

Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2025

David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.
Jie Chen, Ph.D.
Paul Allen

Potomac Economics
Market Monitoring Unit

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Market Highlights

Market Highlights

Executive Summary

- NYISO energy markets performed competitively in the second quarter of 2025.
- All-in prices ranged from \$47/MWh in the North Zone to \$94/MWh in NYC, up 36 to 75 percent across all regions from a year ago. (slide [9](#)) Key drivers include:
 - Energy prices rose by 55 to 91 percent across the system, driven primarily by an increase of 59 to 68 percent in natural gas prices.
 - Load peaked at 31.9 GW (post-DR deployment) during the June 23-25 heat wave at the highest level since 2018.
 - Prices were driven by lengthy shortages of statewide and local operating reserves.
 - Quarterly average exports to Quebec reached a record ~600 MW. (slide [47](#))
 - Capacity costs were relatively flat in NYC, while capacity costs rose by 18 to 54 percent elsewhere primarily because of an increase in the NYCA IRM from 122 to 124.4 percent. (slide [20](#))
- Day-ahead market congestion costs were comparable to last year with most congestion across central east, within NYC, and on Long Island, while real-time congestion rose substantially — driven largely by the three-day heat wave, which alone accounted for 44% of total real-time congestion. (slides [10-11](#))

Market Highlights

Executive Summary – Out-of-Market Actions

- OOM commitment was made for NYC load pocket reserves on 50 days. (slide [13](#))
 - In NYC, we found that 62 percent of the capacity could not be “verified” as needed for reliability based on information made available to NYISO. (slide [19](#))
 - Of NYC commitments that we “verified”, 67 percent was surplus headroom or committed to satisfy minimum runtime requirements.
 - We recommend (#2024-1) modeling underlying needs as local reserve requirements.
- OOM dispatch occurred on 26 days for transmission constraints in NYC. (see [14](#))
 - During outages of two Gowanus-to-Greenwood 138 kV lines, NYISO was unable to accurately model transmission constraints related to specific contingencies in the DA and RT markets, resulting in frequent OOM dispatch.
 - NYISO implemented an enhanced modeling of ring bus configurations in its market models in late April, which should help reduce such OOM actions in the future.
- OOM dispatch occurred on 15 days for a load pocket in south-west Long Island where existing units recently submitted deactivation notices. (slide [13](#))
 - Market-based congestion management provides better incentives for suppliers to maintain generating capacity that is needed for reliability.

Market Highlights

Executive Summary – Capacity Performance during the Heat Wave

- NYISO has engaged in multiple reforms to improve capacity accreditation in recent years. This report analyzes the availability of several resource classes during the heat wave and considers implications for accreditation.
- Fossil-fuel generators – These were less available on average than expected based on their EFORd values. During the June 24 event (slide [21](#)):
 - The 22.3 GW of ICAP evaluated had a composite actual EFORd of 6.4 percent (used for ICAP to UCAP translation), while an average of 18.5 percent was unavailable due to forced outage, forced derating, or other under-performance (not related to ambient conditions).
 - We find that EFORd values over-estimate availability for units that are more likely to experience mechanical problems at higher output levels. (see [21](#) for details)
- External ICAP – Approximately 25 percent was cut by neighboring ISOs during the June 24 peak because the transactions were not scheduled with firm transmission service as required. (slide [23](#))
 - We are currently evaluating whether the tariff-prescribed sanction for failing to deliver external ICAP resources is adequate to motivate reliable performance during extreme load conditions.

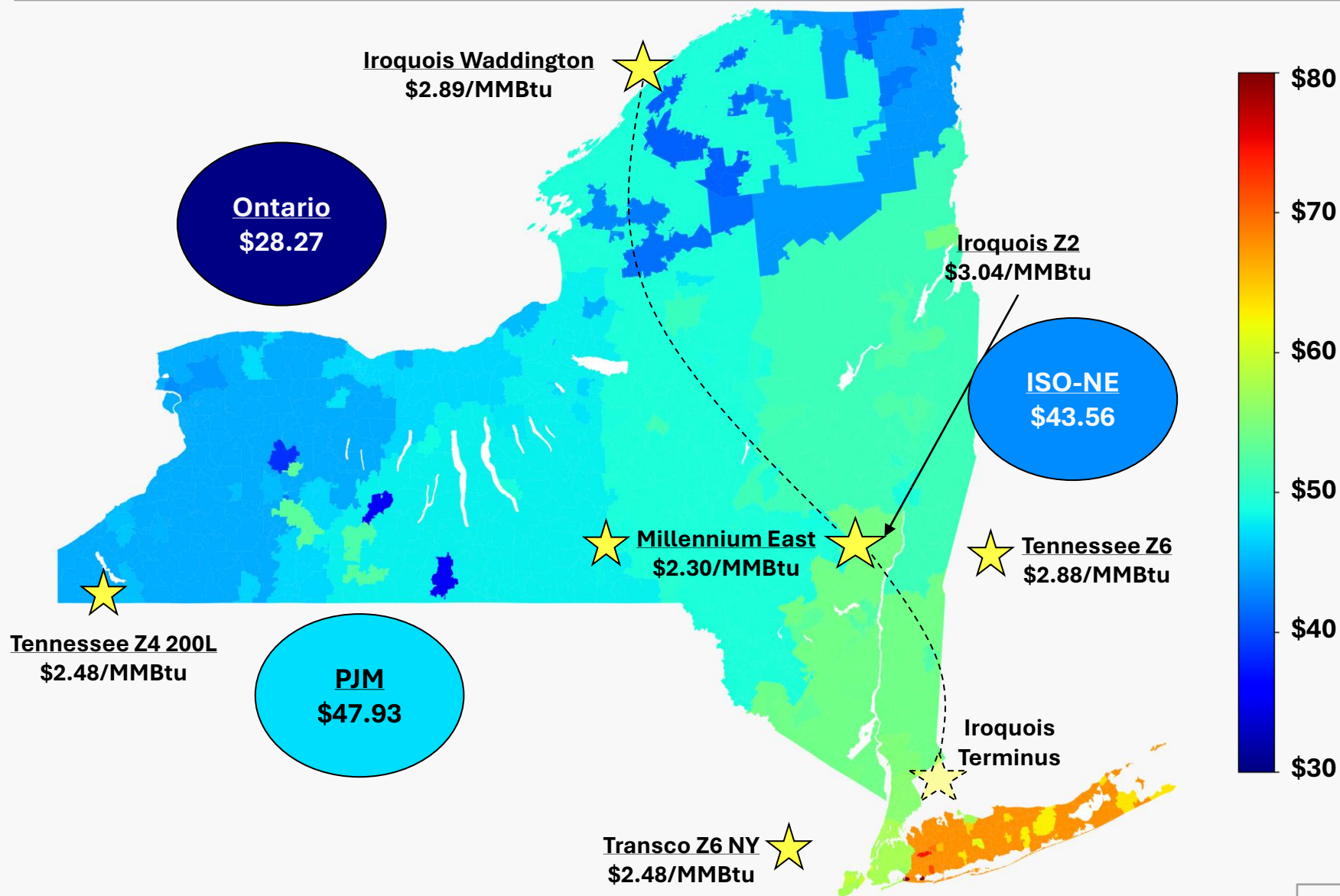
Market Highlights

Executive Summary – Capacity Performance during the Heat Wave (cont'd)

- “Emergency capacity” – Was not used in high load conditions before 2025, but NYISO eliminated the “Capacity Limited Resource” designation and made other reforms requiring emergency capacity to be available to the market and operators starting in May 2025. This report evaluates performance under the new rules during the heat wave of capacity that was offered as “emergency” before 2025. In peak hours of June 24 (slide [22](#)):
 - 147 MW (35 percent) produced energy;
 - 65 MW (15 percent) was unavailable due to ambient conditions; and
 - 213 MW (50 percent) offered as emergency capacity in accordance with the rules but was not scheduled → We recommend NYISO develop procedures to make this capability available to the scheduling software under appropriate conditions.
- Large curtailable loads – Nearly 600 MW participating in SCR+DSASP, DER, and BTM:NG programs were evaluated in this report. (slide [24](#)) While nearly 90 percent of these large loads curtailed in the peak load hour (June 24 Hr 18), we identify several issues:
 - SCR and utility peak shaving programs curtail loads that could provide reserves more cost-effectively.
 - Duration-limited SCRs are not deployed when they would be most valuable.
 - Excess reserves were counted on some resources → NYISO is acquiring telemetry to ensure this does not happen.

Market Highlights

System Price Diagram



Market Highlights

Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the second quarter of 2025.
 - The amount of output gap (slide [81](#)) and unoffered economic capacity (slide [82](#)) remained reasonably consistent with competitive market expectations.
- All-in prices ranged from \$47/MWh in the North Zone to \$94/MWh in New York City, up 36 to 75 percent across all regions from a year ago. (slide [26](#))
 - The increases were driven largely by higher energy prices, which rose by 55 to 91 percent across the system. (slides [36-37](#))
 - The primary driver was a 59 to 68 percent increase in natural gas prices, with the highest levels observed during the June 23-25 heat wave. (slide [28](#))
 - Although average load fell by 2 percent, load spiked substantially during the heat wave, peaking at 31.9 GW on June 24, which was 13 percent higher than last year and the highest level (post-DR deployment) since 2018. (slide [27](#))
 - ✓ On June 24 from 5:00 to 8:00 pm, average real-time LBMPs ranged from ~\$1,300/MWh in central NY to ~\$1,800 in most of eastern NY and ~\$3,500 in Long Island. (slide [37](#))
 - Average exports to Quebec also rose to an all-time high of roughly 600 MW, contributing to elevated energy prices. (slide [47](#))
 - Capacity costs rose by 18 to 54 percent in all regions except NYC, where they fell slightly (2 percent). (see slide [20](#) for further discussion).

Market Highlights

Congestion Patterns, Revenues, and Shortfalls

- Day-ahead congestion revenues totaled \$57 million in 2025-Q2, down modestly from a year ago. (slide [60](#))
 - Day-ahead congestion totaled approximately \$30 million in April and May, more than doubling from a year ago. This increase is consistent with higher natural gas prices and prolonged major transmission outages in NYC this year.
 - Congestion spiked during the June 23-25 heat wave, which accounted for 27 percent of total congestion in the day-ahead market and 44 percent in the real-time market.
- Long Island lines accounted for the largest share of total congestion (27% in DA, 34% in RT) in the second quarter of 2025.
 - One or more of the Shore Road-to-Lake Success 138 kV lines and the Valley Stream-to-Stewart Ave 138 kV lines were switched OOS throughout the quarter to control high voltage during light load conditions.
 - The resulting congestion along their parallel paths accounted for over 50 percent of total quarterly congestion.
 - These line-switching actions led to ~\$3 million in day-ahead congestion shortfalls, which were charged to the responsible TO, and ~\$1 million in balancing congestion shortfalls, which were uplifted to NYCA load.

Market Highlights

Congestion Patterns, Revenues, and Shortfalls (cont.)

- Other key congestion drivers included:
 - Increased flows from Long Island to NYC over the 901/903 lines, which averaged 230 MW in the DAM and 260 MW in the RTM, doubling the levels from a year ago.
 - ✓ These elevated flows reduced associated DAM congestion surpluses (slide [62](#)), but increases in scheduled flow after the DAM contributed to balancing congestion shortfalls (slide [64](#)).
 - Reduced imports over the Cross Sound Cable, which was on a maintenance outage for most of May, which led to more congestion from west to east on Long Island.
- NYC facilities accounted for the second largest share of congestion in 2025-Q2.
 - New York City congestion increased over 80 percent year-over-year.
 - In addition to higher gas prices, transmission outages were a major contributor.
 - The Gowanus-Greenwood 138 kV 42231 line was forced out of service through most of April, while the parallel 42232 line was forced out until early May.
 - The Astoria Annex-E. 13th St. 345 kV Q35L line was forced out from late April through the remainder of the quarter, limiting deliverable generation from the Astoria Annex.
 - These outages contributed approximately \$6 million in day-ahead congestion shortfalls. (slide [62](#))
- RT congestion values more than doubled DA congestion values in 2025-Q2.
 - This was largely driven by sharp spikes in real time congestion during the June heat wave, caused by high load levels, generation deratings and outages, and stressed conditions in neighboring markets that were not fully anticipated in the day-ahead market.

Market Highlights

Allocation of DAM Congestion Residuals

- Day-ahead congestion shortfalls and surpluses (“residuals”) occur when day-ahead network capability differs from the modeled capability in the TCC auctions.
- NYISO allocates DAM congestion residuals to NYTOs using a two-stage process:
 - First, congestion residuals resulted from Qualifying facility changes (e.g., outages, return-to-services, and uprate/derate) are allocated to responsible TOs on a “cost causation” basis. (see OATT 20.2.4 Formula N-5 through N-14)
 - Second, remaining congestion residuals (“Net Congestion Rents”) are socialized to all TOs in proportion to their TCC revenues rather than DAM congestion patterns. (see OATT 20.2.5 Formula N-15)
- In this quarter, ~\$13M of shortfalls were allocated to responsible TOs on a cost causation basis, while ~\$5M of net surpluses were socialized to all TOs.
 - Among socialized residuals, we estimate that: (slides [62](#) - [63](#))
 - \$3.4 million of surpluses were associated with transmission upgrades from the Segment A & B Public Policy projects.
 - \$2.1 million of surpluses accrued on Long Island facilities.
 - We have recommended the NYISO revise the residual allocation method based on incremental transfer capability scheduled in the DAM. (see Rec. #2023-1)

Market Highlights

OOM Actions to Manage Network Reliability

- OOM commitments to satisfy N-1-1 and N-1-1-0 requirements occurred on 12 days in the North Country load pocket and 50 days in NYC load pockets. (slide [66](#))
 - It would be beneficial to incorporate the full reserve requirements into the market model for resource scheduling and pricing in these local areas. (see Rec. #2024-1)
- OOM commitments to address high voltage risks during light load conditions occurred on 58 days on Long Island. (slide [66](#))
 - Large steam turbines were supplementally committed for this need, which reduced LBMPs and led to BPCG uplift.
 - The frequency of OOM commitment for high voltage has increased from the previous year, when high voltage conditions were more frequently addressed by taking lines out of service (to increase reactive power losses). (see slide [10](#))
- OOM dispatch occurred on 15 days in south-west Long Island to secure the West Hempstead-to-Malverne 69kV line.
 - Existing units in this pocket recently submitted a [deactivation notice](#). (slide [67](#))
 - Market-based congestion management provides better incentives for suppliers to maintain generating capacity that is needed for reliability.

Market Highlights

OOM Actions to Manage Network Reliability (cont.)

- OOM actions occurred on 26 days in the second quarter of 2025 to manage transmission constraints in New York City. (slide [66](#))
 - From mid-February to late April, when both Gowanus-Greenwood 138 kV lines were out of service, a circuit breaker contingency within the Greenwood ring bus configuration emerged as the most severe contingency for adjacent facilities.
 - This contingency shifted load within the Greenwood load pocket in a manner not represented in the NYISO market model.
 - To manage this constraint, peaking resources within the load pocket were OOM committed in both day-ahead and real-time markets.
 - Over this two-month period, these OOM actions resulted in a total of ~\$8 million in BPCG uplift payments.
 - The DAM BPCG uplift (~\$1.7M) was allocated to **local** load, while the RT BPCG uplift (~\$6.3M) was socialized across **system-wide** load.
 - NYISO implemented an enhanced modeling of ring bus configurations in its market models in late April, which should help reduce such OOM actions in the future.
 - When congestion is managed through the market, costs are naturally allocated to the **local** zone(s) that benefit from congestion relief.

Market Highlights

Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled \$13.5 million, up 61 percent year-over-year, driven partly by elevated natural gas prices. (slide [78](#))
- New York City accounted for the largest share (50 percent).
 - \$2.5 million was paid to generators committed for N-1-1-0 reliability. (slide [75](#))
 - \$1.7 million was paid to units OOM dispatched to manage congestion into the Greenwood pocket for contingencies not modeled in the RT market model during Gowanus-Greenwood 138 kV line outages. (slide [14](#))
- Long Island accrued nearly \$5 million (or 35 percent) of BPCG uplift this quarter.
 - \$2.0 million was paid to generators committed for managing high voltage during light load conditions.
 - DAMAP payments accounted for \$1.6 million, with over 60 percent accrued during the 3-day heat wave in June.
 - A key driver of payment was an inconsistency between the scheduling and pricing of reserves—reserve clearing prices do not account for the costs of satisfying the Long Island reserve requirements. We have recommended NYISO address this inconsistency. (see Rec. #2019-1)

Market Highlights

Regulation Market Performance

- A single movement-to-capacity ratio is used to formulate composite offer prices for all resources when scheduled for providing regulation.
*Composite offer price = capacity offer price + movement ratio * movement offer price*
- However, resources are deployed according to their actual ramp capability and compensated based on instructed movement and actual performance.
 - Resources exhibited a wide range of movement-to-capacity ratios (slide [45](#)); and
 - The average ratio was close to 13 over the past two years. (slide [44](#))
 - The average ratio has risen due to the entry of new fast-ramping regulation suppliers, primarily battery storage resources.
 - NYISO adjusted the assumed ratio from 8 to 13 recently in May 2025 to improve consistency between scheduling assumptions and actual operations.
 - Using a single movement-to-capacity ratio for all units can significantly underestimate the costs of fast-ramping resources in the scheduling process, which can lead to inefficient scheduling and market incentives.
 - Accordingly, we will continue to monitor regulation market costs.

Market Highlights

RT Pricing of GTs Bidding Multi-Hour MRT

- The fast-start pricing rule is currently not applied to fast-start units that submit a Minimum Run Time (“MRT”) offer exceeding one hour.
 - However, the RT scheduling software (RTC and RTD) and market settlement rules ignore their MRT offers and treat them in every other way the same as a unit that submits a one-hour MRT.
 - This creates an inconsistency between the purpose of fast-start pricing and the eligibility criteria for fast-start pricing, leading to inefficient real-time prices.
- We identified seven groups of GTs in New York City and Long Island that were sometimes not eligible to set price because of this issue. (slide [56](#))
 - In 2025 Q2, LBMPs were below the GTs’ as-bid costs in approximately 40 percent of the hours when these GTs were committed.
 - If these GTs were eligible to set prices like other fast start units, the average LBMP during these hours would have increased by up to \$8 to \$163 per MWh at individual locations.
- We have recommended the NYISO revise the eligibility for fast-start pricing to be based on the minimum run time used for scheduling, rather than the value of the offer parameter. (See Recommendation #2023-2 in our 2024 SOM report).

Market Highlights

Virtual Imports and Exports in the DAM

- We define virtual imports and exports as external transactions that are scheduled in the DAM but withdrawn from the RTM (i.e., no RT bids submitted).
 - These are commonly scheduled between NYISO and neighboring control areas, averaging over 600 MW in the net import direction during the quarter. (slide [50](#))
- We identify two issues related to virtual imports and exports:
 - In the DAM, virtual imports and exports are treated as physical energy but fail post-DAM checkout with neighboring control areas. This may lead:
 - The Forecast Pass of the DAM to not commit sufficient resources, and
 - The need for SRE commitments to address capacity deficiencies after the DAM.
 - Furthermore, we have highlighted market inefficiencies that will arise when the Dynamic Reserve design is implemented because it will treat virtual and non-firm transactions as able to satisfy operating reserve requirements.
 - In RTC, despite failing post-DAM checkout, virtual transactions are treated as:
 - Available in RTC's advisory scheduling time frame, but
 - Unavailable in RTC's binding scheduling time frame.
 - This inconsistency can lead to ramp constraints in RTC's advisory scheduling time frame that distort RT prices and schedules in the binding time frame.

Market Highlights

DARU/LRR/SRE Commitments for N-1-1-0 Requirements in NYC

- Our assessment of supplemental commitments to satisfy N-1-1-0 reliability needs in New York City indicated that: (Slides [75](#) & [118](#))
 - 16 percent was “economic” in the DAM; and
 - 22 percent was “verified” (by the MMU) as needed to satisfy a specific reliability requirement based on information available in the DAM and RTM related to forecasted load, status of generation and transmission equipment, and potential contingencies.
 - Only 33 percent of total verified MWh was needed for the identified requirement, while the remaining 67 percent was surplus headroom on the unit committed (including hours committed to satisfy a Minimum Run Time requirement).
 - Smaller flexible resources like batteries and DERs may be more cost-effective solutions for managing reliability needs. However, the market does not provide incentives for satisfying these local needs. We have recommended modeling these requirements in the market (See Rec #2024-1).
 - 62 percent was “not verified” (by the MMU).
 - Some of this capacity was likely committed due to over-forecasting of load at the time of the DARU or local TO requirements not communicated to NYISO.

Market Highlights

Capacity Market Outcomes

- Spot capacity prices averaged \$13/kW-month in NYC and \$3.99/kW-month elsewhere. (slides [85-86](#))
 - Spot prices increased 20 to 35 percent in all regions except NYC, where they decreased by 6 percent.
- Administrative changes impacting the new Capability Year (beginning May 2025) drove most of the differences in prices year-over-year.
 - The reduction in NYC prices was influenced by a 340 MW reduction in the ICAP requirement, due to a lower load forecast and a decrease in the LCR from 80.4 percent to 78.5 percent.
 - Both LI and G-J Locality prices were consistent with ROS prices, reflecting sufficient supply margin in the two local regions.
 - The elevated ROS prices were attributable to several factors, including:
 - A 667 MW increase in the ICAP requirement, driven primarily by an increase in the IRM from 122 to 124.4 percent;
 - A reduction of approximately 260 MW in internal generation supply; and
 - A decline of 74 MW in average capacity imports.

Market Highlights

Performance during Heat Wave – Fossil Fuel Generators

- Generators sell capacity in the NYISO as Unforced Capacity (UCAP), which is equal to Installed Capacity (ICAP) times EFORd which is meant to measure how much capacity a resource could reliably provide when in demand. (slides [87-89](#))
- We reviewed the performance of fossil fuel resources across the system during the June 23-25 Heat Wave to compare actual performance against their weighted-average EFORds. Over peak hours of the highest load day, we observed:
 - 2.6 GW of outages and derates on conventional steam turbine generators;
 - 1.3 GW of outages and derates on combined cycle generators in eastern NY; and
 - 0.2 GW of outages and derates on fossil-fired peaking units.
 - The 22.3 GW of ICAP evaluated had an average EFORd of 6.4 percent. However, the average amount of capacity on outage or derated over the June 24 peak window was estimated to be 18.5 percent, which is 2.7 GW lower than expected based on EFORds.
- The EFORd metric estimates how frequently a unit is forced out or derated relative to Service Hours (SH). However, all Service Hours are treated the same regardless of output level, so units that: (a) frequently operate at low output levels and (b) are more likely to experience problems at high output levels (such as fossil-fuel steam turbines) have EFORds that tend to under-estimate their likelihood of being unavailable.

Market Highlights

Performance during Heat Wave – Current & Former Emergency Capacity

- The NYISO eliminated the “Capacity Limited Resource” (CLR) program and limited participation in the capacity market by “emergency capacity” (i.e., the output range above UOLn and below UOLe) starting in May 2025. Under the new rules:
 - Output ranges sold as ICAP generally must be offered in the DAM under the UOLn.
 - Exceptions are allowed for: (1) block-loaded peaking units with peak firing capability and (2) combined cycle generators with duct firing.
 - Conventional steam turbines that can boost capacity by making configurational changes must offer that capacity to the DAM as “normal capacity” (i.e., under the UOLn).
- Emergency capacity was generally not used for energy or reserves in high load conditions before 2025, so we are able to evaluate the performance of these resources for the first time.
- For capacity that participated as emergency capacity before May 2025, we observed the following average performance during NYISO’s Energy Warning on June 24 (slide [90](#)):
 - 92 MW was dispatched of which 74 MW performed reliably.
 - 65 MW would have been economic but was derated due to ambient air temperature or water temperature conditions.
 - 73 MW was not scheduled but voluntarily produced anyway.
 - 213 MW was not scheduled for energy or reserves and did not produce energy → This capacity (and the 73 MW that produced voluntarily) was not recognized by the real-time dispatch model as available. Procedures are needed to recognize emergency capacity as available during peak load conditions.

Market Highlights

Performance during Heat Wave – External ICAP Resources

- NYISO operators issued calls for SREs of external ICAP from resources outside of the NYCA on each day of the June 23-25 heat wave.
 - External ICAP resources are obligated to obtain sufficient transmission service to deliver when called upon in the regular SRE process after the day-ahead market.
- In June 2025, just under 2.5 GW of external capacity was sold into the NYISO. We analyzed the performance of these suppliers and found: (slide [91](#))
 - A small deficiency in all hours, generally ranging from about 10-25 MW; and
 - Neighboring ISOs cut imports that were not scheduled with firm transmission service as required in several peak hours on June 24.
- We are currently evaluating whether the tariff-prescribed sanction for failing to deliver external ICAP resources is adequate to motivate reliable performance during extreme load conditions.

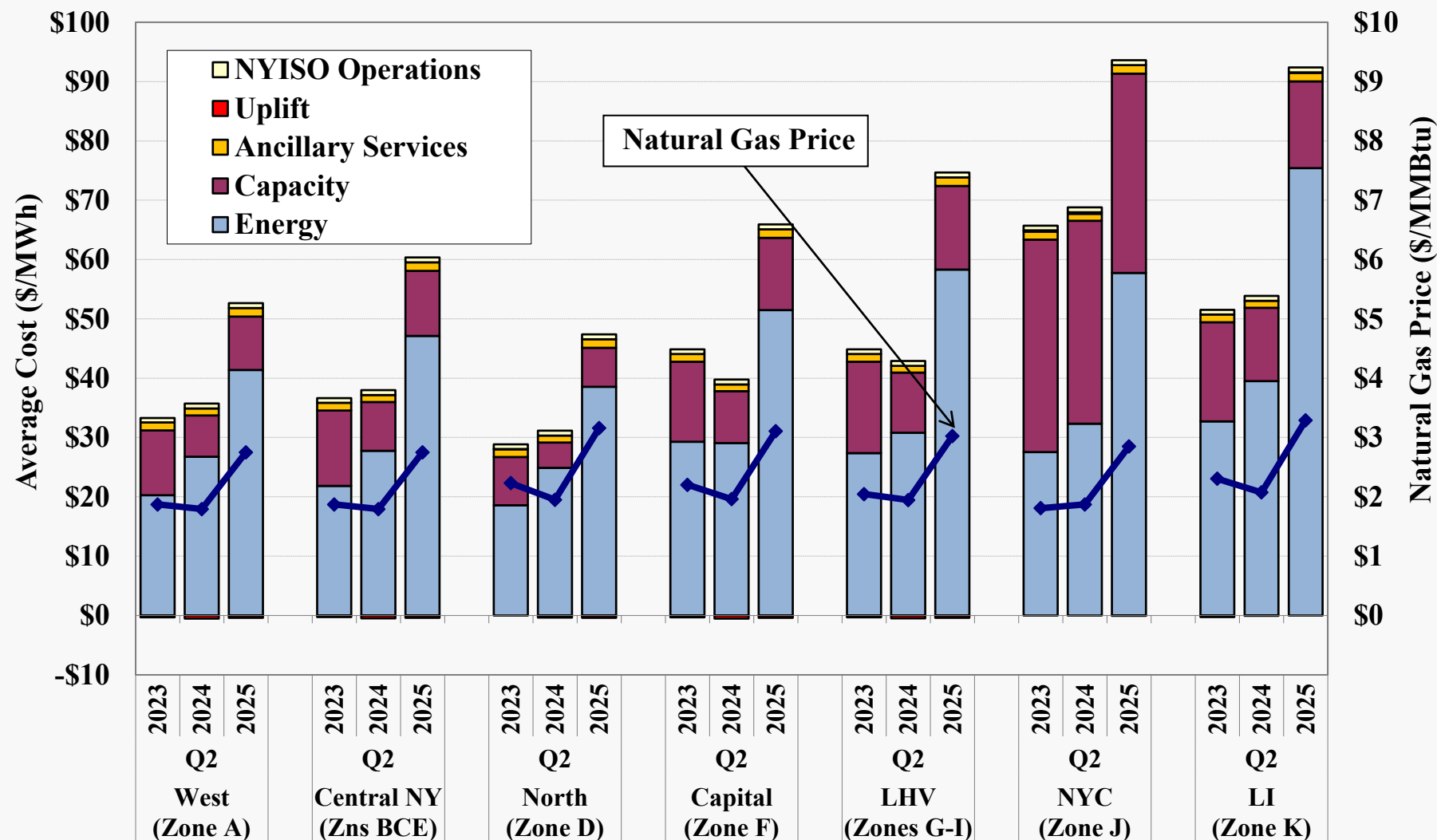
Market Highlights

Performance during Heat Wave – Large Curtailable Loads

- NYISO's DR programs have facilitated voluntary curtailment for over two decades. Large load participation has grown recently at behind-the-meter ("BTM") and standalone facilities. The report examines preliminary data on the performance of nearly 600 MW of large loads participating in SCR+DSASP, DER, and BTM:NG programs. (slide [92](#))
- While nearly 90 percent of these large loads curtailed in the peak load hour (June 24 Hour 18), some curtailable loads were not operated efficiently on the peak days:
 - Over 200 MW of SCRs were curtailed when they would have been more efficient providing reserves (as DSASP resources) → A deficiency of SCR and utility peak shaving programs is that they curtail loads that could provide reserves more cost-effectively.
 - 70 MW of SCRs curtailed for four hours as required but then increased consumption during the highest load hour on each day → Duration-limited SCRs are not deployed when they would be most valuable.
- Up to 300 MW of excess reserves (i.e., where the reserve schedule exceeded the amount of curtailable load at a facility) were counted on some resources → NYISO is acquiring telemetry necessary to ensure that energy and reserve schedules do not exceed the amount of curtailable load at a facility.
- BTM:NG loads generally performed well, fully curtailing during peak periods, although this program does not allow loads to provide reserves when efficient to do so.

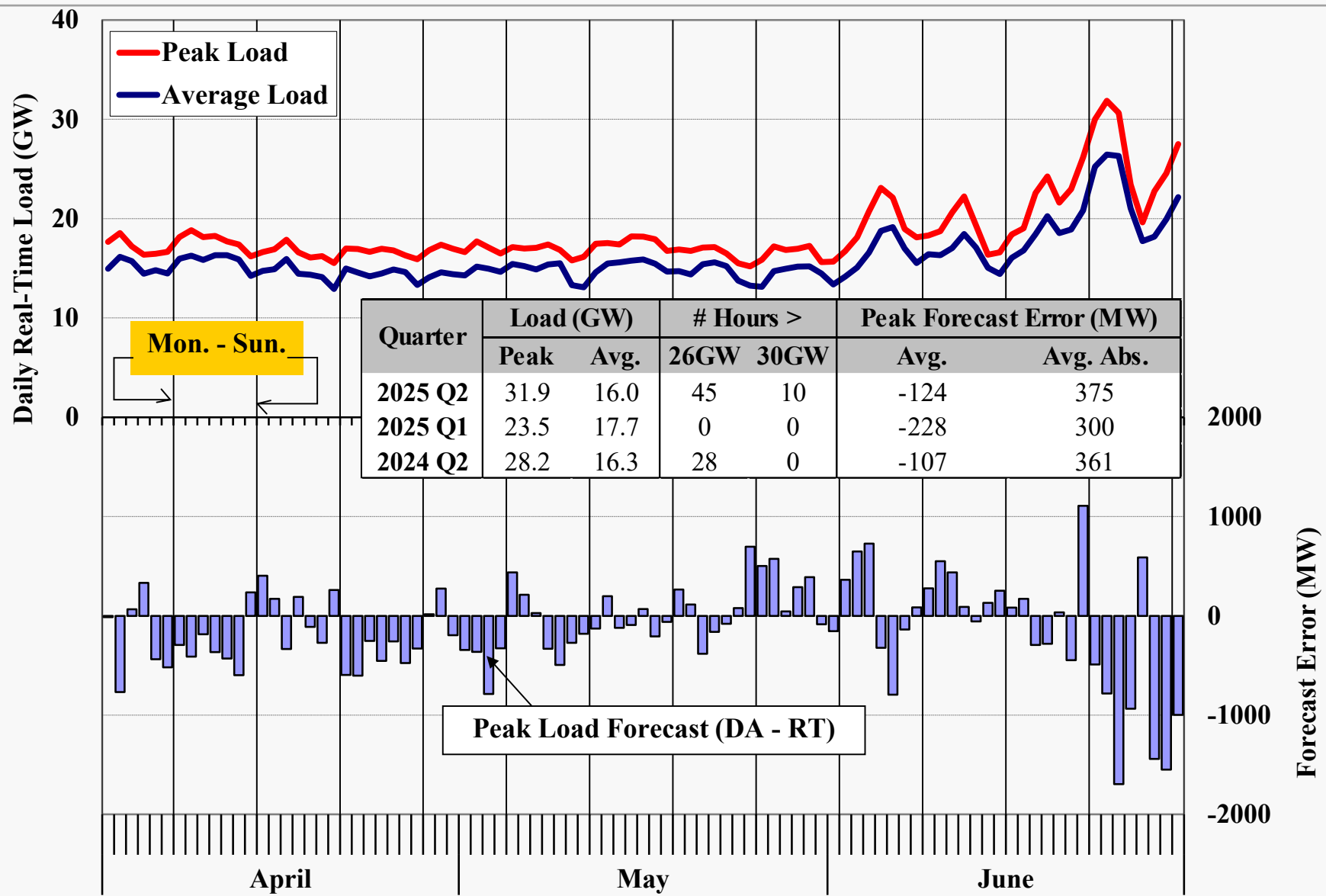
Charts: Market Outcomes

All-In Prices by Region

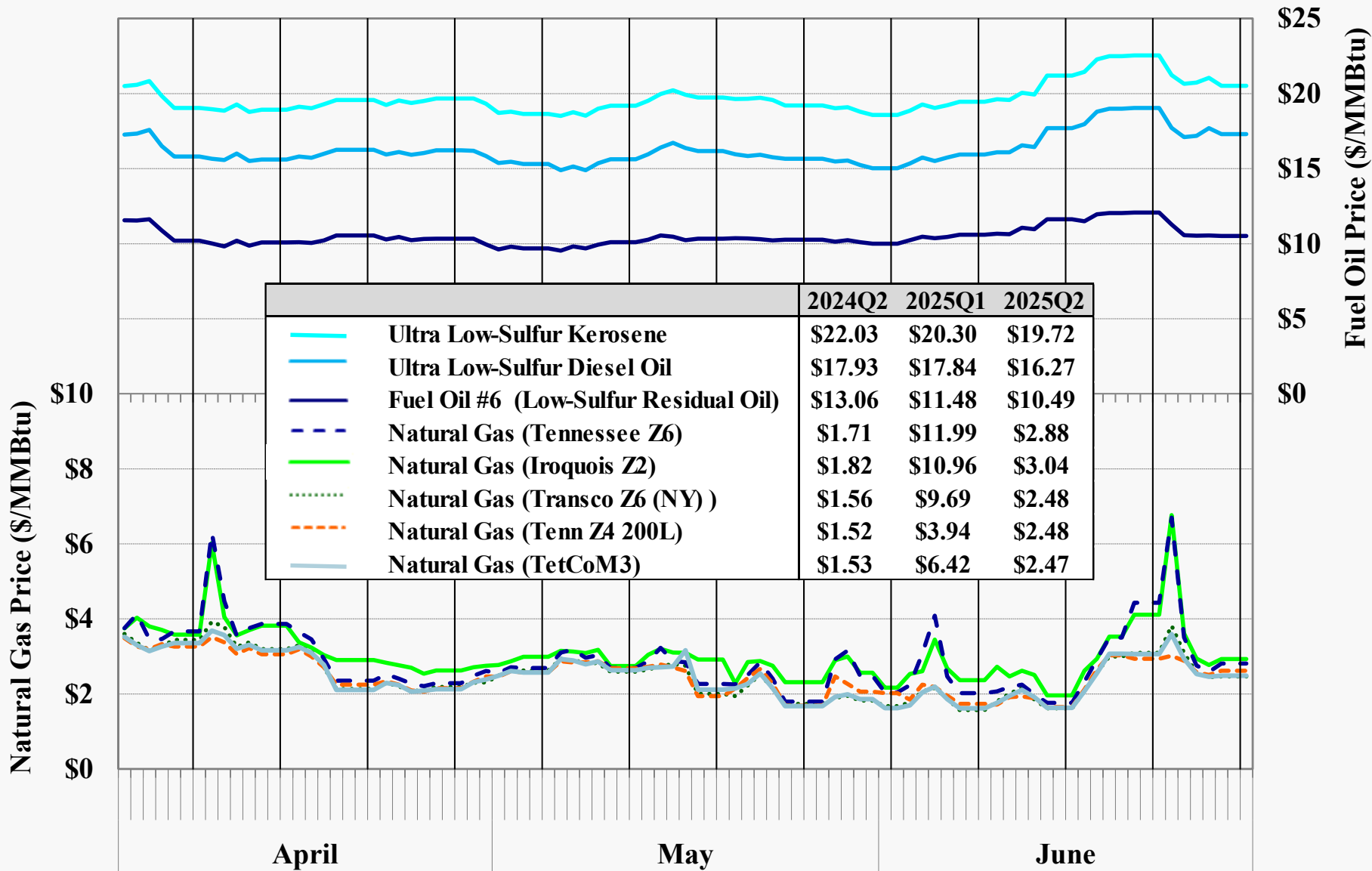


Notes: For chart description, see slide [94](#).

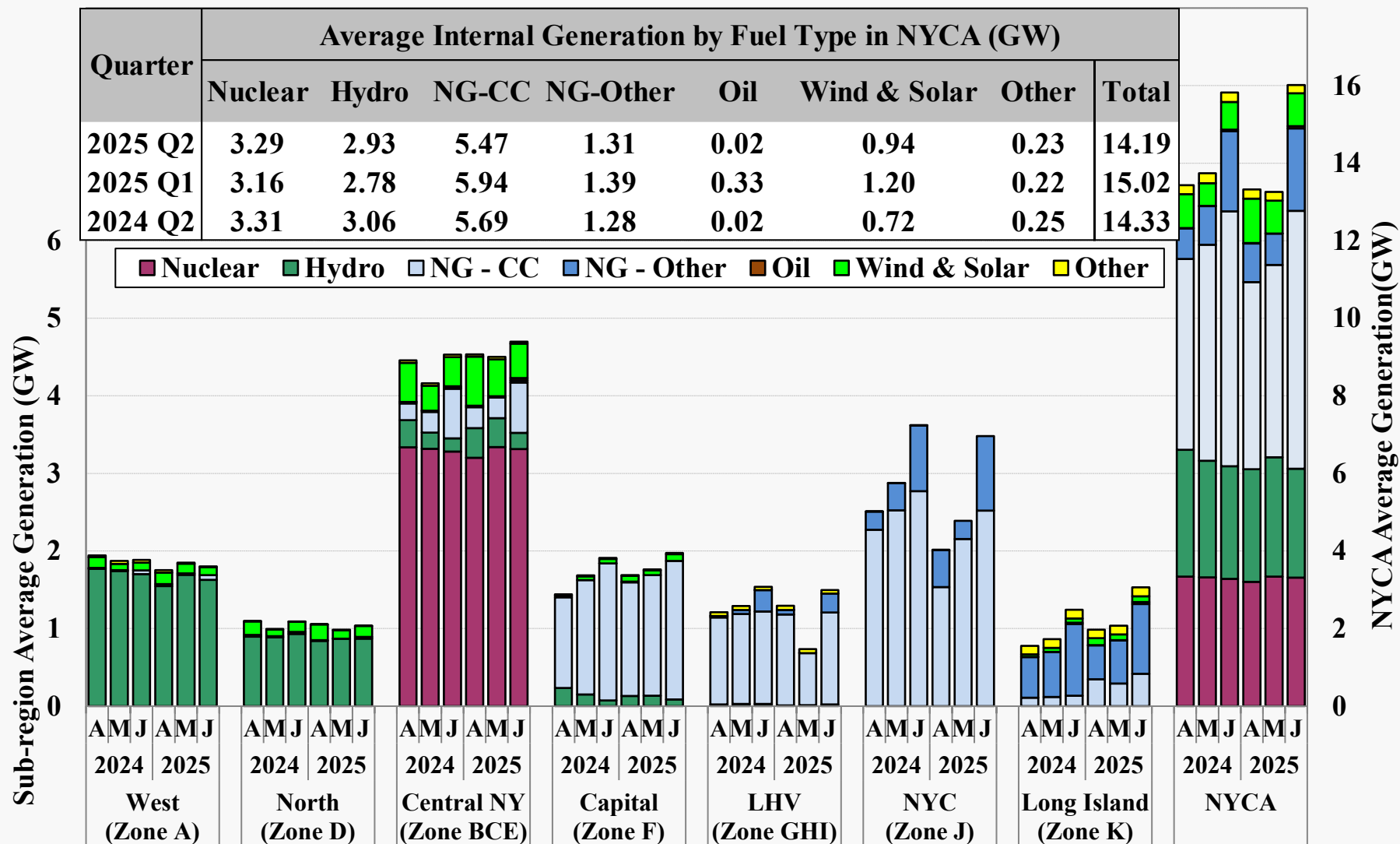
Load Forecast and Actual Load



Natural Gas and Fuel Oil Prices



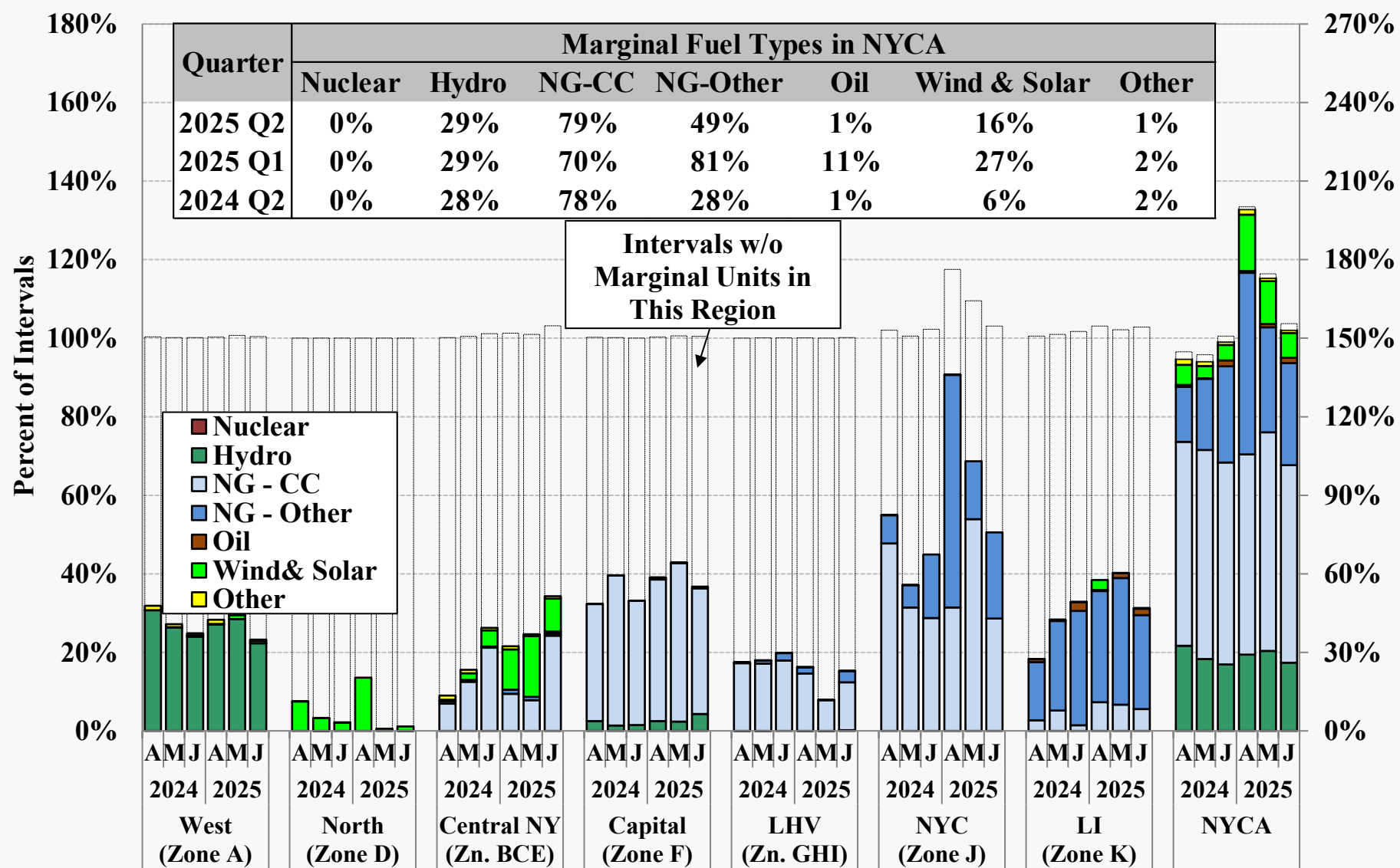
Real-Time Generation Output by Fuel Type



Notes: For chart description, see slide [95](#).

Fuel Type of Marginal Units

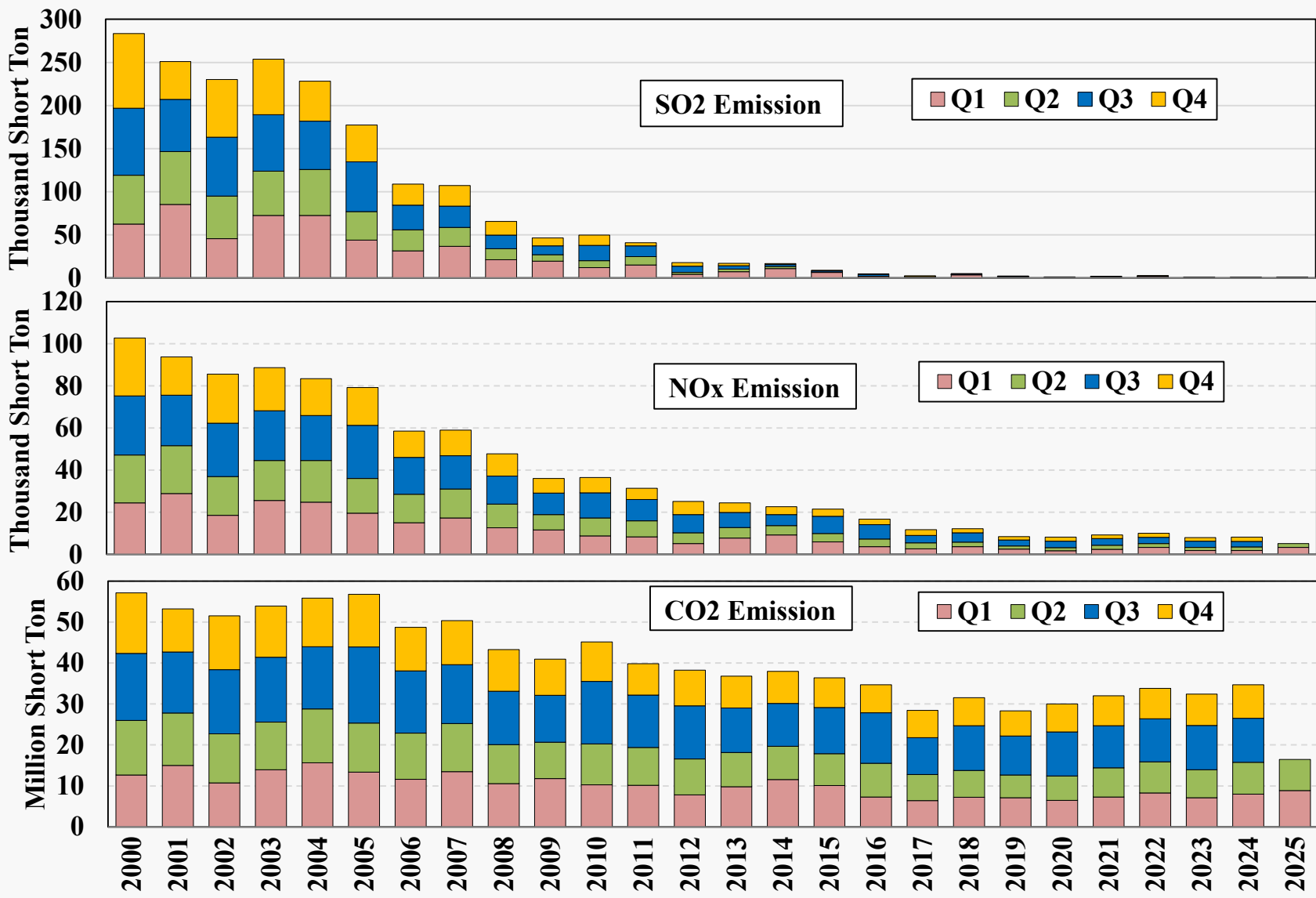
In the Real-Time Market



Notes: For chart description, see slide [95](#).

Historical Emissions by Quarter in NYCA

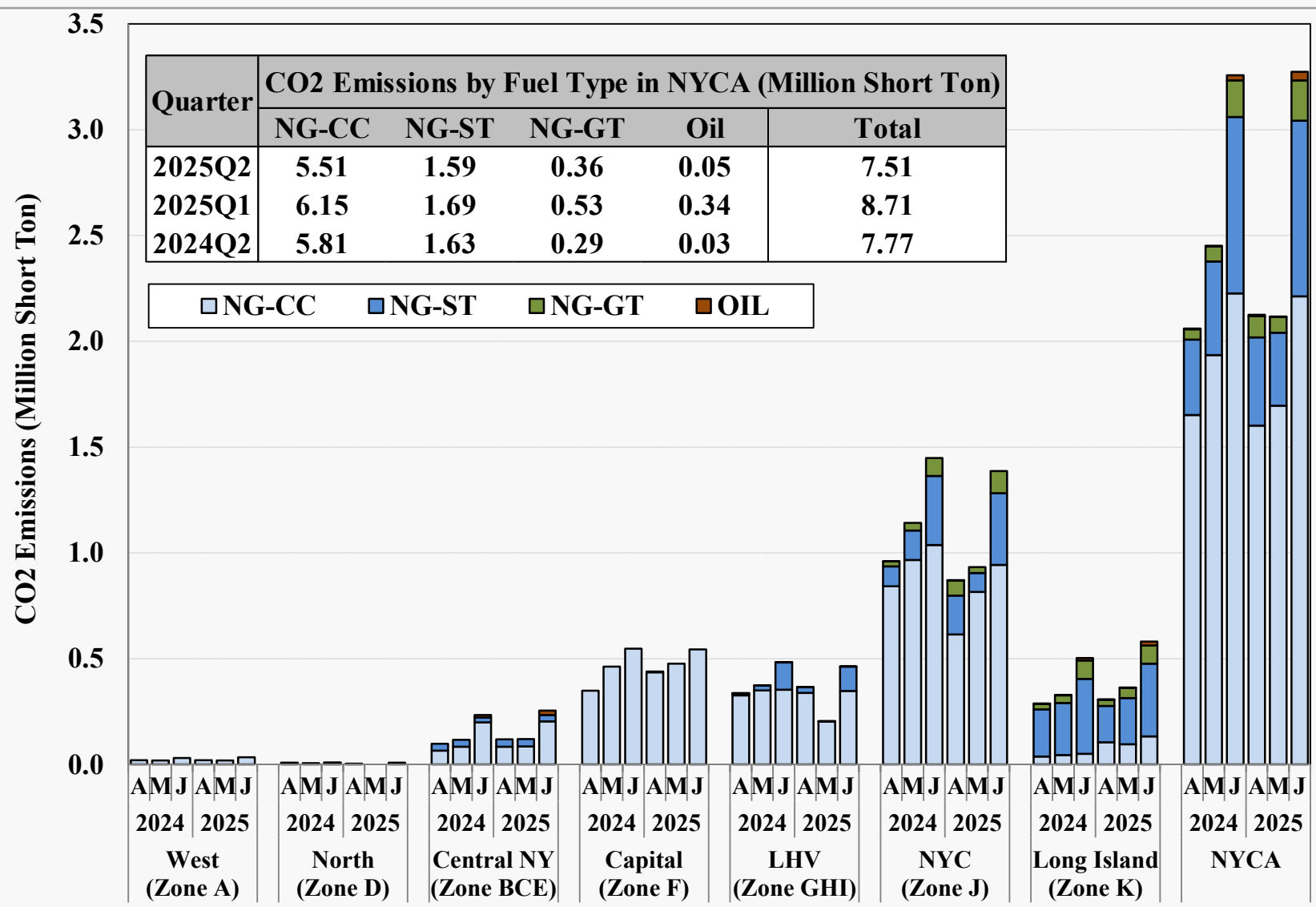
CO₂, SO₂, and NO_x



Notes: For chart description, see slide [96](#).

Emissions by Region by Fuel Type

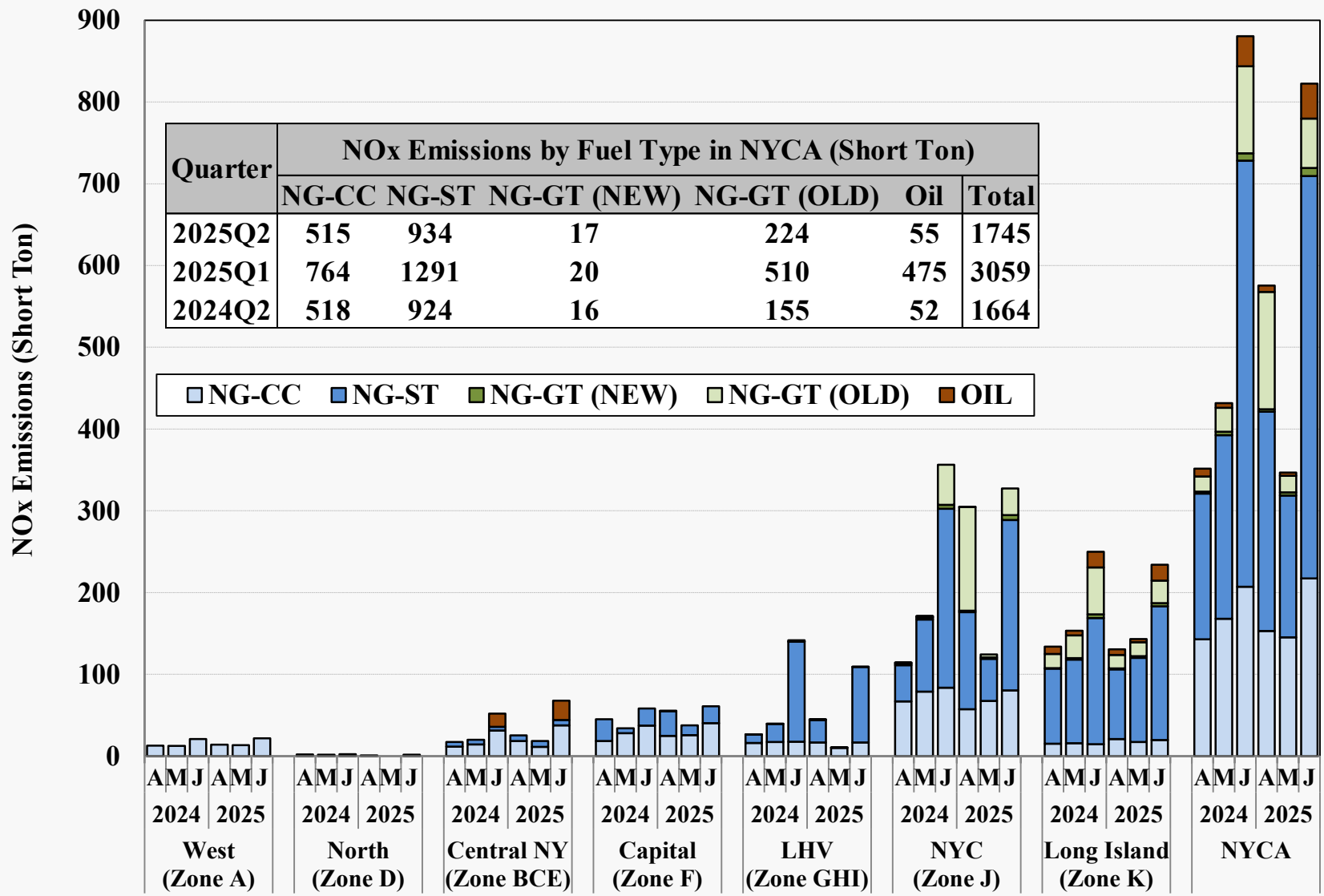
CO₂ Emissions



Notes: For chart description, see slide [96](#).

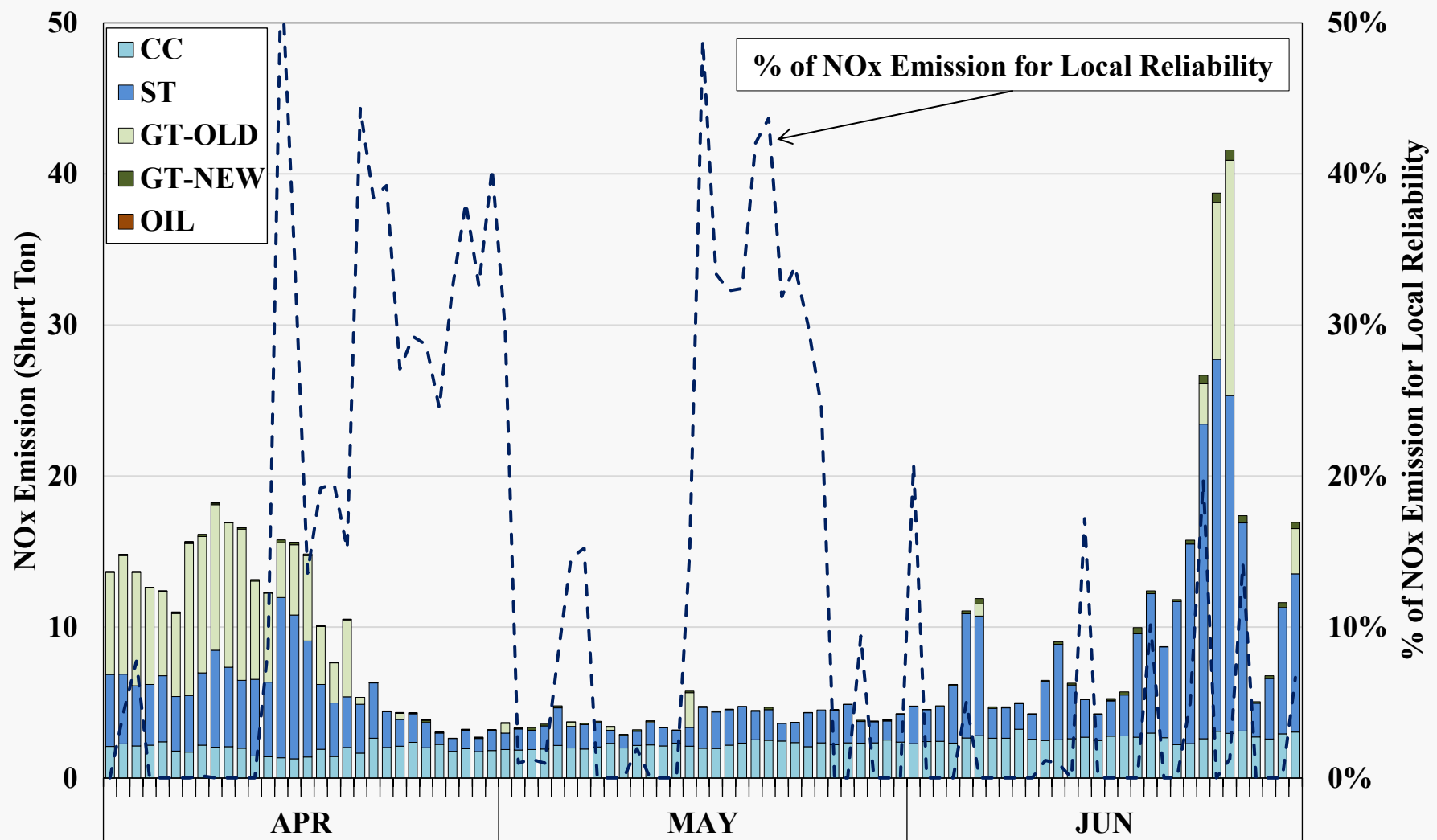
Emissions by Region by Fuel Type

NO_x Emissions



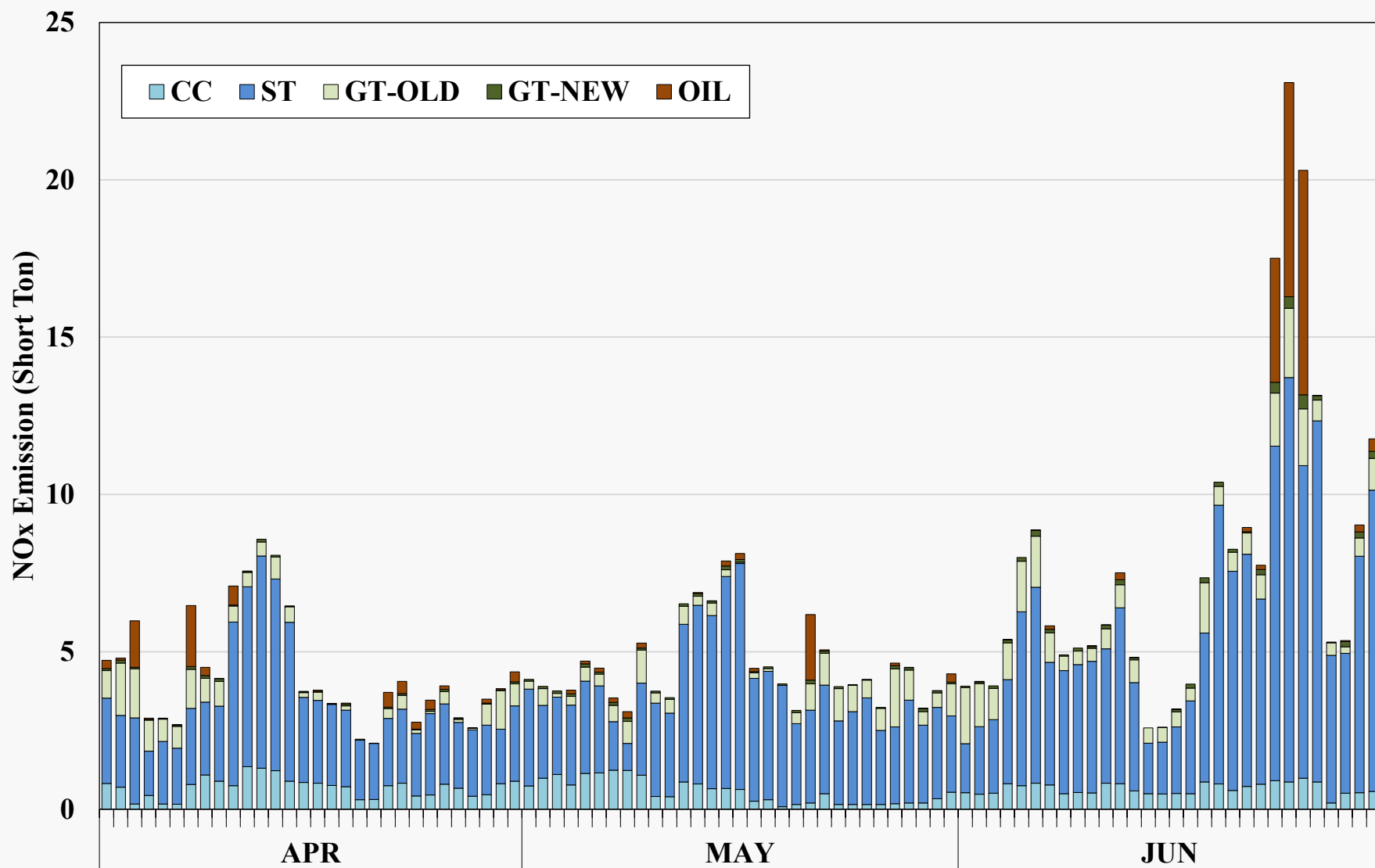
Notes: For chart description, see slide [96](#).

Daily NO_x Emissions in NYC



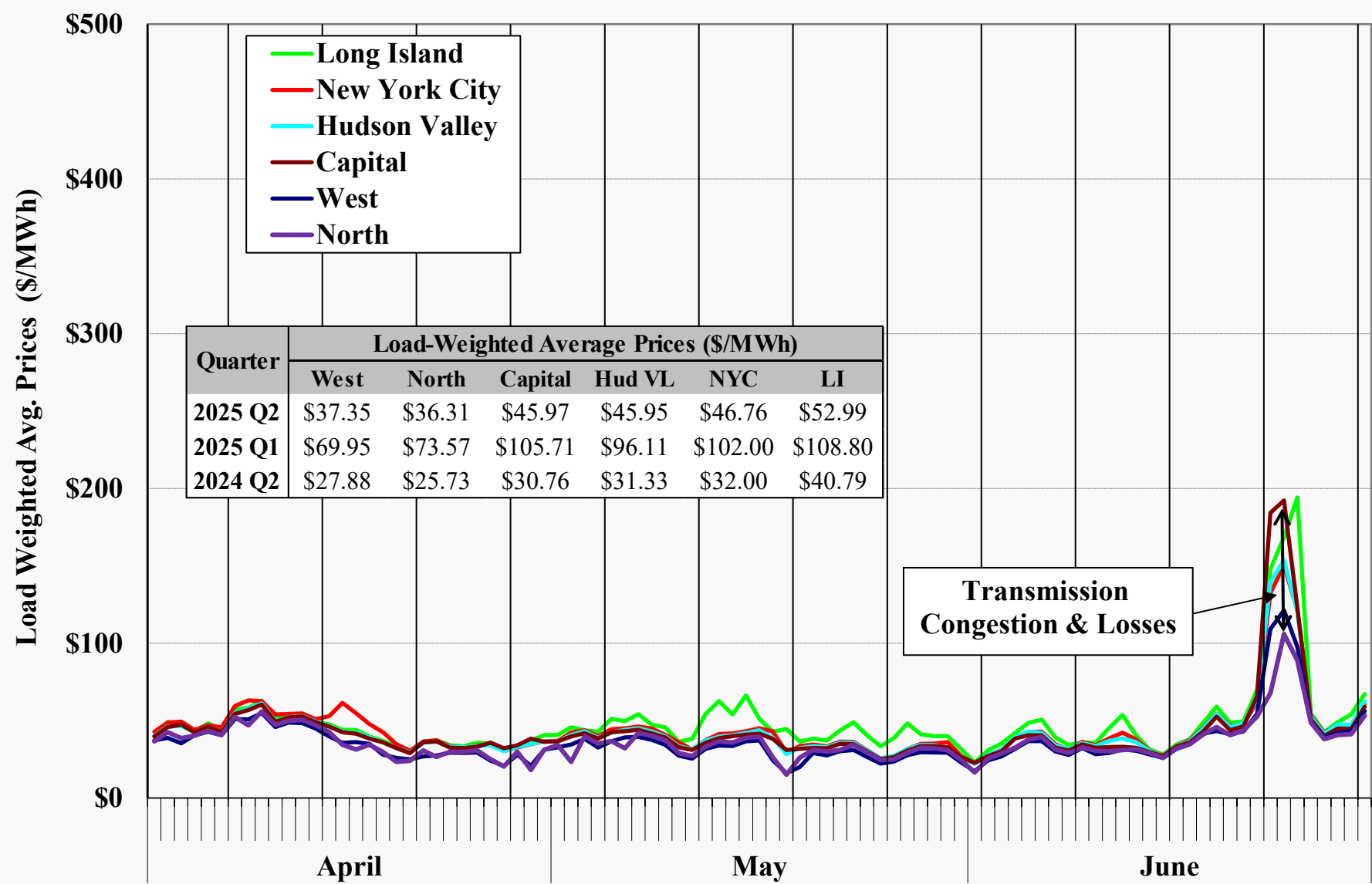
Notes: For chart description, see slide [96](#).

Daily NO_x Emissions in Long Island

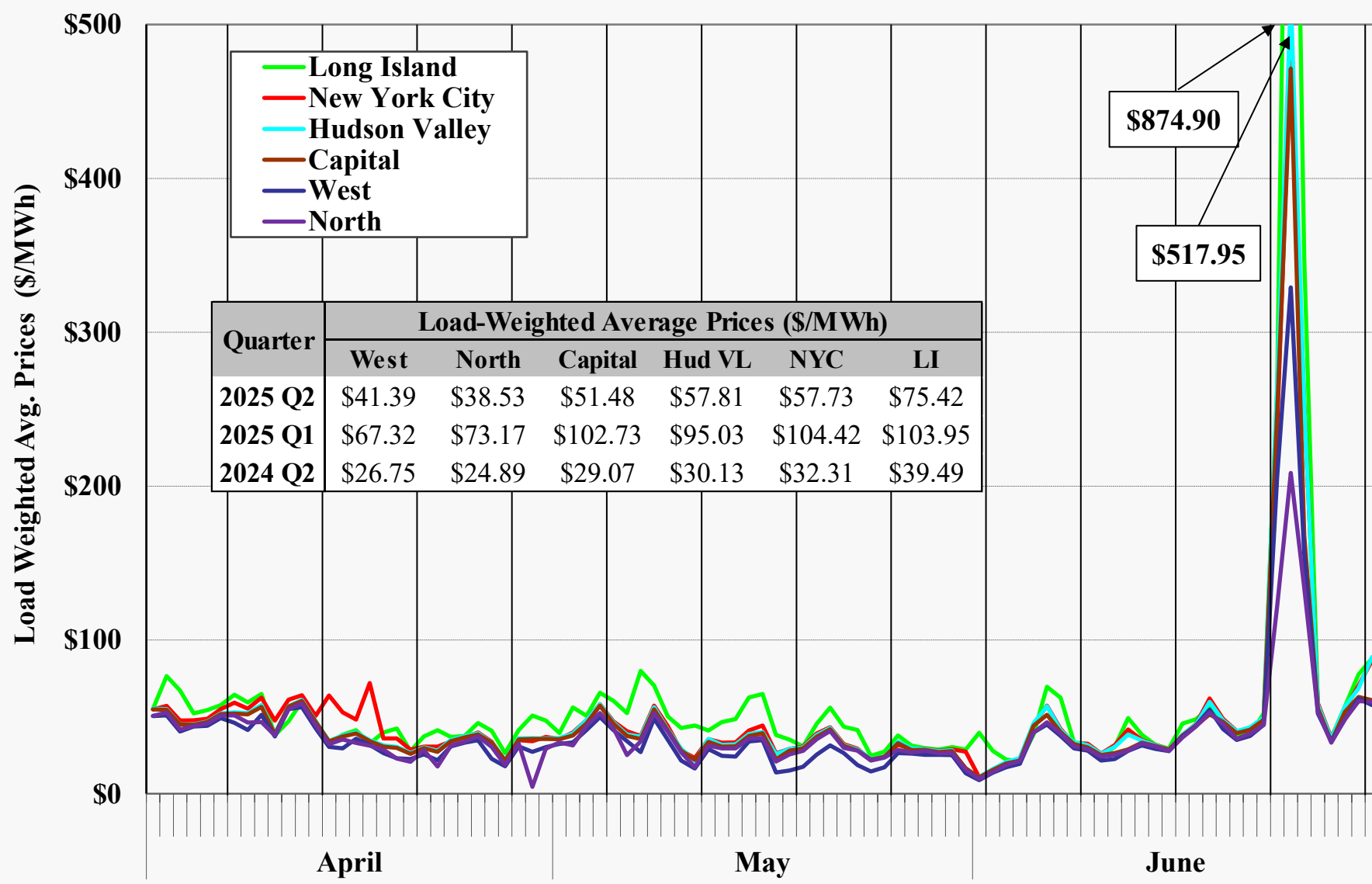


Notes: For chart description, see slide [96](#).

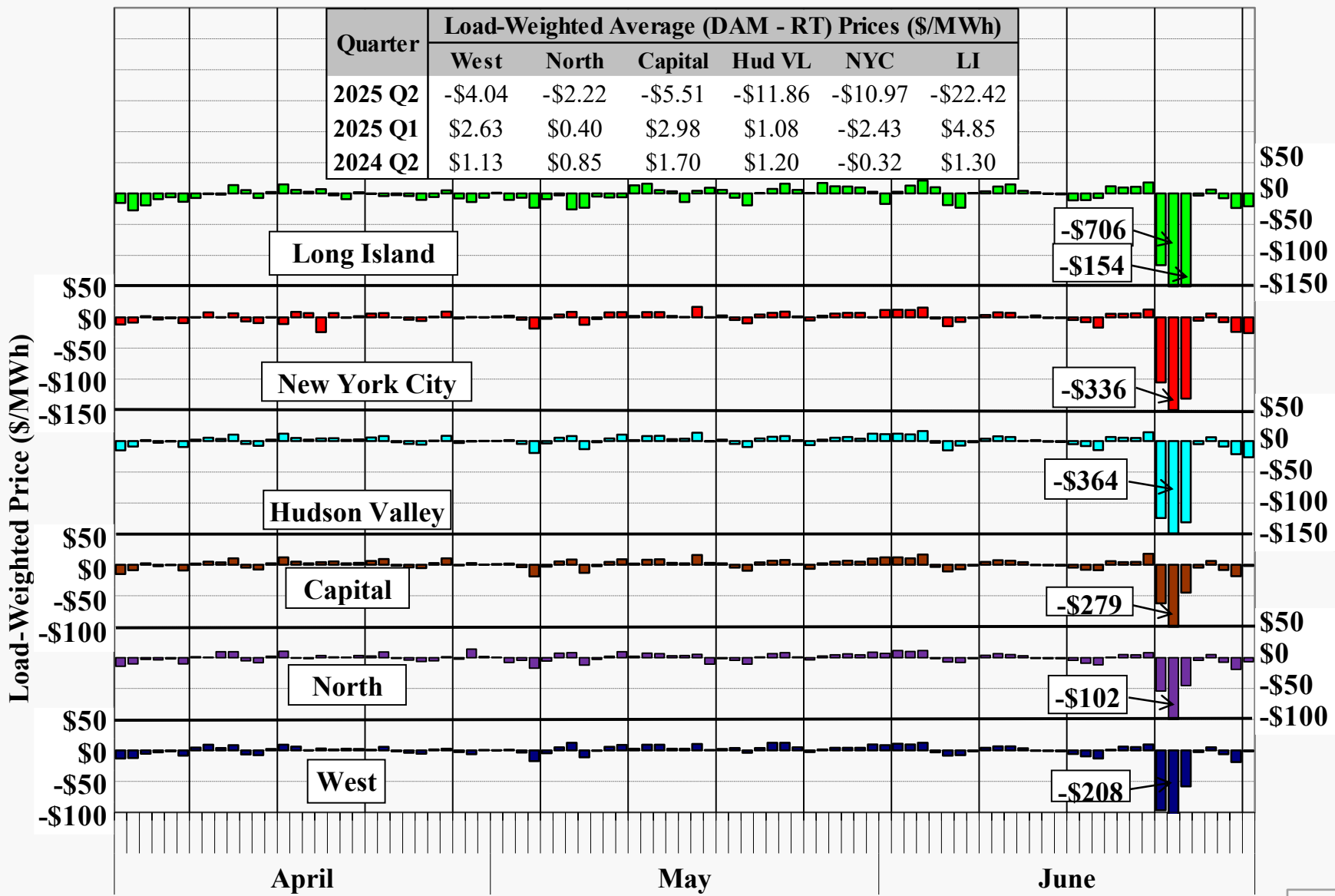
Day-Ahead Electricity Prices by Zone



Real-Time Electricity Prices by Zone



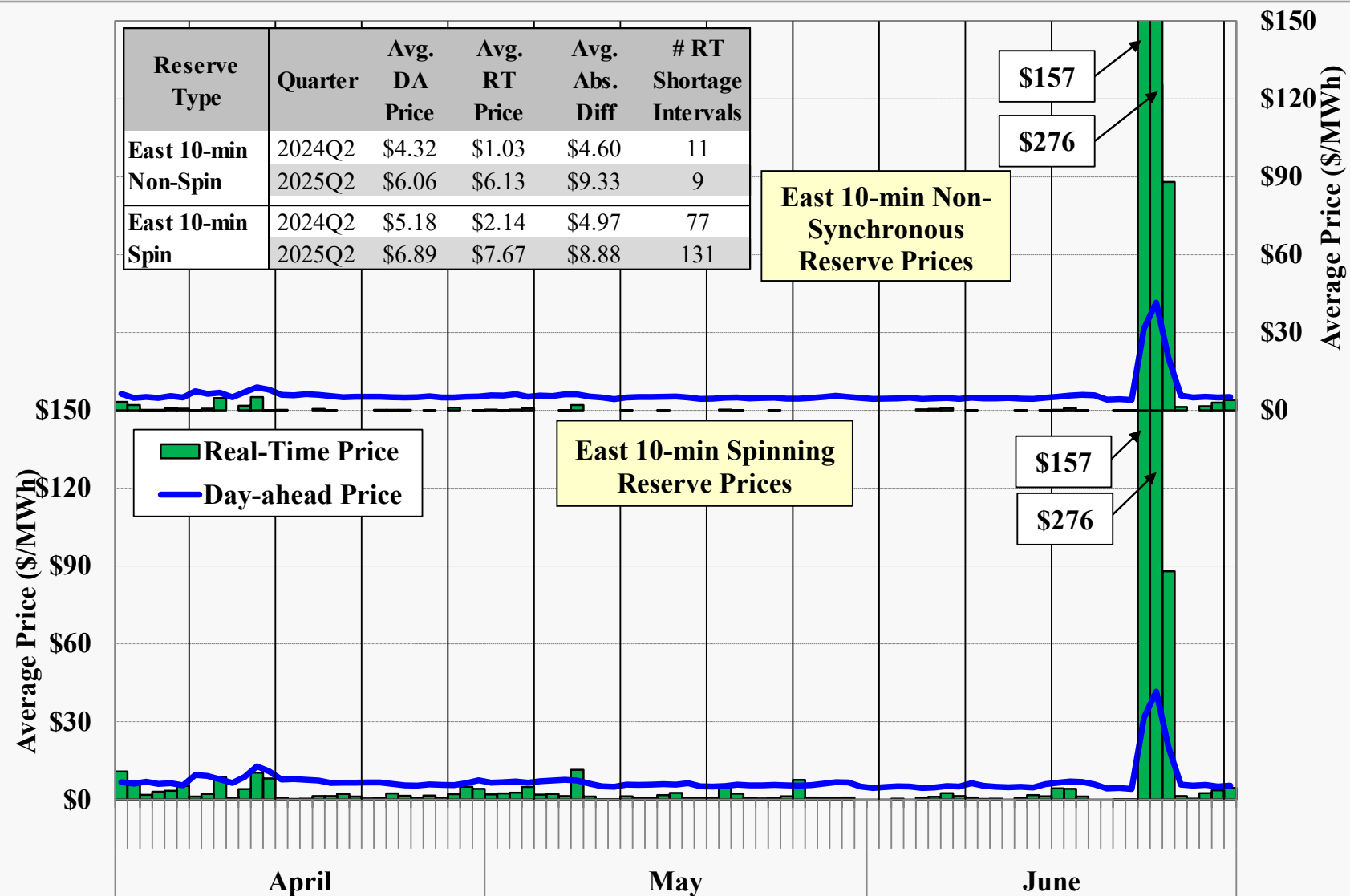
Convergence of Day-Ahead and Real-Time Prices



Charts: Ancillary Services Market

Day-Ahead and Real-Time Ancillary Services Prices

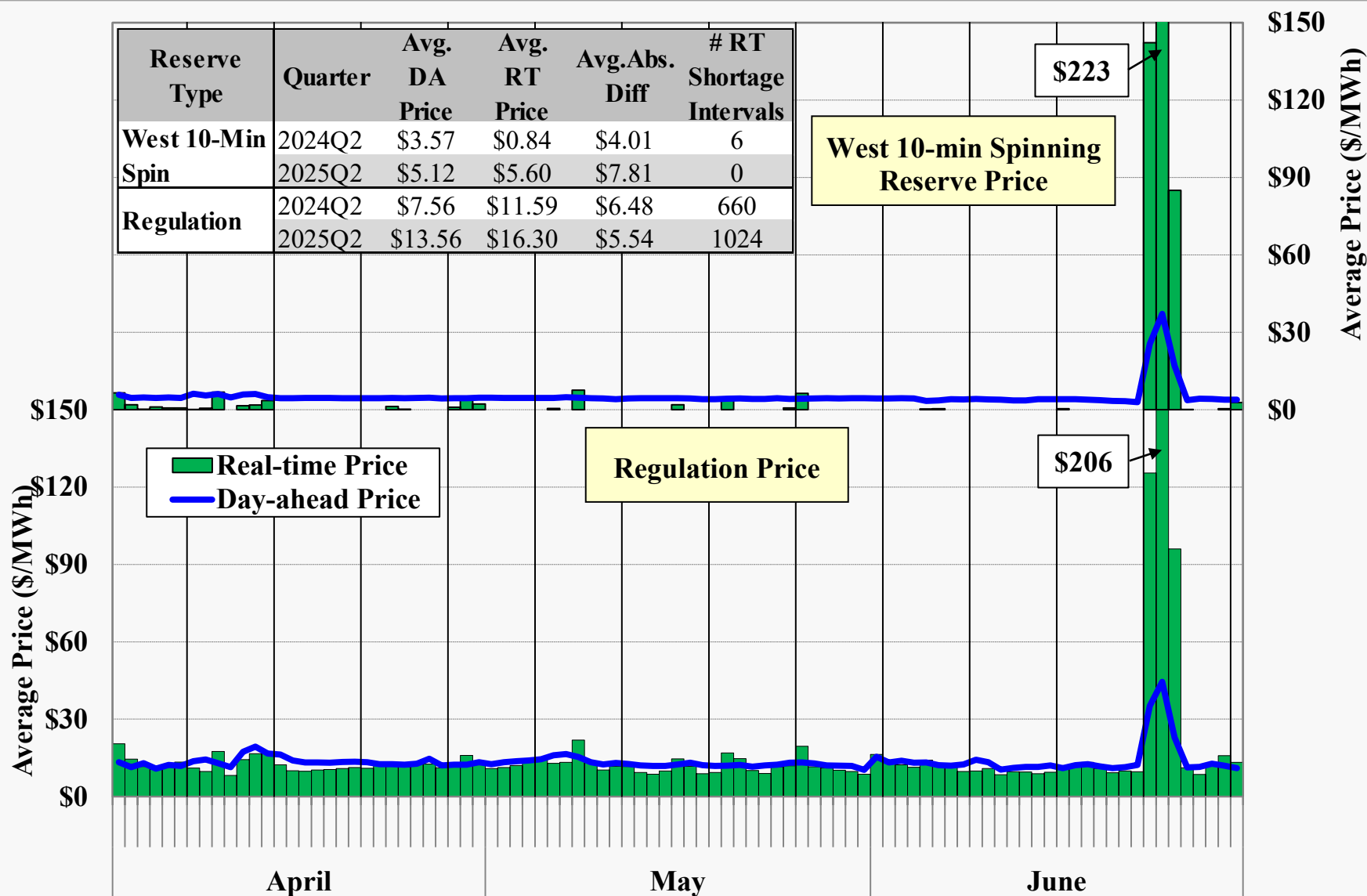
Eastern 10-Minute Spinning and Non-Spinning Reserves



Notes: For chart description, see slide [97](#).

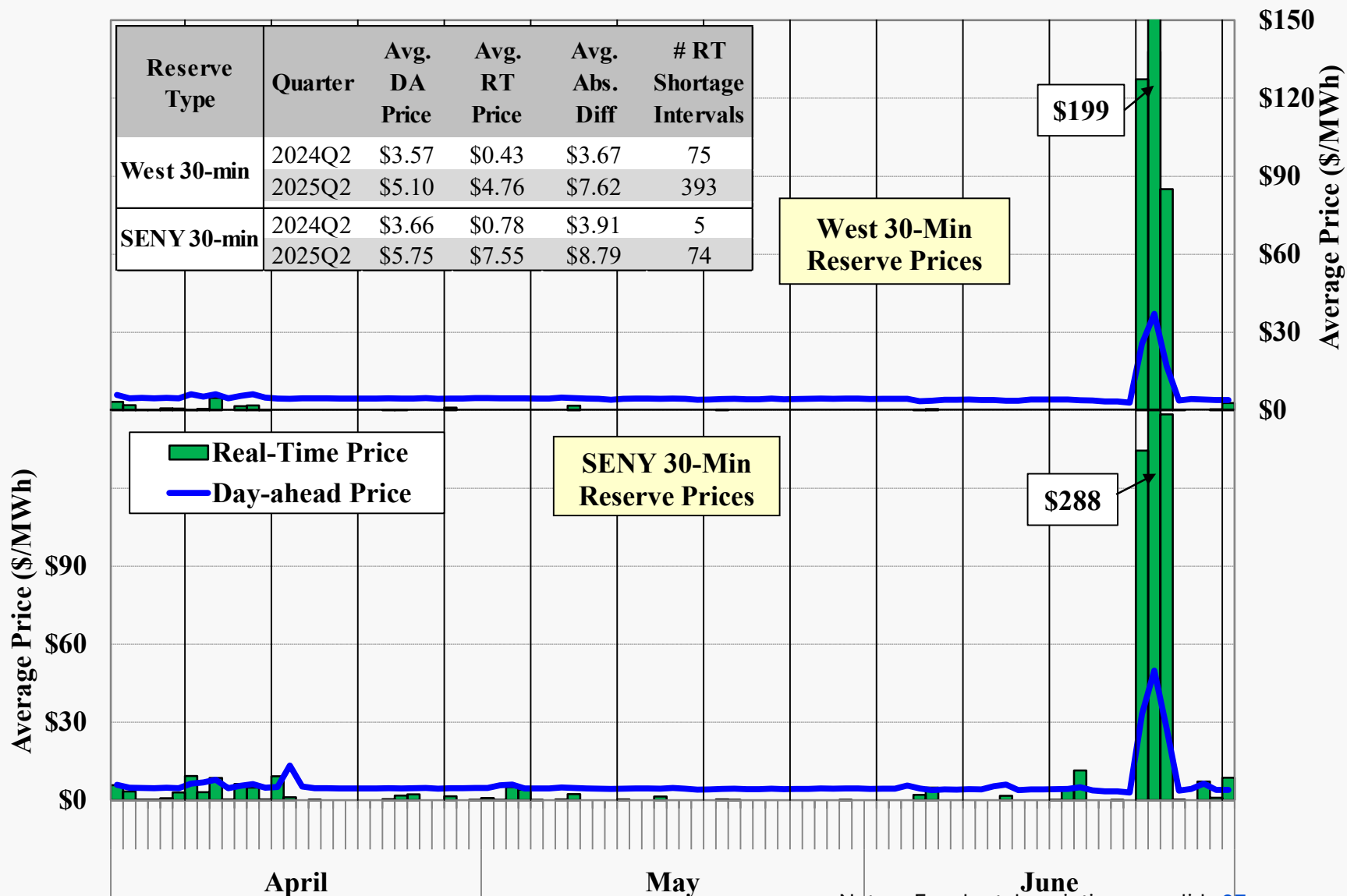
Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



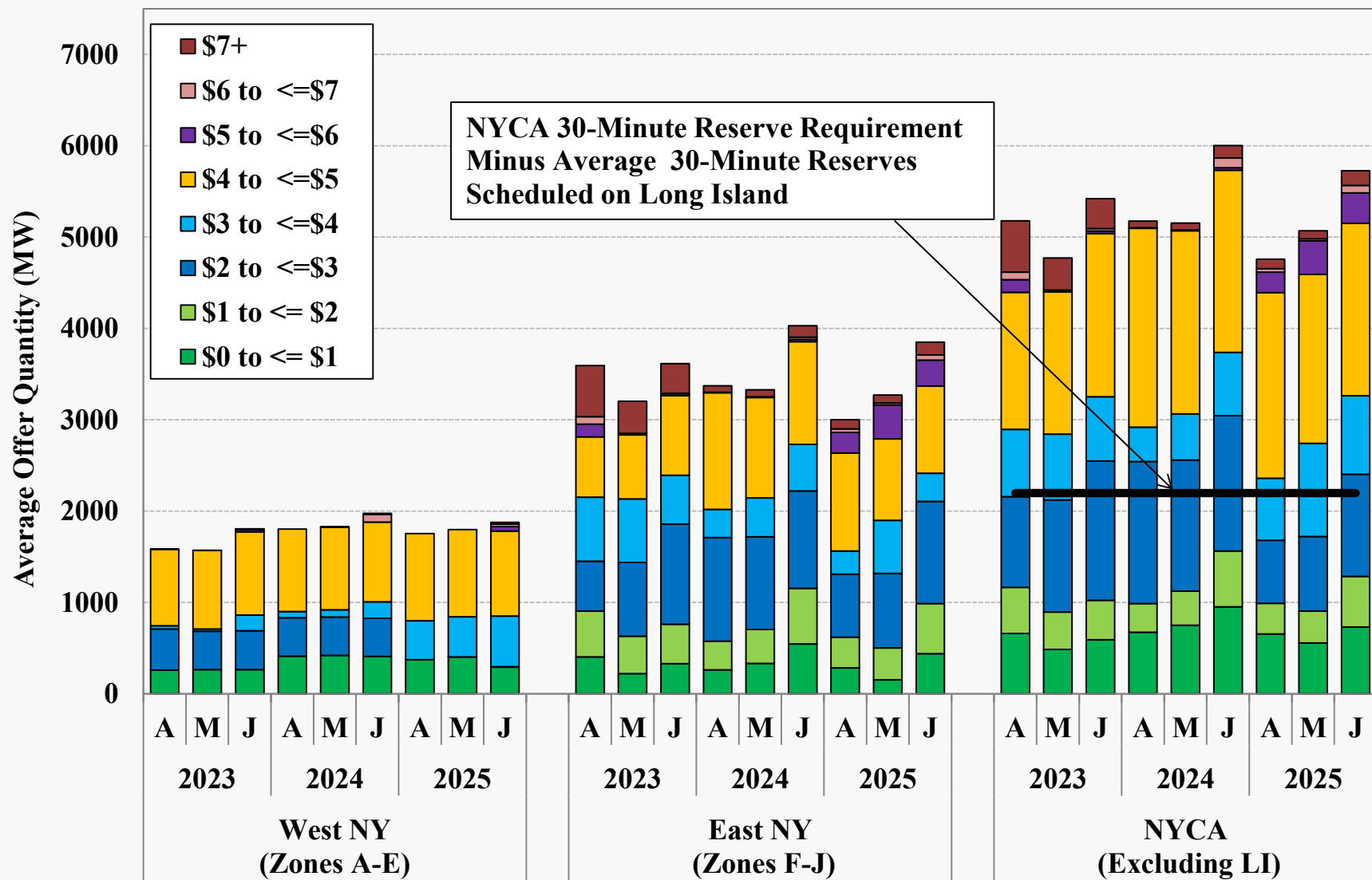
Day-Ahead and Real-Time Ancillary Services Prices

Western and SENY 30-Minute Reserves



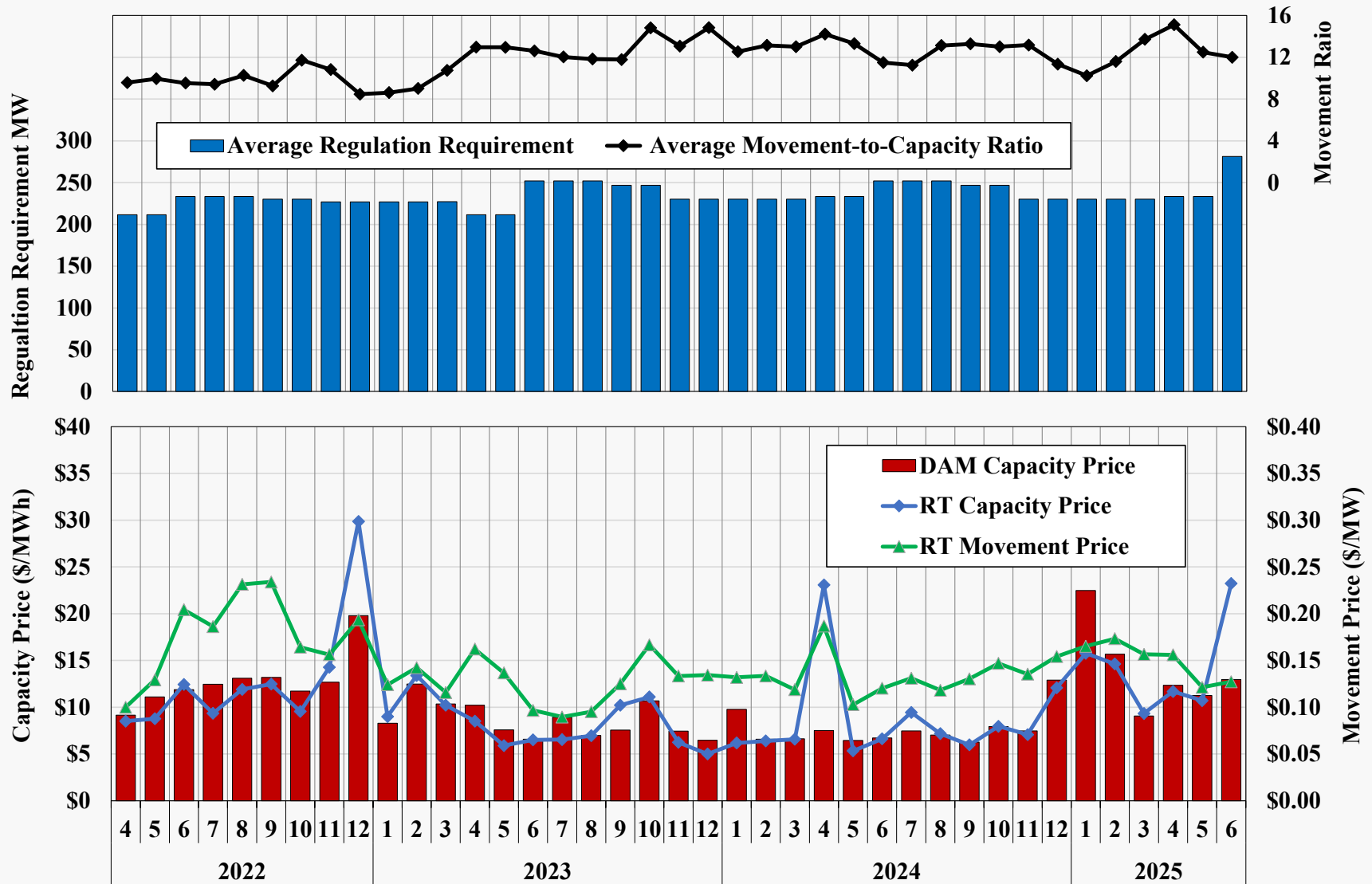
Day-Ahead NYCA 30-Minute Reserve Offers

Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 98.

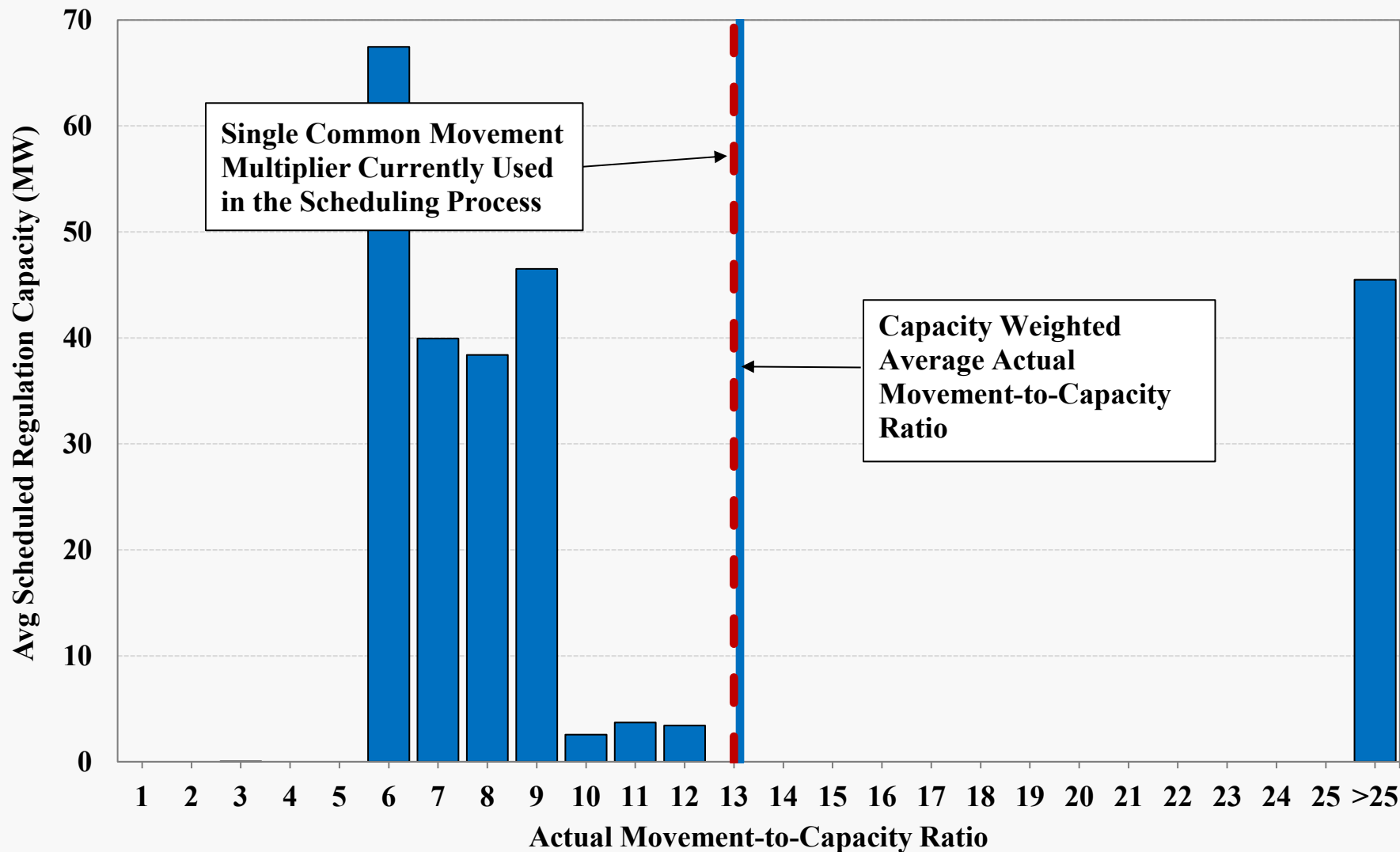
Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month



Notes: For chart description, see slide [99](#).

Distribution of Actual Regulation Movement

The Second Quarter of 2025

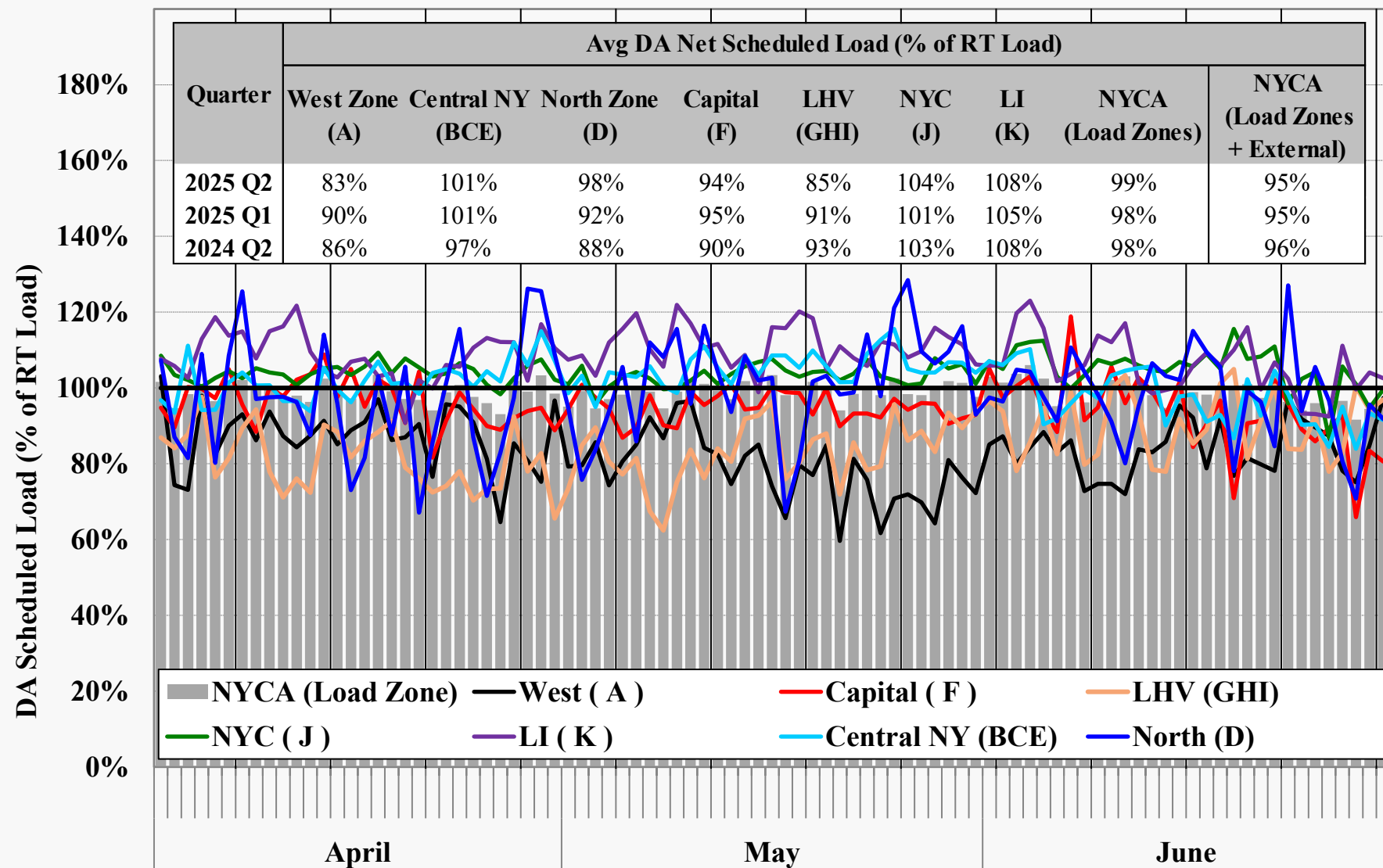


Notes: For chart description, see slide [99](#).

Charts: Energy Market Scheduling

Day-ahead Scheduled Load and Actual Load

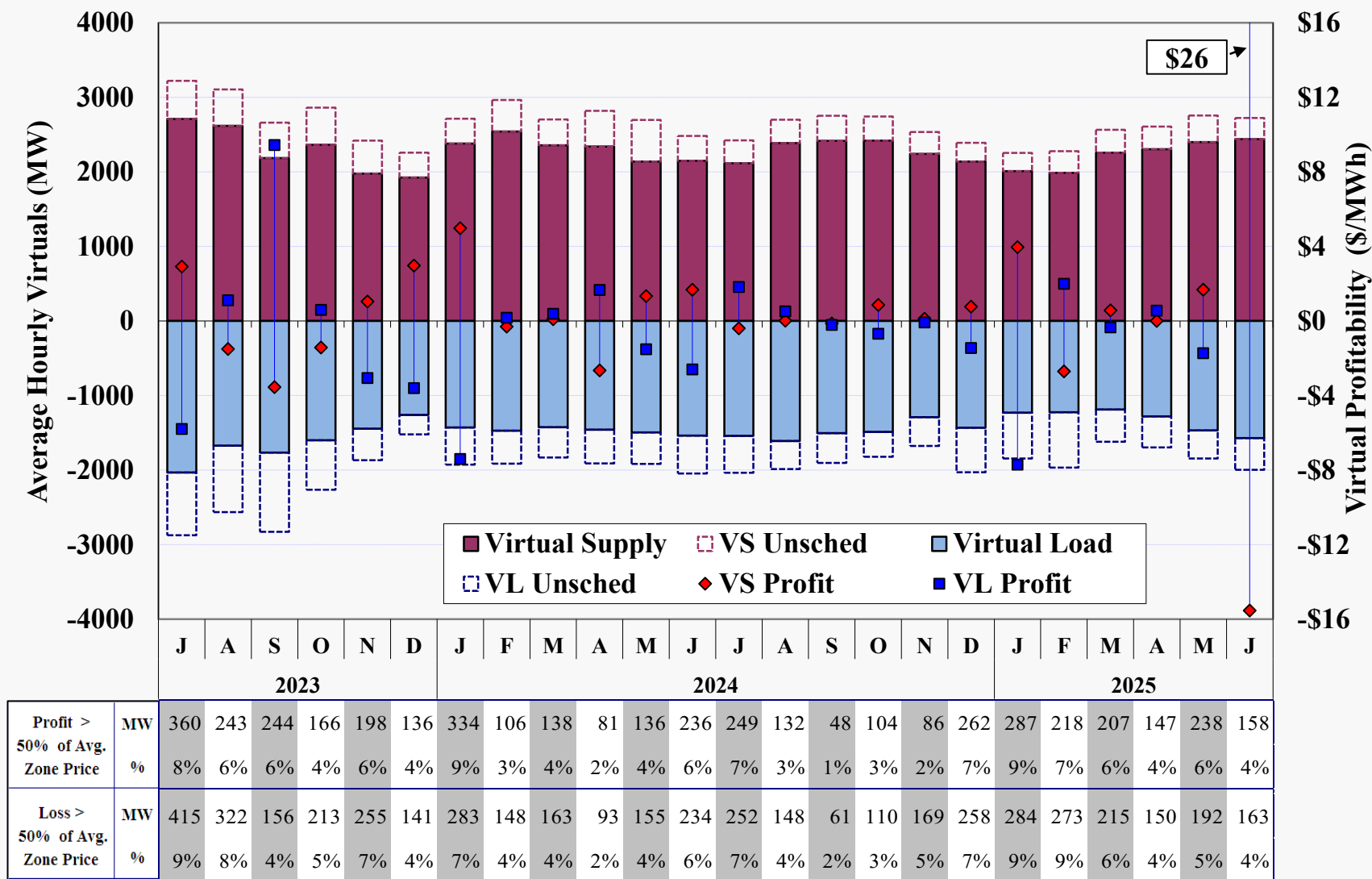
Daily Peak Load Hour



Notes: For chart description, see slide [100](#).

Virtual Trading Activity

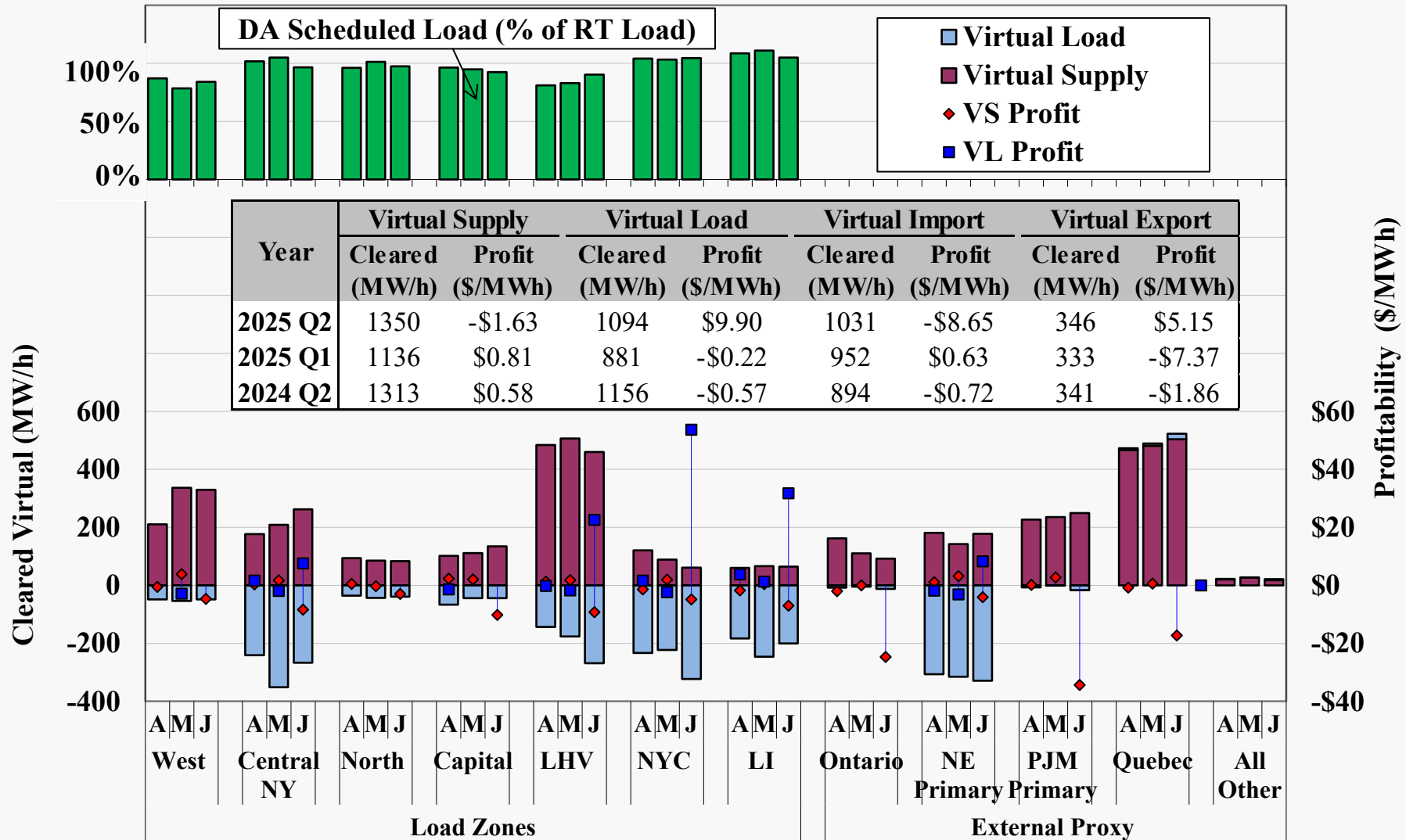
by Month



Notes: For chart description, see slide [100](#).

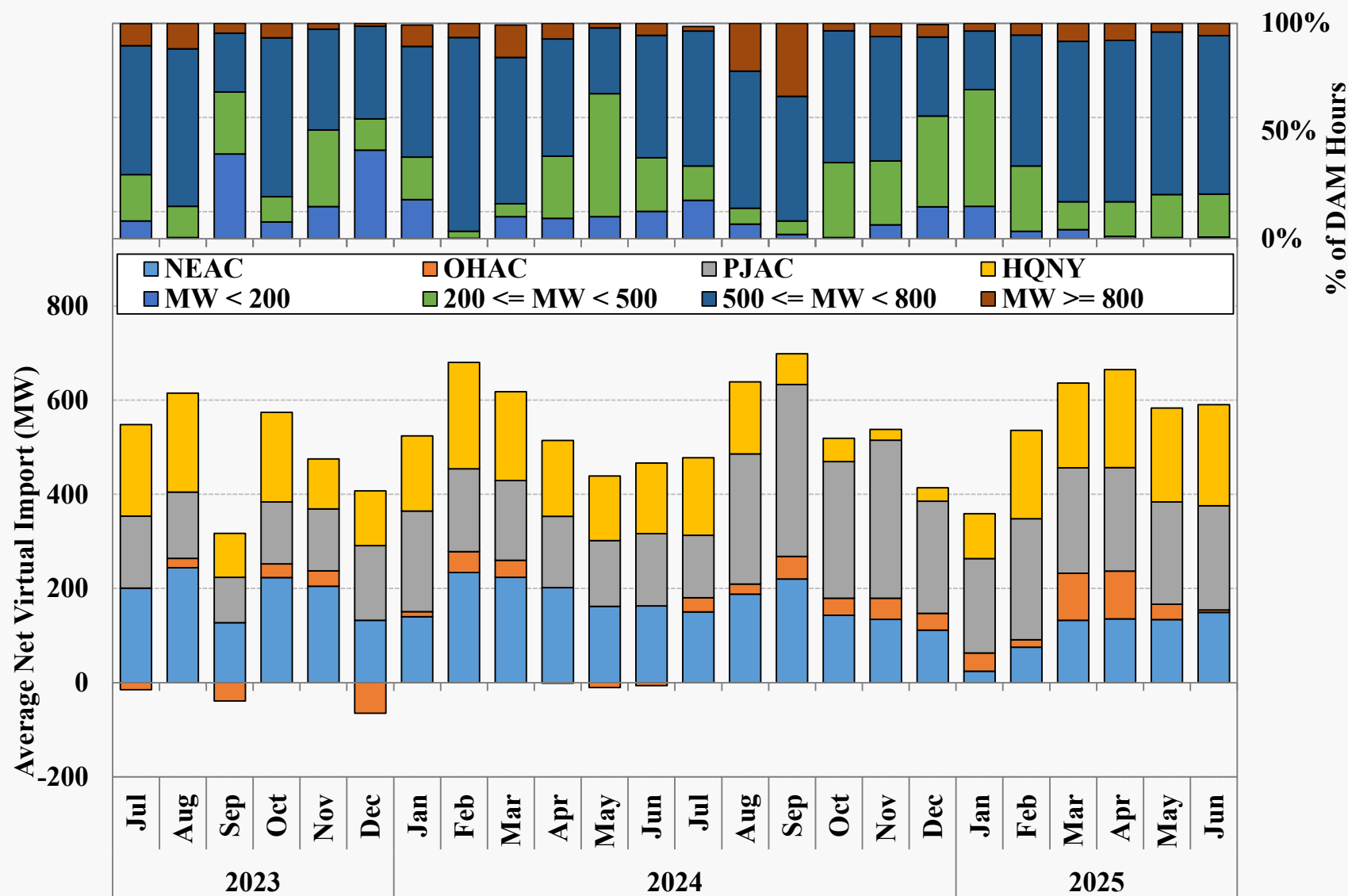
Virtual Trading Activity

by Location



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 [100](#).

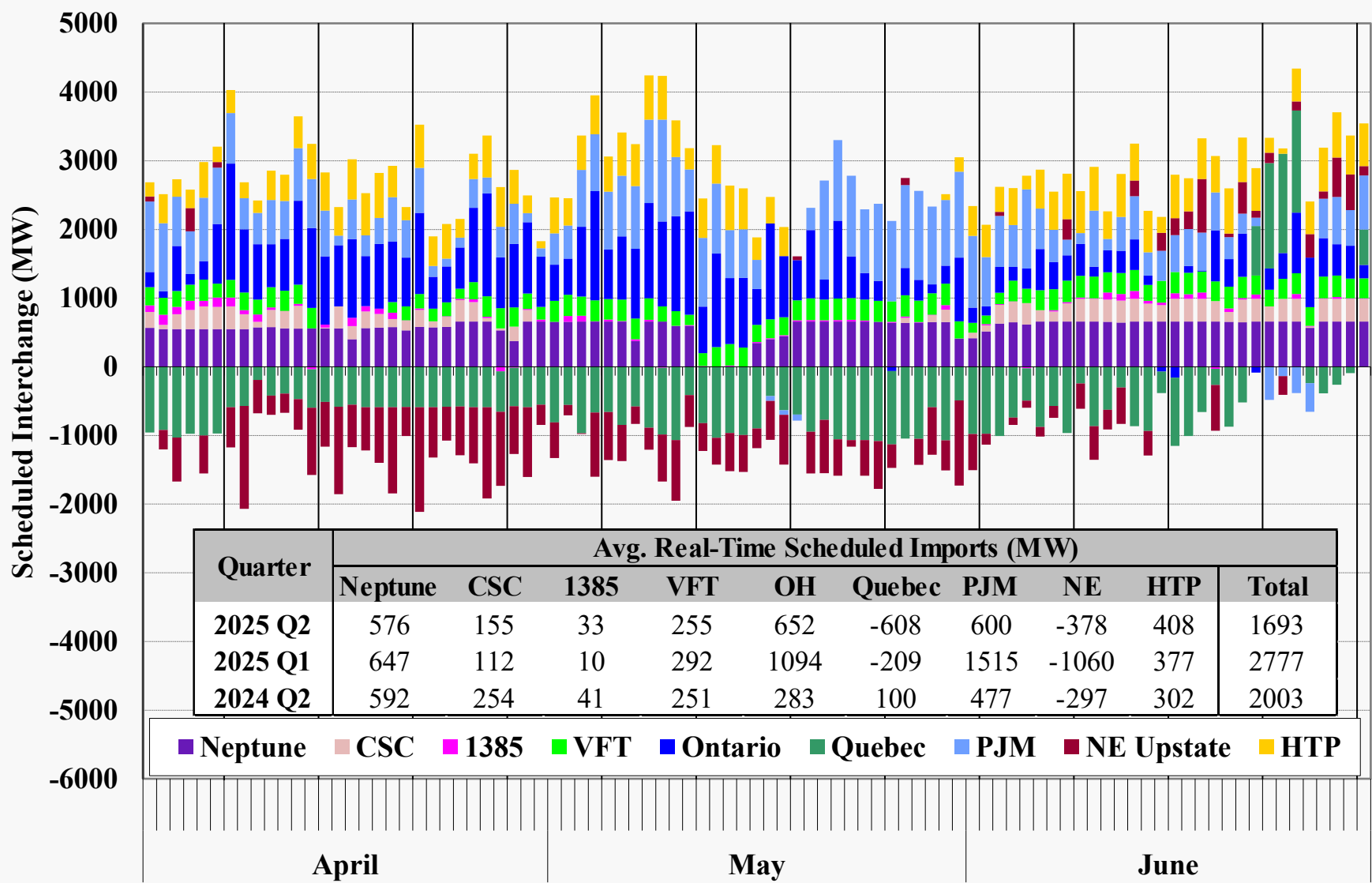
Virtual Imports and Exports in the Day-Ahead Market



Notes: For chart description, see slide [101](#).

Net Imports Scheduled Across External Interfaces

Daily Peak Hours (1-9pm)



Notes: Two Quebec interfaces are combined into one.

Efficiency of Intra-Hour Scheduling Under CTS

Primary PJM and NE Interfaces

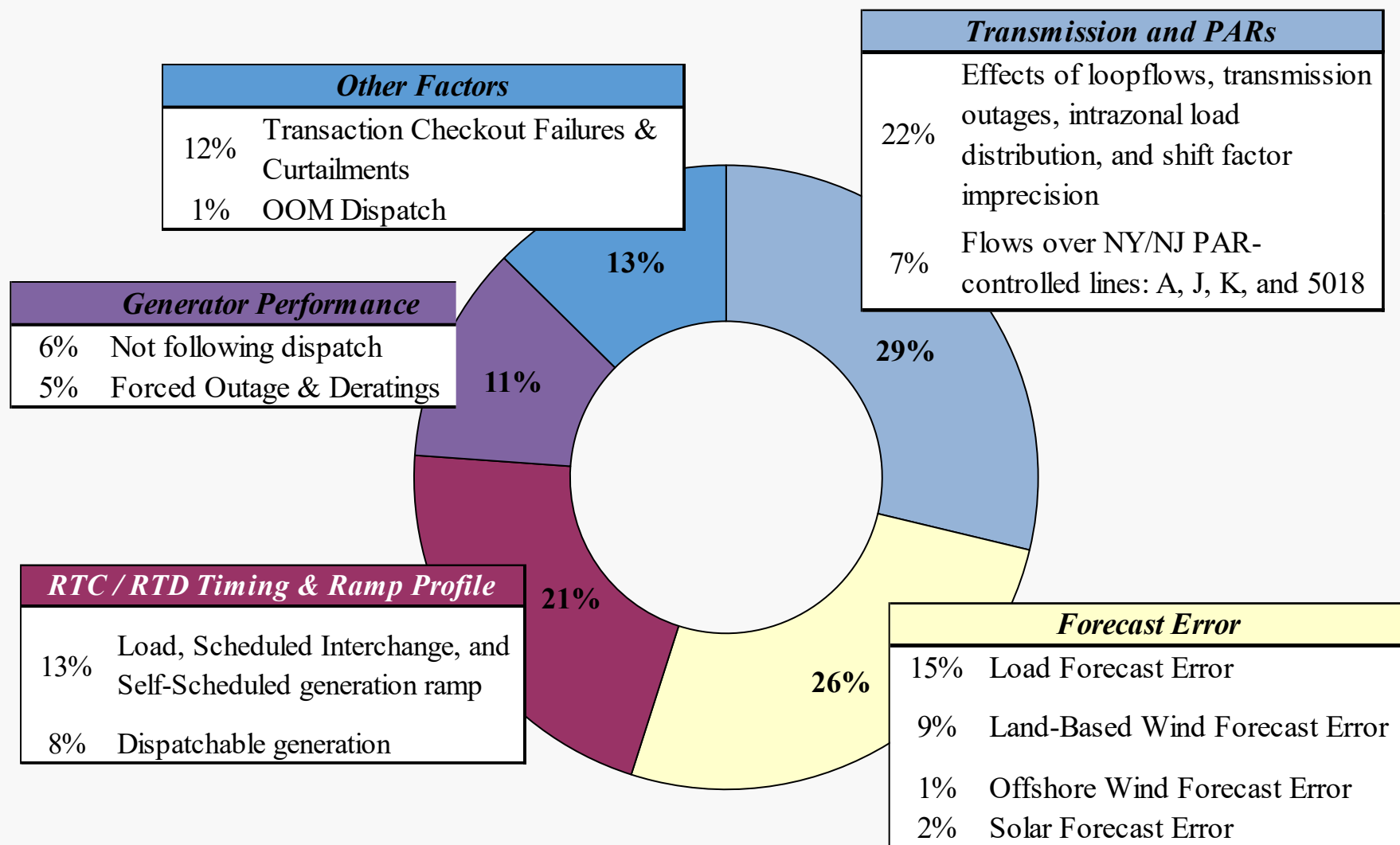
			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= \$20	Any Forecast Error > \$20	Total		Both Forecast Errors <= \$20	Any Forecast Error > \$20	Total	
% of All Intervals w/ Adjustment			81%	9%	90%		40%	16%	56%	
Average Flow Adjustment (MW)	Net Imports		36	40	37		12	-31	0	
	Gross		118	169	123		75	96	81	
Production Cost Savings (\$ Million)	Projected at Scheduling Time		\$2.1	\$1.6	\$3.7		\$0.4	\$3.1	\$3.5	
	Net Over-Projection by:	NY	-\$0.1	-\$0.5	-\$0.6		\$0.0	-\$0.3	-\$0.3	
		NE or PJM	\$0.1	\$0.0	\$0.0		-\$0.1	-\$2.6	-\$2.6	
	Other Unrealized Savings		-\$0.1	-\$0.4	-\$0.5		\$0.0	-\$0.5	-\$0.5	
	Actual Savings		\$1.9	\$0.6	\$2.5		\$0.3	-\$0.2	\$0.1	
Interface Prices (\$/MWh)	NY	Actual	\$35.89	\$84.04	\$40.58	\$39.28	\$33.90	\$88.73	\$49.61	\$42.32
		Forecast	\$36.74	\$78.94	\$40.85	\$39.69	\$34.71	\$88.14	\$50.02	\$42.58
	NE or PJM	Actual	\$34.58	\$58.83	\$36.94	\$36.59	\$31.19	\$86.88	\$47.15	\$40.91
		Forecast	\$34.72	\$60.83	\$37.26	\$37.12	\$33.98	\$116.66	\$57.67	\$52.37
Price Forecast Errors (\$/MWh)	NY	Fcst. - Act.	\$0.85	-\$5.10	\$0.27	\$0.41	\$0.81	-\$0.59	\$0.41	\$0.26
		Abs. Val.	\$3.06	\$43.41	\$6.99	\$6.74	\$3.00	\$28.07	\$10.19	\$7.41
	NE or PJM	Fcst. - Act.	\$0.14	\$2.00	\$0.32	\$0.53	\$2.79	\$29.78	\$10.52	\$11.47
		Abs. Val.	\$3.97	\$28.07	\$6.32	\$6.21	\$5.92	\$85.33	\$28.68	\$24.67

For Adjustment Intervals Only

For All Intervals

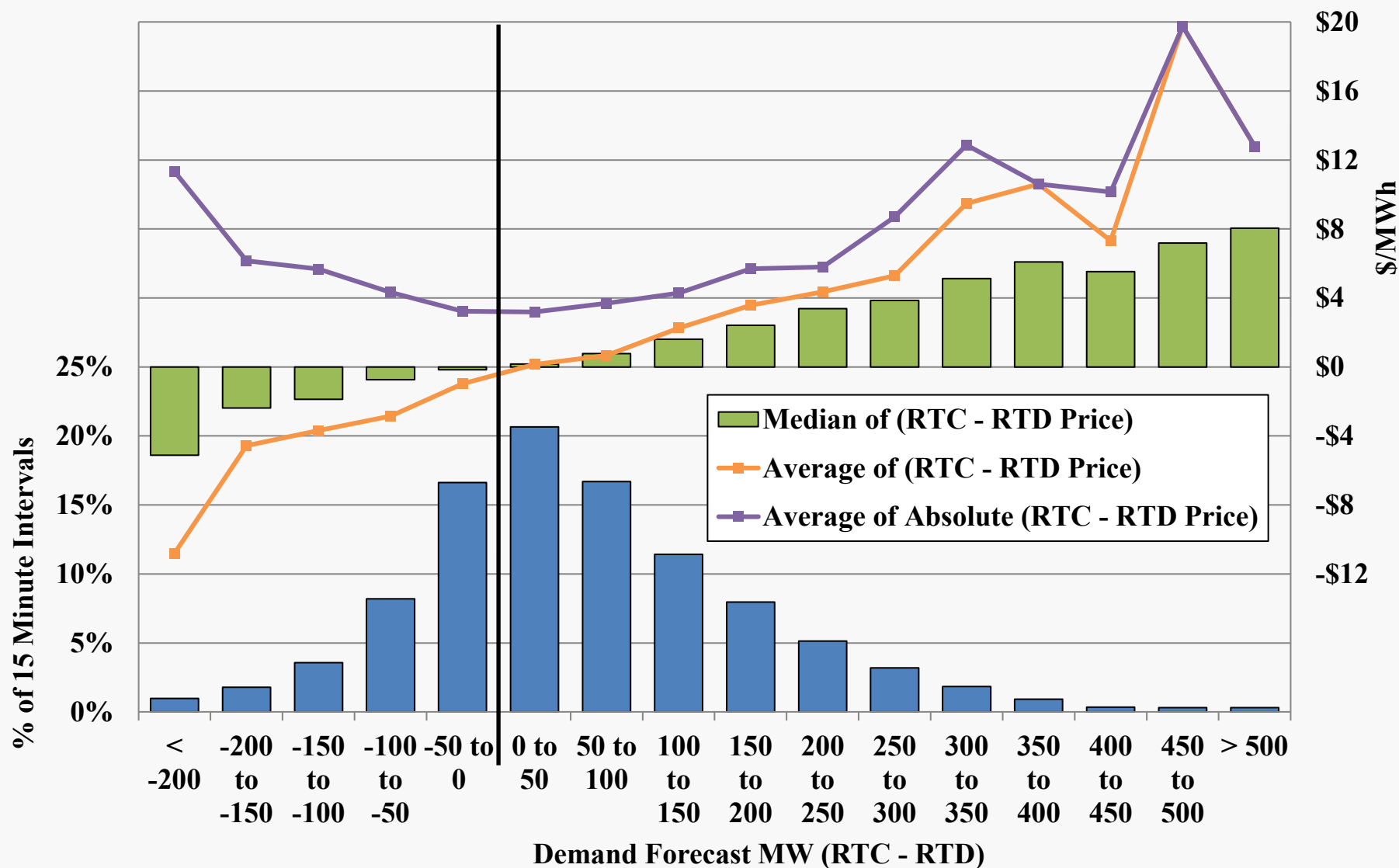
Notes: For chart description, see slide [102](#).

Detrimental Factors to RTC and RTD Price Divergence



Notes: For chart description, see slide [103](#).

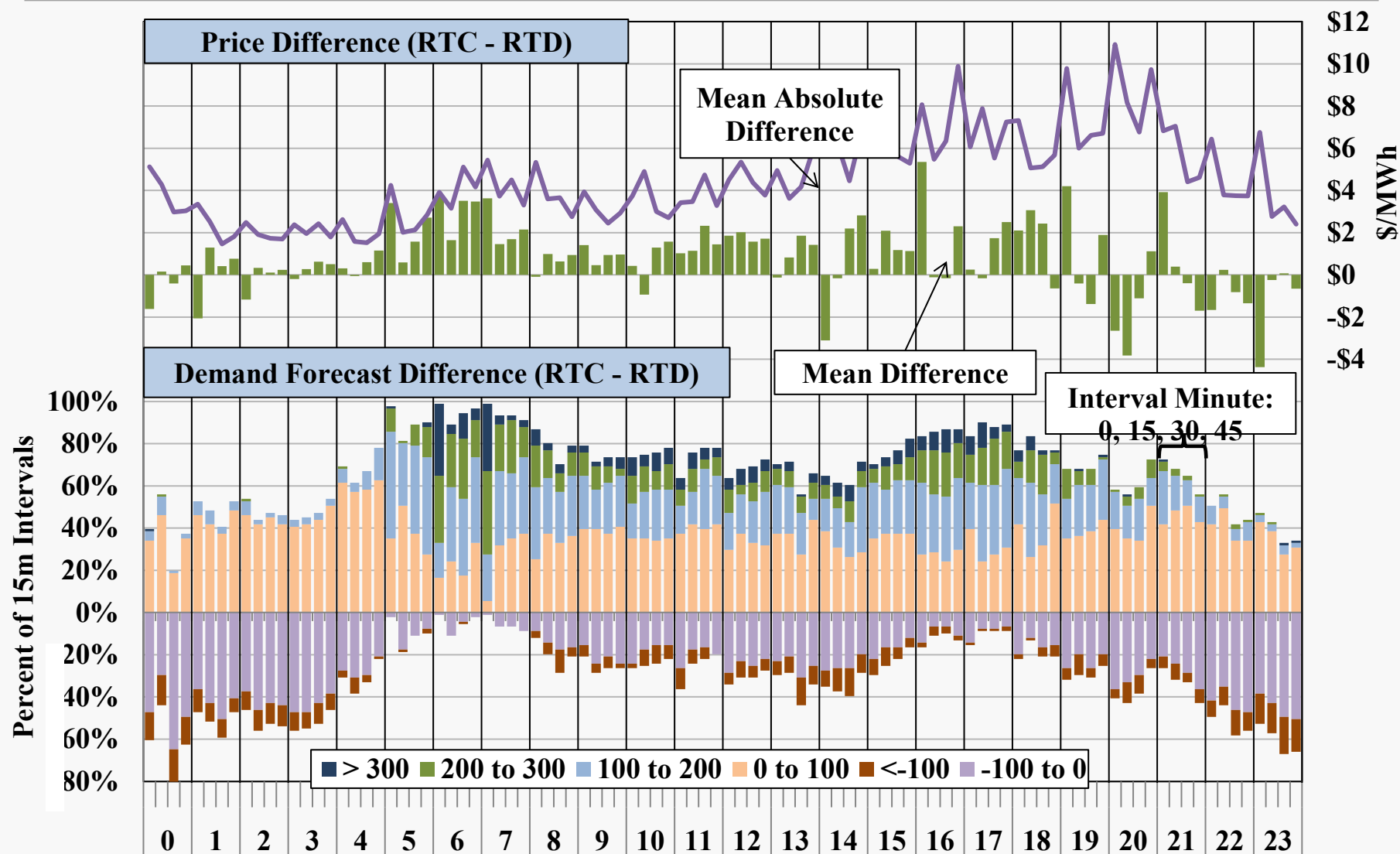
RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide [103](#).

RTC and RTD Price Difference vs Demand Forecast Difference

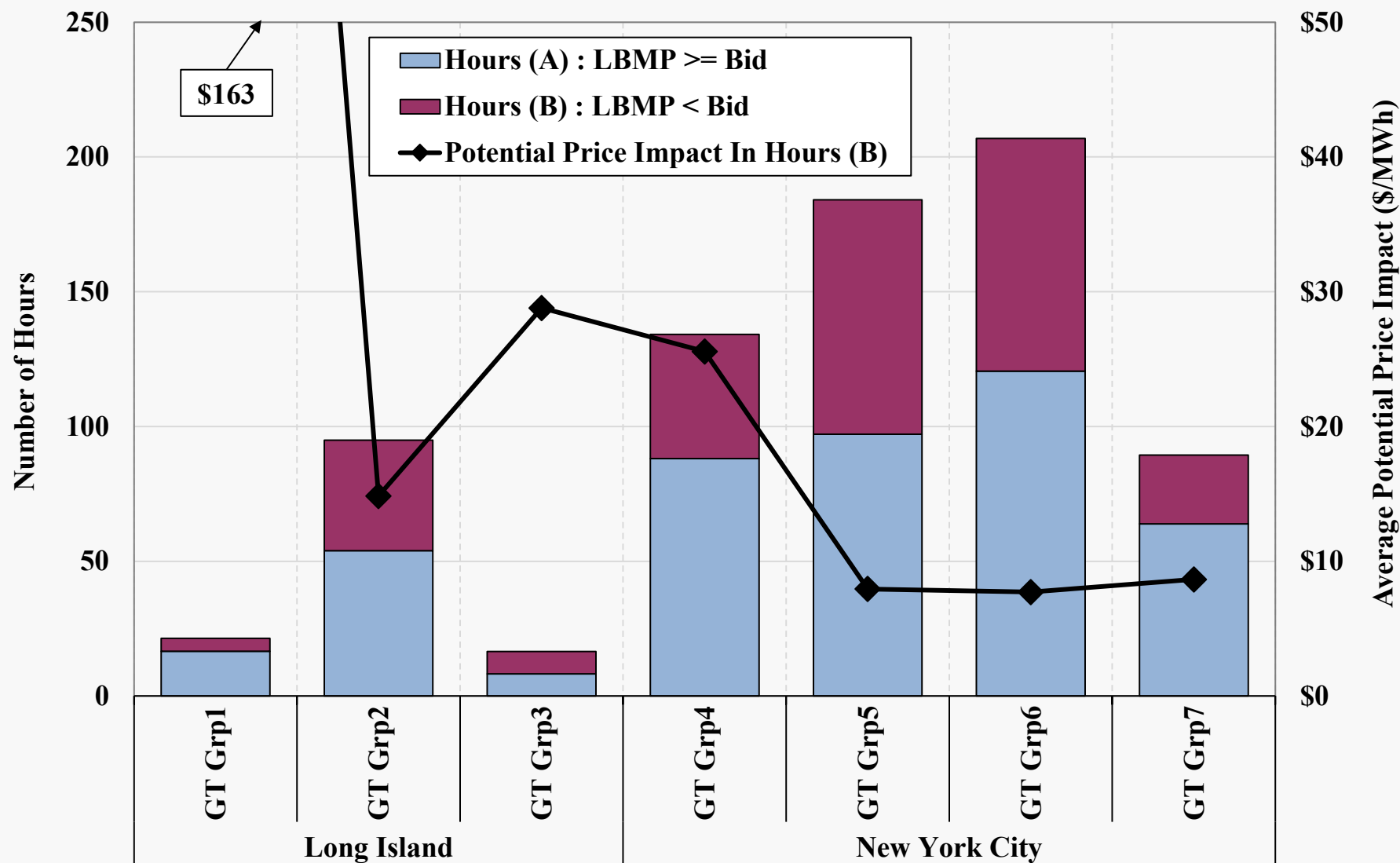
By Time of Day



Notes: For chart description, see slide [104](#).

Real-Time Prices During Commitments of GTs

Units Offering Multi-Hour Minimum Run Times: 2025 Q2

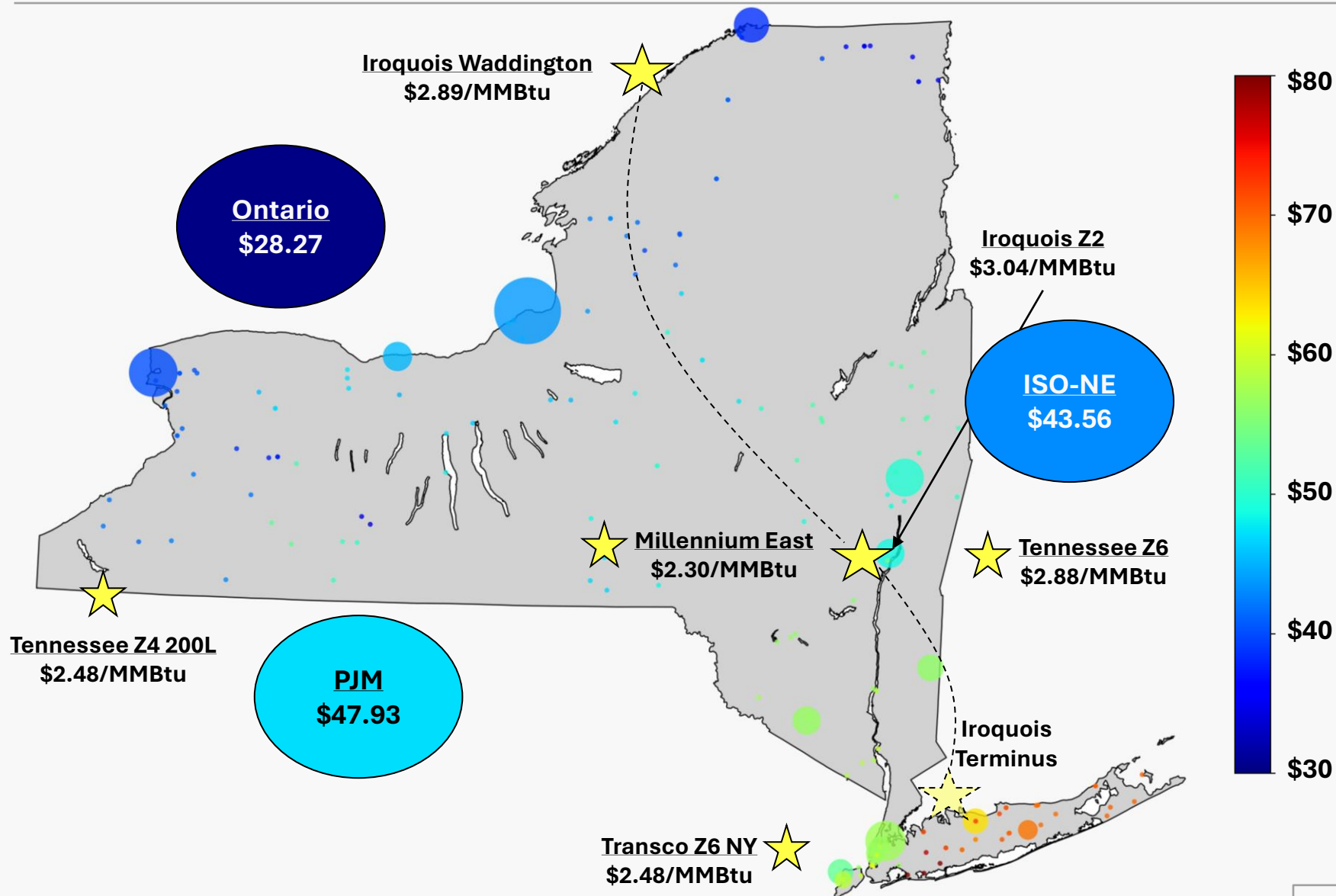


Notes: For chart description, see slide [105](#).

Charts: Transmission Congestion Revenues and Shortfalls

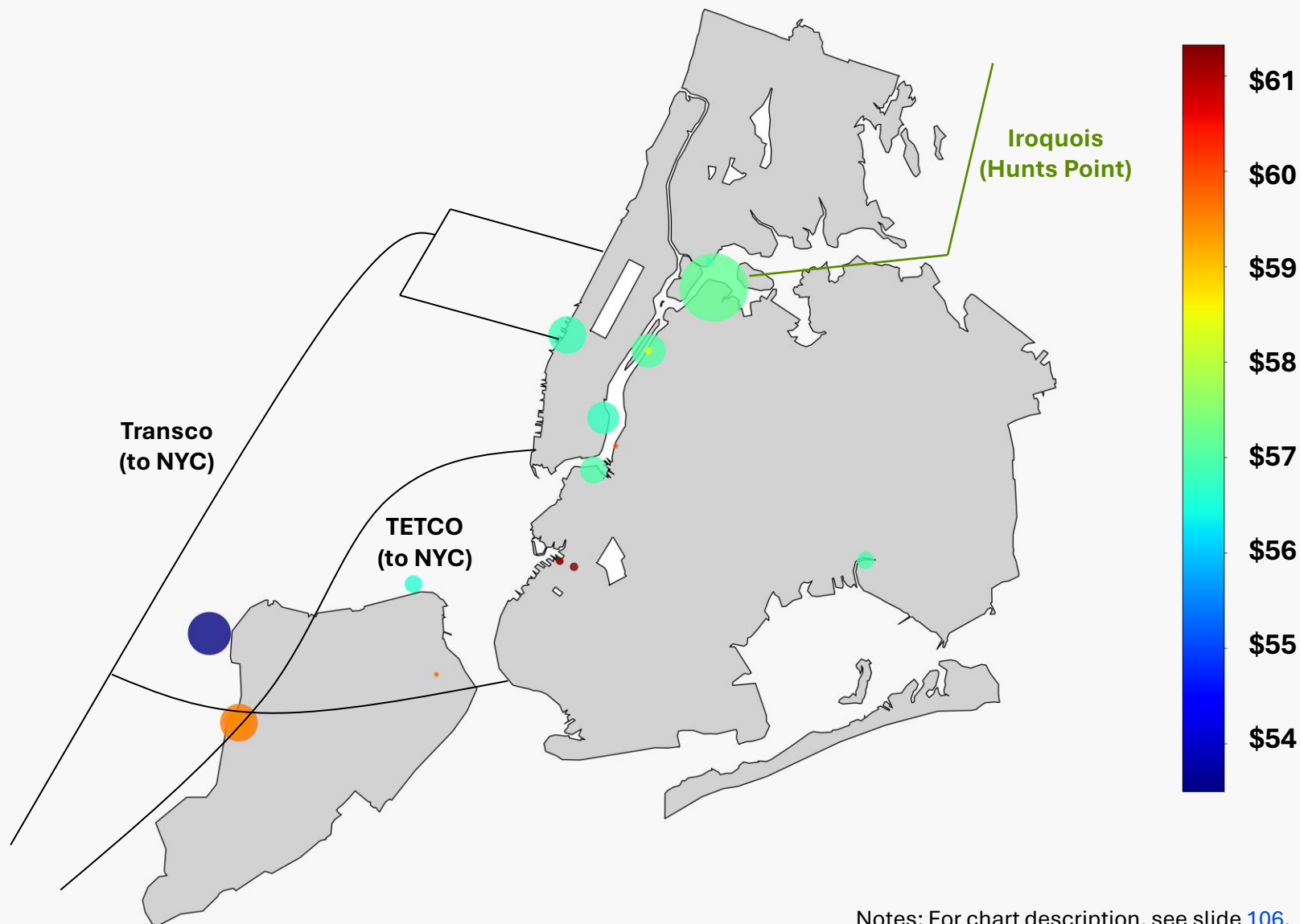
System Congestion

Real-Time Price Map at Generator Nodes



System Congestion

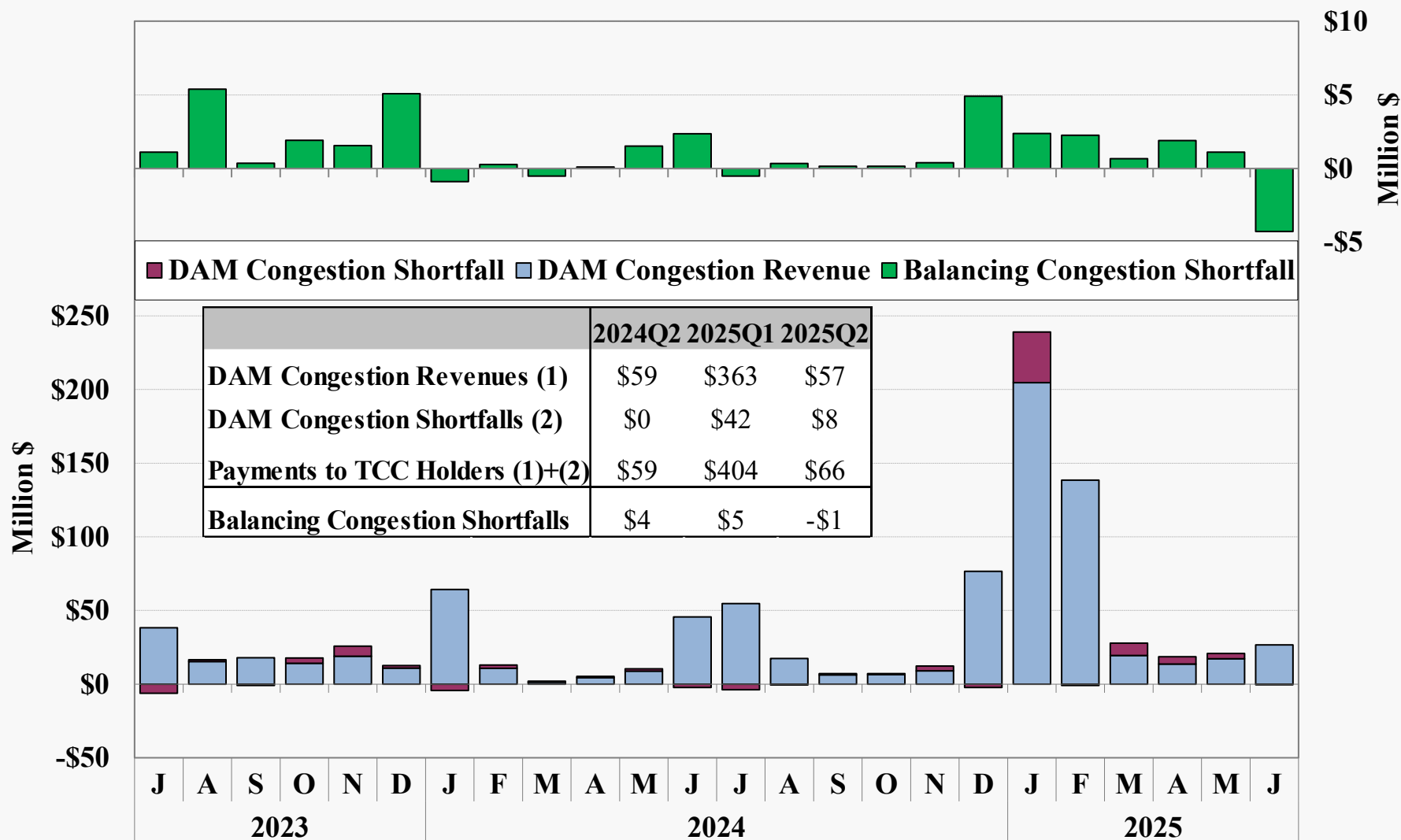
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide [106](#).

Congestion Revenues and Shortfalls

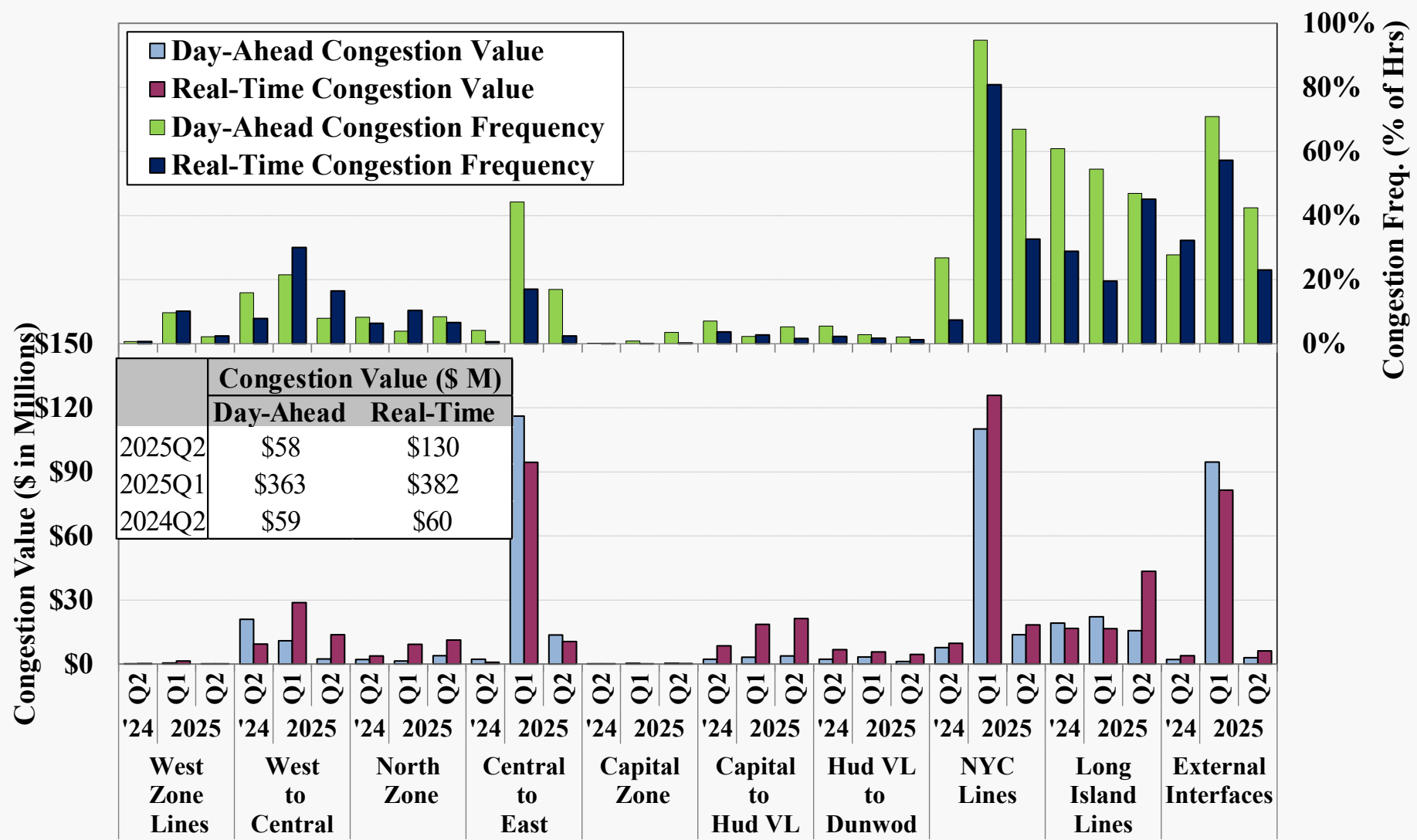
By Month



Notes: For chart description, see slides [107](#) and [108](#).

Day-Ahead and Real-Time Congestion Value

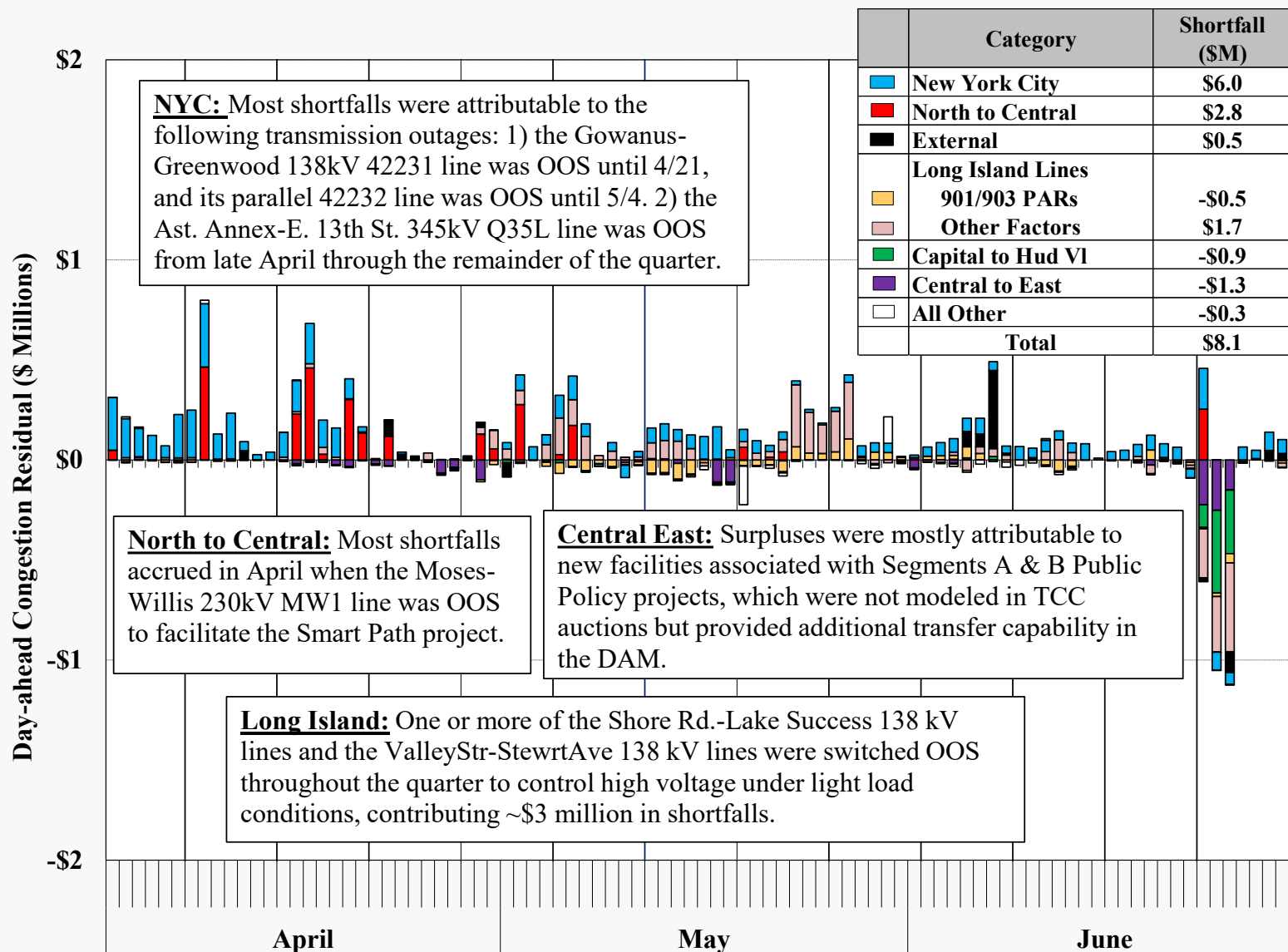
By Transmission Path



Notes: For chart description, see slides [107](#), [108](#), and [109](#).

Day-Ahead Congestion Revenue Shortfalls

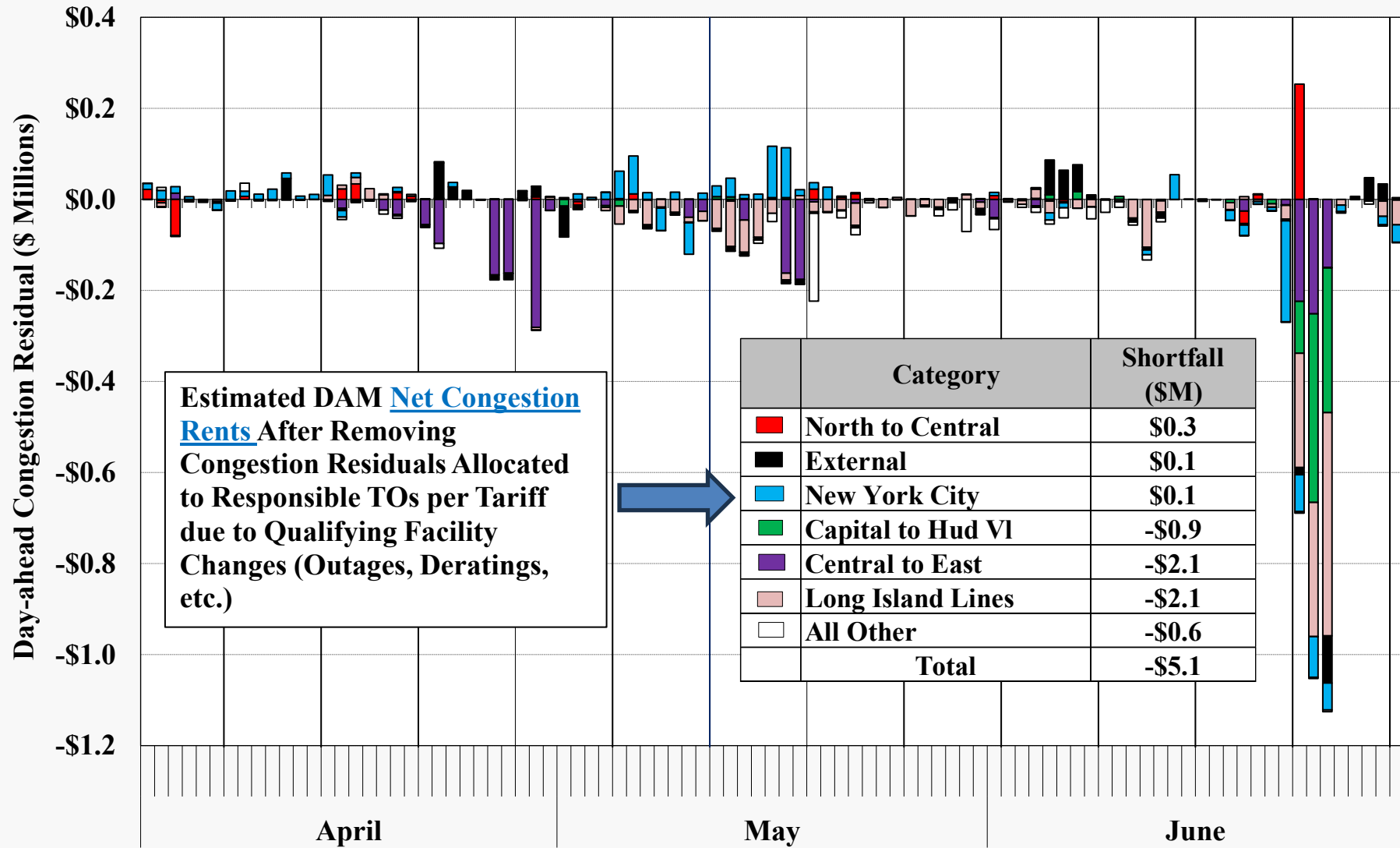
By Transmission Facility



Notes: For chart description, see slides [107](#), [108](#), and [109](#).

Estimated DAM Net Congestion Rents

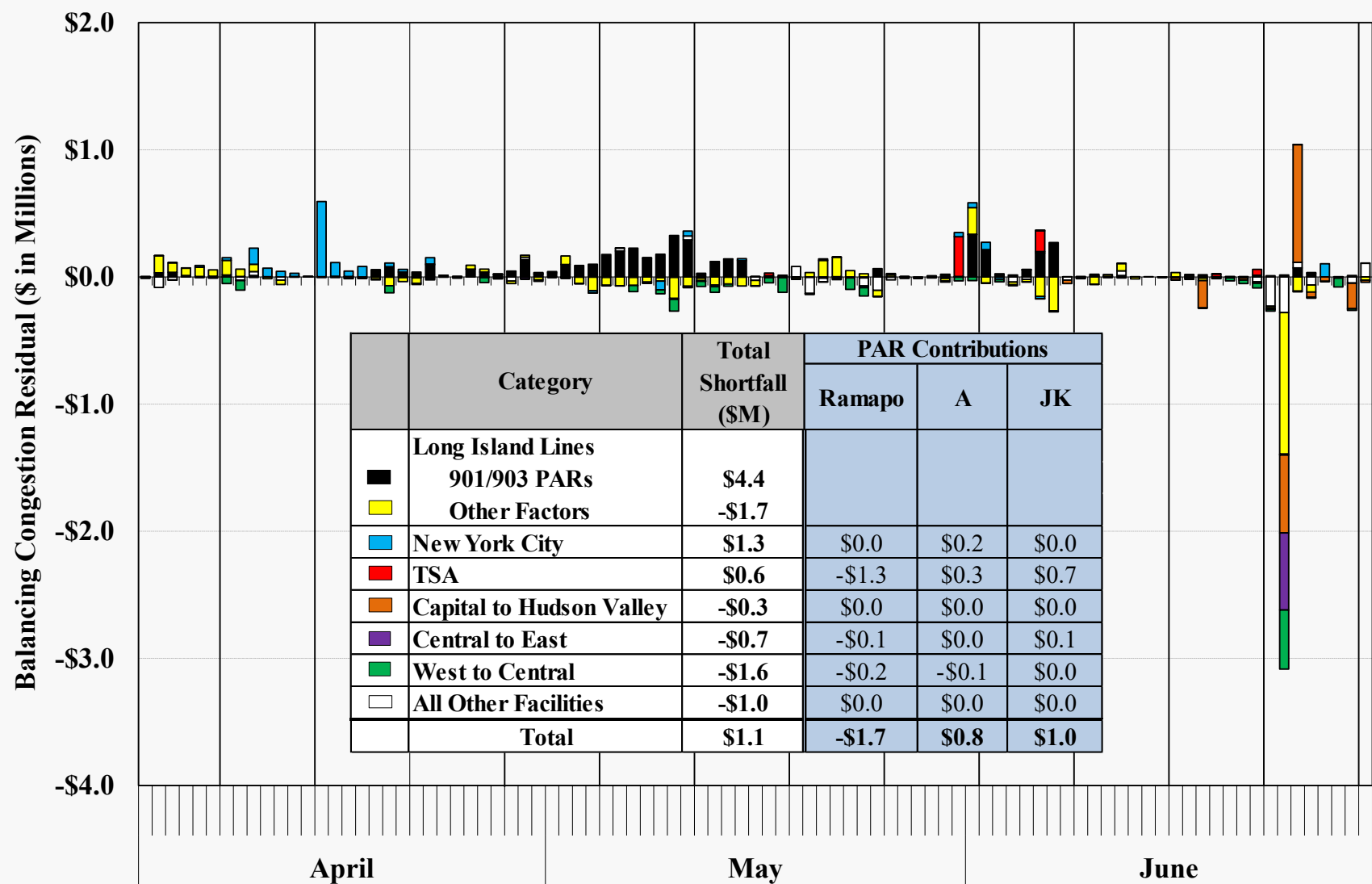
By Transmission Facility



Notes: For chart description, see slides [107](#), [108](#), and [109](#).

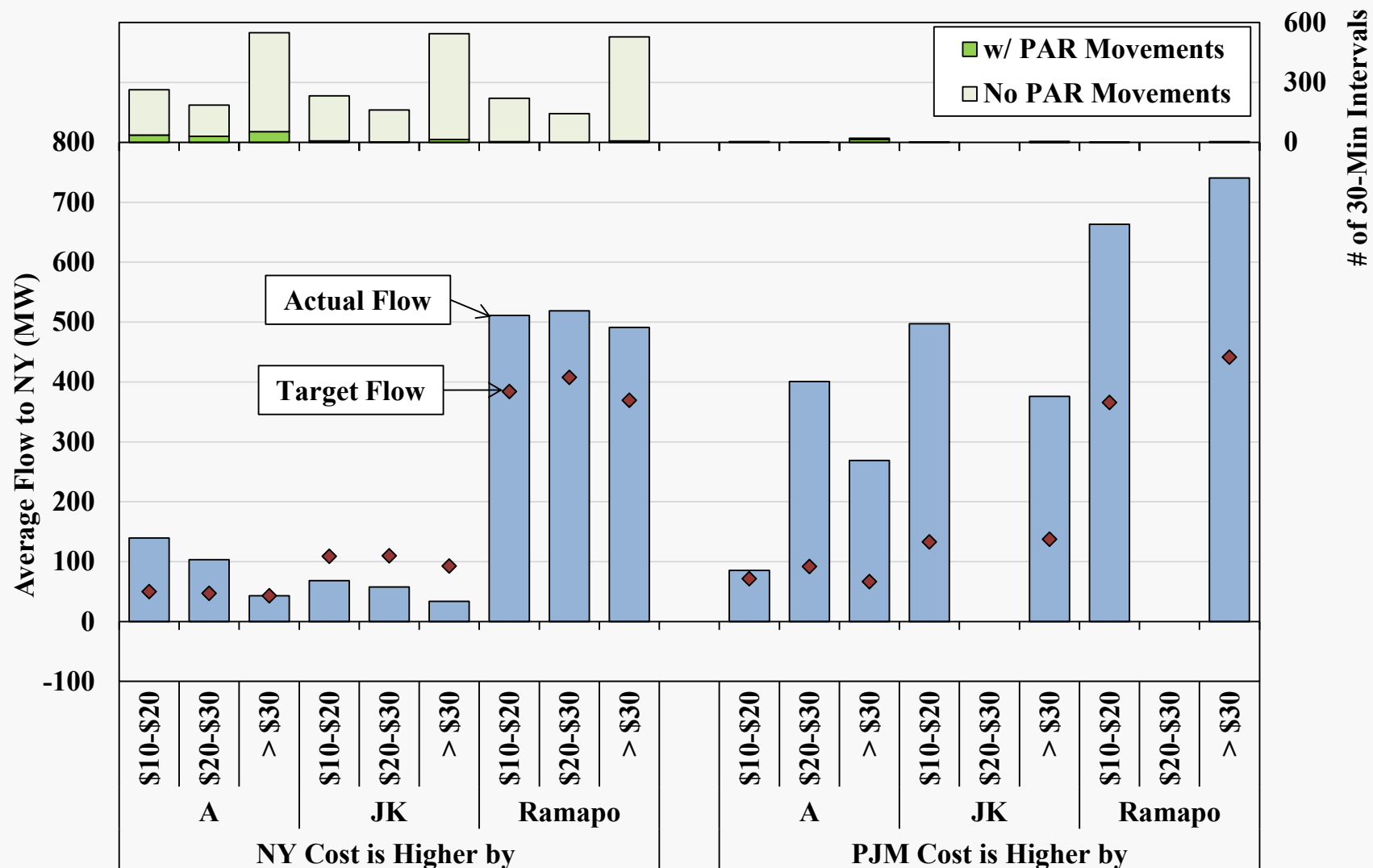
Balancing Congestion Shortfalls

By Transmission Facility



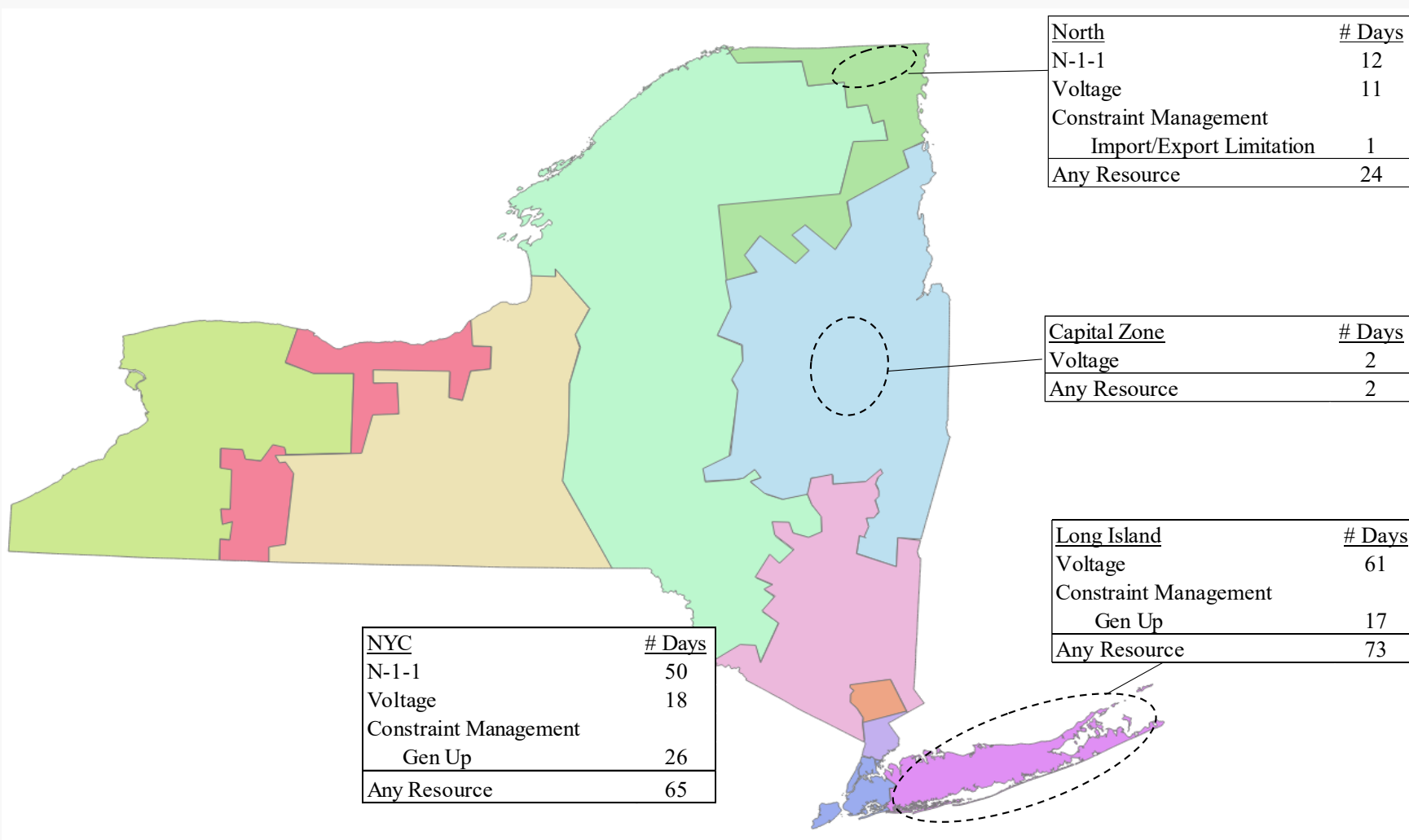
Notes: 1. The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. 2. For chart description, see slides [107](#), [108](#), and [109](#).

PAR Operation under M2M with PJM: 2025 Q2



Notes: For chart description, see slide [110](#).

OOM Actions to Manage Network Reliability



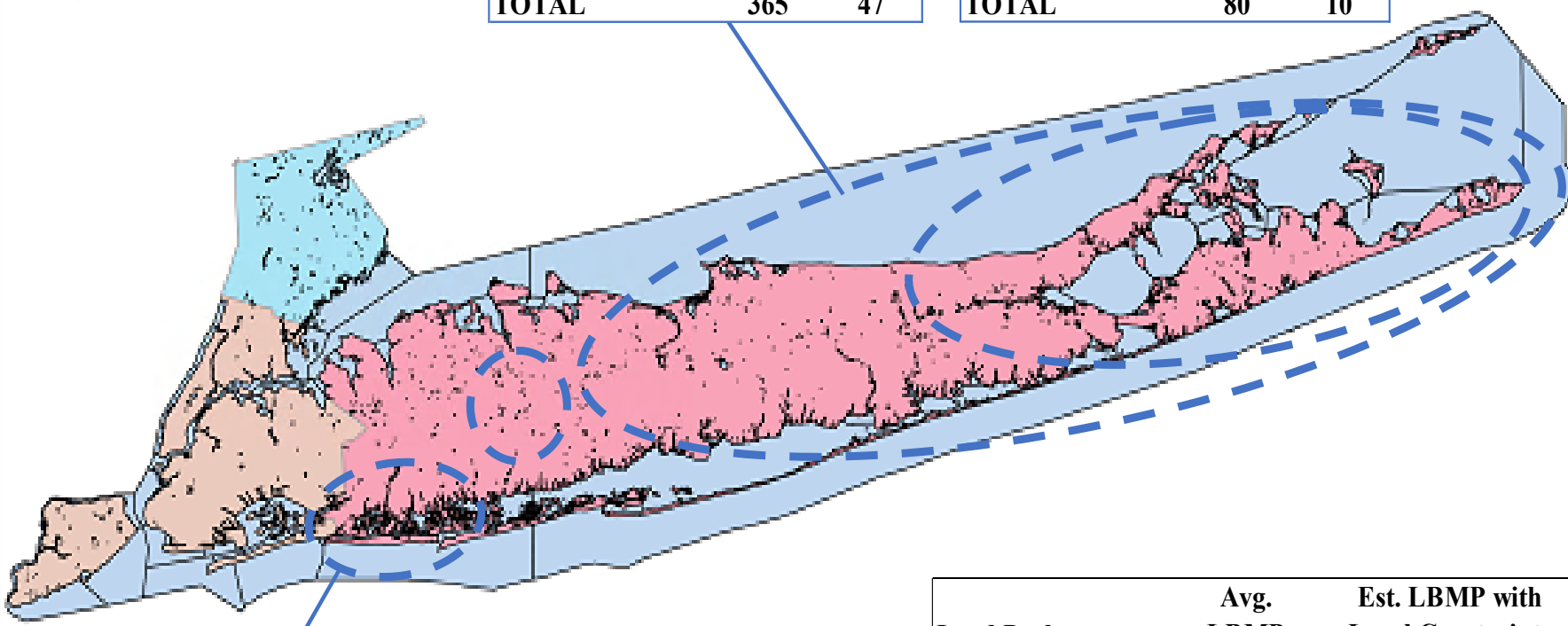
Notes: For chart description, see slide [111](#)

Constraints on the Low Voltage Network

Long Island Load Pockets

<u>East of Northport</u>	<u>#Hours</u>	<u>#Days</u>
69kV OOM	2	1
69kV	340	44
138kV	163	24
TOTAL	365	47

<u>East End</u>	<u>#Hours</u>	<u>#Days</u>
69kV OOM	0	0
TVR	80	10
TOTAL	80	10



<u>Valley Stream</u>	<u>#Hours</u>	<u>#Days</u>
69kV OOM	136	15
138kV	1285	86
TOTAL	1305	86

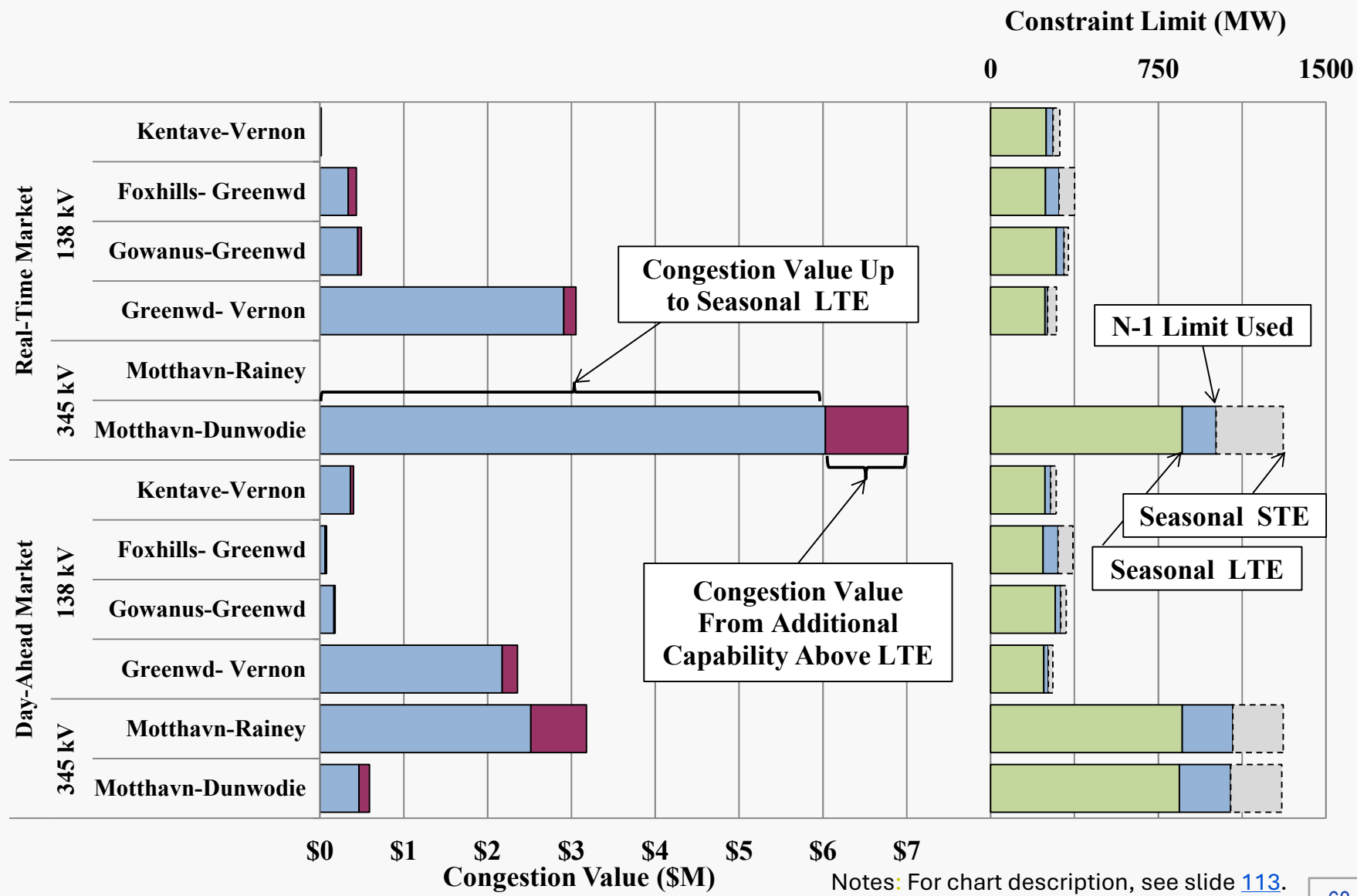
<u>Brentwood</u>	<u>#Hours</u>	<u>#Days</u>
69kV OOM	0	0
69kV	51	12
TOTAL	51	12

<u>Load Pocket</u>	<u>Avg. LBMP</u>	<u>Est. LBMP with Local Constraints</u>
Brentwood	\$50.43	\$50.43
East End	\$52.03	\$56.23
East of Northport	\$51.66	\$51.67
Valley Stream	\$84.76	\$88.86

Notes: For chart description, see slides [111-112](#)

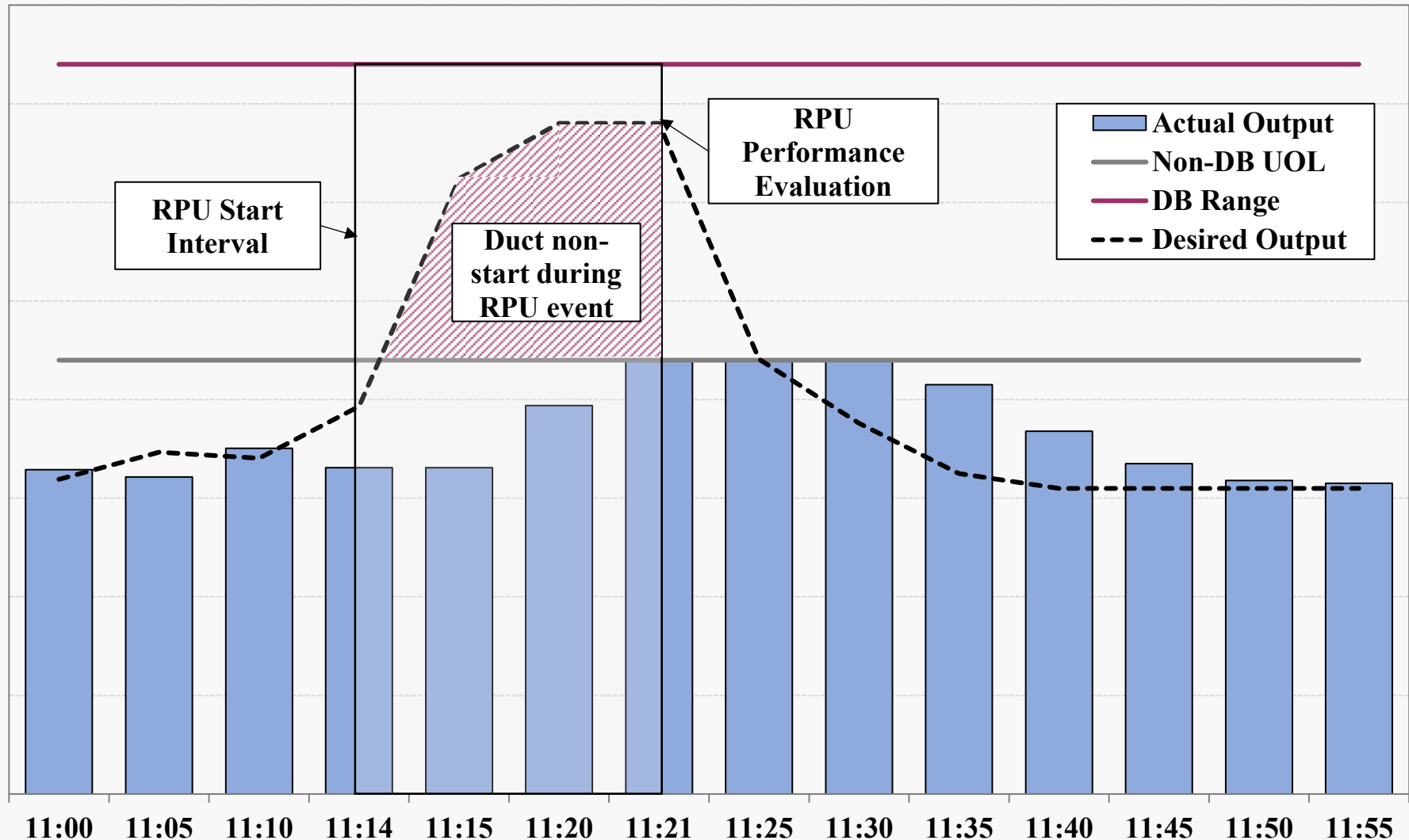
N-1 Constraints in New York City

Limits Used vs Seasonal LTE Ratings



Duct Burner Real-Time Dispatch Issues

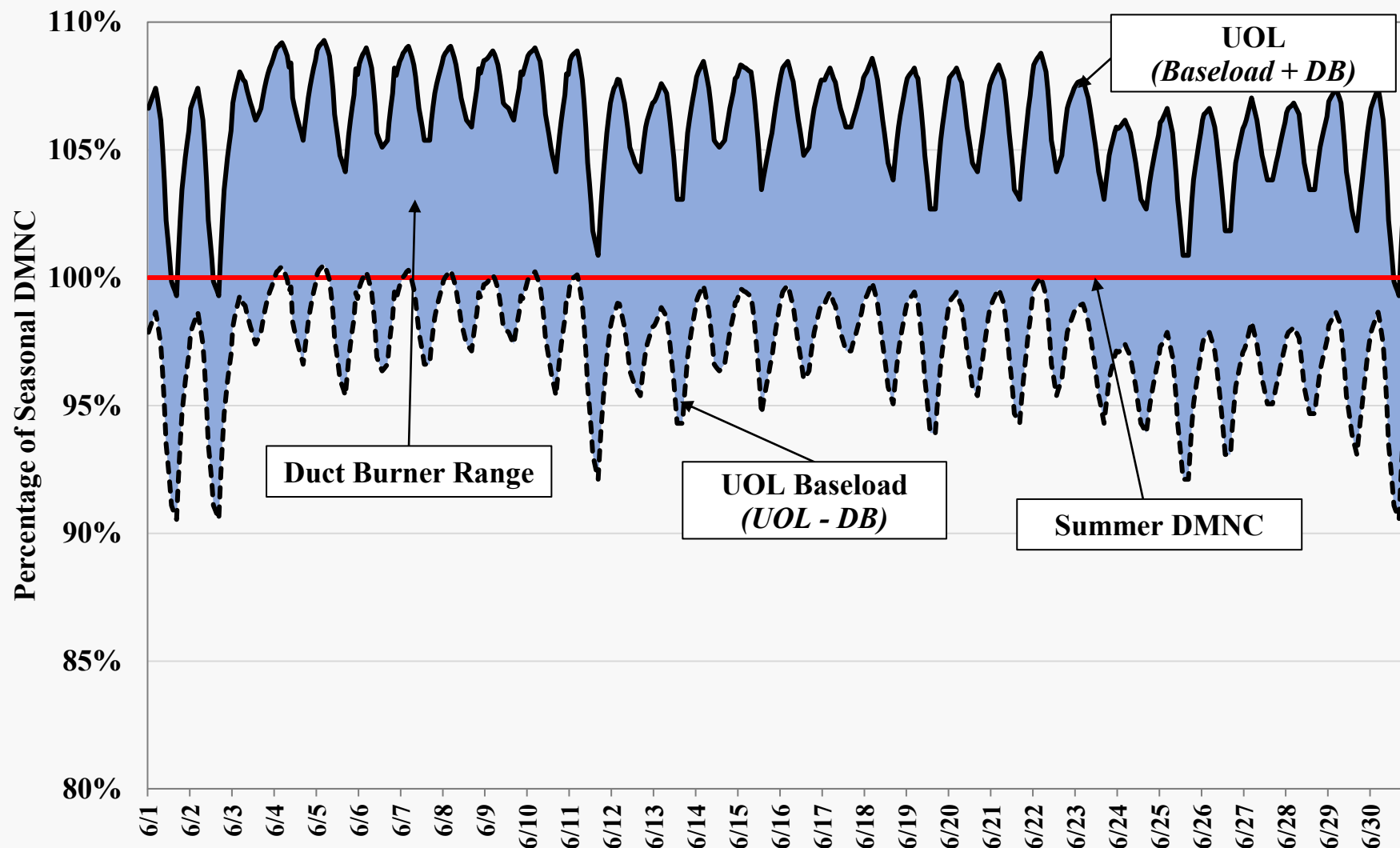
Example of a Failed RPU



Notes: For chart description, see slide [114](#)

Illustration of Duct Burner Range

Example Generator Hourly Capability

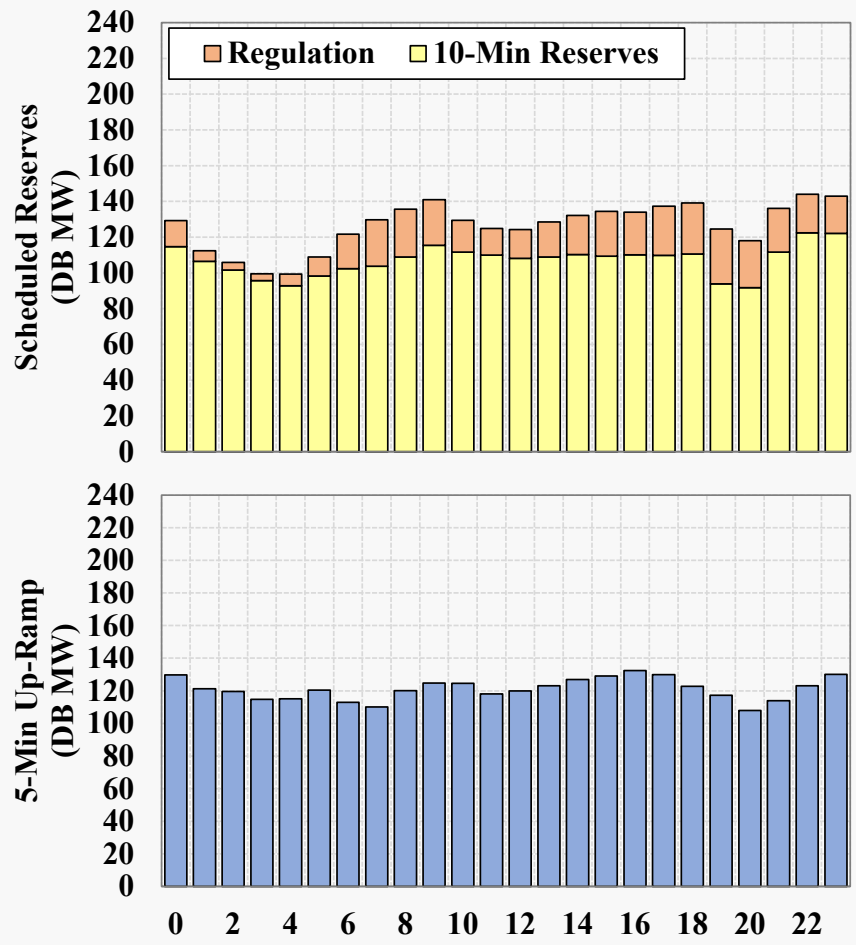


Notes: For chart description, see slide [115](#)

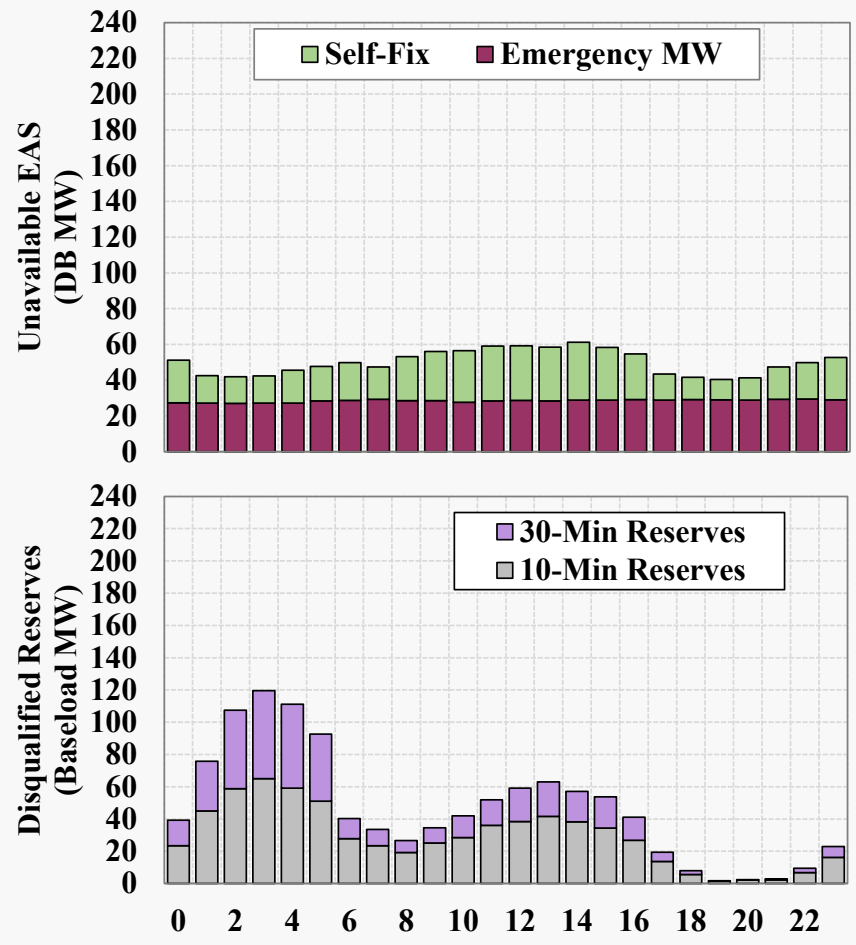
Duct Burner Schedules and Ramp Expectations

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 [114](#)

Gas Turbine Start-up Performance

Economic Starts & Audits

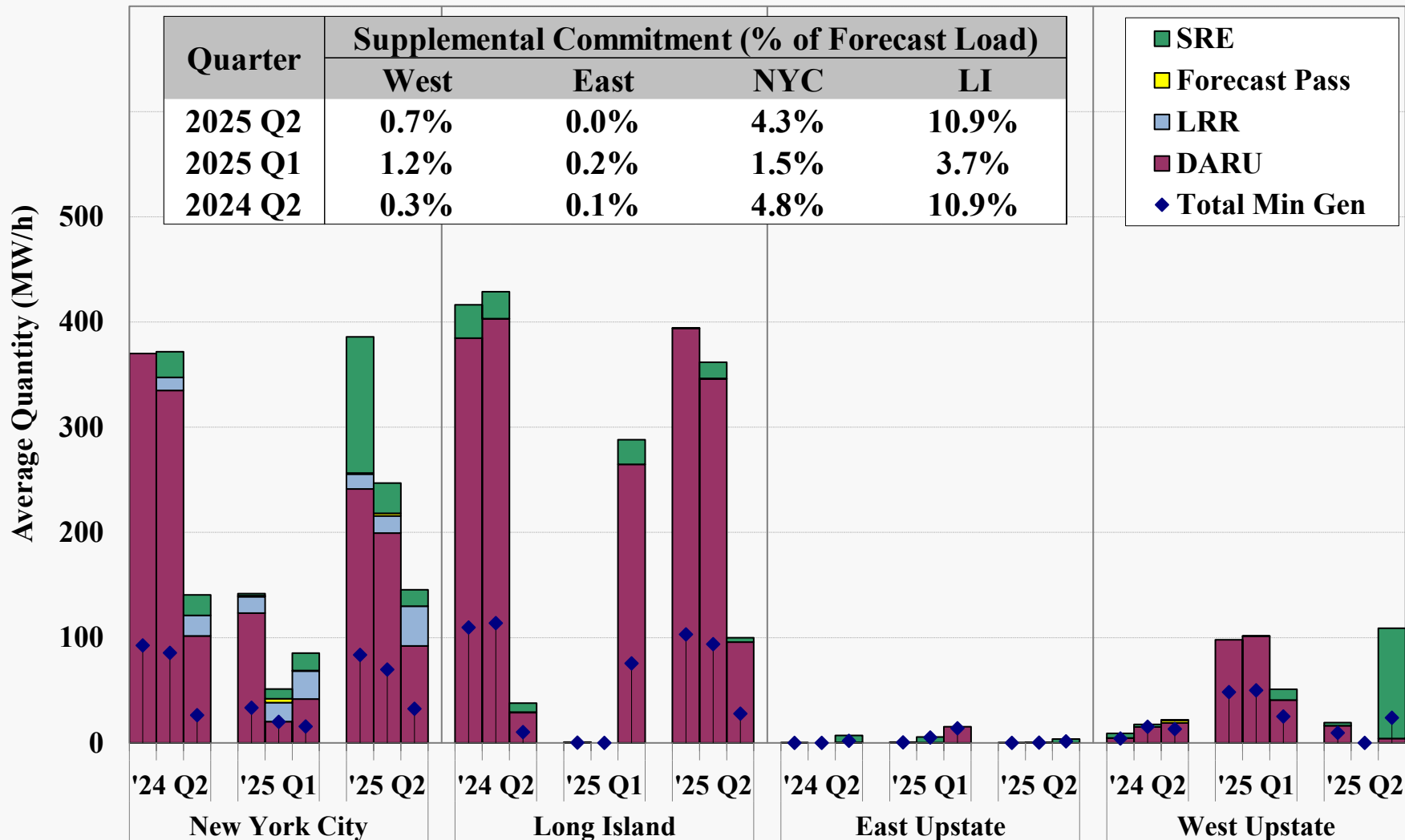
10/30-Minute GT Start Performance - Jul 2024 - Jun 2025						
Performance Category	No. of Units	Total No. of Starts Evaluated	Other Economic Starts and Audits		RPU's + Unforeseen Economic Starts and Audits	
			Avg Performance On Time	Avg Performance 10 Minutes Later	Avg Performance On Time	Avg Performance 10 Minutes Later
0% - 10%	0	0				
10% - 20%	0	0				
20% - 30%	0	0				
30% - 40%	1	16	50.0%	100.0%	37.6%	57.6%
40% - 50%	2	6	64.0%	64.0%	33.3%	33.3%
50% - 60%	1	8	66.7%	66.7%	54.8%	59.8%
60% - 70%	4	59	65.7%	78.6%	65.6%	81.1%
70% - 80%	5	91	76.3%	85.0%	72.5%	77.7%
80% - 90%	26	4084	87.3%	94.6%	85.3%	95.2%
90% - 100%	62	5636	94.2%	96.5%	94.7%	97.0%
TOTAL	101	9900				

Notes: For chart description, see slide [116](#)

Charts: Supplemental Commitment, OOM Dispatch, and BPCG Uplift

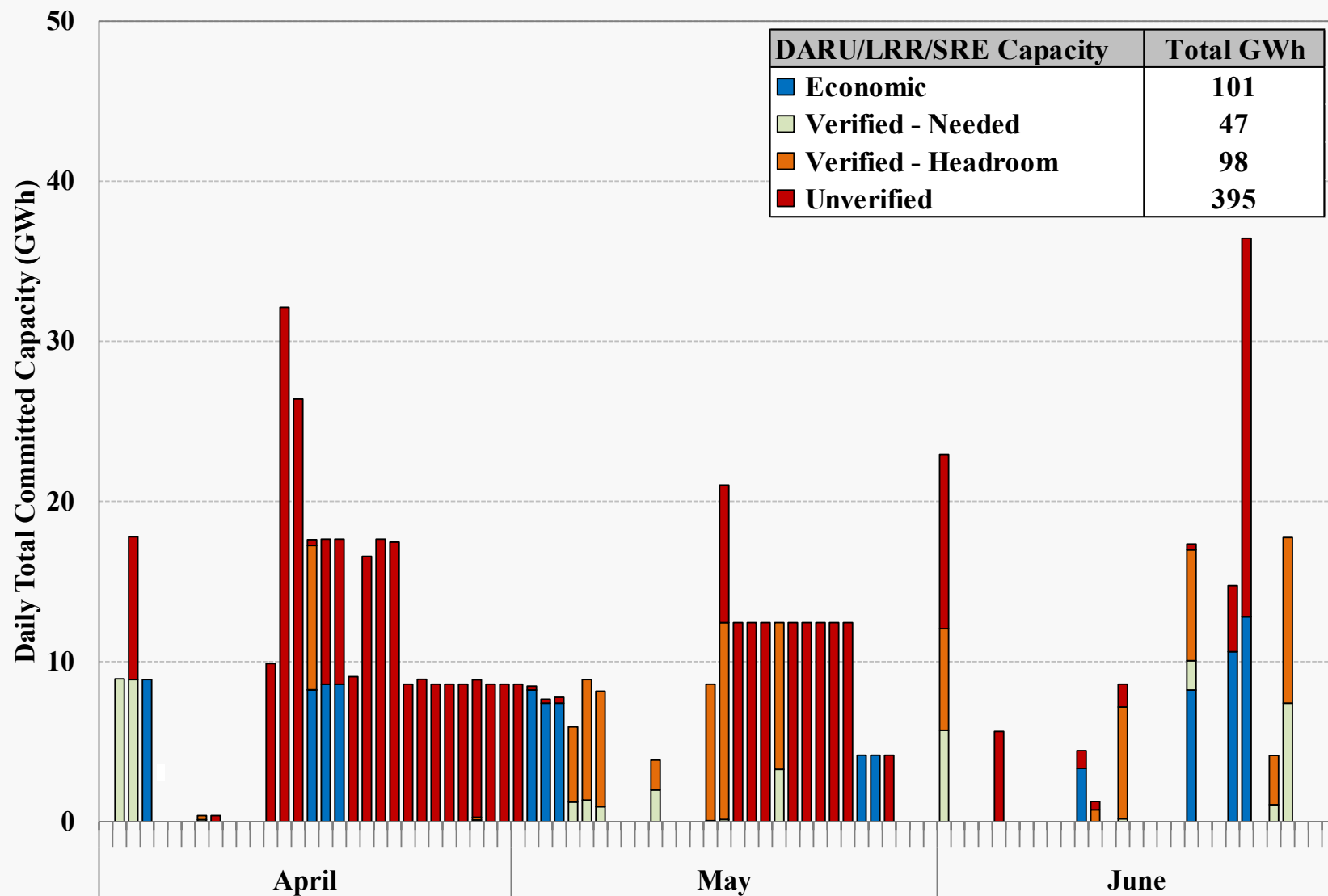
Supplemental Commitment for Reliability

By Category and Region



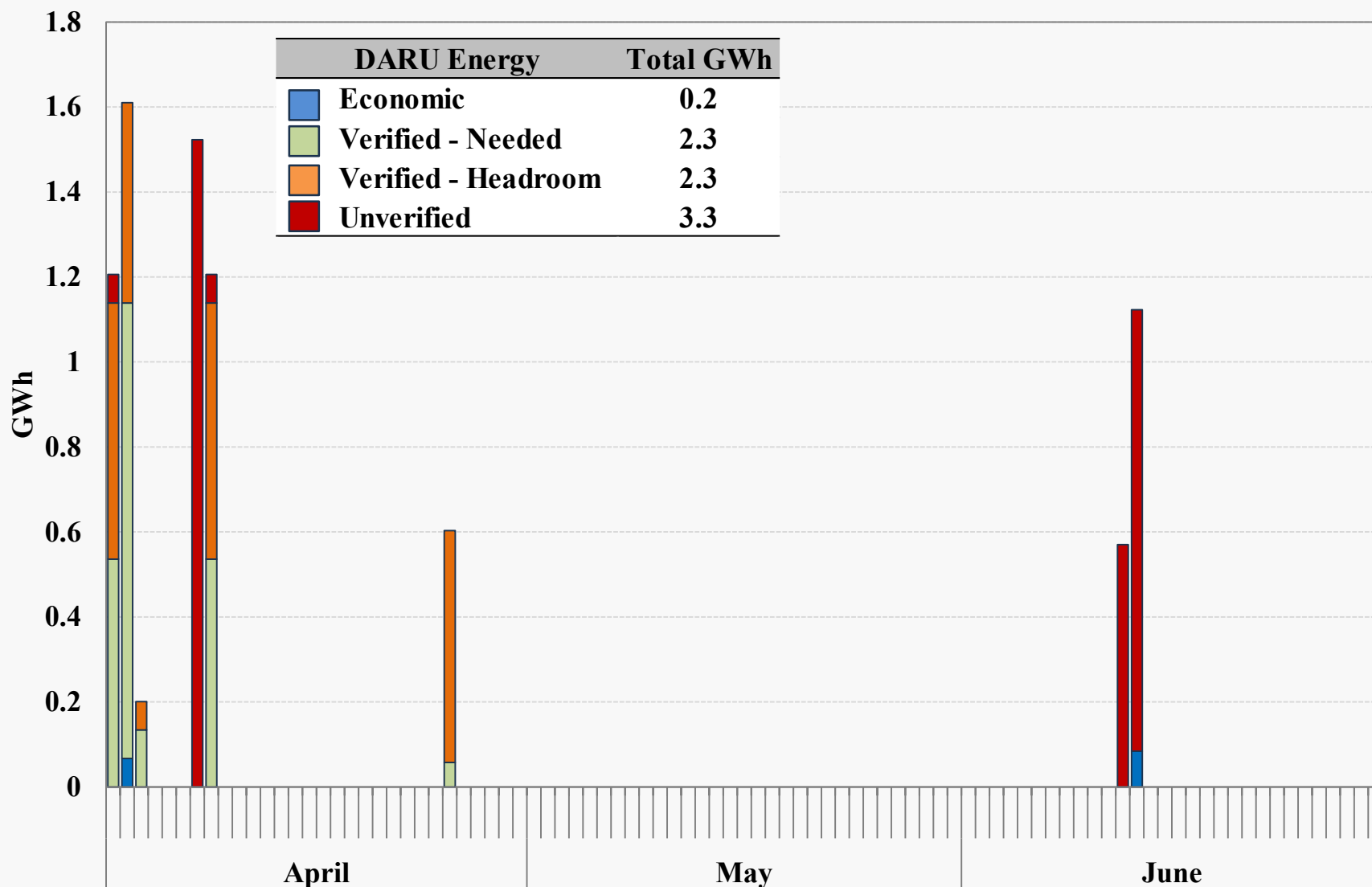
Notes: For chart description, see slides [117](#).

DARU/LRR/SRE Commitments in NYC: 2025 Q2



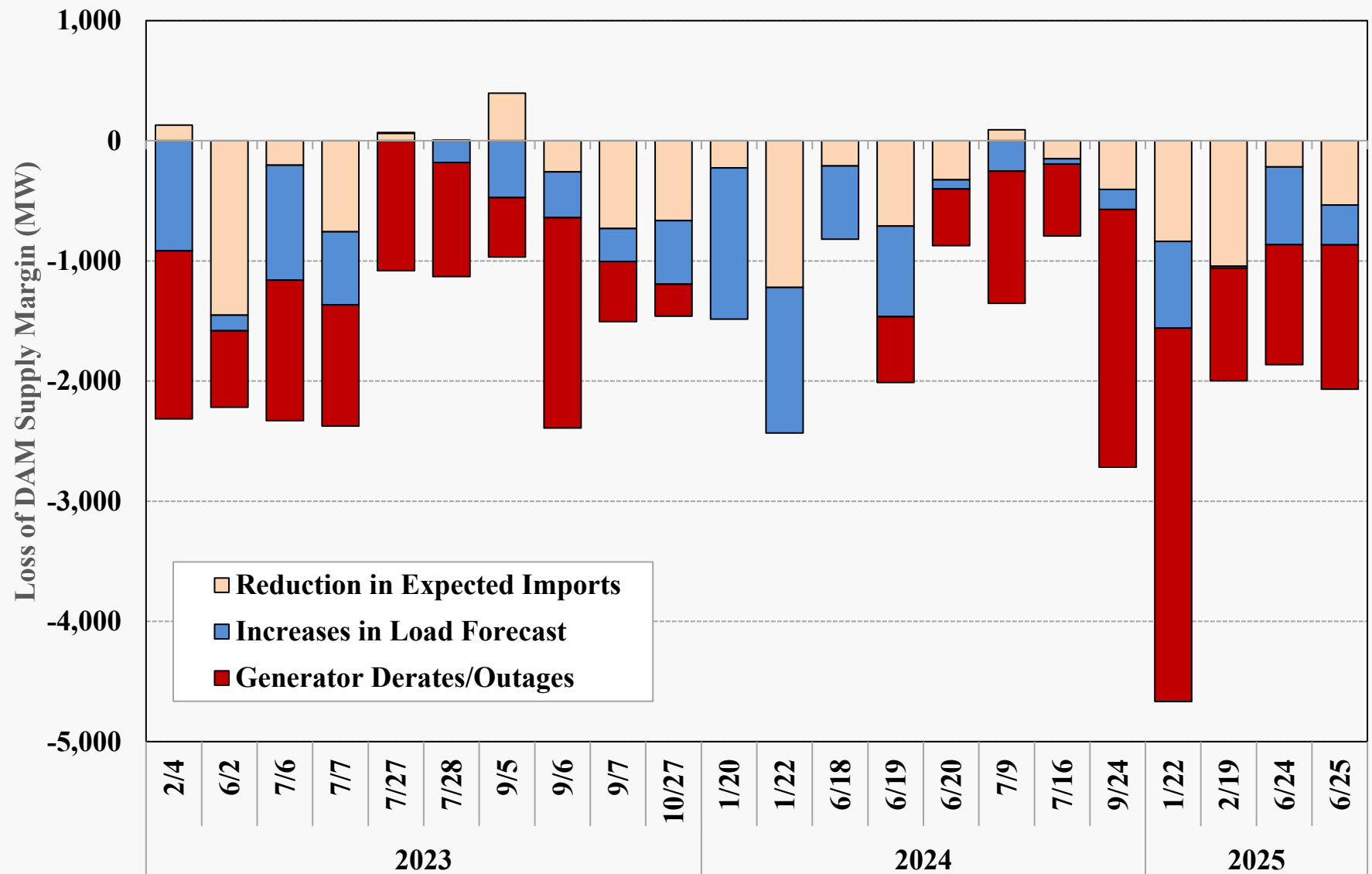
Notes: For chart description, see slide [118](#).

DARU Commitments in North Country: 2025 Q2



Notes: For chart description, see slide [118](#).

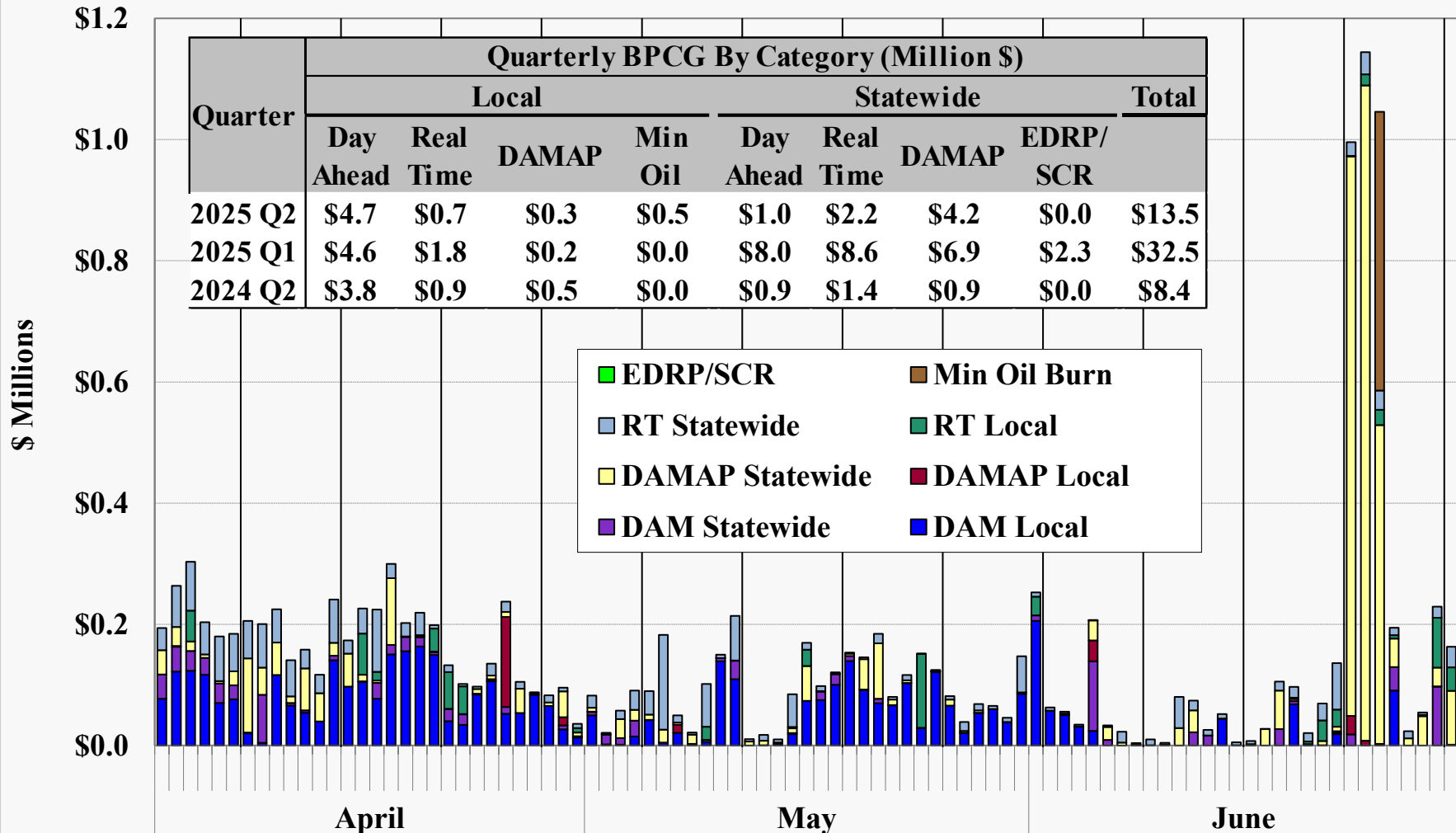
Key Drivers of SRE Commitments for Systemwide Capacity



Notes: For chart description, see slide [119](#).

Uplift Costs from Guarantee Payments

Local and Non-Local by Category

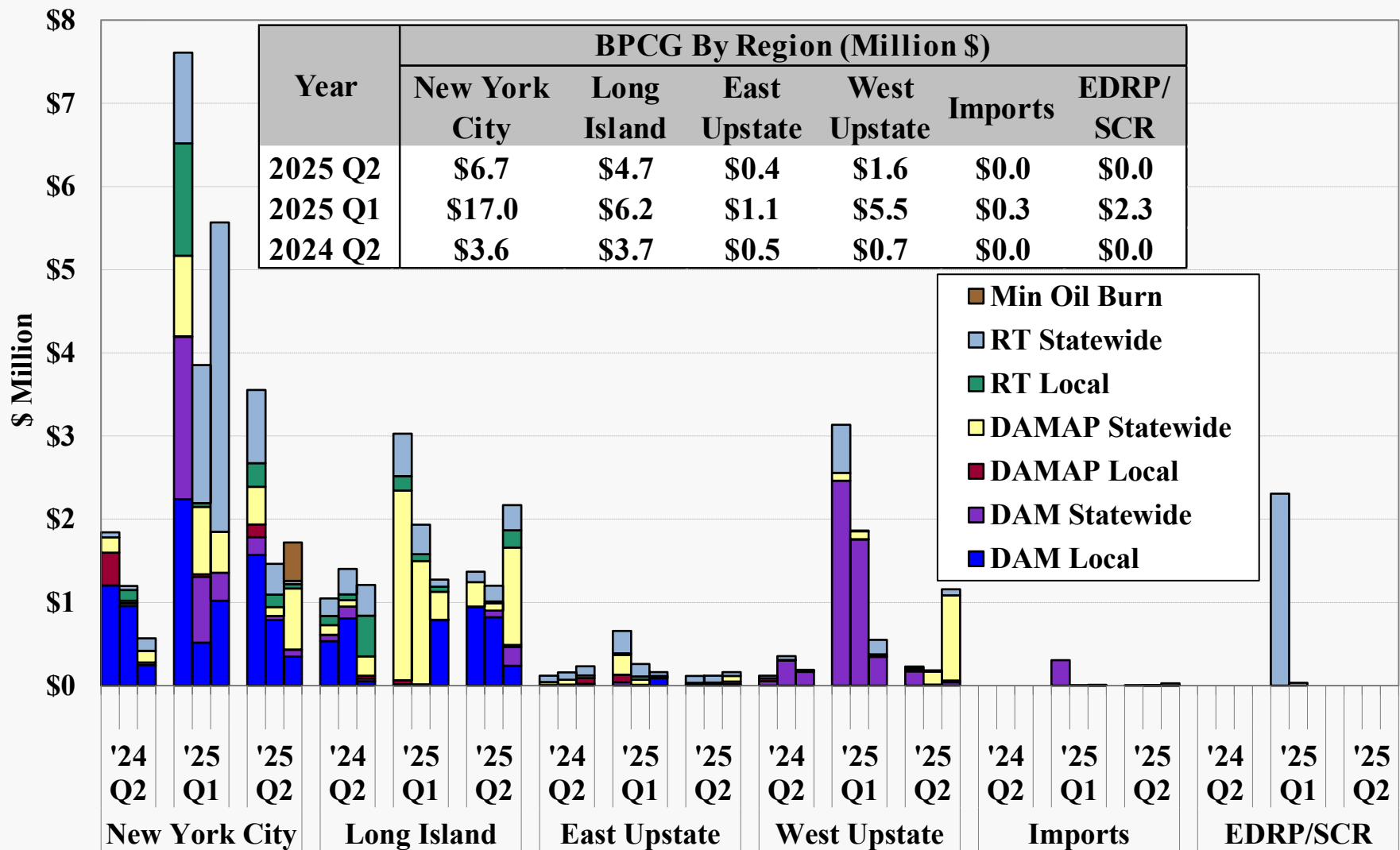


Notes: 1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.

2. For chart description, see slide [120](#).

Uplift Costs from Guarantee Payments

By Category and Region

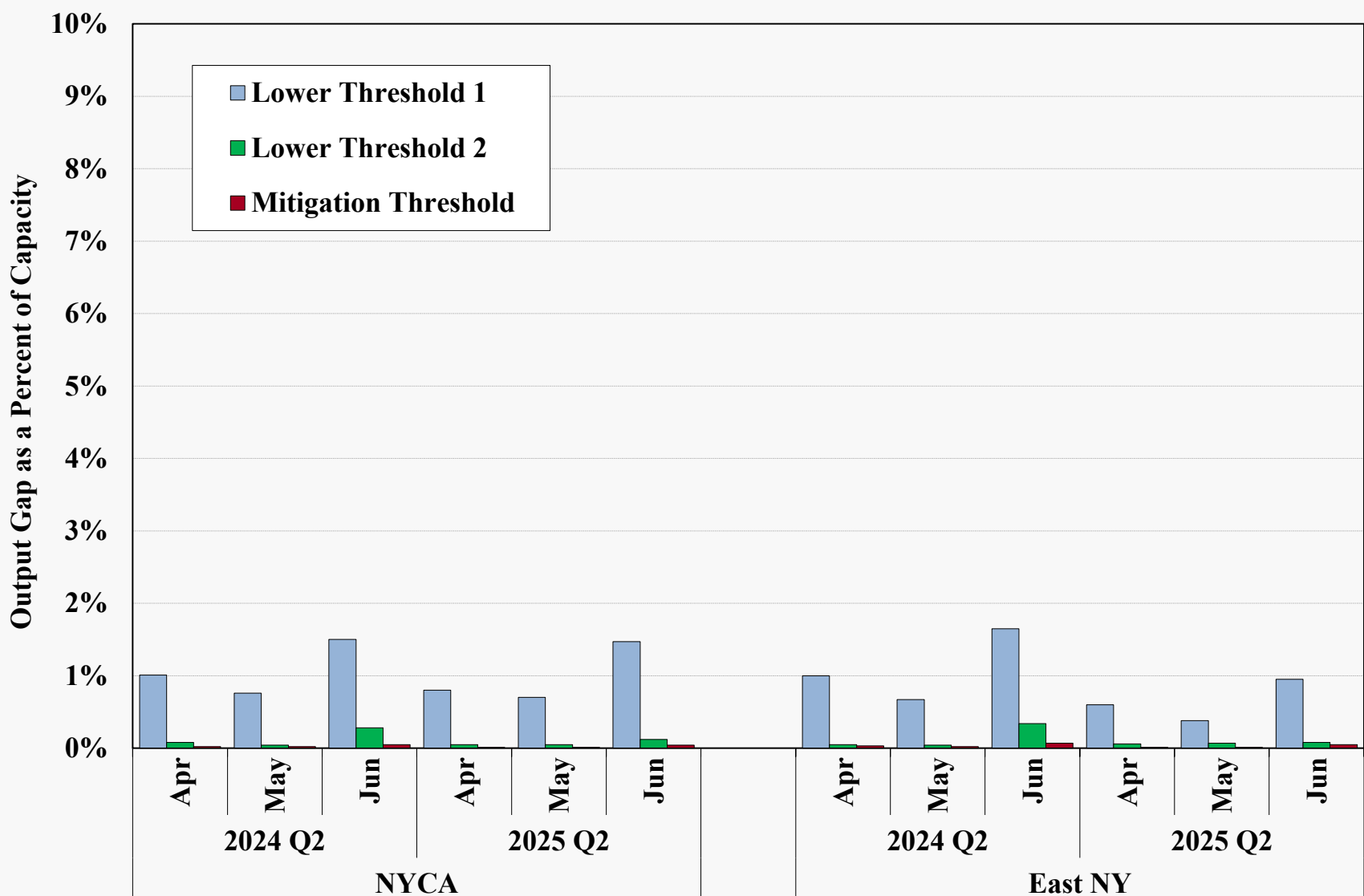


Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide [120](#).

Charts: Market Power and Mitigation

Output Gap by Month

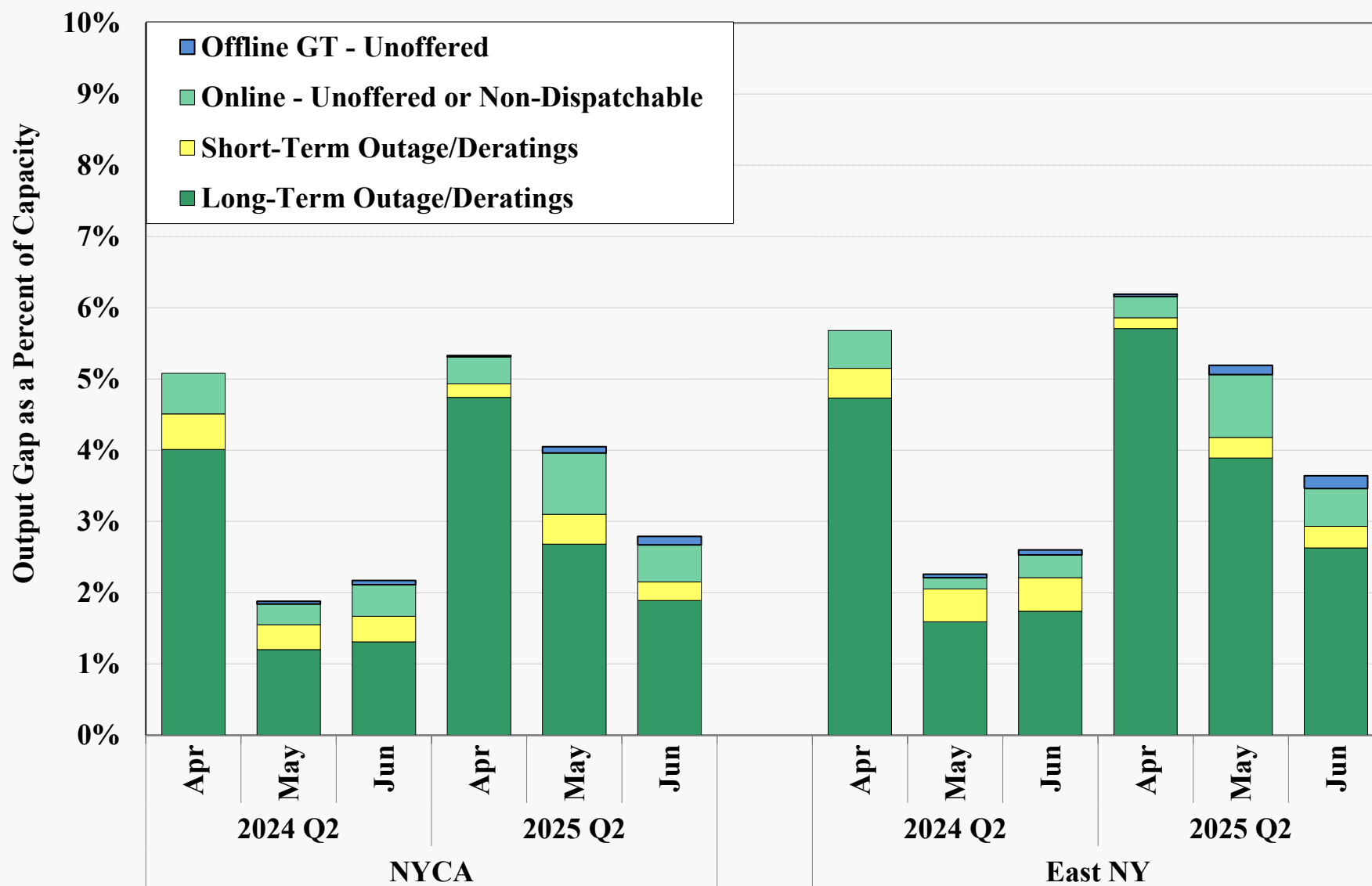
NYCA and East NY



For chart description, see slide [121](#).

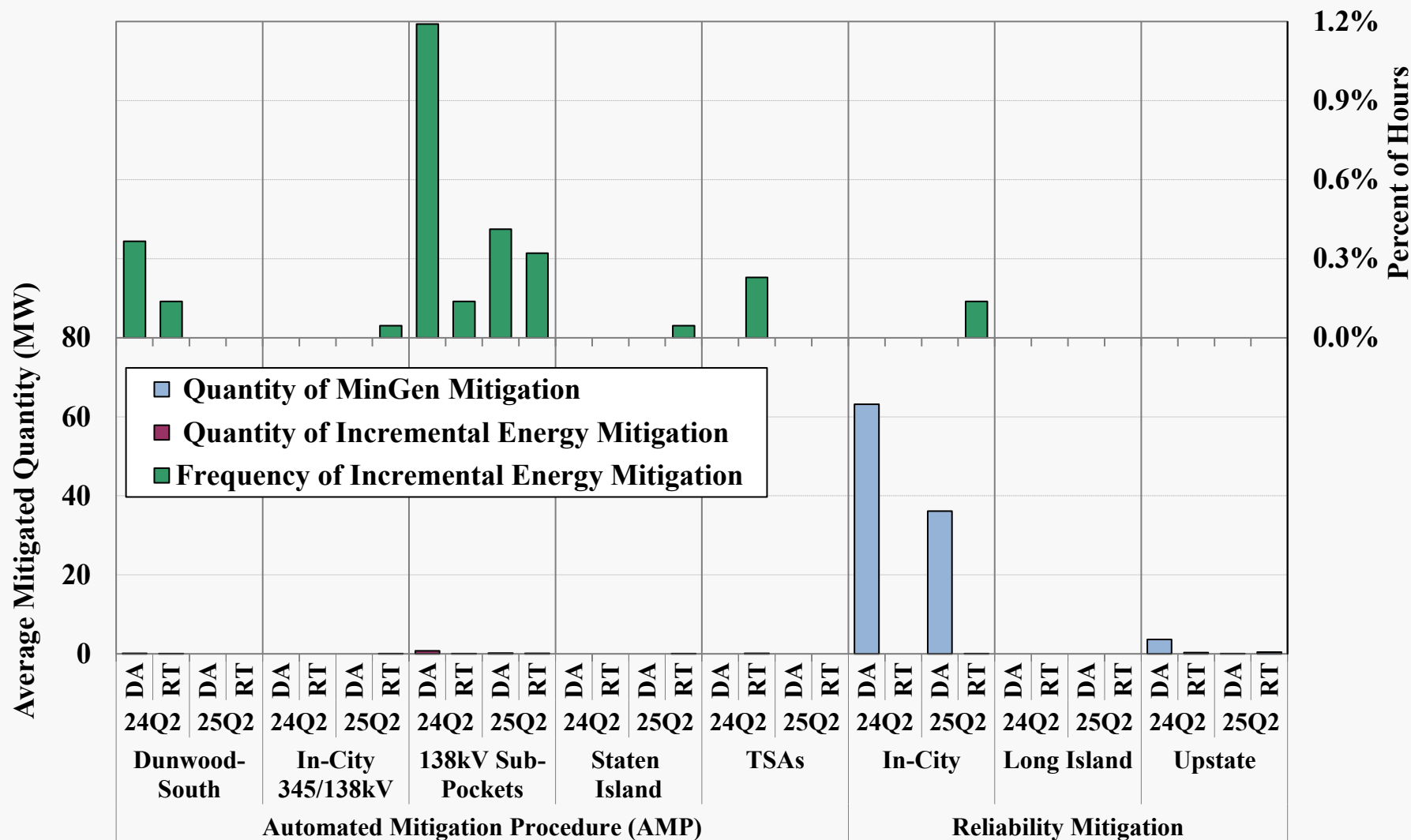
Unoffered Economic Capacity by Month

NYCA and East NY



For chart description, see slide [121](#).

Automated Market Power Mitigation

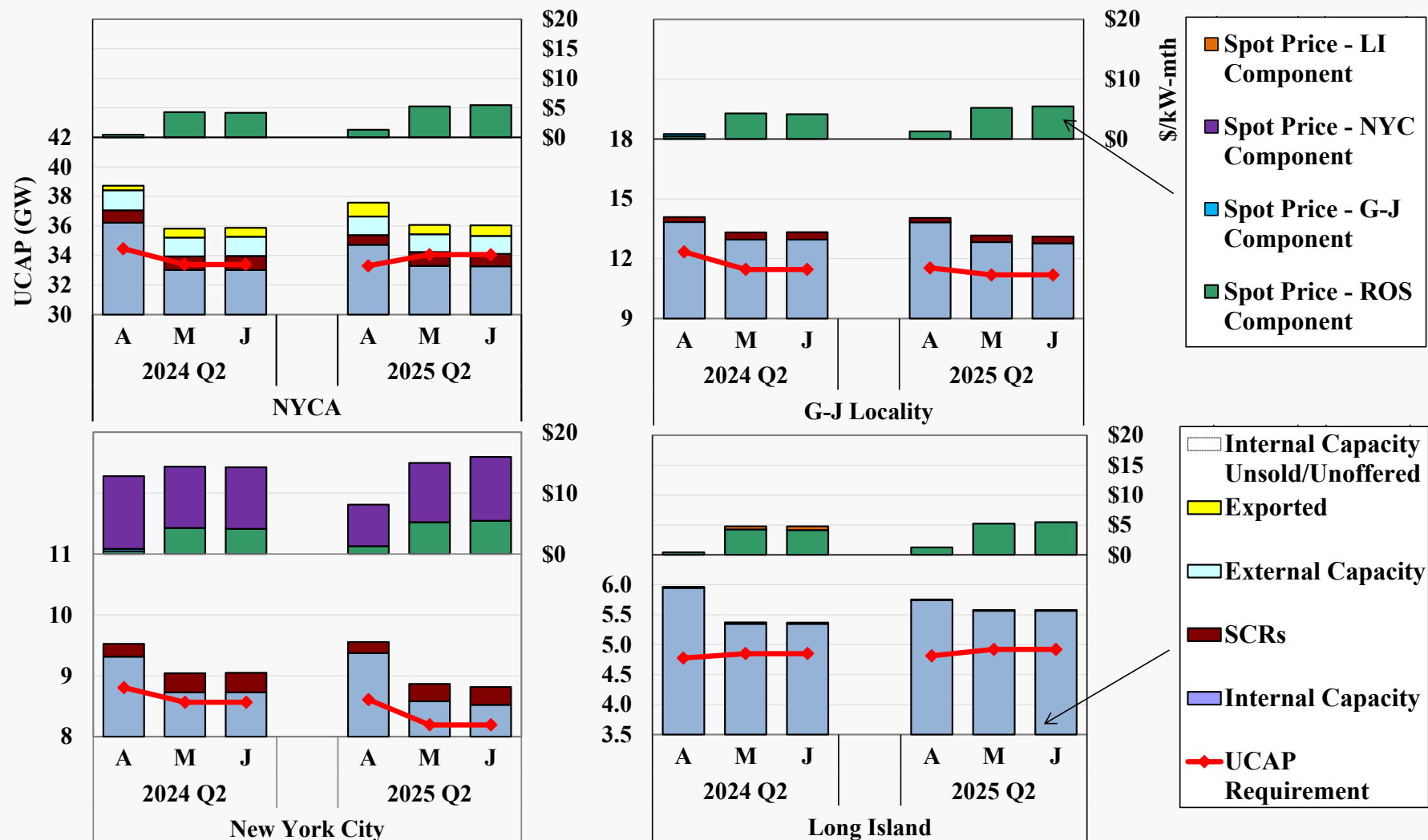


Notes: For chart description, see slide [122](#).

Charts: Capacity Market

Spot Capacity Market Results

Monthly Results by Locality



Notes: For chart description, see slide [123](#).

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2025 Q2 (\$/kW-Month)	\$3.99	\$13.00	\$3.99	\$3.99
% Change from 2024 Q2	35%	-6%	20%	29%
Change in Demand				
Load Forecast (MW)	-72	-163	36	-14
IRM/LCR	2.4%	-1.9%	1.2%	-2.2%
2025/26 Capability Year	124.4%	78.5%	106.5%	78.8%
2024/25 Capability Year	122.0%	80.4%	105.3%	81.0%
ICAP Requirement (MW)	667	-340	99	-346
Key Changes in ICAP Supply (MW)				
<i>Generation & UDR</i>	-262	-83	55	-140
<i>Entry⁽³⁾</i>	73	0	13	2
<i>Exit⁽³⁾</i>	-145	-61	-36	-104
<i>Other Capacity Changes⁽¹⁾</i>	-190	-22	78	-37
<i>Cleared Import⁽²⁾</i>	-74			

(1) Other changes include DMNC ratings, change in exports, unsold capacity, etc.

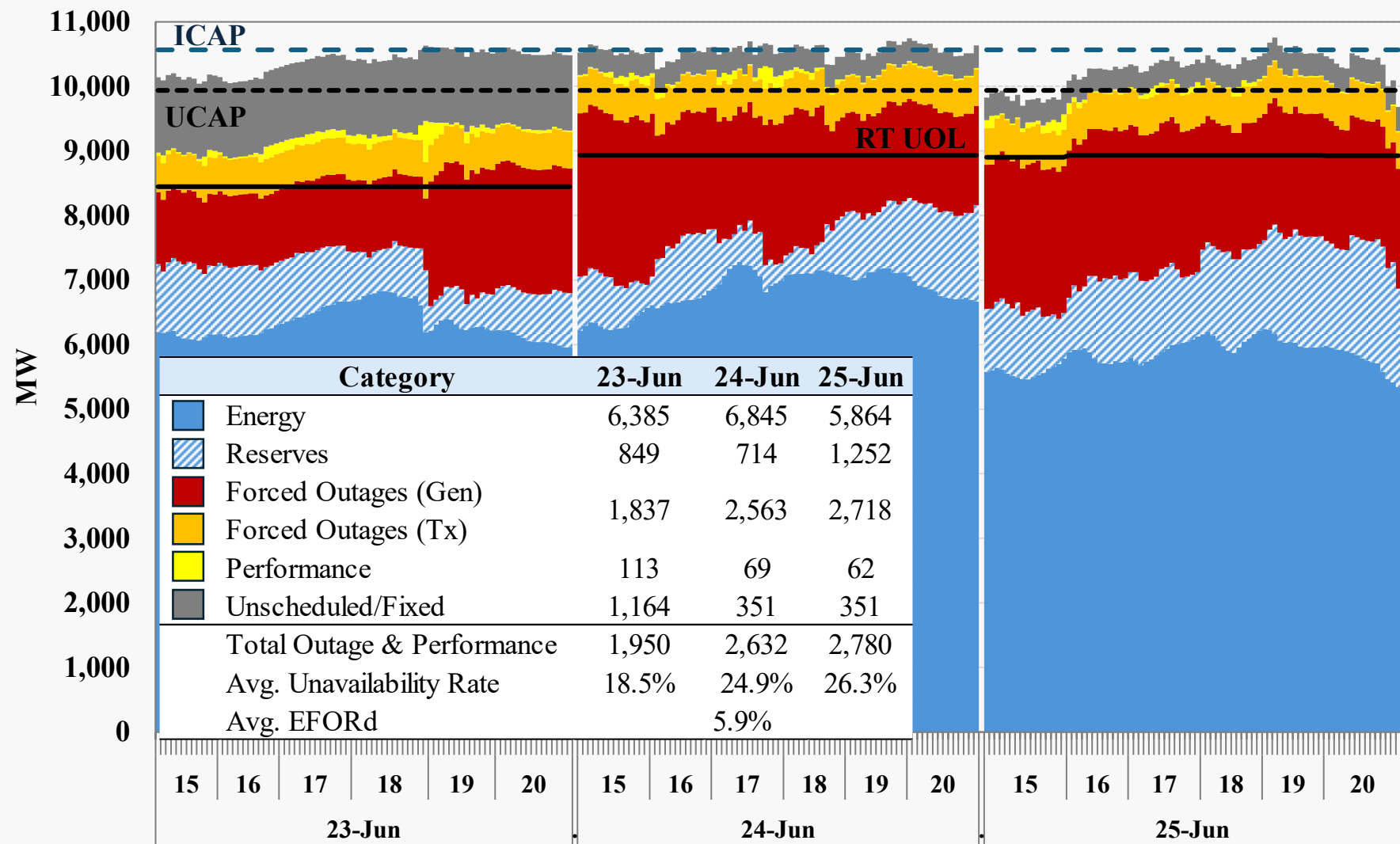
(2) Based on average of quarterly cleared quantity.

(3) Includes entry into or return from IIFO, Mothball, & other unavailable states

Notes: For chart description, see slide [123](#).

Availability Assessment – Fossil Steam Turbines

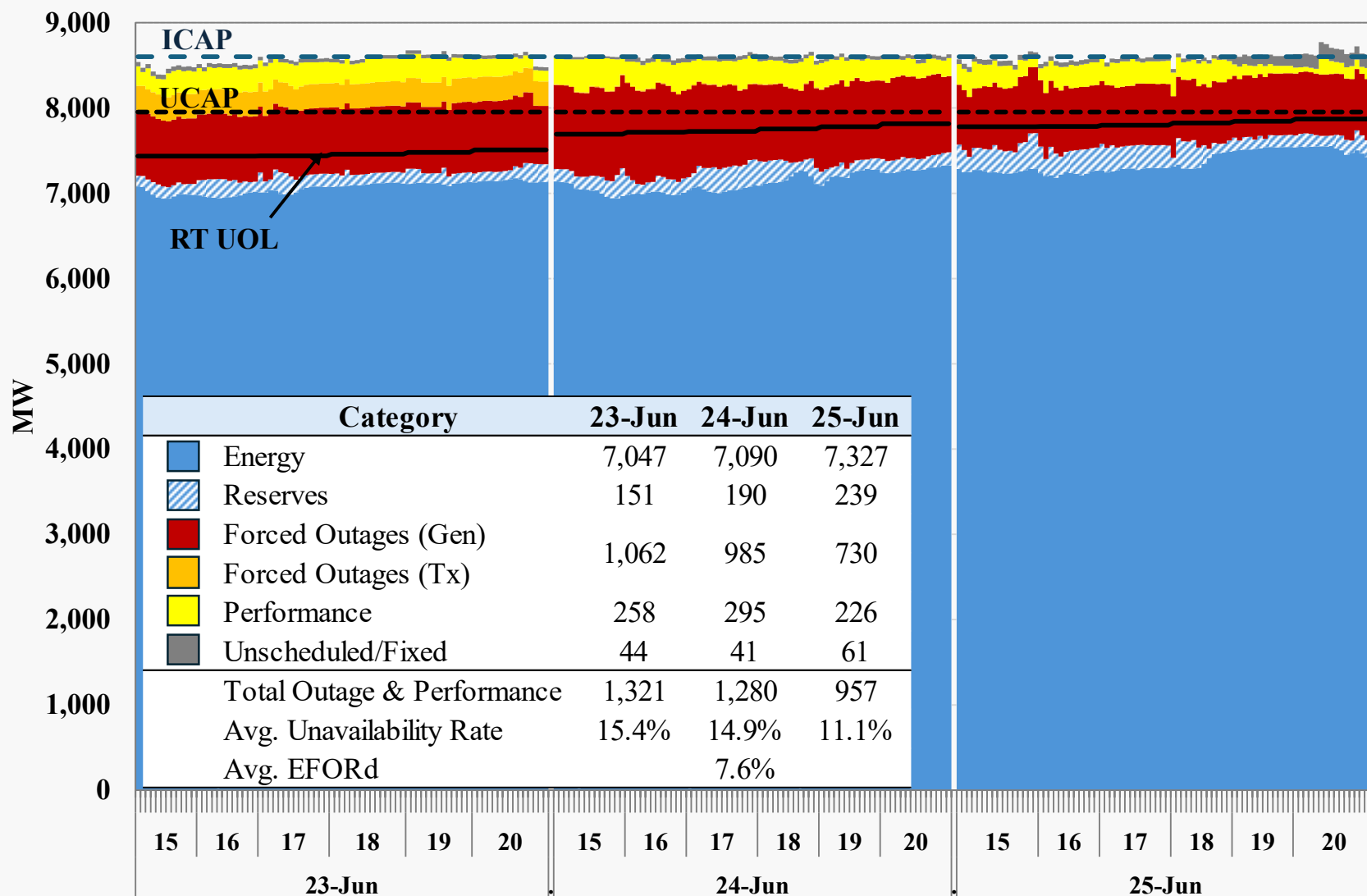
June 23-25, 2025, Heat Wave



Notes: For chart description, see slide [125](#).

Availability Assessment – Combined Cycles (ENY)

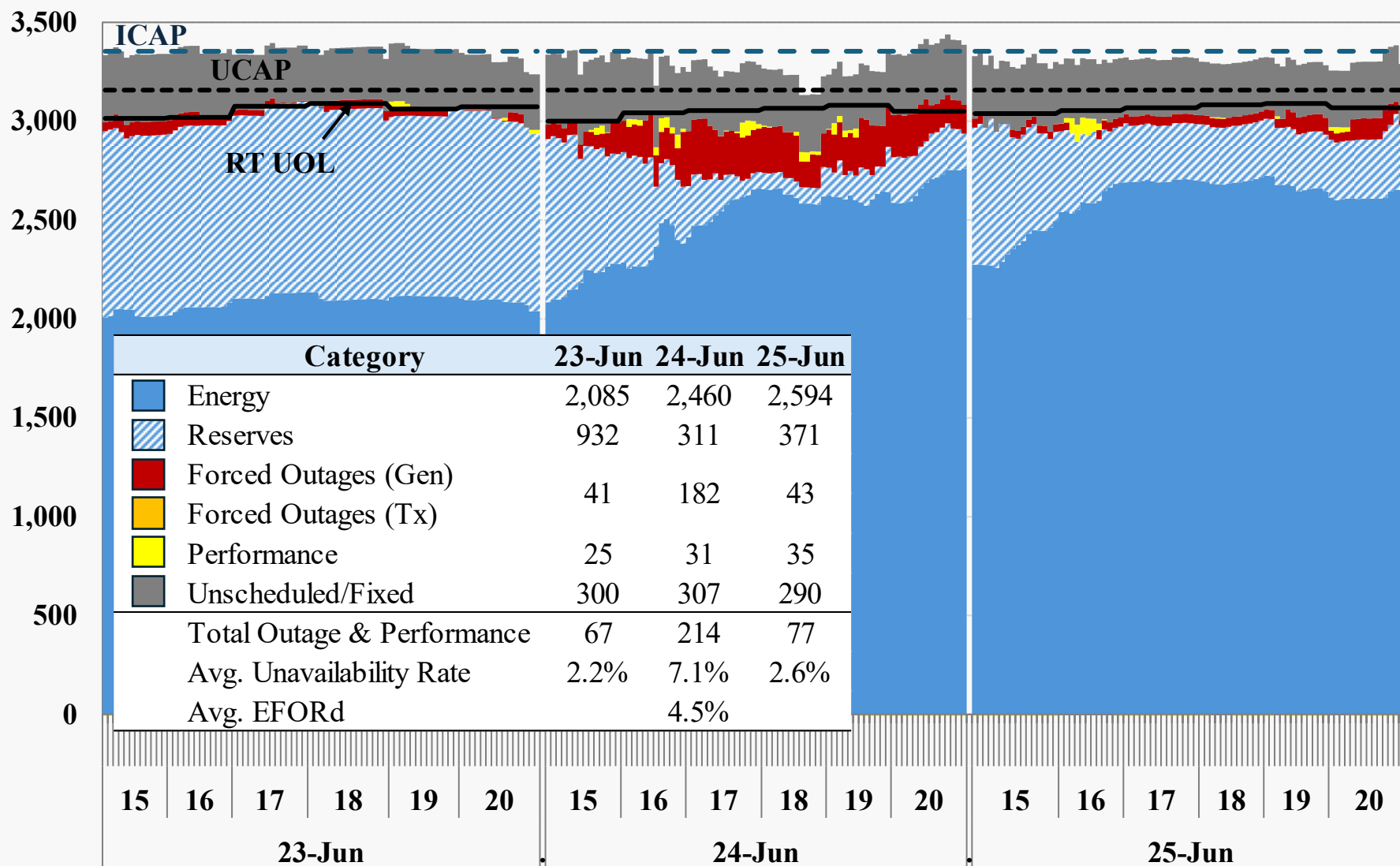
June 23-25, 2025, Heat Wave



Notes: For chart description, see slide [125](#).

Availability Assessment – Fossil Peaking Units

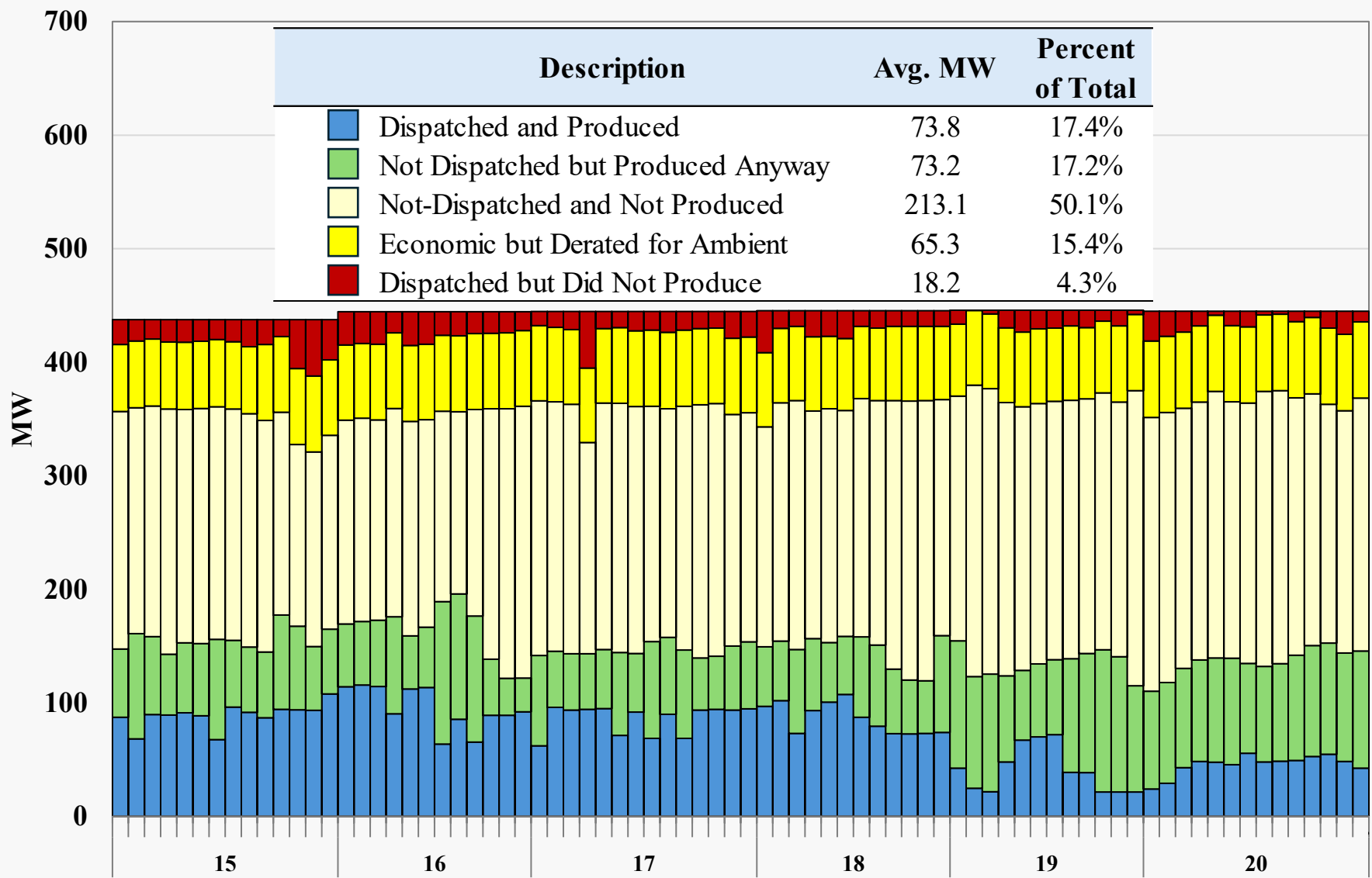
June 23-25, 2025, Heat Wave



Notes: For chart description, see slide [125](#).

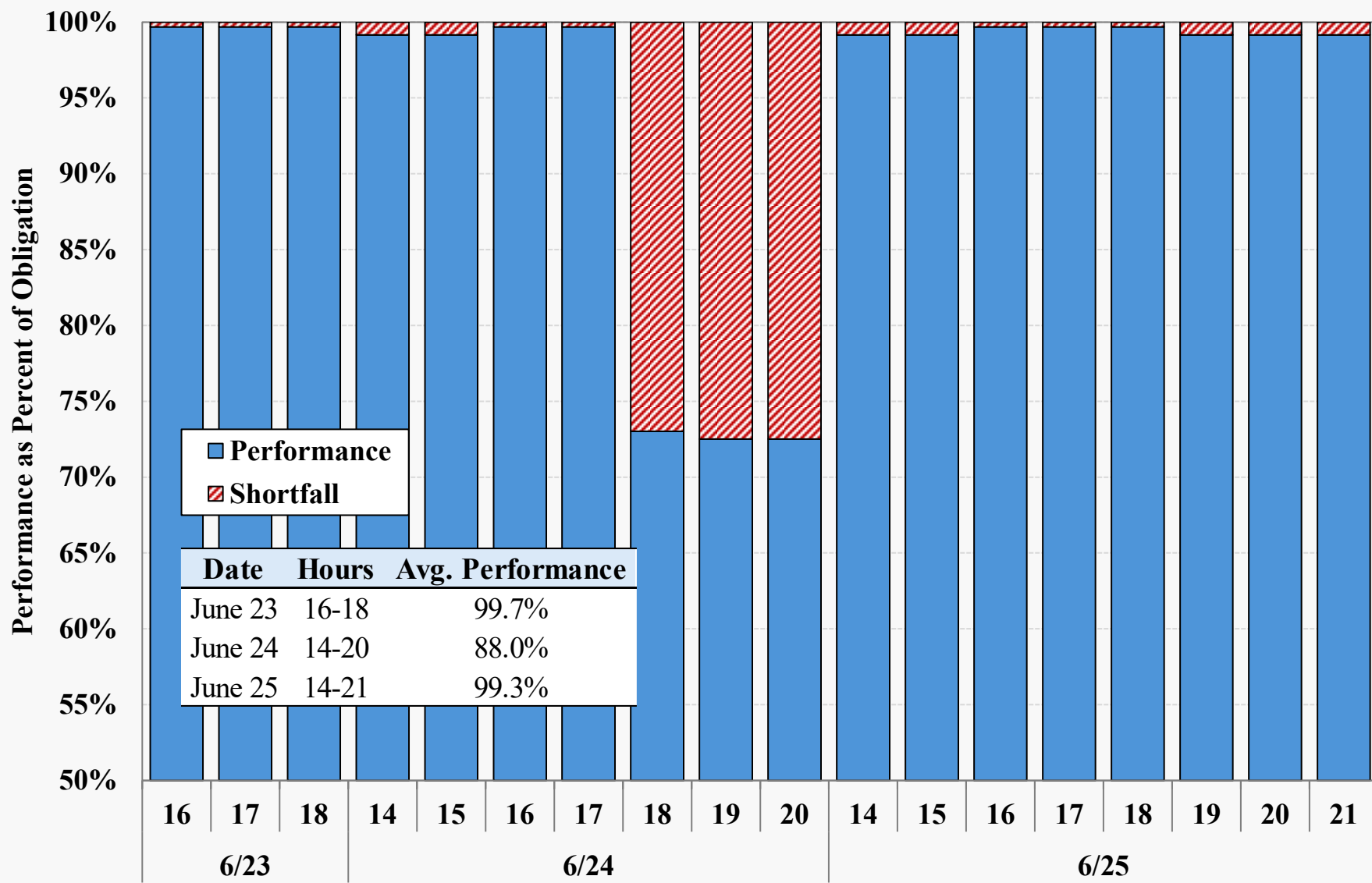
Availability of Emergency Capacity

June 24, 2025 - HB 15-20



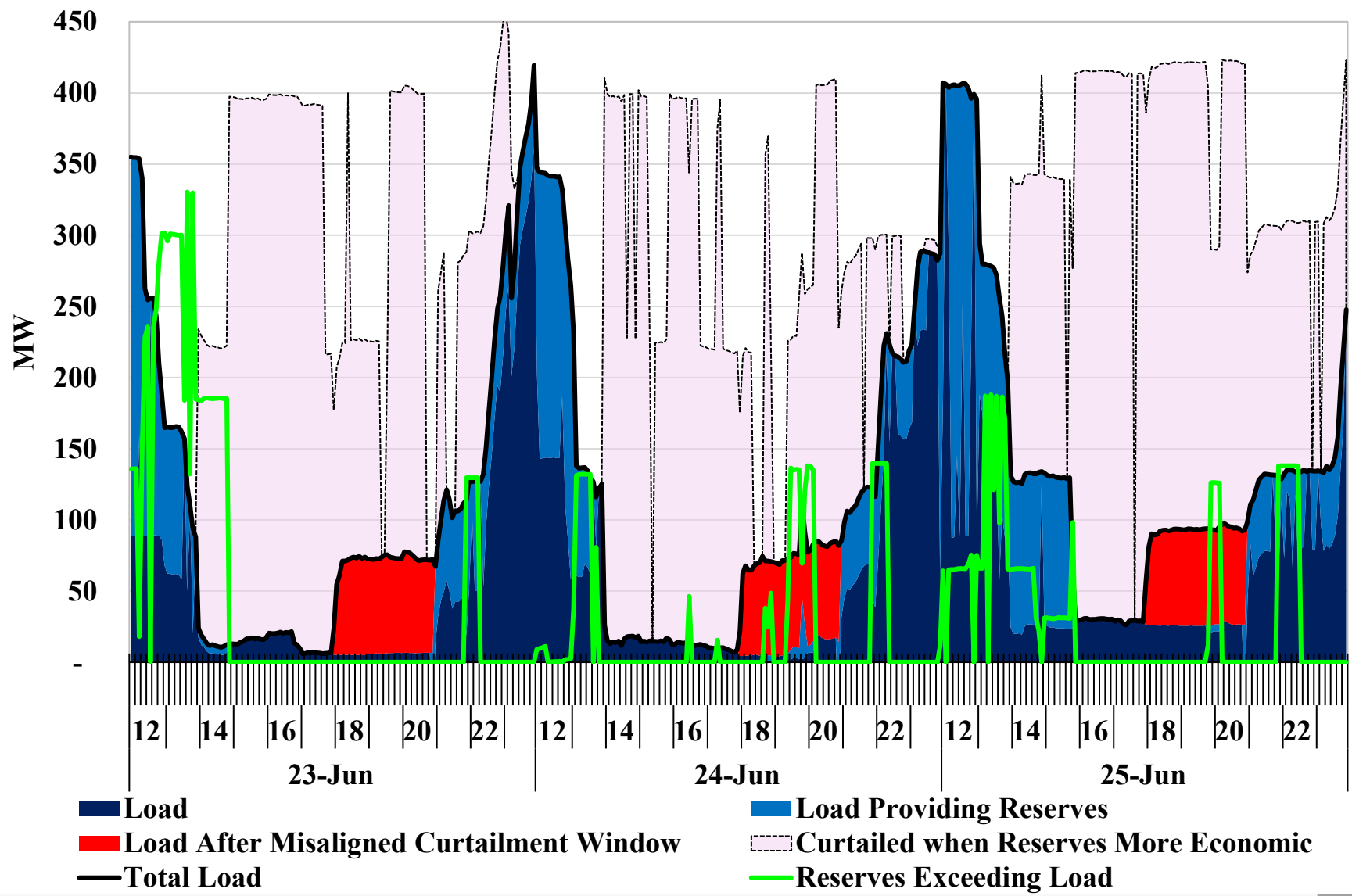
External ICAP Performance during SRE

June 23-25, SRE Hours



Large Curtailable Load Performance during Heat Wave

June 23-25, Hours 12 to 23



Appendix: Chart Descriptions

All-in Price

- Slide [26](#) 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 [29](#) 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 [30](#) 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 [31-35](#) evaluate emissions from generators in the NYISO market.
 - Slide [31](#) shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO₂, NO_x, and SO₂.
 - Slides [32-33](#) show quarterly emissions across the system by generation fuel type for CO₂ 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 [34-35](#) 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 [34](#) 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 [40-42](#) summarize day-ahead and real-time prices for six ancillary services products during the quarter:
 - 10-min spinning reserve prices eastern NY and Western NY;
 - 10-min non-spinning reserve prices in eastern 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 [41](#) are estimated by dividing total movement charges by real-time scheduled regulation capacity.
 - 30-min operating reserve prices in western NY and 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.

Day-Ahead NYCA 30-Minute Reserve Offers

- Slide [43](#) 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 [44](#) 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 top 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.
 - The bottom chart shows the average monthly prices.
 - The columns show the average monthly regulation capacity prices in the DAM.
 - The two lines show the real-time capacity prices and movement prices.
- Regulation resources are scheduled assuming a common regulation movement multiplier of 13 per MW of capability, however, slide [45](#) shows a wide variation in actual movement-to-capacity ratio from one sample day.
 - The blue bars show the average scheduled regulation capacity in each movement-to-capacity ratio tranche.
 - The solid blue line represents the capacity weighted average actual movement-to-capacity ratio for the day, compared to the common multiplier of 8, indicated by the red dash line.

Day-Ahead Load Scheduling and Virtual Trading

- Slide [47](#) 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 [48](#) 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 [49](#) 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.

Virtual Imports and Exports in the Day-Ahead Market

- Slide [50](#) evaluates scheduled virtual imports and exports in the day-ahead market.
 - Virtual imports and exports are defined as external transactions that are scheduled in the day-ahead market but withdrawn from the real-market market (i.e., no RT bids submitted). Wheel transactions are excluded from this analysis.
- The bottom portion of the chart shows the hourly average quantity of net virtual imports for each month.
 - The bars represent the average net virtual imports scheduled across the four primary interfaces between NYISO and neighboring control areas.
 - Virtual imports and exports are rare across the Scheduled-Line interfaces, which are excluded from this analysis.
- The top portion of the chart shows the percentage of hours in each month when total net virtual imports across the four primary interfaces fall into the following ranges:
 - Less than 200 MW;
 - Between 200 and 500 MW;
 - Between 500 and 800 MW; and
 - More than 800 MW.

Efficiency of CTS Scheduling with PJM and NE

- Slide [52](#) 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 [53](#) 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 [54](#) 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.

RTC and RTD Price Difference vs Load Forecast Difference

- Slide [55](#) 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 Prices During Commitments of GTs Offering Multi-Hour Min Run Times

- Slide [56](#) evaluates real-time prices during commitments of gas turbines offering minimum run times greater than one hour in the quarter, focusing on economic commitments made by RTC, RTD, or RTD-CAM.
 - Self-schedule and out-of-market commitments are excluded from the analysis.
- The bars in the figure show the total number of equivalent hours (i.e., the total number of 5-minute RT intervals divided by 12) when GTs are economically committed in the quarter.
 - The blue bars indicate the number of hours when LBMPs exceeded GT costs (i.e., incremental cost + amortized startup cost).
 - The red bars represent the number of hours when LBMPs were below GT costs.
 - The black line shows our estimate of potential price impact if these GTs were allowed to set prices.
- GTs are combined into seven groups in New York City and Long Island based on their electric connection to the grid.

Real-Time System Price Maps at Generator Nodes

- Slides [58](#) and [59](#) 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 [60](#), [61](#), [62](#), and [64](#) 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 [60](#) 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 [61](#) 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 [62](#) and [64](#) 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 [65](#) 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 [66](#) 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 [67](#) 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-Hauppauge 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 [67](#) 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 [68](#) 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 [69](#) 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 [71](#) 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 [70](#) 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

- Slide [72](#) summarizes the average performance of offline GTs in responding to start-up instructions from NYISO audits and economic commitments (including commitments by RTC, RTD, and RTD-CAM) in the past 12-month period.
 - The table's rows categorize performance into 10-percent increments from 0 to 100 percent. A unit's performance for a given start is measured based on its output level at its expected full output time (i.e., at 10 or 30 minutes after receiving a start-up instruction), expressed as a percentage of its Upper Operating Limit ("UOL").
 - For each average performance category, the table shows:
 - Number of Units;
 - Total Number of Associated Unit-Starts;
 - Average Performance On Time: measured at the unit's expected full output time;
 - Average Performance 10 Minute Later.
- Performance metrics are also broken down for two different operating conditions:
 - RPU + Unforeseen Economic Starts & Audits: These include Reserve Pickup ("RPU") events, random NYISO audits, and economic starts that are NOT anticipated in the look-ahead advisory evaluations.
 - Remaining Economic Starts and Audits: These include re-tests conducted within days after an initial audit failure and economic starts that are anticipated in the look-ahead advisory evaluations.

Supplemental Commitments

- Slide [74](#) summarizes out-of-market commitment, which is one of the primary sources of guarantee payment uplift.
- Slide [74](#) 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.

Reliability Commitment in New York City & North Country

- Slides [75](#) and [76](#) show the amount of reliability commitments in New York City and North Country, respectively, for each day of the quarter.
- The chart shows these quantities in stacked bars in four distinct categories:
 - **Economic MWh**: This category represents the total MWh of the initial DARU commitments that eventually qualify as economic capacity (i.e., capacity that would have been committed even if it had not been DARUed) within the scheduling software.
 - **Verified – Needed MWh**: This category represents the total MWh of the initial DARU and applicable LRR and SRE commitments that do not qualify as **Economic** but are verified by the MMU's assessment as necessary for maintaining reliability in the applicable load pockets.
 - Our assessment relies on information available in the DAM and RTM, including factors such as load forecast, resource availability, and transmission network conditions (including information provided by the TO in accordance with Day-Ahead Scheduling Manual §4.2.6).
 - **Verified – Headroom MWh**: This category represents the total MWh that are associated with **Verified** commitments but exceed the amount of **Needed** MWh.
 - For example, if a 100 MW unit is verified for a reliability need of 50 MWh over two hours but has a minimum run time commitment of five hours, the headroom MWh would be 450 MWh ($= 5 \times 100 - 50$).
 - **Unverified MWh**: This category represents the remaining DARU commitments that do not fit into the other three categories.

Key Drivers of SRE Commitments for Systemwide Capacity

- Slide [77](#) highlights three main categories of supply and demand changes after the day-ahead market that contributed to a shortfall in capacity margin and necessitated SRE commitments by NYISO.
 - **Reduction in Expected Imports:** This category represents expected reductions of in scheduled net imports, primarily from virtual external transactions. Additional reduction come from physical transactions that fail to clear the day-ahead checkout process or are expected to reduce because of real-time system conditions.
 - **Increases in Load Forecast:** This category shows the reduction in supply margin due to upward adjustments in load forecasts.
 - **Generator Derates and Outages:** This category represents the reduction in generating capacity caused by resource outages and deratings.
- When the total loss in supply exceeds day-ahead scheduled supply margin, NYISO initiates an SRE commitment to secure additional resources.

Uplift Costs from Guarantee Payments

- Slides [78](#) and [79](#) 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 [78](#) shows these seven categories on a daily basis during the quarter.
 - Slide [79](#) summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides [81](#) and [82](#) 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 [83](#) 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 [85](#) and [86](#) summarize market results and key drivers in the monthly spot capacity auctions.
 - Slide [85](#) 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 [86](#) 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.

Generator Performance during Heat Wave

- Slides [87](#), [88](#), and [89](#) summarize performance of fossil fuel generators during the peak load window (HB 15-20) of the June Heat Wave (June 23-25).
 - Slide 86 shows performance of the fossil-fired steam turbines in the system.
 - Slide 87 shows performance of the combined cycle resources in ENY.
 - Slide 88 shows performance of fossil-fired peaking units in the system.
- Each chart categorizes the capacity of the relevant resources into six different categories:
 - Energy gives the actual telemetered output across the resources.
 - Reserves shows the total operating reserves scheduled from the resources.
 - Forced Outages (Gen) displays the amount of capacity on forced outage where the cause of the outage is believed to be due to issues with the generator.
 - Forced Outages (Tx) displays the amount of capacity on forced outage where the cause of the outage is known to occur upstream of the generator step-up transformer.
 - Performance shows the amount of capacity that dragged basepoint, mostly due to ambient conditions.
 - Unscheduled/Fixed shows the amount of capacity that was either unscheduled in DA and, therefore, unavailable in RT or unscheduled in RT while the resource bid Self-Fixed.
- The inset table provides summary information on the six categories outlined above.
 - The Unavailability Rate is based on the total capacity out due to Forced Outages (Gen), Forced Outages (Tx), and Performance.

Performance of Emergency Capacity during Heat Wave

- Slide [90](#) shows the performance of the capacity that formerly participated in the Capacity Limited Resource (CLR) program as emergency-only capacity.
 - Performance is shown for the peak hours (HB 15-20) of the highest load day, i.e., June 24, 2025.
- The performance is broken into five distinct categories:
 - “Produced and Dispatched” refers to energy produced from this capacity while also being dispatched by the market model.
 - “Produced but Not-Dispatched” refers to energy produced from this capacity but not dispatched by the market model do to being bid in the emergency UOL range.
 - “Not-Produced but Dispatched” refers to capacity that failed to produced the energy that was dispatched in the market model.
 - “Economic but Derated (Ambient)” refers to capacity that did not produce energy that would have been economic because ambient water temperature and tidal conditions are not accounted for in the NYISO’s DMNC setting procedure.
 - “Not-Produced and Not-Dispatched” refers to capacity bid in the emergency UOL that did not produced energy and was not scheduled in the market model.

Performance of External ICAP during Heat Wave

- NYISO Operators issued SREs on external capacity suppliers on each day of the June Heat Wave.
 - External ICAP Suppliers must respond to SREs in accordance with Section 5 of the Market Services Tariff or face potential sanctions.
- Slide [91](#) displays the performance of the transactions submitted on behalf of external ICAP suppliers during the relevant SRE hours of each day of the Heat Wave.
 - The numbers represent what percentage of the total external ICAP either (a) succeeded in delivering the energy equivalent of its ICAP sales or (b) failed to make the energy available to the NYISO.
 - “Performance” displays the successful delivery of energy.
 - “Shortfall” displays the failure rate of the delivery of energy.

Performance of Large Loads during Heat Wave

- Slide [92](#) describes the performance of large loads (including DSASP, DER, and BTM:NG resources that sell capacity) during the June Heat Wave.
- Hour beginning 12 and after for each day are shown
 - These correspond to time periods when load, LBMPs and reserve prices were generally high and performance issues were observed with large loads
- Performance is broken into several categories:
 - Load After Misaligned Curtailment Window: Some SCRs performed during first four hours of SCR activation window (HB14 through HB17) and did not have incentive to align load reduction with peak (HB18)
 - Curtailed When Reserves More Economic: Loads that curtailed due to SCR program participation but could have more economically sold reserves
 - Reserves Exceeding Load: Loads with reserve schedules exceeding their actual real time load