IMM Quarterly Report: Spring 2024

MISO Independent Market Monitor

Carrie Milton
Potomac Economics

MISO Market Subcommittee
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Highlights and Findings: Spring 2024

- The MISO markets performed competitively this spring and market power mitigation was low overall.
- Energy prices fell 4 percent compared to last year because gas prices fell between 21 and 28 percent and average load was 1 percent below last spring.
  - ✓ The peak load was 5 percent below last spring and temperatures throughout the quarter were generally mild, with fewer cooling degree days overall.
- Average hourly wind production was up 11 percent over last year to 13.6 GW, and wind curtailments increased by 8 percent, averaging 1 GW per hour.
  - ✓ Significant wind forecasting errors during the quarter led to unmodeled constraint overloads and extensive operator manual interventions.
  - ✓ Instances of units manually re-dispatched (MRD) and capped doubled over last year, which contributed to higher DAMAP.
- Despite the lower gas prices, real-time congestion was similar to last year and day-ahead congestion rose 23 percent year over year.
  - ✓ Severe storms in mid-May caused transmission outages and resulted in high congestion, and the RDT bound more frequently compared to last spring.

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Quarterly Summary

Spring	Value	Change[1] Prior Qtr.	Change[1] Prior Year
RT Energy Prices ($/MWh)	$25.35	*-19%*	*-4%*
Fuel Prices ($/MMBtu)			
Natural Gas - Chicago	$1.50	*-52%*	*-28%*
Natural Gas - Henry Hub	$1.73	*-38%*	*-21%*
Western Coal	$0.77	*-2%*	*-7%*
Eastern Coal	$1.73	*-4%*	*-40%*
Load (GW)[2]			
Average Load	69.2	*-8%*	*-1%*
Peak Load	98.4	*-8%*	*-5%*
% Scheduled DA (Peak Hour)	99.8%	99.8%	99.1%
Transmission Congestion ($M)			
Real-Time Congestion Value	$560.1	*10%*	*0%*
Day-Ahead Congestion Revenue	$371.6	*0%*	*23%*
Balancing Congestion Revenue[3]	-$8.9	$17.6	$7.5
Ancillary Service Prices ($/MWh)			
Regulation	$12.14	*32%*	*9%*
Spinning Reserves	$2.57	*41%*	*16%*
Supplemental Reserves	$0.27	*59%*	*26%*

	Value	Change[1] Prior Qtr.	Change[1] Prior Year
FTR Funding (%)	93%	96%	92%
Wind Output (MW/hr)	13,631	*16%*	*11%*
Wind Curtailed (MW/hr)	985	*145%*	*8%*
Guarantee Payments ($M)[4]			
Real-Time RSG	$2.1	*-74%*	*-68%*
Day-Ahead RSG	$7.4	*-33%*	*20%*
Day-Ahead Margin Assurance	$13.8	*29%*	*81%*
Real-Time Offer Rev. Sufficiency	$1.1	*-39%*	*-32%*
Price Convergence[5]			
Market-wide DA Premium	-6.3%	8.6%	2.5%
Virtual Trading			
Cleared Quantity (MW/hr)	25,074	*12%*	*-8%*
% Price Insensitive	43%	48%	44%
% Screened for Review	2%	2%	2%
Profitability ($/MW)	$0.6	$0.3	$0.7
Dispatch of Peaking Units (MW/hr)	1,611	1,328	1,516
Output Gap- Low Thresh. (MW/hr)	31	63	120

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 Spring 2024

Uncertainty Management: April 8 Solar Eclipse

- MISO planned for higher uncertainty going into the solar eclipse that occurred on April 8.
  - ✓ MISO increased the regulation, ramp and STR requirements by 600 MW, 400 MW and 1200 MW, respectively, between 12:30 pm and 4:00 pm.
- Although challenges arose, MISO was able to maintain reliability.
  - ✓ During the eclipse, roughly 4 GW of solar resources were unavailable, and an additional unexpected loss of 5 GW of wind occurred.
  - ✓ These changes created a very large demand for the non-intermittent fleet to ramp up going into the eclipse and ramp down coming out of it.
  - ✓ Operators leaned on regulation and avoided unnecessary commitments.
  - ✓ The day-ahead market cleared adequate headroom to manage the event.

Highlights for Spring 2024

Uncertainty Management: Uplift (Slides 21, 35-38)

- Real-time RSG fell 68 percent, but day-ahead RSG was up by 20 percent.
  - ✓ Improved commitment practices was a big contributor to the lower real-time uplift, along with lower gas prices.
  - ✓ Despite lower gas prices, day-ahead RSG rose because a coal-fired unit in a South load pocket was committed for reliability due to generation outages.
- Day-ahead Margin Assurance Payments (DAMAP) were up 81 percent to $14 million because of operational challenges and manual operator actions.
  - ✓ The RDT bound more frequently this quarter, particularly in May.
  - ✓ Sometimes the RDT cleared in violation, causing prices in the Midwest to rise by $500 per MWh – this contributed to large, slower-ramping Midwest units receiving 33 percent of all DAMAP.
  - ✓ Manual operator interventions, including manual-redispatch and caps, led to $2 million in DAMAP to compensate resources for lost market revenues.

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Highlights for Spring 2024

<u>Congestion and Challenging Operational Conditions (Slides 22-24, 30-32)</u>

- Although gas prices fell between 20 and 30 percent, real-time congestion was similar to last year and day-ahead congestion rose 23 percent.
  - ✓ In mid-May, storms in the South and later in the Midwest contributed to high real-time congestion attributable to forced transmission and generation outages.
  - ✓ Ongoing drought conditions in Manitoba and higher prices in PJM in May led to lower average imports this quarter; MISO was a net exporter to Manitoba.
- Constraint violations caused by unmodeled flows are problematic and create problems for MISO operators.
- Unmodeled flows are largely due to intermittent forecast errors and resources not following MISO's dispatch signal. To manage the resulting reliability issues, operators have broad discretion to take out of market actions, including:
  - ✓ Manual redispatch actions and dispatch caps;
  - ✓ Transmission derates using the "limit control" parameter; and
  - ✓ Changing the transmission demand curve (TCDC) level.
- These actions can have substantial effects on the market outcomes and the costs borne by MISO's customers – we provide examples in this report.

Highlights for Spring 2024

<u>Wind Forecasting Issues and Operator Actions (Slide 20)</u>

- We identified significant wind forecasting errors that have caused challenging congestion management issues and led to multiple caps and MRDs of wind.
  - ✓ Most wind resources rely on MISO's forecast, and rules allow wind units to produce all they can when their dispatch signal is equal to the MISO forecast.
  - ✓ This purpose of this rule is reasonable – to prevent wind from being constrained by the forecast when it is low. Curtailment is only justified by congestion.
- Sizable unit-level forecasting errors caused unmodeled constraint overloads.
  - ✓ *Suppliers do not always know when they are curtailed or affecting a constraint* – erroneous drops in forecast can cause a curtailed unit to be "released".
  - ✓ UDS solves as if units will follow dispatch setpoint, which cause LMPs to not reflect constraint overloads when resources are producing above their setpoint.
  - ✓ Since Jan. 2023, renewable forecast error caused 32 percent of physical constraint violations, while those not following dispatch caused 13 percent.
- Operators lack visibility into forecasting errors and why resources may not be following setpoints, prompting them to rely on caps and MRDs.
  - ✓ This leads to higher DAMAP, higher production costs and distorted LMPs.

Highlights for Spring 2024

Wind Forecasting Issues and Operator Actions (Cont'd)

- We identified an error in algorithm MISO uses to indicate to the wind forecast vendor that a units is being curtailed, which caused large sporadic errors.
  - ✓ This was very recently fixed, which will address the most impactful real-time forecasting errors, although other forecasting errors should be investigated.
- As wind and solar penetration grows and puts increasing strain on the grid, it is imperative that MISO prioritize the following to address these problems:
  1. Prioritize creating a dispatch flag ASAP to notify wind units when they must follow the dispatch setpoint (when they are causing flows on a constraint).
  2. Establish a penalty for resources not following setpoint beginning in the first interval of deviation when the dispatch flag is active.
  3. Generate persistence-based forecasts *in-house* – to improve the RT forecast by:
     a) reducing the lag between the output observation and the dispatch model running, which will significantly improve the real-time forecast; and
     b) allowing MISO to make incremental improvements to the persistence logic.
  4. Collect real-time meteorological data from renewable resources.
  5. Improve visualization tools so operators may discern between wind units ignoring curtailments versus units experiencing forecasting errors.

Highlights for Spring 2024

<u>Operating Actions to Manage Constraint: May 21 Example</u>

- MISO has a number of operating actions that can be taken when it is struggling to manage the flows on a constraint.
- Different actions can have different unintended consequences that can prompt the need to take other actions. This occurred on May 21:
  - ✓ Severe storms reduced wind output, causing the RDT limit to be exceeded
  - ✓ Instead of committing up to 700 MW recommended by LAC, MISO derated the RDT interface limit causing prices in the Midwest to rise over $200 per MWh.
  - ✓ The high energy value in the Midwest caused energy output to rise from some units in the Midwest that contributed to constraint violations.
  - ✓ To manage one violation, MISO MRD'd one key coal resource down 1300 MW
    - – This MRD and further RDT derates, caused RDT to go into violation and raised prices in the Midwest by > $700/MWh for more than 30 minutes.
    - – The RDT flows were well below the contract limit during this period.
  - ✓ This led most Midwest units to be dispatched up, causing multiple constraints to be violated (value of RDT violation > value of the constraint violations).
  - ✓ Since the constraint violations are real, MISO MRD'd/capped over a dozen units (700 MW) to address these violations.

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Highlights for Spring 2024

<u>Operating Actions to Manage Constraint: May 21 Example</u>

- These actions ultimately led to distorted prices and over $1 million in DAMAP.
- This highlights the importance of taking the most appropriate operating actions.
- When the initial constraint was violated because the RDT dominated the value of managing the constraint (i.e., the TCDC), MISO could have increased the TCDC so the dispatch would bring it back under control.
- We simulated this alternative approach by replacing the MRDs with a TCDC adjustment for the period from 5 pm to 11 pm, which showed:
  - ✓ $145,000 less constraint violation costs, $85,000 less production costs, $828,000 less DAMAP and much lower real-time energy prices.
  - ✓ The value of real-time energy (price * real-time load) was $20 million lower.
- Given the importance of choosing the best out-of-market action to take under different conditions, we recommend that MISO:
  - ✓ Develop guidelines/procedures and supporting tools that govern manual operator actions. We are working with MISO on these guidelines/tools.
  - ✓ Provide additional training on the secondary impacts of actions.

Highlights for Spring 2024

IMM Summer Assessment (Slide 26)

- We assessed the expected summer capacity margin based on the coincident peak summer forecast and the results of the seasonal capacity auction.
  - ✓ Excluding typical outages and derates, MISO can expect a capacity margin of 20.3 percent, which includes more than 12 GW of emergency-only capacity.
  - ✓ Including typical forced outages of 6.8 GW and average non-firm imports in peak periods of 4.3 GW produces a projected capacity margin of 18.2 percent.
  - ✓ These levels exceed MISO's planning requirements.
- Considering planned outages observed in past summers and demand response likely to be unavailable, the estimated capacity margin falls to 6.4 percent.
- We also evaluate unusually hot conditions where demand is projected to be 7 GW higher and an additional 7.6 GW of supply may be unavailable.
  - ✓ In the high temperature case with only 2-hour demand response assumed to be available, we project a capacity deficit of 6.9 percent.
  - ✓ This is a low-probability case and MISO would likely have access to additional imports from neighboring systems to satisfy its needs.
- Overall, we find that MISO will be capacity sufficient during the summer peak

2024-2025 PRA Results

<u>2024-2025 Planning Resource Auction Results (Slide 27)</u>

- In April MISO cleared its second seasonal capacity auction.
  - ✓ Across the four seasons, market clearing prices average nearly $20 per MW-day, with the lowest unconstrained prices in the winter and highest in spring.
  - ✓ Zone 5 fell short of its local clearing requirement (LCR) in the fall and spring by 872.4 MW and 196.4 MW, respectively.
  - ✓ The shortage was due to the retirement of two large coal-fired resources after the summer and long-duration planned outages in those shoulder seasons.
  - ✓ The report shows that these shortages were priced inefficiently high, which will require zonal RBDCs to address.

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day)	
				Rest of Market	Zone 5 (MO)
Summer 24	136,064	4,624	0.10	$30.00	
Fall 24	125,551	9,327	0.01	$15.00	**$719.81**
Winter 24/25	131,377	17,061	0.01	$0.75	
Spring 25	127,791	8,825	0.01	$34.10	**$719.81**
PRA Year	130,196	9,959	0.13	$19.96	$367.59

Submittals to External Entities and Other Issues

During the Spring 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 Winter Quarterly report to the MSC and recent market results to the ERSC.
- Filed comments in support of MISO’s and MDU’s complaints regarding market-to-market coordination of the Charlie Creek constraint in SPP.
- Continued working with MISO to review proposals to revise the M2M “firm flow entitlement” allocation, which will have large economic impacts.
- Worked with MISO on recommended operational improvements and produced memos and summaries of the recommendations.
- Met with OMS on market issues and planning issues.
- Continued working with MISO and participants to address concerns with LRTP Tranche 2, including presenting concerns regarding the benefit-cost analysis methodologies.

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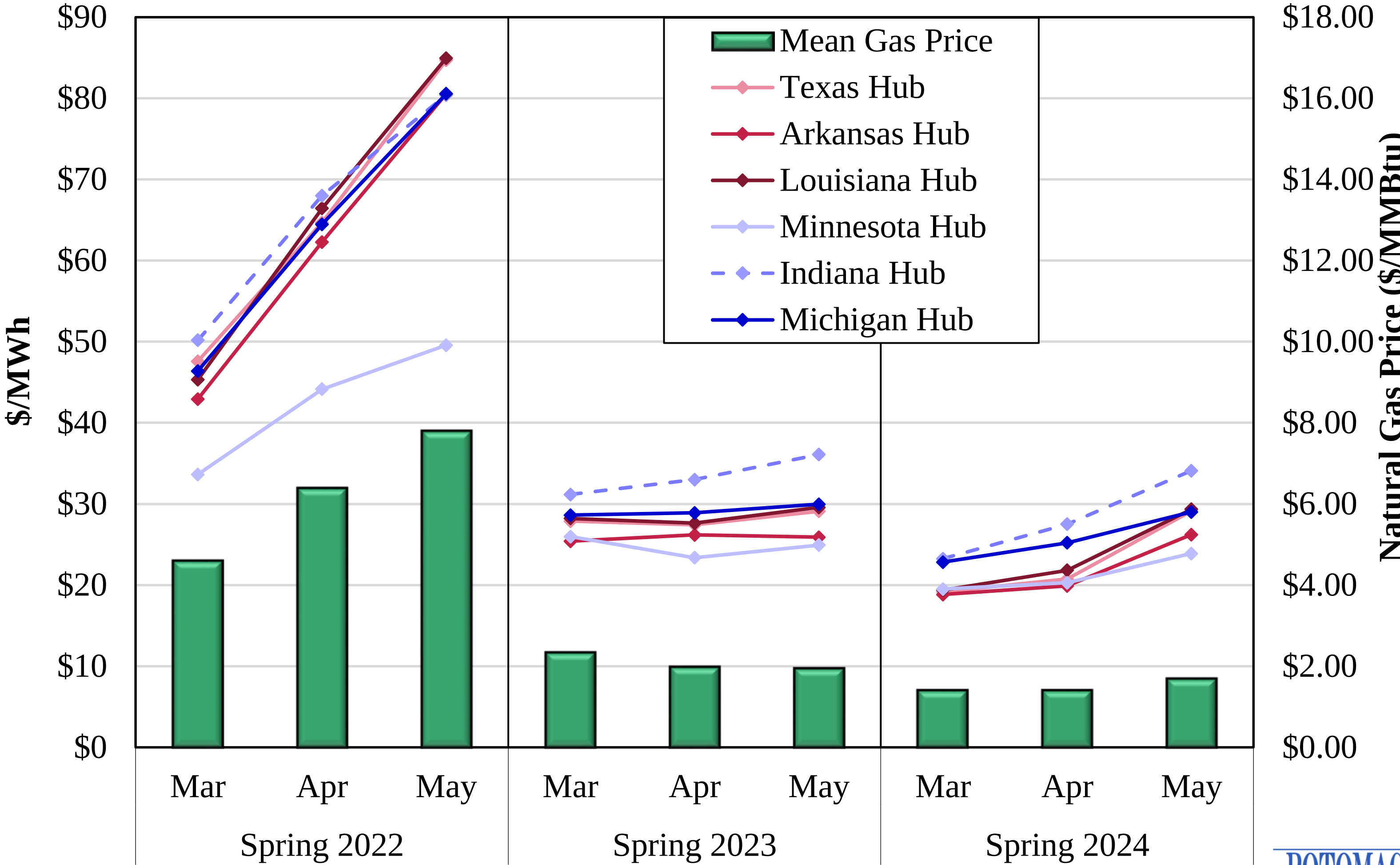
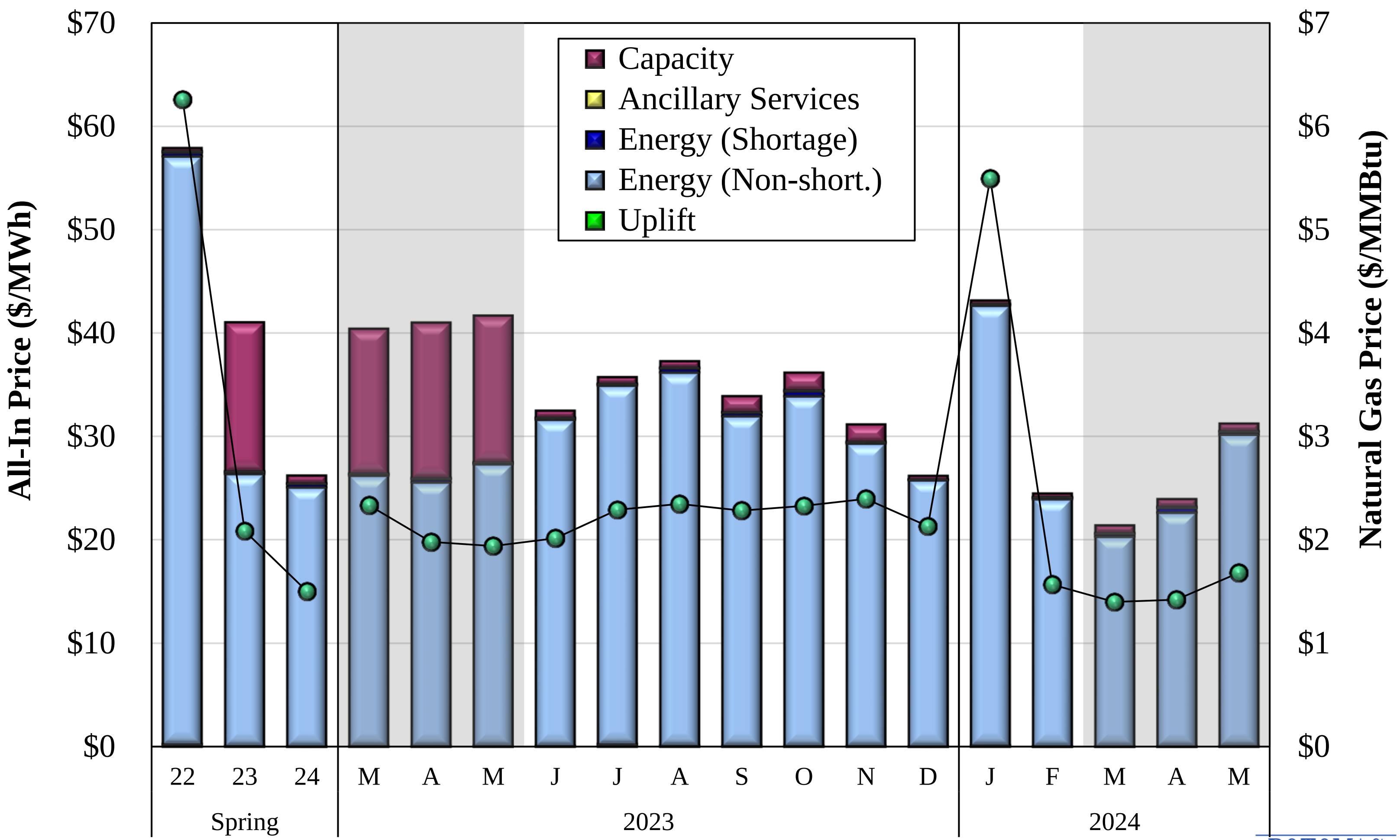
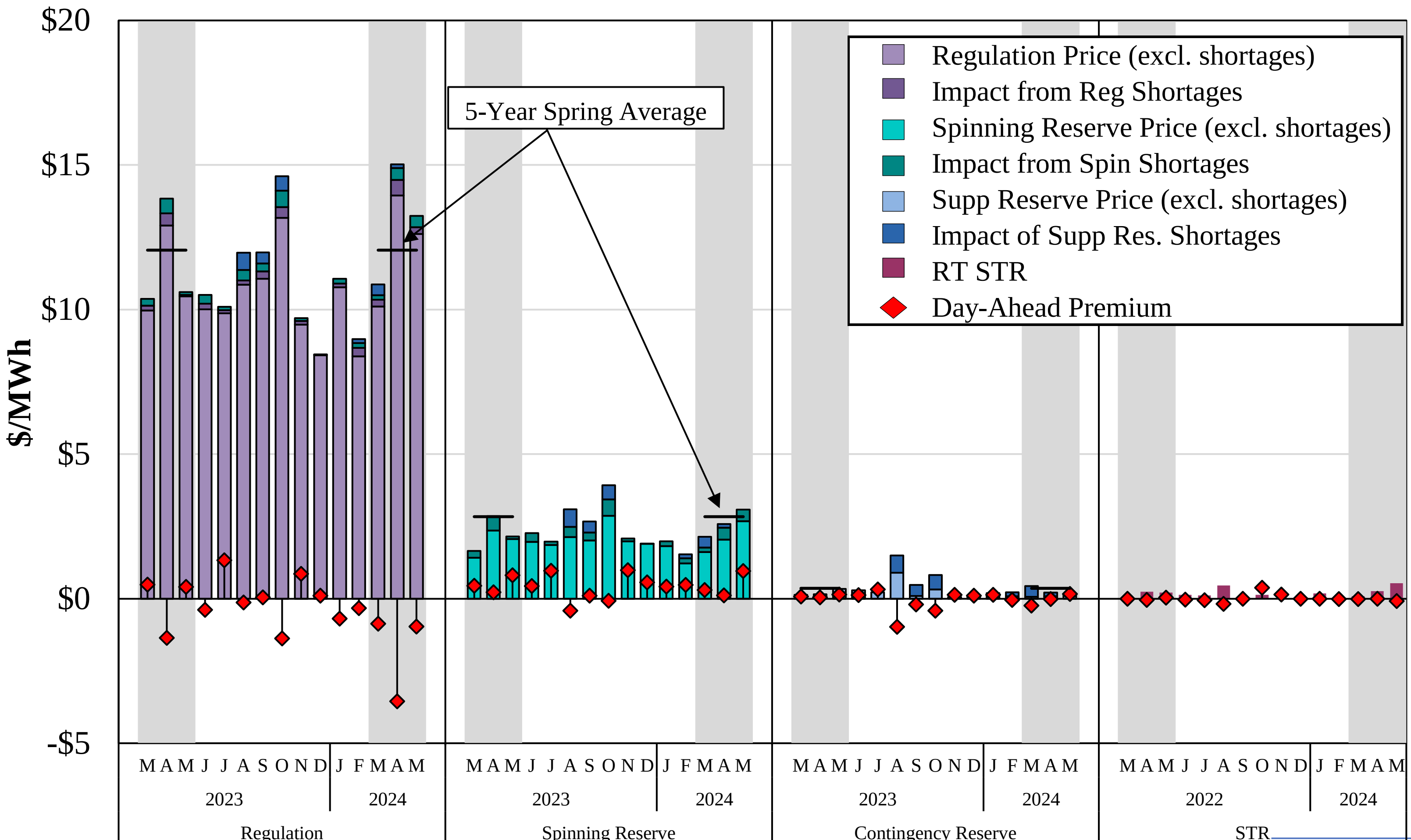
Day-Ahead Average Monthly Hub Prices Spring 2022–2024



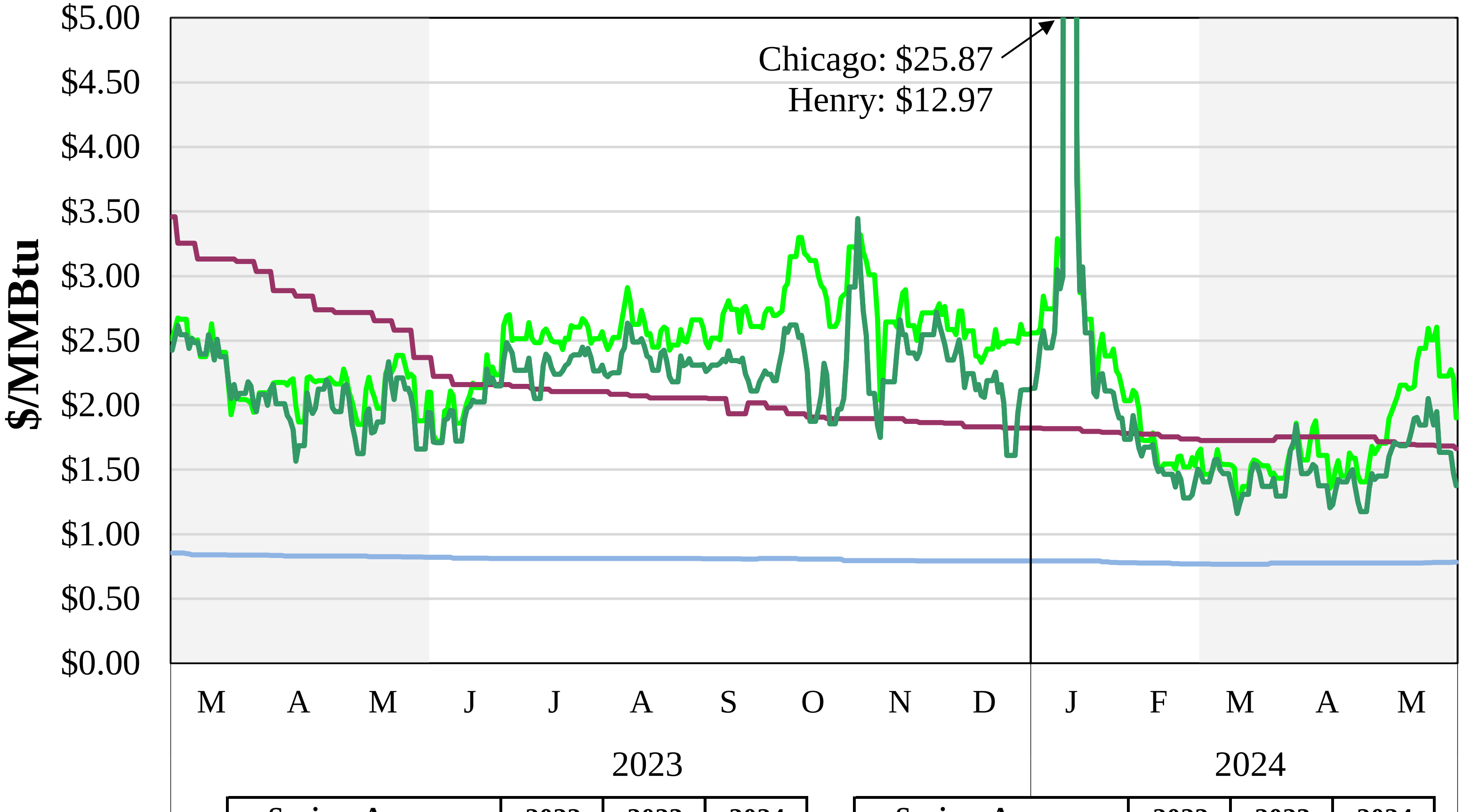
All-In Price
Spring 2022 – 2024



Ancillary Services Prices
Spring 2023–2024



MISO Fuel Prices 2023–2024



Spring Average	2022	2023	2024
Chicago NG	$6.26	$2.08	$1.50
Henry NG	$6.44	$2.19	$1.73

Spring Average	2022	2023	2024
IB Coal	$5.06	$2.88	$1.73
PRB Coal	$0.93	$0.83	$0.77

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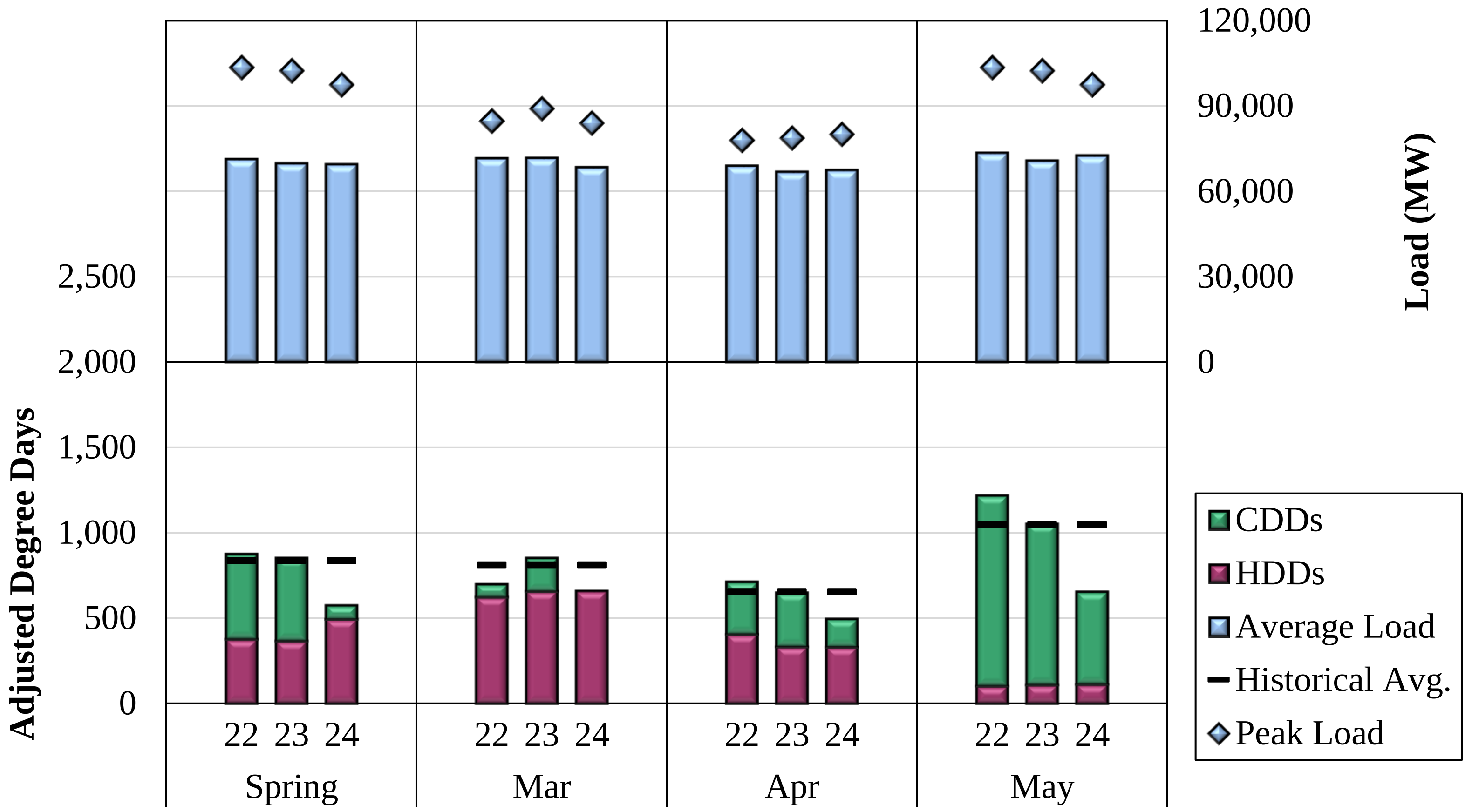
Load and Weather Patterns
Spring 2022–2024



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

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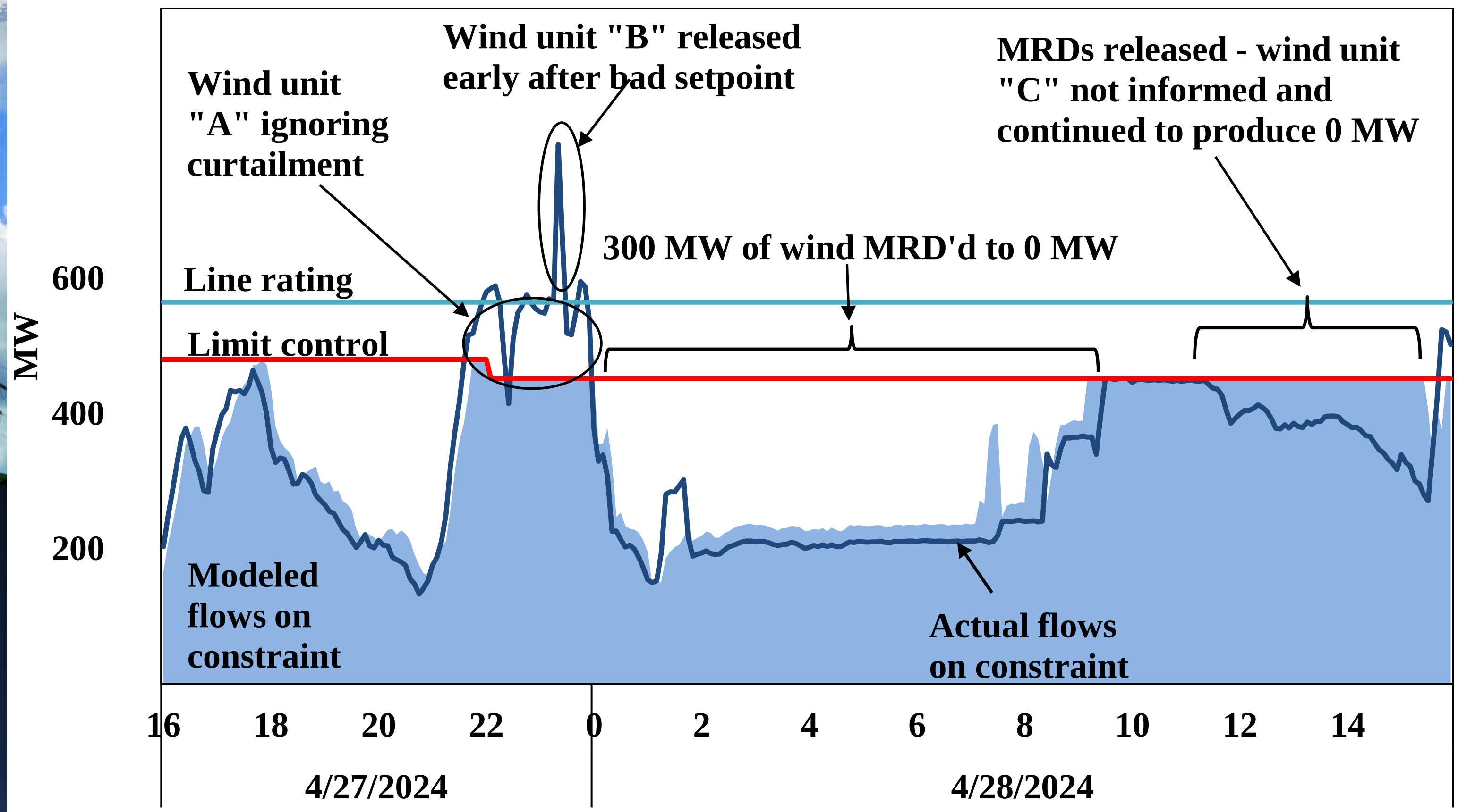
Capacity, Energy and Price Setting Share
Spring 2023–2024

Spring	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2023	2024	2023	2024	2023	2024	2023	2024	2023	2024
Nuclear	10,905	10,869	9%	8%	15%	14%	0%	0%	0%	0%
Coal	40,291	37,638	32%	29%	23%	22%	34%	29%	73%	69%
Natural Gas	60,613	61,931	47%	48%	38%	38%	64%	70%	89%	86%
Oil	1,448	1,506	1%	1%	0%	0%	0%	0%	1%	0%
Hydro	4,034	4,166	3%	3%	2%	2%	1%	0%	3%	1%
Wind	4,769	4,960	4%	4%	19%	21%	0%	0%	78%	77%
Solar	2,808	4,491	2%	3%	0%	2%	0%	0%	9%	20%
Other	2,743	2,822	2%	2%	2%	0%	0%	0%	1%	1%
Total	**127,609**	**128,382**								

Wind-Related Constraint Management Challenges Base Fenoch Constraint



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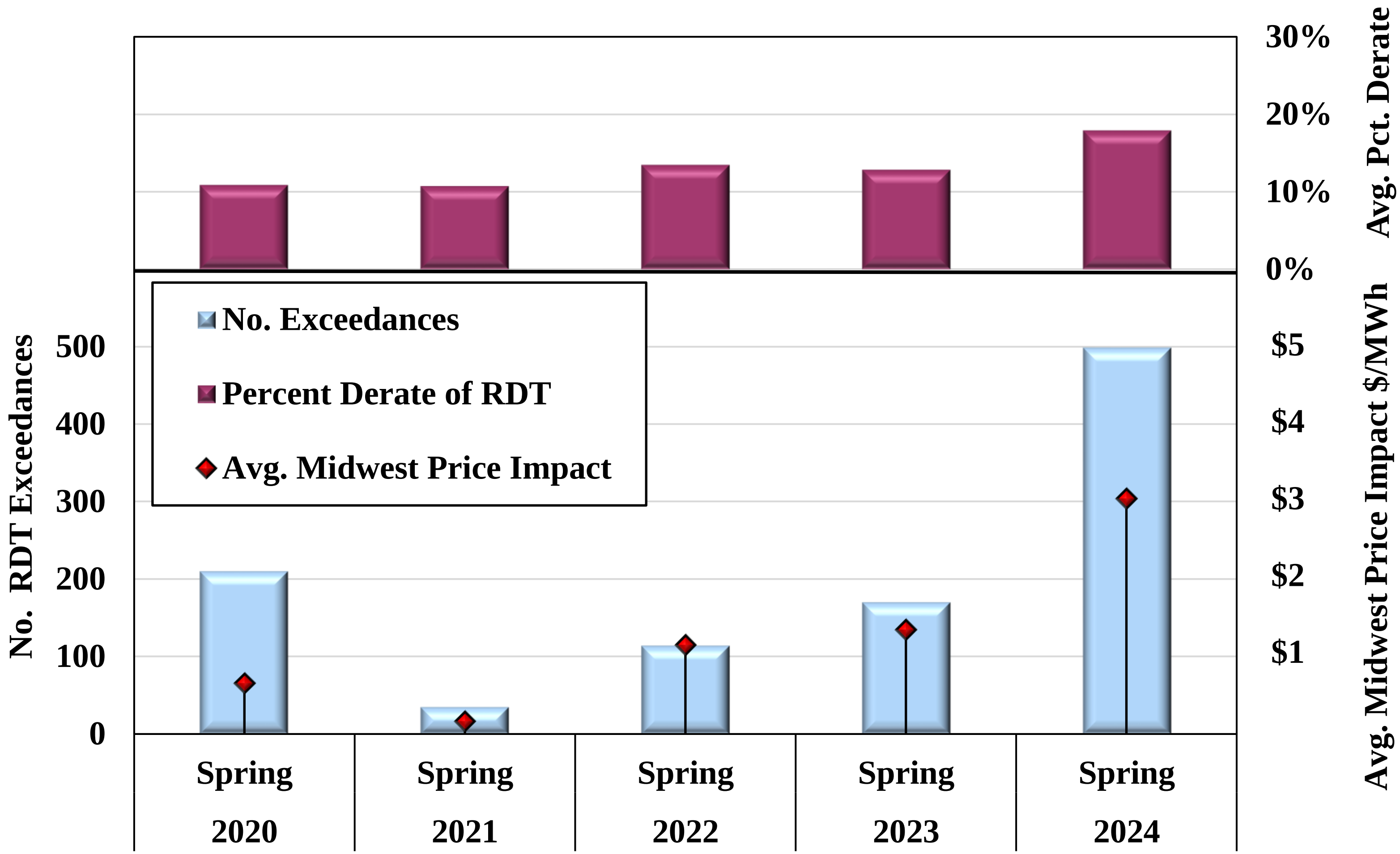
South to North RDT Exceedances, Derates and Midwest Price Impacts



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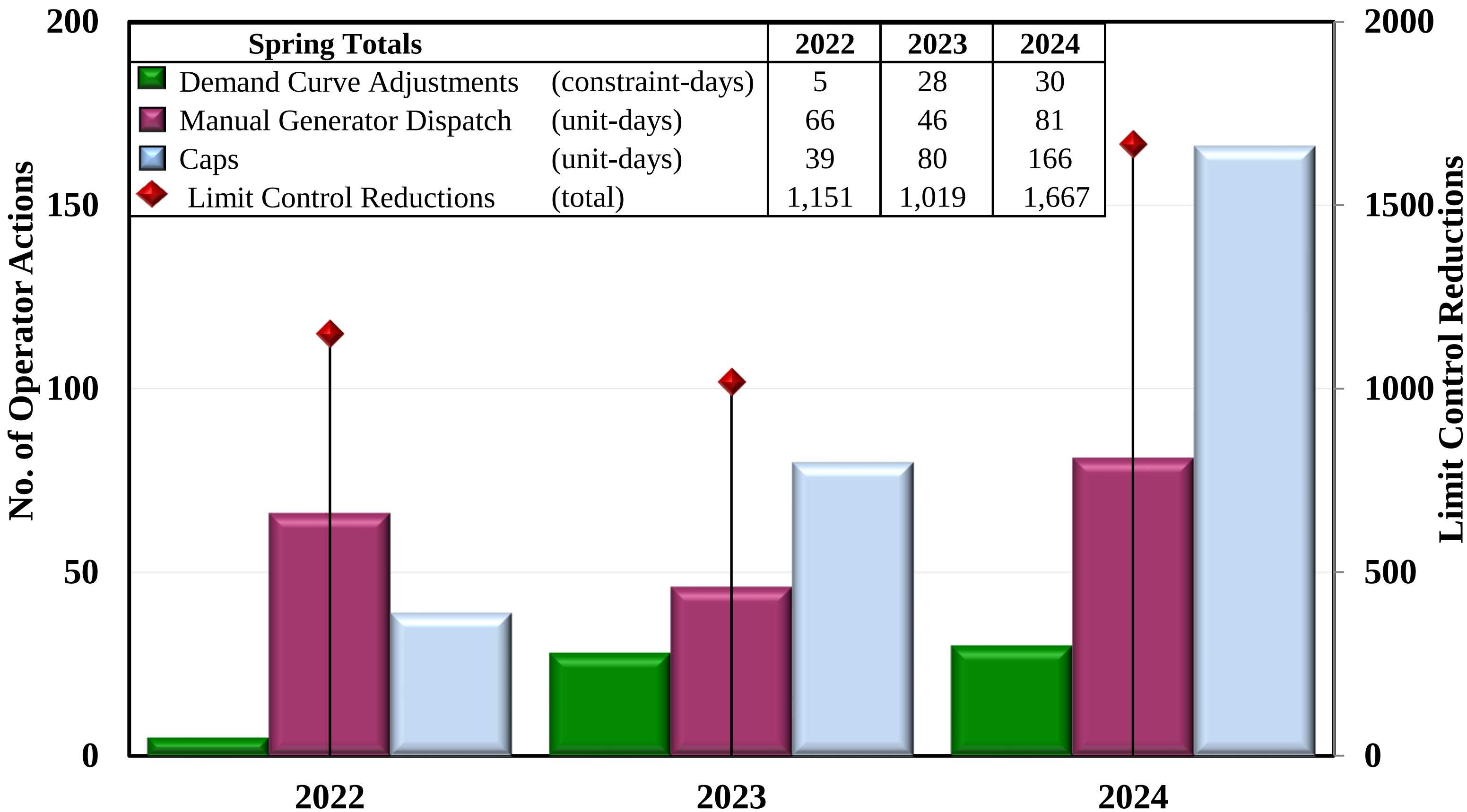
MISO Operator Intervention Decisions

Operator Decisions	Effect of Action	Pros / Cons
TCDC Adjustment	Allows the dispatch model to access more costly dispatch actions to lower constraint flows	Allows the dispatch model to optimally manage the constraint
Commit Resources that can Provide Relief	Reduces flows on constraints by providing counterflows.	When units are economic to commit, they will lower costs, but may raise uplift when uneconomic
Transmission Derate with Limit Control Adjustment	Causes the dispatch to reduce the modeled flows to makes room on the constraint for the unmodeled constraint flows.	An efficient means to account for unmodeled flows. But not efficient when the violation is caused by modeled flows.
Manual Redispatch (MRD)	Manually specifies a dispatch level for a resource to reduce constraint flows.	Provides quick relief, but is rarely efficient. Prevents the dispatch from efficiently pricing the congestion and increases uplift.
Cap Resources	Manually specifies a maximum dispatch level for a resource to prevent increasing constraint flows.	Effectively limits flows, but is rarely efficient. Prevents the dispatch from efficiently pricing the congestion and increases uplift.

MISO Operator Actions for Congestion Management



Spring Totals		2022	2023	2024
Demand Curve Adjustments	(constraint-days)	5	28	30
Manual Generator Dispatch	(unit-days)	66	46	81
Caps	(unit-days)	39	80	166
Limit Control Reductions	(total)	1,151	1,019	1,667

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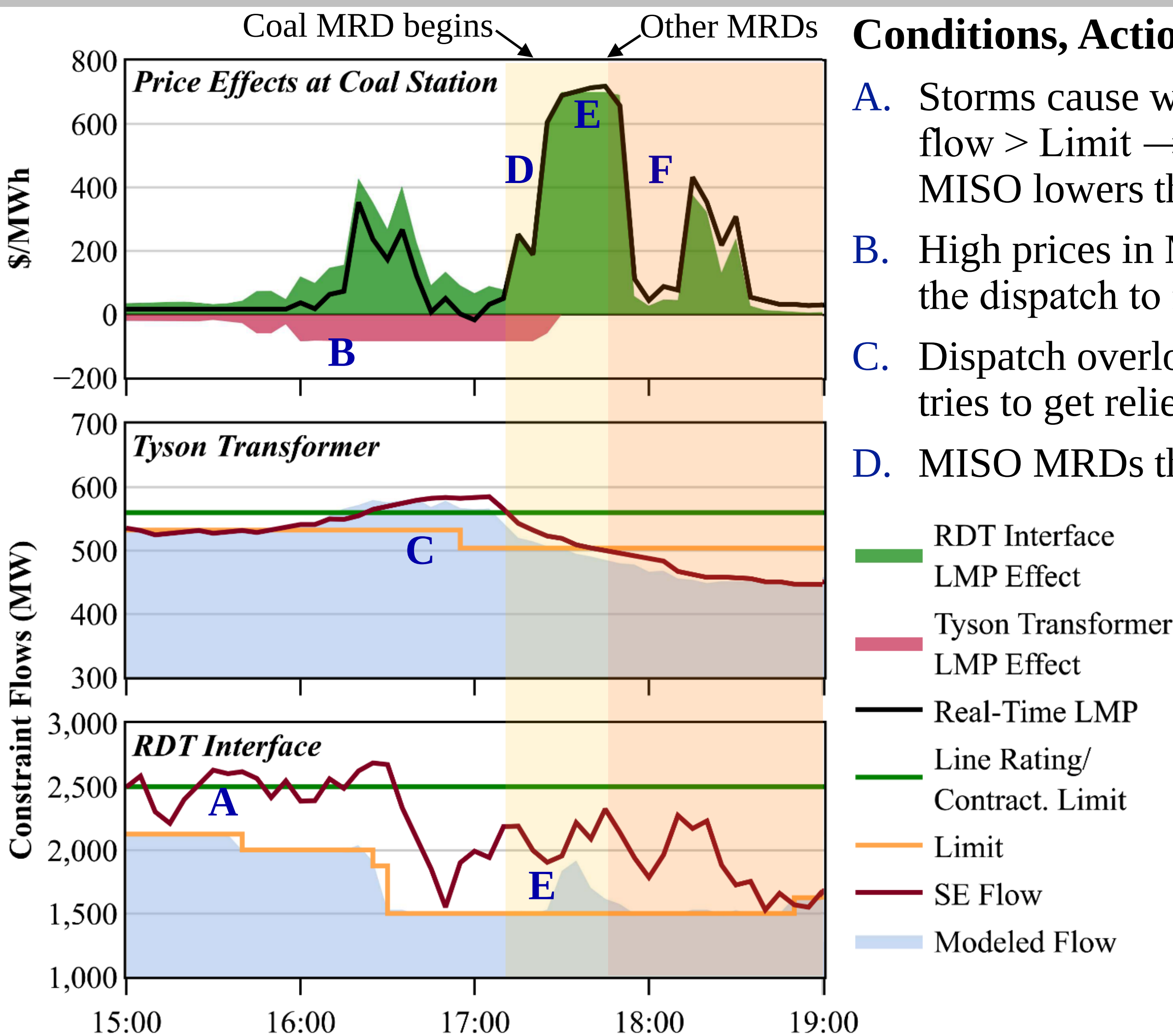
Congestion Management Issues
May 21



Conditions, Actions, and Effects:

A. Storms cause wind to under-perform → RDT flow > Limit → Prices spike in Midwest and MISO lowers the limit control

B. High prices in Midwest (due to the RDT) cause the dispatch to increase the coal unit output →

C. Dispatch overloads Tyson transformer → MISO tries to get relief by lowering limit control

D. MISO MRDs the coal unit down by ~1300

E. Loss of 1300 MW & wind cause Midwest shortage → the modeled RDT flow > dispatch limit → sustained price spike in Midwest →

F. High Midwest prices cause many constraint violations → MISO MRDs 14 units → $900,000 in DAMAP total

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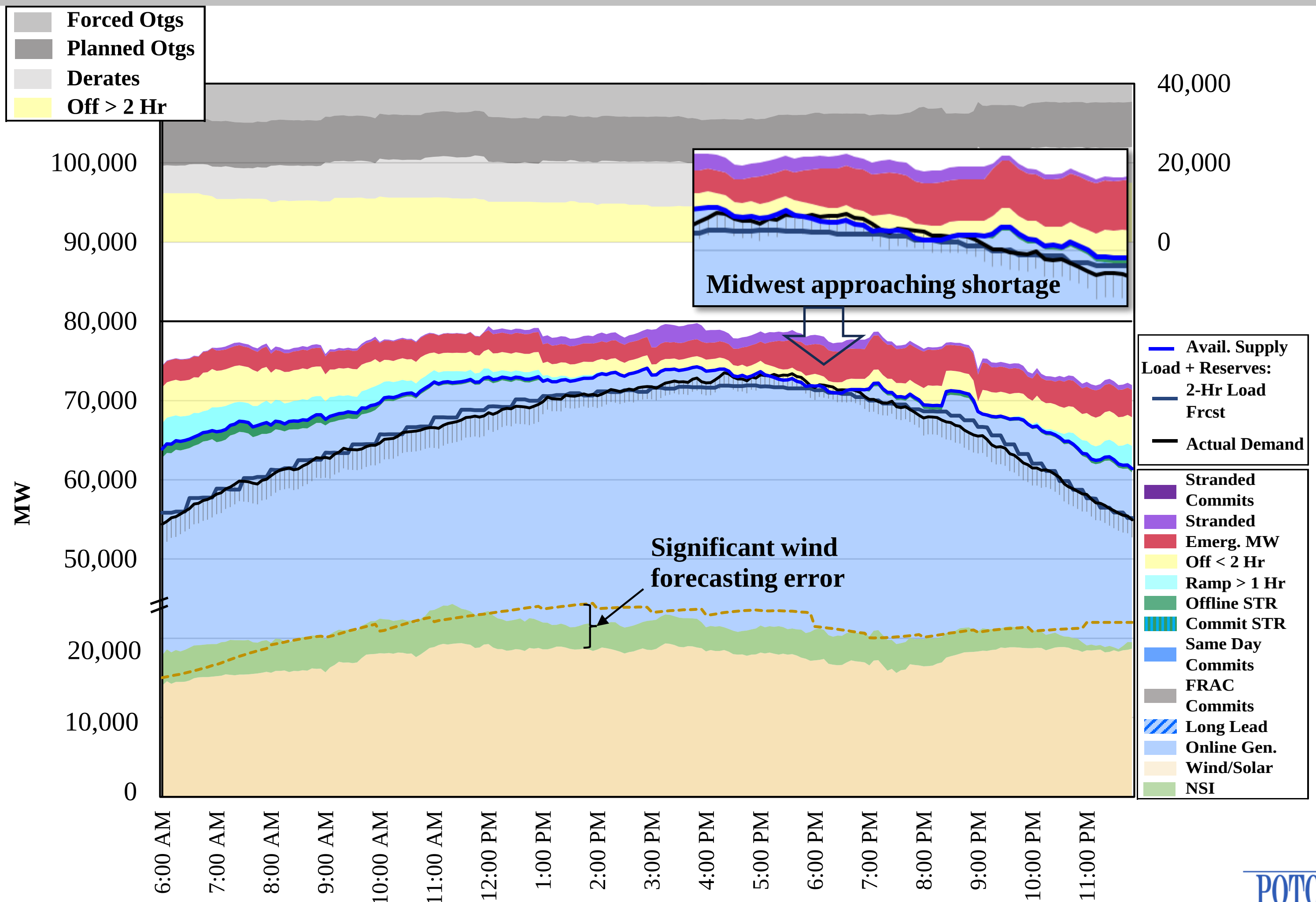
Midwest Shortage Conditions
May 21



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Summer 2024 Planning Reserve Margins

	Base Scenario	Alternative IMM Scenarios*			
				High Temperature Cases	
		Realistic Scenario	Realistic <=2HR	Realistic Scenario	Realistic <=2HR
Load					
Base Case	122,600	122,600	122,600	122,600	122,600
High Load Increase	-	-	-	6,690	6,690
Total Load (MW)	122,578	122,578	122,578	129,290	129,290
Generation					
Internal Generation Excluding Exports	132,120	132,120	132,120	132,120	132,120
BTM Generation	4,331	4,331	3,336	4,331	3,336
Unforced Outages and Derates**	(43)	(12,458)	(12,458)	(20,058)	(20,058)
Adjustment due to Transfer Limit	(1,417)	-	-	-	-
Total Generation (MW)	134,991	123,993	122,998	116,393	115,398
Imports and Demand Response* **					
Demand Response (ICAP)	8,109	6,082	3,080	6,082	3,080
Firm Capacity Imports	4,335	4,335	4,335	4,335	4,335
Margin (MW)	24,857	11,832	7,836	(2,480)	(6,477)
Margin (%)	**20.3%**	**9.7%**	**6.4%**	**-1.9%**	**-5.0%**
Expected Capacity Uses and Additions					
Expected Forced Outages****	(6,823)	(6,702)	(6,702)	(6,702)	(6,702)
Non-Firm Net Imports in Emergencies	4,260	4,260	4,260	4,260	4,260
Expected Margin (MW)	22,295	9,390	5,394	(4,922)	(8,919)
Expected Margin (%)	**18.2%**	**7.7%**	**4.4%**	**-3.8%**	**-6.9%**

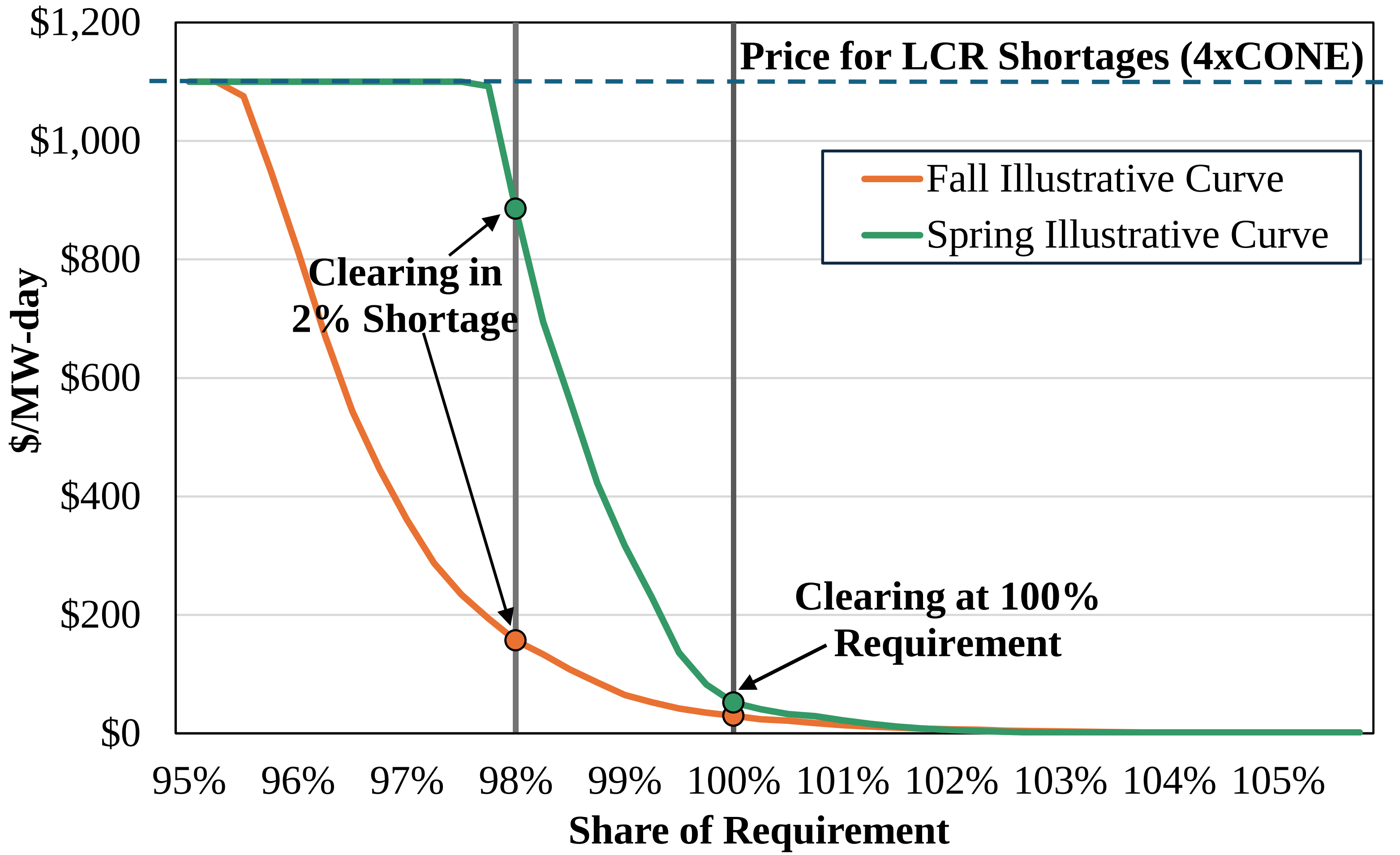
* Assumes 75% response from DR.

** Base scenario shows approved planned outages for summer 2024. Realistic cases use historical averages during peak summer hours. High temp. cases are based upon MISO's 2024 Summer Assessment.

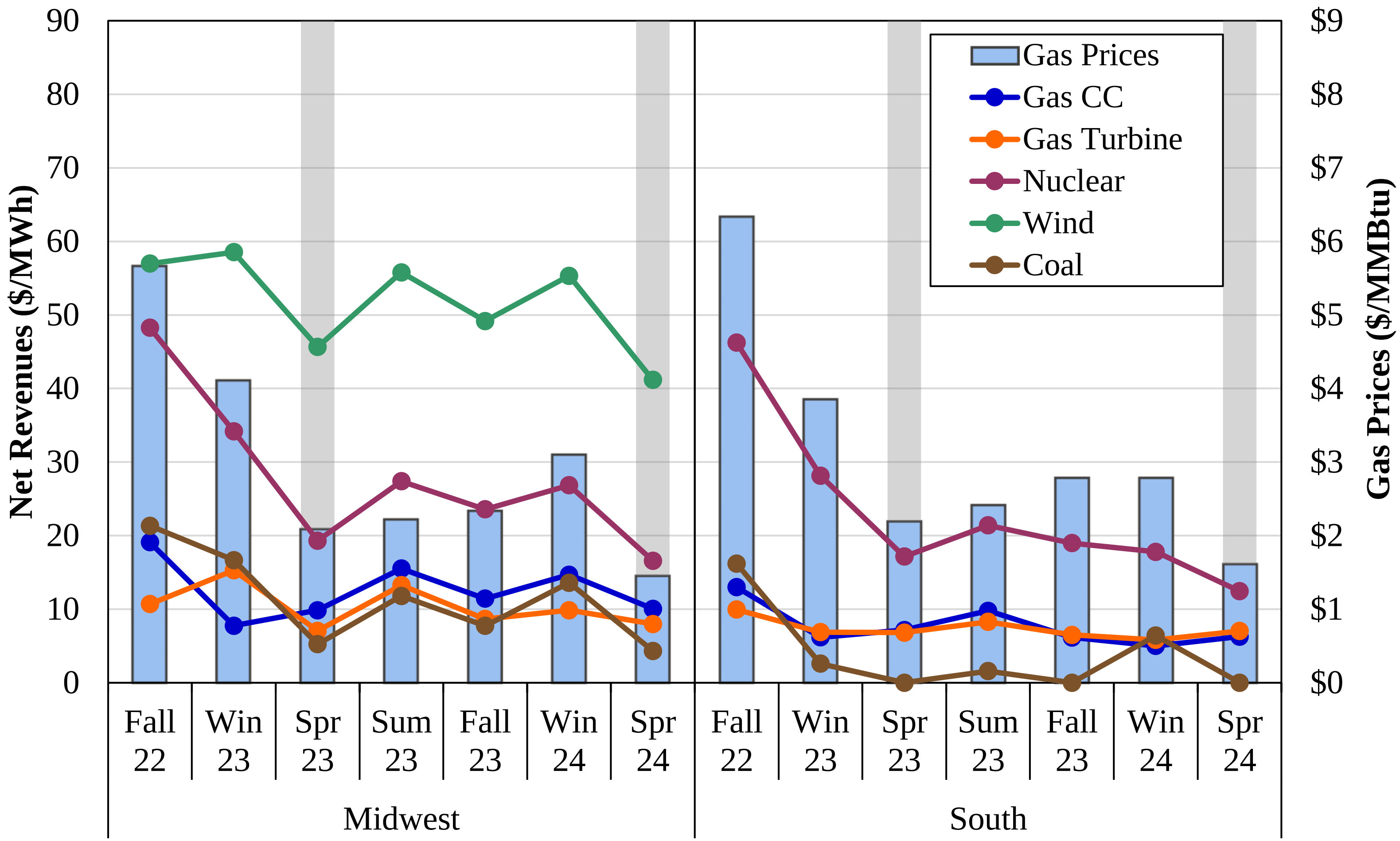
*** Cleared amounts for the Summer Season of the 2024/2025 planning year.

**** Base scenario assumes 5% forced outage rate for internal and BTM generation. Alternative cases use historical average forced outages/derates during peak summer hours.

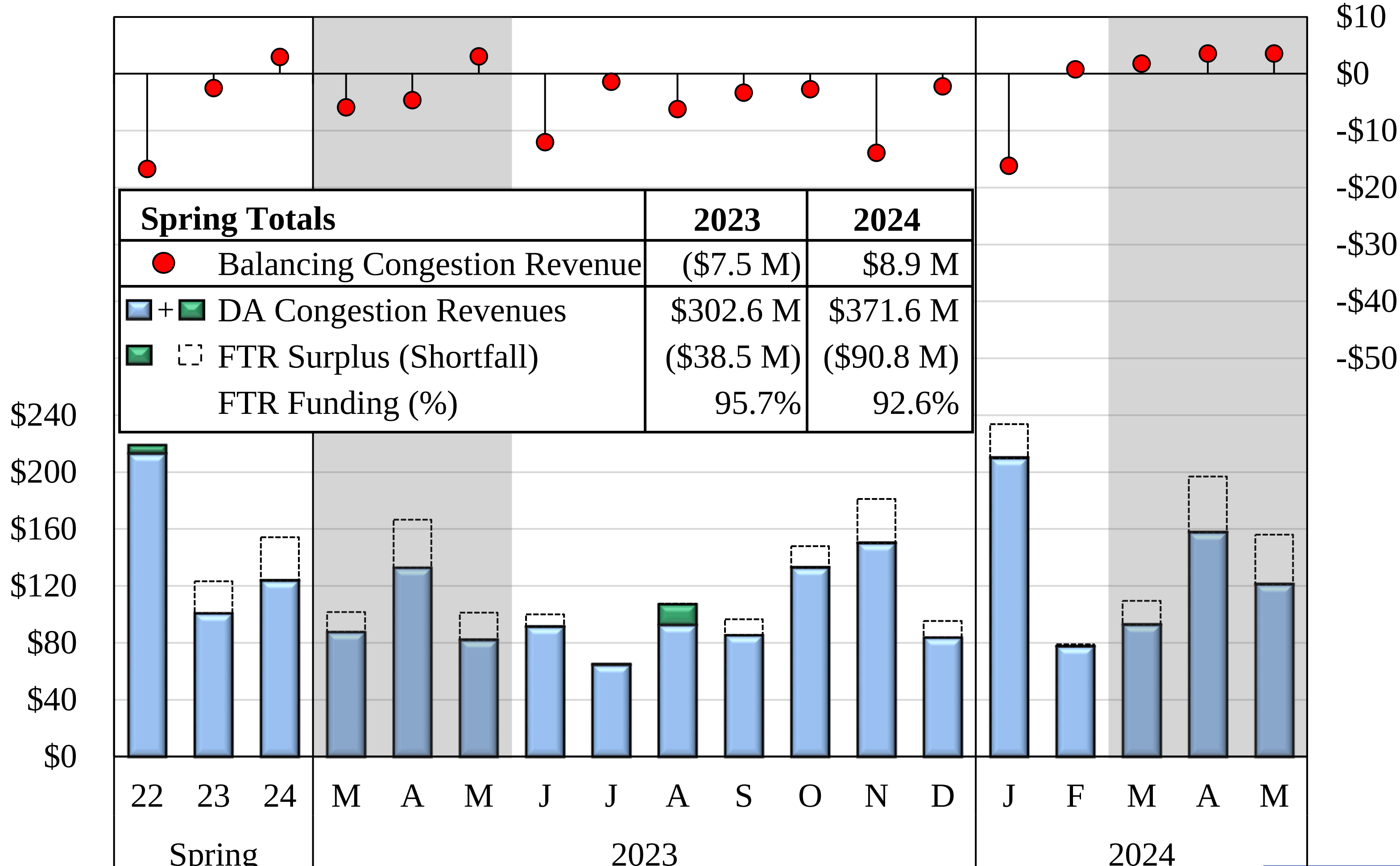
Zone 5 Capacity Clearing



Net Revenues by Technology 2023-2024

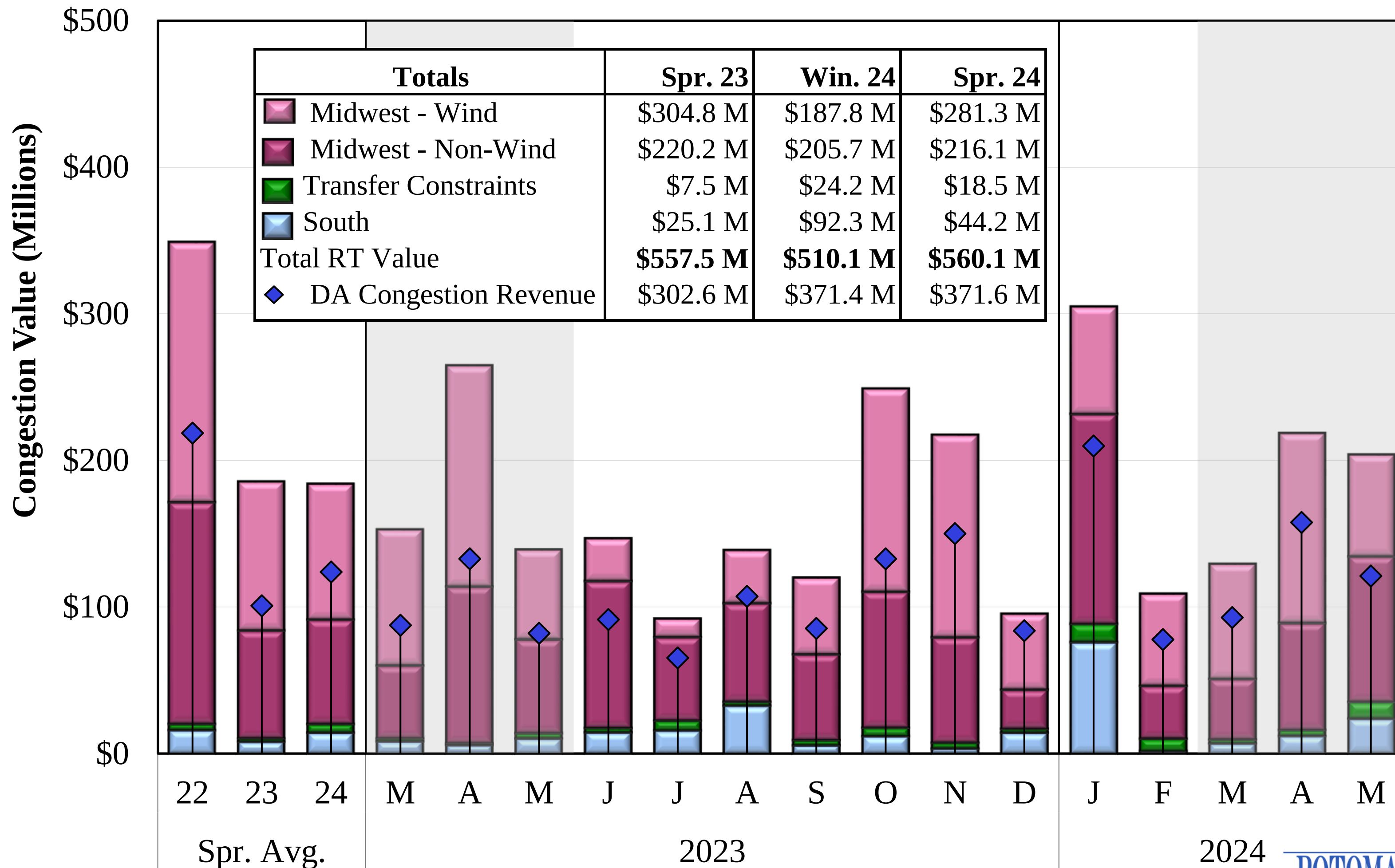


Day-Ahead Congestion, Balancing Congestion, and FTR Underfunding

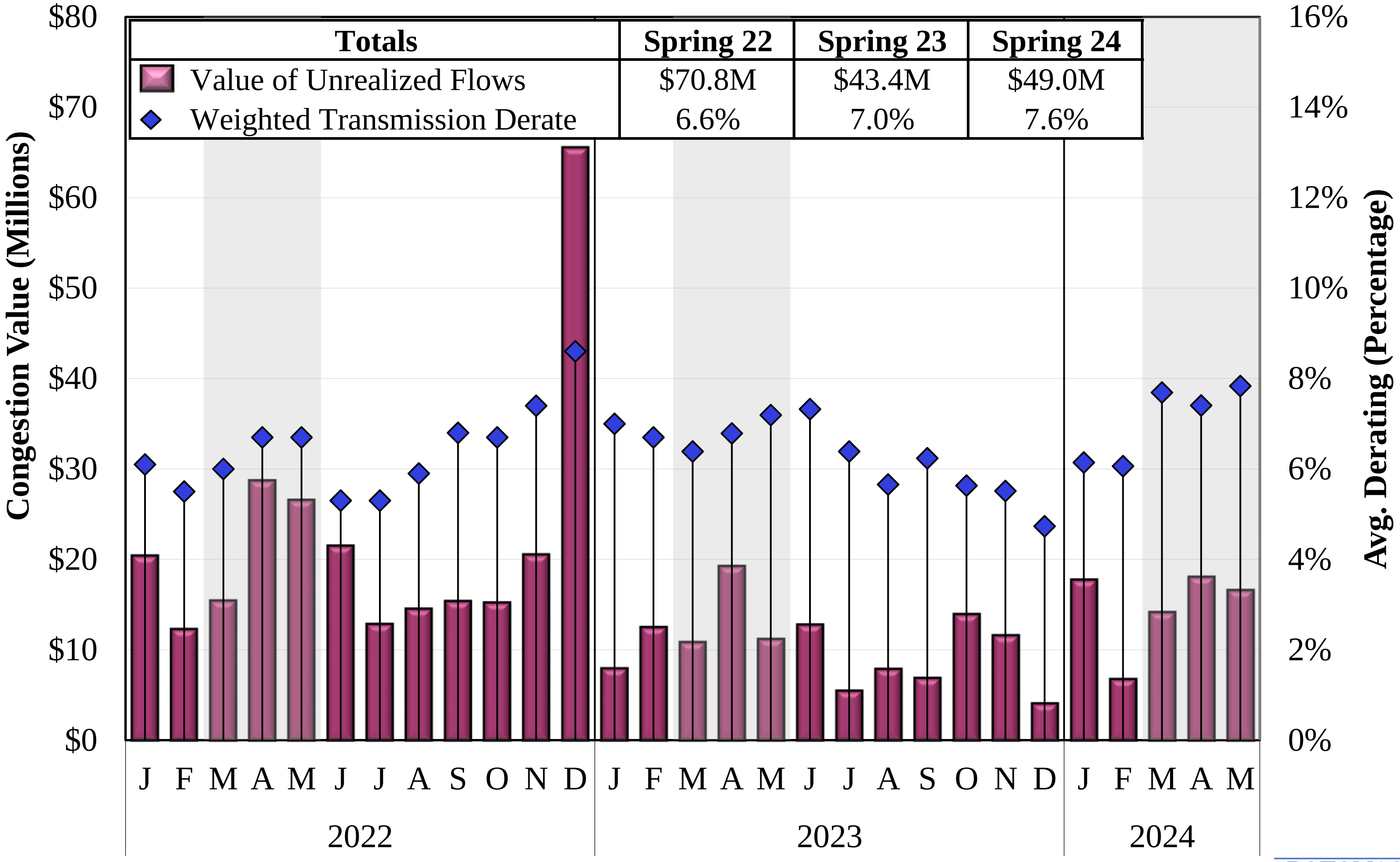


Spring Totals	2023	2024
Balancing Congestion Revenue	($7.5 M)	$8.9 M
DA Congestion Revenues	$302.6 M	$371.6 M
FTR Surplus (Shortfall)	($38.5 M)	($90.8 M)
FTR Funding (%)	95.7%	92.6%

Value of Real-Time congestion
Spring 2022-2024



Value of Unrealized Transmission Flows Due to Use of Limit Control



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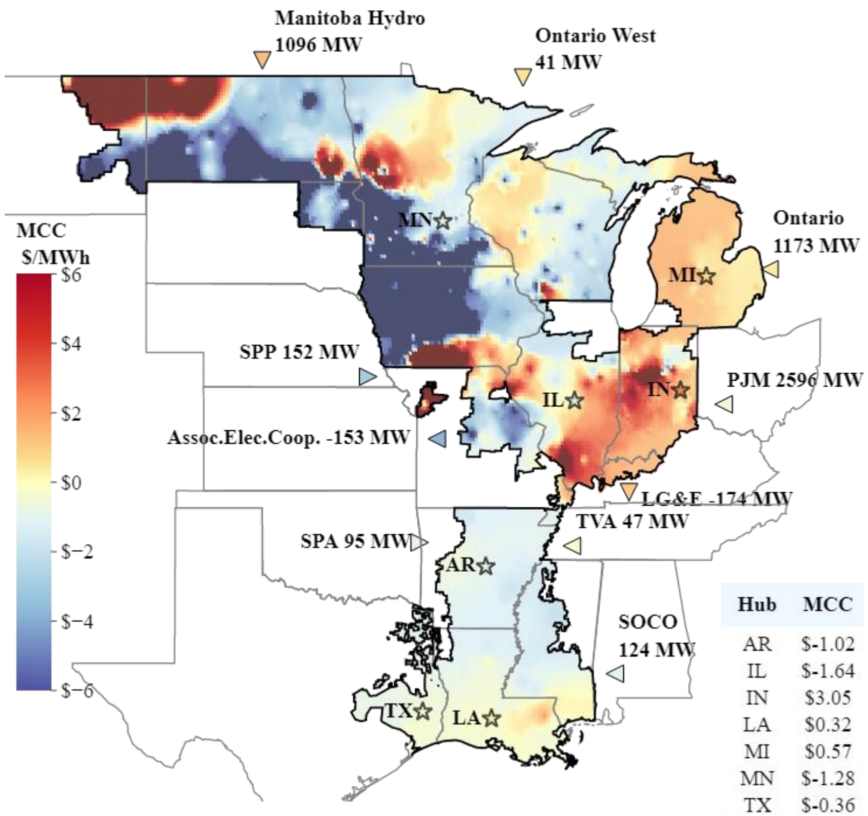
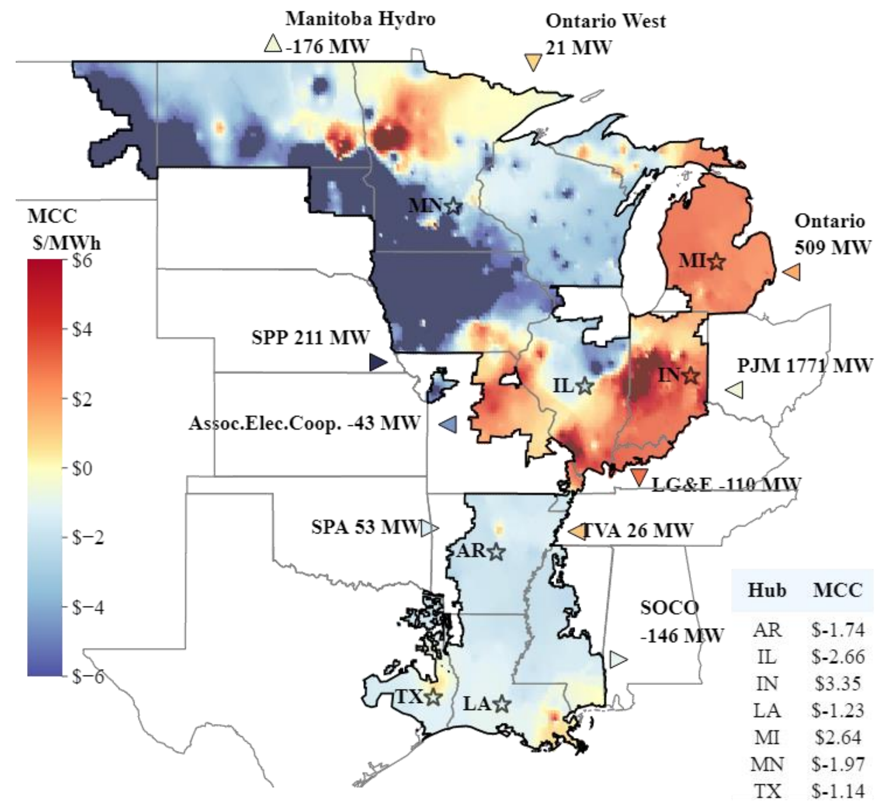
Average Real-Time Congestion Components
Spring 2023 – 2024

Spring 2023



Hub	MCC
AR	$-1.02
IL	$-1.64
IN	$3.05
LA	$0.32
MI	$0.57
MN	$-1.28
TX	$-0.36

Spring 2024



Hub	MCC
AR	$-1.74
IL	$-2.66
IN	$3.35
LA	$-1.23
MI	$2.64
MN	$-1.97
TX	$-1.14

Legend
Avg Interface Flows, MW
◀ Imports/Exports
★ Hubs

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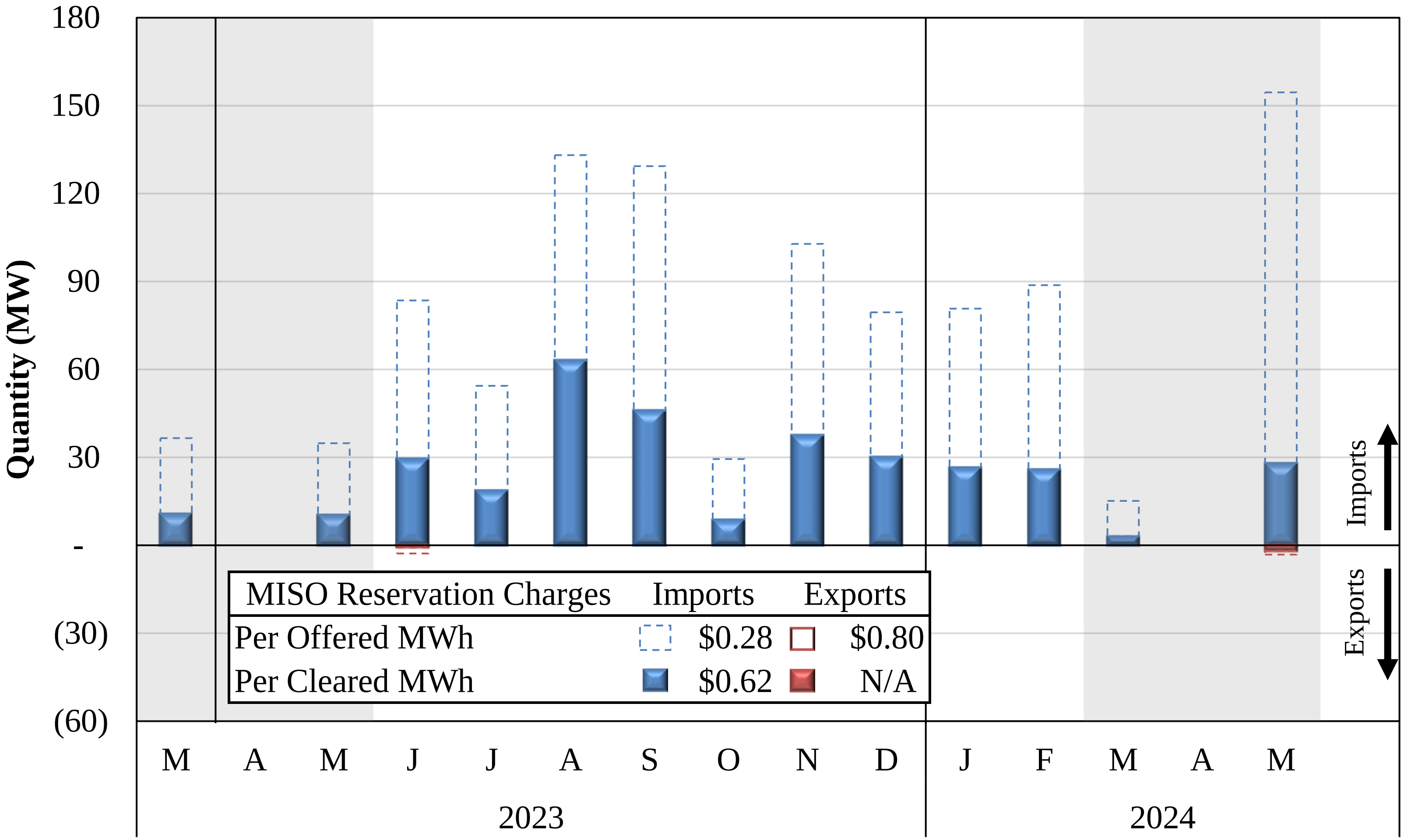
Benefits of Ambient-Adjusted and Emergency Ratings Spring 2023–2024

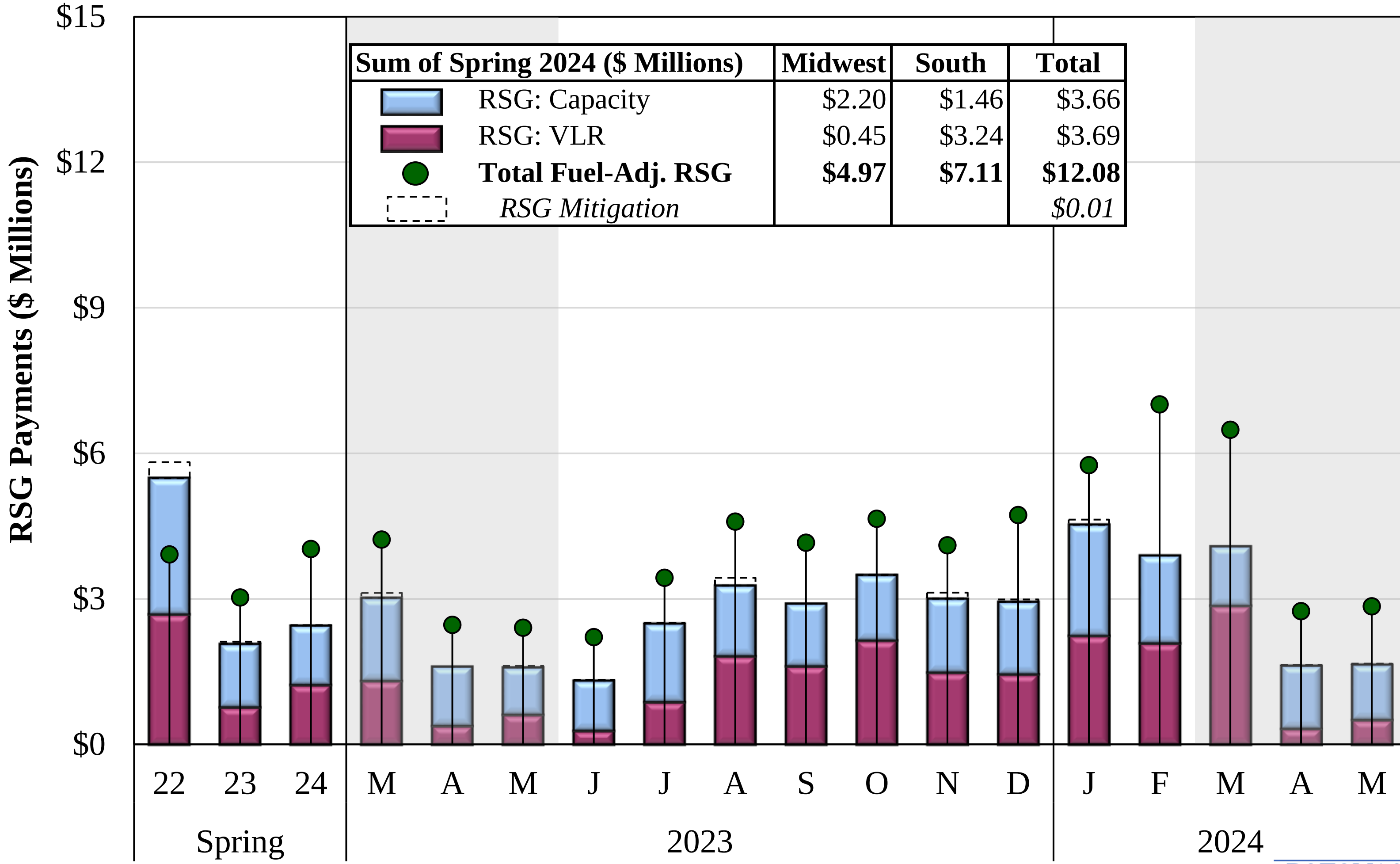
Spring		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2023	**Midwest**	$54.6	$30.09	$84.7	8	15.8%
	South	$0.3	$1.47	$1.8	1	6.1%
	Total	**$54.9**	**$31.6**	**$86.5**	**9**	**15.3%**
2024	**Midwest**	$39.2	$24.82	$64.0	15	12.1%
	South	$0.6	$1.81	$2.4	2	5.2%
	Total	**$39.9**	**$26.6**	**$66.5**	**17**	**11.5%**

POTOMAC ECONOMICS

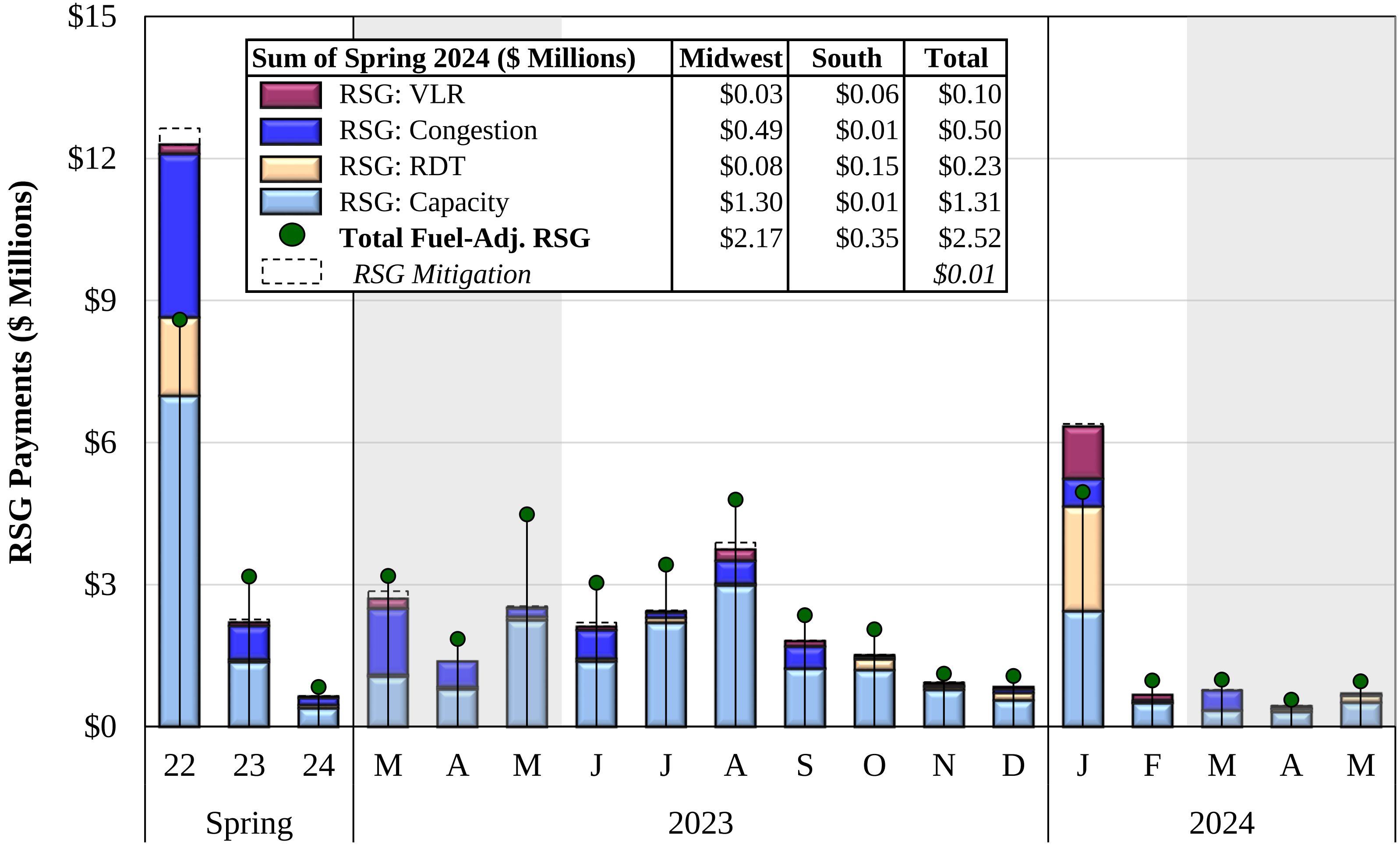
Coordinated Transaction Scheduling (CTS) Spring 2023–2024



Day-Ahead RSG Payments
Spring 2023–2024



Real-Time RSG Payments
Spring 2023–2024



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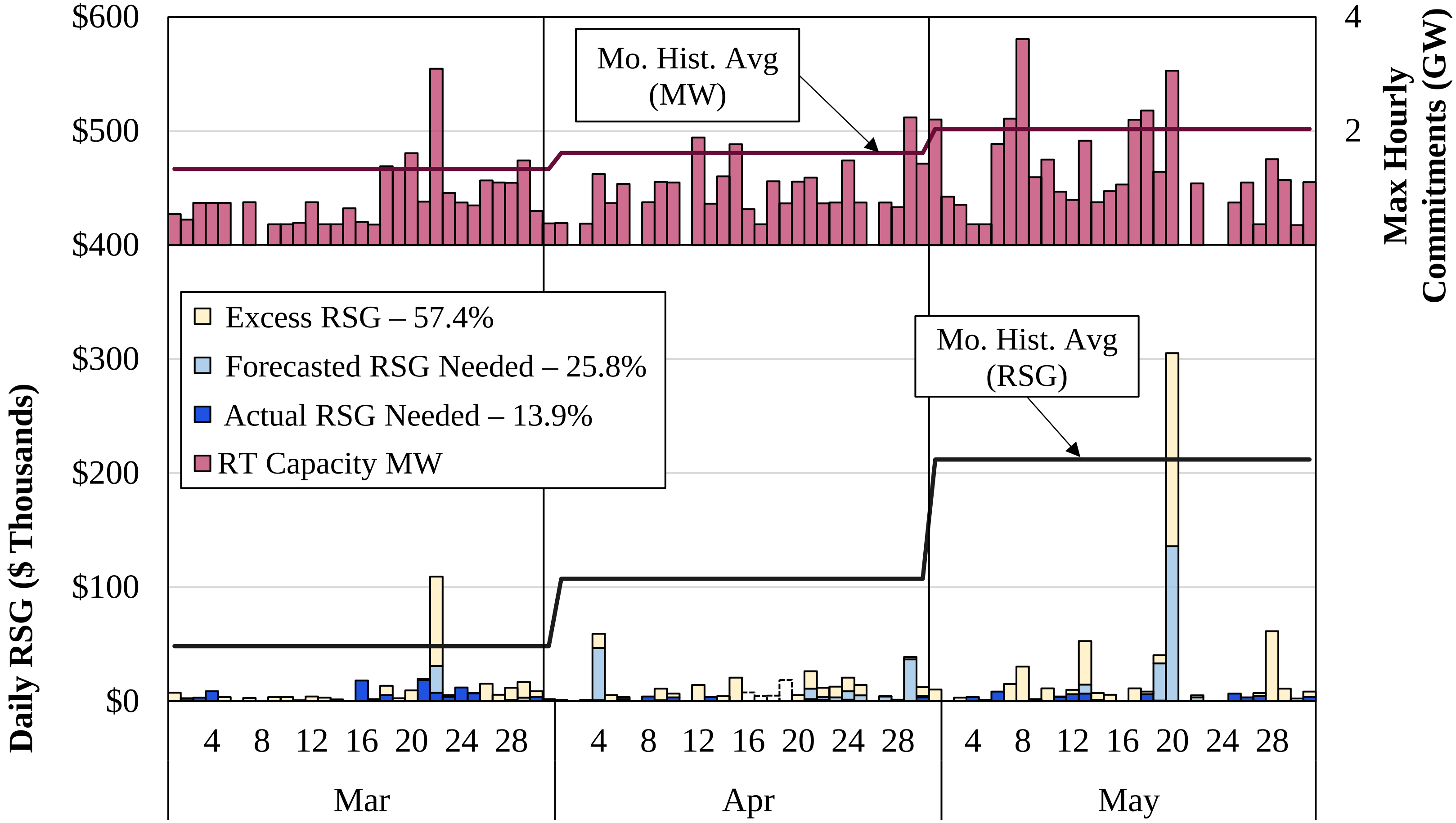
Real-Time Capacity Commitment and RSG Spring 2024



* <1% of the RSG could not be classified due to gaps in market data and is shown in the transparent bars.

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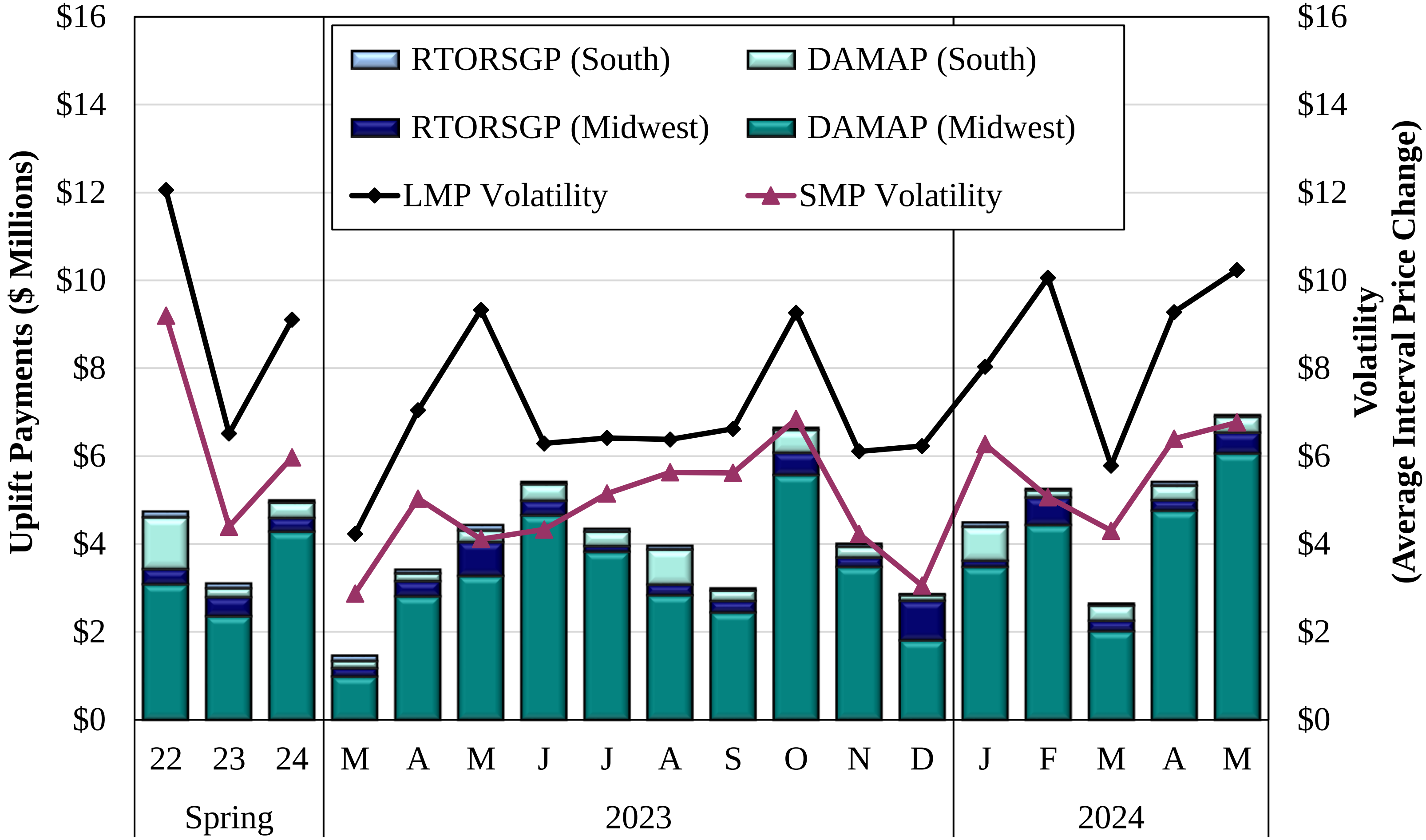
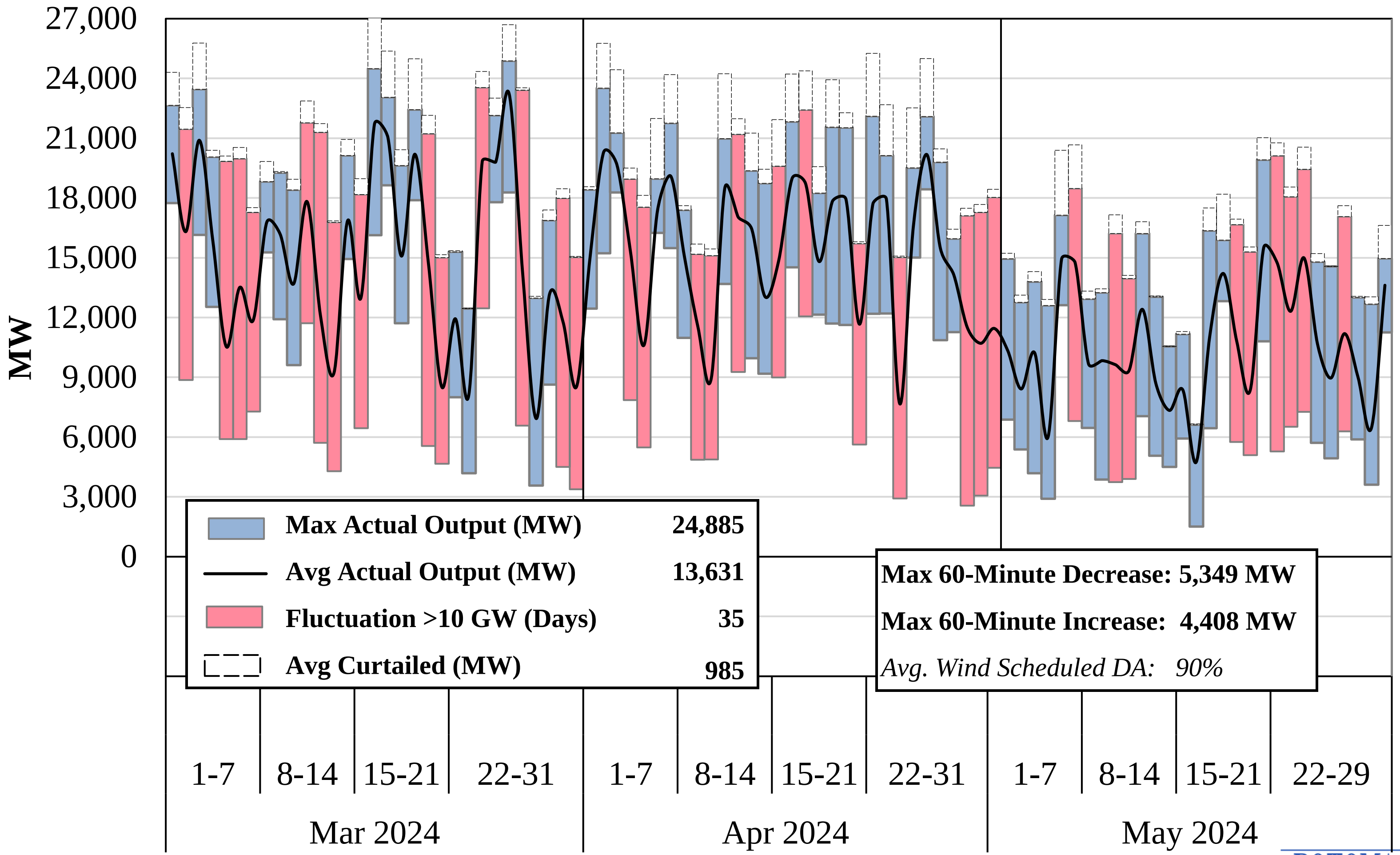
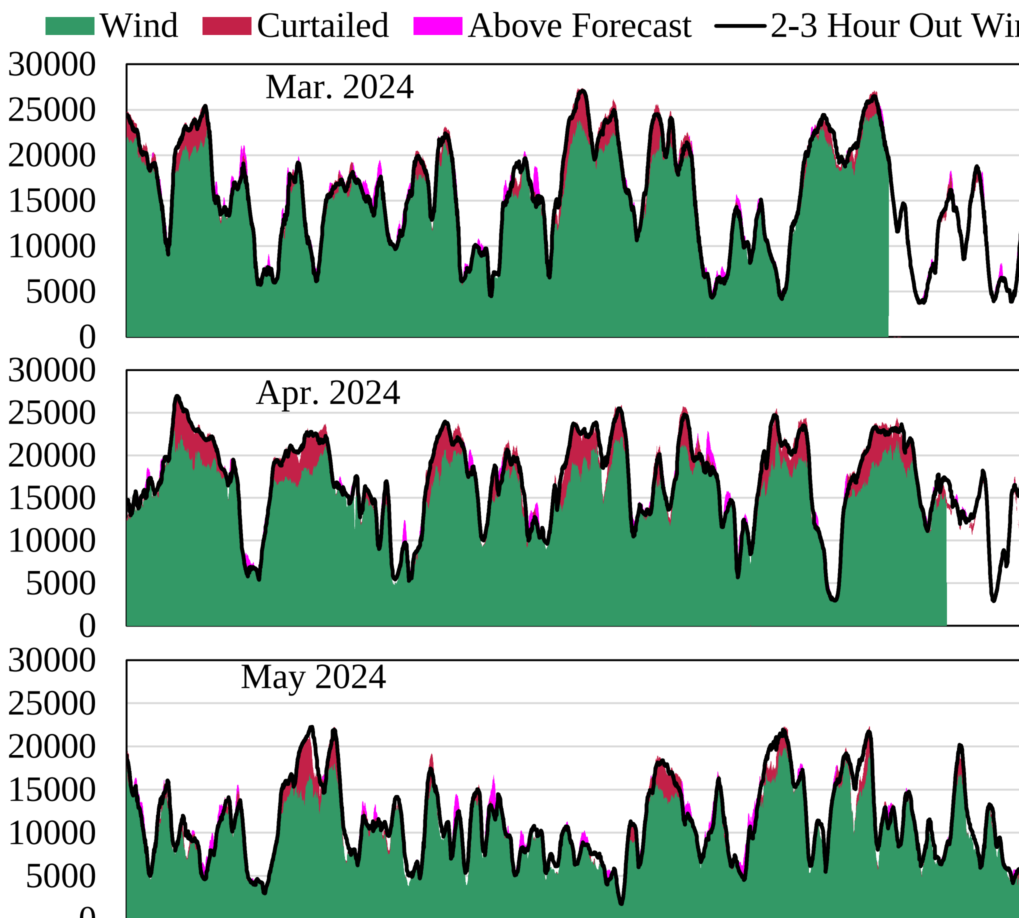
Price Volatility Make Whole Payments
Spring 2022–2024



Wind Output in Real Time
Daily Range and Average

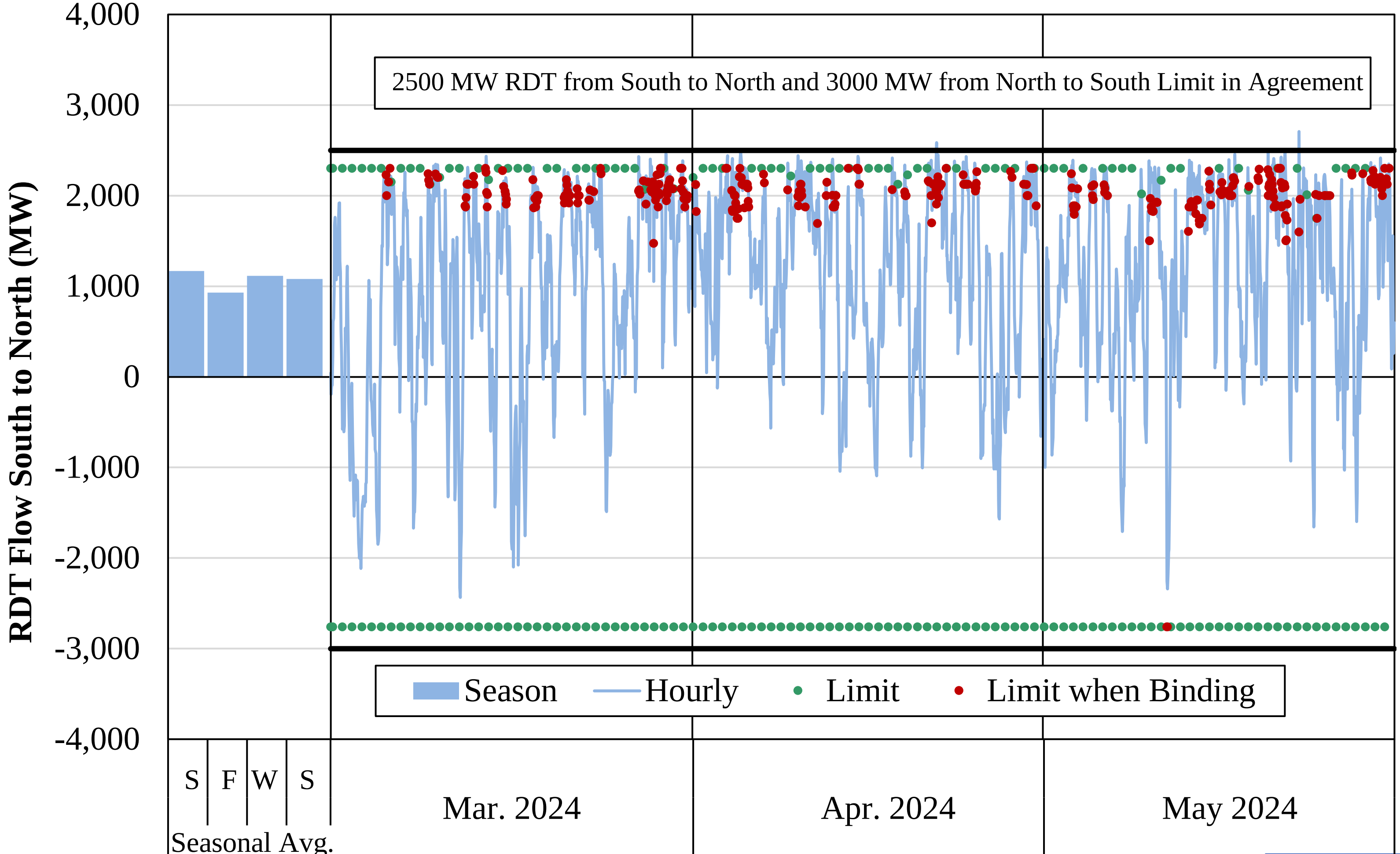


Wind Forecast and Actual Output
Spring 2024

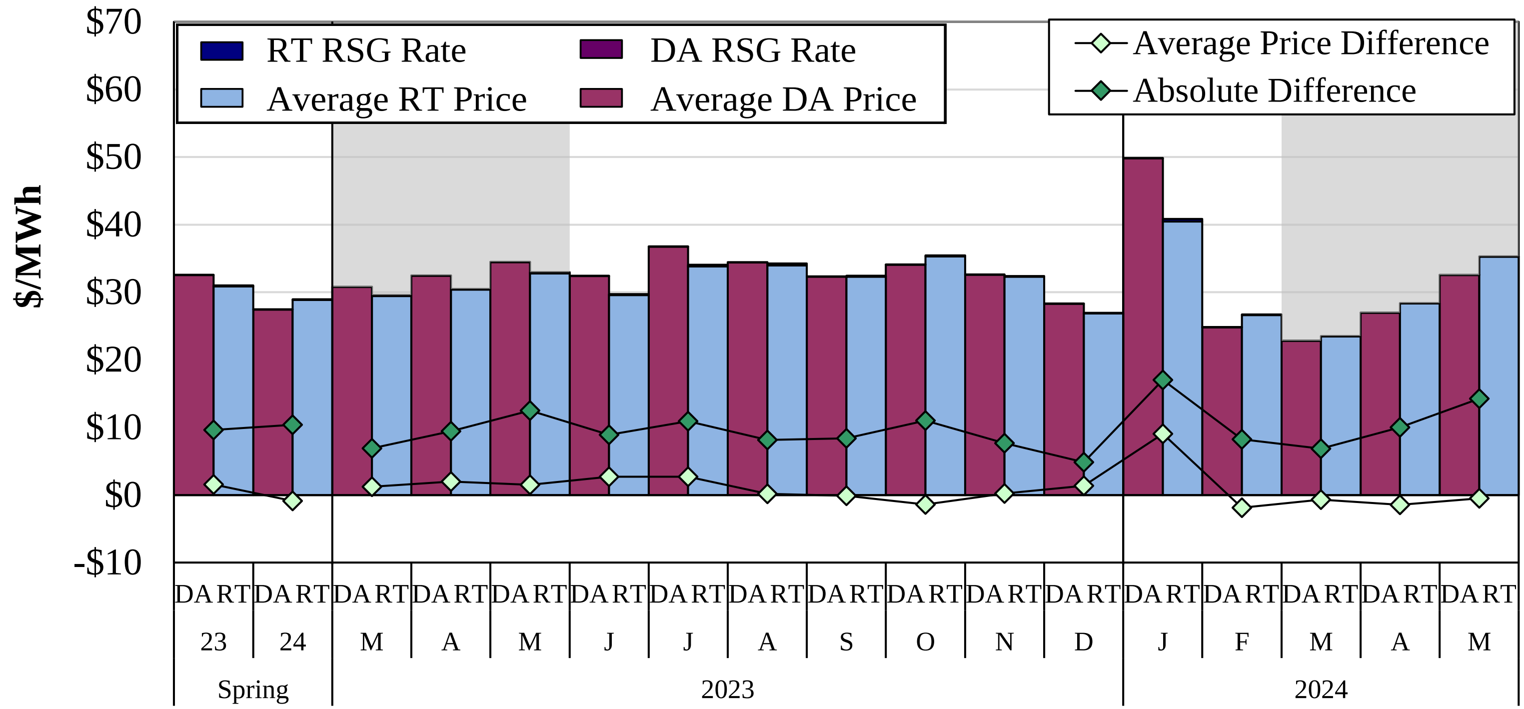


Spring 2024	
Real-Time Wind (MW)	13,631
Day-Ahead Wind (MW)	12,214
Avg Curtailments (MW)	985
Forecast Errors (%)	-0.7%
Absolute Errors (%)	7.7%
Spring 2023	
Real-Time Wind (MW)	12,324
Day-Ahead Wind (MW)	10,744
Avg Curtailments (MW)	910
Forecast Errors (%)	-1.2%
Absolute Errors (%)	7.0%
Winter 2024	
Real-Time Wind (MW)	11,792
Day-Ahead Wind (MW)	10,136
Avg Curtailments (MW)	402
Forecast Errors (%)	-0.9%
Absolute Errors (%)	8.2%

Real-Time Hourly Inter-Regional Flows Spring 2024



Day-Ahead and Real-Time Price Convergence Spring 2023–2024



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

Indiana Hub	5	-5	4	7	5	9	8	0	0	-4	1	5	22	-7	-3	-5	-8
Michigan Hub	4	-10	6	4	1	6	8	2	-5	-7	1	3	21	-5	-1	-4	-23
Minnesota Hub	-1	-5	-6	-10	13	-4	4	-6	-2	-3	7	1	5	-3	-5	-7	-2
Arkansas Hub	4	-4	5	0	5	6	5	2	-3	-4	3	5	14	-4	-3	-4	-6
Texas Hub	5	-4	5	5	4	7	11	4	3	-3	5	3	6	-2	-3	-1	-7
Louisiana Hub	3	-2	1	3	4	11	13	4	0	-3	6	3	13	-3	-3	-3	-1

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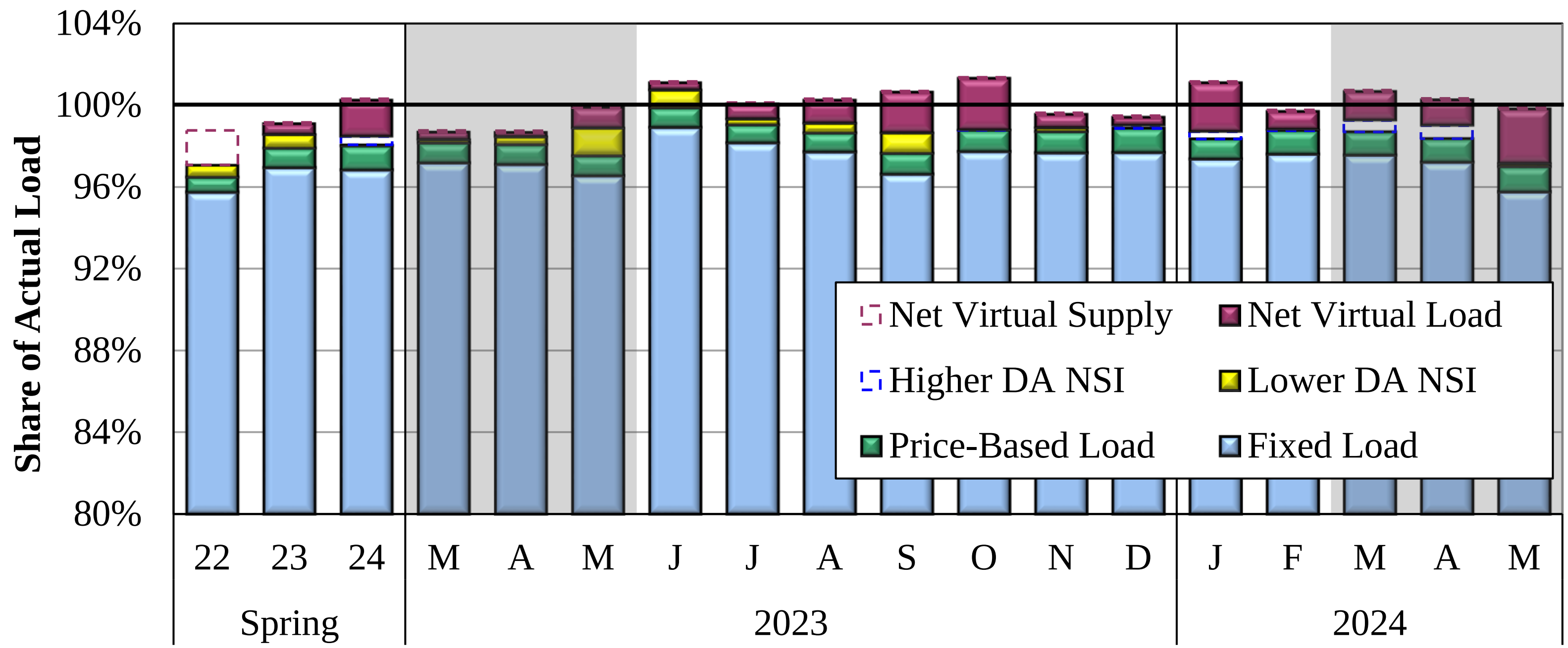
Day-Ahead Peak Hour Load Scheduling Spring 2022–2024



Share of Actual Load (%)

All Hours	97.4	99.3	99.8	98.9	99.1	99.7	101.0	101.6	101.0	100.6	100.3	99.1	98.6	100.5	99.2	99.1	99.3	101.0
Peak Hours Midwest	96.2	98.8	100.2	98.6	98.9	98.8	100.6	99.4	99.8	100.3	101.7	99.7	99.5	100.8	99.9	100.9	99.4	100.3
Peak Hours South	99.0	101.3	100.2	101.4	99.7	102.9	102.4	101.3	101.7	100.7	102.1	100.7	101.3	101.5	99.4	100.8	99.1	100.8

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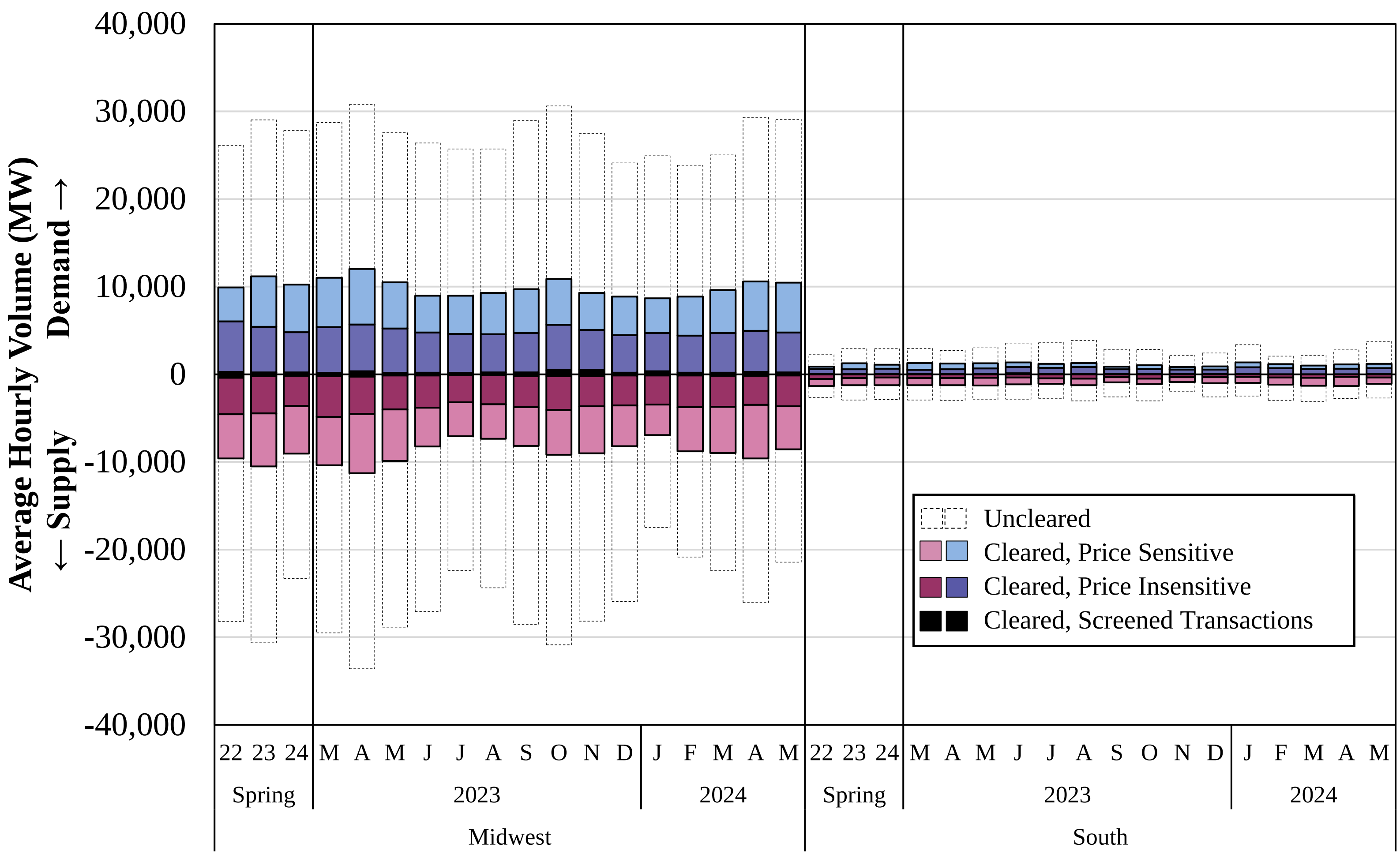
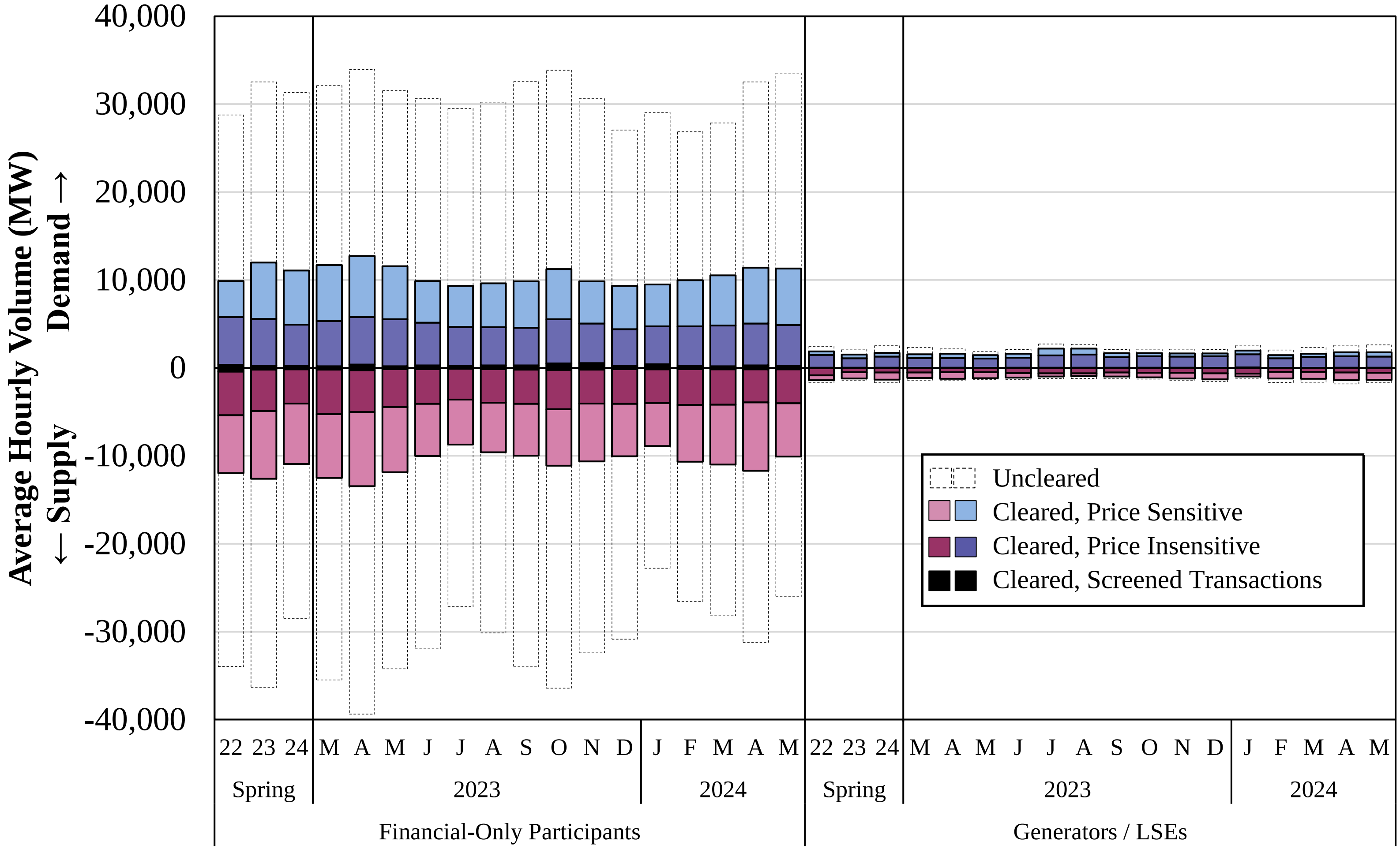
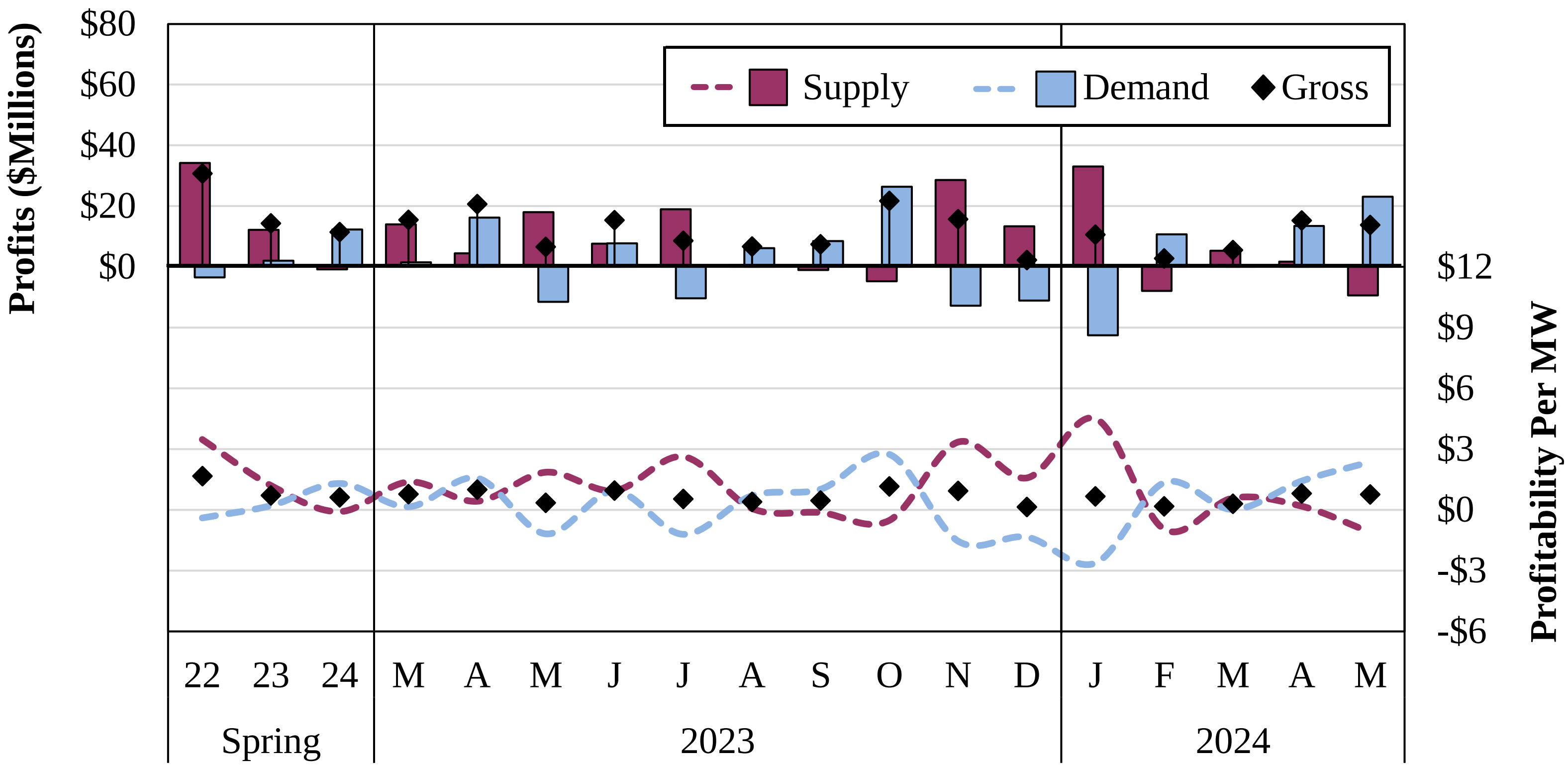
Virtual Load and Supply
Spring 2022–2024



Virtual Load and Supply by Participant Type Spring 2022–2024



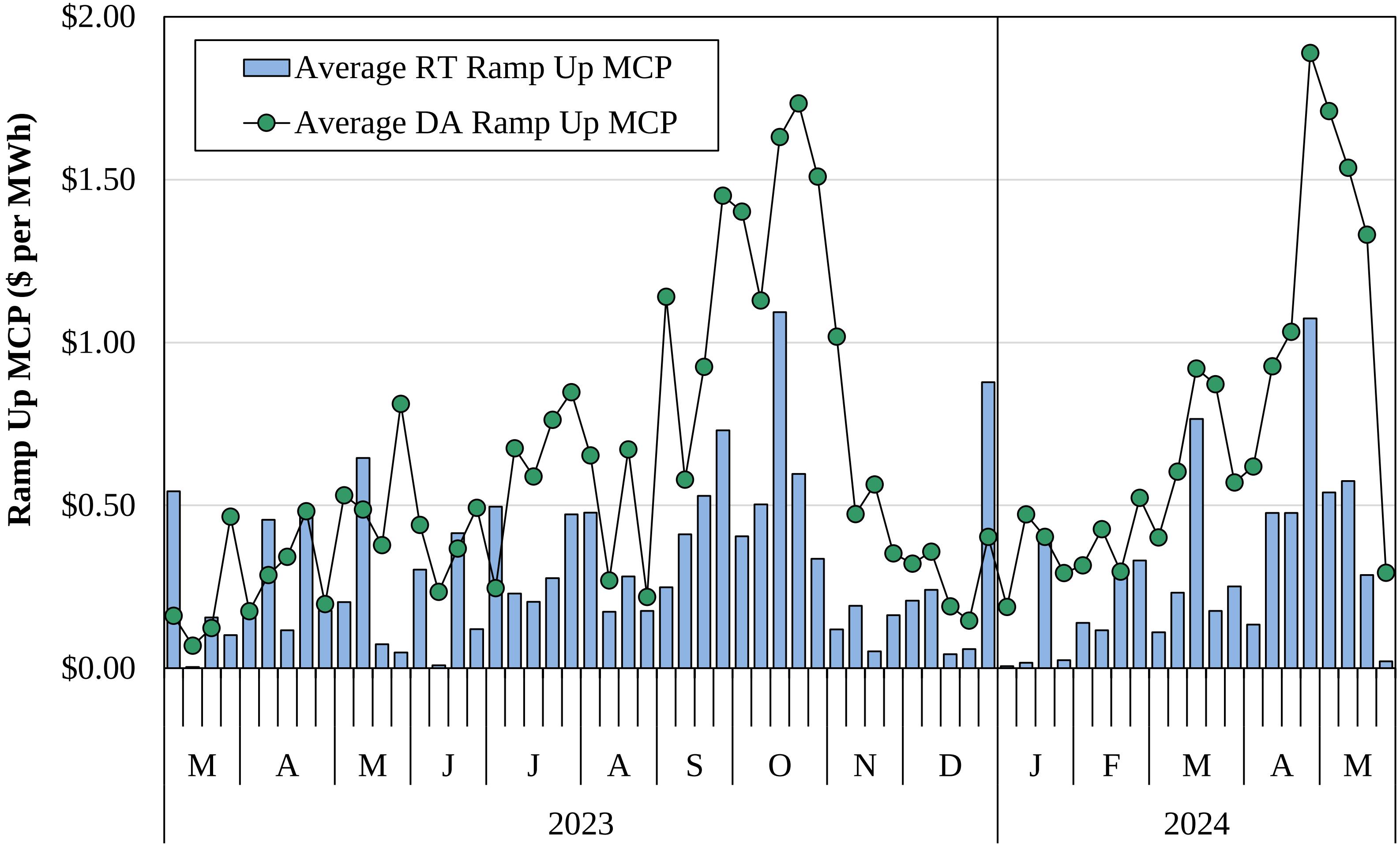
Virtual Profitability
Spring 2022–2024



Percent Screened

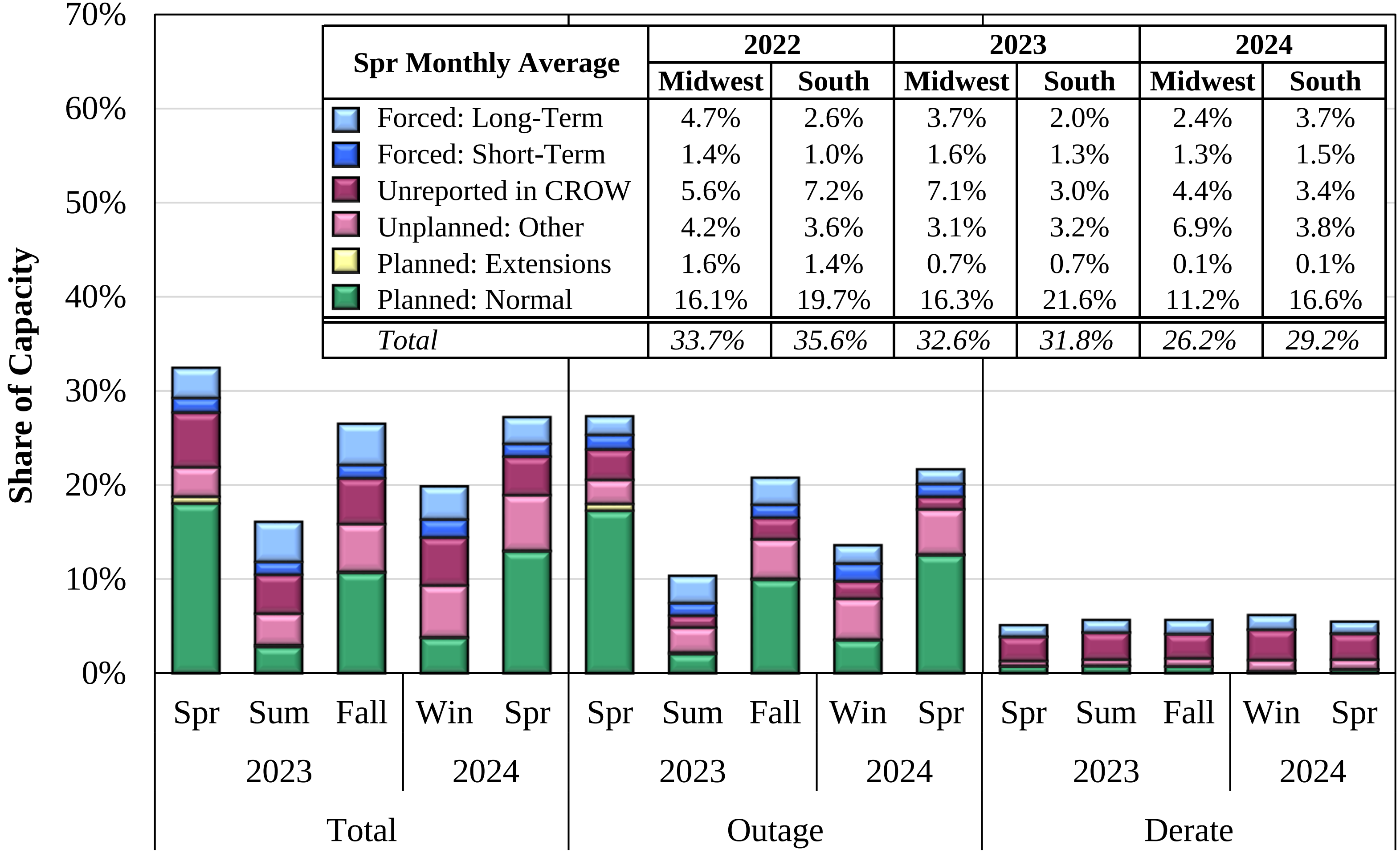
	22	23	24	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
Supply	3.4	1.5	1.4	1.5	1.9	1.0	1.4	1.0	1.2	2.0	1.9	1.9	1.3	1.7	1.2	1.6	1.3	1.5
Demand	3.2	2.0	2.0	1.4	2.8	1.6	2.7	2.1	2.7	2.6	4.2	4.9	2.0	4.3	2.1	1.6	2.3	2.0
Total	3.3	1.7	1.7	1.5	2.3	1.3	2.1	1.6	2.0	2.3	3.1	3.4	1.7	3.1	1.6	1.6	1.8	1.7

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



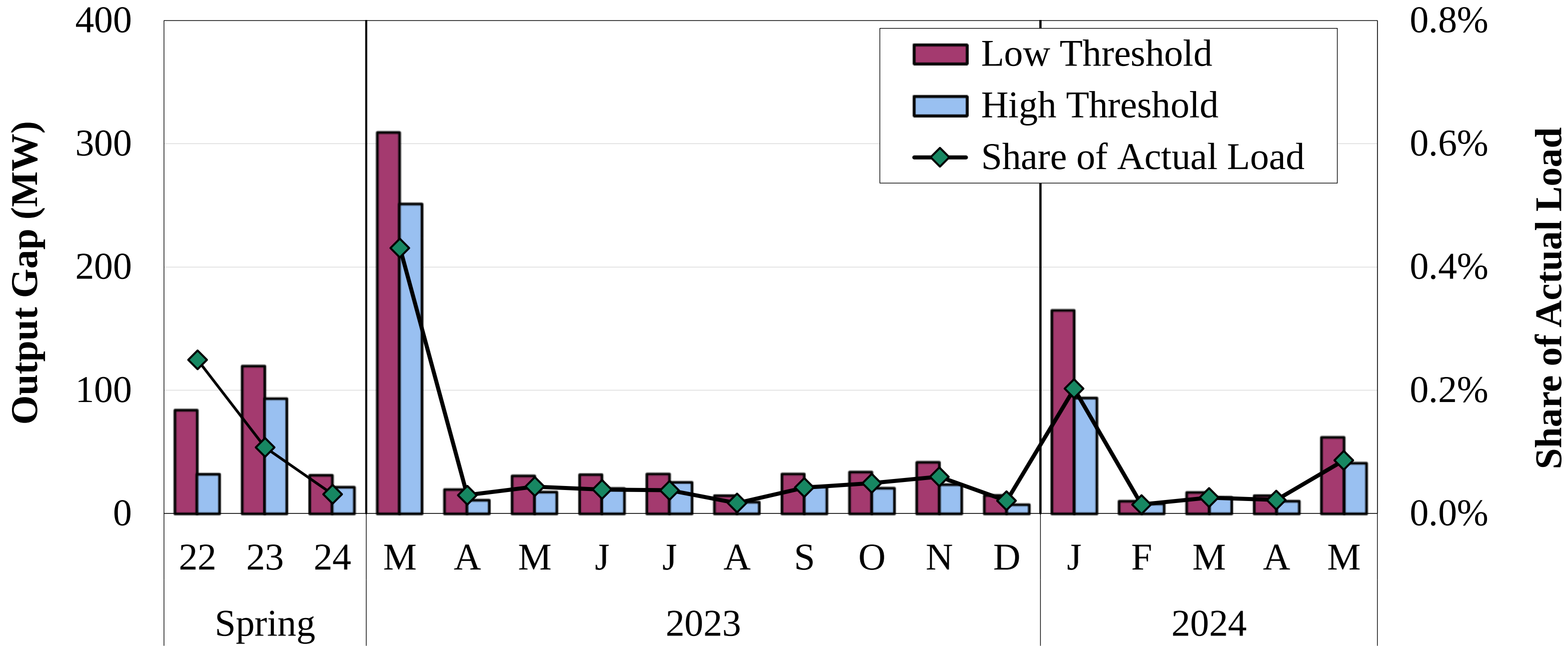
POTOMAC ECONOMICS

Generation Outages and Deratings
Spring 2022–2024



Spr Monthly Average	2022		2023		2024	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	4.7%	2.6%	3.7%	2.0%	2.4%	3.7%
Forced: Short-Term	1.4%	1.0%	1.6%	1.3%	1.3%	1.5%
Unreported in CROW	5.6%	7.2%	7.1%	3.0%	4.4%	3.4%
Unplanned: Other	4.2%	3.6%	3.1%	3.2%	6.9%	3.8%
Planned: Extensions	1.6%	1.4%	0.7%	0.7%	0.1%	0.1%
Planned: Normal	16.1%	19.7%	16.3%	21.6%	11.2%	16.6%
Total	*33.7%*	*35.6%*	*32.6%*	*31.8%*	*26.2%*	*29.2%*

Monthly Output Gap
Spring 2022–2024



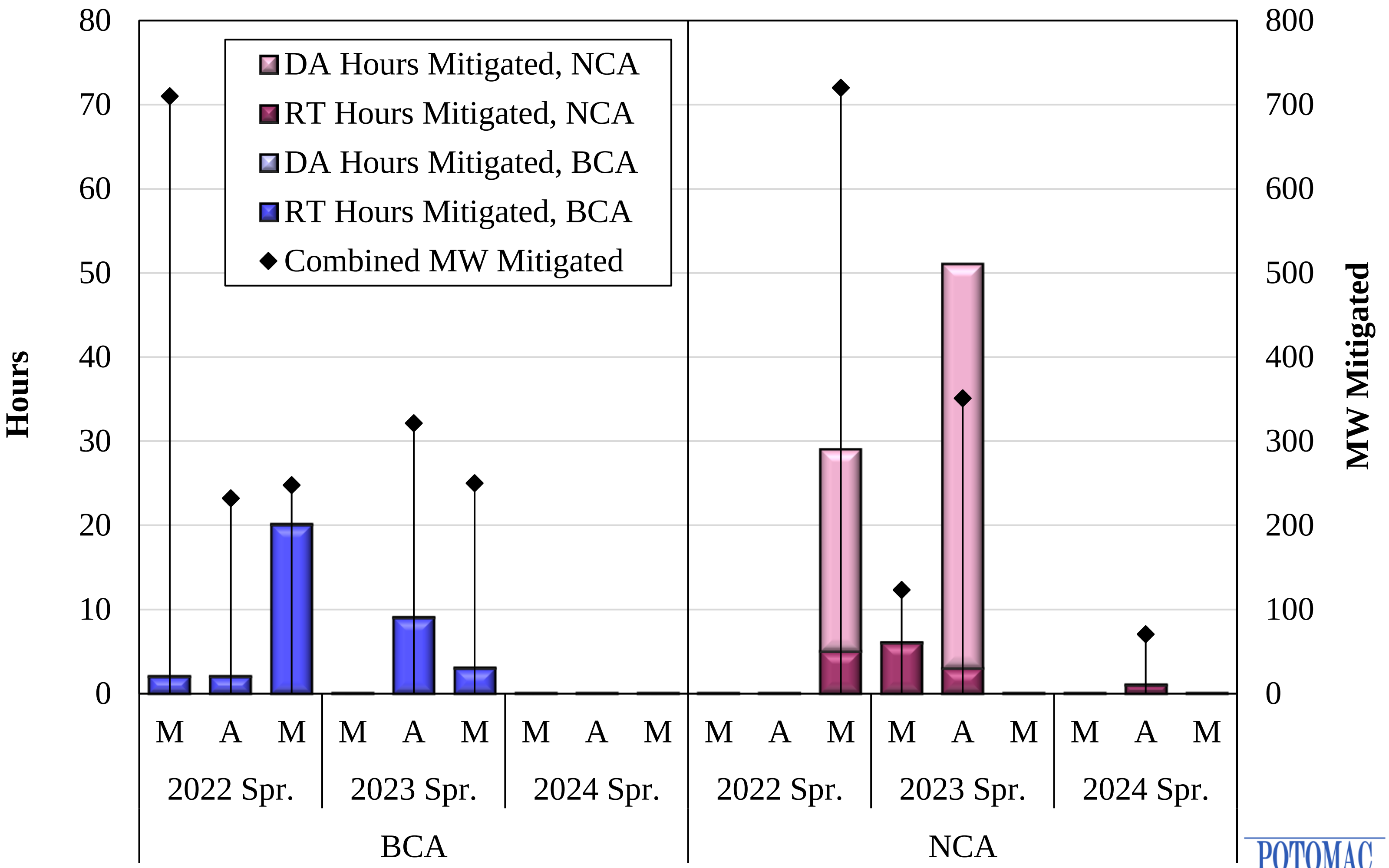
Low Threshold Results by Unit Status (MW)

Offline	47	112	23	301	11	23	22	23	6	25	17	27	4	98	3	8	6	56
Online	37	8	8	8	9	8	10	9	8	7	17	15	11	66	7	10	9	6

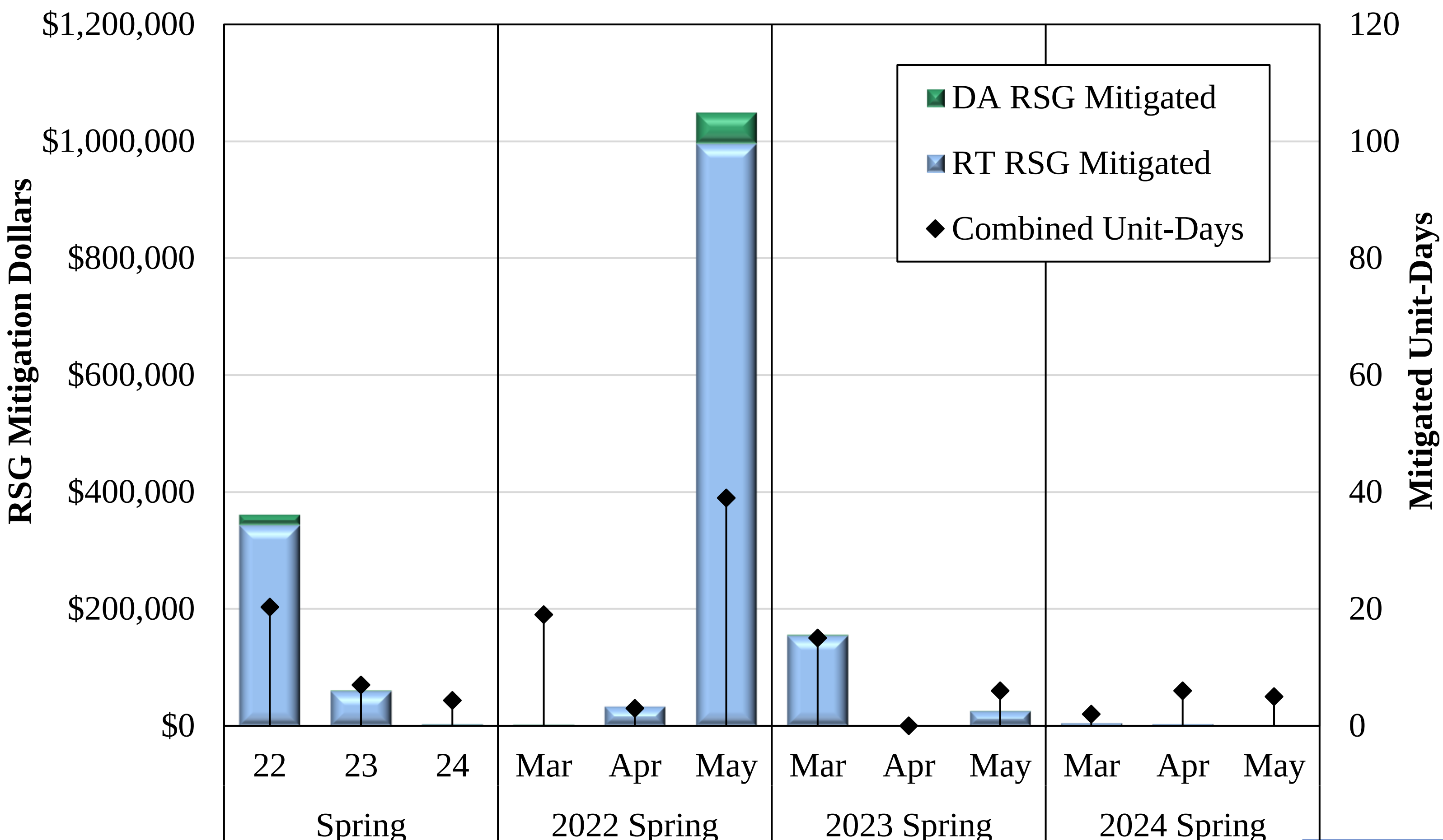
High Threshold Results by Unit Status (MW)

Offline	27	88	16	247	6	12	15	21	6	19	16	21	4	84	3	6	4	37
Online	5	5	6	4	5	6	5	5	4	3	5	3	3	9	6	7	6	4

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



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



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