UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Voltus, Inc.	)	
Complainant,	)	
v.	)	Docket No. EL20-_____
Midcontinent Independent System Operator, Inc.	)	
Respondent.	)	

COMPLAINT OF VOLTUS, INC. REQUESTING FAST TRACK PROCESSING

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Dated: October 20, 2020

TABLE OF CONTENTS

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Pursuant to Sections 206 and 306 of the Federal Power Act, 16 U.S.C. §§ 824e, 825e, and Rules 206 and 212 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. §§ 385.206 and 385.212, Voltus Inc., ("Voltus") hereby files this Complaint against Midcontinent Independent System Operator, Inc. ("MISO" or "Respondent").

This Complaint requests:

1) that the Commission find that MISO tariff provisions authorizing states to bar third party demand response providers from participating in MISO's wholesale market are: (i) inconsistent with the jurisdictional provisions of the Federal Power Act, and (ii) not just and reasonable, and are unduly discriminatory and preferential;

2) that the Commission issue an order interpreting its own regulation, 18 C.F.R. § 35.28(g)(iii), and find that certain relevant electric retail regulatory authorities ("RERRAs") in MISO issued prohibitions against third party demand

response providers in a manner inconsistent with the terms of that regulation and that such prohibitions are therefore void; and

3) that the Commission issue a notice of proposed rulemaking to repeal the provisions set forth in 18 C.F.R § 35.28(g)(iii) permitting RERRAs to bar third party demand response aggregators from participating in wholesale markets, on the grounds that these provisions are: (i) inconsistent with the jurisdictional provisions of the Federal Power Act and (ii) result in rates that not just and reasonable and are unduly discriminatory and preferential.

This Complaint is supported by the declarations of Paul Centolella and Gregg Dixon.[1]

I. COMMUNICATIONS

Communications regarding this matter should be addressed to the following persons, who should also be designated for service on the Commission's official list:

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[1] The Testimony Prepared for Earthjustice By Paul Centolella is attached as Exhibit A ("Centolella, Ex. A") and Declaration of Gregg Dixon is attached as Exhibit B ("Dixon, Ex. B"). A summary table of state opt-outs is attached as Exhibit C ("State Opt-out Chart, Ex. C").

II. THE PARTIES

1. Voltus

Voltus is a provider of demand response services to commercial and industrial customers across the United States and Canada. As an Aggregator of Retail Customers ("ARC") Voltus enables profitable participation in demand response programs across the MISO footprint. Voltus enables its commercial and industrial customers to deliver to wholesale and retail markets the benefits that their behind-the-meter assets (*i.e.*, load curtailment, energy storage, distributed generation, and energy efficiency) provide in delivering energy, capacity, and ancillary services that these markets need to operate. In return, Voltus secures market revenues for these assets as a form of payment to incentivize their participation in markets.

2. Respondent

MISO is a Commission-approved RTO responsible for reliability coordination of the wholesale bulk power and electric transmission system in fifteen U.S. states and one Canadian province. Currently, MISO directs the operation of over 65,000 miles of high-voltage transmission, approximately 185,000 megawatts of power-generating resources across its footprint, and manages one of the world's largest energy markets. MISO is a North American Electric Reliability Corporation certified balancing authority responsible for maintaining load-interchange-generation balance within its balancing authority area and for supporting the Eastern Interconnection frequency in real time. MISO has its principle operations in Carmel, Indiana. MISO also maintains backup control centers and data rooms in Indianapolis, Indiana; Eagan, Minnesota; and Little Rock, Arkansas.

III. INTRODUCTION AND EXECUTIVE SUMMARY

Long-standing federal policy aims to foster demand competition in wholesale energy markets because such competitive pressure has the effect of reducing wholesale power prices, increasing awareness of energy usage, providing more efficient operation of wholesale markets, mitigating market power, enhancing reliability, and supporting the integration of renewable energy resources. The inability of third party aggregators of demand response to freely participate in MISO's wholesale market unnecessarily restricts and stifles such competition. The ability for states to target ARCs and specifically carve them out of MISO's wholesale market as codified in the "opt-out" provisions of Order 719[2], contravenes FERC's responsibilities pursuant to the Federal Power Act, results in rates that are unjust and unreasonable, and also unduly discriminates against demand response resources generally and demand response aggregators specifically. In MISO in particular, the pervasive extent of state opt-outs has resulted in an anemic market for wholesale demand response, which, in light of ongoing changes to the resource mix, now poses an imminent threat to efficient and reliable grid operation. This Complaint focuses on the harm imposed by the state opt-outs in MISO, which are authorized under Order 719 and implemented through MISO's tariff. However, because the Complaint raises flaws that strike to the heart of the legality of the opt-

[2] Wholesale Competition in Regions with Organized Electric Markets, 125 FERC ¶ 61,071 (Oct. 17, 2008) ("Order 719").

out adopted in Order 719, the Complaint seeks reversal of the opt-out through rulemaking in addition to immediate redress of the unjust, unreasonable, and unduly discriminatory rates in MISO that adversely impact Voltus.

The Commission has previously recognized the key role demand response plays in supporting a healthy and well-functioning grid, which also has the benefit of supporting just and reasonable rates. Demand response has proven to, among other things, flatten load profiles, reduce overall costs, increase reliability, and help properly balance supply and demand. Furthermore, the Commission and other regulatory entities have recognized that aggregators of demand response, such as Voltus, provide numerous enhanced benefits to the grid by expanding the amount of demand response in the market, lowering prices, enhancing the reliability of the system, encouraging implementation of innovative technology, and simplifying delivery of grid services.

Most recently, the Commission has again recognized the distinct value of distribution-connected resources, and of aggregators capable of ensuring their effective participation in wholesale markets, in the historic Order 2222.[3] Indeed, the Commission found that "[a]gregations of new and existing distributed energy resources [of which demand response is one] can provide new cost-effective sources of energy and grid services and enhance competition in wholesale markets as new

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[3] Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs, 172 FERC ¶ 61,247 (Sept. 17, 2020) ("Order 2222").

market participants."[4] The Commission concluded that existing RTO/ISO rules "present barriers to the participation of distributed energy resource aggregations in the RTO/ISO markets, and such barriers reduce competition and fail to ensure just and reasonable rates."[5] The Commission then directed RTOs to adopt reforms to remove barriers to participation of distributed energy resource aggregations into its wholesale markets.[6]

In spite of its uncontroverted benefits, the full capabilities of demand response technology remain largely untapped. An assessment conducted at the Commission's direction found that the potential market for demand response in the United States would be close to 200,000 MW by 2019.[7] Yet in 2018 electric utilities have delivered a mere fraction of that latent potential of demand response.[8] In MISO, where the flexibility, availability, and other operational features of the fleet

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[4] *Id.* at P 27; *see also id.* at PP 160, 163 (discussing how the final rule enhances competition and improves reliability by requiring RTOs/ISOs to allow participation of distributed energy resources in both wholesale and retail or multiple wholesale programs).

[5] *Id.* at P 26; *see also id.* at P 29 (finding that the reforms in this final rule "will enhance the competitiveness, and in turn the efficiency, of RTO/ISO markets").

[6] *Id.* at PP 26, 29.

[7] FERC Staff, *A National Assessment of Demand Response Potential*, The Brattle Group *et al.* at 27-28 (June 2009) ("The reduction in peak demand under [the full participation] scenario is 188 GW by 2019, representing a 20 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs."), https://www.ferc.gov/sites/default/files/2020-05/06-09-demand-response_1.pdf.

[8] U.S. Energy Information Administration's Annual Electric Report (2019), https://www.eia.gov/electricity/annual/pdf/epa.pdf, at tbl 1.2 ("Summary Statistics for the United States, 2008 – 2018"); *see also* 2019 Assessment of Demand Response and Advanced Metering, FERC Staff Report at 13-17 (2019) (retail and wholesale demand response each ~30,000 MW in last reporting year).

of predominantly utility-run demand response lags substantially behind that of other regions, the gap between the potential of the technology and reality is particularly wide.

The failure to unleash demand competition poses an acute threat in MISO, where a combination of factors including reduced reserve margins, increased forced outages, and the integration of variable renewable resources has led to increased Maximum Generation Emergency events, signaling increasing operational risk to the grid. MISO has stated that current reliance on demand response to meet load-serving entities ("LSE") planning reserve margin requirements "has never been greater" and that these resources "are one of MISO's 'last lines of defense' before having to engage in firm load shedding."[9] However, MISO's demand response to date has largely underperformed or possessed inadequate operational characteristics to meet these increasing challenges.

The opt-out directly contributes to MISO's market inefficiencies and operational risk. At a moment when MISO's evolving grid conditions most acutely require the enhanced capabilities of flexible demand response, the near ubiquity of state opt-outs within MISO has eviscerated demand competition, and thereby significantly impeded demand response development in the grid operator's footprint.

[9] MISO Filing to Enhance Accreditation of Load Modifying Resources Participating in MISO Markets, ER20-1846 at 2 (May 18, 2020) ("MISO 2020 LMR filing").

The opt-out is unlawful for numerous reasons. First, jurisprudence since the adoption of Order 719 now dictates that the opt-out approach taken in Order 719 is inconsistent with the Federal Power Act's basic jurisdictional divide, as states simply do not possess the authority to directly determine whether resources are permitted to participate in RTO/ISO markets. The Commission's recent landmark orders on storage and distributed energy resources recognize this shift and have abandoned Order 719's blanket opt-out in favor of a considered framework for coordination between wholesale and distributional system operators with respect to participation of these resources. The Commission's conclusion that its exclusive jurisdiction over wholesale market rates precludes states from barring participation of storage or distributed energy resources applies with equal force to demand response. Order 719's anomalous treatment of demand response can no longer stand.

Second, the opt-outs adopted under Order 719 have become a significant barrier to competition in the market, which act to insulate utility demand response programs from competitive pressures and result in rates that are nor just and reasonable. Absent this competitive pressure, the market cannot unlock latent demand response resources or spur the innovation and technological development of demand response capability that would otherwise ensure just and reasonable rates. There is no question that removing the primary barrier to aggregators of demand response participating in the market would increase the net amount of demand response and generate competitive pressure to produce operationally superior technology, such that power demand could more effectively respond to the wholesale price of electricity. The Commission broadly recognizes this principle in its Order 2222, where it states that "removing the barriers to participation by distributed energy resource aggregations will enhance the competitiveness" which "encourages entry and exit and promotes innovation, incents the efficient operation of resources, and allocates risk appropriately between consumers and producers."[10] Moreover, substantial evidence demonstrates the opt-out has stymied the development of demand response in MISO specifically, impacting both the quantity and quality of demand response participation, harming market efficiency and failing to ensure just and reasonable rates.

Lastly, the opt-out is unduly discriminatory. First, there is no basis for demand response resources to face limitations on participation that energy efficiency, other forms of energy storage, and other distributed energy resources do not. Such an approach defies the Commission's longstanding commitment to technology-neutral market rules. As the Commission recently recognized,

> [L]imiting the types of technologies that are allowed to participate in RTO/ISO markets through a distributed energy resource aggregator would create a barrier to entry for emerging or future technologies, potentially precluding them from being eligible to provide all of the capacity, energy, and ancillary services that they are technically capable of providing.[11]

Yet that is precisely the limit imposed on current and future demand response technologies, which face barriers to entry throughout much of MISO.

[10] Order 2222 at P 18.
[11] *Id.* at P 141.

Second, the way in which the opt-outs are deployed in MISO is unduly discriminatory because it allows the states to treat demand response aggregators differently than utility-affiliated programs. The Commission has clearly recognized that key consideration in this context is whether the "operational characteristics" of differing distributed energy resources can be aggregated to meet "certain qualification and performance requirements."[12] Therefore, the implementing entity or ownership of a particular demand response program is not a valid basis for discrimination, as it is immaterial to the program's operational capabilities. The opt-out results in unequal treatment for resources capable of comparable performance - the hallmark of a discriminatory rule in wholesale electricity markets.

To alleviate the ongoing and worsening harms posed by state opt-outs in MISO, Voltus requests the Commission find MISO's existing tariff provisions are not just and reasonable and are unduly discriminatory;[13] direct MISO to disregard certain state actions that invalidly seek to block aggregators from participating in MISO through measures other than state law or regulation; and require MISO to initiate a process to incorporate mechanisms for coordination with distribution system operators, specific to demand response and parallel to those that apply to distributed energy resources under Order 2222. Voltus further requests that the

[12] *Id*. at P 26.
[13] MISO's provisions to implement the state opt-outs are set forth in Section 38.6 of the Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff").

Commission eliminate the unlawful opt-out adopted in Order 719 via rulemaking. Ultimately, Voltus seeks that the sea change in enhancing market competition, which began with storage resources in Order 841 and continued with distributed energy resources in Order 2222, extend now to demand response resources. The sensible approach to coordination with retail authorities and distribution system operators adopted in those seminal Orders can and must be applied to demand response.

IV. REQUEST FOR FAST TRACK PROCESSING

1. Voltus is Materially Harmed by the Opt-Outs and Requests Fast Track Processing Pursuant to 18 CFR § 385.206(h) and 18 CFR § 385.206(b)(11)

At the time of filing, Voltus may only operate as an ARC in a small portion of MISO, which includes MISO Illinois, Michigan (serving the 10% of load that is allowed to buy competitive electricity supply), MISO Texas, and a limited set of municipal and cooperative utilities that have consented to allow Voltus to operate in their service territories (*e.g.*, the City of New Orleans).[14] The state opt-outs, made available to states under Order 719 and the MISO tariff provisions implementing it, prevent Voltus from operating in the other states in MISO's footprint.[15] Voltus estimates that but-for the opt-outs, Voltus could be delivering over 9,000 MWs of demand response in MISO states,[16] and further estimates that if Voltus were delivering the same demand response that utilities currently provide, that Voltus

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[14] *See* Dixon, Ex. B at P 49.
[15] *Id*. at P 52.
[16] *Id*. at P 53.

would be saving ratepayers $130 million per year, while delivering better quality service via its technology platforms.[17]

The state opt-outs represent nearly a half a billion dollars in potential lost revenue to Voltus.[18] As a result of upcoming auction deadlines, standard processing of the Complaint will not be adequate, and Voltus requests fast track processing pursuant to 18 CFR § 385.206(h) and 18 CFR § 385.206(b)(11). Each year in MISO a Planning Resource Auction ("PRA") is held that allows demand response to bid into the market alongside any supply-side capacity resource.[19] The PRA auction takes place in March of each year with results posted in April for delivery in the same year beginning in June.[20] Resources that want to participate in the auction need to be approved for participation by MISO in February of each year.[21] Voltus requests fast track processing such that Voltus would be able to bid demand response into the market from all MISO states by that timeframe.[22] To generate such bids, Voltus would need to prepare their requests for approval to register in the PRA well in advance of when Voltus is required to have all information submitted to MISO for those resources to participate in the 2021/2022 PRA.

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[17] *Id.* at P 43.
[18] *Id.* at P 53.
[19] *Id.* at P 54.
[20] *Id.* at P 55.
[21] *Id.*
[22] *PJM Interconnection, L.L.C.* ("PJM"), 135 FERC ¶ 61,211, 62,219 (May 31, 2011) (finding fast track processing appropriate where an entity had to register participating resources before a specified delivery date); *Morgan Stanley Capital Grp. Inc. (Complainant)*, 92 FERC ¶ 61,112, 61,430 (July 28, 2000) (where the complaint involved alleged harm to market participants); *see also Allegheny Elec. Coop., Inc., et al.*, 119 FERC ¶ 61,165, 62,021 (May 18, 2007).

V. BACKGROUND

1. Legal Background

a. Order 719 Aims to Remove Barriers to Demand Response to Improve Wholesale Market Competition.

In 2008, spurred by Congress' urging in the Energy Policy Act of 2005 that it is the "policy of the United States" to encourage demand response[23], the Commission issued Order 719.[24] Recognizing that "[i]mproving the competitiveness of organized wholesale markets is integral to the Commission fulfilling its statutory mandate to ensure supplies of electric energy at just, reasonable and not unduly discriminatory or preferential rates," Order 719 sought to eliminate barriers to demand response participation in RTO or ISO markets.[25] Among other reforms, Order 719 required grid operators, except in certain circumstances, to permit an aggregator of retail customers to bid demand response on behalf of retail customers directly into its organized markets.[26] The Commission found that permitting aggregators to participate reduces a barrier to demand response, and that "aggregating small retail customers into larger pools of resources expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."[27] The Commission further concluded that experiences with aggregation programs in PJM, New York Independent

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[23] 119 Stat. 594 § 1252(f), 119 Stat. 965, 16 U.S.C. § 2642; *see also FERC v. EPSA*, 136 S.Ct. 760, 771 (2016).
[24] Order 719, 125 FERC ¶ 61,071 at P1.
[25] *Id.*
[26] *Id.* at PP 3, 154.
[27] *Id.* at P 154.

System Operator, Inc. ("NYISO"), and ISO New England show that such programs increase demand responsiveness in a region, and that permitting ARCs to participate in wholesale markets could encourage development of demand response programs.[28]

Certain parties to the proceeding opposed the requirement to permit direct participation of aggregators in the wholesale markets, arguing that the rule would violate the lines between federal and state jurisdiction and such aggregation of retail demand would require regulatory commission approval.[29] To address the concerns of state and local retail regulatory entities and avoid new jurisdictional concerns, the Commission adopted its proposal to require participation of ARCs into regional markets "unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate in this activity."[30]

On rehearing, the Commission rejected arguments that its order to allow direct participation by aggregators into wholesale markets exceeds its authority under the Federal Power Act.[31] The Commission reaffirmed that "well-functioning competitive wholesale electric markets should reflect current supply and demand conditions"; that "wholesale markets work best when demand can respond to the wholesale price"; and that the ARC requirement is one element of achieving the

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[28] *Id.*
[29] *Id.* at PP 141–143.
[30] *Id.* at P 155.
[31] Wholesale Competition in Regions with Organized Electric Markets, 128 FERC ¶ 61,059 at P 44 (July 16, 2009) ("Order 719-A").

Commission's statutory goals.[32] The Commission again recognized the direct and indirect benefits of demand response on wholesale market prices, including by enhancing reliability.[33]

The Commission further explained that its rule "did not challenge the role of states and others to decide the eligibility of retail customers to provide demand response . . . ."[34] The Commission adopted changes to Order 719 to address alleged burdens that the rule could place on smaller entities: for small utilities that distribute less than four million megawatt-hours, the grid operator cannot accept an ARC bid unless the relevant electric retail regulatory authority *permits* such a bid; whereas for utilities larger than that threshold, the grid operator must accept an ARC bid unless the relevant authority *prohibits* it.[35] However, the Commission rejected claims that Order 719 imposes upon the relevant regulator a burden to clarify for an RTO/ISO whether an ARC may aggregate demand response within its jurisdiction.[36] The Commission reiterated that Order 719 "indicated only that the RTO and ISO must accept bids from an ARC unless the laws or regulations of the relevant electric retail regulatory authority do not permit the ARC to bid."[37] Thus, "the Final Rule does not require retail regulators to take any action whatsoever."[38]

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[32] *Id.*
[33] *Id* at PP 46-47.
[34] *Id.* at P 49.
[35] *Id.* at PP 51, 60.
[36] *Id.*at P 57.
[37] *Id.*
[38] *Id.*

Several parties sought rehearing of the revised Order 719. Among other concerns, the rehearing requests sought clarity on the treatment of LSEs and third-party agents who may be designated by LSEs to provide demand response.[39] The request argued LSEs should not inadvertently be included in the definition of an ARC and that third party agents for LSEs should not be treated as ARCs, because the automatic exclusion of such entities from providing demand response in small utility service territories would perversely create a barrier to demand response programs.[40] The Commission rejected the request as contrary to the goal of the proceeding to "improve the operation of wholesale competitive markets in organized market regions."[41] The Commission explained that providing such "special treatment" to LSEs and their third-party agents would afford them a "competitive advantage" over ARCs that is contrary to the Commission goal of enhancing competitive markets.[42] Further, the Commission was "not persuaded that such action is consistent with [its] obligation to prevent undue discrimination."[43] Ultimately, no party challenged Order 719 in court.

b. The Supreme Court Upheld Commission Authority to Set Rules for Demand Response Participation in Wholesale Markets.

In 2011, the Commission issued Order 745 to address compensation for

[39] Order Denying Rehearing and Providing Clarification, 129 FERC ¶ 61,252 at PP 18–21 (Dec. 1, 2009) ("Order 719-B").
[40] *Id*. at P 18, 20.
[41] *Id*. at P 22–23.
[42] *Id*. at PP 22–24
[43] *Id*. at P 24.

demand response in wholesale energy markets.[44] The Commission reiterated that "a market functions effectively only when both supply and demand can meaningfully participate" and found that compensation levels inhibited meaningful demand side participation.[45] On rehearing, parties again challenged the Commission's authority to regulate demand response because "demand response is a retail non-purchase and retail rates have traditionally been subject to State or local regulation."[46] Parties also alleged that Order 745 interfered with existing retail demand response programs, and therefore intruded on state jurisdiction.[47] Ultimately on appeal, the Supreme Court rejected these arguments. The Court concluded that market operators' payment of demand response commitments directly affect wholesale rates; that in addressing those practices, the Commission does not regulate retail sales, and; finally, that finding the opposite would contradict the core purposes of the Federal Power Act.[48] The Court recognized that the Federal Power Act bars the Commission from regulating retail rates, but concluded that FERC regulation does not constitute retail regulation merely because it affects "even substantially" the "quantity or terms of retail sales."[49] Because "every aspect of the regulatory plan happens exclusively on the wholesale market and governs exclusively that market's

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[44] Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 (March 15, 2011) ("Order 745").
[45] *Id*. at P 1.
[46] Order on Rehearing and Clarification, 137 FERC ¶ 61,215 at PP 12–19 (Dec. 15, 2011) ("Order 745-A").
[47] *Id*. at P 17.
[48] *FERC v. EPSA,* 136 S.Ct. 760, 773 (2016).
[49] *Id*. at 775–76.

rules," Order 745 remains within the Commission's jurisdictional bounds.[50]

No party challenged FERC's provision for state opt-outs, first adopted in Order 719 and maintained in Order 745. As such, the Court did not address the lawfulness of this aspect of the Commission's regulations. However, the Court noted that such solicitude toward the States was a "finishing blow" to opponents' jurisdictional arguments.[51]

c. The Commission Declined to Afford State "opt-outs" for Energy Efficiency Resources and Electric Storage Resources.

In the years following the definitive ruling of the Supreme Court upholding the Commission's authority to regulate wholesale participation of demand resources, the Commission has declined to extend state authority to ban other resources from participating in wholesale markets, notwithstanding that such participation may result in significant impacts to retail sales.

In 2017, Advanced Energy Economy, a trade organization, sought a declaratory petition to establish, *inter alia*, the Commission's exclusive jurisdiction to regulate the participation of certain energy efficiency resources ("EER") in the wholesale electricity markets.[52] A retail regulatory commission sought to restrict the ability of EERs to participate in wholesale markets.[53] The grid operator, PJM, then launched a stakeholder process to consider a mechanism parallel to the demand response opt-out to enable RERRAs to limit EER participation within their

[50] *Id*. at 776.
[51] *Id*. at 779–80.
[52] *Advanced Energy Economy*, 161 FERC ¶ 61,245 at P 1 (Dec. 1, 2017).
[53] *Id*. at P 9.

retail service area.[54] Advanced Energy Economy argued that because Order 719 did not provide for such an EER opt-out, only the Commission held the authority to adopt one. The Commission agreed, finding that: "the Commission has exclusive jurisdiction over the participation of EERs in wholesale markets."[55] Further, the Commission concluded that "EERs' connection to retail electric service does not dictate the jurisdictional authority of RERRAs regarding EERs' wholesale market participation."[56] Instead, "[a] unilateral state action that directly prohibits or limits the participation of EERs in the wholesale markets directly impacts which EERs are eligible for participation and impermissibly intrudes upon the wholesale electricity market, a domain Congress reserved to the Commission alone."[57] The Commission did not grant a blanket power to states to ban EER participation in wholesale markets, stating that the Commission would consider any such requests "in a manner consistent with the Commission's obligations to ensure that the rates, terms, and conditions of wholesale markets are just and reasonable and not unduly discriminatory or preferential."[58]

In the landmark Order 841, the Commission likewise declined to grant states the ability to block energy storage resources ("ESR") participation in wholesale

[54] *Id.*
[55] *Id.* at P 57.
[56] *Id.* at P 59.
[57] *Id.* at P 61. (citing *Hughes v. Talen Energy Marketing LLC*, 136 S.Ct. 1288, 1292 (2016) (internal quotation omitted)).
[58] *Id* at P 72.

markets, even where ESRs are interconnected at the distribution-level.[59] The Commission again concluded that it "has exclusive jurisdiction over the wholesale markets and the criteria for participation in those markets, including the wholesale market rules for participation of resources connected at distribution-level voltages or behind the meter."[60] The Commission considered the effects the wholesale sales from ESRs would have on the distribution system in deciding whether to exercise its discretion to grant an opt-out, but concluded that "the benefits of allowing electric storage resources broader access to the wholesale market outweigh any policy considerations in favor of an opt-out."[61] The Commission reasoned that the opt-out could limit participation, and impact the significant benefits of removing barriers to ESRs participation.[62]

The Commission acknowledged that nothing in Order 841, however, preempted the states' right to regulate the safety and reliability of the distribution system.[63] The Commission explained that the order does not modify states' authority to provide terms of access, so long as the states "do not aim directly at the RTO/ISO markets."[64] Thus, states have the authority to include conditions in their own retail programs that prohibit participants from also selling into RTO/ISO

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[59] Electric Storage Participation in Markets Operated by RTOs and ISOs, 162 FERC ¶ 61,127 at PP 29, 31 (Feb. 15, 2018) ("Order 841").
[60] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 167 FERC ¶ 61,154 at P 38 (May 16, 2019) ("Order 841-A").
[61] *Id*. at P 56.
[62] *Id*.
[63] *Id*. at P 46.
[64] *Id*. at P 48 (internal quotation omitted).

markets.[65] Market participants then possess a choice between participating in retail or wholesale markets. States, however, "may not take away that choice by broadly prohibiting all retail customers from participating in RTO/ISO markets."[66]

d. The D.C. Circuit Upheld Order 841, Recognizing That the Commission Holds Exclusive Authority to Determine Who May Participate in the Wholesale Markets.

Parties challenged Order 841 and the Commission's failure to incorporate a state opt-out in court as inconsistent with the jurisdictional limits of the Federal Power Act, but the D.C. Circuit fully rejected these arguments. The Court "swiftly" concluded that the Commission's proscription against blanket bans on wholesale participation "directly affects wholesale rates."[67] Order 841 "hits the [jurisdictional] bullseye" because "keeping the gates open to all types of ESRs," regardless of their interconnection points, ensures technological advances are fully realized in the markets, leads to greater competition, and thereby reduces wholesale rates.[68] The Court further concluded that Order 841 did not regulate matters left to the states under the Federal Power Act.[69] While "favorable participation models will lure local ESRs to the federal marketplace" and therefore impact the distribution system through which they connect, such effects are permissible.[70]

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[65] *Id.* at P 41.
[66] *Id.*
[67] *Nat'l Ass'n of Regulatory Util. Commissioners ("NARUC") v. FERC*, 964 F.3d 1177, 1186 (D.C. Cir. 2020).
[68] *Id.*
[69] *Id.* at 1187.
[70] *Id.*

In response to the argument that Order 841 deprives states of the authority to block local ESRs from seeking access to wholesale markets through distributional facilities, the Court explained that it is not Order 841 that has the effect of depriving states of this authority, but rather the "well-established principles of federal preemption."[71] The Supremacy Clause dictates this result.[72] The Court elaborated:

> Any effort that aims directly at destroying FERC's jurisdiction by necessarily dealing with matters which directly affect the ability of the Commission to regulate comprehensively or effectively over that which it has exclusive jurisdiction invalidly invades the federal agency's exclusive domain.[73]

Order 841, by taking off the table blanket state opt-outs but acknowledging that other forms of state regulation of local ESRs is permissible, merely repeats the ordinary principle that State's regulations "aimed directly" at matters in FERC's jurisdiction are preempted, "and those aimed at" fulfilling a State's own jurisdictional obligations are not.[74]

e. The Commission Declined to Afford State "opt outs" for Distributed Energy Resources.

Most recently, the Commission again declined to extend state authority to ban resources from participating in wholesale markets in the context of distributed energy resources ("DER").[75] The final rule enables DERs to participate in the

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[71] *Id.*
[72] *Id.*
[73] *Id.* at 1187–88 (internal quotation and citation omitted).
[74] *Id.* at 1189.
[75] Order 2222 at P 8, 56.

regional organized wholesale capacity, energy and ancillary services markets alongside traditional resources.[76] Multiple DERs can aggregate to satisfy minimum size and performance requirements that they might not meet individually.[77] The order is an outgrowth of FERC Order 841, which set similar rules for batteries and other energy storage systems to serve in wholesale markets. However, Order 2222 is much broader in scope, and provides guidance for how various types of aggregated resources can be integrated into wholesale markets. Order 2222 requires that:

> For each RTO/ISO, the tariff provisions addressing distributed energy resource aggregations **must** (1) allow distributed energy resource aggregations to participate directly in RTO/ISO markets and establish distributed energy resource aggregators as a type of market participant. . .[78]

The Order further adopts a technology neutral definition of distributed energy resources that expressly includes, *inter alia*, "demand response."[79] The Commission further clarified "that, because demand response falls under the definition of distributed energy resource, an aggregator of demand response could participate as a distributed energy resource aggregator."[80]

In the final rule the Commission sought to "remove barriers to the participation of distributed energy resource[] aggregations in the Regional Transmission Organization (RTO) and Independent System Operator (ISO) markets

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[76] *Id*. at PP 1, 26, 141.
[77] *Id*. at P 142.
[78] *Id*. at P 8 (emphasis added).
[79] *Id*. at P 114.
[80] *Id*. at P 118.

(RTO/ISO markets)."[81] The Commission found that "existing RTO/ISO market rules are unjust and unreasonable in light of barriers that they present to the participation of distributed energy resource aggregations."[82] The Commission concluded that "establishing the criteria for participation in RTO/ISO markets, including with respect to resources located on the distribution system or behind the meter, is essential to the Commission's ability to fulfill its statutory responsibility to ensure that wholesale rates are just and reasonable."[83] In this context, the Commission specifically declined to grant states the ability to block DER participation in wholesale markets,[84] finding that the "reliability, transparency, and market-related benefits" of participation by aggregators "outweigh the policy considerations in favor of an opt-out."[85]

However, the Commission inexplicably and contradictorily preserved the opt-out in Orders 719 and 719-A, thus allowing retail authorities to bar participation only one specific type of resource, aggregators of demand response resources.[86] FERC's Order 2222 nevertheless underscores the importance of DR benefits to competition, just and reasonable rates, and the value of using aggregators. Indeed, the Commission specifically recognized that an opt-out can "substantially limit

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[81] *Id*. at P 1 (citation omitted).
[82] *Id*.
[83] *Id*. at P 57.
[84] *Id*. at P 56.
[85] *Id*. at P 60.
[86] *Id*. at PP 59, 145.

[resource] participation" and thereby deprive RTO/ISO markets of "significant" benefits.[87]

2. Factual Background

a. The Need for the Flexibility of Demand Response to Ensure Affordable, Reliable Service in MISO has Never Been Greater.

The circumstances that have led to unprecedented reliance on demand response within MISO are "well documented" in a series of MISO-published whitepapers dating back to March 2019, as well as related MISO filings and corresponding Commission Orders.[88] As MISO describes:

> The MISO Region is transitioning from a generation portfolio dominated by coal and nuclear generation resources to a portfolio that relies on an increasing quantity of intermittent and emergency only resources – even to meet MISO's planning reserve requirements. Base load generation retirements have increased the pace of this transition and have caused MISO to operate with actual capacity margins that have consistently been decreasing towards minimum resource requirements. As a result, MISO has experienced a decrease in operational flexibility as capacity margins continue to diminish.[89]

MISO explains that operating at or near minimum reserve margin requirements results in greater exposure to correlated risks, such as extreme weather events.[90] At the same time, MISO states that it faces increasing forced outage rates for

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[87] *Id.* at P 60; *see also id.* at P 4 (explaining that integrating distributed energy resources' capabilities into RTO/ISO planning and operations will help the RTOs/ISOs account for the impacts of these resources on installed capacity requirements and day-ahead energy demand, thereby reducing uncertainty in load forecasts and reducing the risk of over procurement of resources).
[88] MISO 2020 LMR Filing, ER20-1846 at 3 (citing various MISO whitepapers and reports); *see also MISO*, 172 FERC ¶ 61,138 (Aug. 14, 2020) (accepting tariff change in light of heightened reliance on demand response in MISO to ensure reliability).
[89] MISO 2020 LMR Filing, ER20-1846 at 3.
[90] *Id.*

generation and significant correlation in the timing of planned outages and derates.[91] These circumstances result in resource risk outside of the traditional summer peak times. Further, MISO describes that increased reliance on intermittent and variable resources creates the need for intra-day flexibility.[92] MISO has experienced a significant increase in the number of Maximum Generation Emergencies, including alerts, warning, events, and more of such emergencies outside of the traditional summer peak.[93] MISO explains that this combination of factors increases the need for resources that can respond with short notification times, before emergency operations begin. Consequently, demand response resources now serve a particularly crucial role to ensuring reliability in MISO. Moreover, it is not merely the *quantity* of such resources, but the *quality* – i.e., their operational characteristics, including availability, notification time, and performance during emergency conditions – that is critical to effective, efficient and reliable operations.[94] MISO explains that current reliance on demand response to meet LSE planning reserve margin requirements "has never been greater" and that these resources "are one of MISO's 'last lines of defense' before having to engage in firm load shedding."[95] Nor is reliance on demand response a near-term phenomenon. MISO projects that its reforms to resource adequacy will continue to

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[91] *Id.*
[92] *Id.*
[93] *Id.* at 4.
[94] *See e.g.,* MISO Motion for Leave to Answer and Answer, ER20-1846 (July 2, 2020) at 6 (LMR must have certain operational characteristics to have significant reliability impact).
[95] MISO 2020 LMR filing, ER20-1846 at 3.

focus on enhancing resource availability, visibility, and flexibility, as the shift in the resource mix and other factors driving reliance on demand response will only intensify in the future.[96]

b. Even as Reliance on Demand Response is at its Height, MISO Continues to Lack the Requisite Operational Quality of Demand Response.

At the same time that MISO recognizes that the additional operational flexibility offered by demand response is critical to the challenges it faces now and for the foreseeable future, it considers the suite of demand response resources currently available insufficient to meet operational needs. In particular, although a large quantity of capacity participates in MISO as "load modifying resources" ("LMR"), MISO has found the historical performance and operating characteristics of existing LMRs to be inadequate to meet MISO's changing needs.

MISO defines demand response as "actions taken to reduce consumption when the value of consumption is less than the marginal cost to supply the electricity,"[97] and offers a number of different demand response market

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[96] *Id.* at 7 (notwithstanding recent reforms, "more is currently needed, and will continue to be required going forward, to ensure reliable system operations, including with respect to LMRs."); *see also id.* at Prepared Direct Test. of Shawn McFarlane ("McFarlane Test."), at 3:17–3:19; MISO Filing to Enhance LMR Participation in MISO Markets ("MISO 2018 LMR Availability Filing"), ER19-650 at Prepared Direct Test. of Jeff Bladen ("Bladen Test."), at 8:3–8:8 (Dec. 21, 2018); MISO, *Aligning Resource Availability and Need* at 10 (Dec. 2019), https://cdn.misoenergy.org/20191218%20Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf; MISO, *MISO Forward 2020*, *Utilities of the Future: What do they need from a grid operator?* at 4-6 (March 2020), http://view.ceros.com/miso-energy/misoforward2020/p/1 .

[97] Potomac Economics, *2018 State of the Market Report for the MISO Electricity Market ("*2018 State of the Market Report"), Analytic Appendix at 161 (July 2019).

mechanisms allowing resources to participate in the wholesale market. Although MISO offers three different categories of demand products, including 1) LMRs; 2) Emergency Demand Response Resources ("EDR"), and 3) Demand Response Resources ("DRR"),[98] the vast majority – roughly 90% – of demand response in MISO appear as LMR resources.[99] LMRs include demand response resources and behind-the-meter generation that clear MISO's PRA and provide interruptible load services during capacity shortages to help meet the energy balance.[100]

Although MISO procures a high proportion of demand response relative to its load,[101] historically LMRs have been relied upon infrequently. Since MISO's market inception in 2005, there have only been ten instances[102] where LMRs were called to address capacity shortages – seven of which occurred since 2017.[103] In only one of

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[98] *Id*. at 91.
[99] *Id*. at 92.
[100] More detailed information about eligibility and performance requirements of LMRs are described in the MISO 2020 LMR filing, ER20-1846 at McFarlane Test. at 4–6.
[101] Steve Dahlke & Matt Prorok, *Consumer Savings, Price, and Emissions Impacts of Increasing Demand Response in Midcontinent Electricity Market*, 40(3) THE ENERGY JOURNAL (2019) (noting MISO has a high share of demand response relative to load compared to other RTOs); *see also* Potomac Economics, *2019 State of the Market Report for the MISO Electricity Market* ("2019 State of the Market Report") at 107 (MISO's demand response capability is about 10 percent of peak load, a larger proportion than NYISO but slightly less than ISO-NE).
[102] The emergency events occurred on August 1, 2006; February 3-5, 2007; April 4, 2017; January 17-18 2018; September 15, 2018; January 30, 2019; May 16, 2019. In some cases, LMRs were scheduled more than once related to the same event.
[103] *See* MISO, *Load Modifying Resources, Capacity Instruments Affecting Resource Availability and Need* ("MISO LMR Whitepaper") at 4 (May 25, 2018) (as of May 2018, LMRs have only been called on eight occasions), https://cdn.misoenergy.org/20180531%20RSC%20Item%2009%20LMR%20Issues%20Whitepaper206830.pdf; *see also* Potomac Economics, *2018 State of the Market Report* at 94 (LMRs called in Jan 2018, Sept 2018, and Jan 2019) ; Potomac

those occasions did MISO call upon all LMRs.[104] MISO explains that, in the past, capacity surpluses exceeded 40% of coincident peak, and LMR-type resources were used to meet infrequent "super-peaking" needs when demand was much higher than the expected forecast.[105] Given the limited prior reliance on demand response, MISO explains that its LMR participation rules "focused on accommodating existing utility programs and capabilities."[106]

Now put to the test under recent conditions of tighter supply, MISO has repeatedly expressed concerns that it cannot rely on existing LMR to be available and perform during emergencies. The notification time for LMR is substantially longer than demand response capabilities in other RTO/ISOs. Prior to reforms adopted over the past year, nearly a third of LMRs required 12-hour notice and another 60 percent could be available within a four-hour window.[107] Subsequent to its tariff reforms, MISO reports that notification requirements have declined significantly, yet some 20 percent of LMRs continue to require longer than 6 hour notification to be available.[108] In contrast, emergency demand response products in PJM, CAISO, and NYISO allow for only 30-minute to at most 2-hour notice.[109] Lack of LMR with short notification times has resulted in MISO being able to call only a

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Economics, *2019 State of the Market Report*, Analytic Appendix at 59–62 (June 2020) (LMRs scheduled four times between January and May of 2019).

[104] MISO LMR Whitepaper at 1.

[105] *Id.* at 3–4.

[106] *Id.* at 1.

[107] *Id.*at 5.

[108] MISO 2020 LMR Filing, ER20-1846 at McFarlane Test. at 8.

[109] *MISO*, 172 FERC ¶ 61,138 at n. 13 (citing MISO 2020 LMR filing and McFarlane Test.).

small fraction of LMR during an emergency.[110] In the lead up to emergency events where MISO was able to provide longer notification time, existing LMR has underperformed.[111]

Recent tariff reforms, including changes to allow MISO to schedule long-lead LMRs in advance of emergencies[112]; a requirement on LMRs to offer based on actual availability in all seasons[113]; LMR testing requirements[114]; and limiting full accreditation to LMRs meeting certain shorter-notification requirements and availability requirements[115], are projected to continue to enhance LMR availability and transparency around LMR capabilities. Yet MISO has never contended that these "short term fixes intended to moderate current operational concerns" would alleviate the need for "a more holistic set of longer term solutions."[116] Indeed, even as MISO reported greater availability and flexibility in LMR at the time of registration, actual availability of LMR in operations decreased over the past year.[117] Moreover, the recently-approved reforms are projected to result in declines in total LMR, potentially leading to the loss of as much as 2.6 GWs of capacity

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[110] *See e.g.*, MISO Filing to Implement Demand Response Testing ("MISO 2018 LMR Testing Filing"), ER19-651, at Prepared Direct Test. of Timothy Aliff ("Aliff Test") at 11-12 (Dec. 21, 2018) (during one emergency event, MISO could only call on 1.4 MWs of LMR, though 1288 MWs cleared the PRA in MISO South region. Ultimately, LMRs "overperformed" when ~130 MWs were available in that hour.).
[111] *Id*. at 10, 12.
[112] *See MISO,* 166 FERC ¶ 61,116 (Feb. 19, 2019).
[113] *Id*.
[114] *See MISO*, 166 FERC ¶ 61,235 (Mar. 29, 2019).
[115] *See MISO*, 172 FERC ¶ 61,138, ER20-1846.
[116] MISO 2018 LMR Testing Filing, ER19-651 at 2 (Dec. 21, 2018).
[117] MISO 2020 LMR Filing, ER20-1846 at McFarlane Test. at 9.

depending on how rapidly market participants respond to changing accreditation requirements.[118] Such losses will occur even as MISO's reforms have not addressed larger structural concerns about LMR availability, including the discrepancy between where most LMRs are located (in North and Central MISO) and where most emergency events arise and LMRs or other flexible demand response are most needed (in MISO South).[119] In sum, MISO continues to need the capabilities of flexible, available demand response in order to ensure efficient, reliable and affordable operation both now and for the foreseeable future.

c. RERRAs have Blocked Aggregator Participation in MISO Across Nearly the Whole of the MISO Footprint.

MISO covers all or part of 15 states. In all but three states, aggregators of demand response that are not acting on behalf of an LSE are barred from directly participating in MISO.[120] Most states[121] adopted restrictions on ARC participation around 2009 or shortly thereafter, subsequent to the Commission's decision on rehearing of Order 719.[122] In several cases, the bans on ARC participation were adopted by orders that were styled as temporary to allow for further deliberation.[123] Many of these early orders raised basic questions about matters such as the benefits of demand response to retail customers, or the mechanism by which non-utility

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[118] Order Accepting Tariff Revisions, 172 FERC ¶ 61,138, ER20-1846 at P6.
[119] MISO 2018 LMR Availability Filing, ER19-650 at Aliff Test. at 10.
[120] *See* Centolella, Ex. A at Appendix B; *see also* State Opt-out Chart, Ex. C.
[121] The term "state" throughout the Complaint includes both RERRAs and state legislatures.
[122] Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin. Centolella, Ex. A at Appendix B; *see also* State Opt-out Chart, Ex. C.
[123] Specifically, Iowa, Michigan, Minnesota, Missouri, and Wisconsin. *Id.*

participants could be credited for reductions in load.[124] A decade later, these "temporary" orders largely stand unchanged.[125] Other early orders provided little or no rationale at all, and also remain in force, unchanged.[126]

The remaining states that have adopted orders banning ARCs did so recently, in response to efforts by aggregators to do business within the regulated utility service territory.[127] In two instances, the mere notification of the registration of an ARC prompted, without deliberation, interim orders barring further activity by ARCs.[128]

Only one state in MISO has adopted a law restricting ARCs. In 2013, the Arkansas General Assembly passed legislation restricting ARC unless the Arkansas

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[124] Missouri Pub. Serv. Comm'n, *Order Temporarily Prohibiting the Operation of Aggregators of Retail Customers*, Docket No. EW-2010-0187 (Mar. 31, 2010) (identifying list of questions to be resolved); Wisconsin Pub. Serv. Comm'n, *Order Temporarily Prohibiting Operation of Aggregators of Retails Customers*, Docket No. 5-UI-116, at 4 (Oct. 14, 2009) ("Further investigation is warranted about the effective utilization of demand response options in retail and wholesale markets that will provide benefits to all Wisconsin consumers.").

[125] The Michigan Public Service Commission reopened a proceeding in 2017 to consider certain changes to the 2009 order banning ARCs, but ultimately retained the ban in its original order. *See* Michigan Pub. Serv. Comm'n, *Order*, Case No. U-20348 (Aug. 8, 2019).

[126] North Dakota Pub. Serv. Comm'n, *Order Prohibiting ARC Operations*, Case No. PU-10-59 (Aug. 24, 2010); South Dakota Pub. Serv. Comm'n, *Order Prohibiting Customers and Aggregators from Participating in Wholesale Electric Markets*, Docket No. EL-10-003 (May 25, 2010).

[127] In Kentucky, Louisiana and Mississippi, the utility commission issued orders in 2017, 2019, and 2019 respectively, after regulated utilities provided the retail authority notice of the aggregator's activity. *See* Ex. C, State Opt-out Chart.

[128] *See* Mississippi Pub. Serv. Comm'n, *Order*, Docket No. 2018-AD-141 (Mar. 5, 2019) (*sua sponte* order restricting ARCs); Louisiana Pub. Serv. Comm'n, *General Order 3-7-2019*, Docket No. R-34948, at 2 (Mar. 7, 2019) (describing the September 19, 2018 interim directive restricting ARCs).

Public Service Commission ("Arkansas Commission") determines such action to be in the public interest.[129] After long dormancy, the Arkansas Commission opened an informational docket and then, on July 7, 2020, established a procedural schedule to consider the matter.[130] On August 28, 2020, Arkansas Commission staff filed comments recommending that it is in the public interest to allow ARC participation.[131] The proceeding is ongoing, with further opportunity for comment anticipated before the Arkansas Commission issues a decision in the matter.[132]

At the same time that nearly all states in the MISO footprint have prohibited the participation of ARCs in the wholesale market, several states have encouraged generally or approved specific ARCs to serve as a third-party agents for an LSE.[133] Such arrangements typically take two forms, one version in which certain ARCs are qualified by the utility to sign up retail customers, but the utility itself enrolls the customers in the wholesale demand response program.[134] Alternatively, a utility

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[129] Regulation of Electric Demand Response Act, Act 1078 of 2013, Arkansas Code §§ 23-18-1001 *et. seq*.

[130] Arkansas Comm'n, *Order No. 10*, Docket No. 16-028-U (July 27, 2018) (expanding scope of docket to include "DER aggregation matters"); Arkansas Comm'n, *Order No. 9*, Docket No. 09-090-U (July 7, 2020) (establishing schedule for comments on aggregators of retail customers and demand response programs).

[131] General Staff of Arkansas Comm'n, *Initial Comments and Legal Br. Pursuant to Order No. 9*, Docket No. 09-090-U (Aug. 28, 2020) ("Arkansas Comm'n General Staff's Comments").

[132] Arkansas Comm'n, *Order No. 13*, Docket No. 09-090-U (Oct. 13, 2020) (determining that certain issues should be addressed by further rounds of comment).

[133] Indiana, Louisiana, Minnesota, Missouri, Mississippi, Montana, North Dakota and South Dakota. *See* Centolella, Ex. A at Appendix B.

[134] *See* Advanced Energy Management Alliance, *Advancing Demand Response in the Midwest. Expanding Untapped Potential* at 10-11 (Feb. 12, 2018) (describing the so-called "Indiana model").

may contract with a single demand response provider, setting explicit terms for enrollment, design, and implementation of the entire program.[135] In each case, the LSE retains significant control over the design of the demand response program and terms of compensation. As discussed further herein, efforts to enable aggregator participation through such arrangements have largely been unsuccessful. Such arrangements have not supported significant opportunities for aggregators to participate in MISO markets, nor provided a substitute for robust competition of demand response in MISO markets.

VI. DISCUSSION

1. States Lack Authority to Adopt a Blanket Ban on Wholesale Demand Response Participation.

a. Caselaw since the Adoption of Order 719 Now Shows that Blanket State Opt-Outs are Inconsistent with the Federal Power Act.

The Commission adopted provisions in Order 719 for states to categorically limit retail customer participation in wholesale markets at a time when its authority over demand response resources remained uncertain. Subsequent legal developments have clarified not only that the Commission has the authority to set the eligibility and other terms of participation of resources that are composed of retail customer actions or that connect at the distribution system in wholesale markets, but that this authority is exclusive.[136] The D.C. Circuit's recent decision

[135] *Id*. at 12–13.
[136] *EPSA*, 136 S.Ct. 760, 771 (2016); *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016).

upholding Order 841 now leaves no doubt that the approach taken in Order 719 is inconsistent with the Federal Power Act's basic jurisdictional divide.

Order 841 omitted, over the objection of retail regulators, the opt-out afforded in Order 719. Yet in upholding the consistency of Order 841 with the Federal Power Act, the Court did not conclude that withholding such an opt-out was merely a reasonable choice within the Commission's discretion. Rather, the D.C. Circuit upheld Order 841 on grounds that have broader implications. The Court explained that Commission's denial of such an opt-out is not an usurpation of state authority, but "simply a restatement of the well-established principles of federal preemption."[137] In other words, under the plain terms of the Federal Power Act, states *do not possess authority* to directly determine whether resources are permitted to participate in RTO/ISO markets. Such state actions directly "aim at" wholesale transactions and are therefore field preempted.[138] As the Court described, a categorical ban on wholesale participation of certain resources "aims directly at destroying FERC's jurisdiction" – such state actions prohibit the very wholesale transactions that are the subject of FERC's authority, and necessarily impact the ability of the Commission to regulate comprehensively and effectively.[139]

The Commission acknowledges this clear shift in case law in Order 2222, where the Commission explains that it is the Commission that "has exclusive jurisdiction over the wholesale markets and the criteria for participation in those

[137] *NARUC*, 964 F.3d at 1187.
[138] *Id*.
[139] *Id*. at 1187–88.

markets,"[140] and therefore that a RERRA "cannot broadly prohibit the participation" of a category of resources or resource aggregators "as doing so would interfere with the Commission's statutory obligation to ensure that wholesale electricity markets produce just and reasonable rates."[141] The Commission simply failed to apply this legal framework to the opt-out in Order 719.

While *EPSA*, *Hughes,* and *NARUC* did not directly address the legality of the state-opt out in Order 719, the Commission can no longer evade their implications. The legal landscape has shifted since 2009, and the opt-out originally afforded states in Order 719 is no longer legally viable.

b. The Commission Lacks a Legally Relevant Basis to Distinguish Between Categorical Bans on the Participation of Demand Response and Those Prohibiting Other Resources.

Assuming *arguendo* that the Commission has some discretion in the matter, the Commission could not reasonably conclude that a state opt-out of demand response is consistent with the Federal Power Act, but that state opt-outs of storage and DERs are not. The Commission has already forcefully taken the position that a state ban on storage resources would be "preempted" because such a state action "aims directly at the wholesale markets."[142] The Commission cannot make a principled distinction between a state ban on wholesale participation of demand response resources and a ban on wholesale participation by storage resources or

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[140] Order 2222 at P 57.
[141] *Id*. at P 58.
[142] *See generally* D.C. Circuit Court of Appeals, *Brief for Respondent FERC*, Docket Nos. 19-1142 and 19-1147, at 53–63 (Mar. 13, 2020) (quoting language of Order 841-A) ("FERC Storage Brief").

DERs. Each of these state actions categorically bar a type of *wholesale transaction* and therefore "aim at" or "target" the wholesale markets to exactly the same degree.

The Commission itself has argued that "preemption turns on the subject or target of the state action, not its effects."[143] The Commission then made clear that a "state law—e.g., legislation, rule, or administrative order—categorically barring" a wholesale resource transaction would "aim[] *directly* at the [wholesale] markets subject to FERC's exclusive jurisdiction and, accordingly, would intrude on that exclusive federal field."[144]

When a regulator exercises its authority in a manner that aims to regulate that which is reserved to the other sovereign's exclusive authority, it oversteps its jurisdictional bounds just as if it had directly set a rate subject to the other regulator's control.[145] In the Order 841 litigation, FERC examined *Hughes*, citing it as "recent guidance on when a state program impermissibly aims at FERC's regulatory turf."[146] FERC then argued that a hypothetical ban on storage facilities would be field preempted under Hughes because "[w]hile the [state] law regulated entities over which States exercise control—generation resources, 16 U.S.C. § 824(b)(1)—it did so in a way that targeted FERC's statutory domain."[147] The

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[143] *Id*. at 54; *see also Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 385 (2015) ("Those precedents emphasize the importance of considering the *target* at which the state law *aims* in determining whether that law is pre-empted").
[144] FERC Storage Brief at 54 (internal quotations omitted) (emphasis original).
[145] *Hughes*, 136 S. Ct. at 1297.
[146] FERC Storage Brief at 55.
[147] *Id*. at 56.

Commission cited to a plethora of additional authorities in support for the proposition.[148]

FERC's argument in the Order 841 litigation is consistent with its position with regard to energy efficiency resources, where it found that state and local prohibitions on certain energy efficiency resources directly affect wholesale rates and therefore infringed upon the Commission's statutory mandate. Specifically, the Commission found that:

> A unilateral state action that directly prohibits or limits the participation of EERs in the wholesale markets directly impacts which EERs are eligible for participation and impermissibly intrudes upon the wholesale electricity market, a domain Congress reserved to the Commission alone.[149]

The logical consequence of the Commission's position, as articulated consistently in recent proceedings addressing storage, energy efficiency and distributed energy resources, is that the state actions that prohibit third party aggregators or individual retail customers from participating in MISO's wholesale markets are preempted.

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[148] *Id.* (string-citing *EPSA*, 136 S. Ct. at 780 ("The [Federal Power Act] leaves no room either for direct state regulation of the prices of interstate wholesales *or for regulation that would indirectly achieve the same result.*") (emphasis added; internal quotation marks omitted); *Elec. Power Supply Ass'n v. Star*, 904 F.3d 518, 523–24 (7th Cir. 2018) (upholding Illinois subsidy program for electricity generation because, unlike the Maryland program in *Hughes*, it did not supplement the wholesale market clearing price or require generators to bid into and clear the wholesale auction), *cert. denied*, 139 S. Ct. 1547 (2019); *accord Coal. for Competitive Elec. v. Zibelman*, 906 F.3d 41, 54 (2d Cir. 2018) (same conclusion for New York program), *cert. denied*, 139 S. Ct. 1547 (2019).")

[149] *Advanced Energy Economy*, 161 FERC ¶ 61,245 at P 61 (internal quotation marks omitted).

Nor do the factual distinctions between the different technologies – their differing characteristics, ways of interacting with the distribution system, or spillover effects on retail rates – change that conclusion. No doubt wholesale participation by storage resources, energy efficiency resources, demand response resources, and other forms of distributed energy resources each impose differing types and degrees of impacts on the legitimate interests of retail authorities. Yet, the Commission has been clear that such impacts are "legally irrelevant."[150] As the Commission pointed out in the Order 841 litigation, *Hughes* found that States "may not seek to achieve ends, *however legitimate*, through regulatory means that intrude on FERC's authority over interstate wholesale rates."[151] In each case, it is the direct aim of the state actions at wholesale transactions that matters, not the type of resource affected, or the potentially significant and legitimate state objectives.

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[150] FERC Storage Brief at 59; *see also Advanced Energy Economy,* 161 FERC ¶ 61,245 at PP 59, 62 *(*"EERs' connection to retail electric service does not dictate the jurisdictional authority of RERRAs regarding EERs' wholesale market participation").

[151] *Hughes*, 136 S. Ct. at 1290–91 (emphasis added); *see also Northern Natural Co. v. State Corp. Comm'n of Kan*, 372 U.S. 84, 93 (1963) ("We have already held that a purpose, *however legitimate* … does not warrant direct interference by the States with the prices of natural gas wholesales in interstate commerce.") (emphasis added); *New Eng. Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 290 (D.C. Cir. 2014) ("We have previously held that the Commission has jurisdiction to regulate certain parameters of the capacity market related to the price of capacity, even if those determinations touch on states' authority") (citing *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481–83 (D.C. Cir. 2009)).

c. The Commission Cannot Lawfully Cede its Authority Over Just and Reasonable Wholesale Rates to Retail Authorities.

Order 719 aimed to eliminate barriers to demand response, improve the competitiveness of wholesale markets, and thereby ensure just and reasonable rates. Yet by incorporating a blanket opt-out, the Commission placed retail authorities in the position of determining whether Order 719 will be fully implemented and its objectives achieved. In addition to the grounds described above, the opt-out adopted in Order 719 is *ultra vires* because it is an impermissible relinquishment of the Commission's duty to ensure just and reasonable and not unduly discriminatory rates.

The terms of the Federal Power Act are clear:

> Whenever the Commission . . . shall find that any rate . . . or that any rule . . . affecting such rate . . . is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract *to be thereafter observed and in force*, and shall fix the same by order.[152]

In each of Order 719 and 745, the Commission found that barriers to demand response impact the competitiveness of RTO/ISO markets, and reducing those barriers is necessary to ensuring rates that are just, reasonable and not unduly discriminatory or preferential.[153] The Commission concluded that reforms were needed to ensure demand response is "treated comparably to other resources."[154]

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[152] 16 U.S.C § 824e(a) (emphasis added); *New York v. FERC*, 535 U.S. 1, 27 (2002) ("Were FERC to investigate [] and make findings concerning undue discrimination . . . , § 206 of the [Federal Power Act] would require FERC to provide a remedy for that discrimination.").
[153] Order 719 at P 1; Order 745 at PP 8–10.
[154] Order 719 at P 15.

Order 719 specifically found that permitting aggregators to participate would "expand[] the amount of resources available to the market, increase[] competition, help[] reduce prices to consumers and enhance[] reliability."[155]

Yet, even as the Commission identified the changes necessary to address the market flaws, the Commission failed to ensure that these reforms shall be "thereafter observed and in force." States can block (and have done so to an extensive degree in the MISO footprint) the participation of aggregators and thereby obstruct the expansion of demand response resources and increased competition that the Commission found would contribute to reduced prices and enhanced reliability. The Commission cannot on one hand find that market rules fail to meet statutory muster and then, on the other, leave to chance the measures it has found necessary to remedy the inadequacy. The blanket opt-out afforded states in Order 719 represents precisely such an abdication of the Commission's statutory mandate. The Commission cannot leave fulfilment of its duty to ensure just and reasonable rates to the unmediated discretion of state authorities.

2. The Absence of Competition Among Demand Response Providers in MISO Due to Pervasive State Opt-outs Results in Rates That Are Not Just And Reasonable.

Fostering competitive bulk power markets is the bedrock of the Commission's statutory task to ensure just and reasonable rates in RTO/ISOs. Yet the opt-out in Order 719 has perversely become a significant barrier to competition. The near total adoption of bans on non-utility affiliated demand response within MISO insulates

[155] *Id*. at P 154.

utility demand response programs from competitive pressures. The resulting harm is significant, ongoing, and will worsen absent action from the Commission to eliminate barriers to competition. MISO is deprived of robust competition from demand response aggregators, specialists who are capable of providing cutting edge technologies at lowest cost. Absent inducements of the retail regulator, traditionally regulated utilities face little to no incentive to adopt ambitious demand response programs. Unsurprisingly, the operational capabilities of existing demand response assets in MISO lag significantly behind that of other organized markets, even though many utility-run programs are supported by significant subsidies through retail rate charges. Lack of competition brings exactly the lackluster results one would expect: high cost and poor performance.

Worse, the absence of competition is holding back the full capability of demand response within MISO at a time when it is needed more than ever to provide the grid flexibility in the face of shrinking reserve margins and a changing resource mix. During some recent events, a mere hundred megawatts or so of demand response, available in the right location and able to respond quickly, could have alleviated tight supply conditions. Yet, MISO lacked the flexible, responsive resources it needed. As MISO itself has documented, the strains on grid reliability are expected to worsen, and readily available, fast-responding demand response will remain essential to the grid.

Unlocking competition among demand response resources within MISO would both increase the amount of demand response in locations where it is currently lacking while creating the pressure for innovation and enhanced demand response capability. Enhanced competition is needed to drive the adoption of advanced demand response technologies that will be crucial to long-term affordability and reliability as conditions in MISO continue to evolve.

a. The Commission Has Long Recognized That Robust Participation of Demand Response Increases Market Competitiveness and Ensures Just and Reasonable Rates.

FERC has "on numerous occasions . . . expressed the view that the wholesale electric power market works best when demand can respond to the wholesale price."[156] FERC is guided by the general principle that increased demand response in organized wholesale markets "improve[s] the functioning and competitiveness of those markets."[157]

FERC has identified numerous benefits of demand response that support a healthy and well-functioning grid, that in turn supports just and reasonable rates. For example, FERC has found that demand response can "provide competitive pressure to reduce wholesale power prices."[158] Demand response "balance[es] supply and demand, and thereby, helps produce just and reasonable energy prices . . . because customers who choose to respond will signal to the RTO or ISO and energy market their willingness to reduce demand on the grid which may result in reduced

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[156] Order 719 at P 18.

[157] Order 745 at P 10; *see also* Demand Response Compensation in Organized Wholesale Energy Markets, Notice of Proposed Rulemaking, 75 FR 15362 at P 4 (Mar. 29, 2010) ("Demand response acting as a resource in organized wholesale energy markets helps to improve the functioning and competitiveness of such markets in several ways").

[158] Order 719 at P 16.

dispatch of higher-priced resources to satisfy load."[159] Furthermore, the Commission has identified that demand response also "tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy."[160] A plethora of studies confirm the beneficial cost reductions due to demand response.[161]

The Commission has also concluded that demand response can "mitigate generator market power," because "the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high."[162] The

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[159] Order 745 at P 10.
[160] *Id*. at n. 16.
[161] A study by PJM demonstrated that "a modest three percent load reduction in the 100 highest peak hours corresponds to a price decline of six to 12 percent." *See* Order 745 at n. 15 (citing ISO-RTO Council Report, *Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets* (Oct. 16, 2007); *see also*, Ahmad Faruqui *et al.*, *The Power of Five Percent*, THE ELECTRICITY JOURNAL (Oct. 2007) (conservatively estimating that a five percent reduction in peak demand through DR programs could lead to $35 billion in savings over a 20 year period), https://www.sciencedirect.com/science/article/abs/pii/S1040619007000991?via%3Dihub; FERC Staff, *A National Assessment of Demand Response* (potential to reduce peak demand by ten to twenty percent through demand respose, effectively eliminating the equivalent of between 1,000 and 2,500 peaking units); Stoll, Brady, Elizabeth Buechler, and Elaine Hale, "The Value of Demand Response in Florida," 30 THE ELECTRICITY JOURNAL 57 (Nov. 10, 2017) (studying value of demand response under high renewable penetration scenarios and finding $76 million to $259 million in cost savings due to increased deployment of demand response); Potomac Economics, *2019 State of the Market Report*, Analytical Appendix at 168 (June 2020) (citing "[r]eductions in price volatility and other market costs").
[162] Order 745 at P 10.

Commission has also examined the impact of demand response on grid reliability, and found that it has the effect of "support[ing] system reliability," as demand response "can provide quick balancing of the electricity grid."[163] In addition to these benefits, FERC has found that demand response can also "increase[] awareness of energy usage" and "encourag[es] development and implementation of new technologies, including renewable energy and energy efficiency resources, distributed generation and advanced metering."[164] Combined, these positive attributes of demand response have the effect of "improving the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power."[165]

Finally, a recent study points to additional benefits of demand response on power systems with increasing penetration of variable renewable energy generation, as demand response resources can provide the flexibility and other essential grid services needed to maintain reliable operations.[166]

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[163] *Id.*; *see also id.* at n. 17 ("Demand response 'contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power.'"); *id.* at n. 19 ("Demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings . . . .").
[164] Order 719 at P 48.
[165] *Id.* at P 16; *see also* Centollela, Ex. A at 3 (MISO's independent market monitor identified similar benefits of demand response within MISO).
[166] *See* Elaine Hale et al., *Potential Roles for Demand Response in High-Growth Electric Systems with Increasing Shares of Renewable Generation*, National Renewable Energy Lab (Dec. 2018) (identifying potential for demand response to provide needed peak load shifting, regulation reserves, ramping reserves, virtual

b. The Absence of Competition From Aggregators Deprives MISO of Their Unique Value and Stymies Robust Demand Response Participation.

The participation of unaffiliated DR aggregators contributes to just and reasonable rates in several ways. Such demand response providers afford unique value to the markets because their specialization can both increase the total quantity of demand response resources, and the operational capabilities of the resources participating in the market. Moreover, the competitive pressure that results from their participation will have the tendency to spur utility programs and affiliate demand response providers to innovate and provide services more efficiently.

The lack of competition from non-utility affiliated demand response providers manifests in the failure of demand response to even remotely achieve its potential in the region. MISO both lacks demand response resources in some regions, and particularly in MISO South, and too much of its existing demands response resources either underperform or possess inadequate operational characteristics.

i. Aggregators offer specialized capabilities.

The Commission has specifically recognized the benefit of aggregators of demand response, explaining that "[a]ggregating small retail customers into larger pools of resources expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances

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energy storage, respond to contingency events, and manage load growth and capacity needs), https://www.nrel.gov/docs/fy19osti/70630.pdf reliability."[167] Furthermore, "existing aggregation programs in PJM, NYISO, and ISO New England have shown that these programs have increased demand responsiveness in these regions."[168]

Most recently, the Commission again acknowledged the particular value of aggregators in Order 2222. In declining to set restrictive limits on the scope of DER aggregations, which may include demand response, the Commission found that "the benefits of allowing heterogeneous aggregations outweigh [a grid operator's] preference to limit the types of resources that can participate in aggregations."[169] The Commission further explained that "[a]ggregations of new and existing distributed energy resources can provide new cost-effective sources of energy and grid services and enhance competition in wholesale markets as new market participants."[170] The Commission concludes that excluding such aggregators from wholesale markets "fail[s] to ensure just and reasonable rates."[171]

State regulators have also recognized the value of allowing demand response aggregators to participate in wholesale markets – even a number of those who have adopted prohibitions on the participation of such aggregators. For example, the Iowa Utility Board has noted that "ARCs could encourage implementation of innovative demand response programs and greater use of existing programs and allow large customers with more than one location to consolidate their demand

[167] *Id*. at 154.
[168] *Id*.
[169] Order 2222 at P 145.
[170] *Id*. at P 27.
[171] *Id*. at PP 1, 26.

response activities with a single ARC."[172] Likewise, the Wisconsin Public Service Commission noted the potential of aggregators to encourage the "implementation of innovative demand response technologies, while also finding that '[f]or retail customers that take service at multiple locations from more than a single utility, ARCs may also provide them the opportunity to consolidate their demand response activities with a single vendor."[173] Most recently, the Arkansas Public Utility Commission staff assessed whether permitting ARC participation in wholesale markets is in the public interests, and concluded that such participation "provides a variety of public policy benefits."[174] Staff acknowledged that, "very few retail customers will be able to market and sell DR into wholesale electricity markets without the aid of an ARC" due to the many barriers retail customers face to access wholesale markets.[175]

As Gregg Dixon, the CEO of Voltus, describes in his attached declaration, there are several reasons that demand response providers are able to provide value that is different and better than utility-run demand response programs. First and foremost, demand response companies face the right incentives to deliver more robust demand response services.[176] It is well understood that traditionally

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[172] State of Iowa Utilities Board, *Order Temporarily Prohibiting Aggregators of Retail Customers from Operating in Iowa and Allowing Comments*, Docket No. NOI-08-2 at 3 (Mar. 29, 2010).
[173] Wisconsin Public Service Commission, *Order Temporarily Prohibiting Operation of Aggregators of Retail Customers*, Docket No. 5-UI-116 at 3 (Oct. 14, 2009).
[174] Arkansas Comm'n General Staff's Comments, 90-090-U at P 9.
[175] *Id.* at P 19.
[176] Dixon, Ex. B at P 8.

regulated utilities will fail to invest in reductions in energy demand, because under cost-of-service regulation a utility will earn more on the large capital expenditures necessary to increase supply, compared to the relatively small capital expenditures to develop a demand response product.[177] Economist and former Commissioner of the Public Utility Commission of Ohio ("PUCO") Paul Centolella explains further:

> A utility's economic interests are not aligned with encouraging efficient demand participation in wholesale power markets. Most utility business models are based on earning a return on rate base, capital invested to meet consumer demand. Reducing customer demand often is in direct competition with opportunities for the utility to invest and increase future profitability. Moreover, demand reductions that reduce sales also may erode near term profits. In some jurisdictions, when sales to its own customers decline, the utility may not be able to retain any savings in fuel costs and / or profits from any off-system sales.[178]

In contrast, demand response providers like Voltus only remain financially viable where they excel in producing high quality products that retail customers value and are willing to sign up for.[179] Correspondingly, demand response providers develop a deep expertise in the core skills needed to produce innovative demand response: identifying demand response potential; excellent salesmanship; tailoring the product to the operational needs of the retail customer while meeting regulatory

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[177] *Id.*; *see also* Lilli Ambort & John Farrell, *Sparking Grid Savings Starts at Home: Demand Response 2020 Edition*, Institute for Local Self Reliance, at 5 (Sept. 2020) ("Demand response programs have lagged behind their technical and economic opportunity largely because, with the current rules, utilities make less money using them."), https://cdn.ilsr.org/wp-content/uploads/2020/09/Demand-Response-Report-2020.pdf.
[178] Centolella, Ex. A at 22.
[179] Dixon, Ex. B at P 49.

requirements; and development of the technology needed to support demand response performance.[180]

Because of their specialized expertise and different financial incentives, demand response providers eliminate barriers to participation in demand response products that utility-run (or even utility-affiliated) programs cannot. Demand response providers are able, unlike typical utility programs, to assume the burden of financial penalties by managing the risk of asset non-performance at a portfolio level.[181] This eliminates the financial risk that is commonly the most significant barrier to customer participation in demand response programs.[182] Additionally, demand response providers can offer customers with multiple facilities located across jurisdictional lines a single, simple user experience; navigating the complexities of multiple regulatory requirements on the customer's behalf.[183] The upshot of the advantages offered by demand response providers is that they can reach demand response potential that more regimented, less innovative utility-affiliated programs cannot. Voltus' experience in southern Illinois, in which the company was able to develop 800 MWs over a short two years of operation – representing close to 10% of regional load – demonstrates concretely the additional resources an aggregator can bring to MISO when allowed to compete for the opportunity.[184]

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[180] *Id*. at P 16.
[181] *Id*. at 19.
[182] *Id*.
[183] *Id*.
[184] *Id*. at 39.

Demand response providers not only unlock a greater quantity of untapped demand response, but also offer demand response of greater operational quality. Because unaffiliated demand response providers face fierce competition, there is strong pressure to continue to innovate and stay on top of technological advances. Voltus prides itself in being able to offer "instant communication of dispatches, real-time visibility and control of load curtailment, immediate settlement of dispatch performance, and automated financial transactions between markets and customers."[185] This presents a stark contrast with MISO's concerns about lack of visibility and uncertainty surrounding the availability and performance of a significant proportion of existing LMRs.[186]

Finally, because of the competitive forces they face, demand response providers provide these enhanced capabilities more cheaply than utility-run programs that are insulated from competition. In a Louisiana Public Service Commission proceeding, for example, Voltus compared the cost ratepayers are charged for load curtailment under existing utility-run demand response programs to its own cost to deliver the same service.[187] Whereas industrial customers participating in the utility's interruptible load program receive a rate-payer subsidized premium above the wholesale market price, and thus charge ratepayers between $30,960 to $63,849 per Megawatt-Year of service, Voltus is willing and able

[185] *Id.* at 16.
[186] *Supra* sections V.2.a—V.2.b.
[187] *See* Dixon, Ex. B at Attach. A, Louisiana Public Service Commission, *Voltus's Comments on the Initial Staff Report and Recommendation*, LPSC Docket No. R-34948, (Dec. 10, 2018).

to provide the same service at the wholesale market price – $13,000 to $32,000 per Megawatt-Year less than the cost of the utility-run program. Similarly, in Arkansas Voltus estimates that it can provide services at a cheaper rate *by a factor of three*, as compared to a utility-affiliated program.[188] In MISO broadly, Voltus calculates that it could deliver the same amount of demand response currently delivered by utilities for approximately $118 million, delivering a savings to ratepayers of $130 million per year while elevating the quality of that demand response substantially.[189] And consistent with study after study, demand response (even at the more costly utility-run rate) remains cheaper than the cost to construct a new generator to meet peak demand.[190] In one of the few service territories in MISO that holds competitive solicitations, Voltus has repeatedly been a successful bidder, further demonstrating that demand response providers can provide the same services more cheaply where they are allowed to compete.[191]

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[188] *See* Dixon, Ex. B at PP 41–43.
[189] *Id.* at P 43.
[190] *See Id.* at Attach. A at 2–3.
[191] The Illinois Power Agency, pursuant to discretionary statutory authority and a Commission-approved plan, procures capacity each year to meet a portion of the MISO Zone 4 capacity needs. *See generally* Illinois Power Agency, *Spring 2020 Procurement Events for Block Energy and Capacity Requests for Proposals Process and Rules* (Mar. 23, 2020), https://www.ipa-energyrfp.com/wordpress/wp-content/uploads/2020/03/0_BEC_RFP-Process-and-Rules_Spring-2020_23-MAR.pdf. Voltus has been winning supplier in these procurements. *See* Illinois Power Agency, *Fall 2018 Procurement Events Block Energy and Capacity RFP Results: Capacity Procurement Event Results* (Sept. 12, 2018), https://www.ipa-energyrfp.com/?wpfb_dl=1771; Illinois Power Agency, *Block Energy and Capacity RFP Results*, https://www.ipa-energyrfp.com/block-energy-and-capacity/results/ (last visited Oct. 16, 2020).

ii. Significant Latent Potential for Demand Response Remains Untapped in MISO.

The gap between the potential for flexible, responsive demand and the on-the-ground reality of LMR in MISO demonstrate the harm that is being caused by the lack of competition. The resources showing up in MISO today are nowhere near the latent potential of demand response. Significant advances have occurred that should enable much greater demand response capability, from a wider variety of sources. Yet, this fleet of flexible, more advanced demand response has not materialized in MISO.

The technological advances in demand response since 2009-10, when a majority of the state opt-outs were first put in place, have been considerable. Centolella explains that advanced metering infrastructure, only limitedly available at the time of Order 719's issuance, has now reached over half of electric customers in the United States.[192] By the end of 2020, the industry expects 60% of consumers in MISO will have such advanced meters in service.[193] Further:

> Today, inexpensive embedded processors and sensors, near ubiquitous connectivity, advances in data analytics and machine learning allow intelligent systems to control industrial processes, agricultural equipment, data center operations, building environments, distributed energy resources, electric vehicle charging, and multiple devices in our homes. Intelligent systems can learn preferences and optimize the timing of electricity use in response to multiple inputs. Such inputs can include the instructions of demand response aggregators, RTO control signals, energy prices, or local grid conditions. Intelligent systems can shape usage patterns based on forward prices, shift

[192] Centolella, Ex. A at 6–7.
[193] *Id.*

> demand out of high price periods during the operating day, and flexibly modulate demand on a near real-time basis.[194]

Such technological advances both expand the range of customers, end uses, and distributed resources that can participate in demand response, as well as enable demand response to become more flexible and dynamic.[195] Some advanced forms of demand response should be able to respond rapidly to changes in markets or grid conditions, such as in the case of residential end uses that have been aggregated to provide ancillary services.[196]

Studies of the potential for growth of such flexible demand response show substantial opportunities. A Brattle study projects that more than 120 GWs of cost-effective flexible demand will be added to U.S. power systems by 2030, and analysts at Wood McKenzie assess that 60 GWs will be added to the grid by 2023 through technology such as smart thermostats and residential EV charging.[197] Centolella opines that the order of magnitude of such estimates is reasonable, considering that end uses where the management of thermal inertia could provide timing flexibility account for 37% of all U.S. electricity consumption.[198]

Without the spur of competition, utilities are far less likely than demand response providers to make use of the significant new technical capabilities to deploy advanced forms of demand response. And the evidence is stark that the

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[194] *Id*. at 7.
[195] *Id*. at 8.
[196] *Id*.
[197] *Id*.
[198] *Id*.

predominantly utility-run programs in MISO have failed to deliver on the potential of flexible demand response. Instead, MISO LMRs are largely relics of an earlier era when expectations for demand response technology were quite limited.

As former Commissioner Centolella describes based on his experience working in the industry during the relevant time period, through the 1980s and 90s large industrial and commercial customers sought special arrangements to reduce their costs and avoid increasing electric rates.[199] Utilities offered discounted interruptible rates in response to such customer demands. These rates were often approved, not primarily to meet the operational needs of the power system, but to meet economic development goals.[200] The expectations of these, often politically powerful, large customers was that service would be curtailed only infrequently and under emergency conditions.[201] "The successors of these interruptible rates make up the larger portion of MISO LMRs today."[202] Following advocacy efforts to promote energy efficiency and demand side management programs, utilities adopted additional air conditioner cycling and other direct load control programs, which can reduce peak demand while having a limited total impact on utility sales.[203] Such programs allowed utilities to reduce demand by sending a signal to customers, but

[199] *Id.* at 20
[200] *Id.*
[201] *Id.*
[202] *Id.*
[203] *Id.*

by their nature such programs cannot readily be adapted to following 5-minute dispatch instructions.[204]

The proof of the pudding is in the eating. As of this filing, 94% of demand response in MISO is only available in the lead up to an emergency.[205] The vast majority of the remaining 6% can only be turned on or off by a utility calling an event in response to MISO dispatch instructions.[206] Less than one percent of demand response in MISO can respond to continuous dispatch instructions.[207] Moreover, as MISO itself describes in its recent LMR reform filings, even the demand response that is limitedly available to serve during an emergency event has at times underperformed, and almost all such resources require substantially longer notification times than other RTOs' emergency-only resources.[208]

Likewise, data at the level of the large investor-owned MISO member utilities tell the same story. While the utility demand response programs vary significantly among states and in a few states utilities have or are being directed to develop significant demand response programs, in many states there is "little evidence of significant demand response activity."[209] States in the latter category comprise much of MISO South, and include: Louisiana, Kentucky, Missouri,

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[204] *Id.*
[205] *Id* at 21.
[206] *Id.*
[207] *Id.*
[208] MISO 2020 LMR Filing, ER20-1846 at McFarlane Test at 17:3-17:9, MISO 2018 LMR Availability Filing, ER19-650 at Aliff Test. at 10–12.
[209] Centolella, Ex. A at 22.

Mississippi, North Dakota, South Dakota, and Texas.[210] Further, interruptible and curtailable rates were by far the most common form of demand response, and were complemented in some states by direct load control programs.[211] Yet, "interruptible and curtailable rates and direct load control programs often are available only in limited circumstances and typically do not support flexible continuously dispatchable responses."[212] Thus, both RTO-level and utility data tell the same story: demand response capability in MISO states is grossly lagging behind its potential.

Independent analysis concludes that the economic value left on the table due to the lack of more robust demand response participation in MISO is substantial. Dahlke and Prorok modelled the annual consumer savings that would result from increasing dispatch of incentive-based demand response (the form of demand response that remains prevalent throughout MISO today) assuming a competitive demand response market, and found average price reductions across simulations to range from three to nine percent.[213] Moreover, the authors found that the benefits under steep price spikes, which have been historically rare but are increasingly probable under current MISO conditions, can result in substantially higher estimates of consumer savings, particularly in MISO South where the market may

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210 *Id.*
211 *Id.*
212 *Id.*
213 Steve Dahlke and Matt Prorok, *Consumer Savings, Price, and Emissions Impacts of Increasing Demand Response in Midcontinent Electricity Market*, 40(3) The Energy Journal at 258 (2019), http://www.iaee.org/en/publications/ejarticle.aspx?id=3361.

be clearing in a steep portion of the supply curve.[214] These findings are notable because they show significant benefits to market efficiency *without* factoring in the considerable additional benefits of more advanced forms of flexible demand response. Brattle, for example, estimates the national benefits of load flexibility could exceed $15 billion/year by 2030.[215] As described below, unleashing the forces of competition is necessary to unlock the tremendous benefits of advanced demand response in MISO.

iii. The Pervasive State-opt Outs are a Critical Contributing Factor to Anemic Demand Response Within MISO, and This Barrier to Competition Must be Eliminated to Ensure Just and Reasonable Rates.

The absence of more robust demand response participation in MISO is attributable in significant part to the lack of competition due to pervasive state opt-outs. Centolella identified four key ways in which these opt-outs negatively impact the wholesale power market:

(1) Opt-outs put utilities in the role of gatekeeper over demand response participation in wholesale markets, while such utilities lack the correct incentives to maximize demand response contribution to market value.[216]

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214 *Id*. The authors exclude the potential benefits in extreme price events as an outlier, and the 3–9% cost savings do not factor those exponentially higher costs savings into the estimate.
215 Ryan Hledik et al., *The National Potential for Load Flexibility: Value and Market Potential Through 2030* The Brattle Group (June 2019), https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf.
216 Centolella, Ex. A at 22.

(2) Opt-outs perpetuate the disconnect between customers and market prices. The design limitations of typical utility-run programs – offering small reductions in rates in return for commitments to curtail demand on a limited number of occasions – fail to create the necessary relationship between the rate discount and the time and location-specific market value of demand reductions. Absent this fundamental connection between customer action and market prices, demand response cannot enhance market efficiency to the same degree.[217]

(3) State opt-outs block innovation. The regulatory process to adopt utility-run programs lags significantly behind the cycle of technological and market changes. A utility program will typically have to be proposed a year in advance, require analysis to warrant implementation, and may require piloting before widespread deployment. Non-utility providers are in a much better position to rapidly innovate, adjust plans, and use new tools.[218]

(4) State opt-outs result in a patchwork of program requirements and incentives that undercut the efficiency of scale. This patchwork is costly to navigate and creates a significant barrier to participation in the wholesale market.[219]

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[217] *Id.* at 23.
[218] *Id.*
[219] *Id.*

In Order 2222, the Commission expressly acknowledged that opt-outs can "substantially limit [] participation" of aggregators and threaten the benefits to reliability, transparency, and market efficiency that such participation brings to RTO/ISO markets.[220]

Nor does the so-called "participation model," by which a utility offers demand response into the market on behalf of the aggregator, or other means by which aggregators deliver all are part of demand response service under a utility program, ameliorate these negative impacts.[221] While nine states have permitted or suggested utilities might be allowed to form agreements with demand response aggregators to facilitate wholesale demand response participation, the approach has failed to support robust demand response participation.[222] With a few limited exceptions, the utilities in these states have not made necessary agreements for aggregators. And, where a utility has had such an arrangement in place for a number years, limited potential demand reductions are purchased through a single aggregator. participate.[223]

Former PUCO Commissioner Centolella opines that, if demand response opt-outs were eliminated in MISO, "demand response participation would increase significantly and include more flexible demand capable of continuously following dispatch instructions and providing real-time balancing and ancillary services."[224]

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[220] Order 2222 at P 60.
[221] Centolella, Ex. A at 21.
[222] *Id.*
[223] *Id.*
[224] *Id.* at 28.

In addition to the sound economic principles and reasoning set forth above, Centolella finds support for his conclusion from two independent studies assessing the potential of more flexible demand response technologies in MISO states, and a contrasting third study showing likely developments in the footprint under the status quo.[225]

The first two studies, one focused on Northern States Power (Minnesota distribution utility) and the second on Indiana investor-owned utilities (IOUs), are particular informative of the likely benefits of eliminating the opt-outs because: 1) their estimates of cost-effective demand response potential are not limited to existing utility programs, and 2) they identify opportunities to expand demand response in states in which the existing programs already provide significant demand response. Both studies reveal significant further potential for development of flexible demand response participation in service territories that already show some of the highest penetrations of utility demand response in MISO. Although Northern States Power already has 850 MWs of load curtailment capability, equal to approximately 10% of its peak demand, the Brattle Group examined the potential of eight new programs in the footprint, and found between approximately 400-700

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[225] *Id*. (citing *citing* Ahmad Faruqui & Ryan Hledik, *The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory*, Brattle Group (July 12, 2019) ("2019 Brattle Group Report"), https://www.brattle.com/news-and-knowledge/news/brattle-economists-author-a-report-on-load-flexibility-for-xcel-energys-integrated-resource-plan-filing; Indiana Advanced Energy Economy, *Potential for Peak Demand Reduction in Indiana*, Demand Side Analytics (Feb. 7, 2018) ("2018 Demand Side Analytics Report") https://info.aee.net/hubfs/IN%20DR%20Study%20Final.Feb.7.2018.pdf.

additional MWs of flexible demand response could be developed by 2030.[226] These resources would have the capability of "providing around-the-clock 'load flexibility' in which electricity consumption is managed in real-time to address economic and system reliability conditions."[227] In the same vein, the Indiana study found that, while some (but not all) of the Indiana IOUs had reached most of the commercial and industrial demand response potential under existing programs, there remained considerable potential to increase commercial and industrial demand response at utilities with less extensive programs and more broadly in a high avoided cost case.[228] Additionally, the study analyzed the impact of increasing the market share of residential smart thermostats and found that smart thermostats could increase existing residential demand reductions by 83% to 460%.[229]

In contrast, a 2018 report developed by Applied Energy Group (AEG) to support MISO's transmission planning estimated peak demand reductions using a base reference case.[230] The reference case was intended to reflect continuation of the status quo, and was developed based upon existing demand response programs savings, costs, and program participation rates, as gathered through utility surveys and secondary research.[231] AEG found that demand response, "is not expected to

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[226] *Id.*
[227] *Id.* (quoting 2019 Brattle Group Report at 6–7).
[228] *Id.* (describing the 2018 Demand Side Analytics Report)
[229] *Id.* at 30.
[230] Applied Energy Group, *DR, EE, DG Potential Assessment for Midcontinent Independent System Operator* (Mar. 19, 2018) ("2018 AEG Report").
[231] Centolella, Ex. A at 22–23.

grow significantly – amounting to 4.8% of baseline peak demand by 2038."[232] In percentage terms, this represents a small decline from 4.9% in 2019.[233] MISO consultants do not expect significant new demand response capability to be developed under the status quo – even though significant untapped potential remains in the footprint. These studies provide additional backing to Centolella's conclusion that elimination of the opt-out would result in participation of flexible demand response in the MISO wholesale market that would not otherwise be developed.

It is now clear that provision for a state opt-out in Order 719 opened the door to the near ubiquitous adoption of bans on non-utility demand response participation in MISO. The opt-out is, on its face, anti-competitive and harmful to the functioning of the wholesale market and therefore results in rates that are not just and reasonable. Moreover, substantial evidence, including the grid operator's own testimony that the Commission has previously relied upon, shows that the lack of competition due to the opt-outs is currently harming MISO by failing to support sufficient levels of participation of flexible, responsive demand response. Finally, robust study of MISO market conditions supports the conclusion that unlocking competition by eliminating state opt-outs would increase supply of flexible, responsive demand response. Even before one considers the acute operational strains and threat to reliability looming in MISO, the evidence before the

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[232] *Id*. (quoting the AEG report).
[233] *Id*. at 21.

Commission compels the conclusion that the pervasive state opt-outs within MISO result in rates that are not just and reasonable.

c. The Absence of Demand Response Competition Contributes to Threats to Reliability in MISO.

The evolving market conditions and resource mix within MISO provide additional grounds to conclude that the state opt-out must be eliminated. While reducing barriers to robust demand response is critical to just and reasonable rates in any organized market, MISO's operational needs for flexible resources due to tightening reserve margins and increased penetration of renewables gives particular urgency here. The failure to eliminate a barrier to the participation of the responsive, flexible resources MISO needs today and for the foreseeable future exacerbates the threat to reliability in MISO.

i. Greater Demand Response Capability in MISO Would Mitigate Ongoing Reliability Risks.

In recent years, MISO has experienced a significant increase in the frequency and severity of generation emergencies.[234] Though it had previously not experienced a Maximum Generation (MaxGen) emergency since 2007, between 2016 and 2019 MISO experienced twenty-seven such emergencies.[235] It additionally declared a MaxGen Alert requiring Conservative Operation on February 21st 2020, and again in July and August.[236] In MISO's most recent Fall 2020 Seasonal Outlook, it again

[234] Centolella, Ex. A at 9–10 (discussing conclusions in MISO's independent market monitor State of the Market Report).
[235] *Id*. at 9.
[236] *Id*.

identified the likelihood that, "[a] combination of both high load and high outage 'worst case' scenarios may require emergency procedures to access additional resources."[237]

MISO's investigations have led it to identify "Five key drivers" that contribute to the increasing MaxGen events, including (i) Aging and retirement of generating units; (ii) Correlated generation outages; (iii) growing reliance on emergency-only LMRs; (iv) Growing reliance on unscheduled resources; and (v) Growth in Variable Energy Resources.[238] As Centolella explains, wind resource output in MISO is already experiencing large changes. On one specific day, for example, MISO wind output dropped first by nearly 4,000 MWh within two hours, and then again for a total drop of 8,600 MWh over a total of four hours – representing 13% of demand in all of MISO.[239] Such rapid changes pose significant operational challenges to grid operators, challenges that can be more ably navigated through greater demand flexibility.

MISO has recognized that, "[a]n increased reliance on intermittent and variable resources creates the need for intra-day flexibility, placing a premium on resources that can rapidly respond."[240] MISO's renewable integration assessment

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[237] The report attributes these unusual fall reliability risks to rescheduling of planned outages that would normally occur in spring, but did not due to Covid-19. *See* MISO Market Subcommittee, *Seasonal Outlook. Fall 2020* at 2 (Sept. 10, 2020), https://cdn.misoenergy.org/20200910%20MSC%20Item%2003%20Fall%20Seasonal%20Outlook472521.pdf.
[238] *See supra*, Section V.2.a; *see also* Centolella, Ex. A at 10–11.
[239] Centolella, Ex. A at 13.
[240] *Id*. at 14 (quoting MISO report).

further suggests that load shifting strategies such as demand control and energy storage could reduce the resource adequacy risks associated with greater reliance on renewable resources.[241] Indeed, MISO has identified among its four "strategic imperatives" to "[e]nhance communication and coordination across the transmission and distribution interface – to address today's challenges with Load Modifying Resources and with an eye toward emerging tech and active demand."[242] MISO could not be clearer that it needs operational capabilities beyond those available from existing LMR to navigate ongoing resource adequacy challenges. Centolella elaborates on the mechanisms by which demand response can mitigate ongoing risks to reliable operations:

> Flexible demand response can mitigate and reduce the upward and downward slope in the ramping of other resources needed to offset changes in the output of renewable generation. Flexible demand response can reduce and shape peaks in net load – demand after accounting for variable renewable output – to match real-time resource availability, thereby lowering costs and avoiding emergencies. Finally, in response to dynamic pricing or innovative incentives, flexible demand could shift into periods when there is excess supply, avoiding the need to curtail low marginal cost renewable resources while maintaining minimum operating levels for generation that remains online to be able to respond to later reductions in renewable output.[243]

The near-term reliability benefit of eliminating state opt-outs is perhaps most starkly demonstrated by examining recent MaxGen events, during which relatively modest changes in capacity availability can make all the difference in mitigating or

[241] *Id.*
[242] MISO, *MISO Forward 2020. Utilities of the Future: What do they need from a grid operator?* at 2 (Mar. 2020), http://view.ceros.com/miso-energy/misoforward2020/p/1.
[243] Centolella, Ex. A at 15.

avoiding an emergency event. For example, the Independent Market Monitor's (IMM) analysis of the MaxGen event on September 15, 2018 highlights the challenges posed both by the limited LMR available in MISO South, and the severe operational limitations of the LMR that is available. The IMM noted that multiple factors led to tight conditions in the lead up to the event, including a forced outage of the largest market resource and temperature forecast errors that, in turn, led to load forecast error.[244] As tight conditions continued, the IMM observed that the operator's decision to call the event at 3:00pm, rather than at 11:30am when emergency conditions could first be projected, impacted LMR availability.[245] By 3pm, almost no LMR could be called, whereas 90MW of LMR would have been available if the operator had acted sooner.[246] After the event was called, emergency energy purchases of 600 MWs were implemented.[247] Ultimately, the high prices triggered by the event prompted an additional 1GW of imports that resolved the shortage.[248] Yet if, in place of the limited and outdated utility demand response programs, MISO South had available to it even modest quantities of flexible

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[244] Potomac Economics, *IMM Quarterly Report : Fall 2018 Revised* at 4–6, 16–18 (Dec 4, 2018), https://www.potomaceconomics.com/wp-content/uploads/2018/12/Quarterly-Report-Fall-2018.pdf.
[245] *Id*. at 5.
[246] *Id*.
[247] MISO, *MISO September 15 Maximum Generation Event Overview* at 5, 8 (Oct. 11, 2018), https://cdn.misoenergy.org/20181011%20MSC%20Item%2003%20Max%20Gen%20Event282648.pdf.
[248] Potomac Economics, *supra* n 242 at 4.

demand response, the unexpected outage and load forecast error would have posed less risk, and the event could have been more readily resolved.

Taking steps to eliminate barriers to demand response with the higher operational capability MISO needs – the increased availability, flexibility, and responsiveness – would help MISO manage ongoing threats to reliable operations.

ii. Competition is Essential To Unlock the Next Generation of Demand Response Capabilities As MISO's Resource Mix Continues to Evolve.

MISO is clear-eyed that the factors leading to increasing resource adequacy risks and frequent emergency events are expected to persist or intensify over time, and that longer term structural reforms will be necessary to manage the resultant operational challenges.[249] The shift of the resource mix toward deeper penetration of renewables is certain to continue. Centolella points out that wind and solar represent the substantial majority of new resources expected to come on line from 2020 to 2022.[250] In September 2019, wind and solar comprised over 80% of new resources in the interconnection queue.[251] This trend continued, with renewables again comprising the overwhelming majority of interconnection requests in the application period ending June 2020.[252] Moreover, both states and utilities within the footprint have set ambitious decarbonization targets that will continue to drive the resource mix toward larger shares of renewables. As many as eleven of MISO's

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[249] MISO 2020 LMR filing, ER20-1846 at 7.
[250] Centolella, Ex. A at 11.
[251] *Id.*
[252] *Id.* (including 36 GW of solar, 8 GW of wind, 4 GW of hybrid systems, and 2 GW each of storage and gas-fired generation).

large utility members have set 80% or higher clean energy targets and five additional utilities have 50% clean energy goals.[253] Based on utility announcements, wind and solar are expected to provide 30% of energy in MISO by 2030.[254] Additional proposed state policy changes in Illinois, Minnesota, and Wisconsin could further accelerate renewable resource growth, leading to wind and solar providing 35% of the energy in MISO by 2030.[255] As the resource mix continues to evolve, the need for operational flexibility, market valuation of a greater range of resource capabilities and services, enhanced communication and coordination, and other foundational market reforms grows.

Achieving the deeper, more structural reforms MISO contemplates in order to meet future challenges will be facilitated by the elimination of barriers to demand competition. MISO's experience working with stakeholders on its second round of LMR reforms, which aimed at changes to LMR accreditation, are illustrative. A significant set of stakeholders were strongly opposed to the reforms, until MISO agreed to delay implementation.[256] These stakeholders voiced concerns about the "aggressive" timeline in light of the potentially lengthy regulatory tariff changes and modifications to contract arrangements.[257] While all market participants depend to some extent on regulatory certainty and need time to adjust to market reforms, utility demand response programs are particularly dependent upon

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[253] *Id.* at 12.
[254] *Id.* at 11.
[255] *Id.*
[256] MISO 2020 LMR Filing, ER20-1846 at 16–17.
[257] *Id.* at 17.

incentives or requirements adopted by retail regulators. As such, as discussed above, changes to such programs are particularly slow, and are reactive rather than proactive. Absent the pressure of competition, utility demand response programs simply will not exhibit the adaptability and innovation that unaffiliated demand response providers do. The predominance of utility demand response programs is a part of the institutional inertia that resists structural change, rather than, as the competitive business does, anticipate evolving market conditions and seek to gain competitive advantage because of them. Eliminating the demand response opt-out will not only address near-term threats to reliability, it will unleash the competitive forces that are crucial to succeed in rapidly evolving and novel market conditions. Incremental, plodding change has worked well enough where the bulk power system saw little change for decades at a time. A more nimble response is called for in the face of the rapid pace of technological and economic changes that are shaping today's market.

d. Eliminating the Opt-out Would Ensure Order 2222 Achieves Its Full Potential.

Order 2222 aims to eliminate barriers to distributed energy technologies and represents a crucial step to realizing the potential of such resources to serve as new cost-effective sources of energy and other grid services and enhance the market competition. Yet the tremendous potential of Order 2222 will remain unrealized while the demand response opt-out remains in place. Due to the opt-out, aggregators are barred from the full range of business models, emerging technologies, and the enhanced capabilities that result from combining different technologies. As the Commission explained cogently in Order 2222, a restrictive approach to the technologies that may be aggregated, or the business model under which an aggregator may operate, is a barrier to resource participation that undercuts the benefits of Order 2222:

> We find that limiting the types of technologies that are allowed to participate in RTO/ISO markets through a distributed energy resource aggregator would create a barrier to entry for emerging or future technologies, potentially precluding them from being eligible to provide all of the capacity, energy, and ancillary services that they are technically capable of providing.[258]

The Commission further explained that restricting RTO/ISOs from excluding any particular type of technology will "ensure that more resources are able to participate in such aggregations, thereby helping to enhance competition and ensure just and reasonable rates."[259] Indeed, one of the particular strengths of this approach is that, while individual resources or technologies may not meet qualification or performance requirements to provide certain services on their own, an aggregation may be able to do so where the individual resources provide complementary capabilities.[260] Yet keeping the demand response opt-out in place takes off the table DER aggregations that incorporate the complementary capabilities of existing and enhanced demand response technologies – capabilities that are increasingly valuable to efficient and reliable operation of the grid as the resource mix continues to shift. The ability of demand response to shape customer

[258] Order 2222 at P 141.
[259] *Id.*
[260] *Id.* at P 142.

load profiles, shift demand in response to price or other signals, and modulate demand to mitigate short-run ramps, grid disturbances, and contingencies on very short timescales supports integration of large shares of variable renewable resources, and creates significant economic and reliability benefits.[261] These benefits are lost, and the great promise of Order 2222 truncated, while the opt-out remains in place.

For these reasons, Order 2222 is not enough to ensure just and reasonable rates in MISO. Moreover, the distributed energy technologies that Order 2222 may ultimately encourage will be years in coming before their services are available to grid operators and to the benefit of consumers. RTO/ISO compliance filings are due nine months from the Order, and full implementation is not expected until a year later. While such extended implementation schedules may be necessary to implement groundbreaking changes to RTO/ISO rules, this timeline nonetheless means that MISO will not see the benefits of greater DER participation affect market outcomes for years. In the meantime, demand response technology is already available and able to serve MISO's needs – if unleashed from the constraints on competition it faces under the opt-out.

3. The Manner In Which Opt-outs Are Deployed In MISO Results In Undue Discrimination

The Federal Power Act requires that all rates, charges, and classifications of service must be just and reasonable and cannot be unduly discriminatory or

[261] Centolella, Ex. A at 15.

preferential.[262] This standard prohibits one type of market participant from receiving preference over another type that can provide a similar service without an adequate justification. Here, particularly as currently applied within MISO, the opt-out provision of Order 719 clearly violates the principle of undue discrimination in at least two ways. First, the opt-out discriminates against direct retail customers and ARCs for demand response by allowing an entity that provides identical service but that is affiliated with a utility – or is the utility itself – to participate in Commission jurisdictional wholesale markets. Second, ARCs offering demand response can provide the same services to the grid as other technologies such as storage or behind the meter generation, yet are treated differently under the opt-out. Independently, either form of undue discrimination would be sufficient to find that the opt-out, as implemented within MISO, is unlawful.

a. Undue Discrimination Under The Federal Power Act

As the Commission has observed, the Act "bristles with concern about undue discrimination."[263] Indeed, courts have long held that an "unjustifiable difference in rates for substantially similar service works an unlawful discrimination" that is prohibited under the Federal Power Act.[264] The Commission has explained that

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[262] *See* 16 U.S.C. § 824d, 16 U.S.C. § 824e.
[263] *Am. Elec. Power Serv. Corp.,* 67 FERC ¶ 61,168, at 61,490 (1994) (citing *Associated Gas Distributors v. FERC,* 824 F.2d 981, 998 (D.C. Cir. 1987)).
[264] *Towns of Alexandria, Minn. v. FPC,* 555 F.2d 1020, 1028 (D.C. Cir. 1977); *see also Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 72 Fed. Reg. 12,266, 12,318 (P 425) (Mar. 15, 2007) (the Commission "has a duty to prevent undue discrimination").

different treatment is unduly discriminatory "when there is a difference in rates or services among similarly situated entities."[265] Determining that entities are similarly situated "does not mean that there are no differences between them; rather, it means that there are no differences that are material to the inquiry at hand."[266] Entities are similarly situated "if they are in the same position with respect to the ends that the law seeks to promote or the abuses that it seeks to prevent, even if they are different in many other respects."[267] Irrelevant differences will not make parties dissimilarly situated.[268]

b. States Discriminate Against ARCs By Treating Them Differently Than Utility-Affiliated Programs

The vast majority of retail authorities within MISO bar aggregators representing retail customers in the wholesale market, and most also prohibit direct participation of large retail customers, yet many permit LSEs, or select aggregators working on behalf of LSEs, to participate in the wholesale market.[269] There is no

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265 *Calpine Oneta Power, L.P.,* 116 FERC ¶ 61,282 at P 36 (2006); *El Paso Nat. Gas Co. Aera Energy, LLC, et al., Complainants,* 104 FERC ¶ 61,045 at P 115 (2003).
266 *New York Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,124 at *3 (Feb. 15, 2018) (Order granting, in part, and denying, in part, rehearing and clarification, and requiring further compliance).
267 *Id.* The Commission further explained "Consistent with those precedents, the Commission has, for example, determined that new and existing generators were similarly situated for 'reactive power compensation purposes' because they were equally capable of providing that service, notwithstanding other significant differences." *Id.* (citing *Calpine Oneta Power, L.P.*, 116 F.E.R.C. ¶ 61282 (Sept. 26, 2006)).
268 *Calpine Corp., et al. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61035 at *124 (Apr. 16, 2020).
269 Centolella, Ex. A at 27–28.

reasonable wholesale market basis for distinguishing between these entities, each which seeks to offer precisely the same wholesale market service.

Utility-affiliated demand response providers, ARCs, and direct retail customer participants are similarly situated for purposes of Order 719 "with respect to the ends that the law seeks to promote or the abuses that it seeks to prevent," as both can provide the same technological grid services.[270] Indeed, the very goal of Order 719 is to eliminate barriers to demand response and ensure comparable treatment of demand response, in order to enhance market competition, maintain reliability, and allocate energy during a shortage to those who value it most.[271] The Commission has expressly concluded that granting a preference to utility-affiliated demand response providers is "contrary to the goal of [the Order 719] proceeding."[272] In response to a request to exempt only LSE-affiliated demand response located in small systems from the requirement to make an affirmative showing before being permitted to participate in wholesale markets, the Commission explained that eliminating this barrier selectively "would effectively have the Commission provide load-serving entities and their designees with a competitive advantage over other ARCs."[273] The Commission

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[270] *See New York Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,124 at *3.
[271] Order 719, 125 FERC ¶ 61,071 at P 235.
[272] Order 719-B, 129 FERC ¶ 61,252 at P 22; *see also ISO New England & New England Power Pool*, 131 FERC ¶ 61,194 (May 28, 2010) (Rejecting proposed tariff language as inconsistent with Order 719 and concluding "RTOs and ISOs may not prohibit participation by one type of aggregator but allow participation by another").
[273] Order 719-B, 129 FERC ¶ 61,252 at P 24.

concluded that it was "not persuaded that such action is consistent with our obligation to prevent undue discrimination."[274]

Yet, as it has been implemented throughout the MISO footprint, that is exactly how the opt-out functions today: as a means to provide utilities and their affiliates a "competitive advantage" over independent providers. Because of the opt-out, demand response providers lack leverage in negotiations with LSEs and must accept significant concessions in their terms of service in order to access the wholesale markets (where access is available at all).[275] The disparate treatment of utilities and their affiliates within MISO achieves the opposite of the goals of Order 719; by "restricting demand participation, constraining the development of flexible demand response, and preventing third party providers with specialized expertise from offering innovative products and services" the existing tariff squelches competition rather than enhance it.[276]

The only relevant characteristic for the Commission to consider with regard to the eligibility of demand response to participate in wholesale markets is operational, specifically, the services demand response can provide.[277] "From the perspective of the transmission grid, demand response produces a load reduction in the wholesale

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[274] *Id.*
[275] *See* Centolella, Ex. A at Appendix B (describing significant "administration fees" imposed by the monopoly utility for demand response services provided via an affiliated aggregator).
[276] *Id.* at 5–6.
[277] *See Demand Response Supporters v. N.Y. Indep. Sys. Operator, Inc.* 145 FERC ¶ 61,162 at PP 31–32 (Nov. 22, 2013) (different forms of demand response must be allowed to compete on "equal footing" regardless of the mechanism used to reduce the amount of energy purchased).

market from a validly established baseline," regardless of the underlying business model of the owner/operator.[278] Indeed, Order 2222 most recently reiterated this core principle that it is the service, not the form of the technology or the business model, that matters. Throughout the Order, the Commission rejected efforts to narrowly define the scope of technology or the business model that may comprise a DER.[279] ISO New England, for example, argued that allowing heterogenous aggregations of demand response with other DERs would pose additional challenges. The Commission, however, was unconvinced, emphasizing that "the means by which an aggregation is able to provide wholesale services does not change the value of that service to the grid."[280]

Finally, the Commission's recent decision in *New York Independent System Operator, Inc.*, reflect the Commission's conclusion that state policy choices do not provide a valid basis for less favorable treatment of some resources.[281] There, the Commission rejected NYISO's proposed changes to the buyer-side market power mitigation rules based on state public policy choices.[282] Specifically, NYISO proposed

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[278] *Id.* at P 32.
[279] *See e.g.*, Order 2222 at P 265 (rejecting standard metering and telemetry requirements in light of the variety of potential aggregation business models), P 340 (market participation agreements for DERs "should not limit the business models under which distributed energy resource aggregators can operate"), 353 (allowing aggregators with varying business models to be included in such agreements increases ability for DERs to participate in markets).
[280] Order 2222 at P 145.
[281] 172 FERC ¶ 61,206 (Sept. 4, 2020).
[282] *Id.* at P 29.

to change the order in which projects are evaluated to allow Public Policy Resources[283] to be reviewed before non-Public Policy Resources.[284] Ultimately, the Commission found that NYISO's "proposal is unduly discriminatory because it does not provide sufficient justification for prioritizing the evaluation of Public Policy Resources before non-Public Policy Resources, independent of cost."[285] The Commission found the two types of resources similarly situated, despite the fact that state law treats the two categories differently, because the two meet the same qualification and performance requirements. The Commission reasoned that, operationally, non-Public Policy Resources could adhere to the same requirements for interconnection and participation as Public Policy Resources, and non-Public Policy Resources could also meet the same identified capacity needs in the market, and thus treating them differently would constitute undue discrimination.[286] The Commission's rationale applies equally to state law-based preferences for utility-administered demand response programs. Throughout MISO, utility programs are eligible to provide wholesale services, while ARCs are precluded from providing exactly the same service *based solely upon state policy choice*. Under the Commission's ruling, granting such preferences – regardless of the legitimacy of those state policy choices – is unlawful.

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[283] Defined as a facility that is an "Energy Storage Resource, or an Intermittent Power Resource solely powered by wind or solar energy, or that is determined by the ISO to be a zero-emitting resource." *Id*. at n. 12.
[284] *Id*. at P 30.
[285] *Id*. at P 29.
[286] *Id*. at P 30.

In this context, where the services offered are technologically and operationally equivalent, the ownership of the resource provides no reasonable basis for discrimination.[287] Here, there is no question that ARCs, or sophisticated large retail customers, are technically capable of providing the same demand response services as utilities. Indeed, years of experience now demonstrate that ARCs operate successfully in vertically integrated jurisdictions without impeding the traditional regulatory structure.[288] Consistent with its longstanding precedent on undue discrimination, the Commission must find the opt-outs as applied within MISO unduly discriminatory and preferential.

c. The MISO Tariff Discriminates Against Demand Response Resources By Treating Their Eligibility To Participate Differently Than Resources That Provide The Same Services

By the same core principles, where different technologies appear operationally equivalent to the grid, there is no basis for differentiating eligibility to

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[287] *Cf Calpine Oneta Power L.P.* 113 F.E.R.C. ¶ 63015 (Oct. 28, 2005), *aff'd Calpine Oneta Power L.P.* 116 F.E.R.C. ¶ 61,282 at PP 26–27 (Sep. 26, 2006)(independent power producer and traditional vertically integrated utility are similarly situated for purposes of being compensated for their reactive power); *Michigan Elec. Transmission Co.*, 97 FERC ¶ 61,187 at 61,852–53 (2001) ("it is hardly consistent to allow an affiliate to have different and/or superior terms and conditions for interconnection than non-affiliates").

[288] For example, in Virginia, state agencies and public utilities can participate in demand response through an ARC, known throughout the PJM footprint as a Curtailment Service Provider ("CSP"). *See* Dept. of Mines, Mineral, and Energy, *Division of Energy – VEMP – Demand Response*, Virginia.gov, https://www.dmme.virginia.gov/DE/DemandResponseContract.shtml (last accessed October 16, 2020). Over a three-year period, the Virginia Department of Mines and Minerals and Energy ("DMME"), the government department responsible for overseeing the DR program on behalf of Virginia, reported nearly $10 million in revenue for the Commonwealth.

participate in the market. The opt-out is also unduly discriminatory because it treats the eligibility of demand response programs within an aggregation differently from comparable resources, like storage or behind-the-meter generation. Order 2222, which, effectively singles out demand response technologies for less favorable treatment by leaving the opt-out in place, only amplifies the irrationality, unworkability, and discriminatory nature of the current legal framework.

Order 2222 recognized that other forms of distributed energy resources and demand response are often technically capable of providing the same service and indeed, are so operationally equivalent from the perspective of the grid operator that, lacking any other avenue to participate, other distributed energy technologies have actually participated in RTO/ISO markets as demand response.[289] The Commission ultimately adopted an expansive definition of DERs to include, "any resource located on the distribution, any subsystem thereof or behind a customer meter," so as to "encompass current and future technologies" and not to exclude some resources that could be aggregated to sell energy, capacity, or ancillary services.[290] Moreover, the Commission directed RTO/ISOs not to prohibit heterogeneous aggregations of DER technologies, because such limits could become a barrier to emerging or future technologies and prevent them from being eligible to "provide all of the capacity, energy, and ancillary services that they are technically capable of providing."[291] Order 2222 goes to great lengths to recognize that it is not

[289] Order 2222 at P 2.
[290] *Id* at PP 114, 116.
[291] *Id*. at P 141.

the nature of the technology that is central to its eligibility to participate in RTO/ISOs, but rather the ability of a single resource or aggregation of resources to meet the qualification and performance requirements to provide the service they are offering to the market.[292]

Moreover, Order 2222 is consistent with a long line of precedent recognizing that it is the ability to provide the requisite service that counts, not the mechanism producing it.[293] For example, the Commission concluded that the source of a load reduction, whether it came from behind-the-meter generation or operational shutdown, was irrelevant to a resource's eligibility to participate as demand response in NYISO markets.[294]

Yet under the opt-out, resources that have precisely the same ability to meet the qualification and performance requirements to participate in MISO are treated differently depending on the label by which they come to the market. Voltus has sought to register curtailable load as a resource in South Dakota, but was denied access because of the state opt-out in place.[295] Yet where the same customer was able to produce the *same grid service* by placing some of its load on a lithium ion uninterruptible power supply, Voltus was permitted to register the resource as an electric storage resource and provide the service to MISO.[296] This outcome, in which the ability to compete in the market turns not on the services provided or their cost,

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[292] *Id.* at P 117.
[293] *See supra* notes 262–263.
[294] *Demand Response Supporters,* 145 FERC ¶ 61,162 at P 32.
[295] Dixon, Ex. B at P 22.
[296] *Id.*

but instead on the equipment by which the service is produced, makes a mockery of the Commission's long commitment to technology-neutral markets. Yet this is precisely the unjust and irrational outcome that is perpetuated while the demand response opt-out remains in place.

Because Order 841 and Order 2222 have rightly denied state opt-outs to technologies except for demand response, many other forms of technology are eligible to provide services that appear, from the grid operator's perspective, exactly the same as demand response, while demand response cannot. As Centolella explains, the only material difference between a battery and flexible demand is the medium used to store useful energy.[297] With an intelligent control system, the thermal inertia of a building, water heater, or refrigerator unit can operate in a manner that is in direct competition with the services provided by a lithium-ion.[298] Energy storage resources can be deployed to shape load profiles, shift demand, or modulate demand in the same manner as many demand response technologies. And thus we have arbitrary rules that, for example, allows a battery or a flywheel storage resource to provide a service to the grid, but does not allow thermal storage to provide exactly the same service, although the value of those two services to the grid and to customers is equivalent. There is no justification for such discriminatory treatment based solely on the type of equipment by which the service is delivered.

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[297] Centolella, Ex. A at 26.
[298] *Id.*

VII. REMEDY REQUESTED

While a complainant bears the burden to establish that existing rates are not just and reasonable, or unduly discriminatory, it does not face a burden to offer an alternate replacement rate that meets statutory requirements.[299] Nevertheless, here Voltus identifies three components of a remedy to both immediately address the aspects of MISO's tariff that are currently resulting in rates that are not just and reasonable, and commence proceedings that will ensure MISO's rates remain just and reasonable and not unduly discriminatory over the longer term. Each of these forms of relief is premised on a finding that implementation of the opt-out in MISO results in rates that are not just and reasonable and are unduly discriminatory, and/or a finding that the opt-out as a whole is unlawful under the Federal Power Act.

First, Voltus requests that the Commission find that MISO is improperly recognizing and must disregard state opt-outs that are invalid under existing regulations codifying Order 719's opt-out, thus ensuring that demand response aggregators are immediately eligible to participate in the upcoming PRA throughout the vast majority of MISO's footprint. In issuing Order 719, the Commission never expected that RERRAs would cavalierly eliminate competition from demand response aggregators; the Commission at that time viewed the opt-out as a concession that undercut its goal to eliminate barriers to demand response, but

[299] *See e.g., New England Power Generators Ass'n, Inc.,* 153 FERC ¶ 61,222, at P 11 (2015) (If complainant meets its burden, the Commission then determines the just and reasonable replacement rate).

was nonetheless warranted in light of legitimate and substantial state interests. Yet over a decade of implementation, it is now clear that RERRAs throughout much of MISO have not utilized the opt-out only where faced by particular and unavoidable burdens, but rather as a default without due deliberation. That nearly all the states with utilities located in MISO at the time of Order 719 automatically issued opt-outs, often as so-called "temporary" measures, but then have failed to more rigorously assess the benefits or impacts of those opt-outs over the following decade, demonstrates the unconsidered nature of these opt-outs.[300] This pattern persists in states that joined MISO subsequent to Order 719, where RERRAs react to efforts by aggregators to compete in the footprint by reflexive, at times *ex parte*, decisions to impose an out-out.[301]

However, the Commission need not examine each opt-out to determine whether it was adequately considered or not: in issuing Order 719, the Commission was crystal clear: aggregations shall be permitted unless the *laws or regulations* do not permit a retail customer to participate in wholesale markets.[302] While subsequent rehearing requests resulted in a change to the regulation's text, even after those changes, the Commission continued to express its unambiguous

[300] *Supra* Section V.2.c, notes 123–126.
[301] *Supra* Section V.2.c, notes 127–128.
[302] Order 719, 125 FERC ¶ 61,071 at P 155

interpretation that aggregations are only to be barred where such a prohibition is found in the "laws or regulations" of the RERRA.[303]

With the exception of Arkansas, which has adopted a law (and in which the utility commission is, in fact, now deliberating over the public benefits of permitting aggregators as called for by that law), no RERRA in MISO has an opt-out codified in law or regulation. Thus, MISO's acceptance of opt-outs other than that of Arkansas is inconsistent with Order 719. By enforcing implementation of this aspect of Order 719, the Commission can achieve immediate relief for aggregators like Voltus facing undue discrimination, and provide a near-term remedy for the unjust and unreasonable rates that result from the pervasive state opt-outs.

Second, the Commission should order MISO at minimum, and potentially all other RTO/ISOs, to incorporate consideration of demand response aggregators in the ongoing stakeholder work to implement Order 2222 coordination mechanisms. The Commission has already adopted alternative coordination mechanisms in Order 2222 that do a better job than the opt-out, in terms of balancing the legitimate interests of distribution system operators and RERRAs against the wholesale market benefits of greater competition. The Commission should take immediate steps to ensure that implementation of those mechanisms factors extends to the coordination and information-sharing needs related to participation of demand response aggregators. By incorporating consideration of ARCs into those

[303] Order 719-A, 128 FERC ¶ 61,059 at P 57 ("RTO and ISO must accept bids from an ARC unless the laws or regulations of the relevant electric retail regulatory authority do not permit the ARC to bid.").

soon-to-be launched discussions, RTO/ISOs can ensure coordination with distribution utilities and RERRAs is dealt with comprehensively rather than piecemeal. Absent Commission action, RERRAs that have adopted opt-outs will have no reason to engage with RTO/ISOs on issues related to demand response aggregation, and further tariff revisions would ultimately be necessary to fully incorporate such coordination mechanisms into RTO/ISO rules. In MISO in particular, which is facing near-term impacts due to the lack of demand competition and flexible demand response, such additional delays in integrating demand response resources is unacceptable.

Third, Voltus requests that the Commission issue a notice of proposed rulemaking to amend its regulations and permanently eliminate Order 719's opt-out. Initiating such a rulemaking proceeding is ultimately necessary to ensure just and reasonable rates within MISO, and to reconcile an otherwise inconsistent and arbitrary regulatory scheme that singles out demand response for less favorable treatment. Moreover, such a step is the only means to eliminate the unlawful nature of the opt-out, which grants authority to RERRAs to determine eligibility to participate in wholesale markets in a manner that conflicts with the fundamental structure and text of the Federal Power Act.

VIII. RULE 206 REQUIREMENTS

To the extent not already provided herein, Voltus provides the following additional information required by Rule 206 of the Commission's Rules of Practice and Procedure:

1. <u>Good Faith Estimate of Financial Impact or Harm (Rule 206 (b)(4))</u>:

Voltus estimates that the opt-out provisions cost Voltus up to half a billion dollars in lost revenue.[304] Voltus also estimates that if Voltus were to provide the demand response services currently provided utilities, they could save ratepayers over $130 million.[305]

2. Operational or Nonfinancial Impacts (Rule 206 (b)(5)): The issues presented here have the effect of creating unjust and unreasonable rates in MISO's wholesale market, and also stifle innovation and competition among providers of demand response.

3. Other Pending Matters (Rule 206 (b)(6)): While the specific issue presented here is not pending in an existing Commission proceeding or a proceeding in any other forum in which Voltus is a party, overlapping issues may be presented in the context of Order 2222, Commission Docket No. RM18-9.

4. Specific Relief or Remedy Request (Rule 206 (b)(7)): The specific relief sought by Voltus is set forth in detail in the Complaint.

5. Documents Supporting the Complaint (Rule 206 (b)(8)): Voltus has attached to this Complaint the Testimony Prepared for Earthjustice By Paul Centolella, the Declaration of Gregg Dixon, and the Chart of State Opt-Outs in support of its request for relief.

[304] Dixon Ex. B, at P 53.
[305] *Id*. at P 43

6. Alternative Dispute Resolution (Rule 206 (b)(9)): Voltus has not used the Commission's Enforcement Hotline or Dispute Resolution Services and does not believe at this time that alternative dispute resolution would resolve the issues underlying this Complaint. Voltus has no reason to expect that alternative dispute resolution would result in the relief requested herein.

7. Form of Notice (Rule 206 (b)(10)): A form of notice of Complaint suitable for publication in the Federal Register is attached hereto.

8. Fast Track Processing (Rule 206 (b)(11)): As described in the Complaint, as result of upcoming auction deadlines, standard processing of the Complaint will not be adequate, and Voltus requests fast track processing pursuant to 18 CFR § 385.206(h) and 18 CFR § 385.206(b)(11). Each year in MISO the PRA is held that allows demand response to bid into the market alongside any supply-side capacity resource.[306] The PRA auction takes place in March of each year with results posted in April for delivery in the same year beginning in June.[307] Resources that want to participate in the auction need to be approved for participation by MISO in February of each year.[308] Voltus requests fast track processing such that Voltus would be able to bid demand response into the market from all MISO states by that

[306] *Id*. at P 54.
[307] *Id*. at P 55.
[308] *Id*.

timeframe. To prepare such bids, Voltus would need to prepare their requests for approval to register in the PRA by as soon as possible.

9. Service (Rule 206 (c)): Voltus has served a copy of this Complaint upon representatives for the Respondent (including those corporate officials designated by MISO on the FERC website for receipt of complaints) via electronic mail, simultaneous with the filing of this Complaint.

IX. CONCLUSION

For the foregoing reasons, Voltus respectfully requests the Commission grant the Complaint on an expedited basis, and provide Voltus with the relief described above.

Dated: October 20, 2020.

Respectfully submitted,

/s/ Kim Smaczniak

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CERTIFICATE OF SERVICE

I hereby certify that I have on this date caused a copy of the foregoing document to be served upon Midcontinent Independent System Operator, L.L.C., at the following addresses obtained from the Commission's list of corporate officials designated to receive service pursuant to 18 C.F.R. § 385.2010(k):

Dated: October 20, 2020.

/s/ Kim Smaczniak
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EXHIBIT A

Testimony Prepared for Earthjustice By Paul Centolella

TESTIMONY PREPARED FOR EARTHJUSTICE BY PAUL CENTOLELLA
OCTOBER 13, 2020

I. Introduction

Q. Would you please state your name, employment, and business address?

A. My name is Paul Centolella. I am the President of Paul Centolella & Associates, LLC. The business address of my firm is 63 Grace Road, Newton, Massachusetts.

Q. Would you please summarize your professional background and qualifications?

A. For more than thirty-five years, I have addressed issues in utility regulation as an expert consultant, utility regulator, and utility consumer advocate. My current consulting practice focuses on utility regulatory policy, changing utility business models, the design and analysis of electric power markets, the integration of flexible demand and other applications of advanced energy technology, and initiatives to modernize the power system. I advise utility regulatory commissions and a broad range of private sector clients examining the challenges and opportunities facing regulators and power sector participants. This has included advising utilities on fundamental changes in their business and regulatory models, detailed analysis on the implications of changes in rate design, and the development of concepts for extending locational marginal pricing and resource valuation into distribution systems.

I have served on a number of expert panels and advisory committees, including as Chair the National Institute of Standards and Technology ("NIST") Smart Grid Advisory Committee, as a member of the U.S. Department of Energy's Electricity Advisory Committee, where I Chaired the Smart Grid Subcommittee, the Advisory Committee for the MIT Utility of the Future Study, the National Academies of Sciences, Engineering, and Medicine's Committee on Determinants of Market Adoption of Advanced Energy Efficiency and Clean Energy Technologies, the Electric Power Research Institute's Advisory Council where I serviced on the Council's Executive Committee, the Governing Board and Board of Directors for the Smart Grid Interoperability Panel ("SGIP"). I was Vice President and a member of the Board of the Organization of PJM States, which represents state regulators on issues involving the PJM Interconnection, LLC ("PJM").

I was a Commissioner on the Public Utilities Commission of Ohio from 2007 to 2012. In that capacity, I participated in the development and implementation of Ohio's 2008 electricity legislation that provided authority for the Commission to approve multi-year rate plans and created the State's energy efficiency and renewable portfolio standards. I was a member of the National Association of Regulatory Utility Commissioners ("NARUC") – Federal Energy Regulatory Commission ("FERC") Smart Response, Smart Grid, and Demand Response ("DR") Collaboratives. And, I worked with the leadership of both PJM and the Midcontinent Independent System Operator ("MISO"), which during that period included Ohio utilities among its members. While a

Commissioner, I also helped lead and participated in smart grid or grid modernization initiatives both in Ohio and nationally.

From 1992 to 2007, I was a Senior Economist in the Energy Solutions Group of Science Applications International Corporation ("SAIC"), a Fortune 500 consulting services and technology company. At SAIC, I managed and led projects related to utility regulation, the analysis and design of energy and environmental markets, power system operations, and energy policy. My work there included supporting the development and regulatory approval of the energy and ancillary services markets and analysis of options for ensuring resource adequacy for MISO, which was then known as the Midwest Independent Transmission System Operator. Additionally, I led the economic analysis and participated in management of the Tennessee Valley Authority's Power System Optimization Project, one of the first major initiatives applying the Common Information Model to integrate utility operating and information systems. For the U.S. Department of Energy, I led one of the first studies of Locational Marginal Pricing in wholesale power markets, modeling the New York power system. While at SAIC, I also helped design, the U.S. Environmental Protection Agency's Sulfur Dioxide Emission Allowance Tracking and Trading Systems.

From 1982 to 1992, I was a Senior Utility Attorney and the Senior Energy Policy Advisor in the Office of the Ohio Consumers' Counsel ("OCC"), the state's residential utility consumer advocate. In that capacity, I both appeared in numerous utility regulatory proceedings and analyzed and addressed a broad range of regulatory policy issues. I helped initiate the first energy efficiency collaboratives in Ohio. And, I helped develop and advance Ohio's position supporting the sulfur dioxide cap-and-trade program enacted in 1990 Clean Air Act Amendments.

I have a law degree from the University of Michigan Law School and a bachelor's degree with Honors in Economics from Oberlin College. I am a member of Institute of Electrical and Electronics Engineers, Power Engineering Society; the International Association for Energy Economics; and the American Economic Association.

Q. What is the purpose of your testimony?

A. My testimony evaluates the impact of decisions by relevant electric retail regulatory authorities to opt-out of allowing retail customers and aggregators representing retail customers to participate in MISO demand response programs. I assess the effects of these opt-outs in light of the changes in technology and market conditions since Order 719, which permitted such opt-outs, in 2008.[1] I will describe the challenges facing the MISO market and the impacts of retail regulatory authorities prohibiting direct customer and aggregator participation in MISO demand response programs. Based on circumstances in the MISO market, I will recommend that FERC direct MISO to remove the undue barrier to broader demand response participation created by the prevalence of opt-outs in MISO. FERC should direct MISO to develop a non-discriminatory participation model for

[1] *Wholesale Competition in Regions with Organized Elec. Markets*, 125 FERC ¶ 61,071 (Oct. 17, 2008) ("Order 719").

demand response that will remove barriers to the broader demand response participation in MISO, while facilitating coordination with distribution planning and operations, ensuring comparable treatment of utility and third party demand resources, and accommodating appropriate voluntary participation of retail regulatory authorities. Finally, I will discuss FERC's inconsistent treatment of demand response and other distributed energy resources that provide functionally equivalent services.

II. The Role of Demand Response in Wholesale Power Markets and Federal Energy Policy

Q. What is the role of demand response in wholesale power markets?

A. To understand the role of demand response, it is useful to review why society relies on markets. Markets are a means of communicating information. How much does it cost to produce an additional unit of energy? What value does that next unit of energy have for the consumer? An efficient market answers such questions with the information participants reveal in offers and bids. They reveal the portions of their marginal cost and marginal value functions necessary to complete transactions. Their transactions balance supply and demand at prices that make each participant as well off as possible given their initial endowments of resources. Moreover, the prices are dynamic, adjusting as costs, quantities, and values change. We use markets because they are an efficient way to exchange privately held information. By contrast, society has learned, often through painful experience, that central planners rarely have sufficient information to achieve similar results given changing and varied cost and value functions.

Unfortunately, wholesale power markets are incomplete. They generally fail to communicate prices to electricity consumers or accurately reflect how consumers value electricity. As the U.S. Supreme Court said:

> Many State regulators insulate consumers from short-term fluctuations in wholesale prices by insisting that LSEs set stable retail rates…. That, one might say, short-circuits the normal rules of economic behavior. Even in peak periods, as costs surge in the wholesale market, consumers feel no pinch, and so keep running the AC as before.[2]

Demand response is how power markets correct for the failure of retail rates to communicate dynamic market prices to most consumers of electricity. It is a substitute for the self-correcting properties of dynamic pricing in other markets. As FERC stated in recognizing the role of demand response in Order 719, "enabling demand-side resources, as well as supply-side resources, improves the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power."[3]

[2] *FERC v Elec. Power Supply Ass'n,* 136 S. Ct. 760, 768 (2016).
[3] Order 719 ¶ 16.

Q. How does wholesale demand response support national energy policy?

A. It is national policy to foster competition in wholesale power markets. "Demand response can provide competitive pressure to reduce wholesale power prices; increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability; and in combination with certain new technologies, can support the use of renewable energy resources, distributed generation, and advanced metering."[4] On numerous occasions, FERC, "has expressed the view that the wholesale electric power market works best when demand can respond to the wholesale price."[5] FERC relies on competitive markets to set market based rates that are just, reasonable, and not unduly discriminatory. To help achieve that objective, FERC has repeatedly acted to remove barriers to demand response participation in wholesale markets.

In doing so, the Commission also has been implementing a statutory directive. The Energy Policy Act of 2005, 119 Stat. 594, at §1252(f) declares that,

> It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

Q. What are the implications of recognizing the benefits of demand response that accrue to those who are part of the same regional electricity entity?

A. In regional electricity power markets, demand response affects the matching of demand and supply and market prices across the market. Thus, if a single utility or state restricts the participation of demand response in a regional wholesale market, the impact of withholding demand response is regional in scope and not confined to that particular utility or state. In this case, it is important to recognize that the impact of one retail regulatory authority opting out of MISO demand response programs has regional impacts.

Q. Why is demand response important in MISO power markets?

A. The MISO Market Monitor described the value of demand response as follows:

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[4] *Id.*
[5] *Id.* ¶ 18.

> Demand response contributes to: Improved operational reliability in the short term; Least-cost resource adequacy in the long term; Reductions in price volatility and other market costs; and Mitigation of market power. Additionally, price-responsive demand has the potential to enhance wholesale market efficiency. Even modest reductions in consumption by end-users during high-priced periods can greatly reduce the costs of committing and dispatching generation. These benefits underscore the value of facilitating efficient demand response through wholesale market mechanisms and transparent economic signals. Hence, it is important to provide efficient incentives for demand response resources and to integrate it into the MISO markets in a manner that promotes efficient pricing and other market outcomes.[6]

As I will describe later in my testimony, demand response, particularly flexible demand, can help avoid emergency conditions and facilitate the integration of an expected increase in variable renewable generation in MISO markets.

III. How Circumstances Have Changed since Order 719

Q. Are the prohibitions on retail customers and aggregators participating in demand response programs a barrier to efficient and reliable wholesale power markets in MISO?

A. Yes. In 2008, FERC made an exception to Order 719 on demand response participation, "for circumstances where the laws and regulations of the relevant retail regulatory authority do not permit a retail customer to participate."[7] MISO market conditions and technology have changed significantly in the last twelve years. The retail regulatory exception has become a barrier to efficient and reliable MISO wholesale power markets.

MISO's markets are designed to enable the reliable delivery of low-cost energy through efficient, innovative operations and planning.[8] They ensure consumers have access to affordable and reliable power while enabling the achievement of public policy objectives. Active and flexible demand participation is essential to meeting these design objectives under current and likely future market conditions. Unfortunately, retail regulatory prohibitions on aggregation and direct customer participation are forcing MISO to rely on utility demand response programs that are available only after an emergency is declared and do not address current needs. These prohibitions restrict demand participation, constrain the development of flexible demand response, and prevent third party providers

[6] Potomac Economics, *2019 State of the Market Report for the MISO Electricity Markets*, p. 107 (June 2020) ("Potomac Economics 2020").
[7] *Wholesale Competition in Regions with Organized Electric Markets.* Order No. 719, 73 FR 64,100-01, *64,119 (Oct. 28, 2008); FERC Stats. & Regs. ¶ 31,281 at 158 (2008); Order on Rehearing, Order No. 719-A 128 FERC ¶ 61,059 (July 16, 2009).
[8] MISO, *MISO Forward 2020 – Utilities of the Future: What do they need from a grid operator?*, p. 3 (Mar. 2020) ("MISO 2020a").

with specialized expertise from offering innovative products and services. They increase costs and reliability risks.

As a former state regulator, I support cooperative federalism and appreciate the importance of transmission system operators respecting the operational requirements of distribution utilities. However, a blanket prohibition on aggregation and direct retail customer participation in MISO demand response programs is an unnecessarily restrictive approach.

To ensure efficient and reliable markets, in light of changed circumstances, FERC should require MISO to eliminate the undue barrier to demand response participation created by opt-outs. FERC should direct MISO to work with utilities, relevant electric retail regulatory authorities, and other interested stakeholders to develop a participation model that enables broader wholesale market demand participation, facilitates coordination, ensures comparable treatment of utility and third party DRs, and accommodates appropriate voluntary participation of retail regulatory authorities. FERC should align the opportunities for demand response to participate in MISO markets with the opportunities available to other distributed energy resources. And, in doing so, FERC should enable the participation of demand response resources that will be available without MISO having to initiate an Emergency event.

Q. How has technology changed since the adoption of Order 719?

A. An obvious change has been the deployment of Advanced Metering. Advanced Metering Infrastructure ("AMI") enables utilities to record and retrieve interval usage data, which can be used in wholesale market settlements, retail pricing and billing, and to measure and verify performance in demand response programs.[9] In 2008, relatively few customers had advanced meters. Only 4.7% of customer meters (6.7 million) supported advanced metering functionality.[10] And, it was not until 2010 that more than ten million advanced meters had been installed.[11] Since then the deployment of advance meters has accelerated. By 2018, more than 86 million advanced meters were in service providing

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[9] Advanced metering historically was defined as: "a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and provides for daily or more frequent transmittal of measurements over a communication network to a central collection point." FERC, *Staff Report: 2008 Assessment of DR and Advanced Metering*, p. 5 (Dec. 2008) ("FERC 2008"). The definition currently includes clarifications and distinguishes advanced meters from other systems such as automated meter reading ("AMR"). It defines advanced meters as " '[m]eters that measure and record usage data[,] at a minimum, in hourly intervals and provide usage data at least daily to energy companies and may also provide data to consumers. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.' Other types of meters currently in use – such as standard electromechanical, standard solid state, and automated meter reading (AMR) meters – are not considered advanced meters..." FERC, *Staff Report: 2019 Assessment of DR and Advanced Metering*, p. 1 n.2 (Dec. 2019) ("FERC 2019"); U.S. Energy Information Administration ("EIA"), *Annual Electric Power Industry Report, Form EIA-861 detailed data files* (Oct. 1, 2019) (U.S. EIA 2018).

[10] FERC 2008, p. 3.

[11] U.S. EIA, *Electric Power Annual 2018* (Oct. 18, 2019) ("U.S. EIA 2020a").

usage data for 56% of electric customers.[12] By the end of 2020, the industry estimates that more 107 million advanced meters will be in service for nearly 70% of U.S. electric customers, including approximately 60% of the customers in MISO.[13]

With the deployment of advanced meters and communications systems, most consumers today could shape, shift, and modulate demand based in part on wholesale market conditions if barriers to their participation in MISO demand response programs were removed.

Q. What other changes in technology have occurred since 2008?

A. Digital technology and the Internet of Things have fundamentally changed products and services.[14] Smart technology was only beginning to have an appreciable impact when FERC issued Order 719. The first iPhone had just been introduced in 2007.

Today, inexpensive embedded processors and sensors, near ubiquitous connectivity, advances in data analytics and machine learning allow intelligent systems to control industrial processes, agricultural equipment, data center operations, building environments, distributed energy resources, electric vehicle charging, and multiple devices in our homes. Intelligent systems can learn preferences and optimize the timing of electricity use in response to multiple inputs. Such inputs can include the instructions of demand response aggregators, RTO control signals, energy prices, or local grid conditions. Intelligent systems can shape usage patterns based on forward prices, shift demand out of high price periods during the operating day, and flexibly modulate demand on a near real-time basis.

Intelligent systems enable the timing of demand to be managed in a manner comparable to managing the charge in a battery. Tapping this underutilized demand flexibility is comparatively inexpensive since the storage medium – thermal inertia, timing, or locational flexibility – already exists. In many instances, sensors, communications, and control systems are also present. As a result, flexible demand response can provide significant economic and reliability benefits to consumers and the power system.[15]

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[12] *Id.*

[13] Adam Cooper and Mike Shuster, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2019 Update)* (Dec. 2019); Minnesota Public Utilities Commission ("MN PUC"), *Integrated Distribution Plan (2020–2029)*, Docket No. E002/M-19-666, In the Matter of Xcel Energy's 2019 Integrated Distribution Plan (IDP) and Advanced Grid Intelligence and Security Certification Request (Nov. 1, 2019).

[14] Michael E. Porter and James E. Heppelmann, *How Smart, Connected Products Are Transforming Companies*, Harvard Business Review (Nov. 2014). The total number of Internet of Things connected devices worldwide was estimated to exceed 23 billion in 2019 and is forecast to be more than 75 billion by 2025. Statista Research Department, *Internet of Things – number of connected devices worldwide 2015–2025*, Statista (Nov. 27, 2016).

[15] MIT Energy Initiative, *Utility of the Future: An MIT Initiative response to an industry* (Dec. 2016) ("MIT Utility of the Future").

The ability of intelligent systems to manage demand has two important effects. First, it expands demand response potential and the range of customers, end uses, and distributed resources that can participate in demand response. Second, it enables demand response to become flexible and dynamic, such that it can in many cases respond rapidly to changes in markets or grid conditions. For example, residential end uses in other power markets are being aggregated to provide ancillary services.[16]

Q. How significant is the growth in flexible demand response?

A. There have been a number of studies looking at the potential growth in flexible demand. Building on an analysis prepared for Xcel Energy's Northern States Power Service Territory,[17] the Brattle group estimated that the U.S. power system will add more than 120 GW of cost-effective flexible demand by 2030. This would be in addition to a modest expansion in existing demand response programs.[18] Analysts at Wood Mackenzie have projected that the adoption of smart thermostats could create more than 40 GW and that residential EV charging and behind-the-meter storage could provide nearly 20 GW of additional flexible demand in the U.S. by 2023. The California Public Utilities Commission sponsored a detailed study on the potential and cost of demand response resources and found that by 2025 automation could cost-effectively shift up to 20% of California electricity demand.[19]

Considering how electricity is used, these estimates appear reasonable. Heating, cooling, ventilation, and refrigeration – end uses where the management of thermal inertia could provide timing flexibility – account for 37% of all U.S. electricity consumption.[20] It should be possible to modify the timing of demand in these end uses with little apparent impact on the energy services that customers enjoy. For example, one study of residential demand response potential found that managing thermal inertia within narrow limits, 1^{o}C for home heating and cooling, 2^{o}C for residential refrigeration, and 3^{o}C in residential water heaters, could shift a majority of residential demand in California.[21]

Q. How have MISO markets changed since 2008?

A. There have been significant changes in the structure of MISO markets. In 2008, the Midcontinent region was still evolving from individual utilities to a regional market

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[16] David Holmberg and Farhad Omar, *Characterization of Residential Distributed Energy Resource Potential to Provide Ancillary Services*, NIST (Oct. 2018).
[17] Ryan Hledik et al., *The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory*, The Brattle Group (2019) ("Hledik et al. 2019").
[18] Ryan Hledik et al., *The National Potential for Load Flexibility: Value and Market Potential Through 2030*, The Brattle Group (June 2019) ("Hledik et al. 2019a").
[19] Peter Alstone et al., *Final Report on Phase 2 Results: 2025 California DR Potential Study – Charting California's Demand Response Future*, Lawrence Berkeley National Laboratory, p. 6-1 (Mar. 1, 2017).
[20] U.S. EIA 2020a; Lisa Schwartz et al., *Electricity end uses, energy efficiency, and distributed energy resources baseline*, Lawrence Berkeley National Laboratory (Jan. 2017).
[21] Johanna L. Mathieu, *Modeling, Analysis, and Control of DR Resources*, Lawrence Berkeley National Laboratory (May 2012).

framework. MISO implemented its energy market and trading in financial transmission rights in 2005.[22] In early 2009, MISO launched its ancillary service market and became a regional balancing authority.[23] MISO began operating monthly Voluntary Capacity Auctions in 2009.[24] After a multi-year development process, MISO held its first Planning Resource Auction in 2013.[25] In late 2013, MISO completed an agreement to extend its operations into its Southern region.[26]

Market conditions have also changed. As the market developed, MISO enjoyed the operational flexibility of having capacity that exceeded its minimum planning reserve requirements. In 2013, for example, MISO had a 28% reserve margin, nearly double its planning reserve margin requirements.[27] However, "MISO's capacity surplus has dwindled in recent years as older baseload units have entered long-term suspension or retired."[28] Conventional coal, gas, and nuclear generators provided the vast majority of the region's energy and 90% of MISO installed capacity in 2006.[29] Since 2006, more than 24 GW of coal, gas, and oil capacity have retired or received approval to retire.[30] "Over the past few years, MISO has experienced a significant increase in the frequency and severity of generation emergencies. Much of this increase is attributable to a narrowing reserve margin and impacts of the market's evolving generation mix. … Increased intermittent output and its associated fluctuations, along with increased reliance on [Load Modifying Resources ("LMRs")] that can only be deployed during emergencies, has resulted in more frequent emergency events."[31] From 2016 to 2019, MISO had 27 Maximum Generation ("MaxGen") Emergencies.[32] It also declared a MaxGen Alert requiring Conservative Operations on February 21st of this year.[33] And, MaxGen events were declared on July 7, attributed in part to an atypical outage pattern impacted by COVID-19, and during Hurricane Laura in August 2020.[34] Prior to 2016,

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[22] Francisco Flores-Espino et al., *Competitive Electricity Market Regulation in the United States: A Primer*, at 30, National Renewable Energy Laboratory ("NREL") (Dec. 2016).
[23] *Id.*
[24] Potomac Economics, *2012 State of the Market Report for the MISO Electricity Markets* (June 2013) ("Potomac Economics 2013").
[25] Potomac Economics, *2012 State of the Market Report for the MISO Electricity Markets* (June 2013) ("Potomac Economics 2014").
[26] Francisco Flores-Espino et al., *Competitive Electricity Market Regulation in the United States: A Primer*, at 30, NREL (Dec. 2016).
[27] MISO, *MISO Overview and Challenges for RTOs as Energy Generation Changes*, Midwest Rural Energy Council (February 14, 2020) ("MISO 2020k").
[28] Potomac Economics 2020; *see also* MISO, *MTEP 2019 Report* (Dec. 2019) ("MISO 2019g").
[29] MISO, *MISO 2020 Interconnection Queue Outlook: A forward-looking view of MISO interconnection queue activity*, p. 2 (May 2020) ("MISO 2020b").
[30] MISO, *Aligning Resource Availability and Need: Ensuring reliable and efficient operations every hour of the year*, p. 7 (Dec. 2019) ("MISO 2019").
[31] Potomac Economics 2020, p. 36.
[32] MISO 2019.
[33] David Patton, *IMM Quarterly Report: Winter 2020*, Potomac Economics (Mar. 24, 2020) ("Potomac Economics 2020c").
[34] David Patton, *IMM Quarterly Report: Summer 2020*, Potomac Economics (Sept. 15, 2020) ("Potomac Economics 2020b").

MISO had last experienced a MaxGen emergency in 2007. While notice times can vary, "MISO frequently declares emergencies less than 15 minutes prior to the beginning of the emergencies when conditions are generally tightest…These short lead times are not surprising because emergencies tend to occur when there are multiple concurrent contingencies and/or higher than expected load that is not foreseen far in advance."[35] Such events place a premium on flexible resources that are able to rapidly respond to the change in system conditions.

MISO has investigated the drivers and trends that are changing its resource mix and its need for additional flexible resources. In 2018, MISO initiated a Resource Availability and Need ("RAN") analysis to identify resource needs and near-term solutions.[36] "Five key drivers of change were identified as major contributors of increasing MaxGen emergencies. These five drivers identified market conditions which would impact reliability in the near-term and become even more prominent in the future."[37] In planning documents and FERC filings, MISO identified these trends as:

- Aging and retirement of generating units. In addition to generation retirements, MISO has reported higher generator outage rates. These factors have reduced available capacity and eroded MISO's reserves.
- Correlated generation outages: While MISO has year-round resource needs, it has been planned based summer capacity commitments. With lower overall capacity and higher outage rates, this reduced available capacity in non-summer months when generators typically plan maintenance outages.
- Growth in LMRs – the primary form of demand response in MISO – which are available only during emergencies, as a percent of the resource portfolio: Over 11 GW of LMRs cleared in MISO's 2020/2021 Planning Resource Auction representing 9.4% of forecast peak demand and 8.4% of planning reserve margin requirements.
- Growing reliance on unscheduled resources: MISO, "now relies more heavily upon uncertain or otherwise non-committed supply resources. In the last few years MISO has become a significant importer of energy from neighboring systems. About half of this energy is scheduled in real time with submission of interchange due just 20 minutes prior to each 15-minute interval. While MISO has arrangements in place for the purchase of emergency energy from neighboring systems during declared emergency conditions (as occurred in January 2018), availability of such energy remains highly uncertain."[38]
- Growth in Variable Energy Resources (Wind and Solar): MISO is already experiencing the impacts of additional wind and solar generation. These resources

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[35] Potomac Economics 2020, p. 43; MISO, *Filing to Enhance LMR Participation in MISO Markets*, FERC Docket No. ER19-650-000 (Dec. 21, 2018) ("MISO 2018a").

[36] MISO, Resource Availability and Need: Issues Statement Whitepaper (Mar. 30, 2018) ("MISO 2018b").

[37] MISO 2019, p. 1. *See also* MISO 2018a, Tab C: Prepared Direct Test. of Jeff Bladen ("Bladen 2018"); MISO, *Filing to Enhance Accrediation of LMR Participating in MISO Markets, Tab C: Test. of Shawn McFarlane*, FERC Docket No. ER20-1846-000 (May 18, 2020) ("McFarlane 2020").

[38] MISO 2019, p. 8; Bladen 2018 and "McFarlane 2020."

have different operational characteristics than MISO's legacy thermal resources. With these variable resources, "there is no assurance that the accredited capacity will be available during a particular emergency event."[39]

Q. How will MISO market conditions continue to change in the future?

A. MISO will continue to see a significant shift in its generation mix as legacy fossil fuel and nuclear generating units age and retire and variable wind and solar resources are added and play an expanded role in providing the energy needed to serve its customers.

Wind and solar resources with signed interconnection agreements represent a substantial majority of the new resources expected to come online in MISO in the period 2020 through 2022.[40] As of September 2019, wind and solar made up over 80% of the new resources in MISO's total interconnection queue. In 2018, wind and solar generation accounted for 7% of the MISO energy mix. Based on utility announcements, wind and solar are expected to provide 30% of the energy in MISO by 2030. And, more aggressive utility decarbonization goals and proposed state policy changes in Illinois, Minnesota, and Wisconsin could accelerate renewable resource growth, leading to wind and solar providing 35% of the energy in MISO by 2030.[41]

Recent interconnection requests provide further evidence of the growth in solar and wind resources. In the application period ending in June 2020, 52 GW of capacity requests were added to MISO's interconnection queue. This included 36 GW of solar, 8 GW of wind, 4 GW of hybrid systems, and 2 GW each of storage and gas-fired generation. MISO now expects more than 80% of the new market capacity coming online in 2021 and 2022 will be solar and wind generation.[42]

Additionally, planning reserve margins will likely continue to decrease as fossil and nuclear resources retire and are replaced by renewable resources.[43] As a result, MISO could continue to face periodic generation emergencies.

Q. What factors may drive this increase in wind and solar generation in MISO?

A. Rapid growth in wind and solar energy in MISO is being driven by three factors.

First, wind and solar generation costs have declined significantly. Since 2009, the unsubsidized levelized cost of utility scale wind has fallen by 70% and of utility scale solar by 89%.[44] Wind and solar energy costs are expected to continue to decline with ongoing research and development and greater market adoption.[45]

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[39] MISO 2019, p. 8. *See also* Bladen 2018 and MacFarlane 2020.
[40] MISO 2020b, p. 4.
[41] R. Doying, *Resource Availability and Need: Strategy and Update* (Sept. 17, 2019) ("Doying 2019").
[42] MISO, *Generator Interconnection: Overview* (Oct. 1, 2020).
[43] Potomac Economics 2020.
[44] Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 13.0*, p. 7 (Nov. 2019) ("Lazard 2019").
[45] NREL, *Annual Technology Baseline: Electricity* (2020) ("NREL 2020").

Second, MISO benefits geographically from states with a high potential for the development of cost-effective wind and solar resources.[46] These first two factors have made levelized generation costs for wind and solar increasingly competitive with and often below the cost of fossil fuel generation.[47]

Third, many utility and business leaders and policy makers support expanded investment in clean energy. MISO gathered the views of stakeholders throughout its footprint and found that, "utility, corporate and policy leaders highlighted the need to consider decarbonization goals and customer preferences in their own investment decision making. These two go hand in hand, propelled by falling costs for wind and solar plants and the ability to hedge fuel cost risk. These trends contribute to forecasts for MISO's footprint that could include 40% wind and solar, 25% gas, 25% coal and 10% nuclear/other (including storage) by 2030."[48] MISO identified eleven of its large utility members with 80% or higher clean energy targets and five additional utilities with 50% clean energy goals.[49]

Q. What type of changes will MISO need to make to address the anticipated growth in renewable resources?

While its RAN initiative focused on short-run solutions, MISO recognizes that it faces long-term challenges. MISO identified a number of key trends: growth in zero and low marginal cost resources (de-marginalization), distributed energy resources (decentralization), and the revolution in information and communication technologies (digitalization), that, "will intensify the operational impact" of the drivers that contributed to recent emergency events. Such that, "[s]olutions implemented now must not only address near-term issues, but they must also take the future portfolio into account. To that end, RAN is exploring one of the most complex and critical questions in the industry: What changes should MISO make to address near-term reliability challenges while also preparing for a future portfolio likely to be comprised of far less thermal dispatchable resources, more emergency-only resources, and a large percentage (e.g., 40 percent) of renewable resources?"[50]

As MISO CEO John Bear stated,

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[46] *Id.*; Anthony Lopez et al., *U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis*, NREL (July 2012).
[47] NREL 2020. *See also* Lazard 2019 and Ryan Wiser et al., *2018 Wind Technologies Market Report* (Aug. 2019).
[48] MISO 2020a, p. 6.
[49] *Id.* Utilities with 80% or higher targets include: American Electric Power ("AEP"), Alliant, Ameren, Consumers Energy, DTE, Manitoba Hydro (achieved target), MidAmerican, Northern Indiana Public Service, Vistra, WEC Energy Group, and Xcel. Utilities with 50% targets included: Duke, Entergy, Great Energy, Indianapolis Power and Light, and Vectren / Southern Indiana Gas and Electric.
[50] *Id.*

> Utilities need MISO to act now to develop transitional and transformational solutions. …[W]e heard four strategic imperatives:
> 1) Establish future reliability criteria that reflect increasing uncertainty across all hours of the year. This includes addressing current issues with the Planning Resource Auction and rethinking resource accreditation.
> 2) Redefine markets and ensure prices reflect underlying conditions such as scarcity and the value of flexibility.
> 3) Update the investment approach for transmission by building off the value identified in new market constructs and reliability criteria to improve deliverability of key grid needs.
> 4) Enhance communication and coordination across the transmission and distribution interface – to address today's challenges with Load Modifying Resources and with an eye toward emerging tech and active demand.[51]

As the fourth strategic imperative indicates, MISO will need to move beyond its current reliance on LMR and expand the active participation of flexible demand.

Q. What are the implications of the growth in variable renewable resources for MISO resource requirements and operations?

A. Wind and solar generation are both intermittent and variable. Their output can fall off rapidly when the winds calm, storm clouds block the sun, or snow covers solar panels. Photovoltaic panels generate only during daylight hours and their output also changes seasonally and hourly with the angle of the sun. Continuous changes in wind speed and irradiation also produce short-term variability in renewable resource output. A combination of flexible demand and other resources are needed to offset changes in wind and solar generation.

MISO already is experiencing large changes in the output of its wind generation. For example, in the hour ending at 4:00pm on April 14, 2020, wind generators in MISO provided 13,269 MWh. Two hours later their output had fallen by nearly 3,900 MWh. And, by 8:00 pm wind units were producing only 4,656 MWh. This was a 65% four hour decline in wind output, more than 8,600 MWh or 13% of the total demand in the MISO system.[52] Wind generation in MISO peaked in April at 18,132 MW. However, MISO also experienced a decrease in wind generation of 4,441 MW in one 60-minute period.[53]

MISO has undertaken a Renewable Integration Impact Assessment, including modeling its system with different levels of renewable energy. With a 30% reliance on wind and solar energy, the minimum level anticipated by the end of the decade, the four hour ramp in net load resulting from changes in renewable output could be as high as 15,200 MW. In modeling for its Renewable Integration Assessment, MISO has, "assumed the current

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[51] *Id.,* p. 3.
[52] MISO Market Reports, *Historical Hourly Wind Data and Historical Daily Forecast and Actual Load by Local Resource Zone* (downloaded June 12, 2020).
[53] David Patton, *IMM Quarterly Report: Spring 2020*, Potomac Economics, p. 25 (June 16, 2020) ("Potomac Economics 2020a").

level of load flexibility."[54] In the absence of more flexible demand, such rapid changes in renewable output present a risk of exhausting ramping capacity and operating reserves, increasing price volatility, and creating spikes in real-time prices, particularly in a limited number of evening hours when declining solar output may coincide with a reduction in wind generation.[55]

Changes in wind and solar production will have varying impacts across the MISO system. As renewable generation increases toward the 30% level, MISO is forecasting increased curtailment of low cost wind generation, particularly in its North region. Additionally, at 30% renewable energy, the ramping required from fossil generators will increase, internal power flows will increase and become more variable, and MISO will become more dependent on power imported from other regions.[56] MISO's Integration Assessment indicates that operational complexity will increase sharply and the system may face reliability challenges if the penetration of renewables exceeds 30%.[57]

Without greater demand flexibility, MISO and it customers will face significant economic and reliability challenges integrating the anticipated growth in renewable energy. MISO has recognized that, "[a]n increased reliance on intermittent and variable resources creates the need for intra-day flexibility, placing a premium on resources that can rapidly respond."[58] Its renewable integration assessment suggests that load shifting strategies such as demand control and energy storage could reduce the resource adequacy risks associated with greater reliance on renewable resources.[59]

Q. How could additional demand response and the removal of regulatory prohibitions on aggregators help MISO address its near-term and future challenges?

A. Historically, demand response in MISO has focused on inducing customers to shed load during emergency events. With the deployment of advanced meters and smart technology, aggregators could offer specialized expertise to help customers manage demand, bring additional demand response resources into MISO markets, and provide dynamic and flexible responses to meet the changing needs MISO has identified. Given efficient wholesale pricing, these demand response specialists can help consumers meet their energy service needs while more efficiently controlling the timing and level of their electricity use. They would bring innovation and competition into the market for demand

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[54] Energy Systems Integration Group, *Webinar: MISO's Renewable Integration Impact Assessment*, Q&A: Q. 10 (May 21, 2020).
[55] MISO, *Renewable Integration Impact Assessment: Finding integration inflection points of increasing renewable energy, Third Workshop, Energy Adequacy – Markets & Operations* (Nov. 14–15, 2019); *see also* Potomac Economics 2020.
[56] MISO, *Renewable Integration Impact Assessment: Finding integration inflection points of increasing renewable energy, Third Workshop, Energy Adequacy* (Nov. 14–15, 2019).
[57] MISO, *Renewable Integration Impact Assessment: Finding integration inflection points of increasing renewable energy*, ESIG *(May 21, 2020)*; *see also* Potomac Economics 2020.
[58] MISO 2018a.
[59] MISO, *Renewable Integration Impact Assessment: Finding integration inflection points of increasing renewable energy, Third Workshop, Resource Adequacy* (Nov. 14–15, 2019).

response services. Demand response increasingly would: Shape customer load profiles, enabling changes in underlying usage patterns in response to typical patterns in wholesale prices or time-varying retail rates; Shift demand, on a day-ahead or same day basis, in response to changes in anticipated prices and the potential for resource scarcity; and Modulate demand, dynamically adjusting demand to mitigate short-run ramps, grid disturbances, and contingencies on timescales ranging from less than a second to a few hours. Demand response could occur on a continuous basis to avoid MaxGen emergencies and offset the variability of renewable generation. Today, most MISO demand response can be activated only to shed load during an emergency event.[60]

Q. What impact would additional and more flexible demand response have on the integration of variable renewable resources?

A. Flexible demand response can mitigate and reduce the upward and downward slope in the ramping of other resources needed to offset changes in the output of renewable generation. Flexible demand response can reduce and shape peaks in net load – demand after accounting for variable renewable output – to match real-time resource availability, thereby lowering costs and avoiding emergencies.

Finally, in response to dynamic pricing or innovative incentives flexible demand could shift into periods when there is excess supply avoiding the need to curtail low marginal cost renewable resources while maintaining minimum operating levels for generation that remains online to be able to respond to later reductions in renewable output.

The directional impact of flexible demand response is to flatten the shape of net load. This could have significant economic and reliability benefits. For example, in an illustrative simulation of a 60% renewable energy case for ERCOT, Goldenberg et al. suggest that flexible demand might be able to reduce the peak in net load by 24%, lower the average magnitude of multi-hour ramps by 56%, and eliminate the need for 40% of renewable energy curtailments.[61]

Q. In a prior answer you mentioned "efficient wholesale pricing," do MISO markets provide efficient pricing?

A. MISO's energy and ancillary services markets have created significant value by providing more efficient price signals. However, additional improvements are being considered and may be needed to respond the challenges MISO is facing.

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[60] Potomac Economics 2020; MISO, *Filing to Enhance Accreditation of LMRs Participating in MISO Markets*, FERC Docket No. ER20-1846-000 (May 18, 2020) ("MISO 2020d"). *See also*, Section IV below on Demand Response in MISO Power Markets.
[61] Cara Goldenberg, et al., *Demand Flexibility: The Key to Enabling a Low-Cost, Low-Carbon Grid*, Rocky Mountain Institute (Feb. 2018).

For example, MISO has an active work program evaluating continued improvements in scarcity pricing and price formation.[62] Improved scarcity pricing in combination with flexible demand response could help MISO avoid emergencies and better manage variability in renewable energy output by providing a scarcity signal before operating reserves have been depleted.

With additional demand response potential, MISO also will have an opportunity to work with stakeholders as needs become apparent to develop products that enable demand response resources to more efficiently balance the variable output of renewable resources.

IV. Demand Response in MISO Power Markets

Q. What forms of demand response currently participate in MISO markets?

A. There are four forms of demand response participating directly in MISO markets: LMRs; Emergency demand response ("EDR"); Demand Response Resources ("DRR") – Type I; and DRRs – Type II.

LMRs can be scheduled to reduce demand during emergencies and count towards fulfilling the capacity obligations of Load Serving Entities. EDR provides an opportunity for market participants to offer voluntary demand reductions during an emergency at specific price points. DRRs can participate in MISO's energy market and in specified ancillary service markets.

The most recent MISO State of the Market Report states that, "Approximately 90 percent of the MISO demand response is in the form of LMRs that are interruptible load developed under regulated utility programs and behind-the-meter-generation ("BTMG")."[63] These regulated utility programs include interruptible rates for commercial and industrial customers and direct utility control of air conditioners or water heaters. Participants in these programs typically agreed to reduce consumption by or to a predetermined level or give the utility limited control over their devices in exchange for a small reduction in their per-kWh retail rates. The State of the Market report identified 13,611 MW of demand response participation in MISO markets in 2019. This included LMRs totaling 12,164 MW: 7,684 MW of Demand Resources and 4,480 MW of BTMG. Additionally, there were 624 MW of EDR in MISO in 2019. DRRs, the only types of demand response available to MISO when it is not in an emergency, included 811 MW of Type I DRRs and 13 MW of Type II DRRs in 2019.[64]

Updated figures on LMR participation are available from the results of MISO's 2020-21 Planning Resource Auction ("PRA"). In the April 2020 PRA, 7,557 MW of Demand Resources and 3,892 MW of BTMG cleared the auction and qualified for PRA resource

[62] MISO, *Emergency & Scarcity Pricing Evaluation (IR071and IR077), Market Subcommittee* (Mar. 5, 2020).
[63] Potomac Economics 2020, p. 107.
[64] *Id.*, p. 108.

credits. More than 97% of LMR Demand Resource and BTMG offers were accepted in this PRA.[65]

Q. What are the basic characteristics of LMRs?

A. LMRs are a legacy form of demand response that existed prior to the development of MISO markets. "MISO originated from 26 separate balancing authorities, each with its own resource adequacy requirements.…Well before and since the energy markets were launched in 2005, Load Serving Entities (LSEs) have relied on LMRs in part to meet their Resource Adequacy Requirements." Utilities and state regulators helped shape the opportunities for demand response participation in MISO markets. "At MISO's start, LSEs and [Relevant Electric Retail Regulatory Authorities ("RERRAs")] requested continued use of LMRs to meet their resource adequacy obligations."[66]

Initially, MISO had little need for emergency resources. "In the past MISO had surpluses higher than 40% of coincident peak, and consequently MISO's rules governing LMR capacity participation focused on accommodating existing utility programs and capabilities as long as the minimal resource adequacy reliability requirements were met."[67] LMRs provided utilities capacity recognition of interruptible and curtailable rates that often had been used to promote economic development with an expectation that service would rarely be interrupted or curtailed.

Some MISO utilities make little use of LMRs, while five of the ten Local Resource Zones in MISO contribute over 80% of the ISO's LMR capacity.[68]

LMRs are capacity resources. Limitations on their ability to perform during recent emergencies led to new requirements "focused on improving current operational concerns.,[69] and changes to LMR accreditation to encourage greater availability.[70]

However, even with the recent changes, the role of LMRs remains limited. LMRs are available only as, "one of MISO's last lines of defense before having to engage in firm load shedding."[71] They can be deployed only when MISO has declared a MaxGen Emergency and is at Step 2a or higher in its Emergency Operating Procedures. This occurs after MISO has first issued a Capacity Advisory, a MaxGen Alert, and a MaxGen Warning and implemented emergency actions including: increasing transmission transfer capabilities, moving to short term emergency transmission ratings, suspending the coordination of transaction scheduling, curtailing exports from the affected area, implementing emergency pricing, and committing emergency Generation Resources and

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[65] MISO, *2020/2021 Planning Resource Auction (PRA) Results* (Apr. 14, 2020) ("MISO 2020c").
[66] MISO, *Load Modifying Resources: Capacity Instruments affecting Resource Availability and Need*, p. 4 (May 25, 2018) ("MISO 2018").
[67] *Id.*, p. 1.
[68] *Id.*, p. 5.
[69] MISO 2019.
[70] MISO 2020d.
[71] *Id.*, p. 2.

emergency Type 1 and Type 2 DRR. Entering a MaxGen Emergency Step 2a also requires MISO to declare a Level 2 North American Electric Reliability Corporation Energy Emergency Alert ("EEA-2").[72]

When LMRs are called, MISO issues "scheduling instructions" indicating the MW quantities to be reduced during the emergency. However, LMRs are not under MISO's direct control, are not dynamically dispatched, and generally have not been modeled in MISO's operations.[73] When LMRs are used, demand reductions may be prorated among LMRs in the area where the emergency has been declared.[74] Without the ability to model their operational impact or dynamically dispatch LMRs, LMRs cannot be optimally deployed. LMRs have a specific function: to help avoid shedding firm load when virtually all other options have been exhausted. They are not designed to provide the flexible response MISO increasingly will need.

Q. What are the basic characteristics of EDR?

A. Emergency Demand Response permits market participants to offer demand reductions that can be called when MISO declares an emergency event.[75] Each day a market participant can decide how much EDR it wishes to make available the following day and the shutdown and hourly curtailment costs at which it is willing to respond. This permits MISO to commit and dispatch these demand reductions in economic merit order, curtailing loads in order of increasing value to participating customers. If dispatched, EDRs are compensated for verified demand reductions at the higher of the Real-time Locational Marginal Price ("LMP") at its Commercial Node or offered costs, including shutdown costs plus the EDR's hourly curtailment price.

EDR participation is voluntary. However, market participants offering EDRs can participate in the PRA and receive capacity credits if they also register as an LMR. Under a dual registration, the resource would be obligated to curtail as an LMR when instructed to do so.[76] Out of more than 7,300 MW of Demand Resource LMRs in the MISO market in 2019, only 9 with 180.8 MW of capacity also registered as EDRs.[77]

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[72] MISO, MISO Market Capacity Emergency: SO-P-EOP-00-002 Rev: 3 ("MISO 2020i").
[73] MISO 2018.
[74] MISO 2020i.
[75] Emergency DR could be triggered by a North American Electric Reliability Corporation EEA-2, which MISO would call upon entering Maximum Generation Emergency Step 2a, which is when LMRs also would be called, or an EEA-3 Alert which would occur when interruption of firm load was imminent or in progress.
[76] MISO, *Manual No. 026, Business Practices Manual: Demand Response, BPM-026-r4* (July 10, 2019) ("MISO 2019b").
[77] MISO, *Data Req. Comments of the Midcontinent Independent System Operator, Inc.*, FERC Docket No. RM18-9-000, p. 14 (Oct 7, 2019) ("MISO 2019c").

Q. What is the role of DRRs in MISO?

A. Demand Response Resources are the only forms of demand response available to operators when MISO is not in an emergency. DRR can be dispatched by MISO, are offered at specified prices, can set prices, and participate in MISO capacity, energy, and certain ancillary markets.[78] This makes them fundamentally different from LMRs and interruptible or curtailable retail electric service.

In 2019, DRRs represented less than 6% of all MISO demand response and less than 0.7% of MISO's forecast coincident peak demand.[79] "Although 41 DRRs were active in the MISO markets in 2019, roughly one-third of these became active in the second half of the year and only cleared a small amount of energy and reserves in the MISO markets."[80] There are currently two types of DRRs in MISO. In 2019, almost 90% of DRRs were Type I DRRs providing contingency reserves.[81]

Both types of DRR can be used to provide energy and certain types of reserves and to meet Planning Resource Requirements and receive capacity credits. Unlike LMRs and EDR that can offer as little as 100 kW, each DRR must offer at least 1 MW of response to participate in any of these MISO markets.

Q. What are the basic characteristics of Type I DRRs?

A. A Type I DRR must be capable of providing a fixed, prespecified quantity of demand reduction through reduced demand or behind-the-meter generation. Type I DRR can be dispatched with instructions to turn on or off but are not required to follow dynamic set point instructions. Type I DRR can aggregate resources located across various Elemental Pricing Nodes in the same Load Balancing Area. Type I DRR can be used to provide energy or contingency (Spinning and Supplemental) reserves. Due to its on / off nature, Type I DRR are not permitted to provide Regulation Service or MISO's Ramp Capability Product.

Q. What are the basic characteristics of Type II DRRs?

A. Type II DRR are flexible resources and can actively respond to MISO dispatch instructions. They are a very small portion of MISO's resources: 13 MW in 2019 in a market with a peak demand of more than 119,000 MW.[82]

Type II DRR can provide varying levels of energy or operating reserves on a five-minute basis in response to changing prices or instructions. They can provide energy, Spinning reserves, Supplemental reserves, the Ramp Capability Product, or with appropriate

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[78] Potomac Economics 2020.
[79] Potomac Economics 2020; Douglas J. Gotham, et al., *2019 MISO Energy and Peak Demand Forecasting for System Planning* (Nov. 2019).
[80] Potomac Economics 2020, p. 109.
[81] *Id.*
[82] *Id.*

telemetry Regulation Service. Unlike DRR Type I, Type II DRR must be located at a single Elemental Pricing Node and meet the same reliability standards as generators.[83]

Q. Are you aware of any additional demand response in the MISO system?

A. Yes, a 2019 survey of utilities by the Organization of MISO States ("OMS") identified Distributed Energy Resources not currently participating in MISO markets, including 249 MW of demand response capacity.[84]

Additionally, 1.8% of retail customers in MISO were on some form of a time-varying or dynamic retail rate in 2018.[85]

Q. How have utilities and state regulatory authorities helped shape the opportunities for demand response participation in MISO markets?

A. Most of the relevant electric retail regulatory authorities in MISO have prohibited direct retail customer and / or aggregator participation in MISO demand response programs. As a result, the dominant form of demand response in MISO, LMRs, reflect the historical development of utility demand response programs in the region. Utilities have developed only a limited amount of flexible dispatchable demand response.

Q. Can you provide an overview of how demand response developed?

A. Starting in the 1970s and when I worked as a residential utility consumer advocate in the 1980s and early 1990s, large industrial and commercial customers sought special arrangements to reduce their costs and avoid increasing electric rates. In many states, this was a period of rapidly increasing electric utility costs tied to costly investments in generation. In response to customer demands and to retain a portion of the revenue from their sales to large customers, utilities offered discounted interruptible rates. Such rates were approved, in part, to meet economic development goals, often with an expectation that service would be curtailed only infrequently and under emergency conditions. The successors to these interruptible rates make up the larger portion of MISO LMRs today. They specify that service can be curtailed only during emergencies.

In the 1980s and 1990s, consumer advocates and regulators started trying to get utilities to adopt energy efficiency and demand side management programs. For utilities, broader energy efficiency measures meant larger reductions in sales and revenue. Air conditioner cycling and other direct load control programs offered an alternative means to have the capability to reduce peak demand while having only a limited impact on total utility sales. As a result, a number of utilities adopted direct load control programs that gave the utility the option to curtail demand a limited number of times per year. In such programs, utilities can reduce demand by sending a signal to curtail demand. Utilities are making on

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[83] MISO 2019b.
[84] MISO 2019c; *see also* OMS, *2019 OMS DER Survey Results* (2019).
[85] U.S. EIA 2019.

/ off choices for blocks of customers. Such programs cannot be easily adapted to following 5-minute dispatch instructions.[86]

Recently, a smaller number of utilities have proposed smart thermostat programs. These programs are a variation on earlier utility load control programs in that utilities can now provide customers notification of peak demand periods. However, most smart thermostat programs are not structured to facilitate dynamic responses to changing real time prices.

The result is that, as of 2019, 94% of the demand response in MISO is only available during emergencies. The vast majority of the remaining 6% can only be turned on or off in response to MISO dispatch instructions. Less than 0.1% of the demand response in MISO can both respond to continuous changing dispatch set points and is available under normal non-emergency operating conditions.[87]

Q. Have you reviewed actions taken by the retail regulatory authorities and the demand response programs of major utilities in each of the MISO states?

A. A summary of my review can be found in Appendix B to my testimony.

Twelve of the fifteen MISO states have used the regulatory opt-out provisions in Order 719 to prohibit third-party aggregation of demand response for most or all retail customers. Most of these states also prohibit direct retail customer participation in wholesale demand response programs.

Most MISO investor owned electric utilities are state regulated and vertically integrated. Two MISO states permit retail access to supply for some retail customers: Illinois for customers of Ameren Illinois and Michigan for 10% of retail sales. Aggregated and direct customer participation in wholesale demand response programs are permitted for customers with access to competitive retail suppliers in these states.

Eight of the states have encouraged or allowed utilities to form agreements with demand response aggregators as a way to facilitate participation in wholesale demand response. In this participation model, the utility would offer demand response into MISO on behalf of the aggregator. In most of these states, this approach at this point has not succeeded. Most of the utilities in these states have not entered the necessary agreements with aggregators, denying aggregators the ability to participate in jurisdictions that, in theory, allow such arrangements.

I also reviewed publicly available information on demand response programs of large investor owned MISO member utilities.

Utility demand response programs varied significantly among the states. In a few states, Michigan and Minnesota for example, utilities have significant programs and are being

[86] *See also* Peter Cappers, et al., *Market and Policy Barriers for DR Providing Ancillary Services in U.S. Markets*, Lawrence Berkeley National Laboratory (Mar. 2013) ("Cappers et al. 2013").
[87] Potomac Economics 2020.

encouraged or directed by regulators to expand demand response. In several other states, including Louisiana, Kentucky, Missouri, Mississippi, North Dakota, South Dakota, and Texas, I found little evidence of significant demand response activity.[88]

Interruptible and curtailable rates were by far the most common way in which utilities secured demand response potential. In several states, utilities indicated that they also offered direct load control programs. Interruptible and curtailable rates and direct load control programs often are available only in limited circumstances and typically do not support flexible continuously dispatchable responses.

Q. What have been the primary impacts of state regulatory limitations on customer participation in MISO demand response programs?

A. State decisions prohibiting independent service providers from enrolling customers and direct customer participation in wholesale demand response force MISO to rely primarily on utility demand response programs. This negatively affects wholesale power markets in four ways:

First, these decisions make utilities the gatekeepers on participation in wholesale demand response. Most utilities have continued to rely on interruptible rates and direct load control programs, have not entered into agreements with aggregators who specialize in demand response, and have failed to develop demand response programs that reflect dynamic market value. This is not surprising. A utility's economic interests are not aligned with encouraging efficient demand participation in wholesale power markets. Most utility business models are based on earning a return on rate base, capital invested to meet consumer demand. Reducing customer demand often is in direct competition with opportunities for the utility to invest and increase future profitability. Moreover, demand reductions that reduce sales also may erode near term profits. In some jurisdictions, when sales to its own customers decline, the utility may not be able to retain any savings in fuel costs and / or profits from any off-system sales. Cappers et al. provide the following case study:

> Wisconsin with its regulated retail environment and restriction on ARCs [Aggregators of Retail Customers] providing demand response programs, faces both regulatory and business model barriers that limit their utilities' interest in pursuing demand response resources. … Since they rely on their own generation assets to serve customers' needs, any reductions in non-fuel operating expenses from more efficiently operating this fleet of resources can be captured by the utility but only until new rates are set which reflect these now lower costs. Although these types of demand response programs also create an opportunity for the state's utilities to convert reserved generation capacity into energy which can be sold off-system, state regulators do not allow the utility to retain any of these

[88] *See also* Applied Energy Group ("AEG"), DR, EE, DG Potential Assessment for Midcontinent Independent System Operator. Walnut Creek: CA: Applied Energy Group Inc. (Mar. 19, 2018) ("AEG 2018").

> profits but instead require the utility to turn them over to ratepayers. Furthermore, the electric utilities profit from investing in capital assets, like new generating stations, which is often not true for demand response investments. As such, Wisconsin utilities have only modest financial incentives to pursue demand response in general, while state regulators have restricted ARCs from doing business in the State.[89]

Comparable regulatory and business disincentives can be found across the region. Most of the large utilities in the MISO region both own generation and, as distribution companies, are the monopoly retail suppler in their service territory.

Second, state opt-outs contribute to a fundamental disconnect between demand response and the wholesale market. In an efficient market, customers observe and respond to market price signals, each responding based on individual dynamic value functions. The connection between customer demand and market value is almost entirely lost in existing utility programs. These programs were designed by planners, approved by regulators, and offered by utilities who, at best, have limited information on customer value functions. Utilities typically offer small reductions in rates in return for being able to curtail demand on a limited number of occasions. There is no necessary relationship between the rate discount and the time- and location-specific market value of demand reductions. Most of utility demand response allows demand to be curtailed only during emergencies. Utility programs have provided few DRRs, the flexible and dispatchable demand response that increasingly will be needed to offset variability in renewable resources.

Third, technology and market conditions are changing. The capacity to innovate, adjust plans, and use new tools has become increasingly important. The regulatory process will create lags in adapting to such changes. Utility demand response programs generally have to be analyzed, proposed in an integrated resource or demand-side management plan, approved by regulators in a process that can take well over a year, then piloted and evaluated, before being resubmitted for wider deployment. At the same time, non-utility providers with specialized expertise, experience in multiple jurisdictions, and the economic incentive to adapt to changing technology and conditions are being prohibited from participating in MISO markets.

Finally, the state opt-outs have created a patchwork of program requirements and incentives that vary from state to state and among the utilities in each state. For customers with facilities in multiple jurisdictions or utilities, inconsistent requirements and incentives create complexity and impede their ability to manage costs. For an individual consumer, their opportunity to control their electricity costs will depend on the service territory in which they are located. For demand response service providers, inconsistent and changing regulatory and utility requirements increase costs and business risk. For many of potential providers, varied and changing requirements may deter their participation in the MISO market.

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[89] Cappers et al. 2013.

Q. Is the current approach to demand response in MISO with state opt outs and reliance on utility programs consistent with MISO market requirements?

A. No. A continuation of the current approach to demand response, even with MISO's proposed changes to LMR accreditation, is not a viable strategy for meeting market requirements.

First, almost all utility sponsored demand response in the MISO market is only available after an emergency has been declared. This means that MISO has already taken steps to suspend normal operating procedures before it can take advantage of this demand response capacity. Moreover, MISO does not actively track the precise location of the LMR and EDR resources that it can call upon during an emergency.[90] LMRs typically have not been modelled as part of MISO operations and are not dynamically dispatched.[91] Each of these factors presents a barrier to optimizing the use of available demand response capabilities. MISO needs to expand the DRRs that it can rely upon before declaring an emergency. MISO's dependence on LMRs and EDRs that are only available in declared emergencies is not a reasonable long-term approach for to addressing current operational challenges or longer term requirements.

Second, the anticipated growth of renewable resources in MISO will increase the need for flexible resources to offset the variability in wind and solar output and maintain the demand – resource balance. DRRs will need to be deployed more frequently as large baseload resources are replaced by intermittent resources.[92] Flexible demand response, such as that provided by DRRs Type II, could be a very efficient way to offset wind and solar variability but is extremely limited in MISO.

Third, additional demand participation is needed to support an efficient market with competitive prices. Federal energy policy, including the development of ISOs, is based on using markets to form just, reasonable, and non-discriminatory rates. However, markets can identify efficient prices only if both demand and supply are able to actively participate. With limited exceptions, consumers in MISO purchase electricity at fixed rates set by RERRAs and do not have the ability to choose their power supplier. Time- and location-specific variations in energy and ancillary service prices are hidden from these consumers. And, in many jurisdictions, local regulatory opt-outs and utility practices are significant barriers to consumer participation in demand response programs. The lack of active demand response participation in the normal operations of MISO markets increases costs and reliability risks. It undermines the ability to rely on markets to set just, reasonable, and non-discriminatory prices in MISO.

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[90] MISO 2019; and MISO 2019c.
[91] MISO 2018.
[92] Potomac Economics 2020.

Q. Is the continuation of FERC's policy of permitting opt-out for demand response technology neutral?

A. No. The Commission permits retail regulatory authorities to opt-out of aggregator and customer demand response participation in RTO/ISO markets while not permitting retail regulatory authorities to prohibit the participation of aggregations of other Distributed Energy Resources ("DER") and storage technologies. In Order 2222, the Commission found that rules limiting DER participation in RTO/ISO markets unjust and unreasonable. Such rules often required DER to participate in the RTO/ISO markets as demand response. Opening wholesale markets to DER aggregation, the Commission denied requests for a retail regulatory DER opt-out but retained the opt-out for demand response and applied this opt-out to demand response included in DER aggregations.[93]

This discretionary policy choice reduces competition and undermines the efficient operation of MISO markets. It is inconsistent with the objectives of Order 2222, which states:

> We find that limiting the types of technologies that are allowed to participate in RTO/ISO markets through a distributed energy resource aggregator would create a barrier to entry for emerging or future technologies, potentially precluding them from being eligible to provide all of the capacity, energy, and ancillary services that they are technically capable of providing. Requiring that each RTO's/ISO's rules do not exclude any particular types of technology from participating in distributed energy resource aggregations in RTO/ISO markets will ensure a technology-neutral approach to distributed energy resource aggregations, which will ensure that more resources are able to participate in such aggregations, thereby helping to enhance competition and ensure just and reasonable rates.[94]

As described in Section III above, flexible demand is a significant DER. If regulatory barriers are removed, flexible demand, including smart buildings and intelligent charging of electric vehicles, could become the dominant form distributed resource in the power system. It will play an essential role in the efficient operation of markets that are adding wind and solar resources.

When the Commission issued Order 719 in 2008, demand response might have been seen as primarily in terms of shedding load during periods of peak demand. However, this is no longer the only or let alone the most important form of demand response. Modern control technology has made it cost-effective and increasingly common place to be able shape customer demand profiles, shift demand in response to anticipated scarcity, and change demand levels in near real time. In these use cases, flexible demand is providing

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[93] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 179 FERC ¶ 61,247 (Sept. 17, 2020) ("Order 2222").
[94] *Id.* at P 141.

the same customer and grid services that a lithium-ion battery or any another form of short-term energy storage might provide.

In Order 841, the Commission denied retail regulatory authorities the authority to opt-out and prevent energy storage resources from participating in wholesale power markets.[95] The Commission should extend the policy it adopted in Order 841 to comparable MISO demand response resources.

The only material difference between the battery and flexible demand is in the medium used to store useful energy. In the case of demand response, heat or cooling may be stored in the thermal inertia of a building, water heater, or refrigeration unit. Given an intelligent control system the thermal inertia of the building, water heater, or refrigeration unit is in direct competition with services that can be provided by the lithium-ion battery.

A home heating and cooling system and a residential water heater, for example, can be operated within a small temperature dead-band in much the same way a battery charges and discharges to provide equivalent energy services. Presenting a case study on the competition between battery storage and flexible demand, the MIT Utility of the Future study concluded that, "demand flexibility has a significant negative impact on the profitability of batteries. As amount of flexibility increases, the cost of batteries must significantly decline for batteries to be profitable. These simulations show that demand flexibility has the potential to diminish battery revenue streams."[96] The two technologies are in direct competition with one another.

Given modern control technology, flexible demand can be the functional equivalent of and indistinguishable in terms of power system impacts from other forms of energy storage, including: flywheels (mechanical storage), batteries (electrochemical storage), capacitors (electrical storage), and molten salt or ice (thermal storage).

Q. Is current FERC policy consistent with the goal of Order 719?

A. No. The Commission's goal in Order 719 was, "to eliminate barriers to the participation of demand response in the organized power markets by ensuring comparable treatment of resources."[97] However, current FERC policy no longer meets that objective. With the use of intelligent technology, demand response is no longer limited to the interruptible tariffs and utility load control programs that often characterized demand response in 2008. Flexible demand has the technical capability of participating in MISO markets in a manner comparable to other energy storage technologies and distributed energy resources. In the absence of opt-outs, MISO's Demand Response Resource products would allow flexible demand to compete with storage and other distributed energy resources.

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[95] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System* Operators, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("Order 841").
[96] MIT Utility of the Future, p. 44.
[97] Order 719 at P 16.

Q. Does current FERC policy provide consistent treatment for behind-the-meter generation?

A. No. Nearly one-third of demand response in MISO in 2019 was provided by behind-the-meter generators that reduced the net demand of their host facilities.[98] A new behind-the-meter generator, which reduces the net requirements of its host, could be prohibited from participating as demand response by a regulatory opt-out. However, under Order 2222, the same distributed generator could participate in DER aggregation, assuming it is willing to incur generator metering and telemetry costs that may be required for DER aggregation. In each case, the function of the generator is to reduce the net demand of its host. Neither generator may ever deliver power to the grid, although each might have the potential to do so. The two participation models treat the same resource differently without a resource-based distinction which provides a basis for doing so.

Q. Does current FERC policy ensure just and reasonable rates in MISO?

A. No. The regulatory opt-outs for demand response permitted under Orders 719 and 2222 have limited customer and aggregator participation and undermined the ability of the market to support just and reasonable rates.

As resources become increasingly scarce, the wholesale price of electricity should increase reflecting its value to different consumers. Price increases should begin, and consumers should an opportunity to modify their demand, before an Emergency has to be declared. However, most of the demand response in MISO (94% in 2019) is available only during an emergency; and LMRs, which are non-market resources, account for nearly all of this emergency capacity.[99]

MISO has recognized that, "[m]arket prices have often not appropriately reflected system conditions during emergencies and shortages."[100] And, it is considering changes in its Operating Reserve Demand Curve and Emergency pricing. However, without expanding demand participation, this will be a partial and inefficient solution.

Q. Should the Commission require MISO to eliminate the barriers posed to demand response participation by opt-outs ?

A. Yes. Although several of the retail regulatory authorities in MISO have authorized the use of demand response in emergencies or to reduce utility peak demand, many of the existing program designs predate the widespread use of advanced metering, development of intelligent technologies, and the need to integrate increasing quantities variable renewable resources. Unlike the circumstances in 2008, when entities were concerned

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[98] Potomac Economics 2020.
[99] *Id.*
[100] MISO, Emergency and Scarcity Pricing Evaluation (IR071 and IR077), Market Subcommittee (Mar. 5, 2020) ("MISO 2020m"); Potomac Economics, *2018 State of the Market Report for the MISO Electricity Markets* (June 2019); and Potomac Economics 2020.

that wholesale programs could divert the "best" demand response away from retail programs, depriving load serving entities of important resources, the primary issue today is how best to expand the portfolio of DRRs beyond current program designs to respond to recent and emerging challenges. The Commission should direct MISO to eliminate the undue barrier created by the opt-outs.

FERC should direct MISO to create a non-discriminatory participation model for demand response in the MISO markets. Such a model should facilitate coordination with distribution planning and operations, ensure comparable treatment of utility and non-utility demand response, accommodate appropriate voluntary participation by retail regulatory authorities, and enable broader flexible demand participation in MISO markets.

Enabling broader participation in MISO DRRs should be a priority. Unlike most of the demand response in MISO, DRR do not require an Emergency event. They can be dispatched by MISO, offer and participate in MISO markets, and set prices, helping ensure rates are just and reasonable. Expanding DRR participation would enable flexible demand to help offset variability in wind and solar output.

V. Potential Impact of Removing Barriers to demand response in MISO

Q. If FERC directs MISO to eliminate the barrier to demand response created by opt-outs how would this affect demand response participation in MISO?

A. If done in a reasonable manner, demand response participation would increase significantly and include more flexible demand capable of following dispatch instructions and providing real-time balancing and ancillary services.

There have been two recent independent studies that considered the impact of one or more flexible demand response technologies in MISO states:

- The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, prepared by the Brattle Group;[101] and
- Potential for Peak Demand Reduction in Indiana, prepared by Demand Side Analytics.[102]

These studies are directionally significant because 1) their estimates of cost-effective demand response potential are not limited to existing utility programs and 2) they identify opportunities to expand demand response in states in which the existing programs already provide significant demand response. Each identifies cost-effective demand response potential that significantly exceeds what is available from the existing utility programs. And, each study evaluates flexible demand response technologies that could help shape, shift, or modulate demand during normal, non-emergency system operations.

[101] Hledik et al. 2019.
[102] J. Smith, et al., *Potential for Peak Demand Reduction in Indiana*, Indiana Advanced Energy Economy (Feb. 2018) ("Smith et al. 2018").

The first study was performed for Xcel's Minnesota distribution utility, Northern States Power, in response to a Minnesota Public Utilities Commission directive. Northern States Power already has one of the largest demand response portfolios in the country, with 850 MW of load curtailment capability, equal to approximately 10% of its peak demand. The study examined, "opportunities enabled by the rapid emergence of consumer-oriented technologies" that, "enable demand response to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions." In addition to conventional direct load control and interruptible rates, the study considered smart thermostats, demand bidding, time-of-use rates, critical peak pricing, home and workplace EV charging load control, timer-based water heating load control and a more advanced "smart" water heating program, behavioral response, ice based thermal storage, and automated demand response for lighting and HVAC of commercial and industrial customers. While the potential for growth was limited through 2023 by the utility's on-going roll out of advanced meters, the study identified significant opportunities to expand cost-effective demand response by the end of the decade. It considered both a base case and a high sensitivity case that captured the impact of the growing adoption of renewable resources on the economic benefits of more demand response. It found that Northern States Power could increase its cost-effective demand response potential from 850 MW to 1,318 MW in the base case or 1,555 MW in the sensitivity case with additional renewable resources.[103]

The Indiana study examined three strategies: commercial and industrial load curtailment, residential connected thermostats, and battery storage. It reported results for both a medium and a high avoided cost case, which bracketed the avoided costs used by Indiana utilities' in their integrated resource plans. Their analysis showed that, "cost-effective demand response and energy storage in Indiana have the potential to generate net benefits ranging from $448 million to $2.3 billion over 10 years, in scenarios representative of expected avoided cost in Indiana."

For commercial and industrial ("C&I") demand, the researchers developed potential estimates to account for differences in avoided costs and the extent of advance notice. They considered a day-ahead notice case in which demand profiles could be shaped to reflect expected prices and a day-of notice scenario, reflecting the notice periods in Duke Energy's existing programs. The study noted the significant differences in C&I demand response reported by different Indiana utilities in their integrated resource plans: Duke Energy Indiana 694 MW, 10.5% of C&I peak demand, Northern Indiana Public Service ("NIPSCO") 530 MW, 16.8% of C&I peak demand, Indiana & Michigan Power 298 MW, 6.7% of C&I peak demand,[104] Vectren 35 MW, 3.2% of C&I peak demand, and Indianapolis Power and Light 1 MW, 0.03% of C&I peak demand – a total of 1,558 MW. Given that demand response depends on the programs offered by specific utilities, the study finds that, "Most of the C&I potential identified in the Medium Avoided Cost scenario appears to have been realized by Duke, NIPSCO, and Indiana Michigan Power

[103] Hledik et al. 2019.
[104] Indiana Michigan Power is an AEP affiliate in PJM.

under existing tariffs. But there remains considerable C&I potential, largely concentrated in Vectren and Indianapolis Power and Light service territories." The study identified a total C&I demand response potential of up to 2,159 MW or 9.6% of forecast 2027 peak demand in the medium avoided cost case and 3,917 MW or 17.5% of 2027 peak demand in the high avoided cost case.[105]

For smart thermostats, the researchers analyzed the increasing market share of connected thermostats among thermostats sold in the state and considered potential demand impacts based on industry experience in other smart thermostat programs. The study finds that the cost-effective achievable potential demand reduction from smart thermostats is 230 MW under a medium avoided cost scenario and 580 MW in a high avoided cost case. This increases potential residential demand reductions by 83% to 460%, when compared to the 126 MW that can be called under the utilities' existing air conditioning cycling programs.

With respect to batteries, the study found that cost effective potential in Indiana depends on finding locations where storage provides value in addition to avoided energy and capacity costs. In examining these options, the researchers identified 139 MW to 329 MW of cost-effective potential.[106]

These studies examined a utility and a state where the base level of existing demand response was already as high or higher than anywhere else in MISO. And, they each found significant potential that could tapped if MISO was not limited by the capabilities of existing utility demand response programs. In some other states or utilities, comparatively little demand response capability has been developed. With respect to LMRs, which are the dominant form of demand response, MISO reports that, "Some MISO local resource zones (LRZs) make little use of LMRs, while five of the LRZs [out of 10] have over 80% of LMR capacity."[107]

Q. Is demand response likely to expand significantly if MISO has to continue to rely primarily on utility demand response programs?

A. I support, and in other contexts have advocated for, efficient retail rate designs that incorporate dynamic market-based pricing. Until retail rates include a dynamic component that reflects efficient market pricing, demand response programs will remain the primary way in which flexible demand can participate in markets. I would welcome advances in utility demand response programs. However, I recognize that current practices have a long history and that some utilities may not support more efficient rate designs or expanded demand response programs that could reduce peak demand and their opportunities for capital investment. As a result, it is difficult to predict when change may happen without removing the opt-out barrier. Given current and anticipated market

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[105] Smith et al. 2018, p. vii.

[106] *Id.*

[107] MISO, *Load Modifying Resources: Capacity Instruments affecting Resource Availability and Need* (May 25, 2018) ("MISO 2018d"). See also differences in LRZs demand response potential based on existing programs as reported in AEG 2018.

conditions in MISO, the development of a new demand participation model should not be deferred.

A 2018 report provides a view of what could happen under the current participation model in which state opt-outs largely limit demand response to utility programs. MISO retained AEG to develop a reference case forecast of demand impacts to inform the development of futures scenarios in the MISO Transmission Expansion Planning process. AEG developed its estimates of peak demand reductions, "through a survey of load serving entities within MISO, as well as secondary research." The reference case, "was developed by calibrating savings, costs, and program participation rates based on results of the utility survey and secondary data collection. This reference case also assumes that existing programs will continue as they are currently designed and implemented with only very minor changes in participation each year over the 20-year study horizon." AEG found that demand response, "is not expected to grow significantly – amounting to 4.8% of baseline peak demand by 2038." In percentage terms, this represents a small decline from 4.9% in 2019.[108]

VI. Regulatory Opt-outs are Unnecessarily Restrictive

Q. How would you respond to the concerns of retail regulators and utilities that may have led states to opt out of wholesale demand response markets?

A. As a former state regulator, I can appreciate the need to understand the implications of market participation prior to allowing aggregators and retail customers to offer into wholesale demand response programs. An opt-out provided a way to defer addressing novel issues. In many states, opt-outs initially were adopted as a temporary measure or under time constraints due to a pending application to participate in MISO programs.

Further delaying greater participation in MISO demand response programs will create reliability risks, complicate market operations, and increase costs. The lack of greater active and flexible demand participation, particularly during non-emergency operations, has become a time sensitive issue that needs to be addressed.

I believe it will be possible to address any genuine substantive concerns in the development of a non-discriminatory participation model. Unlike the blanket opt-out, the development of such a participation model would be an example of true collaborative federalism. There are three major issues that a collaborative demand response participation model should address.

First, it is should enable timely coordination between wholesale demand response and the planning and operation of distribution systems. It may include a transparent review process to ensure that demand response will not pose significant risks to the reliable and

[108] AEG 2018. AEG also examined the potential impacts of energy efficiency and distributed generation. Given current FERC policy it was reasonable for purposes of transmission planning for AEG to develop an analysis of DR based survey responses from load serving entities and continued MISO reliance on utility DR programs.

safe operation of distribution systems. And, MISO will need to create a mechanism, through the MISO Communication System ("MCS") or some other means, and specify necessary exchanges of operational information with distribution system operators, aggregators, and customers who are direct market participants. Where dispatch or scheduling of a distributed resource may affect distribution operations, coordination will be required. This might require tracking the location of demand resources, sharing scheduling and dispatch instructions, and allowing distribution operators to place operational limits or price the impacts that the quantity and / or ramping of resources may have on distribution operations. Distribution operators also may acquire the right to call on demand resources for local needs. There will need to mechanism that reconciles any potentially conflicting obligations and avoids undue double counting of demand impacts and incentives. Parties also may need to exchange information after the fact on the actual performance of demand resources.[109]

Second, the participation model should treat utility and wholesale market demand response in a comparable and non-discriminatory manner. In reviewing state proceedings, I encountered a concern that while utility programs would reduce planning resource requirements and operational forecasts, utilities would be obligated to provide capacity to serve as firm load the full potential requirements of participants in RTO programs, presumably including demand that customers have offered to curtail.[110] The basis for this concern was not clear, although it might be related to MISO's use of LSE load projections in determining resource adequacy and LSE treatment of interruptible demand in these projections. The participation model should treat comparable demand resources identically whether they originate in a utility program or from an aggregator or an individual customer's participation in MISO programs.

Third, the participation model should accommodate the voluntary participation of relevant electric retail regulatory authorities where appropriate. For example, states also should be able to implement reasonable consumer protection regulations to address any deceptive or fraudulent practices in contracts between individual consumers and a demand response provider. This might include an ability to bar providers who violate consumer protection statutes from representing customers in MISO markets. Other issues should remain under the authority of retail regulators. Retail regulators and utilities have expressed concern that participation in wholesale programs could permit participants to avoid and shift the recovery of utility costs that are not avoided by reducing demand. This is an issue that retail regulators should be free to address through reasonable changes in retail rate design.

The regulatory opt-out is unnecessarily restrictive approach to address what in certain cases may be reasonable concerns. I am confident that any such concerns can be

[109] Resources with dual registration participating in more than one MISO demand response program are already required to update their status in the MCS to avoid conflicts. MISO, *Business Practice Manual No. 11: Resource Adequacy*, BPM-011-r23 (Mar. 31, 2020).
[110] *See* Appendix B - State Regulatory Opt-Out Decisions and Utility Demand Response and the discussion of opt-out decisions in Michigan and Indiana.

addressed in the development of open and non-discriminatory demand response participation model.

VII. Conclusions and Recommendations

Q. Can you please summarize your conclusions and recommendations?

A. Based on my review of current market conditions and the likely deployment of additional variable renewable resources in MISO, the effects of retail regulatory authorities opting out of MISO demand response programs, and the limited quantity and types of demand response available from utility demand response programs, FERC should require MISO to take immediate steps to eliminate the barriers to demand respond participation that result from the widespread use of opt-outs.

FERC should replace the opt-out with a directive that MISO consult retail regulatory authorities, distribution operators and other stakeholders, to develop and submit for FERC approval a non-discriminatory demand response participation model that enables retail customers and aggregators to participate in MISO demand response programs. This model should:

- Encourage the cost-effective participation of additional DRs and flexible demand, including placing a priority expanding DRRs participation and, where available, integrating price responsive demand that can help set reasonable market prices and avoid the need to initiate Emergency events;
- Create a process and develop tools for coordination between in wholesale demand response and the planning and operation of distribution systems. This process should avoid potential conflicts and undue double counting.
- Treat demand response in a uniform and non-discriminatory manner whether it has been developed in a utility or LSE program or has been offered by an individual customer or aggregator, correcting for any differences in their treatment; and
- Accommodate the appropriate voluntary participation of relevant electric retail regulatory authorities, while leaving to retail regulation matters that do not materially affect wholesale markets and can best be addressed by retail regulators.

The development of a reasonable participation model is a natural extension of MISO’s market platform. It is a means to meet wholesale market requirements while respecting the need for coordination with distribution operators and retail regulatory authorities.

This concludes my testimony.

APPENDIX A: CV OF PAUL CENTOLELLA

Paul A. Centolella

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Mr. Centolella has more than 35 years of experience as a practitioner, policy maker, and innovator in energy and environmental economics, market design and analysis; technology and standards development; utility regulation; and public utility and environmental law. His work has contributed to the development of environmental and electric power markets, modernization of power systems, and the evolution of utility business and regulatory models. Mr. Centolella was a Commissioner on the Public Utilities Commission of Ohio ("PUCO") and has been nationally recognized for his contributions as a utility regulator. He has served on a range of expert committees and task forces, including the Secretary of Energy's Electricity Advisory Committee, the National Academy of Sciences Committee on the Determinants of Market Adoption of Advanced Energy Efficiency and Clean Energy Technologies, the National Institute of Standards and Technology ("NIST") Smart Grid Advisory Committee, Massachusetts Institute of Technology Utility of the Future Study Advisory Committee, the Electric Power Research Institute's Advisory Council, the Governing Board and Board of Directors for the Smart Grid Interoperability Panel ("SGIP"), Americans for a Clean Energy Grid Advisory Council, the National Regulatory Research Institute's Regulatory Training Initiative Advisory Board, and the Board of the Organization of PJM States.

Professional Experience:

President, Paul Centolella and Associates, Chestnut Hill, MA (2014 – Present) and Senior Consultant, Tabors Caramanis Rudkevich, Boston, MA (2015 – Present)

Mr. Centolella provides expert advice and testimony for a range of clients on emerging business and regulatory models, energy and environmental market design, utility regulation and pricing, and innovation and the application of intelligent and clean energy technologies in building an economically and environmentally sustainable energy future.

He often addresses issues at the intersection of economics and market design, regulatory law and policy, and the development and application of new technology. He has advised clients on:

- Economic incentives for reducing greenhouse gas emissions and deploying clean energy technologies;
- Valuation of distributed resources and the development distributed locational marginal pricing;
- Wholesale power market design, Federal Energy Regulatory Commission policy, and the integration of advanced transmission technologies;
- Rethinking electric rate design, including the use dynamic and market-based rates, integration of flexible demand, and alternate approaches to the equitable recovery of residual utility revenue requirements;

- Utility regulatory models including formula rates, incentive and performance-based regulation, and the treatment of value added customer services;
- Grid modernization and the role of distribution system operators;
- Platform business models, including transactive power markets and marketplaces for connected home and other energy related products and services;
- Implications of the power grid's evolution as a cyber-physical system with a growing number of autonomous intelligent devices; and
- Development and commercialization of innovative energy technologies.

Key accomplishments:

- Contributed to framing and writing the National Academies of Sciences, Engineering, and Medicine report, *The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies*. The report examines approaches to strengthening the nation's energy innovation ecosystem and deploying clean technologies to mitigate climate risks. It includes overarching recommendations, to price pollution and significantly increased support for innovation, and twenty-four more detailed recommendations for realizing a clean energy future.
- Advised senior leadership of a large utility in a multi-year process of considering fundamental changes to its business and regulatory models, including evaluation of alternative rate setting mechanisms, statutory changes in regulation, performance incentives, provision of additional services, new investment opportunities, platform and transactive energy markets, a consumer marketplace, valuation of distributed energy resources, energy storage investments, and potential applications of blockchain and distributed ledger technology. Additionally, helped coordinate the utility's planning for and participation in a state regulatory proceeding on the utility of the future.
- For New York State, co-authored a foundational paper on the design and development of distribution level power markets with Distributed Locational Marginal Pricing ("DLMP") and digital platform markets for transactions in electricity products and customer services. These concepts were further developed in academic publications and have informed work on the valuation of distributed resources, utility rate design, and the integration of intelligent devices into power system operations.
- Advising a major electric utility on how to reimagine rate design to improve system efficiency, integrate flexible demand, appropriately value distributed resources, equitably allocate common costs, protect low-income customers, and reduce the variability in customer bills. This engagement introduced new concepts and includes an analysis of the impact of rate design alternatives on households in different income categories, based on analyzing interval usage data for 500,000 customers.
- During litigation that challenged state Zero Emission Credit ("ZEC") programs, advised respondents on energy and environmental regulatory policy and jurisdictional issues, which supported a successful defense in Federal Court of state programs to maintain the operation of nuclear generators that might otherwise retire.
- Advised electric distribution utilities, technology companies, and state public utility commissions on issues related to grid modernization. This included, for example, advising the PUCO throughout its Power Forward initiative. The Power Forward

proceeding included workshops evaluating technological, market, and regulatory innovations and more than 120 expert and stakeholder presentations to the Commissioners. It led to the development of a grid modernization roadmap, negotiations addressing utility grid modernization plans, and on-going stakeholder working groups.

- Supported a multi-state utility in developing a roadmap for modernizing its electric transmission system, demonstrations of advanced transmission technologies, and formulating a regulatory strategy for pursuing cost recovery and incentives for investments in advanced transmission technologies;
- Advised researchers and firms on the commercialization of advanced power electronics including a consortium that is demonstrating the use of advanced solid-state transformers to provide inverter and control functions in commercial and utility scale solar projects and a firm that is applying fast power electronics in Volt-VAr control to achieve demand and energy savings and expand PV hosting capacity.
- As Chair of the National Institute of Standards and Technology Smart Grid Advisory Committee, initiated development of a functional model for power systems that can integrate intelligent devices and autonomous systems and advised the Institute during the development for Release 4.0 of NIST's Framework and Roadmap for Smart Grid Interoperability Standards (expected in 2020).
- As Chair of the Smart Grid Subcommittee of the Secretary of the Department of Energy's Electricity Advisory Committee, led reviews of: the Department's draft Multi-year Cyber Security Plan leading to changes in the final Plan, the impact of the Internet of Things on power systems, and methodologies for assessing the value of distributed energy resources. Additionally, coordinated the preparation of recommendations for the Department to develop information and tools that could assist state regulators in considering alternative models of electric utility regulation.
- Provided testimony that shifted the New York Public Service Commission's policy regarding the calculation of greenhouse gas emission reduction incentives, such that these incentives will be based on marginal emission rates.

Vice President (2012 – 2014) and Affiliate (2014 – 2015), Analysis Group, Boston, MA

Mr. Centolella led consulting engagements and provided expert testimony and advice to utilities, power market participants, technology companies, industry organizations, and other stakeholders on electricity and natural gas markets, utility regulatory economics and policies, emerging utility business and regulatory models, grid modernization, regulation of and governance practices related to cyber security, and power sector investments.

Key accomplishments:

- Led assessments of challenges facing electric utilities, financial impacts of various frameworks for utility regulation, and alternative regulatory frameworks.
- Provided expert testimony on grid modernization including the adoption of new technology, cost recovery, and the development of metrics.
- Provided expert testimony and quantitative analyses on alternative regulatory models including performance-based regulation and earnings sharing mechanisms.

- Analyzed the regulation of utility cyber security and opportunities for enhancing cyber security governance.
- Evaluated impacts of environmental regulation on natural gas development and markets.
- Assessed options to more efficiently price retail electricity supply and the potential of price responsive demand to reduce costs.

Commissioner, Public Utilities Commission of Ohio ("PUCO"), Columbus, OH (2007 – 2012)

As a PUCO Commissioner, Mr. Centolella oversaw a broad range of utility services, including electric, natural gas, telephone, water, pipeline safety, and transportation, ensuring consumers access to reliable utility services at reasonable and competitive prices.

Key accomplishments while a Commissioner, included:

- Implementing Ohio's 2008 electricity legislation that created a glide path to market pricing; included energy efficiency, peak demand reduction, advanced and renewable energy standards; required the establishment of distribution reliability standards; and led to the development of multi-year rate plans.
- Accelerating replacement of aging natural gas infrastructure and the development of trackers for recovery of related costs.
- Aligning Commission positions on wholesale power market issues with competition policy and securing capabilities for the PUCO to become the only commission in the region able to model power markets and forecast electricity prices.
- Development of the PJM Interconnection's Price Responsive Demand ("PRD") tariff proposal that would integrate dynamic retail pricing into PJM's markets and operations, based on a foundational paper co-authored with PJM's Senior Vice President for Markets.
- Advancing Commission policies on grid modernization through workshops and Commission initiated proceedings on distribution reliability, advanced metering, customer access to energy usage data, privacy, cyber-security, distribution voltage optimization, dynamic retail pricing, on-bill financing, and a residential real-time pricing and distribution level energy market pilot program.
- Creating Ohio's Smart Grid Cluster that connected research and workforce development activities at major universities and research centers with electric utilities and technology companies.
- Helping guide the development of SGIP, a public-private partnership initiated by the National Institute of Standards and Technology, which has accelerated standards development by as much as 80% and created an authoritative catalog of smart grid standards.

Senior Economist, Science Applications International Corporation (SAIC), McLean, VA (1992 – 2007)

Managed major projects and cases in the energy practice and advised clients in the areas of:

- Energy and environmental market design, modeling and market analysis for electric power, gas, coal, and environmental markets;
- Economic analysis related to utility regulation, cost allocation, electric restructuring, and energy policy; and
- Power system operations including grid modernization and deployment of real-time information systems.

Key client relationships and related accomplishments include:

- *Adoption and implementation of Midwest Independent Transmission System Operator ("MISO") Energy and Ancillary Service Markets (2003 – 2007)*: Advised MISO senior executives regarding development, and securing stakeholder and regulatory approval of MISO's energy and ancillary service markets and MISO's resource adequacy plan. Led the economic analysis and litigation support team for MISO to secure FERC and state commission approval of its energy markets, including modeling and market analysis of MISO and interconnected systems, preparation of expert testimony, and conducting stakeholder briefings. Served as the senior advisor to MISO's Operational Process Review assessing MISO implementation of its FERC tariff, developing integrated process maps and databases, addressing stakeholder concerns, and recommending operational improvements and metrics.
- *Development and management of TVA's Power System Optimization Project ("PSOP") (2002 – 2003)*: Led the economic analysis for a strategic initiative to enhance operating systems and provide enterprise-wide access to real time data, resulting in more than $400 million in operational benefits. Supported the program management office through the first year of PSOP implementation, ensuring that project activities were aligned with the achievement of anticipated net benefits.
- *Management consulting for various clients (1999 – 2001)*: Led projects for making process and operational improvements based on the application of information systems and transfer of knowledge through organizational learning. These included projects to optimize the economic operation of power generation facilities and to capture and transfer lessons learned from an asset sale by a large power company.
- *Development of the U.S. Department of Energy's policies supporting electric industry restructuring (1994 – 2000)*: Was principal economic consultant advising the Department's Policy Office and led one of the first major studies demonstrating that Locational Marginal Pricing ("LMP"), as subsequently implemented in the organized markets, can significantly lower production costs and prices. Led an assessment of the market power potential of generation suppliers in competitive power markets including an analysis of ownership patterns, the implications of transmission constraints, and potential mitigation measures.
- *Development of the U.S. Environmental Protection Agency's Allowance Tracking and Trading System (1992 – 1993)*: Led the design of U.S. EPA's systems for tracking and trading SO_2 emission allowances under Title IV of the 1990 Clean Air Act Amendments.

Senior Energy Policy Advisor and Senior Utility Attorney, Office of the Ohio Consumers' Counsel (OCC), Columbus, OH (1982 – 1992)

Represented Ohio on issues related to the 1990 Clean Air Act Amendments, led analyses of alternative cap-and-trade and command-and-control regulatory models, was among the first proponents of using a cap-and-trade approach for sulfur dioxide control, testified before Congress on the development of environmental markets, and served on the U.S. Environmental Protection Agency's Acid Rain Advisory Committee. Led collaborative initiatives with utilities to design and implement energy efficiency programs. Contributed to the development of state policy on a range of energy issues including utility resource planning, review of utility investments, and the opening of natural gas supply markets for retail competition. Represented municipalities and residential consumers in more than seventy state and federal utility rate and regulatory policy proceedings and in more than one hundred municipal negotiations to set utility rates.

Attorney in private practice, Washington State and California (1977 – 1981)

Focused on natural resources law including fisheries protection and Native American fishing rights and on commercial litigation. Helped found a legal assistance program.

Education

1977 J.D., University of Michigan Law School
1973 B.A., Economics, Oberlin College, with honors

Selected Committees, Boards, & Delegations

- Member, Americans for a Clean Energy Grid Advisory Council (2019 – present)
- Member, National Regulatory Research Institute's Regulatory Training Initiative Advisory Board (2019 – present)
- Member, National Institute of Standards and Technology Smart Grid Advisory Committee (2015 – 2019), Chairman (2017 – 2019)
- Member, Secretary of the Department of Energy's Electricity Advisory Committee (2012 – 2017), Chair of Smart Grid Subcommittee and member of the Power Delivery, Grid Modernization, and Clean Power Plan Subcommittees
- Member, Varentec Advisory Committee (2012 – present)
- Member, Massachusetts Institute of Technology Utility of the Future Study Advisory Committee (2014 – 2016)
- Member, National Academy of Sciences Committee on the Determinates of Market Adoption of Advanced Energy Efficiency and Clean Energy Technologies (2013 – 2016)
- Member, Advisory Group to Bipartisan Policy Center, Cyber Security Governance across Multiple Agencies: The Electric Power Sector (2013 – 2014)
- Member, Board of Directors, Smart Grid Interoperability Panel 2.0 (2012 – 2013), Board Executive Committee and Board Technical Committee

- Member, Governing Board, Smart Grid Interoperability Panel (2009 – 2012); Home Area Network Task Force; System and Device Integration Working Group; Communications, Marketing and Education Working Group
- Member, Advisory Council, Electric Power Research Institute (2009 – 2012); Advisory Council Executive Committee (2010 – 2012)
- Member, Board of the Organization of PJM States, Inc. ("OPSI") (2007 – 2012); Vice President (2010 – 2011); Secretary (2009 – 2010)
- Co-convener of 2012 Asia-Pacific Economic Cooperation ("APEC") Workshop on Regulatory Approaches to Smart Grid Investment and Deployment
- U.S. delegation to 2011 APEC Senior Officials Meeting
- U.S. delegation to 2012 World Forum on Energy Regulation, Quebec City, Canada
- U.S. delegation to 2009 World Forum on Energy Regulation, Athens, Greece
- Member, Energy Resources and Environment Committee, National Association of Regulatory Utility Commissioners ("NARUC") (2007 – 2012)
- Member, FERC / NARUC Smart Grid Collaborative and Demand Response Collaborative (later known as the Smart Response Collaborative) (2007 – 2012)
- Member, NARUC Smart Grid Working Group (2010 – 2012)
- Member, NARUC Climate Change Task Force (2007 – 2010)
- Member, Technical Advisory Committee, Ohio Coal Development Office (2007 – 2012)

Selected Publications

- Rethinking Electric Rate Design: Rates for a Twenty-first Century Power System. Paul Centolella & Associates Working Paper (August 2019)
- "Distributed Energy Resources: New Products and New Markets," Proceedings of the Hawaii International Conference on System Sciences (January 2017) (with R. Tabors, M. Caramanis, E. Ntakou, G. Parker, M. VanAlstyne, and R. Hornby)
- The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies, A Report of the National Academies of Sciences, Engineering, and Medicine (Washington, D.C: The National Academies Press, September 2016) (Member of the Committee on the Determinants of Market Adoption of Advanced Energy Efficiency and Clean Energy Technologies)
- White Paper on Developing Competitive Electricity Markets and Pricing Structures, Prepared for New York State Energy Research and Development Authority and the New York Department of Public Service for the New York Reforming the Energy Vision Public Service Commission Proceeding (with additional principal authors M. Caramanis, G. Parker, and R. Tabors) (April 2016)
- Next Generation Demand Response: Responsive Demand through Automation and Variable Pricing (March 2015)
- Recommendations Regarding Emerging and Alternative Regulatory Models and Modeling Tools to Assist in Analysis (Working Group Chair for U.S. Department of Energy Electricity Advisory Committee) (September 2014)
- "Results-Based Regulation: A More Dynamic Approach to Grid Modernization," Public Utilities Fortnightly (with D. Malkin) (March 2014)
- "Understanding the Value of Uninterrupted Service," Proceedings of the CIGRE 2013 Grid of the Future Symposium (with M. McGranaghan) (November 2013)

- Results-Based Regulation: A Modern Approach to Modernize the Grid, General Electric (with D. Malkin) (October 2013)
- “Reexamining Rate Regulation: 1-2-3,” Utility Horizons Quarterly (March 2013)
- “Smarter demand response in RTO markets: The evolution toward price responsive demand in PJM,” (with S. Bressler, S. Covino, and P. Sotkiewicz) Energy Efficiency: Towards the End of Electricity Demand Growth, Fereidoon P. Sioshansi, Editor (February 2013)
- “Incentive Regulation for Grid Reliability,” Electroindustry Magazine, National Electrical Manufacturers Association (November 2012)
- “A Pricing Strategy for a Lean and Agile Electric Power Industry,” Electricity Policy (September 2012)
- “The Smart Grid Needs Smart Prices to Succeed,” Harvard Business Review Blog (October 14, 2010)
- “The integration of Price Responsive Demand into Regional Transmission Organization (RTO) wholesale power markets and system operations” Energy, Vol. 35, No. 4 (April 2010)
- Integration of Price Responsive Demand into PJM Wholesale Power Markets and System Operations, (with A. Ott) (March 2009)
- “The Future of Demand Response in RTO Energy Markets: Midwest ISO Studies on Resource Adequacy,” (with R. McNamara) Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, American Council for an Energy Efficient Economy (August 2006)
- Estimates of the Value of Uninterrupted Service for the Midwest Independent System Operator, Midwest Independent Transmission System Operator (April 2006)
- “Energy Services in the Information Age: The Convergence of Energy, Communications, and Information Technologies,” Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, American Council for an Energy Efficient Economy (August 1998)
- The Structure of Competitive Power Markets, U.S. Department of Energy, Electricity Policy Office (January 1997)
- “Making Performance-Based Ratemaking Consistent with Market Transformation,” Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, American Council for an Energy Efficient Economy (August 1996)
- The Organization of Competitive Wholesale Power Markets and Spot Price Pools (The Electric Industry Restructuring Series), National Council on Competition and the Electric Industry (1996)
- “Safeguarding the Environment amid a Competitive Power Market” (with B. Hobbs), IEEE Spectrum, 32(3), 1995, pp. 8.
- “Environmental Policies and Their Effects on Utility Planning and Operations,” Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, American Council for an Energy Efficient Economy (August 1994)
- “Applying Cost Allocation Principles to Demand-Side Resources: A Case Study of Industrial Opt-Out Proposals,” Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, American Council for an Energy Efficient Economy (August 1994)

- Public Utility Commission Treatment of Environmental Externalities (with K. Rose and B. Hobbs), National Regulatory Research Institute, Columbus, OH, 1994
- Cost Allocation for Electric Utility Conservation and Load Management Programs, principal author, National Association of Regulatory Utility Commissioners (November 1992)
- Energy Efficiency and the Environment: Forging the Link (with E. Vine and D. Crawley), American Council for an Energy-Efficient Economy in cooperation with University-wide Energy Research Group, University of California, 1991

Testimony and Technical Conference Comments

- Testimony on the topic of Earnings Adjustment Mechanisms, New York Public Service Commission Cases No. 19-E-0065 and 19-G-0066 (May 2019)
- Platform Markets and Grid Services: A Market and Functional Model, Illinois Commerce Commission Next Grid Working Group 5 (June 2018)
- Economics of Modern Rate Design: Efficient Pricing & Equitable Rates, Illinois Commerce Commission Next Grid Working Group 7 (July 2018)
- Design of Distribution System Markets: Platform Markets and Practical Considerations, Public Utility Commission of Ohio Power Forward Workshop (March 2018)
- Economics of Modern Rate Design: Optimizing Value for the Customer and System, Public Utility Commission of Ohio Power Forward Workshop (March 2018)
- Comments of Paul Centolella, Grid Reliability and Resilience Pricing, FERC Docket No. RM 18-1-000 (October 2017)
- Comments of Paul Centolella on the Application of Interval Settlements to Load Serving Entities, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, FERC Docket No. RM15-24-000 (November 2015)
- Presentation of Paul Centolella on Behalf of National Grid, Panel 2 New Technology Adoption, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, Before the Massachusetts Department of Public Utilities (February 2014)
- Presentation of Paul Centolella on Behalf of National Grid, Panel 4 Cost Recovery, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, Before the Massachusetts Department of Public Utilities (February 2014)
- Presentation of Paul Centolella on Behalf of National Grid, Panel 6 Metrics, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, Before the Massachusetts Department of Public Utilities (February 2014)
- Prepared Direct Testimony of Paul Centolella on behalf of the Fédération canadienne de l'entreprise indépendante and Summary of Direct Testimony of Paul Centolella, Proceeding on the Hydro Quebec Request for Approval of Rate of Return on Own Capital and The Mechanism of Treatment of Deviations of Performance, Before the Quebec Régie de l'énergie (October 2013)
- Direct Testimony of Paul Centolella, Vice President of Analysis Group on behalf of Environmental Defense Fund, Proceeding on Motion of the Commission as to the Rates,

Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Docket No. 13-E-0030 (May 2013)

- Comments of Commissioner Paul A. Centolella Supplementing his Technical Conference Remarks, Demand Response Compensation in Organized Wholesale Energy Markets, FERC Docket No. RM10-17-000 (October 2010)
- Remarks of Commissioner Paul A. Centolella, FERC Technical Conference on Demand Response Compensation in Organized Wholesale Energy Markets, Docket No. RM10-17-000 (September 2010)
- Testimony of the Honorable Paul A. Centolella, Commissioner Public Utilities Commission of Ohio on Energy Efficiency Resource Standards, U.S. Senate Energy and Natural Resources Committee (April 2009)
- Prepared Remarks of Commissioner Paul A. Centolella, FERC Technical Conference on Capacity Market Design (May 2008)
- Testimony of Commissioner Paul A. Centolella on SB 221, Ohio House of Representatives, Public Utilities Committee (March 2008)

Selected Conference Presentations

- Rethinking Electric Rate Design: Rates for a 21st Century Power System, FRI Advanced Seminar in Utility Pricing (September 2019)
- Coordination of Standards Development for a Distributed Intelligent Energy Future, National Institute of Standards and Technology, Smart Grid Advisory Committee (June 2019)
- Developing a Roadmap for Energy System Modernization & "Prosumer" Integration, Energy Policy Roundtable in the PJM Footprint (November 2018)
- Creating the Functional Model for a Flexible and Efficient Power System, Workshop for SLAC National Accelerator Laboratory (October 2018)
- Transforming Rate Design for the Modern Grid: Efficient Pricing and Equitable Rates, FRI Advanced Seminar in Utility Pricing (September 2018)
- Planning the Grid the Islands Need: Observations on Integrated Grid Planning, Hawaiian Electric Companies Integrated Grid Planning Symposium (November 2017)
- Improving Markets for the Efficient Integration of Distributed Renewable Resources, Illinois Commerce Commission Policy Forum: The Market Challenges of Integrating Renewables (October 2017)
- Distributed Intelligence and the Future of Dynamic Pricing, Price Responsive Demand, and Demand Response in PJM, Energy Policy Roundtable in the PJM Footprint (September 2017)
- Looking Forward – A Former Regulator's Perspective, Georgia Tech Center for Distributed Energy Thought Leaders Symposium (May 2017)
- Paths to a Utility of the Future: Perspectives of a Former Regulator, Northeast Clean Energy Council Emerging Trends Series (January 2017)
- Competitive Markets and Pricing Structures: Reforming Retail Rates to Integrate DER, New England Restructuring Roundtable (September 2016)
- Competitive Markets and Pricing Structures: Implications for the Value of DER, Energy Policy Roundtable in the PJM Footprint (September 2016)

- The Future of the Power Industry: Implications for Network Regulation, Australian Competition and Consumer Commission / Australian Energy Regulator Regulatory Conference (August 2016)
- The Impact of Missing Price Signals, Harvard Electricity Policy Group (June 2016)
- Tomorrow's Utility: Business Models to Create Cost Savings and Shared Value, Energy Bar Association Midwest Annual Meeting (March 2016)
- The Future of Electric Distribution: System Operations and Platform Markets, Illinois State University, Institute for Regulatory Policy Studies (April 2015)
- Innovation and Policy: Challenges and Strategies, IEEE Power Engineering Society Innovative Smart Grid Technologies Conference (February 2015)
- Next Generation Demand Response: Responsive Demand through Automation and Variable Pricing, New England Electricity Restructuring Roundtable (November 2014)
- Critical Issues: Fundamental Transformations in Grid 3.0, National Institute of Standards and Technology Electric Sector Issues Roundtable: Grid 3.0 and Beyond (November 2014)
- Information & Tool Development to Support Consideration of Future Regulatory Models, U.S. Department of Energy Electricity Advisory Committee (July 2014)
- A Future for Demand Participation in Organized Markets, FERC – NARUC Collaborative (July 2014)
- The Utility Industry of the Future, NYU Environmental Law Society and Environmental Law Journal, 2014 Environmental Law Seminar (March 2014)
- Electric Grid Modernization: Regulatory Challenges and Opportunities, LSI Transmission in the Northeast Conference (February 2014)
- Modern Regulatory Frameworks for a Flexible, Resilient, and Connected Grid, CIGRE Grid of the Future Symposium (November 2013)
- Developing a Twenty-First Century Model for Regulating Electric Utilities, National Governors' Association Policy Institute (September 2013)
- Efficiently Powering Smart Cities: A Case for Price Transparency, Presentation to National Town Meeting on Demand Response and Smart Grid (July 2013)
- Powering the Future: Advancing Regulatory Reforms, Presentation to the Energy Future Coalition Steering Committee (June 2013)
- Reframing Regulation of Electric Utilities: The Pursuit of Value, Presentation to IEEE EnergyTech Conference (May 2013)
- Grid Modernization: Creating a Coherent Strategy, Presentation to the National Governors' Association Experts' Roundtable on Modernizing the Electric Grid (April 2013)
- Preparing for Disruptive Events: Developing an Economic and Regulatory Framework, Presentation to Electric Light & Power Conference (January 2013)
- Demand Side Management & Next Generation Grid Modernization: Markets, Regulation & Business Case, Presentation to DistribuTECH Course –A Primer on the Next Generation in Integrated Demand Side Management: Applications, Challenges, Regulation, Markets, Technology and Policy for the Next Generation in Grid Modernization (January 2013)
- Aligning Ratemaking and Grid Modernization, Presentation to the Massachusetts Department of Public Utilities Grid Modernization Working Group Steering Committee (December 2012)

- Beyond Order 745: A Demand Optimization Strategy, Presentation to Restructuring Today Order 745 Webinar (October 2012)
- Overview of Utility Regulatory Policy and Development of a Smart, Secure, Sustainable Grid, Presentation to the Secretary of the Navy's Advisory Panel (September 2012)
- Future Directions in Regulatory Policy, Presentation to Southern California Edison Futures Workshop (September 2012)
- Dynamic Pricing: Lean and Agile Strategy for Electricity, Presentation to the National Association of Regulatory Utility Commissioners (July 2012)
- Efficient & Resilient Power: Changing Approaches to Regulation and Electric Utility Business Models, Kentucky Smart Grid Workshop Series (June 2012)
- The Impact of Environmental Law: Utility Regulation and PUC Governance, Workshop on the Role of Public Utility Commissions in Climate and Energy Policy (June 2012)
- Dynamic Pricing Done Right: Building an Efficient and Resilient Power System, Smart Grid Today Webinar (June 2012)
- Electricity Markets and Technology: Changing the Role of Regulation, John Glenn School of Public Policy, The Ohio State University (January 2012)
- An Obligation of Transparency: Providing Opportunities for Retail Demand Response, Conference on the Law of Demand Response, George Washington University Law School (October 2011)
- Opportunities for Innovation: New Technologies and Smart Grid Implementation, Organization of PJM States, Inc., Annual Meeting (October 2011)
- Regulatory Reform Efforts and Emerging Business Models, White House Forum on Grid Modernization (June 2011)
- Utility Regulation, Innovation, and Collaborative Federalism, American Academy of Arts & Sciences, Social Science and the Alternative Energy Future (May 2011)
- Regulatory & Policy Approaches to Smart Grid Interoperability Standards: U.S. Collaborative Federalism, ARCAM Dialogue on Smart Grid Interoperability Standards, Asia Pacific Economic Cooperation Senior Officials Meeting (May 2011)
- Placing Electric Vehicles and Battery Storage in a Regulatory Context, National Alliance for Advanced Technology Batteries, Annual Meeting (December 2010)
- Consumer Engagement: Lessons Learned from Early Deployments, World Economic Forum Smart Grid Workshop (November 2010)
- Smart Pricing: The Key to Smart Grid Benefits, GridWeek 2010
- Smart Grid Consumer Policies: Moving Toward Consensus, International Energy Agency, Smart Grid – Smart Customer Workshop (September 2010)
- Engaging and Protecting Consumers: Key Issues for Regulators, Mid-Atlantic Conference of Regulatory Utility Commissioners (June 2010)
- Regulatory Policy & Smart Pricing, Connectivity Week (May 2010)
- Planning and Policy in a Time of Uncertainty: Expanding Available Options, Midwest Independent Transmission System Operator Annual Stakeholders Meeting (April 2010)
- Smart Grid Architecture: Opportunities, Vision, & Choices, Utilities Telecom Council Policy Summit (April 2010)
- Ohio's Energy Future and the Smart Grid, University of Toledo College of Law Conference on Climate Change and the Future of Energy (March 2010)
- An Essential Attribute: Facilitating a Transition to Efficient Markets, PJM Long Term Capacity Issues Symposium (January 2010)

- Low Carbon Technologies: A Smart Energy Path, World Forum on Energy Regulation IV (October 2009)
- Distributed Coordination in the 21st Century Power Grid: Emerging Business Models, GridWeek (September 2009)
- Public Interest Research at an Inflection Point, Electric Power Research Institute Advisory Council (August 2009)
- Price Responsive Demand in Wholesale Electricity Markets, Energy Bar Association Webinar (July 2009)
- Creating a 21st Century Grid: Distribution and Demand Response, Aspen Institute Energy Policy Forum (July 2009)
- Price Responsive Demand: A Third Generation of Demand Response, Demand Response & Energy Efficiency World Conference (May 2009)
- Scarcity Pricing in a Smart Energy Future, Harvard Electricity Policy Group (March 2009)
- Integrating Price Responsive Demand into Regional Power Markets and System Operations, FERC-NARUC Demand Response Collaborative (February 2009).

National Honors & Awards

- GridWeek Leadership Award for advancing policies for modernizing the electric power system, 2011
- Smart Grid Leadership Award, Demand Response Coordinating Council, 2010
- Gridwise Applied Award, Gridwise Architecture Council, for development of regulations and policies advancing the principles of technology interoperability, 2010
- SGIP Appreciation Award, Smart Grid Interoperability Panel, for ensuring access to information about smart grid standards, 2010

Memberships

- Institute of Electrical and Electronics Engineers, Power Engineering Society (2015 – present)
- Energy Bar Association (2014 – present)
- International Association for Energy Economics (2005 – present)
- American Economic Association (2001 – present)
- Ohio State Bar Association (1982 – present)
- California State Bar Association (1979 – present)
- Washington State Bar Association (1978 – 2019)

APPENDIX B

STATE REGULATORY OPT-OUT DECISIONS AND UTILITY DEMAND RESPONSE

Arkansas

The regulation of demand response in Arkansas is governed by a state statute which provides:

> "Marketing or selling of demand response prohibited. The marketing, selling, or marketing and selling of demand response into wholesale electricity markets by an aggregator of retail customers or by a retail customer is prohibited unless the Arkansas Public Service Commission or the governing authority of a municipally owned electric utility or a consolidated municipal utility improvement district determines that the marketing, selling, or marketing and selling of demand response into wholesale electricity markets by aggregators of retail customers or by retail customers is in the public interest."[111]

Arkansas investor owned electric utilities and municipally owned utilities are excluded from this prohibition.[112]

The Arkansas Public Service Commission is considering whether demand response participation in wholesale markets is in the public interest in two pending cases.

First, Walmart, one of the largest energy users in Arkansas, recently filed an application with the Arkansas Commission seeking to be allowed to offer demand response into the Midcontinent Independent System Operator ("MISO") market using a non-utility Aggregator of Retail Customers ("ARC").[113] Some of Walmart's Arkansas facilities participate in Entergy Arkansas's Optional Interruptible Service ("OIS") Rider, although this program is not appropriate for all Walmart facilities in Entergy's service territory. The OIS Rider targets conditions on Entergy's system, as opposed to focusing on MISO markets. The OIS Rider includes an option for Entergy to register customer demand reductions as a MISO Load Modifying Resources ("LMR"), but it does not permit customers to participate in MISO's Emergency DR or DR Resource programs. The other Arkansas utilities that serve Walmart facilities do not offer comparable DR programs.[114] Allowing Walmart to participate in MISO demand response through a non-utility aggregator would nearly double the number of Walmart locations in the state that could

[111] Ark. Code § 23-18-1004 (2016).
[112] Ark. Code § 23-18-1002 (2016).
[113] Arkansas Public Service Commission, *Formal Application*, Docket No. 20-027-U, In the Matter of the Application of Walmart Inc. for Approval to Bid Demand Response into Wholesale Electricity Markets through an Aggregator of Retail Customers (May 20, 2020) ("Walmart Formal Application 2020").
[114] Arkansas Public Service Commission, *Direct Testimony and Exhibits of Alex J. Kronauer on Behalf of Walmart Inc.*, Docket No. 20-027-U, In the Matter of the Application of Walmart Inc. for Approval to Bid Demand Response into Wholesale Electricity Markets through an Aggregator of Retail Customers, p. 6 (May 20, 2020).

participate in DR.[115] Walmart wants to participate through a non-utility aggregator to utilize a DR service provider's specialized expertise, reduce participation costs, and diversify performance risks over the aggregator's portfolio of participating facilities.[116]

Second, in July 2020, the Arkansas Public Service Commission reopened a 2009 proceeding on the impacts of FERC Orders 719 and 710-A. In this generic proceeding, the Commission is taking comments on whether it is in the public interest to allow aggregators or retail customers to directly sell demand response into wholesale power markets and what are the proper terms and conditions for marketing and selling demand response.[117] The Commission Staff has taken a position that it is in the public interest to allow aggregators to market and sell demand response in wholesale markets. [118] Multiple other parties have filed comments.

Entergy Arkansas is the largest electric utility in the state. In addition to interruptible service, it also offers customers a Summer Advantage air conditioner direct load control program, an Agricultural Irrigation Direct Load Control Program, and a Bring Your Own Thermostat pilot program, which together provided 43 MW of demand savings in 2019.[119]

Indiana

In a 2010 decision, the Indiana Utility Regulatory Commission held that, unless otherwise authorized, retail customers should not participate in Regional Transmission Operator ("RTO") DR programs directly or through non-utility aggregators. At the same time, it directed Indiana utilities to expand their DR programs to include participation in the RTO's programs and encouraged, but did not require, the utilities to work with aggregators.[120]

Indiana utilities historically offered interruptible rates and direct load control programs. And, the Commission had approved the participation of several large industrial customers in PJM DR

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[115] Arkansas Public Service Commission, *Direct Testimony and Exhibits of Lisa V. Perry on Behalf of Walmart Inc.*, Docket No. 20-027-U, In the Matter of the Application of Walmart Inc. for Approval to Bid Demand Response into Wholesale Electricity Markets through an Aggregator of Retail Customers, pp. 7, 19 (May 20, 2020).
[116] Walmart Formal Application 2020, pp. 29–31.
[117] In the Matter of the Impact of Federal Energy Regulatory Commission (FERC) Orders 719 and &19-A in FERC Docket No. RM01-19-001 on the Regulatory Authority of the Arkansas Public Service Commission, *Order No. 9* (July 20, 2020) ("Arkansas Public Service Commission 2020").
[118] In the Matter of the Impact of Federal Energy Regulatory Commission (FERC) Orders 719 and &19-A in FERC Docket No. RM01-19-001 on the Regulatory Authority of the Arkansas Public Service Commission, *Initial Comments and Legal Brief Pursuant to Order No. 9* (Aug. 28, 2020) ("General Staff of the Arkansas Public Service Commission 2020").
[119] Janine Migden-Ostrander, John Shenot, Camille Kadoch, Max Dupuy, and & Carl Linvill, *Enabling Third-Party Aggregation of Distributed Energy Resources: Report to the Public Service Commission of Arkansas*, pp. 23–24, Regulatory Assistance Project (Feb. 2018).
[120] Indiana Utility Regulatory Commission, *Order*, Cause No. 43566, In the Matter of the Commission's Investigation into any and all Matters Related to Commission Approval of Participation by Indiana End-Use Customers in Demand Response Programs Offered by the Midwest ISO and PJM Interconnection, pp. 42–43 (July 28, 2010).

programs in proceedings for individual customers.[121] And, the 2010 decision found that encouraging participation in the RTO demand response programs is in the public interest. It concluded that aggregators may provide opportunities for small and medium sized commercial and industrial customers that may be underserved by traditional utility DR programs or may require additional effort to participate. However, the Commission recognized that there were differences in RTO treatment of demand reductions in utility programs and reductions offered into wholesale programs, which had cost and uncertainty implications. Reductions in utility programs can reduce utility planning resource requirements and short-term operational forecasts. However, utilities would be obligated to provide generating capacity to serve as firm load the full potential requirements of participants in RTO programs including demand that customers have offered to curtail.

This led to a participation model that would in theory allow DR service providers to sign up retail customers to participate in wholesale programs based on agreements with the utilities. Instead of enrolling customers directly, the service provider would register them with the distribution utility that would subsequently enroll the customers in the RTO program. The model was intended to enable the utility to receive full capacity credit for the demand reduction, avoiding the need to build or procure resources for demand that can be curtailed.[122]

However, the success of this approach depends on the willingness of utilities to facilitate third-party participation. It has so far proven to be a disappointment. Indiana utilities file annual reports on participation in RTO DR programs. As of 2019, no Indiana electric utility had entered into an agreement with a third-party aggregator and none of the four utilities in MISO had enrolled any customers in the ISO's DR programs.[123]

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[121] *Id.* ("*See*, *In re Petition of Steel Dynamics, Inc.*, Cause No. 43138 (IURC, 07/25/2007); *In re Joint Petition of Indiana Michigan Power Co. and I/N Tek*, Cause No. 43330 (IURC, 08/08/2007); *In re Petition of AK Steel Corporation*, Cause No. 43503 (IURC, 09/03/2008)").

[122] Advanced Energy Management Alliance, *Advancing Demand Response in the Midwest: Expanding Untapped Potential*, pp. 9–13 (Feb. 12, 2018).

[123] Indiana Utility Regulatory Commission, *Duke Energy Indiana, LLC 2019 Annual Report*, Cause No. 43566 MISO-3, In the Matter of the Commission's Investigation into any and all Matters Related to Commission Approval of Participation by Indiana End-Use Customers in Demand Response Programs Offered by the Midwest ISO and PJM Interconnection (Mar. 11, 2020); Indiana Utility Regulatory Commission, *Respondent Indianapolis Power & Light Company's Submission of Demand Response Annual Report*, Cause No. 43566, In the Matter of the Commission's Investigation into any and all Matters Related to Commission Approval of Participation by Indiana End-Use Customers in Demand Response Programs Offered by the Midwest ISO and PJM Interconnection (Mar. 9, 2020); Indiana Utility Regulatory Commission, *Northern Indiana Public Service Company LLC's Compliance Filing – Annual Report*, Cause No. 43566, In the Matter of the Commission's Investigation into any and all Matters Related to Commission Approval of Participation by Indiana End-Use Customers in Demand Response Programs Offered by the Midwest ISO and PJM Interconnection (Mar. 5, 2020); Indiana Utility Regulatory Commission, *Submission of 2019 Annual Report by Southern Indiana Gas and Electric Company / Vectren 2020,* Cause No. 43566 (March 9, 2020) *See also* Indiana Utility Regulatory Commission, *Respondent Indiana Michigan Power Company's Submission of Demand Response Annual Report*, Cause No. 43566, In the Matter of the Commission's Investigation into any and all Matters Related to Commission Approval of Participation by Indiana End-Use Customers in Demand Response Programs Offered by the Midwest ISO and PJM Interconnection (Mar. 11, 2020) ("Indiana Michigan

Indiana utilities continue to offer interruptible service and load control programs. At least a portion of the resulting demand reductions are offered into MISO as LMRs. Duke Energy Indiana, LLC offers direct load control and smart thermostat air conditioning cycling programs and load curtailment options for non-residential customers.[124] Indianapolis Power & Light Company offers an air conditioner control program and has proposed adding a water heater and electric vehicle charging.[125] Northern Indiana Public Service offers programs for direct load control of central air conditioning, space heating, and water heating in addition to interruptible load tariffs.[126] Vectren offers an air conditioning cycling and smart thermostat program.[127]

Illinois

Illinois does not restrict the participation of retail customers or aggregators in wholesale DR programs.

Customers of Ameren Illinois can purchase retail electric supply from competitive retail electric suppliers, from Ameren at an hourly pricing rate based on MISO Day-Ahead market prices, or at a flat rate based on resource procurements by the Illinois Power Agency. Non-residential customers can buy power at Day-Ahead prices under Ameren's hourly supply service. And, more than 13,000 residential customers buy power on Ameren's Power Smart hourly pricing rate.[128] Ameren also offers a Peak Time Rewards program that provides bill credits for reducing electricity use during periods of high demand. More than 100,000 Ameren Illinois customers participate in Peak Time Rewards, which provided 13.8 MW of capacity in MISO's 2019-2020 Planning Resource Auction.[129]

Power Company 2019 Annual Report"). Indiana Michigan Power (an AEP subsidiary) is in the PJM Interconnection. It has not entered into any agreements with aggregators, but "prefers to maintain agreements" with individual customers. Sixty-four medium sized commercial and industrial customers are participating in PJM's Emergency Demand Response service through Indiana Michigan Power's PJM demand response service rider. Indiana Michigan Power Company 2019 Annual Report, p. 1.

[124] Duke Energy Indiana 2018, pp. 136, 148–149, 150–151.

[125] Indiana Utility Regulatory Commission, *Petitioner's Submission of Direct Testimony of Zac Elliot*, Cause No. 45370, In the Matter of the Verified Petition of Indianapolis Power & Light for Approval of Demand Side Management (DSM) Plan, Including Energy Efficiency (EE) Programs, and Associated Accounting and Ratemaking Treatment, Including Timely Recovery, through IPL's Existing Standard Contract Rider No. 22, of Associated Costs Including Program Operating Costs, Net Lost Revenue, and Financial Incentives, p. 18–19 (Apr. 23, 2020).

[126] Northern Indiana Public Service Company LLC, *2018 Integrated Resource Plan*, pp. 91–92 (Oct. 31, 2018), https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15.

[127] Cadmus, *2018 Vectren Demand-Side Management Portfolio Process and Electric Impacts Evaluation*, pp. 4–7 (May 30, 2019).

[128] Ameren Illinois Power Smart Pricing, *2018 Annual Report*, p. 6 (Apr. 24, 2019), https://www.powersmartpricing.org/wp-content/uploads/2018-PSP-Annual-Report-and-Appendix-FINAL.pdf.

[129] Illinois Power Agency, *Electricity Procurement Plan: 2020 Plan*, p. 75 (Sept. 30, 2019), https://www2.illinois.gov/sites/ipa/Documents/2020%20Filed%20Electricity%20Plan/IPA%202020%20Electricity%20Procurement%20Plan%20for%20ICC%20Approval%20%289-30-19%29.pdf.

MidAmerican offers interruptible rates and a residential direct load control program in Illinois. However, neither program was activated during periods of peak demand in 2019.[130]

Iowa

In 2010, the Iowa Utilities Board temporarily suspended and prohibited the transfer of demand response load reductions to MISO markets by retail customers or by third-party Aggregators of Retail Customers. The Board cited a concern that aggregation might violate Iowa's exclusive utility service territory law. This Board's decision failed to make a distinction between the provision of electric service and demand response services.[131] In a separate 2012 Order the Board continued the prohibitions against retail customers or third-party aggregators transferring demand response load reductions to MISO markets. The Board did not offer an additional rationale for its decision.[132]

MidAmerican Energy offers a direct load control program for residential central air conditioners and air source heat pumps. It did not call for any demand reductions in 2019. The maximum demand reduction which could have achieved if all controls had been simultaneously activated would have been 17MW. MidAmerican also has a Nonresidential Load Management program that can curtail demand during the utility's system peak hours. MidAmerican offers such reductions into MISO as an LMR. In 2019, the Nonresidential Load Management program reduced peak demand by 249 MW. However, participation in the program fell in 2019 and no new participants were added to the program in either 2918 or 2019.[133] Interstate Power and Light offers a residential direct load control program, which can provide 29 MW of demand reduction when fully deployed, and interruptible service for large non-residential customers. Interstate has the potential to interrupt 241 MW of non-residential demand. However, this capacity was not utilized in 2019.[134] Interstate can apply its potential interruptible service demand reductions to lower its MISO planning resource requirements. The total demand response potential reported in the MidAmerican and Interstate plans appears to lower than the DR resources reported by Iowa MISO member companies in response to a 2008 survey.[135] The interruptible service targets reductions in peak demand on the respective utility systems. It is not designed to provide flexible DR in other hours.[136]

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[130] *Id.*

[131] Iowa Utilities Board, *Order Temporarily Prohibiting Aggregators of the Retail Customers from Operating in Iowa and Allowing Comments*, In re: PURPA Standards in the Energy Independence and Security Act of 2007, Docket No. NOI-08-03 (Mar. 29, 2010); Iowa Public Utility Regulation Code Section 476.25.

[132] Iowa Utilities Board, *Smart Grid Report and Order Continuing Prohibitions of ARCs*, In re: PURPA Standards in the Energy Independence and Security Act of 2007, Docket No. NOI-08-03 (June 25, 2012).

[133] Iowa Utility Board, MidAmerican Energy, *2019 Annual Report*, Docket Nos. EEP-2012-0002 and EEP-2018-0002 (May 1, 2020).

[134] Iowa Utilities Board, Interstate Power and Light Co., *2019 Annual Report*, Docket No. EEP-2018-0003 (May 1, 2020).

[135] Ranjit Bharvirkar et al., *Coordination of Retail DR with Midwest ISO Wholesale Markets*, Lawrence Berkeley National Laboratory (May 2008) ("Bharvirkar et al. 2008").

[136] Iowa Utilities Board, *Final Order*, In Re: Interstate Power and Light Co., Docket Nos. EEP-2018-003 and TF-2018-0010 (Mar. 26, 2019).

Kentucky

In a series of cases culminating in 2017 decision, the Kentucky Commission has effectively prohibited any direct customer or third-party aggregator participation in wholesale demand response programs. The Commission held that, "Any Kentucky retail customer that participates directly or indirectly in any wholesale electric market in the absence of authorization under a tariff or contract on file with the Commission is in violation of Kentucky statutes and Commission Orders and is subject to termination of service by its retail electric supplier."[137] No MISO member utilities in Kentucky reported having demand response programs in the U.S. Energy Information Administration Form 861 Data for 2019.[138]

Louisiana

After a DR service provider began soliciting customers to participate in MISO DR programs, the Louisiana Public Service Commission initiated an investigation. In 2019, the Commission adopted a rule that prohibited third-party aggregation of customers from participation in RTO demand response programs without prior Commission approval. The Commission cited the 2010 decision of the Indiana Utility Regulatory Commission and a 2016 order of the Michigan Public Service Commission, which restricted third-party aggregation. The Louisiana Commission left open an opportunity an aggregator to petition to operate based on a demonstration that its practices are just, reasonable, and in the best interests of ratepayers.[139]

Future DR participation in MISO markets may be impacted by the outcome of pending proceedings.

The Louisiana Commission has an open proceeding to consider a rule that could allow large commercial and industrial customers to directly participate in RTO demand response programs.[140]

In 2019, Entergy Louisiana filed two demand response applications pending before the Louisiana Commission:

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[137] Kentucky Public Service Commission, *Order*, In the Matter of Appl. of East Kentucky Power Coop., Inc. for a Declaratory Order Confirming the Effect of Kentucky Law and Commission Precedent on Retail Electric Customers' Participation in Wholesale Electric Markets, Case No. 2017-00129, p. 20 (June 6, 2017).
[138] U.S. EIA 2019.
[139] Louisiana Public Service Commission, *General Order 3-7-2019 (R-34948)*, In re: Rulemaking to study the implications of participation of Aggregators of Retail Customers to determine whether, and under what conditions, such activity should be allowed in the Louisiana Public Service Commission 's jurisdiction, Docket No. R-34948 (Feb. 21, 2019).
[140] Louisiana Public Service Commission, *Notice of Issuance of Staff Initial Report and Recommendation and of Comment Deadline*, Rulemaking to Determine Need for Rate Schedules and Programs Offering Demand Response Products, Development of Such Rate Schedules and Programs, Determination of Customer Participation in Such Programs, Allocation and Recovery of Program Costs, and Whether Such Programs Shall be Mandatory or Voluntary for Utilities as set Forth in Section 3 of the Rule Adopted in the General Order Dated March 7, 2019 in Docket No. R-34948, Docket No. R-35136 (Oct. 9, 2019).

For an experimental service enabling interruptible customers to register as MISO LMRs and DRR;[141] and to allow customer participation in and aggregation for MISO DR programs through an Entergy Market Value Demand Response Rider. Under this proposal, Entergy would be the sole Market Participant allowed to offer DR into the MISO market and would retain 10% of demand response revenue to cover administrative expenses.[142]
In September 2020, Entergy, the Louisiana Commission Staff, and the Louisiana Energy Users Group filed an uncontested Stipulated Settlement modifying Entergy's proposed Market Value Demand Response Rider. The Commission subsequently approved the settlement. Under the settlement agreement, a qualifying firm load customer or aggregator may authorize Entergy to register and offer DR on their behalf. Entergy will retain 5% of the monthly net revenue received from MISO as a result of the customer's or aggregator's participation in MISO DR programs.[143]

Entergy also is exploring direct load control programs and dynamic pricing.[144]

Entergy Louisiana currently serves customers under a legacy interruptible rate that has been closed to new business since 1999. In the subsequent twenty years, the volume of its interruptible load has declined from 700 MW to 300MW. The remaining interruptible loads are registered as MISO LMRs.[145]

Michigan

Most Michigan consumers cannot participate directly or through a third-party aggregator in wholesale demand response programs. A fraction of mostly large commercial and industrial customers, who are served by competitive Alternative Electric Suppliers ("AES"), can contract with aggregators to offer DR in wholesale markets. Retail competition in Michigan is limited to 10% of utility sales.

The issue of direct and aggregated customer participation wholesale DR has been litigated in Michigan for nearly a decade. In 2010, the Michigan Public Service Commission ("MPSC") found that rate and reliability issues may arise when aggregators offer demand response into

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[141] Louisiana Public Service Commission, Entergy Louisiana, LLC., *Appl. For Authorization to Implement an Experimental Interruptible Option, Rider EIO, and Related Relief*, Docket No. U-35443 (Dec. 16, 2019).
[142] Louisiana Public Service Commission, Entergy Louisiana, LLC., *Appl. For Authorization to Implement Market Value DR Rider Schedule MVDR*, Docket No. U-35443 (Dec. 16, 2019).
[143] In Re: Application to Change Rates by Filing Market Valued Demand Response Rider Schedule MVDR, *Report of Proceedings and Submission of Stipulation for Consideration by Commissioners* (Sept. 2, 2020) ("Entergy Louisiana. 2020").
[144] Entergy Louisiana, LLC., *2019 Integrated Resource Plan* (May 2019).
[145] Louisiana Public Service Commission, Voltus Inc., *Comments on the Initial Staff Report and Recommendation*, In re: Rulemaking to study the implications of participation of Aggregators of Retail Customers to determine whether, and under what conditions, such activity should be allowed in the Louisiana Public Service Commission 's jurisdiction, Docket No. R-34948 (Dec. 10, 2018).

wholesale power markets. It encouraged utilities to propose tariffs that would allow aggregators to participate in wholesale markets in a manner where:

Participating load is not inadvertently counted by both the utility and aggregator;
Rates are fair to both participating and non-participating customers;
The utilities' responsibility to manage all load during emergencies is appropriately recognized;
Advanced notification of load interruption is addressed; and
Administrative and cost recovery issues are resolved.
Pending its review of the utility proposals, the MPSC imposed a temporary ban on retail customers or aggregators participating in RTO markets.[146]

Following FERC's issuance of Order 745, the MPSC in 2012 set aside a directive for utilities to propose tariffs permitting demand response participation in wholesale markets. After the U.S. Supreme Court ruling in FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760 (2016), the MPSC, in a 2016 decision, continued a temporary prohibition on participation in wholesale markets. The Commission indicated that concerns had been raised regarding (1) operational considerations related to capacity planning and emergency operations, (2) lack of MPSC oversight of third-party aggregators, (3) duplicate enrollment in demand response programs, and (4) cross-subsidization, that had not yet been adequately addressed. The Commission said this was not a permanent prohibition and that it would address demand response opportunities and barriers in other proceedings.[147]

In 2017, the MPSC confirmed the ability of AES to provide demand response through third-party aggregators and initiated a further review of demand response participation for customers of regulated utilities.[148]

In 2018, the MPSC directed its Staff to start a collaborative process to examine issues related to DR aggregation. The Staff issued its Report and recommendations in May 2019.[149] In a 2019 Order, the MPSC largely followed its Staff's recommendations. It maintained a ban on wholesale DR participation for the 90% of load served under bundled service rates, citing the introduction of uncertainty and complexity into integrated planning and operational challenges if non-utility wholesale DR participation was not implemented in a transparent manner. The MPSC also noted Staff's discussion of a Consumers Energy presentation addressing these concerns and that an

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[146] MPSC, *Order*, In the matter of the joint request of The Detroit Edison Company, Indiana Michigan Power Company, The Michigan Electric and Gas Association and Consumers Energy Company to initiate an investigation of the licensing rules and regulations needed to address the effect of the participation of Michigan retail customers, including those associated with aggregators of retail customers, in a regional transmission organization wholesale market, Case No. U-16020 (Dec. 2, 2010).
[147] MPSC, *Order*, In the matter of the joint request of The Detroit Edison Company, Indiana Michigan Power Company, The Michigan Electric and Gas Association and Consumers Energy Company to initiate an investigation of the licensing rules and regulations needed to address the effect of the participation of Michigan retail customers, including those associated with aggregators of retail customers, in a regional transmission organization wholesale market, Case No. U-16020 (Mar. 29, 2016).
[148] MPSC, *Order*, In the matter, on the Commission's own motion, initiating a process to address demand response issues for regulated utilities, Case No. U-18369 (Sept. 15, 2017).
[149] MPSC, *Demand Response Aggregation Staff Report and Recommendations*, Case No. U-20348 (May 30, 2019) ("Michigan Public Service Commission 2019a").

aggregator model could force utilities to plan to meet all customer load regardless of offers to curtail.[150] The MPSC again encouraged utilities to develop an aggregator – utility collaboration model or a proposal to permit aggregator participation in wholesale markets.[151] However, Michigan utilities have sought to limit third-party participation in wholesale demand response.[152] It remains unclear whether most Michigan consumers will have an opportunity to participate directly or through aggregators in wholesale demand response programs.

Consumers Energy has a residential air conditioner cycling, a commercial and industrial economic DR, and a commercial and industrial emergency demand response program. It also offers residential dynamic peak pricing and interruptible rates. In 2019, Consumers Energy received 543 MW of DR MISO Zonal Resource Credits that could help meet it resource planning requirements.[153] DTE Energy offers water heating and space conditioning control programs and interruptible supply service.[154] DTE Energy's revised 2020 Integrated Resource Plan includes 709 MW of LMRs for the 2019-20 planning year.[155]

Minnesota

The Minnesota Commission prohibited third party DR aggregation in a 2010 Order, stating that, "utilities must have meaningful influence or control over their customers' demand response." At the same time, the Commission indicated that it remained open to well-designed pilot aggregation programs.[156]

In 2013 following a review of existing utility DR programs, the state Commission refused to relax its prohibition on aggregators operating autonomously in Minnesota but held that they are free to pursue opportunities in conjunction with Minnesota utilities.[157]

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[150] *Id.*
[151] MPSC, *Order*, In the matter, on the Commission's own motion, to address outstanding issues regarding demand response aggregation for alternative electric supplier load, Case No. U-20348 (Aug. 8, 2019).
[152] Michigan Public Service Commission 2019a.
[153] Consumers Energy, *2019 Consumers Energy Company Integrated Resource Plan Annual Report*, In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t and for other relief, Case No. U-20165 (June 12, 2020).
[154] Michigan Public Service Commission 2019a.
[155] Michigan Public Service Commission, DTE Energy Co., *DTE Electric Company's MCL 460.6t(7) Incorporation of Commission Changes to its Integrated Resource Plan*, In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan under MCL 460.6t and for other relief, Case No. U-20471 (Mar. 20, 2020).
[156] Minnesota Public Utilities Commission, *Order Prohibiting Bidding of Demand Response Into Organized Markets by Aggregators of Retail Customers and Requiring further Filings by Utilities*, In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into the MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A, Docket No. E-999/CI-09-1449 (May 18, 2010).
[157] Minnesota Public Utilities Commission, *Order Accepting Compliance Filings*, In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into the MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A, Docket No. E-999/CI-09-1449 (Apr. 16, 2013).

In a 2019 decision, the Minnesota Commission recognized that, "there is currently no significant financial incentive for utilities to invest in demand response," and ordered Xcel Energy to implement a series of metrics on demand response potential and performance that could become the basis future performance incentives.

Minnesota electric companies operate DR programs. Northern States Power / Xcel offers time of day pricing and, for general service customers, a peak demand control rate.[158] Moreover to comply with a Commission directive in its prior Integrated Resource Plan proceeding, Xcel has proposed increasing its controllable demand potential from 800 MW in 2018 to over 1,200 MW by 2023. With more wind and solar resources, the utility recognizes that flexible, "non-traditional demand response will be an important part of our energy future." However, it concludes that, "the traditional model for cost recovery of demand response is an impediment to the growth of these resources."[159] Minnesota Power / Allete offers duel fuel interruptible electric service and a rate for non-residential customers with energy storage.[160] Otter Tail Power offers interruptible rates. At least a portion of the reductions from such programs are offered into the MISO market. However, the Minnesota Commission continues to prohibit retail customers from participating directly or through aggregators in MISO DR programs.

Missouri

In 2010, the Missouri Commission prohibited the transfer of DR load reductions to ISO and RTO markets by retail customers or third-party aggregators, citing a number of unresolved issues.[161]

In its energy efficiency plans for 2019–2021, Ameren Missouri proposed developing two new DR programs, a residential smart thermostat program expected to achieve 40 MW of demand savings and a business DR program using an aggregator to procure 75 MW of demand reduction that would be registered in MISO as an LMR.[162] Earlier Ameren demand side resource plans, under the 2009 Missouri Energy Efficiency Investment Act, were focused on energy efficiency programs that provide a fixed profile of energy savings.

[158] Northern States Power Co., *Minnesota Electric Rate Book – MPUC No. 2*.
[159] Minnesota Public Utilities Commission, Xcel Energy, *Upper Midwest Integrated Resource Plan 2020 – 2034*, Docket No. E002/RP-19-368 (July 1, 2019) ("Xcel Energy 2019a").
[160] Minnesota Public Utilities Commission, *Order Establishing Performance Metrics*, In the Matter of a Commission Investigation to Identify Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operation, Docket No. E-002/CI-17-401 (Sept. 18, 2019).
[161] Missouri Public Service Commission, *Order Temporarily Prohibiting the Operation of Aggregators of Retail Customers*, In the Matter of an Investigation into the Coordination of State and Federal Regulatory Policies for Facilitating the Deployment of all Cost-Effective Demand-Side Savings to Electric Customers of All Classes Consistent With the Public Interest, File No. EW-2010-0187 (Mar. 31, 2010).
[162] Ameren Missouri, *2019–21 MEEIA Energy Efficiency Plan* (2018).

In 2008, MISO member companies in Missouri reported having approximately 200 MW of interruptible demand.[163] For 2018, 50.9 potential peak demand savings were reported for Ameren Missouri in U.S. EIA's detailed data files.[164]

Mississippi

In March 2019, prompted by third-party service providers soliciting customers to participate in MISO DR programs, the Mississippi Commission temporarily barred aggregators from registering retail customers or participating in wholesale market programs on their behalf.[165]

In May, Entergy proposed a Market Value Demand Response ("MVDR") schedule to define the parameters under which Entergy customers and aggregators could participate in MISO markets. The utility argued that making it the sole representative of its retail customers in MISO markets would provide visibility of DR for planning, provide a means to fairly allocate costs, and retain state regulatory oversight. Entergy would retain 10% of the DR revenue from MISO to cover administrative costs before the net proceeds are paid to the participating customer or aggregator. The record of this proceeding did not include any estimate of Entergy's actual administrative costs or testimony regarding the impact of Entergy's revenue retention on customers or aggregators participating in MISO DR programs.[166]

In September 2019, the Mississippi Commission approved Entergy's MVDR proposal, making the utility the only MISO Market Participant allowed to represent retail customers and aggregators.[167]

For 2019, no potential peak demand savings for Entergy Mississippi appear U.S. EIA's detailed data files.[168]

Montana, North Dakota, and South Dakota

Based on an uncontested utility request, the South Dakota Public Utilities Commission in 2010 prohibited demand response load reductions from being bid or transferred into any wholesale market either directly by customers or through an aggregator.[169] Acting on a similar 2010 utility

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[163] Bharvirkar et al. 2008
[164] U.S. EIA 2019.
[165] Mississippi Public Service Commission, *Order*, In re: Mississippi Public Service Commission Omnibus Docket: Aggregators of Retail Customers, Docket No.: 2018-AD-141 (Mar. 5, 2019).
[166] Mississippi Public Service Commission, Entergy Mississippi, Inc., *Direct Test. of D. Andrews Owens Director, Regulatory Research Entergy Services, LLC on Behalf of Entergy Mississippi LLC.*, In re: Notice of Intent of Entergy Mississippi LLC to Change Rates by Filing Market Valued Demand Response Rider, Docket No. 2019-UN-082 (May 2019).
[167] Mississippi Public Service Commission, *Order*, In re: Notice of Intent of Entergy Mississippi LLC to Change Rates by Filing Market Valued Demand Response Rider, Docket No. 2019-UN-082 (Sept. 10, 2019).
[168] U.S. EIA 2019.
[169] Public Utilities Commission of South Dakota, *Order Prohibiting Customers and Aggregators from Participating in Wholesale Electric Markets*, In the Matter of the Request of Xcel Energy to Take Action

request, the North Dakota Public Service Commission also prohibited the aggregation of DR, finding that aggregators were effectively offering to resell electric service.[170]

Montana Dakota Utilities, operating in both the Dakotas and Montana, has a demand response participation model in which the utility out-sourced marketing and operation of a DR program, based on curtailing commercial and industrial demand, to a single demand-side energy management company, CPower. The program focuses on customers with loads of 150 kW and higher. Launched in 2012, its goal was to achieve 25 MW of demand reduction capability. The program is fully subscribed and closed to new customers.[171]

Otter Tail power has direct load control programs and interruptible rate options available for its customers in North and South Dakota.[172] Northern States Power / Xcel Energy excluded all incremental DR from its resource plan for North Dakota, including demand response options it plans to pursue in its Minnesota service territory.[173]

Texas

Entergy Texas' Load Management Program pays qualified large customers a fixed amount per kW for curtailing demand when called upon to do so. For 2019, Entergy Texas reported less than 11 MW of potential peak demand savings to U.S. EIA.[174]

Wisconsin

In a 2009 Order, the Wisconsin Commission prohibited the transfer of DR reductions to MISO markets either directly by retail customers or by third party aggregators.[175]

Prohibiting the Operation of Aggregators of Retail Electric Customers in South Dakota, Docket No. EL10-003 (May 25, 2010).

[170] North Dakota Public Service Commission, *Order Prohibiting ARC Operations*, Northern States Power Company Aggregators of Retail Customers Investigation, Case No. PU-10-59 (Aug. 24, 2010).

[171] North Dakota Public Service Commission, Montana-Dakota Utilities Co., *Demand Response Program Snapshot* (Nov. 2019); Montana-Dakota Utilities Co., Integrated Resource Plan 2019 – Vol. I: Main Report (July 15, 2019) ("Montana-Dakota Utilities Co 2019a."); *see also* Advanced Energy Management Alliance, *Advancing Demand Response in the Midwest: Expanding Untapped Potential* (Feb. 12, 2018).

[172] Otter Tail Power Company, *Application for Resource Plan Approval 2017–2031*, Submitted to Minnesota Public Utilities Commission Docket No. EO17/RP16-386, North Dakota Public Service Commission, and South Dakota Public Utilities Commission (June 1, 2016).

[173] Xcel Energy 2019a.

[174] U.S. EIA 2019.

[175] Public Service Commission of Wisconsin, *Order Temporarily Prohibiting Operation of Aggregators of Retail Customers*, Investigation to Develop and Analyze Alternative Electric and Natural Gas Rate Design and Load Management Options which have the Potential to Reduce Emissions of Greenhouse Gases, Docket No. 5-UI-116 (Oct. 14, 2009).

The largest Wisconsin electric companies offer interruptible and other rate programs.[176] Wisconsin Electric Power / We Energies offers customers a choice of curtailable, interruptible, cooperative load reduction, and partially non-firm rates. Wisconsin Public Service offers different time-of-use and critical peak pricing options. Wisconsin Power & Light / Alliant Energy offers a discounted rate in return for agreeing to reduce to a specified usage level when called. These three companies combined reported potential peak demand savings of more than 330 MW to U.S. EIA for 2019.[177]

[176] Public Service Commission of Wisconsin, *Final Strategic Energy Assessment 2016–2024* (Aug. 3, 2016); and Public Service Commission of Wisconsin, *Final Strategic Energy Assessment 2018–2024* (Aug. 8, 2018).
[177] U.S. EIA 2019.

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EXHIBIT B

Declaration of Gregg Dixon

DECLARATION OF GREGG DIXON

Pursuant to 28 U.S.C. § 1746, I, Gregg Dixon, hereby declare:

1) I am the Chief Executive Officer of Voltus, Inc. ("Voltus").

2) Voltus is a provider of demand response services to commercial and industrial customers across the United States and Canada.

3) As an Aggregator of Retail Customers ("ARC"), Voltus's technology and services enable these customers to deliver to wholesale and retail electricity markets the benefits that their behind-the-meter assets (load curtailment, energy storage, distributed generation, and energy efficiency) provide in delivering energy, capacity, and ancillary services that these markets need to operate.

4) In return, Voltus secures market revenues, and savings, for these assets as a form of payment to incentivize their participation in markets.

How Voltus and Other ARCs Provide Demand Response Services in Comparison To Traditional Utility Affiliated Programs

5) Voltus delivers its demand response services in a much more innovative and customer-centric manner than utilities do, the net effect of which is that Voltus, and companies like us, are able to unlock the full potential of demand response in any given region. Voltus technology provides energy markets and end use consumers with real-time telemetry and control capabilities that automates market participation.

6) Several key distinctions between utilities and companies like Voltus drive the unique and additive value that demand response providers bring to their customers, the market, and to the public at large. First, utilities typically have had little to no incentive to implement demand response other than regulatory edict. Due to the fact that demand response is not a capital expenditure in most cases, utilities typically do not earn a rate of return from their demand response programs. In fact, demand response programs reduce the need for generation, transmission, and distribution investments upon which utilities are paid a guaranteed rate of return. Traditionally regulated utilities have a perverse incentive to minimize the amount of demand response that they are required by state utility commissions to deliver.

7) Data from the U.S. Energy Information Administration's Annual Electric Power Industry Report (Form 861), make this clear: in 2018 all US electric utilities delivered 12,522 MWs of actual demand response (1.5% of the US electricity system peak demand of approximately 800,000 MWs). More than ten years ago FERC's *National Assessment of Demand Response Potential* study of the potential of demand response found that the market potential in the US was 188,000 MWs. Despite the fact that utilities have been required to deliver demand response programs for decades, less than 10% of the potential of the least expensive, most reliable on-peak, and cleanest resource available to rate-payers have been tapped by utilities.

8) On the contrary, Voltus, and companies like us, employ at-risk capital (meaning, we don't get a guaranteed rate of return from ratepayers) to bring innovative offerings to customers with the promise of delivering a much more competitive and compelling offer, creating a match between energy market needs and a customer's needs. Our profits are derived from our innovations and commercial offerings, not from ratepayer guaranteed rates of return. We have to earn our keep with every single customer. If we fail, our business fails. In this context, and often in the face of the barriers put in place by utilities, state commissions, and system operators, we have innovated ways to bring far more MWs into energy markets than utilities have.

9) Second, we only sell demand response. Utilities often know their customers quite well, but Voltus makes a living by reaching out to, educating, and transacting with customers. Our salespeople are among the best in the world. They make a living only if they sell demand response.

10) Third, we create customer-centric agreements, which in turn create new and additional market and public value. Unlike a utility that serves every single customer with the exact same tariff and agreement, often with strict stipulations on what types of customers are eligible to participate, Voltus has the ability to create a commercial offering that meets a specific customers' operational needs and allows every type of customer to participate in energy markets.

11) Further, as an important means to attract customers into demand response programs, Voltus bears all technology integration costs and performance risk on behalf of customers.

12) Fourth, we have developed state-of-the-art technology to support customer participation in demand response. Voltus customers are provided a web-based platform that provides real-time electricity data and visualizations that help them ensure delivery of load reductions and asset management when called upon.

13) Additionally, our technology provides automation for those customers who have systems that can be controlled by our technology, making demand response program participation seamless and virtually unnoticeable.

14) Exactly 0% of customers who deliver demand response through utility interruptible rates in the MISO market have real-time technology to support their demand response program participation.

15) In fact, this is a major point of contention for MISO because there is no way for MISO to know exactly how much load curtailment is provided by these utilities when MISO dispatches their demand response program. In essence, MISO flies blind when they dispatch their demand response portfolio.

16) On the other hand, Voltus technology delivers a truly modern technological experience for customers: instant communication of dispatches, real-time visibility and control of load curtailment, immediate settlement of dispatch performance, and automated financial transactions between markets and

customers. Our technology is the connective tissue needed to fully tap the potential of demand response in every market.

17) Fifth, we homogenize the demand response experience for customers. In many cases, a customer who has many facilities will want to participate in multiple demand response programs. In fact, many of Voltus's national account customers, who have hundreds, or even thousands, of facilities, participate in dozens of different demand response programs. But one of the biggest barriers for these types of customers is simply understanding and complying with the dozens of different tariffs or market rules across each program. As reported by the U.S. Energy Information Administration's Annual Electric Power Industry Report (Form 861), of the 3,300 electric utilities in the US, more than four hundred offer one or more demand response programs, each with their own rules and operational requirements.

18) Voltus's platform simplifies and standardizes all of this into a single experience that makes it easy for customers to access every program without the burden of synthesizing and managing the complexities and nuances of each. For example, instead of a customer worrying about how to translate a program dispatch email from dozens of different utilities that may affect hundreds of different facilities, and worrying about how to communicate these instructions to each individual facility, Voltus manages all of this on behalf of the customer in a standard format with a single technology interface, ensuring that instructions for dispatch aren't missed and that

facilities curtail load according to their commitments. Voltus settles performance and manages program payments all on a single platform, with the benefits of real time electricity data that automates dozens of manual processes, eliminating the administrative burden that often prevents customers from entering demand response programs to begin with.

19) Another significant barrier to demand response programs offered exclusively through utilities is that utilities financially penalize customers who don't perform in each dispatch. The prospect of having to pay a penalty for not curtailing load is often the single biggest barrier to customers enrolling in these programs. Voltus assumes the burden of financial penalties on behalf of customers by committing itself to performance at a portfolio level and only passing through to customers financial rewards for demand response program participation, without burdening the customer with the prospect of financial penalty. In so doing, Voltus is able to calculate and manage risk by applying simple actuarial science to create a market place for the aggregation of loads that may not perform perfectly in every program dispatch as individual assets but can be managed to perform perfectly as a collective.

The Technology Implementing Demand Response Has Become More Sophisticated Since 2009

20) Barely more than ten years ago the first Apple iPhone was introduced. Since this time, broadband, highspeed wireless communication has not only become

ubiquitous but it has become incredibly inexpensive and an expected feature of virtually every modern product or service, from thermostats to airline apps on our devices. Yet, less than 1% of electricity ratepayers have the option of seeing real-time data about their electricity consumption offered by their electric utility. Voltus provides state-of-the-art technology that delivers what consumers have come to expect in modern life: simple, powerful innovations that unlock measurable value through service delivery, including the real-time delivery of data and insights that make their lives easier. Unlike any electric utility in the US, Voltus combines the power of real-time data, cloud-based software, and mobile applications that connect them to energy markets that value their operational flexibility.

21) Today, demand response and energy storage are essentially the same thing. The ability to remotely change the setpoint of a chiller at a cold storage facility to provide measurable and predictable load reduction for four hours is no different than a lithium ion battery that provides four hours of power behind a meter to reduce a facility's consumption of electricity from the grid. To a grid operator, in this example, it operates and is compensated in an identical manner: four hours of reduced consumption from the grid. This makes sense, of course. Cold storage is energy storage, but in this case the energy stored takes the form of ice that releases its energy over time as the surrounding air warms, no differently than a lithium ion battery releases its energy as its stores are drawn down by electrical loads at the facility. Taken

further, both "charge" similarly with the chiller consuming electricity to store its energy in colder ice while the lithium ion battery consumes electricity to charge the lithium ion chemistry.

22) As an example of why the treatment of distributed energy resources should be unified by FERC in wholesale markets, one of our customers was denied entry into the MISO demand response market by the South Dakota Public Utility Commission as curtailable load (demand response) because the state banned ARCs in 2010 without providing the opportunity for meaningful public notice and comment. Yet, this same customer has the ability to put some of its load on an Uninterruptible Power Supply (lithium ion UPS), which the state cannot deny entry into the MISO market due to FERC Order 841 preventing retail regulatory authorities from denying energy storage access to wholesale markets. As a result, MISO accepted this customer's registration as an energy storage resource.

<u>Voltus's Good Faith Attempts To Gain Access To MISO Wholesale Markets Have Been Futile In The Majority Of MISO States</u>

23) Voltus has made efforts in numerous states to gain access to the wholesale markets only to be thwarted by regulatory authorities citing the opt-out provision in Order 719.

24) For example, the Louisiana Public Service Commission ("LPSC") denied access of aggregated demand response, from third parties like Voltus, to the MISO market (which Louisiana belongs to).

25) Upon Entergy Louisiana bringing ARC activity to the attention of the LPSC, the LPSC immediately banned ARCs without meaningful due process. In assessing whether ARCs should be allowed to operate in LPSC jurisdiction, the LPSC ignored clear evidence that Louisiana consumers would benefit economically and through increased grid resilience. Indeed, the latent potential for demand response in the state is significant. As Louisiana State University noted in its *Foundations for an Intelligent Energy Future: Demand Response Potential in Louisiana*, Louisiana has only 2.4 MWs of demand response across the entire state, out of a peak demand of 17,147 MWs according to the U.S. Energy Information Administration's Annual Electric Power Industry Report (Form 861).

26) Following on the heels of the LPSC's decision to ban aggregated demand response access to its wholesale market, the Mississippi Public Service Commission ("MPSC") also banned aggregated demand response in the MISO market.

27) The MPSC didn't even invite those who were bringing these aggregated demand response resources to market to participate in the decision-making process. This would be akin to the local board of taxi regents holding a closed door meeting to decide the fate of ride sharing operators. In the MPSC's

ruling on this matter it set a 120-day timeline within which the order would remain in effect "while the Commission studies this issue." Yet no studying whatsoever occurred and the no formal plan has been enacted to bring the benefits of demand response to the State of Mississippi.

28) Another example involved a large industrial customer in Illinois that takes power at one of its sites from Southern Illinois Power Cooperative ("SIPC"). As is the requirement in the MISO demand response registration process, the local utility is given the opportunity to review a demand response registration of a retail load in its territory and approve or deny it. Not only did SIPC deny Voltus the opportunity to bring this demand resource to the MISO market but SIPC offered to cut Voltus out and take the site into the MISO market itself. The irony is that this same coop, SIPC, denied a number of separate demand response registrations citing concerns that this might unfairly burden its other customers. Yet, it should have been SIPC that brought this innovation to its customer in the first place as the customer's purported expert in electricity.

29) Even in the limited circumstances where Voltus has gained limited access to MISO's markets the progress has been slow and bogged down in politics. Much to their credit, the Michigan Public Service Commission ("MPSC") has taken up the effort to unlock the benefits of demand response. It has made progress. However, Michigan customers still await the $260 million in annual

savings and the associated local resiliency benefits that the MPSC claims are needed.

30) Despite these eye-popping savings, the MPSC allows only 10% of their consumers to access wholesale market demand response programs. This is due to the fact that the bargain made back in 2008 for Alternative Retail Energy Suppliers ("ARES") who deliver competitive supply, so the MPSC applied that construct to DERs as an act of expedience.

31) Yet, the MPSC allows regulated electric utilities to deliver more than 1,000 MWs of DERs into the MISO market, which most recently performed at 65% during the 2019 January polar vortex, according to the *January 16, 2020 MI Power Grid Overview* report issued by MISO and the MPSC.

32) This is a state-subsidized resource that FERC just ruled is the very thing that interferes with wholesale market operations that are meant to deliver just and reasonable rates.

33) Unfortunately, the MPSC's lack of action on this cost Michigan rate payers nearly $90 million more than they needed to be charged in the 2020/21 MISO planning resource auction ("PRA") when the price cleared at the maximum allowable level ($93,998/MW-year) because Michigan's zone 7 came up 123 MWs short of meeting their local resource requirement.

34) Voltus offered the MPSC a 500 MW local resource lifeline in the form of demand response for the 90% of the customers in Michigan who can't access the MISO market directly and Voltus has been flat out denied access.

35) In Nebraska, a state that is entirely within the Southwest Power Pool ("SPP") wholesale market, where no current regulation or law prevents a retail load from accessing a wholesale market, Nebraska Public Power denied a 30 MW data center from enrolling its demand response in the SPP operating reserves market.

36) Surprisingly, NPPD documented its denial, citing competitive reasons, among others, for denying the customer's access to benefit from and deliver benefits to SPP and its member states: "Allowing Voltus, Inc. to register Compute North's Load in SPP as a Demand Response Resource and having Voltus, Inc. bid it into the SPP market allowing it to be eligible to receive revenues for ancillary services or energy would result in Voltus, Inc. directly competing with NPPD Power Plants that also sell ancillary services and energy to the SPP market, resulting in a loss of revenue to NPPD. These revenues from SPP that NPPD Power Plants receive directly lower the cost of the electricity sold to its customers and if reduced would result in higher electricity rates overall."

37) This is a brazen admission on the part of a utility that is rarely documented, yet it is a direct admission that a utility is preventing a federally-regulated market from arriving at just and reasonable rates for consumers.

Aggregators Of Demand Response Add Value And Provide Meaningful Services To The Grid At Significant Savings

38) There are great savings to be unleashed via demand response that remains locked away as a result of the opt-out.

39) The simple fact that demand response is all we sell makes us, and companies like ours, especially good at bringing demand response to market. In fact, as an innovative start-up, we were able to bring 800 MWs of demand response into the MISO market in Southern Illinois alone, in under two years, in a market with a system peak of about 9,000 MWs. That's nearly a 10% penetration of the region. The combined actual demand response MWs of all electric utilities in this region of Southern Illinois totals 53 MWs.

40) As a further illustration, in 2018, according to the U.S. Energy Information Administration's Annual Electric Power Industry Report (Form 861), US utilities delivered 12,522 MWs of actual peak demand response at a total cost to ratepayers of $1.55 billion, or $123,785 per MW per year. In MISO, utilities deliver 2,364 MWs of actual demand response at a total cost to ratepayers of $248 million, or $105,047 per MW per year.

41) Digging deeper into a state that bans ARCs, like Arkansas, we see that Entergy Arkansas delivers 40 MWs of demand response at a total cost of $6.8 million or $172,015 per MW per year.

42) Voltus delivers its MWs in the MISO markets where it can participate at less than $50,000 per MW per year, on average.

43) In MISO alone, Voltus could deliver the same 2,364 MWs of demand response currently delivered by utilities for approximately $118 million, delivering a savings to ratepayers of $130 million per year while elevating the quality of those MWs substantially with its technology platform.

44) Additionally, looking back to Arkansas, data from the U.S. Energy Information Administration's Annual Electric Report indicates that the system peak there is approximately 12,592 MWs. The demand response potential in the state is 20% of this system peak across all customer classes, or approximately 2,518 MWs. Yet, only 311 MWs of demand response has been secured by Arkansas utilities, or approximately 2.5% of system peak. This is not a surprise considering the demand response tariff limitations imposed upon Arkansas demand response customers.

45) For instance, Entergy Arkansas' interruptible rate (Rate Schedule No. 41) requires participants to curtail a minimum of 100 kWs per site to participate. Yet, there are thousands of sites in Arkansas that have between 10 kW and 100 kWs of demand response capability.

46) Furthermore, if a customer fails to perform Entergy Arkansas passes through to the customer unlimited and unknown penalties for all financial losses incurred by Entergy Arkansas.

47) Despite the fact that ARCs are banned by the Arkansas Public Service Commission, Voltus has already contracted with Arkansas customers for approximately 100 MWs of demand response capability, yet we can't bring

these MWs to market because Arkansas has banned market access. Many of these customers have sites that are less than 100 kWs of demand response (e.g., big box and small box national retailers who are accustomed to participating in demand response throughout the country with Voltus).

48) These customers simply like what we have to offer; a no-cost, no-risk means to deliver and earn value in energy markets with terms and conditions that make sense for the customer to sign up, using a single technology platform that simplifies complex energy market participation in every region of the country.

Expedited Action Is Required To Provide Meaningful Relief To Voltus

49) Currently Voltus is only allowed to operate in a small portion of MISO, which includes MISO Illinois, Michigan (serving the 10% of load that is allowed to buy competitive electricity supply), MISO Texas, and a limited set of municipal and cooperative utilities that have consented to allow Voltus to operate in their service territories (e.g., the City of New Orleans).

50) In total, this amounts to approximately 14,000 MWs of peak demand that we can sell our technology and services to.

51) ARCs are currently expressly banned in 11 of the 15 MISO states, including Louisiana, Mississippi, Arkansas, Missouri, Kentucky, Indiana, Iowa, South Dakota, North Dakota, Minnesota, and Wisconsin.

52) Voltus estimates that in each of these states in which we have been banned from operating, we could deliver similar results as we have in Southern

Illinois (i.e., 800 MWs in a 9,000 MW system peak territory, or 9%). These states add up to approximately 111,000 MWs of system peak that could be address with our technology and services, delivering approximately 9,867 MWs of demand response at $50,000 per MW per year or $493 million in annual revenue.

53) Each year in MISO the Planning Resource Auction ("PRA") is held that allows demand response to bid into the market alongside any supply-side capacity resource.

54) This auction takes place in March of each year with results posted in April for delivery in the same year beginning in June. Resources that want to participate in the auction need to be approved for participation by MISO in February of each year.

55) Because Voltus needs lead time to prepare to participate in the 2021/2022 PRA, Voltus requests the Commission to take action as soon as possible.

I declare under penalty of perjury that the foregoing is true and correct.

Executed: October 20, 2020

Gregg Dixon
Chief Executive Officer
Voltus, Inc.

EXHIBIT C

State Opt-out Chart

State Opt-out Chart

State	Restricts direct customer participation?	Restricts ARCs	Law or regulation	Additional Information
Arkansas	Yes.	Yes.	Yes, by state statute in 2013.	Walmart application for participation through a non-utility aggregator is pending, and the Arkansas Commission has an open proceeding in which it is considering whether to allow direct and aggregator participation more broadly. PSC Staff has recommended allowing participation of aggregators is in the public interest.
Illinois	No.	No.	N/A	Aggregators can and successfully do compete in capacity solicitations.
Indiana	Yes.	Yes.	No, by series of orders issued between 2008–2011.	Aggregator participation is allowed through a negotiated agreement with a utility. However, as of 2019, none of the MISO utilities have agreements with an aggregator for participation in MISO DR programs.
Iowa	Yes	Yes	No, by 2010 and 2012 orders.	Demand response is limited to utility programs. Initially a temporary ban; expanded in 2012 without further justification.
Kentucky	Yes.	Yes.	No, by 2017 order.	Customers can participate only in utility programs. Customers attempting to participate directly or through an aggregator without the prior approval of the KPSC are subject to the loss of retail electric service.
Louisiana	Yes.	Yes.	No, by 2019 order.	Open Commission proceeding is considering whether to allow direct participation by large C&I customers. Louisiana Commission recently accepted Entergy application to allow ARC participation through the utility subject to utility retention of 5% of revenue.

State	Restricts direct customer participation?	Restricts ARCs	Law or regulation	Additional Information
Michigan	Yes, for 90% of sales.	Yes, for 90% of sales.	No, by 2009 order as modified by 2017 and 2019 orders.	There are no limitations for the 10% of sales subject to retail competition. Direct customer and aggregator participation is prohibited for other customers. Michigan utilities operate DR programs.
Minnesota	Yes	Yes.	No, by 2010 order.	Any aggregator participation would be limited to access through a utility. However, we are not aware of any utility that has permitted aggregator participation. Minnesota utilities operate DR programs.
Missouri	Yes	Yes	No, by 2010 order	One utility has proposed working with an aggregator to provide a C&I DR program. All other demand response is limited to utility programs.
Mississippi	Yes	Yes.	No, by 2019 order on rate filing.	Mississippi Commission temporarily barred all aggregator participation. It subsequently approved an Entergy application making the utility the sole representative of customers in MISO programs and permitting direct customer and aggregator participation through the utility, subject to Entergy retaining 10% of DR revenue.
Montana	No.	No.	N/A	Portions of MT, ND, SD w/in MISO are all served by the same utility. Since 2012, one aggregator has been granted exclusive right to run a DR program on behalf of that utility, with participation capped at 25 MW. SD 2010 Order provided no rationale.
North Dakota	No.	Yes	No, by 2010 order.	
South Dakota	Yes.	Yes	No, by 2010 order.	
Texas	No.	No.	N/A	N/A
Wisconsin	Yes	Yes	No, by 2009 order.	Demand response is limited to utility programs.

<u>Sources</u>

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