structures

ARCs can and do operate flexibly under a variety of regulatory and market models and have proven adept at managing the diversity of energy management technologies available to customers today. ARCs are traditionally not regulated as public utilities and do not face the same challenges and impediments in providing energy management services to a diverse group of customers. Indeed, a hallmark of the ARC business model is the ability to manage performance risk across a diverse group of customers by aggregating customers into groups that are appropriate for specific needs or services.

Additionally, ARCs have:

- Gained significant experience in helping customers identify and execute load flexibility strategies.
- Enabled customers to participate in DR programs that allow them to provide valuable grid services that can be monetized at both the bulk power system and distribution system levels.
- Built and continue to innovate technologies that help customers view and manage their energy usage and monitor their performance during DR events in real-time.
- Developed and deployed capabilities for two-way communications and controls.
- Automated load reduction and DER optimization strategies to reduce the impacts to customers' daily operations or comfort.
- Established relationships with commercial and industrial facilities in markets where ARCs are currently allowed to operate. These relationships can be leveraged to quickly scale up participation in DR programs when new programs allow for ARC participation, thereby bringing new resources to market faster than it would take for a new generator to be built from the ground up.

The ARC Dilemma and a RERRA Solution

ARCs have participated in RTO/ISO wholesale electricity markets in the US since the 2000s. ARCs were a new type of agent — they were neither a utility nor wholesale supplier,[8] but were nevertheless subject to regulation[9] by FERC. "ARC" did not exist in the regulatory lexicon in any widespread use until FERC adopted the term in 2008. Today, ARCs are known by several terms, such as curtailment service providers, responsible interface parties, or DR/DER aggregators or providers.

Although FERC asserted jurisdiction over ARC participation in wholesale markets from the beginning, questions lingered in the 2000s over whether FERC regulation preempted state and local jurisdiction and the extent to which RERRAs could also regulate ARCs. In an attempt to clarify the jurisdictional question, FERC codified new regulation in what came to be known as the "Opt-Out/Opt-In Rule" in Order 719 in 2008.[10]

In an effort to clarify that FERC was not trying to usurp state and local regulation, FERC provided that RERRAs would have the ability to determine retail customer eligibility to participate in wholesale market DR. The regulation establishes that RERRAs have the authority to opt out in the case of large utilities or opt in in the case of smaller utilities.

The timing of ARCs' debut and Order 719 was unfortunate, coming not long after the crisis created by Enron. As a result, a perception grew in some circles that ARCs, while not competitive retail suppliers, were part of the utility deregulation movement, which had been rejected

8. ARCs only engaged in providing DR services make no sales for resale and are not a public utility required to have a tariff rate on file with the Commission. EnergyConnect, Inc., 130 FERC ¶ 61,031 at P 30 (2010).

9. Id. at P 32.

10. Order No. 719, 125 FERC ¶ 61,071 (2008); Codified at 18 C.F.R. §35.28(g)(1)(iii) (2022).

in the majority of Midwestern states. It could be said there was concern that ARCs were the proverbial "camel's nose under the tent" for promoting retail competition policies in states that had not deregulated retail supply of electricity or were otherwise inconsistent with traditional utility regulation.

Unfortunately, the structure of the Opt-Out/Opt-In Rule also led to early incorrect interpretations that the RERRA's authority was a binary decision to allow or disallow ARCs to participate, and that if permitted, the RERRA could not regulate ARC activities. In response to the assertion that ARCs were related to utility deregulation that was disfavored in many Midwestern states, and perceiving an "all or nothing" choice, many Midwestern RERRAs with traditional regulation passed temporary or permanent restrictions on ARC participation. Although there have been a few changes, most of the restrictions adopted by RERRAs in the late 2000s remain today.

This perception that ARC participation was inconsistent with traditional regulation, and that therefore regulated states should prohibit ARCs, did not take hold in other parts of the US. For example, Vermont, Virginia and West Virginia are traditionally regulated states in which DR participation through ARCs has always been permitted. California, which largely re-regulated its retail utility market following the Enron crisis, not only continued to permit ARCs, but leveraged ARCs to implement important demand-side innovations in partnership with regulated utilities.

States with traditional utility regulation, as well as electric cooperatives and municipal electric utilities, have a particular interest in protecting their regulatory authorities.

To the extent that ARCs are permitted to operate in a utility subject to a RERRA's jurisdiction, RERRAs want to see that ARC activities are coordinated with that utility's resource planning and operations of the local utility.

RERRAs also have ratemaking considerations. RERRAs want to make sure that DR participation does not create cross-subsidies or cost shifting or other distortions of retail rate design. These are valid issues for RERRAs, and any policy permitting ARC participation should be in full harmony with retail regulatory models at the state and local level. The remainder of this whitepaper is devoted to explaining why RERRAs do not need to cede jurisdiction to FERC if ARCs are permitted, and outlines why RERRAs have ample authority to create or impose regulatory requirements they deem appropriate.

RERRAs Have Plenary Jurisdiction to Regulate ARCs Under the Opt-Out/In Rule

While RERRAs have several avenues for asserting jurisdiction over ARCs and ARC activities pursuant to traditional regulatory authorities under state laws, the Opt-Out/Opt-In Rule itself is a powerful tool for RERRAs to exercise jurisdiction to regulate ARCs authorized under federal law. RERRA jurisdiction under the Opt-Out/Opt-In Rule is analyzed below, followed by RERRA jurisdiction pursuant to state and local law in the following section.

While the Opt-Out/Opt-In Rule gives RERRAs the authority to simply opt out or opt in, it also creates authority for states to establish conditions and limitations on ARC participation. These conditions and limitations include requirements that ARCs comply with requirements established by the RERRA. In other words, the Opt-Out/Opt-In Rule provides RERRAs regulatory jurisdiction to establish the criteria and requirements for ARCs to provide services to retail customers in RTO/ISO markets.

FERC emphasized in Order 719 that its decision to require RTO/ISO markets to permit DR aggregators was to be implemented in a way that

"Wholesale demand response as implemented in the Rule is a program of cooperative federalism, in which the States retain the last word."

– U.S. Supreme Court in "EPSA v. FERC"[11]

11. EPSA v. FERC, 136 S. Ct. 760, slip op. at 25 (2016) (referring to the ability of a RERRA to opt out or not opt in.)

would allow states to exercise retail regulatory jurisdiction, including the ability to regulate ARCs and DR aggregation. In Order 719, FERC indicated that it was giving a very broad deference to states.[12] FERC made this point even more succinctly in Order 719-A (which was approved by FERC following requests for rehearing of Order 719): "[W]e leave it to the appropriate state or local authorities to set and enforce their own requirements."[13]

12. Id. at P 155.

13. Order 719-A, 128 FERC ¶ 61,059 at P 54 (2009).

Not An All-or-Nothing Decision

Despite its deferential language, FERC did not articulate what, if any, conditions states could impose if they decided to opt in. FERC's language in Order 719 was ironically too broad in that it did not clearly articulate that states could place whatever conditions they wanted on allowing DR aggregation. This unfortunately left state regulators with the mistaken impression that permitting DR aggregation may be an "all or nothing" proposition. This incorrect view held that states could either 1) opt out and preserve all retail regulatory jurisdiction over DR, or 2) opt in and cede such authorities to FERC. In the face of this false choice, several Midwestern states opted out.

FERC later cleared up this issue by making clear that it intended broad deference to states. As part of the PJM Interconnection, LLC ("PJM") compliance proposal pursuant to the then newly adopted Opt-Out/Opt-In Rule, PJM originally proposed an "all or nothing" approach that would not permit RERRAs to attach conditions or requirements to an opt-in to allow DR aggregation.[14] Noting that "Order No. 719-A [] clarified that [RERRAs] retain substantial flexibility in establishing requirements for eligibility of retail customers to provide demand response," FERC rejected PJM's approach and required the RTO to submit revisions on compliance that would permit retail regulatory authorities to condition eligibility of retail customers to participate in PJM's DR programs.[15]

PJM subsequently revised its proposal to permit RERRAs to establish conditions for ARC participation. In its second order accepting the revisions, FERC stated:

We will accept PJM's compliance filing as it relates to eligibility determinations. PJM's proposed revisions appropriately recognize the right of a retail regulatory authority to condition the eligibility of retail customers to participate in PJM's [DR] Programs.[16]

This clarification in 2010 was unfortunately too little, too late. By the time that FERC's exceptionally deferential approach to RERRA jurisdiction was fully clarified, the die was cast. Many Midwestern states had already opted out or otherwise did not pick up on this clarification resulting from a proceeding applicable to a different region.

Finally, perhaps the only remaining loose end with respect to RERRA flexibility under the Opt-Out/Opt-In Rule relates to whether a RERRA can change its mind once it opts in, with or without conditions. Can a RERRA revoke or modify a decision to opt in? FERC has addressed that issue as well, and the answer is a resounding yes. In the same PJM compliance case discussed above, FERC was confronted with the question of what to do if a RERRA revokes its opt-in while a resource is actively participating in an RTO/ISO capacity market during a delivery year. FERC determined that a revocation of an opt-in by a RERRA will be applied prospectively. Any ARC resource that was committed under an annual program would be permitted to fulfill its

14. PJM Interconnection, L.L.C., 128 FERC ¶ 61,238, at P 15 (2009).

15. Id. at P 22.

16. PJM Interconnection, L.L.C. 131 FERC ¶ 61,069, at P 23 (2010).

commitment in the current delivery year when the opt-in was in effect. However, such resources would be subject to the new RERRA determination for any future participation.[17]

In light of FERC's deferential approach to RERRA jurisdiction, a total or near total ban on DR aggregators is not necessary to protect RERRA jurisdiction. Quite the contrary, the Opt-Out/Opt-In Rule establishes the right of RERRAs to establish and enforce their own regulatory requirements. A far more constructive approach to RERRA regulation is to allow ARC participation subject to requirements that RERRAs deem appropriate, adapted to local needs and preferences.

17. Supra, note 8, at P 35.

Regulating ARCs Under the State Regulatory Authorities

In addition to the Opt-Out/Opt-In Rule, RERRAs have tools and authorities to regulate ARCs pursuant to state law and policy. RERRAs are created or authorized under statutes or state constitutions, which typically establish the powers and duties of a state commission or the authority of electric cooperatives or municipal electrical utilities (typically under local regulation or self-regulation provisions). Statutes must be analyzed on a state-by-state basis, but the statutory grant of authority may include authority to directly regulate entities, such as ARCs providing energy services in the state.

Even without a statute that authorizes direct regulation of ARCs, RERRAs have broad jurisdiction to regulate utilities, and therefore can regulate ARCs through the utilities they regulate. The Missouri Public Service Commission Staff has recommended precisely such an approach to ensuring that the retail regulatory jurisdiction is retained.[18]

RERRAs rely upon their direct regulatory jurisdiction over utilities to regulate all manner of utility business practices. Since ARCs need to do business with and otherwise need the cooperation of utilities in a variety of ways, RERRAs can regulate ARCs by regulating the utility's relationship with ARCs.

This type of regulation of businesses doing business with regulated utilities is commonplace. RERRAs do not directly regulate banks or tree-trimming companies, or any number of other businesses that work with utilities. Yet, because RERRAs do regulate the utility and can regulate the arrangements that a utility makes with vendors and others, RERRAs can impose requirements that banks, tree-trimming companies and all manner of vendors must comply with if they want to do business with the utility. Similarly, if ARCs want to do business with utilities, RERRAs can require that ARCs play by the rules they establish.

Some have suggested that ARCs may be regulated as public utilities. For a variety of reasons, this approach is impractical, and no state currently regulates ARCs as public utilities. ARCs do not sell electricity or distribute power or operate poles, wires or substations. Nor do ARCs require a franchise to operate or have a monopoly over a service territory or have an obligation to serve customers as utilities typically do. From a federal regulatory standpoint, FERC assiduously avoided ARCs participating in DR as public utilities under the Federal Power Act.[19]

18. Missouri Public Service Commission Staff, Staff Report on Distributed Energy Resources, Mo. P.S.C. File No. EW-2017-0245, at p19-22 (April 5, 2018).

19. EnergyConnect, Inc., 130 FERC ¶ 61,031, P 30-32 (2010).

Even if it may be possible to regulate ARCs as a form of public utility – it is not advisable to do so. Rate regulation does not serve the DR business well because customers are quite different in their abilities to perform as resources. The first problem with regulating ARCs as utilities is the non-discrimination obligation that typically comes with regulation of utilities. The value of the DR that each customer can provide can be quite different and therefore needs to be priced accordingly.

- Some customers may be able to respond very reliably, while others may be less so.
- Some customers can respond for a short duration, while others can respond for longer periods.
- Some customers can tolerate frequent dispatches, others not.
- Some can respond 24/7, while others can respond only during business hours.
- Some customers can respond on very short notice or automatically, while others need more advance notice of events.
- And the list goes on.

ARCs manage this diversity through a portfolio of resources, and contract with customers for the value they bring. Individual customers within an ARC's portfolio may receive different compensation depending upon the value that customer can provide.

By comparison to the ARC model, the typical approach that regulated utilities have taken to demand-side management programs as a regulated service is to provide a single, one-size-fits-all set of rules and requirements.

This approach avoids the non-discrimination problem, but it also means that a lot of latent DR capability will not be realized because customers who cannot fit the mold of the tariff are not able to participate. A major part of the value proposition of ARCs is that they can offer services to more customers with a diverse set of capabilities to participate in DR because they have flexibility of contract that is not easily achieved if ARCs are regulated as utilities.

Existing Models of ARC Regulation by RERRAs

As discussed in a prior section, the ability to impose conditions when a RERRA opts in to permit ARC participation is black letter law. There are a variety of examples of RERRAs adopting various local requirements under the Opt-Out/Opt-In Rule. Several RERRAs that permit ARCs have elected not to pursue ARC regulations or have adopted relatively light regulation. Several other RERRAs have adopted more comprehensive approaches that regulate the interactions between the ARC and utilities as well as ARCs and retail customers.

Perhaps the most comprehensive example of regulation relying upon the Opt-Out/Opt-In Rule for jurisdiction[20] has been adopted by the California Public Utilities Commission ("CPUC"). The ARC rules in California, known as Rule 24 (applicable to Pacific Gas & Electric[21] and Southern California Edison[22]) and Rule 32 (applicable to San Diego Gas & Electric[23]) clearly define how ARCs may interact with utilities and customers. The rules exist in the form of tariffs approved by the CPUC for each of California's jurisdictional investor-owned utilities.

Rules 24/32 apply to any ARC seeking to aggregate a utility's customers for participation in either the utility's DR programs or programs in the California ISO market. The rule requires an ARC to have a service agreement in place with a utility and specifies the roles and responsibilities of ARCs as well as the utilities and meter data access requirements. The rule also requires ARCs to register with the CPUC, which allows regulatory oversight and provides consumer protections in the form of customer notification requirements, posting of a performance bond and complaint resolution and enforcement actions in the event of violations.

20. Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols, California Public Utilities Commission, Decision 10-06-002 (June 2010) at page 23, Conclusion of Law 1.

21. See, Pacific Gas & Electric, Electric Rule 24 Direct Participation Demand Response, available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_24.pdf.

22. See, Southern California Edison, Rule 24 Direct Participation Demand Response, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M037/K189/37189001.pdf.

23. See, San Diego Gas & Electric Company, Rule 32 Direct Participation Demand Response, available at: https://tariff.sdge.com/tm2/pdf/tariffs/ELEC_ELEC-RULES_ERULE32.pdf.

New York has adopted a similar framework of regulations for ARCs, the Uniform Business Practices for Distributed Energy Resource Suppliers ("NY UBP DERS").[24] Technically, the New York rules are related to state jurisdictional retail DR programs rather than RTO/ISO programs. However, the rules are de facto applicable to ARCs participating in the New York Independent System Operator programs because New York's utility DR programs that permit ARC participation are designed to work in harmony with NYISO participation. The state's DR programs provide distribution-level services for utilities that are distinct and different from wholesale market products and allow for dual participation by retail customers in the NYISO's market. ARCs in New York overwhelmingly seek to participate under both the utility programs and NYISO programs, and thus are subject to the NY UBP DERS. Like the California Rules 24/32, the NY UBP DERS rules may be instructive for any state seeking to adopt business rules for ARCs.

Several RERRAs have taken a lighter approach to regulation, mostly consisting of informational disclosures and registration by ARCs, and perhaps a bond requirement and periodic reporting. These regulations stop short of some of the more extensive requirements found in the California and New York examples. Ohio and Maryland are two states that require ARCs to register as energy brokers/retail suppliers and to comply with requirements applicable to retail suppliers. Although ARCs are not retail suppliers and do not sell electricity at wholesale or retail, these states have elected to apply the body of regulatory requirements applicable to retail suppliers to ARCs participating in the RTO/ISO markets.

RERRAs with jurisdiction over the smaller Opt-In utilities have also adopted regulatory requirements covering ARCs. For example, Cleveland Public Power ("CPP") establishes qualifications for ARCs and requires CPP approval to operate.[25] The rules also place a 30 MW soft cap on participation that is waivable at the discretion of CPP, which does so on a case-by-case basis. In this way, CPP can keep track of the ARCs operating in its service territory and has contacts with each ARC in the event any concerns arise.

In addition to establishing rules for ARC participation, some RERRAs have elected to exercise jurisdiction to restrict participation to specific customers or customer classes. For example, the Michigan Public Service Commission ("MPSC") is in the process of evaluating ARC participation in the Michigan market. As an initial step toward reversing its total restriction on ARC participation, the MPSC has allowed any customer that participates in retail competition to participate in DR through an ARC. This is the result of a modification of a prior decision that was a complete ban on aggregator participation. The decision to open DR aggregation to retail competition customers can best be viewed as a transitional step for Michigan. The MPSC has opened another proceeding to further review whether the restriction on all customers should be lifted.[26] Additionally, the Minnesota Public Utilities Commission ("MPUC") is expected to soon initiate a docketed proceeding to explore several issues, including whether it should remove the Opt-Out from allowing ARCs to participate and what regulations should be in place to oversee ARC participation.[27]

24. See, New York Public Service Commission, Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products, Order Establishing Oversight Framework and Uniform Business Practices for Distributed Energy Resource Suppliers (March 14, 2019), Appendix A.

25. City of Cleveland, OH, City Council Resolution No. 144-11, (2011).

26. See, MPSC Case No. U-20348.

27. See, MPUC Docket No. E002/M-21-101, Order Approving Modified Load-Flexibility Pilots and Demonstration Projects, Authorizing Deferred Accounting, and Taking Other Action (March 15, 2022), at p.28.

DR Procurement Models Conforming to Utility Requirements

DR Feed in Tariff - "The Indiana Model"[28]

A DR Feed in Tariff ("DR FIT") is an approach whereby the utility has a standard offer available through a tariff, under which it will purchase DR resources that qualify for participation as resources in RTO/ISO DR programs. The ARC registers its DR resources as a part of the utility's resource portfolio with the RTO/ISO. The ability for the utility to obtain resource adequacy credit for the resources developed from the utility's customers makes this approach particularly attractive from a resource planning perspective.

An early version of the DR FIT approach was adopted by the Indiana Utility Regulatory Commission ("IURC") for Indiana Michigan Company customers for participation in PJM's DR programs and is still in effect today.[29] The approach approved by the IURC functions well, but experience has demonstrated that it could be improved upon, as discussed below.

Under the DR FIT, the ARC works with a utility's customers under a utility tariff that governs the relationship between the utility and the ARC as well as the ARC's business practices. The terms of the utility tariff for DR participation mirror the requirements for participation as capacity under rules in the relevant RTO/ISO. When an ARC enrolls a customer, the ARC handles RTO/ISO registration requirements and assigns the resource to the utility's RTO/ISO account. The ARC, not the utility or the customer, is responsible to the RTO/ISO for performance and compliance obligations, including any penalties for non-performance. The utility pays the ARC according to the terms of the utility tariff, and the ARC pays the customer according to the contractual terms agreed to between the ARC and the customer.

Under the DR FIT approach, the utility is purchasing the DR capabilities of its customers represented by an ARC. The utility uses the credit that it receives for the capacity resource coming from the utility's customers in satisfying its obligation as a load serving entity ("LSE"). In this way, the utility can incorporate the DR resources developed in its service territory in its short- and long-term resource plans.

ARC participation enables more robust participation and more and diverse customer participation by leveraging the resources and expertise of ARCs to market the program to customers, enable participation and complete enrollments. Utilities often have limited resources and personnel to address all the requirements of DR customer enablement to develop a robust participation level. For most ARCs, developing and managing DR and DER resource potential is all they do.

28. The label "Indiana Model" was used in a Missouri PSC staff report that evaluated and recommended the approach for use in Missouri. See supra, note 9.

29. Indiana Michigan Power Company tariff, Original Sheet No. 33, Rider D.R.S.1 (Demand Response Service – Emergency).

A particularly attractive feature of the DR FIT approach is that the utility is purchasing the resource at a price stated in the tariff rather than relying upon the RTO/ISO capacity auction, which is complex and can involve uncertainty at the time of enrollment and volatile pricing. As an example, take MISO's Planning Resource Auction, which is conducted a few months before the start of the planning year. Clearing prices in the auction have seen drastic swings in recent years.

The rules require that all participating resources register before the auction is conducted – before the price is known. However, customers are understandably reluctant to commit to an enrollment before they understand pricing components. This design component of the MISO capacity is much less favorable towards developing and maintaining robust DR participation when compared with a firm price that enables certainty for customers before they commit.

The Indiana Model was an important and constructive innovation that demonstrated that ARCs can and do work with and cooperate with utilities operating under a traditional regulatory framework. Experience with it has resulted in a couple of valuable lessons that could be improved upon in program design of future DR FIT approaches.

One feature of the Indiana Model that has proven challenging is that every individual customer under the program is required to make a minimum four-year commitment in order to begin participation, and to provide a three-year notice to discontinue participation. This is decidedly unattractive for customers. At the same time, it is understandable that the utility wants certainty regarding future years. This term could be corrected by requiring any required commitment periods to run to the ARC, rather than the individual customer. That way, an ARC could enroll a new customer if a customer wants to disenroll or reduce its level of participation.

Another challenge of the Indiana Model is that performance is measured and penalties, if applicable, are assessed at the individual customer level. This precludes an ARC's ability to engage in portfolio performance aggregation where overperformance of some customers may be netted against underperformance by other customers. Without the ability to manage performance at the portfolio level, the ARC must pass performance penalty exposure on to customers. Whereas, with portfolio performance aggregation, ARCs can insulate customers from penalties, which is a particularly attractive feature for customers. This challenge would also be easy to resolve by evaluating the performance of the ARC's enrolled customers at the portfolio level and allowing for aggregation.

DR PPAs with Utilities

Another way to integrate ARC activities with utility resource planning is to facilitate ARC eligibility to participate in utility procurements, either as part of an "all source" procurement or a procurement that is designed to either specifically procure DR or procure attributes that DR can provide. As part of the terms of participation in the procurement, the RERRA would conditionally opt in to allow ARC participation and include whatever regulatory requirements deemed necessary as part of the procurement.

One example of this approach is utilized by the Illinois Power Agency ("IPA"), which procures energy and capacity on behalf of several utilities. The IPA conducts a state-run procurement that is open to DR and ARCs as well as generation suppliers. The procurement is for resources to meet a utility's resource adequacy obligations under the MISO Fixed Resource Adequacy Plan. If an ARC is awarded a contract pursuant to the IPA procurement, the ARC enters into a power purchase agreement ("PPA")-style agreement (such as a forward Zonal Resource Credit contract) with the utility. To fulfill the agreement, the ARC registers DR customers and transfers the associated credits to the utility's MISO account to satisfy its resource adequacy requirements as a load-serving entity. Then the ARC is paid by the utility according to the agreement. As the market participant representing the resources, the ARC (and not the utility) is responsible and liable to MISO for all market participation requirements and subject to MISO charges and penalties, as appropriate.

The benefits of enabling the DR PPA approach include providing utilities and other LSEs with longer-term certainty of the resources they can rely upon in their resource plans, as well as providing price certainty to ARCs and customers providing these resources.

ARC-Facilitated DR Program Administration

DR program administration for utilities by ARCs entails utilities entering contracts with ARCs to design, implement and administer DR programs within a utility's service territory. This approach is currently in use by several utilities in the Midwest and allows for regulatory oversight by a RERRA. The ARC is subject to applicable RERRA regulation because it operates as a vendor under contract to the utility.

Under the DR program administration approach, utilities can contract with one or more ARCs to run programs, thereby leveraging the experience and innovation of ARCs to enable customer participation within the DR program(s). The utility may utilize the DR programs as the utility and its regulator deems best. For example, the utility may register the DR program participants in one or more RTO/ISO DR programs and receive credit for the resources to offset its obligation to procure capacity, energy or ancillary services. Alternatively, the utility may operate the program outside of the wholesale market and deploy DR to peak shave or dispatch DR for economic or reliability reasons.

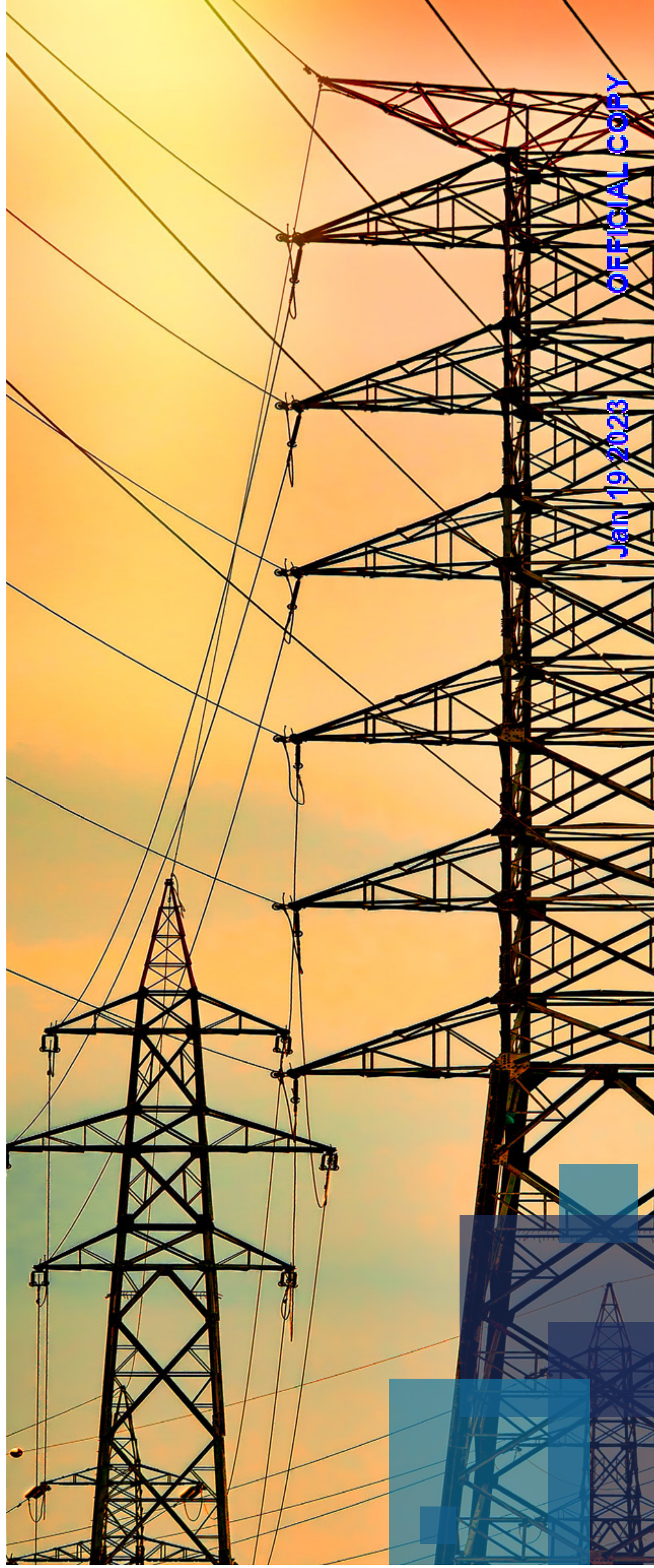
An advantage of the DR Program Administration model is that the RERRA and utility can more directly control the ARC managing the program to ensure that it is developing resource potential to its fullest. In rural areas where DR opportunities may be sparse, there may be few or no ARCs willing to invest resources to develop the limited DR potential unless they are working closely with the RERRA on an exclusive basis. Rather than risk that customers will miss out on opportunities to earn revenue to remain competitive and innovate, a better approach in such cases may be to contract with a single ARC that will focus on the utility's customers or an electric cooperative's members.

One drawback of the DR Program Administration approach is that it can limit the benefits that competition amongst ARCs can provide. It can also be cumbersome for companies with national footprints. Customers with hundreds or thousands of stores and facilities nationwide may prefer to work with a single ARC or only use a few who can help them participate in the many programs available where their stores or facilities are located.

Conditional Opt-In

This approach is appropriate for a RERRA that wants to allow customers to participate in DR but may not want to commit the utility to purchasing the DR from customers to meet the utility's resource needs or does not have the resources to devote to a DR program. The RERRA and the utility may nevertheless want to have a means to obtain information from the ARC about the activities of customers in the utility's service territory or for other reasons. Under this approach, the RERRA would opt in to allow participation of ARCs in an RTO/ISO program and attach conditions to the opt-in to ensure that ARCs are subject to appropriate requirements. Rule 24/32 in California discussed in the previous section is an example of a conditional opt-in.

The utility may purchase the credits associated with DR resources developed by the ARC but is not obligated to do so. The ARC may register resources in the RTO/ISO DR programs, and the resource credit would go to the utility (or other LSE) purchasing the credit. Although the utility will not receive credit for a resource if it is not the ultimate purchaser, the RERRA may nevertheless impose regulatory requirements upon ARCs as a condition of the opt-in election or pursuant to state jurisdiction. One advantage of this approach is that customers may still be able to participate in DR even if their own utility does not have a need for additional resources. Another advantage is that the ability to sell DR to other utilities or LSEs enhances the liquidity of the RTO/ISO market, which increases market efficiency and reduces costs for all customers.



Pros/Cons of Approaches to Regulating ARC Participation

While the section above lays out the options available for state regulators, it is important to discuss the merits and detractors when considering which approach may yield the most benefits. The table below offers some helpful context for balancing regulatory oversight, contribution of ARC-enabled participation towards resource adequacy ("RA") and the full potential of benefits to the grid and all consumers.

ARC Participation Option	Allows Regulatory Oversight by RERRA	Contributes to Utility/LSE Resource Adequacy	Maximizes Latent DR Potential & Participation	Enables ARC-provided benefits	Allows Customer Selection of ARCs
DR Feed in Tariff	Yes	Yes	Yes	Yes	Yes
ARC DR PPAs	Yes	Yes	Yes	Yes	Yes
Conditional Opt In	Yes	Yes	Yes	Yes	Up to the RERRA
ARC-facilitated DR Program Administration for Utilities	Yes	Yes	No	Depends upon design	Typically, no
Traditional Tariff (w/o ARC participation)	Yes	Yes	No	No	No

Examples of ARC Participation in the Midwest

To provide further context of the approaches to enabling ARCs that RERRAs should consider, it's helpful to provide examples of these models in use today in areas of the Midwest.

DR Feed in Tariff:

Indiana Michigan Company DR Tariff

Indiana Michigan Company has a retail tariff in which customers can be enrolled to participate in the PJM demand response programs through the utility. The capacity credits from customers enrolled in the program are assigned to meet the utility's resource adequacy obligation. The price paid to customers for participation as a capacity resource is based upon a trailing three-year average of the PJM capacity auction price. Customers are permitted to contract with, and enroll in the program through ARCs, although the tariff requirements run to each individual customer.

Xcel Energy Peak Flex Credit Pilot (MN)

On March 15, 2022, the MPUC approved Xcel Energy's proposed Peak Flex Credit pilot program in Docket No. E002/M-21-101. The MPUC took the opportunity to explore aggregator participation and doubled the pilot size (in MW), creating two tranches of 43MW. One of the tranches is dedicated to participants directly enrolled through Xcel Energy, with a second tranche open to third-party aggregators. On Sept. 8, 2022, the MPUC approved Xcel Energy's final compliance filing, and the tariff became effective as of Sept. 12, 2022.

Interested aggregators must first be approved by Xcel to participate in the pilot by executing an Aggregator Agreement and satisfying the eligibility requirements. In addition to the base tariff provisions that outline the program parameters that will be applicable to all customers, the Aggregator Agreement contains additional requirements to which participating aggregators must adhere. As the pilot is to be administered via a utility tariff, there is regulatory oversight by the MPUC.

ARC DR PPA:

Illinois Power Agency Block Energy and Capacity Procurement (Ameren Illinois)

The Illinois Power Agency ("IPA") each year administers one or more procurement events soliciting suppliers capable of delivering ZRCs in MISO Zone 4 for the prompt Planning Year (and sometimes for future Planning Year) on behalf of customers whose LSE is the Ameren Illinois Company ("AIC"). The procurement events are open to all entities capable of registering capacity resources, including LMRs, and converting the resources' MWs into ZRCs in the MISO Module E Capacity Tracking ("MECT") tool.

Successful bidders must execute a bilateral contract with the IPA and adhere to all provisions of the contract, which is subject to oversight and approval by the Illinois Commerce Commission ("ICC"). Following contract execution and upon successful resource registration with MISO, the supplier must transfer the ZRCs to AIC within the MECT. AIC then uses the transferred ZRCs to meet its RA obligation as an LSE.

As the bilateral contracting structure is reviewed and approved by the ICC, the ICC as the state regulator can confirm that appropriate provisions are in place to ensure the delivery of ZRCs by the supplier, beyond the rules and regulations applicable to a MISO Market Participant, subject to jurisdiction by FERC.

ARC-Facilitated DR Program Administration:

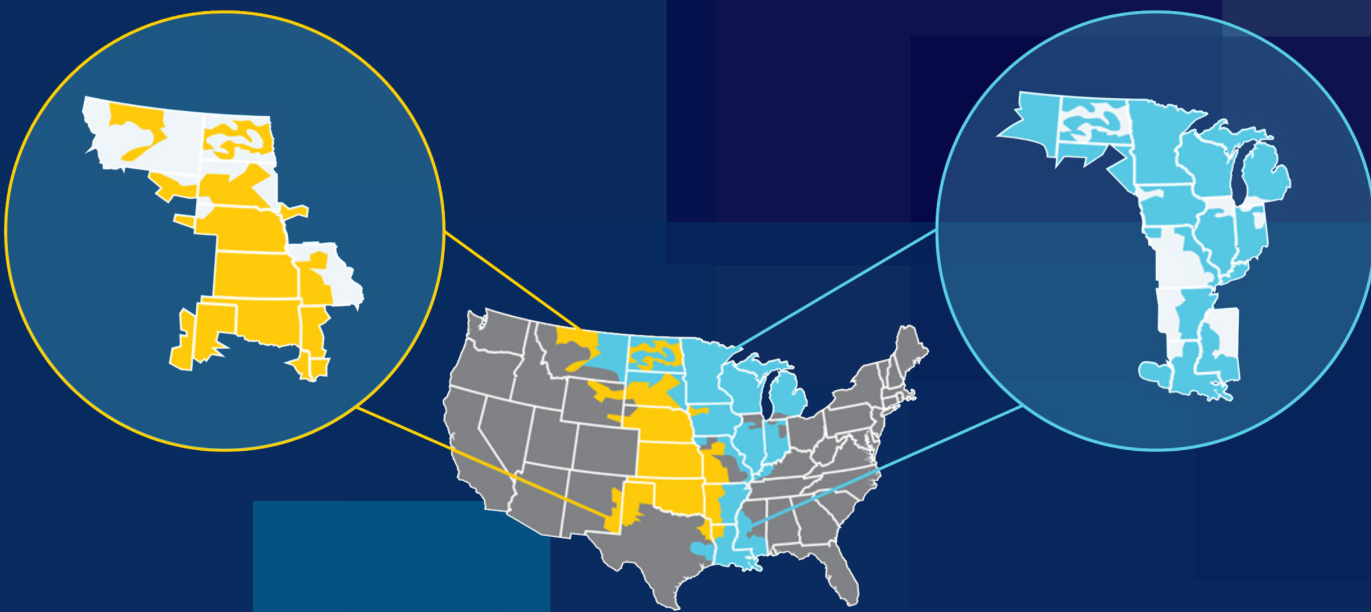
Montana-Dakota Utilities DR Program

Since 2012, CPower has administered a turnkey DR program for commercial and industrial customers for Montana-Dakota Utilities ("MDU"). CPower has handled all customer recruitment (assisted at times by MDU account managers), load curtailment engineering plans, dispatch and performance verification for participating customers. MDU registers the participants with MISO as LMRs and uses the Zonal Resource Credits ("ZRCs") to meet resource adequacy requirements.

Conclusion

Hopefully, this whitepaper proves informative and useful to RERRAs and helps to dispel popular misconceptions about whether RERRAs may maintain regulatory oversight over ARCs should a RERRA choose to explore the enabling models described here. DR is a powerful tool that can be leveraged to meet resource adequacy needs, as well as to help reliability and provide flexibility as the grid transitions. ARCs are best positioned to maximize the potential of DR through aggregating customers with differing capabilities and enabling ARCs through one of these models should be considered.

RERRAs and utilities are encouraged to consider the ideas and models adopted in various other regions and utilities discussed in this whitepaper.



Conclusion

For easy access, all the decisions, tariffs and documents cited in this whitepaper have been collected and are available for download:

https://cpowerenergymanagement.com/midwest-dr-framework-sources

The authors are also available to discuss any of the topics raised herein, and invite interested individuals to contact them:

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CPower

About CPower

CPower Energy is the national leader of grid balancing and reliability solutions, creating a Customer-Powered Grid™ that will enable a flexible, clean and dependable energy future. With 6.3 GW of capacity at more than 17,000 sites across the U.S., we unlock the full value of distributed energy resources to strengthen the grid when and where it's needed most. CPower is based in Baltimore, Maryland and is owned by LS Power, a development, investment, and operating company focused on the power and energy infrastructure sector. For more information, visit: www.cpowerenergymanagement.com.