IMM Quarterly Report: Spring 2021

MISO Independent Market Monitor

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Highlights and Findings: Spring 2021

- The MISO markets performed competitively this Spring, market power mitigation was infrequent, and conduct was highly competitive overall.
- Energy prices rose 40 percent relative to last spring, attributable to:
  - ✓ An increase in gas prices by almost 60 percent from last spring;
  - ✓ Average load, while still impacted by COVID, rose to more typical levels.
- Average and peak load grew 4 and 7 percent, respectively, from last spring because COVID-related public measures impacted load more last year.
  - ✓ These effects on average load fell from 7 percent last spring to 2 percent.
- Congestion was much higher this spring relative to prior years, as day-ahead and real-time congestion both doubled over last spring, largely due to wind.
  - ✓ A new record wind peak output of 20.7 GW occurred on March 30.
- Day-ahead RSG increased 83 percent and real-time RSG doubled over last year – these values were in line with gas prices and typical RSG levels.
- Higher gas prices led to changes in generation – the share of energy produced from coal grew from 27 to 36 percent this year, while the share produced from natural gas resources fell from 37 to 28 percent.

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Quarterly Summary

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
RT Energy Prices ($/MWh)	Monitor/Discuss	$25.67	*-30%*	*40%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago	Monitor/Discuss	$2.59	*-71%*	*58%*
Natural Gas - Henry Hub	Monitor/Discuss	$2.67	*-21%*	*56%*
Western Coal	Expected	$0.68	*1%*	*-1%*
Eastern Coal	Expected	$1.29	*5%*	*6%*
Load (GW)[2]				
Average Load	Expected	67.8	*-13%*	*4%*
Peak Load	Expected	98.2	*-5%*	*7%*
% Scheduled DA (Peak Hour)	Expected	97.7%	97.9%	98.8%
Transmission Congestion ($M)				
Real-Time Congestion Value	Monitor/Discuss	$446.2	*-59%*	*108%*
Day-Ahead Congestion Revenue	Monitor/Discuss	$280.3	*448%*	*120%*
Balancing Congestion Revenue[3]	Expected	$7.1	$45.2	$6.5
Ancillary Service Prices ($/MWh)				
Regulation	Expected	$11.34	*-10%*	*42%*
Spinning Reserves	Expected	$3.42	*16%*	*61%*
Supplemental Reserves	Expected	$0.70	*-55%*	*331%*

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
FTR Funding (%)	Expected	100%	102%	99%
Wind Output (MW/hr)	Monitor/Discuss	10,496	*16%*	*29%*
Guarantee Payments ($M)[4]				
Real-Time RSG	Monitor/Discuss	$14.3	*-88%*	*117%*
Day-Ahead RSG	Expected	$11.4	*-78%*	*83%*
Day-Ahead Margin Assurance	Expected	$6.6	*-65%*	*18%*
Real-Time Offer Rev. Sufficiency	Monitor/Discuss	$1.3	*-30%*	*246%*
Price Convergence[5]				
Market-wide DA Premium	Expected	-2.5%	0.9%	2.7%
Virtual Trading				
Cleared Quantity (MW/hr)	Expected	17,613	*0%*	*-24%*
% Price Insensitive	Expected	33%	31%	25%
% Screened for Review	Expected	2%	2%	0%
Profitability ($/MW)	Expected	$0.81	$2.00	$0.60
Dispatch of Peaking Units (MW/hr)	Expected	648	588	829
Output Gap- Low Thresh. (MW/hr)	Expected	73	237	55
Other:				

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 2021

<u>Higher Day-Ahead and Real-Time Congestion (Slides 21-23)</u>

- Average real-time congestion in the Spring was the highest since 2014.
  - ✓ Significant drivers included a 58 percent increase in gas prices, higher wind output, and higher market-to-market congestion with SPP and PJM.
- Higher wind penetration and growing reliance on wind energy output contributed to a 138 percent increase in congestion in the Midwest Region.
  - ✓ Congestion attributable to wind rose more than tripled from last spring.
  - ✓ The constraint with the highest quarterly congestion ($39 million) was impacted by 16 new wind resources that entered MISO totaling 2,700 MW.
- Congestion related to MISO's seams increased by roughly 300 percent.
  - ✓ Congestion associated with SPP's M2M constraints more than doubled over last year because of higher wind in both markets, and in neighboring LBAs.
    - – SPP's wind capacity and output grew 22 and 33 percent, respectively.
  - ✓ MISO incurred $18 million in congestion on PJM's M2M constraints, 72 percent of which was on a constraint mainly impacted by PJM's wind units.
- We estimate $50 million in congestion savings would have resulted from the use of ambient-adjusted and short-term emergency transmission ratings.

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Highlights for Spring 2021

<u>Key Improvement: Generation Shift Factor Cutoff (GSF) (Slide 24)</u>

- In the day-ahead and real-time markets, MISO employs a 1.5 percent GSF cutoff that limits the re-dispatch and pricing at electrically-distant locations.
  - ✓ This reduces the complexity and solution time of MISO's market software, but it is inefficient because it eliminates economic relief.
  - ✓ No GSF cutoff is employed in the FTR markets or in the market-to-market (M2M) settlements – this inconsistency generates significant costs.
  - ✓ For certain constraints, the loss of congestion relief may adversely impact reliability, increase M2M settlements, and cause FTR shortfalls.
    - This is likely why SPP and PJM no longer apply a cutoff on M2M constraints.
- We estimate that lowering the GSF cutoff to 0.5 percent in 2021 would have:
  - ✓ Reduced the FTR shortfalls by $44 million; and
  - ✓ Provided $53 million in congestion value of additional relief.
  - ✓ Allowed the market to provide more relief on M2M constraints and lowered M2M uplift by $37 million.
- Lowering the GSF cutoff simply requires a reduction in the parameter and could be accomplished in stages to assess its impact on system performance.

Highlights for Spring 2021

Wind Scheduling, Output, and Fluctuations (Slides 17, 26-28)

- Wind production increased by 29 percent over last spring and its share of all energy produced in MISO rose from 14 percent last spring to 17 percent.
  - ✓ Over 3.5 GW of wind entered MISO since last spring in the Midwest Region, a 16 percent increase in installed capacity.
- Wind resources tend to schedule less output in the day-ahead market than they produce in real time, which can create price convergence issues.
  - ✓ On average, day-ahead wind was scheduled at 86 percent of real-time output.
  - ✓ Virtual transactions on the 10 highest wind-impacted constraints offset under-scheduled flows by roughly 80 percent since the beginning of the year.
- As wind production has grown, fluctuations in wind output have created more uncertainty and at times has led to operating reserve shortages.
  - ✓ In March, MISO managed three days when the range in wind output approached 15 GW.

Highlights for Spring 2021

<u>Wind Forecasting and Events Caused by Fluctuations (Slides 26-28)</u>

- Between April 19 and 22, MISO experienced multiple evening periods when wind fell sharply and caused operating reserve shortages.
  - ✓ The operating reserve shortages generally occur when wind output drops earlier than forecasted, which can cause forecast errors of 2 to 3 GW.
- April 19: wind fell over 5 GW in 2 hours and MISO exhibited 5 intervals with operating reserve shortages.
- April 21: wind dropped nearly 5 GW in 1 hour and load rose 2 GW, resulting in operating reserve shortages for 6 intervals and real-time prices as high as $3,500 per MWh.
- Improving the wind forecast used by LAC up to 2 hours in advance is very important because the LAC will signal the need to commit resources.
  - ✓ The forecast used by LAC as wind dropped on April 19 and 21 was not accurate and did not quickly adjust once the errors appeared.
  - ✓ Even with accurate forecasts, the 5 GW drop on April 21 would have been difficult to manage.
  - ✓ The ability to dynamically adjust the system's ramp requirements when large fluctuations are anticipated could be valuable.

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Highlights for Spring 2021

<u>2021 Summer Readiness (Slide 19)</u>

- We have summarized MISO’s expected summer capacity levels and the associated adequacy for satisfying the summer peak loads for 2021.
  - ✓ Assumptions may substantially change the anticipated reserve margin.
- We present the Base Case that aligns with MISO’s assumptions in the Summer Assessment, including the 1,900 MW transfer limit from the South to Midwest.
  - ✓ The reserve margin of 19.3 percent is above the 18.3 percent requirement.
  - ✓ Expected forced outages would reduce the margin to 17.1 percent.
- We present *Realistic Scenarios* that estimate the likely available margin:
  - ✓ <u>Revised Assumptions</u>: expected outages and derates > 10 GW, the transfer limit assumed to be 2,300 MW, and accounts for long-lead LMRs and forced outages.
  - ✓ Expected reserve margin = 10 to 13 percent, which is still sufficient to provide operating reserves and respond to expected forced outages.
- *High Temperature Scenarios* estimate the margin under unusually hot conditions.
  - ✓ <u>Revised assumptions</u>: Outages and derates expected to approach 18 GW, and the peak load increases by more than 7.5 GW.
  - ✓ Expected reserve margin = -2 to 1 percent. This would not cover MISO’s reserve needs and forced outages so shortages would be likely. It will be important for MISO’s prices to motivate up to 6 GW of additional non-firm imports.

Highlights for Spring 2021

<u>Planning Resource Auction and Alternate Clearing (Slide 18)</u>

- Auction clearing prices in MISO's annual capacity market in the Midwest and South were $5 and $0.01 per MW-day, respectively.
  - ✓ Prices in the South were effectively zero, signaling that resources procured for reliability in the South have no value at the margin.
- These low prices are the result of the flawed vertical demand curve that assumes capacity above the minimum requirement has no reliability value.
- We re-solved the auction using a sloped demand curve to determine the impacts on various types of market participant groups.
  - ✓ The alternative clearing prices would have been $172.86 per MW-day in the Midwest and $28.31 per MW-day in the South.
  - ✓ Vertically-integrated utilities would have been significantly better off.

Type of MP	Net Revenue Increases	Net Revenue Decreases	Total
Vertically Integrated LSEs	$185.6M	-$65.8M	$119.8M
Municipal/Cooperative	$89.1M	-$50.3M	$38.8M
Merchant	$349.8M	-$61.4M	$288.4M
Retail Choice Suppliers		-$447.0M	-$447.0M

Submittals to External Entities and Other Issues

- We responded to several FERC questions related to prior referrals and FERC investigations. We continued to meet with FERC on a weekly basis and we responded to several requests for information on market issues.
  - ✓ We made several additional referrals and notifications during this period.
  - ✓ We have a number of investigations ongoing.
- We participated in the FERC Conference on Climate Change/Weather impacts on Reliability.
- We continued discussing several existing and new recommendations with MISO on Scarcity Pricing and Capacity Accreditation.
- We presented our Winter Quarterly Report to the Market Subcommittee and in March we presented a report on market results to the ERSC.
- We met with OMS to discuss the latest market results, findings, and recommendations.

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Submittals to External Entities and Other Issues

- We reviewed and developed comments on the latest proposed framework for allocating Firm Flow Entitlements (property rights to the transmission system)
  - ✓ We provided comments to the inter-RTO working group negotiating this agreement raising concerns that it would inequitably transfer property rights from MISO to PJM for transmission that MISO's customers solely funded.
  - ✓ This would relieve PJM of its obligation to pay for flows that it currently must pay MISO to flow and could cause MISO to increasingly have to pay PJM for dispatch flows it produces on its own system.
  - ✓ We will be presenting these comments to the working group and recommending changes to the proposed agreement.
- We continued to discuss development of Ambient Adjusted Rating (AAR) Programs and use of Emergency Ratings with TOs and MISO.
  - ✓ As we noted FERC has issued a proposed rule to require AARs that is largely consistent with our past recommendations (RM20-16)
  - ✓ We filed comments on this NOPR in March and Reply comments in April.
  - ✓ Progress in this area will generate substantial economic and reliability benefits for MISO's customers.

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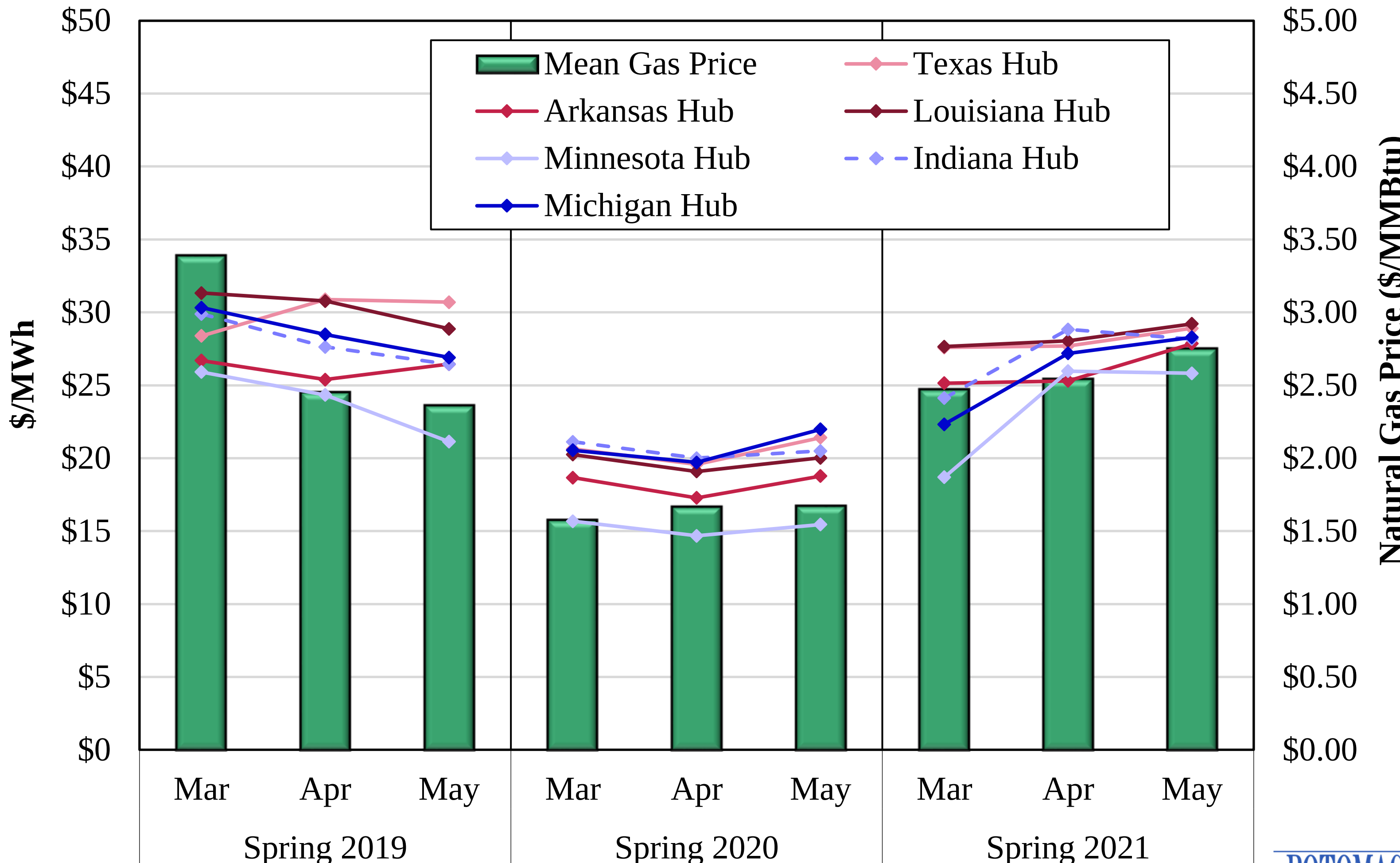
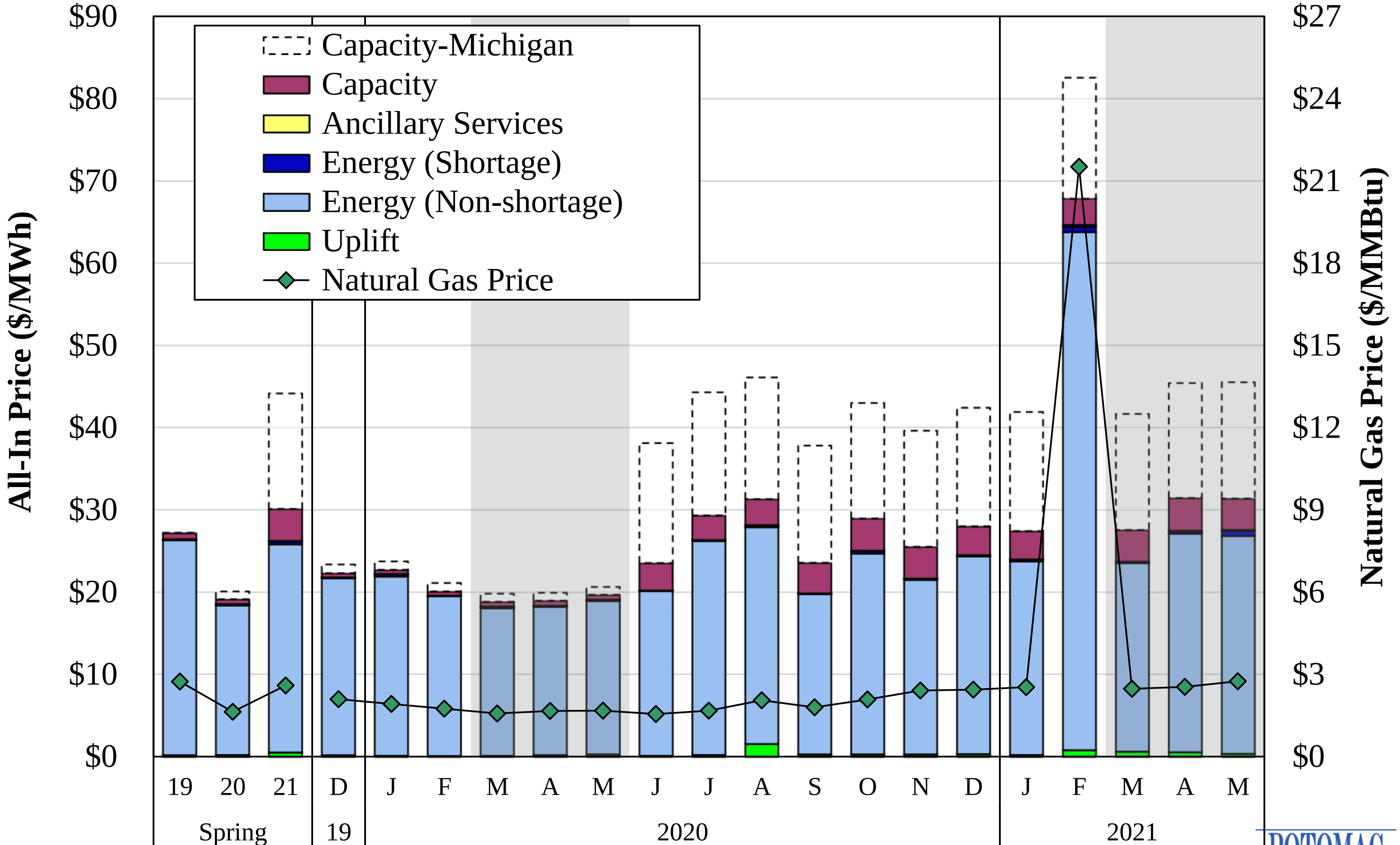
Day-Ahead Average Monthly Hub Prices Spring 2019–2021



All-In Price
Spring 2020 – 2021



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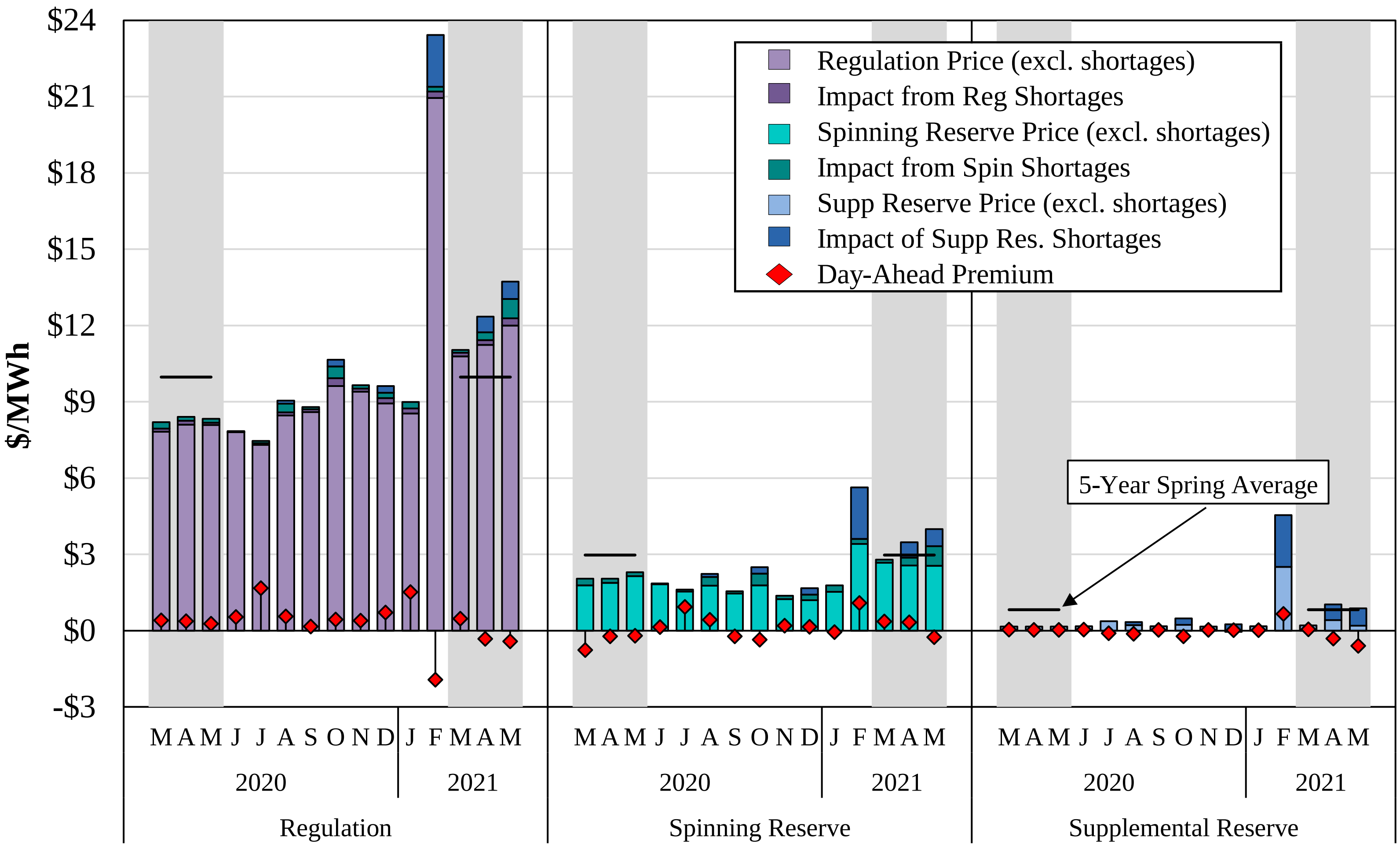
Ancillary Service Prices
Spring 2020–2021



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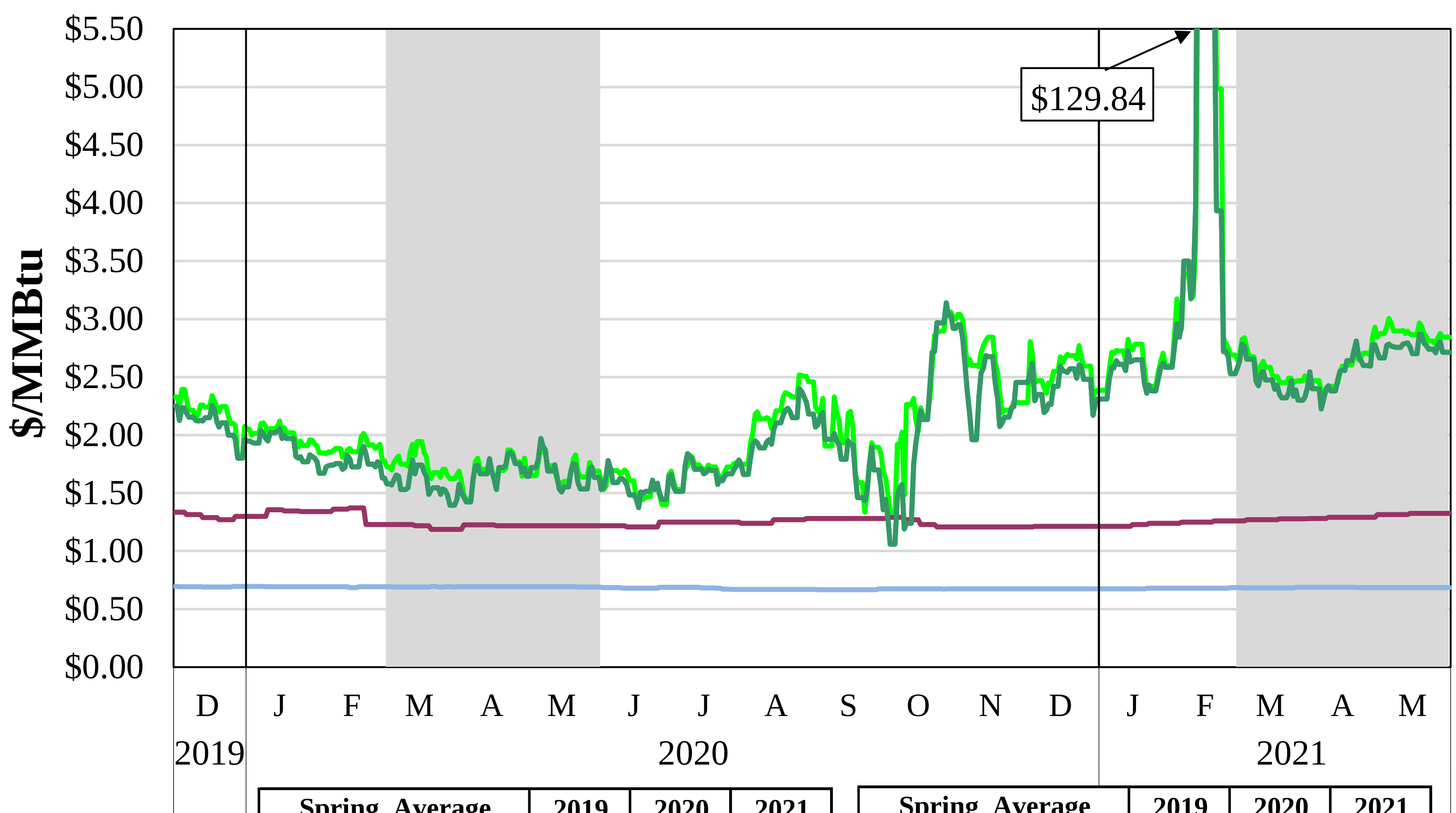
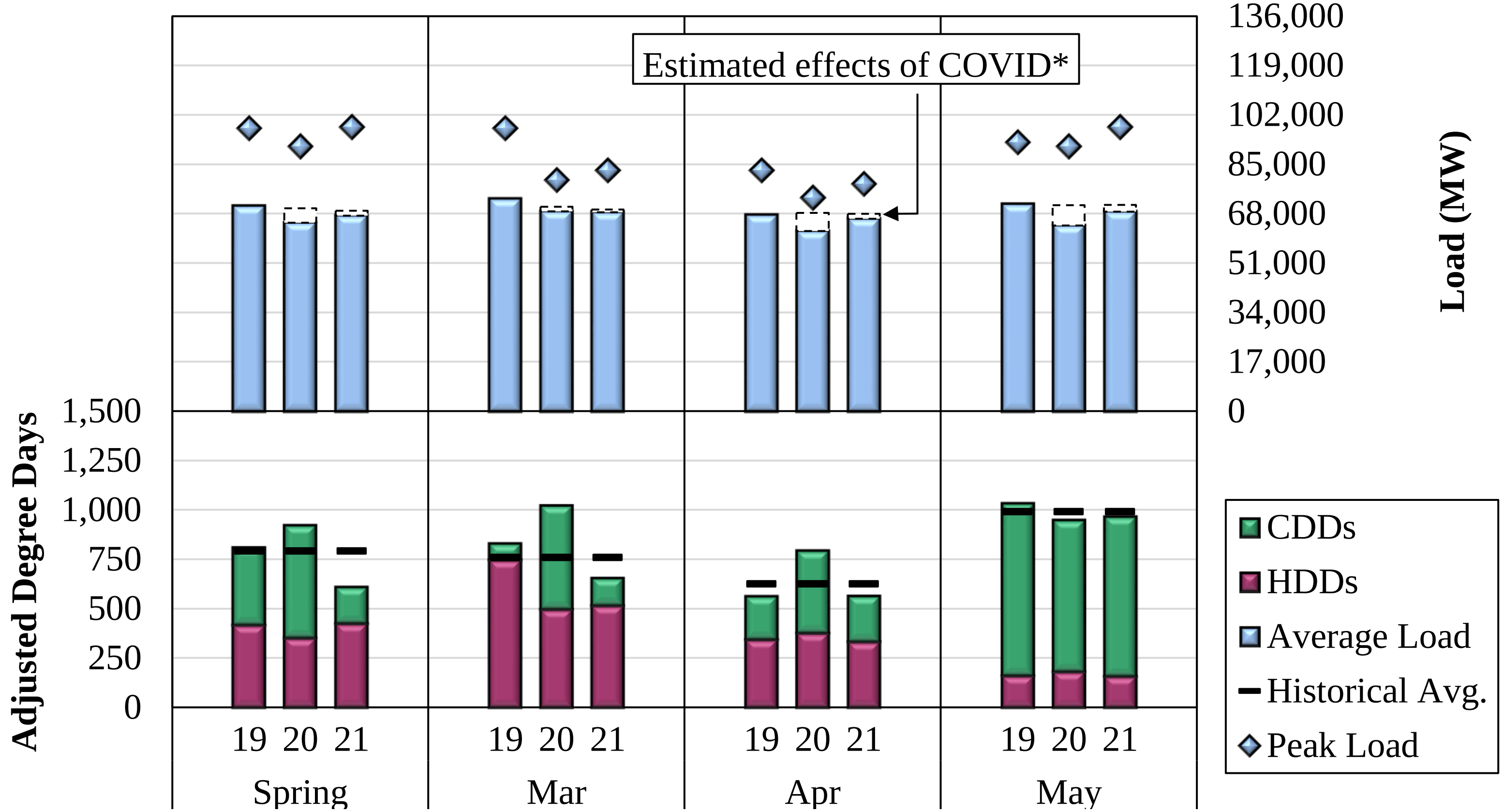
MISO Fuel Prices
Winter 2019 – Spring 2021



Spring Average	2019	2020	2021
Chicago NG	$2.74	$1.64	$2.59
Henry NG	$2.70	$1.71	$2.67

Spring Average	2019	2020	2021
IB Coal	$1.70	$1.22	$1.29
PRB Coal	$0.70	$0.69	$0.68

Load and Weather Patterns Spring 2019–2021



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 2021

Spring	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2020	2021	2020	2021	2020	2021	2020	2021	2020	2021
Nuclear	12,107	11,866	9%	9%	18%	16%	0%	0%	0%	0%
Coal	46,864	46,740	37%	36%	27%	36%	35%	43%	79%	88%
Natural Gas	56,673	58,431	44%	45%	37%	28%	63%	56%	94%	97%
Oil	1,568	1,636	1%	1%	0%	0%	0%	0%	0%	1%
Hydro	4,034	3,671	3%	3%	2%	2%	1%	1%	2%	2%
Wind	3,660	4,304	3%	3%	14%	17%	1%	0%	60%	72%
Other	2,703	3,145	2%	2%	1%	1%	0%	0%	3%	9%
Total	**127,608**	**129,794**								

2021–2022 Planning Resource Auction

Local Resource Zone (LRZ)	Midwest							South			External Zones*	System
	Z1 (MN, ND, WI)	Z2 (WI, MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	Z8 (AR)	Z9 (LA, TX)	Z10 (MS)		
Capacity Quantities												
Capacity Procured	18,688	13,948	10,712	8,332	7,811	15,746	21,549	9,929	20,634	4,966	1,587	133,903
Offered Not Cleared	1,602	32	115	1,174	-	86	117	713	2,383	388	52	6,662
Total	20,289	13,980	10,827	9,506	7,811	15,832	21,666	10,643	23,017	5,354	1,639	140,565
Pricing ($/MW-Day)												
Auction Clearing Price	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$0.01	$0.01	$0.01	$4.01	
Sloped Demand Curve (SDC) Price	$172.86	$172.86	$172.86	$172.86	$172.86	$172.86	$172.86	$28.31	$28.31	$28.31	$143.31	
SDC Price with IMM Recommendations**	$191.00	$191.00	$191.00	$191.00	$191.00	$191.00	$191.00	$72.37	$72.37	$72.37	$166.75	

* Prices are weighted based on cleared volume in each external zone.

** Alternative scenario prices are the combination of: (1) disqualifying LMRs that require more than six hours of notification time to deploy, and (2) reflecting additional MWs needed to serve behind-the-meter firm load. The combined affect is the removal of nearly 1,340 MW of UCAP. See 2020 State of the Market Report, Section VIII.

2021 Summer Assessment

		Alternative IMM Scenarios*			
				High Temperature	
	Base Scenario	Realistic Scenario	Realistic <=2HR	Realistic Scenario	Realistic <=2HR
Load					
Base Case	122,397	122,397	122,397	122,397	122,397
High Load Increase	-	-	-	7,528	7,528
Total Load (MW)	122,397	122,397	122,397	129,925	129,925
Generation					
Internal Generation Excluding Exports	134,953	134,953	134,953	134,953	134,953
BTM Generation	4,463	4,463	3,167	4,463	3,167
Unforced Outages and Derates**	(920)	(10,141)	(10,141)	(17,741)	(17,741)
Adjustment due to Transfer Limit	(3,519)	(431)	-	-	-
Total Generation (MW)	134,977	128,845	127,980	121,676	120,380
Imports and Demand Response* **					
Demand Response	7,152	5,364	3,123	5,364	3,123
Firm Capacity Imports	3,929	3,929	3,929	3,929	3,929
Margin (MW)	23,661	15,741	12,634	1,044	(2,493)
Margin (%)	**19.3%**	**12.9%**	**10.3%**	**0.8%**	**-1.9%**
Expected Capacity Uses and Additions					
Expected Forced Outages	(6,971)	(6,971)	(6,971)	(6,971)	(6,971)
Non-Firm Net Imports in Emergencies	4,293	4,293	4,293	4,293	4,293
Expected Margin (MW)	20,983	13,063	9,956	(1,634)	(5,171)
Expected Margin (%)	**17.1%**	**10.7%**	**8.1%**	**-1.3%**	**-4.0%**

* Assumes 75% response from DR.

** Base scenario shows approved planned outages for summer 2021. Realistic cases use historical average unforced outages/derates during peak summer hours. High temp. cases are based upon MISO's 2020 Summer Assessment.

*** Cleared amounts for the 2021/2022 planning year.

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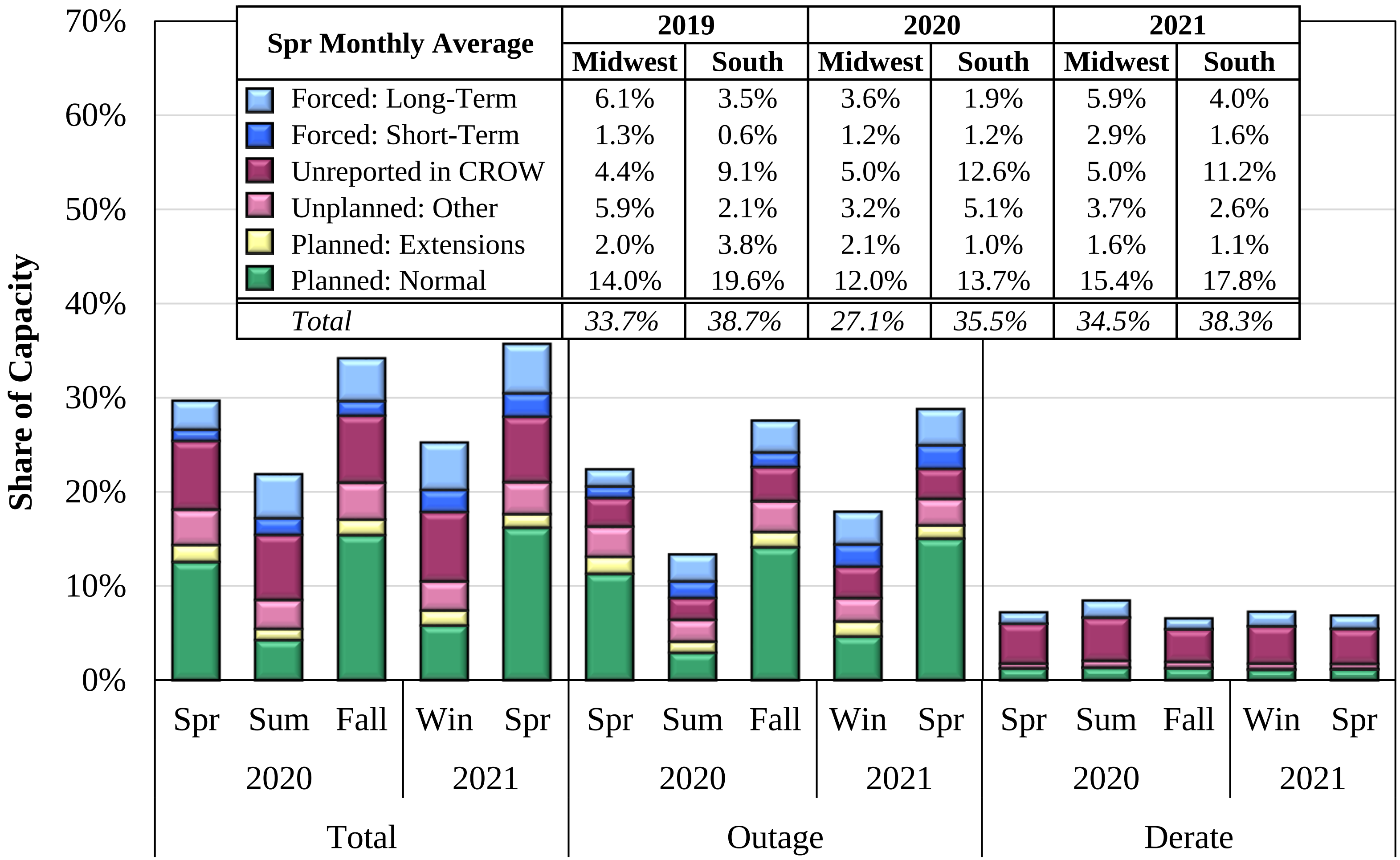
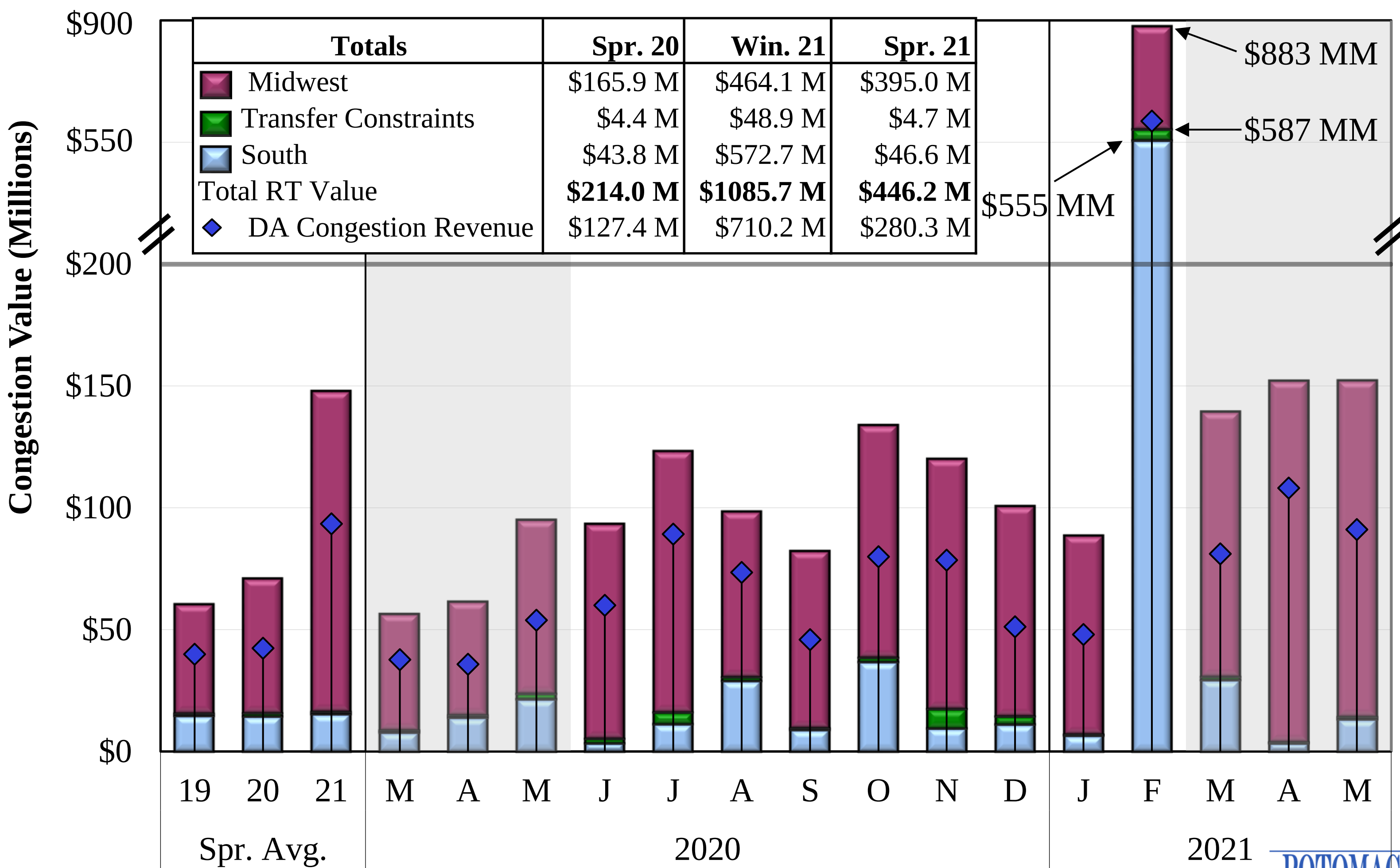
Generation Outages and Deratings 2020–2021



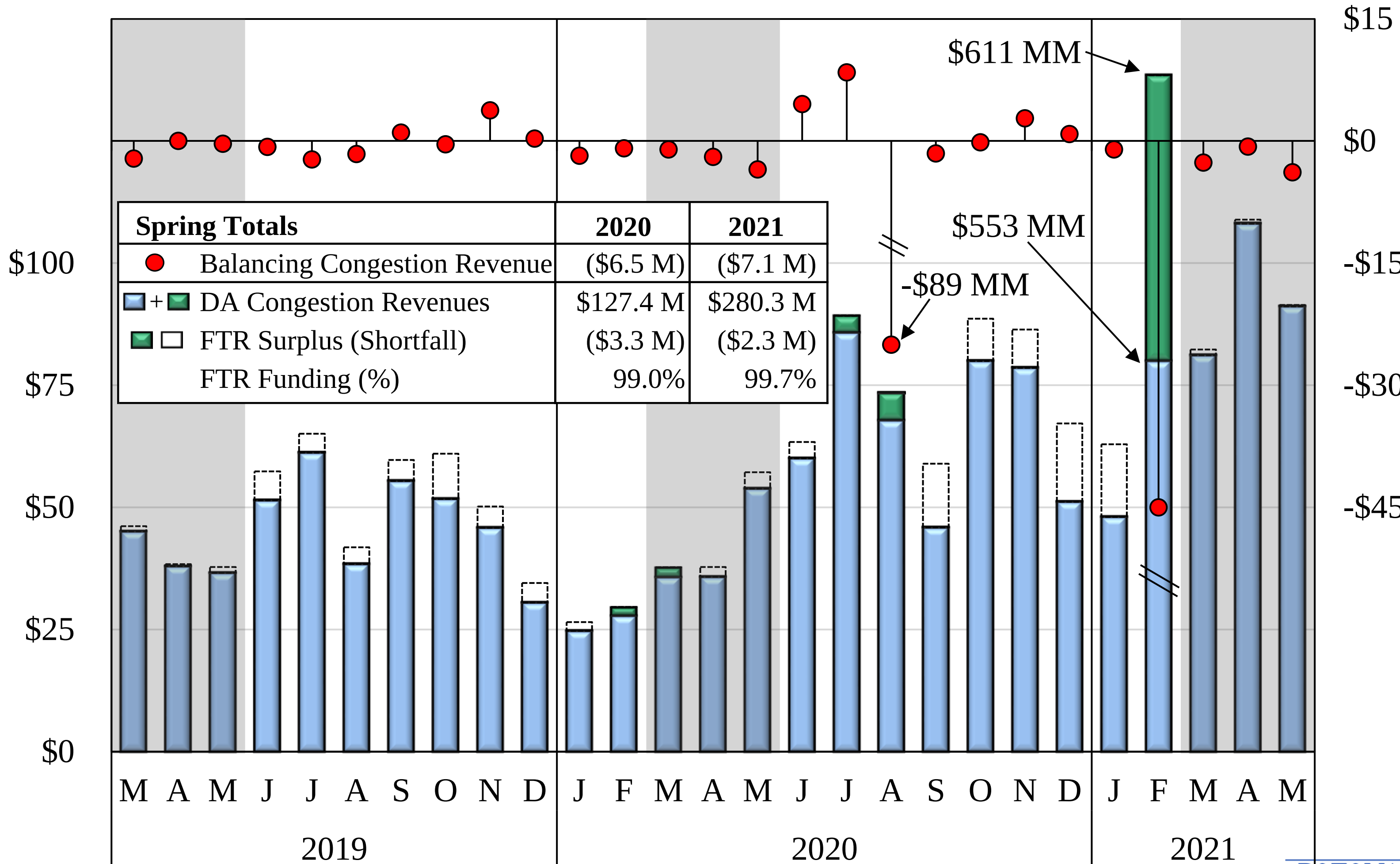
Spr Monthly Average	2019 Midwest	2019 South	2020 Midwest	2020 South	2021 Midwest	2021 South
Forced: Long-Term	6.1%	3.5%	3.6%	1.9%	5.9%	4.0%
Forced: Short-Term	1.3%	0.6%	1.2%	1.2%	2.9%	1.6%
Unreported in CROW	4.4%	9.1%	5.0%	12.6%	5.0%	11.2%
Unplanned: Other	5.9%	2.1%	3.2%	5.1%	3.7%	2.6%
Planned: Extensions	2.0%	3.8%	2.1%	1.0%	1.6%	1.1%
Planned: Normal	14.0%	19.6%	12.0%	13.7%	15.4%	17.8%
Total	*33.7%*	*38.7%*	*27.1%*	*35.5%*	*34.5%*	*38.3%*

Value of Real-Time Congestion Spring 2020–2021



Totals	Spr. 20	Win. 21	Spr. 21
Midwest	$165.9 M	$464.1 M	$395.0 M
Transfer Constraints	$4.4 M	$48.9 M	$4.7 M
South	$43.8 M	$572.7 M	$46.6 M
Total RT Value	**$214.0 M**	**$1085.7 M**	**$446.2 M**
DA Congestion Revenue	$127.4 M	$710.2 M	$280.3 M

Day-Ahead Congestion, Balancing Congestion and FTR Underfunding



Spring Totals	2020	2021
Balancing Congestion Revenue	($6.5 M)	($7.1 M)
+ DA Congestion Revenues	$127.4 M	$280.3 M
FTR Surplus (Shortfall)	($3.3 M)	($2.3 M)
FTR Funding (%)	99.0%	99.7%

Benefits of Ambient-Adjusted and Emergency Ratings Spring 2020–2021

	Spring	Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2020	**Midwest**	$12.8	$9.25	$22.0	3	12.2%
	South	$1.3	$2.15	$3.4	1	8.5%
	Total	**$14.1**	**$11.4**	**$25.5**	**4**	**11.5%**
2021	**Midwest**	$28.7	$18.61	$47.4	9	11.5%
	South	$0.8	$1.79	$2.6	1	5.7%
	Total	**$29.6**	**$20.4**	**$50.0**	**10**	**11.0%**

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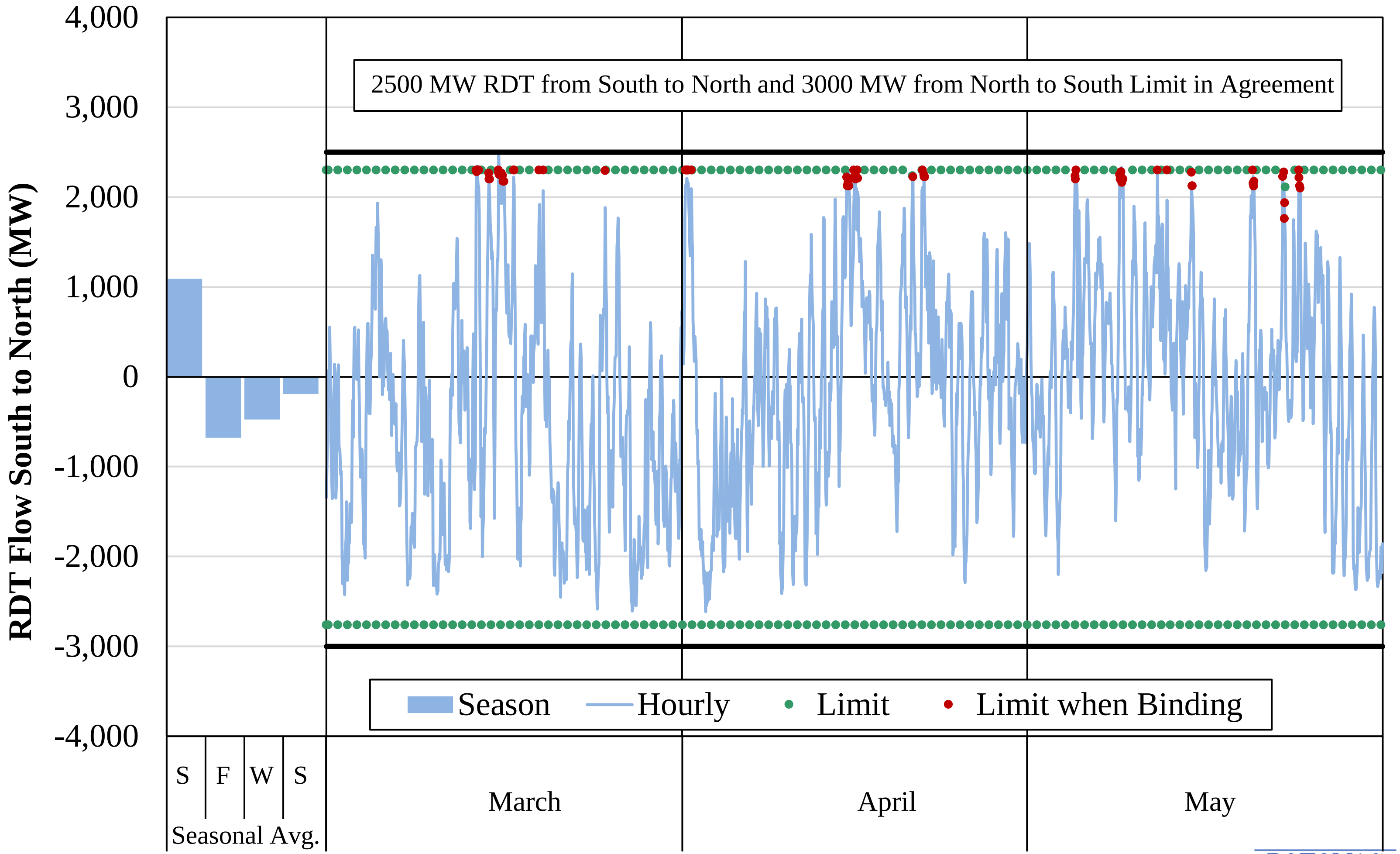
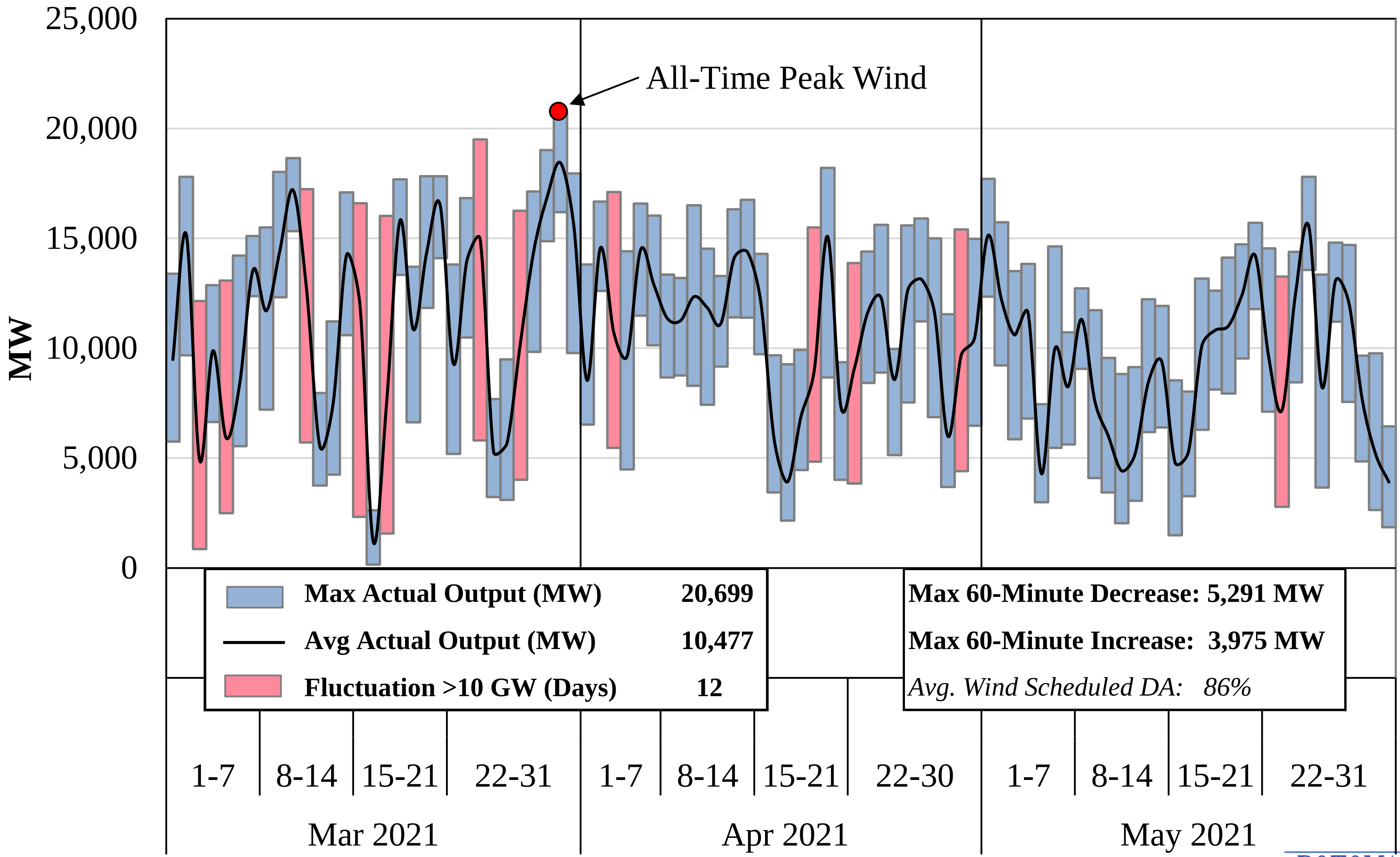
Key Improvement: Impacts of 1.5 Percent GSF Cutoff 2021 Year to Date

Description		Constraints		
		No GSF Cutoff	1.5% GSF Cutoff	Impact
Future Market	FTR Auction	✓		$44 Million FTR Shortfall (0.5% GSF Cutoff in DA)
	DA Market		✓	
Spot Market	RT Market		✓	$53 Million Unavailable Economic Relief (0.5% Cutoff in RT)
Post RT Market Settlements	M2M Settlements	✓		$37 Million M2M Settlement Payments

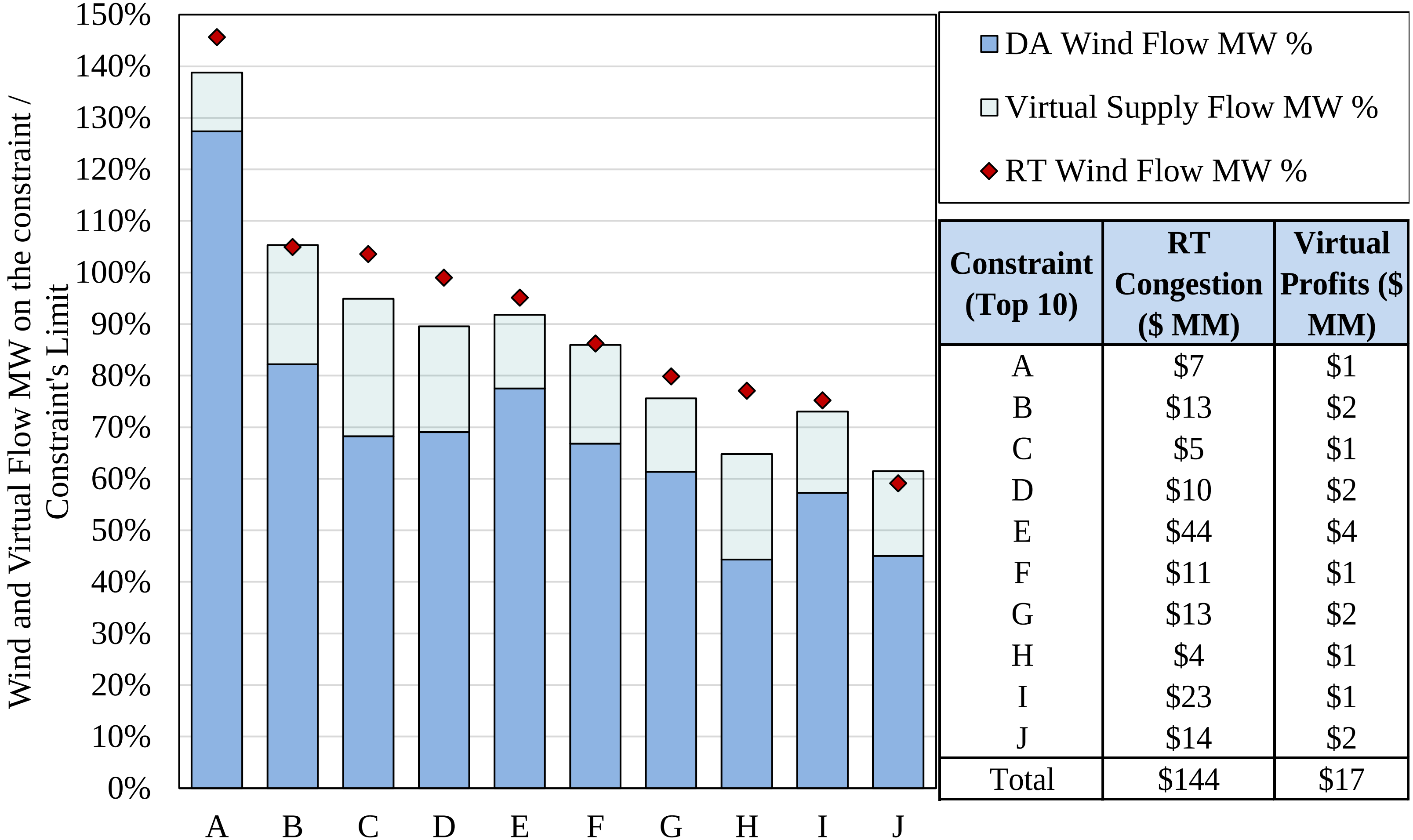
Real-Time Hourly Inter-Regional Flows
Spring 2021



Wind Output in Real Time
Daily Range and Average

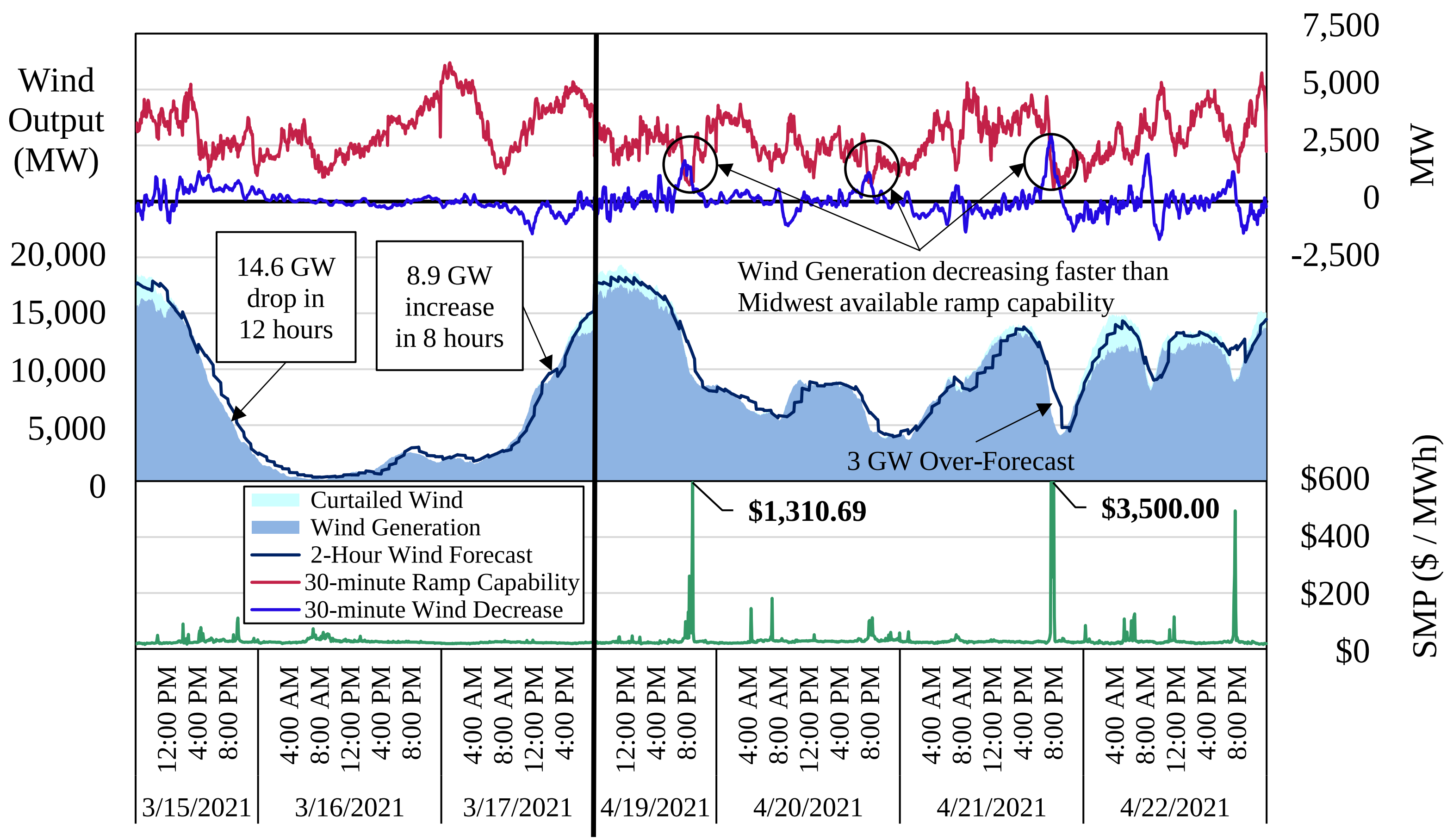


Virtual Activity on Wind-Impacted Constraints January 1, 2021 – May 31, 2021

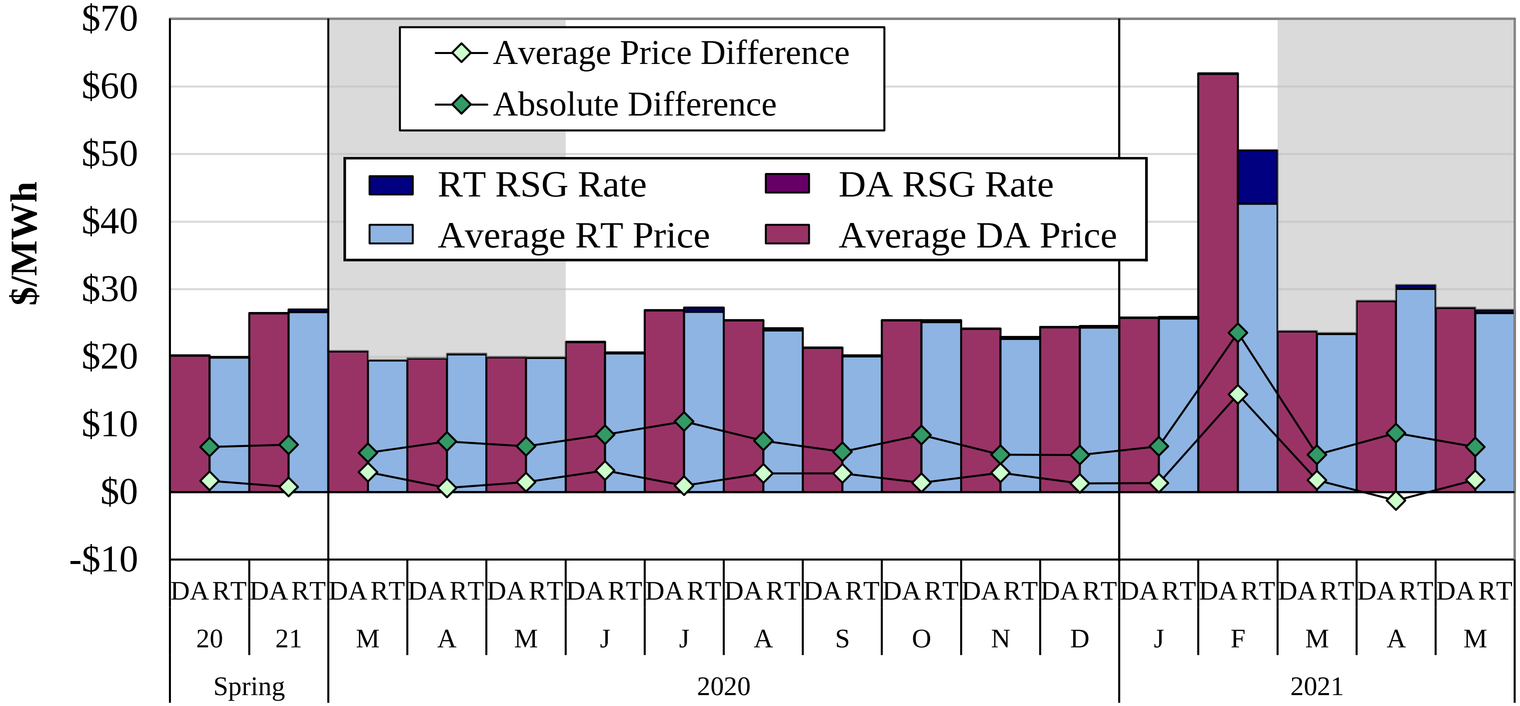


Constraint (Top 10)	RT Congestion ($ MM)	Virtual Profits ($ MM)
A	$7	$1
B	$13	$2
C	$5	$1
D	$10	$2
E	$44	$4
F	$11	$1
G	$13	$2
H	$4	$1
I	$23	$1
J	$14	$2
Total	$144	$17

Significant Wind Events



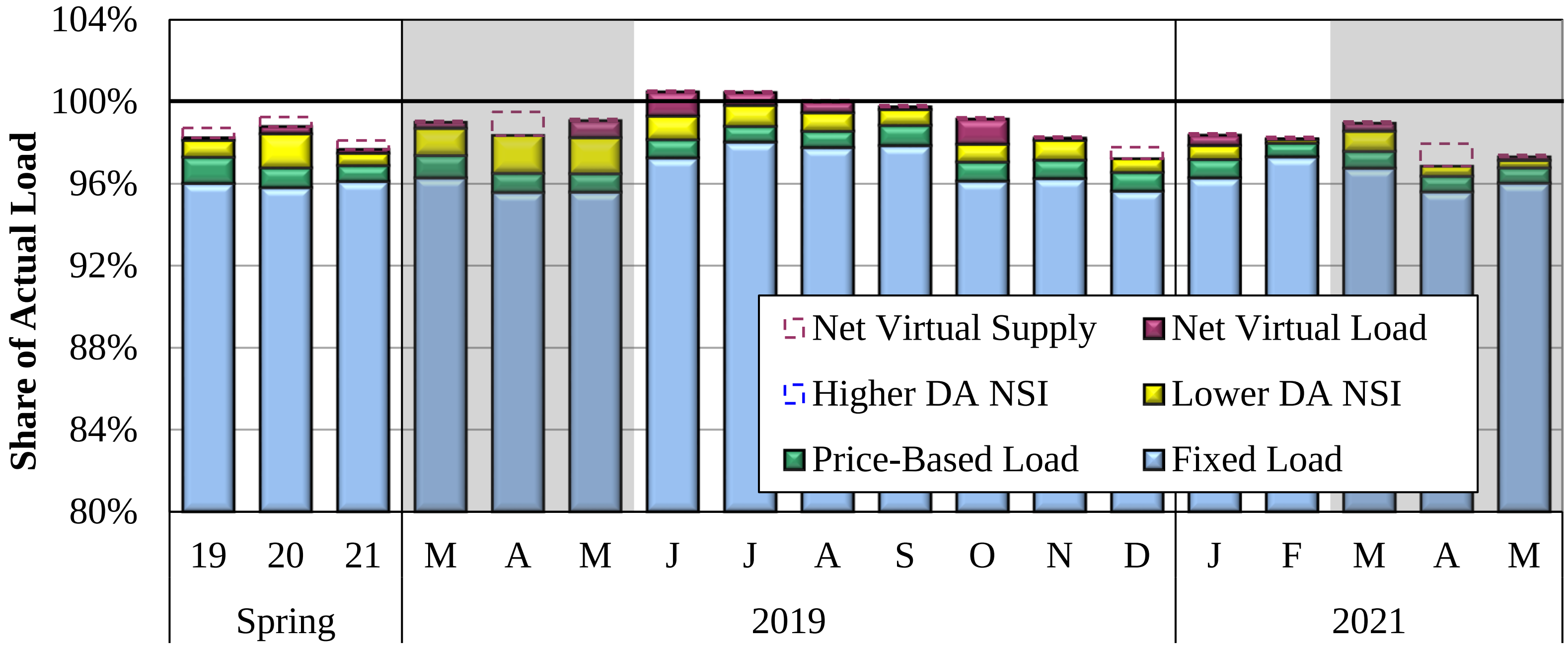
Day-Ahead and Real-Time Price Convergence Spring 2020–2021



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

Indiana Hub	1	-2	7	-3	0	8	-2	5	6	0	5	-1	0	23	1	-8	1
Michigan Hub	2	-1	7	-6	4	3	-5	3	6	-2	5	-1	0	14	-1	-4	1
Minnesota Hub	2	-7	3	1	0	-5	-3	1	0	-4	-3	-7	-1	6	3	-15	-9
Arkansas Hub	6	-3	6	5	6	6	-7	2	3	-5	0	1	3	-14	-3	-6	-1
Texas Hub	9	-3	10	5	13	7	2	3	6	9	4	1	0	-10	-6	0	-2
Louisiana Hub	7	-3	12	4	5	6	1	0	8	-5	1	3	1	-14	-10	0	1

Day-Ahead Peak Hour Load Scheduling Spring 2020–2021



Share of Actual Load (%)

All Hours	98.5	99.2	97.7	98.9	99.0	99.5	100.4	101.5	101.0	99.7	98.8	98.4	97.8	98.5	98.5	98.3	97.2	97.7
Peak Hours Midwest	97.8	98.9	96.6	100.2	98.2	98.4	99.9	99.8	99.0	99.5	98.8	98.5	96.6	98.5	97.4	97.3	96.0	96.4
Peak Hours South	99.2	100.2	100.6	98.2	101.0	101.5	101.2	101.8	102.1	100.0	100.7	98.5	98.2	101.3	103.6	102.3	100.3	99.2

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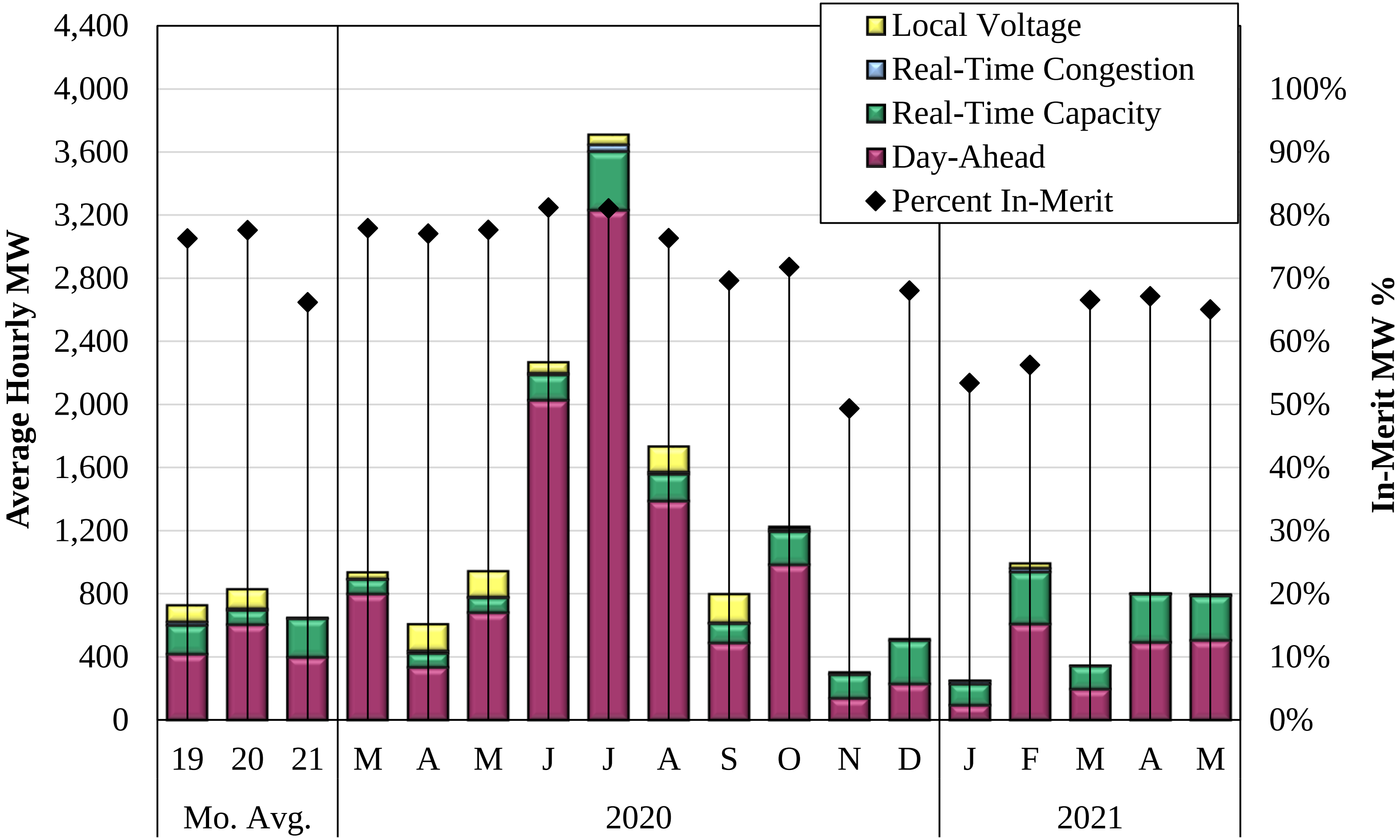
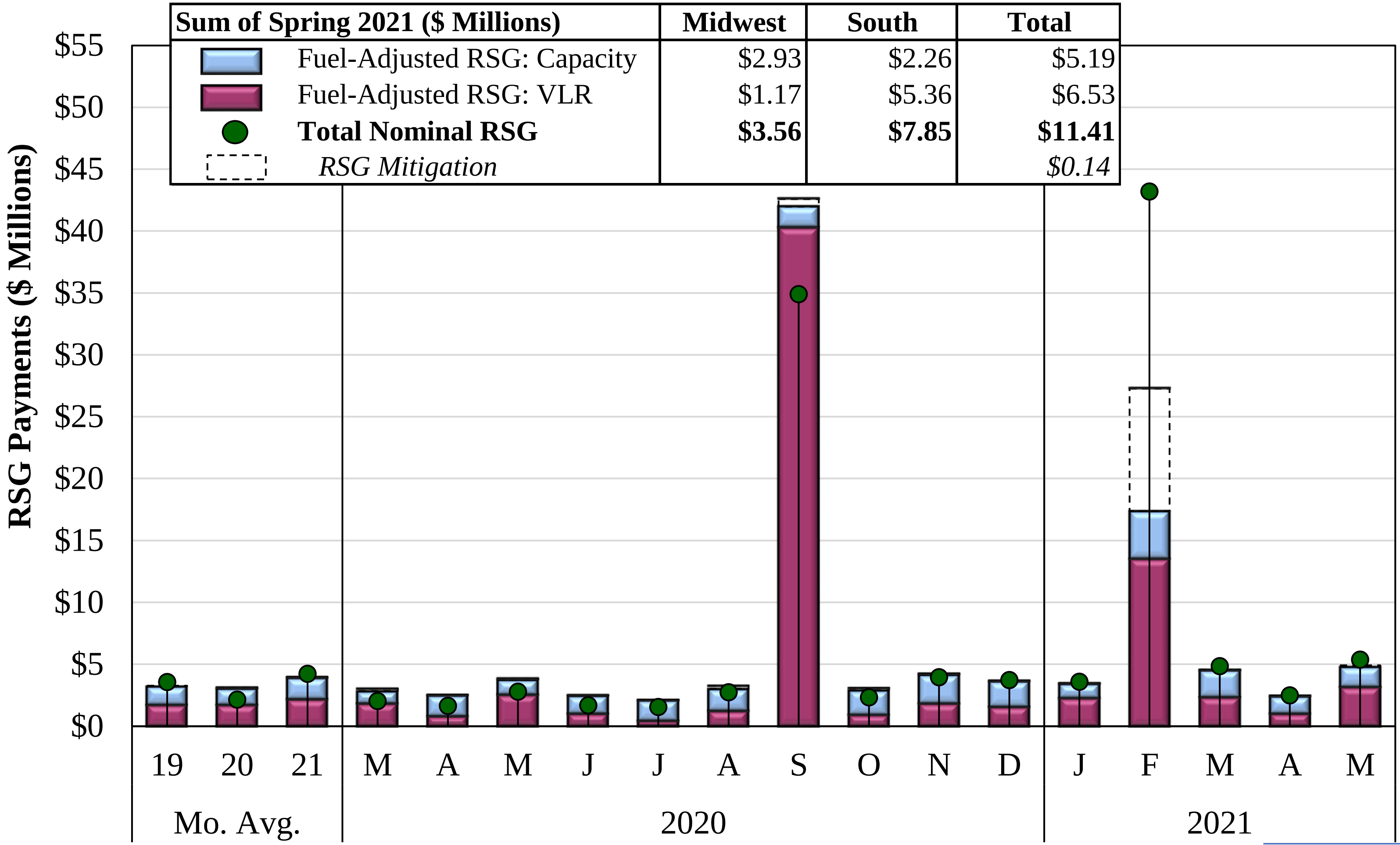
Peaking Resource Dispatch
Spring 2020–2021

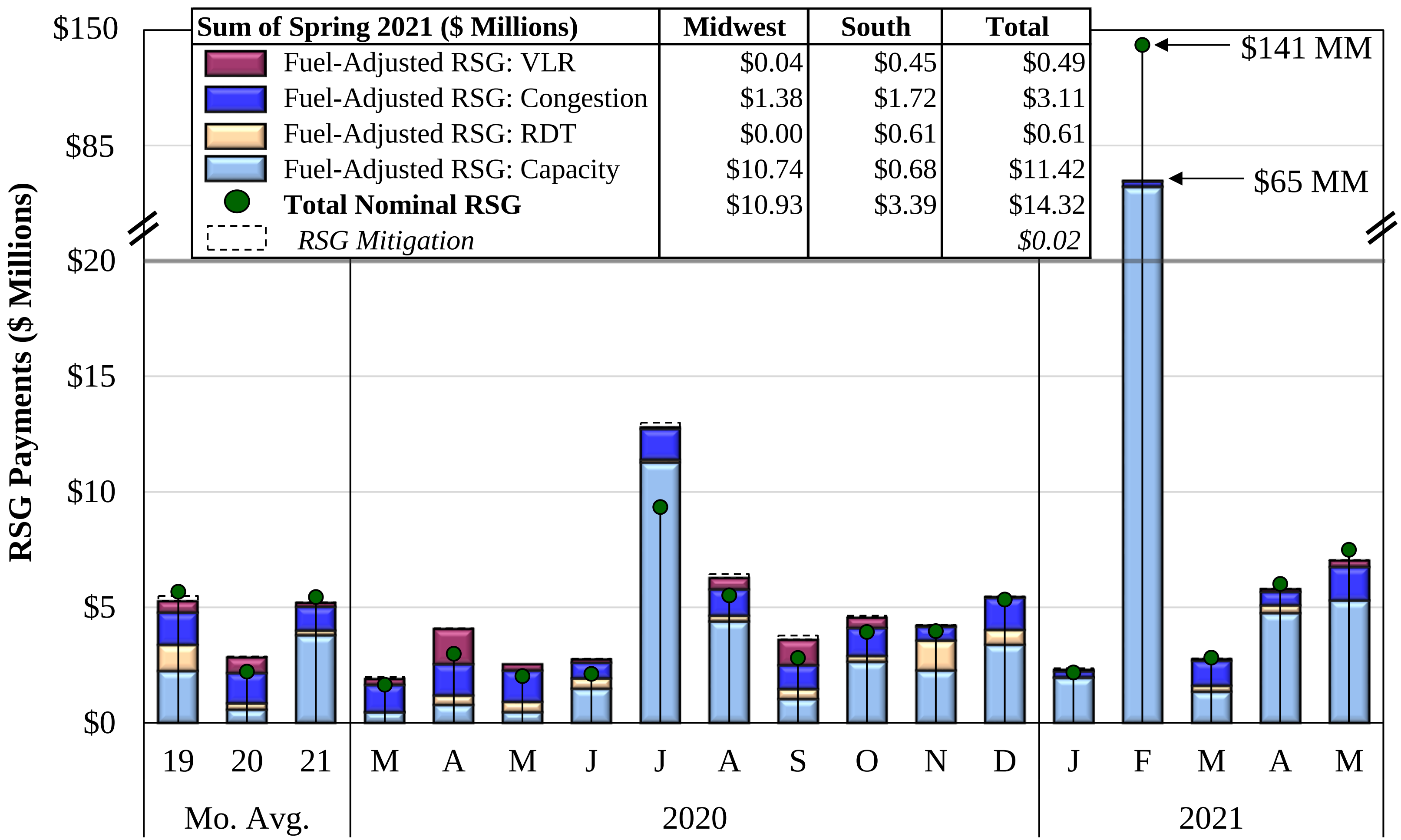


Day-Ahead RSG Payments
Spring 2020–2021



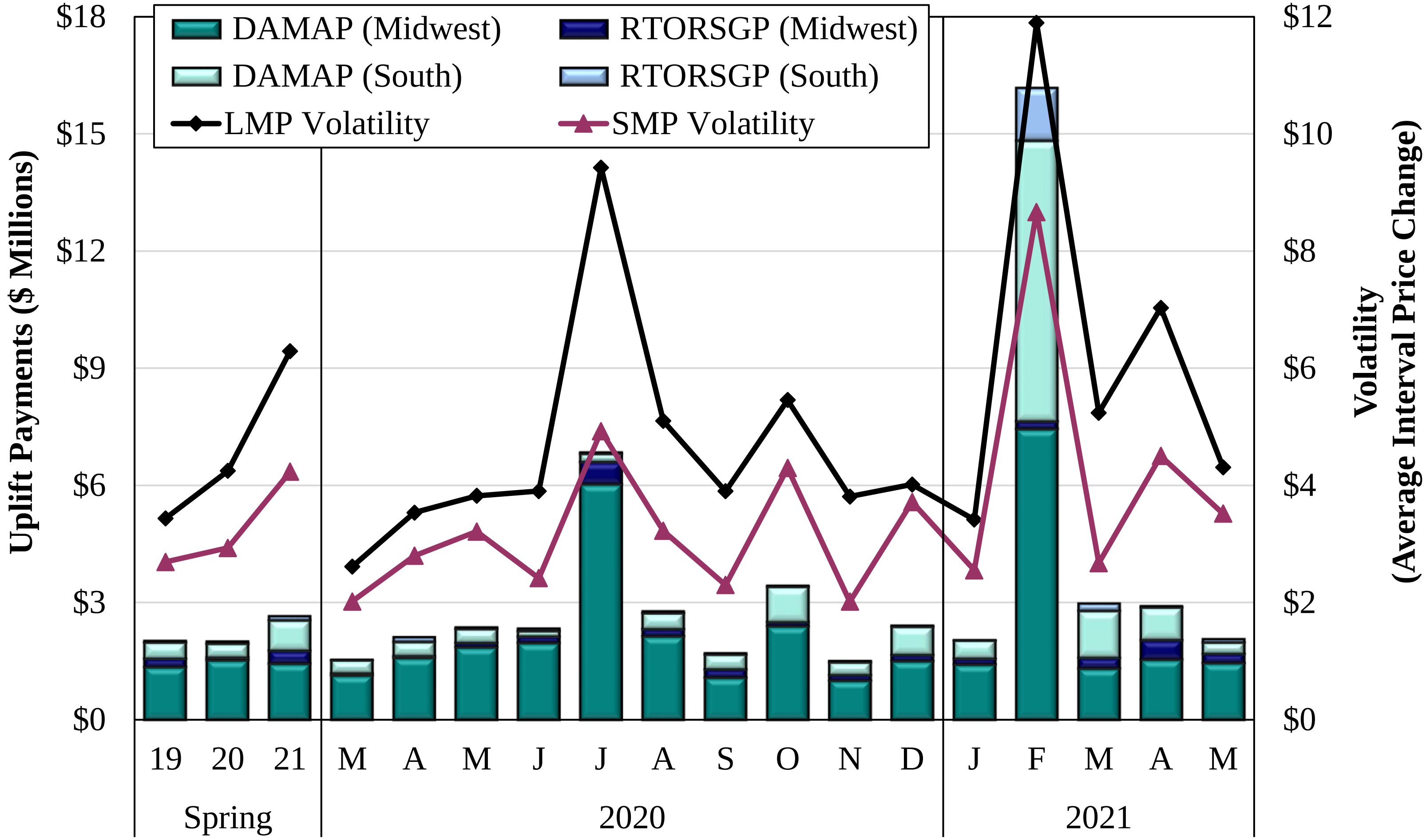
Sum of Spring 2021 ($ Millions)	Midwest	South	Total
Fuel-Adjusted RSG: Capacity	$2.93	$2.26	$5.19
Fuel-Adjusted RSG: VLR	$1.17	$5.36	$6.53
Total Nominal RSG	**$3.56**	**$7.85**	**$11.41**
RSG Mitigation			*$0.14*

Real-Time RSG Payments
Spring 2020–2021



Sum of Spring 2021 ($ Millions)	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$0.04	$0.45	$0.49
Fuel-Adjusted RSG: Congestion	$1.38	$1.72	$3.11
Fuel-Adjusted RSG: RDT	$0.00	$0.61	$0.61
Fuel-Adjusted RSG: Capacity	$10.74	$0.68	$11.42
Total Nominal RSG	$10.93	$3.39	$14.32
RSG Mitigation			*$0.02*

Price Volatility Make Whole Payments
Spring 2020–2021



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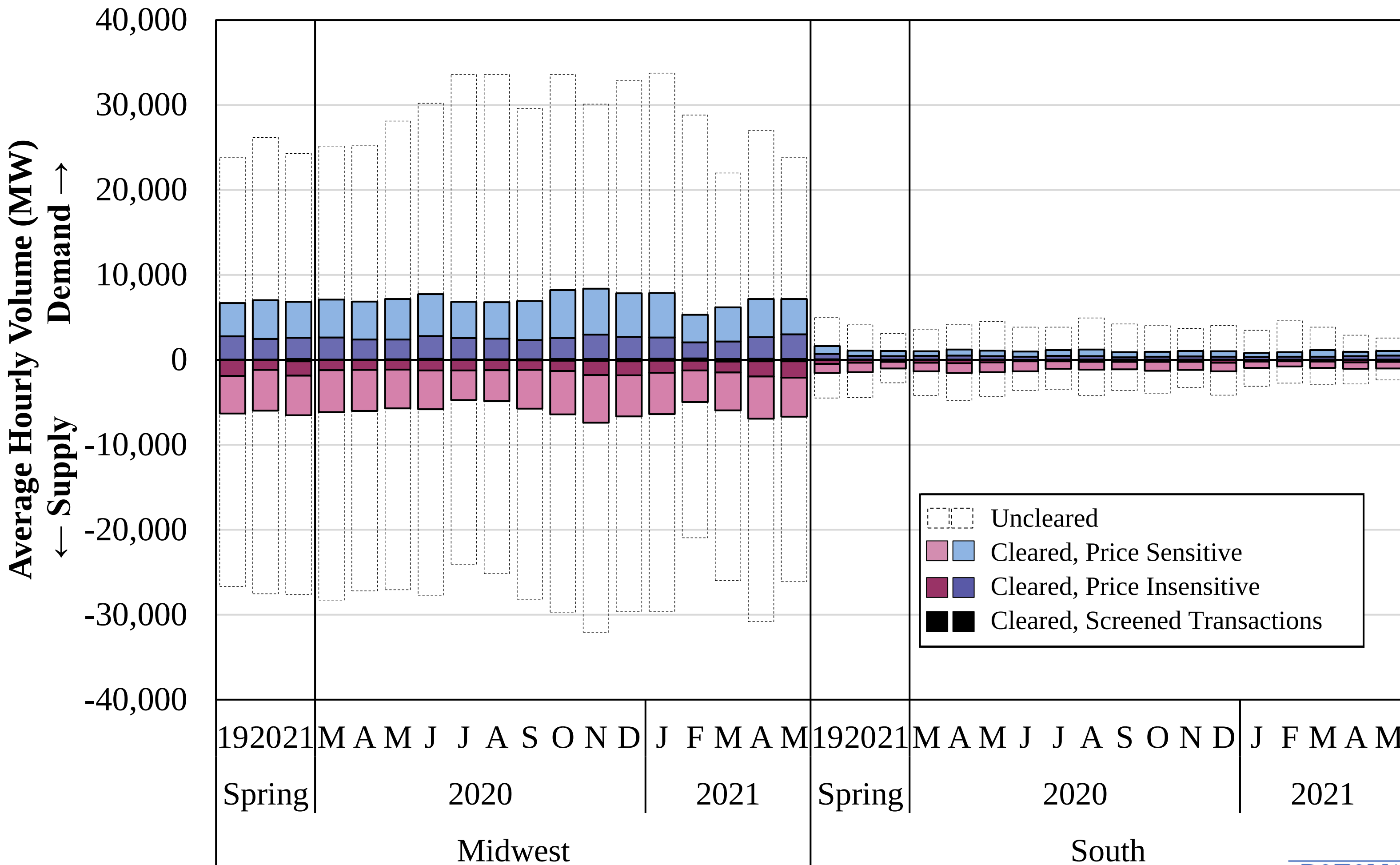
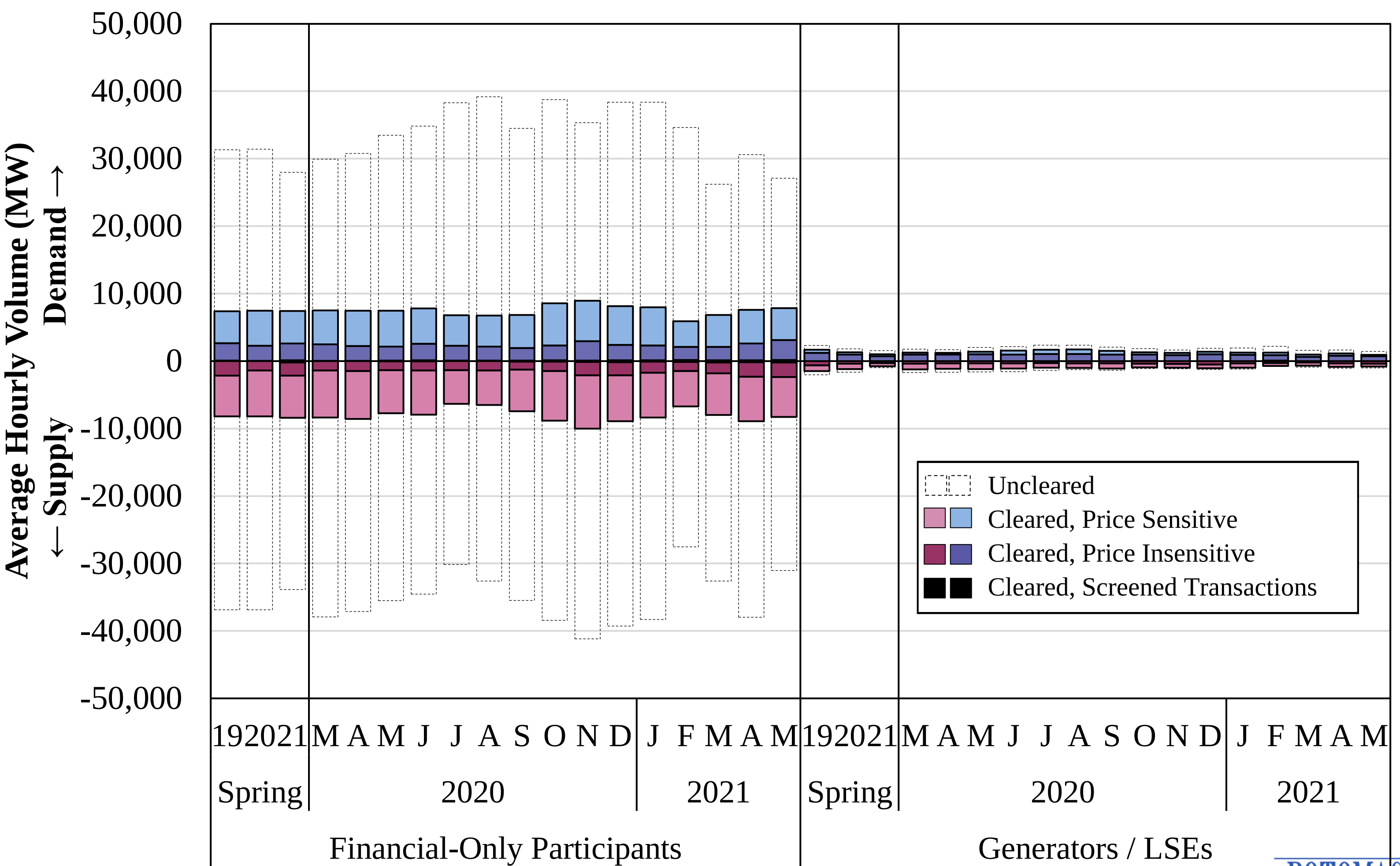
Virtual Load and Supply
Spring 2020–2021



Virtual Load and Supply by Participant Type
Spring 2020–2021



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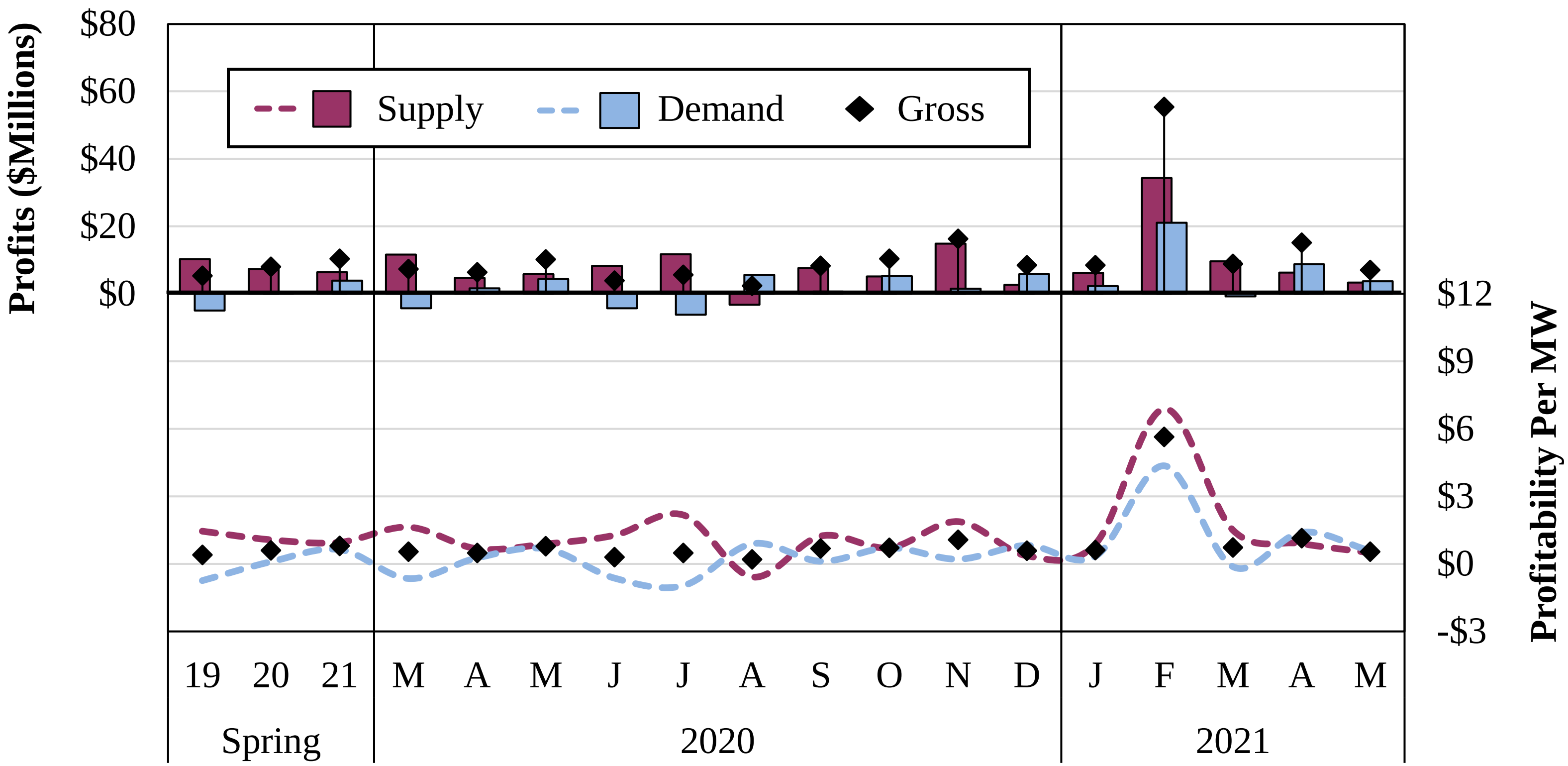
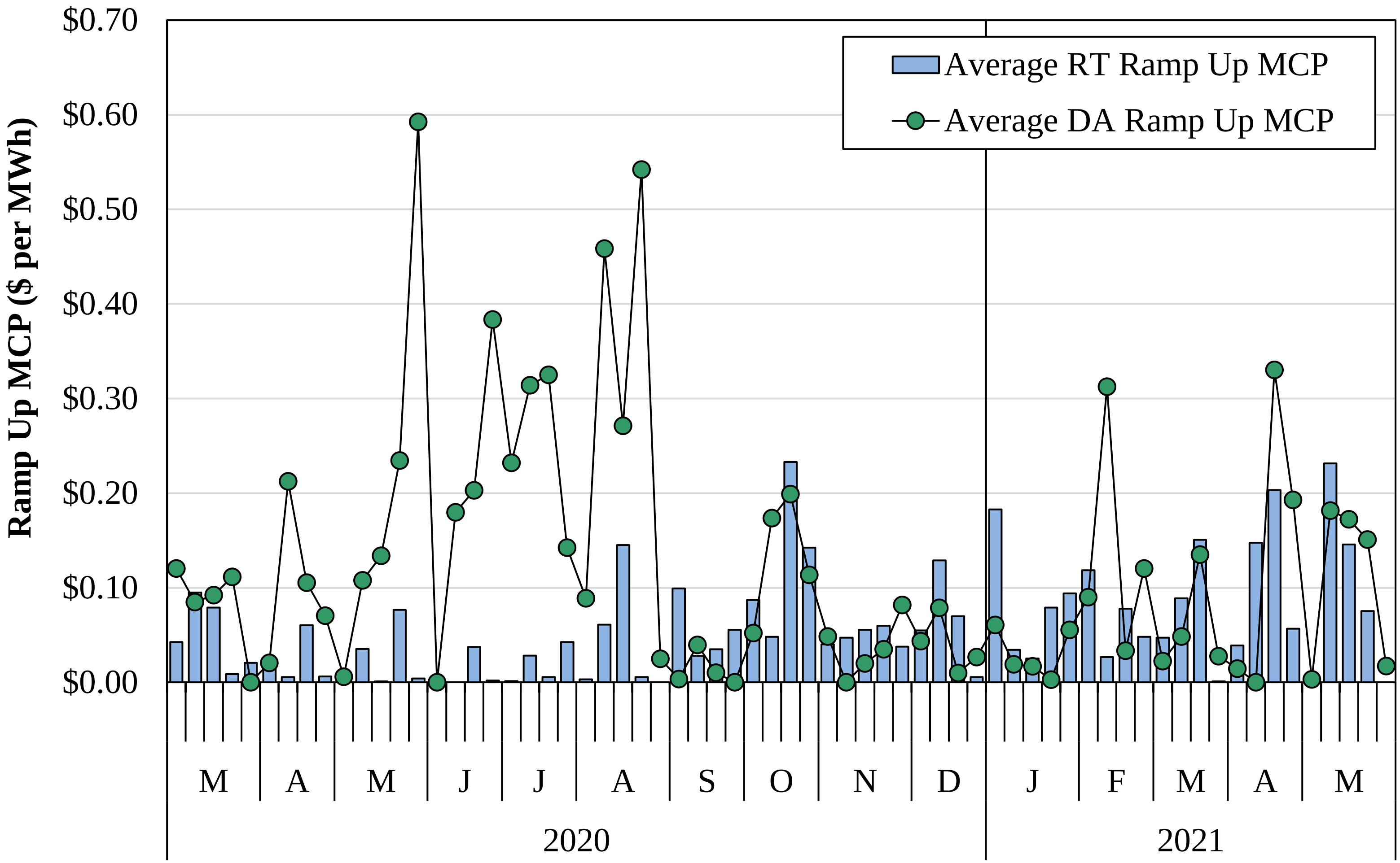
Virtual Profitability
Spring 2020–2021



Percent Screened

Supply	0.2	0.3	2.3	0.2	0.2	0.4	0.5	0.3	0.3	0.9	1.0	1.3	1.7	1.0	1.8	2.5	2.0	2.3
Demand	0.9	0.6	1.6	0.5	0.4	0.9	1.6	1.2	1.1	0.8	1.2	1.1	1.3	1.4	3.7	1.4	1.7	1.8
Total	0.6	0.4	2.0	0.4	0.3	0.6	1.0	0.8	0.7	0.9	1.1	1.2	1.5	1.2	2.7	2.0	1.9	2.1

Day-Ahead and Real-Time Ramp Up Price 2020–2021



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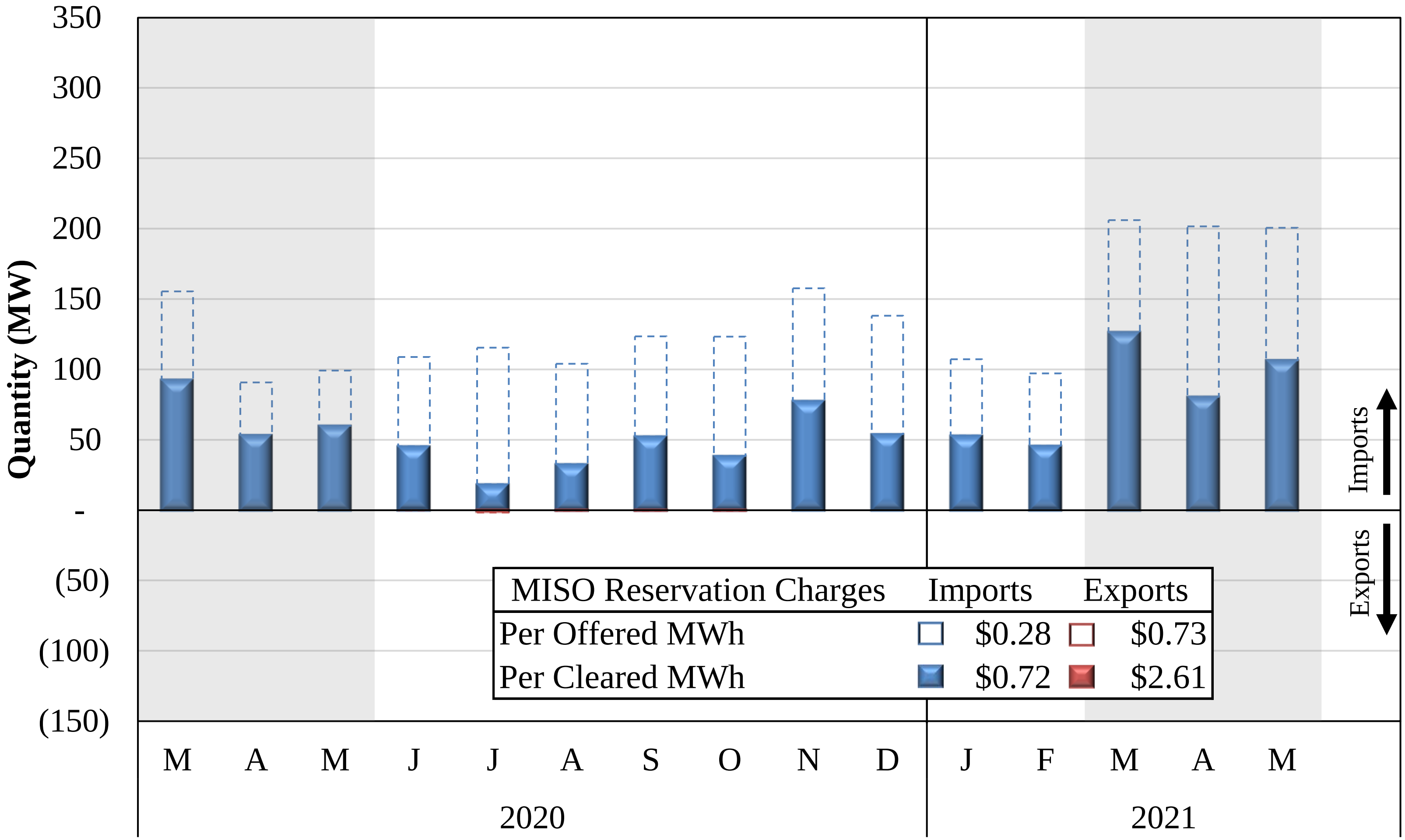
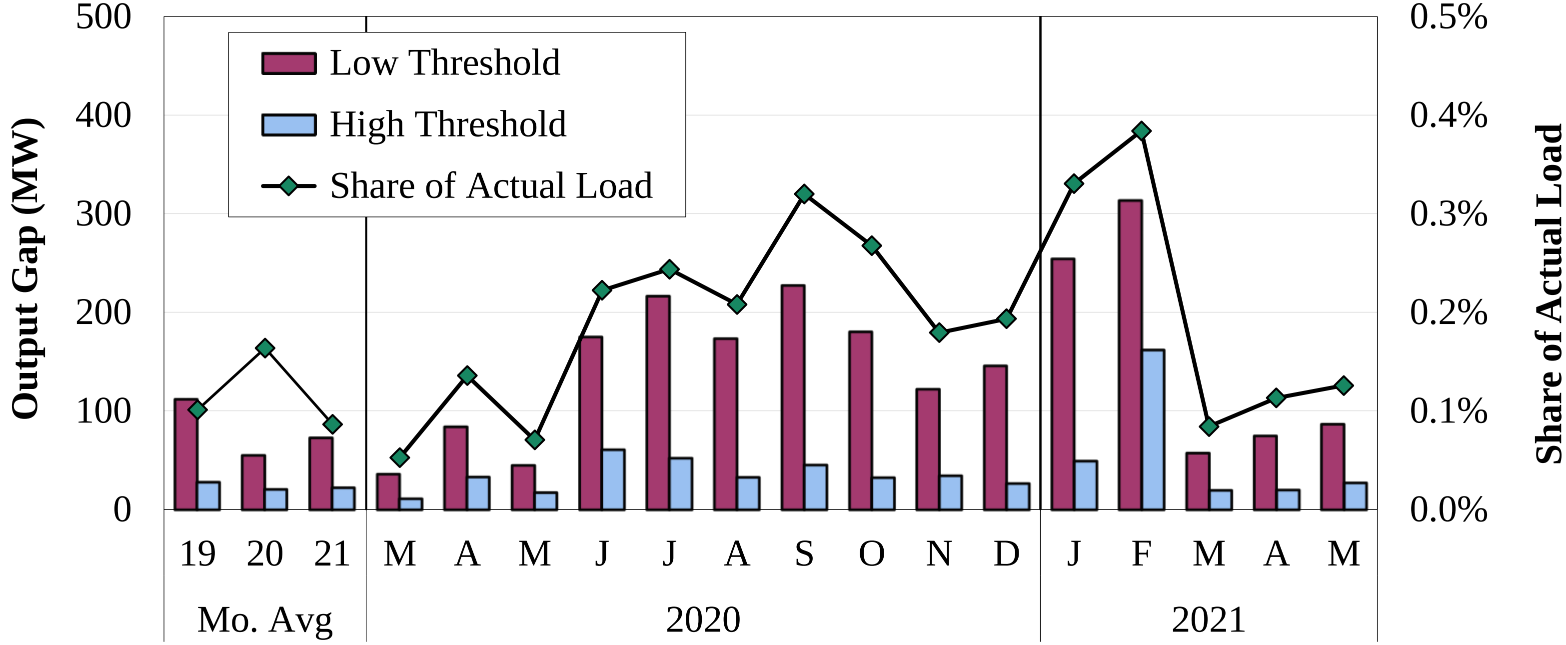
Coordinated Transaction Scheduling (CTS) Spring 2020–2021



Monthly Output Gap
Spring 2020–2021



Low Threshold Results by Unit Status (MW)

Offline	16	1	4	0	0	3	12	36	18	4	8	10	2	0	90	3	0	9
Online	95	54	69	36	84	42	163	180	156	223	172	112	144	254	223	55	75	77

High Threshold Results by Unit Status (MW)

Offline	13	1	3	0	0	3	11	31	16	4	7	7	2	0	70	2	0	8
Online	15	20	19	11	33	15	50	21	17	41	25	28	25	49	91	18	20	20

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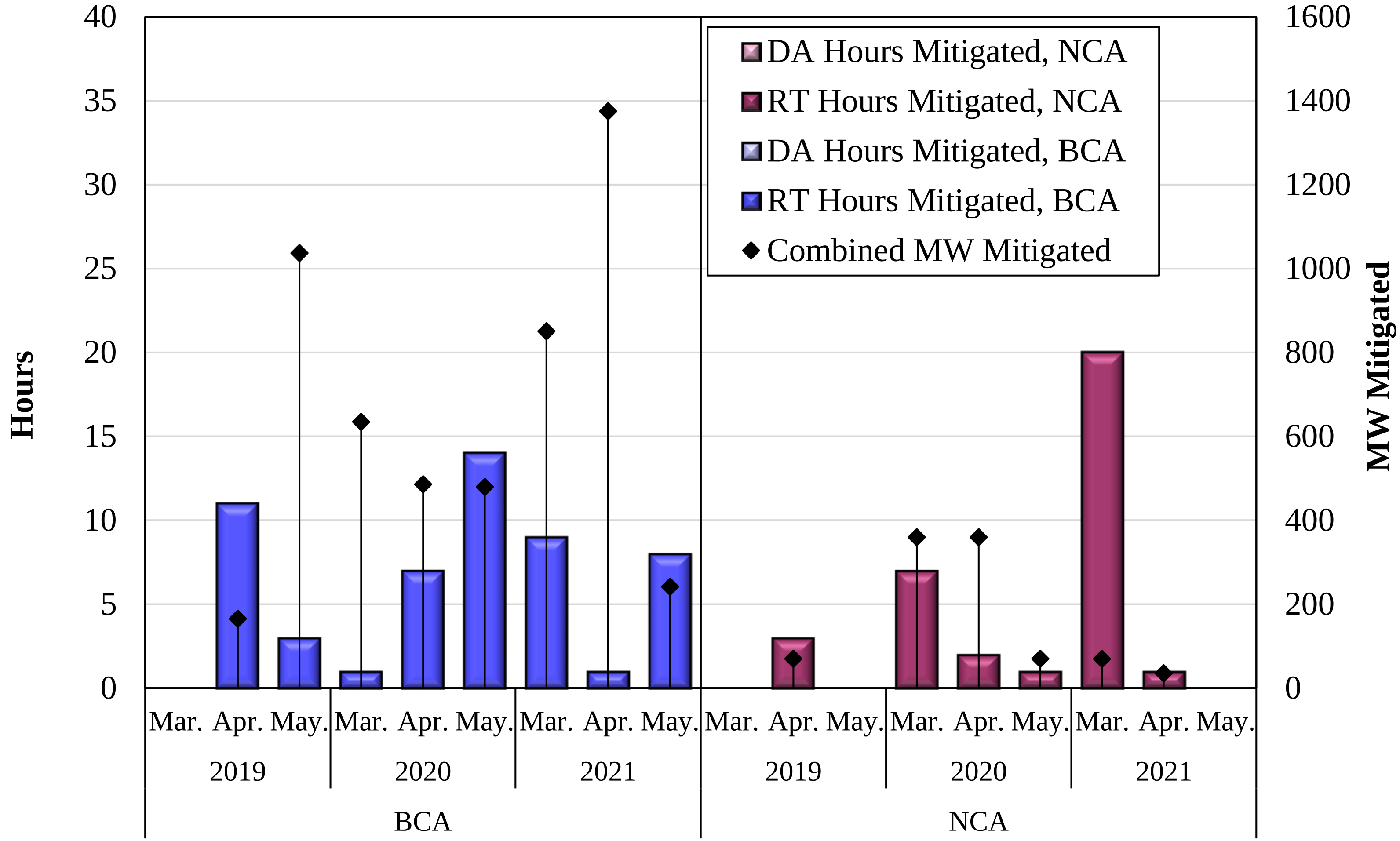
Day-Ahead And Real-Time Energy Mitigation Spring 2020 and 2021



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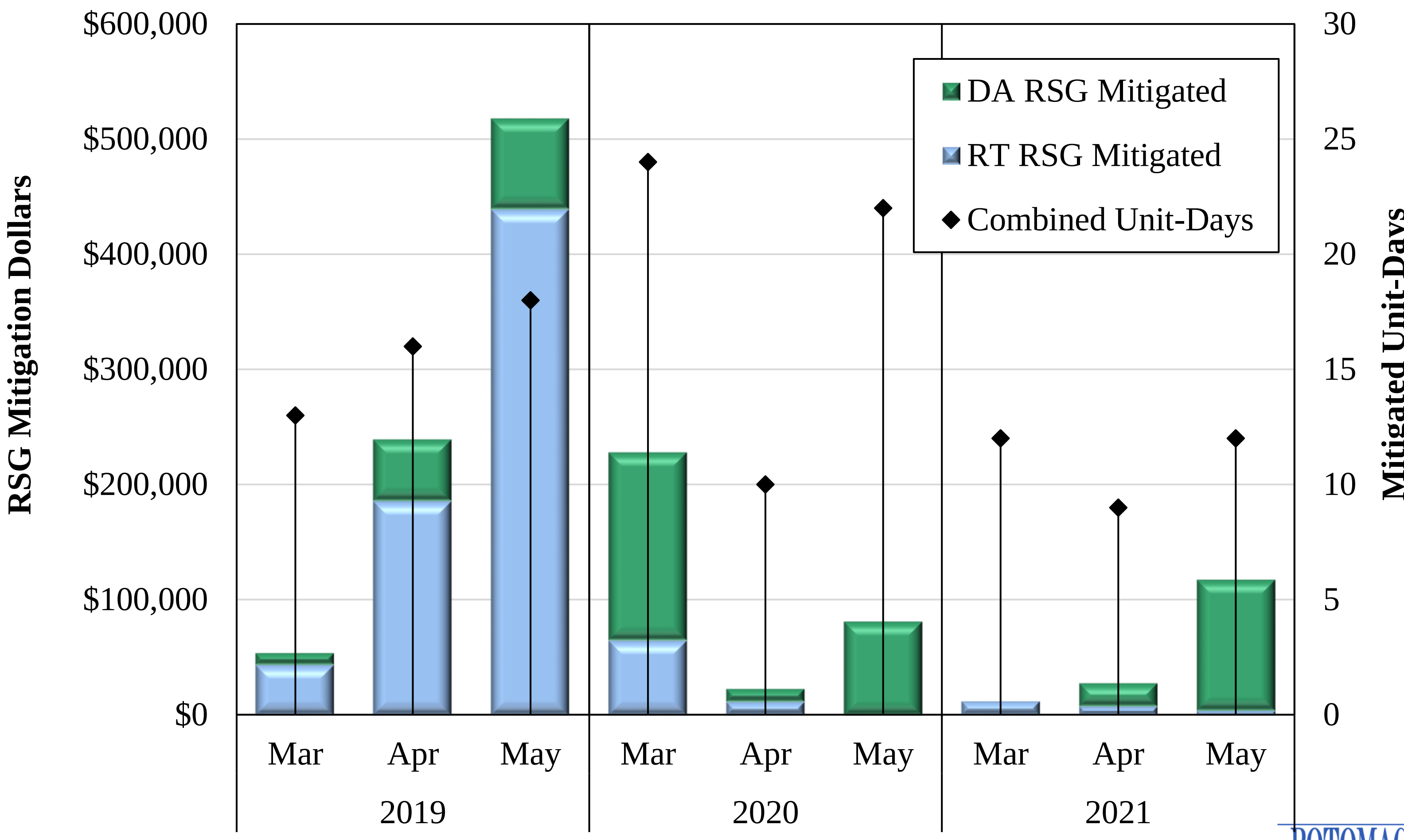
Day-Ahead and Real-Time RSG Mitigation Spring 2020 and 2021



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 Curve	Operating Reserve Demand
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
STE	Short-Term Emergency
SMP	System Marginal Price
SOM	State of the Market
TLR	Transmission Loading Relief
TCDC	Transmission Constraint Demand Curve
VLR	Voltage and Local Reliability
WUMS	Wisconsin Upper Michigan System

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