Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2020

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Market Highlights

Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the third quarter of 2020.
- All-in prices ranged from $22 in North Zone to $69/MWh in NYC. (slide 7)
  - ✓ All-in prices were up in Zones A-F (1-11%) and in NYC (21%) but down in the Hudson Valley (-18%) and in Long Island (-6%).
  - ✓ As reported in our 2020 Q2 report, capacity costs constituted the majority of NYC all-in prices (62 percent) because of an increased LCR and very low energy prices.
  - ✓ Natural gas prices remained historically low with average prices this quarter being lower than any third quarter for more than a decade.
  - ✓ Load levels were comparable to 2019 Q3 levels as the effects of the Covid-19 pandemic were largely offset by warmer summer weather.
- Lower load levels and natural gas prices led to lower transmission congestion (slides 8-9) and uplift. (slide 13)
- Generation patterns and the distribution of installed capacity have changed with the retirement of the Indian Point 2 nuclear unit and last two coal plants and with the new entry of the Cricket Valley Energy Center. (slides 24 & 73)

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Market Highlights:
Executive Summary

- Out-of-market actions were used frequently during the third quarter of 2020 to maintain reliability and transmission security.
  - ✓ In New York City, OOM commitments occurred daily to maintain adequate reserves to satisfy N-1-1-0 criteria for several 138 kV load pockets and for the 345 kV system. (slides 13 & 17)
  - ✓ On Long Island, OOM dispatch occurred on 71 days to secure 69 kV transmission facilities in four load pockets. (slides 11-13)
  - ✓ In upstate New York, OOM commitments occurred in the forecast-pass of the DAM and/or in the SRE-commitment process on 12 days to satisfy NYCA reserve requirements. (slides 13-14)
  - ✓ In New York City, transmission congestion is often managed scheduling operating reserves through an OOM cost-of-service agreement. (slide 18)
  - ✓ These OOM actions led to significant uplift charges and depressed clearing prices, particularly for operating reserves.
- Satisfying these operational requirements through the market would significantly improve incentives for investment in flexible resources.
  - ✓ We have recommended addressing these issues (see SOM Recommendations #2015-16, #2016-1, #2017-1, and #2018-1).

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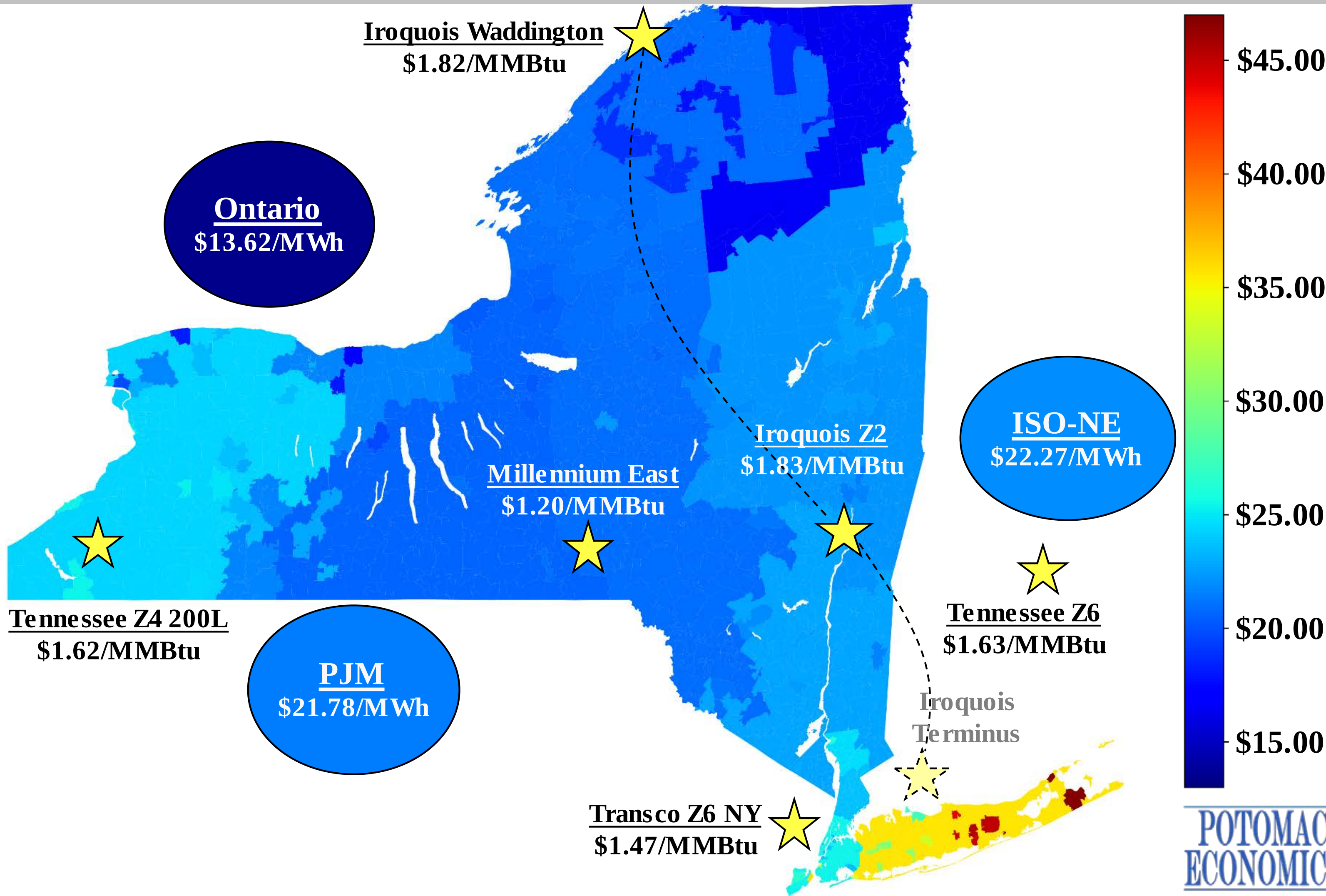
Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- The amount of output gap (slide 68) and unoffered economic capacity (slide 69) remained low and reasonably consistent with competitive market expectations.
- Average all-in prices ranged from roughly \$22/MWh in the North Zone to \$69/MWh in NYC. (slide 21)
  - ✓ All-in prices fell by as much as 18 percent in LHV but rose by 21 percent in NYC.
  - ✓ Energy prices decreased in all regions, falling by 1 to 11 percent from the previous year (slides 26-27), driven primarily by historically low natural gas prices.
    - – Average natural gas prices fell 15 to 24 percent from a year ago (slide 23), resulting in the lowest quarterly average price for a third quarter seen since at least 2009.
    - – Load levels fell on average (1 percent) but peak load rose to a small extent (1 percent): (slide 22).
      - Effects of the COVID pandemic may have reduced average load by about 3 percent for the quarter.
      - Load reductions were largest in NYC (6 percent) while many other regions saw increased load for the quarter (2 percent in Long Island, for example).
  - ✓ Capacity costs fell by 16 percent on Long Island and 42 percent in LHV, but capacity costs rose by 52 percent in NYC and between 60-103 percent in the ROS regions for the reasons discussed later (slide 19).

Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $84 million, down 34 percent from a year ago, primarily because of lower gas prices. (slide 48)
  - ✓ The Covid-19 pandemic muted much of the effects of an otherwise hot summer which helped to prevent otherwise higher levels of congestion, especially in NYC.
- Long Island accounted for the largest share of congestion (33 percent) this quarter, which rose 69 percent in DA ($11.4 million) and 11 percent in RT ($2.2 million) from a year ago.
  - ✓ LI natural gas prices, despite historic lows, were the highest among East NY regions. (slide 23)
  - ✓ Load increased on Long Island in line with shift to higher residential cooling needs from the Covid-19 pandemic and the hotter than normal summer weather.
  - ✓ Several major transmission outages also contributed to higher LI congestion.
    - The Dunwoodie-Shore Rd 345 kV (“Y50”) line was OOS for several brief periods in July and August for a total of roughly two weeks;
    - The Neptune line was affected by outages from early September throughout the quarter, reducing import capability from 660 to 375 MW; and
    - The Cross Sound Cable was OOS from early July throughout the quarter, increasing congestion in the East of Northport load pocket.

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

- West Zone accounted for the second largest share of congestion (28 percent).
  - ✓ West Zone congestion fell 27 percent in DA and 33 percent in RT from a year ago.
  - ✓ Most of this congestion occurred on the transmission facilities in the Niagara area, driven partly by multiple transformer outages (slide 50).
  - ✓ The DA saw more congestion share along 115 kV constraints (66 percent) while the RT congestion was driven more by 230 kV constraints (66 percent).
- New York City constraints accounted for just about 14 percent of congestion in the third quarter of 2020. (slide 49)
  - ✓ Congestion fell by nearly 42 percent in NYC from the prior year.
  - ✓ The Covid-19 pandemic impacted commercial load in NYC, reducing NYC load by 7-8 percent (based on weather-normalized values).
  - ✓ NYC generation became more economic as a result of lower gas prices.
- North Zone congestion rose by 41 percent from a year ago. (slide 49)
  - ✓ Nearly all of this congestion occurred on the Moses-Adirondack 230 kV MA1 line when the parallel MA2 line was OOS all quarter. (slide 50)
    - – This outage has been primarily related to the Moses-Adirondack Smart Path Reliability Project.

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Market Highlights:
Regulation Market Costs and Performance

- The overall market costs of procuring and deploying regulation have been declining since 2018. (slide 35)
  - ✓ Regulation capacity and movement prices have fallen consistent with energy prices.
  - ✓ The regulation requirement, which generally varies by hour by season, was increased modestly in September 2020.
  - ✓ Average regulation movement (relative to scheduled regulation capacity) has varied substantially from month to month.
- Although resources are scheduled assuming a Regulation Movement Multiplier of 13 MW per MWh of Regulation Capacity, they are deployed according to their ramp capability and system requirements and compensated based on instructed movement.
  - ✓ Individual resources exhibit a wide range of movement-to-capacity ratios although the average ratio was close to 13. (slide 36)
  - ✓ Using a common multiplier for all units (i.e., 13) can significantly underestimate the cost of fast-ramping resources in the scheduling process.
    - This led to uplift (with uplift $ per movement MW of up to 150 percent of movement clearing price) for some fast-ramping resources.
    - This gives some fast-ramping resources incentives to raise their movement offer prices above marginal cost, which is not efficient. We will continue to monitor regulation market performance as the number of fast-ramping resources increases.

Market Highlights:
Out of Market Actions to Manage Congestion

- The NYISO has greatly reduced the use of OOM actions over the last two years to manage low-voltage transmission constraints by modeling most 115kV constraints in the DA and RT market models.
  - ✓ The NYISO has an ongoing process to evaluate and add unmodelled 115kV constraints to the market models.
- However, OOM actions to manage lower-voltage network congestion were frequent in Long Island (71 days) this quarter. (slide 53)
  - ✓ OOM actions were frequently used to manage 69 kV constraints in several load pockets, including the East of Northport (35 days) and Valley Stream (58 days) load pockets. (slide 54)
  - ✓ Lack of gas service to the East End of Long Island required high-cost oil-fired peakers to be OOMed for TVR under high load conditions on 70 days. (slide 54)
  - ✓ Frequent OOM actions undermine market efficiency, leading to:
    - – Inefficient scheduling (slide 12);
    - – Depressed price signals (slide 54); and
    - – High BPCG uplift (slides 65-66).

Market Highlights:

Use of Oil-fired Generation in East of Northport

- Oil-fired peakers are often used to manage congestion into the East of Northport load pocket on 69 kV (35 days) and 138 kV (68 days) circuits. (slide 54)
  - ✓ 69 kV constraints are currently not secured in the market software.
  - ✓ One of the 138 kV lines on the interface into the pocket is controlled by the Pilgrim PAR and generally operated to reduce flows over the 69 kV lines into the pocket.
    - – PAR-adjustments to relieve 69 kV lines increase flows over parallel 138 kV lines.
    - – Since 69 kV constraints are not modeled, Pilgrim PAR-adjustments are not forecasted accurately by SCUC or RTC, so they do not have information necessary to schedule generation and external transactions efficiently. (slide 55)
    - – NYISO made an improvement in mid-July to forecast Pilgrim PAR flows more accurately in the DAM, which helps commit generation more efficiently inside the pocket.
- Low-cost (e.g., gas-fired) resources were frequently available to manage congestion without oil-fired generation on these days. (slide 55)
  - ✓ Sufficient low-cost resources were available to manage congestion without oil-fired generation in an estimated 170 hours.
  - ✓ Inefficient operation of oil-fired units could be reduced significantly by securing certain 69 kV circuits using the market models.

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $20.6 million, up 16 percent from the third quarter of 2019 (slides 65-66).
  - ✓ The increase was driven primarily by OOM commitment and dispatch for local reserve needs and transmission congestion, particularly on Long Island.
- $5.5 million (or 26 percent) of BPCG payments were paid to NYC units that were committed for local reliability needs. (slide 66)
  - ✓ Reliability commitments in NYC accounted for nearly 91 percent of all reliability commitments this quarter. (slide 59)
- $13 million (or 63 percent) of BPCG payments were paid to Long Island units mostly OOMed to manage local reliability on the 69 kV network and TVR needs on the East End of Long Island. (slides 61, 66)
- Forecast-pass commitments in the DAM were significant on several days, although they did not generate much BPCG uplift. (slide 58)
  - ✓ This was to fill in the gap between the statewide: (a) forecast load plus reserve requirement and (b) scheduled energy plus reserves.
- Modeling the unpriced reliability needs (i.e., reserve needs in NYC load pockets, 69 kV Long Island constraints, statewide forecast load plus reserves) would greatly improve market efficiency for resource scheduling and pricing.

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Market Highlights:
SRE for Capacity on High Load Days

- Despite several heat waves this summer, load exceeded 30 GW on just one day because of the load-reducing effect of the Covid-19 pandemic.
  - ✓ Summer load peaked at 30.7 GW on July 27, roughly 95 percent of the 50/50 forecast of 32.3 GW.
  - ✓ NYISO did not activate any EDRP/SCRs in the third quarter of 2020.
  - ✓ However, NYISO SREed resources for statewide capacity needs on four days.
  - ✓ See presentation "NYISO Summer 2020 Hot Weather Operations" by Wes Yeomans at 9/23 MC meeting for more details.
- Our evaluation suggests that, in retrospect,
  - ✓ SREs were needed to prevent brief NYCA capacity deficiencies on August 10 and 24, but they were not needed on August 11 and 25. (see slides 62 and 63)
    - – SREs are necessary to avoid a capacity deficiency when:

      normal 30-min reserve need > all available capacity (without SRE)
    - – On August 11 and 25, actual load was far below forecast (by ~1-2 GW), and 30-minute reserves were priced at $0/MWh during afternoon peak hours.
  - ✓ Although the additional costs associated with these SREs (i.e., BPCG uplift) were not large in this period, they were incurred to satisfy reserve needs that are not fully reflected in the day-ahead market.

Market Highlights:
Utility DR Activations on High Load Days

- Various amounts of Utility DR were activated on 21 days this quarter, although the quantity exceeded 100 MW on just eight days.
  - ✓ Roughly half of utility DR activations on these eight days were for peak-shaving and distribution system security in New York City and the other half for peak-shaving outside NYC.
  - ✓ The statewide DR quantity ranged up to nearly 550 MW on July 27 (when NYCA peak demand was roughly 30.7 GW).
  - ✓ Utility DR deployments are not considered when NYISO evaluates whether to SRE or deploy emergency DR resources, which can lead to unnecessary OOM actions.
- Utility DR deployments helped avoid a brief NYCA capacity deficiency on just two days (7/9 and 7/27). (see slide 62)
  - ✓ Utility DR tests occurred on two days.
  - ✓ The economics of the energy market did not indicate a need for peak load reduction on the other four days.
  - ✓ Utility DR resources are paid primarily for availability (including capacity).
    - – Utility programs often provide large payments (~$1,000/MWh) for peak-shaving that are far above the value of the load reduction in the real-time market.

Market Highlights:
Auditing of Non-synchronous Reserve Providers

- The NYISO routinely audits 10- and 30-minute non-synchronous reserve providers to ensure that they are capable of providing these reserve services.
  - ✓ Recent NYISO procedural enhancements aim to audit each GT either (a) once per Capability Period or (b) at least once per Capability Year.
- We reviewed NYISO audit results and found that the frequency of GT audits has increased markedly in recent months. (slide 57)
  - ✓ There have been 121 audits (on 114 unique GTs) during the Summer 2020 Capability Period (not including October), much higher than historically observed—an average of 49 GT audits were performed annually from 2016 to 2019).
    - – Units with relatively poor performance and/or infrequent market-based commitment have been audited much more frequently under these new procedures.
    - – Units that have performed poorly in recent years have been 100 percent successful during this period when audited.
- Further enhancements to this process could be beneficial such as:
  - ✓ Using performance during reserve pick-ups or economic starts in lieu of audits would reduce out-of-market actions and uplift costs.
  - ✓ Since units that perform well during audits may still perform poorly during normal market operations, it may be necessary to suspend or disqualify poor performers.

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Market Highlights:
Excess NOx-Rule LRR Commitments in NYC

- The NOx rule prevents NYC GTs in two portfolios from generating during the Ozone season unless steam turbines in the same portfolios are also producing such that the portfolio-average NOx emission satisfies the DEC standard.
  - ✓ A steam turbine was committed solely to satisfy the NOx rule on 26 days during the third quarter. On 15 days, steam turbine commitments were either not needed or not the least cost resource for satisfying the reliability need. (slide 64)
  - ✓ Our evaluation shows that even if the committed steam turbine and the associated GTs were unavailable, all N-1-1-0 criteria in the associated load pockets could have been satisfied by other committed resources on 13 days or lower-cost resources on the other two days.
    - – The supply margin (excluding the committed steam turbine and associated GTs) was often very large, although conditions tightened towards the end of September as units began taking seasonal maintenance outages. (slide 64)
    - – This suggests that these NOx-only steam turbine commitments could have been avoided if the market software was allowed to consider whether the GTs were actually needed for reliability (before committing the associated steam turbine).
  - ✓ These avoidable NOx-only commitments depress prices, generate uplift, and cause excess production costs and NOx emissions.

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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 2020-Q3, 56 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 56)
  - ✓ The additional capability above LTE averaged from about 10 to 25 MW for the 138 kV constraints in the Greenwood load pocket to roughly 215 to 235 MW for 345 kV facilities in other NYC load pockets.
    - These increases were largely due to operating reserve providers in NYC, but they are not compensated for this service.
    - This reduces 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 should efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria. (see Recommendation #2016-1 in our 2019 SOM report)

Market Highlights:
Capacity Market

- Average spot capacity prices ranged from $2.61/kW-month in ROS and the G-J Locality to $18.79/kW-month in New York City this quarter. (slides 72-73)
- Capacity prices rose in ROS (91 percent) and in NYC (40 percent) but fell in the G-J Locality (46 percent) and in Long Island (8 percent) from a year ago.
  - ✓ Changes in demand were one primary driver of these price changes, due largely to changes in IRM and LCRs. Peak load forecast fell slightly in all regions.
    - – The NYCA IRM rose from 117 to 118.9 percent and the LCR rose from 82.8 to 86.6 percent in NYC.
    - – However, the LCR fell from 92.3 to 90.0 percent in the G-J Locality and from 104.1 to 103.4 percent on Long Island.
  - ✓ Changes in supply were also a key driver.
    - – In the G-J Locality, Indian Point 2 retired at the end of April, which was, however, roughly offset by the entry of the Cricket Valley energy center.
    - – In ROS, Kintigh retired at the end of March and both Cayuga units retired in June, marking the end of coal-fired generation in NYISO.
    - – Higher imports and fewer exports helped partially offset the increase in ROS prices.
  - ✓ ICAP Reference Prices rose in all Localities, from $0.82 in NYCA to $1.92 per kW-month in Long Island.

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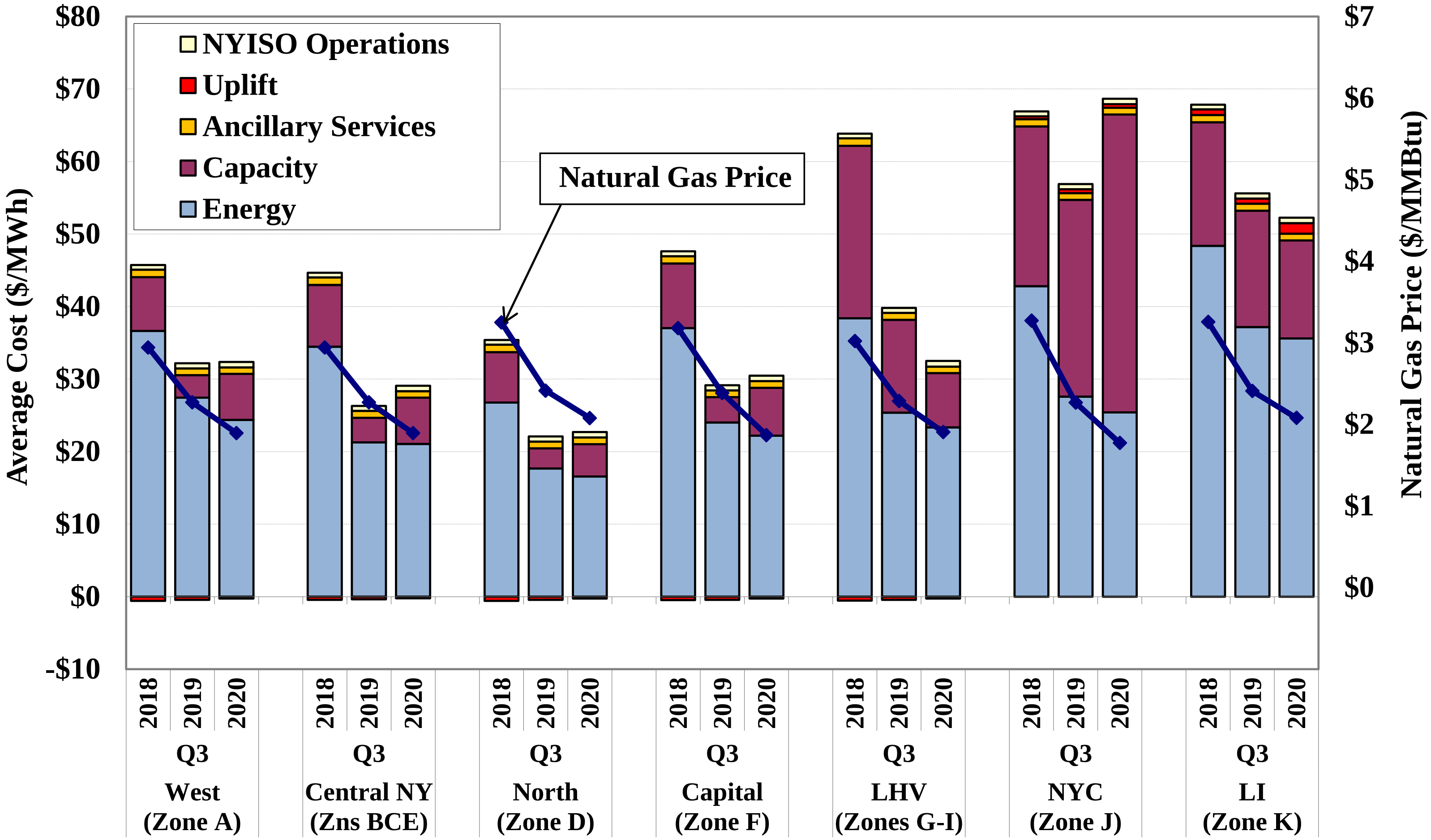
Charts:

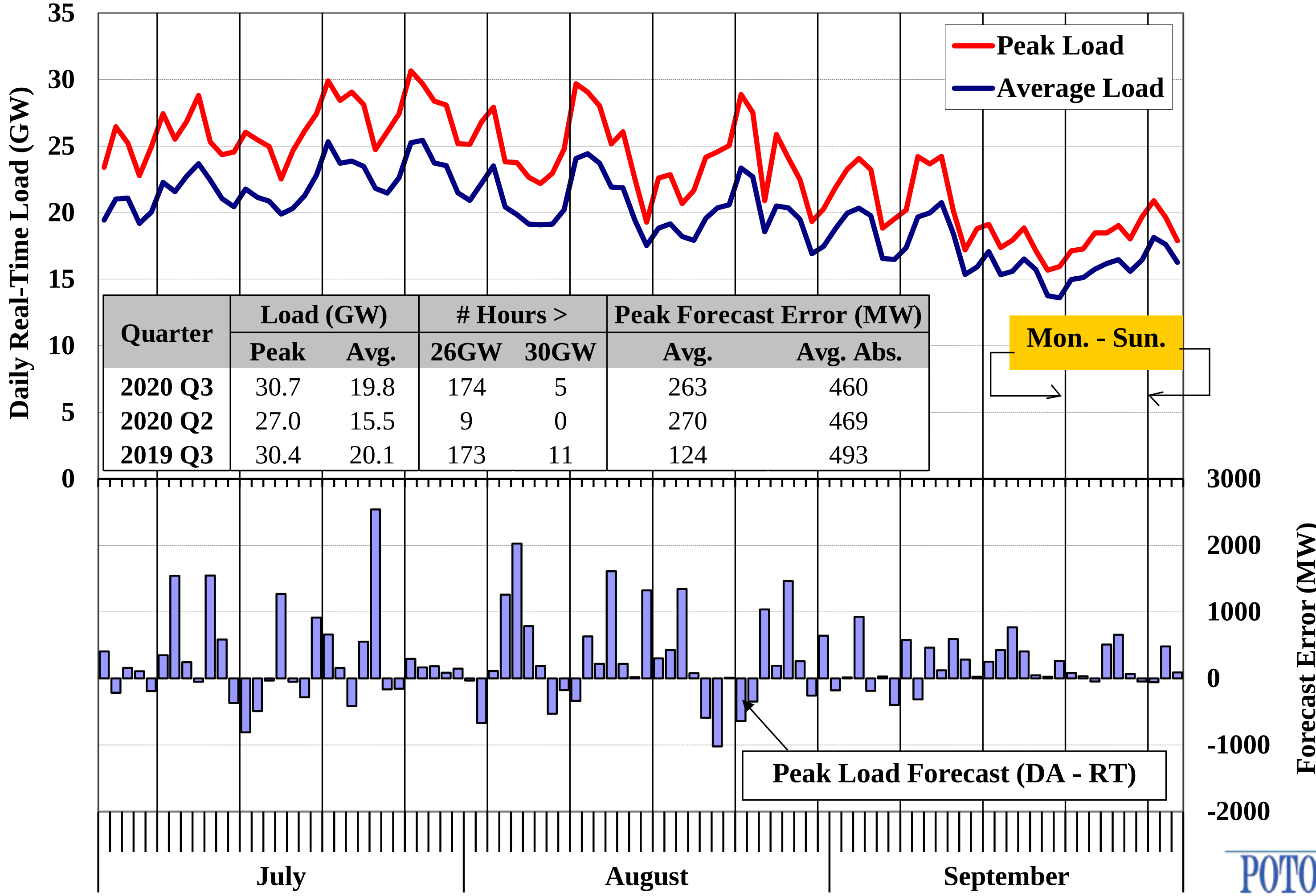
Market Outcomes

All-In Prices by Region



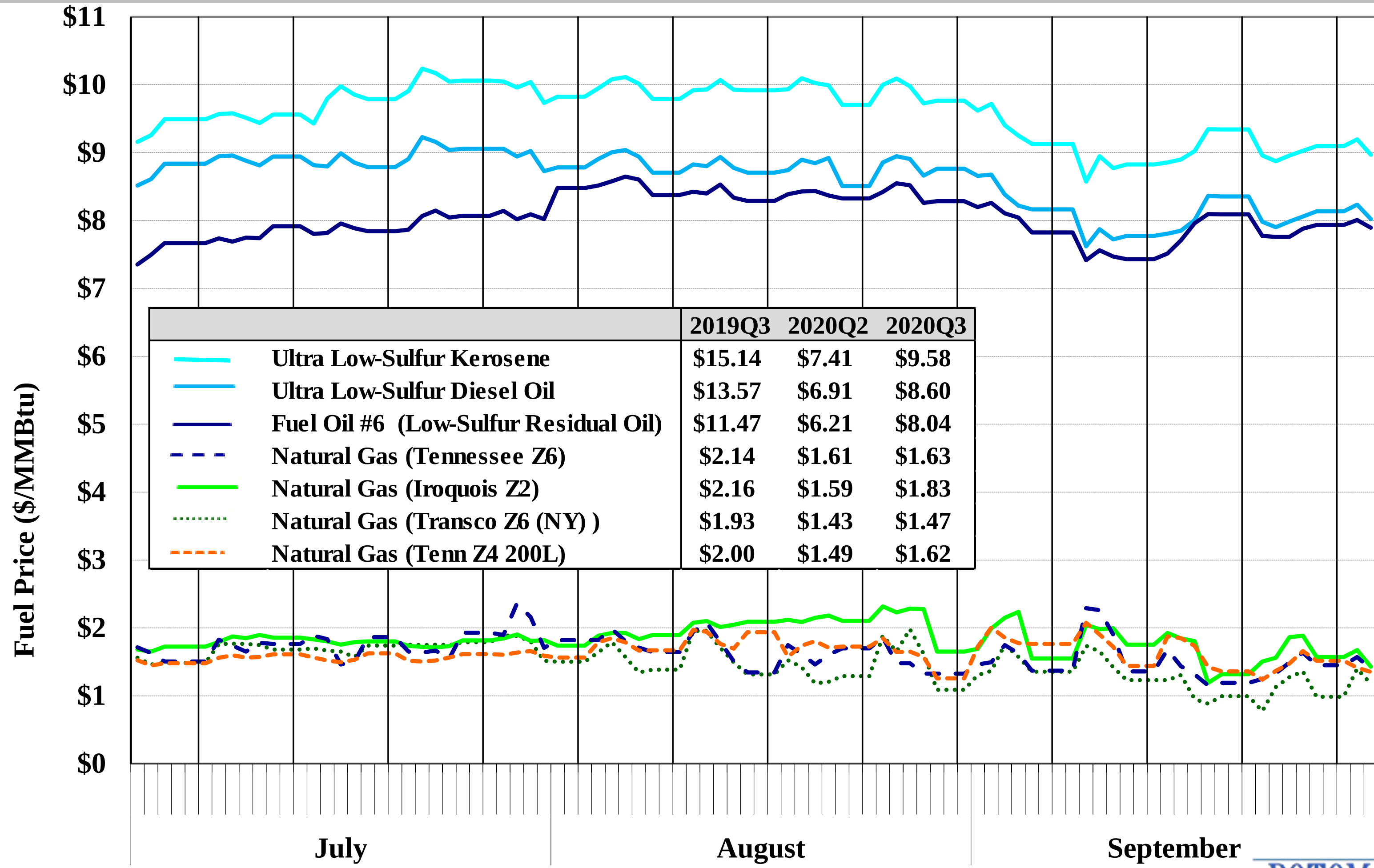
Notes: For chart description, see slide 75.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2020 Q3	30.7	19.8	174	5	263	460
2020 Q2	27.0	15.5	9	0	270	469
2019 Q3	30.4	20.1	173	11	124	493

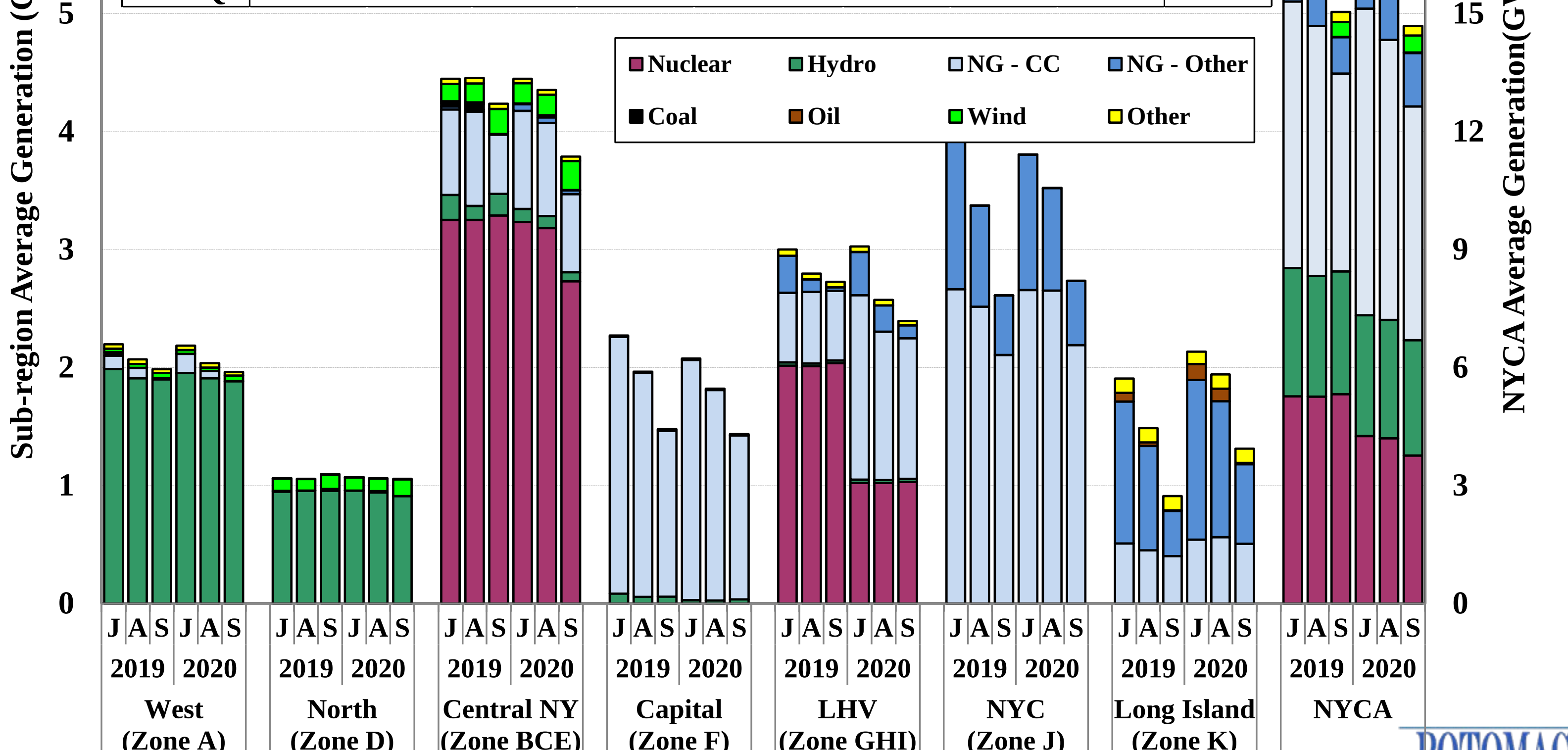
Natural Gas and Fuel Oil Prices



	2019Q3	2020Q2	2020Q3
Ultra Low-Sulfur Kerosene	$15.14	$7.41	$9.58
Ultra Low-Sulfur Diesel Oil	$13.57	$6.91	$8.60
Fuel Oil #6 (Low-Sulfur Residual Oil)	$11.47	$6.21	$8.04
Natural Gas (Tennessee Z6)	$2.14	$1.61	$1.63
Natural Gas (Iroquois Z2)	$2.16	$1.59	$1.83
Natural Gas (Transco Z6 (NY))	$1.93	$1.43	$1.47
Natural Gas (Tenn Z4 200L)	$2.00	$1.49	$1.62

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
2020 Q3	4.08	3.00	0.00	6.96	2.20	0.10	0.35	0.25	16.94
2020 Q2	4.22	3.30	0.00	4.32	0.81	0.01	0.46	0.27	13.39
2019 Q3	5.28	3.15	0.04	6.07	1.88	0.05	0.32	0.27	17.04



Notes: For chart description, see slide 76.

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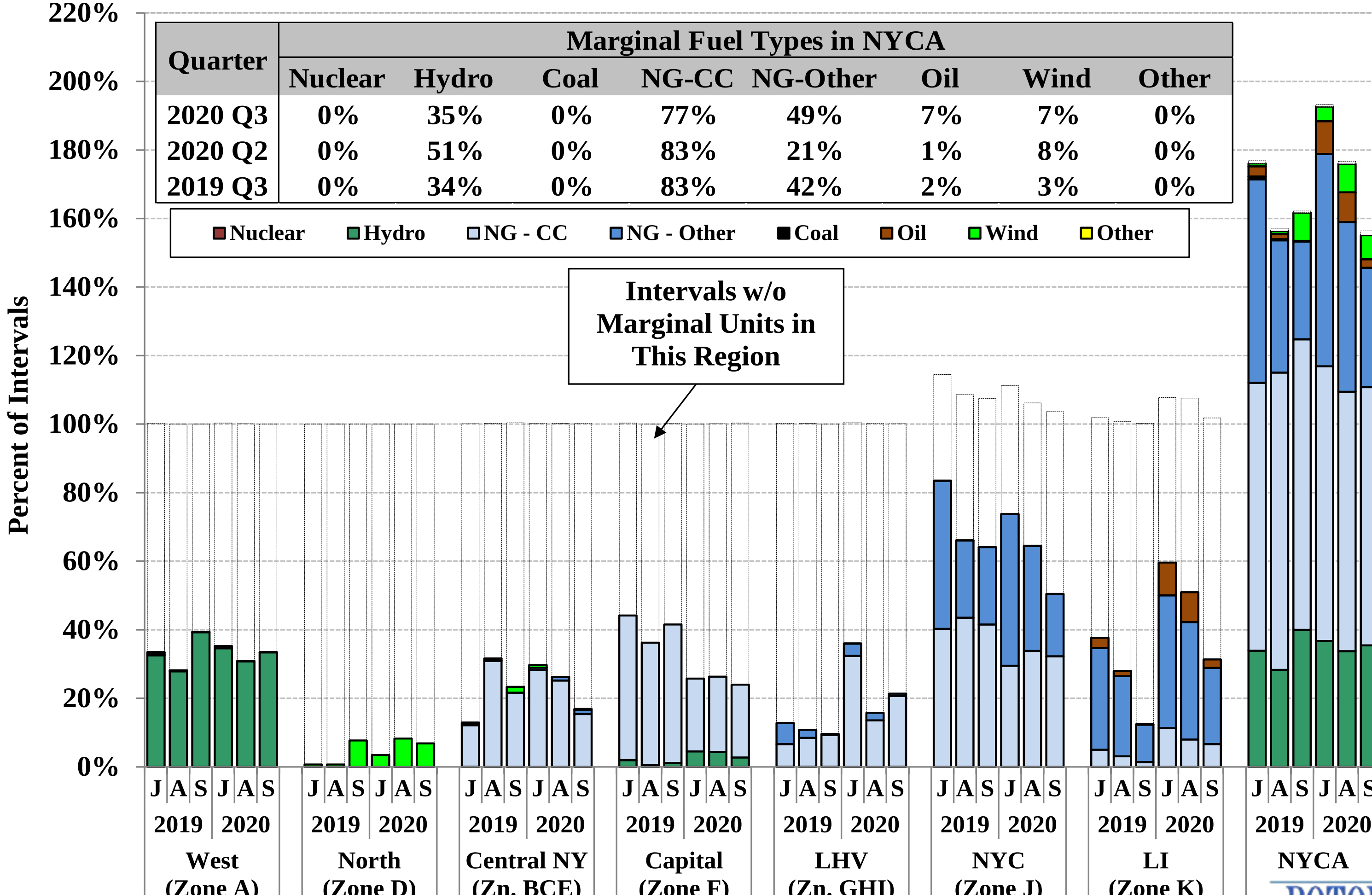
Fuel Type of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2020 Q3	0%	35%	0%	77%	49%	7%	7%	0%
2020 Q2	0%	51%	0%	83%	21%	1%	8%	0%
2019 Q3	0%	34%	0%	83%	42%	2%	3%	0%



Notes: For chart description, see slide 76.

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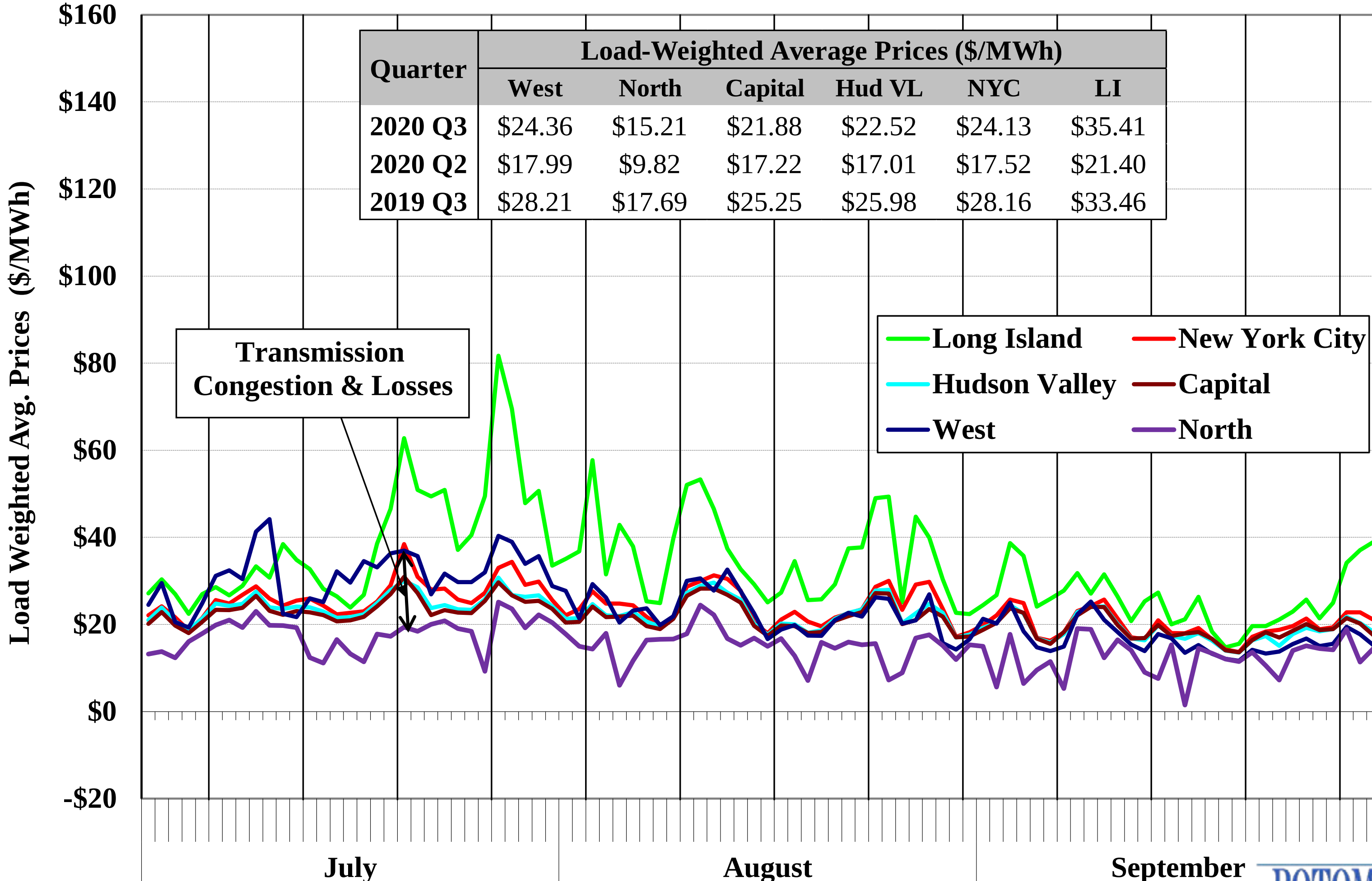
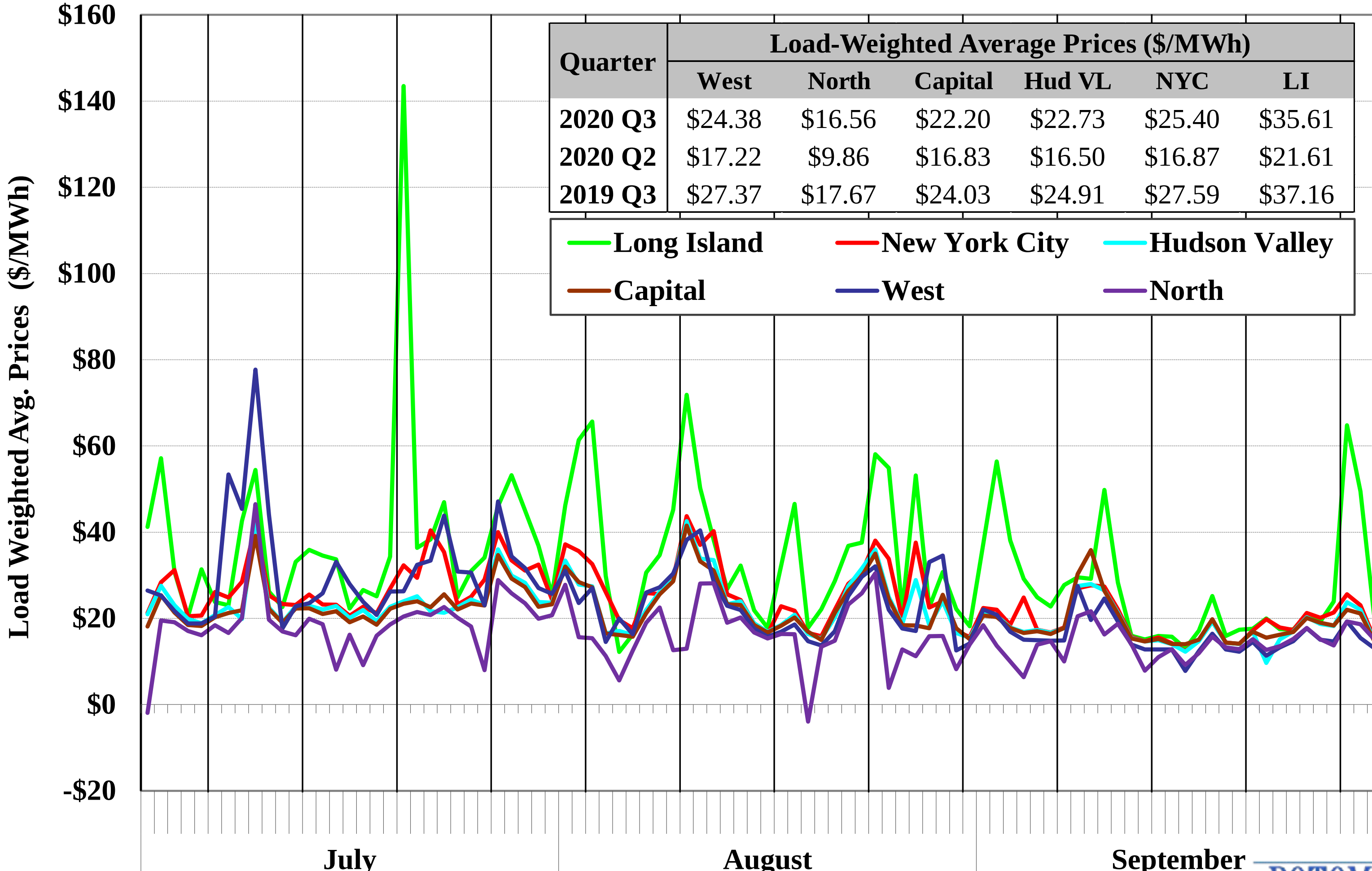
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q3	$24.36	$15.21	$21.88	$22.52	$24.13	$35.41
2020 Q2	$17.99	$9.82	$17.22	$17.01	$17.52	$21.40
2019 Q3	$28.21	$17.69	$25.25	$25.98	$28.16	$33.46

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q3	$24.38	$16.56	$22.20	$22.73	$25.40	$35.61
2020 Q2	$17.22	$9.86	$16.83	$16.50	$16.87	$21.61
2019 Q3	$27.37	$17.67	$24.03	$24.91	$27.59	$37.16

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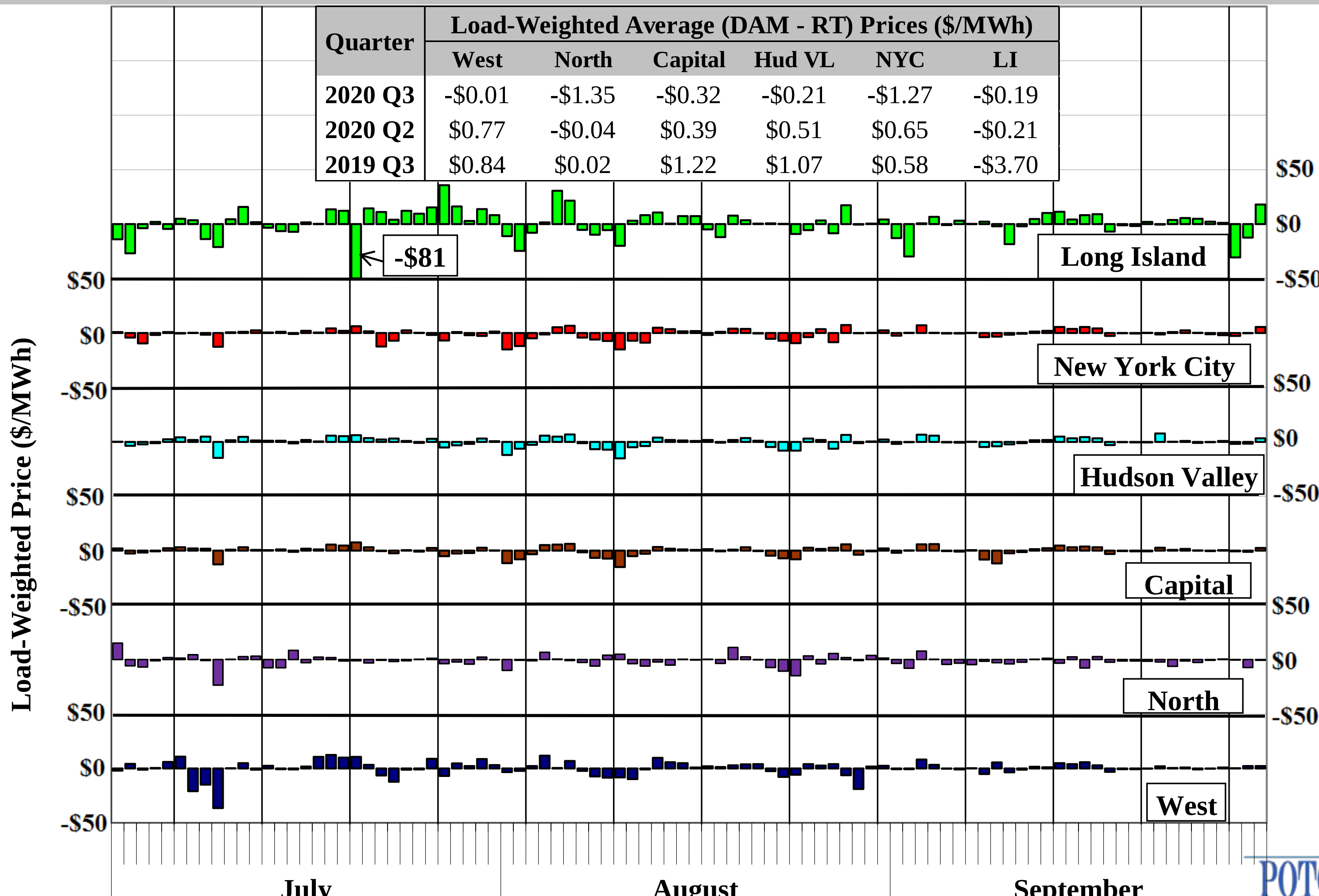
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q3	-$0.01	-$1.35	-$0.32	-$0.21	-$1.27	-$0.19
2020 Q2	$0.77	-$0.04	$0.39	$0.51	$0.65	-$0.21
2019 Q3	$0.84	$0.02	$1.22	$1.07	$0.58	-$3.70

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Charts:
Ancillary Services Market

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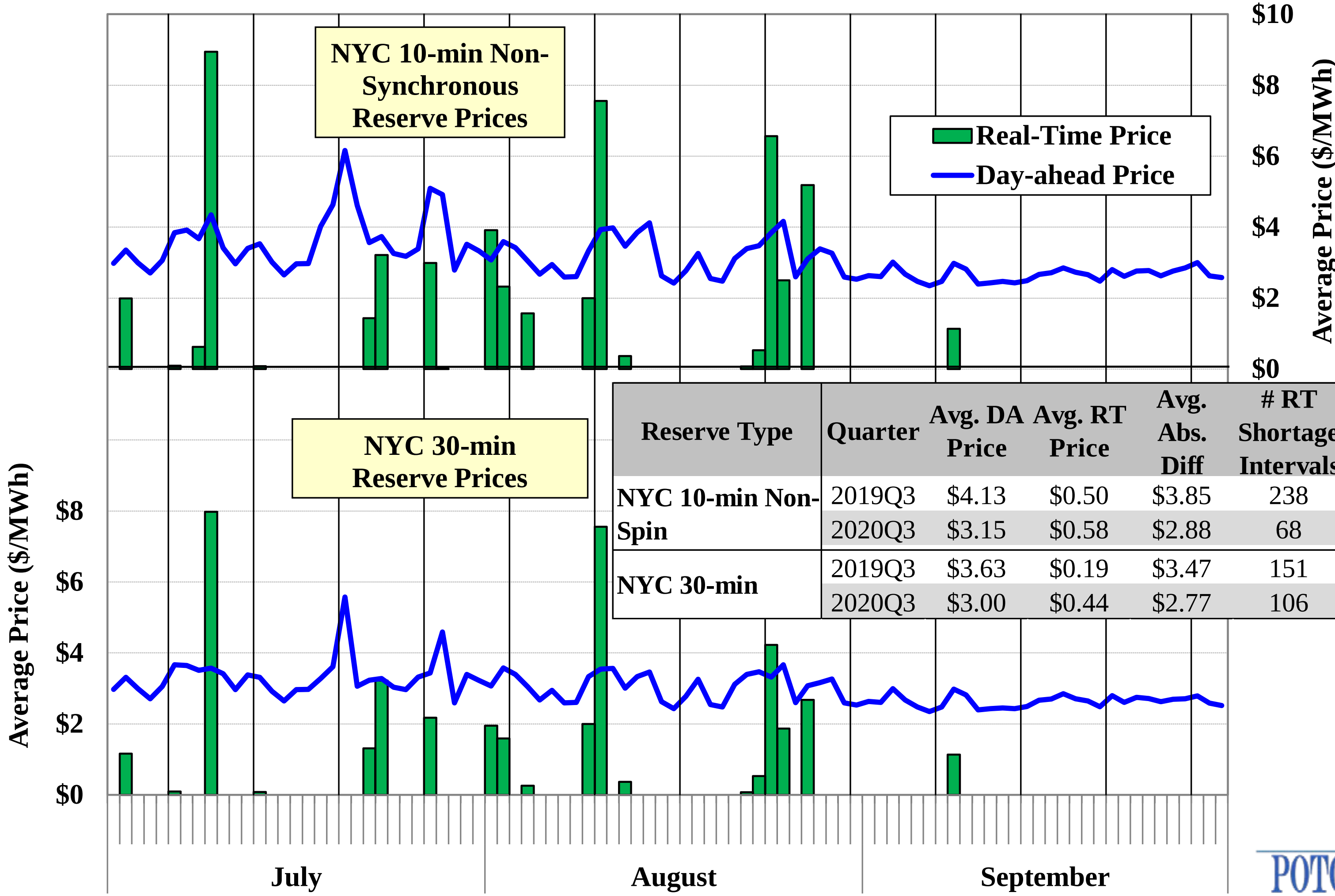
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Non-Spinning and 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2019Q3	$4.13	$0.50	$3.85	238
	2020Q3	$3.15	$0.58	$2.88	68
NYC 30-min	2019Q3	$3.63	$0.19	$3.47	151
	2020Q3	$3.00	$0.44	$2.77	106

Notes: For chart description, see slide 77.

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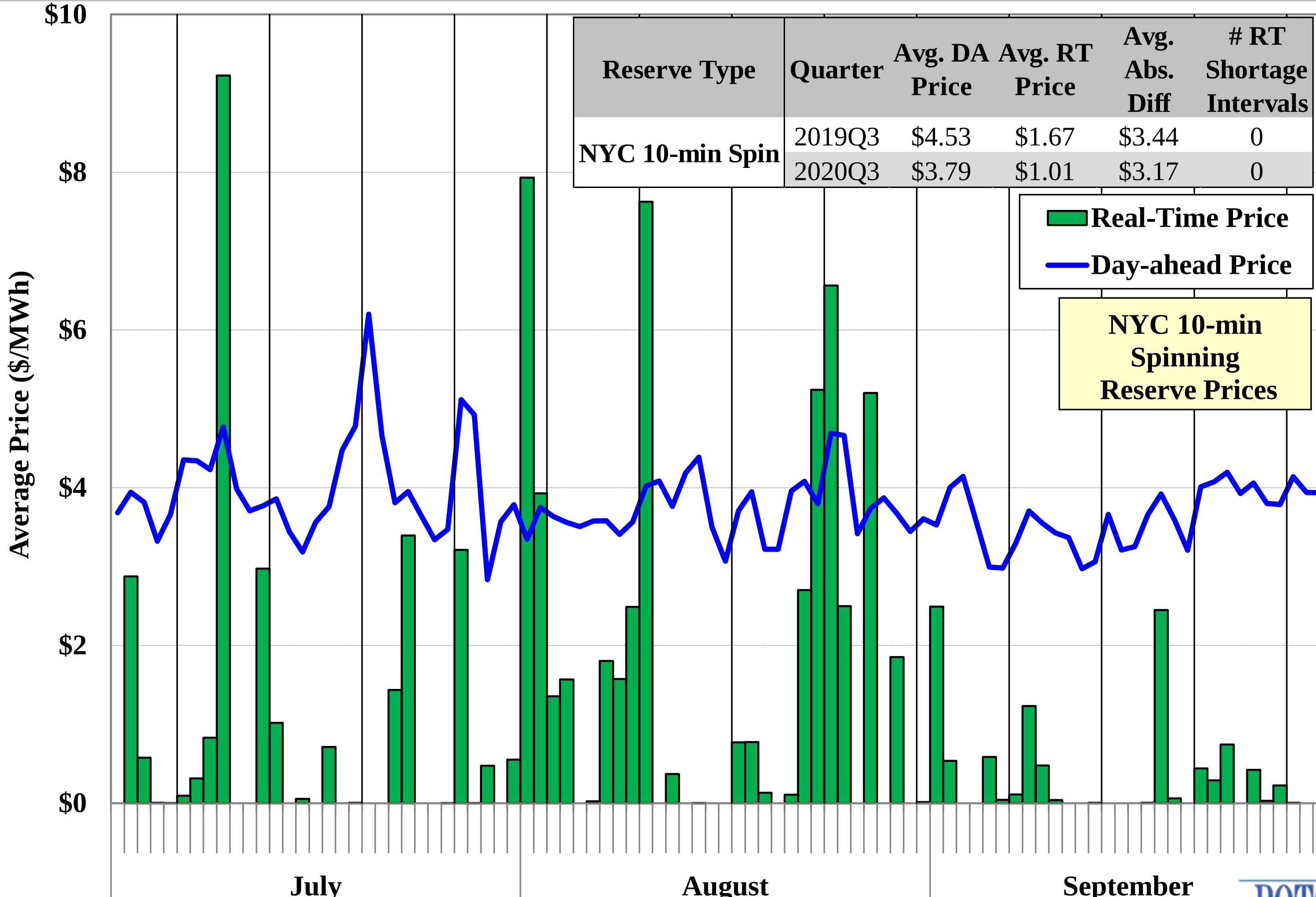
Day-Ahead and Real-Time Ancillary Services Prices

NYC 10-Minute Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2019Q3	$4.53	$1.67	$3.44	0
	2020Q3	$3.79	$1.01	$3.17	0

Notes: For chart description, see slide 77.

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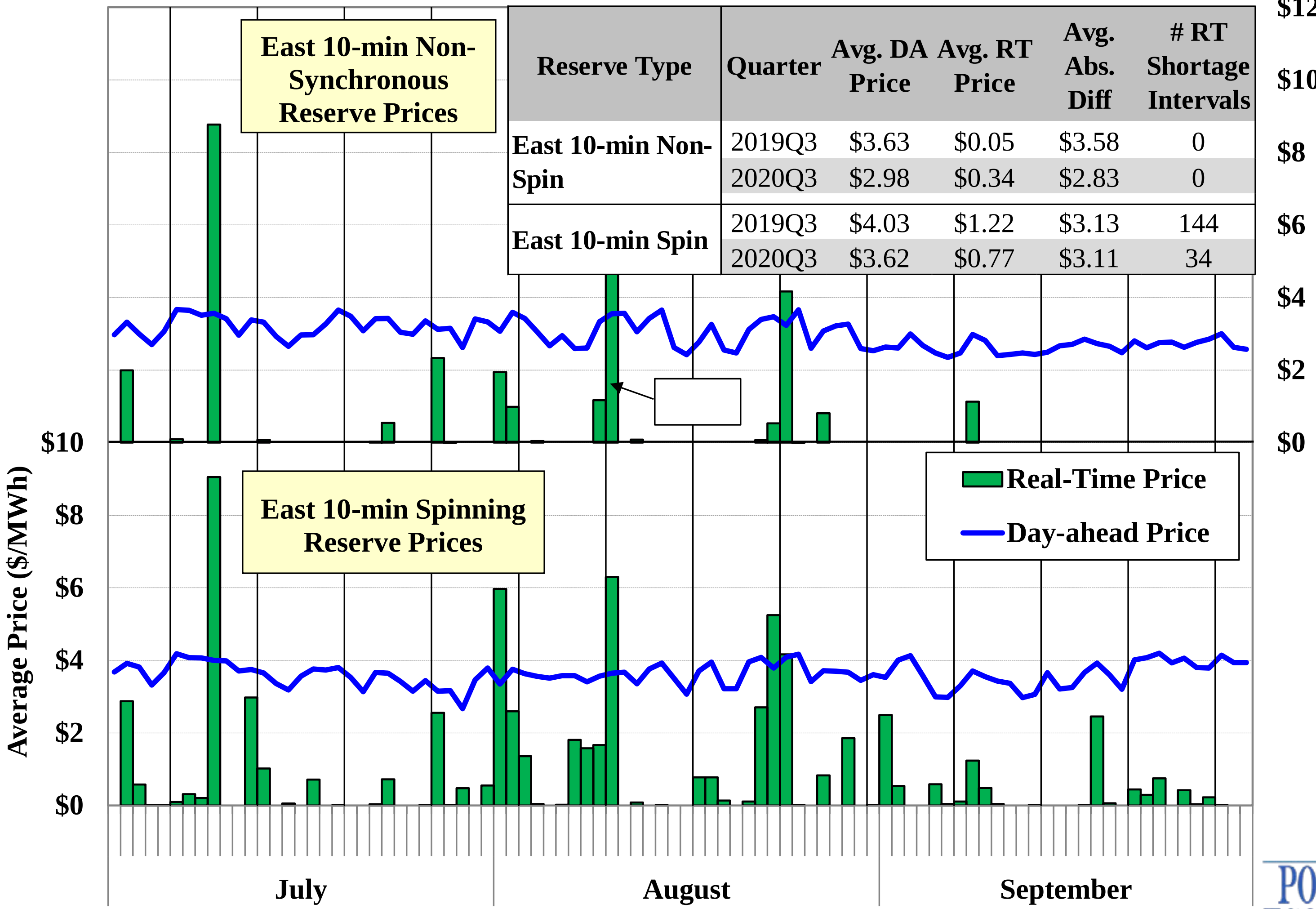
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2019Q3	$3.63	$0.05	$3.58	0
	2020Q3	$2.98	$0.34	$2.83	0
East 10-min Spin	2019Q3	$4.03	$1.22	$3.13	144
	2020Q3	$3.62	$0.77	$3.11	34

Notes: For chart description, see slide 77.

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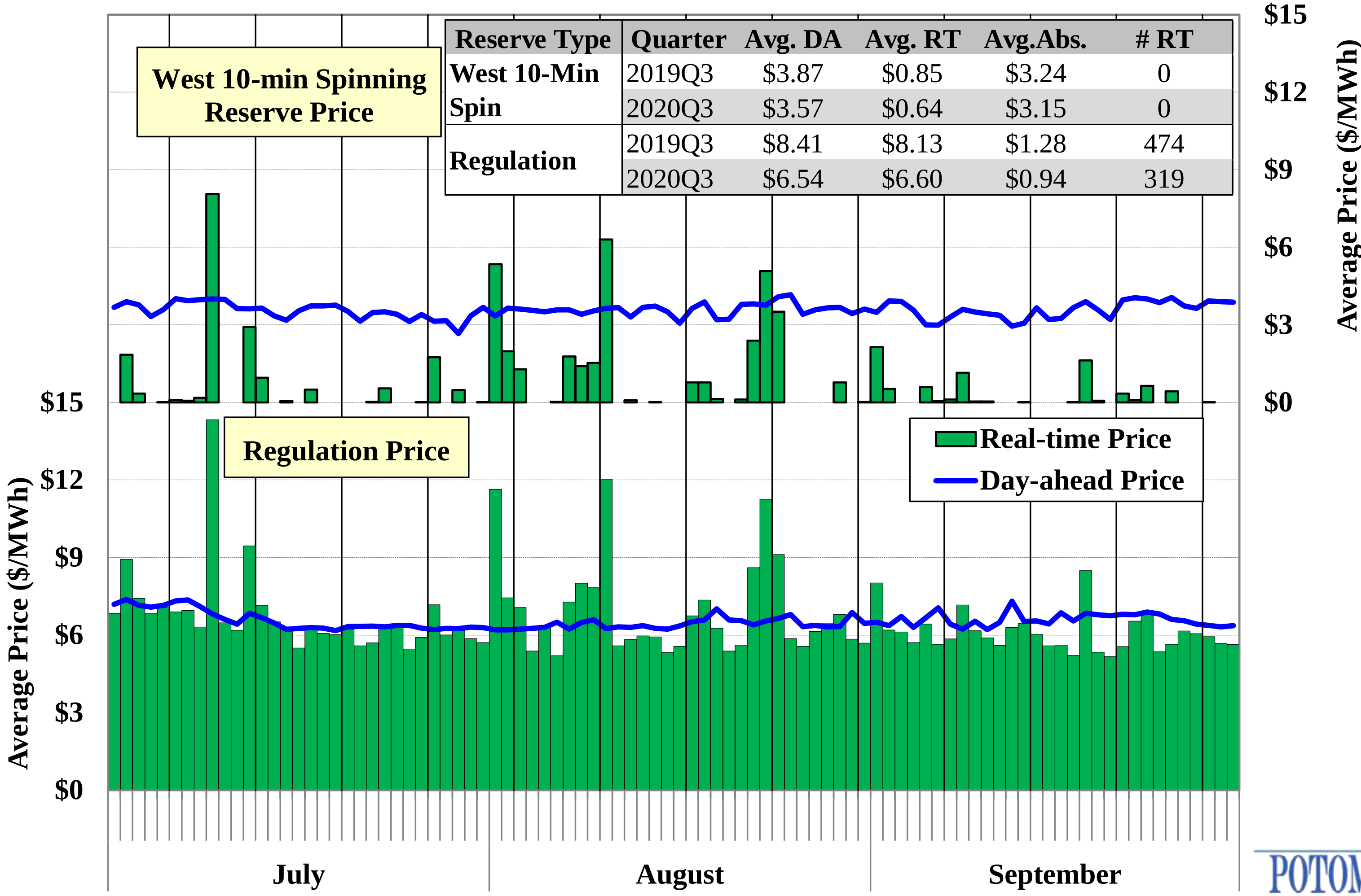
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation

Reserve Type	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2019Q3	$3.87	$0.85	$3.24	0
	2020Q3	$3.57	$0.64	$3.15	0
Regulation	2019Q3	$8.41	$8.13	$1.28	474
	2020Q3	$6.54	$6.60	$0.94	319



Notes: For chart description, see slide 77.

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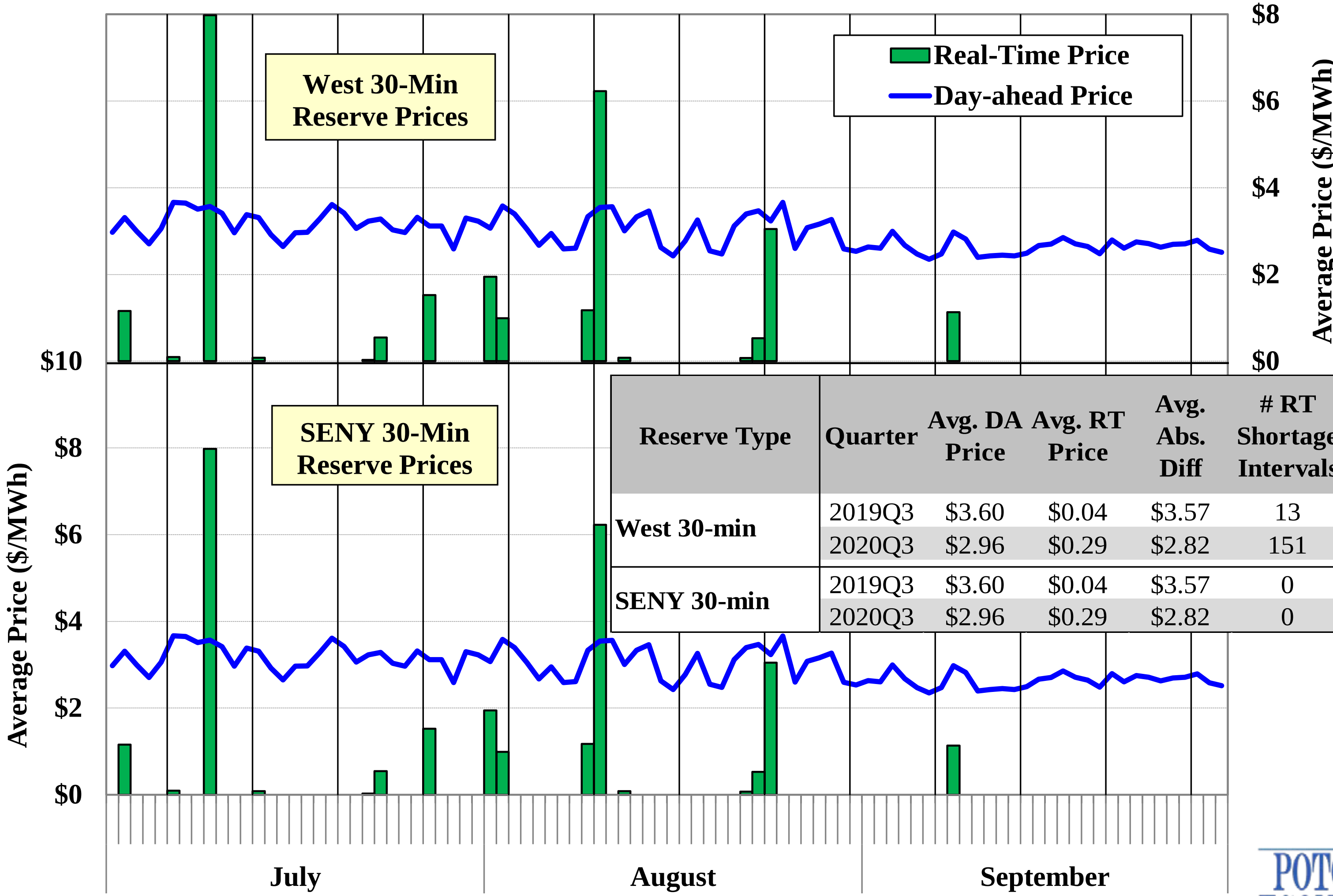
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves

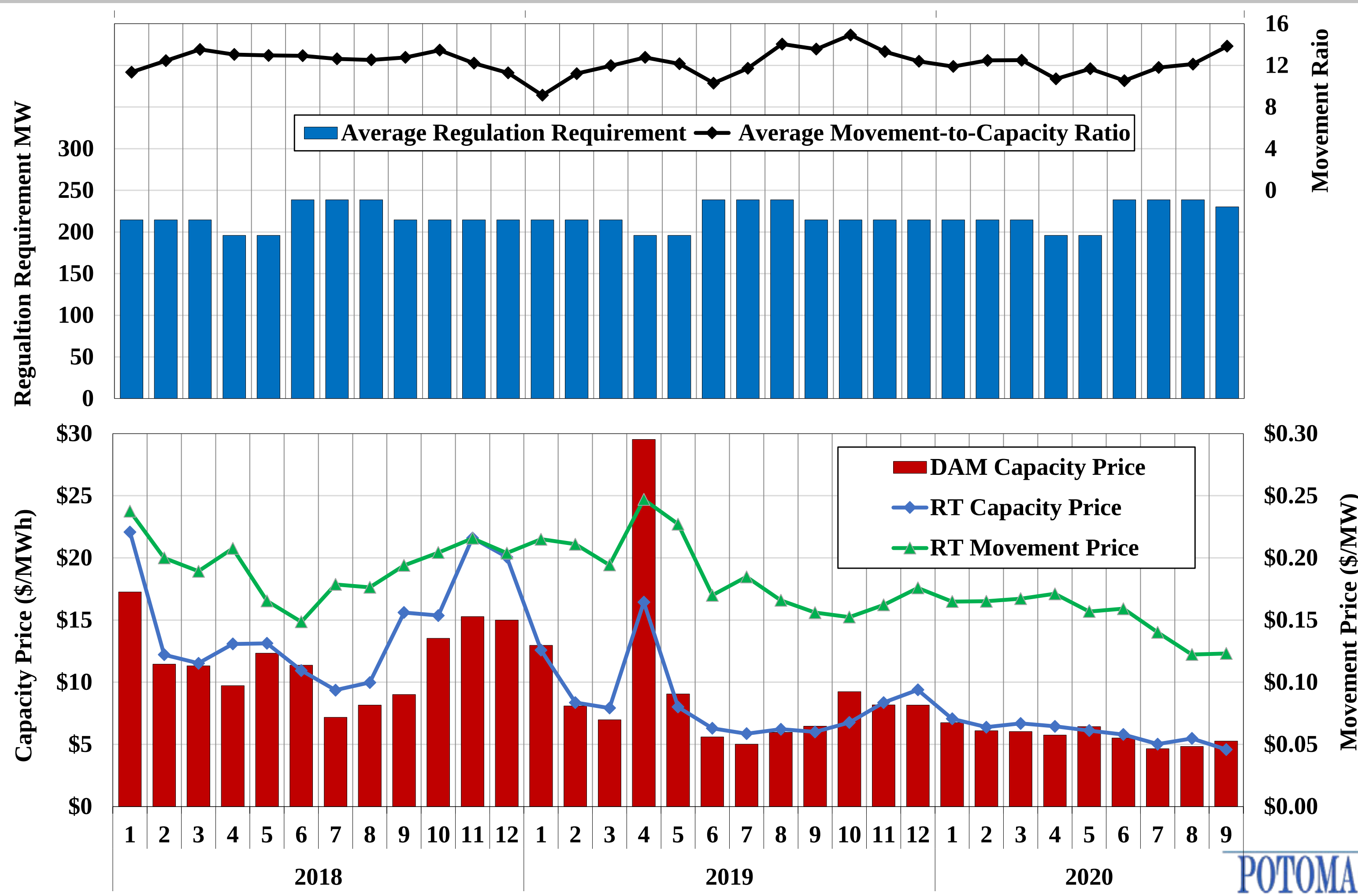


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2019Q3	$3.60	$0.04	$3.57	13
	2020Q3	$2.96	$0.29	$2.82	151
SENY 30-min	2019Q3	$3.60	$0.04	$3.57	0
	2020Q3	$2.96	$0.29	$2.82	0

Notes: For chart description, see slide 77.

POTOMAC ECONOMICS

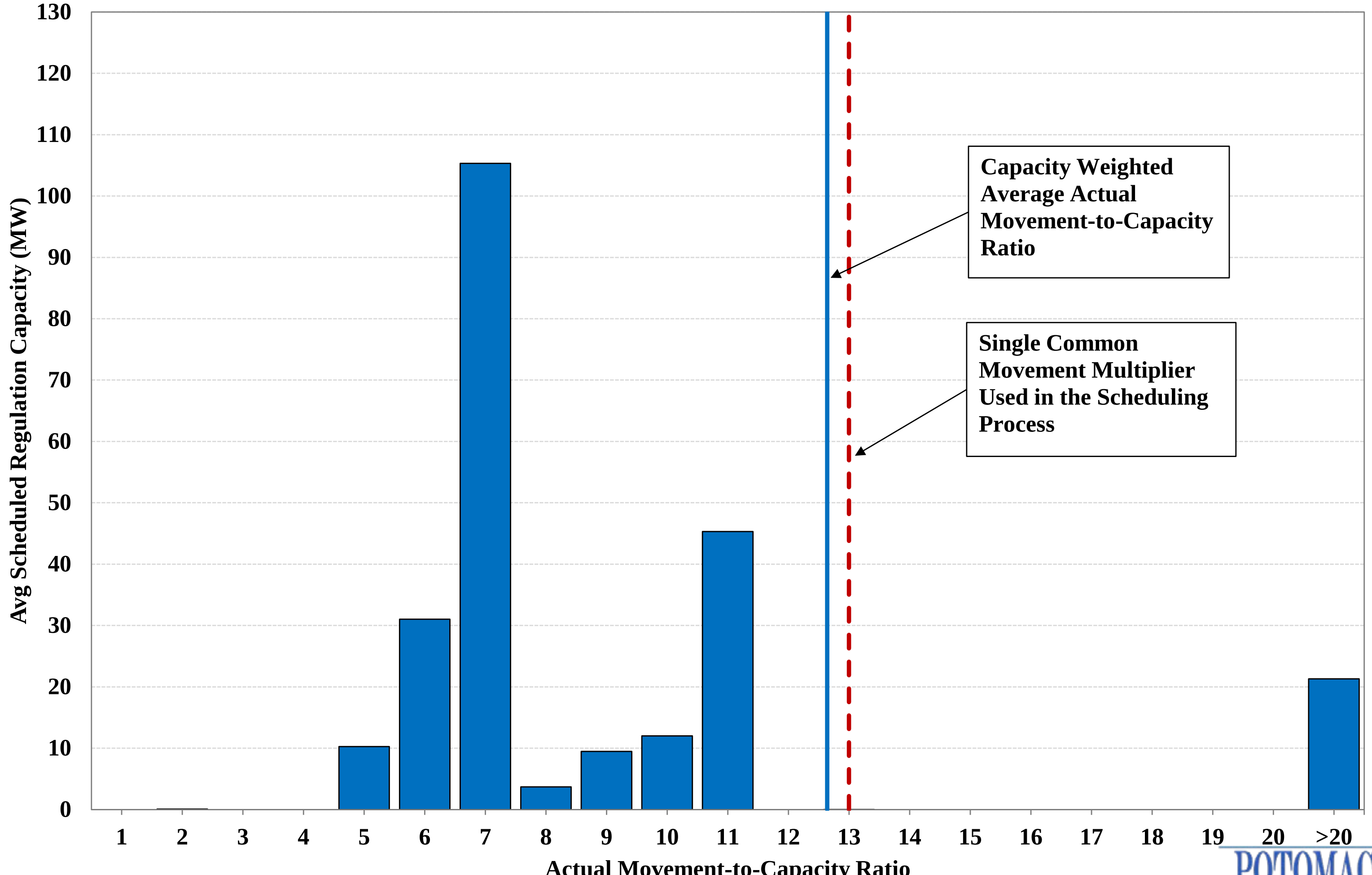
Regulation Requirements, Prices, and Movement-to-Capacity Ratios by Month



Notes: For chart description, see slide 78.

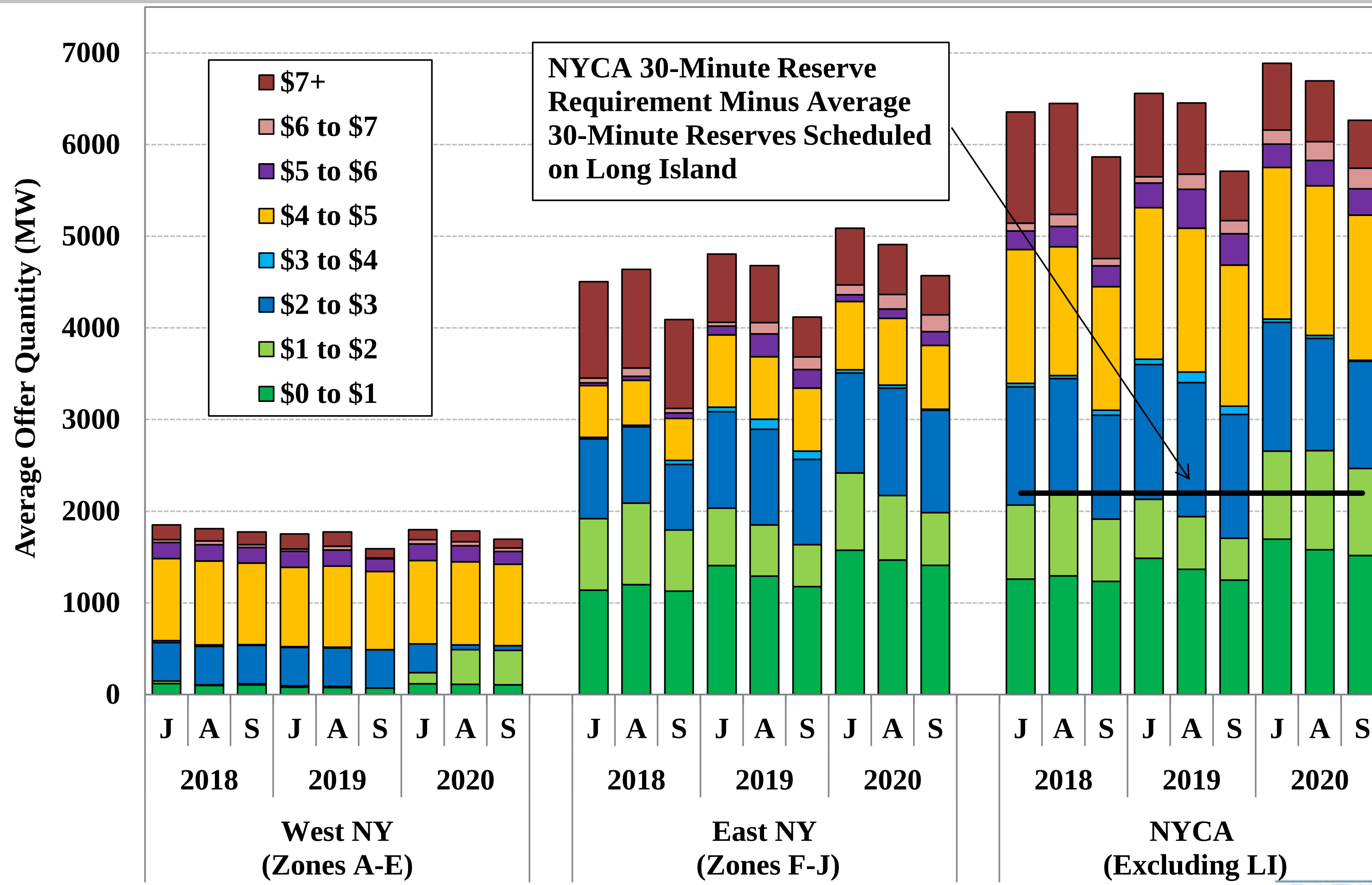
POTOMAC ECONOMICS

Distribution of Actual Regulation Movement from One Sample Day



Notes: For chart description, see slide 78.

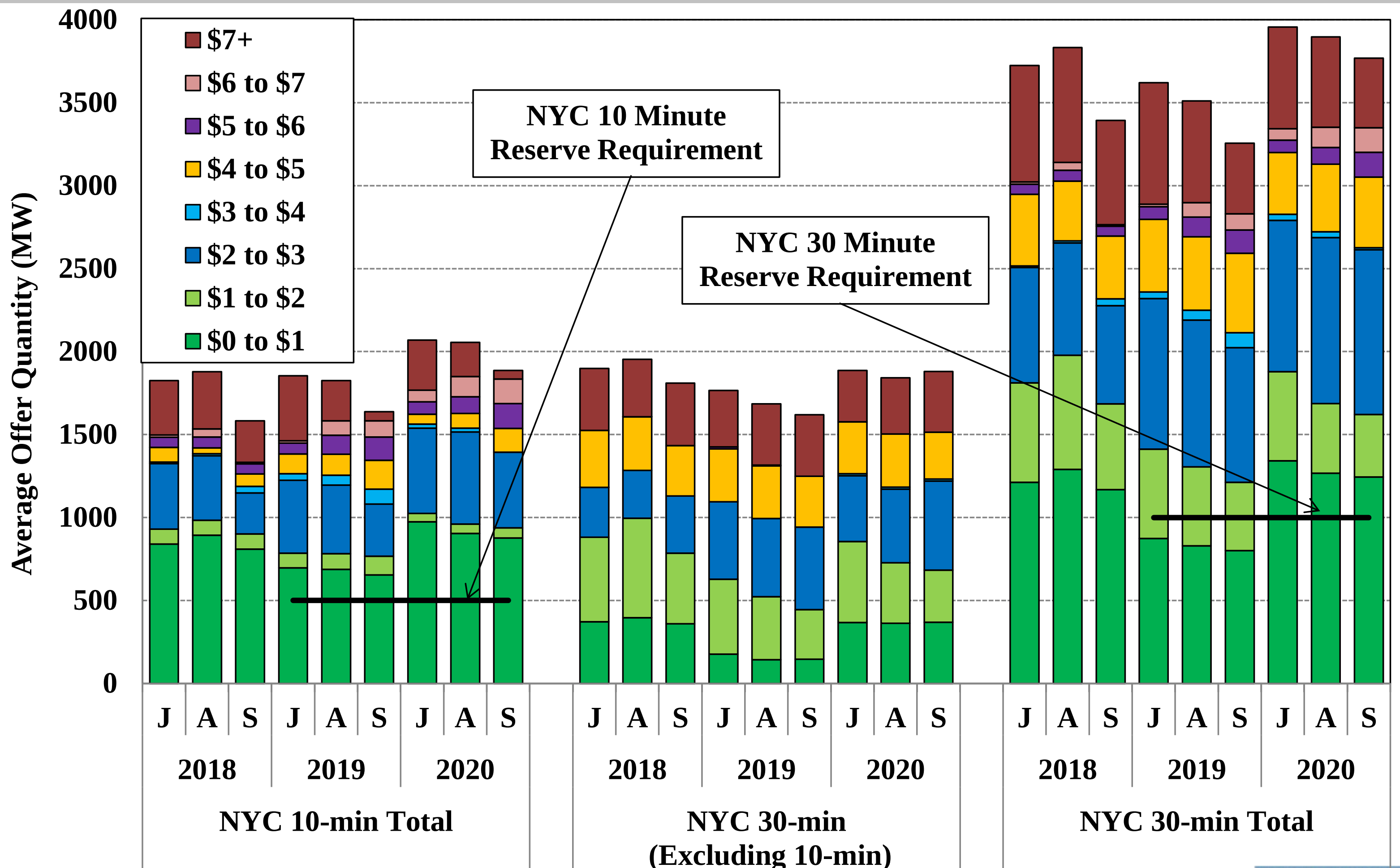
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 79.

POTOMAC ECONOMICS

Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 79.

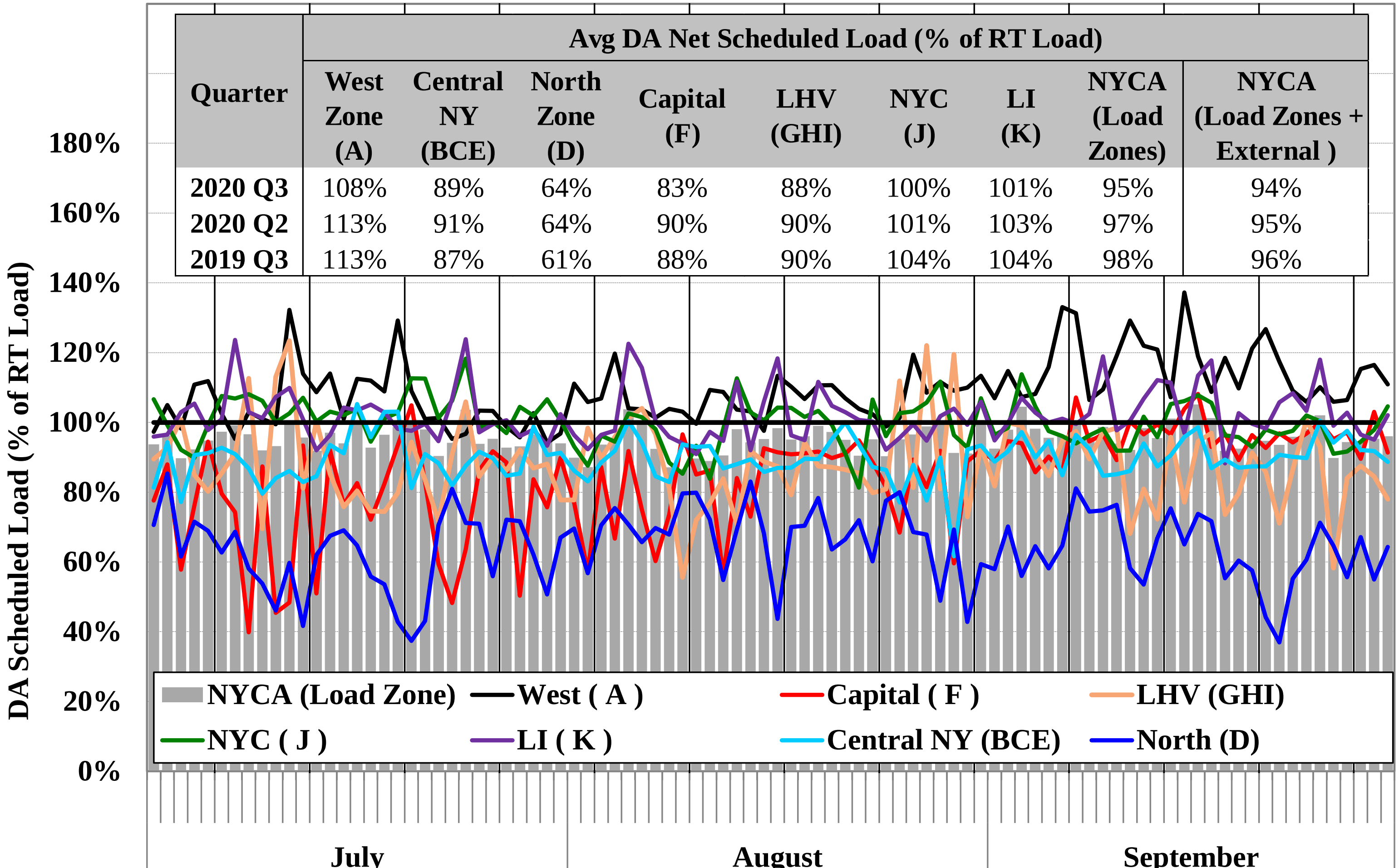
POTOMAC ECONOMICS

Charts:

Energy Market Scheduling

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

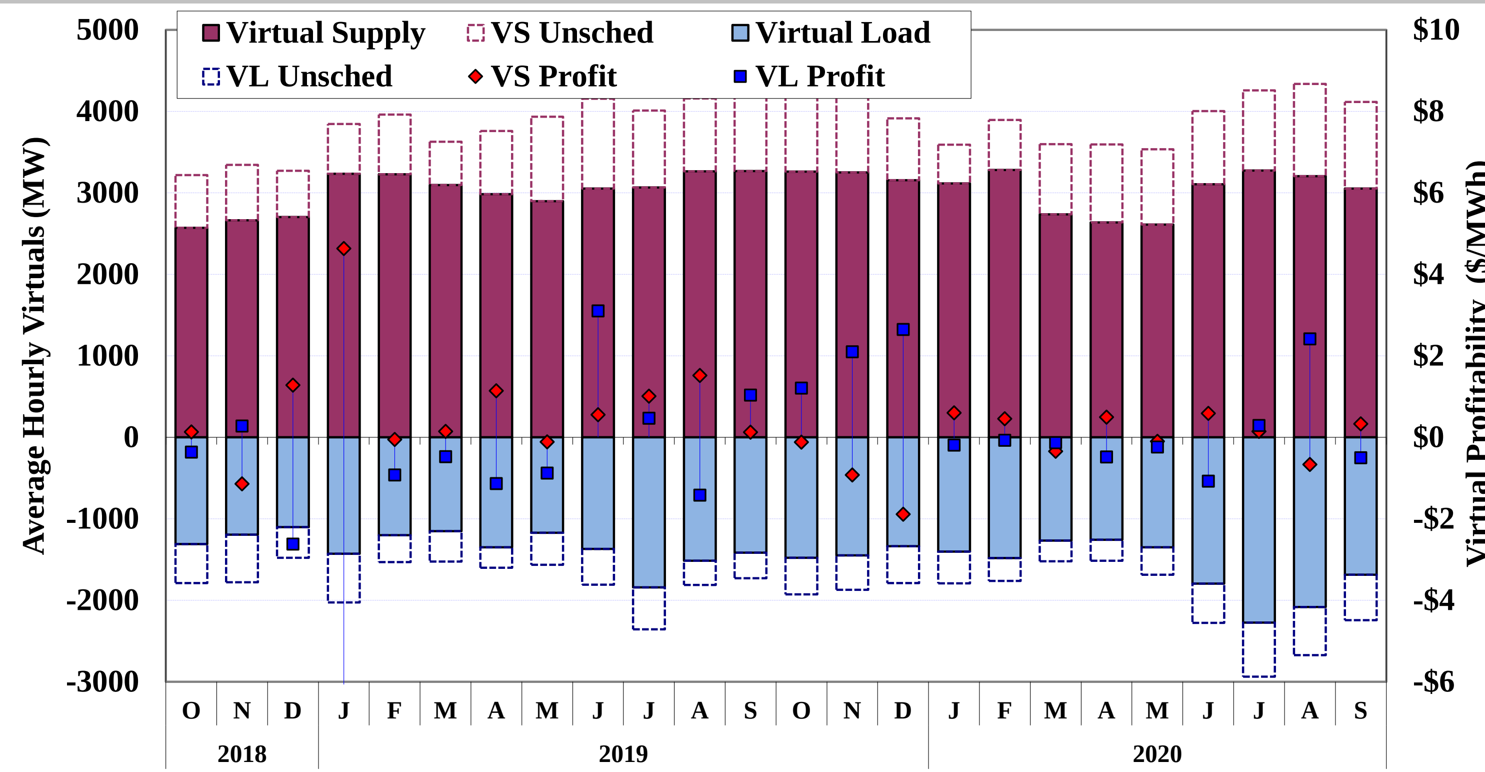
Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2020 Q3	108%	89%	64%	83%	88%	100%	101%	95%	94%
2020 Q2	113%	91%	64%	90%	90%	101%	103%	97%	95%
2019 Q3	113%	87%	61%	88%	90%	104%	104%	98%	96%



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

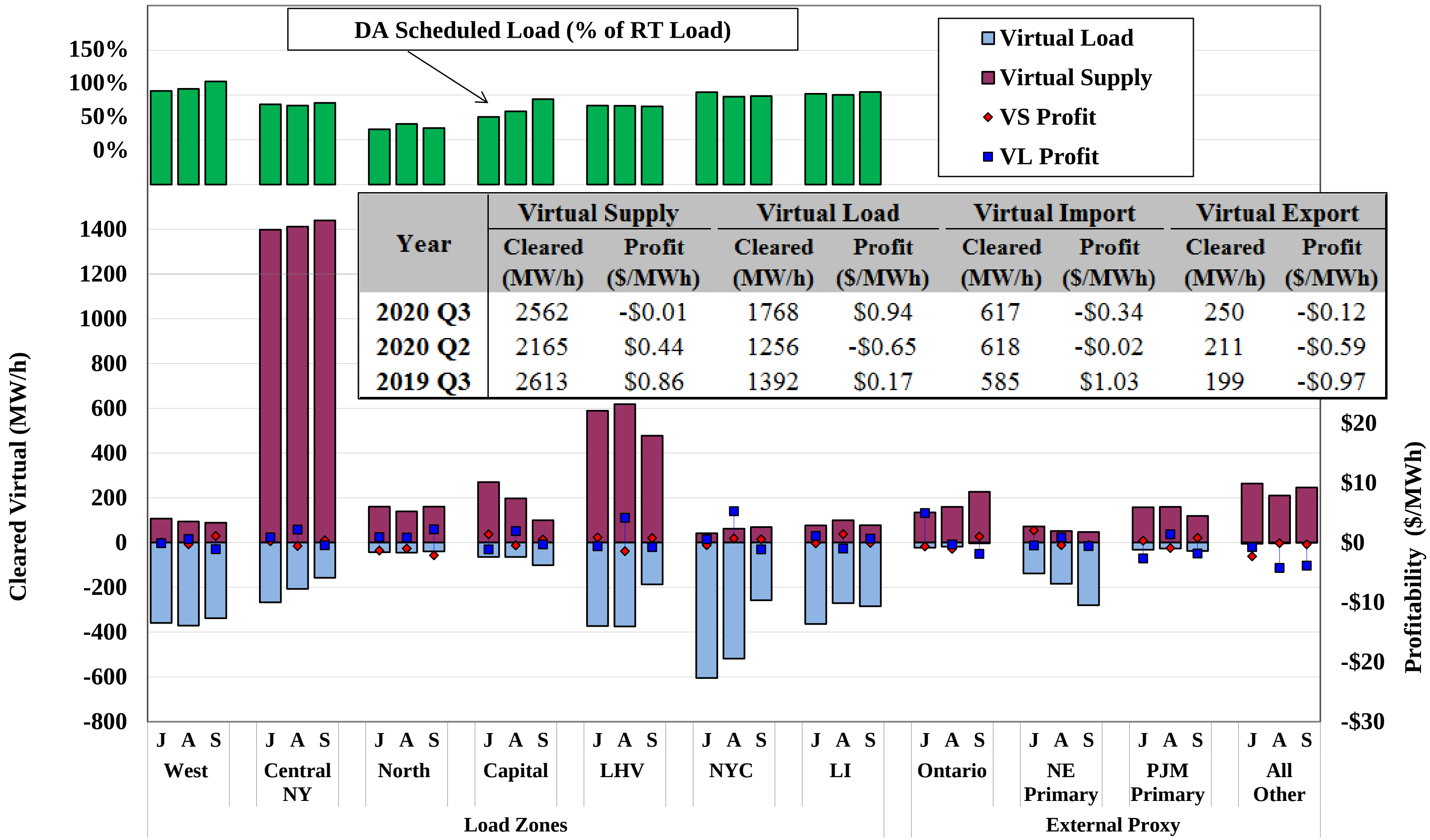
Virtual Trading Activity
by Month



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
		2018			2019												2020								
Profit > 50% of Avg. Zone Price	MW	596	398	360	281	261	490	243	507	585	449	645	502	593	439	257	271	320	396	373	450	419	376	475	620
	%	13%	9%	8%	6%	6%	12%	6%	13%	15%	11%	15%	10%	12%	9%	6%	6%	7%	10%	9%	12%	11%	10%	14%	16%
Loss > 50% of Avg. Zone Price	MW	517	413	411	419	345	587	284	336	514	454	553	542	568	466	418	399	412	478	442	342	401	466	537	531
	%	12%	9%	9%	9%	8%	14%	7%	9%	13%	11%	13%	11%	11%	10%	9%	9%	9%	12%	11%	9%	11%	13%	16%	14%

Notes: For chart description, see slide 80.

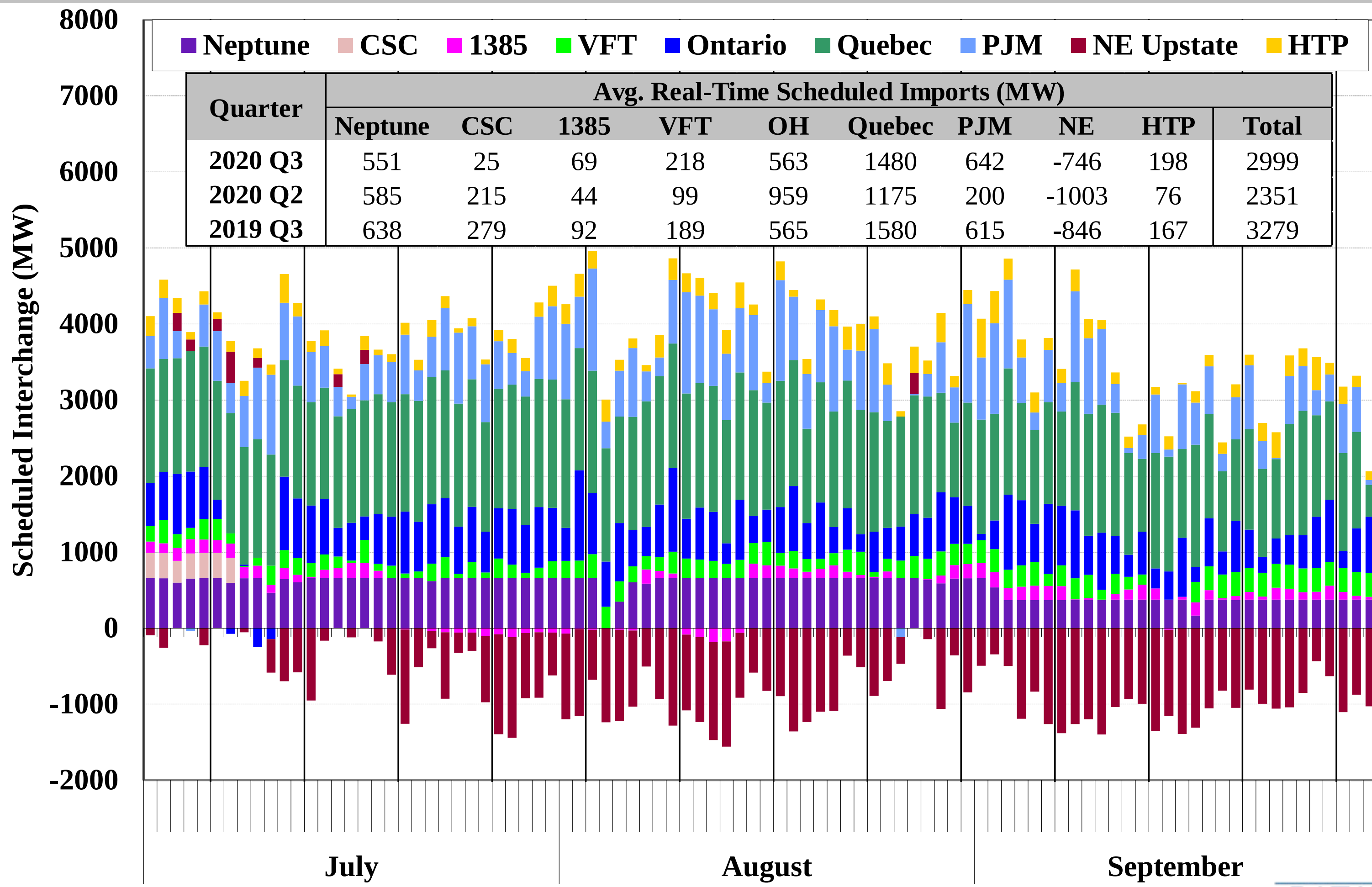
Virtual Trading Activity
by Location



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)
2020 Q3	2562	-$0.01	1768	$0.94	617	-$0.34	250	-$0.12
2020 Q2	2165	$0.44	1256	-$0.65	618	-$0.02	211	-$0.59
2019 Q3	2613	$0.86	1392	$0.17	585	$1.03	199	-$0.97

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 80.

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
2020 Q3	551	25	69	218	563	1480	642	-746	198	2999
2020 Q2	585	215	44	99	959	1175	200	-1003	76	2351
2019 Q3	638	279	92	189	565	1580	615	-846	167	3279

Notes: Two Quebec interfaces are combined into one.

POTOMAC ECONOMICS

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

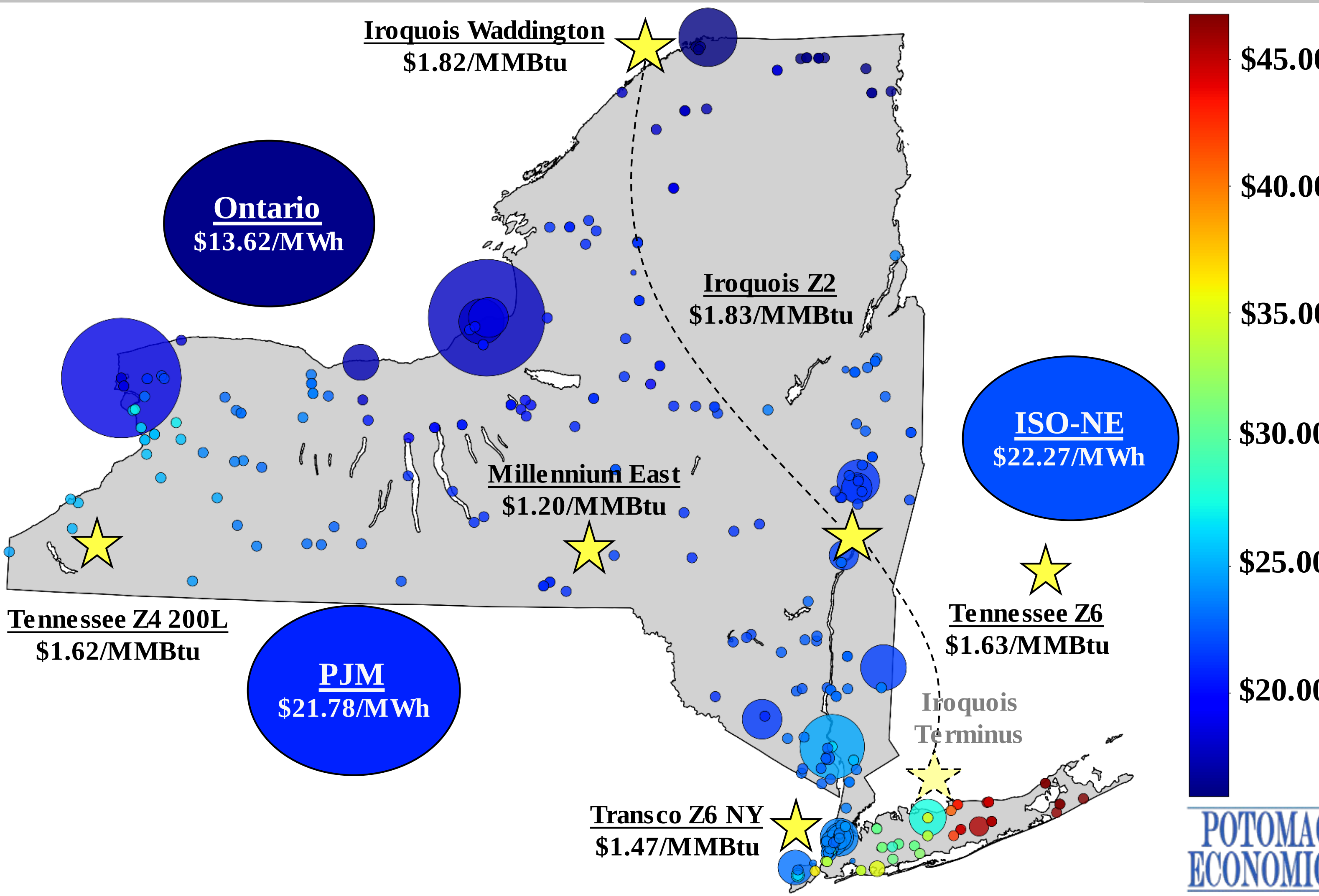
			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			84%	3%	**87%**	28%	6%	**34%**
Average Flow Adjustment (MW)	Net Imports		36	43	**36**	-6	-50	**-14**
	Gross		110	166	**112**	59	113	**69**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$1.2	$0.2	**$1.4**	$0.1	$0.4	**$0.6**
	Net Over-Projection by:	NY	-$0.2	-$0.1	**-$0.3**	$0.0	-$0.1	**-$0.1**
		NE or PJM	-$0.1	$0.0	**$0.0**	-$0.1	-$0.3	**-$0.4**
	Other Unrealized Savings		$0.0	$0.0	**-$0.1**	$0.0	$0.0	**$0.0**
	Actual Savings		$0.9	$0.1	**$1.0**	$0.1	$0.0	**$0.1**
Interface Prices ($/MWh)	NY	Actual	$19.40	$46.08	**$20.39**	$20.37	$37.31	**$23.48**
		Forecast	$20.56	$56.83	**$21.91**	$22.27	$50.26	**$27.40**
	NE or PJM	Actual	$19.08	$60.93	**$20.64**	$19.22	$47.85	**$24.47**
		Forecast	$18.07	$60.73	**$19.66**	$21.68	$59.06	**$28.54**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.16	$10.75	**$1.52**	$1.89	$12.95	**$3.92**
		Abs. Val.	$2.12	$39.37	**$3.50**	$3.26	$25.29	**$7.31**
	NE or PJM	Fcst. - Act.	-$1.01	-$0.20	**-$0.98**	$2.47	$11.21	**$4.07**
		Abs. Val.	$2.43	$40.45	**$3.84**	$3.94	$41.06	**$10.75**

Notes: For chart description, see slide 81.

Charts:

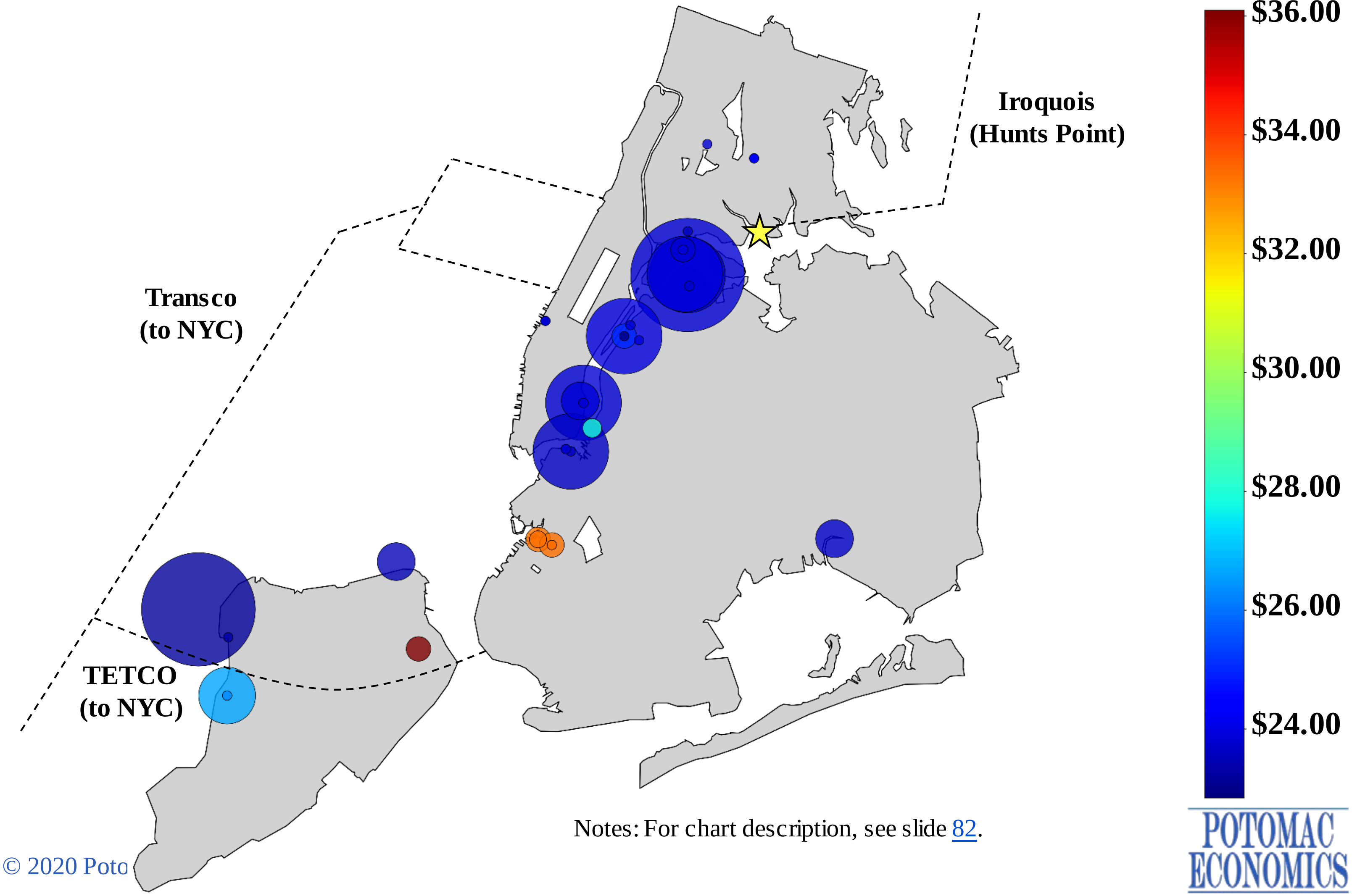
Transmission Congestion Revenues and Shortfalls

System Congestion
Real-Time Price Map at Generator Nodes



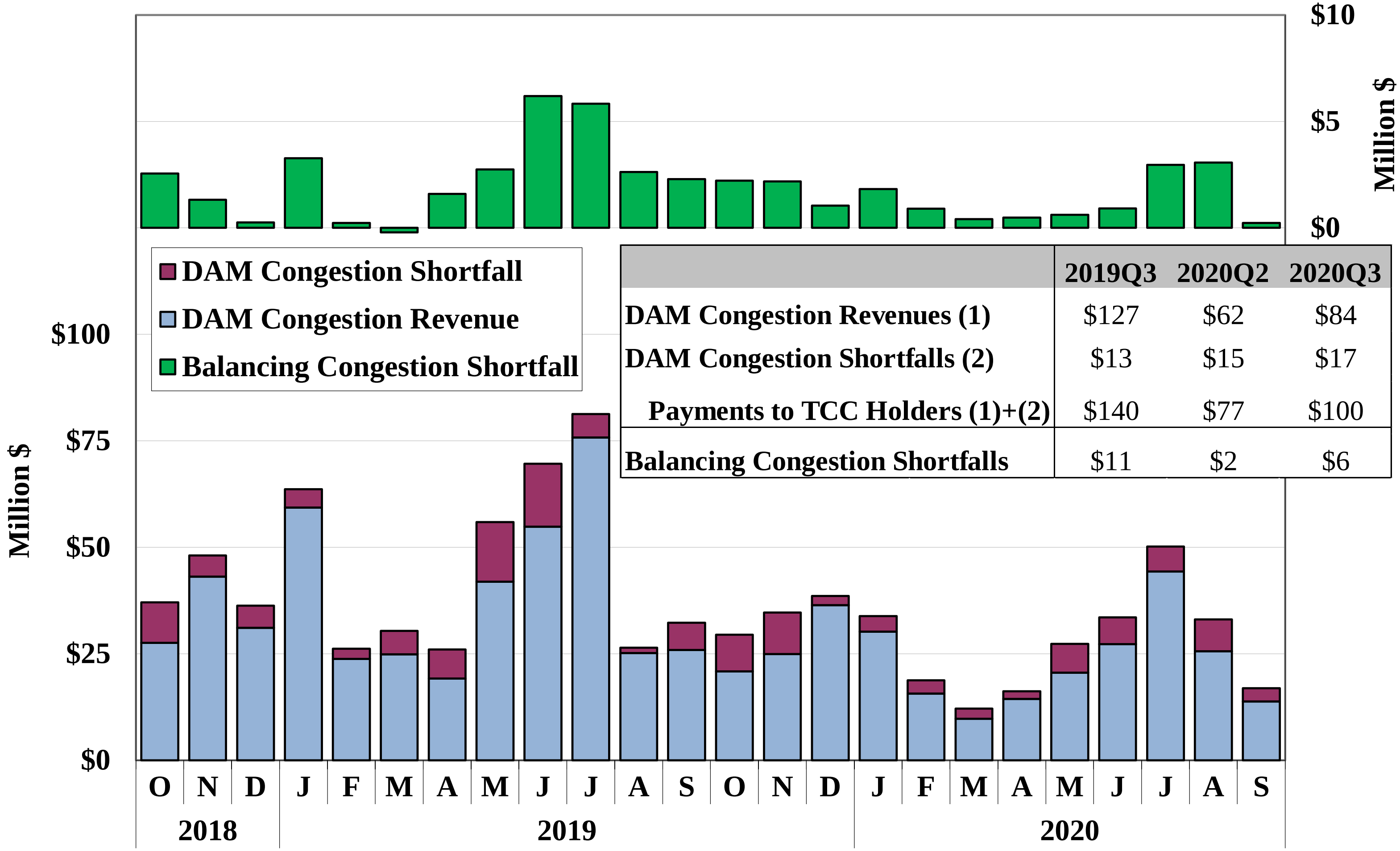
POTOMAC ECONOMICS

System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 82.

Congestion Revenues and Shortfalls by Month

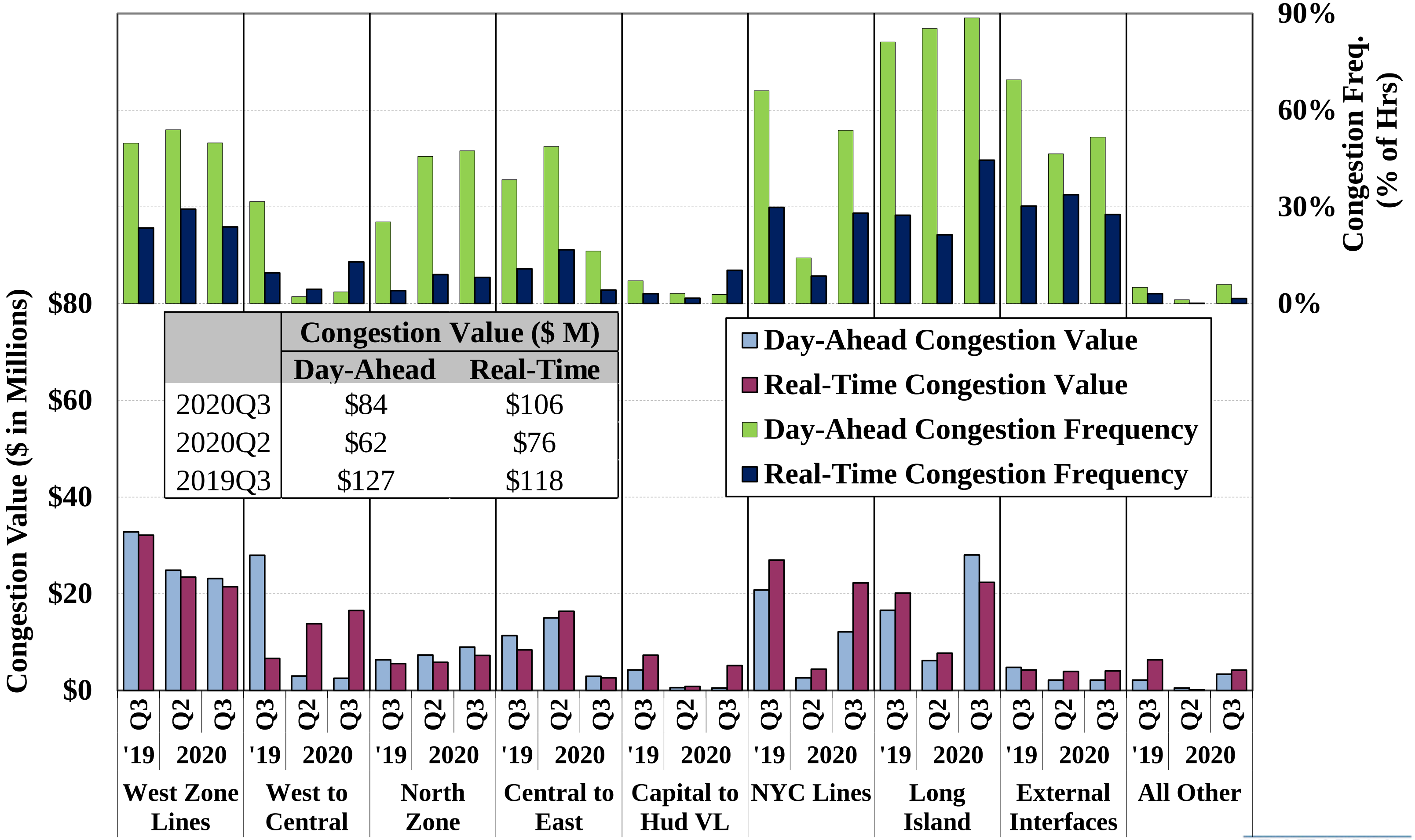


	2019Q3	2020Q2	2020Q3
DAM Congestion Revenues (1)	$127	$62	$84
DAM Congestion Shortfalls (2)	$13	$15	$17
Payments to TCC Holders (1)+(2)	$140	$77	$100
Balancing Congestion Shortfalls	$11	$2	$6

Notes: For chart description, see slides 83 and 84.

POTOMAC ECONOMICS

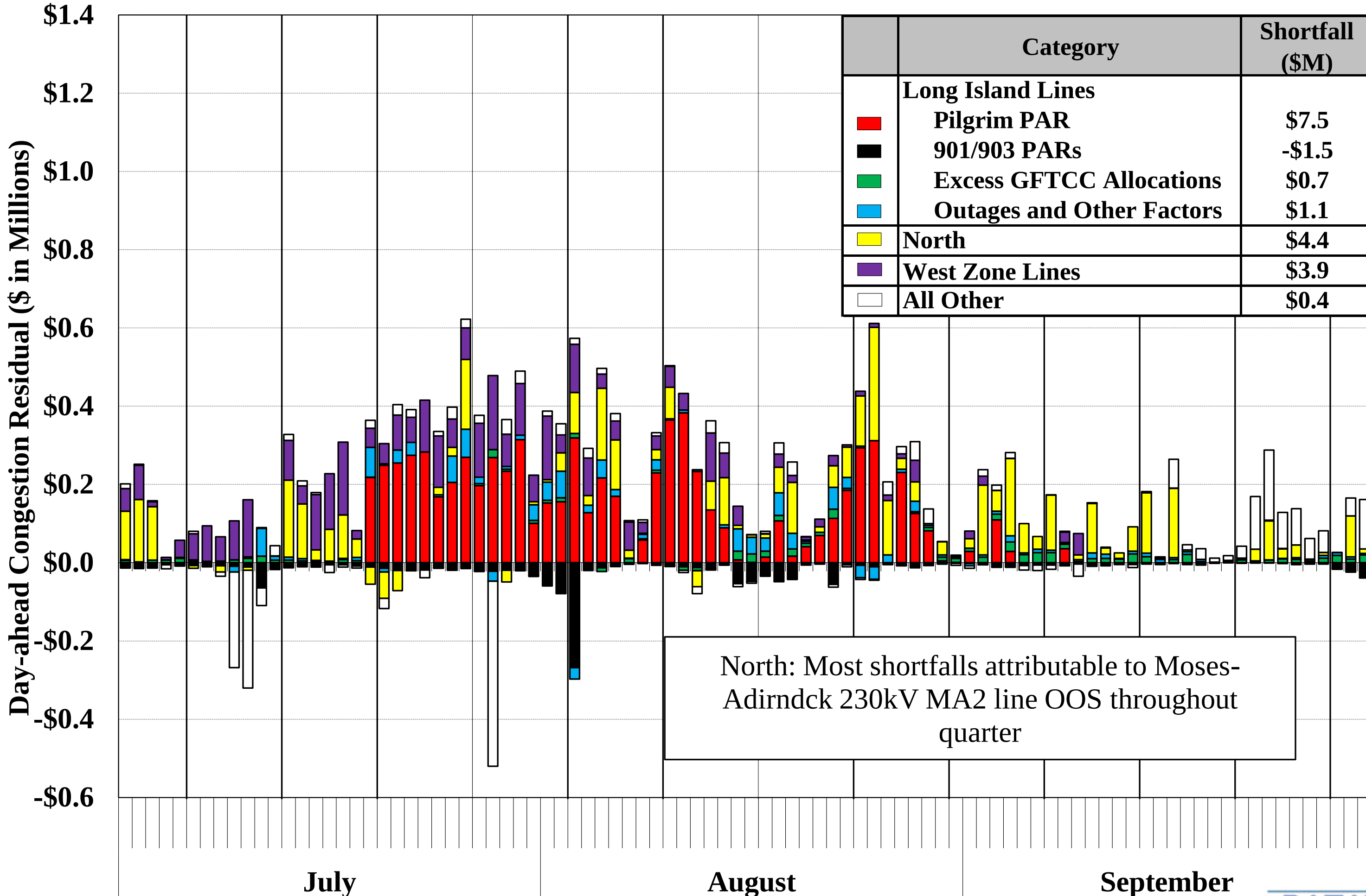
Day-Ahead and Real-Time Congestion Value
by Transmission Path



	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2020Q3	$84	$106
2020Q2	$62	$76
2019Q3	$127	$118

Notes: For chart description, see slides 83, 84, and 85.

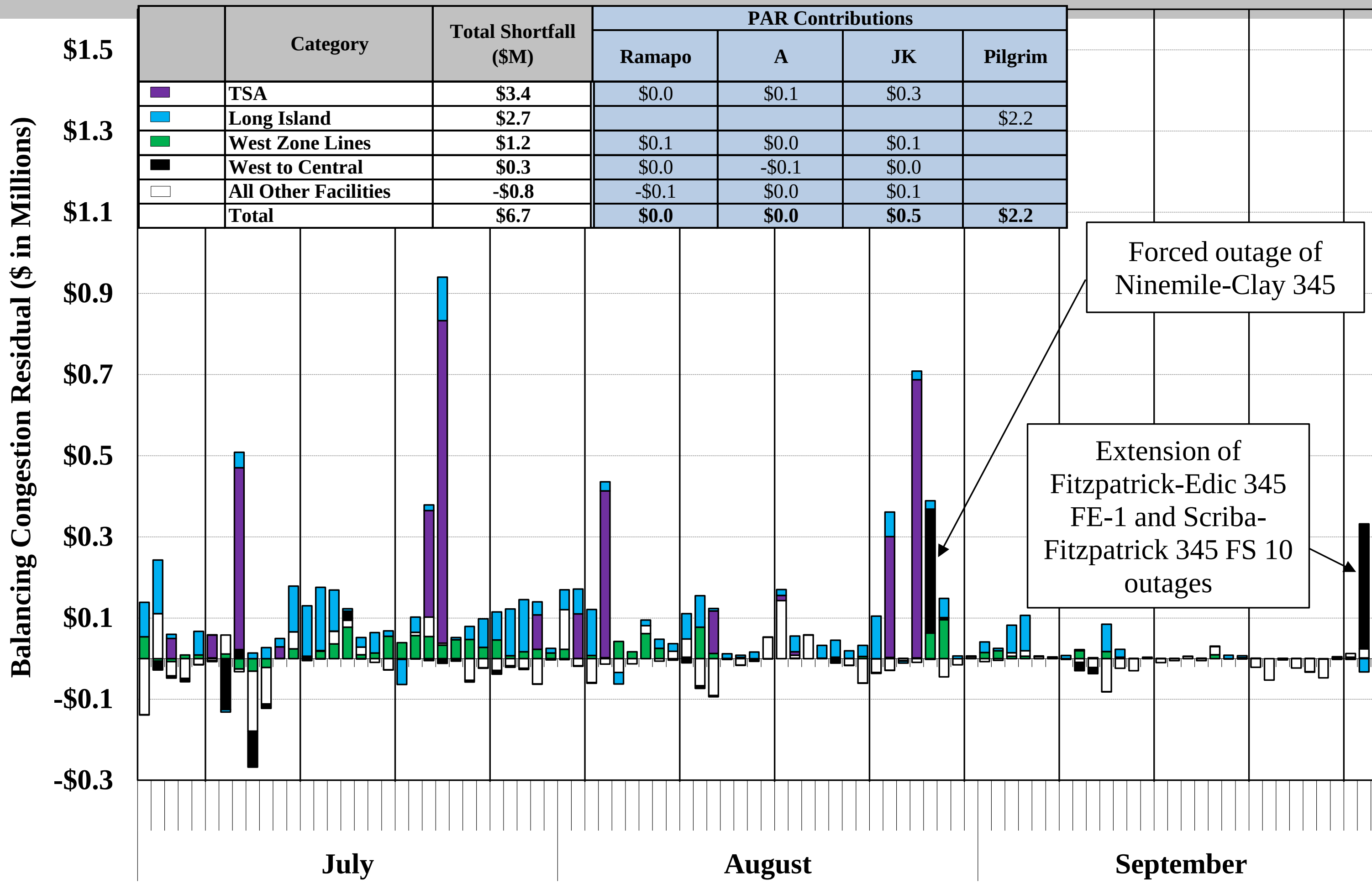
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 83, 84, and 85.

Balancing Congestion Shortfalls by Transmission Facility

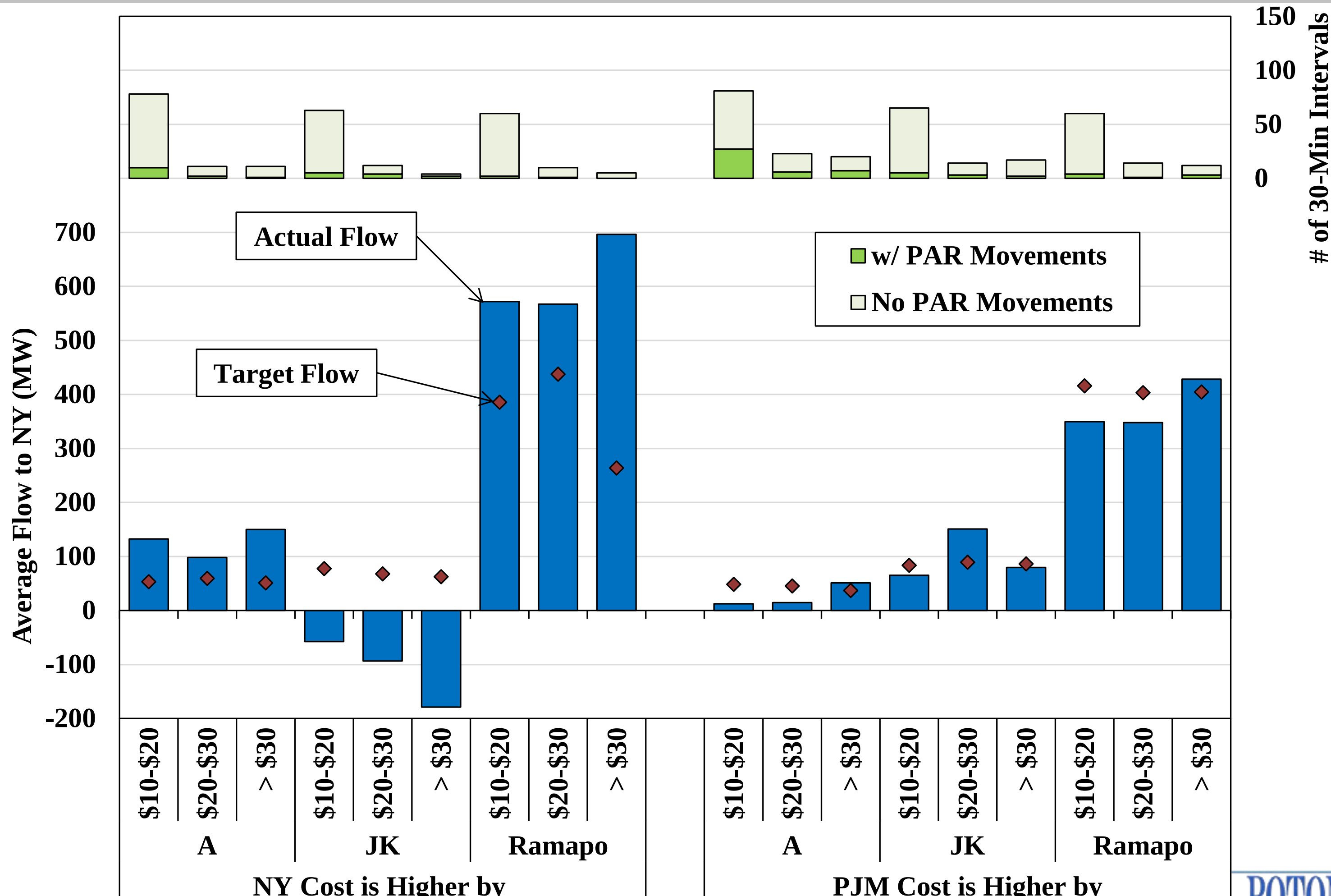
	Category	Total Shortfall ($M)	PAR Contributions			
			Ramapo	A	JK	Pilgrim
	TSA	$3.4	$0.0	$0.1	$0.3	
	Long Island	$2.7				$2.2
	West Zone Lines	$1.2	$0.1	$0.0	$0.1	
	West to Central	$0.3	$0.0	-$0.1	$0.0	
	All Other Facilities	-$0.8	-$0.1	$0.0	$0.1	
	Total	$6.7	$0.0	$0.0	$0.5	$2.2



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 83, 84, and 85.

POTOMAC ECONOMICS

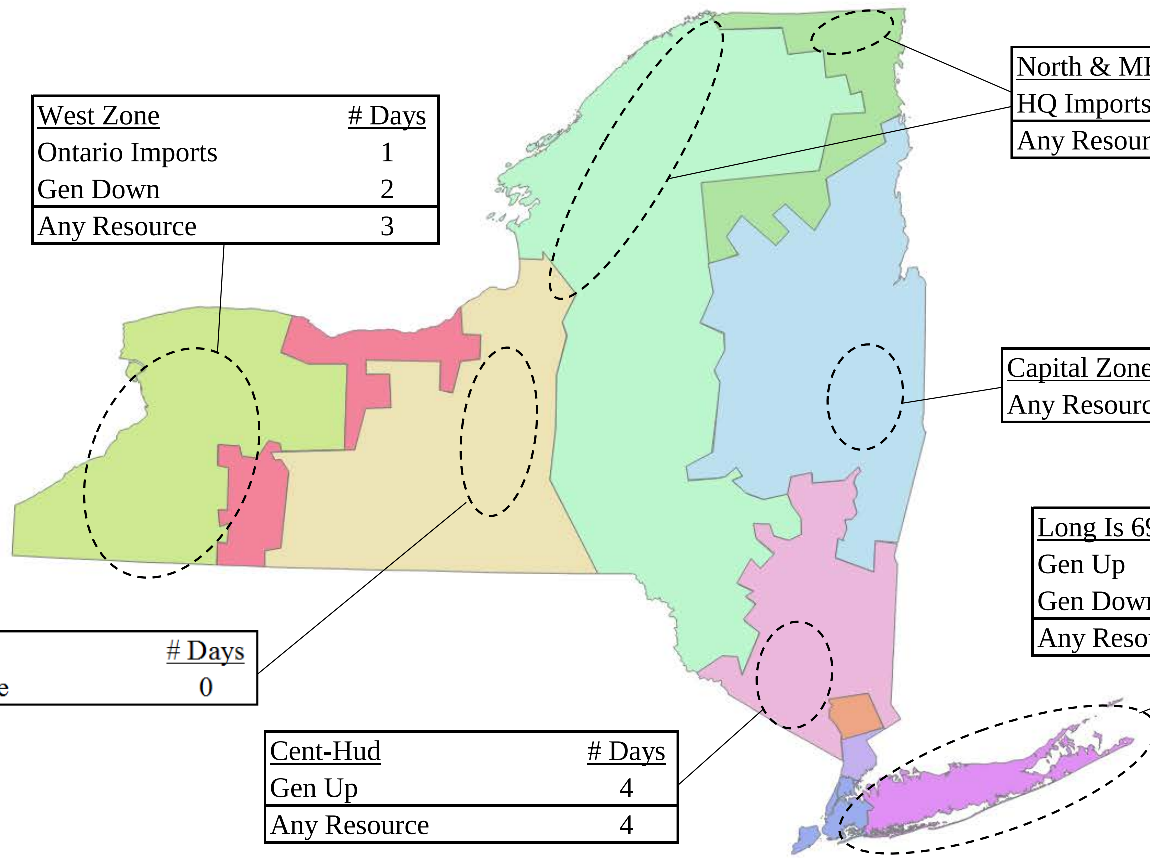
PAR Operation under M2M with PJM
2020 Q3



Notes: For chart description, see slide 87.

POTOMAC ECONOMICS

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



West Zone	# Days
Ontario Imports	1
Gen Down	2
Any Resource	3

North & MHK VL Zones	# Days
HQ Imports	3
Any Resource	3

Capital Zone	# Days
Any Resource	0

Long Is 69kV	# Days
Gen Up	71
Gen Down	5
Any Resource	71

Central Zone	# Days
Any Resource	0

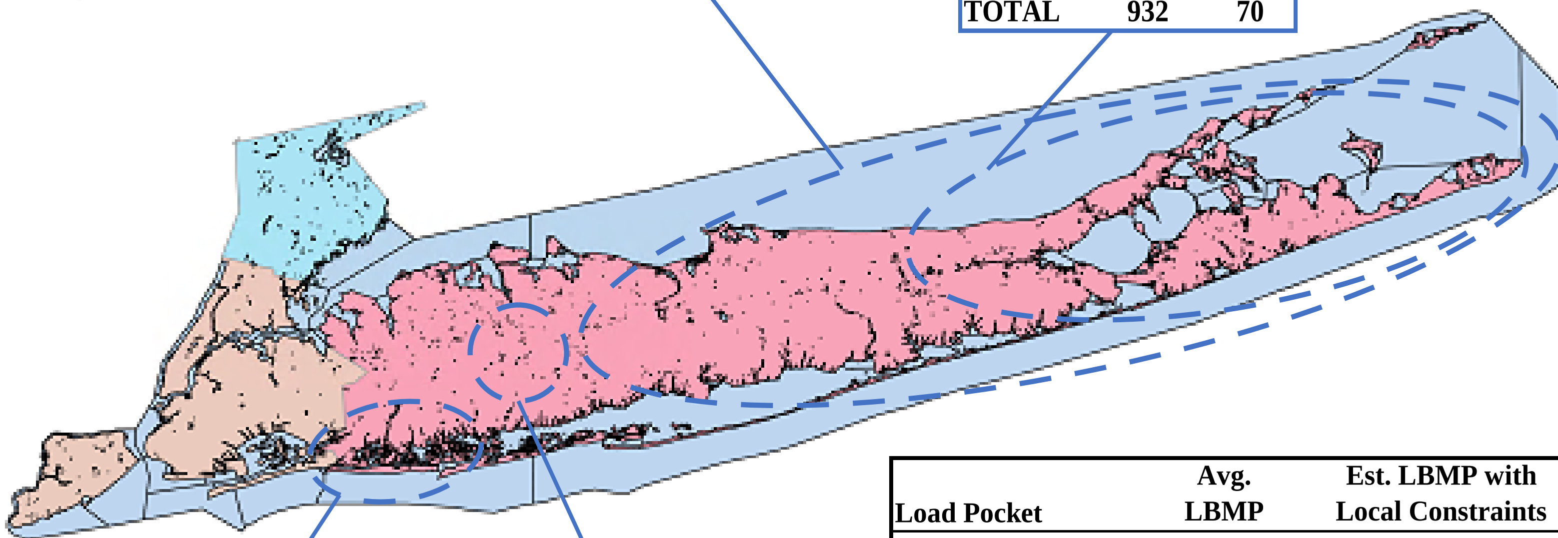
Cent-Hud	# Days
Gen Up	4
Any Resource	4

Notes: For chart description, see slides 86-88

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV	329	35
138kV	1102	68
TOTAL	1146	68

East End	#Hours	#Days
69kV	48	5
138kV	2	1
TVR	930	70
TOTAL	932	70



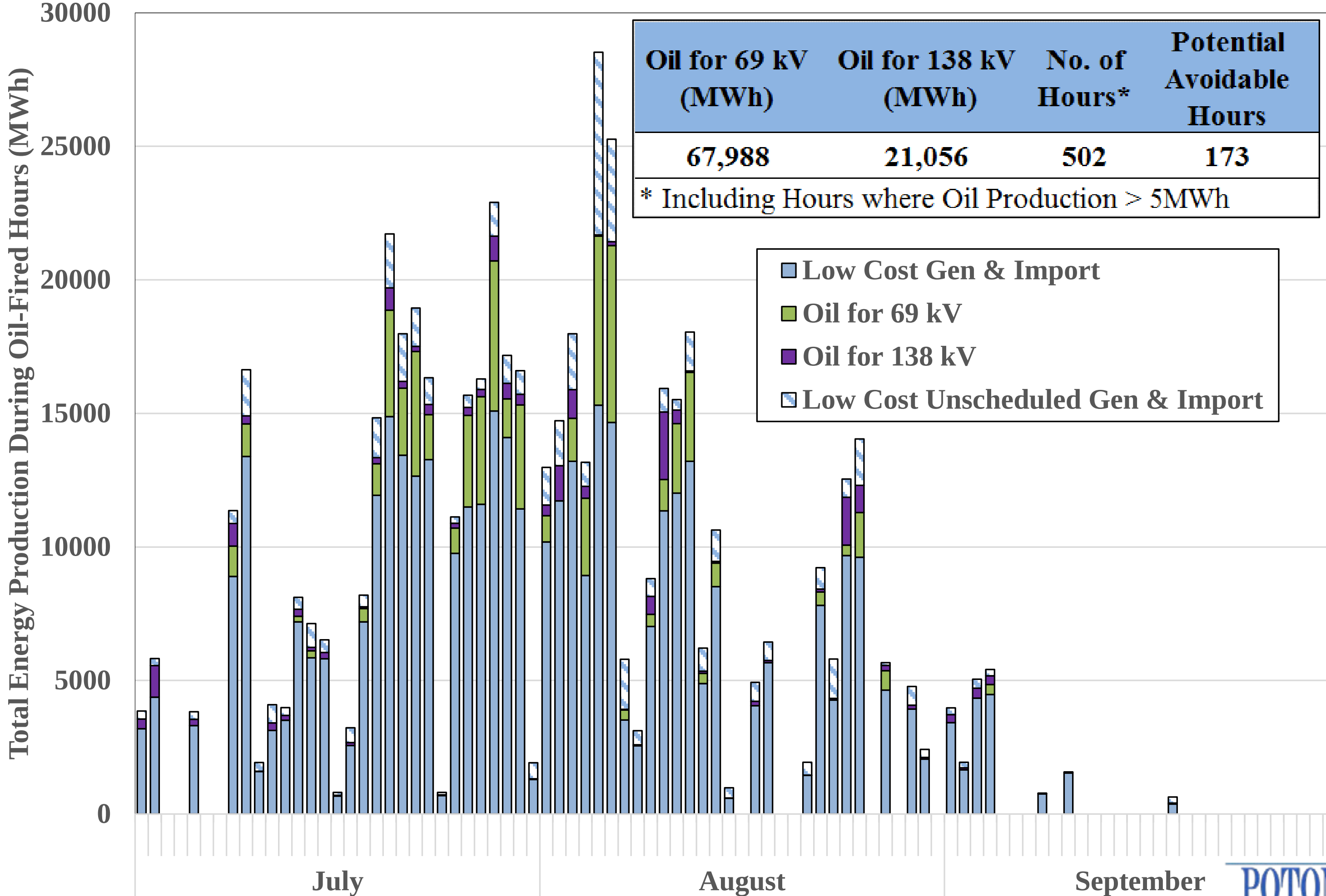
Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$29.39	$31.17
East End	$39.72	$87.60
East of Northport	$38.71	$50.18
Valley Stream	$31.60	$45.00

Valley Stream	#Hours	#Days
69kV	687	58
138kV	1100	77
TOTAL	1396	80

Brentwood	#Hours	#Days
69kV	270	42
138kV	0	0
TOTAL	270	42

Notes: For chart description, see slides 86-88

Use of Oil-Fired Generation to Manage Congestion
East of Northport on Long Island

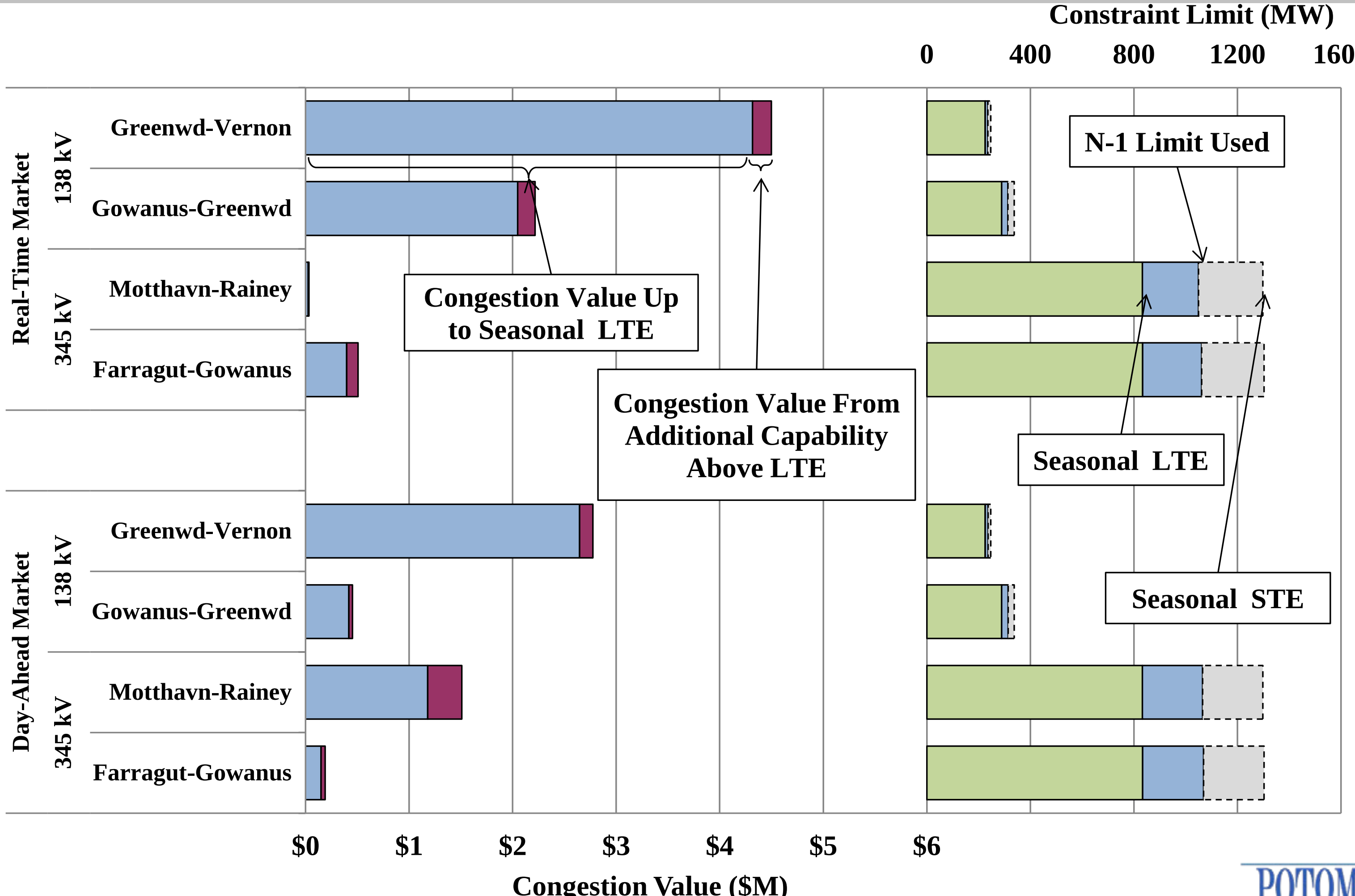


Oil for 69 kV (MWh)	Oil for 138 kV (MWh)	No. of Hours*	Potential Avoidable Hours
67,988	21,056	502	173

* Including Hours where Oil Production > 5MWh

Notes: For chart description, see slide 89

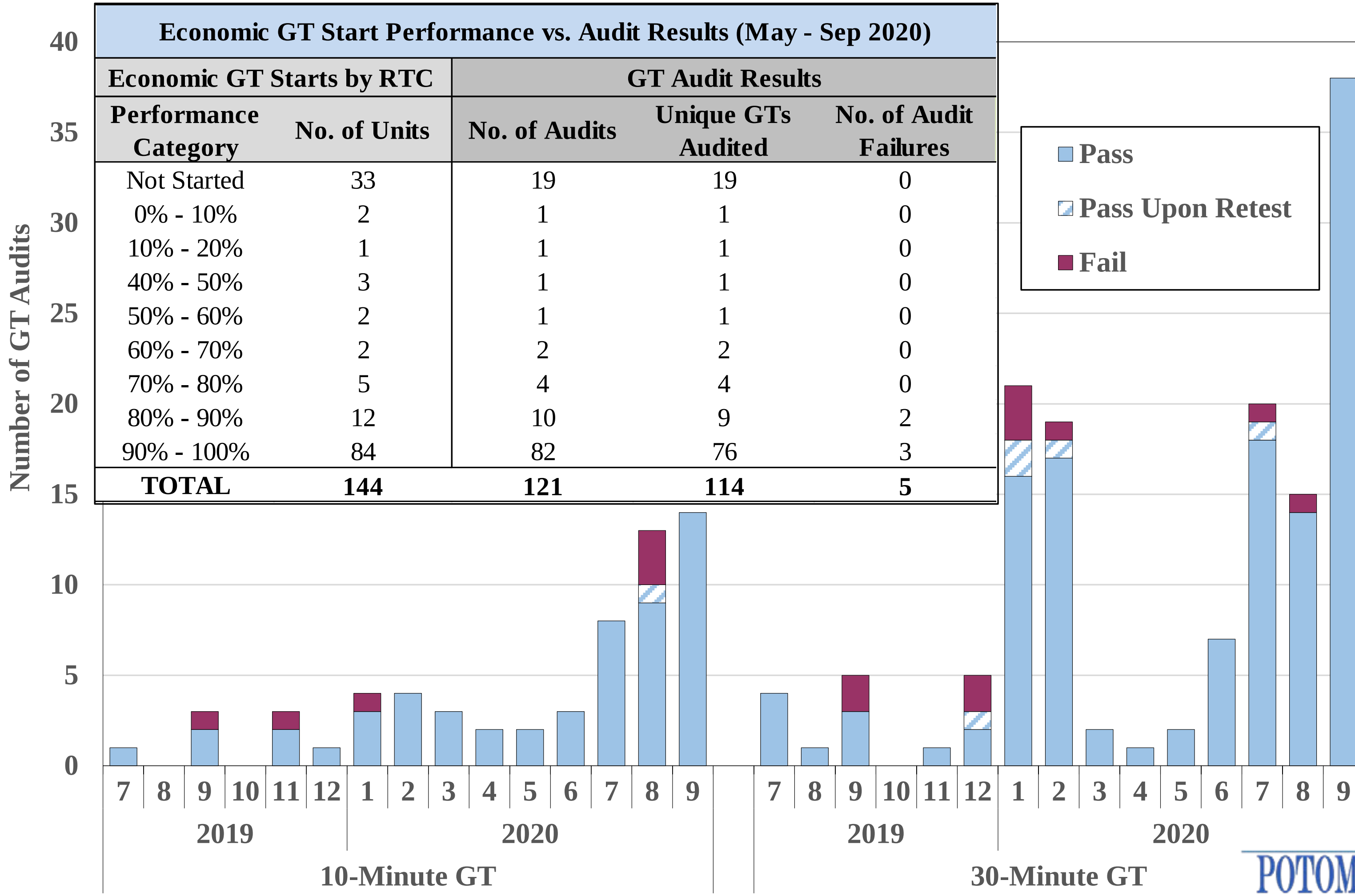
N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings



 Notes: For chart description, see slide 90.

GT Start Audit Performance
Tracking Audit Frequency & Unit Selection

Economic GT Start Performance vs. Audit Results (May - Sep 2020)				
Economic GT Starts by RTC		**GT Audit Results**		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Started	33	19	19	0
0% - 10%	2	1	1	0
10% - 20%	1	1	1	0
40% - 50%	3	1	1	0
50% - 60%	2	1	1	0
60% - 70%	2	2	2	0
70% - 80%	5	4	4	0
80% - 90%	12	10	9	2
90% - 100%	84	82	76	3
TOTAL	**144**	**121**	**114**	**5**



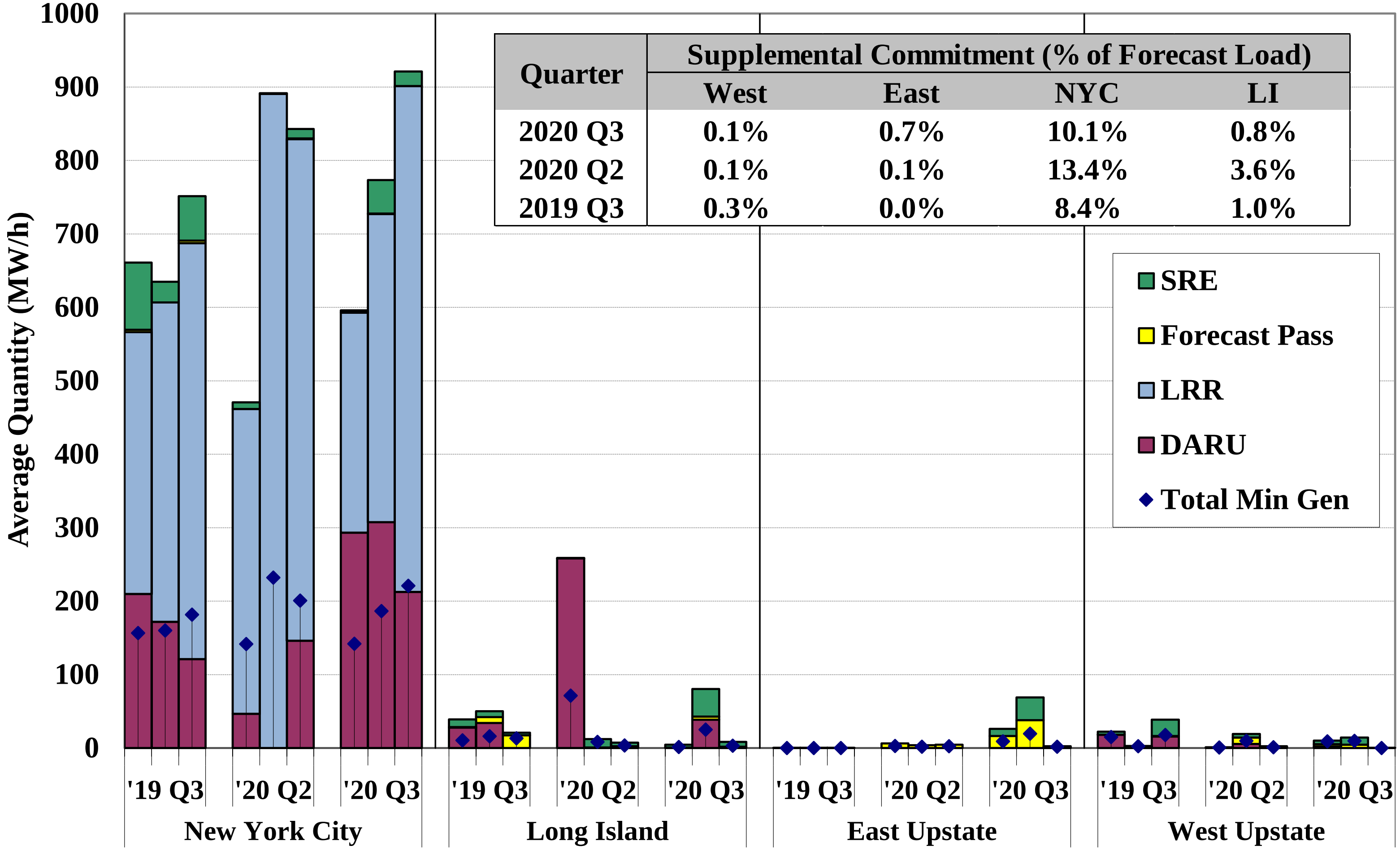
 Notes: For chart description, see slide 91.

POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability by Category and Region

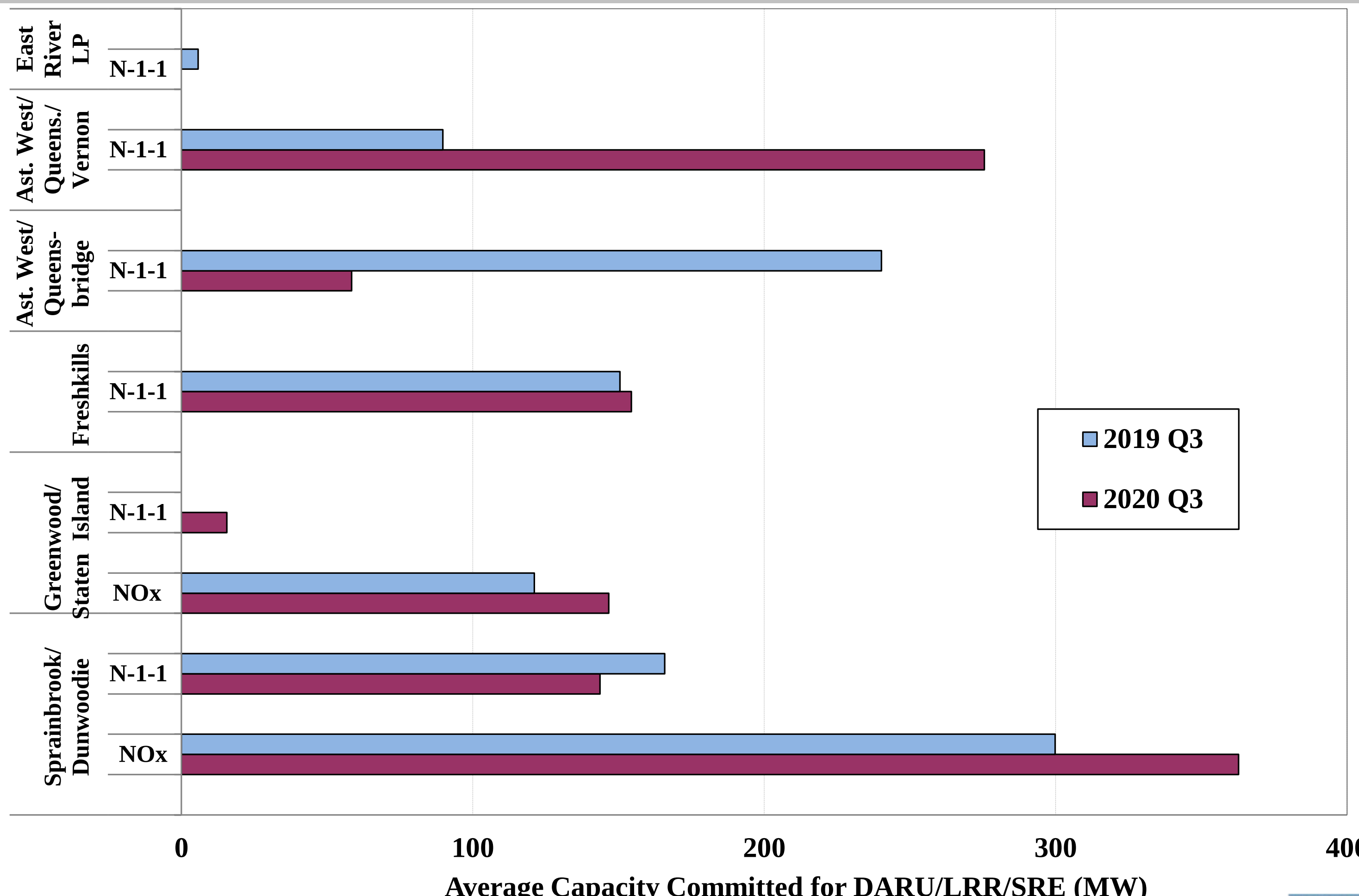


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2020 Q3	0.1%	0.7%	10.1%	0.8%
2020 Q2	0.1%	0.1%	13.4%	3.6%
2019 Q3	0.3%	0.0%	8.4%	1.0%

Notes: For chart description, see slides 92 and 93.

POTOMAC ECONOMICS

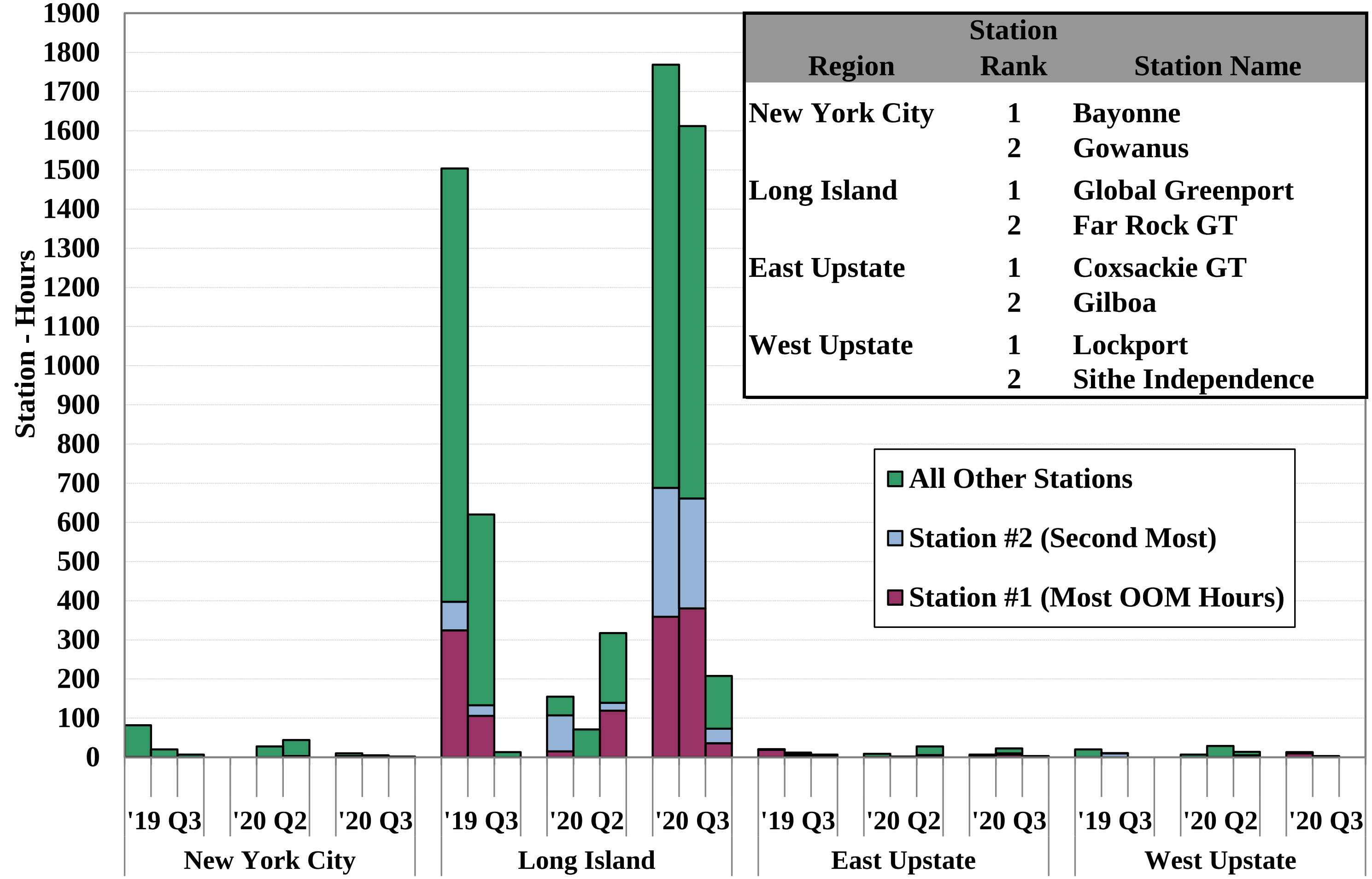
Supplemental Commitment for Reliability in NYC
by Reliability Reason and Load Pocket



Notes: For chart description, see slides 92 and 93.

POTOMAC ECONOMICS

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

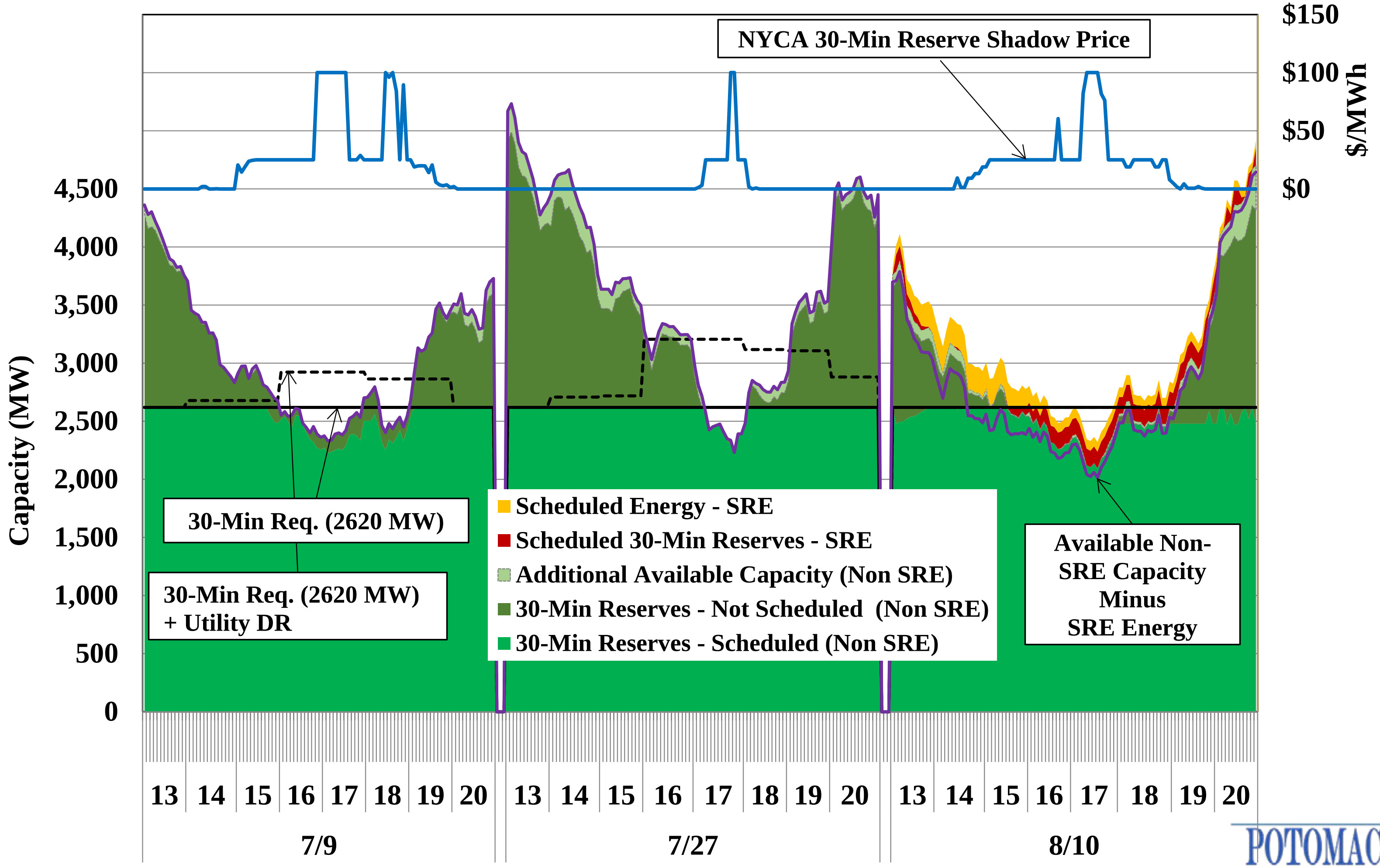


Region	Station Rank	Station Name
New York City	1	Bayonne
	2	Gowanus
Long Island	1	Global Greenport
	2	Far Rock GT
East Upstate	1	Coxsackie GT
	2	Gilboa
West Upstate	1	Lockport
	2	Sithe Independence

For chart description, see slides 92 and 93.

POTOMAC ECONOMICS

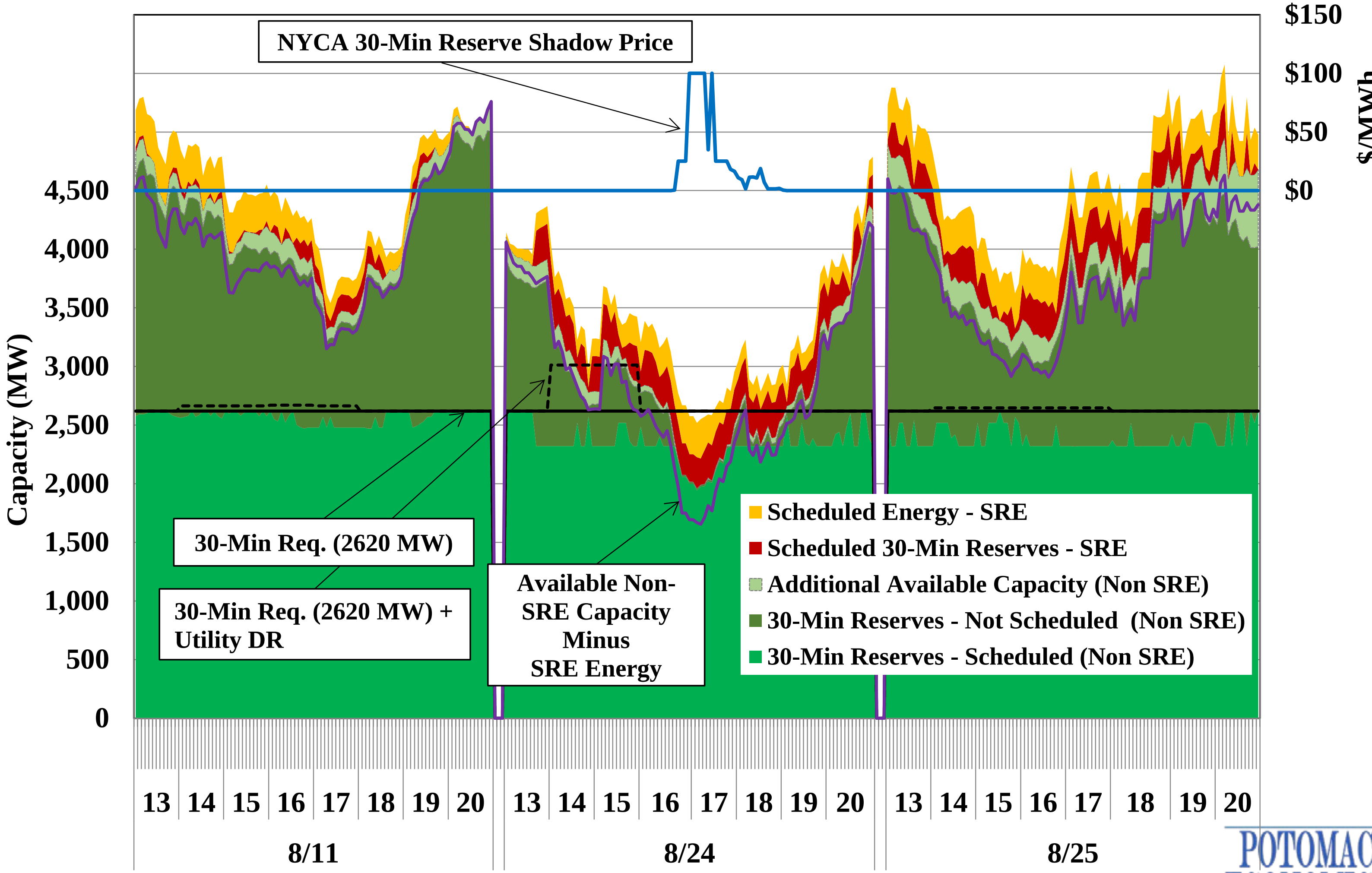
SRE Commitments for Capacity and Utility DR Deployments on High Load Days



Notes: For chart description, see slide 94.

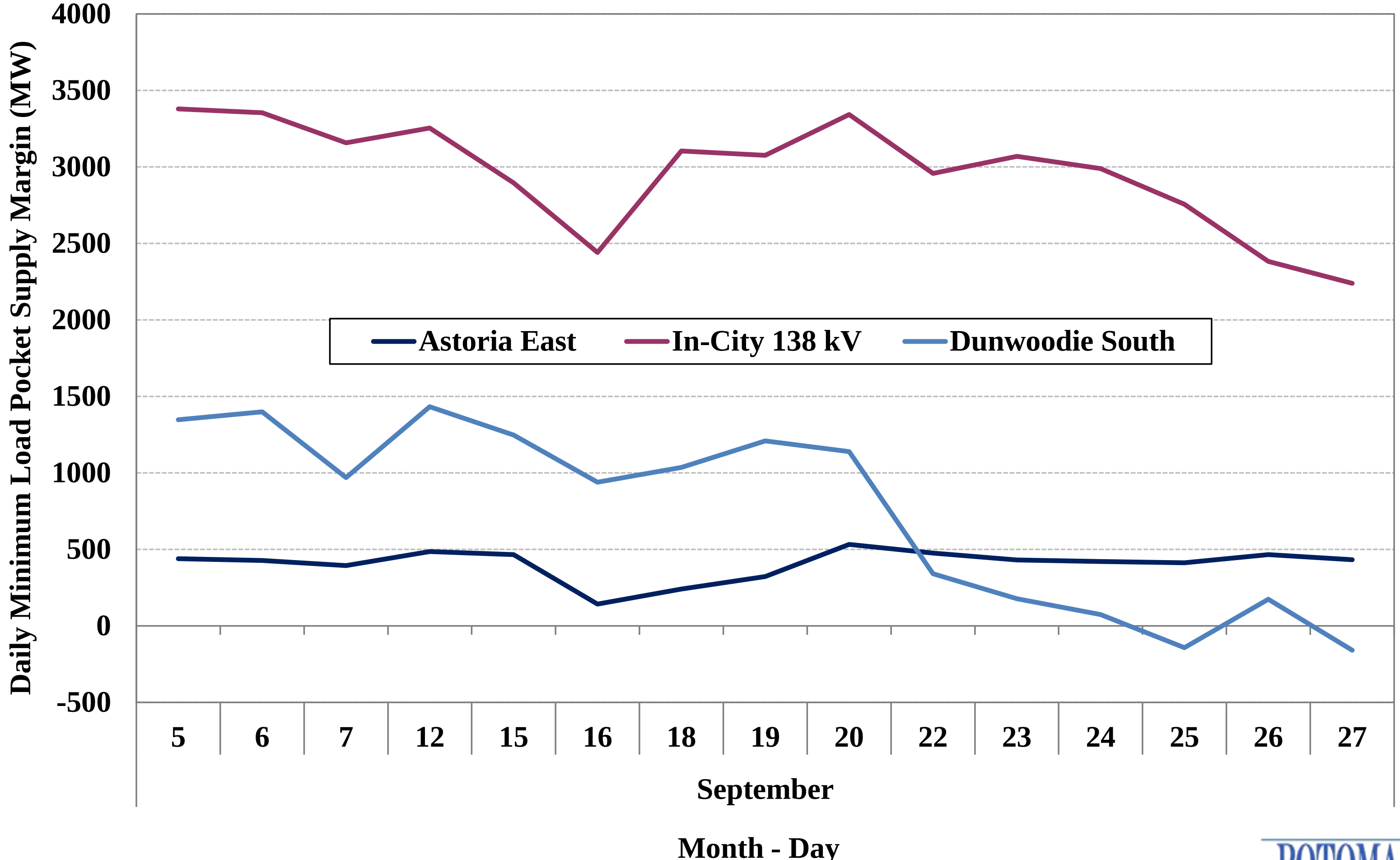
POTOMAC ECONOMICS

SRE Commitments for Capacity and Utility DR Deployments on High Load Days



Notes: For chart description, see slide 94.
POTOMAC ECONOMICS

Supply Margin in NYC Load Pockets
After Removing NOx-only Committed ST and GT in the NOx Bubble

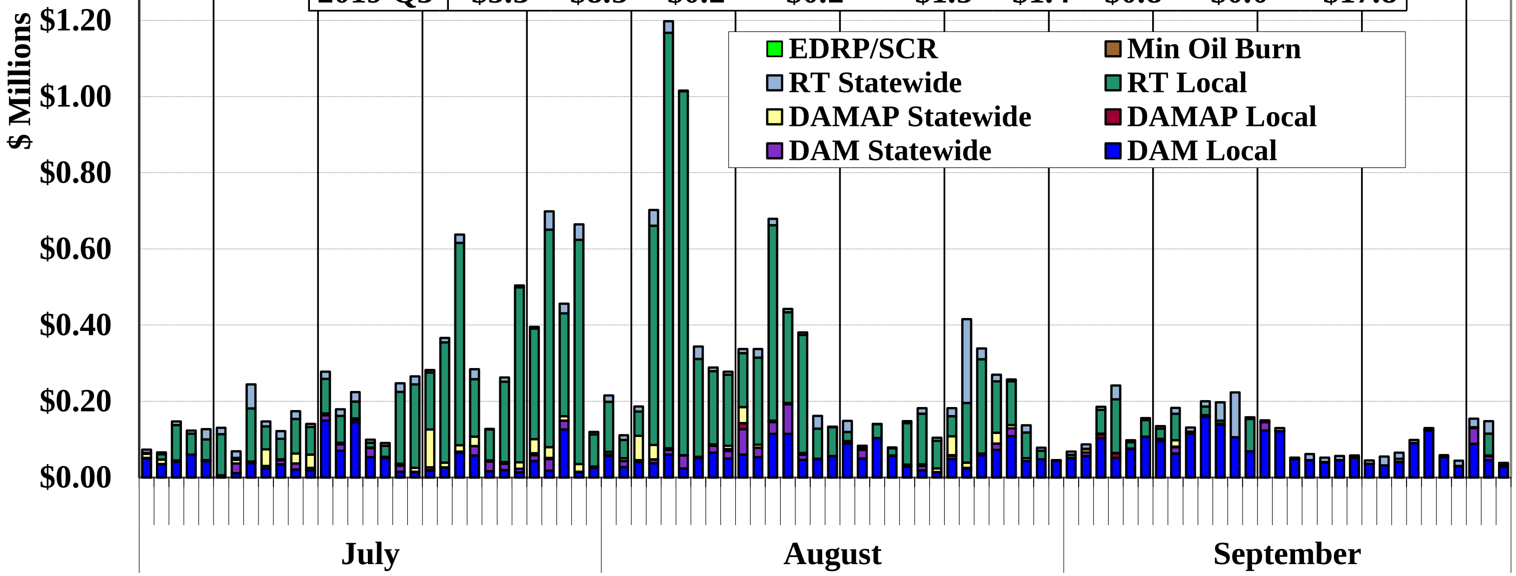


For chart description, see slide 95.

POTOMAC ECONOMICS

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

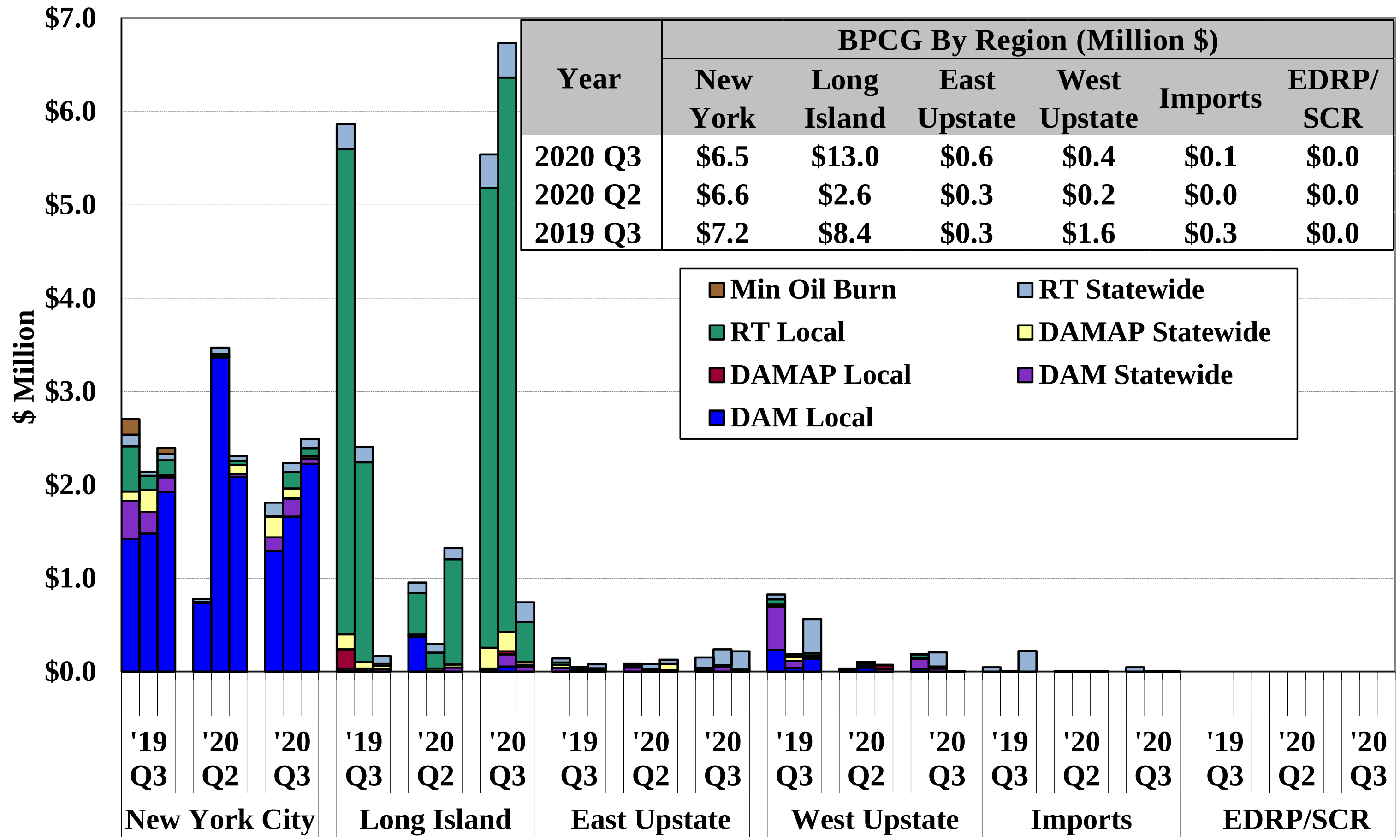
Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DA MAP	Min Oil Burn	Day Ahea	Real Time	DA MAP	EDRP/ SCR	
2020 Q3	$5.3	$11.9	$0.1	$0.0	$0.8	$1.7	$0.9	$0.0	$20.6
2020 Q2	$6.6	$1.9	$0.1	$0.0	$0.3	$0.6	$0.3	$0.0	$9.7
2019 Q3	$5.3	$8.5	$0.2	$0.2	$1.5	$1.4	$0.8	$0.0	$17.8



Notes:1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.
2. For chart description, see slide 96.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region



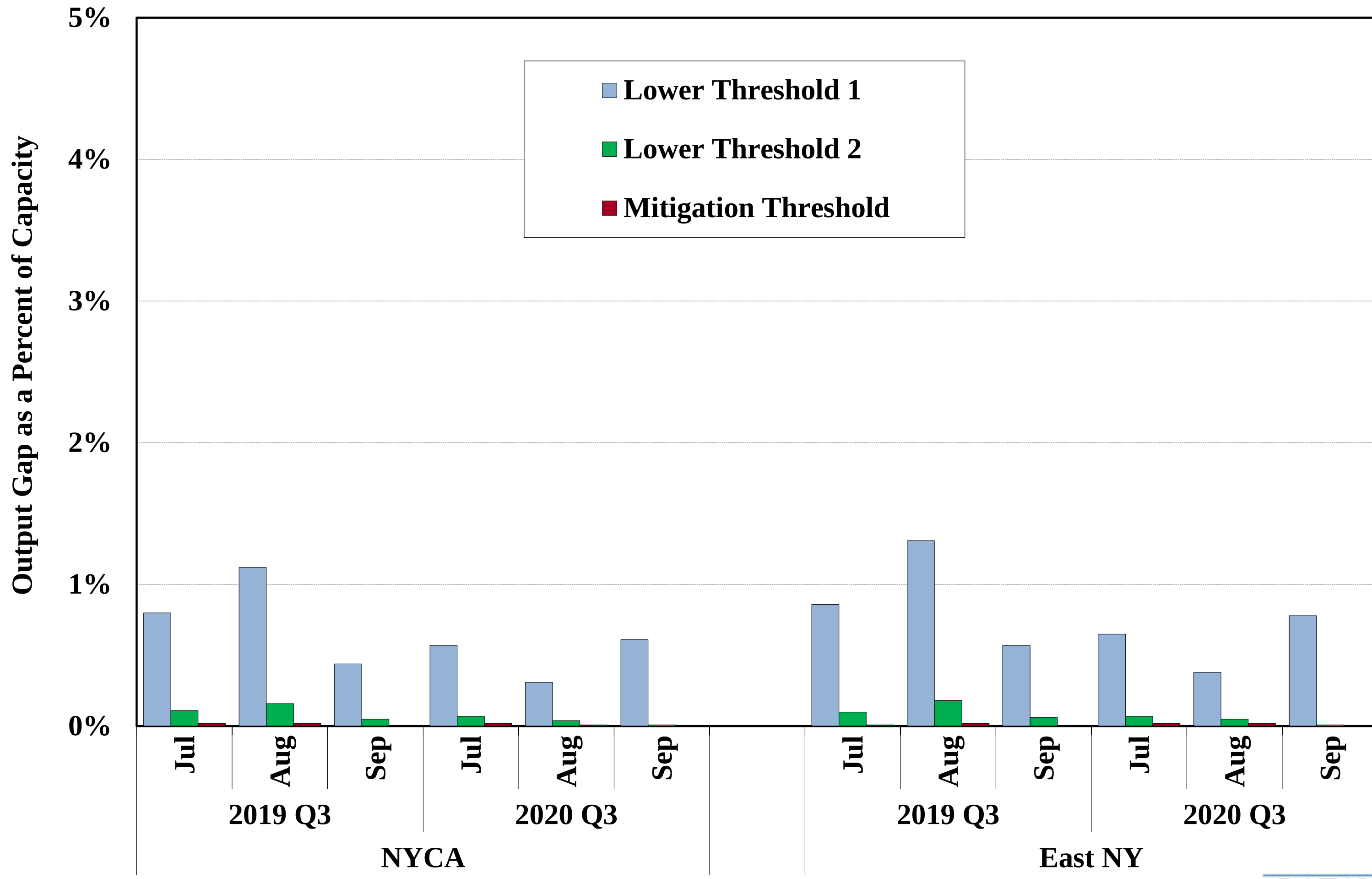
Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2020 Q3	$6.5	$13.0	$0.6	$0.4	$0.1	$0.0
2020 Q2	$6.6	$2.6	$0.3	$0.2	$0.0	$0.0
2019 Q3	$7.2	$8.4	$0.3	$1.6	$0.3	$0.0

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 96.

Charts:

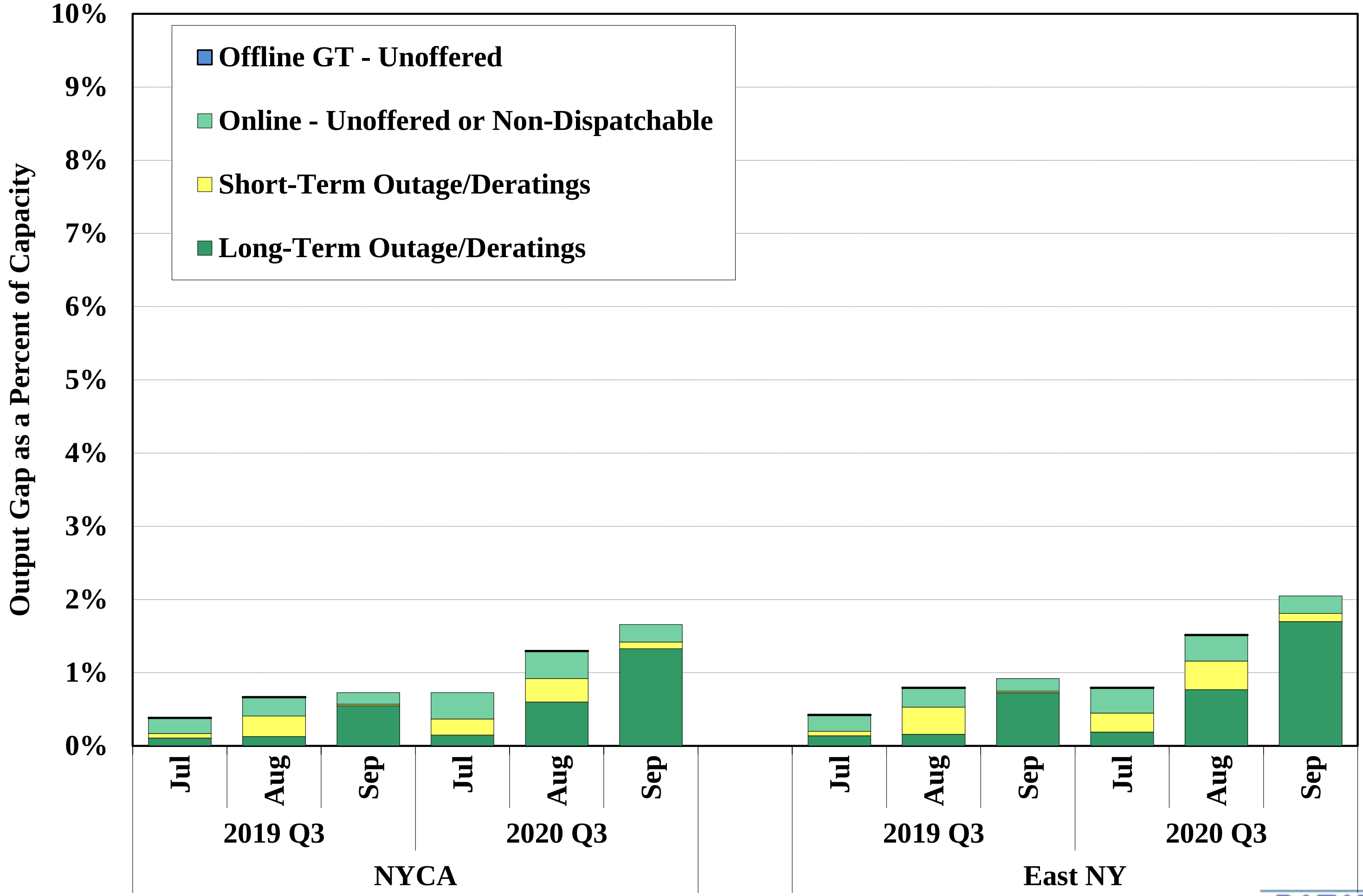
Market Power and Mitigation

Output Gap by Month
NYCA and East NY



For chart description, see slide 97.

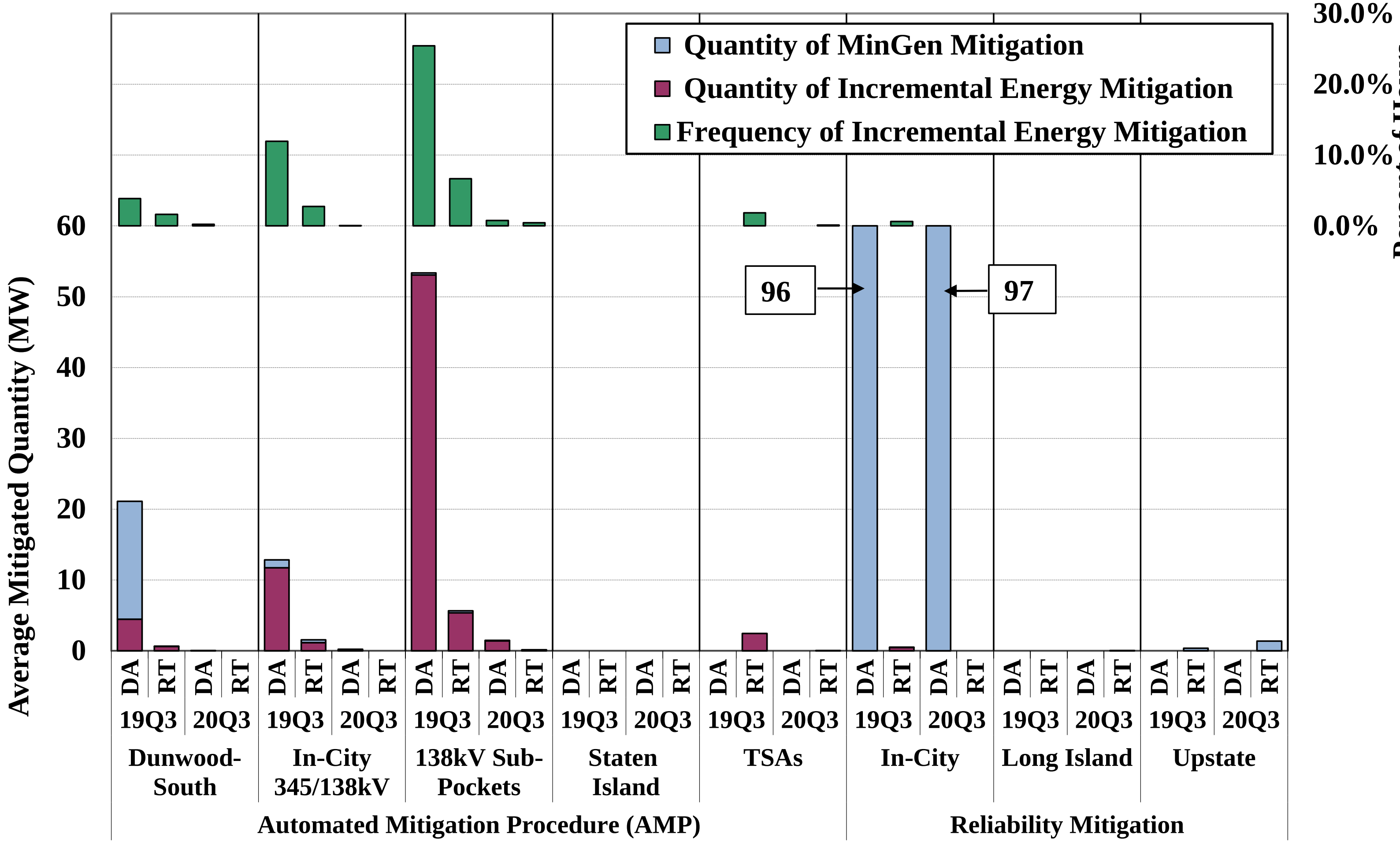
Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 97.

POTOMAC ECONOMICS

Market Power Mitigation
Reliability Mitigation and AMP



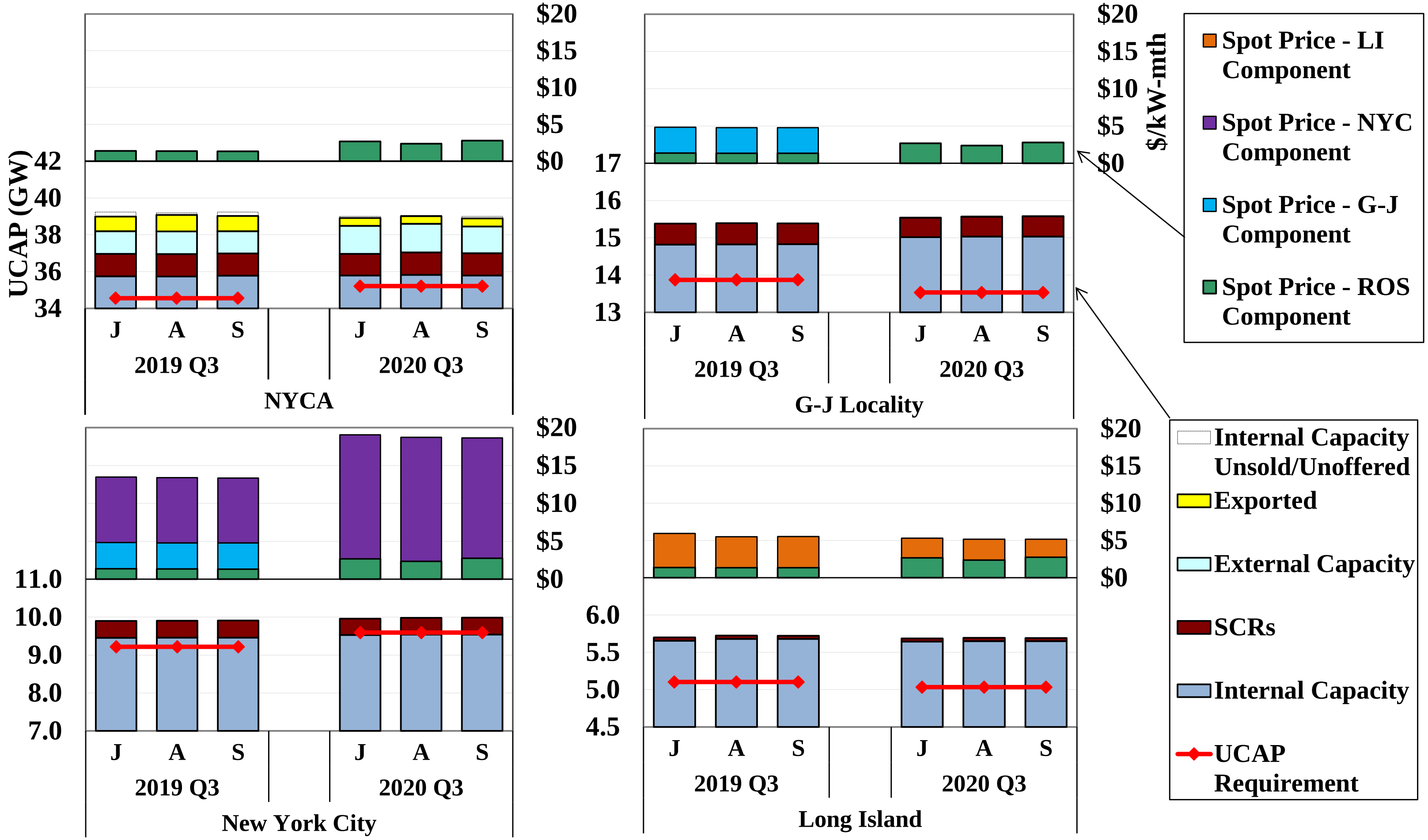
Notes: For chart description, see slide 98.

POTOMAC ECONOMICS

Charts:
Capacity Market

POTOMAC
ECONOMICS

Spot Capacity Market Results
2019-Q3 & 2020-Q3



Notes: For chart description, see slide 99.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2020 Q3 ($/kW-Month)	$2.61	$18.79	$5.22	$2.61
% Change from 2019 Q3	**91%**	**40%**	**-8%**	**-46%**
Change in Demand				
Load Forecast (MW)	-87	-130	-13	-150
IRM/LCR	1.9%	3.8%	-0.7%	-2.3%
2020/21 Capability Year	*118.9%*	*86.6%*	*103.4%*	*90.0%*
2019/20 Capability Year	*117.0%*	*82.8%*	*104.1%*	*92.3%*
ICAP Requirement (MW)	**512**	**329**	**-50**	**-501**
Key Changes in ICAP Supply (MW)				
Generation	**-910**	**-35**	**0**	**-42**
Entry	1020	0	0	1020
Exit[1]	-1930	-35	0	-1062
Cleared Import[2]	**290**			
Cleared Export[2,3]	**416**			

(1) Includes Generators' ICAP associated with BTM load.

(2) Based on average of quarterly cleared quantity.

(3) Positive values indicate fewer exports in this table.

Notes: For chart description, see slide 99.

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Appendix: Chart Descriptions

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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 zone, allocated over the energy consumption in that zone.
  - ✓ 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 transportation charges equal to $0.27 per MMBtu for Zones A through I, $0.20 per MMBtu for New York City, and $0.25 per MMBtu for Long Island):
    - (a) Tennessee Z4 200L index for the West Zone, (b) the minimum of TN Z6 and Iroquois Zone 2 indices during the months Dec through Feb, and TN Z4 200L index otherwise for Central New York; (c) Iroquois Waddington index for North Zone; (d) the minimum of TN Z6 and Iroquois Z2 indices for the Capital Zone; (e) the average of Iroquois Z2 index and the Tetco M3 index for Lower Hudson Valley; (f) Transco Zone 6 (NY) index for New York City, and (g) the Iroquois Z2 index for Long Island. 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.

Ancillary Services Prices

- Slides 30-34 summarize day-ahead and real-time prices for nine 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 13 per MW of capability, but they are compensated according to actual movement.
  - ✓ 30-min operating reserve prices in western NY and NYC; 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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Regulation Requirement, Price, and Movement-to-Capacity Ratio

- Slide 35 tracks the cost and performance of regulation service in recent years. The figure summarizes the following quantities by month:
  - ✓ Average capacity prices in the day-ahead market;
  - ✓ Average capacity and movement prices in the real-time market;
  - ✓ Average regulation requirement;
    - The requirement varies by hour by season.
  - ✓ Average actual regulation movement-to-capacity ratio
    - This equals to total Movement MW divided by total scheduled regulation capacity in each month.
- Regulation resources are scheduled assuming a common regulation movement multiplier of 13 per MW of capability, however, slide 36 shows a wide variation in actual movement-to-capacity ratio.
  - ✓ The figure shows the distribution of actual movement-to-capacity ratio of all scheduled regulation suppliers from one sample day.
    - The blue bars show the average scheduled regulation capacity in each movement-to-capacity ratio tranche.
    - The solid blue line represents the capacity weighted average actual movement-to-capacity ratio for the day, compared to the common multiplier of 13.

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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.

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Real-Time System Price Maps at Generator Nodes

- Slides 46 and 47 show maps of real-time LBMPs at generator nodes across the entire NYISO system and in New York City specifically to illustrate congestion patterns in both areas.
  - ✓ Prices are load-weighted real-time hourly LBMPs.
  - ✓ Generators are marked as circles of various sizes and colors which are determined based on market outcomes:
    - – Circle size is developed based on real-time generation from each generator across the quarter.
    - – Colors are scaled based on the load-weighted real-time prices at each node.
    - – However, both circle sizes and color scales are not necessarily the same at the same generator location in the system map and the NYC map. Because these are independently determined based on the set of generators analyzed in each map.
  - ✓ Natural gas prices for major indices and load-weighted external energy prices are also provided.
    - – External LBMPs are not scaled to size in like manner as the generators.
    - – Natural gas pipeline connections are given for the NYC price map to illustrate approximate gas delivery points to the city from three major pipelines.

Transmission Congestion and Shortfalls

- Slides 48, 49, 50, and 51 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 48 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 49 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 50 and 51 show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.

Transmission Congestion and Shortfalls (cont.)

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

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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 53 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;
  - ✓ Central Zone;
  - ✓ Capital Zone:
  - ✓ North & Mohawk Valley Zones; and
  - ✓ Long Island (mostly constraints on the 69kV system).

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NY-NJ PAR Operation Under M2M with PJM

- Slide 52 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

- Slide 54 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 in the DA and RT markets.
- Slide 54 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.

Use of Oil-Fired Generation to Manage Congestion East of Northport on Long Island

- Slide 55 evaluates the efficiency of using oil-fired generation to manage constraints in the East of Northport pocket of Long Island in the real-time market.
- The figure summarizes the following quantities from resources in the East of Northport pocket for each day when oil-fired generation was used to manage 69 kV (by OOM) or 138 kV (by market model) constraints in this area:
  - ✓ Oil-fired generation - scheduled to manage congestion on the 69 kV network by OOM or on the 138 kV network by the market model broken out by these characterizations.
  - ✓ Low-cost generation & imports – generation scheduled from all other resources in the pocket, including scheduled CSC imports and oil production that is either self-scheduled, audited, or OOMed for TVR support on the East End of Long Island.
  - ✓ Low-cost unscheduled generation & imports - unscheduled generation in the pocket, which includes the unscheduled portions of baseload combined cycles in the load pocket, unscheduled imports on the CSC (excluding outages), unscheduled portions of Port Jeff ST units (when online in real-time), and unscheduled gas GT generation.
- The daily results are limited to summarizing hours where oil-fired generation was scheduled for 69 kV or 138 kV constraints.
- The table provides details on oil-fired generation (as defined above) for the quarter and the number of hours where unscheduled low-cost generation & imports was greater than the amount of oil-fired generation.

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 56 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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GT Start Audit Performance
Tracking Audit Frequency & Unit Selection

- Slide 57 displays the results of the NYISO's auditing process for 10- and 30-minute GT reserve providers from over the past 15-months. Specifically:
  - ✓ The figure shows the total number of audits performed each month, broken into three categories:
    - – The number of audits that pass on the first time (the blue bar);
    - – The number of audits that pass upon retesting after an initial failure (the blue/white patterned bar); and
    - – The total number of audit failures (the red bar).
    - – A GT that fails its first audit but passes upon retest shows up once in the blue/white pattern bar and once in the red bar.
  - ✓ The inset table summarizes the audit results during the current Capability Year from May through September 2020, compared to performance measured for economic GT starts by RTC in the same period.
    - – The performance is measured as the GT output at 10 or 30 minutes after receiving a start-up instruction as a percent of its UOL, with a 10% increment from 0 to 100%.
    - – The units that are in service but were never started by RTC during this period are placed in a separate category of "Not Started".
    - – An example read of the table: "12 GTs exhibited a response rate of 80%-90%, 9 of them were audited 10 times in total with two failures".

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.

SRE Commitments for Capacity and Utility DR Deployments On High Load Days

- Slides 62 and 63 summarize market outcomes on select high load days when SRE commitments were made for capacity and/or utility DR were deployed by TO. The figures report the following quantities in each interval of afternoon peak hours (HB 13 - HB 20) for NYCA:
  - ✓ Available capacity from non-SRE resources – including 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).
  - ✓ Schedules from SRE resources – including energy and total 30-minute reserves.
  - ✓ Constraint shadow prices on the NYCA 30-minute reserve requirement.
  - ✓ 30-minute reserves requirement (solid black line).
  - ✓ Utility DR deployed plus 30-minute reserves requirement (dashed black line).
  - ✓ Available capacity from non-SRE resources minus SRE energy schedules (solid blue line).
    - Shortage w/o SRE = solid black line – solid blue line
    - Shortage w/o (Utility DR & SRE) = dashed black line – solid blue line

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Supply Margin in NYC Load Pockets After Removing NOx-only Committed ST and GT in the NOx Bubble

- Steam units in New York City are often LRR-committed solely to satisfy the NOx Bubble requirement in the Ozone season.
  - ✓ On many of these days, even if both the committed ST and its supported GTs were unavailable, all N-1-1 criteria could be satisfied by other resources.
    - – This questions the necessity of such commitments in each day of the Ozone season.
- Slide 64 shows our evaluation of the necessity in the quarter.
  - ✓ The figure shows the daily minimum supply margin in the relevant load pockets after the removal of the NOx-committed STs and their supported GTs in the NOx Bubble.
  - ✓ The evaluation is done on days when the ST is NOx-only committed in the day-ahead market.
  - ✓ A positive minimum supply margin indicates that both the ST and associated GTs are not needed to satisfy any N-1-1 criteria in the load pocket, while a negative supply margin indicates that one portion of the ST and associated GTs are needed.

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Uplift Costs from Guarantee Payments

- Slides 65 and 66 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 65 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 66 summarizes uplift costs by region on a monthly basis.

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Potential Economic and Physical Withholding

- Slides 68 and 69 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 70 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 72 and 73 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 72 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 73 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.

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