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

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Market Highlights

Market Highlights:
Executive Summary

- All-in prices rose 19 to 62 percent from the third quarter of 2017 largely because of higher LBMPs, which were driven primarily by higher load levels and natural gas prices. (see slide 7)
- Modeled congestion occurred mainly in Long Island (27%), NYC (25%), the West Zone (20%), and from the North Zone to central NY (13%). (see slides 8-9)
  - ✓ New York City congestion was more frequent because of three extended outages of 345kV transmission facilities (the 71 line and B&C lines).
- OOM actions were frequently used to manage constraints on low-voltage networks on Long Island (67 days) and in the West Zone (48 days). (see slide 10)
  - ✓ The NYISO plans to incorporate 115 kV constraints in Western NY into the day-ahead and real-time market software by the end of 2018.
  - ✓ It would also be beneficial to consider modeling local constraints on Long Island in the market software. (see slide 10)
- Large quantities of OOM commitment (700 MW on average) were needed to maintain adequate operating reserves in NYC load pockets. (see slide 11)
  - ✓ Reflecting NYC operating reserve requirements in the day-ahead and real-time markets would provide better incentives to suppliers and investors. (NYISO will discuss with stakeholders as part of the 2019 "More Granular…" project.)

Market Highlights:
Executive Summary

- Under peak conditions, OOM actions were often needed to maintain adequate reserves, but the costs of these actions were not adequately reflected in spot prices.
  - ✓ The NYISO activated demand response on three days to maintain adequate reserves in New York City. (see slides 12-13)
    - – Scarcity pricing was triggered in <10 percent of intervals during these events mainly because NYC reserve needs are not represented in the market software.
  - ✓ Utility demand response programs were activated on 12 days. It would be beneficial for the NYISO to work with TOs to evaluate the feasibility of incorporating such events into the scarcity pricing framework. (see slide 13)
  - ✓ After a major supply contingency in New England on September 3, New York experienced a deep sustained shortage of operating reserves. (see slide 14)
    - – Operating reserve demand curves were not sufficiently high to schedule adequate resources, requiring a series of OOM actions.
- OOM actions were used frequently to maintain adequate reserves and secure transmission when the market did not schedule resources to satisfy the needs.
  - ✓ Reflecting these requirements in the day-ahead and real-time markets would lead to more efficient scheduling and better investment signals. (see especially SOM Recommendations #2014-12, #2017-1, #2017-2)

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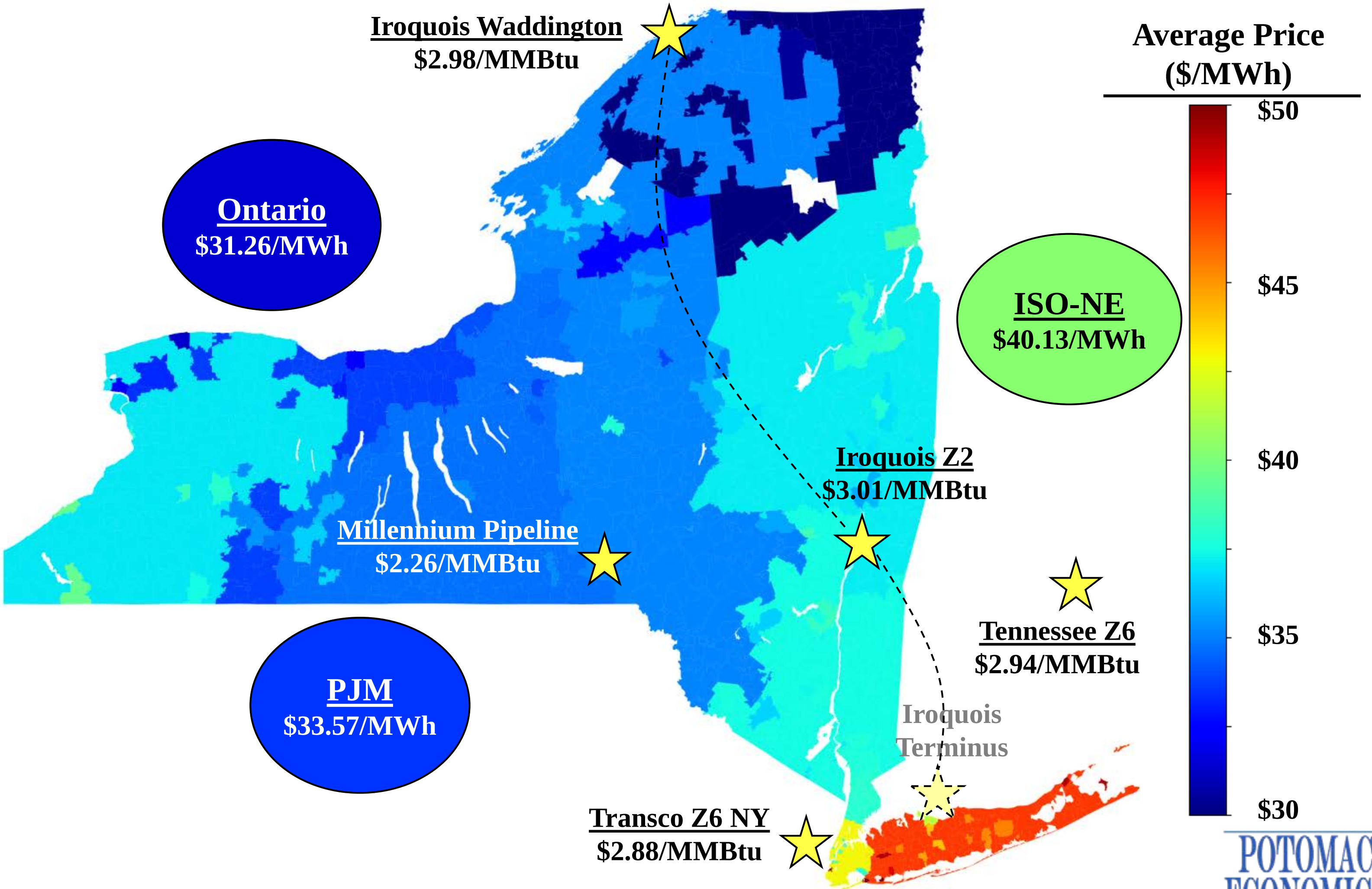
Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the third quarter of 2018.
  - ✓ Variations in regional wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
  - ✓ The amount of output gap (slide 62) and unoffered economic capacity (slide 63) remained modest and reasonably consistent with competitive market expectations.
- Average all-in prices rose in all regions and ranged between $37/MWh in the North Zone to $69/MWh in Long Island, up 19 to 62 percent from a year ago. (slide 21)
  - ✓ Energy prices accounted for the largest component of the increase, rising by 29 to 71 percent (slides 26-27), due largely to:
    - Higher load levels – average load rose 8 percent and peak load (31.9 GW on 8/29) rose 7 percent (slide 22); and
    - Higher natural gas prices - average natural gas prices rose between 20 and 41 percent from a year ago with the larger increases in western NY. (slide 23)
    - Contributing factors also include lower nuclear generation, which fell by an average of 360 MW because of more deratings and outages. (slide 24)
  - ✓ Capacity costs rose by 50 percent in the areas outside SENY but fell modestly (1-6 percent) in SENY regions for the reasons discussed in slide 19.

Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $126 million, up 21 percent from the third quarter of 2017. (slide 46)
  - ✓ Most of the increases occurred on facilities in Long Island, New York City, and the North Zone. (slide 47)
- Long Island facilities accounted for the largest share of day-ahead congestion revenues in the third quarter of 2018. (slide 47)
  - ✓ In contrast to the pattern observed in recent summers, the 138 kV facilities accounted for the vast majority of Long Island congestion (the 345 kV facilities accounted for only 18 percent this quarter).
    - The two 345 kV lines into Long Island were frequently OOS in recent summers but both were in service for the vast majority of the third quarter of 2018.
  - ✓ Several 138 kV facilities in the East End of Long Island accounted for more than 50 percent of total congestion.
    - Most of this congestion occurred in August on high-load days.
    - Unexpectedly high congestion on these facilities led more power to flow over these constraints than anticipated in the TCC auctions, resulting in over $8 million of congestion revenue surpluses in the day-ahead market. (slide 48)

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

- Congestion in the New York City zone increased from a year ago.
  - ✓ In addition to higher load levels, the increase was also attributable to two lengthy transmission outages.
    - – One Dunwoodie-Motthaven 345 kV line ("71 Line") and two PAR-controlled Farragut 345 kV lines ("B & C Lines") were all OOS for the entire quarter, which reduced the import capability into NYC and led to over $2 million of congestion shortfalls in the day-ahead market. (slide 48)
    - – Imports across the HTP interface greatly increased, likely in response to increased NYC prices. (slide 43)
- Congestion on the path from Northern NY to Central NY also increased, primarily due to more costly transmission outages.
  - ✓ Most of this congestion occurred when one of the two Marcy 765/345 kV transformers was OOS, primarily in September.
    - – The outage led to more than $6 million of day-ahead congestion shortfalls (slide 48) and over $2 million of balancing congestion shortfalls. (slide 49)
  - ✓ Newly modeled Browns Falls-Taylorville-Boonville 115 kV lines contributed to higher congestion partly because they have CRM values that are very high compared to their ratings. (see slide 17 for more discussion)

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

- Out-of-market actions to manage lower-voltage (115 kV and below) network congestion were frequent in the third quarter of 2018. (slide 51)
  - ✓ OOM actions were most frequent in Long Island (67 days), Western NY (48 days), Northern NY (21 days), and the Capital Zone (17 days).
- The costs of congestion in the lower-voltage network could be reduced by modeling certain 115 kV and 69 kV constraints in the DA and RT market systems.
  - ✓ The NYISO plans to model the remaining 115 kV constraints previously identified for securing in Western NY by the end of 2018.
    - – An enhanced Niagara modeling will also be implemented, which is expected to help coordinate the management of 115 kV and 230 kV congestion in the West Zone.
- OOM actions to manage 69 kV constraints and voltage constraints (TVR requirement on the East End) were frequent on Long Island. (slide 52)
  - ✓ We suggest that the NYISO consider modeling the 69 kV constraints and East End TVR needs (likely via a surrogate thermal constraint) in the market software.
  - ✓ This would greatly reduce associated BPCG uplift (slide 11), better compensate resources that satisfy the needs, and better signal the needs for future investment.
    - – Our estimates show that, in the third quarter, average LBMPs would rise $18/MWh East of Northport and $78/MWh in the East End load pocket. (slide 52)

Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $33 million, up 290 percent from 2017-Q3. (slides 59-60)
- NYC accounted for $18 million of BPCG (slide 60), of which:
  - ✓ $5.5 million accrued from the Min Oil Burn requirements;
    - One or more steam units burned a blend of oil and gas in 220 hours.
  - ✓ $6.5 million was largely due to increased reliability commitment.
    - Reliability commitment in NYC averaged 703 MW, accounting for 86 percent of all reliability commitments this quarter and up 40 percent from last year. (slide 56)
    - Higher loads and lengthy transmission outages increased the need to commit generation for the 345 kV system. (slide 57)
  - ✓ We recommend that the NYISO satisfy the reliability needs that drive these out-of-market costs with local reserve requirements in the DA & RT markets.
- BPCG payments increased notably on Long Island, totaling $11 million this quarter and up more than 400 percent from a year ago. (slide 60)
  - ✓ High-cost peaking resources were frequently OOMed to manage congestion on the 69 kV network and voltage needs on the East End of Long Island, due partly to higher load levels. (slides 52, 58)

Market Highlights:
Demand Response Deployments and Scarcity Pricing

- NYISO activated EDRP/SCR in Zone J on three days (7/2, 8/28, and 8/29), all for NYC operating reserve needs.
  - ✓ Peak load ranged from roughly 31.3 GW on 7/2 to 31.9 GW on 8/29.
  - ✓ NYISO activated 480-495 MW of EDRP/SCR each day, while most utilities activated their own DR programs, adding additional 375-390 MW on each of the three days as well.
  - ✓ In addition, NYISO SREed three units (Danskammer 4, Bowline 1, and Oswego 5) for 7/2 and one unit (Oswego 6) for 8/29 for forecasted capacity needs.
  - ✓ See presentation "NYISO Summer 2018 Hot Weather Operations" by Wes Yeomans at 9/26 MC meeting for more details.
- Our evaluation suggests that, in retrospect:
  - ✓ Both SREs and DR were needed to prevent brief NYCA capacity deficiencies on 8/28 and 8/29, but they were not needed on 7/2. (see slide 29)
    - – SREs and/or DR are necessary to avoid a capacity deficiency when:

      DR deploy + normal 30-min reserve need > all available capacity (without SRE)
    - – On 7/2, actual load was far below forecast (by ~2 GW) due to pop-up showers, and 30-minute reserves were priced at $0/MWh during the DR activation.

Market Highlights:

Demand Response Deployments and Scarcity Pricing

- Utility DR MW is not considered in the current scarcity pricing rules.
  - ✓ Additional Utility DR deployments helped avoid a NYCA capacity deficiency for an additional 11 intervals on 8/28. However, 30-minute reserves were priced only at an average of $88/MWh during these intervals. (slide 29)
  - ✓ Various amounts of Utility DR were activated on nine other days when the NYISO did not call EDRP/SCR, but prices did not reflect the cost of these actions.
  - ✓ It would be beneficial for the NYISO to work with TOs to evaluate the feasibility of including Utility DR deployments in the scarcity pricing rules.
- NYISO deployments prevented NYC capacity deficiencies on 8/28 & 29. (slide 31)
  - ✓ This is shown in the figure when the dashed red line is higher than all areas.
  - ✓ Estimated actual reserve needs (based on the N-1-1 thermal requirement for NYC) averaged nearly 650 MW during DR deployments (see the solid red line).
  - ✓ However, this reserve need is not explicitly modeled in the market software.
    - – Out-of-market actions (DARU, LRR, SRE, OOM, and DR calls) are often needed to satisfy the reserve requirement, which led to over $10 million of BPCG uplift in NYC this quarter. (slides 56 – 60)
  - ✓ We have recommended the NYISO model local reserve requirements in NYC load pockets (see Recommendation #2017-1 in our 2017 SOM report).

Market Highlights:
Operations and Pricing During NE’s PFP Event

- The first Pay-for-Performance event occurred on 9/3 in NE, where its system capacity deficiency occurred from 15:40 to 18:15, resulting primarily from under-forecast (~2.5 GW) and forced generation loss (~1.6 GW).
- In this event, NE had the following actions that affected NY markets: (slide 33)
  - ✓ NE cut Cross-Sound Cable exports to Long Island (330 MW) from 16:00 to 20:00.
    - – NY responded via OOM-starting peaking resources on Long Island.
  - ✓ NE made emergency purchases from NY (up to 251 MW from 17:00 to 18:00).
    - – NY was also in a 30-minute reserve shortage, so it made emergency purchases from Ontario in order to provide requested emergency energy to NE.
    - – The export limit to NE was temporarily increased from 1400 MW to 1650 MW to facilitate the emergency purchase.
    - – NY curtailed several export transactions to PJM (< 100 MW).
- NY and NE both experienced shortages of 30-minute reserves. (slide 32)
  - ✓ However, market incentives were substantially different in the two markets.
    - – Energy prices on the NY side rarely exceeded $200/MWh, while energy prices plus pay-for-performance incentives ranged from $3000/MWh to $4700/MWh on the ISO-NE side.

Market Highlights:
Operations and Pricing During NE's PFP Event

- NE had substantially higher market incentives during shortages because:
  - ✓ The demand curve value for the system-wide 30-minute reserves requirement is set at a high value of $1000/MW for any amount of shortage in NE, while it is set at below $200/MW in NY when the shortage is less than 955 MW. (slide 32)
  - ✓ NE has a pay-for-performance incentive of $2000/MWh (which is scheduled to rise to $5455 in 2022), while NY currently does not have one.
    - – PJM has a similar rate to incent performance under tight system conditions.
- The operating reserve demand curves in NY are relatively low considering incentives provided in neighboring markets during shortages.
  - ✓ The market incentives to import power into NY under tight conditions were not sufficient. (slide 33)
    - – The interface between Ontario and NY had more than 1 GW of available transfer capability during this event.
    - – NY had to curtail several export transactions to PJM for system security as well.
- Therefore, we have recommended that the NYISO consider modifying operating reserve demand curves to ensure reliability after PJM and NE implement PFP rules. (see Recommendation #2017-2 in our 2017 SOM report)

Market Highlights:

Use of Operating Reserves to Manage NYC Congestion

- Transmission facilities in New York City can be operated above their Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) are available to quickly reduce flows to LTE.
  - ✓ The availability of post-contingency actions is important because they allow the NYISO to increase flows into load centers in NYC and reduce congestion costs.
- Most of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 53)
  - ✓ The additional capability above LTE averaged from over 20 MW for the 138 kV constraints in the Greenwood load pocket to over 200 MW for 345 kV facilities.
    - – These increases were largely due to operating reserve providers in NYC, but they are not compensated for this service.
    - – This reduces their incentives to be available in the short term and to invest in flexible resources in the long term.
    - – In addition, when the market dispatches this reserve capacity, it can reduce the transfer capability in NYC.
- We have recommended that the NYISO efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria. (see Recommendation #2016-1 in our 2017 SOM report)

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Market Highlights:
Use of CRM in Congestion Management

- A Constraint Reliability Margin ("CRM") reduces the available transfer limit in the market software to account for loop flows and other un-modeled factors.
  - ✓ Currently, the tariff does not allow CRM values between 0 and 20 MW.
- The default CRM value of 20 MW is used for most facilities. On average, this was:
  - ✓ 1 to 4 percent of the transfer capability of the 345 kV constrained facilities;
  - ✓ 4 percent of the transfer capability of the 230 kV constrained facilities;
  - ✓ 9 percent of the transfer capability of the 138 kV constrained facilities; and
  - ✓ 14 percent of the transfer capability of the 115 kV constrained facilities. (slide 54)
  - ✓ Loop flows and other un-modeled factors do not rise in this pattern at low voltages.
- The 20 MW CRM is overly conservative for lower-voltage constraints, which leads to unnecessarily high congestion costs in these areas.
  - ✓ The average size of shortages on the 115 kV constraints was less than 5 MW.
  - ✓ Over-constraining these small facilities has large effects on inter-regional flows.
    - – For example, a 10-MW reduction in flows across a Browns Falls-Taylorville 115 kV line can reduce overall transfers from Northern NY to Central NY by 100 MW.
- The NYISO recognized this issue and proposed revisions to its tariff to permit the use of non-zero CRM values less than 20 MW. We support this change.
  - ✓ This is expected to be effective in late November.

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Market Highlights:
Use of CRM in Congestion Management (cont.)

- Higher CRMs are used for a small set of facilities to account for more uncertain loop flows and other un-modeled factors.
  - ✓ For example, a 50 MW CRM is used for the Dunwoodie-Shore Rd 345 kV line (from upstate to Long Island) and the Packard-Sawyer 230 kV lines (near the Ontario border in Western NY).
  - ✓ These lines accounted for a significant portion of congestion in their areas. In the third quarter:
    - The Dunwoodie-Shore Rd line accounted for 33 percent of real-time congestion in Long Island; and
    - The Packard-Sawyer line accounted for 90 percent of real-time congestion in the West Zone.
  - ✓ However, actual flows were frequently well below their operational limits (because of the high CRM) during periods of modeled congestion.
    - The average shortage quantity was only 9 MW on the Packard-Sawyer constraint and 16 MW on the Dunwoodie-Shore Rd constraint. (slide 54)
- Since the CRM values have a significant impact on the costs of congestion management, it is important to reassess the appropriateness of the CRM values on an on-going basis.

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Market Highlights: Capacity Market

- Average spot capacity prices ranged from $3.66/kW-month in ROS to $9.69/kW-month in New York City in the third quarter of 2018. (slide 66-67)
- Spot capacity prices did not significantly differ from prices during the same quarter of 2017, except for ROS which saw a 66 percent increase on average.
  - ✓ Load forecasts were lower in all regions (down from 51 MW in LI to 275 MW for NYCA), but higher reference point prices on the UCAP Demand Curves (up 9 to 15 percent) helped offset this impact.
  - ✓ LCRs rose in NYCA and in the G-J Locality (0.2 and 3 percent, respectively), but fell in NYC (1 percent). No change occurred in the LI LCR value.
  - ✓ Changes in ICAP supply were also a key driver of these price changes.
    - – Cleared import capacity fell by an average of 740 MW.
    - – Several Ravenswood GTs in NYC have been in an IIFO (“ICAP Ineligible Forced Outage”) since April 2018.
    - – These reductions were partly offset by the new entry of the CPV Valley units (Zone G) and two new Bayonne CTG units (Zone J).
      - Net changes to internal generation were positive in NYCA and G-J, largely due to the entry of the CPV Valley station.

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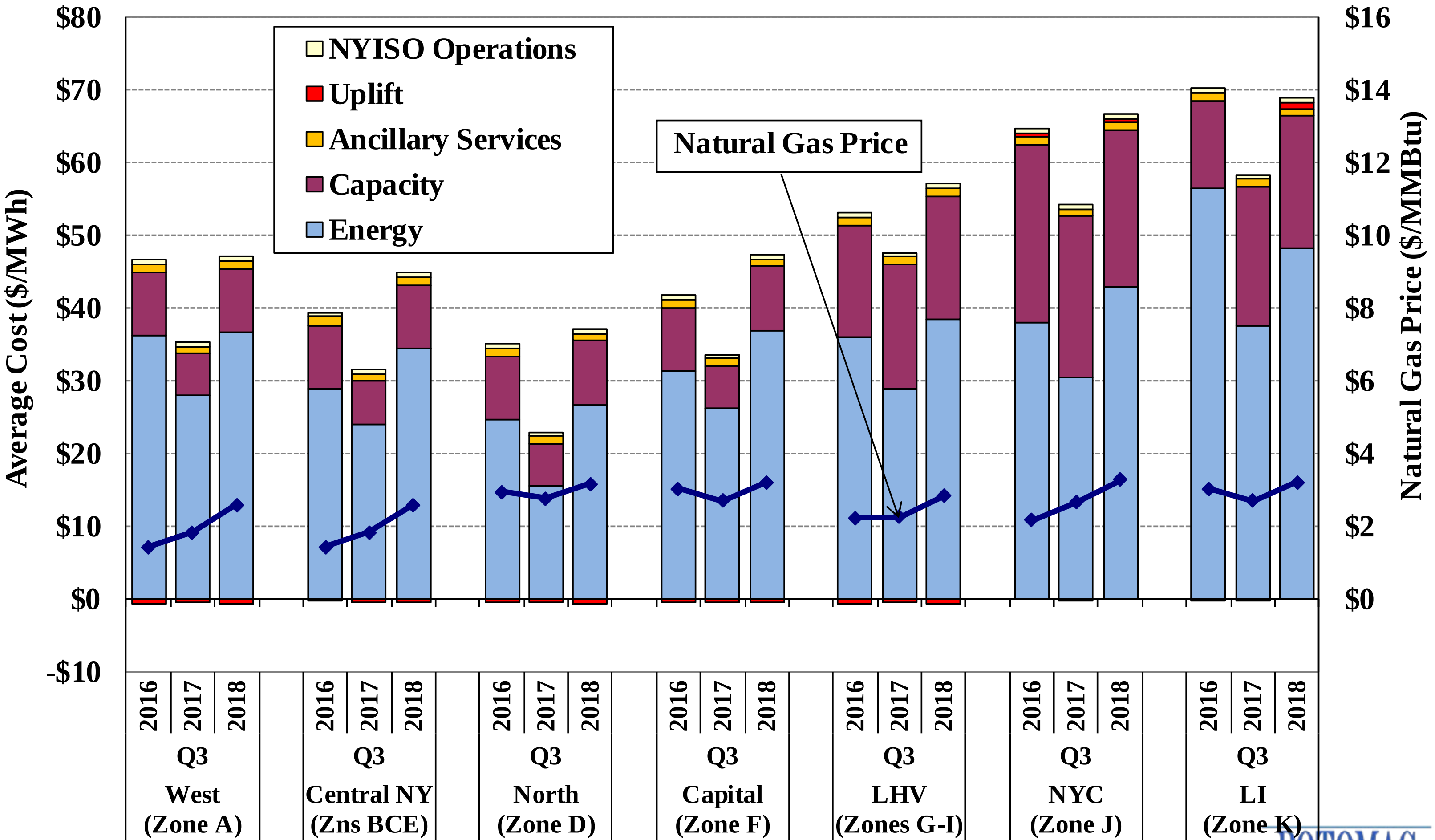
Charts:

Market Outcomes

All-In Prices by Region



Notes: For chart description, see slide 69.

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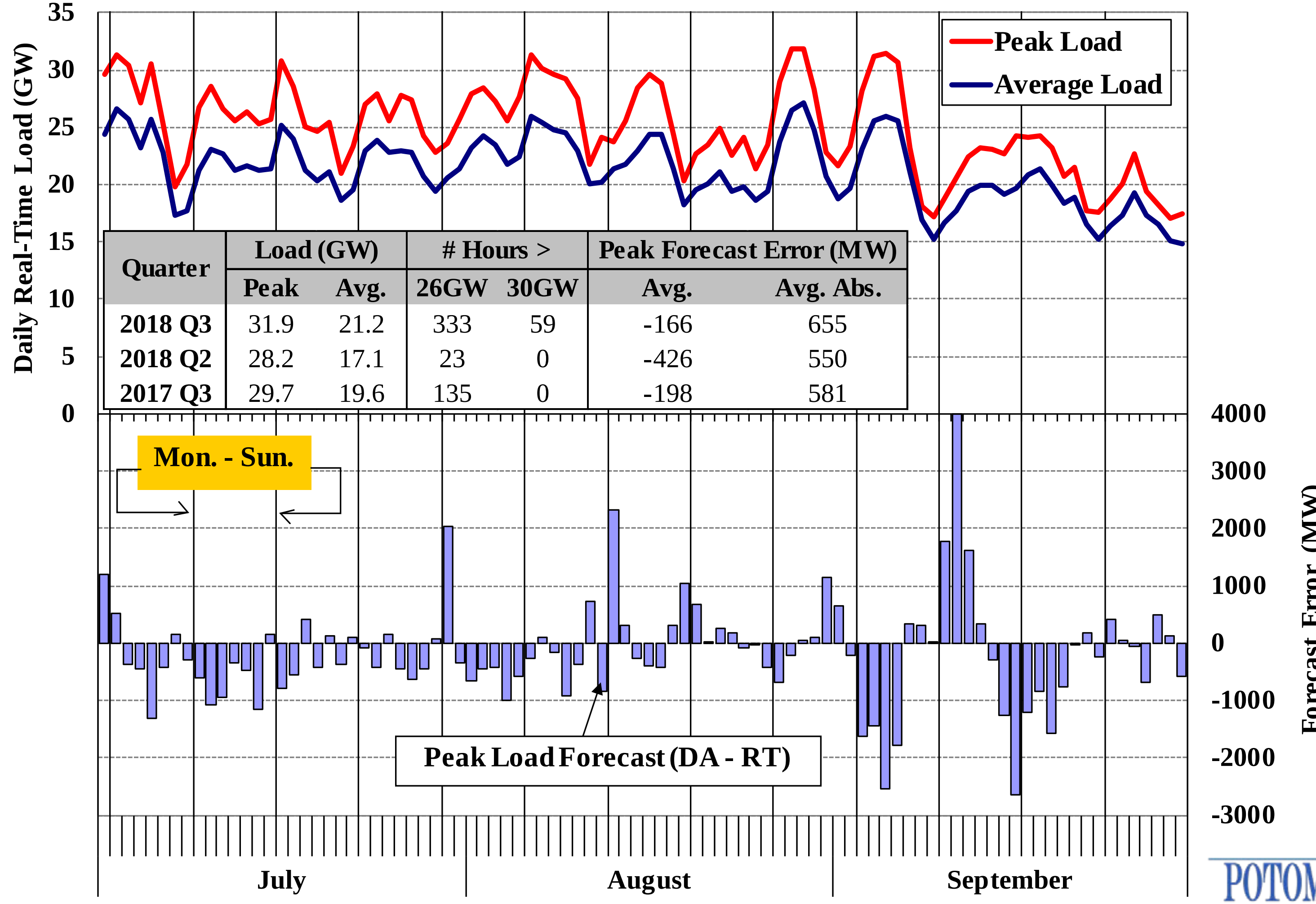
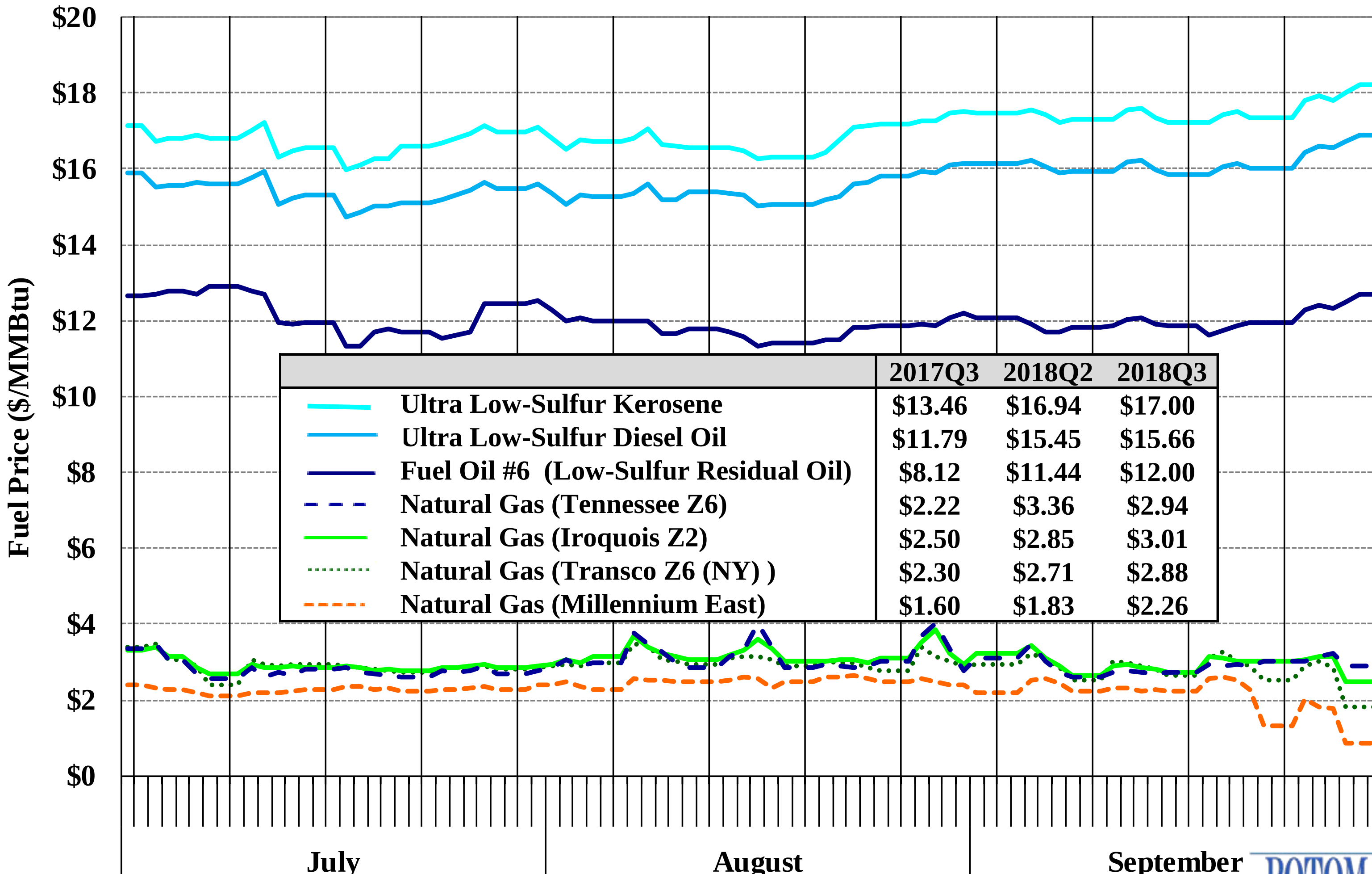
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2018 Q3	31.9	21.2	333	59	-166	655
2018 Q2	28.2	17.1	23	0	-426	550
2017 Q3	29.7	19.6	135	0	-198	581

Natural Gas and Fuel Oil Prices



	2017Q3	2018Q2	2018Q3
Ultra Low-Sulfur Kerosene	$13.46	$16.94	$17.00
Ultra Low-Sulfur Diesel Oil	$11.79	$15.45	$15.66
Fuel Oil #6 (Low-Sulfur Residual Oil)	$8.12	$11.44	$12.00
Natural Gas (Tennessee Z6)	$2.22	$3.36	$2.94
Natural Gas (Iroquois Z2)	$2.50	$2.85	$3.01
Natural Gas (Transco Z6 (NY))	$2.30	$2.71	$2.88
Natural Gas (Millennium East)	$1.60	$1.83	$2.26

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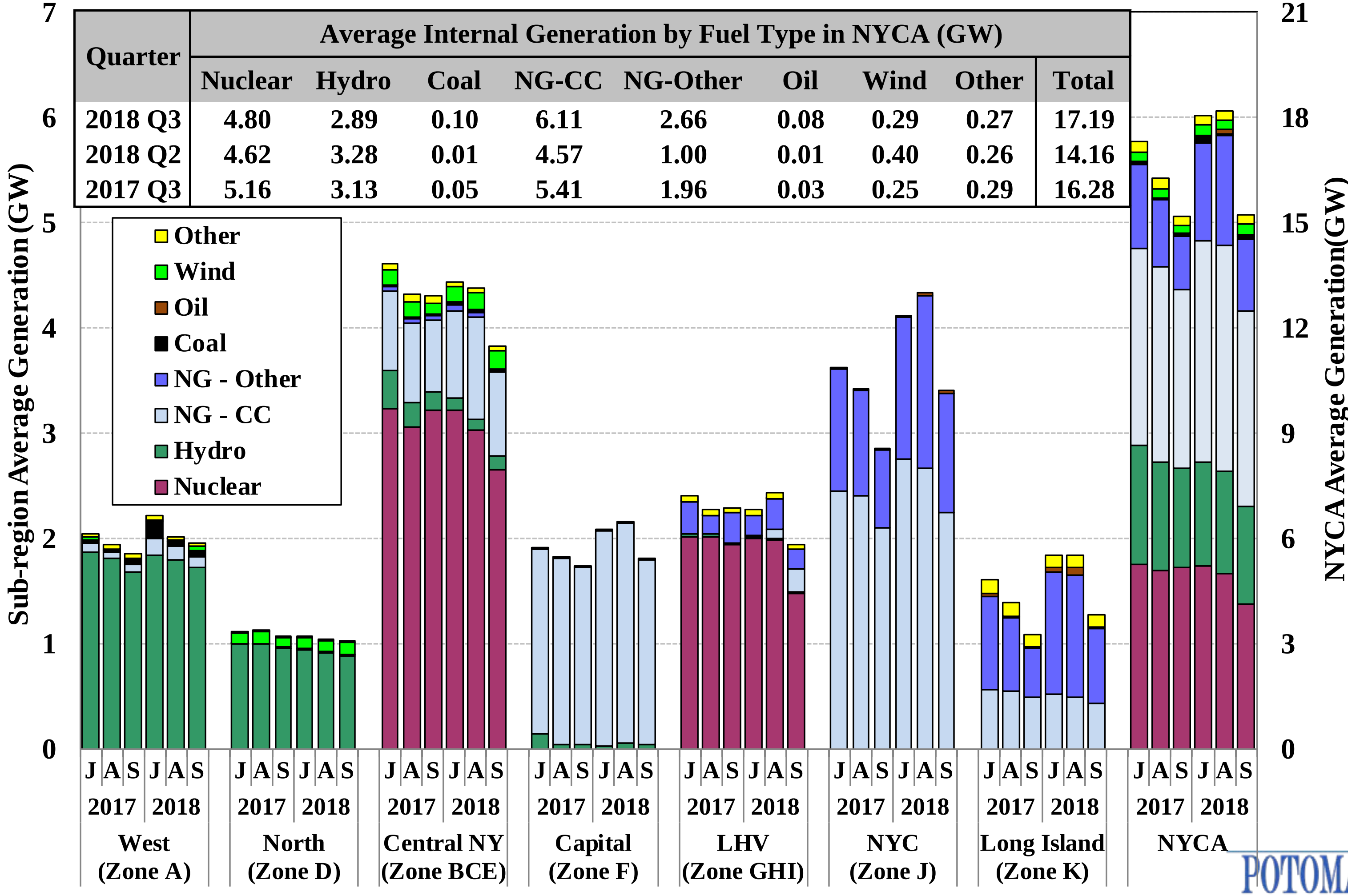
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2018 Q3	4.80	2.89	0.10	6.11	2.66	0.08	0.29	0.27	17.19
2018 Q2	4.62	3.28	0.01	4.57	1.00	0.01	0.40	0.26	14.16
2017 Q3	5.16	3.13	0.05	5.41	1.96	0.03	0.25	0.29	16.28



Notes: For chart description, see slide 70.

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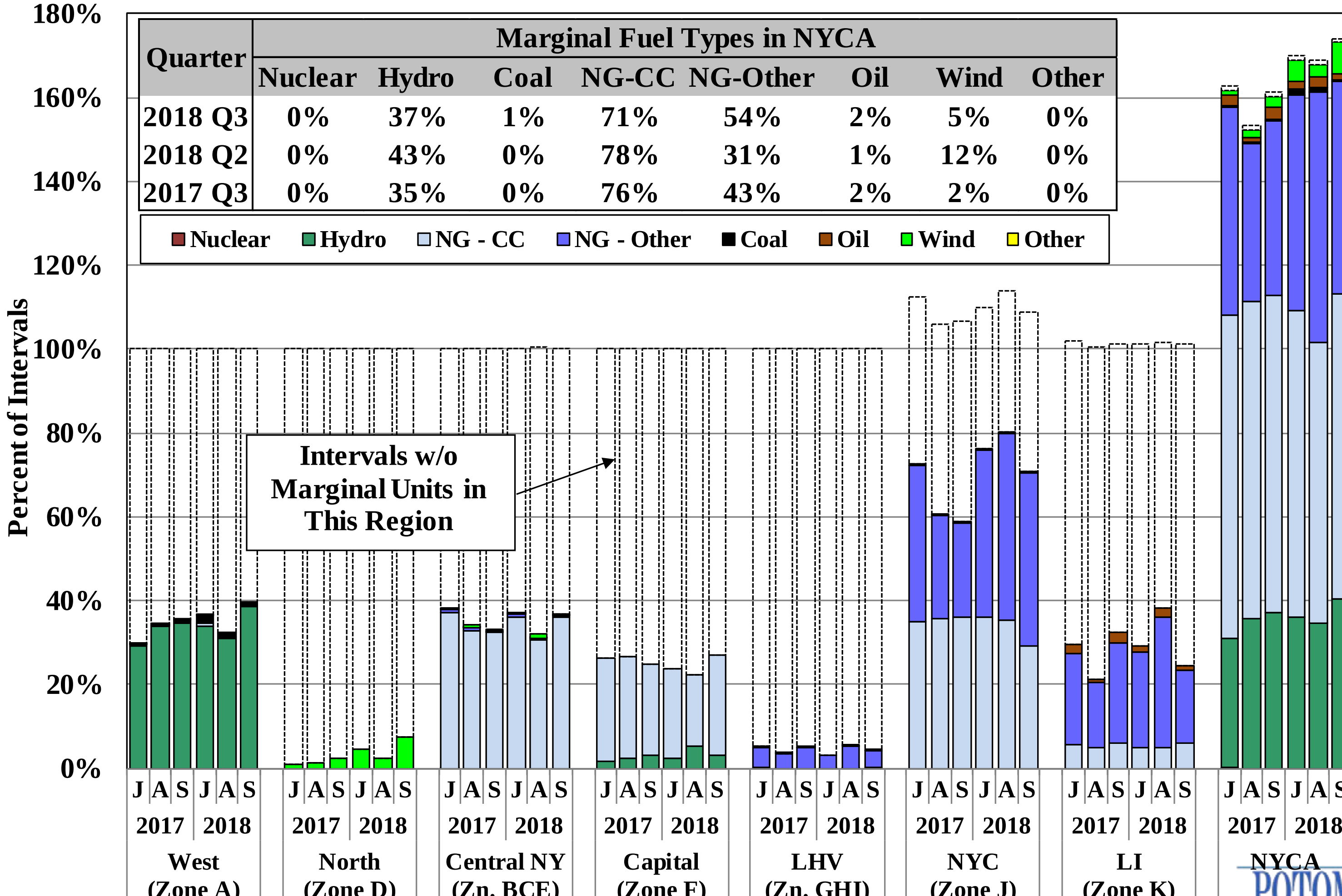
Fuel Type of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2018 Q3	0%	37%	1%	71%	54%	2%	5%	0%
2018 Q2	0%	43%	0%	78%	31%	1%	12%	0%
2017 Q3	0%	35%	0%	76%	43%	2%	2%	0%



 Notes: For chart description, see slide 70.

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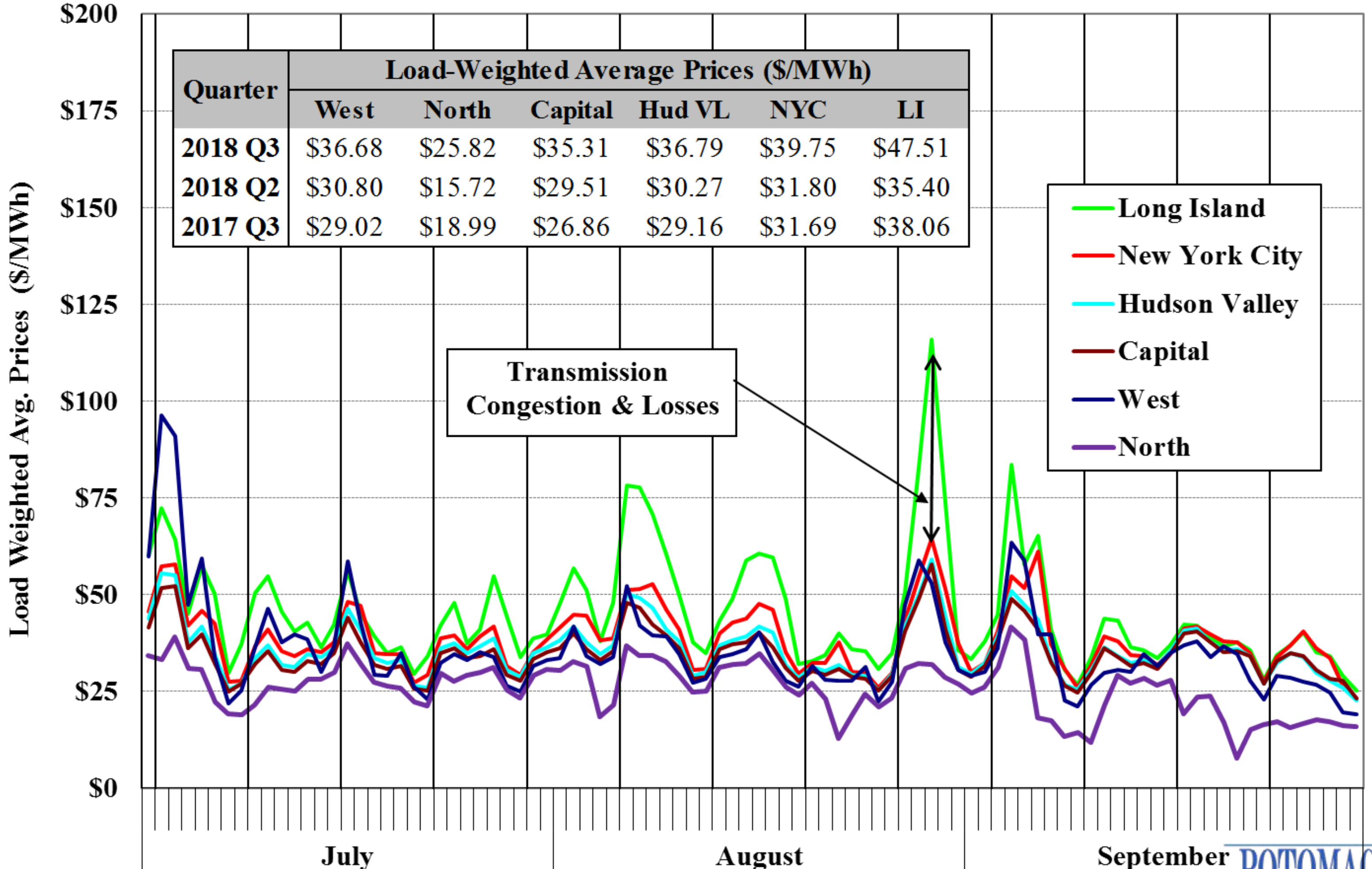
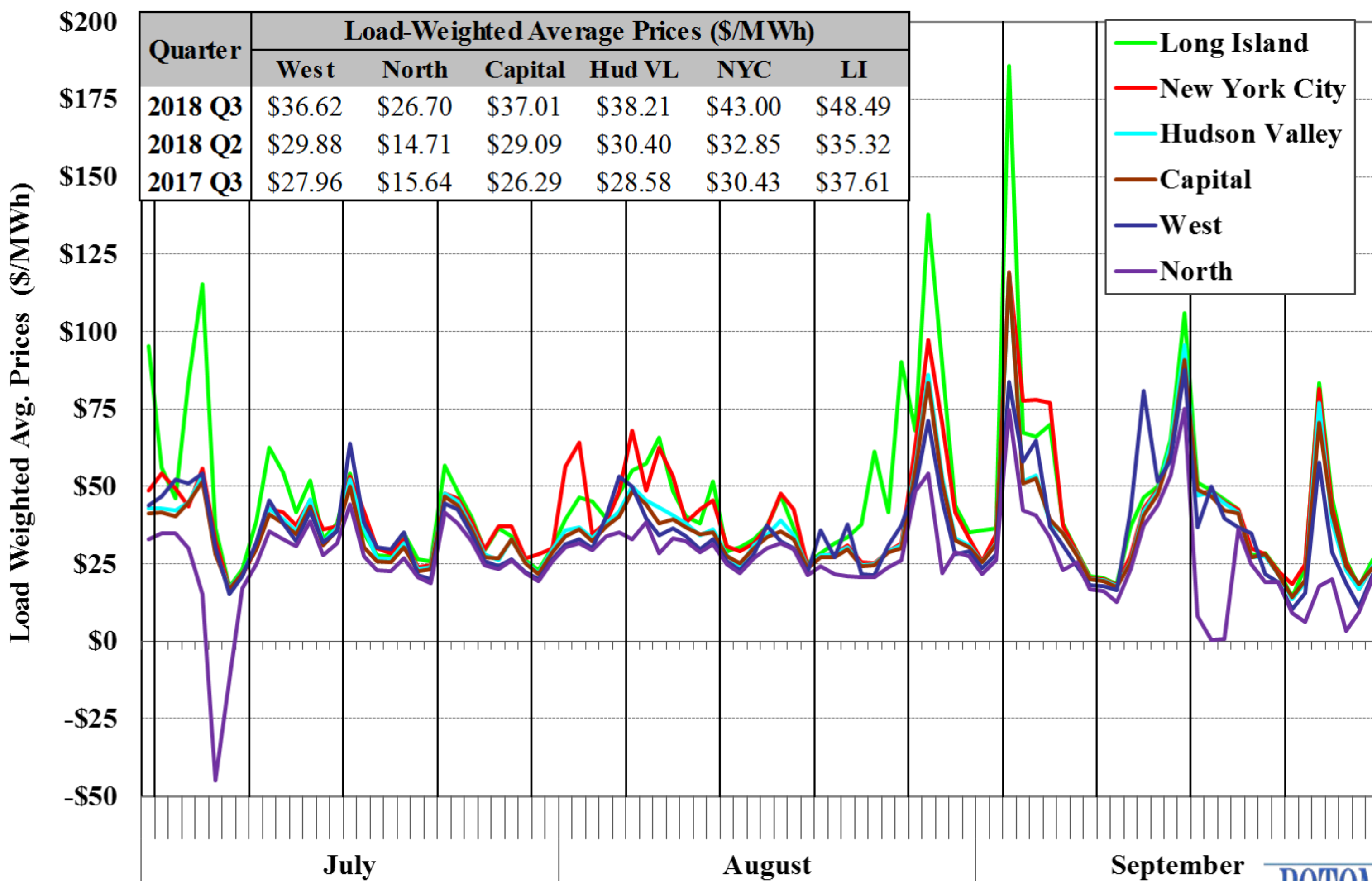
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q3	$36.68	$25.82	$35.31	$36.79	$39.75	$47.51
2018 Q2	$30.80	$15.72	$29.51	$30.27	$31.80	$35.40
2017 Q3	$29.02	$18.99	$26.86	$29.16	$31.69	$38.06

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q3	$36.62	$26.70	$37.01	$38.21	$43.00	$48.49
2018 Q2	$29.88	$14.71	$29.09	$30.40	$32.85	$35.32
2017 Q3	$27.96	$15.64	$26.29	$28.58	$30.43	$37.61

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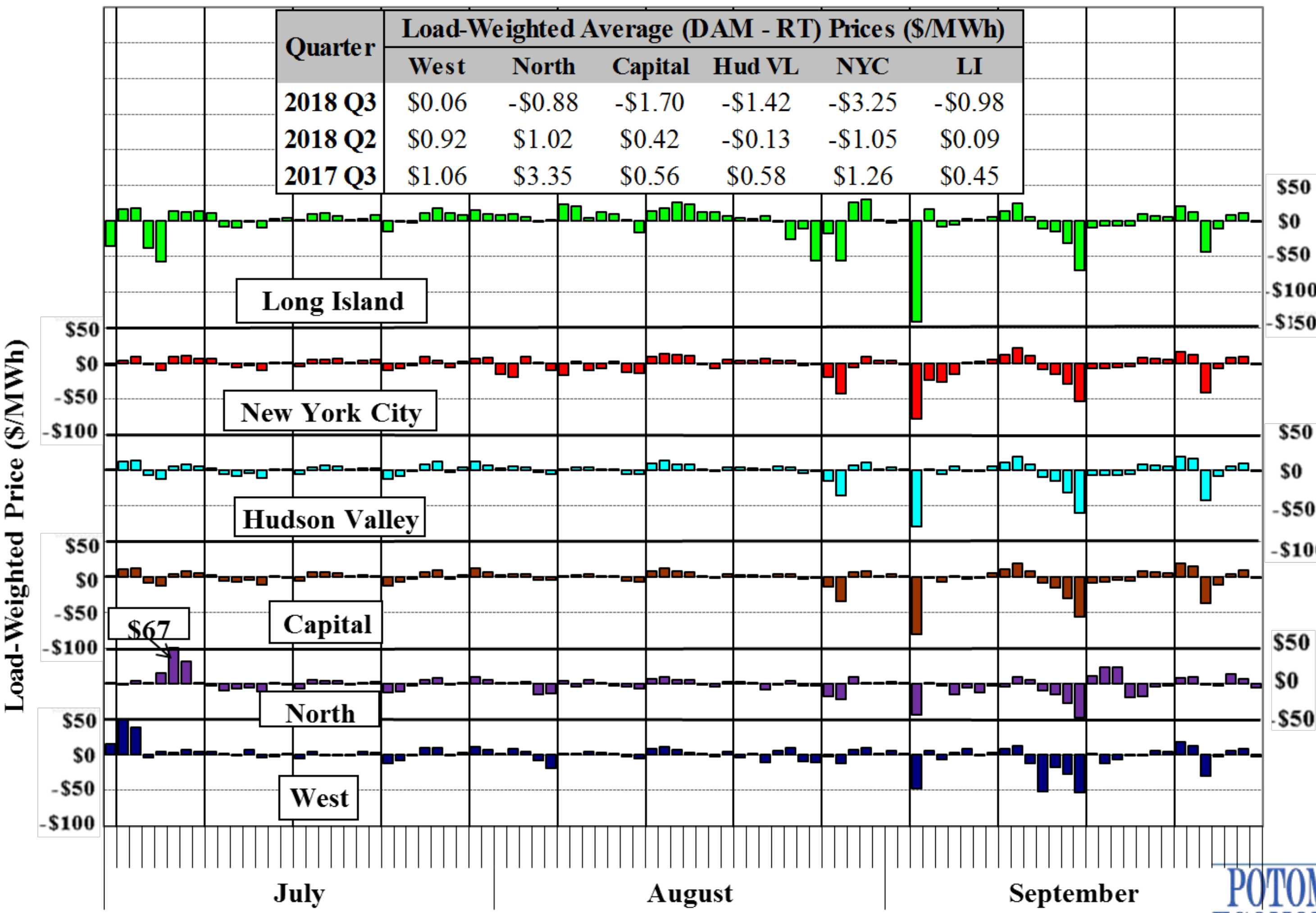
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q3	$0.06	-$0.88	-$1.70	-$1.42	-$3.25	-$0.98
2018 Q2	$0.92	$1.02	$0.42	-$0.13	-$1.05	$0.09
2017 Q3	$1.06	$3.35	$0.56	$0.58	$1.26	$0.45



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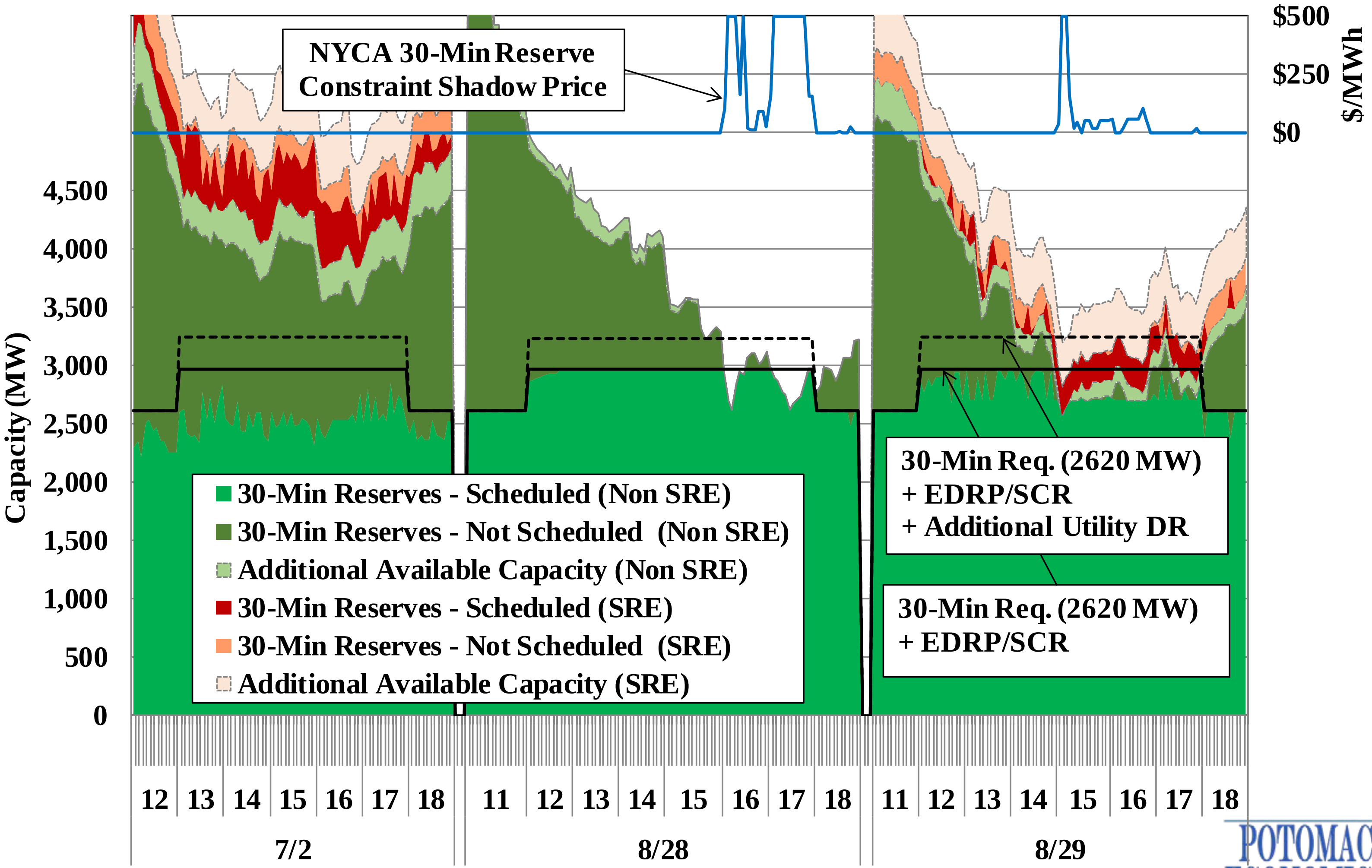
DR Deployments and Scarcity Pricing
NYCA



 Notes: For chart description, see slide 71.

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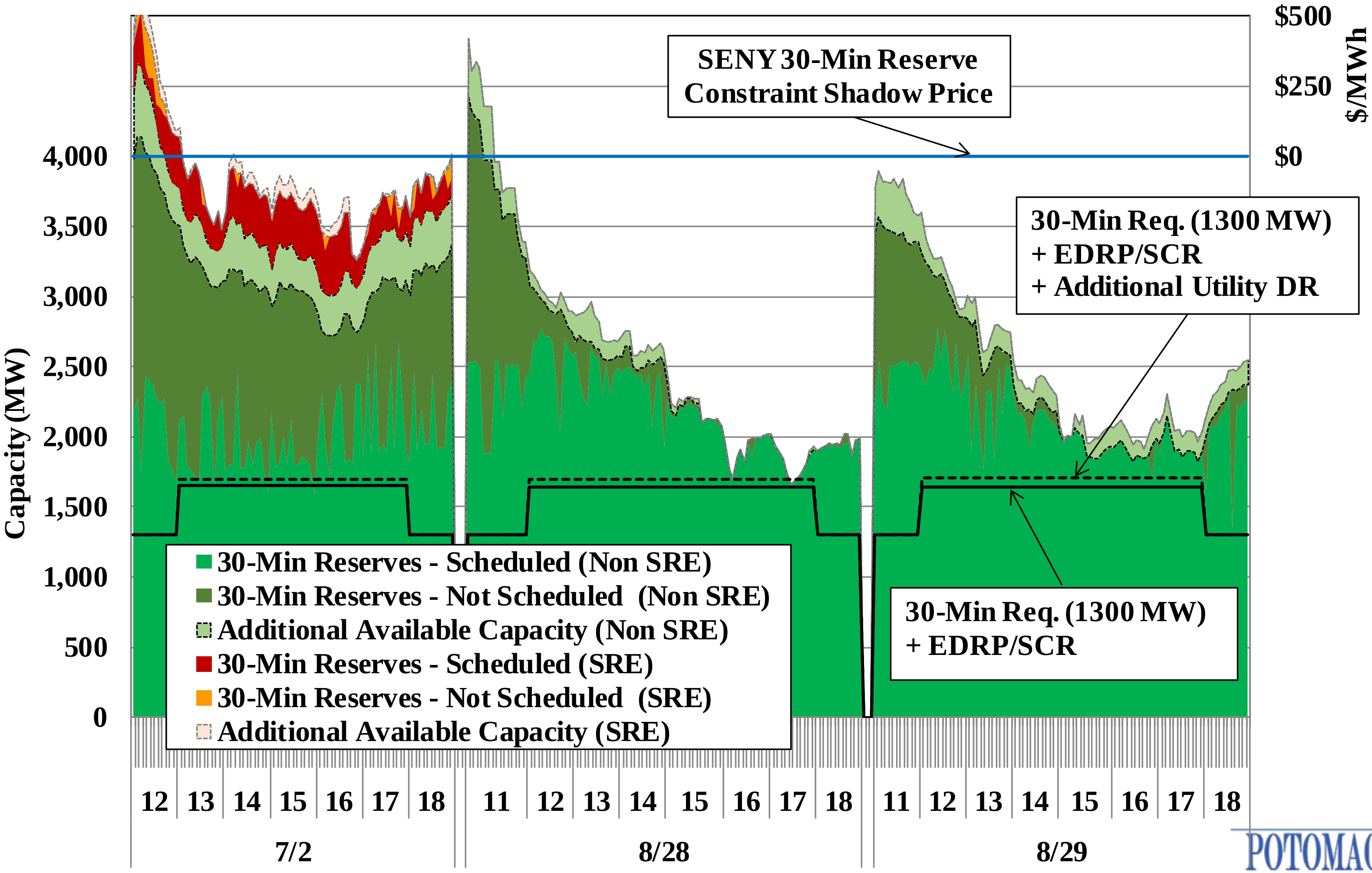
DR Deployments and Scarcity Pricing
Southeast New York



Notes: For chart description, see slide 71.

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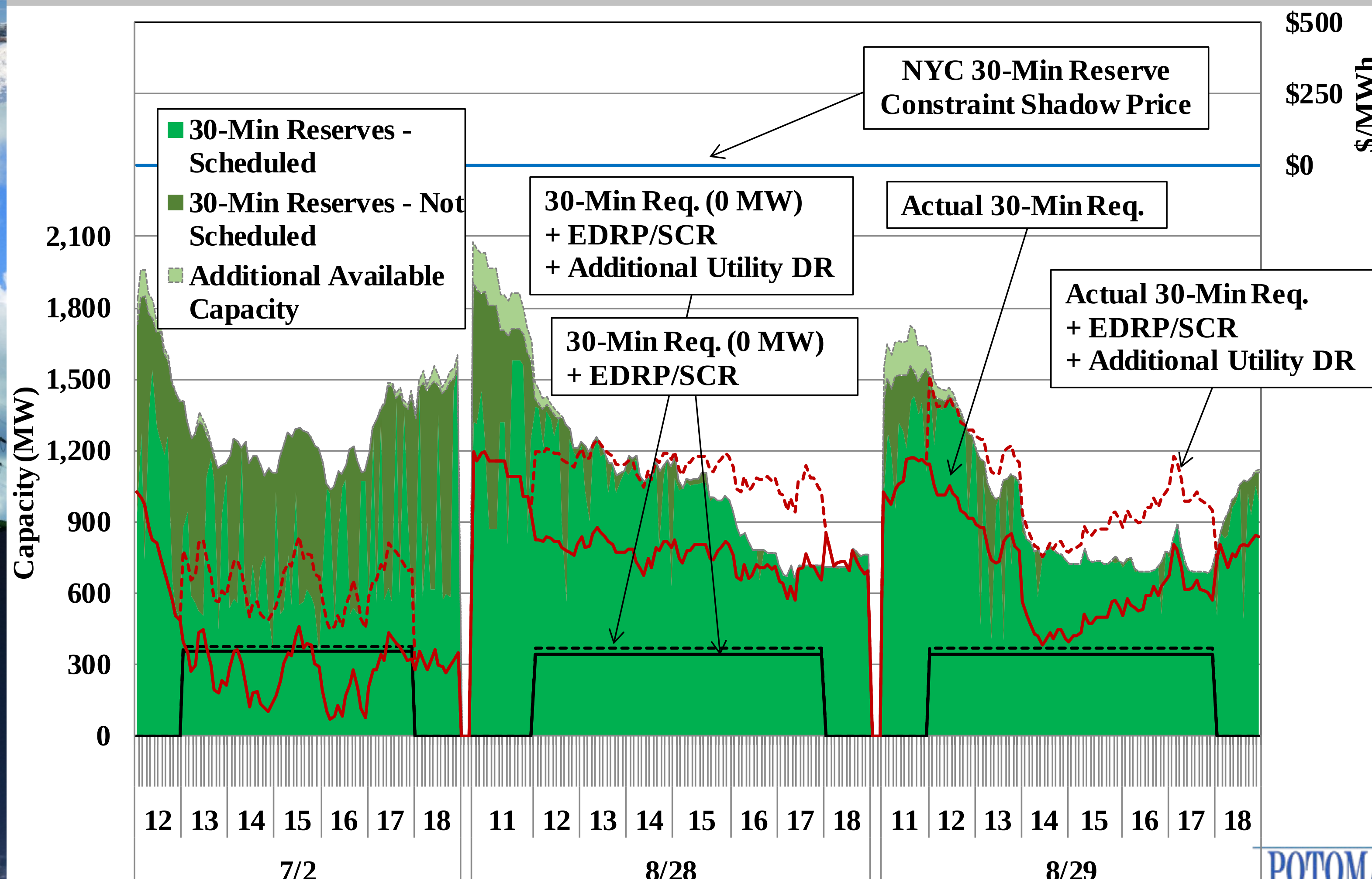
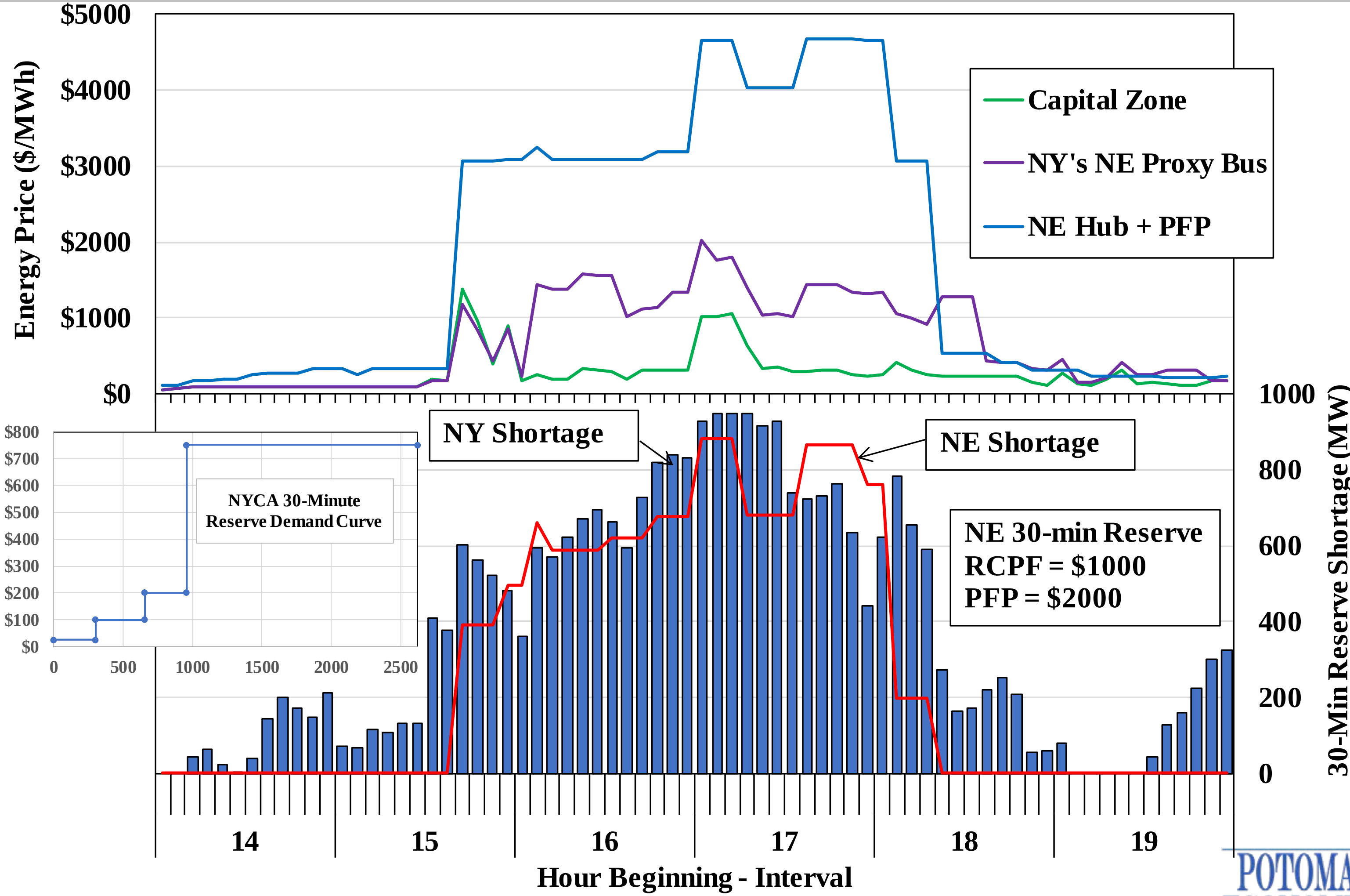
DR Deployments and Scarcity Pricing
New York City



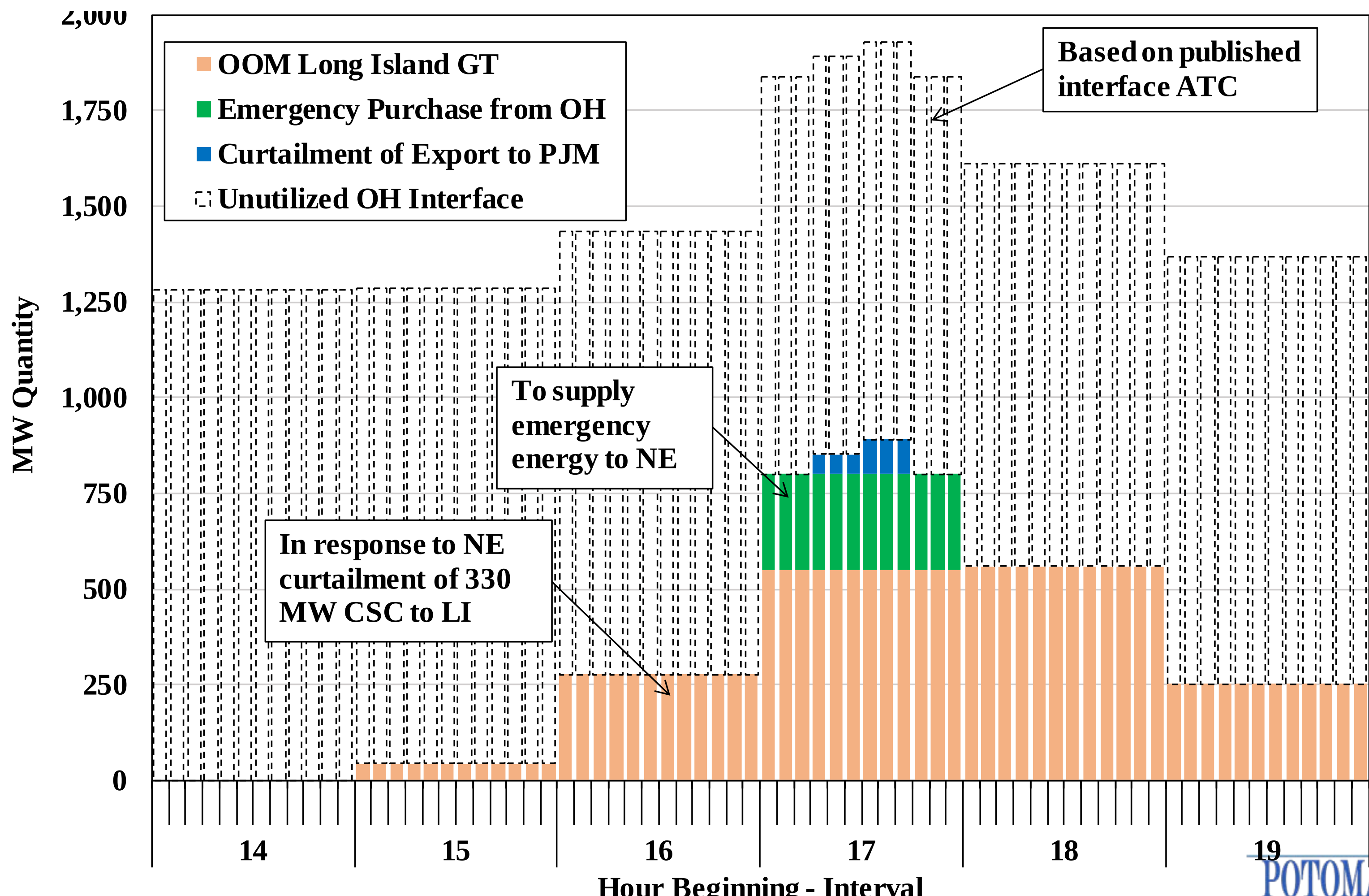
Notes: For chart description, see slide 71.

Market Operations and Pricing During NE's Pay-for-Performance Event on 9/3



Notes: For chart description, see slide 72.

Market Operations and Pricing
During NE’s Pay-for-Performance Event on 9/3



Notes: For chart description, see slide 72.
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<u>Charts:</u>
Ancillary Services Market

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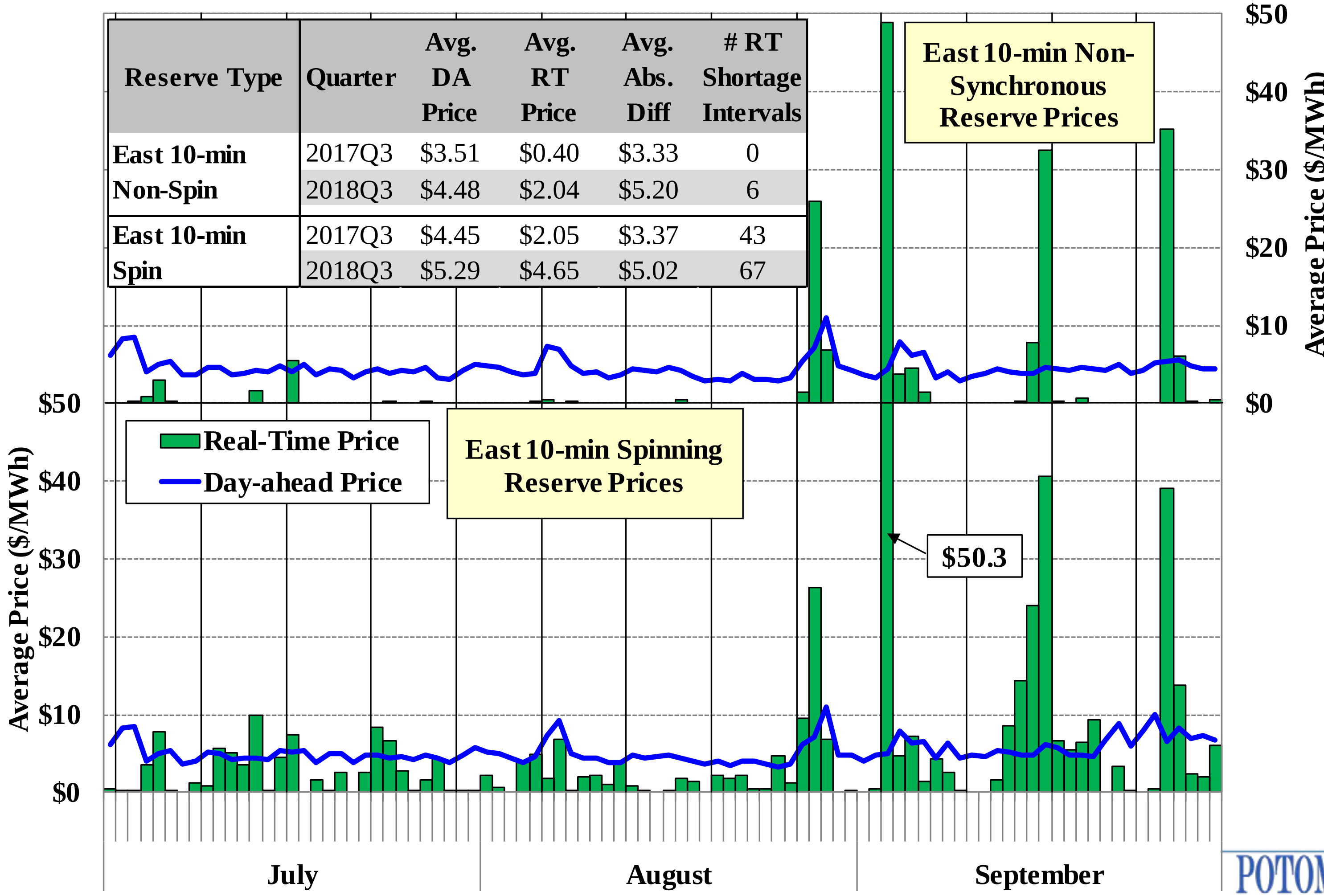
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2017Q3	$3.51	$0.40	$3.33	0
	2018Q3	$4.48	$2.04	$5.20	6
East 10-min Spin	2017Q3	$4.45	$2.05	$3.37	43
	2018Q3	$5.29	$4.65	$5.02	67

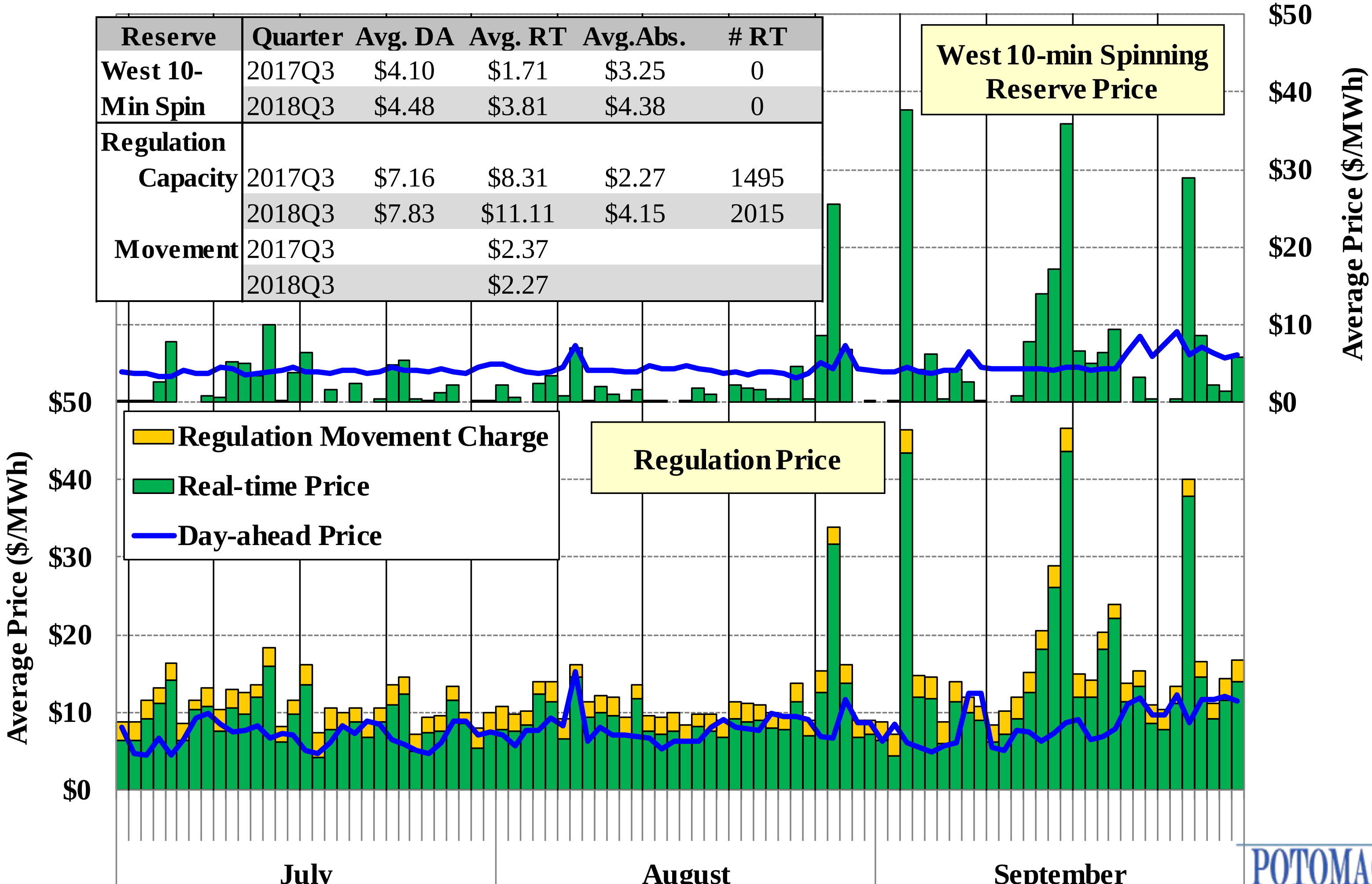


Notes: For chart description, see slide 73.

POTOMAC ECONOMICS

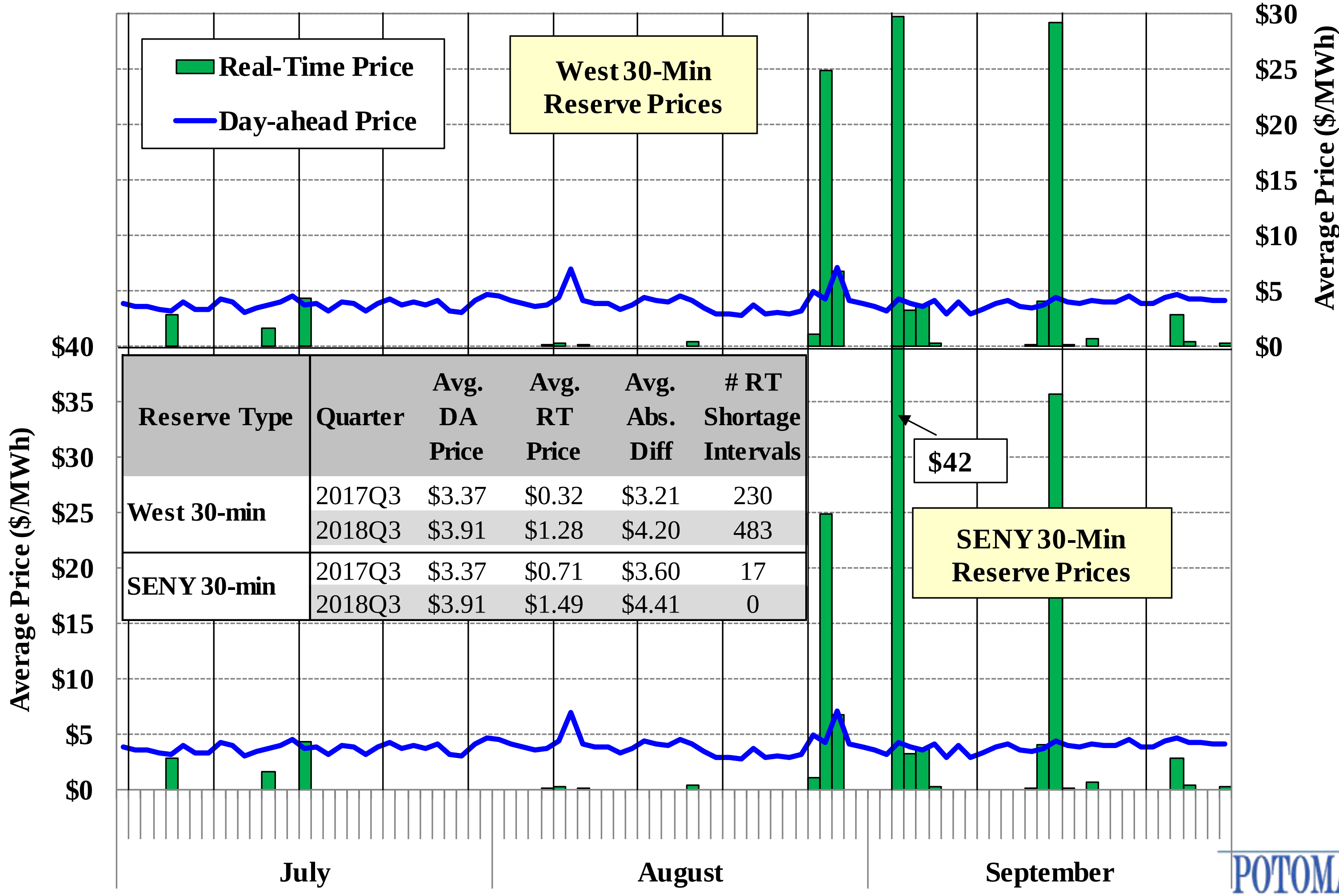
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation

Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2017Q3	$4.10	$1.71	$3.25	0
	2018Q3	$4.48	$3.81	$4.38	0
Regulation					
Capacity	2017Q3	$7.16	$8.31	$2.27	1495
	2018Q3	$7.83	$11.11	$4.15	2015
Movement	2017Q3		$2.37		
	2018Q3		$2.27		



Notes: For chart description, see slide 73.

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

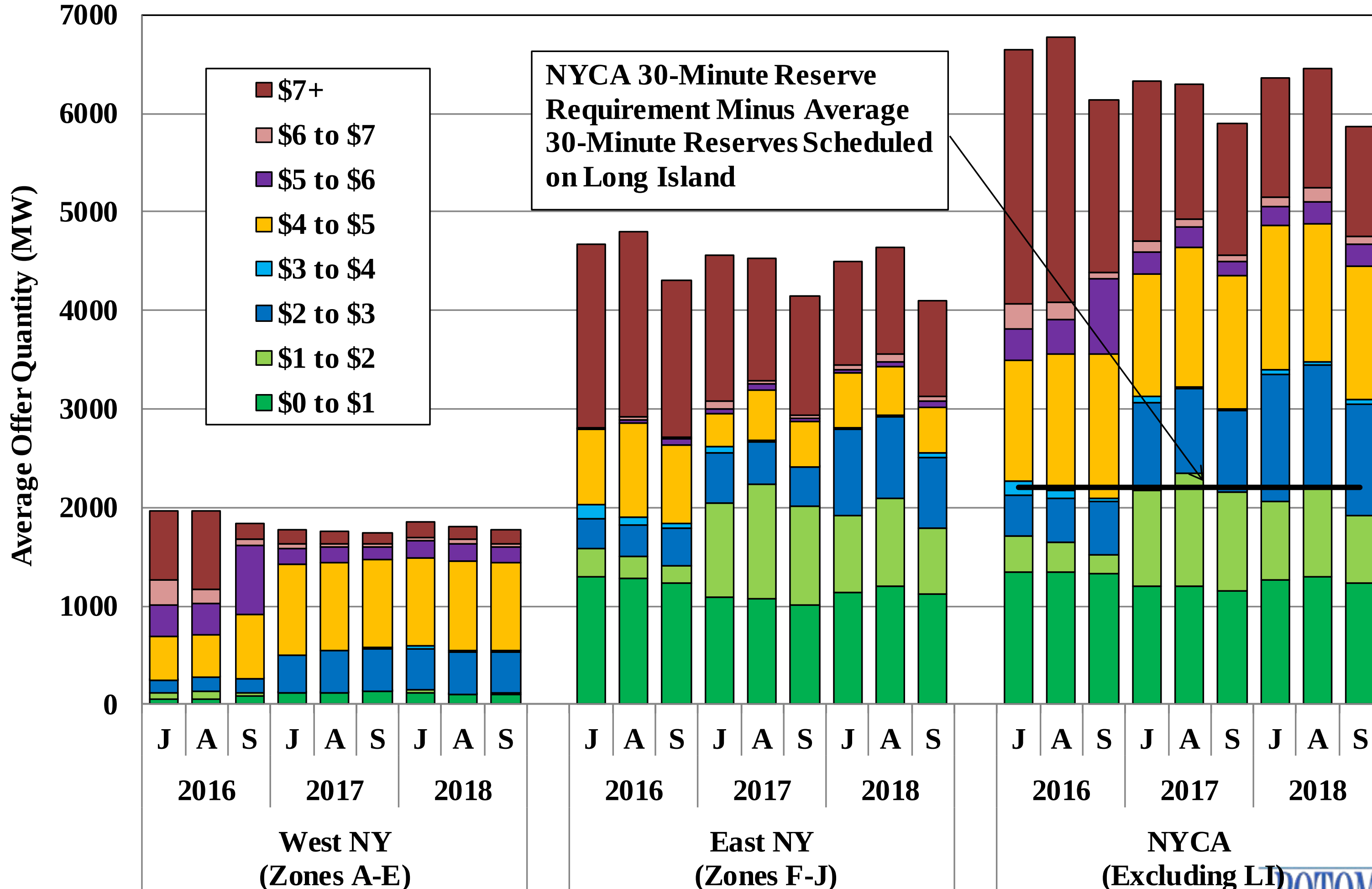


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2017Q3	$3.37	$0.32	$3.21	230
	2018Q3	$3.91	$1.28	$4.20	483
SENY 30-min	2017Q3	$3.37	$0.71	$3.60	17
	2018Q3	$3.91	$1.49	$4.41	0

Notes: For chart description, see slide 73.

POTOMAC ECONOMICS

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



Notes: For chart description, see slide 74.

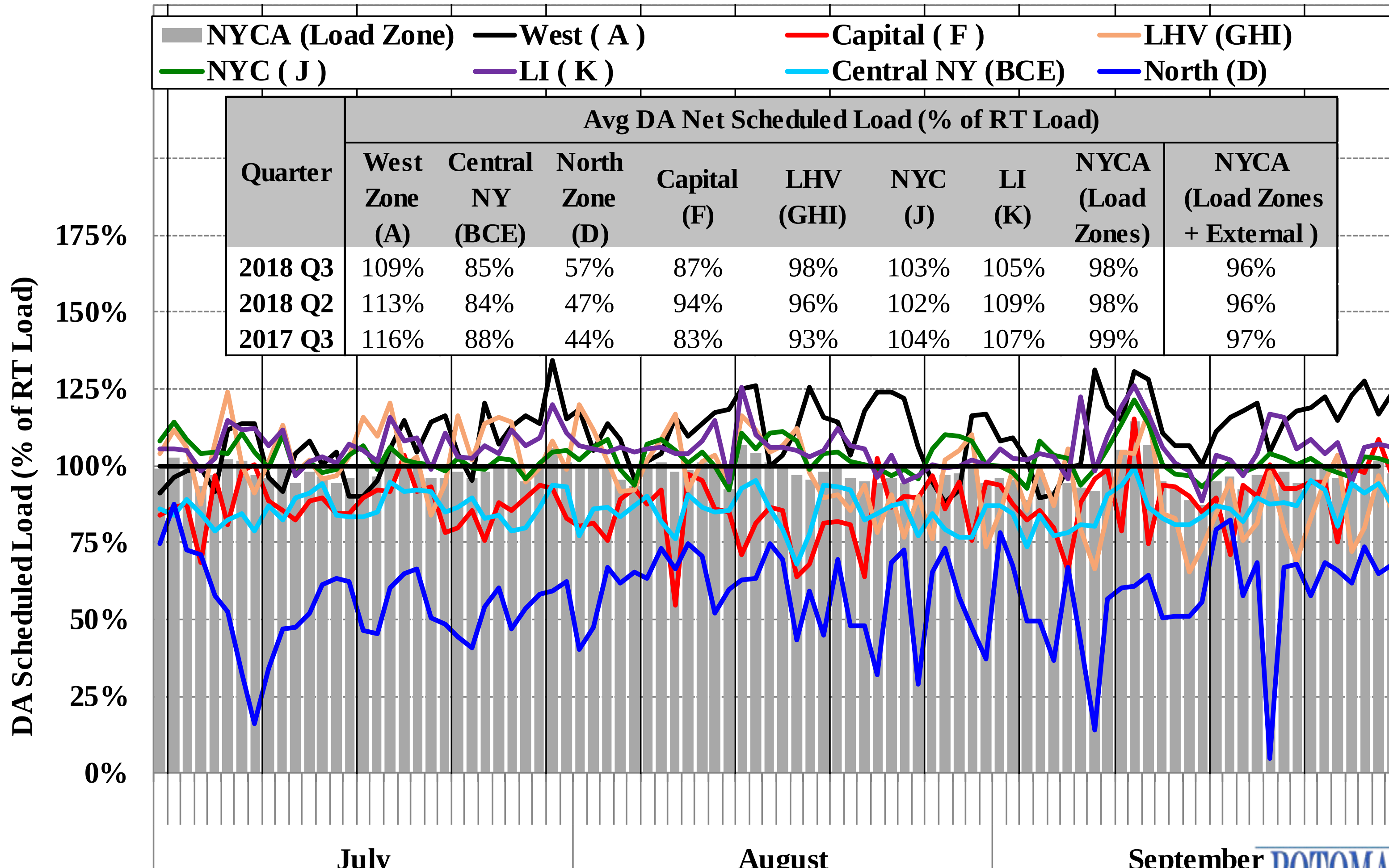
POTOMAC ECONOMICS

Charts:

Energy Market Scheduling

POTOMAC ECONOMICS

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

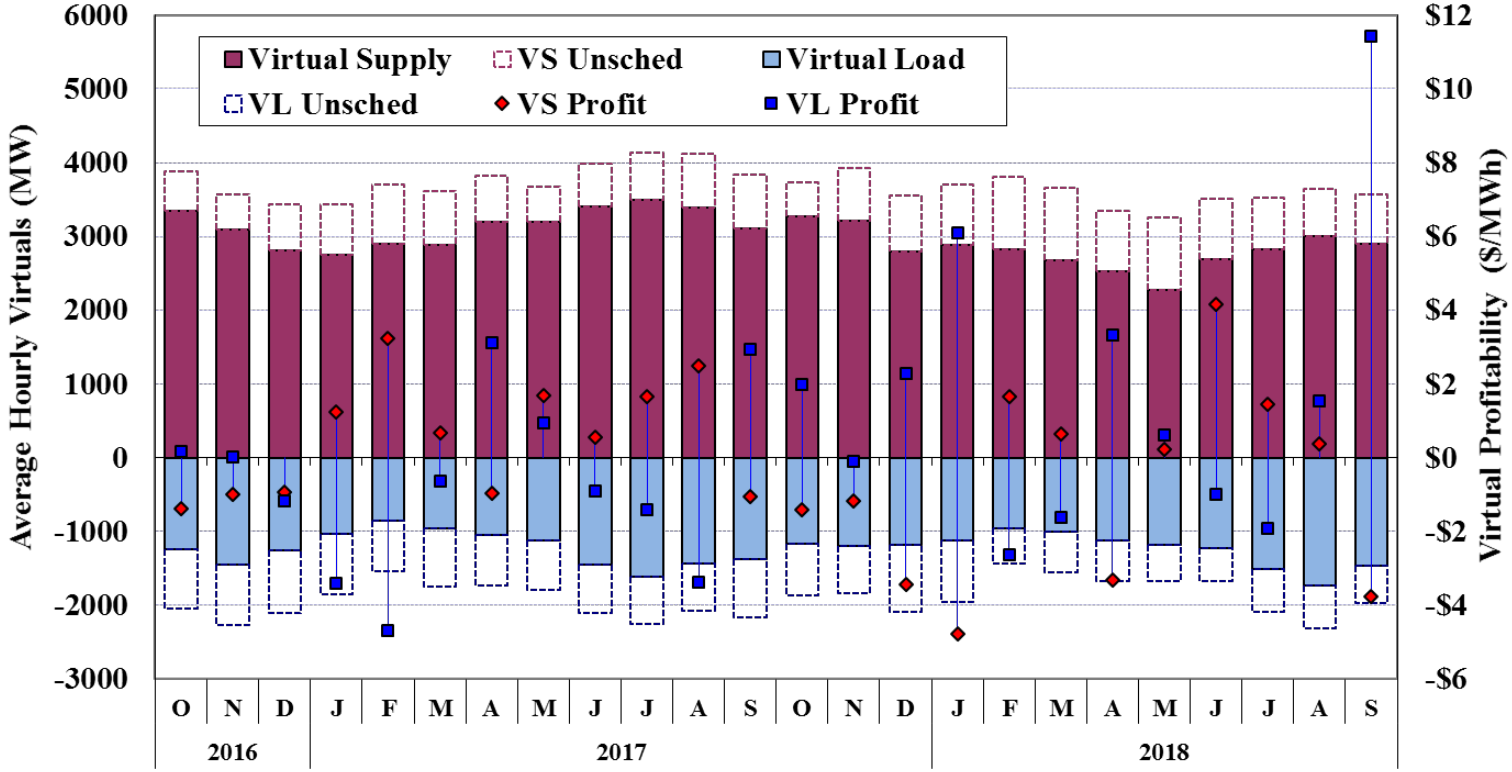


Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2018 Q3	109%	85%	57%	87%	98%	103%	105%	98%	96%
2018 Q2	113%	84%	47%	94%	96%	102%	109%	98%	96%
2017 Q3	116%	88%	44%	83%	93%	104%	107%	99%	97%

Notes: For chart description, see slide 75.

POTOMAC ECONOMICS

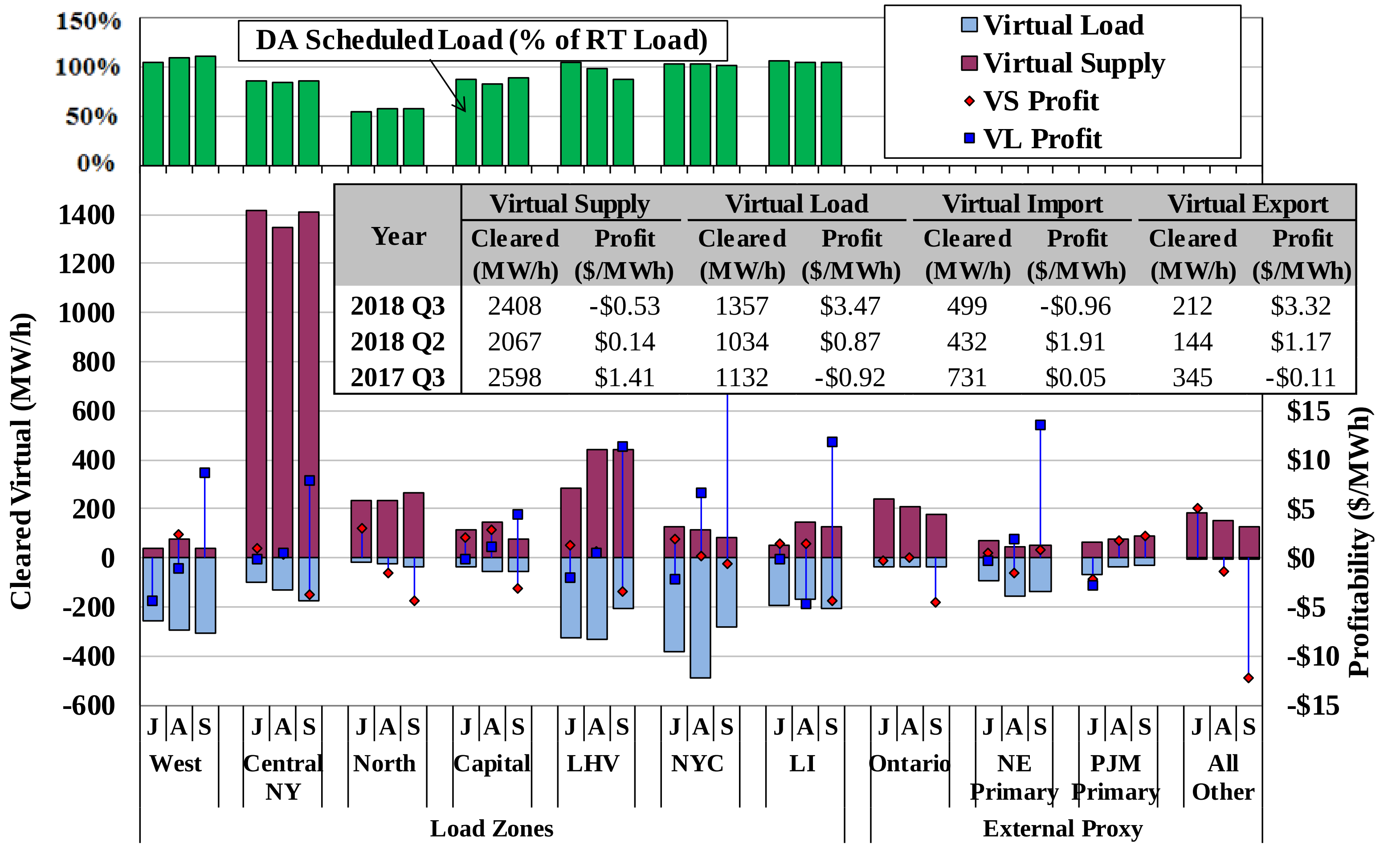
Virtual Trading Activity
by Month



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
Profit > 50% of Avg. Zone Price	MW	281	261	490	243	507	585	449	645	502	593	439	257	271	320	396	373	450	419	376	475	620	320	299	437
	%	6%	6%	12%	6%	13%	15%	11%	15%	10%	12%	9%	6%	6%	7%	10%	9%	12%	11%	10%	14%	16%	7%	6%	10%
Loss > 50% of Avg. Zone Price	MW	419	345	587	284	336	514	454	553	542	568	466	418	399	412	478	442	342	401	466	537	531	329	328	428
	%	9%	8%	14%	7%	9%	13%	11%	13%	11%	11%	10%	9%	9%	9%	12%	11%	9%	11%	13%	16%	14%	8%	7%	10%

Notes: For chart description, see slide 75.
POTOMAC ECONOMICS

Virtual Trading Activity by Location

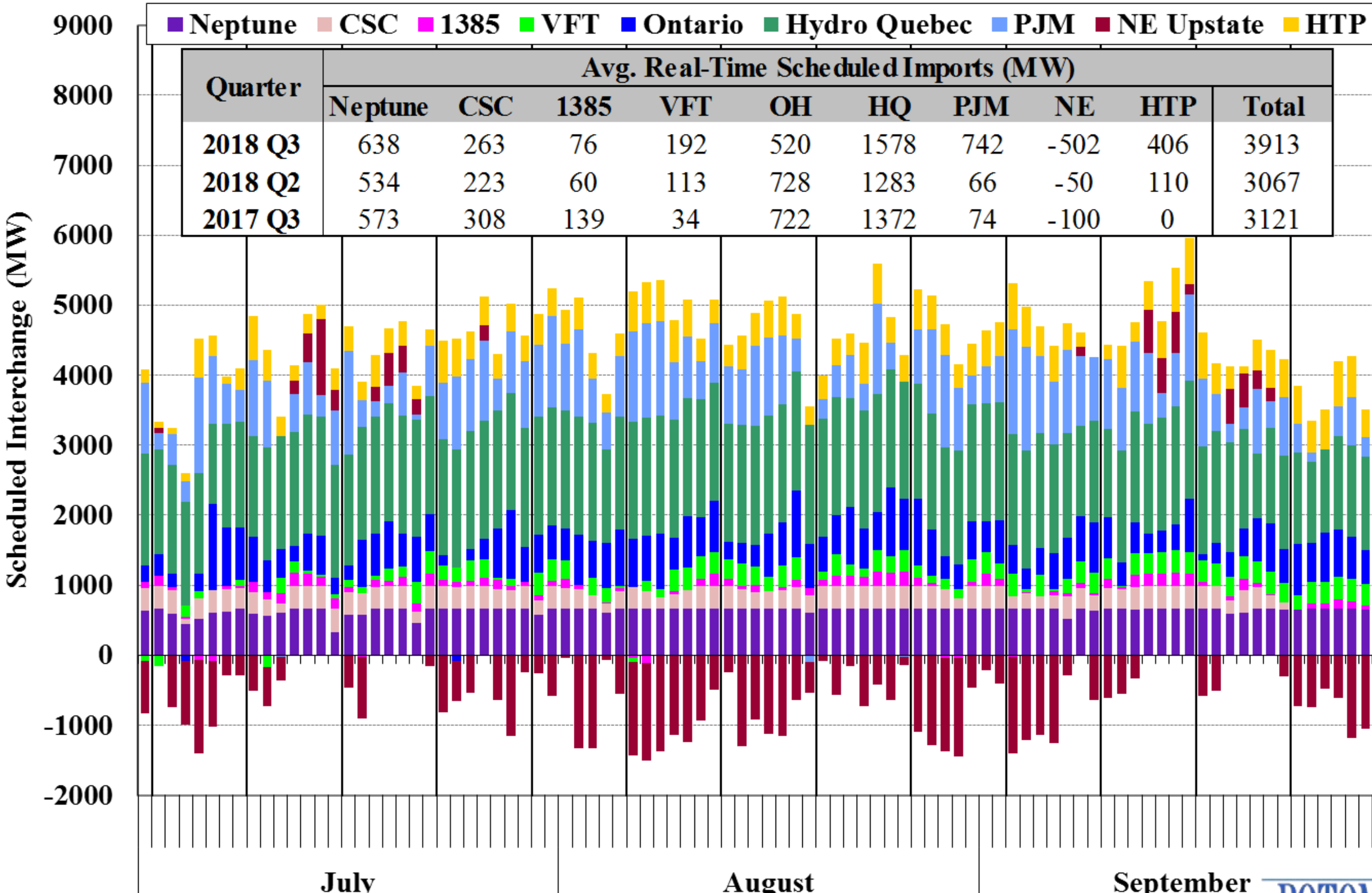


Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2018 Q3	2408	-$0.53	1357	$3.47	499	-$0.96	212	$3.32
2018 Q2	2067	$0.14	1034	$0.87	432	$1.91	144	$1.17
2017 Q3	2598	$1.41	1132	-$0.92	731	$0.05	345	-$0.11

Notes: 1. Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.
2. For chart description, see slide 75.

POTOMAC ECONOMICS

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 Q3	638	263	76	192	520	1578	742	-502	406	3913
2018 Q2	534	223	60	113	728	1283	66	-50	110	3067
2017 Q3	573	308	139	34	722	1372	74	-100	0	3121

Notes: Two HQ interfaces are combined into one.

POTOMAC ECONOMICS

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

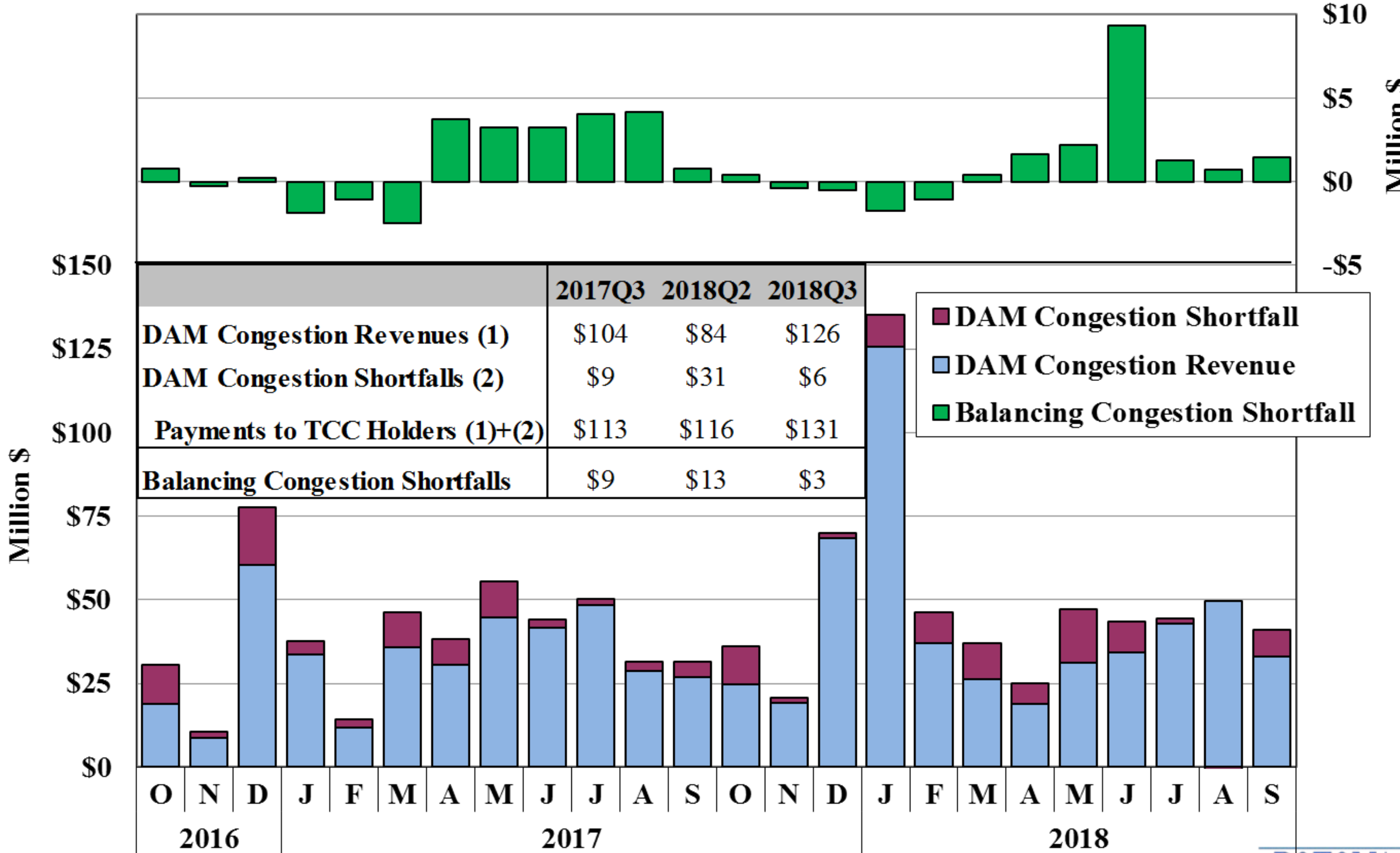
			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			84%	7%	**92%**	53%	9%	**62%**
Average Flow Adjustment (MW)	Net Imports		12	-19	**9**	25	6	**22**
	Gross		92	120	**94**	82	122	**88**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$1.1	$0.9	**$2.1**	$0.5	$0.9	**$1.4**
	Net Over-Projection by:	NY	-$0.04	-$0.1	**-$0.2**	-$0.03	-$0.3	**-$0.4**
		NE or PJM	$0.03	-$0.1	**-$0.1**	-$0.2	-$0.9	**-$1.0**
	Other Unrealized Savings		-$0.05	-$0.1	**-$0.1**	-$0.02	$0.01	**$0.0**
	Actual Savings		$1.1	$0.6	**$1.7**	$0.3	-$0.3	**$0.0**
Interface Prices ($/MWh)	NY	Actual	$29.68	$73.63	**$33.20**	$27.87	$62.14	**$33.11**
		Forecast	$30.48	$67.56	**$33.46**	$28.59	$56.42	**$32.85**
	NE or PJM	Actual	$30.66	$85.67	**$35.07**	$27.05	$62.21	**$32.43**
		Forecast	$30.08	$93.12	**$35.13**	$26.94	$67.73	**$33.18**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.80	-$6.07	**$0.25**	$0.72	-$5.72	**-$0.26**
		Abs. Val.	$2.85	$40.84	**$5.90**	$2.75	$30.34	**$6.97**
	NE or PJM	Fcst. - Act.	-$0.58	$7.46	**$0.06**	-$0.11	$5.52	**$0.75**
		Abs. Val.	$3.50	$47.66	**$7.04**	$3.97	$49.92	**$11.00**

Notes: For chart description, see slide 76.

Charts:

Transmission Congestion Revenues and Shortfalls

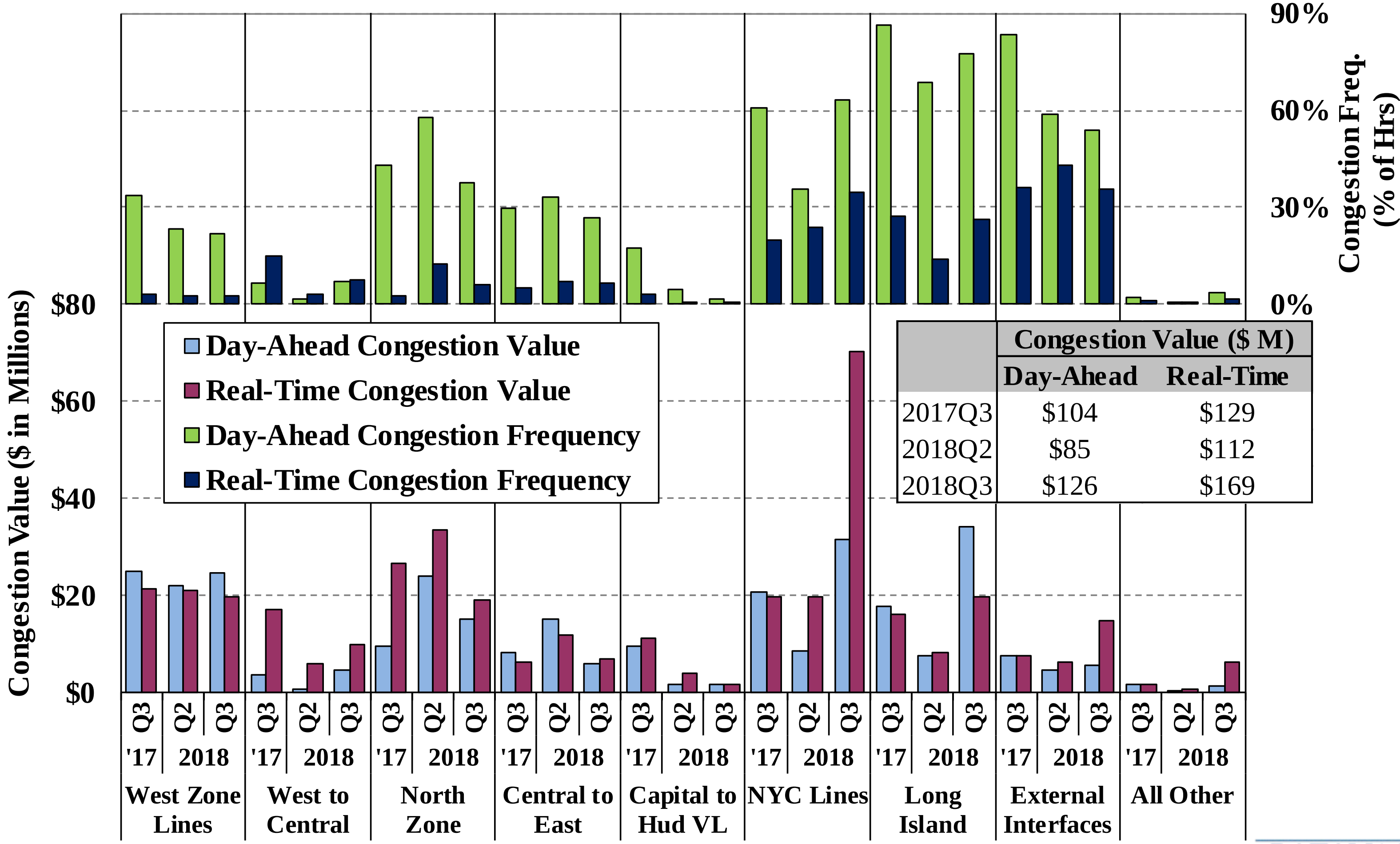
Congestion Revenues and Shortfalls by Month



	2017Q3	2018Q2	2018Q3
DAM Congestion Revenues (1)	$104	$84	$126
DAM Congestion Shortfalls (2)	$9	$31	$6
Payments to TCC Holders (1)+(2)	$113	$116	$131
Balancing Congestion Shortfalls	$9	$13	$3

Notes: For chart description, see slides 77 and 78.

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

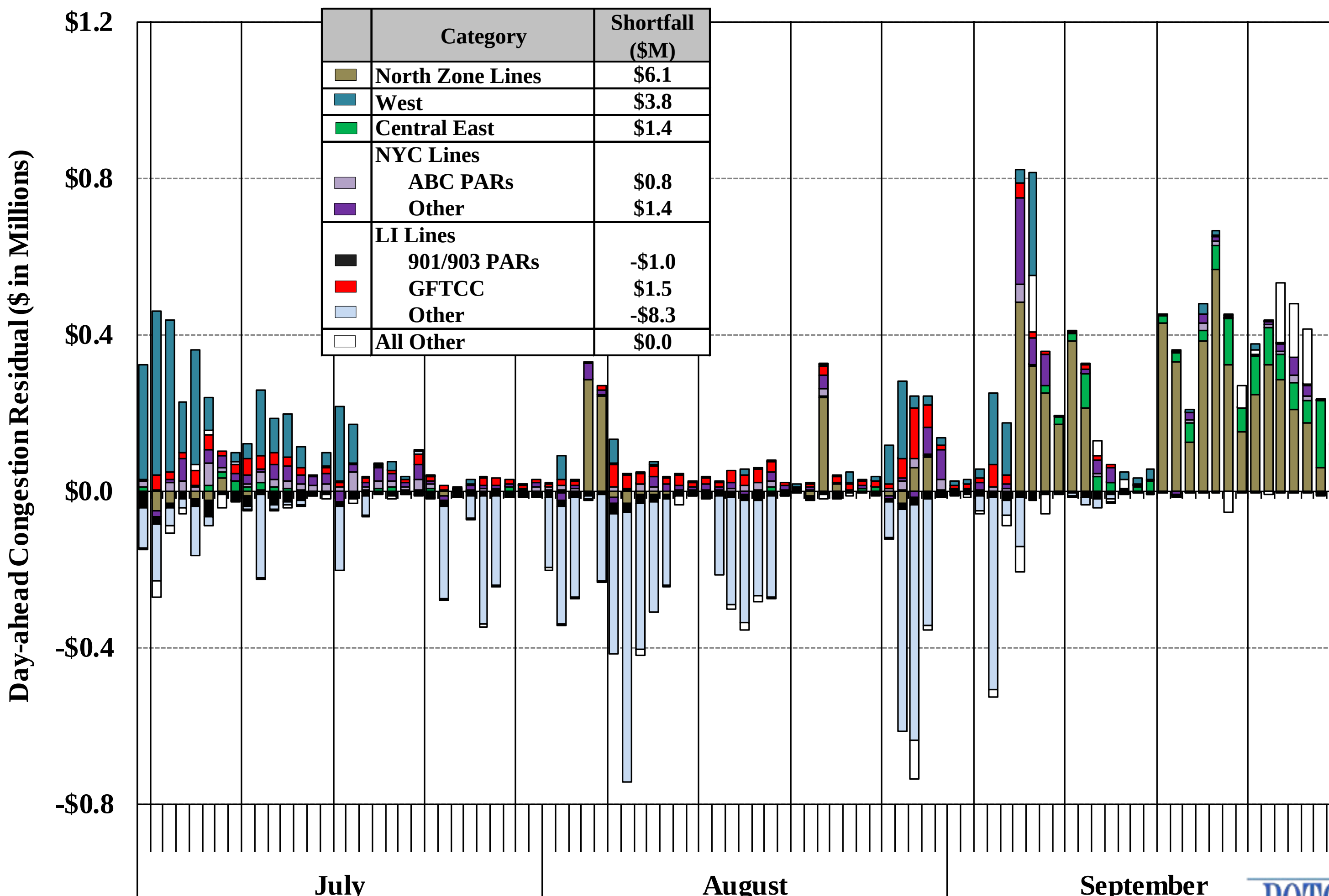


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2017Q3	$104	$129
2018Q2	$85	$112
2018Q3	$126	$169

Notes: For chart description, see slides 77, 78, and 79.

POTOMAC ECONOMICS

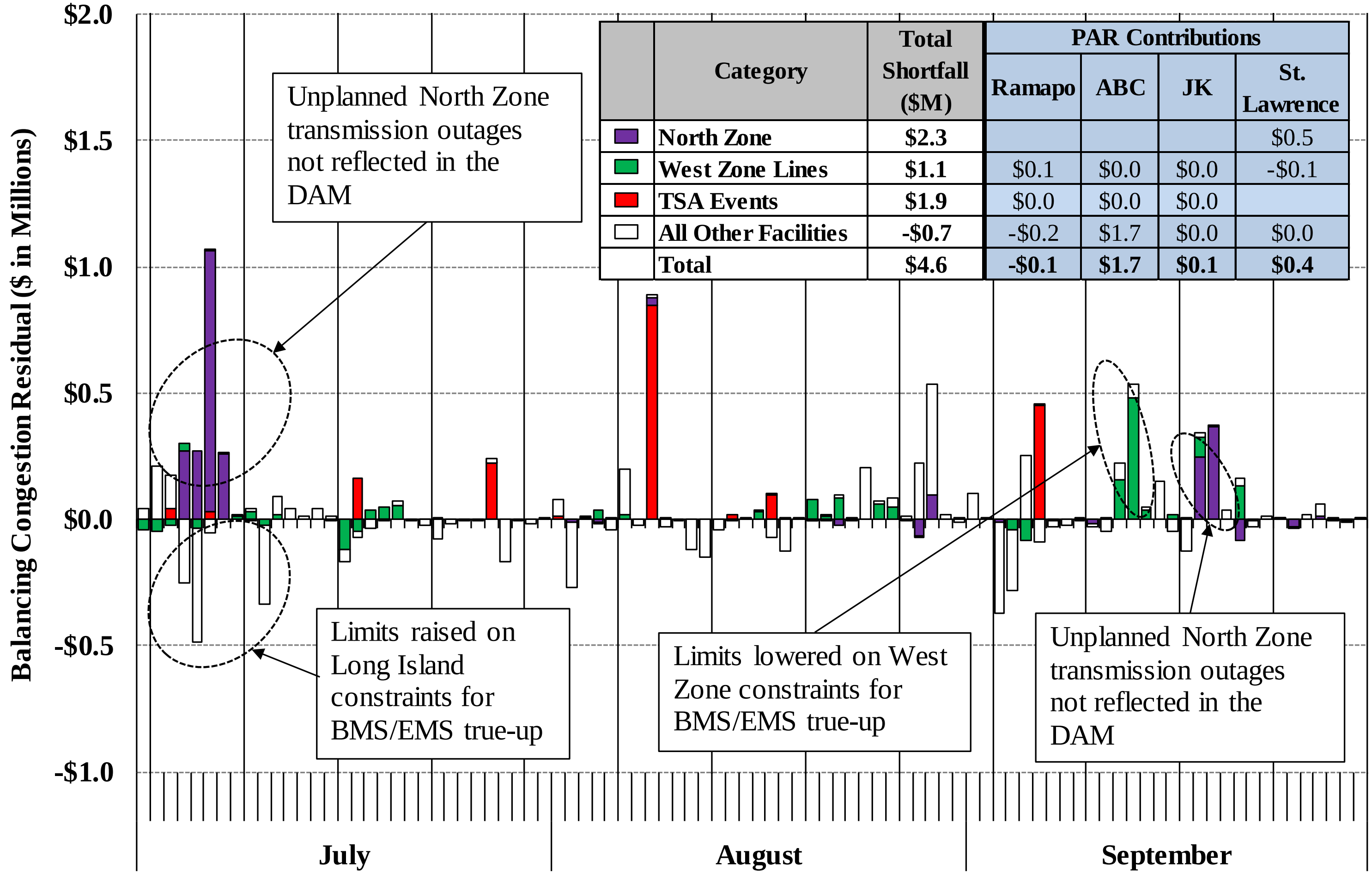
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 77, 78, and 79.

POTOMAC ECONOMICS

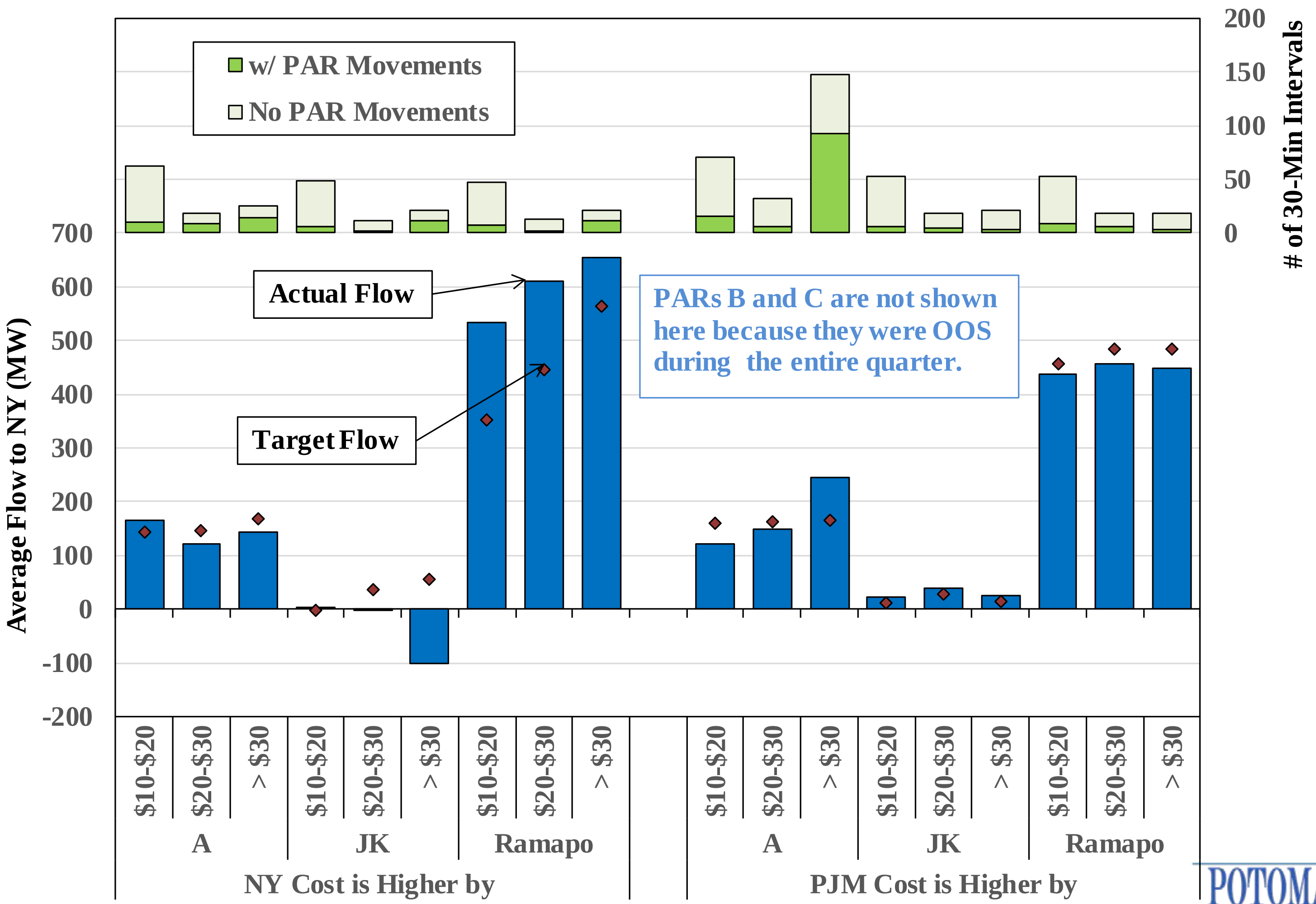
Balancing Congestion Shortfalls by Transmission Facility



Category	Total Shortfall ($M)	PAR Contributions			
		Ramapo	ABC	JK	St. Lawrence
North Zone	**$2.3**				$0.5
West Zone Lines	**$1.1**	$0.1	$0.0	$0.0	-$0.1
TSA Events	**$1.9**	$0.0	$0.0	$0.0	
All Other Facilities	**-$0.7**	-$0.2	$1.7	$0.0	$0.0
Total	**$4.6**	**-$0.1**	**$1.7**	**$0.1**	**$0.4**

Notes: 1. The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. 2. For chart description, see slides 77, 78, and 79.

PAR Operation under M2M with PJM
2018 Q3

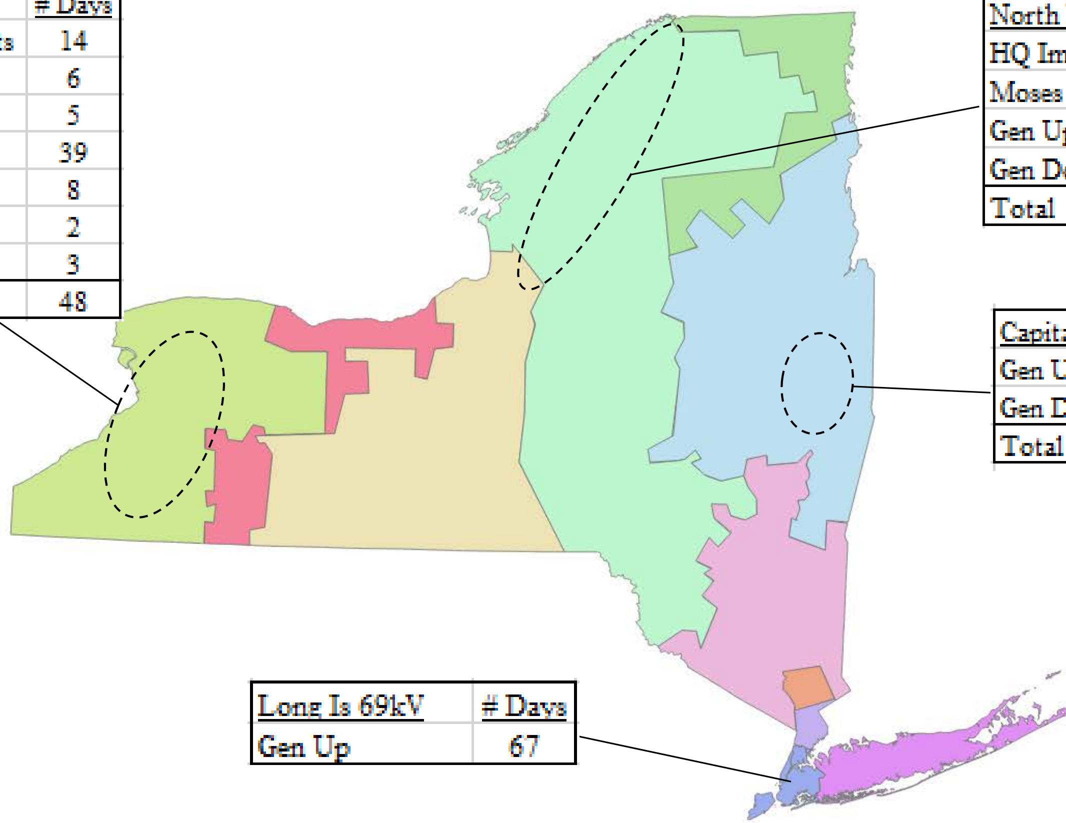


Notes: For chart description, see slide 80.

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

West NY	# Days
Ontario Imports	14
Dysinger East	6
Gen Up	5
Gen Down	39
St. Lawr PARs	8
Ramapo PARs	2
ABC PARs	3
Total	48

North NY	# Days
HQ Imports	4
Moses South	1
Gen Up	17
Gen Down	1
Total	21



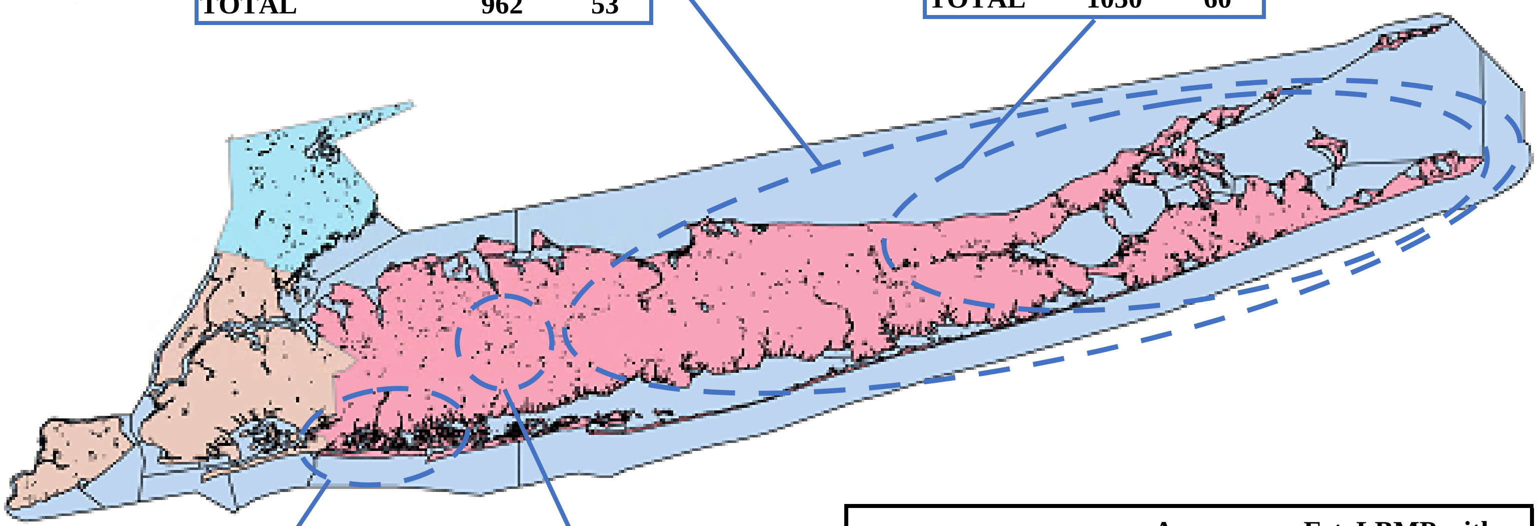
Capital Zone	# Days
Gen Up	1
Gen Down	17
Total	17

Long Is 69kV	# Days
Gen Up	67

Notes: For chart description, see slides 81-82

POTOMAC ECONOMICS

Constraints on the Low Voltage Network:
Long Island Load Pockets



East of Northport	#Hours	#Days
69kV	253	34
138kV	919	47
TOTAL	962	53

East End	#Hours	#Days
69kV	126	9
138kV	792	33
TVR	623	56
TOTAL	1050	60

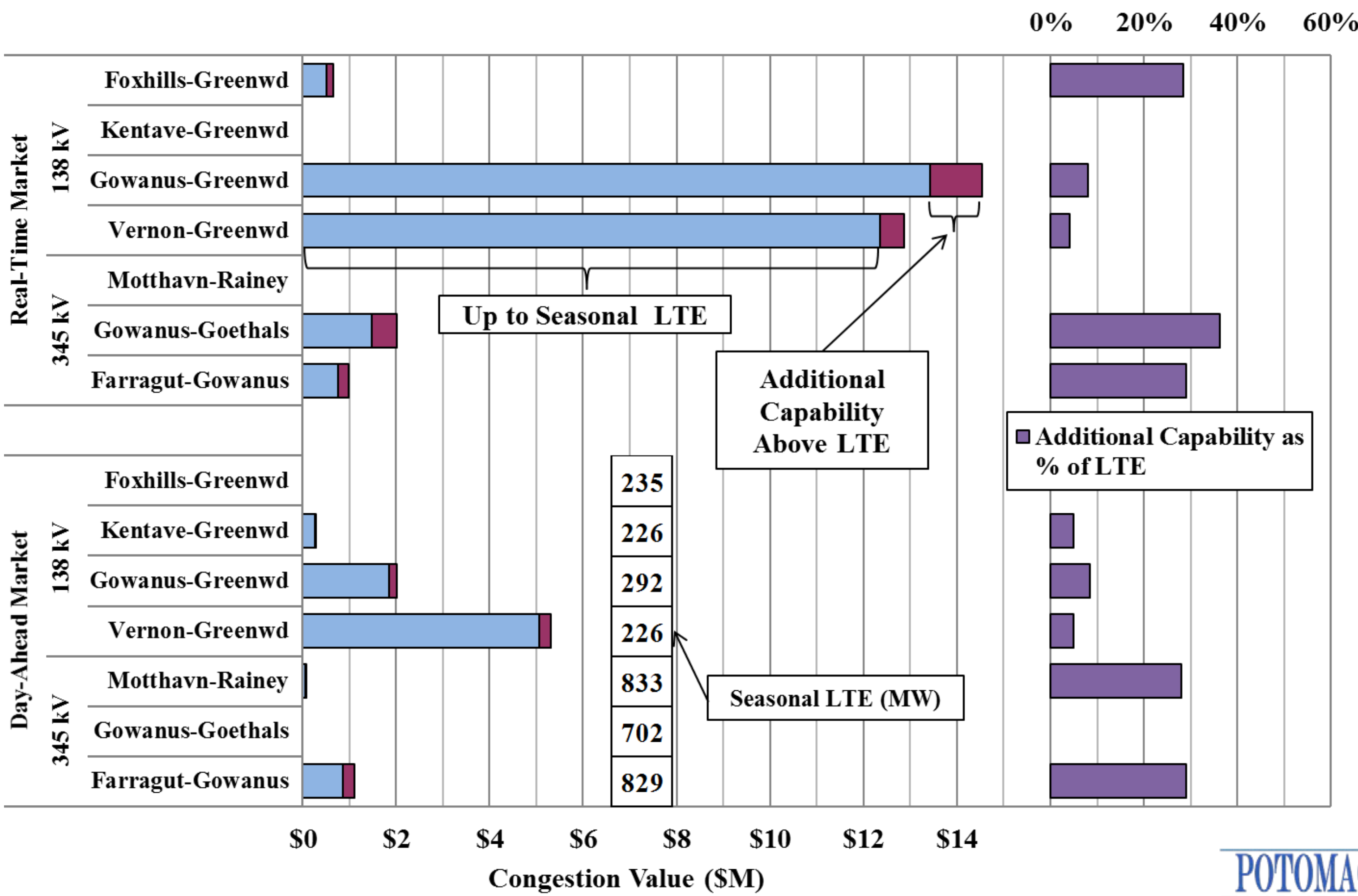
Brentwood	#Hours	#Days
69kV	321	48

Valley Stream	#Hours	#Days
69kV	116	20
138kV	2184	91
TOTAL	2184	91

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$40.54	$41.18
East End	$45.01	$122.88
East of Northport	$41.69	$59.39
Valley Stream	$58.03	$59.18

Notes: For chart description, see slides 81-82

N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide 83.

POTOMAC ECONOMICS

Constraint Limit and CRM in New York
During Real-Time Transmission Shortage Intervals

Constraint Voltage Class	Constraint Location	# of Constraint-Shortage Intervals	Avg Constraint Limit (MW)	Avg CRM (MW)	Avg Shortage MW		CRM as % of Limit
					Recognized in Model	Excluding Offline GT	
115 kV	**North**	479	139	20	4	4	14%
138 kV	**New York City**	3361	225	20	6	6	9%
	Long Island	911	285	27	5	7	9%
230 kV	**West**	576	646	48	9	9	7%
	North	7	493	20	2	2	4%
	All Others	9	505	20	2	2	4%
345 kV	**New York City**	406	549	20	8	9	4%
	North	61	1618	50	18	18	3%
	Long Island	468	716	50	1.3	16	7%
	All Others	47	1827	20	7	41	1%

Notes: 1. In this analysis, a transmission shortage is measured excluding the congestion-relief effects from offline GTs.
2. For chart description, see slide 84.

POTOMAC ECONOMICS

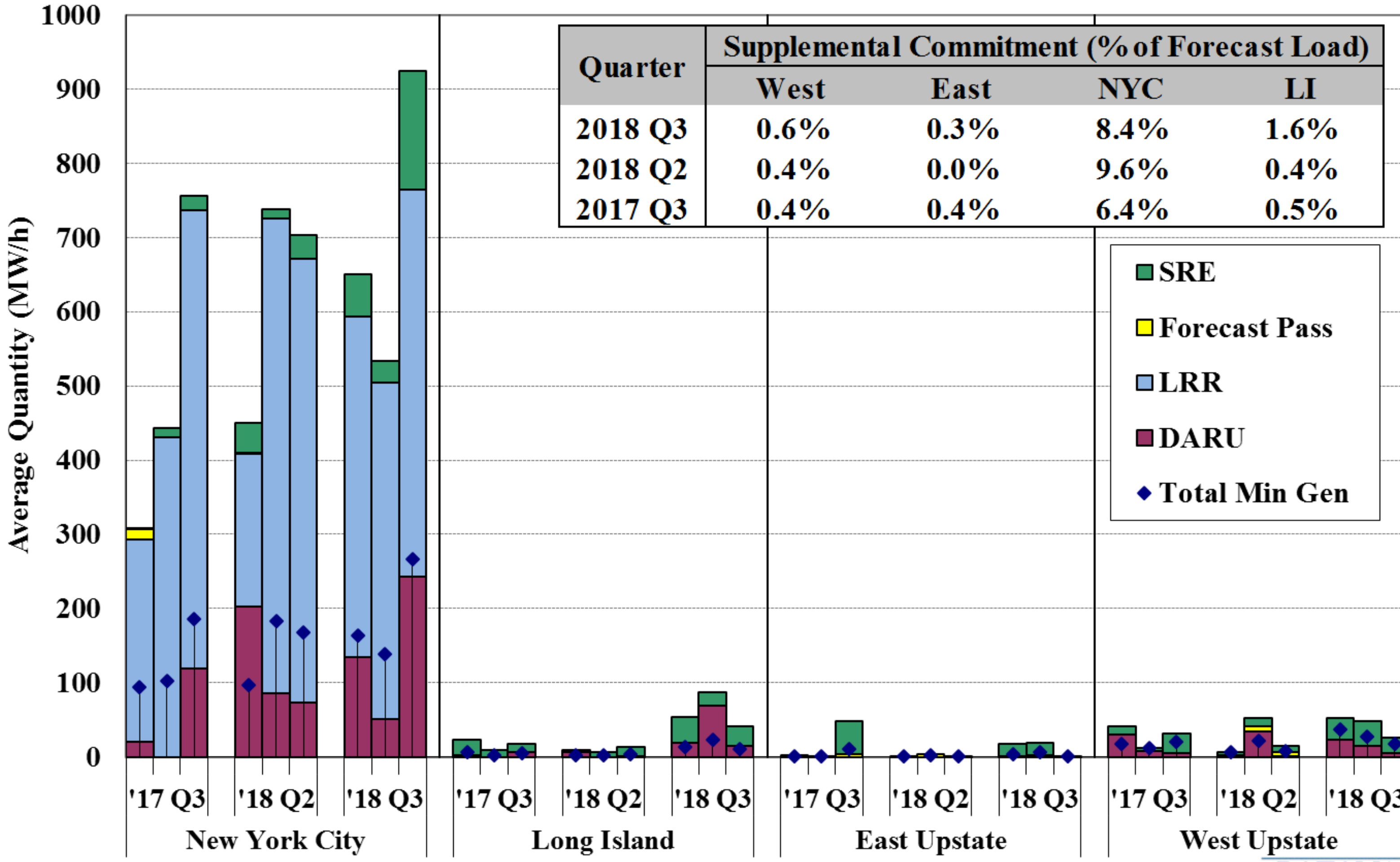
Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

Supplemental Commitment for Reliability
by Category and Region

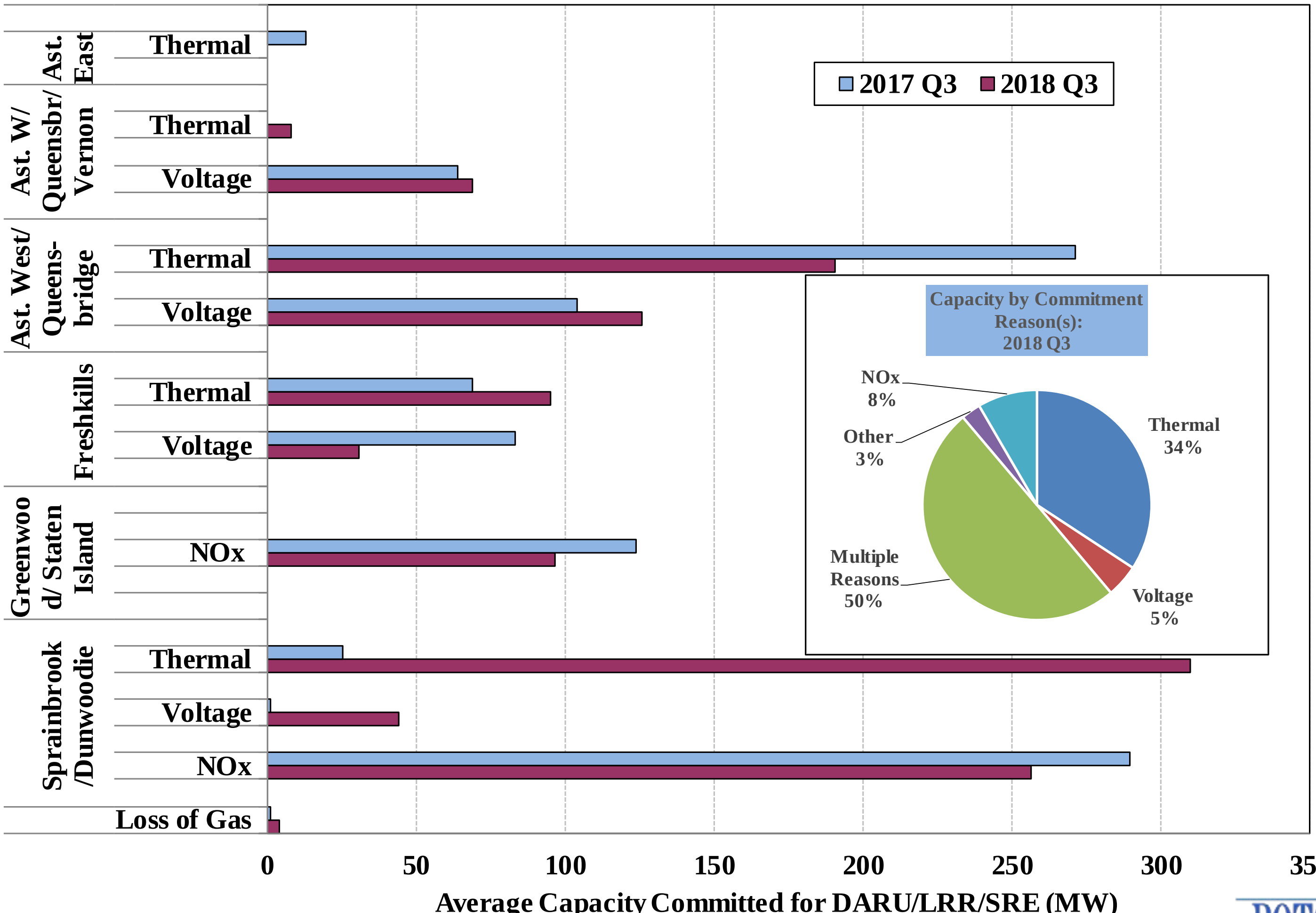
Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2018 Q3	0.6%	0.3%	8.4%	1.6%
2018 Q2	0.4%	0.0%	9.6%	0.4%
2017 Q3	0.4%	0.4%	6.4%	0.5%



Notes: For chart description, see slides 85 and 86.

POTOMAC ECONOMICS

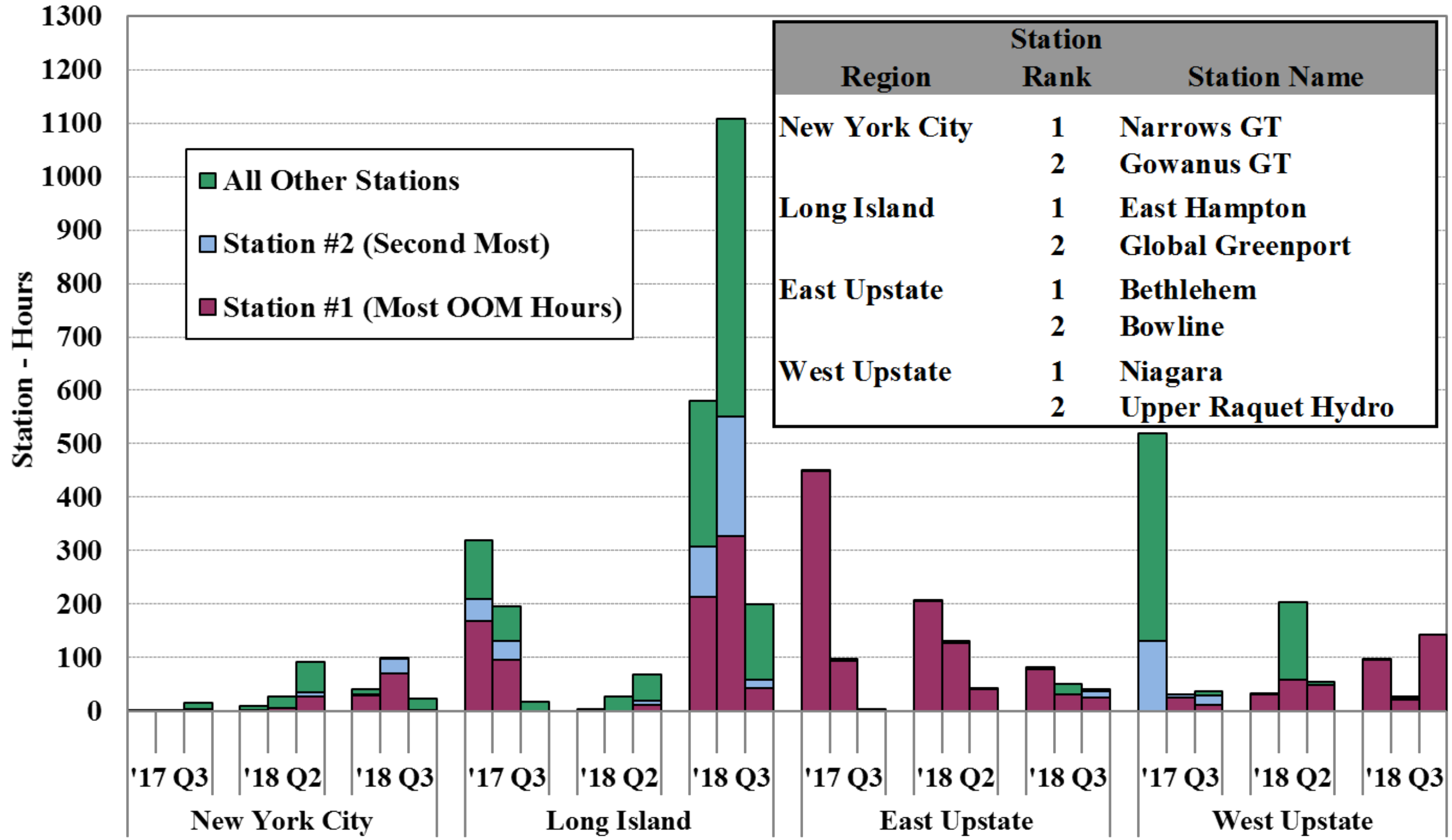
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



Notes: For chart description, see slides 85 and 86.

POTOMAC ECONOMICS

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

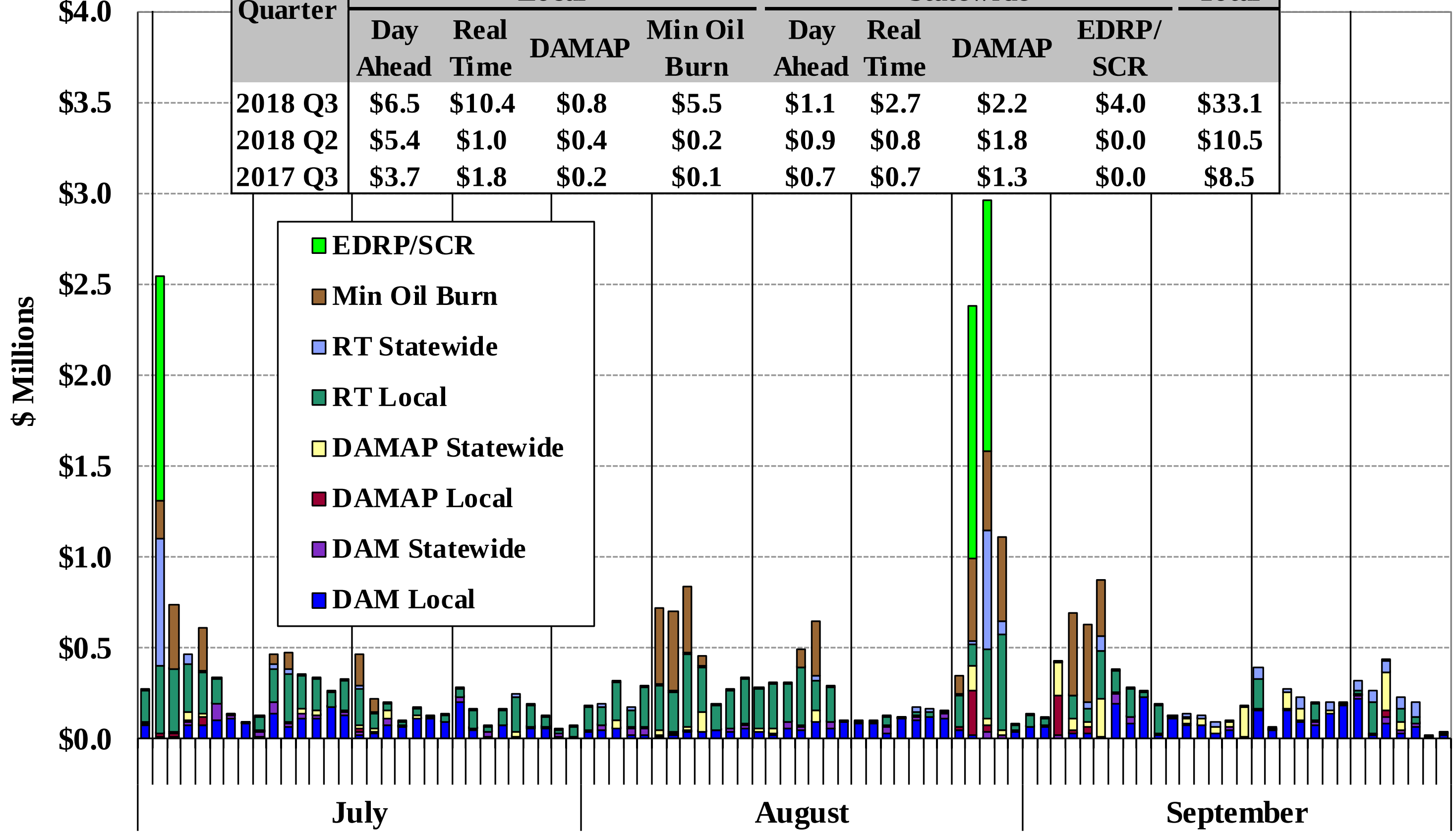


Notes: 1. The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 395 hours in 2017-Q3, 382 hours in 2018-Q2, and 525 hours in 2018-Q3. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

2. For chart description, see slides 85 and 86.

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 Q3	$6.5	$10.4	$0.8	$5.5	$1.1	$2.7	$2.2	$4.0	$33.1
2018 Q2	$5.4	$1.0	$0.4	$0.2	$0.9	$0.8	$1.8	$0.0	$10.5
2017 Q3	$3.7	$1.8	$0.2	$0.1	$0.7	$0.7	$1.3	$0.0	$8.5

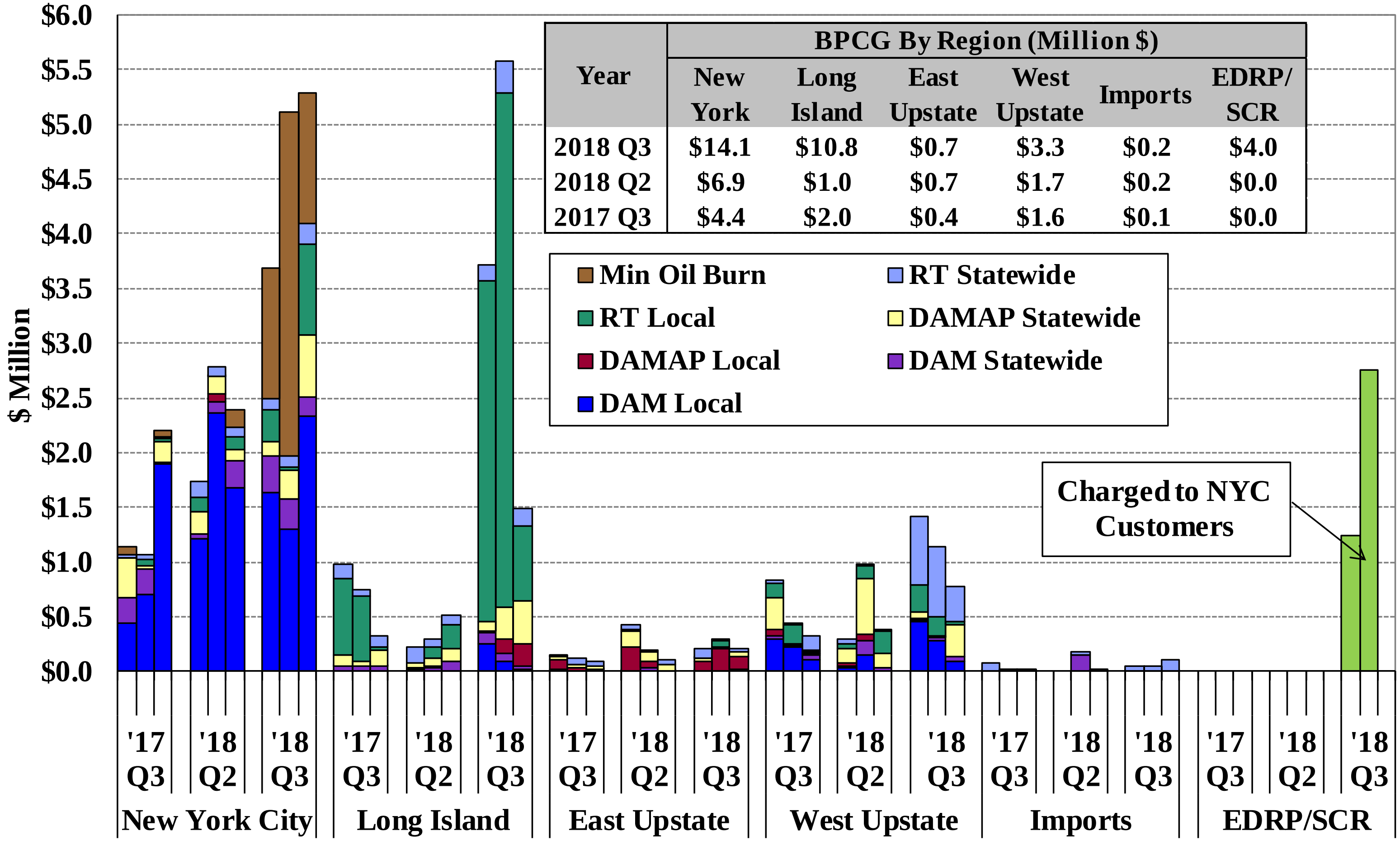


Notes:1. These data are based on information available at the reporting time and do not include some manual adjustments to mitigation, so they can be different from final settlements.

2. For chart description, see slide 87.

Uplift Costs from Guarantee Payments
By Category and Region

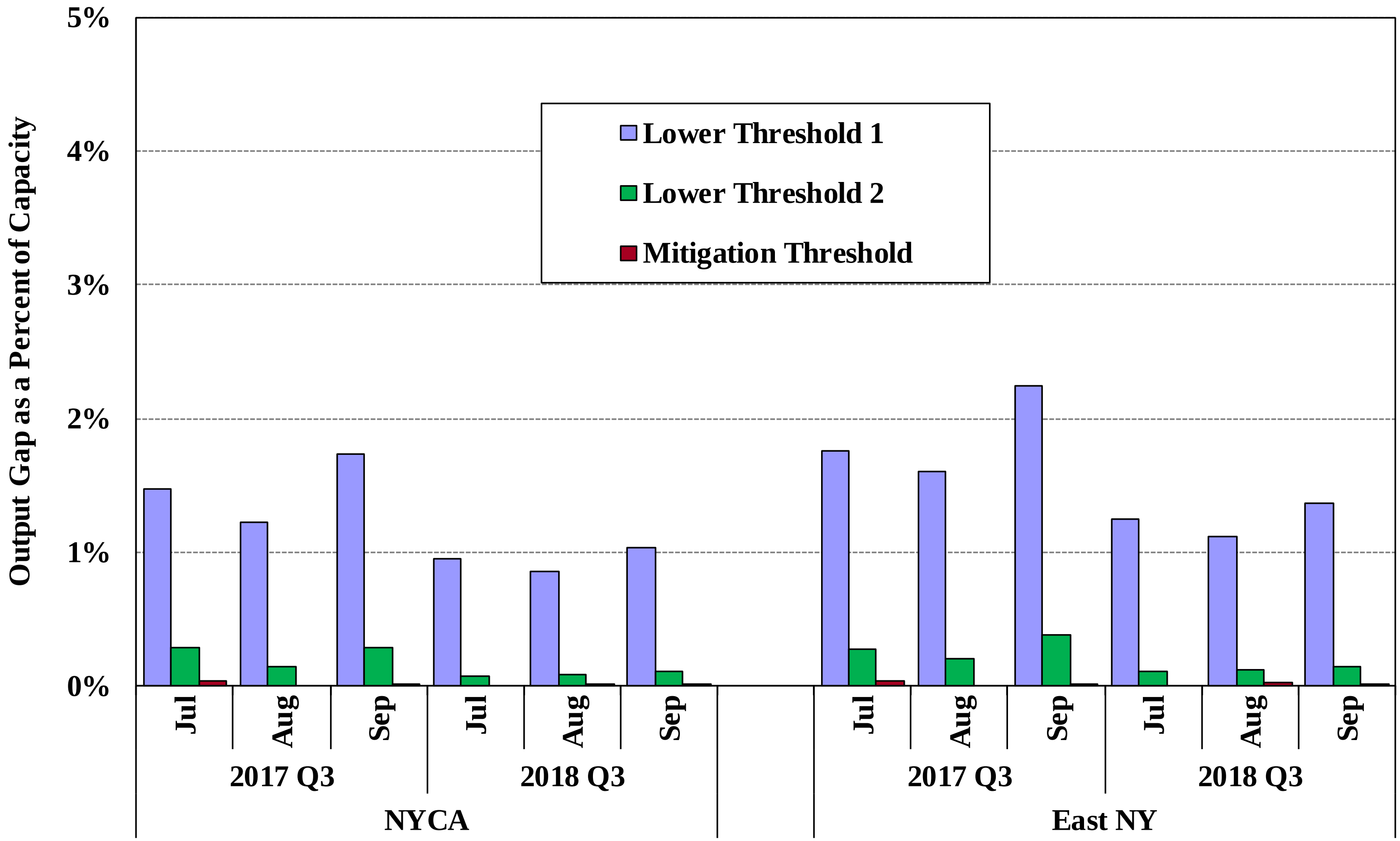
Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2018 Q3	$14.1	$10.8	$0.7	$3.3	$0.2	$4.0
2018 Q2	$6.9	$1.0	$0.7	$1.7	$0.2	$0.0
2017 Q3	$4.4	$2.0	$0.4	$1.6	$0.1	$0.0



Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 87.

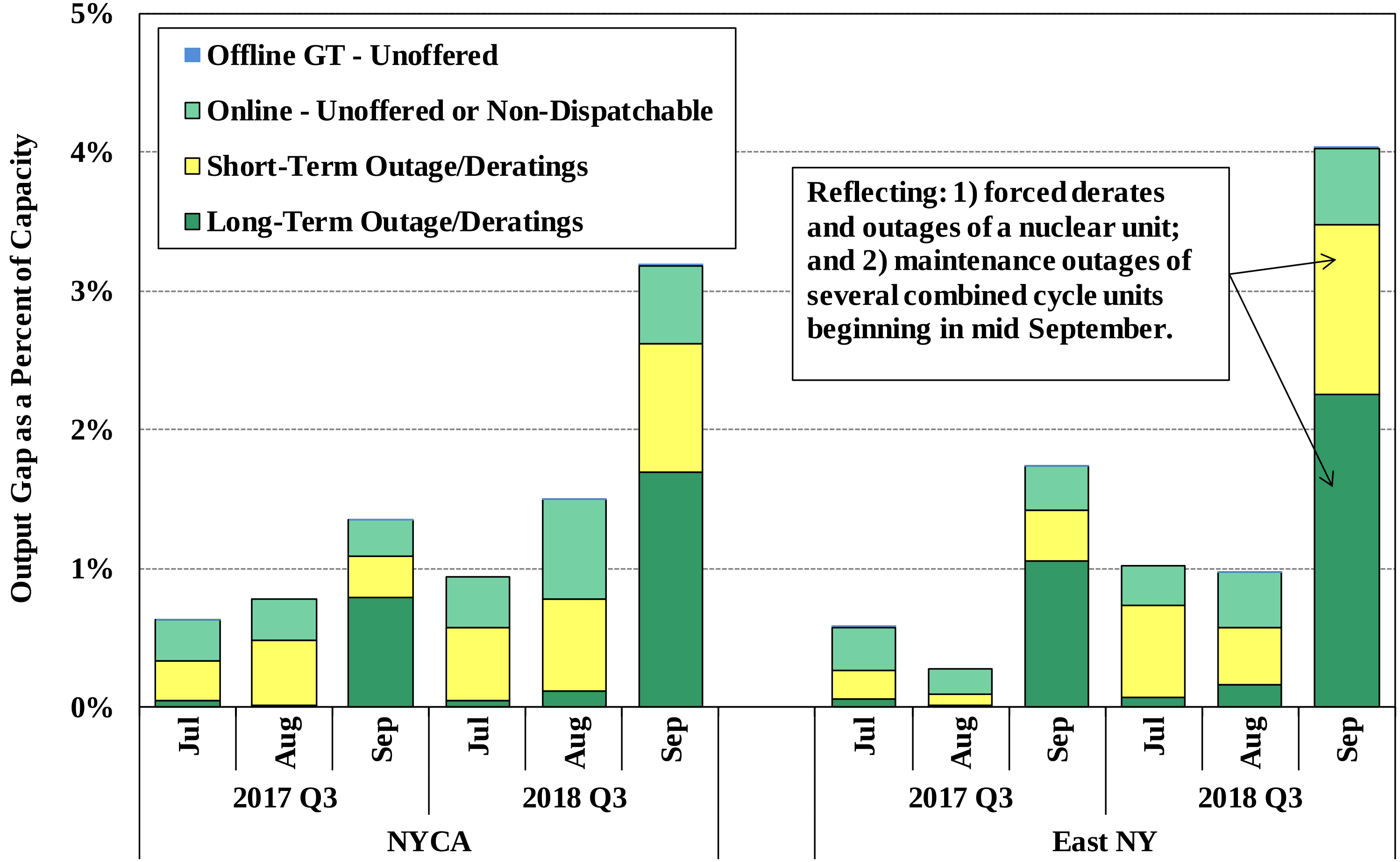
Charts:
Market Power and Mitigation

Output Gap by Month
NYCA and East NY



Notes: 1. Numbers reported here for historical periods may be slightly different from the ones reported previously because of improved assumptions and methodology for the calculation. 2. For chart description, see slide 88.

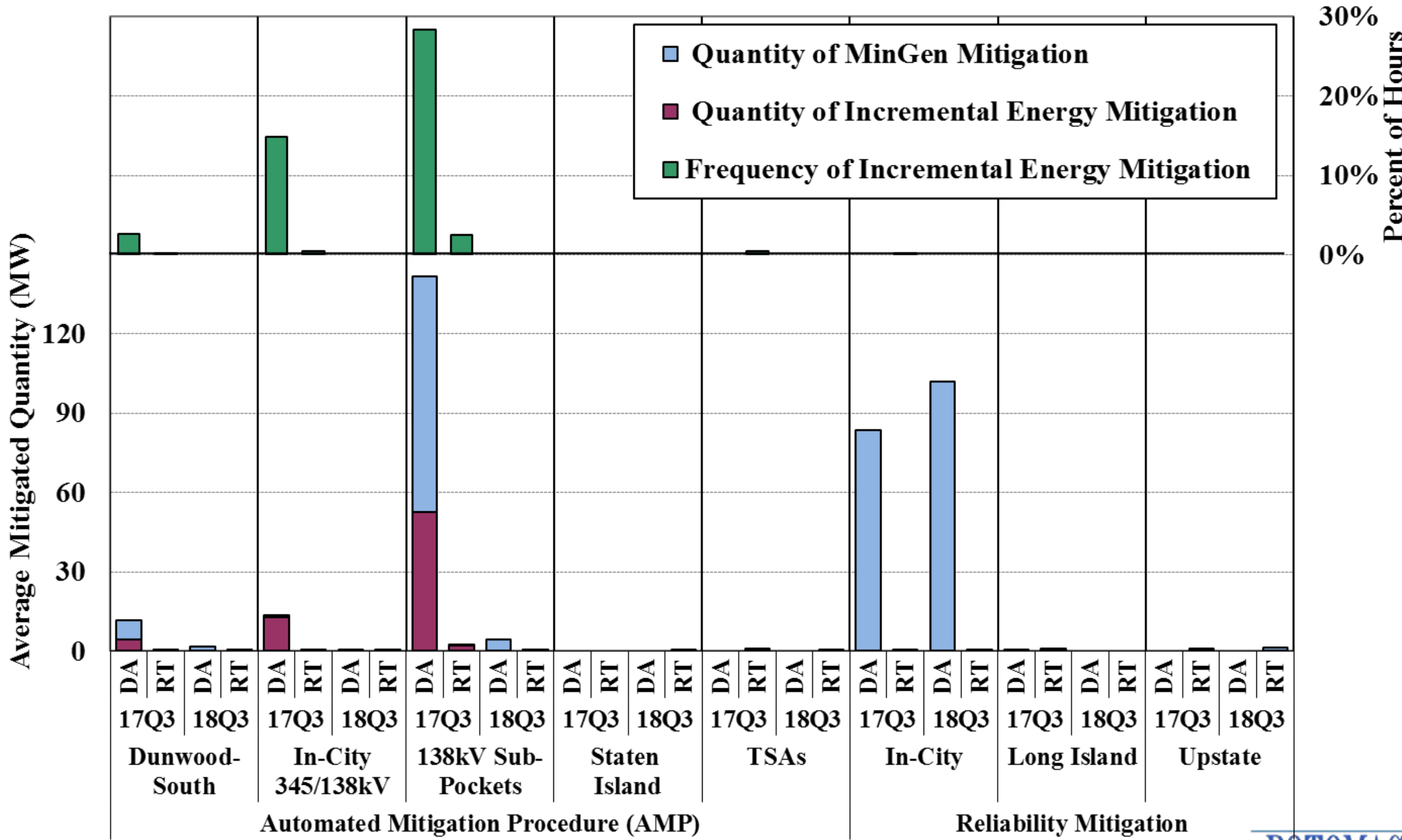
Unoffered Economic Capacity by Month
NYCA and East NY



Notes: 1. Numbers reported here for historical periods may be slightly different from the ones reported previously because of improved assumptions and methodology for the calculation. 2. For chart description, see slide 88.

POTOMAC ECONOMICS

Automated Market Power Mitigation



Notes: For chart description, see slide 89.

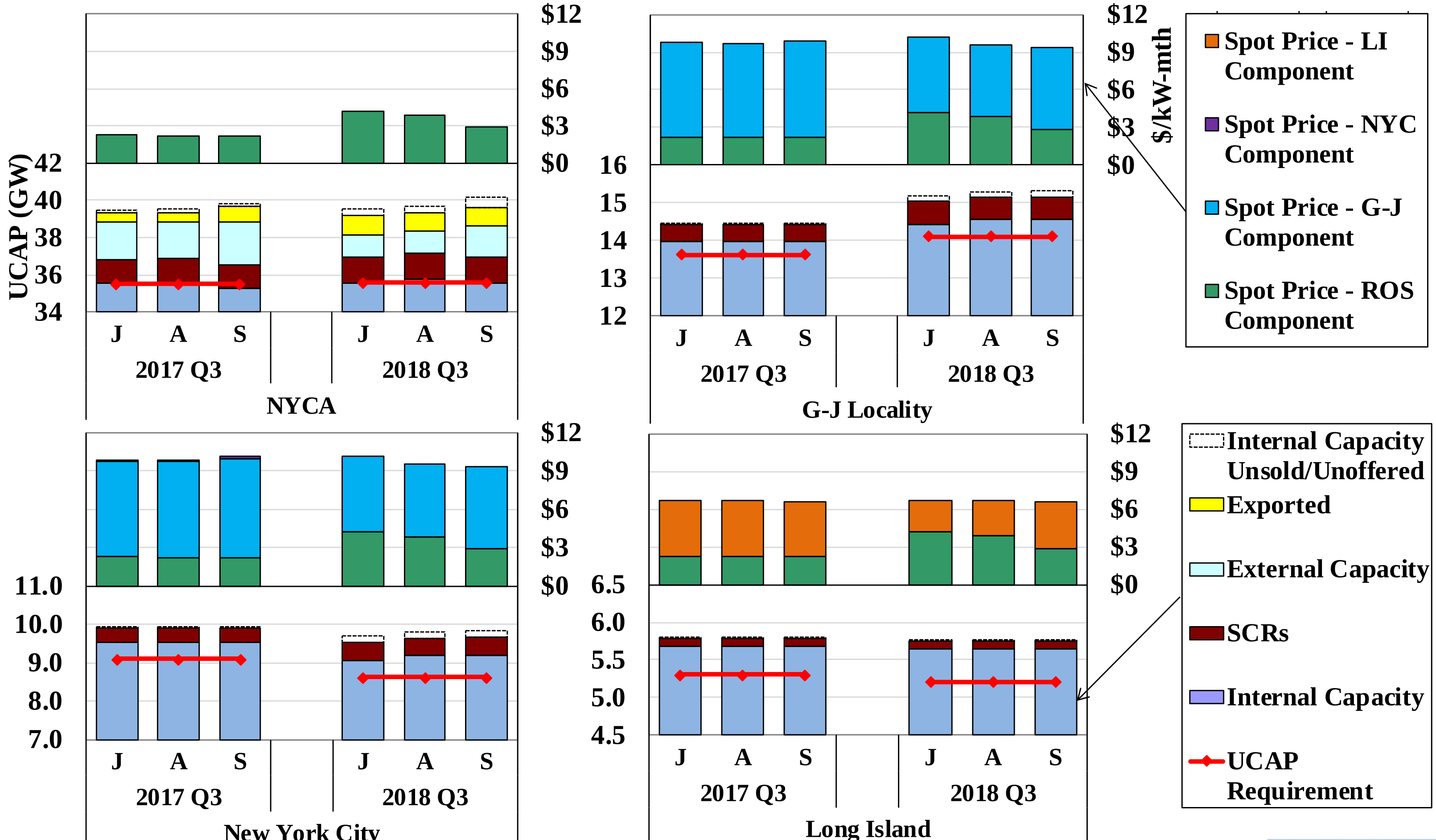
POTOMAC ECONOMICS

<u>Charts:</u>

Capacity Market

POTOMAC ECONOMICS

Spot Capacity Market Results
2017-Q3 & 2018-Q3



Notes: For chart description, see slide 90.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2018 Q3 ($/kW-Month)	$3.66	$9.69	$6.66	$9.69
% Change from 2017 Q3	**66%**	**-3%**	**0.2%**	**-1%**
Change in Demand				
Load Forecast (MW)	-275	-131	-51	-144
IRM/LCR	0.2%	-1.0%	0.0%	3.0%
2018/2019 Summer	*118.2%*	*80.5%*	*103.5%*	*94.5%*
2017/2018 Summer	*118.0%*	*81.5%*	*103.5%*	*91.5%*
ICAP Requirement (MW)	**-259**	**-222**	**-53**	**346**
Key Changes in ICAP Supply (MW)				
Generation	**448**	**-94**	**-19**	**601**
Entry	798	120		798
Exit	-257	-213		-213
DMNC	-93	-1	-19	16
Cleared Import (1)	**-740**			
Change in Demand Curve				
UCAP Based Reference Price @ 100% Req.				
% Change from 2017/2018 Summer	10%	15%	13%	9%

(1) Based on quarterly average cleared quantity.

Notes: For chart description, see slide 90.

POTOMAC ECONOMICS

Appendix: Chart Descriptions

POTOMAC ECONOMICS

All-in Price

- Slide 21 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 24 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 25 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.

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DR Deployment and Scarcity Pricing

- Slides 29, 30, and 31 summarize scarcity pricing outcomes during EDRP/SCR deployments on 7/2, 8/28, and 8/29. The figures report the following in each interval of the events for three regions – NYC, SENY, and NYCA:
  - ✓ Available capacity – Includes three categories of unloaded capacity of online units and the capacity of offline peaking units up to the Upper Operating Limit:
    - 30-Minute Reserves – Scheduled;
    - 30-Minute Reserves – Unscheduled; and
    - Additional Available Capacity (beyond 30-min rampable).
    - Each category is shown for SRE and non-SRE resources separately as well.
  - ✓ EDRP/SCR deployed plus 30-minute reserves requirement (see solid black line).
  - ✓ EDRP/SCR deployed plus 30-minute reserves requirement plus additional Utility DR deployed (see dashed black line).
  - ✓ Constraint shadow prices on the 30-minute reserve requirement in each region.
- Two additional quantities are shown for NYC (which currently has no reserves requirement) on slide 31:
  - ✓ Actual needs for 30-minute reserves (see solid red line); and
  - ✓ Actual needs for 30-minute reserves plus EDRP/SCR deployed plus additional Utility DR deployed (see dashed red line).

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Market Operations and Pricing During NE's Pay-for-Performance Event

- Slides 32 and 33 summarize pricing outcomes and market operations during NE's first pay-for-performance event on 9/3.
- Slide 32 shows the following pricing outcomes in each interval during the event:
  - ✓ The shortage quantity of 30-minute reserves in NY;
  - ✓ The shortage quantity of 30-minute reserves in NE;
  - ✓ The energy price at the Capital Zone;
  - ✓ The energy price at the NE's proxy bus in NY; and
  - ✓ The energy price at the NE Hub plus a PFP rate of $2000/MWh.
  - ✓ An inset figure also shows the 30-minute reserve demand curve for NYCA.
- Slide 33 shows the following quantities in each interval during the event:
  - ✓ The amount of peaking resources that are OOMed by NYISO;
  - ✓ The amount of emergency energy purchase from Ontario;
  - ✓ The amount of curtailed exports (by NYISO) to PJM; and
  - ✓ The unutilized interface transfer capability from Ontario to NY.
    - – This is based on published interface ATC.

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Ancillary Services Prices

- Slides 35, 36, and 37 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 36 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.

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Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 38 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 40 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 41 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 42 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.

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Efficiency of CTS Scheduling with PJM and NE

- Slide 44 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.

Transmission Congestion and Shortfalls

- Slides 46, 47, 48, and 49 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).

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Transmission Congestion and Shortfalls (cont.)

- Slide 46 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 47 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 48 and 49 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.

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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.

NY-NJ PAR Operation Under M2M with PJM

- Slide 50 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).

Constraints on the Low Voltage Network

- Transmission constraints on the 115 kV and lower voltage networks in 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 51 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
  - ✓ Long Island: Mostly constraints on the 69kV system on Long Island.

Constraints on the Low Voltage Network

- Slide 52 shows the number of hours and days in the quarter when various resources were used to manage 69 kV and TVR ("Transient Voltage Recovery") constraints in four local areas of Long Island:
  - ✓ Valley Stream: Mostly constraints around the Valley Stream bus;
  - ✓ Brentwood: Mostly constraints around the Brentwood bus;
  - ✓ East of Northport: Mostly the C._ISLIP-Hauppaug and the Elwood-Deposit circuits;
  - ✓ East End: Mostly the constraints around the Riverhead bus and the TVR requirement.
  - ✓ For a comparison, the tables also show the frequency of congestion management on the 138 kV constraint via the market model.
- Slide 52 also shows our estimated price impacts in each LI load pocket that result from explicitly modeling these 69 kV and TVR constraints in the market software.
  - ✓ The following generator locations are chosen to represent each load pocket:
    - Barrett ST for the Valley Stream pocket;
    - NYPA Brentwood GT for the Brentwood pocket;
    - Holtsville IC for the East of Northport pocket; and
    - Green Port GT for the East End pocket.

N-1 Constraints in New York City

- The NYISO sometimes operates a facility above its Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE.
  - ✓ The use of post-contingency actions is important because it allows the NYISO to increase flows into load centers and reduce congestion costs.
  - ✓ However, the service provided by these actions are not properly compensated.
- Slide 53 shows such select N-1 constraints in New York City. In the figure,
  - ✓ The left panel summarizes their DA and RT congestion values in the quarter.
    - – The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities (i.e., constraint shadow cost*seasonal LTE summed over all intervals); and
    - – The red bars represent the congestion values measured for the additional transfer capability above LTE (i.e., constraint shadow cost*(modeled constraint limit – seasonal LTE) summed over all intervals).
    - – The number stacks show the seasonal LTE ratings of these facilities.
  - ✓ The purple bars in the right panel shows the average additional transfer capability above LTE as a percent of LTE for these facilities (i.e., average modeled constraint limit/seasonal LTE – 100%).

Constraint Limit and CRM in New York

- A Constraint Reliability Margin ("CRM") is a reduction in actual physical limit used in the market software, largely to account for loop flows and other un-modeled factors.
  - ✓ A default CRM value of 20 MW is used for most facilities across the system regardless of their actual physical limits. (Currently, Tariff only allows to use a CRM value of 0 MW or greater than 20 MW on specific constraints)
- Slide 54 summarizes the following quantities for the transmission constraints grouped by facility voltage class and by location:
  - ✓ # of Constraint-Shortage Intervals – the total number of constraint-shortage intervals in each facility group during the quarter.
  - ✓ Avg Constraint Limit – The average transmission limit in each facility group.
  - ✓ Avg CRM – The average CRM MW used in each facility group.
  - ✓ Avg Shortage MW – This includes: a) the average transmission shortage MW that is recognized in the market model; and b) additional shortages when removing the congestion-relief effect from offline GTs.
  - ✓ CRM as % of Limit – The average CRM as a percentage of average limit
  - ✓ These quantities are summarized over real-time transmission shortage intervals and for transmission constraints that have a 20+ MW CRM.

Supplemental Commitments and OOM Dispatch

- Slides 56, 57, and 58 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 56 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 57 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 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.
  - Thermal – If needed for ARR 37 and no other reason.
  - 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, NOx, 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 58 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 59 and 60 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 59 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 60 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 62 and 63 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.

Automated Market Power Mitigation

- Slide 64 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.

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Spot Capacity Market Results

- Slides 66 and 67 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 66 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.
  - ✓ Slide 67 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.