POTOMAC ECONOMICS

IMM Quarterly Report: Fall 2025

Presented to:

Markets Committee of the Board of Directors

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Fall Summary

- MISO's markets performed competitively and mitigation was infrequent
- Energy prices rose 44 percent compared to last fall as gas prices rose between 53 and 56 percent and average load rose 2 percent
  - Shortage pricing rose significantly – MISO experienced operating reserve shortages on 7 days, including one event lasting 40 minutes in September
- Day-ahead congestion rose 38 percent, while real-time congestion rose 52 percent consistent with rising gas prices
  - Average hourly wind output fell 8 percent, and curtailments were down 41 percent year over year because of shifting weather patterns
  - Drought conditions in Canada led MISO to export to Manitoba on average, and flows across the RDT were generally in the South to North direction
- Real-time RSG more than doubled over last year
  - More than half was attributable to a long-lead time unit repeatedly committed in MISO South as indicated by a transmission outage study
  - It may be advisable to validate the study results in operations to ensure such commitments are efficient and necessary

Quarterly Summary

POTOMAC ECONOMICS

Fall		Value	Change[1] Prior Qtr.	Change[1] Prior Year
RT Energy Prices ($/MWh)		$39.20	*-19%*	*44%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago		$3.00	*9%*	*56%*
Natural Gas - Henry Hub		$3.27	*8%*	*53%*
Western Coal		$0.84	*4%*	*5%*
Eastern Coal		$2.08	*4%*	*20%*
Load (GW)[2]				
Average Load		73.6	*-16%*	*2%*
Peak Load		106.3	*-13%*	*0%*
% Scheduled DA (Peak Hour)		100.2%	99.2%	101.6%
Transmission Congestion ($M)				
Real-Time Congestion Value		$597.2	*43%*	*52%*
Day-Ahead Congestion Revenue		$452.3	*56%*	*38%*
Balancing Congestion Revenue[3]		-$43.5	-$41.1	-$8.6
Ancillary Service Prices ($/MWh)				
Regulation		$22.15	*28%*	*53%*
Spinning Reserves		$3.53	*4%*	*31%*
Supplemental Reserves		$2.08	*-18%*	*178%*
Short-Term Reserves		$0.24	*-87%*	*22%*

		Value	Change[1] Prior Qtr.	Change[1] Prior Year
FTR Funding (%)		99%	101%	100%
Wind Output (MW/hr)		10,739	*55%*	*-8%*
Wind Curtailed (MW/hr)		460	*146%*	*-41%*
Guarantee Payments ($M)[4]				
Real-Time RSG		$10.1	*2%*	*161%*
Day-Ahead RSG		$9.7	*5%*	*42%*
Day-Ahead Margin Assurance		$16.0	*11%*	*25%*
Real-Time Offer Rev. Sufficiency		$1.3	*113%*	*45%*
Price Convergence[5]				
Market-wide DA Premium		-0.2%	-0.7%	0.4%
Virtual Trading				
Cleared Quantity (MW/hr)		25,222	*22%*	*10%*
% Price Insensitive		58%	57%	49%
% Screened for Review		3%	2%	2%
Profitability ($/MW)		$0.7	$0.3	$0.4
Dispatch of Peaking Units (MW/hr)		1,825	3,999	1,684
Output Gap- Low Thresh. (MW/hr)		71	59	33

Key:
- Expected
- Monitor/Discuss
- Concern

Notes:
1. Values not in italics are the values for the past period rather than the change.
2. Comparisons adjusted for any change in membership.
3. Net real-time congestion collection, unadjusted for M2M settlements.
4. Includes effects of market power mitigation.
5. Values include allocation of RSG.

Quarterly Highlights: Fall 2025

Net Load Ramp Challenges and Reserve Shortages (Slides 17-18)

- Net load ramp challenges continue to rise as solar penetration grows
  - Solar capacity grew 47 percent from last fall, increasing the average net load demand from 3 to 7 pm to almost 12 GW, up from 7 GW last fall
  - This doubled the contingency reserve shortages this fall, mainly from 5 - 7 pm
- One 40-minute contingency reserve shortage occurred on September 25 when prices averaged $3150 per MWh
  - Changes in dynamic STR requirements could mitigate such shortages because they would lead to more resource commitments and imports
  - We analyzed the impacts of raising the STR requirements to be no lower than would be needed to replace its reserves after the largest contingency
    - We reran commitment and dispatch engines with this floor on the requirement
    - LAC would have recommended more than 1200 MW of commitments
    - This additional supply would have lowered the duration and magnitude of shortage pricing during this event by 50 percent
    - The effects would have been larger had imports responded sooner
  - We recommend MISO establish a floor on the dynamic STR requirement

Quarterly Highlights: Fall 2025

Congestion-Related Issues (Slides 20, 23, and 26)

- Congestion patterns changed this fall compared to last year because of:
  - Fewer imports from Manitoba Hydro due to drought conditions in Canada
  - An 8 percent reduction in average hourly wind output – average hourly curtailments were down more than 40 percent
  - These changes led to higher relative prices in the North this fall, compared to last fall, when prices in the North were lower than the system average prices
- Congestion was substantially inflated this fall by a number of factors:
  1. The TOs in the North switch from summer to winter ratings as late as Dec. 1
     - One constraint generated $63 million in congestion from Oct. 1 until its rating was increased on Dec. 1 – Switching to a winter rating earlier (or otherwise adjusting for temperature) would have virtually eliminated this congestion
  2. Using Ambient Adjusted Ratings (AARs) and emergency ratings in real time would substantially reduce MISO's congestion (by $96 million this fall)
     - MISO can accept real-time AARs in multiple ways today, yet less than 20 percent of binding constraints are adjusted for temperature

Quarterly Highlights: Fall 2025

MISO South Transmission Emergency mid-September (Slide 22)

- On September 16, a major 500 kV transmission element was forced out of service, overloading 2 constraints and causing $12 million in congestion
- MISO's operators declared a Transmission Emergency and took multiple actions in quick succession to avoid firm load shed, including:
  - Raised the top of the TCDC for the impacted constraints to $8000 per MWh
  - Dispatched two units into their offered emergency ranges
  - Started 700 MW of generation to manage the constraints, including issuing early starts to multiple units that had day-ahead commitments
  - Manually re-dispatched (MRD) a nuclear unit and three other large units that continued long after the line's return and produced $800,000 in DAMAP
- Key takeaways from the event
  - Operators' swift actions were key for preventing firm load shed and improved communications helped ensure units responded into their emergency ranges
  - The MRDs produced quick responses initially, but using improved TCDCs would substantially lower costs and better manage the violated constraints
  - We found a software issue that led to reserve shortages with no fix available

Quarterly Highlights: Fall 2025

Software Error and Market Re-pricing on TLR Constraints (Slide 24)

- In September, we identified an issue related to the TLR process, and MISO found that it affected TLR limits in the market for 8 days
  - MISO repriced the market under its Continuing Error provisions in 19 hours
- Effects on Oct. 9 were large as forced outages compounded the TLR error
  - 6 GW of wind was curtailed because of the TLR modeling error in hour 12
  - Forced outages of a nuclear and coal steam unit (1400 MW) in the South in the same hour led to high prices and prompted a large increase in imports
  - We collaborated with MISO using our market simulation system to determine appropriate pricing for this hour and other affected periods
  - However, re-pricing issues that affect the dispatch prices, and settlements throughout MISO is harmful to the integrity of the market
- We recommend MISO:
  1. Mitigate re-settlement harm by limiting market repricing to localized errors
  2. When repricing is warranted, employ reruns of the market software to produce accurate prices

Quarterly Summary of IMM Investigations

- We conducted multiple audits and investigations this quarter, including:
  - Four units for physical withholding and two units for overproduction
  - Two units for a potential Tariff violation related to inaccurate values in offers
  - Inaccurate generation testing data (GVTC)
  - Multiple wind and solar units failing to follow curtailment instructions
- We recommended MISO implement two sanctions for overproduction
- We continued to investigate past DR conduct, including:
  - Enrolled LMR capacity that reflect demand not included in the capacity requirements, a portion of which never existed at all
  - DRR failing to curtail when deployed for Contingency Reserve Deployments
- We have been investigating resource performance during emergencies
  - This has raised concerns that some resources have been over-accredited because their ability to perform during emergencies is overstated
  - We believe penalties comparable to proposed LMR penalties are needed

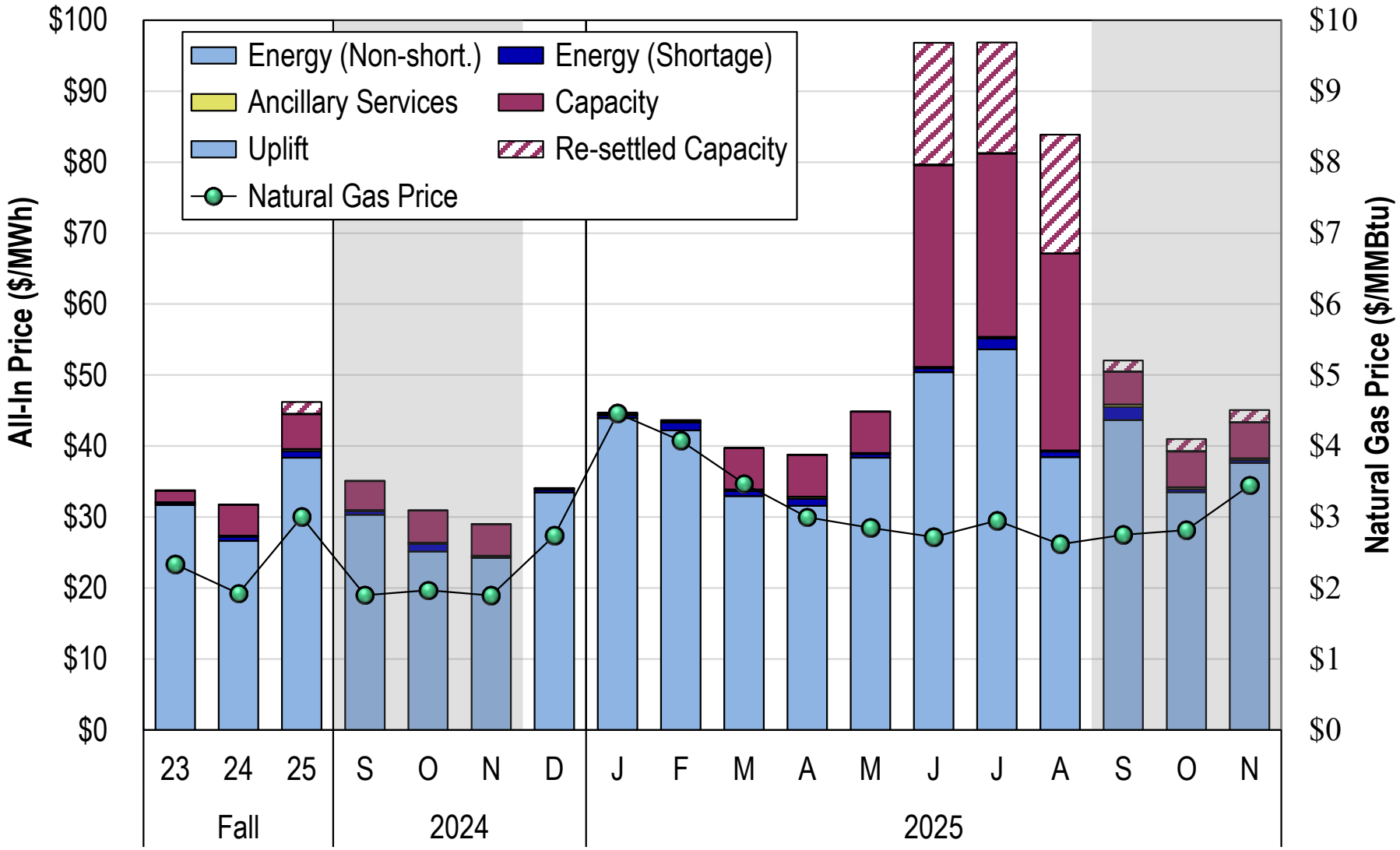
Submittals to External Entities and Other Issues

- During the Fall Quarter, we:
  - Responded to several FERC questions related to prior referrals and FERC investigations and responded to requests for information on market issues
  - Met with MISO on the Futures assumptions and provided feedback on the base case and sensitivity cases
- We continued to work with MISO to develop proposed new rules for determining firm flow entitlements for market-to-market settlements
- MISO implemented its Uninstructed Deviation Enhancement (UDE) flag in August to notify renewables they are flowing on binding constraints
  - Results have been mixed because of forecast errors, the low thresholds for sending the flag, and the lack of settlement incentives to follow dispatch
  - MISO is working to improve forecasting and maintaining higher thresholds
  - We are working with MISO to develop critical settlement penalties to provide efficient incentives to respond to the flag – planned implementation in Q2 2026
- NERC has released its 2025-2026 Winter Assessment and determined MISO is a normal risk, meaning no anticipated reserve shortages

Quarterly Market Results: Fall 2025

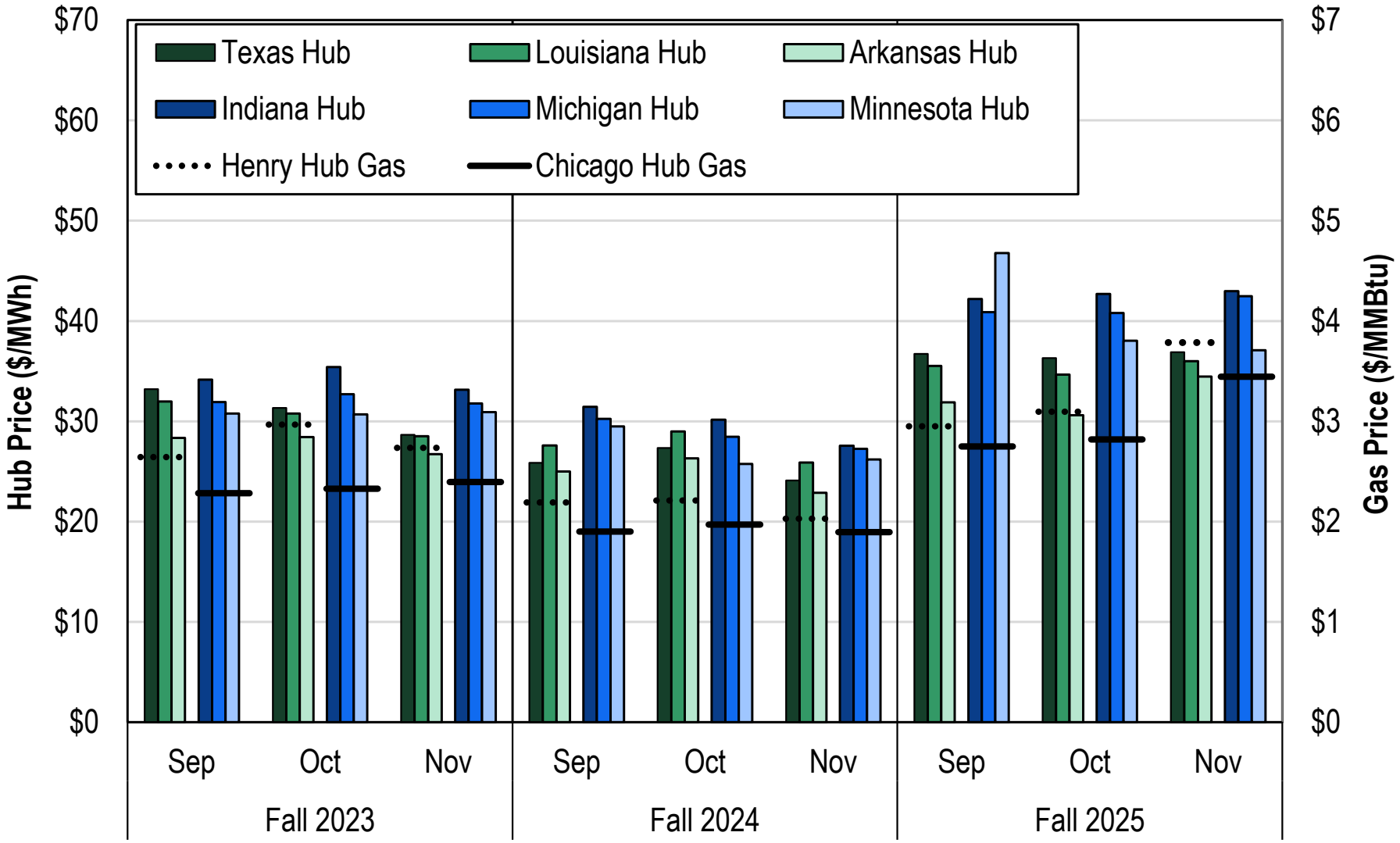
All-In Price

Fall 2023 – 2025



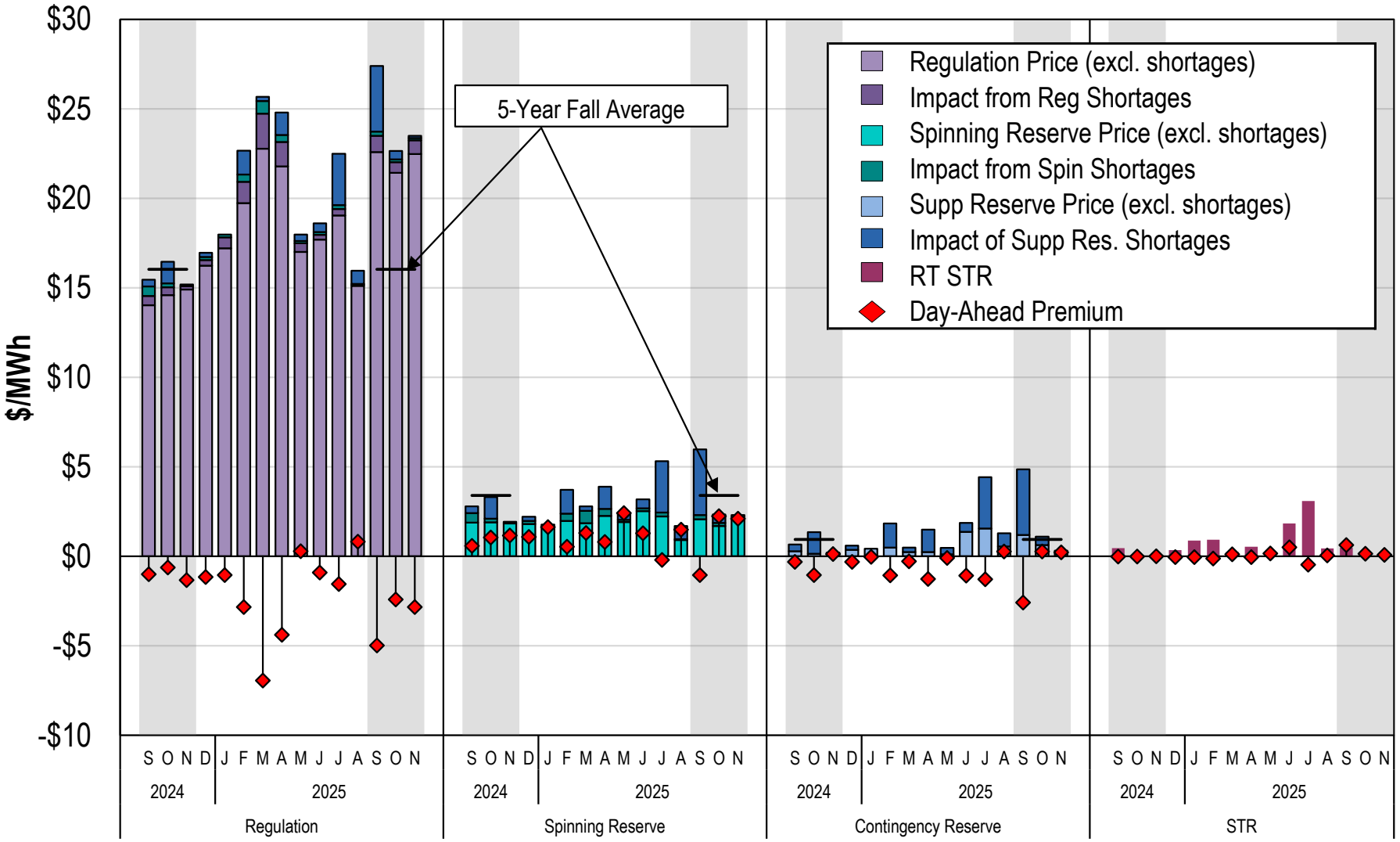
Day-Ahead Average Monthly Hub Prices

Fall 2023 – 2025



Ancillary Services Prices

Fall 2023 – 2025



MISO Fuel Prices

2023 – 2025

Fall Average	2025	2024	2023
Chicago NG	$3.00	$1.92	$2.34
Henry NG	$3.27	$2.14	$2.78

Fall Average	2025	2024	2023
IB Coal	$2.08	$1.73	$1.94
PRB Coal	$0.84	$0.80	$0.80

Capacity, Energy and Price Setting Share

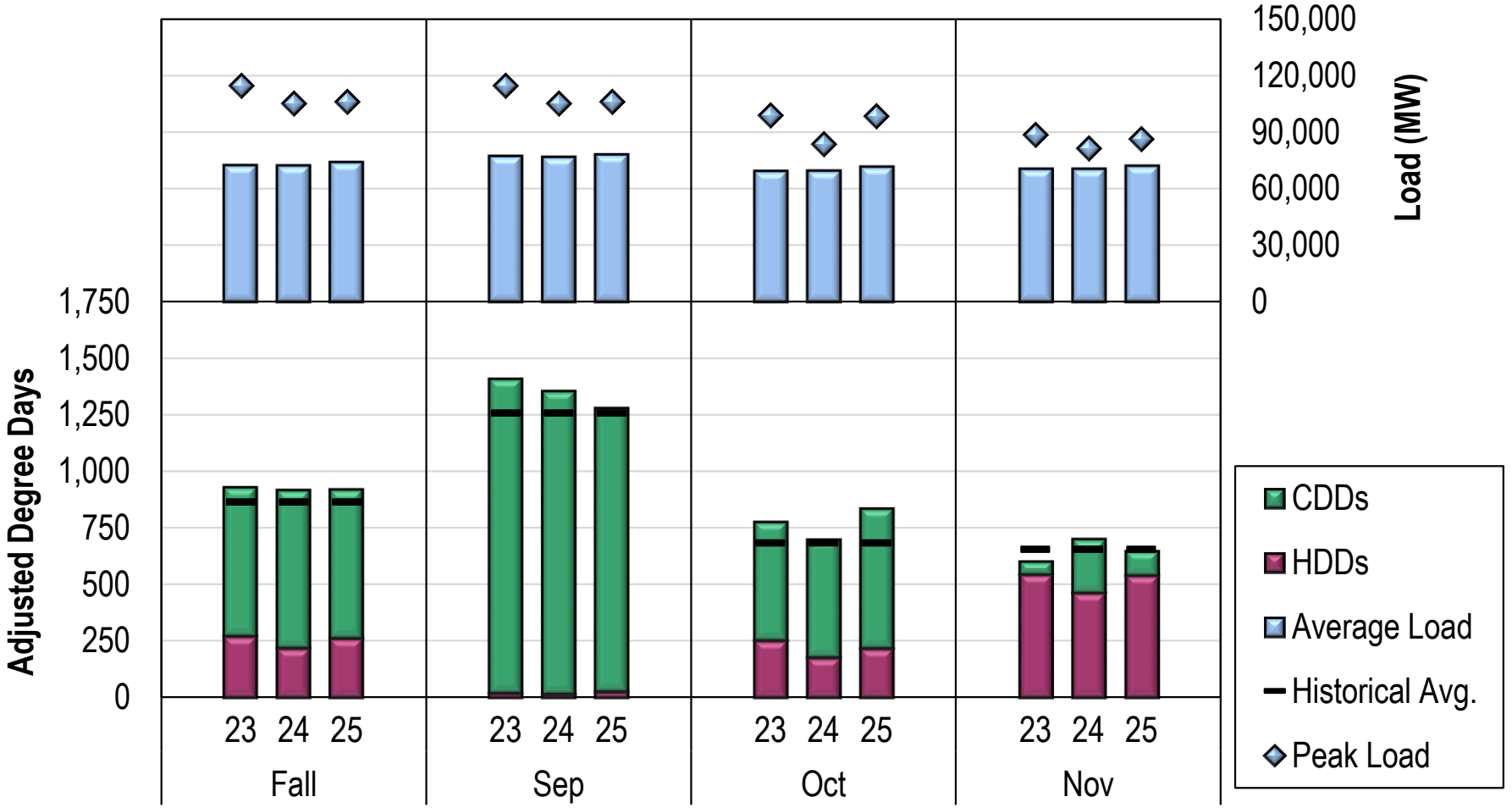
Fall 2024 – 2025

Fall	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025
Nuclear	11,229	11,404	9%	8%	15%	14%	0%	0%	0%	0%
Coal	37,862	37,007	30%	27%	26%	28%	36%	21%	78%	59%
Natural Gas	61,177	62,700	48%	46%	37%	37%	62%	75%	89%	92%
Oil	1,333	1,266	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,735	3,571	3%	3%	1%	1%	1%	0%	2%	2%
Wind*	5,150	10,054	4%	7%	17%	15%	1%	1%	72%	66%
Solar	5,793	8,566	5%	6%	3%	5%	0%	0%	6%	21%
Other	1,934	2,475	2%	2%	1%	1%	0%	2%	1%	6%
Total	**128,212**	**137,043**								

* The seasonal wind ELCC rose from 15.6% in Fall 2024 to 30.7% in Fall 2025.

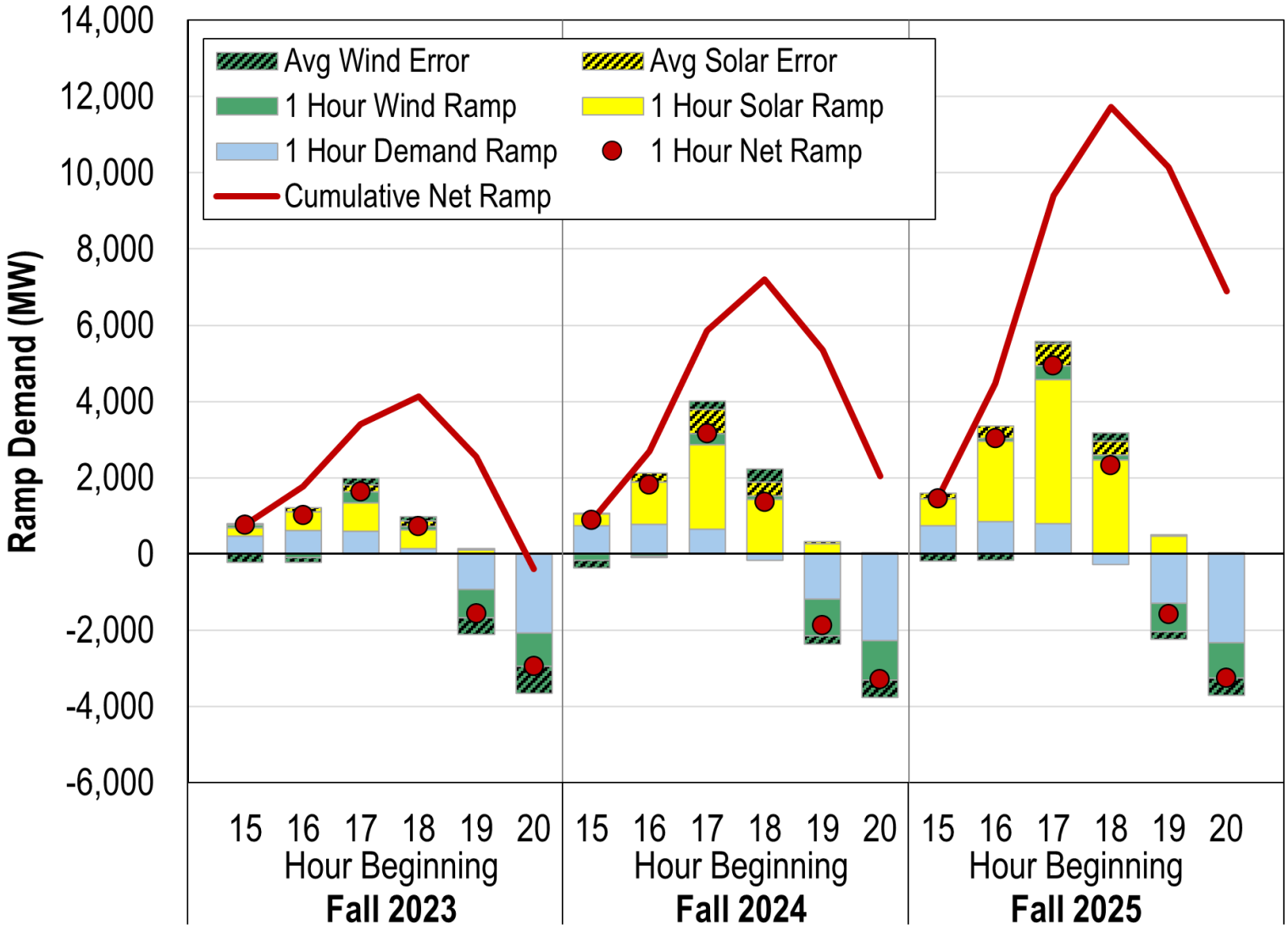
Load and Weather Patterns

Fall 2023 – 2025

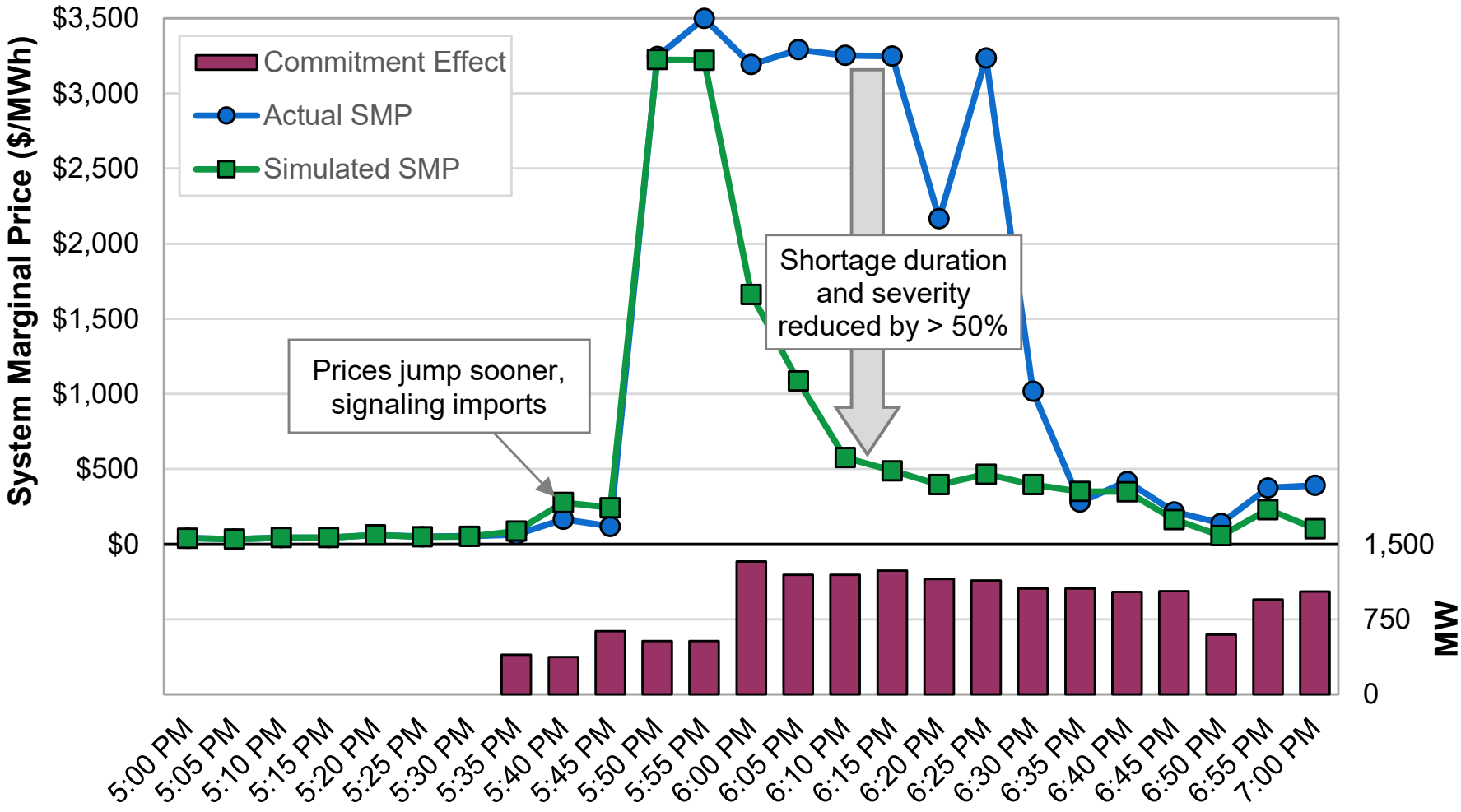


Notes: Midwest degree day calculations include four reprsentative cities: Indianapolis, Detroit, Milwaukee and Minneapolis. The South region includes Little Rock and New Orleans.

Evening Hours Net Load Ramp

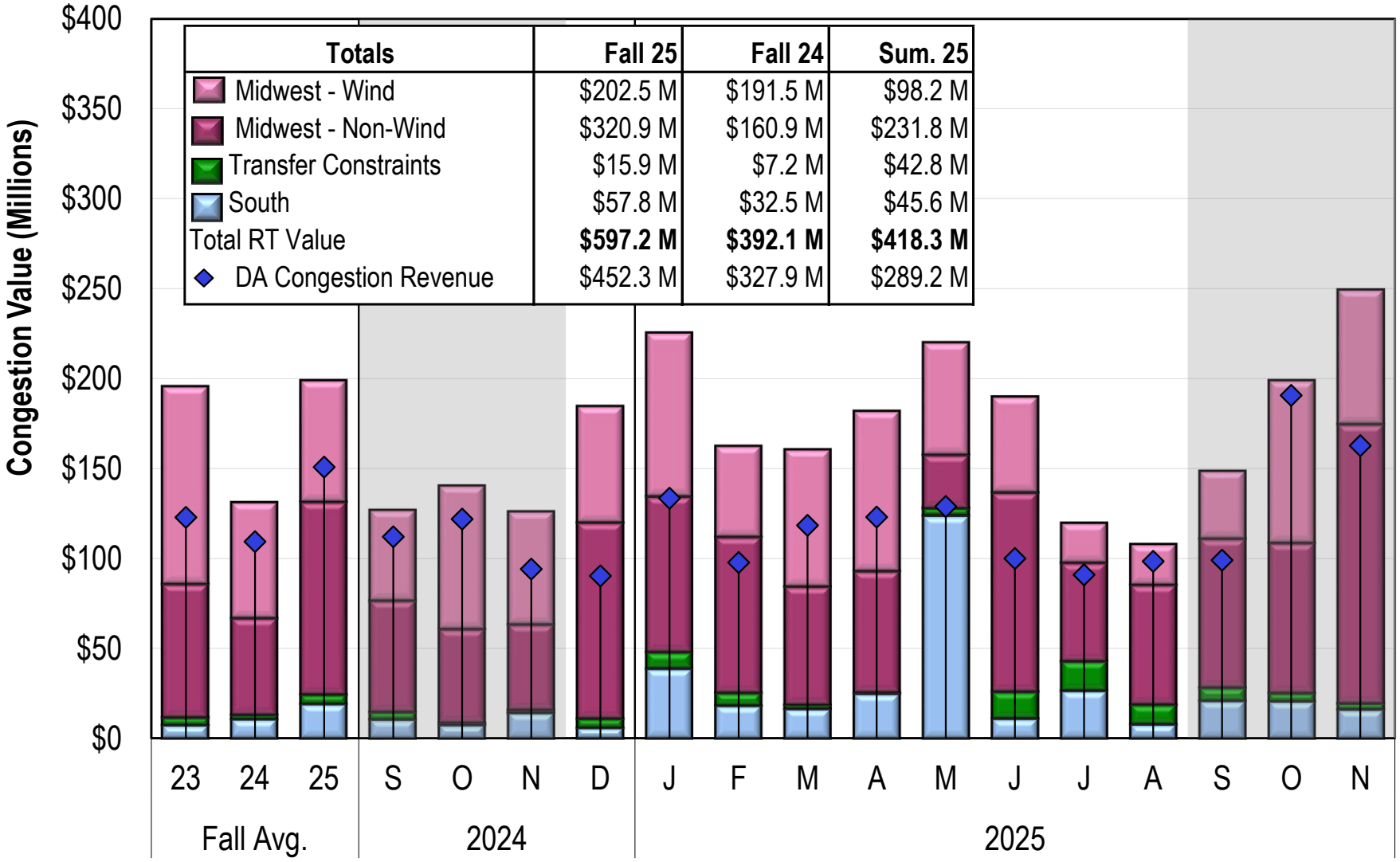


September 25 Extended Operating Reserve Shortage



Value of Real-Time Congestion

Fall 2023 - 2025



Average Real-Time Congestion Components

Fall 2024 – 2025

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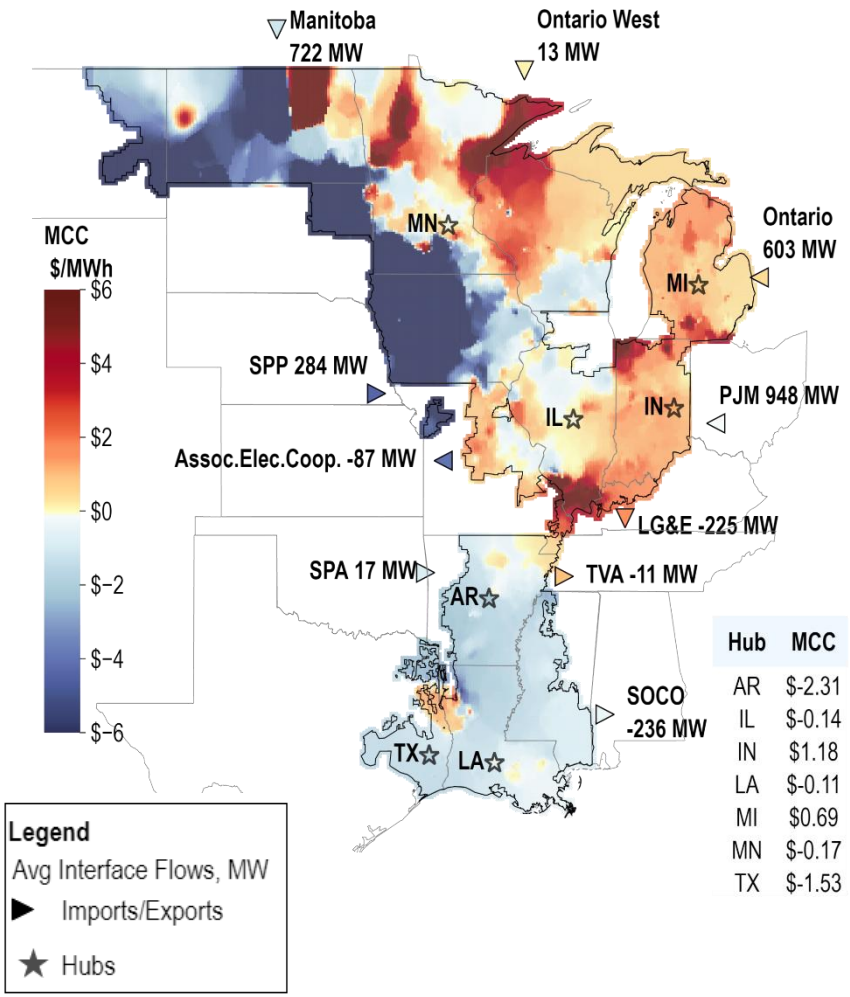
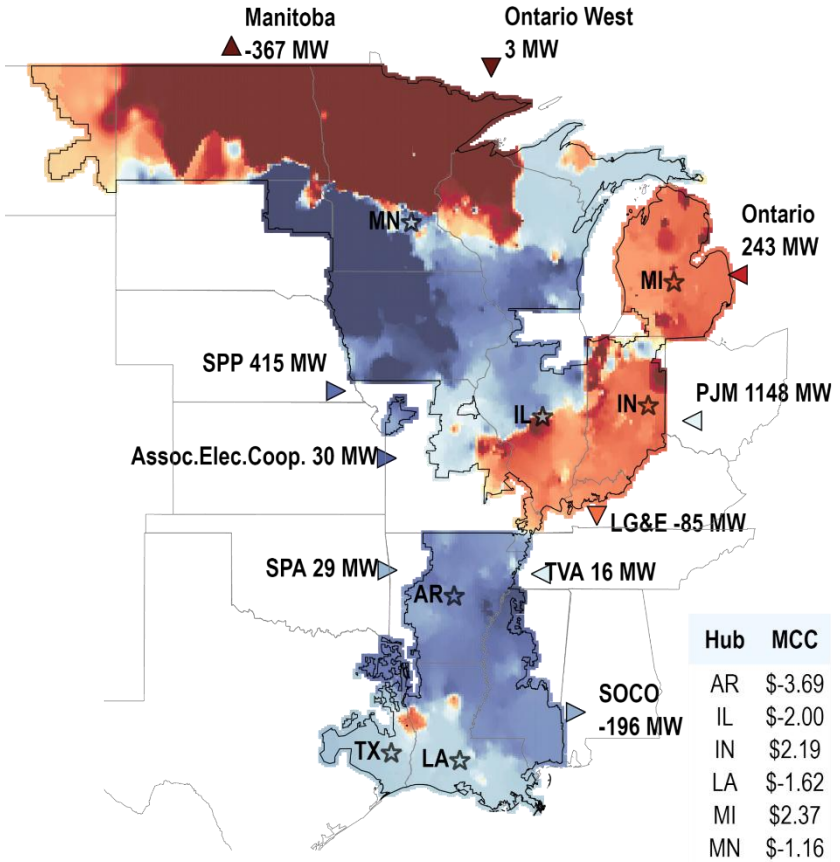
Fall 2024



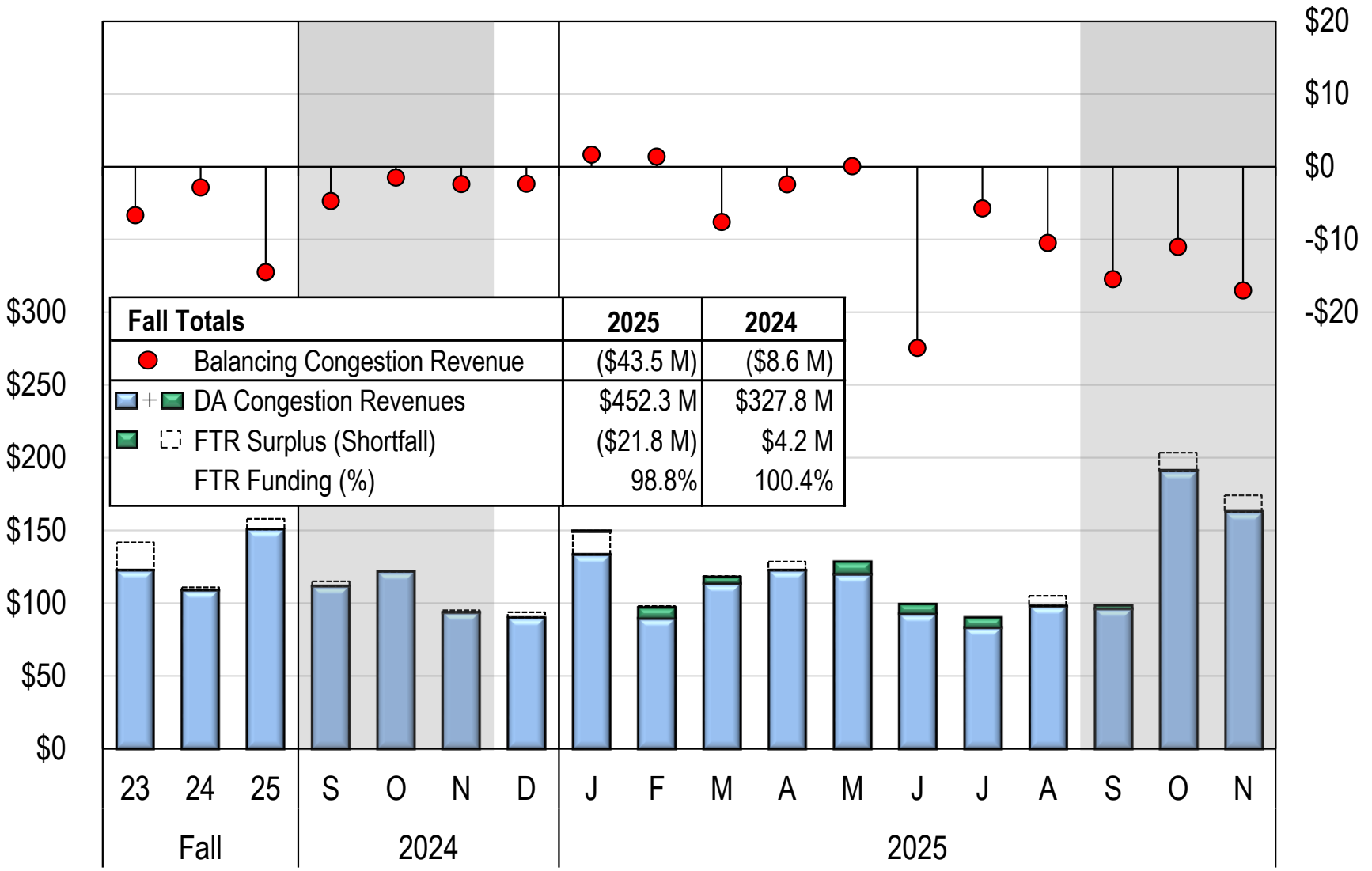
Hub	MCC
AR	$-2.31
IL	$-0.14
IN	$1.18
LA	$-0.11
MI	$0.69
MN	$-0.17
TX	$-1.53

Fall 2025



Hub	MCC
AR	$-3.69
IL	$-2.00
IN	$2.19
LA	$-1.62
MI	$2.37
MN	$-1.16
TX	$-2.03

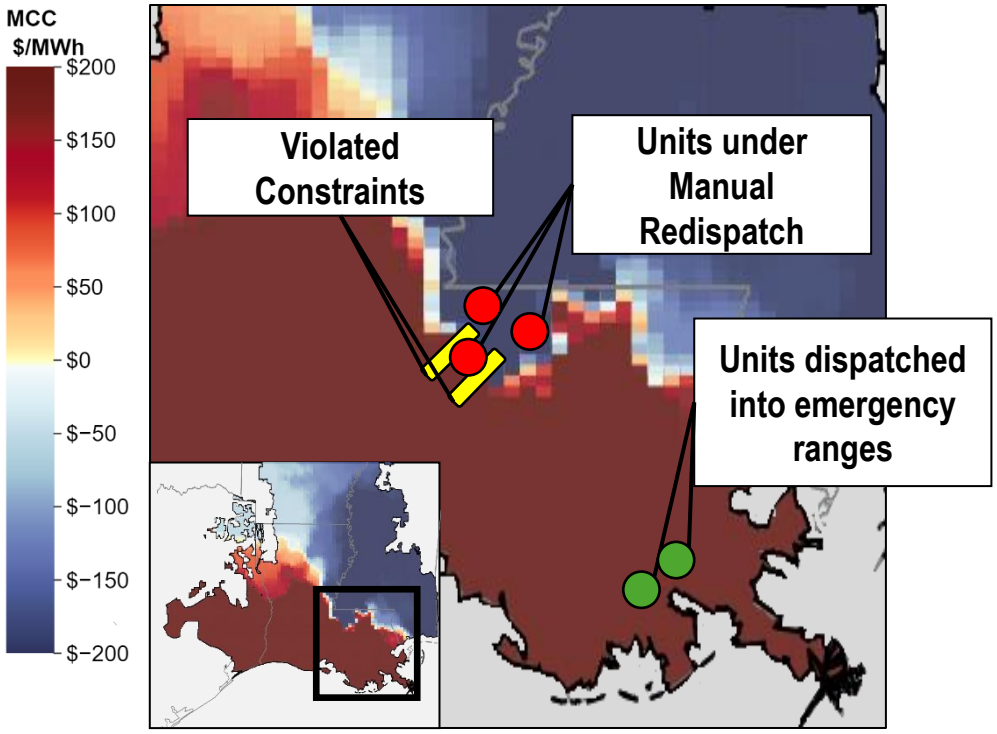
Day-Ahead and Balancing Congestion and FTR Funding

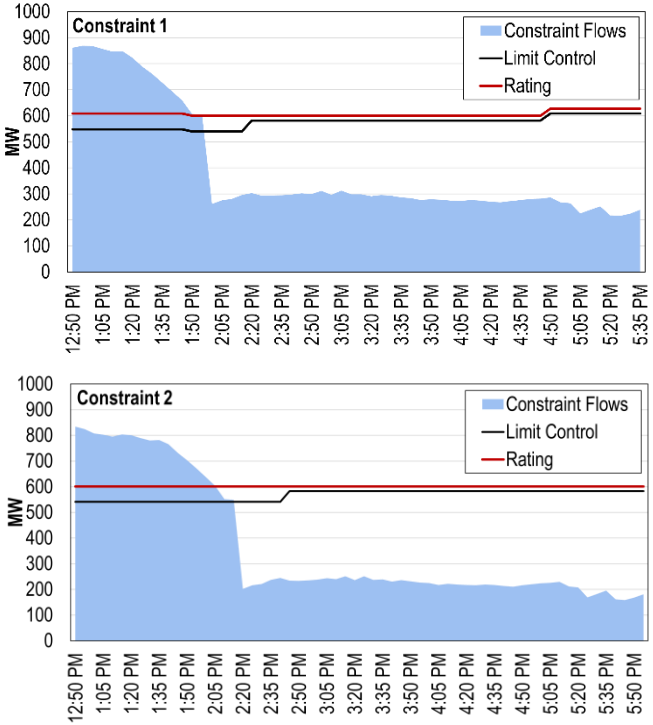


Local Transmission Emergency (LTE) on September 16

Management of LTE in the South

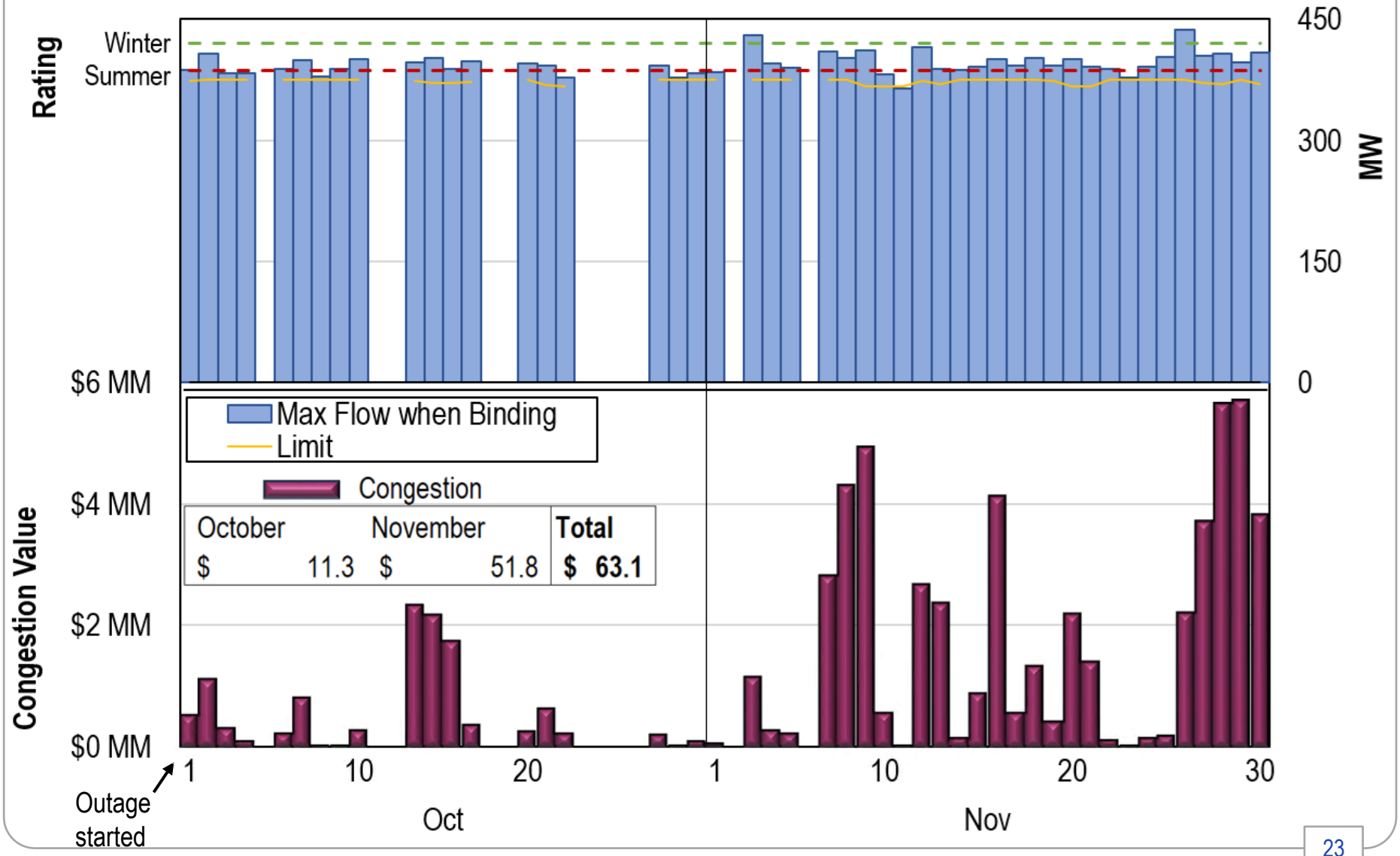
- MISO declared an LTE on Sept. 16 when a 500 kV forced line outage caused severe violations on two constraints – MISO took quick actions to avoid load shed
- Units with opposite effects on the constraints were manually dispatched to balance the violations on the two constraints, causing nearly $800,000 in DAMAP
  - Recommended changes in constraint demand curves would allow the market dispatch to balance these violations, lowering costs and eliminating the DAMAP





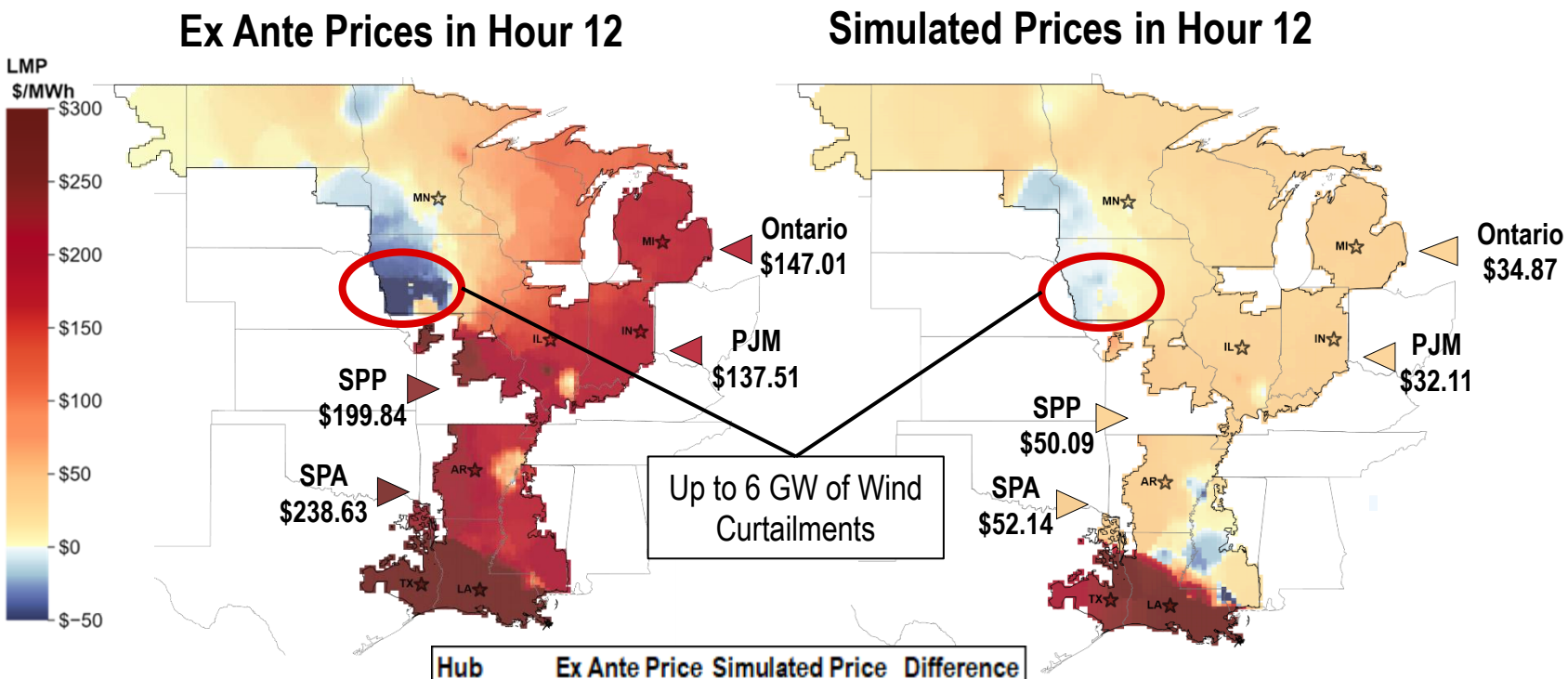
Daily Congestion on Outage-Impacted Constraint

Effects of Switching to Winter Ratings



Continuing Error for TLR Constraints

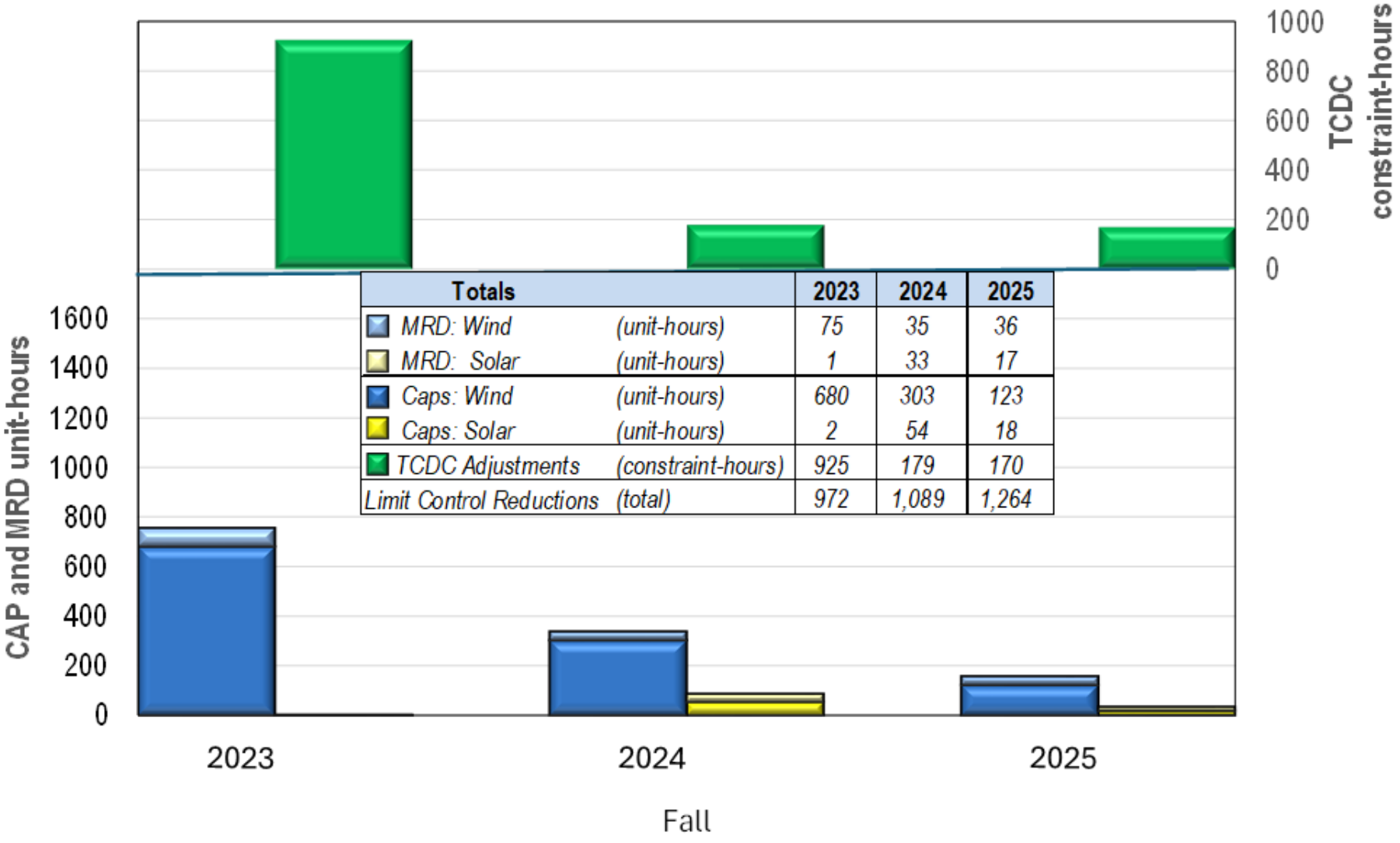
October 9 Re-pricing Results



Hub	Ex Ante Price	Simulated Price	Difference
AR	$237.54	$85.27	-$152.27
IL	$148.53	$55.25	-$93.28
IN	$177.04	$61.62	-$115.42
LA	$462.48	$357.20	-$105.28
MI	$173.87	$61.67	-$112.20
MN	$27.91	$22.32	-$5.59
TX	$383.77	$270.74	-$113.03

MISO Operator Actions for Congestion Management

Fall 2023 – 2025



Totals		2023	2024	2025
MRD: Wind	(unit-hours)	75	35	36
MRD: Solar	(unit-hours)	1	33	17
Caps: Wind	(unit-hours)	680	303	123
Caps: Solar	(unit-hours)	2	54	18
TCDC Adjustments	(constraint-hours)	925	179	170
Limit Control Reductions	(total)	972	1,089	1,264

Benefits of Ambient-Adjusted and Emergency Ratings

Fall 2024 – 2025

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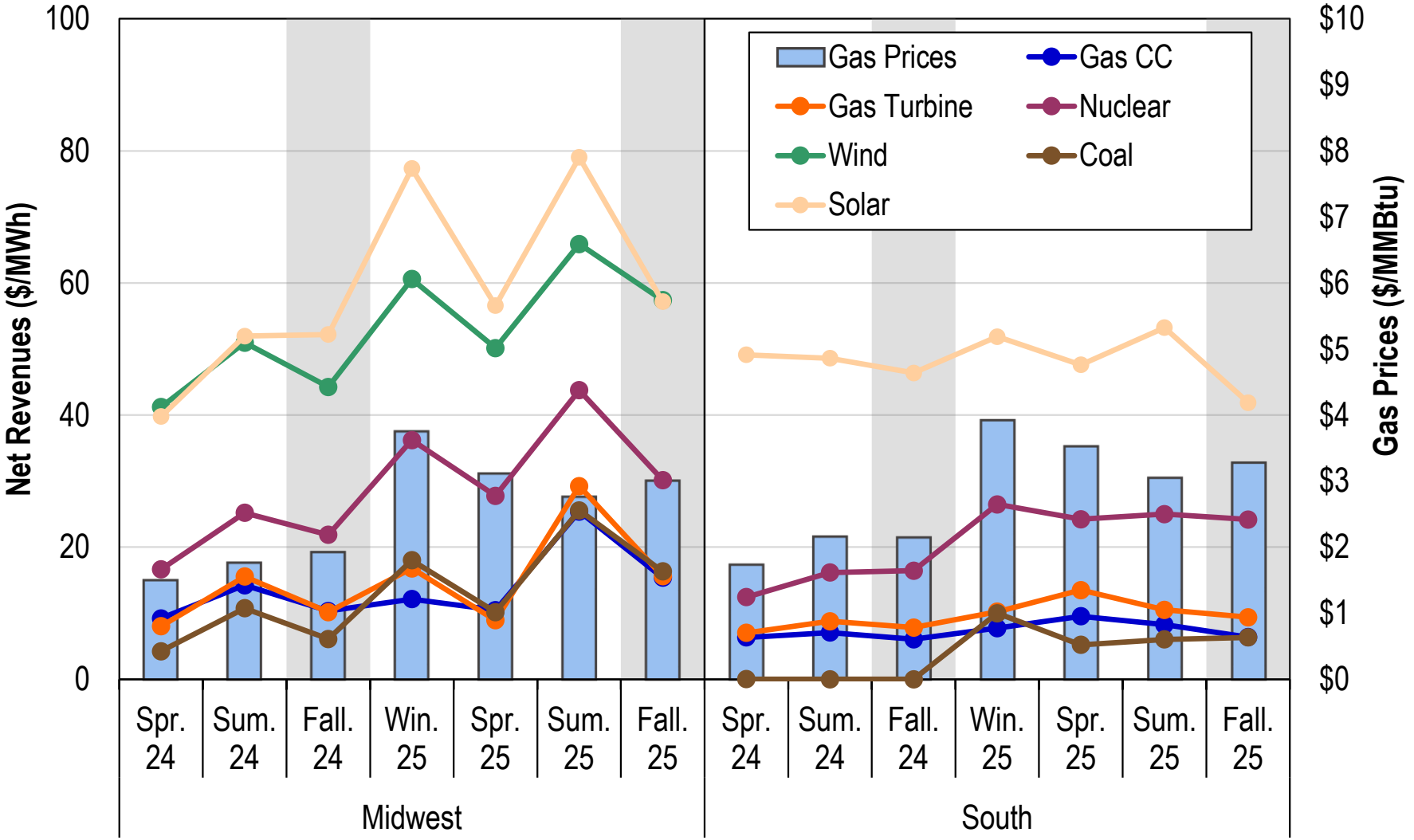
	Fall	Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2024	Midwest	$27.2	$25.04	$52.3	17	12.6%
	South	$0.7	$0.87	$1.6	3	4.2%
	Total	**$27.9**	**$25.9**	**$53.8**	**20**	**11.9%**
2025	Midwest	$71.0	$21.79	$92.8	15	17.0%
	South	$1.4	$1.62	$3.0	3	5.0%
	Total	**$72.4**	**$23.4**	**$95.8**	**18**	**15.8%**

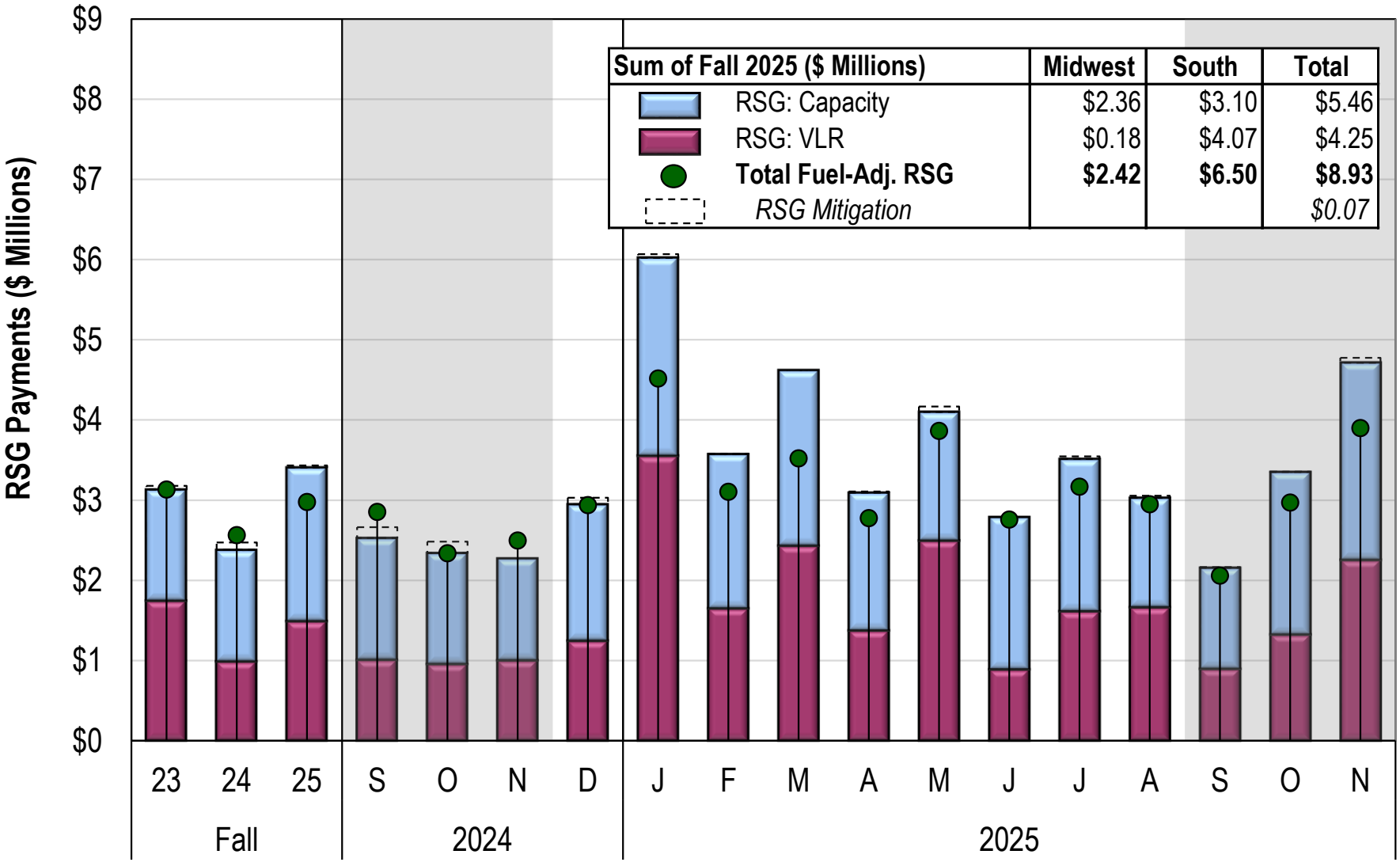
Net Revenues by Technology

2023 - 2025



Day-Ahead RSG Payments

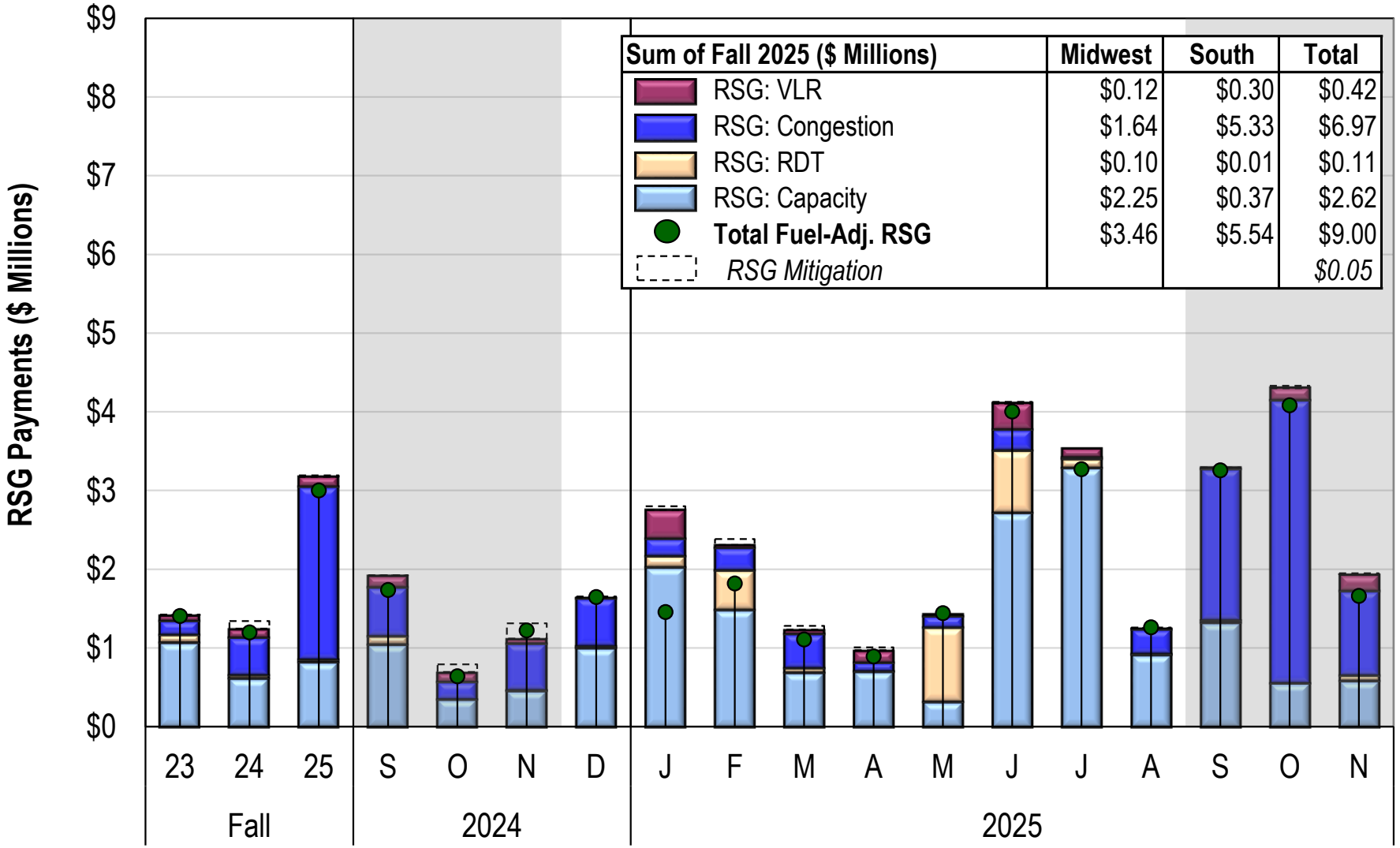
Fall 2023 – 2025



Sum of Fall 2025 ($ Millions)	Midwest	South	Total
RSG: Capacity	$2.36	$3.10	$5.46
RSG: VLR	$0.18	$4.07	$4.25
Total Fuel-Adj. RSG	**$2.42**	**$6.50**	**$8.93**
RSG Mitigation			*$0.07*

Real-Time RSG Payments

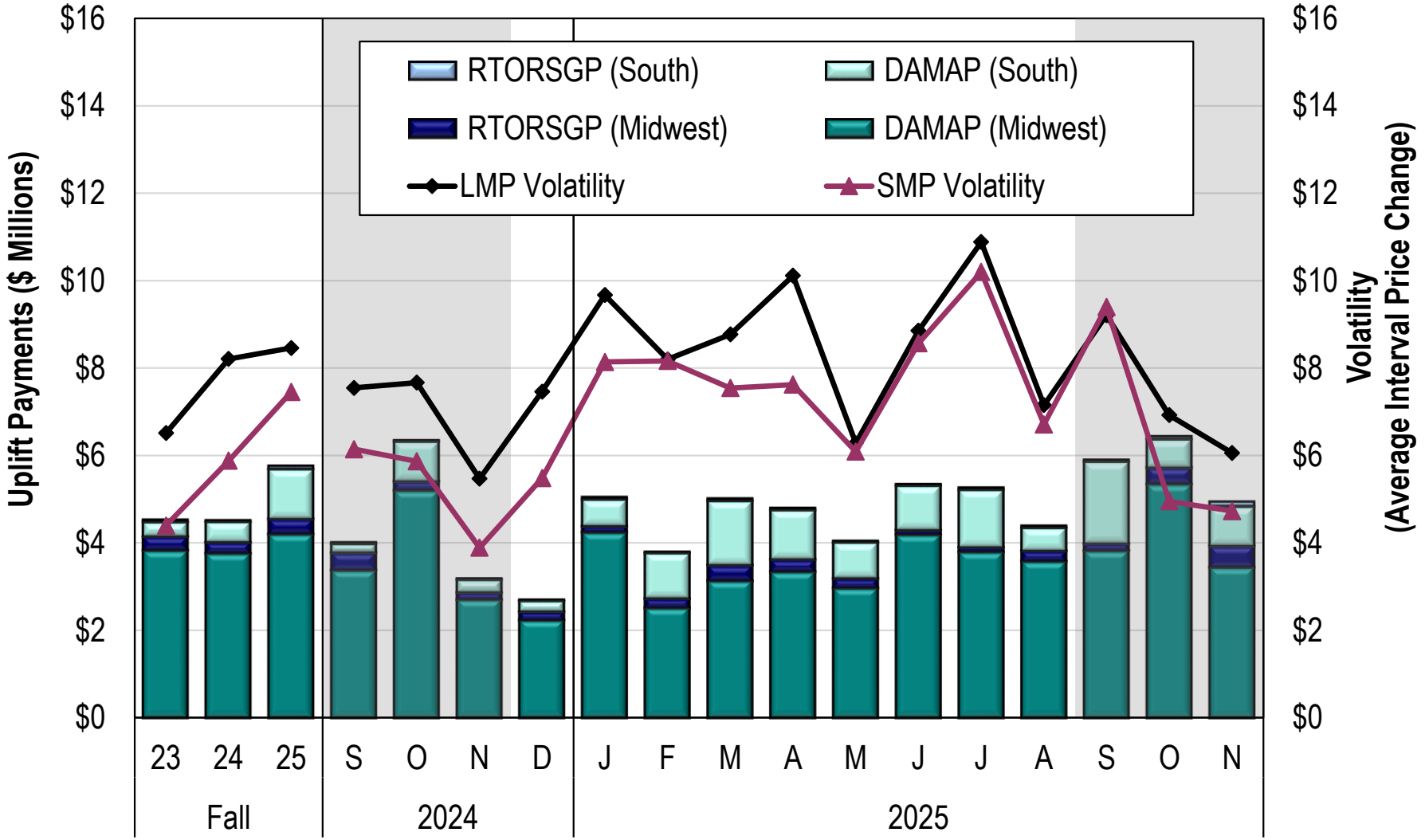
Fall 2023 – 2025



Sum of Fall 2025 ($ Millions)	Midwest	South	Total
RSG: VLR	$0.12	$0.30	$0.42
RSG: Congestion	$1.64	$5.33	$6.97
RSG: RDT	$0.10	$0.01	$0.11
RSG: Capacity	$2.25	$0.37	$2.62
Total Fuel-Adj. RSG	$3.46	$5.54	$9.00
RSG Mitigation			*$0.05*

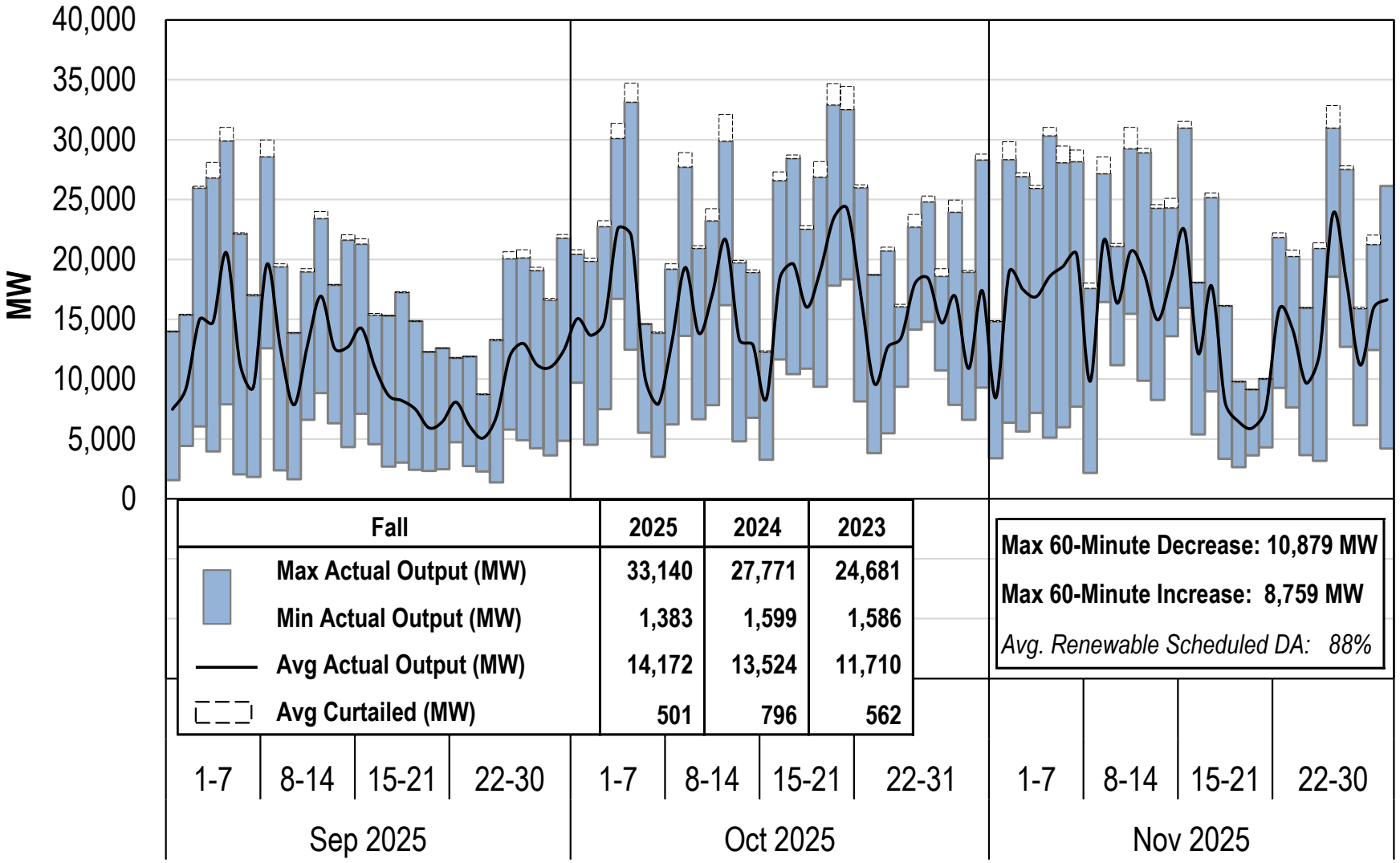
Price Volatility Make Whole Payments

Fall 2023 – 2025



Wind and Solar Output in Real Time

Daily Range and Average



Fall	2025	2024	2023
Max Actual Output (MW)	33,140	27,771	24,681
Min Actual Output (MW)	1,383	1,599	1,586
Avg Actual Output (MW)	14,172	13,524	11,710
Avg Curtailed (MW)	501	796	562

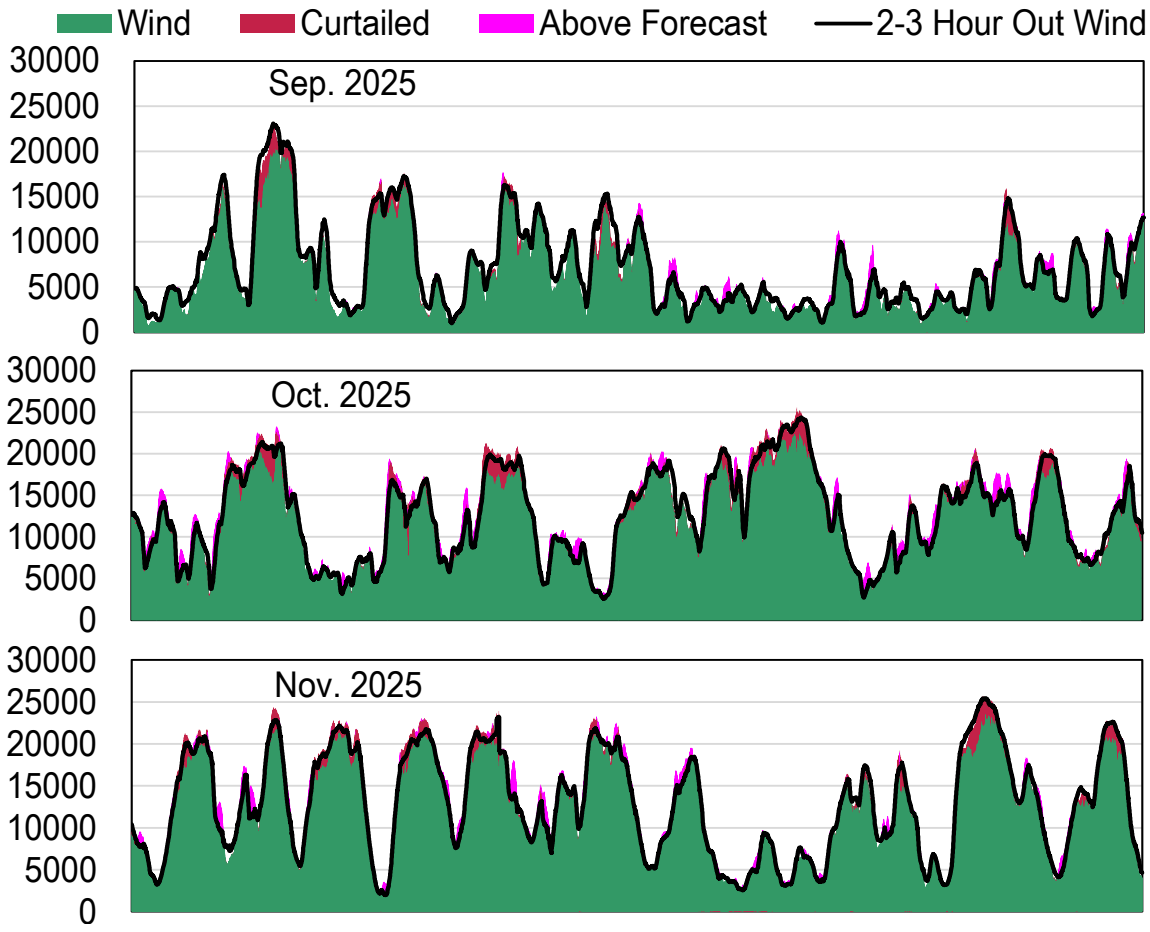
Max 60-Minute Decrease: 10,879 MW

Max 60-Minute Increase: 8,759 MW

Avg. Renewable Scheduled DA: 88%

Wind Forecast and Actual Output

Fall 2025



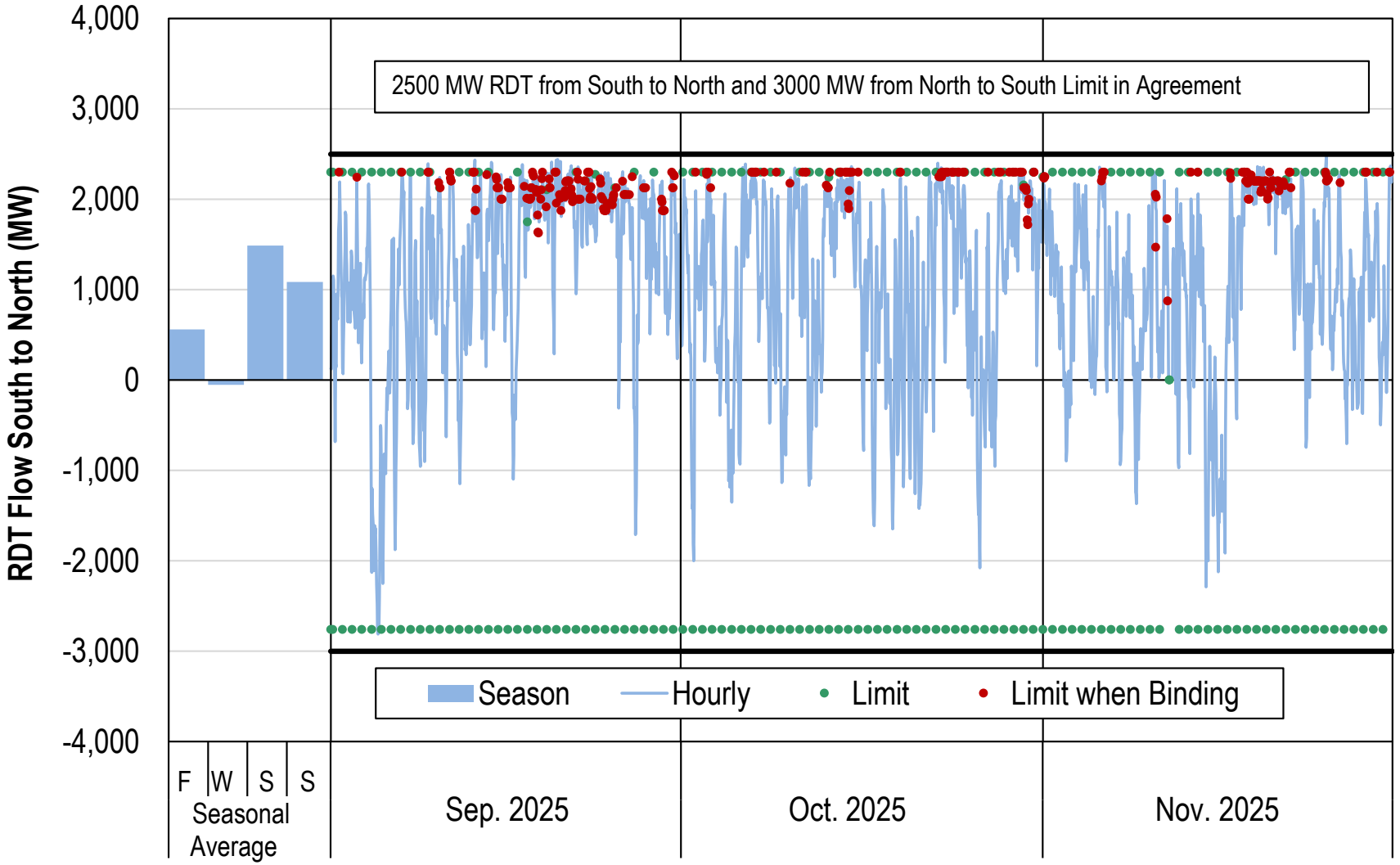
Fall 2025	
Real-Time Wind (MW)	10,739
Day-Ahead Wind (MW)	9,348
Avg Curtailments (MW)	460
Forecast Errors (%)	0.3%
Absolute Errors (%)	10.7%

Fall 2024	
Real-Time Wind (MW)	11,611
Day-Ahead Wind (MW)	10,548
Avg Curtailments (MW)	780
Forecast Errors (%)	0.3%
Absolute Errors (%)	7.6%

Summer 2025	
Real-Time Wind (MW)	6,921
Day-Ahead Wind (MW)	6,405
Avg Curtailments (MW)	187
Forecast Errors (%)	8.5%
Absolute Errors (%)	16.6%

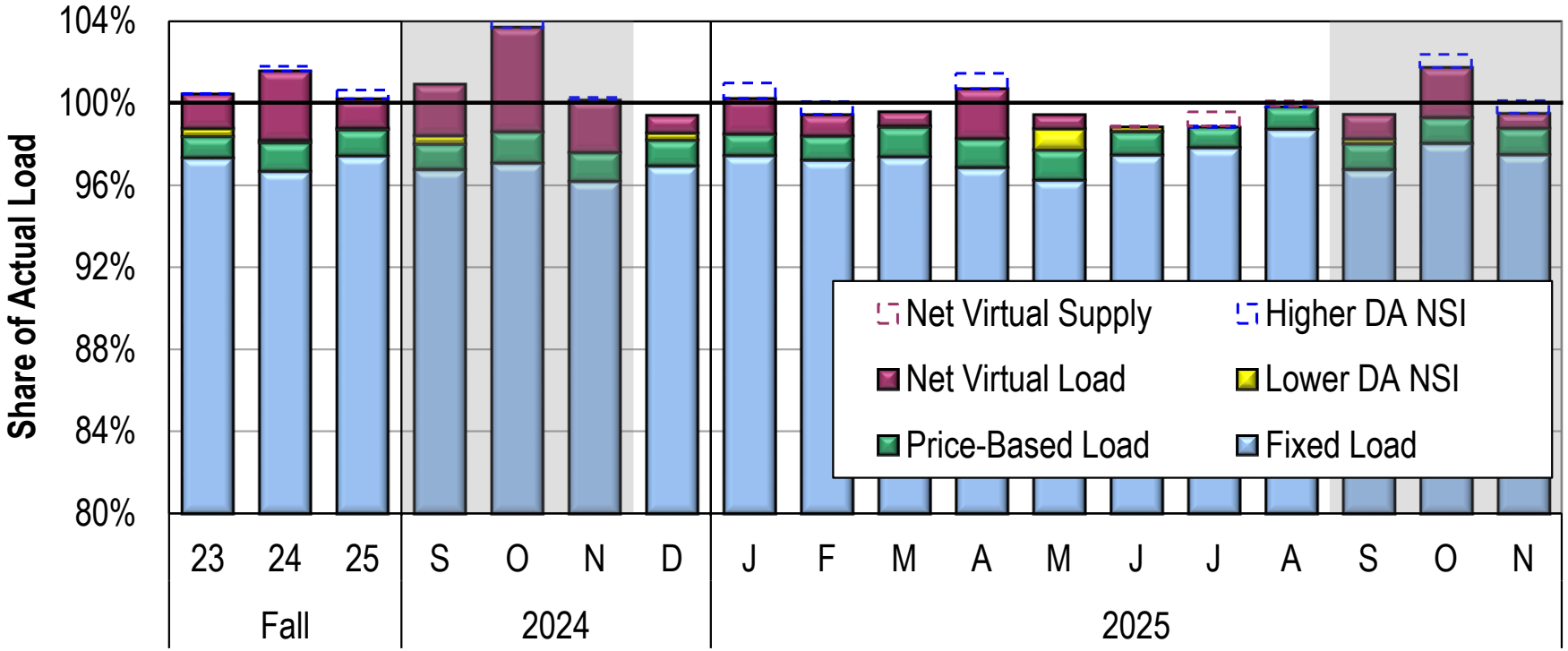
Real-Time Hourly Inter-Regional Flows

Fall 2025



Day-Ahead Peak Hour Load Scheduling

Fall 2023 – 2025

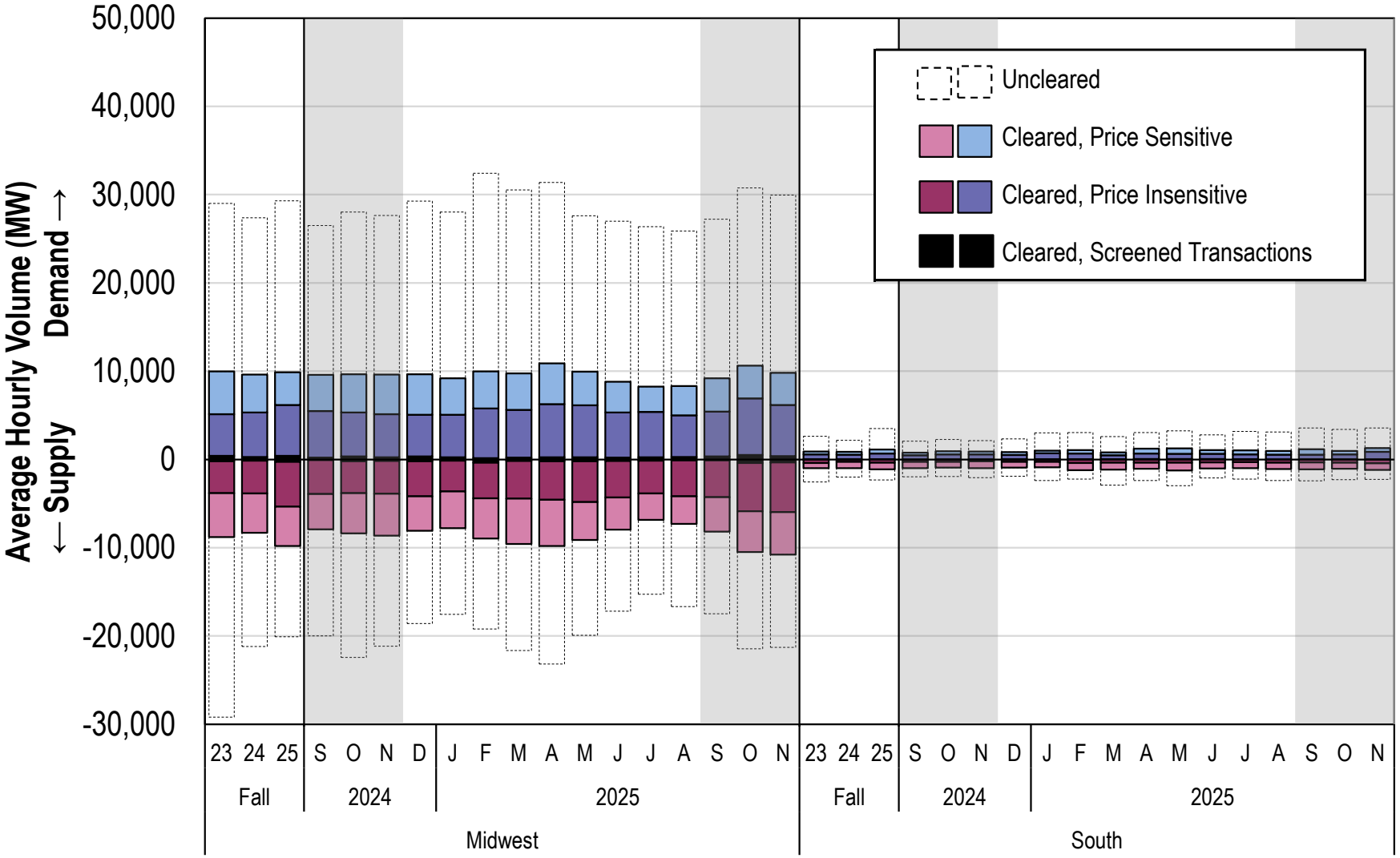


Share of Actual Load (%)

All Hours	100.0	100.1	99.1	100.7	100.4	99.2	99.5	100.2	99.1	98.1	99.8	99.5	99.6	100.6	100.5	99.8	99.1	98.4
Peak Hours Midwest	100.6	102.4	100.1	101.7	105.1	100.5	99.6	100.1	100.0	99.1	100.1	99.2	98.4	98.5	99.4	98.9	101.5	99.9
Peak Hours South	101.1	101.3	101.5	100.2	103.1	100.5	100.7	100.5	102.5	102.5	103.1	101.5	101.4	99.1	102.1	101.9	101.0	101.7

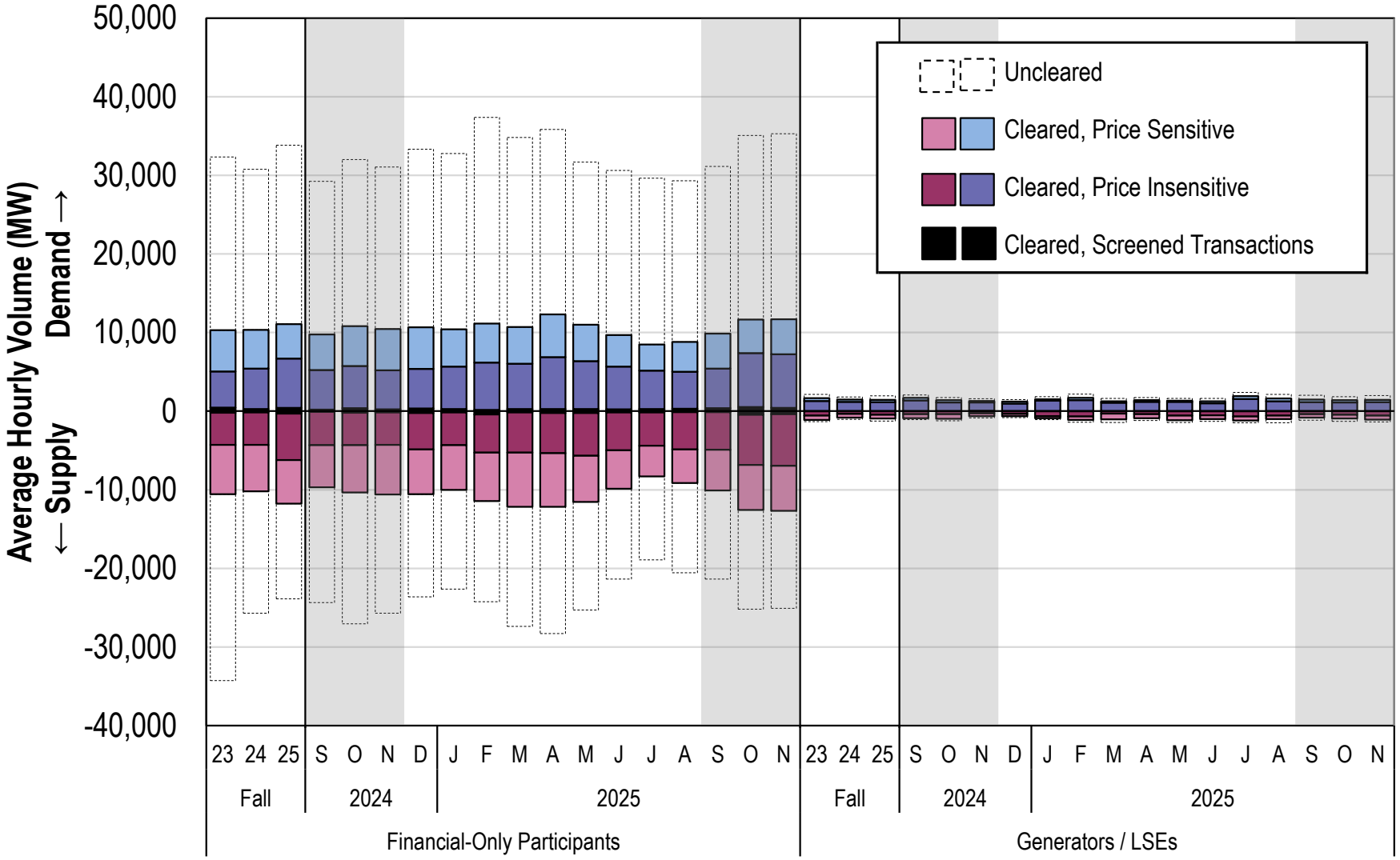
Virtual Load and Supply

Fall 2023 – 2025



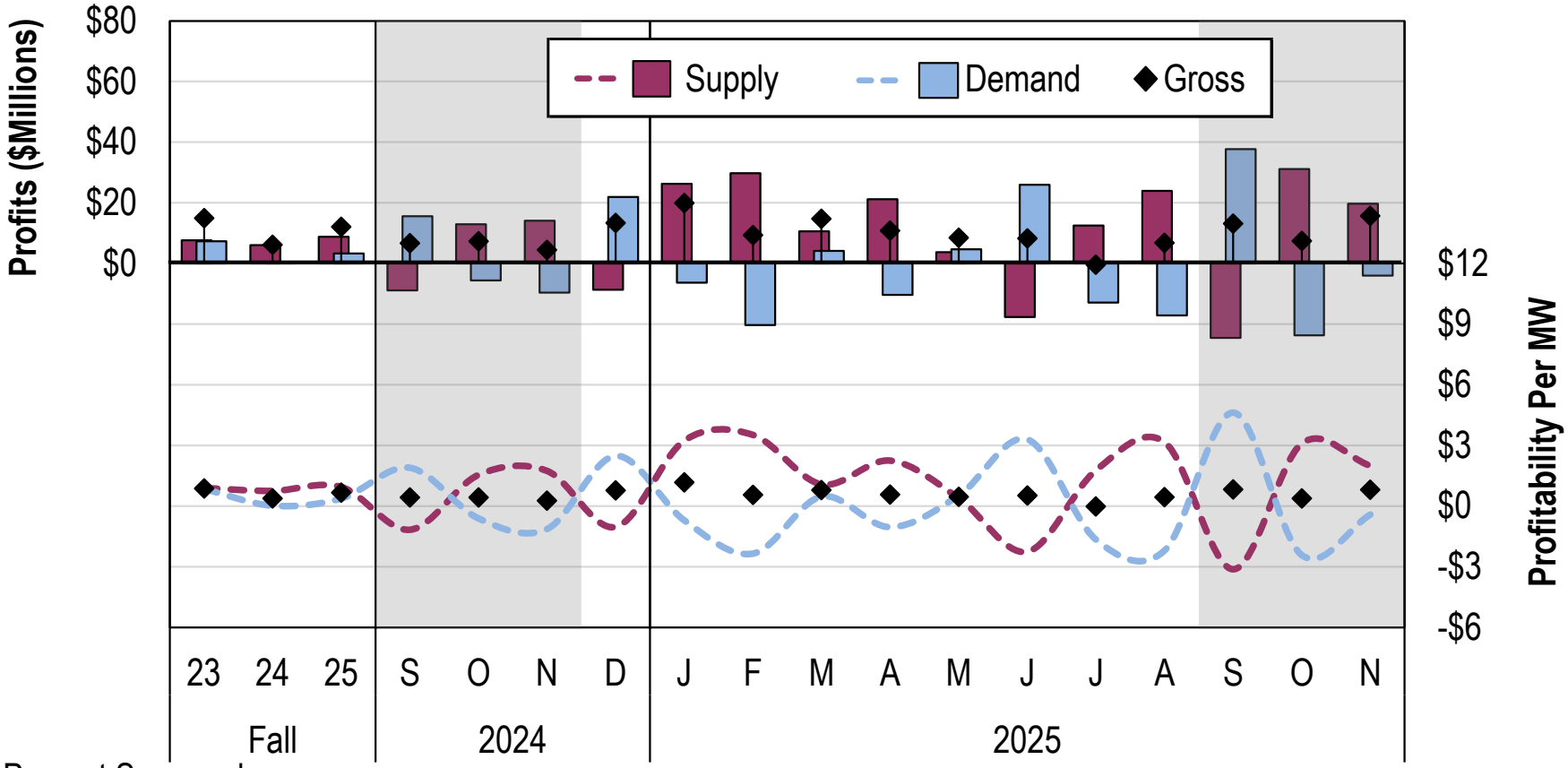
Virtual Load and Supply by Participant Type

Fall 2023 – 2025



Virtual Profitability

Fall 2023 – 2025

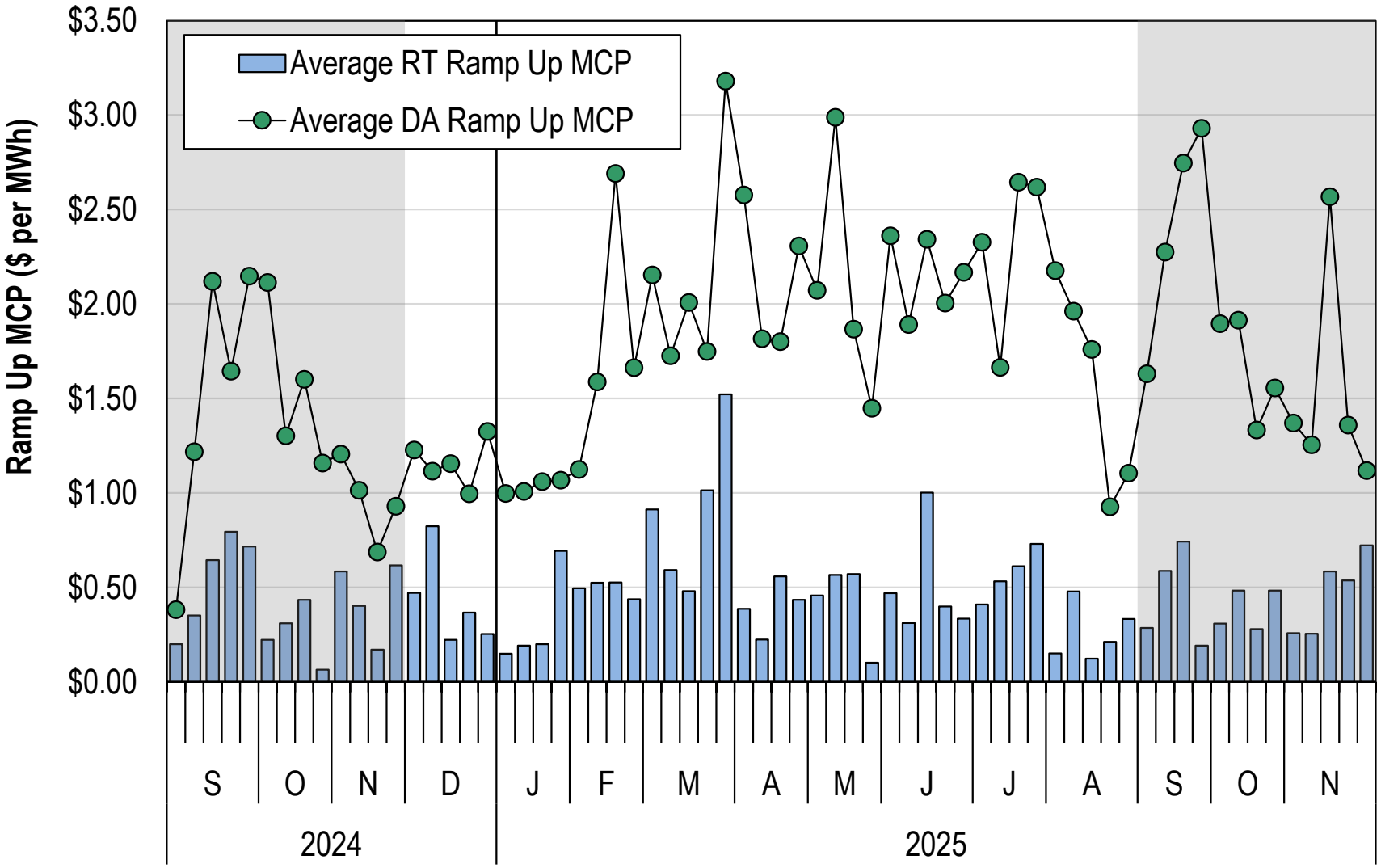


Percent Screened

Supply	1.9	1.4	2.5	0.9	1.9	1.5	2.0	1.7	3.6	1.4	1.9	1.8	1.7	1.7	1.2	1.2	3.4	2.8
Demand	3.9	2.5	3.6	1.9	3.3	2.4	3.1	2.5	1.5	2.3	2.3	2.4	2.4	2.8	3.0	3.5	4.3	3.2
Total	2.9	2.0	3.1	1.4	2.6	1.9	2.6	2.1	2.5	1.9	2.1	2.1	2.0	2.3	2.1	2.3	3.8	3.0

Day-Ahead and Real-Time Ramp Up Price

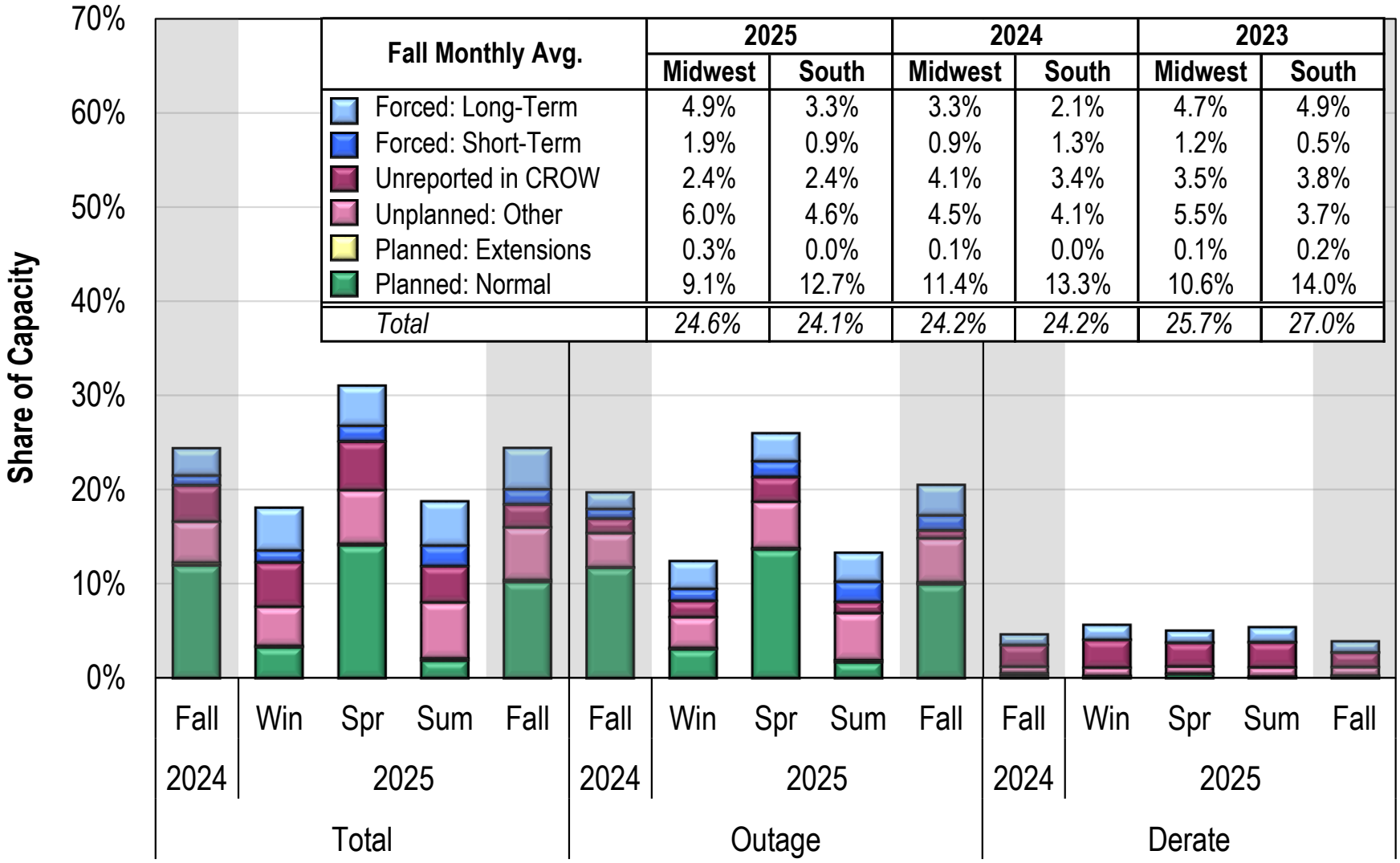
Fall 2024 – 2025



Generation Outages and Deratings

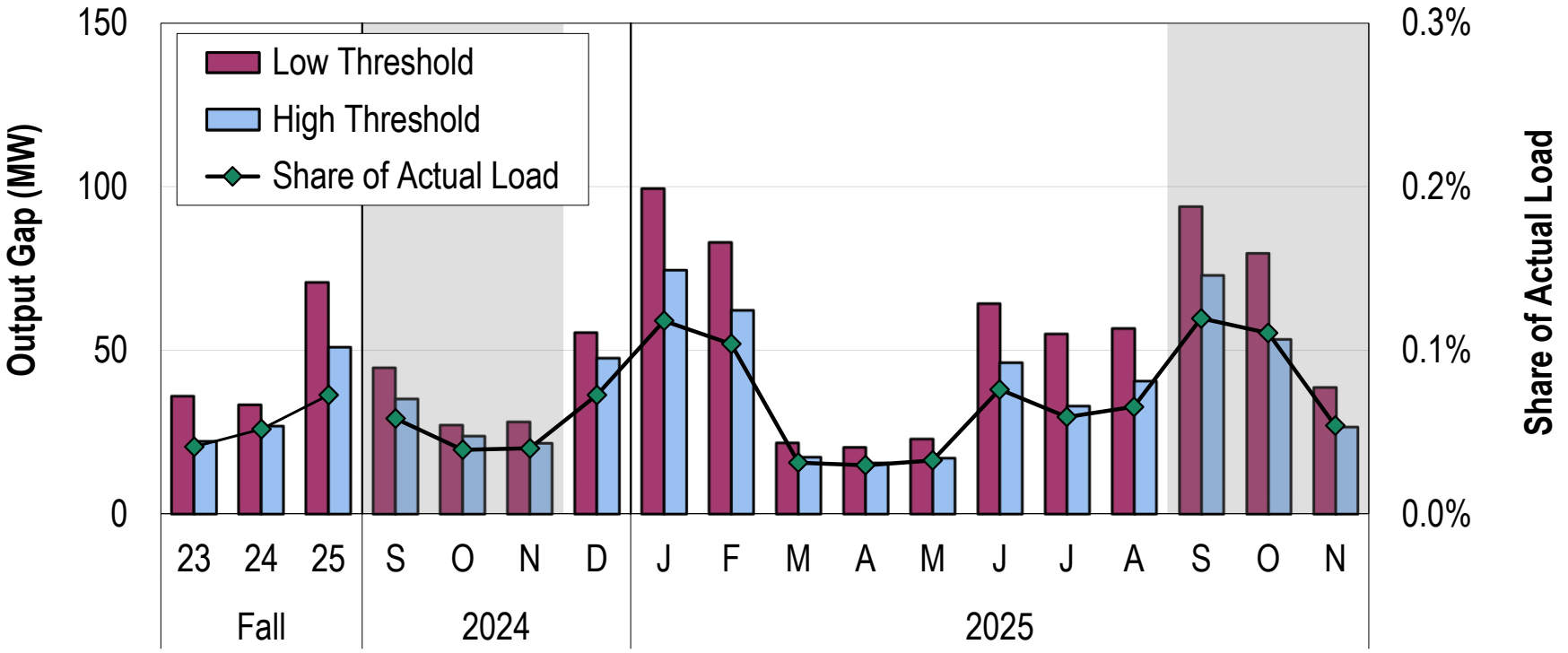
Fall 2023 – 2025

Fall Monthly Avg.	2025		2024		2023	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	4.9%	3.3%	3.3%	2.1%	4.7%	4.9%
Forced: Short-Term	1.9%	0.9%	0.9%	1.3%	1.2%	0.5%
Unreported in CROW	2.4%	2.4%	4.1%	3.4%	3.5%	3.8%
Unplanned: Other	6.0%	4.6%	4.5%	4.1%	5.5%	3.7%
Planned: Extensions	0.3%	0.0%	0.1%	0.0%	0.1%	0.2%
Planned: Normal	9.1%	12.7%	11.4%	13.3%	10.6%	14.0%
Total	*24.6%*	*24.1%*	*24.2%*	*24.2%*	*25.7%*	*27.0%*



Monthly Output Gap

Fall 2023 – 2025



Low Threshold Results by Unit Status (MW)

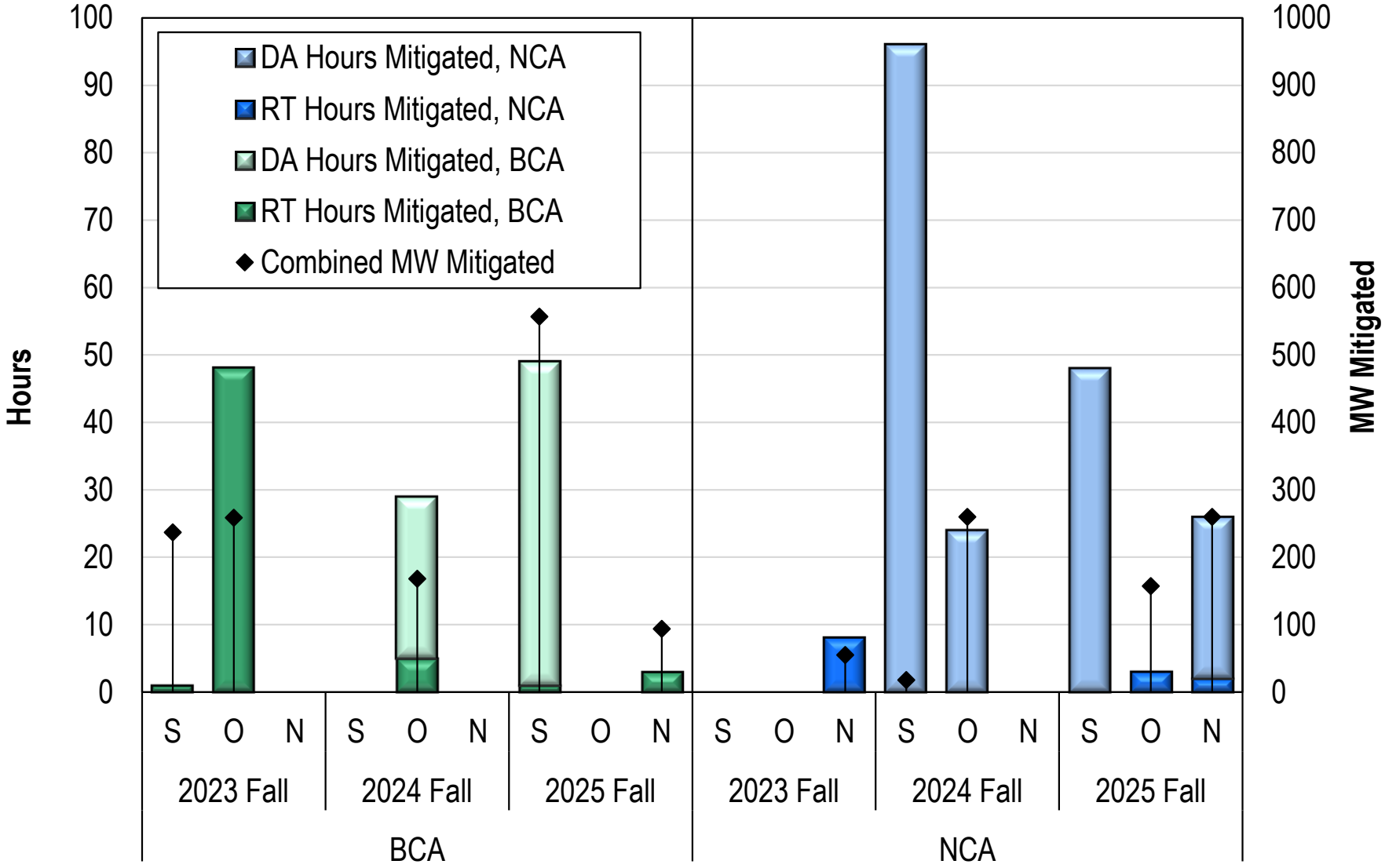
Offline	23	27	62	37	22	24	49	71	62	13	13	16	42	31	43	84	71	31
Online	13	6	9	8	6	4	7	28	21	9	8	7	22	24	13	10	8	8

High Threshold Results by Unit Status (MW)

Offline	19	23	46	31	20	19	44	66	56	12	11	13	35	24	34	69	48	22
Online	4	4	4	4	4	3	3	9	6	5	4	5	11	9	6	4	5	4

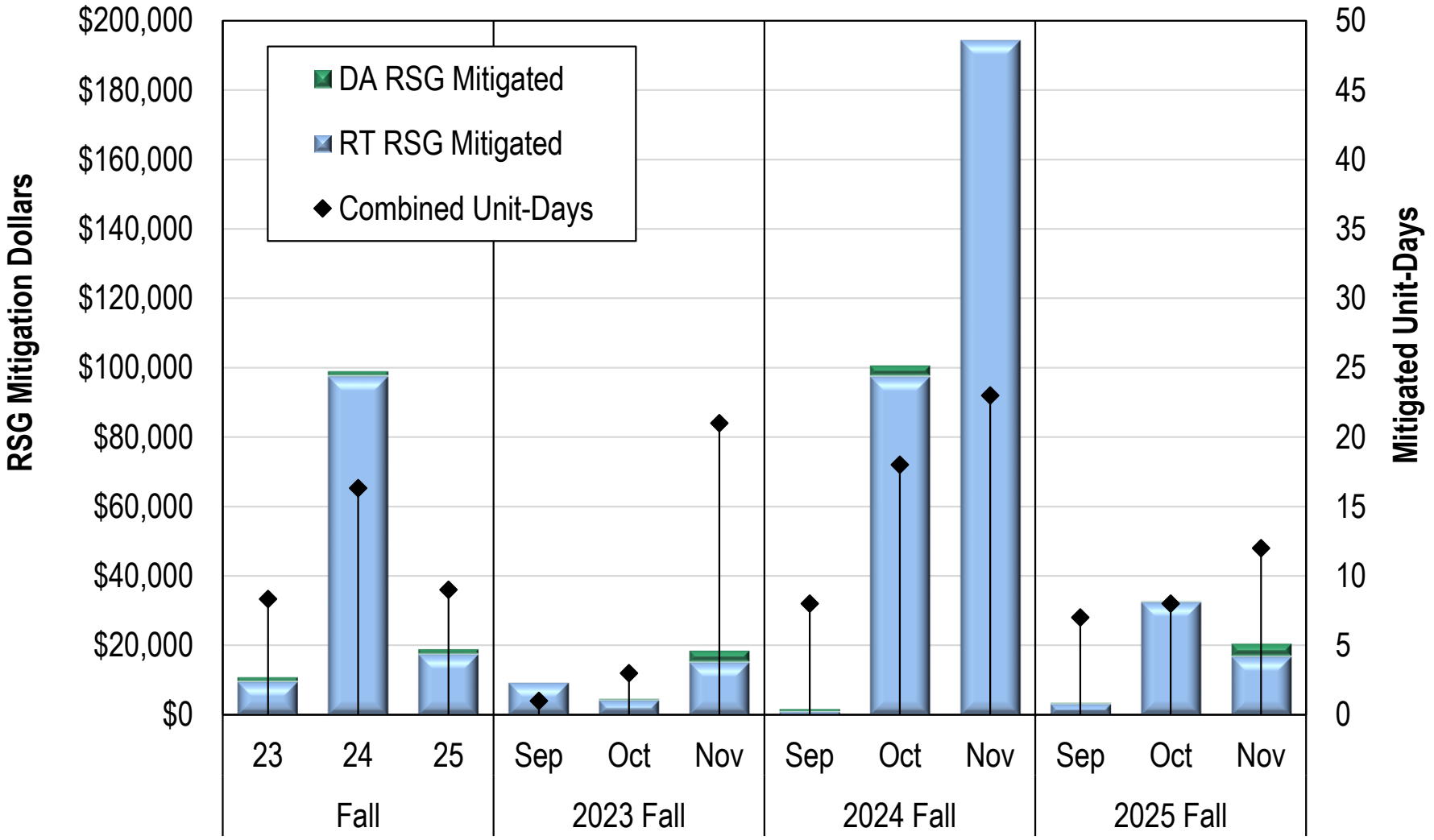
Day-Ahead And Real-Time Energy Mitigation

Fall 2023 - 2025



Day-Ahead And Real-Time RSG Mitigation

Fall 2023 - 2025



List of Acronyms

- AAR — Ambient-Adjusted Ratings
- AMP — Automated Mitigation Procedures
- BCA — Broad Constrained Area
- CDD — Cooling Degree Days
- CMC — Constraint Management Charge
- CTS — Coordinated Transaction Scheduling
- DAMAP — Day-Ahead Margin Assurance Payment
- DDC — Day-Ahead Deviation & Headroom Charge
- DIR — Dispatchable Intermittent Resource
- HDD — Heating Degree Days
- ELMP — Extended Locational Marginal Price
- JCM — Joint and Common Market Initiative
- JOA — Joint Operating Agreement
- LAC — Look-Ahead Commitment
- LSE — Load-Serving Entities
- M2M — Market-to-Market
- MSC — MISO Market Subcommittee
- NCA — Narrow Constrained Area
- ORDC — Operating Reserve Demand Curve
- PITT — Pseudo-Tie Issues Task Team
- PRA — Planning Resource Auction
- PVMWP — Price Volatility Make Whole Payment
- RAC — Resource Adequacy Construct
- RDT — Regional Directional Transfer
- RSG — Revenue Sufficiency Guarantee
- RTORSGP — Real-Time Offer Revenue Sufficiency Guarantee Payment
- SMP — System Marginal Price
- SOM — State of the Market
- STE — Short-Term Emergency
- STR — Short-Term Reserves
- TLR — Transmission Loading Relief
- TCDC — Transmission Constraint Demand Curve
- UD — Uninstructed Deviation
- VLR — Voltage and Local Reliability
- WUMS — Wisconsin Upper Michigan System