UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Midcontinent Independent System Operator, Inc.	)	Docket No. _____________
	)	

WRITTEN TESTIMONY
OF
Dr. KATHLEEN SPEES,
Dr. SAMUEL A. NEWELL,
AND
Dr. LINQUAN BAI

September 28, 2023

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Introduction

Our names are Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Linquan Bai. We are employed by The Brattle Group, Drs. Spees and Newell as Principals and Dr. Bai as an Associate. On behalf of the Midcontinent Independent System Operator (MISO), we submit this testimony to the Federal Energy Regulatory Commission (FERC, or Commission) to provide our assessment of MISO's proposed Reliability Based Demand Curves (RBDCs) to be used to support resource adequacy in its Planning Resource Auctions (PRAs). We summarize the challenges associated with the current construct's reliance on vertical demand curves; describe the conceptual basis for adopting a downward-sloping demand curve; and present our probabilistic modeling assessment of the likely performance of MISO's proposed reliability based demand curves (RBDCs) compared to the status quo vertical demand curves. Throughout our analysis, we consider the context of MISO's unique regulatory landscape predominated by vertically integrated utilities that support resource adequacy under state oversight, alongside states relying on merchant investments to support resource adequacy and public power entities that utilize a combination of self-supply and market purchases.

Our qualifications as experts derive from our extensive experience evaluating capacity markets and alternative market designs for resource adequacy. Our experience working for Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) across North America and internationally has given us a broad perspective on the practical implications of nuanced capacity market design rules under a range of different economic and policy conditions. For MISO, we have worked with staff at various stages of the resource adequacy construct's evolution to evaluate performance and recommend enhancements. We have also worked on a number of assignments for regulators and market participants operating within the MISO footprint, which has provided us insights on how the capacity market construct may impact the business decisions and other interests of suppliers, customers, utilities, and state regulators.

A subset of our market design work has focused on evaluating sloped demand curves for achieving reliability and other market design objectives. That experience includes: (1) PJM Interconnection (PJM) capacity market reviews of 2008, 2011, 2014, 2018, and 2022 that assessed market performance, including statistical simulations of that market's Variable Resource Requirement curve and recommending curve updates; (2) ISO New England's (ISO-NE's) first downward-sloping demand curve design filed before the Federal Energy Regulatory Commission in 2014; (3) a study on the economics of reliability for the Commission in 2013, including calculating a value-based capacity demand curve designed to procure an economically optimal quantity of capacity from a risk-neutral societal perspective; (4) support to the Ontario Independent Electricity System Operator (IESO) to develop its two-season capacity market demand curves; and (5) assistance in defining or refining the capacity market demand curves for four other international capacity markets.[1]

Dr. Spees is an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and analysis. She earned a Ph.D. in Engineering and Public Policy and an M.S. in Electrical and Computer Engineering from Carnegie Mellon University, and a B.S. in Mechanical Engineering and Physics from Iowa State University. Dr. Newell is an economist and engineer with expertise analyzing and modeling electricity wholesale markets, the transmission system, and market rules. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College. Dr. Bai is a consultant with experience in wholesale electricity market and power system modeling and analysis. He earned a Ph.D. in Electrical Engineering from University of Tennessee at Knoxville and a M.S./B.Sc. in Electrical Engineering from Tianjin University, China.

1 See Kathleen Spees, Samuel Newell, Andrew Thompson, Xander Bartone "Fifth Review of PJM's Variable Resource Requirement Curve for Planning Years Beginning 2026/27," April 19, 2022, "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," Attachment to ISO New England and New England Power Pool submission before the Federal Energy Regulatory Commission, April 1, 2014, Docket ER14-1639-000, ("Newell and Spees Testimony on Behalf of ISO New England"), and Johannes P. Pfeifenberger, Kathleen Spees, Kevin Carden, and Nick Wintermantel, "Resource Adequacy Requirements: Reliability and Economic Implications," prepared for FERC, September 2013, ("Pfeifenberger et al. FERC Resource Adequacy Report").

Executive Summary

The vertical demand curve that MISO uses in its Planning Resource Auction (PRA) has long been a source of concern. For many years, it has contributed to low auction clearing prices, since a vertical demand curve sets the price close to zero when the market has even a small surplus of capacity (and produces the opposite problem of prices at the cap if there is even a small 1 MW shortfall). The low prices produced over most of the PRA's history did not recognize the incrementally increasing value of capacity as reserve margins tightened. The resulting low prices were not sufficient to attract new investment and have contributed to premature retirements of both merchant and utility resources as regulators and market participants alike have responded rationally to the persistent low prices. A vertical curve fails to provide meaningful information to the marketplace on the relative value of capacity over time, by season, or by location; it can only provide a blunt signal that a shortfall has arrived after it is too late to react. A sloping demand curve, by comparison, offers a more actionable signal for managing resources that encourages utilities and merchant resource owners to offer potentially cost-effective resources into the PRA; allowing for more rationalized decisions to attract and retain resources as supply becomes tight.

MISO has not previously implemented a sloped demand curve largely because when the MISO Resource Adequacy construct was first implemented, many states and utilities did not anticipate that such a curve would be needed in the context of a region that relies primarily on state authorities and utility planning to meet resource adequacy needs. A variation on this view was that a sloping demand curve may be needed only for states with retail competition and that rely on merchant power investments. However, as policymakers and market participants across the MISO footprint have gained experience with the Resource Adequacy construct, it has become apparent how many different types of entities have come to rely on the PRA to inform their decision-making and manage a portion of their portfolios. In the 2022/23 PRA, load serving entities (LSEs) operating under all business models including competitive retailers, utilities, and public power arrived at the auction with a supply shortfall.

Downward-sloping demand capacity curves can support resource adequacy more effectively. All other jurisdictions with centralized capacity market auctions have adopted sloped demand curves to produce more meaningful price signals that recognize the reliability value of additional capacity above the target, to set prices high enough on average to support adequate investment to meet reliability objectives, and to mitigate price volatility and abuses of market power. Customers and market participants across the MISO footprint could enjoy similar benefits from adopting a sloping demand curve. A sloping demand curve can contribute to attracting merchant investment where needed, signalling cost-effective retirements when appropriate, while also providing better investment and planning signals to traditionally-regulated utilities. MISO's proposal to utilize demand curves that align with the relative reliability value of incremental capacity will further help the region rationalize the quantity and type of resource investments needed across four seasons, and between the two subregions.

The drawbacks of a downward-sloping demand curve include increased administrative complexity, the need to develop additional PRA parameters such as the Net Cost of New Entry (Net CONE), and exposing LSEs to quantity uncertainty in the PRA clearing (though MISO proposes to mitigate this last drawback via an opt-out mechanism).

We have worked closely with MISO staff to support the development of their proposed Reliability Based Demand Curves (RBDCs), drawing on experience from other regions' capacity demand curves and adapting that experience into the MISO context. MISO's initial system-wide RBDC across each of the four seasons is summarized in Figure 1. The key features of the MISO demand curve include:

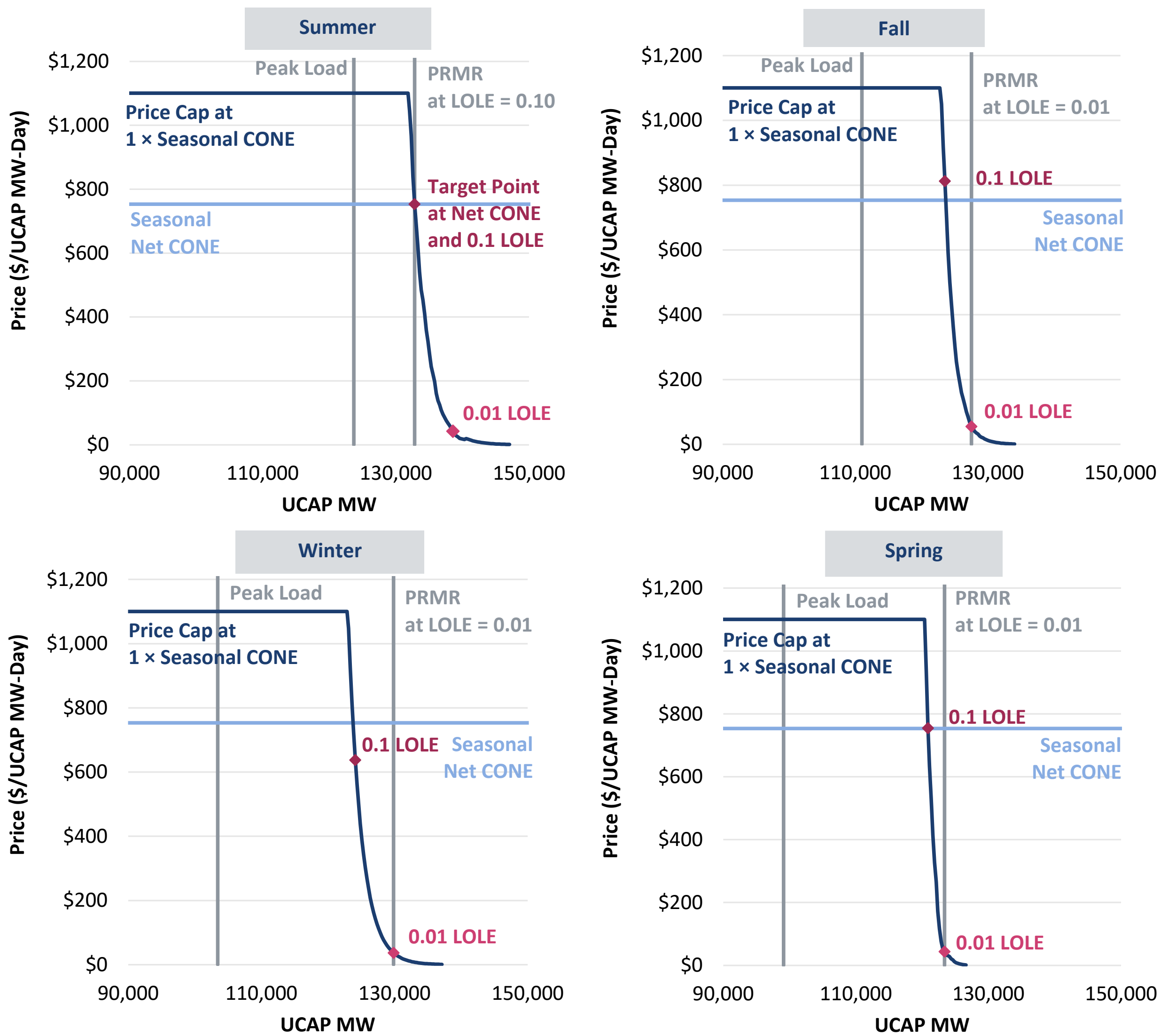
- **Target point** defined by: (a) x-axis centered on MISO's reliability requirement at 0.1 loss of load events (LOLE) per year; and (b) y-axis centered on the estimated Net CONE that would be needed to attract new resources. This target point reflects the central concept acknowledged by all capacity markets' demand curves that price levels must be consistent with achieving system reliability objectives;
- **Curve proportional to incremental reliability value**, such that prices decline with increasing quantities of capacity, and such that pricing levels are rationalized against reliability risk across each of the four seasons. A similar annual reliability-based capacity demand curve has previously been successfully implemented by ISO-NE in its annual capacity market;[2] and
- **Price cap** at 1 × Cost of New Entry (CONE, or Gross CONE) in each season, and 4 × CONE in total across the four seasons.

MISO further proposes to adopt RBDCs for the two subregions of the system, utilizing the same reliability-based concept. Similar to the ISO-NE approach, these subregions' demand curves will reflect the additional reliability value that capacity resources can contribute by being located in a subregion with more acute reliability needs than the broader system. The total reliability value (and price) awarded to capacity in a particular subregion will reflect the sum of its contribution to avoiding system-wide reliability events (reflected in the system RBDC) plus its contribution to avoiding additional reliability events that would occur in the subregion (reflected by the

[2] ISO-NE, Transmission, Markets, and Services Tariff, Market Rule 1 – Section 13, December 3, 2019.

subregional RBDC). In total, MISO proposes to utilize 12 RBDCs for any particular planning year (4 seasonal curves for the system, 4 seasonal curves for the North/Central subregion, and 4 seasonal curves for the South subregion).

FIGURE 1: INITIAL SYSTEM RBDCS IN MISO'S FOUR-SEASON MARKET



Sources and Notes: Prices in 2023$. Parameters consistent with 2023/24 planning year.

To assess the likely performance of MISO's proposed system and subregional RBDCs, we conducted a Monte Carlo simulation analysis to compare the potential price, quantity, and reliability outcomes with the proposed curves, as compared to the current vertical curves construct. Table 1 summarizes our assessment of vertical curve and RBDC performance under base assumptions. As expected, the RBDC approach performs better on dimensions of improved reliability and price volatility. The current vertical curves would support reliability levels at 0.23 LOLE (1-in-4.3) considering only system-wide shortfall events, or 0.56 (1-in-1.8) North/Central and 0.49 (1-in-2.0) South if also considering sub-regional shortfall events; this level of reliability is substantially poorer than MISO's 1-in-10 reliability target.

The proposed RBDCs would produce reliability at 0.06 LOLE (1-in-16.7) considering only system-wide shortfalls, or 0.18 (1-in-5.6) North/Central and 0.11 (1-in-9.1) South when also considering sub-regional shortfall events. Overall, adopting system-wide and subregional RBDCs greatly improves resulting reliability outcomes compared to status quo vertical curves, reducing expected system-wide shortfall events by 73% and total subregional events by 68% and 78% in the North/Central and South subregions respectively. These improvements in reliability are achieved by attracting and retaining more capacity, which incurs an associated cost.

Price volatility is also reduced under the proposed RBDC construct. We estimate that price volatility under the RBDC construct will be improved by 30% in the North/Central subregion and 18% in the South subregion. This reduction in price volatility is realized through the introduction of more meaningful and graduated pricing signals aligned with the relative supply-demand balance in each season and subregion over time.

TABLE 1: SIMULATED PERFORMANCE OF MISO CAPACITY DEMAND CURVES STATUS QUO VERTICAL CURVE VS. PROPOSED RELIABILITY-BASED DEMAND CURVES

	Price			Avg. Excess (Deficit), System				Avg. Excess (Deficit), Subregional		Reliability		Cost
	Average - Total	Standard Deviation - Total	Frequency at Cap	Local Excess (Deficit)	Imports (Exports)	Total Excess (Deficit)	Frequency Below PRMR	Excess (Deficit)	Frequency below Target	System LOLE	System + Subregion LOLE	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(MW)*	*(MW)*	*(MW)*	*(%)*	*(MW)*	*(%)*	*(LOLE)*	*(LOLE)*	*($mill)*
	[A]	[B]	[C]	[D]	[E]	[F] = [D] + [E]	[H]	[I]	[K]	[L]	[M]	[N]
Status Quo - North/Central Subregion												
Annual	$200	$149	11%							0.23	0.56	$7,097
Summer	$712	$472	57%	(2,674)	1,218	(1,455)	57.0%	(4,186)	100%	0.19	0.50	$6,323
Fall	$86	$248	0%	53	(162)	(109)	10.1%	(1,483)	95%	0.01	0.03	$737
Winter	$4	$58	0%	1,754	(1,754)	0	0.0%	497	29%	0.01	0.01	$36
Spring	$0	$0	0%	209	(210)	(0)	0.1%	1,358	0%	0.01	0.01	$0
Status Quo - South Subregion												
Annual	$160	$146	1%							0.23	0.49	$1,923
Summer	$543	$461	36%	1,170	(1,218)	(49)	10.6%	630	21%	0.19	0.24	$1,626
Fall	$85	$247	0%	(164)	162	(2)	0.9%	(836)	94%	0.01	0.11	$259
Winter	$13	$96	0%	(1,756)	1,754	(2)	1.0%	(1,491)	100%	0.01	0.11	$38
Spring	$0	$0	0%	(211)	210	(2)	0.7%	(299)	100%	0.01	0.04	$0
RBDC, MISO Proposal - North/Central Subregion												
Annual	$200	$104	0%							0.06	0.18	$7,337
Summer	$781	$395	46%	1,479	1,092	2,571	15.5%	(33)	51%	0.05	0.17	$7,158
Fall	$20	$59	0%	5,619	(1,299)	4,320	0.0%	4,082	4%	0.00	0.00	$174
Winter	$1	$1	0%	7,498	(2,885)	4,614	0.0%	6,242	0%	0.01	0.01	$5
Spring	$0	$0	0%	4,904	(2,520)	2,384	0.0%	6,052	0%	0.00	0.00	$0
RBDC, MISO Proposal - South Subregion												
Annual	$160	$120	0%							0.06	0.11	$1,975
Summer	$115	$145	1%	1,940	(1,092)	848	15.5%	1,400	1%	0.05	0.05	$346
Fall	$68	$101	0%	1,212	1,299	2,510	0.0%	540	15%	0.00	0.01	$211
Winter	$428	$273	3%	(933)	2,885	1,952	0.0%	(668)	88%	0.01	0.04	$1,326
Spring	$30	$41	0%	1,217	2,520	3,737	0.0%	1,130	3%	0.00	0.00	$92

Notes: Prices represent the total capacity price per MW of UCAP in each region, reflecting the values on both the system-wide and regional RBDC curves in the clearing engine, expressed in 2023$. Parameters consistent with 2023/24 planning year. Procurement costs are calculated as PRA clearing price times total cleared volume calculated as if no entities engaged in self-supply; under MISO's implementation proposal self-supply volumes would not be settled at the PRA clearing price.

We also assessed the expected performance of the RBDCs under a range of sensitivity assumptions, as summarized in Table 2, related to the magnitude of supply and demand variability anticipated, the level of Net CONE, estimation uncertainties for Net CONE, and scenarios in which reliability risks shift away from summer and into other seasons. We find that the proposed RBDC reliability performance is robust across all scenarios on a system-wide basis, with reliability equal to or better than the reliability target in all nine of the scenarios we analyzed.

If also considering subregional reliability events, we find that the RBDC construct achieves reliability similar to our base results in all nine scenarios we analyzed in the North/Central subregion; reliability in the North/Central is never worse than 0.22 LOLE (1-in-4.5) in the most pessimistic scenario we examined. In the South subregion, the RBDC construct achieves reliability equal to or better than the 1-in-10 reliability target in four of the nine scenarios we analyze; reliability in the South subregion is never worse than 0.15 LOLE (1-in-6.7) in the most pessimistic scenario we examined. This analysis suggests that our findings are robust to a range of modeling assumptions, and that the RBDC construct is likely to produce reliability outcomes far better than the current vertical curve construct across a range of plausible scenarios that may materialize over the upcoming years after its implementation.

We place particular emphasis on the proposed RBDC construct's performance considering alternative tight-season assumptions, in which we presume that winter may become the tight season in one or both subregions or where the relative tightness becomes more balanced across the four seasons. The proposed RBDC construct performs well under all of these scenarios, with prices in each season and subregion adjusting in ways that better reflect the level of reliability need; the result is to offer more nuanced pricing signals and lower overall volatility when reliability needs are more similar across the seasons. We anticipate that this tendency for the system, subregional, and seasonal curves to signal reliability needs in a meaningful way will help market participants to adjust their resource decisions and the overall resource mix toward those that offer the greatest reliability value. The seasonal RBDCs further will allow market participants to allocate reliability risks across the seasons in a way that best manages total system investment costs, while still aligning with the reliability target. This dynamic rationalization of reliability and cost is not possible under the current vertical curves approach.

TABLE 2: SIMULATED PERFORMANCE OF MISO CAPACITY DEMAND CURVES ACROSS ALTERNATIVE MODELING SCENARIOS

	Price			Reliability		Cost
	Average - Total *($/MW-d)* [A]	Standard Deviation - Total *($/MW-d)* [B]	Frequency at Cap *(%)* [C]	System LOLE *(LOLE)* [D]	System + Subregion LOLE *(LOLE)* [E]	Average Procurement Cost *($mill)* [F]
North/Central Subregion						
Status Quo	$200	$149	11%	0.23	0.56	$7,097
RBDC, MISO Proposal	**$200**	**$104**	**0%**	**0.06**	**0.18**	**$7,337**
50% Smaller Supply and Demand Shocks	$200	$99	0%	0.06	0.17	$7,341
50% Larger Supply and Demand Shocks	$200	$111	0%	0.07	0.19	$7,327
25% Smaller Net CONE and CONE	$150	$75	0%	0.06	0.17	$5,511
25% Larger Net CONE and CONE	$251	$134	0%	0.06	0.18	$9,162
25% Smaller Estimated Net CONE and CONE	$200	$105	0%	0.08	0.22	$7,297
25% Larger Estimated Net CONE and CONE	$200	$104	0%	0.05	0.15	$7,368
Tight Summers	$200	$103	0%	0.08	0.19	$7,345
Tight Winters	$200	$189	0%	0.03	0.15	$7,020
Increased Seasonal Balance	$200	$250	0%	0.10	0.13	$6,894
South Subregion						
Status Quo	$160	$146	1%	0.23	0.49	$1,923
RBDC, MISO Proposal	**$160**	**$120**	**0%**	**0.06**	**0.11**	**$1,975**
50% Smaller Supply and Demand Shocks	$160	$98	0%	0.06	0.10	$1,975
50% Larger Supply and Demand Shocks	$160	$145	0%	0.07	0.12	$1,974
25% Smaller Net CONE and CONE	$120	$85	0%	0.06	0.10	$1,482
25% Larger Net CONE and CONE	$200	$157	0%	0.06	0.11	$2,467
25% Smaller Estimated Net CONE and CONE	$160	$113	0%	0.08	0.14	$1,961
25% Larger Estimated Net CONE and CONE	$160	$118	0%	0.05	0.09	$1,984
Tight Summers	$160	$96	0%	0.08	0.15	$1,945
Tight Winters	$160	$113	0%	0.03	0.07	$1,989
Increased Seasonal Balance	$160	$157	0%	0.10	0.15	$1,930

Notes: Prices represent the total capacity price per MW of UCAP in each region, reflecting the values on both the system-wide and regional RBDC curves in the clearing engine, expressed in 2023$. Parameters consistent with 2023/24 planning year. Procurement costs are calculated as PRA clearing price times total cleared volume calculated as if no entities engaged in self-supply; under MISO's implementation proposal self-supply volumes would not be settled at the PRA clearing price.

Overall, we find that the current approach relying on vertical curves suffers from limitations that are well understood and have produced the expected pattern of price volatility and unnecessarily poor reliability. The proposed RBDCs will offer substantial benefits by improving price signals, aligning PRA outcomes with reliability objectives, reducing price volatility, supporting improved coordination amongst market participants, and enabling traditionally-regulated and merchant actors to improve resource entry and exit decisions. These benefits are particularly important at the present moment, given the substantial pace of resource transition in the footprint that may materially alter the patterns of reliability needs across seasons and subregions.

I. The Need for a Reliability-Based Capacity Demand Curve

After nearly two decades of experience with capacity markets (and predicted by academic literature before that) the limitations of relying on a vertical capacity demand curve are well understood. We, along with MISO's independent market monitor (IMM) and others, have recommended to address these challenges by adopting a downward-sloping demand curve for more than a decade.[3] The Commission has also acknowledged the challenges associated with vertical demand curves, which have contributed to the adoption of sloping demand curves in all other capacity markets that rely on centralized procurement auctions.[4]

The conceptual and practical advantages of a downward-sloping demand curve to improve reliability, price formation, and resource entry/exit decisions are similarly well-understood. We summarize these advantages here, and describe their relevance and importance in MISO's unique regulatory context.

A. Challenges with MISO's Current Vertical Demand Curves

A vertical demand curve tends to produce large changes in prices that can be caused by small and unpredictable changes in supply or demand. Vertical curves therefore tend to produce excess price volatility, more frequent pricing at the auction price cap, and more frequent capacity shortfalls.

The reliability and price volatility issues to which the vertical demand curve contributes can be observed in MISO's historical PRAs, the prices from which are summarized in Figure 2. MISO's Resource Adequacy construct was first implemented in 2008, and updated to reflect the current locational PRA structure in 2013, at a time when the system had a substantial supply excess associated with prior utility planning processes that required utilities to hold higher individual reserve margins. The advent of the MISO's resource adequacy construct allowed states and utilities to update planning processes to take advantage of the reserve sharing on a region-wide system and locational basis, reducing individual utilities' need to maintain excess reserves. In the early years of the MISO Resource Adequacy construct, the low prices illustrated in Figure 2 were

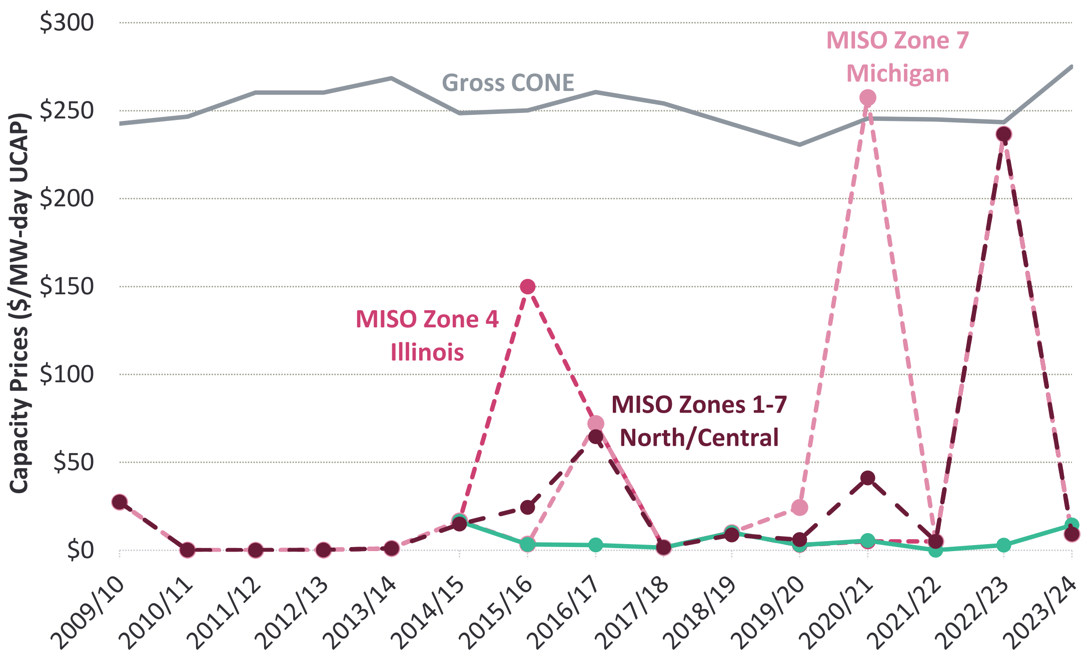
3 Potomac Economics, 2010 State of the Market Report for the MISO Electricity Markets, June 2011, p. 24. The Brattle Group, How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals, September 2019, p. 19

4 See 147 FERC ¶ 61,173, May 30, 2014; 103 FERC ¶ 61, 201, May 20, 2003; 115 FERC ¶ 61, 079 April 20, 2006.

an accurate reflection of capacity excess that signaled cost-effective adjustments to reduce total capacity holdings and therefore total system costs.

Over time however, as total capacity supplies have continued to decline across the entire MISO footprint, system and locational reserve margins have tightened to the point that the region requires greater investment to retain and develop more capacity resources. Prices (excepting the recent 2022/23 auction) have remained low despite declining reserve margins and have not risen in a fashion that accurately reflects the tightening supply-demand balance or increasing system reliability needs.

FIGURE 2: HISTORICAL CAPACITY PRICES IN MISO

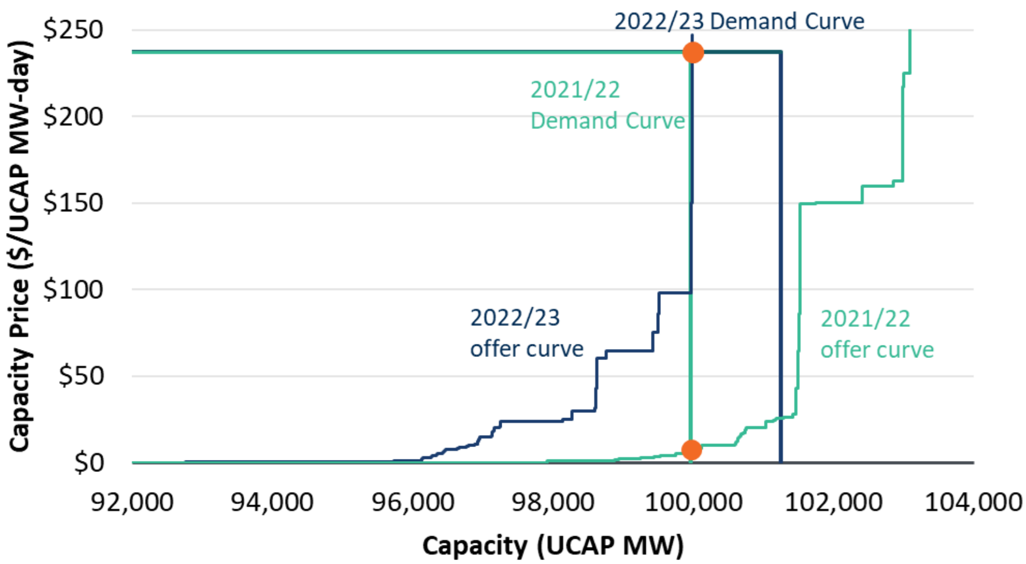


Sources and Notes: MISO clearing prices from MISO, State of Market Reports 2009-2013 and MISO, 2013/14–2023/24 Planning Resource Auction Results; Gross CONE from MISO Annual Calculation of the Cost of New Entry value ("CONE") for each Local Resource Zone ("LRZ") in the MISO Region of Midcontinent Independent System Operator, Inc., filed with FERC.

Rather than reflecting the underlying market fundamentals, recent low capacity prices are a reflection of MISO's capacity market design with vertical demand curves that tends to create structurally highly volatile pricing. Even a small surplus drives prices to near zero, as observed in almost all historical MISO auctions on a system-wide basis. Then as the market encounters even a minor shortage, prices can jump suddenly higher or up to the price cap. This price volatility has previously been observed in more focused examples in the 2015/16 PRA when Zone 4 Illinois produced a one-year price spike to $150/MW-day, and in the 2020/21 PRA when Zone 7 Michigan produced a similar one-year price spike to $258/MW-day.

A more severe illustration of the same structural market volatility occurred in the recent 2022/23 PRA, which cleared at the price cap of $237/MW-day with a 1,230 MW capacity shortfall in the MISO North/Central region, as capacity shrank further and demand grew. Figure 3 illustrates the difference between the supply/demand balance in the 2021/22 PRA that produced a $5/MW-day price with no shortfall and the subsequent 2022/23 PRA that produced a near fiftyfold price increase. The notional supply-demand balance of the MISO North region decreased by only 1.2% (considering only cleared supply) or 4.4% (considering both cleared and uncleared supply). Similarly-sized changes to the system supply-demand balance should be expected in most years, with proportionally much greater year-to-year changes anticipated in smaller capacity zones where individual resource additions and retirements contribute a more substantial share of local needs. The results of the 2022/23 PRA illustrate extreme price sensitivity to small changes in quantity.

FIGURE 3: CAPACITY SUPPLY AND DEMAND IN NORTH/CENTRAL (ZONES 1-7) IN THE 2021/22 AND 2022/23 PLANNING RESOURCE AUCTIONS



Sources and Notes: MISO, PRA Detailed Report 22–23PY, May 25, 2022; MISO, 2021_22 PRA Detailed Report, July 29, 2021.

By comparison, a downward-sloping demand curve would produce prices that more meaningfully reflect the underlying supply-demand balance and associated reliability needs. As early as 2010, MISO's IMM articulated the need for a downward-sloping demand curve in the Resource Adequacy construct, stating that a "sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement and produce more efficient capacity prices."[5] Though MISO and stakeholders examined the potential for a sloping demand

[5] Potomac Economics, 2010 State of the Market Report for the MISO Electricity Markets, June 2011, p. 24.

curve at the time, it was not adopted based on a prevailing (but not uniform) view that a demand curve was not needed in a region that relies primarily on utility planning and state oversight to support resource adequacy needs.

MISO and others have long understood the particular challenge to meeting resource adequacy needs on behalf of consumers in regions with competitive retail choice and that must rely on accurate capacity prices to support capacity investments.[6] For customers in these states, reliability cannot be guaranteed by the outcomes of state planning processes. Instead, market participants must expect that prices will rise high enough over a sustained time period to attract and retain capacity when needed. Under MISO's current construct with vertical curves and structural price volatility, prices should not be expected to rise high enough to attract capacity unless the market is at the price cap (and hence in shortfall) on a relatively frequent basis.

What was not predicted a decade ago was the extent to which traditionally regulated states, vertically integrated utilities, and public power entities might also begin to utilize the PRA (and the bilateral market it informs) to source a portion of their supply needs and inform the timing of investment and retirement decisions. States and utilities across the MISO region utilize the planning parameters established by MISO to guide their planning decisions, and in some cases consider market prices to help determine whether to pursue purchases, sales, investments, retirements, uprates, retrofits, and other resource decisions. The attractiveness of relying on market purchases for at least a portion of supply needs has been amplified by persistently low historical PRA prices. In the early years of the PRA, this produced substantial economic efficiencies as states and utilities with capacity needs could fill them with low-cost short-term purchases while deferring large investments; utilities with excess capacity could offer them under short-term agreements that would defer costs to their own customers. More recently however, the same low pricing signals created by the vertical demand curve have led to excess reliance on market purchases, even as reserve margins tightened.

Table 3 and Table 4 below illustrate that the interest to rely on the PRA for market purchases is not limited to competitive retailers in retail choice states, but rather extends to differently-situated LSEs across the footprint. The table summarizes the quantity of net short positions in the 2022/23 PRA of LSEs in different market participant segments and in different capacity zones (calculated as their customers' capacity requirement, minus their capacity supply holdings when they entered the PRA). LSEs representing all of MISO's regulatory models (including rate-regulated utilities, competitive retailers, public power, and power marketers) arrived at the

[6] See, for example, K. Spees, S.A. Newell, R. Lueken, Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint: Options for MISO, Utilities, and States, November 2015.

2022/23 PRA with shortfalls relative to their individual and collective capacity requirements. Other market participants also offer their respective long positions into the PRA, but the excess capacity available from those entities was not sufficient to prevent a system-wide shortfall. If these demand and supply-side market participants had been exposed to demand-curve-based pricing signals in prior years, more of them would have focused on increasing their capacity holdings or retaining more excess to offer for sale bilaterally or in the PRA.

TABLE 3: LSE SHORT POSITIONS BY ZONE IN THE 2022/23 PRA

	Z1 *(MW)*	Z2 *(MW)*	Z3 *(MW)*	Z4 *(MW)*	Z5 *(MW)*	Z6 *(MW)*	Z7 *(MW)*	Z8 *(MW)*	Z9 *(MW)*	Z10 *(MW)*	Total *(MW)*
LSE short position	609	430	165	5,095	1,343	3,112	940	409	2,163	497	14,762

TABLE 4: LSE SHORT POSITIONS BY LSE SEGMENT IN THE 2022/23 PRA

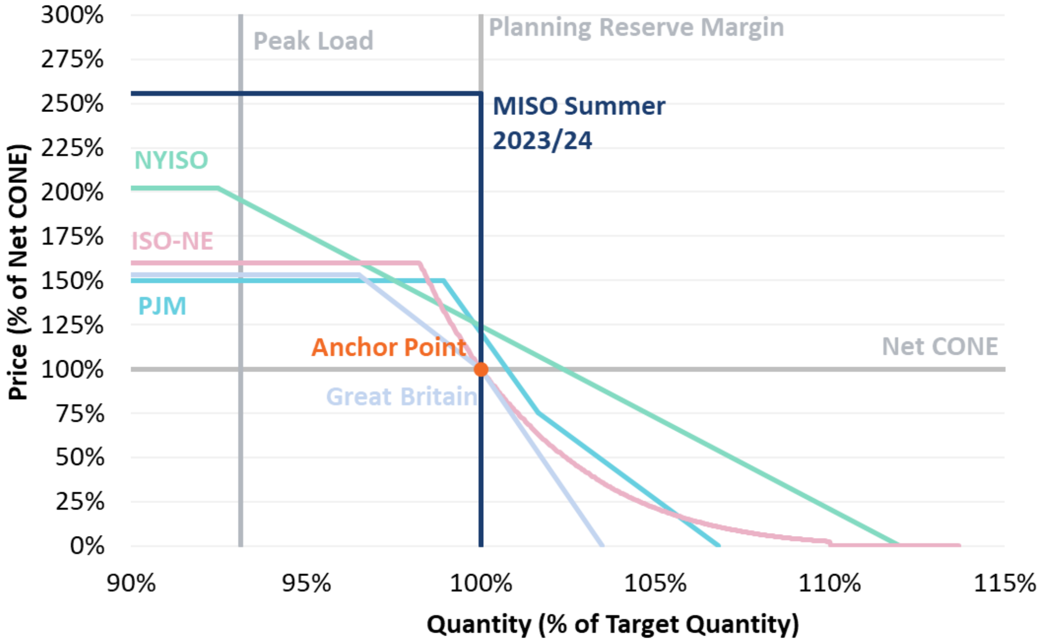
	Municipal/Cooperative *(MW)*	Power Marketers/Brokers *(MW)*	Integrated Utilities *(MW)*	Competitive Retailer *(MW)*
LSE short position	902	1,977	6,533	5,350

Sources and Notes: LSE positions data provided by MISO. Gross short positions are reported; most of these short positions were filled via the PRA with a smaller 1,230 MW system-wide aggregate shortfall position remaining after all available capacity was procured.

B. How Demand Curves Have Been Utilized in Other Capacity Markets

The other established capacity markets in PJM, ISO New England, New York, and Great Britain have all adopted sloping demand curves, as illustrated in Figure 4, and have incorporated these curves into market designs with sufficient pricing incentives to attract resource investments when needed. Though most of these regions rely more heavily than the MISO region on merchant capacity investments, all accommodate a mixture of business and investment models including utility planning, public power, state-approved contracting, competitive power producers, and retail choice entities.

FIGURE 4: MISO AND OTHER CAPACITY MARKETS' DEMAND CURVES



Sources and Notes: PJM curve from 2024/25 Base Residual Auction Planning Parameters; MISO reserve margin from Planning Resource Auction Results 2023/24, price cap from FERC Docket ER22-495-000, Order Accepting Proposed Tariff Revisions Subject to Condition, August 31,2022 and Reliability-Based Demand Curves; NYISO curve from ICAP/UCAP Translation of Demand Curves and NYISO, Annual Update for 2023/23 ICAP Demand Curves; ISO NE curve from FCA 18 Demand Curve; Great Britain T-4 2027/28 Curve from UK Government, Full Details of Auction Parameters and Interconnector De-Rating Factors.

Compared to these other established capacity markets, MISO is the only region that still relies on a vertical demand curve. The other capacity markets have all adopted sloping demand curves that recognize the value of incremental capacity and produce price signals that get high enough to signal when to retain or invest in capacity, without introducing excess price volatility.

Though the specific shapes of the demand curves in each market differ, they all have a broadly similar conceptual basis. All of these capacity demand curves are drawn through, or somewhat to the right of, an "anchor point" defined by the reliability target and Net CONE. This is to ensure that prices can reach the long-run cost of supply, or Net CONE, when incremental investment is needed to support reliability. The graduated slope produces low prices when the system is long and retirements can be accommodated, with prices increasing gradually along with tightening system conditions and prices increasing so as to match or exceed Net CONE if capacity investments are badly needed. On average and in expectation, a curve drawn through the anchor point should support investments consistent with the reliability target on a long-run equilibrium basis.

Several markets also explicitly consider the incremental value of reliability as a factor when setting their demand curve shapes or slopes. In PJM and New York, the slope and shape of the marginal reliability impact (MRI) curve have been considered as a means to inform the most desirable slope and shape of the demand curve.[7] In ISO New England, the curve is drawn through the anchor point, and the MRI curve is directly used to set the shape of the system and locational demand curves, so that prices are proportional to the incremental reliability value of adding 1 MW of perfectly-available capacity to the system. This approach provides a coherent basis for rationalizing price levels with reliability over time and locations.[8] MISO proposes to use a similar concept to derive its proposed RBDCs that will rationalize prices with reliability over time, across the seasons, and by subregion.

If MISO adopts a downward-sloping demand curve, it will realize the same benefits as those considered in other capacity markets, including: enhanced reliability, improved ability to signal cost-effective resource decisions, lower price volatility, and reduced susceptibility to the exercise of market power.

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[7] PJM Interconnection, Fifth Review of PJM's Variable Resource Requirement Curve, April 19, 2022 p. 25, Potomac Economics, 2022 State of the Market Report for the New York ISO Markets, May 2023, p.46.

[8] ISO New England Inc. and New England Power Pool, **Order Accepting Tariff Revisions**, 155 FERC ¶ 61,319, Docket No. ER16-1434-000, June 2016.

II. Reliability-Based Demand Curve Design Proposal

We describe here the design objectives and conceptual approach used to develop the RBDCs that MISO proposes to implement in its future PRAs. We supported MISO staff to develop the conceptual basis for the proposed RBDCs and demonstrate the calculation of these curves using current-year reliability modeling. In total, MISO will utilize 12 RBDCs in its future PRAs, reflective of four seasons for capacity commitments, in each case defined on a system-wide basis, for the North/Central subregion, and for the South subregion.

A. Design Objectives of MISO's Demand Curve

The following design objectives have informed the development and our assessment of MISO's proposed RBDCs:

- **Reliability Objectives (Primary):** The primary design objective is to meet MISO's resource adequacy reliability target of 1-in-10 LOLE. On a system-wide basis, this reliability objective aligns with 0.1 LOLE caused by system-wide capacity shortfalls (as estimated in a copper-sheet reliability modeling run). On a subregional basis, this reliability objective aligns with 0.1 LOLE in any specific subregion (whether the events are caused by system-wide shortages or subregion-specific shortages).
- **Price Formation:** Price signals sent to resources making investment decisions should not suffer from excess year-to-year volatility or the inability to efficiently recognize the marginal reliability value of incremental capacity. The frequency of extremely low and extremely high prices (at the administrative price cap) should be limited, as should exposure to the exercise of market power.
- **Robustness:** The curves should perform well under a range of market conditions and changes in administrative parameters and estimation errors.

We take these design objectives as the benchmark for designing the RBDC for MISO and evaluating its market performance.

B. System-Wide Reliability Based Demand Curves (Four Seasons)

MISO's proposed system-wide and subregional RBDCs are drawn in proportion to reliability value at each quantity point and are drawn through the target point at the reliability requirement and

Net CONE. The approach is similar to that utilized in ISO New England's capacity market, but adapted to MISO's unique context.

The system-wide RBDC is defined in proportion to system-wide MRI, which is measured by expected unserved energy (EUE), or the reductions to load shedding (MWh per year) that would be achieved by adding one more UCAP MW of capacity to the system. This is derived from the seasonal loss of load hours (LOLH) predicted at a specific quantity of supply, and the observation that 1 MW of perfectly-available UCAP supply would have avoided 1 MW-hour of outages across all of the simulated events. Mathematically, MRI is defined in Equation 1.

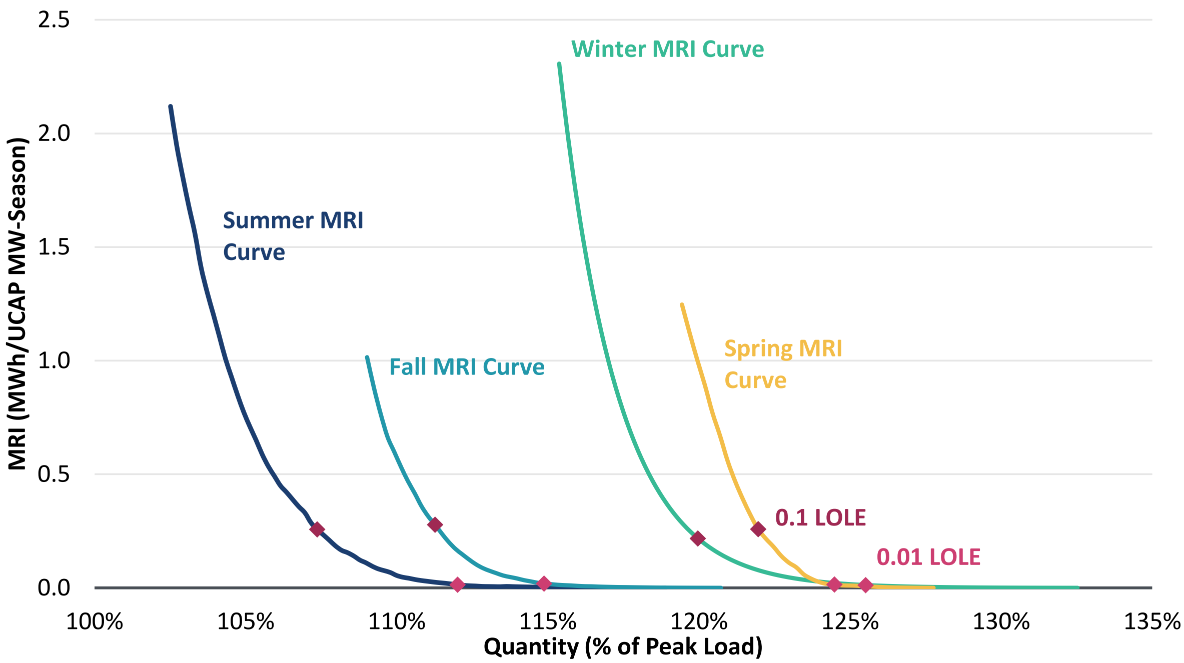
Equation 1	MRI = Avoided EUE from Incremental Capacity = LOLH × 1 MW UCAP WHERE: **MRI** (MWh per UCAP MW) is the incremental reliability value of adding 1 UCAP MW of capacity to the system **Avoided EUE** (MWh per season) is the reduction in expected involuntary load shedding caused by adding incremental capacity **Incremental Capacity** (UCAP MW) is the volume of perfectly-available capacity added (assumed to be 1 UCAP MW to calculate the marginal impact) **LOLH** (hours per year) is the duration of outage hours (which may occur across one or many events) predicted in reliability simulations across the season in question, consistent with a specific quantity of UCAP MW available in that season

To calculate the MRI as a function of capacity, MISO utilized the same system reliability modeling platform that it has historically used to calculate system-wide seasonal planning resource requirements. The system-wide MRI curves for the four seasons calculated by MISO using data consistent with the 2023/24 PRA parameters are shown in Figure 5. The MRI curve is a convex, downward-sloping function that represents the diminishing reliability value of capacity when supply is abundant (and the increasing reliability value when supply is scarce). The MRI curve is calculated above and below the reliability requirement by first establishing the quantity at which the system achieves the 1-in-10 reliability target, and then adding/subtracting perfectly-available UCAP MW of capacity to determine the marginal reliability value of supply.[9] In MISO's seasonal

9 The relative positions of the curves correspond to the seasonal Planning Reserve Margins MISO has under its current construct. The summer curve is furthest left because that is when load is greatest and supply-demand becomes tightest and we accept the most risk, and because the low rate of planned maintenance outages then allows for acceptable reliability even at relatively low planning reserve margins in an accounting sense. Spring is furthest right for the opposite reasons. Fall appears closest to summer because it includes some summer-like conditions in September.

construct, the PRM standard can be based on LOLE between 0.01 and 0.1 in each season; in this case it is 0.1 LOLE for the tightest season (summer) and 0.01 LOLE for other seasons.

FIGURE 5: SYSTEM-WIDE MRI CURVES FOR THE MISO SYSTEM IN FOUR SEASONS



Sources and Notes: Results based on "copper sheet" (without considering the transfer limit between MISO North and MISO South or any zonal import/export limits) LOLE modeling conducted by MISO for Planning Year 2023/24.

Translating the MRI curves (in units of reliability per MW) into a capacity demand curve (in units of dollars per MW-day) requires a System Scaling Factor. Following the logic utilized in New England, the scaling factor in MISO's RBDCs is calculated so as to support annual average prices at (annualized) Net CONE when the system is at the reliability requirement of 0.1 LOLE. The System Scaling Factor in this case is calculated based on 0.1 LOLE in the summer tight season. However, if more than one season shared a meaningful portion of the LOLE risk, the 0.1 LOLE risk could be summed from the estimated values across 2–4 seasons. The calculation and relevant unit conversions for calculating the scaling factor are illustrated in Equation 2.

Equation 2	System Scaling Factor = System Annual Net CONE ÷ System MRI @ 0.1 LOLE WHERE: System Scaling Factor ($/MWh) is the payment rate at which the system-wide reliability-based demand curves would seek to procure additional supply System Annual Net CONE ($/UCAP MW-year) is administrative estimate of the net annualized cost to develop new capacity resources (i.e., the long-run marginal cost of supply) on a system-wide basis System MRI @ 0.1 LOLE (MWh/UCAP MW-year) is the marginal reliability impact of additional capacity, as estimated on a system-wide copper-sheet basis (i.e., without considering transmission constraints) when the system is at 0.1 annual LOLE. The MRI at this point may be from only one tight season at 0.1 LOLE, or it may be the sum of MRI across 2–4 seasons with a total of 0.1 LOLE

Table 5 summarizes the economic parameters that are to be used in the system RBDC, as well as the subregional RBDCs discussed in the next section. Gross CONE and Net CONE are defined both annually and seasonally. The annual value is the daily payment rate that a resource would need to earn on average across the year; Annual Net CONE is the target our seasonal capacity simulation model uses to determine how much entry is needed to reach economic equilibrium. The seasonal values are given by the annual revenue requirements divided by days in the 3-month season in the case we have where the risk is concentrated in a single season (summer). The prices in that season's curve have to reflect the concentrated seasonal Net CONE at the quantity corresponding to 0.1 LOLE allowed in that season, assuming resources would earn (near) zero in the other seasons. In the other seasons, we report a similarly-derived "seasonal Net CONE" although that is not used directly in forming the curves. The prices on all the curves are derived by multiplying the MRI curves by the uniform Scaling Factor (in $/MWh of EUE avoided) given by an entrant's annual revenue requirement from the capacity market at the LOLH corresponding to 0.1 LOLE.

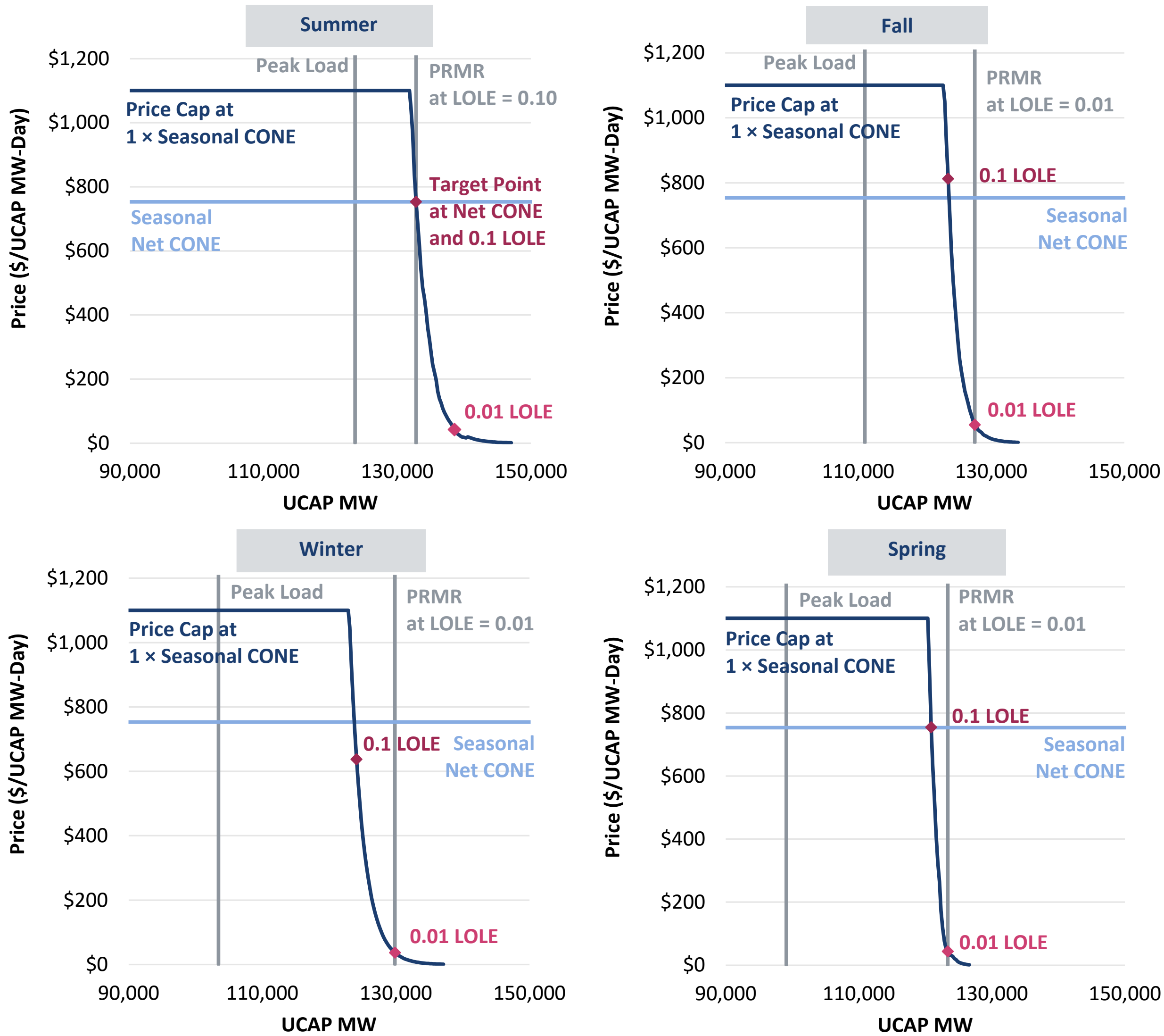
TABLE 5: ECONOMIC PARAMETERS USED IN DEVELOPING THE SYSTEM-WIDE RBDCS

			System		North/Central		South	
			Annual	Seasonal	Annual	Seasonal	Annual	Seasonal
CONE								
CONE - UCAP	[A]	*($/MW-day)*	$275	$1,100	$282	$1,129	$258	$1,033
CONE - ICAP	[B]	*($/MW-day)*	$254	$1,016	$261	$1,043	$238	$954
Net CONE								
Net CONE - UCAP	[C]	*($/MW-day)*	$188	$753	$200	$802	$160	$641
Net CONE - ICAP	[D]	*($/MW-day)*	$174	$696	$185	$740	$148	$592
Price Cap								
Equation	[E]		4 x Annual	1 x Seasonal	4 x Annual	1 x Seasonal	4 x Annual	1 x Seasonal
Price Cap	[F]	*($/MW-day)*	$1,100	$1,100	$1,129	$1,129	$1,033	$1,033
Target Point								
MRI @ 0.1 LOLE	[G]	*(MWh/(MW-day))*	0.26		0.30		0.19	
Scaling Factor	[H]	*($/MWh)*	$266,737		$245,661		$311,981	

Sources and Notes: All prices in 2023$/UCAP MW-day, [A], [C]: MISO, Reliability-Based Demand Curve(s), Aug. 2023, Seasonal CONE = Annual CONE × 4, Seasonal Net CONE = Annual Net CONE × 4; [B], [D]: UCAP values converted to ICAP using 0.92 UCAP:ICAP ratio from summer gas plants, data provided by MISO; [E]: MISO proposal, [F]: [E] applied to Annual/Seasonal CONE values; [G]: Provided by MISO, [H]: Calculated so Summer RBDC passes through 0.1 LOLE at seasonal Net CONE.

Once the System Scaling Factor is calculated, the same value is utilized to calculate the RBDCs across all four seasons, as illustrated in Figure 6. The four curves reflect a self-consistent set of economic parameters that signal the relative value of capacity across each season. These four RBDCs will therefore support differentiated prices in each season that are always consistent with the level of reliability events that are likely to be faced in each season given its respective supply-demand balance. The curves all reflect a convex shape reflective of the diminishing value of reliability at higher quantities, but have different horizontal placement relative to peak load and different rates of diminishing return that reflect the unique system challenges faced across each season. Summer has the highest peak load, so the curve is at the highest overall quantity in the summer; however the other seasons face more uncertainty in net load across weather years and so their curves are more right-shifted compared to seasonal peak load. A season that faces greater variability and uncertainties in outage and resource availability risks may also produce a somewhat flatter curve (e.g., winter and summer); while a season facing fewer such uncertainties may produce a steeper curve (e.g., spring).

FIGURE 6: SYSTEM-WIDE RBDCS FOR THE MISO SYSTEM IN FOUR SEASONS CACLULATED AS SYSTEM SCALING FACTOR × SYSTEM MRI IN EACH SEASON



Sources and Notes: Results based on LOLE modeling conducted by MISO for Planning Year 2023/24.

One of the most valuable features of the RBDC construct, when combined with the seasonal nature of MISO's reliability construct, is the ability to dynamically shift the allocation of LOLE risk across the four seasons in response to resource availability and cost, in a way that economically rationally supports the reliability objectives. Even if capacity offers change across seasons in ways that differ from expected, the seasonal RBDC curves will pay the same rate per MWh of expected load shedding avoided across seasons and any possible clearing points. Furthermore, the curves support investment to an economic equilibrium that should meet the annual reliability objectives in expectations (that is, given the accuracy of the annual Net CONE estimates, the accuracy of modeled risks at each possible reserve margin in each season, and stability in the ratio of annual LOLH to LOLE as differences in cleared quantities shift risks around the year).

In contrast, as discussed above, the current vertical curve construct requires MISO to predict in advance which season(s) will be tight and allocate LOLE risk across the seasons, while ensuring that LOLE risk is between 0.01 and 0.1 in each season at that seasonal Planning Reserve Margin Requirement (PRMR). The current vertical curve is then applied at each seasons' PRMR, which is at a relatively high quantity in any season that has been allocated 0.01 LOLE risk. If the predicted long market conditions are accurate, prices may clear at low prices in the long season even with a vertical curve (which is efficient). However, if a season that was predicted to be long actually materializes with a moderate level of tightness, a vertical demand curve could produce a false scarcity and problematic unnecessary price spike. For example, consider a scenario in which winter was predicted to be long and winter PRMR and vertical curve was set at the 0.01 LOLE quantity point shown above. If in reality winter supply-demand balance is just incrementally beginning to tighten, the offered quantity in the PRA could materialize at a level consistent with 0.02 LOLE (still very strong reliability and indicating excess supply). This situation would materialize under the vertical demand curve as a shortfall situation and prices would jump immediately to the price cap; it would send strong, emergency-level signals that capacity immediately needed to be developed even at high cost to support winter needs. By comparison, the more gradual and rationalized winter RBDC shown above would produce more moderate prices of approximately $50/MW-day, signalling that capacity is increasingly valuable and should be prioritized if the cost is in line with that value.

In the future as MISO's system evolves and the new risks it faces become better understood, the RBDC construct will naturally adapt and update to manage those risks by incorporating signals for the most important risks to each system and signaling to market participants and regulators what types of resources should be pursued and retained to most meaningfully support system reliability. The RBDC construct, combined with MISO's seasonally-specific resource capacity value parameters, will enable the marketplace to better meet reliability needs and weigh the relative costs against value of resources with stronger capacity contributions in the seasons that matter most.

C. Regional Reliability Based Demand Curves (Four Seasons)

The same RBDC concept described above is similarly extended to apply in MISO's two planning subregions in order to provide relevant pricing signals for capacity needs in both of these subregions. This is accomplished by utilizing subregion-specific Net CONE values to calculate Subregional Scaling Factors, which are multiplied by the subregional MRI curves in each season to calculate the RBDCs. The approach used to estimate RBDCs for MISO's subregions is similar to the approach used in ISO New England, but has been adapted to MISO's reliability context and seasonal market.

The MISO proposed subregional RBDCs curves reflect the additional reliability value associated with capacity that can avoid reliability events that occur only in that subregion due to import limits (but that are not experienced system-wide). Beyond the import capability, only capacity located in that subregion can help to avoid those localized shortfall events, so the incremental reliability and pricing value awarded would only apply to local capacity resources. The subregional RBDCs are calculated considering only local outage events, not considering system-wide outage events that are driven by system-wide supply shortfalls. Therefore, the regional RBDCs are defined as additive in nature to the system RBDCs. The role of the system-wide demand curve is to signal the value of adding more capacity in total in MISO (regardless of where it is located); the role of the subregional RBDCs is to signal where within the system capacity is most needed (and where additional capacity cannot be as effectively utilized).

The subregional MRI curves employ the same reliability modeling analysis described for the system curve, but after applying capacity transfer limits between MISO North/Central and MISO South reflected within the modeling. The steps for calculating the subregional RBDCs include:

1. **Initialize Reliability Modeling using 0.1 Annual LOLE in Each Subregion as the reliability target:** Beginning with the system-wide reliability model, apply regional transfer limits. Then add or subtract capacity until each subregion is at the subregional reliability target, reflecting season-specific subregional LOLE between 0.01 and 0.1, and annual subregional LOLE at 0.1 in each subregion. Total system LOLE may be between 0.1 LOLE (if both subregions experience all events at the same time) and 0.2 LOLE (if the subregions experience entirely unique events). This reliability target reflects the subregional interpretation of the 1-in-10 LOLE used as the basis for setting starting points in the subregional RBDCs.
2. **Calculate Subregional Seasonal Reliability Metrics Across Reserve Margins for Each Subregion**: From this starting point, add (or subtract) perfectly-available UCAP MW capacity to the subregion in each season. Adding capacity to the system and the relevant region and observing the change in LOLE, LOLH, and EUE measures the incremental value of locating capacity in that region. When the subregion in question becomes highly import-dependent, reliability events in that subregion will become large (even though the broader system will maintain similar levels of reliability). When the region becomes a large exporter of capacity, local reliability events will drop to zero (even though system-

wide events will not drop to zero given that the maximum capacity limit will be enforced more often and local excess supply will not be possible to export in all cases).

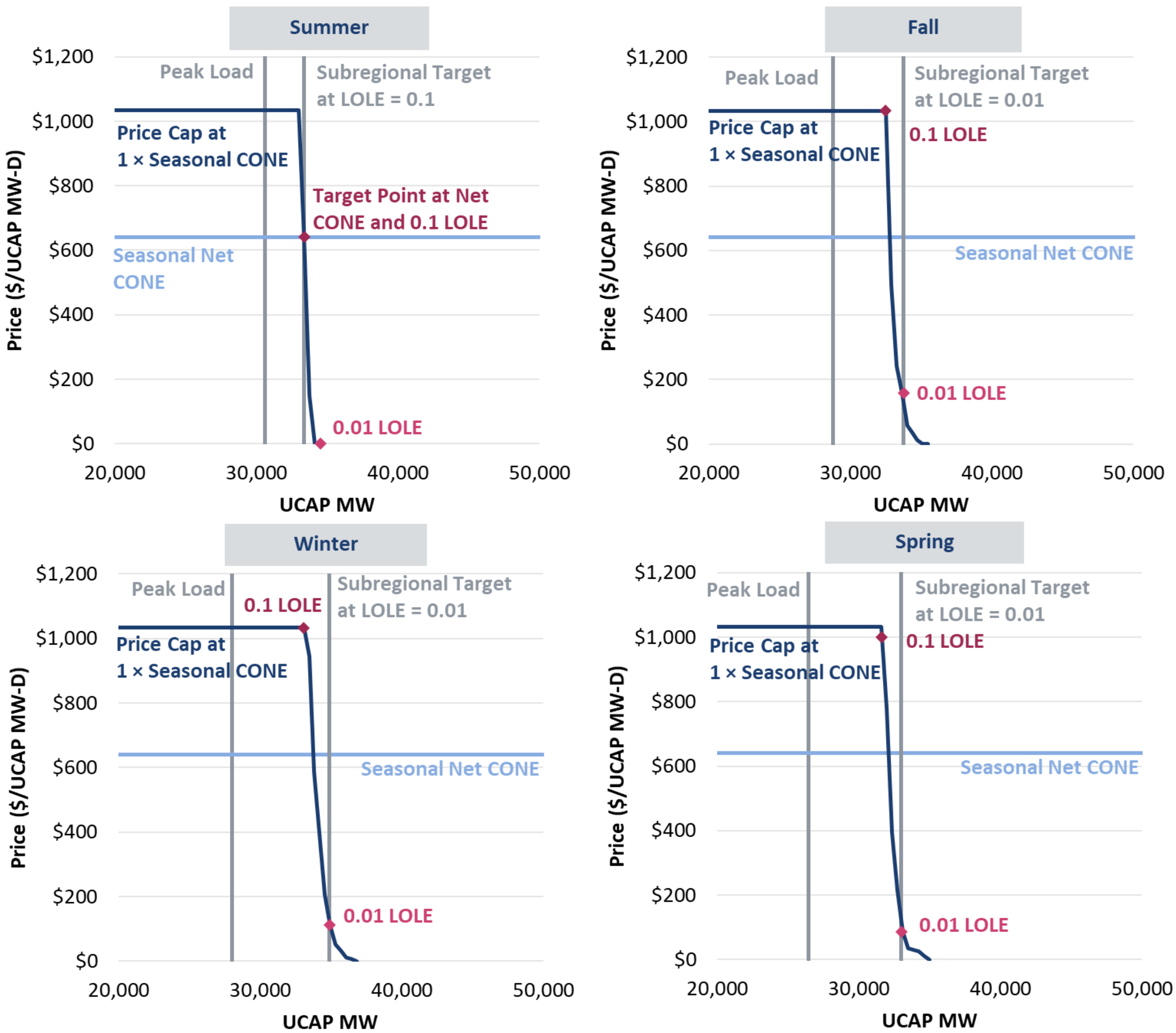
3. **Calculate Subregional, Seasonal MRI Curves:** The subregional MRI curve has a somewhat different meaning as compared to the system-wide MRI curve described in the prior section, in that the subregional MRI curve aims to measure the *additional* value achieved by locating capacity within a particular import-constrained region (beyond the value already reflected by the system curve). Subregional MRI will be positive when the region is import-constrained and zero when the subregion has excess capacity. Therefore, the MRI curve for each subregion is first calculated as the total MRI including both system-wide and subregional events (the direct model result), and then the share of system-wide events is subtracted out (as estimated at the same total system-wide MW quantity in the copper-sheet run discussed above). The resulting MRI curve reflects subregional events only.
4. **Calculate the Subregional Scaling Factor:** Calculate the Subregional Scaling Factor from the Subregional Net CONE value, divided by the subregional MRI at a quantity consistent with the reliability target of 0.1 LOLE (from Step 1).
5. **Calculate Subregional, Seasonal RBDCs** Calculate the RBDCs for capacity in each subregion based on the MRI curve times the Subregional Scaling Factor from Step 4. The resulting subregional RBDC will produce a positive price whenever the subregion is anticipated to be import constrained during times of potential shortage, and incremental capacity in that subregion would help to alleviate the shortfall.

Figure 7 and Figure 8 below illustrate the subregional RBDCs for MISO North/Central and MISO South Subregions. The drivers of reliability outcomes and therefore of locational economic value of capacity are similar to those discussed above, except that the subregional curves help to supplement the system-wide signals by reflecting the seasonal reliability value of resources in import-constrained conditions that is not already captured in the system curve.

FIGURE 7: MRI-BASED SEASONAL RBDCS FOR MISO NORTH/CENTRAL SUBREGION

Sources and Notes: North Annual Net CONE equal to $200/UCAP MW-D; North Annual CONE equal to $282/UCAP MW-D; North Seasonal Price Cap equal to North Seasonal CONE, North Annual Price Cap equals 4 × North Annual CONE; reliability data provided by MISO, Net CONE and CONE data from MISO, Reliability-Based Demand Curve(s), Aug. 2023.

FIGURE 8: MRI-BASED SEASONAL RBDCS FOR MISO SOUTH SUBREGION



Sources and Notes: South Annual Net CONE equal to $160/UCAP MW-D; South Annual CONE equal to $258/UCAP MW-D; South Seasonal Price Cap equal to South Seasonal CONE, South Annual Price Cap equals 4 × South Annual CONE; reliability data provided by MISO, Net CONE and CONE data from MISO, Reliability-Based Demand Curve(s), Aug. 2023; All prices in 2023$.

III. Probabilistic Modeling Approach

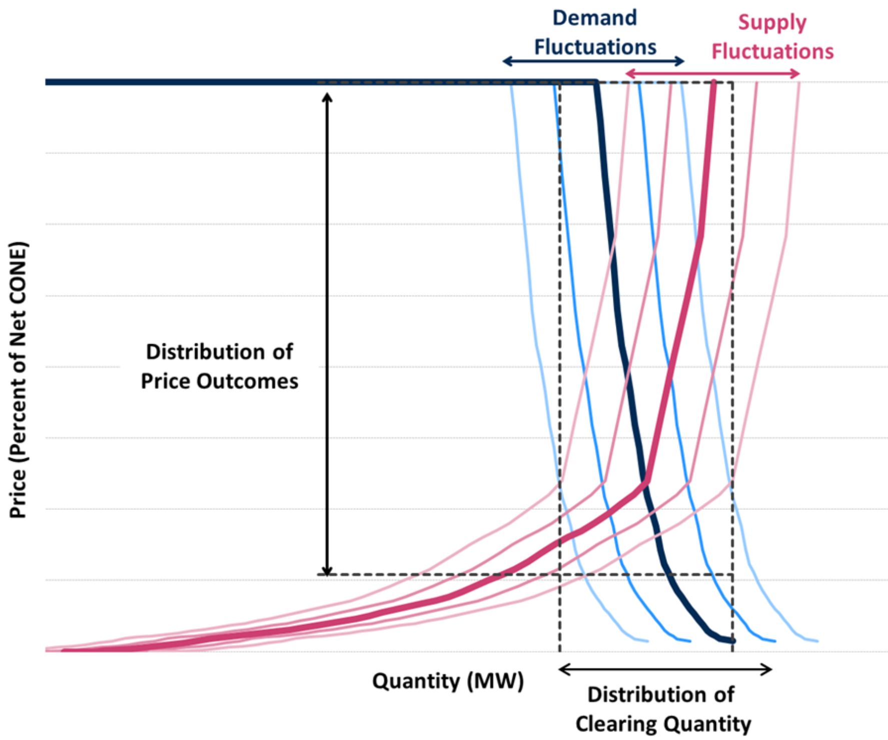
We employ a probabilistic modeling approach to evaluate the ability of the RBDC construct to encourage utilities and merchant generators to invest in building and retaining enough supply to maintain resource adequacy in MISO. Our analysis evaluates the performance of the proposed RBDC construct compared to the status quo vertical curves using a Monte Carlo simulation that captures the impact of year-to-year seasonal variability in supply and demand conditions. The underlying variability in market conditions will translate to a particular distribution of price, quantify, and reliability outcomes that might be realized based on the market design and demand curve shapes. We describe here the primary components of this model and input assumptions, including our characterization of supply, demand, reliability, and auction clearing. We apply this simulation approach to evaluate the likely performance of the proposed RBDCs, the current vertical demand curve, and other alternatives, and present the simulations results under alternative demand curves and scenario assumptions in the following Section IV.

A. Overview of Monte Carlo Model Structure

Our Monte Carlo model provides meaningful indicators of performance because its mechanics and inputs are directly tied to historical market data and experience. To evaluate the performance of the RBDCs for MISO over the long term, we conduct a Monte Carlo simulation by randomly applying 1,000 draws for realistic variations to supply and demand, with the variation sizes based on historical PRA data from MISO. We use seasonal auction clearing reflective of current locational auction clearing mechanics under both the status quo vertical curve and the proposed RBDC construct to clear the auction in each draw and calculate the cleared prices and quantities based on supply and demand curves in each season and subregion (including accounting for transfer limits between the subregions). Supply curves have the shapes from MISO's historical capacity auctions for planning years 2018/19 through 2022/23.

A stylized depiction of the price and quantity distributions driven by supply and demand variations is shown in Figure 9 below, with the intersection of supply and demand determining price and quantity distributions under a particular demand curve. We also assume economically rational new entry, with new supply added until the long-term average price (as summed across the four seasons) equals the Net Cost of New Entry (Net CONE). As such, our simulations reflect long-term conditions at economic equilibrium on average as utilities and other market participants align their planning choices with the reliability needs signaled via the resource adequacy construct; the results do not reflect a forecast of outcomes over the next several years or any other particular year.

FIGURE 9: STYLIZED DEPICTION OF SUPPLY AND DEMAND VARIATIONS IN MONTE CARLO ANALYSIS



Note: Illustrative variations are not intended to reflect the exact variation magnitudes used in our simulations.

B. Supply Offer Behavior and Equilibrium Conditions

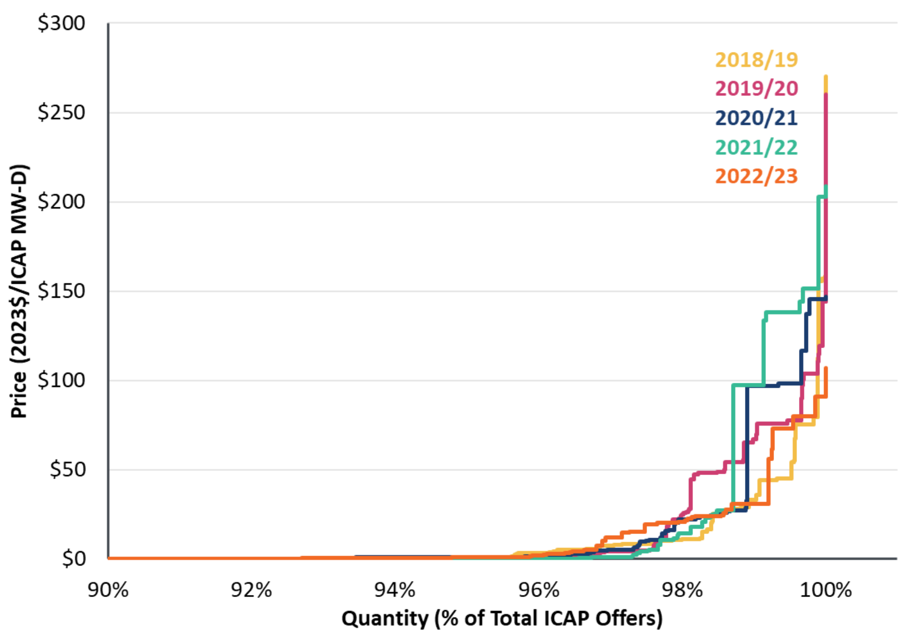
The supply curve shape is an important driver of volatility in cleared price and quantity in our modeling, as in real capacity markets. A gradually-increasing, elastic supply curve will result in relatively stable prices and quantities near the reliability requirement even in the presence of variations to supply and demand, while a steep supply curve will result in greater volatility in both price and reliability outcomes.

We use historical MISO PRA offer prices and quantities to create realistic supply curve shapes that are incorporated in each simulated auction, consistent with the supply curves from MISO PRAs for planning years 2018/19 through 2022/23. To develop comparable supply curve shapes using data from multiple years, we escalate all offer prices to 2023 dollars. The resulting supply curve shapes are presented in Figure 10 below, reflected as a percentage of the total quantity offered. To translate the historical offer curves into the four-season context, we applied unit specific (where available) and class average (otherwise) translations from resources' annual

UCAP values into season-specific planning resource MW capacity rating values. We assume that resources will require total prices over the year to equal their offered price in order to clear the market (this outcome will be directly achieved by MISO's auction clearing if and when it implements seasonally co-optimized auction clearing; until then, market participants will seek to achieve this same outcome by managing their offer prices across the four seasons.)

To simulate rational economic planning decisions by utilities and market-based entry or exit decisions merchant capacity suppliers, we increase or decrease the quantity of zero-priced supply under each demand curve so that the average clearing price over all draws is equal to Net CONE such that a rational supplier would earn an adequate return on investment. Too much zero-priced supply would result in an average price below Net CONE, while too little supply would result in a price above Net CONE. Under the standard long-term economic equilibrium assumption, the RBDCs and alternative demand curves would achieve the same average price.[10] We evaluate the average reliability, frequency of low reliability events, and price volatility that the RBDC and other demand curves produce under that same equilibrium condition.

FIGURE 10: MONTE CARLO ANALYSIS SUPPLY CURVE SHAPES



Note: Data provided by MISO, 2018/19–2022/23 ICAP supply curves are converted into UCAP supply curves for the Monte Carlo model by applying the SAC ratings from the 2023/24 PRA to resources' annual ICAP ratings (shown above); resources without SAC ratings are converted to seasonal UCAP values using class-average SAC ratings; curves are normalized to total annual ICAP supply offered in the 2023/24 PRA.

[10] In modeling terms, we conduct 10,000 simulation draws in which we use the first 9,000 draws to achieve convergence on the quantity of zero-prices supply needed to achieve long-run pricing at Net CONE on average. The last 1,000 draws we treat as "long run equilibrium" outcomes that are reported in this testimony.

C. Variability in Supply and Demand

Year-to-year variations in supply and demand are modeled in our Monte Carlo simulation analysis, with the size of these year-to-year variations derived from historical experience in MISO's PRA auctions. We utilize this year-to-year variability as a key input to our analysis, and simulate PRA clearing outcomes to derive distributions of clearing prices, quantities, and reliability for each subregion and season. We use historical PRA data from planning years 2018/19 through 2022/23 to inform the expected variations.

Our approach to estimating the appropriate variation sizes is as follows:

- **On the supply side**, we reviewed supply offer data from historical PRAs and found that the system summer supply variations were approximately 1.2% of seasonal peak load for the system. Historical supply variability is measured relative to a linear trend. Non-summer supply variations were calculated from the summer supply variation and the average ratio of non-summer UCAP supply to summer UCAP supply from all supply curves used in the model.[11] Total seasonal variability was apportioned between MISO North and MISO South based on peak load share. Subregional variability incremental to the total seasonal variability was modeled based on historical local supply variability incremental to system-wide supply variability. The apportioned total seasonal variability and incremental variability sum to equal the final seasonal supply variability. Positive variations to supply indicate the entry of new resource or uprates of existing resources while negative variations reflect retirements or down-rates of existing resources. We assume that overall supply variations are normally distributed.
- **On the demand side**, we reviewed seasonal coincident peak load forecasts provided by MISO from the periods of the 2014/15 PRA to the 2023/24 PRA. The year-to-year system demand variations were approximately 0.6% of peak load in the summer, with an additional 0.5–0.6% seasonal peak load variability in non-summer seasons. Historical variability is measured relative to a linear trend in peak load. Demand variations could be driven by increase or decrease in the load forecast or LOLE modeling results. Similar to the supply variability methodology, total demand variability was apportioned between the North and South based on peak load share. Subregional variability incremental to the total seasonal variability was again modeled based on historical subregional coincident forecast peak load variability

11 Ratio of non-summer UCAP supply: summer UCAP supply is based on the supply curves used in the model, which are calculated from historical annual ICAP offers and the seasonal SAC ratings from the MISO 23/24 PRA. See Supply Offer Behavior and Equilibrium Conditions section for more detail.

incremental to RTO supply variability. We model variations to demand as normally distributed around the expected value based on the 2023/24 PRA parameters.

We summarize the distributions for the size of the variations applied to the system, MISO North/Central, and MISO South in Table 6 below.

TABLE 6: VARIATIONS TO SUPPLY AND DEMAND

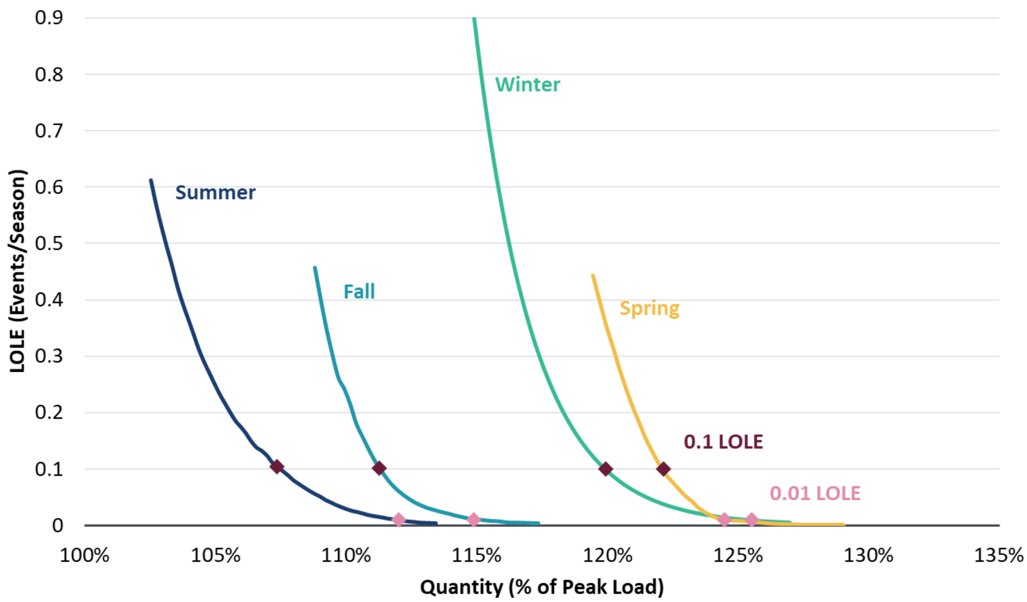
		(Unit)	Summer	Fall	Winter	Spring
System Parameters						
Peak Load	[A]	(MW)	123,706	111,012	103,455	99,113
PRMR	[B]	(UCAP %)	7.4%	14.9%	25.5%	24.5%
North Parameters						
Peak Load	[C]	(MW)	93,108	82,226	75,443	72,667
Regional Target	[D]	(UCAP %)	9.0%	16.7%	27.2%	22.9%
South Parameters						
Peak Load	[E]	(MW)	30,598	28,785	28,013	26,446
Regional Target	[F]	(UCAP %)	9.1%	17.2%	24.6%	24.8%
Supply Variability						
Summer UCAP Supply Variability	[G]	(Std. Dev in % of Peak Load)	1.2%			
Summer UCAP Supply Variability	[H]	(Std. dev in UCAP MW)	1,425			
Total UCAP Supply Variability	[I]	(Std. Dev in % of Seasonal Coincident Peak Forecast)	1.2%	1.3%	1.4%	1.4%
Total UCAP Supply Variability	[J]	(Std. dev in UCAP MW)	1,425	1,397	1,433	1,384
Demand Variability						
Seasonal Peak Load	[K]	(% of Summer Peak Load)	100%	89%	83%	80%
Summer Peak Load Variability	[L]	(Std. Dev in % of Summer Peak Load)	0.6%			
Summer Peak Load Variability	[M]	(Std. Dev in MW)	775			
Incremental Non-Summer Peak Load Variability	[N]	(Std. Dev in % of Summer Peak Load)		0.6%	0.5%	0.6%
Incremental Non-Summer Peak Load Variability	[O]	(Std. Dev in MW)		766	648	699
Total Peak Load Variability	[P]	(Std. Dev in % of Summer Peak Load)	0.6%	0.9%	0.8%	0.8%
Total Peak Load Variability	[Q]	(Std. dev in MW)	775	1,071	950	998

Note: [A],[B], [C], [E]: provided by MISO; [D],[F]: Regional targets reflect point at which regional LOLE is equal to 0.1 (summer) or 0.01 (non-summer seasons); [G], [I], [K],[L], [N], [P]: derived from data provided by MISO; [H]: [A] × [G]; [J]: [A] × [I]; [M]: [L] × Summer([A]), [O]: [N] × Summer([A]), [Q]: [P] × Summer([A])

D. Reliability Outcomes

We calculate reliability outcomes for each Monte Carlo simulation draw based on the same LOLE modeling analysis that MISO staff uses to determine its system and regional 0.1 LOLE reliability targets. Figure 11 shows the relationship between reserve margins and LOLE and highlights that the relationship is asymmetrical, with reliability outcomes deteriorating more quickly at reserve margins below the requirement but improving only gradually at reserve margins above the requirement. Table 7 summarizes LOLE values by season at the subregional reliability targets.

FIGURE 11: SYSTEM RESERVE MARGIN VS SYSTEM LOLE



Note: Reliability data provided by MISO, figures shown represent copper sheet reliability.

TABLE 7: SUBREGIONAL CAPACITY QUANTITIES AT SEASONAL LOLE RELIABILITY TARGITS

		Summer	Fall	Winter	Spring
North					
Regional Target Point	*(UCAP % Peak Load)*	9.0%	16.7%	27.2%	22.9%
Regional LOLE at Sub-Regional Reliability Target	*(Events/Season)*	0.10	0.01	0.01	0.01
South					
Regional Target Point	*(UCAP % Peak Load)*	9.1%	17.2%	24.6%	24.8%
Regional LOLE at Sub-Regional Reliability Target	*(Events/Season)*	0.10	0.01	0.01	0.01

Note: Reliability data provided by MISO, LOLE values shown represent total regional LOLE (i.e., including system and regional events for the relevant region).

IV. Performance Evaluation of MISO's Proposed Reliability-Based Demand Curve

In this Section, we evaluate MISO's proposed RBDC compared to the current vertical demand curve, using the Monte Carlo simulation analysis described in Section III above. As predicted by theory, our simulations demonstrate that the RBDC construct improves reliability and reduces price volatility.

We also present sensitivity analyses evaluating the performance of RBDC under alternative modeling assumptions including the magnitude of supply and demand variations, the value of Net CONE and estimation uncertainty in Net CONE, and alternative assumptions regarding which seasons show the tightest supply-demand balance. We demonstrate that our findings regarding RBDC performance are robust to these factors. Our analysis of alternative tight season scenarios, in particular, illustrate the benefits of the RBDC construct to help guide market utilities and other market participants to meaningfully balance reliability needs and resource costs across the four seasons.

A. Performance of the Proposed Curve Compared to the Current Vertical Demand Curve

We first compare the performance of MISO's proposed RBDC curves to the the status quo vertical demand curves under base modeling assumptions, as summarized in Table 8 below. As expected from a theoretical analysis and experience in other markets, our simulations show that the proposed RBDCs would support improved reliability and lower price volatility compared to the status quo vertical demand curves.

The proposed RBDCs would produce reliability at 0.06 LOLE (1-in-16.7) considering only system-wide shortfalls under "copper-sheet" assumptions, or 0.18 (1-in-5.6) North/Central and 0.11 (1-in-9.1) South when also considering sub-regional shortfall events. The higher LOLE in North/Central corresponds to the higher frequency of the price cap binding in summer, combined with lower risks and revenues in other seasons.

Overall, adopting system-wide and subregional RBDCs greatly improves resulting reliability outcomes compared to status quo vertical curves, reducing expected system-wide shortfall events by 73% and total subregional events by 68% and 78% in the North/Central and South subregions respectively. These improvements in reliability are achieved by attracting and retaining more capacity, which incurs an associated cost.

Price volatility is also reduced under the proposed RBDC construct. We estimate that price volatility under the RBDC construct will be improved by 30% in the North/Central subregion and 18% in the South subregion. This reduction in price volatility is realized through the introduction of more meaningful and graduated pricing signals aligned with the relative supply-demand balance in each season and subregion over time.

**TABLE 8: SIMULATED PERFORMANCE OF MISO CAPACITY DEMAND CURVES
STATUS QUO VERTICAL CURVE VS. PROPOSED RELIABILITY-BASED DEMAND CURVES PERFORMANCE**

	Price			Avg. Excess (Deficit), System				Avg. Excess (Deficit), Subregional		Reliability		Cost
	Average - Total	Standard Deviation - Total	Frequency at Cap	Local Excess (Deficit)	Imports (Exports)	Total Excess (Deficit)	Frequency Below PRMR	Excess (Deficit)	Frequency below Target	System LOLE	System + Subregion LOLE	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(MW)*	*(MW)*	*(MW)*	*(%)*	*(MW)*	*(%)*	*(LOLE)*	*(LOLE)*	*($mill)*
	[A]	[B]	[C]	[D]	[E]	[F] = [D] + [E]	[H]	[I]	[K]	[L]	[M]	[N]
Status Quo - North/Central Subregion												
Annual	$200	$149	11%							0.23	0.56	$7,097
Summer	$712	$472	57%	(2,674)	1,218	(1,455)	57.0%	(4,186)	100%	0.19	0.50	$6,323
Fall	$86	$248	0%	53	(162)	(109)	10.1%	(1,483)	95%	0.01	0.03	$737
Winter	$4	$58	0%	1,754	(1,754)	0	0.0%	497	29%	0.01	0.01	$36
Spring	$0	$0	0%	209	(210)	(0)	0.1%	1,358	0%	0.01	0.01	$0
Status Quo - South Subregion												
Annual	$160	$146	1%							0.23	0.49	$1,923
Summer	$543	$461	36%	1,170	(1,218)	(49)	10.6%	630	21%	0.19	0.24	$1,626
Fall	$85	$247	0%	(164)	162	(2)	0.9%	(836)	94%	0.01	0.11	$259
Winter	$13	$96	0%	(1,756)	1,754	(2)	1.0%	(1,491)	100%	0.01	0.11	$38
Spring	$0	$0	0%	(211)	210	(2)	0.7%	(299)	100%	0.01	0.04	$0
RBDC, MISO Proposal - North/Central Subregion												
Annual	$200	$104	0%							0.06	0.18	$7,337
Summer	$781	$395	46%	1,479	1,092	2,571	15.5%	(33)	51%	0.05	0.17	$7,158
Fall	$20	$59	0%	5,619	(1,299)	4,320	0.0%	4,082	4%	0.00	0.00	$174
Winter	$1	$1	0%	7,498	(2,885)	4,614	0.0%	6,242	0%	0.01	0.01	$5
Spring	$0	$0	0%	4,904	(2,520)	2,384	0.0%	6,052	0%	0.00	0.00	$0
RBDC, MISO Proposal - South Subregion												
Annual	$160	$120	0%							0.06	0.11	$1,975
Summer	$115	$145	1%	1,940	(1,092)	848	15.5%	1,400	1%	0.05	0.05	$346
Fall	$68	$101	0%	1,212	1,299	2,510	0.0%	540	15%	0.00	0.01	$211
Winter	$428	$273	3%	(933)	2,885	1,952	0.0%	(668)	88%	0.01	0.04	$1,326
Spring	$30	$41	0%	1,217	2,520	3,737	0.0%	1,130	3%	0.00	0.00	$92

Notes: All values in 2023$, quantity parameters consistent with 2023/24 Planning Year parameters, North/Central subregion Net CONE = $200 /UCAP MW-D, South subregion Net CONE = $160/UCAP MW-D.

B. Sensitivity to the Magnitude of Supply and Demand Variability

We next test the sensitivity of our findings regarding potential RBDC performance by simulating alternative assumptions regarding the size of variability in supply and demand. Table 9 summarizes estimated performance if assumed variability is 50% smaller and 50% larger than base assumptions. The proposed RBDC supports system reliability levels at 0.06 LOLE (1-in-16.1) under the base assumptions and with 50% smaller variability in both supply and demand. System reliability worsens to 0.07 LOLE (1-in-14.6) with 50% larger supply and demand variability, but reliability remains better than the 1-in-10 LOLE target. Price volatility is also affected, with 50% increase in supply-demand variability driving 7–21% higher price volatility (and 50% lower variability producing 5–18% lower price volatility) depending on the subregion. Prices and average costs are not materially affected by assumed levels of supply-demand variability, because the underlying cost of building new resources remains constant across these scenarios. Subregional reliability outcomes are also directionally affected: lower assumed variability in supply and demand corresponds to better reliability, while higher assumed variability corresponds to poorer reliability. Both system-wide and subregionally, we observe that estimated reliability changes by no more than 0.01 LOLE, indicating that our findings regarding the performance of the RBDC construct are robust across alternative assumptions regarding supply-demand variability. Seasonal patterns of reliability and price levels are relatively consistent in this sensitivity analysis, given that the underlying seasonality in supply-demand balance does not change (though we separately test scenarios with different seasonal patterns in Section IV.E below.)

TABLE 9: SENSITIVITY OF PERFORMANCE TO MAGNITUDE OF SUPPLY AND DEMAND SHOCKS

	Price			Avg. Excess (Deficit), System				Avg. Excess (Deficit), Subregional		Reliability		Cost
	Average - Total	Standard Deviation - Total	Frequency at Cap	Local Excess (Deficit)	Imports (Exports)	Total Excess (Deficit)	Frequency Below PRMR	Excess (Deficit)	Frequency below Target	System LOLE	System + Subregion LOLE	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(MW)*	*(MW)*	*(MW)*	*(%)*	*(MW)*	*(%)*	*(LOLE)*	*(LOLE)*	*($mill)*
	[A]	[B]	[C]	[D]	[E]	[F] = [D] + [E]	[H]	[I]	[K]	[L]	[M]	[N]
RBDC, 50% Smaller Supply and Demand Shocks - North/Central Subregion												
Annual	$200	$99	0%							0.06	0.17	$7,341
Summer	$790	$385	45%	1,469	1,064	2,533	13.2%	(43)	49.0%	0.05	0.16	$7,233
Fall	$12	$31	0%	5,737	(1,357)	4,380	0.0%	4,201	0.6%	0.00	0.00	$104
Winter	$0	$1	0%	7,562	(2,880)	4,681	0.0%	6,306	0.0%	0.01	0.01	$4
Spring	$0	$0	0%	4,874	(2,491)	2,383	0.0%	6,023	0.0%	0.00	0.00	$0
RBDC, 50% Smaller Supply and Demand Shocks - South Subregion												
Annual	$160	$98	0%							0.06	0.10	$1,975
Summer	$109	$114	0%	1,897	(1,064)	833	13.2%	1,357	0.4%	0.05	0.05	$328
Fall	$60	$70	0%	1,170	1,357	2,527	0.0%	498	11.8%	0.00	0.01	$187
Winter	$443	$246	2%	(976)	2,880	1,904	0.0%	(711)	90.7%	0.01	0.04	$1,374
Spring	$28	$24	0%	1,178	2,491	3,669	0.0%	1,090	1.3%	0.00	0.00	$86
RBDC, MISO Proposal - North/Central Subregion												
Annual	$200	$104	0%							0.06	0.18	$7,337
Summer	$781	$395	46%	1,479	1,092	2,571	15.5%	(33)	50.9%	0.05	0.17	$7,158
Fall	$20	$59	0%	5,619	(1,299)	4,320	0.0%	4,082	3.8%	0.00	0.00	$174
Winter	$1	$1	0%	7,498	(2,885)	4,614	0.0%	6,242	0.0%	0.01	0.01	$5
Spring	$0	$0	0%	4,904	(2,520)	2,384	0.0%	6,052	0.0%	0.00	0.00	$0
RBDC, MISO Proposal - South Subregion												
Annual	$160	$120	0%							0.06	0.11	$1,975
Summer	$115	$145	1%	1,940	(1,092)	848	15.5%	1,400	0.8%	0.05	0.05	$346
Fall	$68	$101	0%	1,212	1,299	2,510	0.0%	540	14.6%	0.00	0.01	$211
Winter	$428	$273	3%	(933)	2,885	1,952	0.0%	(668)	87.7%	0.01	0.04	$1,326
Spring	$30	$41	0%	1,217	2,520	3,737	0.0%	1,130	3.1%	0.00	0.00	$92
RBDC, 50% Larger Supply and Demand Shocks - North/Central Subregion												
Annual	$200	$111	0%							0.07	0.19	$7,327
Summer	$767	$403	45%	1,463	1,140	2,603	17.0%	(49)	50.6%	0.06	0.18	$7,020
Fall	$34	$103	0%	5,524	(1,353)	4,171	1.1%	3,987	6.6%	0.00	0.00	$298
Winter	$1	$3	0%	7,383	(2,875)	4,508	0.9%	6,126	0.0%	0.01	0.01	$8
Spring	$0	$1	0%	4,824	(2,444)	2,379	0.0%	5,972	0.0%	0.00	0.00	$0
RBDC, 50% Larger Supply and Demand Shocks - South Subregion												
Annual	$160	$145	0%							0.07	0.12	$1,974
Summer	$120	$175	1%	2,005	(1,140)	865	17.0%	1,465	1.7%	0.06	0.06	$360
Fall	$79	$136	1%	1,275	1,353	2,628	1.1%	603	18.7%	0.00	0.01	$244
Winter	$407	$303	6%	(865)	2,875	2,010	0.9%	(600)	80.6%	0.01	0.04	$1,263
Spring	$35	$69	0%	1,261	2,444	3,706	0.0%	1,174	5.8%	0.00	0.00	$107

Notes: All values in 2023$, quantity parameters consistent with 2023/24 Planning Year parameters, North/Central subregion Net CONE = $200/UCAP MW-D, South subregion Net CONE = $160/UCAP MW-D.

C. Sensitivity to Higher or Lower Net CONE

We report here simulated performance of the proposed RBDCs if Net CONE and CONE are 25% smaller and 25% larger than base assumptions, and continue to be an accurate estimate of the true cost faced by the marketplace to develop new capacity resources. Varying the Net CONE and CONE values does not change the underlying shape of the demand curves, only the price levels. Results from this sensitivity are summarized in Table 10 below.

As shown in Table 10, the proposed RBDC achieves comparable levels of reliability under the tested range of Net CONE and CONE values. Reliability outcomes differ by no more than 0.01 LOLE on a system-wide and subregional basis, with lower Net CONE corresponding to somewhat improved reliability. Higher assumed Net CONE similarly produces somewhat poorer reliability, but the difference is smaller than the 0.01 LOLE precision reported in this table. These results demonstrate that the RBDC's estimated performance is robust to a range of possible Net CONE parameters that could be utilized in the future.

Average prices and costs increase in proportion to the assumed Net CONE, as intended and as they would need to in order to align with the long-run marginal cost of supply. This outcome demonstrates the ability of the proposed RBDC construct to adapt to a range of outcomes with respect to Net CONE, with the curves adjusting to match market conditions. This desired outcome is achieved by MISO's proposed RBDCs by the central concept to tie price and quantity parameters to the "target point" of Net CONE and the system reliability target. As predicted by theory and as demonstrated in other regions, this approach will allow the RBDCs to produce reliability outcomes in line with reliability objectives even as Net CONE changes over time.

TABLE 10: SENSITIVITY OF PERFORMANCE TO LEVEL OF NET CONE

	Price			Avg. Excess (Deficit), System				Avg. Excess (Deficit), Subregional		Reliability		Cost
	Average - Total *($/MW-d)* [A]	Standard Deviation - Total *($/MW-d)* [B]	Frequency at Cap *(%)* [C]	Local Excess (Deficit) *(MW)* [D]	Imports (Exports) *(MW)* [E]	Total Excess (Deficit) *(MW)* [F] = [D] + [E]	Frequency Below PRMR *(%)* [H]	Excess (Deficit) *(MW)* [I]	Frequency below Target *(%)* [K]	System LOLE *(LOLE)* [L]	System + Subregion LOLE *(LOLE)* [M]	Average Procurement Cost *($mill)* [N]
RBDC, 25% Smaller Net CONE and CONE - North/Central Subregion												
Annual	$150	$75	0%							0.06	0.17	$5,511
Summer	$589	$288	0%	1,526	1,090	2,616	13.5%	14	48.2%	0.05	0.16	$5,401
Fall	$12	$38	0%	5,724	(1,365)	4,360	0.0%	4,188	2.8%	0.00	0.00	$106
Winter	$0	$1	0%	7,549	(2,901)	4,649	0.0%	6,293	0.0%	0.01	0.01	$3
Spring	$0	$0	0%	4,949	(2,566)	2,384	0.0%	6,098	0.0%	0.00	0.00	$0
RBDC, 25% Smaller Net CONE and CONE - South Subregion												
Annual	$120	$85	0%							0.06	0.10	$1,482
Summer	$87	$100	0%	1,951	(1,090)	861	13.5%	1,412	0.7%	0.05	0.05	$262
Fall	$49	$69	0%	1,209	1,365	2,574	0.0%	537	14.1%	0.00	0.01	$151
Winter	$323	$203	0%	(935)	2,901	1,966	0.0%	(670)	86.6%	0.01	0.04	$1,003
Spring	$22	$27	0%	1,217	2,566	3,782	0.0%	1,129	2.0%	0.00	0.00	$66
RBDC, MISO Proposal - North/Central Subregion												
Annual	$200	$104	0%							0.06	0.18	$7,337
Summer	$781	$395	46%	1,479	1,092	2,571	15.5%	(33)	50.9%	0.05	0.17	$7,158
Fall	$20	$59	0%	5,619	(1,299)	4,320	0.0%	4,082	3.8%	0.00	0.00	$174
Winter	$1	$1	0%	7,498	(2,885)	4,614	0.0%	6,242	0.0%	0.01	0.01	$5
Spring	$0	$0	0%	4,904	(2,520)	2,384	0.0%	6,052	0.0%	0.00	0.00	$0
RBDC, MISO Proposal - South Subregion												
Annual	$160	$120	0%							0.06	0.11	$1,975
Summer	$115	$145	1%	1,940	(1,092)	848	15.5%	1,400	0.8%	0.05	0.05	$346
Fall	$68	$101	0%	1,212	1,299	2,510	0.0%	540	14.6%	0.00	0.01	$211
Winter	$428	$273	3%	(933)	2,885	1,952	0.0%	(668)	87.7%	0.01	0.04	$1,326
Spring	$30	$41	0%	1,217	2,520	3,737	0.0%	1,130	3.1%	0.00	0.00	$92
RBDC, 25% Larger Net CONE and CONE - North/Central Subregion												
Annual	$251	$134	0%							0.06	0.18	$9,162
Summer	$974	$505	0%	1,459	1,096	2,555	16.1%	(53)	51.7%	0.05	0.17	$8,917
Fall	$27	$79	0%	5,616	(1,330)	4,286	0.0%	4,079	4.2%	0.00	0.00	$238
Winter	$1	$2	0%	7,461	(2,873)	4,588	0.0%	6,205	0.0%	0.01	0.01	$7
Spring	$0	$0	0%	4,891	(2,507)	2,384	0.0%	6,039	0.0%	0.00	0.00	$0
RBDC, 25% Larger Net CONE and CONE - South Subregion												
Annual	$200	$157	0%							0.06	0.11	$2,467
Summer	$144	$190	0%	1,939	(1,096)	843	16.1%	1,400	1.0%	0.05	0.05	$433
Fall	$88	$135	0%	1,219	1,330	2,549	0.0%	547	16.0%	0.00	0.01	$271
Winter	$531	$351	0%	(926)	2,873	1,948	0.0%	(661)	88.3%	0.01	0.04	$1,644
Spring	$38	$55	0%	1,223	2,507	3,730	0.0%	1,135	3.5%	0.00	0.00	$118

Notes: All values in 2023$, quantity parameters consistent with 2023/24 Planning Year parameters, North/Central subregion Net CONE = $200/UCAP MW-D, South subregion Net CONE = $160/UCAP MW-D, 0.75 × North/Central subregion Net CONE = $150/UCAP MW-D, 0.75 × South subregion Net CONE = $120/UCAP MW-D, 1.25 × North/Central subregion Net CONE = $251/UCAP MW-D, 1.25 × South subregion Net CONE = $200/UCAP MW-D.

D. Performance with Estimation Uncertainty in Net CONE

In a related set of scenarios, we evaluate the performance of the proposed RBDCs if estimates of Net CONE are over- or under-estimated. The "true" Net CONE needed to attract capacity investment is constant across these scenarios, and market-based investment/retirement responses produce average prices at the same level as under base assumptions. However, we assume that the estimate of both CONE and Net CONE is either 25% higher or 25% lower than the "true" Net CONE faced by the marketplace. Higher (or lower) estimates in Net CONE translate to higher (or lower) price points in the RBDCs that would be used in the PRAs. These scenarios are useful to evaluate the extent to which the proposed RBDCs may be susceptible to poor reliability when Net CONE is under-estimated, or susceptible to over-procurement when Net CONE is over-estimated. Results are summarized in Table 11.

If Net CONE is underestimated by 25%, reliability worsens but system reliability remains better than the 1-in-10 threshold at 0.08 LOLE (1-in-12.8). Subregional reliability worsens by 0.04 LOLE in the North/Central subregion and 0.03 LOLE in the South. Across all sensitivities examined in this testimony, this is the poorest reliability outcome that we identify (but still far better than the very poor 1-in-2 level of reliability we simulate with the current vertical demand curve). This result indicates that the proposed RBDC construct will greatly improve reliability under long-run equilibrium conditions, even if Net CONE were to be persistently under-estimated.

If Net CONE is persistently overestimated by 25%, this would attract approximately 0.4% more capacity into the market on average in the summer season and increase costs by the same 0.4%. This increase in total procured quantity and cost is quite small relative to the relatively large over-estimate in Net CONE, indicating that the convex shape of the RBDCs offers robust protection against the potential for over-procurement even if Net CONE were to be persistently over-estimated.

TABLE 11: SENSITIVITY OF PERFORMANCE TO UNCERTAINTY IN ESTIMATED NET CONE

	Price			Avg. Excess (Deficit), System				Avg. Excess (Deficit), Subregional		Reliability		Cost
	Average - Total (\$/MW-d) [A]	Standard Deviation - Total (\$/MW-d) [B]	Frequency at Cap (%) [C]	Local Excess (Deficit) (MW) [D]	Imports (Exports) (MW) [E]	Total Excess (Deficit) (MW) [F] = [D] + [E]	Frequency Below PRMR (%) [H]	Excess (Deficit) (MW) [I]	Frequency below Target (%) [K]	System LOLE (LOLE) [L]	System + Subregion LOLE (LOLE) [M]	Average Procurement Cost (\$mill) [N]
RBDC, 25% Smaller Estimated Net CONE and CONE - North/Central Subregion												
Annual	\$200	\$105	0%							0.08	0.22	\$7,297
Summer	\$776	\$391	40%	877	1,098	1,975	23.3%	(635)	57.4%	0.07	0.20	\$7,073
Fall	\$25	\$64	0%	5,306	(1,263)	4,043	0.3%	3,770	6.3%	0.00	0.00	\$217
Winter	\$1	\$2	0%	7,173	(2,887)	4,286	0.2%	5,917	0.0%	0.01	0.01	\$6
Spring	\$0	\$0	0%	4,886	(2,503)	2,383	0.0%	6,034	0.0%	0.00	0.00	\$0
RBDC, 25% Smaller Estimated Net CONE and CONE - South Subregion												
Annual	\$160	\$113	0%							0.08	0.14	\$1,961
Summer	\$147	\$174	0%	1,754	(1,098)	656	23.3%	1,215	1.6%	0.07	0.07	\$439
Fall	\$73	\$100	0%	1,024	1,263	2,287	0.3%	352	25.4%	0.00	0.01	\$223
Winter	\$391	\$218	0%	(1,125)	2,887	1,762	0.2%	(860)	91.5%	0.01	0.05	\$1,206
Spring	\$30	\$44	0%	1,032	2,503	3,535	0.0%	944	6.0%	0.00	0.00	\$92
RBDC, MISO Proposal - North/Central Subregion												
Annual	\$200	\$104	0%							0.06	0.18	\$7,337
Summer	\$781	\$395	46%	1,479	1,092	2,571	15.5%	(33)	50.9%	0.05	0.17	\$7,158
Fall	\$20	\$59	0%	5,619	(1,299)	4,320	0.0%	4,082	3.8%	0.00	0.00	\$174
Winter	\$1	\$1	0%	7,498	(2,885)	4,614	0.0%	6,242	0.0%	0.01	0.01	\$5
Spring	\$0	\$0	0%	4,904	(2,520)	2,384	0.0%	6,052	0.0%	0.00	0.00	\$0
RBDC, MISO Proposal - South Subregion												
Annual	\$160	\$120	0%							0.06	0.11	\$1,975
Summer	\$115	\$145	1%	1,940	(1,092)	848	15.5%	1,400	0.8%	0.05	0.05	\$346
Fall	\$68	\$101	0%	1,212	1,299	2,510	0.0%	540	14.6%	0.00	0.01	\$211
Winter	\$428	\$273	3%	(933)	2,885	1,952	0.0%	(668)	87.7%	0.01	0.04	\$1,326
Spring	\$30	\$41	0%	1,217	2,520	3,737	0.0%	1,130	3.1%	0.00	0.00	\$92
RBDC, 25% Larger Estimated Net CONE and CONE - North/Central Subregion												
Annual	\$200	\$104	0%							0.05	0.15	\$7,368
Summer	\$785	\$396	47%	1,906	1,088	2,994	11.0%	393	45.5%	0.04	0.14	\$7,221
Fall	\$16	\$54	0%	6,030	(1,595)	4,434	0.0%	4,493	2.1%	0.00	0.00	\$144
Winter	\$0	\$1	0%	7,696	(2,899)	4,797	0.0%	6,440	0.0%	0.01	0.01	\$4
Spring	\$0	\$0	0%	4,943	(2,559)	2,384	0.0%	6,091	0.0%	0.00	0.00	\$0
RBDC, 25% Larger Estimated Net CONE and CONE - South Subregion												
Annual	\$160	\$118	0%							0.05	0.09	\$1,984
Summer	\$101	\$129	1%	2,073	(1,088)	985	11.0%	1,534	0.4%	0.04	0.04	\$305
Fall	\$65	\$100	0%	1,342	1,595	2,938	0.0%	670	10.4%	0.00	0.01	\$202
Winter	\$444	\$288	9%	(799)	2,899	2,100	0.0%	(535)	85.1%	0.01	0.04	\$1,383
Spring	\$30	\$40	0%	1,341	2,559	3,900	0.0%	1,253	1.8%	0.00	0.00	\$94

Notes: All values in 2023\$, quantity parameters consistent with 2023/24 Planning Year parameters, "True" Net CONE held at base levels, i.e., North/Central subregion Net CONE = \$200/UCAP MW-D and South subregion Net CONE = \$160/UCAP MW-D, "estimated" Net CONE equal to 0.75 and 1.25 × "true" subregional Net CONE.

E. Alternative Tight Seasons Assumptions

In a final set of scenario analyses, we examined the performance of the proposed RBDC construct in scenarios in which the seasonal supply-demand balance varies such that a different pattern of seasonal "tightness" would occur. Under the base scenario, the tightest season in the North/Central subregion is the summer, while the tightest season in the South is the winter. The relative tightness of these seasons is observable both in the price formation and the average seasonal excess (or deficit) relative to reliability target. We make adjustments to supply in these scenarios to change this pattern of supply-demand balance by season. The tested scenarios are not meant to reflect specific predictions about the supply-demand balance, but rather to test the performance of the RBDC under a range of possible scenarios. The distribution of prices and reliability outcomes in these scenarios demonstrate that the proposed RBDC is robust to a range of possible market conditions in which the supply-demand balance may change across the seasons.

Table 12 summarizes the adjustments to zero-price supply made in each season, to achieve varying levels of "tightness" across each of the constructed scenarios. In addition to base assumptions, we examine scenarios in which both subregions are tight in the summer, both are tight in the winter, and where a more balanced level of supply vs. demand is observed across all four seasons.

TABLE 12: SUBREGIONAL SUPPLY ADJUSTMENTS FOR TIGHT SEASON SENSITIVITY

	North				South			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
1. Tight Summers	0	0	0	0	-2,000	0	+2,000	0
2. Base (Tight Summer in North, Tight Winter in South)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
3. Tight Winters	+7,500	0	-7,500	0	0	0	0	0
4. Increased Seasonal Balance	+6,900	-800	-6,100	-9,300	-700	+800	+1,800	+500

Notes: Supply adjustments are made to 0-priced blocks in the demand curve; adjustments are not meant to reflect specific predictions about the seasonal supply-demand balance but rather to test a range of possibilities.

Across these scenarios, we observe that reliability risks shift to the tight season (as expected in constructing the scenarios), but that total annual reliability outcomes are less affected. In total, annual system + subregional reliability improves by as much as 0.05 LOLE depending on the subregion; and annual reliability can erode by up to 0.04 LOLE depending on the subregion. These outcomes cover a relatively modest range in LOLE outcomes given the large changes in seasonal supply-demand balance that we have applied and the relatively large shifts in where and when reliability outcomes occur. This robustness in anticipated reliability outcomes is a direct result of the RBDC construct design concept, which aims to meet the defined reliability objectives without pre-specifying in what season those risks might be most prominent.

The results of all these scenarios illustrate the rationalized pricing formation across the seasons and regions, such that the seasons with the greatest reliability risk produce the highest average prices. This outcome will signal utilities and merchant market participants alike to invest in and retain the most valuable resources to manage reliability needs and balance these costs across the seasons.

TABLE 13: PERFORMANCE OF MISO'S PROPOSED RBDC CURVES WITH DIFFERENT TIGHT SEASONS

	Price			Avg. Excess (Deficit), System				Avg. Excess (Deficit), Subregional		Reliability		Cost
	Average - Total	Standard Deviation - Total	Frequency at Cap	Local Excess (Deficit)	Imports (Exports)	Total Excess (Deficit)	Frequency Below PRMR	Excess (Deficit)	Frequency below Target	System LOLE	System + Subregion LOLE	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(MW)*	*(MW)*	*(MW)*	*(%)*	*(MW)*	*(%)*	*(LOLE)*	*(LOLE)*	*($mill)*
	[A]	[B]	[C]	[D]	[E]	[F] = [D] + [E]	[H]	[I]	[K]	[L]	[M]	[N]
1. Tight Summers - North/Central Subregion												
Annual	$200	$103	0%							0.08	0.19	$7,345
Summer	$786	$397	47%	1,689	62	1,751	25.6%	176	48.0%	0.07	0.18	$7,207
Fall	$15	$50	0%	5,837	(1,274)	4,562	0.0%	4,300	3.0%	0.00	0.00	$137
Winter	$0	$0	0%	7,678	(2,418)	5,260	0.0%	6,421	0.0%	0.01	0.01	$1
Spring	$0	$0	0%	4,839	(2,456)	2,384	0.0%	5,988	0.0%	0.00	0.00	$0
1. Tight Summers - South Subregion												
Annual	$160	$96	0%							0.08	0.15	$1,945
Summer	$607	$351	27%	638	(62)	576	25.6%	98	33.7%	0.07	0.14	$1,837
Fall	$19	$47	0%	1,831	1,274	3,105	0.0%	1,159	2.6%	0.00	0.00	$61
Winter	$5	$13	0%	1,700	2,418	4,118	0.0%	1,965	0.1%	0.01	0.01	$17
Spring	$10	$15	0%	1,749	2,456	4,205	0.0%	1,661	0.2%	0.00	0.00	$30
2. Base (Tight Summer in North, Tight Winter in South) - North/Central Subregion												
Annual	$200	$104	0%							0.06	0.18	$7,337
Summer	$781	$395	46%	1,479	1,092	2,571	15.5%	(33)	50.9%	0.05	0.17	$7,158
Fall	$20	$59	0%	5,619	(1,299)	4,320	0.0%	4,082	3.8%	0.00	0.00	$174
Winter	$1	$1	0%	7,498	(2,885)	4,614	0.0%	6,242	0.0%	0.01	0.01	$5
Spring	$0	$0	0%	4,904	(2,520)	2,384	0.0%	6,052	0.0%	0.00	0.00	$0
2. Base (Tight Summer in North, Tight Winter in South) - South Subregion												
Annual	$160	$120	0%							0.06	0.11	$1,975
Summer	$115	$145	1%	1,940	(1,092)	848	15.5%	1,400	0.8%	0.05	0.05	$346
Fall	$68	$101	0%	1,212	1,299	2,510	0.0%	540	14.6%	0.00	0.01	$211
Winter	$428	$273	3%	(933)	2,885	1,952	0.0%	(668)	87.7%	0.01	0.04	$1,326
Spring	$30	$41	0%	1,217	2,520	3,737	0.0%	1,130	3.1%	0.00	0.00	$92
3. Tight Winters - North/Central Subregion												
Annual	$200	$189	0%							0.03	0.15	$7,020
Summer	$185	$216	1%	6,245	(37)	6,208	0.0%	4,732	1.1%	0.01	0.02	$1,757
Fall	$87	$160	0%	3,358	(16)	3,341	2.0%	1,821	17.5%	0.00	0.01	$762
Winter	$529	$442	27%	(229)	(619)	(849)	72.1%	(1,486)	78.0%	0.02	0.12	$4,500
Spring	$0	$1	0%	4,561	(2,187)	2,375	0.0%	5,710	0.0%	0.00	0.00	$1
3. Tight Winters - South Subregion												
Annual	$160	$113	0%							0.03	0.07	$1,989
Summer	$45	$107	0%	2,003	37	2,040	0.0%	1,464	1.0%	0.01	0.01	$139
Fall	$75	$107	0%	1,210	16	1,226	2.0%	538	15.2%	0.00	0.01	$232
Winter	$491	$290	10%	(934)	619	(315)	72.1%	(670)	87.8%	0.02	0.05	$1,525
Spring	$30	$42	0%	1,215	2,187	3,401	0.0%	1,127	3.2%	0.00	0.00	$93
4. Increased Seasonal Balance - North/Central Subregion												
Annual	$200	$250	0%							0.10	0.13	$6,894
Summer	$189	$209	1%	6,305	(936)	5,370	0.0%	4,793	0.8%	0.01	0.02	$1,800
Fall	$86	$150	0%	3,214	241	3,455	1.1%	1,677	16.0%	0.00	0.01	$748
Winter	$171	$305	5%	1,835	(214)	1,621	14.6%	578	38.8%	0.01	0.03	$1,476
Spring	$356	$417	17%	(2,057)	1,401	(655)	66.5%	(908)	68.4%	0.07	0.07	$2,869
4. Increased Seasonal Balance - South Subregion												
Annual	$160	$157	0%							0.10	0.15	$1,930
Summer	$366	$346	10%	829	936	1,765	0.0%	289	21.3%	0.01	0.05	$1,115
Fall	$37	$60	0%	1,546	(241)	1,305	1.1%	874	4.5%	0.00	0.01	$114
Winter	$79	$92	0%	391	214	605	14.6%	656	10.3%	0.01	0.01	$255
Spring	$160	$242	2%	1,256	(1,401)	(145)	64.1%	1,168	1.9%	0.07	0.08	$446

Notes: All values in 2023$, quantity parameters consistent with 2023/24 Planning Year parameters, North/Central subregion Net CONE = $200/UCAP MW-D, South subregion Net CONE = $160/UCAP MW-D, supply adjustments are not meant to reflect specific predictions about the seasonal supply-demand balance but rather to test a range of possibilities.

Affidavit of Kathleen Spees

COUNTY OF HAYS)
)
STATE OF TEXAS)

Kathleen Spees, being duly sworn, deposes and states that she prepared the Prepared Direct Testimony of Kathleen Spees, and the statements contained therein are true and correct to the best of her knowledge and belief.

Kathleen Spees

Kathleen Spees

SUBSCRIBED AND SWORN BEFORE ME, this 29th day of September, 2023.

Edward Rico

Notary Public, State of Texas

My Commission Expires: 03/08/2025

NOTARY PUBLIC STATE OF TEXAS

Edward Rico

ID NUMBER
1226750-2
COMMISSION EXPIRES
March 8, 2025

Notarized online using audio-video communication

My County of Residence: Hays

Affidavit of Samuel A. Newell

COUNTY OF SUFFOLK)
)
STATE OF MASSACHUSETTS)

Sam Newell, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Sam Newell, and the statements contained therein are true and correct to the best of his knowledge and belief.

Samuel A. Newell

SUBSCRIBED AND SWORN BEFORE ME, this 28th day of September, 2023.

My Commission Expires: March 22, 2030

My County of Residence: Suffolk

JENNIFER M. OSSEN
Notary Public, Commonwealth of Massachusetts
My Commission Expires March 22, 2030

Affidavit of Linquan Bai

COUNTY OF SUFFOLK)
)
STATE OF MASSACHUSETTS)

Linquan Bai, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Linquan Bai and the statements contained therein are true and correct to the best of his knowledge and belief.

Lin Bai

Linquan Bai

SUBSCRIBED AND SWORN BEFORE ME, this 28th day of September, 2023.

My Commission Expires: March 22, 2030

My County of Residence: Suffolk

JENNIFER M. OSSEN
Notary Public, Commonwealth of Massachusetts
My Commission Expires March 22, 2030