IMM Quarterly Report: Fall 2024

Presented to:

Market Subcommittee

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Potomac Economics

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Fall Summary

- The MISO markets performed competitively, and market power mitigation was infrequent during the fall.
- Energy prices fell 15 percent compared to last year because gas prices fell around 20 percent and average load was similar to last fall.
  - The fall peak load of 106 GW was almost 10 percent lower than last year.
  - Shortage pricing intervals occurred more frequently, which contributed to average price increases for ancillary services as high as 65 percent.
- MISO declared a Severe Weather Alert and Conservative Operations for the South in September due to Hurricane Francine that made landfall on the 10th.
  - Although 36 transmission lines tripped, there were no major market impacts.
- Lower gas prices contributed to a 33 percent decrease in real-time congestion.
  - FTRs were fully funded, which was an improvement over last fall.
- Average hourly wind production increased 6 percent over last year, while wind curtailments were up 42 percent, averaging 780 MW per hour.
- Day-ahead and real-time RSG fell by 23 and 24 percent, respectively, primarily because of operational improvements and lower natural gas prices.

Quarterly Summary

Fall		Value	*Change*[1] Prior Qtr.	Prior Year			Value	*Change*[1] Prior Qtr.	Prior Year
RT Energy Prices ($/MWh)		$27.23	*-12%*	*-15%*	**FTR Funding (%)**		100%	103%	95%
Fuel Prices ($/MMBtu)					**Wind Output (MW/hr)**		11,611	*51%*	*6%*
Natural Gas - Chicago		$1.92	*9%*	*-18%*	Wind Curtailed (MW/hr)		780	*198%*	*42%*
Natural Gas - Henry Hub		$2.14	*-1%*	*-23%*	**Guarantee Payments ($M)**[4]				
Western Coal		$0.80	*1%*	*-1%*	Real-Time RSG		$3.6	*-31%*	*-24%*
Eastern Coal		$1.73	*1%*	*-11%*	Day-Ahead RSG		$7.1	*36%*	*-23%*
Load (GW)[2]					Day-Ahead Margin Assurance		$12.8	*-14%*	*3%*
Average Load		72.1	*-16%*	*0%*	Real-Time Offer Rev. Sufficiency		$0.9	*12%*	*-23%*
Peak Load		105.5	*-15%*	*-9%*	**Price Convergence**[5]				
% Scheduled DA (Peak Hour)		101.6%	101.2%	100.5%	Market-wide DA Premium		0.4%	0.7%	-1.2%
Transmission Congestion ($M)					**Virtual Trading**				
Real-Time Congestion Value		$392.1	*46%*	*-33%*	Cleared Quantity (MW/hr)		22,835	*7%*	*-3%*
Day-Ahead Congestion Revenue		$327.9	*75%*	*-11%*	% Price Insensitive		49%	50%	47%
Balancing Congestion Revenue[3]		$8.7	$11.9	$20.1	% Screened for Review		2%	1%	3%
Ancillary Service Prices ($/MWh)					Profitability ($/MW)		$0.4	$0.2	$0.9
Regulation		$14.51	*14%*	*29%*	**Dispatch of Peaking Units (MW/hr)**		1,684	3,007	1,509
Spinning Reserves		$2.69	*-10%*	*-8%*	**Output Gap- Low Thresh. (MW/hr)**		33	32	36
Supplemental Reserves		$0.75	*-50%*	*65%*					

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.

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Quarterly Highlights: Fall 2024

<u>Congestion Patterns during the Quarter (Slides 18-20)</u>

Real-time congestion during the fall quarter fell to almost a third of the congestion levels last year because of a number of factors:

- In 2023, drought conditions in Manitoba led to frequent exports to Manitoba and contributed to substantial congestion in the North region.
  - Conditions improved in 2024 and led to imports over the Manitoba interface of 722 MW per hour, which eased congestion in the North Region this fall.
- In 2023, SPP constraints coordinated with MISO (most notably the Charlie Creek-Watford constraint) were severely congested.
  - SPP implemented a “Remedial Action Scheme” for this constraint that, together with lower imports from Manitoba, reduced this congestion by 95 percent.
- Average hourly wind grew by 6 percent and wind curtailments were up 46 percent, yet wind-related congestion fell by 41 percent from last fall.
  - This is partly due to MISO’s continued reliance on manual dispatch actions and dispatch caps that prevent the market from pricing this congestion.
  - Transmission constraint demand curve adjustments allow the market to manage and price the congestion – MISO made fewer adjustments this fall.

Quarterly Highlights: Fall 2024

Winter Assessment (Slide 40)

- We assessed MISO readiness for the upcoming winter, based on its winter peak demand forecast of 103 GW and its available seasonal capacity.
  - MISO forecasts a margin of 32% including assumed scheduled planned outages and a 5% forced outage rate and 11 GW of emergency-only capacity.
  - When typical planned outage rates and winter peak forced outages are included, this margin drops to 20%, which is sufficient under normal conditions.
- Extreme winter events have become more frequent in recent years, which produce unusually high load and high outage rates.
  - We estimate the increases in load and outages/derates based on MISO’s experiences during Winter Storms Uri, Elliott, and Heather.
  - Assuming these effects of extreme winter weather events, the margin falls to just 2 percent.
  - This indicates that even under relatively extreme conditions that MISO will have adequate available resources.

Quarterly Highlights: Fall 2024

Operational Challenges of Renewable Resources (Slide 41)

- Solar capacity continues to grow rapidly – solar output set a new peak on October 16 at 8,030 MW and nearly 4 GWs are expected to enter by this winter.
- The growth in solar resources together with the existing wind resources will result in increasing operational challenges this winter.
  - Load peaks in the morning and evenings during the winter months, generally when solar output is low or falling – substantially increasing the need to ramp non-renewable resources.
  - We show that the evening net load ramp on a high load day in 2022 was 6 GW from 3 pm to 7 pm – high solar output on the same day this winter would produce a net load ramp over the same period of 12 GW.
- MISO experienced two shortages during the fall that caused prices to spike to $3500 per MWh -- one was primarily caused falling renewable output and the other by large top-of-hour decommitments of resources.
  - Operational improvements to commitment and decommitment processes will be key to avoid such shortages in the future – the upcoming shortage pricing changes will raise such price spikes to $10,000 per MWh.

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Submittals to External Entities

During the Fall Quarter, we:

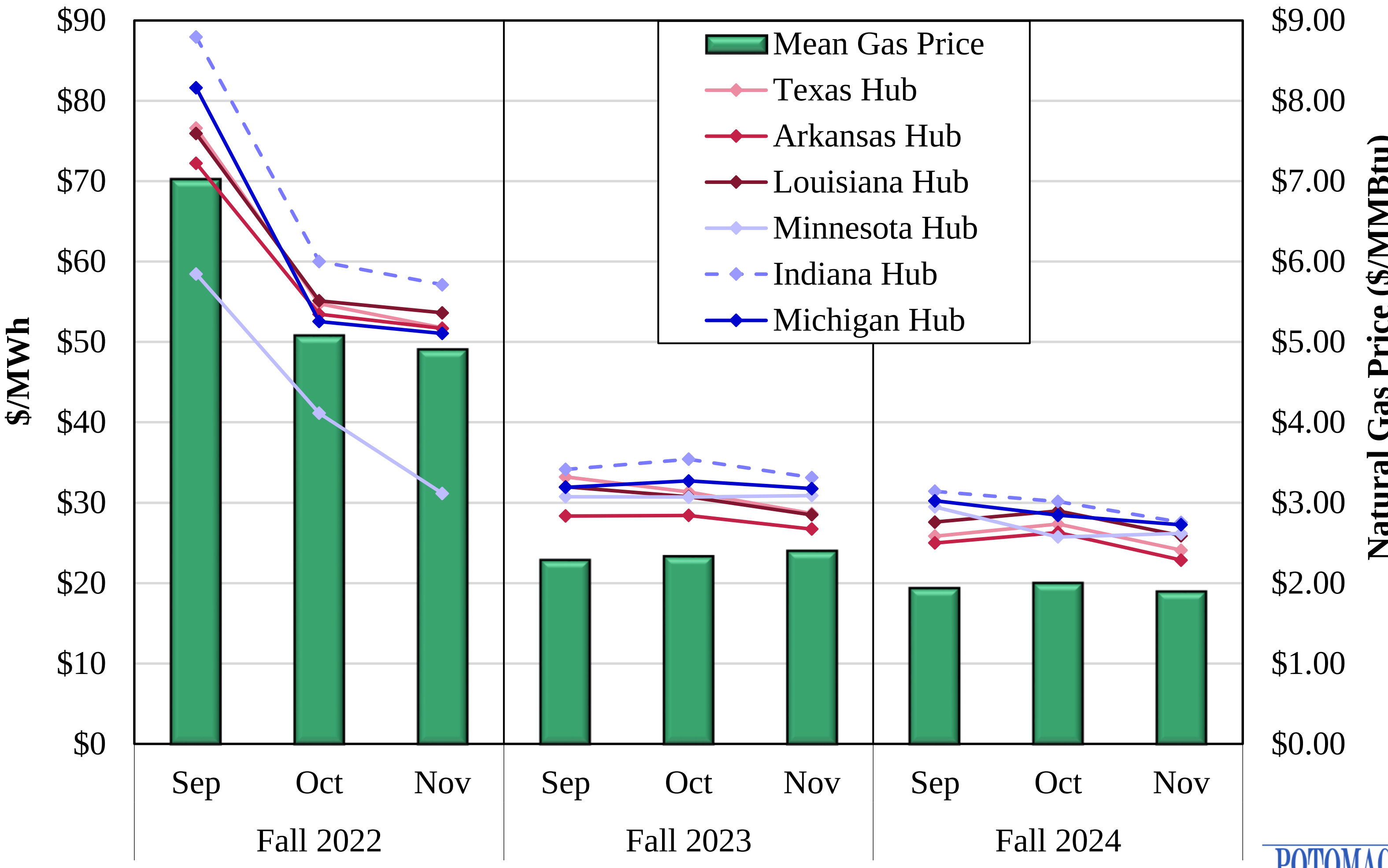
- Responded to several FERC questions related to prior referrals and FERC investigations, and we responded to requests for information on market issues.
- Made two referrals to FERC enforcement this quarter for:
  - Failure to report forced outages to GADS; and
  - Failure to report known transmission outages in advance of the FTR auction.
- Issued a sanction recommendation to MISO for physical withholding.
- Presented the IMM Summer Quarterly report to the MSC and recent market results to the ERSC.

Other Issues

- We worked with MISO on additional recommended operations improvements.
- We developed recommended market design improvements related to demand response participation and LMR accreditation changes, including:
  - Removing Batch Load Demand Response resources in November from its Business Practice Manuals.
  - Eliminating Emergency Demand Response in the near future.
  - Incorporating recommended changes pertaining to registration, testing, and accreditation of demand response resources.
- We continued to investigate potential tariff violations in the market-to-market coordination of congestion between SPP, PJM and MISO.
- We also continued to support upcoming filings to:
  - Reform MISO’s shortage pricing to provide more efficient incentives for resources to be available and support the reliability of the system; and
  - Improve provisions governing Demand Response Resources to address market manipulation vulnerabilities.

Quarterly Market Results: Fall 2024

Day-Ahead Average Monthly Hub Prices Fall 2022–2024



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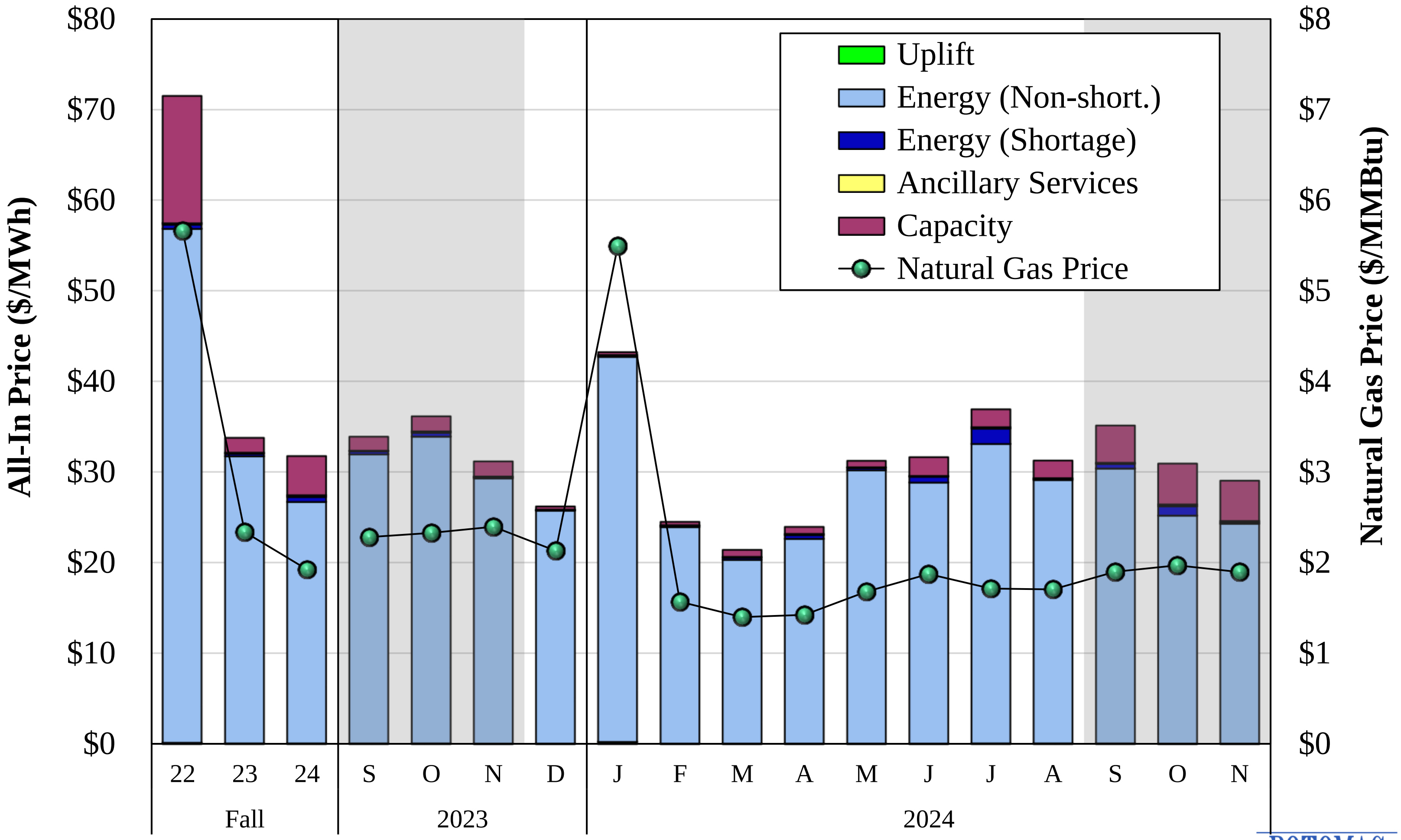
All-In Price
Fall 2022 – 2024



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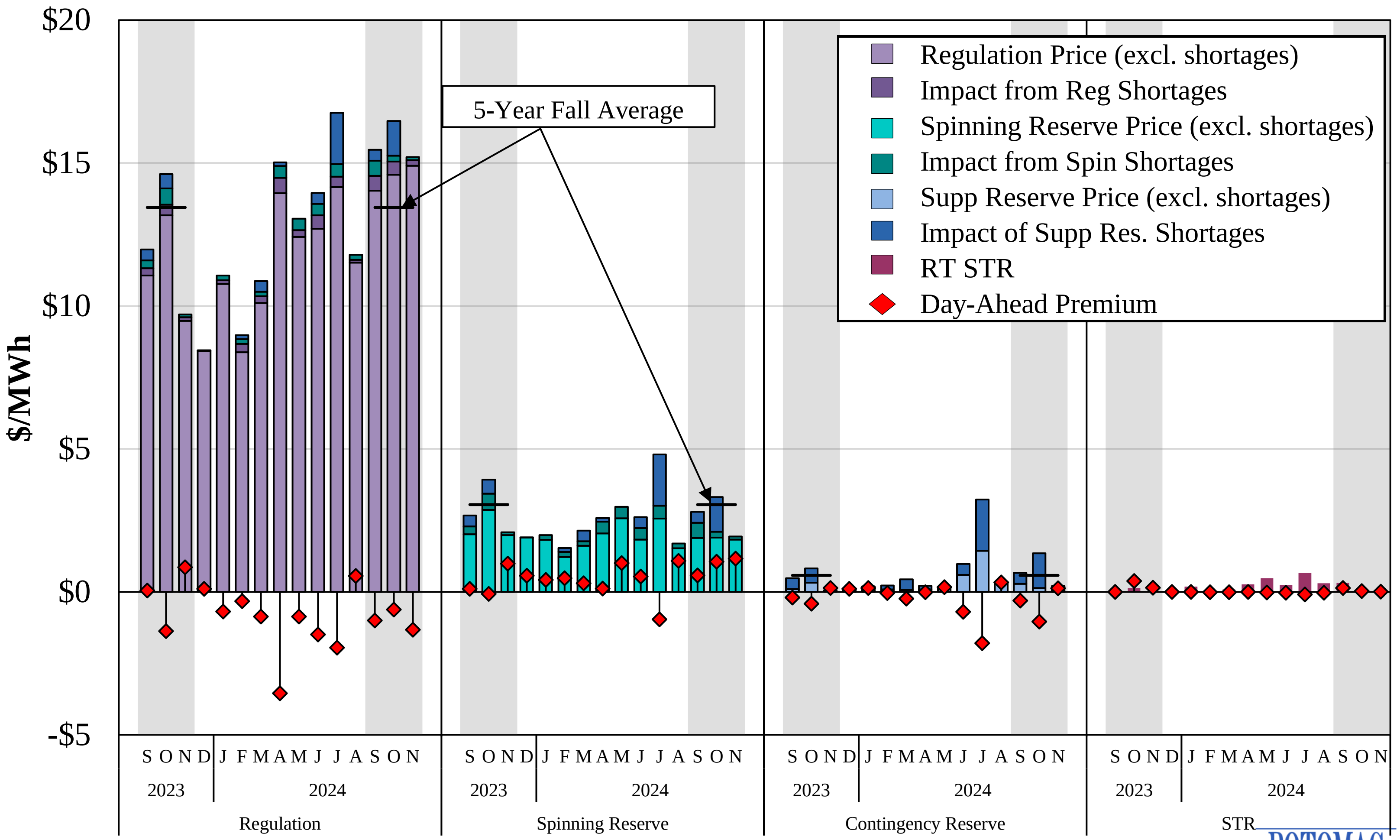
Ancillary Services Prices
Fall 2023–2024



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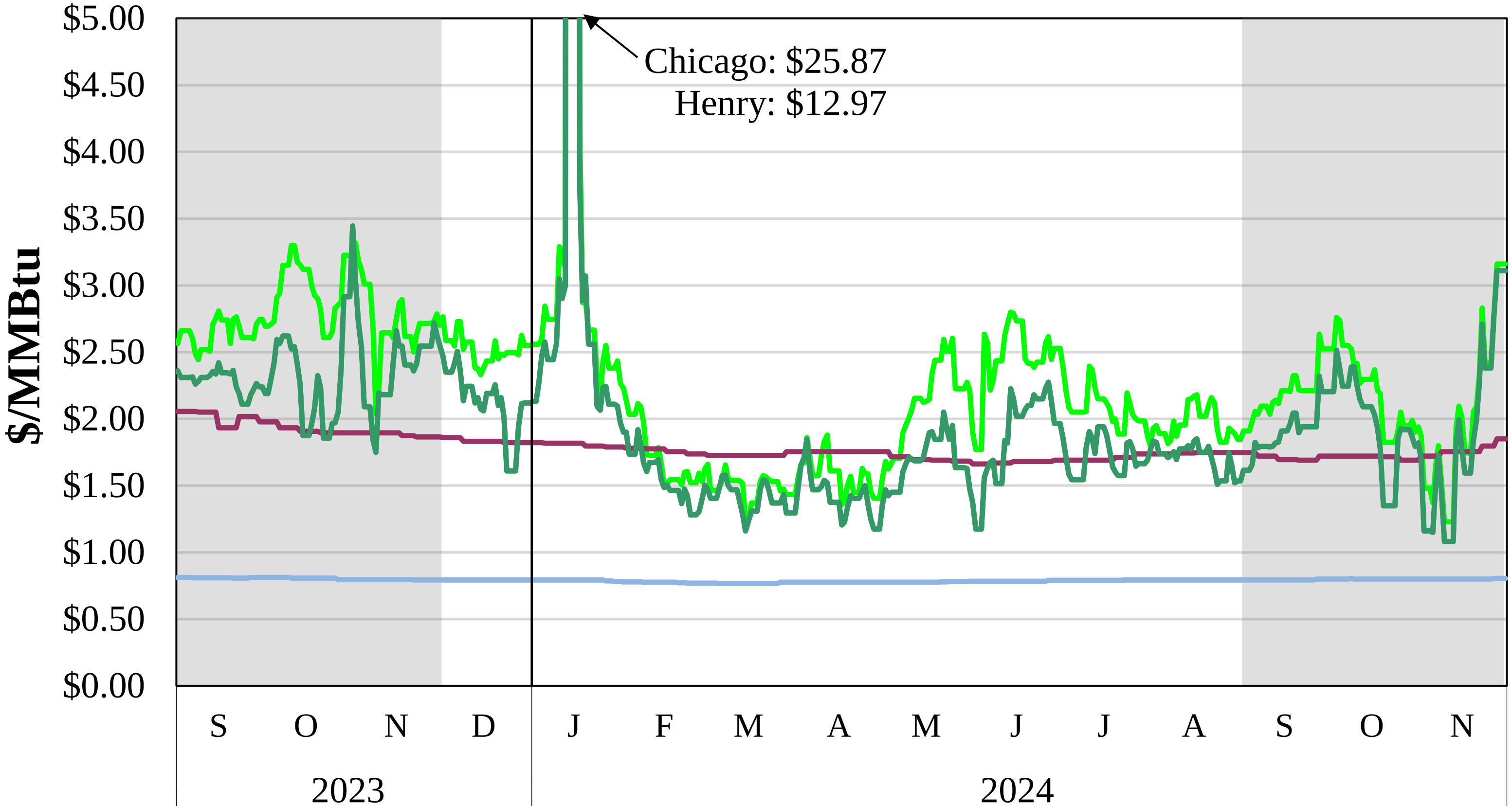
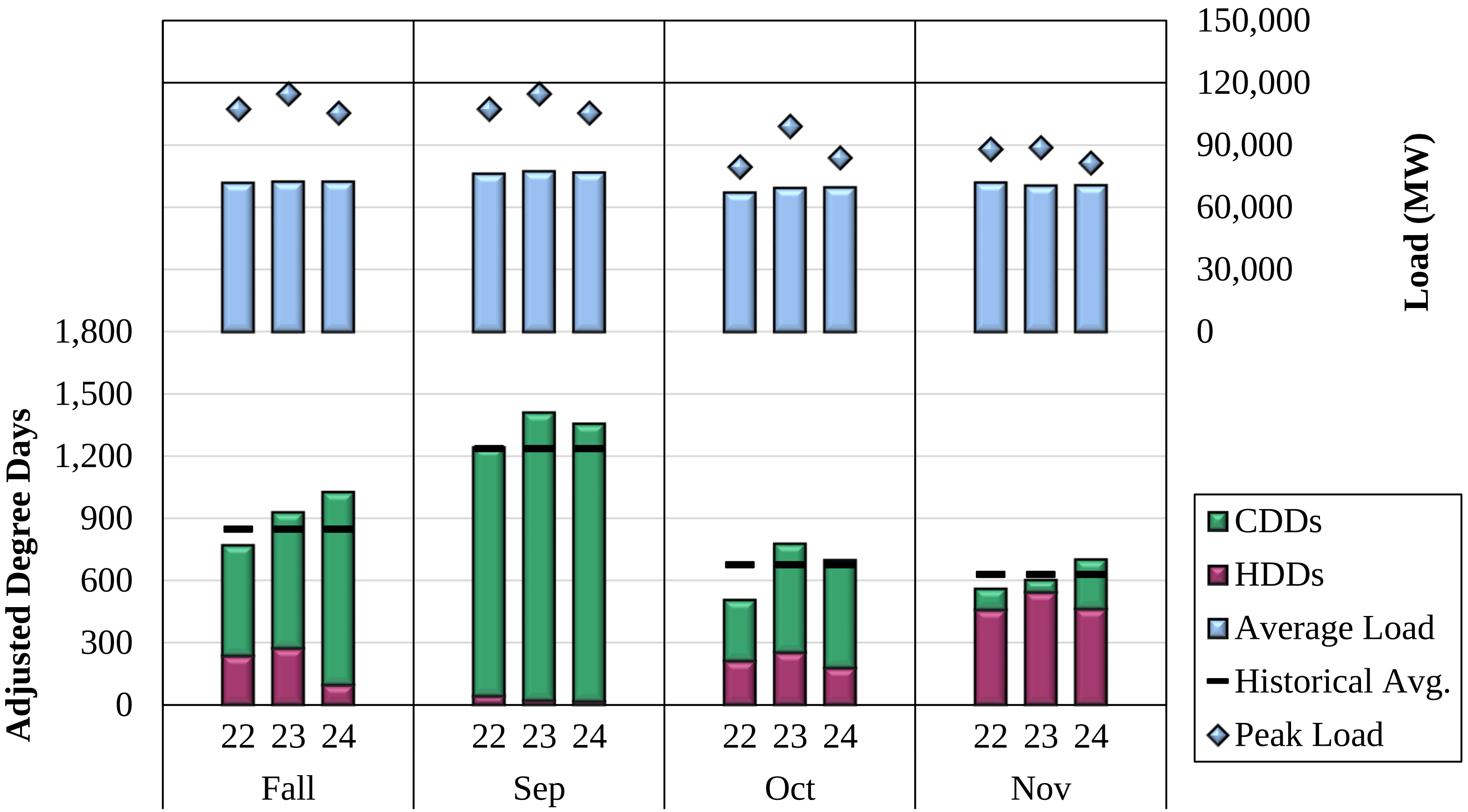
MISO Fuel Prices 2023–2024



Fall Average	2024	2023	2022
Chicago NG	$1.92	$2.34	$5.66
Henry NG	$2.14	$2.78	$6.33

Fall Average	2024	2023	2022
IB Coal	$1.73	$1.94	$7.44
PRB Coal	$0.80	$0.80	$0.96

Load and Weather Patterns
Fall 2022–2024

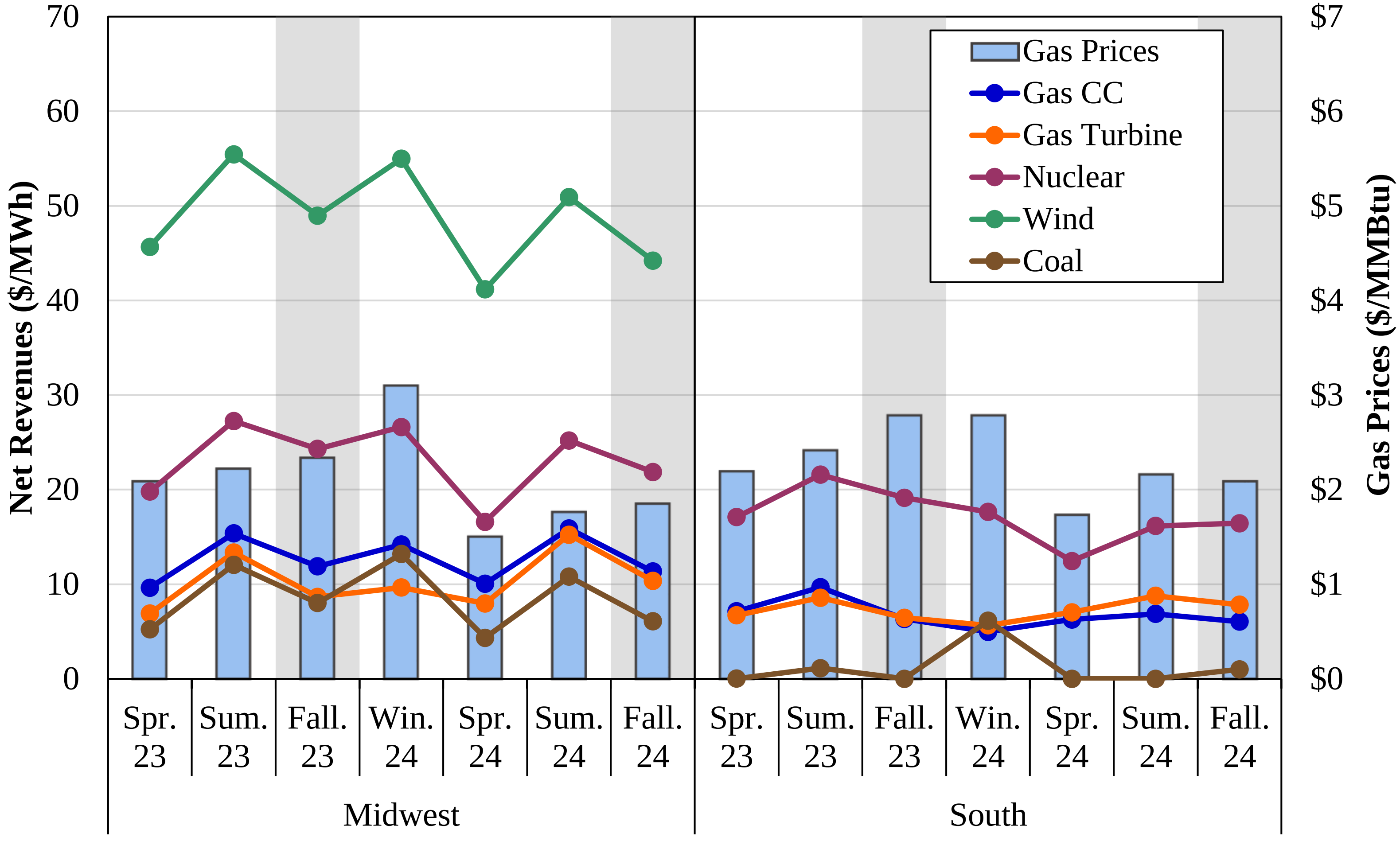


Notes: Midwest degree day calculations include four reprsentative cities: Indianapolis, Detroit, Milwaukee and Minneapolis. The South region includes Little Rock and New Orleans.

Capacity, Energy and Price Setting Share
Fall 2023–2024

Fall	Accredited Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2023	2024	2023	2024	2023	2024	2023	2024	2023	2024
Nuclear	10,869	11,797	8%	9%	13%	15%	0%	0%	0%	0%
Coal	38,182	34,546	30%	27%	29%	26%	37%	39%	79%	78%
Natural Gas	62,040	61,150	48%	48%	38%	38%	62%	58%	93%	89%
Oil	1,506	1,618	1%	1%	0%	0%	0%	0%	1%	0%
Hydro	4,184	3,700	3%	3%	1%	1%	0%	1%	1%	2%
Wind	4,867	4,877	4%	4%	16%	17%	0%	1%	61%	72%
Solar	3,679	7,389	3%	6%	1%	3%	0%	0%	7%	6%
Other	2,666	2,612	2%	2%	1%	1%	0%	0%	1%	1%
Total	**127,993**	**127,688**								

Net Revenues by Technology 2023-2024



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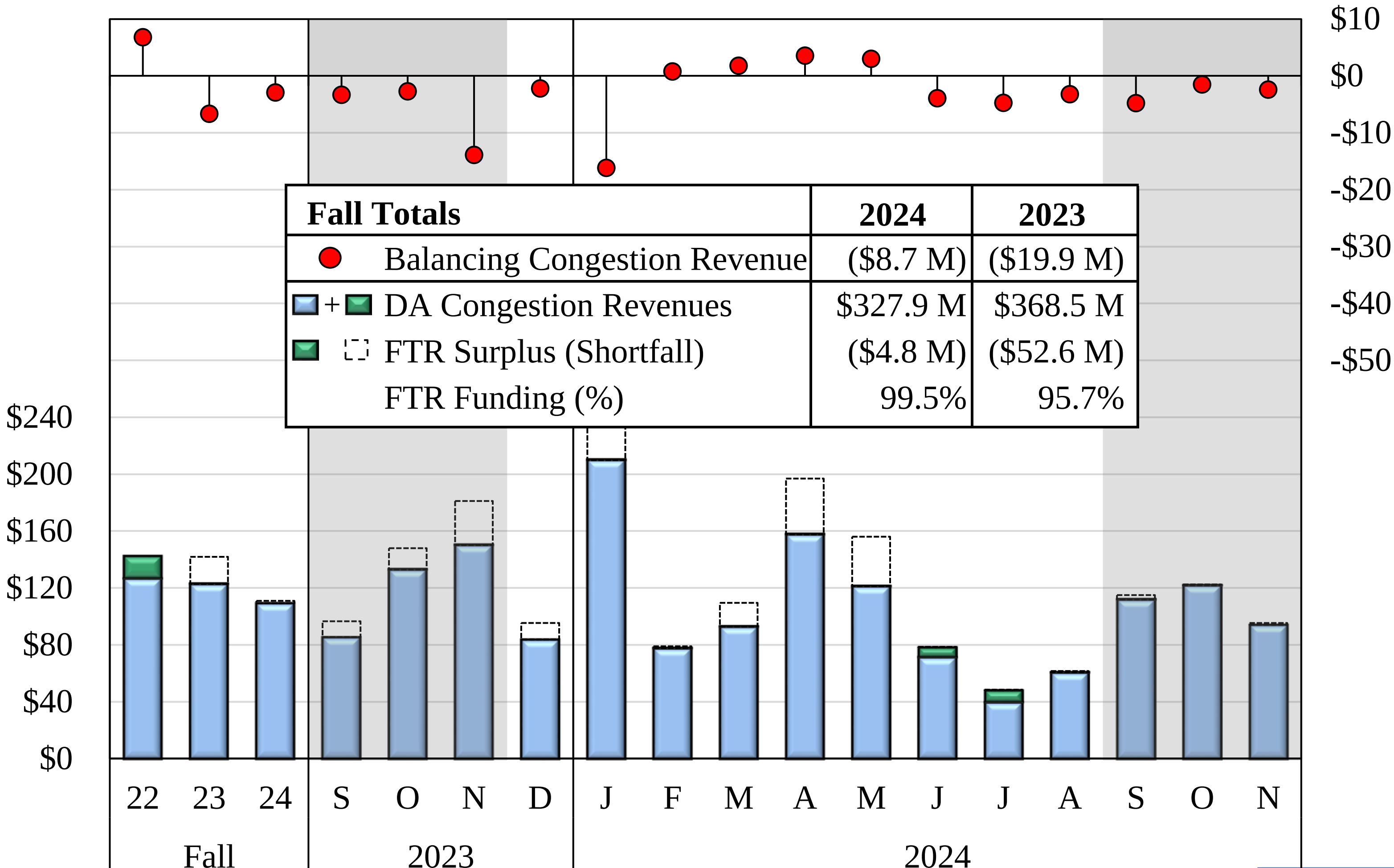
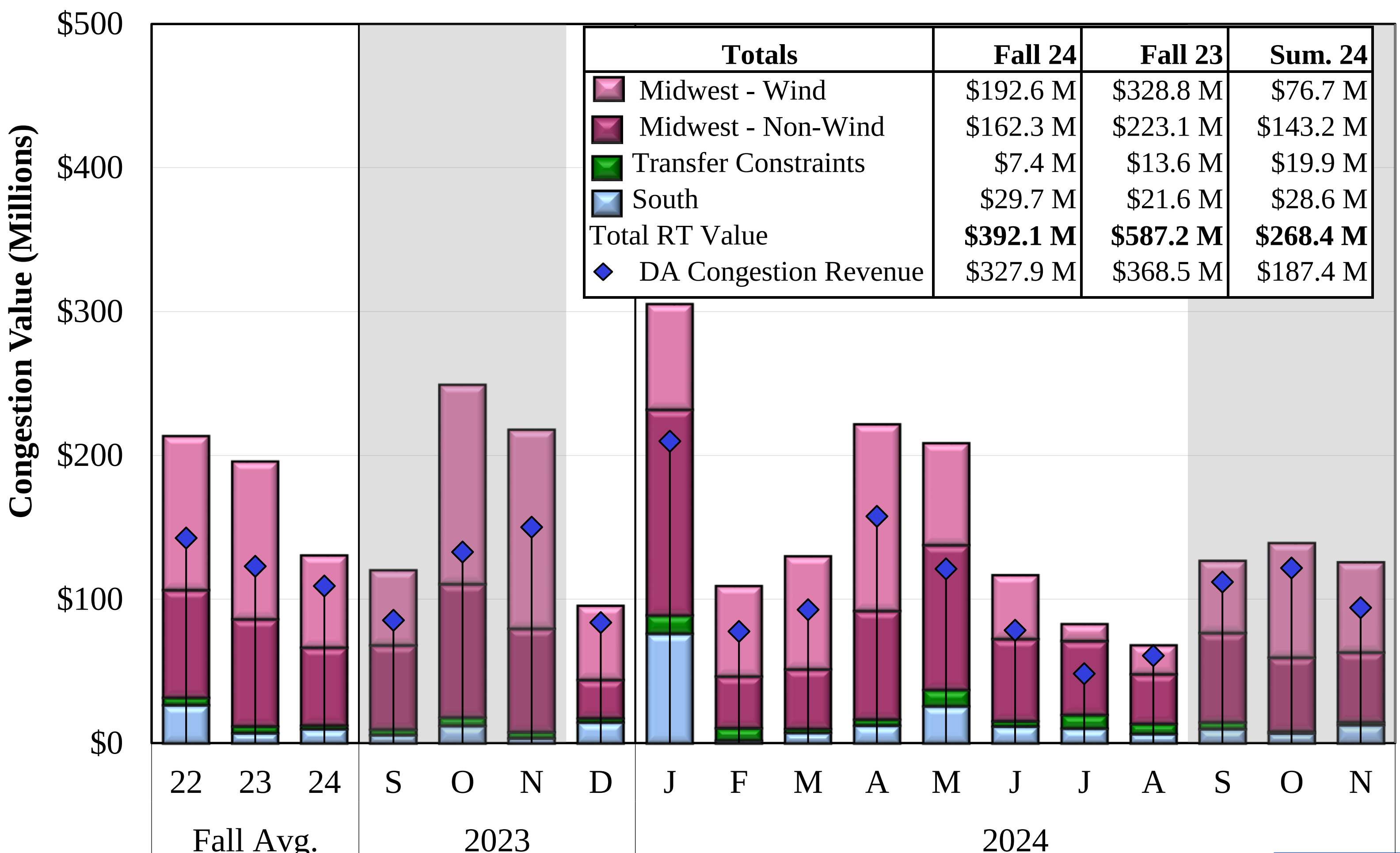
Day-Ahead Congestion, Balancing Congestion, and FTR Underfunding



Fall Totals	2024	2023
Balancing Congestion Revenue	($8.7 M)	($19.9 M)
DA Congestion Revenues	$327.9 M	$368.5 M
FTR Surplus (Shortfall)	($4.8 M)	($52.6 M)
FTR Funding (%)	99.5%	95.7%

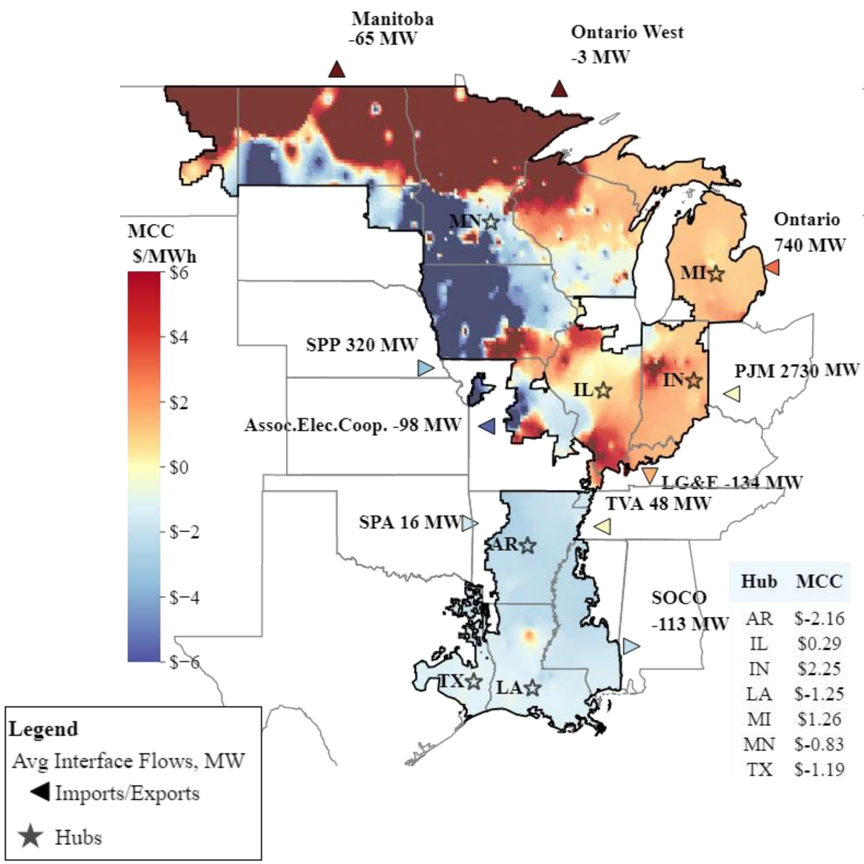
Value of Real-Time congestion
Fall 2022-2024



Totals	Fall 24	Fall 23	Sum. 24
Midwest - Wind	$192.6 M	$328.8 M	$76.7 M
Midwest - Non-Wind	$162.3 M	$223.1 M	$143.2 M
Transfer Constraints	$7.4 M	$13.6 M	$19.9 M
South	$29.7 M	$21.6 M	$28.6 M
Total RT Value	**$392.1 M**	**$587.2 M**	**$268.4 M**
DA Congestion Revenue	$327.9 M	$368.5 M	$187.4 M

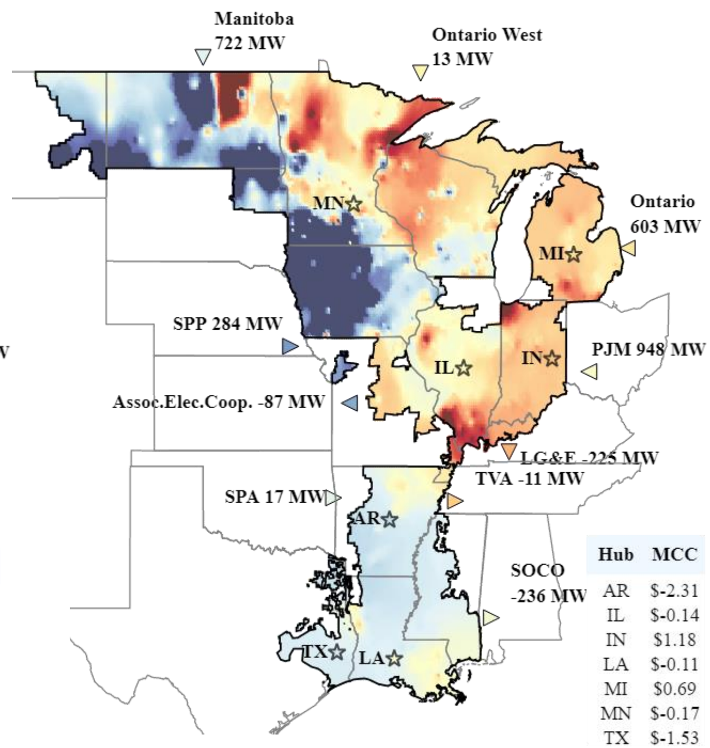
Average Real-Time Congestion Components
Fall 2023 – 2024

Fall 2023



Hub	MCC
AR	$-2.16
IL	$0.29
IN	$2.25
LA	$-1.25
MI	$1.26
MN	$-0.83
TX	$-1.19

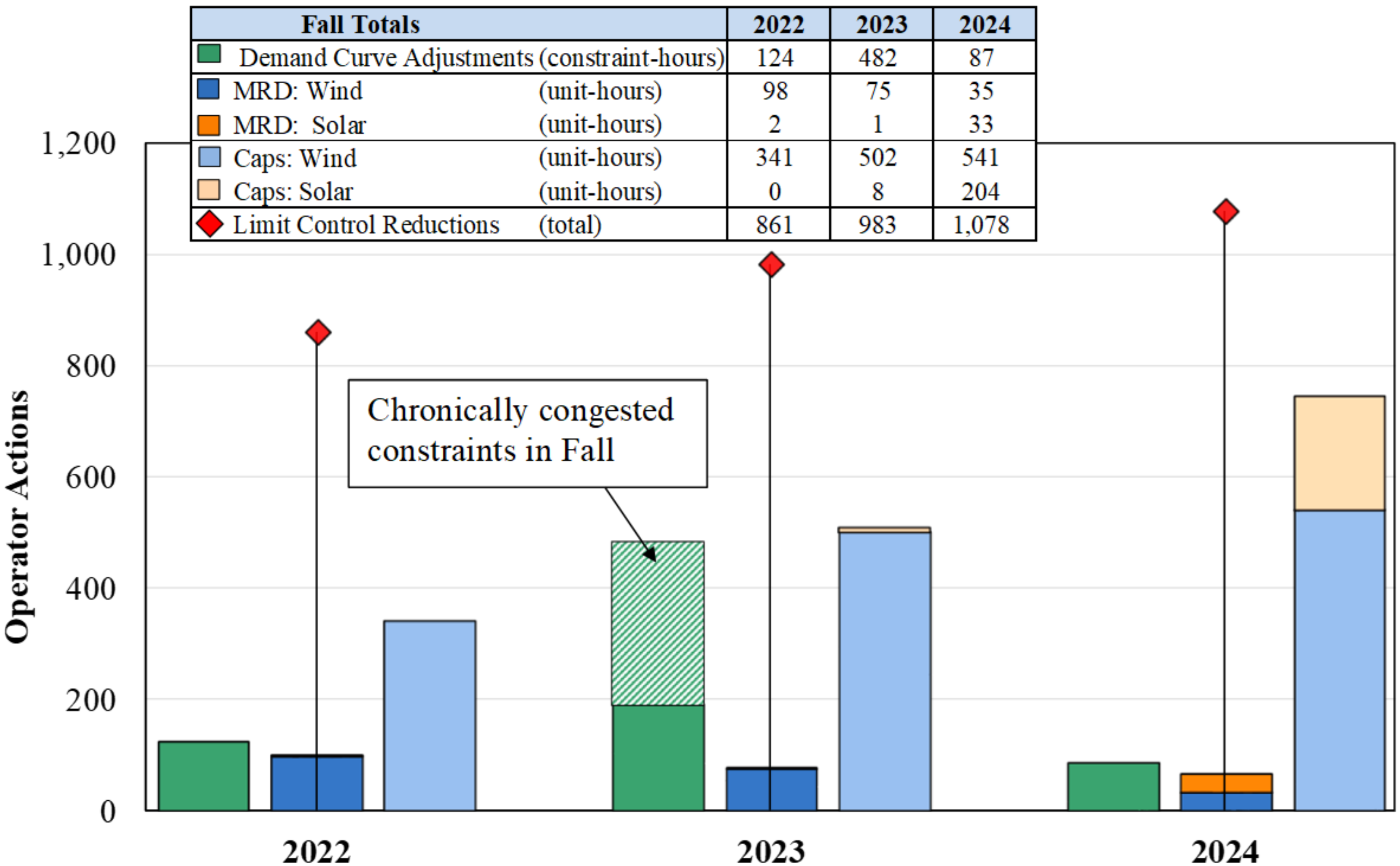
Fall 2024



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

MISO Operator Actions for Congestion Management

Fall Totals		2022	2023	2024
Demand Curve Adjustments	(constraint-hours)	124	482	87
MRD: Wind	(unit-hours)	98	75	35
MRD: Solar	(unit-hours)	2	1	33
Caps: Wind	(unit-hours)	341	502	541
Caps: Solar	(unit-hours)	0	8	204
Limit Control Reductions	(total)	861	983	1,078



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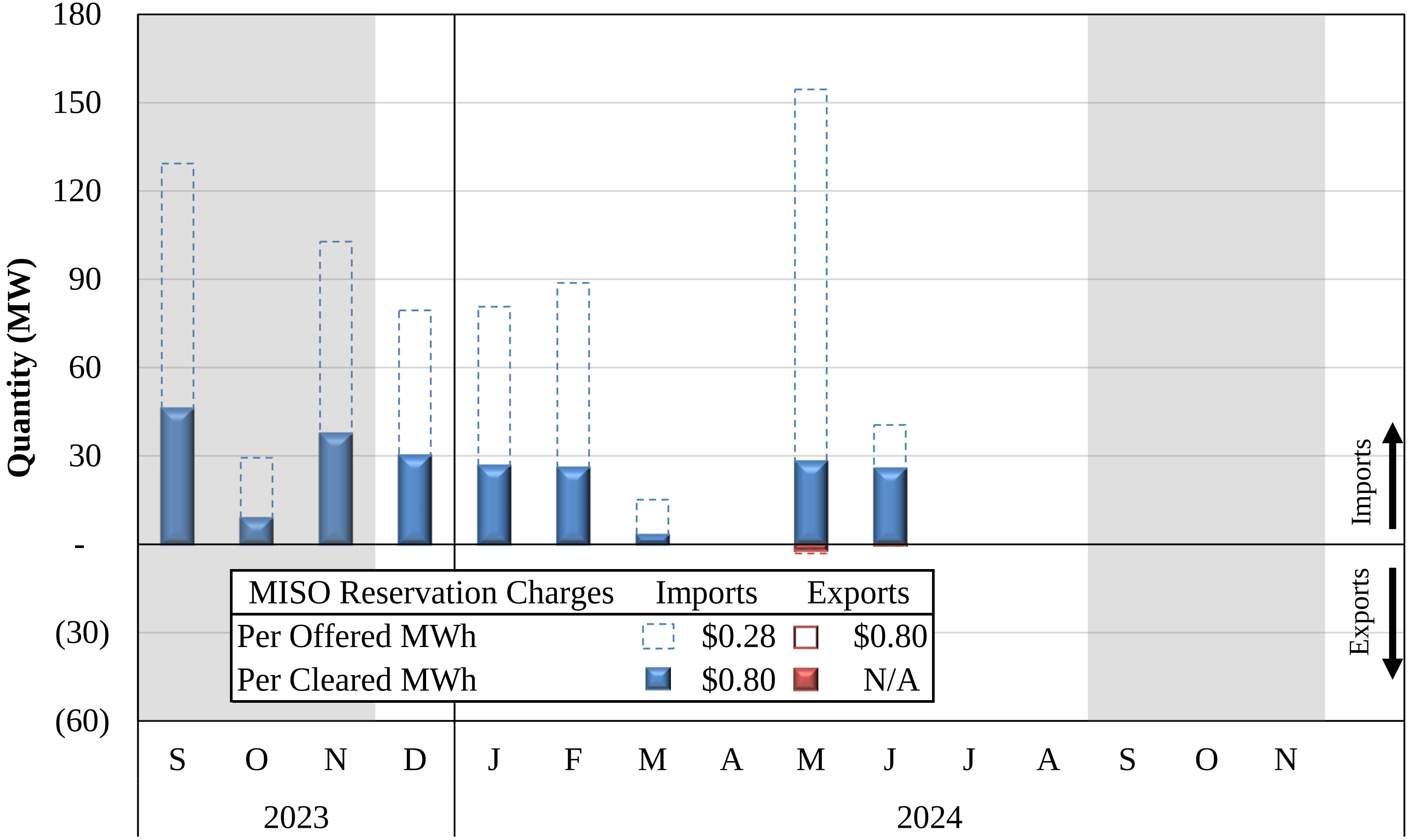
Benefits of Ambient-Adjusted and Emergency Ratings Fall 2023–2024

	Fall	Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2023	Midwest	$63.0	$31.19	$94.1	11	18.4%
	South	$0.2	$0.64	$0.9	2	6.0%
	Total	**$63.2**	**$31.8**	**$95.0**	**13**	**18.0%**
2024	Midwest	$27.3	$25.04	$52.3	18	12.4%
	South	$0.6	$0.87	$1.5	3	4.9%
	Total	**$27.9**	**$25.9**	**$53.8**	**21**	**11.9%**

Coordinated Transaction Scheduling (CTS)
Fall 2023–2024



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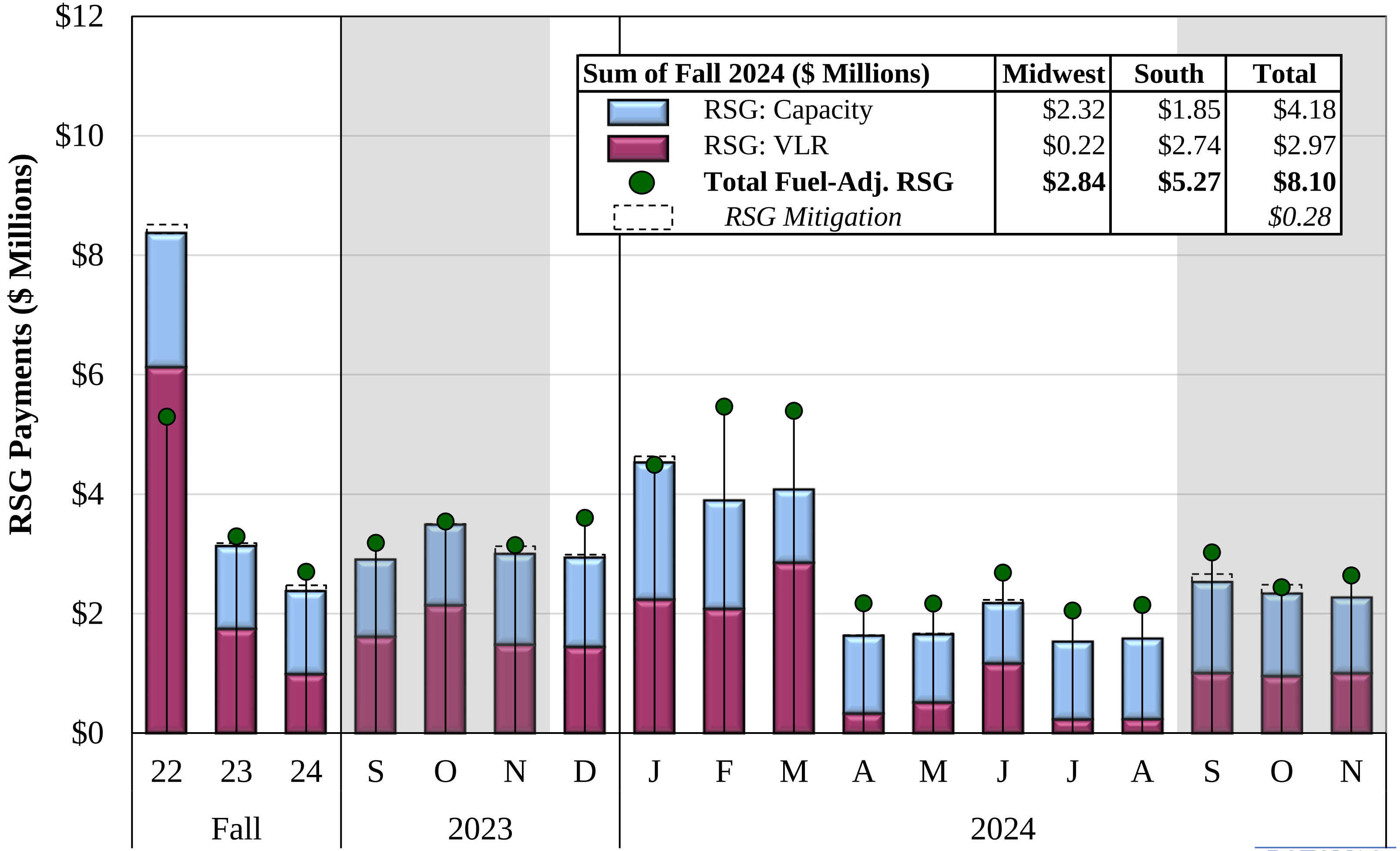
Day-Ahead RSG Payments
Fall 2023–2024



Sum of Fall 2024 ($ Millions)	Midwest	South	Total
RSG: Capacity	$2.32	$1.85	$4.18
RSG: VLR	$0.22	$2.74	$2.97
Total Fuel-Adj. RSG	**$2.84**	**$5.27**	**$8.10**
RSG Mitigation			*$0.28*

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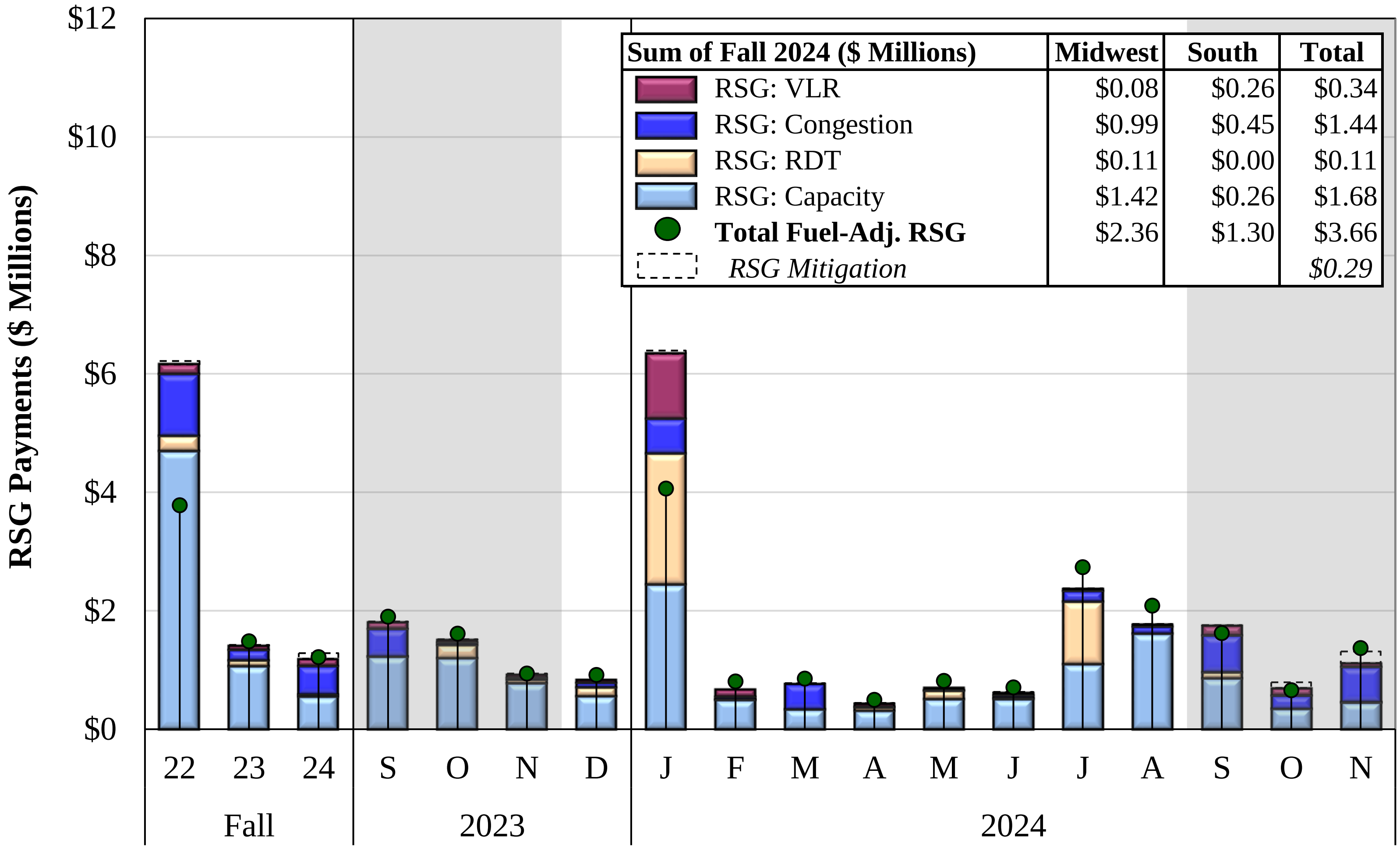
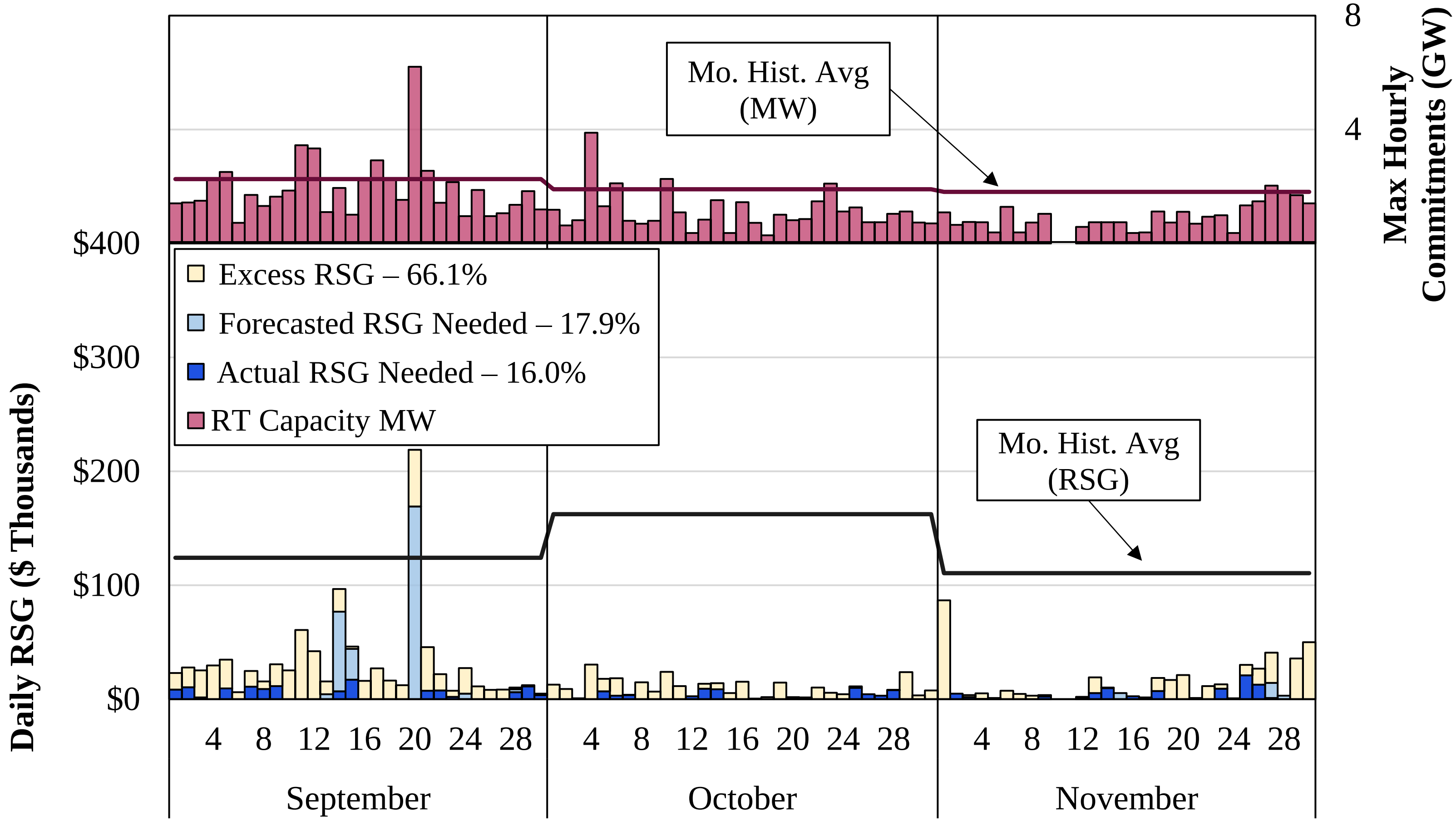
Real-Time RSG Payments
Fall 2023–2024



Real-Time Capacity Commitment and RSG Fall 2024



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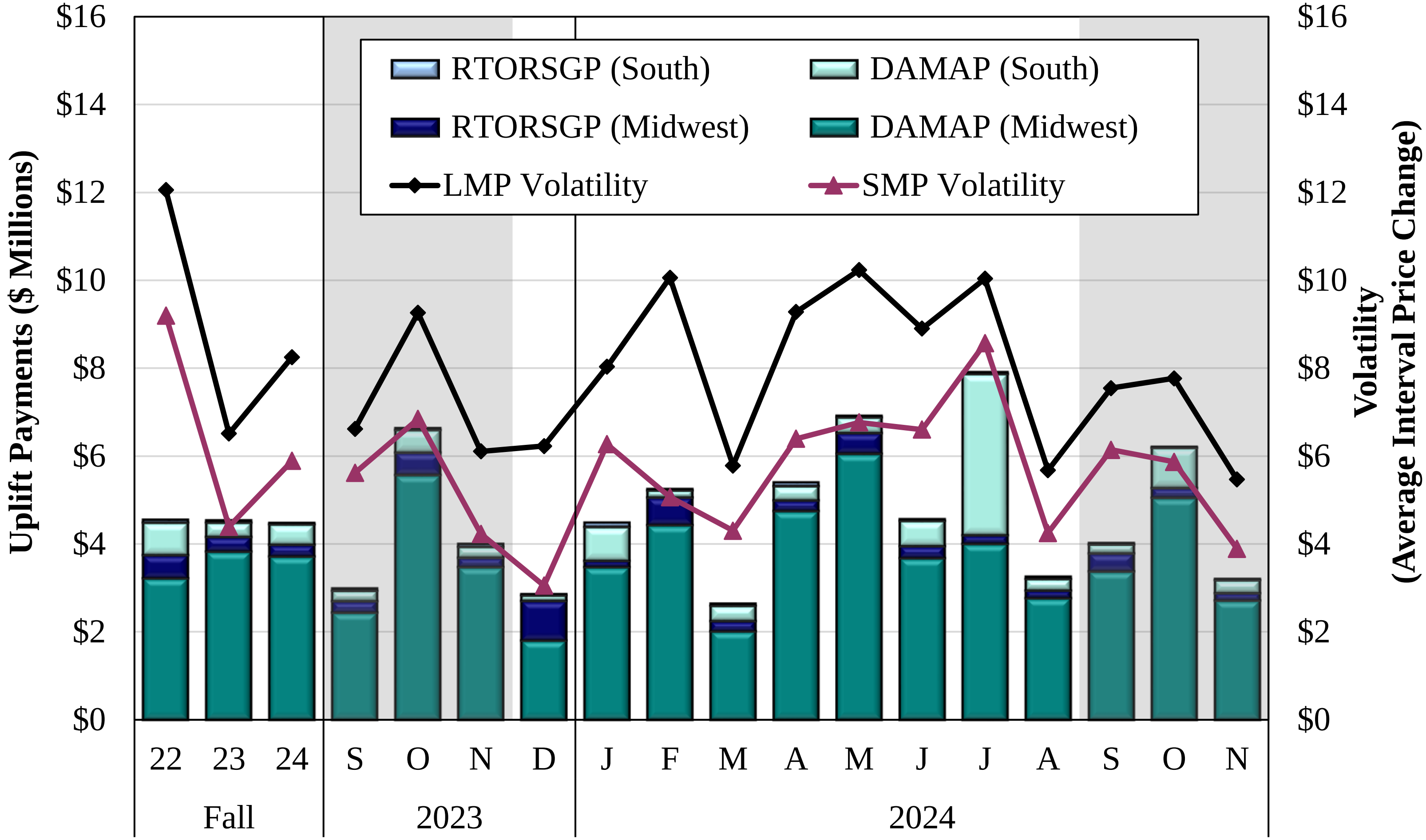
Price Volatility Make Whole Payments Fall 2022–2024



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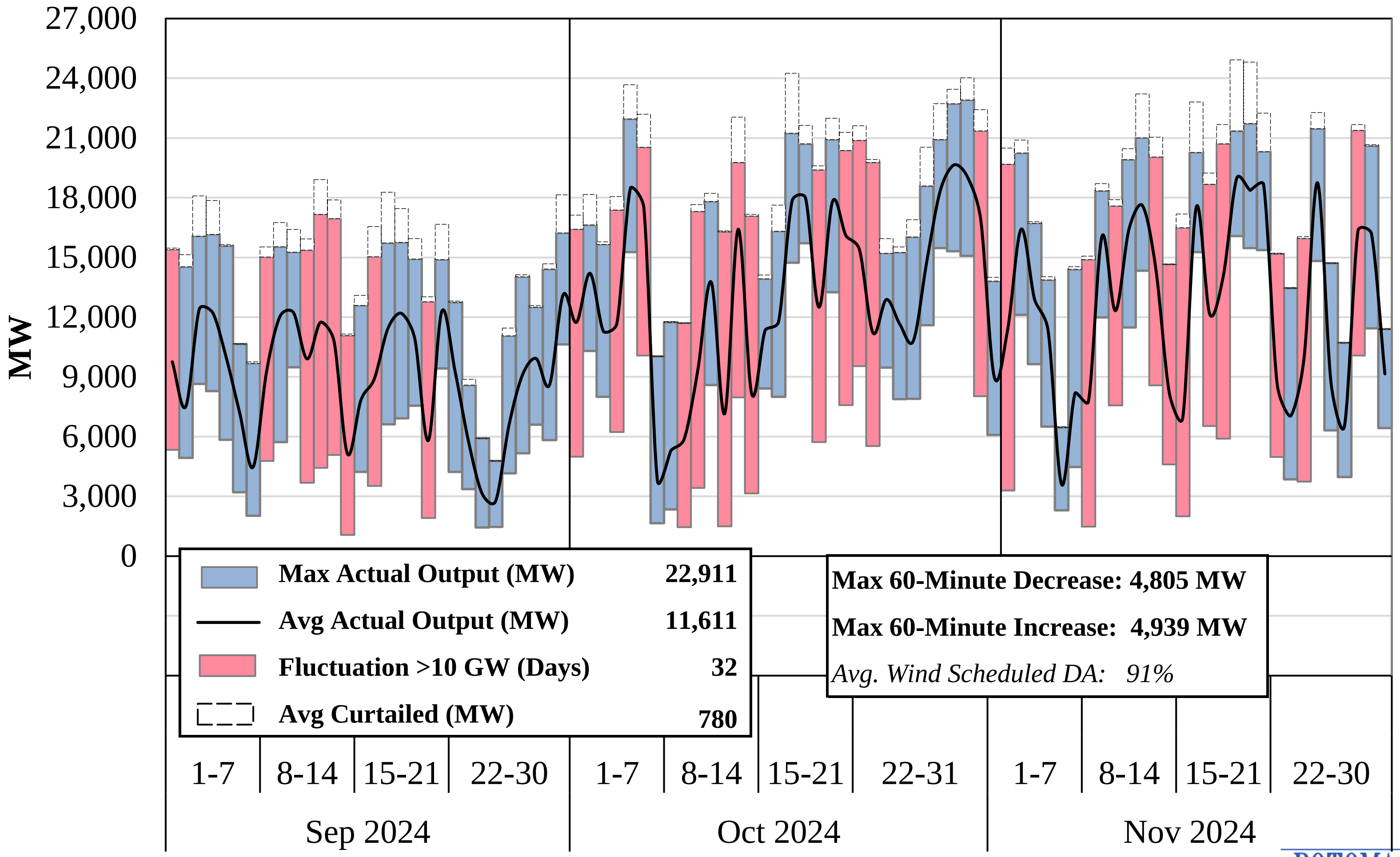
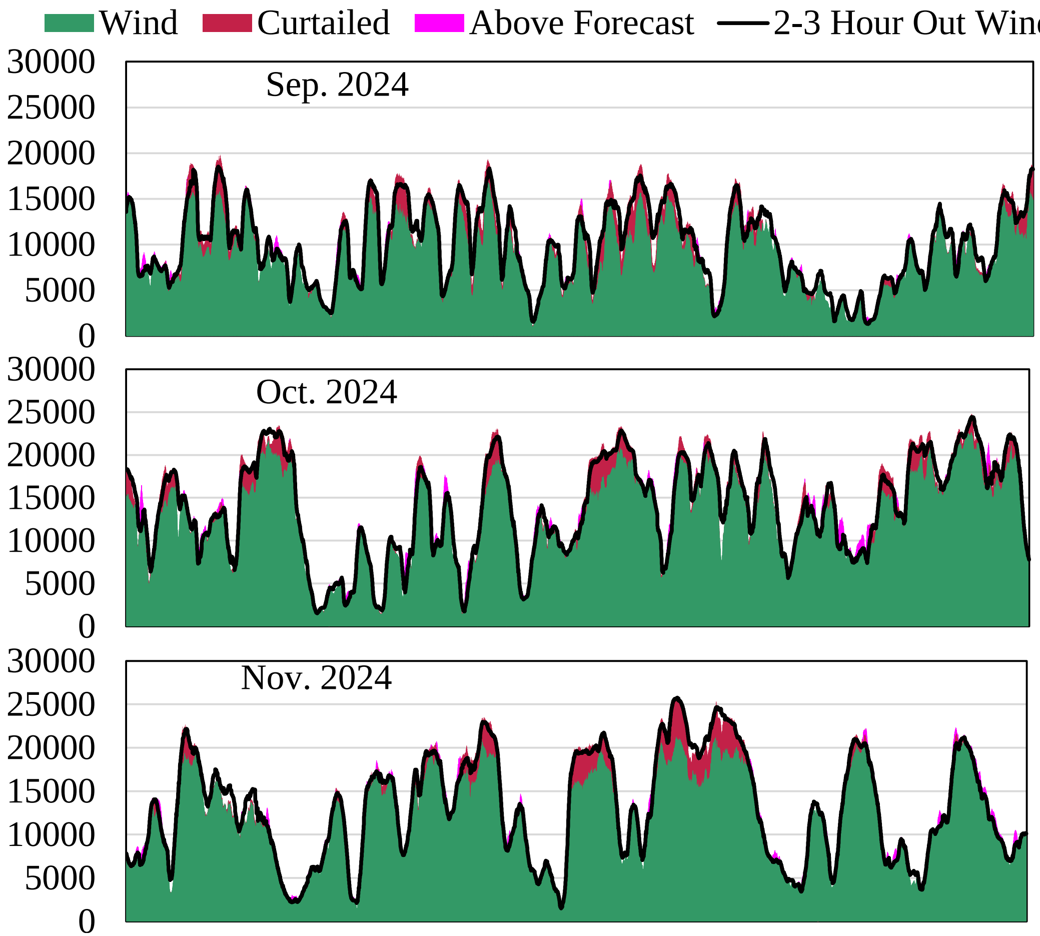
Wind Output in Real Time
Daily Range and Average

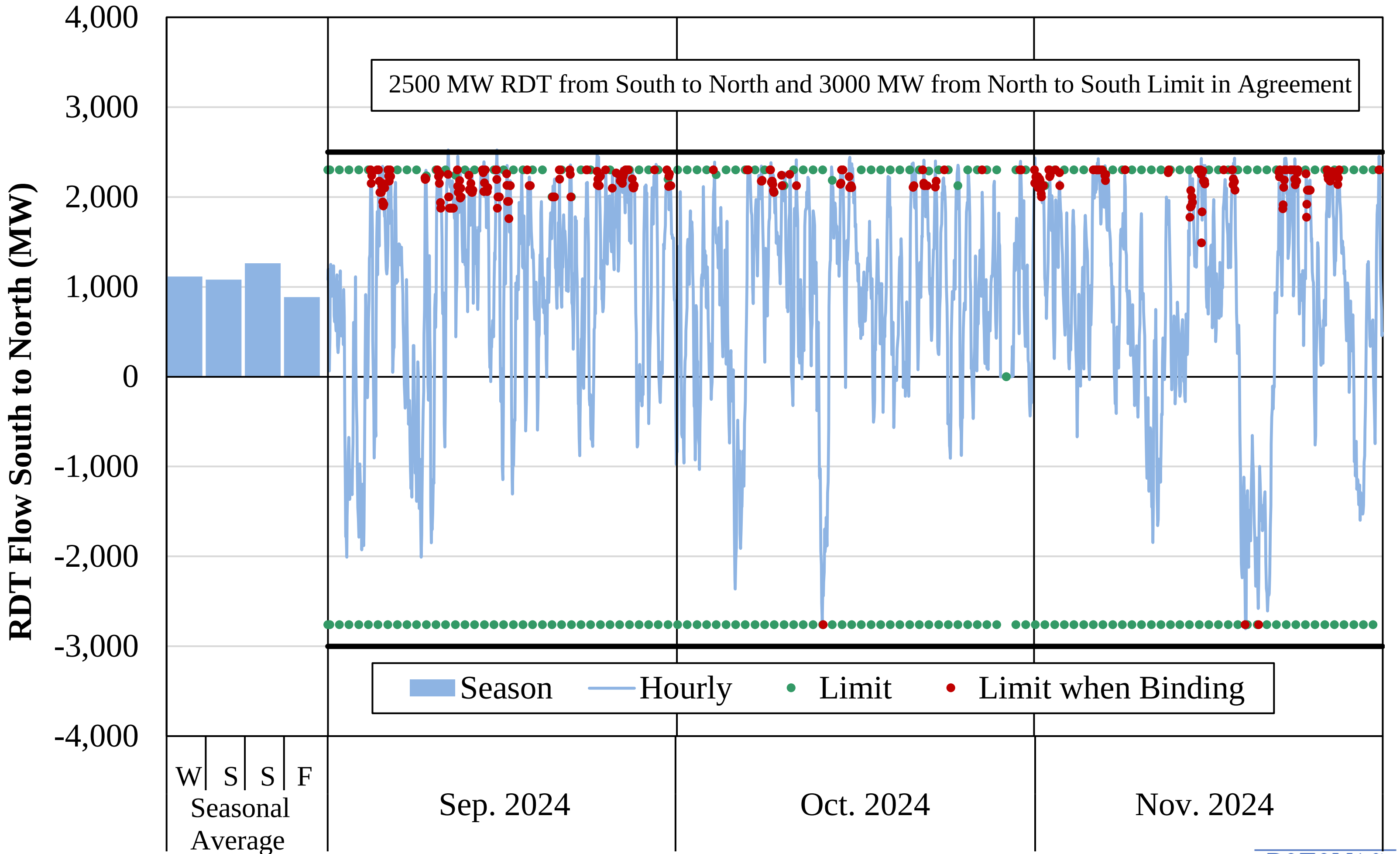


Wind Forecast and Actual Output
Fall 2024

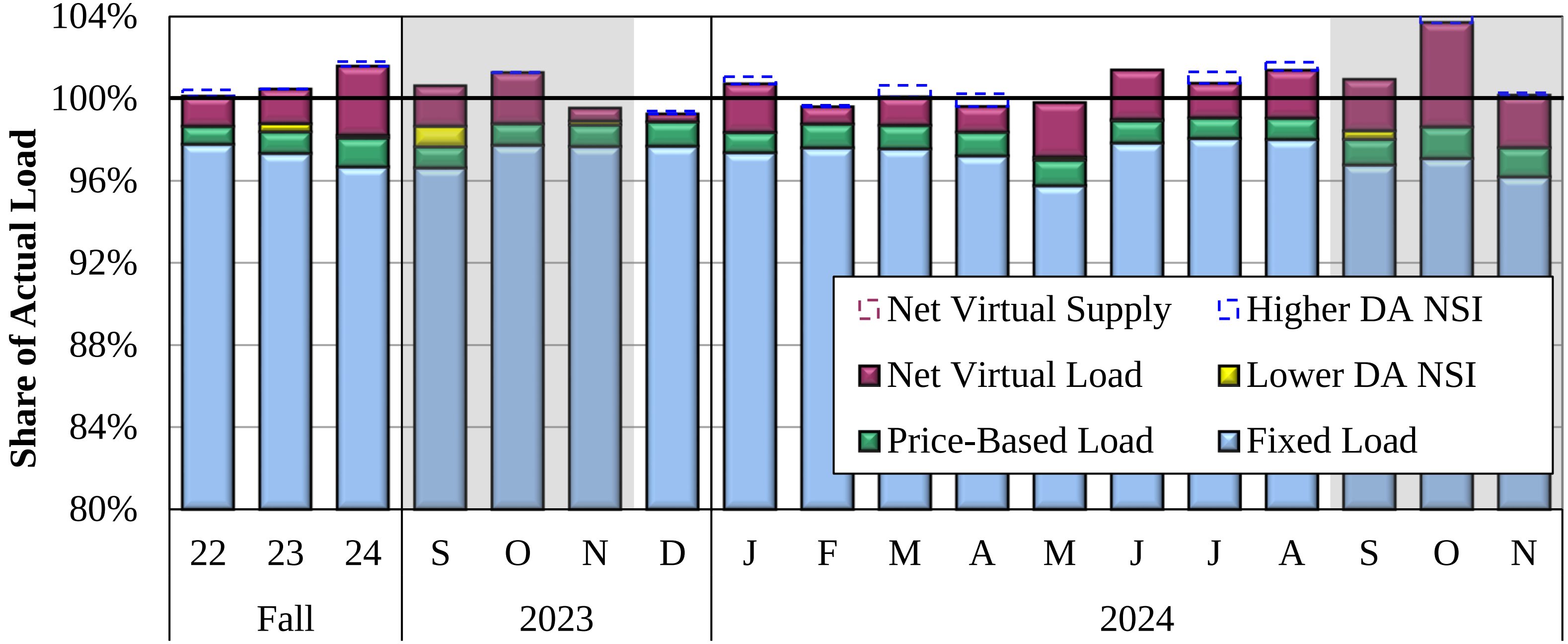


Fall 2024	
Real-Time Wind (MW)	11,611
Day-Ahead Wind (MW)	10,548
Avg Curtailments (MW)	780
Forecast Errors (%)	0.3%
Absolute Errors (%)	7.6%
Fall 2023	
Real-Time Wind (MW)	10,949
Day-Ahead Wind (MW)	9,872
Avg Curtailments (MW)	548
Forecast Errors (%)	-0.3%
Absolute Errors (%)	8.3%
Summer 2024	
Real-Time Wind (MW)	7,710
Day-Ahead Wind (MW)	7,218
Avg Curtailments (MW)	265
Forecast Errors (%)	1.8%
Absolute Errors (%)	16.5%

Real-Time Hourly Inter-Regional Flows
Fall 2024



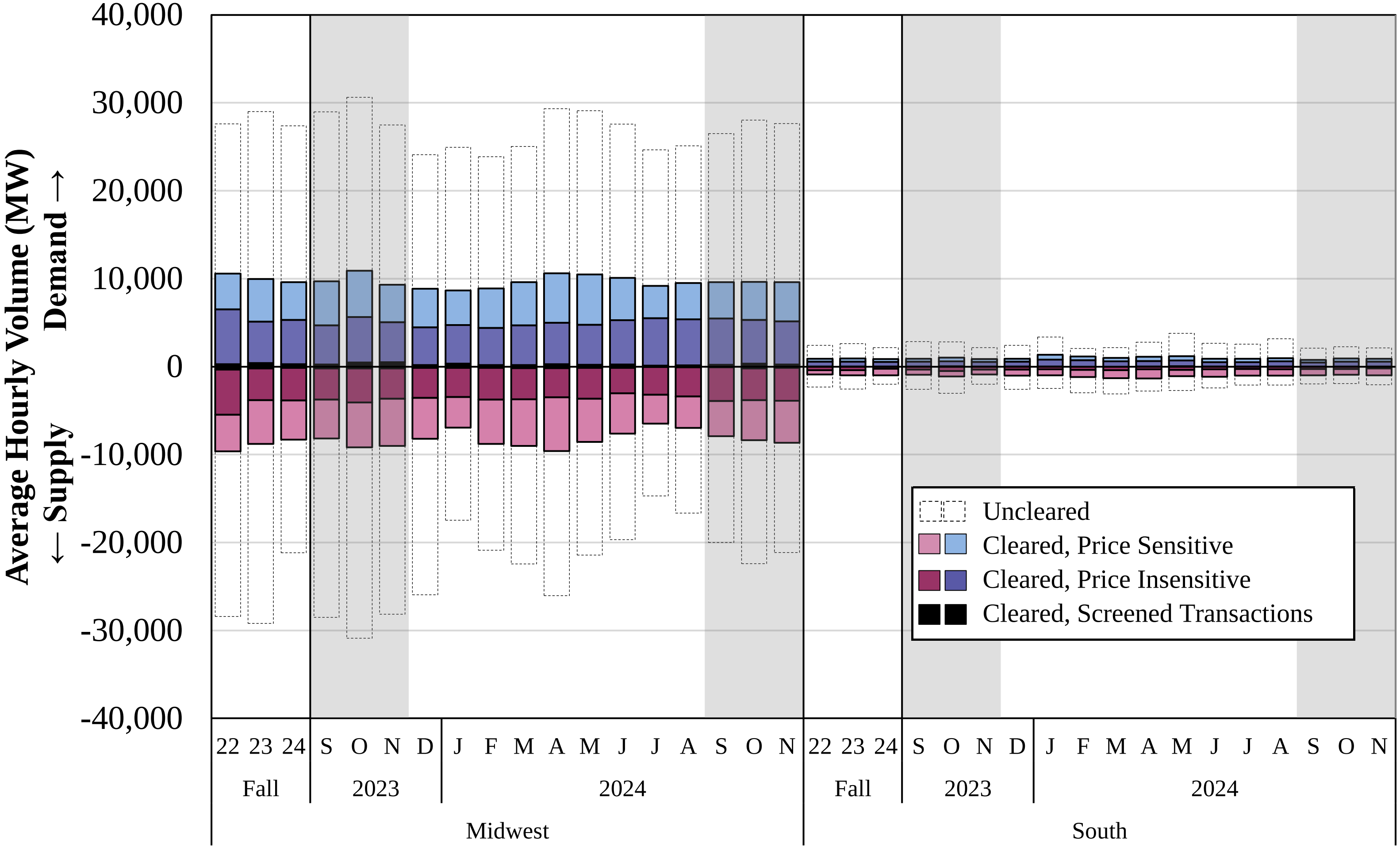
Day-Ahead Peak Hour Load Scheduling
Fall 2022–2024



Share of Actual Load (%)

	Fall 22	Fall 23	Fall 24	2023 S	2023 O	2023 N	2023 D	2024 J	2024 F	2024 M	2024 A	2024 M	2024 J	2024 J	2024 A	2024 S	2024 O	2024 N
All Hours	99.4	100.0	100.1	100.6	100.3	99.1	98.6	100.5	99.2	99.1	99.3	101.0	101.4	102.0	101.9	100.7	100.4	99.2
Peak Hours Midwest	100.5	100.6	102.4	100.3	101.7	99.7	99.5	100.8	99.9	100.9	99.4	100.3	102.6	101.3	101.9	101.7	105.1	100.5
Peak Hours South	100.0	101.1	101.3	100.7	102.1	100.7	101.3	101.5	99.4	100.8	99.1	100.8	100.7	99.9	100.6	100.2	103.1	100.5

Virtual Load and Supply
Fall 2022–2024



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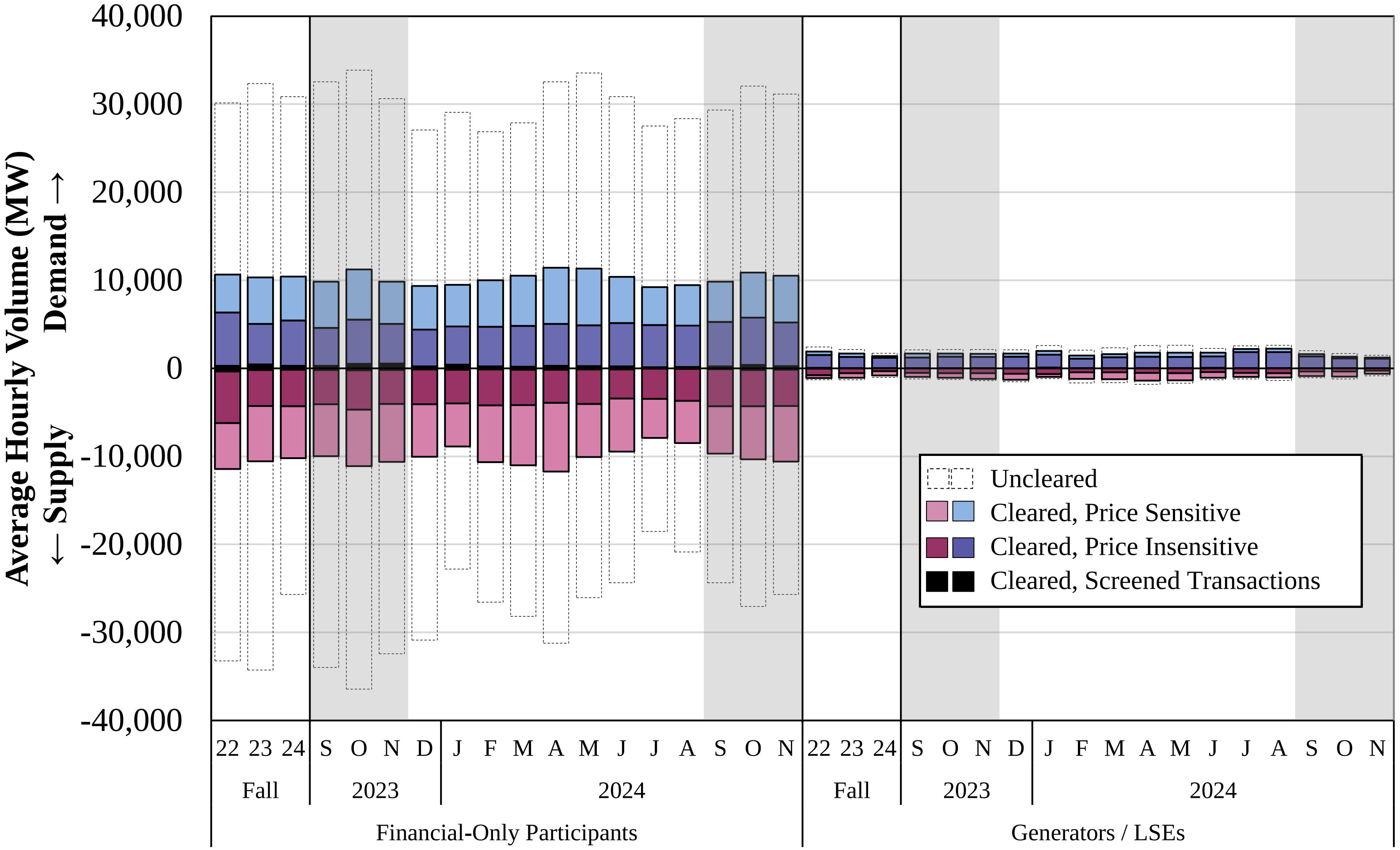
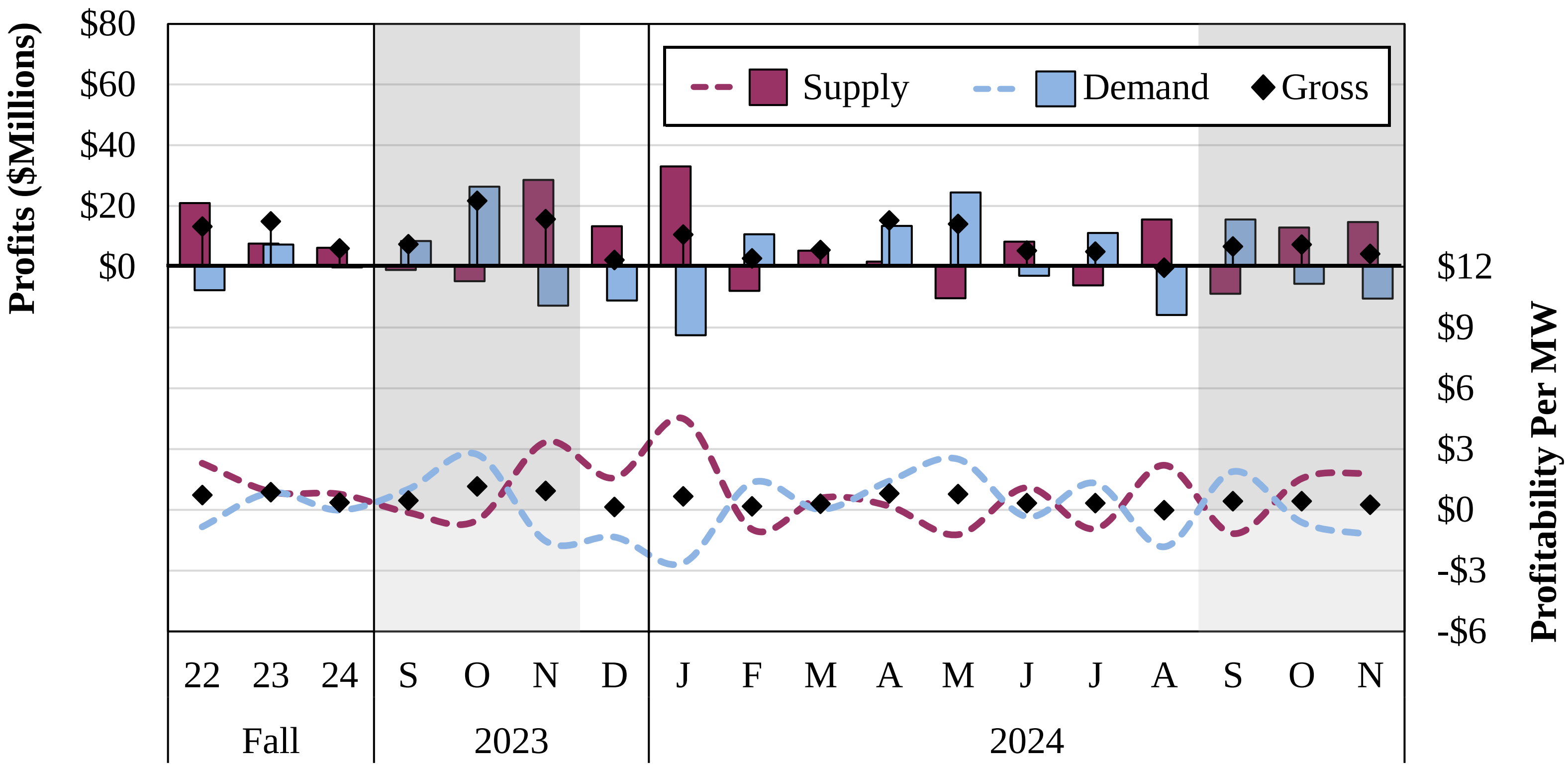
Virtual Load and Supply by Participant Type
Fall 2022–2024



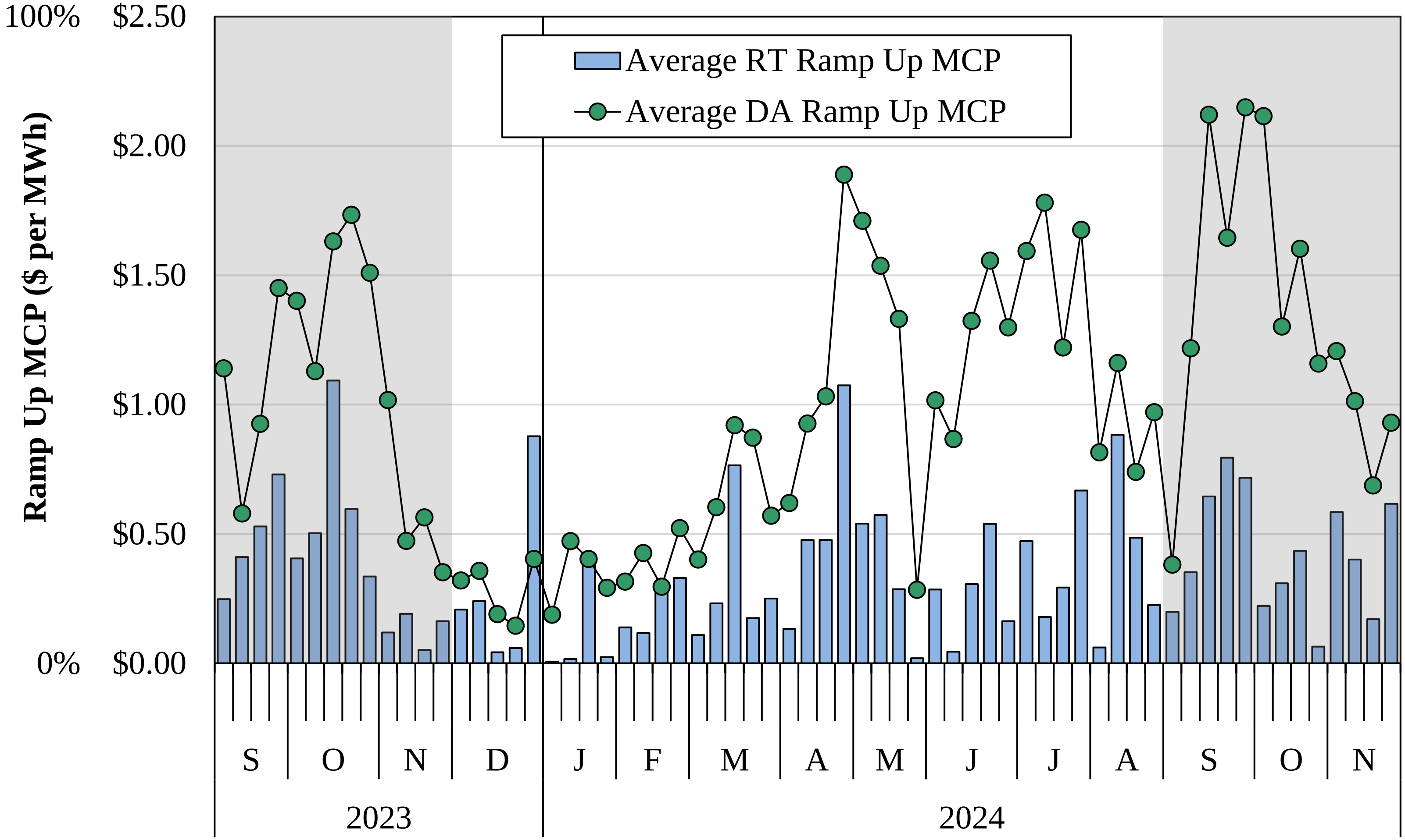
Virtual Profitability
Fall 2022–2024



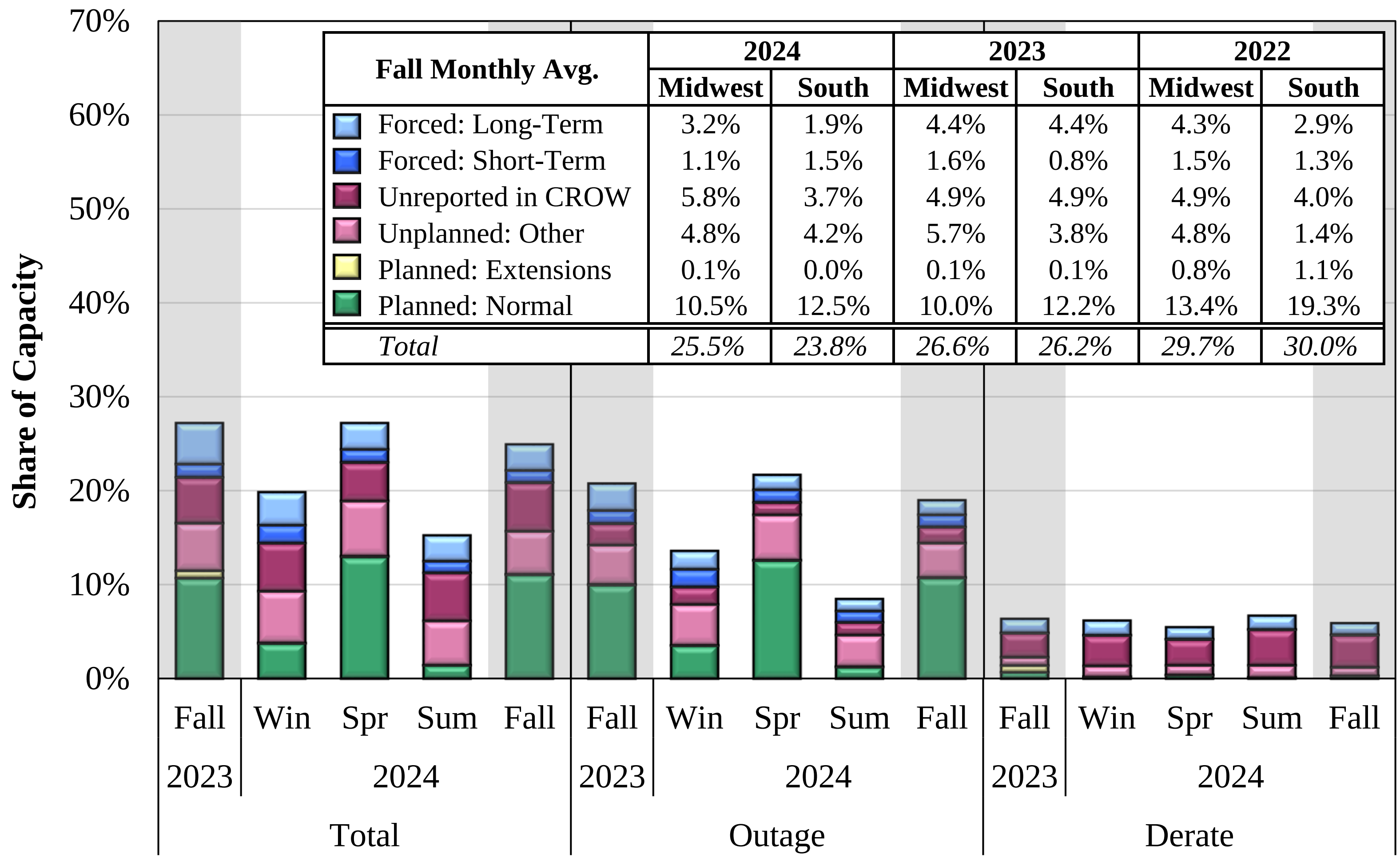
Percent Screened

	Fall 22	Fall 23	Fall 24	2023 S	2023 O	2023 N	2023 D	2024 J	2024 F	2024 M	2024 A	2024 M	2024 J	2024 J	2024 A	2024 S	2024 O	2024 N
Supply	3.1	1.9	1.4	2.0	1.9	1.9	1.3	1.7	1.2	1.6	1.3	1.5	1.5	0.7	0.8	0.9	1.9	1.5
Demand	2.5	3.9	2.5	2.6	4.2	4.9	2.0	4.3	2.1	1.6	2.3	2.0	2.2	1.2	1.5	1.9	3.3	2.4
Total	2.8	2.9	2.0	2.3	3.1	3.4	1.7	3.1	1.6	1.6	1.8	1.8	1.9	1.0	1.2	1.4	2.6	2.0

Day-Ahead and Real-Time Ramp Up Price
Fall 2022–2024

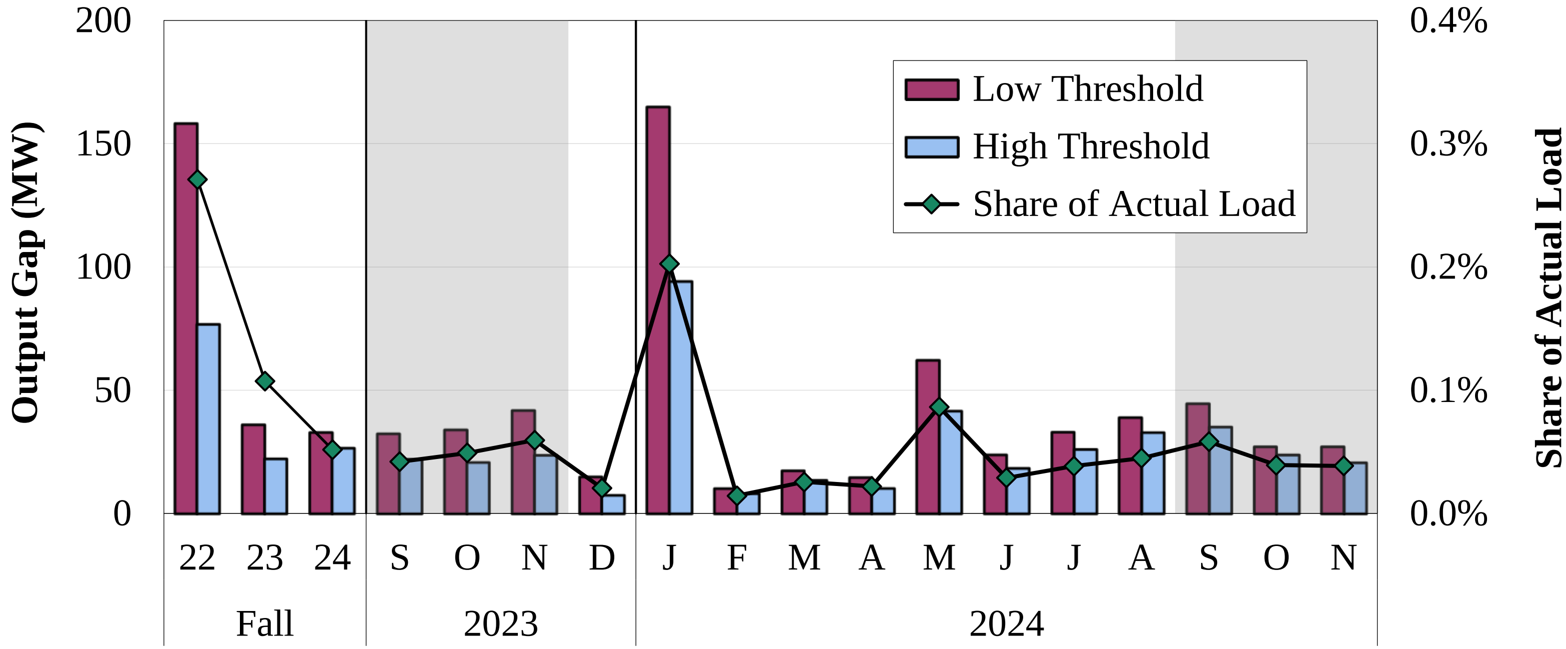


Generation Outages and Deratings
Fall 2022–2024



Fall Monthly Avg.	2024		2023		2022	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	3.2%	1.9%	4.4%	4.4%	4.3%	2.9%
Forced: Short-Term	1.1%	1.5%	1.6%	0.8%	1.5%	1.3%
Unreported in CROW	5.8%	3.7%	4.9%	4.9%	4.9%	4.0%
Unplanned: Other	4.8%	4.2%	5.7%	3.8%	4.8%	1.4%
Planned: Extensions	0.1%	0.0%	0.1%	0.1%	0.8%	1.1%
Planned: Normal	10.5%	12.5%	10.0%	12.2%	13.4%	19.3%
Total	*25.5%*	*23.8%*	*26.6%*	*26.2%*	*29.7%*	*30.0%*

Monthly Output Gap
Fall 2022–2024



Low Threshold Results by Unit Status (MW)

Offline	110	23	27	25	17	27	4	98	3	8	6	56	18	25	31	37	22	23
Online	48	13	6	7	17	15	11	66	7	10	9	6	6	8	7	8	6	4

High Threshold Results by Unit Status (MW)

Offline	66	19	23	19	16	21	4	84	3	6	4	38	14	22	29	31	20	18
Online	10	4	4	3	5	3	3	9	6	7	6	4	5	4	4	4	4	3

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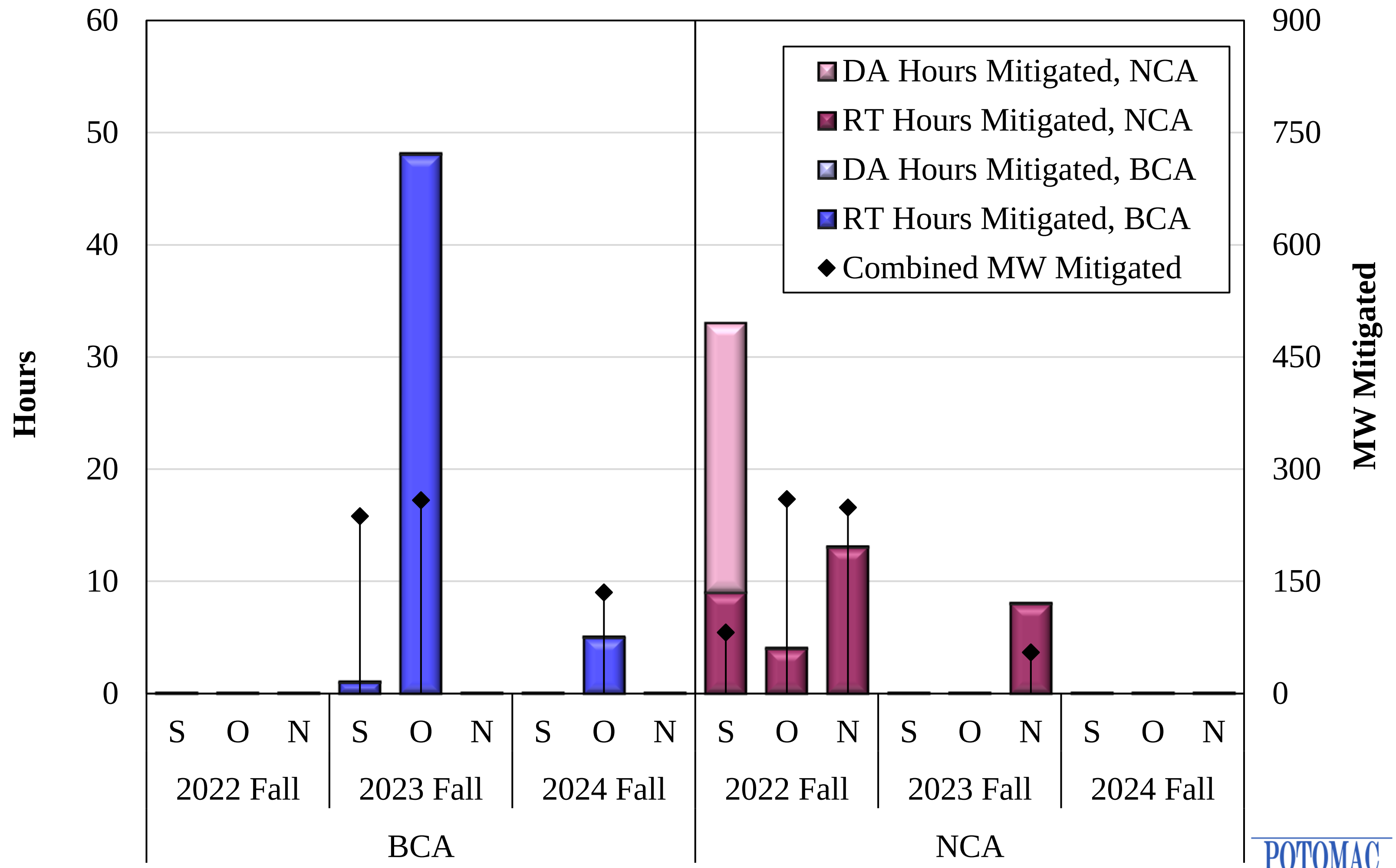
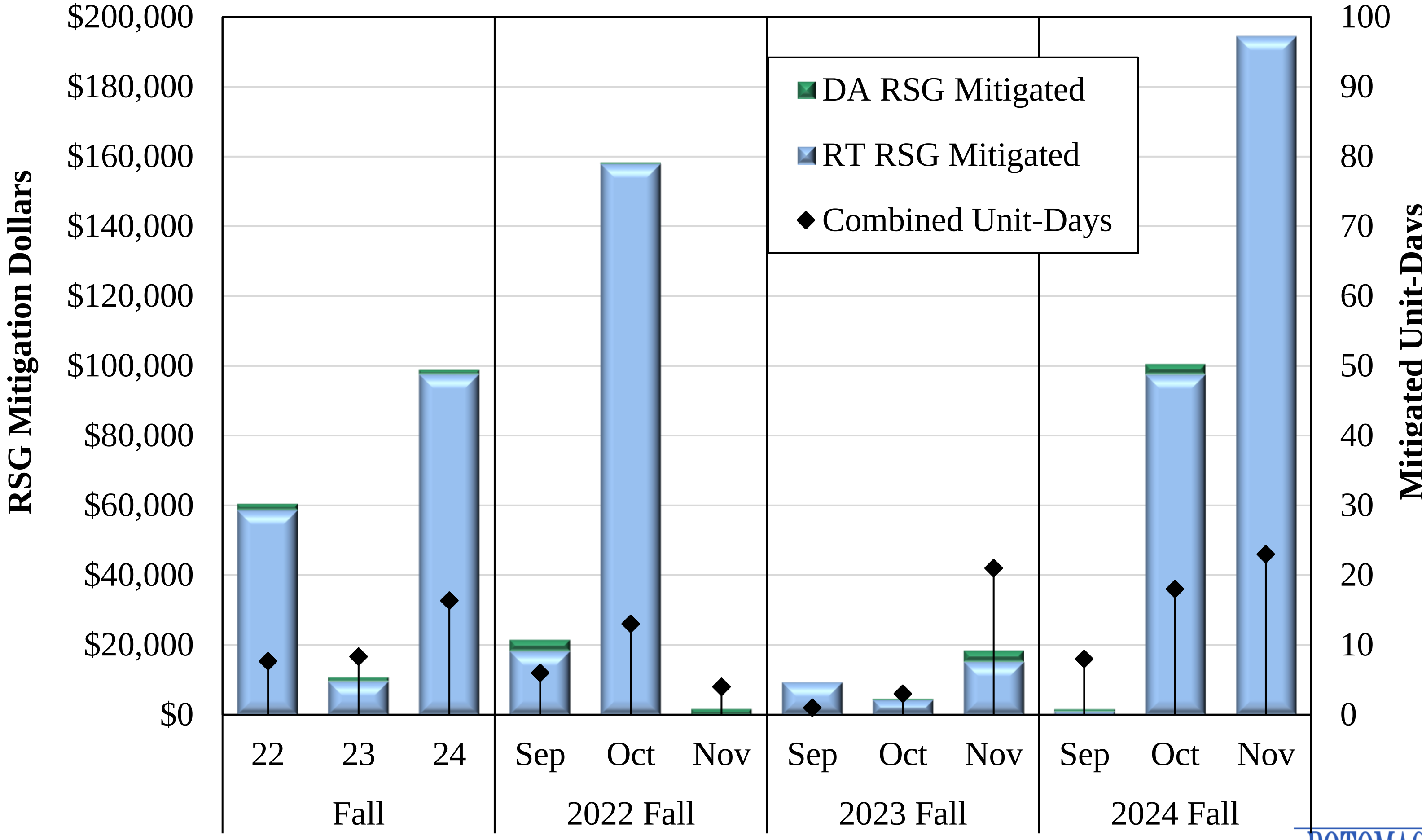
Day-Ahead And Real-Time Energy Mitigation
Fall 2022 - 2024



Day-Ahead and Real-Time RSG Mitigation Fall 2022 - 2024



Other Key Market Issues

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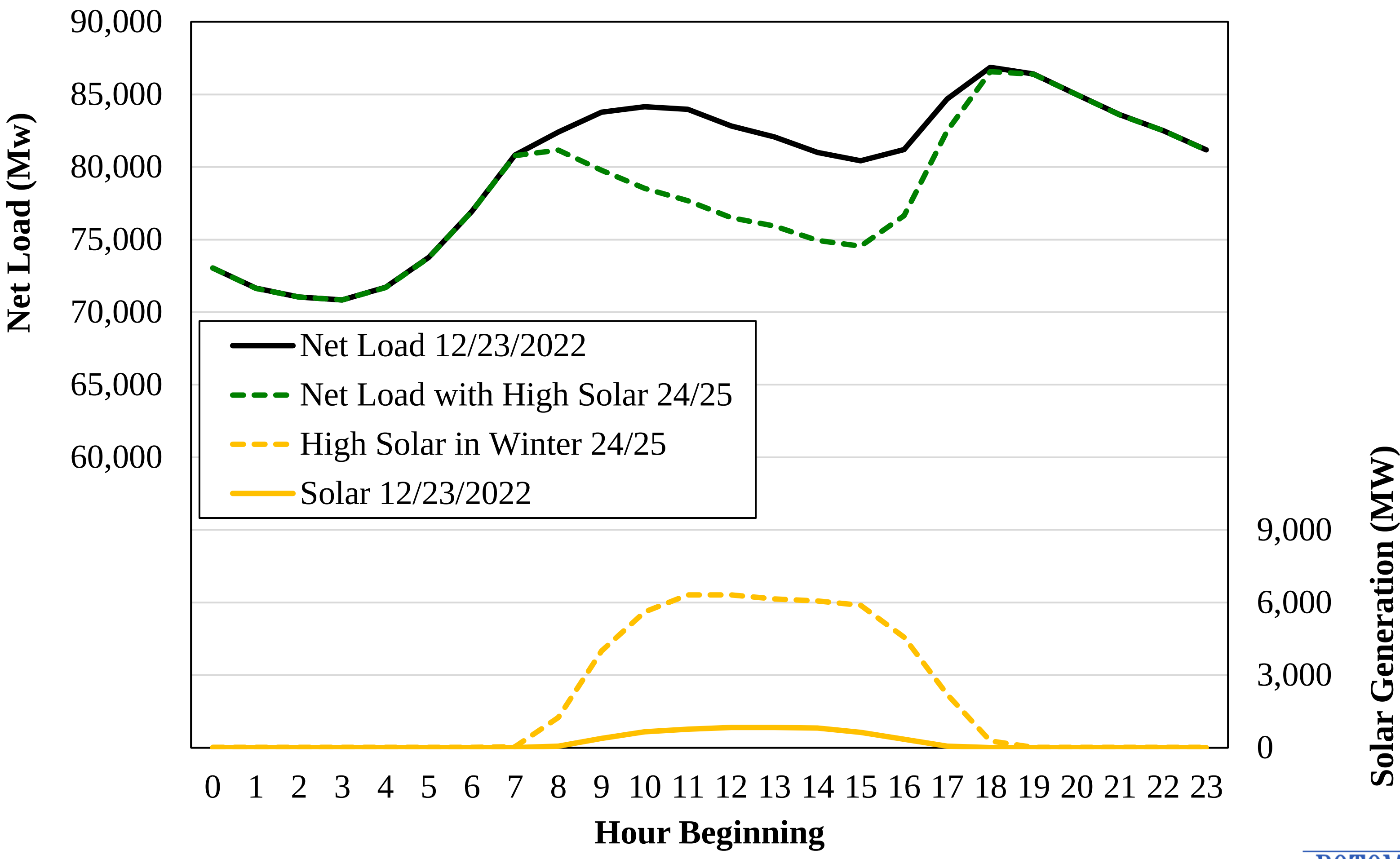
2024–2025 Winter Assessment

	Base Scenario	Alternative IMM Scenarios*: Realistic Scenario	Extreme Event: High Load	Extreme Event: High Load, High Outage
Load				
Base Case	103,122	103,122	103,122	103,122
High Load Increase	-	-	3,849	3,849
Total Load (MW)	103,092	103,092	106,970	106,970
Generation				
Internal Generation Excluding Exports	142,102	142,102	142,102	142,102
BTM Generation	3,406	2,453	2,453	1,839
Unforced Outages and Derates**	(12,243)	(17,114)	(13,114)	(13,114)
Adjustment due to Transfer Limit	-	-	(874)	-
Total Generation (MW)	133,265	127,441	130,568	130,828
Imports and Demand Response* **				
Demand Response (ICAP)	6,823	3,591	3,591	3,591
Firm Capacity Imports	3,314	3,314	3,314	3,314
Margin (MW)	40,310	31,255	30,503	30,763
Margin (%)	**39.1%**	**30.3%**	**28.5%**	**28.8%**
Expected Capacity Uses and Additions				
Expected Forced Outages****	(7,105)	(13,006)	(13,006)	(28,306)
Non-Firm Net Imports in Emergencies	-	2,400	-	-
Expected Margin (MW)	33,205	20,649	17,497	2,458
Expected Margin (%)	**32.2%**	**20.0%**	**16.4%**	**2.3%**

* Assumes 75% response from short-lead DR and 33% response from longer-lead DR.
** Base scenario shows approved planned outages for winter 2024. Realistic cases use historical average unforced outages/derates during peak winter hours. Low temp. cases are based upon MISO's 2024-25 Winter Assessment.
*** Cleared amounts for the Winter Season of the 2024/2025 planning year.
**** Base scenario assumes 5% forced outage rate for internal generation. Alternative cases use historical average forced outages/derates during peak winter hours.

Winter Challenges from Rapidly Growing Solar Capacity



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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