IMM Quarterly Report: Spring 2023

MISO Independent Market Monitor

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Highlights and Findings: Spring 2023

- The MISO markets performed competitively this spring – market power mitigation was infrequent, and conduct was highly competitive overall.
- Energy prices fell by more than half over last spring because gas prices dropped by two thirds from the high levels seen last spring.
- Mild spring weather contributed to a 2 percent decrease in average load and 1 percent decrease in peak load.
- Day-ahead and real-time congestion fell 54 and 47 percent, respectively, consistent with the falling gas prices.
- MISO realized an 80 percent reduction in real-time RSG, a 59 percent reduction in day-ahead RSG and almost 40 percent reduction in DAMAP.
  - ✓ Falling gas prices, milder weather conditions, and the removal of the headroom requirement in the LAC engine were contributing factors.
- MISO's first seasonal capacity auction cleared at relatively low prices for each season, and prices ranged from $2 to $15 per MW-day in unconstrained zones.
  - ✓ The prices continue to be undermined by MISO's vertical demand curve.
  - ✓ Only Zone 9 in the South separated from the rest of the footprint, clearing at $59 per MW-day in the Fall season and $19 per MW-day in the Winter.

Quarterly Summary

Spring		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
RT Energy Prices ($/MWh)	Monitor/Discuss	$26.39	*-45%*	*-54%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago	Monitor/Discuss	$2.08	*-49%*	*-67%*
Natural Gas - Henry Hub	Monitor/Discuss	$2.19	*-43%*	*-66%*
Western Coal	Expected	$0.83	*-5%*	*-11%*
Eastern Coal	Expected	$2.88	*-42%*	*-43%*
Load (GW)[2]				
Average Load	Expected	69.7	*-8%*	*-2%*
Peak Load	Expected	103.2	*-4%*	*-1%*
% Scheduled DA (Peak Hour)	Expected	99.1%	98.4%	97.1%
Transmission Congestion ($M)				
Real-Time Congestion Value	Monitor/Discuss	$552.4	*-31%*	*-47%*
Day-Ahead Congestion Revenue	Monitor/Discuss	$302.6	*-4%*	*-54%*
Balancing Congestion Revenue[3]	Expected	$8.9	-$48.5	$50.2
Ancillary Service Prices ($/MWh)				
Regulation	Expected	$11.17	*-31%*	*-36%*
Spinning Reserves	Expected	$2.24	*-53%*	*-41%*
Supplemental Reserves	Expected	$0.21	*-93%*	*-56%*

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
FTR Funding (%)	Expected	92%	104%	101%
Wind Output (MW/hr)	Monitor/Discuss	12,324	*-1%*	*-4%*
Wind Curtailed (MW/hr)	Monitor/Discuss	910	*96%*	*-30%*
Guarantee Payments ($M)[4]				
Real-Time RSG	Monitor/Discuss	$7.4	*-79%*	*-80%*
Day-Ahead RSG	Monitor/Discuss	$6.2	*-47%*	*-59%*
Day-Ahead Margin Assurance	Monitor/Discuss	$8.0	*-74%*	*-38%*
Real-Time Offer Rev. Sufficiency	Expected	$1.8	*117%*	*26%*
Price Convergence[5]				
Market-wide DA Premium	Expected	1.9%	-15.7%	1.7%
Virtual Trading				
Cleared Quantity (MW/hr)	Expected	27,337	17%	9%
% Price Insensitive	Expected	44%	52%	54%
% Screened for Review	Expected	2%	2%	3%
Profitability ($/MW)	Expected	$0.7	$1.8	$1.7
Dispatch of Peaking Units (MW/hr)	Expected	1,599	761	771
Output Gap- Low Thresh. (MW/hr)	Expected	119	136	84

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 2023

<u>Falling Gas Prices and Associated Market Outcomes (Slides 14, 16, 19)</u>

- Gas prices fell by two thirds over last spring, impacting energy prices, coal resource dispatch, congestion, uplift, and resource net revenues.
  - ✓ Lower withdrawals from storage during the winter, lower domestic demand, fewer exports to Mexico, and increased production were contributing factors.
  - ✓ Storage levels were nearly 20 percent above average levels the previous 5 years.
- The change in the relative fuel prices between gas and coal year over year led gas resources to be more economic than coal that was more frequently marginal.
  - ✓ Coal and gas both accounted for 31 percent of energy output in 2022, while coal dropped to 24 percent and gas rose to 38 percent in 2023.
- The significant drop in natural gas prices affected resource scheduling and dispatch and led to lower net revenues across all resource classes.
  - ✓ Compared to last summer, net revenues this spring for coal, nuclear and wind have fallen by roughly 90 percent, 70 percent and 45 percent, respectively.
  - ✓ Coal supply constraints have eased up across the MISO footprint and no coal units currently have opportunity cost-based references.

Highlights for Spring 2023

<u>Congestion Patterns in MISO Footprint (Slides 20-23, 42)</u>

- Congestion in the MISO footprint fell to roughly $550 million, consistent with lower gas prices since gas units tend to be on the margin to manage constraints.
  - ✓ Wind continued to account for more than half the quarterly congestion, even though wind curtailments were 30 percent lower than last year.
- FTRs were not fully funded and realized a shortfall of more than $60 million.
  - ✓ Transmission outages that were moved and topology changes between MISO's FTR market and the day-ahead market contributed to the shortfalls.
- We estimated that $63 million, or 11 percent, of quarterly congestion could have been avoided were TOs to provide ambient-adjusted emergency ratings.
- We continue to note increasing transmission limit derates by MISO with its "limit control" parameter, which averaged almost 7 percent in the spring.
  - ✓ We calculated $40 million in congestion costs associated with the deratings, up 44 percent since spring 2021, even though gas prices are 17 percent lower.
  - ✓ Flow uncertainty on transmission constraints affected by wind volatility have contributed to the increase in limit control usage.

Highlights for Spring 2023

MRD, IMM Proposed Penalty for Not Following Dispatch (Slides 24-26)

- MISO has increasingly relied on manual out-of-market actions, such as manual re-dispatch (MRD) of resources, to manage transmission constraints.
  - ✓ Operational concerns with wind units not following dispatch is accelerating and often leads operators to MRD them – they benefit by receiving DAMAP.
- Wind resources often have little incentive to follow dispatch.
  - ✓ MISO's current penalty provisions exempt resources from penalties for setpoint deviations less than 20 minutes outside the UD tolerance thresholds.
  - ✓ When penalties do apply, resources exceeding their dispatch targets are paid at the lower of the LMP and the resources' as-offered costs, which is not punitive.
- We propose a new deviation penalty to charge the congestion component of a resource's LMP when not following setpoint and loading a constraint.
  - ✓ This is aligned with reliability concerns of the conduct – *constraint violations*.
  - ✓ Units exceeding dispatch targets would be charged a rising portion the MCC – e.g., 25% of MCC for deviation in interval 1 rising to 100% in interval 4.
  - ✓ Our analysis of this proposal shows that it would have produced penalties of more than $3 million for wind units ($41/MWh of deviations) in 2022, but very small penalties for all other resources.

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Highlights for Spring 2023

IMM Summer Assessment (Slide 18)

- 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 19.2 percent, which includes more than 12 GW of emergency-only capacity.
  - ✓ Including typical forced outages of almost 7 GW and average non-firm imports in peak periods of 5 GW produces a projected capacity margin of 17.5 percent.
  - ✓ These levels exceed MISO planning requirements.
- Considering planned outages observed in past summers and demand response likely to be unavailable, the estimated capacity margin falls to 6.8 percent.
- We also evaluate hotter than normal 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 8.1 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.

Highlights for Spring 2023

<u>Seasonal Planning Resource Auction Results (Slide 17)</u>

- MISO implemented its first seasonal PRA in May after a delay because FERC required MISO to correct its availability accreditation values.
- The auction cleared $2 per MW-day in the winter and $15 per MW-day in the fall, while the spring and summer seasons cleared at $10 per MW-day.
  - ✓ The Local Clearing Requirement (LCR) in Zone 9 was binding in the Fall and Winter quarters, which cleared at $59 and $19 per MW-day, respectively.
- Prices cleared much lower than the CONE of $237 per MW-day set last year in the Midwest because of: (a) a 6 GW rise in net summer capacity this planning year and (b) the flawed vertical demand curve used in the PRA:
  - ✓ 2.1 GW decrease in requirements from lower peak load forecasts and a lower planning reserve margin (“PRM”);
  - ✓ 1.1 GW addition of new thermal capacity that offset 0.9 GW of retirements;
  - ✓ 640 MW new solar, 450 MW new wind, and 740 MW increase in existing wind capacity (from procuring more firm deliverability); and
  - ✓ 1.1 GW increase in LMRs – mostly external resources and demand response.
- These changes in net capacity are hard to predict year-to-year.

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Highlights for Spring 2023

<u>Seasonal Planning Resource Auction Results (Slide 17)</u>

- Some aspects of the new seasonal capacity market could be improved:
  - ✓ The penalty applied to resources on outage for more than 31 days of the season raises concerns because:
    - – Resources out the whole season can have the incentive to participate; and
    - – Resource’s have incentives to straddle seasons to avoid the penalty.
  - ✓ The sequencing of the seasonal auctions and lack of annual parameters can make it challenging for participants to represent their costs efficiently.
  - ✓ We will be working with MISO to consider improvements to address these aspects of the market.
- The seasonal market is still not designed to send efficient price signals to meet MISO’s reliability needs – improvements underway to address this include:
  - ✓ A reliability-based demand curve (RBDC); and
  - ✓ Improving accreditation of resources to reflect their marginal reliability value.

Submittals to External Entities and Other Issues

- We responded to several FERC questions related to prior referrals and FERC investigations, and we responded to requests for information on market issues.
  - ✓ We referred a transmission owner to FERC for failing to report planned transmission outages that resulted it acquiring unwarranted FTRs.
- We presented Spring market results to the MSC and the ERSC.
- We continue to meet with states and participants on reforming MISO’s PRA demand curve and implement marginal accreditation of non-thermal resources.
- We continued to meet with MISO on recommended operational improvements and produced memos and summarizes of the recommendations.
- We participated in meeting of international market monitors in May and U.S. market monitors at FERC in May and June.
- We continue to evaluate the LRTP benefit-cost analysis for the upcoming tranches and discussing improvements with MISO so the LRTP:
  - ✓ Results in economic investments that avoid inefficient costs for MISO’s customers; and
  - ✓ Does not undermine the performance of the wholesale markets.

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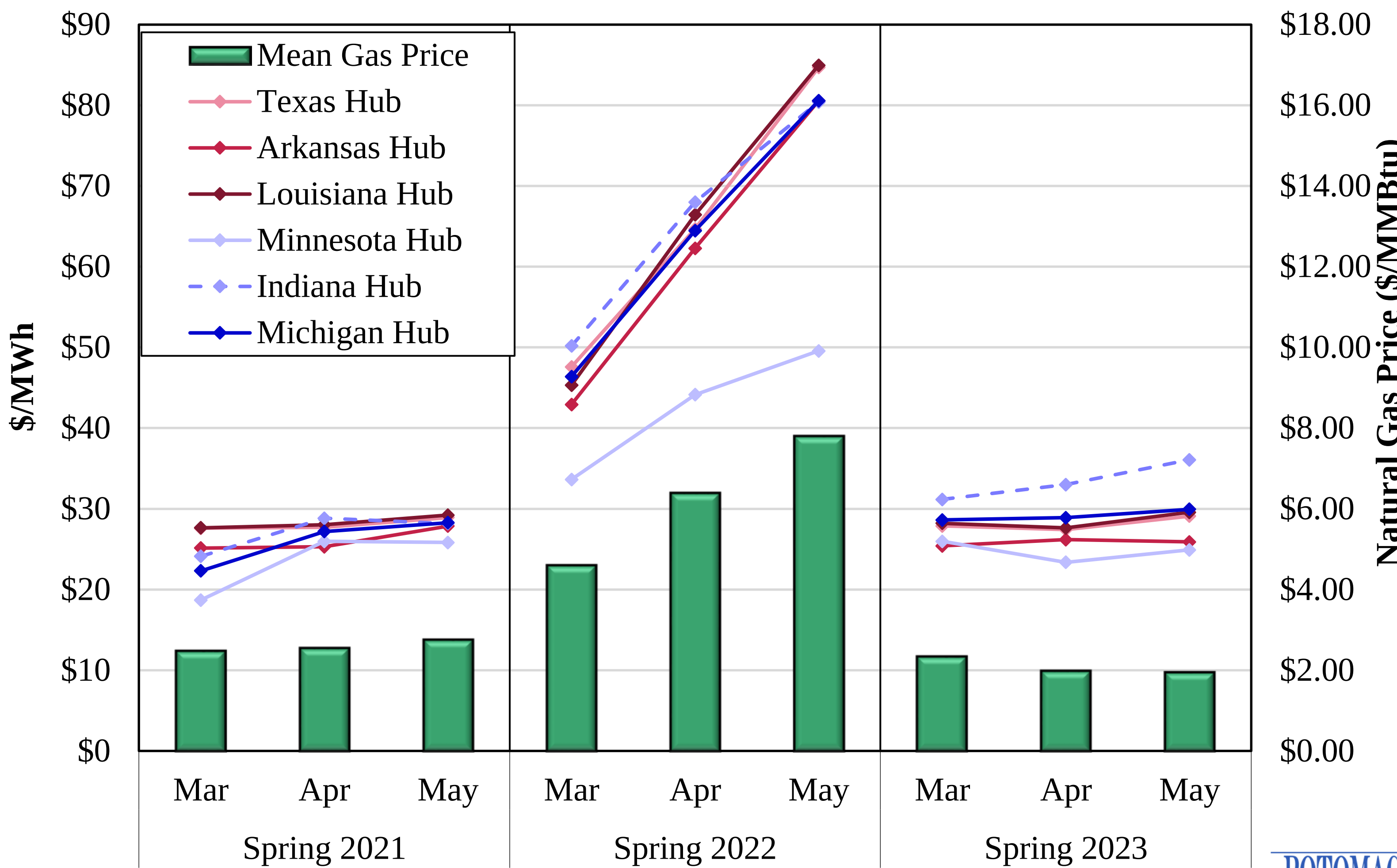
Day-Ahead Average Monthly Hub Prices Spring 2021–2023



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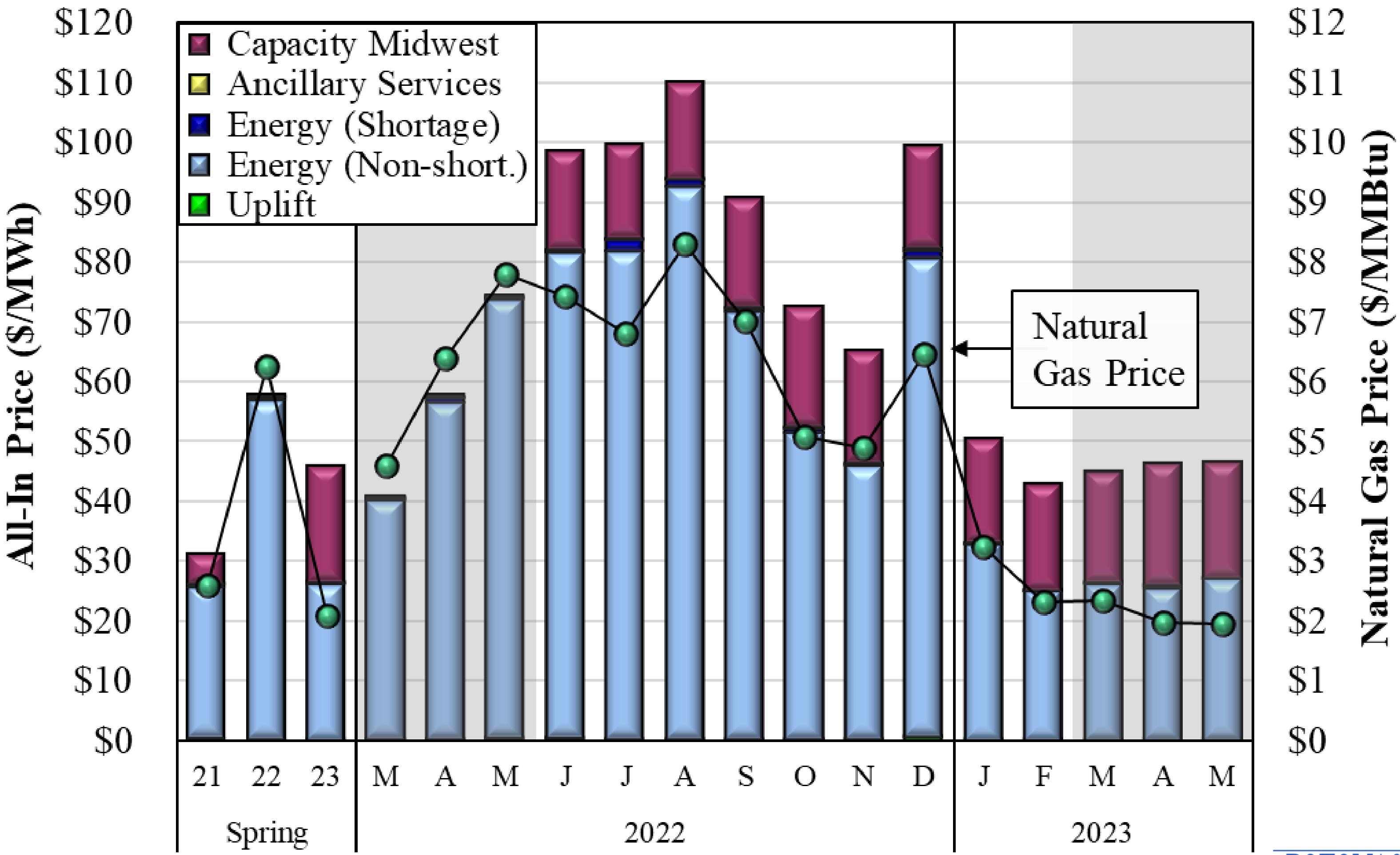
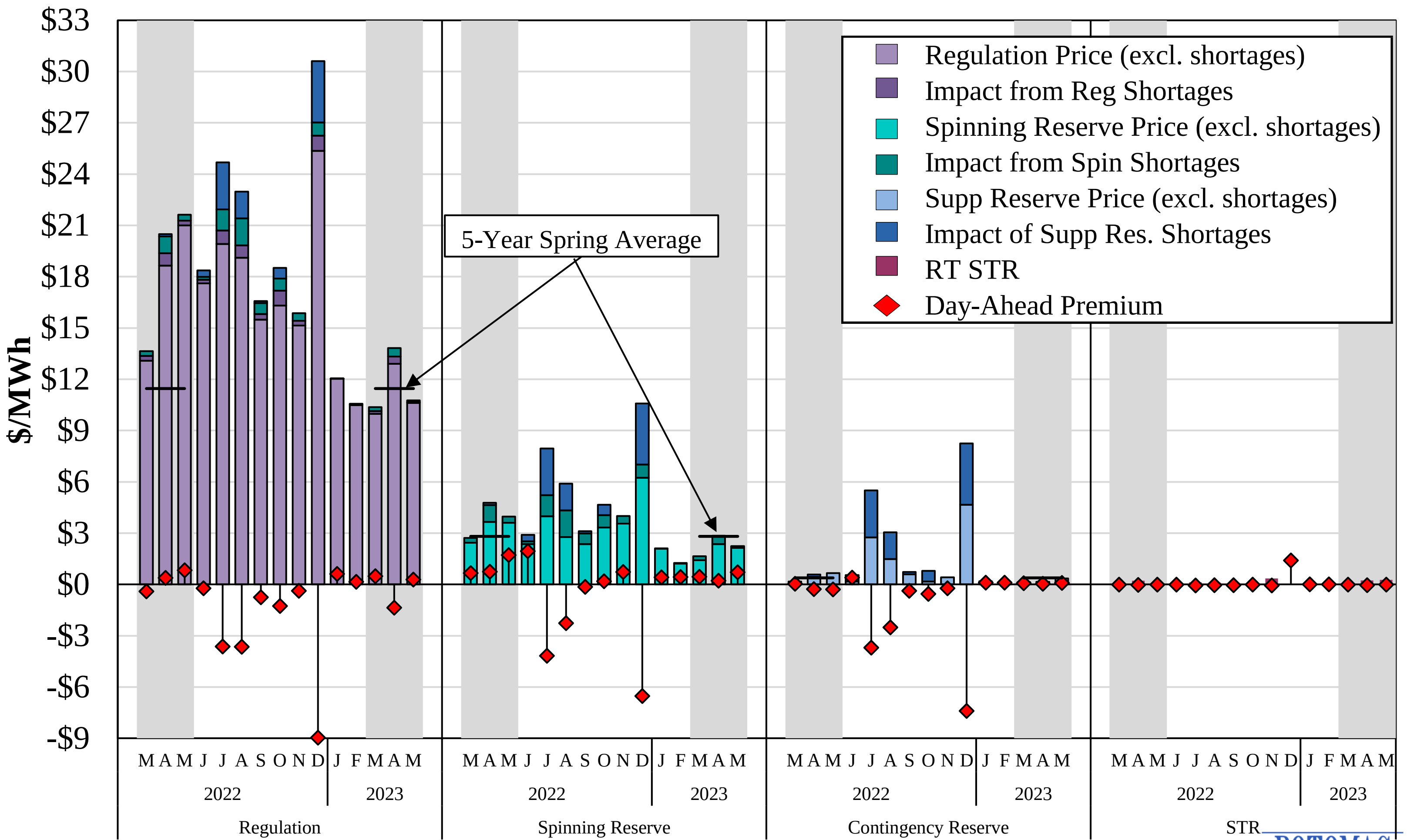
All-In Price
Spring 2021 – 2023



Ancillary Services Prices
Spring 2022–2023



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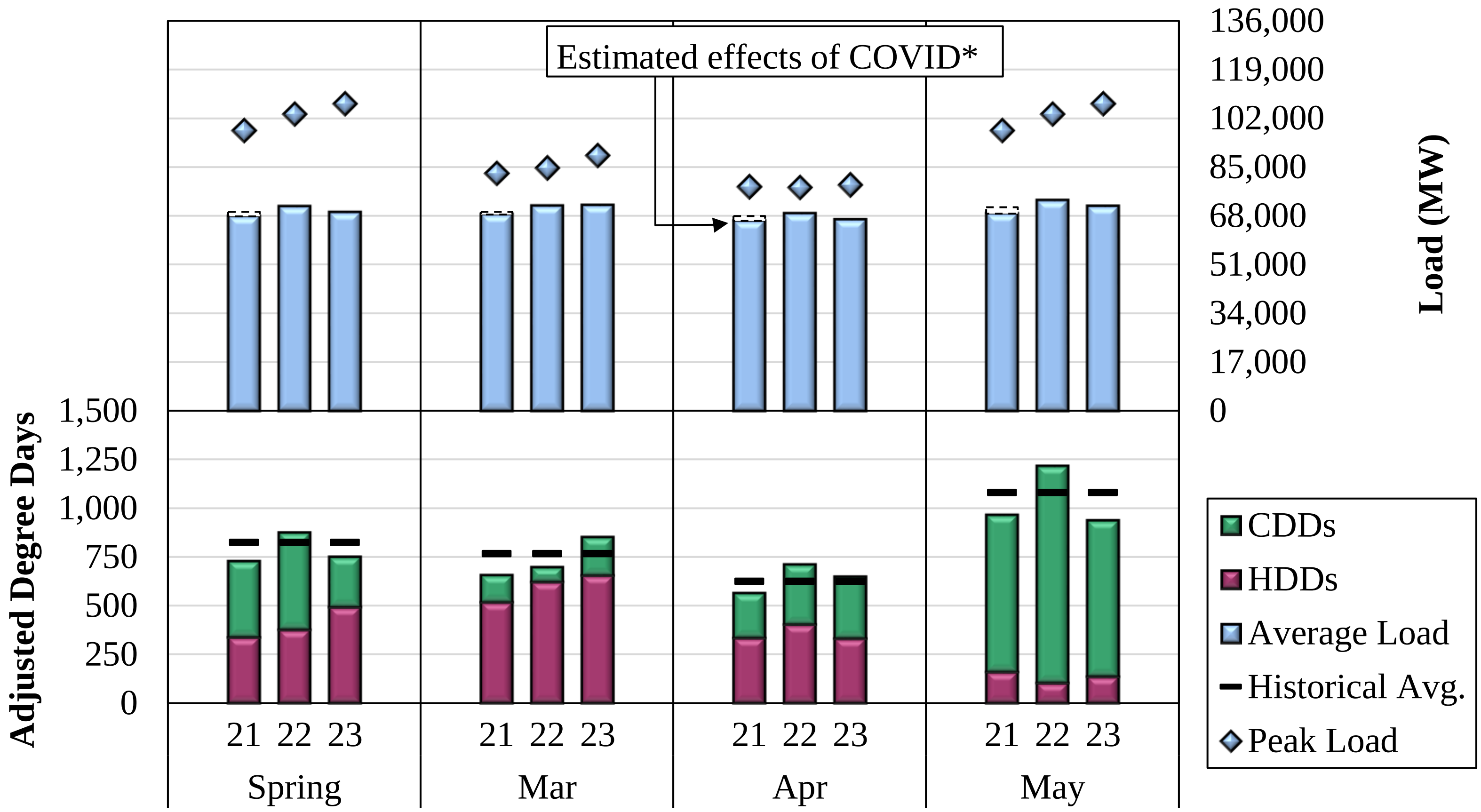
MISO Fuel Prices 2022–2023

Spring Average	2021	2022	2023
Chicago NG	$2.59	$6.26	$2.08
Henry NG	$2.67	$6.44	$2.19

Spring Average	2021	2022	2023
IB Coal	$1.29	$5.06	$2.88
PRB Coal	$0.68	$0.93	$0.83

Load and Weather Patterns
Spring 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.
*Effects estimated by MISO through back-casting using its load forecasting model.

Capacity, Energy and Price Setting Share
Spring 2022–2023

Spring	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
Nuclear	11,701	10,870	9%	9%	14%	15%	0%	0%	0%	0%
Coal	43,123	39,544	34%	31%	31%	24%	20%	34%	44%	73%
Natural Gas	59,901	61,032	47%	48%	31%	38%	79%	64%	83%	89%
Oil	1,474	1,523	1%	1%	0%	0%	0%	0%	0%	1%
Hydro	3,695	4,228	3%	3%	2%	2%	1%	1%	2%	3%
Wind	4,454	5,507	3%	4%	20%	19%	0%	0%	82%	78%
Solar	1,037	1,808	1%	1%	0%	1%	0%	0%	6%	9%
Other	2,734	2,599	2%	2%	3%	0%	0%	0%	4%	1%
Total	**128,120**	**127,110**								

PRA Results for the 2023–2024 Planning Year

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day)	
				Rest of Market	Zone 9 (LA,TX)
Summer 23	132,891	6,483	0.10	$10.00	
Fall 23	125,795	10,587	0.01	$15.00	$59.21
Winter 23/24	128,104	11,378	0.01	$2.00	$18.88
Spring 24	124,389	10,049	0.01	$10.00	
PRA Year	127,795	9,624	0.13	$9.25	$24.52

Summer 2023 Planning Reserve Margins

		Alternative IMM Scenarios*			
				High Temperature Cases	
	Base Scenario	Realistic Scenario	Realistic <=2HR	Realistic Scenario	Realistic <=2HR
Load					
Base Case	123,735	123,735	123,735	123,735	123,735
High Load Increase	-	-	-	7,040	7,040
Total Load (MW)	123,729	123,729	123,729	130,775	130,775
Generation					
Internal Generation Excluding Exports	132,837	132,837	132,837	132,837	132,837
BTM Generation	4,333	4,333	3,104	4,333	3,104
Unforced Outages and Derates**	-	(13,270)	(13,270)	(20,870)	(20,870)
Adjustment due to Transfer Limit	(2,067)	-	-	-	-
Total Generation (MW)	135,103	123,900	122,671	116,300	115,071
Imports and Demand Response* **					
Demand Response (ICAP)	8,304	6,228	3,108	6,228	3,108
Firm Capacity Imports	4,136	4,136	4,136	4,136	4,136
Margin (MW)	23,813	10,535	6,186	(4,110)	(8,459)
Margin (%)	**19.2%**	**8.5%**	**5.0%**	**-3.1%**	**-6.5%**
Expected Capacity Uses and Additions					
Expected Forced Outages****	(6,858)	(6,798)	(6,798)	(6,798)	(6,798)
Non-Firm Net Imports in Emergencies	4,708	4,708	4,708	4,708	4,708
Expected Margin (MW)	21,662	8,445	4,096	(6,201)	(10,549)
Expected Margin (%)	**17.5%**	**6.8%**	**3.3%**	**-4.7%**	**-8.1%**

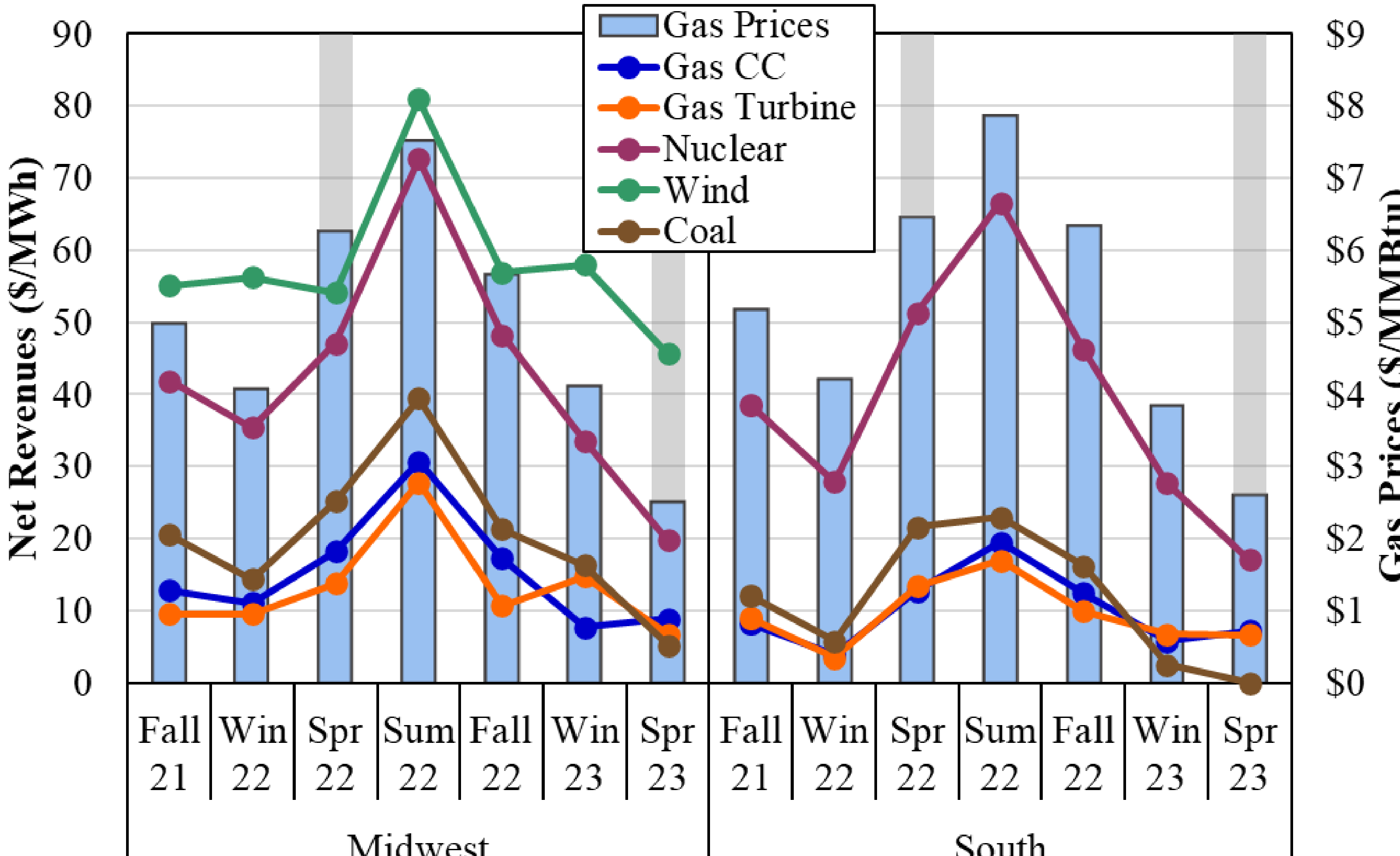
* Assumes 75% response from DR.

** Base scenario shows approved planned outages for summer 2023. Realistic cases use historical average unforced outages/derates during peak summer hours. High temp. cases are based upon MISO's 2023 Summer Assessment.

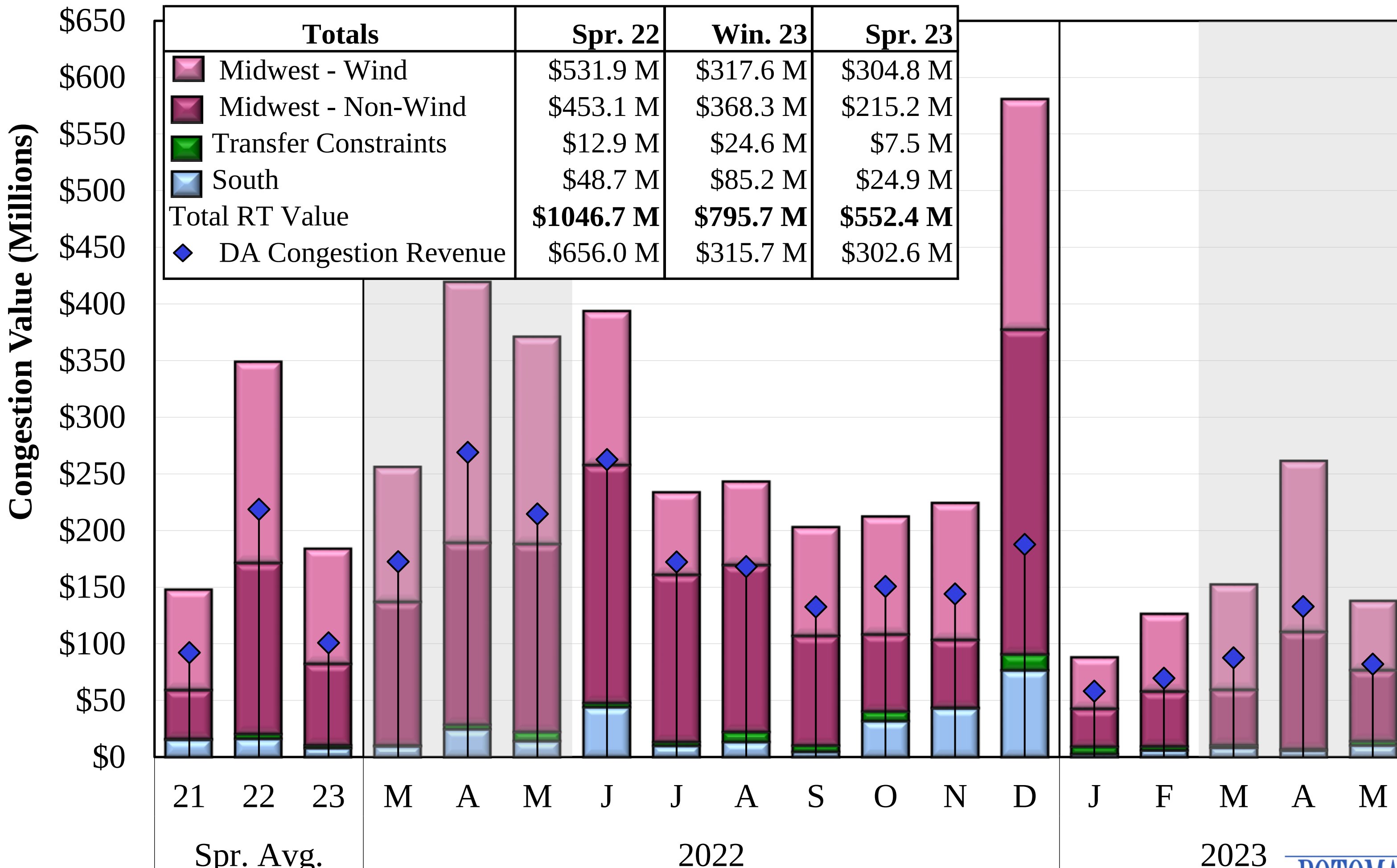
*** Cleared amounts for the Summer Season of the 2023/2024 planning year.

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

Net Revenues by Technology 2021-2023



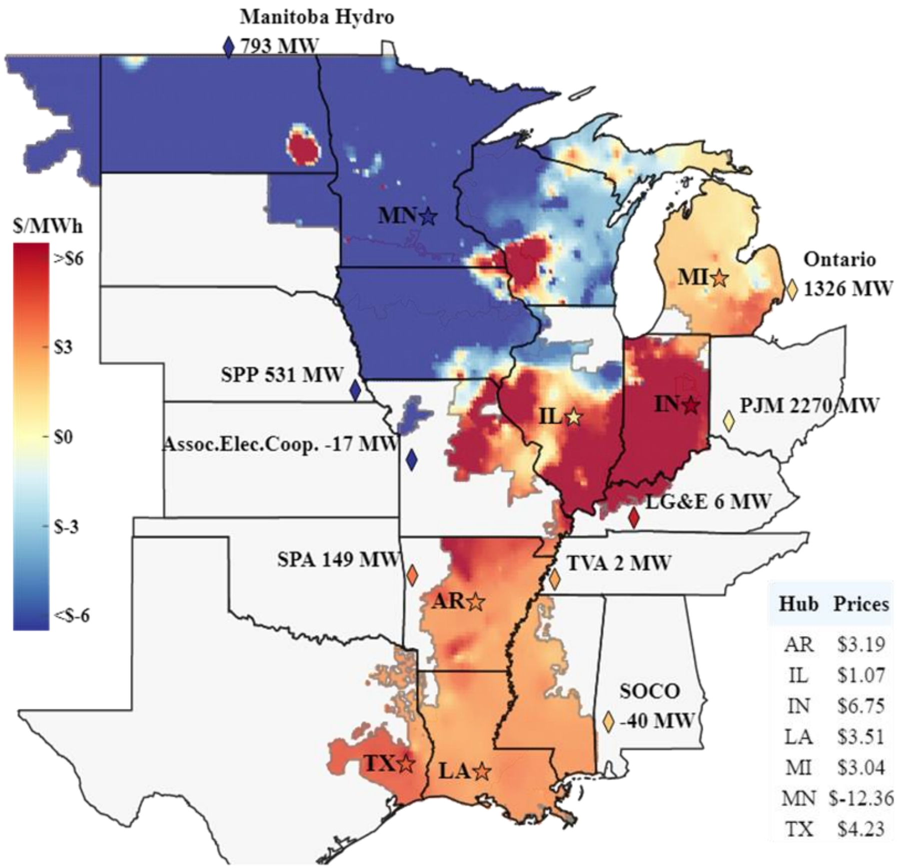
Value of Real-Time Congestion
Spring 2021–2023



Totals	Spr. 22	Win. 23	Spr. 23
Midwest - Wind	$531.9 M	$317.6 M	$304.8 M
Midwest - Non-Wind	$453.1 M	$368.3 M	$215.2 M
Transfer Constraints	$12.9 M	$24.6 M	$7.5 M
South	$48.7 M	$85.2 M	$24.9 M
Total RT Value	**$1046.7 M**	**$795.7 M**	**$552.4 M**
DA Congestion Revenue	$656.0 M	$315.7 M	$302.6 M

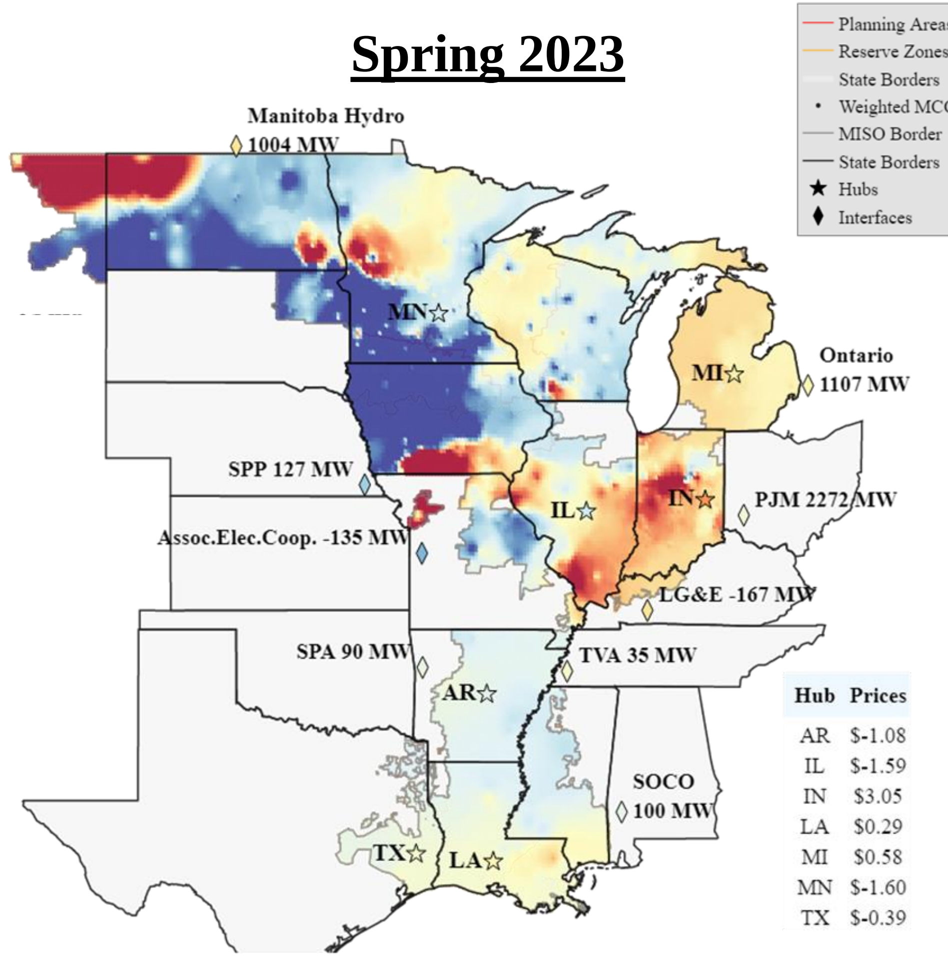
Average Real-Time Congestion Components Spring 2022–2023

Spring 2022



Hub	Prices
AR	$3.19
IL	$1.07
IN	$6.75
LA	$3.51
MI	$3.04
MN	$-12.36
TX	$4.23

Spring 2023



Hub	Prices
AR	$-1.08
IL	$-1.59
IN	$3.05
LA	$0.29
MI	$0.58
MN	$-1.60
TX	$-0.39

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

Spring		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2022	**Midwest**	$76.1	$51.75	$127.8	9	13.1%
	South	$0.1	$1.41	$1.5	1	4.7%
	Total	**$76.2**	**$53.2**	**$129.4**	**10**	**12.8%**
2023	**Midwest**	$37.3	$23.66	$61.0	9	11.4%
	South	$0.3	$1.46	$1.7	1	5.9%
	Total	**$37.5**	**$25.1**	**$62.7**	**10**	**11.1%**

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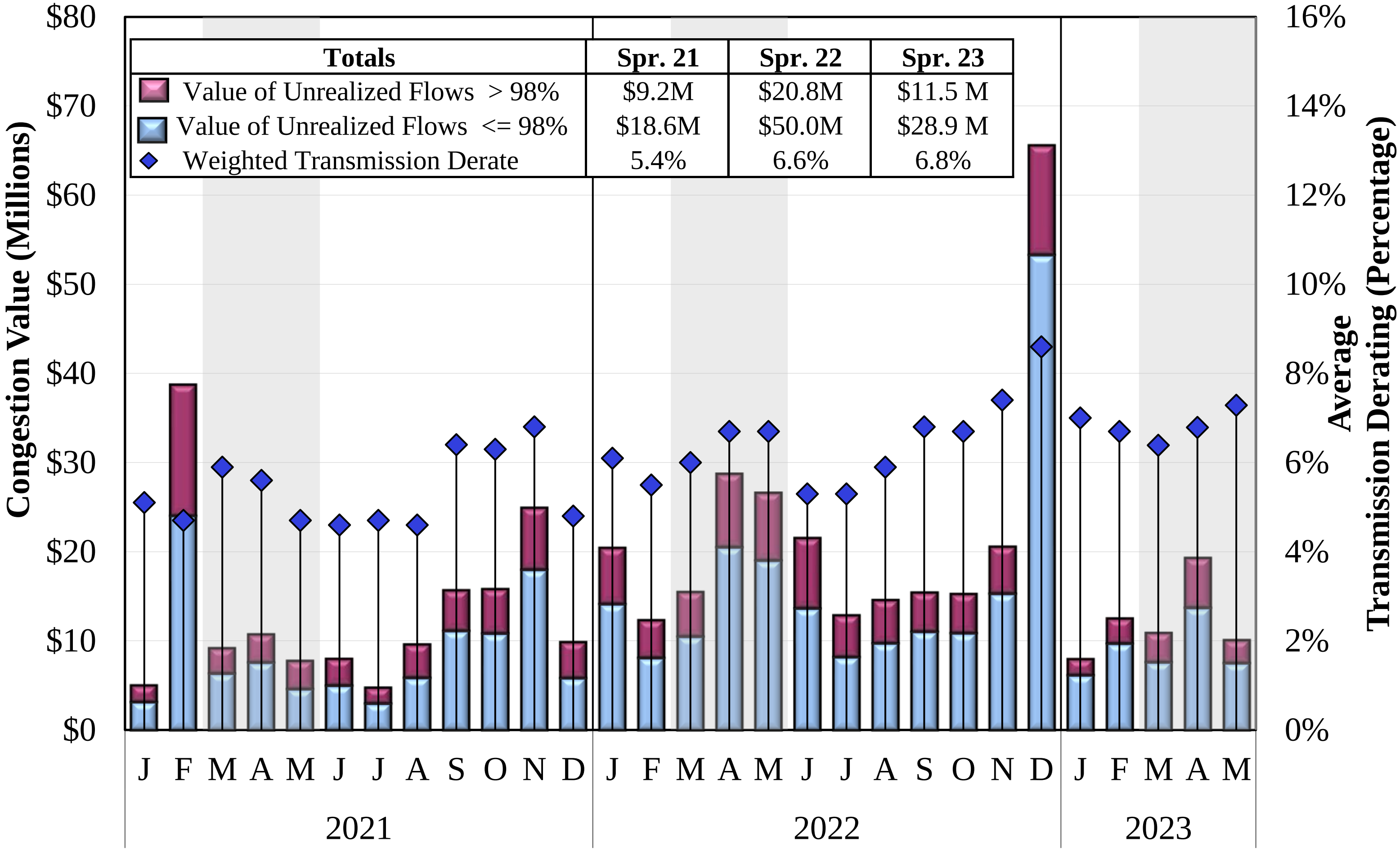
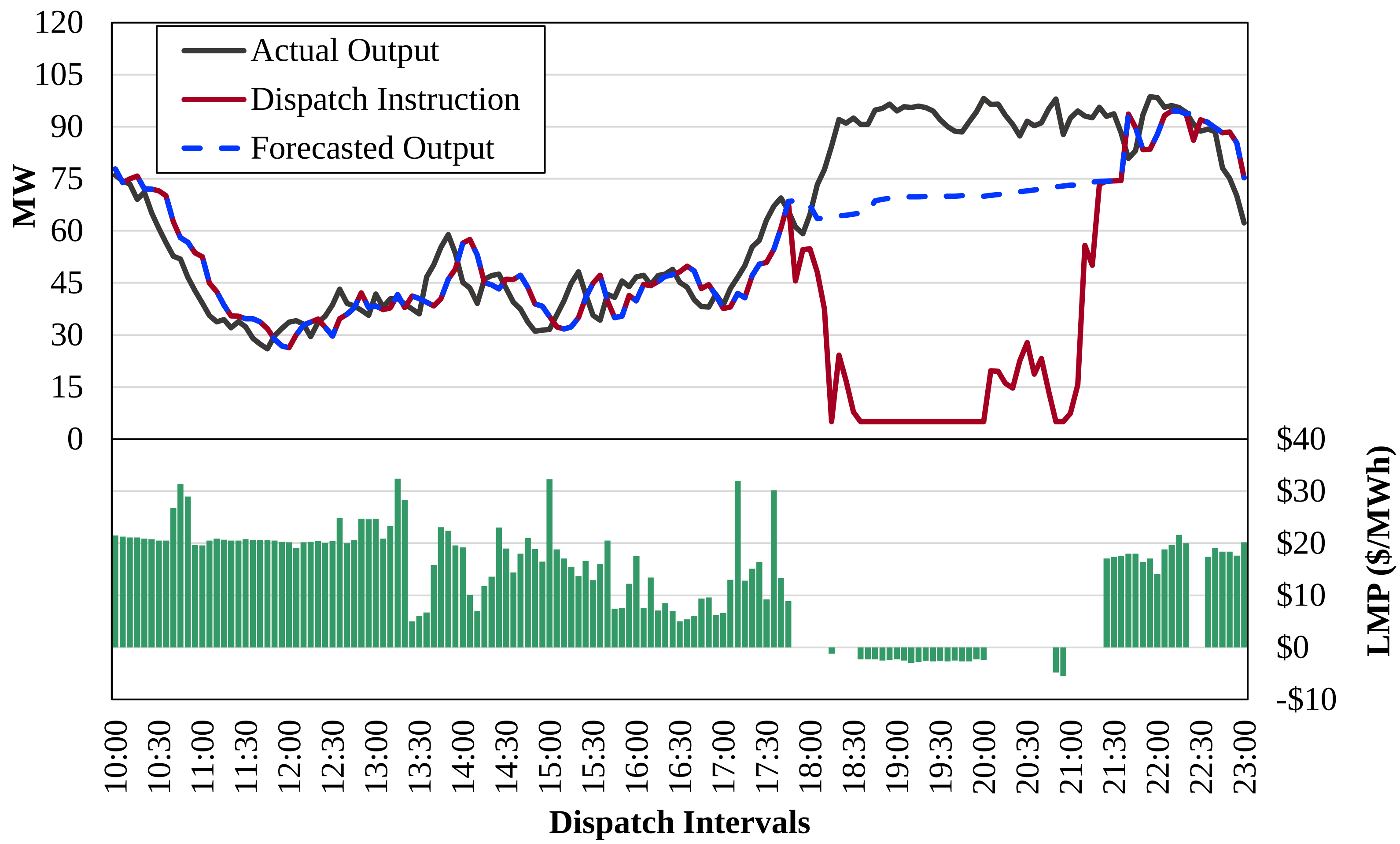
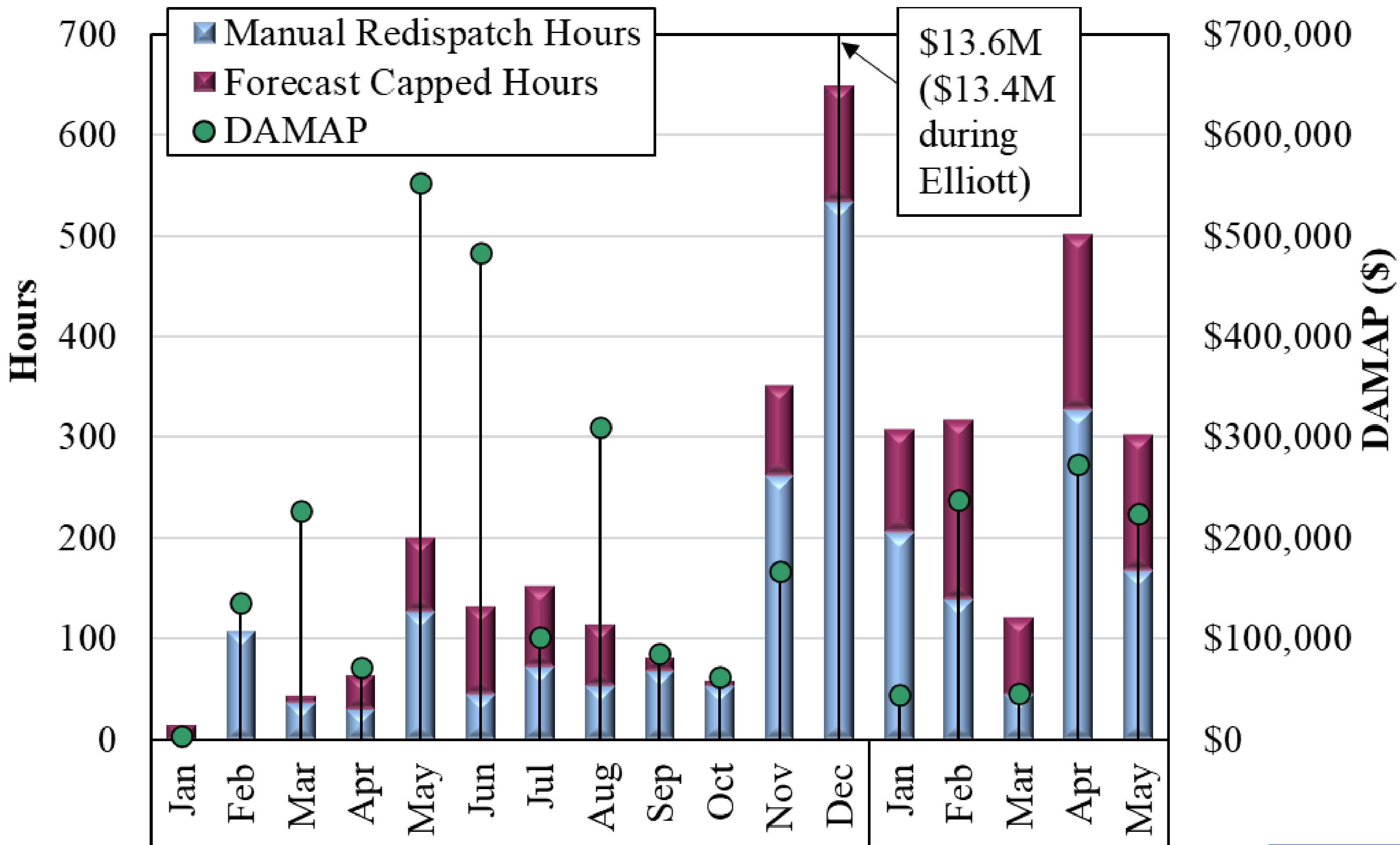
Value of Unrealized Transmission Flows Due to Use of Limit Control



Wind Resource Failing to Follow Dispatch



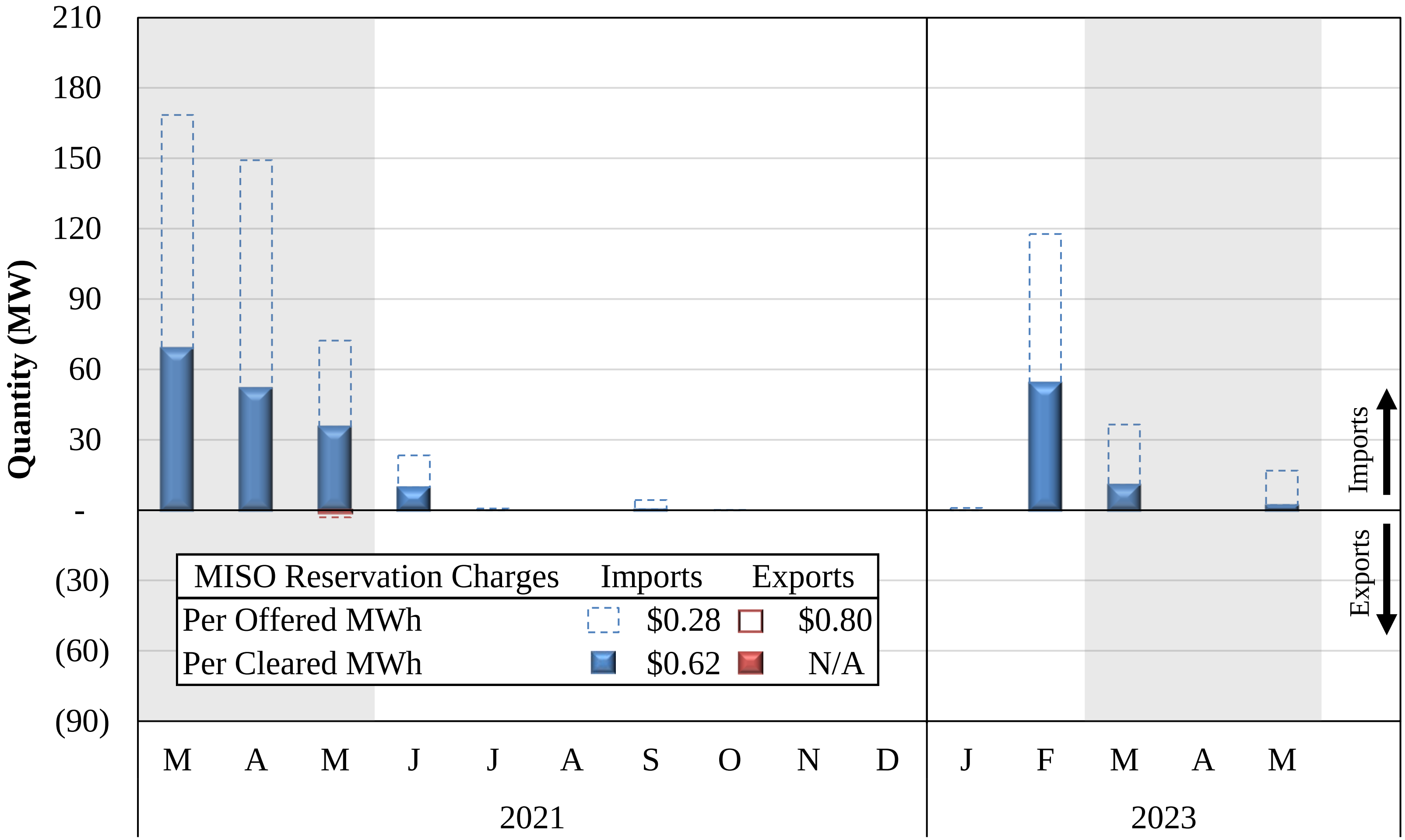
MISO MRD and Capping of Wind Resources Spring 2022 - 2023



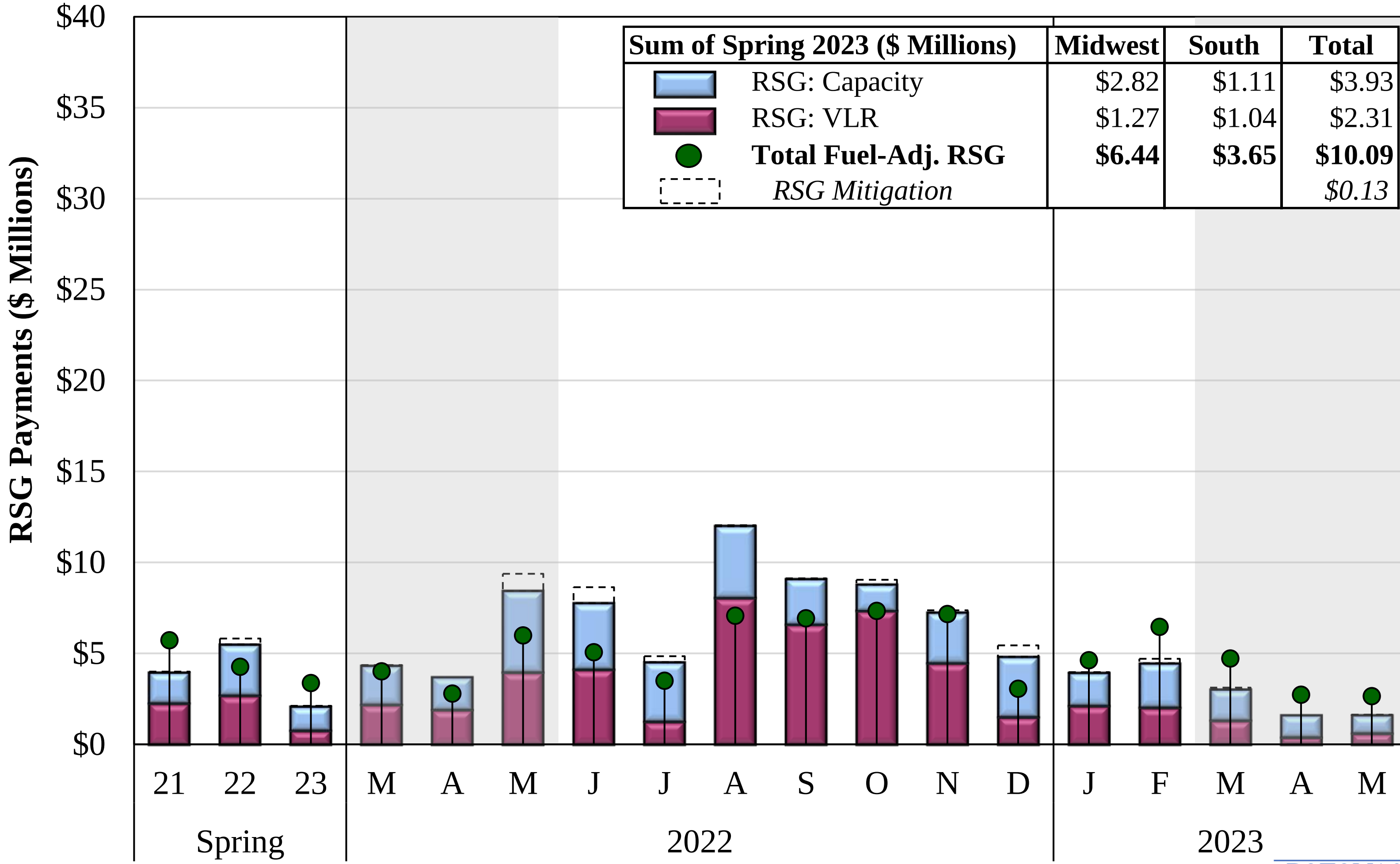
Impacts of Proposed IMM UD Penalty by Resource Class: 2022

		Avg. Deviation Penalty ($/MWh)		Average Penalty ($/MWh of Output)	
Unit Type	**Total Penalty**	**Excessive**	**Deficient**	**Excessive**	**Deficient**
Gas Turbine	$405,553	$6.12	$5.43	$0.003	$0.003
Coal	$1,033,785	$11.58	$6.50	$0.003	$0.002
Gas CC	$489,974	$4.82	$4.02	$0.002	$0.002
Other	$645,519	$5.65	$4.77	$0.002	$0.003
Solar	$71,627	$10.01	$3.60	$0.009	$0.008
Wind	$3,298,440	$40.83	$1.81	$0.032	$0.001

Coordinated Transaction Scheduling (CTS) Spring 2021–2023

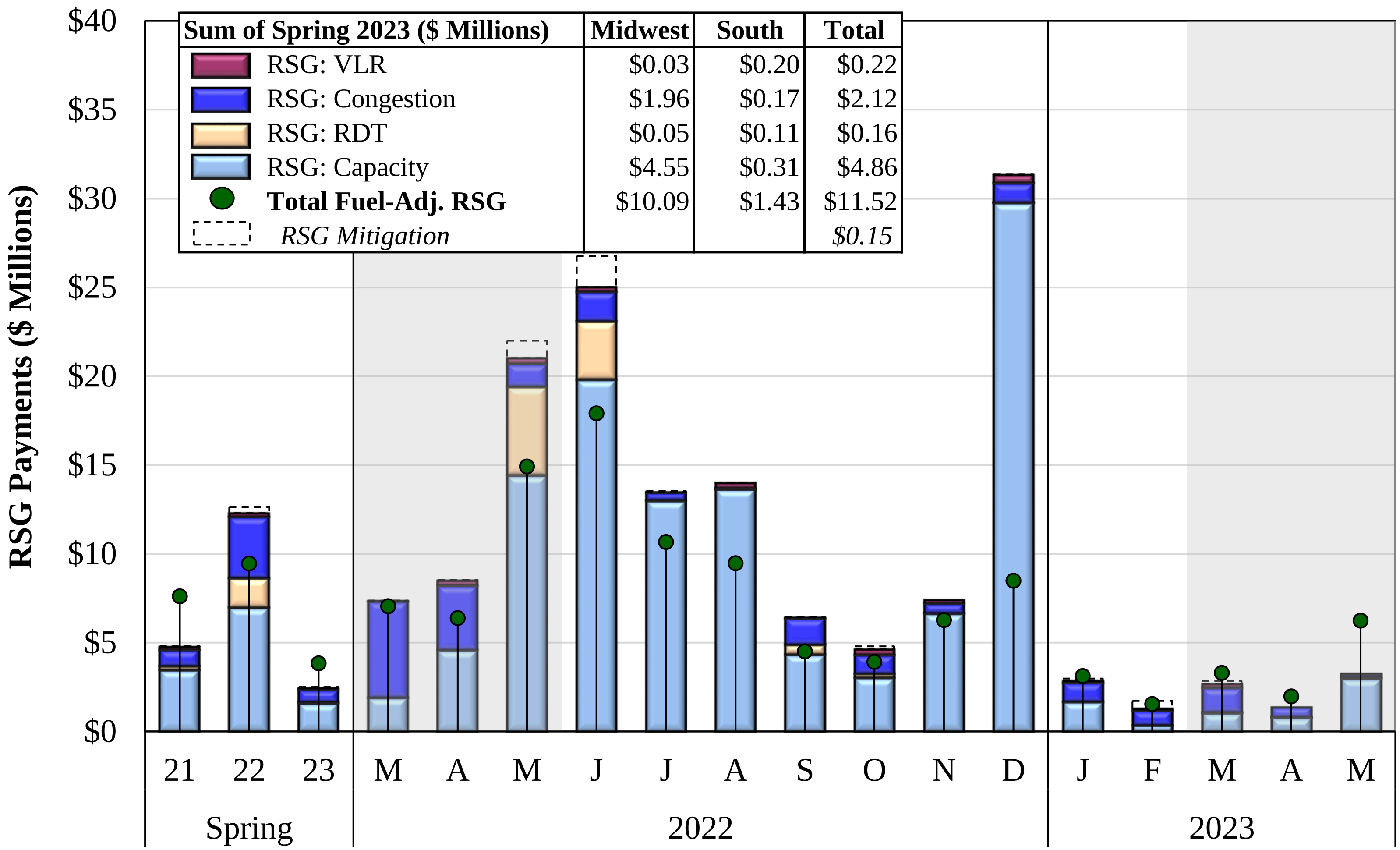


Day-Ahead RSG Payments
Spring 2021–2023

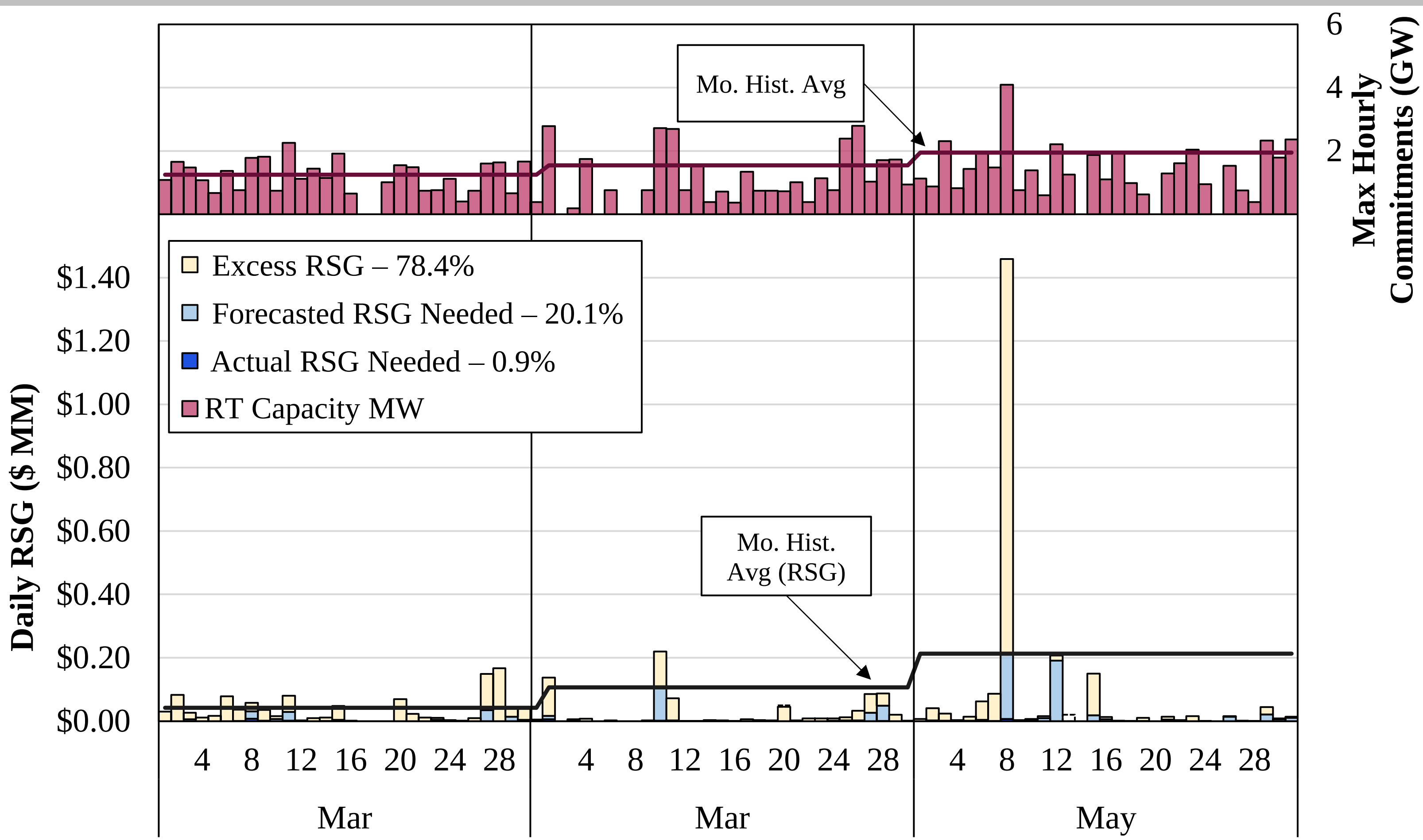


Sum of Spring 2023 ($ Millions)	Midwest	South	Total
RSG: Capacity	$2.82	$1.11	$3.93
RSG: VLR	$1.27	$1.04	$2.31
Total Fuel-Adj. RSG	**$6.44**	**$3.65**	**$10.09**
RSG Mitigation			*$0.13*

Real-Time RSG Payments
Spring 2021–2023

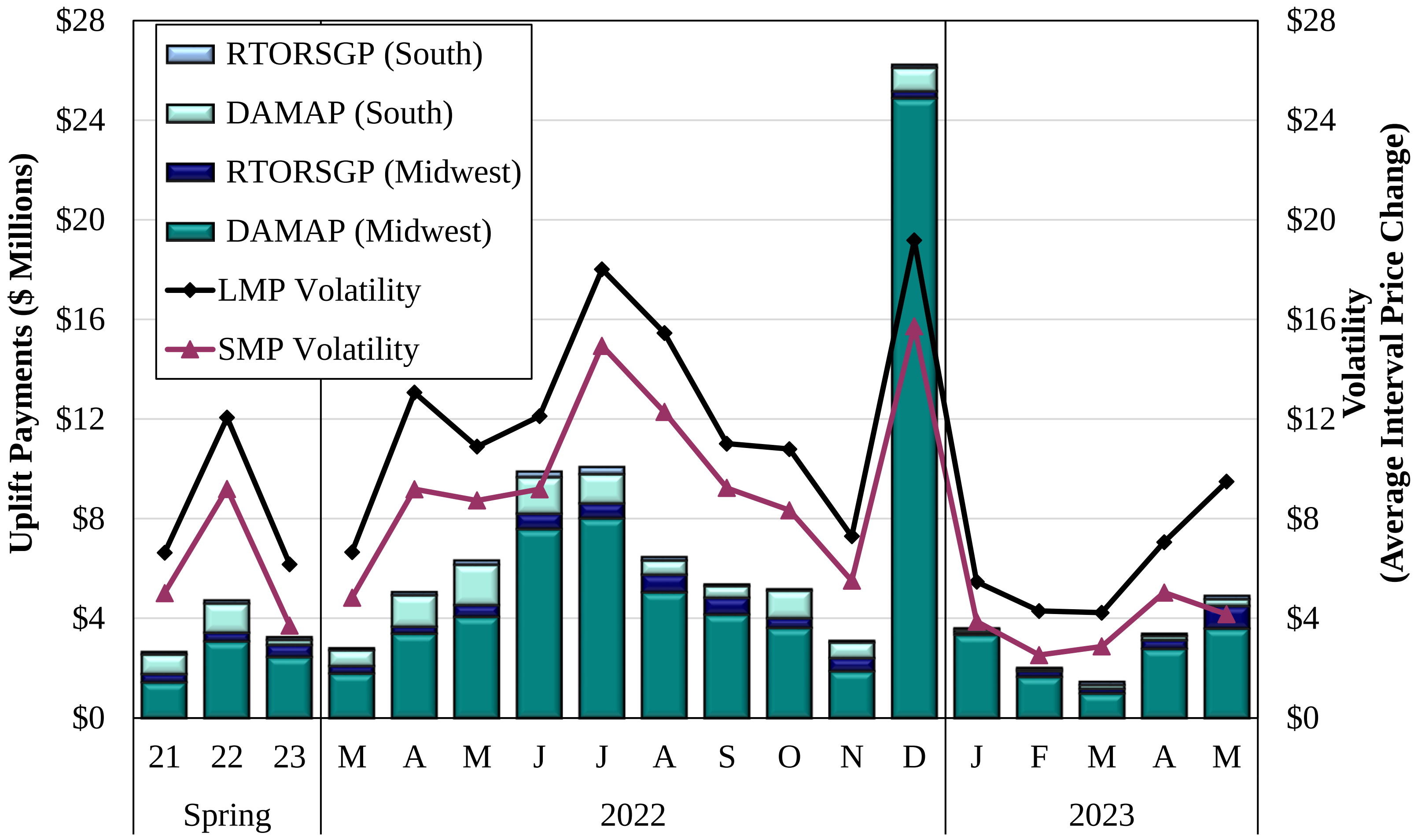


Real-Time Capacity Commitment and RSG

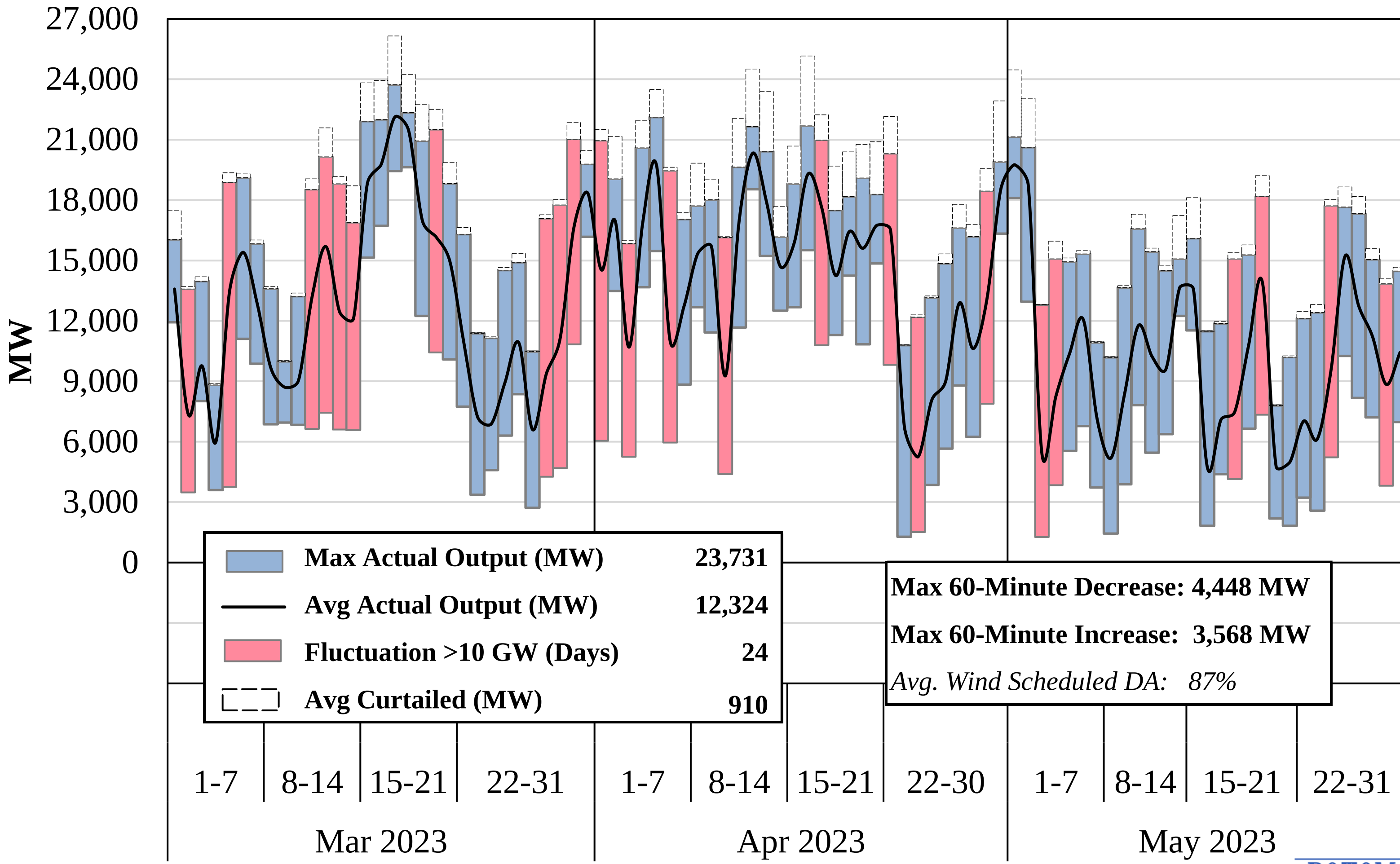


* <1% of the RSG could not be classified due to gaps in market data and is shown in the transparent bars.

Price Volatility Make Whole Payments Spring 2021–2023



Wind Output in Real Time
Daily Range and Average



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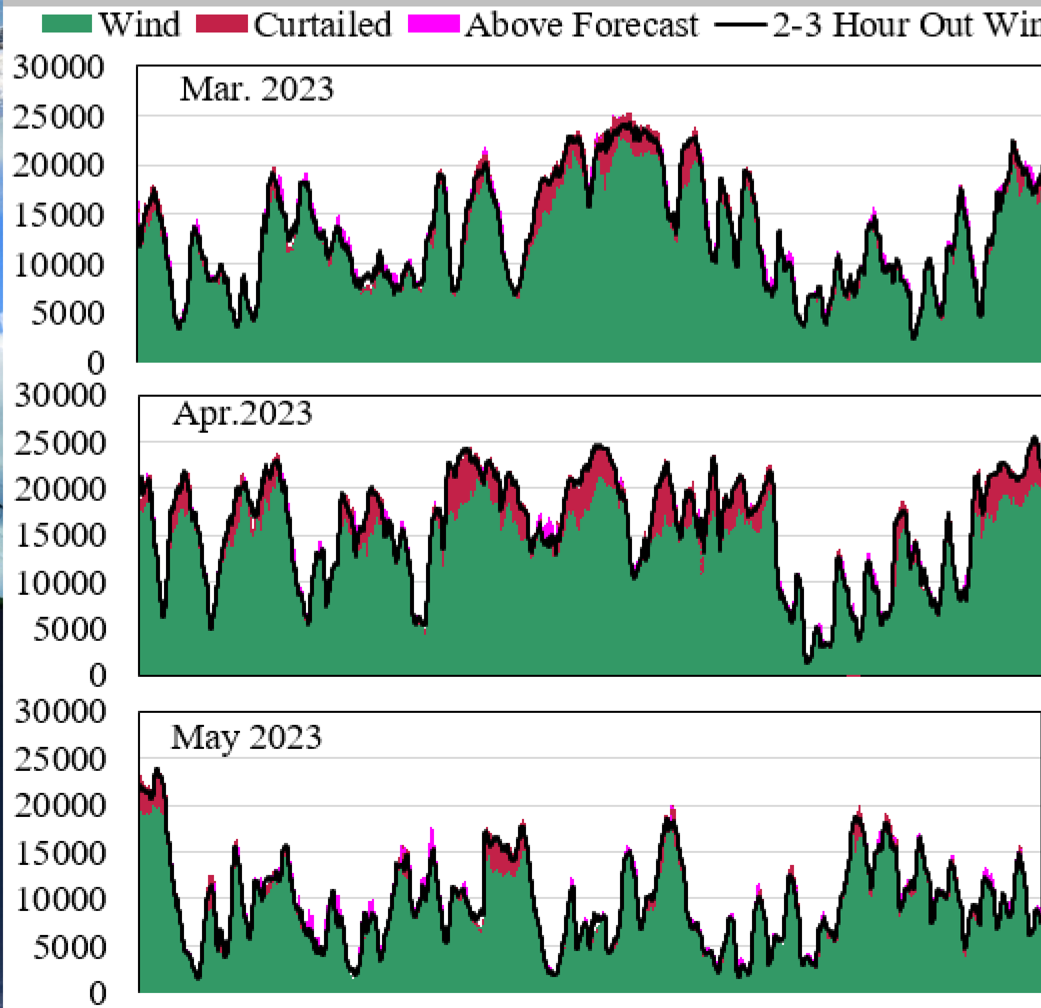
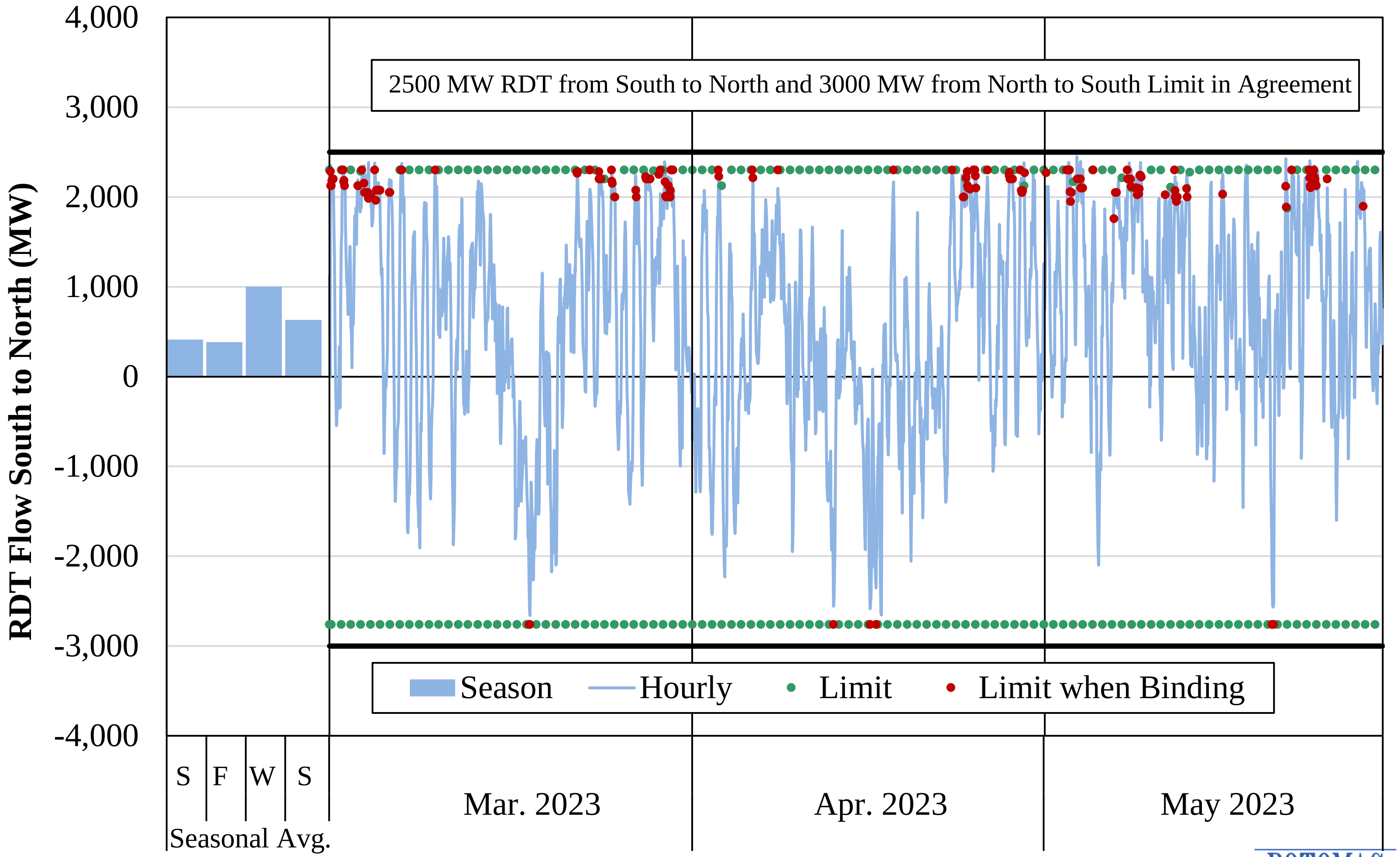
Wind Forecast and Actual Output Spring 2023

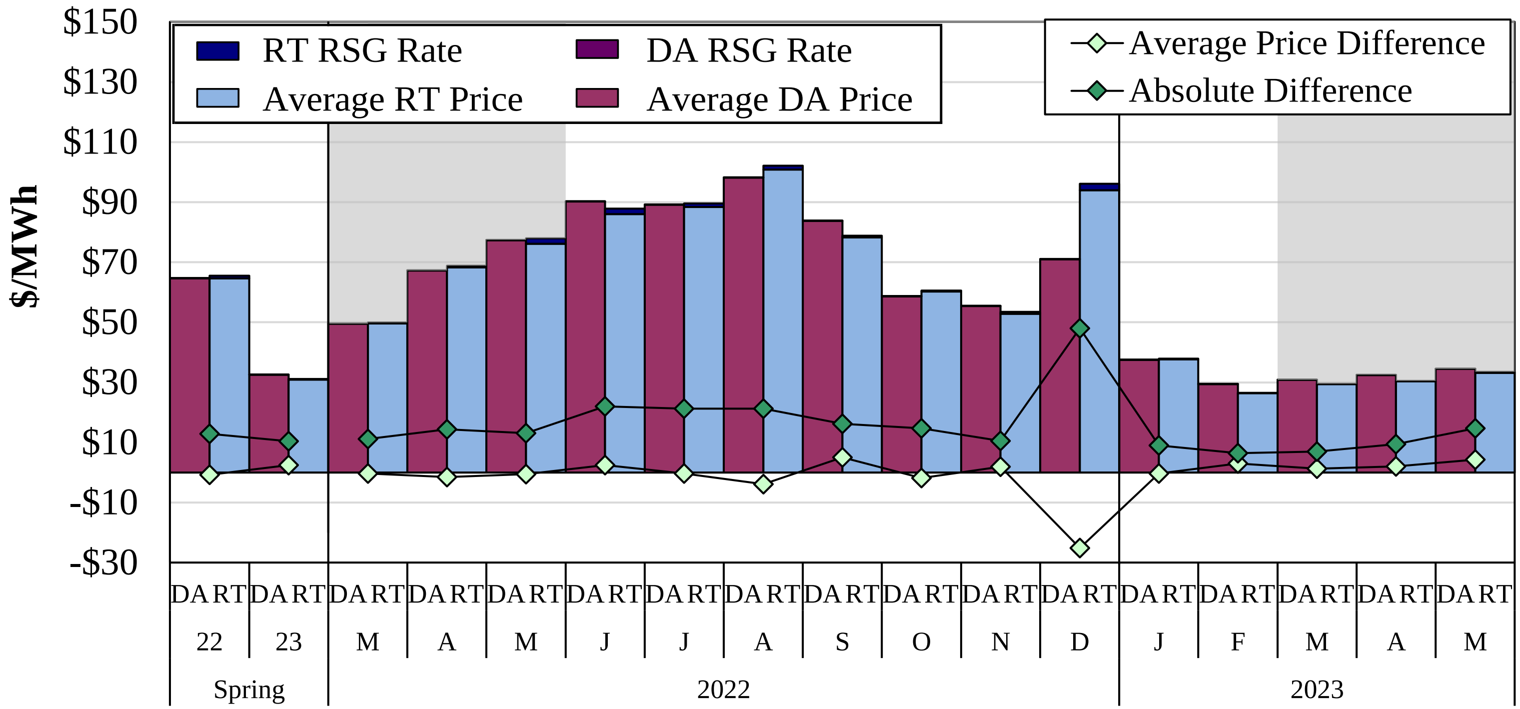


Spring 2023	
Real-Time Wind (MW)	12,324
Day-Ahead Wind (MW)	10,744
Avg Curtailments (MW)	910
Forecast Errors (%)	-1.2%
Absolute Errors (%)	7.0%
Spring 2022	
Real-Time Wind (MW)	12,886
Day-Ahead Wind (MW)	11,625
Avg Curtailments (MW)	1,297
Forecast Errors (%)	-0.4%
Absolute Errors (%)	6.6%
Winter 2023	
Real-Time Wind (MW)	12,491
Day-Ahead Wind (MW)	10,579
Avg Curtailments (MW)	446
Forecast Errors (%)	0.8%
Absolute Errors (%)	7.5%

Real-Time Hourly Inter-Regional Flows
Spring 2023



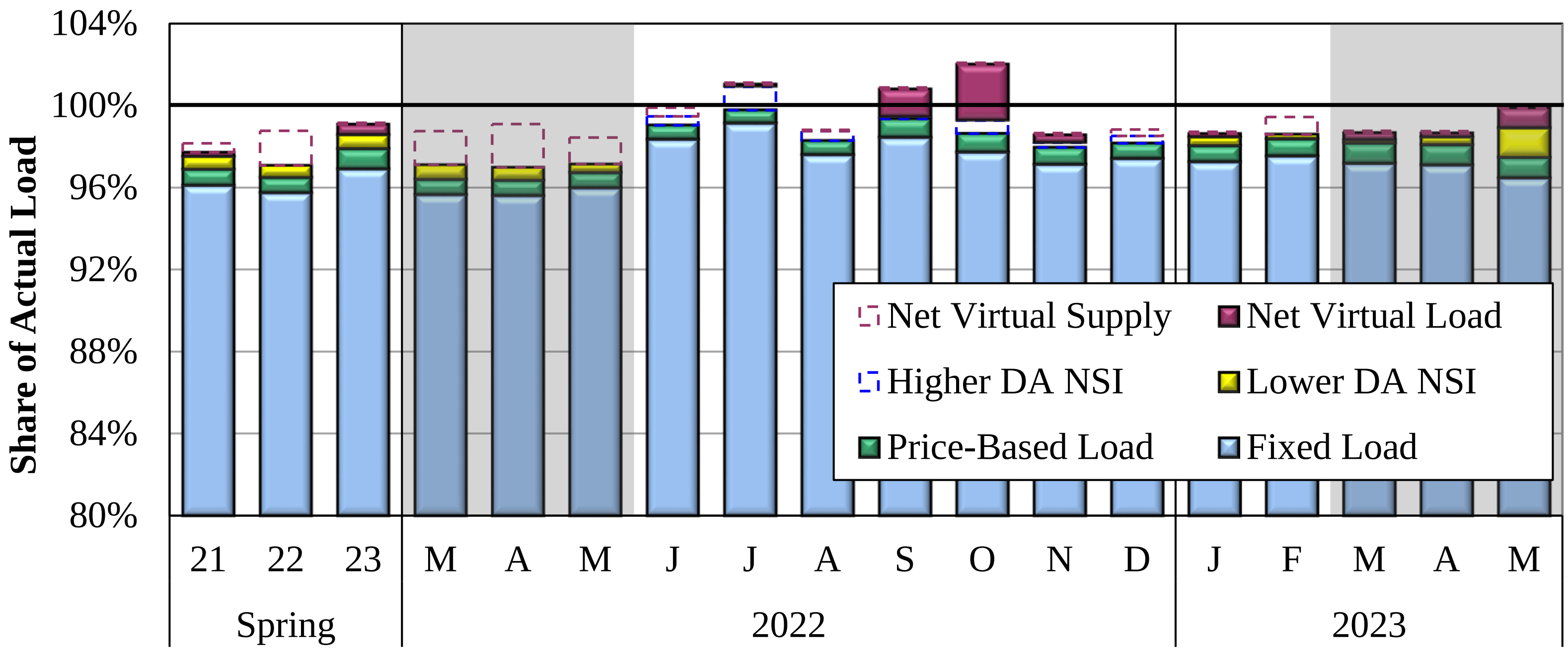
Day-Ahead and Real-Time Price Convergence Spring 2022–2023



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

Indiana Hub	-1	5	-1	-2	-1	3	0	-4	6	-3	4	-26	-1	11	4	7	3
Michigan Hub	2	3	3	-3	5	6	-1	-3	7	1	4	-21	5	12	6	4	-1
Minnesota Hub	3	0	8	2	-1	10	-2	-5	7	0	3	-17	-1	-7	-6	-10	14
Arkansas Hub	4	3	3	3	6	3	-5	-7	4	-3	-3	-18	-1	3	5	0	3
Texas Hub	5	4	4	1	9	4	-2	-7	4	-1	-2	-24	1	7	5	5	2
Louisiana Hub	5	2	4	4	8	5	0	-7	3	-1	-1	-23	0	6	1	3	2

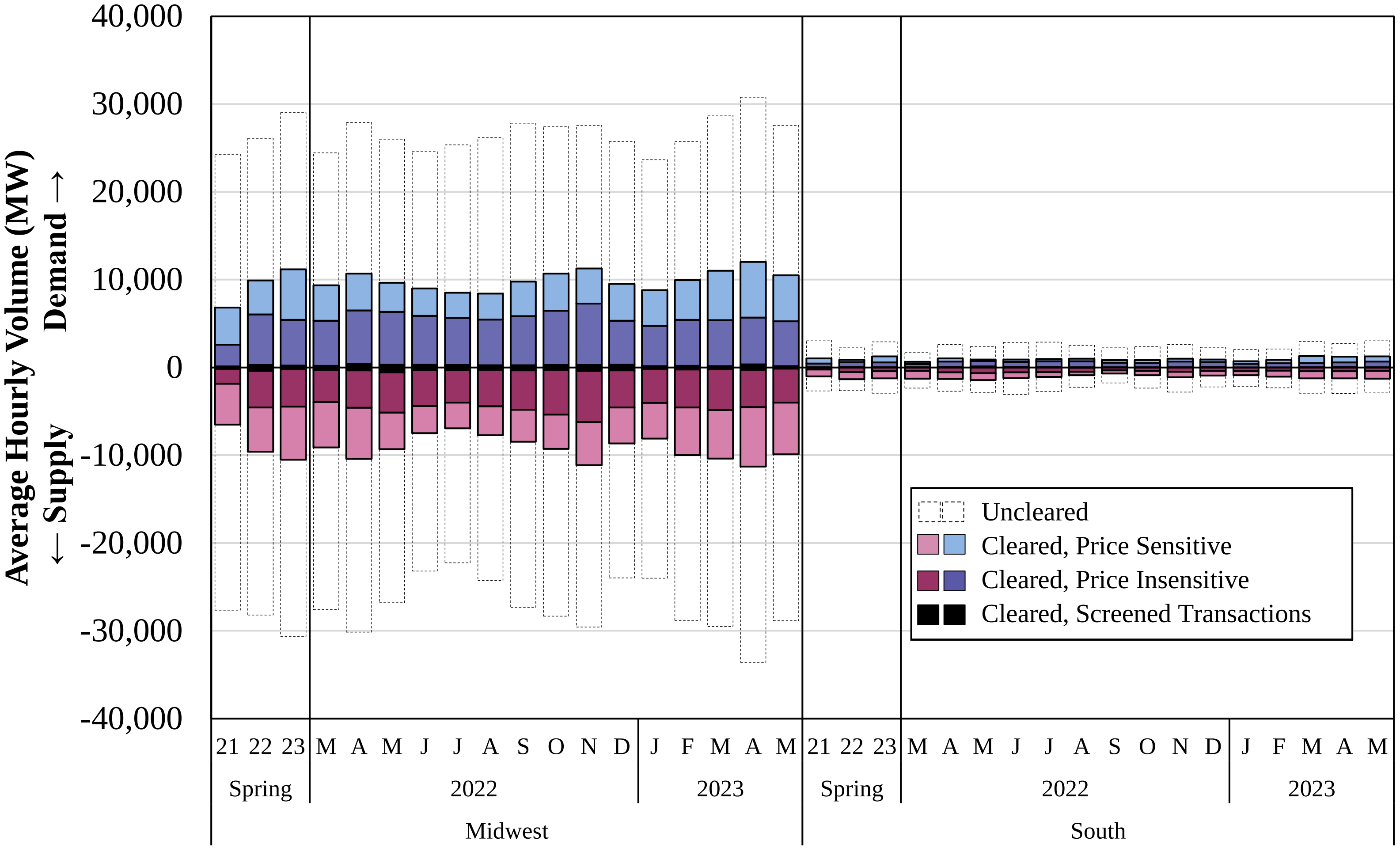
Day-Ahead Peak Hour Load Scheduling Spring 2021–2023



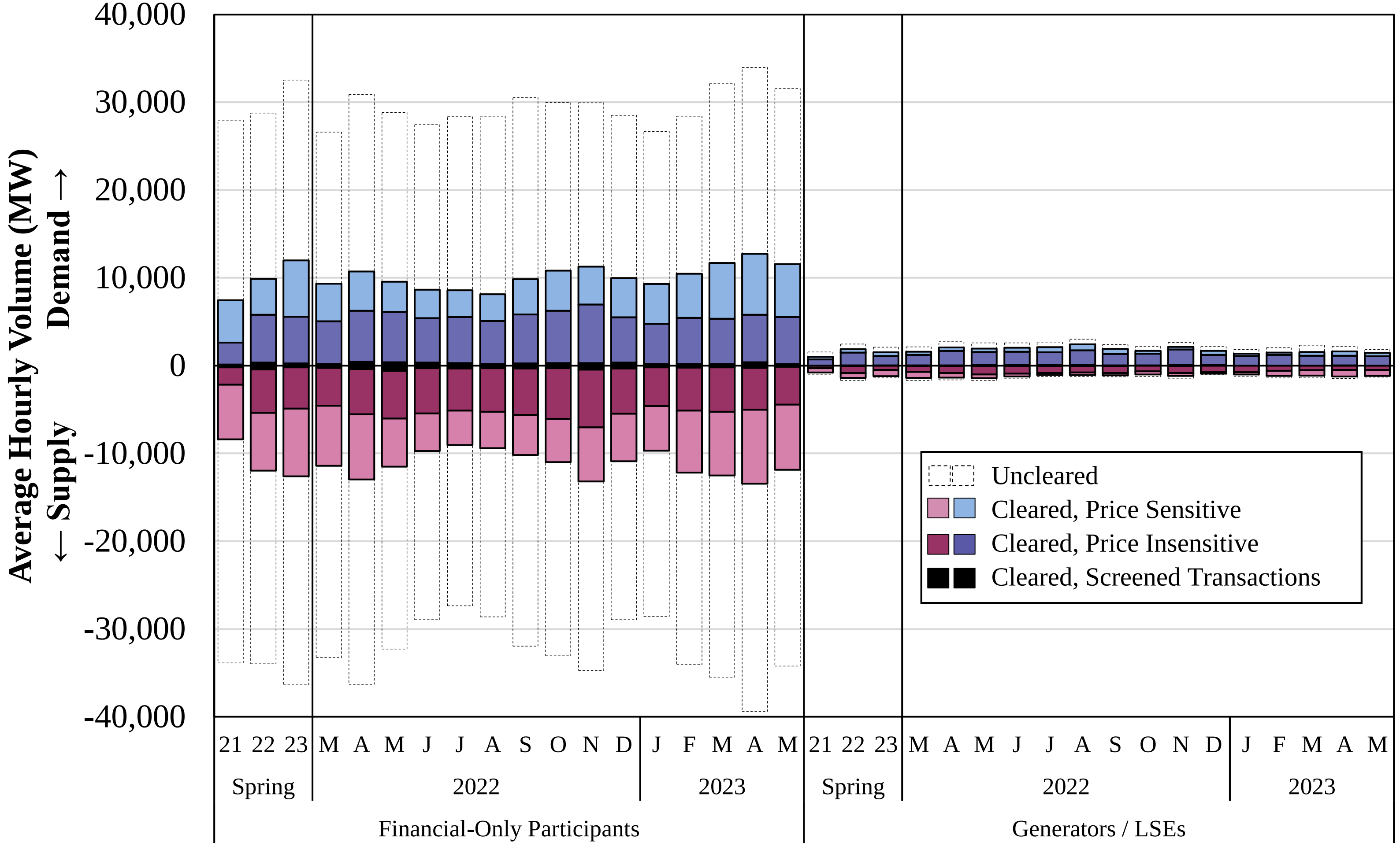
Share of Actual Load (%)

All Hours	97.8	97.4	99.2	97.3	97.5	97.6	99.2	99.8	98.9	100.8	99.7	97.6	98.7	99.0	98.4	98.9	99.1	99.5
Peak Hours Midwest	96.6	96.2	98.8	96.5	96.0	96.2	98.2	99.7	98.4	101.0	101.5	99.0	98.5	99.2	98.8	98.6	98.9	98.7
Peak Hours South	100.6	99.0	101.4	98.8	99.1	99.0	99.7	99.7	98.7	101.8	100.1	98.1	100.8	99.7	98.5	101.4	99.7	103.1

Virtual Load and Supply
Spring 2021–2023

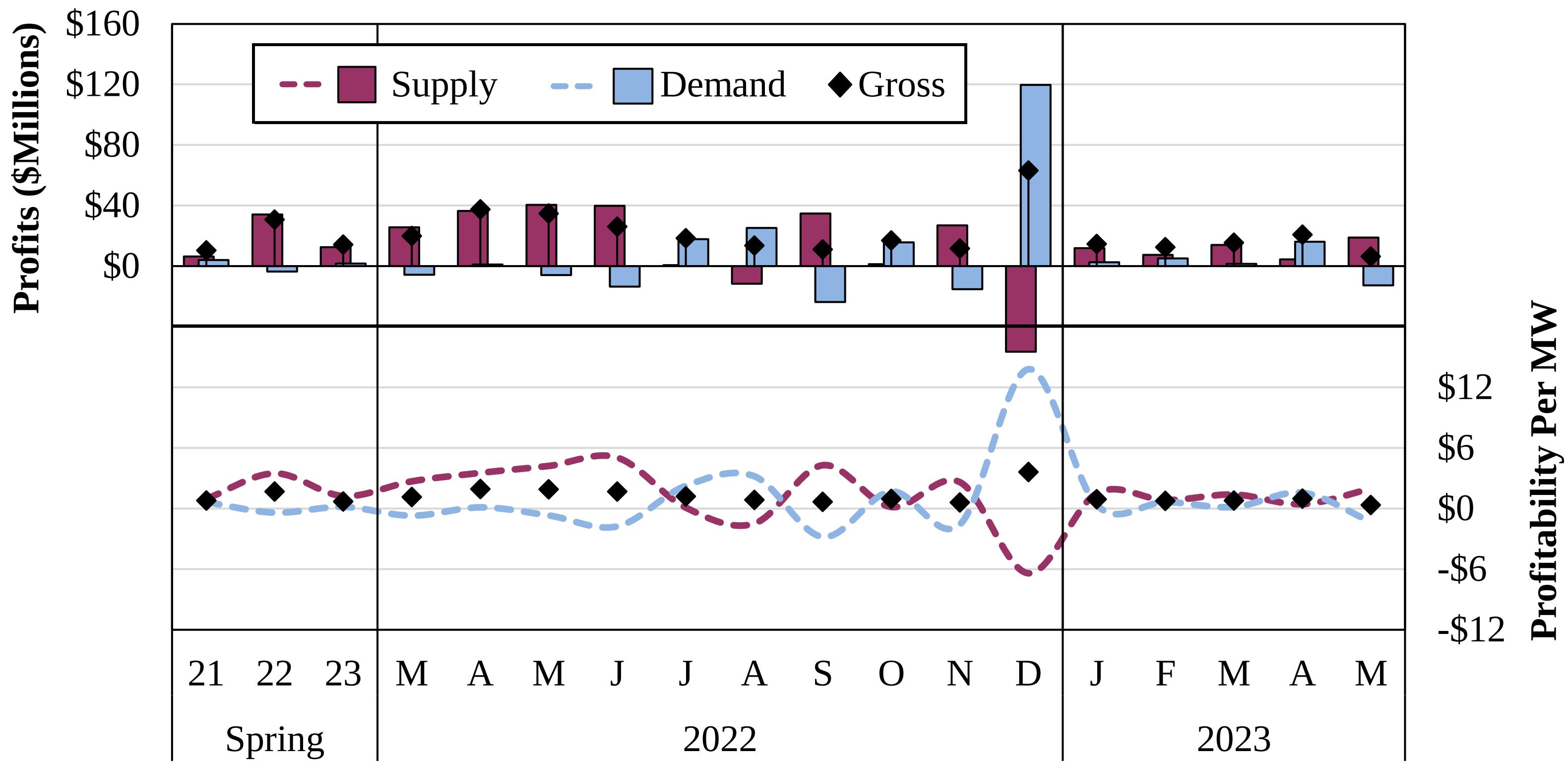


Virtual Load and Supply by Participant Type
Spring 2021–2023



POTOMAC ECONOMICS

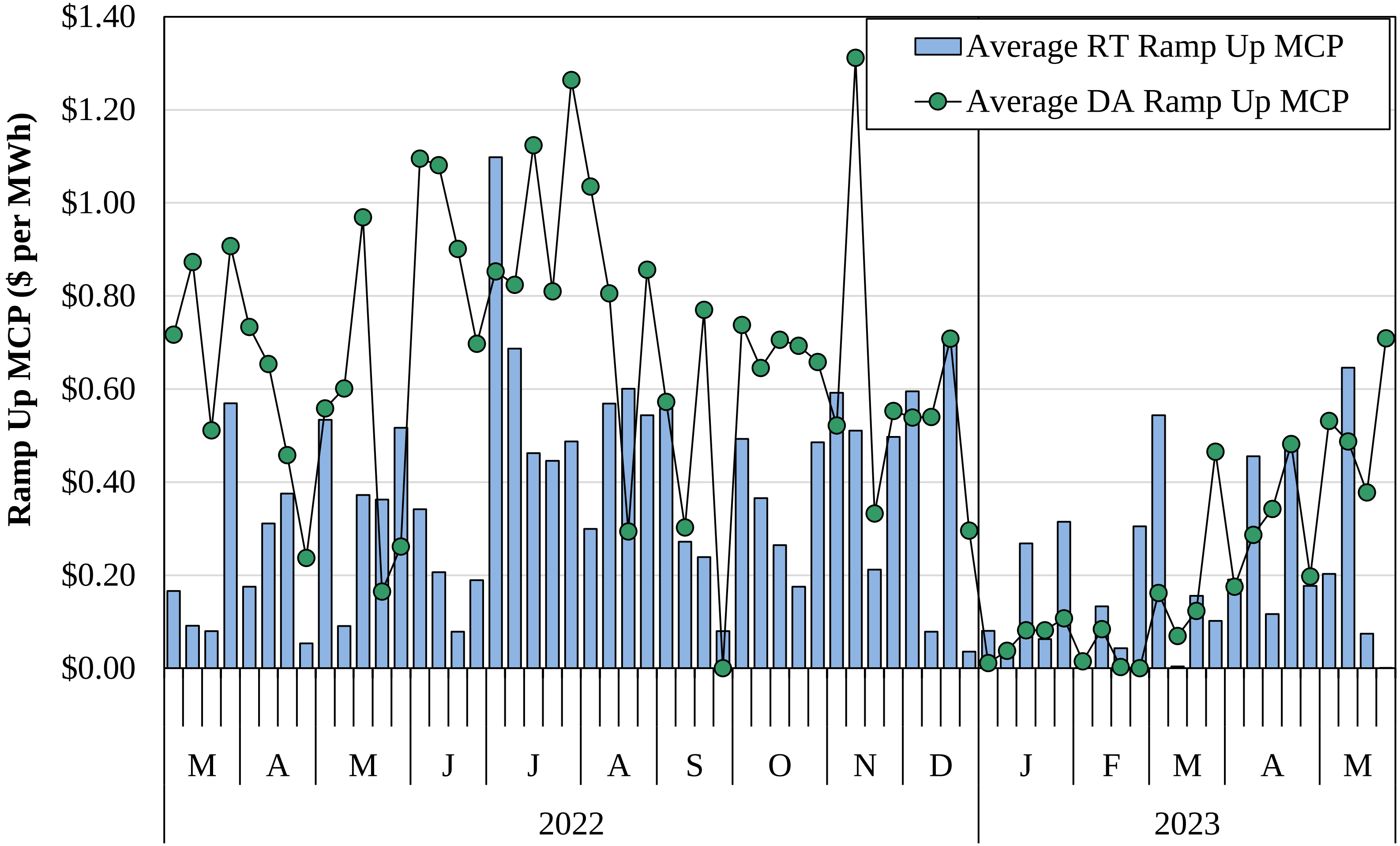
Virtual Profitability
Spring 2021–2023



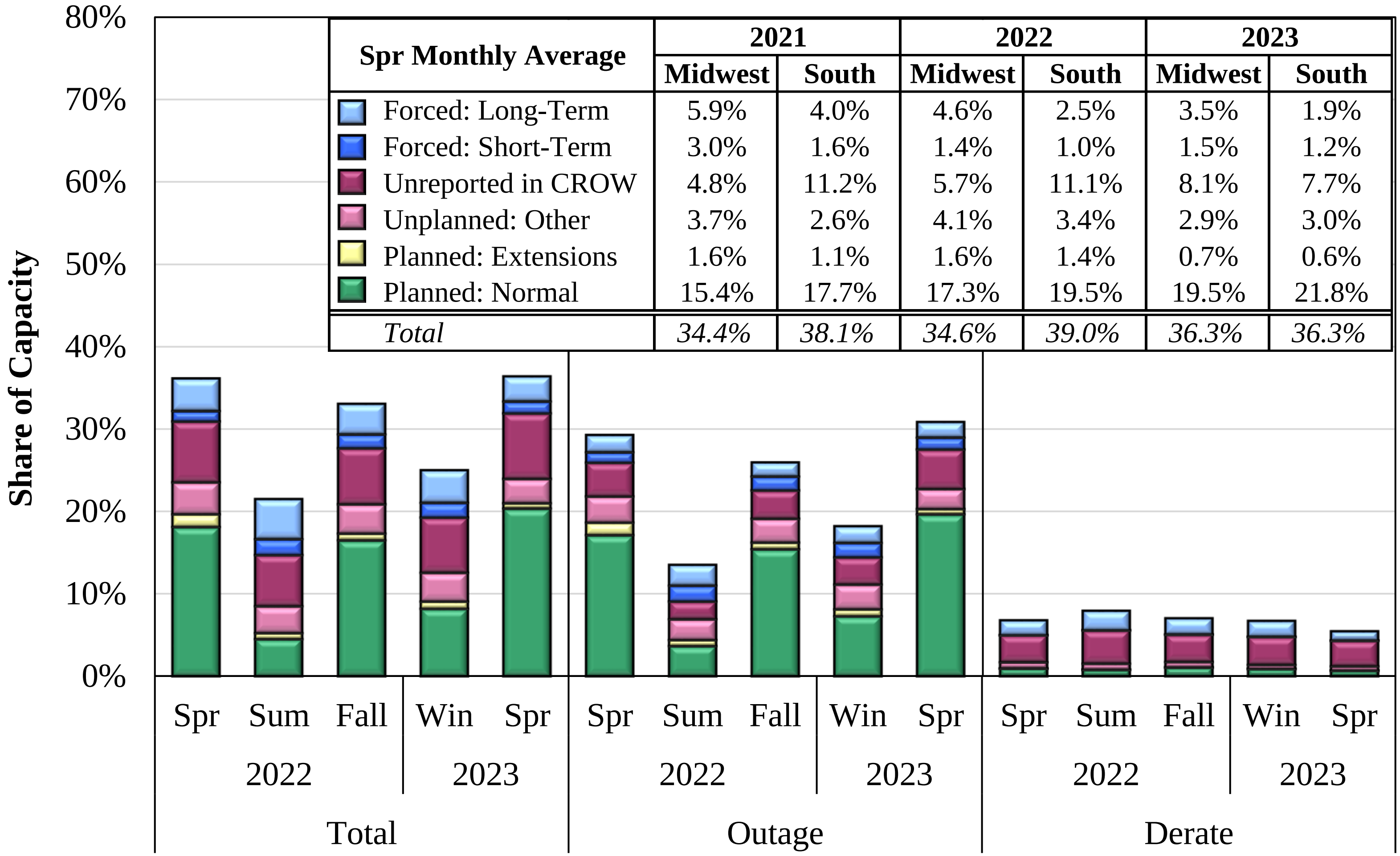
Percent Screened

	21	22	23	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
Supply	2.3	3.4	1.5	2.4	3.0	4.9	2.9	3.7	3.3	3.2	2.7	3.3	3.0	1.8	1.8	1.5	1.9	1.0
Demand	1.6	3.2	2.0	1.9	3.8	3.8	3.7	3.2	2.5	2.6	2.6	2.4	3.4	1.7	1.6	1.4	2.8	1.6
Total	2.0	3.3	1.7	2.2	3.4	4.4	3.3	3.4	2.9	2.9	2.6	2.9	3.2	1.8	1.7	1.5	2.3	1.3

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



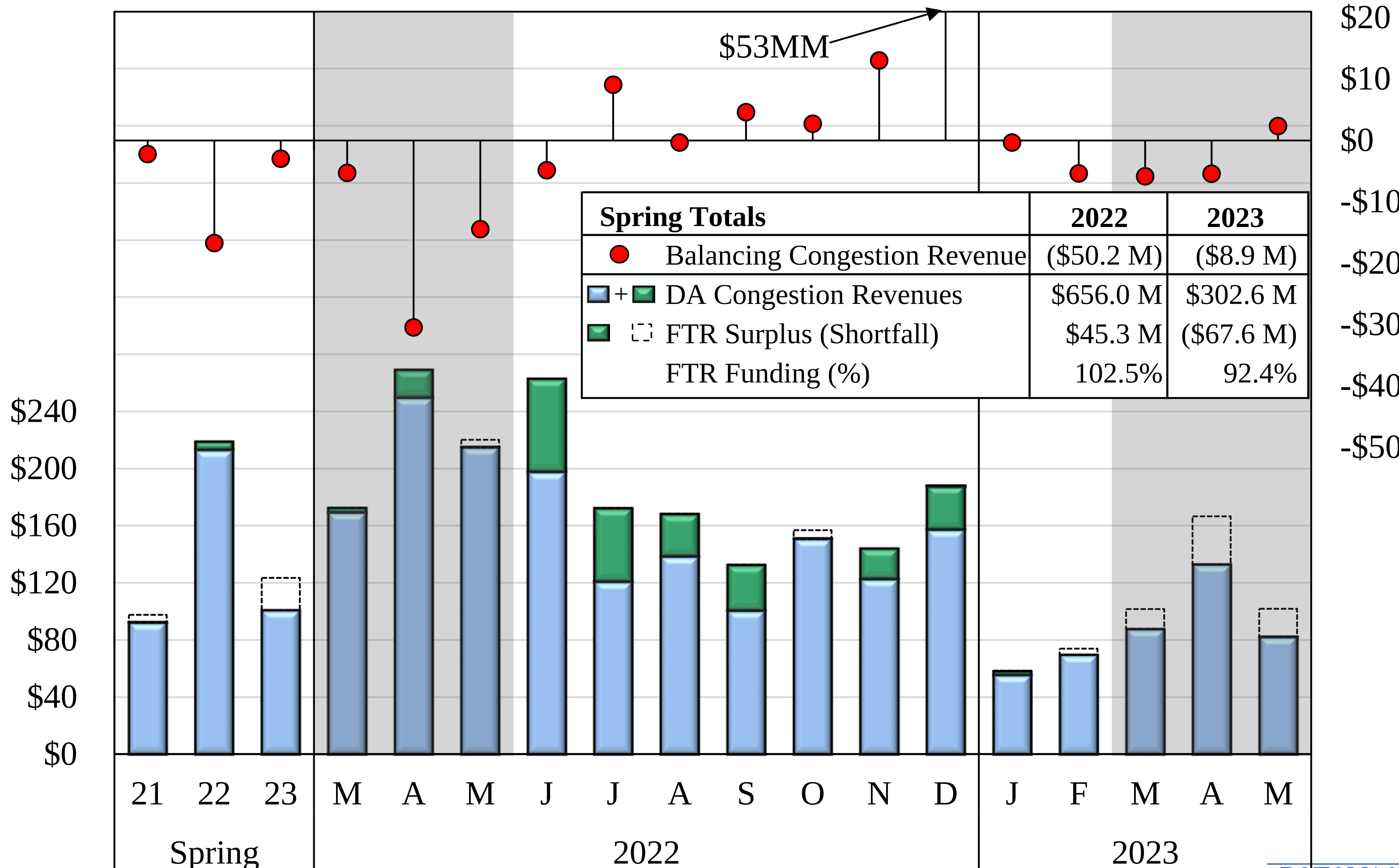
Generation Outages and Deratings
Spring 2021–2023



Spr Monthly Average	2021		2022		2023	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	5.9%	4.0%	4.6%	2.5%	3.5%	1.9%
Forced: Short-Term	3.0%	1.6%	1.4%	1.0%	1.5%	1.2%
Unreported in CROW	4.8%	11.2%	5.7%	11.1%	8.1%	7.7%
Unplanned: Other	3.7%	2.6%	4.1%	3.4%	2.9%	3.0%
Planned: Extensions	1.6%	1.1%	1.6%	1.4%	0.7%	0.6%
Planned: Normal	15.4%	17.7%	17.3%	19.5%	19.5%	21.8%
Total	*34.4%*	*38.1%*	*34.6%*	*39.0%*	*36.3%*	*36.3%*

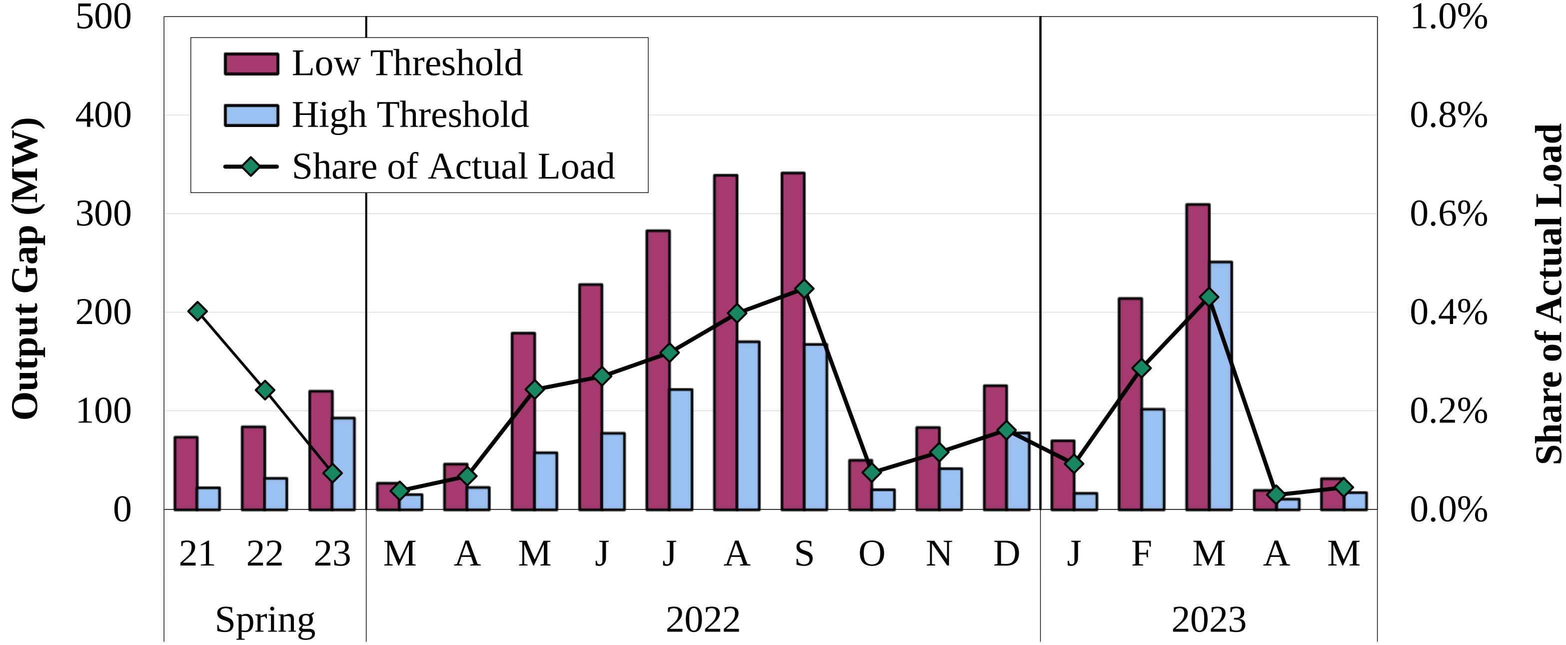
POTOMAC ECONOMICS

Day-Ahead Congestion, Balancing Congestion, and FTR Underfunding



Spring Totals	2022	2023
Balancing Congestion Revenue	($50.2 M)	($8.9 M)
DA Congestion Revenues	$656.0 M	$302.6 M
FTR Surplus (Shortfall)	$45.3 M	($67.6 M)
FTR Funding (%)	102.5%	92.4%

Monthly Output Gap
Spring 2021–2023



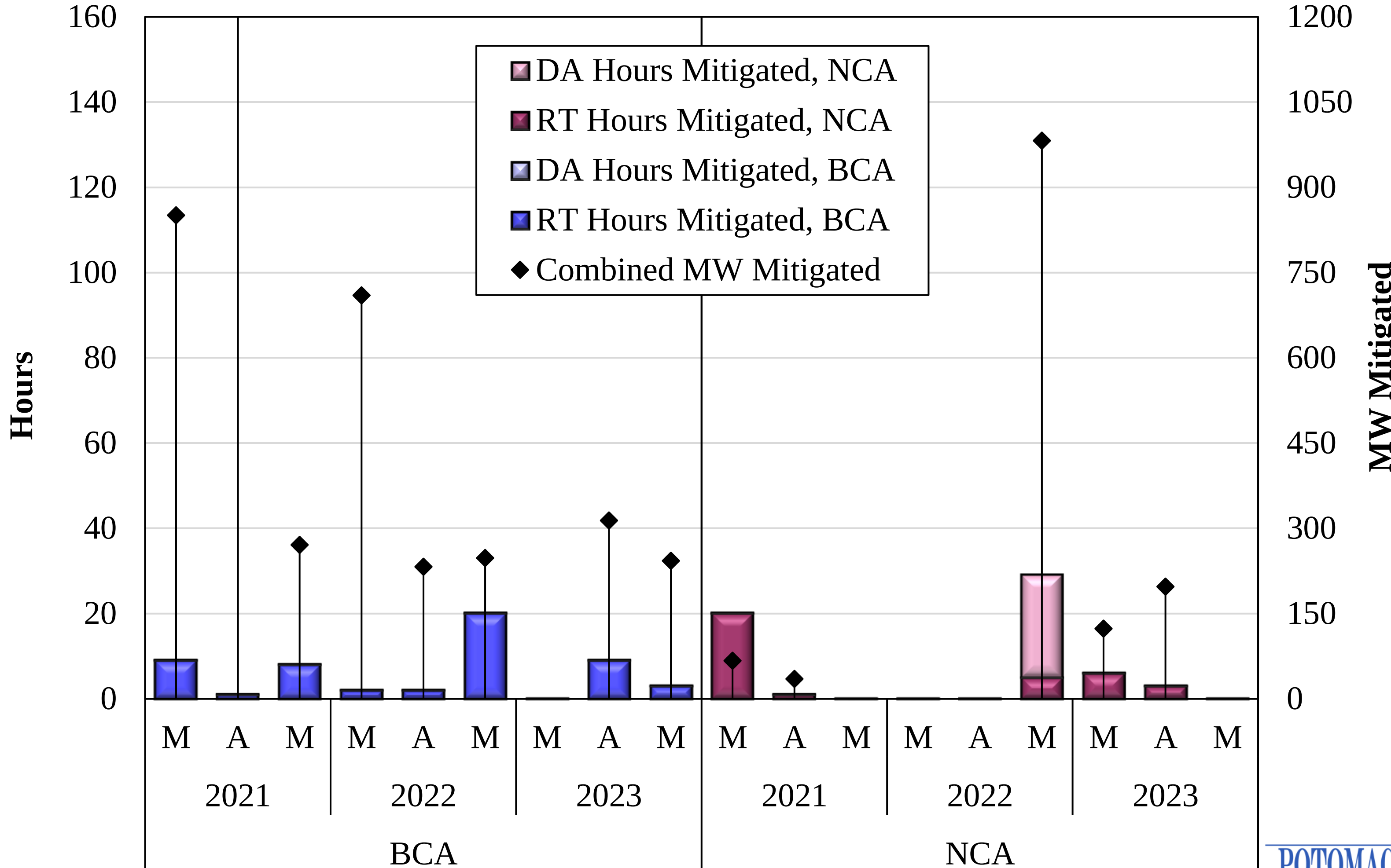
Low Threshold Results by Unit Status (MW)

Offline	4	47	112	17	20	103	118	184	238	256	27	47	82	29	170	301	11	24
Online	69	37	8	11	27	75	110	98	100	84	23	36	43	41	43	8	9	8

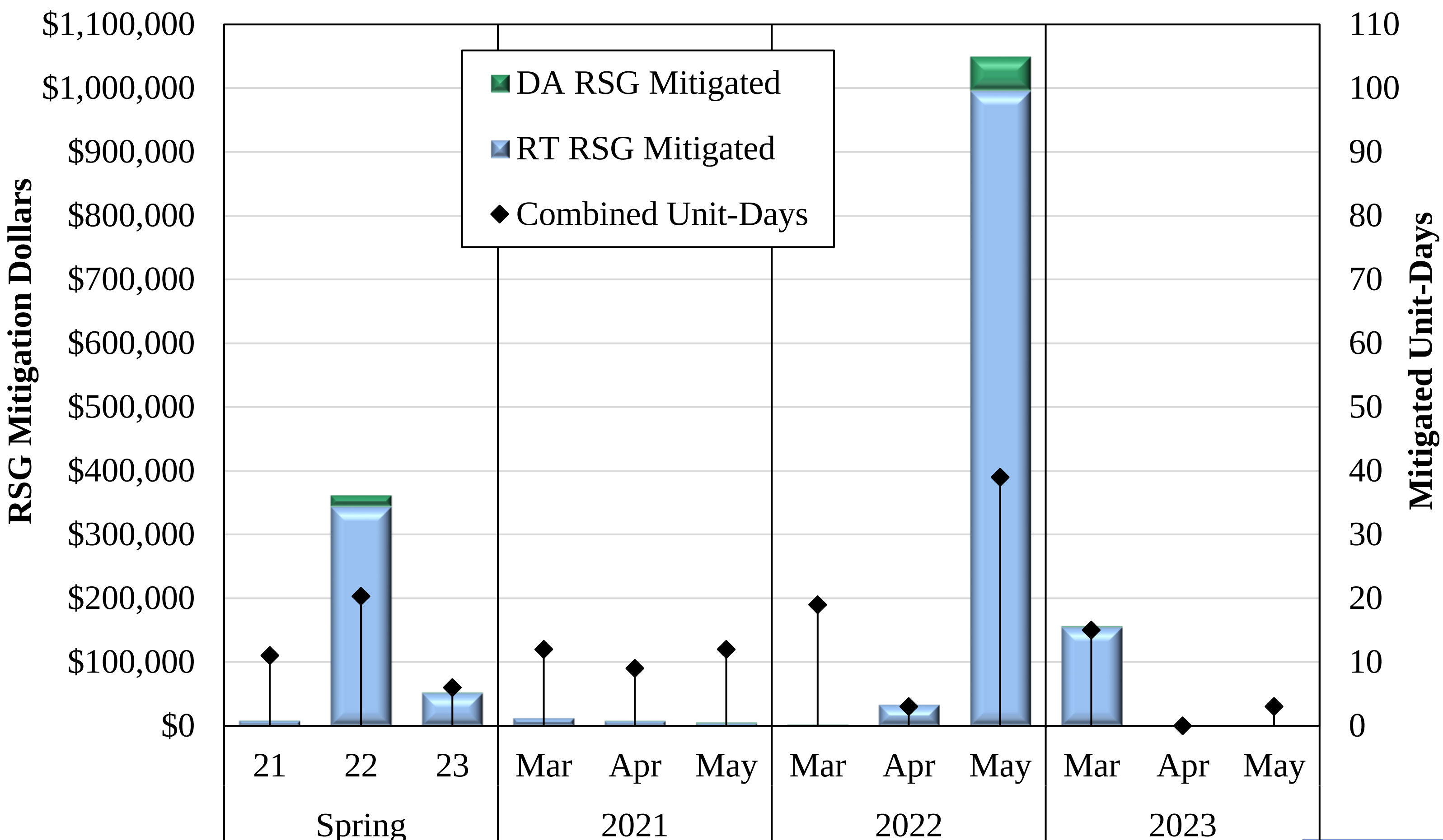
High Threshold Results by Unit Status (MW)

Offline	3	27	88	12	17	51	67	110	156	151	12	36	59	12	94	247	6	12
Online	19	5	5	4	6	7	10	12	14	16	8	6	19	5	7	4	5	6

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



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



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