Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2022

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Market Highlights: Executive Summary

- NYISO energy markets performed competitively in the second quarter of 2022.
- All-in prices ranged from $34 in the North Zone to $113 per MWh in Long Island, up 57 to 85 percent from 2021-Q2 in individual regions. (slide 8)
  - ✓ Energy prices rose 115 to 131 percent across the system primarily because of higher gas prices (up 152 to 174 percent). (slide 22)
  - ✓ Other contributing factors include:
    - – Increased congestion across the Central-East interface from planned transmission outages that reduced the transfer capability by more than 1 GW in April and May.
    - – High levels of congestion from Upstate New York to Long Island because one (out of two) 345 kV circuits were forced out for most of the quarter.
    - – Higher emissions costs from rising RGGI prices and CSAPR Group 3 NOx emissions allowance prices. (slide 23)
  - ✓ Capacity costs fell by 28 to 55 percent as a result of lower IRM and peak load forecast. (slide 18)
- The increased levels of planned outages from transmission upgrade projects led to high levels of day-ahead congestion revenue shortfall uplift ($175 million), especially related to the Central East interface ($162 million). (slide 57)

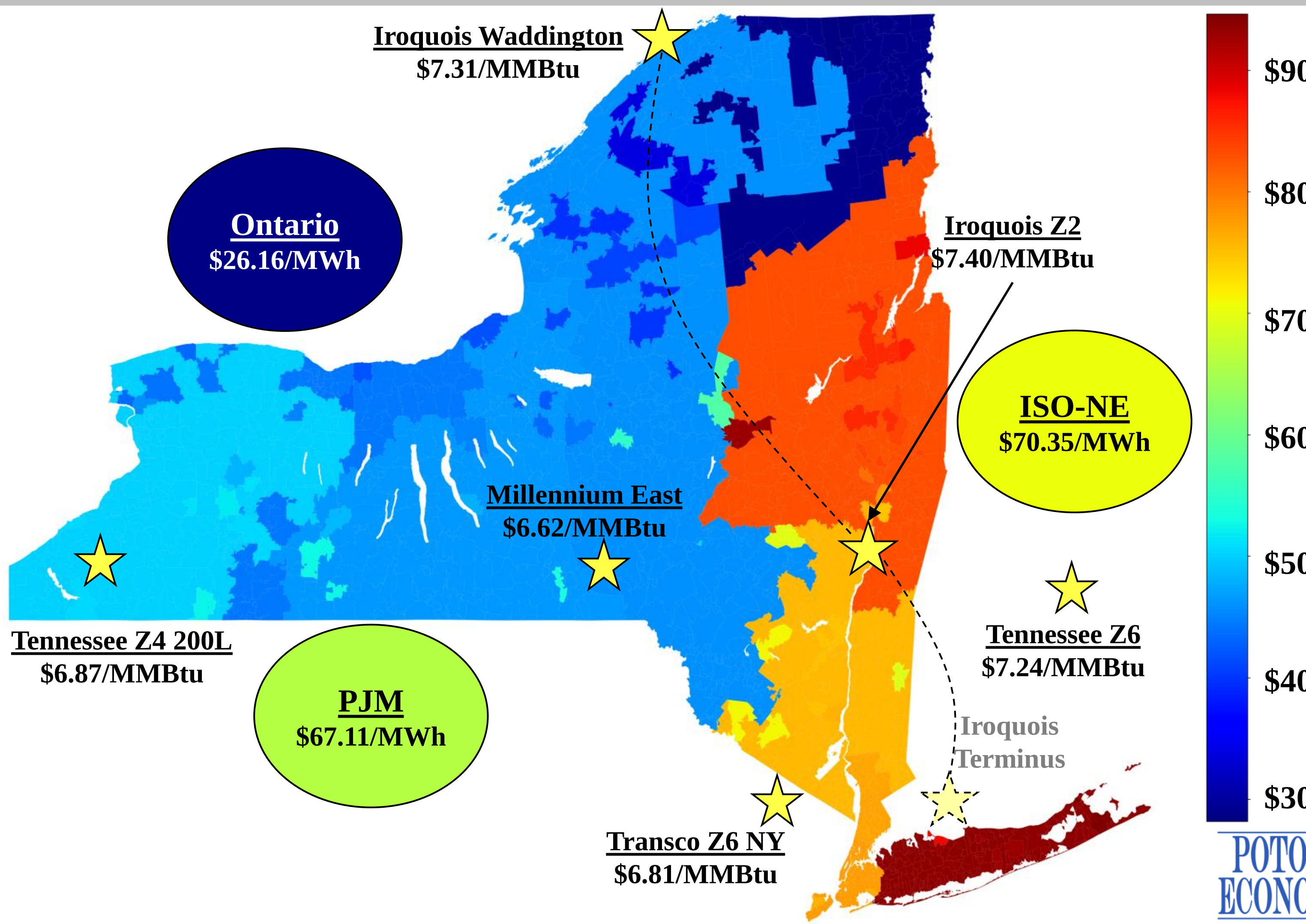
Market Highlights: Executive Summary

- Although NYISO has reduced OOM dispatch for 69kV congestion on Long Island, other OOM actions increased significantly in 2022-Q2 from previous years.
  - ✓ OOM actions to secure facilities in the West Zone occurred on 50 days, and supplemental commitment for local reserve needs occurred in the Capital Zone on 12 days and Long Island on 12 days. (slides 13, 60)
  - ✓ Commitment of steam turbines in NYC for NOx bubble constraints could have been avoided on 31 days if ARR-37 allowed NYISO to consider whether the GTs in a particular NOx bubble were truly necessary for reliability. (slide 17)
- Price convergence between NYISO and neighboring areas was relatively poor as the average price in PJM exceeded NYISO's by nearly $6/MWh and the average price in NYISO exceeded ISO-NE's by more than $4/MWh. (slide 48)
  - ✓ Inefficient utilization of the ISO-NE interface results from price forecast errors and OOM transaction cuts after CTS transactions are scheduled. (slides 48-49)
    - – Price forecast error rose this year as the contribution from load forecast error also rose. Load forecast adjustments are often made in RTC when operators anticipate the load forecasts in future intervals is off. (slides 12, 50-51)
  - ✓ Under-utilization of the PJM interface is exacerbated by large fees charged to exports from NYISO to PJM. (see 2021 SOM Recommendation #2015-9)

Market Highlights:
Executive Summary

- Duct burner operations of CCs continued to present challenges both for generator bidding and operator scheduling of resources. (slides 15 & 64) On average:
  - ✓ More than 250 MW of duct burner capacity was offered as capable of providing services (including 10-minute reserves, regulation, and following 5-minute instructions) but physically unable to respond within the required timeframes.
  - ✓ More than 150 MW of CC capacity (including both duct burner and baseload ranges) was unavailable for energy and/or reserves because of no offer, inflexible bidding, and being disqualified from providing reserves.
  - ✓ In addition, understated ramping capability of some CCs contributed to transient high congestion in some local areas.
- The NYISO has increased efforts to audit GTs that provide 10 and 30-minute non-synchronous reserves over the past two years. (slide 16) However:
  - ✓ Most audits are conducted on units that regularly demonstrate fast-start capability in normal market operations.
  - ✓ Some units that performed poorly in audits and in normal market operations remain qualified (despite being scheduled for reserves frequently).
  - ✓ Most rarely-started 30-minute units were also not audited in the last 12 months.

Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the second quarter of 2022.
  - ✓ The amount of output gap (slide 75) and unoffered economic capacity (slide 76) remained reasonably consistent with competitive market expectations.
- All-in prices ranged from $34/MWh in the North Zone to $113/MWh in Long Island, rising 57 to 85 percent from last year across all zones. (slide 20)
  - ✓ Energy prices more than doubled from a year ago, up by 115 to 131 percent across the system. (slides 31-32)
    - – The increases were driven primarily by higher natural gas prices, which rose 152 to 174 percent across the system from a year ago. (slide 22)
    - – Other contributing factors include:
      - Lengthy major transmission outages, which led to significant congestion across the Central-East interface and further elevated prices in East NY. (slide 55)
      - Lower net imports, which fell by 900 MW in the afternoon peak hours. In particular, higher gas prices and reduced Central-East interface capability made it less (more) economic to import from (export to) PJM. (slide 47)
      - Higher emission costs (including CO2, NOx) which rose by 87 to 201 percent for gas-fired CCs, GTs, and STs. (slide 23)
  - ✓ However, capacity costs fell in all areas as discussed in slide 18.

Market Highlights:
Generation by Fuel and Emission

- Average nuclear generation fell by roughly 290 MW from a year ago, because of the retirement of the last Indian Point nuclear unit at the end of April 2021.
- Average hourly net imports from external control areas also decreased by over 900 MW from 2021 Q2 due primarily to relative economics. (slide 47)
- Gas-fired generation rose by roughly 12 percent despite much higher natural gas prices. (slide 24)
  - ✓ Gas-fired combined cycles accounted for 97 percent of this increase (720 MW).
    - Output from Capital Zone combined cycle units rose by 500 MW on average due to the high levels of transmission congestion along the Central East interface.
    - Hudson Valley combined cycles also ran more (250 MW) due to the increase localized congestion from Capital to Hudson Valley. (slide 56)
    - Although these led to increased emissions from 2021-Q2 (slides 27-30), the emission levels have been at historical low levels. (slide 26)
- Steam turbines accounted for 52 percent of NOx emission in New York City in the second quarter of 2022.
  - ✓ Roughly 20 percent of ST NOx emission was from STs that were supplementally committed for local reliability. (slide 29)

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Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $219 million, up 124 percent from the second quarter of 2021. (slide 55)
- The Central-East interface accounted for the largest share ($141 million or 64 percent) of day-ahead congestion revenues this quarter. (slide 56)
  - ✓ This congestion value was noticeably higher than seen in the recent second quarters and was driven primarily by lengthy transmission outages.
    - Multiple line outages reduced the interface capability by more than 1,000 MW for most of April and May, contributing to a total of $162 million of day-ahead congestion shortfalls in the quarter. (slide 57)
  - ✓ Higher gas prices coupled with lower nuclear generation in East NY, as a result of Indian Point 3 retirement, also contributed to this congestion. (slide 24).
- Congestion from Capital to Hudson Valley rose from prior quarters, accounting for the second largest share of overall congestion (10% DA, 17% RT) this quarter.
  - ✓ Transmission outages taken to facilitate Public Policy transmission projects were a key driver of higher congestion in this area.
  - ✓ Congestion on the Cricket Valley-Pleasant Valley 345 kV line was prevalent throughout the quarter, especially in real time.

Market Highlights:

Congestion Patterns, Revenues and Shortfalls (cont.)

  - Loop flows between NY and NE across the line were a key driver in real time.
  - Ramping capability of some CCs was understated in order to manage offers involving their duct burner ranges, contributing to frequent transient high congestion spikes in real time.

- LI accounted for roughly 8 percent of overall congestion this quarter.
  - ✓ Most of this congestion occurred on the 345 kV inter-ties between upstate regions and Long Island.
    - The Y49 345 kV line was OOS during most of the quarter, contributing to a total of $15 million of day-ahead congestion shortfalls. (slide 57)
    - As a result, gas-fired steam turbines and peaking units on Long Island were often on the margin. (slide 25)
      - Higher emission costs for gas-fired STs and GTs contributed to higher LBMPs on Long Island. (slide 23)
- North zone accounted for another 8 percent of overall congestion.
  - ✓ 92 percent of this congestion occurred on the Moses-Adirondack 230 kV line when the parallel line was OOS during most of the quarter. (slide 57)
  - ✓ These outages have been primarily related to the Moses-Adirondack Smart Path Reliability Project.

Market Highlights:
Load Forecast Errors on RTC/RTD Divergence

- RTC schedules non-dispatchable resources with lead times of 15 minutes to one hour (e.g., external transactions and fast-start units).
  - ✓ Inconsistency between RTC and RTD prices is an indicator that some scheduling decisions of RTC may be inefficient.
- We performed a systematic evaluation of factors that led to inconsistent RTC and RTD prices in the second quarter of 2022. (slide 49)
  - ✓ Load forecasting errors increased as a contributor to price differences between RTC and RTD, accounting for 23 percent of the overall divergence this quarter.
    - – On average, RTC load was higher than RTD load by nearly 100 MW, contributing to higher RTC LBMPs (than RTD LBMPs by an average of $3/MWh). (slide 50)
    - – Operator adjustments to the RTC load forecast were a key driver. (slide 51)
      - RTC load forecast adjustments have been more frequent in 2022 because of less accurate BTM solar forecasting.
    - – Although load forecast adjustments may be justified for many reasons, large changes in adjustment values may contribute to divergences between RTC and RTD prices, inefficient scheduling, and RT price volatility.
    - – Therefore, it would be beneficial to evaluate the current procedure for determining load forecast adjustments in RTC for any potential improvements.

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Market Highlights:
OOM Actions to Manage Network Reliability

- OOM actions to manage network reliability were frequent in some regions this quarter - West Zone (50 days), Long Island (25 days), and the Capital Zone (19 days). (slide 60)
- OOM actions in the West Zone rose this quarter.
  - ✓ Most of these OOM actions occurred during the planned outage of the Dunkirk 115 kV M2 Bus, where one unit was supplementally committed almost every day to satisfy local voltage and thermal needs.
- Supplemental commitments to satisfy the N-1-1 requirements occurred on: (a) 3 days in the North Country load pocket; (b) 12 days in the Capital Zone 115 kV load pocket; and (c) 12 days in the Long Island load pocket.
  - ✓ We have recommended the NYISO model full reserve requirements for Long Island in our 2021 SOM report. It would be beneficial to model full reserve requirements in other applicable local areas as well, such as North Country and Capital Zone.
- OOM actions to manage 69 kV congestion on Long Island occurred on only two days. (slide 61)
  - ✓ Four 69kV constraints that were frequently managed by OOM actions in the past have been incorporated in the market software.

Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $27 million, up 205 percent from 2021-Q2 and driven primarily by higher natural gas prices.
  - ✓ Higher supplemental commitments (slide 68) and more frequent OOM actions (slide 70) were also key contributors.
- $16 million (or 59 percent) of BPCG payments accrued in NYC, 89 percent of which were paid to units that were committed for local reliability. (slide 73)
  - ✓ NOx emission costs for gas-fired STs rose to an average of $12/MWh in June (slide 23), contributing to higher uplift. However, only a subset of ST-owners have requested to reflect this cost in reference levels.
- West Upstate accounted for nearly $4 million of BPCG uplift.
  - ✓ Most of this uplift accrued on units that were supplementally committed for local voltage and thermal needs.
- RT BPCG spiked more than $1 million on June 11. (slide 72)
  - ✓ This large BPCG was driven primarily by uneconomic over-production by some units, which is under review and may result in sanction.
    - – Since this event, the amount of flexible generation offered in certain export-limited areas during the morning ramp (i.e., hours 6-9) has increased dramatically.
    - – Updates to the RT BPCG eligibility criteria to prevent this scenario (in the future) were approved by stakeholders and effective starting June 29.

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Market Highlights: Performance and Availability of Duct Burners

- Most combined cycle generators in the NYISO footprint offer supplemental output from their duct burners, totaling roughly 800 MW of summer capacity.
  - ✓ This capacity often presents difficulties in real-time due to inconsistencies between the market design and the physical limitations of duct burners.
- Slide 63 shows an example of a combined-cycle unit that could not follow dispatch instructions during a Reserve Pickup (RPU) event, due largely to its inability to fire the duct burner within the 10-minute timeframe.
  - ✓ However, this duct burner capacity is considered capable of following 5-minute dispatch signals in the market scheduling and pricing software.
- Slide 64 shows duct-firing capacity that was offered but not physically capable of providing a given service in the required timeframe. During afternoon hours, on average: (a) 123 MW was offered but not capable of following 5-minute ramp instructions; (b) 65 MW was scheduled but not capable of providing 10-minute reserves; and (c) 26 MW was scheduled but not capable of providing regulation.
  - ✓ In addition, (a) 54 MW of duct-firing capacity was unavailable because this range was not offered; and (b) 115 MW of 10- and 30-minute reserves were not offered from baseload capacity (i.e., non-duct ranges) due to an inability to perform in audits of the duct burner range.

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Market Highlights:
Performance 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 the services that they sell.
- We reviewed NYISO audit results and found that in the 12-month period from July 2021 to June 2022: (slides 65-66)
  - ✓ Using performance during reserve pick-ups (RPUs) in lieu of regular audits for 10-minute GTs has been more frequent.
    - More than 60 percent of 10-minute GT audits were RPU audits.
    - This has helped reduce out-of-market actions and associated uplift costs.
  - ✓ The number of audit failures rose notably as a result of more frequent RPU audits.
    - There were a total of 47 audit failures, 30 of which were RPU audit failures.
      - 22 percent of RPU audits failed, compared to just 8 percent of regular audit failures.
    - This demonstrates that units that perform well during regular audits may still perform poorly during normal market operations (including reserve pickups and other RTC and RTD economic starts).
      - It would be beneficial to use performance during economic starts in lieu of regular audits for all GTs as RPU audits only apply to 10-minute GTs.
      - It would be appropriate to disqualify poor performers and discount reserve revenues based on performance during normal market operations.

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 LRR-committed solely to satisfy the NOx rule on many days during the Ozone season.
    - – This occurred on 31 days in the second quarter of 2022. (slide 71)
  - ✓ 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 resources on each of the 31 days.
    - – The supply margin (excluding the committed steam turbine and associated GTs) generally exceeded 450 MW each day. (slide 71)
    - – This suggests that these NOx-only steam turbine commitments could have been avoided if ARR-37 allowed the NYISO to consider whether the GTs were truly necessary for reliability (before committing the associated steam turbine).
      - The GTs would not be available in real time absent a NOx-only ST commitment.
  - ✓ These avoidable NOx-only commitments reduce market efficiency by depressing LBMPs and generating uplift and excess production costs (including high emission costs with high CSAPR Group 3 NOx allowance prices).
    - – However, this will not be an issue after May 1, 2023 when some of the affected generators will no longer be permitted to operate during the ozone season.

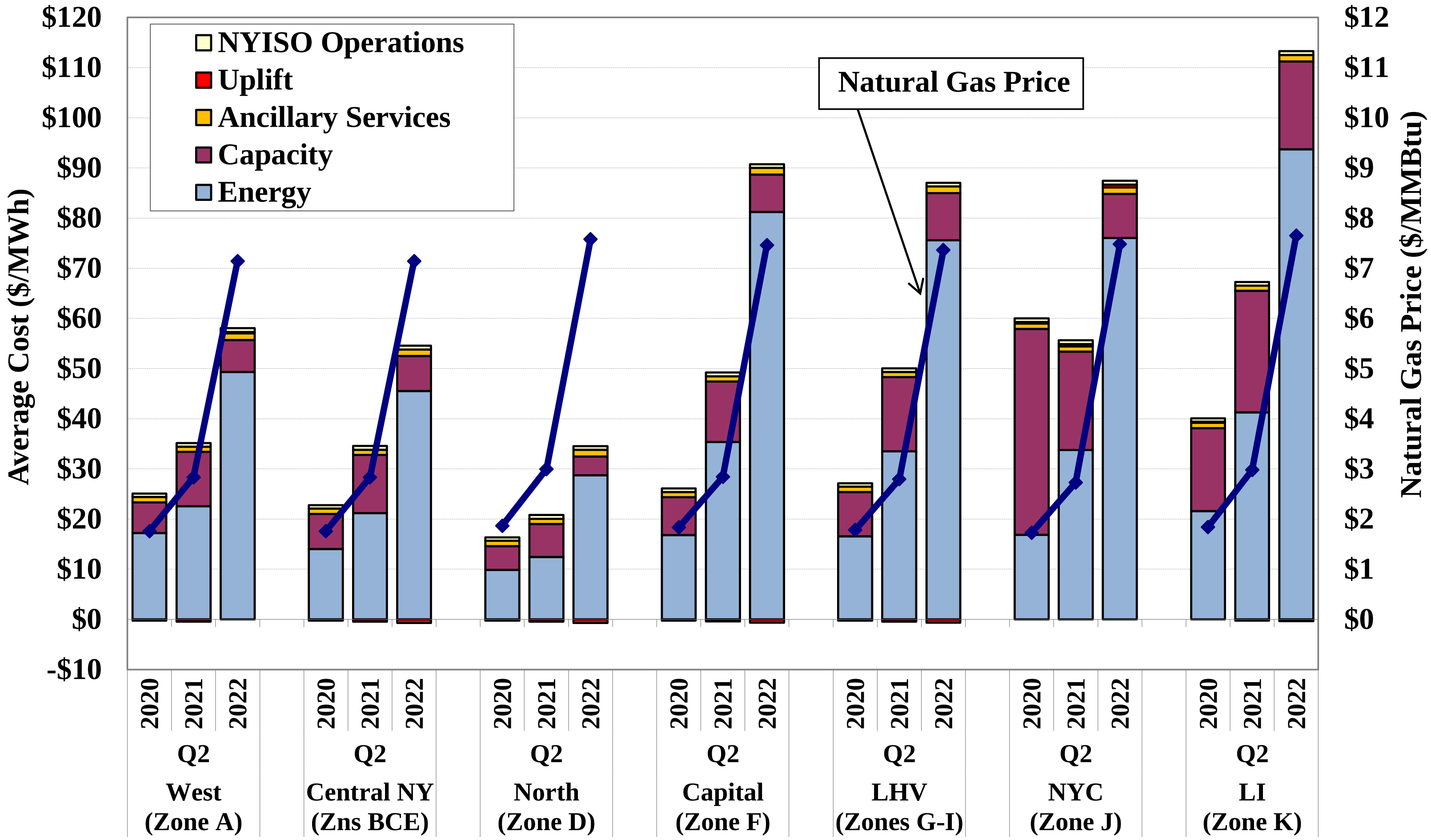
Market Highlights:
Capacity Market

- Spot capacity prices fell by 27 to 58 percent from a year ago, averaging from $2.27/kW-month in ROS to $4.83/kW-month in LI this quarter. (slides 79-80)
- The ROS prices fell by 41 percent from the prior year, driven primarily by a lower ICAP requirement for the 2022/23 Capability Year.
  - ✓ The ICAP requirement fell by roughly 1 GW because:
    - Peak load forecast fell by 566 MW; and
    - The IRM fell from 120.7 to 119.6 percent.
  - ✓ Higher imports also contributed to lower ROS prices.
    - Monthly variations of cleared imports were normally a key driver of monthly variations in spot prices within the same Capability Period.
- The UCAP requirements in NYC and the G-J Locality were either not or just barely binding, leading spot prices in both localities to be comparable to ROS prices.
  - ✓ Although LCRs rose from the prior Capability Year in both localities, their ICAP requirements were still lower because of lower peak load forecasts.
  - ✓ The high volatility in LCR values year-over-year (despite the lack of significant changes in transmission capability) highlights inefficiencies in the IRM and LCR-setting processes which are discussed in our 2021 SOM Report.

Charts:

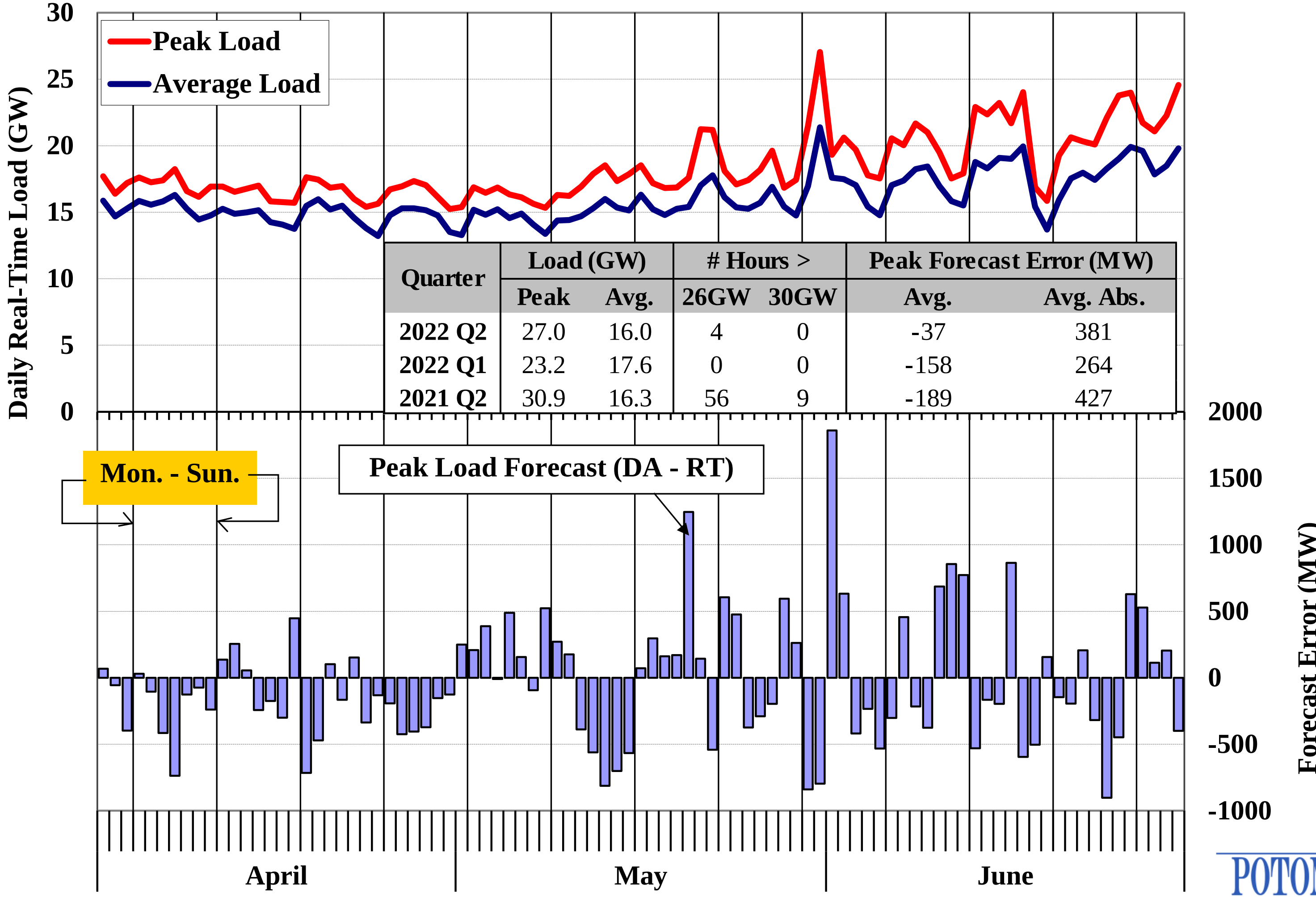
Market Outcomes

All-In Prices by Region



Notes: For chart description, see slide 82.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2022 Q2	27.0	16.0	4	0	-37	381
2022 Q1	23.2	17.6	0	0	-158	264
2021 Q2	30.9	16.3	56	9	-189	427

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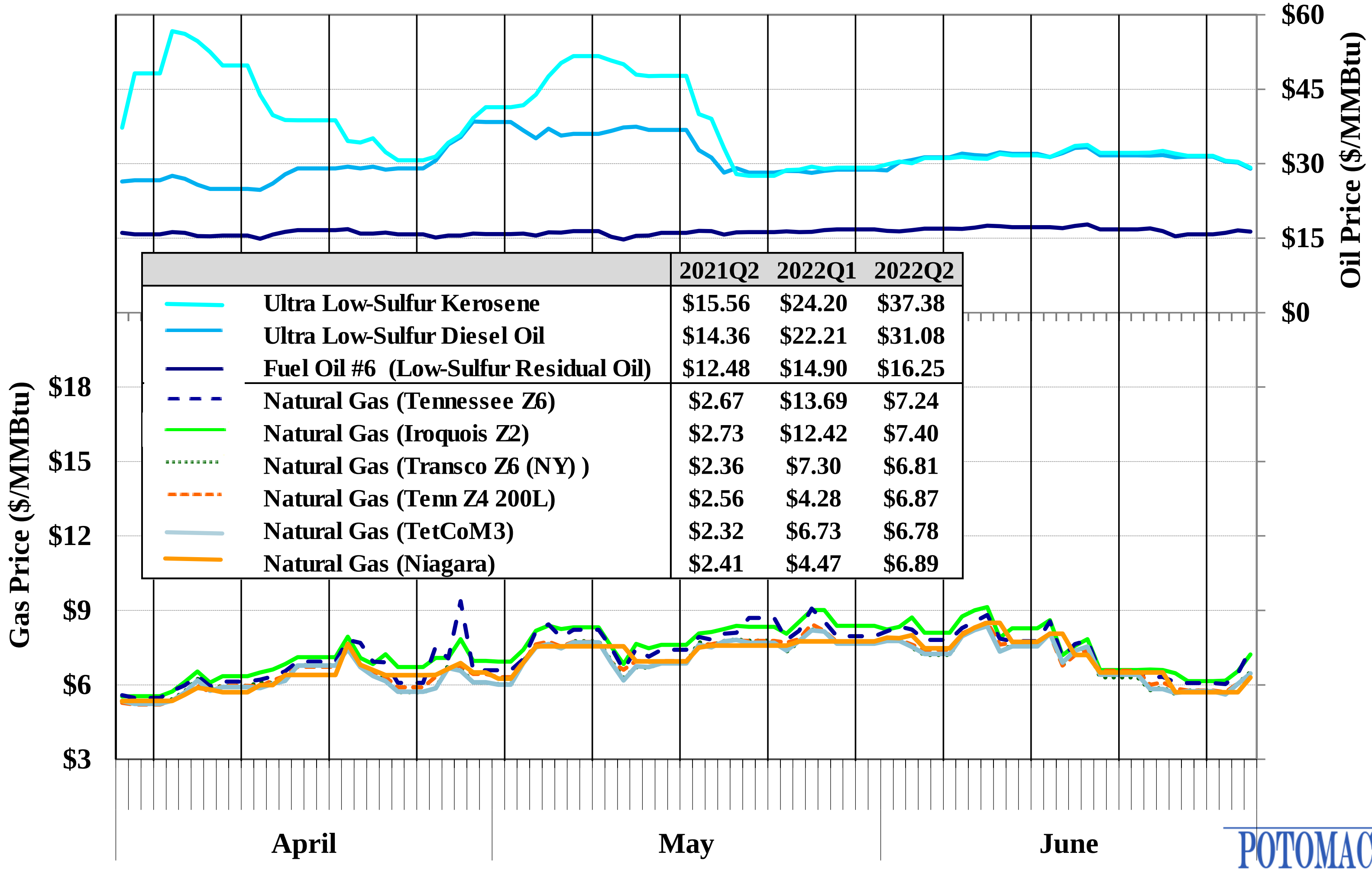
Natural Gas and Fuel Oil Prices



	2021Q2	2022Q1	2022Q2
Ultra Low-Sulfur Kerosene	$15.56	$24.20	$37.38
Ultra Low-Sulfur Diesel Oil	$14.36	$22.21	$31.08
Fuel Oil #6 (Low-Sulfur Residual Oil)	$12.48	$14.90	$16.25
Natural Gas (Tennessee Z6)	$2.67	$13.69	$7.24
Natural Gas (Iroquois Z2)	$2.73	$12.42	$7.40
Natural Gas (Transco Z6 (NY))	$2.36	$7.30	$6.81
Natural Gas (Tenn Z4 200L)	$2.56	$4.28	$6.87
Natural Gas (TetCoM3)	$2.32	$6.73	$6.78
Natural Gas (Niagara)	$2.41	$4.47	$6.89

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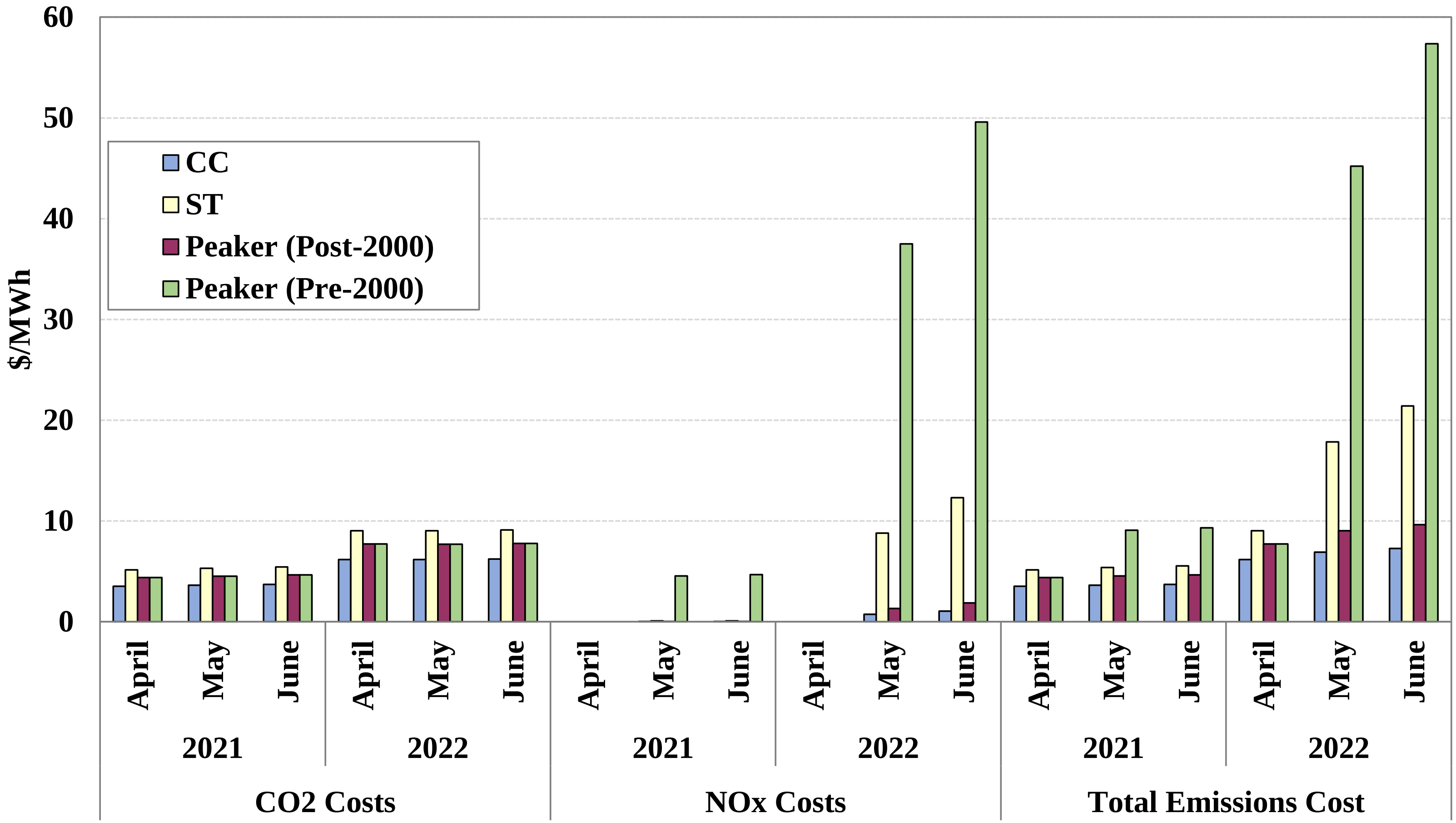
Emissions Costs by Unit Type
Natural Gas Fired Resources



Notes: For chart description, see slide 85

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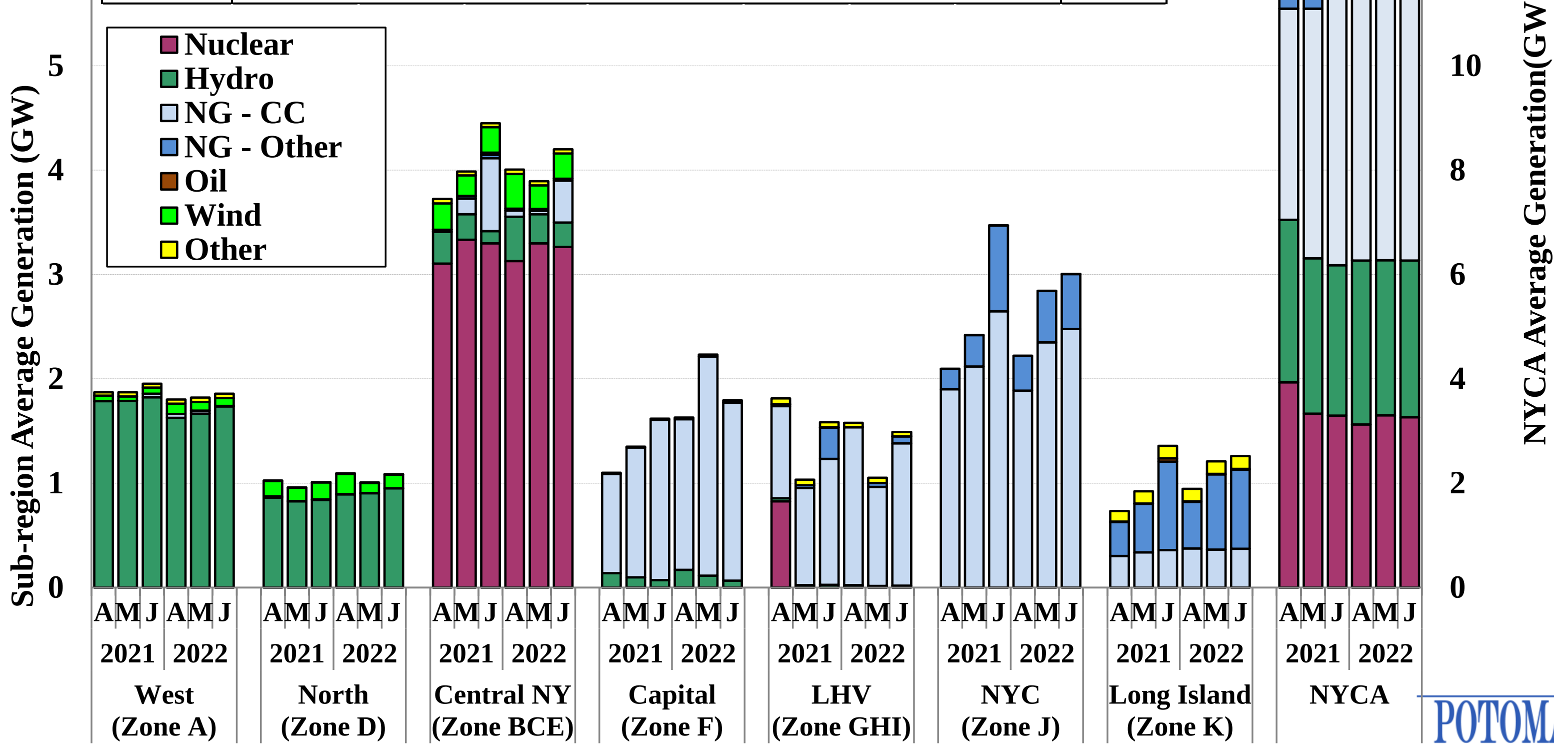
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Total
2022 Q2	3.23	3.04	5.82	1.15	0.01	0.49	0.27	14.01
2022 Q1	2.95	3.22	5.09	1.34	0.54	0.68	0.24	14.07
2021 Q2	3.52	2.99	5.10	1.12	0.02	0.43	0.25	13.44



  Notes: For chart description, see slide 83.

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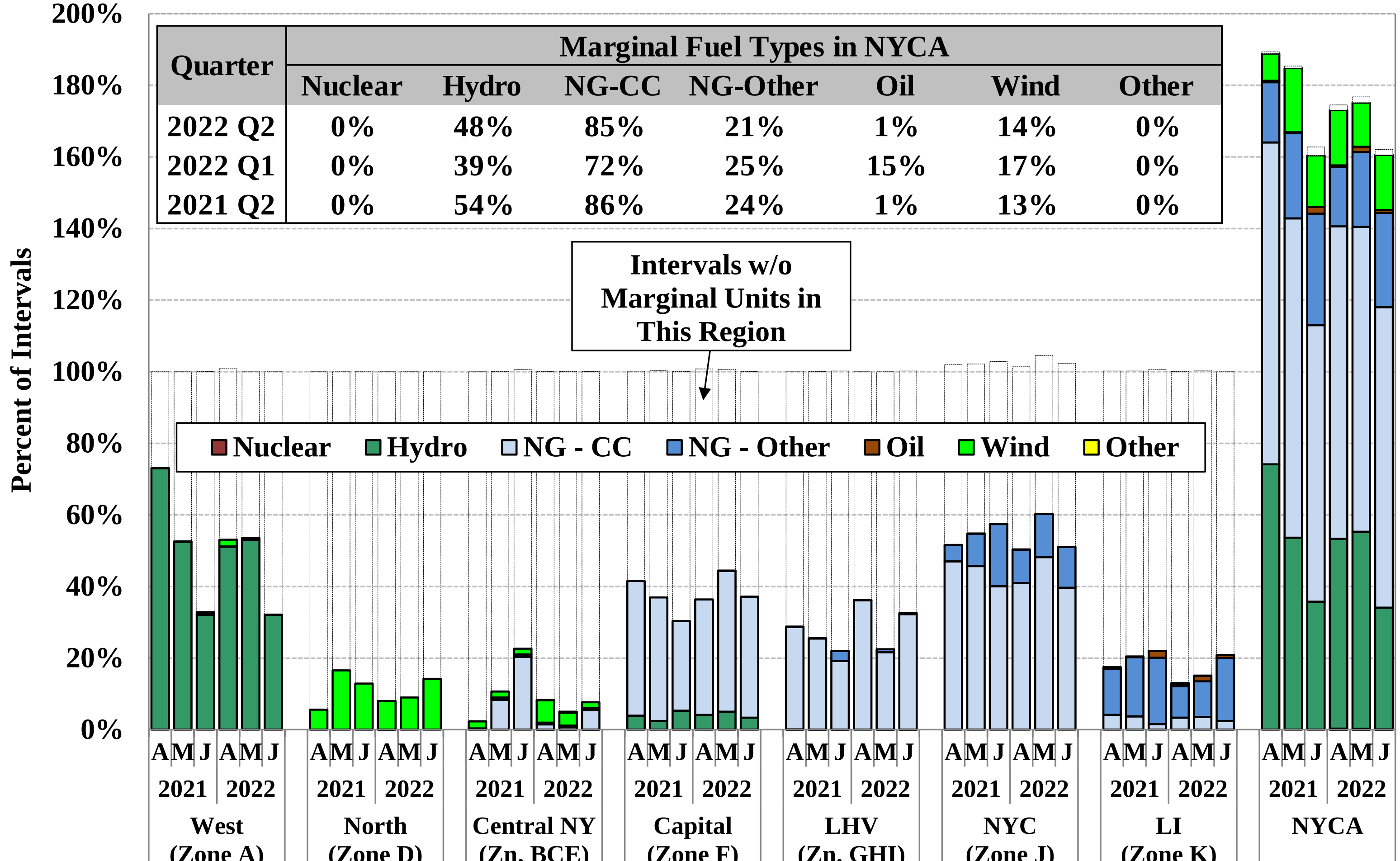
Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other
2022 Q2	0%	48%	85%	21%	1%	14%	0%
2022 Q1	0%	39%	72%	25%	15%	17%	0%
2021 Q2	0%	54%	86%	24%	1%	13%	0%

Notes: For chart description, see slide 83.

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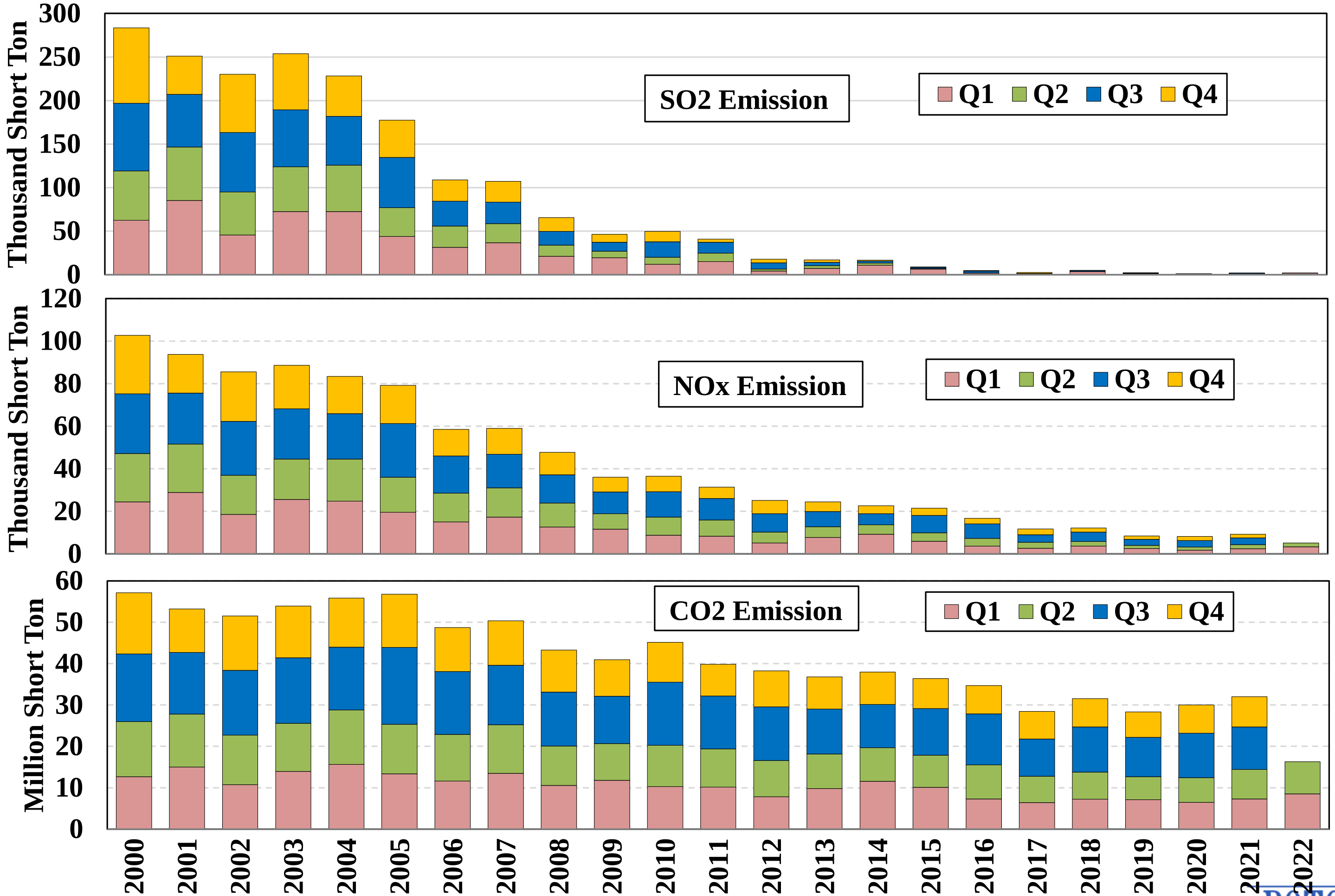
Historical Emissions by Quarter in NYCA

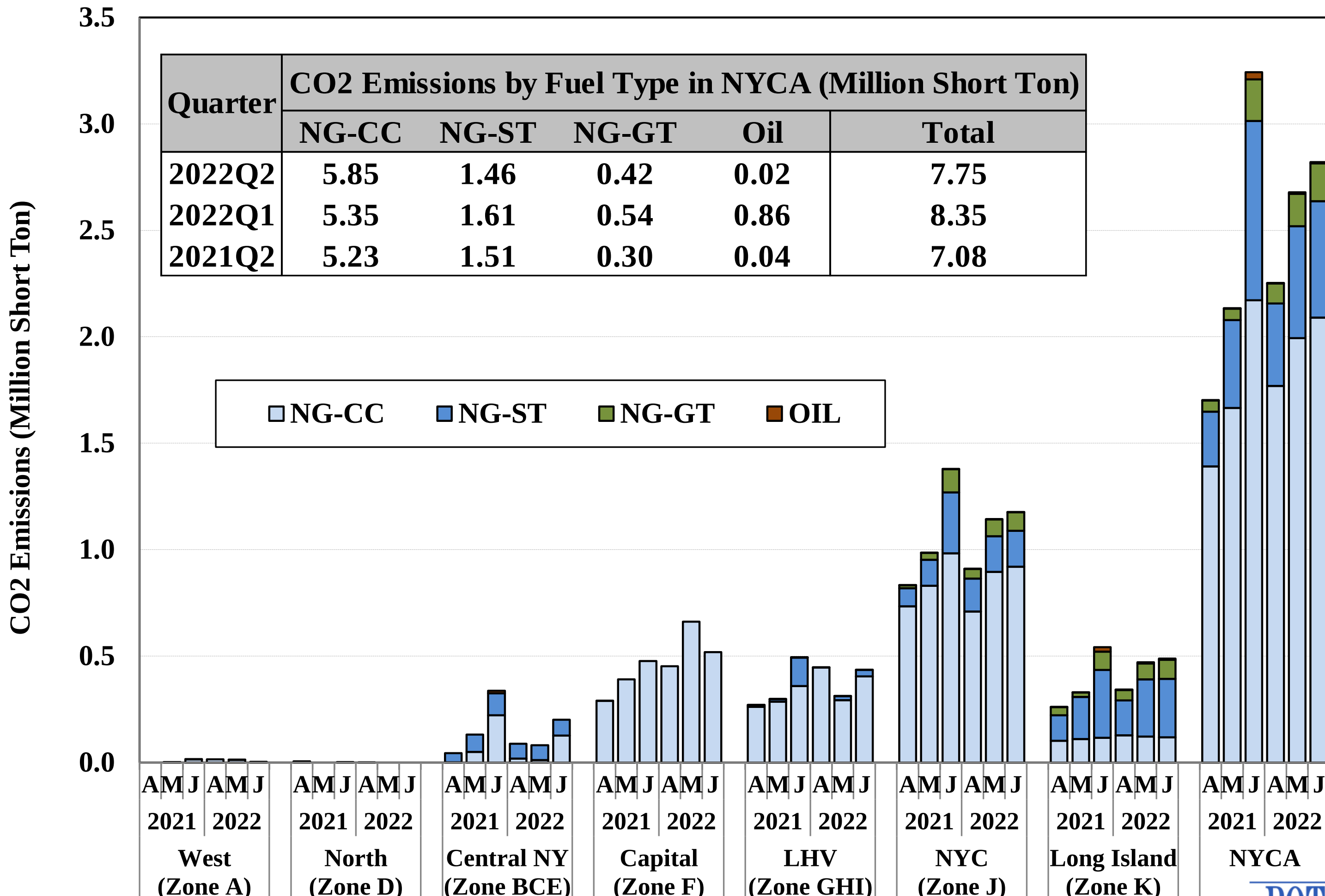
CO_2, SO_2, and NO_X



Notes: For chart description, see slide 84.

Emissions by Region by Fuel Type
CO_2 Emissions

Quarter	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)				
	NG-CC	NG-ST	NG-GT	Oil	Total
2022Q2	5.85	1.46	0.42	0.02	7.75
2022Q1	5.35	1.61	0.54	0.86	8.35
2021Q2	5.23	1.51	0.30	0.04	7.08



Notes: For chart description, see slide 84.

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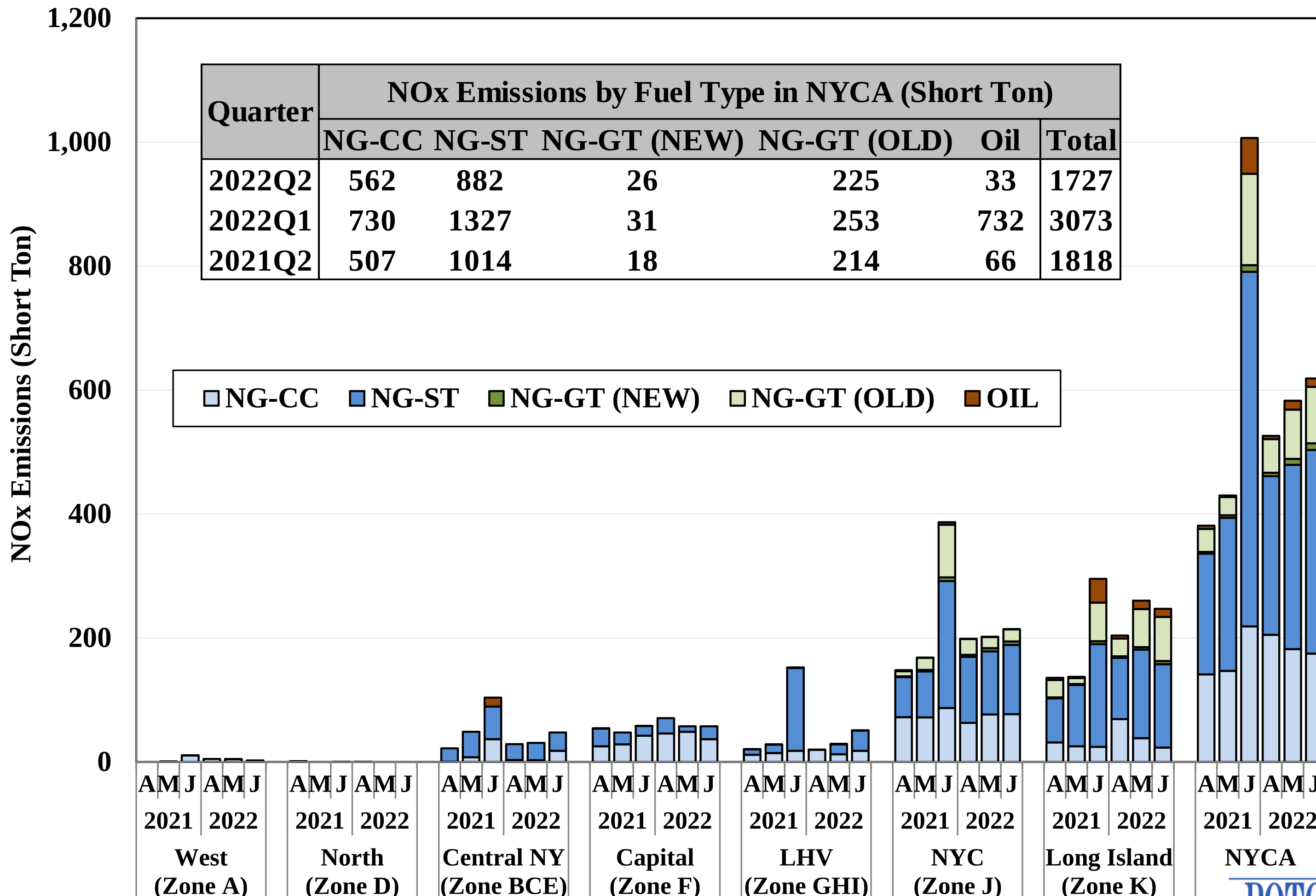
Emissions by Region by Fuel Type
NO_X Emissions



Quarter	NOx Emissions by Fuel Type in NYCA (Short Ton)					
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Total
2022Q2	562	882	26	225	33	1727
2022Q1	730	1327	31	253	732	3073
2021Q2	507	1014	18	214	66	1818

Notes: For chart description, see slide 84.

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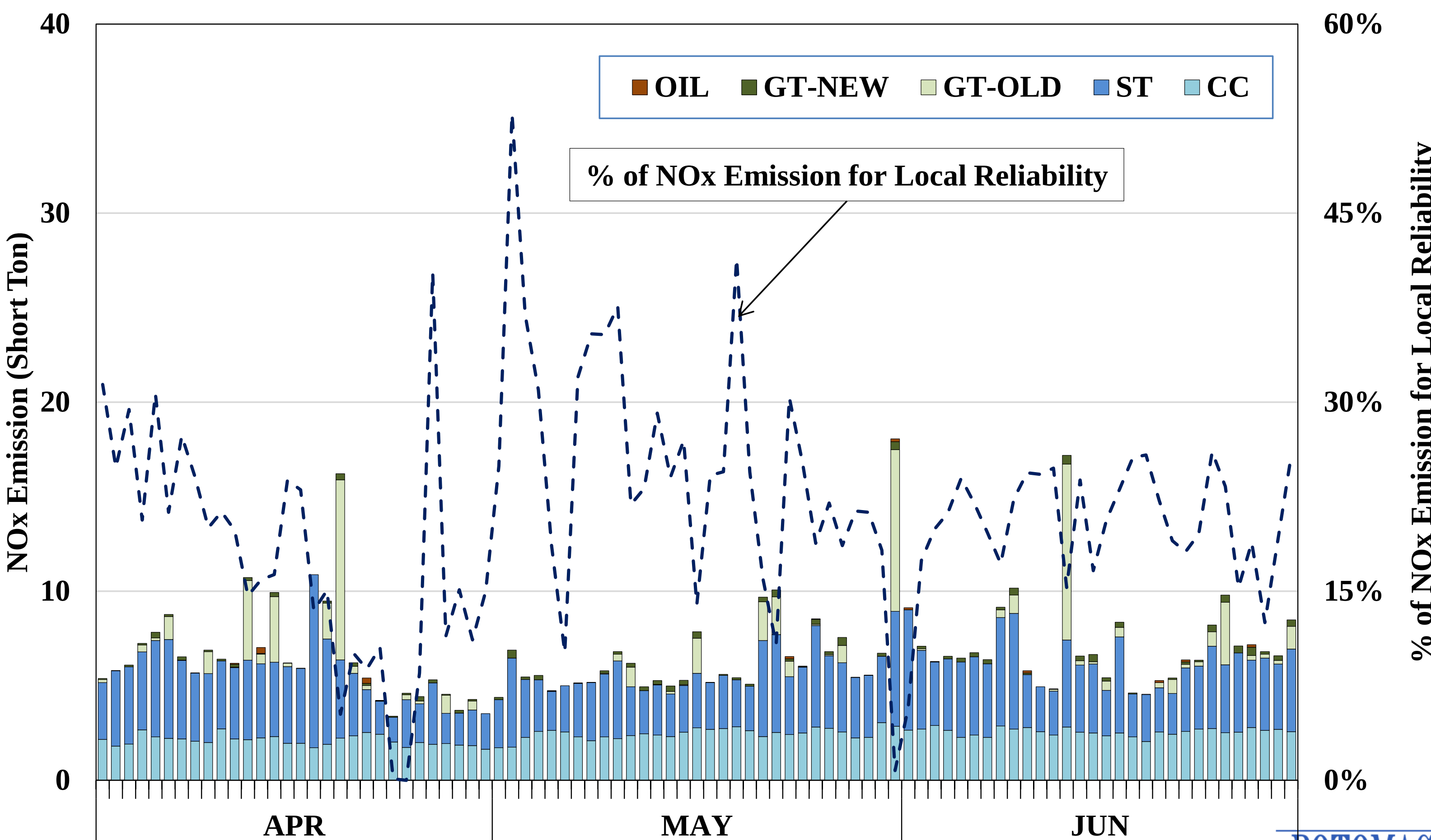
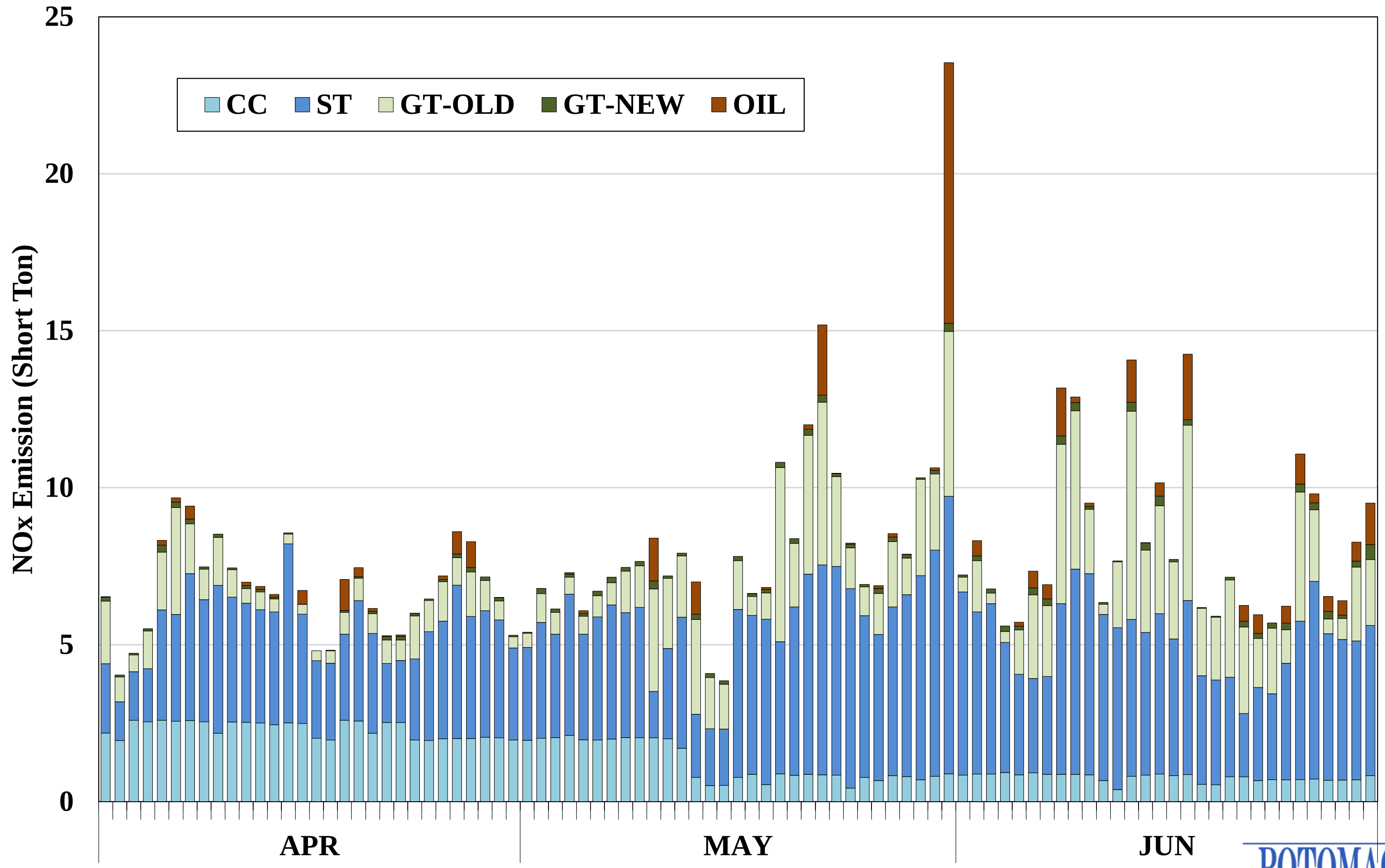
Daily NO_X Emissions in NYC



Notes: For chart description, see slide 84.

Daily NO_X Emissions in Long Island



Notes: For chart description, see slide 84.

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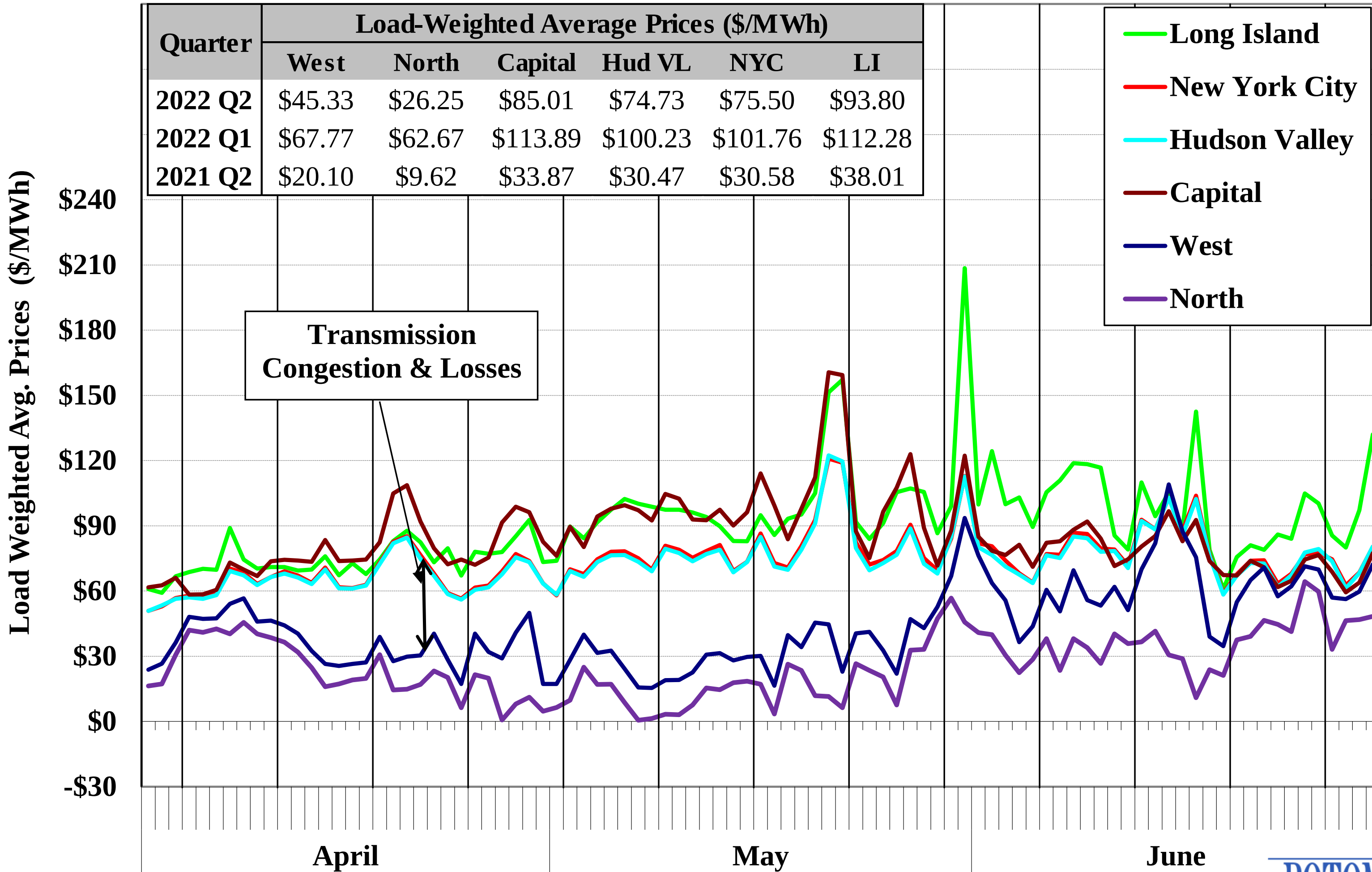
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q2	$45.33	$26.25	$85.01	$74.73	$75.50	$93.80
2022 Q1	$67.77	$62.67	$113.89	$100.23	$101.76	$112.28
2021 Q2	$20.10	$9.62	$33.87	$30.47	$30.58	$38.01

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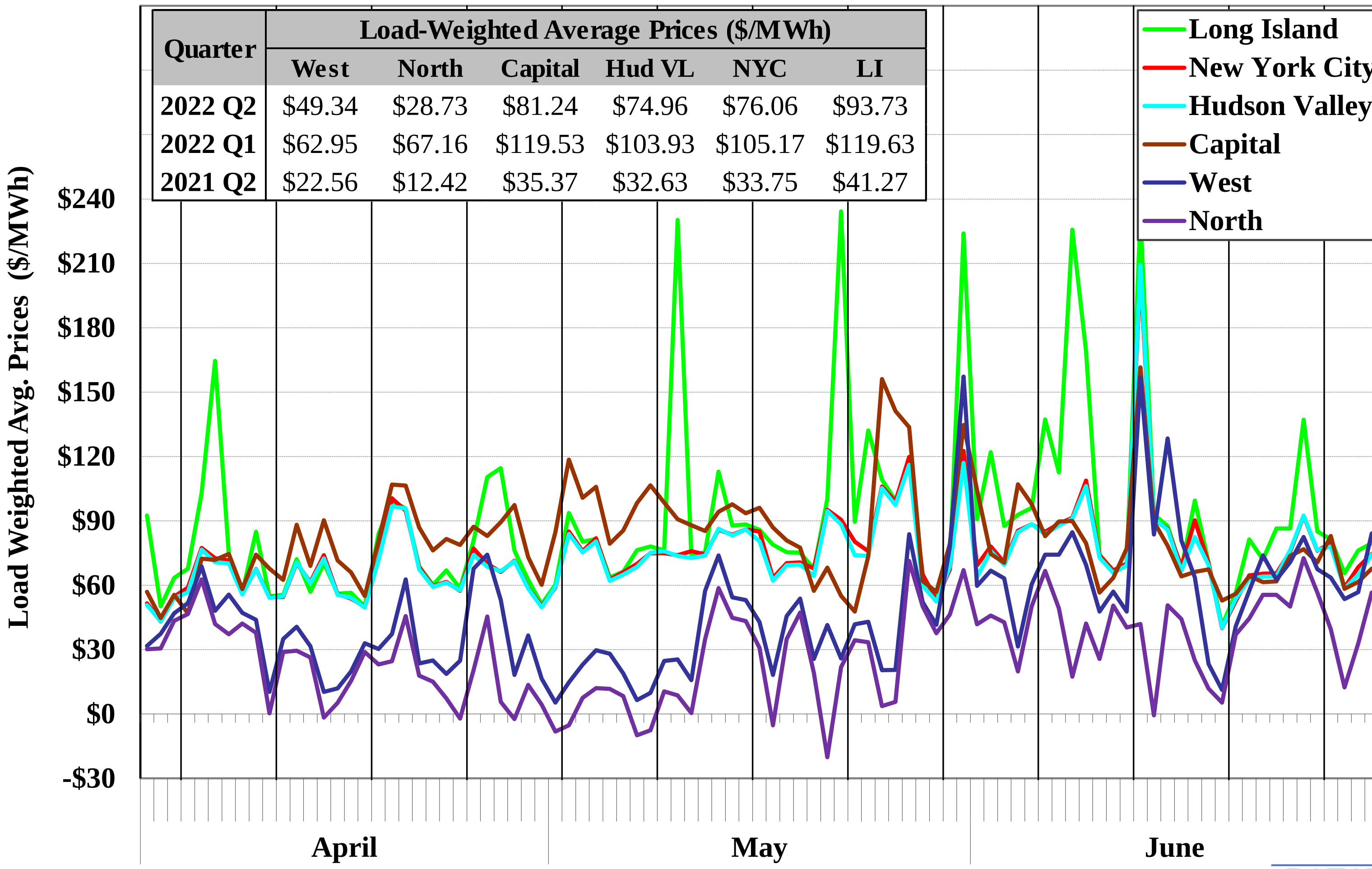
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q2	$49.34	$28.73	$81.24	$74.96	$76.06	$93.73
2022 Q1	$62.95	$67.16	$119.53	$103.93	$105.17	$119.63
2021 Q2	$22.56	$12.42	$35.37	$32.63	$33.75	$41.27

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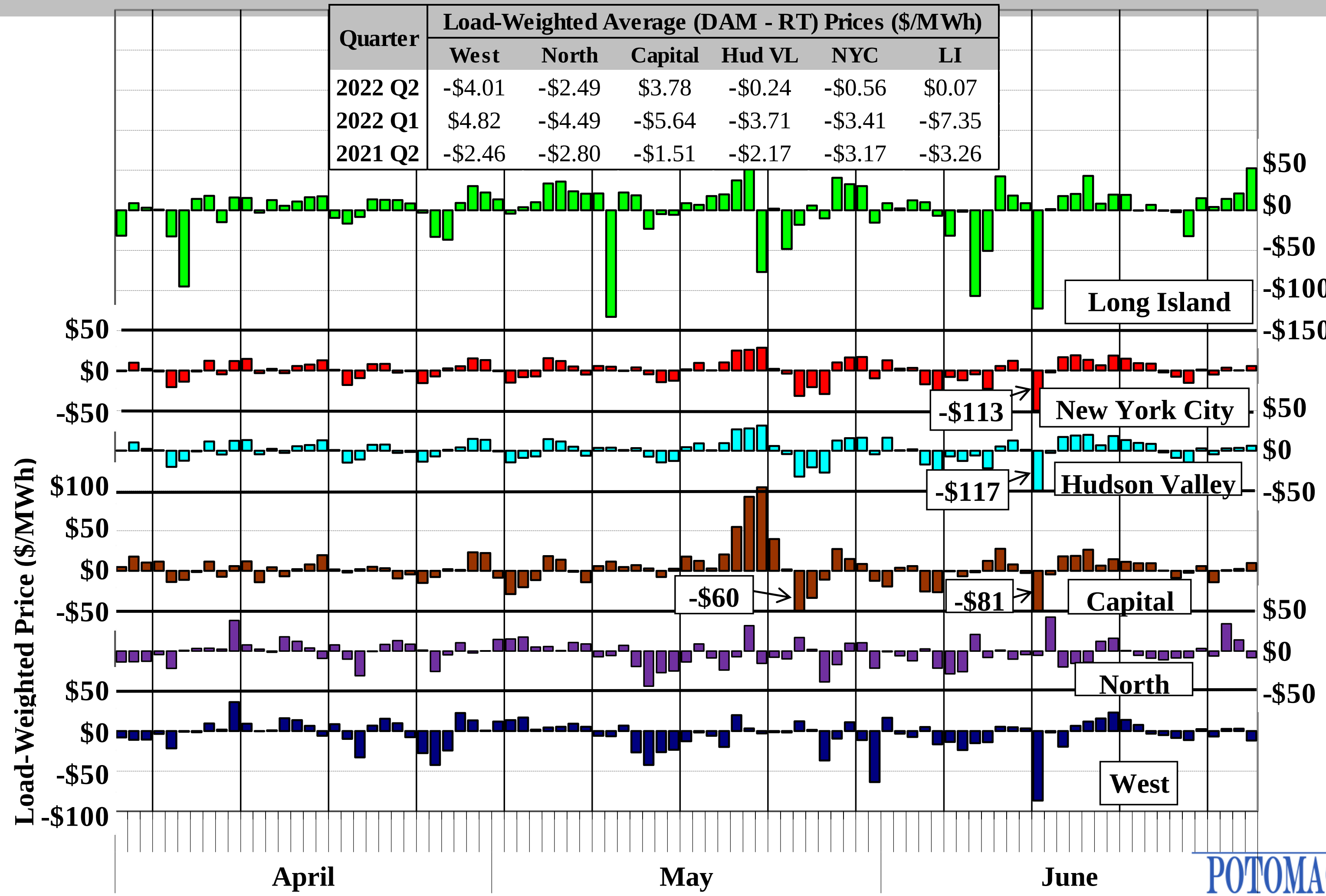
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q2	-$4.01	-$2.49	$3.78	-$0.24	-$0.56	$0.07
2022 Q1	$4.82	-$4.49	-$5.64	-$3.71	-$3.41	-$7.35
2021 Q2	-$2.46	-$2.80	-$1.51	-$2.17	-$3.17	-$3.26



Charts:
Ancillary Services Market

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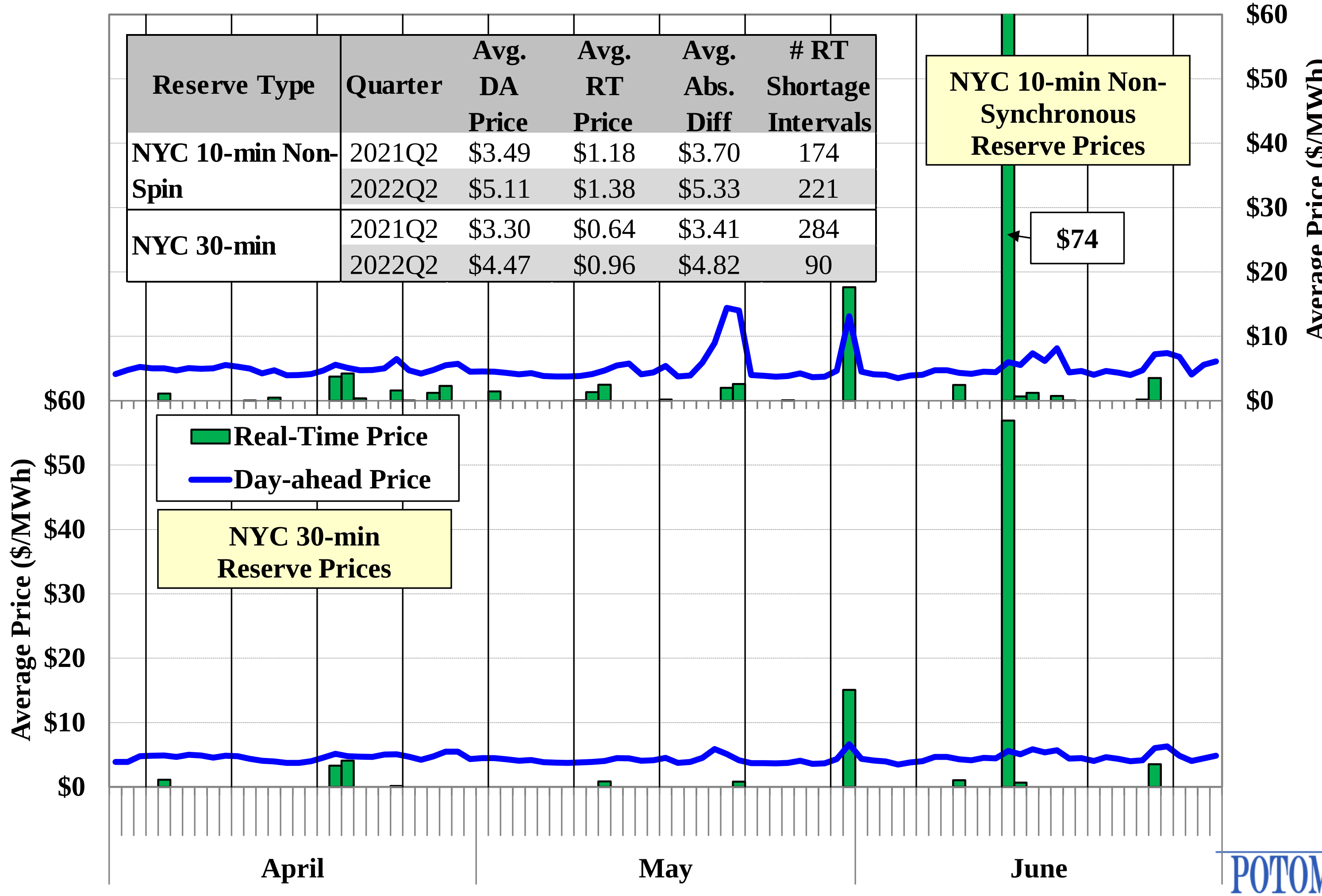
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Non-Spinning and 30-Minute Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2021Q2	$3.49	$1.18	$3.70	174
	2022Q2	$5.11	$1.38	$5.33	221
NYC 30-min	2021Q2	$3.30	$0.64	$3.41	284
	2022Q2	$4.47	$0.96	$4.82	90



Notes: For chart description, see slide 86.

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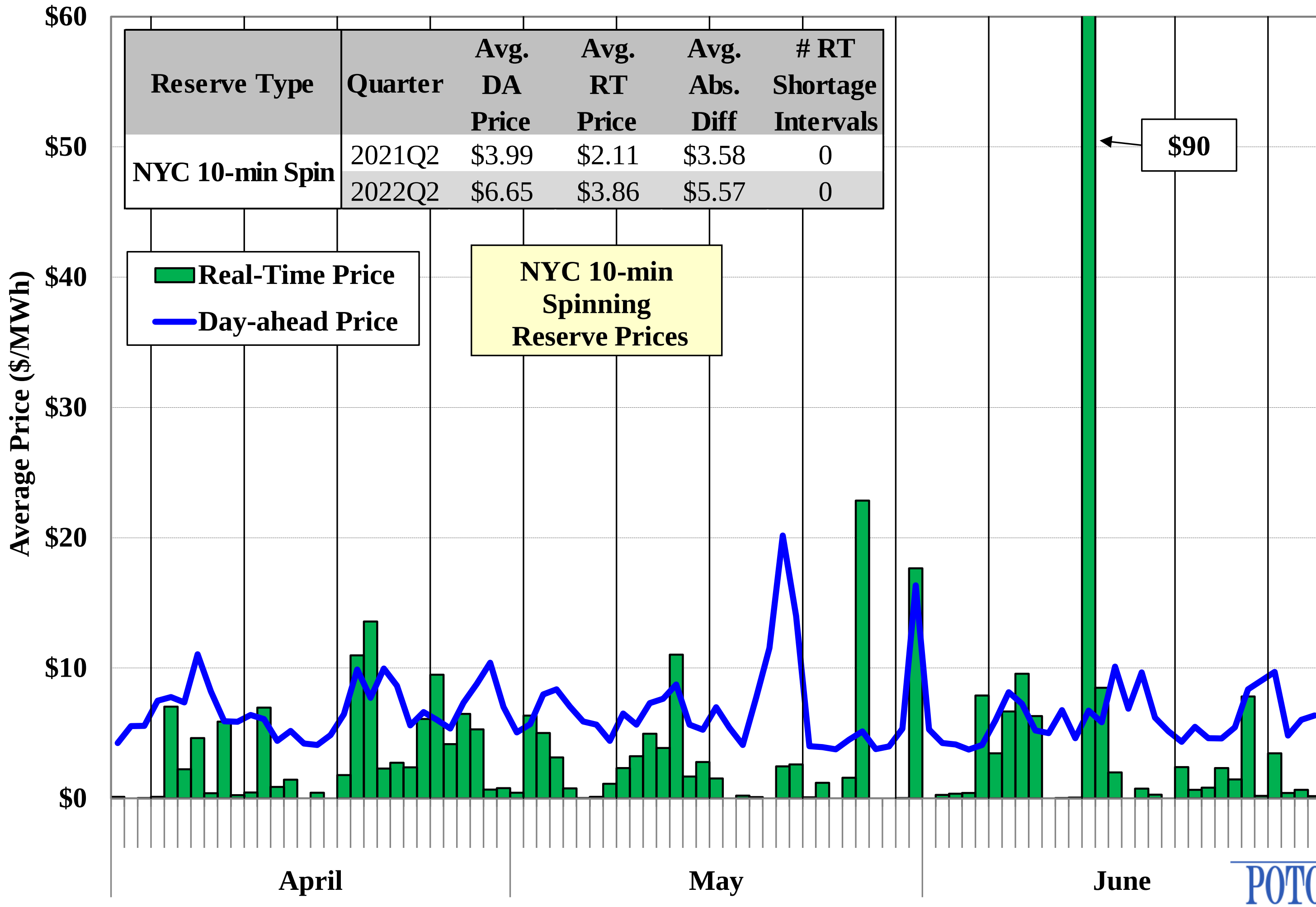
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Spinning Reserves

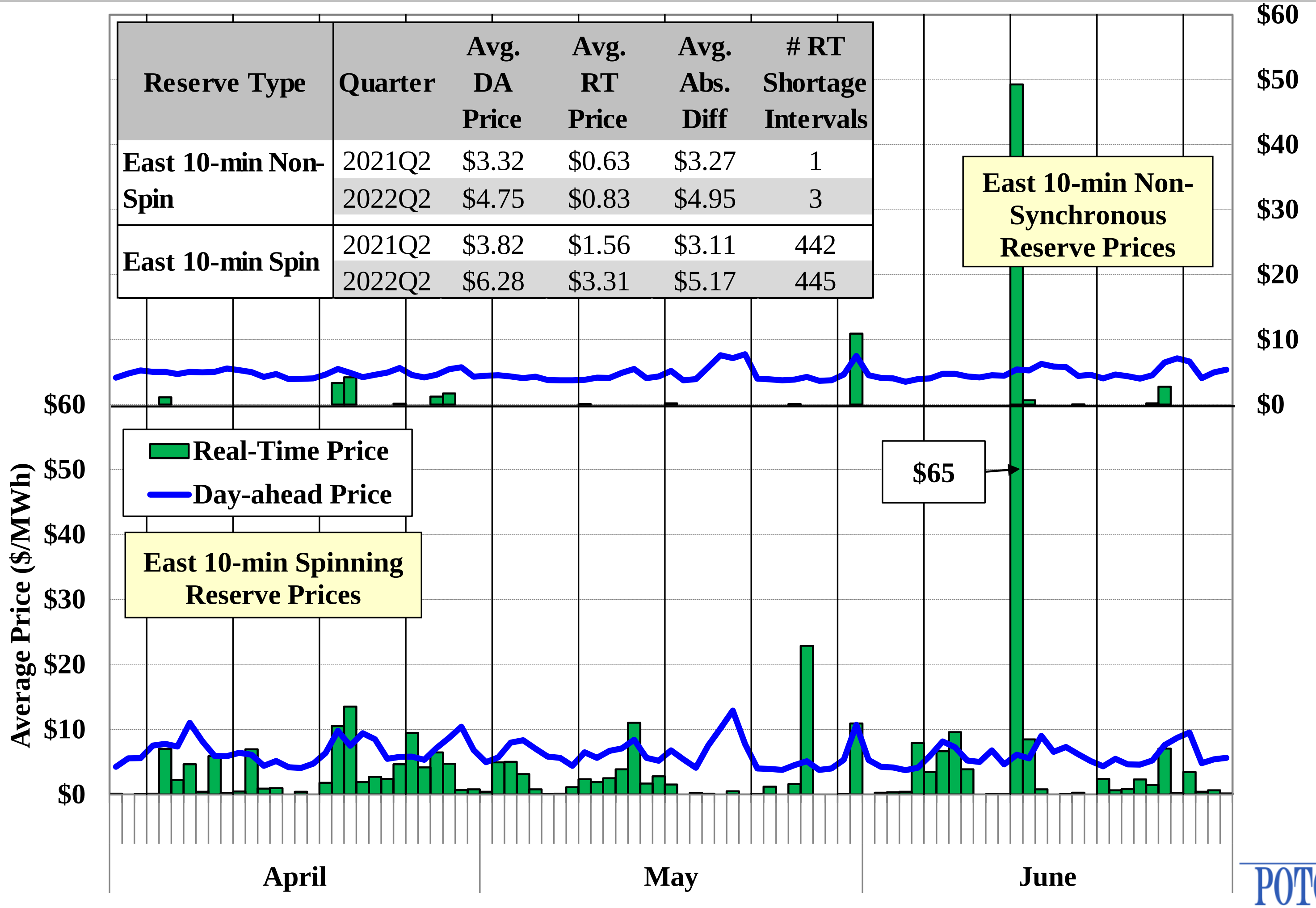


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2021Q2	$3.99	$2.11	$3.58	0
	2022Q2	$6.65	$3.86	$5.57	0

Notes: For chart description, see slide 86.

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	2021Q2	$3.32	$0.63	$3.27	1
	2022Q2	$4.75	$0.83	$4.95	3
East 10-min Spin	2021Q2	$3.82	$1.56	$3.11	442
	2022Q2	$6.28	$3.31	$5.17	445

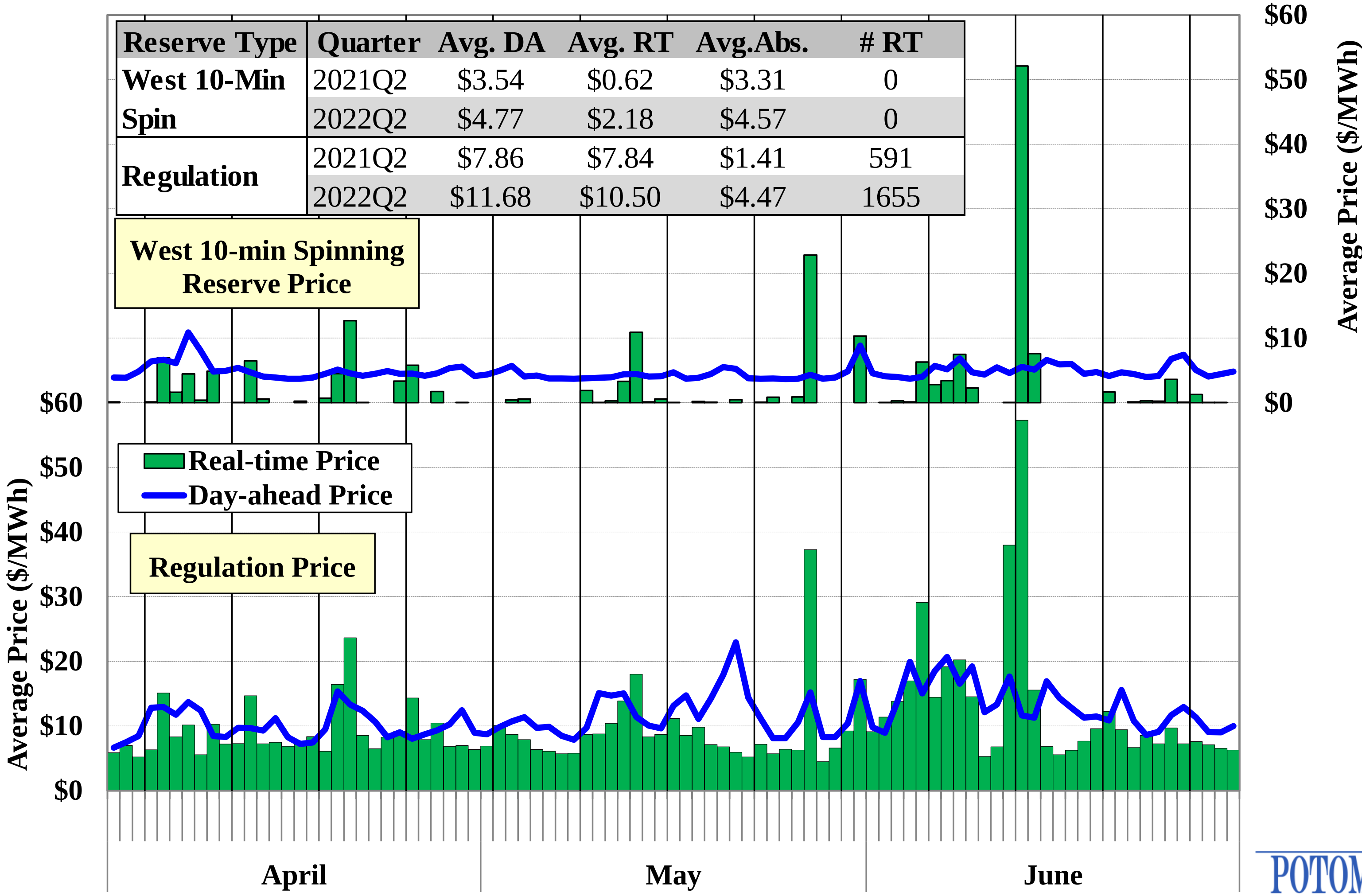


  Notes: For chart description, see slide 86.

POTOMAC ECONOMICS

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	2021Q2	$3.54	$0.62	$3.31	0
	2022Q2	$4.77	$2.18	$4.57	0
Regulation	2021Q2	$7.86	$7.84	$1.41	591
	2022Q2	$11.68	$10.50	$4.47	1655

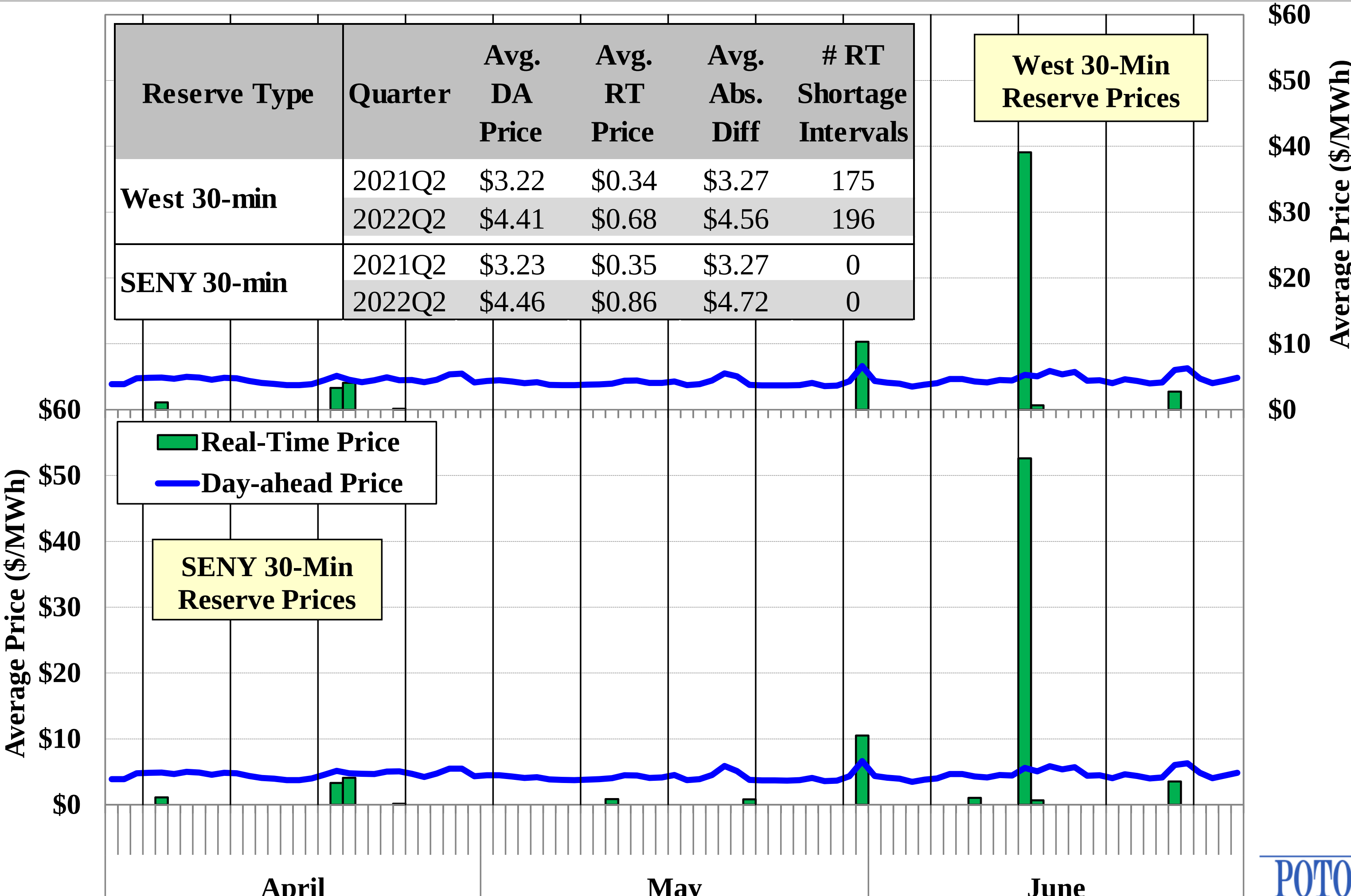


Notes: For chart description, see slide 86.

POTOMAC ECONOMICS

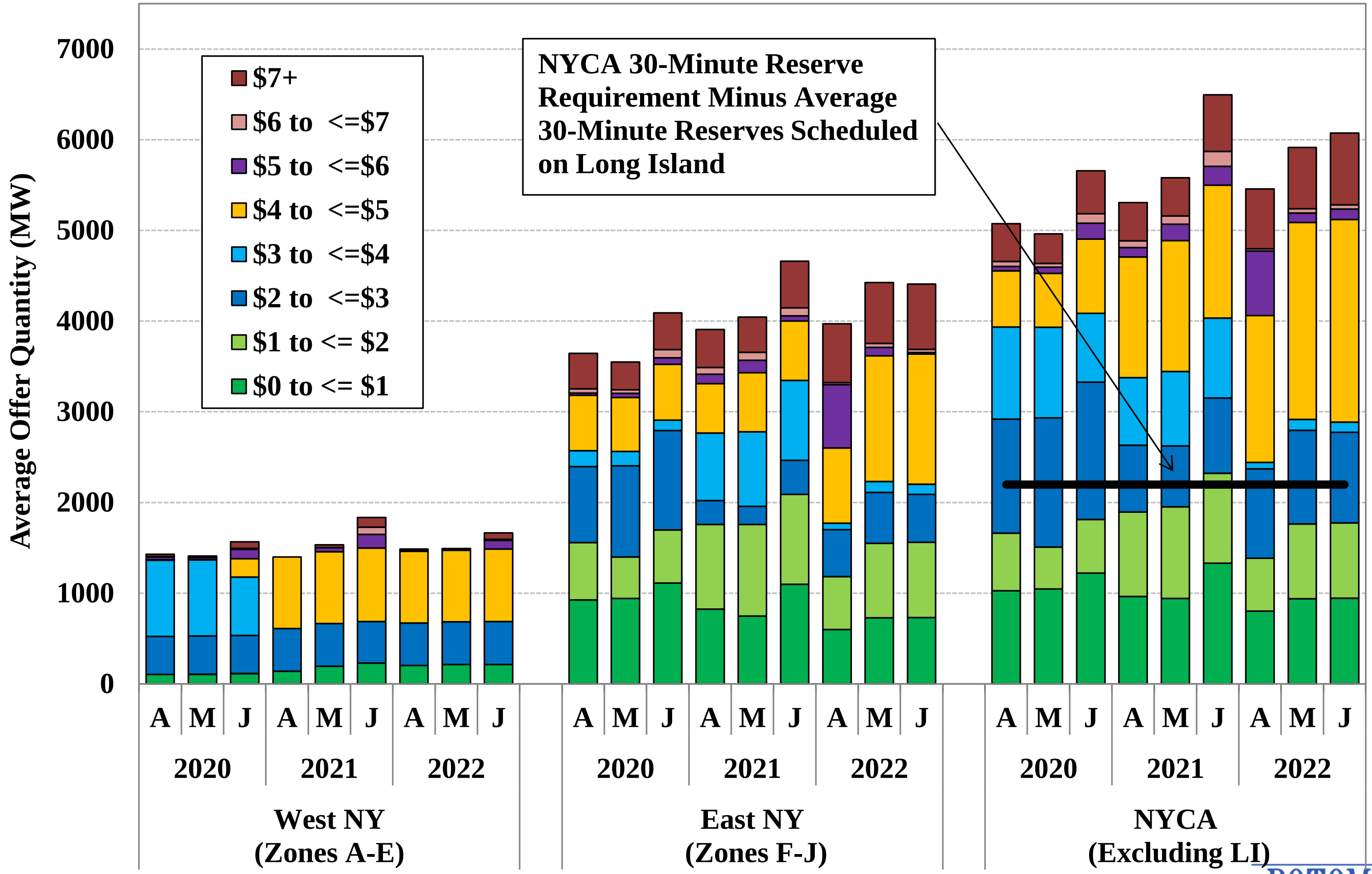
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2021Q2	$3.22	$0.34	$3.27	175
	2022Q2	$4.41	$0.68	$4.56	196
SENY 30-min	2021Q2	$3.23	$0.35	$3.27	0
	2022Q2	$4.46	$0.86	$4.72	0



  Notes: For chart description, see slide 86.

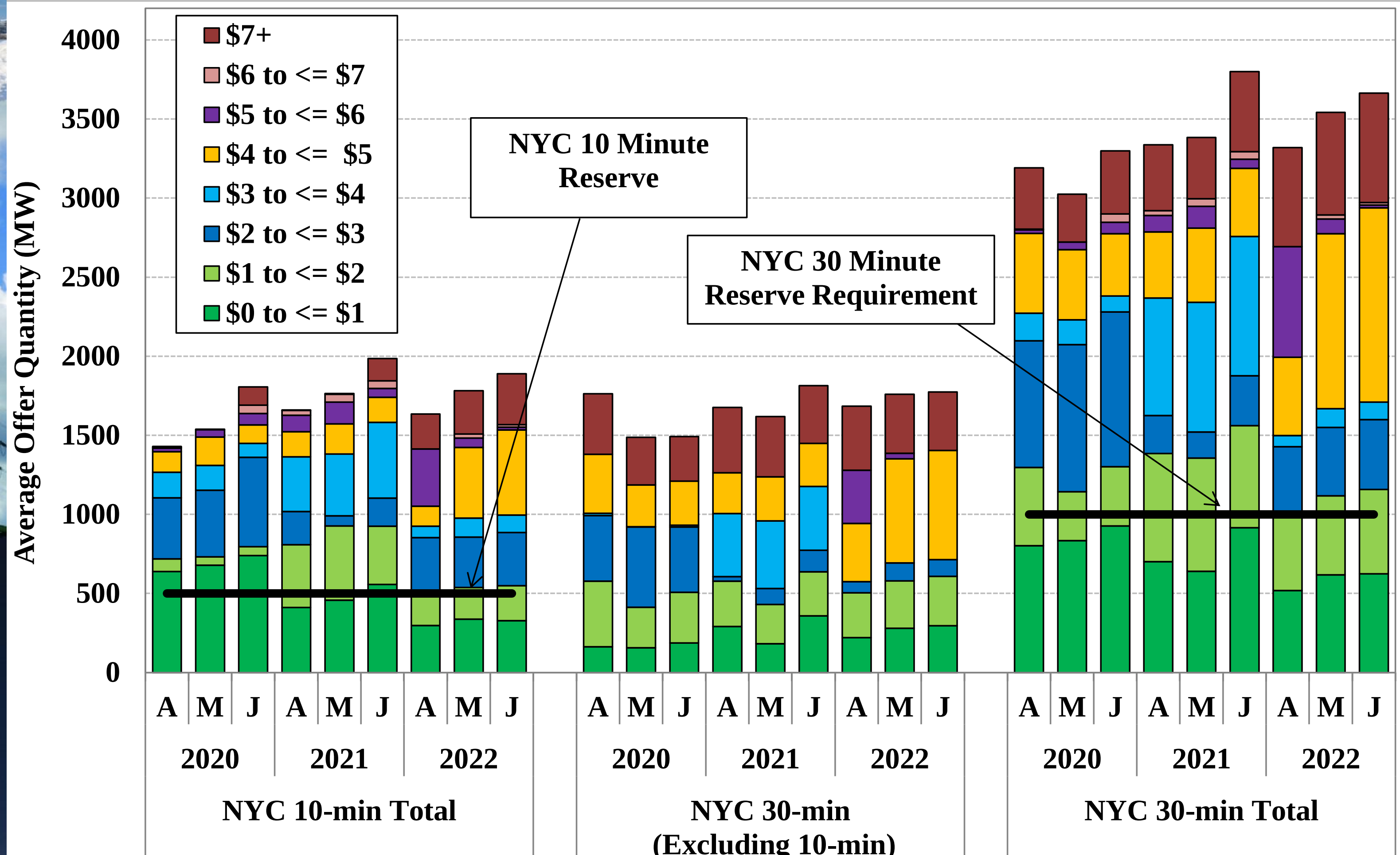
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 87.

POTOMAC ECONOMICS

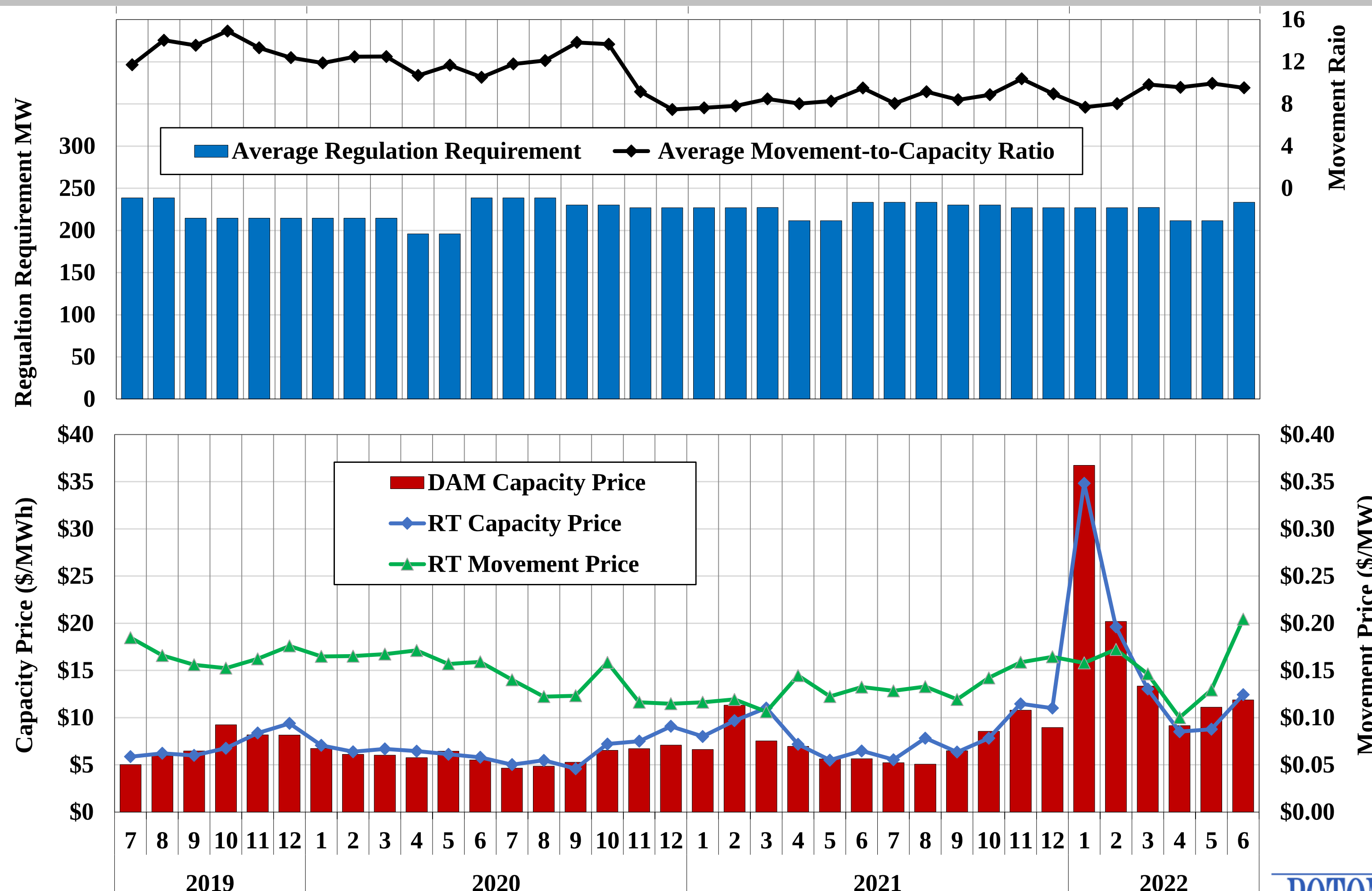
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 87.

POTOMAC ECONOMICS

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

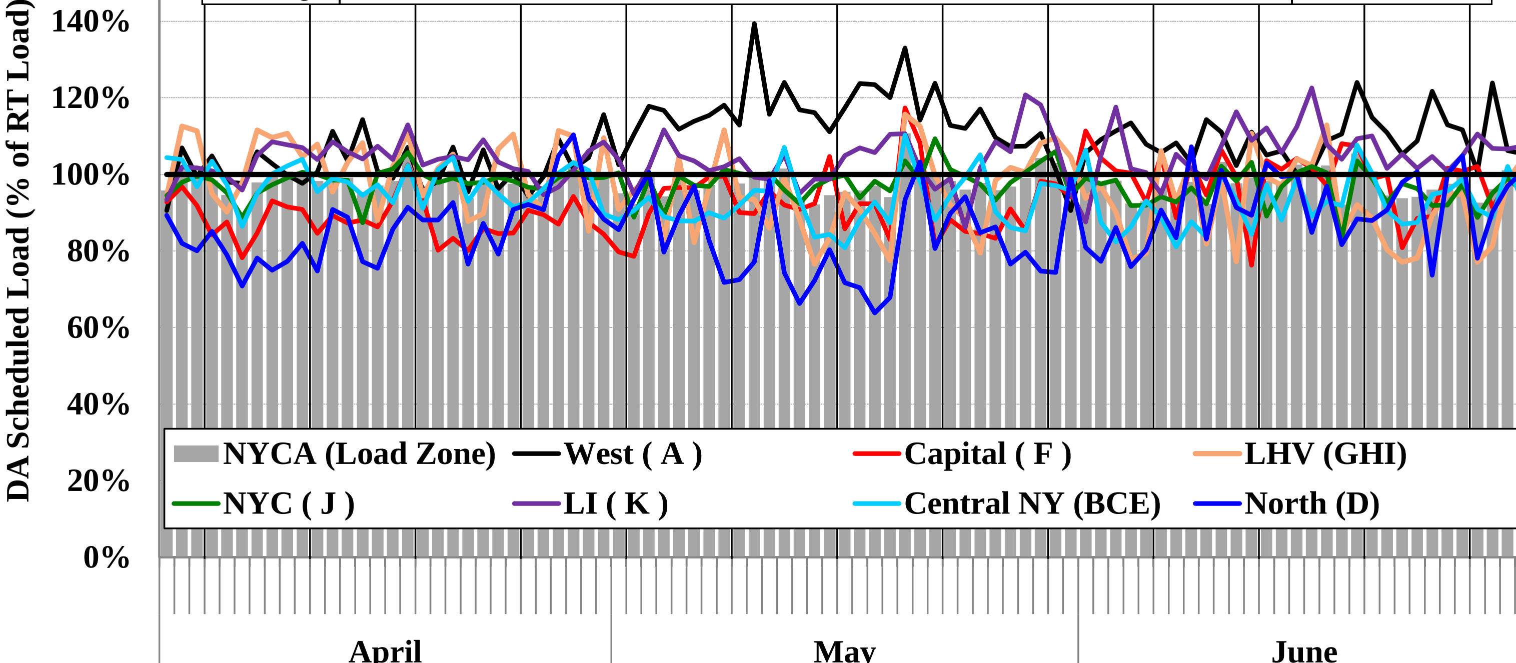


Notes: For chart description, see slide 88.
POTOMAC ECONOMICS

Charts:
Energy Market Scheduling

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

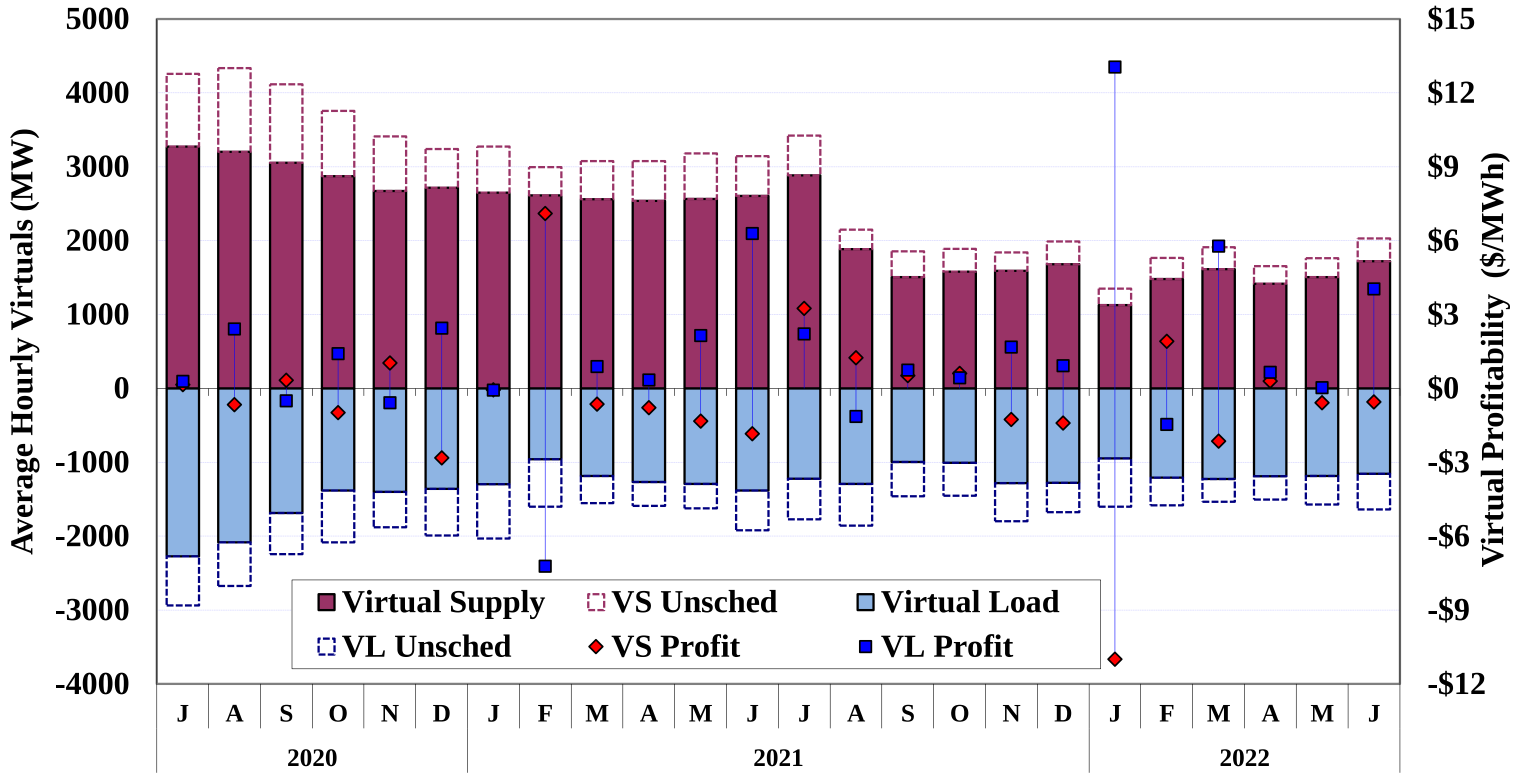
Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2022 Q2	109%	94%	86%	93%	96%	97%	104%	98%	96%
2022 Q1	99%	96%	83%	98%	95%	98%	103%	97%	95%
2021 Q2	108%	93%	66%	93%	89%	98%	101%	96%	94%



Notes: For chart description, see slide 89.

POTOMAC ECONOMICS

Virtual Trading Activity
by Month

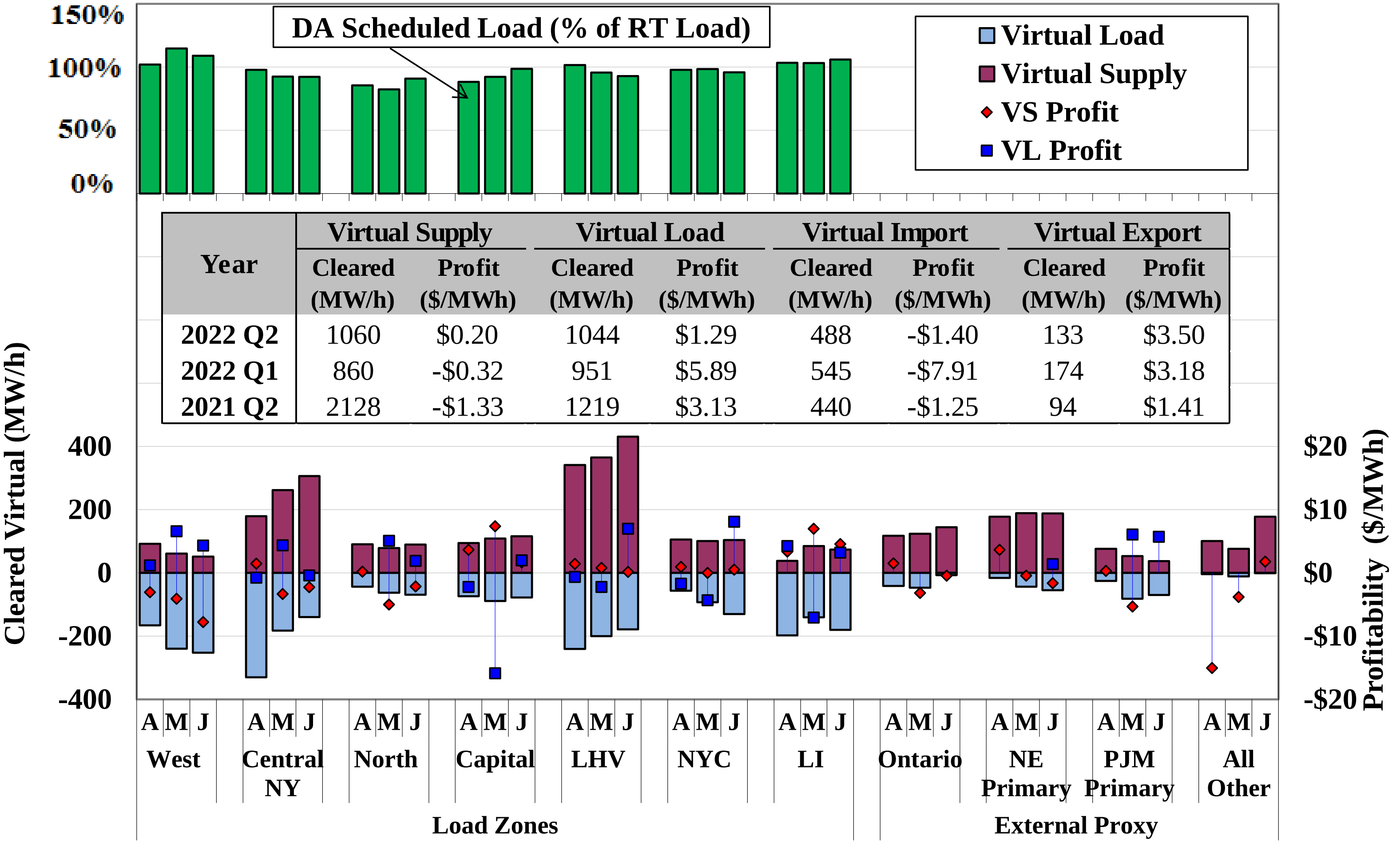


		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	416	377	196	235	619	375	320	658	514	549	378	325	413	158	158	96	182	195	225	307	217	291	324	183
	%	8%	7%	4%	6%	15%	9%	8%	18%	14%	14%	10%	8%	10%	5%	6%	4%	6%	7%	11%	11%	8%	11%	12%	6%
Loss > 50% of Avg. Zone Price	MW	377	304	198	312	528	440	283	388	491	688	498	271	234	174	140	88	197	215	208	278	226	306	304	180
	%	7%	6%	4%	7%	13%	11%	7%	11%	13%	18%	13%	7%	6%	5%	6%	3%	7%	7%	10%	10%	8%	12%	11%	6%

Notes: For chart description, see slide 89.

POTOMAC ECONOMICS

Virtual Trading Activity by Location

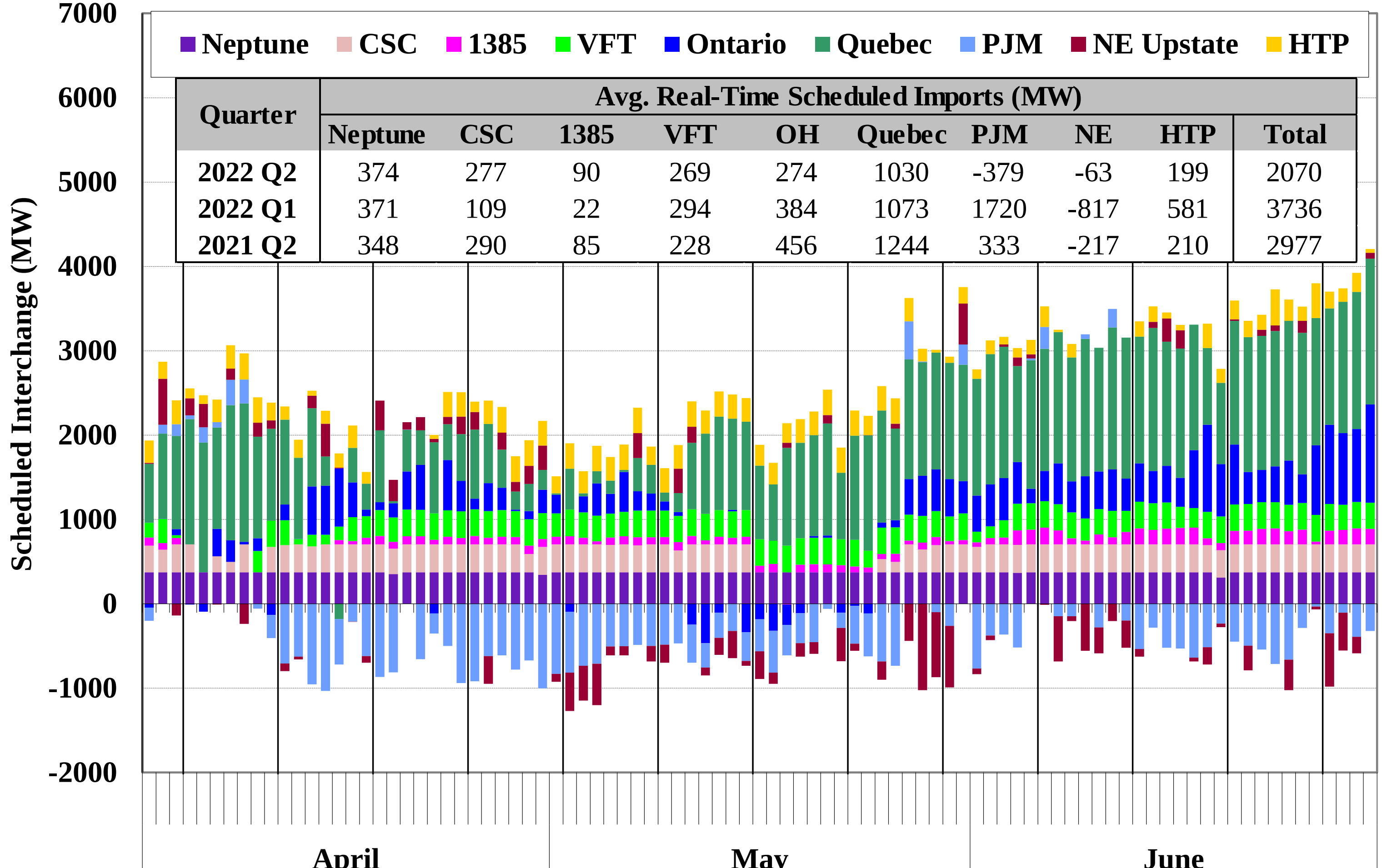


Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2022 Q2	1060	$0.20	1044	$1.29	488	-$1.40	133	$3.50
2022 Q1	860	-$0.32	951	$5.89	545	-$7.91	174	$3.18
2021 Q2	2128	-$1.33	1219	$3.13	440	-$1.25	94	$1.41

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 89.

POTOMAC ECONOMICS

Net Imports Scheduled in Real Time 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
2022 Q2	374	277	90	269	274	1030	-379	-63	199	2070
2022 Q1	371	109	22	294	384	1073	1720	-817	581	3736
2021 Q2	348	290	85	228	456	1244	333	-217	210	2977

Notes: Two Quebec interfaces are combined into one.

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

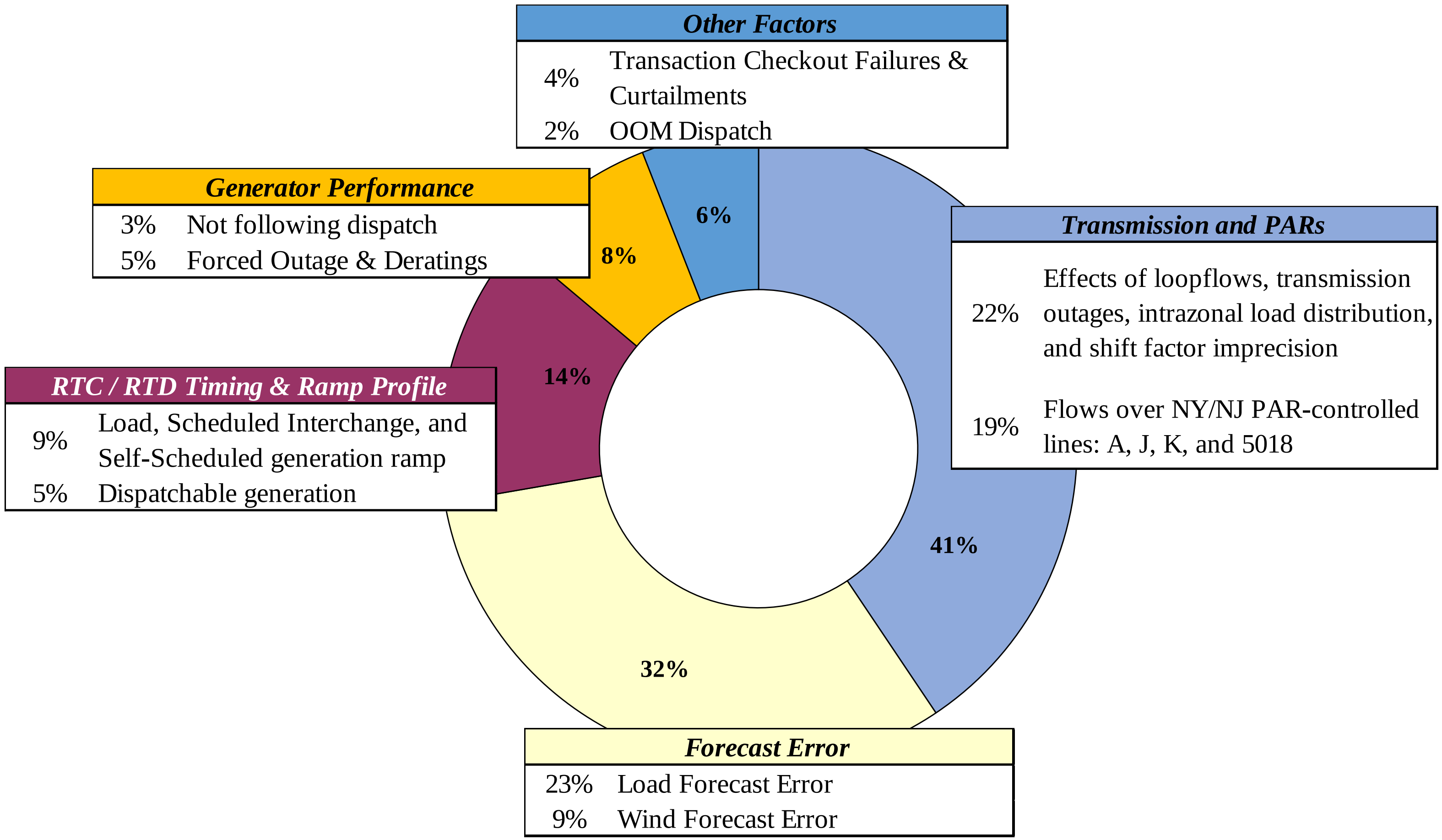
			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total		Both Forecast Errors <= $20	Any Forecast Error > $20	Total	
% of All Intervals w/ Adjustment			73%	19%	**92%**		41%	17%	**58%**	
Average Flow Adjustment (MW)	Net Imports		16	17	**16**		-2	-17	**-7**	
	Gross		103	138	**110**		68	88	**74**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$2.2	$1.5	**$3.7**		$0.5	$1.4	**$1.9**	
	Net Over-Projection by:	NY	-$0.2	-$0.8	**-$1.0**		-$0.1	-$0.5	**-$0.6**	
		NE or PJM	$0.0	$0.0	**$0.1**		-$0.1	-$0.9	**-$1.0**	
	Other Unrealized Savings		-$0.1	-$0.2	**-$0.3**		$0.0	-$0.1	**-$0.1**	
	Actual Savings		$2.0	$0.5	**$2.5**		$0.3	-$0.1	**$0.2**	
Interface Prices ($/MWh)	NY	Actual	$65.51	$94.35	**$71.36**	**$71.78**	$53.12	$78.76	**$60.66**	**$57.82**
		Forecast	$67.45	$96.17	**$73.27**	**$74.09**	$55.19	$85.90	**$64.23**	**$60.21**
	NE or PJM	Actual	$62.93	$88.88	**$68.19**	**$67.64**	$56.93	$88.16	**$66.12**	**$63.55**
		Forecast	$62.36	$86.57	**$67.27**	**$66.70**	$59.90	$101.42	**$72.11**	**$69.10**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.94	$1.82	**$1.92**	**$2.31**	$2.07	$7.14	**$3.56**	**$2.39**
		Abs. Val.	$4.97	$44.90	**$13.07**	**$13.25**	$4.90	$28.33	**$11.79**	**$9.73**
	NE or PJM	Fcst. - Act.	-$0.57	-$2.31	**-$0.92**	**-$0.95**	$2.97	$13.26	**$6.00**	**$5.55**
		Abs. Val.	$4.16	$26.25	**$8.64**	**$8.56**	$6.33	$48.50	**$18.74**	**$16.72**

For Adjustment Intervals Only

For All Intervals

Notes: For chart description, see slide 90.

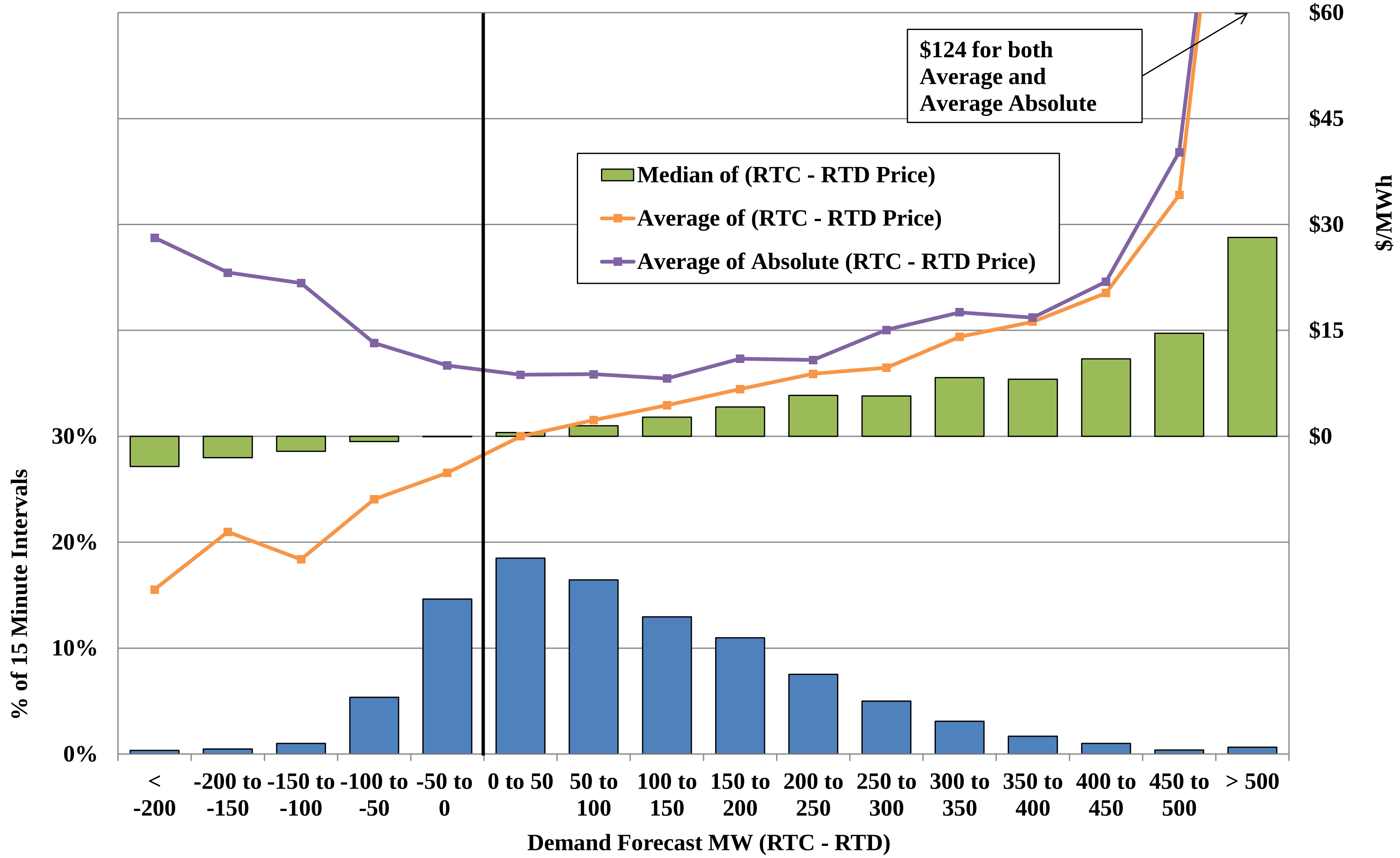
Detrimental Factors to RTC and RTD Price Divergence



Notes: For chart description, see slide 91.

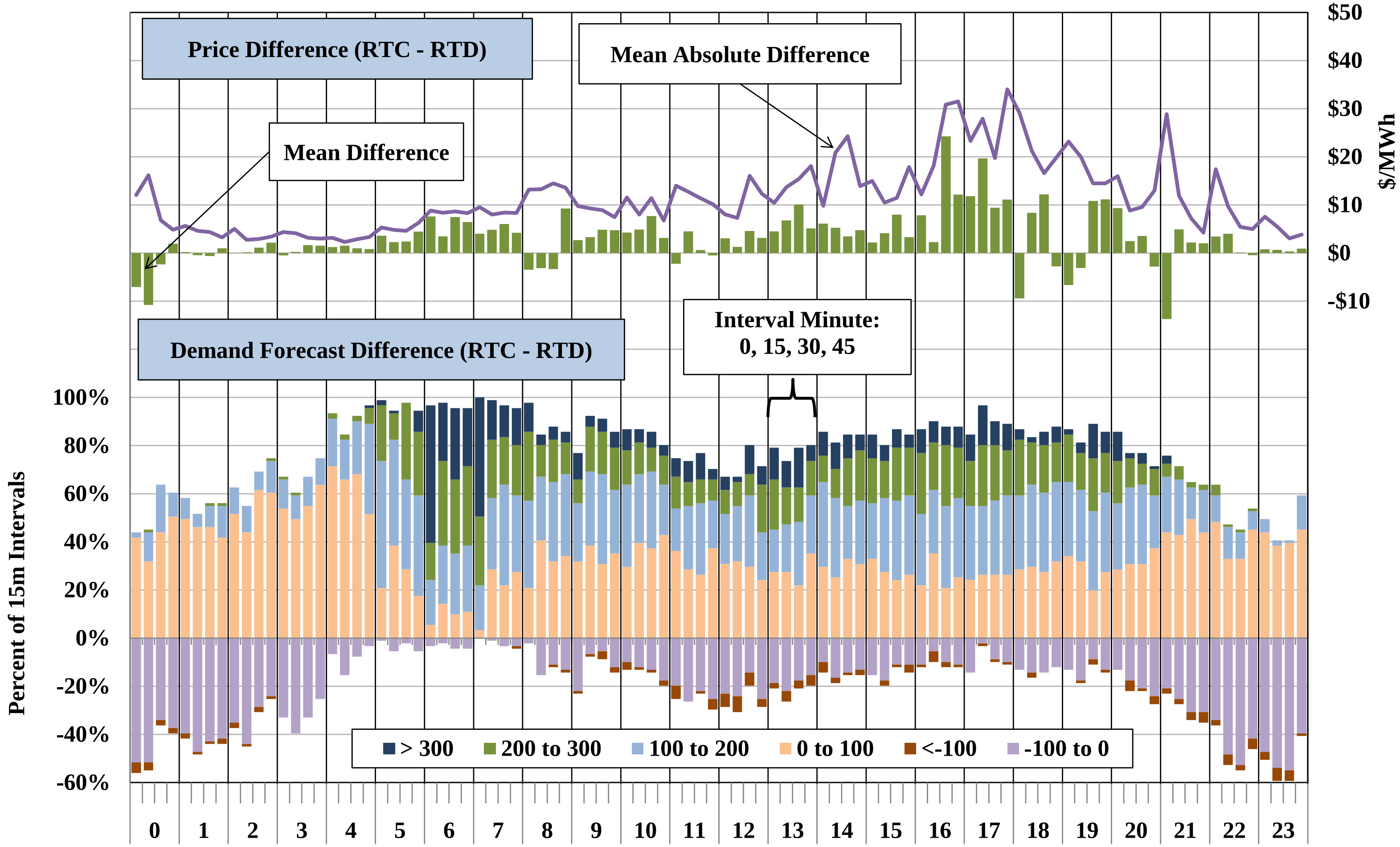
POTOMAC ECONOMICS

RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide 91.

RTC and RTD Price Difference vs Demand Forecast Difference
by Time of Day

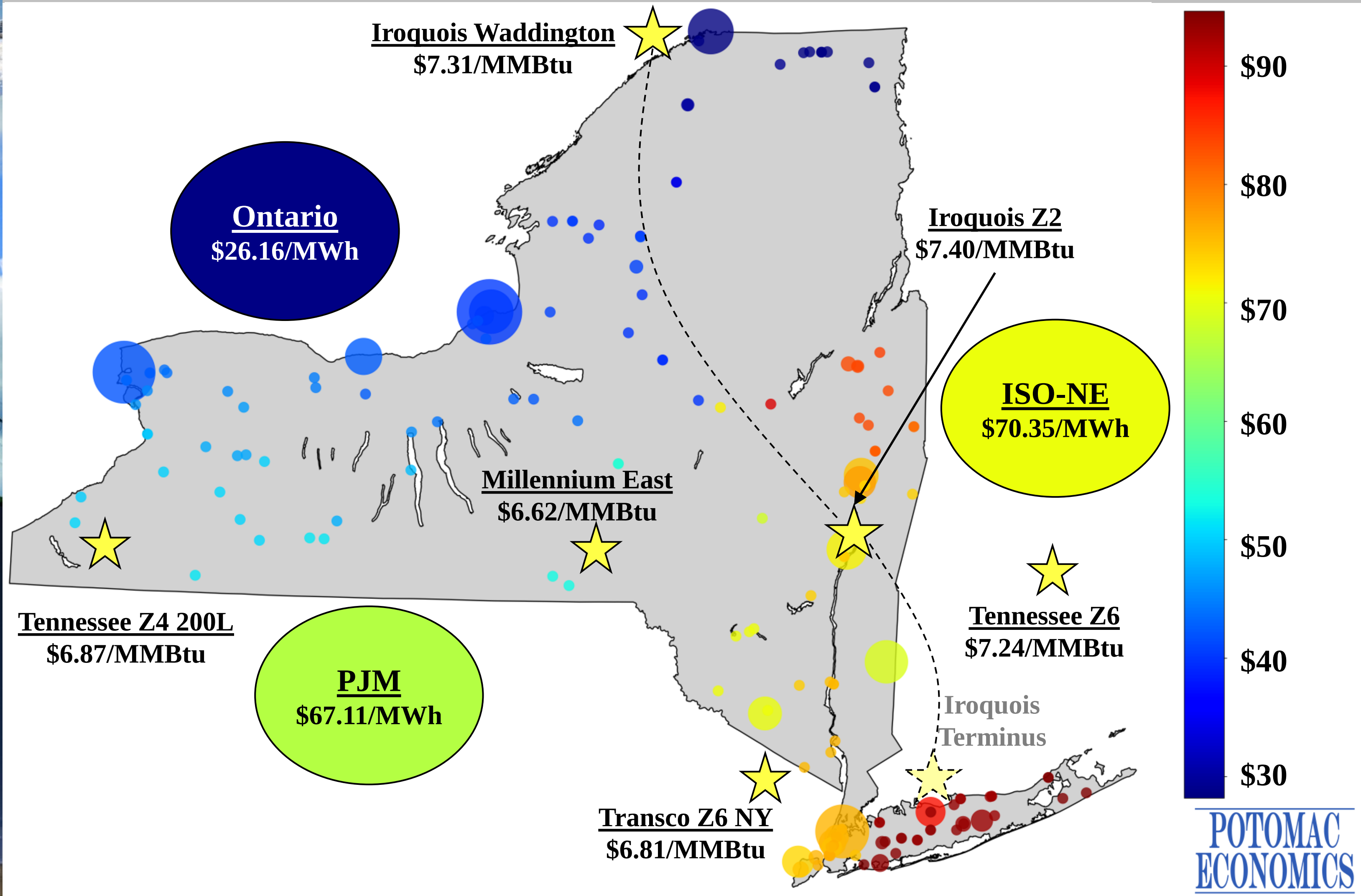


Notes: For chart description, see slide 92.

Charts:

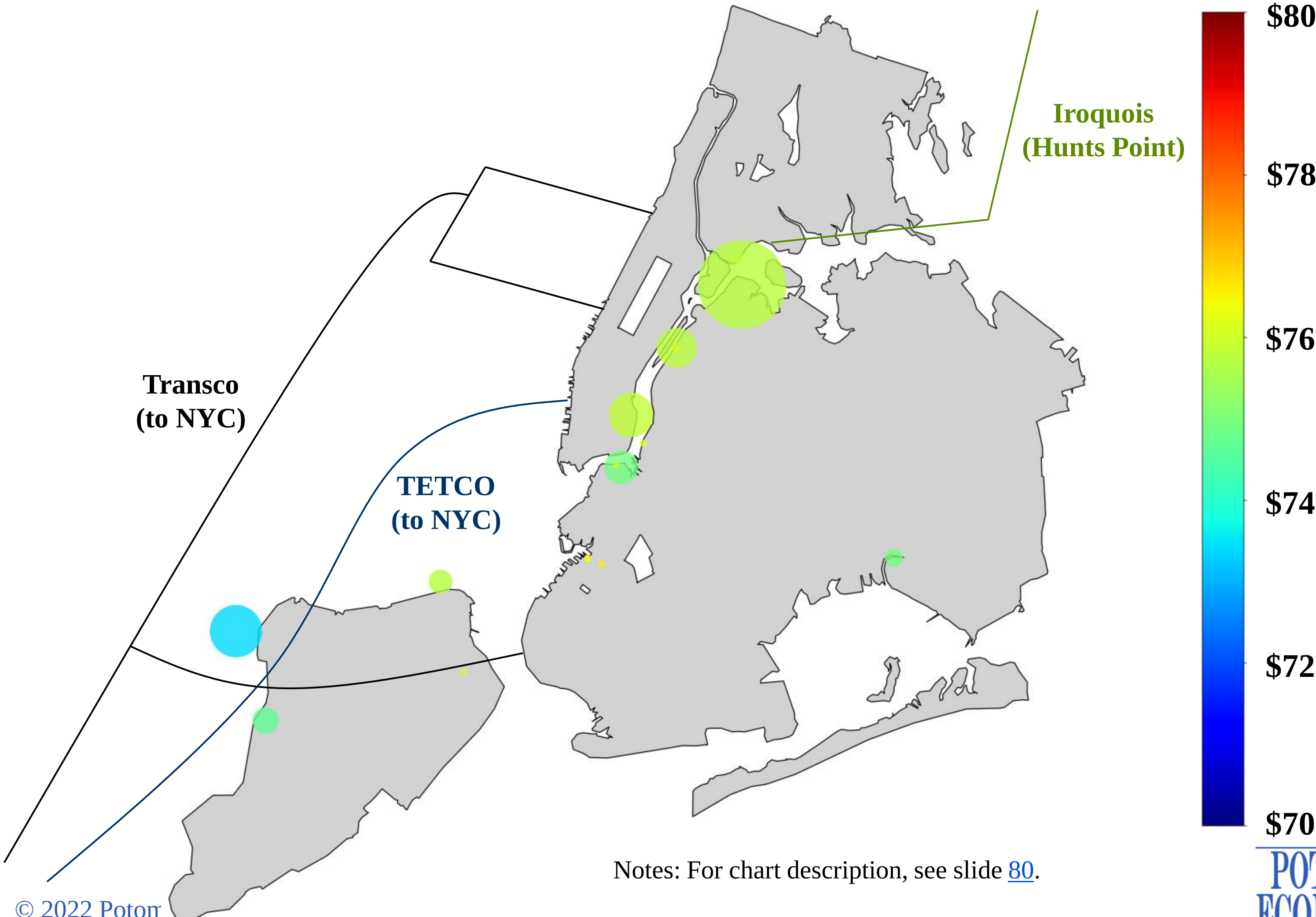
Transmission Congestion Revenues and Shortfalls

System Congestion
Real-Time Price Map at Generator Nodes



POTOMAC ECONOMICS

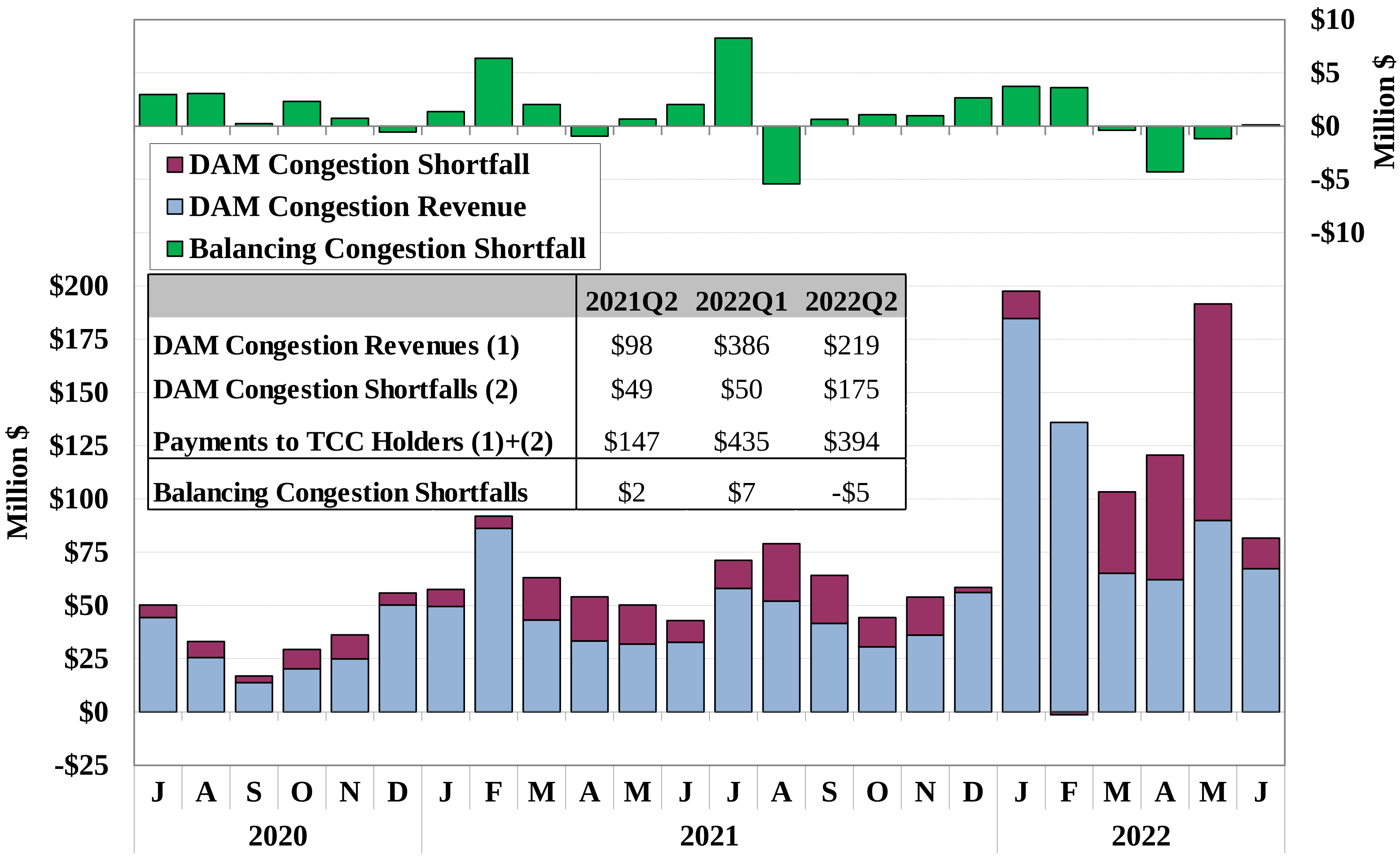
System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

Congestion Revenues and Shortfalls by Month

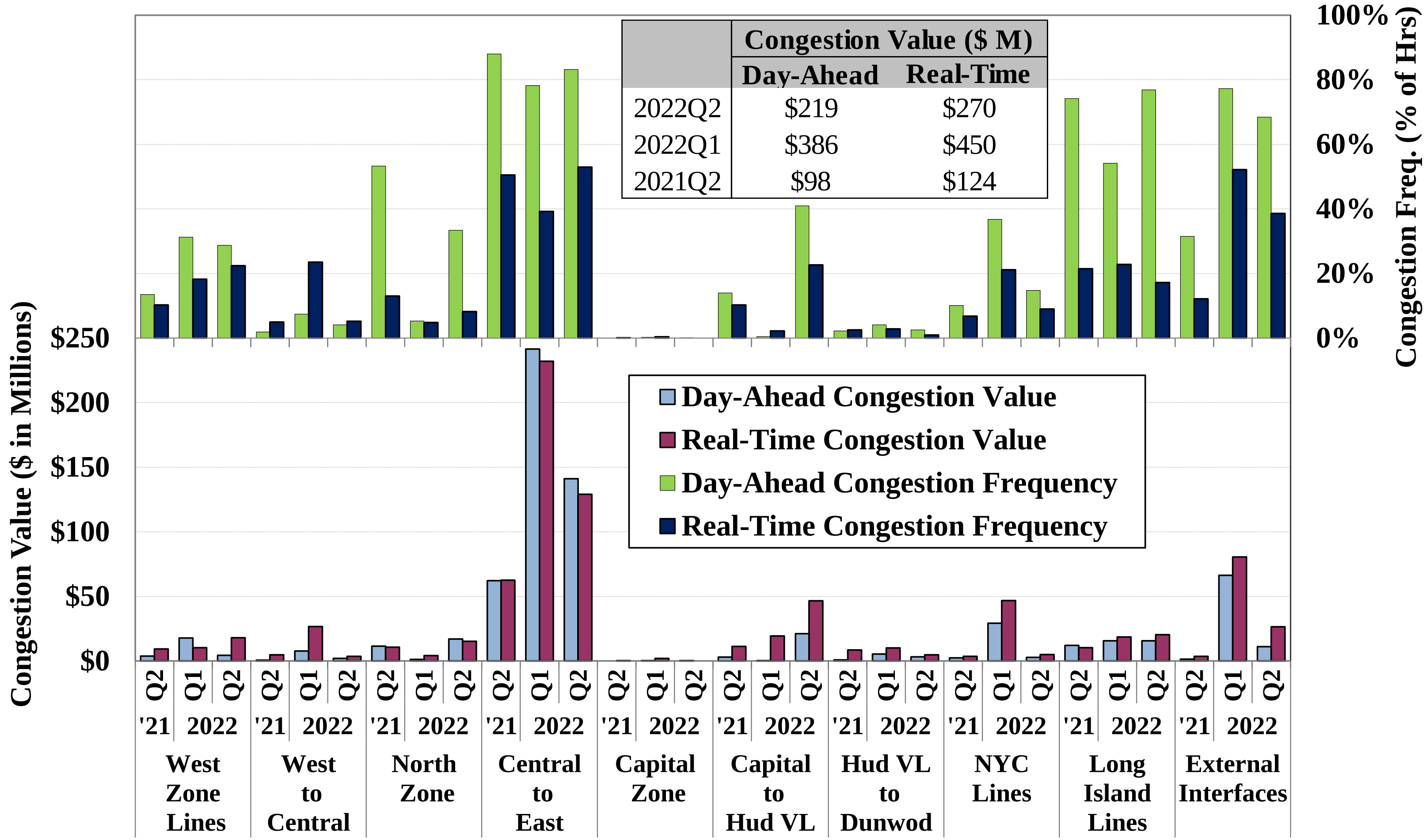


	2021Q2	2022Q1	2022Q2
DAM Congestion Revenues (1)	$98	$386	$219
DAM Congestion Shortfalls (2)	$49	$50	$175
Payments to TCC Holders (1)+(2)	$147	$435	$394
Balancing Congestion Shortfalls	$2	$7	-$5

Notes: For chart description, see slides 94 and 95.

POTOMAC ECONOMICS

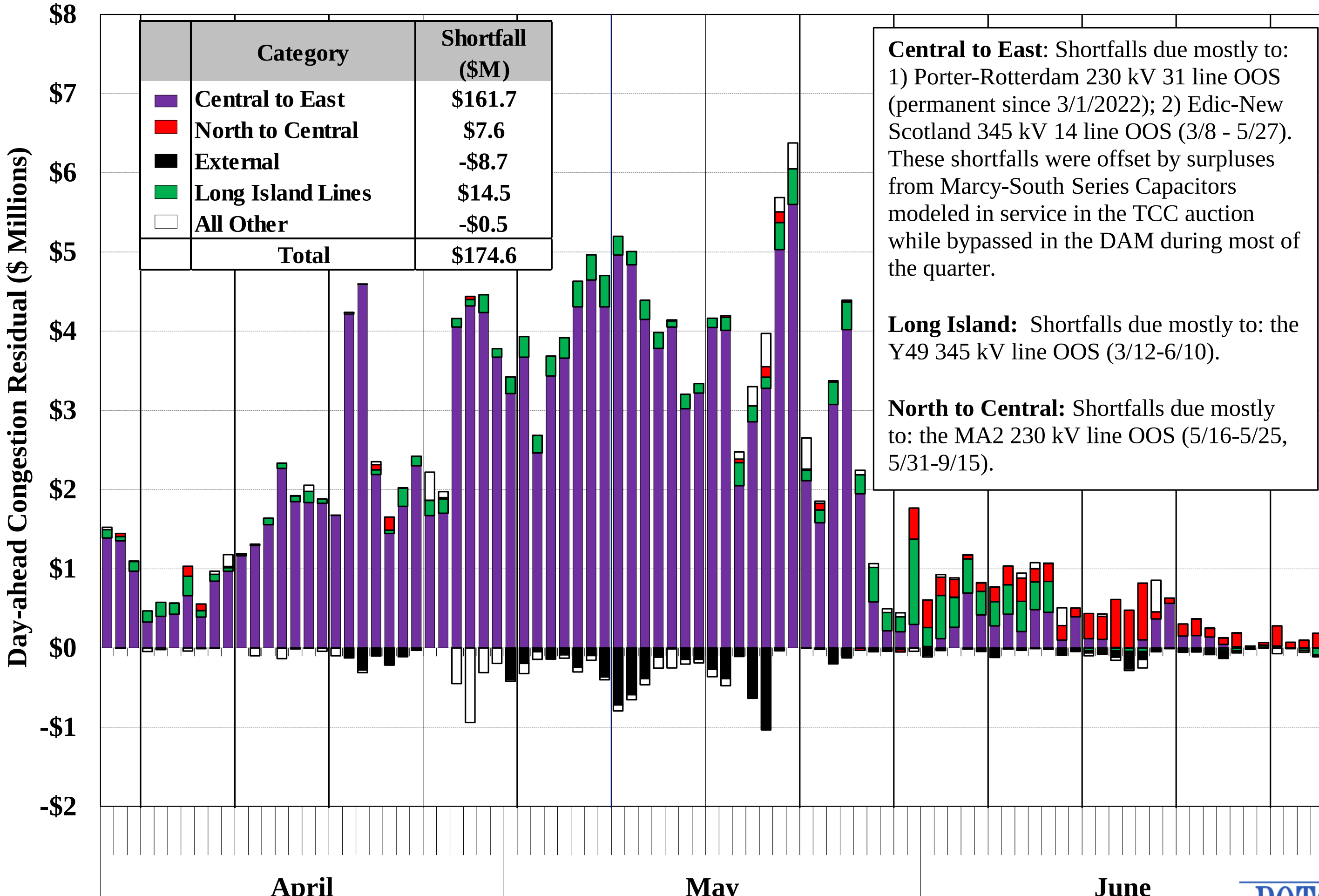
Day-Ahead and Real-Time Congestion Value by Transmission Path



Notes: For chart description, see slides 94, 95, and 96.

POTOMAC ECONOMICS

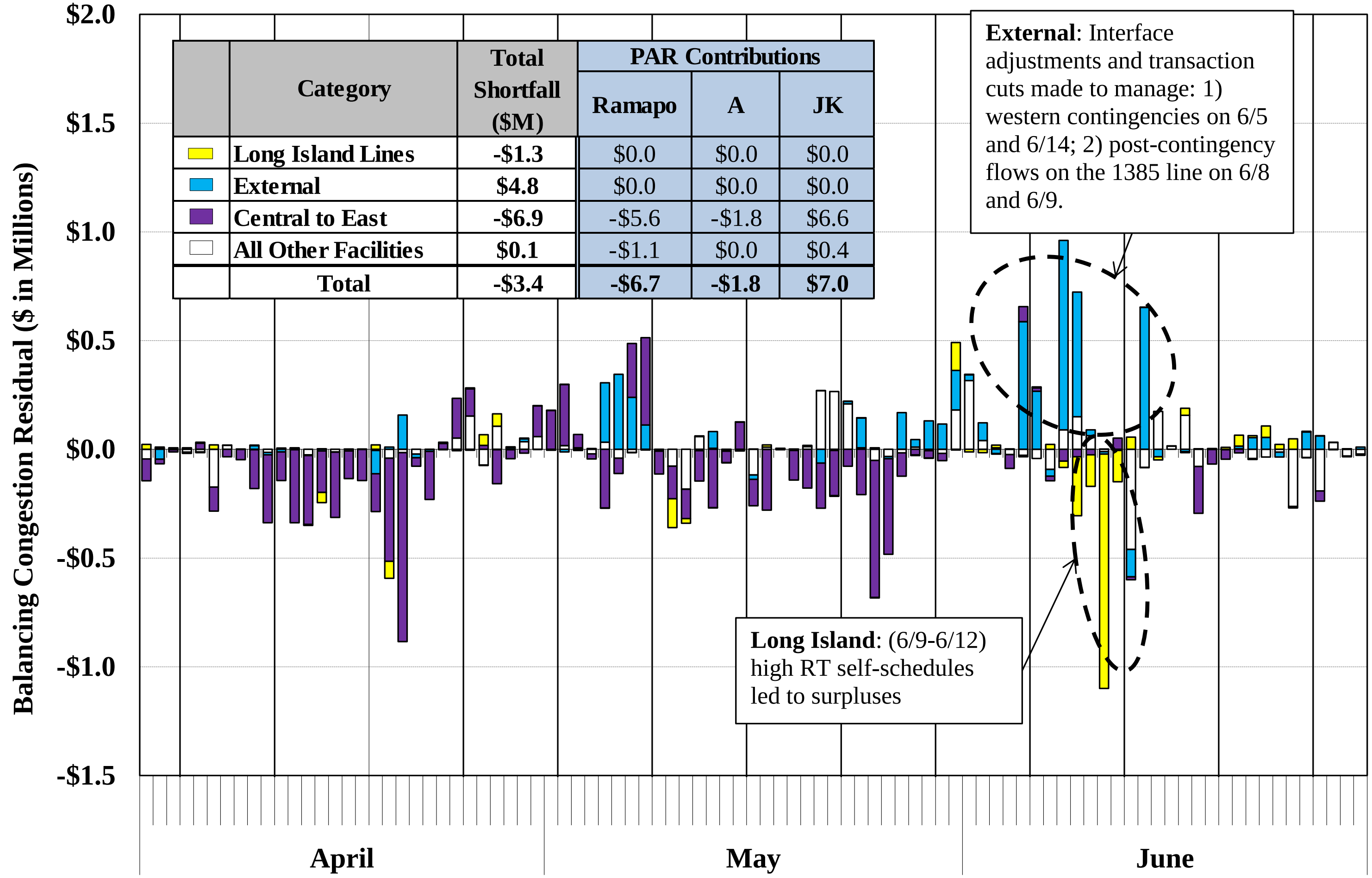
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Category	Shortfall ($M)
Central to East	$161.7
North to Central	$7.6
External	-$8.7
Long Island Lines	$14.5
All Other	-$0.5
Total	$174.6

Notes: For chart description, see slides 94, 95, and 96.

Balancing Congestion Shortfalls by Transmission Facility

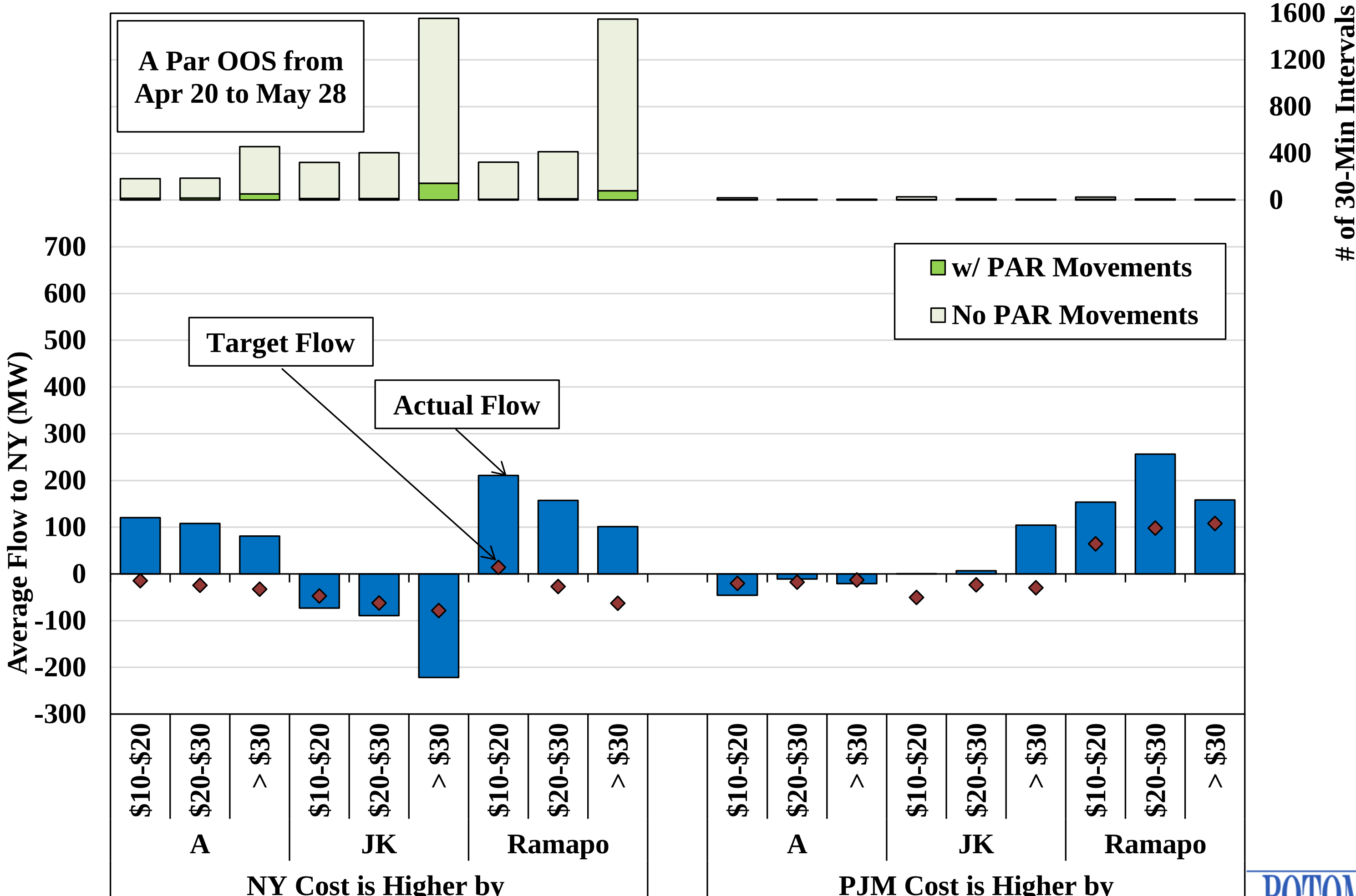


Category	Total Shortfall ($M)	PAR Contributions		
		Ramapo	A	JK
Long Island Lines	-$1.3	$0.0	$0.0	$0.0
External	$4.8	$0.0	$0.0	$0.0
Central to East	-$6.9	-$5.6	-$1.8	$6.6
All Other Facilities	$0.1	-$1.1	$0.0	$0.4
Total	**-$3.4**	**-$6.7**	**-$1.8**	**$7.0**

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 94, 95, and 96.

POTOMAC ECONOMICS

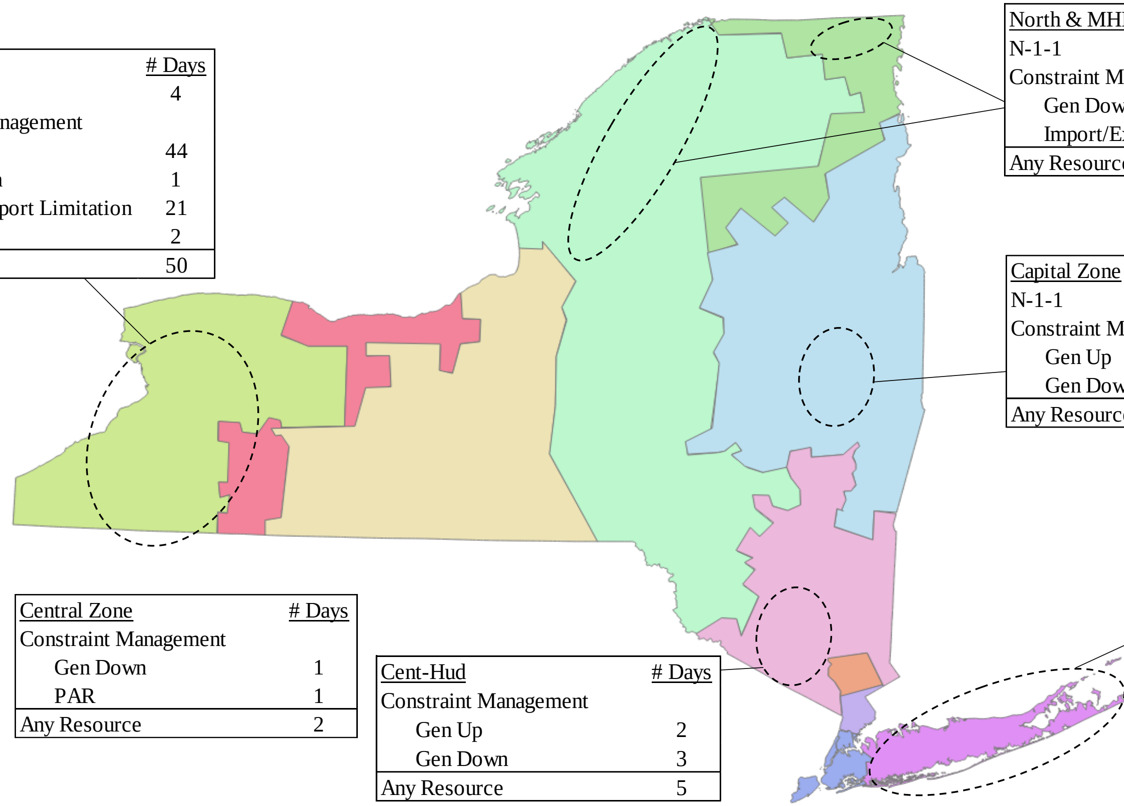
PAR Operation under M2M with PJM
2022 Q2



  Notes: For chart description, see slide 97.

POTOMAC ECONOMICS

OOM Actions to Manage Network Reliability



West Zone	# Days
Voltage	4
Constraint Management	
Gen Up	44
Gen Down	1
Import/Export Limitation	21
PAR	2
Any Resource	50

North & MHK VL Zones	# Days
N-1-1	3
Constraint Management	
Gen Down	2
Import/Export Limitation	4
Any Resource	9

Capital Zone	# Days
N-1-1	12
Constraint Management	
Gen Up	2
Gen Down	9
Any Resource	19

Long Island	# Days
N-1-1	12
Voltage	1
Constraint Management	
Gen Up	9
Gen Down	4
Import/Export Limitation	4
Any Resource	25

Central Zone	# Days
Constraint Management	
Gen Down	1
PAR	1
Any Resource	2

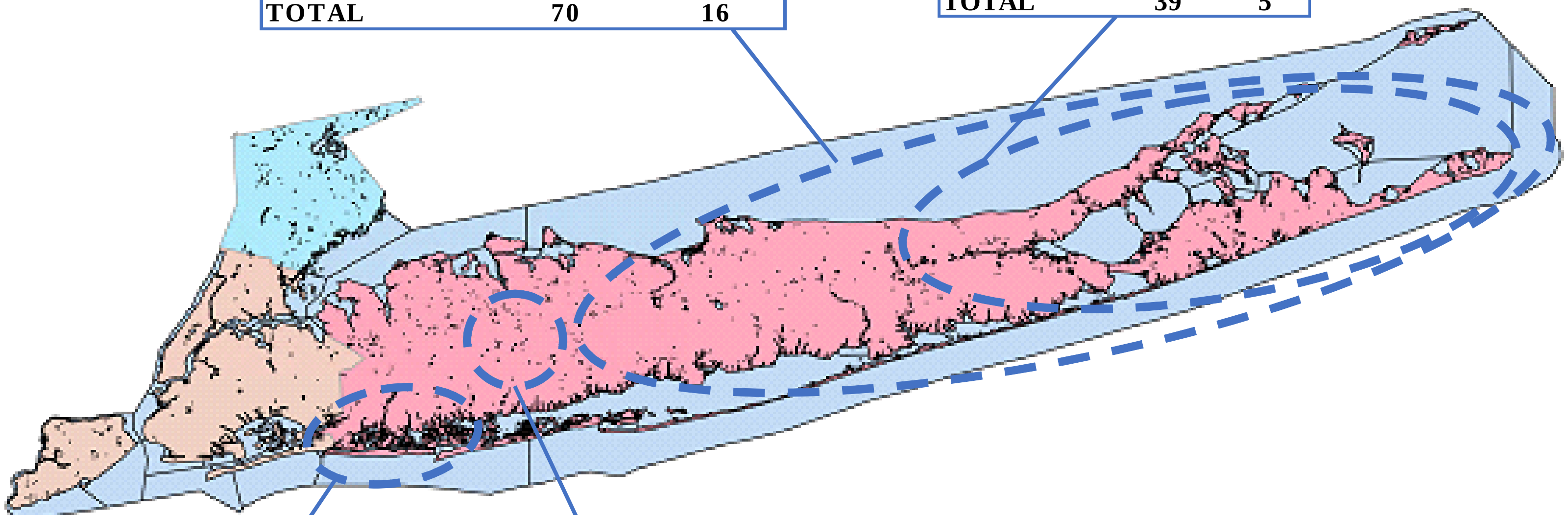
Cent-Hud	# Days
Constraint Management	
Gen Up	2
Gen Down	3
Any Resource	5

Notes: For chart description, see slides 98-99

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV	48	12
138kV	37	10
TOTAL	70	16

East End	#Hours	#Days
TVR OOM	39	5
TOTAL	39	5



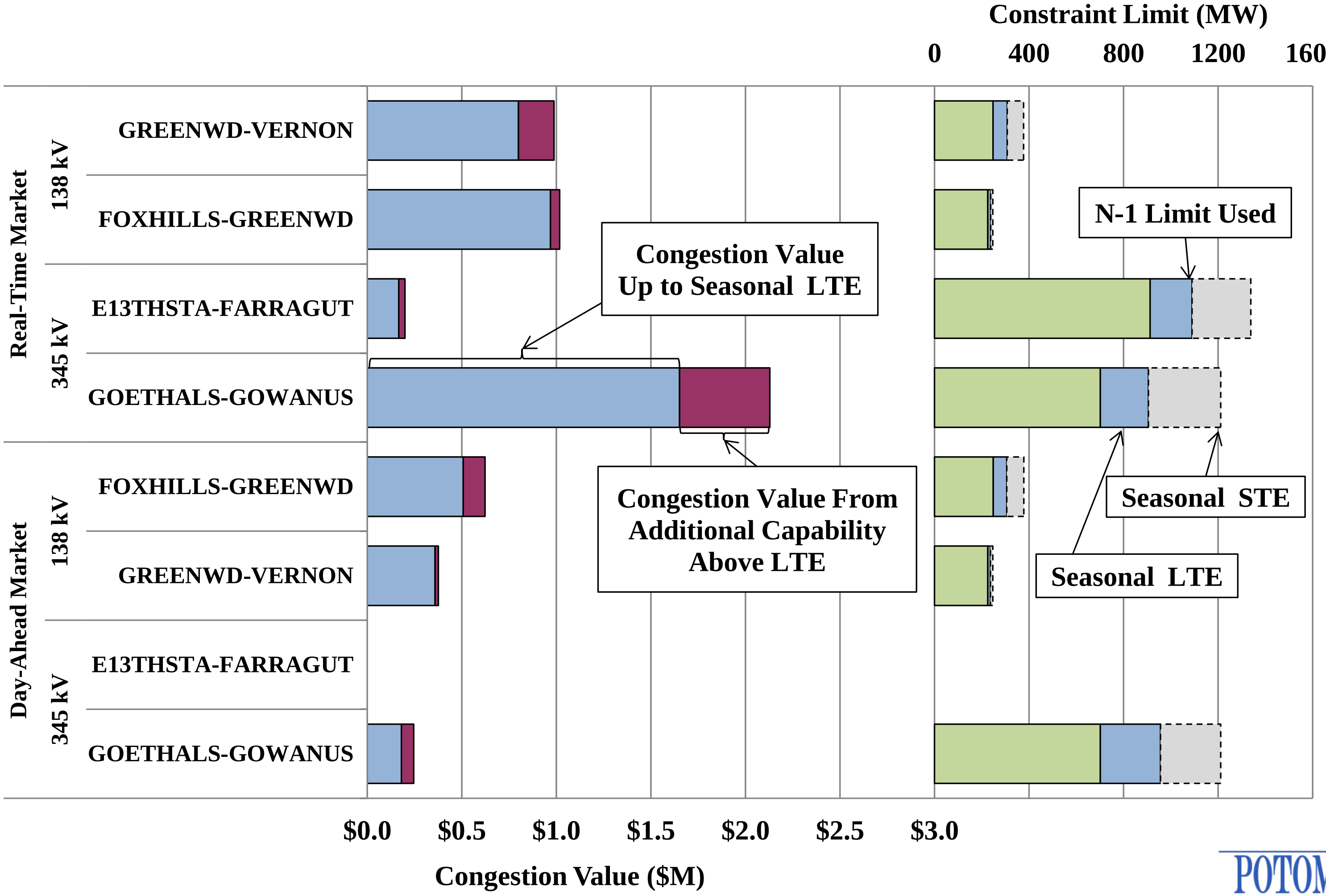
Valley Stream	#Hours	#Days
69kV OOM	6	1
138kV	93	10
TOTAL	99	10

Brentwood	#Hours	#Days
69kV OOM	1	1
69kV	81	16
TOTAL	82	17

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$86.44	$86.46
East End	$87.21	$92.21
East of Northport	$85.95	$85.95
Valley Stream	$86.38	$86.46

Notes: For chart description, see slides 98-99

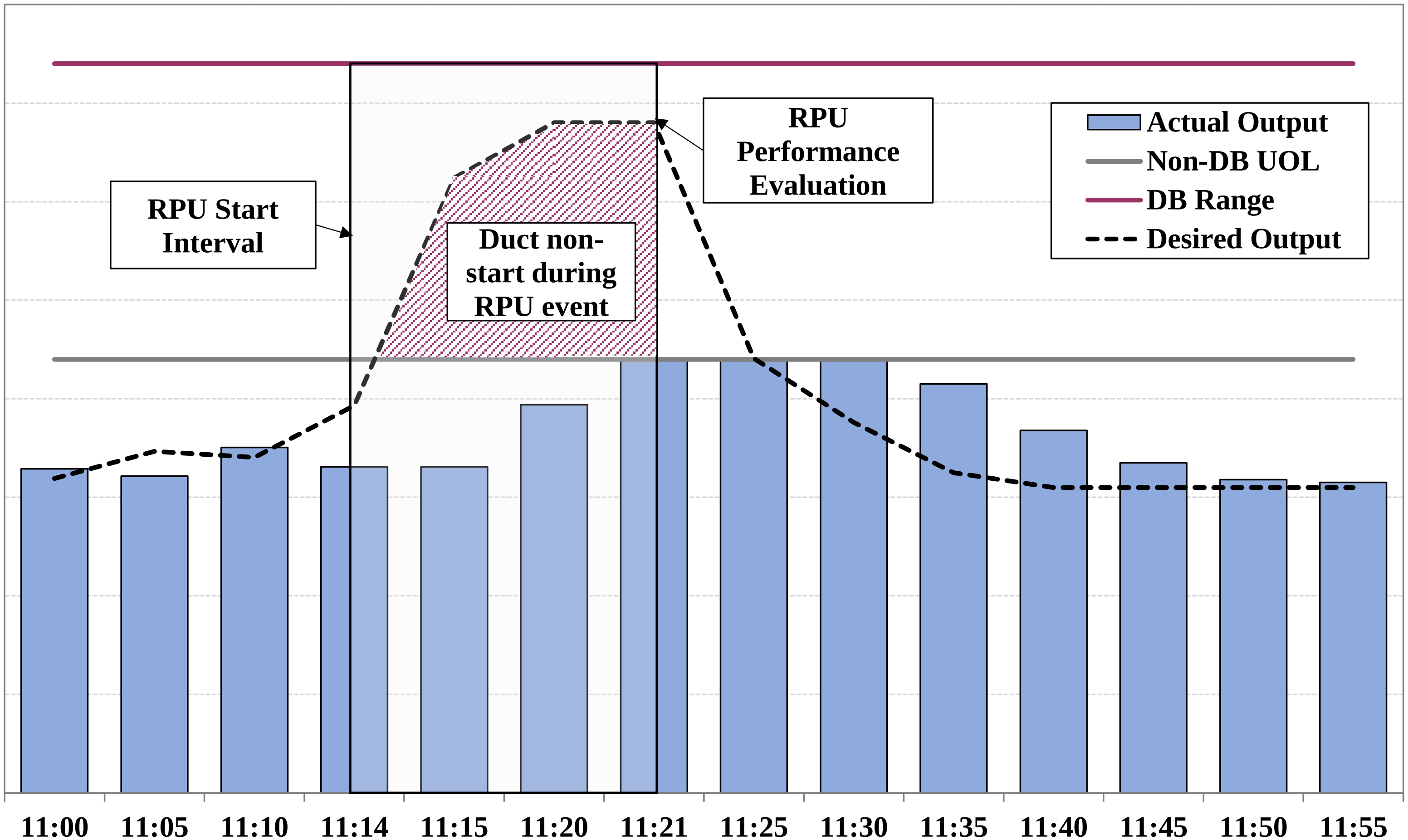
N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide 100.

POTOMAC ECONOMICS

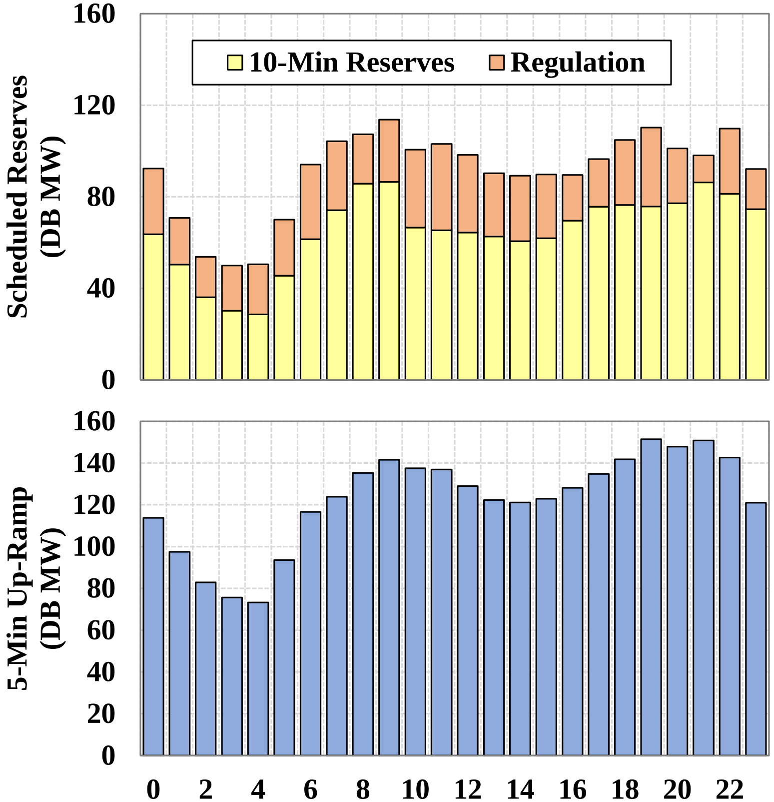
Duct Burner Real-Time Dispatch Issues
Example of a Failed RPU



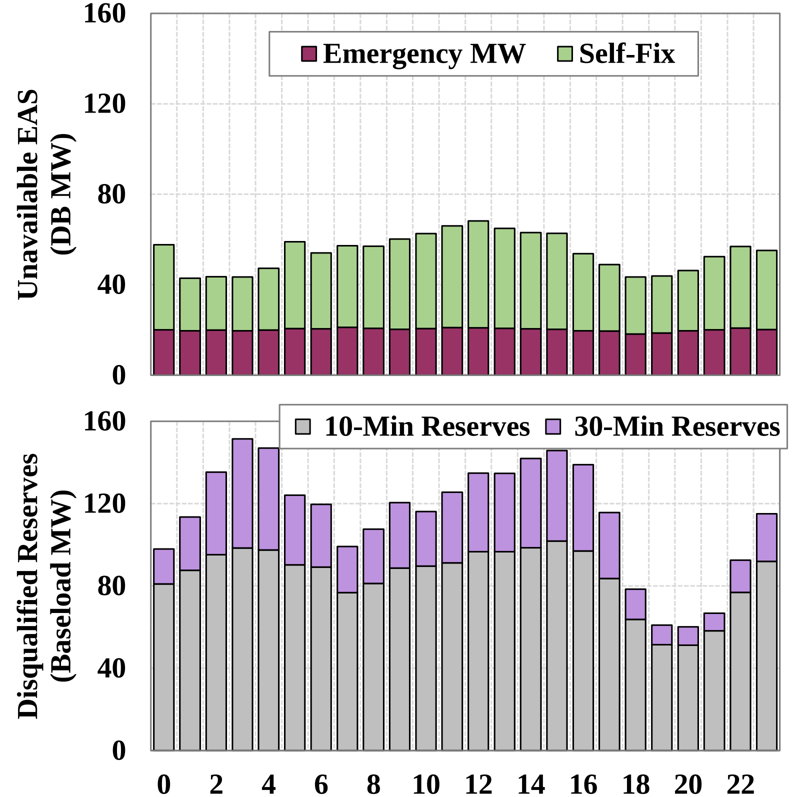
Notes: For chart description, see slide 101

Duct Burner Schedules and Ramp Expectations Evaluation of Duct Availability in Real-Time

Scheduled or Offered Duct Capacity – but Unable to Follow RT Instructions



Unoffered Energy and/or Reserves (Including Duct and Baseload)



Notes: For chart description, see slide 101

10-Minute Gas Turbine Start-up Performance
Economic Starts vs. Audits

10 Minute Economic GT Start Performance vs. Audit Results (July 2021 - June 2022)				
Economic GT Starts (RTC, RTD, and RTD-CAM)		**GT Audit Results**		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Evaluated [1]	1	0	0	0
0% - 10%	0	0	0	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	1	1	1	1
40% - 50%	1	4	1	2
50% - 60%	3	4	2	1
60% - 70%	1	1	1	0
70% - 80%	1	3	1	1
80% - 90%	26	111	26	22
90% - 100%	19	96	19	13
TOTAL	**53**	**220**	**51**	**40**

Note: 1. Including units that were OOM- or self-started, units that were never started in the time period, and units that were omitted from the analysis due to certain data issues for reliable performance assessment.

 Notes: For chart description, see slide 102.

30-Minute Gas Turbine Start-up Performance

Economic Starts vs. Audits

30 Minute Economic GT Start Performance vs. Audit Results (July 2021 - June 2022)

Economic GT Starts (RTC)		GT Audit Results		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Evaluated [1]	15	13	5	3
0% - 10%	4	1	1	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	0	0	0	0
40% - 50%	1	3	1	1
50% - 60%	1	4	1	1
60% - 70%	1	2	1	0
70% - 80%	8	11	8	0
80% - 90%	29	49	26	2
90% - 100%	33	55	29	0
TOTAL	**92**	**138**	**72**	**7**

Note: 1. Including units that were OOM- or self-started, units that were never started in the time period, and units that were omitted from the analysis due to certain data issues for reliable performance assessment.

Notes: For chart description, see slide 102.

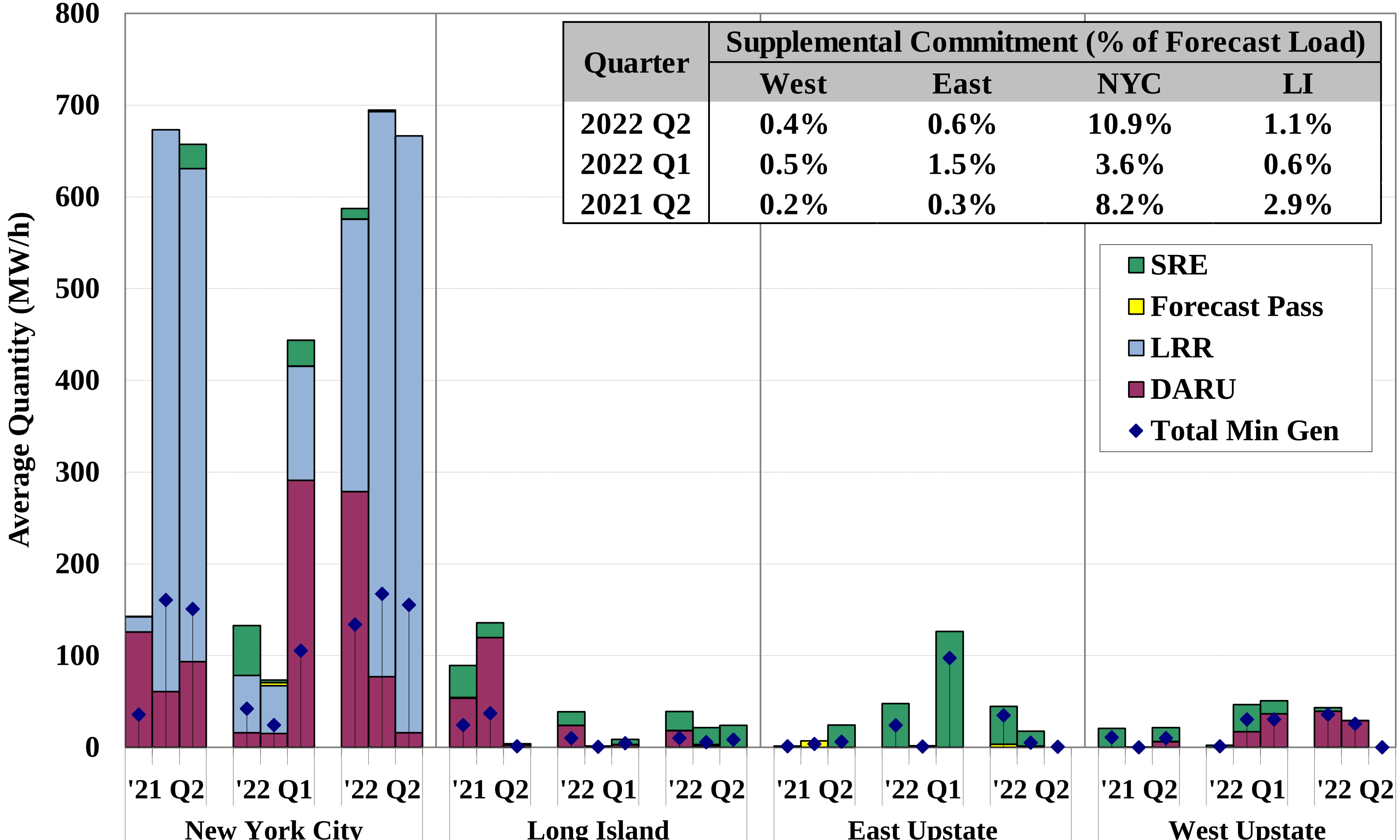
POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

Supplemental Commitment for Reliability
by Category and Region

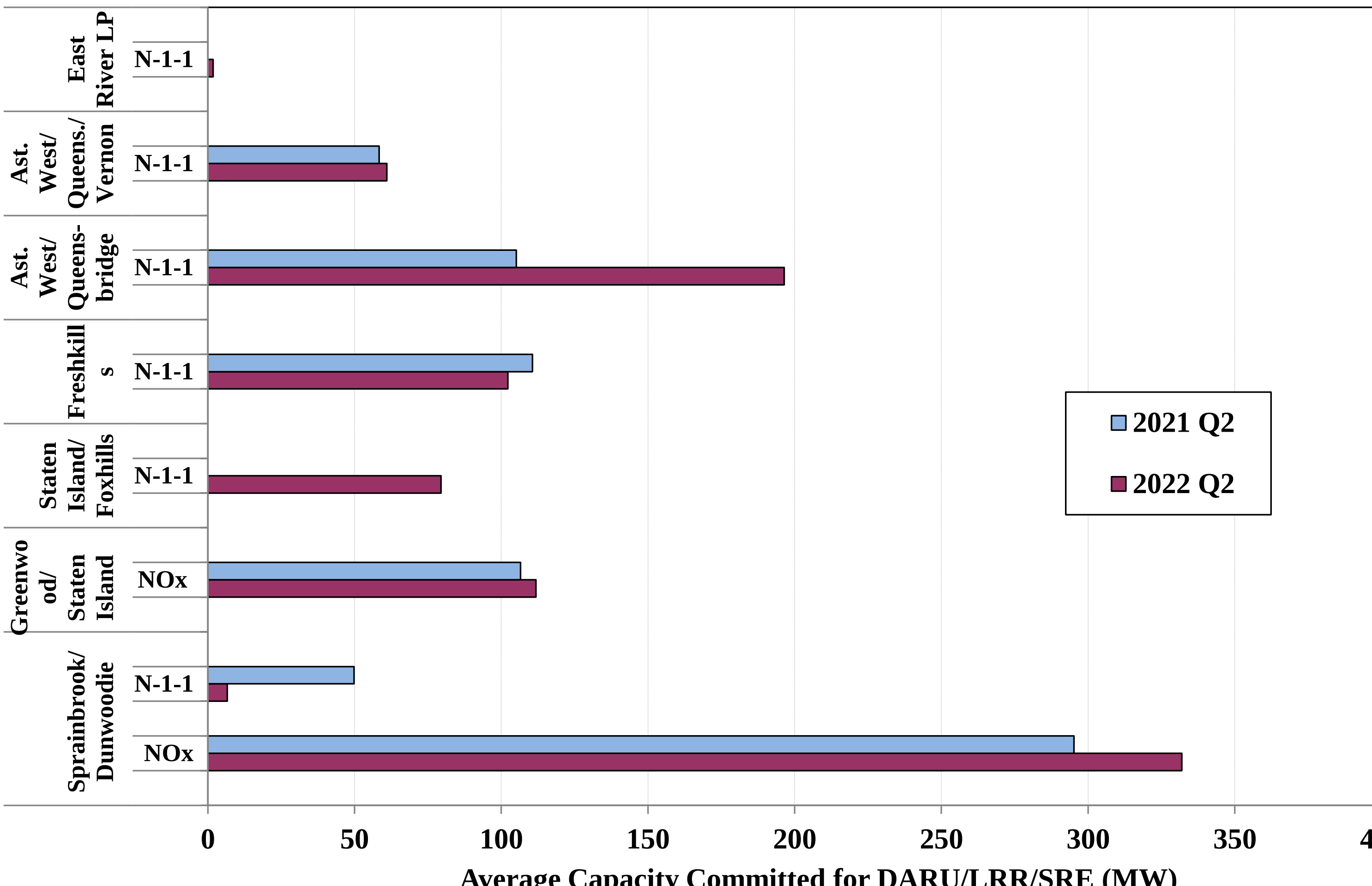


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2022 Q2	0.4%	0.6%	10.9%	1.1%
2022 Q1	0.5%	1.5%	3.6%	0.6%
2021 Q2	0.2%	0.3%	8.2%	2.9%

Notes: For chart description, see slides 103 and 104.

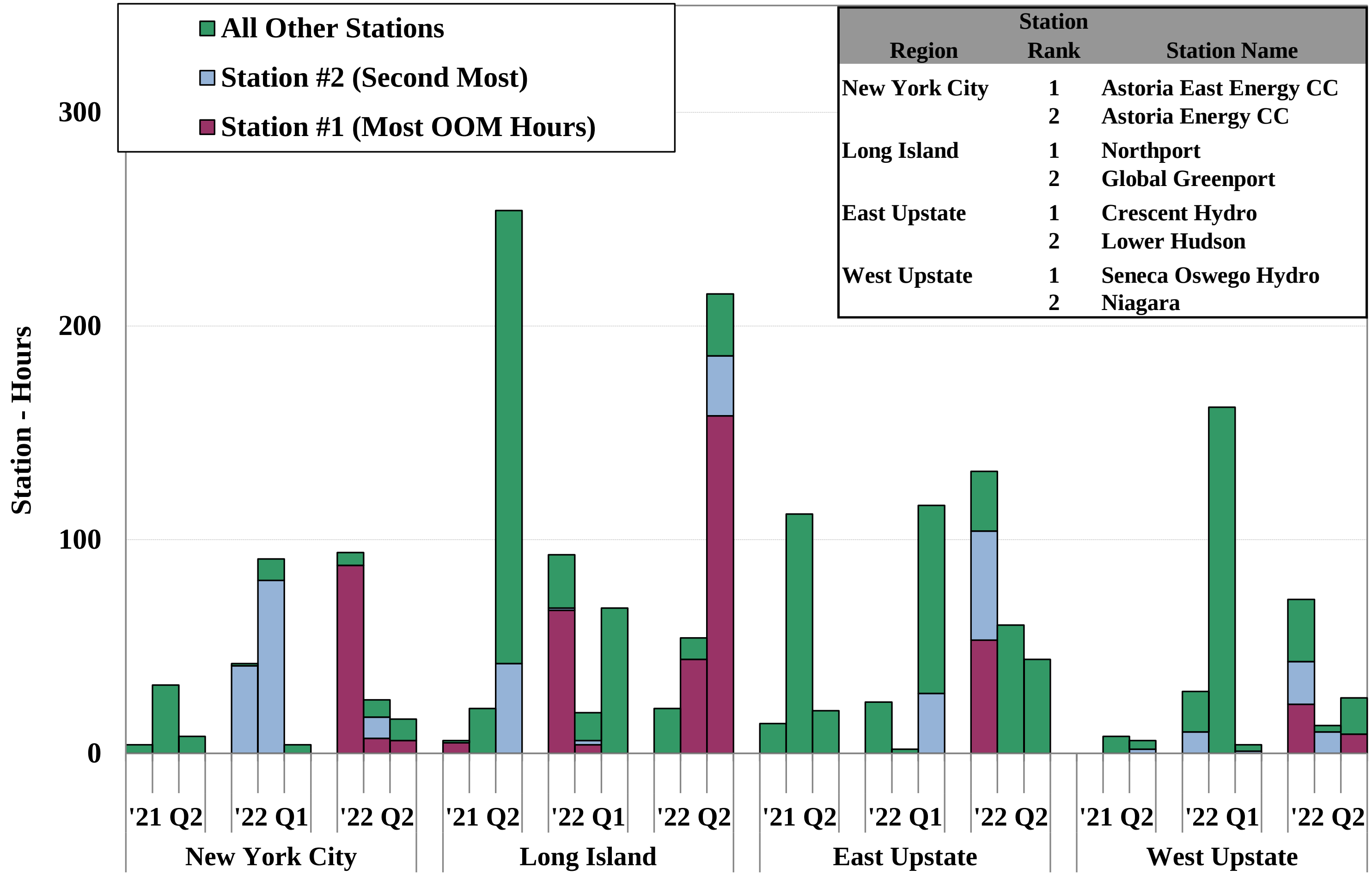
POTOMAC ECONOMICS

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



Notes: For chart description, see slides 103 and 104.

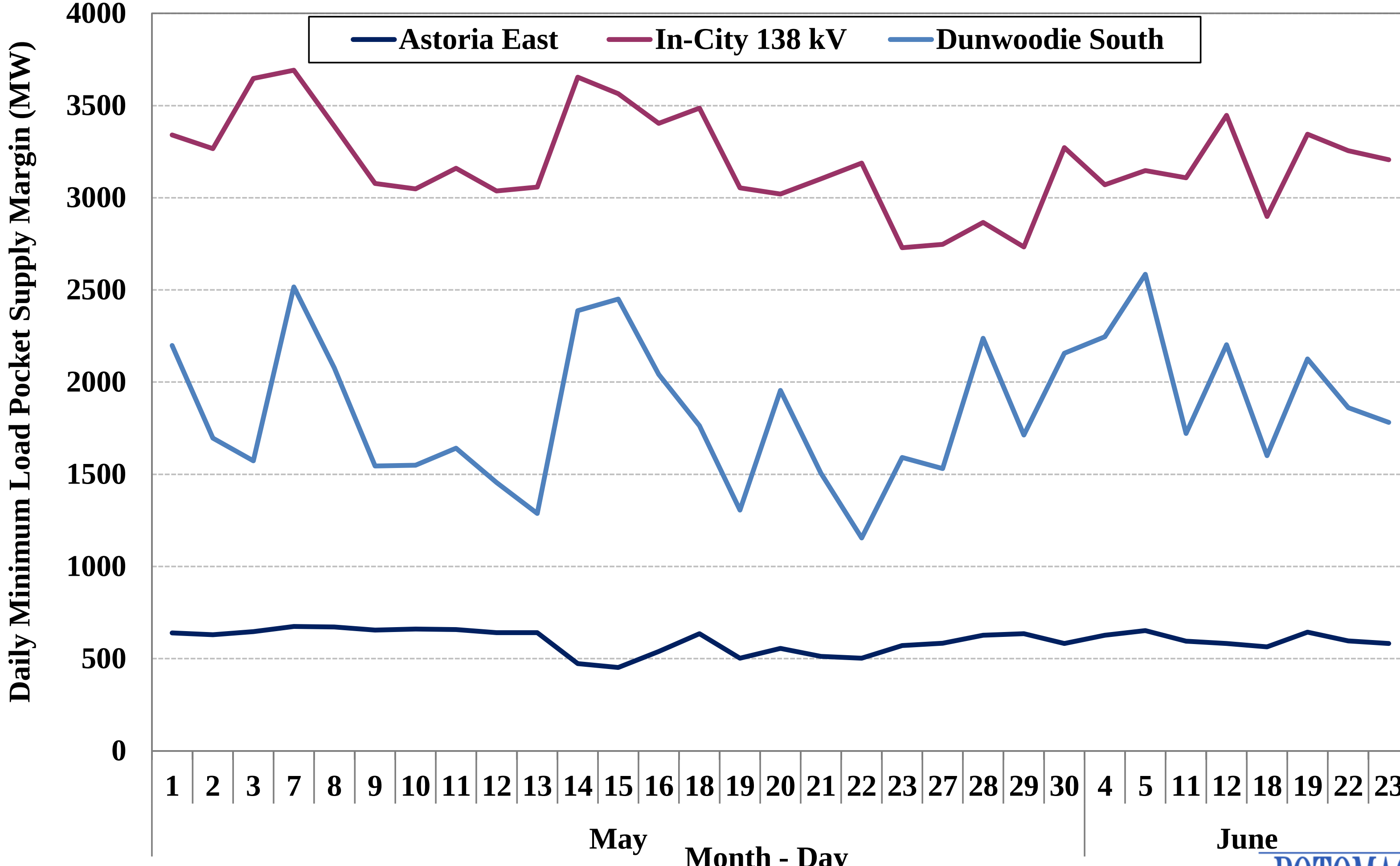
Frequency of Out-of-Merit Dispatch by Region by Month



Region	Station Rank	Station Name
New York City	1	Astoria East Energy CC
	2	Astoria Energy CC
Long Island	1	Northport
	2	Global Greenport
East Upstate	1	Crescent Hydro
	2	Lower Hudson
West Upstate	1	Seneca Oswego Hydro
	2	Niagara

For chart description, see slides 103 and 104.

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



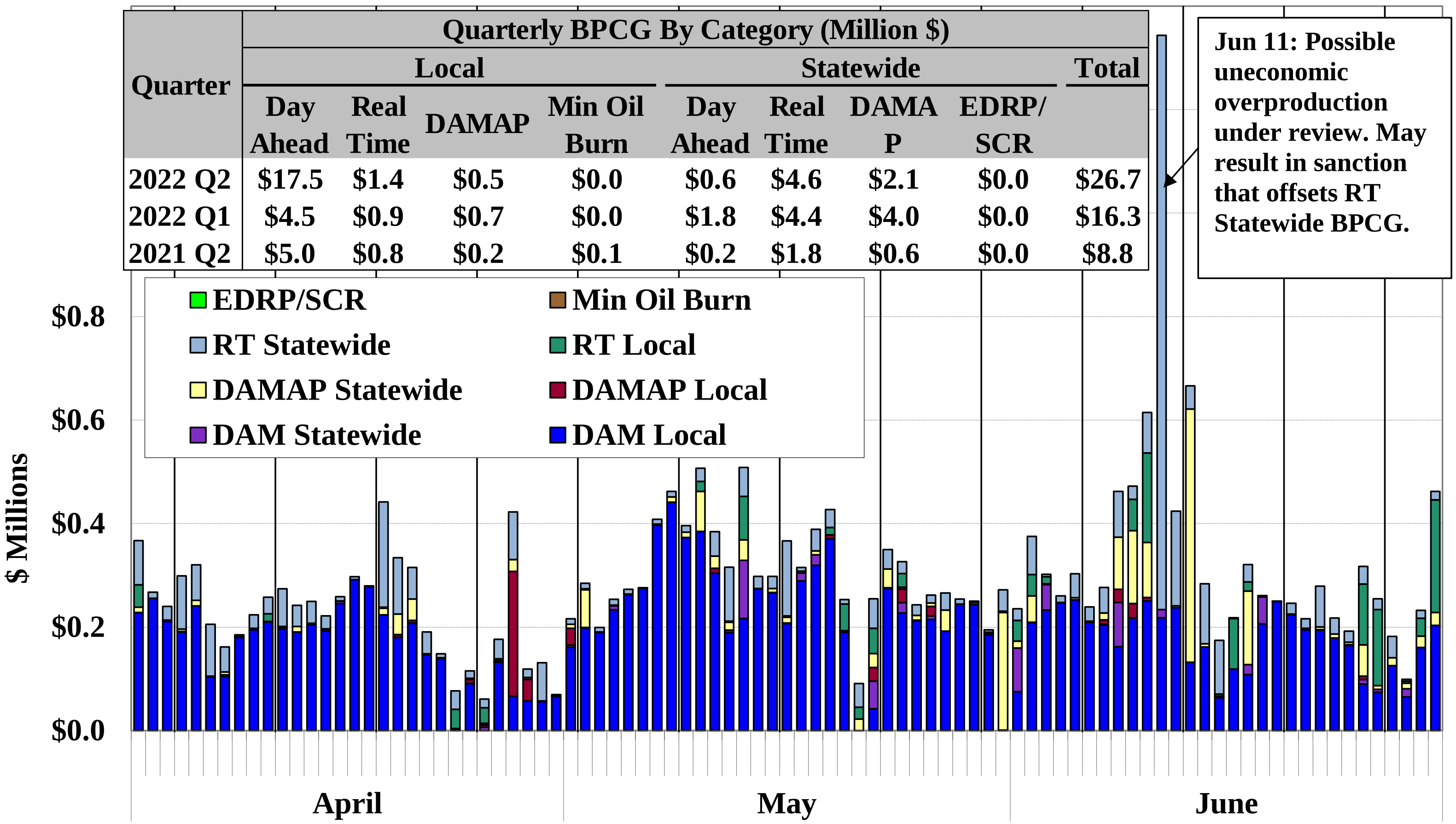
For chart description, see slide 105.

POTOMAC ECONOMICS

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

Quarterly BPCG By Category (Million $)

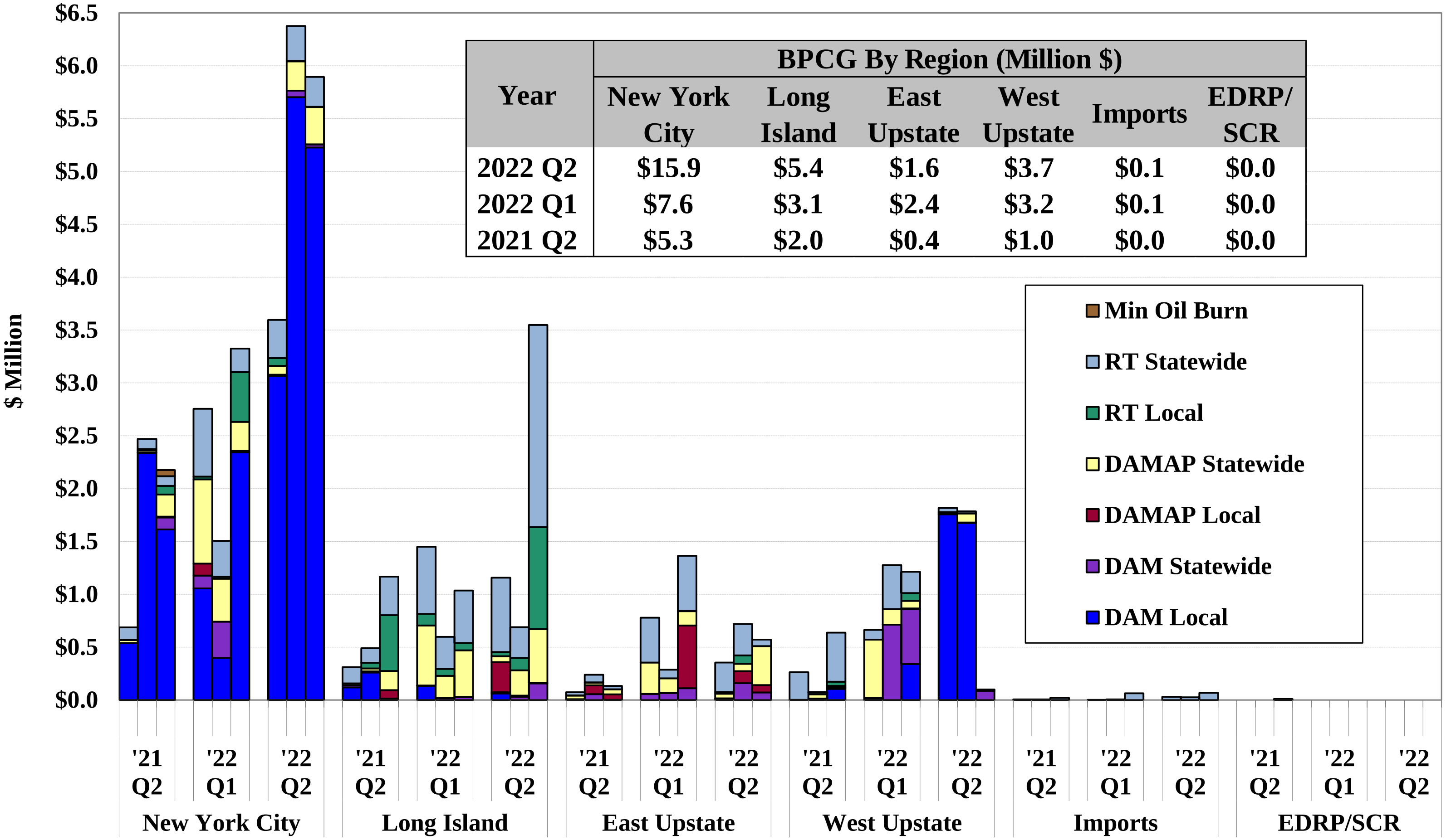
Quarter	Local: Day Ahead	Local: Real Time	Local: DAMAP	Local: Min Oil Burn	Statewide: Day Ahead	Statewide: Real Time	Statewide: DAMAP	Statewide: EDRP/SCR	Total
2022 Q2	$17.5	$1.4	$0.5	$0.0	$0.6	$4.6	$2.1	$0.0	$26.7
2022 Q1	$4.5	$0.9	$0.7	$0.0	$1.8	$4.4	$4.0	$0.0	$16.3
2021 Q2	$5.0	$0.8	$0.2	$0.1	$0.2	$1.8	$0.6	$0.0	$8.8



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 106.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region

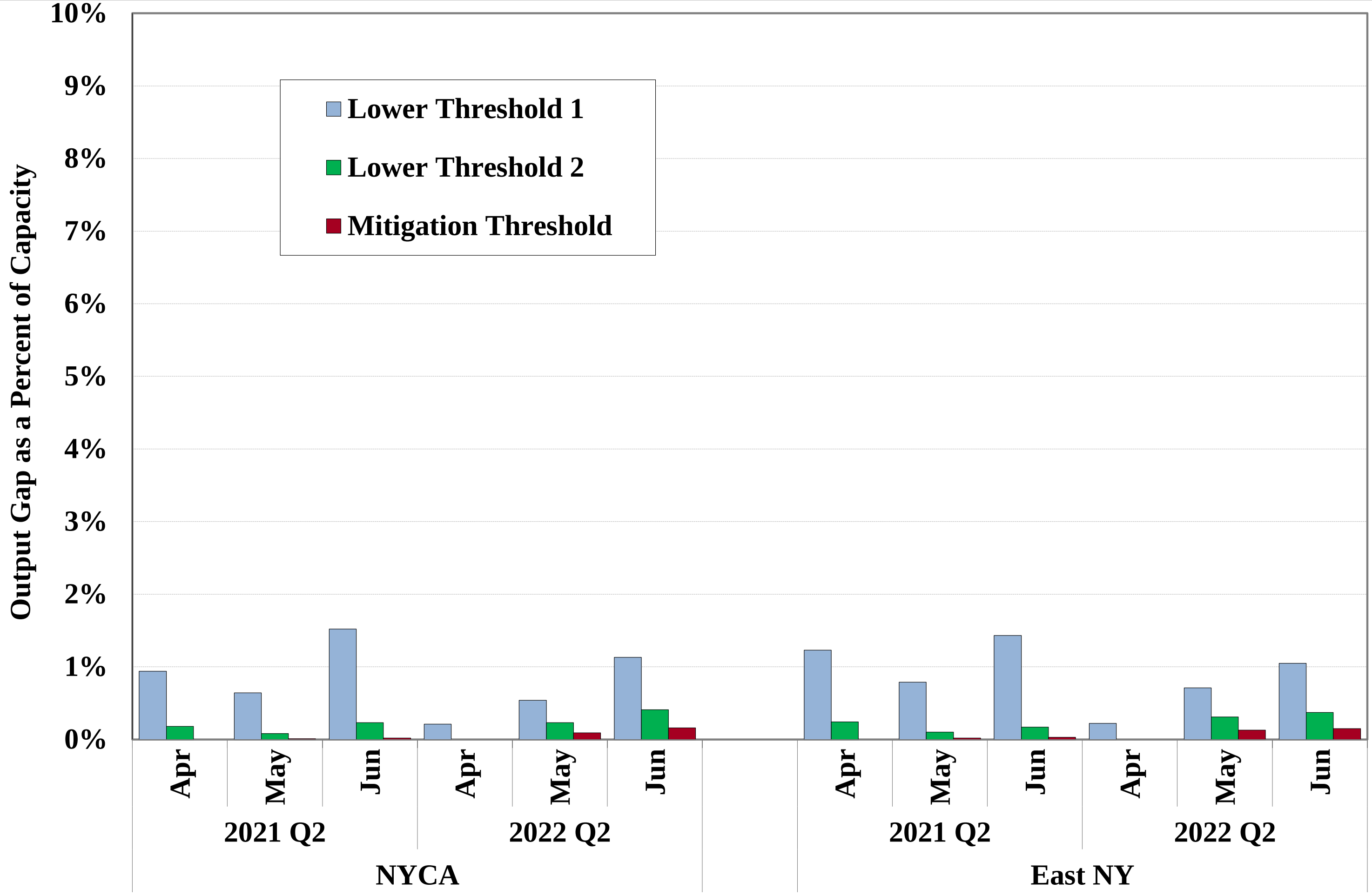


Year	BPCG By Region (Million $)					
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2022 Q2	$15.9	$5.4	$1.6	$3.7	$0.1	$0.0
2022 Q1	$7.6	$3.1	$2.4	$3.2	$0.1	$0.0
2021 Q2	$5.3	$2.0	$0.4	$1.0	$0.0	$0.0

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 106.

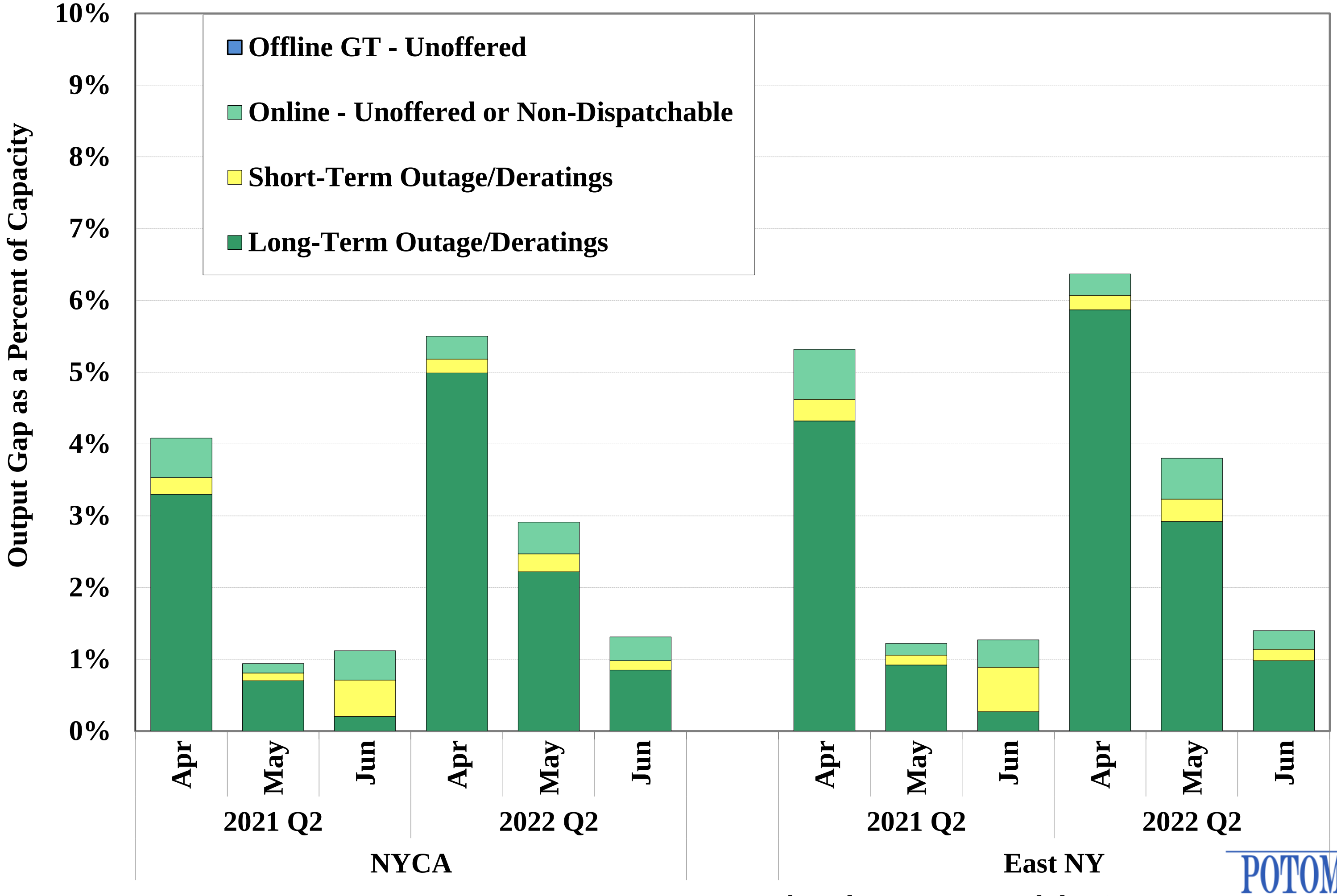
Charts:
Market Power and Mitigation

Output Gap by Month
NYCA and East NY



For chart description, see slide 107.

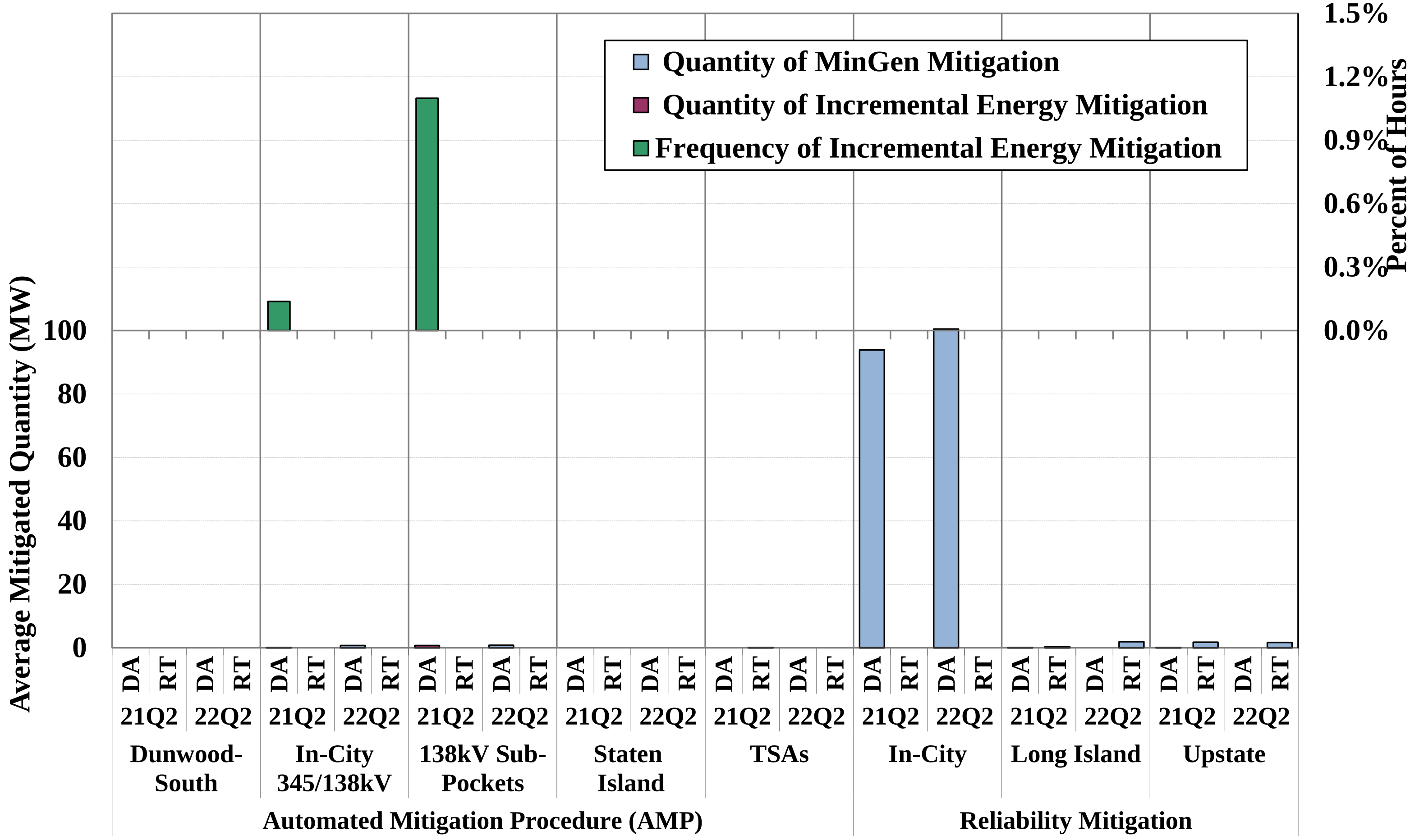
Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 107.

POTOMAC ECONOMICS

Automated Market Power Mitigation

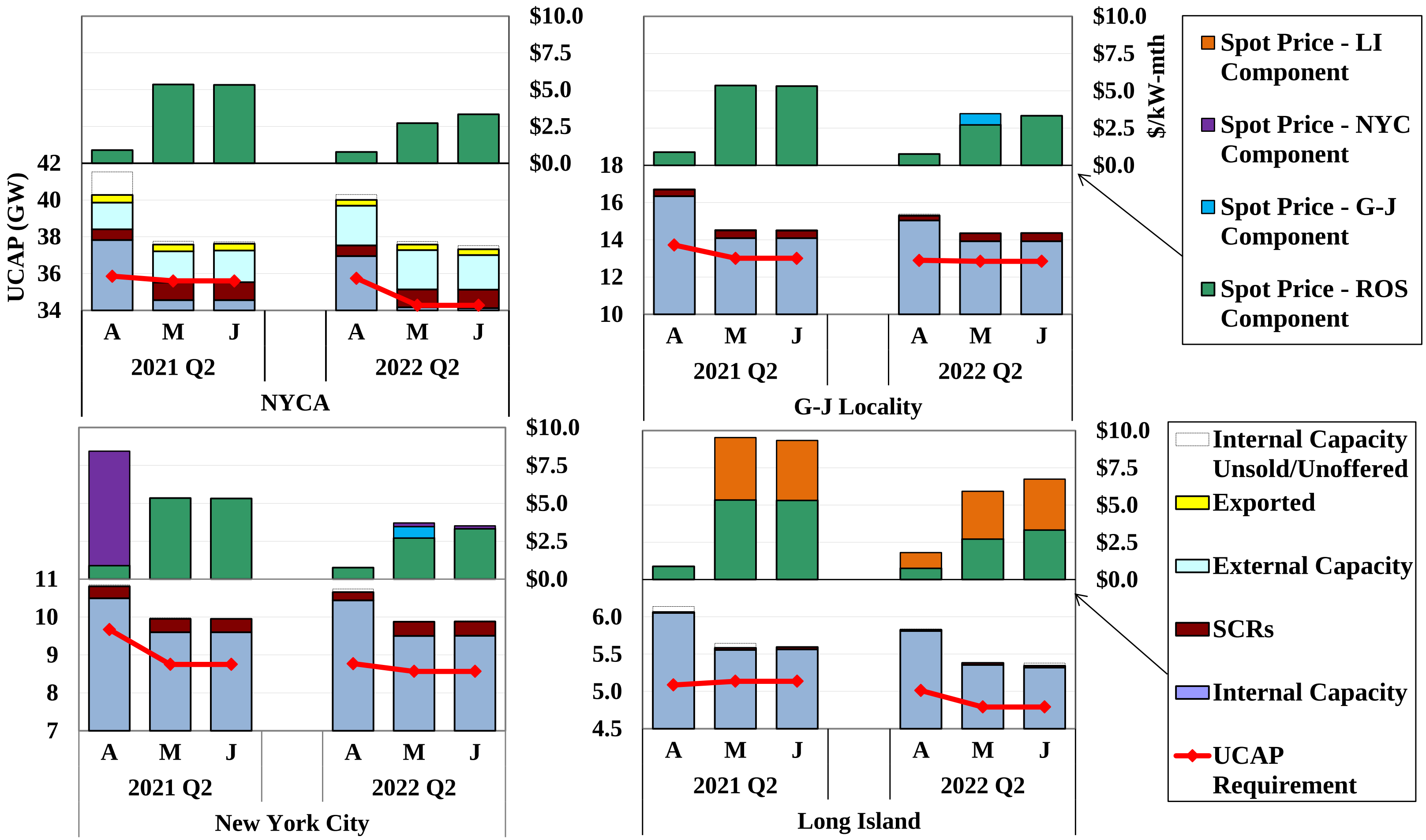


Notes: For chart description, see slide 108.

POTOMAC ECONOMICS

Charts:
Capacity Market

Spot Capacity Market Results
Monthly Results by Locality



Notes: For chart description, see slide 109.

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2022 Q2 ($/kW-Month)	$2.27	$2.66	$4.83	$2.52
% Change from 2021 Q2	**-41%**	**-58%**	**-27%**	**-35%**
Change in Demand				
Load Forecast (MW)	-566	-293	-111	-286
IRM/LCR	-1.1%	0.9%	-3.4%	1.6%
2022/23 Capability Year	*119.6%*	*81.2%*	*99.5%*	*89.2%*
2021/22 Capability Year	*120.7%*	*80.3%*	*102.9%*	*87.6%*
ICAP Requirement (MW)	**-1,033**	**-137**	**-289**	**-7**
Key Changes in ICAP Supply (MW)				
Generation	**-37**	**-27**	**-108**	**-328**
Entry (3)	0	6	0	6
Exit (3)	-480	-27	-33	-373
Other Capacity Changes (1)	443	-6	-75	39
Cleared Import (2)	**358**			

(1) Other changes include DMNC ratings, former exports, unsold capacity, etc.
(2) Based on average of quarterly cleared quantity.
(3) Includes change in sales from UDR line(s)

Notes: For chart description, see slide 109.

Appendix: Chart Descriptions

All-in Price

- Slide 20 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.

POTOMAC ECONOMICS

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.

Emission by Region

- Slides 26-30 evaluate emissions from generators in the NYISO market.
  - ✓ Slide 26 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_X, and SO_2 .
  - ✓ Slides 27-28 show quarterly emissions across the system by generation fuel type for CO_2 and NO_X .
    - – Emission values are given for 7 regions as well as the system as a whole.
    - – The emission tonnage is given by aggregating the total pollution from operations on the various fossil fuel types for each month of the quarter.
    - – The inset tables in each chart provides summary data on the total tonnage of emissions by fuel type for three recent quarters.
  - ✓ Slides 29-30 evaluate NO_X emission during the quarter in the non-attainment areas in New York City and Long Island, respectively, on a daily basis.
    - – The emission tonnage is shown separately for oil-fired units and gas-fired units in stacked bars, where gas-fired units are also grouped based on technology: (a) combined-cycle; (b) steam turbine; (c) gas turbines that were in service before 2000; and (d) gas turbines that were in service since 2000.
    - – The line in slide 29 shows the emission from STs in NYC that were supplementally committed for local reliability as a percent of total emission in NYC.

Emission Costs by Unit Type
Natural Gas Fired Resources

- Slide 23 shows estimates for the generation-weighted average hourly marginal costs of the two main emissions, CO_2 and NOx, by month for each of the following unit types firing on natural gas:
  - ✓ Combined cycles, Steam Turbines, and Peaking units.
- Emission cost estimates are calculated based on:
  - ✓ Daily price indexes for RGGI (CO_2) and CSAPR Group 3 (NOx) emissions allowances.
  - ✓ CO_2 emission coefficient of 118 Lb/MMBtu for natural gas.
  - ✓ Generation-weighted average hourly NOx emission rates for each unit type based on actual operations during June 2022 from EPA CEMS data.
  - ✓ Heat rate assumptions of 7.5 MMBtu/MWh for combined cycles, 11 MMBtu/MWh for steam turbines, 9.4 MMBtu/MWh for Peakers (post-2000), and 13.25 MMBtu/MWh for Peakers (pre-2000).
- Actual unit-specific emission rates and associated costs may vary substantially for each individual unit based on factors like (a) heat rate efficiency, (b) level of emission control technology at the plant, and (c) typical output factor during operations, etc.

POTOMAC ECONOMICS

Ancillary Services Prices

- Slides 35-39 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 8 per MW of capability, but they are compensated according to actual movement.
    - – Real-time Regulation Movement Charges shown on Slide 38 are estimated by dividing total movement charges by real-time scheduled regulation capacity.
  - ✓ 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.

POTOMAC ECONOMICS

Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 40 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).

Regulation Market Requirements and Prices

- Slide 42 displays several aspects pertaining to the regulation requirements, prices, and relationship between scheduled regulation capacity and actual regulation movement in the past 36-month period.
- The topmost chart displays information relevant to the regulation requirement and the regulation movement-to-capacity ratio.
  - ✓ The blue column bars show the average monthly regulation requirement.
  - ✓ The secondary y-axis shows the average movement-to-capacity ratio for each month.
- The bottom chart shows the average monthly prices.
  - ✓ The columns show the average monthly regulation capacity prices in the day-ahead market.
  - ✓ The two lines show the real-time capacity prices and movement prices.

Day-Ahead Load Scheduling and Virtual Trading

- Slide 44 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 45 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 46 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 48 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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RTC and RTD Price Difference vs Load Forecast Difference

- Slide 49 summarizes the RTC/RTD divergence metric results for detrimental factors in the second quarter of 2022.
  - ✓ See Section IV.D and Figure A-79 in the Appendix of our SOM 2021 report for detailed descriptions of the metric and chart.
- Slide 50 shows a histogram of the differences in systemwide load forecasts (including load biases by operators) between RTC and RTD at the quarter-hour intervals (i.e., at :00, :15, :30, :45) in the second quarter of 2022.
  - ✓ For each tranche of the histogram, the figure summarizes the accuracy of the RTC price by showing:
    - – The average of the RTC LBMP minus the RTD LBMP;
    - – The median of the RTC LBMP minus the RTD LBMP; and
    - – The mean absolute difference between the RTD and RTC LBMPs.
  - ✓ LBMPs are shown as zonal-load-weighted prices at the quarter-hour intervals for both RTC and RTD.

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RTC and RTD Price Difference vs Load Forecast Difference

- Slide 51 shows these pricing and load forecasting differences by time of day.
  - ✓ The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD load forecast levels in tranches.
  - ✓ The upper portion of the figure summarizes the accuracy of the RTC price forecast by showing:
    - the average RTC LBMP minus the average RTD LBMP; and
    - the mean absolute difference between the RTD and RTC LBMPs.

Real-Time System Price Maps at Generator Nodes

- Slides 53 and 54 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.

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Transmission Congestion and Shortfalls

- Slides 55, 56, 57, and 58 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 55 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 56 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 57 and 58 show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.

Transmission Congestion and Shortfalls (cont.)

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

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NY-NJ PAR Operation Under M2M with PJM

- Slide 48 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).

OOM Actions to Manage Network Reliability

- 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 60 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).
- In addition, the figure also reports the number of days when OOM commitments were made to satisfy N-1-1 reserve needs in several local load pockets.

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Constraints on the Low Voltage Network

- Slide 61 shows the number of hours and days in the quarter when various resources were used to manage 69 kV ("69 kV OOM") 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 69 kV and 138 kV constraints via the market model.
- Slide 61 also shows our estimated LBMP impacts in each LI load pocket that result from explicitly modeling 69 kV and TVR constraints in the market software.
  - ✓ The following generator locations are chosen to represent each load pocket:
    - Barrett ST for the Valley Stream pocket;
    - NYPA Brentwood GT for the Brentwood pocket;
    - Holtsville IC for the East of Northport pocket; and
    - Green Port GT for the East End pocket.

N-1 Constraints in New York City

- The NYISO sometimes operates a facility above its Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE.
  - ✓ The use of post-contingency actions is important because it allows the NYISO to increase flows into load centers and reduce congestion costs.
  - ✓ However, the service provided by these actions are not properly compensated.
- Slide 62 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.

Duct Burner RPU Performance and Real-Time Availability

- Slide 63 shows a case study of real-time performance of a combined-cycle unit that failed to follow 5-minute instructions during an RPU event due to its inability to fire the duct burner within 10-minutes.
  - ✓ The two lines show the levels where resource capacity shifts from baseload without duct burners (gray line) to the duct burner range (red line). Capacity values are not given for confidentiality purposes.
  - ✓ The blue columns show the actual output produced by the resource in each RTD and RTD-CAM interval. The black dotted line shows the 5-minute instructions by the market model.
  - ✓ A faded box highlights the RPU timeframe and the red-patterned area between the columns and the instructed output line outlines the duct burner output that was not delivered by the station.
- Slide 64 shows quarterly average real-time duct burner data across all applicable units during this quarter on an hourly basis.
  - ✓ The two charts on the left side show the amount of duct burner capacity scheduled or made available for scheduling within the timeframes that are unlikely deliverable for energy and reserves. These values show: (a) the average amount of MWs scheduled to provide 10-minute spinning reserves and regulation services; and (b) the amount of 5-minute up-ramping capability assumed to be available by duct burners.
  - ✓ The two charts on the right side show capacity that was not made available in offers for either energy and/or reserves from units with duct burners, including: (a) the average amount of duct burner capacity unavailable in real-time because of no offer in this range or non-dispatchable due to inflexible self-schedule level; and (b) the average amount of baseload capacity that was available but not offered for reserves in real-time because the units were disqualified from offering reserves.

POTOMAC ECONOMICS

GT Start-up Performance

- Slides 65-66 show the results of the NYISO's auditing process for 10- and 30-minute GTs in the past 12-month period, compared to performance measured for economic GT starts by the market model (including starts by RTC, RTD, and RTD-CAM) in the same period. In each table,
  - ✓ 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.
  - ✓ The rows show the number of units with an average performance in the quarter that falls in each performance range from 0 to 100% with a 10% increment.
    - The left hand side of the table shows these numbers based on performance measured during economic starts;
    - While the right hand side of the table shows numbers based on audit results.
    - The units that are in service but were never started by RTC, RTD, or RTD-CAM in the examined period are placed in a separate category of "Not Evaluated", which also includes units that we could not assess their performance reliably because of data issues.
  - ✓ An example read of the table (slide 65): "26 10-minute GTs exhibited a response rate of 90 to 100 percent during economic starts in the examined period, 26 of them were audited 56 times in total with 2 failures".

Supplemental Commitments and OOM Dispatch

- Slides 68, 69, and 70 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 68 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 69 examines the reasons for reliability commitments in NYC where most reliability commitments occur.
  - ✓ Based on a review of operator logs and LRR constraint information (where a unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity), each NYC commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:

Supplemental Commitments and OOM Dispatch (cont.)

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

- Slide 70 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.

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 71 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 were not needed to satisfy any N-1-1 criteria in the load pocket.

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Uplift Costs from Guarantee Payments

- Slides 72 and 73 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 72 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 73 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 75 and 76 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 77 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 79 and 80 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 79 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 80 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 2021 to 2025.