Quarterly Report on the New York ISO Electricity Markets First Quarter of 2018

David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.
Jie Chen, Ph.D.

Potomac Economics
Market Monitoring Unit

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Market Highlights:
Executive Summary

- All-in prices rose 46 to 63 percent from the first quarter of 2017 because very cold weather led to high loads and natural gas prices.
- During the cold spell from January 1-8, LBMPs averaged $115 to $187/MWh.
  - ✓ Oil-fired generation peaked at 8.2 GW when it accounted for 64 percent of all generation in East NY.
- The Central East Interface accounted for most (54 percent) of the congestion as a result of west-to-east congestion on the natural gas pipeline system.
- NYC congestion increased from previous years primarily because transmission outages and the expiration of the ConEd-PSEG wheel reduced imports to the city.
  - ✓ Large amounts of capacity (570 MW on average) were committed out-of-market to maintain adequate operating reserves throughout New York City.
- The M2M congestion management process continues to be used sparingly—there was limited use of the NYISO-PJM PAR-controlled lines to manage congestion.
- 115 kV congestion occurred on 46 days in West Upstate NY, generally limiting Ontario imports and hydro generation.
  - ✓ The only interfaces constrained more often were Central East, Upstate-to-NYC, and Upstate-to-Long Island.

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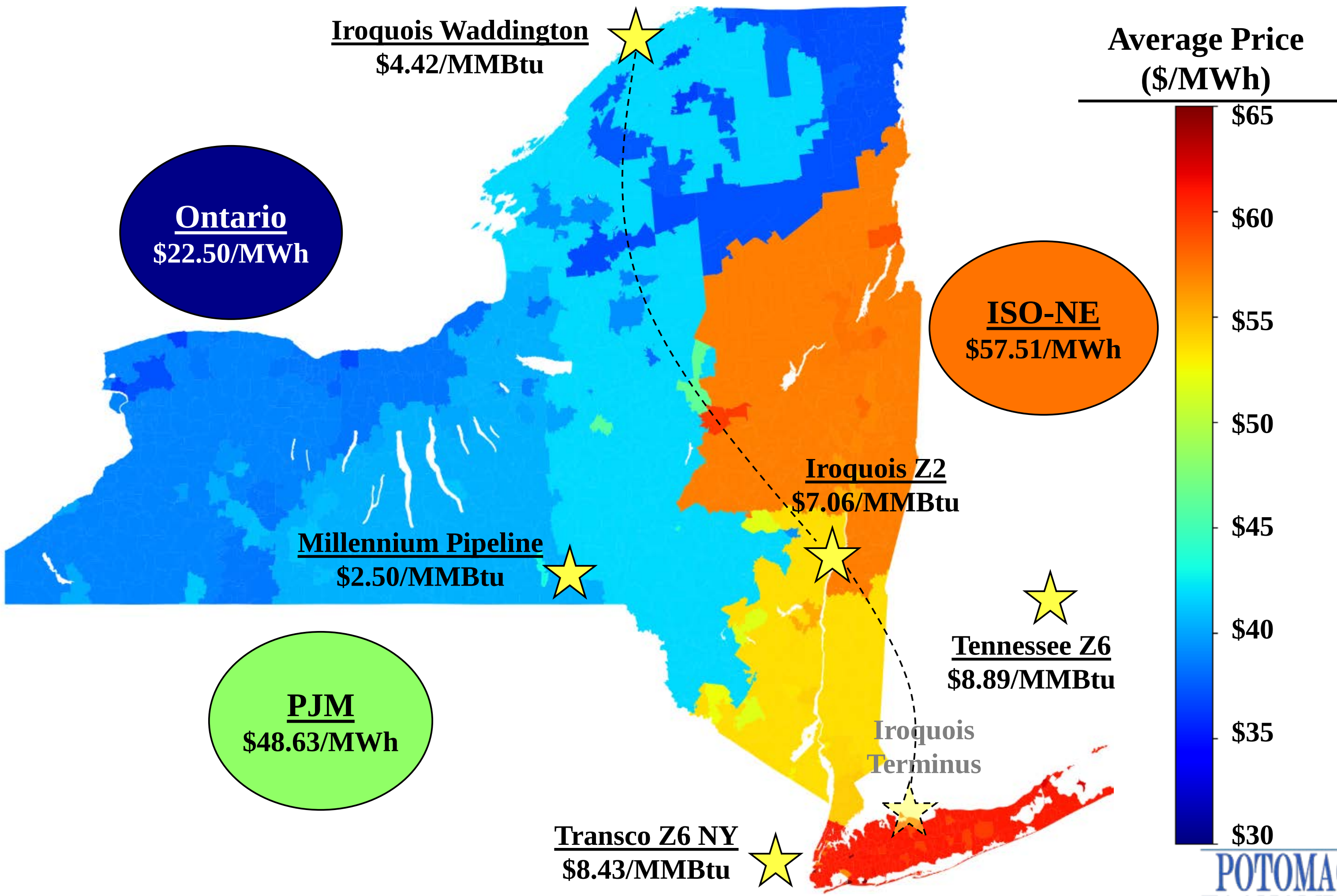
Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the first quarter of 2018.
  - ✓ Variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
  - ✓ The amount of output gap (slide 55) and unoffered economic capacity (slide 56) remained modest and was reasonably consistent with expectations for a competitive market.
- This quarter was characterized by extreme cold weather conditions from January 1st to 8th (the "*Bomb Cyclone*", this cold spell started in late December 2017).
  - ✓ This cold spell led to substantially elevated load levels and natural gas prices, and resultant high energy and reserve costs during this period.
    - – This period had a large effect on year-over-year changes in prices, congestion values, and uplift costs (which are discussed later).
- Average all-in prices (slide 18) ranged from roughly $39/MWh in the North Zone to $71/MWh in New York City in the first quarter of 2018.
  - ✓ All-in prices rose in all regions from a year ago, from 46 percent in the West Zone to 63 percent in Long Island, driven primarily by higher energy prices.

Market Highlights:
Summary of Energy Market Outcomes

- Energy prices rose 54 to 75 percent (slides 23-24) across the state from the first quarter of 2017, driven primarily by higher natural gas prices.
  - ✓ Natural gas prices rose 75 to 149 percent from a year ago in East NY (slide 20).
    - – Prices were particularly high in the first eight days of January because of extreme cold weather conditions.
    - – Transco Zone 6 (NY) index prices averaged nearly \$52/MMbtu in the first 8 days, and reached an all-time high of \$141/MMbtu on the 5th.
    - – Oil-fired generation rose substantially and was frequently on the margin in the first 8 days (slides 21-22) and oil prices also rose more than 20 percent from a year earlier.
  - ✓ Average load rose 3 percent and peak load rose 7 percent from a year ago (slide 19) largely driven by the cold spell, contributing to the increase in LBMPs as well.
    - – Load peaked at 25.1 GW on the 5th, approximately 660 MW below the all-time winter peak set in January 2014.
  - ✓ Average nuclear generation increased by roughly 520 MW (slide 21) because of fewer outages and deratings, which partly offset the increase in LBMPs.

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Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- DA congestion revenues totaled $189 million, up 133 percent from a year ago, largely because of increased gas prices. (slide 42)
  - ✓ $56 million (or 29 percent) of congestion revenues accrued in the first 8 days with particularly high natural gas prices.
- The Central-East interface accounted for $101 million (or 54 percent) of day-ahead congestion revenues, up 60 percent from a year earlier, driven primarily by larger spreads in gas prices between West NY and East NY. (slide 43)
  - ✓ 38 percent of this congestion occurred in the first 8 days.
  - ✓ Despite higher overall congestion revenues, the frequency of Central-East congestion fell 11 percent from a year ago, mainly because of fewer costly transmission outages as seen in the first quarter of 2017.
    - – The Central-East interface contributed $0.8 million of day-ahead congestion *surpluses* (slide 44) in the first quarter of 2018 (compared to nearly $16 million of *shortfalls* in the first quarter of 2017).
  - ✓ Lower exports to New England because of interface deratings also contributed to less frequent congestion on the Central-East interface. (slide 38)

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Market Highlights:
Congestion Patterns, Revenues, and Shortfalls (cont.)

- NYC lines accounted for the second largest share (22 percent) of day-ahead congestion in the first quarter of 2018. (slide 43)
  - ✓ Congestion in New York City has increased in recent quarters as:
    - The ConEd/PSEG Wheeling Agreement expired in May 2017; and
    - Natural gas prices rose in New York City relative to other portions of East NY.
  - ✓ More costly transmission outages were also a key driver of higher NYC congestion in the first quarter of 2018.
    - One Gowanus-Greenwood 138 kV line was OOS in most of the quarter, leading to increased congestion into the Greenwood load pocket.
    - The B & C PAR-controlled lines and the W49th St-E13th St 345 kV line were OOS in most of the quarter, and the Dunwoodie-Motthaven 345 kV line was OOS in the entire month of March, leading to higher congestion in the NYC 345 kV system.
    - These outages accounted for the majority of $16 million of day-ahead congestion shortfalls that accrued on NYC lines. (slide 44)

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Market Highlights:
Congestion Patterns, Revenues, and Shortfalls (cont.)

- Congestion across the primary NY/NE interface was unusually high this quarter.
  - ✓ The interface limit was greatly reduced (to 500~600 MW) when:
    - The New Scotland-ALPS 345 kV line was OOS from mid January to mid February;
    - The Long Mountain-Pleasant Valley 345 kV line was OOS from late February to the end of March.
  - ✓ These two outages accounted for more than $11 million of day-ahead congestion shortfalls. (slide 43)
- Although congestion on the 230+ kV system of upstate NY was not significant this quarter, actions used to manage lower-voltage network congestion were still frequent. (slide 47)
  - ✓ The costs and reliability effects of this congestion could be reduced by modeling the 115kV constraints in the day-ahead and real-time market systems.
    - The NYISO began modeling the Brownfalls-Taylorville 115 kV lines in May 2018 and plan to incorporate more 115 kV constraints by the end of this year.
  - ✓ The NYISO is also working on an initiative to improve the modeling of the Niagara plant, which is expected to help coordinate the management of 115 kV and 230 kV congestion in the West Zone.

Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments were $19 million, up 119 percent from a year ago. (slides 52-53)
  - ✓ The increase was due largely to higher fuel costs, particularly in the first 8 days of January that saw a total of $8.2 million (43 percent) BPCG uplift.
- Nearly 60 percent ($11.2 million) was paid to NYC generators, up 116 percent from the first quarter of 2017. (slide 53).
  - ✓ Increased fuel costs and reliability commitments were keys drivers. (slides 49-50)
  - ✓ Reliability commitments averaged 570 MW, up 42 percent from last year.
    - – The increase occurred primarily in March, because multiple transmission and generation maintenance outages led to increased needs in the 345 kV system and the Astoria West/Queensbridge/Vernon load pocket.
- East upstate NY accounted for more than $4 million of BPCG uplift.
  - ✓ Most of this uplift occurred in the first week of January as several Bethlehem and Empire units were DARUed for local reliability. (slide 49)
  - ✓ Bethlehem units (which accounted for 65 percent of OOM station-hours) were frequently OOMed to manage post-contingency flows on the Albany-Greenbush 115 kV lines. (slide 51)

Market Highlights:
Capacity Market

- Average spot capacity prices ranged from $0.26/kW-month in ROS to $3.21/kW-month in New York City in the first quarter of 2018. (slides 59-60)
  - ✓ In ROS, spot prices fell by 50 percent (or $0.26/kW-month) mainly because of higher awarded excess.
    - – Internal ICAP supply increased by 210 MW, reflecting new wind capacity, the return of Greenidge unit, and changes in DMNC values.
    - – However, this was offset by lower net import levels, particularly from PJM resources.
  - ✓ Spot prices in NYC cleared at the same levels as in the G-J Locality, which fell by 6 percent from a year ago.
    - – The modest decrease reflected higher DMNC values for several units in NYC and higher awarded excess.
    - – However, this was partly offset by the increase in the demand curve reference point.
  - ✓ In Long Island, spot prices rose by 34 percent primarily because of the increase in the demand curve reference point.
- IRM/LCRs rose in all regions as a result of the recent NYSRC study.
  - ✓ However, the peak load forecasts fell across regions, neutralizing the price impact from higher IRM/LCRs.

Market Highlights:
Case Study of RTC/RTD Price Divergence

- Poor RTC forecasting leads to inefficient scheduling of external transactions and peaking units.
  - ✓ Our 2017 SOM Report found that the NYISO-PJM PAR-controlled lines (i.e., the A, B, C, J, K, and 5018 lines) were a key driver.
- Two hours (13:00-15:00) on January 5th provide an illustration (slide 40):
  - ✓ Central-East shadow prices deviated substantially between RTD and RTC.
    - – The RTC-RTD price differential ranged from -\$336 to \$1023 per MWh.
  - ✓ The NYISO-PJM PAR-controlled lines accounted for 56 percent of the divergence.
    - – When RTC flow > RTD flow → RTC shadow prices << RTD shadow prices, and vice versa; and
    - – Under tight conditions, a modest flow difference can lead to a large price difference.
  - ✓ PAR-controlled line flows are assumed to equal the last telemetered value plus an adjustment for expected changes in interchange between NYISO and PJM.
    - – However, as illustrated in the figure, actual flows are affected by the redispatch of resources in PJM and NYISO and normally deviate from assumed schedules.
    - – The inconsistency between modeling assumptions and actual flows is a significant contributing factor to RTC/RTD divergence. (see our 2017 SOM report)

Market Highlights:
Fuel Usage in Eastern New York During the Cold Spell

- During the cold spell (12/28 to 1/8), 39 percent of the eastern NY capacity that we estimate would have been economic to burn oil was actually burning oil. (slide 27)
- To the extent these units were not burning oil, it was primarily due to:
  - ✓ Long-term outages of equipment for burning oil, accounting for 1.4 GW of unutilized capacity;
  - ✓ Outages and deratings, which averaged 1.1 GW;
  - ✓ Inventory-limited units, accounting for 0.9 GW of unutilized capacity;
  - ✓ Emission-limited units, accounting for 0.8 GW of unutilized capacity; and
  - ✓ Units burning natural gas, which averaged 1.7 GW. Approximately one-quarter of the gas burn was to manage emission limitations.
- Inventory limitations, outages and deratings, and oil equipment failures accounted for a large share of unutilized oil-fired output that appeared economic.
  - ✓ Generators that have fuel while in a forced outage are no more valuable than generators without fuel.
  - ✓ This highlights the importance of providing efficient price signals so that suppliers area appropriately motivated not only to procure fuel, but also to maintain their units in a reliable condition.

Market Highlights:
Fuel Cost Adjustment During the Cold Spell

- We monitor fuel cost adjustments to ensure that generators do not use them inappropriately to avoid mitigation and inflate energy prices.
  - ✓ We have recommended rule changes to deter such behavior.
- For the gas days during the cold spell from December 27 to January 8. (slide 27)
  - ✓ An average of 1.9 GW (or 18 percent) of NYC generating capacity submitted fuel cost adjustments for gas before the day-ahead market. On average:
    - – 770 MW of capacity submitted FCAs between 110% and 150% of index costs; and
    - – 360 MW of capacity submitted FCAs that were more than 150% of index costs.
- While some fuel cost adjustments did not appear to be reasonable, the LBMP impact was small because imports, oil-fired generation, and self-scheduled generation were generally sufficient to satisfy demand.
- Large deviations between submitted fuel costs and published index costs normally occurred when gas prices were changing rapidly from one day to the next, reflecting the volatility of gas prices and associated risk factors.
  - ✓ However, a significant under-adjustment (relative to Index) occurred on January 5 because the index cost approached $150 while the adjustment was limited by the software to no more than $100.

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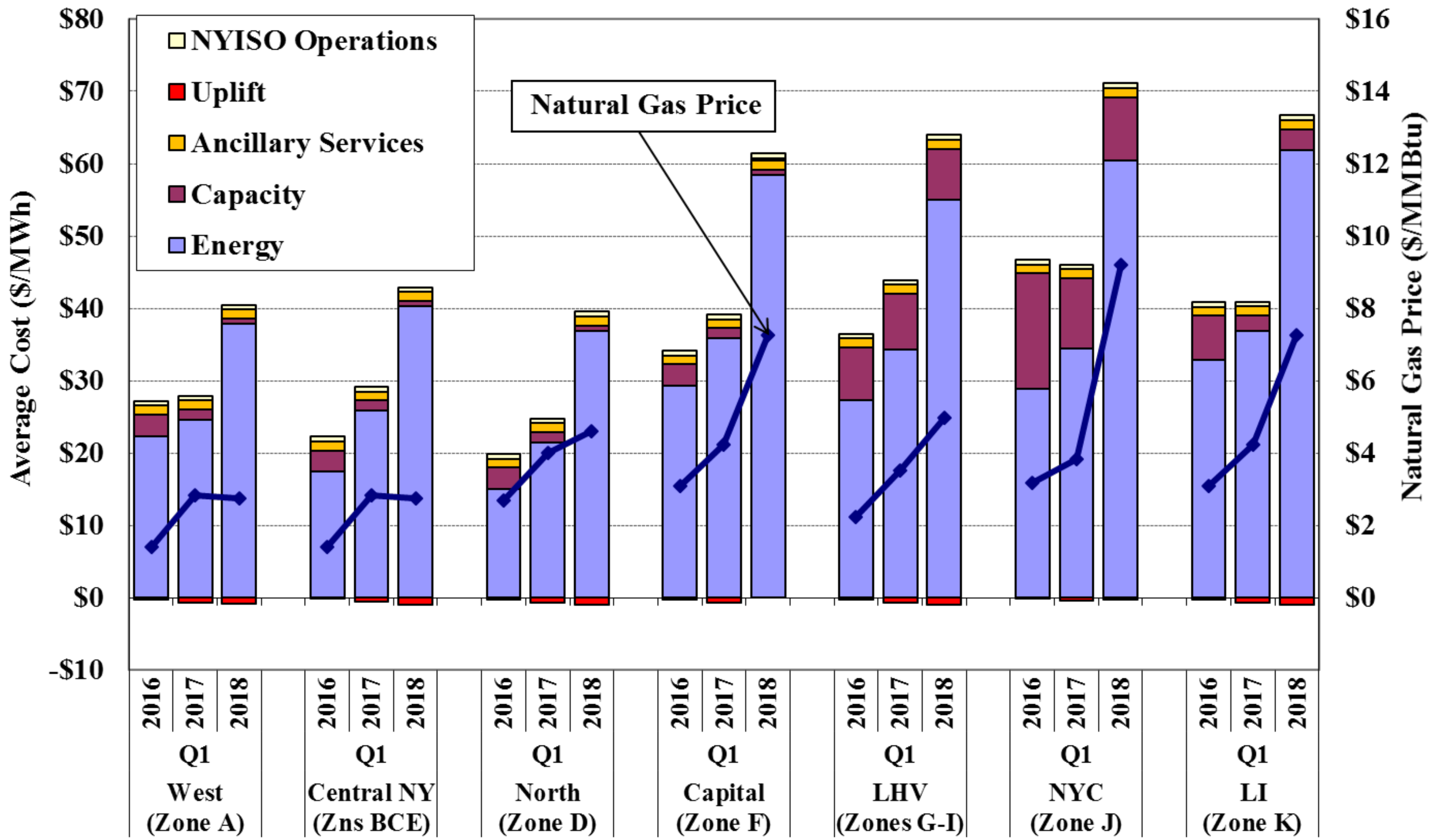
Charts

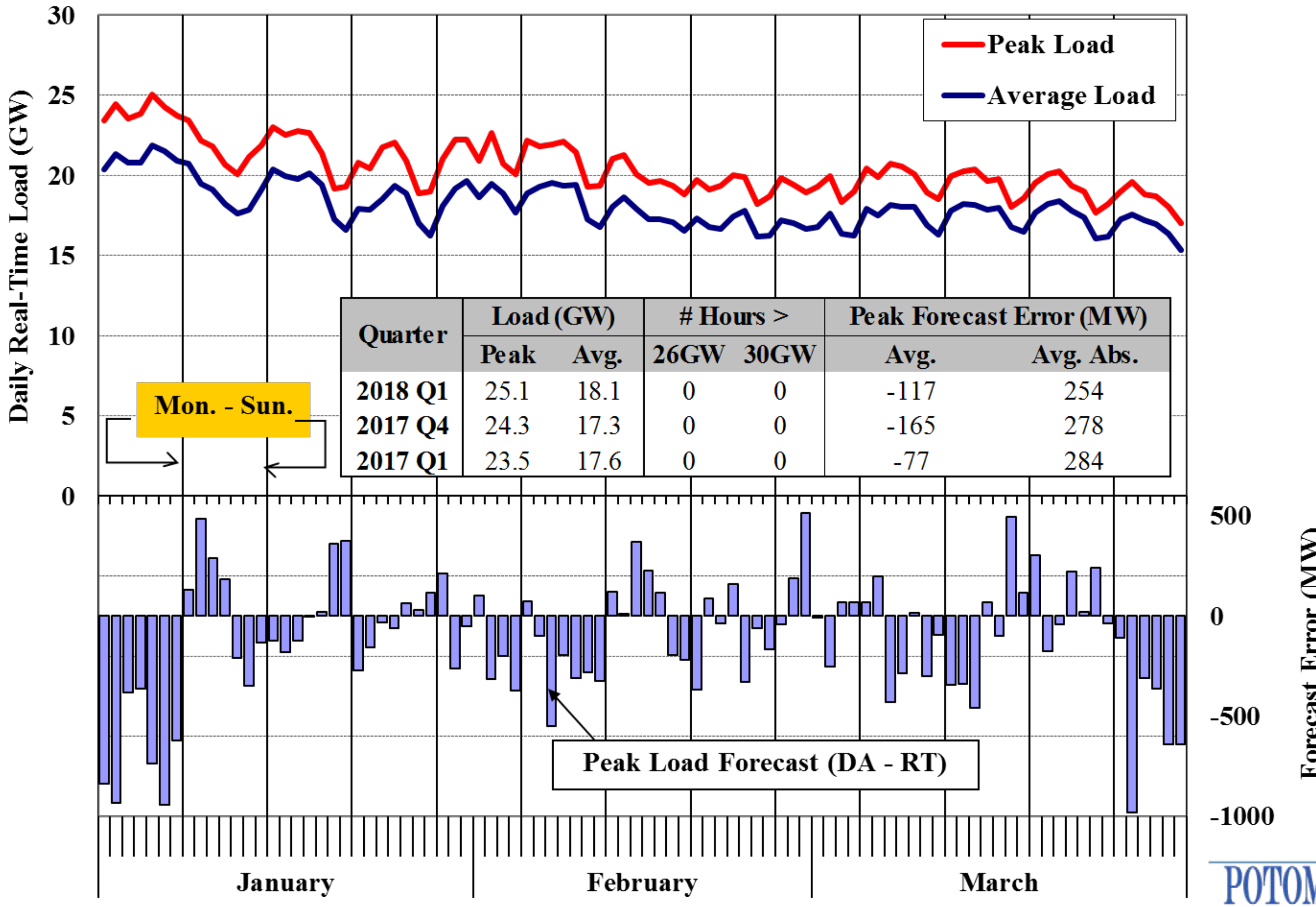
Market Outcomes

All-In Prices by Region



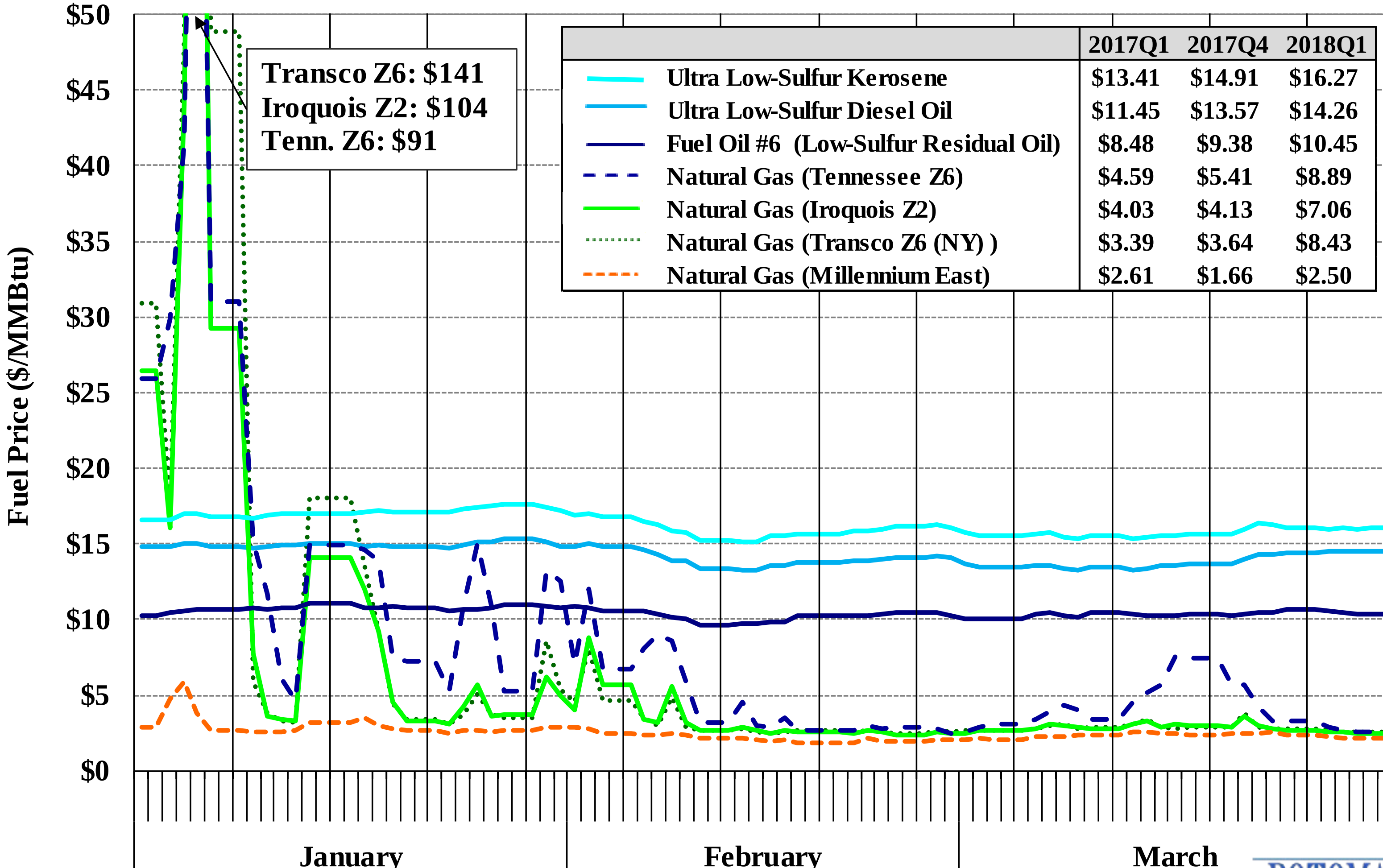
For chart description, see slide 62.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2018 Q1	25.1	18.1	0	0	-117	254
2017 Q4	24.3	17.3	0	0	-165	278
2017 Q1	23.5	17.6	0	0	-77	284

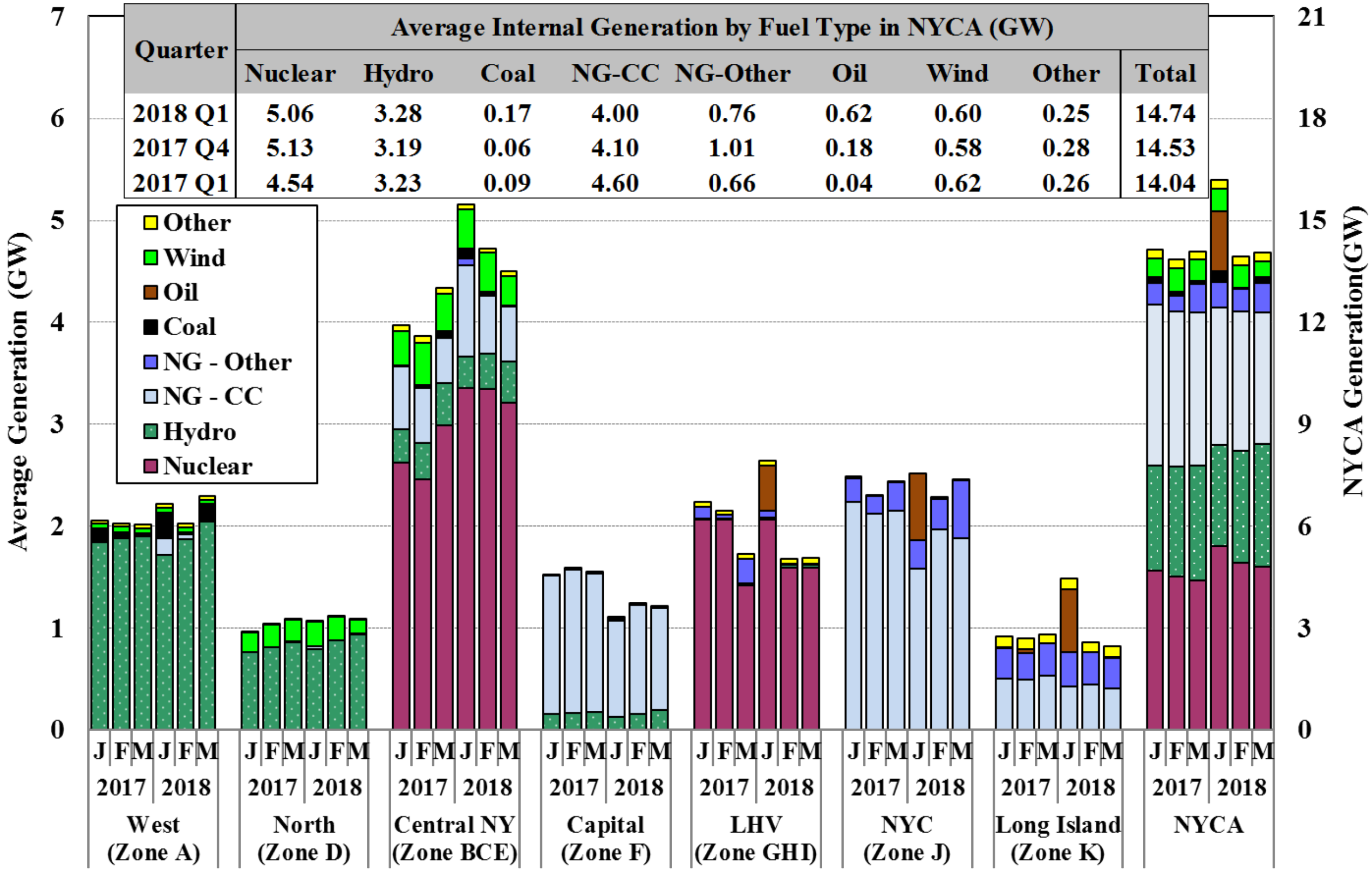
Natural Gas and Fuel Oil Prices



	2017Q1	2017Q4	2018Q1
Ultra Low-Sulfur Kerosene	$13.41	$14.91	$16.27
Ultra Low-Sulfur Diesel Oil	$11.45	$13.57	$14.26
Fuel Oil #6 (Low-Sulfur Residual Oil)	$8.48	$9.38	$10.45
Natural Gas (Tennessee Z6)	$4.59	$5.41	$8.89
Natural Gas (Iroquois Z2)	$4.03	$4.13	$7.06
Natural Gas (Transco Z6 (NY))	$3.39	$3.64	$8.43
Natural Gas (Millennium East)	$2.61	$1.66	$2.50

Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2018 Q1	5.06	3.28	0.17	4.00	0.76	0.62	0.60	0.25	14.74
2017 Q4	5.13	3.19	0.06	4.10	1.01	0.18	0.58	0.28	14.53
2017 Q1	4.54	3.23	0.09	4.60	0.66	0.04	0.62	0.26	14.04



Notes: For chart description, see slide 63.

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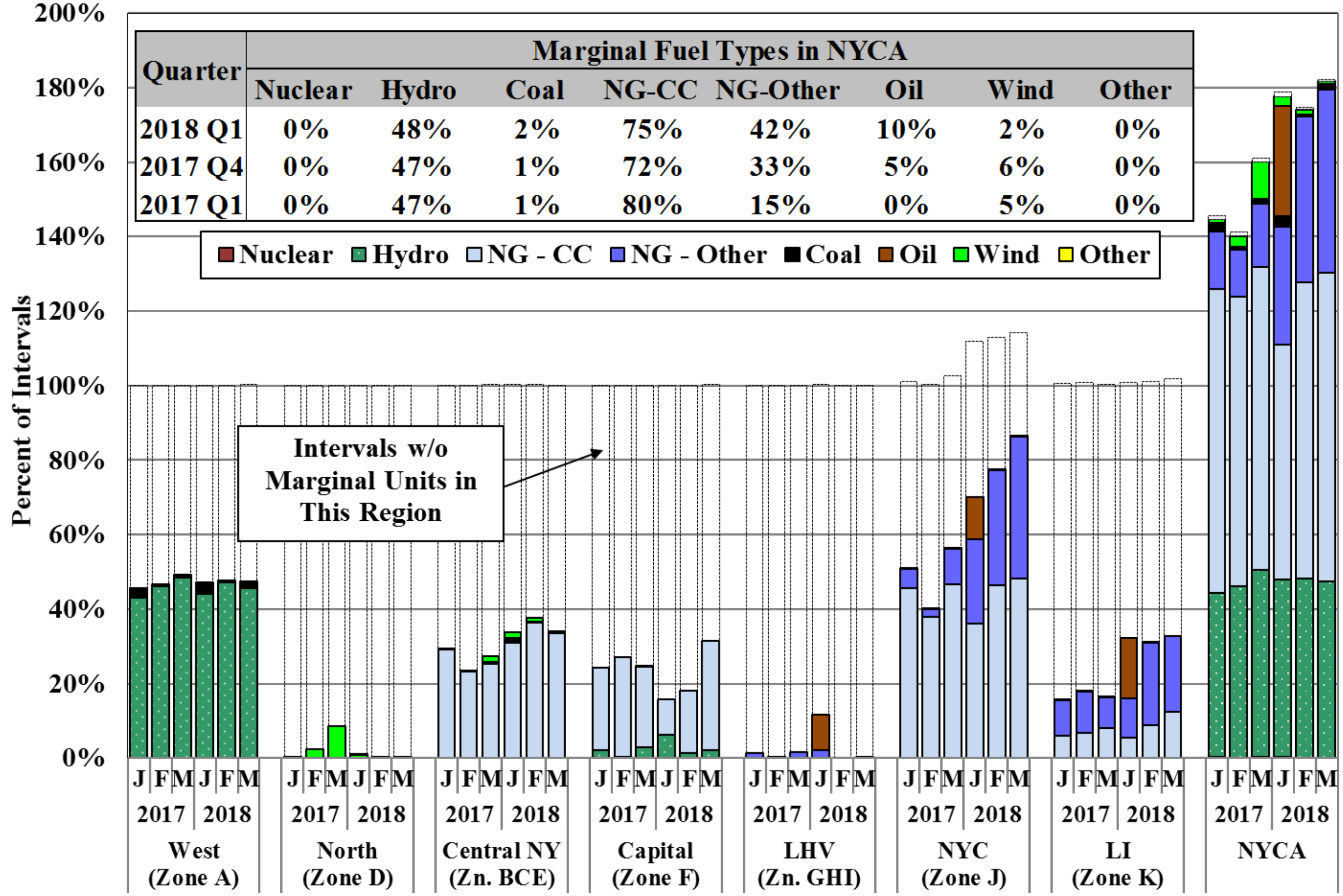
Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2018 Q1	0%	48%	2%	75%	42%	10%	2%	0%
2017 Q4	0%	47%	1%	72%	33%	5%	6%	0%
2017 Q1	0%	47%	1%	80%	15%	0%	5%	0%

Notes: For chart description, see slide 63.

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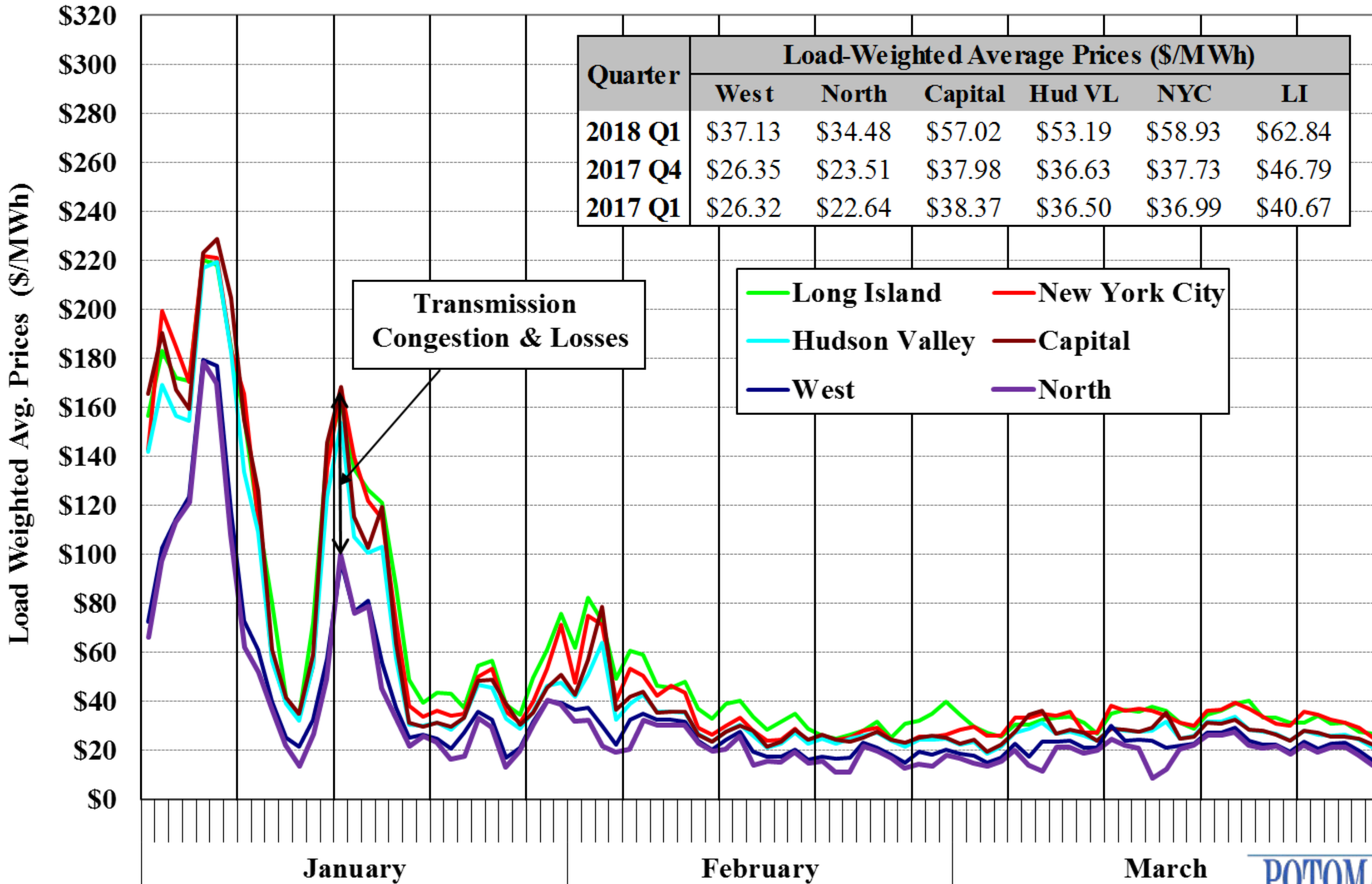
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q1	$37.13	$34.48	$57.02	$53.19	$58.93	$62.84
2017 Q4	$26.35	$23.51	$37.98	$36.63	$37.73	$46.79
2017 Q1	$26.32	$22.64	$38.37	$36.50	$36.99	$40.67

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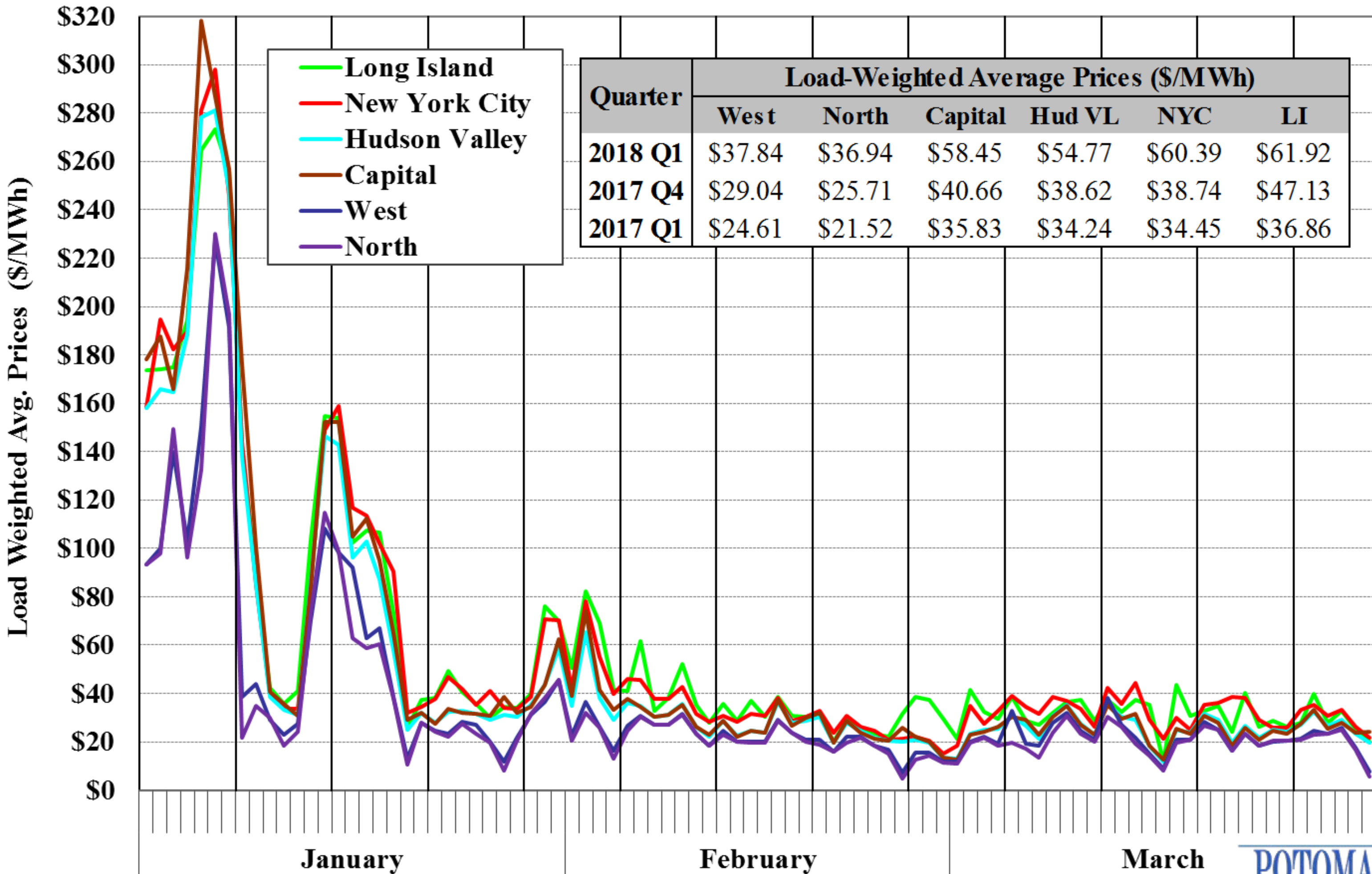
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q1	$37.84	$36.94	$58.45	$54.77	$60.39	$61.92
2017 Q4	$29.04	$25.71	$40.66	$38.62	$38.74	$47.13
2017 Q1	$24.61	$21.52	$35.83	$34.24	$34.45	$36.86

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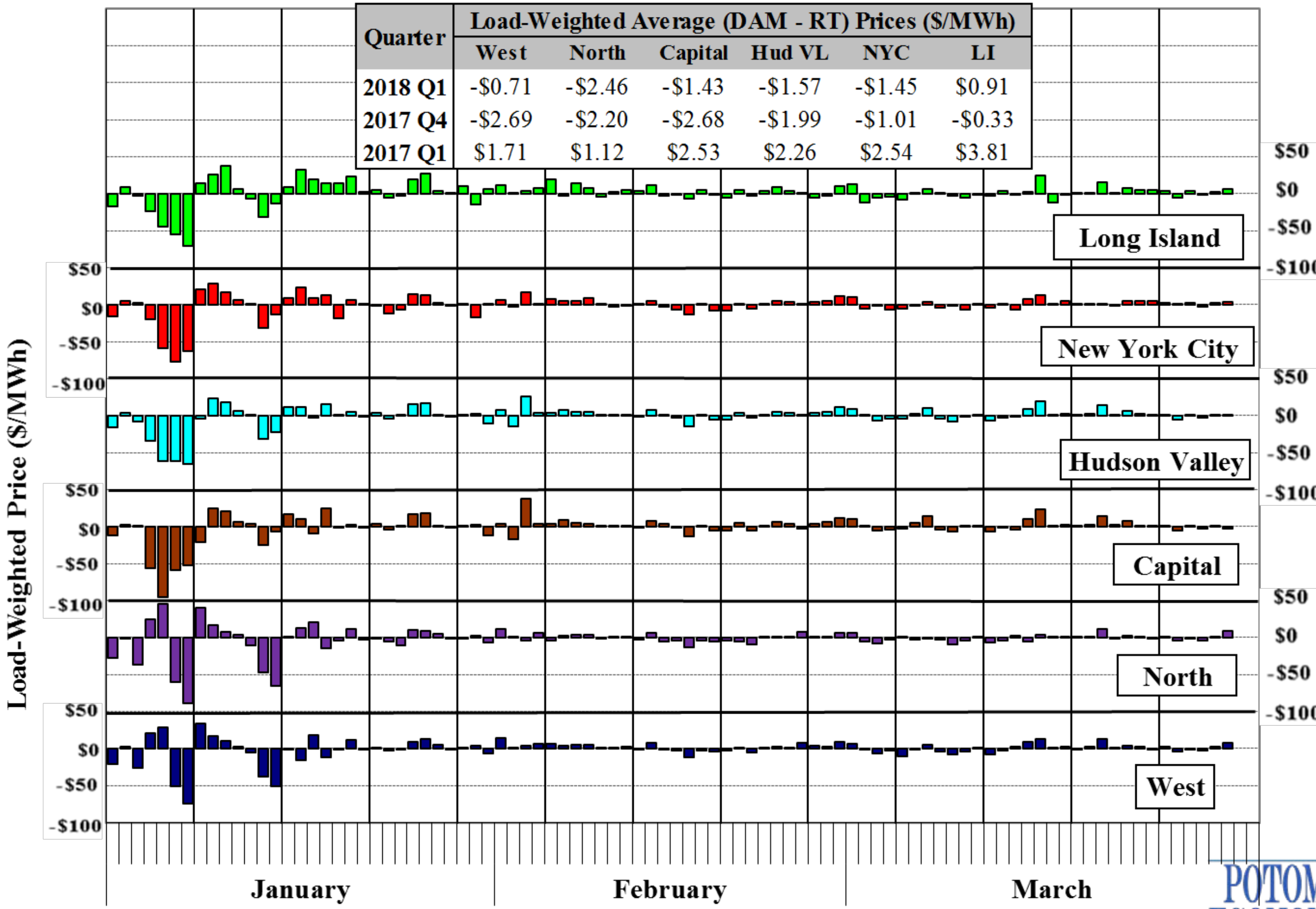
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q1	-$0.71	-$2.46	-$1.43	-$1.57	-$1.45	$0.91
2017 Q4	-$2.69	-$2.20	-$2.68	-$1.99	-$1.01	-$0.33
2017 Q1	$1.71	$1.12	$2.53	$2.26	$2.54	$3.81

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Market Operations During the Cold Spell

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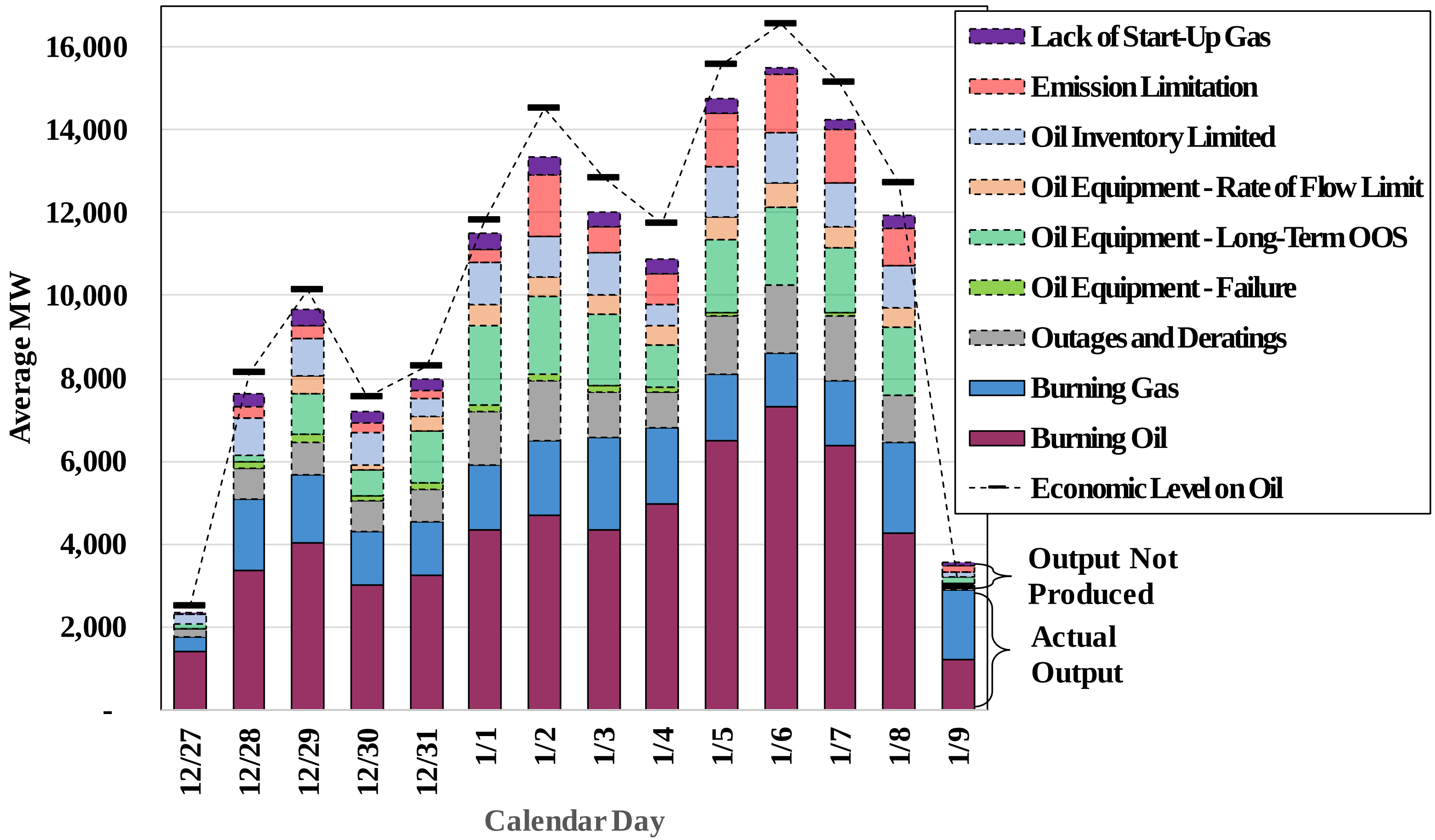
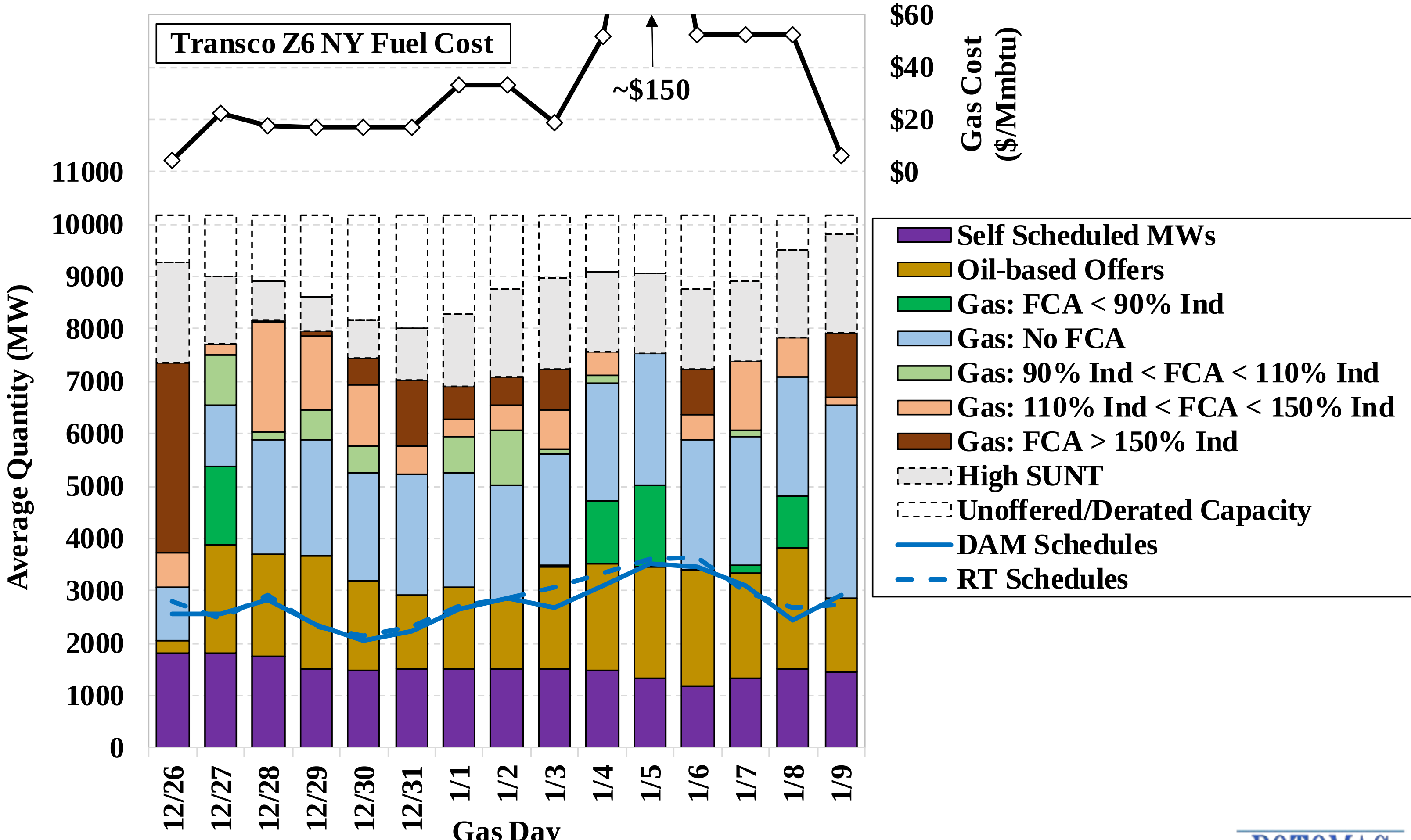
Utilization of Oil-Fired and Dual-Fuel Capacity
Eastern New York During the Cold Spell



Note: For chart description, see slide 64.

Fuel Cost Adjustments ("FCA") During Cold Spell
DAM FCAs in New York City



Note: For chart description, see slide 65.

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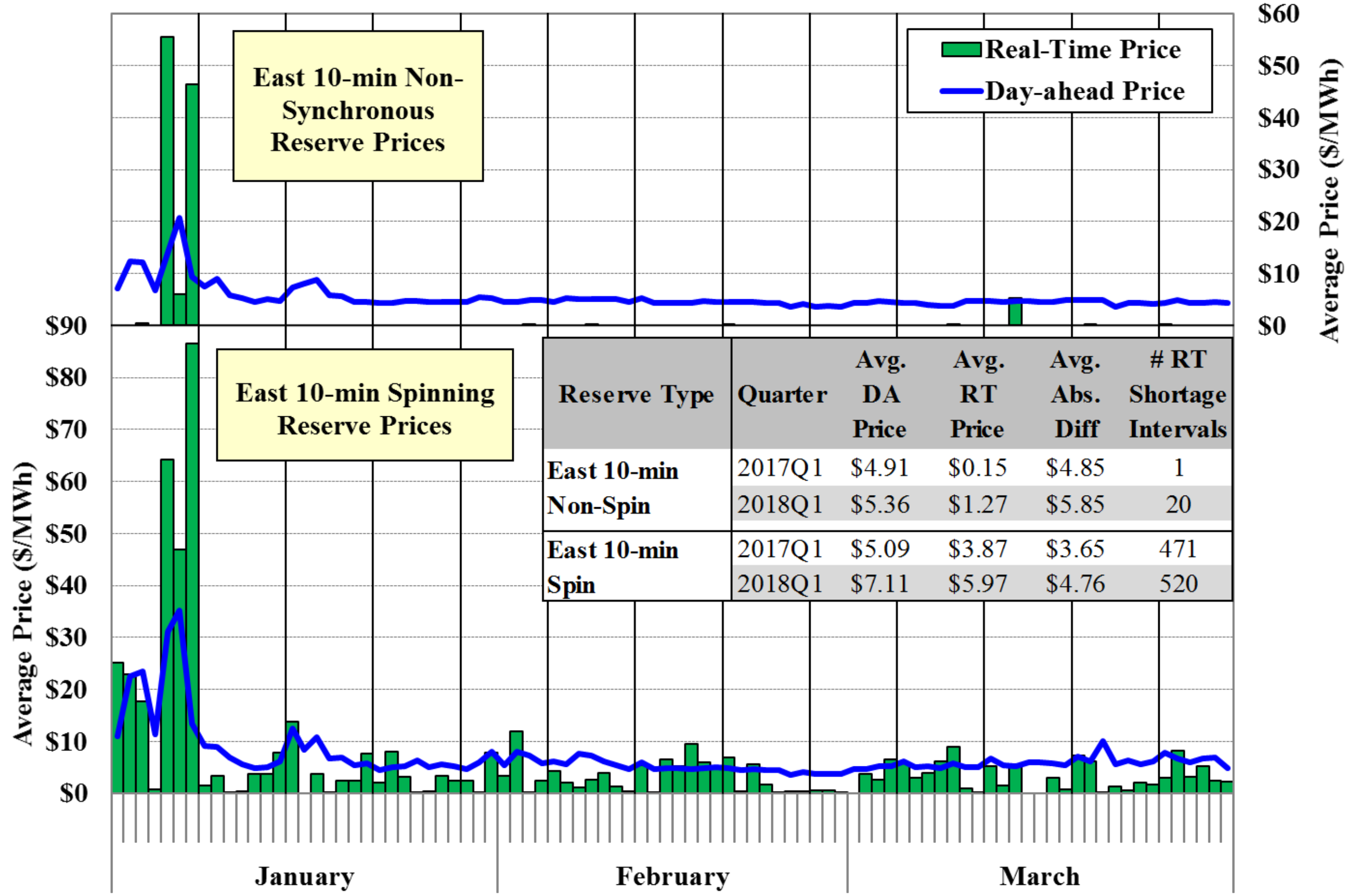
Ancillary Services Market

Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2017Q1	$4.91	$0.15	$4.85	1
	2018Q1	$5.36	$1.27	$5.85	20
East 10-min Spin	2017Q1	$5.09	$3.87	$3.65	471
	2018Q1	$7.11	$5.97	$4.76	520

Note: For chart description, see slide 66.

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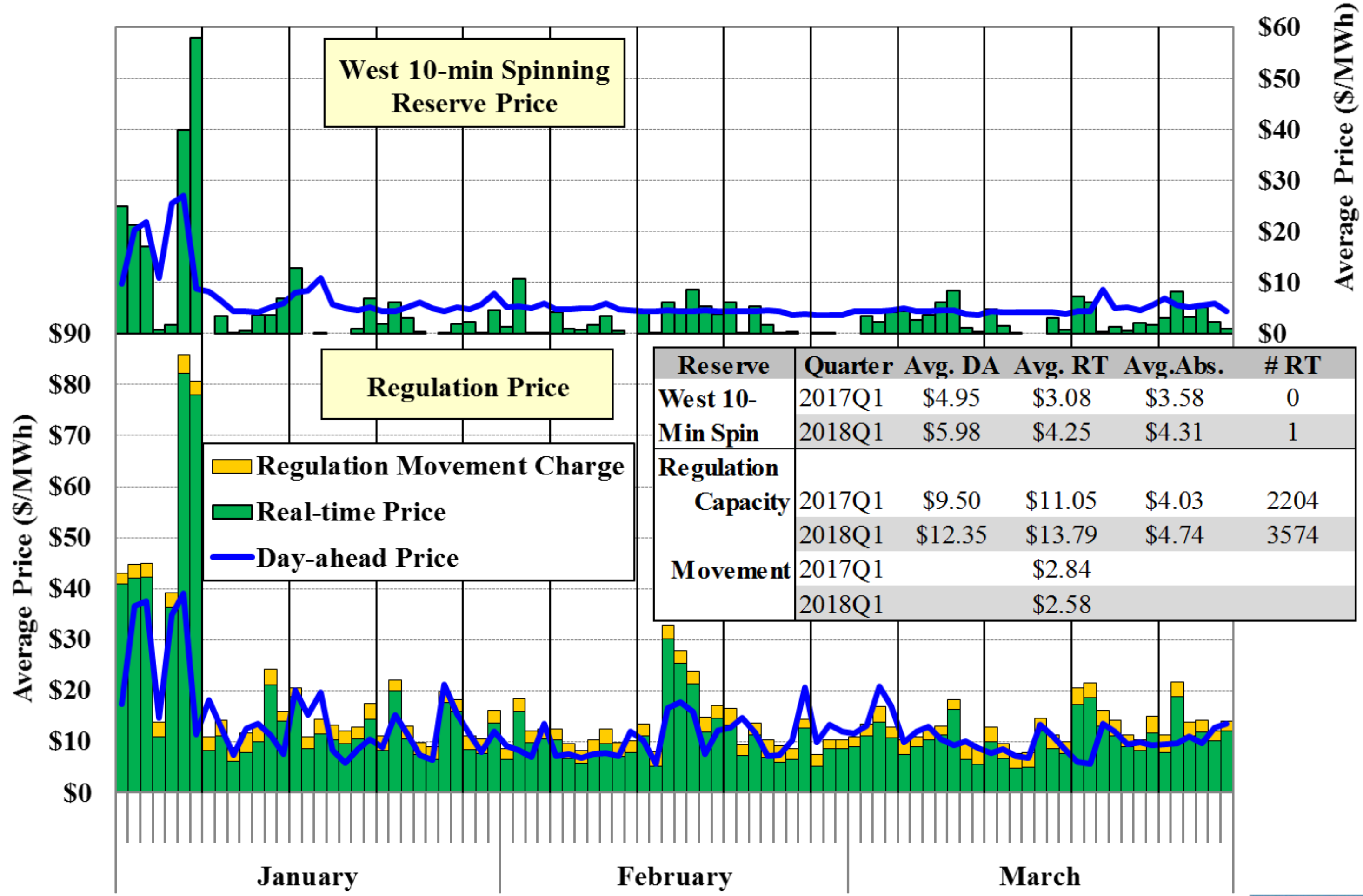
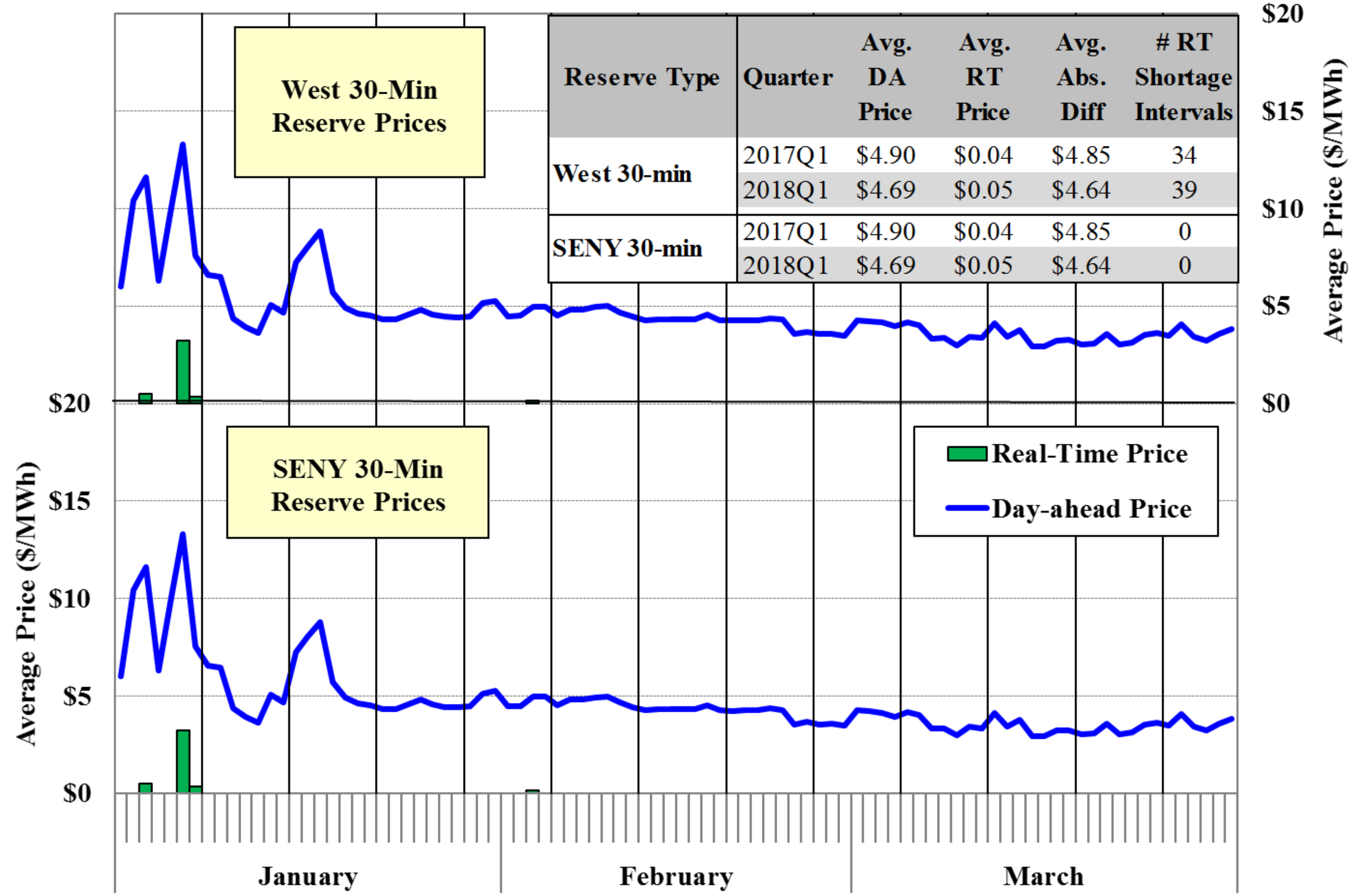
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2017Q1	$4.95	$3.08	$3.58	0
	2018Q1	$5.98	$4.25	$4.31	1
Regulation					
Capacity	2017Q1	$9.50	$11.05	$4.03	2204
	2018Q1	$12.35	$13.79	$4.74	3574
Movement	2017Q1		$2.84		
	2018Q1		$2.58		

For chart description, see slide 66.

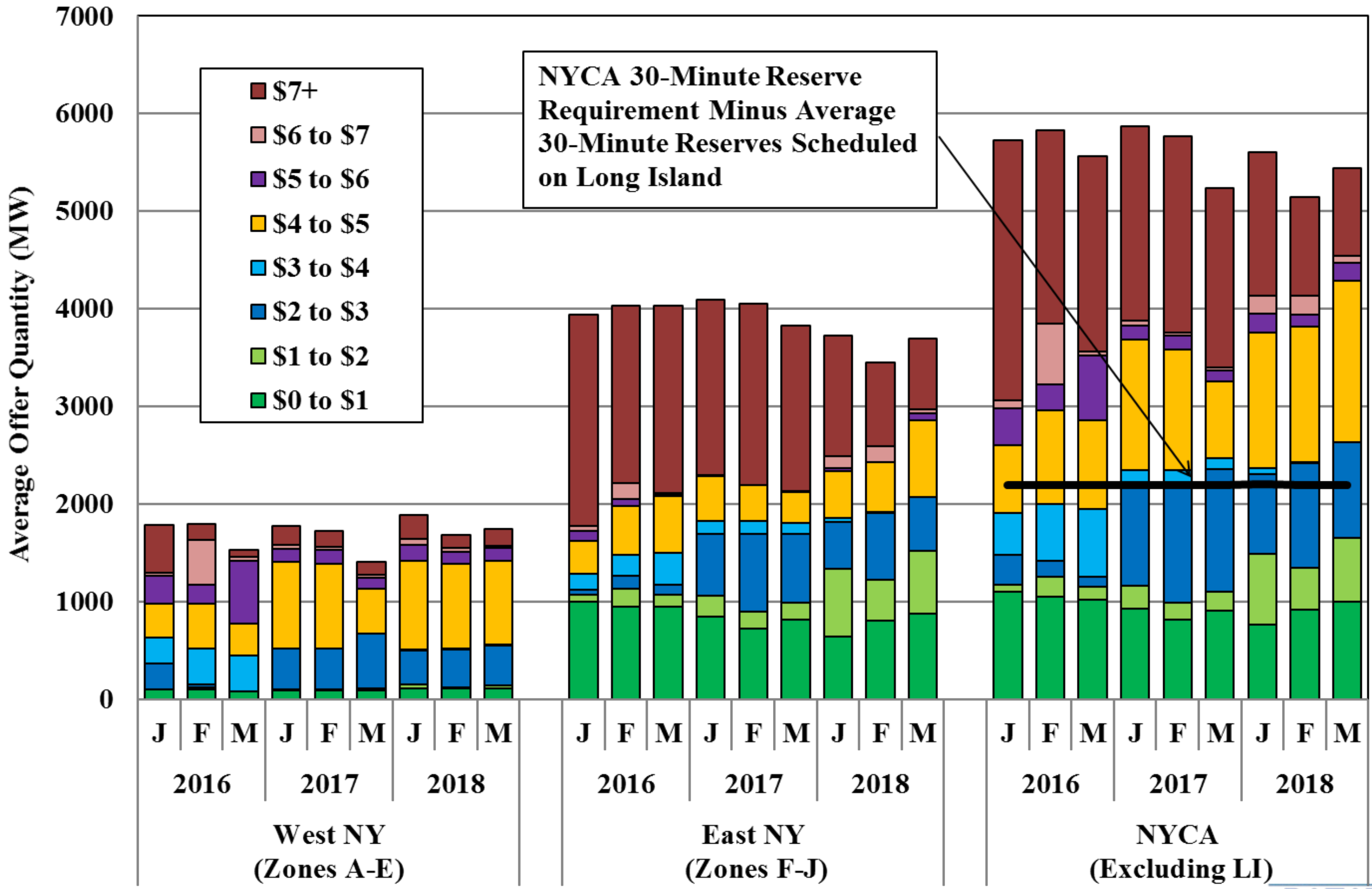
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2017Q1	$4.90	$0.04	$4.85	34
	2018Q1	$4.69	$0.05	$4.64	39
SENY 30-min	2017Q1	$4.90	$0.04	$4.85	0
	2018Q1	$4.69	$0.05	$4.64	0

Note: For chart description, see slide 66.

Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Note: For chart description, see slide 67.

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Energy Market Scheduling

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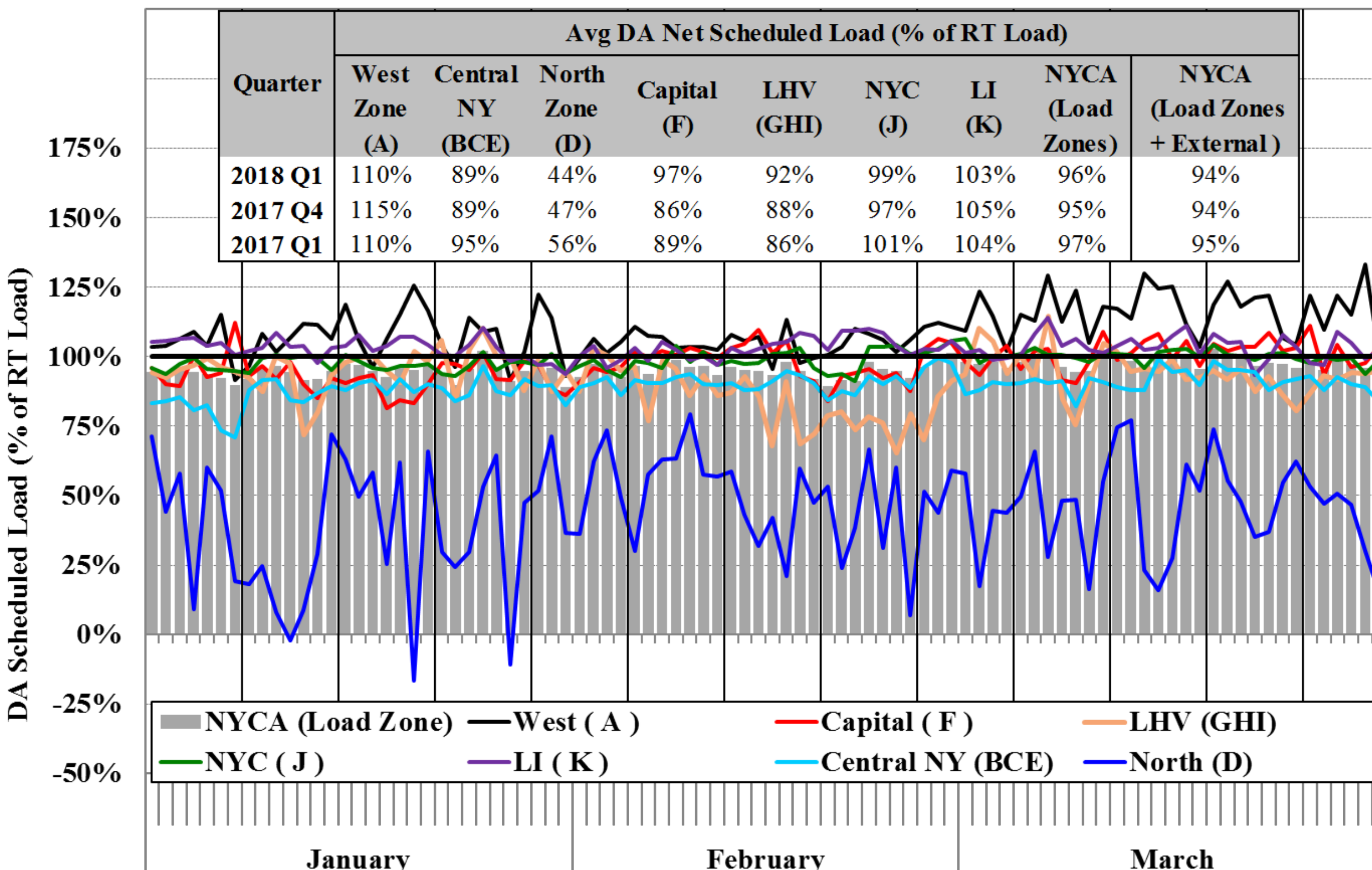
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour



Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2018 Q1	110%	89%	44%	97%	92%	99%	103%	96%	94%
2017 Q4	115%	89%	47%	86%	88%	97%	105%	95%	94%
2017 Q1	110%	95%	56%	89%	86%	101%	104%	97%	95%

Note: For chart description, see slide 68.

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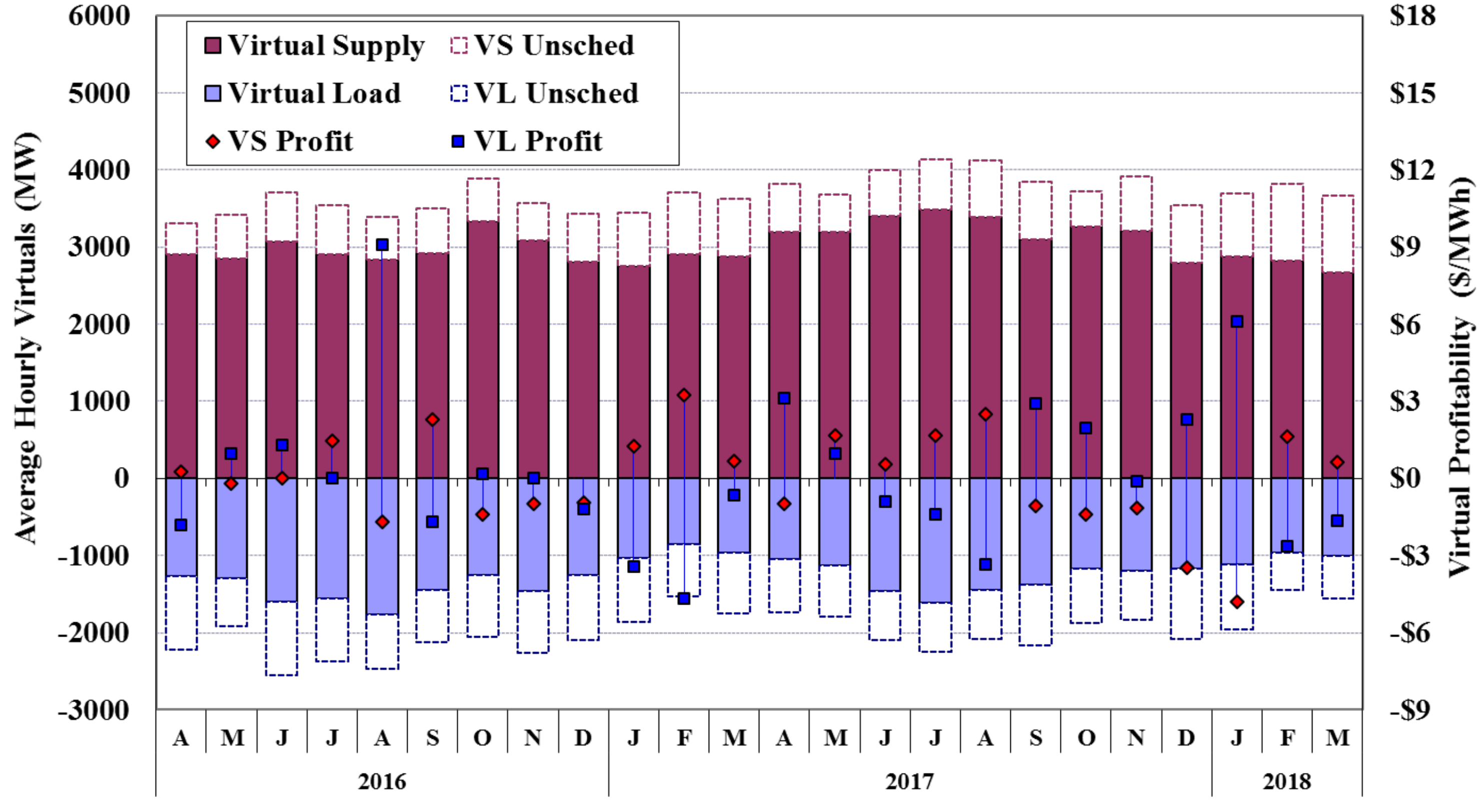
Virtual Trading Activity
by Month



		A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M
Profit > 50% of Avg. Zone Price	MW	354	431	460	596	398	360	281	261	490	243	507	585	449	645	502	593	439	257	271	320	396	373	450	419
	%	8%	10%	10%	13%	9%	8%	6%	6%	12%	6%	13%	15%	11%	15%	10%	12%	9%	6%	6%	7%	10%	9%	12%	11%
Loss > 50% of Avg. Zone Price	MW	682	550	528	517	413	411	419	345	587	284	336	514	454	553	542	568	466	418	399	412	478	442	342	401
	%	16%	13%	11%	12%	9%	9%	9%	8%	14%	7%	9%	13%	11%	13%	11%	11%	10%	9%	9%	9%	12%	11%	9%	11%

Note: For chart description, see slide 68.

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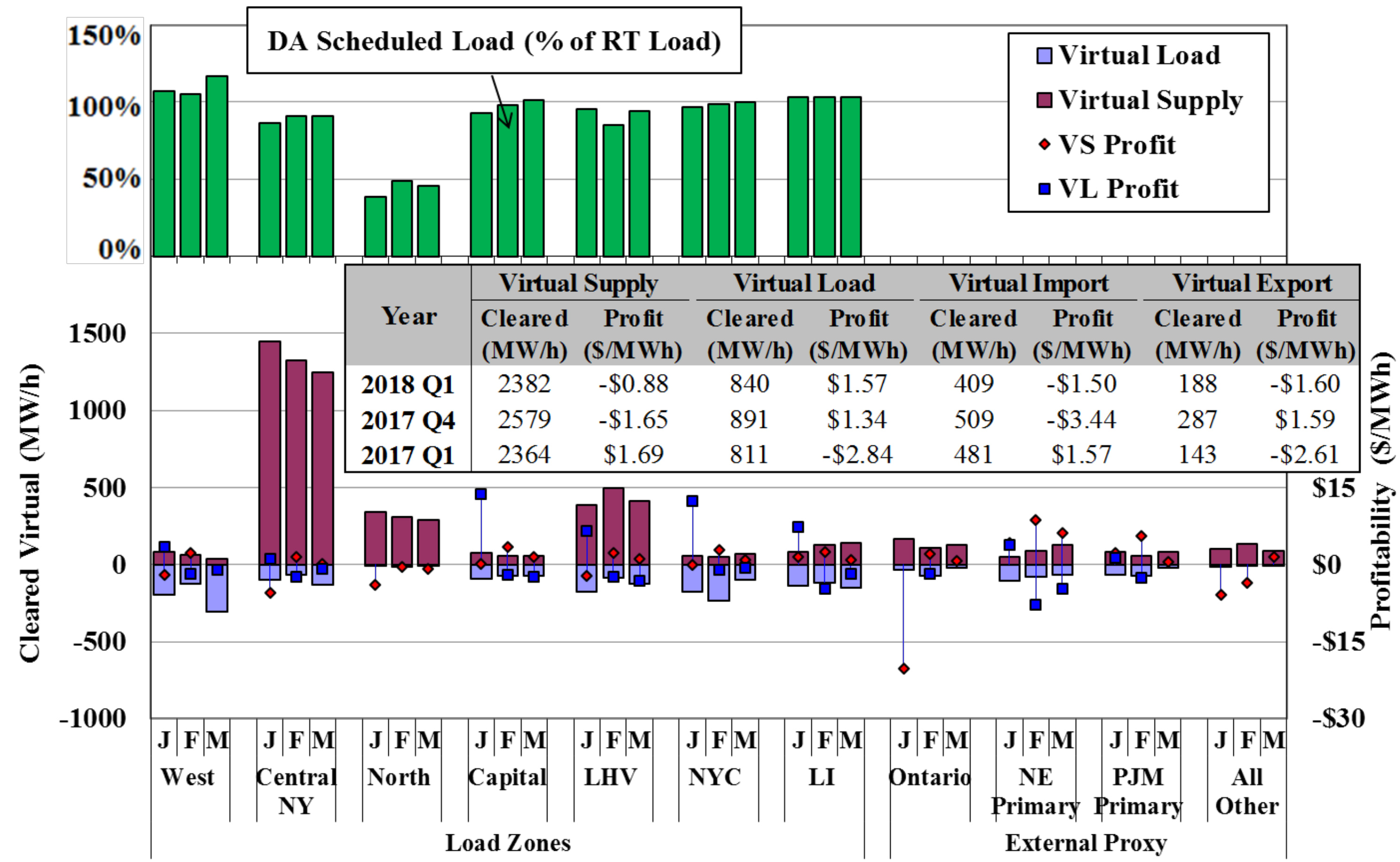
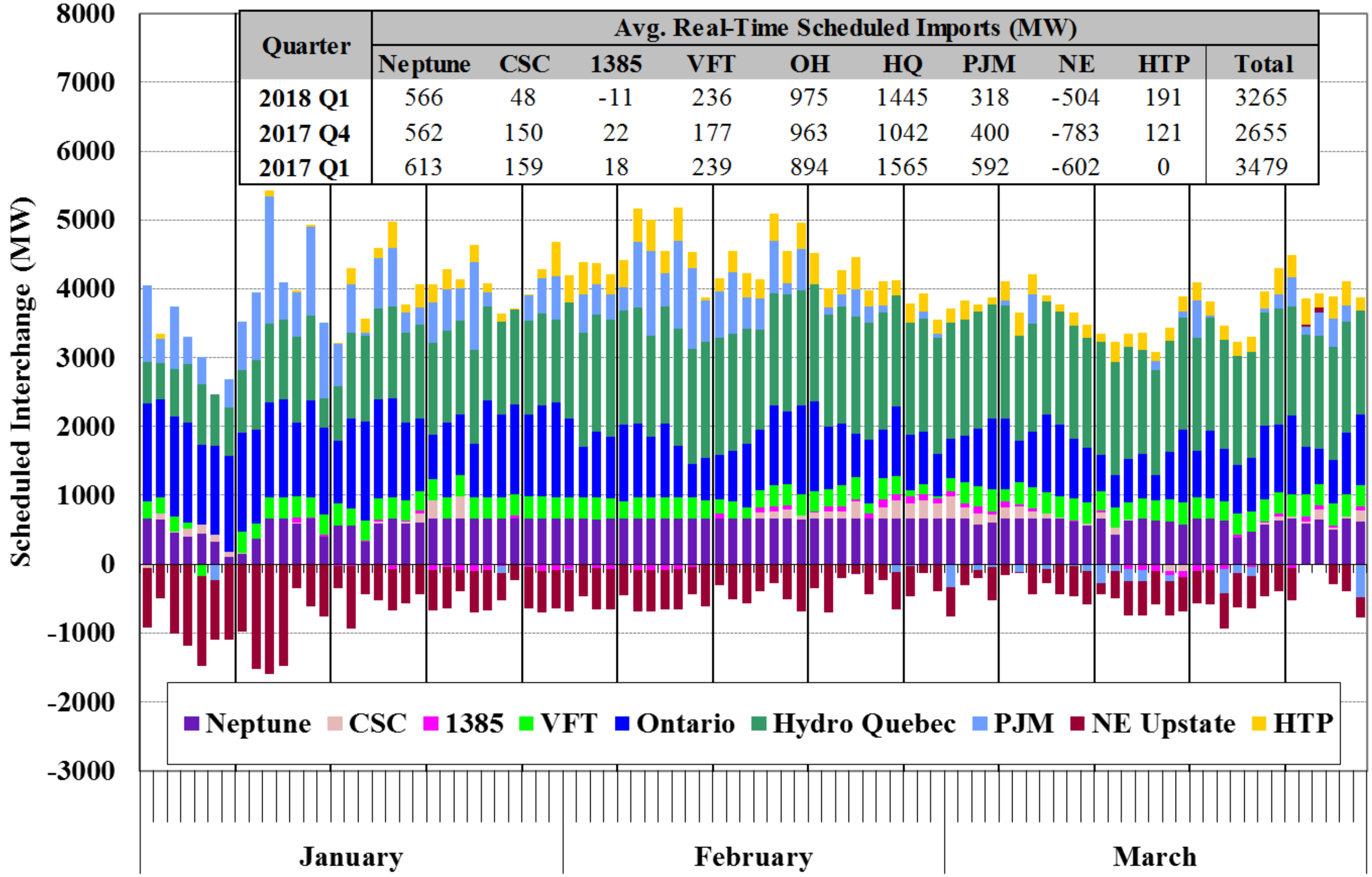
Virtual Trading Activity
by Location



Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2018 Q1	2382	-$0.88	840	$1.57	409	-$1.50	188	-$1.60
2017 Q4	2579	-$1.65	891	$1.34	509	-$3.44	287	$1.59
2017 Q1	2364	$1.69	811	-$2.84	481	$1.57	143	-$2.61

Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.
For chart description, see slide 68.

Net Imports Scheduled Across External Interfaces
Daily Peak Hours (1-9pm)



Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2018 Q1	566	48	-11	236	975	1445	318	-504	191	3265
2017 Q4	562	150	22	177	963	1042	400	-783	121	2655
2017 Q1	613	159	18	239	894	1565	592	-602	0	3479

Note: Two HQ interfaces are combined into one.

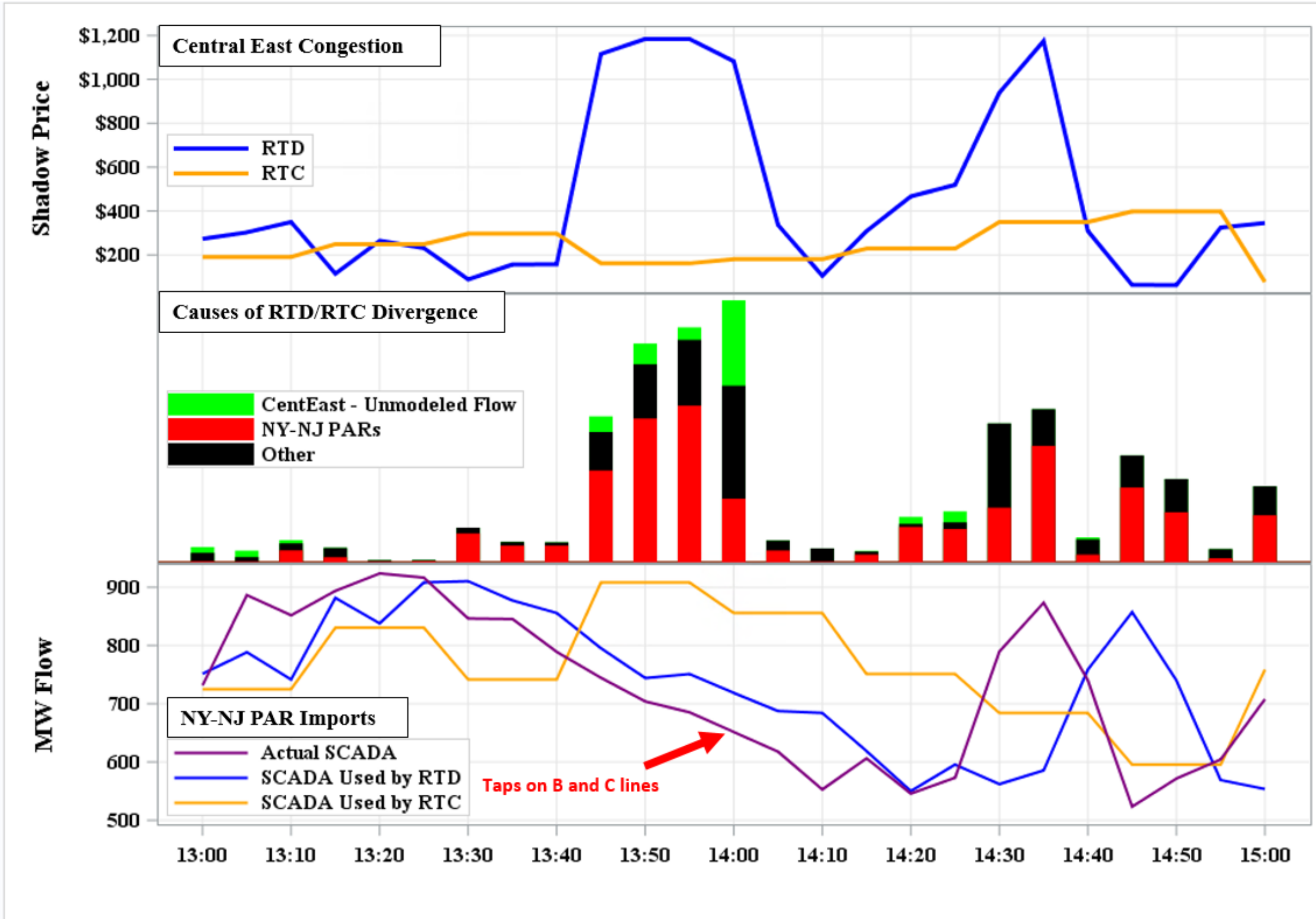
POTOMAC ECONOMICS

Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM and NE Interfaces

			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			51%	14%	**65%**	52%	16%	**68%**
Average Flow Adjustment (MW)	Net Imports		9	3	**8**	18	32	**21**
	Gross		85	100	**88**	59	83	**64**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.8	$1.1	**$1.9**	$0.4	$0.8	**$1.2**
	Net Over-Projection by:	NY	-$0.04	$0.2	**$0.1**	-$0.05	$0.05	**$0.0**
		NE or PJM	$0.03	-$0.03	**$0.0**	-$0.1	-$0.6	**-$0.7**
	Other Unrealized Savings		-$0.03	-$0.1	**-$0.2**	-$0.01	$0.05	**$0.0**
	Actual Savings		$0.7	$1.1	**$1.9**	$0.3	$0.3	**$0.6**
Interface Prices ($/MWh)	NY	Actual	$40.97	$139.28	**$62.24**	$29.37	$118.78	**$50.21**
		Forecast	$42.17	$115.58	**$58.06**	$30.22	$100.30	**$46.56**
	NE or PJM	Actual	$41.98	$127.97	**$60.59**	$28.85	$131.39	**$52.75**
		Forecast	$40.59	$110.97	**$55.82**	$27.73	$92.32	**$42.79**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.20	-$23.71	**-$4.19**	$0.85	-$18.48	**-$3.66**
		Abs. Val.	$4.83	$55.98	**$15.90**	$3.93	$38.11	**$11.90**
	NE or PJM	Fcst. - Act.	-$1.39	-$17.00	**-$4.77**	-$1.12	-$39.07	**-$9.97**
		Abs. Val.	$3.97	$28.83	**$9.35**	$3.42	$66.05	**$18.02**

Note: For chart description, see slide 69.

Contributing Factors to RTC/RTD Divergence
A Case Study on January 5th

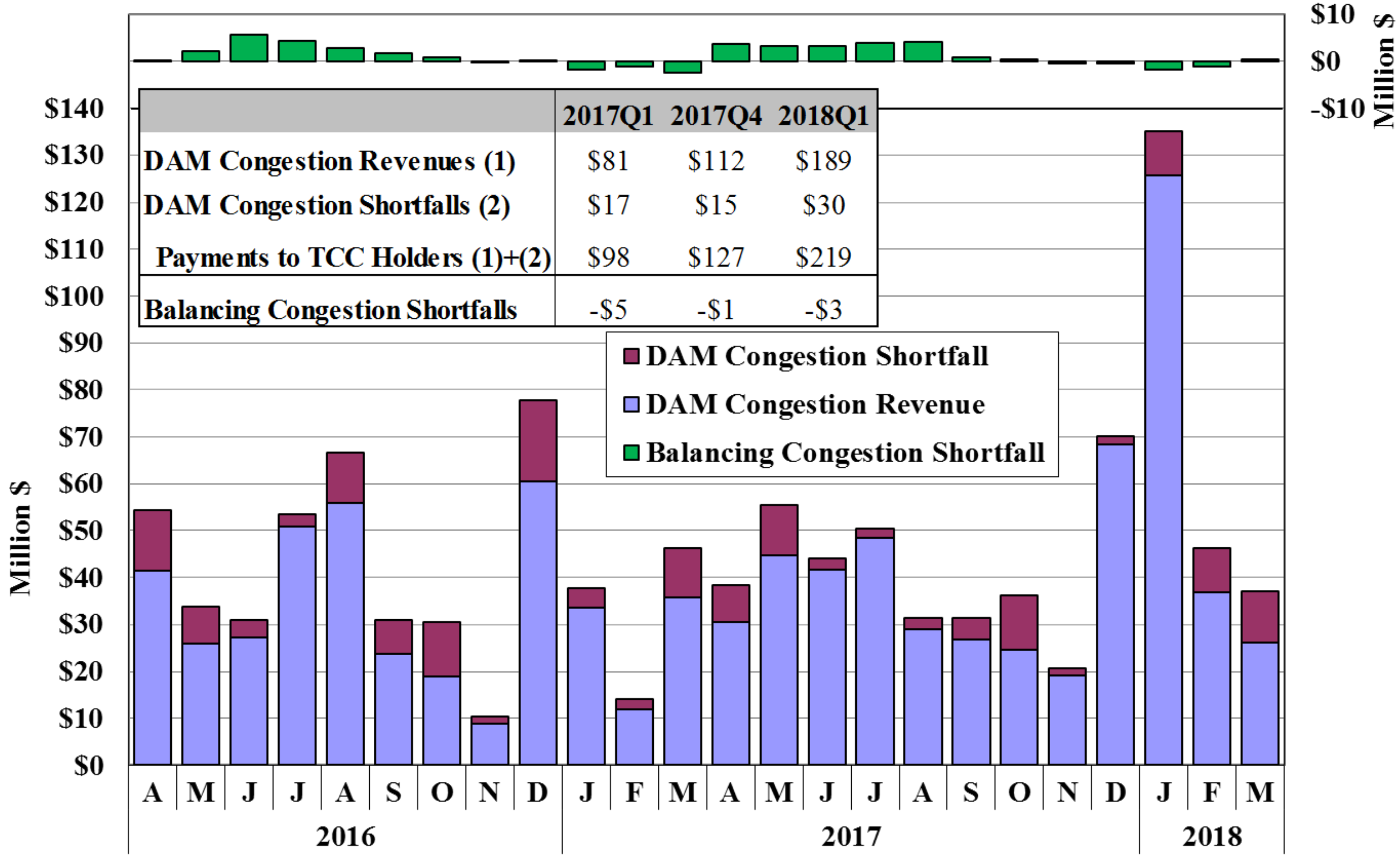


Note: For chart description, see slide 70.

POTOMAC ECONOMICS

Transmission Congestion Revenues and Shortfalls

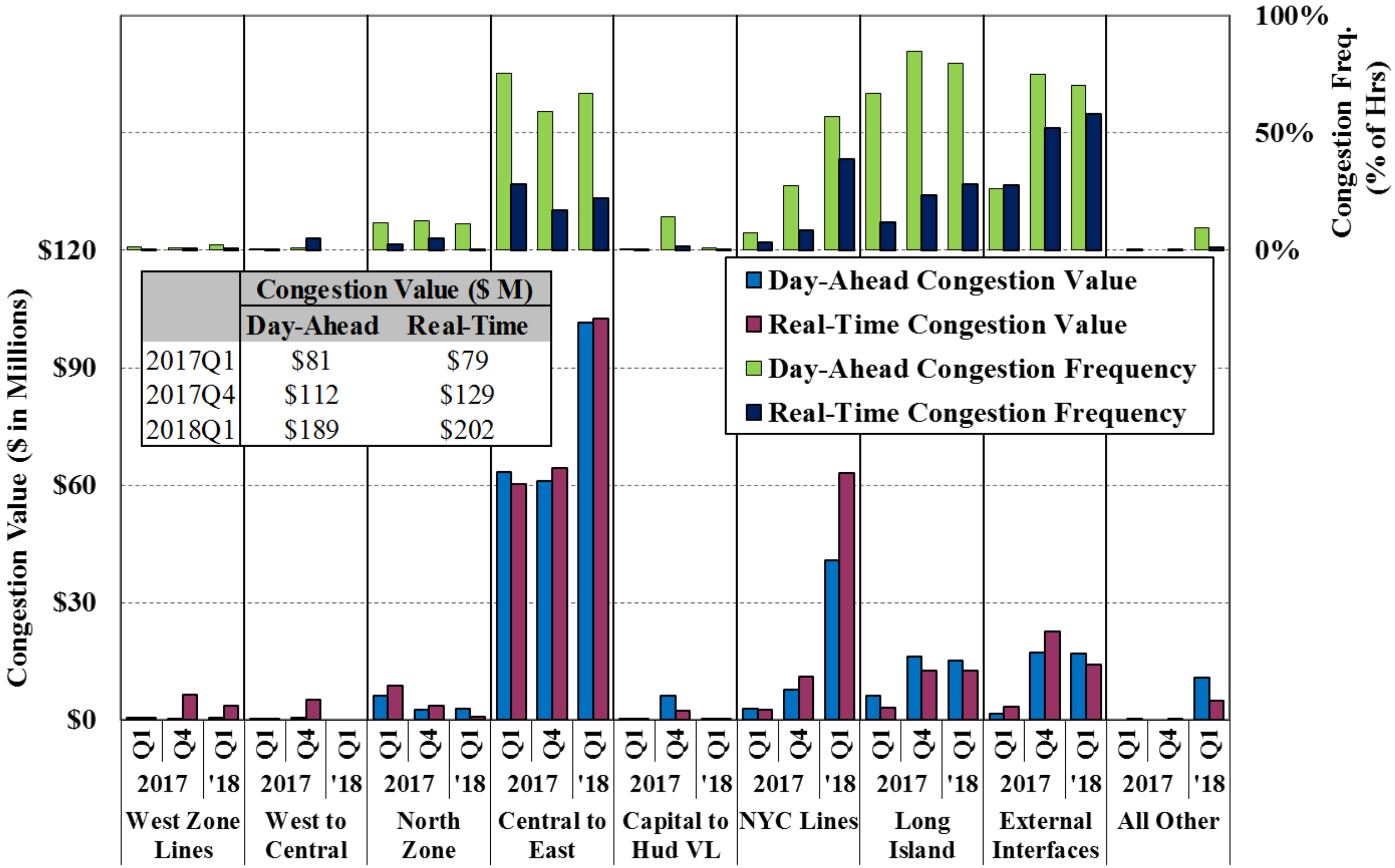
Congestion Revenues and Shortfalls by Month



Note: For chart description, see slides 71 and72.

POTOMAC ECONOMICS

Day-Ahead and Real-Time Congestion Value
by Transmission Path

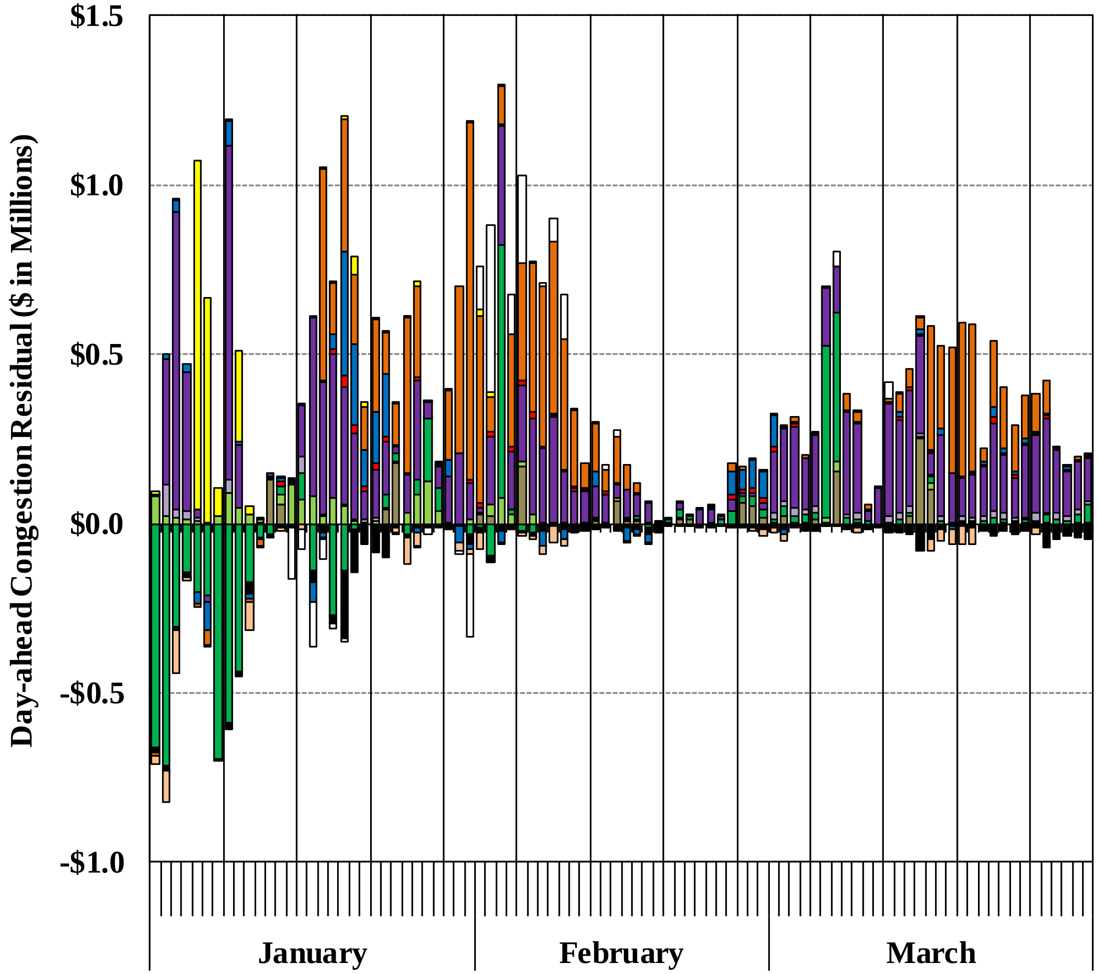


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2017Q1	$81	$79
2017Q4	$112	$129
2018Q1	$189	$202

Note: For chart description, see slides 71, 72, and 73.

POTOMAC ECONOMICS

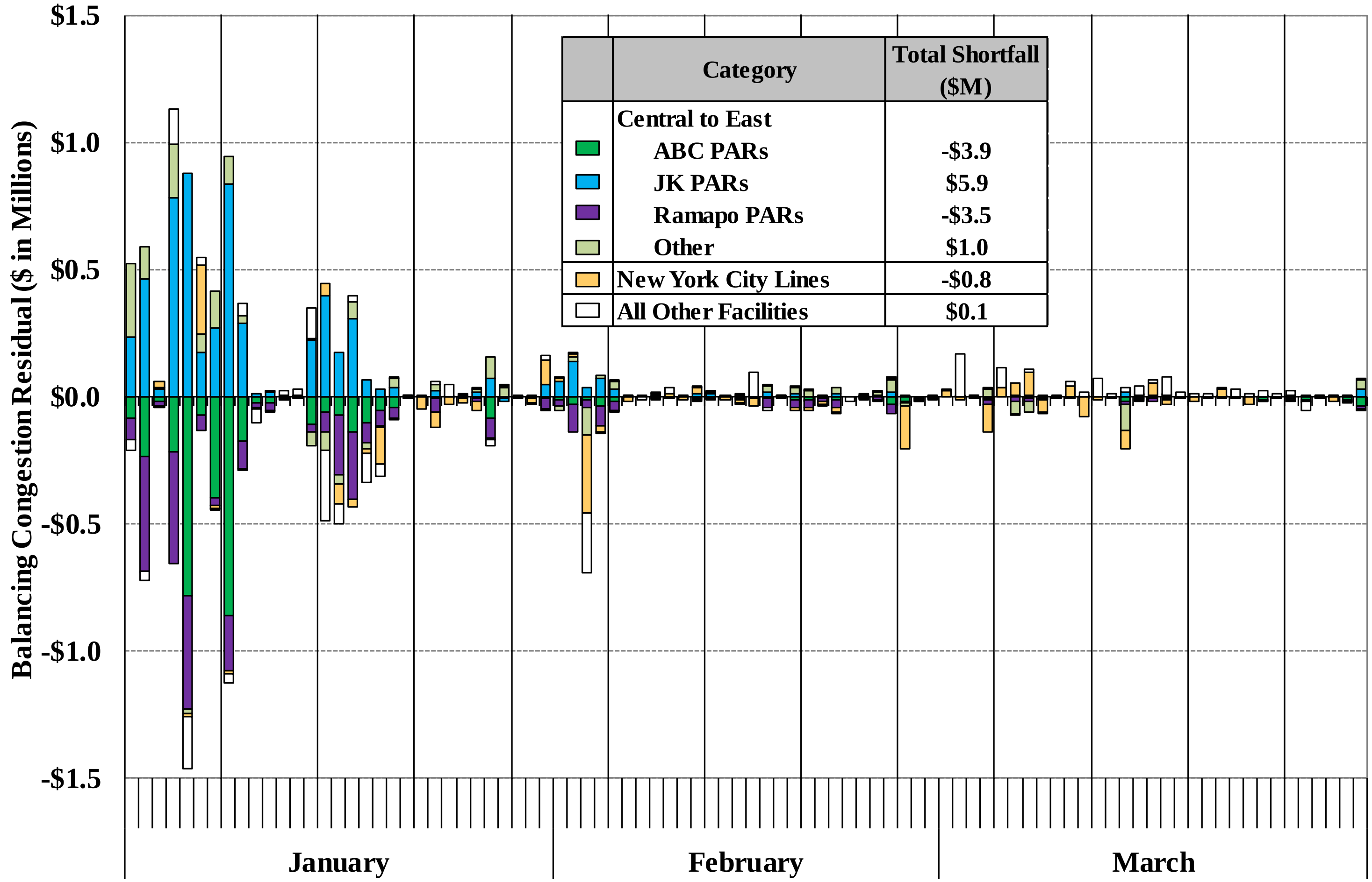
Day-Ahead Congestion Revenue Shortfalls
by Transmission Facility



	Category	Shortfall ($M)
	North Zone Lines	$1.4
	Central East	
	ABC, JK, Ramapo	$1.4
	Other	-$2.2
	NYC Lines	
	ABC PARs	$0.7
	Other	$15.0
	LI Lines	
	901/903 PARs	-$1.8
	GFTCC	$0.5
	Other	$1.4
	External Interfaces	
	Primary NY/NE	$11.5
	Primary NY/HQ	$2.2
	Other	-$1.1
	All Other	$0.6

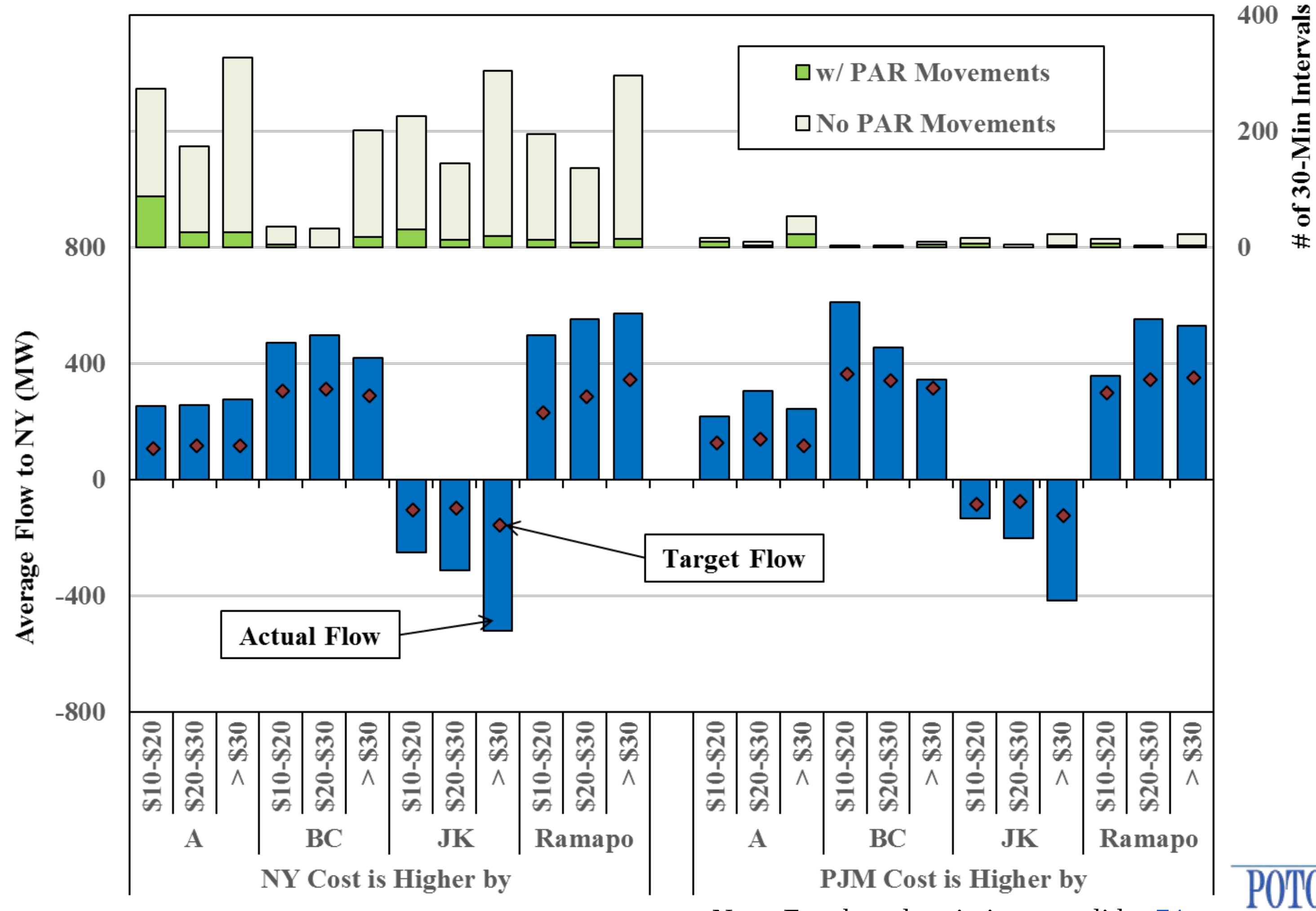
Note: For chart description, see slides 71, 72, and 73.

Balancing Congestion Shortfalls by Transmission Facility



Note: The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. For chart description, see slides 71, 72, and 73.

PAR Operation under M2M with PJM
2018 Q1



Note: For chart description, see slides 74.

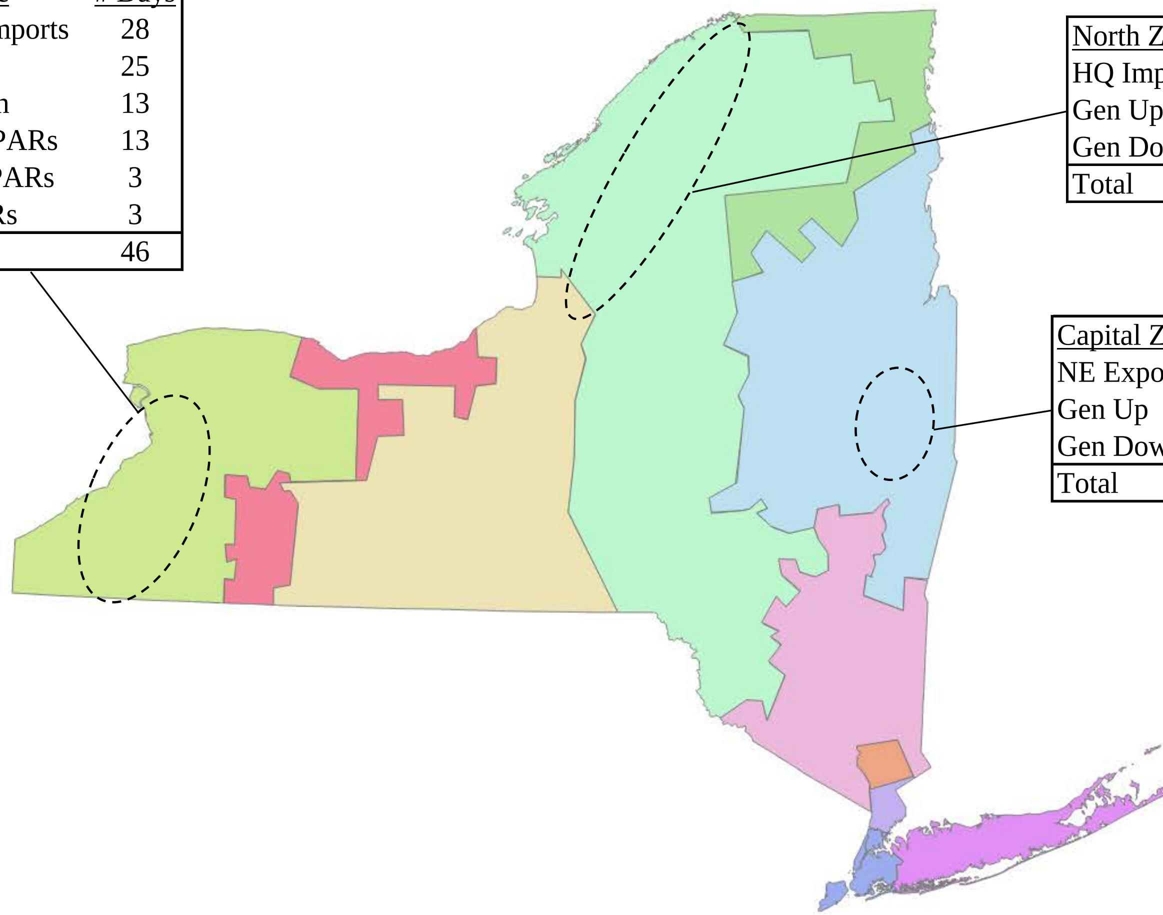
POTOMAC ECONOMICS

Constraints on the Low Voltage Network Upstate:
Summary of Resources Used to Manage Congestion

West Zone	# Days
Ontario Imports	28
Gen Up	25
Gen Down	13
St. Lawr PARs	13
Ramapo PARs	3
ABC PARs	3
Total	46

North Zone	# Days
HQ Imports	2
Gen Up	12
Gen Down	4
Total	17

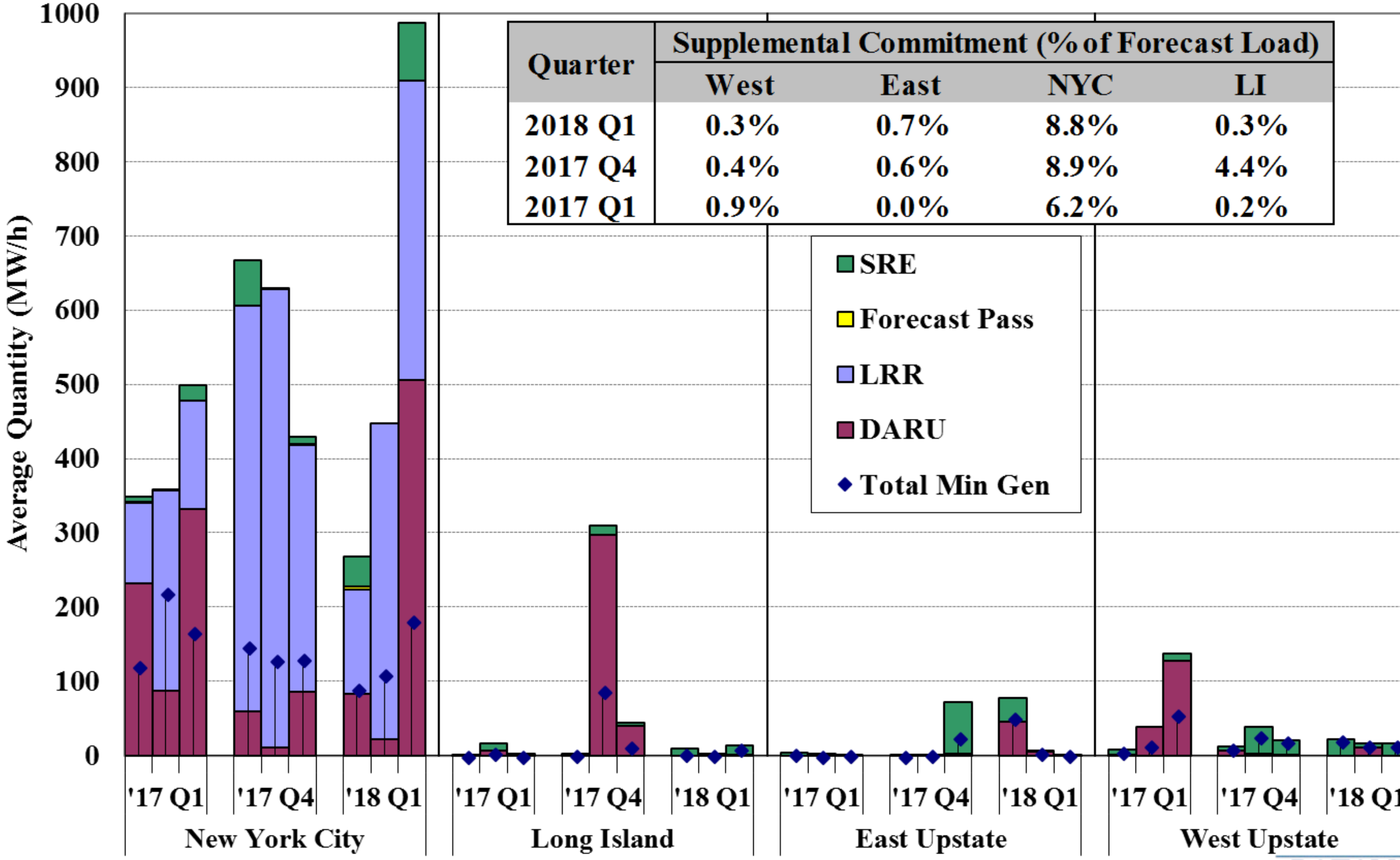
Capital Zone	# Days
NE Exports	4
Gen Up	11
Gen Down	44
Total	54



Note: For chart description, see slides 75.

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability
by Category and Region

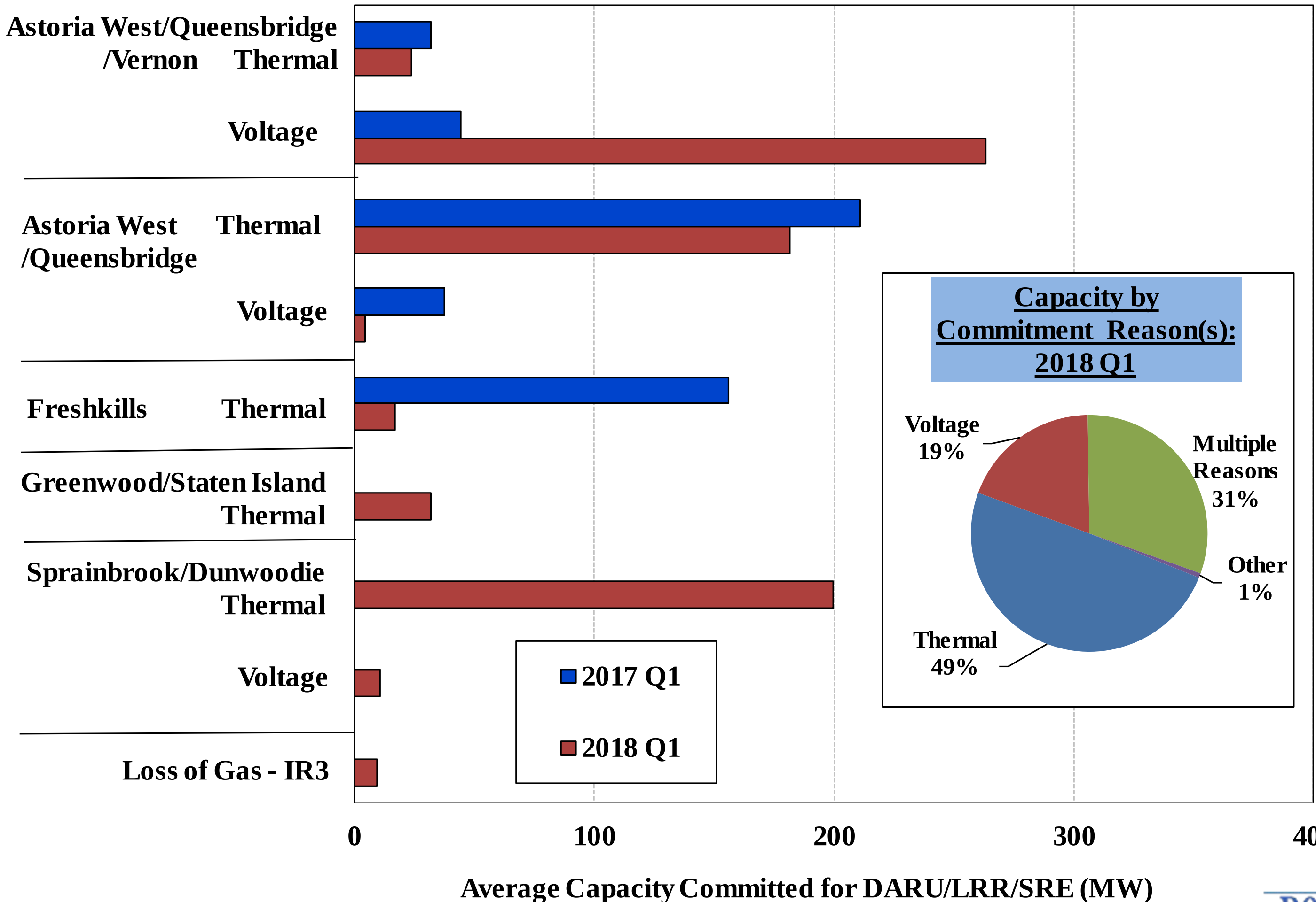


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2018 Q1	0.3%	0.7%	8.8%	0.3%
2017 Q4	0.4%	0.6%	8.9%	4.4%
2017 Q1	0.9%	0.0%	6.2%	0.2%

Note: For chart description, see slides 76 and 77.

POTOMAC ECONOMICS

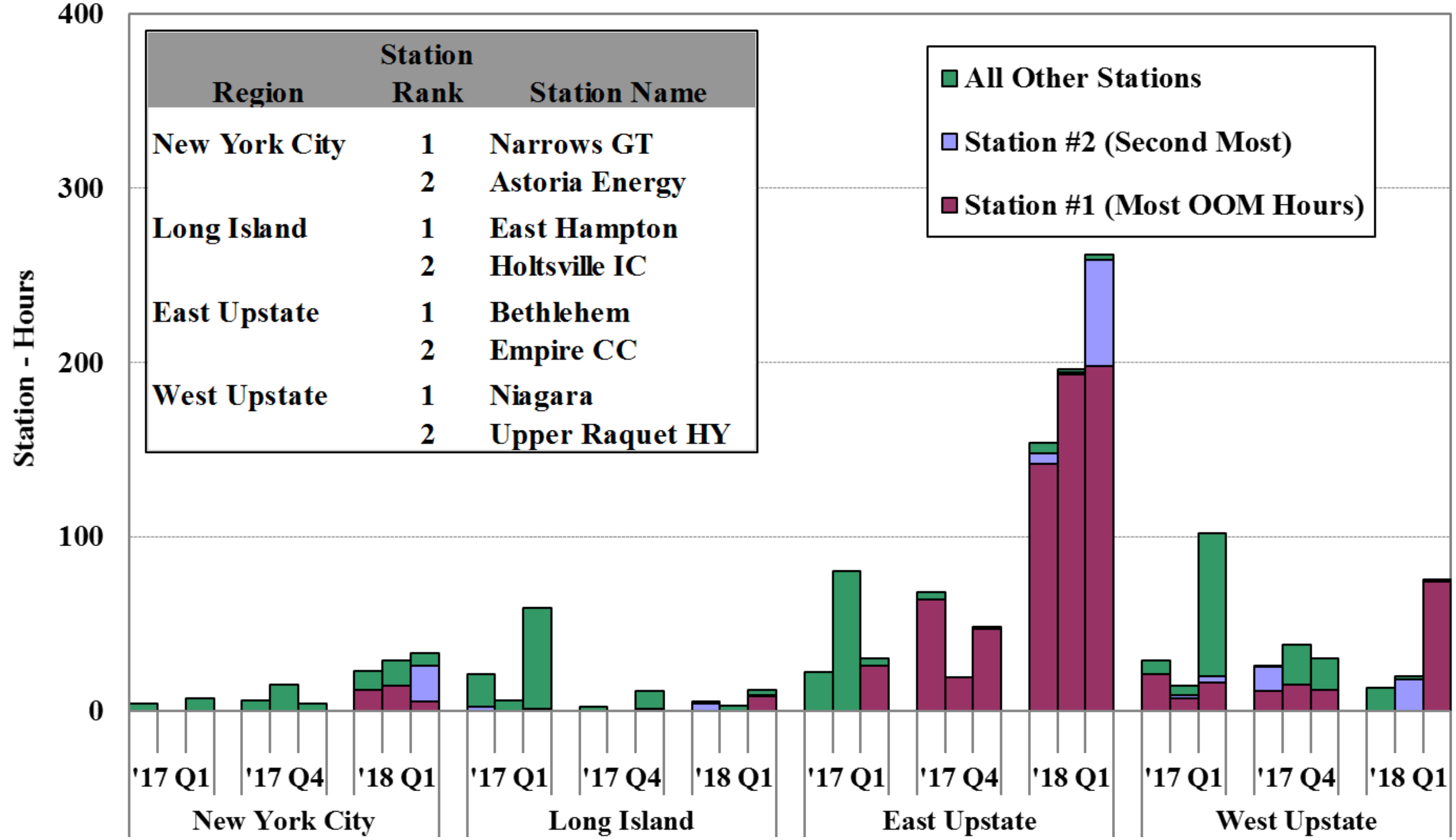
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



Note: For chart description, see slides 76 and 77.

POTOMAC ECONOMICS

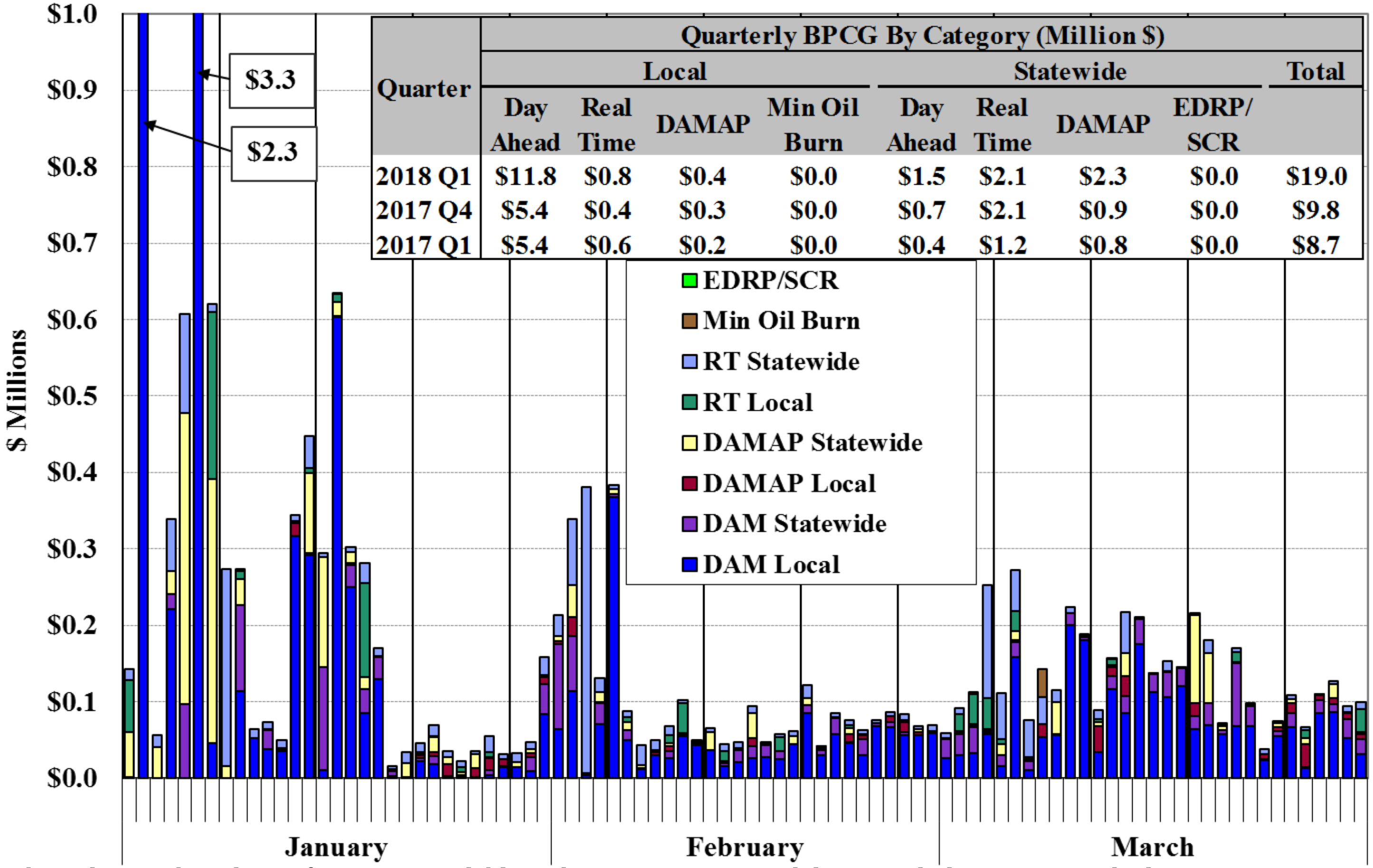
Frequency of Out-of-Merit Dispatch
by Region by Month



Note: The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 252 hours in 2017-Q1, 237 hours in 2017-Q4, and 247 hours in 2018-Q1. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

For chart description, see slides 76 and 77.

Uplift Costs from Guarantee Payments
Local and Non-Local by Category



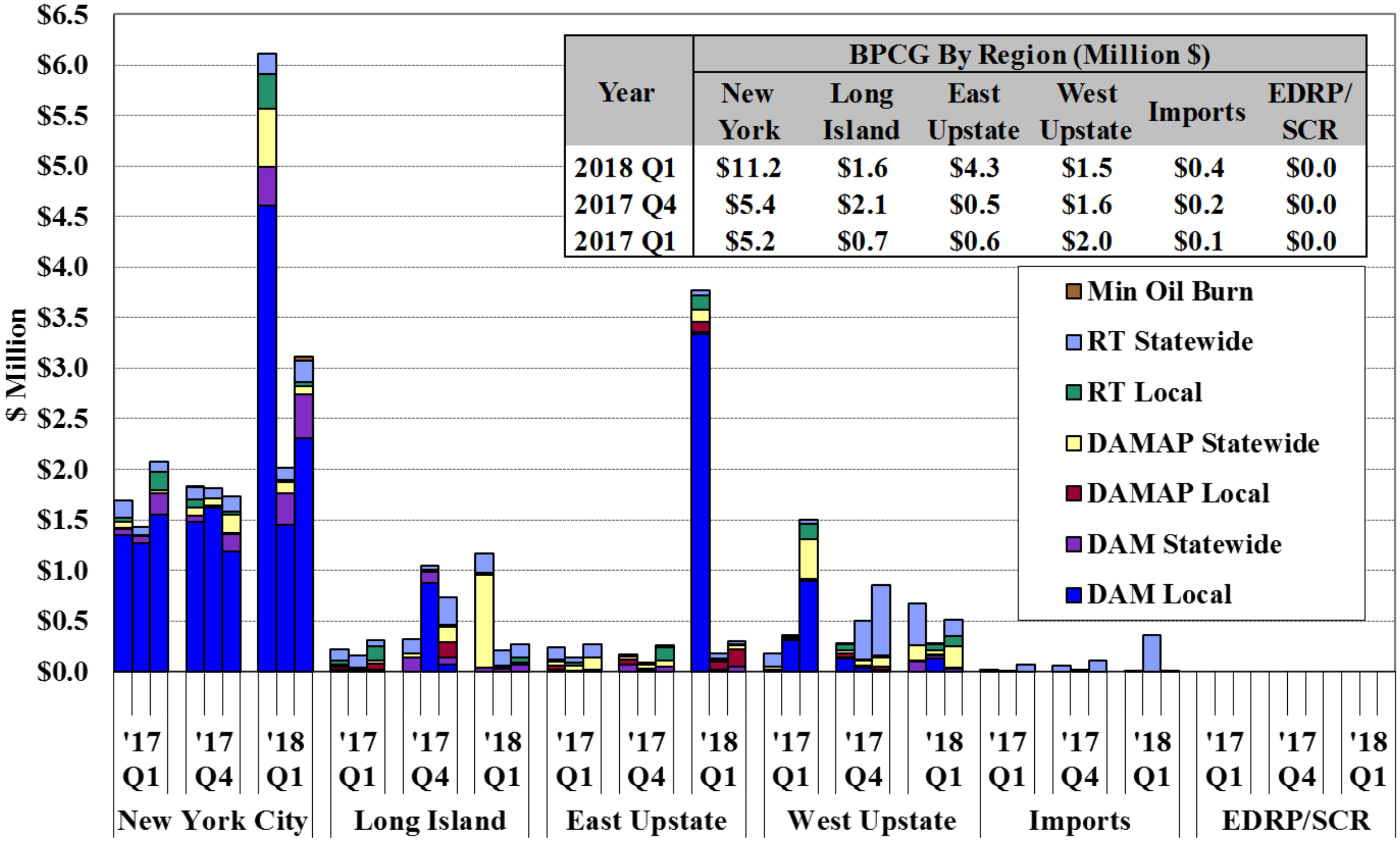
Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2018 Q1	$11.8	$0.8	$0.4	$0.0	$1.5	$2.1	$2.3	$0.0	$19.0
2017 Q4	$5.4	$0.4	$0.3	$0.0	$0.7	$2.1	$0.9	$0.0	$9.8
2017 Q1	$5.4	$0.6	$0.2	$0.0	$0.4	$1.2	$0.8	$0.0	$8.7

Note: These data are based on information available at the reporting time and do not include some manual adjustments to mitigation, so they can be different from final settlements.

For chart description, see slide 78.

Uplift Costs from Guarantee Payments
By Category and Region

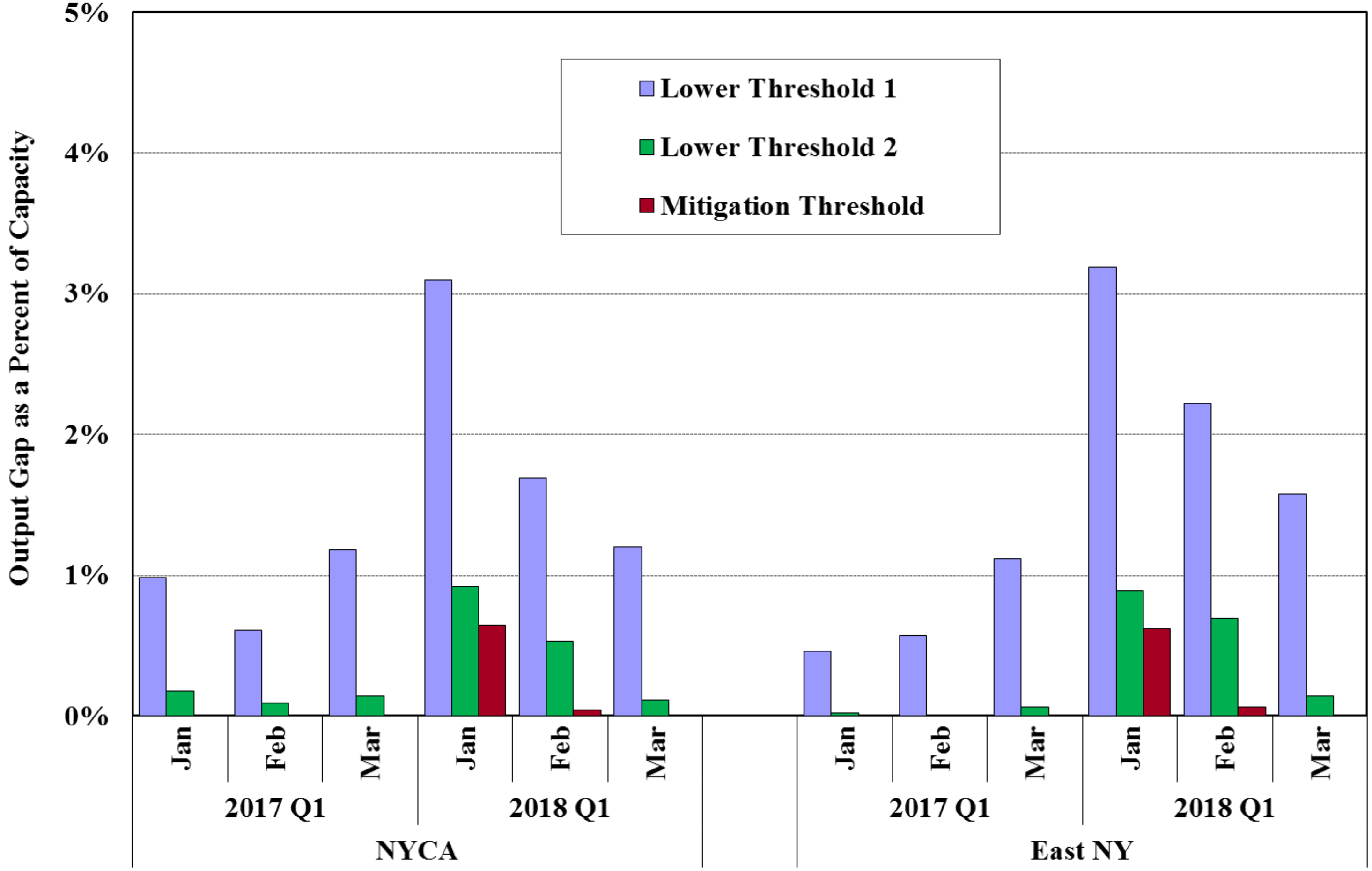
Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2018 Q1	$11.2	$1.6	$4.3	$1.5	$0.4	$0.0
2017 Q4	$5.4	$2.1	$0.5	$1.6	$0.2	$0.0
2017 Q1	$5.2	$0.7	$0.6	$2.0	$0.1	$0.0



Note: BPCG data are based on information available at the reporting time that can be different from final settlements.
For chart description, see slide 78.

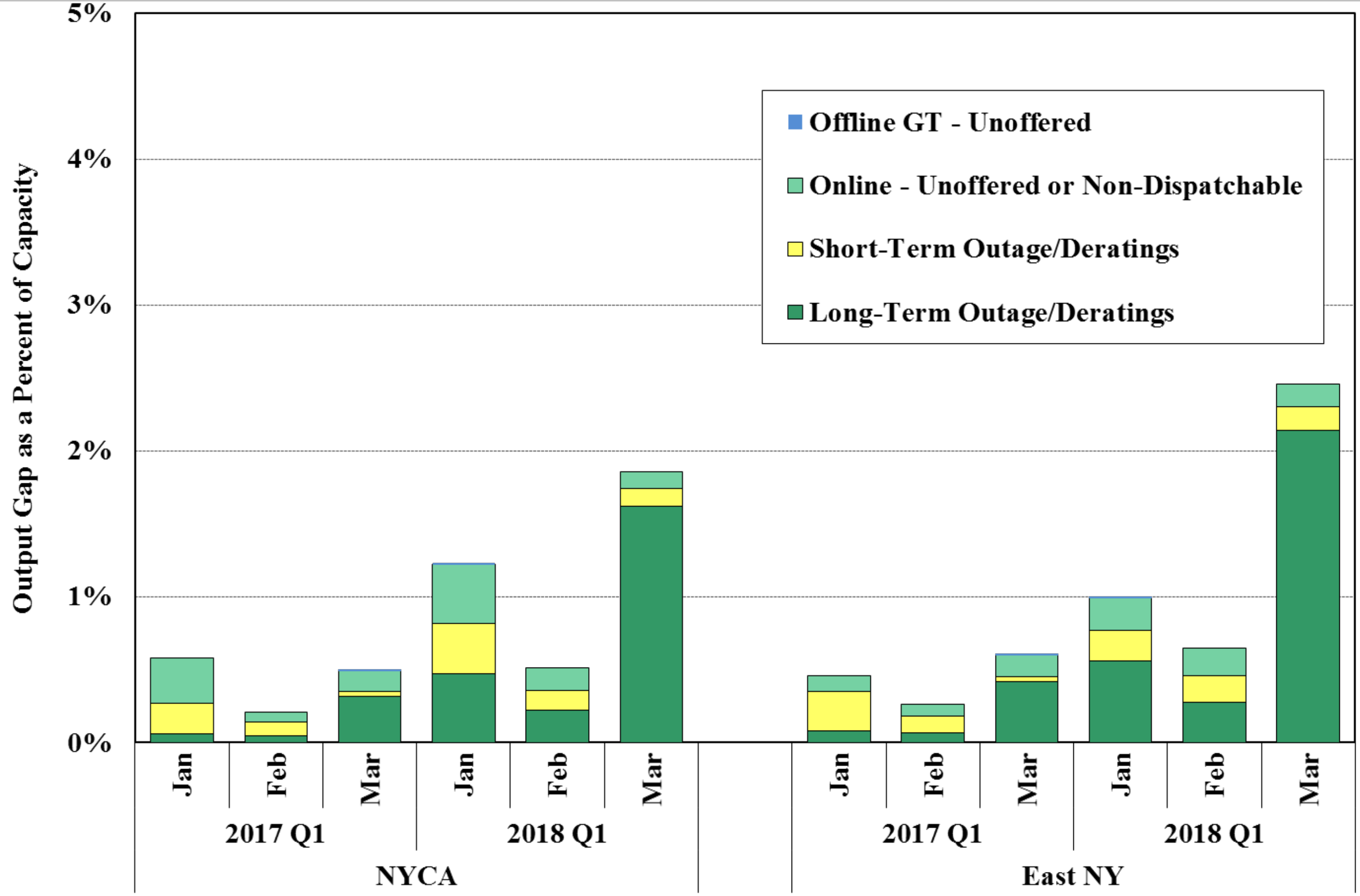
Market Power and Mitigation

Output Gap by Month
NYCA and East NY



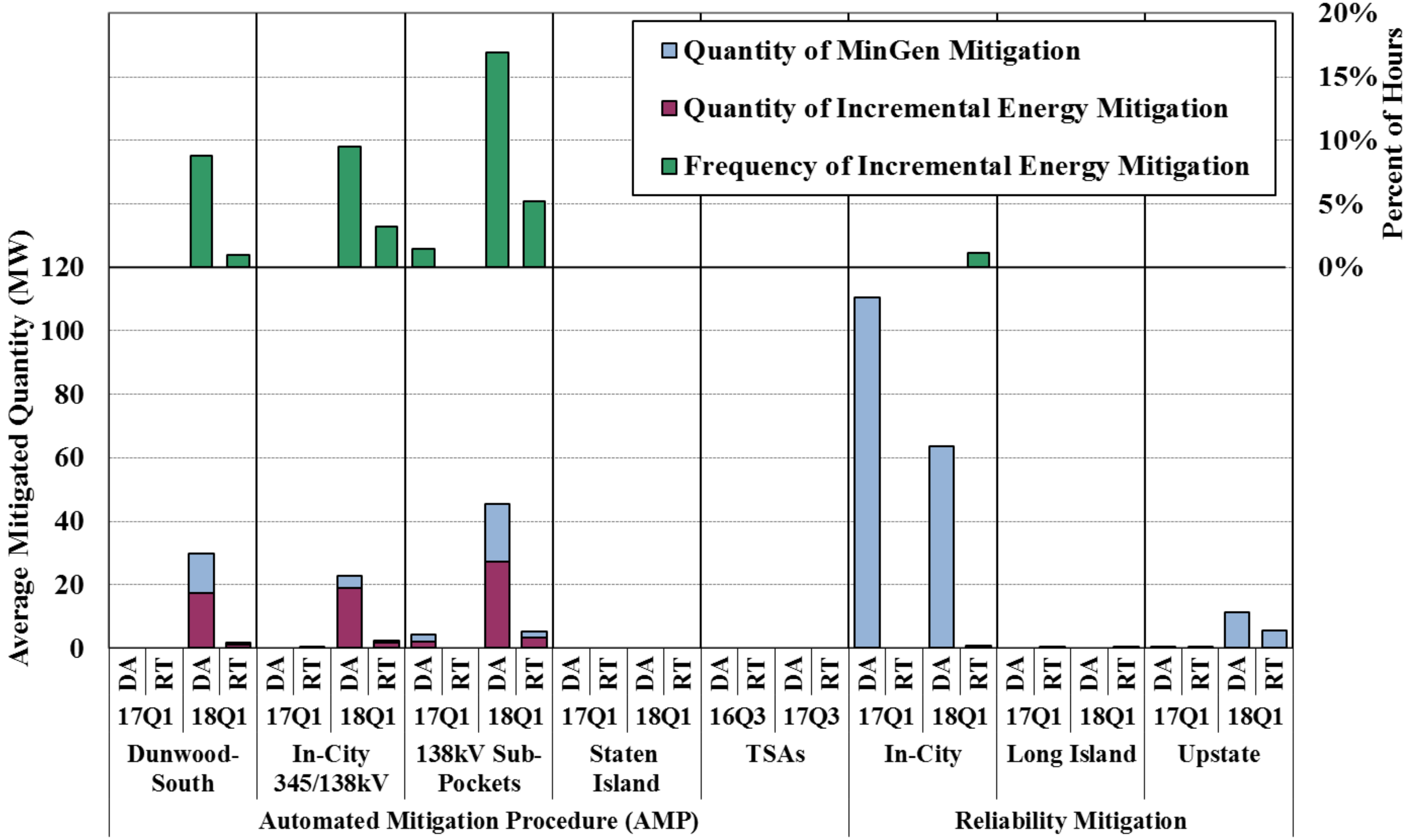
Note: Numbers reported here for historical periods may be slightly different from the ones reported previously because of improved assumptions and methodology for the calculation. For chart description, see slide 79.

Unoffered Economic Capacity by Month
NYCA and East NY



Note: Numbers reported here for historical periods may be slightly different from the ones reported previously because of improved assumptions and methodology for the calculation. For chart description, see slide 79.

Automated Market Power Mitigation



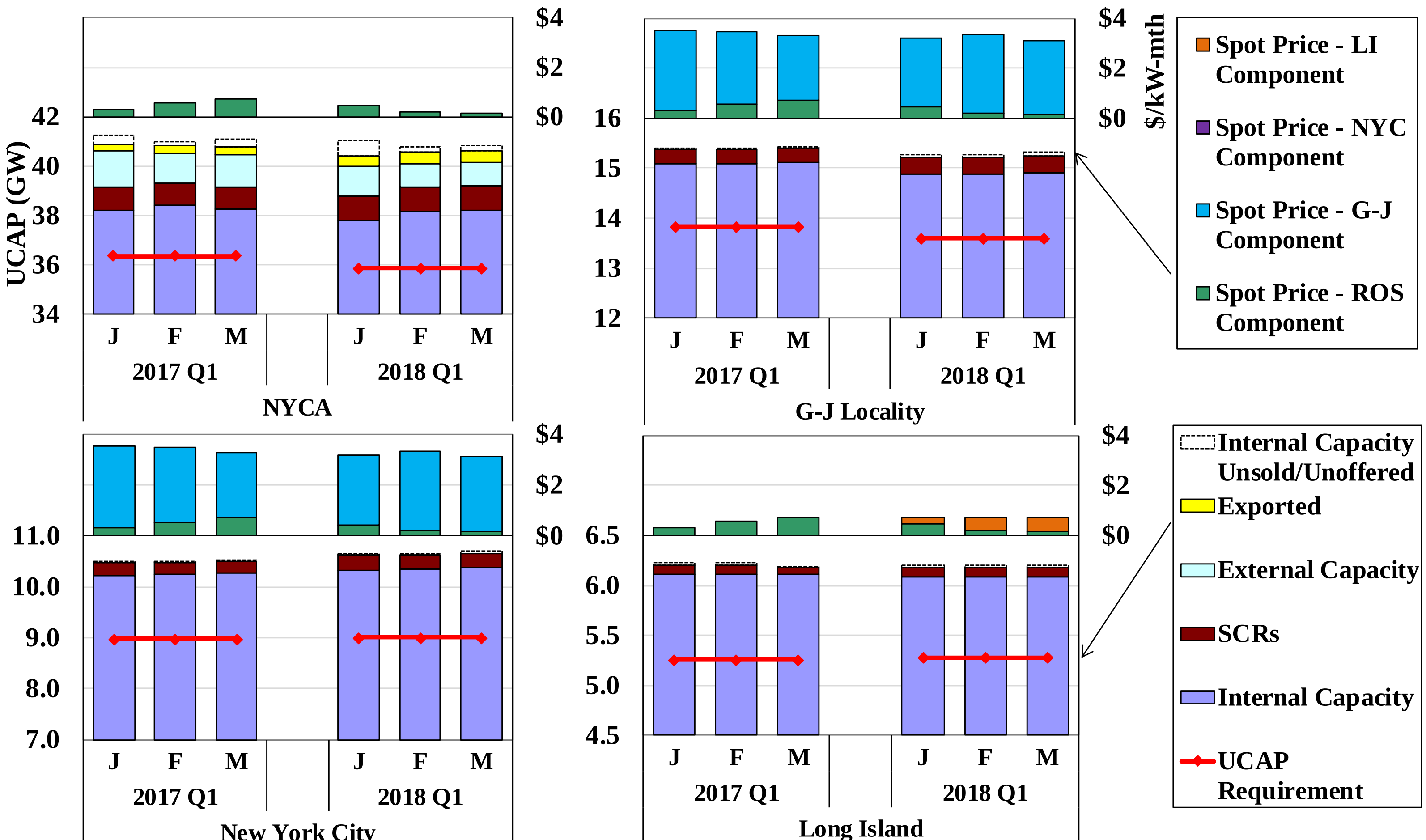
Note: For chart description, see slide 80.

POTOMAC ECONOMICS

Capacity Market

POTOMAC ECONOMICS

Spot Capacity Market Results
2017-Q1 & 2018-Q1



Note: For chart description, see slide 81.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2018 Q1 ($/kW-Month)	$0.26	$3.21	$0.70	$3.21
% Change from 2017 Q1	**-50%**	**-6%**	**34%**	**-6%**
Change in Demand				
Load Forecast (MW)	-181	-124	-51	-248
IRM/LCR	0.5%	1.0%	1.0%	1.5%
2017/18 Winter	*118.0%*	*81.5%*	*103.5%*	*91.5%*
2016/17 Winter	*117.5%*	*80.5%*	*102.5%*	*90.0%*
ICAP Requirement (MW)	**-47**	**17**	**2**	**18**
Change in ICAP Supply (MW) - Quarter Avg				
Generation	**209**	**88**	**-29**	**79**
Cleared Import	**-261**			
Change in Demand Curve and and Awarded Excess				
UCAP Bsed Reference Price @ 100% Req.				
% Change from 2017 Q1	-0.3%	-4%	53%	19%
UCAP Awarded Excess				
MW Change from 2017 Q1	75	118	-31	95
Demand Curve Slope (UCAP)				
Delta $/kW-month per 100 MW Increments	-$0.23	-$1.21	-$1.43	-$0.79

Note: For chart description, see slide 81.

Appendix: Chart Descriptions

All-in Price

- Slide 18 summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component that is calculated based on clearing prices in the monthly spot capacity auctions and capacity obligations in each area, allocated over the energy consumption in that area.
  - ✓ An uplift component that is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area.
  - ✓ An ancillary services component that is based on costs associated with operating reserves, regulation, voltage support, and black start.
    - – For the purpose of this metric, these costs are distributed evenly across all locations.
  - ✓ The figure also shows representative natural gas prices for each location that is based on the following indices (plus a transportation charge of $0.20/MMBtu):
    - – a) the Millennium East index for West Zone and Central NY; b) the Iroquois Waddington index for North Zone; c) the Iroquois Zone 2 index for Capital Zone and LI; d) the average of Millennium East and Iroquois Zone 2 for LHV; and e) the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.

Real-Time Output and Marginal Units by Fuel

- Slide 21 shows the quantities of real-time generation by fuel type.
  - ✓ Real time generation by fuel type is derived from data reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").
  - ✓ Pumped-storage resources in pumping mode are treated as negative generation. "Other" includes Methane, Refuse, Solar & Wood.
- Slide 22 summarizes how frequently each fuel type was on the margin and setting real-time LBMPs in these regions.
  - ✓ More than one type of generator may be on the margin in an interval, particularly when a transmission constraint is binding. Accordingly, the total for all fuel types may be greater than 100 percent.
    - – For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent.
  - ✓ When no generator is on the margin in a particular region, the LBMPs in that region are set by:
    - – Generators in other regions in the vast majority of intervals; or
    - – Shortage pricing of ancillary services, transmission constraints, and/or energy in a small share of intervals.

POTOMAC ECONOMICS

Utilization of Oil-Fired and Dual-Fuel Capacity
Eastern New York During the Cold Spell

- Slide 27 evaluates the use of oil-fired and dual-fuel capacity in Eastern New York during the Cold Spell from December 27, 2017 to January 9, 2018.
- The figure shows the estimated generation that would have been economic to burn oil based on day-ahead and real-time clearing prices during this period.
- The figure shows the capacity in the following categories:
  - ✓ Actual output, including:
    - Oil-fired generation; and
    - Gas-fired generation;
  - ✓ The amount of economic oil-fired generation that was unavailable because of:
    - Outages and deratings;
    - Oil equipment long-term OOS – mothballed or decommissioned oil equipment;
    - Oil equipment rate of fuel flow is limited
    - Oil equipment failures – short-term equipment outages;
    - Emission limitations;
    - Oil Inventory limitations; and
    - Lack of gas to start up.

Fuel Cost Adjustments During the Cold Spell

- Slide 28 outlines our review of generator fuel cost adjustments to reference levels during the cold spell for potentially inappropriate fuel cost submissions.
- The top portion of the chart shows fuel costs in the day-ahead market in NYC, which is based on the Transco Zone 6 (NY) index price (including a $0.2 transportation charge and a 6.9% tax rate).
- The bottom portion of the chart shows the offer pattern in the day-ahead market for gas-capable units in NYC. Generator offers are classified as:
  - ✓ Self-scheduled (including quantities offered in Self Flex and Self Fix modes, and quantities offered at a price less than $10/MWh);
  - ✓ Estimated oil-based offers;
  - ✓ Estimated gas-based offers without FCA;
  - ✓ High SUNTs; and
  - ✓ Offers with gas FCA in the following adjustment ranges:
    - FCA <= 90% index;
    - 90% index < FCA <= 110% index;
    - 110% index < FCA <= 150% index; and
    - FCA > 150% index

Ancillary Services Prices

- Slides 30, 31, and 32 summarize day-ahead and real-time prices for six ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices in eastern NY;
  - ✓ 10-min non-spinning reserve prices in eastern NY;
  - ✓ 10-min spinning reserve prices in western NY;
  - ✓ Regulation prices, which reflect the cost of procurement, and the cost of moving generation of regulating units up and down.
    - – Resources were scheduled assuming a Regulation Movement Multiplier of 13 MW per MW of capability, but they are compensated according to actual movement.
    - – Real-time Regulation Movement Charges shown on Slide 31 are estimated by dividing total movement charges by real-time scheduled regulation capacity.
  - ✓ 30-min operating reserve prices in western NY; and
  - ✓ 30-min operating reserve prices in SENY.
- The number of shortage intervals in real-time for each ancillary service product are also shown.
  - ✓ A shortage occurs when a requirement cannot be satisfied at a marginal cost less than its "demand curve".
  - ✓ The highest demand curve values are currently set at $775/MW.

POTOMAC ECONOMICS

Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 33 summarizes the amount of reserve offers in the day-ahead market that can satisfy the statewide 30-minute reserve requirement.
  - ✓ These quantities include both 10-minute and 30-minute and both spinning and non-spin reserve offers. (However, they are not shown separately in the figure.)
  - ✓ Only offers from day-ahead committed (i.e., online) resources and available offline quick-start resources are included, since they directly affect the reserve prices.
  - ✓ The stacked bars show the amount of reserve offers in each select price range for West NY (Zones A to E), East NY (Zones F to J), and NYCA (excluding Zone K).
    - – Long Island is excluded because the current rules limit its reserve contribution to the broader areas (i.e., SENY, East, NYCA).
    - – Thus, Long Island reserve offer prices have little impact on NYCA reserve prices.
  - ✓ The black line represents the equivalent average 30-minute reserve requirements for areas outside Long Island.
    - – The equivalent 30-minute reserve requirement is calculated as NYCA 30-minute reserve requirement minus 30-minute reserves scheduled on Long Island.
    - – Where the lines intersect the bars provides a rough indication of reserve prices (less opportunity costs).

Day-Ahead Load Scheduling and Virtual Trading

- Slide 35 shows the quantity of day-ahead load scheduled as a percentage of real-time load in each of seven regions and statewide by day.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Slide 36 shows monthly average scheduled and unscheduled quantities and gross profitability for virtual trades in the past 24 months.
  - ✓ The table identifies virtual trades with relatively large profits or losses that exceed 50 percent of the average zone LBMP.
  - ✓ Large profits may indicate modeling inconsistencies between day-ahead and real-time markets, and large losses may indicate manipulation of the day-ahead market.
- Slide 37 summarizes virtual trading by region including average quantities of scheduled virtual supply and load and gross profitability for seven NY regions and four groups of external proxy buses.
  - ✓ The top portion of the chart also shows average day-ahead scheduled load (as a percent of real-time load) by geographic region.
  - ✓ Virtual imports/exports are included as they have similar effects on scheduling.
    - – A transaction is deemed-“virtual” if its day-ahead schedule is greater than its real-time schedule.

Efficiency of CTS Scheduling with PJM and NE

- Slide 39 evaluates the performance of CTS with PJM and NE at their primary interfaces in the quarter. The table shows:
  - ✓ The percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule).
  - ✓ The average flow adjustment from the estimated hourly schedule.
  - ✓ The production cost savings that resulted from CTS, including:
    - Projected savings at scheduling time, which is the expected production cost savings at the time when RTC determines the interchange schedule.
    - Net over-projected savings, which is the portion of savings that was inaccurately projected because of PJM, NYISO, and ISO-NE price forecast errors.
    - Other Unrealized savings, which are not realized due to: a) real-time curtailment; and b) interface ramping.
    - Actual savings (= Projected – Over-projected – Other Unrealized).
  - ✓ Interface prices, which are forecasted prices at the time of RTC scheduling and actual real-time prices.
  - ✓ Price forecast errors, which show the average difference and the average absolute difference between actual and forecasted prices across the interfaces.

Contributing Factors to RTC/RTD Divergence
A Case Study

- Slide 40 illustrates major factors that contribute to price divergence between RTC and RTD via an example on January 5th. In the chart,
  - ✓ The top portion shows the RTC/RTD shadow prices on the Central-East interface.
  - ✓ The middle portion shows three groups of factors that contributed to the shadow price divergence between RTC and RTD:
    - NY-NJ PARs: include differences in modeled schedules between RTC and RTD on A, B, C, J, K, and Ramapo PARs.
    - Central-East unmodeled flows: include differences in unmodeled flows on the Central-East interface that result from loop flows, inaccurate PAR modeling assumptions, and other modeling assumptions that lead to BMS/EMS differences.
    - Other: include all other factors.
    - The stacked bars measure their contributions based on our evaluation metric. (see Section IV.D in the Appendix of our 2017 SOM report for more details on the evaluation metric and the contributing factors).
  - ✓ The bottom portion illustrates the most significant contributor in this example.
    - One line shows the actual aggregated SCADA readings for the NY-NJ PARs
    - Two lines show the SCADA readings at the time when RTC and RTD initialized.

Transmission Congestion and Shortfalls

- Slides 42, 43, 44, and 45 evaluate the congestion patterns in the DAM and RTM and examine the following categories of resulting congestion costs:
  - ✓ Day-Ahead Congestion Revenues are collected by the NYISO when power is scheduled to flow across congested interfaces in the DAM, which is the primary funding source for TCC payments.
  - ✓ Day-Ahead Congestion Shortfalls occur when the net day-ahead congestion revenues are less than the payments to TCC holders.
    - Shortfalls (or surpluses) arise when the TCCs on a path exceed (or is below) its DAM transfer capability in periods of congestion.
    - These typically result from modeling differences between the TCC auction and the DAM, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ Balancing Congestion Shortfalls arise when DAM scheduled flows over a constraint exceed what can flow over the constraint in the RTM.
    - The transfer capability of a constraint falls (or rises) from day-ahead to real-time for the similar reasons (e.g., deratings and outages of transmission facilities, inconsistent assumptions regarding PAR schedules and loop flows, etc.).
    - In addition, payments between the NYISO and PJM related to the M2M process also contribute to shortfalls (or surpluses).

Transmission Congestion and Shortfalls (cont.)

- Slide 42 summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years on a monthly basis.
  - ✓ The upper portion of the figure shows balancing congestion revenue shortfalls, and the lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls. The sum of these two categories is equal to the total net payments to TCC holders in each month.
- Slide 43 examines in detail the value and frequency of day-ahead and real-time congestion along major transmission paths by quarter.
  - ✓ The value of transfers is equal to the marginal cost of relieving the constraint (i.e., shadow price) multiplied by the scheduled flow across the transmission path.
  - ✓ In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO.
  - ✓ In the real-time market, the value of congestion does not equal the congestion revenue collected by the NYISO, since most real-time power flows settle at day-ahead prices rather than real-time prices.
- Slides 44 and 45 show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.

Transmission Congestion and Shortfalls (cont.)

- Congestion is evaluated along major transmission paths that include:
  - ✓ West Zone Lines: Primarily 230 kV transmission constraints in the West Zone.
  - ✓ West to Central: Including transmission constraints in the Central Zone and interfaces from West to Central.
  - ✓ North Zone: The Moses-South interface and other lines in the North Zone and leading into Southern New York.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.
  - ✓ Capital to Hudson Valley: Primarily lines leading into SENY (e.g., the New Scotland-Leeds line, the Leeds-Pleasant Valley line, etc.)
  - ✓ NYC Lines: Including lines into and within the NYC 345 kV system, lines leading into and within NYC load pockets, and groups of lines into NYC load pockets that are modeled as interface constraints.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ External Interfaces – Congestion related to the total transmission limits or ramp limits of the external interfaces.
  - ✓ All Other – All of other line constraints and interfaces.

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NY-NJ PAR Operation Under M2M with PJM

- Slide 46 evaluates operations of NY-NJ PARs under M2M with PJM during the following periods of noticeable congestion differential between NY and PJM:
  - ✓ When NY costs on relevant M2M constraints exceed PJM costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh.
  - ✓ When PJM costs on relevant M2M constraints exceed NY costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh;
  - ✓ The market cost is measured as the constraint shadow price multiplied by the PAR shift factor, summed over relevant M2M constraints in each 5-minute market interval and then averaged over each half-hour period.
  - ✓ The top portion of the figure shows two stacked bars for each evaluation group, representing the total number of 30-minute intervals with and without any PAR tap movements.
  - ✓ The bottom portion of the figure shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).

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Constraints on the Low Voltage Network in Upstate New York

- Transmission constraints on the 115 kV and lower voltage networks in upstate New York are often resolved in ways that include:
  - ✓ Out of merit dispatch and supplemental commitment of generation;
  - ✓ Curtailment of external transactions and limitations on external interface limits;
  - ✓ Use of an internal interface transfer limit that functions as a proxy for the limiting transmission facility; and
  - ✓ Adjusting PAR-controlled lines on the high voltage network.
- Slide 47 shows the number of days in the quarter when various resources were used to manage constraints in five areas of upstate New York:
  - ✓ West Zone: Mostly Niagara-to-Gardenville and Gardenville-to-Dunkirk circuits;
  - ✓ Central Zone: Mostly constraints around the State Street 115kV bus;
  - ✓ Capital Zone: Mostly Albany-to-Greenbush 115kV constraints;
  - ✓ North & Mohawk Valley Zones: Mostly 115kV constraints on facilities that flow power south from the North Zone and through the Mohawk Valley Zone between the Colton 115kV and Taylorville 115kV buses; and
  - ✓ Hudson Valley Zone: Mostly constraints on the 69kV system in the Hudson Valley.

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Supplemental Commitments and OOM Dispatch

- Slides 49, 50, and 51 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 49 shows the quantities of reliability commitment by region in the following categories on a monthly basis:
  - ✓ Day-Ahead Reliability Units (“DARU”) Commitment – occurs before the economic commitment in the DAM at the request of local TO or for NYISO reliability;
  - ✓ Day-Ahead Local Reliability (“LRR”) Commitment – occurs in the economic commitment in the DAM for TO reliability in NYC;
  - ✓ Supplemental Resource Evaluation (“SRE”) Commitment – occurs after the DAM;
  - ✓ Forecast Pass Commitment – occurs after the economic commitment in the DAM.
- Slide 50 examines the reasons for reliability commitments in NYC where most reliability commitments occur.
  - ✓ Based on a review of operator logs and LRR constraint information (where a unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit’s capacity), each NYC commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:

Supplemental Commitments and OOM Dispatch (cont.)

  - NOx Only – If needed for NOx bubble requirement and no other reason.
  - Voltage – If needed for ARR 26 and no other reason except NOx.
  - Thermal – If needed for ARR 37 and no other reason except NOx.
  - Loss of Gas – If needed for IR-3, a sudden loss of gas supply in NY, and no other reason except NOx.
  - Multiple Reasons – If needed for two or three of the following reasons: voltage support, thermal support, or loss of gas. The capacity is shown multiple times for each separate reason in the bar chart.
- ✓ For voltage and thermal constraints, the capacity is shown by the load pocket that was secured.

- Slide 51 summarizes the frequency (measured by the total station-hours) of Out-of-Merit dispatches by region on a monthly basis.
  - ✓ The figure excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.
  - ✓ In each region, “Station #1” is the station with the highest number of OOM hours in its region in the current quarter; “Station #2” is the station with the second-highest number of OOM hours; all other stations are grouped together.

Uplift Costs from Guarantee Payments

- Slides 52 and 53 show uplift charges in the following seven categories.
  - ✓ Three categories of non-local reliability uplift are allocated to all LSEs:
    - – Day Ahead: For units committed in the DAM (usually economically) whose day-ahead market revenues do not cover their as-offered costs.
    - – Real Time: Typically for quick-start resources that are scheduled economically, or units committed or dispatched OOM for bulk system reliability whose real-time market revenues do not cover their as-offered costs.
    - – Day Ahead Margin Assurance Payment (“DAMAP”): For generators that incur losses because they are dispatched below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.
  - ✓ Four categories of local reliability uplift are allocated to the local TO:
    - – Day Ahead: From Local Reliability Requirements (“LRR”) and Day-Ahead Reliability Unit (“DARU”) commitments.
    - – Real Time: From Supplemental Resource Evaluation (“SRE”) commitments and Out-of-Merit (“OOM”) dispatched units for local reliability.
    - – Minimum Oil Burn Program: Covers spread between oil and gas prices when generators burn oil to satisfy NYC gas pipeline contingency reliability criteria.
    - – DAMAP: For units that are dispatched OOM for local reliability reasons.
  - ✓ Slide 52 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 53 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 55 and 56 show the results of our screens for attempts to exercise market power, which may include economic and physical withholding.
- The screen for potential economic withholding is the Output Gap, which is the amount of economic capacity that does not produce energy because a supplier submits an offer price above the unit's reference level by a substantial threshold.
  - ✓ We show output gap in NYCA and East NY, based on:
    - The state-wide mitigation threshold (the lower of $100/MWh and 300 percent); and
    - Two other lower thresholds (100 percent and 25 percent).
- The screen for potential physical withholding is the Unoffered Economic Capacity, which is the amount of economic capacity that is not available to the market because a supplier does not offer, claims a derating, or offers in an inflexible way.
  - ✓ We show the unoffered economic capacity in NYCA and East NY, from:
    - Long-term outages/deratings (at least 7 days);
    - Short-term outages/deratings (less than 7 days);
    - Online capacity that is not offered or offered inflexibly; and
    - Offline GT capacity that is not offered in the real-time market.
  - ✓ Long-term nuclear outages/deratings are excluded from this analysis.

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Automated Market Power Mitigation

- Slide 57 summarizes the automated mitigation that was imposed in the day-ahead and real-time markets (not including BPCG mitigation) in the quarter.
  - ✓ The bars in the upper panel shows the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category.
  - ✓ The bars in the lower panel shows the average mitigated capacity.
    - – Mitigated quantities are shown separately for flexible output range of units (i.e., Incremental Energy) and the non-flexible portion (i.e., MinGen).
  - ✓ The left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on economically committed units in NYC load pockets.
  - ✓ The right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.
  - ✓ Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

Spot Capacity Market Results

- Slides59 and 60 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide59 summarizes available and scheduled Unforced Capacity (“UCAP”), UCAP requirements, and spot prices that occurred in each capacity zone by month.
    - – Sales associated with Unforced Deliverability Rights (“UDRs”) are included in “Internal Capacity,” but unsold capacity from resources with UDRs is not shown.
  - ✓ Slide60 compares the year-over-year changes in capacity spot prices by Locality and shows variations in key factors that drove these changes, including:
    - – The changes in the UCAP requirements, which are affected by changes in the forecasted peak load, the minimum capacity requirement, and the derating factors;
    - – The changes in the UCAP supply, which are affected by changes in new entry, mothballing and retirement, and DMNC test values; and
    - – The changes in the demand curves, which are mostly affected by the assumptions used in each demand curve reset process.
      - The most recent reset was done for the Capability Periods from 2017 to 2021.