

Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2023

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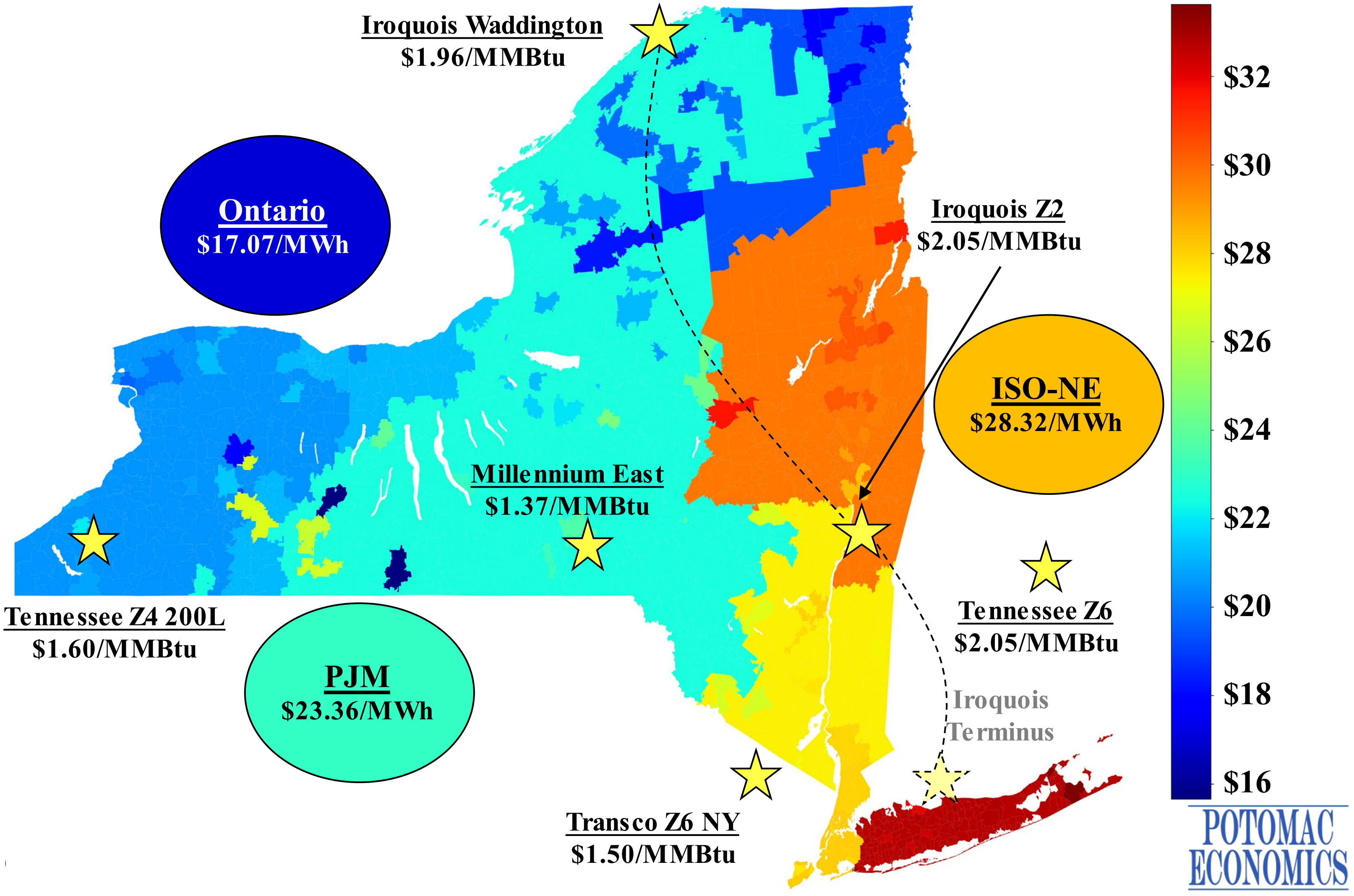
Table of Contents

Market Highlights

Market Highlights: Executive Summary

- NYISO energy markets performed competitively in the second quarter of 2023.
- All-in prices ranged from $27 in the North Zone to $56 per MWh in New York City, down 19 to 58 percent from 2022-Q2 in individual regions. (slide 6)
  - ✓ Energy prices fell by 35 to 65 percent across the system primarily because of lower gas prices (down 70 to 76 percent). (slide 17) Other contributing factors include:
    - Fewer planned transmission outages, especially along the Central East interface.
    - Lower load conditions which fell by 5 percent on average (15 percent at the peak).
    - Lower emissions costs, particularly CSAPR NOx allowance prices.
  - ✓ Capacity costs increased considerably due to the retirement of 850 MW of downstate peakers since the summer of 2022. Capacity costs rose by: (slide 13)
    - 68 to 77 percent in upstate zones,
    - 51 percent in Hudson Valley, and
    - 292 percent in New York City.
- Transmission outages related to Public Policy Transmission Project Segments A and B were less frequent this year, contributing to a 76 percent reduction in congestion value along the Central East Interface. (slide 50)

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 2023.
  - ✓ The amount of output gap (slide 69) and unoffered economic capacity (slide 70) remained reasonably consistent with competitive market expectations.
  - ✓ Although the AMP software did not function properly for most of the quarter, this had virtually no impact on market outcomes due to low levels of NYC congestion.
- All-in prices ranged from $27/MWh in the North Zone to $56/MWh in New York City, falling 19 to 58 percent from last year across all zones. (slide 15)
  - ✓ Energy costs fell dramatically (35 to 61 percent) across the system. (slides 25-26)
    - – Lower natural gas prices were the main driver, having fallen by 70 to 76 percent from a year ago. (slide 17)
    - – Other contributing factors include:
      - Fewer planned major transmission outages—Last year, Public Policy Transmission Project-related outages led to higher-than-average congestion across the Central-East interface and further elevated prices in East NY. (slide 51)
      - Lower load conditions, with average load falling 5 percent. (slide 16)
  - ✓ However, capacity costs rose substantially in all areas outside of Long Island due primarily to the peaker retirements as discussed in slide 13.

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Market Highlights:
Generation by Fuel and Emissions

- Average internal generation fell by ~1.1 GW from last year while average net imports from external control areas rose by ~250 MW. (slides 18 and 41)
  - ✓ Most of the reduction was associated with gas-fired generation (750 MW), nuclear generation (220 MW), and hydro generation (100 MW). (slide 18)
  - ✓ Gas-fired combined cycle output fell by an average of 530 MW.
    - – Increased flows across the Central East interface drove down production by Capital Zone CCs.
    - – In other zones, output from combined cycles rose or fell consistent with relative gas prices. Output in the Central Zone and New York City rose (250 MW combined), while Hudson Valley output fell (160 MW) because of higher gas prices.
- NOx Emissions from steam turbines in New York City fell 37 percent from the same quarter of the previous year.
  - ✓ Roughly 20 percent of Steam turbine NOx emissions were from STs that were supplementally committed for local reliability. (slide 23)
  - ✓ The elimination of the NOx Bubble commitment requirements in the DAM resulted in at least 27 days where one or more steam turbine supplemental commitments were avoided and is estimated to have resulted in 48k tons of reduced CO_2 emissions.

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Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $52 million, down 76 percent from the second quarter of 2022. (slide 49)
  - ✓ This represents the lowest congestion value for the second quarter since 2014 and was 55 percent lower than the most recent 5-year average value.
- The Central-East interface accounted for the largest share ($33 million or 65 percent) of day-ahead congestion revenues this quarter. (slide 50)
  - ✓ This fell because of fewer significant transmission outages and lower gas prices.
- Congestion from West-to-Central Zones accounted for the second highest share ($5.7 million or 11 percent) of the total day-ahead congestion revenues.
  - ✓ Most of this congestion accrued on bottlenecks limiting west-to-east flows along the Southern Tier of Central New York.
- New York City congestion was very low with day-ahead values totaling just $0.6 million (1 percent).
  - ✓ As the NYISO reported in early July, a software issue caused the Automated Mitigation Process to not function for most of this quarter.
  - ✓ However, the absence of significant congestion in NYC limited the potential impact of this market issue (also making it more difficult to detect).

Market Highlights:
Load Forecast Errors and 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 2023. (slide 43)
  - ✓ Load forecasting errors accounted for 18 percent of the overall divergence between RTC and RTD prices this quarter.
    - – On average, RTC load was higher than RTD load by roughly 65 MW, contributing to higher RTC LBMPs (than RTD LBMPs by an average of $0.46/MWh). (slide 44)
      - This is an improvement from a year ago when RTC load was higher by approximately 100 MW.
    - – Upward adjustments to the RTC load forecast are frequently made to offset the risk of over-forecasting BTM solar generation. (slide 45)
    - – Although load forecast adjustments may be justified, they contribute to divergences between RTC and RTD prices and inefficient scheduling. Therefore, it would be beneficial to enhance the BTM solar forecast and to evaluate the procedure for determining load forecast adjustments in RTC for potential improvements.

Market Highlights:
OOM Actions to Manage Network Reliability

- OOM actions to manage network reliability were frequent in some regions this quarter - North Zone (23 days), Long Island (15 days), and the Central Zone (14 days). (slide 54)
- OOM actions in the North Zone rose this quarter.
  - ✓ Most of these OOM actions were to manage flows on a Moses-Alcoa 115kV line.
- Supplemental commitments to satisfy the N-1-1 requirements occurred on: (a) 15 days in the North Country load pocket; and (b) 77 days in New York City.
  - ✓ North Country N-1-1 supplemental commitments were largely driven by outages for the now-completed (June 2023) Smart Path transmission project.
  - ✓ 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 the North Country and Capital Zone.
- OOM actions for 69 kV congestion on Long Island occurred on ten days, which is a significant reduction from previous years. (slide 55)
  - ✓ Five 69kV facilities are now modeled in the DAM and RT market, reducing the use of OOM actions.

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $9 million, down 66 percent from 2022-Q2. Several factors contributed to the decline, including:
  - ✓ Lower load levels,
  - ✓ The elimination of NOx bubble requirements in the DAM software, (slide 64) and
  - ✓ Lower natural gas prices which reduced the production costs of thermal generators.
- $6.3 million (or 69 percent) of BPCG payments accrued in NYC, 91 percent of which were paid to units that were committed for local reliability. (slide 67)
  - ✓ CSAPR Group 3 NOx emission prices for gas-fired steam turbines fell 68 percent.
    - However, no steam turbine-owners requested the inclusion of CSAPR NOx costs in their units' reference levels in 2023-Q2, which likely reflects that the CSAPR program has an allowance allocation mechanism that largely offsets the costs of compliance under some conditions.
  - ✓ Over $4 million of BPCG accrued on just four days in mid-June for supplemental commitments during a local gas pipeline outage.
    - BPCG for these commitments was increased because certain dual fuel steam turbines require natural gas to ramp up incremental output. This required the units to operate at a higher output level on oil for an extended period.

Market Highlights:
Performance and Availability of Duct Burners

- Most CCs in the NYISO offer supplemental output from duct burners, totaling ~800 MW of summer capacity. This capacity is difficult to utilize due to inconsistencies between the market design and physical limitations of duct burners.
- Slide 57 shows an example of a CC 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 59 illustrates the difficulty of offering duct burner capacity given that response rates are not a biddable parameter. Response rates can only be modified through the registration process, which does not accommodate frequent updates.
- Slide 58 shows duct-firing capacity that was offered but not physically capable of providing a given service. During afternoon hours, on average: (a) 116 MW was offered but not capable of following 5-minute ramp instructions; (b) 155 MW was scheduled but not capable of providing 10-minute reserves; and (c) 15 MW was scheduled but not capable of providing regulation.
  - ✓ In addition, (a) 43 MW of duct-firing capacity was unavailable because this range was not offered; and (b) 87 MW of 10- and 30-minute reserves were not offered from baseload capacity (i.e., non-duct ranges) due to their inability to perform in the duct burner range.

Market Highlights:
Capacity Market

- Spot capacity prices averaged $12.75/kW-month in NYC and $4.17/kW-month elsewhere. (slides 73-74)
  - ✓ Compared to a year ago, spot prices rose by 84 percent in ROS and the G-J Locality, rose by 380 percent in New York City, but fell by 14 percent in Long Island.
- The large increase in NYC capacity prices resulted from:
  - ✓ The retirement of nearly 850 MW of peaking capacity since last summer.
  - ✓ The load forecast rose by 333 MW and LCR also rose 0.5 percent from last year.
- The ROS prices also rose, driven primarily by a higher ICAP requirement for the 2023/24 Capability Year and net reductions in supply.
  - ✓ The ICAP requirement rose by roughly 466 MW because:
    - Peak load forecast rose by 282 MW; and
    - The IRM rose from 119.6 to 120 percent.
  - ✓ Net supply fell by more than 1.2 GW due to the downstate peaker retirements and reduced net imports, especially from PJM.
- Long Island prices fell 14 percent despite a 5.7 percent increase in the LCR due to the addition of 142 MW net capacity.

Charts:
Market Outcomes

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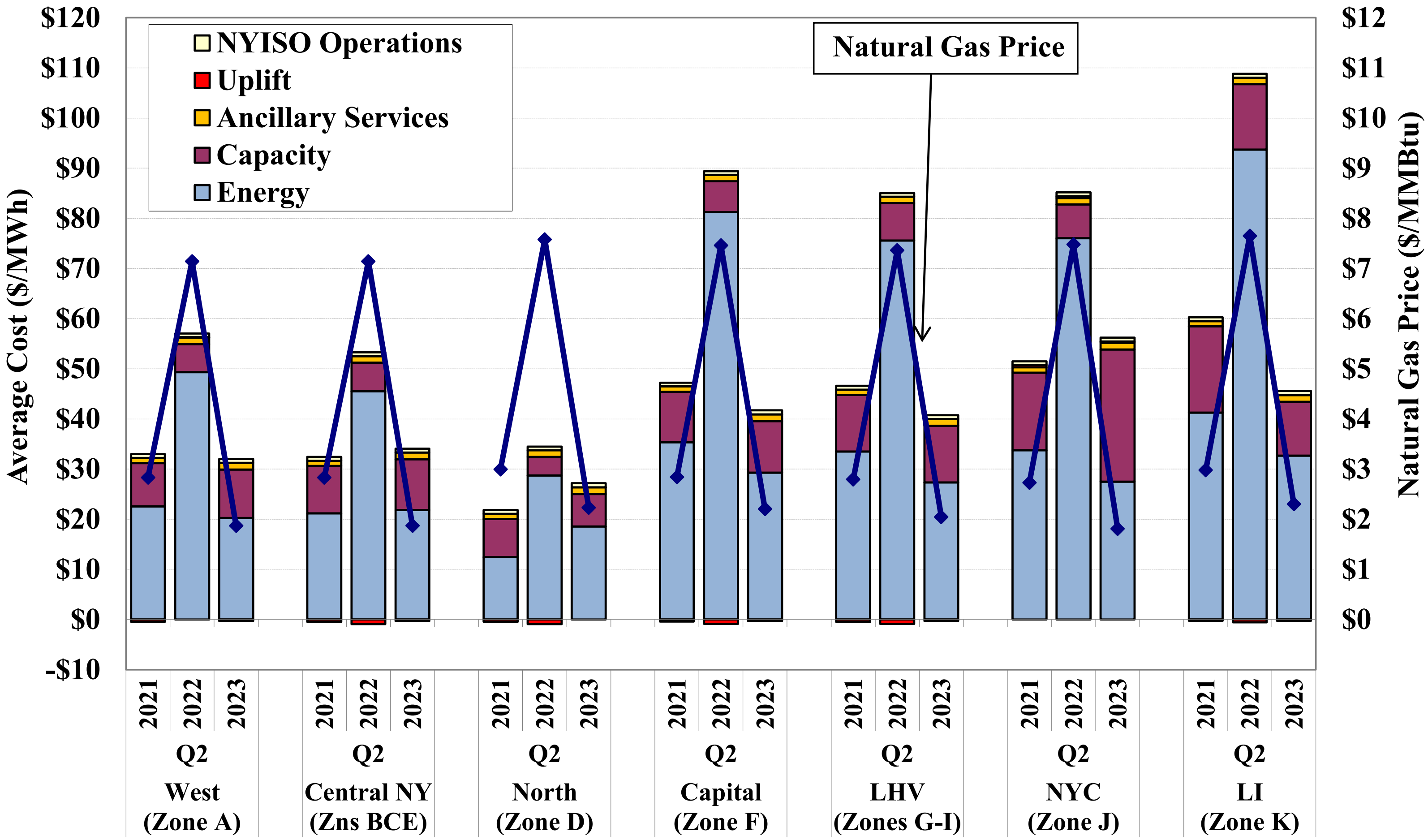
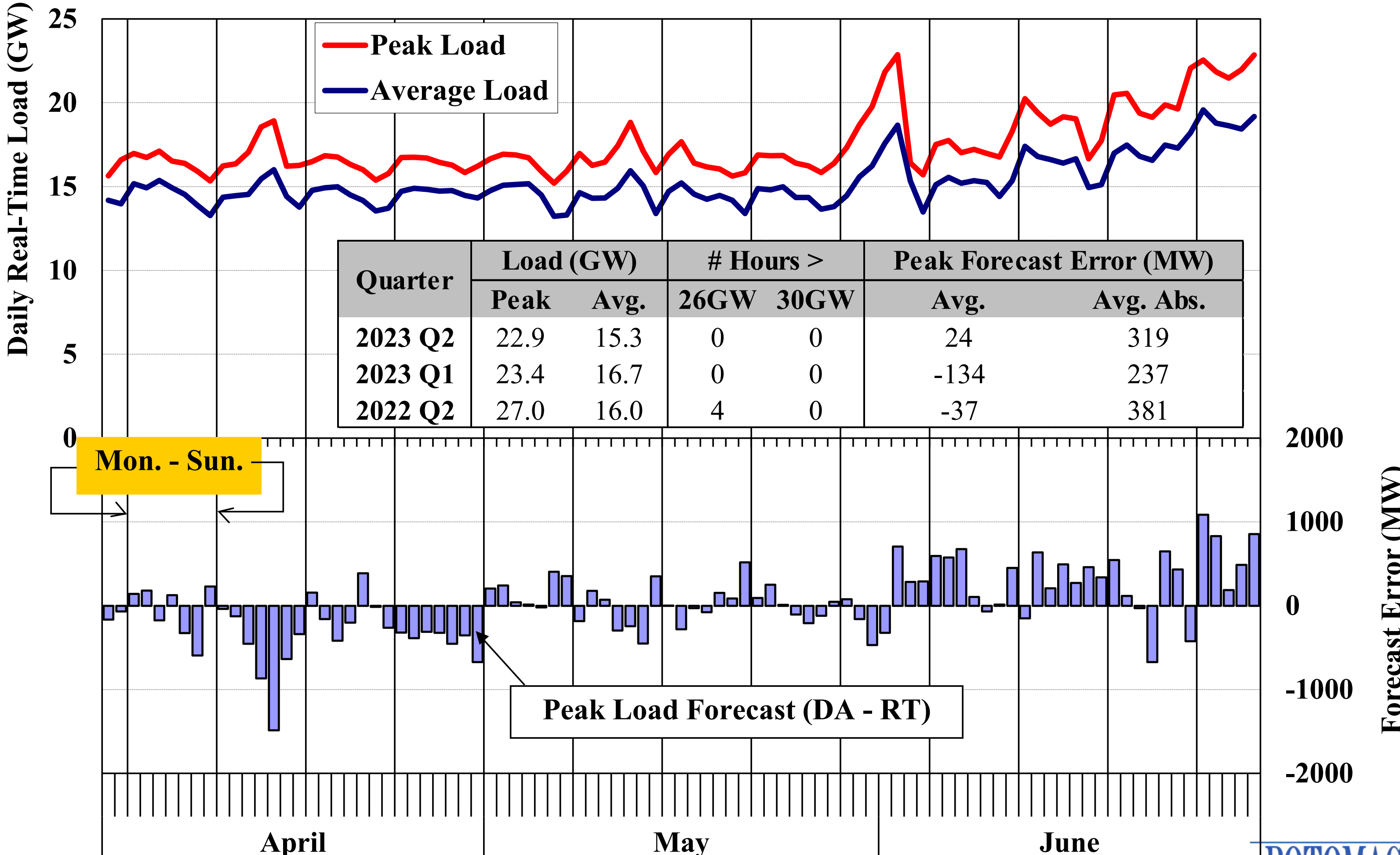
All-In Prices by Region



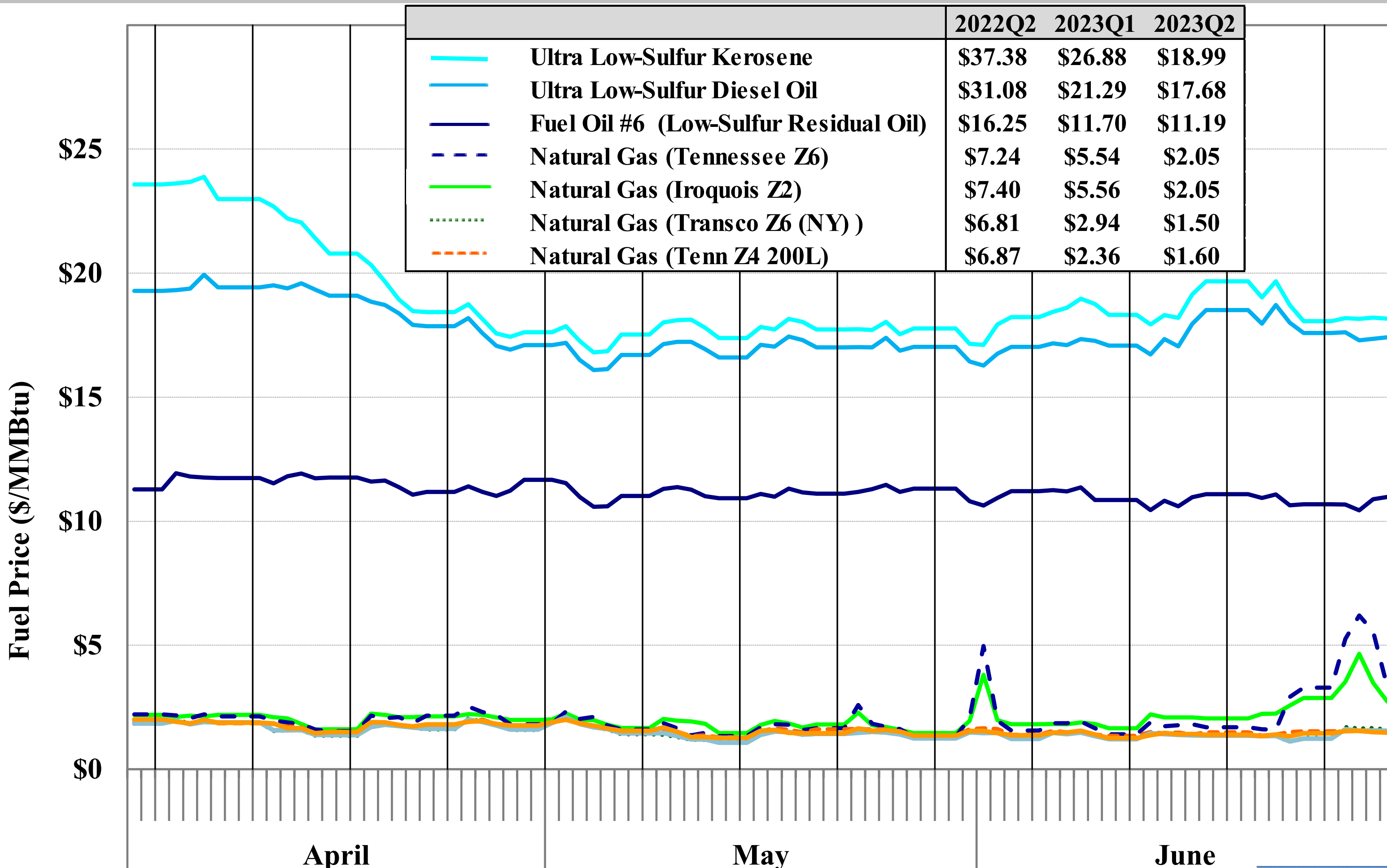
Notes: For chart description, see slide 76.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2023 Q2	22.9	15.3	0	0	24	319
2023 Q1	23.4	16.7	0	0	-134	237
2022 Q2	27.0	16.0	4	0	-37	381

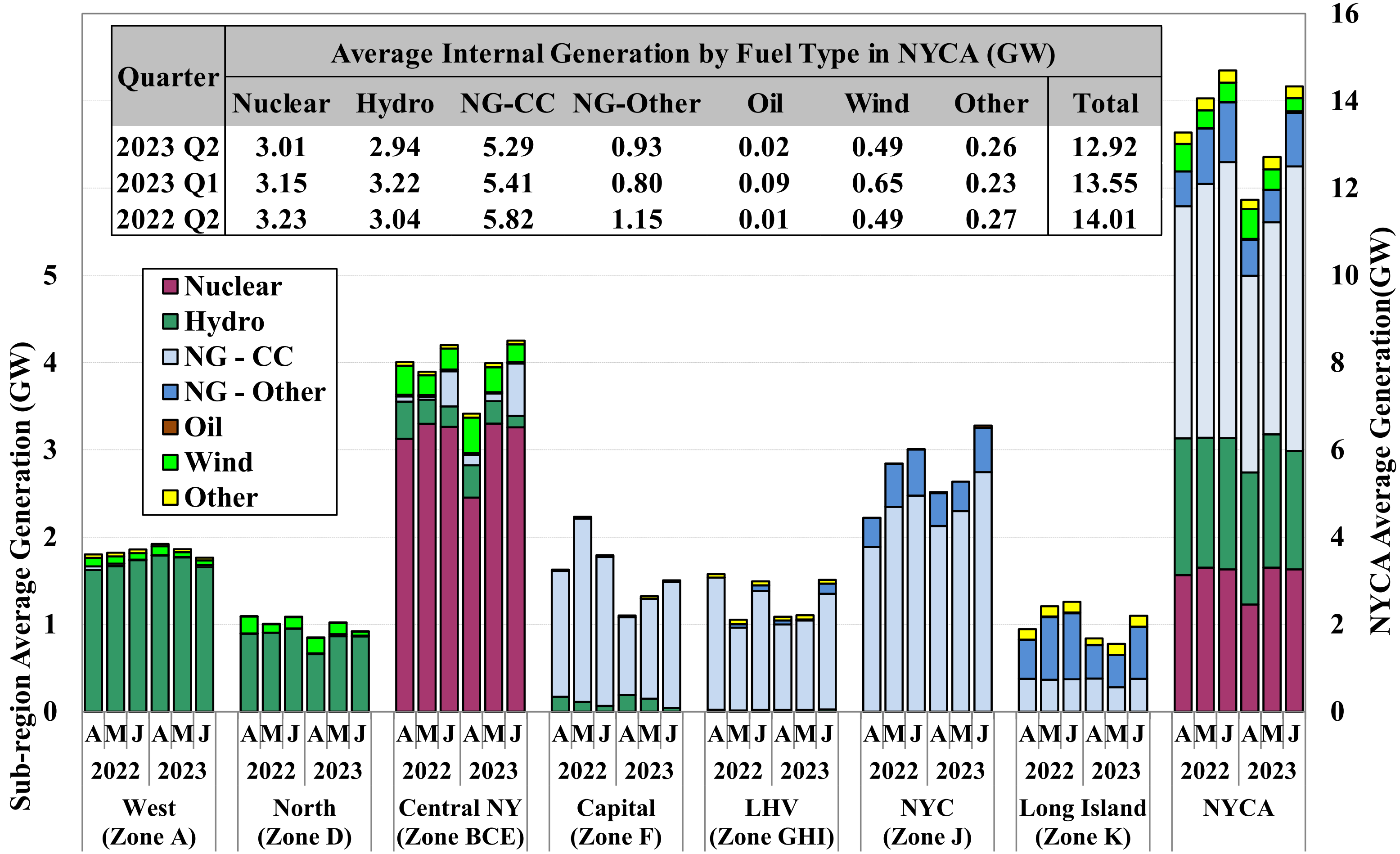
Natural Gas and Fuel Oil Prices



	2022Q2	2023Q1	2023Q2
Ultra Low-Sulfur Kerosene	$37.38	$26.88	$18.99
Ultra Low-Sulfur Diesel Oil	$31.08	$21.29	$17.68
Fuel Oil #6 (Low-Sulfur Residual Oil)	$16.25	$11.70	$11.19
Natural Gas (Tennessee Z6)	$7.24	$5.54	$2.05
Natural Gas (Iroquois Z2)	$7.40	$5.56	$2.05
Natural Gas (Transco Z6 (NY))	$6.81	$2.94	$1.50
Natural Gas (Tenn Z4 200L)	$6.87	$2.36	$1.60

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
2023 Q2	3.01	2.94	5.29	0.93	0.02	0.49	0.26	12.92
2023 Q1	3.15	3.22	5.41	0.80	0.09	0.65	0.23	13.55
2022 Q2	3.23	3.04	5.82	1.15	0.01	0.49	0.27	14.01



Notes: For chart description, see slide 77.

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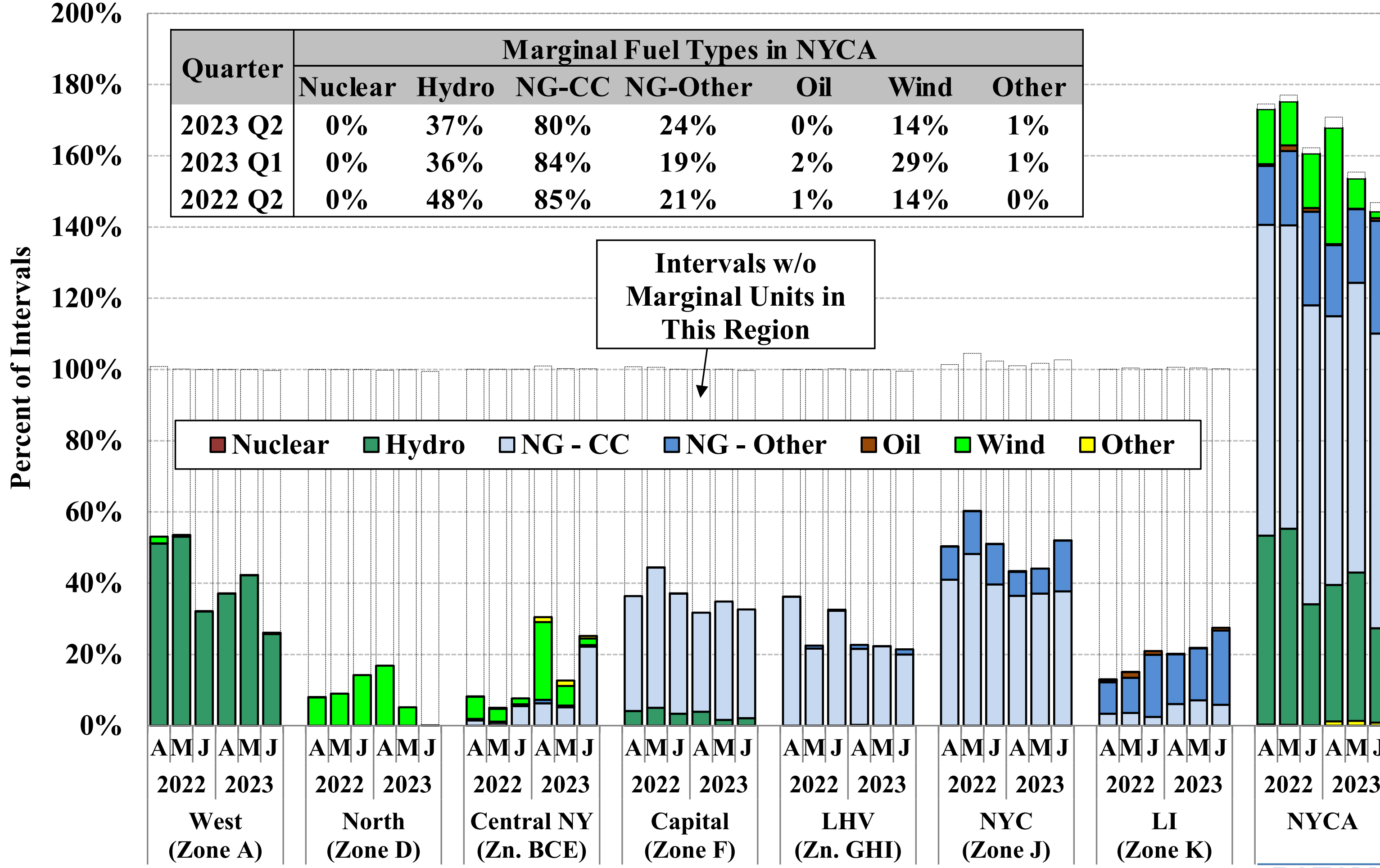
Fuel Type of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other
2023 Q2	0%	37%	80%	24%	0%	14%	1%
2023 Q1	0%	36%	84%	19%	2%	29%	1%
2022 Q2	0%	48%	85%	21%	1%	14%	0%



Notes: For chart description, see slide 77.

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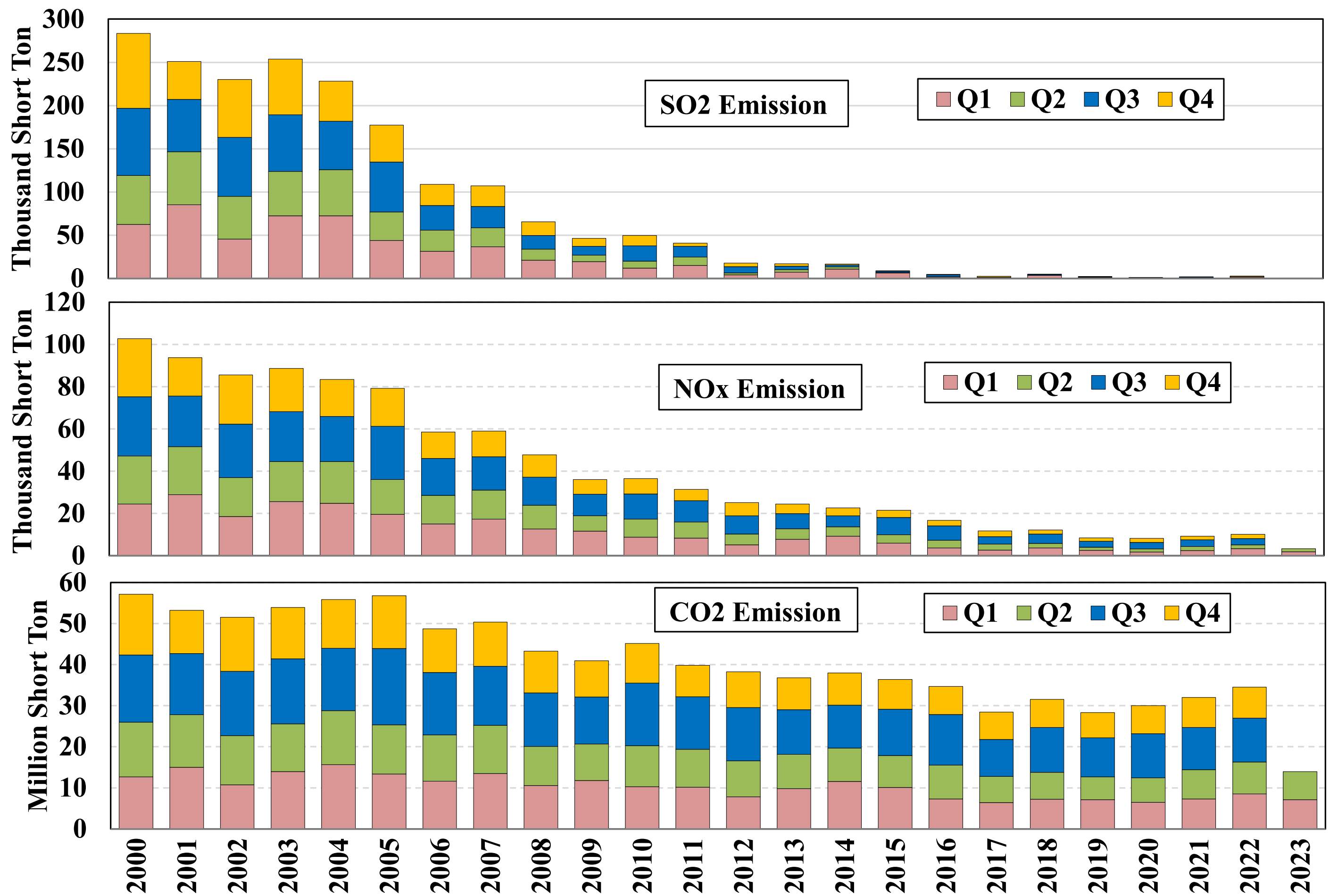
Historical Emissions by Quarter in NYCA
CO_2, SO_2 , and NO_X



Notes: For chart description, see slide 78.

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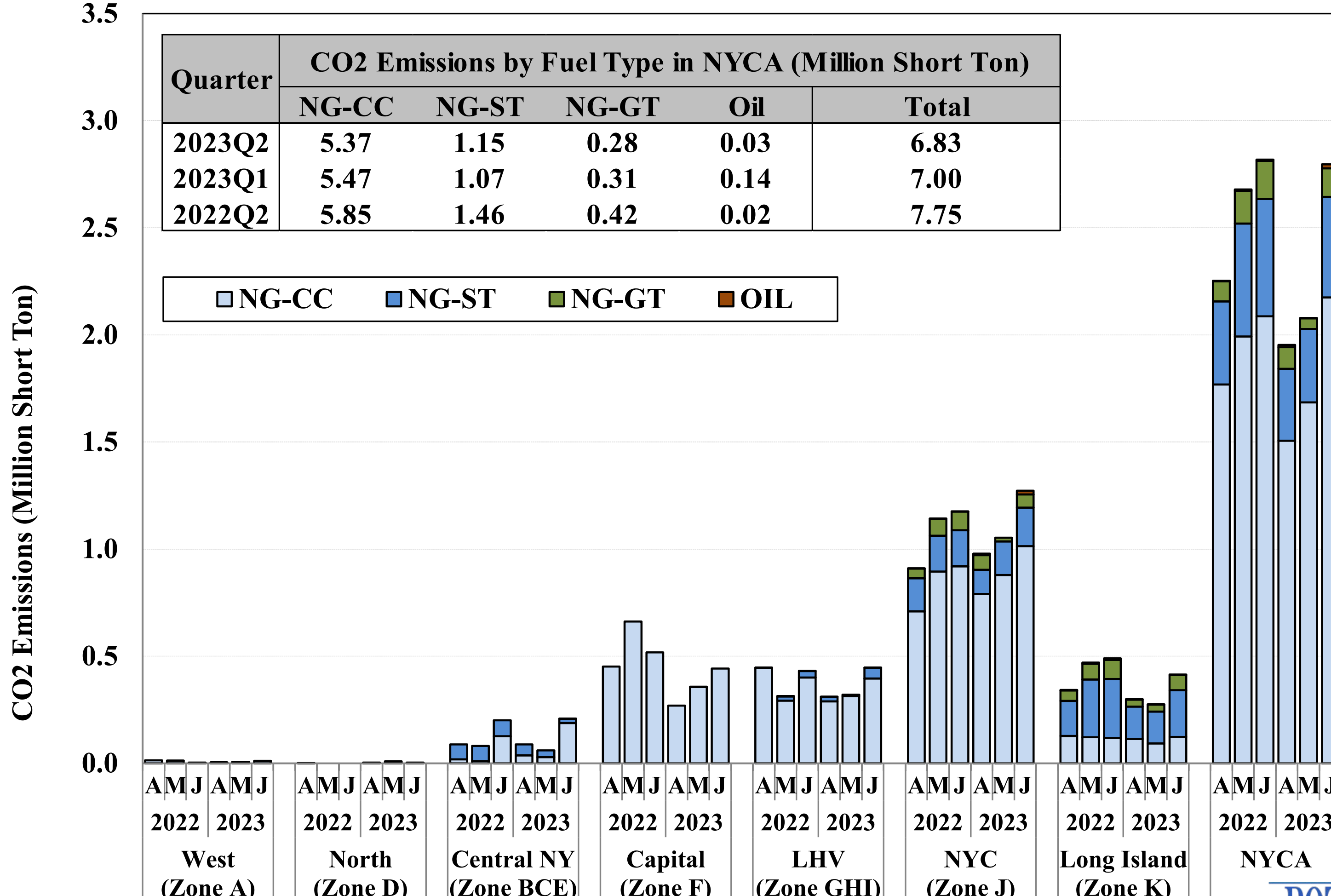
Emissions by Region by Fuel Type
CO_2 Emissions

Quarter	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)				
	NG-CC	NG-ST	NG-GT	Oil	Total
2023Q2	5.37	1.15	0.28	0.03	6.83
2023Q1	5.47	1.07	0.31	0.14	7.00
2022Q2	5.85	1.46	0.42	0.02	7.75



Notes: For chart description, see slide 78.

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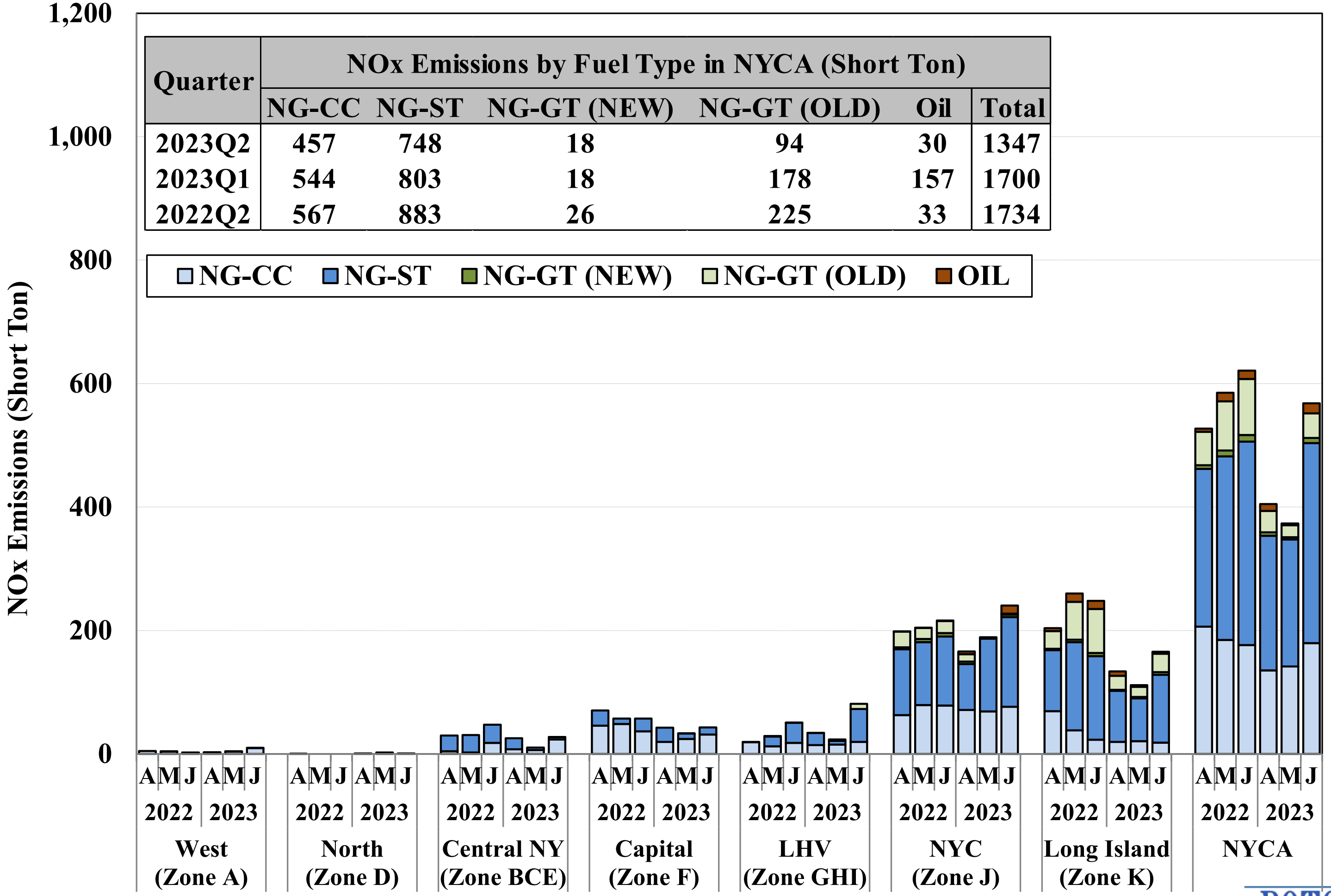
Emissions by Region by Fuel Type
NO_X Emissions

Quarter	NOx Emissions by Fuel Type in NYCA (Short Ton)					
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Total
2023Q2	457	748	18	94	30	1347
2023Q1	544	803	18	178	157	1700
2022Q2	567	883	26	225	33	1734



Notes: For chart description, see slide 78.

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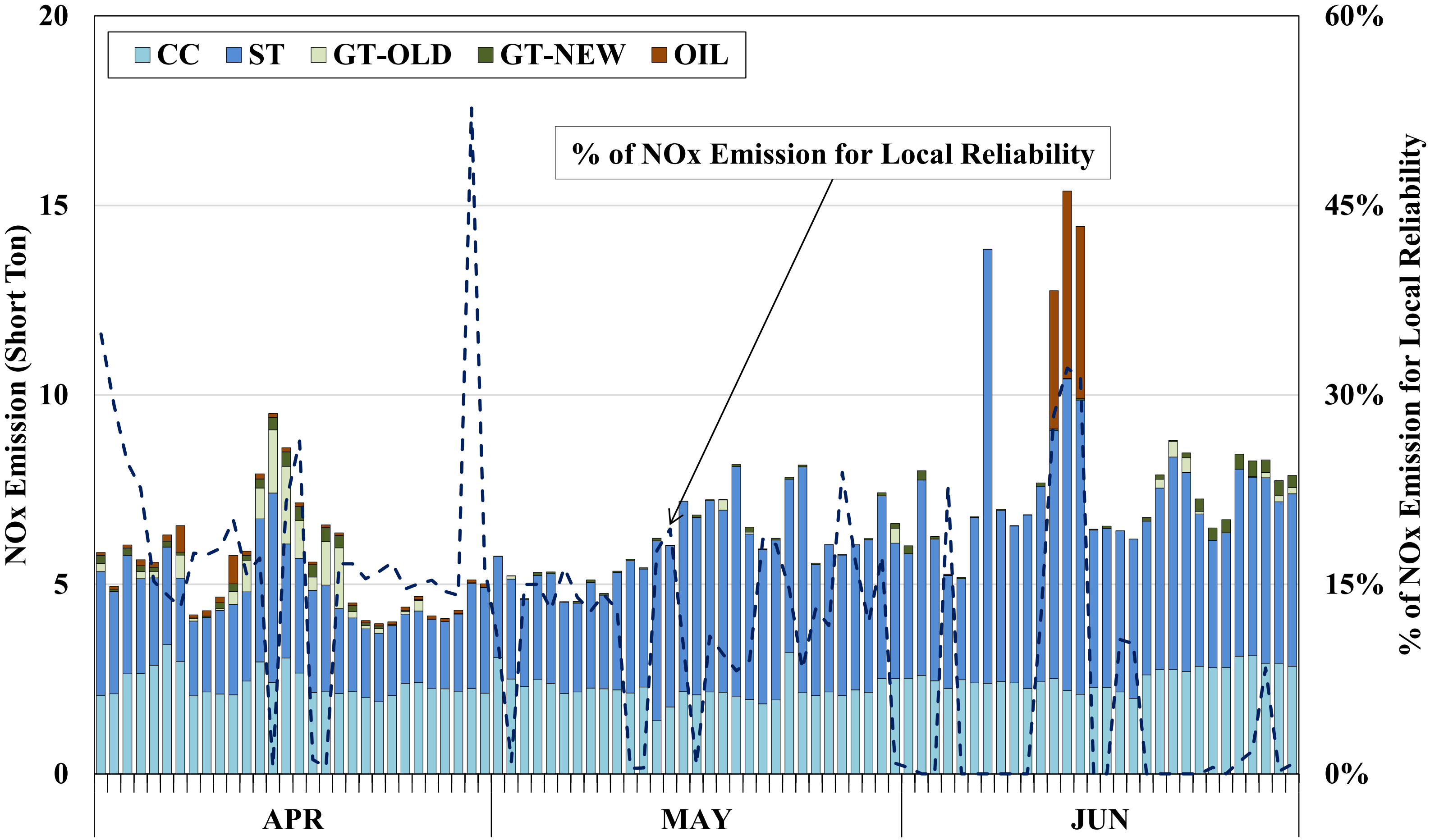
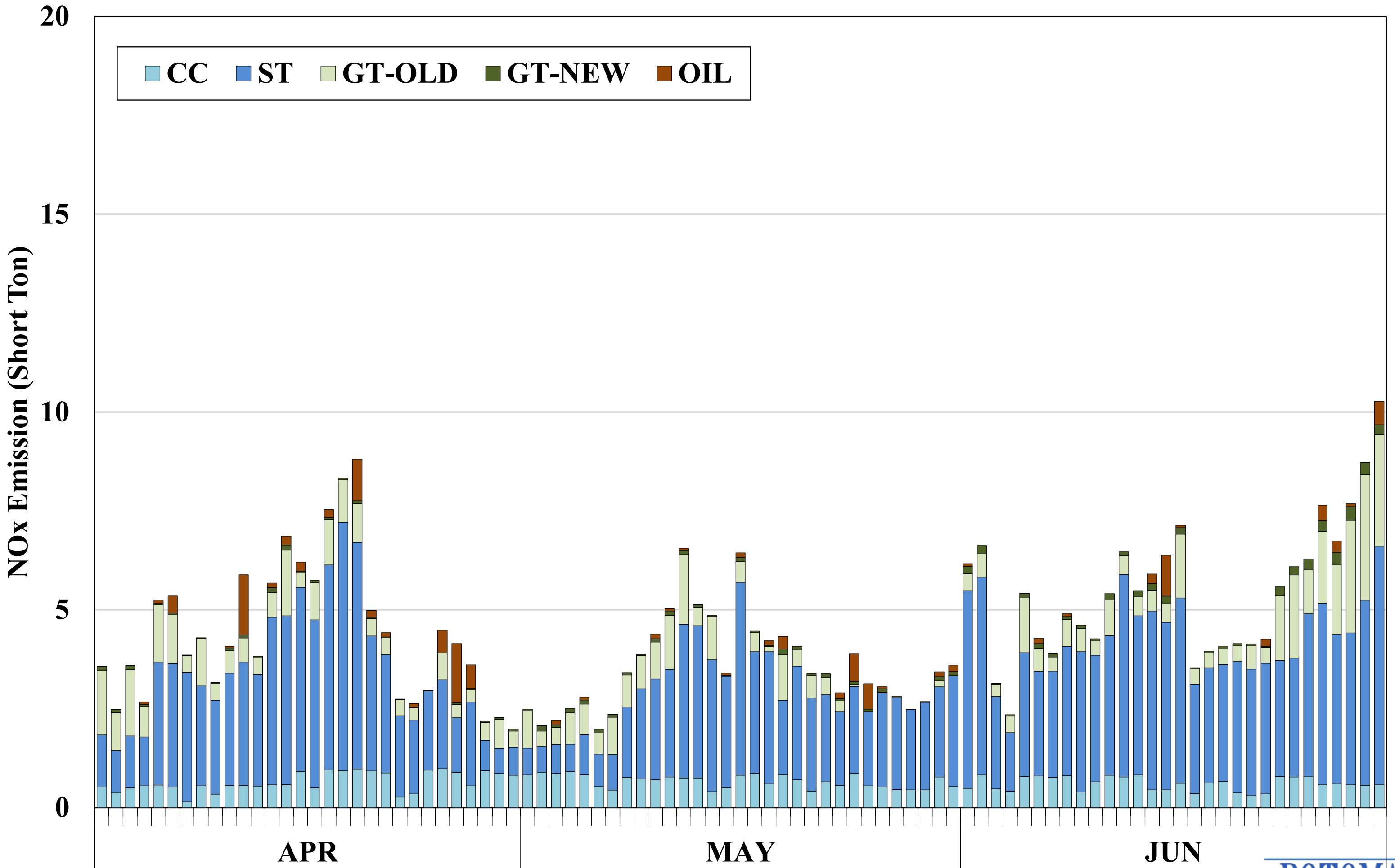
Daily NO_X Emissions in NYC



Notes: For chart description, see slide 78.

Daily NO_X Emissions in Long Island



Notes: For chart description, see slide 78.

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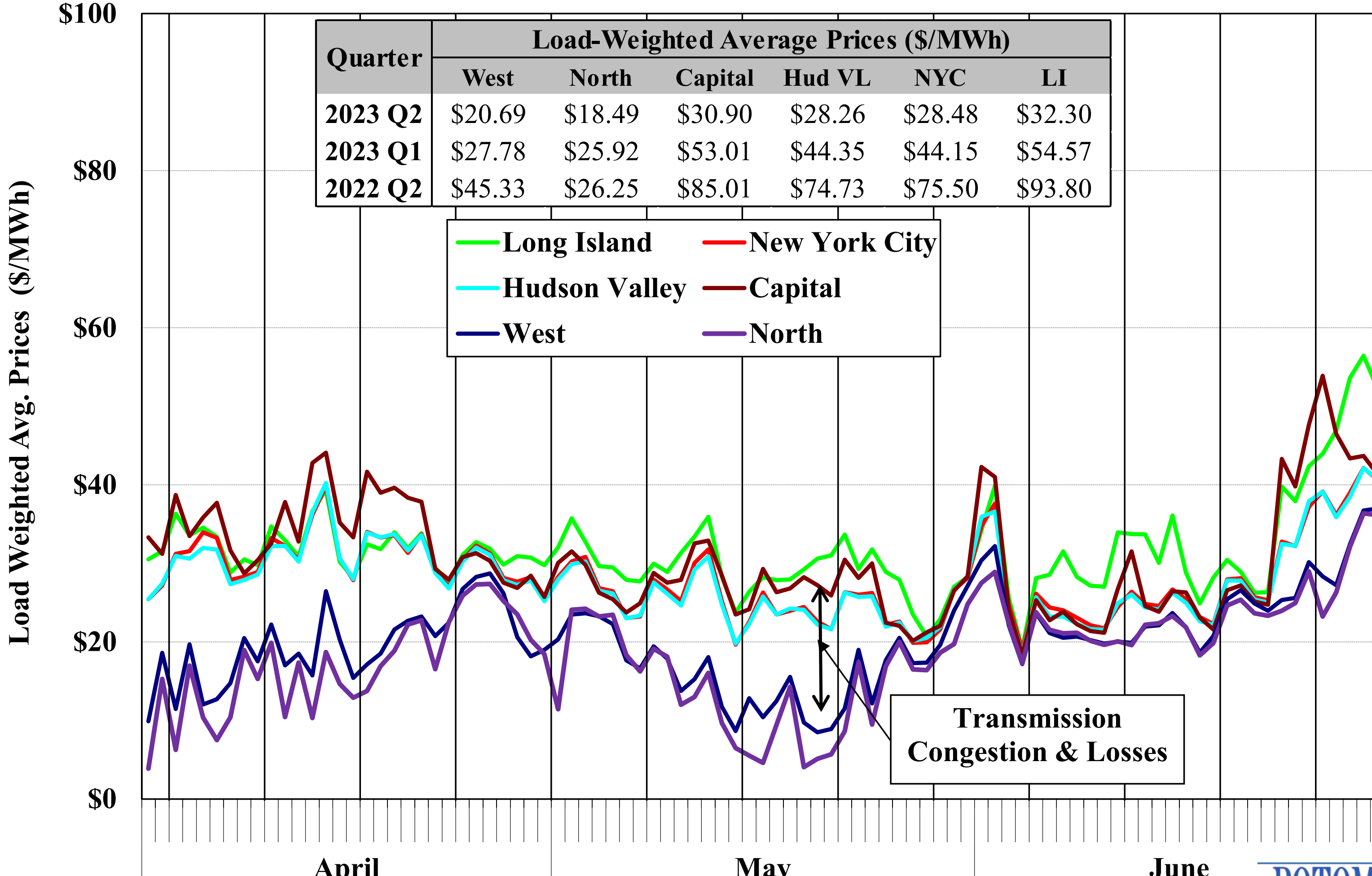
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2023 Q2	$20.69	$18.49	$30.90	$28.26	$28.48	$32.30
2023 Q1	$27.78	$25.92	$53.01	$44.35	$44.15	$54.57
2022 Q2	$45.33	$26.25	$85.01	$74.73	$75.50	$93.80

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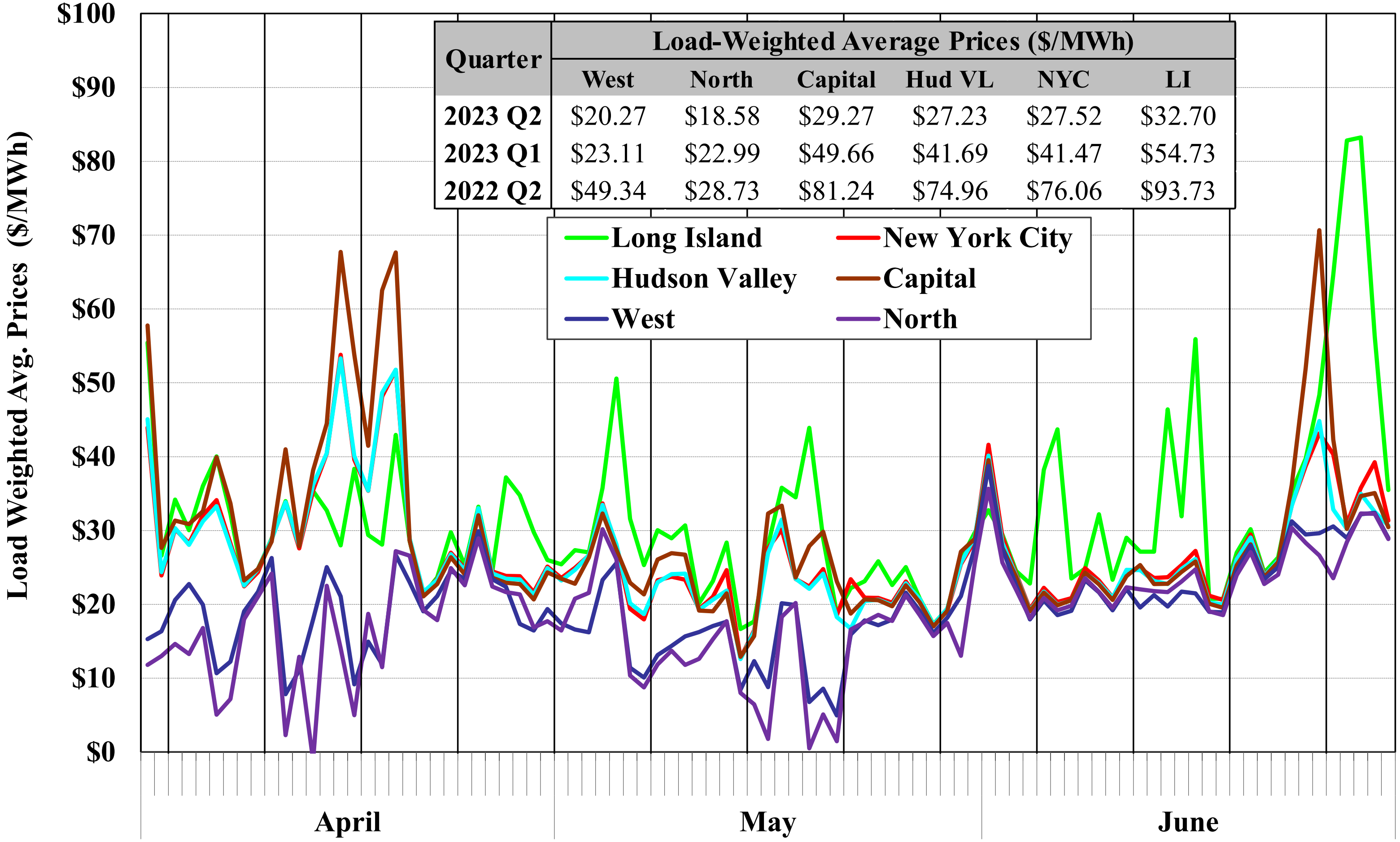
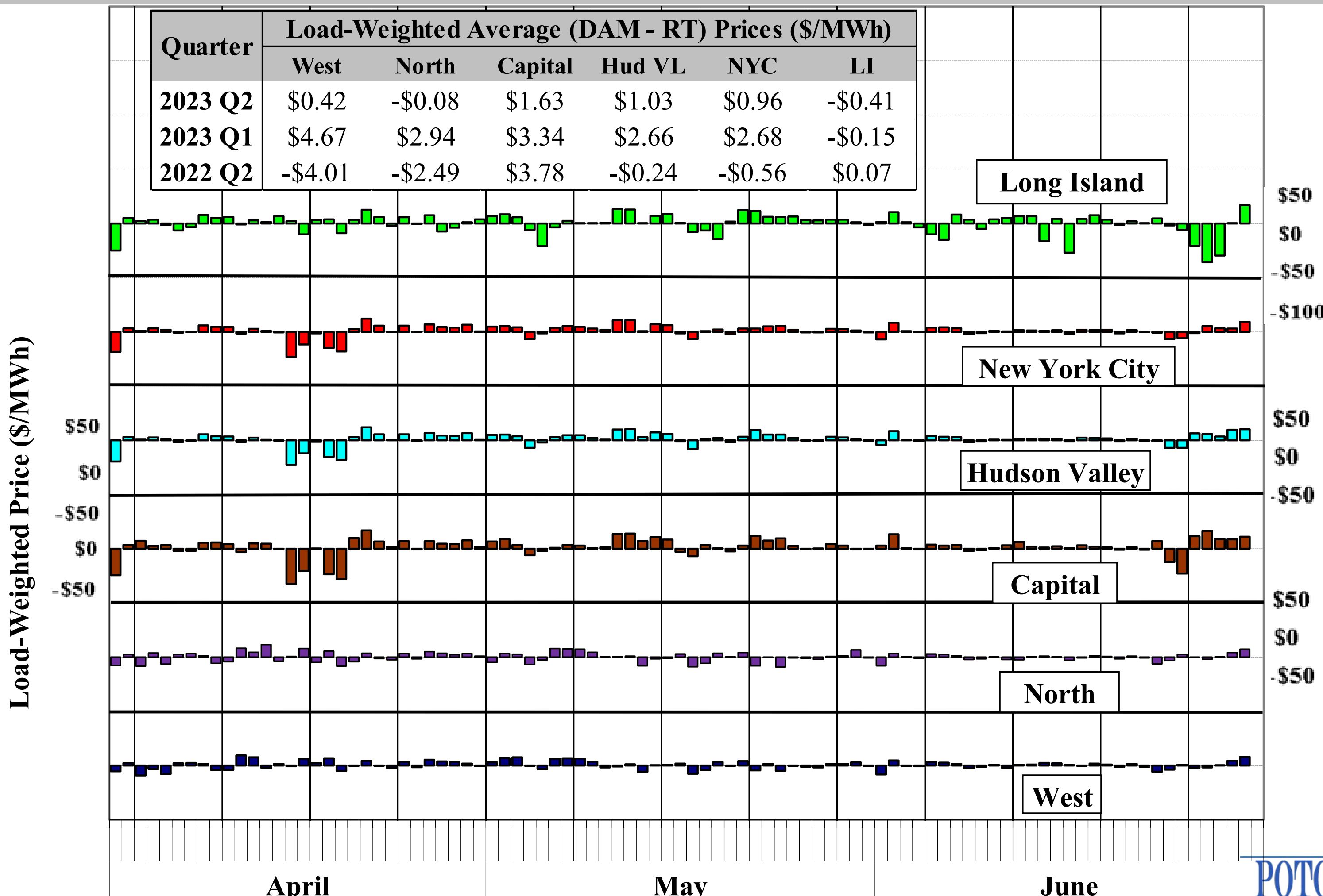
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2023 Q2	$20.27	$18.58	$29.27	$27.23	$27.52	$32.70
2023 Q1	$23.11	$22.99	$49.66	$41.69	$41.47	$54.73
2022 Q2	$49.34	$28.73	$81.24	$74.96	$76.06	$93.73

Convergence Between Day-Ahead and Real-Time Prices

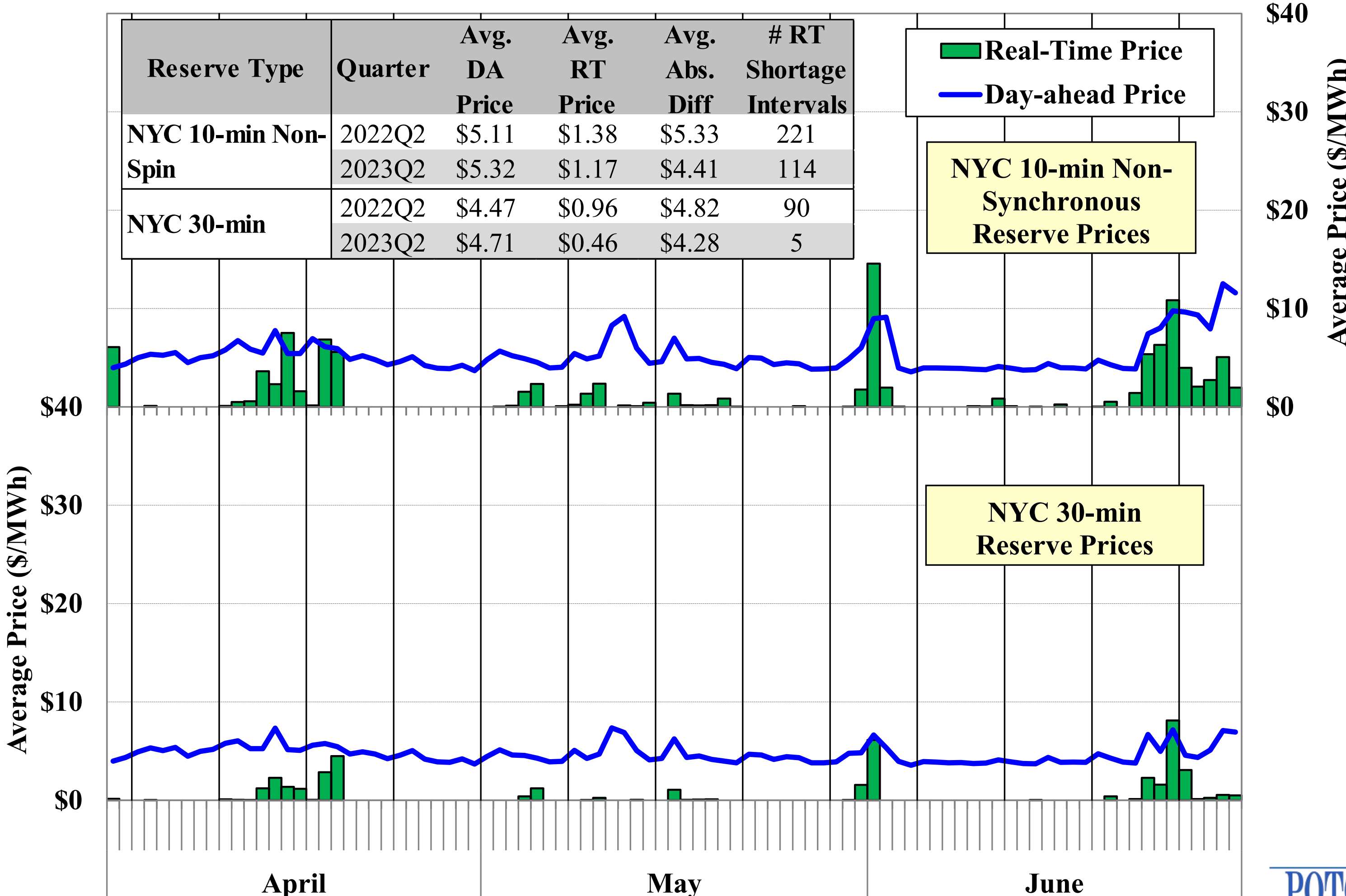
Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2023 Q2	$0.42	-$0.08	$1.63	$1.03	$0.96	-$0.41
2023 Q1	$4.67	$2.94	$3.34	$2.66	$2.68	-$0.15
2022 Q2	-$4.01	-$2.49	$3.78	-$0.24	-$0.56	$0.07



Charts:
Ancillary Services Market

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	2022Q2	$5.11	$1.38	$5.33	221
	2023Q2	$5.32	$1.17	$4.41	114
NYC 30-min	2022Q2	$4.47	$0.96	$4.82	90
	2023Q2	$4.71	$0.46	$4.28	5



  Notes: For chart description, see slide 79.

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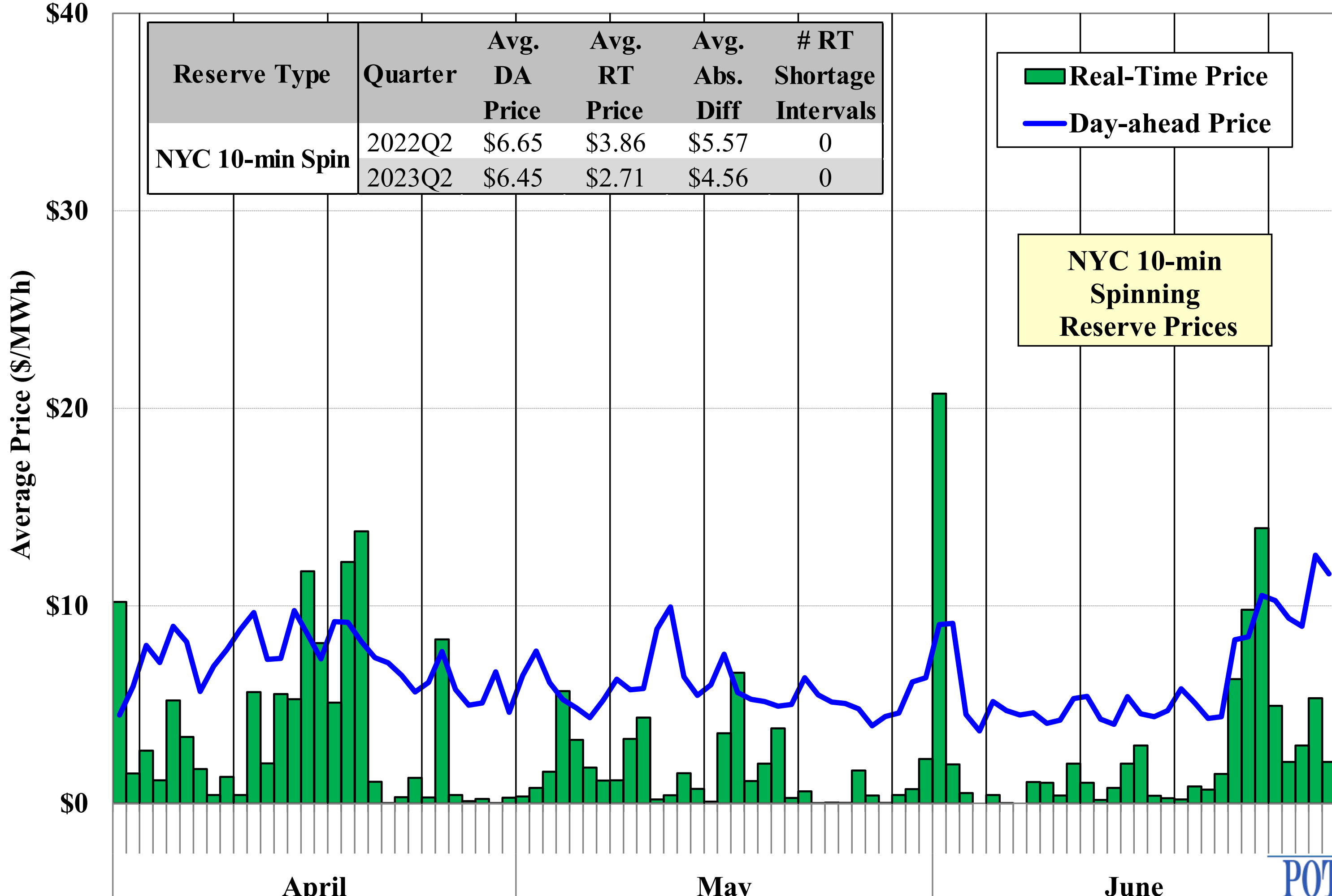
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2022Q2	$6.65	$3.86	$5.57	0
	2023Q2	$6.45	$2.71	$4.56	0

Notes: For chart description, see slide 79.

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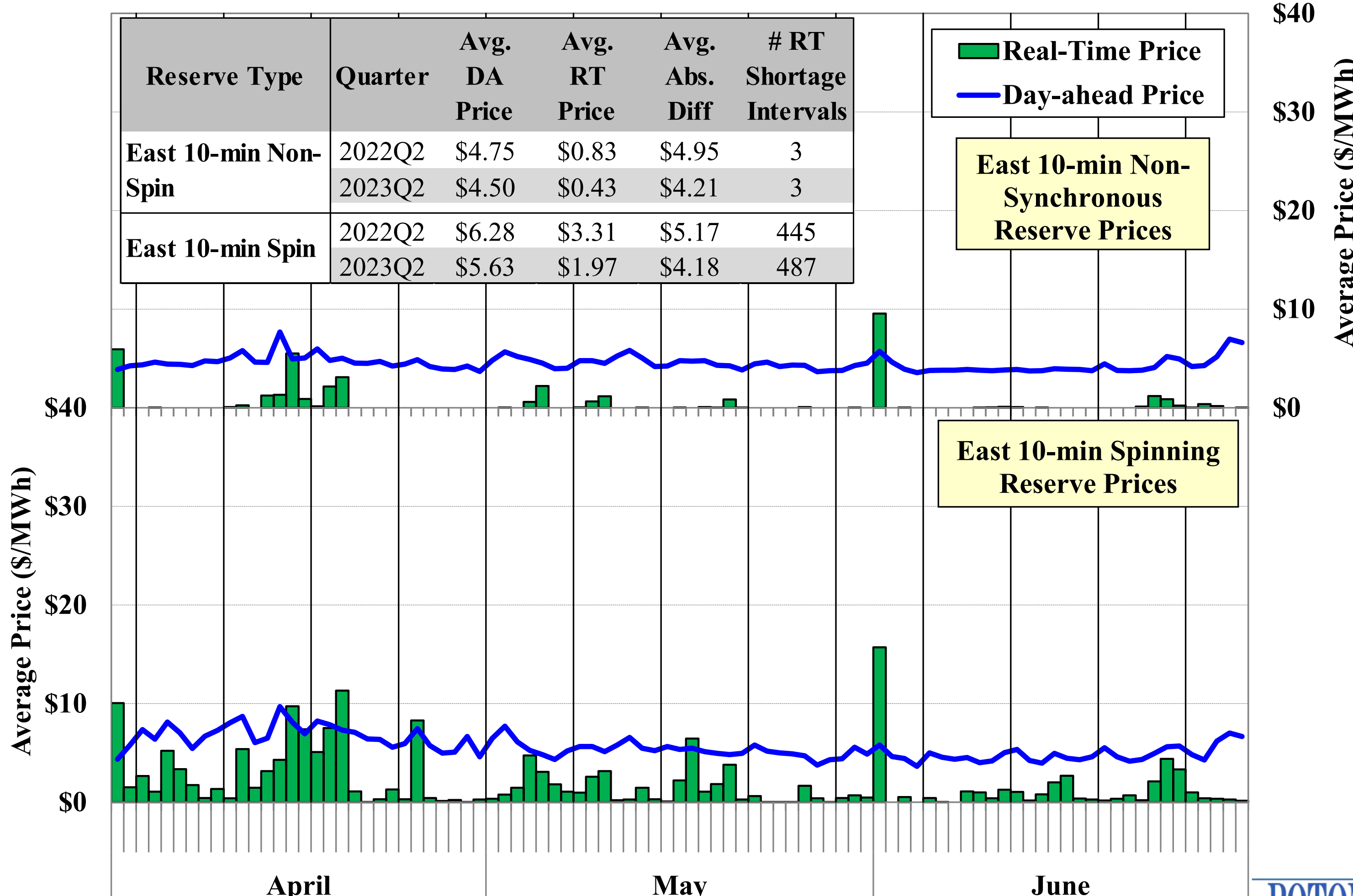
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2022Q2	$4.75	$0.83	$4.95	3
	2023Q2	$4.50	$0.43	$4.21	3
East 10-min Spin	2022Q2	$6.28	$3.31	$5.17	445
	2023Q2	$5.63	$1.97	$4.18	487

Notes: For chart description, see slide 79.

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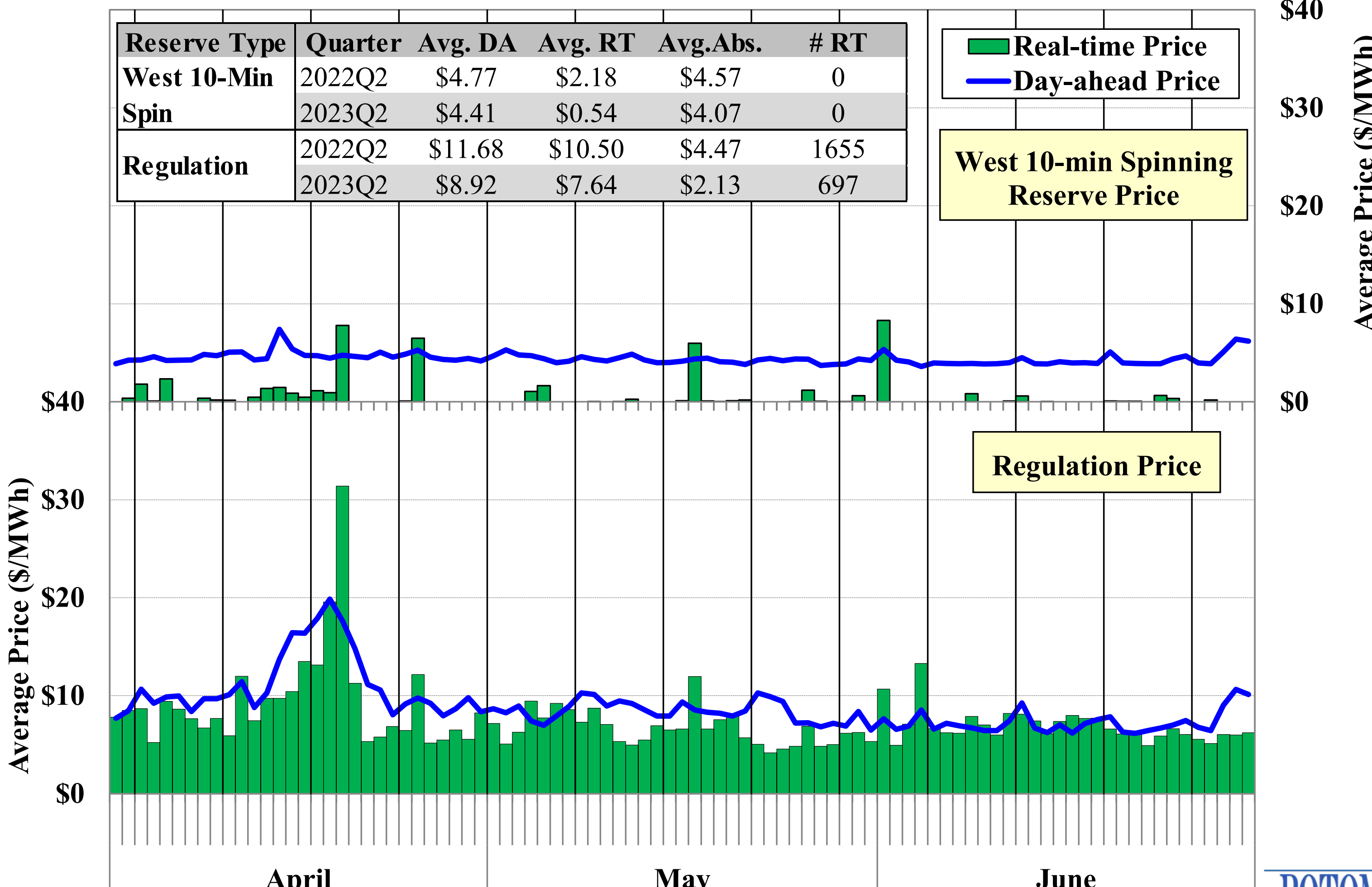
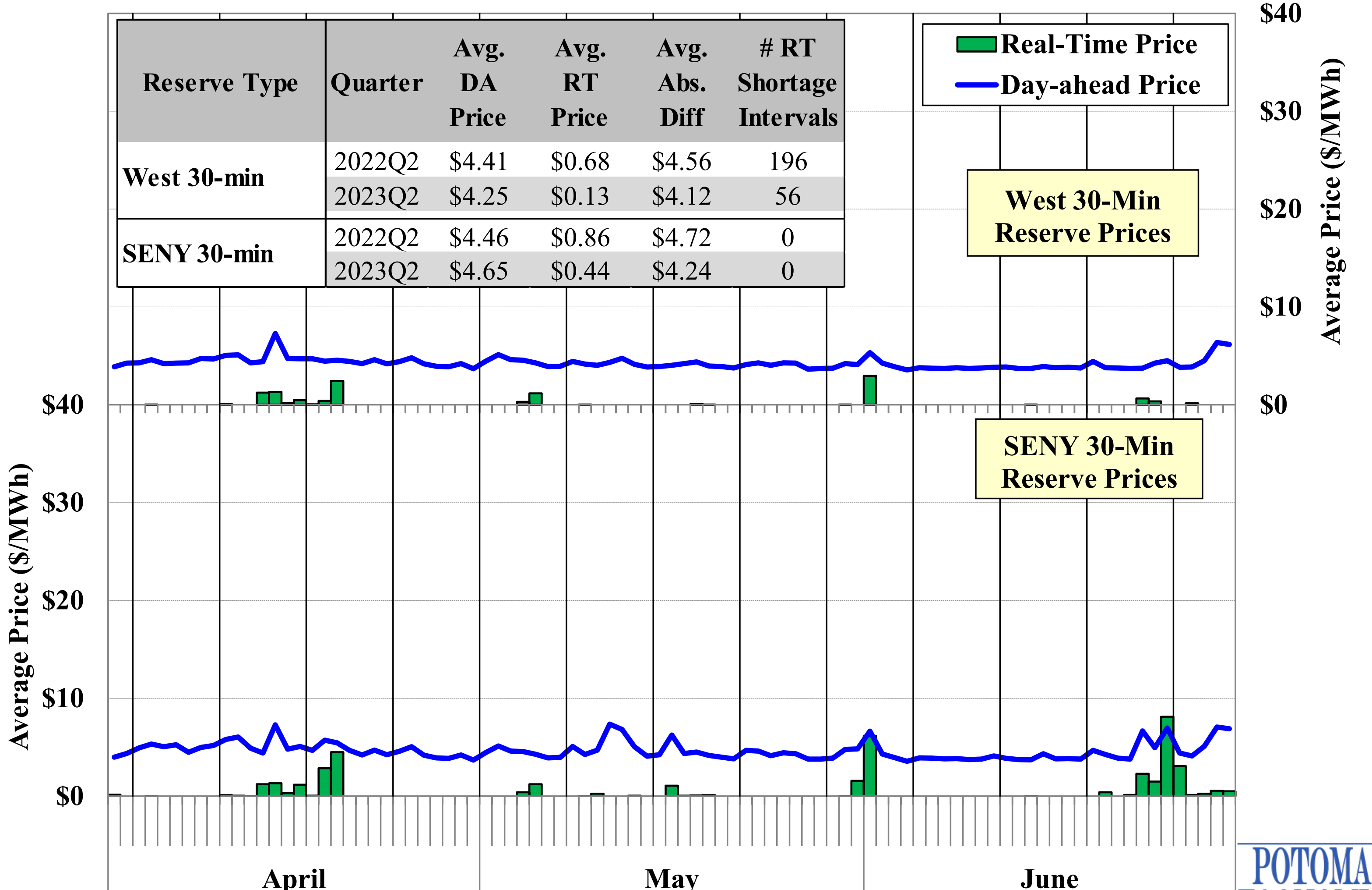
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2022Q2	$4.77	$2.18	$4.57	0
	2023Q2	$4.41	$0.54	$4.07	0
Regulation	2022Q2	$11.68	$10.50	$4.47	1655
	2023Q2	$8.92	$7.64	$2.13	697

Notes: For chart description, see slide 79.

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	2022Q2	$4.41	$0.68	$4.56	196
	2023Q2	$4.25	$0.13	$4.12	56
SENY 30-min	2022Q2	$4.46	$0.86	$4.72	0
	2023Q2	$4.65	$0.44	$4.24	0

Notes: For chart description, see slide 79.

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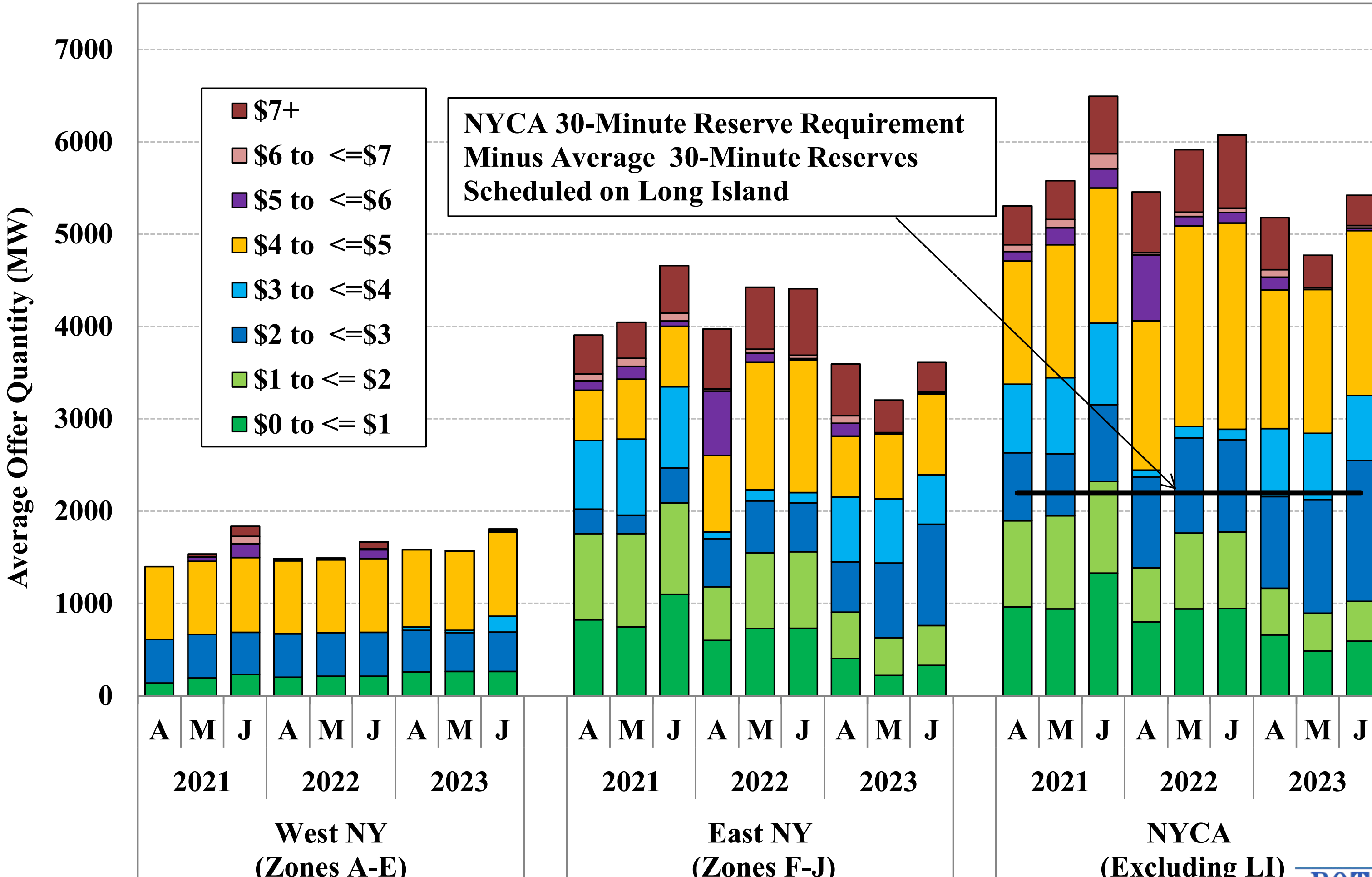
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 80.

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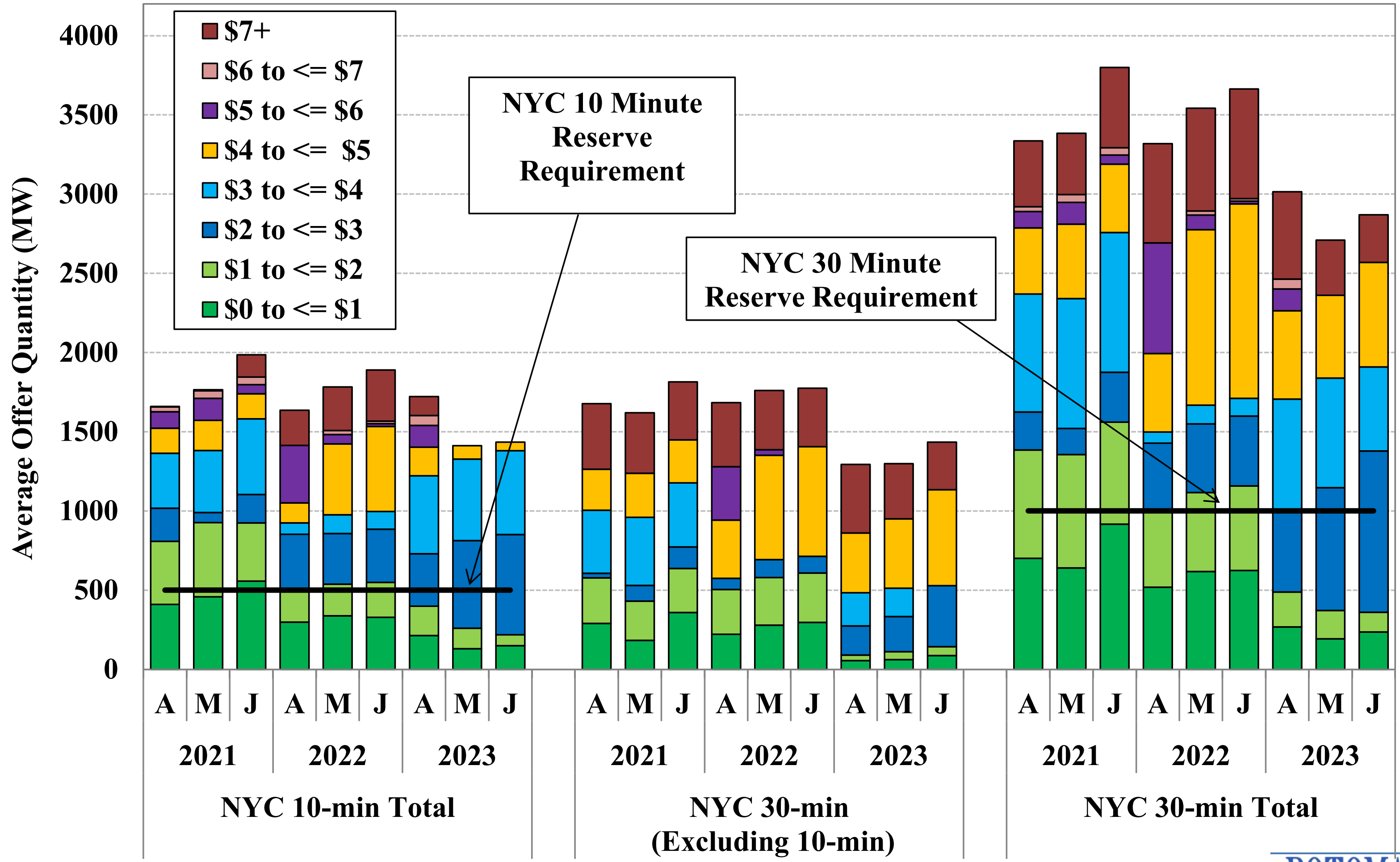
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 80.

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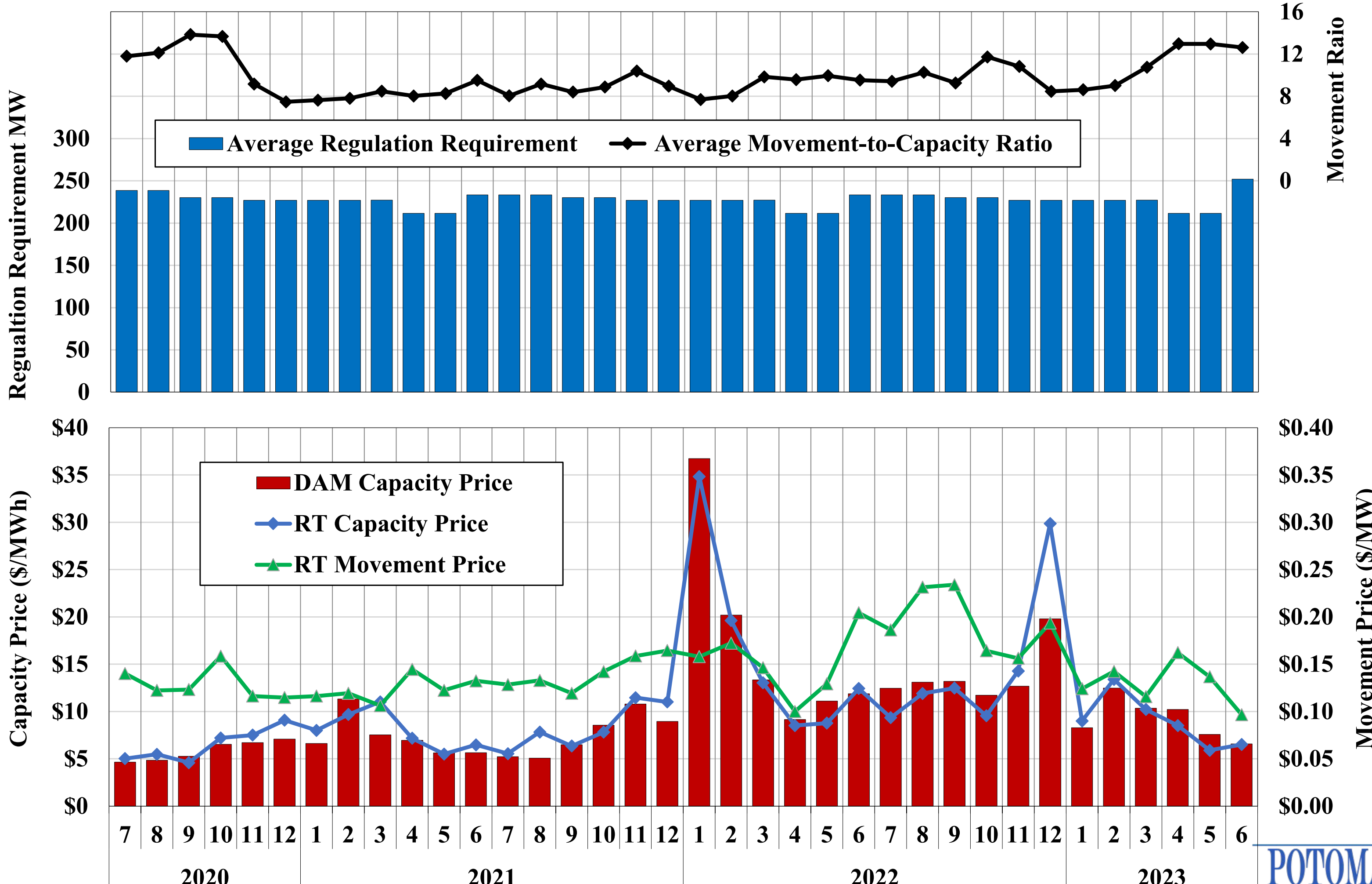
Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month



Notes: For chart description, see slide 81.

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Charts:
Energy Market Scheduling

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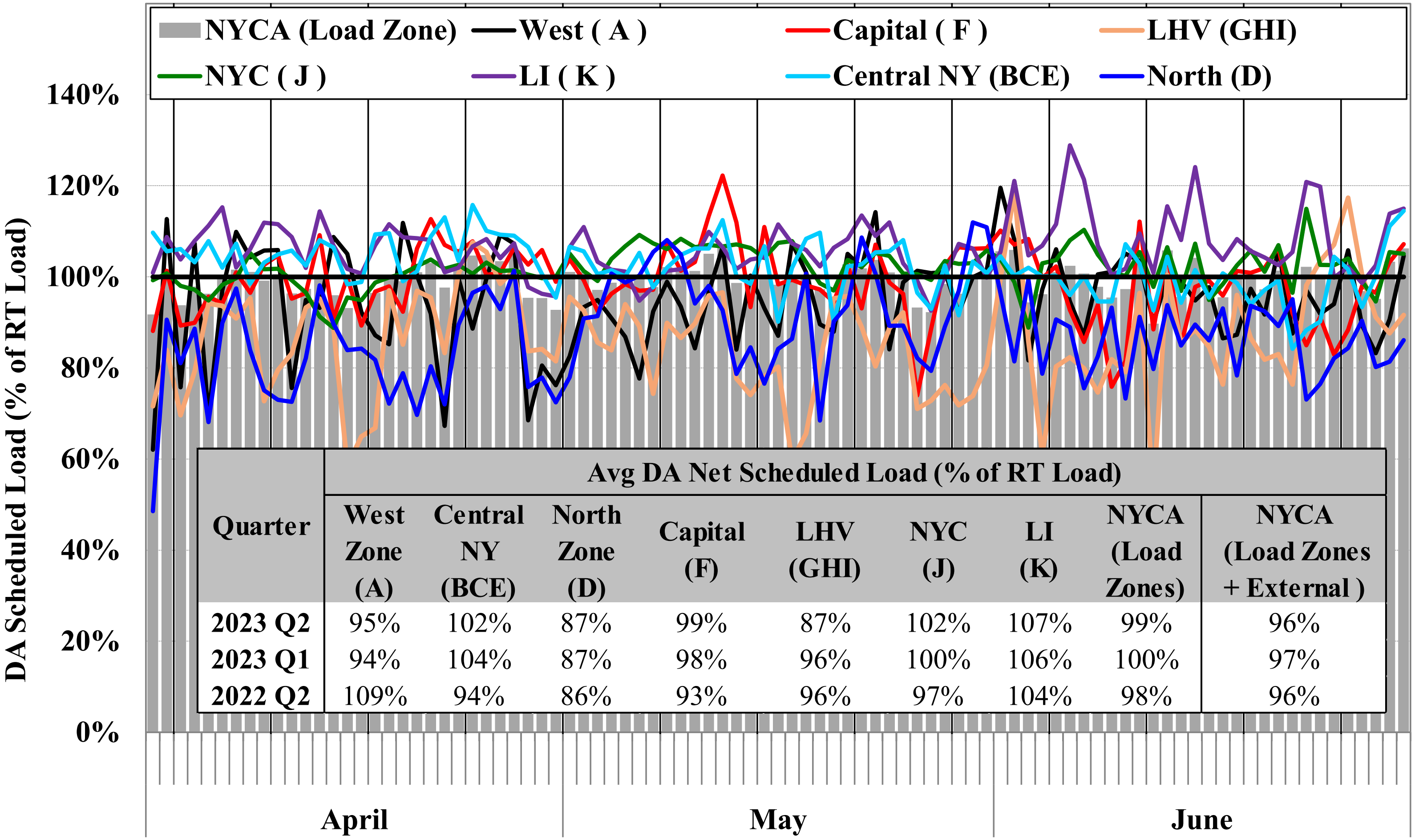
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour



Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2023 Q2	95%	102%	87%	99%	87%	102%	107%	99%	96%
2023 Q1	94%	104%	87%	98%	96%	100%	106%	100%	97%
2022 Q2	109%	94%	86%	93%	96%	97%	104%	98%	96%

Notes: For chart description, see slide 82.

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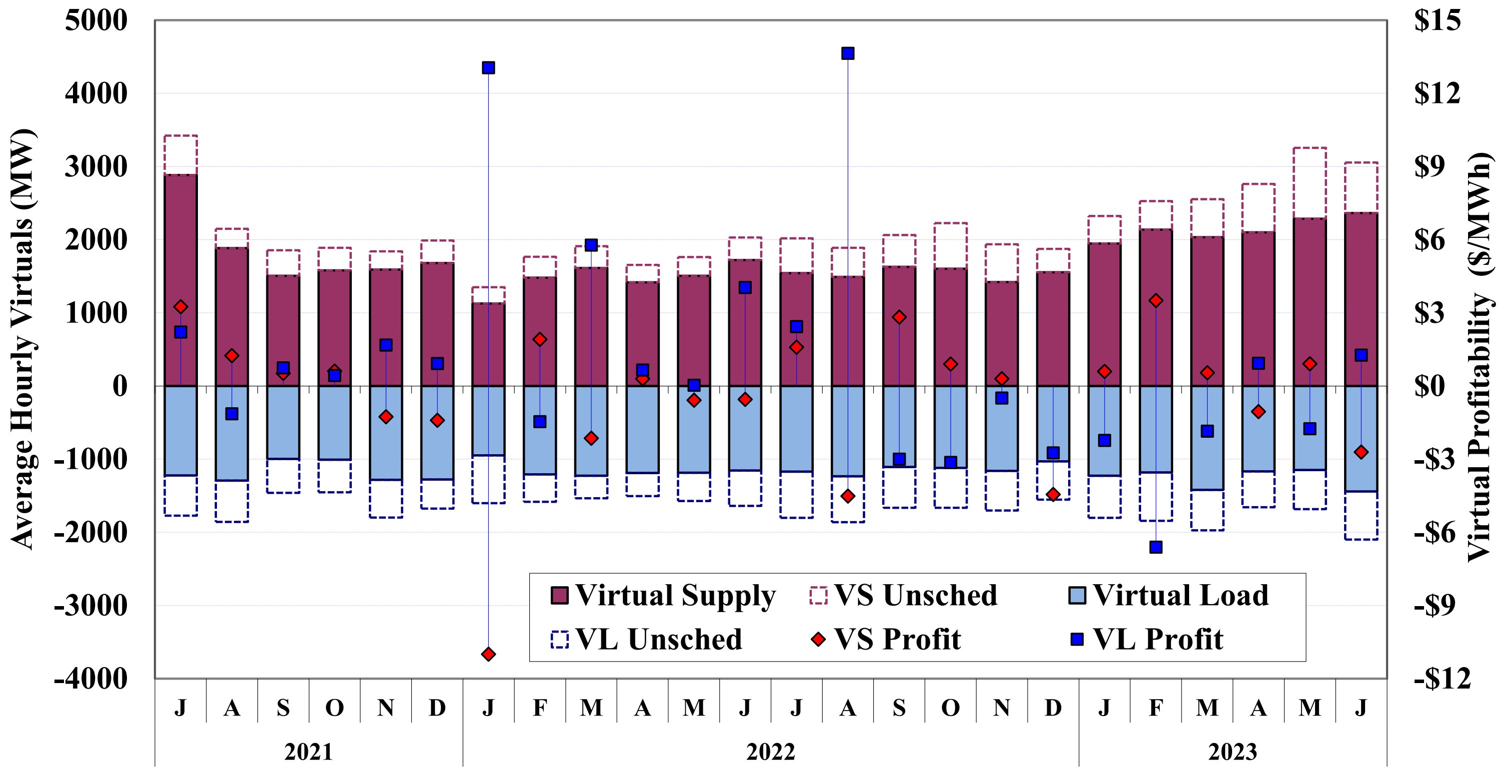
Virtual Trading Activity
by Month

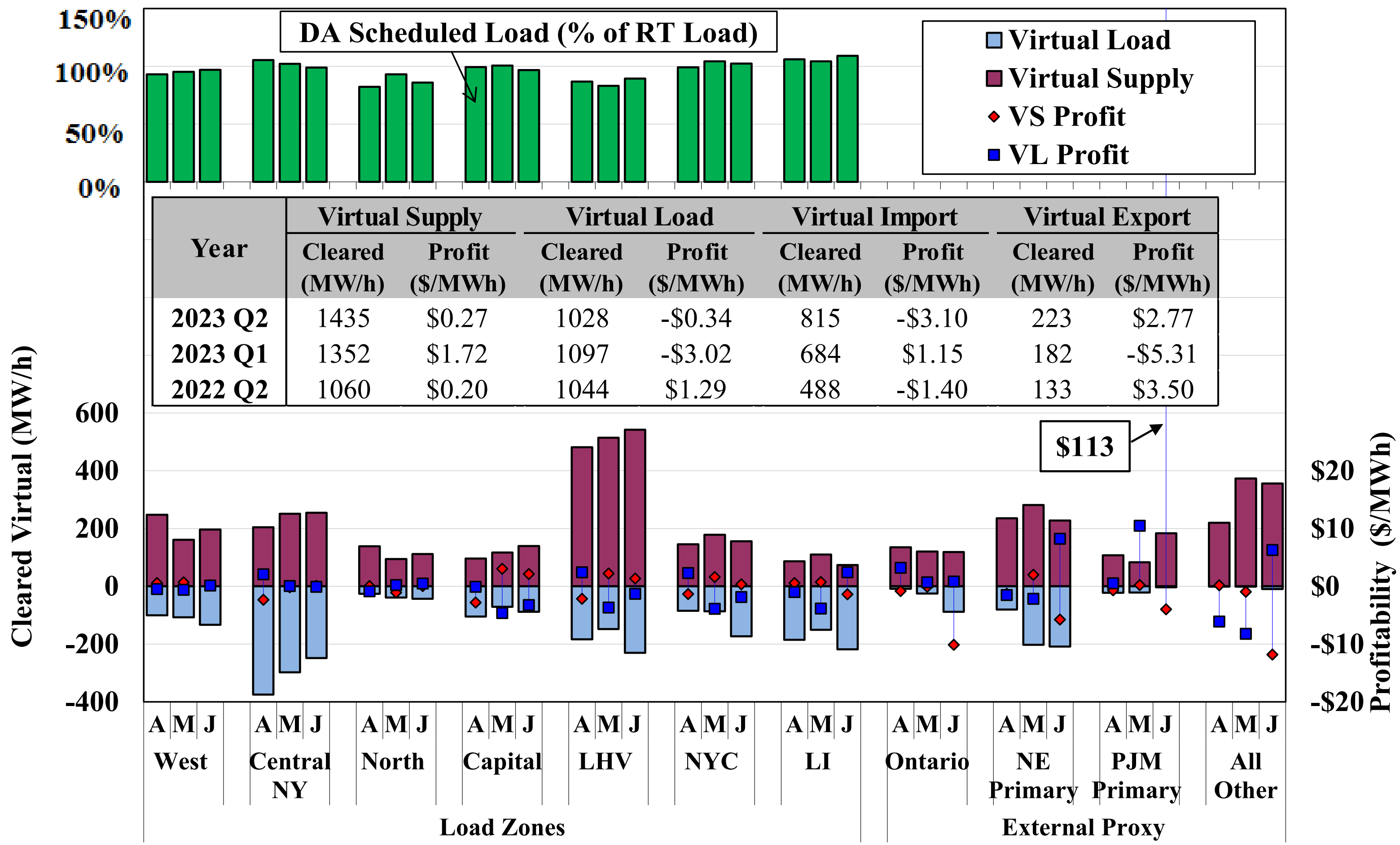


		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	413	158	158	96	182	195	225	307	217	291	324	183	228	153	96	134	250	302	170	455	343	243	275	130
	%	10%	5%	6%	4%	6%	7%	11%	11%	8%	11%	12%	6%	8%	6%	4%	5%	10%	12%	5%	14%	10%	7%	8%	3%
Loss > 50% of Avg. Zone Price	MW	234	174	140	88	197	215	208	278	226	306	304	180	183	124	109	163	289	287	206	412	377	285	296	164
	%	6%	5%	6%	3%	7%	7%	10%	10%	8%	12%	11%	6%	7%	5%	4%	6%	11%	11%	7%	12%	11%	9%	9%	4%

Notes: For chart description, see slide 82.

POTOMAC ECONOMICS

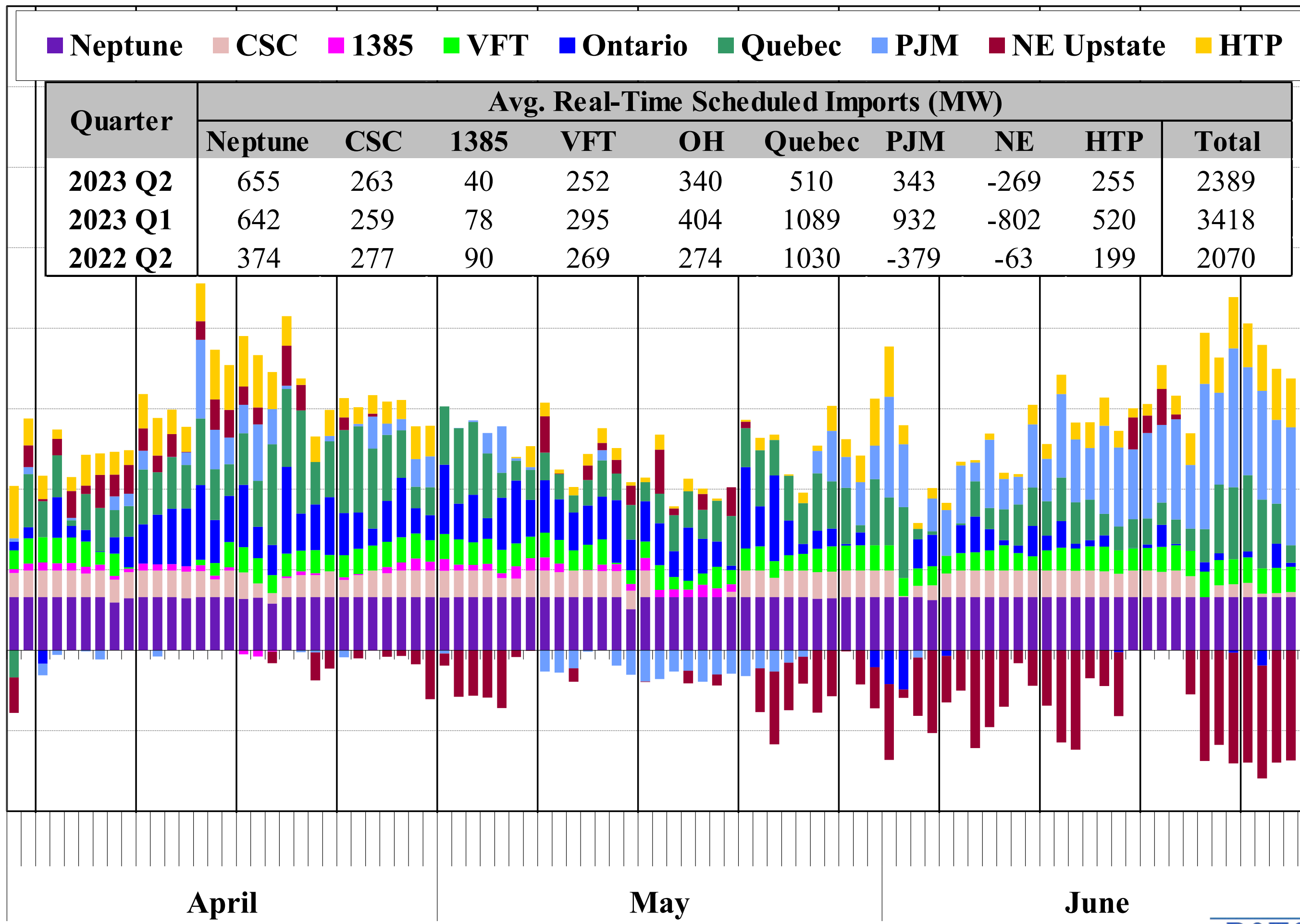
Virtual Trading Activity
by Location



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)
2023 Q2	1435	$0.27	1028	-$0.34	815	-$3.10	223	$2.77
2023 Q1	1352	$1.72	1097	-$3.02	684	$1.15	182	-$5.31
2022 Q2	1060	$0.20	1044	$1.29	488	-$1.40	133	$3.50

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 82.

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
2023 Q2	655	263	40	252	340	510	343	-269	255	2389
2023 Q1	642	259	78	295	404	1089	932	-802	520	3418
2022 Q2	374	277	90	269	274	1030	-379	-63	199	2070

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 > $20	Total	
% of All Intervals w/ Adjustment			79%	6%	**84%**		33%	8%	**41%**	
Average Flow Adjustment (MW)	Net Imports		-6	7	**-5**		-13	-69	**-24**	
	Gross		106	122	**107**		69	102	**76**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$1.0	$0.3	**$1.3**		$0.2	$1.2	**$1.4**	
	Net Over-Projection by:	NY	$0.0	-$0.1	**-$0.1**		$0.0	-$0.1	**-$0.1**	
		NE or PJM	$0.0	$0.0	**$0.0**		-$0.1	-$1.1	**-$1.2**	
	Other Unrealized Savings		-$0.1	-$0.1	**-$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	$23.58	$58.64	**$26.01**	**$26.58**	$22.68	$31.98	**$24.55**	**$23.13**
		Forecast	$24.48	$42.31	**$25.72**	**$26.25**	$23.39	$32.38	**$25.20**	**$23.41**
	NE or PJM	Actual	$23.90	$51.70	**$25.83**	**$27.46**	$21.72	$34.34	**$24.25**	**$22.75**
		Forecast	$22.34	$37.49	**$23.39**	**$25.15**	$24.06	$91.91	**$37.67**	**$32.78**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.90	-$16.33	**-$0.29**	**-$0.33**	$0.72	$0.40	**$0.65**	**$0.28**
		Abs. Val.	$2.03	$36.40	**$4.41**	**$4.53**	$1.93	$12.82	**$4.11**	**$3.38**
	NE or PJM	Fcst. - Act.	-$1.56	-$14.22	**-$2.44**	**-$2.31**	$2.34	$57.57	**$13.42**	**$10.03**
		Abs. Val.	$3.31	$23.00	**$4.67**	**$4.76**	$5.29	$70.87	**$18.45**	**$14.47**

For Adjustment Intervals Only

For All Intervals

Notes: For chart description, see slide 83.

POTOMAC ECONOMICS

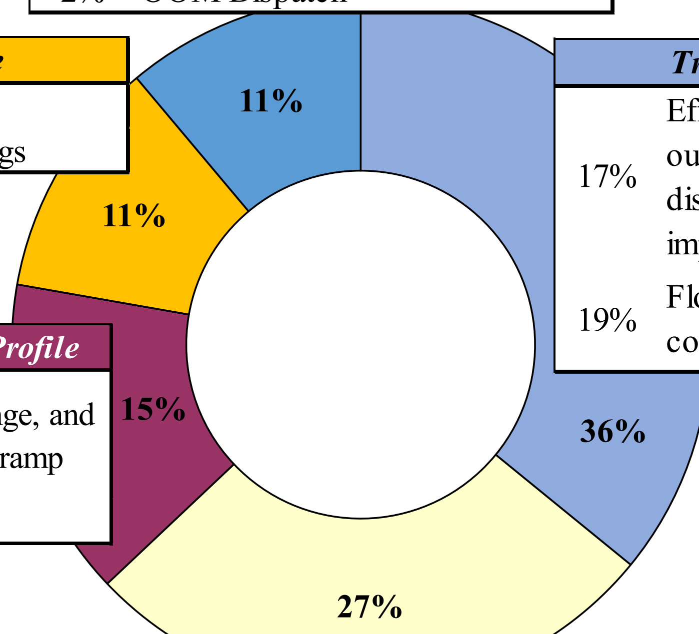
Detrimental Factors to RTC and RTD Price Divergence

Other Factors	
9%	Transaction Checkout Failures & Curtailments
2%	OOM Dispatch

Generator Performance	
6%	Not following dispatch
5%	Forced Outage & Deratings

Transmission and PARs	
17%	Effects of loopflows, transmission outages, intrazonal load distribution, and shift factor imprecision
19%	Flows over NY/NJ PAR-controlled lines: A, J, K, and 5018

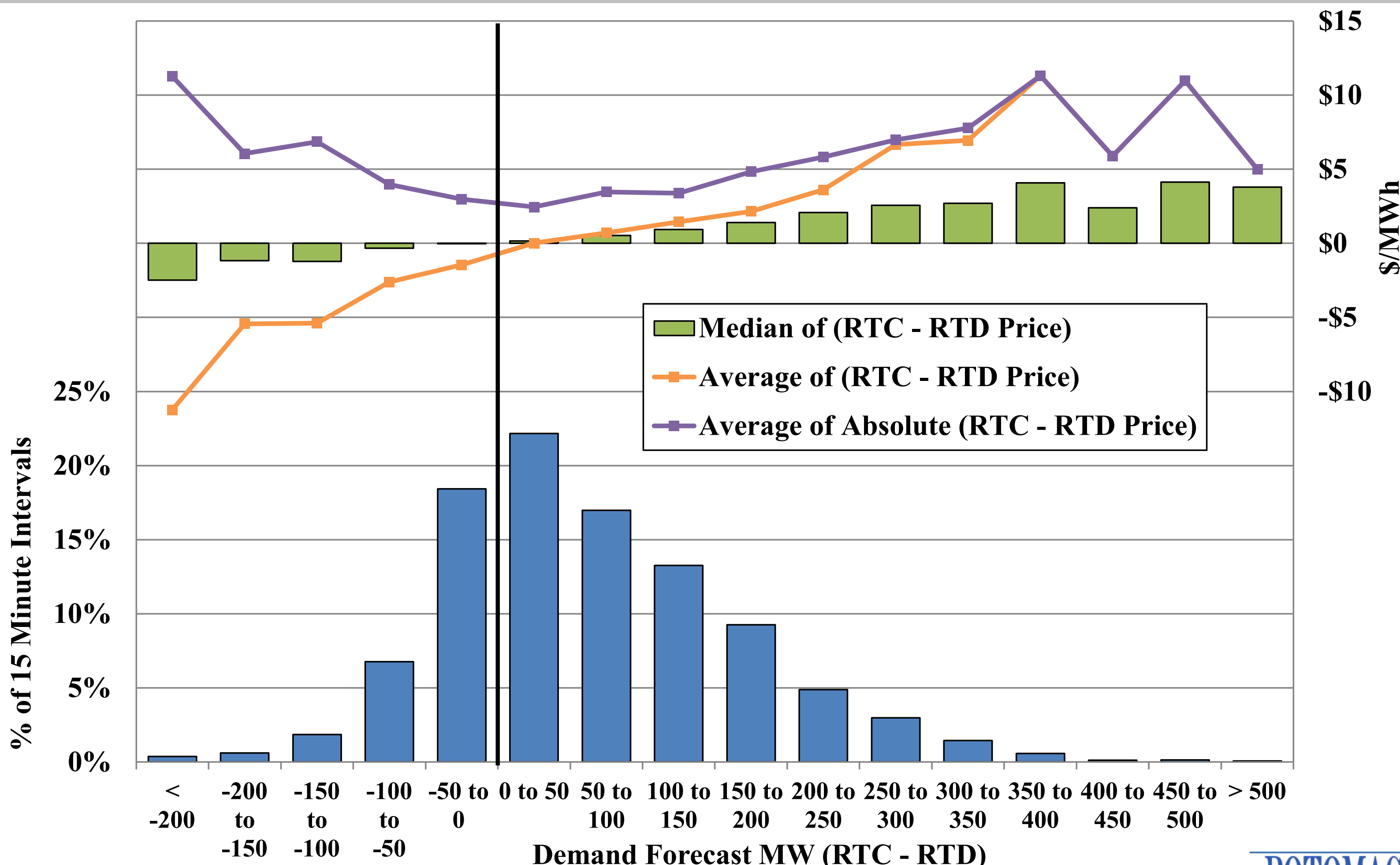
RTC / RTD Timing & Ramp Profile	
10%	Load, Scheduled Interchange, and Self-Scheduled generation ramp
5%	Dispatchable generation



Forecast Error	
18%	Load Forecast Error
9%	Wind Forecast Error

Notes: For chart description, see slide 84.

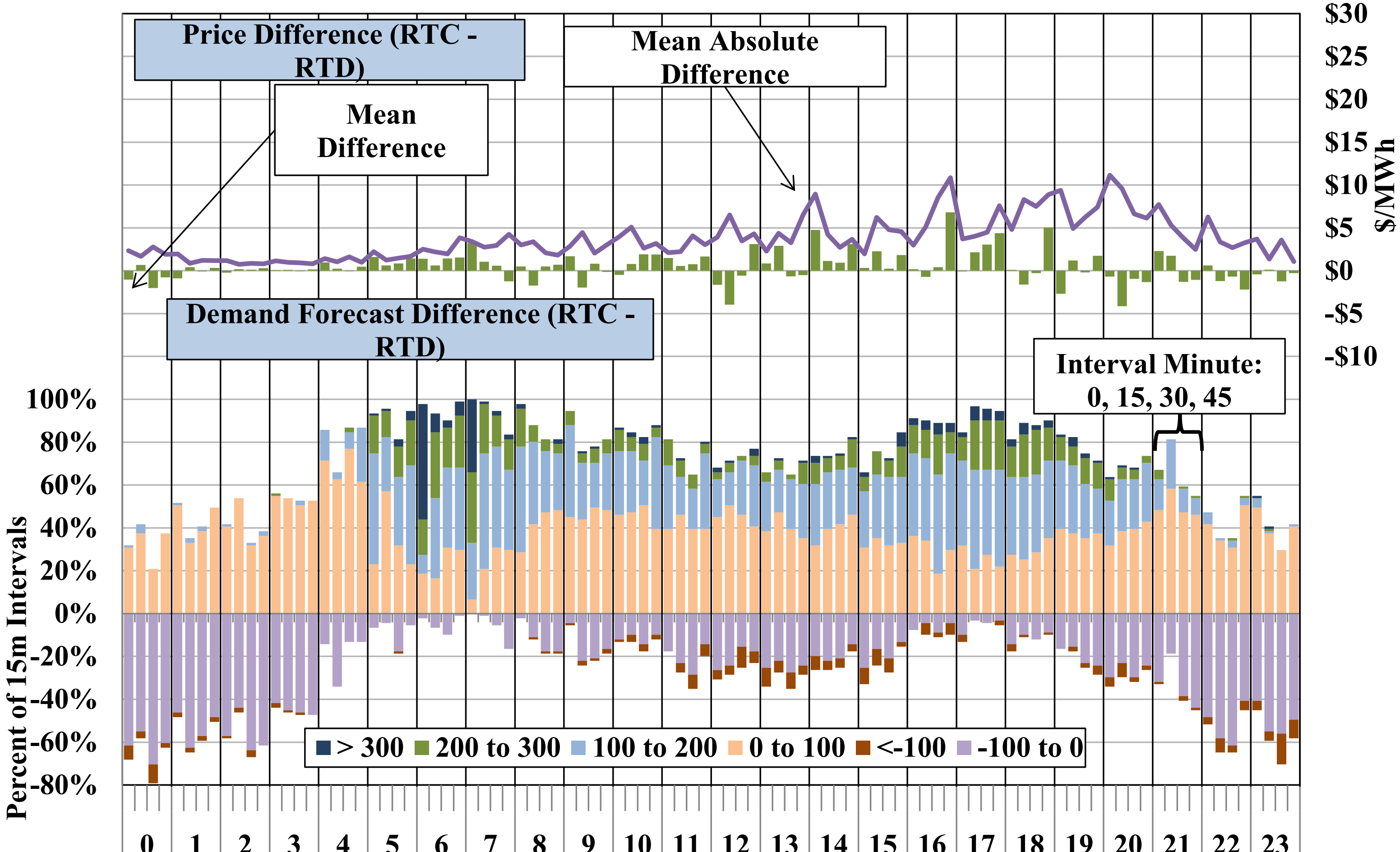
RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide 84.

POTOMAC ECONOMICS

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



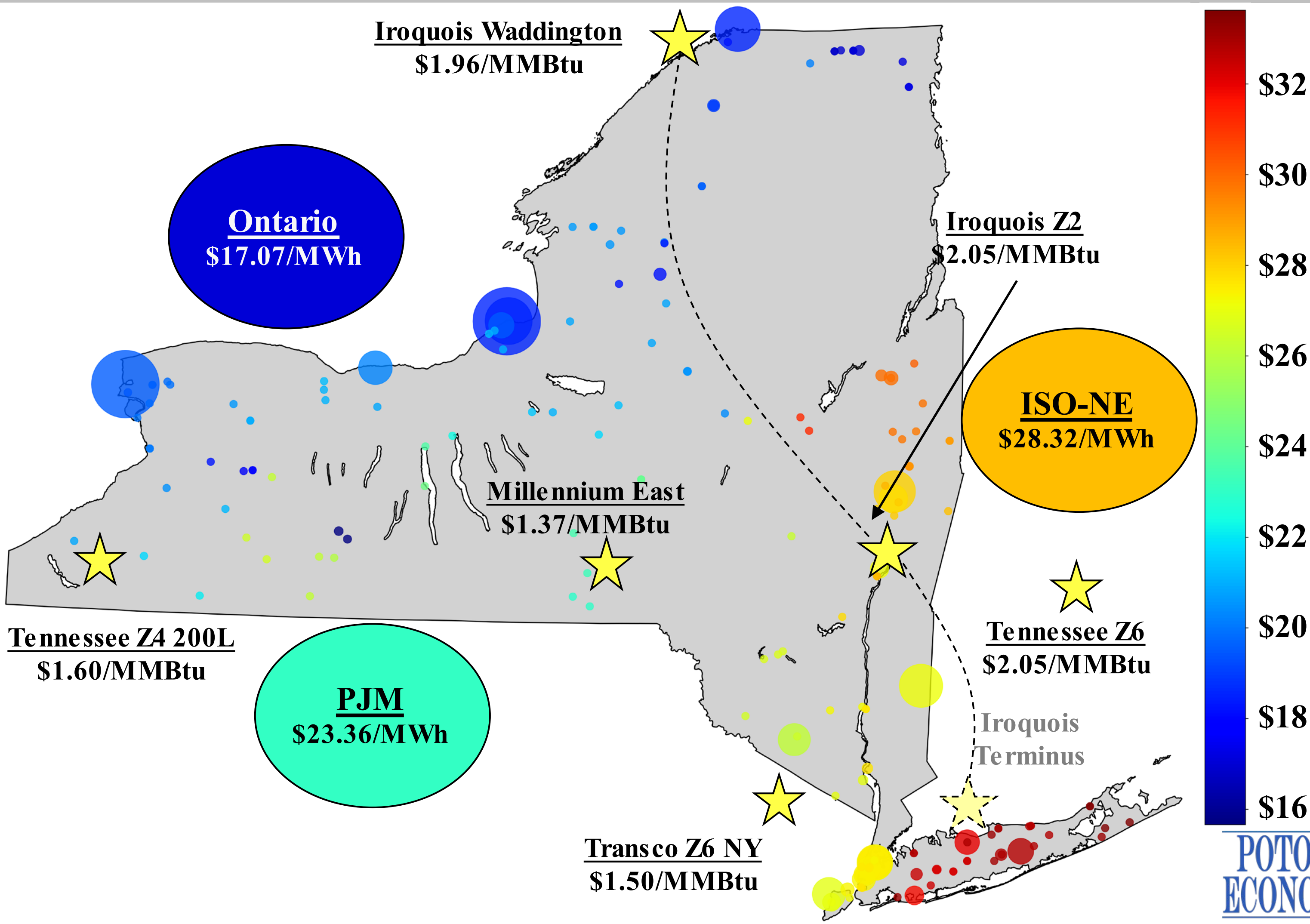
Notes: For chart description, see slide 85.

POTOMAC ECONOMICS

Charts:

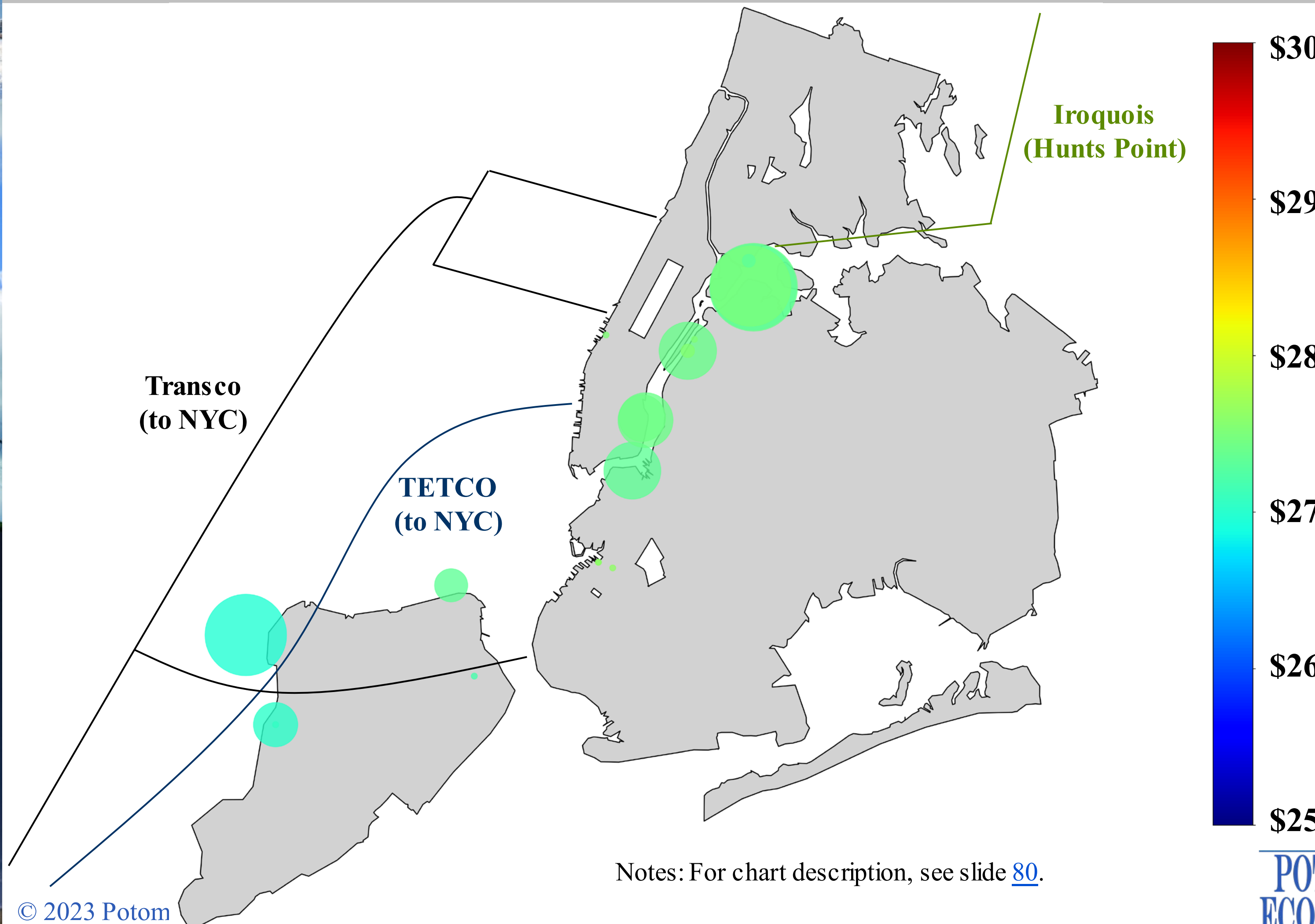
Transmission Congestion Revenues and Shortfalls

System Congestion
Real-Time Price Map at Generator Nodes



POTOMAC ECONOMICS

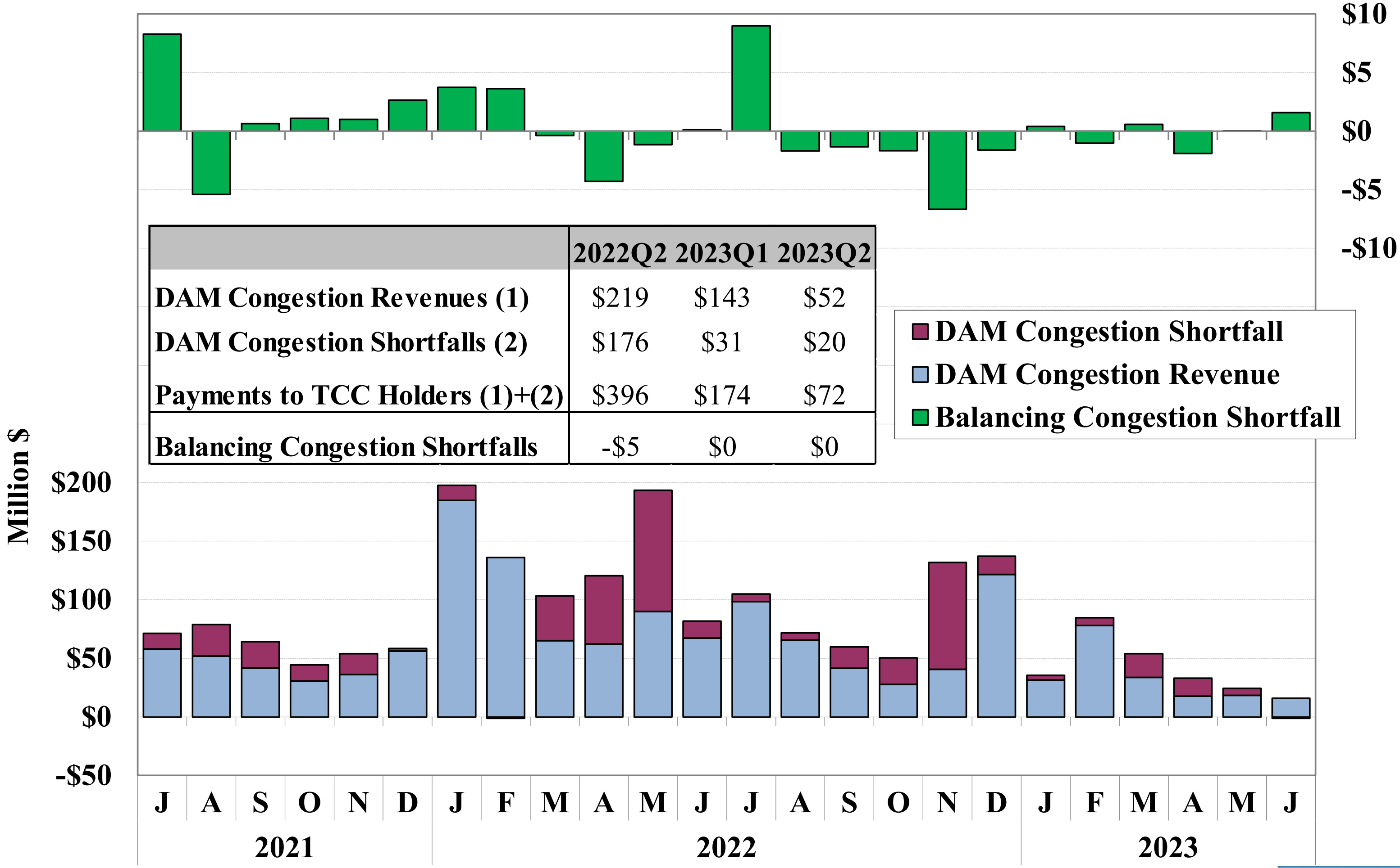
System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

Congestion Revenues and Shortfalls by Month

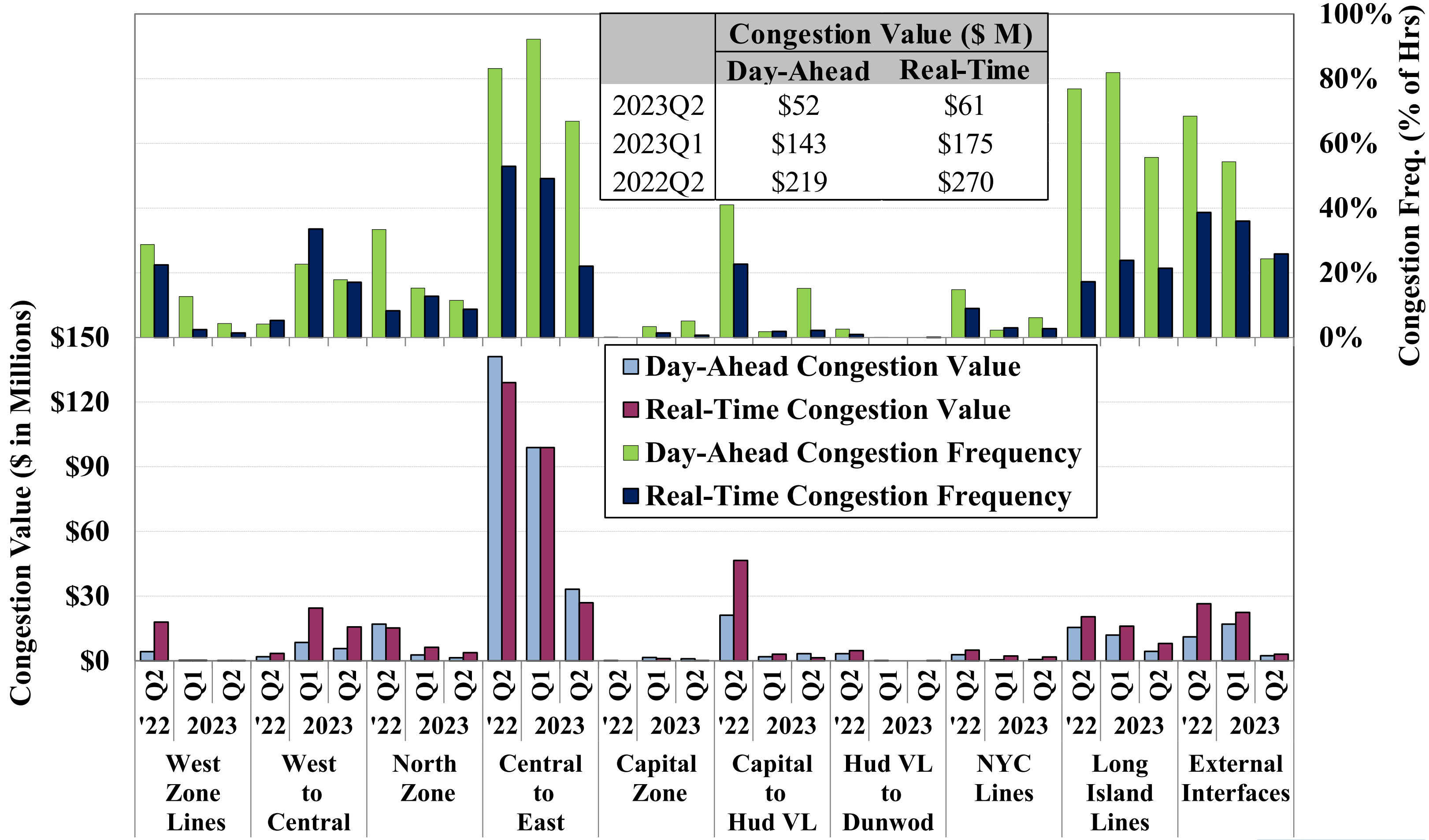


	2022Q2	2023Q1	2023Q2
DAM Congestion Revenues (1)	$219	$143	$52
DAM Congestion Shortfalls (2)	$176	$31	$20
Payments to TCC Holders (1)+(2)	$396	$174	$72
Balancing Congestion Shortfalls	-$5	$0	$0

Notes: For chart description, see slides 87 and 88.

POTOMAC ECONOMICS

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

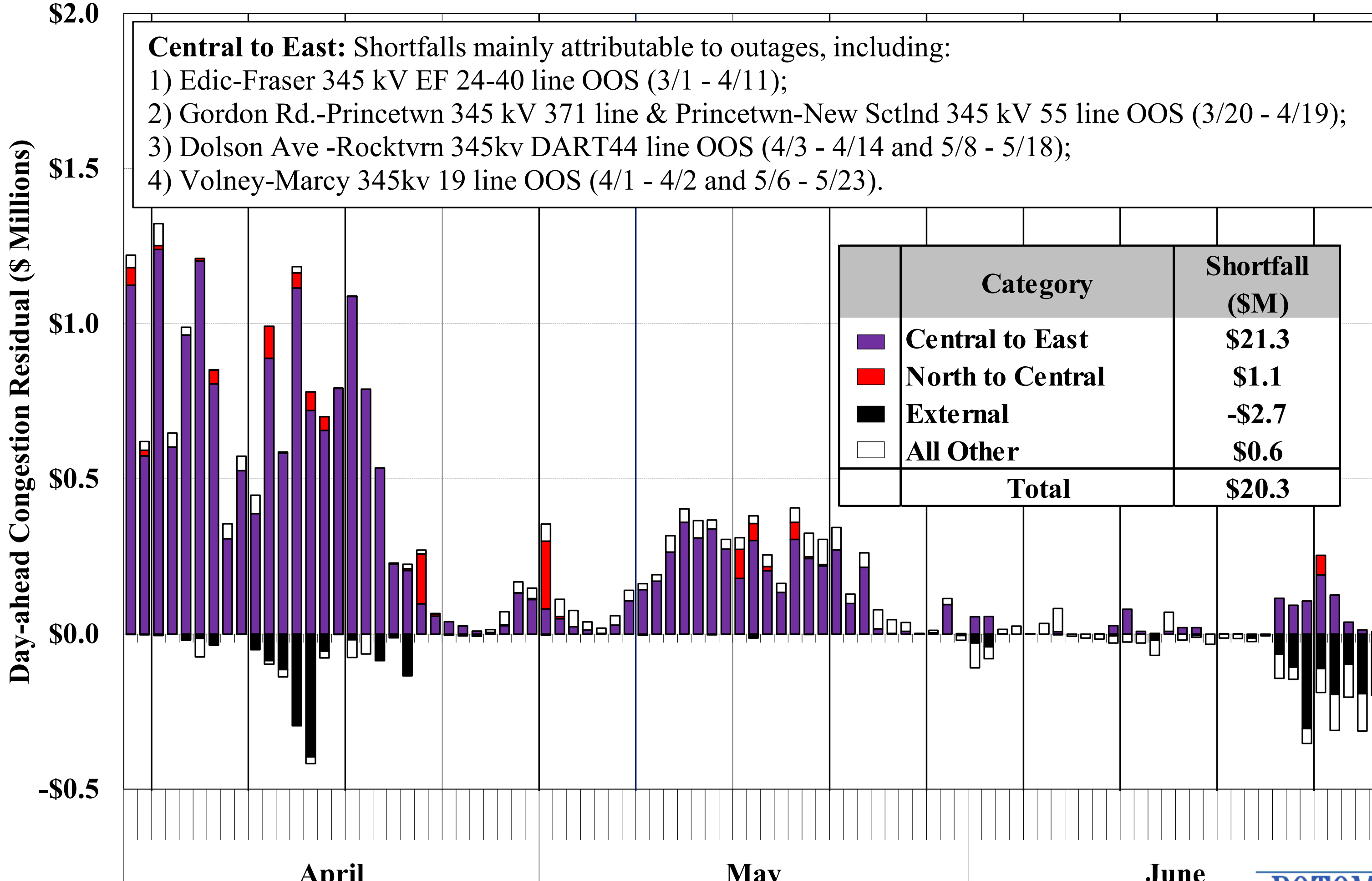


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2023Q2	$52	$61
2023Q1	$143	$175
2022Q2	$219	$270

Notes: For chart description, see slides 87, 88, and 89.

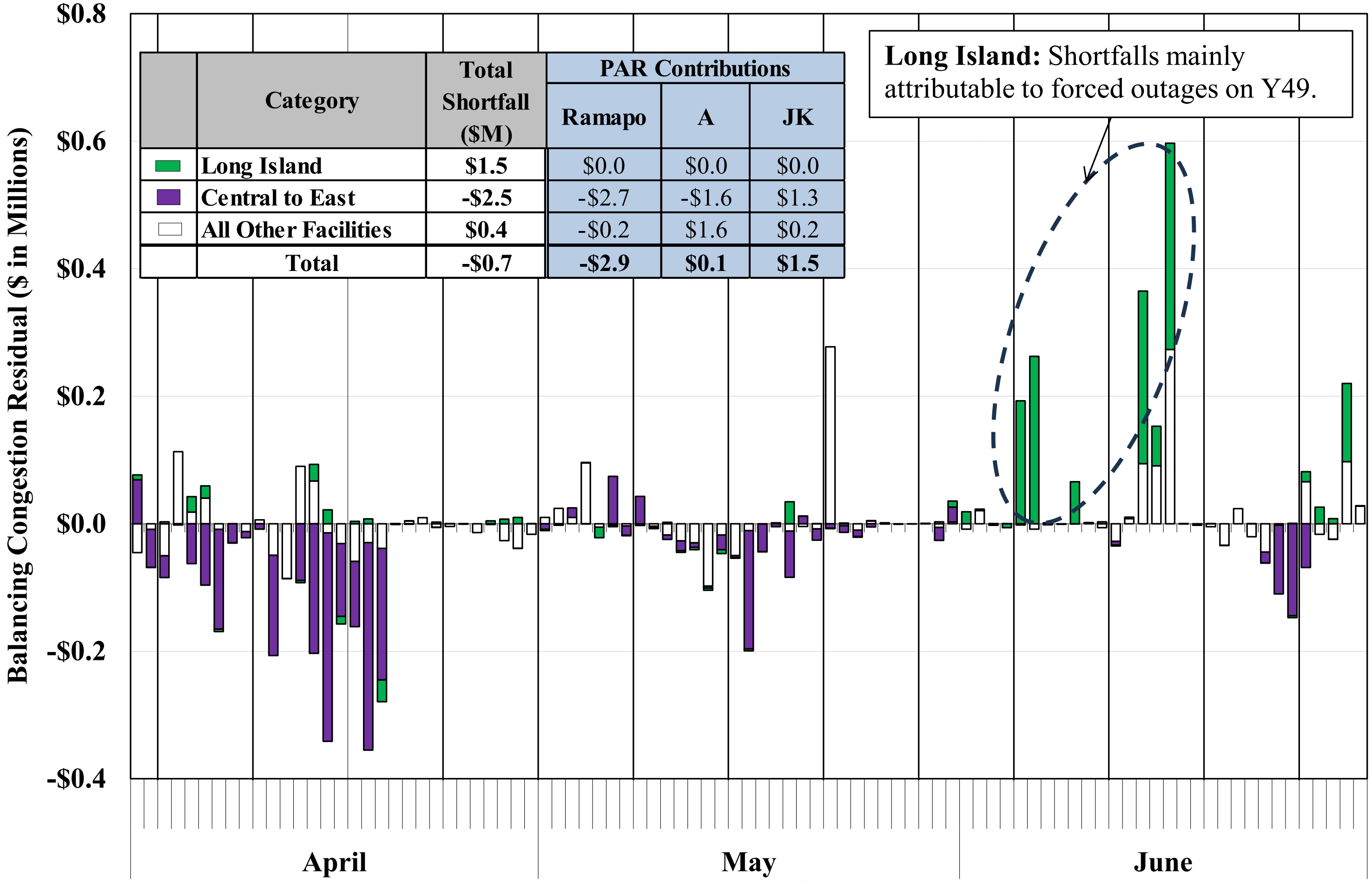
POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 87, 88, and 89.

Balancing Congestion Shortfalls by Transmission Facility

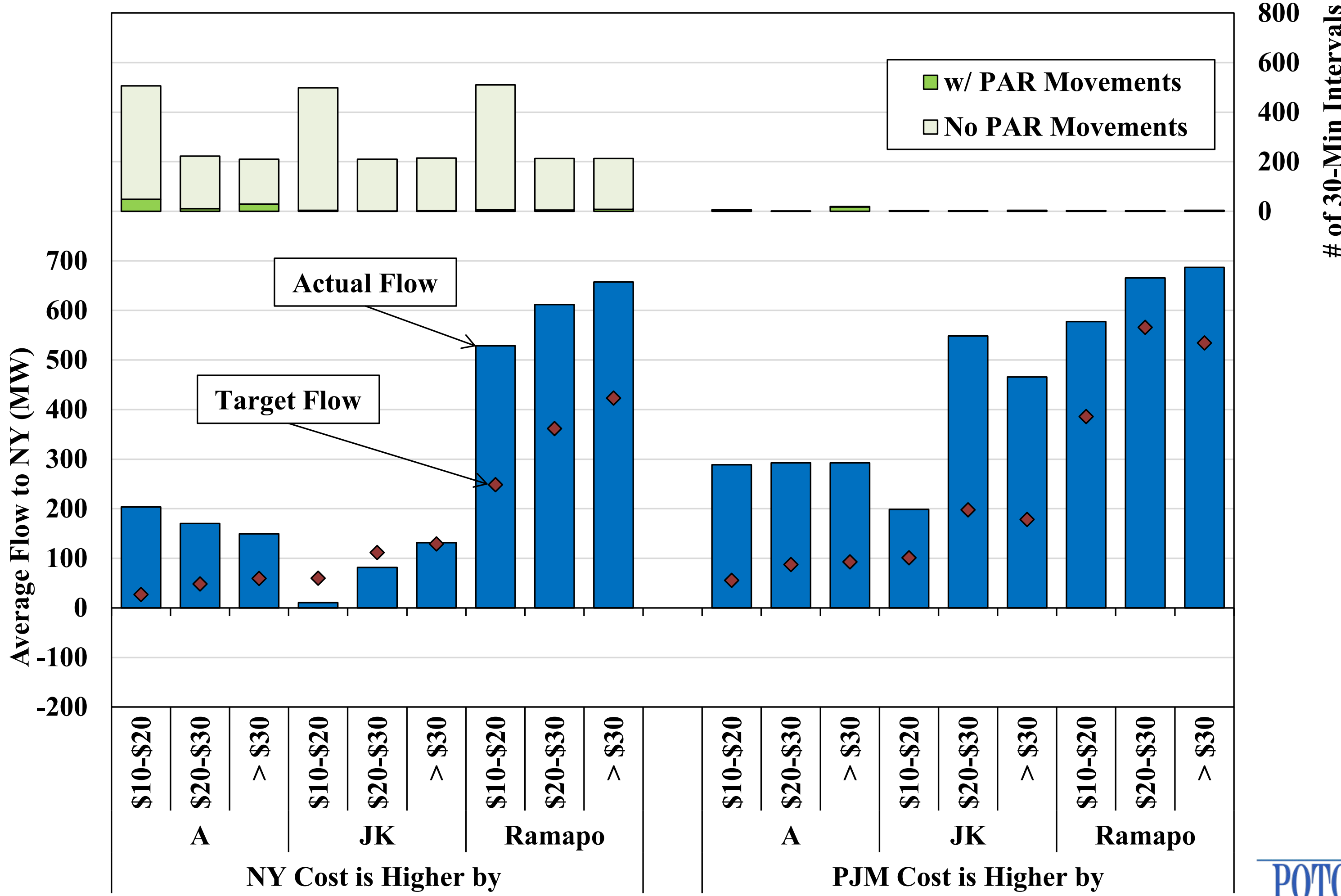


Category	Total Shortfall ($M)	PAR Contributions: Ramapo	A	JK
Long Island	$1.5	$0.0	$0.0	$0.0
Central to East	-$2.5	-$2.7	-$1.6	$1.3
All Other Facilities	$0.4	-$0.2	$1.6	$0.2
Total	-$0.7	-$2.9	$0.1	$1.5

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 87, 88, and 89.

POTOMAC ECONOMICS

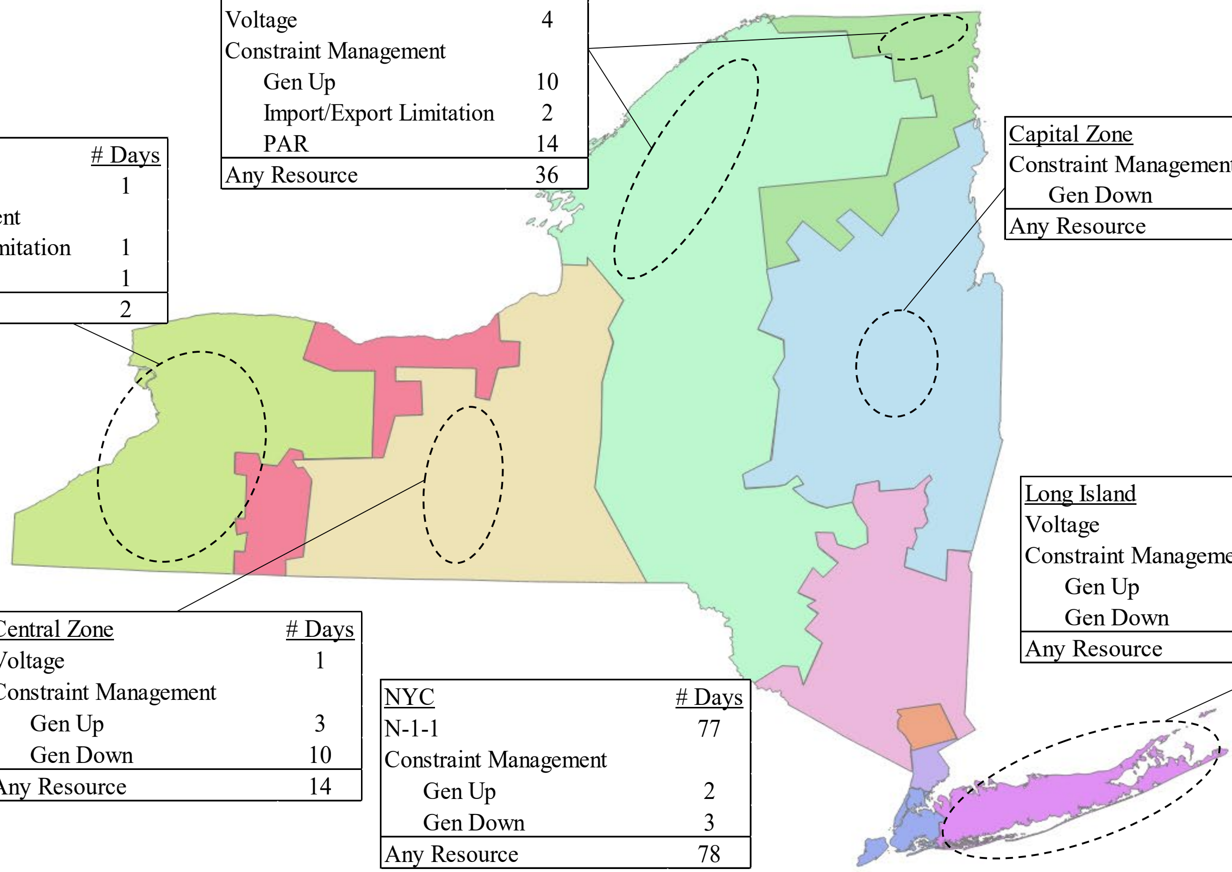
PAR Operation under M2M with PJM
2023 Q2



  Notes: For chart description, see slide 90.

POTOMAC ECONOMICS

OOM Actions to Manage Network Reliability



North & MHK VL Zones	# Days
N-1-1	15
Voltage	4
Constraint Management	
Gen Up	10
Import/Export Limitation	2
PAR	14
Any Resource	36

West Zone	# Days
Voltage	1
Constraint Management	
Import/Export Limitation	1
PAR	1
Any Resource	2

Capital Zone	# Days
Constraint Management	
Gen Down	6
Any Resource	6

Long Island	# Days
Voltage	4
Constraint Management	
Gen Up	8
Gen Down	4
Any Resource	15

Central Zone	# Days
Voltage	1
Constraint Management	
Gen Up	3
Gen Down	10
Any Resource	14

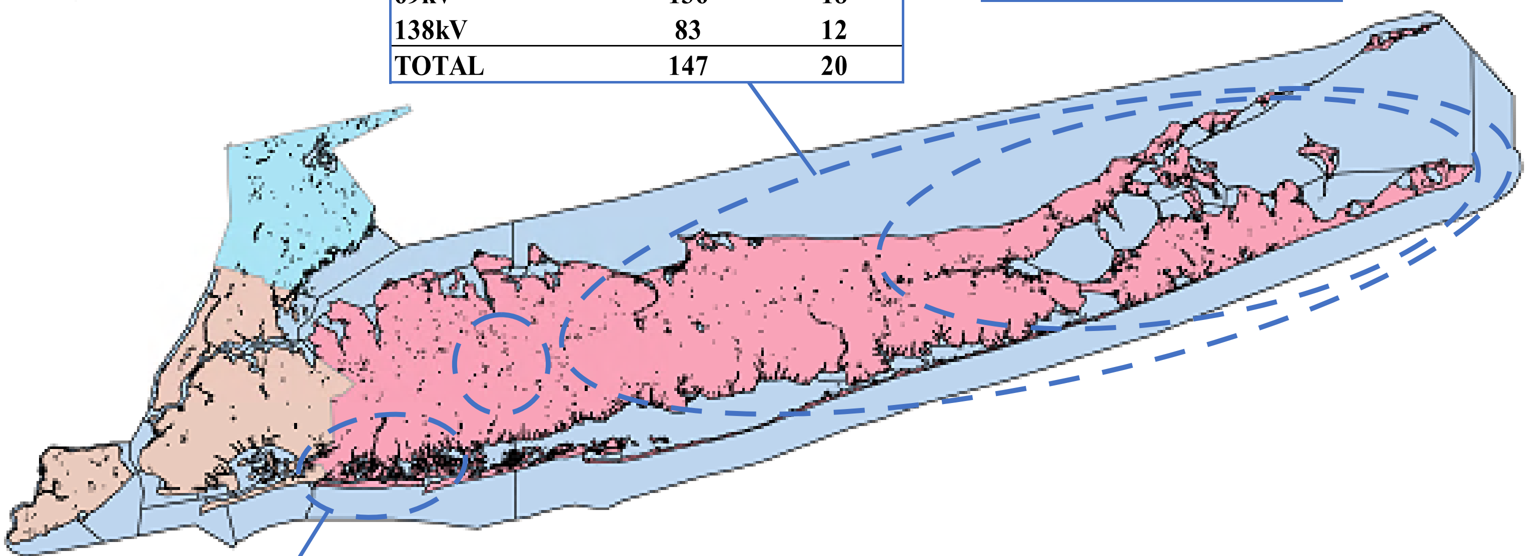
NYC	# Days
N-1-1	77
Constraint Management	
Gen Up	2
Gen Down	3
Any Resource	78

Notes: For chart description, see slides 91-92

Constraints on the Low Voltage Network:
Long Island Load Pockets

East End	#Hours	#Days
69kV OOM	4	1
TVR OOM	13	2
TOTAL	17	3

East of Northport	#Hours	#Days
69kV	136	18
138kV	83	12
TOTAL	147	20



Valley Stream	#Hours	#Days
69kV OOM	29	6
138kV	274	36
TOTAL	302	38

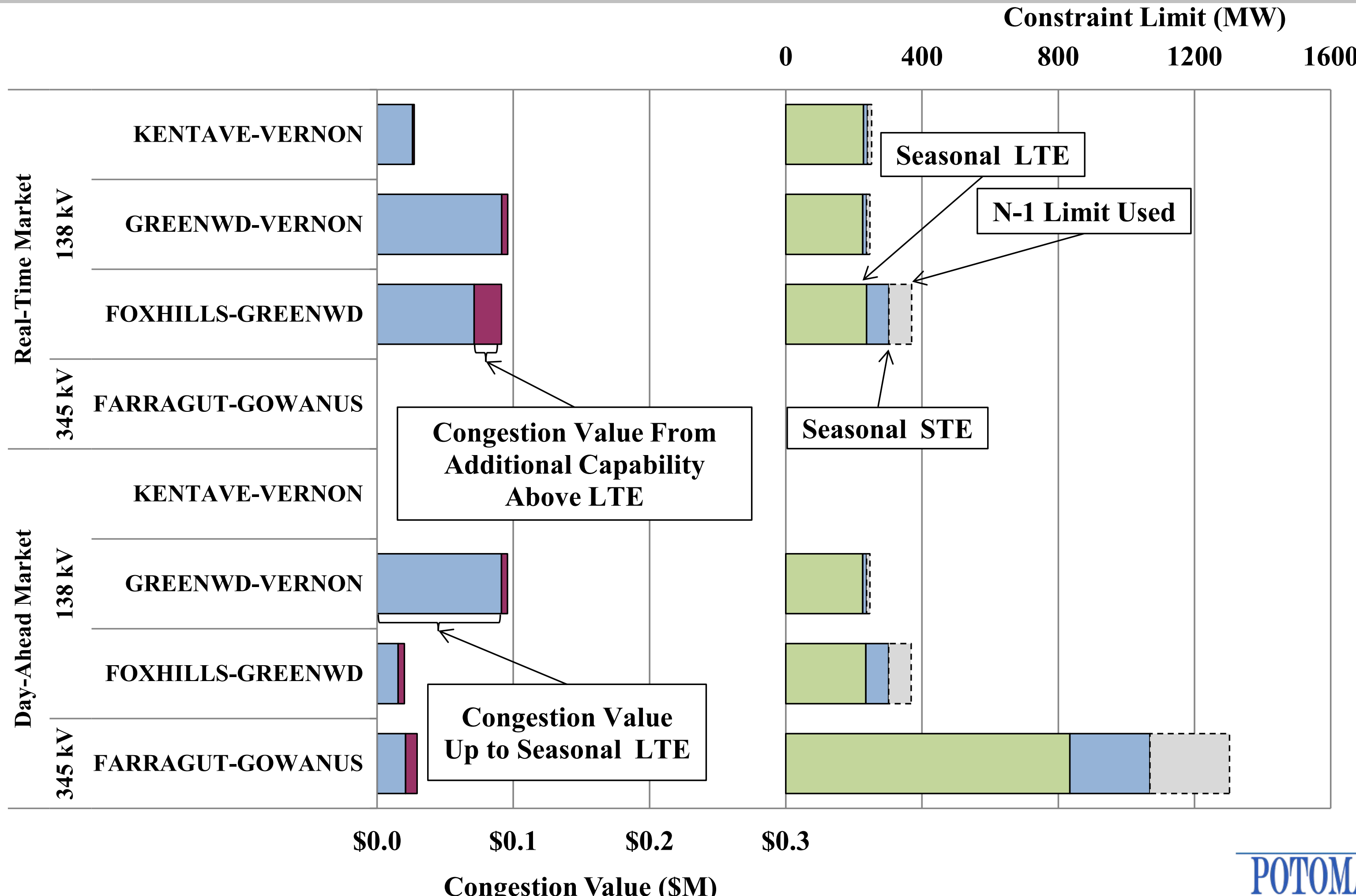
Brentwood	#Hours	#Days
69kV OOM	14	2
69kV	49	12
TOTAL	57	12

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$30.39	$30.53
East End	$31.34	$32.81
East of Northport	$30.68	$30.68
Valley Stream	$29.87	$29.96

Notes: For chart description, see slides 91-92

POTOMAC ECONOMICS

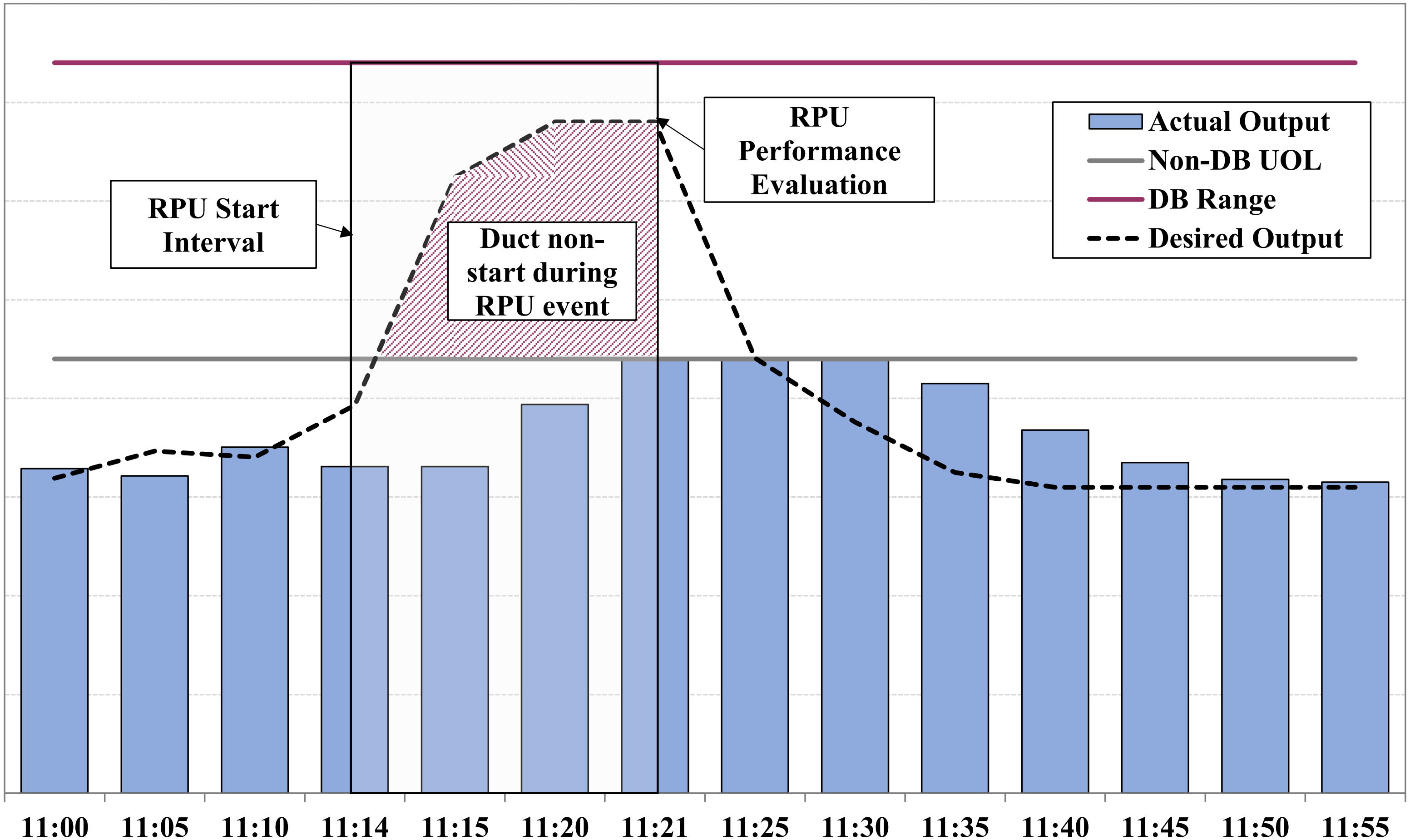
N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide 93.

POTOMAC ECONOMICS

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

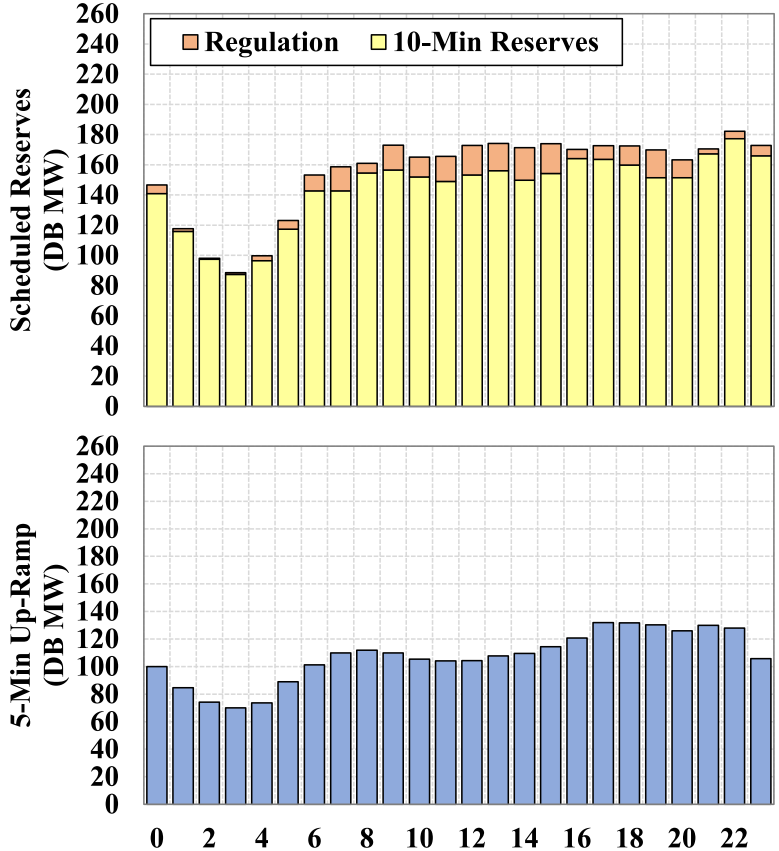


Notes: For chart description, see slide 94

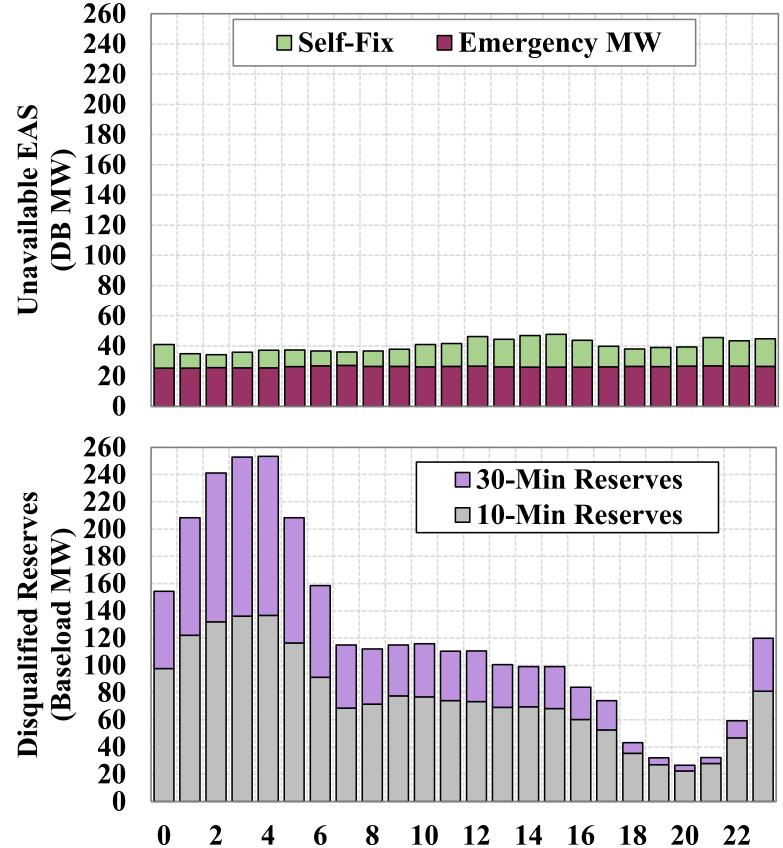
POTOMAC ECONOMICS

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

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



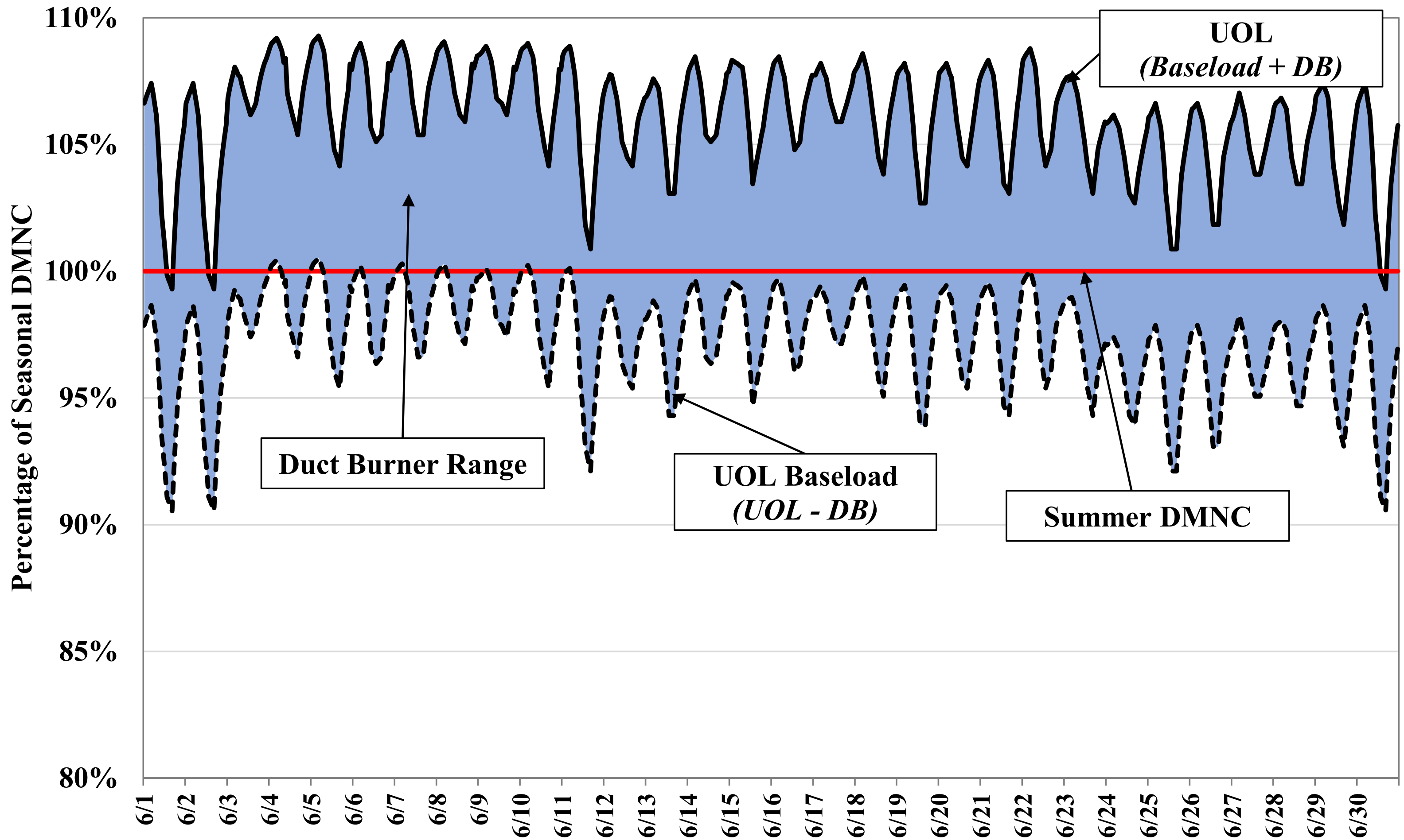
Unoffered Energy and/or Reserves (Including Duct and Baseload)



Notes: For chart description, see slide 94

POTOMAC ECONOMICS

Illustration of Duct Burner Range
Example Generator Hourly Capability



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

10 Minute Economic GT Start Performance vs. Audit Results (July 2022 - June 2023)				
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]	0	0	0	0
0% - 10%	0	0	0	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	1	3	1	1
40% - 50%	3	14	3	8
50% - 60%	1	5	1	3
60% - 70%	0	0	0	0
70% - 80%	4	12	4	1
80% - 90%	6	35	6	0
90% - 100%	25	105	25	8
TOTAL	**40**	**174**	**40**	**21**

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.

Note: 2. Excludes units that retired prior to start of Summer 2023 Capability Period.

 Notes: For chart description, see slide 96.

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

30 Minute Economic GT Start Performance vs. Audit Results (July 2022 - June 2023)

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]	10	12	8	0
0% - 10%	1	2	1	1
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%	0	0	0	0
60% - 70%	0	0	0	0
70% - 80%	2	4	2	1
80% - 90%	25	69	25	14
90% - 100%	28	48	27	1
TOTAL	**67**	**138**	**64**	**18**

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.

Note: 2. Excludes units that retired prior to start of Summer 2023 Capability Period.

 Notes: For chart description, see slide 96.

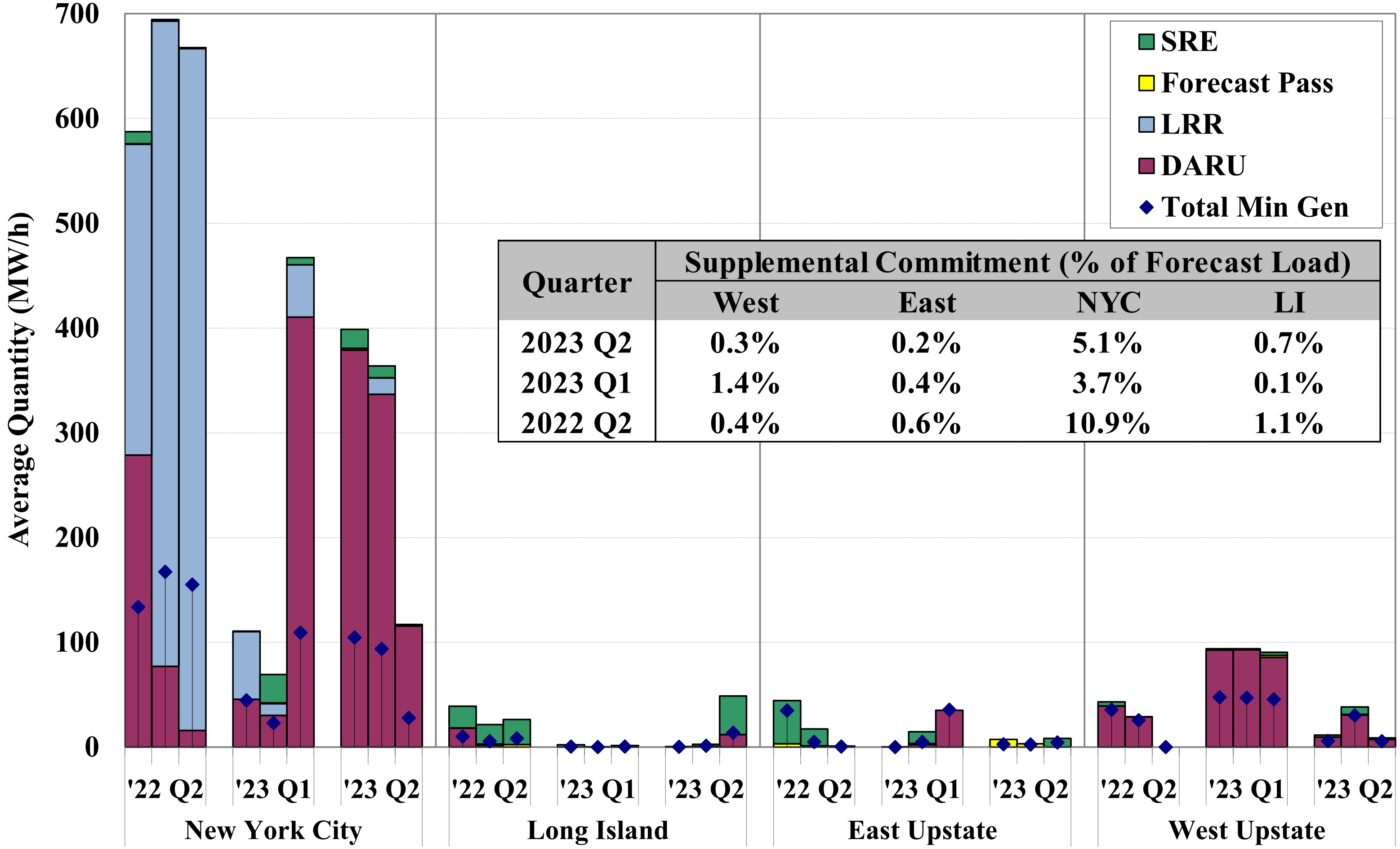
POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

Supplemental Commitment for Reliability
by Category and Region

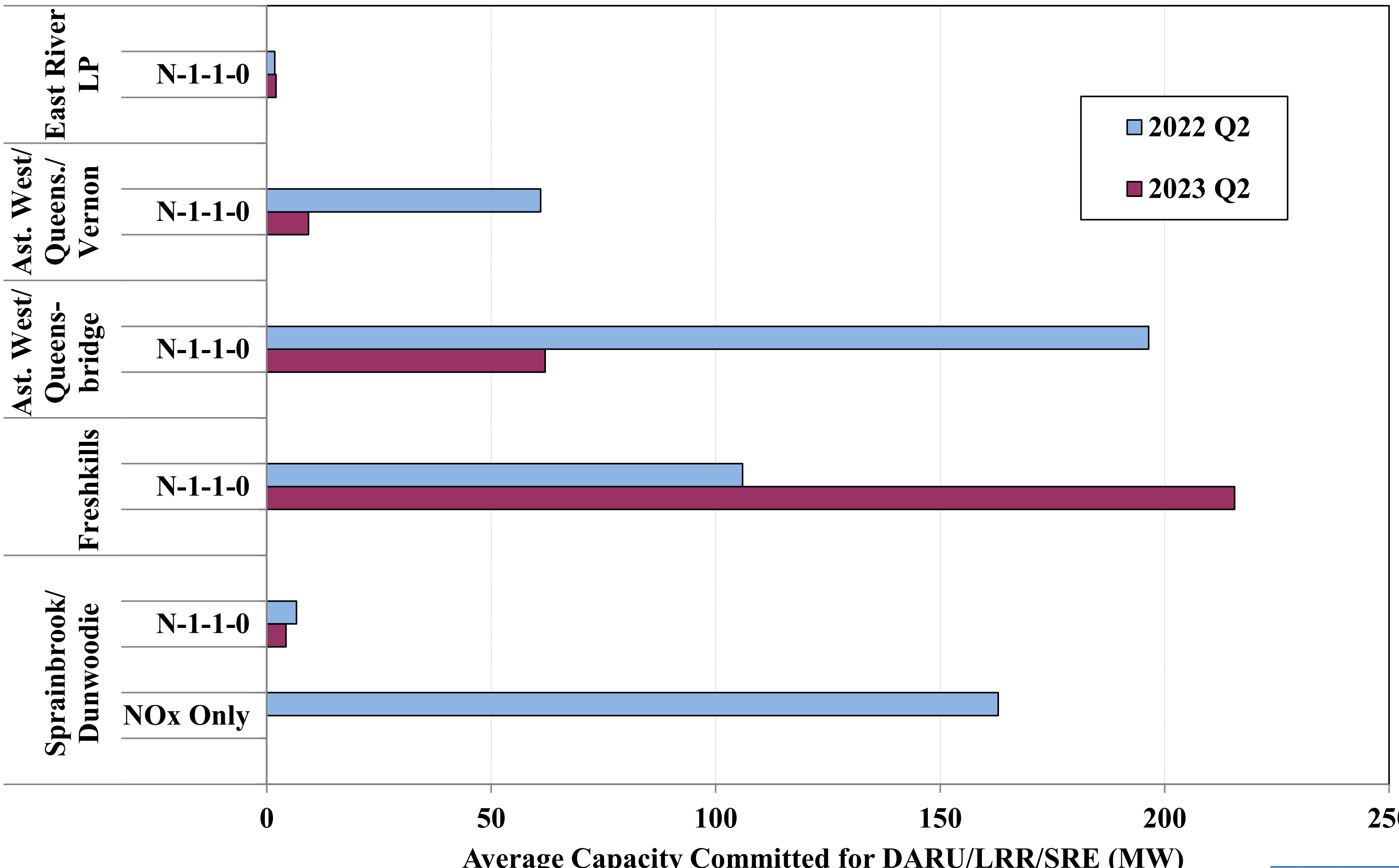


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2023 Q2	0.3%	0.2%	5.1%	0.7%
2023 Q1	1.4%	0.4%	3.7%	0.1%
2022 Q2	0.4%	0.6%	10.9%	1.1%

Notes: For chart description, see slides 97 and 98.

POTOMAC ECONOMICS

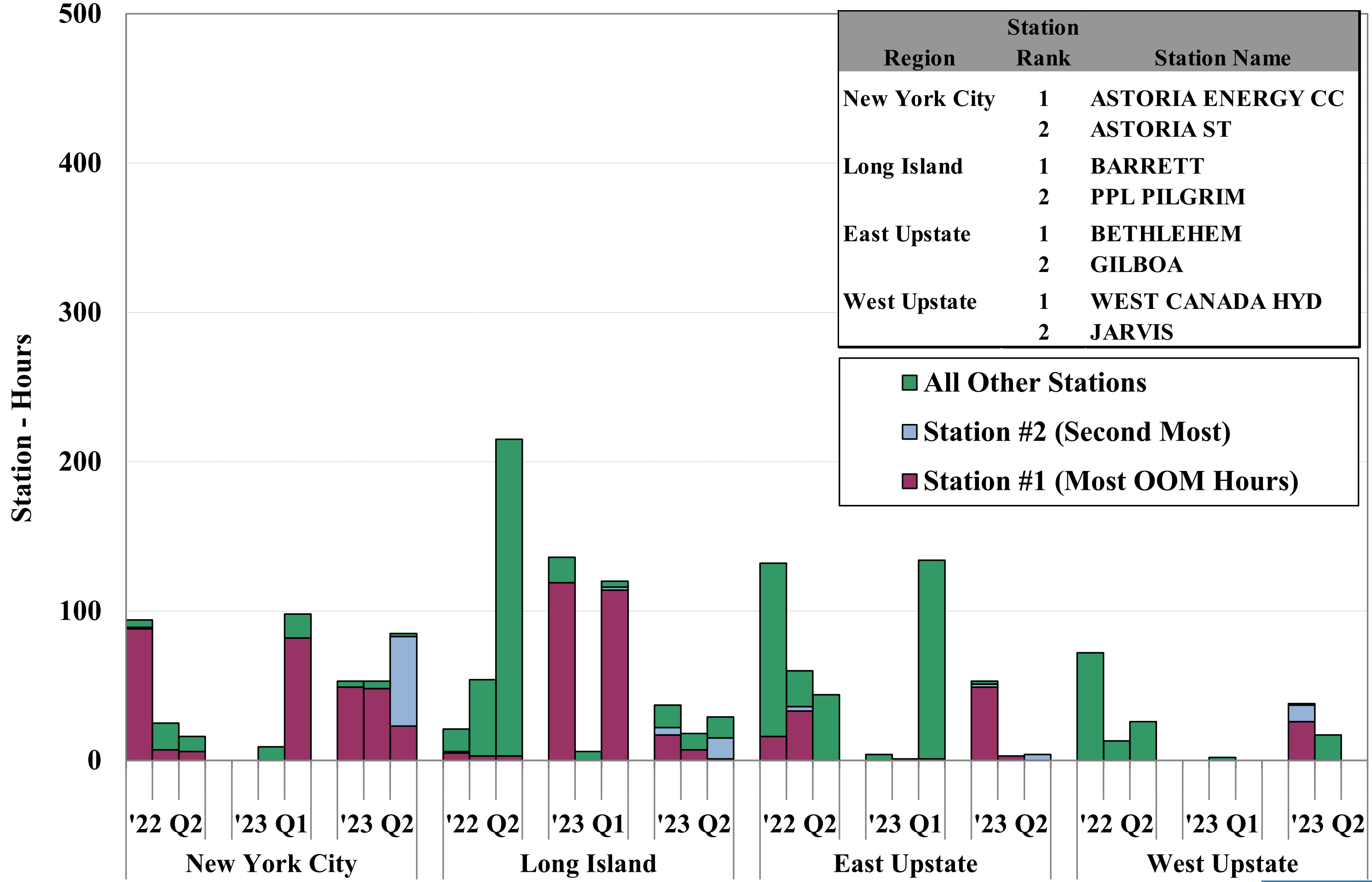
Supplemental Commitment for Reliability in NYC
by Reliability Reason and Load Pocket



Notes: For chart description, see slides 97 and 98.

POTOMAC ECONOMICS

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

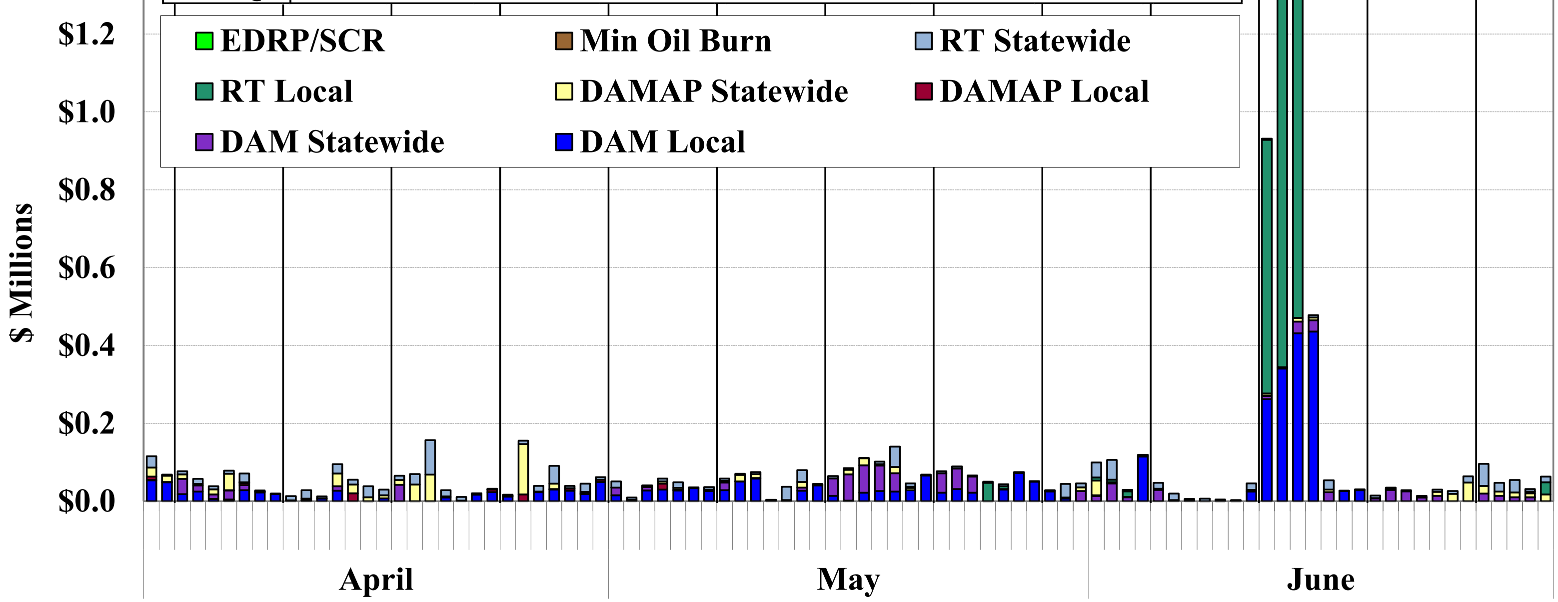


For chart description, see slides 97 and 98.

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

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
2023 Q2	$2.9	$3.0	$0.1	$0.0	$1.0	$1.2	$0.8	$0.0	$9.1
2023 Q1	$1.8	$0.2	$0.1	$0.0	$5.1	$1.5	$1.1	$0.0	$9.9
2022 Q2	$17.5	$1.4	$0.5	$0.0	$0.6	$4.6	$2.1	$0.0	$26.7

Quarterly BPCG By Category (Million $)

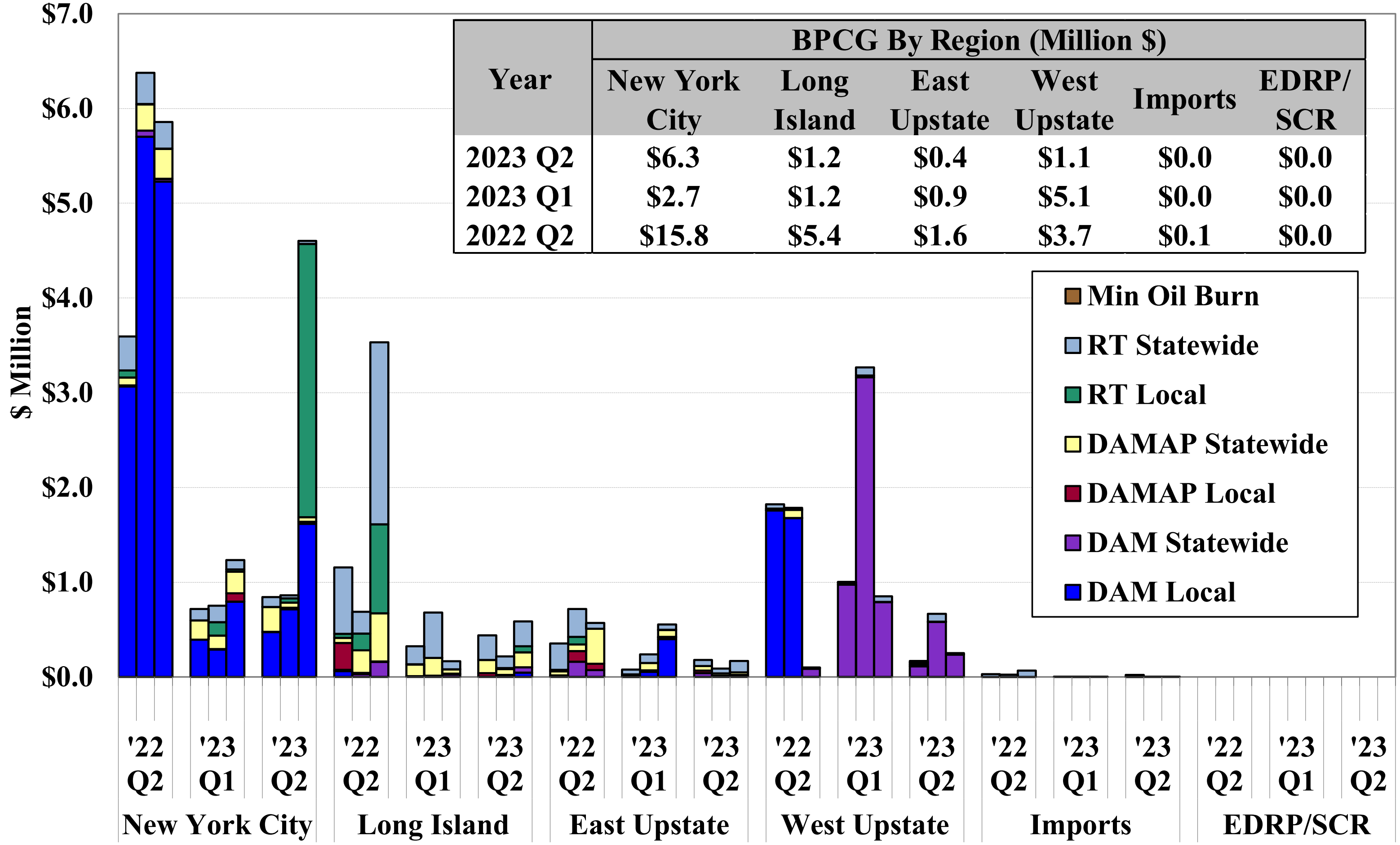


Notes:1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.

2. For chart description, see slide 99.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region



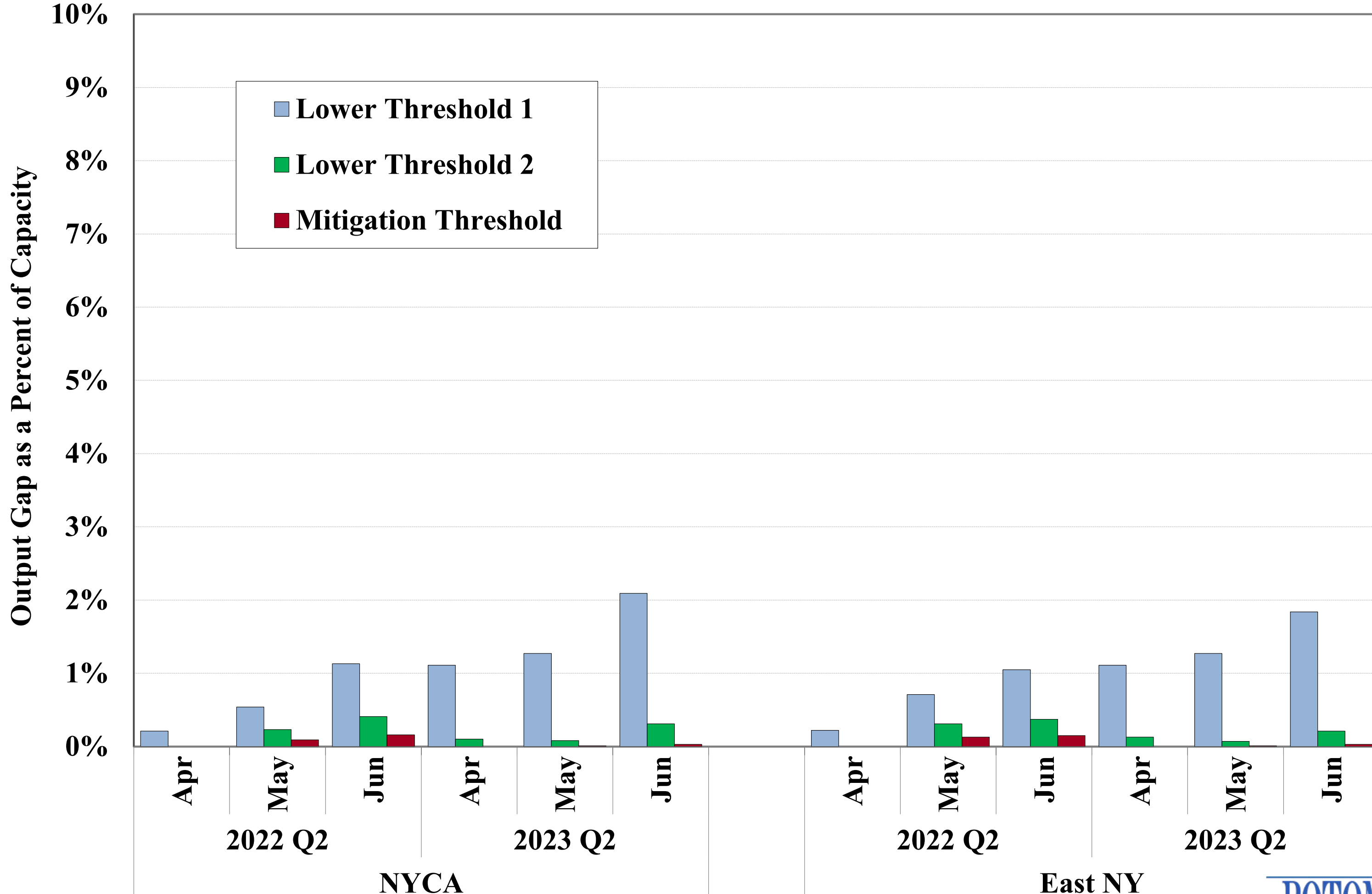
Year	BPCG By Region (Million $)					
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2023 Q2	$6.3	$1.2	$0.4	$1.1	$0.0	$0.0
2023 Q1	$2.7	$1.2	$0.9	$5.1	$0.0	$0.0
2022 Q2	$15.8	$5.4	$1.6	$3.7	$0.1	$0.0

Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 99.

POTOMAC ECONOMICS

Charts:
Market Power and Mitigation

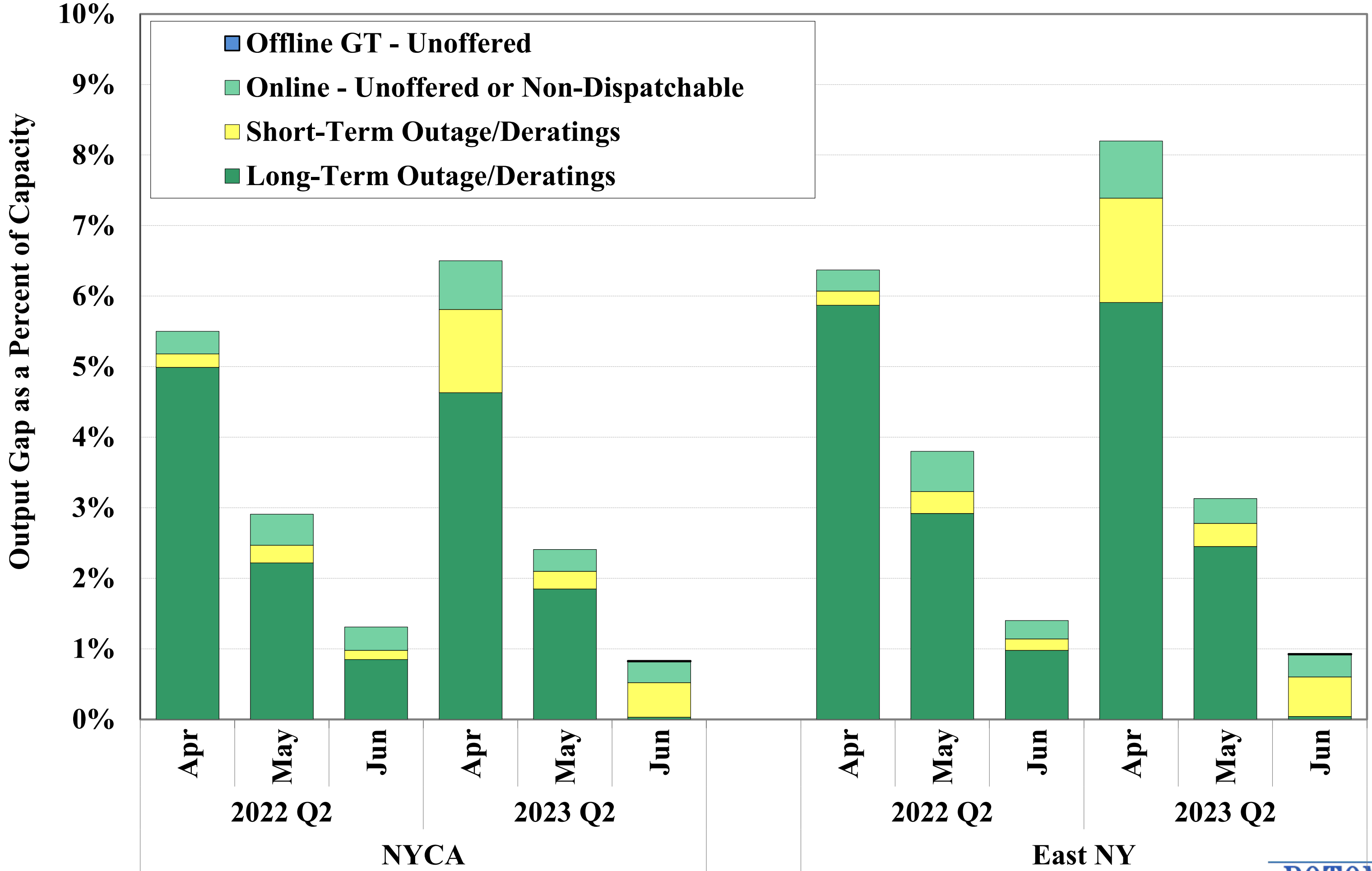
Output Gap by Month
NYCA and East NY



For chart description, see slide 100.

POTOMAC ECONOMICS

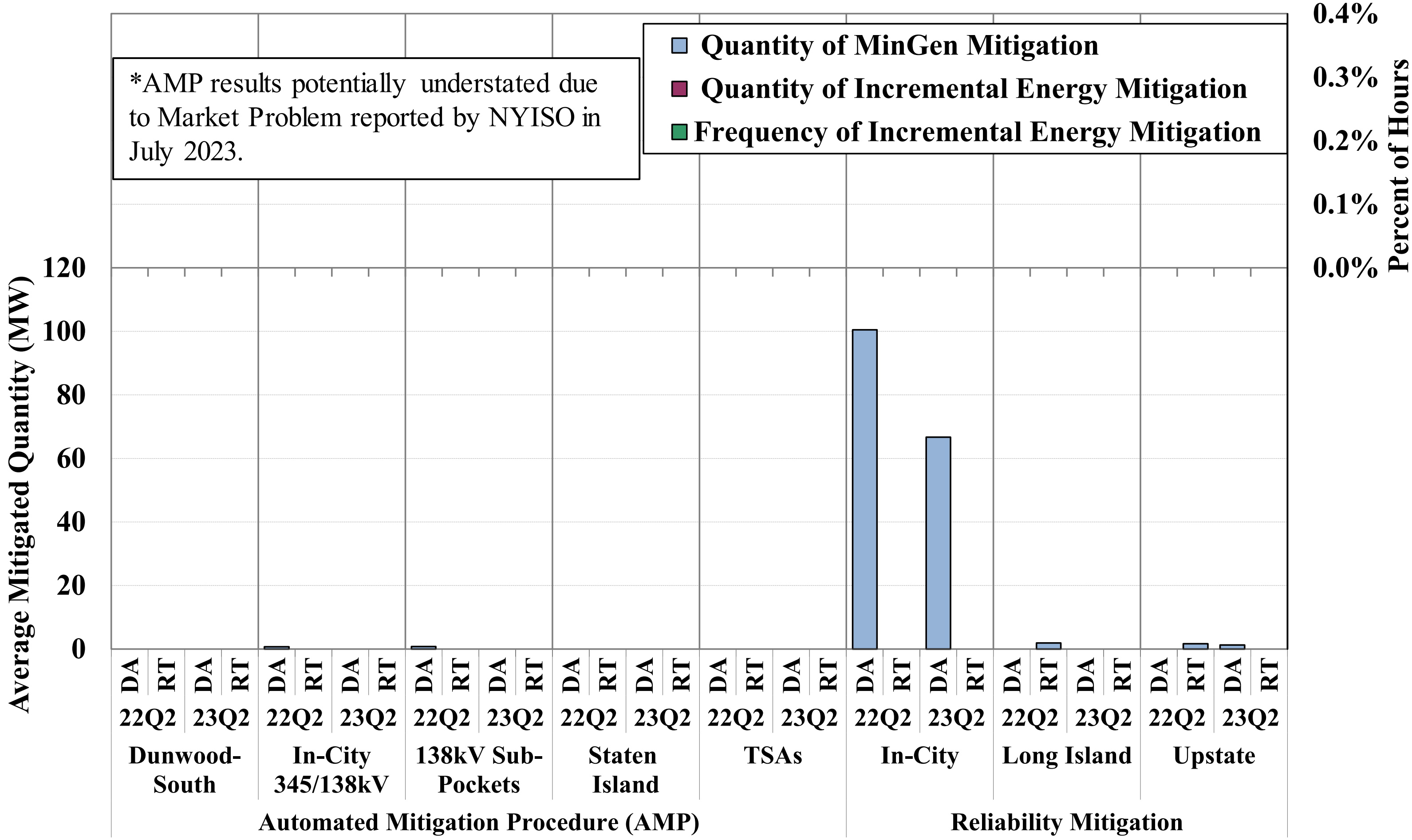
Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 100.

POTOMAC ECONOMICS

Automated Market Power Mitigation

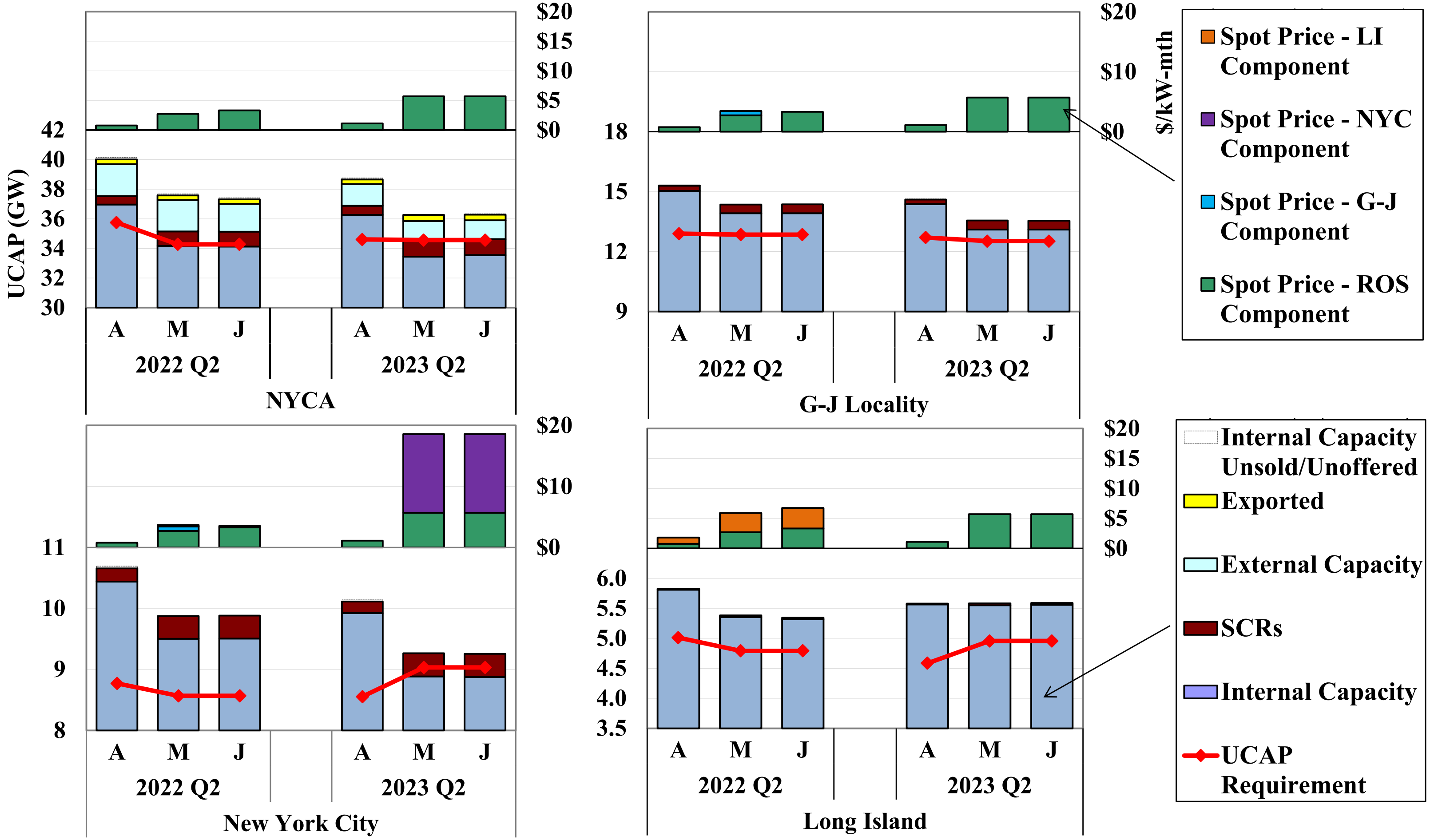


Notes: For chart description, see slide 101.

POTOMAC ECONOMICS

Charts:
Capacity Market

Spot Capacity Market Results
Monthly Results by Locality



Notes: For chart description, see slide 102.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2023 Q2 ($/kW-Month)	$4.17	$12.75	$4.17	$4.17
% Change from 2022 Q2	**84%**	**380%**	**-14%**	**66%**
Change in Demand				
Load Forecast (MW)	282	333	-56	268
IRM/LCR	0.4%	0.5%	5.7%	-3.8%
2023/24 Capability Year	*120.0%*	*81.7%*	*105.2%*	*85.4%*
2022/23 Capability Year	*119.6%*	*81.2%*	*99.5%*	*89.2%*
ICAP Requirement (MW)	**466**	**327**	**234**	**-346**
Key Changes in ICAP Supply (MW)				
Generation	**-522**	**-672**	**142**	**-727**
Entry (3)	81	0	231	0
Exit (3)	-680	-645	-26	-645
Other Capacity Changes (1)	77	-27	-63	-82
Cleared Import (2)	**-697**			

(1) Other changes include DMNC ratings, change in 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 102.

Appendix: Chart Descriptions

All-in Price

- Slide 15 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 18 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 19 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 20-24 evaluate emissions from generators in the NYISO market.
  - ✓ Slide 20 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_X, and SO_2 .
  - ✓ Slides 21-22 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 23-24 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 23 shows the emission from STs in NYC that were supplementally committed for local reliability as a percent of total emission in NYC.

Ancillary Services Prices

- Slides 29-33 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 32 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.

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Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 34 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 36 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 38 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 39 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 40 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 42 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.

RTC and RTD Price Difference vs Load Forecast Difference

- Slide 43 summarizes the RTC/RTD divergence metric results for detrimental factors in the quarter.
  - ✓ 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 44 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 quarter.
  - ✓ 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 45 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.

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Real-Time System Price Maps at Generator Nodes

- Slides 47 and 48 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 49, 50, 51, and 52 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 49 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 50 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 51 and 52 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.

NY-NJ PAR Operation Under M2M with PJM

- Slide 53 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).

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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 54 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.

Constraints on the Low Voltage Network

- Slide 55 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 55 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.

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N-1 Constraints in New York City

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

- Slide 57 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 58 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.

Illustration of Duct Burner Range
Example Generator Hourly Capability

- Slide 59 provides an illustration of how the beginning and end of a typical combined cycle generator's duct-firing ranging varies on an hourly basis across the month of June 2023.
  - ✓ The solid black line shows the hourly Upper Operating Limit ("UOL") of the example generator taken from the day-ahead ("DA") bids across each day of June 2023.
  - ✓ The dashed black line shows the hourly UOL of the generator excluding the duct range, i.e., the UOL of the unit minus its reported duct firing capability.
  - ✓ The shaded blue region shows the capacity associated with the duct burner range. It is assumed that the duct range will be utilized last due to higher costs of firing in that range.
- All capacity values are shown as ratios to the Summer DMNC for the example unit.
  - ✓ For example, it is often the case that a combined cycle will offer a higher UOL than its DMNC due to ambient conditions, especially in the early parts of summer or in the off-peak hours. Thus, the total UOL may be 110% of DMNC and the non-duct burner range ending at 100% of DMNC level.

GT Start-up Performance

- Slides 60-61 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 60): "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".

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Supplemental Commitments and OOM Dispatch

- Slides 63, 64, and 65 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 63 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 64 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 65 summarizes the frequency (measured by the total station-hours) of Out-of-Merit dispatches by region on a monthly basis.
  - ✓ The figure excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.
  - ✓ In each region, “Station #1” is the station with the highest number of OOM hours in its region in the current quarter; “Station #2” is the station with the second-highest number of OOM hours; all other stations are grouped together.

Uplift Costs from Guarantee Payments

- Slides 66 and 67 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 66 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 67 summarizes uplift costs by region on a monthly basis.

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Potential Economic and Physical Withholding

- Slides 69 and 70 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 71 summarizes the automated mitigation that was imposed in the day-ahead and real-time markets (not including BPCG mitigation) in the quarter.
  - ✓ The bars in the upper panel shows the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category.
  - ✓ The bars in the lower panel shows the average mitigated capacity.
    - – Mitigated quantities are shown separately for flexible output range of units (i.e., Incremental Energy) and the non-flexible portion (i.e., MinGen).
  - ✓ The left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on economically committed units in NYC load pockets.
  - ✓ The right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.
  - ✓ Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

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Spot Capacity Market Results

- Slides 73 and 74 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 73 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 74 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.