Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2019

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Market Highlights

Market Highlights:
Executive Summary

- All-in prices fell 14 to 42 percent from the third quarter of 2018 due to lower LBMPs and lower capacity costs outside NYC. (see slide 7)
  - ✓ Energy costs fell 22 to 38 percent because of lower gas prices and load levels.
    - – Natural gas prices fell 23 to 31 percent from the previous year in Eastern NY.
    - – Both the peak and average load levels fell 5 percent from the previous year.
- Day-ahead congestion revenues were similar to the third quarter of 2018 despite lower gas price spreads and load levels. (see slides 8-9)
  - ✓ The largest increase occurred along the West to Central Zone Lines ($23 million) due to increased congestion along the Scriba-Volney 345 kV line.
    - – Limited transfer capability out of the generation pocket frequently constrained otherwise economic output from baseload nuclear and thermal units.
  - ✓ Congestion fell in NYC ($11 million) and Long Island ($18 million):
    - – Lower load levels eased congestion especially on Eastern Long Island.
    - – Fewer significant transmission outages contributed to reduced congestion in NYC.
  - ✓ The West Zone continued to account for the largest share ($33 million) primarily because of congestion on the 115kV system.

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Market Highlights:
Executive Summary

- The NYISO has greatly reduced the use of OOM actions to manage low-voltage transmission constraints by modeling most 115kV constraints in the DA and RT market models. (see slide 11)
  - ✓ However, we observed frequent OOM actions (on 63 days) to manage low-voltage constraints in Long Island.
- West Zone constraints were difficult to manage primarily because volatile loop flows lead to unforeseen periods of severe congestion (see slides 8, 9, 13, 14).
  - ✓ The NYISO made several modeling enhancements that reduced volatility.
  - ✓ We recommend changes in RTC to better account for loop flow variations.
- NYC reserve requirements were implemented on June 26, including 500 MW of 10-minute reserves and 1000 MW of 30-minute reserves. (see slides 15, 16)
  - ✓ These requirements represent some of the local reliability needs that lead to frequent supplemental commitment and out-of-market compensation.
  - ✓ These market requirements led to modest DA & RT price increases and BPCG reductions during the quarter.
  - ✓ OOM commitments were still frequently needed to maintain adequate operating reserves in NYC load pockets. (see slide 12)

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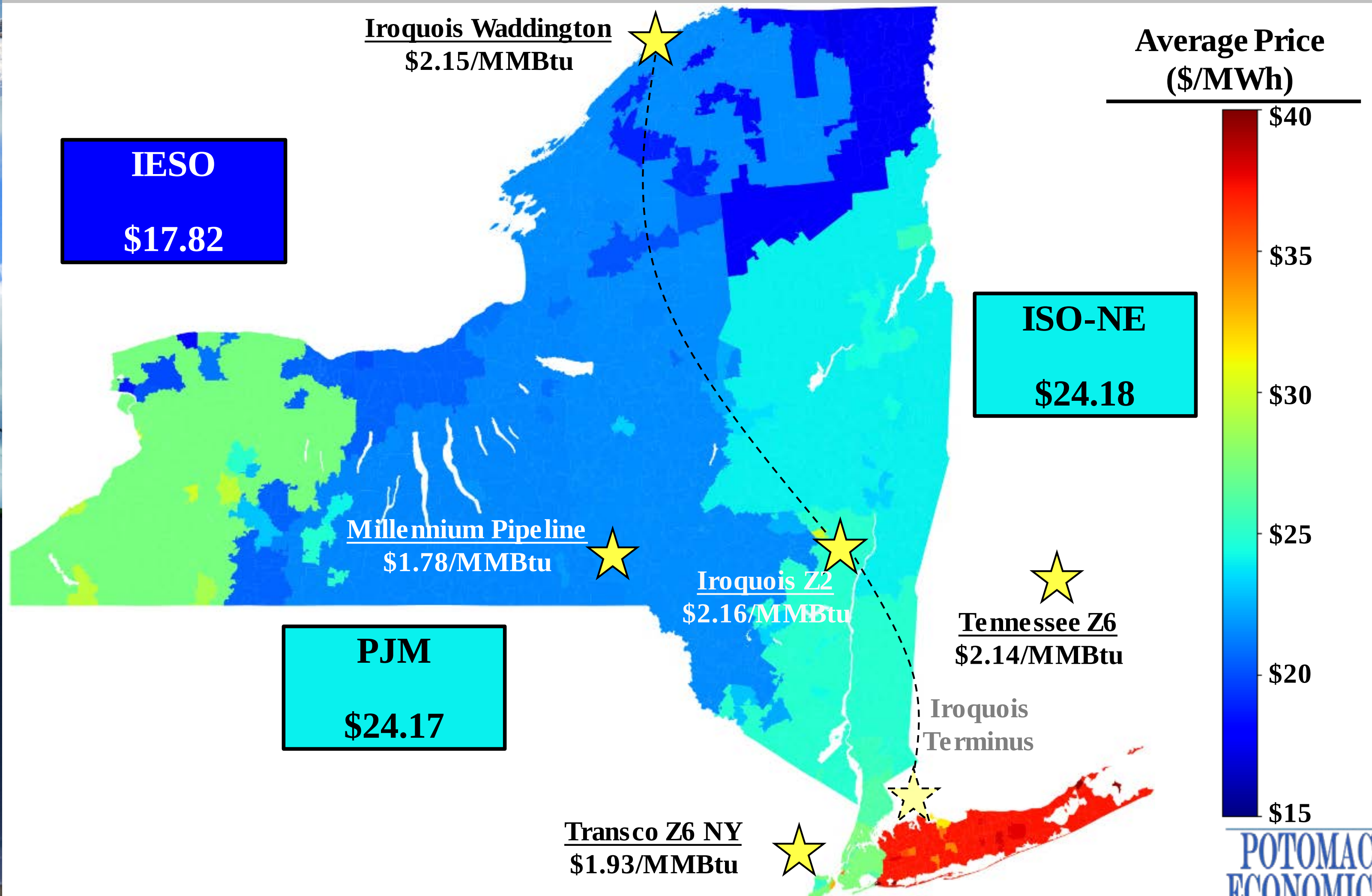
Highlights and Market Summary: Energy Market Outcomes and Congestion



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Market Highlights:

Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the third quarter of 2019.
  - ✓ Variations in regional wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
  - ✓ The amount of output gap (slide 65) and unoffered economic capacity (slide 66) remained modest and reasonably consistent with competitive market expectations.
- Average all-in prices fell in all areas and ranged from $22/MWh in the North Zone to $57/MWh in New York City, down 14 to 42 percent from a year ago. (slide 22)
  - ✓ Energy prices fell in most areas by 22 to 38 percent. (slides 27-28)
    - – Average natural gas prices fell between 23 and 31 percent from a year ago in Eastern NY (slide 24) partly due to higher storage levels.
    - – Peak and average load levels fell 5 percent from a year ago (slide 23).
    - – Nuclear and hydro generation rose by an average of 730 MW (slide 25) from a year ago, contributing to the decrease in LBMPs.
    - – Gas-fired generation in the Hudson Valley increased an average of 420 MW (slide 25) from the previous year reflecting increased operation of the CPV Valley plant.
  - ✓ Capacity costs rose by 27 percent in New York City but fell 14 to 61 percent in other regions for the reasons discussed in slide 20.

Market Highlights: Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $127 million, comparable to the third quarter of 2018 despite decreased load and energy prices. (slide 46)
  - ✓ Most transmission paths exhibited less congestion, but this was offset by higher congestion in the West Zone and on West-to-Central paths. (slide 47)
- West Zone lines accounted for the largest share of congestion (26 percent in DA, 27 percent in RT) in the third quarter of 2019 (slide 47).
  - ✓ High levels of congestion across the West Zone are driven by:
    - The low marginal cost of renewable generation at Niagara and in Ontario; and
    - Volatile loop flows around Lake Erie can shift quickly in the clockwise direction.
  - ✓ Priced congestion across the West Zone rose from the previous year because:
    - 115 kV constraints were previously managed using OOM actions and surrogate transmission constraints, but most of these constraints have been incorporated into the DA and RT markets since December 2018.
      - 115 kV constraints accounted for most (~75 percent) of priced congestion in the West Zone.
      - OOM actions to manage West Zone congestion fell dramatically (slide 52), which has improved scheduling efficiency in this area.

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

- West Zone 115 kV constraints are currently not included in the M2M process with PJM, so the A, JK, and Ramapo PAR-controlled lines are not used to relieve congestion on these lines.
  - These PAR-controlled lines frequently aggravated West Zone congestion, and they accounted for 44 percent of the balancing congestion shortfalls for West Zone constraints in this quarter. (slide 49)
  - The NYISO is working with PJM to incorporate these 115 kV constraints into the M2M process.

- West-to-Central congestion increased considerably (slide 47), reflecting frequent congestion of Scriba-to-Volney 345 kV lines, which limit generation from the Oswego Complex.
- NYC and Long Island congestion fell 35 and 52 percent, respectively (slide 47), leading to a combined $28 million reduction in day-ahead congestion revenues.
  - ✓ This reduction resulted primarily from lower gas prices and summer load conditions.
  - ✓ Fewer costly transmission outages in NYC was a significant contributing factor.
    - One Dunwoodie-Motthaven 345 kV line (“71 Line”) was OOS during the entire quarter of 2018-Q3 but was in service in 2019-Q3.

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Market Highlights:
RT Congestion Value for Key Constraints and Impacts on West Zone LBMPs

- Congestion patterns in the West Zone have led to wide variations in LBMPs across the zone. For example:
  - ✓ The Niagara generating plant's LBMP averaged less than $17/MWh during the quarter; and
  - ✓ The Steel Wind and Erie Wind LBMPs averaged more than $28/MWh.
- The five paths highlighted in slide 50 accounted for more than 90 percent of the RT congestion value during the quarter.
  - ✓ These paths were frequently congested between Niagara and the Buffalo area.
  - ✓ This led to lower prices on the north side of Buffalo and higher prices on the south side.
- The Empire State Line project was selected in the Public Policy Transmission Planning process to relieve congestion in the West Zone.
  - ✓ The project includes construction of a 345 kV line, which will run from north to south on the east side of Buffalo.
  - ✓ The line will allow some power to bypass the highlighted paths and significantly reduce congestion.

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Market Highlights:
OOM Actions to Manage Congestion

- The NYISO has greatly reduced the use of OOM actions over the last year to manage low-voltage transmission constraints by modeling most 115kV constraints in the DA and RT market models.
- OOM actions to manage lower-voltage network congestion were most frequent in Long Island (63 days), the North (10 days), and Central NY (8 days). (slide 52)
  - ✓ On Long Island, OOM actions were used to manage 69 kV constraints of west-to-east lines East of Northport and TVR constraints on the East End. (slide 53)
- Although Ontario imports were never limited to manage unmodeled transmission constraints, the NYISO limited Ontario imports on three days to help manage constraints on facilities that are modeled in the DAM & RTM.
  - ✓ An "operating exception" allows the Niagara 230kV exit facilities to be operated to STE (instead of LTE) when there is sufficient generation on at Niagara to clear the overload.
  - ✓ Thus, reducing Ontario imports ensured the operating exception could be utilized, although verbal instructions to Niagara would have been more direct.

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $17.7 million, down 43 percent from the third quarter of 2018 (slides 62-63).
- Roughly $7 million (or 41 percent) of BPCG payments accrued in NYC. (slide 63)
  - ✓ About $5.6 million was paid to units that were committed for local reliability needs.
  - ✓ We have recommended that the NYISO satisfy the reliability needs that drive these out-of-market costs with local reserve requirements in the DA & RT markets.
    - – The NYISO began to model reserve requirements for the NYC Zone in the DA and RT markets on June 26, 2019. This is an important step to reduce supplemental reliability commitments and to improve the efficiency of scheduling and pricing.
- Long Island BPCG payments were about $8.4 million (48 percent) this quarter, down 22 percent from a year ago. (slide 63)
  - ✓ Most of this uplift was incurred to manage transient voltage reliability needs and reliability and congestion on the 69kV network. (slides 53, 61)
  - ✓ We have recommended that the NYISO model the 69-kV system on Long Island to provide better price signals for commitment and investment. (slide 53)

Market Highlights:
West Zone Congestion Management

- West Zone constraints were hard to manage despite recent modeling enhancements
  - ✓ The closure of the South Ripley-to-Dunkirk line has increased flows significantly across the West Zone, particularly during periods with high clockwise loop flow.
  - ✓ Thermal rating exceedance on facilities connected to the Niagara 230 kV bus accounted for 52 percent of the NYISO's Alert State Declarations in Q3.
- When physical (i.e., EMS) flows exceed flows considered by the scheduling models (i.e., BMS flows) by a significant margin, the NYISO reduces scheduling (i.e., BMS) limits to ensure flows remain at acceptable levels.
  - ✓ Consistency between EMS and BMS flows is desirable because it generally results in more efficient scheduling by RTC and RTD.
  - ✓ The NYISO has taken steps to reduce EMS-BMS differences on West Zone facilities, including allowing more accurate assumptions:
    - In RTD regarding clockwise changes in loop flows around Lake Erie ("LEC") starting in July; and
    - In RTD and RTC regarding the flexibility of the St. Lawrence PARs in August.
    - NYISO continues to work with NYPA to ensure that Niagara output is distributed efficiently to minimize congestion (includes 900+ hours of verbal instructions to the plant that convey the redistribution recommended by BMS in Q3).

Market Highlights:
West Zone Congestion Management (cont.)

- Our past reports have shown a strong correlation between the severity of West Zone congestion and the magnitude and volatility of Lake Erie loop flows.
  - ✓ Unforeseen loop flow variations in the clockwise direction around Lake Erie can lead to severe congestion.
  - ✓ RTC and RTD schedule resources using an assumed LEC level, which is equal to the observed level of LEC when the model initializes (although this is set to 0 MW in RTC whenever LEC is observed to be counter-clockwise). (see slide 57)
  - ✓ We have recommended the NYISO adjust the LEC assumption in RTC to account for the fact that over-estimates of loop flows are generally less costly on average than under-estimates of loop flows. (see SOM Recommendation #2014-9)
- We analyzed variations in LEC and congestion between the initialization times of RTC and RTD to estimate how the assumed LEC in RTC could be adjusted to minimize inconsistencies between RTC and RTD. (slides 56-57) We find that:
  - ✓ Congestion price inconsistency between RTC and RTD increases with the difference in LEC assumptions between RTC and RTD.
    - – However, price inconsistencies are larger when LEC is higher in RTD.
  - ✓ We find that it would be beneficial to adjust the assumed level of LEC in RTC in the clockwise direction under most conditions.

Market Highlights:

New York City Reserve Requirements

- The NYISO started to model two reserves requirements in NYC on June 26. As a result, in the third quarter of 2019:
  - ✓ The 10-minute spin and non-spin reserve prices in NYC were higher than in the rest of SENY by an average of $0.50/MWh in DAM and $0.45/MWh in RTM; and
  - ✓ The 30-minute reserves prices in NYC were higher than in the rest of SENY by an average of $0.03/MWh in DAM and $0.15/MWh in RTM. (slides 31-35)
  - ✓ Accordingly, day-ahead net reserve revenues for NYC reserve providers were roughly $460K higher than otherwise would have resulted at SENY prices.
    - – This increase led to a reduction in DA BPCG uplift, which was lowered by an estimated $100K (22 percent of the increase in net reserve revenues) this quarter.
    - – This increase will lead to additional net energy and ancillary services revenues for NYC resources as well as the Capacity Demand Curve unit.
      - This will also lead to lower capacity prices.
  - ✓ However, these estimated changes in revenues and costs do not consider changes in offer behavior and congestion patterns.
    - – Day-ahead reserve offers in NYC rose modestly from prior periods, although NYC reserve clearing prices were determined primarily by the opportunity costs of not being scheduled for energy. (slide 38)

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Market Highlights:
New York City Reserve Requirements (cont.)

- NYC experienced RT reserve shortages in 265 intervals in the third quarter.
  - ✓ Roughly 80 percent of these intervals coincided with TSA events. (slide 36)
  - ✓ The shortages were moderate in most intervals, averaging roughly 165 MW.
  - ✓ There was sufficient unused transfer capability in most shortage intervals to satisfy the need for NYC reserves.
- Dynamic reserve requirements are needed to schedule resources efficiently during many operating conditions such as TSAs.
  - ✓ We have recommended this in our SOM Reports (see #2015-16).
- Increasing the demand curve from the current $25/MWh level would lead to inappropriately high RT prices and inefficient scheduling until dynamic reserve modeling can be implemented.
  - ✓ After the implementation of dynamic reserve requirements, the NYC reserve demand curves could be increased to levels that reflect appropriate shortage pricing.

Market Highlights:
Impact of Securing In-Series Line Segments

- A number of facilities representing in-series segments of the same transmission line were secured in the market models.
  - ✓ This led to increased congestion prices when multiple in-series segments were priced simultaneously by the GTDC. (see Dave Edelson 9/10 MIWG Presentation)
  - ✓ To address this, the NYISO removed all but one of the segments for each of 21 transmission lines from the market models, effective September 24, 2019.
  - ✓ We support the removal of these additional in-series segments because it can lead to excessively large shortage pricing outcomes.
- We have estimated the market impact of securing multiple in-series portions of line segments in 2019 prior to September 24. (slide 55)
  - ✓ Seven of the 21 transmission lines showed excessive shortage pricing outcomes in 990 real-time intervals.
  - ✓ The line segments in the removal list accounted for $16M of RT congestion value, $1M balancing congestion shortfalls, and affected LBMPs by an average from negative $0.07/MWh in Zone B to $0.36/MWh in Zone A.
  - ✓ The Packard-Erie St 115 kV line ("181-922 line") accounted for the vast majority of the occurrences and the resulting impact.

Market Highlights:
Utility Demand Response Activations

- Utility DR program resources were activated on 15 days during the quarter, although the quantity exceeded 100 MW on just five days.
  - ✓ Resources were activated for peak-shaving and distribution system security mostly in New York City.
  - ✓ The statewide quantity ranged to nearly 600 MW on July 19 (when NYCA peak demand was roughly 30 GW).
- The capacity of utility-activated DR is not considered in DA load forecasts, which can lead to excessive reliability commitments.
  - ✓ It is unclear whether this led to excess reliability commitments on these days.
- Utility DR was activated on days when the economics of the energy market did not indicate a need for peak load reduction.
  - ✓ Utility DR resources are paid primarily for availability (including capacity).
  - ✓ Utility programs often provide large payments (~$1,000/MWh) for peak-shaving when it is not cost-effective.

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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.
- In 2019-Q3, 46 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 54)
  - ✓ The additional capability above LTE averaged from about 10 to 65 MW for the 138 kV constraints in the Greenwood load pocket to roughly 150 to 235 MW for 345 kV facilities in other NYC load pockets.
    - – These increases were largely due to operating reserve providers in NYC, but these units are not compensated for this service, which 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 2018 SOM report)

Market Highlights:
Capacity Market

- Average spot capacity prices ranged from $1.37/kW-month in ROS to $13.40/kW-month in New York City in the third quarter of 2019. (slides 69-70)
- Compared to a year ago, average spot prices fell 63 percent in ROS, 50 percent in the G-J Locality, and 15 percent in Long Island; however, NYC spot prices rose 38 percent.
  - ✓ Demand-side drivers of capacity price changes include:
    - Peak load forecasts fell in all regions except for NYC, where an increase in the load forecast increased the overall requirement by 0.6 percent.
    - LCRs increased in NYC (2.3 percent) and Long Island (0.6 percent) but decreased in the G-J Locality (2.2 percent) and NYCA (1.2 percent).
  - ✓ On the supply side:
    - Up-rates and other DMNC changes increased capacity NYCA-wide by 27 MW, but there was 130 MW net less imports from the prior year.
    - Hudson Ave GT4 left the market via IIFO designation.
    - Arthur Kill Cogen entered the market earlier in 2019 adding a small amount of capacity to NYC.

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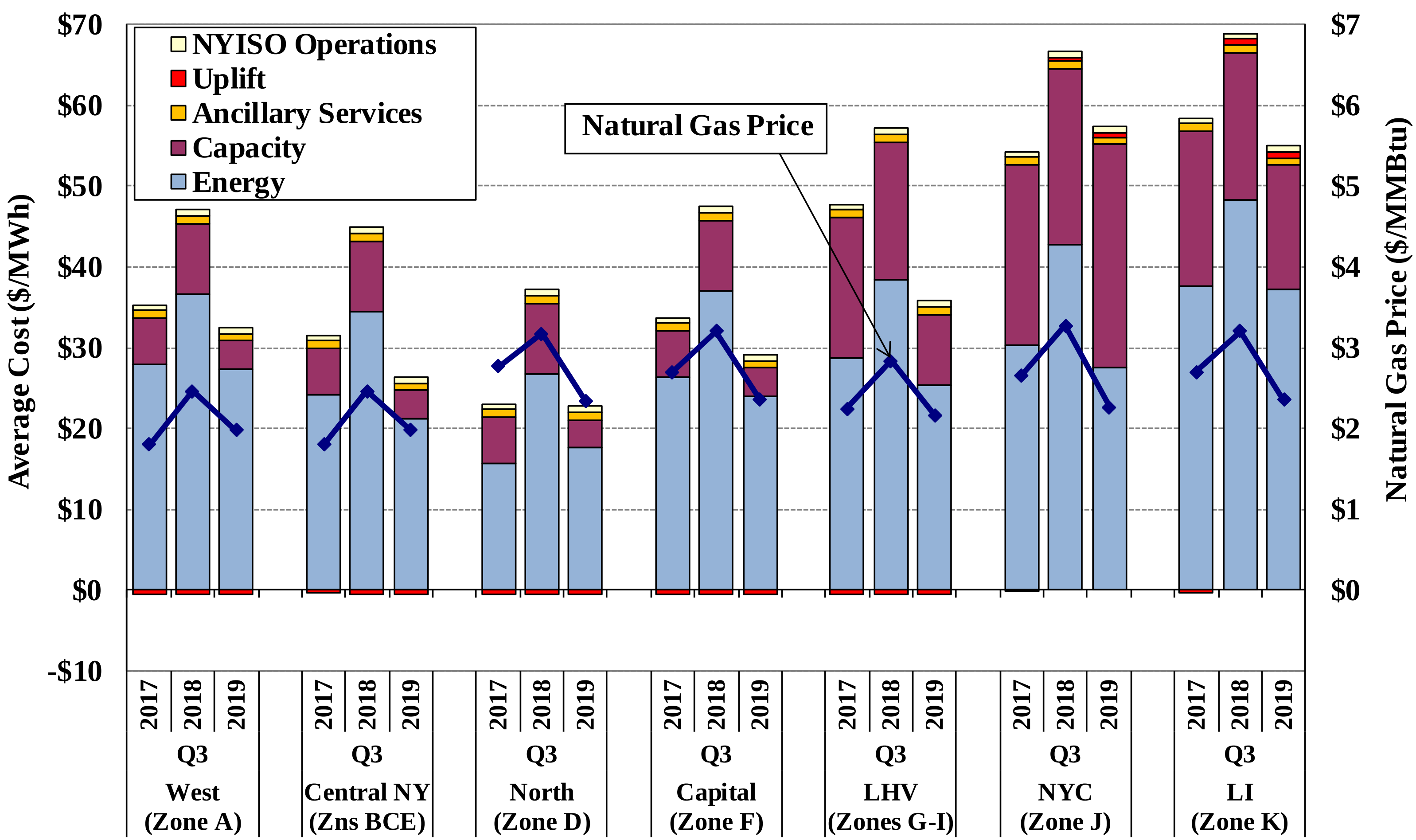
Charts:

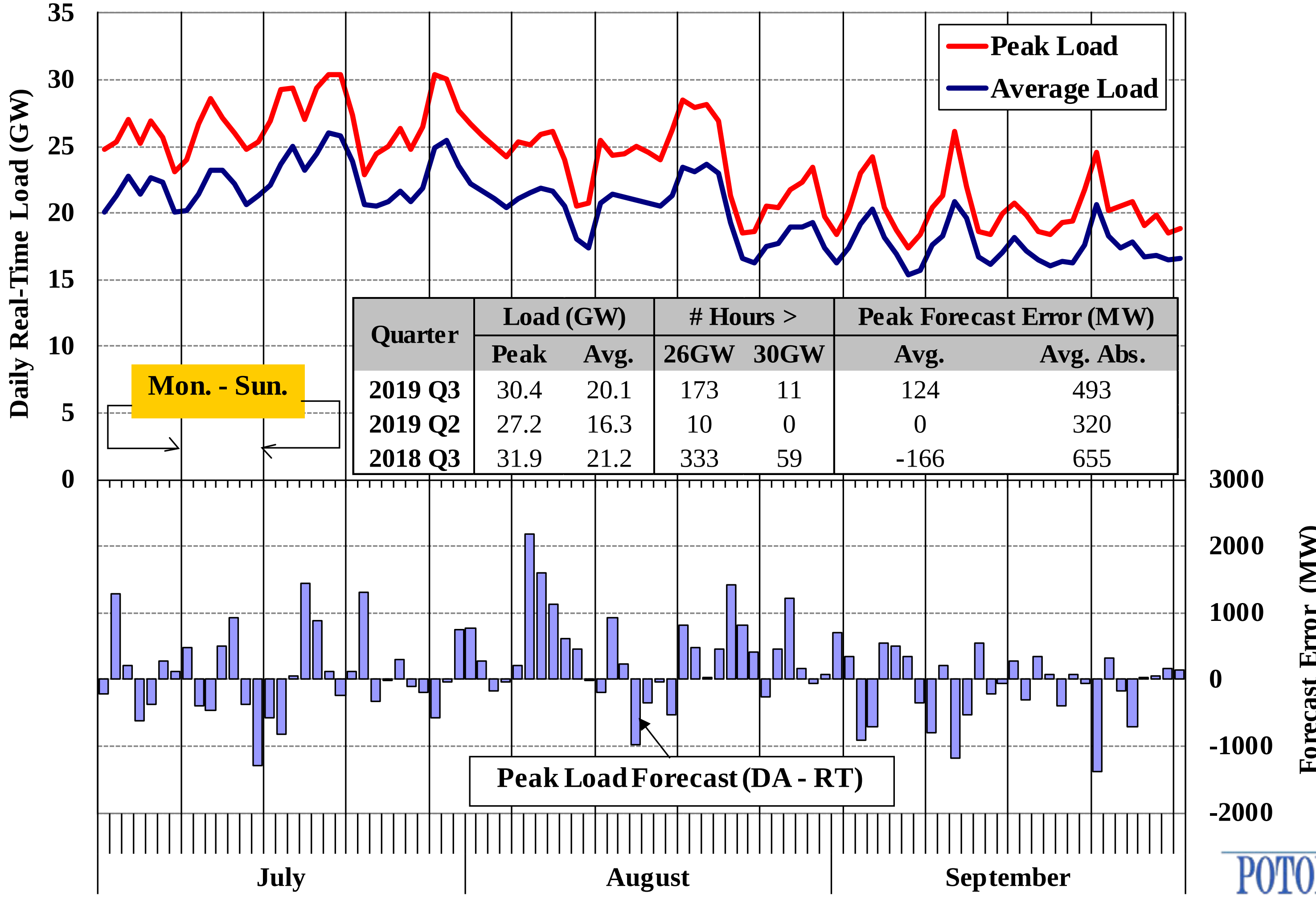
Market Outcomes

All-In Prices by Region



Notes: For chart description, see slide 72.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2019 Q3	30.4	20.1	173	11	124	493
2019 Q2	27.2	16.3	10	0	0	320
2018 Q3	31.9	21.2	333	59	-166	655

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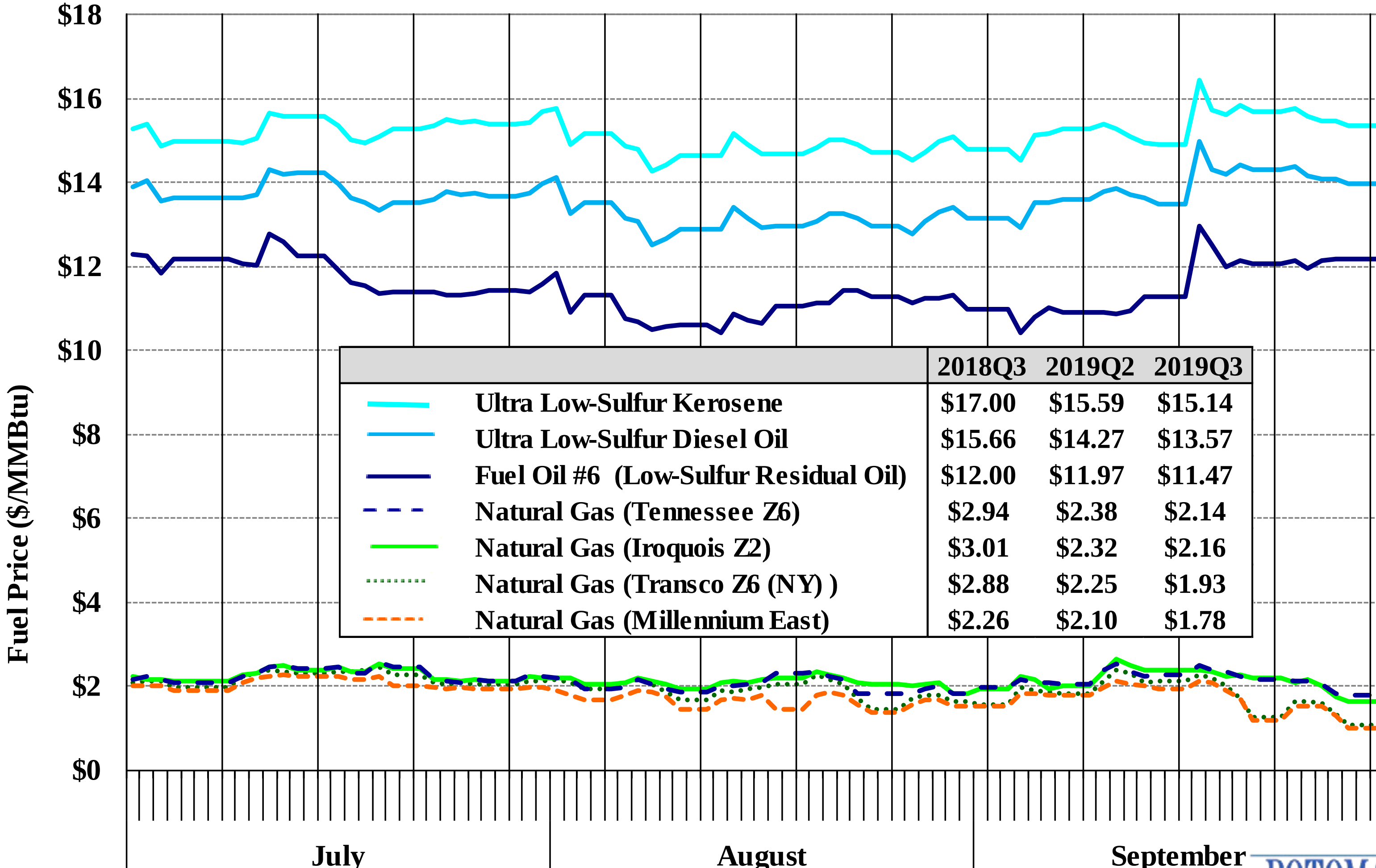
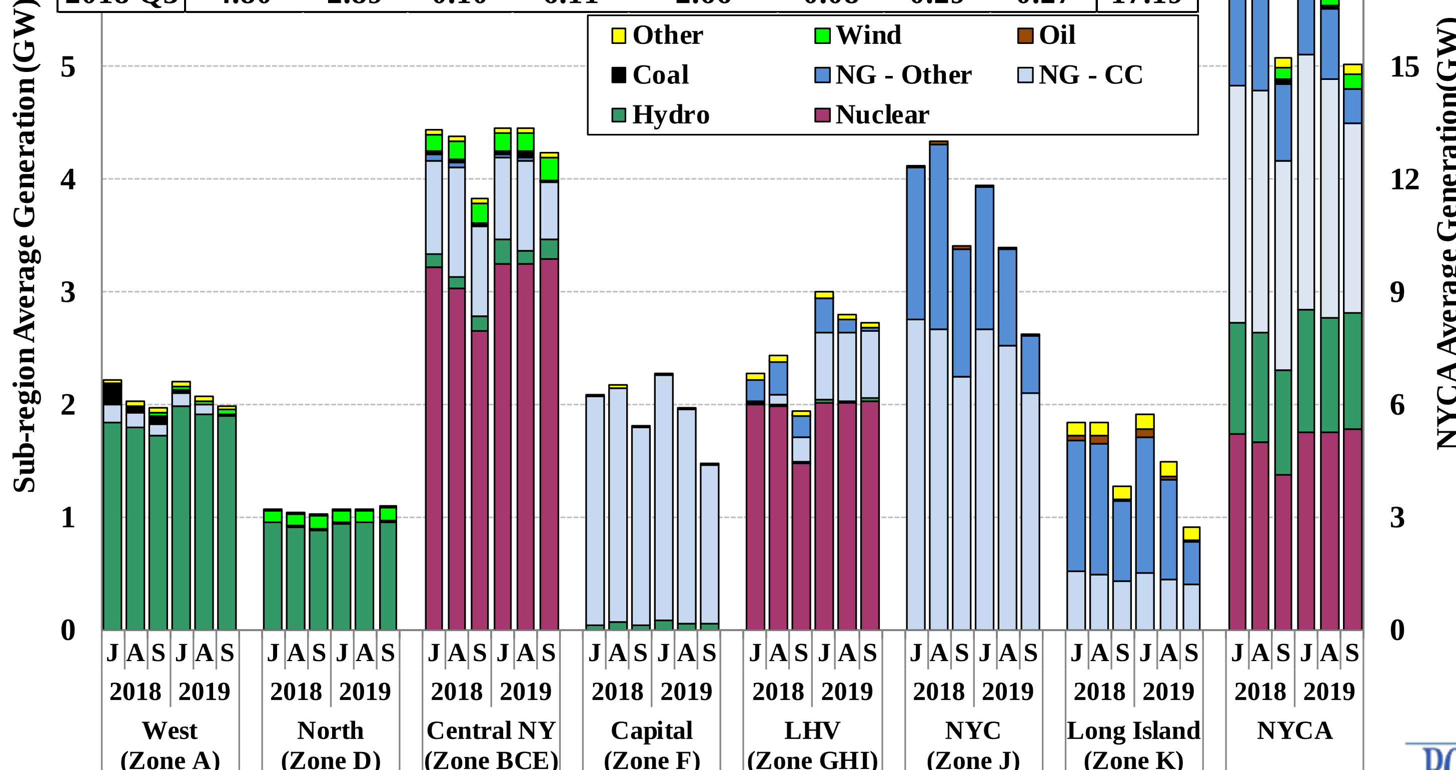
Natural Gas and Fuel Oil Prices



	2018Q3	2019Q2	2019Q3
Ultra Low-Sulfur Kerosene	$17.00	$15.59	$15.14
Ultra Low-Sulfur Diesel Oil	$15.66	$14.27	$13.57
Fuel Oil #6 (Low-Sulfur Residual Oil)	$12.00	$11.97	$11.47
Natural Gas (Tennessee Z6)	$2.94	$2.38	$2.14
Natural Gas (Iroquois Z2)	$3.01	$2.32	$2.16
Natural Gas (Transco Z6 (NY))	$2.88	$2.25	$1.93
Natural Gas (Millennium East)	$2.26	$2.10	$1.78

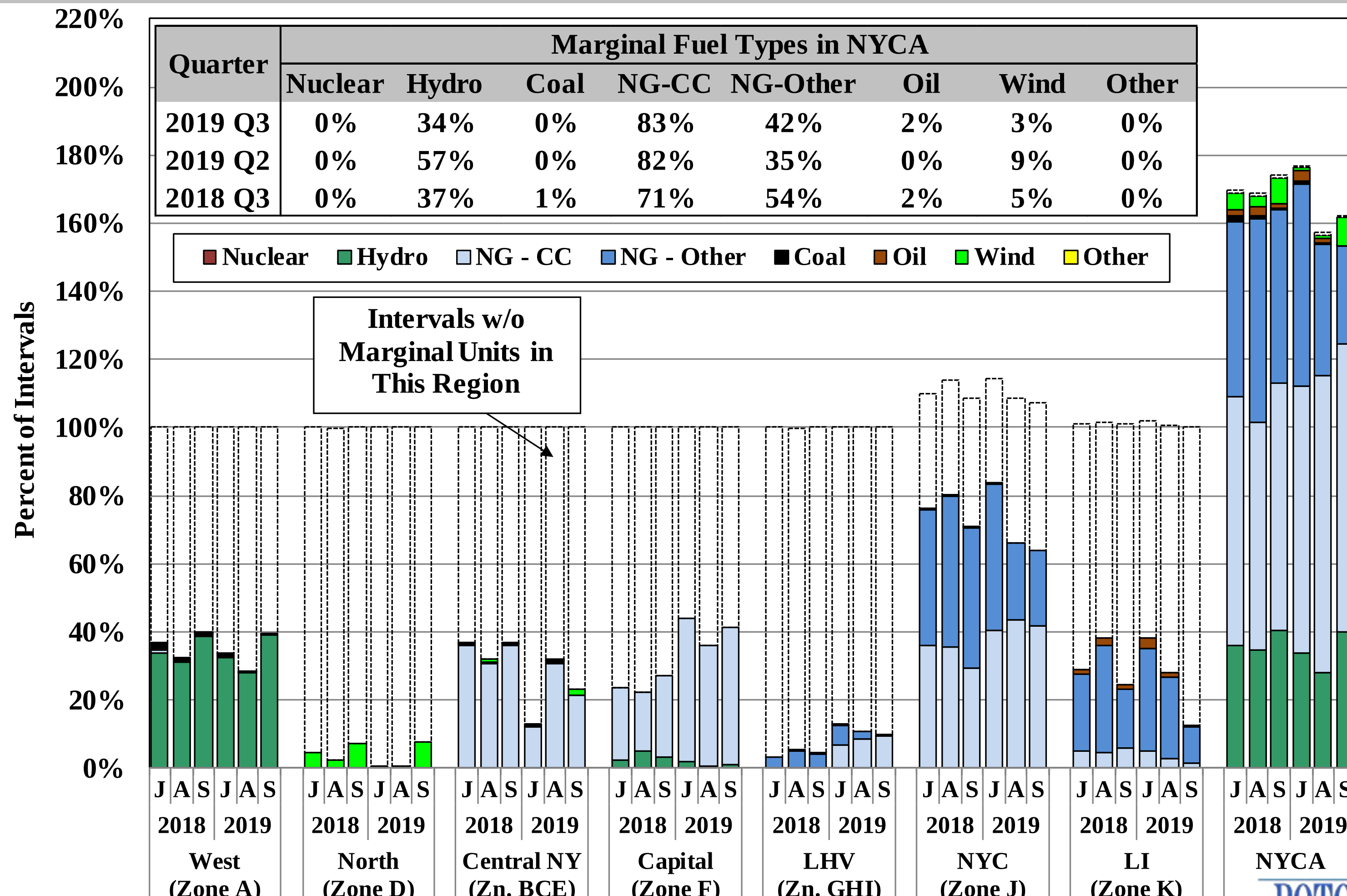
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2019 Q3	5.28	3.15	0.04	6.07	1.88	0.05	0.32	0.27	17.04
2019 Q2	4.96	3.38	0.00	3.91	0.80	0.01	0.48	0.24	13.78
2018 Q3	4.80	2.89	0.10	6.11	2.66	0.08	0.29	0.27	17.19



Notes: For chart description, see slide 73.

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
2019 Q3	0%	34%	0%	83%	42%	2%	3%	0%
2019 Q2	0%	57%	0%	82%	35%	0%	9%	0%
2018 Q3	0%	37%	1%	71%	54%	2%	5%	0%

Notes: For chart description, see slide 73.

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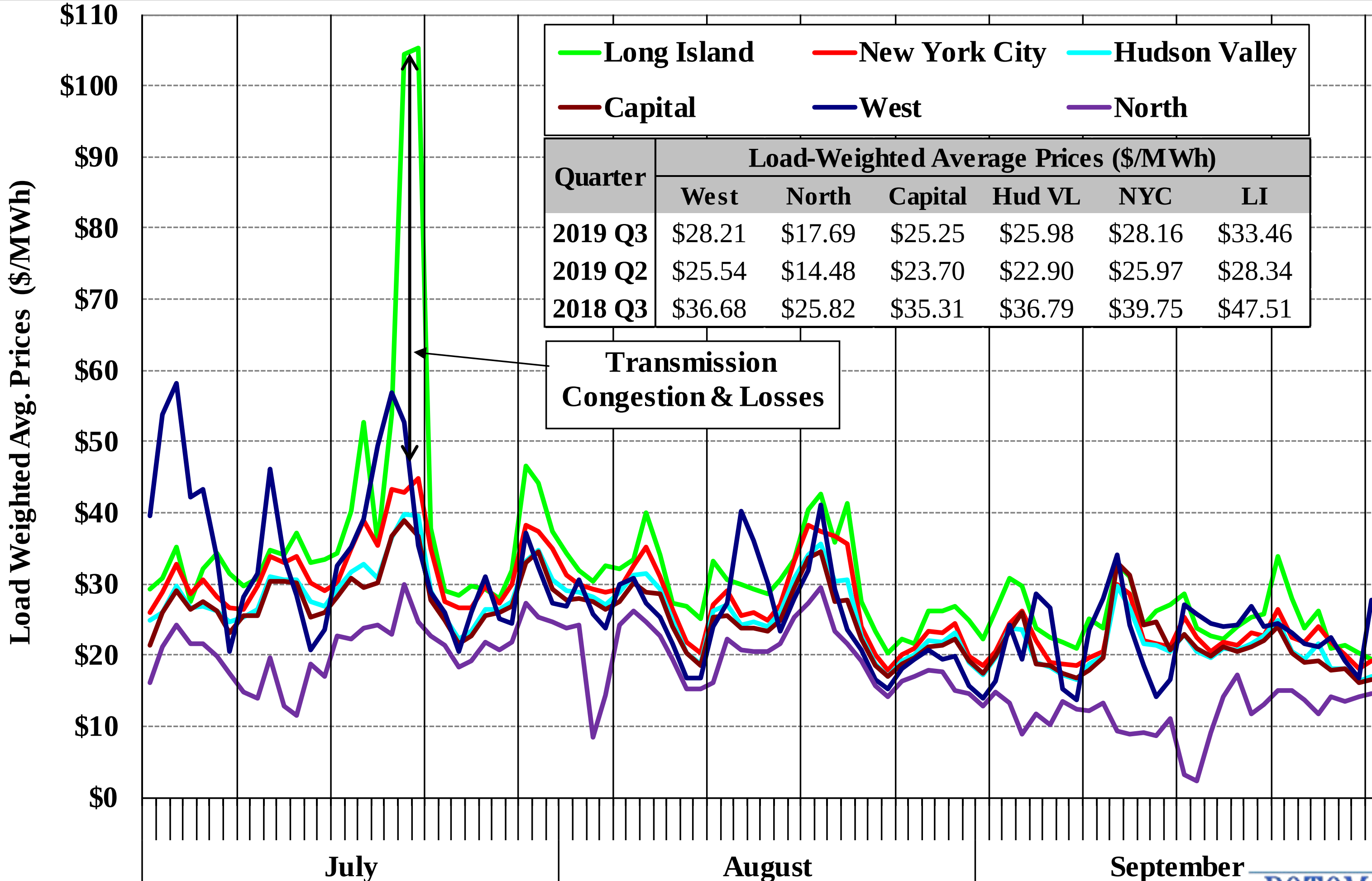
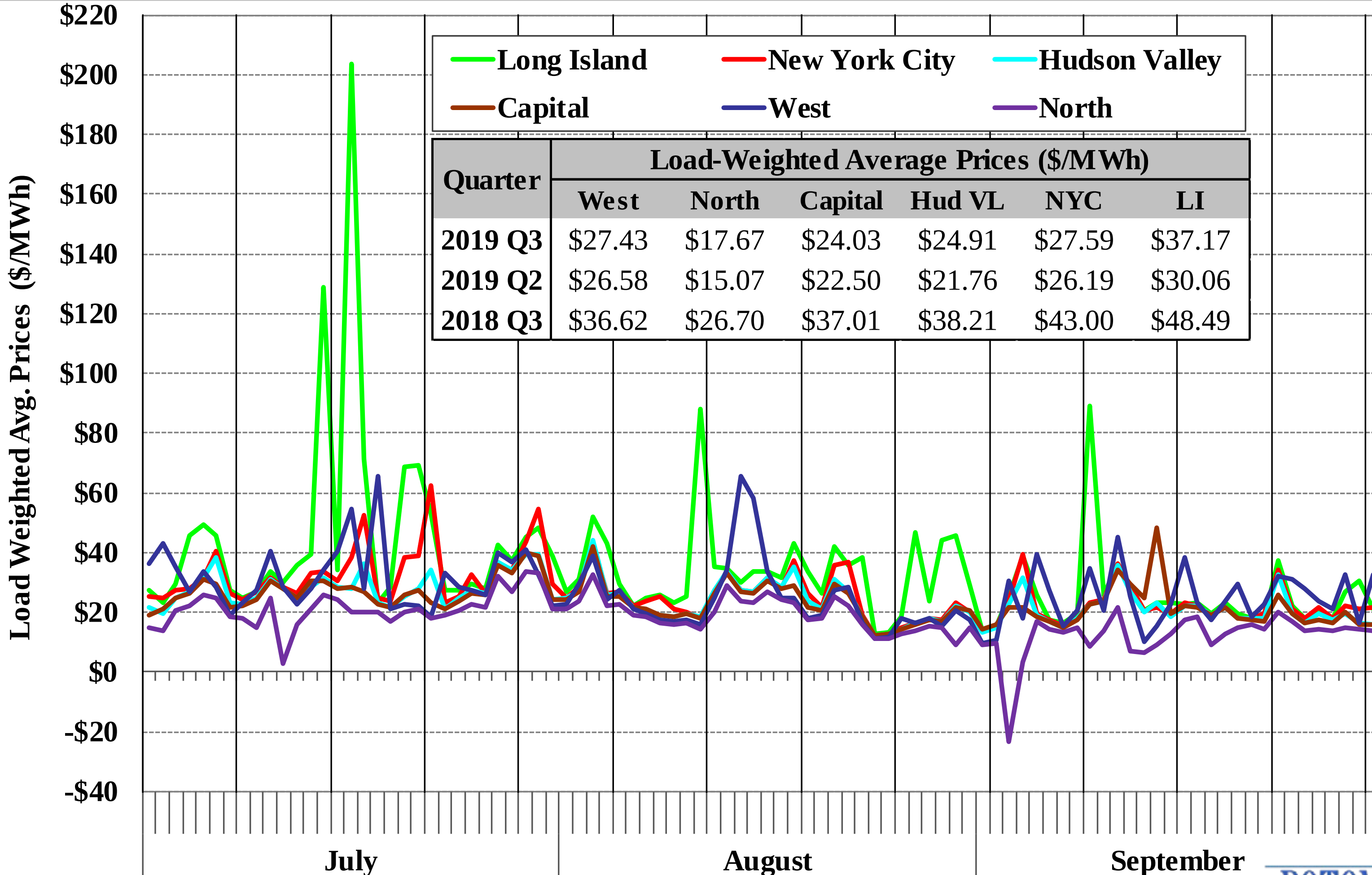
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2019 Q3	$28.21	$17.69	$25.25	$25.98	$28.16	$33.46
2019 Q2	$25.54	$14.48	$23.70	$22.90	$25.97	$28.34
2018 Q3	$36.68	$25.82	$35.31	$36.79	$39.75	$47.51

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2019 Q3	$27.43	$17.67	$24.03	$24.91	$27.59	$37.17
2019 Q2	$26.58	$15.07	$22.50	$21.76	$26.19	$30.06
2018 Q3	$36.62	$26.70	$37.01	$38.21	$43.00	$48.49

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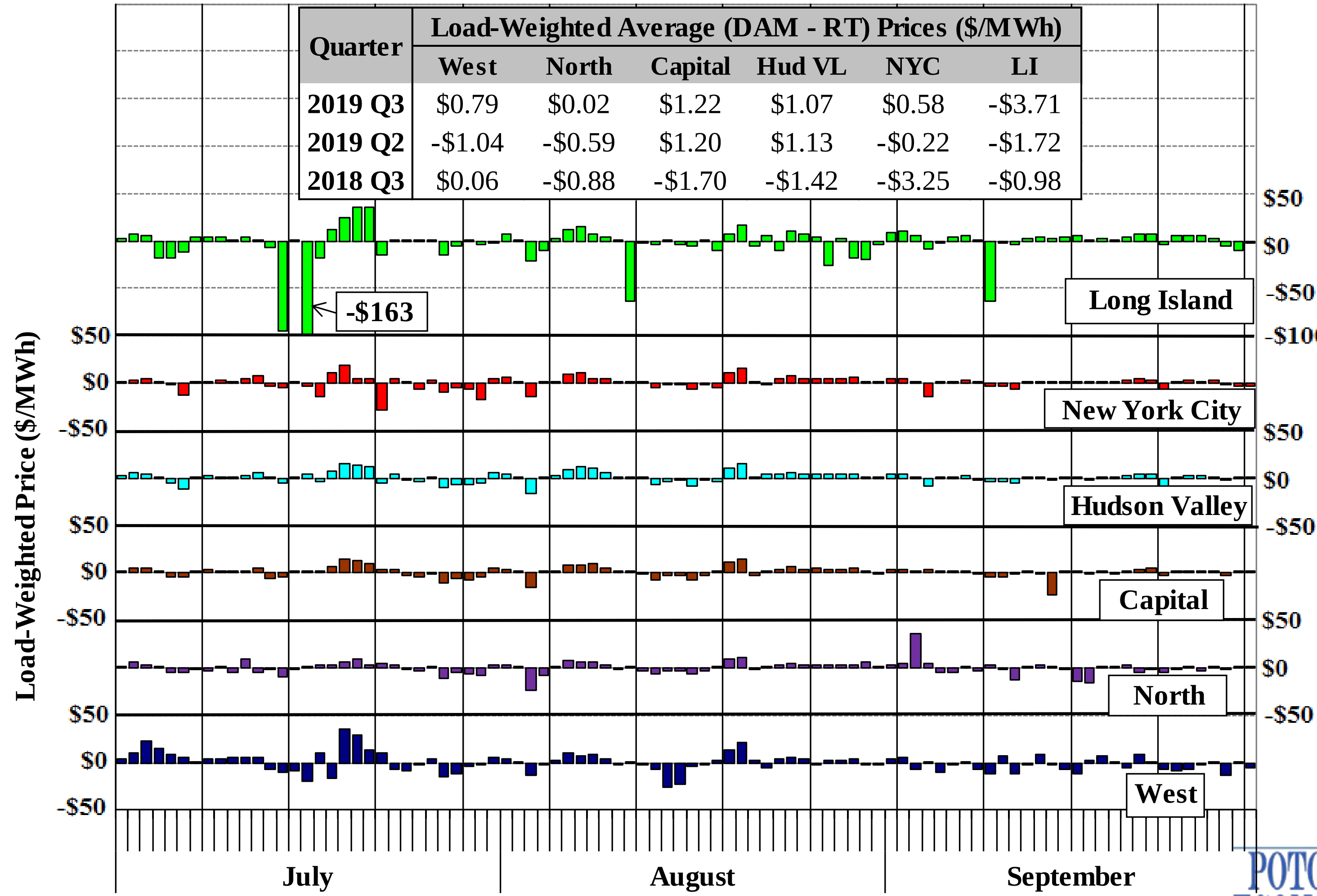
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2019 Q3	$0.79	$0.02	$1.22	$1.07	$0.58	-$3.71
2019 Q2	-$1.04	-$0.59	$1.20	$1.13	-$0.22	-$1.72
2018 Q3	$0.06	-$0.88	-$1.70	-$1.42	-$3.25	-$0.98

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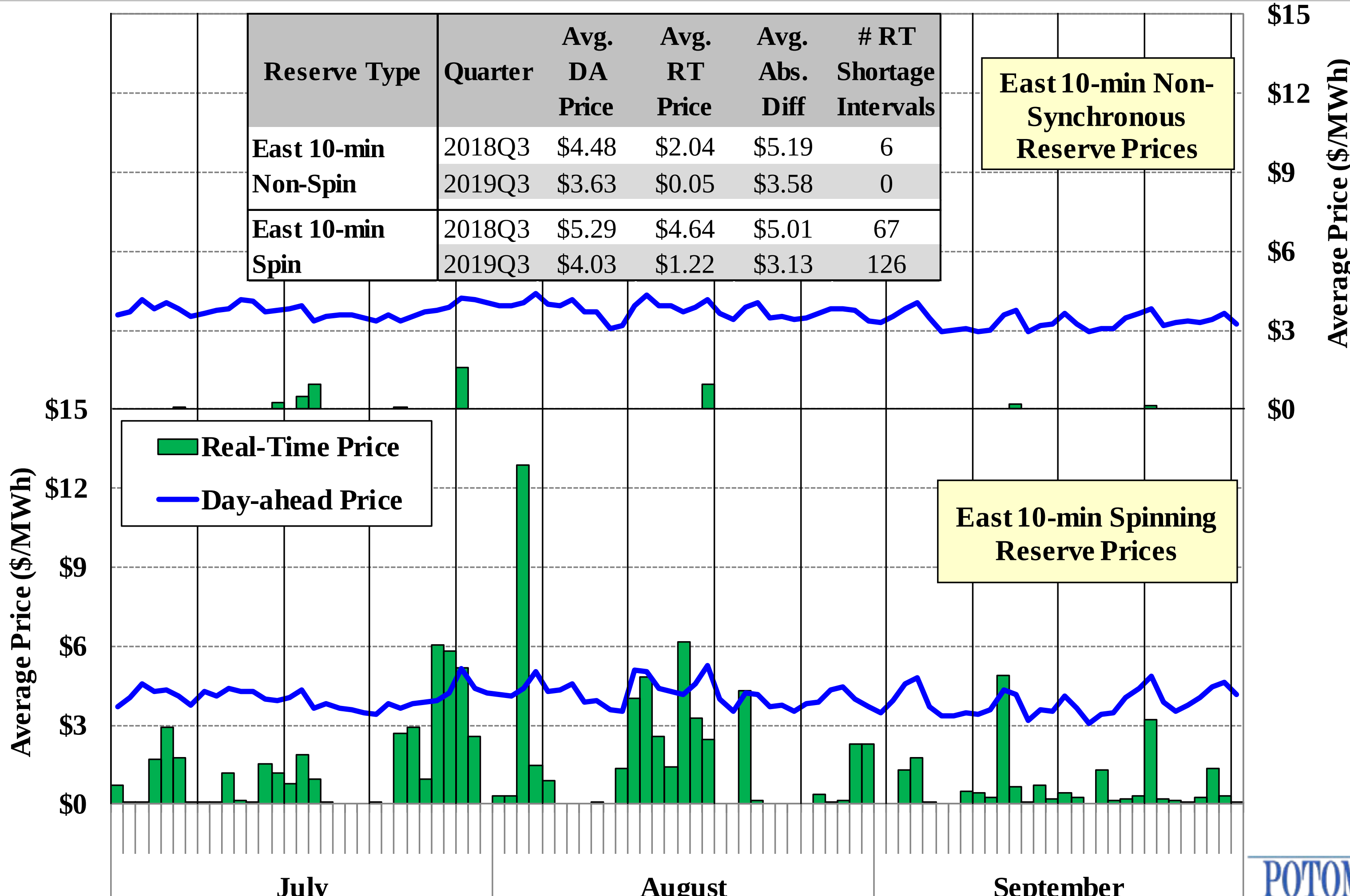
Charts:

Ancillary Services Market

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

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2018Q3	$4.48	$2.04	$5.19	6
	2019Q3	$3.63	$0.05	$3.58	0
East 10-min Spin	2018Q3	$5.29	$4.64	$5.01	67
	2019Q3	$4.03	$1.22	$3.13	126



Notes: For chart description, see slide 74.

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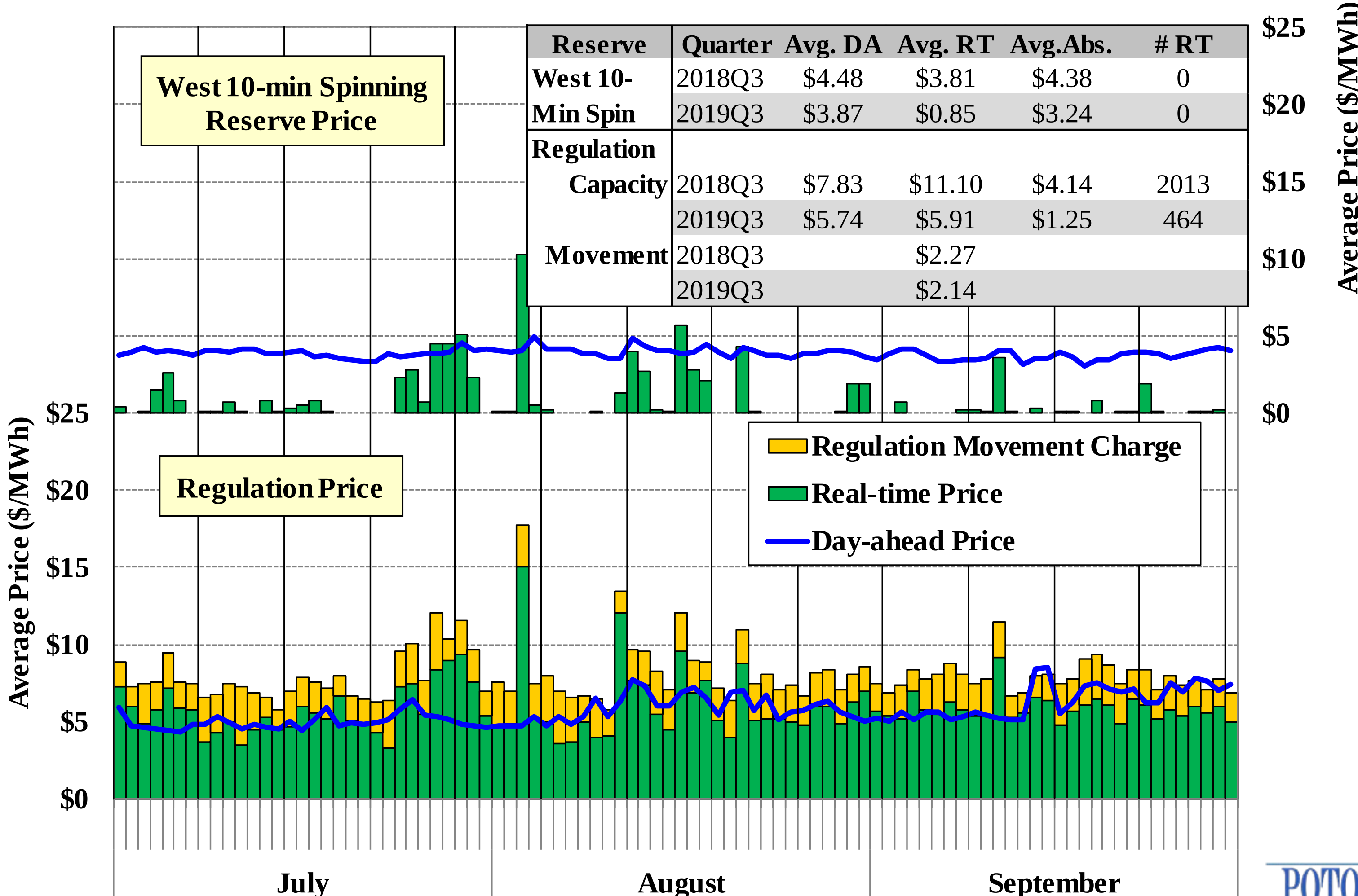
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2018Q3	$4.48	$3.81	$4.38	0
	2019Q3	$3.87	$0.85	$3.24	0
Regulation Capacity	2018Q3	$7.83	$11.10	$4.14	2013
	2019Q3	$5.74	$5.91	$1.25	464
Movement	2018Q3		$2.27		
	2019Q3		$2.14		

Notes: For chart description, see slide 74.

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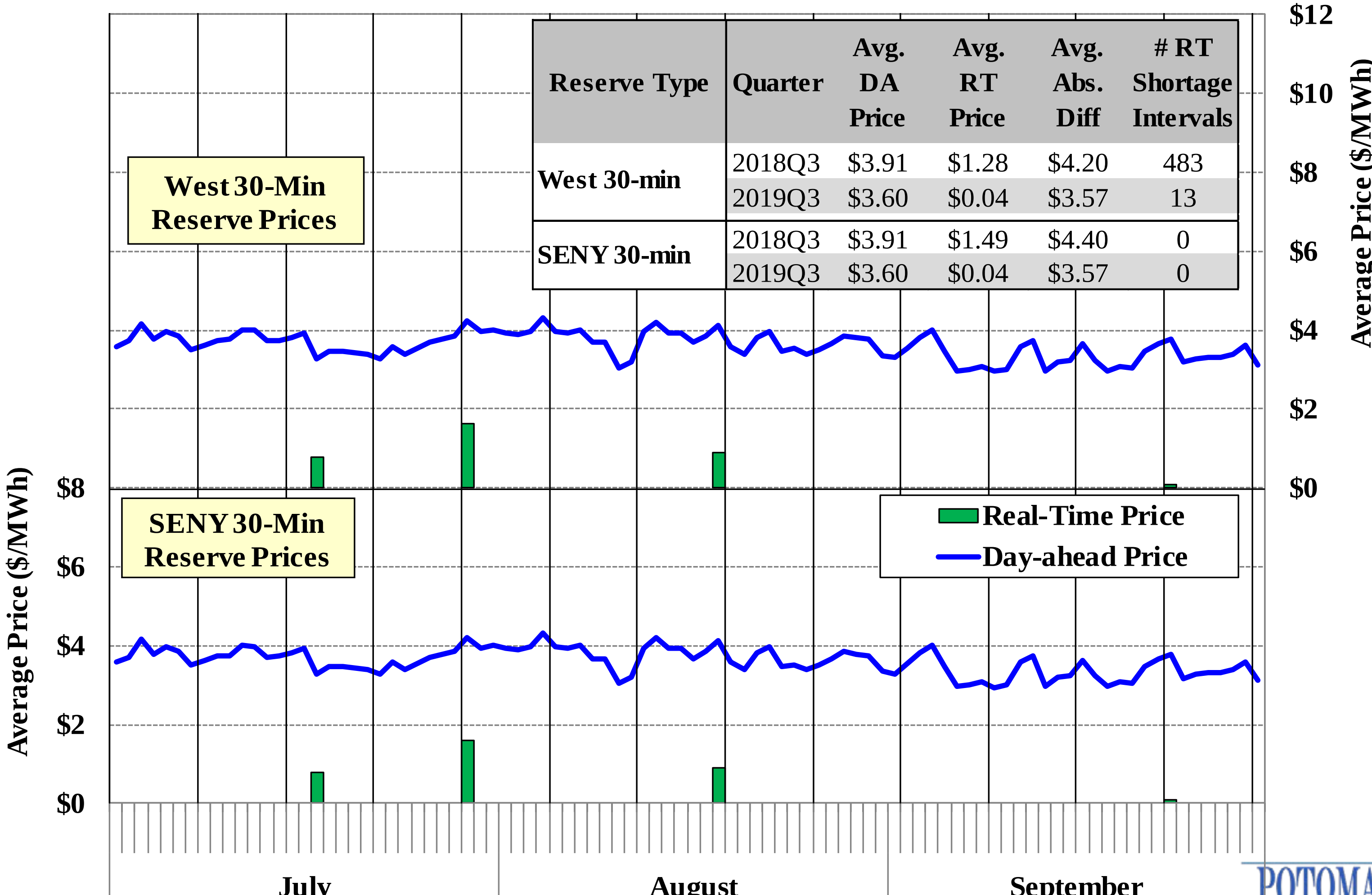
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2018Q3	$3.91	$1.28	$4.20	483
	2019Q3	$3.60	$0.04	$3.57	13
SENY 30-min	2018Q3	$3.91	$1.49	$4.40	0
	2019Q3	$3.60	$0.04	$3.57	0

Notes: For chart description, see slide 74.
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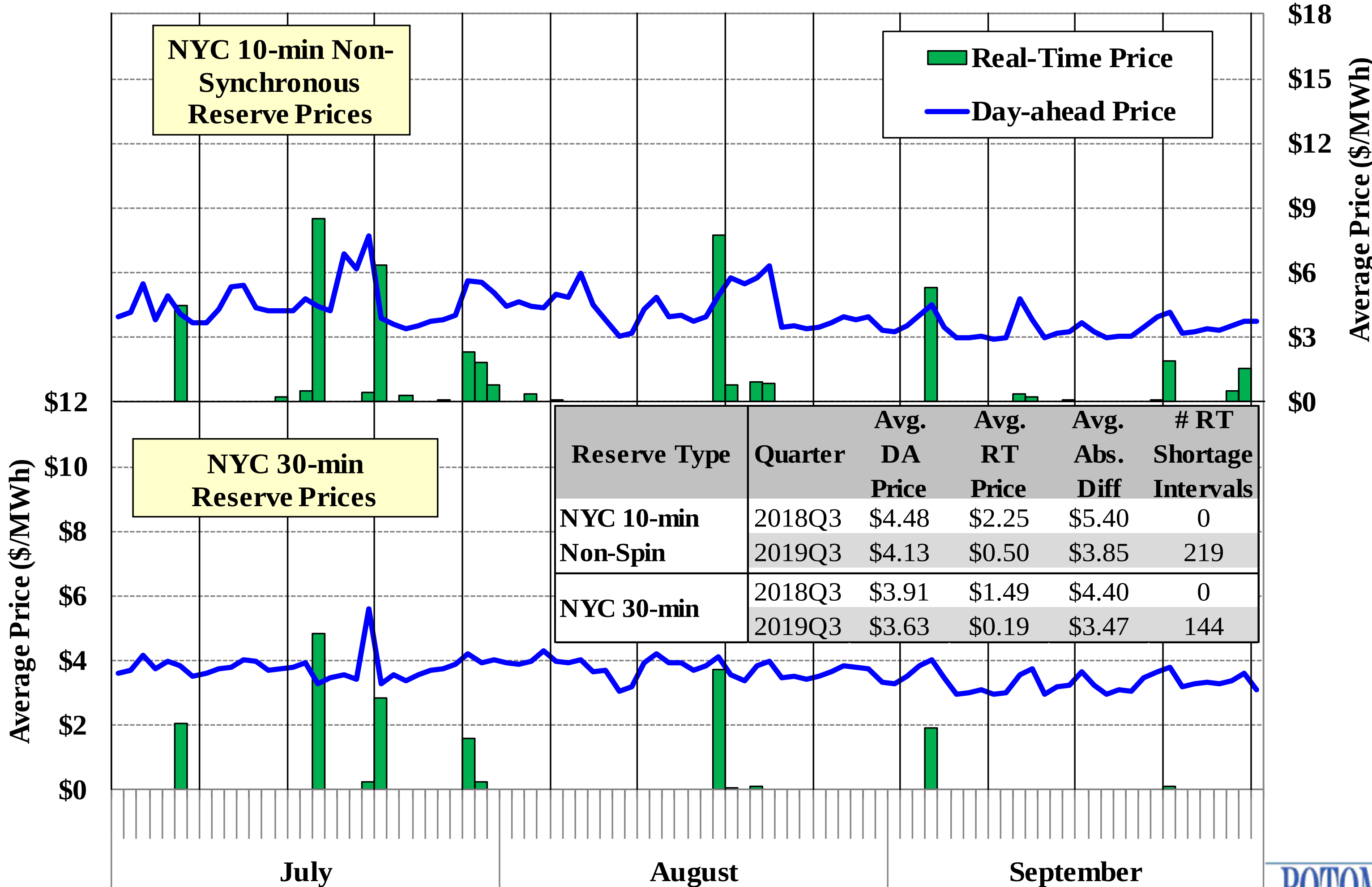
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Non-Spinning and 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2018Q3	$4.48	$2.25	$5.40	0
	2019Q3	$4.13	$0.50	$3.85	219
NYC 30-min	2018Q3	$3.91	$1.49	$4.40	0
	2019Q3	$3.63	$0.19	$3.47	144

Notes: For chart description, see slide 74.

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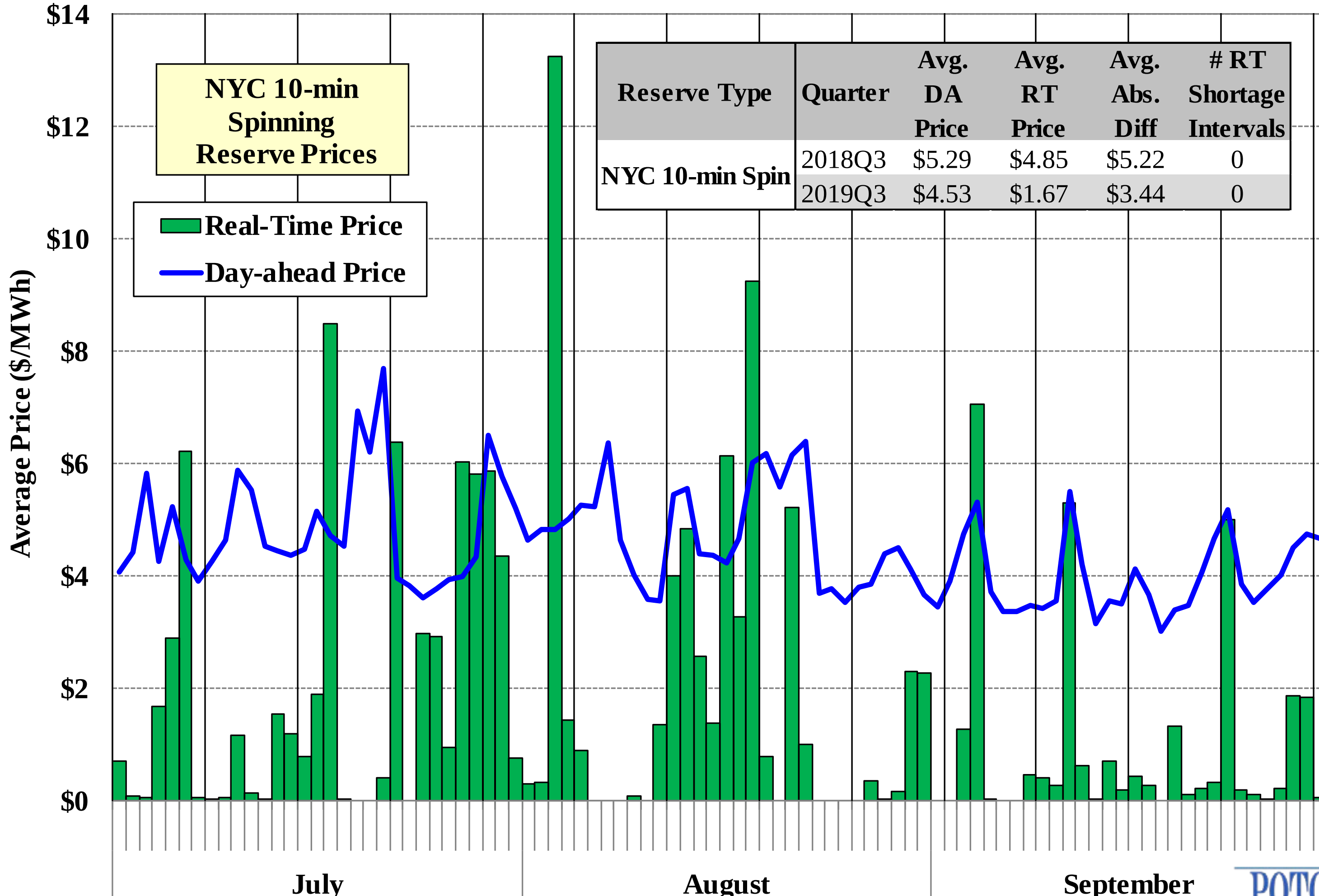
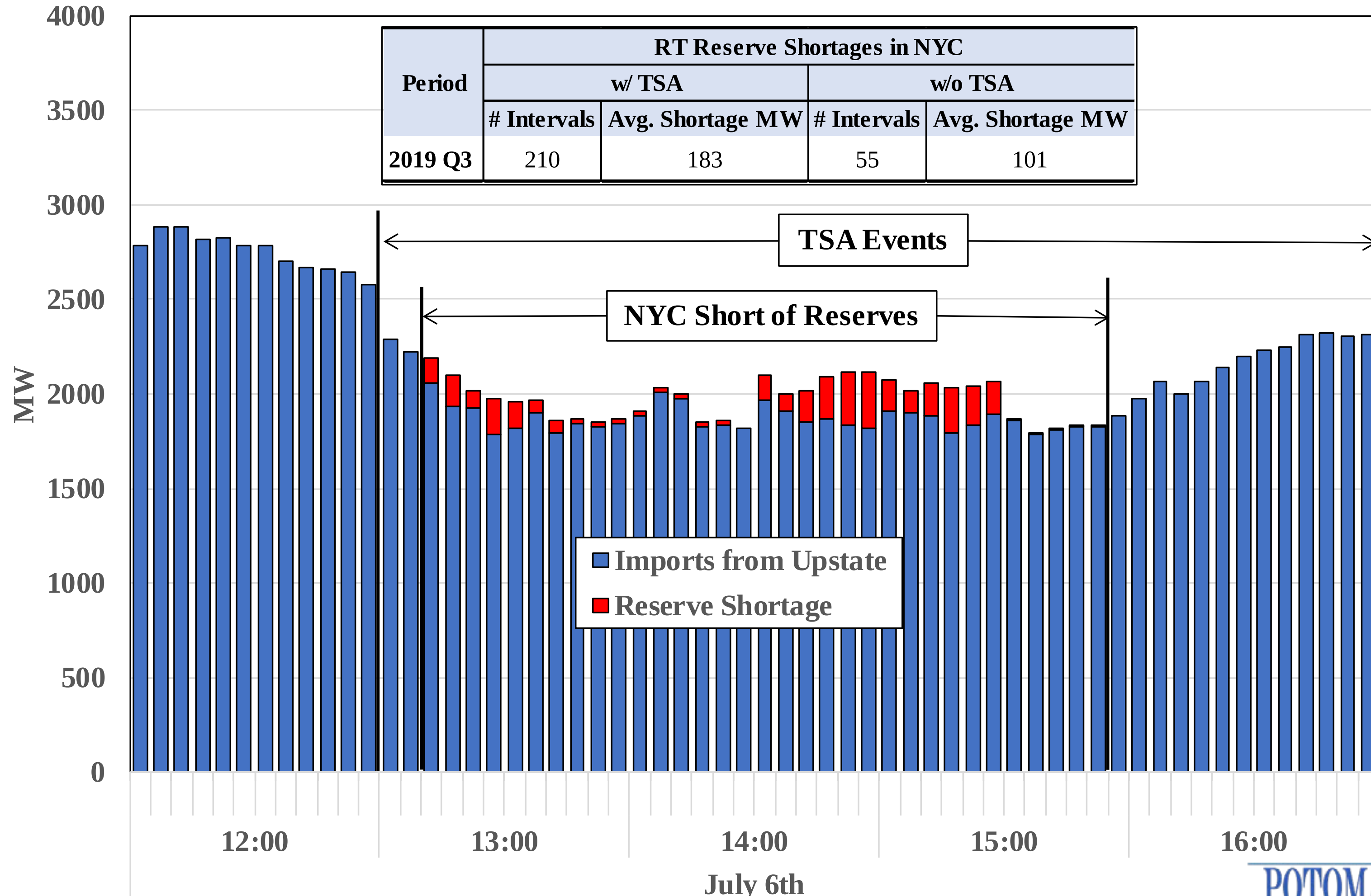
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2018Q3	$5.29	$4.85	$5.22	0
	2019Q3	$4.53	$1.67	$3.44	0

Notes: For chart description, see slide 74.

NYC Reserve Shortages
Sample Event on July 6

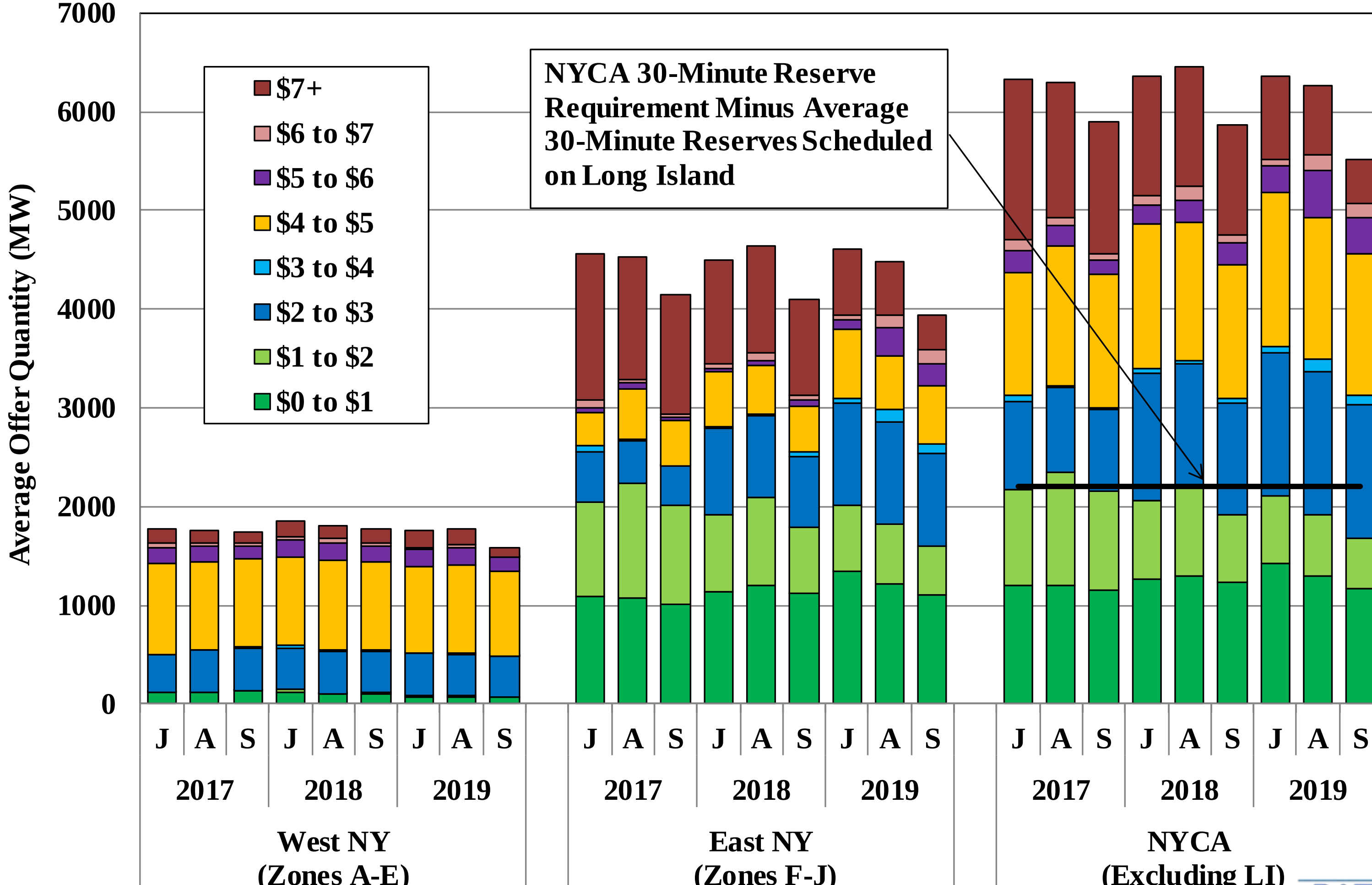


Period	RT Reserve Shortages in NYC			
	w/ TSA		w/o TSA	
	# Intervals	Avg. Shortage MW	# Intervals	Avg. Shortage MW
2019 Q3	210	183	55	101

Notes: For chart description, see slide 75.

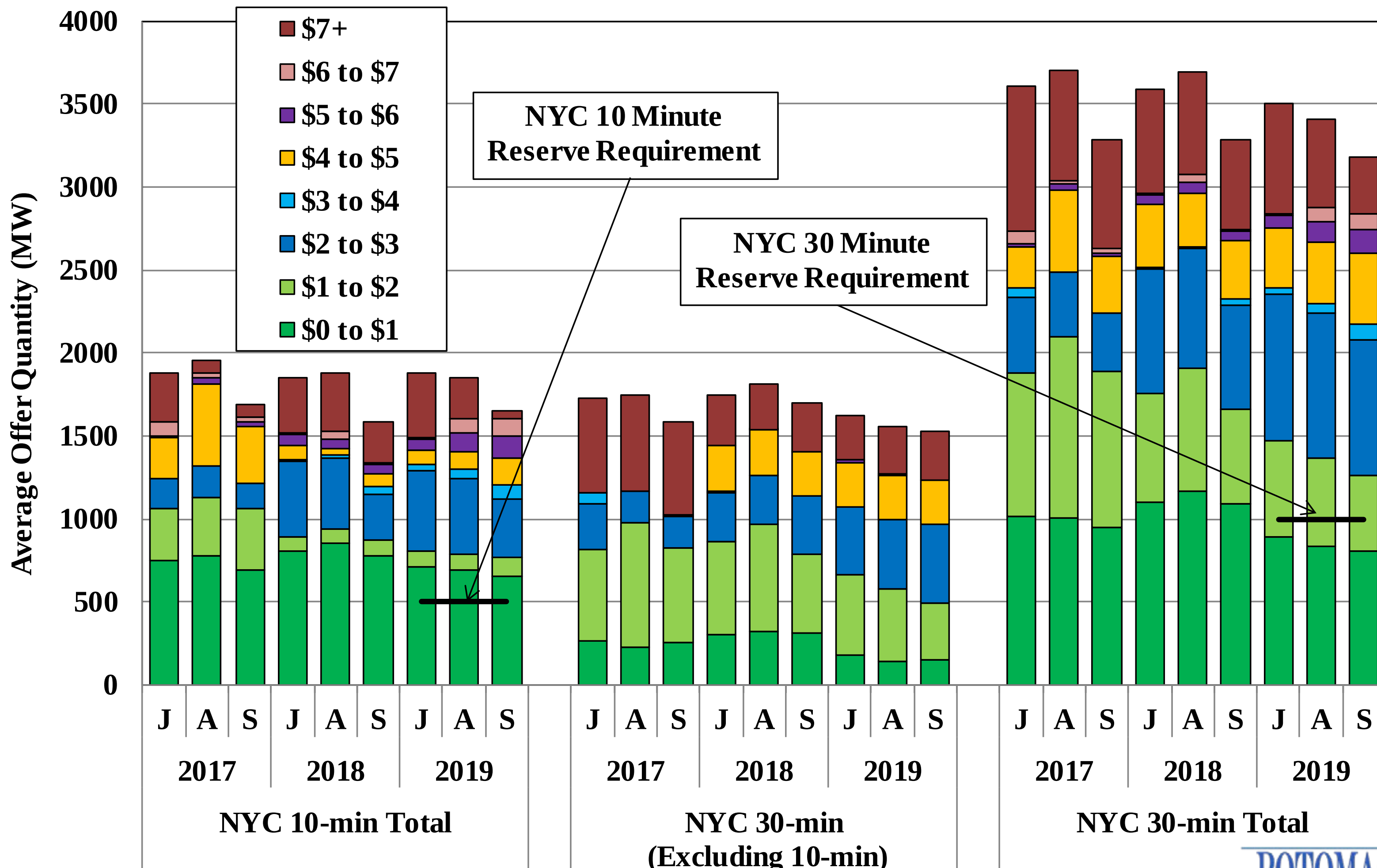
POTOMAC ECONOMICS

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



Notes: For chart description, see slide 76.

Day-Ahead NYC 10-Min & 30-Min Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 76.

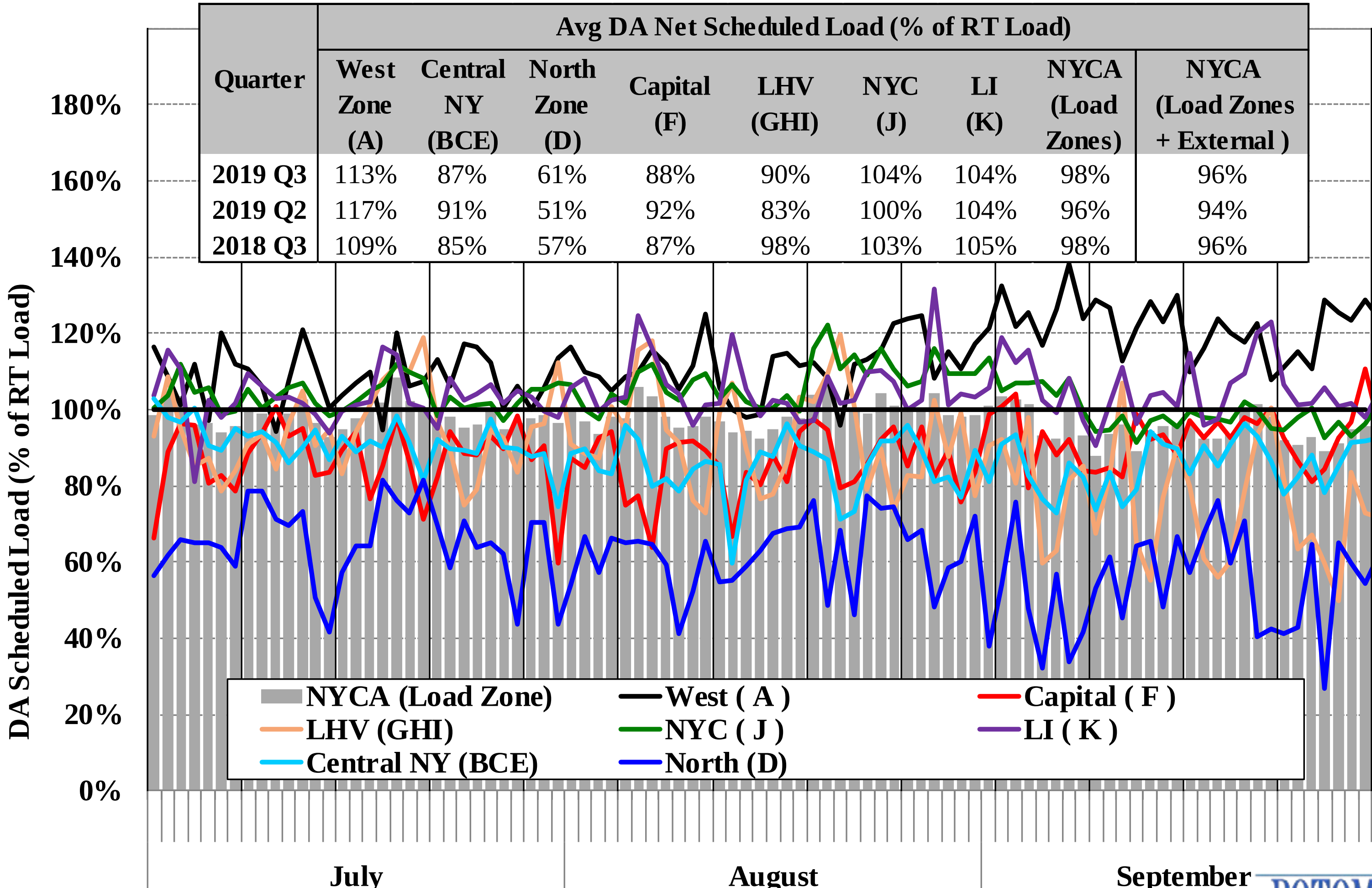
Charts:

Energy Market Scheduling

POTOMAC ECONOMICS

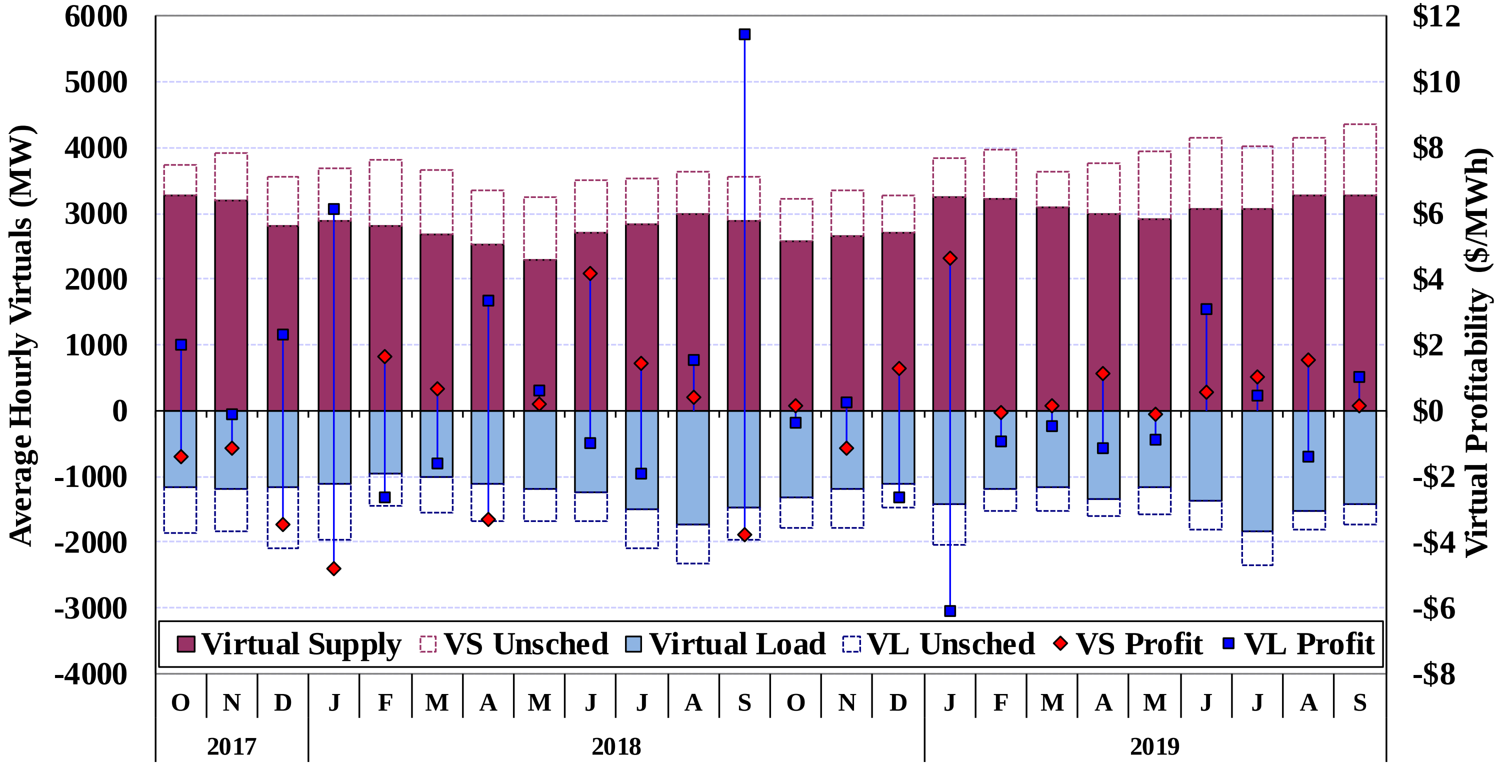
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour

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)
2019 Q3	113%	87%	61%	88%	90%	104%	104%	98%	96%
2019 Q2	117%	91%	51%	92%	83%	100%	104%	96%	94%
2018 Q3	109%	85%	57%	87%	98%	103%	105%	98%	96%



Notes: For chart description, see slide 77.

Virtual Trading Activity
by Month

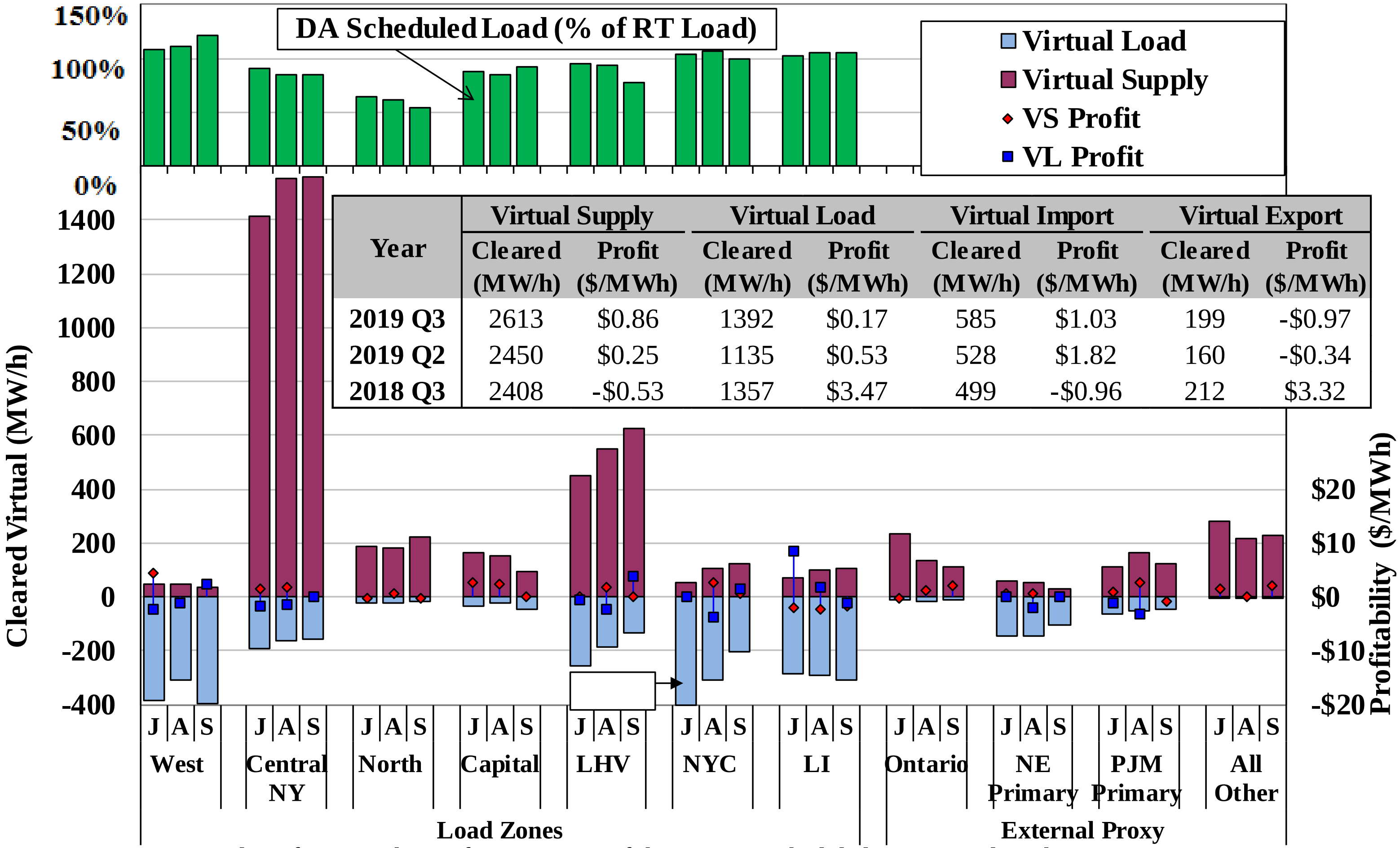


		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
Profit > 50% of Avg. Zone Price	MW	271	320	396	373	450	419	376	475	620	320	299	437	366	312	326	612	279	167	473	477	587	384	396	249
	%	6%	7%	10%	9%	12%	11%	10%	14%	16%	7%	6%	10%	9%	8%	9%	13%	6%	4%	11%	12%	13%	8%	8%	5%
Loss > 50% of Avg. Zone Price	MW	399	412	478	442	342	401	466	537	531	329	328	428	430	345	317	439	331	178	348	591	548	372	321	293
	%	9%	9%	12%	11%	9%	11%	13%	16%	14%	8%	7%	10%	11%	9%	8%	9%	7%	4%	8%	15%	12%	8%	7%	6%

Notes: For chart description, see slide 77.

POTOMAC ECONOMICS

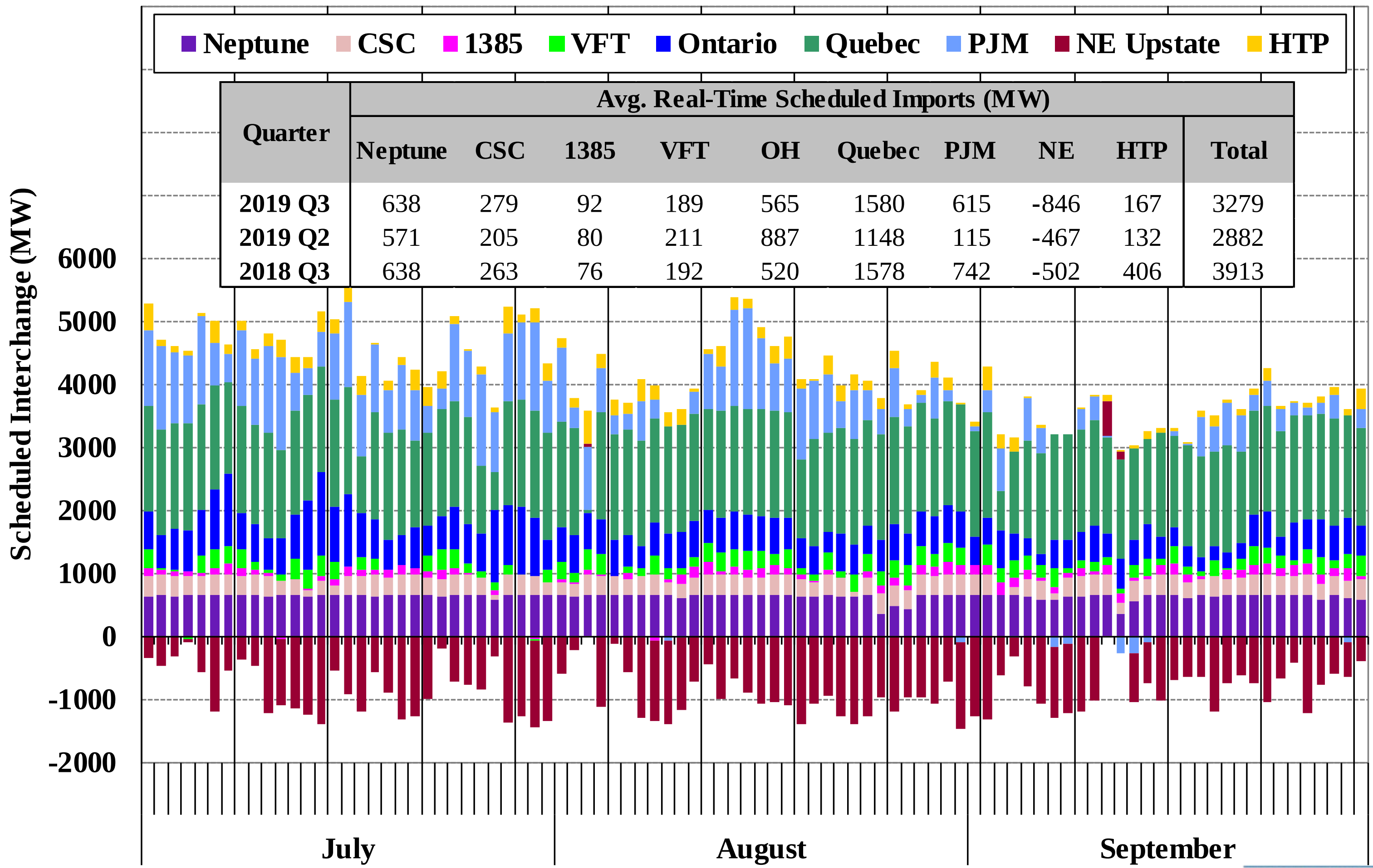
Virtual Trading Activity
by Location



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)
2019 Q3	2613	$0.86	1392	$0.17	585	$1.03	199	-$0.97
2019 Q2	2450	$0.25	1135	$0.53	528	$1.82	160	-$0.34
2018 Q3	2408	-$0.53	1357	$3.47	499	-$0.96	212	$3.32

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 77.

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



Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	Quebec	PJM	NE	HTP	Total
2019 Q3	638	279	92	189	565	1580	615	-846	167	3279
2019 Q2	571	205	80	211	887	1148	115	-467	132	2882
2018 Q3	638	263	76	192	520	1578	742	-502	406	3913

Notes: Two Quebec interfaces are combined into one.

POTOMAC ECONOMICS

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

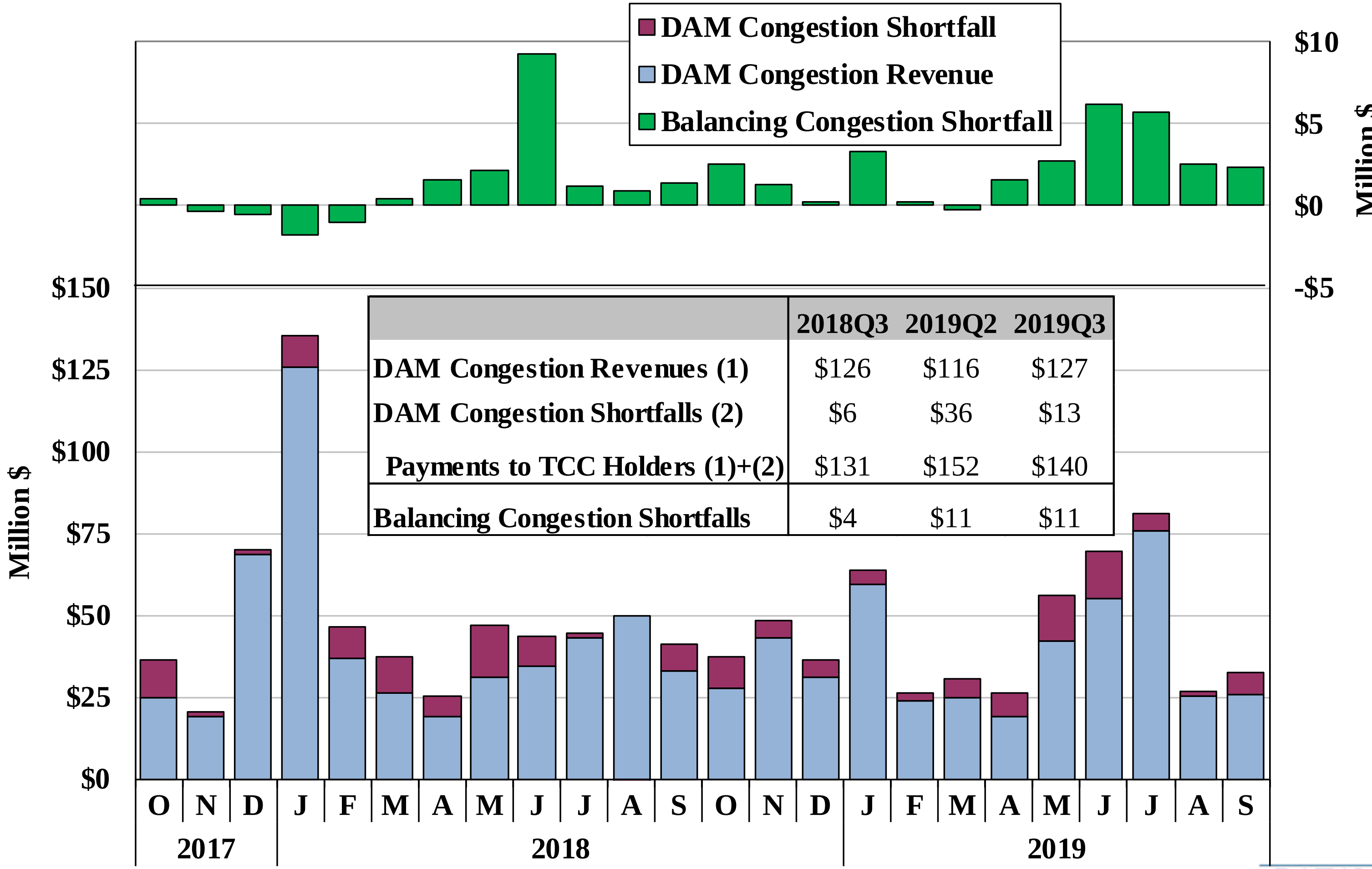
			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			80%	4%	**84%**	43%	9%	**52%**
Average Flow Adjustment (MW)	Net Imports		31	18	**30**	4	-56	**-7**
	Gross		110	154	**112**	76	134	**87**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$1.1	$0.0	**$1.1**	$0.4	$1.3	**$1.6**
	Net Over-Projection by:	NY	-$0.1	$0.1	**$0.0**	-$0.1	-$0.2	**-$0.3**
		NE or PJM	$0.00	-$0.01	**$0.0**	-$0.1	-$1.2	**-$1.2**
	Other Unrealized Savings		-$0.05	-$0.03	**-$0.1**	-$0.01	$0.00	**$0.0**
	Actual Savings		$0.9	$0.1	**$1.0**	$0.2	-$0.1	**$0.1**
Interface Prices ($/MWh)	NY	Actual	$21.90	$49.90	**$23.16**	$22.70	$41.11	**$26.01**
		Forecast	$22.83	$32.72	**$23.28**	$24.39	$39.68	**$27.13**
	NE or PJM	Actual	$22.22	$41.34	**$23.08**	$22.06	$42.02	**$25.64**
		Forecast	$20.94	$32.70	**$21.47**	$24.68	$74.22	**$33.57**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.93	-$17.18	**$0.11**	$1.68	-$1.43	**$1.13**
		Abs. Val.	$2.23	$33.34	**$3.63**	$3.72	$23.14	**$7.21**
	NE or PJM	Fcst. - Act.	-$1.28	-$8.63	**-$1.61**	$2.62	$32.20	**$7.93**
		Abs. Val.	$2.75	$21.06	**$3.58**	$4.03	$53.84	**$12.97**

Notes: For chart description, see slide 78.

POTOMAC ECONOMICS

Charts:
Transmission Congestion Revenues, Patterns, and Shortfalls

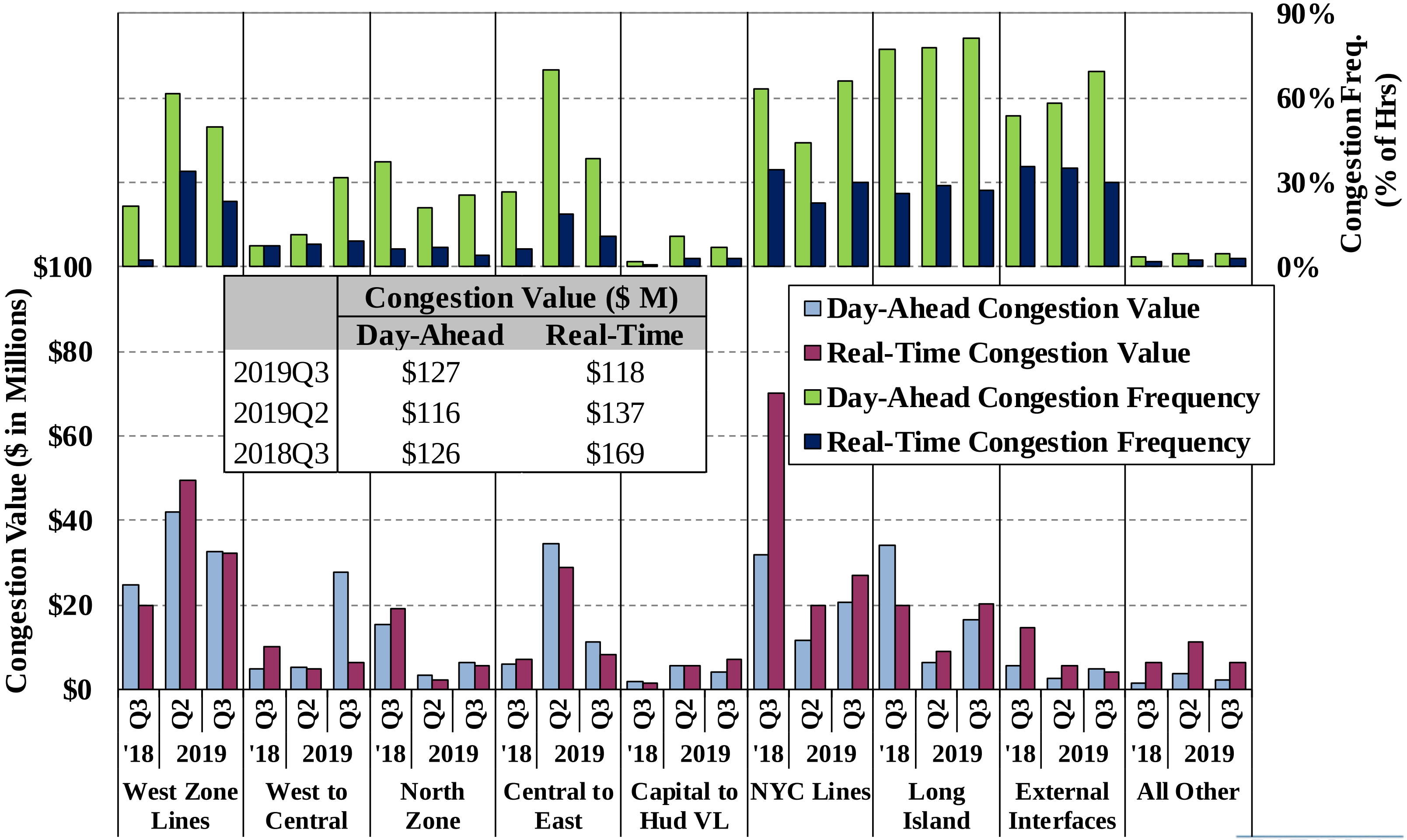
Congestion Revenues and Shortfalls by Month



	2018Q3	2019Q2	2019Q3
DAM Congestion Revenues (1)	$126	$116	$127
DAM Congestion Shortfalls (2)	$6	$36	$13
Payments to TCC Holders (1)+(2)	$131	$152	$140
Balancing Congestion Shortfalls	$4	$11	$11

Notes: For chart description, see slides 79 and 80.

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

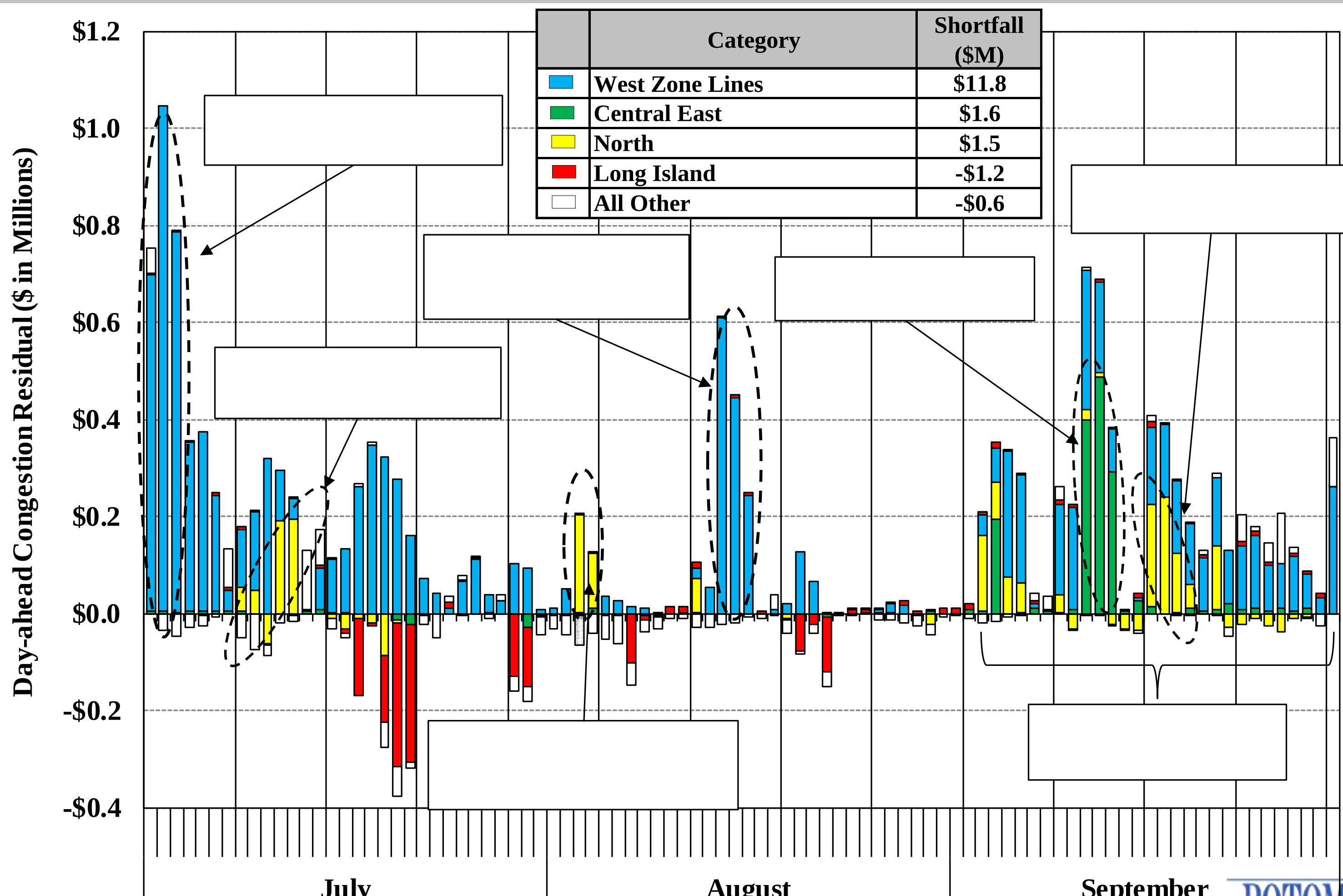


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2019Q3	$127	$118
2019Q2	$116	$137
2018Q3	$126	$169

Notes: For chart description, see slides 79, 80, and 81.

POTOMAC ECONOMICS

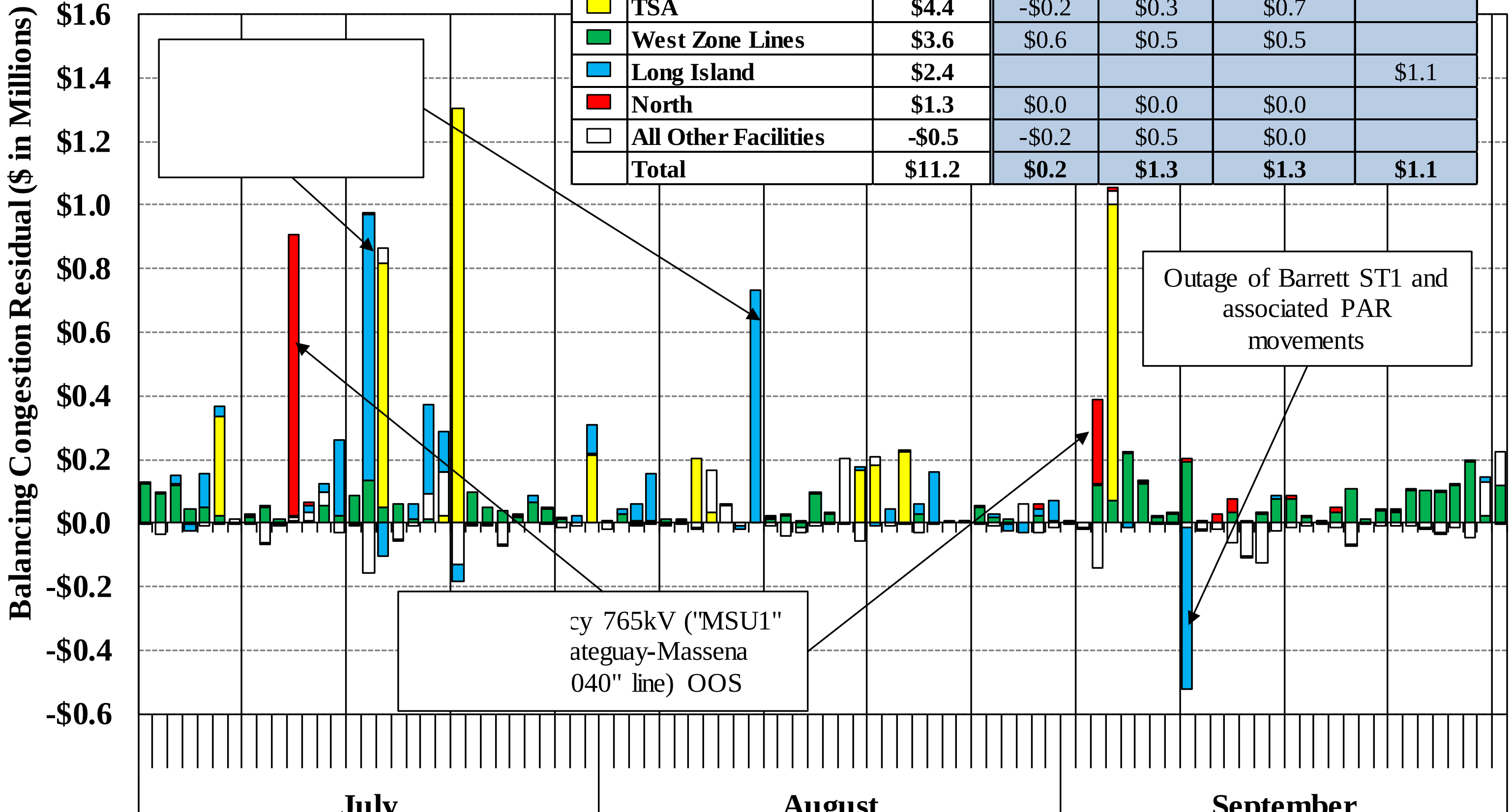
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 79, 80, and 81.

Balancing Congestion Shortfalls by Transmission Facility

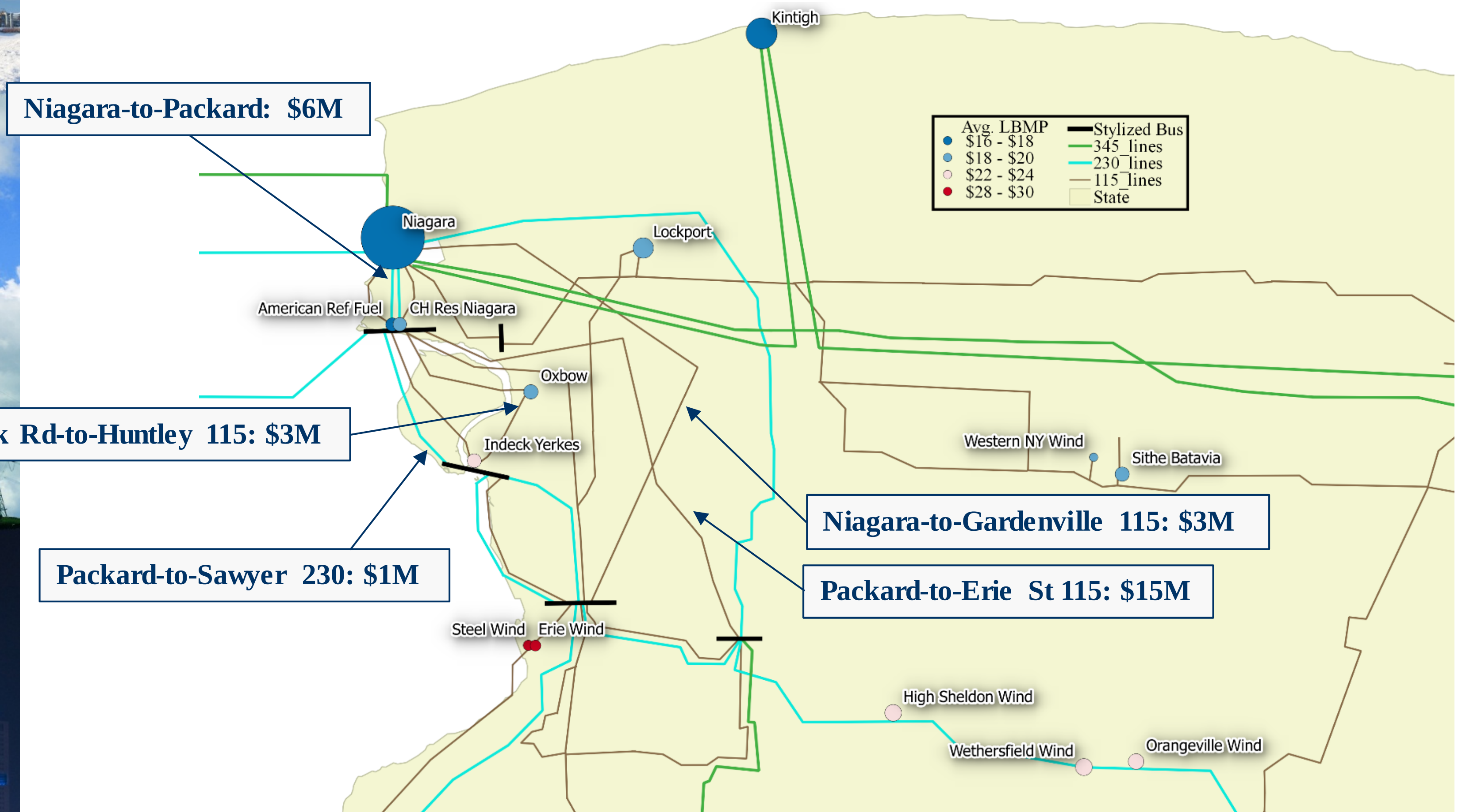
	Category	Total Shortfall ($M)	PAR Contributions			
			Ramapo	A	JK	Pilgrim
	TSA	$4.4	-$0.2	$0.3	$0.7	
	West Zone Lines	$3.6	$0.6	$0.5	$0.5	
	Long Island	$2.4				$1.1
	North	$1.3	$0.0	$0.0	$0.0	
	All Other Facilities	-$0.5	-$0.2	$0.5	$0.0	
	Total	$11.2	$0.2	$1.3	$1.3	$1.1



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 79, 80, and 81.

POTOMAC ECONOMICS

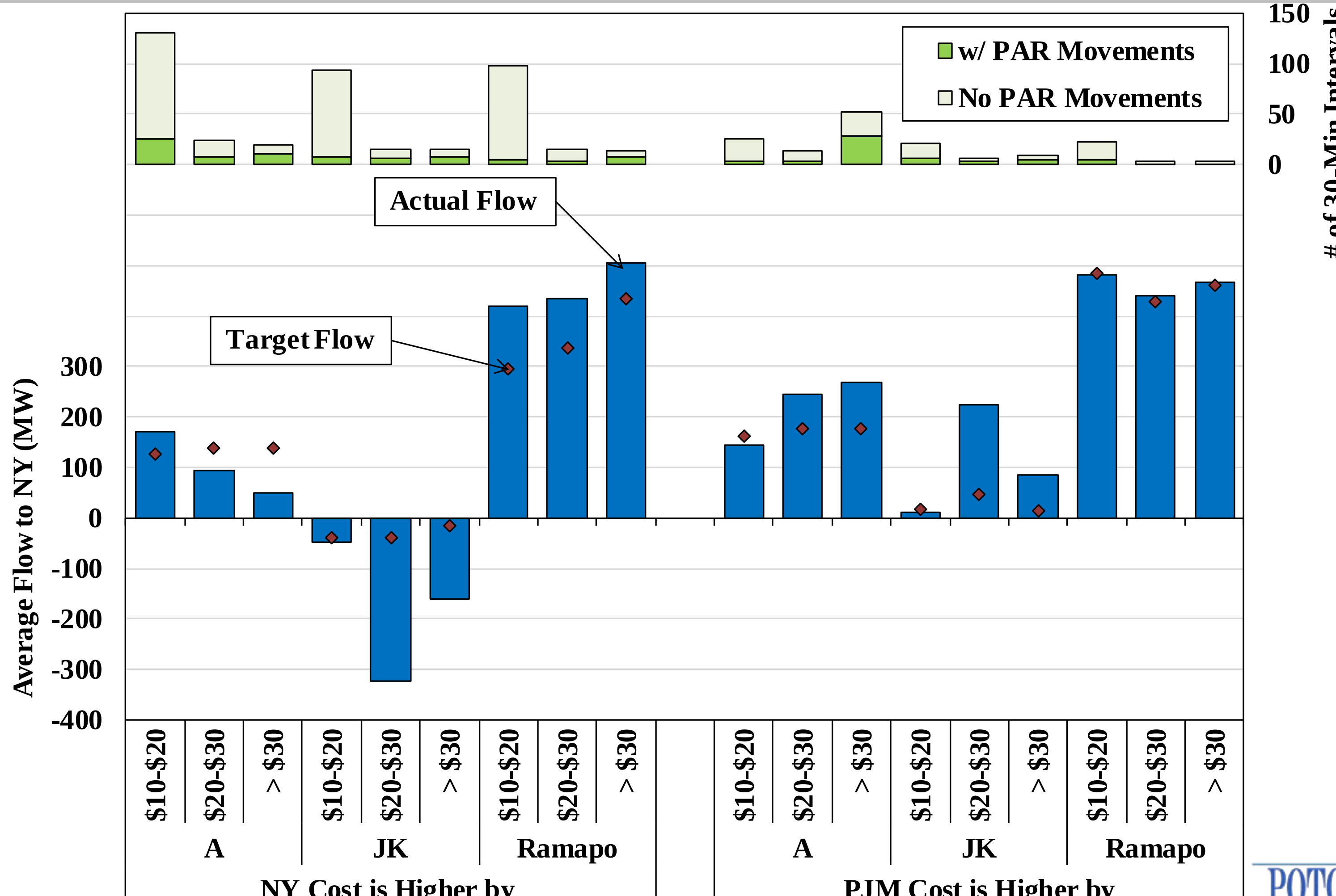
RT Congestion Value for Key Constraints and Impacts on West Zone LBMPs



Note: The map is a stylized depiction of the western New York system excluding some detail and including some aggregation for simplicity. For chart description, see slide 82.

POTOMAC ECONOMICS

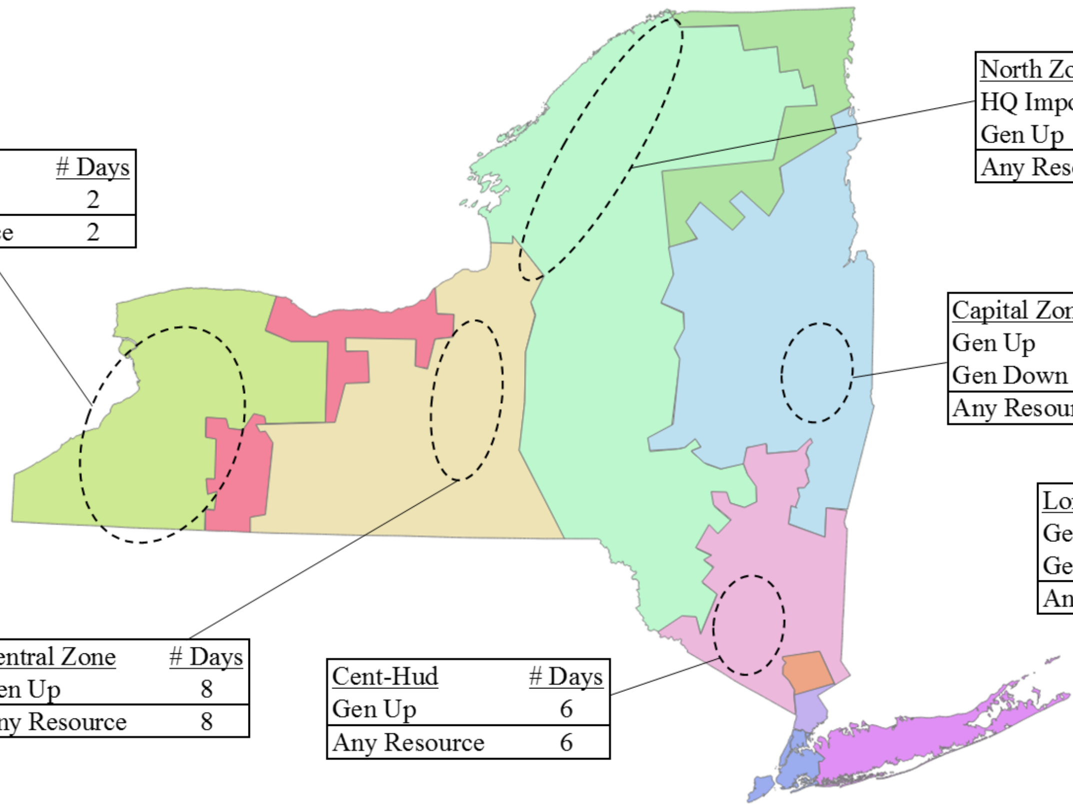
PAR Operation under M2M with PJM
2019 Q3



Notes: For chart description, see slide 83.

POTOMAC ECONOMICS

Unmodeled Constraints on the Low Voltage Network: Resources Used to Manage Constraints



North Zone	# Days
HQ Imports	1
Gen Up	9
Any Resource	10

West Zone	# Days
Gen Up	2
Any Resource	2

Capital Zone	# Days
Gen Up	2
Gen Down	1
Any Resource	3

Long Is 69kV	# Days
Gen Up	62
Gen Down	5
Any Resource	63

Central Zone	# Days
Gen Up	8
Any Resource	8

Cent-Hud	# Days
Gen Up	6
Any Resource	6

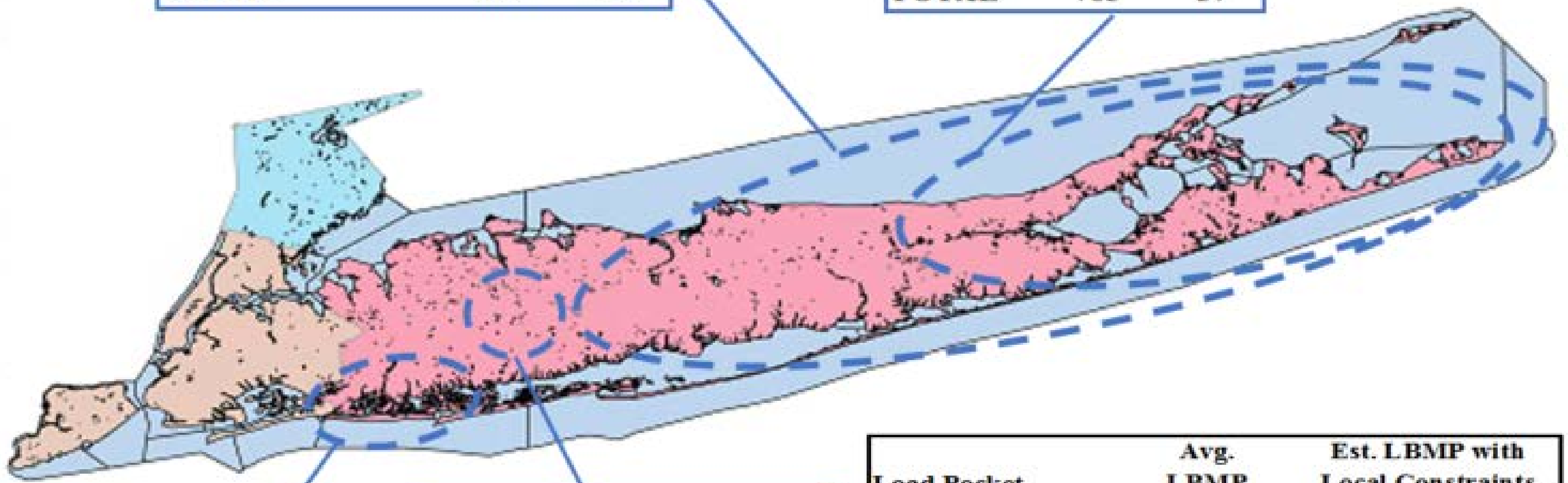
Note: Ontario imports were limited or cut on an additional 3 days to manage modeled western constraints.

Notes: For chart description, see slides 84-85

Unmodeled Constraints on the Low Voltage Network: Long Island Load Pockets

East of Northport	#Hours	#Days
69kV	97	17
138kV	365	51
TOTAL	397	52

East End	#Hours	#Days
138kV	71	13
TVR	760	57
TOTAL	765	57



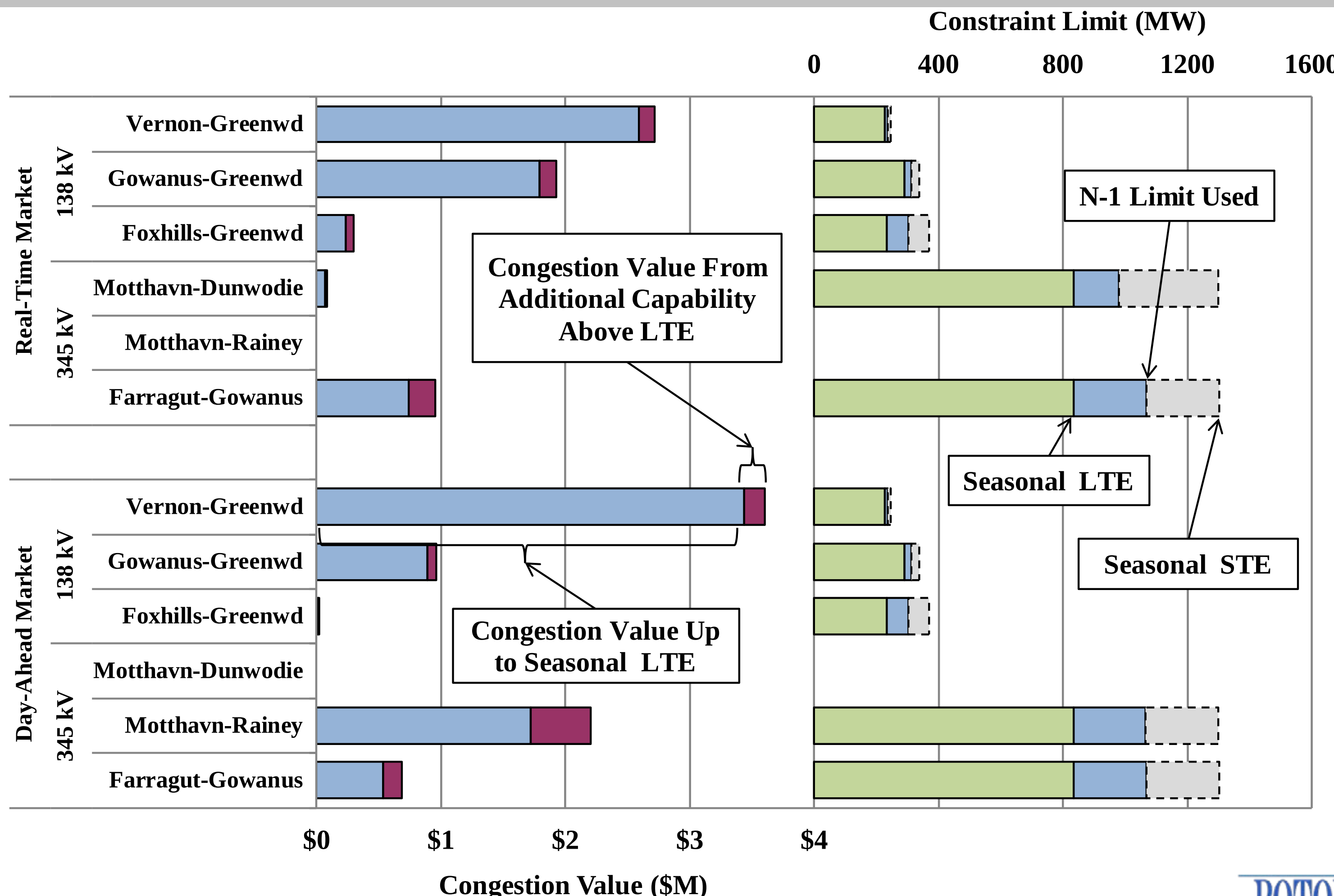
Brentwood	#Hours	#Days
69kV	337	41

Valley Stream	#Hours	#Days
69kV	212	27
138kV	1643	92
TOTAL	1695	92

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$30.60	$32.59
East End	$34.96	$106.19
East of Northport	$33.60	$39.52
Valley Stream	$43.27	$46.26

Notes: For chart description, see slides 84-85

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



 Notes: For chart description, see slide 86.

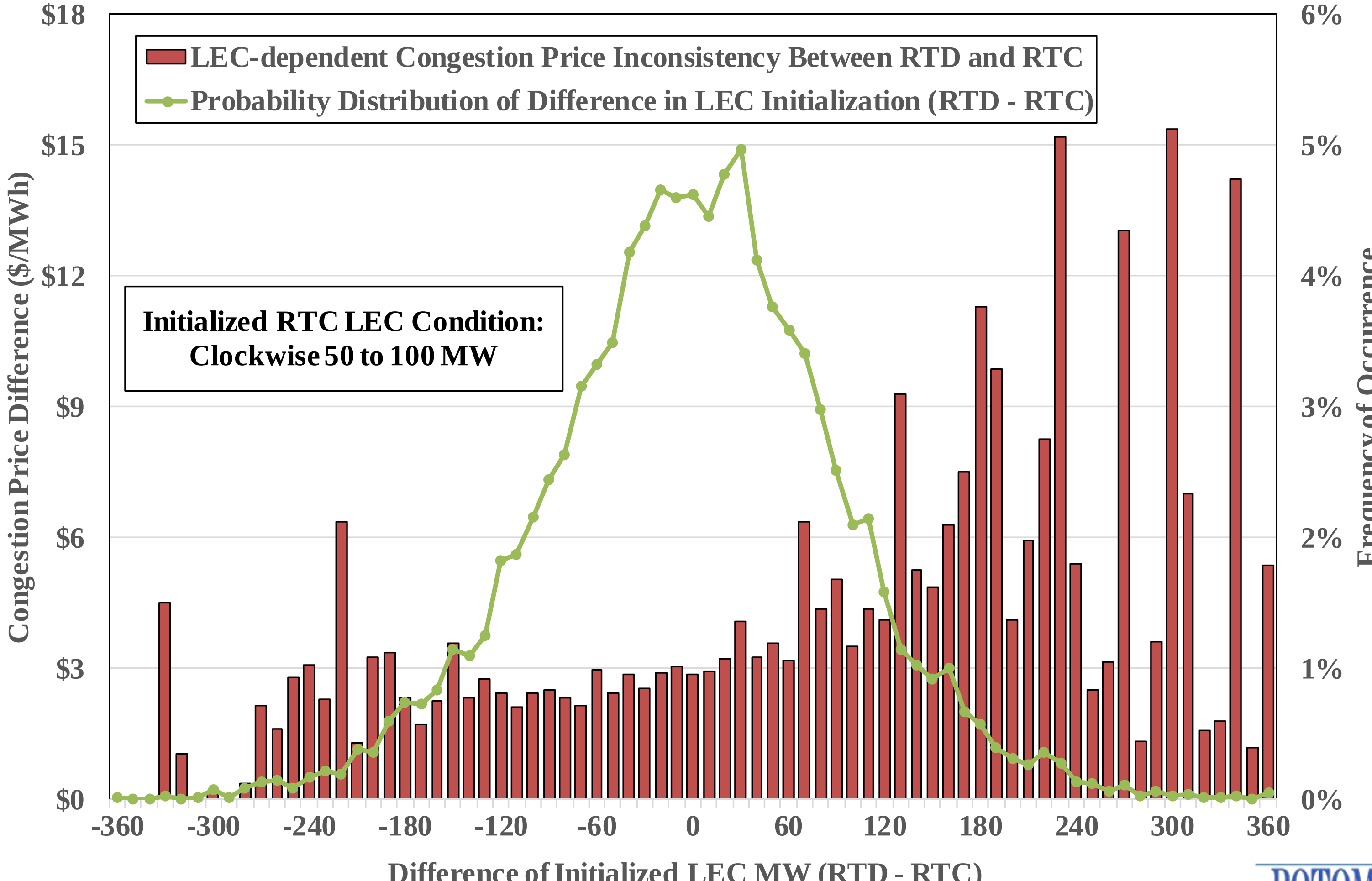
Impact of Securing In-Series Line Segments in the Market Models

January 1 – September 23, 2019

Line	# RT Intervals w/ Multi-Segments Priced Simultaneously at GTDC	Market Impact from Removed In-Series Line Segments During These Intervals					
		RT Congestion Value ($M)	BMCR ($M)	LBMP Impact - Annual Avg ($/MWh)			
				MHK VL	North	Genese	West
Colton - Browns Falls 1	3	$0.1	$0.02	$0.00	-$0.01		
Colton - Browns Falls 2	3	$0.1	$0.03	$0.00	-$0.02		
Huntley - Gardenville 38	5	$0.1	$0.01			$0.00	$0.00
Huntley - Gardenville 39	36	$0.3	$0.02			$0.00	$0.01
WalckRd - Huntley 133	12	$0.3	$0.04			$0.00	$0.01
Packard - Gardenwille 182	10	$0.3	$0.02			$0.00	$0.01
Packard - Erie St 181-922	958	$14.8	$0.90			-$0.06	$0.33
Total	**990**	**$16.1**	**$1.0**	**$0.00**	**-$0.03**	**-$0.07**	**$0.36**

Notes: For chart description, see slide 87.
POTOMAC ECONOMICS

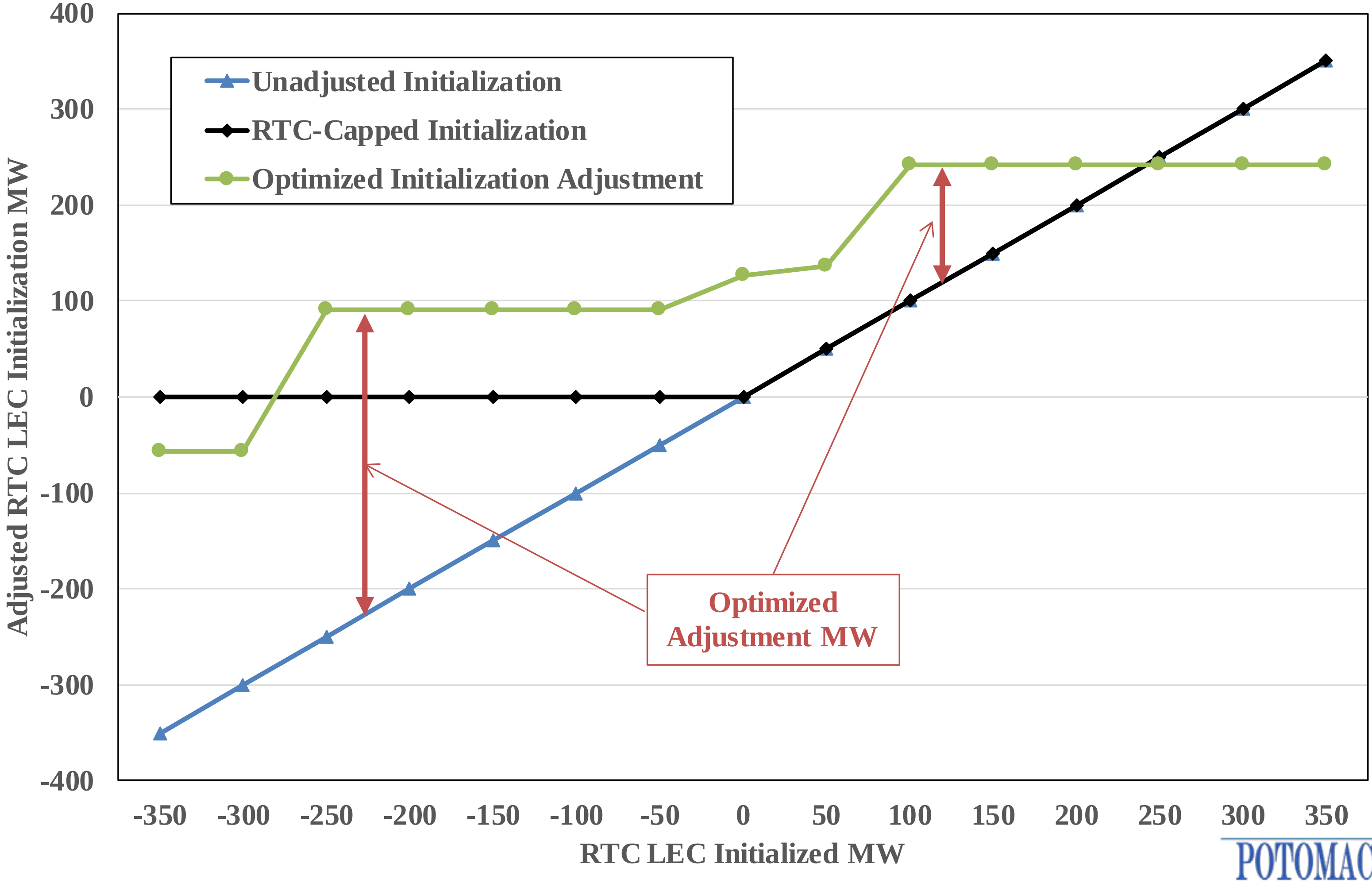
Differences in LEC Initialization and Congestion Inconsistency Between RTC and RTD



 Notes: For chart description, see slide 88.

POTOMAC ECONOMICS

Optimized Adjustment of RTC LEC Initialization



 Notes: For chart description, see slide 89.

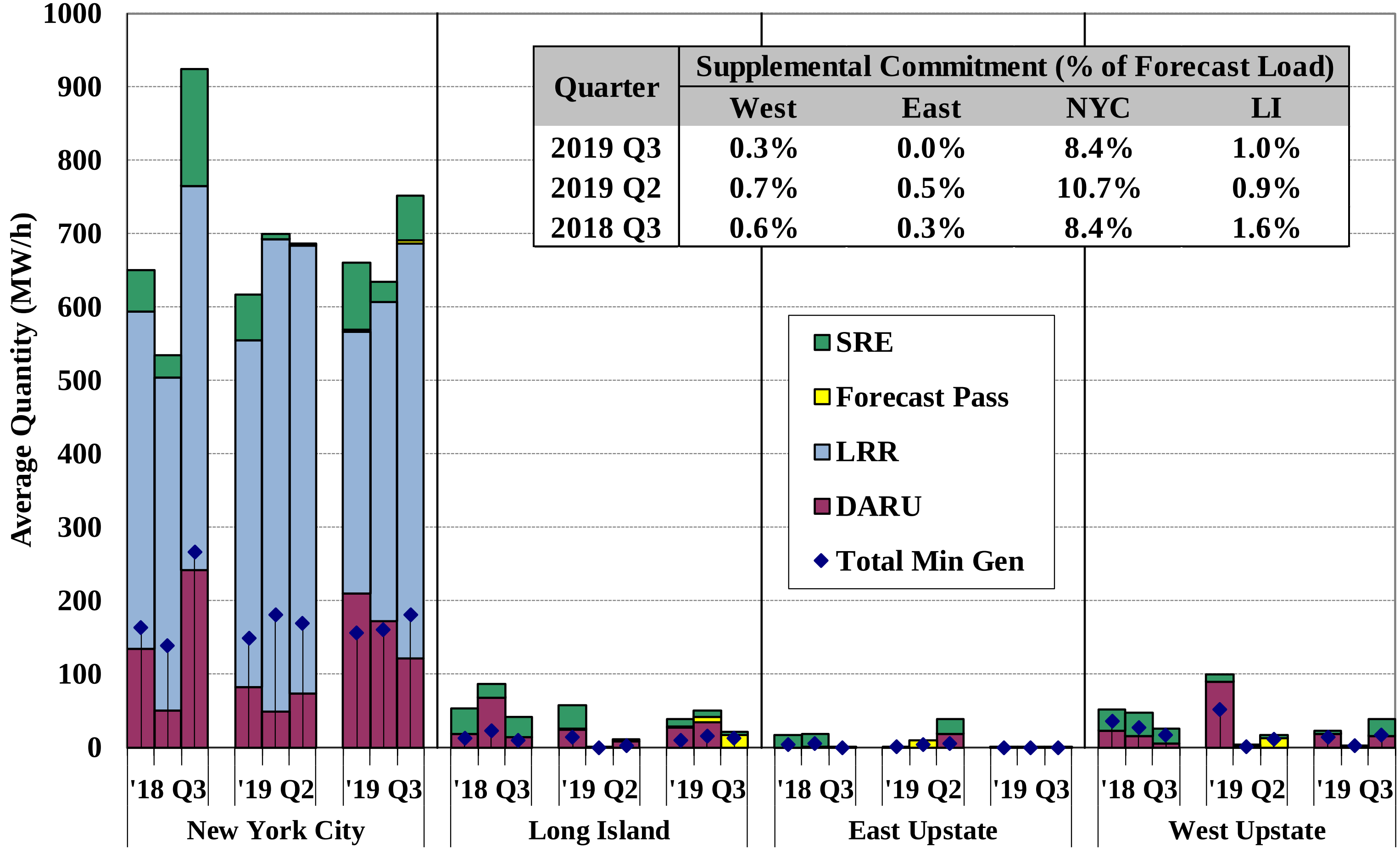
POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability by Category and Region

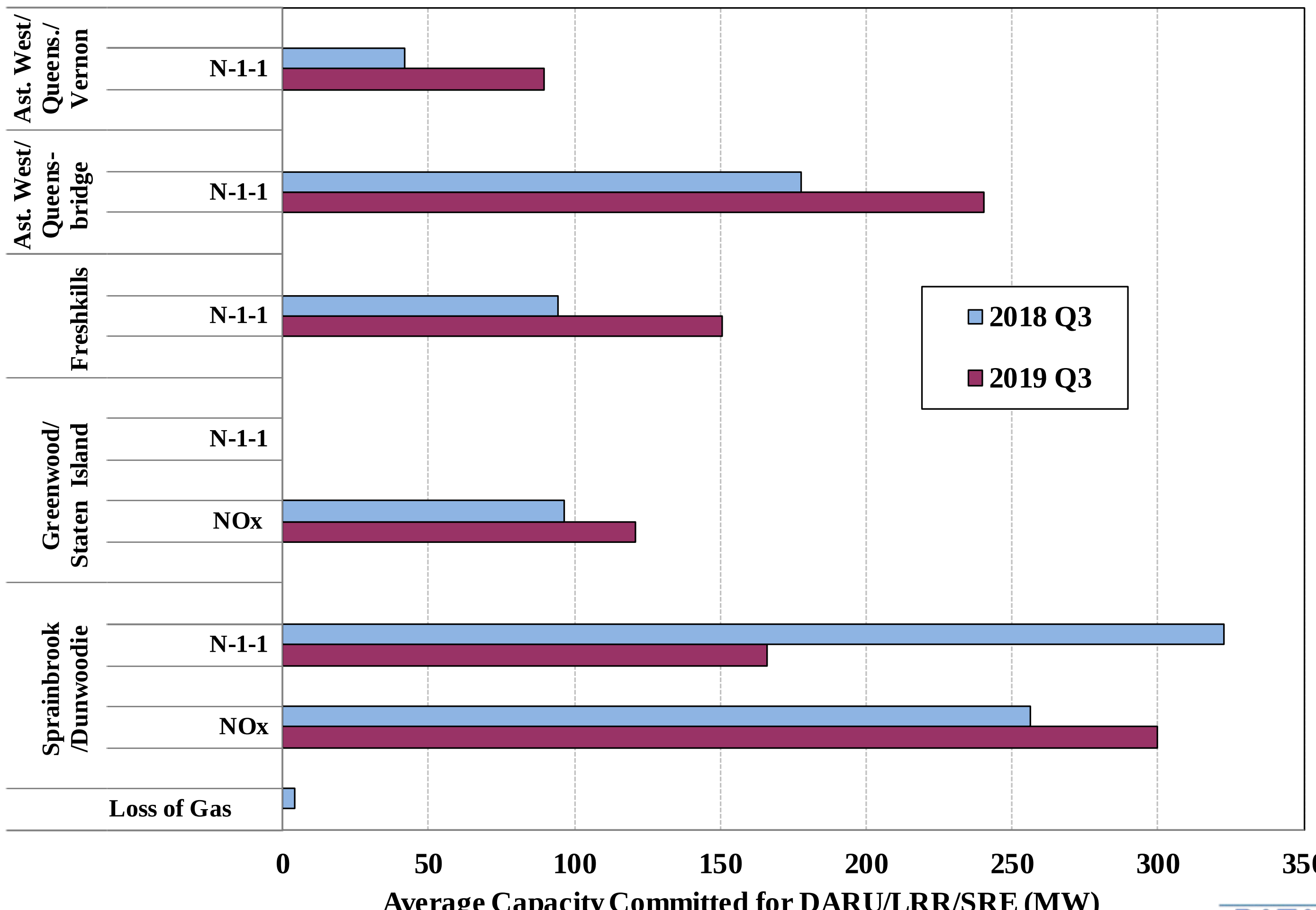
Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2019 Q3	0.3%	0.0%	8.4%	1.0%
2019 Q2	0.7%	0.5%	10.7%	0.9%
2018 Q3	0.6%	0.3%	8.4%	1.6%



Notes: For chart description, see slides 90 and 91.

POTOMAC ECONOMICS

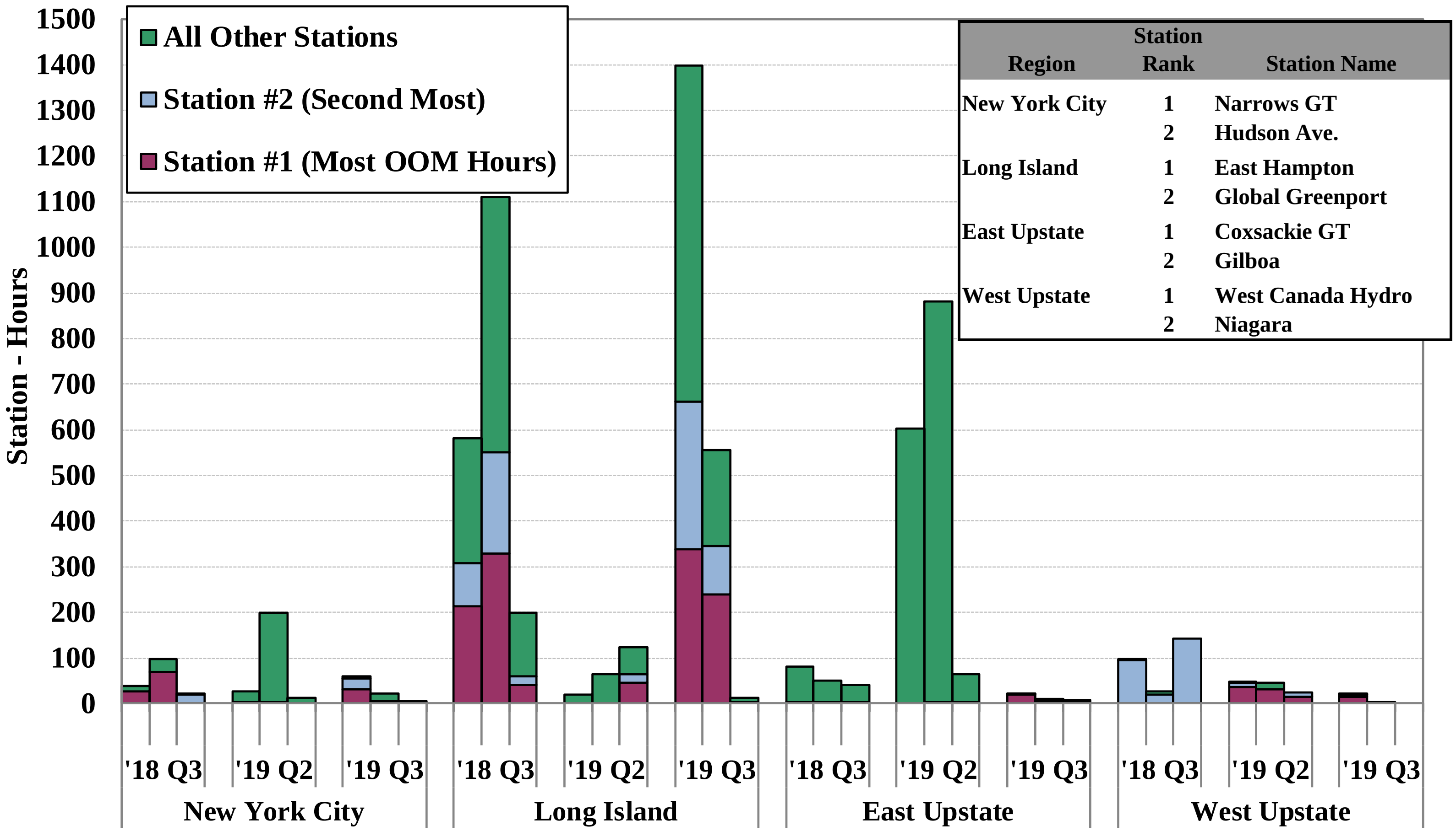
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



Notes: For chart description, see slides 90 and 91.

POTOMAC ECONOMICS

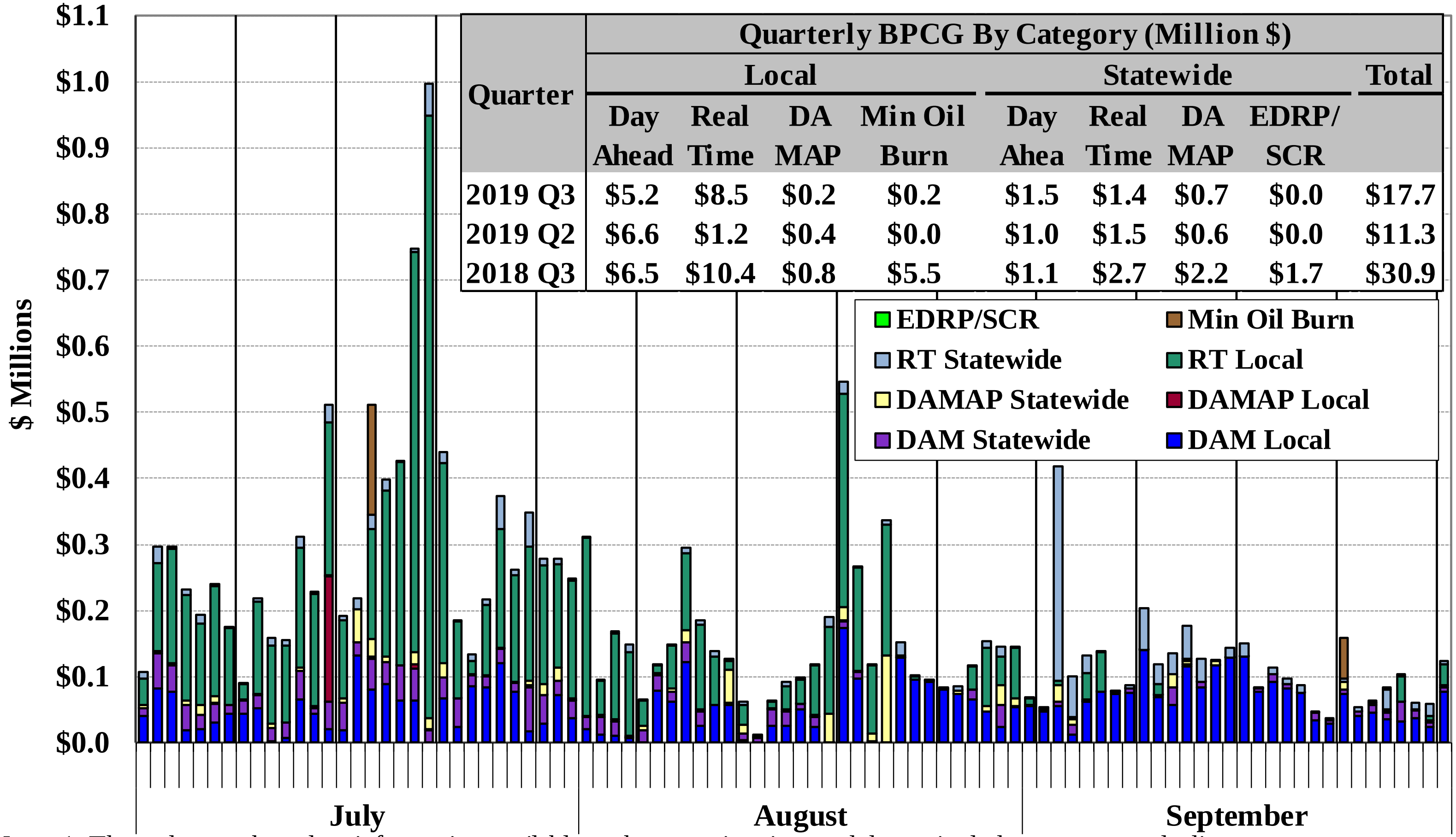
Frequency of Out-of-Merit Dispatch
by Region by Month



Region	Station Rank	Station Name
New York City	1	Narrows GT
	2	Hudson Ave.
Long Island	1	East Hampton
	2	Global Greenport
East Upstate	1	Coxsackie GT
	2	Gilboa
West Upstate	1	West Canada Hydro
	2	Niagara

Notes: 1. For chart description, see slides 90 and 91.

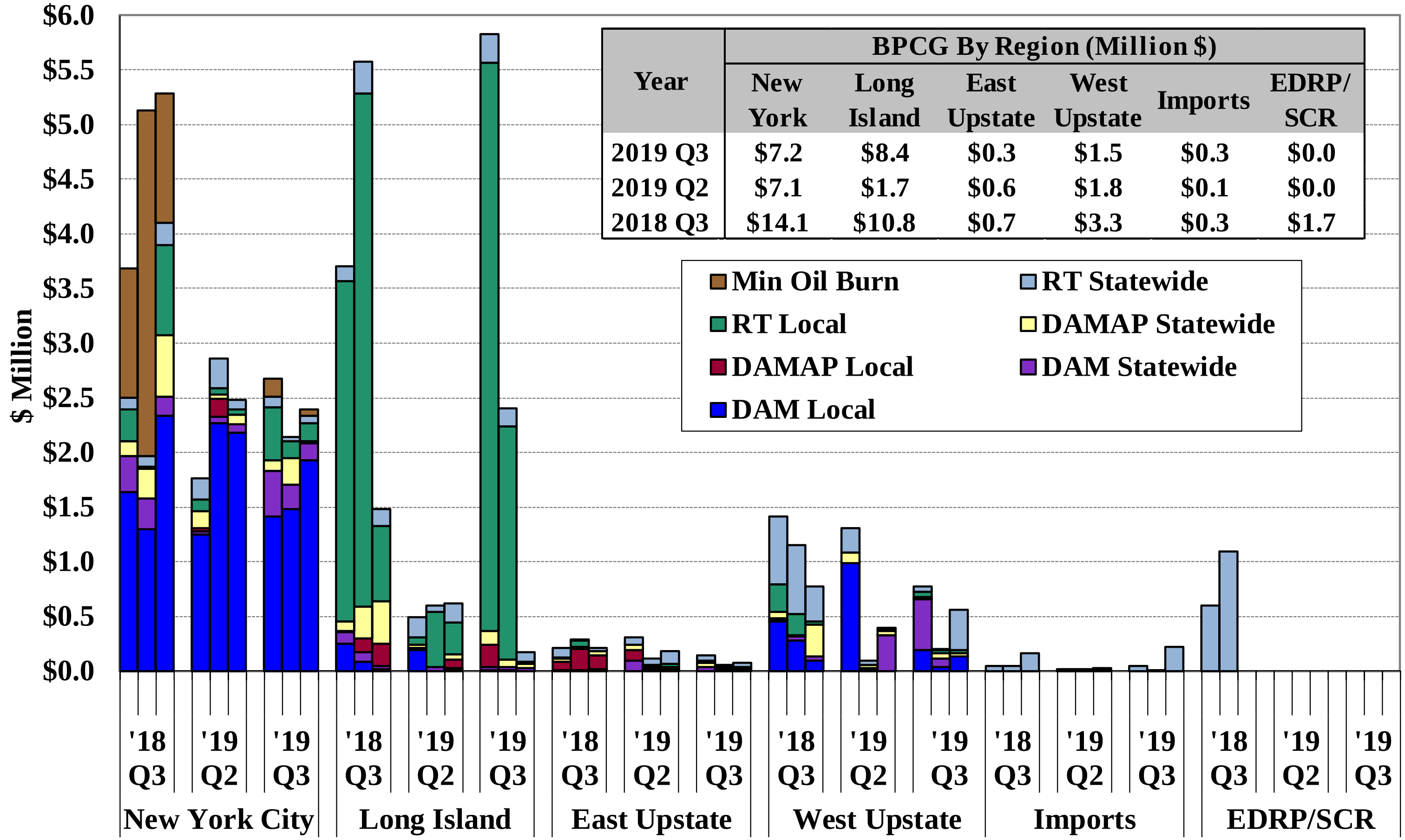
Uplift Costs from Guarantee Payments
Local and Non-Local by Category



Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DA MAP	Min Oil Burn	Day Ahea	Real Time	DA MAP	EDRP/ SCR	
2019 Q3	$5.2	$8.5	$0.2	$0.2	$1.5	$1.4	$0.7	$0.0	$17.7
2019 Q2	$6.6	$1.2	$0.4	$0.0	$1.0	$1.5	$0.6	$0.0	$11.3
2018 Q3	$6.5	$10.4	$0.8	$5.5	$1.1	$2.7	$2.2	$1.7	$30.9

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 92.

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
2019 Q3	$7.2	$8.4	$0.3	$1.5	$0.3	$0.0
2019 Q2	$7.1	$1.7	$0.6	$1.8	$0.1	$0.0
2018 Q3	$14.1	$10.8	$0.7	$3.3	$0.3	$1.7

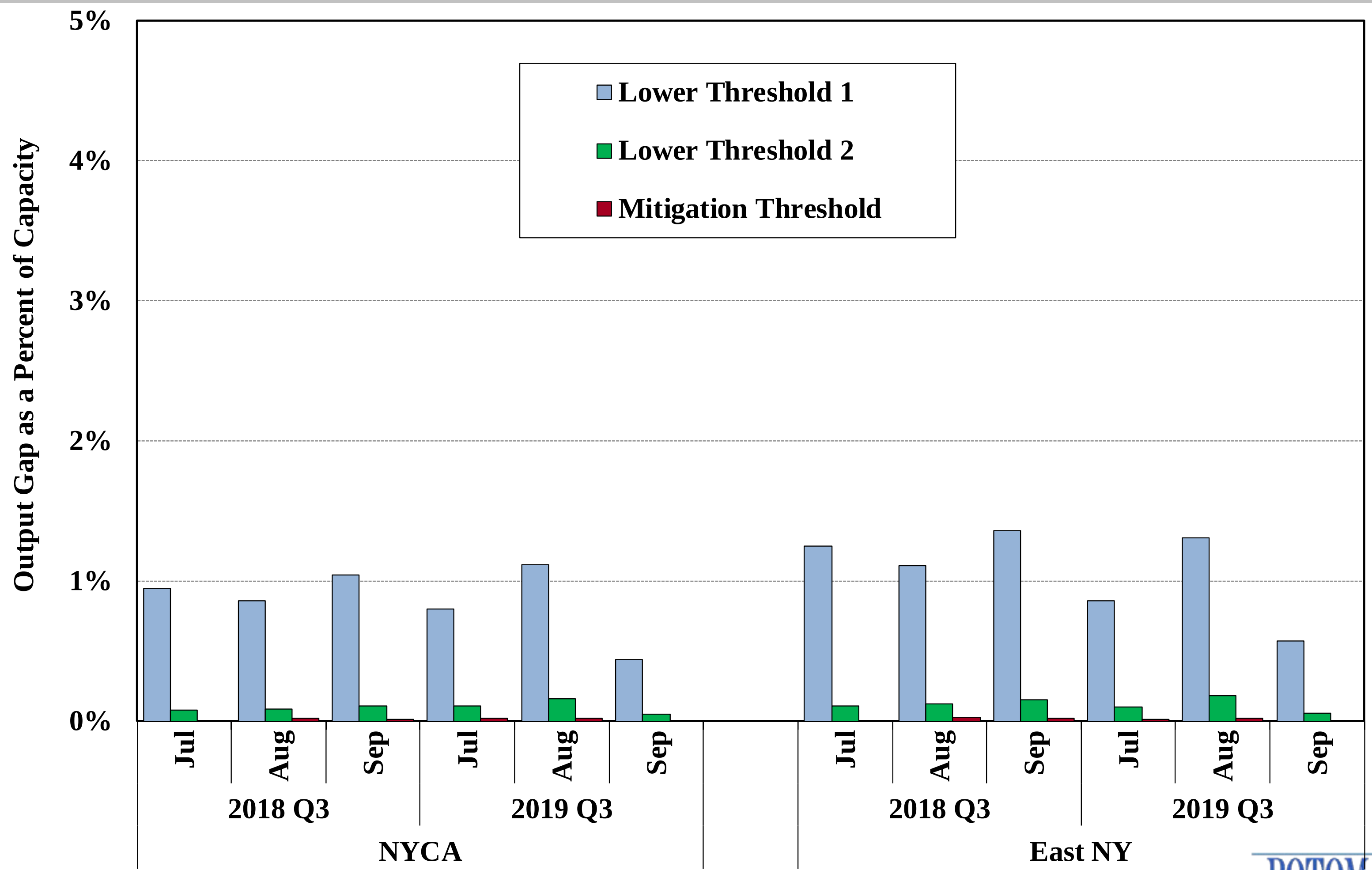
Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 92.

POTOMAC ECONOMICS

Charts:

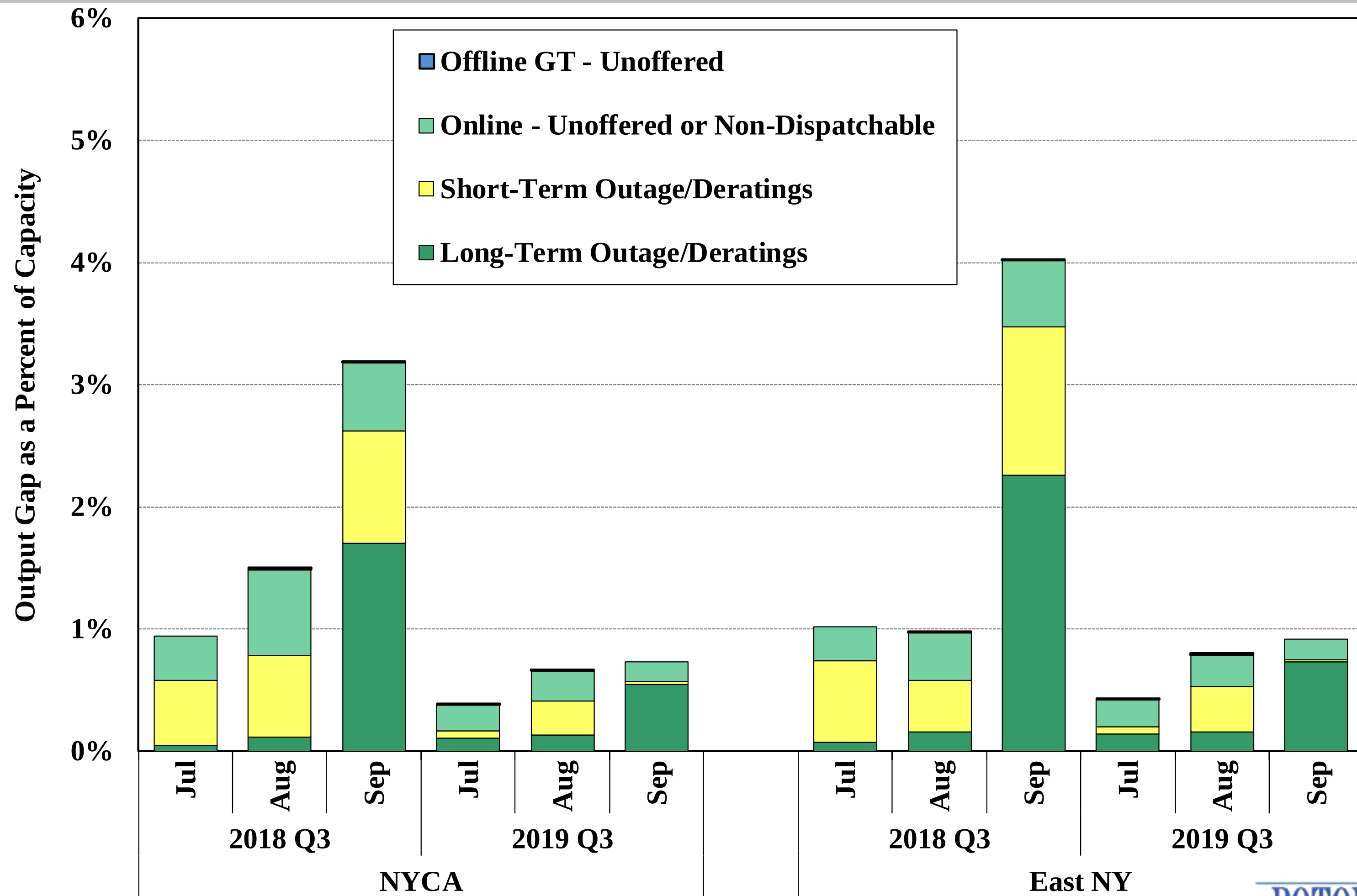
Market Power and Mitigation

Output Gap by Month
NYCA and East NY



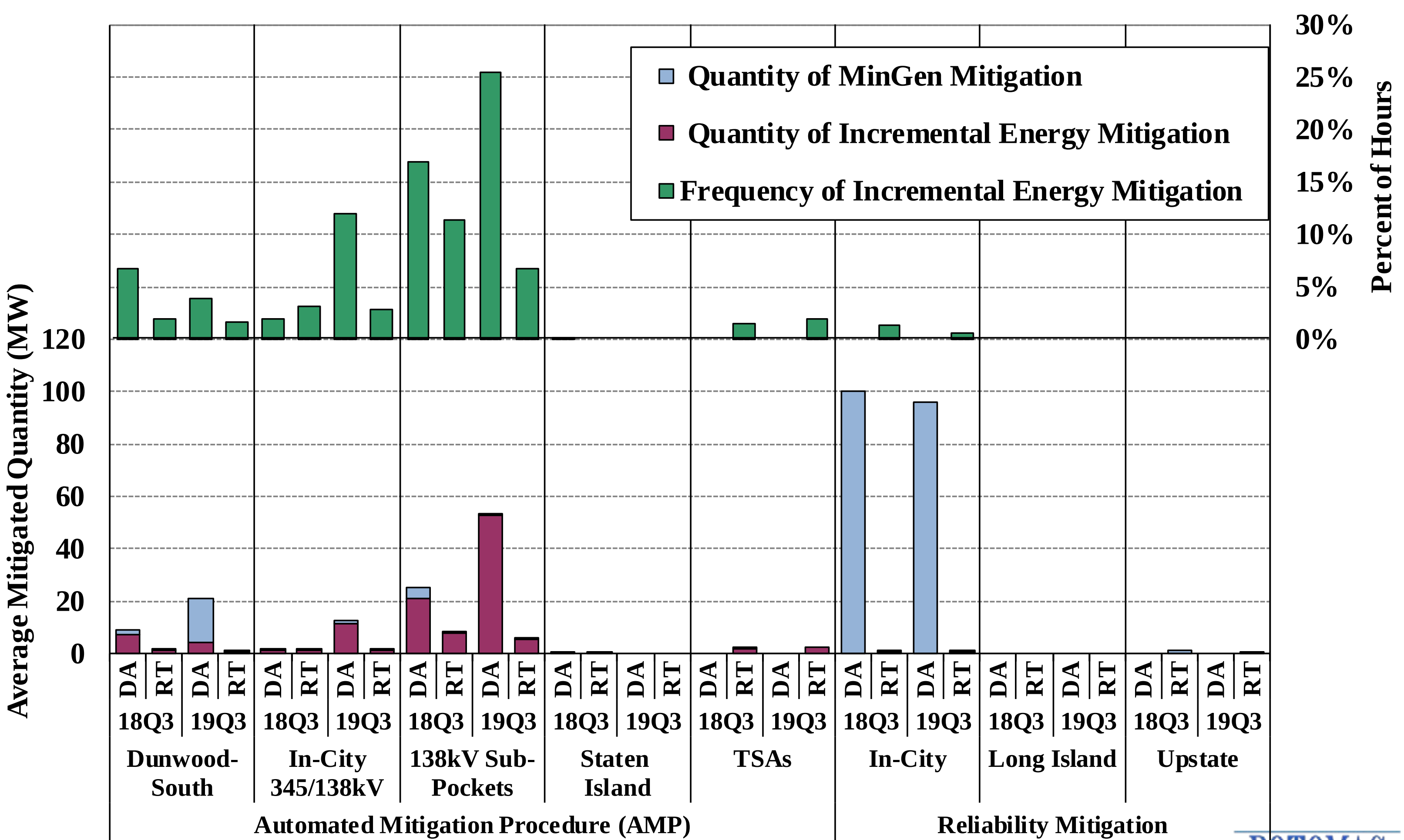
For chart description, see slide 93.
POTOMAC ECONOMICS

Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 93.
POTOMAC ECONOMICS

Automated Market Power Mitigation

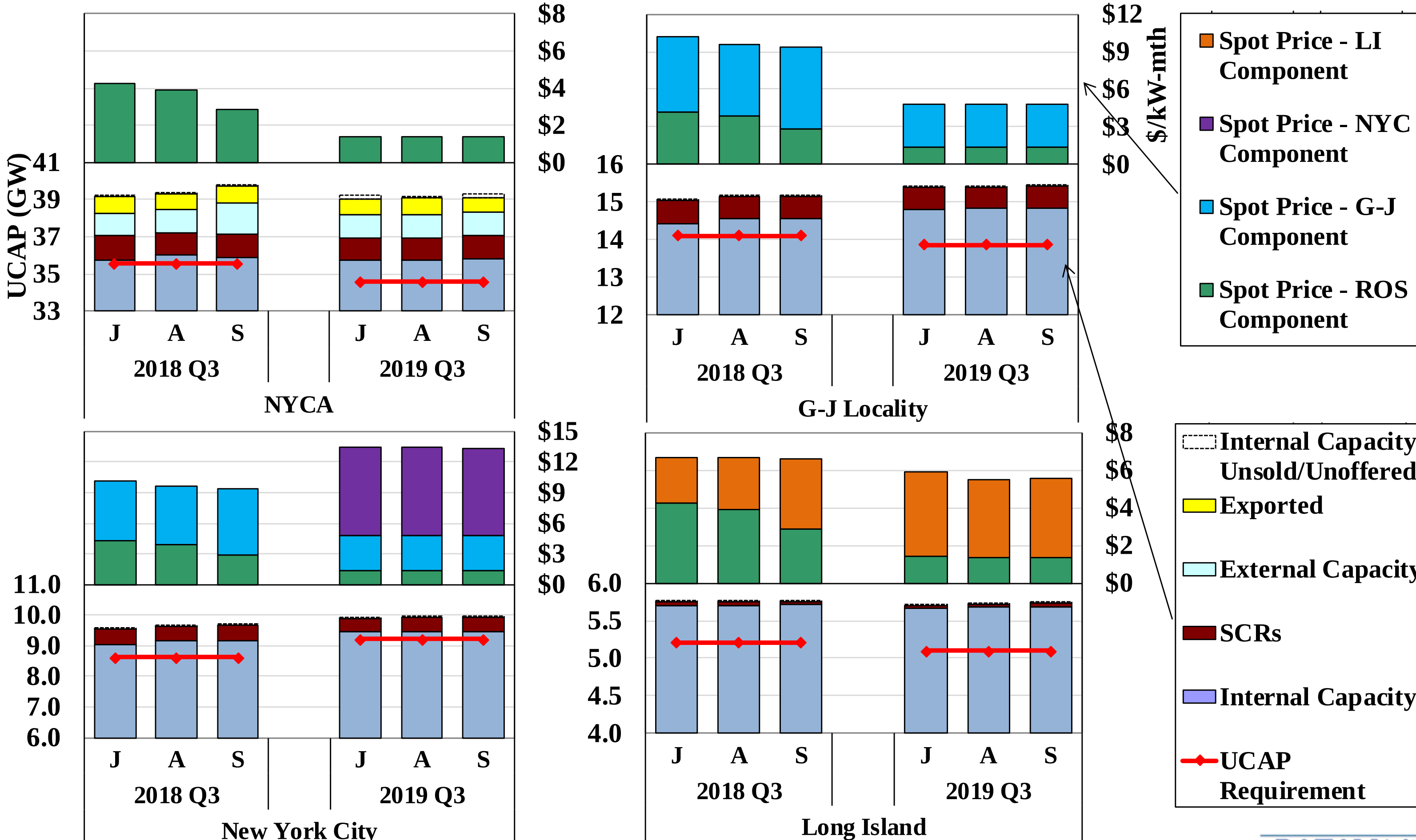


Notes: For chart description, see slide 94.

Charts:

Capacity Market

Spot Capacity Market Results
2018-Q3 & 2019-Q3



Notes: For chart description, see slide 95.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2019 Q3 ($/kW-Month)	$1.37	$13.40	$5.66	$4.80
% Change from 2018 Q3	**-63%**	**38%**	**-15%**	**-50%**
Change in Demand				
Load Forecast (MW)	-519	68	-136	-72
IRM/LCR	-1.2%	2.3%	0.6%	-2.2%
2019 Summer	*117.0%*	*82.8%*	*104.1%*	*92.3%*
2018 Summer	*118.2%*	*80.5%*	*103.5%*	*94.5%*
ICAP Requirement (MW)	**-1,003**	**322**	**-109**	**-417**
Key Changes in ICAP Supply (MW)				
Generation	**24**	**7**	**-16**	**126**
Entry	11	11		11
Exit	-15	-15		-15
DMNC	27	10	-16	130
Cleared Import (1)	**-130**			

(1) Based on quarterly average cleared quantity.

Notes: For chart description, see slide 95.

POTOMAC ECONOMICS

Appendix: Chart Descriptions

All-in Price

- Slide 22 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 25 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 26 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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Ancillary Services Prices

- Slides 31-35 summarize day-ahead and real-time prices for eight ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices in NYC, eastern NY, and Western NY;
  - ✓ 10-min non-spinning reserve prices in NYC, eastern NY, and 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 10 per MW of capability, but they are compensated according to actual movement.
    - – Real-time Regulation Movement Charges shown on Slide 32 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.

NYC Reserve Shortages
Sample Event on July 6

- The NYISO implemented a 10-minute reserve requirement and a 30-minute reserve requirement for New York City in late June.
  - ✓ The demand curve value is set at $25/MWh for both requirements.
- Slide 36 illustrates our initial evaluation of the appropriateness of the $25/MWh value via a sample real-time shortage event on July 6.
  - ✓ An TSA event occurred from 13:00 to 21:00, during which the import capability into SENY was greatly reduced and, accordingly, the SENY 30-minute reserve requirement was reduced to zero.
  - ✓ NYC was short of reserves (either 10-minute or 30-minute or both) from 13:10 to 15:50.
  - ✓ The chart shows the following quantities during shortage intervals (including one hour before and one hour after):
    - – Imports from upstate areas, which are calculated as

      (NYC load – NYC gen – HTP – VFT – Flows on 901/903 lines – Flows on A line)
    - – The amount of reserve shortages, which is calculated as

      Max (10-minute shortage, 30-minute shortage)
  - ✓ The table in the chart summarizes the number of shortage intervals and the average amount of shortages for 2019 Q3.
    - – Periods with and without TSA events are shown separately.

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Day-Ahead NYCA & NYC Reserve Offers

- Slide 37 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).
- Slide 38 summarizes the same quantities for NYC resources only, which also shows 10-minute reserves separately.

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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.

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).

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.

POTOMAC ECONOMICS

RT Congestion Value for Key Constraints and Impacts on West Zone LBMPs – Methodology

- Slide 50 depicts a stylized map of the western New York system, which excludes some detail but also includes some aggregation for simplicity.
  - ✓ Only lines with significant congestion are highlighted, and some buses, like Erie and Stolle Rd., are not represented in detail.
- The text boxes indicate the facilities (including lines and transformers) and the associated RT congestion value during the quarter.
  - ✓ The figure only shows facilities with the largest RT congestion values during the quarter.
  - ✓ The congestion value for the entire line shown includes the sum of any congestion values for any segment of the line.
- The circles in the figure represent generators and vary in size depending on capacity level, while the color represents a simple average RT LBMP at the node during the quarter.
  - ✓ The lower LBMPs are identified with a shade of blue and the lowest value has the darkest shade.
  - ✓ Relatively higher LBMPs are represented with shades of pink to red with the generators associated with the highest LBMPs shown in red.

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NY-NJ PAR Operation Under M2M with PJM

- Slide 51 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 52 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 Gardenville-to-Dunkirk circuits;
  - ✓ Central Zone: Mostly constraints around Syracuse;
  - ✓ Capital Zone;
  - ✓ North Zones: 115kV constraints on facilities that flow power into the North Zone; and
  - ✓ Long Island: Mostly constraints on the 69kV system on Long Island.

POTOMAC ECONOMICS

Constraints on the Low Voltage Network

- Slide 53 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 Pilgrim-Hauppaug and Hauppaug-Central Islip circuits;
  - ✓ East End: Mostly to satisfy 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 53 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.

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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 54 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 bars in the right panel show the seasonal LTE and STE ratings for these facilities, compared to the average N-1 constraint limits used in the market software.

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Impact of Securing In-Series Line Segments in the Market Models

- A number of facilities representing in-series segments of the same transmission line were secured in the market models.
  - ✓ The NYISO identified increased congestion prices when multiple such segments were priced simultaneously by the GTDC.
  - ✓ As a result, the NYISO proposed to remove in-series segments on 21 transmission lines from the market models, effective September 24, 2019.
- Slide 55 summarizes real-time market impact from these line segments in 2019 prior to their removal from the market models.
  - ✓ The table shows the following quantities:
    - – # RT Intervals – the total number of real-time intervals, during which multiple segments of the line were priced simultaneously by the GTDC.
    - – RT Congestion Value – the estimated congestion values on the binding line segments in the real-time market (i.e., constraint shadow price*line flows).
    - – BMCR – the balancing congestion shortfalls accrued on the binding line segments when identified issues occurred.
    - – LBMP Impact – the real-time LBMP impact at relevant Zones that resulted from the identified issues. This is shown as an annual average.

POTOMAC ECONOMICS

Optimized Adjustment of Initialized LEC by RTC

- Slide 56 shows an example distribution of congestion price inconsistencies between RTC and RTD versus differences in initialized LEC MWs.
  - ✓ The sample data are selected from: 1) the RTC intervals that had an initialized LEC MW from 50 to 100 MW in the clockwise direction; and 2) their corresponding RTD intervals.
    - The study period includes the first nine months of 2019.
  - ✓ The x-axis shows the difference in initialized LEC MW between RTC and RTD, grouped by 10 MW. Positive numbers indicate LEC in the clockwise direction.
    - For example, 10 MW on the x-axis indicates that the RTD initialized LEC MW is higher than RTC initialized LEC MW by 0 to 10 MW in the clockwise direction.
  - ✓ The bars represent the congestion price inconsistency between RTC and RTD for each LEC tranche.
    - The congestion price difference is measured at the Niagara plant, which is heavily dependent on LEC, between RTD and RTC.
    - The absolute value of this difference is taken from each RTD interval and then averaged over all intervals for each LEC tranche.
  - ✓ The line shows the frequency distribution of each LEC tranche.

Optimized Adjustment of Initialized LEC by RTC

- Slide 57 shows our preliminary results on optimized adjustments for LEC initialization by RTC.
  - ✓ The optimized adjustment is done in a way that minimizes the congestion price inconsistency between RTC and RTD.
    - In the example shown in slide 56, the congestion inconsistency can be measured by multiplying the frequency distribution (the line) with the congestion price inconsistency (the bar) and summing over all LEC tranches. This is simply done for a no-adjustment scenario.
    - For any adjustment, the optimization moves the frequency distribution either leftwards (for adjustments in the clockwise direction) or rightwards (for adjustments in the counter-clockwise direction), then multiplies the shifted frequency curve with the unshifted bars.
    - The optimized adjustment is identified as the one that results in the smallest congestion inconsistency number.
  - ✓ In the chart,
    - The blue line indicates the unadjusted RTC LEC initialization.
    - The black line indicates adjusted RTC LEC initialization currently done by the NYISO, which caps any counter-clockwise LEC at zero.
    - The green line shows the optimized adjustments from our analysis.

Supplemental Commitments and OOM Dispatch

- Slides 59, 60, and 61 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 59 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 60 examines the reasons for reliability commitments in NYC where most reliability commitments occur.
  - ✓ Based on a review of operator logs and LRR constraint information (where a unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit’s capacity), each NYC commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:

Supplemental Commitments and OOM Dispatch (cont.)

  - NOx – If needed for NOx bubble requirement.
  - N-1-1 – If needed for one or two of the following reasons: voltage support (ARR 26), and thermal support (ARR 37).
  - Loss of Gas – If needed for IR-3, a sudden loss of gas supply in NY, and no other reason except NOx.
- ✓ For N-1-1 constraints, the capacity is shown by the load pocket that was secured.

- Slide 61 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 62 and 63 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 62 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 63 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 65 and 66 show the results of our screens for attempts to exercise market power, which may include economic and physical withholding.
- The screen for potential economic withholding is the Output Gap, which is the amount of economic capacity that does not produce energy because a supplier submits an offer price above the unit's reference level by a substantial threshold.
  - ✓ We show output gap in NYCA and East NY, based on:
    - The state-wide mitigation threshold (the lower of $100/MWh and 300 percent); and
    - Two other lower thresholds (100 percent and 25 percent).
- The screen for potential physical withholding is the Unoffered Economic Capacity, which is the amount of economic capacity that is not available to the market because a supplier does not offer, claims a derating, or offers in an inflexible way.
  - ✓ We show the unoffered economic capacity in NYCA and East NY, from:
    - Long-term outages/deratings (at least 7 days);
    - Short-term outages/deratings (less than 7 days);
    - Online capacity that is not offered or offered inflexibly; and
    - Offline GT capacity that is not offered in the real-time market.
  - ✓ Long-term nuclear outages/deratings are excluded from this analysis.

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Automated Market Power Mitigation

- Slide 67 summarizes the automated mitigation that was imposed in the day-ahead and real-time markets (not including BPCG mitigation) in the quarter.
  - ✓ The bars in the upper panel shows the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category.
  - ✓ The bars in the lower panel shows the average mitigated capacity.
    - – Mitigated quantities are shown separately for flexible output range of units (i.e., Incremental Energy) and the non-flexible portion (i.e., MinGen).
  - ✓ The left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on economically committed units in NYC load pockets.
  - ✓ The right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.
  - ✓ Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

Spot Capacity Market Results

- Slides 69 and 70 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 69 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 70 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.