Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2017

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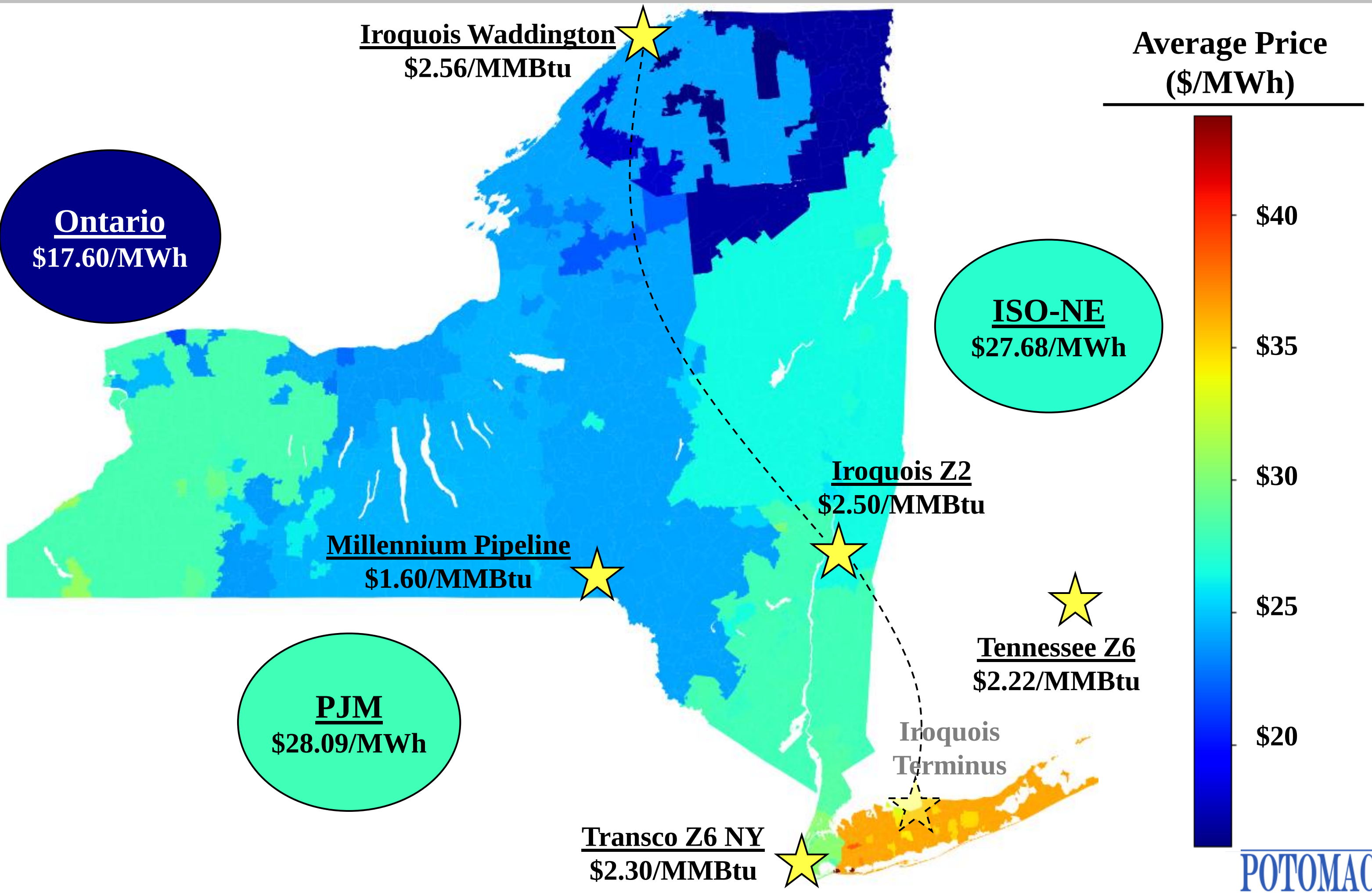
Highlights and Market Summary: Summary of Market Outcomes

- This report summarizes market outcomes in the third quarter of 2017.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- Energy prices fell 16 to 30 percent across the state compared to the third quarter of 2016 because of the confluence of supply and demand factors:
  - ✓ Mild summer temperatures and lower load levels (down 1.8 GW on average);
  - ✓ Lower natural gas prices in most of East NY and New England (down 12 to 19 percent);
  - ✓ Higher output from nuclear and hydro units (up 640 MW on average);
  - ✓ Reduced congestion into Long Island from fewer transmission outages; and
  - ✓ Increased congestion out of the North Zone from more transmission outages.
- These factors also contributed to substantially lower ancillary service prices and uplift costs.
- Although most prices and costs were down substantially compared to last year, we continue to identify potential market performance improvements.

Highlights and Market Summary: Congestion Patterns

- Day-ahead congestion revenue totaled $104 million, down 20 percent from last year partly because of lower load levels. (slides 48 & 53)
  - ✓ West zone lines accounted for the most congestion (25 percent) as Ontario imports and hydro output met with bottlenecks while flowing toward East NY.
  - ✓ NYC lines accounted for 20 percent, increasing because of higher gas prices relative to other regions and the expiration of the ConEd-PSEG wheel.
  - ✓ Long Island accounted for 17 percent, although this was down dramatically because of fewer major transmission outages than in 2016-Q3.
- Flows from the North Zone accounted for 21 percent of real-time congestion as:
  - ✓ Transmission outages and derates and hydroelectric output both increased, and led to several extreme negative pricing events. (slides 20 & 22).
- Actions used to manage 115kV congestion in western and northern New York led to import limitations from Ontario and Quebec, as well as congestion on the 200+kV system in other parts of the state. (slides 68 – 70)
  - ✓ 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.

Highlights and Market Summary:
Energy Market Outcomes and Congestion



Highlights and Market Summary:
Congestion Management and Pricing

- The M2M PAR coordination process expanded in May after the 1,000 MW ConEd/PSEG Wheel expired. (slides 60 – 67)
  - ✓ Congestion increased through Millwood and into New York City.
  - ✓ In general, the A/B/C and J/K lines were operated more efficiently.
  - ✓ However, we observe that these PARs were often not utilized to help manage congestion, being adjusted only 1 to 5 times per day on average.
- The NYISO improved the transmission shortage pricing in June (slides 56 – 59) by:
  - ✓ Modifying the second step of the GTDC from $2,350 to $1,175/MWh; and
  - ✓ Removing the feasibility screen and apply the GTDC to all constraints with a non-zero Constraint Reliability Margin (“CRM”).
  - ✓ As a result, constraint relaxation has been much less frequent (6 percent of violations this quarter vs 59 percent last year) average constraint shadow prices during transmission shortages fell moderately in most areas.
    - – Constraint relaxation leads to inefficient prices that are volatile and uncorrelated with the severity of congestion.
  - ✓ Despite improved pricing outcomes, constraint shadow prices still did not properly reflect the importance of some transmission shortages. Accordingly, we continue to recommend developing constraint-specific transmission demand curves.

Highlights and Market Summary:
Reserve Market Performance

- Day-ahead reserve prices fell by 28 to 44 percent from a year ago, consistent with lower load levels and lower LBMPs. (slides 26 – 29)
  - ✓ The reduction was primarily attributable to the decrease in reserve offer prices. (slide 32)
- After reserve market design changes in November 2015, we have observed offers above the standard competitive benchmark (i.e., estimated marginal cost).
  - ✓ This is partly because it is difficult to accurately estimate the marginal cost of providing operating reserves.
- However, day-ahead reserve offer prices have gradually fallen as suppliers gain more experience.
  - ✓ This quarter, a large amount of reserve capacity (particularly from fast-start resources in East NY) further reduced its offer prices. (slides 30 – 32)
- We continue to monitor day-ahead reserve offer patterns and consider potential rule changes including whether to modify the existing \$5/MWh “safe harbor” for reserve offers in the market power mitigation measures.

Highlights and Market Summary:
Uplift and Revenue Shortfalls

- Guarantee payments were $8.5 million, which was down 55 percent from 2016-Q3. (slides 79 – 82)
  - ✓ The reduction was reflective of lower load levels, fewer transmission outages in LI, and transmission upgrades in the Central Zone, which led to reduced supplemental commitments and OOM dispatches in most areas. (slides 74 – 78)
  - ✓ However, guarantee payments remained comparable in NYC.
    - Reliability commitment rose in NYC because units that were often needed for local reliability became less economic due to lower load levels and higher gas prices.
- Congestion shortfalls were $10 million in the day-ahead market (down 50 percent from last year) and $9 million in the real-time market (comparable to last year).
  - ✓ Transmission outages accounted for the vast majority of DAM shortfalls.
    - $9 million (~ 90%) was allocated to the responsible TO. (see slides 49 & 50 for a list of major transmission outages)
  - ✓ Nearly 90 percent of balancing shortfalls were associated with transmission facilities in the North Zone and the West Zone. (slides 51 & 55)
    - North Zone accounted for 61 percent, most of which occurred on two days as a result of unexpected events.
    - West Zone accounted for 21 percent due to high and volatile loop flows.

Highlights and Market Summary:
Capacity Market

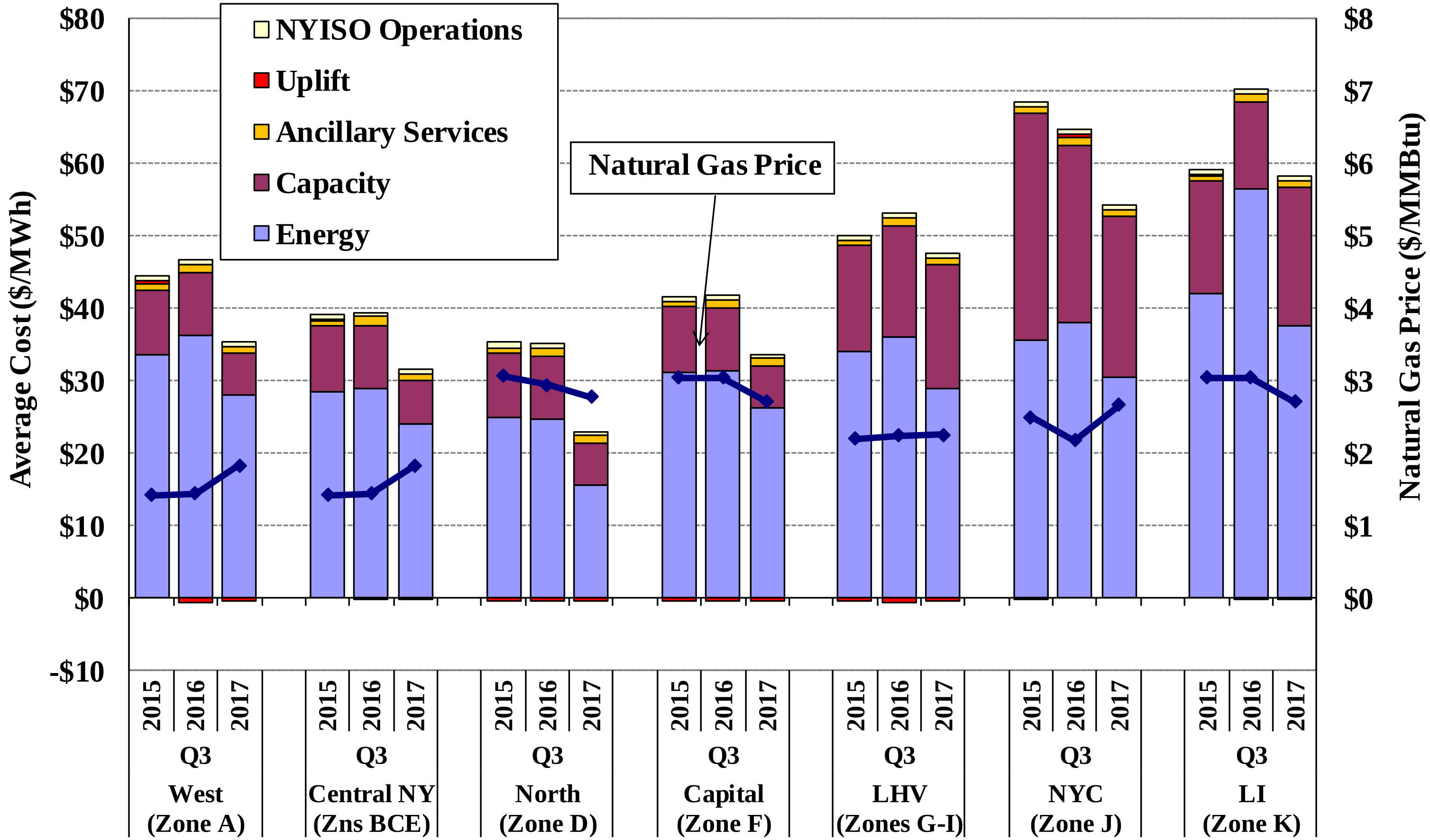
- In this quarter, spot prices ranged from \$2.21/kW-month in ROS to \$9.97/kW-month in NYC. (slides 91 – 93)
- Compared to last year, average spot prices fell 18 percent in NYC and 41 percent in ROS, but rose 6 percent in the G-J Locality and 51 percent in Long Island.
  - ✓ Changes in the Demand Curve Reference Points (which reflected changes to the unit Net CONE assumptions for the proxy unit from the latest Demand Curve Reset process) were a primary driver for the three Localities.
  - ✓ While the change in ICAP supply was a dominant factor for ROS price changes.
    - – The amount of internal ICAP supply increased modestly from a year ago.
      - The increase reflected higher DMNC test values, the revival of the Greenidge 4 Unit and new wind capacity upstate.
    - – Cleared import capacity rose 350 MW from a year ago, primarily from PJM.
      - Cleared import capacity from Ontario increased by an average of 105 MW, which, however, was offset by a similar amount of reduction from New England.
  - ✓ IRM/LCRs rose in all regions as a result of the recent NYSRC study.
    - – However, the peak load forecasts fell across all regions, neutralizing the price impact from higher IRM/LCRs.

Energy Market Outcomes

All-In Prices

- The first figure 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 based on spot prices multiplied by capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Rate Schedule 1 charges.
- Average all-in prices ranged from roughly $23/MWh in the North Zone to $58/MWh in Long Island in the third quarter of 2017. Compared to 2016-Q3:
  - ✓ All-in prices fell in all regions, from 10 percent in LHV to 35 percent in the North Zone.
  - ✓ Real-time LBMPs fell by 16 to 37 percent across the state.
    - – Lower loads (slide 13), lower gas prices in most of East NY (slide 14), and higher hydro and nuclear generation (slide 17) were the primary drivers.
    - – The large decrease in the North Zone was also attributable to more transmission outages that bottlenecked power out of this area, while fewer transmission outages into Long Island led to reduced congestion and lower LBMPs (slide 48 & 53).
  - ✓ Capacity costs rose in Long Island (61%) and Lower Hudson Valley (12%), but fell in NYC (9%) and in Rest of State (33%). (slides 91 – 93)

All-In Prices by Region



Note: Natural Gas Price is based on the following indices (plus a transportation charge of $0.20/MMbtu): the Dominion North index for West Zone and Central NY, the Iroquois Waddington index for North Zone, the Iroquois Zone 2 index for Capital Zone and LI, the average of Millennium East and Iroquois Zone 2 for LHV, the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.

Load Levels and Fuel Prices

- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Load averaged 19.7 GW this quarter and peaked at 29.7 GW on July 19.
  - ✓ Both peak and average load fell dramatically (7-8%) from a year ago primarily because of milder weather conditions this summer.
    - – The total number of cooling degree days fell 32 percent from last summer.
- Natural gas prices rose in most regions from a year ago (25% in NYC, ~30% in Western NY), but fell in other areas (12-19% in Capital and Long Island).
  - ✓ The increases reflected lower storage levels and pipeline expansion projects that have begun to allow more northeastern natural gas production to flow south.
    - – These prices were still lower than in other regions (e.g., $2.93 at Henry Hub).
  - ✓ Compared to 2016-Q3, gas spreads fell between: a) West NY and East NY; b) NYC and rest East NY; and c) East NY and NE.
    - – This has led to variations in generation patterns (slide 17), congestion patterns (slides 48 & 53), and import levels (slide 40).

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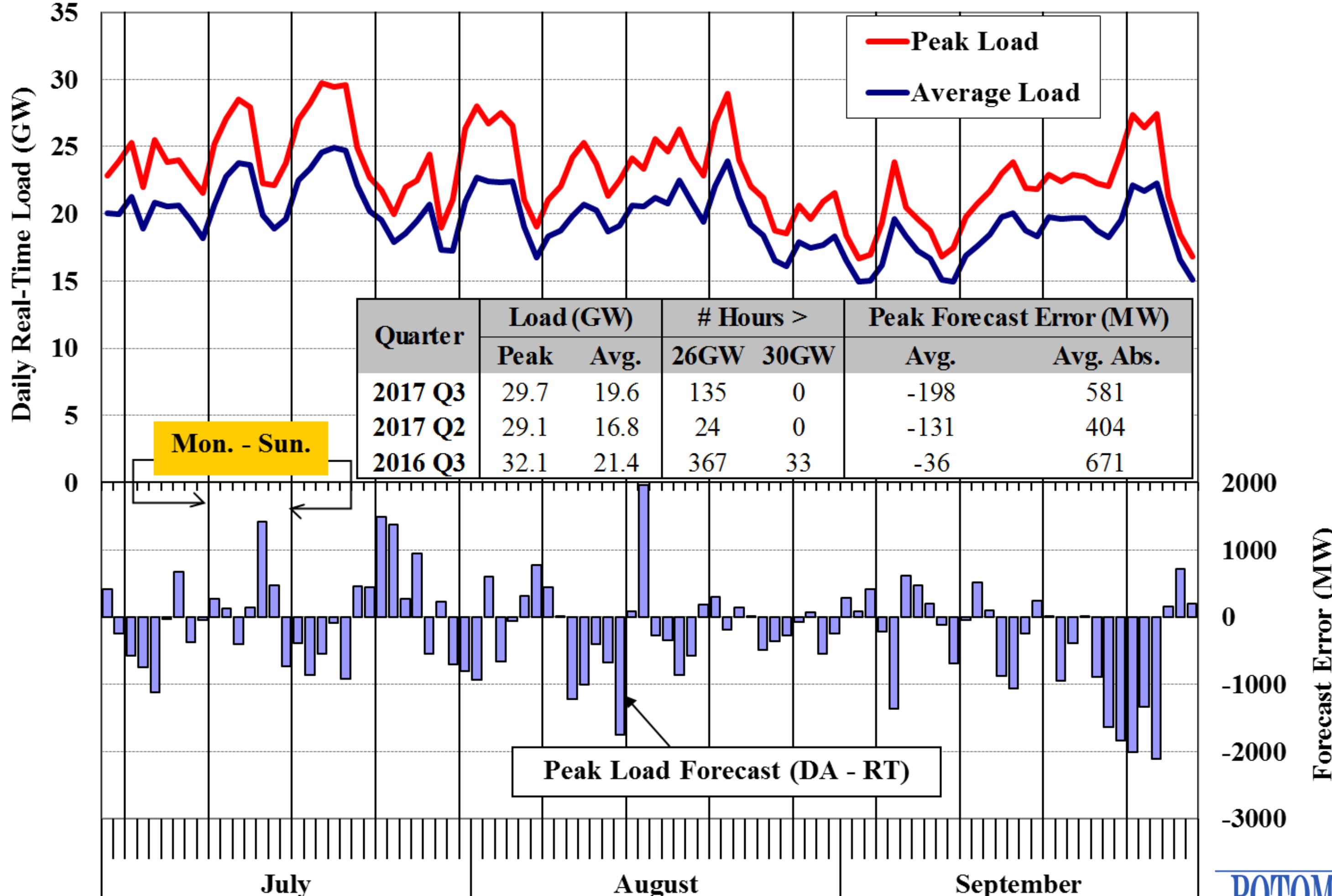
Load Forecast and Actual Load

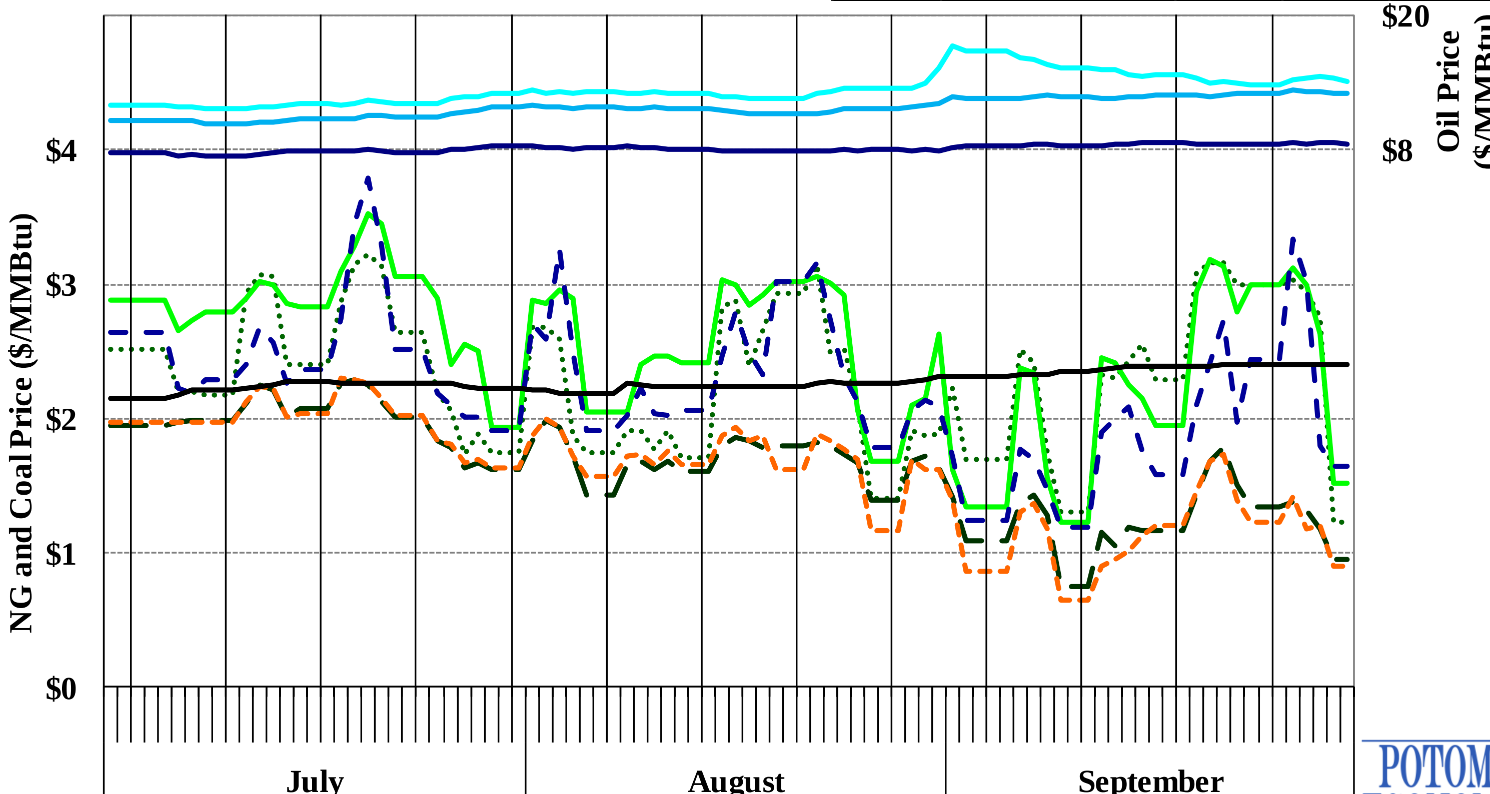


Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2017 Q3	29.7	19.6	135	0	-198	581
2017 Q2	29.1	16.8	24	0	-131	404
2016 Q3	32.1	21.4	367	33	-36	671

Coal, Natural Gas, and Fuel Oil Prices

Oil and Coal Prices	2016Q3	2017Q2	2017Q3
Ultra Low-Sulfur Kerosene	$12.87	$12.32	$13.46
Ultra Low-Sulfur Diesel Oil	$10.02	$10.83	$11.79
Fuel Oil #6 (Low-Sulfur Residual Oil)	$7.22	$7.72	$8.12
Central Appalachian Coal	$1.81	$2.08	$2.28

Natural Gas Prices	2016Q3	2017Q2	2017Q3
Tennessee Z6	$2.74	$2.95	$2.22
Iroquois Z2	$2.84	$2.94	$2.50
Transco Z6 (NY)	$1.84	$2.65	$2.30
Millennium East	$1.25	$2.38	$1.60
Dominion North	$1.25	$2.43	$1.63



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Real-Time Output and Marginal Units by Fuel: Chart Descriptions

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the third quarter of 2017.
- The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
- The second figure 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.

Real-Time Output and Marginal Units by Fuel: Market Results

- Gas-fired (45 percent), nuclear (32 percent), and hydro (19 percent) generation accounted for most of the internal generation in the third quarter of 2017.
  - ✓ Average nuclear generation rose 140 MW from the third quarter of 2016 because of less deratings and outages in West NY.
  - ✓ Average hydro generation rose 500 MW partly because drought conditions reduced output from most facilities in the state in 2016.
  - ✓ Average coal-fired generation fell nearly 300 MW because:
    - Lower LBMPs in the West Zone made it less economic; and
    - Milliken units (previously often DARUed and OOMed) were no longer needed for managing local reliability because of transmission upgrades in the Central Zone.
  - ✓ Gas-fired generation fell markedly across the system, reflecting lower load levels.
- Gas-fired and hydro resources continue to be marginal the vast majority of time.
  - ✓ Natural gas combined cycles units in the Capital and Central Zones were on the margin more frequently because of changes in congestion patterns.
  - ✓ Oil-fired GTs on Long Island were on the margin less frequently, reflecting less operation because of lower load and more upstate imports (from fewer transmission outages).

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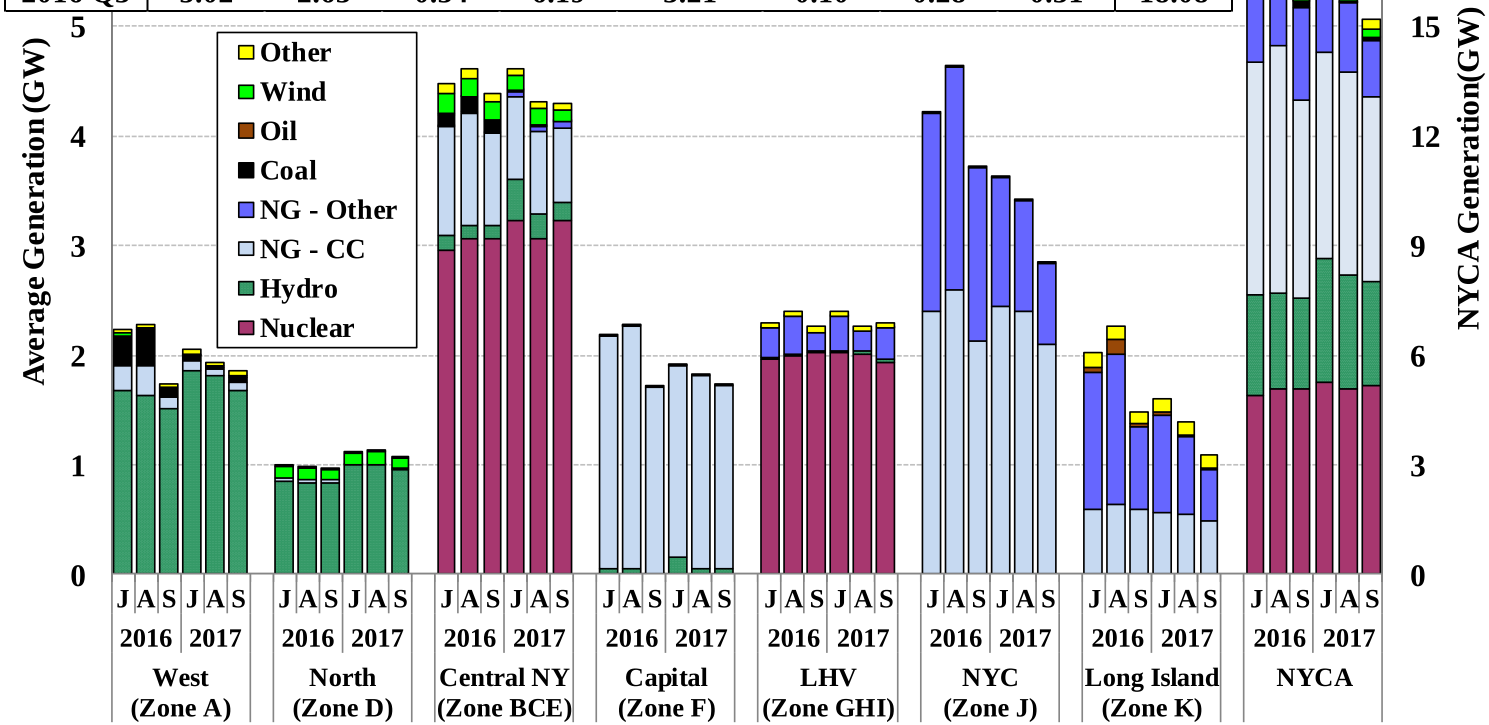
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2017 Q3	5.16	3.13	0.05	5.41	1.96	0.03	0.25	0.29	16.28
2017 Q2	4.42	3.38	0.06	4.27	1.03	0.02	0.48	0.27	13.94
2016 Q3	5.02	2.63	0.34	6.19	3.21	0.10	0.28	0.31	18.08



Notes: Pumped-storage resources in pumping mode are treated as negative generation.
"Other" includes Methane, Refuse, Solar & Wood.

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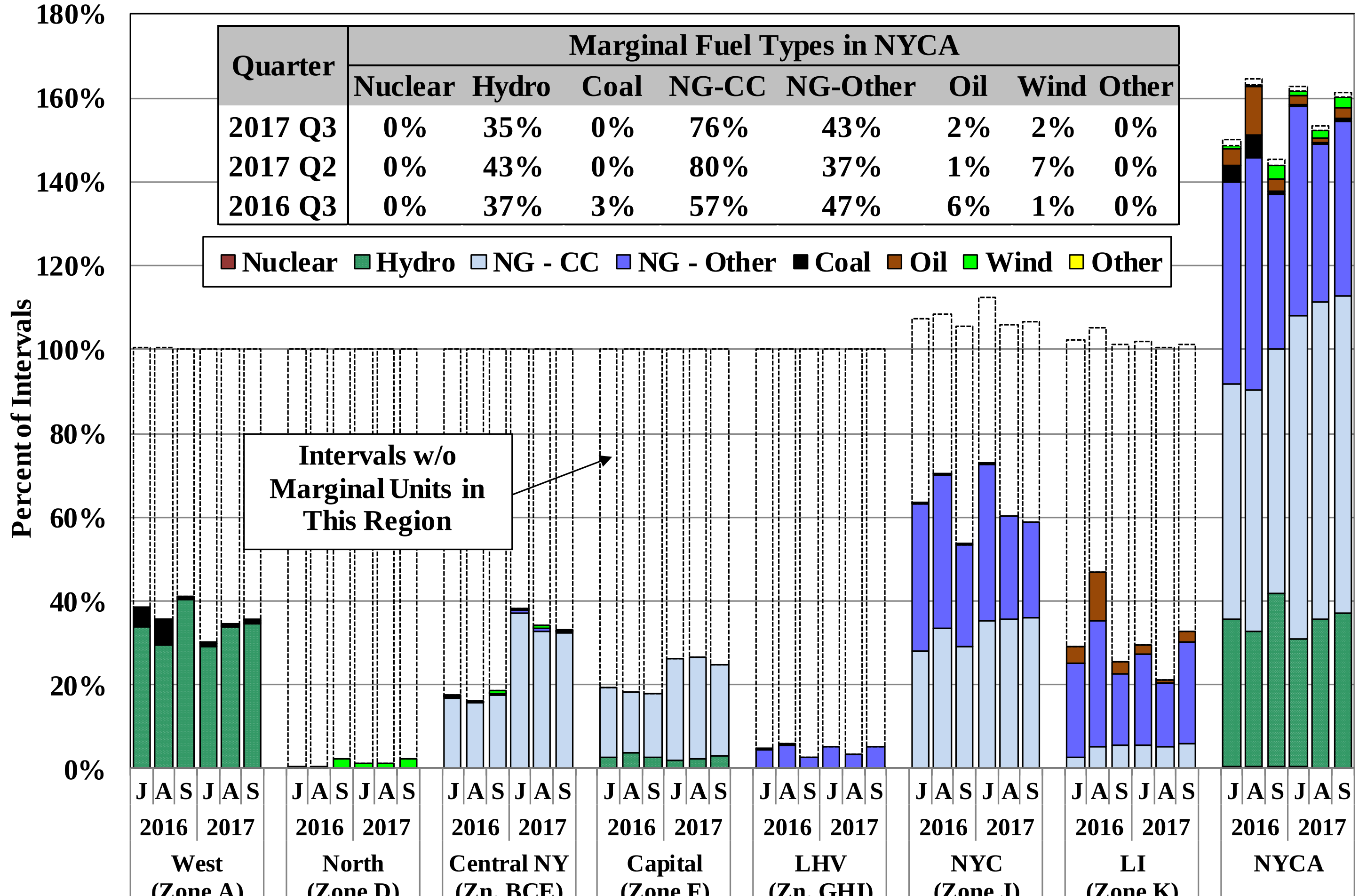
Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2017 Q3	0%	35%	0%	76%	43%	2%	2%	0%
2017 Q2	0%	43%	0%	80%	37%	1%	7%	0%
2016 Q3	0%	37%	3%	57%	47%	6%	1%	0%

Note: "Other" includes Methane, Refuse, Solar & Wood.

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Day-Ahead and Real-Time Electricity Prices

- The following three figures show: 1) load-weighted average day-ahead energy prices; 2) load-weighted average real-time energy prices; and 3) convergence between day-ahead and real-time prices for six zones on a daily basis in the third quarter of 2017.
- Average day-ahead prices ranged from $19/MWh in the North Zone to $38/MWh on Long Island, down 10 to 31 percent from the third quarter of 2016.
  - ✓ The declines were driven primarily by lower load levels (slide 13), lower gas prices in some areas (slide 14), and increased nuclear and hydro generation (640 MW).
  - ✓ Long Island exhibited the largest decrease (31%) among all areas.
    - – This was attributable to fewer and less persistent transmission outages this summer (the Y49 line was OOS and the 677 line was derated during most of last summer).
  - ✓ New York City exhibited the smallest decrease (10%), reflecting increased congestion as a result of:
    - – A 25 percent increase in natural gas prices;
    - – More transmission outages; (slides 49 & 50) and
    - – Reduced imports from New Jersey to New York City across the A,B, and C lines as a result of the expiration of PSEG/ConEd Wheeling agreement in May.

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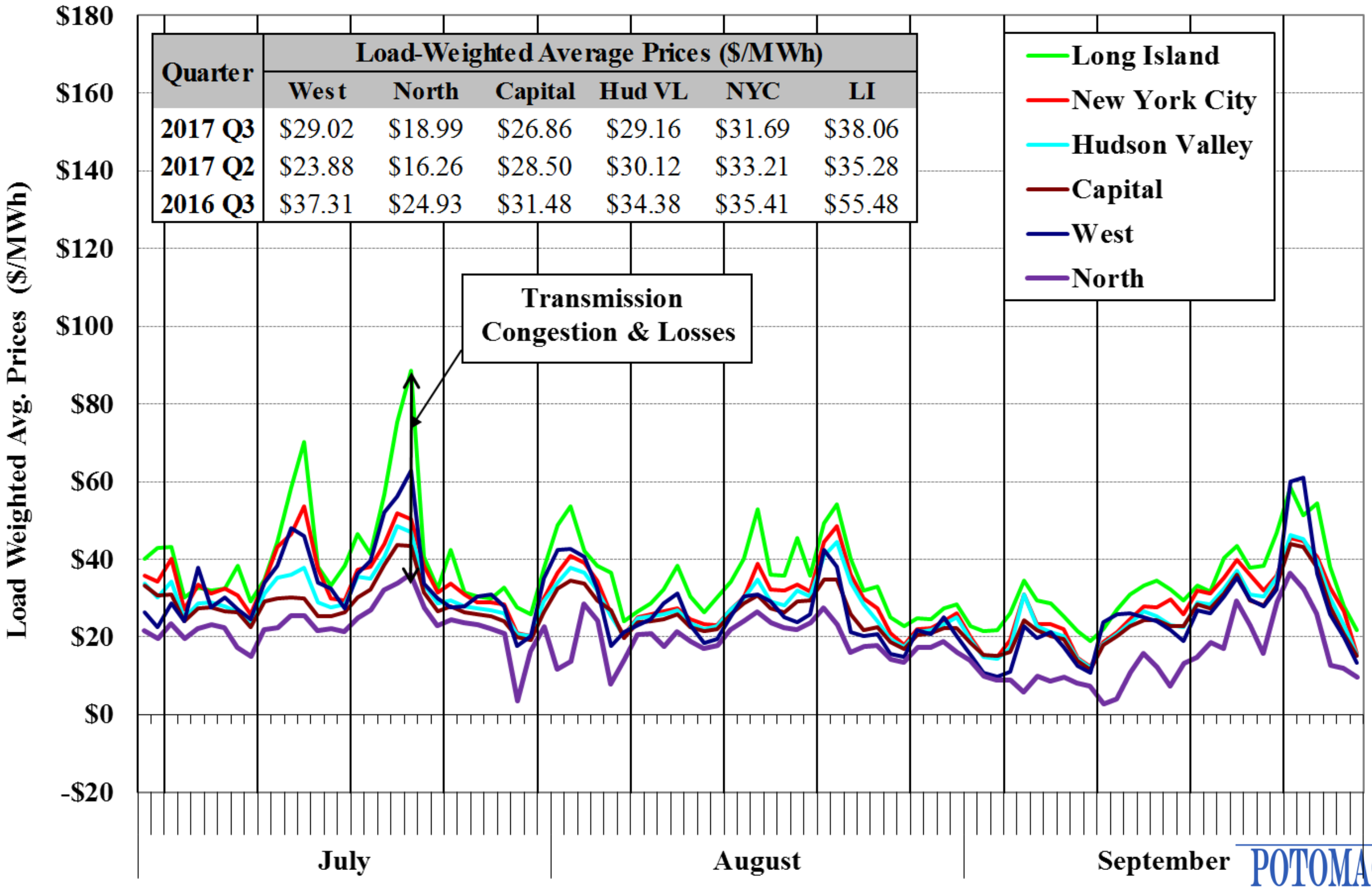
Day-Ahead and Real-Time Electricity Prices

- Prices are generally more volatile in the real-time market than in the day-ahead market because of unexpected events. For example,
  - ✓ On September 7, an unexpected Solar Magnetic Event led operators to reduce transfer limits across the system to ensure system security, which caused particularly severe congestion and large negative prices in the North Zone.
  - ✓ On September 27, unexpectedly high load in real-time (2+ GW higher than day-ahead forecast) contributed to significantly elevated prices in SENY.
- Random factors can cause large differences between day-ahead and real-time prices on some days, while persistent differences may indicate a systematic issue. The table focuses on persistent differences by averaging over the entire quarter.
  - ✓ In most areas, average day-ahead prices were 1 to 4 percent higher than real-time prices. A small average day-ahead premium is typical in a competitive market.
  - ✓ Day-ahead prices exceeded real-time prices by 21 percent in the North zone.
    - – Large negative real-time price spikes were more frequent in the North Zone because of: a) more frequent congestion due to more transmission outages; b) increased generation, and c) shortage pricing on GTDC rather than constraint relaxation.
    - – Constraint-specific GTDCs with lower values would be more suitable for facilities limiting flows from regions with excess supply.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q3	$29.02	$18.99	$26.86	$29.16	$31.69	$38.06
2017 Q2	$23.88	$16.26	$28.50	$30.12	$33.21	$35.28
2016 Q3	$37.31	$24.93	$31.48	$34.38	$35.41	$55.48

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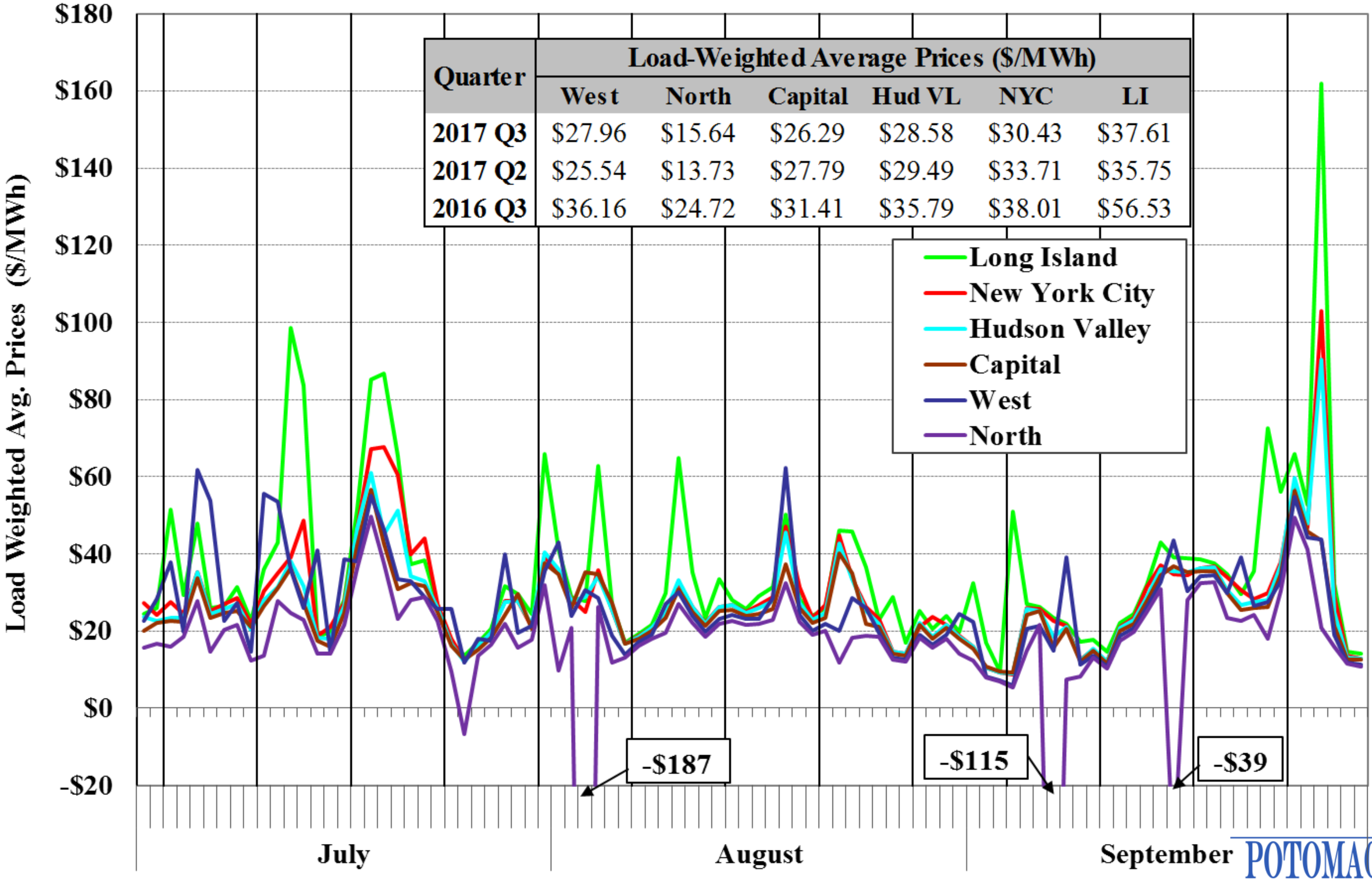
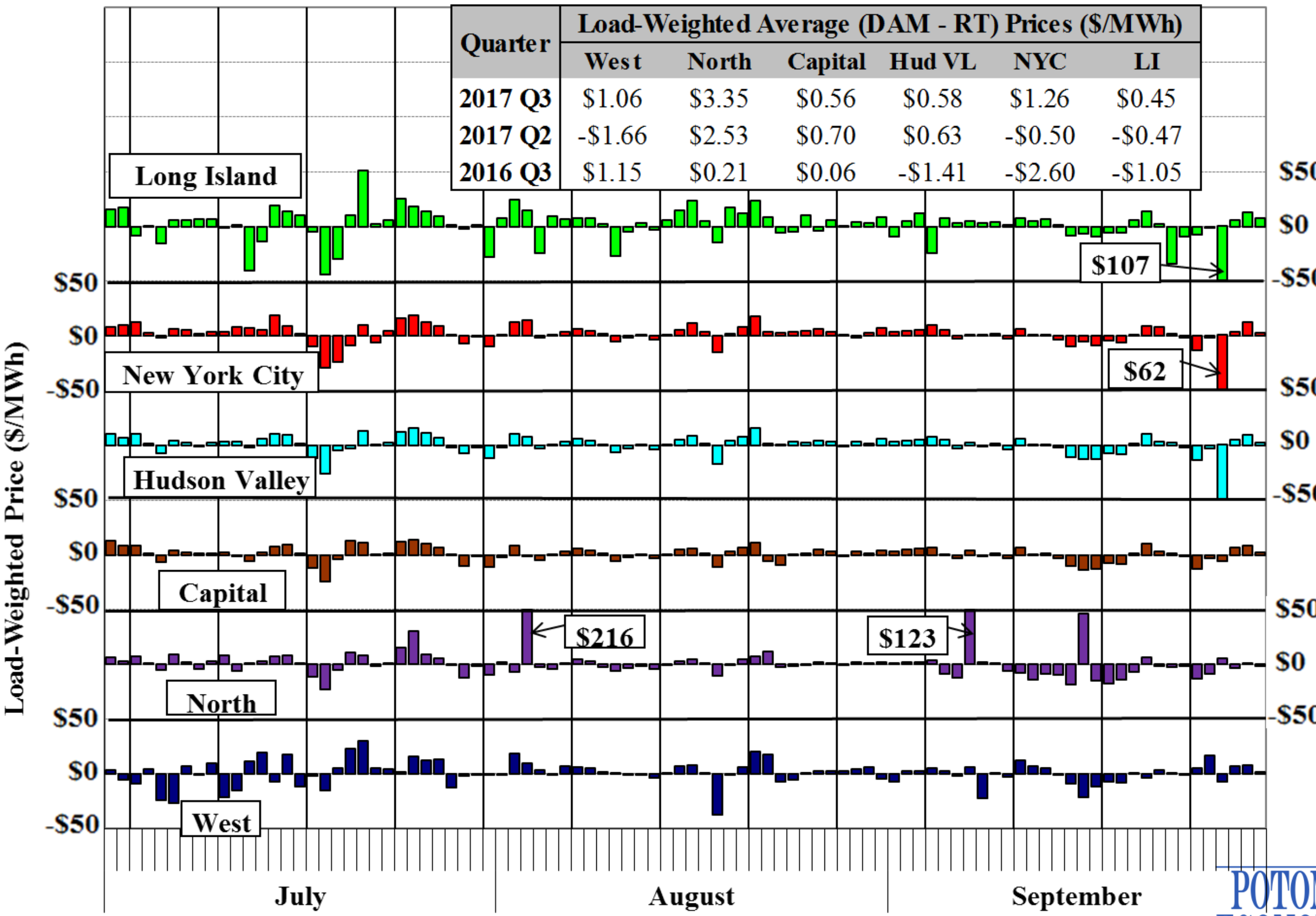
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q3	$27.96	$15.64	$26.29	$28.58	$30.43	$37.61
2017 Q2	$25.54	$13.73	$27.79	$29.49	$33.71	$35.75
2016 Q3	$36.16	$24.72	$31.41	$35.79	$38.01	$56.53

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q3	$1.06	$3.35	$0.56	$0.58	$1.26	$0.45
2017 Q2	-$1.66	$2.53	$0.70	$0.63	-$0.50	-$0.47
2016 Q3	$1.15	$0.21	$0.06	-$1.41	-$2.60	-$1.05

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Ancillary Services Market

Ancillary Services Prices: Chart Descriptions

- The following three figures 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.
  - ✓ 30-min operating reserve prices in western NY; and
  - ✓ 30-min operating reserve prices in SENY.
- The figures also show the number of shortage intervals in real-time for each ancillary service product.
  - ✓ 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.

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Ancillary Services Prices: Market Results

- Average day-ahead reserve prices fell 28 to 44 percent from a year ago, consistent with decreased LBMPs and lower load levels over the same period.
  - ✓ The decreases were also attributable to a general decline in day-ahead 30-minute reserve offer prices from the previous year. As a result:
    - The reserve requirements other than the statewide 30-minute requirement were binding more frequently; and
    - The spreads between various reserve prices rose accordingly from the low levels seen following market rule changes (related to the statewide 30-minute reserve requirement) in November 2015.
- Average day-ahead reserve prices were generally stable, while average day-ahead regulation prices were more volatile.
  - ✓ Higher regulation prices often occurred not only at high load levels but also during low load periods (e.g., weekends and the period from late August to early September this quarter) because:
    - Generally, less capacity is committed (or online) during low load periods, resulting in reduced regulation capability; and
    - The redispatch cost to maintain sufficient capacity for down regulation may be higher when the system is close to Minimum Generation condition.

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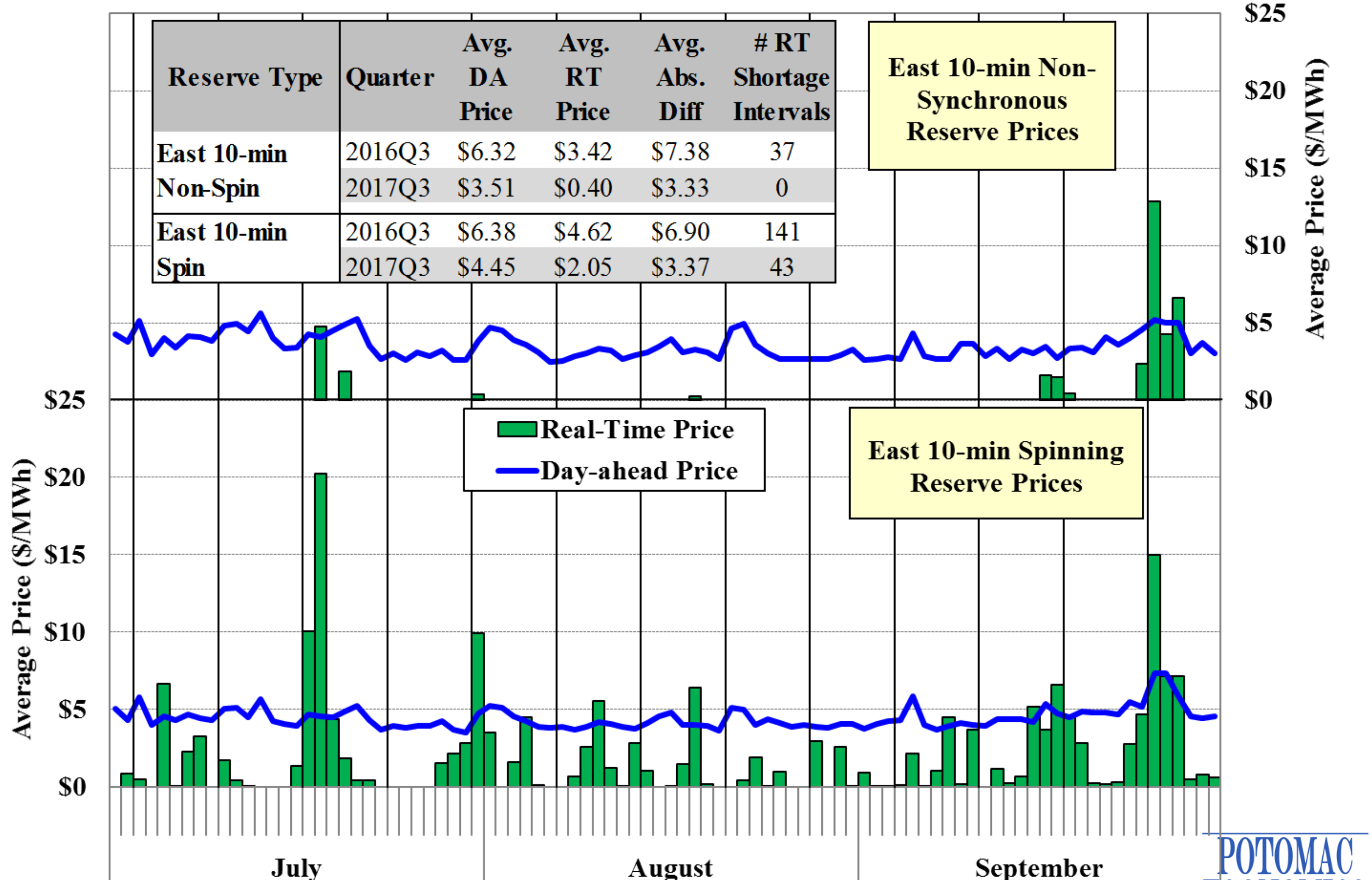
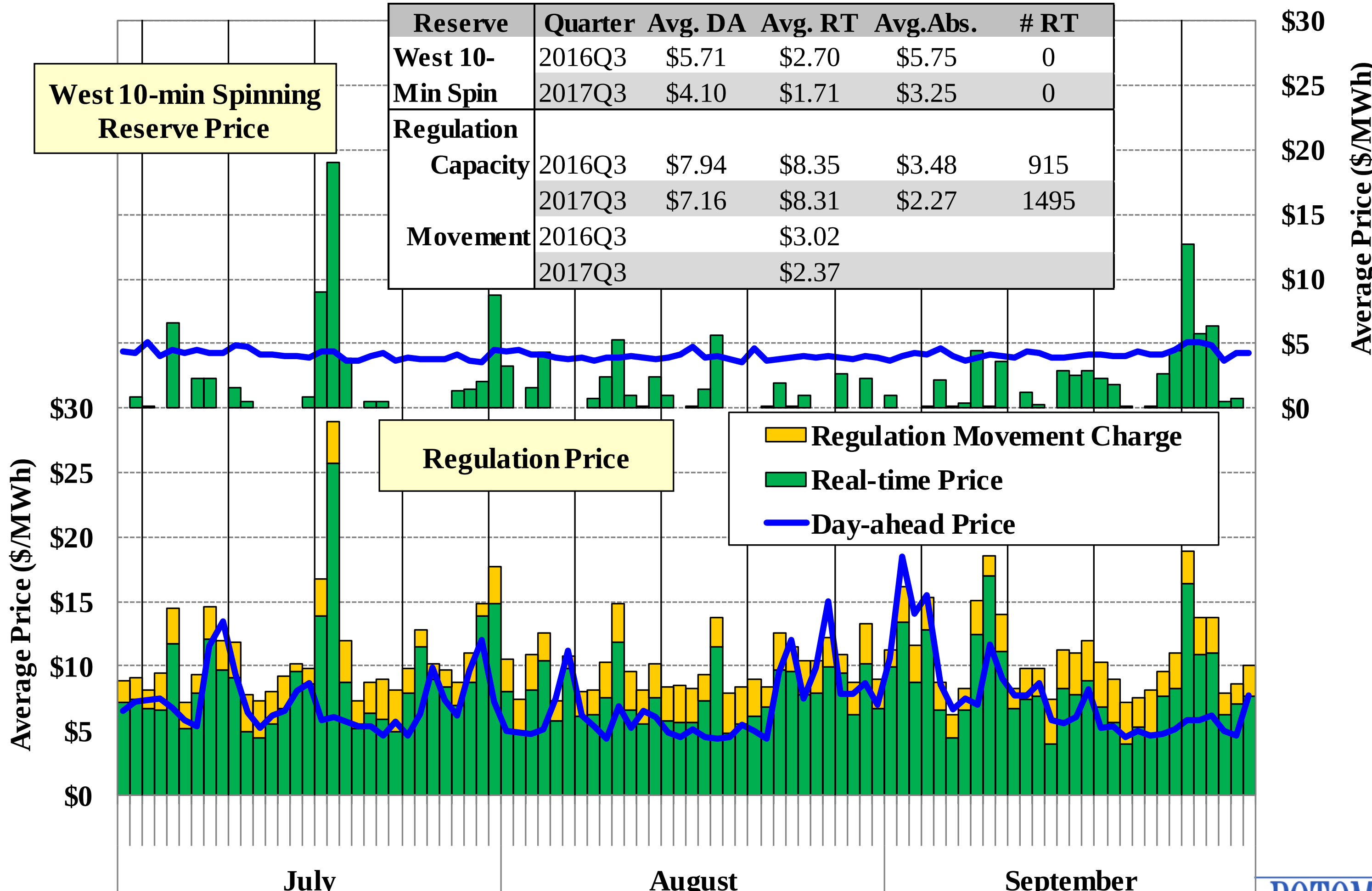
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2016Q3	$6.32	$3.42	$7.38	37
	2017Q3	$3.51	$0.40	$3.33	0
East 10-min Spin	2016Q3	$6.38	$4.62	$6.90	141
	2017Q3	$4.45	$2.05	$3.37	43



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

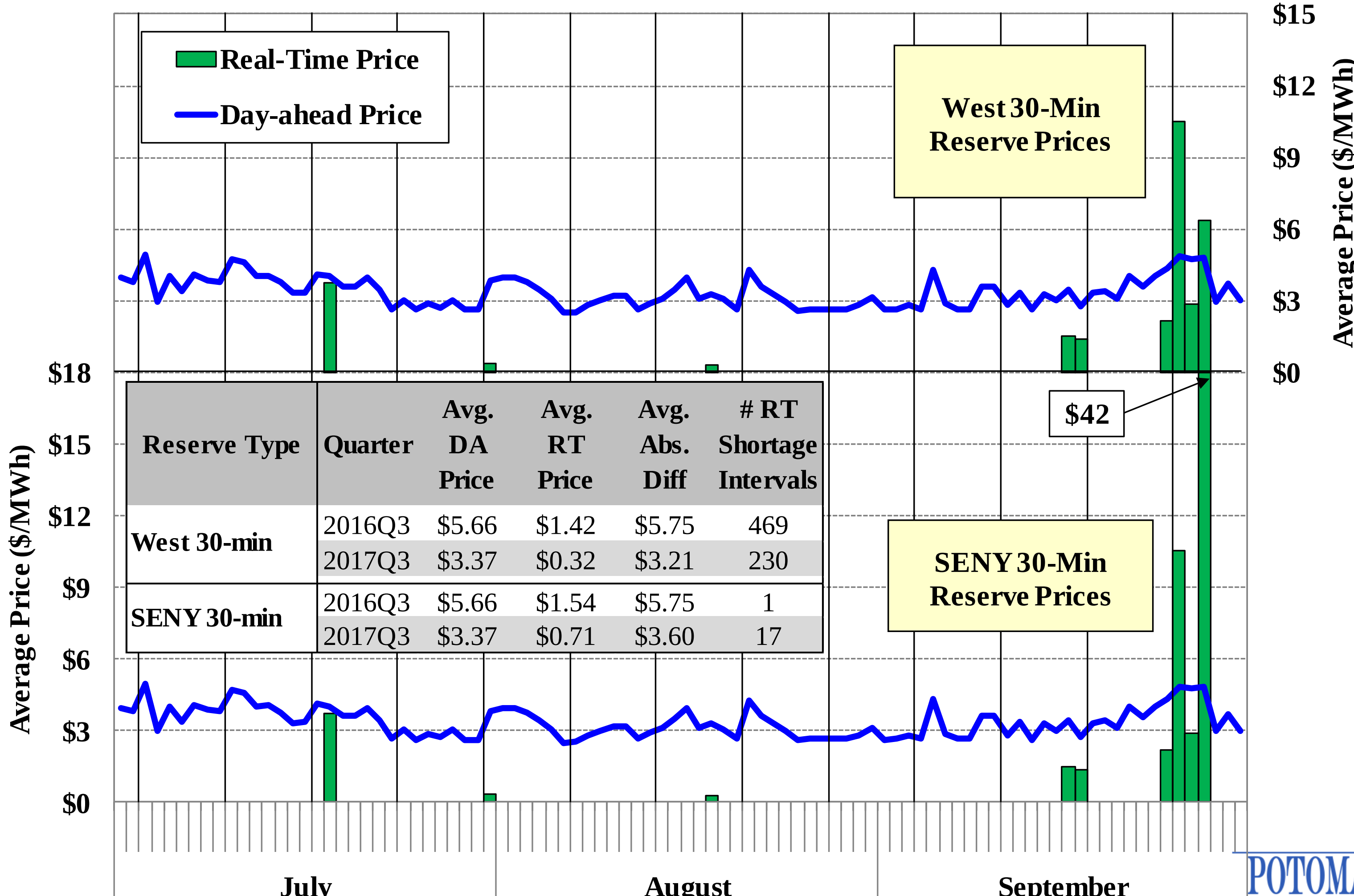


Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2016Q3	$5.71	$2.70	$5.75	0
	2017Q3	$4.10	$1.71	$3.25	0
Regulation Capacity	2016Q3	$7.94	$8.35	$3.48	915
	2017Q3	$7.16	$8.31	$2.27	1495
Movement	2016Q3		$3.02		
	2017Q3		$2.37		

Note: Real-Time Regulation Movement Charges are shown as averaged per MWh of Real-Time Scheduled Regulation Capacity

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	2016Q3	$5.66	$1.42	$5.75	469
	2017Q3	$3.37	$0.32	$3.21	230
SENY 30-min	2016Q3	$5.66	$1.54	$5.75	1
	2017Q3	$3.37	$0.71	$3.60	17

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Day-Ahead NYCA 30-Minute Reserve Offers: Chart Descriptions

- The next figure 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 (however, opportunity costs are not reflected here).

NYCA 30-Minute Day-Ahead Reserve Offers: Market Results

- Day-ahead 30-minute reserve prices became noticeably higher than real-time prices following the market rule change in November 2015, driven primarily by:
  - ✓ The increased 30-minute reserve requirement (up 655 MW);
  - ✓ The limit on scheduled reserves on Long Island (down 250-300 MW); and
  - ✓ The increased reserve offers from some capacity.
- We have reviewed day-ahead reserve offers and found many units that offer above the standard competitive benchmark (i.e., estimated marginal cost).
  - ✓ This is partly due to the difficulty of accurately estimating the marginal cost of providing reserves.
  - ✓ Day-ahead offer prices have fallen (particularly from fast-start resources in East NY) as suppliers have gained more experience. Compared to 2016-Q3:
    - The amount offered below \$3/MWh increased by an average of 990 MW; and
    - The amount offered below \$5/MWh increased by an average of 920 MW.
- We will continue to monitor day-ahead reserve offer patterns and consider potential rule changes including whether to modify the existing \$5/MWh “safe harbor” for reserve offers in the market power mitigation measures.

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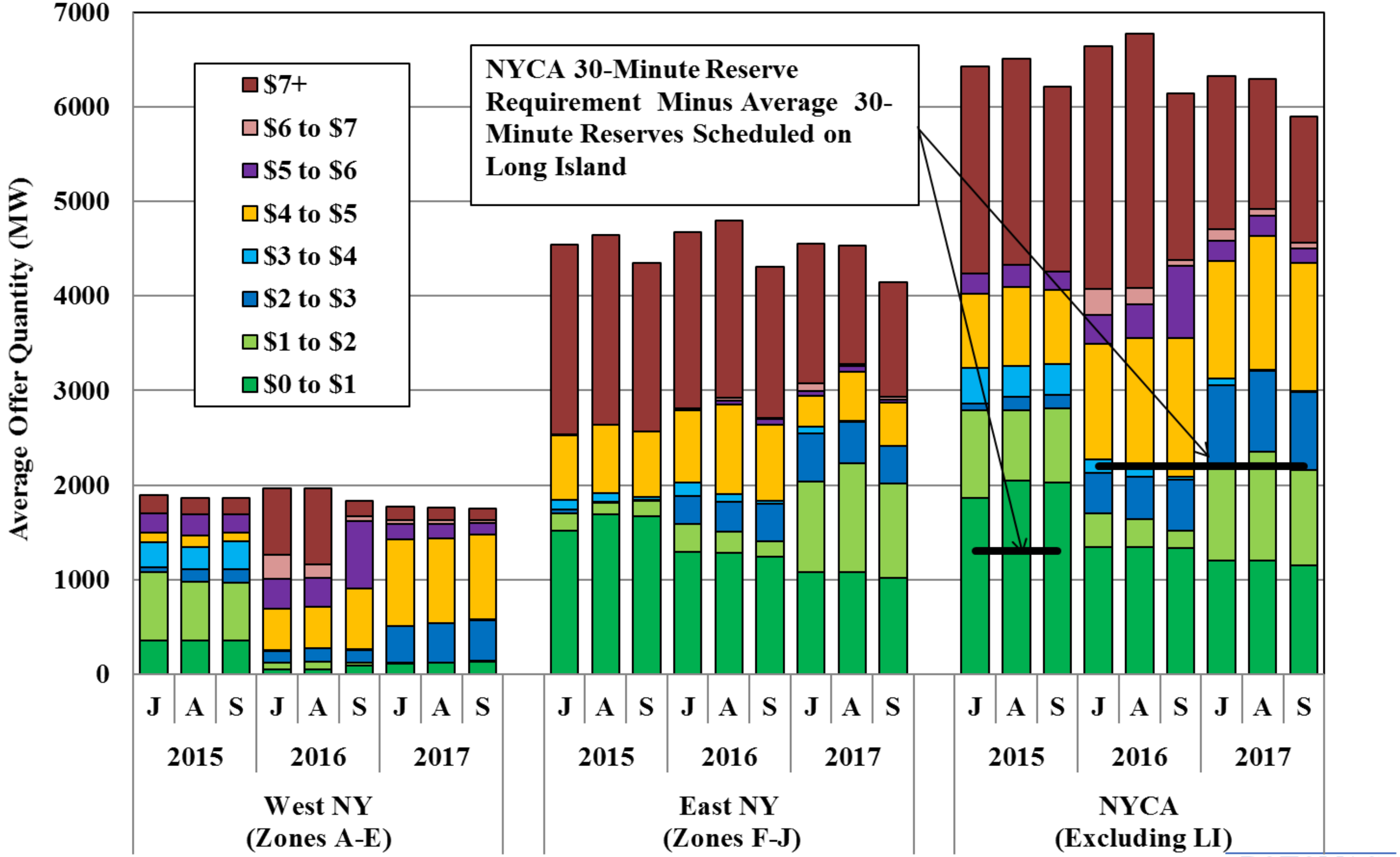
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Energy Market Scheduling

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Day-Ahead Load Scheduling and Virtual Trading:
Chart Descriptions

- The next three figures summarize day-ahead load scheduling and virtual trading.
  - ✓ The first figure summarizes the quantity of day-ahead load scheduled as a percentage of real-time load in each of seven regions and state-wide by day.
    - – Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
  - ✓ The second figure shows monthly average scheduled and unscheduled quantities and gross profitability for virtual trades in the past 24 months.
    - – The table shows a screen for relatively large profits or losses, which identifies virtual trades with profits or losses larger than 50% 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.
  - ✓ The third figure summarizes virtual trading by region.
    - – The top portion of the chart also shows average day-ahead scheduled load (as a percent of real-time load) at each 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. So, a small portion of these "virtuals" result from forced outages or curtailments by NYISO or another control area (rather than the participant).

Day-Ahead Load Scheduling and Virtual Trading: Market Results

- For NYCA, 97 percent of actual load was scheduled in the DAM (including virtual imports/exports) in peak load hours, comparable to the same quarter last year.
  - ✓ The scheduling pattern in each sub-region was also consistent as well.
- Net load scheduling and net virtual load tend to be higher in locations where high real-time prices result from volatile congestion (e.g., NYC, LI, and West Zone).
  - ✓ In Lower Hudson Valley, net load scheduling typically rises in the summer months when congestion into the areas becomes more prevalent.
- Net load is typically low (<50%) in the North Zone because large amounts of virtual supply are often scheduled there.
  - ✓ This is an efficient response to the scheduling patterns of wind units in the zone and imports from Canada, which typically increase in real time (from day ahead).
- Virtual traders netted a $5.8 million profit this quarter. Profitable virtual trades generally improve convergence between day-ahead and real-time prices.
- The quantities of virtual trades with substantial profits or losses were generally consistent with prior periods.
  - ✓ These trades were primarily associated with high price volatility that resulted from unexpected events, which do not raise significant concerns.

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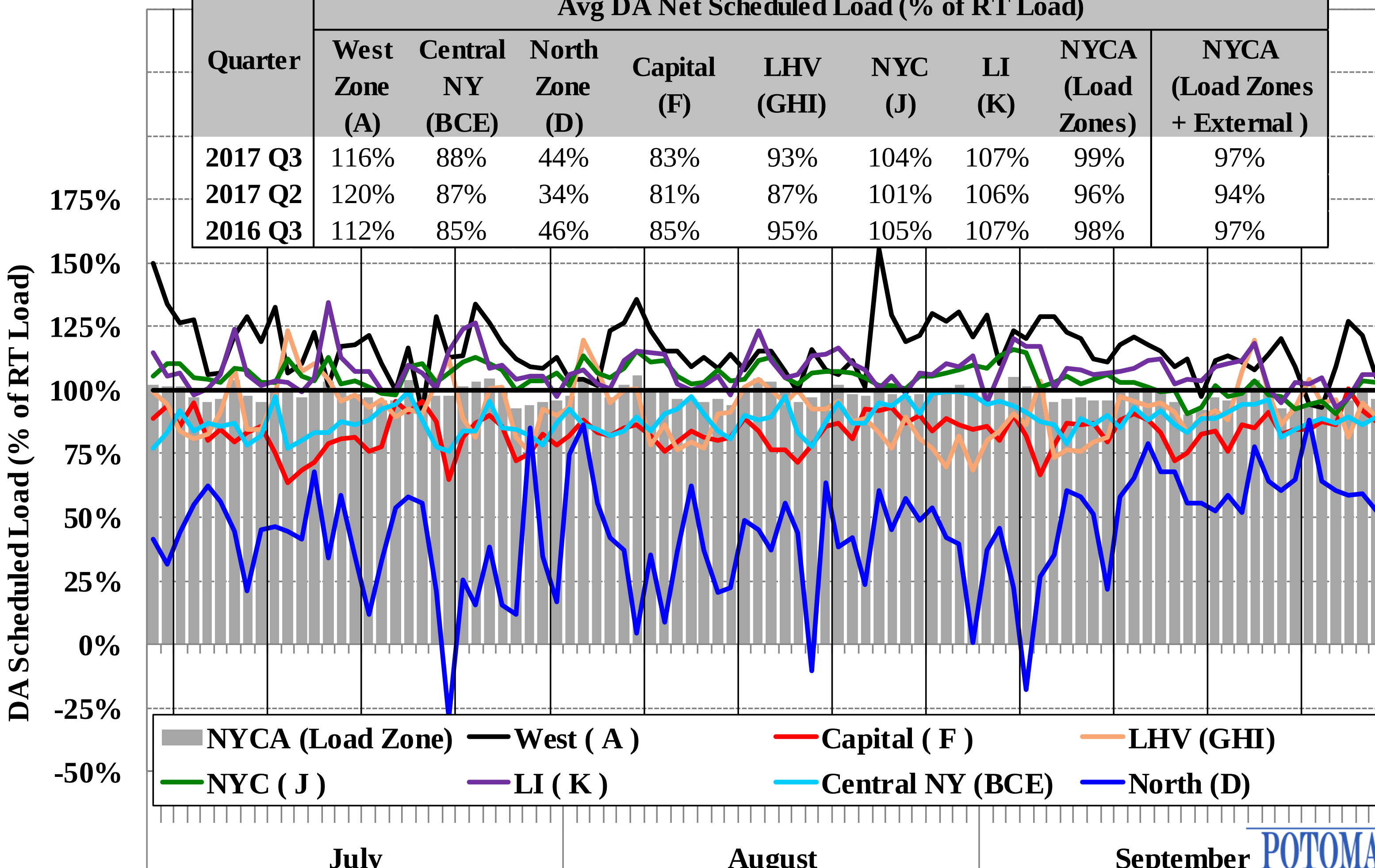
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour

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)
2017 Q3	116%	88%	44%	83%	93%	104%	107%	99%	97%
2017 Q2	120%	87%	34%	81%	87%	101%	106%	96%	94%
2016 Q3	112%	85%	46%	85%	95%	105%	107%	98%	97%



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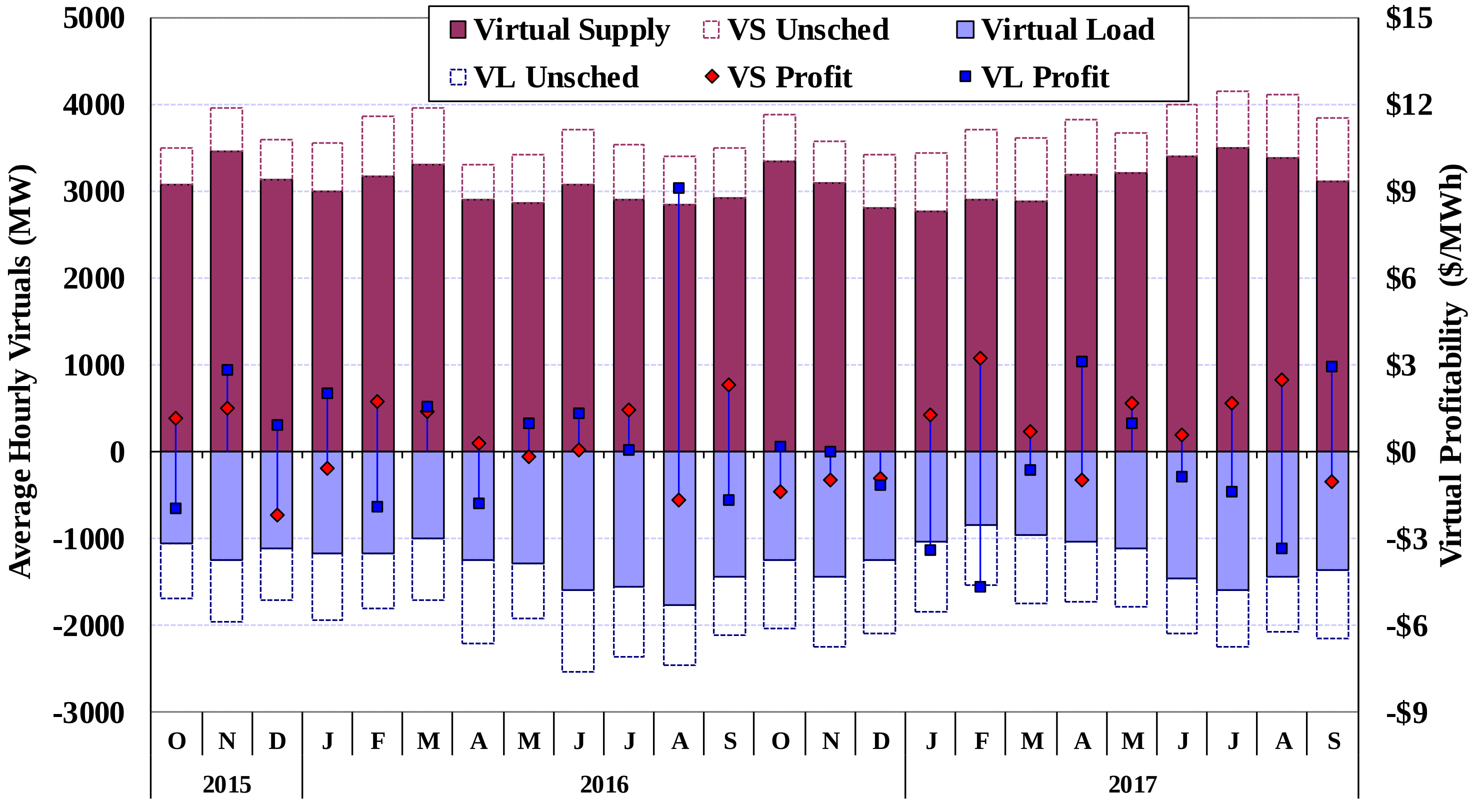
Virtual Trading Activity
by Month



Profit > 50% of Avg. Zone Price	MW	378	1090	643	692	638	1003	354	431	460	596	398	360	281	261	490	243	507	585	449	645	502	593	439	257
	%	9%	23%	15%	17%	15%	23%	8%	10%	10%	13%	9%	8%	6%	6%	12%	6%	13%	15%	11%	15%	10%	12%	9%	6%
Loss > 50% of Avg. Zone Price	MW	375	715	763	553	547	680	682	550	528	517	413	411	419	345	587	284	336	514	454	553	542	568	466	418
	%	9%	15%	18%	13%	13%	16%	16%	13%	11%	12%	9%	9%	9%	8%	14%	7%	9%	13%	11%	13%	11%	11%	10%	9%

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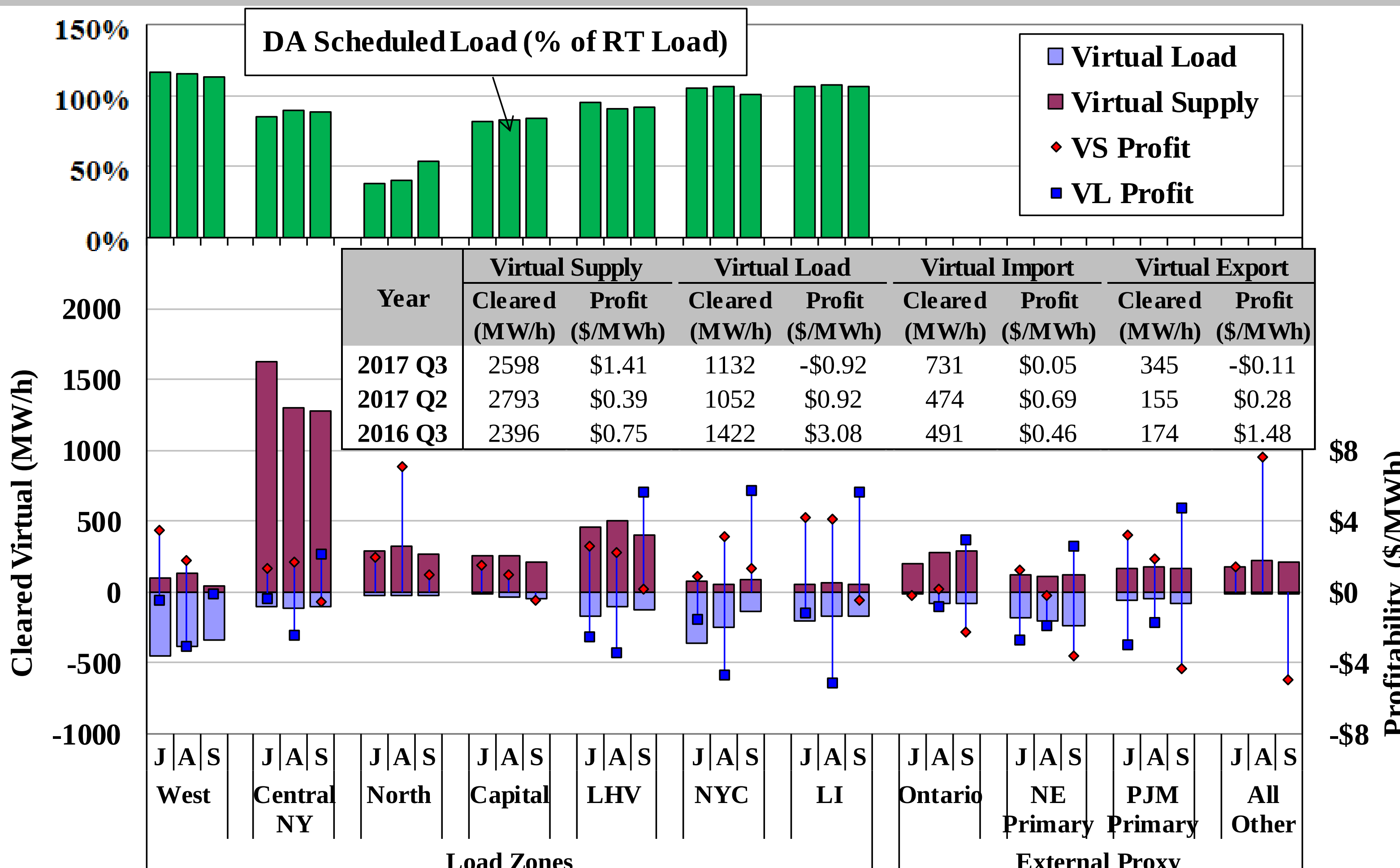
Virtual Trading Activity
by Location



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2017 Q3	2598	$1.41	1132	-$0.92	731	$0.05	345	-$0.11
2017 Q2	2793	$0.39	1052	$0.92	474	$0.69	155	$0.28
2016 Q3	2396	$0.75	1422	$3.08	491	$0.46	174	$1.48

Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.

Net Imports Scheduled Across External Interfaces

- The next figure shows average real-time net imports to NYCA across ten external interfaces (two HQ interfaces are combined) in peak hours (1-9 pm).
- Total net imports averaged roughly 3.1 GW (serving ~16% of all load) during peak hours in the third quarter of 2017, up ~280 MW from the previous year.
- Imports from Hydro Quebec and Ontario averaged nearly 2.1 GW during peak hours, accounting for 67 percent of total net imports.
  - ✓ Imports from Quebec fell ~200 MW from the previous year primarily because of frequent reductions in scheduling limits because of HQ deliverability issues.
  - ✓ However, Ontario imports rose ~260 MW partly due to less West Zone congestion.
- New York is typically a net exporter of power to New England and a net importer of power from PJM across their primary interfaces.
  - ✓ This pattern was generally consistent with the spreads in natural gas prices between these markets (i.e., NE > NY > PJM).
  - ✓ The net direction of flow with NE and PJM varied more by day in the third quarter of 2017, reflecting smaller gas spreads between the three markets. (slide 14)
    - – As a result, the average amount of net imports from PJM and net exports to NE was substantially lower than in the third quarter of last year.

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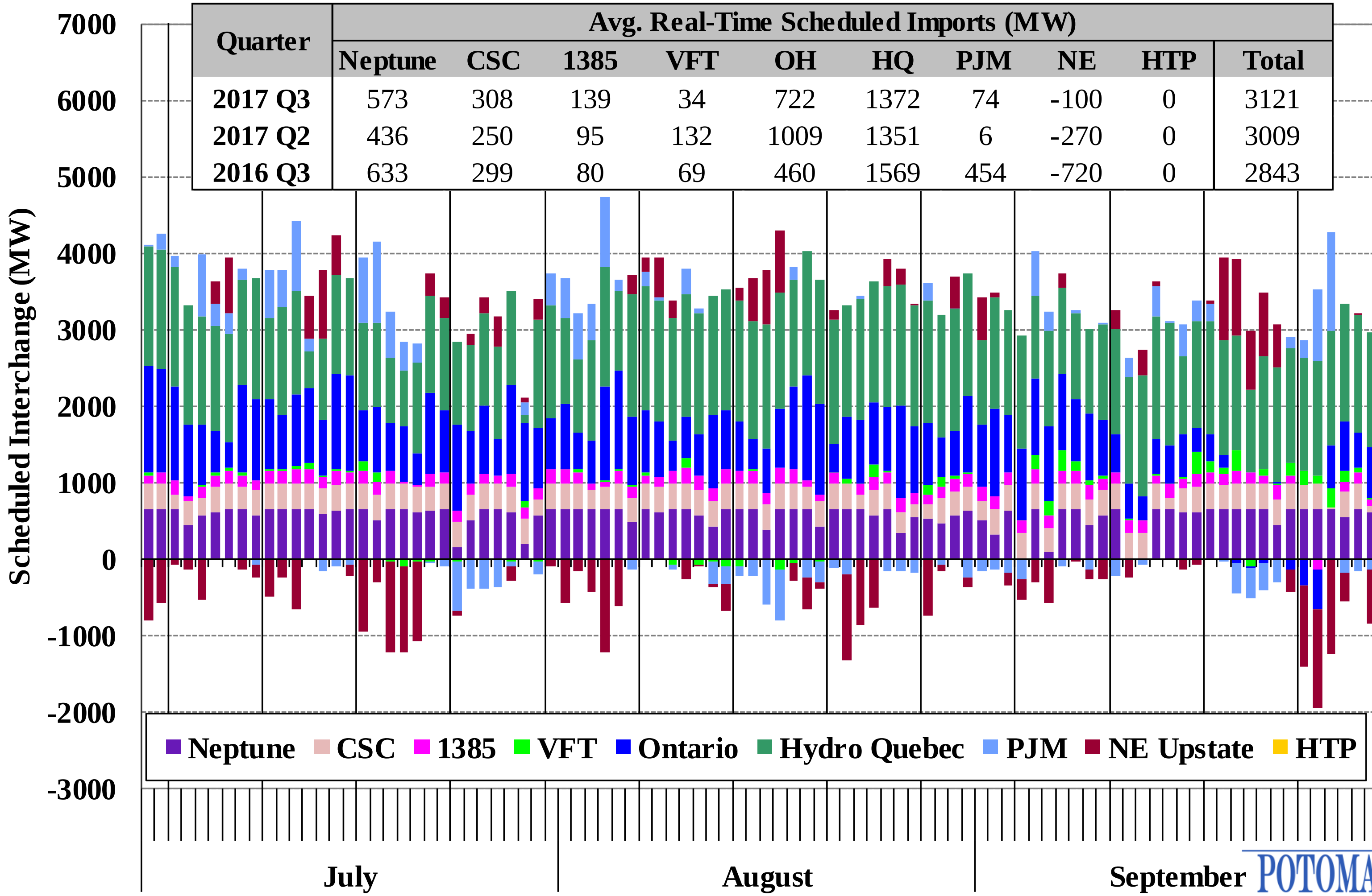
Net Imports Scheduled Across External Interfaces

Daily Peak Hours (1-9pm)

Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2017 Q3	573	308	139	34	722	1372	74	-100	0	3121
2017 Q2	436	250	95	132	1009	1351	6	-270	0	3009
2016 Q3	633	299	80	69	460	1569	454	-720	0	2843



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Efficiency of CTS Scheduling with PJM and NE: Chart Descriptions

- The next table 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.

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Efficiency of CTS Scheduling with PJM and NE: Market Results

- The interchange was adjusted in 97 percent of intervals (from our estimated hourly schedule) at the ISO-NE interface compared to 65 percent at the PJM interface.
  - ✓ This was partly attributable to the larger amount of low-price bids at the ISO-NE interface (compared to the PJM interface).
- Our analyses show that $1.7 million and $1.1 million of production cost savings were projected at the time of scheduling at the ISO-NE and PJM interfaces.
  - ✓ An estimated $1.2 million of savings were realized at the NE interface, while virtually none was realized at the PJM interface due largely to price forecast errors.
    - – It is important to note that our evaluation may under-estimate both projected and actual savings, because the estimated hourly schedules (by using actual bids) likely include some of the efficiencies that result from the CTS process.
    - – Nonetheless, the results of our analysis are still useful for identifying some of the sources of inefficiency in the CTS process.
- Projected savings were relatively consistent with actual savings when the forecast errors were moderate (e.g., less than $20/MWh), while the CTS process produced much more inefficient results when forecast errors were large.
  - ✓ Therefore, improvements in the CTS process should focus on identifying sources of forecast errors.

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 > $20	Total
% of All Intervals w/ Adjustment			89%	8%	**97%**	57%	8%	**65%**
Average Flow Adjustment (MW)	Net Imports		29	7	**27**	2	27	**5**
	Gross		104	131	**106**	71	138	**80**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$1.2	$0.6	**$1.7**	$0.4	$0.7	**$1.1**
	Net Over-Projection by:	NY	-$0.04	$0.0	**-$0.1**	-$0.1	-$0.7	**-$0.8**
		NE or PJM	$0.03	-$0.4	**-$0.4**	-$0.1	-$0.1	**-$0.2**
	Other Unrealized Savings		-$0.1	-$0.03	**-$0.1**	-$0.03	-$0.1	**-$0.2**
	Actual Savings		$1.1	$0.1	**$1.2**	$0.2	-$0.2	**-$0.02**
Interface Prices ($/MWh)	NY	Actual	$22.34	$54.15	**$24.80**	$22.72	$53.01	**$26.63**
		Forecast	$23.19	$49.73	**$25.24**	$23.88	$57.20	**$28.18**
	NE or PJM	Actual	$22.69	$57.90	**$25.42**	$24.44	$48.14	**$27.50**
		Forecast	$22.67	$70.69	**$26.38**	$26.08	$53.93	**$29.68**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.85	-$4.42	**$0.44**	$1.16	$4.20	**$1.55**
		Abs. Val.	$2.53	$29.61	**$4.62**	$2.73	$38.52	**$7.35**
	NE or PJM	Fcst. - Act.	-$0.03	$12.79	**$0.97**	$1.64	$5.79	**$2.18**
		Abs. Val.	$3.32	$44.32	**$6.49**	$3.73	$39.16	**$8.30**

Day-Ahead and Real-Time Transmission Congestion

Transmission Congestion: Chart Descriptions

- The next four figures 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: Chart Descriptions

- The first figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years on a monthly basis.
- The second figure 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.
- The third and fourth figures 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.
- 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.

Transmission Congestion: Chart Descriptions

(cont. from prior slide)

- ✓ 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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Day-Ahead and Real-Time Congestion

- Day-ahead congestion revenue totaled $104 million in 2017-Q3, down 20 percent from 2016-Q3 partly because of lower load levels. (slide 13)
- Congestion fell most (by ~60%) on Long Island primarily because:
  - ✓ Fewer major transmission outages occurred (while the Y49 and 677 lines were OOS/derated for most of 2016-Q3); and
  - ✓ Lower natural gas prices on Long Island. (slide 14)
- However, congestion rose between North Zone and central NY largely because of more transmission outages and increased hydro generation. (slides 17, 49, 50)
- The frequency of day-ahead congestion rose notably in NYC, reflecting: a) more transmission outages; b) higher gas prices; and c) less imports from PJM across the ABC lines following the expiration of the PSEG/ConEd Wheeling agreement.
  - ✓ However, real-time congestion fell noticeably because of fewer transmission shortages and lower shortage costs.
- Modifications to the transmission shortage pricing in June 2017 helped reduce constraint costs during transmission shortages in most areas, contributing to the overall decrease. (see slides 56 – 59 for more detailed discussion).

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Day-Ahead Congestion Shortfalls

- Transmission outages accounted for the vast majority of shortfalls in 2017-Q3.
  - ✓ Roughly $9 (out of $10 million) was allocated to the responsible TO.
- Nearly $5 million of shortfalls accrued on constraints from the North Zone, largely attributable to the following transmission outages:
  - ✓ The Chateauguay-Massena-Marcy 765 kV lines were OOS in late July;
  - ✓ The Marcy-FraserAnnex-Coopers 345 kV lines were OOS in early August;
  - ✓ A Marcy 765/345 transformer was OOS in early September; and
  - ✓ A Moses-Adirondack 230 line was OOS from mid-September to the end of month.
- Over $3.5 million of shortfalls accrued on the transmission paths from Capital to Hudson Valley and across the Central-East interface because of the outages of:
  - ✓ The Coopers-DolsonAve-RockTavern 345 kV lines from late August to early September;
  - ✓ The Gilboa-Leeds 345 kV line on two days in late August;
  - ✓ The Marcy-N.Scotland 345 kV line on several days in early August and mid September; and
  - ✓ The Ramapo PAR during most of the quarter.

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Day-Ahead Congestion Shortfalls

- $2.0 million of shortfalls accrued on 230 kV lines in West Zone primarily because of different loop flow assumptions between the TCC auction and the DAM.
- $1.3 million of shortfalls accrued on New York City lines.
  - ✓ A portion of these shortfalls were attributable to the outage of one Springbrook-W49th St. 345 kV line for one week in mid September.
  - ✓ The PAR-controlled lines between NJ and NYC (i.e., ABC lines) were OOS in various periods of the quarter, contributing to a large share of shortfalls as well.
    - A line was OOS from mid September till the end of month;
    - B line was OOS in most of July and August; and
    - C line was OOS from early to mid July and from mid to late August.
- Long Island lines netted $1 million of surpluses.
  - ✓ $1.4 million of shortfalls resulted from grandfathered TCCs that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island.
  - ✓ This was offset by $2.4 million of surpluses resulted from:
    - Higher assumed flows out of Long Island on the 901/903 lines in the TCC auction than in the DAM; and
    - More flow scheduled in the DAM in the Riverhead-Wildwood area.

Balancing Congestion Shortfalls

- North Zone constraints accounted for most of shortfalls (>$6 million) in 2017-Q3, most of which accrued on two days (August 3 & September 7).
  - ✓ Over $4.5 million of shortfalls accrued during morning hours on August 3.
    - – The Marcy-FraserAnnex 345 kV Line returned to service later than scheduled.
    - – Operators reduced the BMS limit on the Edic-Marcy 345 kV Line to prevent EMS overflow because of large mismatches between its EMS and BMS flows.
  - ✓ Over $1.0 million of shortfalls accrued on September 7.
    - – Operators reduced transfer limits across the system to ensure security during a Solar Magnetic Event, which particularly caused large shortfalls in the North Zone.
- The West Zone 230 kV lines accounted for nearly $3 million of shortfalls.
  - ✓ Unexpected changes in loop flows were a key driver.
- Nearly $1.5 million of shortfalls accrued from Capital to Hudson VL, due largely to TSA events that substantially reduced the transfer capability into SENY.
- The PAR operations contributed $1.2 million of net surpluses.
  - ✓ However, the PAR-controlled JK lines accrued more shortfalls than other PARs, reflecting that JK PARs are operated much less actively to reduce congestion.

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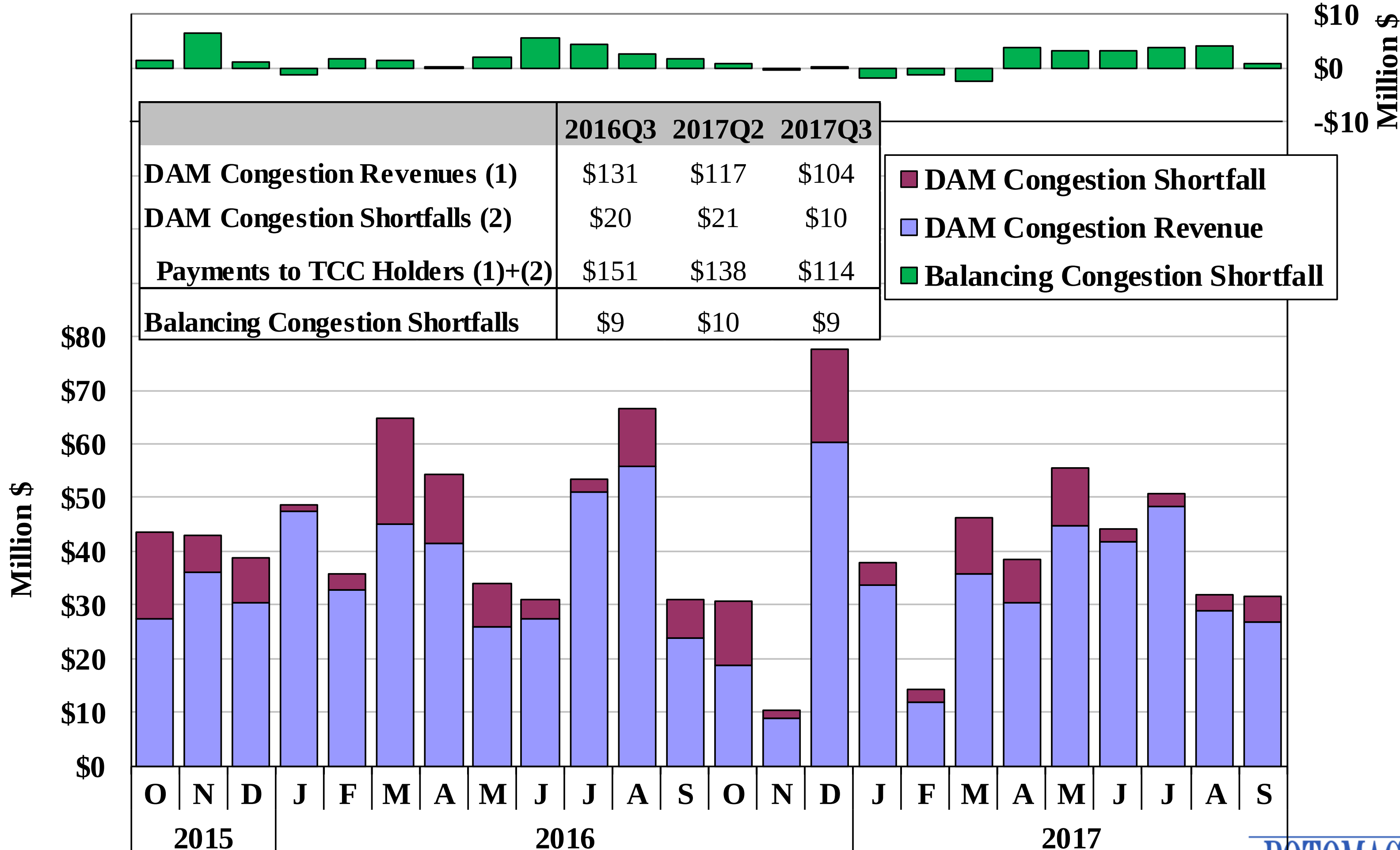
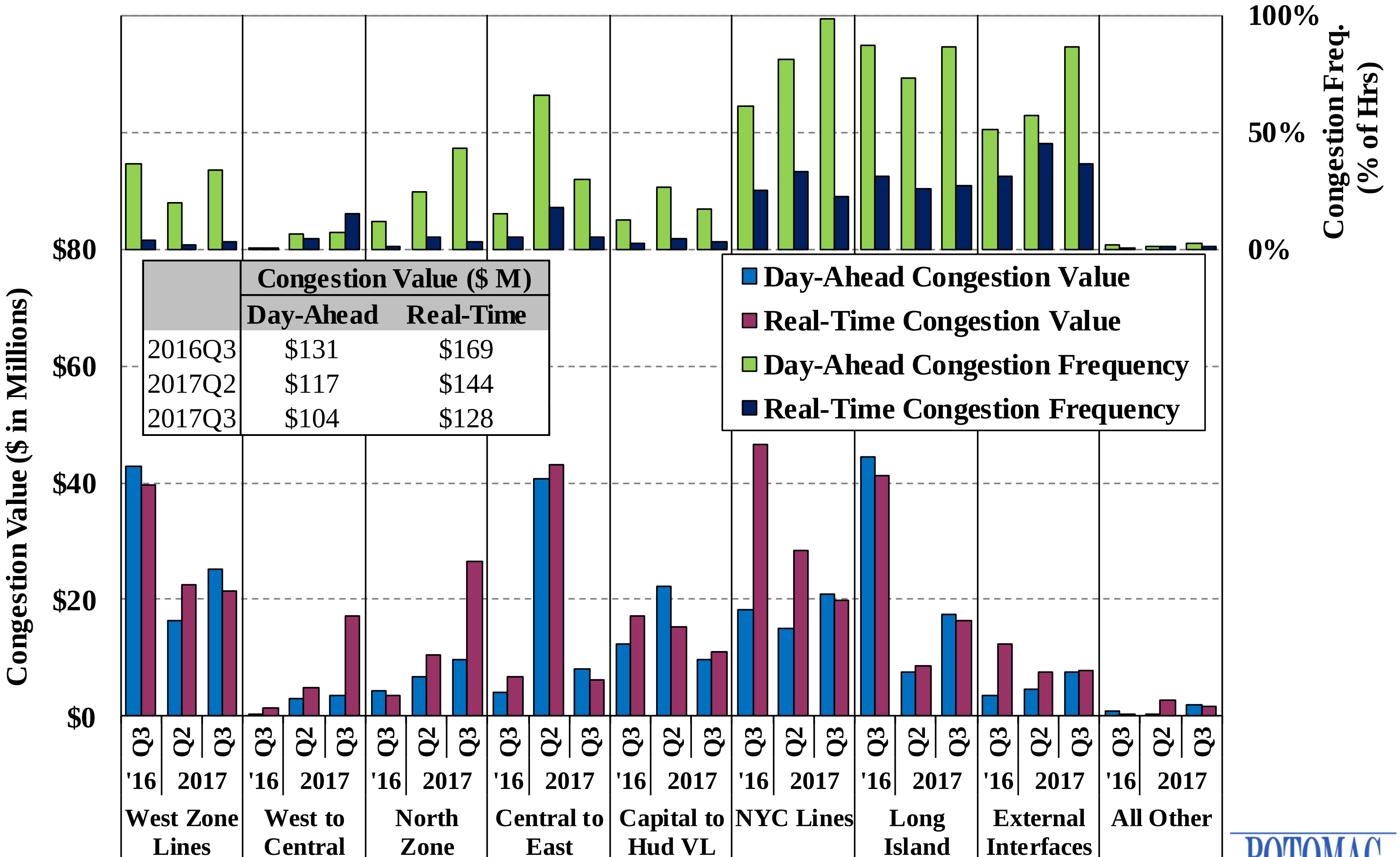
Congestion Revenues and Shortfalls by Month

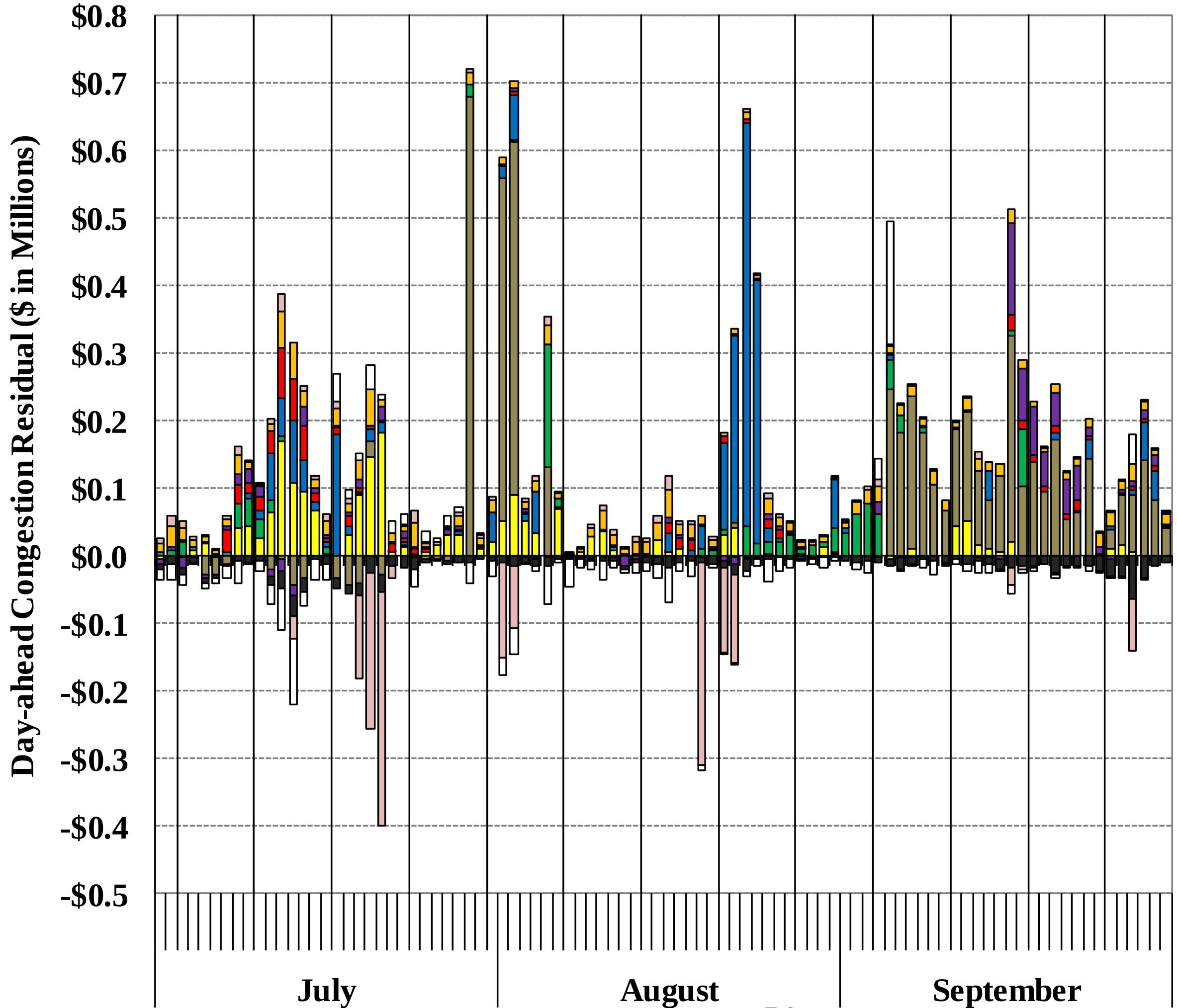


	2016Q3	2017Q2	2017Q3
DAM Congestion Revenues (1)	$131	$117	$104
DAM Congestion Shortfalls (2)	$20	$21	$10
Payments to TCC Holders (1)+(2)	$151	$138	$114
Balancing Congestion Shortfalls	$9	$10	$9

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

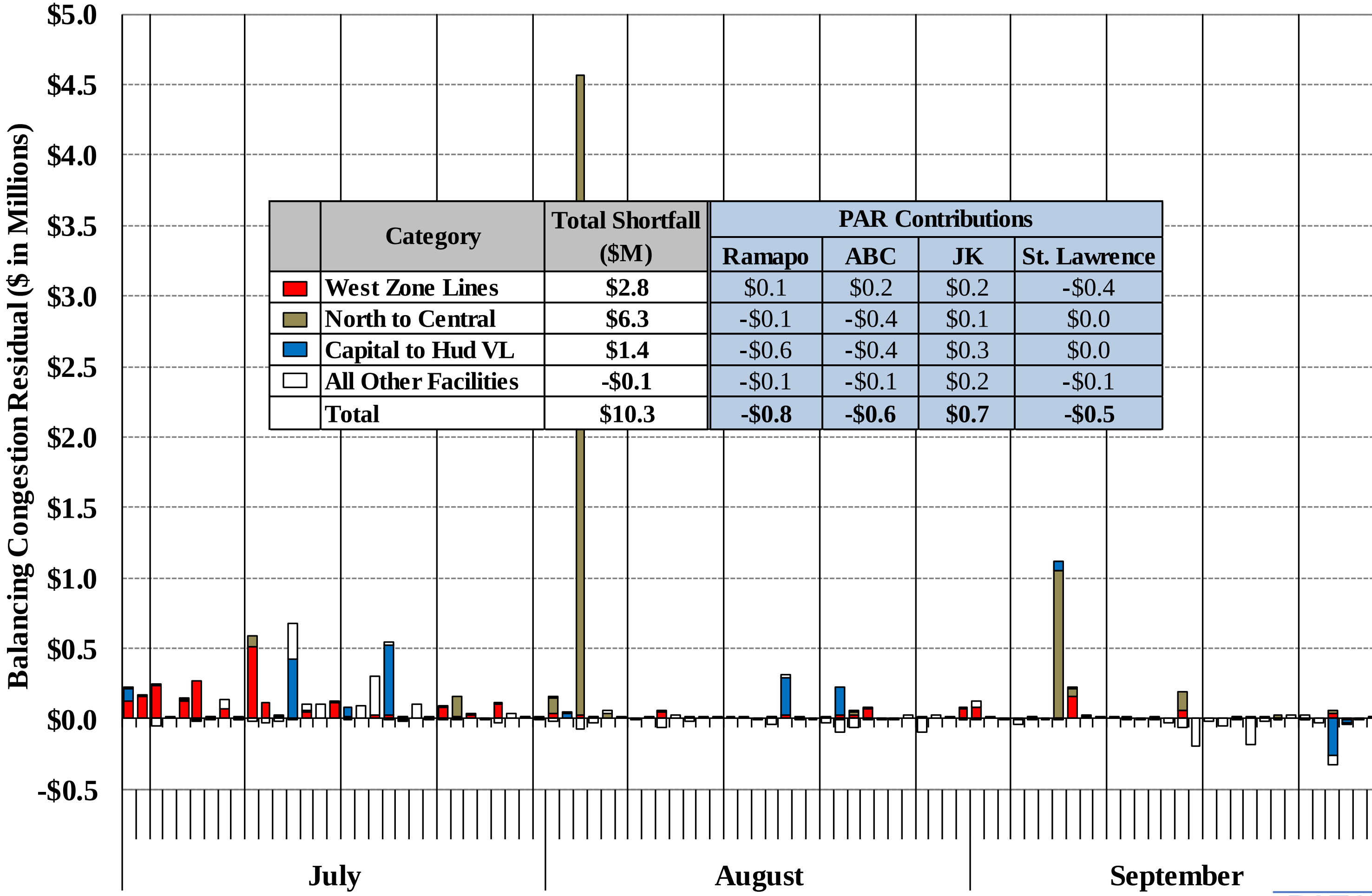


Day-Ahead Congestion Revenue Shortfalls
by Transmission Facility



	Category	Total Shortfall ($M)
	West Zone Lines	$2.0
	North Zone Lines	$4.7
	Central to East	$1.1
	Capital to Hud VL	$2.5
	NYC Lines	
	ABC PARs	$0.6
	Other Factors	$0.7
	Long Island Lines	
	901/903 PARs	-$1.1
	Excess GFTCC	$1.4
	Other Factors	-$1.3
	All Other Facilities	-$0.7

Balancing Congestion Shortfalls
by Transmission Facility



	Category	Total Shortfall ($M)	PAR Contributions			
			Ramapo	ABC	JK	St. Lawrence
	West Zone Lines	$2.8	$0.1	$0.2	$0.2	-$0.4
	North to Central	$6.3	-$0.1	-$0.4	$0.1	$0.0
	Capital to Hud VL	$1.4	-$0.6	-$0.4	$0.3	$0.0
	All Other Facilities	-$0.1	-$0.1	-$0.1	$0.2	-$0.1
	Total	$10.3	-$0.8	-$0.6	$0.7	-$0.5

Note: The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values.

Congestion Management with the GTDC: Chart Descriptions

- The NYISO revised the pricing process of transmission constraint shortages on June 20, 2017 to improve market efficiency during transmission shortages. Key changes include:
  - ✓ Modify the second step of the Graduated Transmission Demand Curve (“GTDC”) from $2,350 to $1,175/MWh; and
  - ✓ Remove the feasibility screen and apply the GTDC to all constraints with a non-zero Constraint Reliability Margin (“CRM”).
- The next two exhibits compare market performance before and after the change.
  - ✓ The first table summarizes the following quantities in 2017-Q3 (vs 2016-Q3) by constraint group:
    - The frequency of transmission constraint shortages;
    - Average constraint shadow prices; and
    - Average shortage quantities relative the BMS limit (adjusted for the CRM).
    - These quantities are shown separately for constraints with different pricing treatments (i.e., various applications of the GTDC vs constraint relaxation).
  - ✓ The second set of figures show this information at 5-minute interval level for four select constraint groups.

Congestion Management with the GTDC: Market Outcomes

- Constraint relaxation has been much less frequent following the revision of transmission shortage pricing in June.
  - ✓ Only 6 percent of all transmission shortages involved constraint relaxation in 2017-Q3 as opposed to 59 percent in 2016-Q3.
  - ✓ It is desirable to minimize the use of constraint relaxation because it:
    - Leads constraint shadow prices to be uncorrelated with the severity of the shortage (e.g., the shortage amount, the duration of the constraint), and
    - Makes congestion less transparent and predictable for market participants.
- Average constraint shadow prices during transmission shortages fell modestly from a year ago in most areas.
  - ✓ This was partly because the GTDC's second step changed from $2,350 to $1,175.
- Despite overall improved market outcomes, at times constraint shadow prices still did not properly reflect the importance and severity of a transmission shortage.
  - ✓ For example, the NYISO uses a higher CRM for certain facilities such as the Dunwoodie-ShoreRd 345kV line (which has a CRM of 50 MW), leading the GTDC to over-value some constraint violations.
  - ✓ Thus, we continue to recommend constraint-specific GTDCs.

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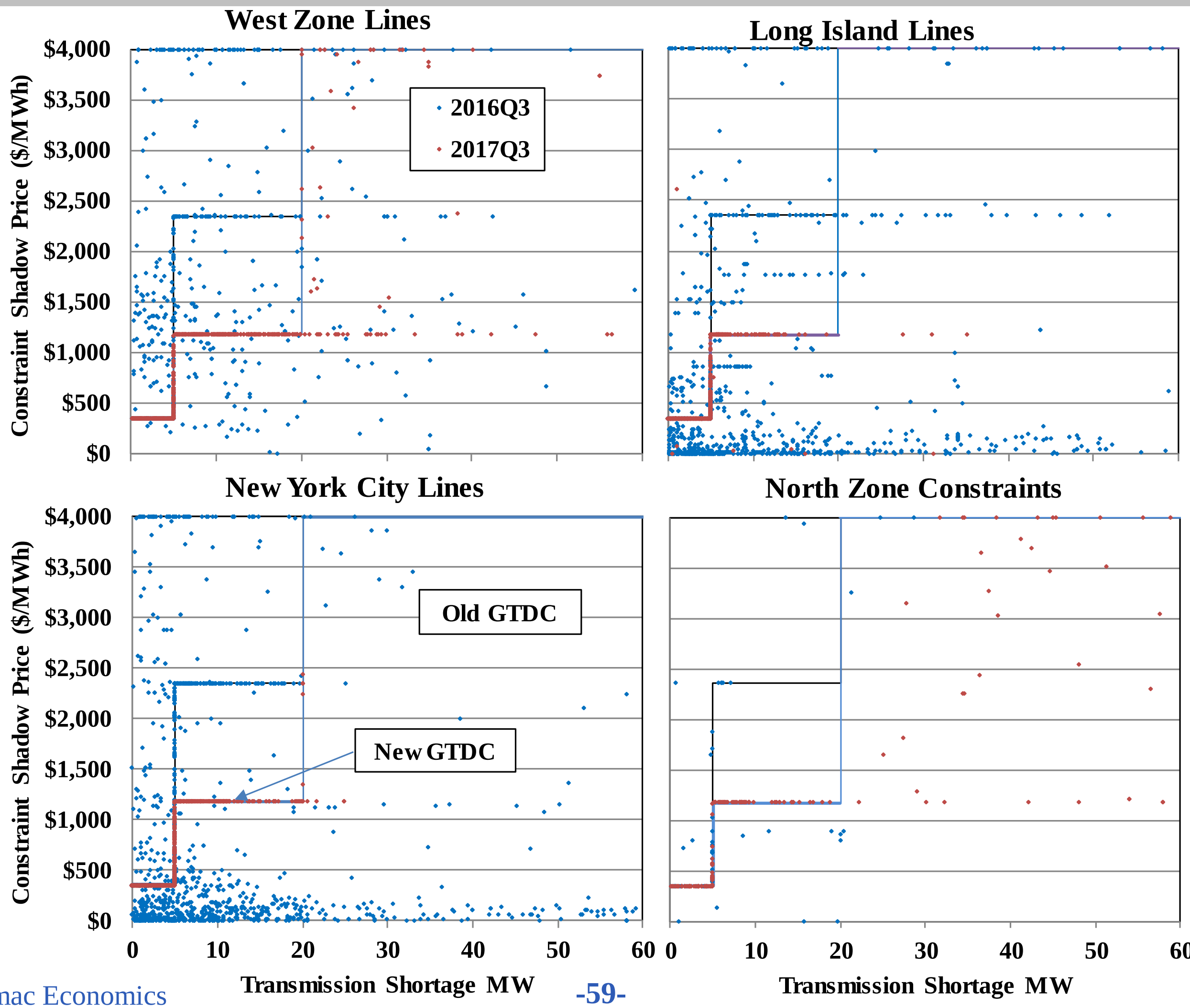
Congestion Management with the GTDC
Summary of Transmission Shortage

Location of Constrained Facilities	CRM = 0?	Shortage Handling	# of Constraint-Intervals		Avg Shadow Price ($/MWh)		Avg Shortage (MW)	
			2016Q3	2017Q3	2016Q3	2017Q3	2016Q3	2017Q3
West Zone	Y	Relaxation Only						
	N	Relaxation & GTDC	10	55	$2,414	$2,331	31	32
		Relaxation Only	339		$1,936		14	
		GTDC Only	291	518	$867	$784	4	7
		SubTotal	**640**	**573**	**$1,457**	**$932**	**10**	**9**
New York City	Y	Relaxation Only	21		$2		58	
	N	Relaxation & GTDC	2	5	$3,020	$1,352	24	110
		Relaxation Only	852		$706		14	
		GTDC Only	795	1043	$797	$575	4	4
		SubTotal	**1670**	**1048**	**$743**	**$578**	**10**	**5**
North Zone	Y	Relaxation Only						
	N	Relaxation & GTDC		69		$2,598		72
		Relaxation Only	19		$1,578		13	
		GTDC Only	58	156	$655	$670	4	5
		SubTotal	**77**	**225**	**$883**	**$1,261**	**6**	**26**
Long Island	Y	Relaxation Only	495	8	$166	$444	23	10
	N	Relaxation & GTDC	25	3	$2,614	$1,175	37	31
		Relaxation Only	439		$967		15	
		GTDC Only	345	640	$680	$531	4	4
		SubTotal	**1304**	**651**	**$619**	**$533**	**16**	**4**
All Other	Y	Relaxation Only	3	12	$2,995	$2,679	87	152
	N	Relaxation & GTDC	1	3	$2,633	$2,738	26	280
		Relaxation Only	24		$2,306		34	
		GTDC Only	80	100	$1,122	$772	7	8
		SubTotal	**108**	**115**	**$1,451**	**$1,022**	**15**	**30**
Grand Total			**3799**	**2612**	**$844**	**$723**	**12**	**8**

Congestion Management with the GTDC
Transmission Shortage Pricing



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PAR Operations under M2M with PJM: Chart Descriptions

- The following exhibits evaluate the PAR operations under M2M with PJM for four PAR groups:
  - ✓ Goethals PAR (i.e., A PAR);
  - ✓ Farragut PARs (i.e., B & C PARs)
  - ✓ Waldwick PARs (i.e., E, F, and O PARs, which control the J and K lines); and
  - ✓ Ramapo PARs.
- Each of four figures shows the following quantities on a daily basis:
  - ✓ The upper portion shows the total number of PAR tap movements (counted as total tap position changes. e.g., if one tap adjustment requires to move two taps, the figure shows two movements rather than one for that adjustment).
  - ✓ The middle portion shows two stacked bars, which indicate the number of 30-minute intervals when average: a) NY costs on relevant M2M constraints exceed PJM costs by \$10, or b) PJM costs exceed NY costs by \$10.
  - ✓ The bottom portion shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).
- The first table summarizes the quarterly average of these quantities for each PAR (during the period when the PAR is in service).

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PAR Operations under M2M with PJM: Market Outcomes

- In May, the ABC and JK lines were incorporated into the M2M process following the expiration of the ConEd-PSEG wheel agreement.
  - ✓ New coordinated flow gates were added mostly in NYC and West Zone.
- For all PARs, actual flows typically exceeded their M2M targets towards NY, resulting in virtually no M2M payments from PJM to NYISO in the third quarter.
- We have observed instances of efficient M2M coordination as PARs were moved in the direction to reduce overall congestion costs in a relatively timely manner.
  - ✓ However, there were instances when PAR adjustments may have been available and would have reduced congestion but no adjustments were made.
  - ✓ In some cases, PAR adjustments were not taken because of:
    - Difficulty predicting the effects of PAR movements under uncertain conditions;
    - Adjustment would push actual flows or post-contingent flows close to the limit;
    - Adjustment was not necessary to maintain flows above the M2M target;
    - The transient nature of congestion; and
    - Mechanical failures (e.g., stuck PARs).
    - However, we lack the information necessary to determine how often some of these factors prevented PAR adjustments.

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PAR Operations under M2M with PJM: Market Outcomes

- The Ramapo and ABC PARs have provided significant benefits to the NYISO in managing congestion on coordinated flow gates.
  - ✓ Balancing congestion surpluses have resulted from relief of transmission paths from North to Central and from Capital to Hudson VL (slide 55), indicating that it reduced production costs and congestion.
  - ✓ Nonetheless, comparable benefits have not been observed from the operation of Waldwick PARs in 2017-Q3.
- We observed potential opportunities for increased utilization of M2M PARs.
  - ✓ The normal limit for each PAR-controlled line was over 500 MW, but flows were generally well below this level.
    - However, flows on these lines sometimes were limited by their post-contingency conditions (but NYISO does not store post-contingency flow data for these lines).
  - ✓ On average, each PAR was adjusted 1 to 5 times per day in 2017-Q3.
    - This was well below the operational limits of 20 taps/day and 400 taps/month.
    - For some PARs, this was also below the average three to four 30-minute blocks of time per day when the congestion differential between PJM and NYISO exceeded \$10/MWh across these PAR-controlled lines.
- We will continue to monitor the performance of the M2M process.

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PAR Operation under M2M with PJM:
Summary Results

M2M PAR		Average Flow/Limit (MW)			Avg. TAP Moves Per Day	# of 30-min Intervals Where Cong. Diff. of (NY - PJM) :	
		Target Flow	Actual Flow	Seasonal Limit		> $10	< -$10
Goethals/ Farragut	A	91	173	540	3.5	1.7	2.0
	B	84	117	508	3.7	1.4	1.5
	C	110	137	508	5.0	1.4	1.5
Waldwick	E	-75	-46	609	1.3	1.6	1.8
	F	-94	-61	557	1.4	1.6	1.8
	O	-94	-97	549	1.4	1.6	1.8
Ramapo	4500	134	167	575	2.3	1.8	1.8

Note: The Ramapo PAR 3500 is not included here because it just returned to service in mid September from an over-a-year-long outage.

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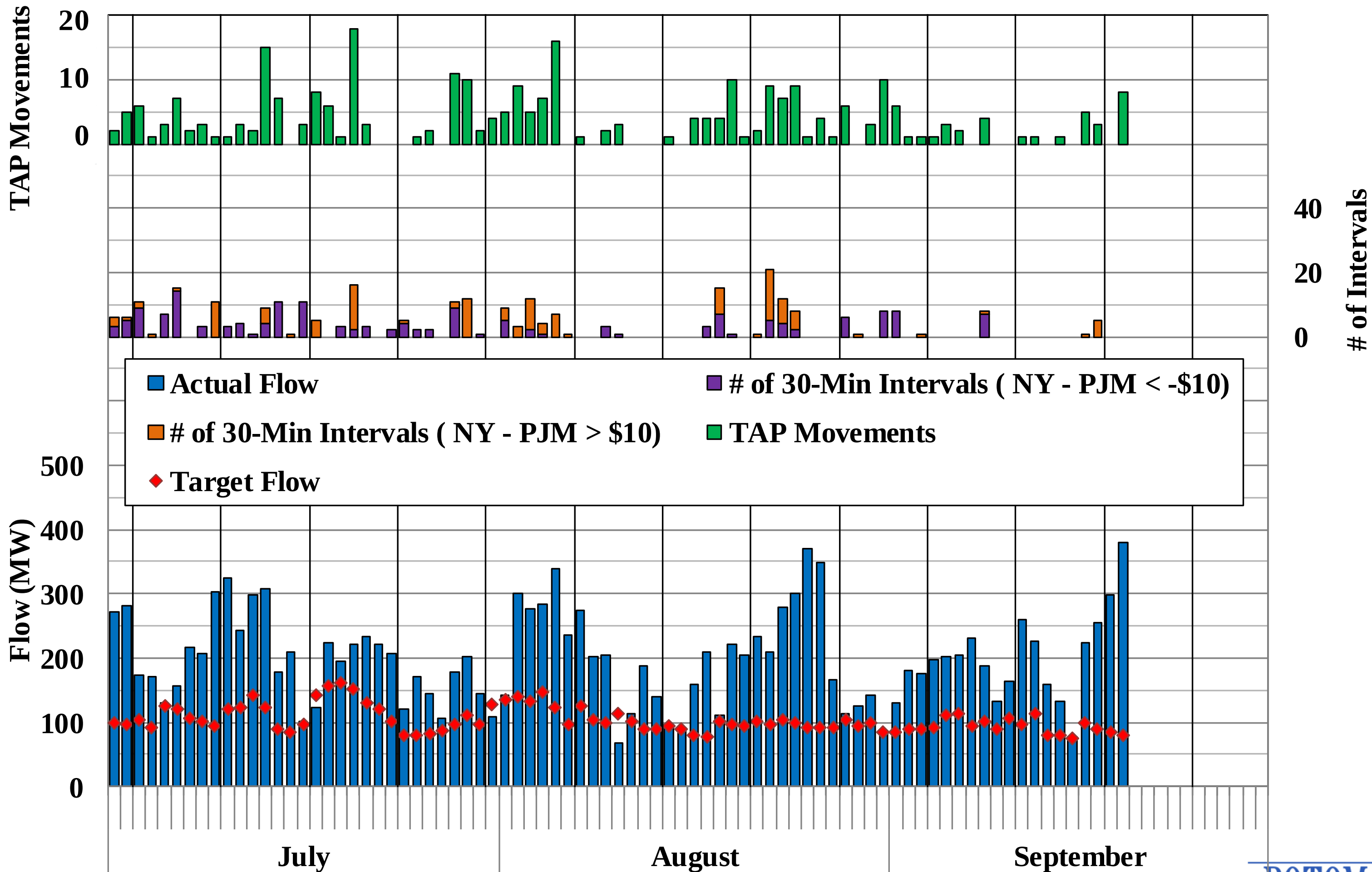
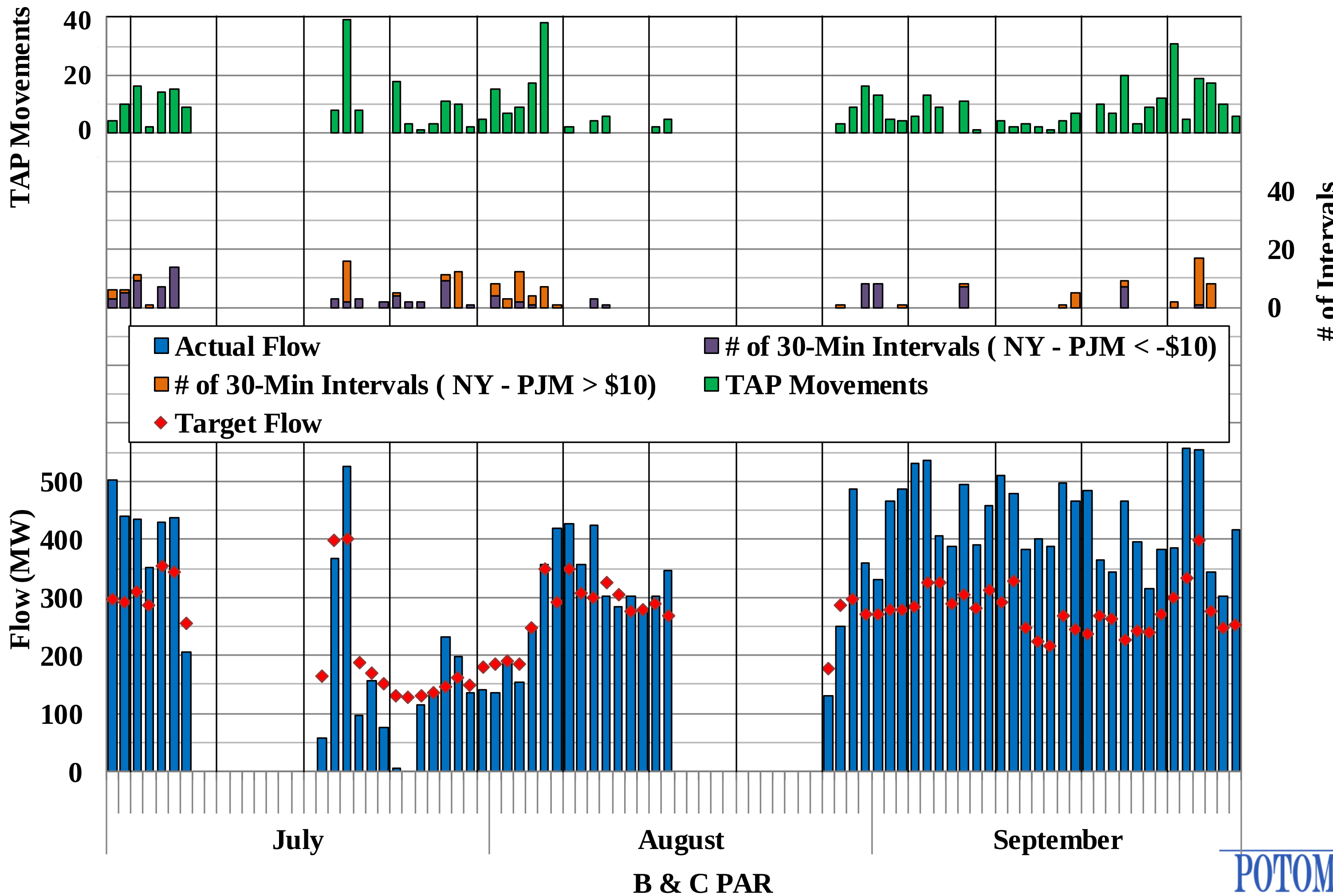
PAR Operation under M2M with PJM: A PAR

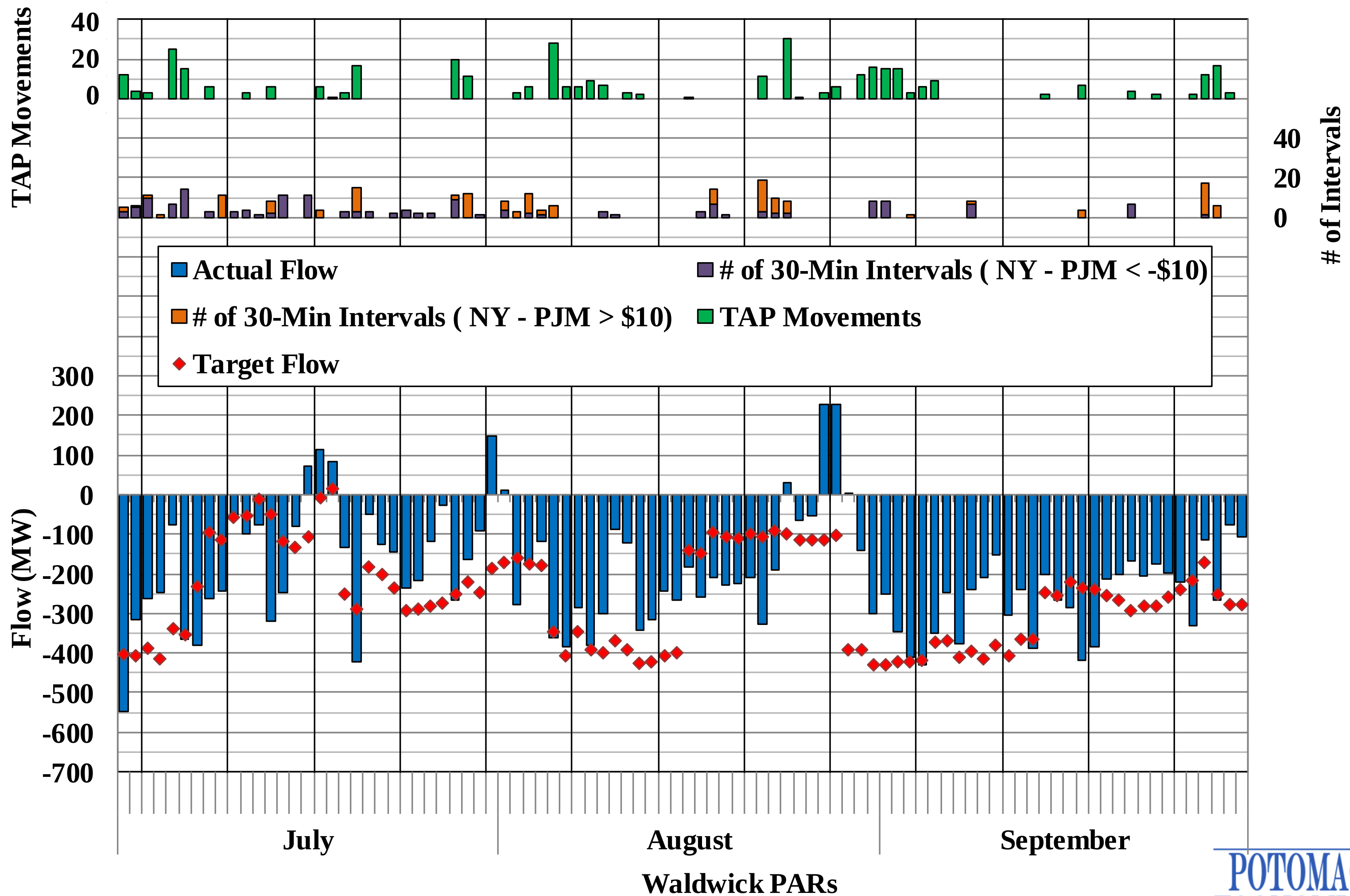


A PAR

PAR Operation under M2M with PJM:
B & C PAR



PAR Operation under M2M with PJM:
Waldwick PARs



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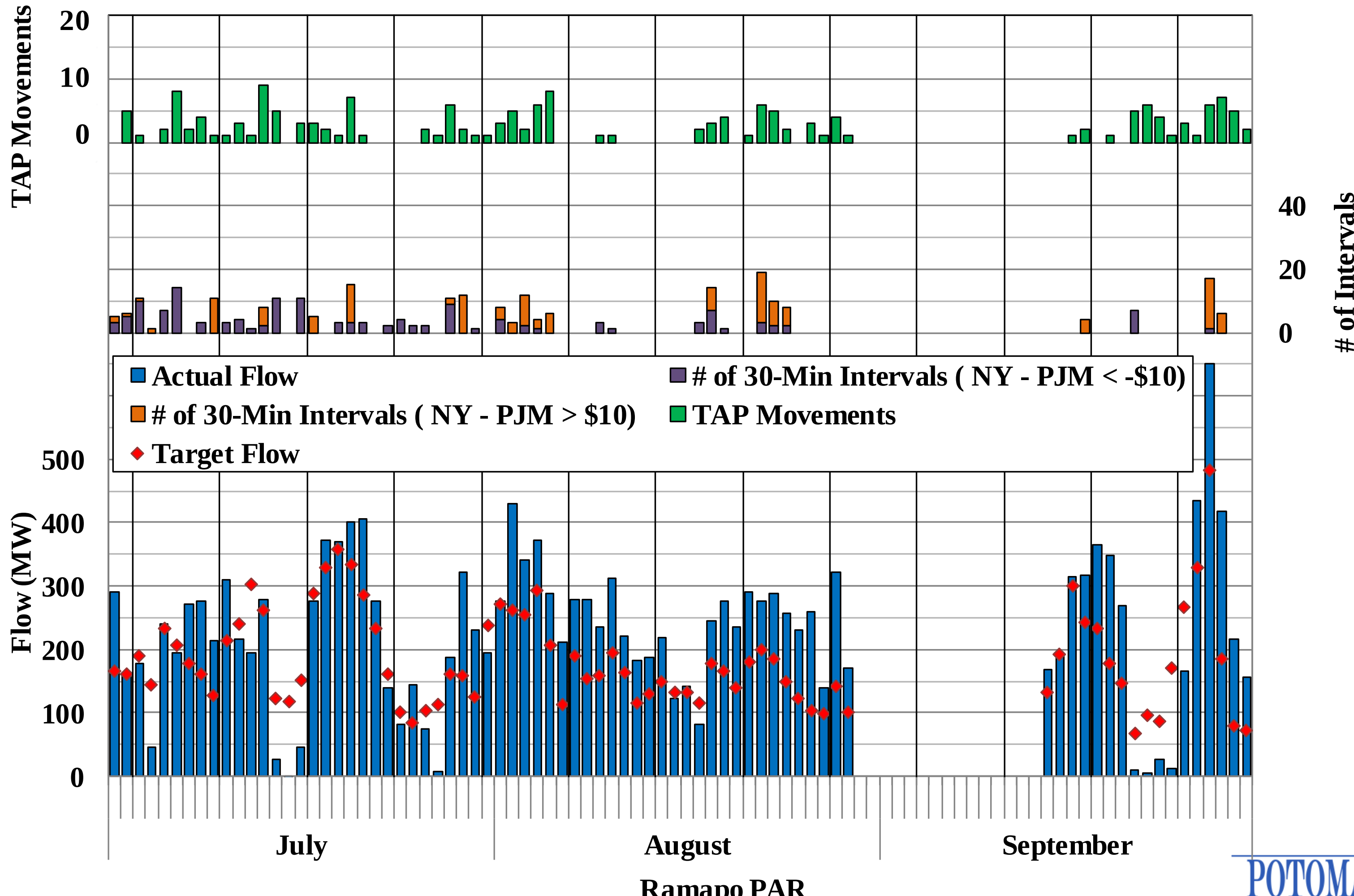
PAR Operation under M2M with PJM:
Ramapo PARs



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Constraints on the Low Voltage Network Upstate

- In upstate New York, constraints on 230 and 345 kV facilities is generally managed through the day-ahead and real-time market systems. This provides several benefits:
  - ✓ Efficient dispatch and scheduling decisions; and
  - ✓ Transparent prices that provide efficient signals for longer lead time decisions such as fuel procurement, external transaction scheduling, and investment.
- However, 115 kV constraints are resolved in other ways, including:
  - ✓ Out of merit dispatch and supplemental commitment;
  - ✓ External interface transfer limits;
  - ✓ Use of an internal interface limit as a proxy for the facility; and
  - ✓ Adjusting PAR-controlled lines.
- The next figure shows the number of days in the third quarter of 2017 when various resources were used to manage constraints in four areas of upstate NY.
  - ✓ 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; and

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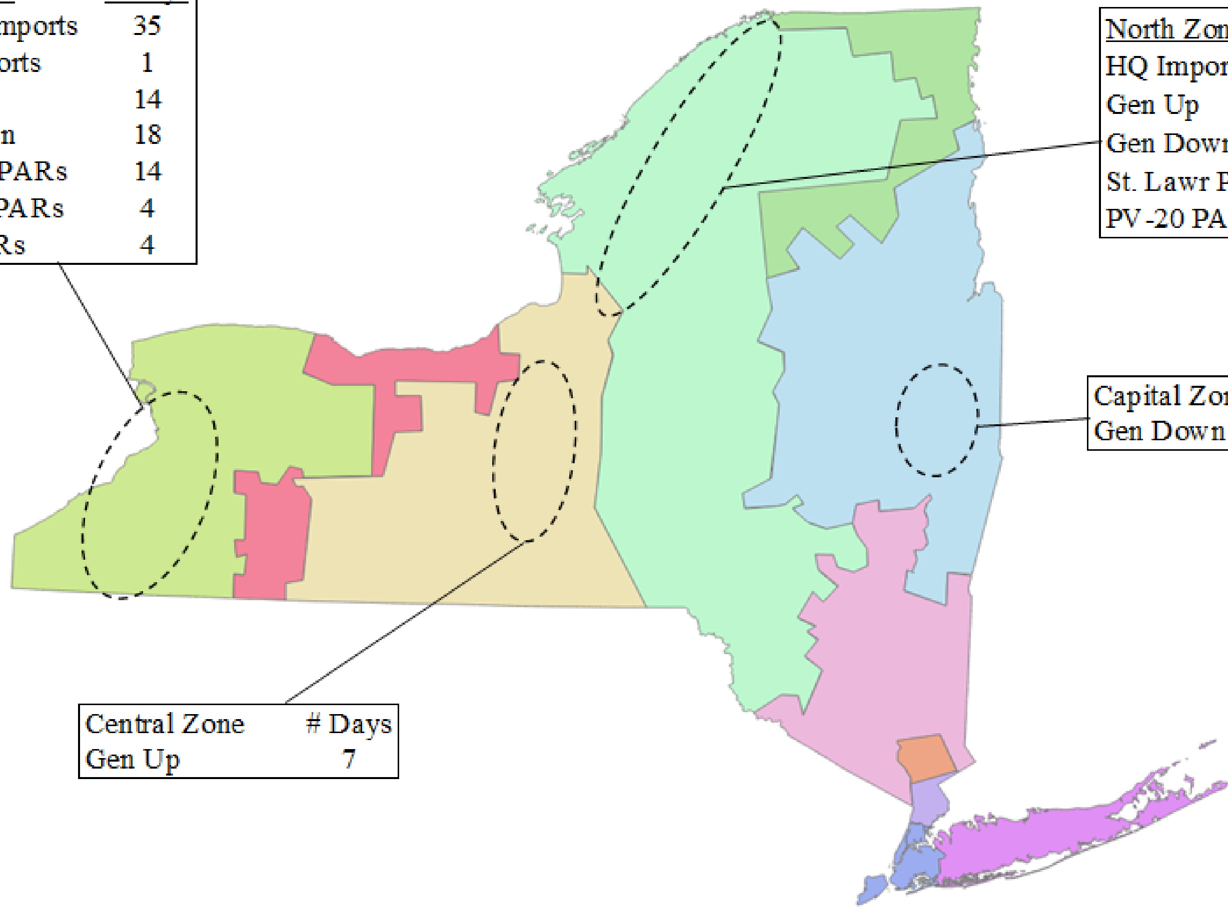
Constraints on the Low Voltage Network Upstate

- ✓ North Zone: Mostly 115kV constraints coming south from the North Zone between the Colton 115kV and Taylorville 115kV buses.
- The West Zone contains the most frequently constrained 115kV facilities.
  - ✓ Generation and Ontario imports were constrained on many days, while PARs in Northern NY and Southeast NY were also used on some days.
  - ✓ West Zone constraint management affected other areas of New York by:
    - – Reducing low-cost imports from Ontario, which raised LBMPs in other areas; and
    - – Using PARs to relieve West Zone constraints tends to exacerbate constraints going south from the North Zone, across the Central East interface, and into NYC.
    - – Thus, the actions should be done in a manner that balances the benefits of relieving constraints in one area against the cost of exacerbating congestion in another.
      - This can be done more effectively if low-voltage constraints were managed using the day-ahead and real-time market systems.
  - ✓ Although the PJM export limit bound on just 1 day, PJM imports are generally helpful for managing 115kV congestion in the West Zone.
    - – Modeling 115kV constraints in the market systems would provide incentives for PJM imports to relieve congestion in NY.

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

West Zone	# Days
Ontario Imports	35
PJM Exports	1
Gen Up	14
Gen Down	18
St. Lawr PARs	14
Ramapo PARs	4
ABC PARs	4

North Zone	# Days
HQ Imports	14
Gen Up	7
Gen Down	29
St. Lawr PARs	9
PV-20 PAR	3



Capital Zone	# Days
Gen Down	36

Central Zone	# Days
Gen Up	7

Supplemental Commitments, OOM Dispatch, and Uplift Charges

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- The next three figures summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- The first figure 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.
- The second figure 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:

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Supplemental Commitment and OOM Dispatch: Chart Descriptions

  - 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 and no other reason except NOx.
  - Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, IR-3. The capacity is shown for each separate reason in the bar chart.
- ✓ For voltage and thermal constraints, the capacity is shown by the following load pocket that was secured:
  - (a) AELP = Astoria East; (b) AWLP = Astoria West/Queensbridge; (c) AVLP = Astoria West/Queensbridge/ Vernon; (d) ERLP = East River; (e) FRLP = Freshkills; (f) GSLP = Greenwood/ Staten Island; and (g) SDLP = Sprainbrook/Dunwoodie.

- The third figure 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, the two stations with the highest number of OOM dispatch hours in the current quarter are shown separately.

Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results

- Reliability commitments averaged ~565 MW, up modestly from a year earlier.
- Nearly 90 percent of reliability commitments occurred in NYC in 2017-Q3.
  - ✓ Reliability commitments increased 100 percent in NYC from 2016-Q3.
  - ✓ However, the increase was not because of increased local reliability needs in 2017-Q3 but reflected changes in economics. Units needed for local reliability were:
    - Economically committed more frequently in 2016-Q3 because of lower gas prices in NYC (relative to the rest of East NY) and higher load levels; but
    - Flagged more often for reliability in 2017-Q3 as a result of increased gas prices relative to other areas of East NY (slide 14) and lower load levels (slide 13).
  - ✓ A portion of reliability commitment in September was also attributable to transmission and generation outages.
- Reliability commitments were rare in other areas in 2017-Q3.
  - ✓ DARU commitments in West NY fell notably since the completion of transmission upgrades in early July that allowed for the expiration of Milliken RSSA.
  - ✓ DARU commitments in Long Island fell from a year ago because lower load levels and fewer transmission outages reduced the capacity needed to prevent voltage collapse from inadequate transient voltage recovery. (see ARR-28C)

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Supplemental Commitment and OOM Dispatch: OOM Dispatch Results

- The NYISO and local TOs sometimes dispatch generators out-of-merit in order to:
  - ✓ Maintain reliability of the lower-voltage transmission and distribution networks; or
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model.
- OOM dispatch occurred for 1709 station-hours, down 46 percent from a year ago.
  - ✓ OOMs fell 62 percent in Western NY due primarily to transmission upgrades in early July, which allowed the Milliken RSSA to expire and reduced OOM needs.
    - – However, two hydro units were frequently OOMed-down in July due to increased local needs on the 115 kV network because of transmission outages.
  - ✓ OOM levels also fell 60 percent in Long Island as lower loads and fewer transmission outages led to decreased needs for voltage support on the East End.
  - ✓ However, these decreases were partly offset by frequent OOMs of the Bethlehem units to manage post-contingency flow on the Albany-Greenbush 115 kV facility.
- The Niagara facility was often manually instructed to shift output among its units to secure certain 115kV and/or 230 kV transmission constraints (which was not included in the OOM counts in the chart). In the third quarter of 2017,
  - ✓ This manual shift required in 289 hours to manage 115 kV constraints and in 106 hours to manage 230 or 345 kV constraints.

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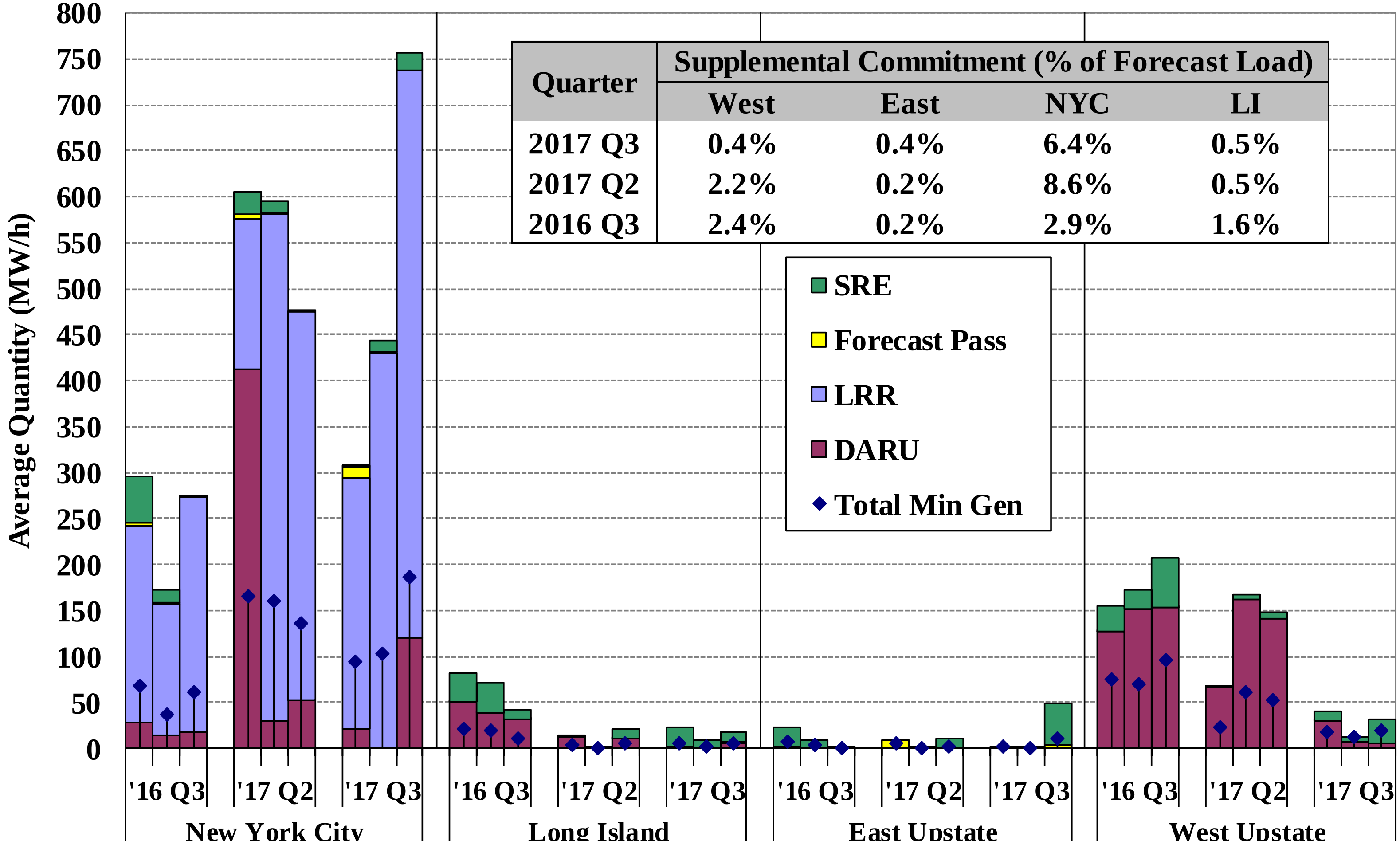
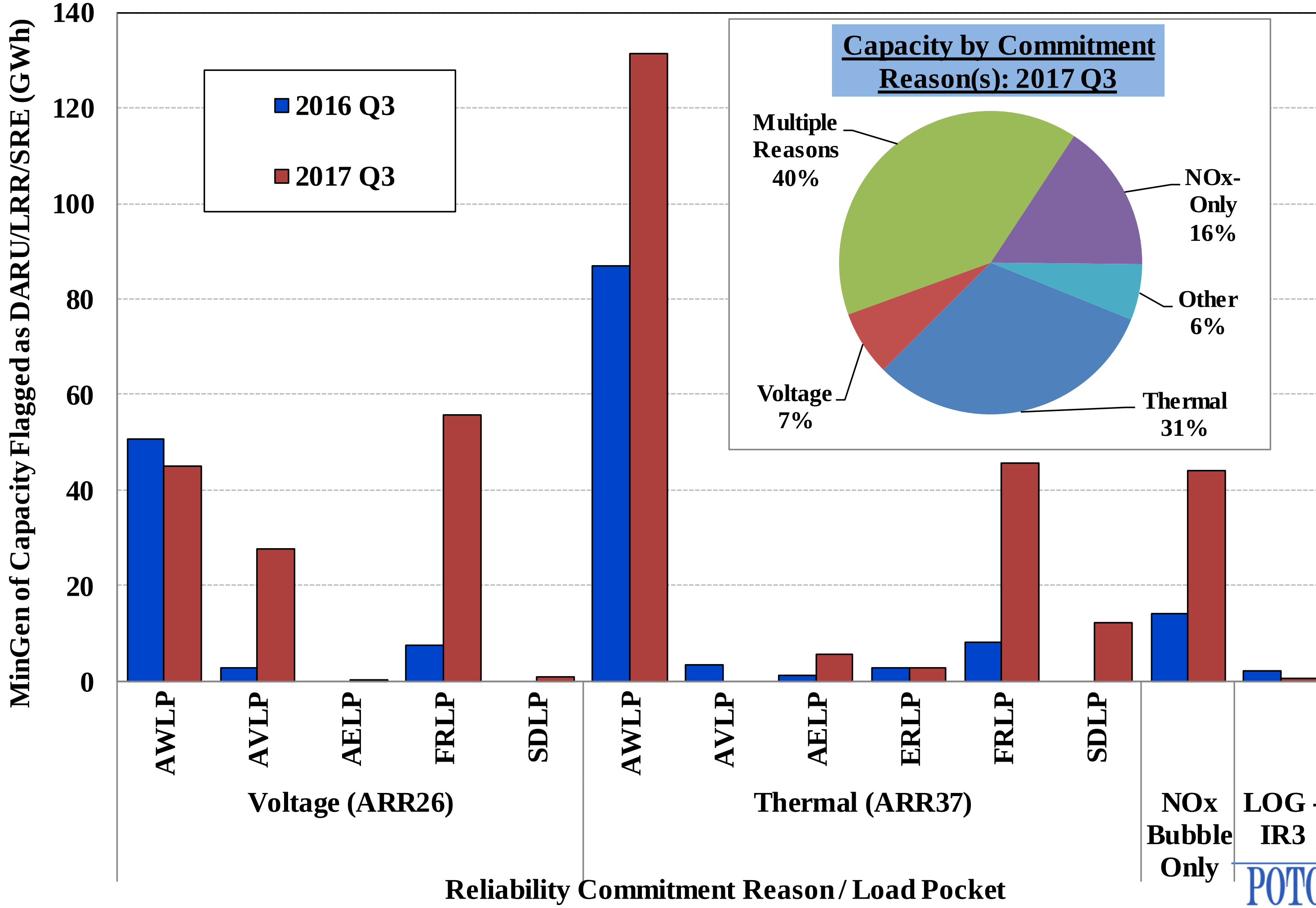
Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2017 Q3	0.4%	0.4%	6.4%	0.5%
2017 Q2	2.2%	0.2%	8.6%	0.5%
2016 Q3	2.4%	0.2%	2.9%	1.6%

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



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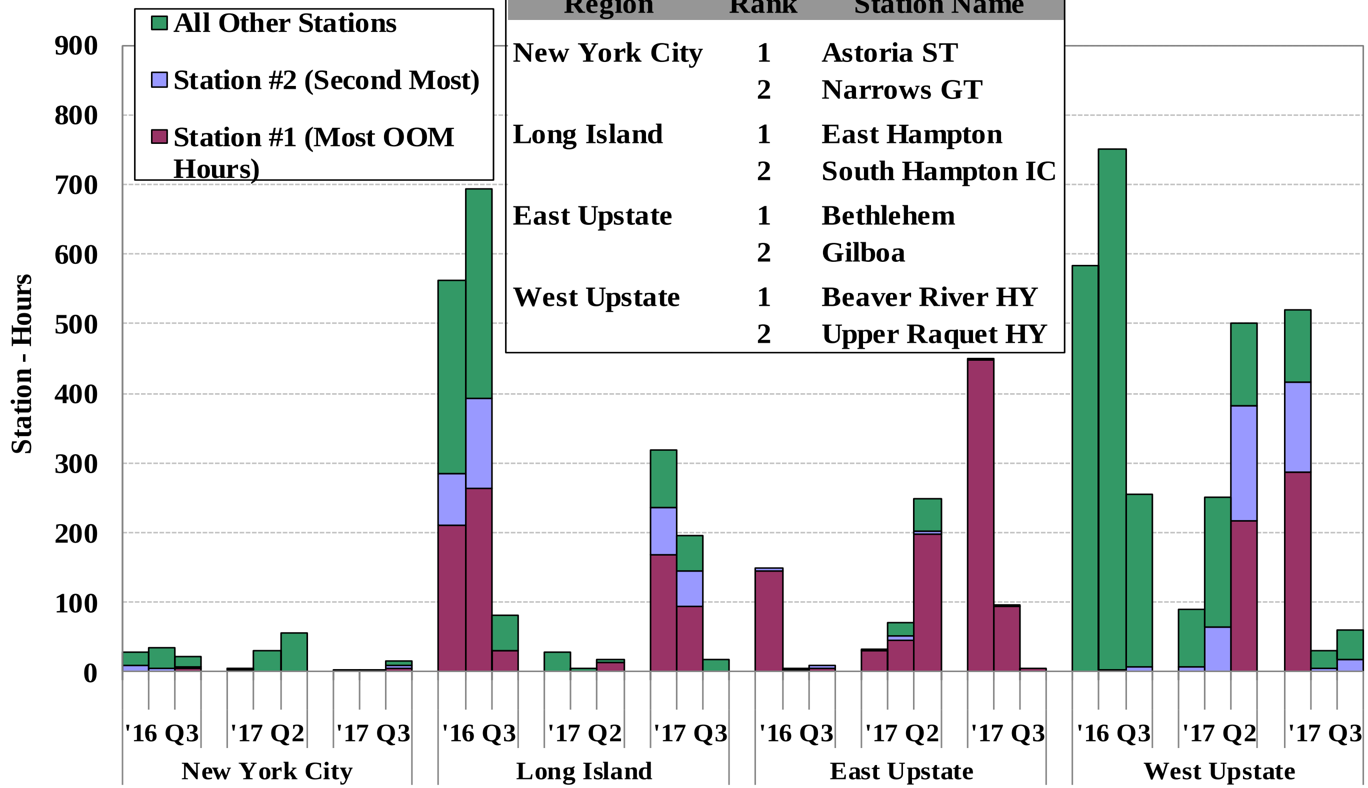
Frequency of Out-of-Merit Dispatch by Region by Month

Region	Station Rank	Station Name
New York City	1	Astoria ST
	2	Narrows GT
Long Island	1	East Hampton
	2	South Hampton IC
East Upstate	1	Bethlehem
	2	Gilboa
West Upstate	1	Beaver River HY
	2	Upper Raquet HY



Note: "Station #1" is the station with the highest number of out-of-merit ("OOM") hours in that region in the current quarter; "Station #2" is that station with the second-highest number of OOM hours in that region in the current quarter.

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 430 hours in 2016-Q3, 289 hours in 2017-Q2, and 395 hours in 2017-Q3. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

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Uplift Costs from Guarantee Payments:
Chart Descriptions

- The next two figures 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.
  - ✓ The first figure shows these seven categories on a daily basis during the quarter.
  - ✓ The second figure summarizes uplift costs by region on a monthly basis.

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Uplift Costs from Guarantee Payments:
Market Results

- Guarantee payments totaled $8.5 million in 2017-Q3, which was down 55 percent from 2016-Q3.
- Guarantee payments in the category of DAMAP, Min Oil Burn, and EDRP/SCR accounted for a reduction of more than $5.5 million.
  - ✓ Most of these uplift charges in 2016-Q3 accrued on several days with high load levels, which, however, were not seen in 2017-Q3 because of milder weather.
- Guarantee uplift fell by 76 percent in Western NY and by 66 percent in Long Island.
  - ✓ The reductions were due primarily to greatly reduced supplemental commitments and OOM levels in these areas for the reasons discussed earlier.
- However, guarantee payments in NYC were comparable to a year ago.
  - ✓ Lower DAMAP and Min Oil Burn payments from a year ago were offset by higher DAM local uplift charges this quarter, due primarily to:
    - – Increased reliability commitments; and
    - – Higher natural gas prices (slide 14), which increased the commitment costs of gas-fired units.

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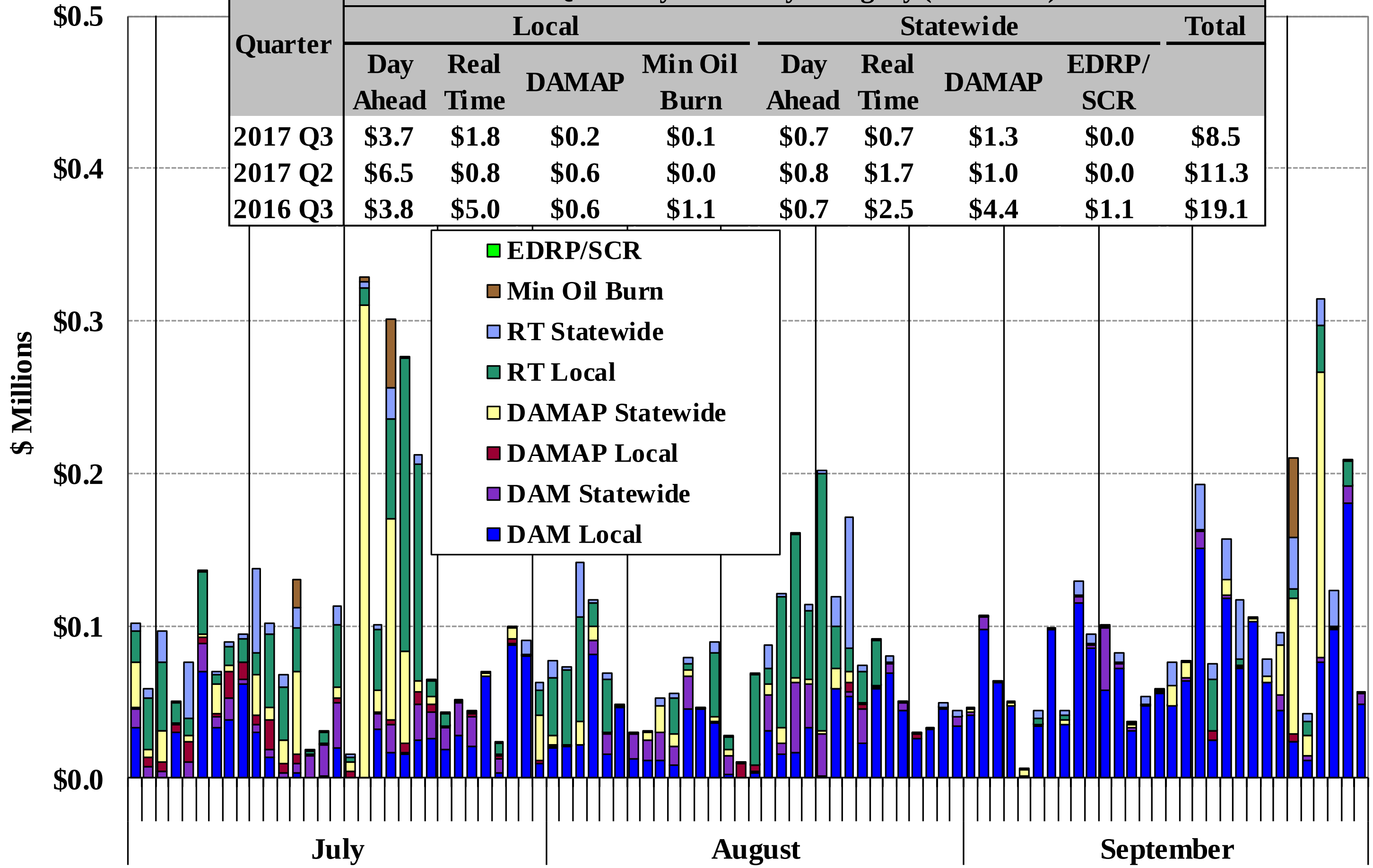
Uplift Costs from Guarantee Payments
Local and Non-Local by Category

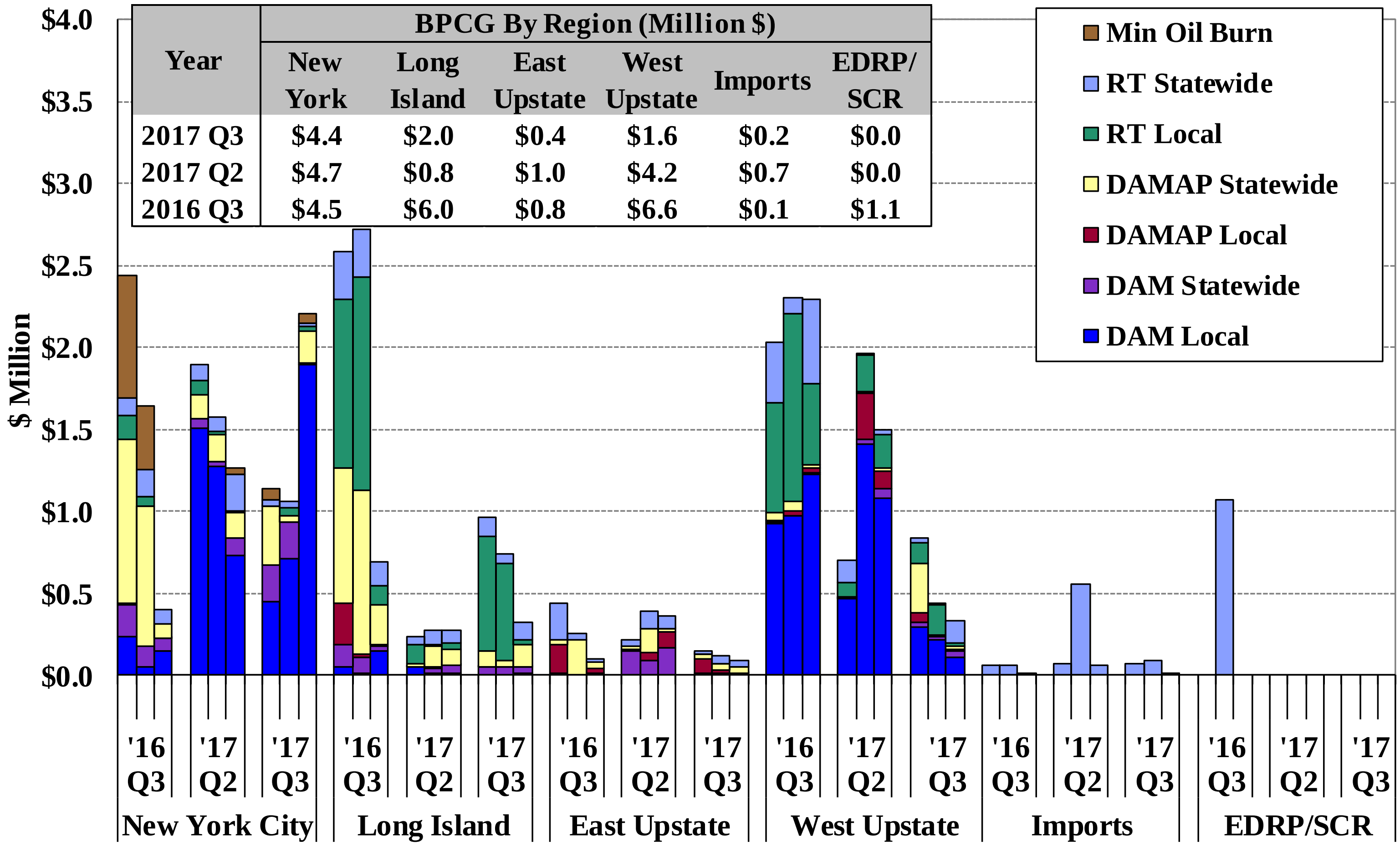
Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2017 Q3	$3.7	$1.8	$0.2	$0.1	$0.7	$0.7	$1.3	$0.0	$8.5
2017 Q2	$6.5	$0.8	$0.6	$0.0	$0.8	$1.7	$1.0	$0.0	$11.3
2016 Q3	$3.8	$5.0	$0.6	$1.1	$0.7	$2.5	$4.4	$1.1	$19.1



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.

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
2017 Q3	$4.4	$2.0	$0.4	$1.6	$0.2	$0.0
2017 Q2	$4.7	$0.8	$1.0	$4.2	$0.7	$0.0
2016 Q3	$4.5	$6.0	$0.8	$6.6	$0.1	$1.1



Note: BPCG data are based on information available at the reporting time that can be different from final settlements.

Market Power and Mitigation

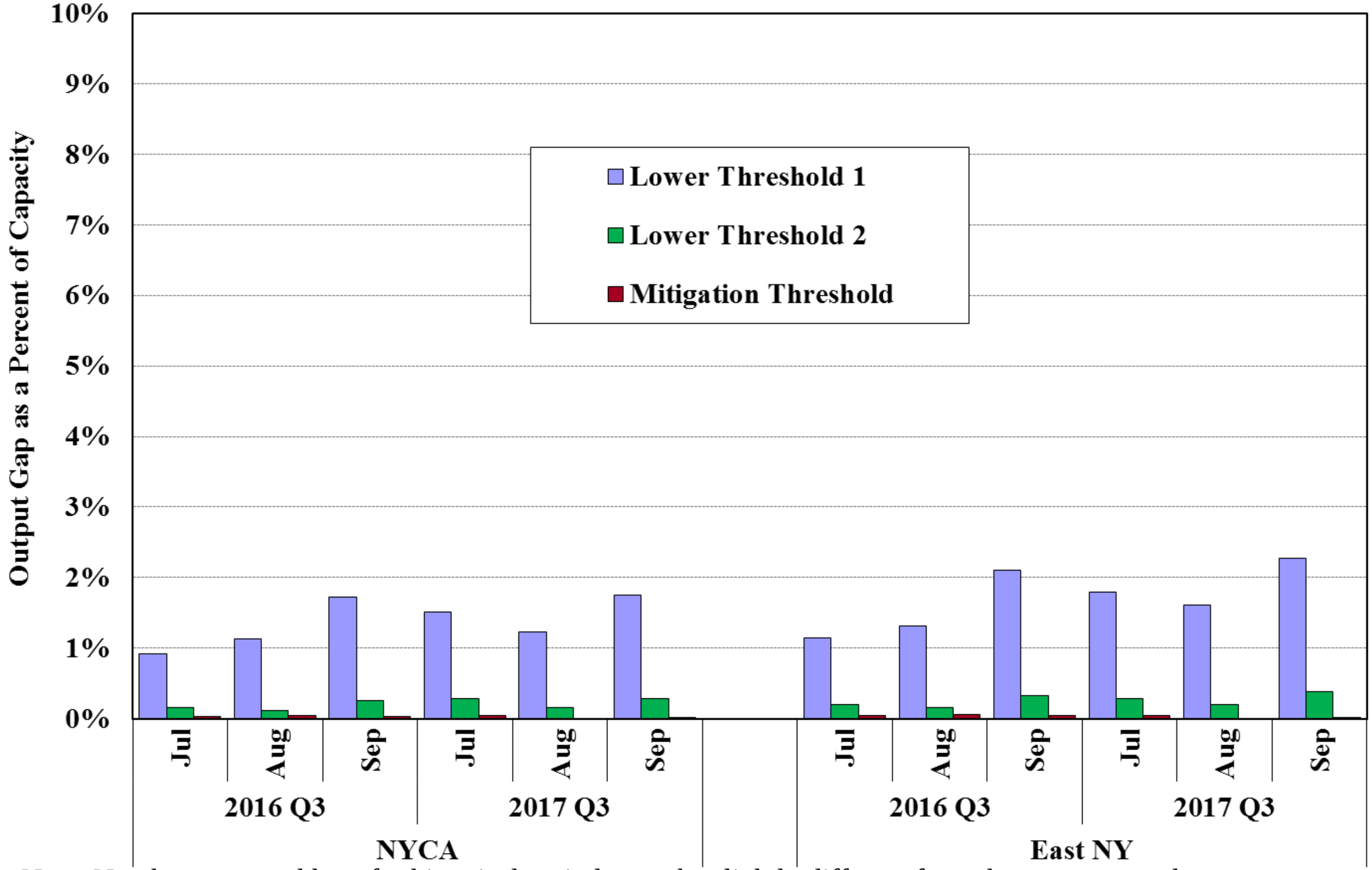
Potential Economic and Physical Withholding: Chart Descriptions

- The next two figures 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.

Potential Economic and Physical Withholding: Market Power Screening Results

- The amount of output gap remained low in 2017-Q3 and raised no significant market power concerns.
  - ✓ Output gap averaged: a) < 0.1% of total capacity at the mitigation threshold; and b) < 2% at the lowest threshold evaluated (i.e., 25%).
  - ✓ A large portion of output gap occurred on units that are owned by small suppliers and located at regions with no significant local congestion.
- The amount of unoffered (including outages/deratings) economic capacity was modest and reasonably consistent with expectations for a competitive market.
  - ✓ Economic capacity on long-term outages/deratings was higher in September compared to July and August as suppliers scheduled more maintenance expecting milder conditions.
    - – In some cases, it would have been efficient to reschedule some of these outages because it would have been economic to operate given actual market conditions.
  - ✓ Economic capacity on outages/deratings (both long- and short-term) was lower than from a year ago largely because of fewer outages/deratings this summer.
    - – A large unit in SENY was forced OOS during most of last summer.
    - – Short-term deratings/outages were less frequent this summer, due partly to fewer hot days.

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.

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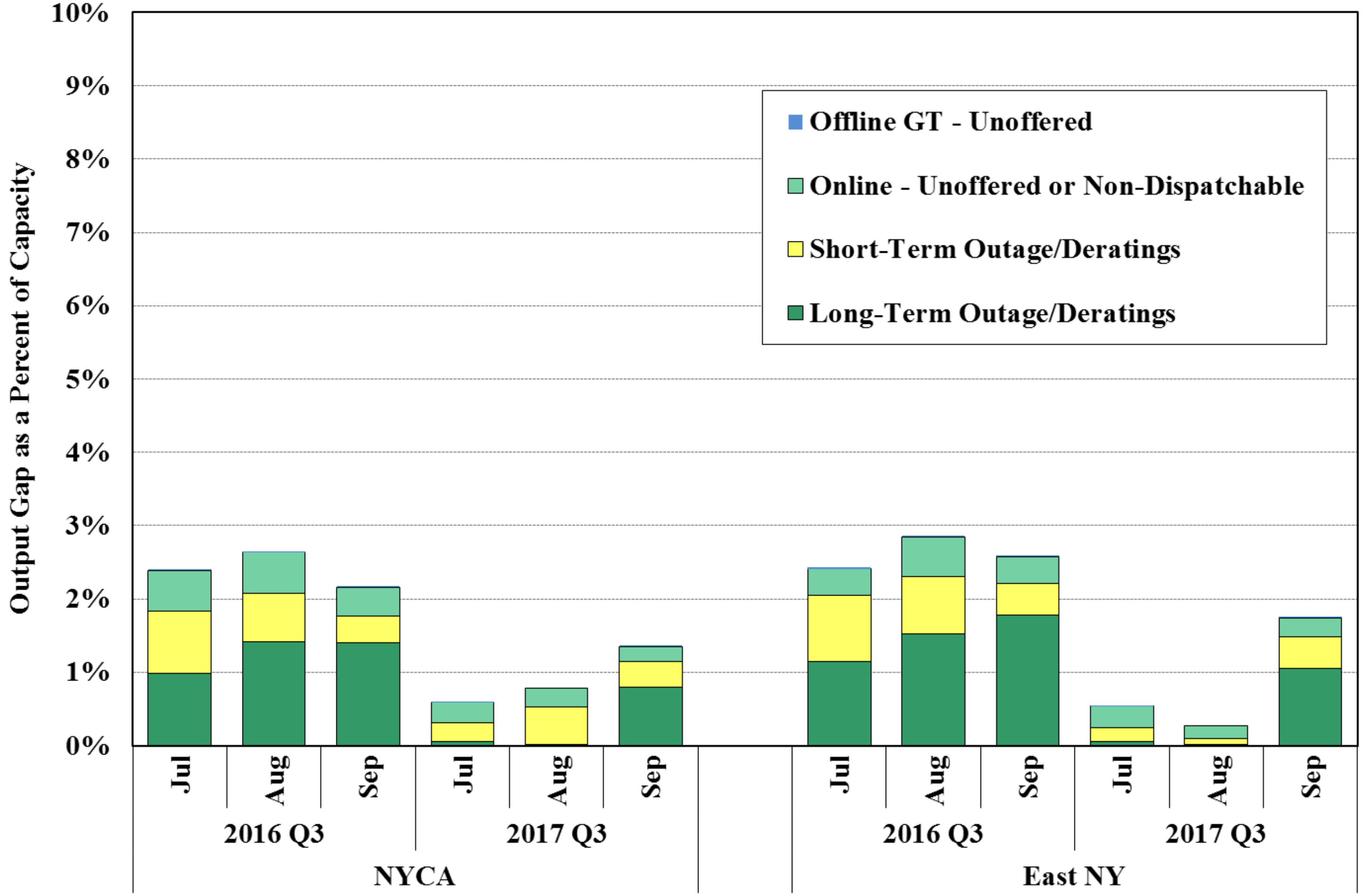
Unoffered Economic Capacity by Month
NYCA and East NY

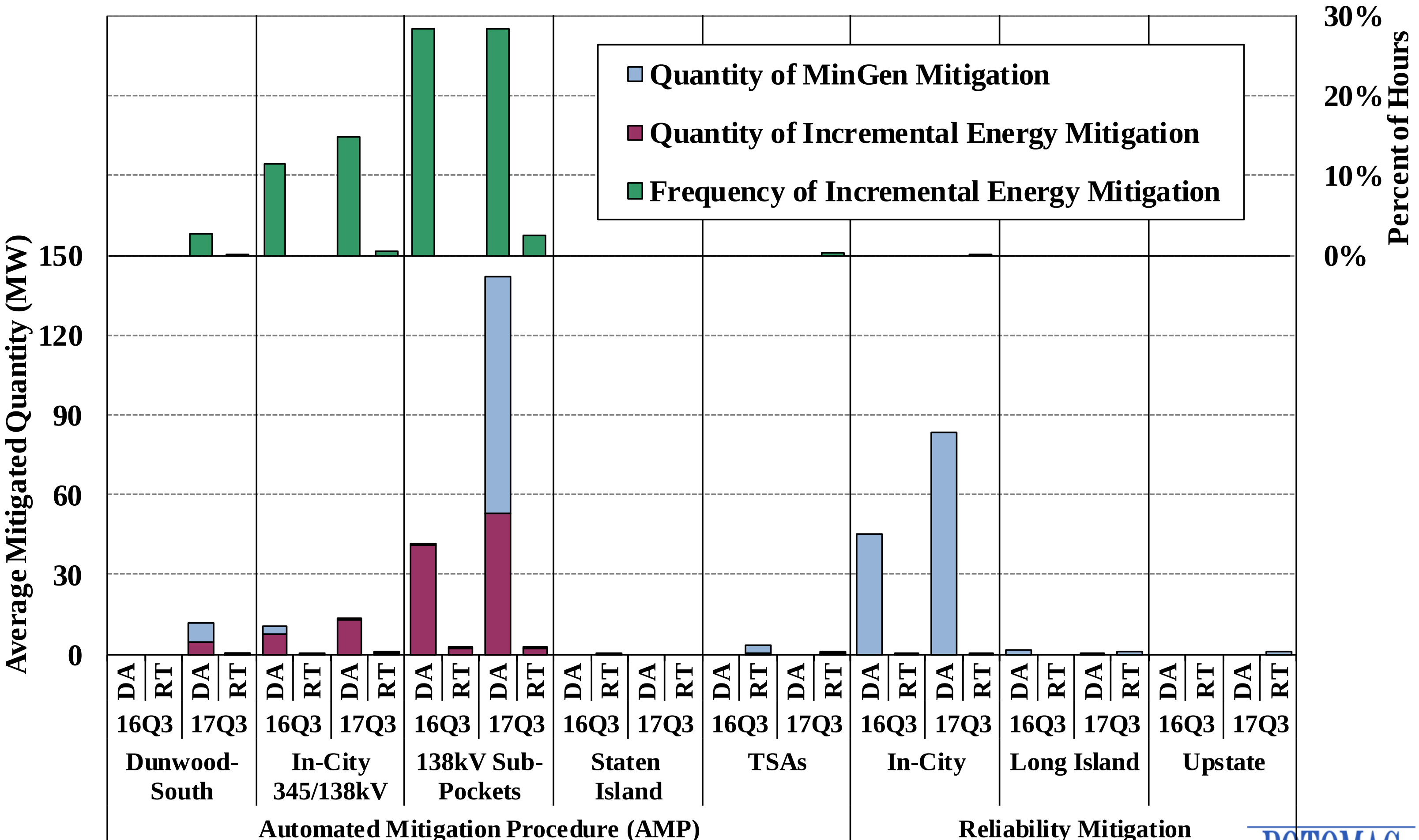


Note: Numbers reported here for historical periods may be slightly different from the ones reported previously because of improved assumptions and methodology for the calculation.

Automated Market Power Mitigation

- The next figure summarizes the automated mitigation that was imposed in the DAM and RTM (not including BPCG mitigation).
  - ✓ The upper panel shows the frequency of incremental energy mitigation, and the lower panel shows the average mitigated capacity, including the flexible output range (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, while the right portion shows for units committed for reliability.
- Most mitigation occurs in the DAM, since that is where most supply is scheduled.
  - ✓ DAM mitigation rose noticeably from a year ago.
    - – Local reliability (i.e., DARU & LRR) mitigation (accounted for 34 percent of DAM mitigation) rose primarily because of higher LRR commitments in NYC. (slides 76 & 77) These affect guarantee payment uplift but not LBMPs.
    - – AMP mitigation accounted for 66 percent of DAM mitigation, up significantly from the prior periods.
      - Most of the increase occurred in the Astoria West load pocket because of more frequent congestion.

Automated Market Power Mitigation



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Capacity Market

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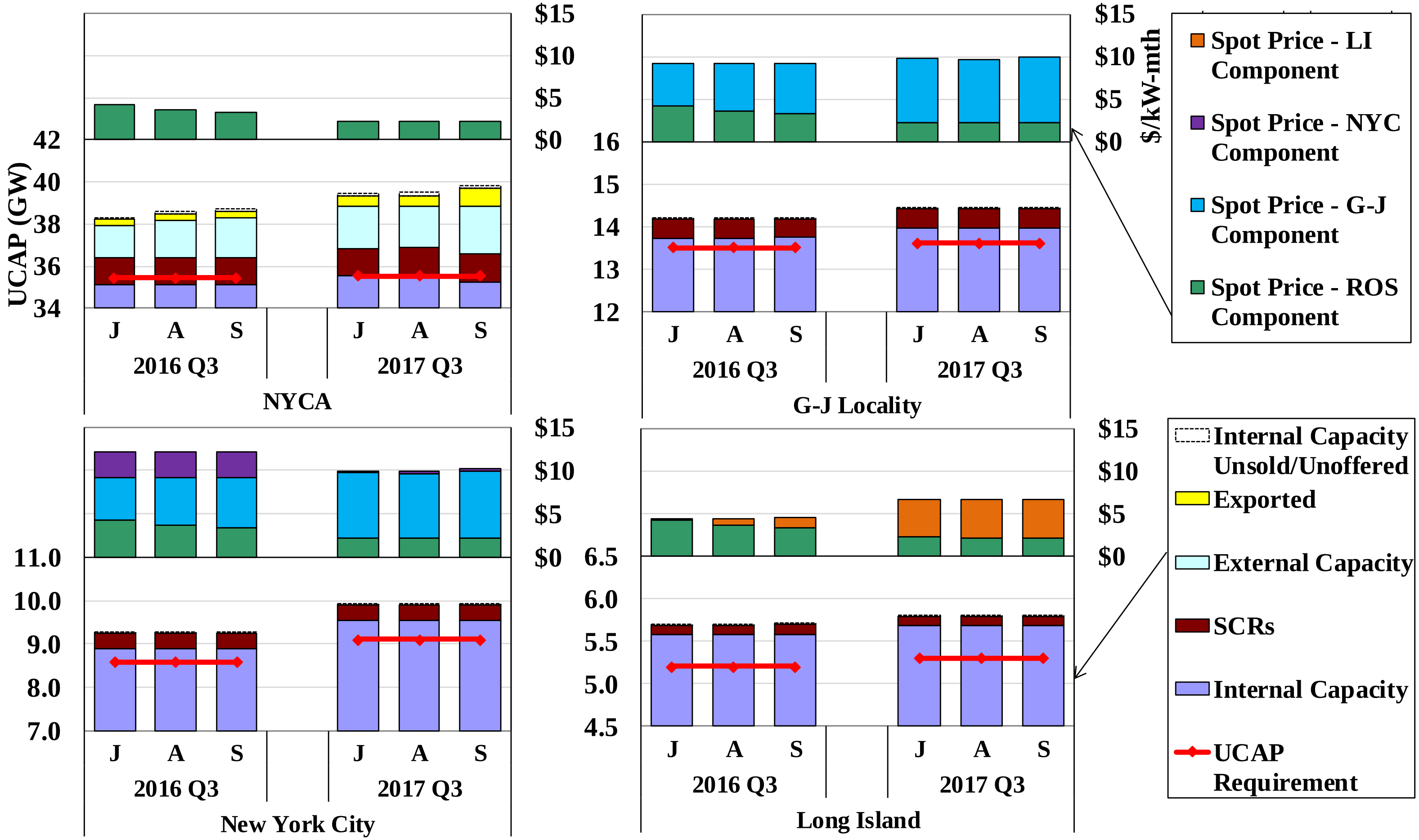
Spot Capacity Market Results

- The next two figures summarize key drivers of capacity market results in 2017-Q3.
  - ✓ The first figure summarizes available and scheduled Unforced Capacity (“UCAP”), UCAP requirements, and spot prices that occurred in each capacity zone by month.
  - ✓ The next table shows: (a) the year-over-year changes in spot prices by locality; and (b) variations in key factors that drove these changes.
- The average spot prices increased in Long Island and the G-J Locality from a year earlier but fell elsewhere.
  - ✓ In the three local capacity zones, the changes in the Demand Curve Reference Points (which reflected changes to the unit Net CONE assumptions for the proxy unit from the latest Demand Curve Reset process) were a primary driver.
    - – Higher ICAP supply contributed to lower capacity prices in NYC and partly offset the increase in the G-J Locality .
  - ✓ In ROS, however, higher ICAP supply was the dominating factor.
    - – In particular, cleared import capacity from neighboring areas rose ~350 MW.
- 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.

Capacity Market Results
2016-Q3 & 2017-Q3



Note: Sales associated with Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity," but unsold capacity from resources with UDRs is not shown.

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Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2017 Q3 ($/kW-Month)	$2.21	$9.97	$6.65	$9.78
% Change from 2016 Q3	**-41%**	**-18%**	**51%**	**6%**
Change in Demand				
Load Forecast (MW)	-181	-124	-51	-248
IRM/LCR	0.5%	1.0%	1.0%	1.5%
2017 Summer	*118.0%*	*81.5%*	*103.5%*	*91.5%*
2016 Summer	*117.5%*	*80.5%*	*102.5%*	*90.0%*
ICAP Requirement (MW)	**-47**	**17**	**2**	**18**
Change in ICAP Supply (MW) - Quarter Avg				
Generation	**165**	**109**	**23**	**125**
Cleared Import	**348**			
Change in Demand Curve				
UCAP Based Reference Price @ 100% Req.				
2017 Summer	*$10.01*	*$19.46*	*$13.47*	*$16.01*
2016 Summer	*$10.21*	*$21.41*	*$8.95*	*$13.77*
% Change	**-2%**	**-9%**	**51%**	**16%**

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