IMM Quarterly Report: Fall 2017

MISO Independent Market Monitor

David Patton, Ph.D.
Potomac Economics

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Highlights and Findings: Fall 2017

- The MISO markets performed competitively this fall, but we identify in this report significant inefficiencies that undermine MISO's market performance.
  - ✓ Natural gas prices increased by 5 percent and contributed to an increase in energy prices of 5 percent.
  - ✓ Market power mitigation was infrequent and offers were competitive.
- In September, the all-in price was 16 percent higher than last year.
  - ✓ Unseasonably warm weather late in the month and high outage rates led to multiple days with operating events (warnings, alerts, or emergencies).
  - ✓ Emergency pricing was triggered on September 22 and 23.
- A new wind output record of 14.6 GW was set on November 21.
- Real-time congestion was significantly higher this quarter compared to last fall in the Midwest, particularly in September. A significant portion is due to:
  - ✓ Problems with the processes to define M2M constraints, one of which we believe is a tariff violation by PJM; and
  - ✓ Continued excessive costs and problems caused by TVA's use of the Transmission Line Loading Relief (TLR) process.
- Real-time RSG was inflated by extremely frequent commitments made by the MISO operators to increase reserve (capacity) levels in MISO South.

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Quarterly Summary

		Value	*Change*[1] Prior Qtr.	Prior Year
RT Energy Prices ($/MWh)	●	$30.01	*0%*	*5%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago	●	$2.87	*2%*	*5%*
Natural Gas - Henry Hub	●	$2.93	*0%*	*5%*
Western Coal	●	$0.67	*4%*	*3%*
Eastern Coal	●	$1.49	*6%*	*8%*
Load (GW)[2]				
Average Load	●	73.1	*-12%*	*1%*
Peak Load	●	115.3	*-5%*	*0%*
% Scheduled DA (Peak Hour)	●	98.4%	99.3%	98.1%
Transmission Congestion ($M)				
Real-Time Congestion Value	●	$453.3	*36%*	*21%*
Day-Ahead Congestion Revenue	●	$203.4	*19%*	*-4%*
Balancing Congestion Revenue[3]	●	-$12.7	$8.2	$8.8
Ancillary Service Prices ($/MWh)				
Regulation	●	$10.04	*7%*	*7%*
Spinning Reserves	●	$2.89	*-6%*	*20%*
Supplemental Reserves	●	$0.74	*-38%*	*-8%*

		Value	*Change*[1] Prior Qtr.	Prior Year
FTR Funding (%)	●	100%	103%	100%
Wind Output (MW/hr)	●	6,315	*73%*	*11%*
Guarantee Payments ($M)[4]				
Real-Time RSG	●	$23.4	*47%*	*56%*
Day-Ahead RSG	●	$9.9	*7%*	*6%*
Day-Ahead Margin Assurance	●	$11.8	*20%*	*13%*
Real-Time Offer Rev. Sufficiency	●	$1.8	*3%*	*-39%*
Price Convergence[5]				
Market-wide DA Premium	●	-3.0%	-0.2%	0.4%
Virtual Trading				
Cleared Quantity (MW/hr)	●	14,023	*5%*	*9%*
% Price Insensitive	●	30%	29%	26%
% Screened for Review	●	1%	1%	1%
Profitability ($/MW)	●	$0.74	$0.72	$0.75
Dispatch of Peaking Units (MW/hr)	●	1,023	1385	881
Output Gap- Low Thresh. (MW/hr)	●	95	61	101
Other:				

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

Notes:
1. Values not in italics are the value 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 Fall 2017

<u>September Prices (Slides 14, 15, 17, 18)</u>

- Real-time energy prices in September increased 16 percent compared to last year and 28 percent over the prior month.
  - ✓ Temperatures were unseasonably high throughout the MISO footprint from September 21 through September 25, reaching 92 degrees.
  - ✓ The monthly peak load of 114.7 GW occurred late in the month.
- Beginning on September 20, MISO experienced several days of Conservative Operations and Maximum Generation Alerts.
- On September 22, MISO issued a Maximum Generation Event Step 1b/c.
  - ✓ Temperature and load were significantly under-forecasted.
  - ✓ High planned outage rates, typical in shoulder months, and 1,100 MW of forced outages contributed to tight system conditions.
  - ✓ MISO set an emergency offer floor of $847/MWh, but it did not set prices.
  - ✓ A TLR issued by TVA led to significant re-dispatch and price distortions.
- On September 25 MISO issued a Maximum Generation Alert caused by high temperatures, load, forced outages, and loss of imports from a TVA TLR.

Highlights for Fall 2017

Transmission Congestion and Coordination Issues (Slides 19-22)

- Real-time congestion increased by 52 percent in the Midwest and decreased by 39 percent in the South for a net increase of 21 percent.
  - ✓ In September, real-time congestion exceeded $250 million, of which 88 percent was in the Midwest.
  - ✓ Extended seasonal transmission outages and coordination problems contributed to high congestion.
- In September and October, MISO incurred $76 million in congestion on uncoordinated constraints that likely should have defined as M2M with PJM.
  - ✓ More than half of this was associated with a single constraint that was not tested for M2M with PJM, but would clearly have passed.
  - ✓ A MISO resource pseudo-tied to PJM significantly aggravated this constraint.
  - ✓ $41 million of congestion was on constraints not defined as M2M with SPP.
- In reviewing coordination concerns, two serious problems have been uncovered regarding PJM’s coordination and compliance with the JOA.
- Additionally, congestion associated with TLR constraints raise serious efficiency and cost concerns.
- The PJM and TVA issues are discussed in the next four slides.

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Highlights for Fall 2017

PJM Problem 1: IDC Credit for Redispatch

- PJM calculation of the relief provided by its market redispatch from its generators below the 5% IDC cutoff has been incorrect since 2009.
  - ✓ These calculations enable PJM (and MISO and SPP) to get full credit for relief provided during TLRs.
  - ✓ MISO identified the error in September after reviewing congestion results during TLR events on Volunteer-Phipps Bend – the error reduced PJM's relief obligation significantly.
  - ✓ MISO will be verifying, but believes PJM has corrected this calculation error going forward.
- The error tends to increase the relief requested on all other parties, including MISO.
  - ✓ This has been very costly for MISO because MISO has incurred extreme costs attempting to provide the relief requested in response to a TLR.
  - ✓ The binding on TVA TLRs alone raised real-time monthly average prices in the Midwest Region by nearly 8 percent in September.

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Problem #2: Failure to Implement M2M Tests

PJM Problem #2: Failure to Implement M2M Tests

- PJM has not implemented a key test under the JOA to identify new M2M constraints, which we believe is a tariff violation (see the CMP Section 3.2.1).
  - ✓ This test identifies constraints affected by the neighbor's generators based on real-time system topology – hence, constraints affected by transmission outages were not properly evaluated.
- This is a significant problem because transmission outages are frequently the cause of severe binding constraints.
- In our 2016 SOM Report, we identified large amounts of congestion that was not coordinated because constraints were not properly identified as M2M.
  - ✓ We've expanded this analysis through Nov 2017 in the figure on slide 21.
  - ✓ From Jan '16 - Nov '17, MISO had $355 million of congestion on constraints that likely should have been coordinated with PJM under the M2M protocols.
  - ✓ Not all of this amount is due to this violation of the JOA. Some is likely due to simply not testing constraints or not testing them in a timely manner.
- Not only did this undermine efficient dispatch and congestion management, but it also effectively entitled PJM to unlimited use of MISO transmission.

Highlights for Fall 2017

TVA TLR Issues

- TLRs called by TVA on the 500 KV Volunteer-Phipps Bend (VPB) line during tight conditions in late September materially inflated Midwest prices.
- When an entity calls a TLR, it requests a certain amount of relief. To provide the relief, MISO activates the constraint in its real-time dispatch.
- This TLR constraint leads to wide-spread price increases in the Midwest and price reductions in the South, which occurred on September 21, 22, and 25.
  - ✓ The average LMP increase in the Midwest on these days was as high as $110 during the TLR, which led to real-time load costs rising by $36 million.
  - ✓ Even the MISO SMP was affected because the TLR reduced our ability to utilize the total supply, rising by $12.60/MWh when it was binding.
- The impact of these TLRs were significantly higher due to the PJM problem (problem 1) discussed on slide 6, which reduced PJM's obligation and inappropriately increased MISO's relief obligation.

Highlights for Fall 2017

<u>TVA TLR Issues (Cont.)</u>

- TLRs are never optimal, but these are worse because TVA called the TLR on VPB as a proxy to acquire relief on a lower voltage constraint.
  - ✓ MISO's effects are grossly inefficient because most of the LMP and dispatch effects are at locations that have *no material effect* on the 161kV constraint.
  - ✓ The competing dispatch effects of VPB constraint in the MISO dispatch caused MISO to incur **100 dispatch violations** of its own constraints.
  - ✓ This is egregious because VPB was not close to its limit and MISO incurred enormous costs to provide very little relief on the 161kV constraints in TVA.
- Conclusions and Takeaways:
  - ✓ Establishing a JOA with TVA is essential for MISO.
    - – TVA's generation is nearly always much more effective and economic for managing a TVA constraint than MISO's.
    - – Paying TVA for economic relief on these constraints would generate significant savings for MISO customers and improve reliability.
  - ✓ MISO's transmission constraint demand curve (willingness to incur costs) to provide very small amounts of relief is much too high for TLR constraints.

Highlights for Fall 2017

<u>Imports and Exports (Slides 31, 32)</u>

- CTS was implemented on October 3, but has produced almost no benefits because there is no liquidity. From October 3 through November 21:
  - ✓ CTS accounted for about 0.7% of all scheduling at the PJM interface.
  - ✓ These transactions averaged a 10 MW net export to PJM.
  - ✓ We will be investigating, but the most significant factor is likely the charges that PJM allocates to CTS transactions.
  - ✓ MISO wisely eliminated these charges, but PJM refused to even though CTS does not cause the costs (if anything, it reduces them).
- We have also begun an evaluation of the interface pricing at the PJM interface since MISO agreed and implemented PJM's proposed "common interface".
  - ✓ Our analysis shows that congestion pricing errors at the interface are up more than 100 percent under the common interface.
  - ✓ The average pricing error is $0.58 per MWh (vs. $0.04 under legacy pricing).
  - ✓ This error is driven by a small number of periods with large errors when constraints are binding near the interface.
  - ✓ We also show a case study for Sept. 23 that shows how inaccurate interface pricing caused large inefficient changes in interchange schedules.

Highlights for Fall 2017

RSG and RDT (Slides 31, 32)

- Real-time RSG increased 56 percent over last year, driven by RSG payments of more than $13 million in September.
- Nearly 40 percent of all real-time RSG was paid to units committed for RDT.
  - ✓ RDT commitments are made after the day-ahead market to ensure MISO can respond to one or more sub-regional contingencies and load forecast errors.
  - ✓ The current tool MISO uses is very conservative and not accurate.
  - ✓ MISO incurred more than $9 million in RSG for the RDT this quarter.
- MISO plans to implement the Reserve Procurement Enhancement to procure and price 10-minute reserves to help satisfy sub-regional capacity needs.
  - ✓ This must be carefully structured to avoid generating costs that exceed the value of the reliability concerns.
  - ✓ Our simulations show that the RPE, as planned by MISO, would have been binding in 24 percent of intervals from March 1 – November 30.
  - ✓ Prices would be affected in these intervals broadly throughout MISO.
- In the long run, implementing a 30-minute reserve product and negotiating the ability to exceed the RDT limit for short periods (less than 30 minutes) after a contingency would be much more efficient.

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 to discuss market outcomes.
  - ✓ We responded to several data requests related to prior referrals.
  - ✓ We made two new referrals related to inaccurate offers.
  - ✓ We made several notifications of potential tariff violations.
- We made several presentations to MISO stakeholder groups.
  - ✓ In October, we presented our Summer Quarterly Report.
  - ✓ At the September and October MSC meetings, we responded to participant questions and comments on our proposed improvements to the Uninstructed Deviation Threshold.
- At the MSC and at the ERSC, we discussed concerns with the current RDT commitment tool and the need for improvements to reduce inefficient commitments.

Submittals to External Entities and Other Issues

- We filed comments opposing the FERC/DOE Grid Resiliency NOPR.
  - ✓ We urged FERC to reject the specific proposal advanced by DOE in the NOPR, and to identify the contingencies that the current RTO planning processes and markets may not be fully considering.
  - ✓ RTO markets can facilitate the innovation and long-term decisions necessary to achieve these resilience objectives and achieve greater reliability improvements at a much lower cost.
  - ✓ We also filed reply comments in response to PJM, explaining why PJM's price formation ideas are not a reasonable approach for achieving resilience objectives in PJM or elsewhere.
  - ✓ PJM's initial price formation proposal (outlined in a June whitepaper) is a more serious threat to competitive markets because it would fundamentally undermine generators' incentives and significantly increase costs to load.
- We filed comments in response to MISO's filing to remove double counting of congestion charges/credits to pseudo-tied resources.
  - ✓ We support the proposed change but continue to recommend that FERC hold a Technical Conference to discuss the myriad of pseudo-tie issues.

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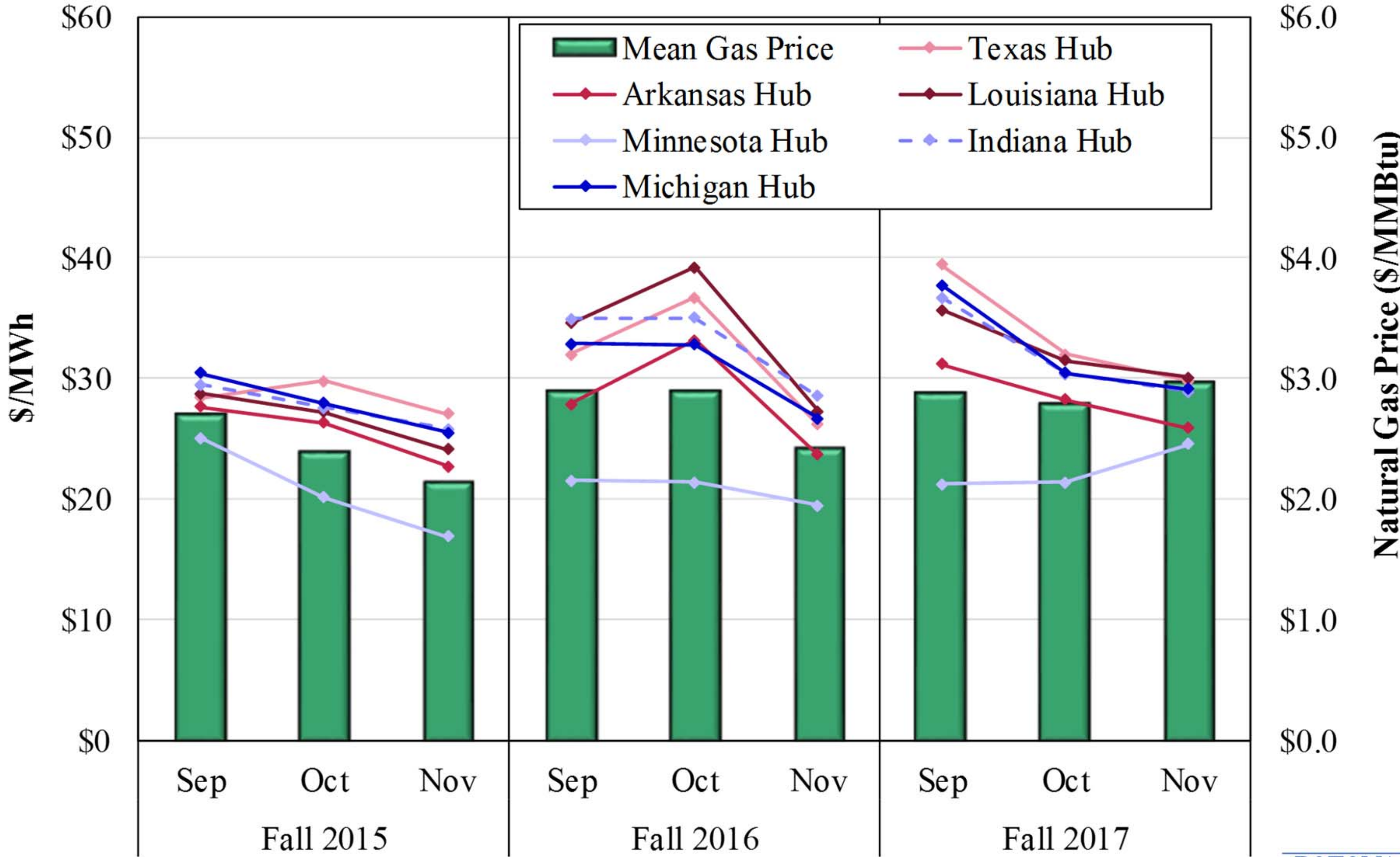
Day-Ahead Average Monthly Hub Prices
Fall 2015 – 2017



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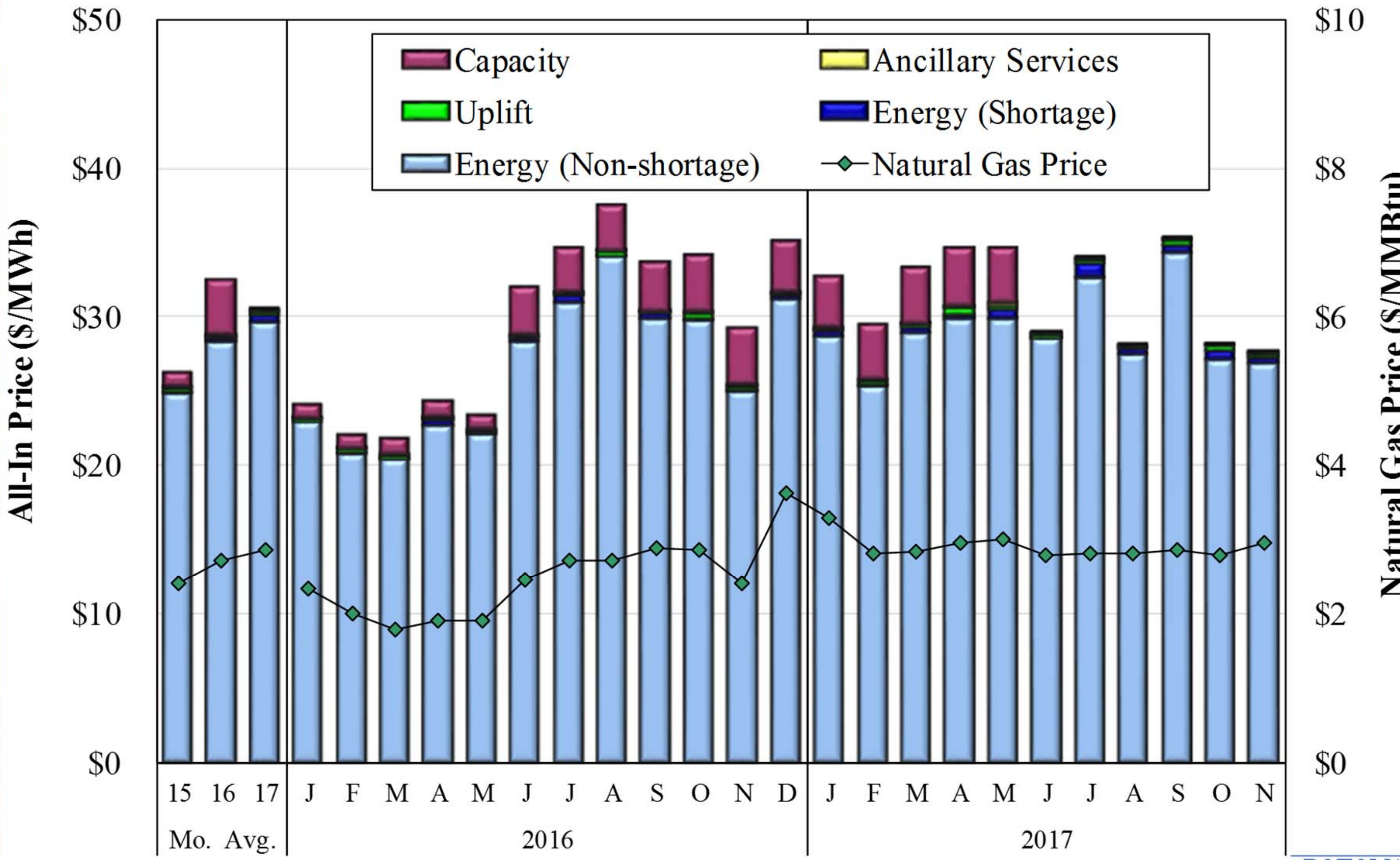
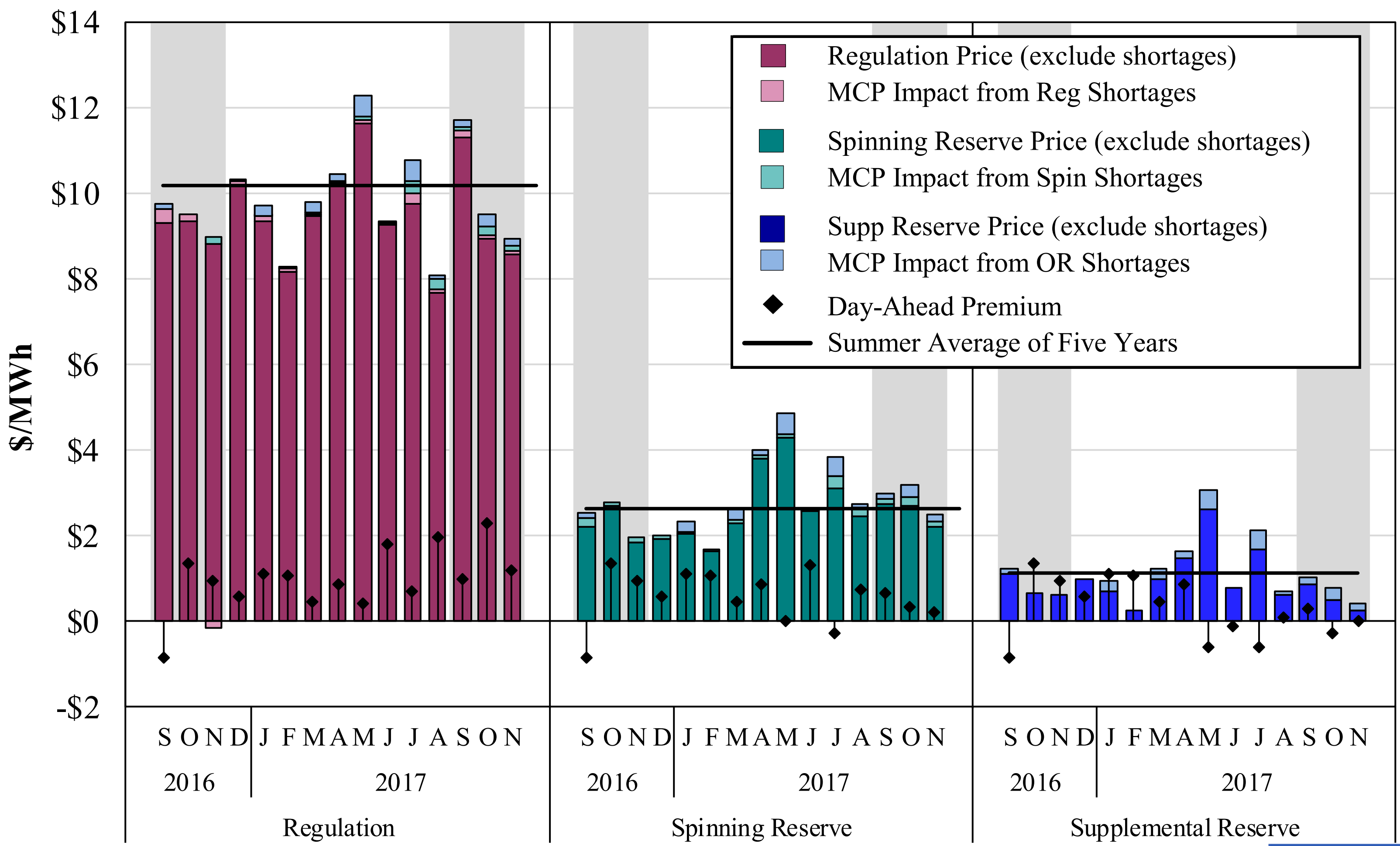
All-In Price
Fall 2015 – 2017



Monthly Average Ancillary Service Prices
Fall 2016 – 2017



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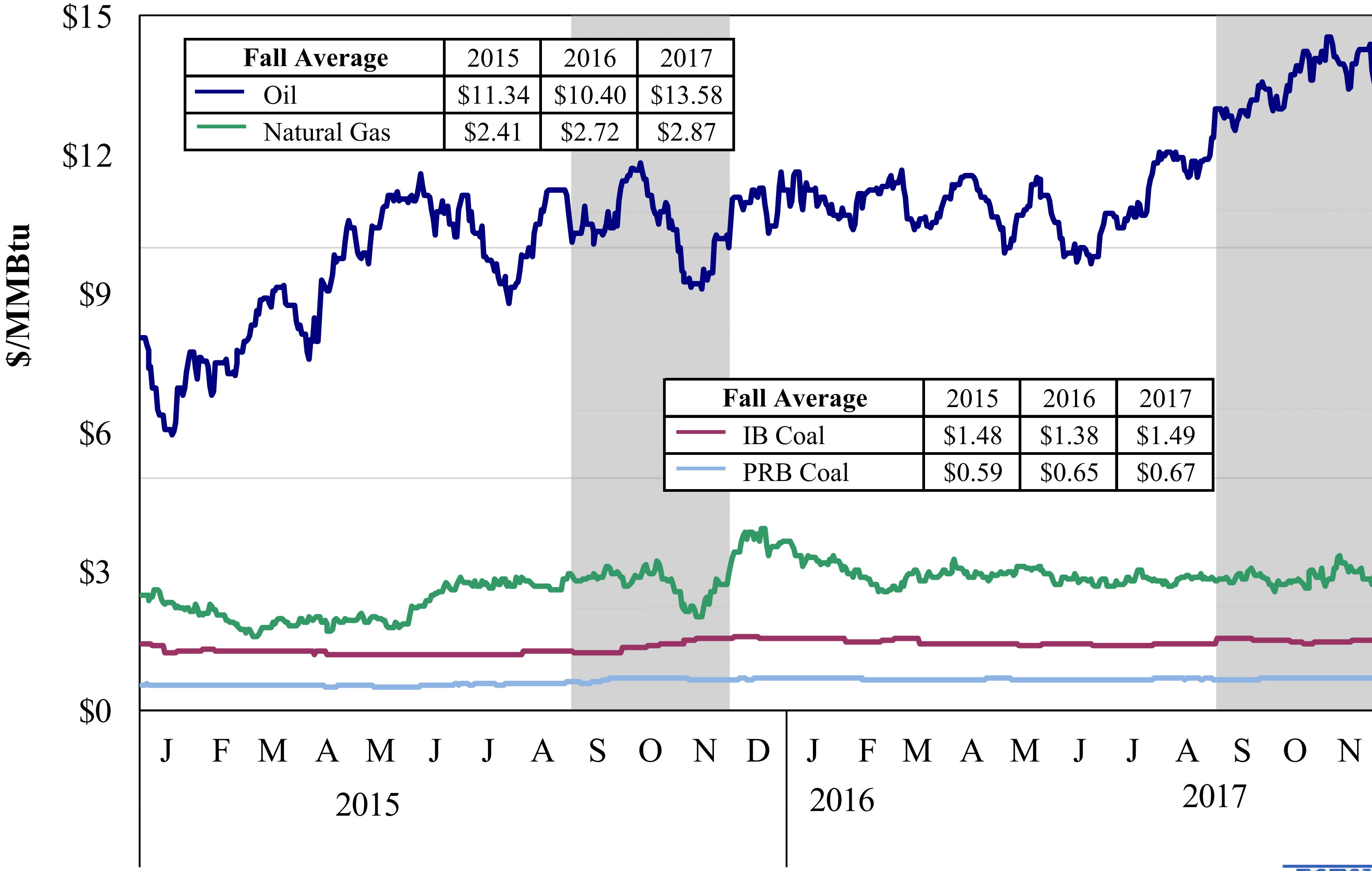
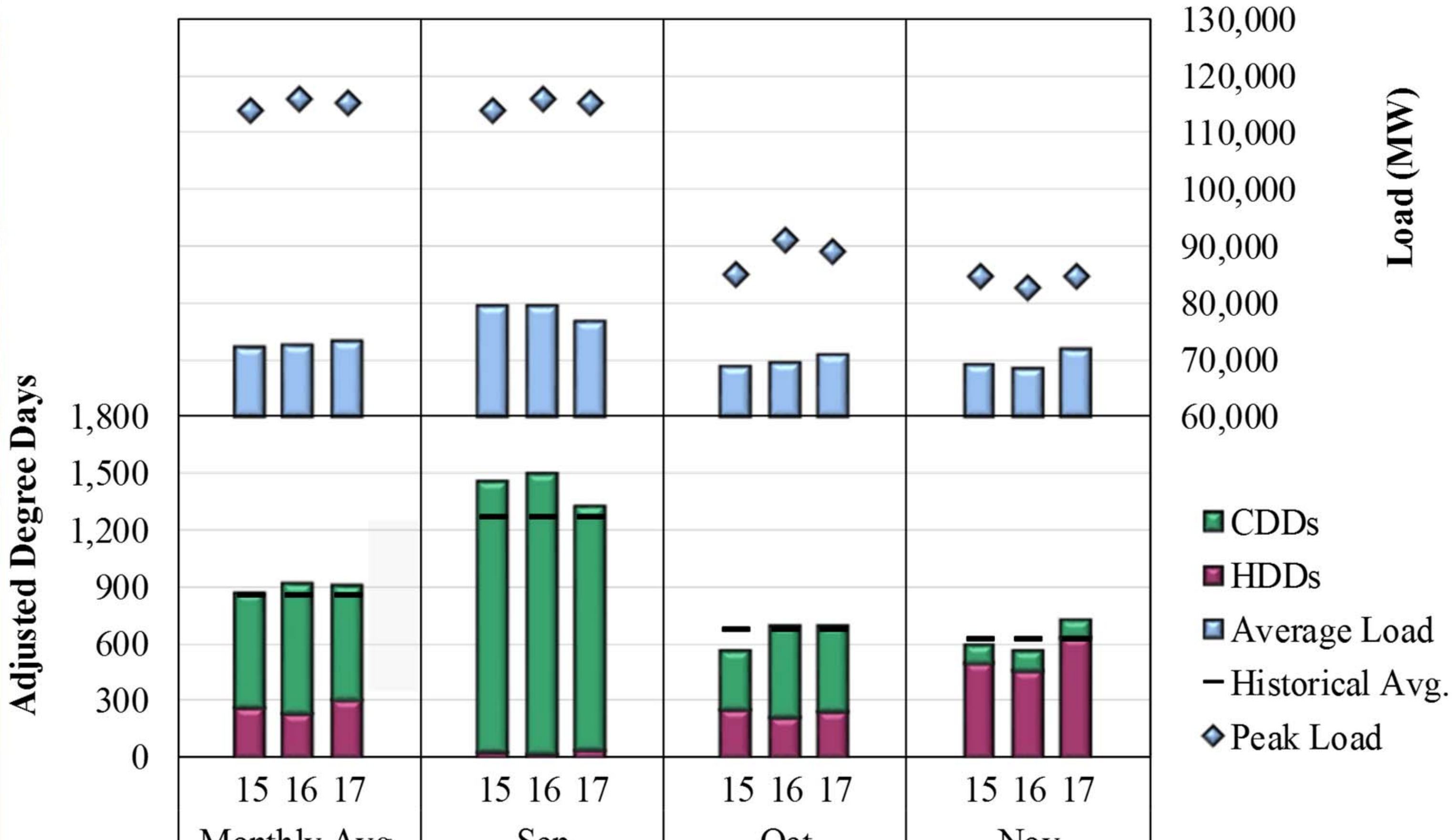
MISO Fuel Prices
2015 – 2017



Fall Average	2015	2016	2017
Oil	$11.34	$10.40	$13.58
Natural Gas	$2.41	$2.72	$2.87

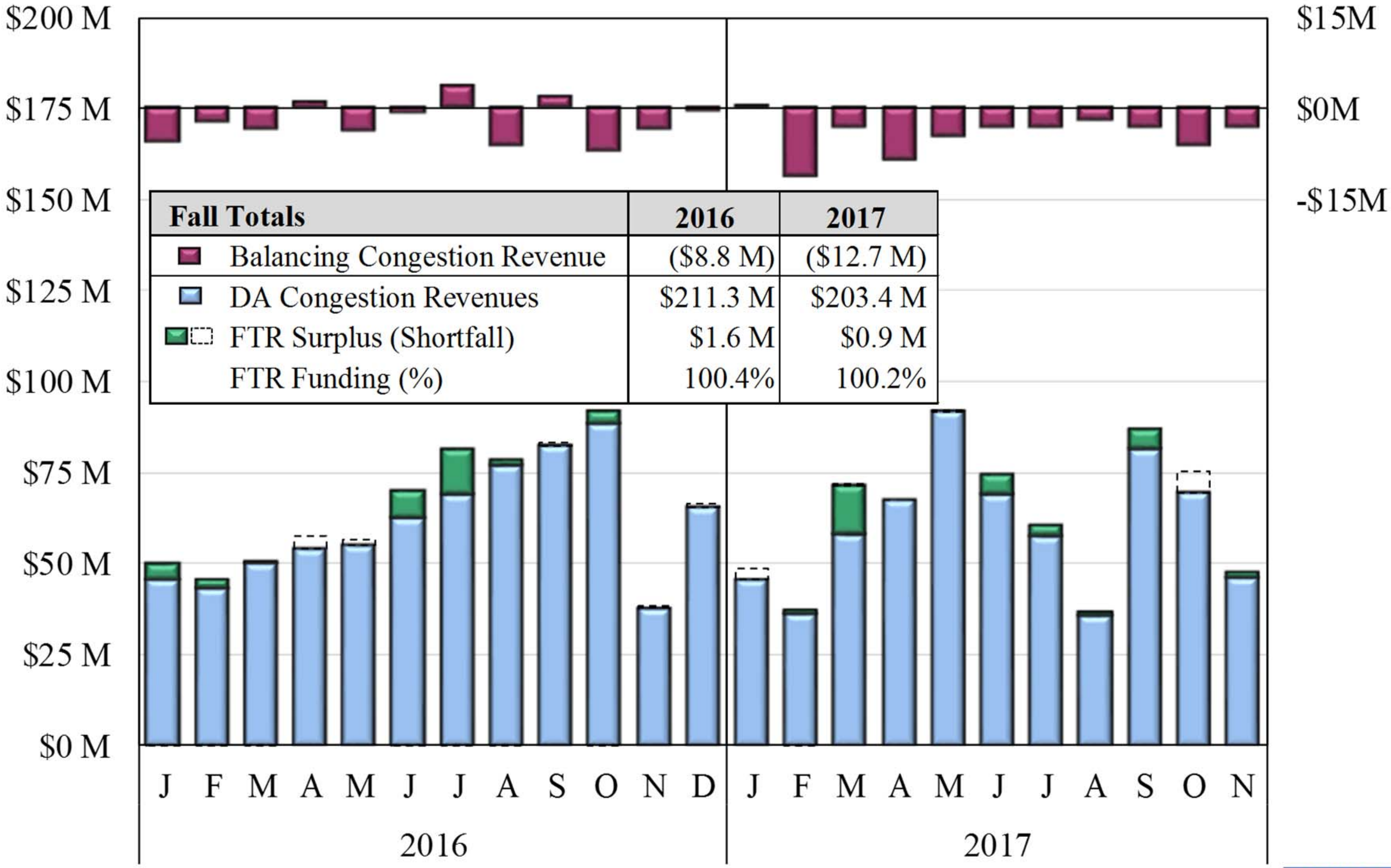
Fall Average	2015	2016	2017
IB Coal	$1.48	$1.38	$1.49
PRB Coal	$0.59	$0.65	$0.67

Load and Weather Patterns Fall 2015 – 2017



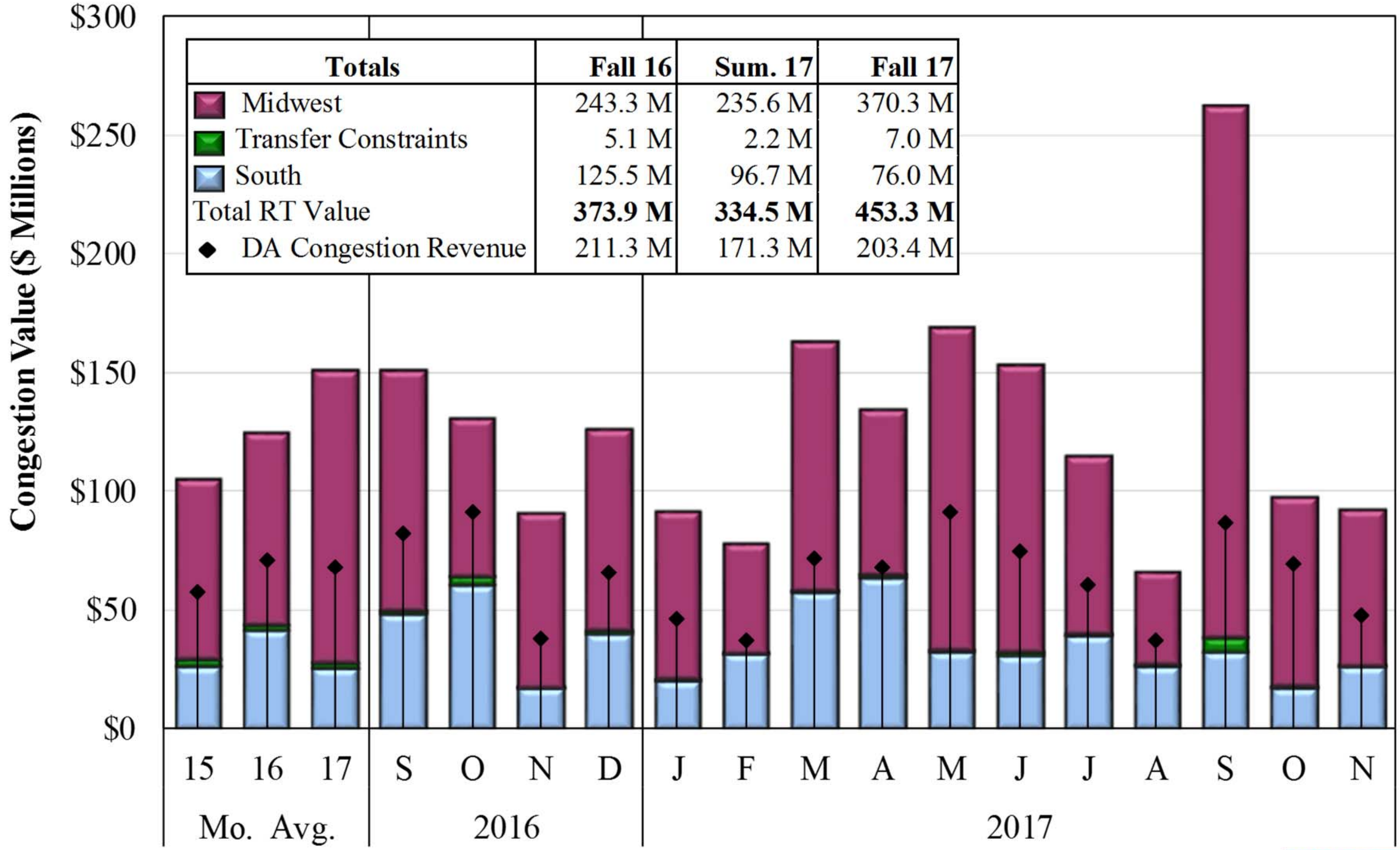
Note: Midwest degree day calculations include four representative cities in the Midwest: Indianapolis, Detroit, Milwaukee and Minneapolis. The South region includes Little Rock and New Orleans.

Day-Ahead Congestion, Balancing Congestion and FTR Underfunding, 2016 – 2017

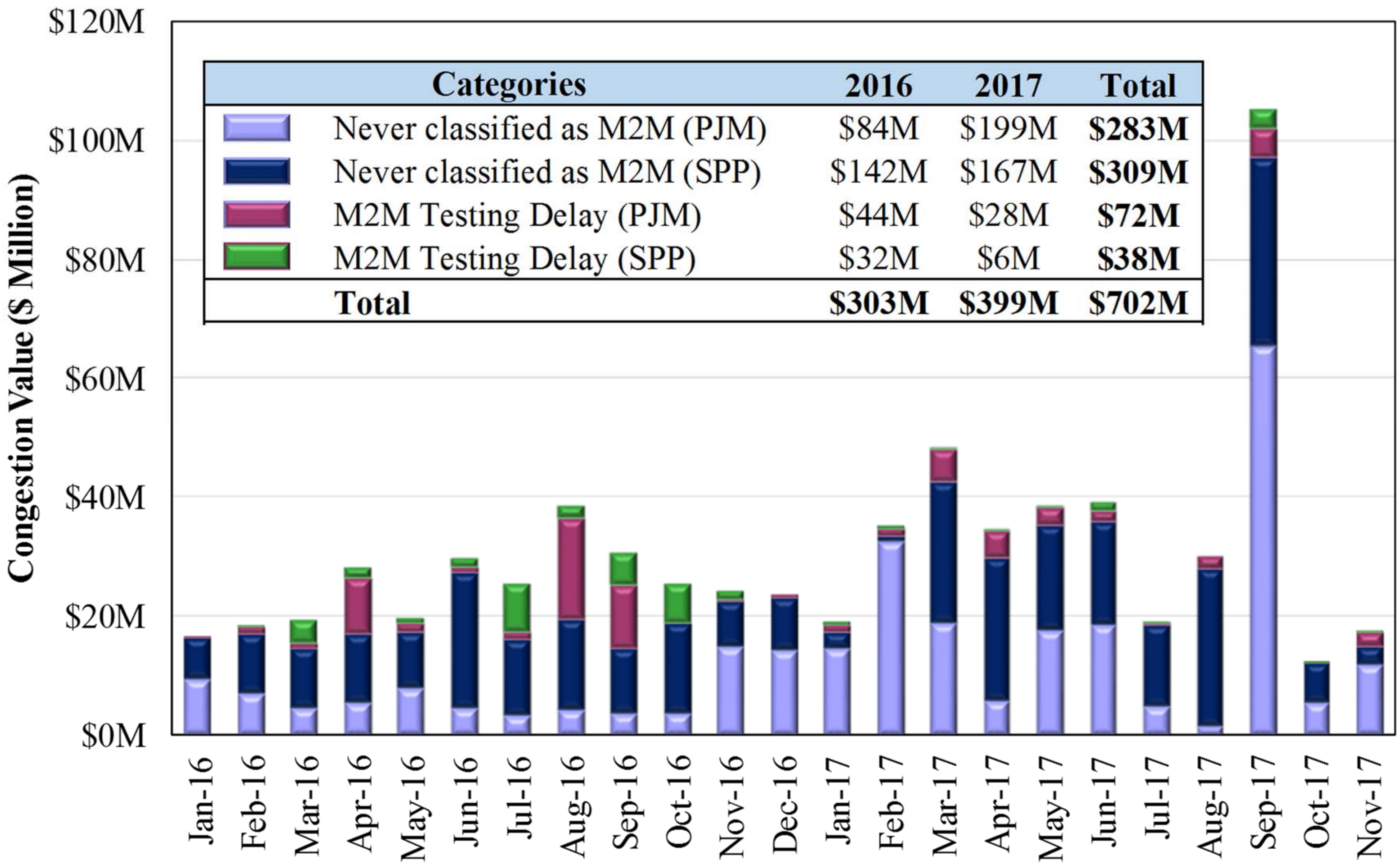


Fall Totals	2016	2017
Balancing Congestion Revenue	($8.8 M)	($12.7 M)
DA Congestion Revenues	$211.3 M	$203.4 M
FTR Surplus (Shortfall)	$1.6 M	$0.9 M
FTR Funding (%)	100.4%	100.2%

Value of Real-Time Congestion
Fall 2016 – 2017



Market-to-Market Testing and Activation Delay Congestion Costs 2016 - 2017



Categories	2016	2017	Total
Never classified as M2M (PJM)	$84M	$199M	**$283M**
Never classified as M2M (SPP)	$142M	$167M	**$309M**
M2M Testing Delay (PJM)	$44M	$28M	**$72M**
M2M Testing Delay (SPP)	$32M	$6M	**$38M**
Total	**$303M**	**$399M**	**$702M**

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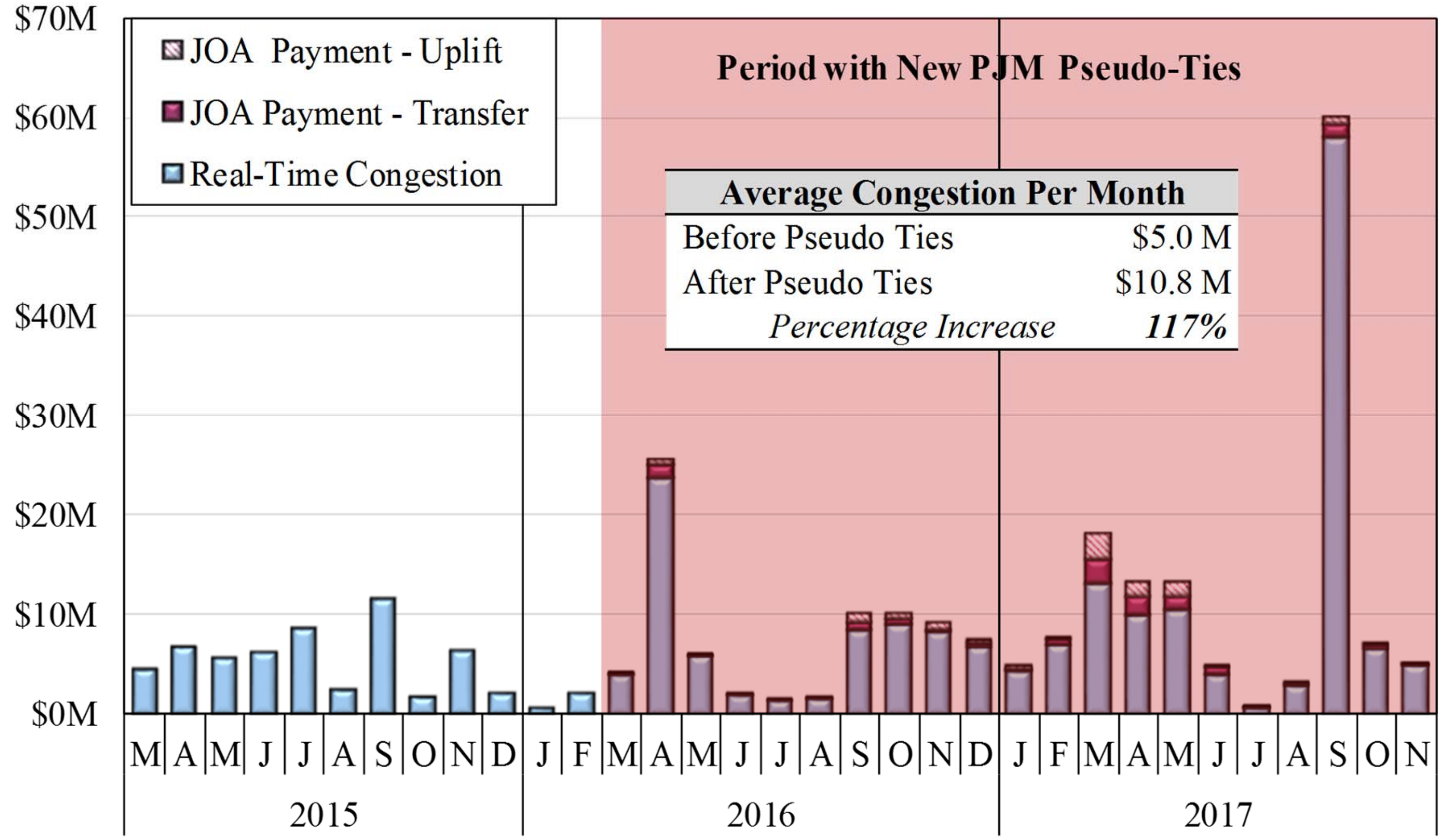
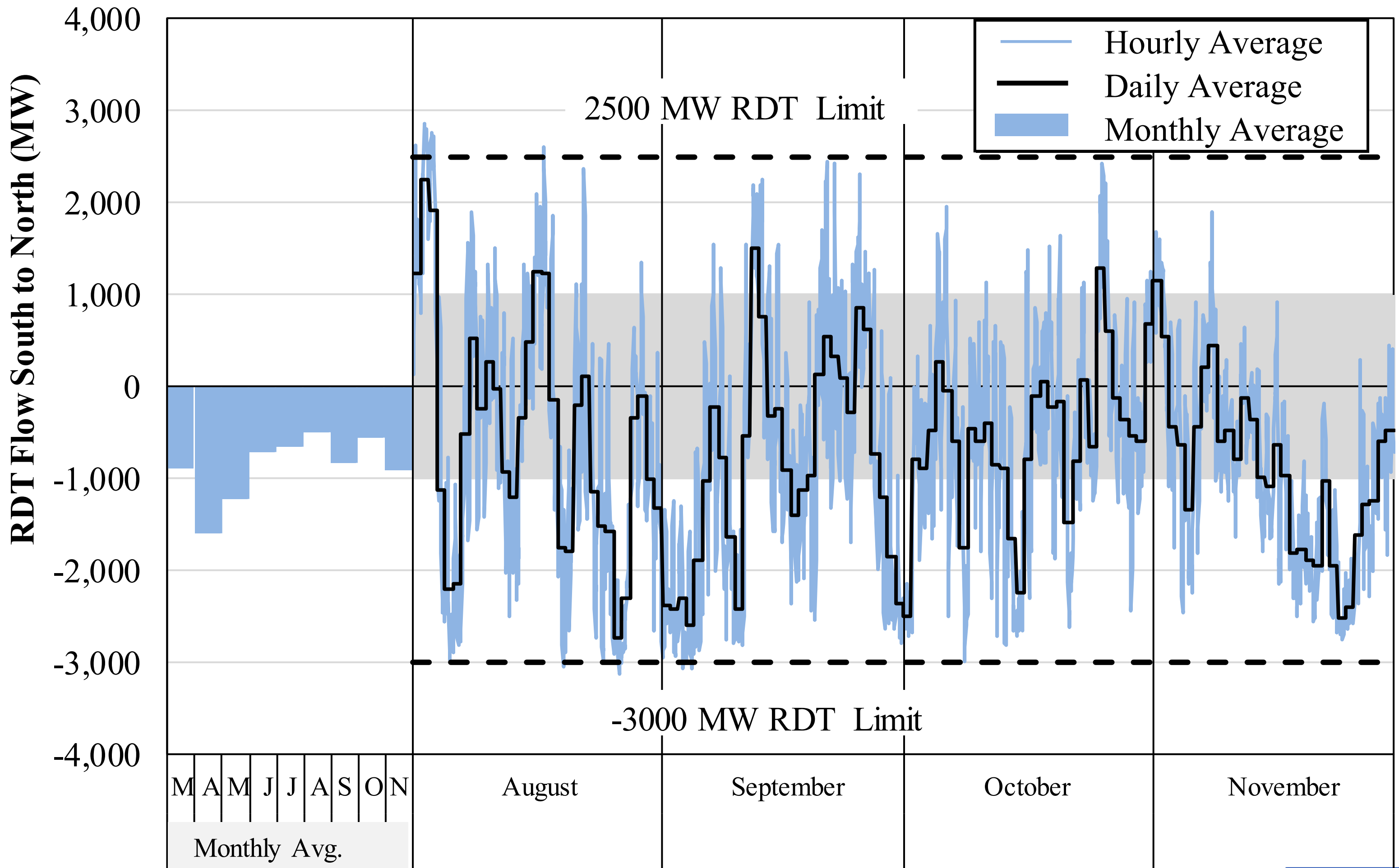
MISO Congestion Value and JOA Settlement Constraints Impacted by Pseudo-Ties

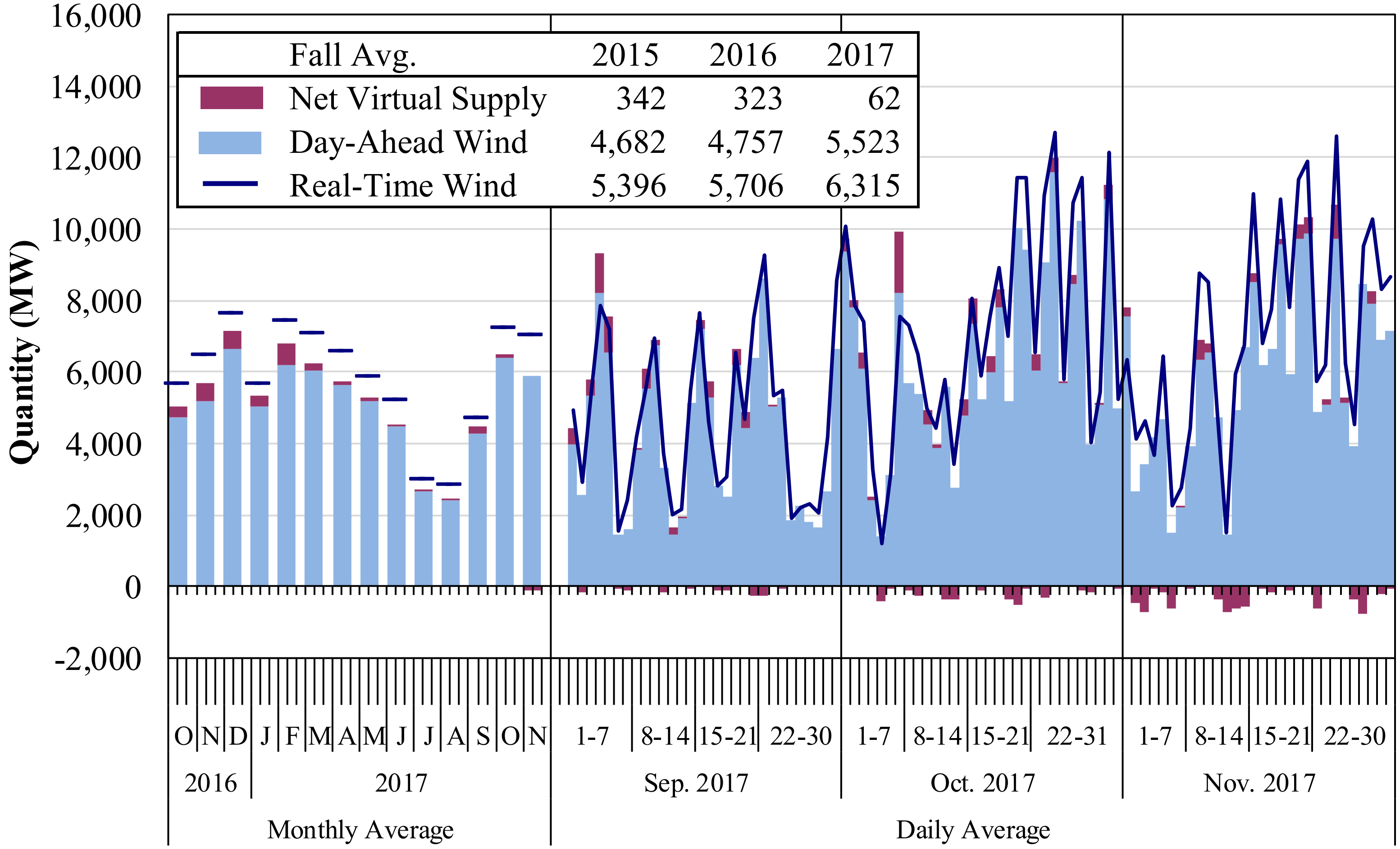


Average Congestion Per Month	
Before Pseudo Ties	$5.0 M
After Pseudo Ties	$10.8 M
Percentage Increase	***117%***

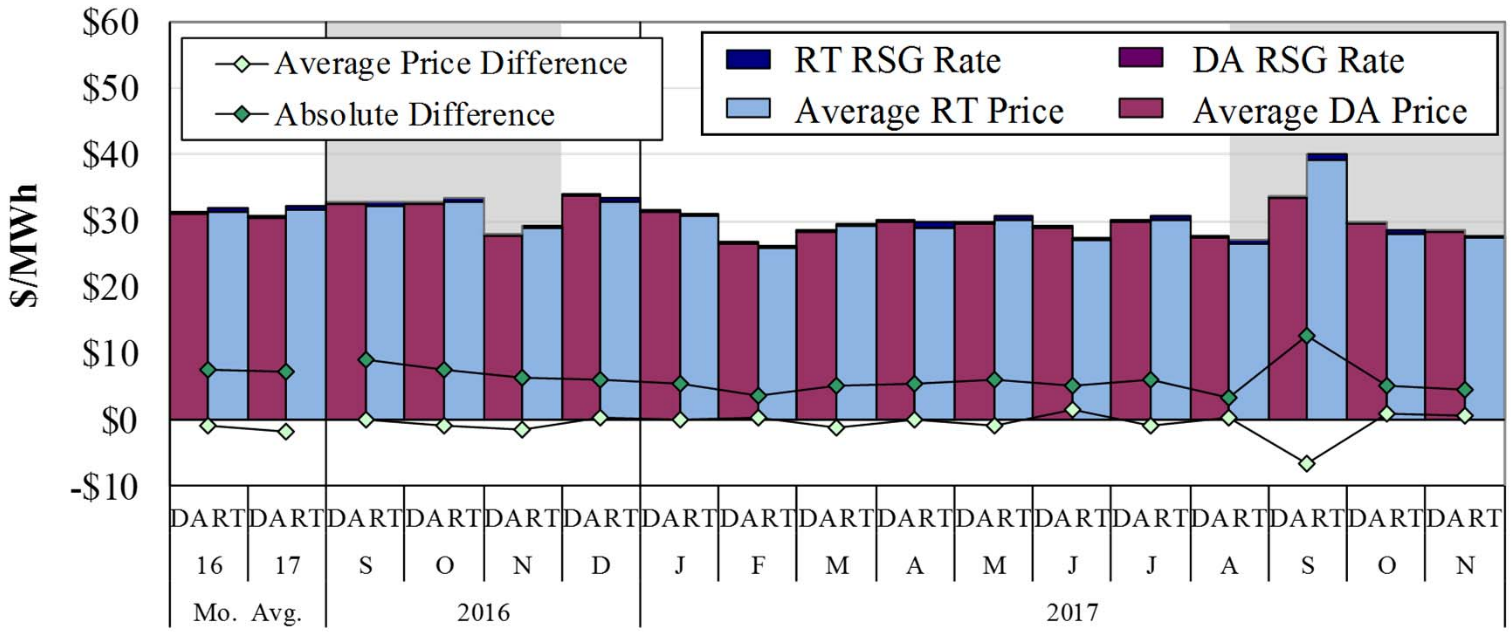
Real-Time Hourly Inter-Regional Flows 2016 - 2017



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



Day-Ahead and Real-Time Price Convergence Fall 2016 – 2017

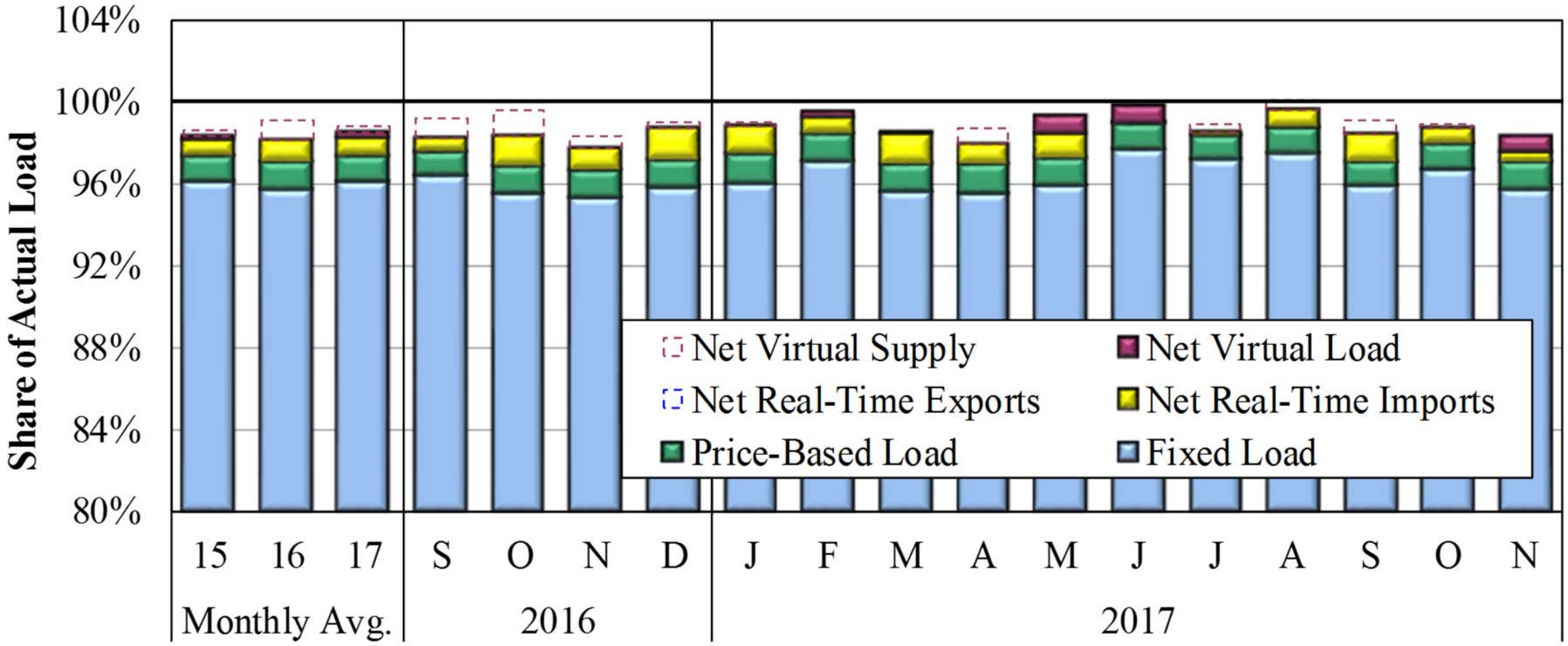


Average DA-RT Price Difference Including RSG (% of Real-Time Price)

Indiana Hub	-2	-4	0	-2	-5	1	0	1	-4	0	-3	5	-3	1	-16	3	2
Michigan Hub	0	-4	-2	4	-1	2	1	1	-6	-1	-1	0	-3	1	-11	-1	0
Minnesota Hub	-1	-5	-2	-2	2	-6	3	3	-1	-5	1	5	-7	2	-7	-10	3
WUMS Area	2	-3	1	4	1	-6	-1	-2	3	-1	3	3	-8	3	-11	0	0
Arkansas Hub	-4	0	-3	-2	-6	0	1	3	-3	0	2	5	-7	2	-2	5	-3
Texas Hub	1	1	2	3	-1	2	-2	3	-2	3	4	-1	-1	3	1	8	-6
Louisiana Hub	-1	-9	-3	1	0	1	1	-2*	2	-4	3	-1	-9	-6	-1	7	-4

* Excluding Feb 7, 2017.

Day-Ahead Peak Hour Load Scheduling
Fall 2016 – 2017



Share of Actual Load (%)

	15	16	17	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N
All Hours	98.2	98.2	98.8	98.3	98.5	97.8	98.9	99.2	98.7	99.1	98.5	99.3	100.2	99.6	99.9	98.9	98.8	98.6
Peak Hours Midwest	98.3	97.7	98.4	97.6	97.6	98.0	97.8	98.0	98.3	97.5	97.0	97.8	99.5	97.3	98.0	98.9	97.6	98.6
Peak Hours South	99.2	99.9	100.6	99.6	100.6	99.3	103.1	103.1	106.4	102.9	100.3	102.3	103.2	102.2	102.9	97.4	103.0	101.4

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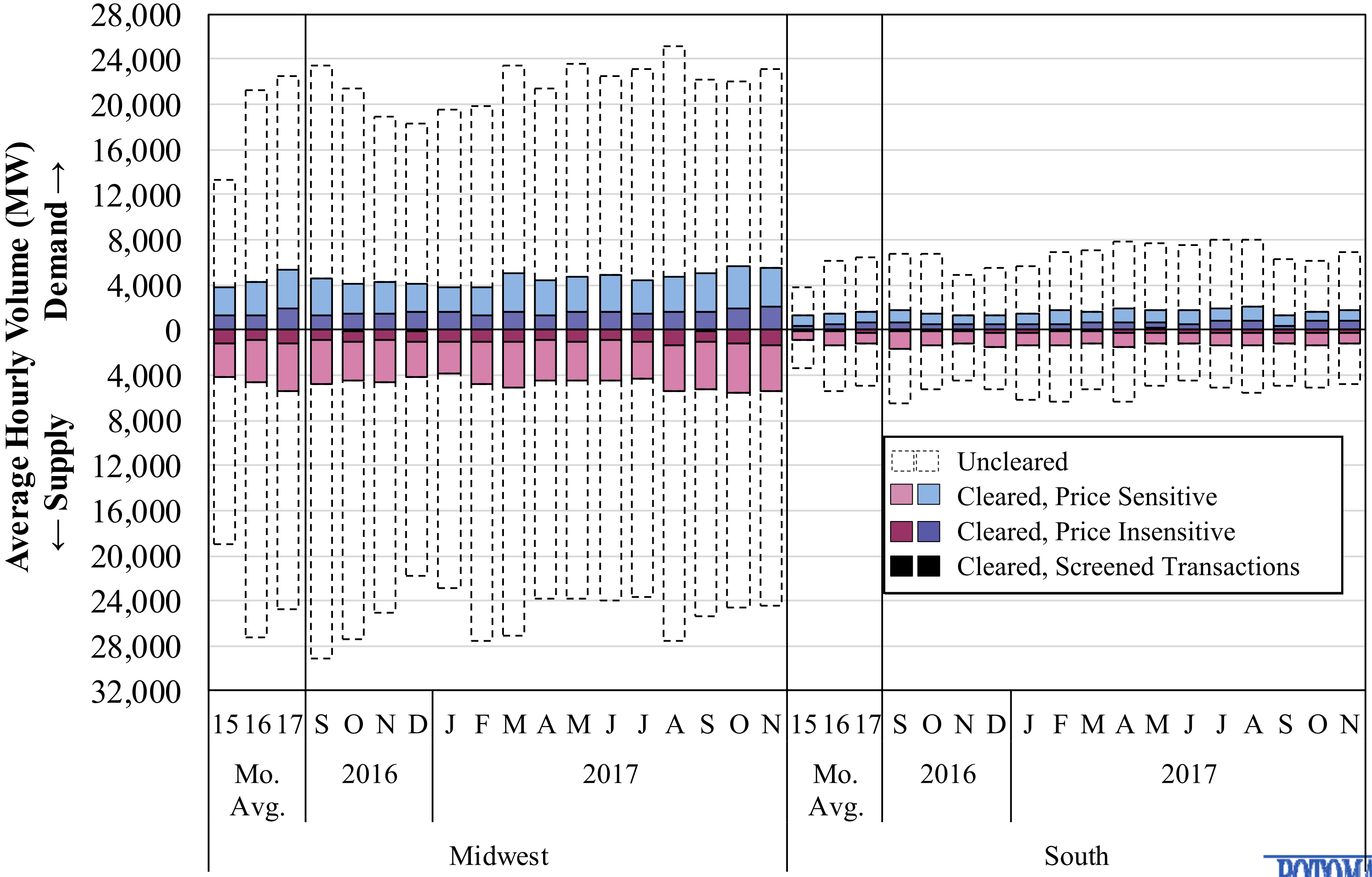
Virtual Load and Supply
Fall 2016 – 2017



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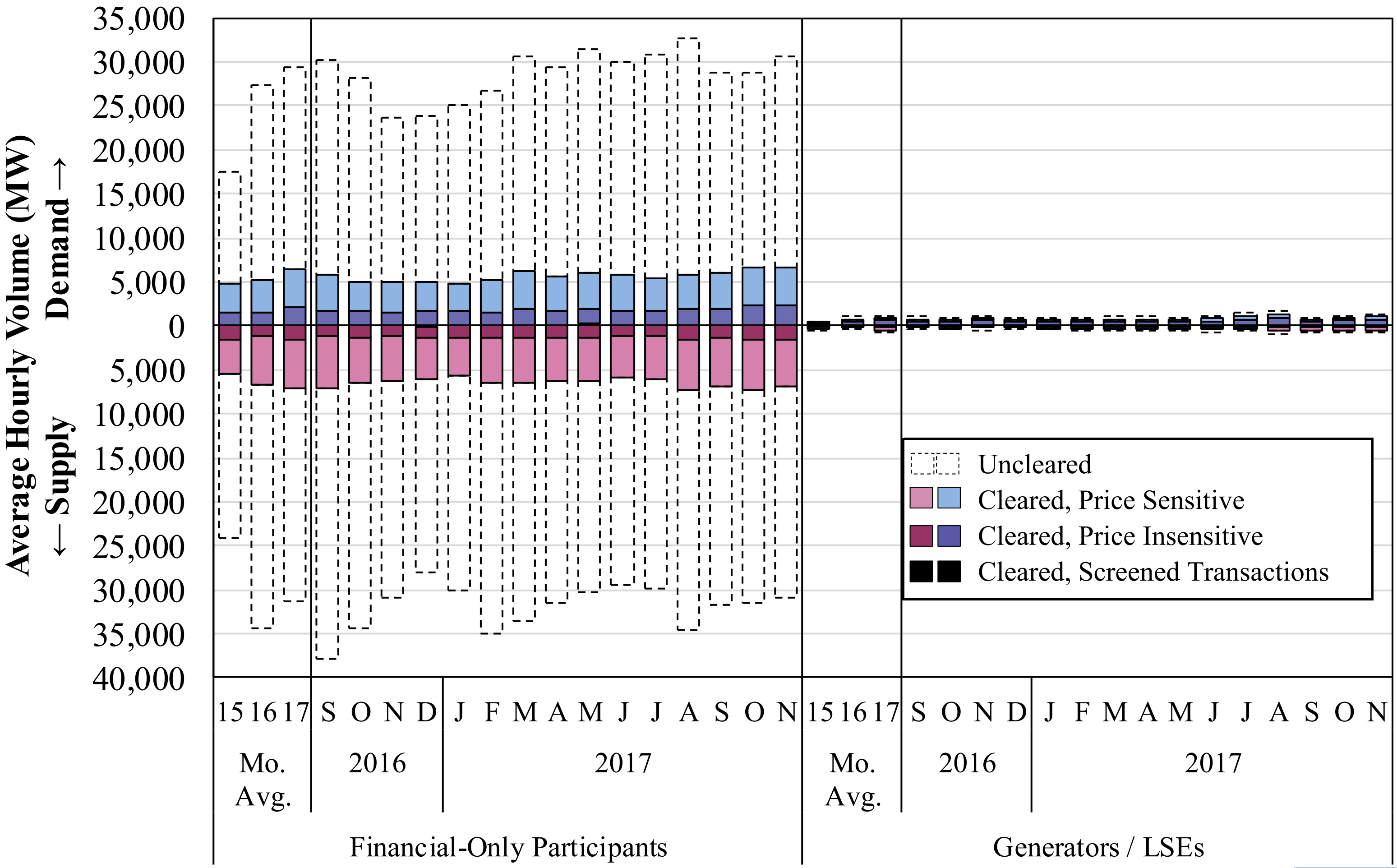
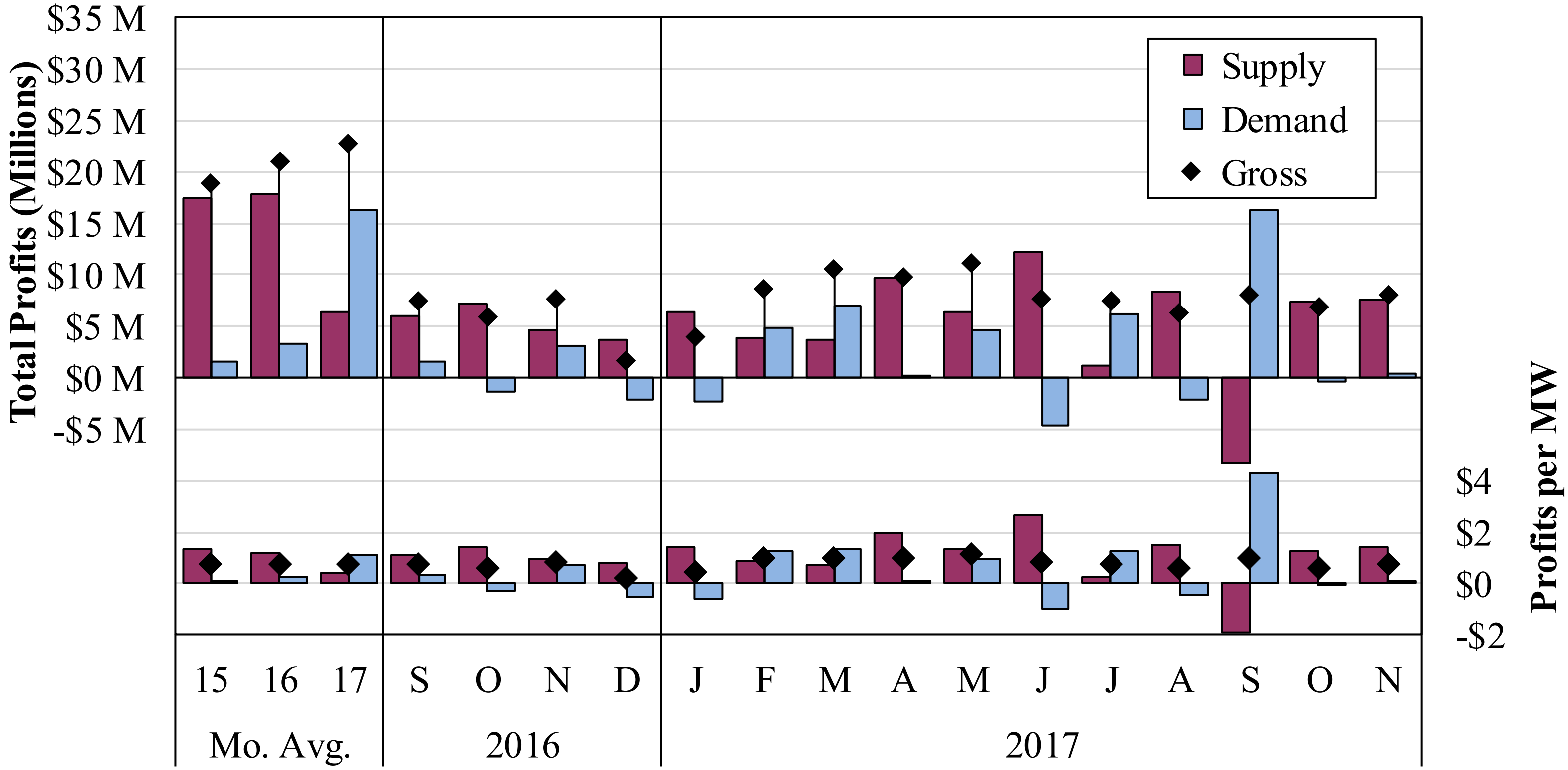
Virtual Load and Supply by Participant Type
Fall 2016 – 2017



Virtual Profitability
Fall 2016 – 2017



Percent Screened

Demand	1.2	1.2	1.2	1.2	2.1	0.4	1.1	0.9	1.3	1.4	2.1	2.8	1.4	1.2	0.5	1.6	1.4	0.7
Supply	0.5	0.4	0.4	0.3	0.6	0.4	0.6	0.3	0.2	0.4	0.4	0.5	0.3	0.1	0.2	0.5	0.4	0.2
Total	0.8	0.8	0.8	0.7	1.2	0.4	0.8	0.6	0.7	0.9	1.2	1.6	0.8	0.7	0.3	1.0	0.9	0.5

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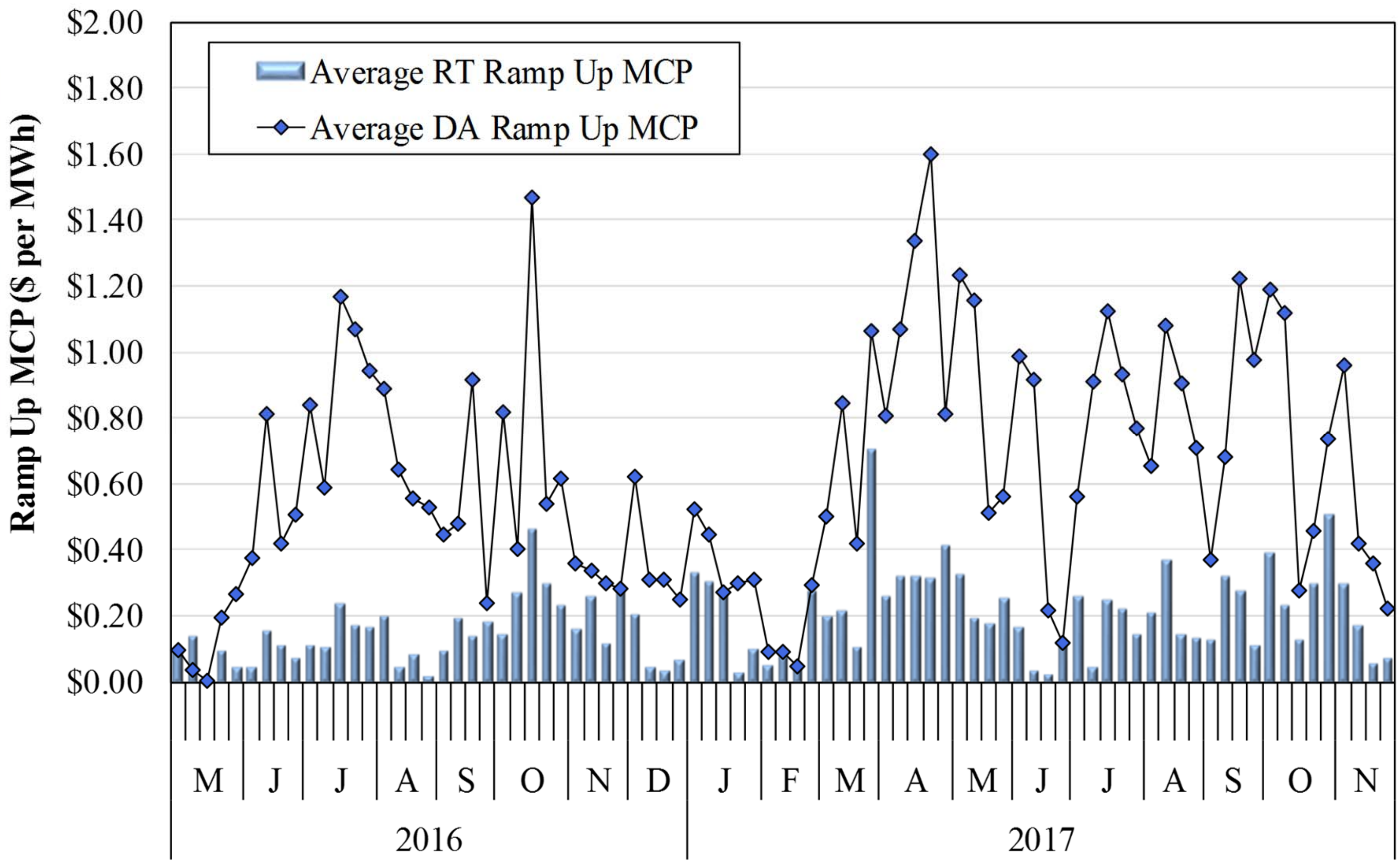
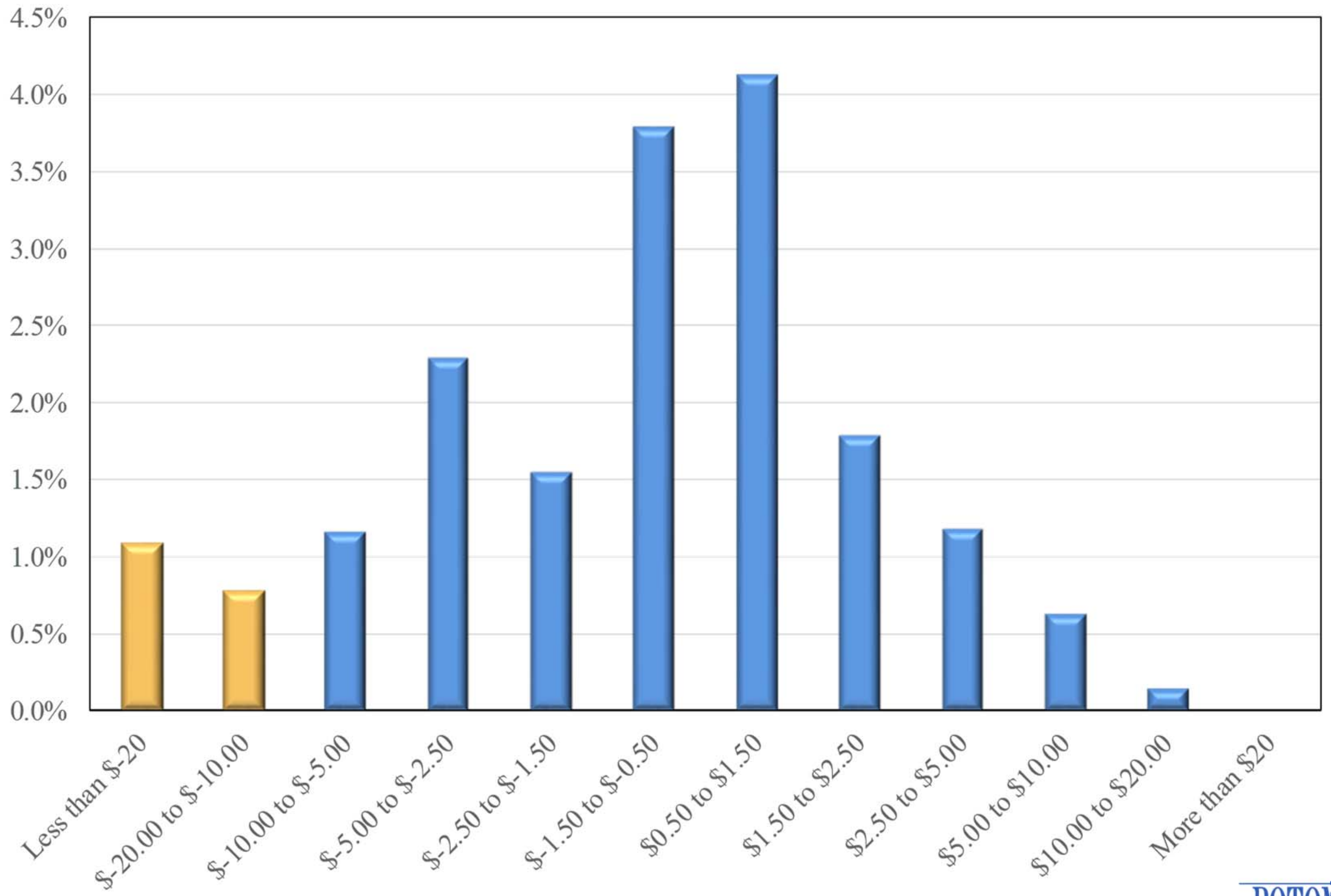
Day-Ahead and Real-Time Ramp Up Price
2016 – 2017



Interface Pricing with PJM (Common Interface) June 1 to November 15



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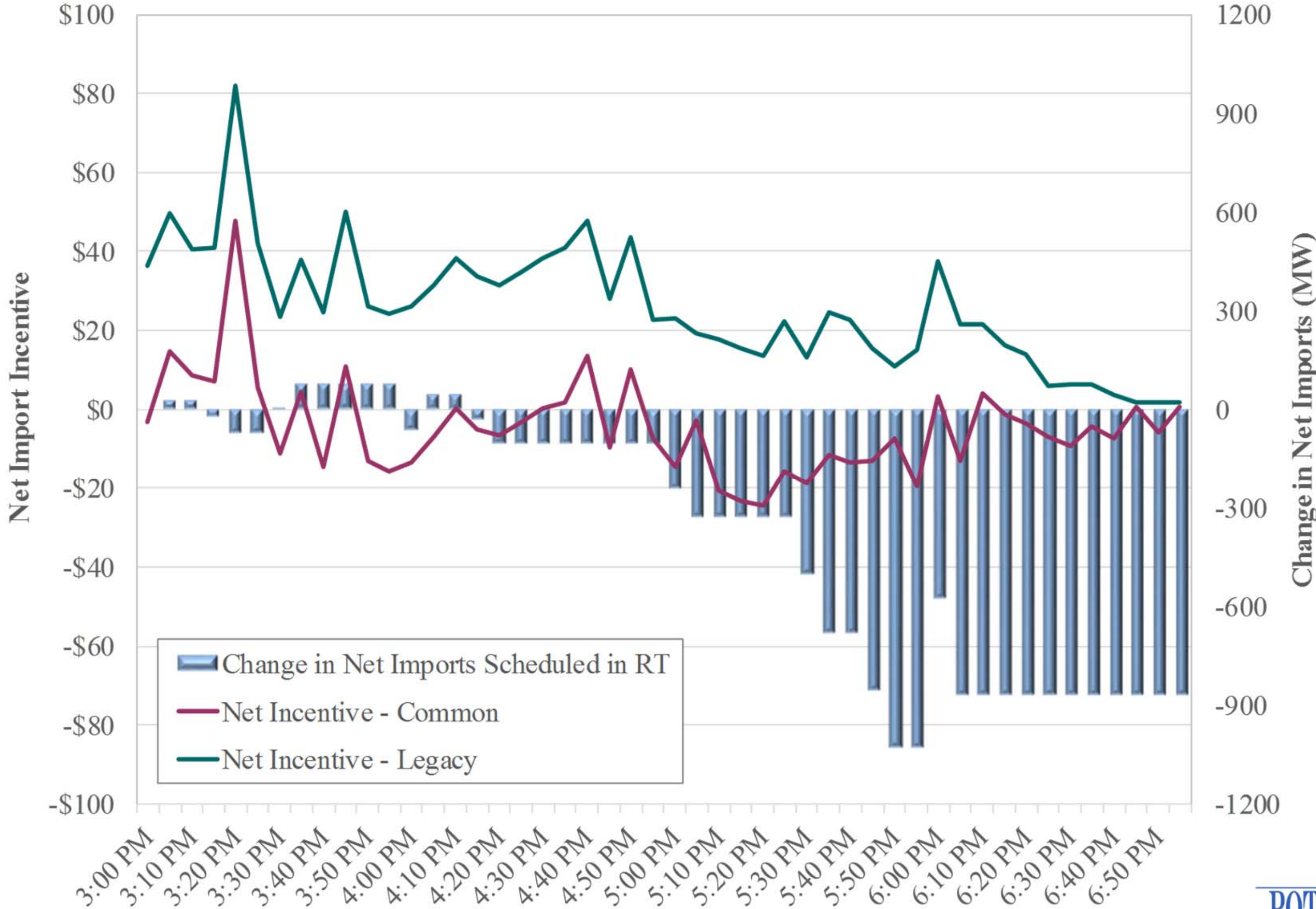
Interchange Incentive Problems Under the Common Interface



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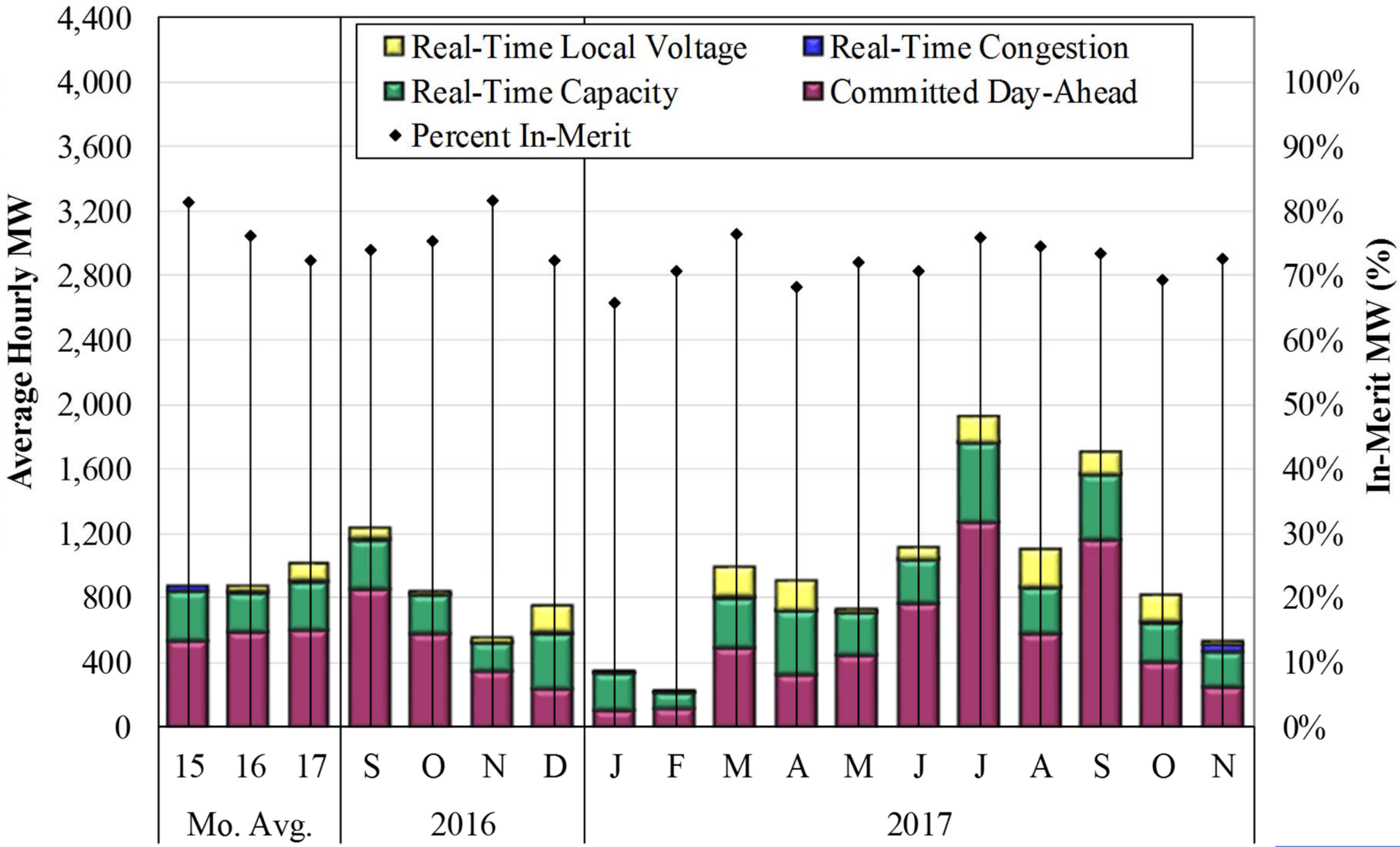
Peaking Resource Dispatch
2016 – 2017



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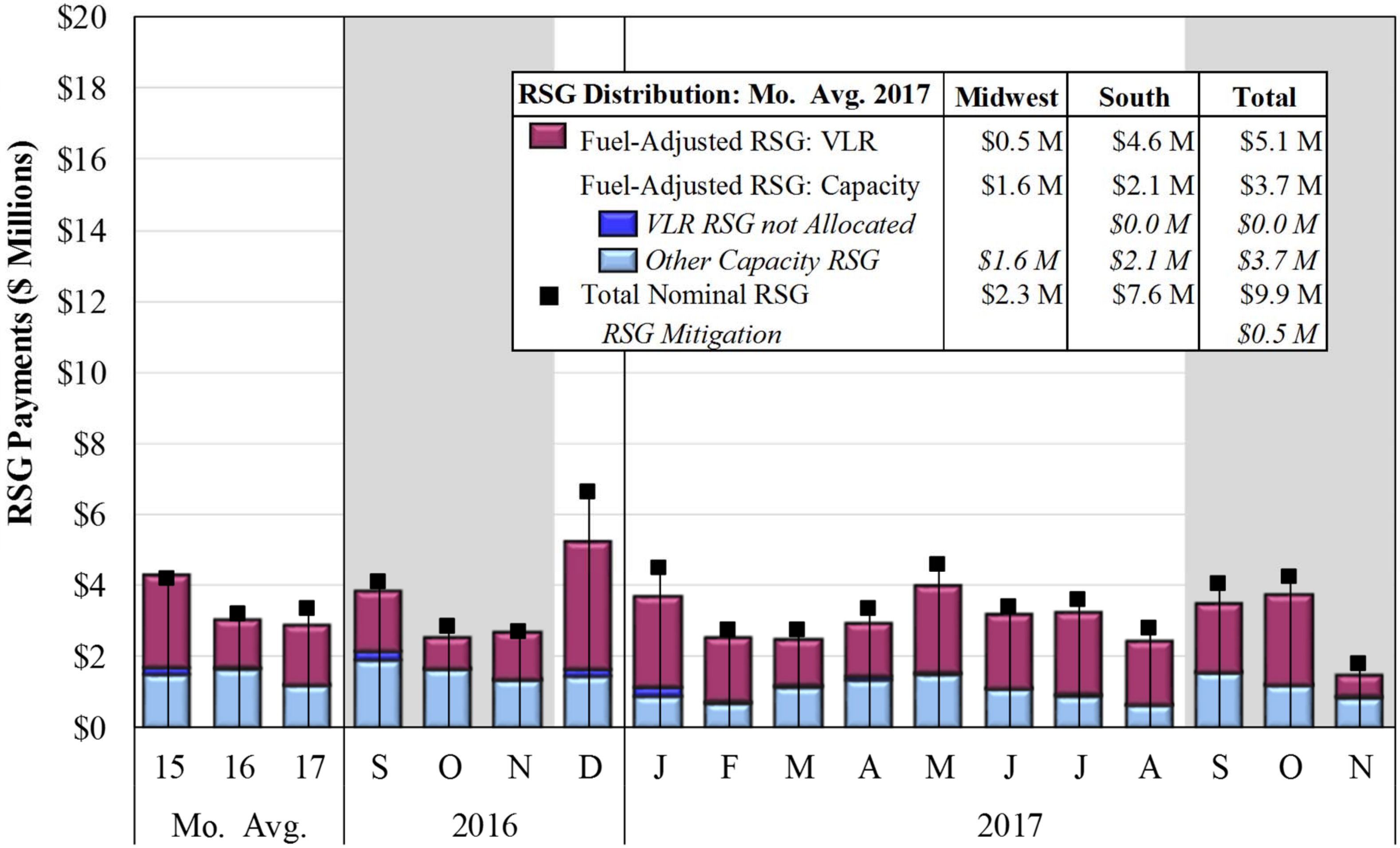
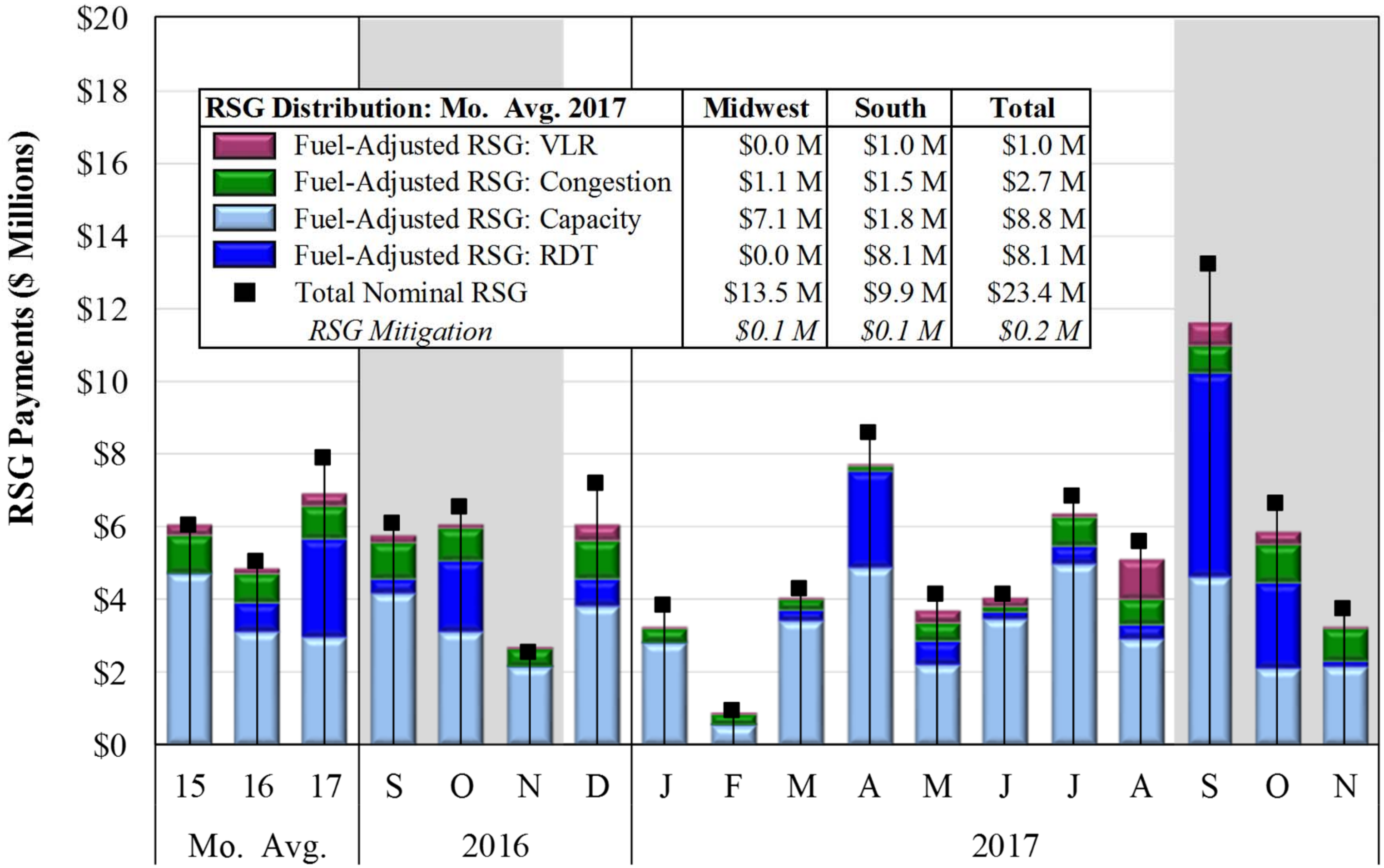
Day-Ahead RSG Payments 2015 – 2017

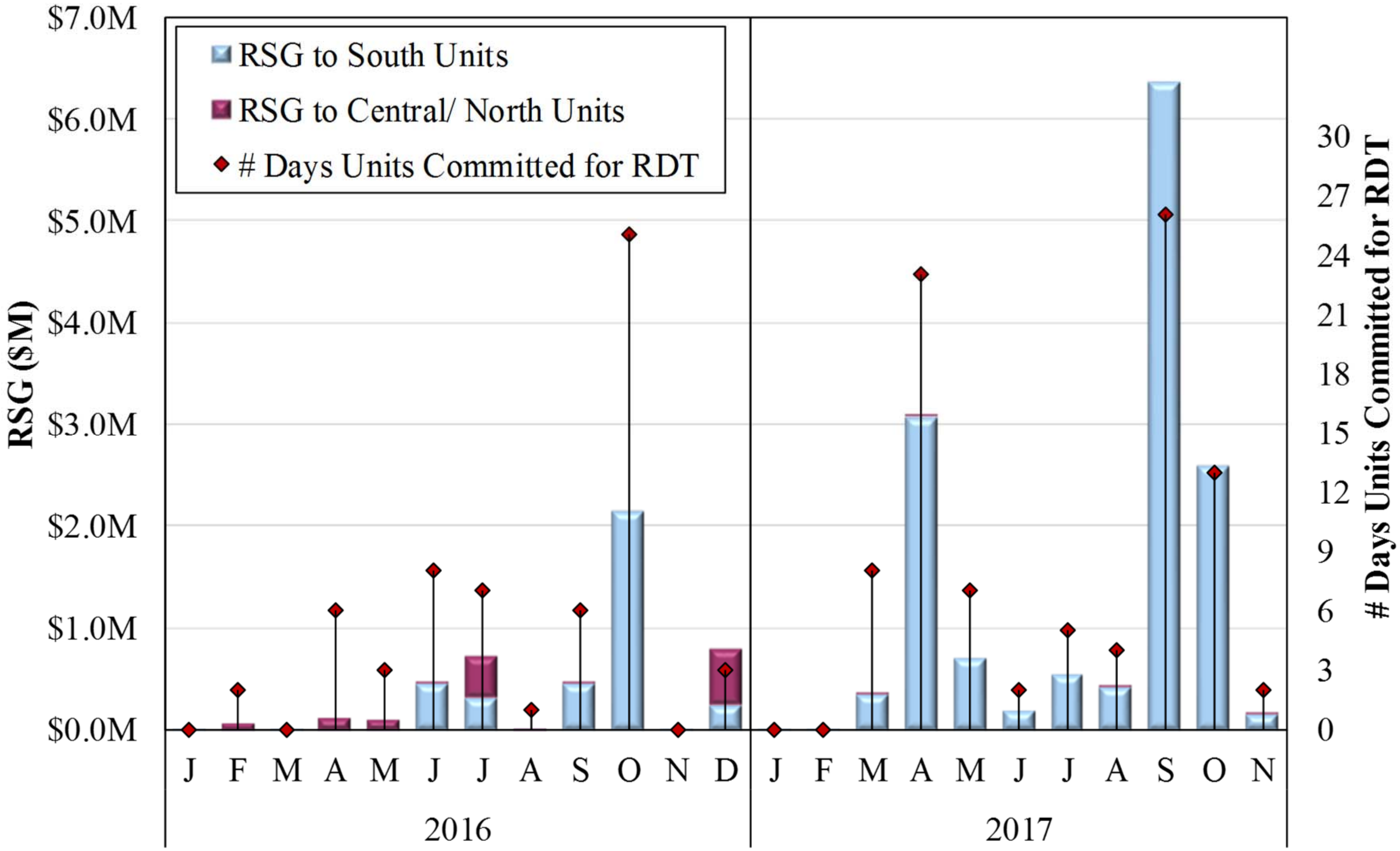


RSG Distribution: Mo. Avg. 2017	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$0.5 M	$4.6 M	$5.1 M
Fuel-Adjusted RSG: Capacity	$1.6 M	$2.1 M	$3.7 M
VLR RSG not Allocated		*$0.0 M*	*$0.0 M*
Other Capacity RSG	*$1.6 M*	*$2.1 M*	*$3.7 M*
Total Nominal RSG	$2.3 M	$7.6 M	$9.9 M
RSG Mitigation			*$0.5 M*

Real-Time RSG Payments
2015 – 2017



RDT Commitment RSG Payments 2016 – 2017



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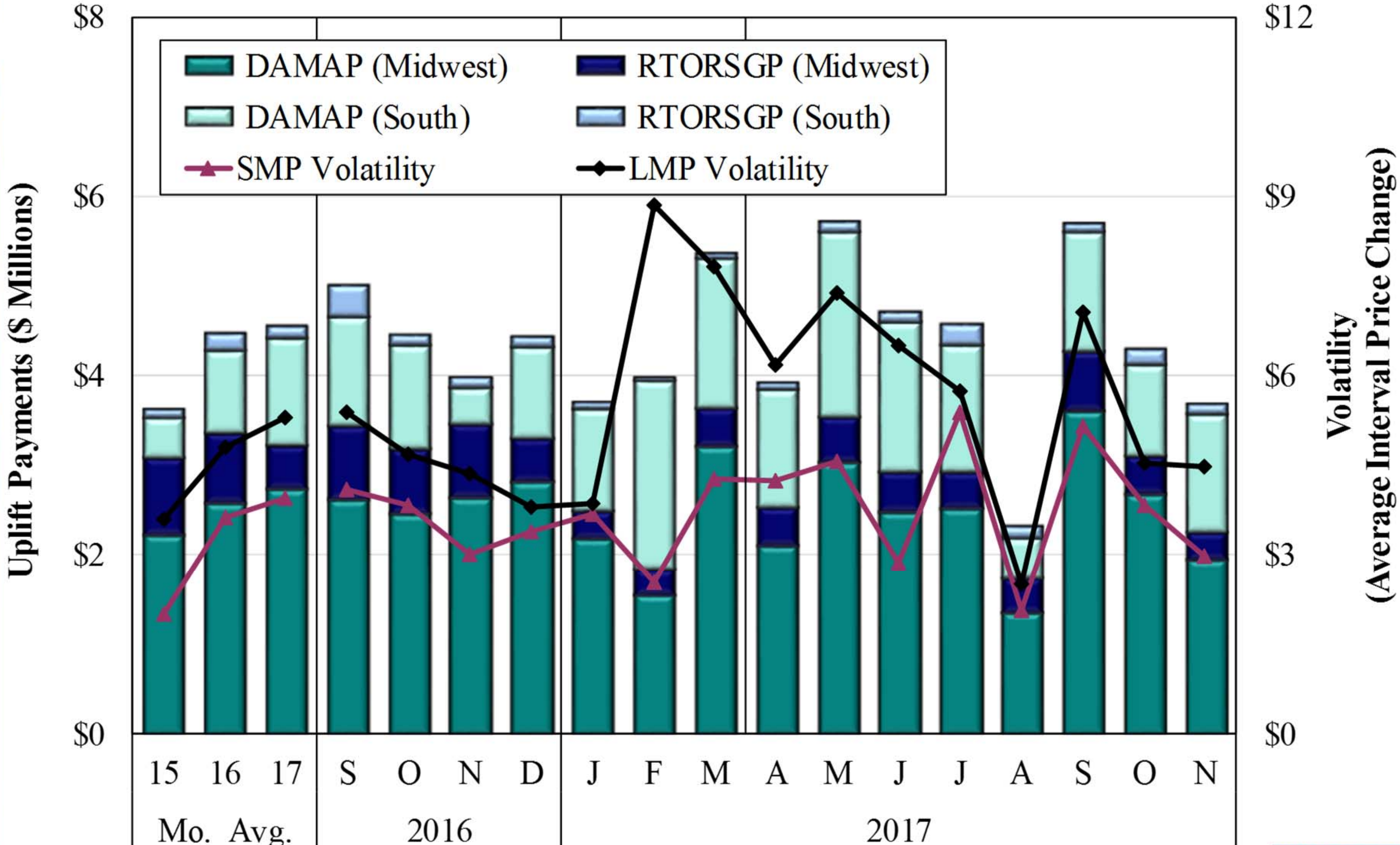
Price Volatility Make Whole Payments 2015 – 2017



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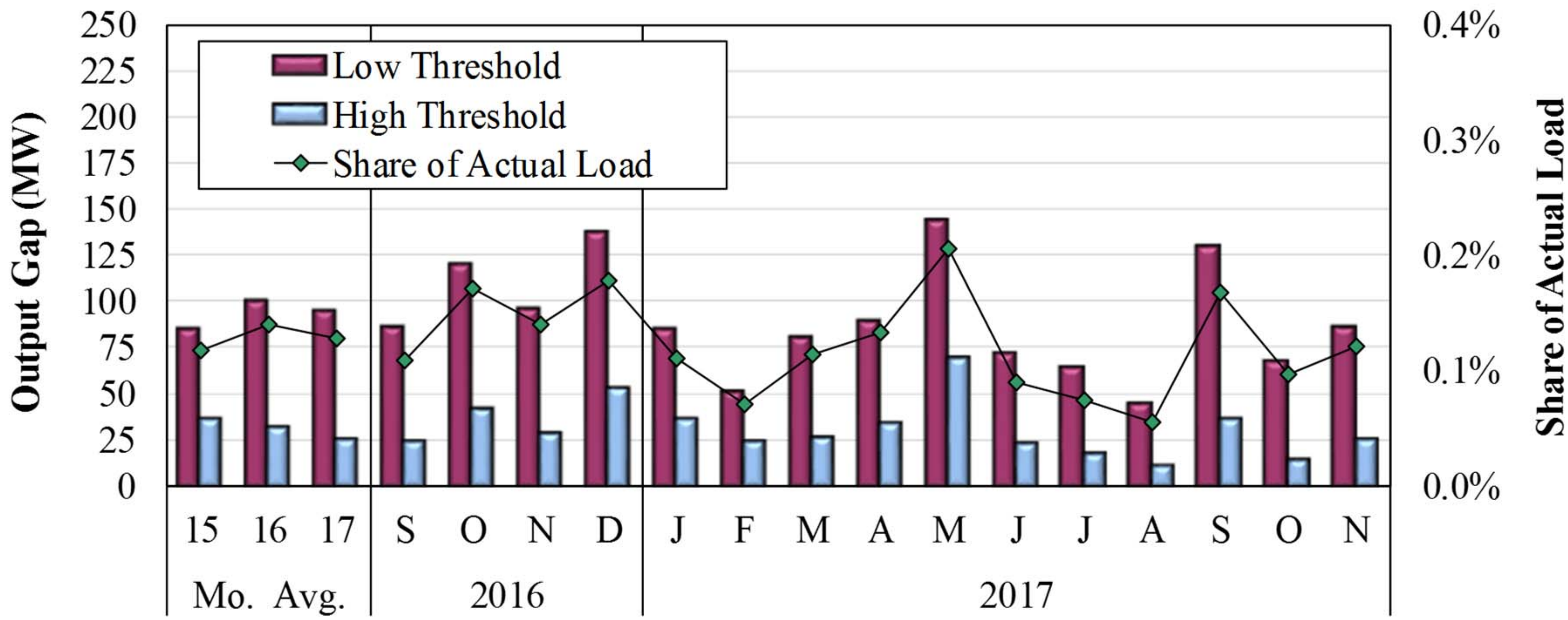
Monthly Output Gap
2015 – 2017



High Threshold Results by Unit Status (MW)

Offline	25	20	4	11	26	21	24	14	6	8	11	14	4	2	1	12	0	0
Online	12	12	22	14	16	8	29	23	19	19	24	55	20	16	10	24	15	26

Low Threshold Results by Unit Status (MW)

Offline	30	22	5	13	30	21	25	14	6	8	11	14	4	2	2	16	0	0
Online	55	79	89	73	89	75	113	72	46	73	79	130	69	63	44	114	68	86

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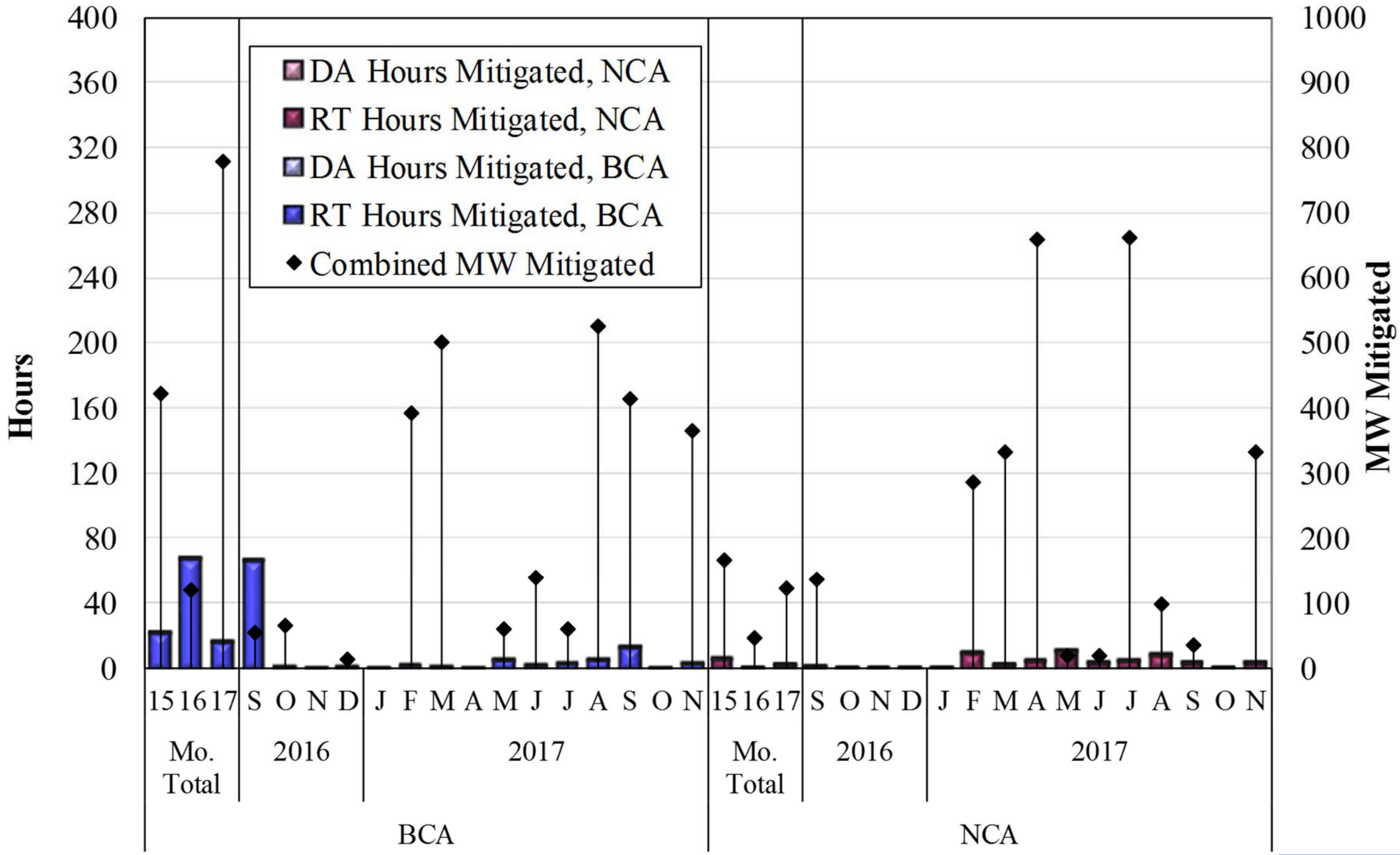
Day-Ahead And Real-Time Energy Mitigation 2016 – 2017



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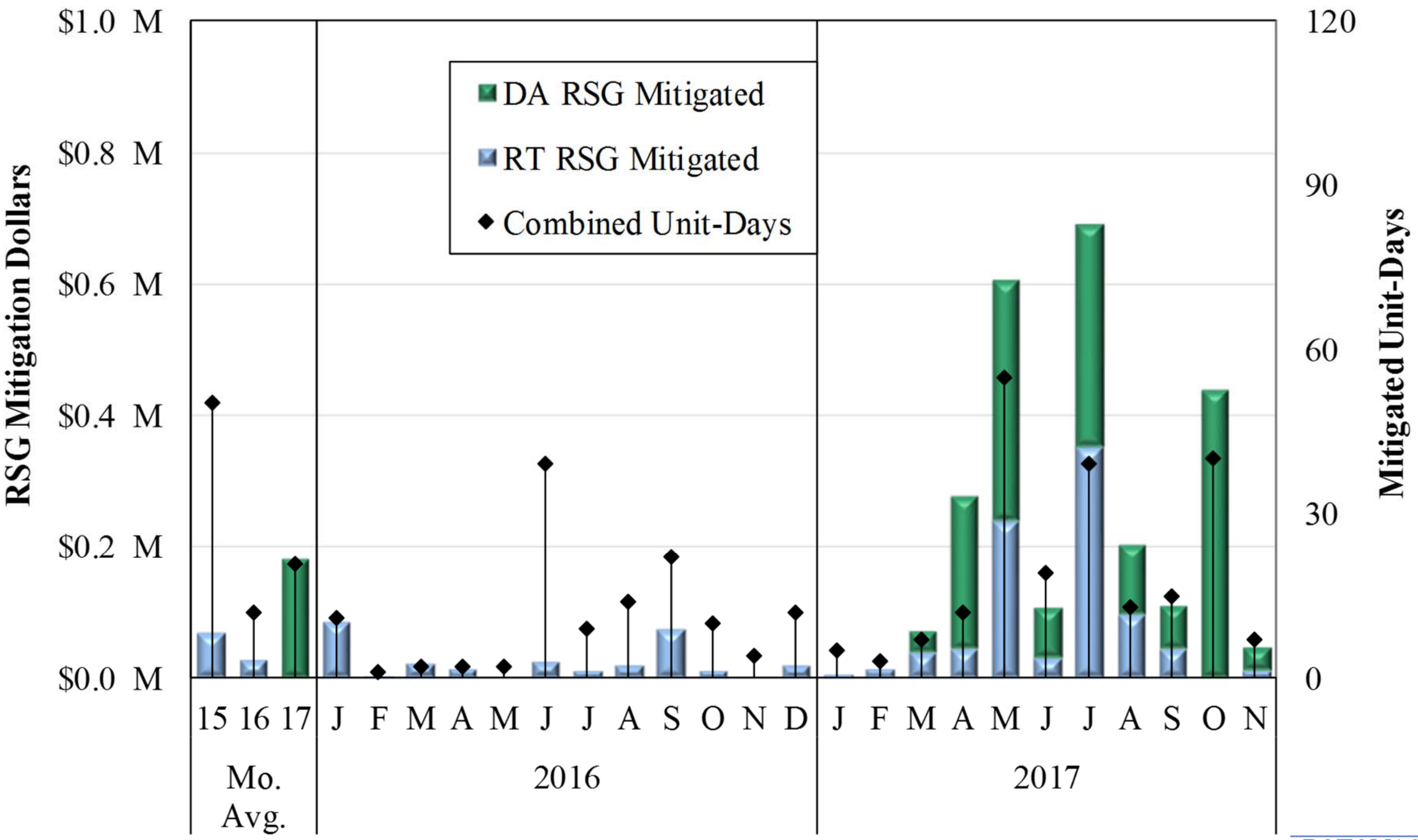
Day-Ahead and Real-Time RSG Mitigation 2015 – 2017



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List of Acronyms

- AMP Automated Mitigation Procedures
- BCA Broad Constrained Area
- CDD Cooling Degree Days
- CMC Constraint Management Charge
- 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
- TLR Transmission Line Loading
- Relief
- TCDC Transmission Constraint Demand Curve
- VLR Voltage and Local Reliability
- WUMS Wisconsin Upper Michigan System