IMM Quarterly Report: Summer 2024

Presented to:

MISO Board of Directors Markets Committee

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Quarterly Highlights: Summer 2024

- The MISO markets performed competitively, and market power mitigation was relatively infrequent the Summer.
- Energy prices fell 10 percent compared to last year because gas prices fell between 10 and 21 percent, and average load was similar to last year.
  - Load peaked at 122 GW on August 26, 3 percent below last year.
  - It would have been 1 percent higher but for voluntary demand response.
- Average hourly wind production increased 24 percent over last year to 7.7 GW. Wind curtailments doubled to an average of 262 MW per hour.
- Hurricane Beryl affected MISO South in July, causing extensive transmission outages and an islanding event.
  - MISO managed the reliability of the system well during this event.
  - However, prices were volatile and not efficient in the affected area.
- Both day-ahead and real-time congestion fell by nearly a third, largely because of falling gas prices, and FTRs were fully funded during the quarter.
- Based on our evaluation of Hurricane Beryl and other events during the summer, we provide **5** operational recommendations and **8** recommendations to address concerns with DR resources.

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Quarterly Summary

Summer		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
RT Energy Prices ($/MWh)		$31.08	*23%*	*-10%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago		$1.76	*17%*	*-21%*
Natural Gas - Henry Hub		$2.16	*25%*	*-10%*
Western Coal		$0.79	*2%*	*-3%*
Eastern Coal		$1.71	*-1%*	*-19%*
Load (GW)[2]				
Average Load		85.3	*23%*	*0%*
Peak Load		122.0	*24%*	*-3%*
% Scheduled DA (Peak Hour)		101.2%	99.8%	100.4%
Transmission Congestion ($M)				
Real-Time Congestion Value		$269.9	*-52%*	*-29%*
Day-Ahead Congestion Revenue		$187.4	*-50%*	*-29%*
Balancing Congestion Revenue[3]		$12.2	-$8.4	$19.6
Ancillary Service Prices ($/MWh)				
Regulation		$12.69	*5%*	*24%*
Spinning Reserves		$2.96	*15%*	*21%*
Supplemental Reserves		$1.46	*446%*	*116%*

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
FTR Funding (%)		103%	93%	101%
Wind Output (MW/hr)		7,710	*-43%*	*24%*
Wind Curtailed (MW/hr)		262	*-73%*	*105%*
Guarantee Payments ($M)[4]				
Real-Time RSG		$4.8	*123%*	*-44%*
Day-Ahead RSG		$5.3	*-28%*	*-23%*
Day-Ahead Margin Assurance		$15.1	*9%*	*18%*
Real-Time Offer Rev. Sufficiency		$0.8	*-27%*	*-11%*
Price Convergence[5]				
Market-wide DA Premium		0.7%	-6.3%	4.3%
Virtual Trading				
Cleared Quantity (MW/hr)		21,396	*-15%*	*-3%*
% Price Insensitive		50%	43%	48%
% Screened for Review		1%	2%	2%
Profitability ($/MW)		$0.2	$0.6	$0.6
Dispatch of Peaking Units (MW/hr)		3,007	1,611	2,729
Output Gap- Low Thresh. (MW/hr)		32	31	26

Key:
- ● Expected
- ● Monitor/Discuss
- ● Concern

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

Quarterly Highlights: Hurricane Beryl and Issues on July 9

Hurricane Beryl and SE Texas (SETEX) Load Pocket

- On July 8-9, Hurricane Beryl impacted Texas and Louisiana, causing forced transmission outages and SETEX Load Pocket islanding.
- Over 70 transmission outages occurred on July 8:
  - A single line connected the SETEX load pocket with the rest of the system.
  - The outages caused load to drop in SETEX down to roughly 400 MW.
  - Late on July 8, the line was lost and the pocket islanded. MISO declared a Restoration Event until the pocket was reconnected around 4 am on July 9.
- MISO did a very good job of maintaining reliability in the pocket during the event, but pricing was volatile and inefficient costs were incurred.
  - To protect the pocket in case the last line failed, MISO modeled it with a limit close to zero – because most resources were being manually dispatched by MISO and Entergy, the market could not always manage this constraint.
  - The resulting constraint violations caused prices in the load pocket to average $1500 per MWh across 2 hours and -$1500 per MWh in a different hour.
  - Units that MISO turned off or down received around $3 million in DAMAP, which was allocated to market participants throughout MISO.

Quarterly Highlights: Hurricane Beryl and Issues on July 9

Hurricane Beryl Pricing Evaluation (Slide 21)

- We simulated market outcomes assuming MISO used a much lower demand curve (TCDC) on the constraint into the pocket modeled at close to zero MW.
  - Prices would have cleared throughout the event at levels reflecting the marginal production costs of the generation serving the pocket.
  - Make-whole payments would have fallen by more than 75 percent.
- We find that the volatile pricing in SETEX during the event was not efficient and led to unwarranted uplift costs.
- Given the amount of load that was forced off by the transmission damage, this event should have qualified to be priced as a Forced Off Asset (FOA) Event.
  - Real-time prices are set equal to day-ahead prices in these events.
  - This event did not qualify because the FOA Revenue Inadequacy criteria is defined too narrowly.
- We recommend:
  - *Excluding constraints modified for reliability purposes from settlements.*
  - *Limiting the dead buses to load buses and including both Revenue Inadequacy and Price Volatility Make-Whole Payments as the financial criteria.*

Quarterly Highlights: Hurricane Beryl and Issues on July 9

<u>Operational Challenges on July 9 in the Midwest (Slides 22-23)</u>

- We have encouraged MISO to avoid uneconomic out-of-market commitments but avoiding economic and needed resource commitments can be harmful.
- On July 9, MISO did not commit resources needed to manage congestion and maintain adequate capacity in the Midwest after significant supply losses.
  - A major generator (540 MW) tripped at 14:30 and the look-ahead commitment model (LAC) began recommending MISO commit replacement resources.
  - MISO did not accept the LAC recommendations, causing the RDT to bind and raise prices throughout the Midwest by up to $240 per MWh.
  - This RDT price effect pushed most generators up, even some that needed to be dispatched down to manage constraints, leading 13 constraints to be violated.
  - To manage the constraints, MISO called transmission line load procedures (TLR) that caused a 790 MW loss in imports and began manually reducing certain units in the Midwest that caused another 1300 MW loss of capacity.
  - This led to inflated congestion, prices, and $852 thousand in DAMAP costs.
- We recommend MISO: *implement identified improvements in the LAC model to increase confidence and acceptance of its recommendations by operators.*

Quarterly Highlights: Hurricane Beryl and Issues on July 9

Regional Dispatch Transfer (RDT) Pricing (Slide 24)

- We identified a pricing inefficiency when the RDT binds in the South-to-North direction because of the combined effects of the Reserve Procurement Enhancement (RPE) and the RDT constraint.
  - Prices throughout the Midwest reflect the shadow prices of the RDT and RPE constraints when both are in violation, raising prices by up to $700 per MWh ($500 for the RDT violation plus $200 for the RPE).
  - STR clearing is adequate to offset the most severe contingency 99 percent of the time RDT is violated; therefore, adding $200 for RPE is inefficient.
  - Over-pricing RDT violations by $200 per MWh when the constraint is in small violation is costly and can cause the dispatch to violate local constraints.
- To address this pricing concern, we recommend MISO:
  - *Drop the highest TCDC step for the RDT from $500 to $300 per MWh so the total violation cost and sub-regional price separation is $500 as intended.*
  - *Move the RPE post-reserve deployment binding limit on the RDT to 102 percent, where the highest TCDC for the RDT also applied.*

Quarterly Highlights: Peak Summer Demand

Peak Load Day and Market Outcomes (Slides 26-28)

- Annual peak demand of roughly 122 GW occurred on August 26, but this peak would have been 1800 MW higher but for voluntary demand response.
- MISO made advanced preparations based on forecasted temperatures and load.
  - MISO declared Conservative Operations and issued alerts that escalated to a Maximum Generation Warning from 1 pm to 8 pm.
  - Max Gen Alerts and Warnings trigger Tier 0 and Tier 1 emergency pricing, respectively, allowing 4-hour GTs and emergency MW to set prices in ELMP.
    - This led to a $60 per MWh price increase on average during the Warning, which sustained PJM imports even though prices in PJM were also high.
- MISO's operations during this event was substantially improved – operators:
  - Prudently avoided escalating to higher-level emergency steps;
  - Increased STR requirements to dynamically to account for risk and uncertainty;
  - Committed fewer resources out of market than in prior hot weather periods;
  - However, some resources were committed that were not needed, indicating opportunities for further process improvements.

Quarterly Highlights: Demand Response Evaluation

<u>Demand Response (DR) Resource Issues in MISO (Slide 30)</u>

- In the past few years, FERC has investigated and taken enforcement actions against multiple demand response providers in MISO.
- A seasonal average of 7 GW of DR cleared in MISO’s 2024-2025 PRA, and over 200 MW of DRR-I participates regularly in energy and ancillary services.
  - Since 2019, DR resources received over $800 million in capacity payments.
- Because MISO relies on a large quantity of DR in both the planning and operating timeframe to maintain reliability, we have been evaluating it.
- Our evaluation of DR deployment performance raises concerns:
  - Of 213 spinning reserve deployments across 22 event days in 2023-2024, more than 40 percent of DRR type 1 resources did not perform adequately.
  - DR resources that fail to respond to spinning reserve deployments face very small penalties – we also identified a settlement flaw that provides them DAMAP, eliminating any incentive to curtail.
  - The worst performing DR class is “Batch-Load DR” (BLDR), introduced in 2020, without supporting tariff provisions. This class of DR is cycling load that agrees *not to increase* rather than to curtail.

Quarterly Highlights: Demand Response Evaluation

Demand Response (DR) Resource Issues in MISO (cont.)

- MISO’s rules, administration, and participant conduct also raises concerns:
  - Up to 25 percent of DR resources submit “mock tests” for accreditation in lieu of actual tests, which presents opportunities for fraudulent data submissions. Penalties for overstating capabilities and underperforming are insufficient.
  - Some DR resources submitting “real tests” measure demand reductions when facilities/processes are otherwise shutting down, which does not demonstrate how they would respond during a reserve deployment or curtailment event.
  - We found one commercial retail end-use customer signed up with multiple market participants for the same load;
  - Some market participants submit unconsummated contracts with critical information redacted that prevent MISO verifying the DR amount or validity;
  - 48 percent of LMRs are cross-registered as Emergency DR;
    - EDRs are called very late in the emergency procedures and serve little purpose. They have never been called by MISO.
    - Hence, this is an effective strategy to receive capacity payments with virtually no chance of having to perform.

Quarterly Highlights: Demand Response Evaluation

<u>IMM Recommendations for Demand Response Resources</u>

- We are actively working with MISO to develop tariff changes to reduce the potential for manipulation or gaming by DR resources.
- Based on our DR review, we recommend the following additional changes:
  1. Eliminate EDR resources as a class of demand response.
  2. Eliminate the Batch Load Demand Resource category in the BPM.
  3. Automate validation of end-use registrations and enact penalties to deter end-use customers from contracting with multiple MPs.
  4. Reform penalties for non-performance that create adequate incentives.
  5. Enforce the tariff when qualifying DR resources including requiring fully executed contracts that show DR amounts.
  6. Eliminate mock tests and require real tests for registered demand resources to be conducted at MISO's choosing that represent actual curtailments.
  7. Require utility-grade meters and 5-minute data for DR providing reserves.
  8. Require real tests for non-capacity DR resources (DRR1 and DRR2).

Submittals to External Entities and Other Issues

During the Summer Quarter, we:

- Responded to several FERC questions related to prior referrals and FERC investigations, and we responded to requests for information on market issues.
  - We made a new referral to FERC regarding overridden meter information.
  - We made a new sanction recommendation to MISO for uneconomic production and MISO acted upon a prior sanction recommendation.
- Presented the IMM Spring Quarterly report to the MSC and recent market results to the ERSC.
- Worked with MISO on recommended operational improvements.
- Continued working with MISO to discuss concerns with the proposed benefit assessment of LRTP Tranche 2 projects.
  - MISO has posted comments that describe our concerns, which are most acute for three classes of benefits likely to be invalid or substantially overstated.
  - MISO has not agreed to address these concerns, which undermines the basis for MISO's Tranche 2 determinations.
  - We will continue to discuss these concerns with MISO and offer potential solutions to address them.

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Submittals to External Entities and Other Issues

Our work with the RTOs to revise the JOA "firm flow entitlements" (FFEs):

- The FFEs drive the M2M settlements and TLR relief priority and are based on the system that existed as of the 2004 "Freeze Date".
  - The current approved JOA process is untenable as the RTO systems have changed dramatically from 2004.
  - The RTOs are at an impasse and all current proposals to revise the FFE rules have been rejected by the 3 RTOs.
  - In absence of a revised JOA, the RTOs have separately made changes to their processes/data that are inconsistent with the approved JOA in each tariff.
    - For example, including post-freeze date units or non-firm energy only units in the FFE calculations.
  - We have also found other errors or inconsistencies that may impact FFEs.
- These issues are serious concerns because they impact 40 to 50 percent of MISO's real-time congestion.
- We are considering possible remedies or potential paths toward a long-term solution for calculating FFEs under the JOA.

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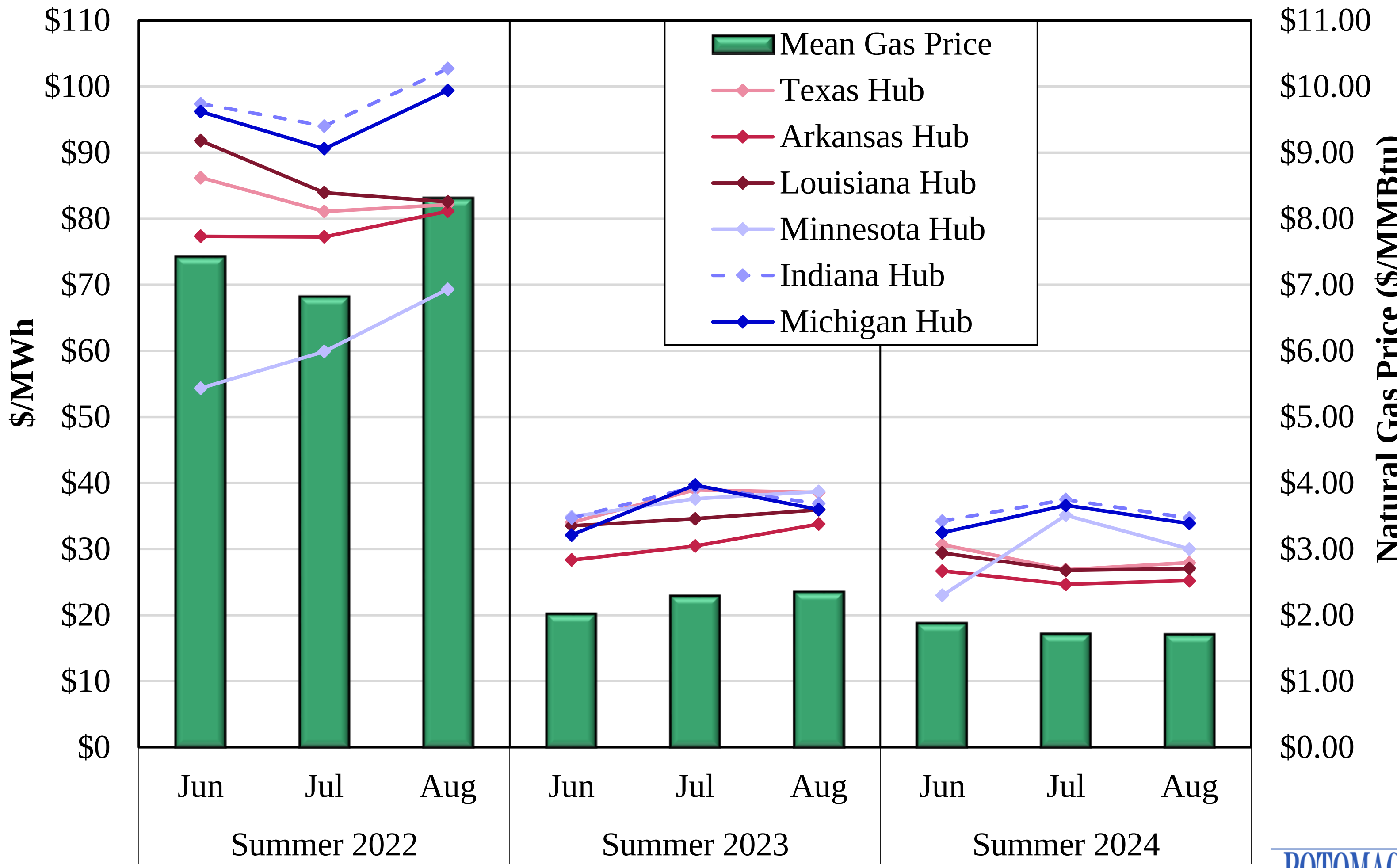
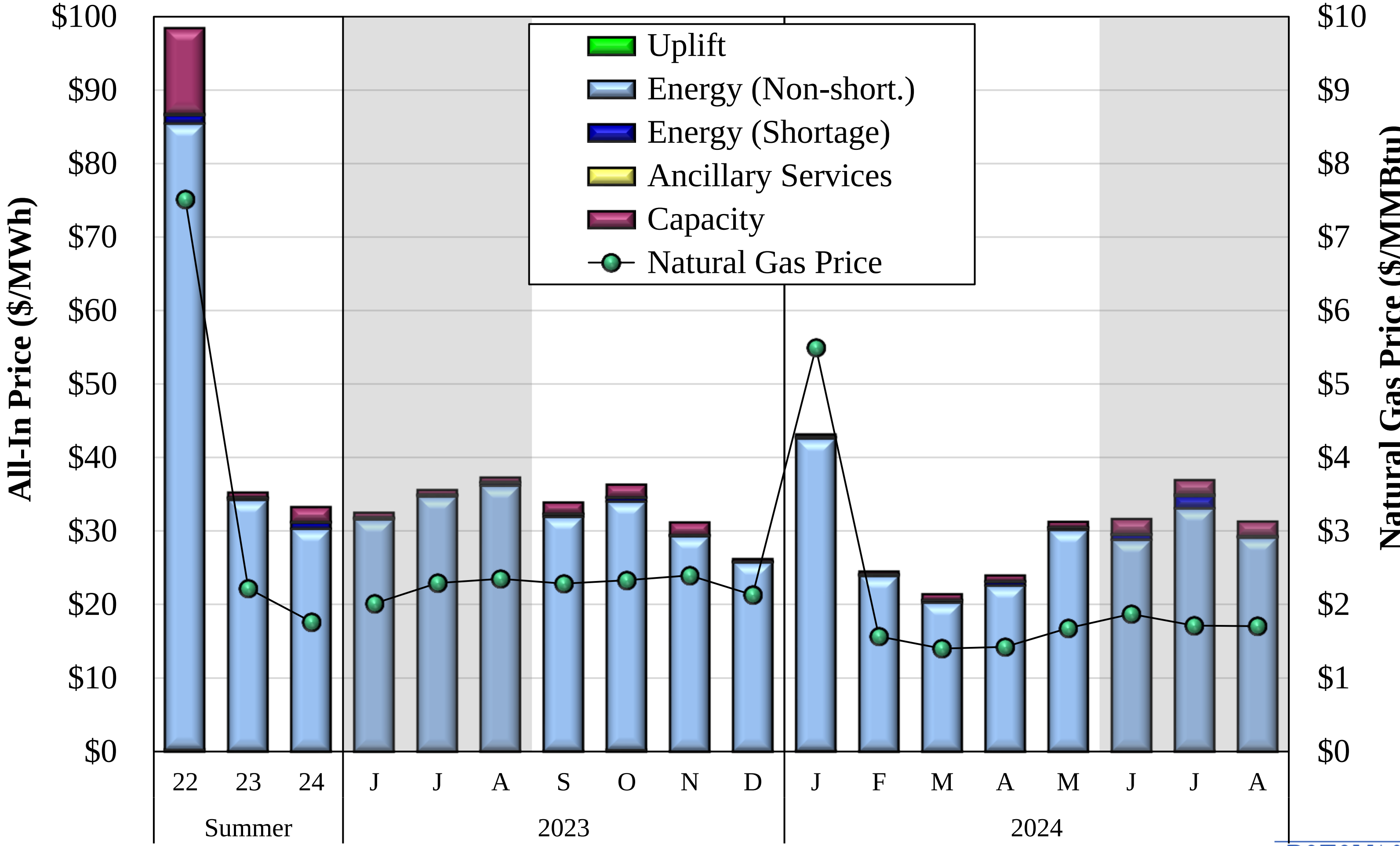
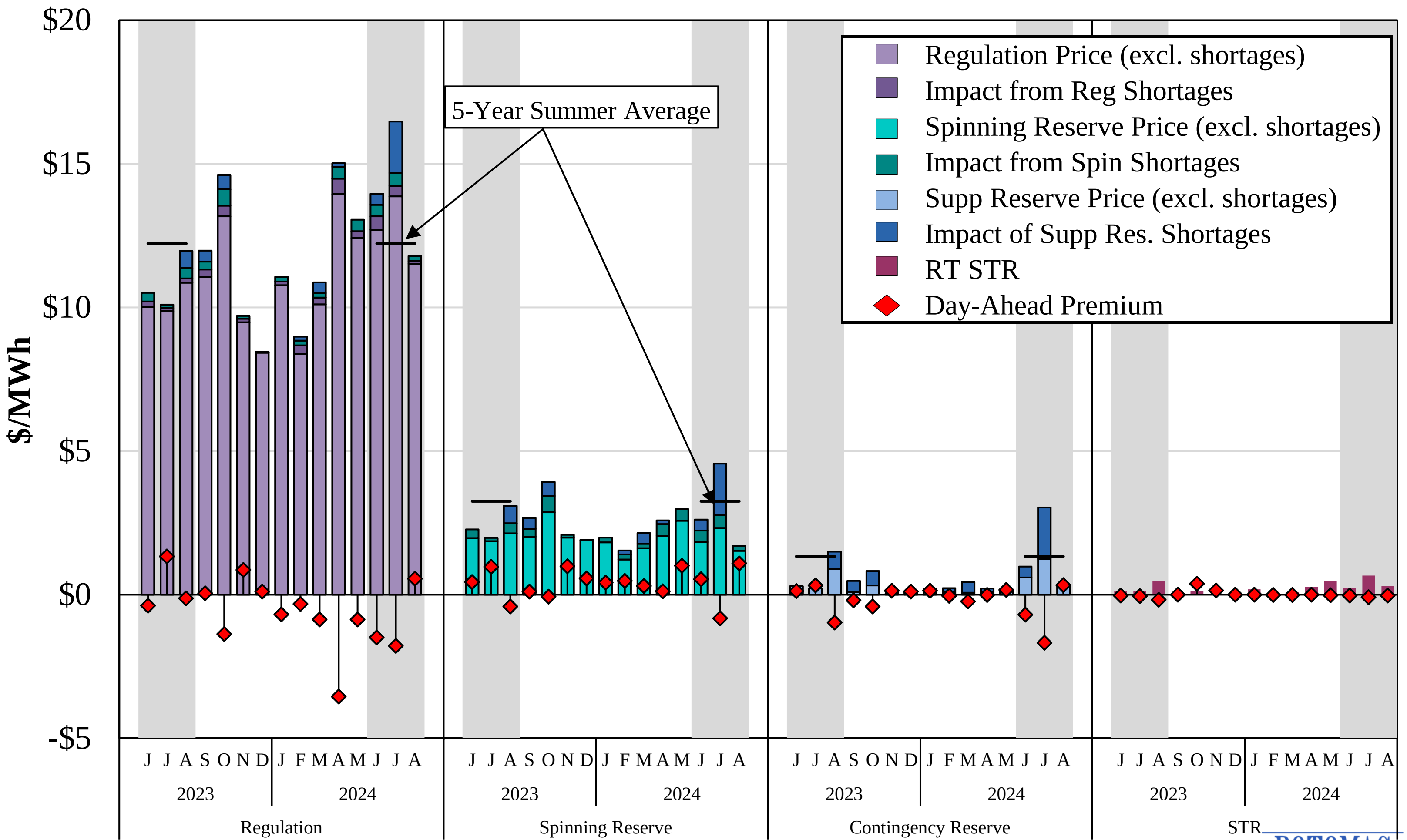
Day-Ahead Average Monthly Hub Prices
Summer 2022–2024



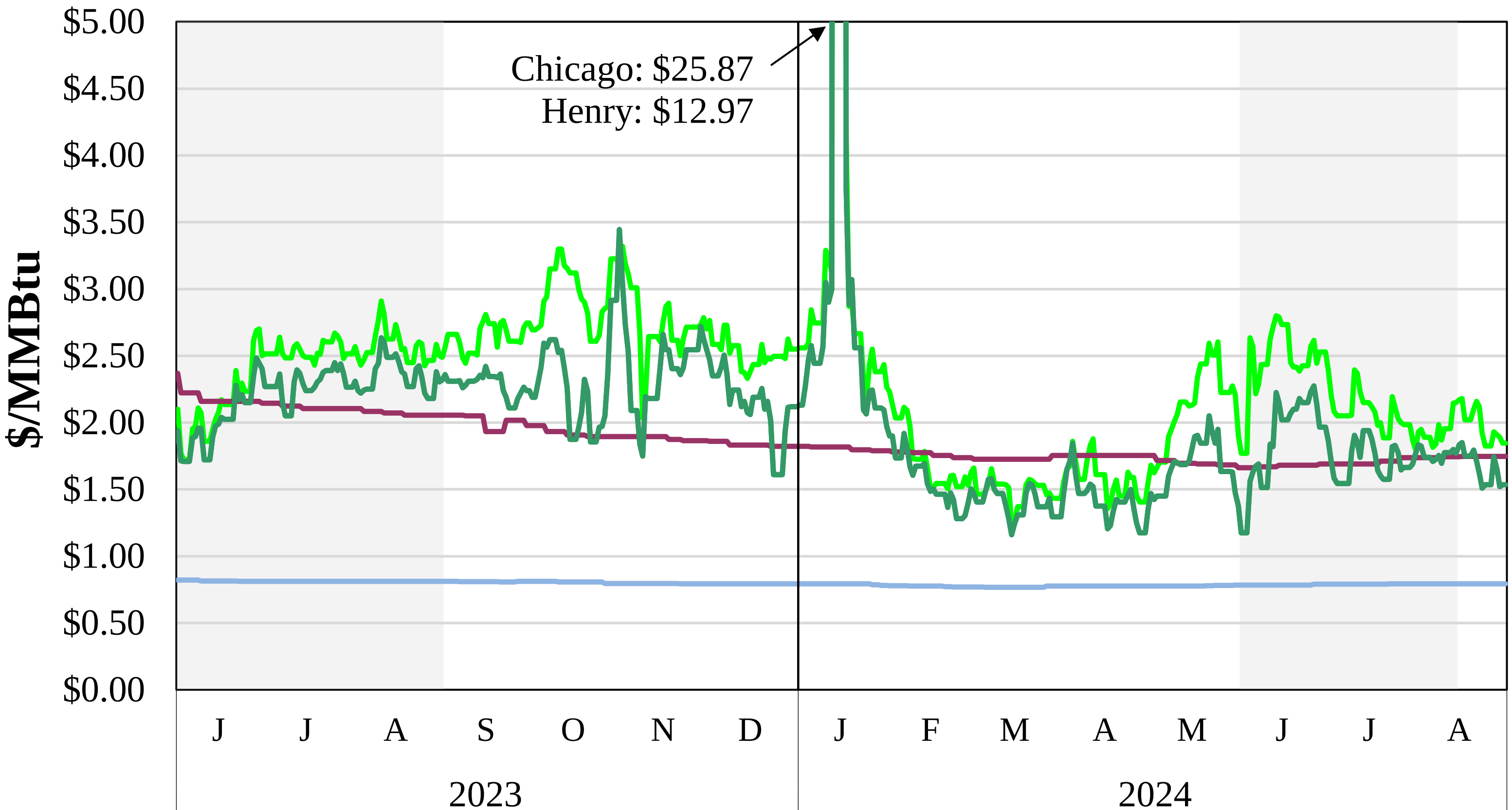
All-In Price
Summer 2022 – 2024



Ancillary Services Prices
Summer 2023–2024



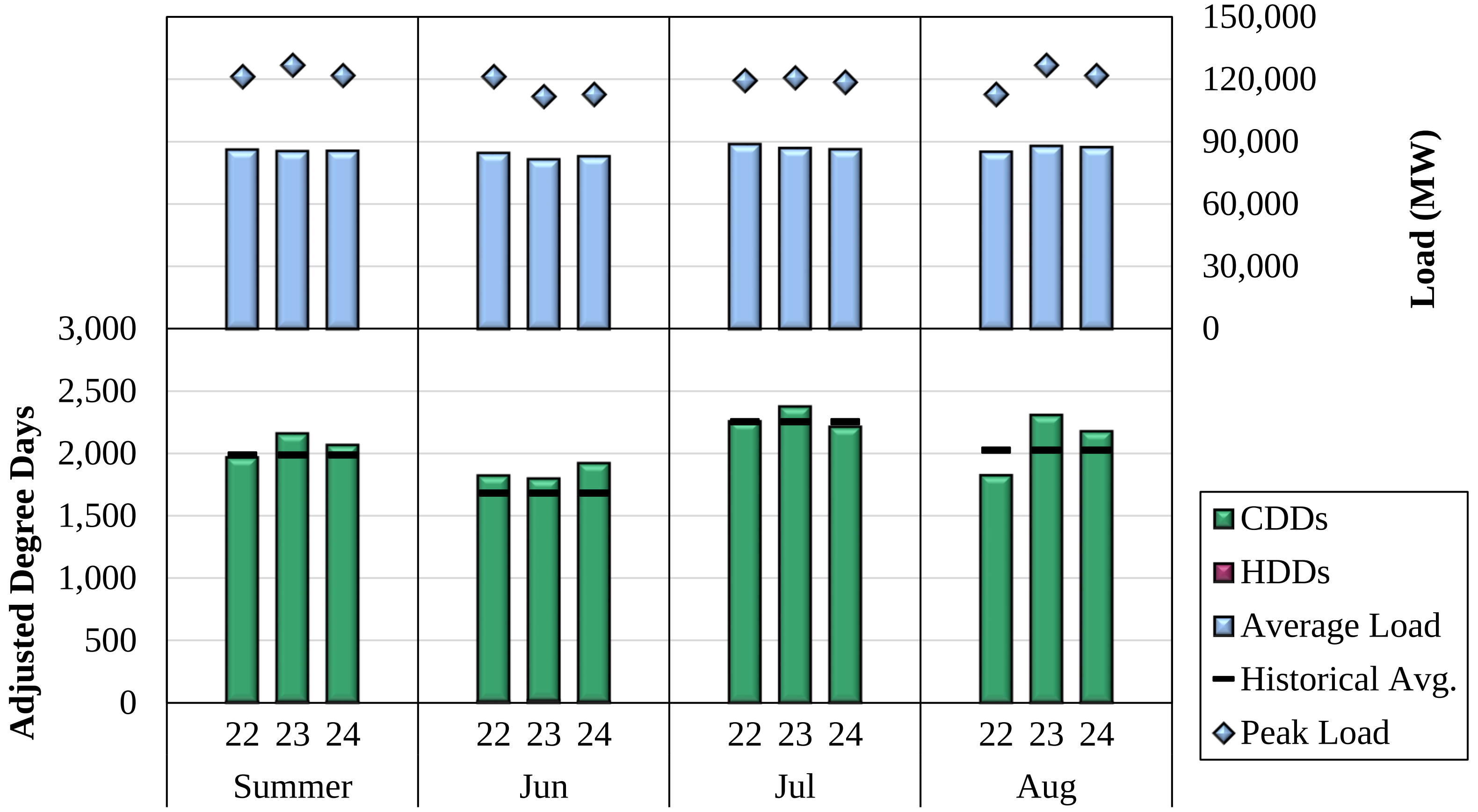
MISO Fuel Prices
2023–2024



Summer Average	2022	2023	2024
Chicago NG	$7.51	$2.22	$1.76
Henry NG	$7.87	$2.41	$2.16

Summer Average	2022	2023	2024
IB Coal	$7.14	$2.12	$1.71
PRB Coal	$0.96	$0.81	$0.79

Load and Weather Patterns
Summer 2022–2024



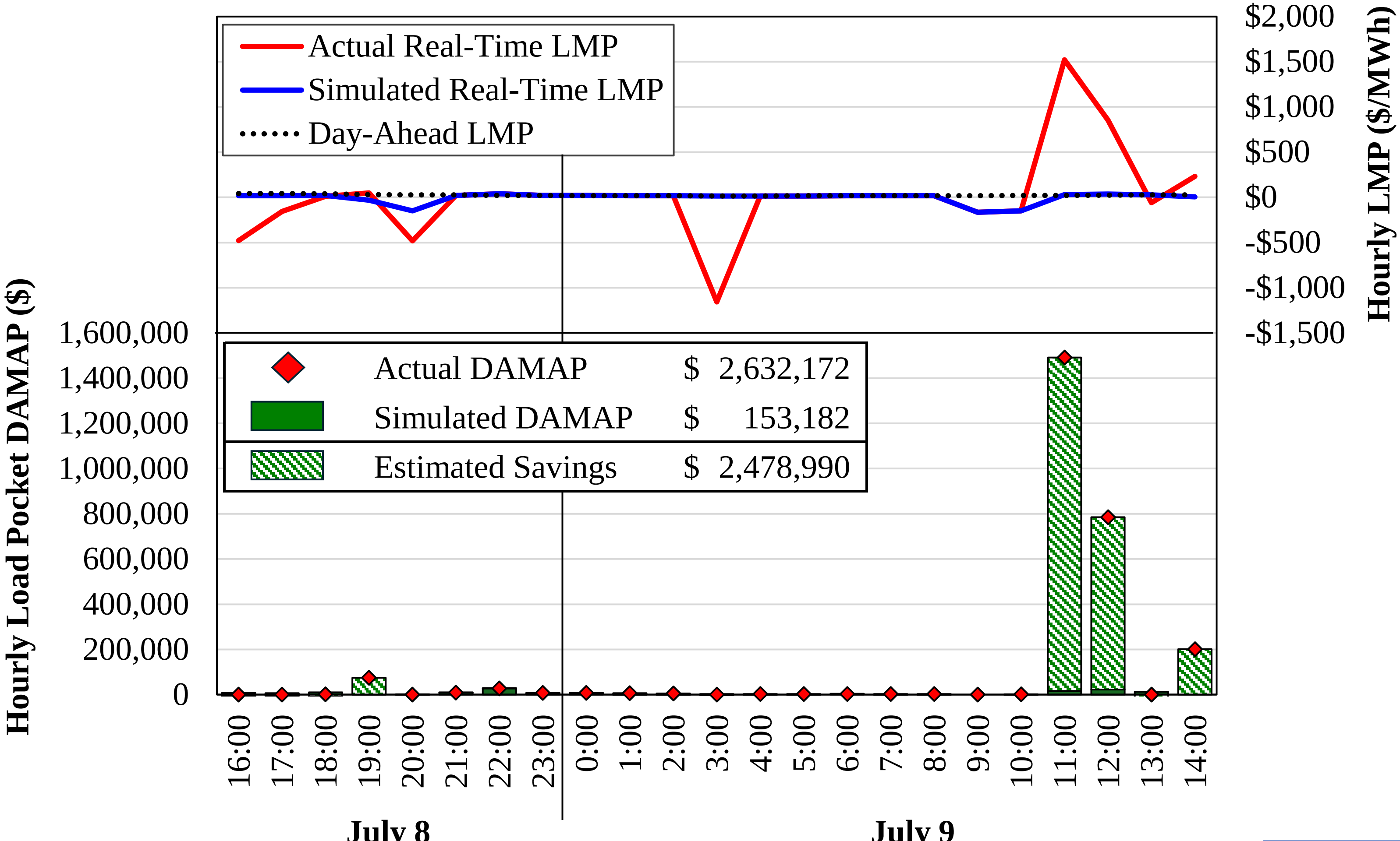
Notes: Midwest degree day calculations include four reprsentative cities: Indianapolis, Detroit, Milwaukee and Minneapolis. The South region includes Little Rock and New Orleans.

Capacity, Energy and Price Setting Share
Summer 2023–2024

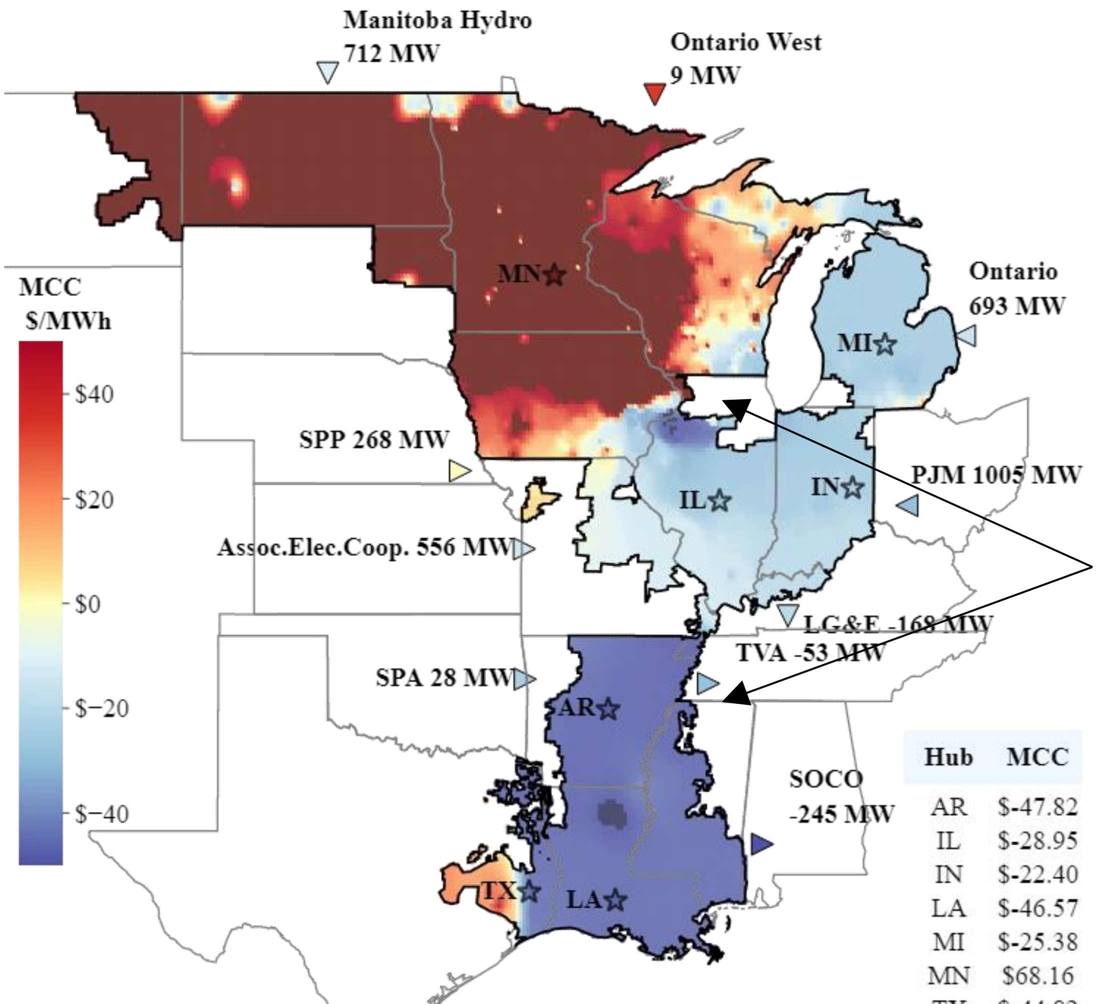
Summer	Accredited Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2023	2024	2023	2024	2023	2024	2023	2024	2023	2024
Nuclear	10,869	11,149	9%	9%	14%	14%	0%	0%	0%	0%
Coal	38,670	38,047	30%	29%	31%	29%	33%	38%	82%	83%
Natural Gas	62,120	61,673	49%	47%	44%	43%	66%	61%	97%	93%
Oil	1,513	1,515	1%	1%	0%	0%	0%	0%	1%	1%
Hydro	4,176	3,862	3%	3%	1%	2%	1%	1%	2%	3%
Wind	4,811	5,403	4%	4%	8%	10%	0%	0%	35%	51%
Solar	2,475	5,852	2%	4%	1%	3%	0%	0%	15%	14%
Other	2,664	2,822	2%	2%	1%	0%	0%	0%	2%	5%
Total	**127,297**	**130,324**								

Hurricane Beryl and Other Issues on July 9

Hurricane Beryl: SE Texas Islanding
July 8-9, 2024



Congestion Management in Midwest
July 9, 2024



Hub	MCC
AR	$-47.82
IL	$-28.95
IN	$-22.40
LA	$-46.57
MI	$-25.38
MN	$68.16
TX	$-44.82

RDT binding causes low prices in the South and high prices in the Midwest

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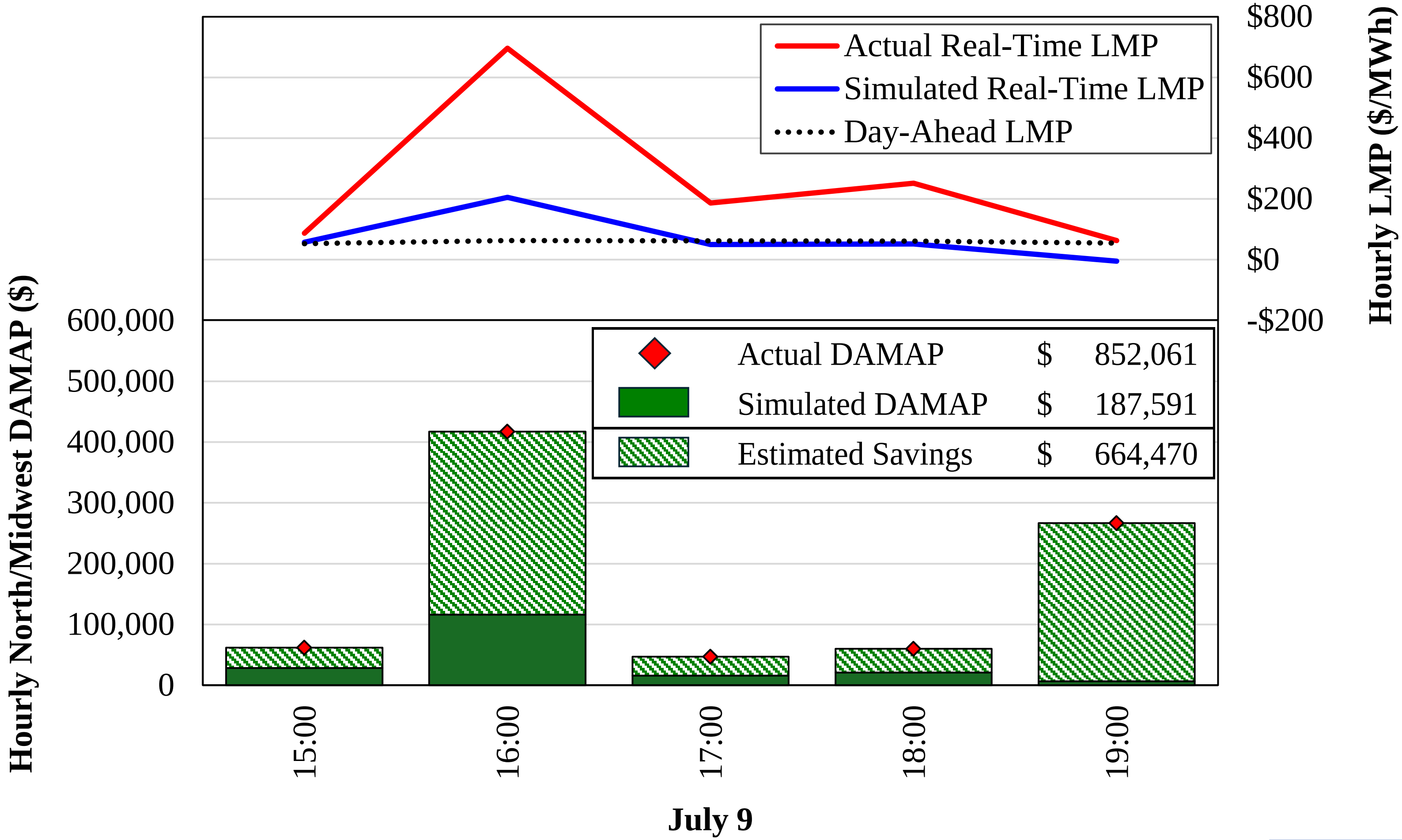
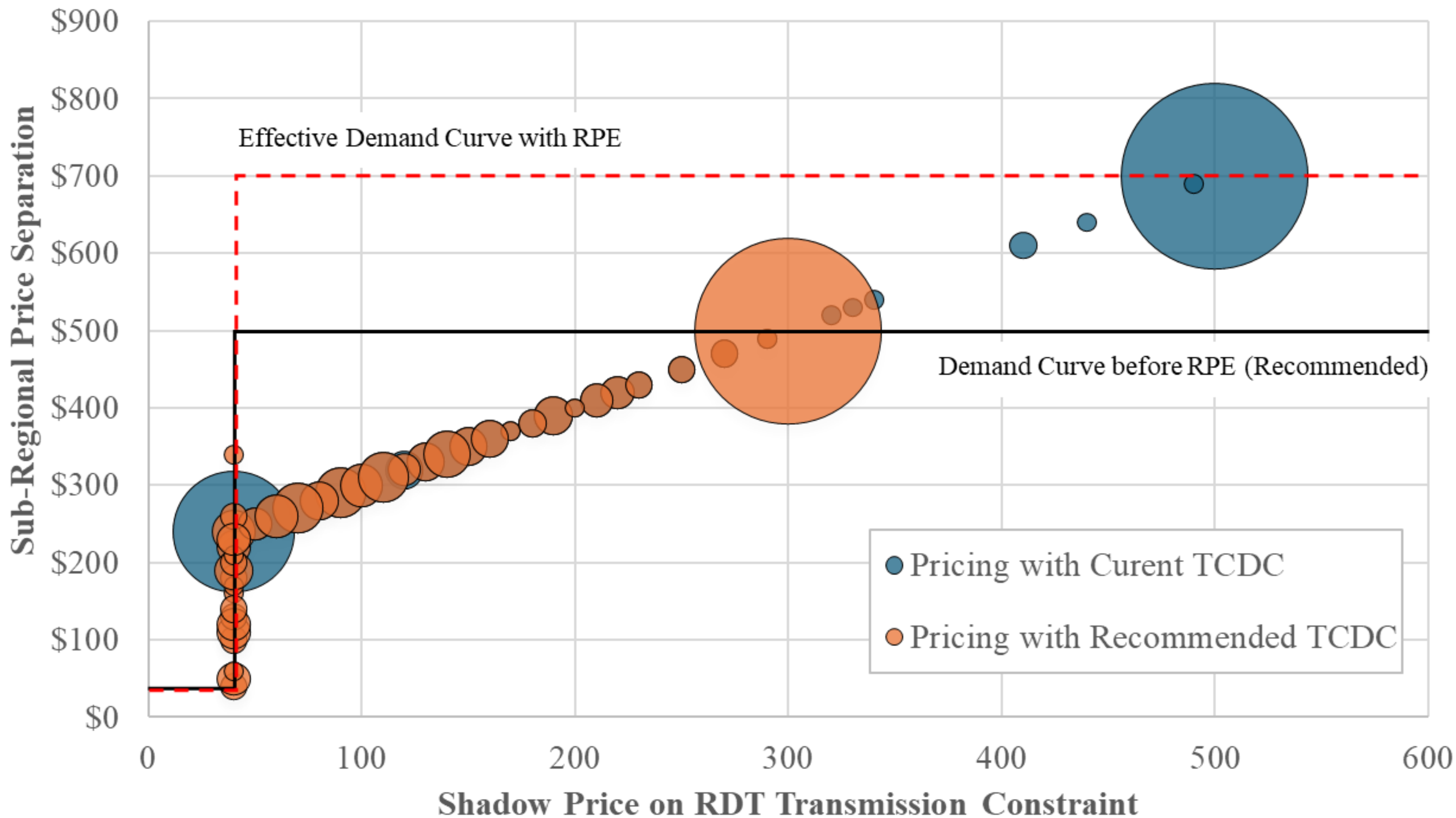
IMM Simulation of MISO Commitments
July 9, 2024



Shadow Price on RDT When Binding and Price Separation South and Midwest



Hot Weather Conditions
August 26-27

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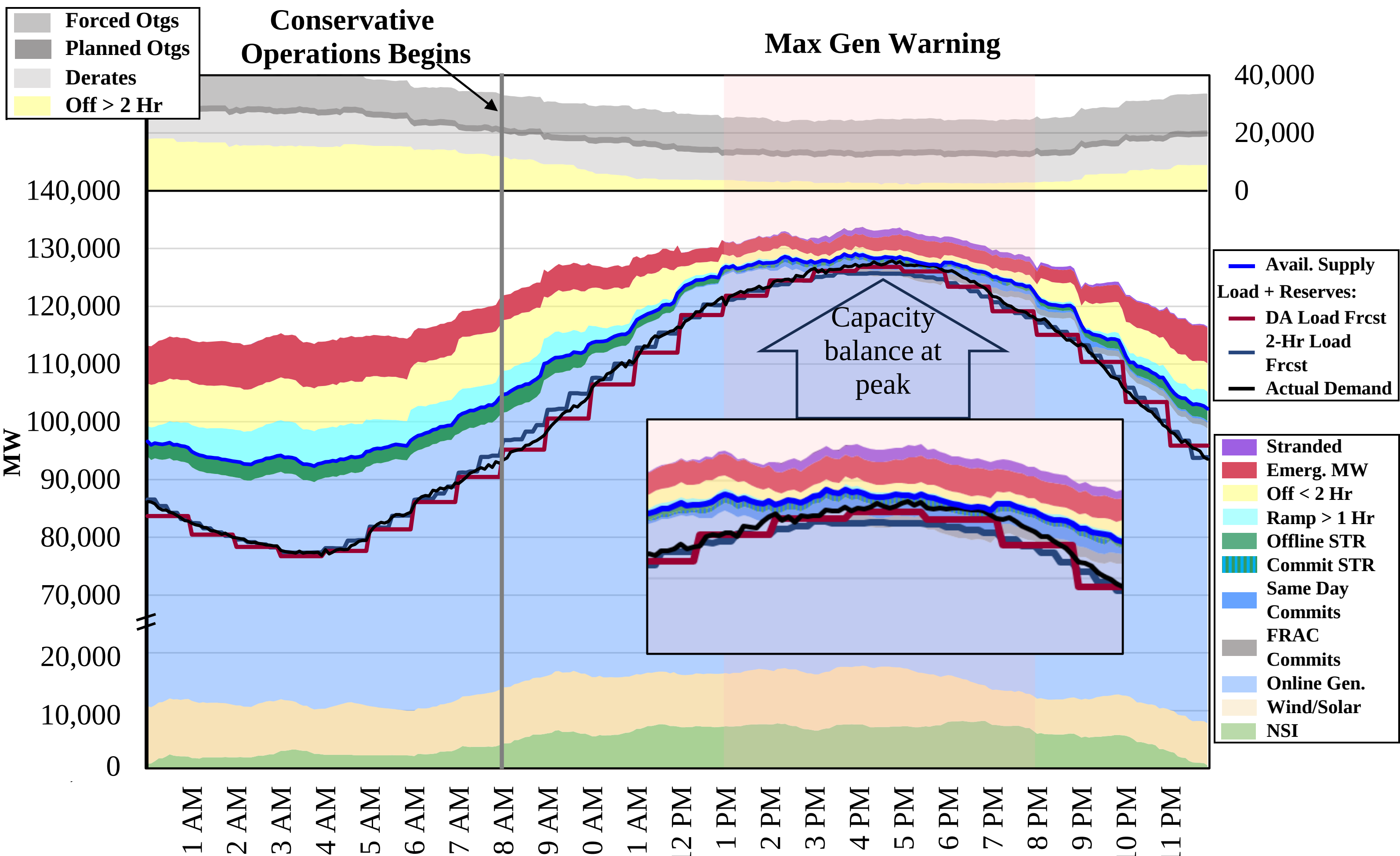
High Temperatures
August 23 – 27, 2024

	Hist. Avg.	Aug-2024				
		23	24	25	26	27
Minneapolis	**80**	80	85	86	91	77
Des Moines	**82**	81	86	93	99	92
Detroit	**80**	79	84	88	91	94
Indianapolis	**84**	83	90	90	91	93
Chicago	**82**	82	90	92	96	99
Little Rock	**91**	96	93	95	98	98
New Orleans	**91**	91	92	87	93	94
Houston	**93**	95	95	96	90	90

Notes: Pink Background Means Above Historical Average By At Least 8 Degrees Fahrenheit.

Midwest Capacity Balance
August 26, 2024



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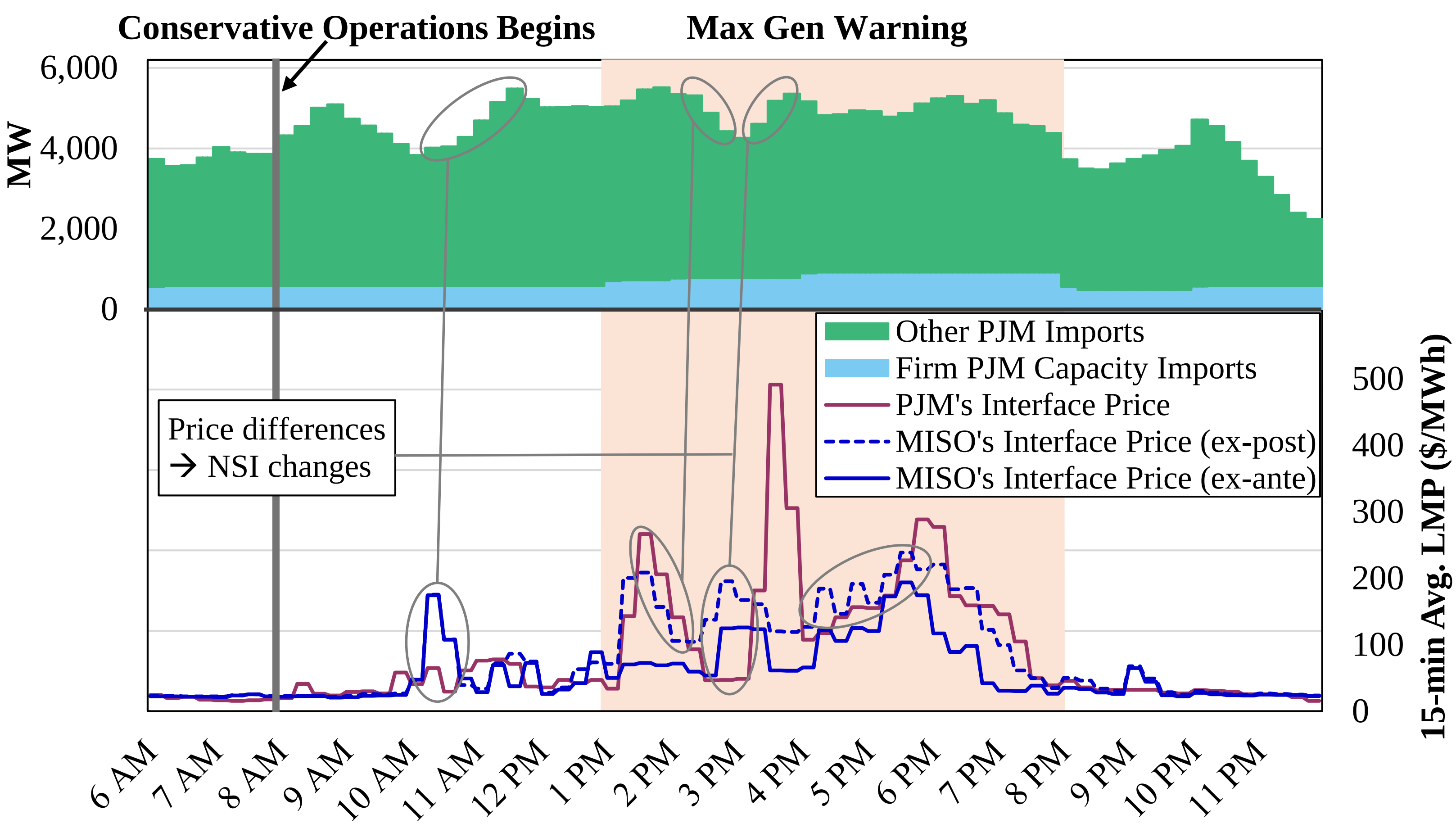
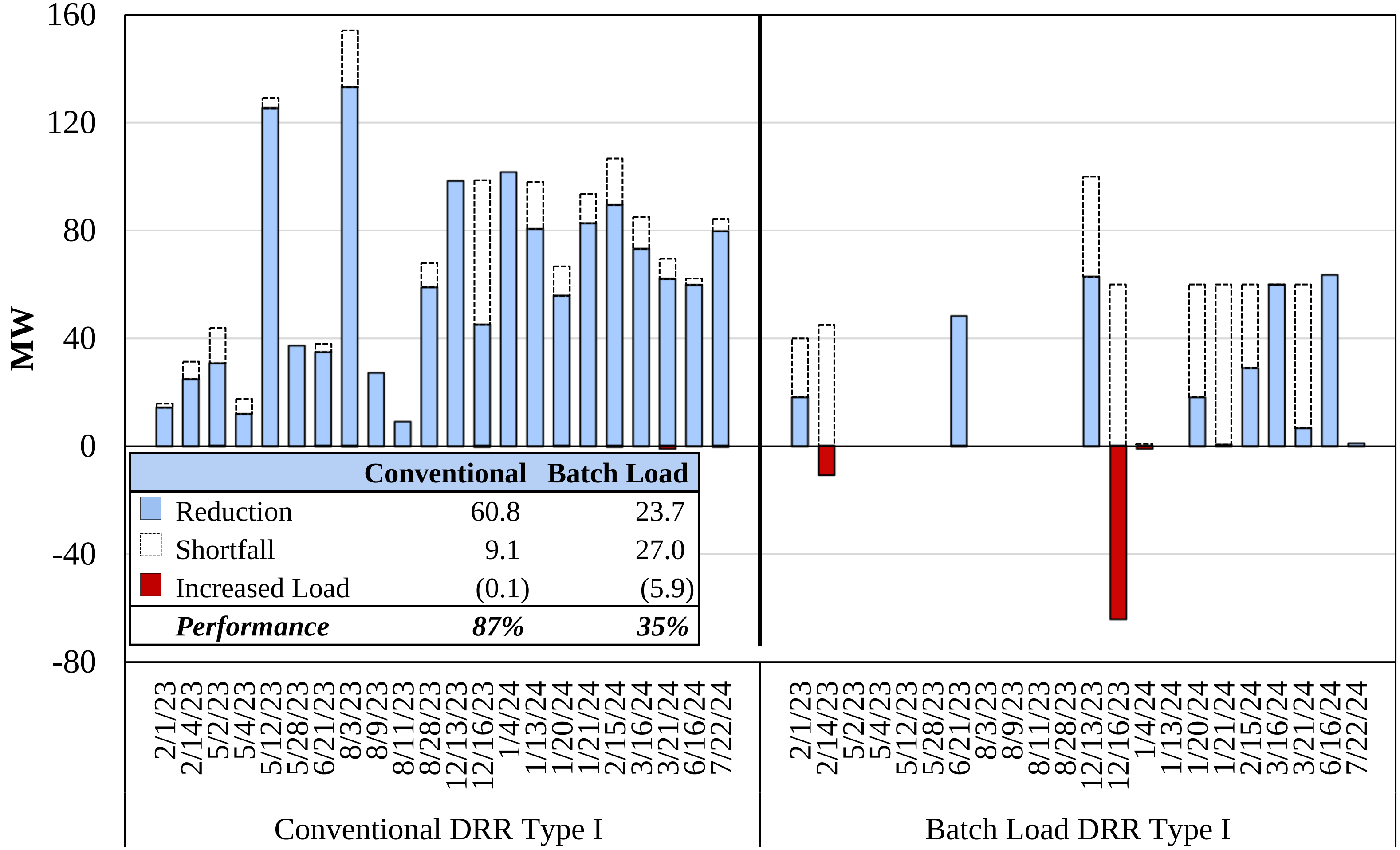
Pricing and Imports from PJM
August 26, 2024

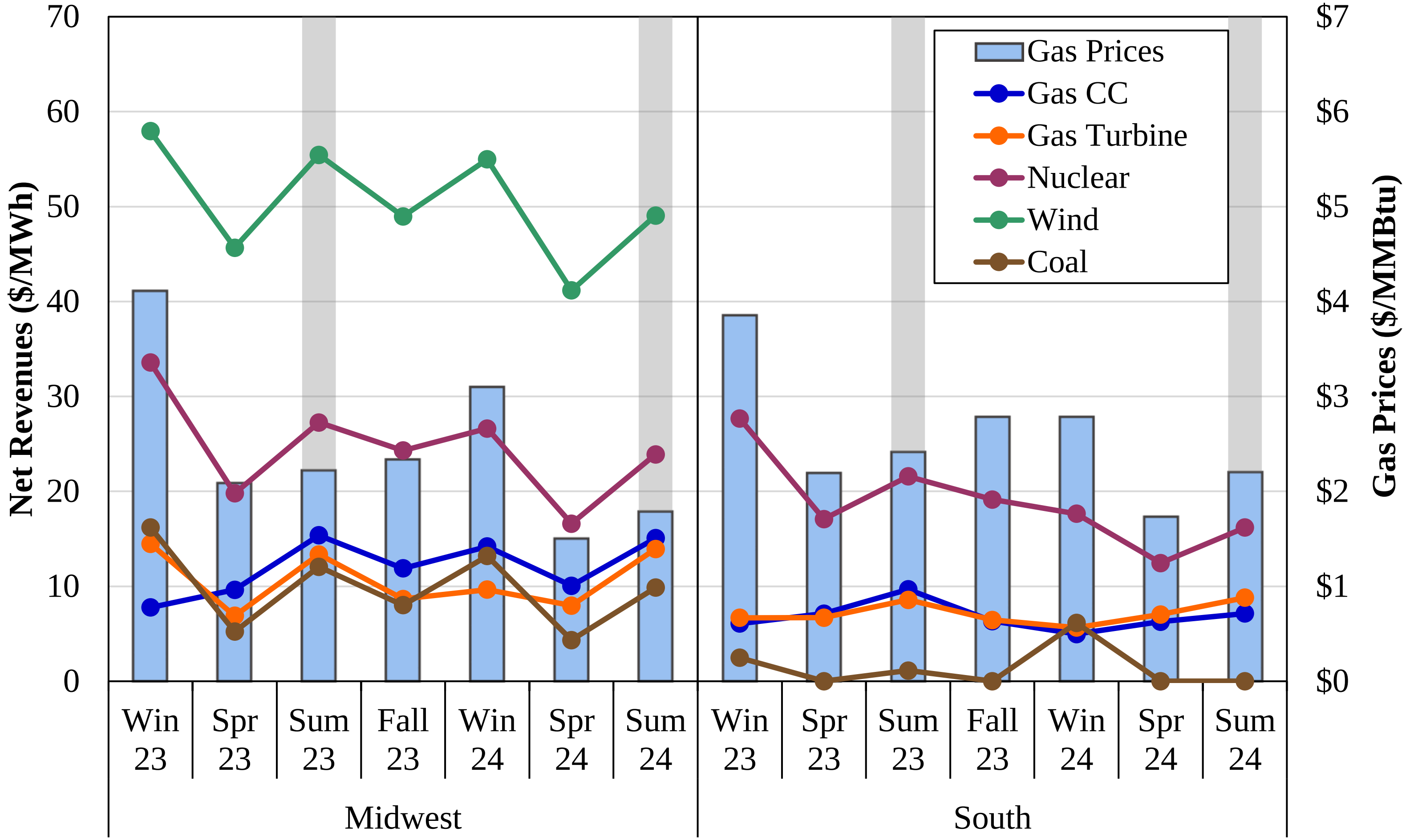


Other Quarterly Figures

DRR1 Reserve Deployment Performance
2023 - 2024



Net Revenues by Technology 2023-2024



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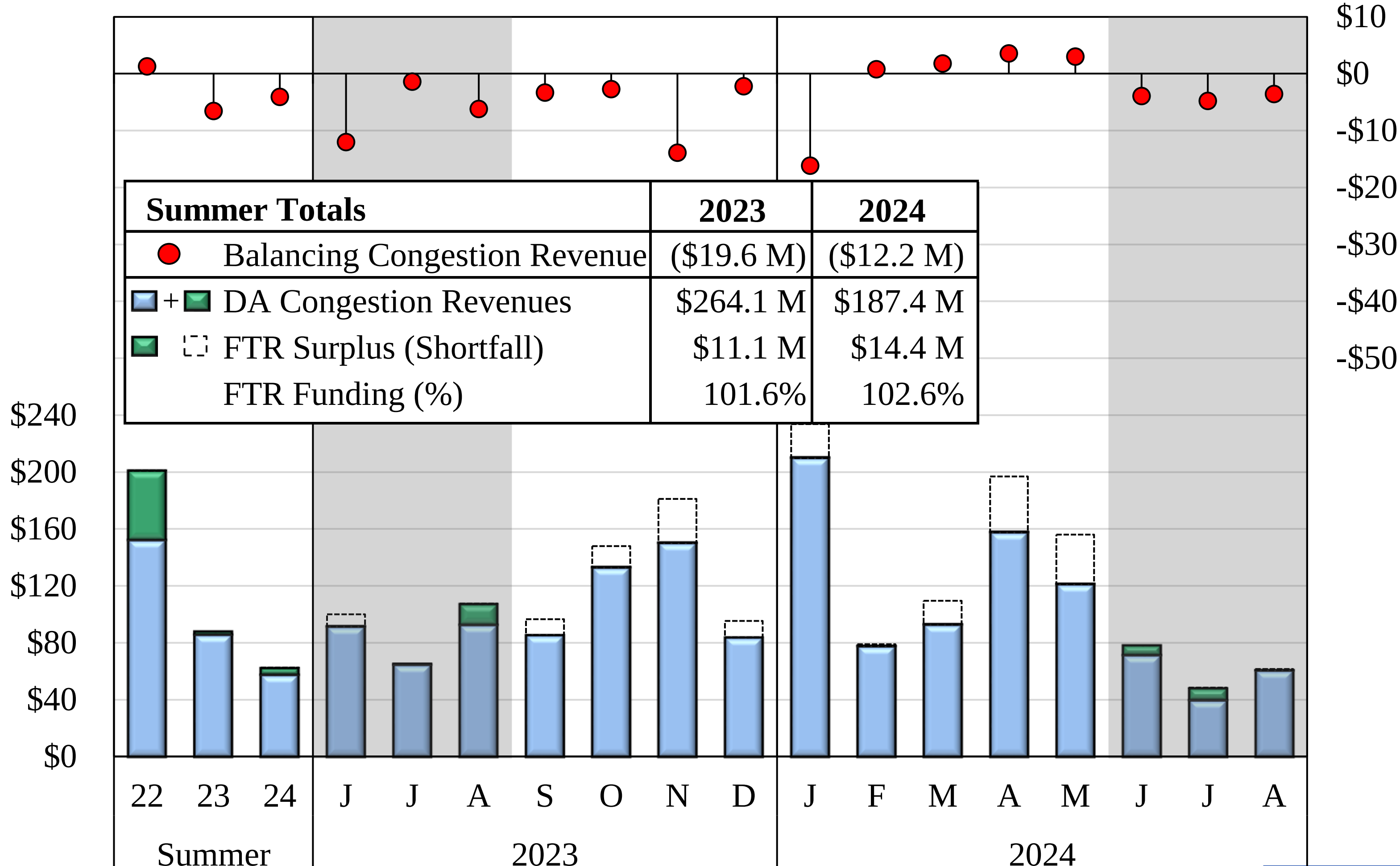
Day-Ahead Congestion, Balancing Congestion, and FTR Underfunding



Summer Totals	2023	2024
Balancing Congestion Revenue	($19.6 M)	($12.2 M)
DA Congestion Revenues	$264.1 M	$187.4 M
FTR Surplus (Shortfall)	$11.1 M	$14.4 M
FTR Funding (%)	101.6%	102.6%

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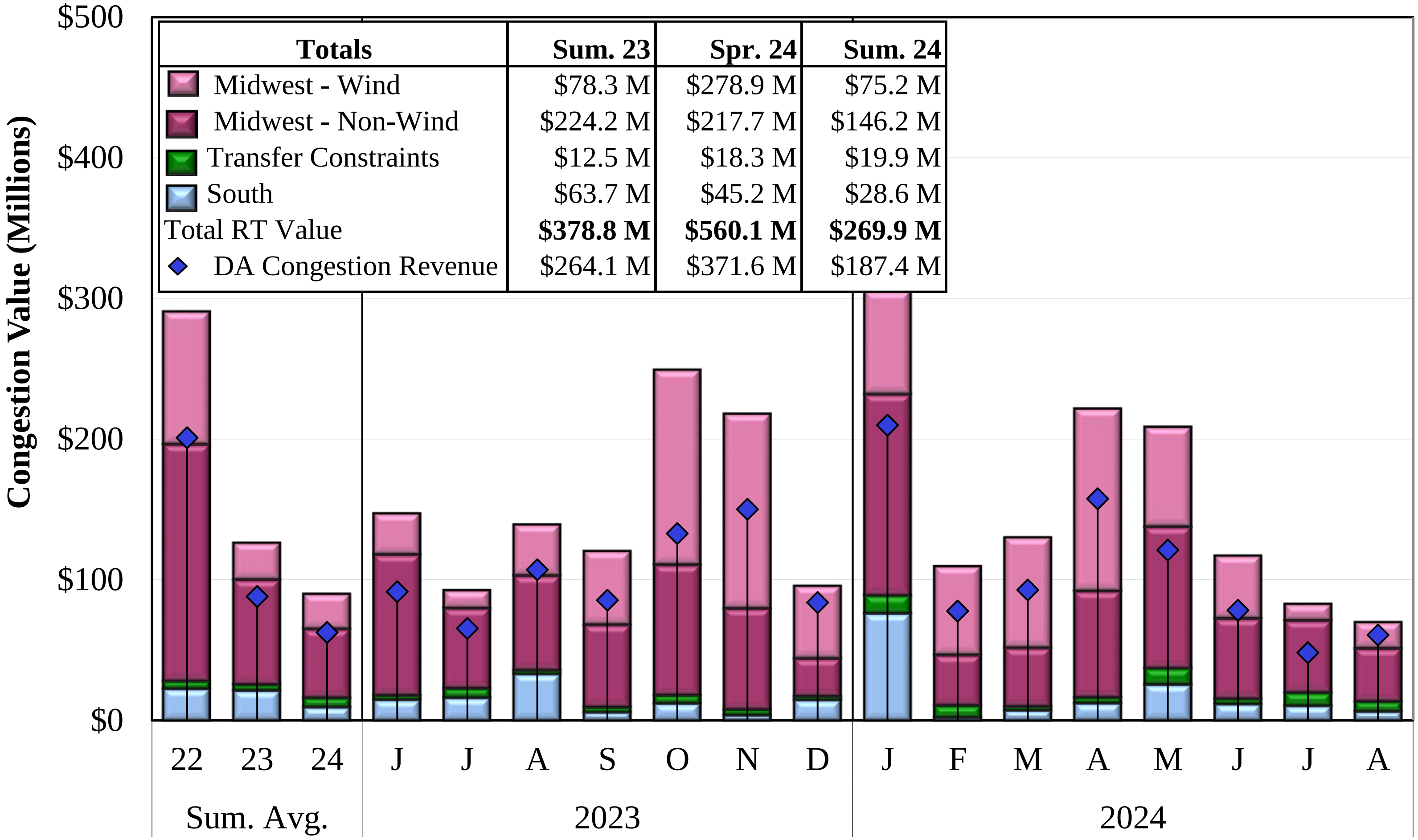
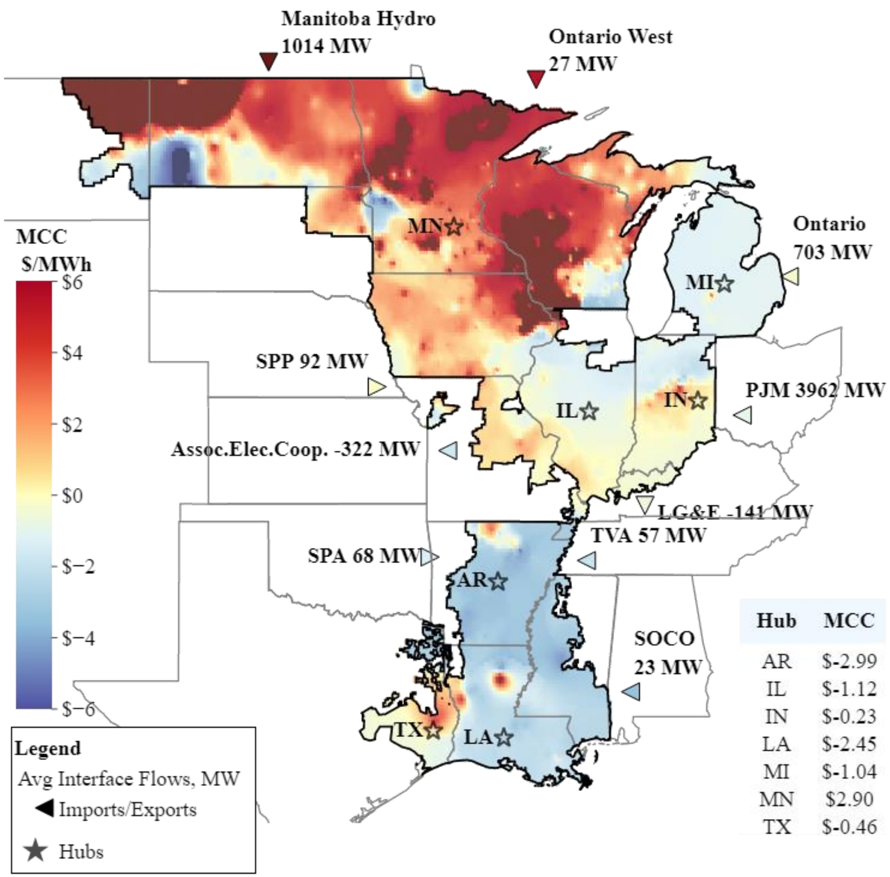
Value of Real-Time congestion Summer 2022-2024



Totals	Sum. 23	Spr. 24	Sum. 24
Midwest - Wind	$78.3 M	$278.9 M	$75.2 M
Midwest - Non-Wind	$224.2 M	$217.7 M	$146.2 M
Transfer Constraints	$12.5 M	$18.3 M	$19.9 M
South	$63.7 M	$45.2 M	$28.6 M
Total RT Value	**$378.8 M**	**$560.1 M**	**$269.9 M**
DA Congestion Revenue	$264.1 M	$371.6 M	$187.4 M

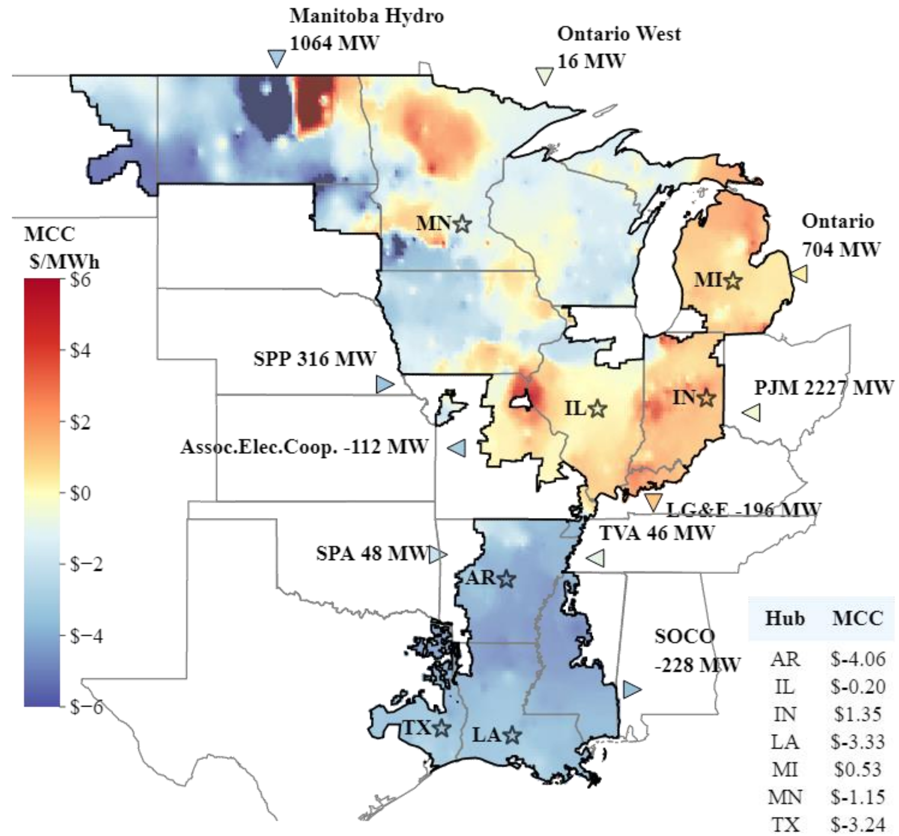
Average Real-Time Congestion Components Summer 2023 – 2024

Summer 2023



Hub	MCC
AR	$-2.99
IL	$-1.12
IN	$-0.23
LA	$-2.45
MI	$-1.04
MN	$2.90
TX	$-0.46

Summer 2024



Hub	MCC
AR	$-4.06
IL	$-0.20
IN	$1.35
LA	$-3.33
MI	$0.53
MN	$-1.15
TX	$-3.24

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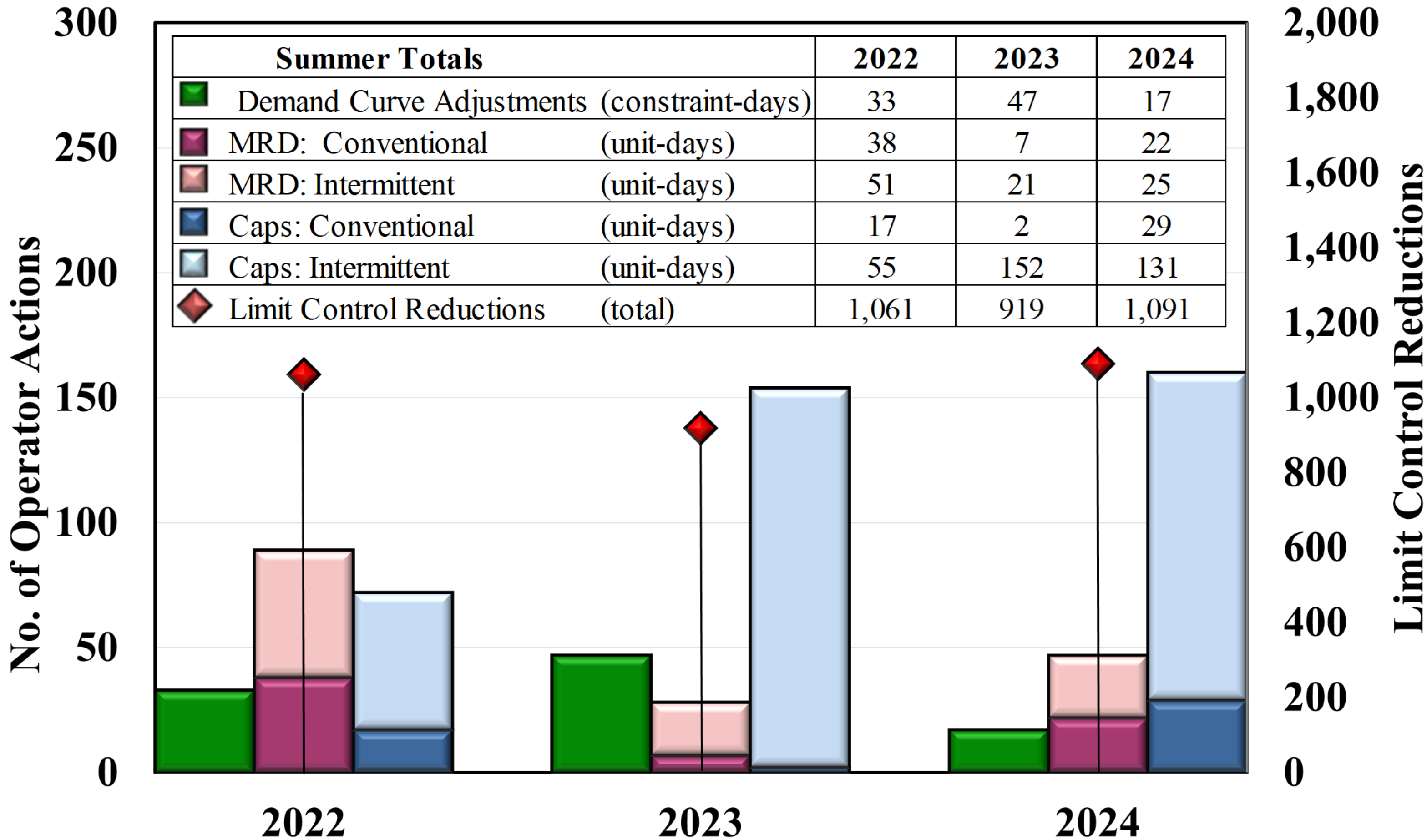
MISO Operator Actions for Congestion Management



Summer Totals		2022	2023	2024
Demand Curve Adjustments	(constraint-days)	33	47	17
MRD: Conventional	(unit-days)	38	7	22
MRD: Intermittent	(unit-days)	51	21	25
Caps: Conventional	(unit-days)	17	2	29
Caps: Intermittent	(unit-days)	55	152	131
Limit Control Reductions	(total)	1,061	919	1,091

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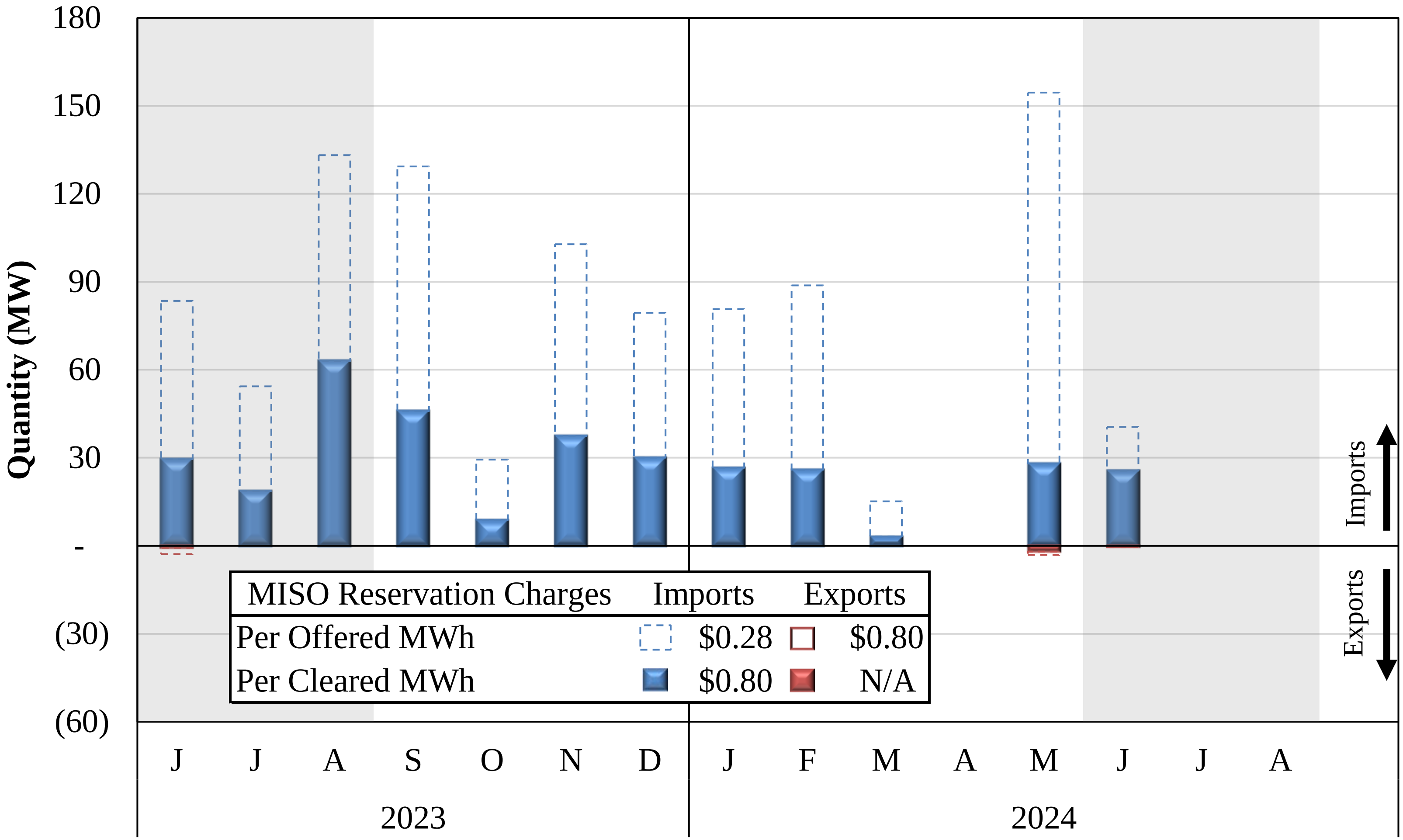
Benefits of Ambient-Adjusted and Emergency Ratings Summer 2023–2024

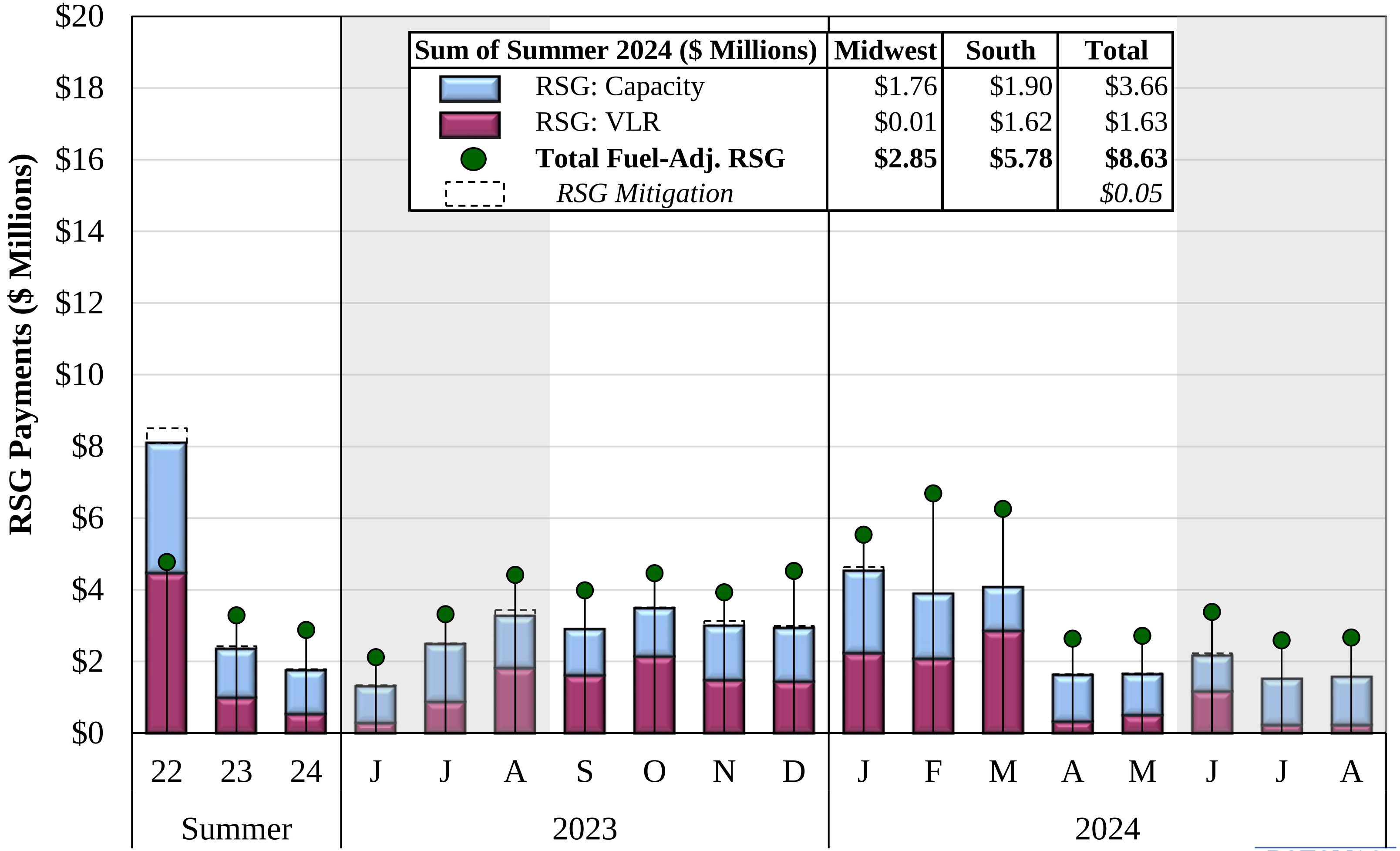
Summer		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2023	**Midwest**	$14.0	$14.10	$28.1	13	10.0%
	South	$0.5	$3.65	$4.2	2	6.6%
	Total	**$14.6**	**$17.7**	**$32.3**	**15**	**9.3%**
2024	**Midwest**	$13.3	$12.60	$25.9	19	10.9%
	South	$0.5	$1.62	$2.2	1	7.2%
	Total	**$13.9**	**$14.2**	**$28.1**	**20**	**10.5%**

Coordinated Transaction Scheduling (CTS) Summer 2023–2024

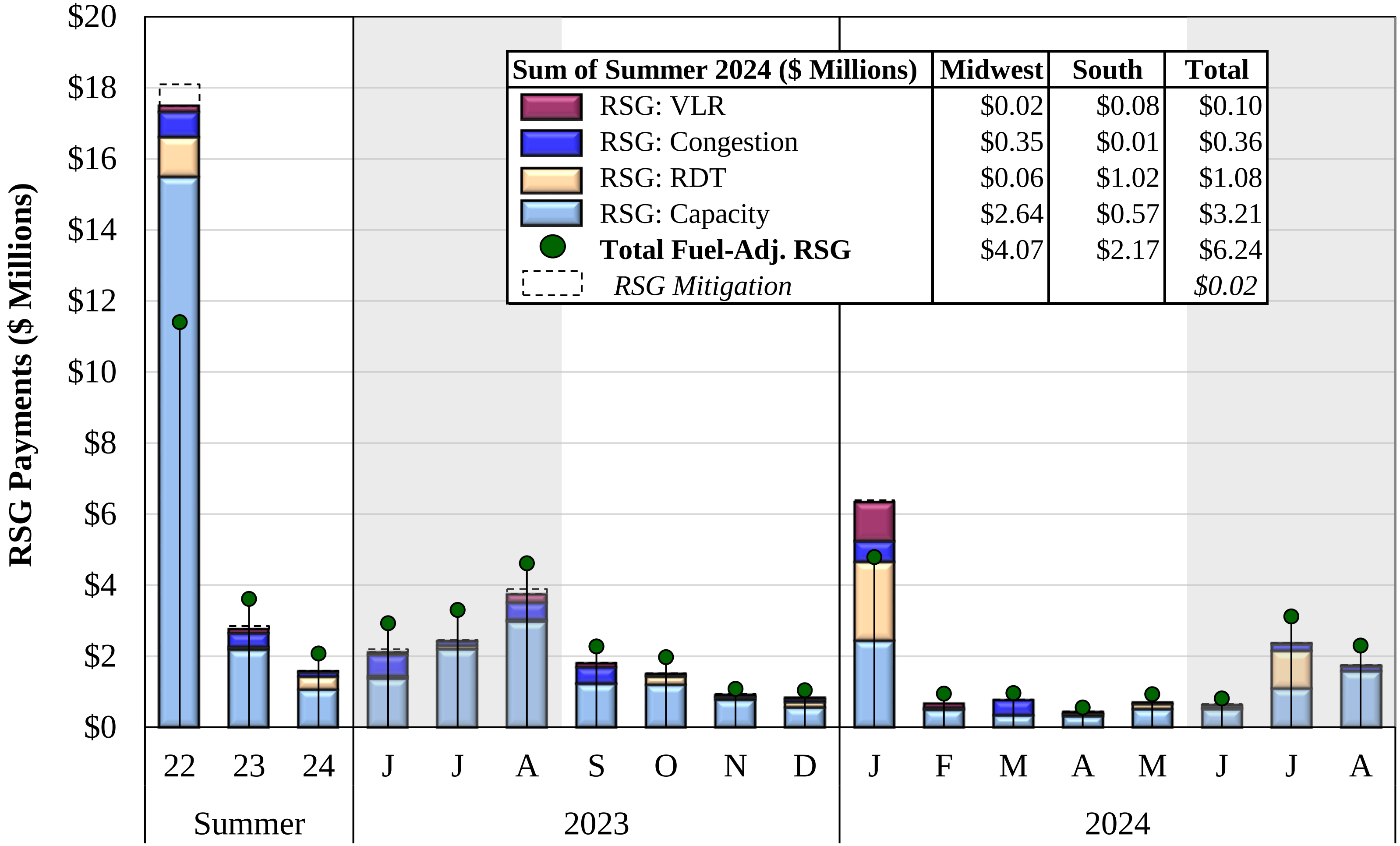


MISO Reservation Charges		Imports		Exports
Per Offered MWh		$0.28		$0.80
Per Cleared MWh		$0.80		N/A

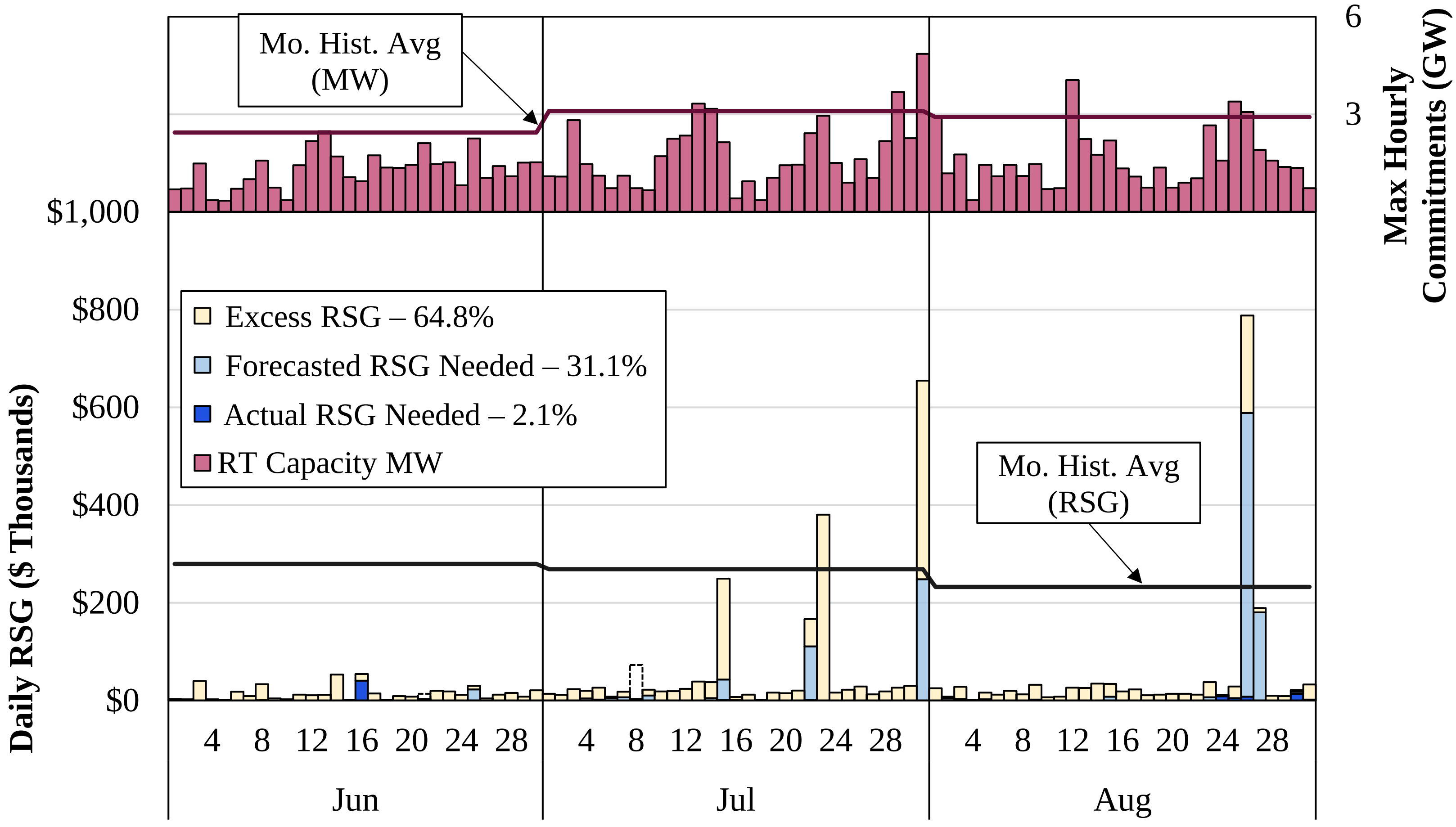
Day-Ahead RSG Payments
Summer 2023–2024



Real-Time RSG Payments
Summer 2023–2024

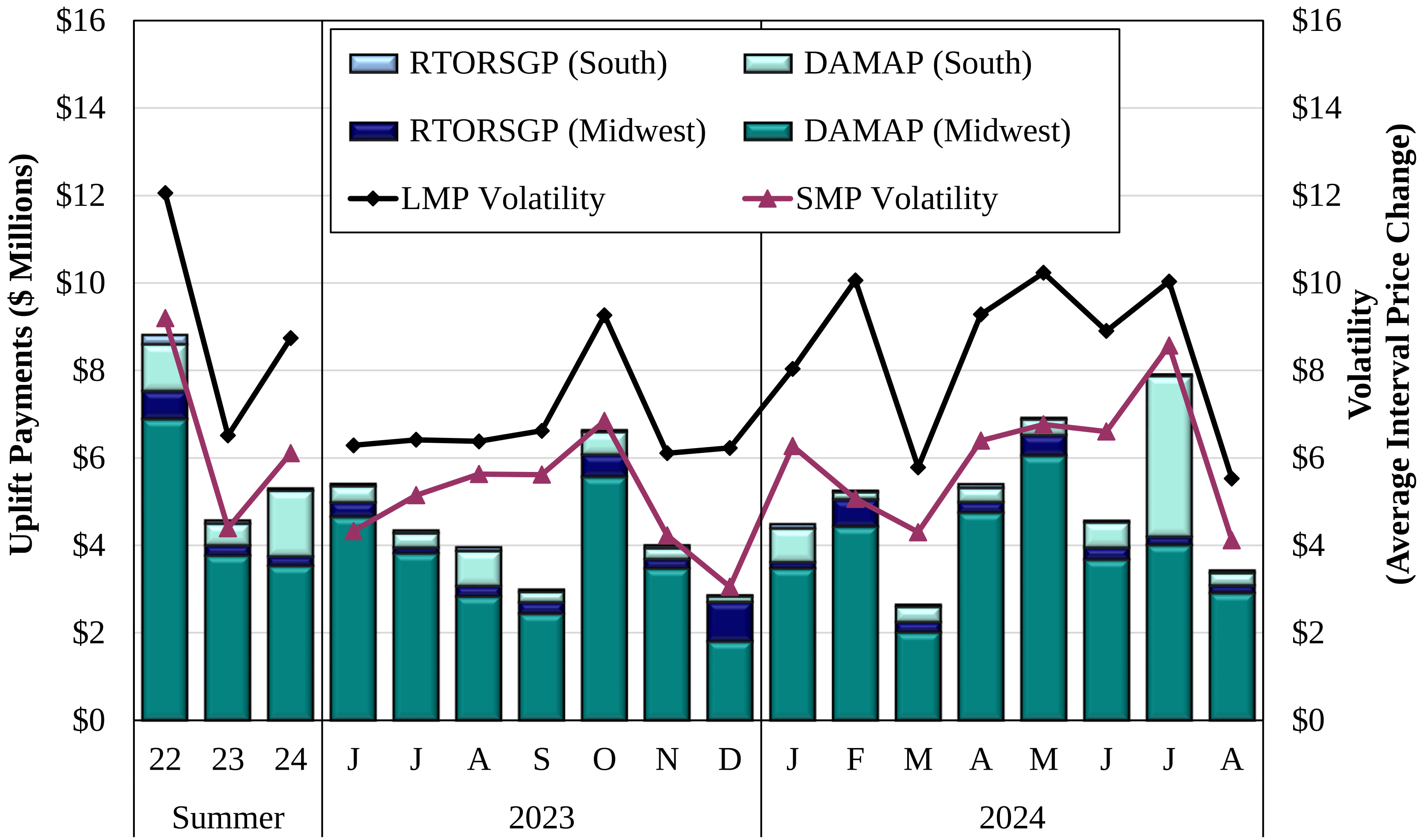


Real-Time Capacity Commitment and RSG Summer 2024

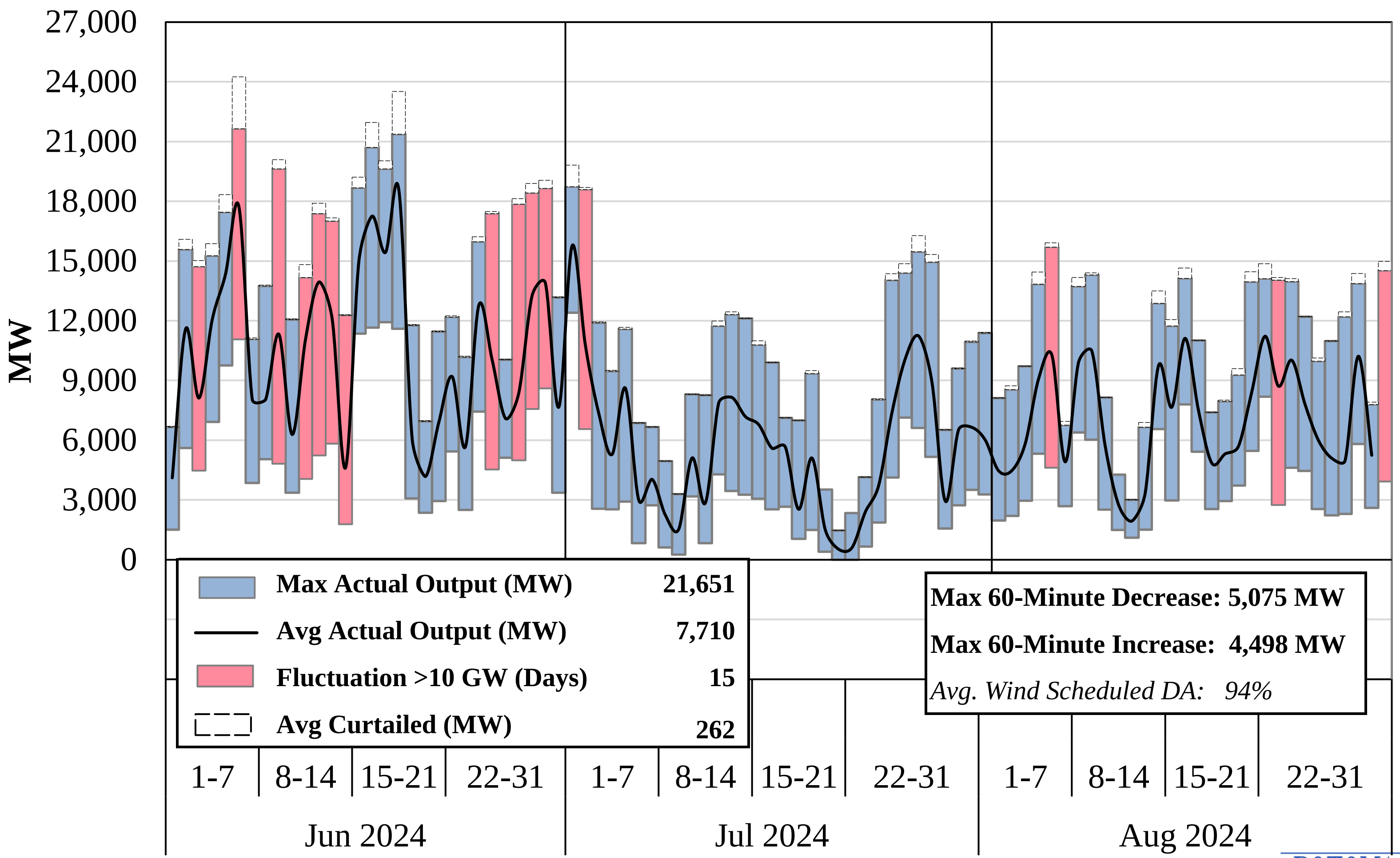


* 2% of the RSG could not be classified due to gaps in market data and is shown in the transparent bars.

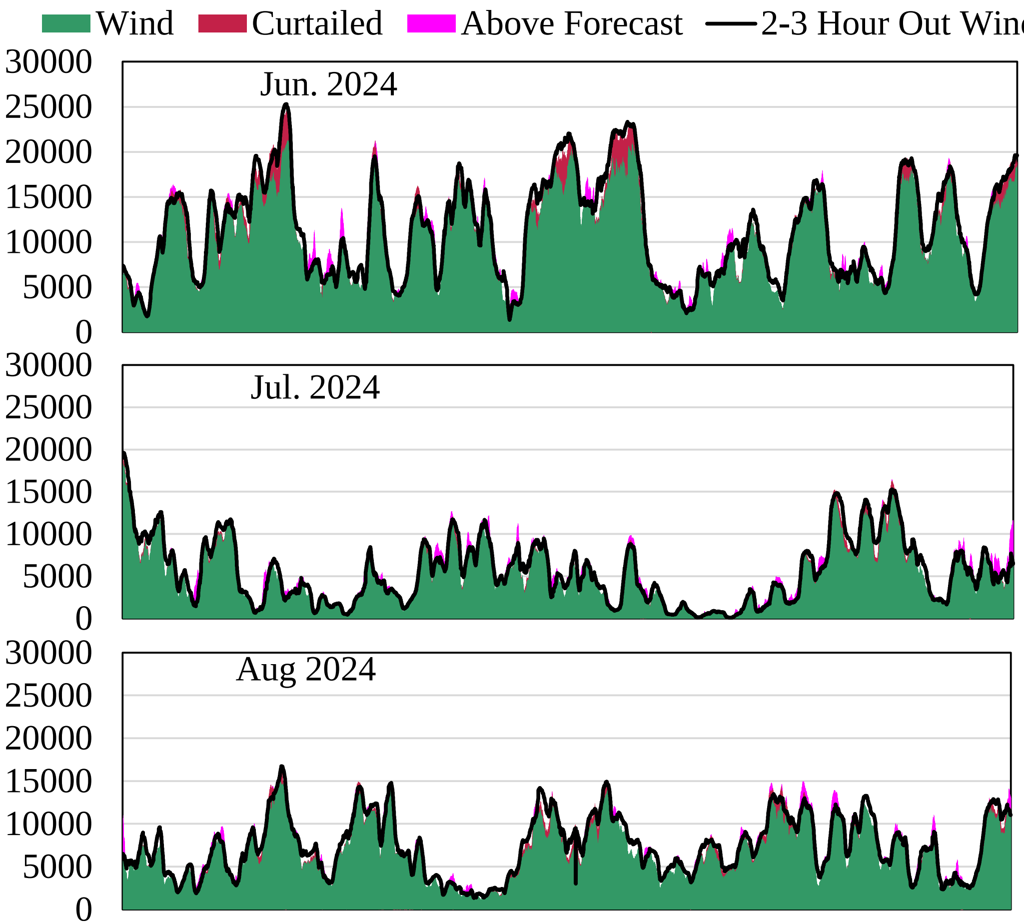
Price Volatility Make Whole Payments
Summer 2022–2024



Wind Output in Real Time
Daily Range and Average



Wind Forecast and Actual Output Summer 2024



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%
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%
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%

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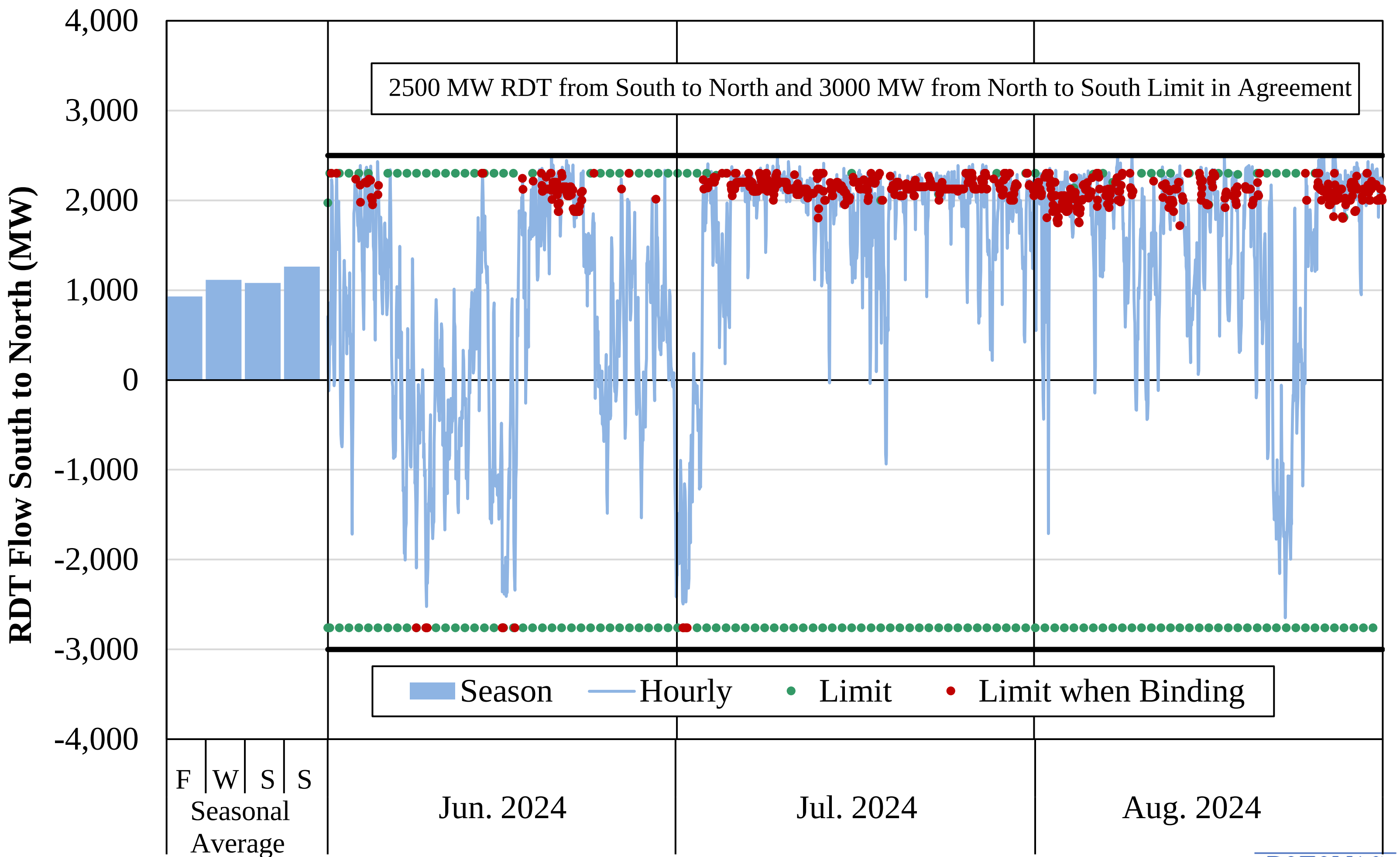
Real-Time Hourly Inter-Regional Flows Summer 2024



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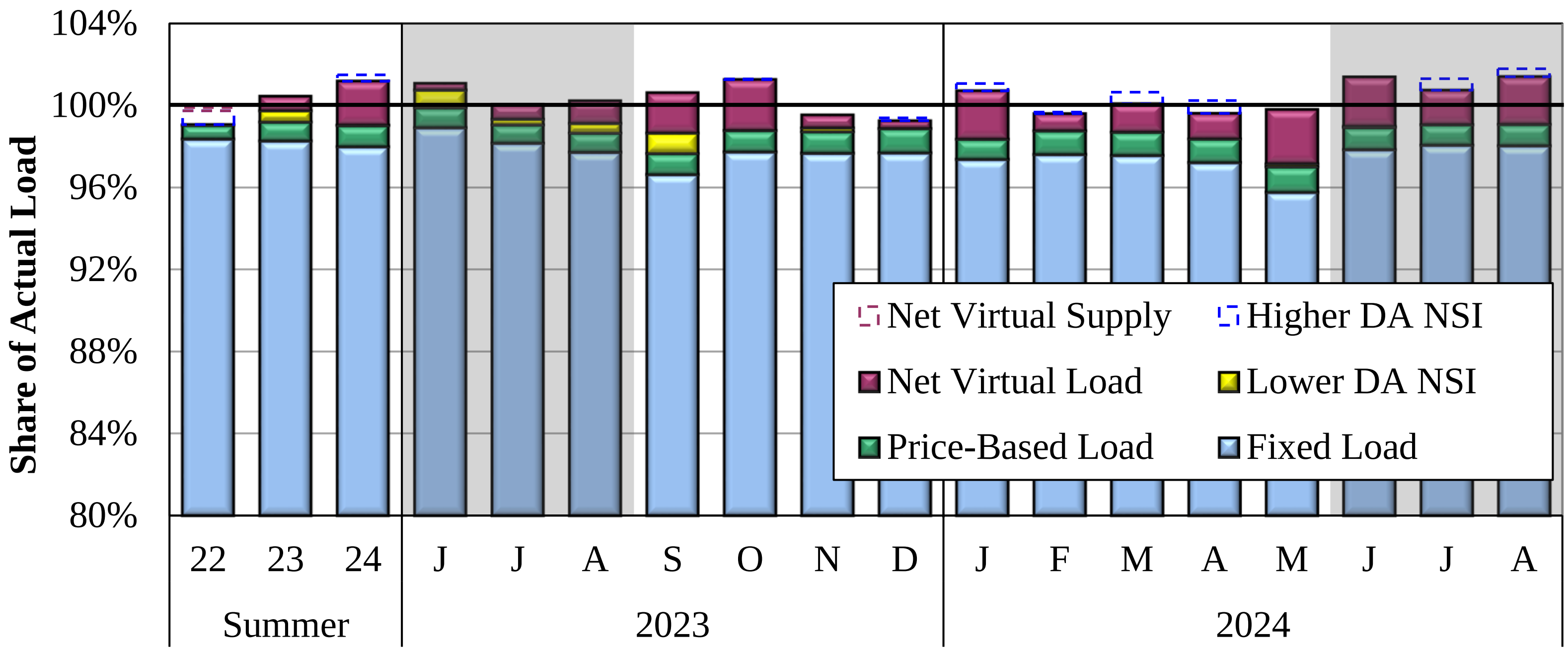
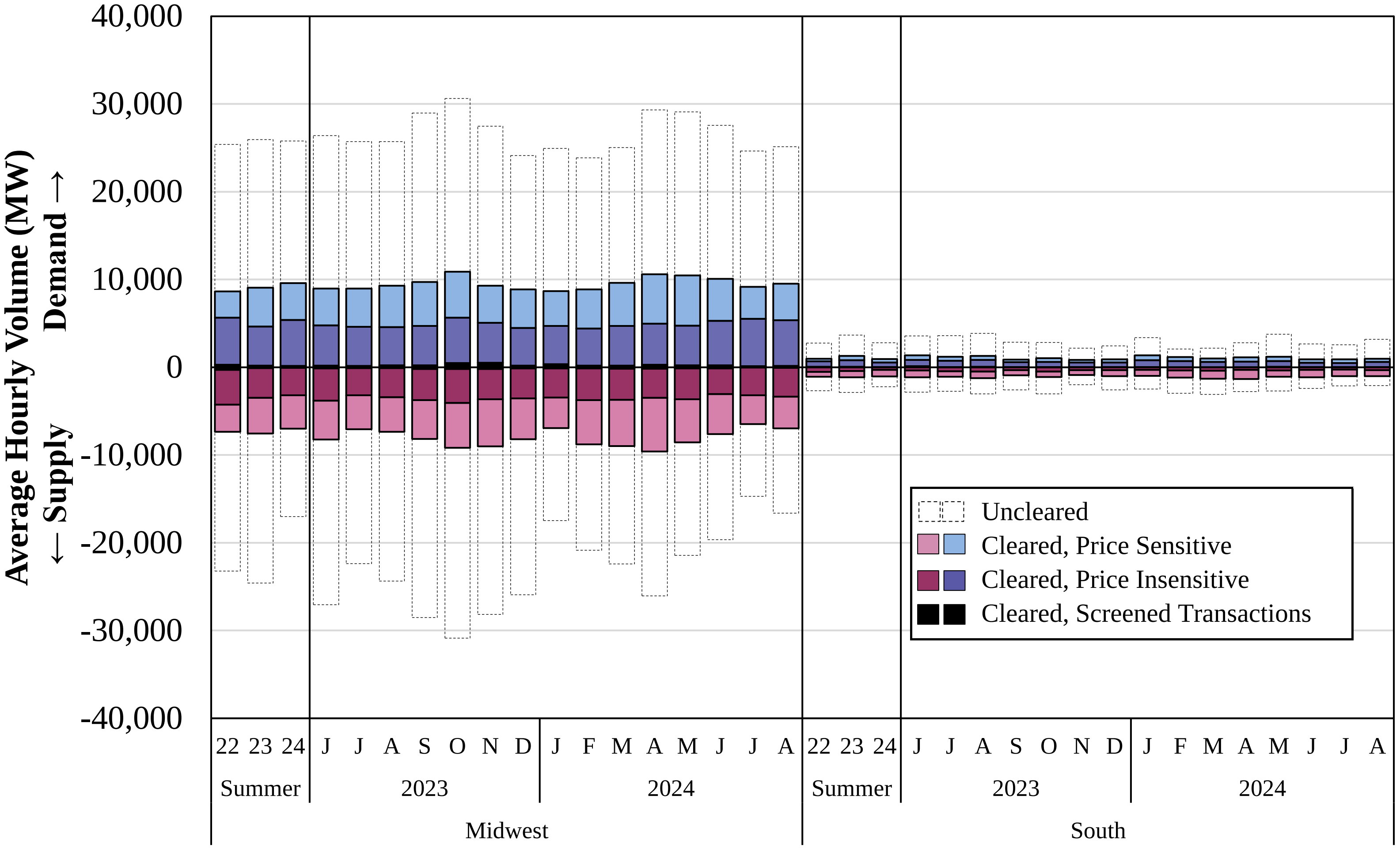
Day-Ahead Peak Hour Load Scheduling
Summer 2022–2024



Share of Actual Load (%)

	Summer 22	Summer 23	Summer 24	2023 J	2023 J	2023 A	2023 S	2023 O	2023 N	2023 D	2024 J	2024 F	2024 M	2024 A	2024 M	2024 J	2024 J	2024 A
All Hours	99.3	101.2	101.8	101.0	101.6	101.0	100.6	100.3	99.1	98.6	100.5	99.2	99.1	99.3	101.0	101.4	102.0	101.9
Peak Hours Midwest	98.8	99.9	101.9	100.6	99.4	99.8	100.3	101.7	99.7	99.5	100.8	99.9	100.9	99.4	100.3	102.6	101.3	101.9
Peak Hours South	99.4	101.8	100.4	102.4	101.3	101.7	100.7	102.1	100.7	101.3	101.5	99.4	100.8	99.1	100.8	100.7	99.9	100.7

Virtual Load and Supply
Summer 2022–2024



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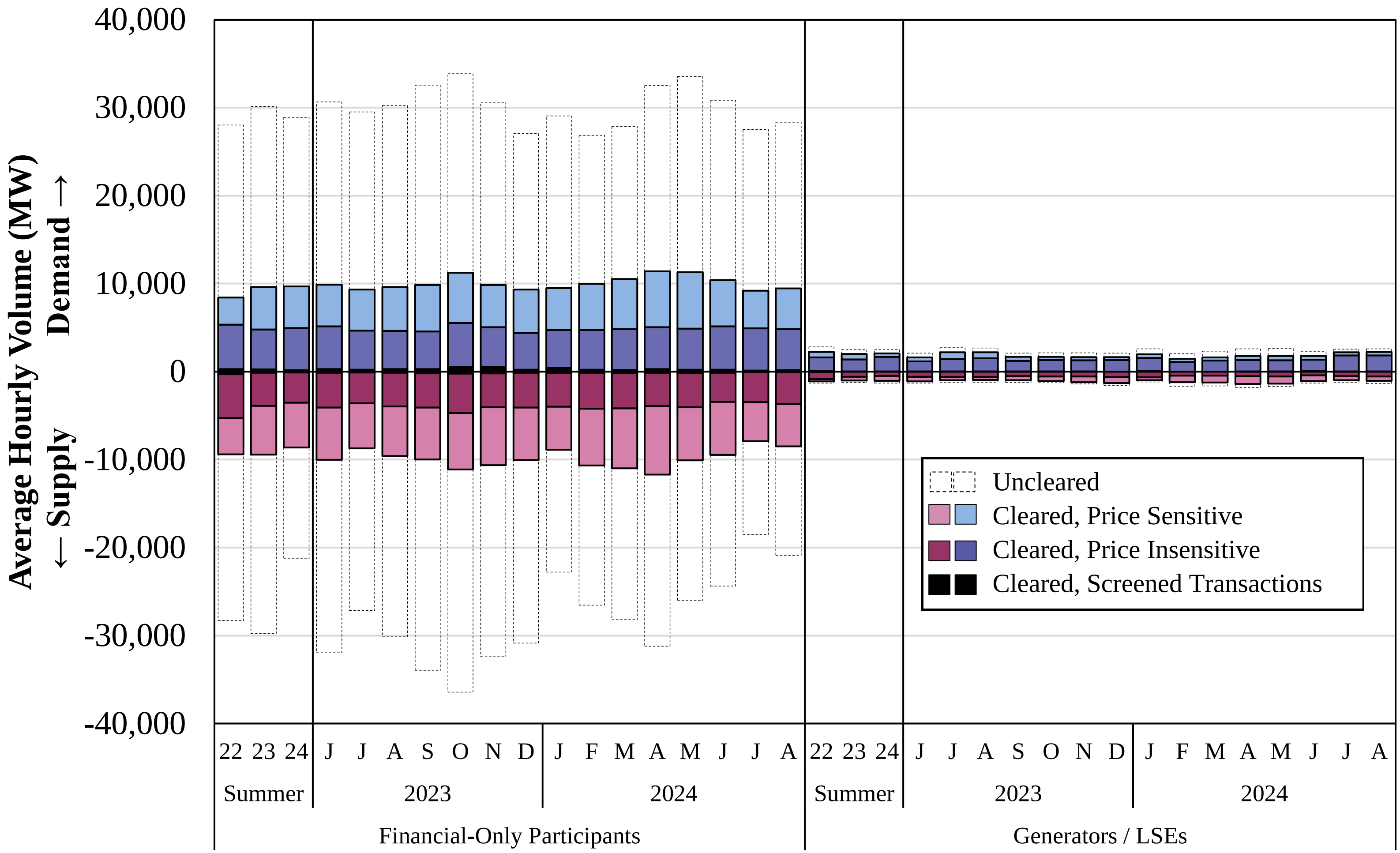
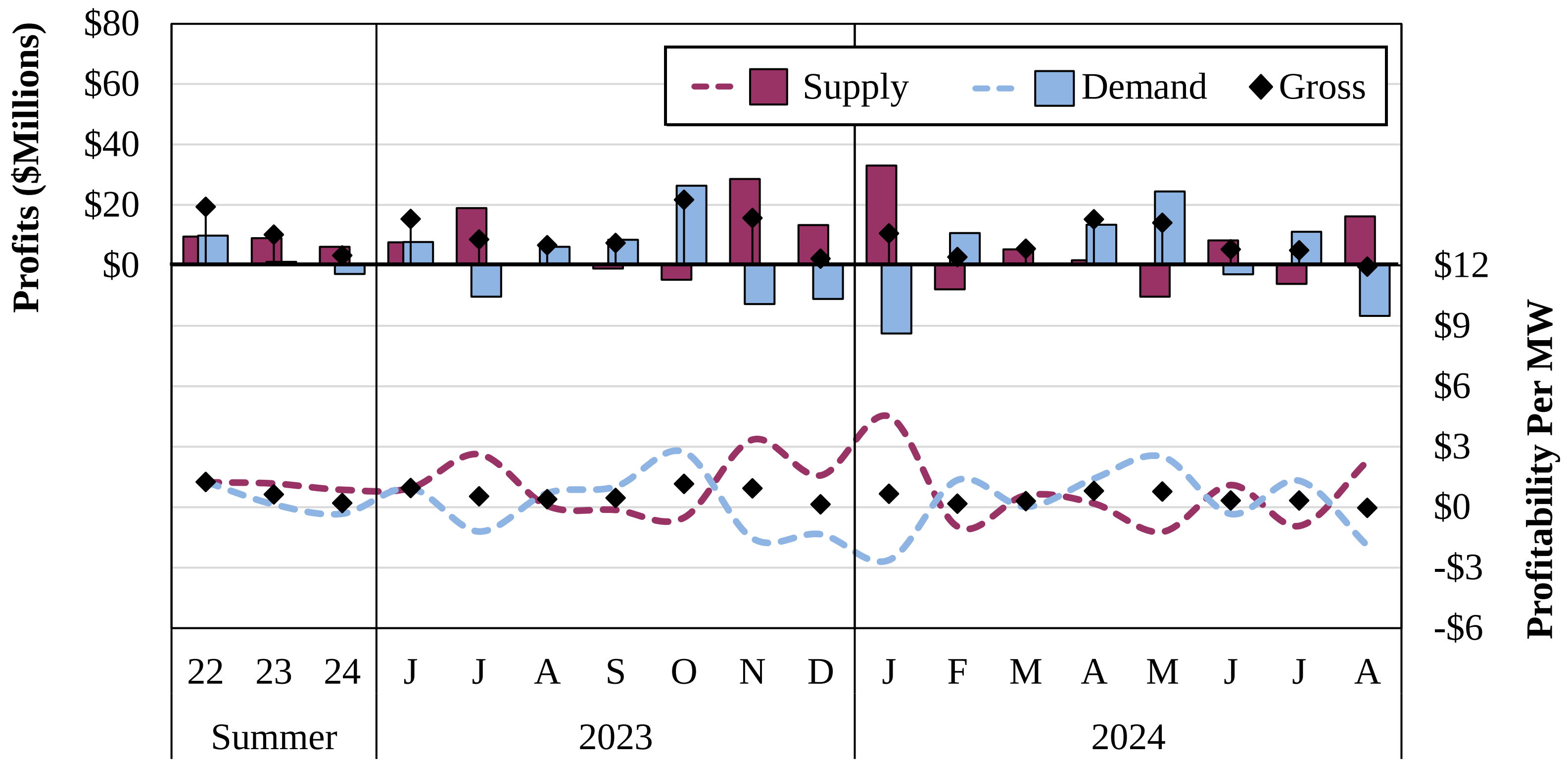
Virtual Load and Supply by Participant Type
Summer 2022–2024



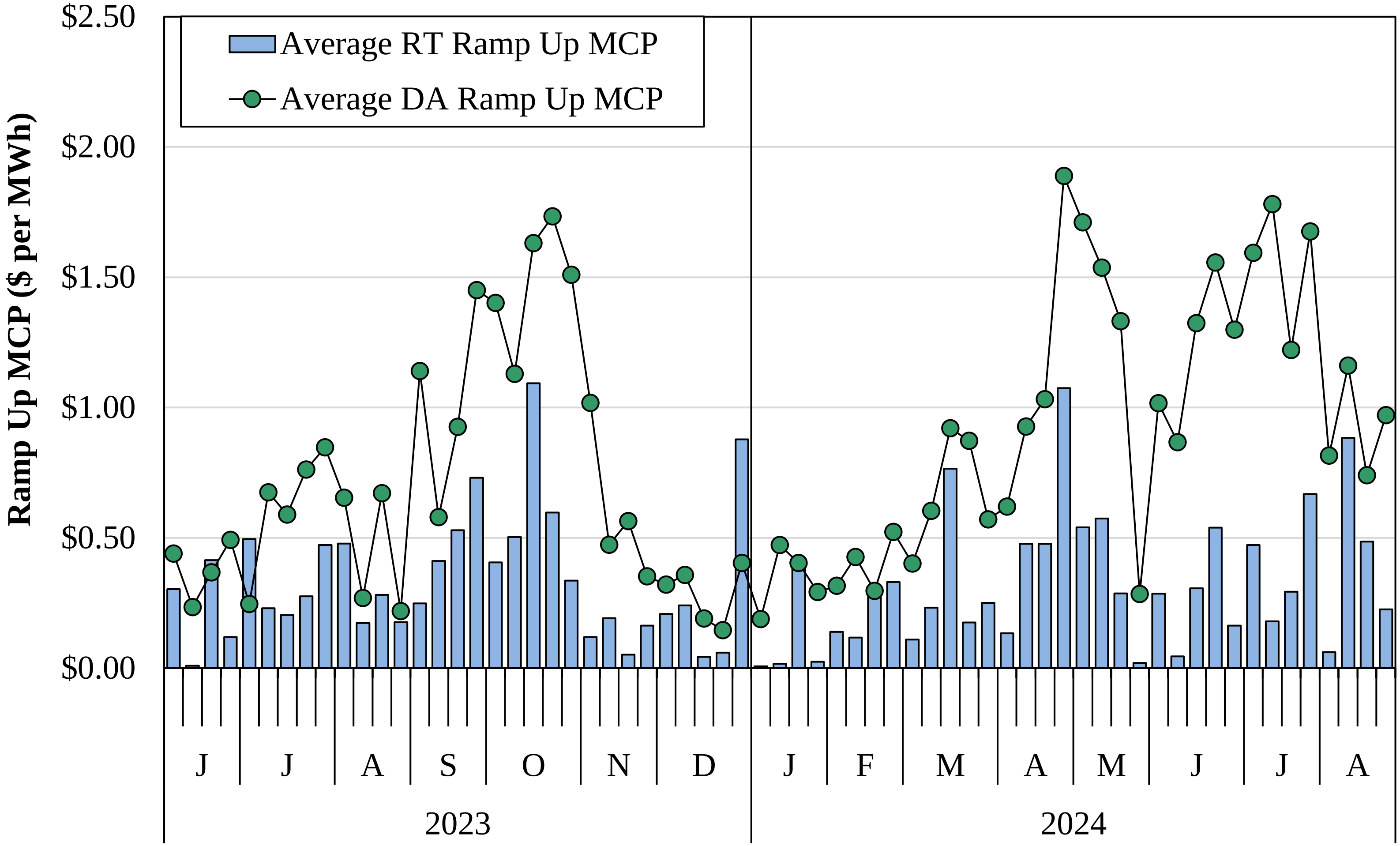
Virtual Profitability
Summer 2022–2024



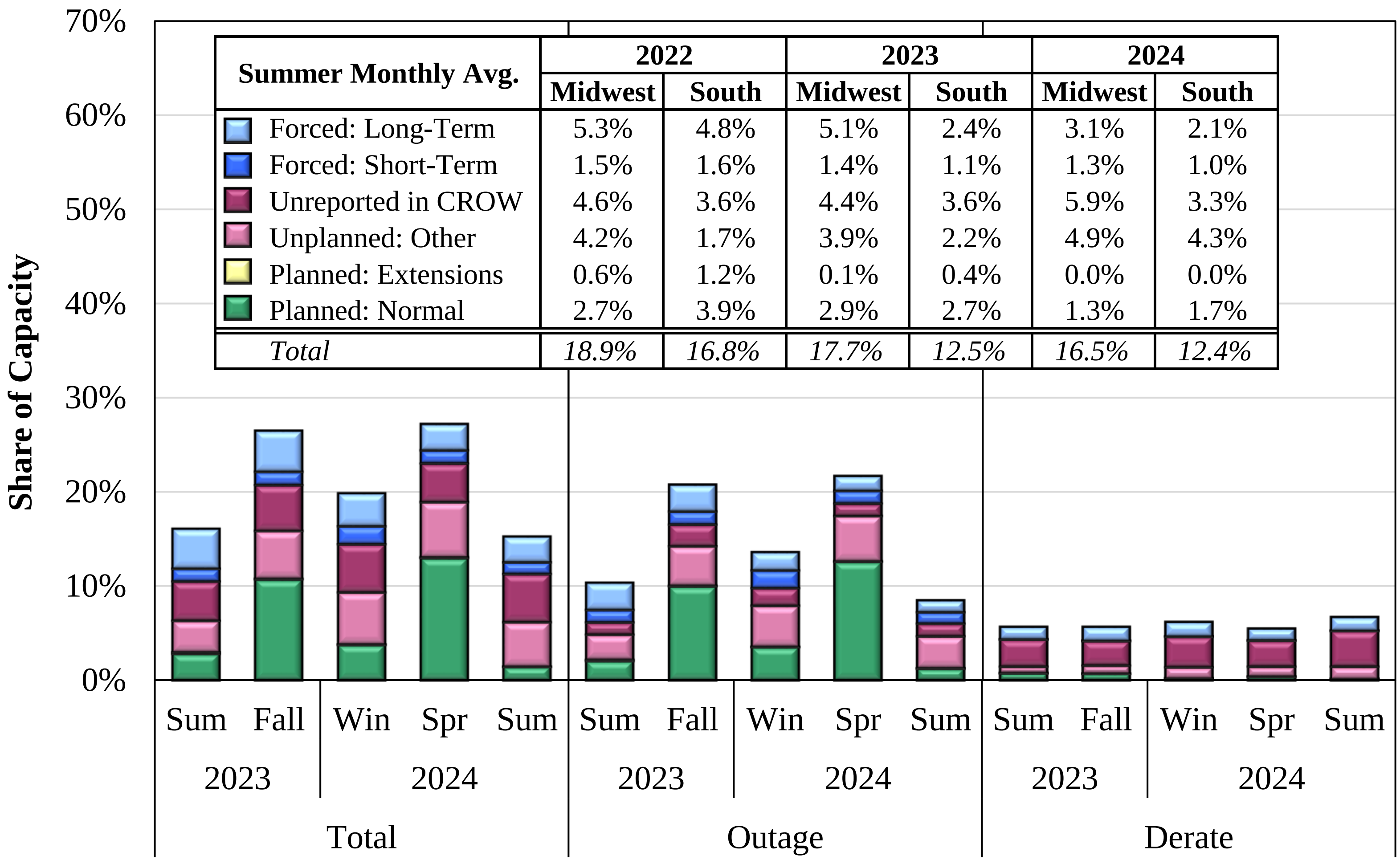
Percent Screened

Supply	3.3	1.2	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	1.5	0.7	0.8
Demand	3.1	2.5	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	2.2	1.2	1.5
Total	3.2	1.9	1.4	2.1	1.6	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

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



Generation Outages and Deratings
Summer 2022–2024



Summer Monthly Avg.	2022		2023		2024	
	Midwest	**South**	**Midwest**	**South**	**Midwest**	**South**
Forced: Long-Term	5.3%	4.8%	5.1%	2.4%	3.1%	2.1%
Forced: Short-Term	1.5%	1.6%	1.4%	1.1%	1.3%	1.0%
Unreported in CROW	4.6%	3.6%	4.4%	3.6%	5.9%	3.3%
Unplanned: Other	4.2%	1.7%	3.9%	2.2%	4.9%	4.3%
Planned: Extensions	0.6%	1.2%	0.1%	0.4%	0.0%	0.0%
Planned: Normal	2.7%	3.9%	2.9%	2.7%	1.3%	1.7%
Total	*18.9%*	*16.8%*	*17.7%*	*12.5%*	*16.5%*	*12.4%*

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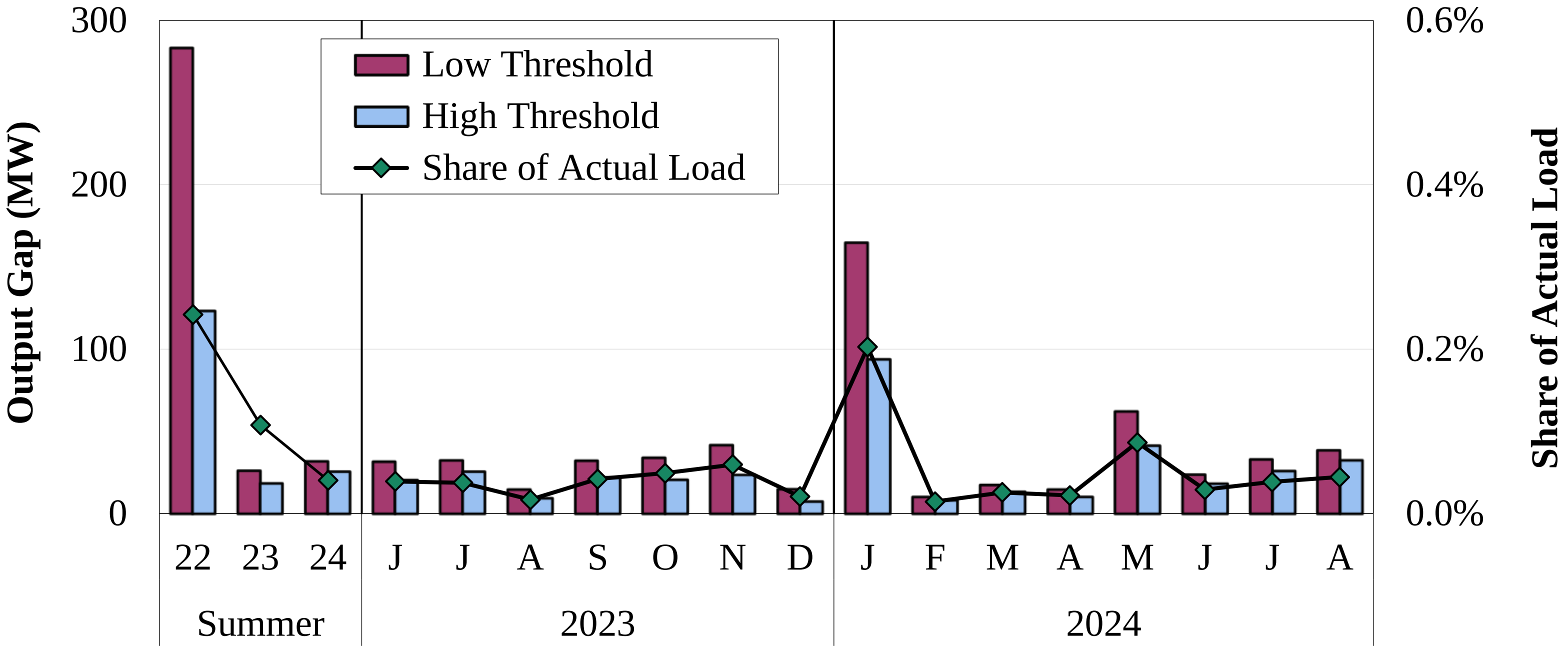
Monthly Output Gap
Summer 2022–2024



Low Threshold Results by Unit Status (MW)

	Summer 22	Summer 23	Summer 24	2023 J	2023 J	2023 A	2023 S	2023 O	2023 N	2023 D	2024 J	2024 F	2024 M	2024 A	2024 M	2024 J	2024 J	2024 A
Offline	180	17	25	22	23	6	25	17	27	4	98	3	8	6	56	18	25	31
Online	103	9	7	10	9	8	7	17	15	11	66	7	10	9	6	6	8	7

High Threshold Results by Unit Status (MW)

	Summer 22	Summer 23	Summer 24	2023 J	2023 J	2023 A	2023 S	2023 O	2023 N	2023 D	2024 J	2024 F	2024 M	2024 A	2024 M	2024 J	2024 J	2024 A
Offline	111	14	21	15	21	6	19	16	21	4	84	3	6	4	38	14	22	28
Online	12	4	4	5	5	4	3	5	3	3	9	6	7	6	4	5	4	4

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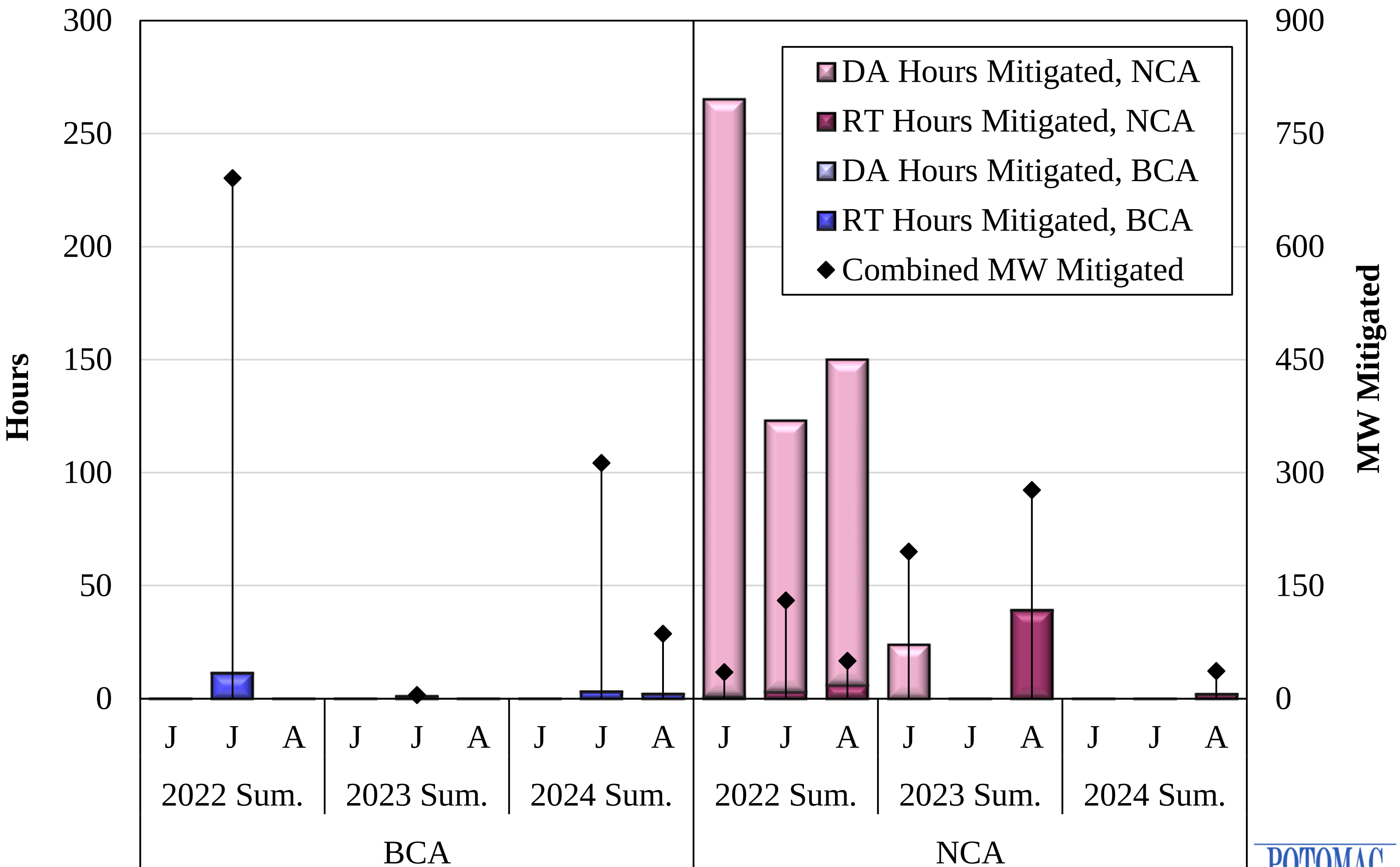
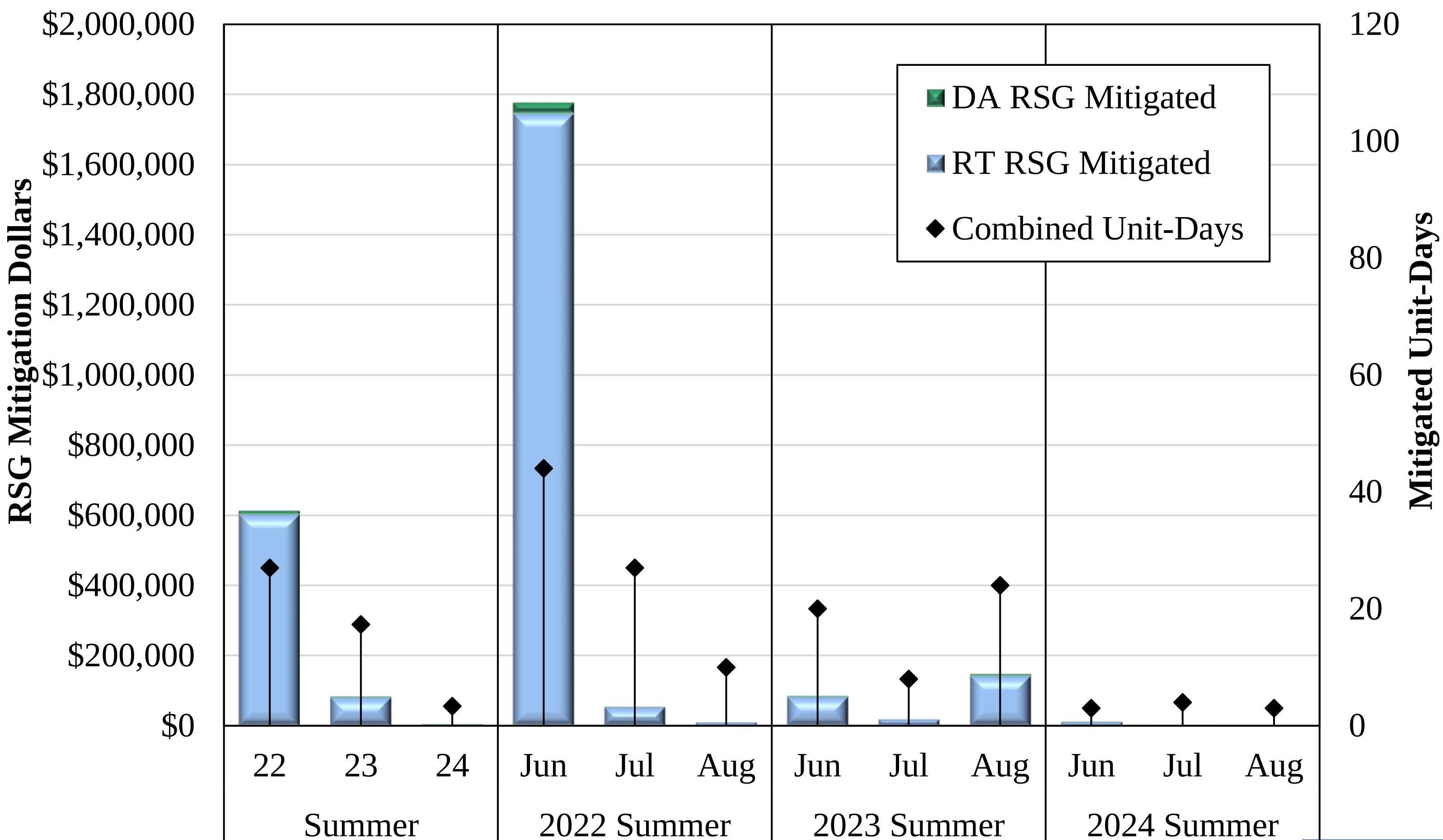
Day-Ahead And Real-Time Energy Mitigation Summer 2022 - 2024



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



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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