IMM Quarterly Report: Spring 2019

MISO Independent Market Monitor

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Potomac Economics

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Highlights and Findings: Spring 2019

- The MISO markets performed competitively this spring and market power mitigation was infrequent and offers were competitive overall.
- Energy prices fell 12 percent this quarter from the prior year because:
  - ✓ Average load and natural gas prices both decreased by 3 percent (excluding an unusually cold period in early March of transitory gas price volatility).
  - ✓ Transmission congestion fell sharply because of network upgrades, fewer outages, and improvements in the market-to-market coordination processes.
- Despite normal seasonal weather patterns in May, planned outage extensions led to multiple capacity alerts and declarations late in the month.
- Wetter than normal conditions this quarter led to fuel supply issues for resources in the South that rely the on Mississippi River.
- On March 15, MISO set a new all-time peak wind record output of 16.3 GW.
  - ✓ Wind output was 22 percent higher than last Spring.
- Price Volatility Make Whole Payments fell by more than half as volatility fell along with congestion.
  - ✓ Improvements in the PVMWP formulas were implemented on May 1.

Quarterly Summary

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
RT Energy Prices ($/MWh)	🟣	$26.06	*-9%*	*-13%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago	🟢	$2.50	*-22%*	*-3%*
Natural Gas - Henry Hub	🟢	$2.70	*-17%*	*-1%*
Western Coal	🟢	$0.70	*0%*	*-1%*
Eastern Coal	🟢	$1.70	*-4%*	*16%*
Load (GW)[2]				
Average Load	🟢	70.5	*-10%*	*-3%*
Peak Load	🟣	98.0	*-4%*	*-12%*
% Scheduled DA (Peak Hour)	🟢	98.2%	99.1%	99.1%
Transmission Congestion ($M)				
Real-Time Congestion Value	🟣	$189.0	*7%*	*-56%*
Day-Ahead Congestion Revenue	🟣	$112.2	*1%*	*-41%*
Balancing Congestion Revenue[3]	🟢	-$2.2	-$1.3	-$9.0
Ancillary Service Prices ($/MWh)				
Regulation	🟢	$9.17	*4%*	*-13%*
Spinning Reserves	🟢	$2.46	*12%*	*-19%*
Supplemental Reserves	🟢	$0.41	*-23%*	*-54%*

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
FTR Funding (%)	🟢	99%	99%	99%
Wind Output (MW/hr)	🟣	7,213	*9%*	*22%*
Guarantee Payments ($M)[4]				
Real-Time RSG	🟢	$12.1	*-61%*	*-16%*
Day-Ahead RSG	🟢	$9.5	*-39%*	*8%*
Day-Ahead Margin Assurance	🟣	$5.2	*-51%*	*-55%*
Real-Time Offer Rev. Sufficiency	🟣	$0.6	*20%*	*-53%*
Price Convergence[5]				
Market-wide DA Premium	🟢	0.0%	0.0%	-0.9%
Virtual Trading				
Cleared Quantity (MW/hr)	🟢	18,272	*6%*	*15%*
% Price Insensitive	🟢	36%	36%	32%
% Screened for Review	🟢	1%	1%	1%
Profitability ($/MW)	🟢	$0.38	$0.68	$0.86
Dispatch of Peaking Units (MW/hr)	🟢	700	523	1433
Output Gap- Low Thresh. (MW/hr)	🟢	103	78	97
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 2019

Significant Decrease in Congestion (Slide 16 - 18)

- Real-time congestion decreased by 56 percent and day-ahead congestion fell by 41 percent this quarter compared to the prior year.
  - ✓ More than half of the lower congestion is attributable to fewer critical transmission outages this Spring and milder weather conditions.
  - ✓ Transmission upgrades completed within the past year contributed to an almost $40 million in the reduction in congestion.
  - ✓ MISO has worked to improve constraint modeling alignment between the day-ahead and real-time markets.
  - ✓ Lower natural gas prices also contributed to lower congestion since natural gas-fired units are generally the marginal source of congestion relief.
- Congestion associated with inefficient market-to-market coordination continued to fall as MISO has made significant improvements to ensure more complete coordination of constraints affected by PJM and SPP.

Highlights for Spring 2019

<u>Uninstructed Deviation Thresholds and Wind (Slide 33, 22)</u>

- In recent State of the Market Reports, we raised concerns regarding generator performance and the incentives provided by MISO's Uninstructed Deviations (UD) rules and Price Volatility Make Whole Payments (PVMWP).
- On May 1, MISO implemented valuable new settlement rules in both areas.
  - ✓ PVMWPs will now be determined by a sliding scale based on the generators' performance in following MISO's dispatch instructions.
  - ✓ MISO also implemented much more effective UD thresholds to determine when UD settlement rules (penalties) should apply to a resource.
  - ✓ These changes substantially improve suppliers' incentives to follow dispatch instructions and to provide physically feasible offer parameters.
  - ✓ These changes likely contributed to some of the sharp decline in PVMWPs that occurred in May 2019 compared to the prior year.
- Additionally, wind resources now have strong incentives to use MISO's forecast rather than their own participant forecasts.
  - ✓ Wind deviations that are generally due to forecast errors are not penalized if the resource is using MISO's wind forecast.

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Highlights for Spring 2019

<u>Wind Forecasting (Slide 22)</u>

- The changes in the UD rules have prompted most wind suppliers to begin using the MISO forecast – which is good because many of participants' forecasts were much more biased than MISO's forecast.
- However, MISO's forecast methodology is also biased (although by less) toward over-forecasting because it uses the higher of:
  - ✓ Its vendor forecast, or
  - ✓ A persistence forecast (the wind unit's output 10 minutes earlier).
- This results in predictable over-forecasts when units are ramping down.
  - ✓ Since its forecasts are now widely used, we recommend MISO improve its criteria for displacing the vendor forecast with the persistence forecast.
  - ✓ This will reduce the predictable bias/forecast error and improve the dispatch.
- Beginning this spring, wind curtailments have increased.
  - ✓ As wind production tax credits have expired, a large number of wind resources have been offering wind at greater than $0.
  - ✓ This has contributed to better constraint management in that region.

Highlights for Spring 2019

<u>May 16 Emergency Event in MISO South (Slide 36)</u>

- MISO declared a regional emergency in the afternoon of May 16 – the risk in this type of emergency is that MISO will not be able to respond if the largest unit is lost (largest contingency) within 30 minutes and will violate the RDT.
  - ✓ The largest contingency was less than 1000 MW on this day – we show the demand plus this contingency compared to the total supply on slide 36.
  - ✓ Capacity deficiency = forecasted demand > total supply (royal blue line).
- On May 15, MISO declared Conservative Operations and a Maximum Generation Alert for the South for May 16.
  - ✓ MISO scheduled over 400 MW of LMRs from 2 p.m. to 8 p.m. due to their long lead times, but cancelled them by noon because capacity was sufficient.
- But at 1:44 p.m., MISO lost the largest unit in the South and declared a Maximum Generation Event Step 2a (EEA2) in the South starting at 2 p.m.
  - ✓ MISO forecasted a capacity deficiency because it utilized an override to its forecast that increased the capacity needs by more than 1000 MW.
- MISO ended the Event at 6 p.m. and extended Conservative Operations through the following day until 8 p.m.

Highlights for Spring 2019

May 16 Event Conclusions (Slide 36)

- Emergency responses:
  - ✓ By scheduling an EEA1 or above, MISO was able to access 482 MW of emergency ranges of online resources.
    - – These ranges are available very quickly (well within 30 minutes).
  - ✓ MISO scheduled and received nearly 70 MW of LMRs between 4 and 6 p.m. – these were not needed to satisfy the capacity needs in the South.
  - ✓ A $322 emergency offer floor did not set the prices -- prices averaged $31.74.
- Forecasting a capacity deficiency is the most reasonable trigger for declaring an emergency, which was very unlikely given the prevailing load levels.
- LMRs are only obligated to respond to five deployments per planning year – MISO called a number of LMRs three times on May 16-17.
- This underscores the value of:
  - ✓ Clear procedures that articulate the triggers for EEA1 and EEA2 events.
  - ✓ Thorough logging of the factors considered in declaring emergencies.
  - ✓ Procuring reserve capability on the RDT constraint from the Joint Parties.
  - ✓ We are working collaboratively with MISO on these issues.

Submittals to External Entities and Other Issues

- We responded to FERC questions related to prior referrals and continued to meet with FERC on a weekly basis. We submitted:
  - ✓ A new referral for failure to provide accurate physical parameters in offers.
  - ✓ Several notifications of other potential tariff violations.
  - ✓ Information on updated prior referrals, including referrals of resources for not providing accurate offers and wind resources chronically over-forecasting.
- We presented our Winter quarterly report in April at the MSC.
- We joined MISO in presenting proposed improvements to the Market Power Mitigation rules (Module D of the Tariff) at the June MSC and met with FERC to review the proposed changes.
- FERC has issued an NOI related to Transmission Incentives Policy and we met with FERC on our recommendation on Dynamic Transmission Ratings.

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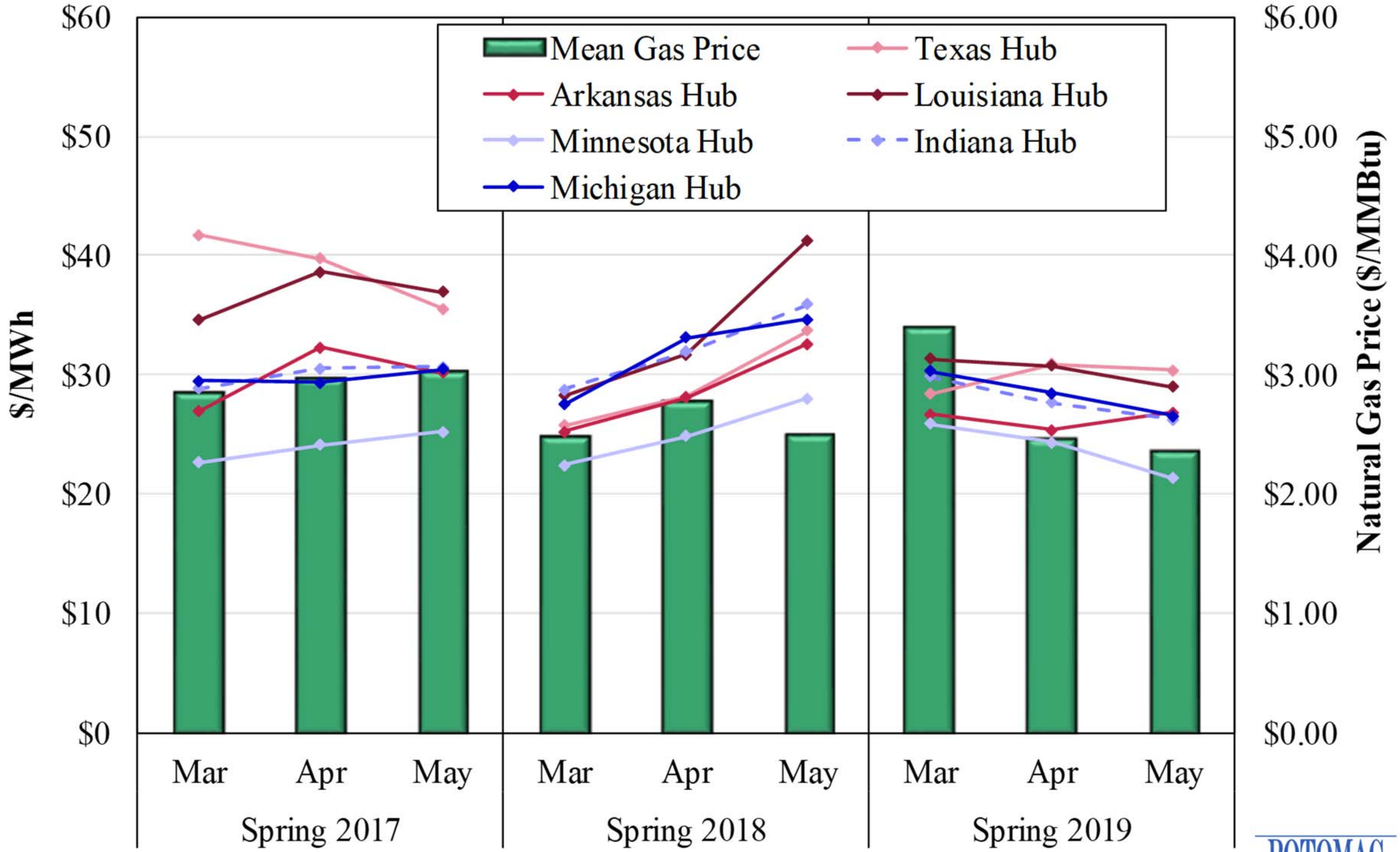
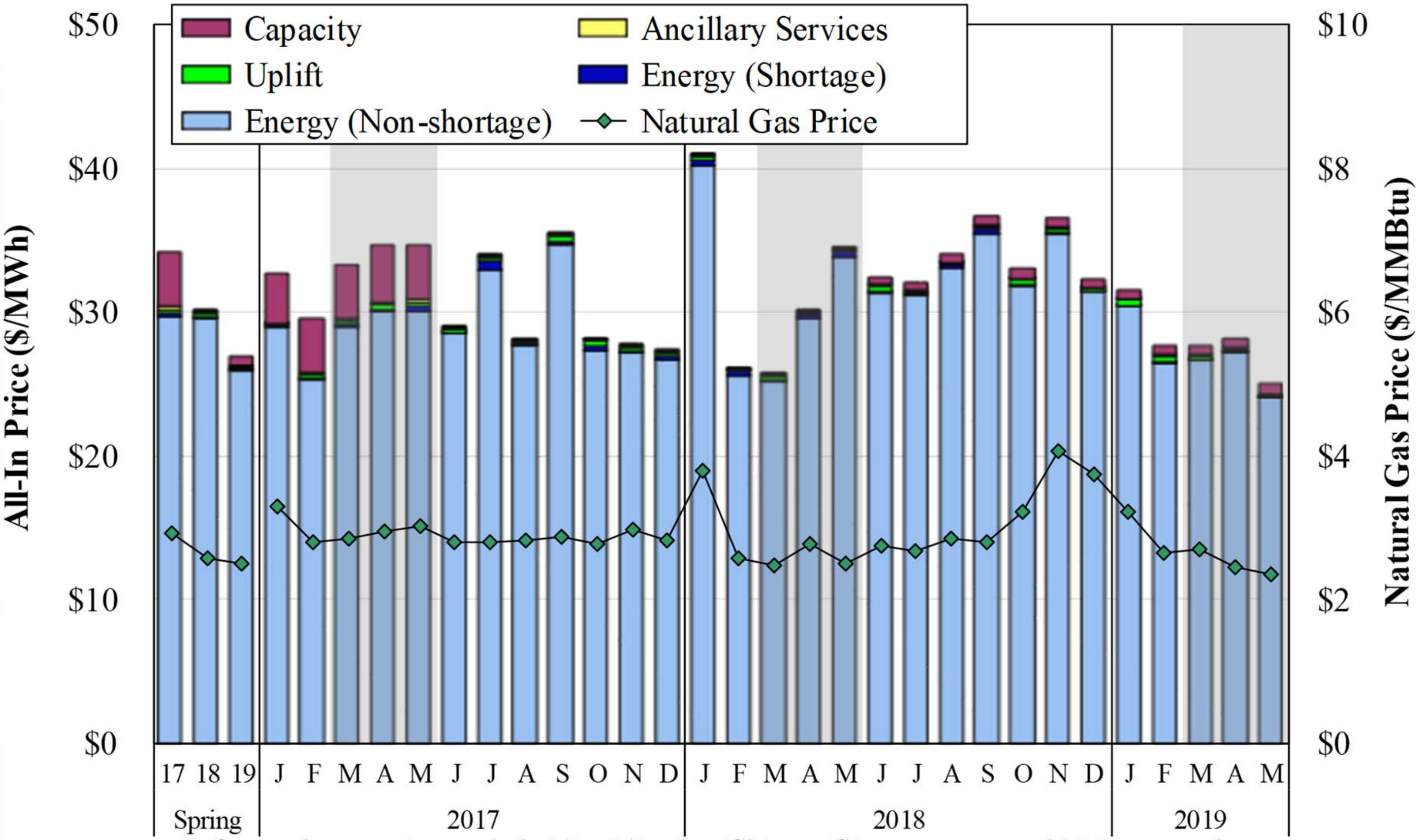
Submittals to External Entities and Other Issues

- We worked with OMS/SPP RSC Seams Committee, and the SPP MMU in identifying and scoping a requested study of Seams issues.
- We will be requesting budget to perform the requested studies.
- We filed comments on a complaint filed in PJM related to issues caused by the pseudo-tie rules and requirements.
- We provided separate comments on Phase 2 and Phase 3 of MISO's RAN initiatives.
- We worked with MISO on its answer to protests regarding Energy Storage Resources (ESRs).
- We hosted and participated in the International Energy Intermarket Surveillance Group – an organization of international market monitors – in late April.

Day-Ahead Average Monthly Hub Prices Spring 2017 – 2019

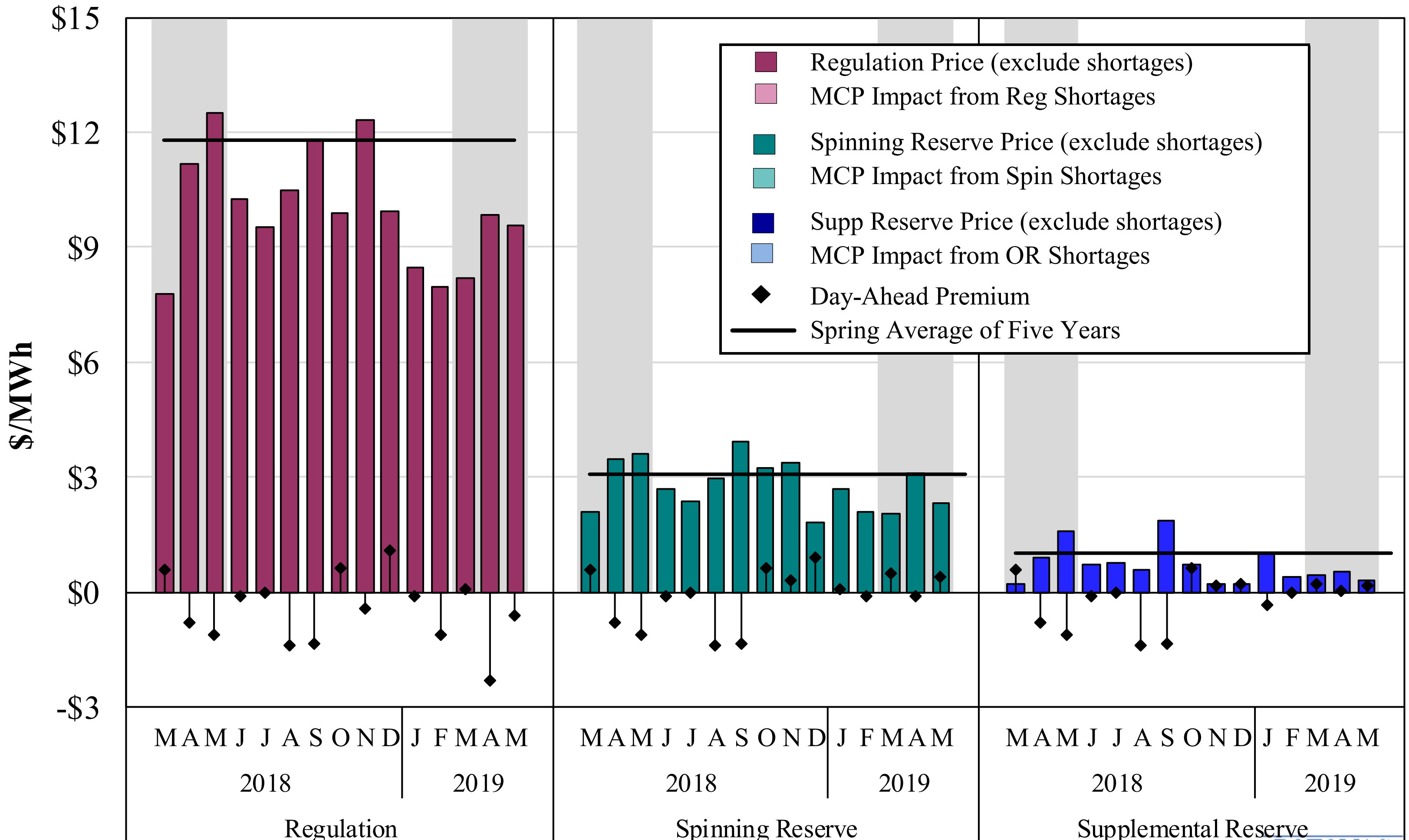


All-In Price
2017 – 2019



Quarterly gas prices exclude 3/1 – 3/5, when Chigago Citygates averaged $6.94 per mmbtu.

Monthly Average Ancillary Service Prices
Spring 2017 – 2019



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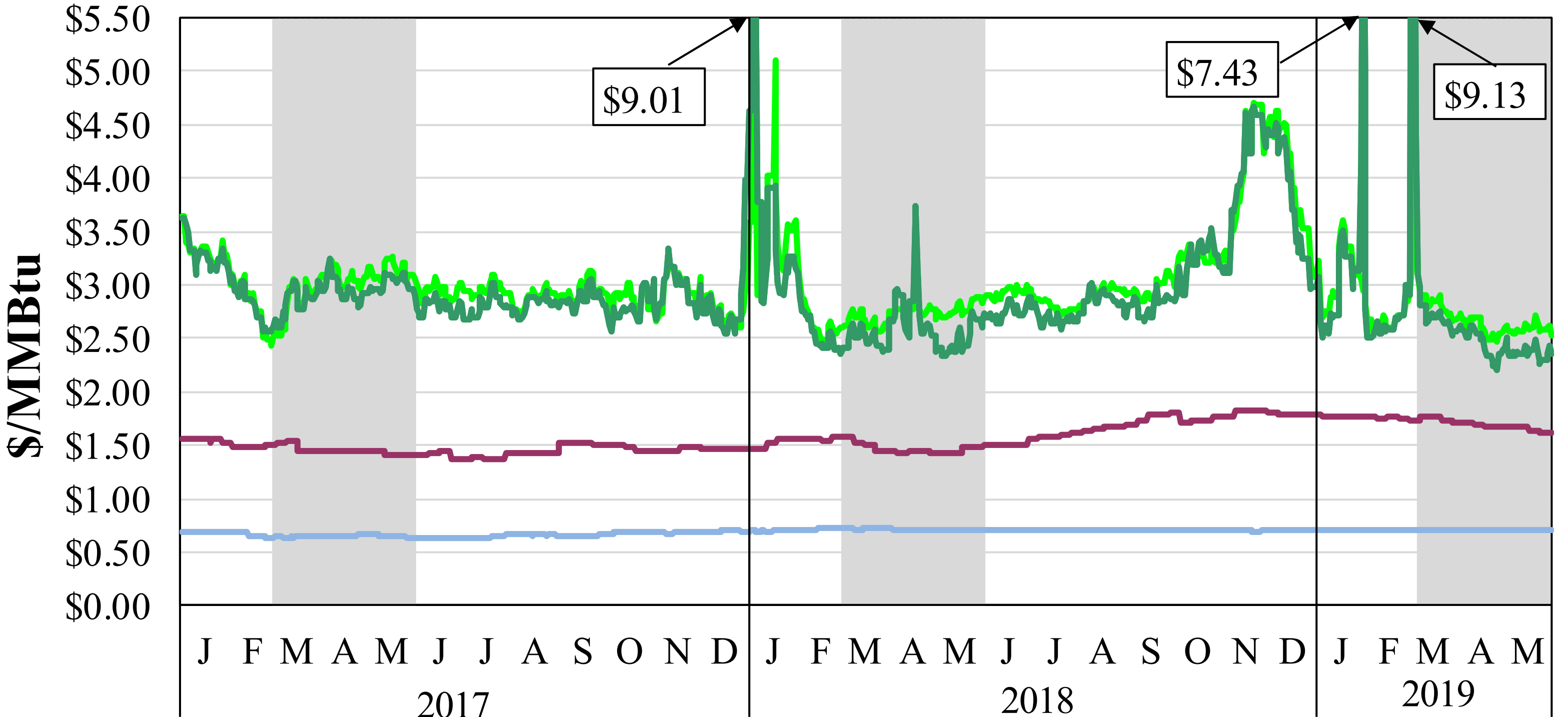
MISO Fuel Prices
Spring 2017 – 2019



Spring Average	2017	2018	2019
Chicago NG	$2.94	$2.58	$2.50*
Henry NG	$3.02	$2.73	$2.70

Spring Average	2017	2018	2019
IB Coal	$1.45	$1.47	$1.70
PRB Coal	$0.66	$0.71	$0.70

**Excludes 3/1-3/5.*

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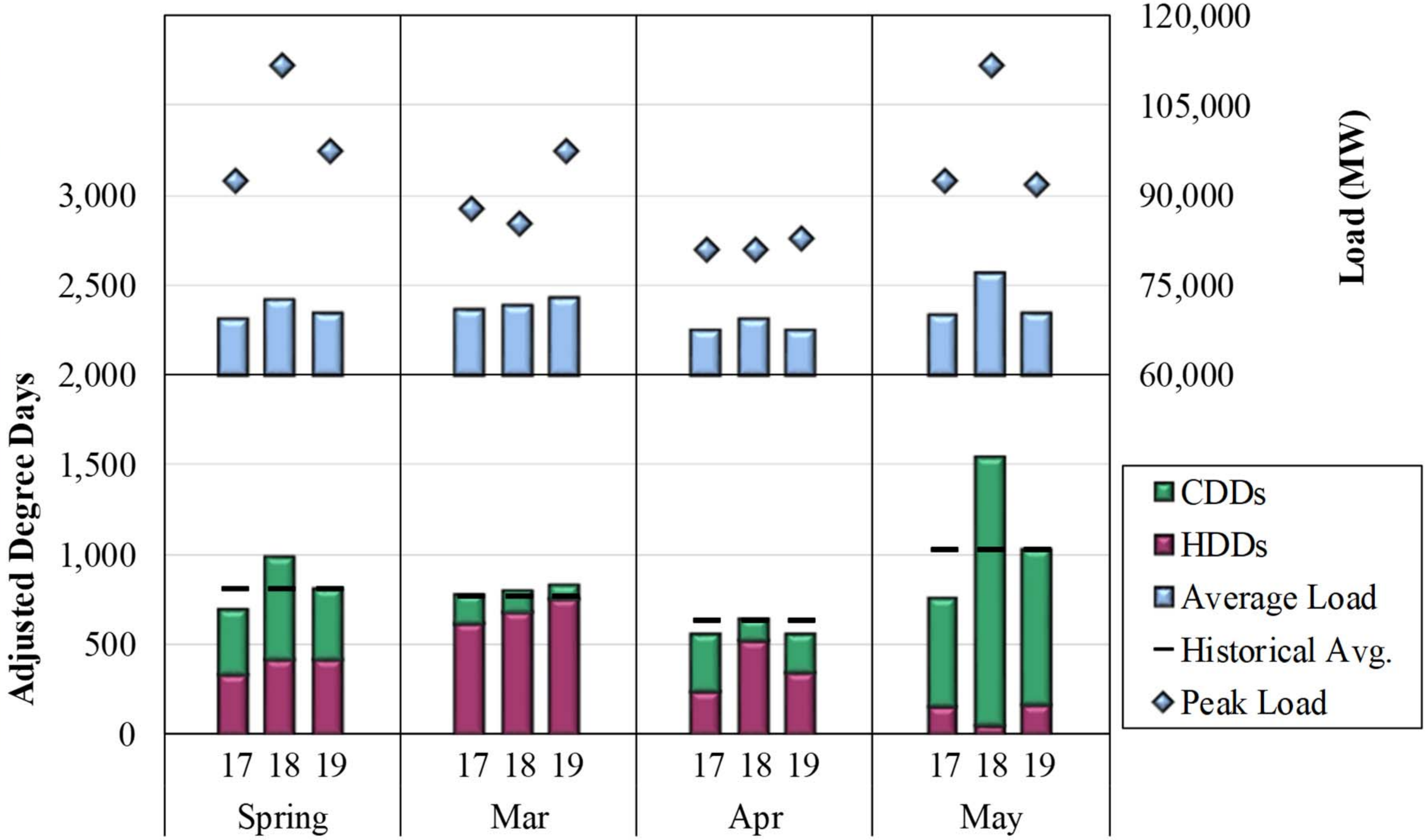
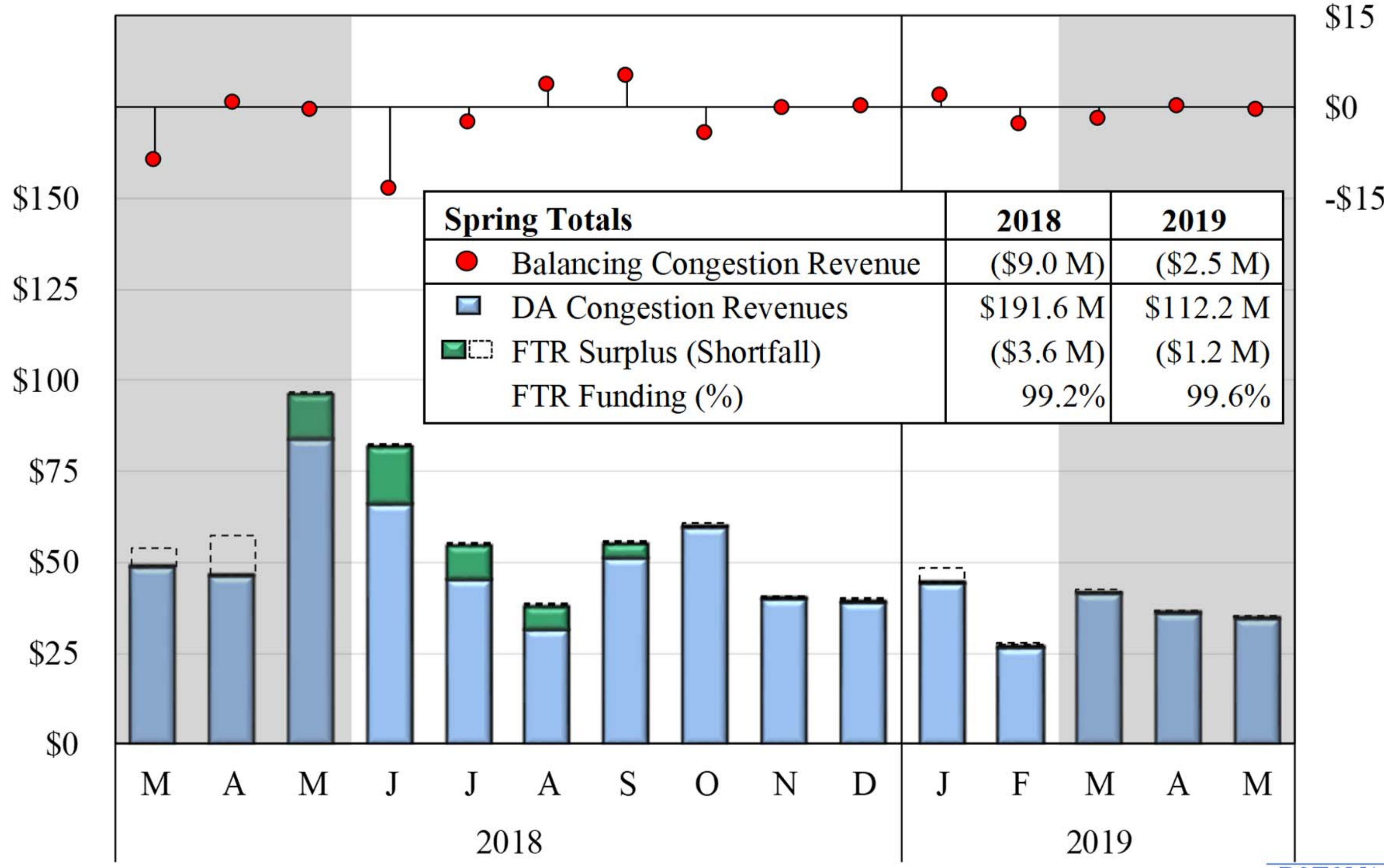
Load and Weather Patterns Spring 2017 – 2019



Note: Midwest degree day calculations include four representative cities in the Midwest: Indianapolis, Detroit, Milwaukee and Minneapolis. The South region includes Little Rock and New Orleans.

Day-Ahead Congestion, Balancing Congestion and FTR Underfunding, 2018 – 2019



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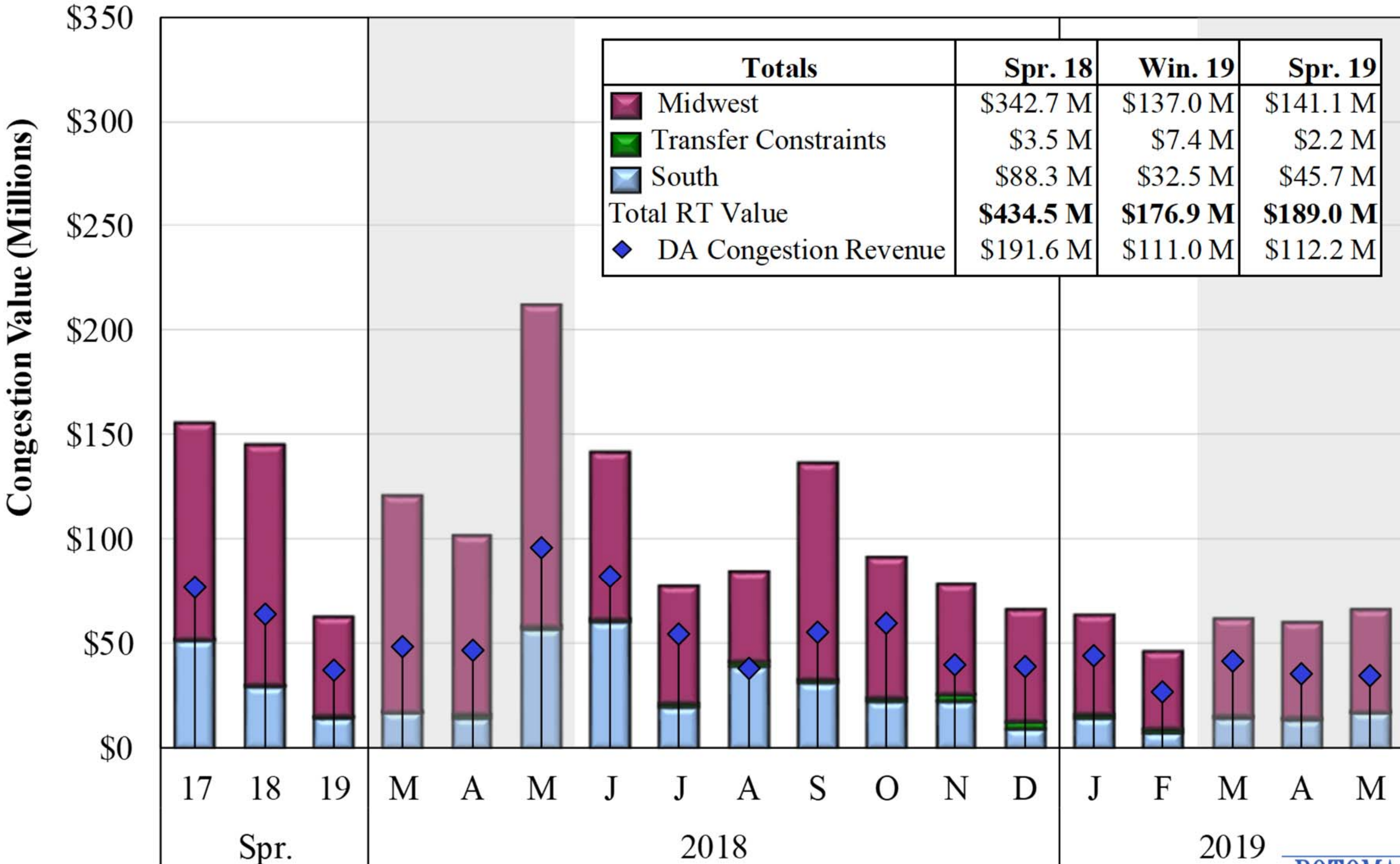
Value of Real-Time Congestion
Spring 2018 – 2019



Totals	Spr. 18	Win. 19	Spr. 19
Midwest	$342.7 M	$137.0 M	$141.1 M
Transfer Constraints	$3.5 M	$7.4 M	$2.2 M
South	$88.3 M	$32.5 M	$45.7 M
Total RT Value	**$434.5 M**	**$176.9 M**	**$189.0 M**
◆ DA Congestion Revenue	$191.6 M	$111.0 M	$112.2 M

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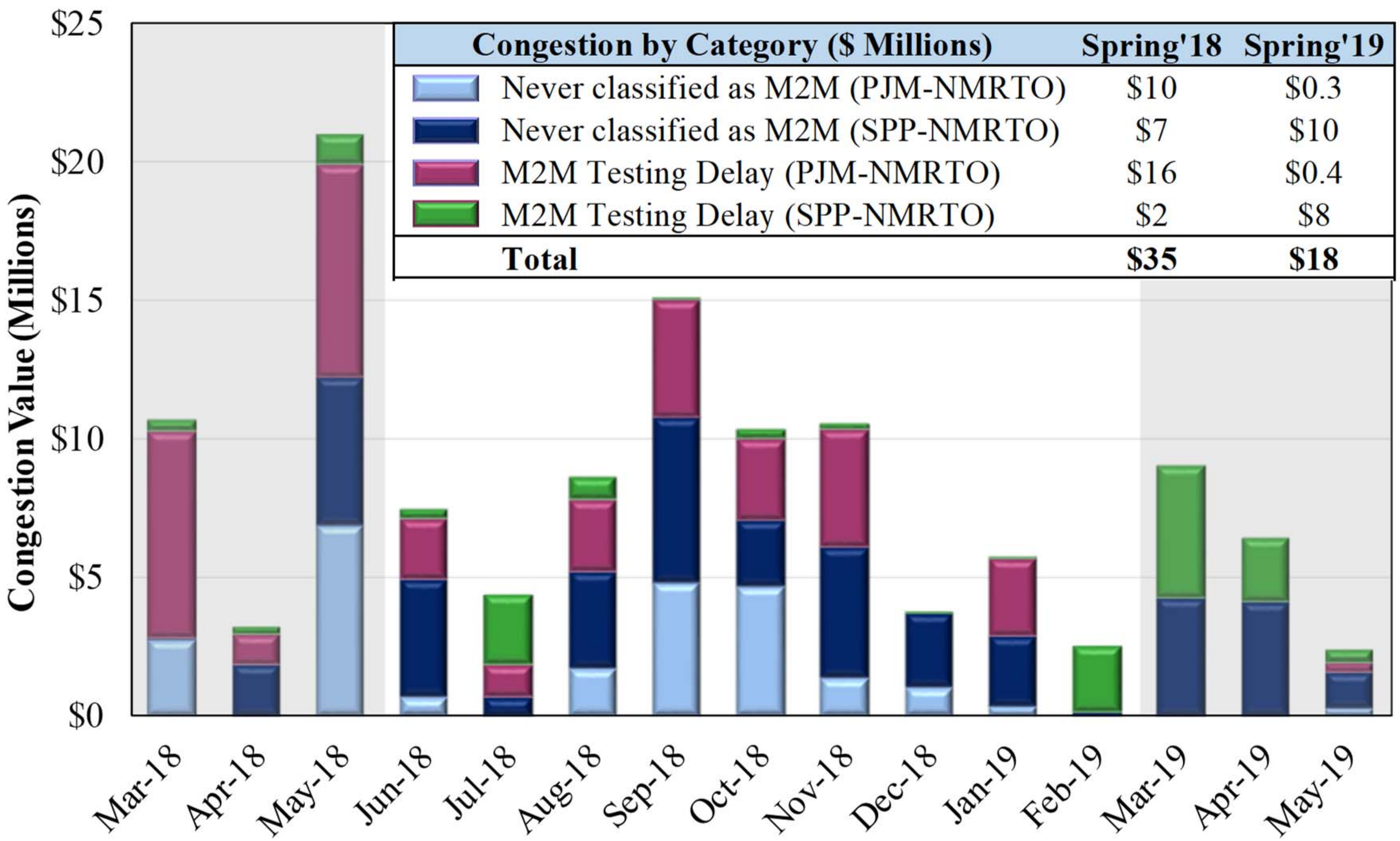
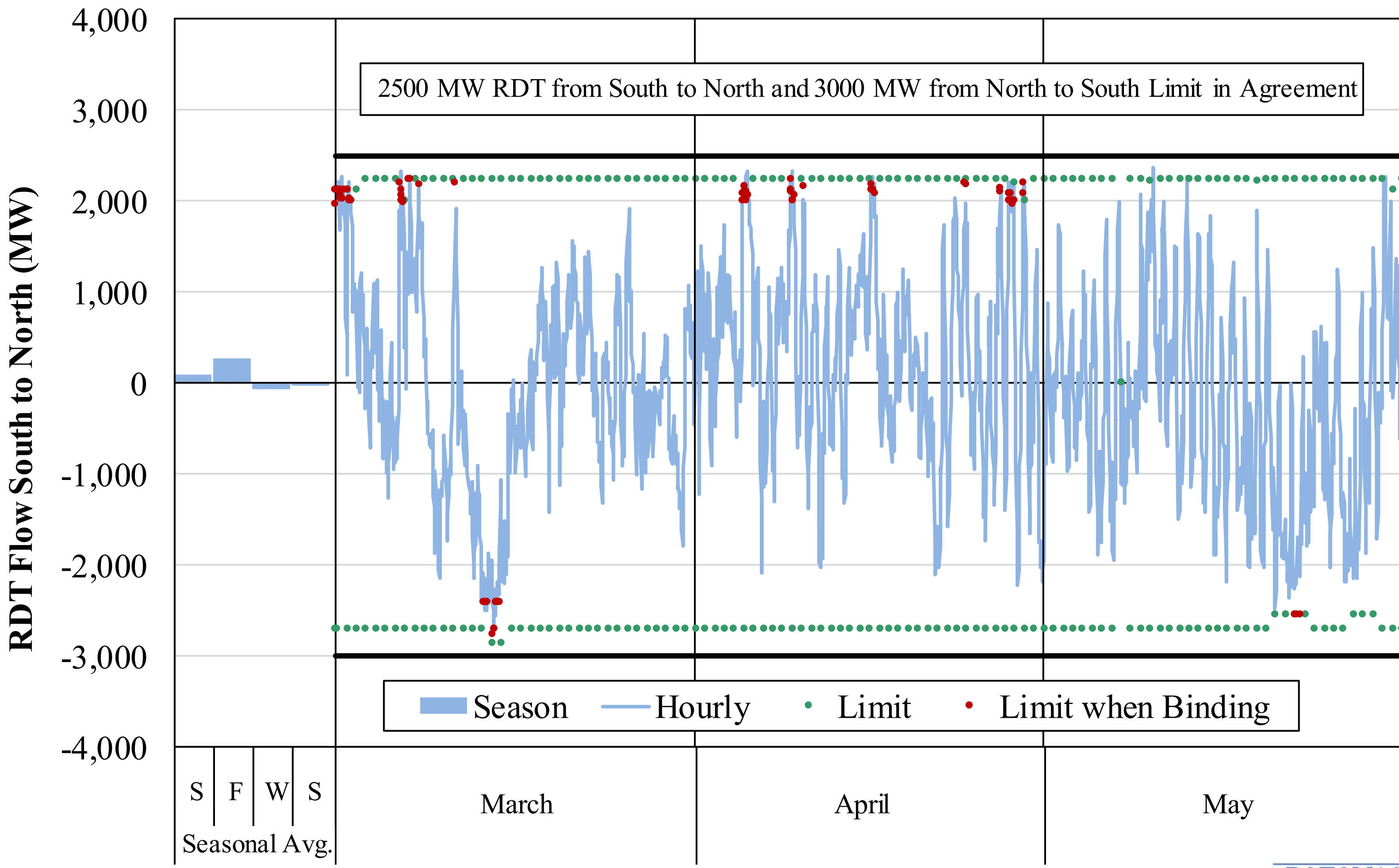
Inefficient Market-to-Market Congestion Spring 2018 - 2019



Congestion by Category ($ Millions)	Spring'18	Spring'19
Never classified as M2M (PJM-NMRTO)	$10	$0.3
Never classified as M2M (SPP-NMRTO)	$7	$10
M2M Testing Delay (PJM-NMRTO)	$16	$0.4
M2M Testing Delay (SPP-NMRTO)	$2	$8
Total	**$35**	**$18**

Real-Time Hourly Inter-Regional Flows Spring 2019



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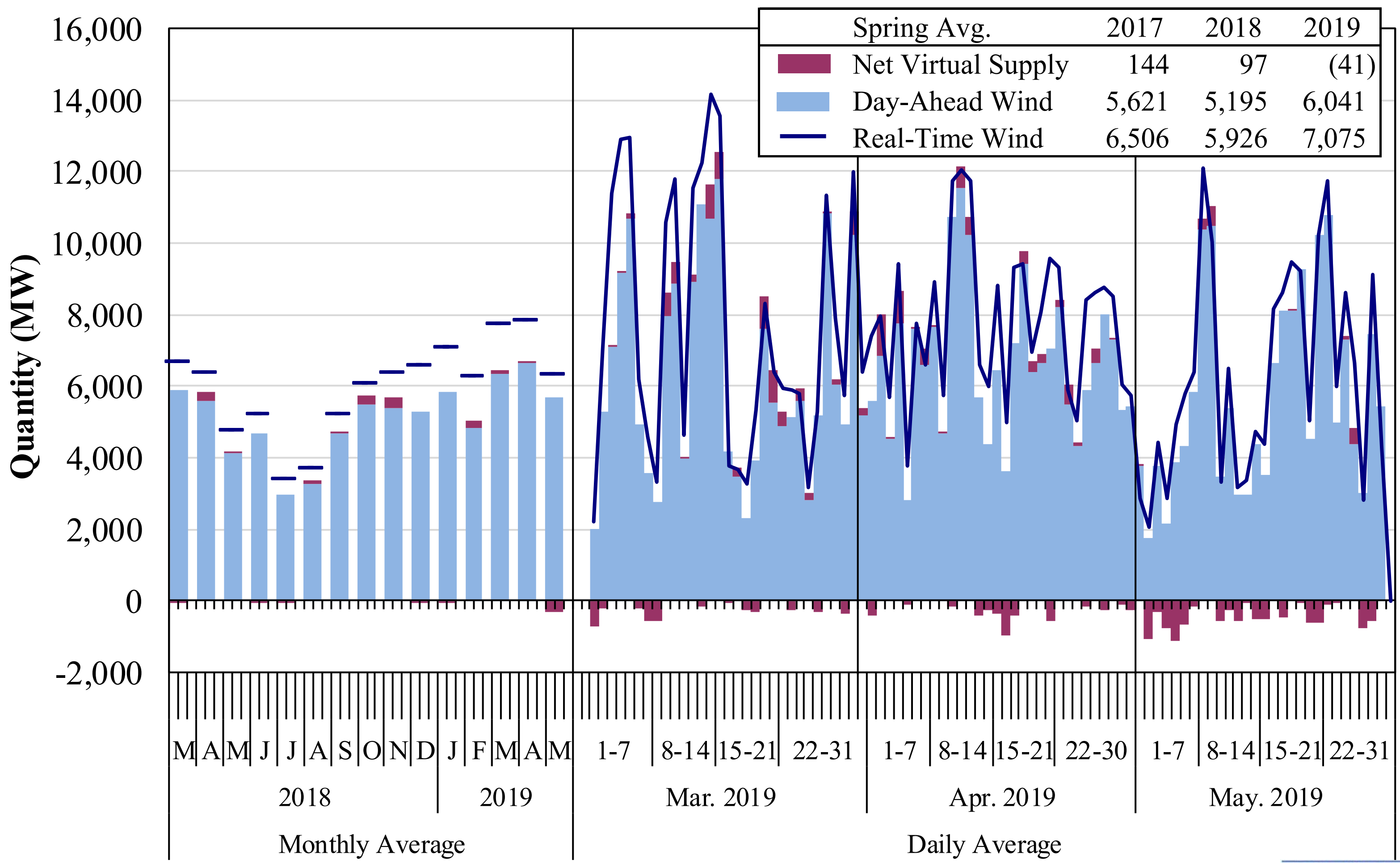
Wind Output in Real-Time and Day-Ahead Monthly and Daily Average



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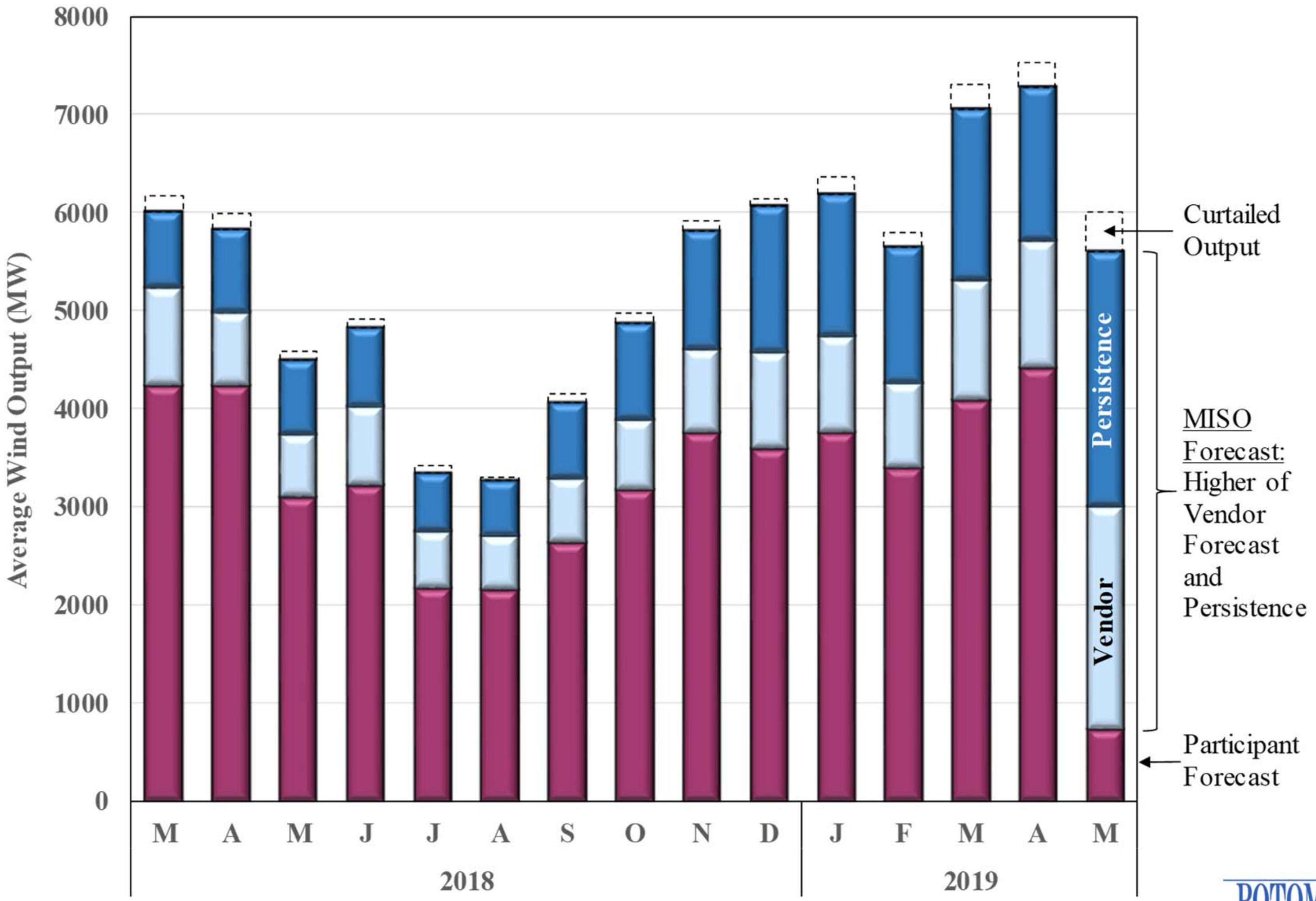
Average Wind Forecasts by Source 2018 - 2019



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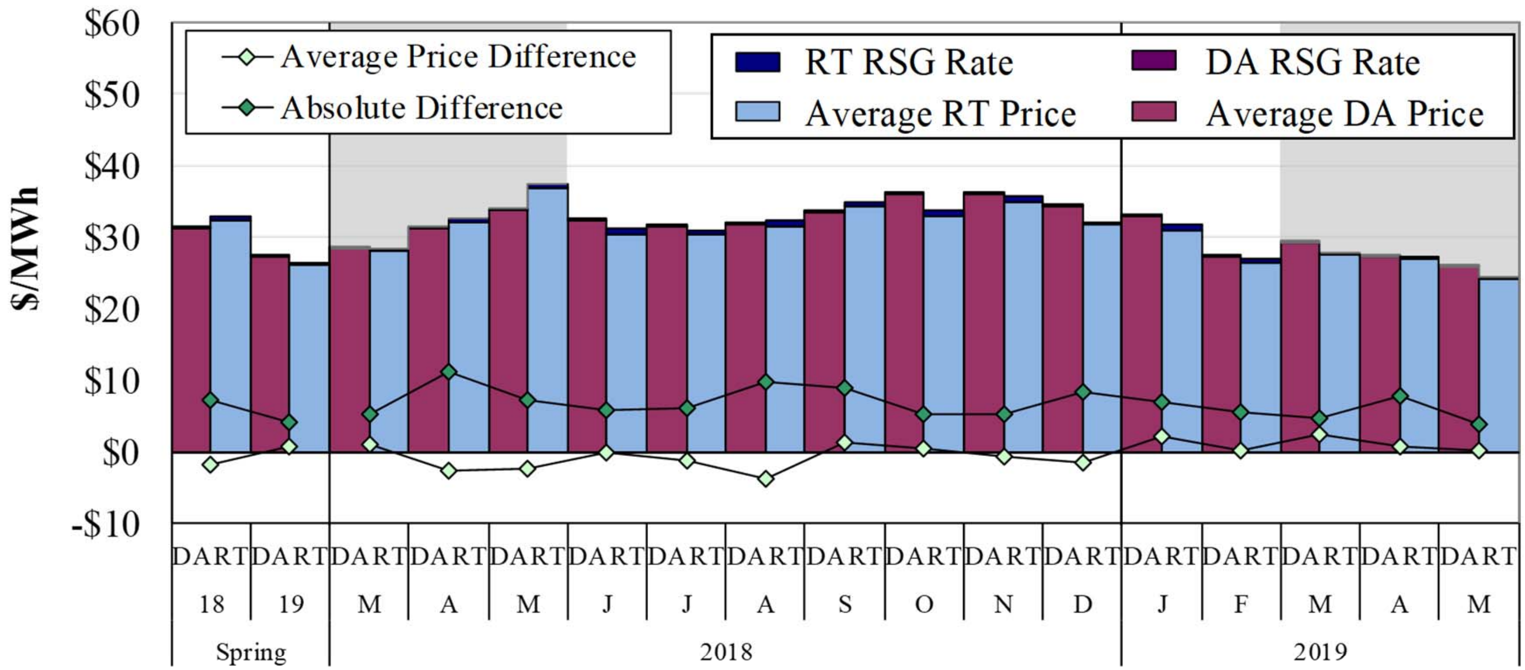
Day-Ahead and Real-Time Price Convergence
Spring 2018 – 2019



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

Indiana Hub	-4	3	0	-4	-10	4	2	-2	-4	7	1	7	3	1	5	-1	6
Michigan Hub	-4	2	-1	-2	-9	4	1	-4	-5	4	-2	5	-6	0	4	-2	5
Minnesota Hub	-1	3	1	0	-4	-2	3	-4	-6	2	1	4	-4	-1	4	0	6
WUMS Area	-2	1	0	-6	-1	-2	-8	1	-4	3	0	7	1	1	7	-12	8
Arkansas Hub	0	5	0	-4	4	4	3	-4	-11	3	-1	4	0	-3	5	1	8
Texas Hub	1	6	0	-5	8	2	4	-5	-12	2	-1	3	1	1	7	0	11
Louisiana Hub	3	13	0	-3	10	-13	9	-12	-18	4	-5	4	0	0	15	9	13

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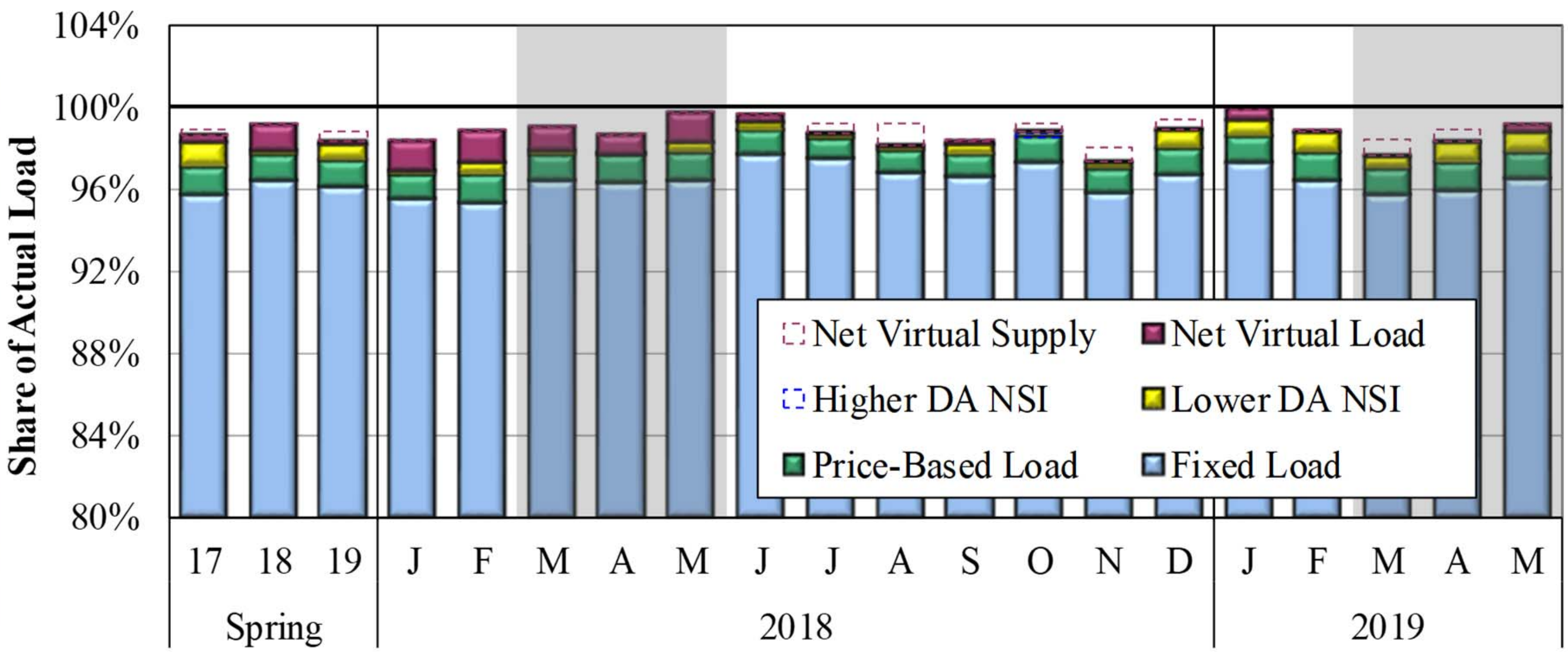
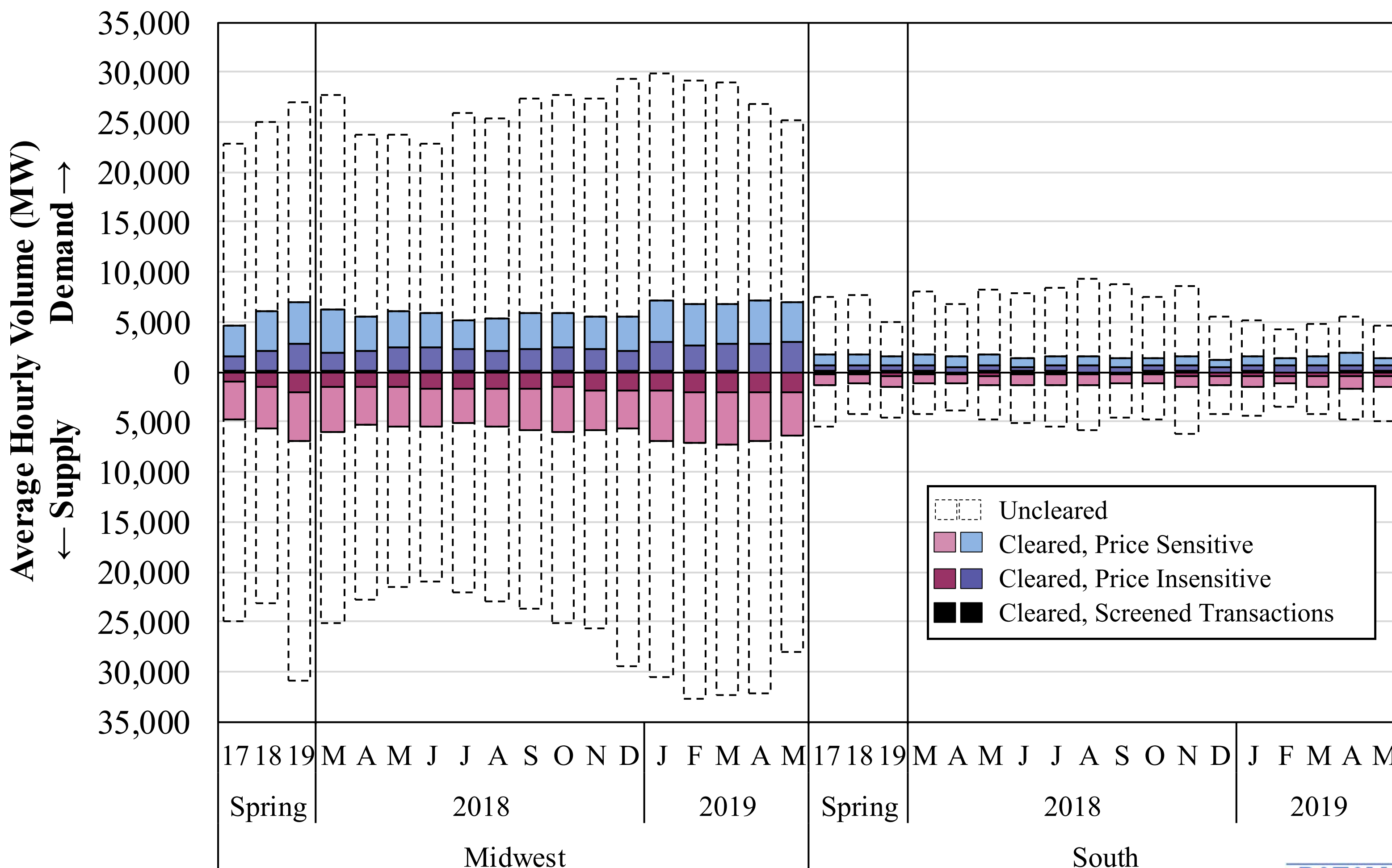
Day-Ahead Peak Hour Load Scheduling Spring 2018 – 2019



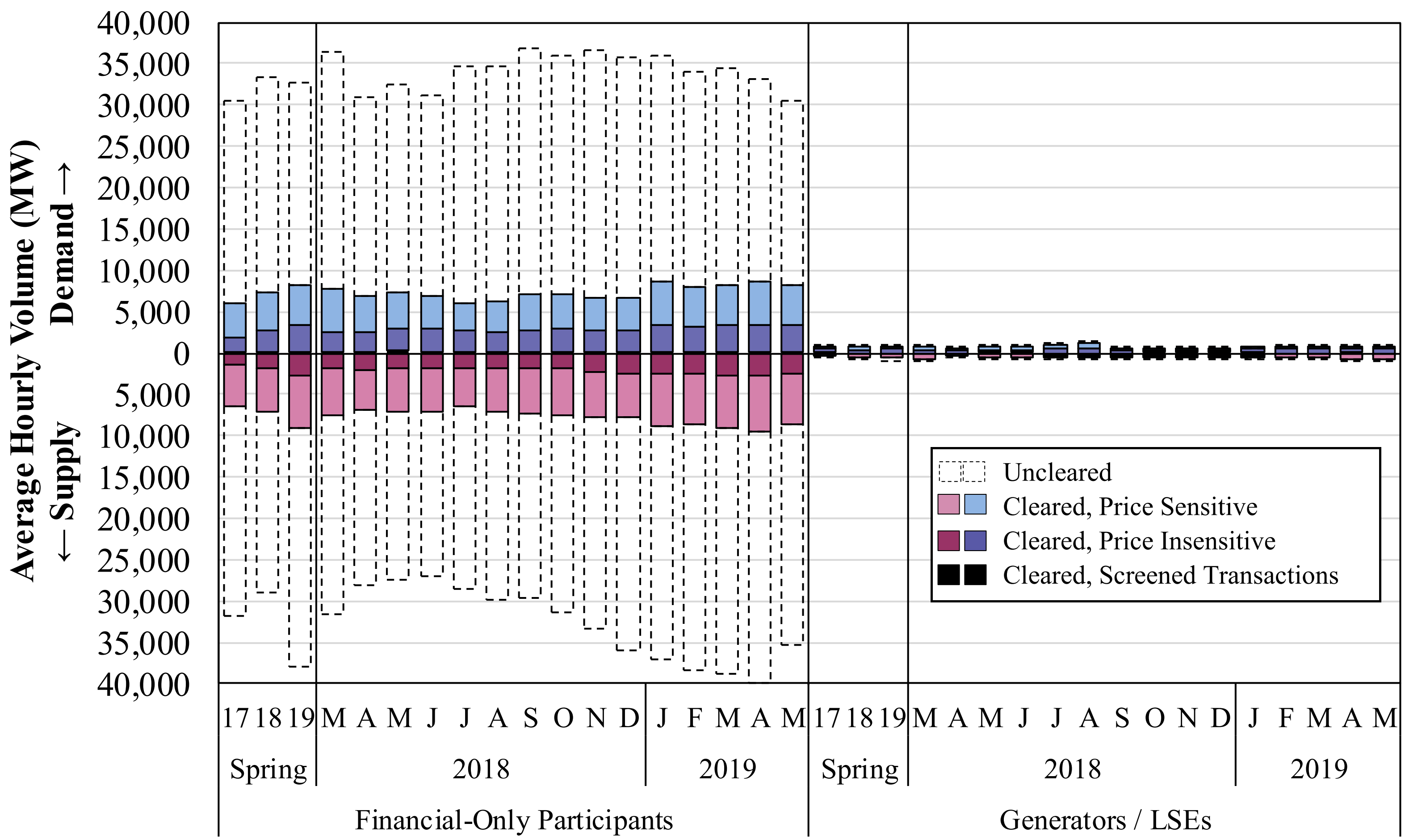
Share of Actual Load (%)

	17	18	19	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
All Hours	99.0	99.3	98.5	98.7	98.6	99.3	98.6	100.0	99.7	99.4	99.3	98.9	99.1	97.5	98.8	99.7	98.8	98.1	98.5	99.0
Peak Hours Midwest	97.4	99.1	97.8	98.1	97.8	99.5	98.3	99.4	99.3	97.9	97.1	97.6	98.1	97.1	98.7	99.2	97.9	97.1	97.4	98.8
Peak Hours South	101.8	101.6	99.2	101.2	102.3	102.0	101.3	101.5	100.4	100.9	100.6	101.0	102.5	100.1	102.2	102.6	100.8	99.3	99.9	98.5

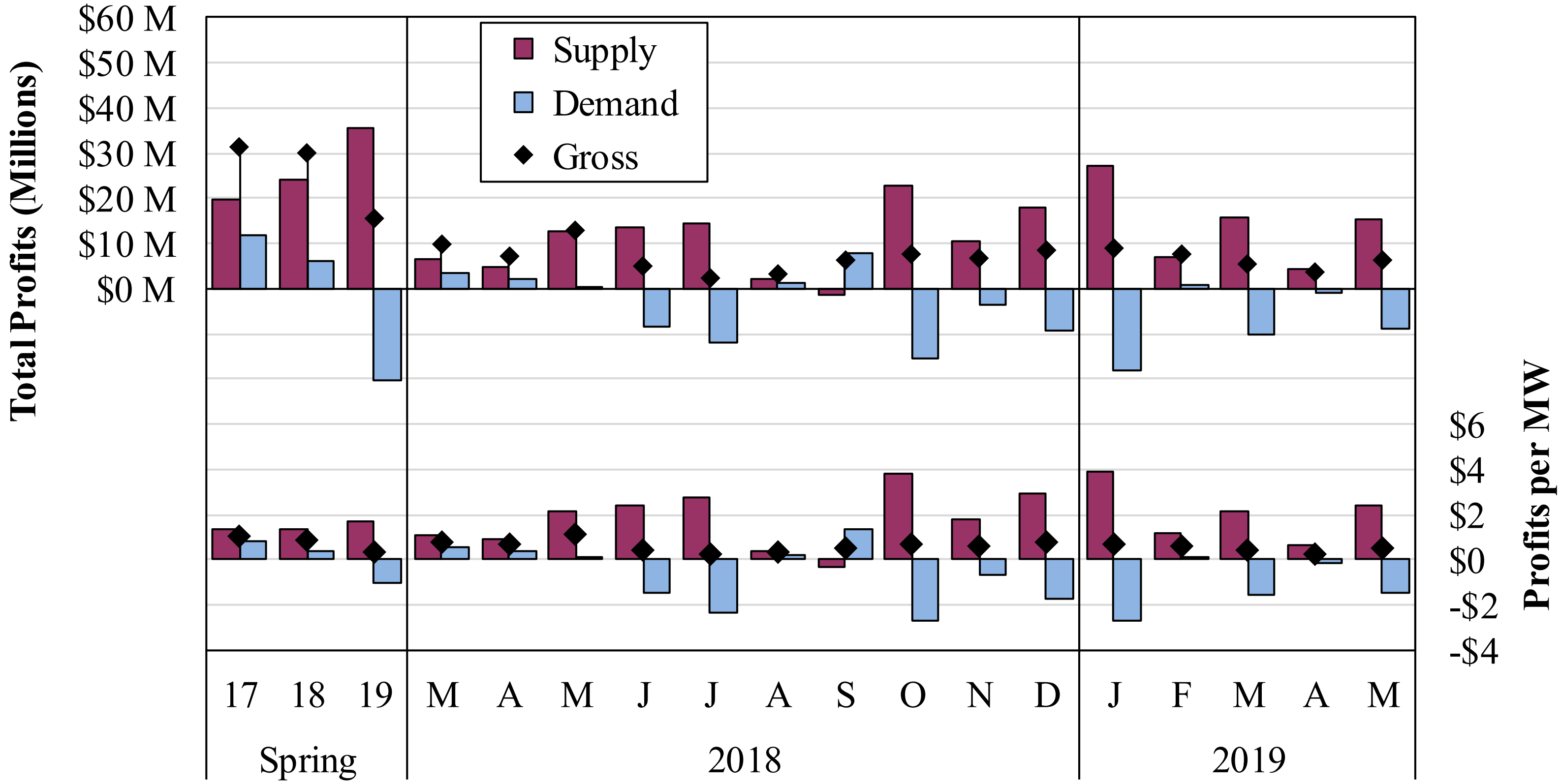
Virtual Load and Supply
Spring 2018 – 2019



Virtual Load and Supply by Participant Type
Spring 2018 – 2019



Virtual Profitability
Spring 2018 – 2019



Percent Screened

	17	18	19	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
Demand	2.1	1.9	0.9	1.2	1.3	3.1	2.7	2.3	0.8	1.2	1.9	1.1	0.6	1.8	0.6	0.9	0.8	0.9
Supply	0.4	0.4	0.2	0.3	0.4	0.5	0.5	0.4	0.1	0.2	0.4	0.4	0.2	0.2	0.1	0.2	0.3	0.2
Total	1.2	1.1	0.6	0.7	0.8	1.9	1.6	1.3	0.4	0.7	1.1	0.7	0.4	1.0	0.4	0.6	0.6	0.5

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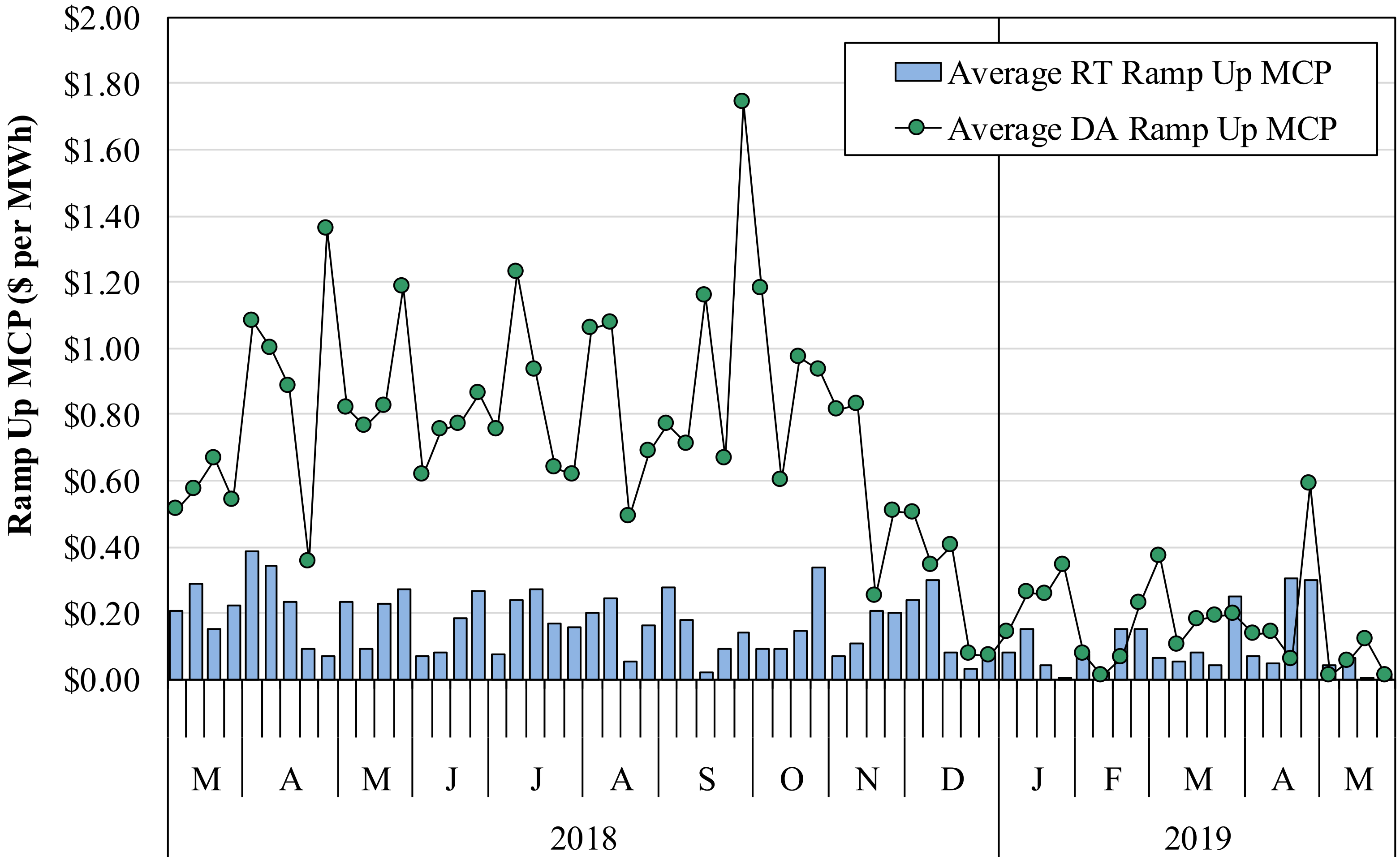
Day-Ahead and Real-Time Ramp Up Price 2018 – 2019



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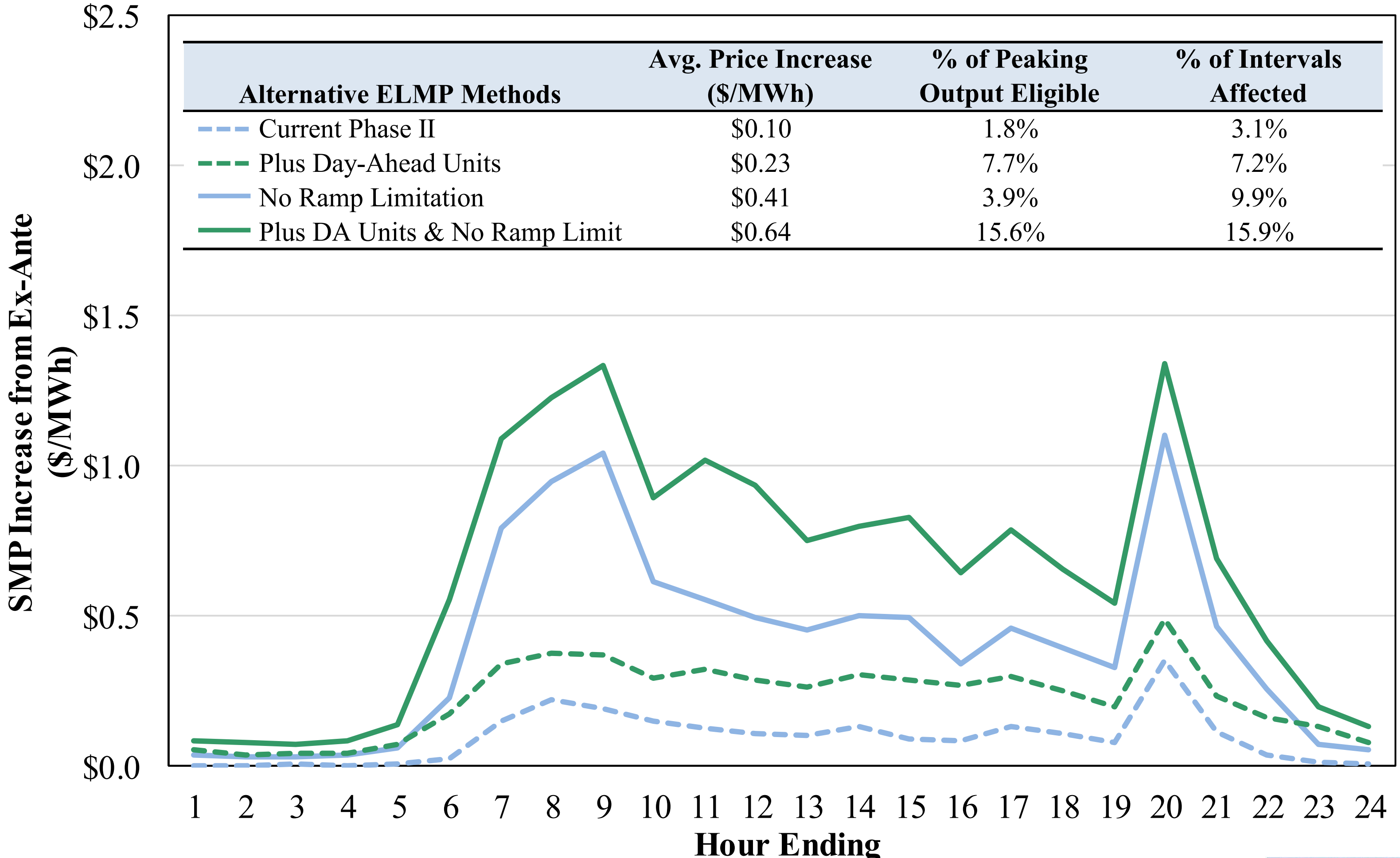
Evaluation of ELMP Assumptions
Spring 2019



Alternative ELMP Methods	Avg. Price Increase ($/MWh)	% of Peaking Output Eligible	% of Intervals Affected
Current Phase II	$0.10	1.8%	3.1%
Plus Day-Ahead Units	$0.23	7.7%	7.2%
No Ramp Limitation	$0.41	3.9%	9.9%
Plus DA Units & No Ramp Limit	$0.64	15.6%	15.9%

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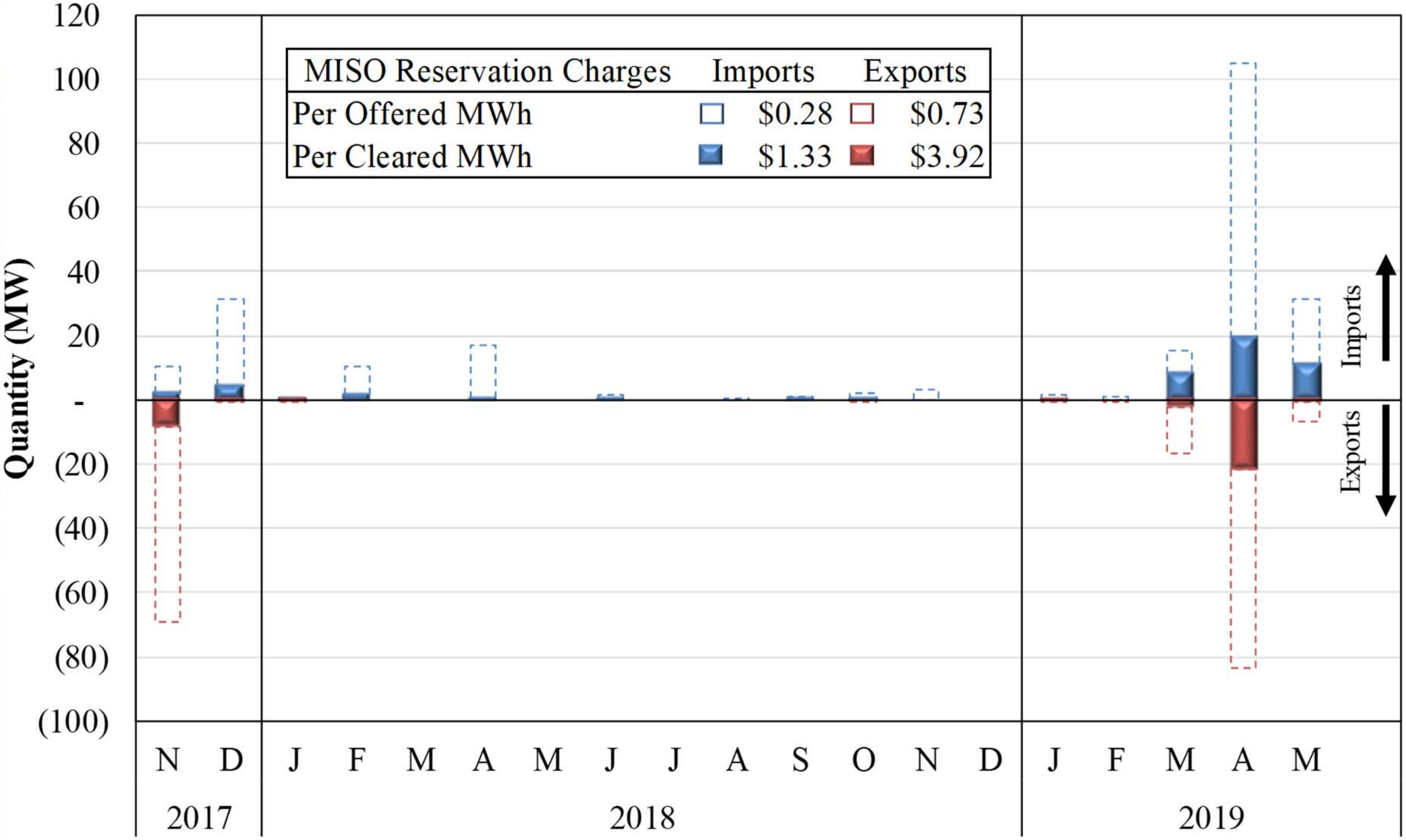
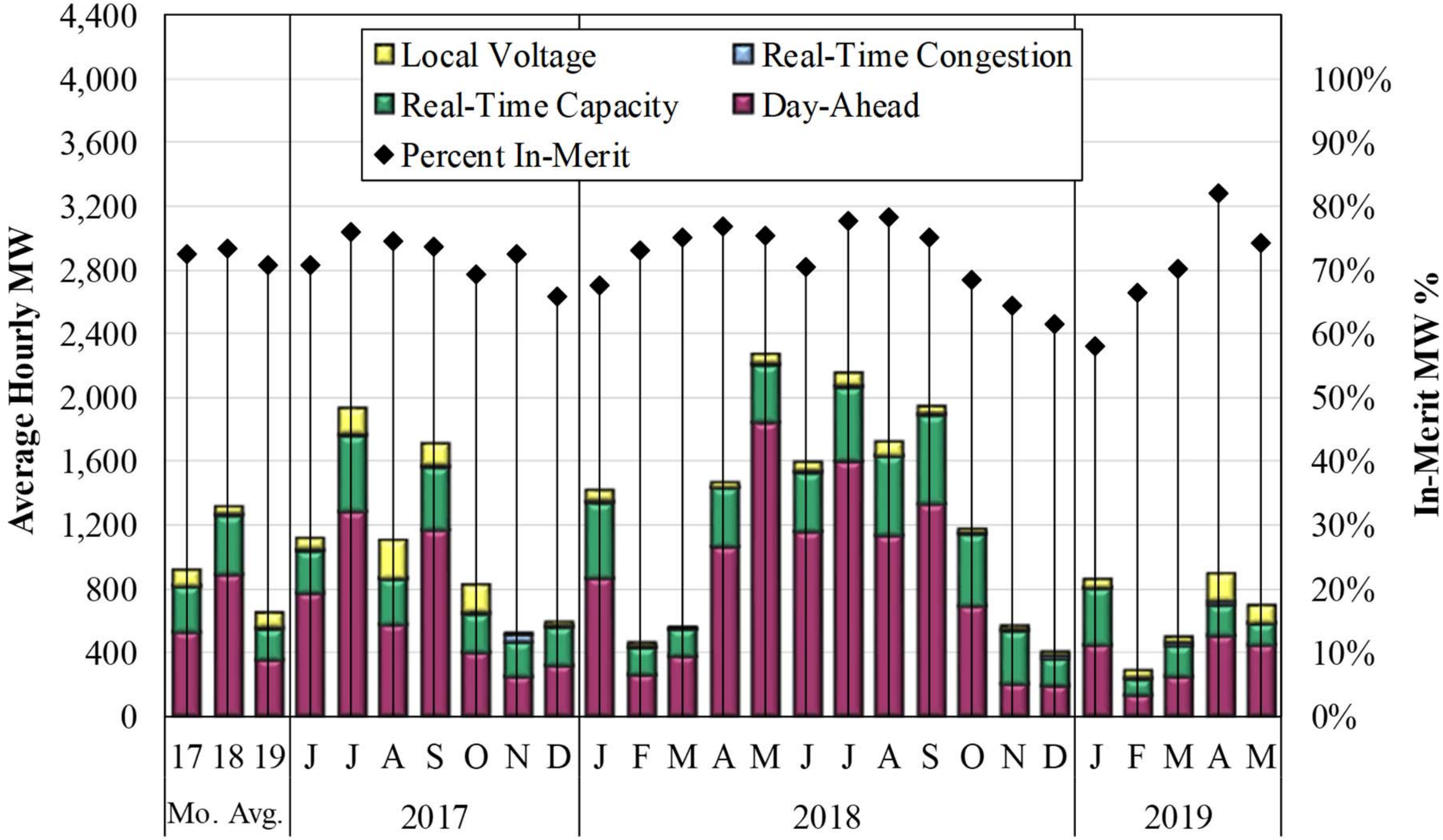
Coordinated Transaction Scheduling (CTS) Spring 2018 - 2019



Peaking Resource Dispatch
Spring 2018 – 2019



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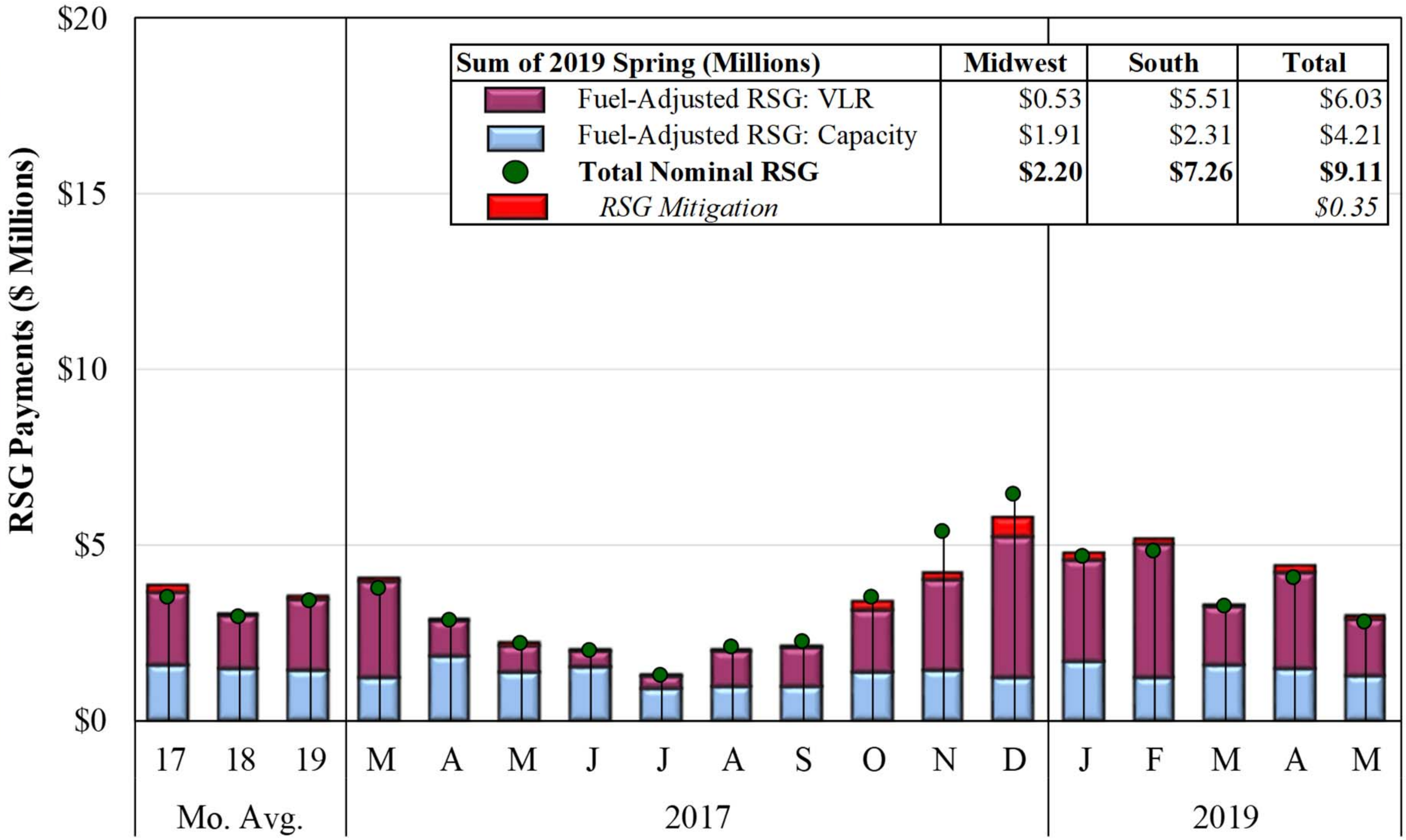
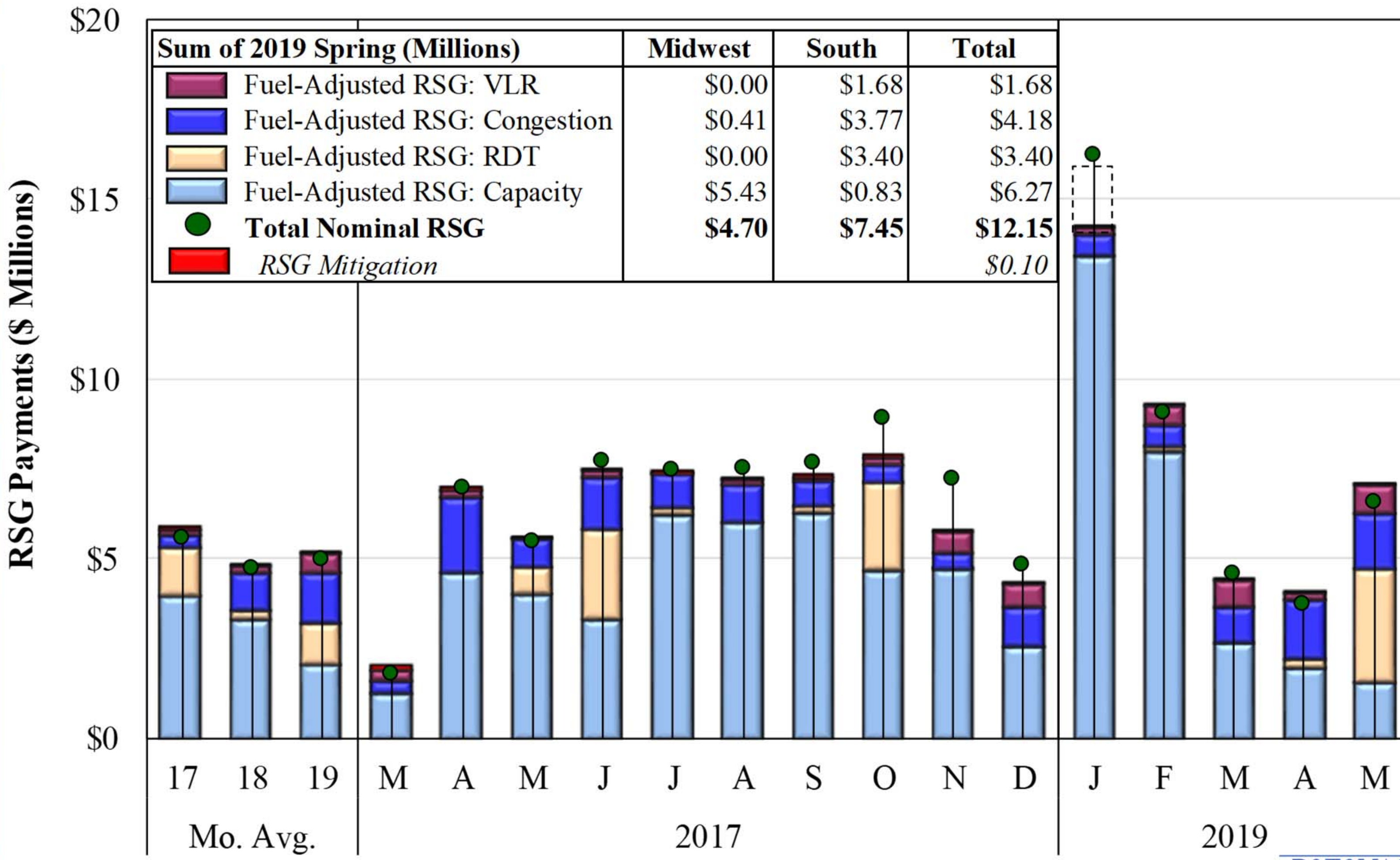
Day-Ahead RSG Payments
Spring 2018 – 2019

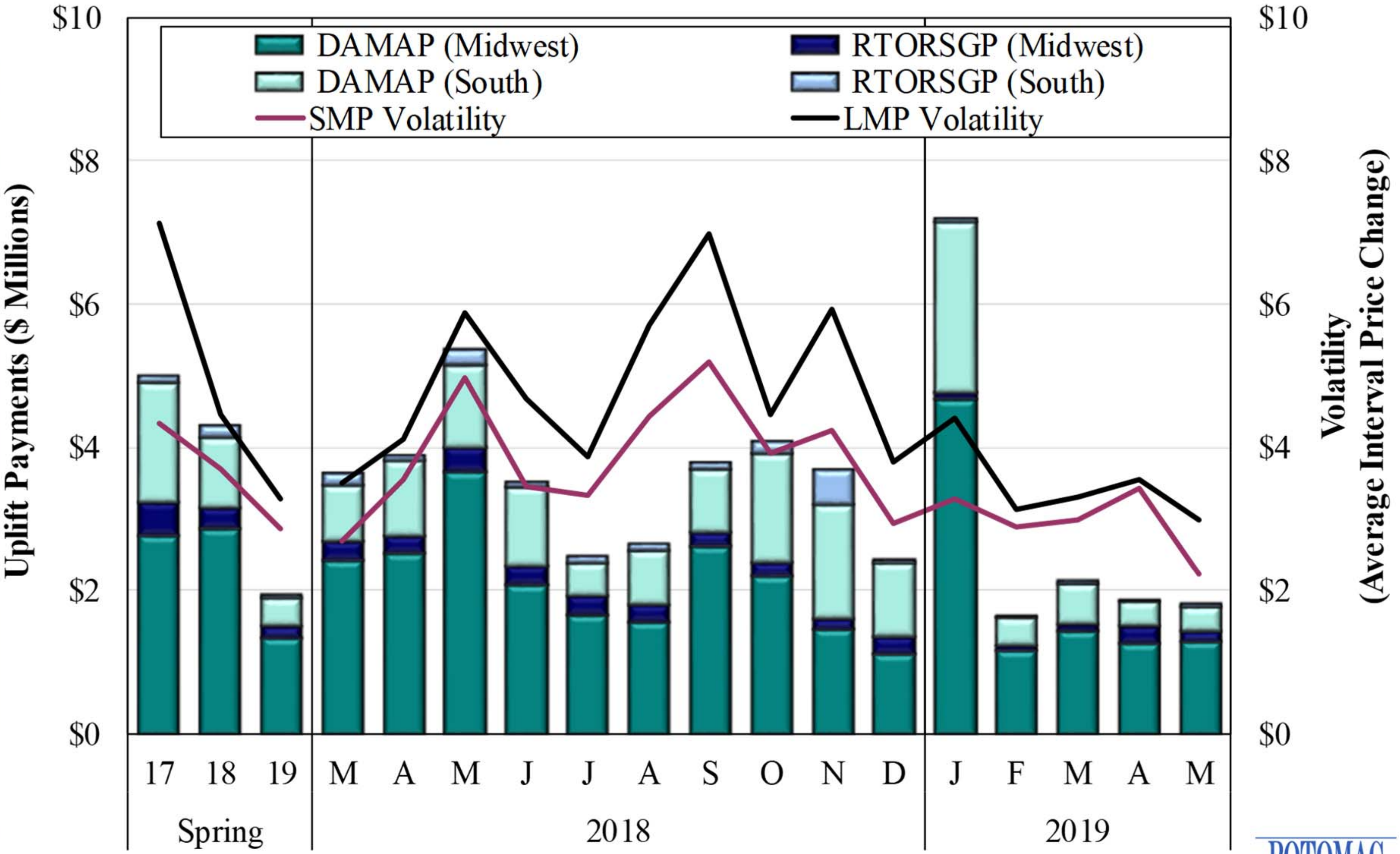


Real-Time RSG Payments
Spring 2018 – 2019



Sum of 2019 Spring (Millions)	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$0.00	$1.68	$1.68
Fuel-Adjusted RSG: Congestion	$0.41	$3.77	$4.18
Fuel-Adjusted RSG: RDT	$0.00	$3.40	$3.40
Fuel-Adjusted RSG: Capacity	$5.43	$0.83	$6.27
Total Nominal RSG	**$4.70**	**$7.45**	**$12.15**
RSG Mitigation			*$0.10*

Price Volatility Make Whole Payments
Spring 2018 – 2019



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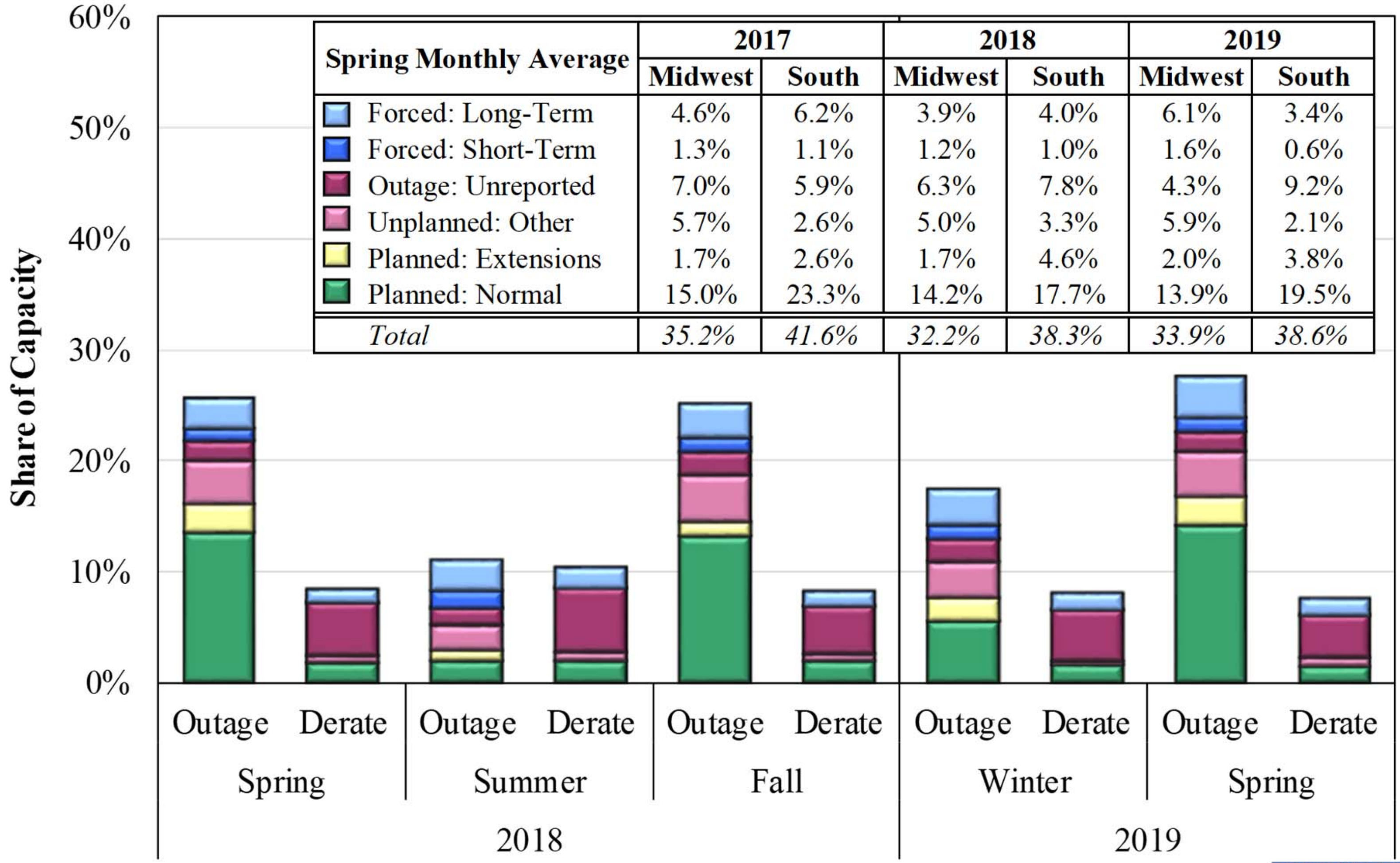
Generation Outage and Derate Rates Spring 2018 - 2019



Spring Monthly Average	2017		2018		2019	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	4.6%	6.2%	3.9%	4.0%	6.1%	3.4%
Forced: Short-Term	1.3%	1.1%	1.2%	1.0%	1.6%	0.6%
Outage: Unreported	7.0%	5.9%	6.3%	7.8%	4.3%	9.2%
Unplanned: Other	5.7%	2.6%	5.0%	3.3%	5.9%	2.1%
Planned: Extensions	1.7%	2.6%	1.7%	4.6%	2.0%	3.8%
Planned: Normal	15.0%	23.3%	14.2%	17.7%	13.9%	19.5%
Total	*35.2%*	*41.6%*	*32.2%*	*38.3%*	*33.9%*	*38.6%*

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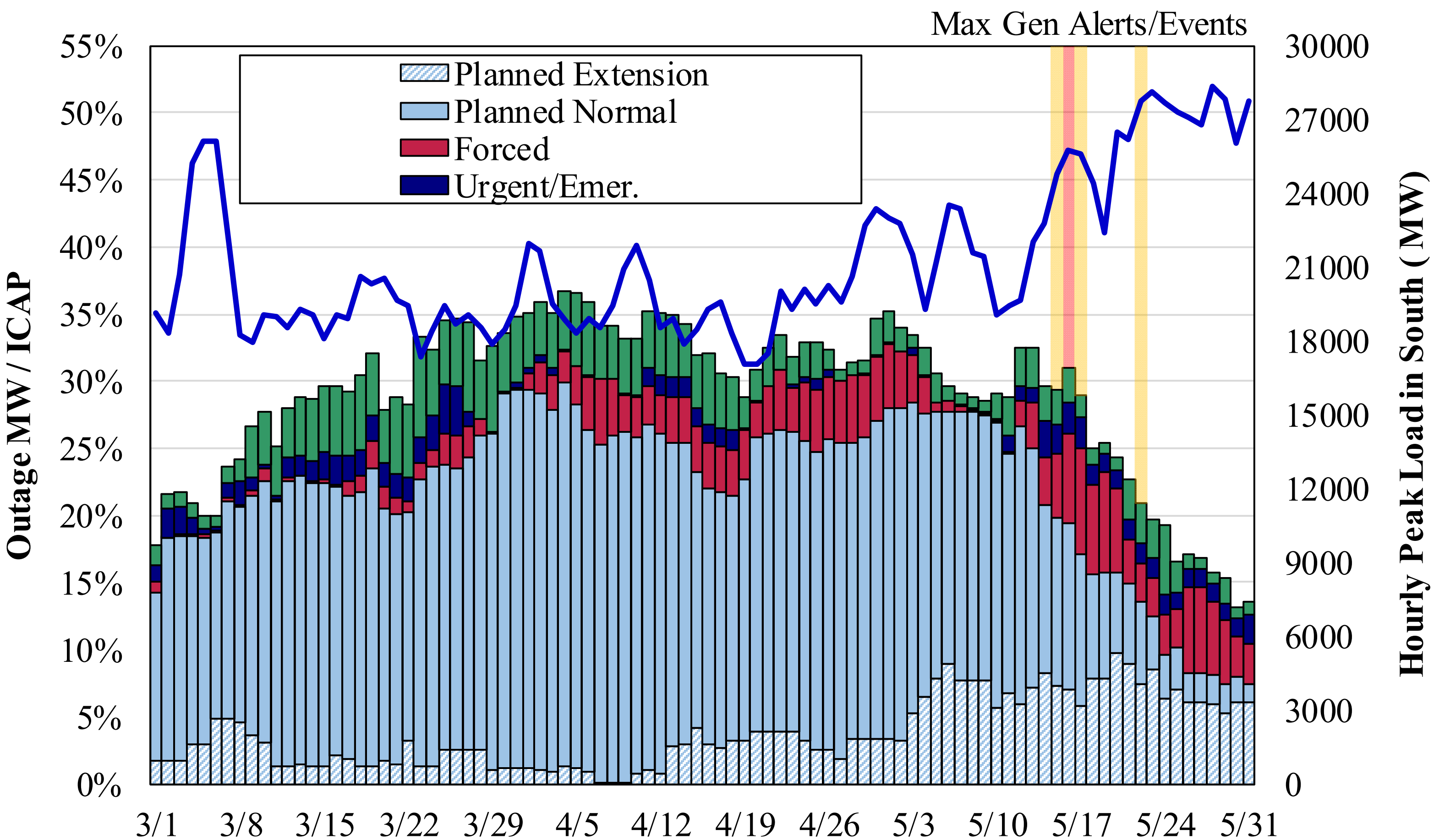
Daily Outages and Load in MISO South Spring 2019



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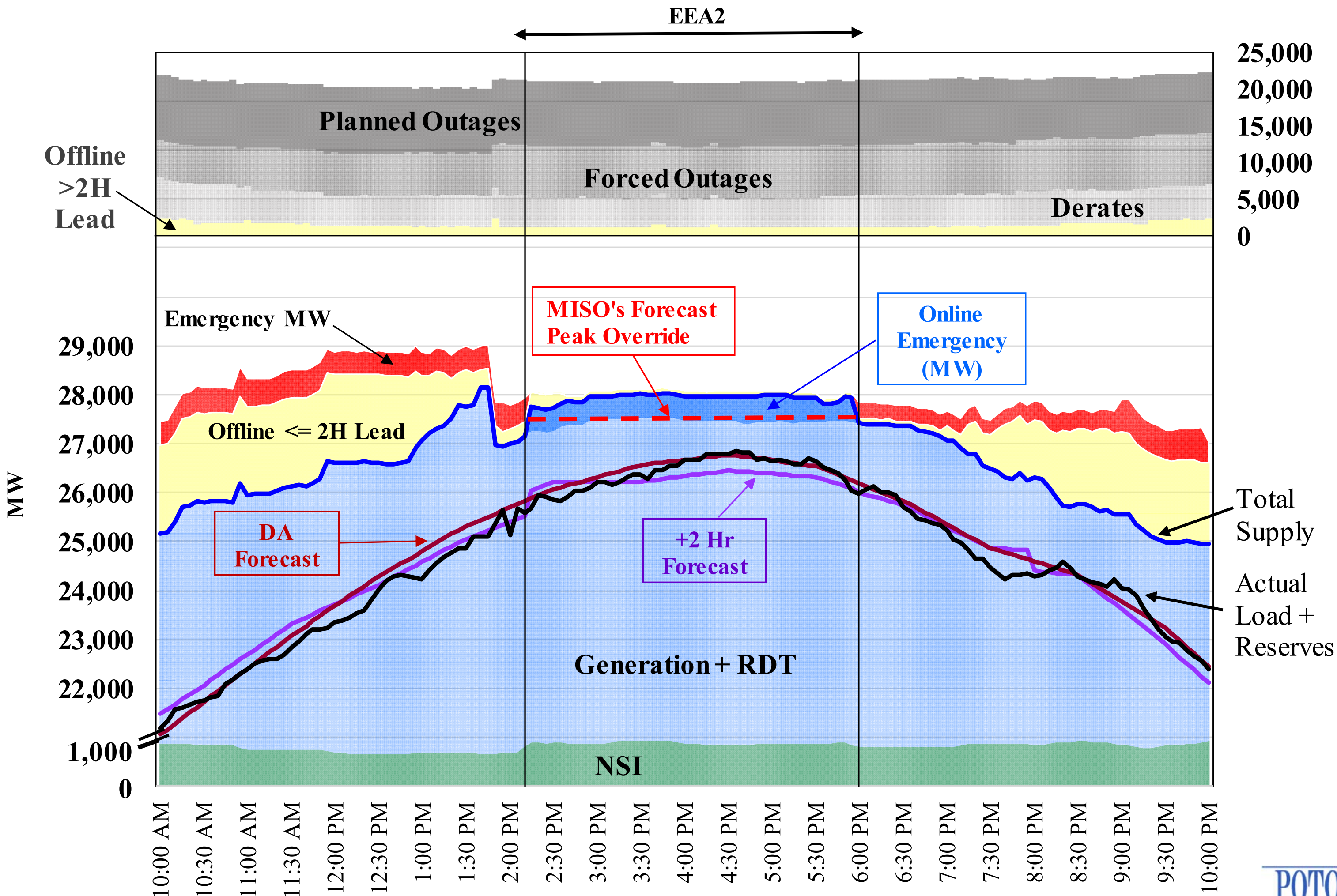
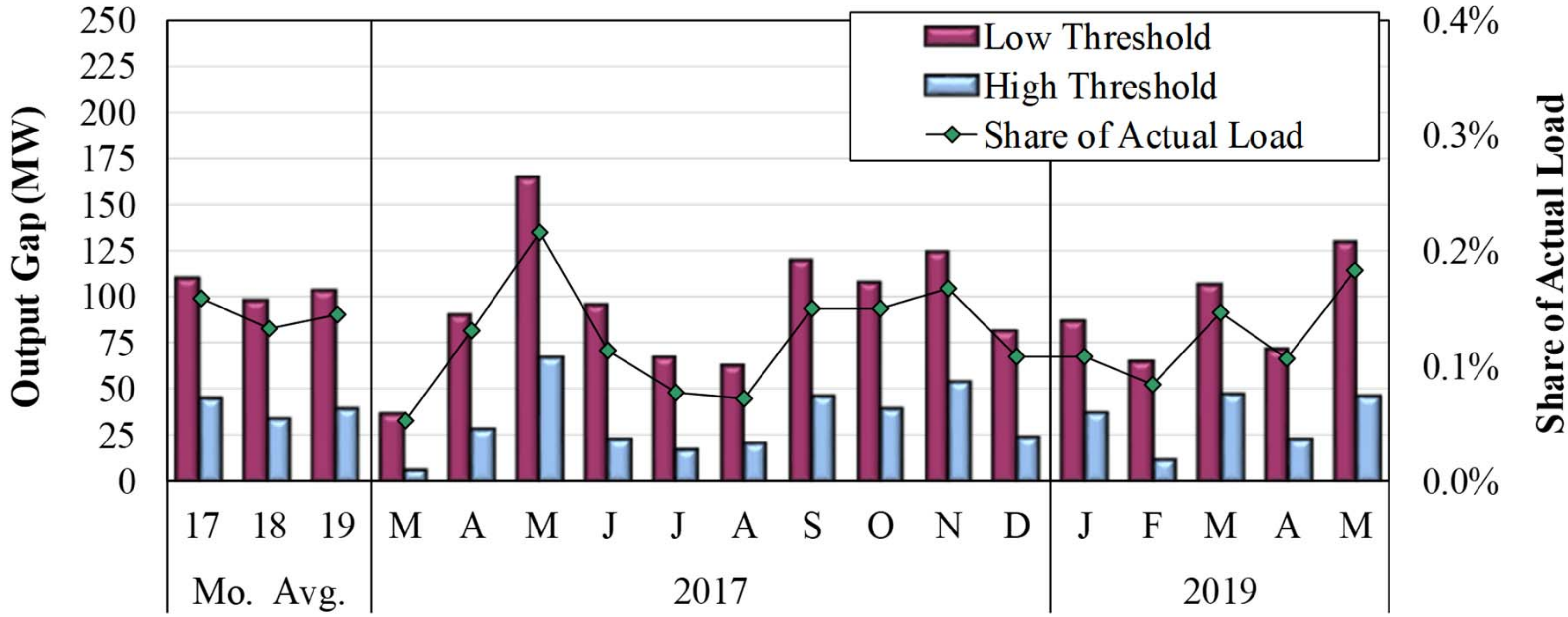
Maximum Generation Event in MISO South
May 16



Monthly Output Gap
Spring 2018 – 2019



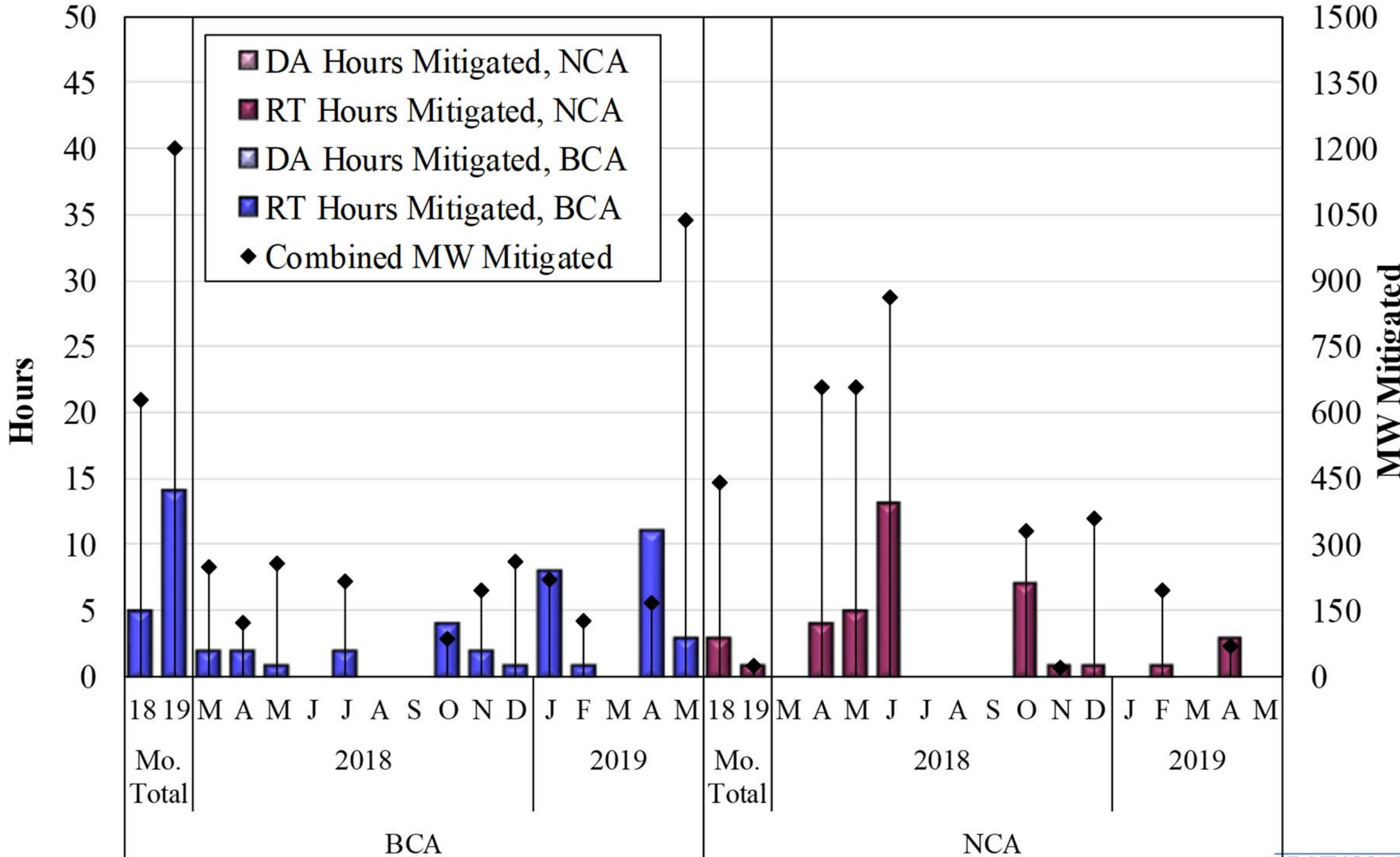
High Threshold Results by Unit Status (MW)

	17	18	19	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
Offline	11	12	15	0	2	33	8	3	8	16	16	5	3	24	2	28	8	10
Online	34	22	23	7	26	33	15	15	13	30	24	48	21	13	11	19	15	36

Low Threshold Results by Unit Status (MW)

	17	18	19	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
Offline	11	14	20	0	3	40	11	4	8	17	17	6	3	30	2	32	12	15
Online	99	83	83	37	88	124	85	64	55	102	90	118	78	56	63	75	60	114

Day-Ahead And Real-Time Energy Mitigation 2018 – 2019



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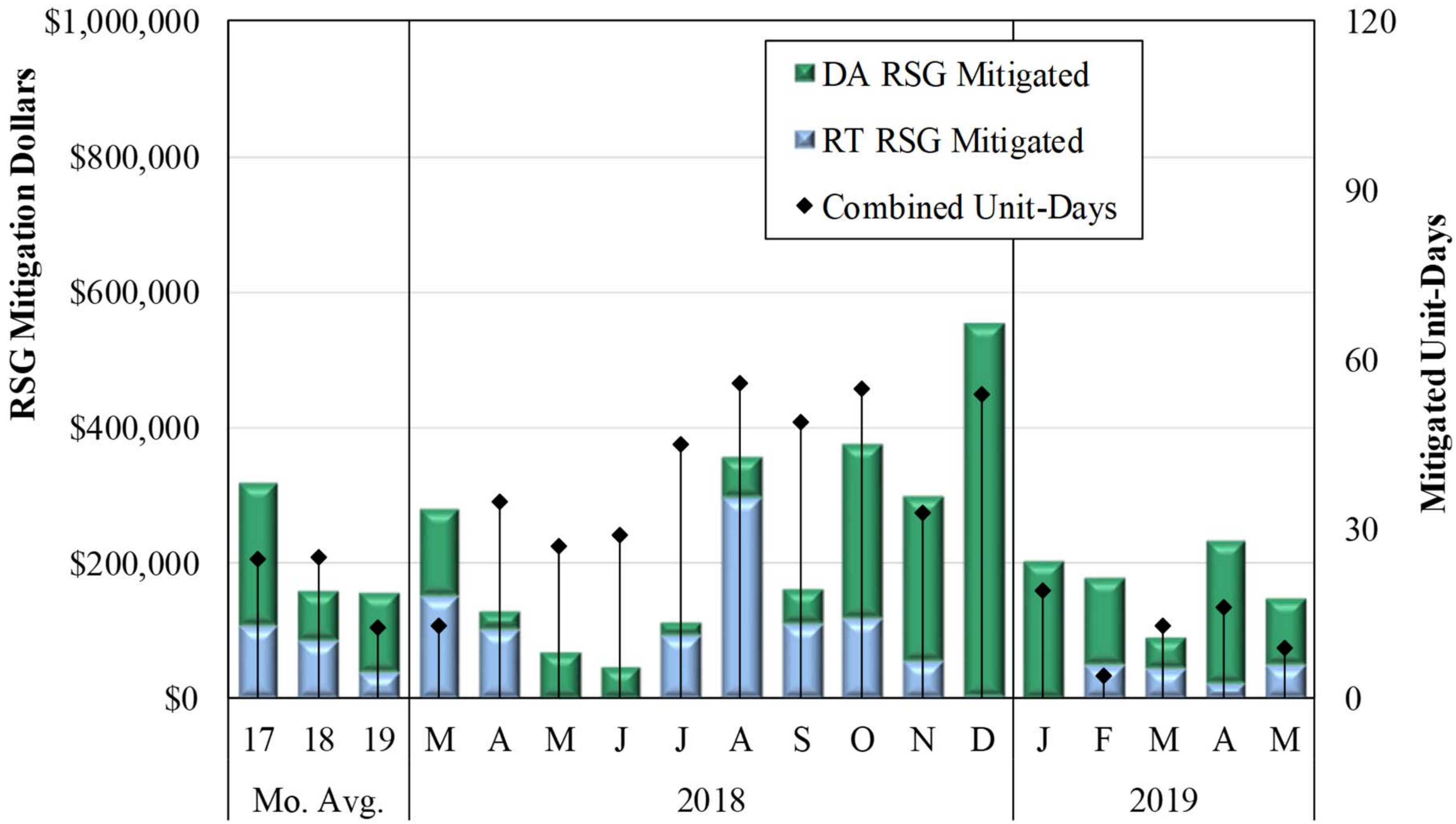
Day-Ahead and Real-Time RSG Mitigation 2018 – 2019



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List of Acronyms

- 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 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
- TLR — Transmission Line Loading Relief
- TCDC — Transmission Constraint Demand Curve
- VLR — Voltage and Local Reliability
- WUMS — Wisconsin Upper Michigan System

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IMM 2019 Summer Readiness and Resource Adequacy

Presented to:

MISO Board Markets Committee

David B. Patton, Ph.D.
MISO Independent Market Monitor

June 18, 2019

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IMM Summer Readiness Scenarios 2019

- We calculated a 19 percent Base Case 2019 summer capacity margin, indicating sufficient capacity exits to meet the 16.8 percent requirement.
  - ✓ Our assumptions generally align with MISO's Base Case, including a 1,500 MW transfer constraint in the South to North direction.
  - ✓ We include offered, deliverable ICAP from internal resources (except wind and solar offered UCAP) and BTMG, cleared external ICAP and DR UCAP.
  - ✓ We calculate an *Expected Margin*, which includes average net summer peak imports of more than 2 GW, that results in 20.7 percent in the Base Case.
    - – In the past MISO has seen imports over 12 GW during tight conditions.
- Realistic Scenario assumptions result in capacity margin of 12.2 percent:
  - ✓ South to North transfer constraint adjusted to 2,300 MW to reflect operations.
  - ✓ Historical average planned, unreported outages and derates in peak hours of July and August substituted for approved upcoming planned outages.
    - – Modifying the Realistic Scenario to exclude emergency-only resources with lead times greater than 2 hours results in a lower margin of 8.3 percent.
- If MISO experiences high-temperatures and high load, the resulting margin could fall as low as 2 percent, given the impacts on both supply and load.

IMM Summer Readiness Scenarios 2019

	Base Scenario	Alternative IMM Scenarios			
		Realistic Scenario	Realistic DR <= 2HR*	High Temperature Cases	
				Realistic Scenario	Realistic <=2HR*
Load					
Base Case	124,744	124,744	124,744	124,744	124,744
High Load Increase	-	-	-	6,554	6,554
Total Load (MW)	124,744	124,744	124,744	131,298	131,298
Generation					
Internal Generation Excluding Exports	134,856	134,856	134,422	134,856	134,422
BTM Generation	4,588	4,588	2,845	4,588	2,845
Unforced Outages**	(725)	(10,486)	(10,486)	(11,833)	(11,833)
Adjustment due to Transfer Limit	(1,220)	-	-	-	-
Total Generation (MW)	137,498	128,958	126,781	127,610	125,434
Imports and Demand Response* **					
Demand Response	7,684	7,684	5,093	7,684	5,093
Capacity Imports	3,272	3,272	3,272	3,272	3,272
Margin (MW)	23,710	15,170	10,402	7,269	2,501
Margin (%)	**19.0%**	**12.2%**	**8.3%**	**5.8%**	**2.0%**
Effects of Non-Firm Imports					
Summer Peak Net Imports	2,161	2,161	2,161	2,161	2,161
Expected Margin (MW)	25,871	17,330	12,563	9,429	4,662
Expected Margin (%)	**20.7%**	**13.9%**	**10.1%**	**7.6%**	**3.7%**

* Assumes 100% response from resources available within 2 hours.

** Base scenario shows approved planned outages for 19/20 summer.
Alternatives use average historical average unforced unit unavailability during July and August peak hours.

*** Cleared amounts for the 2019/2020 planning year.

2019-2020 Capacity Auction Results

- MISO’s annual Planning Resource Auction (PRA) should ideally ensure an adequate supply margin exists during the forecast summer peak:
  - ✓ MISO’s Planning Reserve Margin Requirement (vertical demand curve) is determined through Loss of Load Expectation (LOLE) study that assumes:
    - – Resources do not plan outages across the summer peak;
    - – Emergency-only resources’ lead-times are immaterial and so not modeled.
- In MISO’s 2019/2020 PRA, Zone 7 cleared at $24.30 per MW-day, while the rest of MISO cleared at $2.99 per MW-day.
  - ✓ One resource that offered and cleared in Zone 7 was approved by MISO for a year-long planned outage beginning in mid-May.
  - ✓ Were this resource to have been disqualified, Zone 7 would have cleared at $243.37 per MW-day, or the Cost of New Entry (CONE).
    - – Absent this particular resource, all other zones in MISO would have cleared at $3.17 per MW-day.
  - ✓ We recommend that resources that have no expectation of availability during the summer peak period not qualify as planning resources.

Alternative Capacity Auction Clearing Scenarios 2019 – 2020

- We evaluated alternative clearing prices that would have resulted based on our current and past Resource Adequacy Recommendations:
  - ✓ Excluding resources with scheduled outages across the summer peak: \$4.95 per MW-day across the footprint and \$243.37 per MWh in MI.
  - ✓ Enforcing deliverable ICAP: \$9.82 per MW-day in unconstrained zones and \$24.31 per MW-day in MI.
    - Some resources would likely acquire additional transmission were MISO to implement this change, so these numbers are a high estimate.
  - ✓ Treating Behind-the-Meter load as firm: \$4.95 per MW-day in unconstrained zones and \$24.31 per MW-day in MI.
  - ✓ Combining these scenarios could result in clearing prices as high as \$5.00 per MW-day footprint-wide and \$247.37 per MW-day in MI.
- Alternative clearing scenarios with a sloped demand curve significantly increases the clearing prices in all cases:
  - ✓ Prices could have cleared as high as \$149.07 per MW-day in all zones except MI, where it could have cleared at \$243.37 per MW-day.

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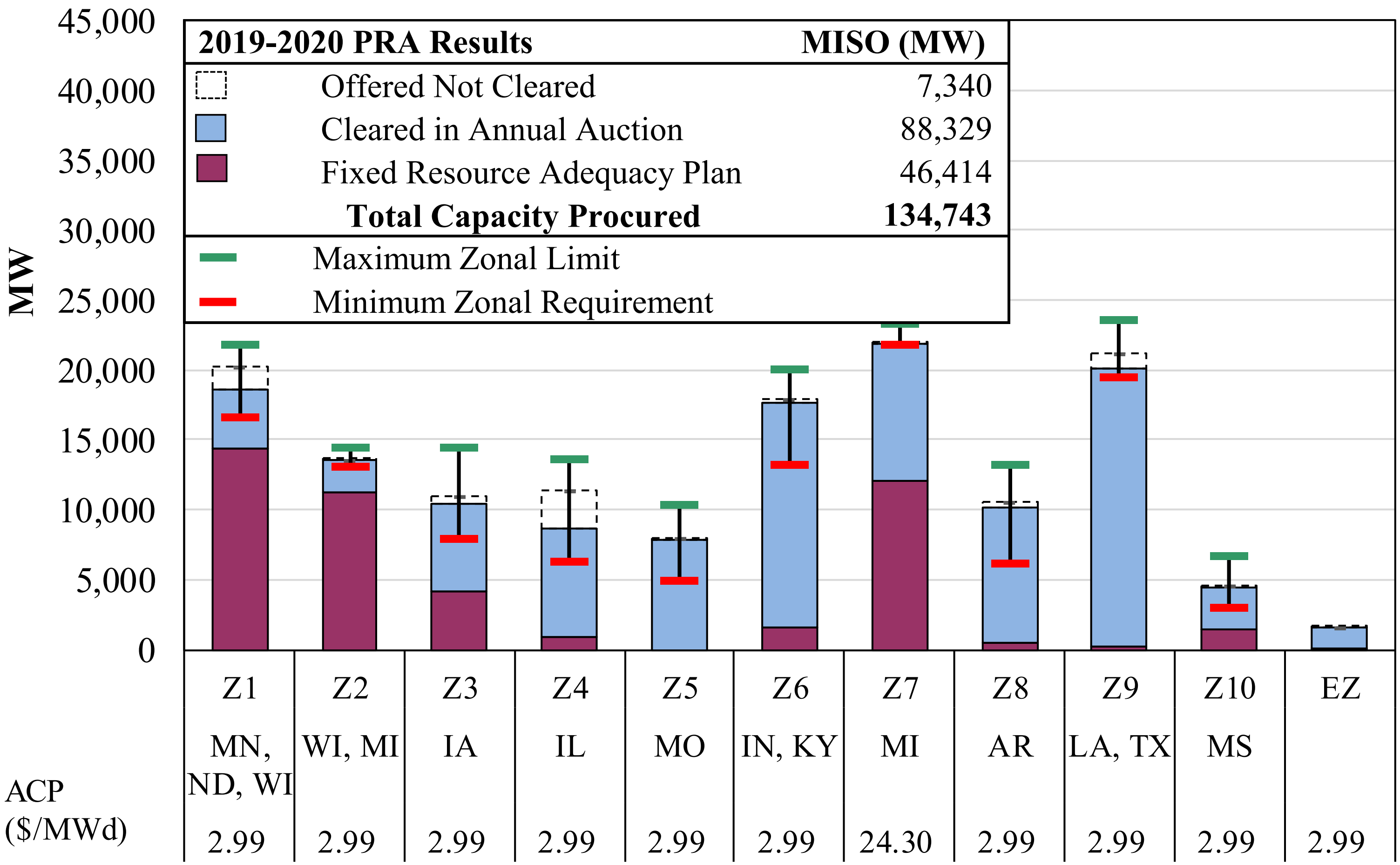
Planning Reserve Auction Results 2019-2020



Alternative Capacity Auction Clearing Scenarios 2019-2020

Alternative Capacity Auction Scenarios	Affected UCAP	Vertical Demand Curve: Unconstrained Price	Vertical Demand Curve: Constrained Price (MI)	Sloped Demand Curve: Unconstrained Price	Sloped Demand Curve: Constrained Price (MI)
Base Scenario		$2.99	$24.30	$110.38	
- Known Outages	635.4	$4.95	$243.37	$121.52	$243.37
- Undeliverable ICAP (Conventional Gen.)	1,515.3	$9.82	$24.31	$137.57	
+ Procurement for BTM Firm Load	306.5	$4.95	$24.30	$115.90	
Combination of Alternative Scenarios					
- Known Outages, BTM Firm Load	941.9	$5.00	$243.37	$127.07	$234.37
- All Changes	2,455.8	$15.00	$243.37	$149.07	$243.37