IMM Quarterly Report: Fall 2023

MISO Independent Market Monitor

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Potomac Economics

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Highlights for Fall 2023

<u>Lower Gas Prices and Market Impacts (Slides 11, 13, 15-16, 28-30)</u>

- Gas prices were around 60 percent lower than last fall, impacting energy prices, coal resource dispatch, congestion, uplift, and resource net revenues.
  - ✓ Although prices at Henry Hub were on average $0.44 per MMBtu higher than Chicago Citygate, flows across the RDT were generally south to north because of available low-cost surplus generation in the South.
  - ✓ Real-time energy prices fell more than 40 percent, and prices for ancillary services fell between 26 and 30 percent.
- Lower prices led to lower net revenues from last fall – particularly for nuclear units, which fell by 49 and 58 percent in the Midwest and South, respectively.
- Day-ahead RSG fell by 63 percent, while real-time RSG fell 76 percent.
  - ✓ While gas prices have contributed to much of this reduction, MISO has also made significant improvements in its commitment processes.
  - ✓ However, opportunities for further improvements exist as more than half of the real-time RSG was from commitments that were not needed.

Highlights and Findings: Fall 2023

- The MISO markets performed competitively this fall and market power mitigation was infrequent.
- Despite higher average and peak load, energy prices fell more than 40 percent compared to last fall because gas prices fell almost 60 percent year over year.
  - ✓ Average load this fall grew one percent from last year.
  - ✓ Parts of the Midwest experienced almost record high temperatures in September – leading to a 7 percent higher peak load than the prior year.
- Although gas prices were much lower this year, real-time congestion fell only slightly as exports to Manitoba and outages contributed to unusual congestion.
  - ✓ Unusual power flows from south to north resulted in high congestion throughout the North.
  - ✓ An SPP constraint created substantial inefficient costs and other issues.
- Average hourly wind output and wind curtailments (averaging 548 MW per hour) were both down by 6 and 15 percent, respectively.
- MISO continued to generate much lower uplift, largely because of lower gas prices and improvements in MISO's commitments.

Quarterly Summary

Fall		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
RT Energy Prices ($/MWh)	🟣	$31.87	*-7%*	*-44%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago	🟣	$2.34	*5%*	*-59%*
Natural Gas - Henry Hub	🟣	$2.78	*15%*	*-56%*
Western Coal	🟢	$0.80	*-1%*	*-16%*
Eastern Coal	🟢	$1.94	*-9%*	*-74%*
Load (GW)[2]				
Average Load	🟢	72.2	*-15%*	*1%*
Peak Load	🟢	115.2	*-8%*	*7%*
% Scheduled DA (Peak Hour)	🟢	100.5%	100.4%	100.1%
Transmission Congestion ($M)				
Real-Time Congestion Value	🟣	$586.8	*55%*	*-8%*
Day-Ahead Congestion Revenue	🟣	$368.5	*40%*	*-14%*
Balancing Congestion Revenue[3]	🟢	$23.9	$19.7	-$20.3
Ancillary Service Prices ($/MWh)				
Regulation	🟢	$11.26	*10%*	*-28%*
Spinning Reserves	🟢	$2.91	*19%*	*-26%*
Supplemental Reserves	🟢	$0.45	*-33%*	*-30%*

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
FTR Funding (%)	🟢	95%	101%	104%
Wind Output (MW/hr)	🟣	10,949	*77%*	*-6%*
Wind Curtailed (MW/hr)	🟣	548	*330%*	*-15%*
Guarantee Payments ($M)[4]				
Real-Time RSG	🟣	$4.6	*-47%*	*-76%*
Day-Ahead RSG	🟣	$9.1	*31%*	*-63%*
Day-Ahead Margin Assurance	🟣	$12.9	*1%*	*9%*
Real-Time Offer Rev. Sufficiency	🟢	$1.1	*25%*	*-36%*
Price Convergence[5]				
Market-wide DA Premium	🟢	-0.2%	4.3%	2.0%
Virtual Trading				
Cleared Quantity (MW/hr)	🟢	23,639	*7%*	*-6%*
% Price Insensitive	🟢	47%	48%	59%
% Screened for Review	🟢	3%	2%	3%
Profitability ($/MW)	🟢	$0.9	$0.6	$0.7
Dispatch of Peaking Units (MW/hr)	🟢	1,503	2,729	1,019
Output Gap- Low Thresh. (MW/hr)	🟢	36	26	158

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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Highlights for Fall 2023

The Role of the Market in Maintaining Reliability (Slide 18)

- MISO's centralized location in the Eastern interconnection provides it over 20 GW of transfer capability with multiple neighboring Balancing Areas.
- In December 2021, MISO implemented Short Term Reserves (STR) to procure 30-minutes reserves and provide forward price signals as the system gets tight.
  - ✓ The STR demand curve raises prices by $100 to $500 per MWh when insufficient 30-minute resources are available.
  - ✓ This is an important new element of the market because it provides earlier price signals that will incent net imports to meet MISO's needs.
- We studied the response of net imports to rising prices in MISO and found:
  - ✓ Sustained prices over $100 (i.e., modest STR shortages) have prompted changes in net imports averaging 600 MW, while prices over $400 (i.e., deeper STR shortages) have prompted changes in net imports averaging 900 MW.
  - ✓ These market responses are critical in allowing markets to facilitate reliability.
- Out-of-market operator actions can preempt these market signals making maintaining reliability more costly.
  - ✓ This explains the importance of the improvements we have recommended to MISO's commitment processes and emergency procedures.

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Highlights for Fall 2023

Congestion Patterns in MISO Footprint (Slides 20-22, 24-26)

- Despite lower gas prices and wind output this fall compared to last fall, real-time congestion fell just 8 percent.
  - ✓ Congestion patterns were very different than normal and than last fall, partly because typical imports from Manitoba became exports.
  - ✓ Exports to Manitoba were caused by drought conditions there, similar to Winter 2022 when exports to Manitoba averaged over 600 MW.
  - ✓ Key dispatchable generation outages exacerbated congestion in the region. One such unit retires in December, which will contribute to congestion in the future.
- MISO operators took fewer out of market actions to manage difficult constraints, resulting in more efficient market outcomes.
  - ✓ Compared to last fall, MISO took 62 percent fewer manual re-dispatch actions, relying instead on 81 percent more transmission constraint demand curve (TCDC) increases to allow the market to secure more congestion relief.
- The use of ambient-adjusted and emergency ratings has not progressed, but we estimate that they could have produced savings of $95 million this fall.
  - ✓ These savings were especially large because many TOs continue to use summer transmission ratings through mid-November.

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Highlights for Fall 2023

<u>MISO Winter Assessment (Slide 17)</u>

- We assessed the expected winter capacity margin based on the peak winter forecast of 102 GW and the available seasonal capacity.
  - ✓ Including planned outages and assuming a 5% forced outage rate yields a capacity margin of 30 percent, including 11 GW of emergency-only capacity.
  - ✓ When all unforced outages/derates and typical forced outages during peak winter conditions are included, the peak capacity margin falls to 21 percent.
  - ✓ These levels are more than sufficient under normal peak winter conditions.
- However, 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 and Elliot.
  - ✓ Assuming a higher peak load of 107 GW and nearly 29 GW of forced outages, the capacity margin falls to less than one percent.
  - ✓ This is conservative because it assumes very little support from other areas.
- These results indicate that MISO should be able to reliably serve load this winter, even under extreme conditions.

Highlights for Fall 2023

Congestion-Related Issues in Fall 2023 (Slides 19, 22-23)

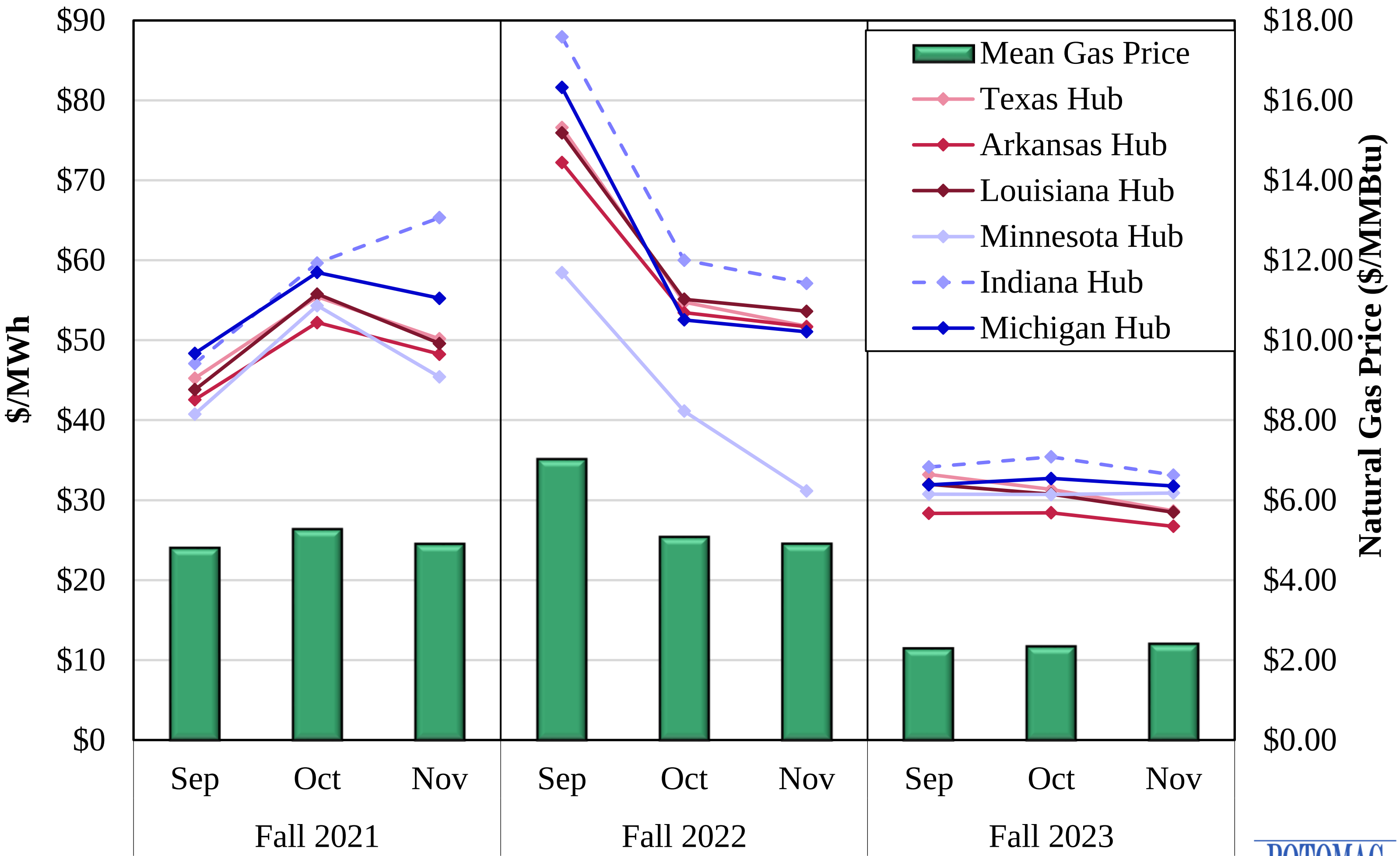
- Most of MISO North switched to winter ratings on November 15, immediately lowering congestion. This highlights the value of AARs and switching earlier.
  - ✓ The most congested constraint, Morris-Grant County, generated $34 million in congestion in the first two weeks of November and produced almost no congestion after switching to winter ratings on November 15.
  - ✓ This constraint accounts for more than half of the FTR shortfalls because a key outage was modelled inaccurately.
- A SPP M2M constraint (Charlie Creek-Watford) inflated congestion levels and distorted Manitoba interface prices, leading to inefficient imports in early fall.
  - ✓ This congestion resulted from interconnection of a 220-MW crypto-currency mining load that is only economic at its retail rates, not at wholesale LMPs.
  - ✓ The constraint is not modeled accurately by SPP, and SPP has not appropriately used transmission line loading relief (TLR) procedures, which both contributed to inefficiently high congestion – totaling $57 million since April.
  - ✓ MISO has paid **$36 million** for this constraint even though its impacts are small and it has no economic relief capability. MISO asked to remove this constraint from the M2M process and resettle the past periods, but SPP has refused.

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 we responded to requests for information on market issues.
- Presented the IMM Summer Quarterly report to the MSC and recent market results to the ERSC.
- Continued working with MISO to review proposals to revise the M2M "firm flow entitlement" allocation, which will have large economic impacts.
- Supported MISO's reliability-based demand curve filing with an affidavit.
- Worked with MISO on recommended operational improvements and produced memos and summaries of the recommendations.
- Met with OMS on market issues and transmission planning issues.
- Participated in a meeting of international market monitors and the Nodal Trader conference.
- Discussed concerns with the results of Future 2A to be used for LRTP Tranche 2 with MISO, the Planning Advisory Committee, and at the LRTP workshop.
  - ✓ MISO will not revise Future 2A, so adding other more reasonable sensitivity cases for evaluating the benefits of Tranche 2 will be critical.

Day-Ahead Average Monthly Hub Prices
Fall 2021–2023



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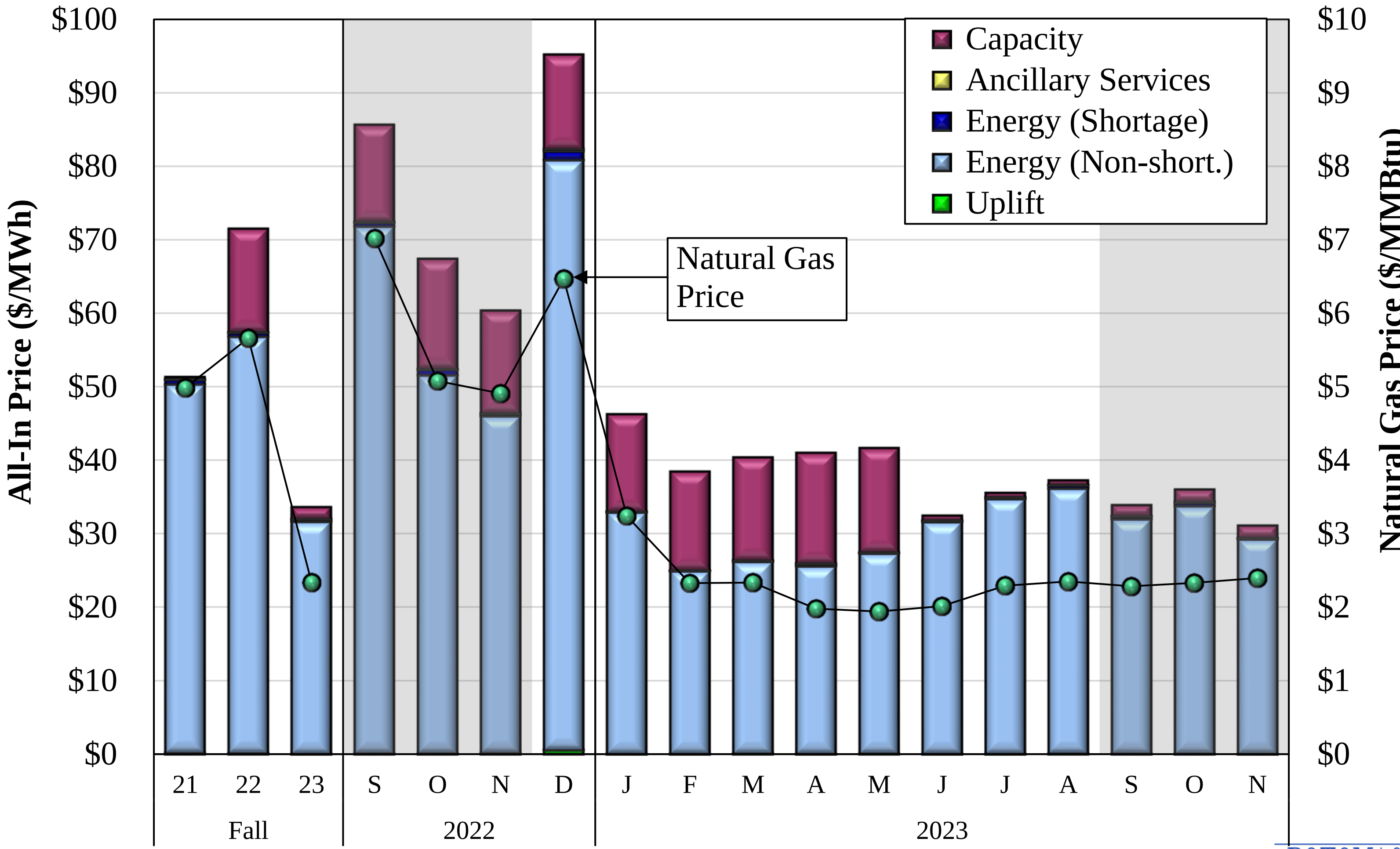
All-In Price
Fall 2021 – 2023



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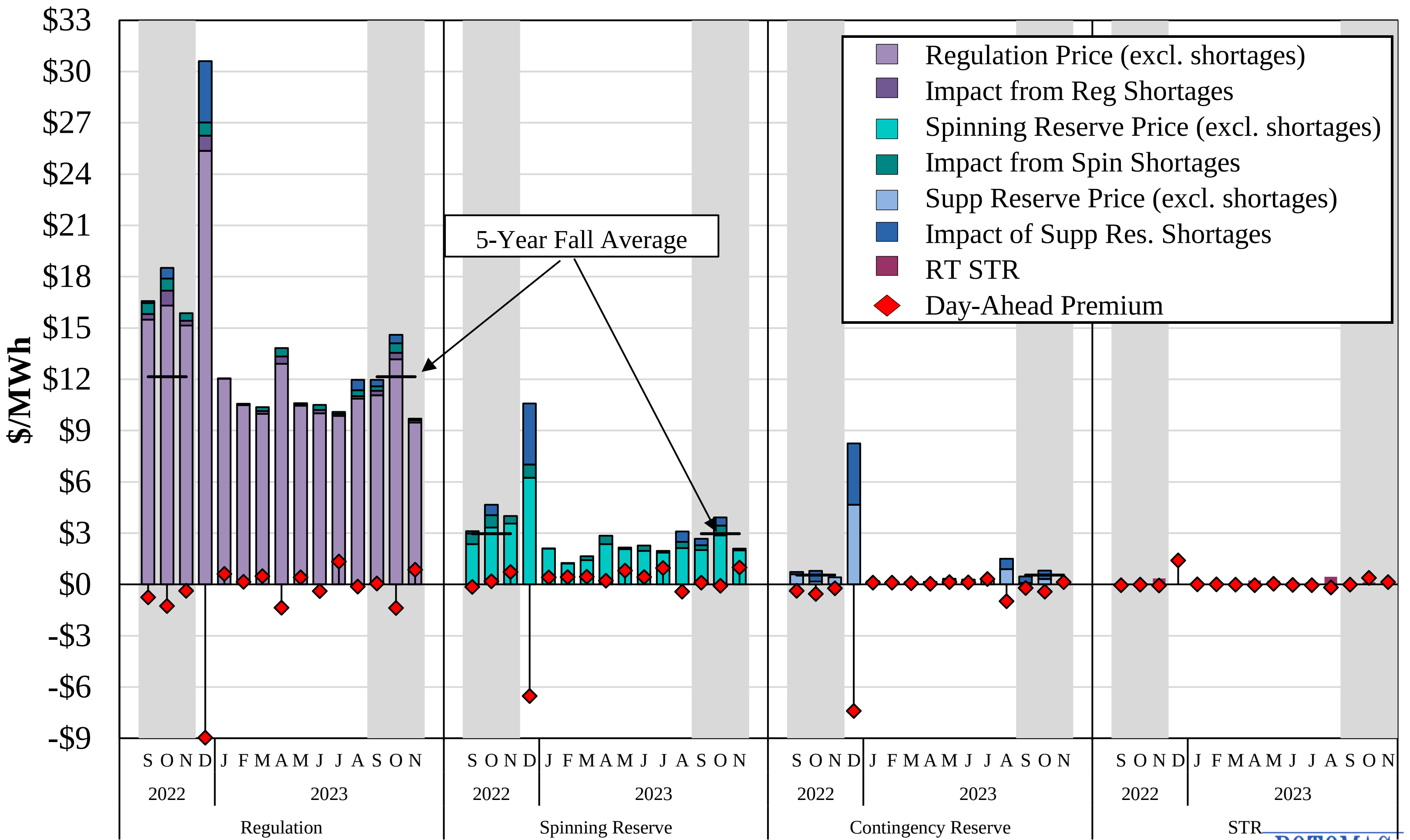
Ancillary Services Prices
Fall 2022–2023



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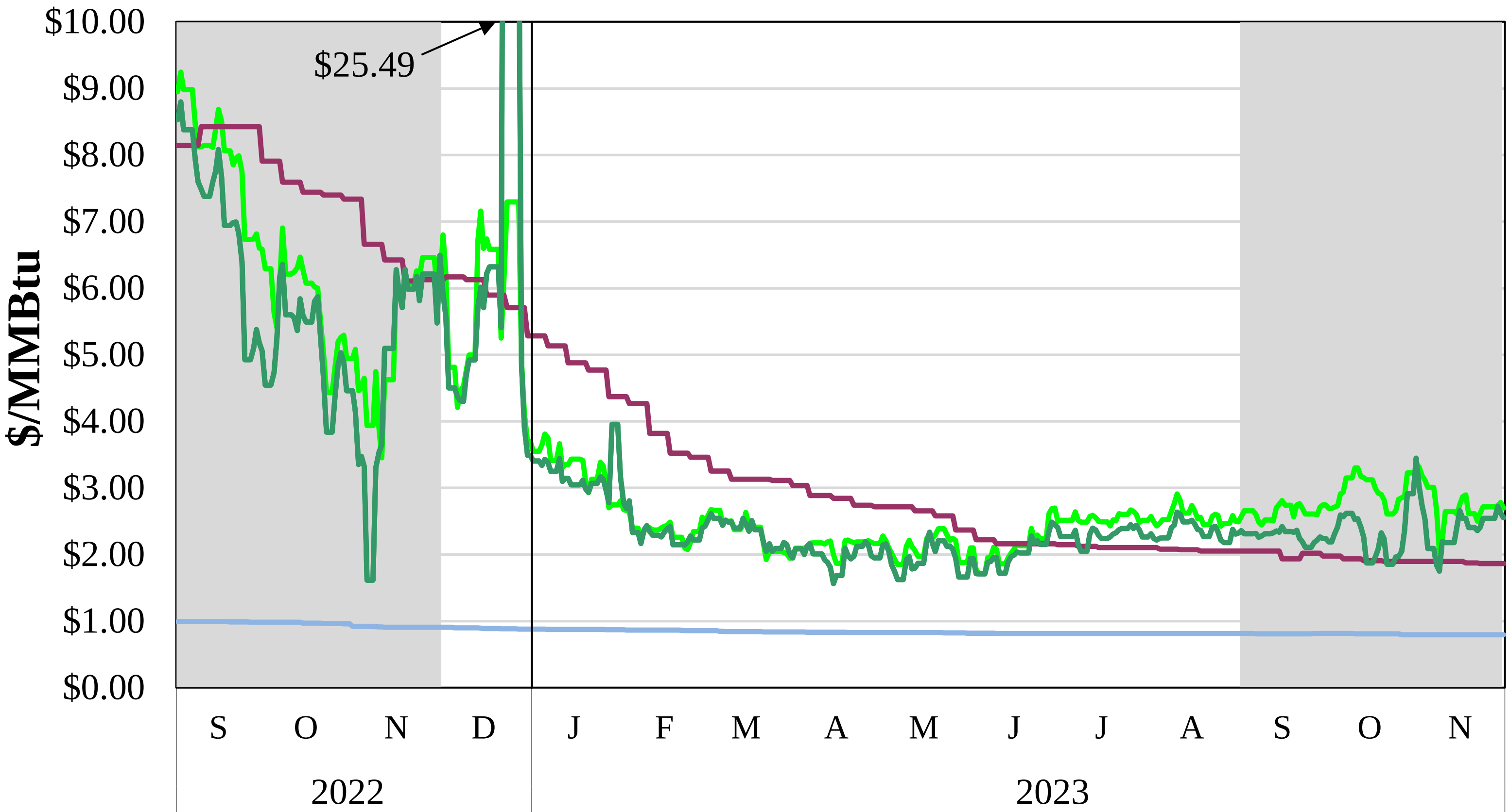
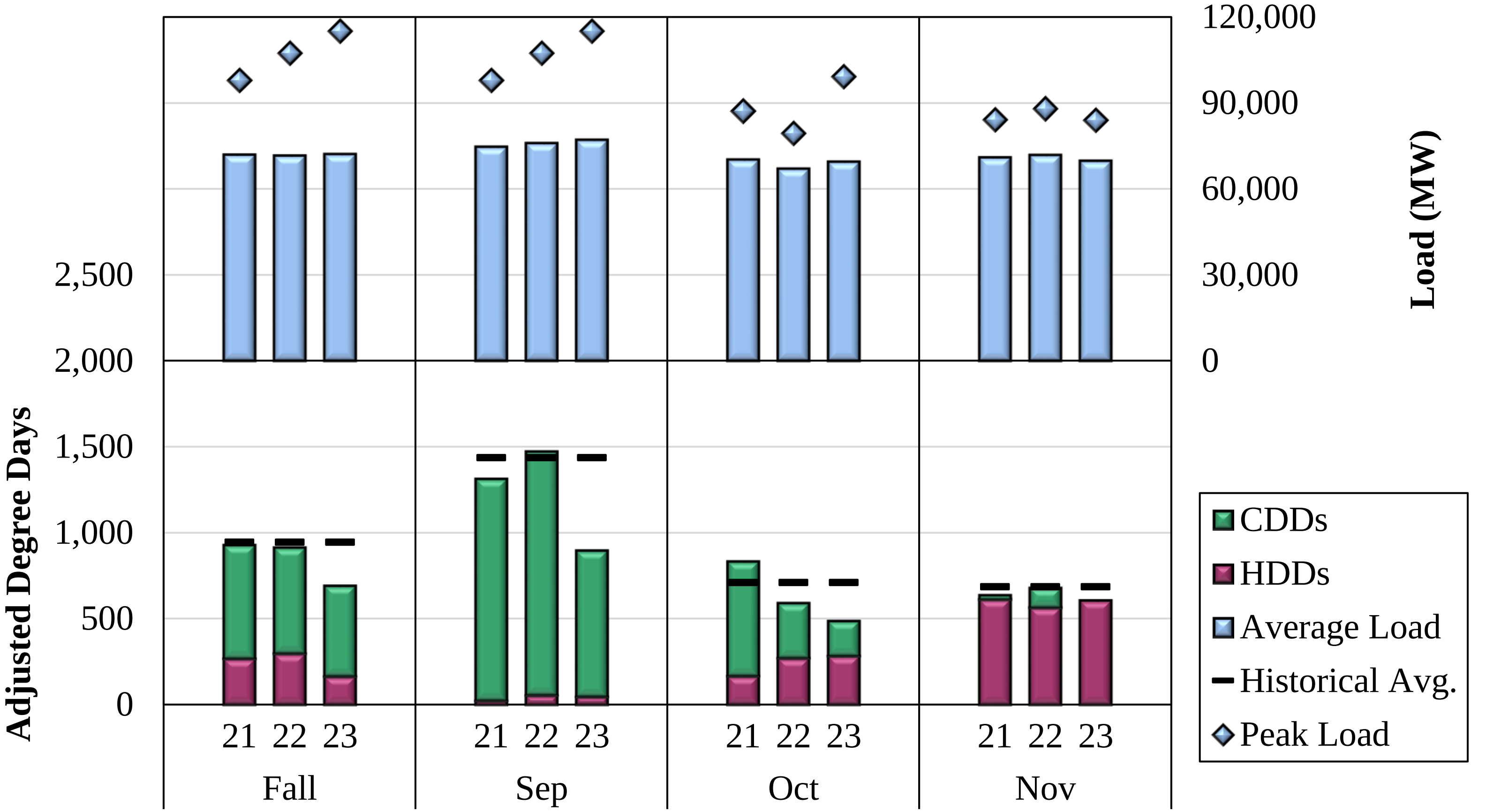
MISO Fuel Prices
2022–2023



Fall Average	2021	2022	2023
Chicago NG	$4.99	$5.66	$2.34
Henry NG	$5.18	$6.33	$2.78

Fall Average	2021	2022	2023
IB Coal	$3.18	$7.44	$1.94
PRB Coal	$1.40	$0.96	$0.80

Load and Weather Patterns
Fall 2021–2023



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

Capacity, Energy and Price Setting Share
Fall 2022–2023

Fall	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
Nuclear	10,905	11,275	9%	9%	17%	13%	0%	0%	0%	0%
Coal	40,328	39,735	32%	31%	31%	30%	27%	37%	66%	79%
Natural Gas	60,600	61,886	48%	48%	32%	38%	72%	62%	89%	93%
Oil	1,459	1,503	1%	1%	0%	0%	0%	0%	0%	1%
Hydro	4,034	3,977	3%	3%	1%	1%	0%	0%	2%	1%
Wind	4,500	5,254	4%	4%	17%	16%	0%	0%	70%	61%
Solar	1,743	2,751	1%	2%	0%	1%	0%	0%	3%	7%
Other	2,810	2,820	2%	2%	1%	0%	0%	0%	4%	1%
Total	**126,378**	**129,201**								

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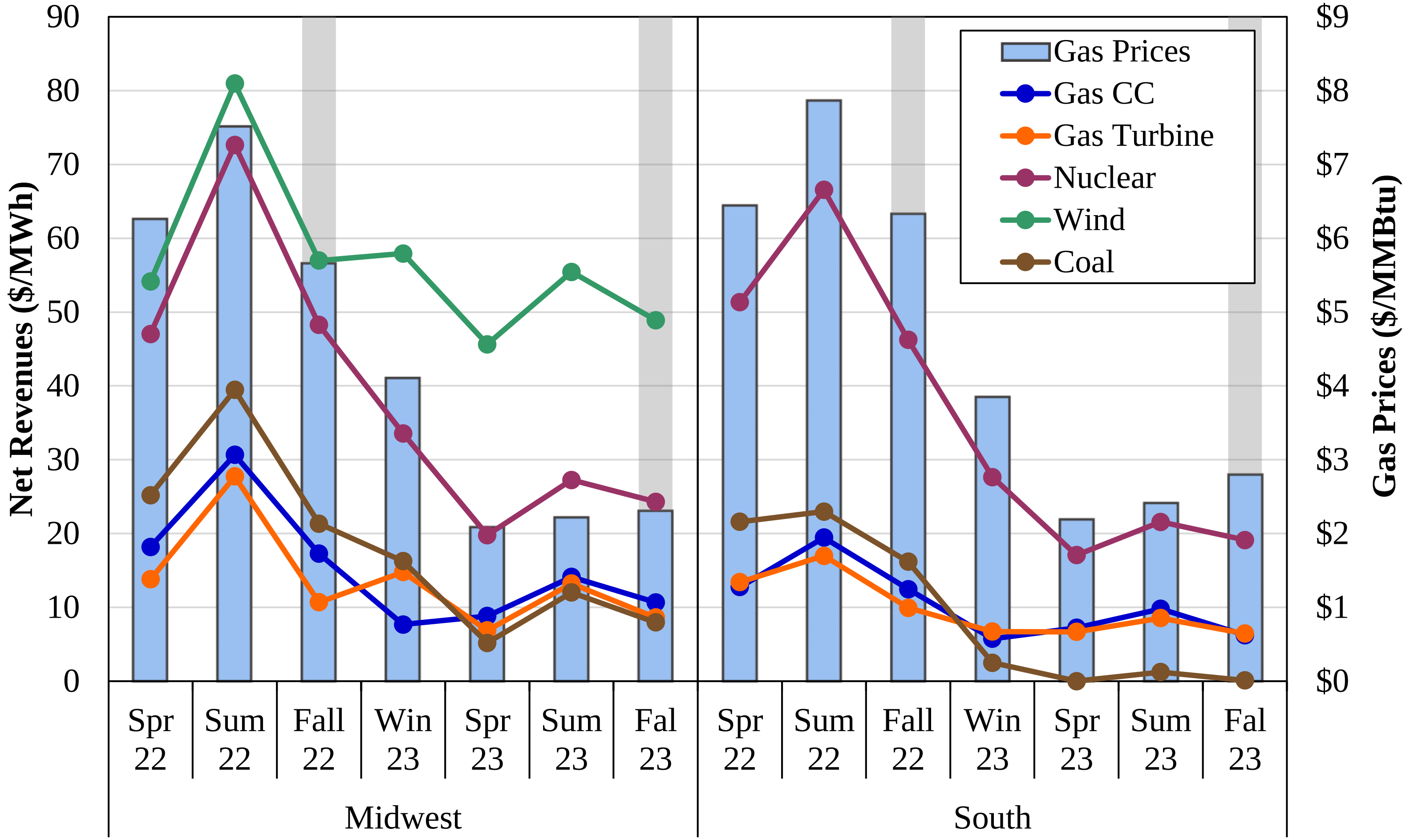
Net Revenues by Technology 2021-2023



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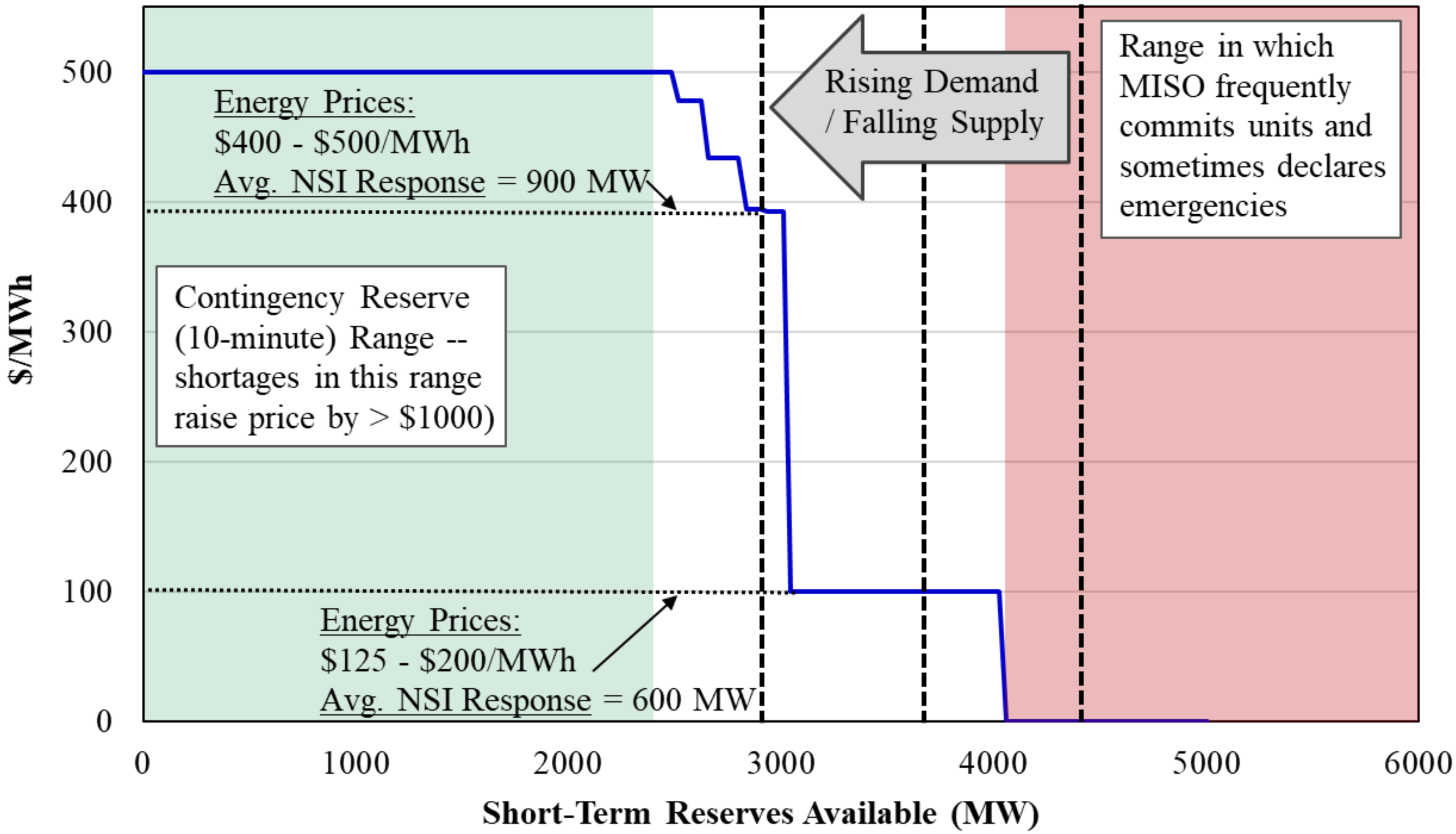
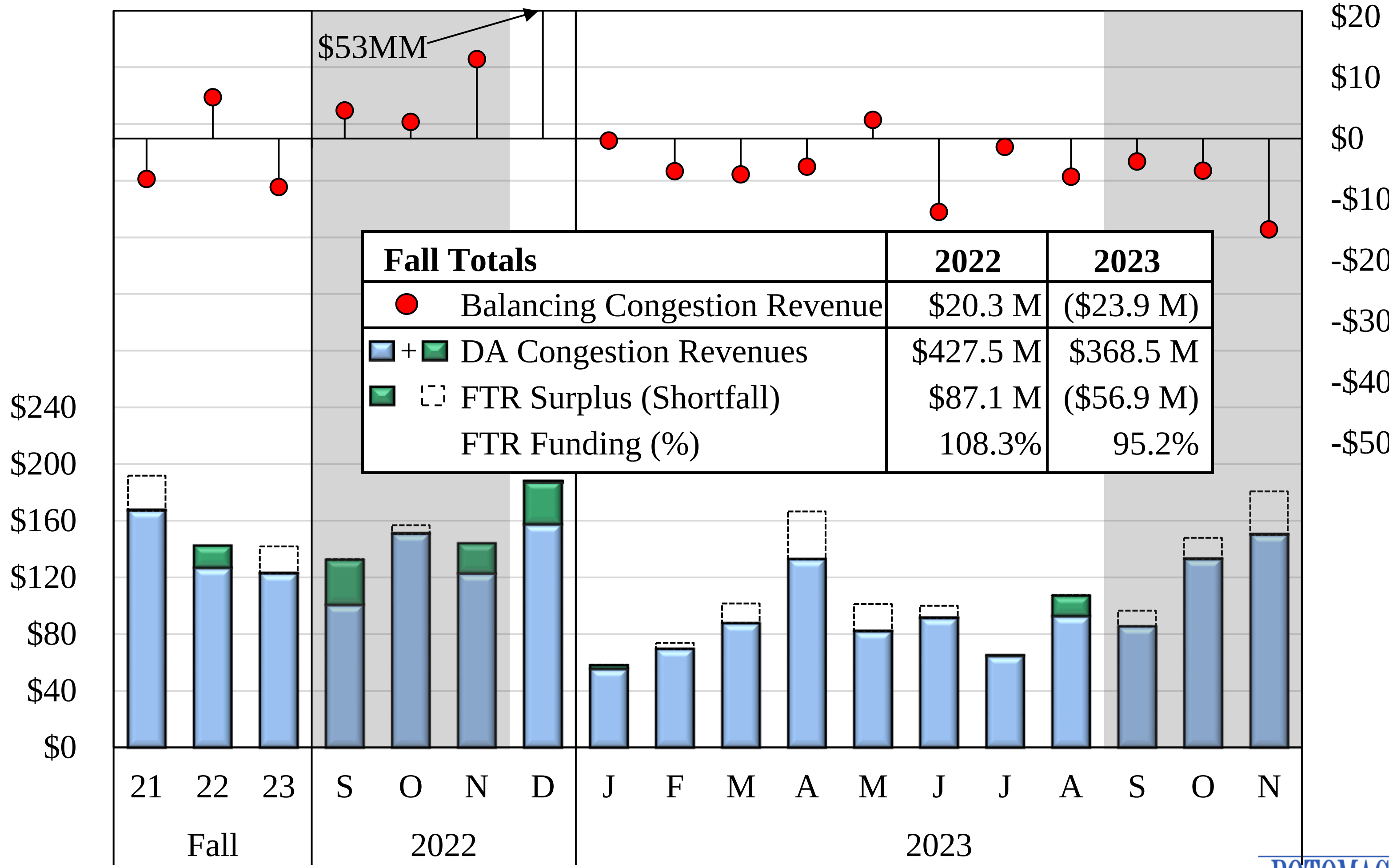
IMM Winter Assessment

	IMM Scenarios			
	Base Scenario	Realistic Scenario	Extreme Event	Notes
Load				
Base Case	102,075	102,075	102,075	
High Load Increase	-	-	4,817	
Total Load (MW)	102,068	102,068	106,892	
Generation				
Internal Generation Excluding Exports	141,725	141,725	141,725	Wind is included UCAP levels, but often produces more during winter peak conditions.
BTM Generation	3,434	2,197	1,648	
Unforced Outages and Derates	(9,716)	(16,696)	(16,696)	Base scenario includes only planned outages. The other cases include average unforced outages/derates during peak winter hours.
Adjustment due to Transfer Limit	(7,112)	(183)	-	
Total Generation (MW)	128,331	127,043	126,677	
Imports and Demand Response				
Demand Response (ICAP)	7,541	3,807	3,807	Cleared amounts for the Winter Season of the 2023/2024 planning year.
Firm Capacity Imports	3,435	3,435	3,435	
Margin (MW)	37,239	32,217	27,026	
Margin (%)	**36.5%**	**31.6%**	**25.3%**	
Expected Capacity Uses and Additions				
Expected Forced Outages	(7,086)	(13,564)	(28,864)	Base scenario assumes 5% forced outage rate. Realistic case includes averages outages during prior peak winter hours. Extreme weather case includes outages during WS Elliot.
Non-Firm Net Imports in Emergencies	-	2,400	2,400	
Expected Margin (MW)	30,153	21,053	562	
Expected Margin (%)	**29.5%**	**20.6%**	**0.5%**	

The Role of Markets in Maintaining Reliability



Day-Ahead Congestion, Balancing Congestion, and FTR Underfunding



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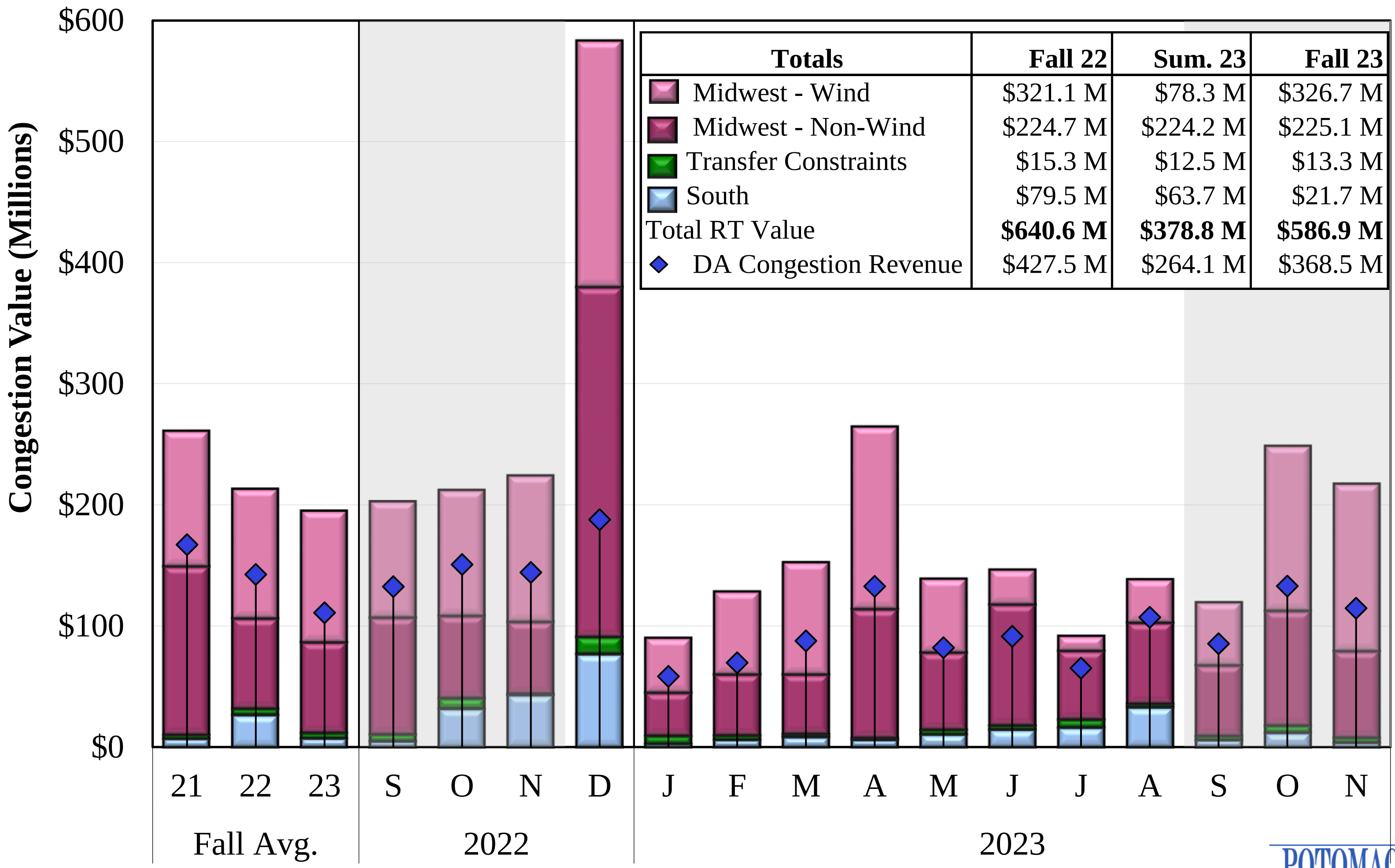
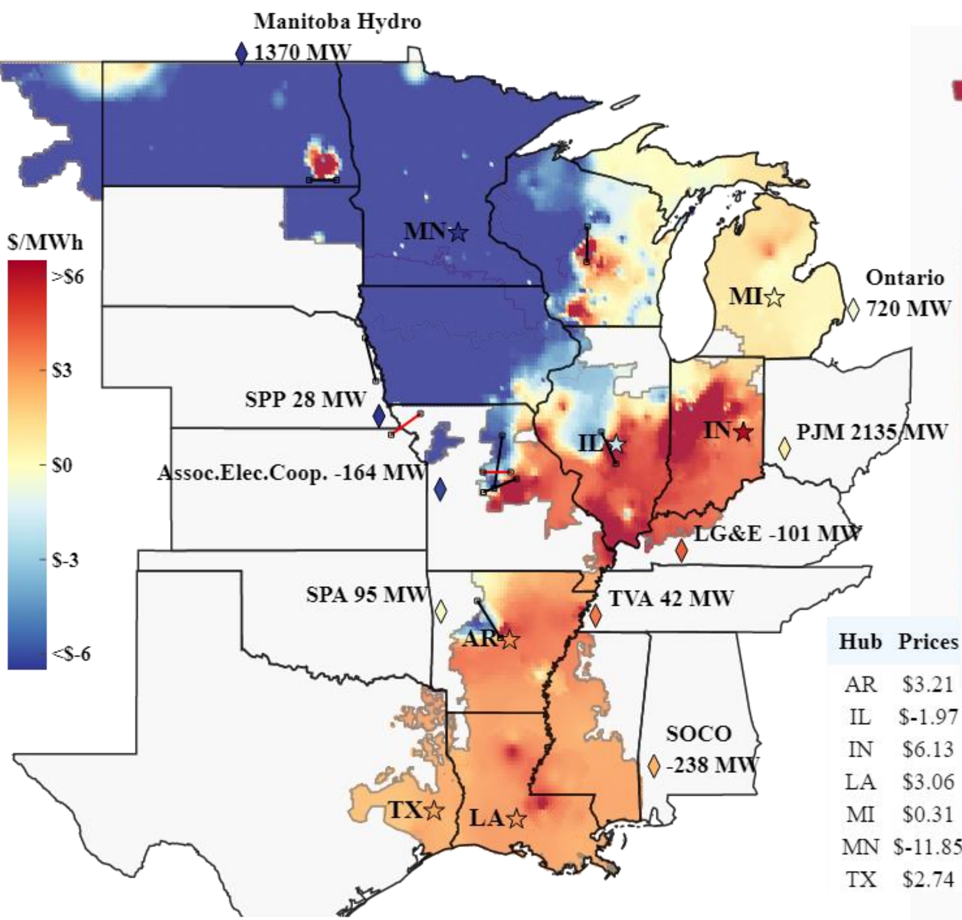
Value of Real-Time Congestion
Fall 2021–2023



Totals	Fall 22	Sum. 23	Fall 23
Midwest - Wind	$321.1 M	$78.3 M	$326.7 M
Midwest - Non-Wind	$224.7 M	$224.2 M	$225.1 M
Transfer Constraints	$15.3 M	$12.5 M	$13.3 M
South	$79.5 M	$63.7 M	$21.7 M
Total RT Value	**$640.6 M**	**$378.8 M**	**$586.9 M**
DA Congestion Revenue	$427.5 M	$264.1 M	$368.5 M

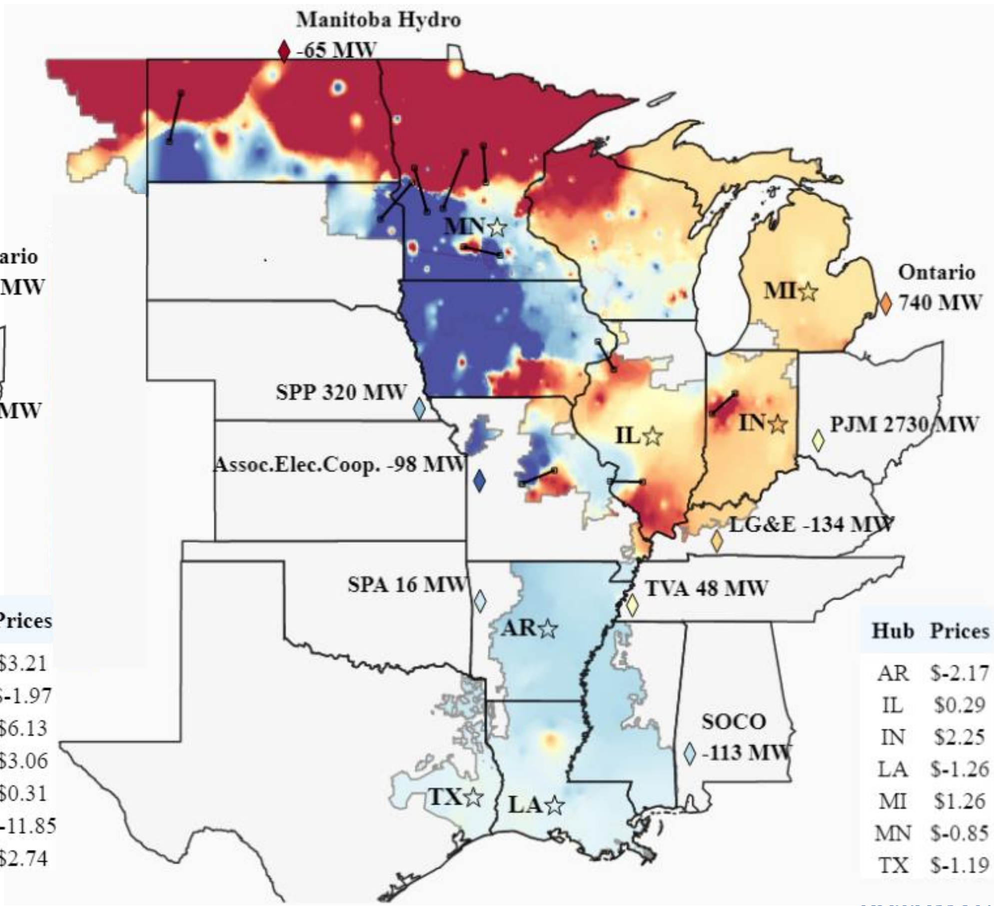
Average Real-Time Congestion Components Fall 2022–2023

Fall 2022



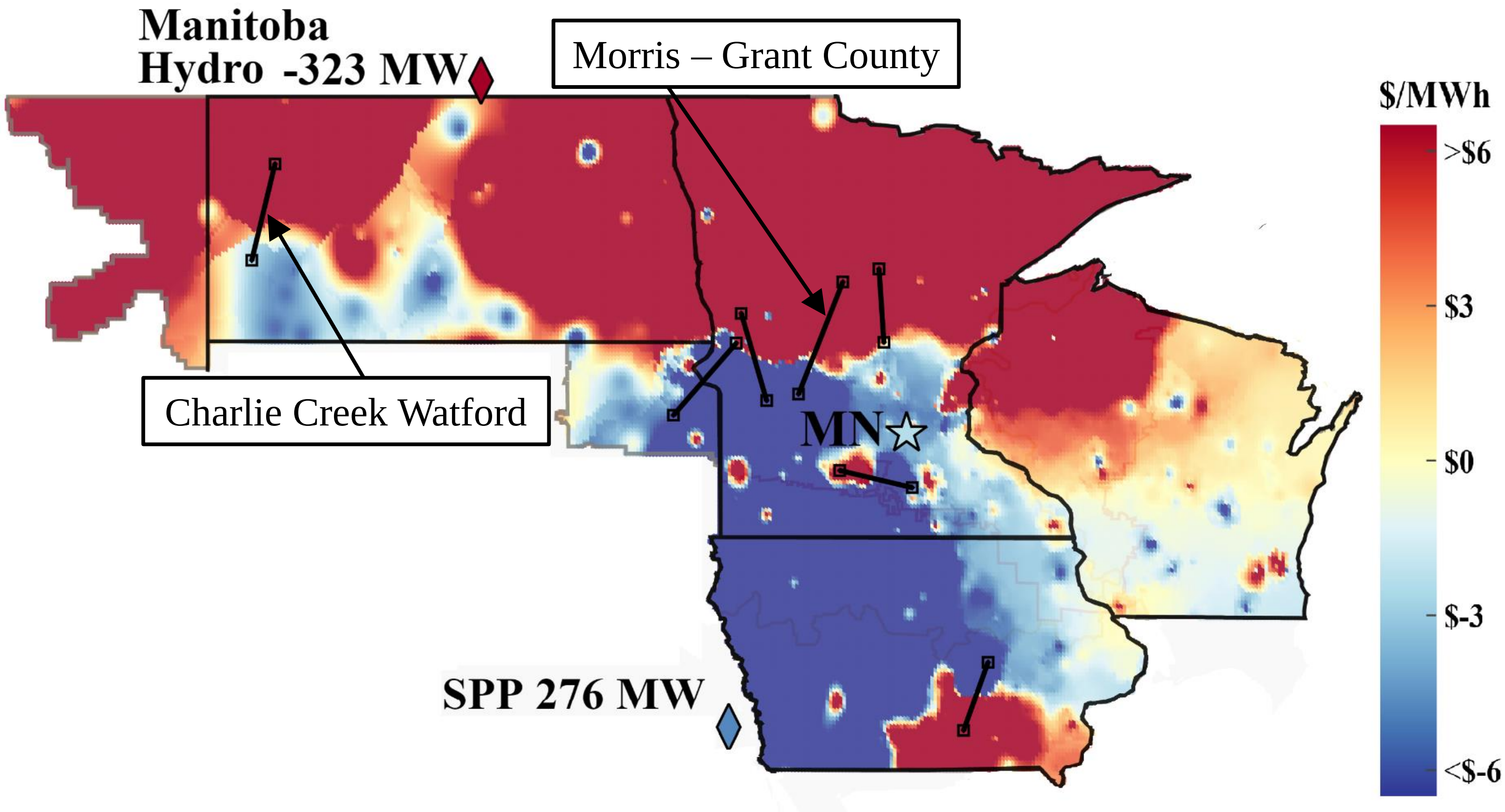
Hub	Prices
AR	$3.21
IL	$-1.97
IN	$6.13
LA	$3.06
MI	$0.31
MN	$-11.85
TX	$2.74

Fall 2023

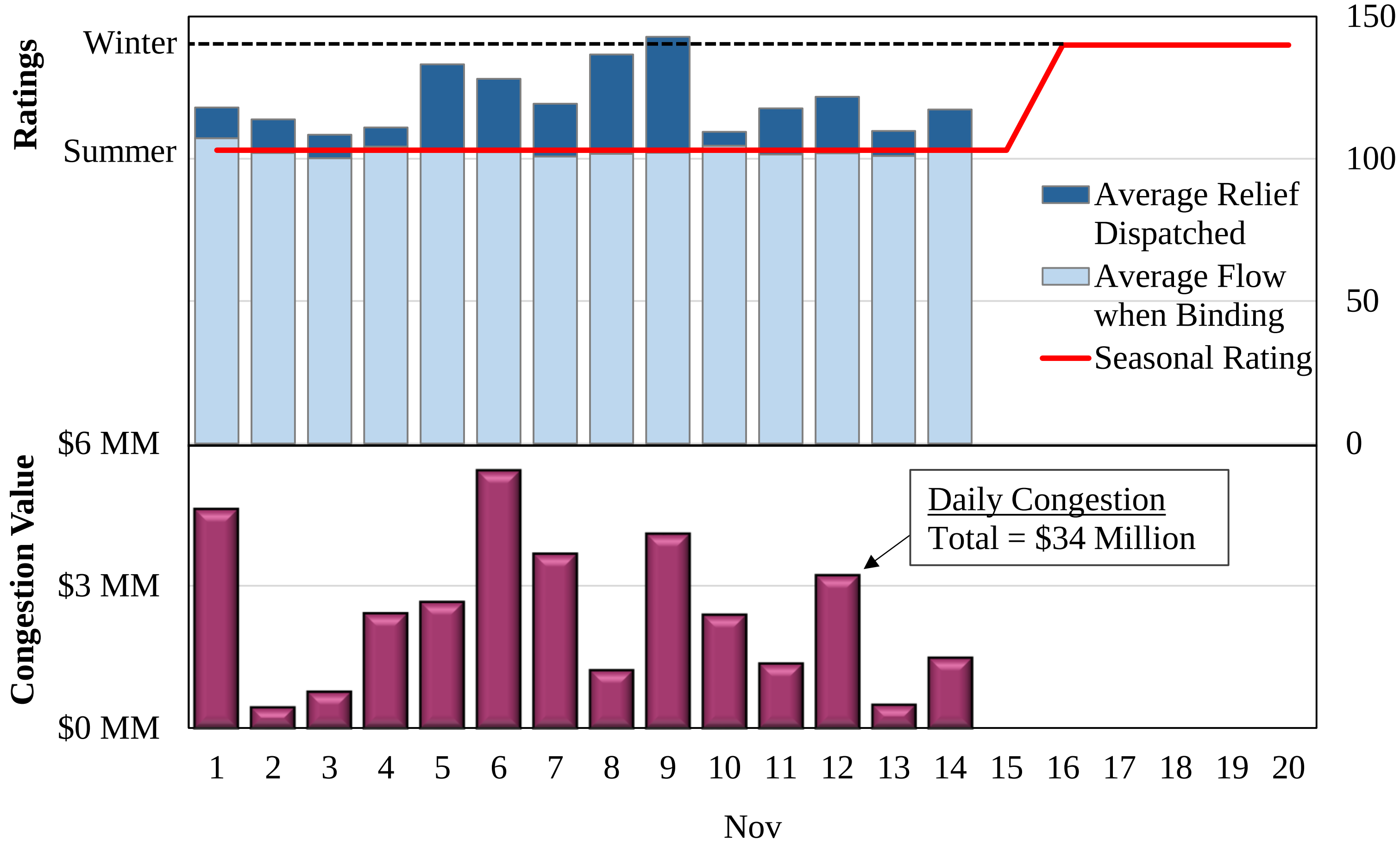


Hub	Prices
AR	$-2.17
IL	$0.29
IN	$2.25
LA	$-1.26
MI	$1.26
MN	$-0.85
TX	$-1.19

Average Real-Time Congestion Components Midwest October 11 – November 15



Daily Congestion on Morris – Grant County Line November 1 – 20, 2023



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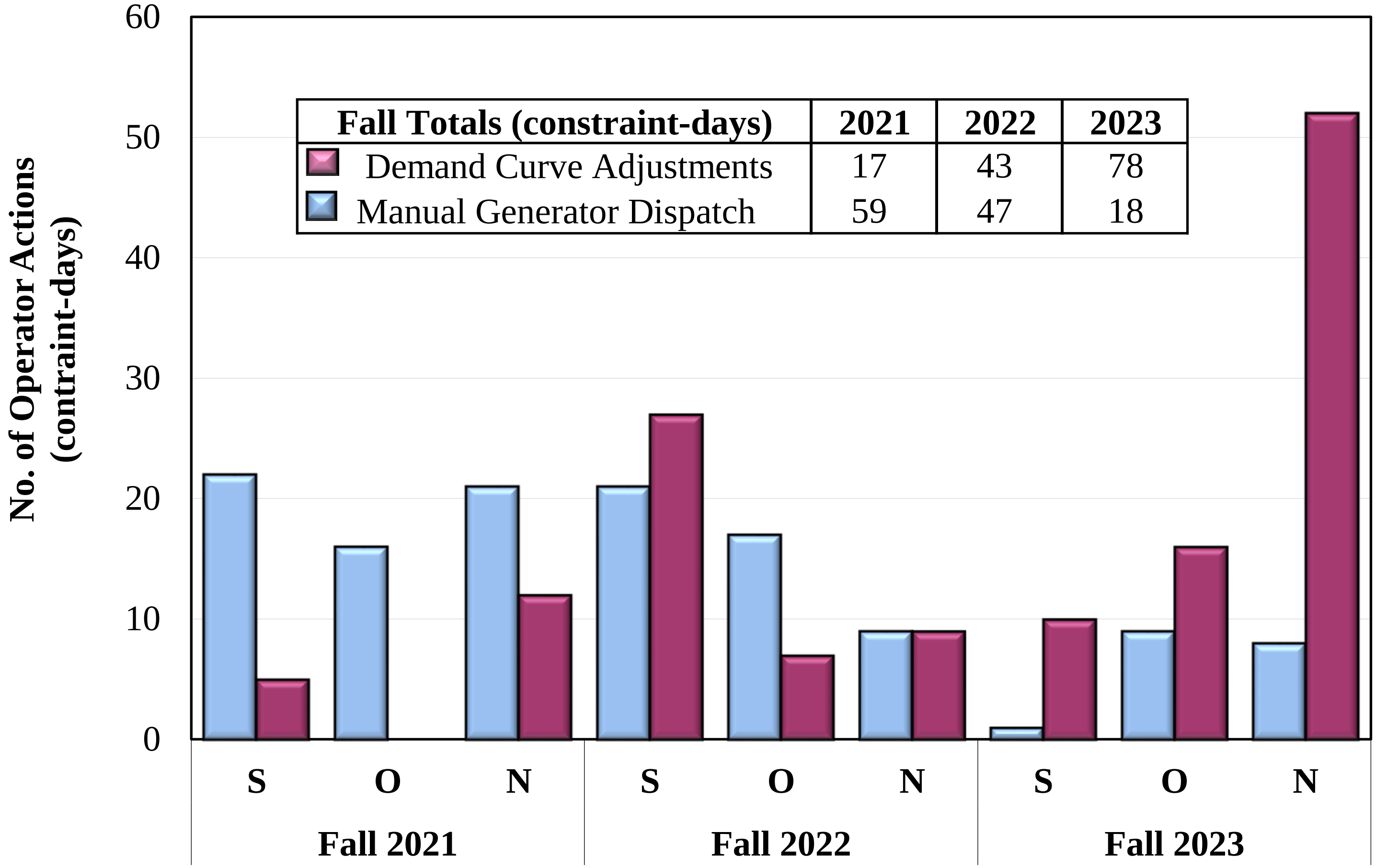
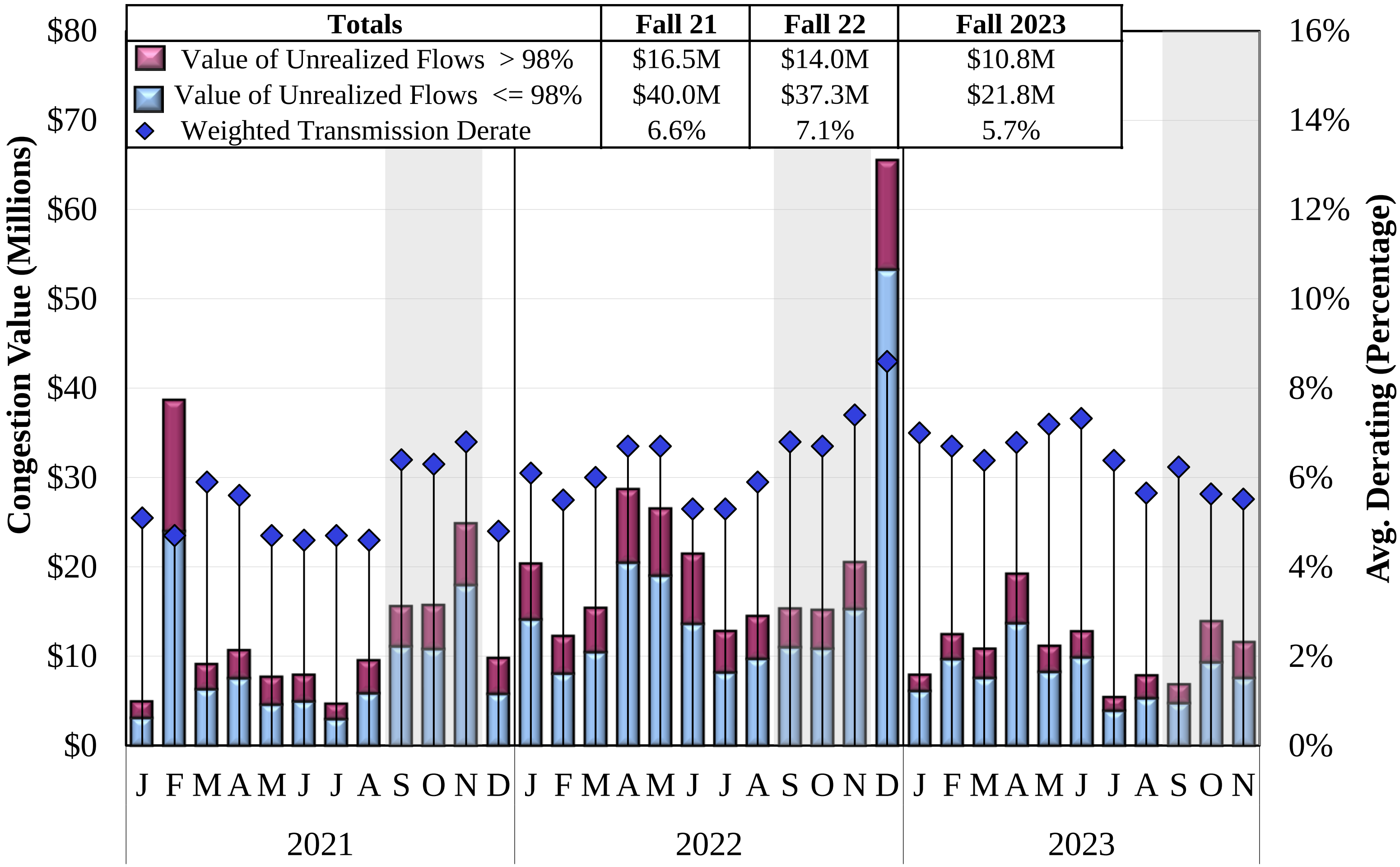
Changes in MISO Operator Actions For Congestion Management



Value of Unrealized Transmission Flows Due to Use of Limit Control



Totals	Fall 21	Fall 22	Fall 2023
Value of Unrealized Flows > 98%	$16.5M	$14.0M	$10.8M
Value of Unrealized Flows <= 98%	$40.0M	$37.3M	$21.8M
Weighted Transmission Derate	6.6%	7.1%	5.7%

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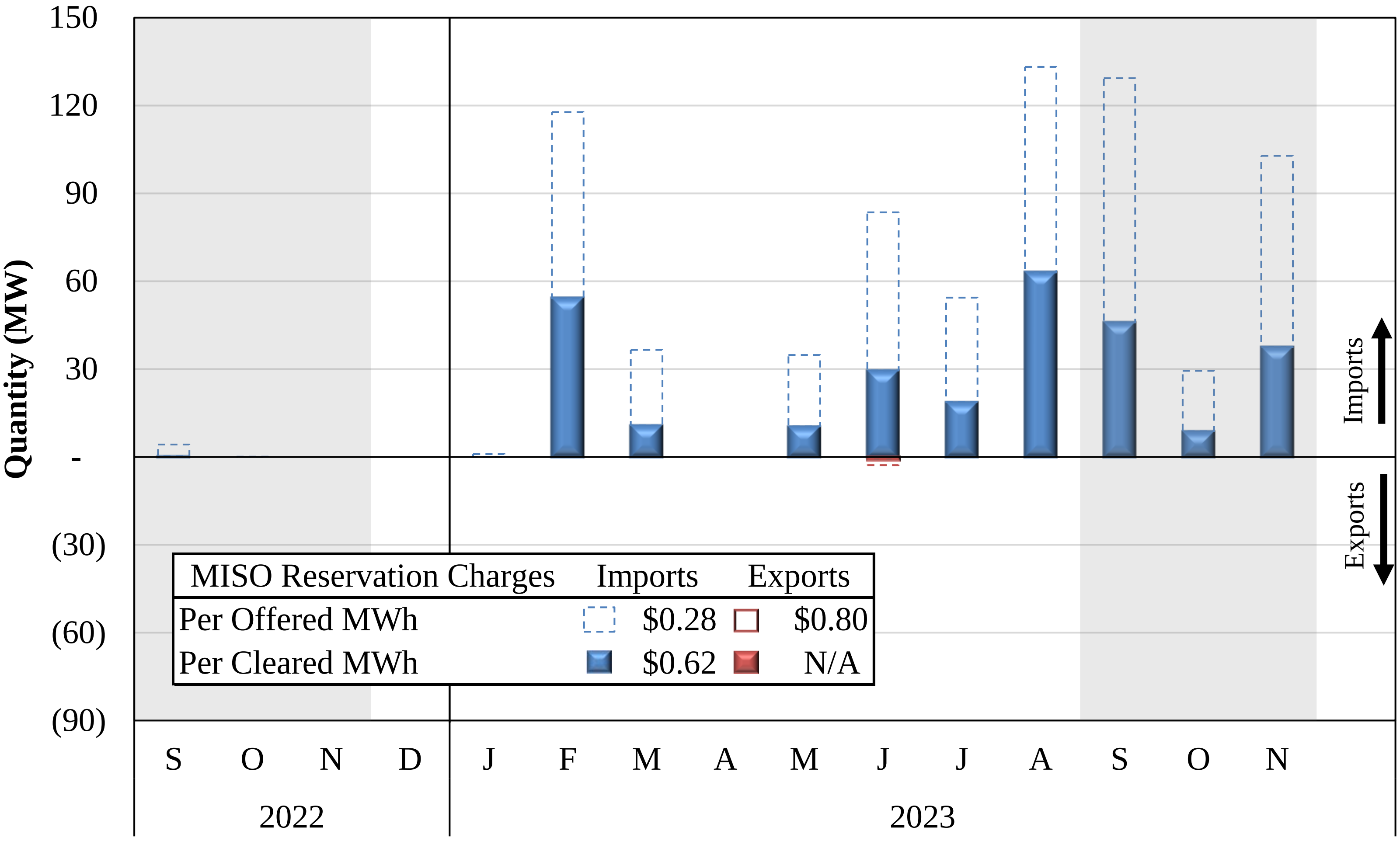
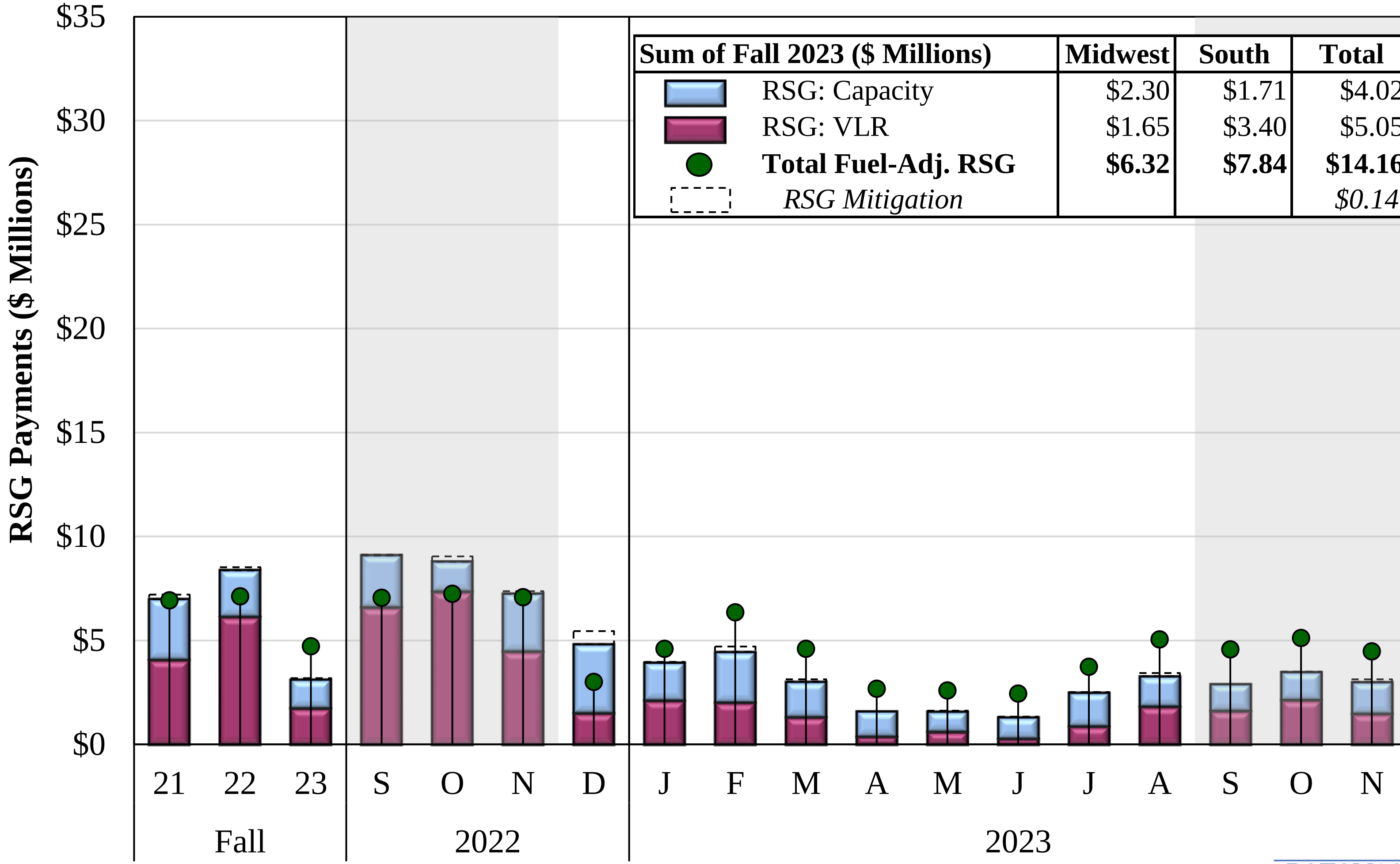
Benefits of Ambient-Adjusted and Emergency Ratings Fall 2022–2023

	Fall	Savings ($ Millions) Ambient Adj. Ratings	Savings ($ Millions) Emergency Ratings	Savings ($ Millions) Total	# of Facilites for 2/3 of Savings	Share of Congestion
2022	**Midwest**	$58.2	$28.44	$86.7	16	14.9%
	South	$1.8	$4.12	$5.9	1	6.6%
	Total	**$60.0**	**$32.6**	**$92.6**	**17**	**13.8%**
2023	**Midwest**	$62.9	$31.22	$94.2	11	18.4%
	South	$0.2	$0.64	$0.9	2	6.0%
	Total	**$63.2**	**$31.9**	**$95.0**	**13**	**18.0%**

Coordinated Transaction Scheduling (CTS) Fall 2021–2023

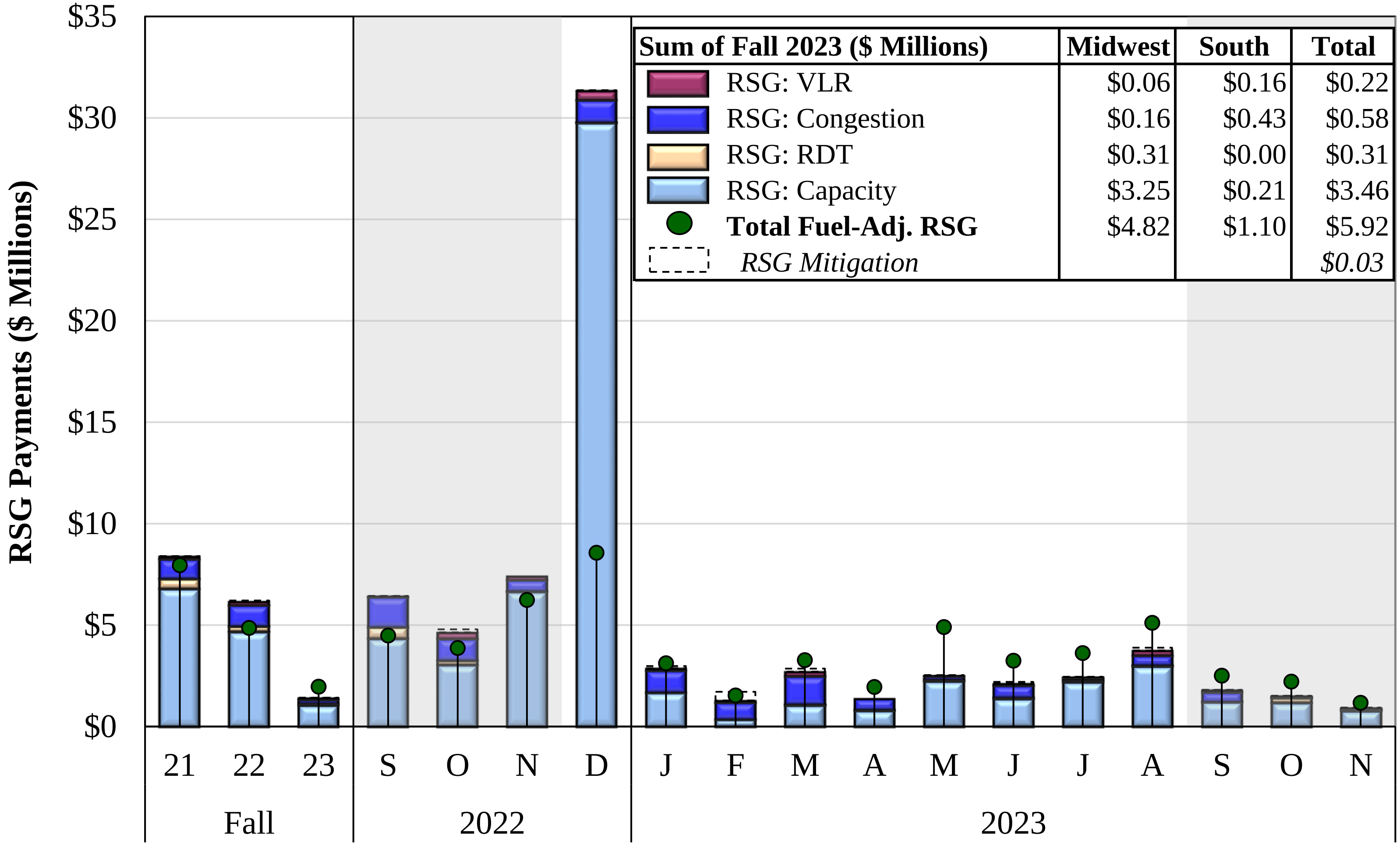


Day-Ahead RSG Payments
Fall 2021–2023



Sum of Fall 2023 ($ Millions)	Midwest	South	Total
RSG: Capacity	$2.30	$1.71	$4.02
RSG: VLR	$1.65	$3.40	$5.05
Total Fuel-Adj. RSG	**$6.32**	**$7.84**	**$14.16**
RSG Mitigation			*$0.14*

Real-Time RSG Payments
Fall 2021–2023



Sum of Fall 2023 ($ Millions)	Midwest	South	Total
RSG: VLR	$0.06	$0.16	$0.22
RSG: Congestion	$0.16	$0.43	$0.58
RSG: RDT	$0.31	$0.00	$0.31
RSG: Capacity	$3.25	$0.21	$3.46
Total Fuel-Adj. RSG	$4.82	$1.10	$5.92
RSG Mitigation			*$0.03*

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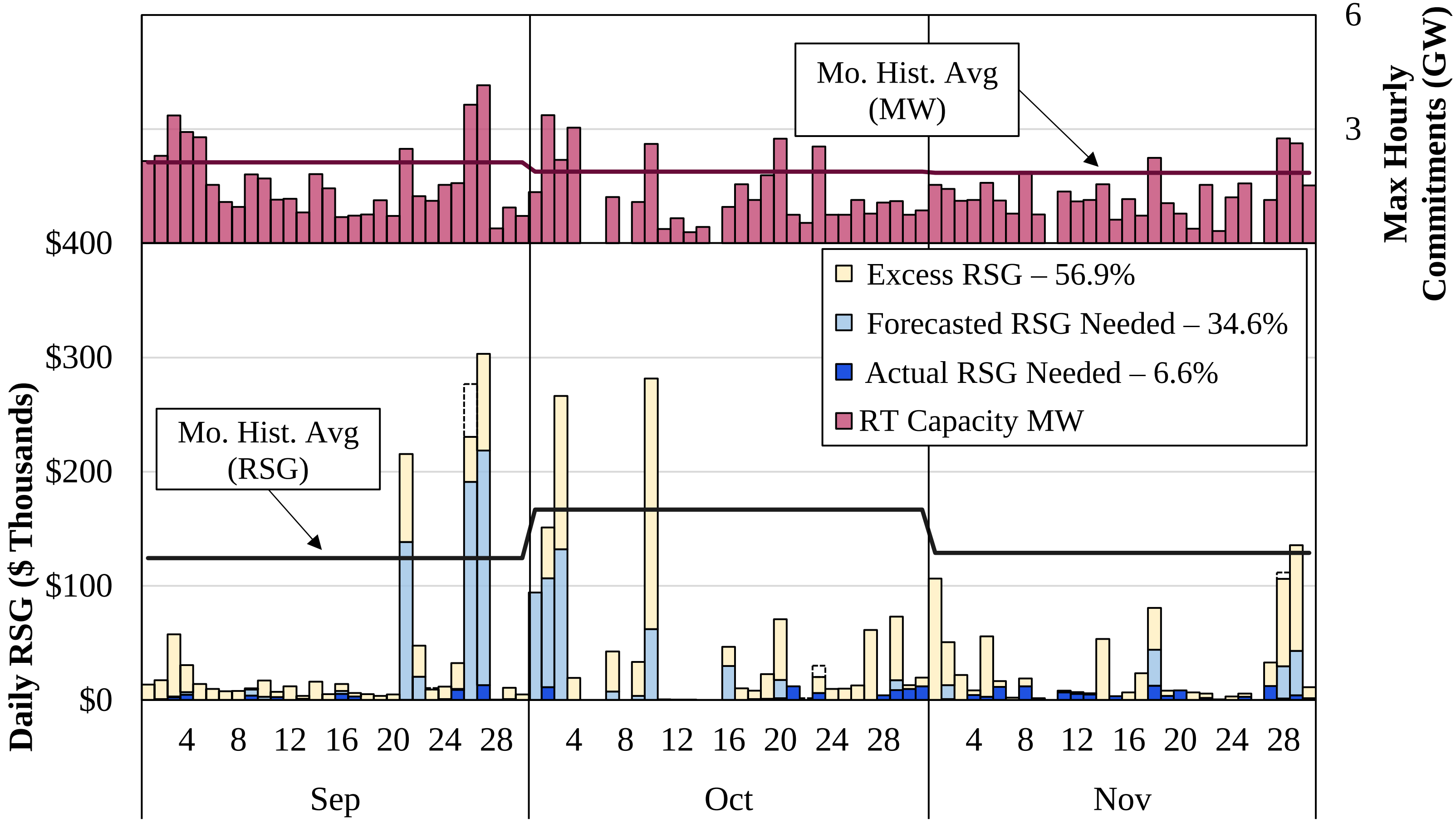
Real-Time Capacity Commitment and RSG



* 2% of the RSG could not be classified due to gaps in market data and is shown in the transparent bars.

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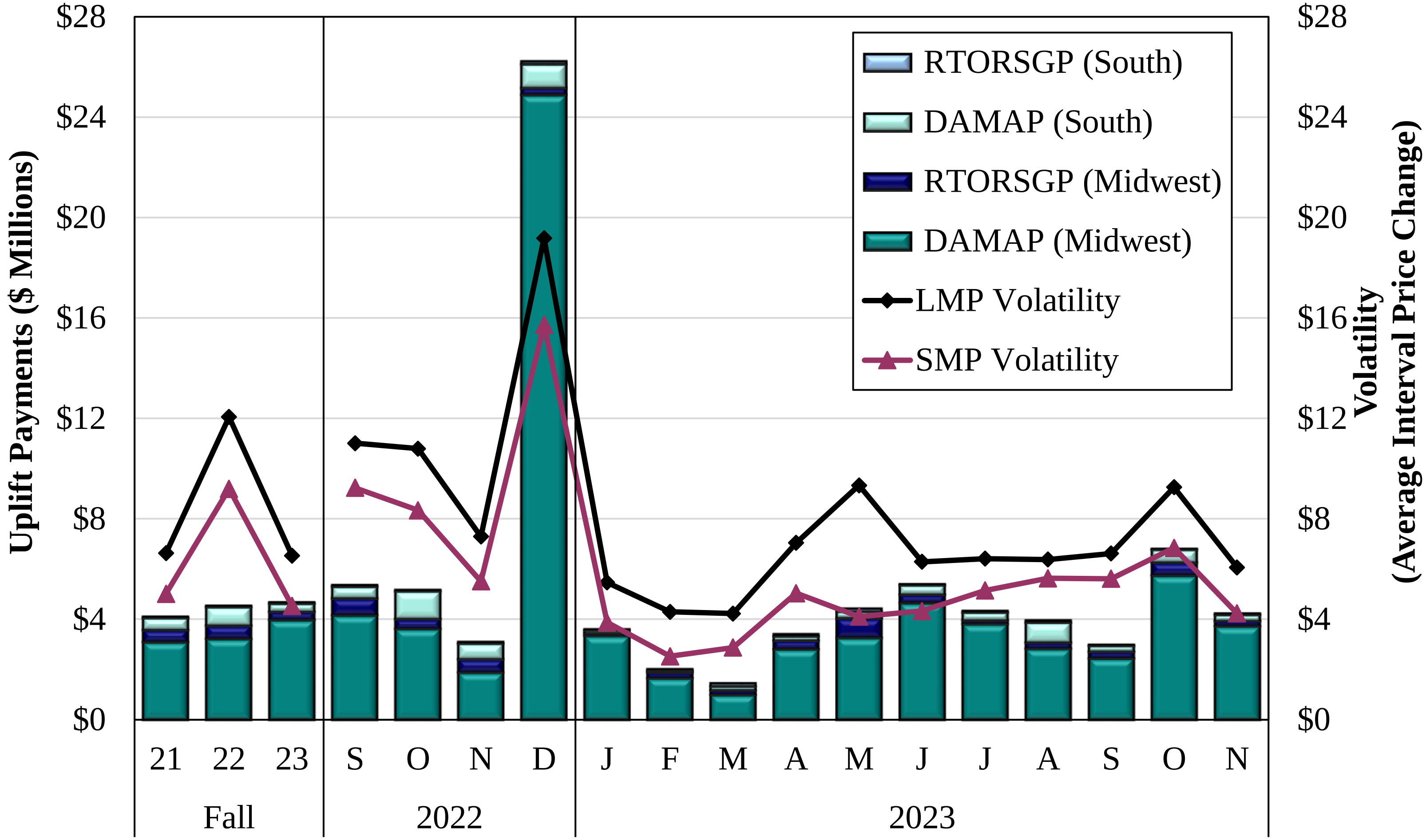
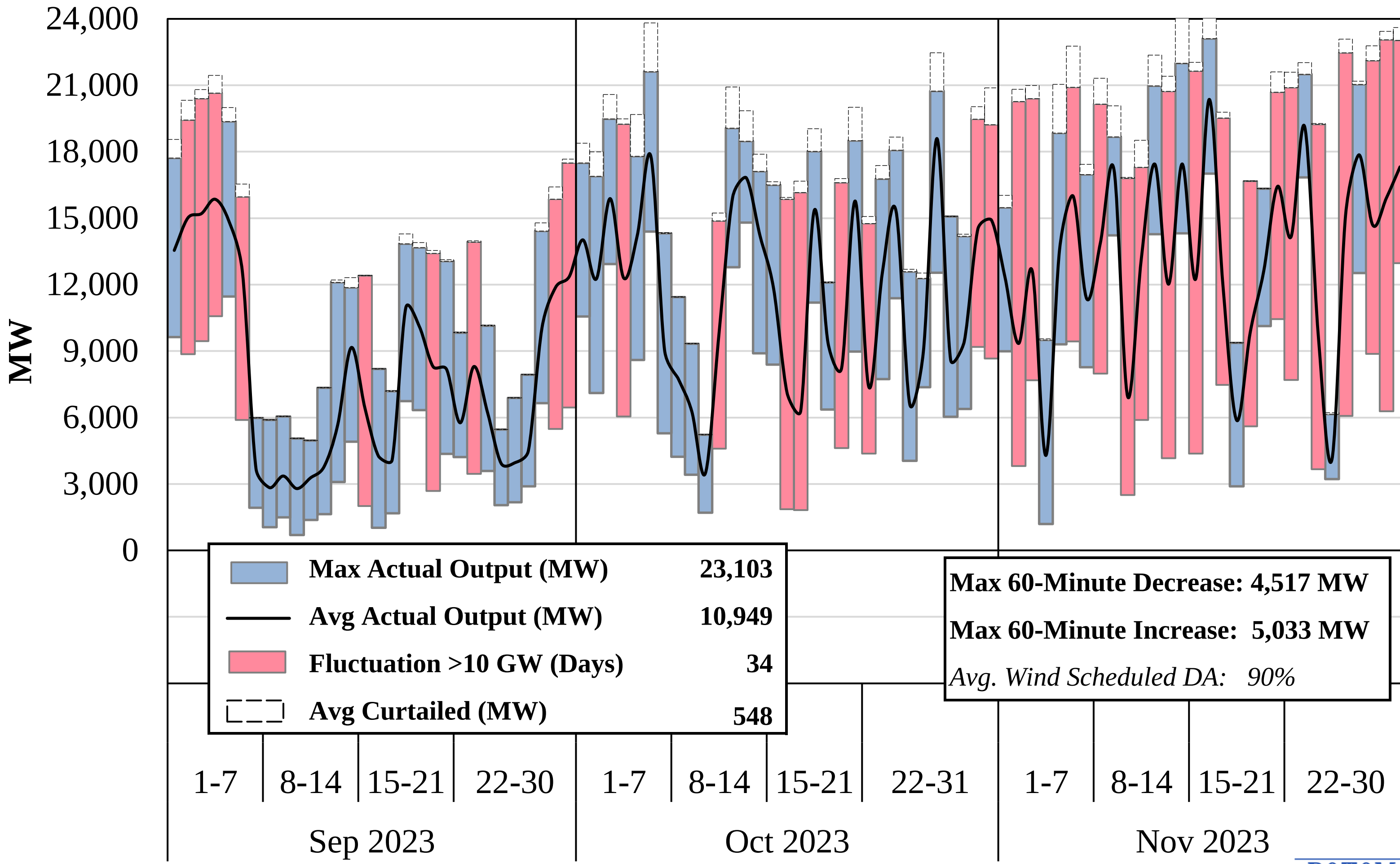
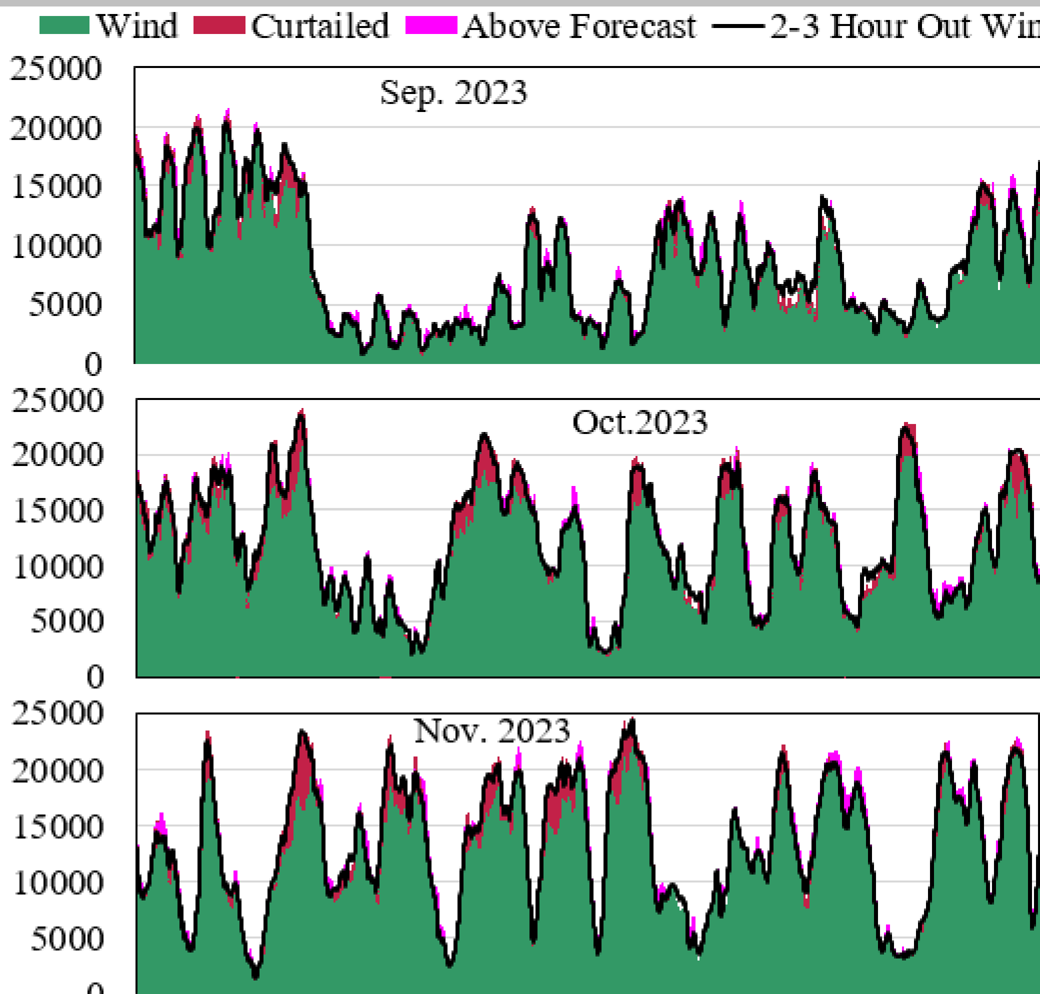
Price Volatility Make Whole Payments Fall 2021–2023



Wind Output in Real Time
Daily Range and Average

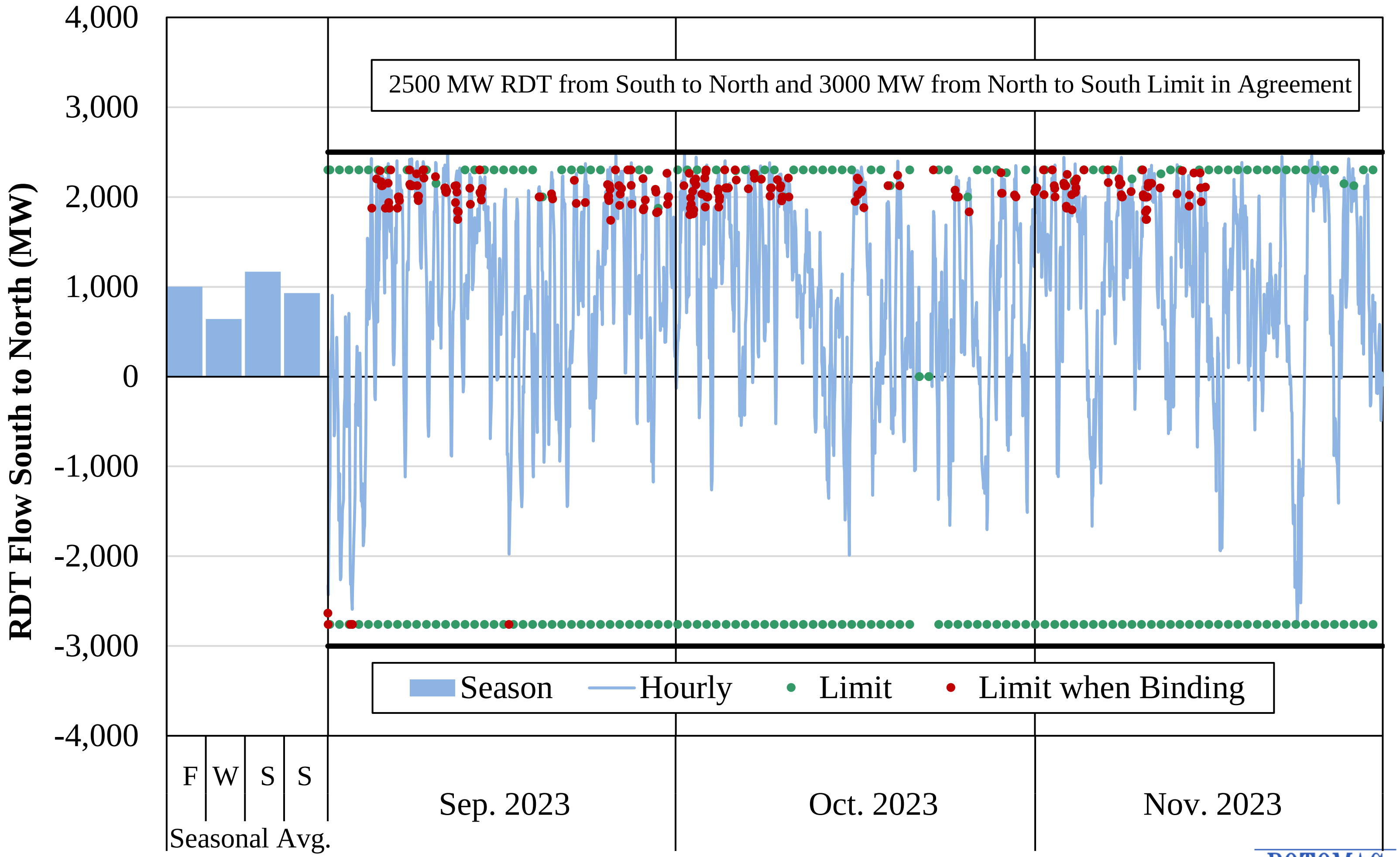


Wind Forecast and Actual Output
Fall 2023

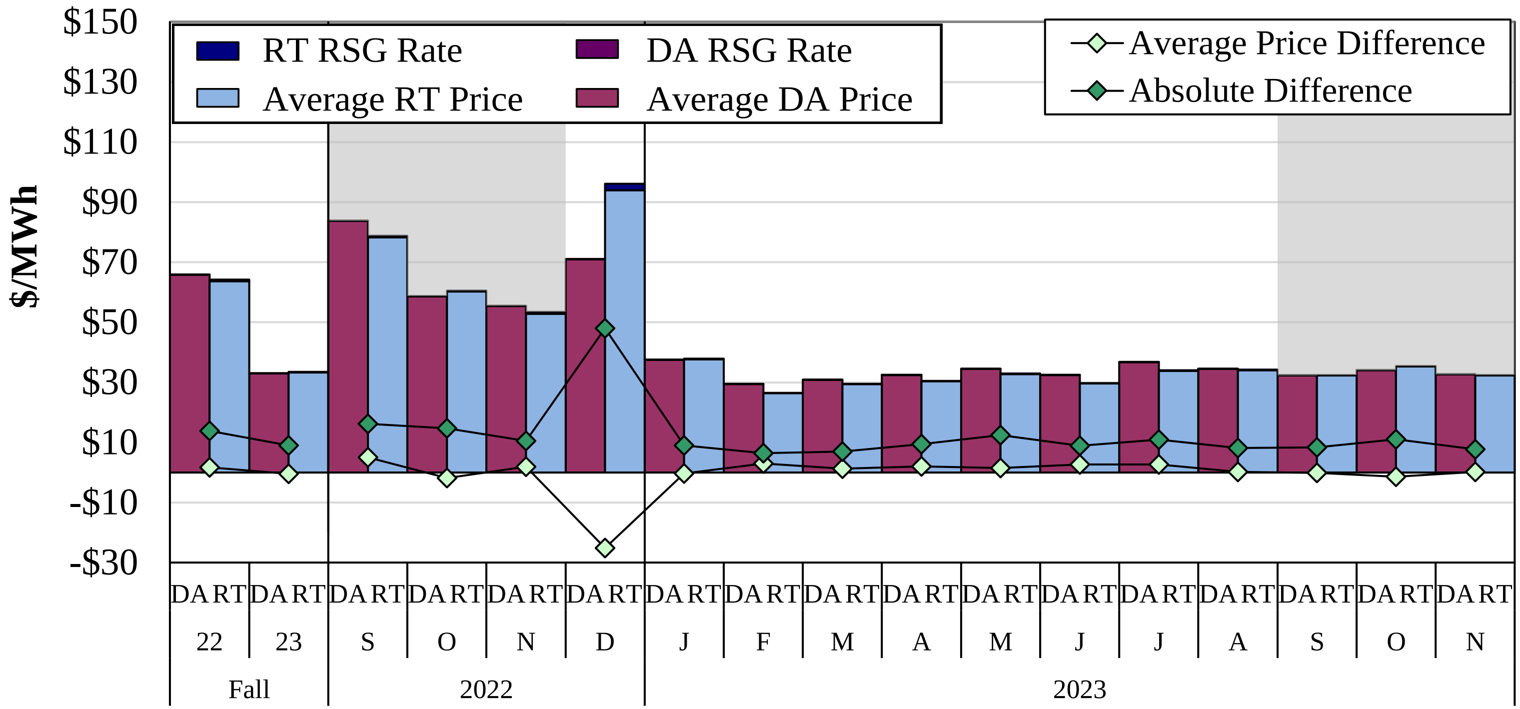


Fall 2023	
Real-Time Wind (MW)	10,949
Day-Ahead Wind (MW)	9,872
Avg Curtailments (MW)	548
Forecast Errors (%)	-0.3%
Absolute Errors (%)	8.3%
Fall 2022	
Real-Time Wind (MW)	11,637
Day-Ahead Wind (MW)	10,678
Avg Curtailments (MW)	642
Forecast Errors (%)	0.3%
Absolute Errors (%)	7.9%
Summer 2023	
Real-Time Wind (MW)	6,198
Day-Ahead Wind (MW)	5,715
Avg Curtailments (MW)	128
Forecast Errors (%)	2.7%
Absolute Errors (%)	12.3%

Real-Time Hourly Inter-Regional Flows
Fall 2023



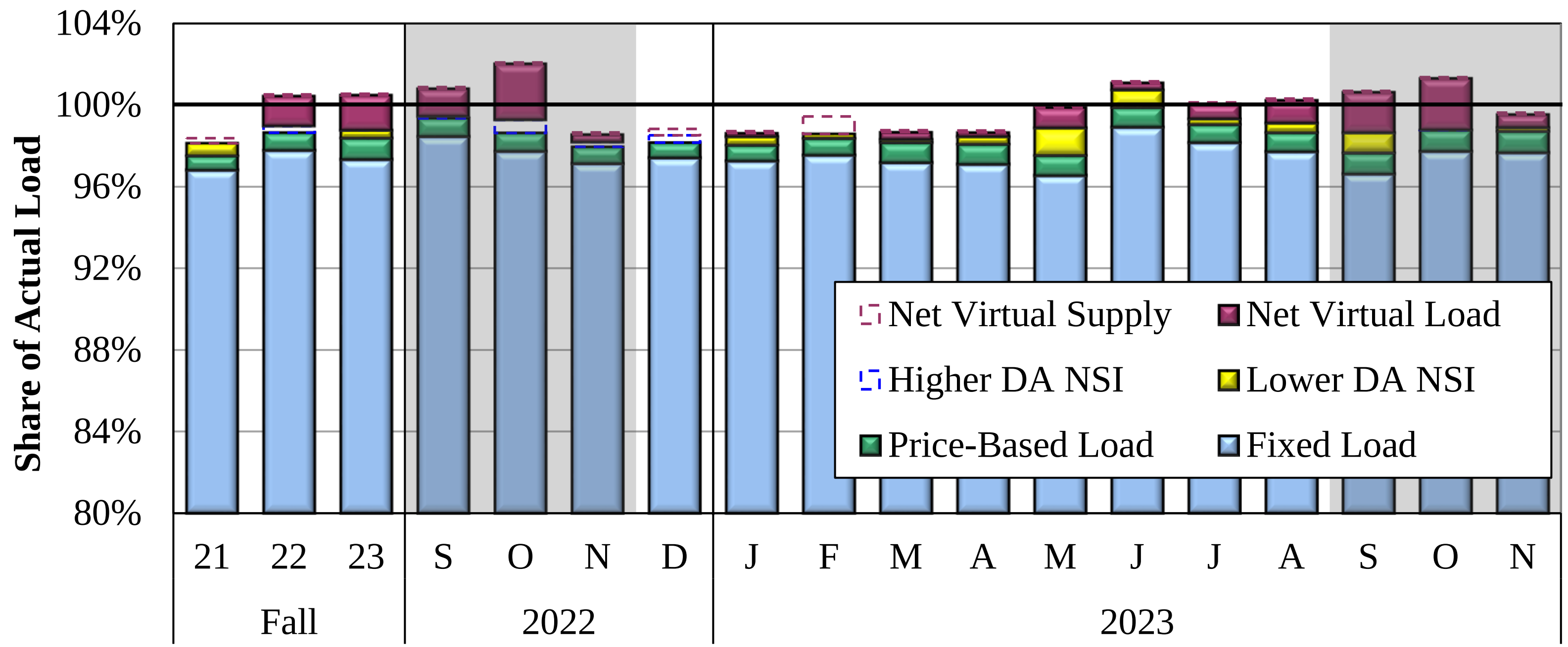
Day-Ahead and Real-Time Price Convergence Fall 2022–2023



Average DA-RT Price Difference Including RSG (% of Real-Time Price)

Indiana Hub	2	-1	6	-3	4	-26	-1	11	4	7	5	9	8	0	0	-4	1
Michigan Hub	4	-3	7	1	4	-21	5	12	6	4	1	6	8	2	-5	-7	1
Minnesota Hub	3	1	7	0	3	-17	-1	-7	-6	-10	13	-4	4	-6	-2	-3	7
Arkansas Hub	-1	-1	4	-3	-3	-18	-1	3	5	0	5	6	5	2	-3	-4	3
Texas Hub	0	2	4	-1	-2	-24	1	7	5	5	4	7	11	4	3	-3	5
Louisiana Hub	0	1	3	-1	-1	-23	0	6	1	3	4	11	13	4	0	-3	6

Day-Ahead Peak Hour Load Scheduling
Fall 2021–2023



Share of Actual Load (%)

	Fall 21	Fall 22	Fall 23	2022 S	2022 O	2022 N	2022 D	2023 J	2023 F	2023 M	2023 A	2023 M	2023 J	2023 J	2023 A	2023 S	2023 O	2023 N
All Hours	98.4	99.4	100.0	100.8	99.7	97.6	98.7	99.0	98.4	98.9	99.1	99.7	101.0	101.6	101.0	100.6	100.3	99.1
Peak Hours Midwest	97.8	100.5	100.6	101.0	101.5	99.0	98.5	99.2	98.8	98.6	98.9	98.8	100.6	99.4	99.8	100.3	101.7	99.7
Peak Hours South	100.3	100.0	101.1	101.8	100.1	98.1	100.8	99.7	98.5	101.4	99.7	102.9	102.4	101.3	101.7	100.7	102.1	100.7

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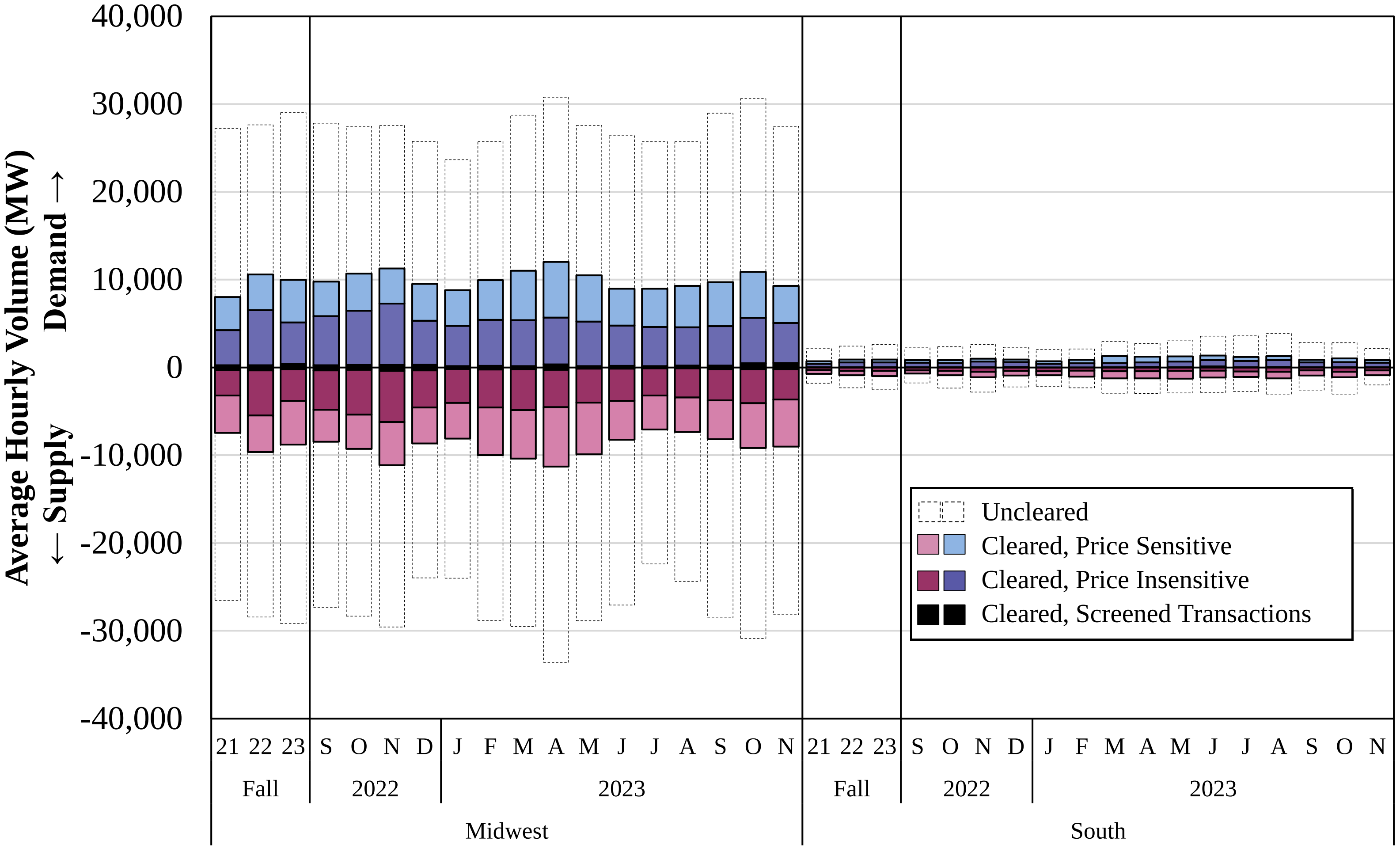
Virtual Load and Supply Fall 2021–2023



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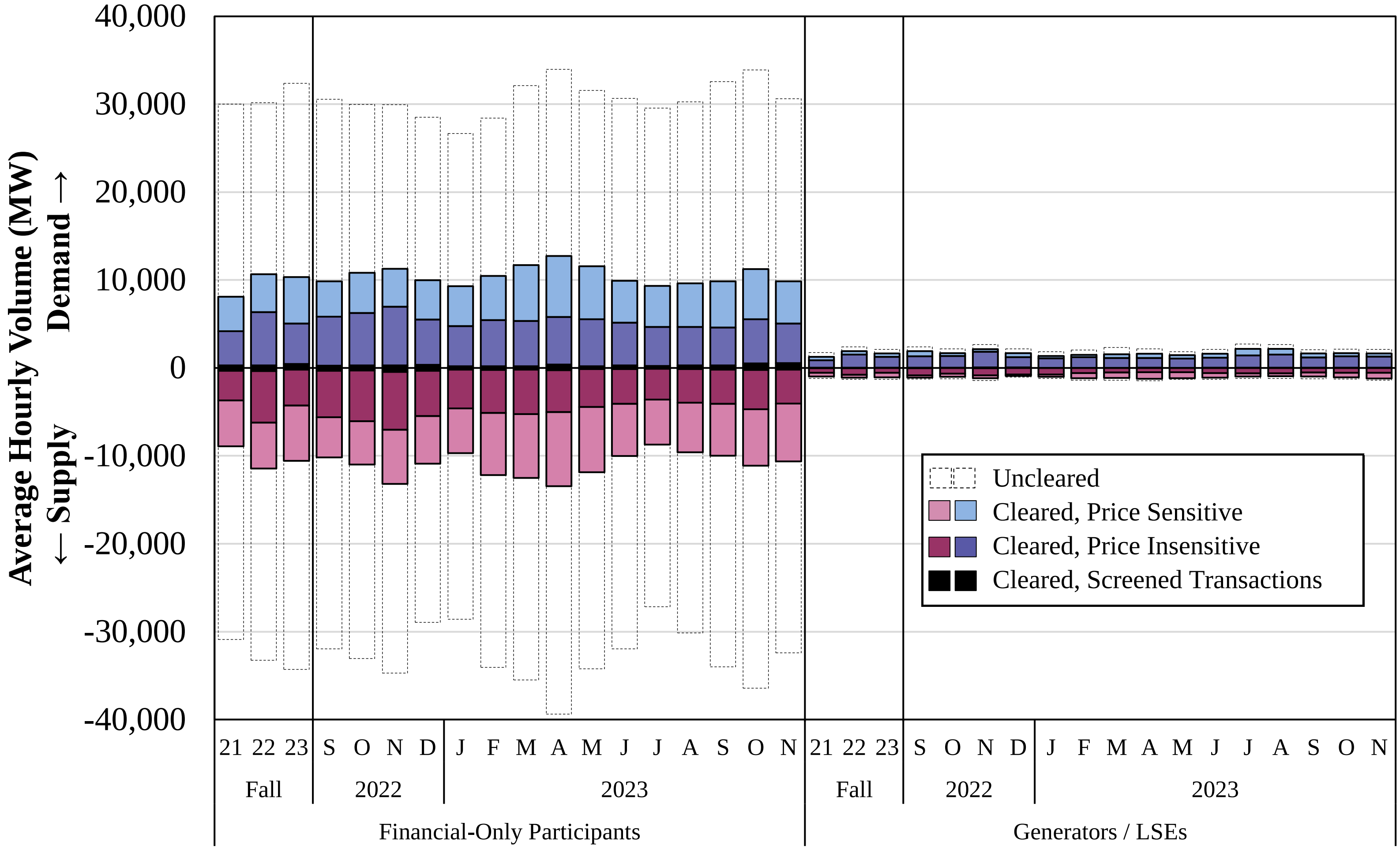
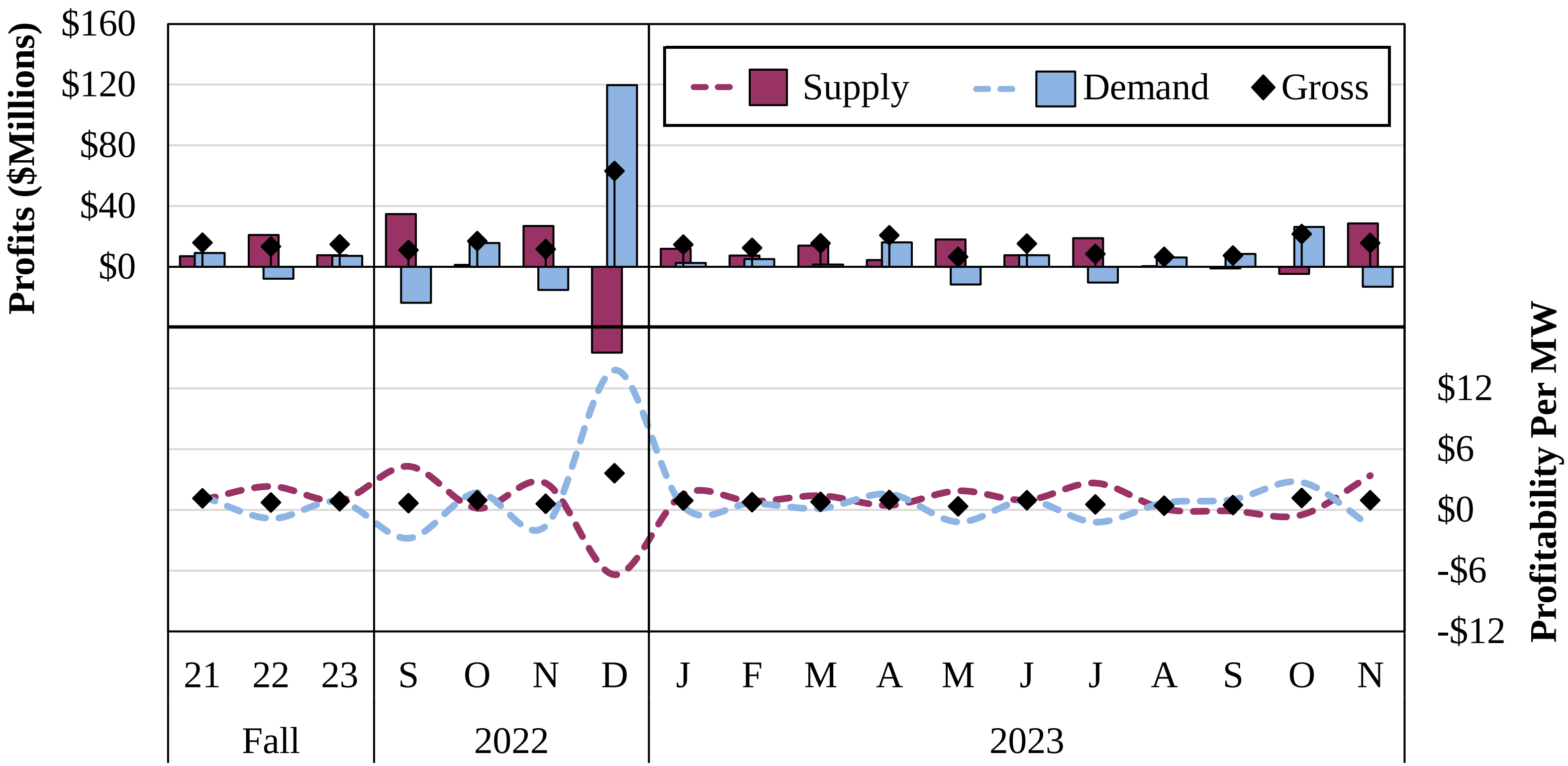
Virtual Load and Supply by Participant Type
Fall 2021–2023



POTOMAC ECONOMICS

Virtual Profitability
Fall 2021–2023



Supply	3.5	3.1	1.9	3.2	2.7	3.3	3.0	1.8	1.8	1.5	1.9	1.0	1.4	1.0	1.2	2.0	1.9	1.9
Demand	3.2	2.5	3.9	2.6	2.6	2.4	3.4	1.7	1.6	1.4	2.8	1.6	2.7	2.1	2.7	2.6	4.2	4.9
Total	3.4	2.8	2.9	2.9	2.6	2.9	3.2	1.8	1.7	1.5	2.3	1.3	2.1	1.6	2.0	2.3	3.1	3.4

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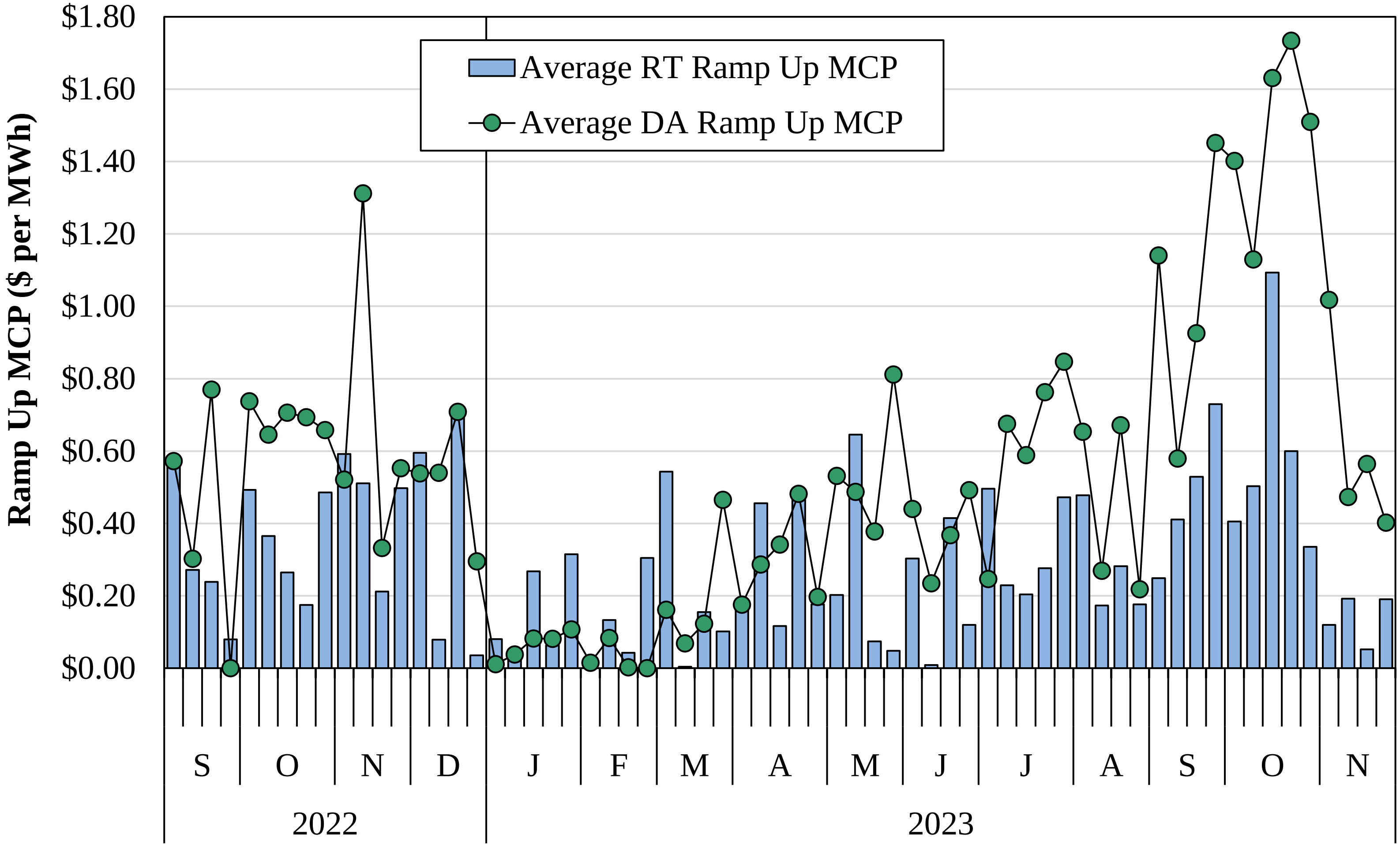
Day-Ahead and Real-Time Ramp Up Price
Fall 2022–2023



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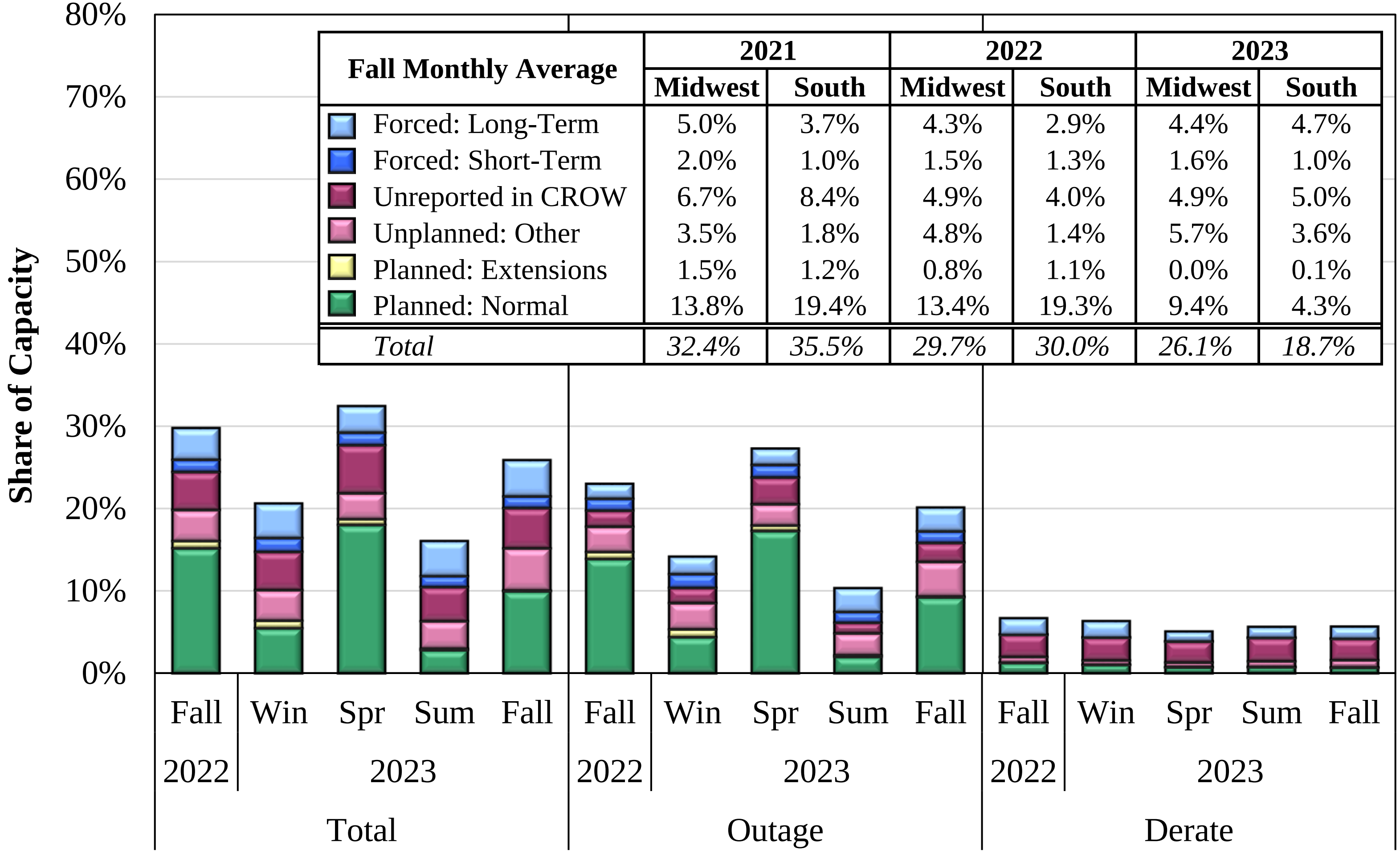
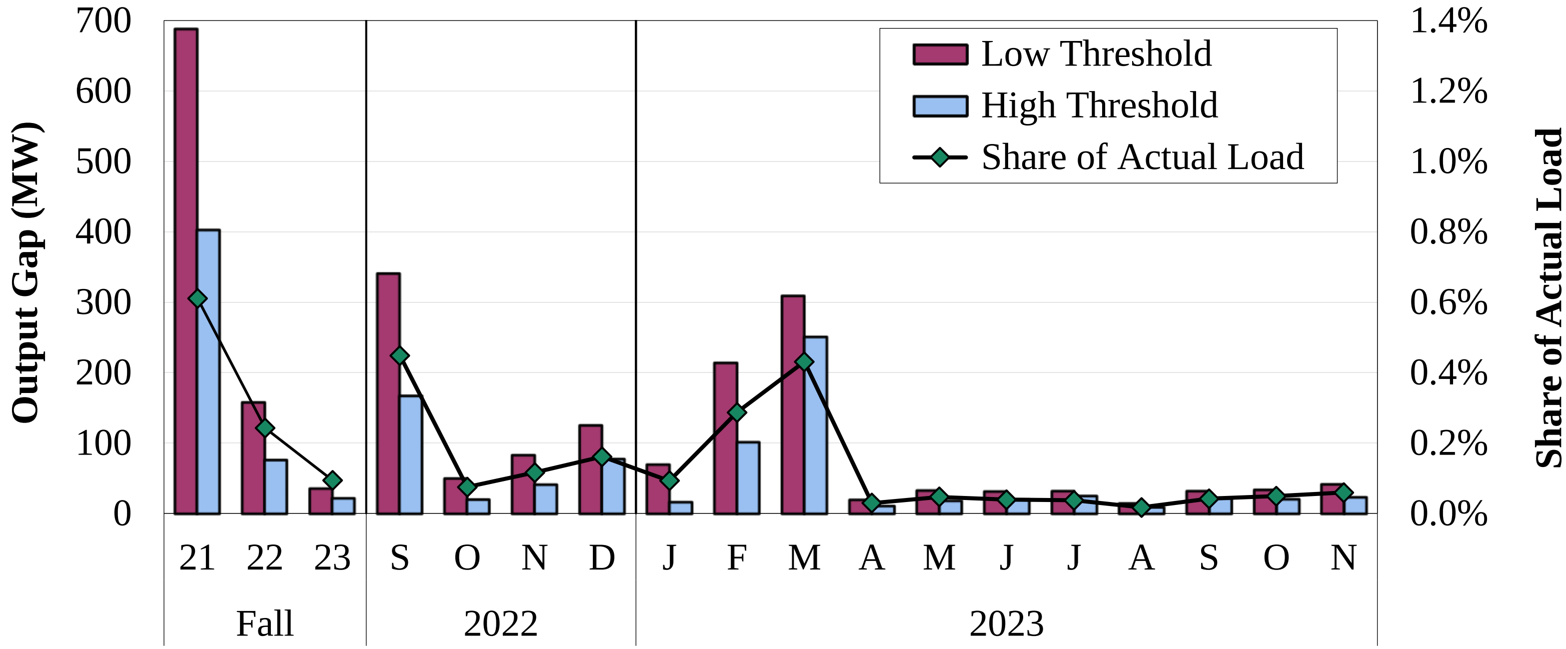
Generation Outages and Deratings
Fall 2021–2023



Fall Monthly Average	2021		2022		2023	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	5.0%	3.7%	4.3%	2.9%	4.4%	4.7%
Forced: Short-Term	2.0%	1.0%	1.5%	1.3%	1.6%	1.0%
Unreported in CROW	6.7%	8.4%	4.9%	4.0%	4.9%	5.0%
Unplanned: Other	3.5%	1.8%	4.8%	1.4%	5.7%	3.6%
Planned: Extensions	1.5%	1.2%	0.8%	1.1%	0.0%	0.1%
Planned: Normal	13.8%	19.4%	13.4%	19.3%	9.4%	4.3%
Total	*32.4%*	*35.5%*	*29.7%*	*30.0%*	*26.1%*	*18.7%*

Monthly Output Gap
Fall 2021–2023



Low Threshold Results by Unit Status (MW)

Offline	89	110	23	256	27	47	82	29	170	301	11	25	22	23	6	25	17	27
Online	598	48	13	84	23	36	43	41	43	8	9	8	10	9	8	7	17	15

High Threshold Results by Unit Status (MW)

Offline	60	66	19	151	12	36	59	12	94	247	6	13	15	21	6	19	16	21
Online	342	10	4	16	8	6	19	5	7	4	5	6	5	5	4	3	5	3

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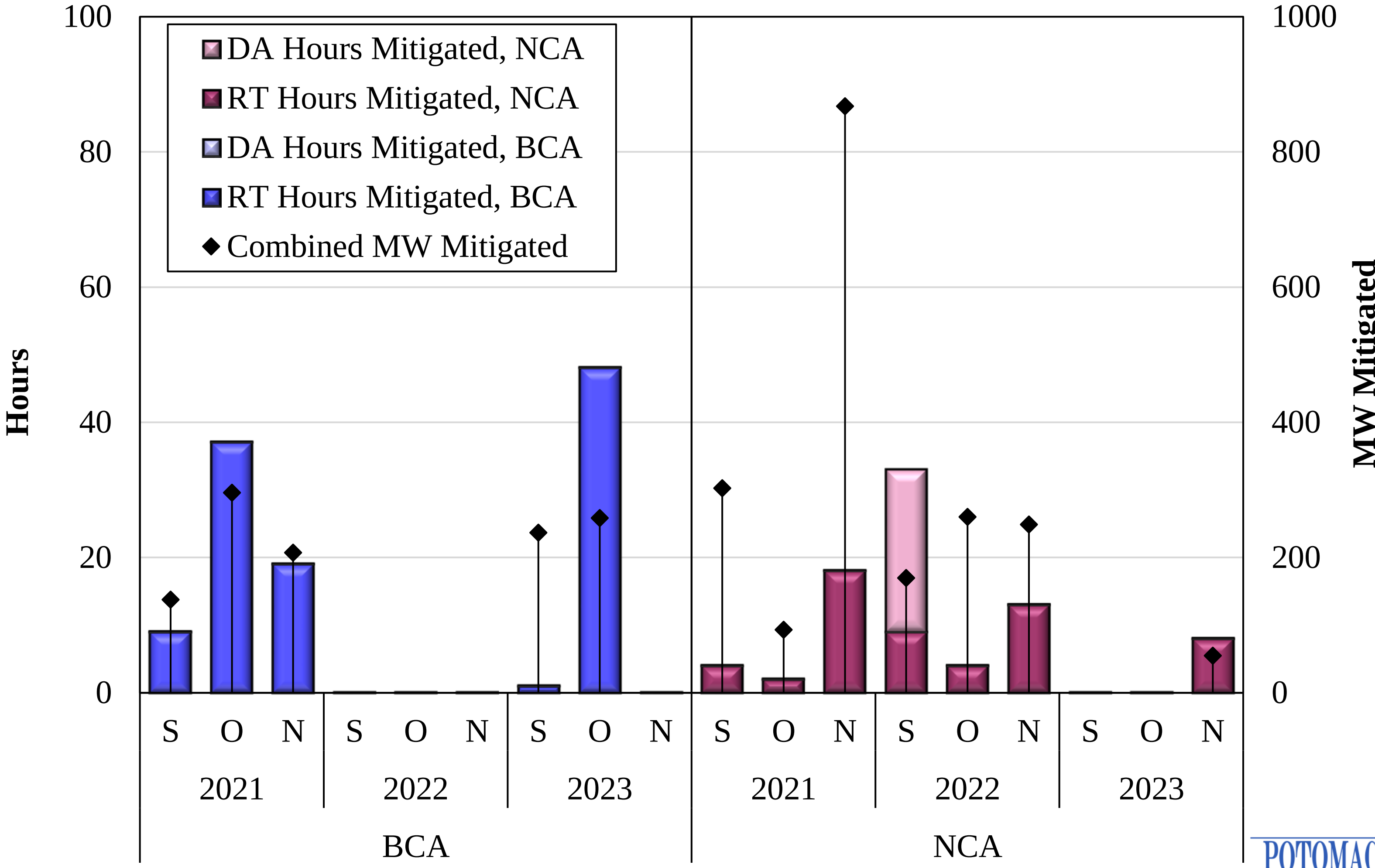
Day-Ahead And Real-Time Energy Mitigation Fall 2021 - 2023



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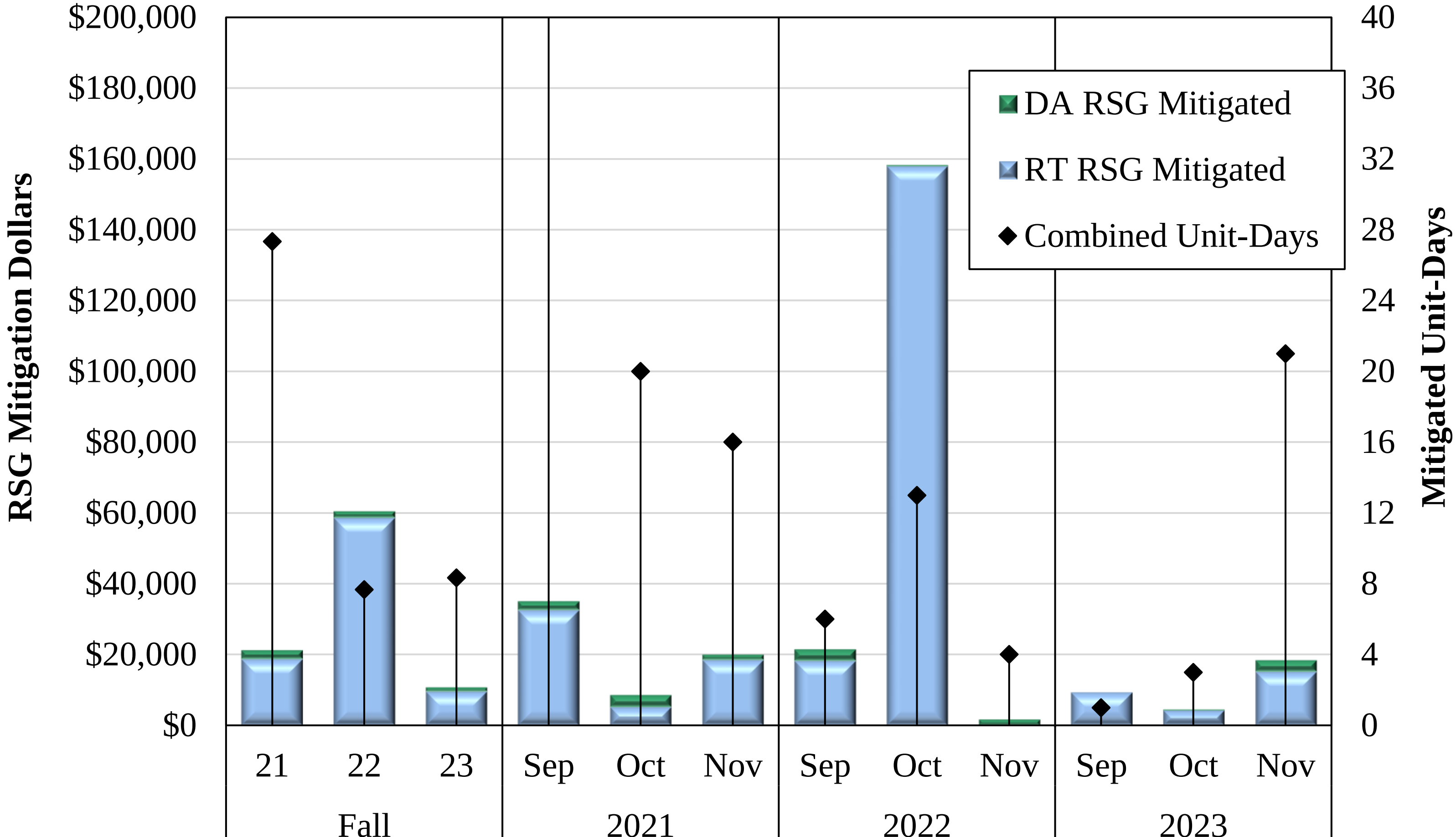
Day-Ahead and Real-Time RSG Mitigation Fall 2021 - 2023



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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