Big Rivers
ELECTRIC CORPORATION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2020 THROUGH OCTOBER 31, 2022	)))))	**Case No. 2023-00013**

Responses to Commission Staff's Third Request for Information

dated November 1, 2023

FILED: November 16, 2023

BIG RIVERS ELECTRIC CORPORATION

AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2020 THROUGH OCTOBER 31, 2022
CASE NO. 2023-00013

VERIFICATION

I, Vicky L. Payne, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Vicky L. Payne

Vicky L. Payne

COMMONWEALTH OF KENTUCKY)
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Vicky L. Payne on this the 14th day of November, 2023.

Kathrine Boley

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

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VERIFICATION

I, Terry Wright, Jr., verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Terry Wright, Jr.

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COMMONWEALTH OF KENTUCKY)
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Terry Wright, Jr. on this the 14th day of November, 2023.

Kathrin Roley

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

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VERIFICATION

I, Christopher A. ("Chris") Warren, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Christopher Warren

Christopher A. "Chris" Warren

COMMONWEALTH OF KENTUCKY)
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Christopher A. ("Chris") Warren on this the 14th day of November, 2023.

Katherine Daley

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

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Item 1) ***Refer to BREC's response to Commission Staff's Second Request for Information (Staffs Second Request), Item 4. Explain BREC's plans for the PY25-26 winter season.***

Response) Please note that the Seasonal Accredited Capacity (SAC) volumes in Big Rivers' response to Commission Staff's Second Request for Information, Item 4, were Big Rivers' best estimates as of a specific point in time. These values could change during the course of a year, depending on generator performance, MISO Planning Reserve Margin Requirements, and the SAC Accreditation process. [redacted]

Witness) Terry Wright Jr.

BIG RIVERS ELECTRIC CORPORATION

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Item 2) ***Refer to BREC's response to Staffs Second Request, Item 5. Regarding Item 5c, the four items mentioned do not appear to have been included in the response. Provide the four items.***

Response) Please see the four attachments to this response, as identified in Big Rivers' response to Staff's Second Request, Item 5c.

Witness) Terry Wright Jr.

Market Redefinition: Accreditation Reform

Resource Adequacy Subcommittee

(RASC-2020-4, 2019-2)

July 11-12, 2023

Purpose & Key Takeaways

Purpose:

1. Share class level preliminary D-LOL results for today's resource mix
2. Discuss design details for proposed D-LOL approach
3. Discuss MISO's proposal to better align PRMR calculation accreditation approaches

Key Takeaways:

- MISO has published D-LOL results based on the current planning year assumptions
  - Additional work is underway to produce future year results in a consistent manner. MISO will share future results when available.
- MISO is moving away from a PRMR based on peak load and would set requirements based on periods with the greatest reliability risk observed in the LOLE model
- MISO is proposing a 3-year transition with step-changes in accreditation with the goal of implementing Direct-LOL after 3 years
- MISO will continue design discussions at the August RASC with a targeted filing in Oct-Nov

Direct-LOL Results

MISO is committed to developing forward looking Direct-LOL results and trends and share with stakeholders in the coming months

- MISO is also evaluating options to calculate D-LOL results for the expanded fleet (e.g., current fleet + higher solar penetration) and share indicative results later this year

- MISO plans to use the Regional Resource Assessment (RRA) to publish forward looking accreditation and planning reserve margin requirement estimates starting with the 2024 RRA

Seasonal Direct-LOL results by resource class will vary depending on input assumptions to the Loss of Load Expectation (LOLE) model and modeled resource mix

PY23-24	Summer - 2,695 hrs		Fall - 269 hrs		Winter - 215 hrs		Spring - 206 hrs	
Resource Class	UCAP	DLOL	UCAP	DLOL	UCAP	DLOL	UCAP	DLOL
Gas	91%	89%	89%	89%	84%	70%	88%	74%
Coal	92%	91%	91%	88%	90%	72%	89%	75%
Hydro	97%	97%	97%	99%	42%	68%	62%	70%
Nuclear	95%	91%	96%	86%	95%	87%	92%	80%
Pumped Storage	99%	98%	91%	97%	94%	57%	89%	75%
Solar	45%	37%	25%	27%	6%	1%	15%	17%
Wind	18%	12%	23%	15%	40%	14%	23%	18%
Storage	95%	94%	95%	94%	95%	94%	95%	95%
Run-of-River	100%	100%	100%	100%	100%	100%	100%	100%

Resource class results expected to change as LOLE modeling enhancements are made to better reflect reliability risks across the year and the changing fleet, e.g., storage results expected to decrease

UCAP = current accreditation methodology by resource type

Detailed Design

MISO has proposed an initial design for the application of Direct-LOL (Class Level Design)

Design Element	Initial Proposal	Other potential options
Hour Selection	Loss of Load (LOL) hours only	• Expand hours to include hours within a certain margin threshold (e.g. 3% margin)
Direct-LOL calculation	Straight average of all LOL hours	• Expected Unserved Energy (EUE) weighted
Resource Classes	Gas, Coal, Hydro, Nuclear, Pumped Storage, Solar, Wind, Storage, Run-of-River	• Location based

MISO suggests extending Schedule 53 to **all resources (except LMRs)** although some design elements may need to be modified (Unit Level Design)

Design Elements		Today under current Schedule 53	Proposed changes to Schedule 53
Hour Selection	Calculation of operating margin to identify RA hours	Online margin + offline margin with 12 hours or less lead time divided by RT load	No Change
	Top X% of tightest margin hours	Tier-1: all hours excluding tight hours in Tier-2 Tier-2: MaxGen hours supplemented with top 3% of tight margin hours per season	No Change
	Margin threshold	25%	No Change
	Seasons with no/ limited RA hours to meet 3% per season (65 hours)	Supplement deficient number of hours with Annual Average Offered Capacity (AAOC) over top 3% of tightest margin hours per year	Fill deficient hours with seasonal class DLOL % (Current UCAP during transition)
	Regionality (N+C/S) (tight margin and MaxGen hours)	Yes	No Change
	Leadtime for offline units (tight margin calc)	24 hours	No Change
Accreditation Calculation	Annual verses seasonal	4 season	No Change
	Tiered weighting	Tier-1 20%; Tier-2 80%	No Change
	Leadtime for offline units	24 hours	No Change
	Real-time offer considered	Tier-1 & Tier-2 Emergency Max	Real-time availability
	Adjustment Ratio	Multiply ISAC by ratio of thermal class UCAP to ISAC	Resource ISAC * (Class DLOL/Class ISAC) (Current UCAP during transition)
Planned Outage Exemption	Exemption removes hours from the Schedule 53 calculations	Yes, full out-of-service outages only with proposed three-level structure (none, Tier-1, Tier-2)	No Change

UCAP = Unforced Capacity ISAC = Intermediate Seasonal Accredited Capacity ELCC = Effective Load Carrying Capability

Hybrid Resources

MISO's exploration suggests advantages in accrediting co-located hybrid resources separately by fuel type, capped at the shared interconnection limit

Reasoning:

- Creating one accreditation class for hybrid resources is not meaningful given the countless combinations of resources that could make up a hybrid
- Creating different classes for each hybrid combination is unmanageable
- MISO's Market Design team has highlighted the advantages of separate co-located market participation over a single-offer hybrid participation path in the MSC* - visibility into each resource's performance during periods of need is another such advantage

Proposal:

- Component level data for co-located hybrid resources will be used to accredit each component within the corresponding resource class. The aggregate accredited value would be capped at the shared interconnection service limit.
- MISO allows single-offer hybrid resources to participate as Hybrid-DIR and does not currently require component resource level metering.** As part of accreditation reform, MISO proposes to require component level metering for both co-located and single-offer hybrid resources.

*Hybrid Resource Participation Model: Co-Located Market Participation , March 2023
** Component level metering currently required by ERCOT, NYISO, CAISO (renewable component), and SPP

Transition Proposal

The current proposed transition will allow enough time to adjust while preparing for the implementation of Direct-LOL approach in the future

	Thermal – Class Level	Thermal – Unit Level	Wind – Class Level	Wind – Unit Level	Solar/Storage – Class Level	Solar/Storage – Unit Level
Current State Planning Year 24-25	UCAP	Tier 1 and Tier 2 Hours	Average ELCC	Peak Load	Peak Load	Peak Load
Transition Planning Years 25 – 26, 26-27, 27-28	UCAP	Tier 1 and Tier 2 Hours	Average ELCC	Tier 1 and Tier 2 Hours	Peak Load	Tier 1 and Tier 2 Hours

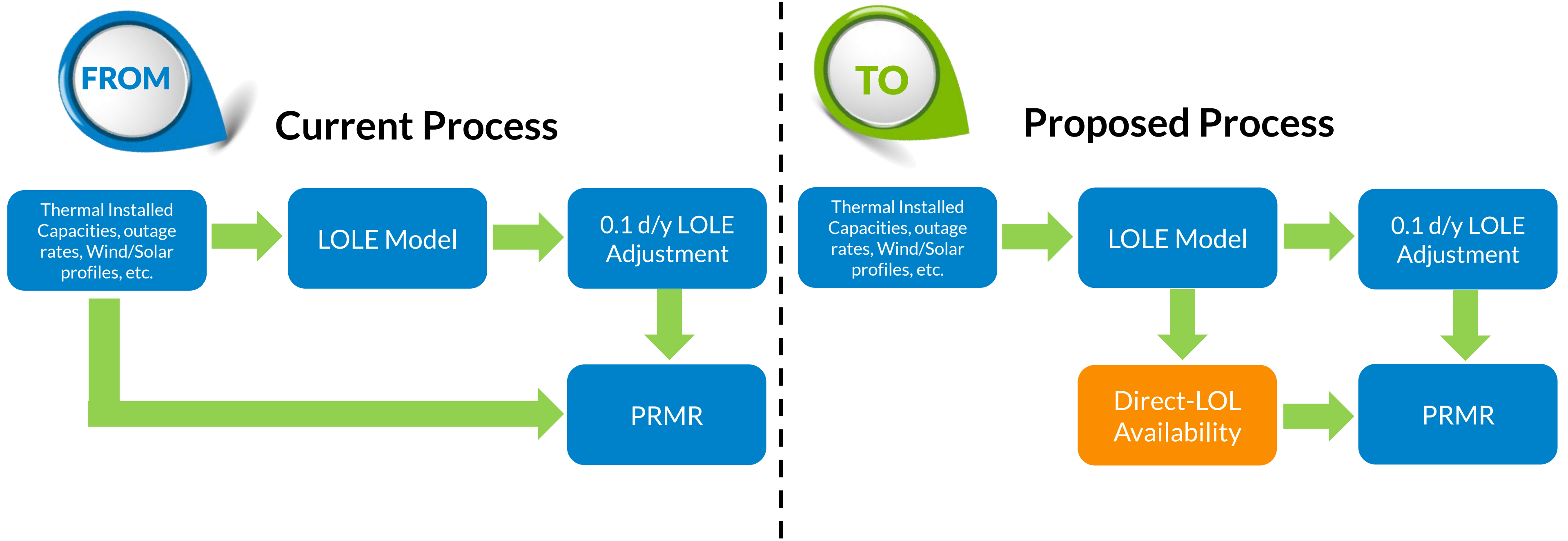
All Resources (except LMRs)

	Class Level	Unit Level
Future State Planning Year 28-29 & Beyond	DLOL	Tier 1 and Tier 2 Hours

***End State:** Consistent accreditation methodology for all resources with continued emphasis and improvements on the probabilistic modeling (i.e., generator capabilities, correlated outages, fuel supply limitations, severe weather).*

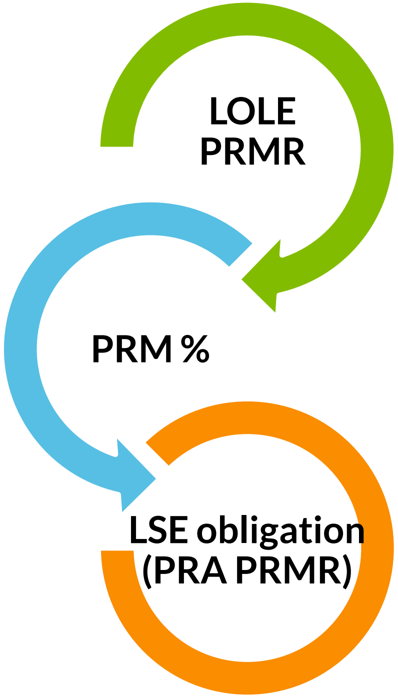
PRMR and Load Serving Entity (LSE) obligations

The current process utilizes Unforced Capacity (UCAP) as an input into the LOLE model and the PRMR calculation, while the proposed Direct-LOL methodology utilizes an output from the LOLE model for the PRMR calculation



UCAP: Unforced Capacity | LOLE: Loss of Load Expectation | LOL: Loss of Load

MISO's current process translates the requirement established in the LOLE study to the obligation in the Planning Resource Auction (PRA)



MISO determines the PRMR through completion of the seasonal Loss of Load Expectation (LOLE) study. The PRMR is equal to the total capacity needed to meet a LOLE of 1 day in ten years.

PRM % is calculated by subtracting the modeled MISO-system coincident peak demand from the PRMR and then dividing by the modeled MISO-system coincident peak demand.

LSE Coincident Peak Forecast multiplied by Transmission Loss % and the PRM %.

PRMR: Planning Reserve Margin Requirement | PRM: Planning Reserve Margin | LSE: Load Serving Entity

Seasonal DLOL PRMR results* are dependent on modeling assumptions

Resource Class Accredited Capacity (MW)	PY 23/24 Summer	PY 23/24 Fall	PY 23/24 Winter	PY 23/24 Spring	Formula Key
Thermal	112,625	110,506	92,398	94,522	[A]
Run-of-River	966	966	966	966	[B]
Wind	3,076	3,816	3,992	4,966	[C]
Solar	1,734	1,689	99	2,041	[D]
Storage	28	28	54	55	[E]
BTMG	4,196	4,218	4,163	4,240	[F]
Demand Response	7,397	7,041	5,388	6,280	[G]
Firm External Support	1,707	1,714	1,857	1,778	[H]
Adj. {1d in 10yr}	(4,000)	(10,000)	(6,200)	(12,750)	[I]
PRMR	**127,729**	**119,978**	**102,717**	**102,098**	[J]= sum of [A] through [I]

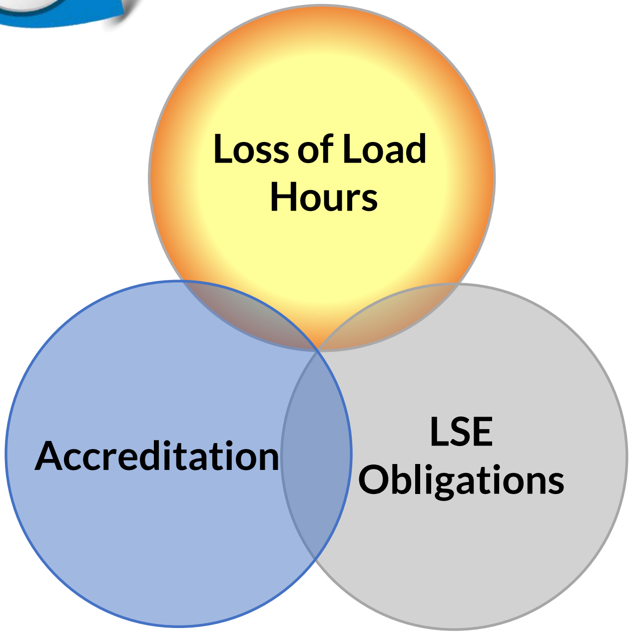
PRMR expected to increase as LOLE modeling enhancements are made to better reflect risk

*New version of SERVM utilized to produce results

BTMG, Demand Response and Firm External Support MW are represented as current UCAP

Load Serving Entity (LSE) obligations should be based on when the risk occurs, which are the hours that will establish resource accreditation

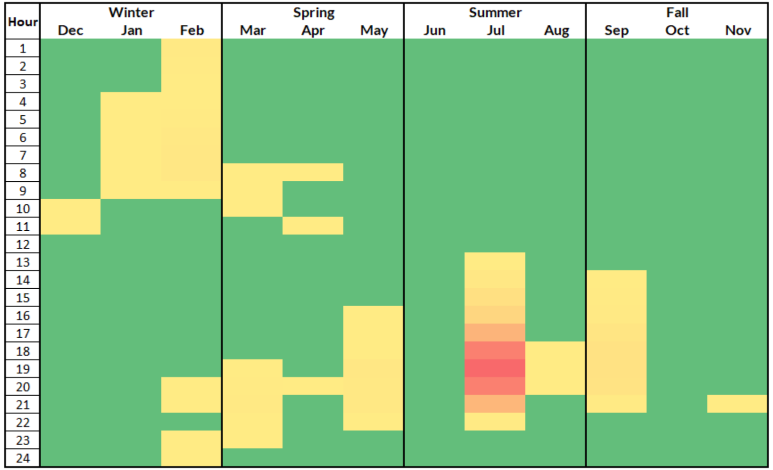
FROM



TO

Improved Alignment

Aligning resource availability with hours of greatest risk (LOL) underscores a need for a shift in how LSE obligations are established to ensure requirements are commensurate with the contribution to risk



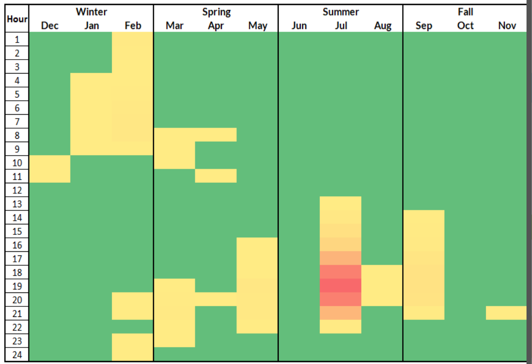
MISO

The planned reforms better leverage the risk model, with future modeling improvements naturally driving more efficiency in the outcomes

Inputs

RISK MODEL

LOLE



Future Enhancements
- Fuel Limitations
- Correlated outages
- Unit modeling (ramp, notification time, etc.)
- Extreme weather

Accreditation

Current
- Thermal units - UCAP and performance during risky hours
- Wind- Average ELCC

Future
- Availability during highest risk hours in the probabilistic models
- Past performance for unit level

Planning Reserve Margin Requirement

Current
- Requirement based on peak

Future
- Based on risky hours

Translation to PRA

Current
- Percentage based

Future
- MW based, TBD

***KEY:** ELCC = Effective Load Carrying Capability*
LOLE = Loss of Load Expectation

MISO

Next Steps

Next Steps:

- Continue the discussion related to outstanding design elements, PRMR and LSE obligations, and transition to the Direct-LOL method

- A FERC filing for Resource Adequacy accreditation reforms is targeted for Q4 2023

Stakeholder Feedback Request

- MISO requests written feedback by July 28, 2023, on the following:
  - DLOL results by resource class
  - Initial design proposal
  - Co-located and single-offer hybrid proposal
  - Planning Reserve Margin Requirement and LSE obligations

- Issue Tracking ID#: RASC2019-2, RASC2020-4

- Feedback requests and responses are managed through the Feedback Tool on the MISO website: https://www.misoenergy.org/stakeholder-engagement/stakeholder-feedback/

Contact Information

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Appendix

Resource Accreditation: The capacity value of a resource based on its contribution to system reliability during periods of highest risk

Why does MISO accredit resources?

- To ensure seasonal Reserve Requirements are met
- To inform long-term investment and retirement decisions by accurately representing the capacity value of a resource in the prompt year
- To reward resources for operating practices and attributes that serve the greatest system need

PREVIOUSLY PRESENTED

Reminder of the problem statement and scope developed by MISO and stakeholders to guide this effort:

Problem Statement

Resource accreditation should reflect the availability of resources when they are most needed. Significant growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, are shifting risk profiles in highly dynamic ways with implications to Resource Adequacy and planning. MISO's existing accreditation methods for non-thermal resources require further evaluation to ensure that the accredited capacity value reflects the capability and availability of the resource during the periods of highest reliability risk.

Scope

Revisit the established accreditation practices for non-thermal resources with a priority focus on those with the greatest reliability impact in the near-term.

MISO's recommendation for accrediting all resources (except Load Modifying Resources) measures a resource's availability when reliability risk is the greatest

Class Level – Size of Pie

Direct-LOL Method

Availability within LOLE model during Loss of Load hours

- Accounts for correlated risks (e.g., low wind, simultaneous forced outages)
- Include more history to account for infrequent risks without penalizing individual resources (e.g., extreme weather)
- **Direct alignment between availability, risk & reliability requirements**

Unit Level – Allocation of Pie

Schedule 53 Method

Based on performance during MISO's recent historical high-risk hours

- Create incentives for individual resources to perform and improve performance over time when those resources are needed the most
- **Accounts for operational, realized risk**

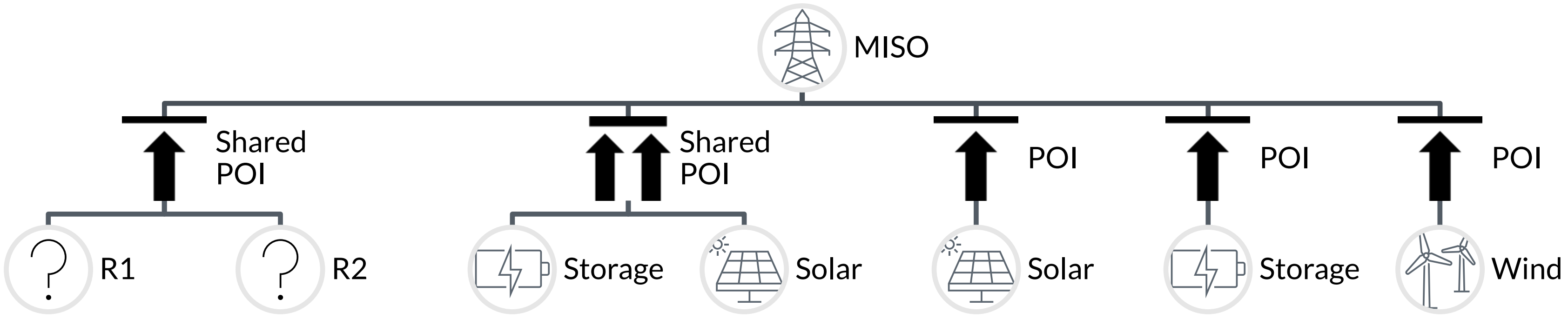
PREVIOUSLY PRESENTED

MISO

Installed Capacities by Resource Class

ICAP (MW)	Spring	Summer	Fall	Winter
Gas	64,821	63,823	64,065	67,708
Coal	44,299	43,990	44,004	44,280
Hydro	2,179	2,175	2,174	2,179
Nuclear	12,064	12,037	12,052	12,212
Pumped Storage	2,649	2,565	2,565	2,451
Solar	12,159	4,738	6,337	11,080
Wind	28,260	25,632	25,944	28,260
Battery	58	30	30	58
Run of River	966	966	966	966

Example: Hybrid and Co-located Resources



Single-offer Hybrid participation limits MISO visibility into capabilities of component Resources

LOLE Modeling and Accreditation Workshop

September 22, 2023

Case No. 2023-00013
Attachment 2 to Response to PSC 3-2

Purpose & Key Takeaways

Purpose: Provide additional education on the LOLE model and process to establish Planning Reserve Margin Requirements

Key Takeaways:

- Loss of Load Expectation analysis is largely driven by load and generation uncertainty
- MISO uses the Strategic Energy Risk Valuation Model (SERVM) Software for LOLE analysis
- Direct-LOL (DLOL) availability is an output from the LOLE model compared to the current UCAP approach, which is established several different ways (Slide 31)
- LOLE modeling will continue to evolve to better capture reliability risks throughout the year

What is LOLE?

Loss of Load Expectation (LOLE) Definition

LOLE is the measure of how often, on average, the available generation capacity is likely to fall short of the load demand

Loss of Load Probability (LOLP) is the probability in a given hour	Sum of the Daily Peak LOLP values is an expectation (LOLE)	Sum of all LOLP values is called Loss of Load Hours (LOLH)

LOLE is used to study Generation (Resource) Adequacy

Generally considered to be the existence of sufficient resources, within a system, to satisfy consumer demand. A product of unit availability, "perfect storm." The study of low probability, high impact events

MISO calculates three probabilistic risk metrics as part of the LOLE study process

- Loss-of-Load Expectation (LOLE): Measures ***frequency*** of load shed events
- Loss-of-Load Hours (LOLH): Measures ***duration*** of load shed events
- Expected Unserved Energy (EUE): Measures ***magnitude*** of load shed events

1-day in 10-years LOLE Criteria

MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:

<1-day in 10-years

NERC Standard BAL-502-RF-03

Calculate a planning reserve margin that will result in the sum of the probabilities for Loss-of-Load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1. (This is comparable to a "one day in 10 year" criterion)

LOLE Modeling Inputs

LOLE Model Inputs Include:

Generation Resources

- Operating Parameters
- Unit Forced Outage Rates
- Planned Maintenance Schedules & Rates
- Dispatch Limits for DR and Interruptible Load

Study System

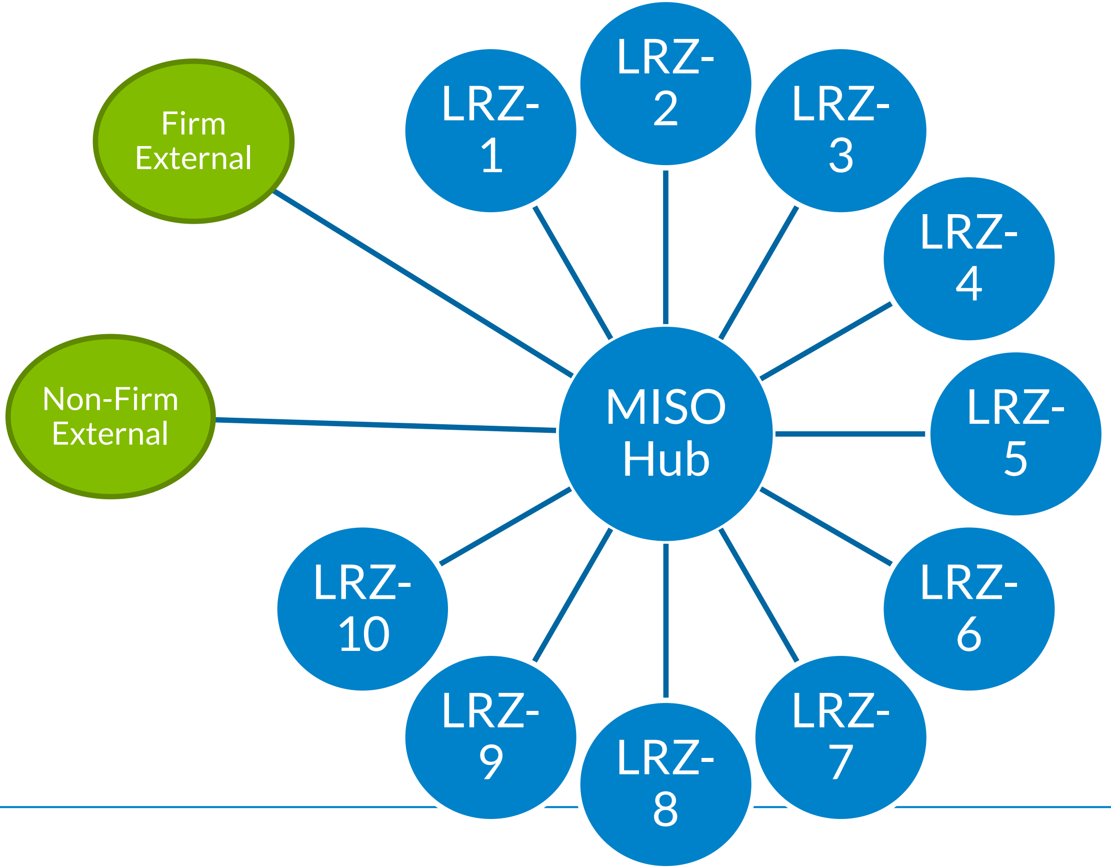
- Zone & Pool definition
- External Tie Limits
- External System Model

Load

- Demand and Energy Forecast
- Load Shape/Profile
- Load Uncertainty

LOLE Model Inputs

MISO System LOLE Model



MISO uses the Strategic Energy Risk Valuation Model (SERVM) Software

Managed by Astrapé Consulting

Originated within Southern Company back in the early 1980's

Uses a sequential Monte Carlo simulation

- Steps through time chronologically and randomly drawing unit availability
- Replicating simulation with different sets of random events until statistical convergence is obtained

SERVM resource adequacy metrics consider

- Wide Variation of Load Shapes
- Growth Uncertainty
- Unit Performance

Utilizes a SQL Server database

Loss of Load Expectation analysis is largely driven by two factors, load uncertainty and generation uncertainty

- Accurately capturing uncertainty is crucial to LOLE analysis
- Load Uncertainty
  - Load Shape
  - Weather Uncertainty
  - Economic Uncertainty
- Generation Uncertainty
  - Forced Outages
  - Planned Outages
  - Weather

Load Modeling

Load Modeling Framework

- Historic weather years are modeled to capture load uncertainty including:
  - Variance in peak demand
  - Variance in load shape
- Results in more diverse and comprehensive load modeling
  - More accurate shoulder and non-peak load variance and uncertainty
- Neural-Net software is used to “train” data resulting in 30 unique load profiles based on 30 historic weather years
  - Allows the model to evaluate the risk that could materialize in the upcoming Planning Year if similar weather patterns historically observed were to be experienced again
  - i.e., Planning Year 2023-24 risk if 2012 weather were to materialize

Load Training Process

Historical load and weather data formatting

5-year load growth adjustment

Neural network training

Neural network predicting

Extreme temperature adjustment

Load forecast adjustment

Load Forecast Adjustment

- Average monthly load of the predicted load shapes adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for study year

- Ratio of 1st years Non-Coincident Peak Forecast to Zonal Coincident Peak Forecast applied to future years Non-Coincident Peak Forecast

Economic Load Uncertainty

- Projected and actual GDP growth rates used for Economic Uncertainty
  - Use Congressional Budget Office (CBO) projections for historic GDP growth
  - Compare with the actual GDP growth taken from the Bureau of Economic Analysis
  - Translate the GDP forecast error into electric utility forecast error by multiplying by a scalar
    - Rate at which electric load grows in comparison to GDP
  - Calculate the standard deviation of forecast error
  - Using the standard deviation, create a normal distribution of forecast error

Economic Load Uncertainty

- The 2023/24 PY LOLE study showed that the economic load uncertainty modeling resulted in a 0.05 percentage point increase to the MISO Planning Reserve Margin

Load Forecast Error (LFE) Levels				
-2.0%	-1.0%	0.0%	1.0%	2.0%

Standard Deviation in LFE
0.90%

Probability assigned to each LFE				
4.8%	24.1%	42.1%	24.1%	4.8%

SERVM Simulation Framework

30 Weather Years (equal probability)	x	5 Economic Uncertainties (Normal Distribution)	=	150 Load Scenarios
150 Load Scenarios	x	300 unit outage draws*	=	45,000 8760 hourly simulations

**Number of unit outage draws used only as an example and are not fixed*

Generation Modeling

Input Sources

- Generation
  - March 2023 Commercial Model: Base Model
  - 2023/24 Planning Resource Auction (PRA): Eligible Capacity
  - PowerGADS: Unit Statistics
  - Attachment Y: Retirements
  - Generator Interconnection Queue: New Units
  - External Areas Capacity Markets/Contracts: MISO Exports

- External
  - 2023/24 PRA : Firm External Imports
  - Probabilistic distribution of Non-Firm Imports based on historic NSI

GADS Data

- GADS (Generator Availability Data System) is the primary data source for historical generator outages
- GADS reports out:
  - Forced Outage Rate statistics
  - Planned Maintenance statistics
  - Net Dependable Capacity (NDC) for monthly capacity profiles
- If a unit has less than 3 months of seasonal data, it gets assigned the class average forced outage rate and maintenance period corresponding to its resource type, assuming there are at least 30 units reporting outage data to GADS for its class – otherwise, the MISO-wide weighted class average EFORd is used for resource classes represented in GADS with less than 30 active units

Seasonal Forced Outage Rates

- All thermal resources in SERVM are modeled with a distribution of Time-to-Fail (TTF) and Time-to-Repair (TTR) values which are determined from their actual Forced Outage Rates
- For any given unit, SERVM will randomly draw a TTF value and begin counting down until it reaches zero at which point the unit becomes unavailable
    - A TTR value will then be randomly drawn and begin counting down again until it reaches zero at which point the unit will come back online
- SERVM will increase the number of forced outages during extreme cold temperatures to reflect coincident outages observed in real-time during extreme weather events

Renewable Resource Modeling

- Wind and solar resources are modeled with hourly output profiles reflecting their intermittent nature
  - Each of the 30 weather years modeled have a unique hourly output for wind and solar units to align with the load profiles
  - Solar and wind profiles are zonal-specific to reflect renewable generation diversity by region
- Other intermittent resources (run of river hydro, biomass, etc.) are modeled at their UCAP value

Planned Outage Modeling

- SERVM utilizes a flexible Planned Outage modeling approach to account for resources' routine maintenance
  - Unlike Forced Outages, Planned Outages are not randomly drawn
- 80% of Planned Outages are scheduled by optimizing around periods with the potential for high demand across all 30 load shapes (i.e., max of daily net peak demand)
  - This minimizes outages in summer and maximizes outages in the shoulder seasons which aligns with actual planned outage behavior
- The remaining 20% of Planned Outages are scheduled optimally for each of 30 load shapes to reflect flexibility to reschedule outages as needed

Cold Weather Outages

- Astrapé performed an analysis that showed as the temperatures decreased, the average MWs of forced outages for coal and gas increases
- A MW/degree relationship was developed and modeled so that at each temperature, there is a specific MW amount of incremental cold weather outages captured for each zone and technology type
- The incremental cold outages are not assigned to a particular resource but rather represent the aggregate impact on the system for the coal and gas groups analyzed

External Support Modeling

Firm and Non-Firm Imports

- Firm imports from the most recent PRA are included in the LOLE analysis and are modeled as resources
- Non-firm imports are modeled as a probabilistic distribution based on historic imports from the most recent 3 Planning Years
  - As the model steps through the simulated hours, it randomly draws from this distribution of imports to serve the demand
  - Non-firm imports reduce the PRM but relying on neighboring regions to serve some of MISO's demand

SERVM incorporates probabilistic distributions of Non-Firm Support for the 2024/25 PY LOLE Study

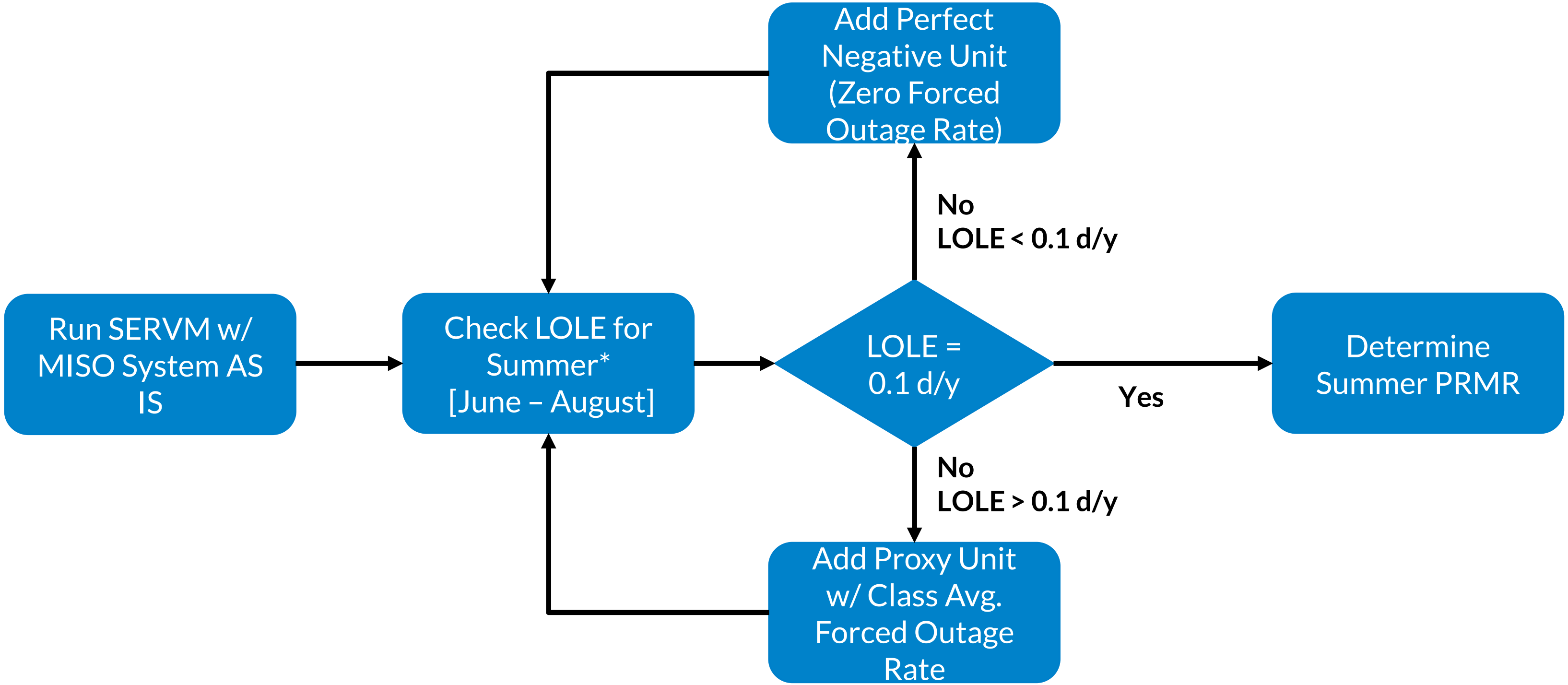
- Historic non-firm imports during historic RA hours are used to create a probabilistic distribution of Non-Firm Support
  - This is done for each of the 4 seasons to capture seasonal variability

- As SERVM steps through the hourly Monte Carlo simulations, the model will randomly draw import values from the seasonal distributions shown below

Season	p5	p10	p25	p50	p75	p90	p95
Summer	1,138	1,440	2,959	4,260	5,198	5,921	6,520
Fall	525	903	1,749	2,601	3,632	4,935	5,748
Winter	9	288	1,223	3,292	5,785	8,097	9,179
Spring	1,384	1,626	2,283	3,717	4,987	6,221	6,497

Capacity Adjustment and PRMR Calculation

Capacity Adjustment Flow Chart



*Each season is determined in the same manner although the non-summer seasons have different LOLE criteria based on seasonal risk distribution and the process changes slightly if risk shows up in the As Is LOLE run

Current determination of Planning Reserve Margin Requirement (PRMR)

- PRMR is established by summing all the capacity in the model (resources and adjustment MW) to reach the reliability criterion
  - PRMR = UCAP MW + Adjustment MW
- Each resource class uses a different methodology to establish capacity for the requirement calculation

Resource Type	Method to establish capacity for PRMR*
Thermal/BTMG	GVTC * (1-EFORd)
Wind/Solar	Effective Load Carrying Capability (ELCC)
Run-of-River/Biomass	Hourly output during peak hours
Demand Response	Seasonal capability and # of calls
Storage	GVTC * 95% or hourly output during peak hours
External Resources	Firm external seasonal capability

MISO Planning Reserve Margin (PRM)	PY 23/24 Summer	Formula Key
MISO System Peak Demand (MW)	123,711	[A]
Thermal (MW)	114,415	[B]
Run-of-River (MW)	966	[C]
Wind (MW)	4,639	[D]
Solar (MW)	2,151	[E]
Storage (MW)	28	[F]
BTMG (MW)	4,196	[G]
Demand Response (MW)	7,397	[H]
Firm External Support (MW)	1,707	[I]
Adj. {1d in 10yr} (MW)	(2,650)	[J]
PRMR (MW)	132,849	[K]=sum [B] through [J]
MISO PRM%	7.4%	[L]=([K]-[A])/[A]

*July for Summer, September for Fall, January for Winter and May for Spring

Reference Materials

- Past LOLE 101 Trainings
- Loss of Load Expectation Report
- Wind Capacity Report
- Loss of Load Expectation Working Group (LOLEWG)
- Supplemental LOLE Materials
- MISO Resource Adequacy Page
- BPM 011 - Resource Adequacy
- MISO Tariff: Module E-1
- NERC Standard BAL-502-RF-03

Resource Accreditation Reform

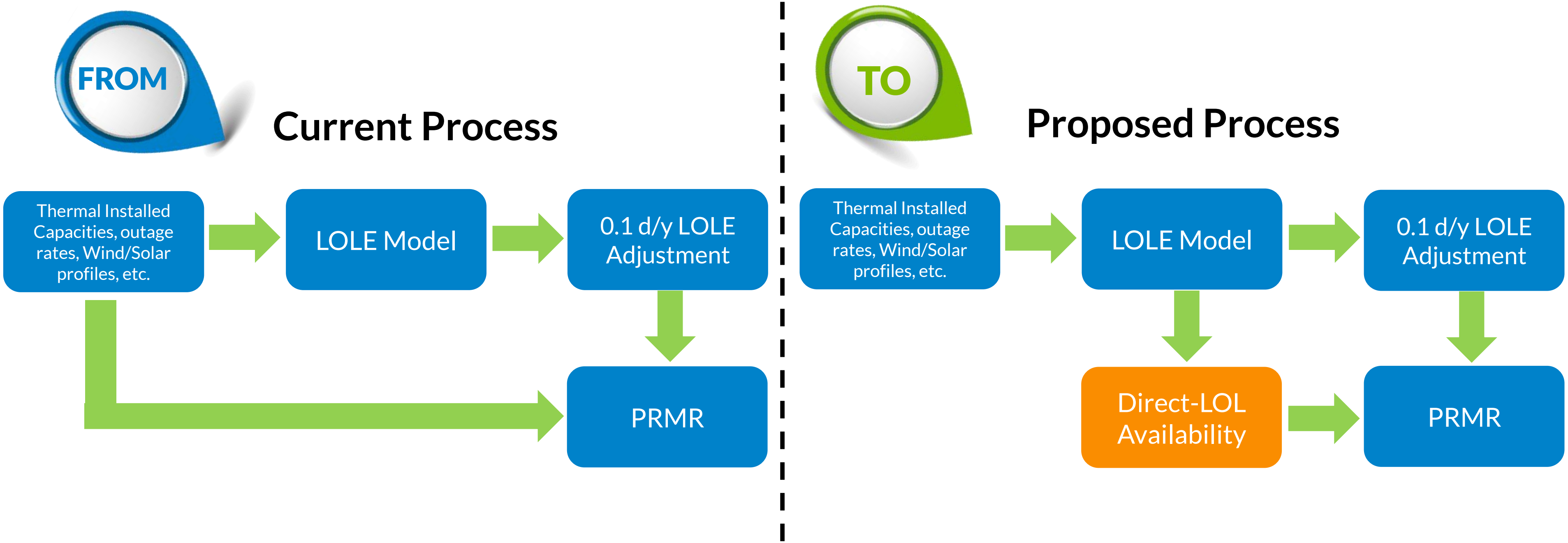
Future determination of Planning Reserve Margin Requirement (PRMR)

- PRMR will continue to be established by summing all the capacity in the model and adjustment MW to reach reliability criterion
- However, each resource class will use the Direct-LOL (DLOL) methodology to establish capacity for the requirement calculation
  - PRMR = DLOL MW + Adjustment MW

Resource Type	Method to establish capacity for PRMR*
Gas, Coal, Hydro, Nuclear, Pumped Storage, Solar, Wind, Storage, Run-of-River, Biomass	Availability during loss of load hours (DLOL)
Demand Response	Seasonal capability and # of calls (ongoing discussion at the RASC for LMR accreditation)
BTMG	GVTC * (1 – seasonal EFORd) (ongoing discussion at the RASC for LMR accreditation)
External Resources	Firm external seasonal capability

*July for Summer, September for Fall, January for Winter and May for Spring

The current process utilizes Unforced Capacity (UCAP) as an input into the LOLE model and the PRMR calculation, while the proposed Direct-LOL methodology utilizes an output from the LOLE model for the PRMR calculation



UCAP: Unforced Capacity | LOLE: Loss of Load Expectation | LOL: Loss of Load

Seasonal Direct-LOL results* by resource class will vary depending on input assumptions to the Loss of Load Expectation (LOLE) model and modeled resource mix

PY23-24 Resource Class	Summer - 2,703 hrs		Fall - 265 hrs		Winter - 201 hrs		Spring - 240 hrs	
	UCAP	DLOL	UCAP	DLOL	UCAP	DLOL	UCAP	DLOL
Gas	91%	89%	89%	88%	84%	70%	88%	72%
Coal	92%	91%	91%	87%	90%	72%	89%	74%
Hydro	97%	97%	97%	99%	42%	69%	62%	74%
Nuclear	95%	90%	96%	83%	95%	84%	92%	77%
Pumped Storage	99%	98%	91%	98%	94%	47%	89%	70%
Solar	45%	36%	25%	28%	6%	0%	15%	15%
Wind	18%	11%	23%	15%	40%	13%	23%	16%
Storage	95%	93%	95%	90%	95%	90%	95%	97%
Run-of-River	100%	100%	100%	100%	100%	100%	100%	100%

Resource class results expected to change as LOLE modeling enhancements are made to better reflect reliability risks across the year and the changing fleet, e.g., storage results expected to decrease

UCAP = current accreditation methodology by resource type

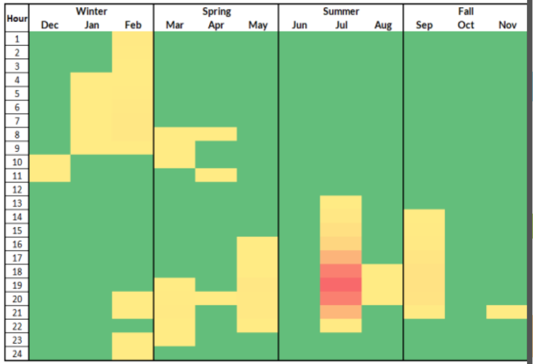
*Results have shifted slightly from the August 2023 RASC due to weighting of Load Forecast Error

The planned reforms better leverage the risk model, with future modeling improvements naturally driving more efficiency in the outcomes

Inputs

RISK MODEL

LOLE



Future Enhancements

- Fuel Limitations
- Correlated outages
- Unit modeling (ramp, notification time, etc.)
- Extreme weather

Accreditation

Current

- Thermal units - UCAP and performance during risky hours
- Wind- Average ELCC

Future

- Availability during highest risk hours in the probabilistic models
- Past performance for unit level

Planning Reserve Margin Requirement

Current

- Requirement based on peak

Future

- Based on risky hours

Translation to PRA

Current

- Percentage based

Future

- MW based, TBD

***KEY:** ELCC = Effective Load Carrying Capability*
LOLE = Loss of Load Expectation

MISO

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Reliability-Based Demand Curves

Conceptual Design White Paper

Version 1.0 – Draft

September 2023

misoenergy.org

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Purpose Statement

This paper provides a primer for the Reliability-Based Demand Curve (RBDC) conceptual design currently under discussion in MISO's Resource Adequacy Subcommittee (RASC). The document helps compile months of stakeholder discussions and captures MISO's proposed RBDC design and rationale for several of those design elements.

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Executive Summary

The MISO region has historically experienced significant reserves that are more than required reserve margins. Such excess reserves are rapidly diminishing, as evidenced by the results of the 2022-2023 PRA and recent OMS/MISO surveys. As a result of these changing circumstances and given the ongoing rapid changes in the nature of the resource fleet, there is increased need for changes to MISO's Resource Adequacy construct, specifically to address the limitations associated with the use of a vertical demand curve to clear the PRA.

The challenges MISO faces in its current Resource Adequacy construct are exacerbated by using a vertical demand curve in the PRA. Specifically, a vertical demand curve presents the following challenges:

- **Price Ineffectiveness:** A vertical demand curve establishes a price for capacity that does not value the reliability benefits of additional capacity. This can result in pricing inefficiencies where the actual supply-demand equilibrium isn't accurately represented, potentially causing capacity to be either overpriced or underpriced. This scenario does not effectively encourage optimal resource distribution.
- **Inadequate Price Signals:** A vertical demand curve offers restricted insights into capacity market fundamentals. It fails to communicate the extent (magnitude) of capacity shortfalls or surpluses. This complicates the ability of market participants to make well-informed choices regarding investments in new capacity or the potential retirement of existing assets.
- **Lack of Investment Incentives:** The price ineffectiveness and inadequate price signals could fail to provide the necessary financial stimulus for attracting new capacity investments. When the price remains relatively low/high irrespective of the length of resource surpluses/shortages, potential investors may exhibit reluctance to invest funds in constructing new capacity resources. This effect is amplified when uncertainties related to demand growth and market conditions are prevalent.
- **Resource Overbuilding or Underbuilding:** The use of a vertical demand curve fails to promote efficient resource planning. It could trigger excessive capacity expansion if prices remain consistently high due to a lack of price responsiveness, potentially burdening consumers with avoidable costs. Conversely, persistently low prices may result in insufficient capacity development, increasing the potential for supply shortages and related reliability risks.
- **Diminished Reliability:** A demand curve that doesn't accurately reflect additional reliability benefits with additional capacity procurement during peak demand periods could potentially result in a shortage of resources available to meet demand in future planning periods. This increases the risk of reliability issues, including potential blackouts during times of high demand.

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More recent events highlight the need to transition to a RBDC in MISO's Resource Adequacy construct. Declining reserve margins and the 2022-2023 PRA shortfall circumstances illuminate the critical role that MISO's Resource Adequacy construct must play in supporting well-informed oversight and planning decisions for all local and state authorities and market participants.

Market participants, regulated utilities, and regulatory authorities have reacted with decisions to expedite retirements, defer investments, and rely more heavily on the PRA for residual capacity needs. These rational decisions are being made due to artificially low-capacity prices created by the currently vertical demand curve construct. The inefficient capacity pricing signals sent during recent PRAs did not adequately signal that market participants and regulators should focus on increasing capacity supplies. More efficient pricing signals provided through a sloped demand curve would have given Load Serving Entities (LSEs) and capacity sellers the timely information needed to predict and prevent the capacity shortfall.

Overall, state and local regulatory authorities, integrated utilities, municipalities, and cooperatives will continue to have ultimate responsibility to ensure resource adequacy for MISO consumers. However, recent market results illustrate the critical role that the Resource Adequacy construct must play to properly inform decisions. To ensure resource adequacy for consumers, the role of efficient PRA pricing signals is even more essential given the lack of regulatory cost recovery for many of the necessary resources. A RBDC will contribute to providing the required pricing signal.

Developing demand curves based on marginal value of reliability is critical to improve market efficiency. The most economically rational demand curve design is a sloped curve that reflects the marginal contribution of incremental capacity to reliability and explicitly ties capacity prices to reliability value. Implementing a RBDC in MISO's Resource Adequacy construct will help address these challenges by allowing: (i) PRA clearing prices to properly value incremental capacity, recognizing that additional capacity above the 0.1 Loss of Load Expectation (LOLE) per year standard has additional reliability value; (ii) capacity prices to better support market participants' investment, retirement and replacement decisions; and (iii) the PRA to clear at more economically efficient outcomes, reflecting an appropriate price of capacity.

MISO's proposed RBDC construct is based on three fundamental tenets:

1) **Reliability principle.** Maximize alignment of market requirements with system reliability requirements by establishing a RBDC that properly values capacity.
2) **Long run sustainability principle.** The new construct should create an outcome that, over time, allows a market participant participating in the PRA the opportunity (but not the guarantee) to recover costs of building and operating an

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asset in excess of rents achieved from energy and operating reserve market participation.

3) **Cost-effective principle.** The purpose of the RBDC framework is to formulate demand curves based on reliability that avoid promoting excessive infrastructure development, prevent capacity shortfalls, and ensure optimal cost efficiency for consumers.

Key elements of MISOs proposed RBDC include:

- System-Wide and Sub-Regional Demand Curves
- Incorporation of Net Cost of New Entry and the Marginal Reliability Impact resulting from MISO's Loss of Load modeling that together determines the value of capacity
- An RBDC Opt-Out provision for states that choose to take responsibility for resource adequacy instead of participating in the PRA with the RBDC

This document briefly reviews MISO's Resource Adequacy principles, provides an overview of RBDC design, and provides a detailed explanation of MISO's proposed methodology for various RBDC design elements.

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1 Introduction

The dynamic evolution of the electricity sector—propelled by a changing resource mix & lower reserve margin, the increasing frequency of extreme weather events, and the rapid advancement of electrification—is creating new and shifting reliability needs in the MISO footprint. This transformation of load and risk amplifies the importance and complexities of procuring sufficient capacity to meet reliability needs through the PRA.

To address these challenges, MISO, in consultation with its members and states, developed the Reliability Imperative to address the urgent and complex challenges to electric system reliability in the MISO region. MISO's response to the Reliability Imperative consists of a host of interconnected initiatives that aim to address the region's challenges in a comprehensive and prioritized fashion. These initiatives are organized into four pillars: Market Redefinition, Operations of the Future, Transmission Evolution, and System Enhancements. Resource Adequacy reform, including RBDC design, is a key component of the Market Redefinition pillar.

The purpose of this white paper is to discuss MISO's RBDC design proposed as a part of Resource Adequacy reform, the issues identified, the options evaluated, and recommendations related to implementing the proposed RBDC in the MISO region.

Resource adequacy is the ability to serve electricity demand and provide enough excess supply to achieve a threshold level of grid reliability. In the MISO footprint, the responsibility for achieving resource adequacy rests with LSEs overseen by states with applicable jurisdiction. MISO facilitates these efforts by administering tariff-defined Resource Adequacy Requirements and the PRA, which LSEs use to demonstrate their ability to serve peak demand and provide a sufficient margin of excess supply.

MISO's market design guiding principles are an important guide to evaluating and developing market enhancements and have been used as a foundation for the transition to a sloped demand curve in the PRA. With these principles as a guide, MISO has determined that the implementation of a RBDC in the PRA will support market participants in making operational, retirement, and investment decisions, as well as maximize alignment of market requirements with system reliability requirements.

MISO Market Design Guiding Principles:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity.
- Facilitate non-discriminatory market participation regardless of resource type, business model, sector, or location.
- Develop transparent market prices reflective of marginal system cost, and cost allocation reflective of cost-causation and service beneficiaries.

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- Support market participants in making efficient operational and investment decisions.
- Maximize alignment of market requirements with system reliability requirements.

1.1 Issue

MISO's approach to ensuring resource adequacy, carried out through the PRA for each Planning Year, has historically used a vertical demand curve. This method, in place since 2013-2014, determines the capacity price in the MISO region. The initial design of MISO's PRA was established with a vertical demand curve due to the prevailing view among some Relevant Electric Retail Rate Authorities (RERRAs) and utilities that a sloped demand curve would not be beneficial within the MISO region's context. Most of the MISO region has traditionally relied on RERRAs and utility-planning processes to address resource adequacy requirements. During the inception of the PRA design, there was a prevailing belief that a sloping demand curve might only be necessary for states with retail competition that heavily depend on merchant power investments. However, market participants have increased reliance on the PRA to guide their decision-making and manage specific portions of their portfolios and commitments.

The MISO region has historically experienced significant reserves that are more than required reserve margins. Such excess reserves are rapidly diminishing, as evidenced by the results of the 2022-2023 PRA and recent OMS/MISO surveys.[1] As a result of these changing circumstances, and given the ongoing rapid changes in the nature of the resource fleet, there is increased need for changes to MISO’s Resource Adequacy construct, specifically to address the limitations associated with the use of a vertical demand curve to clear the PRA.

A vertical demand curve sets the price close to zero when the market has any surplus of capacity and excessively high prices if there is any shortfall. Low prices produced over most of the PRA’s history did not recognize the value of incremental capacity. In turn, these low prices are 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 persistently low prices. Such low prices have encouraged some state policymakers, public power entities, utility planners, and competitive retailers to increase reliance on the PRA for a portion of their capacity purchases and defer their own investment options. Rational responses to low market prices, combined with imperfect information on the exact timing of the systems-wide capacity shortfall, contributed to the capacity shortage and price spikes at CONE in MISO North/Central Sub-Regions in the recent PRA for 2022-2023.

[1] 2023 OMS-MISO Survey Results Workshop - July 14, 2023 (misoenergy.org)

The 2022-2023 PRA results are evidence of the risks identified in the MISO Reliability Imperative as related to resource adequacy. MISO's 2022-2023 PRA resulted in a capacity shortfall against the 0.1 LOLE per year reliability standard for MISO. Additionally, MISO's Independent Market Monitor (IMM) has been recommending implementing a sloping demand curve in the PRA since 2010. As stated by the IMM in its 2022 State of the Market Report for the MISO Electricity Markets, a RBDC that is sloped would more accurately reflect the reliability value of capacity that is more or less than the 0.1 LOLE requirement.[2] Due to these factors, MISO began an exploration of potential enhancements to the current PRA design, including the RBDC, with the support of MISO's IMM and OMS.

MISO's current vertical demand curve construct in the PRA falls short on at least three of the MISO market guiding principles:

1) PRA clearing prices fail to properly value incremental capacity. This leads to uneconomic retirements when PRA results are even slightly more than reserve margins.
2) The current PRA does not facilitate the investment and retirement decisions necessary to maintain the resources needed to meet system reliability.
3) The current PRA is inefficient at accurately pricing capacity. The residual nature of the current PRA makes it highly volatile.

The challenges MISO is facing in the current Resource Adequacy construct are exacerbated by using the vertical demand curve in the PRA. Specifically, a vertical demand curve faces the following challenges:

- **Price Ineffectiveness:** A vertical demand curve establishes a price for capacity that does not value the reliability benefits of additional capacity. This can result in pricing inefficiencies where the actual supply-demand equilibrium isn't accurately represented, potentially causing capacity to be either overpriced or underpriced which will not effectively encourage optimal resource distribution.
- **Inadequate Price Signals:** A vertical demand curve offers restricted insights into capacity market fundamentals. It fails to communicate the extent (magnitude) of capacity shortfalls or surpluses, complicating the ability of market participants to make well-informed choices regarding investments in new capacity or the potential retirement of existing assets.
- **Lack of Investment Incentives:** These price inefficiencies and inadequate price signals could fail to provide the necessary financial stimulus for attracting new capacity investments. When the price remains relatively low/high irrespective of the length of resource surpluses/shortages, potential investors may exhibit

[2] https://cdn.misoenergy.org/2022%20State%20of%20the%20Market%20Report625295.pdf

reluctance to invest funds in constructing new capacity resources. This effect is amplified when uncertainties related to demand growth and market conditions are prevalent.

- **Resource Overbuilding or Underbuilding:** The use of a vertical demand curve fails to promote efficient resource planning. It could trigger excessive capacity expansion if prices remain consistently high due to a lack of price responsiveness, potentially burdening consumers with avoidable costs. Conversely, persistently low prices may result in insufficient capacity development, increasing the potential for supply shortages and related reliability risks.
- **Diminished Reliability:** A demand curve that doesn't accurately reflect additional reliability benefits with additional capacity procurement during peak demand periods could potentially result in a shortage of resources available to meet demand in future planning periods, thereby increasing the risk of reliability issues, including potential blackouts during times of high demand.

Considering these challenges, numerous organized capacity markets have adopted more advanced demand curve configurations. These can include sloped or stepped demand curves which offer a more accurate portrayal of supply-demand market dynamics and create more robust incentives for ensuring resource adequacy. As a result of the lack of slope in the MISO region, capacity prices have been extremely low for many years relative to other regions' capacity prices. Only the 2022-2023 PRA price spike produced a higher value than other ISOs, but these prices were not enough to support average prices near Net CONE. A Resource Adequacy construct that incorporates elements such as a RBDC will produce a more graduated evolution from low prices to prices near Net CONE over time.

The following table developed by Brattle summarizes the approaches taken in other ISO/RTOs[3]:

[3] MISO OATT Module E; PJM OATT Attachment DD; NYISO ICAP Manual; ISO-NE Market Rule 1 Section 13; UK Capacity Market Rules.

Feature	MISO	PJM	New York	New England	Great Britain
Investment Model	Primarily utility planning, also merchant/ retail choice and public power	Primarily merchant/ retail choice, also utility planning, public power and state policies/ contracts	Primarily state policies/ contracts, also public power authorities and merchant/ retail choice	Primarily state policies/ contracts, also utility planning, public power and merchant/ retail choice	Primarily merchant/ retail choice; also, public policies/ contracts
Forward Period	2 months ahead	3 years ahead, with balancing auctions	Prompt	3 years ahead, with balancing auctions	4 years ahead, with balancing auctions
Auction Format	Single round, uniform price	Single round, uniform price	Single round, uniform price	Multi-round, uniform price	Multi-round, uniform price
Demand Curve	Vertical	Sloped	Sloped (but wider/flatter than others)	Curved, as marginal reliability impact	Sloped
Capacity Self-Supply	Enabled by FRAP and pre-auction positions	FRR 5-year capacity market opt-out; also, self-supply and pre-auction positions	Self-supply, pre-auction positions and voluntary forward auctions	Self-supply and pre-auction positions	Self-supply and pre-auction positions
Locational Design	Import and export limits	Import limits	Import limits	Import and export limits	None
Seasonality	4-season	Annual *Proposed:* 2-season	Demand: Annual Supply: 2-season Pricing: Monthly	Annual	Annual
Performance Incentives Concentrated in Shortages	No	Yes	No	Yes	Yes

Table 1 – Comparison of Resource Adequacy constructs in different ISO/RTO markets

MISO's proposed RBDC construct is based on three fundamental tenets:

1) **Reliability principle.** Maximize alignment of market requirements with system reliability requirements by establishing a RBDC that properly values capacity.
2) **Long-run sustainability principle.** The new construct should create an outcome that, over time, allows Market Participants participating in the PRA the opportunity (but not the guarantee) to recover going forward costs of building and operating an asset in excess of rents achieved from energy and operating reserve market participation.
3) **Cost-effective principle.** The purpose of the RBDC framework is to formulate demand curves based on reliability that avoid promoting excessive infrastructure development, prevent capacity shortfalls, and ensure optimal cost efficiency for consumers.

1.2 Solution

Implementing a RBDC in MISO's Resource Adequacy construct will help address these challenges by allowing: (i) PRA clearing prices to properly value incremental capacity, recognizing that additional capacity above the 0.1 LOLE per year standard has additional reliability value; (ii) capacity prices to better support market participants' investment, retirement, and replacement decisions; and (iii) the PRA to clear at more economically efficient outcomes, reflecting an appropriate price of capacity.

The RBDC is a defined curve that measures the resource capacity needed at each price point. The intersection of this well-vetted, administratively determined demand curve with the supply curve determines the market clearing price and quantity of capacity in the PRA.

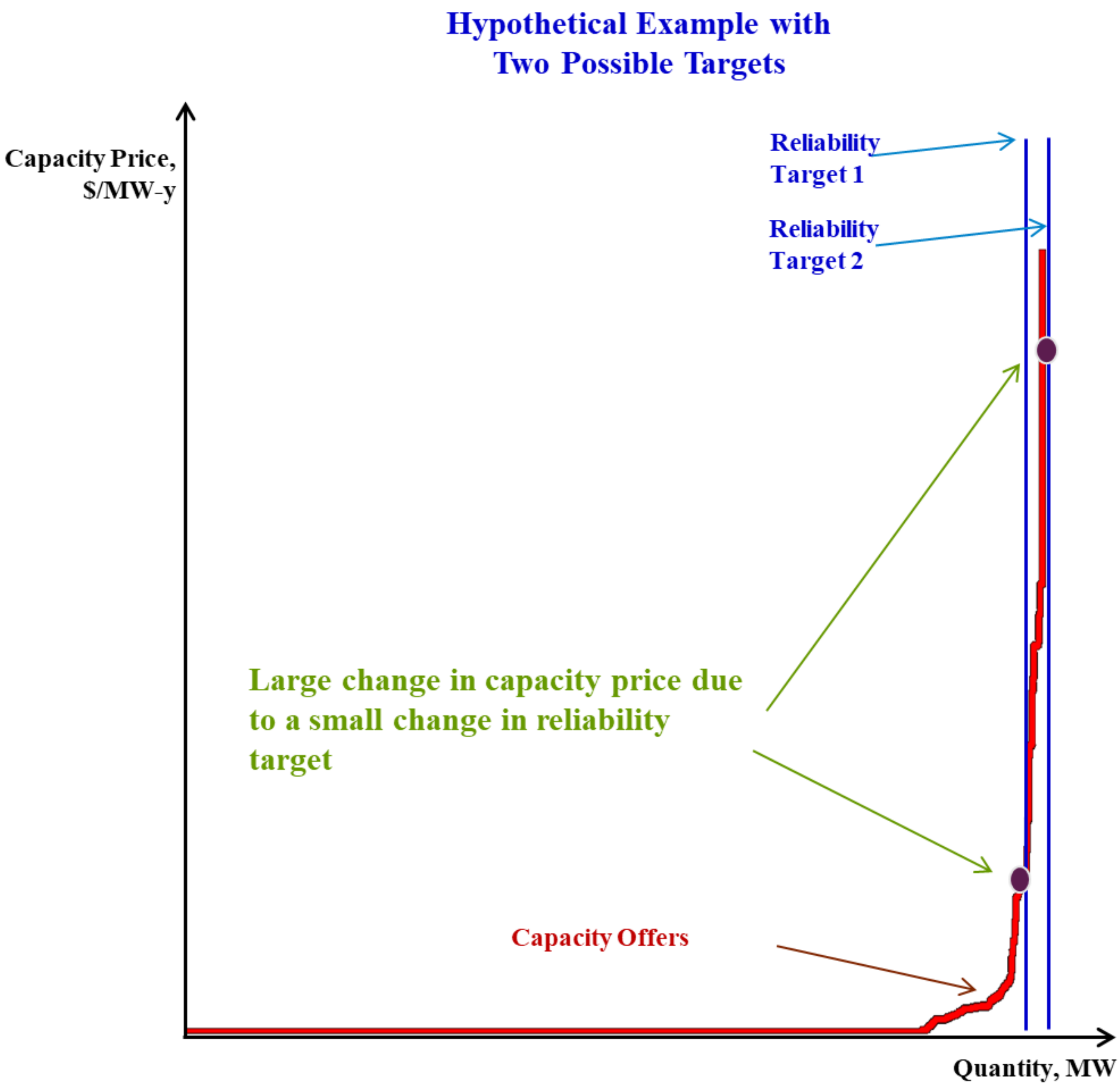

Figure 1. Illustration of MISO's vertical demand curve

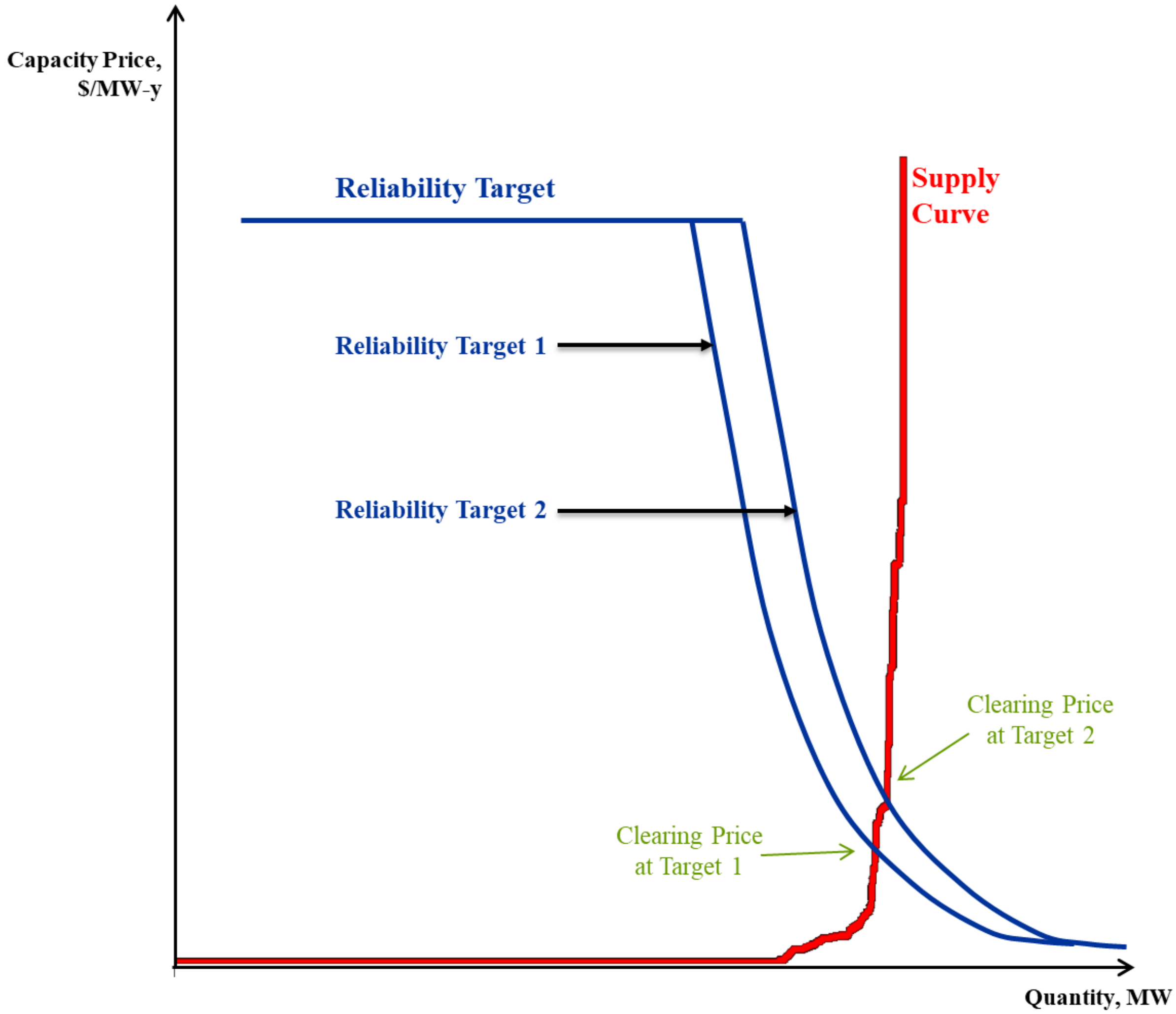

Figure 2. Illustration of a downward sloping demand curve

Other RTOs, such as all the eastern ISOs/RTOs and Great Britain, employ a sloping demand curve to procure capacity needs for their regions. Recently, the IMM did an analysis and found that in the 2019-2021 Planning Years, an efficient capacity clearing price would have ranged from a little more than $100/MW-day in 2019 to $175/MW-day in 2021.[4] The actual clearing price over the period never exceeded $7/MW-day for all but one Local Resource Zone (LRZ). As a result of this artificially low price, the IMM estimates that nearly 5 GW of capacity was retired uneconomically. Had a RBDC been in place, clearing prices would have covered the going-forward costs of these resources, and they could have remained online.

Developing demand curves based on marginal value of reliability is critical to improving market efficiency. The most economically rational demand curve design is a sloped curve

[4] https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf

that reflects the marginal contribution of incremental capacity to reliability and explicitly ties capacity prices to reliability value. In designing a RBDC solution to fit these principles, MISO observed several key considerations and decision points.

Figure 3. Key decision points on the design of a RBDC

1. MISO will consider a RBDC for each location, System-Wide and Sub-Regionally, and season within the PRA.
2. MISO will propose provisions for LSEs to opt out of participating in the RBDC to respect states' rights towards resource adequacy.
3. MISO will formulate a methodology to derive the Marginal Reliability Impact to develop the curve.
4. MISO will address the method of calculating Net CONE to produce annualized prices such that new investment can be justified when needed for reliability.
5. MISO will update algorithms to consider RBDC in the market clearing process. Based on stakeholder feedback, MISO is also considering seasonal PRA co-optimization outside of initial RBDC design scope and may file associated Tariff changes later.
6. MISO will determine the timing for implementation of the RBDC in the PRA.

The remainder of this white paper focuses on the key design elements of the proposed RBDC along with discussion of implementation decisions that will drive MISO forward in the evolution of its Resource Adequacy construct.

2 Key Elements of the RBDC Design

MISO is dividing RBDC design into four critical areas:

2.1 RBDCs (System-Wide and Sub-Regional)

Considering the unique attributes of the MISO footprint, a single System-Wide RBDC demand curve is not sufficient to address all possible reliability benefits. MISO identified the value of Sub-Regional RBDCs to address reliability benefits for each of its two Sub-Regions. MISO developed System-Wide as well as Sub-Regional RBDCs so that on average over time, MISO on a system-wide basis and in both sub-regions will achieve the 0.1 LOLE per year threshold reliability standard. MISO will not be considering implementing zonal RBDCs at this time because of the increased complexity. However, implementation of such zonal RBDCs may be considered as part of a future enhancement.

2.2 Marginal Reliability Impact Curves

The Marginal Reliability Impact (MRI) Curve is a graphical representation that illustrates the relationship between changes in the level of resource capacity and the corresponding impacts on system reliability. This curve shows how adding or removing a unit of capacity to or from the system impacts overall reliability.

The essence of the MRI Curve lies in illustrating the balance between capacity and reliability. As more capacity is added to the system, the system becomes more reliable until a point of saturation is reached, after which increasing capacity has little to no impact on reliability. Inversely, it also demonstrates that small shortages have minor impacts on reliability. A vertical demand curve does not send the necessary signals to the market to show where the system is along the curve. This exposes the MISO region and Sub-Regions to the risks associated with too little or too much capacity.

The MRI curve helps to balance the prices paid to the level of reliability achieved under varying supply-demand conditions, across seasons, and between sub-regions. It also aids in identifying the point where the cost of adding more capacity (i.e., building new power plants) becomes balanced with the benefits of enhanced reliability. Overall, the MRI Curve is a valuable tool to strike the right balance between capacity investments or forestalling uneconomic retirements as well as maintaining a reliable and resilient power system. A more detailed description of the MRI curve analysis used by MISO is provided in Section 3.

2.3 Net CONE

To ensure effective capacity clearing and accurate pricing, MISO currently relies on a well-defined methodology and procedure for calculating the Cost of New Entry (CONE) within each LRZ. To achieve efficient capacity clearing and pricing under a RDBC, it is essential to establish accurate Net CONE values. Net CONE values are developed based on an accurate representation of inframarginal rents, which are derived by subtracting a resource's production costs from its market revenue.

This process will take place at the LRZ level, which ensures accuracy and relevance. Revenues and costs derived from energy and all ancillary services products will be considered. These values offer a comprehensive understanding of the net revenue potential, allowing MISO to better align capacity allocation and pricing signals with the unique attributes of each LRZ.

However, it is important to note that only CONE-specified, technology-based resources will be considered in the analysis. This systematic approach guarantees a comprehensive evaluation of inframarginal rents, providing insights into the economic dynamics of the energy markets and its impact on capacity markets.

2.4 RBDC Opt-Out Options

The majority of LSEs in the MISO region are part of vertically integrated utilities subject to rate regulation by their respective RERRAs. RERRAs in the MISO region maintain authority for establishing resource adequacy requirements, including the authority to override MISO's established requirements, as well as the authority to oversee resource planning decisions for rate-regulated utilities that serve most consumers in their jurisdiction. As state and local regulatory entities have primary jurisdiction over resource adequacy within the MISO footprint, the members of OMS have been clear during the process of developing the RBDC that they would only support a construct that provides LSEs with the option to opt out of the RBDC construct while still meeting their applicable requirements to ensure resource adequacy.

MISO recognizes the important role that state planning plays in the resource adequacy process and the shared responsibility for resource adequacy among different stakeholders in the MISO region. OMS, in turn, has stated that "[c]ontinued reliance on a vertical demand curve may not appropriately value the reliability benefits of excess capacity, may result in over-reliance on the PRA by Load Serving Entities to meet their capacity obligations, may accelerate retirements of existing capacity resources, and may not send an accurate price signal for potential new generation investment."[5] To this end, MISO has designed the RBDC opt out component of the new construct based on feedback

[5] OMS Position Statement on Consideration of a Revised Demand Curve in MISO's Planning Resource Auction (PRA).

from OMS and other stakeholders during the stakeholder process. The objective of the opt out mechanism is to neither incentivize opt out, nor force participation.

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3 Marginal Reliability Impact and RBDCs

3.1 What Are MRI Curves and What Do They Represent System-Wide and Sub-Regionally?

MRI Curves are smoothed representations of reliability as measured by changes in Expected Unserved Energy (EUE) on y-axis as more or less resource capacity (MWs) is included in the LOLE analysis on the x-axis. MISO's RBDC will be defined in proportion to marginal reliability impact. This reflects the reductions to expected unserved energy (MWh per year) that would be achieved by adding one more UCAP MW of capacity to the system. Mathematically, MRI is defined using the equation below.

$$MRI = Avoided\ EUE\ \div Incremental\ Capacity$$

where,

MRI (MWh per UCAP MW) is the incremental reliability value of adding 1 UCAP MW of perfect capacity to the system

Avoided EUE (MWh per year) is the reduction in expected unserved energy by adding incremental capacity

Incremental Capacity (UCAP MW) is the perfectly available capacity added to the system in the LOLE analysis

To calculate MRI as a function of capacity, MISO uses the same system reliability modeling platform with the identical input assumptions and output results that it currently uses to calculate System-Wide seasonal Planning Reserve Margin Requirements (PRMRs) and zonal Local Reliability Requirements (LRRs).

The MRI Curve that results in a convex, downward-sloping function that represents the diminishing reliability value of incremental capacity when supply is abundant and the increasing reliability value of incremental capacity when supply is scarce. The MRI Curve is calculated greater than and less than the reliability target by first establishing the quantity at which the system achieves the 1-day-in-10-years LOLE reliability standard, and then determining the incremental value of adding/subtracting perfectly available UCAP MW at each x-axis quantity.[6]

[6] As a point of precision, this is calculated by simulating annual loss of load hours (LOLH) at each UCAP MW quantity point and estimated MRI as the LOLH × 1 UCAP MW to determine the EUE that would be avoided by adding one more UCAP MW of supply.

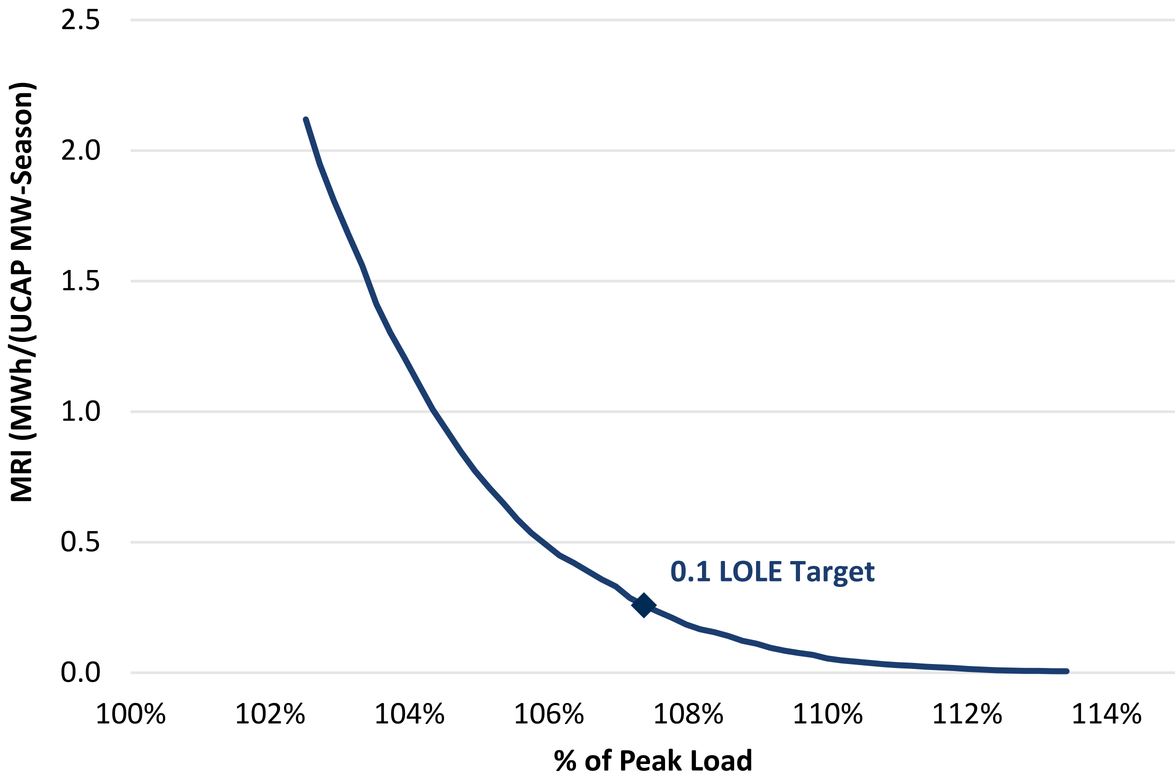

Figure 4. Illustrative example of MRI Curve in MISO footprint

The above illustrative MRI Curve is derived from a simulation of a seasonal capacity market, in which seasonally available, perfect capacity is added (or subtracted) in each simulated modeling run. MISO will establish an MRI Curve for each season through the steps below. Steps 1-2 are the processes MISO currently uses to calculate seasonal reliability requirements, while the subsequent Step 3 is new.

1) Calculate Tight-Season Reliability Requirement: Conduct a reliability modeling analysis of the projected MISO system, adjusting capacity quantities until the system is expected to achieve the 1-in-10 (or 0.1 events/year LOLE) reliability standard. If after Step 1 there is a minimum of 0.01 day per year LOLE in all four seasons, then the seasonal requirements are determined directly from this step (skipping Step 2).
2) Calculate Other Seasons' Reliability Requirements: For any season with LOLE below 0.01 LOLE/year from Step 1, the modeled capacity will be reduced until LOLE for that season achieves the 0.01 LOLE/season minimum seasonal criteria.
3) Calculate Seasonal MRI Curves: Starting with capacity quantities at the seasonal requirements established in Steps 1-2, MISO will calculate the MRI Curve for each

season. For one season at a time, perfectly available UCAP MW will be added (or subtracted) to calculate the avoided EUE in the relevant season.[7]

3.1.1 System-Wide MRI Curve Development

The following process will be used to determine the MRI Curves for the MISO region for each Season in the Planning Year. The specific LOLE analysis performed for the Planning Year with the identical input assumptions for the Planning Reserve Margin (PRM) analysis will be the initial step. Assignment of LOLE risk across the seasons will be the same as used in the PRM analysis. The PRMR for the season established in the LOLE analysis will be the starting point. Then, for each season, a perfect-negative unit of at least 50 MW but no more than 200 MW or a perfect-proxy unit of at least 50 MW but no more than 200 MW will be added to the model and LOLE analysis will be performed. The change in EUE resulting from adding or removing capacity will be calculated from the loss of load hours (LOLH) at each quantity point (with 1 UCAP MW of perfect capacity avoiding 1 MWh of unserved energy for each modeled loss of load hour, or 1 MW * LOLH). Additional capacity will be added or removed in the same amount as the negative and proxy units and the LOLE analysis will be performed again. This process will be repeated until sufficient data is available to fit a curve that measures changes to EUE as MWs are added or removed from the initial minimum PRMR.

The following are preliminary illustrative System-Wide MRI Curves for the Planning Year 2023-2024. The preliminary illustrative System-Wide MRI Curves below result from the LOLE study process where summer is using a 0.1 LOLE target and non-summer seasons are using 0.01 LOLE target.

[7] To streamline the implementation of Step 3, MISO may add or subtract perfect, annually available UCAP MW capacity in each run, but for the purposes of calculating each season's MRI, only the avoided EUE in the relevant season would be tabulated.

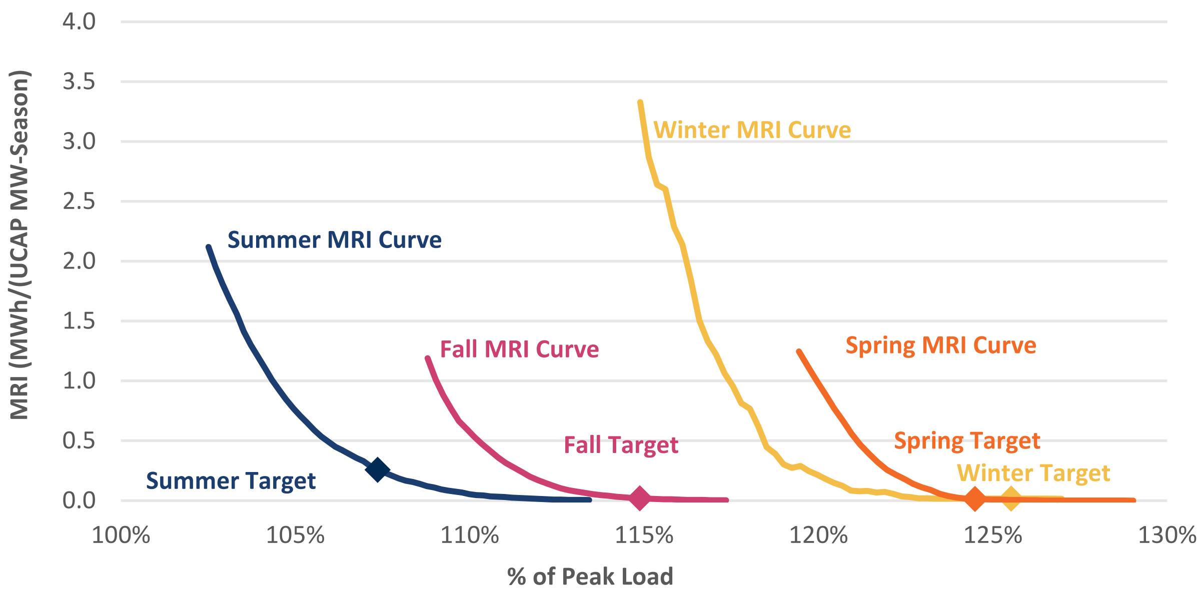

Figure 5. Illustrative System-Wide MRI Curve for PY 2023-2024

3.1.2 Sub-Regional MRI Curve Development

Sub-Regional capacity requirements are developed for the same reasons that LRZs were created and consequently LRRs and LCRs are estimated.[8] Unlike the vertical nature of LRRs and LCRs, however, RBDCs for each Sub-Region can be derived. The process to determine the Sub-Regional MRI Curves for each Season in the Planning Year is similar to that used for determining the System-wide MRI Curves.

Each Sub-Region, First Planning Area (i.e., MISO North/Central) and Second Planning Area (i.e., MISO South), will establish a PRMR for each Season in LOLE analysis as separate but intertied entities under the reliability target at 0.1-0.13 annual sub-regional LOLE established for the MISO region as the starting point. After this initialization, fix the MW quantity associated with the PRMR in the Second Planning Area, then add or remove perfect capacity in the First Planning Area to calculate changes to EUE in the First Planning Area. The Sub-Regional MRI Curve for the First Planning Area is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The same process will be used to determine the Sub-Regional MRI Curve for the Second Planning Area. The MW quantity associated with the PRMR in the First Planning Area will be fixed, and then capacity will be added or removed in the Second Planning Area to calculate changes to EUE in the Second Planning Area. The

[8] Ultimately, reliability-based demand curves should be developed and employed at the LRZ level to reflect the additional reliability benefit that incremental capacity with an LRZ provides. Due to the complexity of developing 10 such curves, for 4 seasons, MISO will postpone this effort until a later stage.

Second Planning Area MRI Curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis.

The following are preliminary Sub-Regional MRI Curves for the First Planning Area and Second Planning Area. The preliminary Sub-Regional MRI Curves below result from the PRM analysis of the LOLE study process where summer is using a 0.1 LOLE target and non-summer seasons are using 0.01 LOLE target.

Finally, once each sub-region's individual MRI curve is developed an additional adjustment is applied to subtract the portion of reliability events associated with system-wide supply shortfalls, rather than sub-region specific supply shortfalls. This is accomplished by lining up the x-axis regional MW quantity of supply with the corresponding level of system-wide MW quantity (from the systemwide MRI curve described above). The system-wide MRI is subtracted from the Sub-Regional MRI to calculate the portion of reliability events caused by sub-regional shortfalls. Only this sub-region portion of the MRI is utilized in calculating the sub-regional demand curve.

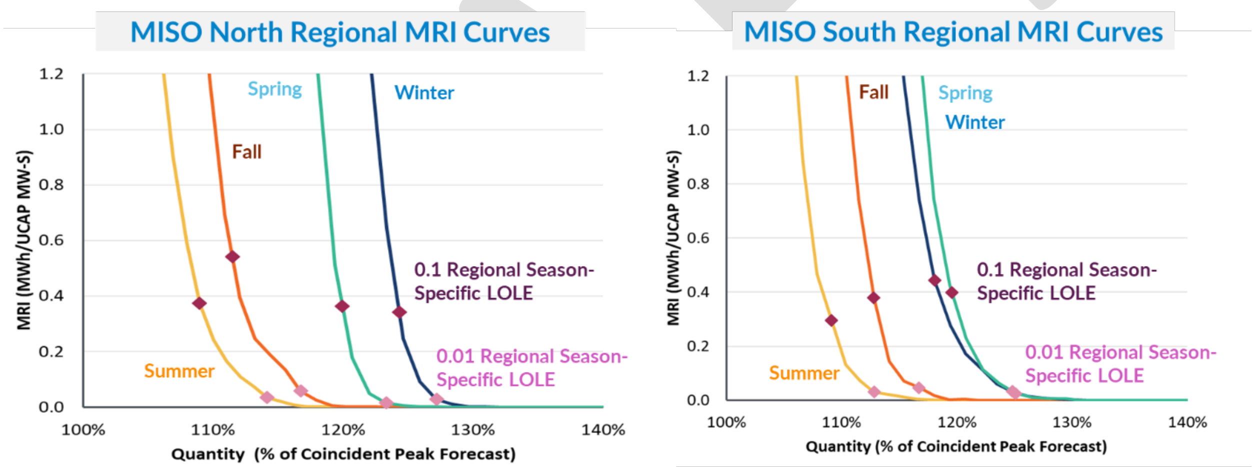

Figure 6. Illustrative Sub-Regional MRI Curve for PY 2023-2024

4 Reliability-Based Demand Curve

The RBDC is a representation of the demand for capacity using an MRI Curve and Net CONE to establish the resource capacity deemed beneficial at every price level. The intersection of this demand curve with the supply curve is the equilibrium point of both the price and the amount of capacity transacted through the PRA. The intention behind this approach is to secure adequate capacity, aligning closely with the target reserve margins derived from reliability metrics, while avoiding excessive procurement.

MISO is proposing two different types of RBDCs with the initial implementation—a System-Wide RBDC and a Sub-Regional RBDC encompassing each Planning Area.

4.1 Need for System-Wide RBDC

A System-Wide RBDC is beneficial in the MISO PRA to address several key issues and optimize resource allocation. These include meeting the following needs:

- **To reflect realistic supply-demand market fundamentals:** An MRI Curve based RBDC acknowledges the reality that the value of capacity changes as the whole system's supply-demand balance shifts over time. It captures the fact that capacity might be more valuable during high-demand seasons and less valuable during low-demand seasons.
- **To encourage efficient resource investment and retention:** A price sensitive RBDC, such as System-Wide RBDC, provides a more accurate representation of capacity's value in different situations. RBDC acknowledges the value of additional capacity beyond 0.1 LOLE. This, in turn, offers appropriate price signals to investors not only to build more but to also to make informed decisions about retirements and suspensions. During times of capacity shortage or high demand, the curve's slope encourages more investment in resources, better supports adequate supply during peak periods, and reduces the risk of involuntary load reductions. Conversely, during times of excess capacity, System-Wide RBDC provides an adequate price signal to market participants to make retirement and suspension decisions for inefficient resources.
- **To enhance resource adequacy:** A System-Wide RBDC supports better resource adequacy planning. It aligns capacity payments more closely with the value of capacity to the grid and incentivizes resources to be available when they are most needed, reducing the likelihood of supply shortfalls. With the integration of renewable energy sources such as wind and solar, the supply of electricity is more variable. A RBDC helps balance these fluctuations by providing better price signals, thus aiding in resource planning and ensuring grid stability.
- **To facilitate market competition:** A RBDC promotes healthy market competition. It encourages efficient suppliers to bid on their capacity at appropriate prices, fostering competitive pricing practices and ultimately leading to better cost management for consumers through efficient use of resources.

In essence, a System-Wide RBDC in a capacity market helps ensure that capacity prices align with the actual value of capacity, optimizes resource investment, and supports grid stability under varying demand conditions.

4.2 Need for Sub-Regional RBDCs

A System-Wide RBDC addresses system-wide reliability needs of the MISO footprint in line with the PRA-focused LOLE study. However, as experienced in the PRA over the last several years, the regional transfer limitation has been a key driver. System-Wide RBDC

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does not address the Sub-Regional and more granular resource adequacy needs and challenges. A Sub-Regional RBDC in a capacity market is essential for addressing specific dynamics and optimizing resource allocation within a particular geographic area. In addition to the benefits described in Section 4.1, a Sub-Regional RBDC provides:

- **To address Sub-Regional characteristics:** After integration of the MISO South Sub-Region, MISO has two distinct Sub-Regions with distinct energy/demand patterns, resource availability, and grid conditions. A Sub-Regional RBDC considers these unique features, ensuring that the capacity pricing accurately reflects the Sub-Regional supply-demand balance and reliability needs.
- **To achieve optimal resource planning:** By reflecting the precise regional load profile, a Sub-Regional RBDC assists in better resource planning. It provides incentives for resource providers to align their capacity offerings with the specific needs of the Sub-Region, ensuring reliable supply during peak demand periods.
- **To address transmission constraints:** Past PRAs have shown that the Sub-Regional Power Balance Constraint (SRPBC) has shown a great impact on MISO's capacity market. A Sub-Regional RBDC can consider transmission limitations, promoting capacity investments where they are most needed and helping alleviate congestion issues.
- **To encourage local investment:** A Sub-Regional RBDC encourages local capacity investment by offering a price that reflects the Sub-Region's unique requirements. This enhances the resilience of the local grid and reduces the need for long-distance electricity transmission.
- **To foster Sub-Regional reliability:** The Sub-Regional RBDC contributes to Sub-Regional reliability by incentivizing capacity provision where it is needed most. It reduces the risk of capacity shortages during Sub-Regional peak demand, enhancing the stability of the entire energy system within the Sub-Region.
- **To improve market efficiency:** Sub-Regional demand variations can lead to Sub-Regional capacity value variations. A Sub-Regional RBDC captures these nuances, promoting efficient behavior by aligning capacity pricing with the actual value of capacity in that Sub-Region. It also helps to improve cost allocation, which can improve overall efficiency of MISO's capacity market.
- **To provide regulatory flexibility:** Sub-Regional RBDC offers an avenue for regulatory flexibility. It allows policymakers to address energy goals and challenges that are specific to Sub-Regional and local circumstances.

A Sub-Regional RBDC recognizes the diversity of capacity markets and their unique requirements. By providing localized price signals that reflect regional supply and demand conditions, it ensures efficient capacity pricing, resource planning, and overall grid reliability for a particular area.

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The PRA will use the System-Wide RBDC, both Sub-Regional RBDCs and the 10 LCRs to represent MISO market demand. Market participants with capacity offers will be aggregated to represent MISO system supply. The PRA auction algorithm will be solved simultaneously across all demand elements in a co-optimized fashion to minimize the difference between the sum of as-offered costs of supply and the sum of as-bid demand (reflected through the RBDCs and LCRs) to maximize social surplus.[9] Sub-Regional RBDCs provide information on the additional reliability benefit to a Sub-Region from additional capacity (in excess of capacity providing System-Wide value) in a certain Sub-Region. If the costs as reflected in the offers for additional capacity are less than the incremental reliability benefits, then the additional capacity will clear in the auction.

4.3 Procedure to Derive the RBDCs from the MRI Curves

A RBDC, whether System-Wide or Sub-Regional, can be derived from the respective MRI Curve by translating the information about the incremental changes in capacity and the corresponding reliability impacts into a pricing structure. The process is demonstrated at a high level in Figure 7.

As stated at the beginning of this section, construction of the RBDC begins with the development of MRI Curves. The MRI Curve provides information about the value of reliability improvements brought about by additional capacity. This value can be expressed in terms of avoided costs, such as EUE. To create a RBDC, the reliability value obtained from the MRI Curve is translated into pricing using Net-CONE information. As capacity increases, the corresponding value of reliability improvement is converted into lower capacity prices. This price decrease signifies the willingness of the market to pay less for additional capacity as incremental capacity contributes a smaller amount to enhanced reliability.

Translating the MRI Curves into the units of a RBDC requires a scaling factor. Following logic similar to that utilized in ISO New England, the scaling factor is calculated to support annual revenue prices at annualized Net CONE when the system is at the reliability requirement in all four seasons. The calculation and relevant unit conversions for calculating the scaling factor are:

$$Scaling\ Factor = Net\ CONE\ \div System\ MRI^{\{PRM\}}$$

where,

Scaling Factor ($/MWh) is the payment rate at which the RBDCs would seek to procure additional supply

[9] Social surplus is defined as the sum of consumer and producer surplus and represents the difference between the price market actors are willing to pay/sell and the price at which they actually pay/sell. No distributional effects are considered.

Net CONE ($/UCAP MW-year) is estimate of the net annualized cost to develop new capacity resources

System $MRI^{\{PRM\}}$ (MWh/UCAP MW-year) is the marginal reliability impact of additional capacity at the Planning Reserve Margin.

Each season's individual MRI Curve then can be multiplied by the scaling factor to establish an RBDC for each season, as illustrated in Figure 8. For the purposes of illustration, we assume a book-end outcome in which one season, summer, is far tighter than the other seasons and so many reliability events, and hence reliability-based economic value, is derived from serving capacity needs in the summer season. To support Net CONE-based capacity pricing on an annual average basis in that scenario, the tight summer season would be the only one with a substantial and strong capacity pricing signal, while the other three seasons would likely produce lower prices. Prices in any one season will vary above and below each season's target in response to how suppliers offer into the market in each season.

The slope of the RBDC depends on various factors, including the existing resource mix, the cost of new capacity, and the value of Net CONE. This step is critical to ensure effectiveness of RBDCs. To ensure that RBDCs are effective in the PRA, MISO plans to review the curves every three years and perform Monte Carlo simulations to make necessary adjustments to the RBDCs. These simulations will be performed using estimates of the distributions of both supply curves and demand curves.

1. Develop MRI Curves using LOLE models

Expressed EUE as MWH/MW-season

2. Convert the MRI Curves to MWH/MW-day

3. Multiply by a scalar/normalization value expressed in $/MWH

- Units on the y-axis are (MWH/MW-season) * (season/# days in season) * ($/MWH) = $/MW-day

4. Monte Carlo simulations performed on supply curves and potential RBDCs to support the achievement of Net CONE in long-run equilibrium analysis

Figure 7. Illustrative process to develop RBDCs from the respective MRI Curve

4.4 System-Wide and Sub-Regional Demand Curves

The following are indicative System-Wide RBDCs for the Planning Year 2023-2024. The indicative System-Wide RBDCs below are a result from the LOLE study process where summer is using a 0.1 LOLE target and non-summer seasons are using 0.01 LOLE target.

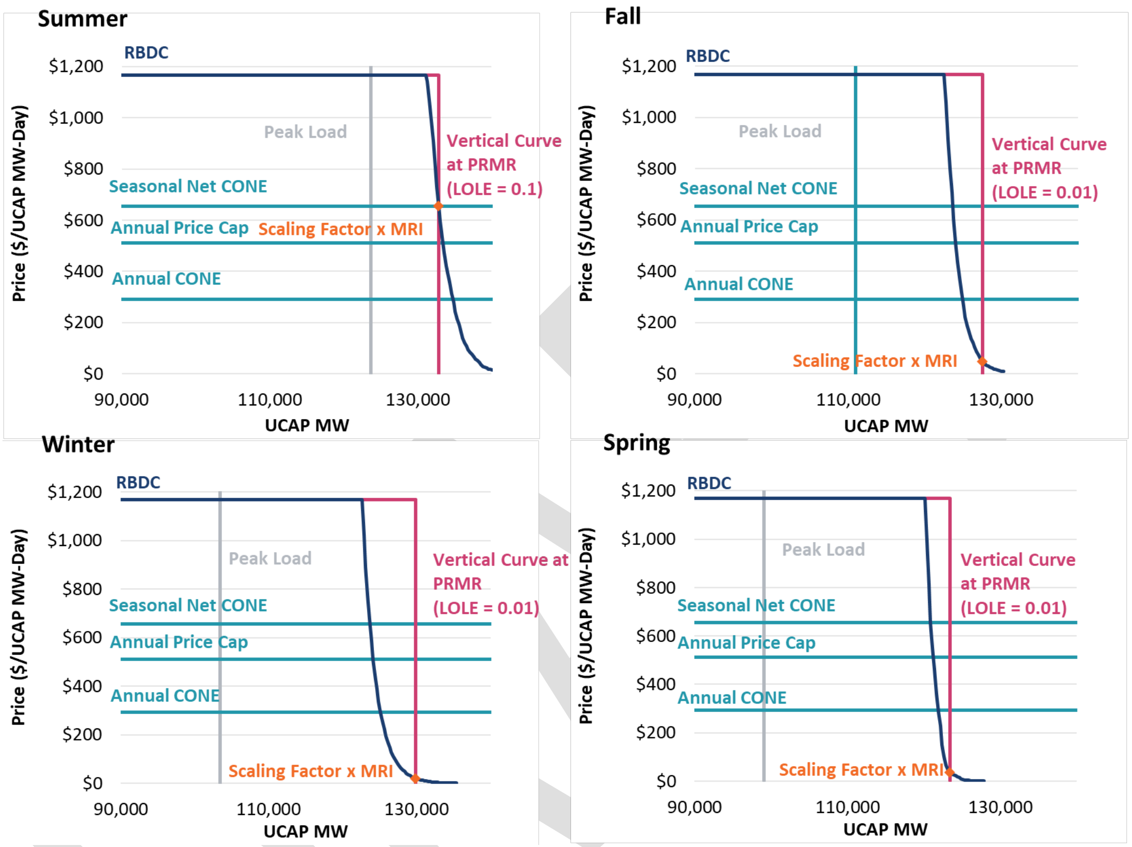

Figure 8. Illustrative System-Wide RBDCs for Planning Year 2023-2024

The following are indicative Sub-Regional RBDCs for the Planning Year 2023-2024. The indicative Sub-Regional RBDCs below result from the PRM analysis of the LOLE study process where summer is using a 0.1 LOLE target and non-summer seasons are using 0.01 LOLE target.

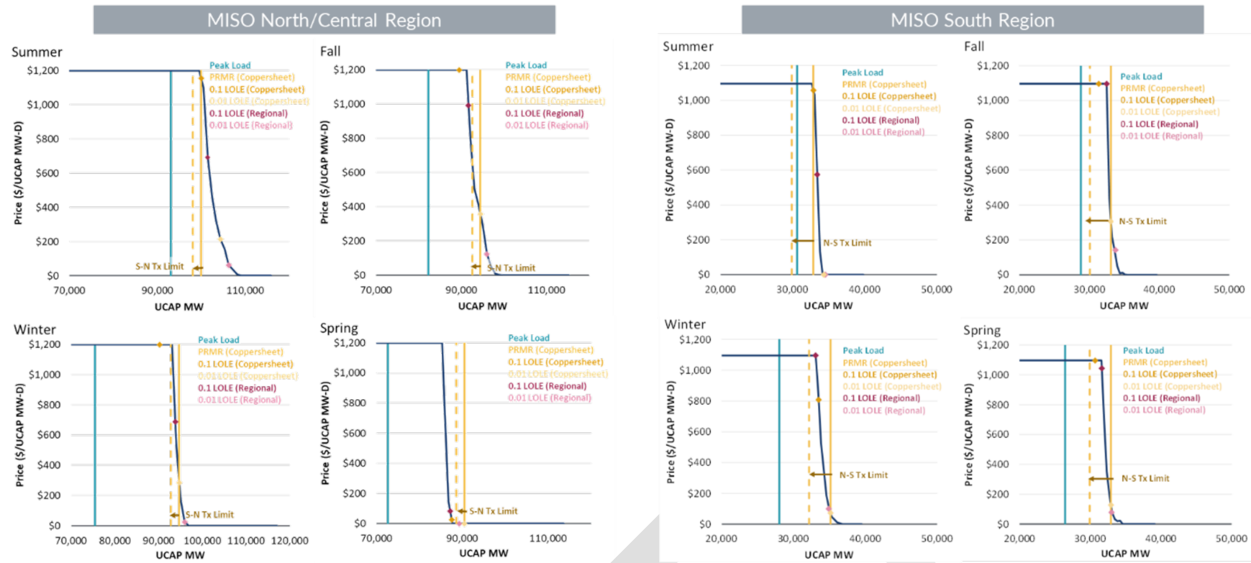

Figure 9. Illustrative Sub-Regional RBDCs for PY 2023-2024.

4.5 Truncation of System-Wide and Sub-Regional Demand Curves

Placeholder – will be updated based on discussions at the RASC

5 Net CONE

Currently, MISO does not determine Net CONE in its footprint, and Net CONE does not play a role in MISO's vertical demand curve construct. Thus, a new methodology must be introduced to determine Net CONE for use with the RBDC. No changes are envisioned at this time either to the methodology described in Section 5.2 used to determine CONE or to the reference technology used in the CONE calculation. MISO is open to considering changes to reference technology in the future after RBDC implementation.

5.1 What Is Net CONE?

Net CONE is defined as the annualized capital, operating financial, and other costs of acquiring a new Generation Resource within the Transmission Provider Region for any designated LRZ, after netting out Inframarginal Rents. Inframarginal Rents are the estimated revenues from MISO's Energy and Operating Reserves Markets that are more than production costs for a Generation Resource.

5.1.1 What Net CONE Represents

The key feature of a Net CONE-based demand curve is a sloping shape that is drawn near the "anchor point" at the reliability target and Net CONE. The underlying concept is to ensure that on average, prices can, over time, 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

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prices increasing gradually along with tightening system conditions to match or exceed Net CONE if capacity investments are needed. A sloping curve can clear a varying amount of capacity, depending on the supply curve. It thus accepts some variation in reliability and requires LSEs to manage their supply plans relative to variable resource requirement.

5.1.2 Why Net CONE is Needed

Anchoring RBDCs around Net CONE provides an opportunity to recover going forward costs for existing and new resources. All other options are more administrative and can result in inefficient prices and clearing volumes.

5.1.3 Options to Determine Net-CONE

MISO considered a fully forward-looking Net CONE approach but opted against this option due to the greater complexity and challenges with data availability. Instead, MISO will use a combination of historical and forward-looking information. MISO will use a scaling parameter to adjust historic actual energy and ancillary services revenues for the prompt year based on expected LMPs and forward-looking gas prices.

5.2 Methodology to Determine Net-CONE

The initial step in determining Net CONE is to determine Inframarginal Rents. To determine Inframarginal Rents, the most recent three Planning Years of historic data will be compiled for each resource of the generation resource type used in the CONE value calculation operating in the MISO region. This data will consist of all revenues for the Resource from MISO's Energy and Operating Reserve Markets, calculated hourly, and production costs calculated hourly. The difference in market revenues and production costs shall be calculated hourly, and the profitable hours are summed for each year, for each resource. Inframarginal Rents outside of two standard deviations from the sample mean are removed from each year's results to avoid data biasing.

Resources are then grouped into LRZs based on their location. The average Inframarginal Rents are calculated for each LRZ and then scaled using a capacity factor for each LRZ. This results in an Inframarginal Rents value for each LRZ for each Planning Year. For use in the PRA, Net CONE values are sorted into values in the First Planning Area and Second Planning Area, based on the location of the Resource. The three-year average of each LRZ's Inframarginal Rents is then subtracted from the LRZ-specific CONE value to get an estimate of Net CONE for each LRZ.

To determine the final estimate of Net CONE to be used for the upcoming Planning Year, MISO will use a scaling factor applied to the estimated historic Net CONE value. This scaling factor will be based on a statistical model between the ratio of LMPs to gas prices against calculated Inframarginal Rents, using the same three-year historic data. A simple estimated model of LMPs to gas prices will be used similarly. Then readily available settled

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futures gas prices for the upcoming Planning Year will be used to calculate the scaling factor.

MISO will arrange for Net CONE values to be calculated in concert with the estimate of CONE values no later than September 1 prior to the relevant Planning Year beginning on September 1, 2024.

5.3 Initial Net-CONE Numbers

The table below provides the Net CONE values for the three most recent Planning Years. In determining these values, the average Net CONE in the First Planning Area (i.e., MISO North/Central) is higher than the Second Planning Area (i.e., MISO South).

<table>
<tr><th>LRZ</th><th>PY19-20 IR</th><th>PY20-21 IR</th><th>PY21-22 IR</th><th>3-yr Avg</th><th>Regional IR</th><th>PY 23-24 CONE</th><th>Net-CONE</th></tr>
<tr><td>LRZ 1</td><td>$18,504</td><td>$46,688</td><td>$63,542</td><td>$42,911</td><td rowspan="7">$29,886</td><td>$104,170</td><td>$74,284</td></tr>
<tr><td>LRZ 2</td><td>$43,762</td><td>$71,080</td><td>$52,432</td><td>$55,758</td><td>$102,240</td><td>$72,354</td></tr>
<tr><td>LRZ 3</td><td>$16,811</td><td>$24,535</td><td>$33,567</td><td>$24,971</td><td>$98,590</td><td>$68,704</td></tr>
<tr><td>LRZ 4</td><td>$7,634</td><td>$12,820</td><td>$22,385</td><td>$14,280</td><td>$102,200</td><td>$72,314</td></tr>
<tr><td>LRZ 5</td><td>$6,650</td><td>$13,375</td><td>$15,127</td><td>$11,717</td><td>$109,580</td><td>$79,694</td></tr>
<tr><td>LRZ 6</td><td>$24,913</td><td>$20,315</td><td>$20,849</td><td>$22,026</td><td>$98,590</td><td>$68,704</td></tr>
<tr><td>LRZ 7</td><td>$15,827</td><td>$46,406</td><td>$50,384</td><td>$37,539</td><td>$105,910</td><td>$76,024</td></tr>
<tr><td>LRZ 8</td><td>$6,777</td><td>$17,347</td><td>$10,309</td><td>$11,478</td><td rowspan="3">$35,791</td><td>$94,890</td><td>$59,099</td></tr>
<tr><td>LRZ 9</td><td>$48,103</td><td>$101,871</td><td>$56,834</td><td>$68,936</td><td>$94,080</td><td>$58,289</td></tr>
<tr><td>LRZ 10</td><td>$14,734</td><td>$34,228</td><td>$31,912</td><td>$26,958</td><td>$93,820</td><td>$58,029</td></tr>
</table>

Table 2 – Calculation example for Net CONE based on most recent three Planning Years

6 RBDC Opt Out

6.1 Need for an Opt Out

Most LSEs in MISO are regulated, municipal, or cooperative utilities that conduct integrated resource plans under RERRA oversight and determine most resource commitments well in advance of the delivery year. These regulated utilities may transact for capacity with other entities, and they may leave some marginal buy/sell or retirement decisions until shortly before the Planning Year. Historically, MISO has observed that 80 – 90% of the capacity that is offered in the PRA comes from self-scheduling of capacity resources and bi-lateral transactions (e.g., Fixed Resource Adequacy Plan option under the MISO Tariff).

The most important reason that a RBDC has not previously been adopted at MISO was the view that it was either not needed or not appropriate in a region where states and the utilities they regulate take the predominant role for ensuring resource adequacy. Given this context, OMS, in an initial assessment in 2011, expressed concern that a demand curve could "undermine a state's right to determine resource adequacy because it could obligate LSEs to purchase capacity beyond the planning reserve margin and make capacity payments to resources not under the states' regulatory control."[10]

MISO developed the RBDC opt out after an extensive stakeholder feedback process and has attempted to strike a balance between these concerns in developing its RBDC construct that:

1) Recognizes the importance of capacity market participation while also respecting states' rights toward resource adequacy

2) Preserves all existing PRA participation/opt out options while adding an additional option that allows LSEs to opt out opt of the RBDC construct.

6.2 Existing Provisions for PRA Participation

Currently, LSEs may demonstrate sufficient capacity through any combination of the following four options under the MISO Tariff:

1) Opt out of the PRA completely by paying the Capacity Deficiency Charge

2) Submit a Fixed Resource Adequacy Plan (FRAP)

3) Self-schedule

4) Submit price sensitive offers into the PRA

[10] Organization of MISO States, State Regulatory Authorities Sector Responses by OMS To the February Advisory Committee Questions, February 10, 2011, p. 3.

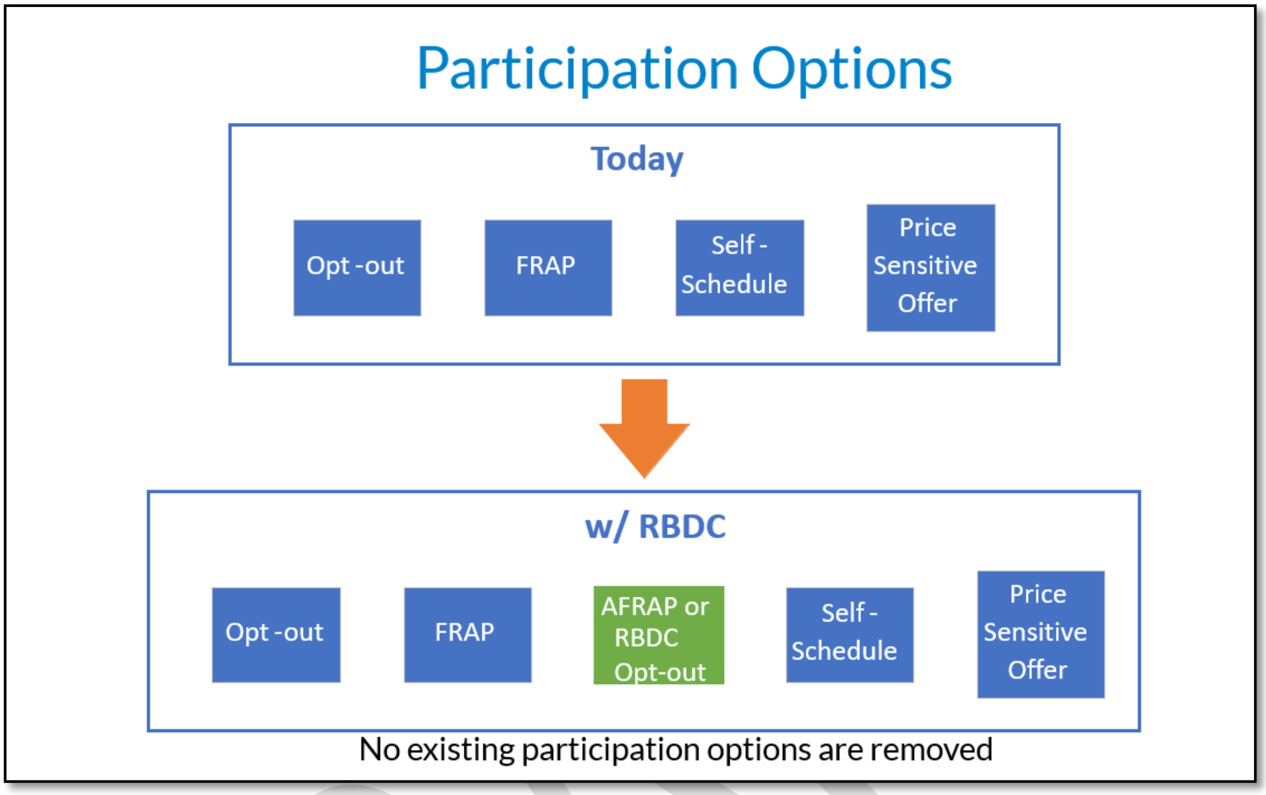

Figure 10. PRA participation options for market participants with RBDC

6.3 Alternatives Considered

MISO initially proposed an Advanced Fixed Resource Adequacy Proposal with detailed design elements presented to stakeholders at the January 2023 meeting of the RASC[11]. MISO received significant stakeholder input, particularly from members of OMS. As a result of this feedback, MISO changed several design elements, resulting in the RBDC opt out discussed below. The primary changes to the design were the calculation of the LSE capacity requirement and in altering the opt out mechanism to allow LSEs to sell excess capacity into the PRA without a withholding requirement.

[11] See slides 20-24 in MISO presentation on Reliability Based Demand Curves at the January 11, 2023 Resource Adequacy Subcommittee meeting.

AFRAP/RBDC Opt-out Design Attributes	AFRAP (previous proposal)	RBDC Opt-out (new proposal)	Comments
OBJECTIVE	Alternate option for LSEs to meet their capacity obligations		All other participation options **remain** (i.e. FRAP, self-scheduling)
REQUIREMENTS	Design should neither unfairly incent RBDC Opt-out nor force RBDC participation		
LSE capacity requirement	Max (current PRM, 3-yr average of past clearing margins)	Current PRM +X%	Initial X: 1.5 to 3% MISO to periodically evaluate & update "X"
Term	Min 3 years in/out		
Partial AFRAP/RBDC Opt-out?	Not allowed		Partial FRAPs are allowed
Locational requirements	Must meet LCR		
Time required to make showing	One month prior to PRA		Moving the showing 6 – 12 months prior to PRA has more costs than benefits
Excess capacity requirement	Withhold an additional y% prior to any sales	No withhold	MISO to periodically evaluate & update "y"
PARTICIPATION			
	RERRA Notification		Respect states' rights towards RA
AUCTION DYNAMICS			
CIL/CEL/SFT	Load/resources subject to these constraints		
RBDC effects	RBDC curves adjusted for AFRAP participation		
SETTLEMENTS			
Subject to ACP?	No. only subject to positive congestion		
Failure to meet obligations?	Charged at CDC rate, and potentially forced back into RBDC		

Figure 11. Comparison of two MISO proposals for market participants to opt out of RBDC

6.4 Chosen Approach

MISO's RBDC construct will add a fifth PRA participation/opt out option: the RBDC opt out, as shown in Figure 10. No existing participation options will be removed, although the RBDC will affect some of the existing participation options' properties (e.g., less certain PRMR for those LSEs choosing a complete FRAP option).

6.4.1 Design Elements

The objective of MISO's RBDC opt out design is to neither disincentivize opt out nor force RBDC participation. RBDC design attributes are detailed in Figure 12:

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Design Attributes	RBDC Opt-out	Comments
OBJECTIVE	Alternate option for LSEs to meet their capacity obligations	All other participation options **remain** (i.e. FRAP, self-scheduling)
REQUIREMENTS	Design should neither unfairly incent RBDC Opt-out nor force RBDC participation	
LSE capacity requirement	*respective PY PRM +X%	MISO will evaluate & update "X" every year "X %" adder stays same for the entire 3 year lock-in period
Term	Min 3 years in/out	
Partial RBDC Opt-out?	Not allowed	Partial FRAPs are allowed
Locational requirements	Must meet LCR	
Time required to make showing	7th Business Day of February prior to PRA	Moving the showing 6 – 12 months prior to PRA has more costs than benefits
Excess capacity requirement	No withhold	MISO to periodically evaluate & update if necessary
PARTICIPATION		
	RERRA Notification	Respect states' rights towards RA
AUCTION DYNAMICS		
CIL/CEL/SFT	Load/resources subject to these constraints	
RBDC effects	RBDC curves will be <u>not</u> adjusted based on RBDC Opt-out participation	
SETTLEMENTS		
Subject to ACP?	No. only subject to positive congestion	
Failure to meet obligations?	Charged at CDC rate, and potentially forced back into RBDC	

**Note: LSEs opting out of RBDC will have a Final PRMR requirement based on PY PRM plus X% adder*

Figure 12. Design attributes for proposed RBDC opt out

All LSEs will need to choose whether they are opting out of the market entirely by paying the Capacity Deficiency Charge, using one of the existing options to participate in the market, or pursuing the RBDC opt out. The RBDC opt out will require an LSE to elect the RBDC opt out for three consecutive Planning Years, which is the RBDC opt out Lock-In Period. Additionally, unlike FRAP, there is no partial RBDC opt out. MISO has designed the LSE capacity requirement in the RBDC opt out to provide comparable treatment to LSEs who participate in the PRA and those who elect the RBDC opt out. To this end, MISO proposes a capacity requirement for an LSE choosing the RBDC opt out consisting of the LSE's PRM plus an adder of X% above the PRM – the RBDC opt out Adder, in each year of the RBDC opt out Lock-In Period.

LSEs selecting the RBDC opt out must still meet their share of LCR. Any resources that LSEs either owned or have contractual rights towards above the RBDC opt out resource adequacy requirements can be offered into the PRA, subject to market monitoring and mitigation provisions currently in the MISO tariff.

In deference to states' rights towards resource adequacy, MISO will notify the RERRA(s) following the submission of an RBDC opt out by an LSE. RERRA(s) may elect to notify MISO within ten (10) business days whether the LSE is authorized to select the RBDC opt out. Upon receipt of such a notification from the RERRA(s) that the LSE is not authorized to elect the RBDC opt out, MISO will reject the LSE's RBDC Opt out and the LSE will participate in the PRA. If MISO receives no notification from the RERRA(s) within the ten (10) business day period, and an LSE has demonstrated that it has designated ZRCs to

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meet its Final PRMR and share of LCR for each LRZ for each season, then the proposed RBDC opt out by the LSE will be accepted by MISO.

LSEs using the RBDC opt out that fail to have sufficient ZRCs to meet its resource adequacy requirements will incur an RBDC opt out Deficiency Charge. This charge will be the product of 2.748 times CONE and the amount of ZRC shortfall.

While the RBC opt out Adder will be calculated for every Planning Year, an LSE electing the RBDC opt out will be required to meet its seasonal PRMR that is calculated based on the seasonal PRM and the RBDC opt out Adder value (X%) established in the first year of the LSE's RBDC opt out Lock-In Period for the entire RBDC opt out Lock-In Period. The RBDC opt out Adder will be constant across the seasons.

MISO intends to use System-Wide and Sub-Regional RBDCs and historical market clearing data to determine initial X% that will be applicable to LSEs that are electing RBDC opt out starting PY25-26. MISO intends to overlay the last three Planning Years' market data that is available along with the applicable System-Wide and Sub-Regional RBDCs to calculate average clearing above PRM. If PRA clearing comes out to be less than the PRM in this analysis, then the corresponding value will be set to zero (0) for the purposes of calculating X% adder.

For example, RBDC opt out Adder (X%) of 3.1% for Summer is calculated using average of (3.9, 0, 1.9, 4.1, 4.2, 4.8) as shown by highlighted cells in table of Figure 13.

Season	PY	PRM	RBDC clearing beyond PRM		
			System-wide	North/Central Region	South Region
Summer	PY 23-24	7.4%	3.9%	Systemwide RBDC is binding	4.1%
	PY 22-23	8.7%	0%		4.2%
	PY 21-22	9.4%	1.9%		4.8%
	3-year Average		3.1%		
Fall	PY 23-24	14.9%	1%	3.6%	3.2%
	Average		3.4%		
Winter	PY 23-24	25.5%	2.5%	2.9%	Systemwide RBDC is binding
	Average		2.7%		
Spring	PY 23-24	24.5%	1%	Systemwide RBDC is binding	2.4%
	Average		1.7%		

Note: Highlighted cells are used to calculate the average of respective seasons to determine Seasonal X% adder. In the case where System-Wide RBDC is binding (instead of Regional RBDC), the System-Wide numbers are used to calculate X% adder.

Figure 13. Calculation example for RBDC opt out Adder (X%)

7 PRA Procedures

MISO will conduct the PRA for each season using the following auction procedures to determine the ACP for each LRZ. The existing PRA has an objective function to minimize as-offered costs. The objective of the RBDC design is to minimize the difference between the sum of as-offered costs of supply and the sum of as-bid demand (reflected through the RBDCs and LCRs) to maximize social surplus, using the as-offered overall costs of capacity procurement and the as-bid overall benefits of capacity procurement reflected in the RBDCs over the time horizon, subject to network constraints, as-offered costs and the SRPBC. A multi-zone optimization methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to meet the supply demand balance both for MISO and for each of the two Planning Areas (i.e. MISO North/Central and MISO South) by clearing ZRC Offers and establishing the Final PRMR, as determined by application of the RBDCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs; and (4) respect the SRPBC, if applicable.

7.1 Offer and Price Caps

Offer caps will remain as they are in the existing PRA, at CONE divided by the number of days in a season. If there are no LCR shortages in an LRZ, seasonal price cap will be at CONE divided by the number of days in a season (i.e. upper bound for RBDC). The RBDC auction structure incorporates downward sloping demand curves, facilitating a seamless reflection of scarcity prices across various MW levels. Hence, no retroactive price adjustment (or administrative price cap) is needed for requirement that is represented by RBDCs. Because the LCR is a vertical requirement and not a RBDC, the price cap for LCR shortages only will remain at 1.75xCONE.

7.2 PRA Settlement

LSEs using the RBDC Opt-Out will have Final PRMRs calculated by multiplying the LSE's forecasted Coincident Peak Demand for each season, including transmission losses, by (1 + PRM + RBDC Opt-Out Adder).

For LSEs not using the RBDC Opt-Out, the Final PRMR calculation will account for the possibilities of clearing different amounts of capacity in MISO North/Central and MISO South, which is dependent on each subregion's RBDC and offers from MPs. LSEs not using the RBDC opt- out will have Final PRMRs calculated by multiplying the LSE's forecasted Coincident Peak Demand for each season, including transmission losses, by (1 + Transmission Provider Region PRM + incremental margin). The incremental margin is determined as the value necessary so that when weighted by the quotient of the MWs of Initial PRMR of LSEs not using the RBDC opt out and the Transmission Provider's Initial PRMR, and added to the RBDC opt out Adder weighted by the quotient of the MWs of Initial PRMR of LSEs using the RBDC opt out and the Transmission Provider's Initial PRMR, this sums to the cleared quantity of MWs in the PRA specified as a percent of the Transmission Provider's Initial PRMR.

8 Timeline

MISO is planning to file RBDC design changes to FERC by end of Q3 2023 as shown below in the timeline that was shared with the stakeholders at the RASC. First implementation of this design is planned for the 25-26 PRA

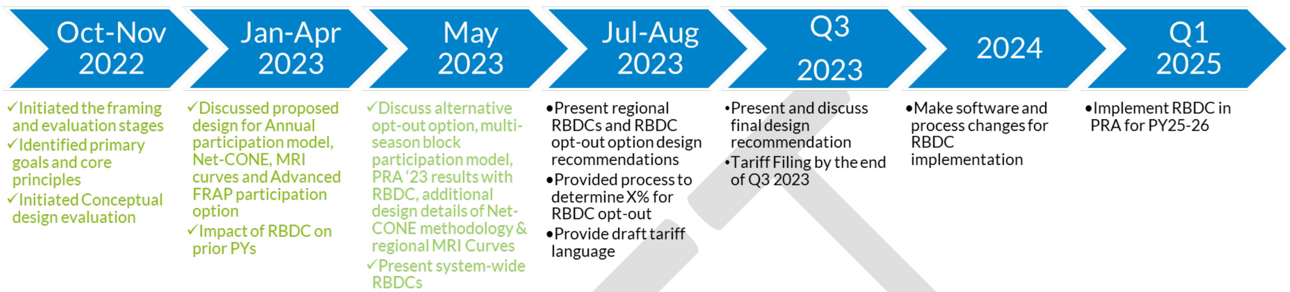

Figure 10. Tentative timeline for RBDC design changes

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9 Acronyms and Definitions

AFRAP	advanced fixed resource adequacy plan
CDC	capacity deficiency charge
CEL	capacity export limit
CIL	capacity import limit
CONE	cost of new entry
EUE	expected unserved energy
FRAP	fixed resource adequacy plan
IRP	integrated resource planning
LCR	local clearing requirement
LOLE	loss of load expectation
LOLH	loss of load hours
LOLP	loss of load probability
LSE	load serving entity
LRZ	local resource zone
MRI	marginal reliability impact
Net CONE	CONE – inframarginal rents in A/S markets
PRA	planning resource auction
PRM	planning reserve margin
PRMR	planning reserve margin requirement
PY	planning year
RBDC	Reliability-Based Demand Curve
RERRA	relevant electric retail regulatory authority
SAC	seasonal accredited capacity
SFT	simultaneous feasibility test
UCAP	unforced capacity
VOLL	value of lost load
WTA/WTP	willingness to accept/pay
ZDC	zonal delivery charge

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Reliability-Based Demand Curve(s)

Resource Adequacy Subcommittee

RASC-2019-8

September 08, 2023

Sep 6th Revision: Updated examples on Slides 13 through 20
Sept 8th Revision: Updated highlighting on Slide 18 and 20

Case No. 2023-00013
Attachment 4 to Response to PSC 3-2

Purpose & Key Takeaways

Purpose: Review MISO's final proposal for design of Reliability-Based Demand Curves

Key Takeaways:

- MISO recommends not to truncate RBDCs
- MISO provides clarification on how PRA clearing will be based on optimization of all modeled constraints
- MISO will retain current administrative price cap (1.75 x annual cone) only for Local Clearing Requirement because of its vertical nature
    - Price cap for each RBDC will be seasonal CONE (annual CONE/# of days in the season)
- MISO is targeting to file necessary tariff changes to FERC by end of Sept. 2023 and will work with stakeholders on necessary BPM edits after the FERC filing.

Outline

- RBDC Truncation and Clearing outcomes
- Price Cap
- PRA Clearing with System-wide and Regional RBDCs
- White Paper

RBDC Truncation and Clearing Outcomes

Based on the stakeholder feedback, MISO previously proposed truncating tail ends of RBDCs at the lower bound of 6% above PRM†

RBDCs (systemwide and sub-regional) to be truncated at 6% above PRM† all seasons

- MW quantities beyond truncation point will not be purchased

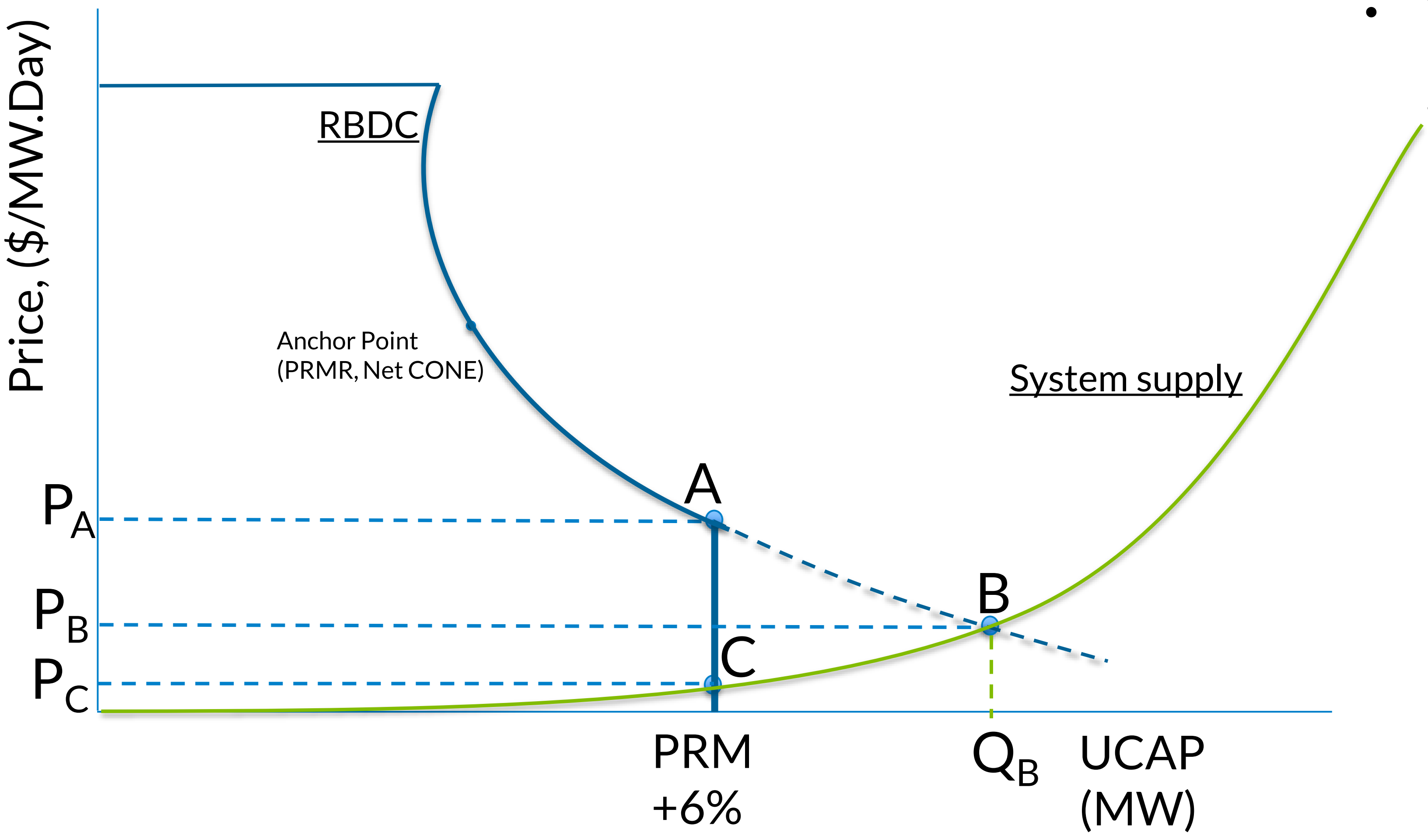
MISO analyzed current RBDCs by using 1% of seasonal offer cap* as reference and proposed above truncating percentage (i.e. 6% above PRM)

- Proposed approach addresses over procurement concerns

†For sub-regional curves, anchor point on curves will be used as reference since PRM refers to system-wide margin percentage only

*Seasonal offer cap (in $/MW.Day) = CONE ($/MW)/# of days in season

There are three alternatives for administratively setting price when supply curve intersects RBDC beyond truncated point



- This illustrative example shows 3 options for clearing using the RBDC that is truncated at 6%
  - Option 1 – Use prices based on Point A (P_A); Prices set by the RBDC or demand (not supply)
  - Option 2 – Use prices based on Point B (P_B); Prices set by the supply based on the intersection point of RBDC and supply curve beyond the truncation point
  - Option 3 – Use prices based on Point C (P_C); Prices set by the supply based on the intersection point on truncated part of RBDC

MISO recommends not to truncate RBDCs and set clearing prices based on intersection of supply and demand curves

- Fully reflect reliability value of incremental capacity
- Ensure transparent market clearing prices
- Truncating RBDCs will require administrative price and quantity setting

Price Cap

MISO will use different price cap for RBDCs and Local Clearing Requirement (LCR) which is a vertical demand curve

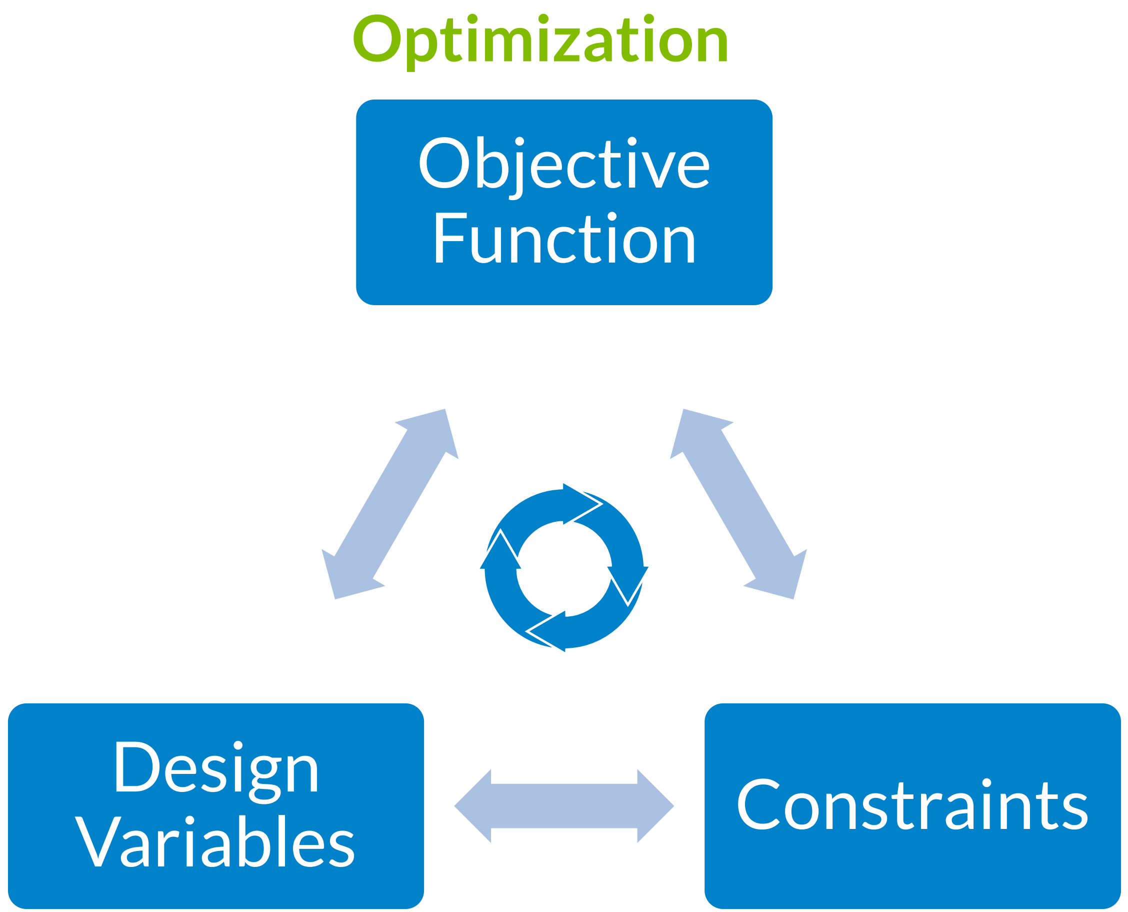
RBDCs	LCR
• Price cap will be same as upper bound of reliability-based demand curve • For each Season, Price Cap will be Annual CONE divided by number of days in the Season (~$1000/MW.Day)	• Administrative price cap of 1.75 x Annual CONE will be applied only for LCR shortage conditions while ensuring that it does not end-up lower than prices set by RBDC.

MISO Rationale

- The current administrative price cap aligns with the present PRA framework where the requirement is fixed and represented by a vertical demand curve
  - A shortage of 1 MW could drive prices to CONE for every season facing scarcity
  - Since MISO is going to continue to represent Local Clearing Requirement (LCR) with a vertical requirement, MISO is proposing use of existing shortage tariff provisions w/ some modifications to only apply for LCR
- The RBDC auction structure incorporates downward sloping demand curves, facilitating a seamless reflection of scarcity prices across various MW levels
  - Implementing a retroactive price adjustment could distort RBDC price signaling and yield suboptimal market results
  - The clearing at seasonal CONE price levels for all four seasons in the PY will rarely, if ever, be attained and in that case Auction prices would be sending transparent signals reflecting shortage across all four seasons.

PRA Clearing Based on Co-optimization

PRA clearing with RBDCs will optimize over multiple constraints



Objective Function

- Minimize difference between offered costs of supply and capacity value of demand

Constraints

- System-wide RBDC
- RBDCs Sub Regional Transfer Constraint (RDT limits)
- Local Clearing Requirement (LCR)
- Local CIL/CEL Requirement

Design Variables

- Generation Clearance
- Demand Curve Clearance

Optimization

- Objective function:

  Minimize (Resource Capacity Cost - Capacity value from system demand curve - Capacity value from regional demand curves)

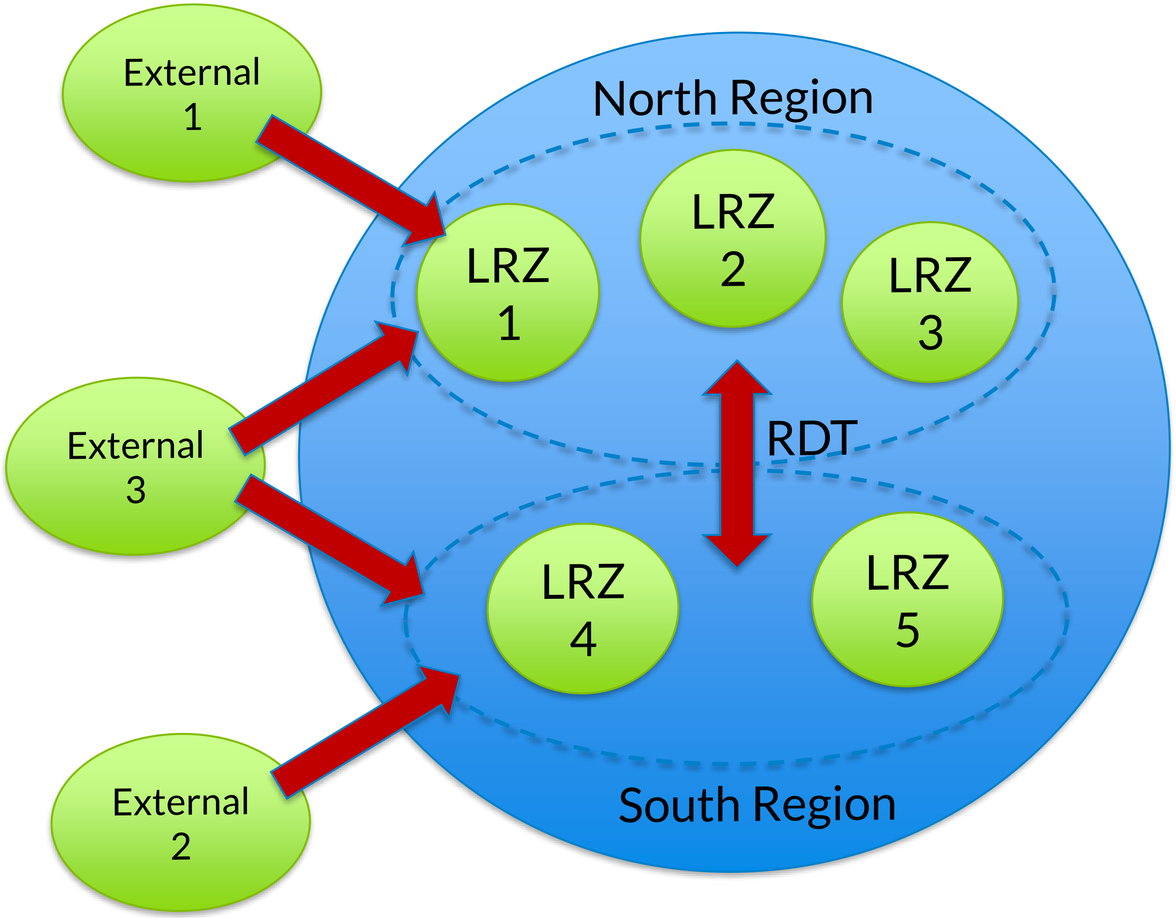
- Constraints applicable to objective function:

  1. System RBDC constraint
  2. Sub-regional RBDC constraints with RDT limits
  3. Zonal clearing requirement constraint (LCR) – No change from today
  4. Zonal import/export limit constraint (CIL and CEL) – No change from today

Optimization Example

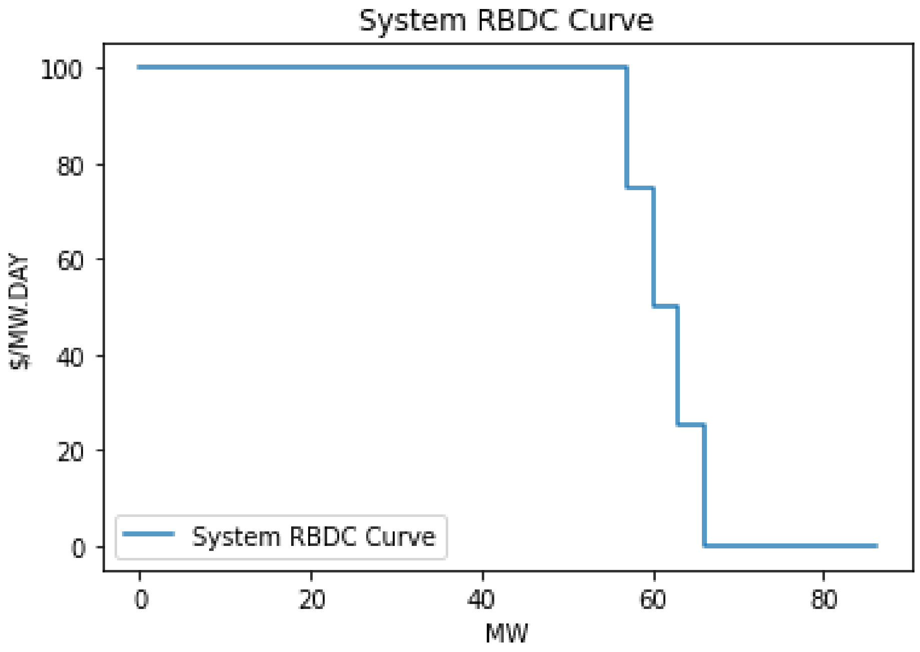
Sub-region /external connection	Zone	Units	UCAP (MW)	Offer ($)	LCR	Initial PRMR ratio to System	CIL/CEL
North	LRZ 1	G1	10	17	8	15%	20/20
	LRZ 2	G2	10	18	9	20%	20/20
	LRZ 3	G3	10	19	15	25%	20/20
		G4	10	20			
South	LRZ 4	G5	10	21	8	16%	20/20
	LRZ 5	G6	10	22	16	24%	20/20
		G7	10	23			
Connected to North	External Zone 1	G8	3	14	N/A	N/A	Na/20
Connected to South	External Zone 2	G9	4	15	N/A	N/A	Na/20
Double connected N(60%)/(40%)	External Zone 3	G10	5	16	N/A	N/A	Na/20

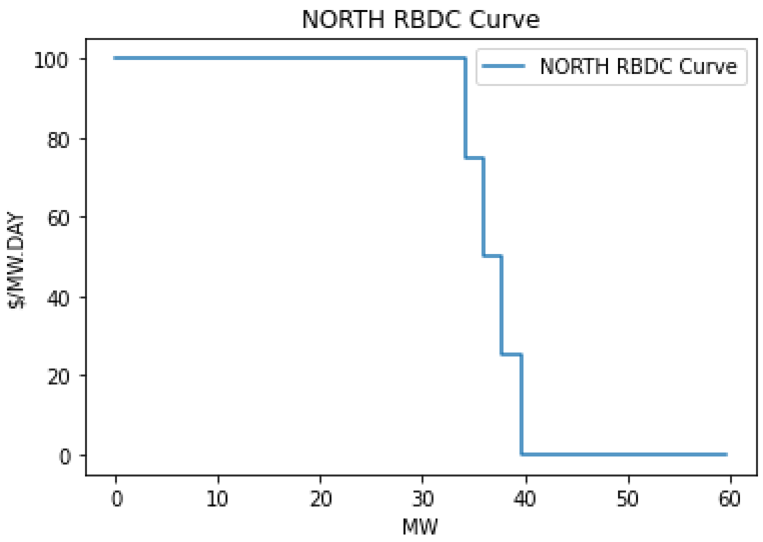
RDTSN = 50; RDTNS = 50

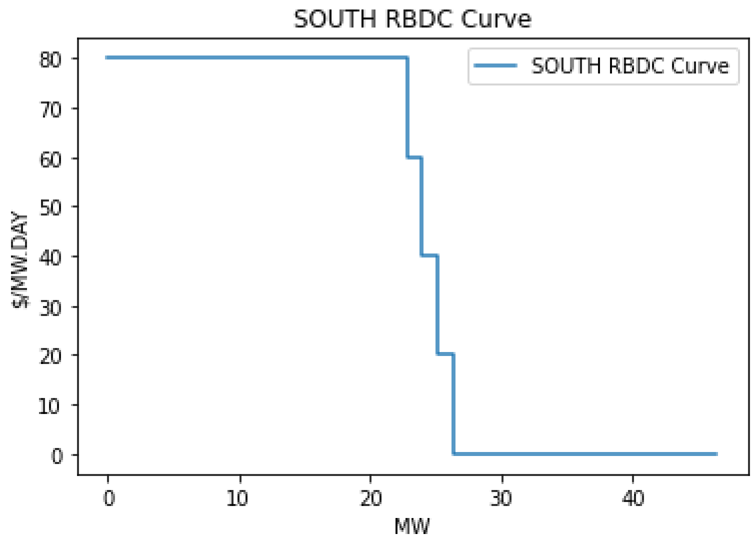


Optimization Example (contd.)

RBDC	CONE	PR MR	Curve point 1 (MW/$)	Curve point 2 (MW/$)	Curve point 3 (MW/$)	Curve point 4 (MW/$)	Curve point 5 (MW/$)
System	100	60	54/100	57/75	60/50	63/25	66/0
North	100	36	32.4/100	34.2/75	36/50	37.8/25	39.6/0
South	80	30	27/80	28.5/60	30/40	31.5/20	33/0







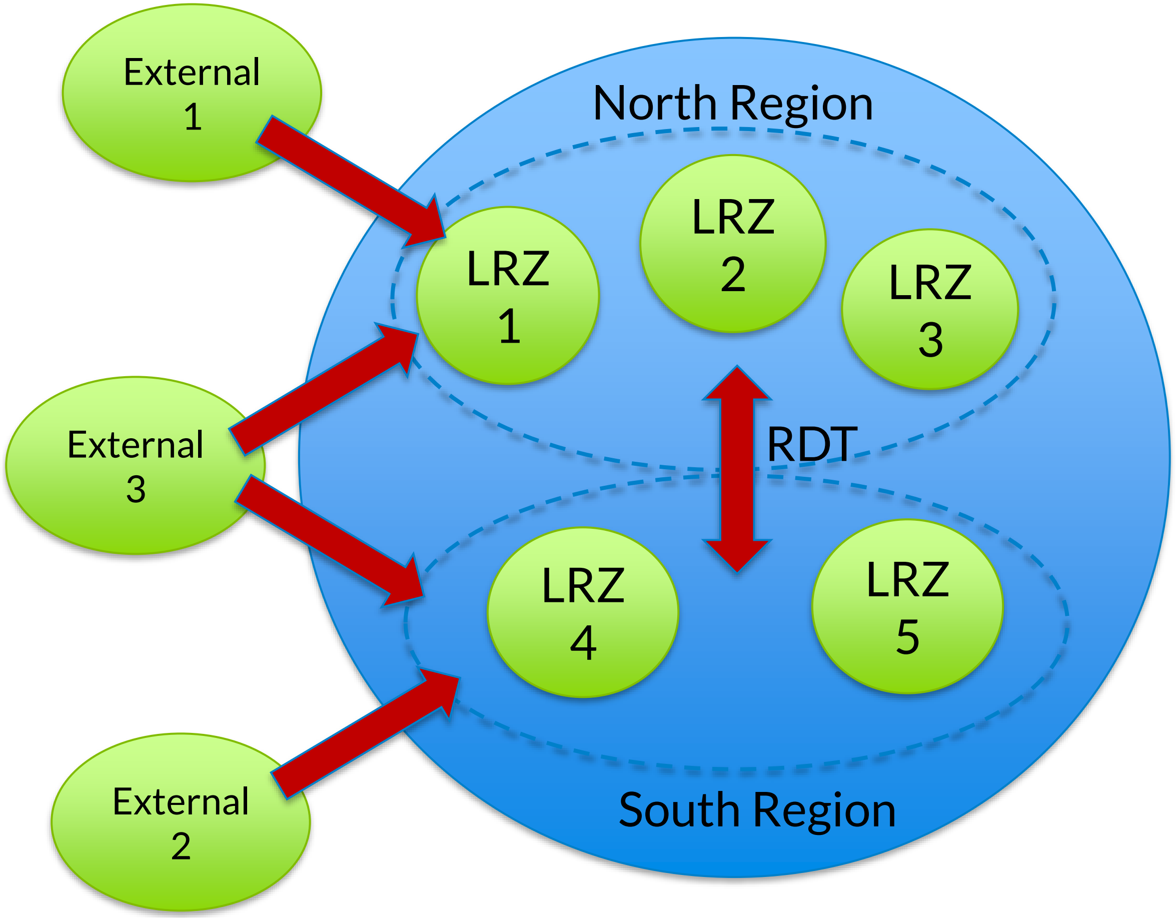
Clearing Example # 1 – System-wide Requirement is binding

- The RDT limit, LCR, CIL/CEL are set high (not binding)
  - System RBDC constraint is binding with shadow price $22
  - Shadow Price for all other constraints will be $0 as they are not binding

<table>
<tr><th>Constraint</th><th>LRZ 1 (in North)</th><th>LRZ 2 (in North)</th><th>LRZ 3 (in North)</th><th>External1 (connect to North)</th><th>LRZ 4 (in South)</th><th>LRZ 5 (in south)</th><th>External2 (connect to South)</th><th>External3 (double connect with 60% to North and 40% to South</th></tr>
<tr><td>System RBDC Shadow Price</td><td colspan="8">$22</td></tr>
<tr><td>Sub-regional RBDC Shadow Price</td><td colspan="4">0</td><td colspan="3">0</td><td>0</td></tr>
<tr><td>LRZ LCR Shadow Price</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>LRZ CIL Shadow Price</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>LRZ CEL Shadow Price</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>Final ACP</td><td>$22</td><td>$22</td><td>$22</td><td>$22</td><td>$22</td><td>$22</td><td>$22</td><td>$22</td></tr>
</table>

Clearing Example #1 (Contd.)

Sub-region /external connection	Zone	Units	UCAP (MW)	Offer ($)	Clearance (MW)	ACP($)
North	LRZ 1	G1	10	17	10	22
	LRZ 2	G2	10	18	10	22
	LRZ 3	G3	10	19	10	22
		G4	10	20	10	22
South	LRZ 4	G5	10	21	10	22
	LRZ 5	G6	10	22	5.8	22
		G7	10	23	0	22
Connected to North	External Zone 1	G8	3	14	3	22
Connected to South	External Zone 2	G9	4	15	4	22
Double connected N(60%)/(40%)	External Zone 3	G10	5	16	5	22



Binding constraint(s):

- System RBDC with Shadow price = $22

Clearing Example # 2 – System-wide Requirement and Sub-regional RBDC (South) are binding

- From the Example 1, change the RDTSN limit to 8MW and RDTNS limit to 7MW
  - System RBDC constraint binds with SP =$22
  - North region RBDC with RDTNS limit constraint binds with SP=-$2
  - Shadow Price for all other constraints will be $0 as they are not binding

Constraint	LRZ 1 (in North)	LRZ 2 (in North)	LRZ 3 (in North)	External1 (connect to North)	LRZ 4 (in South)	LRZ 5 (in south)	External2 (connect to South)	External3 (double connect with 60% to North and 40% to South
System RBDC Shadow Price	$22							
Sub-regional RBDC Shadow Price	-$2				$0			-$1.2
LRZ LCR Shadow Price	$0	$0	$0	$0	$0	$0	$0	$0
LRZ CIL Shadow Price	$0	$0	$0	$0	$0	$0	$0	$0
LRZ CEL Shadow Price	$0	$0	$0	$0	$0	$0	$0	$0
Final ACP	$20	$20	$20	$20	$22	$22	$22	$20.8

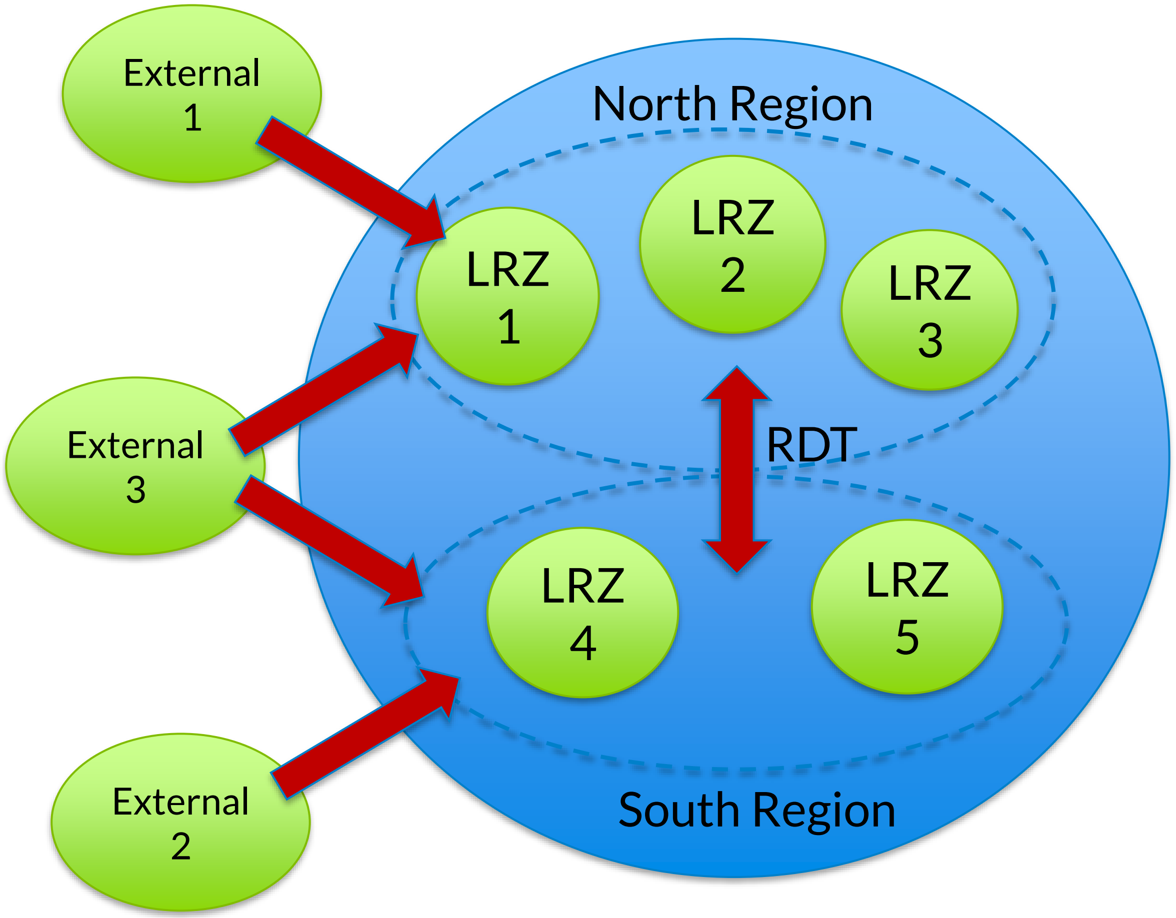
MISO

Clearing Example #2 (Contd.)

Sub-region /external connection	Zone	Units	UCAP (MW)	Offer ($)	Clearance (MW)	ACP ($)
North	LRZ 1	G1	10	17	10	20
	LRZ 2	G2	10	18	10	20
	LRZ 3	G3	10	19	10	20
		G4	10	20	8.8	20
South	LRZ 4	G5	10	21	10	22
	LRZ 5	G6	10	22	7	22
		G7	10	23	0	22
Connected to North	External Zone 1	G8	3	14	3	22
Connected to South	External Zone 2	G9	4	15	4	22
Double connected N(60%)/(40%)	External Zone 3	G10	5	16	5	20.8

Binding constraint(s):

- System RBDC Shadow price = $22
- Sub-regional RBDC Shadow Price = -$2 (which is the difference between G6 ($22) and G4 ($20))



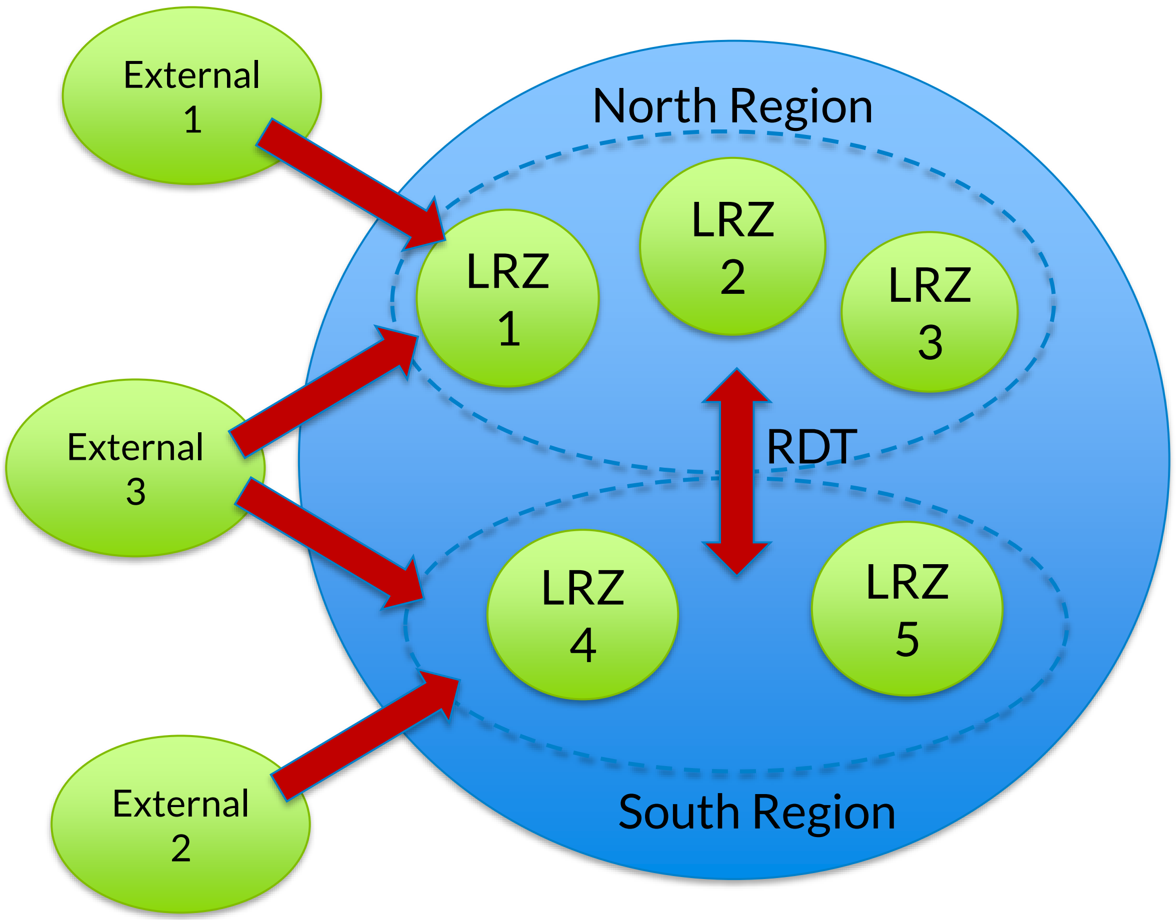
Clearing Example # 3 – System-wide Requirement, sub-regional RBDC(South) and LCR (LRZ 5) are binding

- Based on Example 2, apply 15MW as the LRZ 5 LCR requirement
  - System RBDC constraint is binding at $21
  - North region RBDC with RDT limit constraint binds with SP=-$1
  - LRZ 5 LCR is binding at $2
  - Shadow Price for all other constraints will be $0 as they are not binding

Constraint	LRZ 1 (in North)	LRZ 2 (in North)	LRZ 3 (in North)	External1 (connect to North)	LRZ 4 (in South)	LRZ 5 (in south)	External2 (connect to South)	External3 (double connect with 60% to North and 40% to South
System RBDC Shadow Price	$21							
Sub-regional RBDC Shadow Price	-$1				$0			-$0.6
LRZ LCR Shadow Price	$0	$0	$0	$0	$0	$2	$0	$0
LRZ CIL Shadow Price	$0	$0	$0	$0	$0	$0	$0	$0
LRZ CEL Shadow Price	$0	$0	$0	$0	$0	$0	$0	$0
Final ACP	$20	$20	$20	$20	$21	$23	$21	$20.4

Clearing Example #3 (Contd.)

Sub-region /external connection	Zone	Units	UCAP (MW)	Offer ($)	Clearance (MW)	ACP ($)
North	LRZ 1	G1	10	17	10	20
	LRZ 2	G2	10	18	10	20
	LRZ 3	G3	10	19	10	20
		G4	10	20	8.8	20
South	LRZ 4	G5	10	21	2	21
	LRZ 5	G6	10	22	10	23
		G7	10	23	5	23
Connected to North	External Zone 1	G8	3	14	3	20
Connected to South	External Zone 2	G9	4	15	4	21
Double connected N(60%)/(40%)	External Zone 3	G10	5	16	5	20.4



Binding constraint(s):

- System RBDC Shadow Price = $21
- Sub-regional RBDC Shadow Price = -$1 (the offer difference between G4 ($20) and G5 ($21))
- LCR constraint on LRZ 5 Shadow Price = $2 (the offer difference between G7 ($23) and G5 ($21))

RBDC Draft White Paper

MISO has published a draft white paper on RBDC Conceptual Design

- The goal of this white paper is to summarize MISO's RBDC design
- The white paper includes description of the key drivers and design elements that were discussed at RASC since Oct 2022
- MISO intends to expand the white paper during the implementation phase

Next Steps

MISO plans to make a Tariff filing in Sep ‘23 with expected effective date of Sep ‘24 and target implementation in ‘25 PRA for PY25-26

Oct-Nov 2022

- ✓ Initiated the framing and evaluation stages
- ✓ Identified primary goals and core principles
- ✓ Initiated Conceptual design evaluation

Jan-Apr 2023

- ✓ Discussed proposed design for Annual participation model, Net-CONE, MRI curves and Advanced FRAP participation option
- ✓ Impact of RBDC on prior PYs

May 2023

- ✓ Discuss alternative opt-out option, multi-season block participation model, PRA ‘23 results with RBDC, additional design details of Net-CONE methodology & regional MRI Curves
- ✓ Present system-wide RBDCs

Jul-Aug 2023

- ✓ Present regional RBDCs and RBDC opt-out option design recommendations
- ✓ Provided process to determine X% for RBDC opt-out
- ✓ Provide draft tariff language

Sep 2023

- Present and discuss final design recommendation
- Tariff Filing by the end of Sep 2023

2024

- Make software and process changes for RBDC implementation

Q1 2025

- Implement RBDC in PRA for PY25-26

Zhaoxia Xie – zxie@misoenergy.org

BIG RIVERS ELECTRIC CORPORATION

AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2020 THROUGH OCTOBER 31, 2022 CASE NO. 2023-00013

Responses to Commission Staff's Third Request for Information Dated November 1, 2023

November 16, 2023

Item 3) ***Refer to BREC's response to Staffs Second Request, Item 14.***

a. Explain whether BREC has any future plans to employ any gas traders to handle the necessary spot market gas procurement for its units.

b. Explain how much BREC has paid for the services it receives from ACES.

Response)

a. Big Rivers currently does not have any future plans to employ any gas traders for handling spot market gas procurement.

b. The cost associated with payments made to ACES for services received by Big Rivers does not flow through the FAC. Big Rivers uses ACES for a number of other services in addition to gas trading and has not requested that ACES separate the amount Big Rivers paid solely for handling spot market gas procurement in billing invoices. Please see the attached copy of the ACES November 2023 billing invoice, which shows the current monthly service fee of $198,315.98.

Witness) Terry Wright, Jr.

SRDT 10/19/2023

Approver:

ACES
excellence in energy

4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 20015
Owensboro, KY 42304

Invoice #:	23A6941-IN
Invoice Date:	10/19/2023
Due Date:	11/1/2023
For the month of:	**November 2023**

Attention: Elizabeth Tutor

400001	2023 Monthly Service Fee	$198,315.58

Total Invoice Amount:	**$198,315.58**
Outstanding Balance:	$0.00
Total Due:	**$198,315.58**

Direct questions to:
Shannon Brand at [redacted]

Remit Payment via:

[redacted]

[redacted]
Account Name: Alliance for Cooperative Energy
Services Power Marketing LLC
d/b/a ACES Power Marketing
[redacted]

Case No. 2023-00013
Attachment to Response to PSC 3-3

BIG RIVERS ELECTRIC CORPORATION

AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2020 THROUGH OCTOBER 31, 2022 CASE NO. 2023-00013

Responses to Commission Staff's Third Request for Information Dated November 1, 2023

November 16, 2023

Item 4) ***Refer to BREC's response to Staffs Second Request, Item 15. The response seems to indicate that when electricity demand is high and when BREC's Green and Reid units may be profitable, it may not be able to transport spot gas to its city gate. Consequently, it may be paying more for energy than it would otherwise. Explain whether BREC has performed a study to determine whether it would be worthwhile to obtain firm transmission pipeline transportation.***

Response) Big Rivers has fully investigated available options and determined that it is not advantageous or economical to obtain firm transmission pipeline transportation, but did not generate a related written study or report. In order to maintain firm gas Big Rivers would incur a large monthly fee and an additional separate fee to maintain firm transportation. Both firm contracts would have to be in place to guarantee uninterruptible gas flow. Those fees have to be paid every month regardless whether the units run or not. Big Rivers' gas units do not get called upon to run enough to justify paying the large monthly fees.

Witness) Vicky L. Payne

BIG RIVERS ELECTRIC CORPORATION

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Responses to Commission Staff's Third Request for Information Dated November 1, 2023

November 16, 2023

Item 5) ***Refer to BREC's response to Staff's Second Request, Item 15b. Explain in detail what BREC means by "ACES nominates gas with the natural gas supplier selected ."***

Response) If and when the market calls for Big Rivers' natural gas unit(s) to run, ACES will nominate gas on the pipeline. This means that ACES will submit bid requests for the natural gas amounts needed to suppliers with which Big Rivers has executed contracts for the sale/purchase of natural gas. The natural gas contracts follow guidelines published by the North American Energy Standards Board ("NAESB"). All natural gas contracts are filed with the Public Service Commission.

Witness) Vicky L. Payne

BIG RIVERS ELECTRIC CORPORATION

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Responses to Commission Staff's Third Request for Information Dated November 1, 2023

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Item 6) ***Refer to BREC's response to Staff's Second Request, Item 17.***

a. With respect to coal prices, the response provided is not clear. Explain how burning less coal compensates for higher prices as a justification for leaving the base fuel rate unchanged.

b. Confirm that natural gas prices are not expected to be higher in the next two-year period than they are currently.

Response)

a. The explanation of the change in Big Rivers' generating assets was to illustrate that there is not a comparable month during the review period to match Big Rivers' current fuel expense and operating practices.

b. Big Rivers cannot confirm natural gas prices are not expected to be higher in the next two-year period than they are currently. Many factors influence natural gas prices, and recent history shows that the market is subject to much volatility. For example, in the previous two years, (October 2021 to October 2023), the Henry Hub Natural Gas Spot Price (which is widely used as an index to compare natural gas prices) has ranged from a high of $8.81 per Million Btu in September of 2022, to a low of $2.15 per Million Btu in May of 2023.

Witness) Christopher A. Warren

AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2020 THROUGH OCTOBER 31, 2022 CASE NO. 2023-00013

Responses to Commission Staff's Third Request for Information Dated November 1, 2023

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Item 7) ***Refer to BREC's response to Staffs Second Request, Item 26. In the spreadsheet, using the BREC.WISON1 tab as an example, confirm that various OFFER QTY and OFFER PRICE tabs represent the unit's offer curve at various levels of output and the DA Clearing tab represents the level of output that was cleared in the market at any given hour.***

Response) That is correct. On the TAB BREC.WILSON1, Columns L through AE represent the unit's offer curve at various levels of output. Offer QTY is the MW Breakpoint and OFFER_PRICE is the corresponding price at that output level. Column AG is the Day-Ahead Clearing for that unit.

Witness) Terry Wright Jr.

BIG RIVERS ELECTRIC CORPORATION

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APPLICATION OF THE FUEL ADJUSTMENT CLAUSE
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CASE NO. 2023-00013**

**Responses to Commission Staff's Third Request for Information
Dated November 1, 2023**

November 16, 2023

Item 8) ***Explain in detail the circumstances that would result in BREC reporting a negative dollar value for a Coal burned, Pet Coke burned, Oil burned, Gas burned, or Propane burned under Company Generation in its FAC Form A rate sheet filing.***

Response) A negative dollar value for coal, pet coke, fuel, gas, etc. burned under Company Generation in its FAC Form A rate sheet filing could occur if Big Rivers had a favorable inventory adjustment in the same month that no units were running.

Witness) Vicky L. Payne