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

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Market Highlights

Market Highlights

Executive Summary

- NYISO E&AS markets were generally competitive in the third quarter of 2025.
- All-in prices ranged from $62/MWh in the North Zone to $100/MWh in New York City, up 36 to 50 percent across all regions from a year ago. (slide 9)
  - Energy prices rose by 35 to 53 percent across the system, driven primarily by an increase of 42 to 66 percent in natural gas prices. In addition:
    - Net imports from Canada fell 1.4 GW on average. NYISO became a net exporter to Quebec for the first time in summer, averaging 480 MW of exports. (slide 50)
    - July had three heat waves and load peaked at 30.6 GW, up 6 percent year-over-year. The reconstituted peak load of 31.8 GW on July 29 exceeded the Gold Book forecast by 350 MW.
  - Capacity costs rose by 13 percent in NYC and 46 to 52 percent elsewhere, due primarily to changes in administrative parameters. (slide 21)
- Day-ahead congestion revenues rose 35 percent year-over-year.
  - Transmission outages were a key contributor to increased congestion in Western New York and New York City. (slides 10 - 12)

Market Highlights

Executive Summary – Out of Market Actions

- OOM commitment in NYC for operating reserves decreased significantly because of new transmission into the 138kV system, while OOM actions on Long Island to manage voltage needs and local transmission congestion became more frequent.
  - NYC: OOM commitments were for load pocket reserves on 30 days. (slide 14)
    - We found that 23 percent of the capacity could not be "verified" as needed for reliability based on information made available to NYISO. (slide 20)
    - Of NYC commitments that we "verified" as needed, 73 percent was surplus headroom or committed to satisfy minimum runtime requirements.
      - ✓ We recommend (#2024-1) modeling underlying local reserve requirements.
  - Far Rockaway pocket on Long Island: where units recently submitted deactivation notices, congestion was managed with OOM dispatch on 40 days. (slide 15)
    - Market-based congestion management provides better incentives for suppliers to maintain and operate generating capacity efficiently that is needed for reliability.
    - Reliance on OOM dispatch rewards generators for having higher variable costs.
  - On Long Island Voltage: high voltage issues were managed by taking transmission OOS on 35 days and OOM commitment on 17 days, while OOM dispatch was used on 52 days for transient voltage recovery (TVR) needs. (slides 14 & 15)

Market Highlights

Executive Summary – Market Power Mitigation & Generator Outage Scheduling

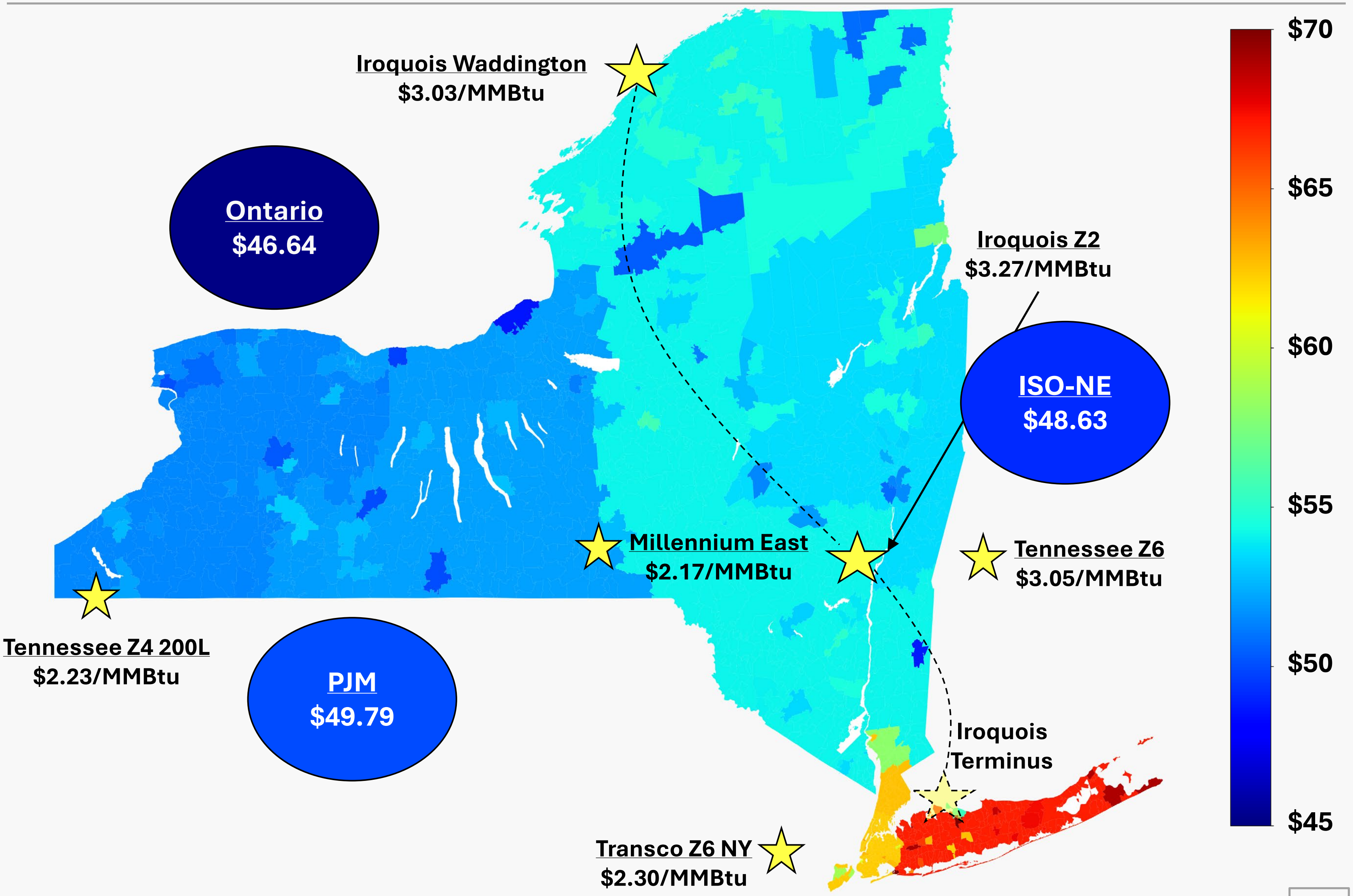
- Tighter market power mitigation thresholds may be warranted in certain load pockets outside NYC. (slides 12, 15, & 16)
  - Relatively high Rest of State ("ROS") thresholds ($100/300%) generally apply when generation is dispatched to manage local *congestion*.
  - Tighter ROS thresholds ($10/10%) apply only to units committed for local *reserve* needs.
  - This allowed resources in several areas to submit bids significantly above their estimated marginal costs.
- We reviewed outage schedules of fossil-fuel units during the summer. (slide 89)
  - Forced outage/deratings – This capacity averaged 2.2 GW on ten high (>28 GW) load days, which was higher than anticipated based on market EFORds (1.6 GW).
    - Transmission forced outages accounted for 0.6 GW of the forced outage capacity on the ten high load days. These outages are considered in the planning reliability studies but *not* in the capacity market's transmission security-based LCRs.
  - Planned outages (i.e., outages classified in GADS as "planned" or "maintenance") were generally scheduled outside of peak load conditions, although at least one planned/maintenance outage was approved on four high (>28 GW) load days.
    - We are investigating whether these were appropriately classified as "planned/maintenance" outages rather than as "forced."

Market Highlights

Executive Summary – Generator Availability during Heat Waves

- During the most intense heat wave of Q3 (July 28-30), we observed additional unavailable capacity beyond the reported forced outages/deratings. (slides 86-88)
  - Unavailable in real-time – An average of 0.2 GW was unavailable in real-time due to an apparent inability to ramp up to UOL.
    - We are investigating whether these should have been recorded as forced derates.
  - Ambient water temperature conditions – An average of 0.2 GW was unavailable in real-time due to this factor.
    - Neither the planning studies nor the market requirements consider these effects.
  - Ambient humidity conditions – An average of 0.2 GW was unavailable in real-time due to this factor.
    - NYISO is implementing rule changes that will consider this factor in the capacity market and planning processes starting in summer 2026.
- Overall, the observations related to outage scheduling and generator availability on high load days reinforce concerns that the available capacity assumed to determine the capacity market requirements is over-stated significantly.

Market Highlights
System Price Diagram



Market Highlights

Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the third quarter of 2025.
  - The amount of output gap (slide 80) and unoffered economic capacity (slide 81) remained reasonably consistent with competitive market expectations.
- All-in prices ranged from $62/MWh in the North Zone to $100/MWh in New York City, up 36 to 50 percent across all regions from a year ago. (slide 25)
  - The rise was driven primarily by higher energy prices, which rose by 35 to 53 percent across the system. (slides 35-36)
    - The primary driver was a 42 to 66 percent increase in natural gas prices, peaking during the July 16-17 heat wave. (slide 27)
    - Additionally, net imports from Canada fell by ~1400 MW year-over-year (in Hours 13 to 20), while NYISO became a net exporter to Quebec for the first time in summer, averaging 480 MW of exports. (slide 50)
    - Although average load fell 2 percent, peak load rose 6 percent year over year, reaching 30.6 GW and exceeding 28 GW on six days during the July heat waves. (slide 26)
      - ✓ On these peak days, NYISO and local TOs activated up to 1,200 MW (estimated) of demand responses.
  - Capacity costs rose by 13 to 66 percent in all regions. (see slide 21 for further discussion).

Market Highlights

Congestion Patterns, Revenues, and Shortfalls

- Day-ahead congestion revenues totaled $106 million in 2025-Q3, up 35 percent from a year ago. (slide 59)
  - Despite higher natural gas prices, congestion revenues in July and August were roughly in line with those of the prior year.
  - However, in September, congestion revenues rose substantially from $6 million to $35 million, accounting for most of the year-over-year quarterly increase.
    - The rise in congestion was driven largely by lengthy major transmission outages, particularly in New York City, in the North Zone, and from West to Central.
- Long Island lines accounted for the largest share of total congestion (24% in DA, 26% in RT) in the third quarter of 2025.
  - Approximately 75 percent of congestion occurred in July, particularly on high-load days.
  - Most congestion arose on transmission paths serving the Valley Stream, Elwood, and Pilgrim load pockets on Long Island, while less than 10 percent occurred on the 345 kV inter-zonal facilities that import power from upstate to Long Island.

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

- West-to-Central paths accounted for more than 20 percent of total congestion in both day-ahead and real-time markets.
  - Nearly all of this congestion occurred on the Scriba-Volney 345 kV line, which frequently limited exports of gas-fired and nuclear generation from the Oswego Complex under:
    - High load conditions in July; and
    - Transmission outage conditions in September, which incurred $5 million in day-ahead congestion shortfalls. (slide 61)
- Day-ahead congestion in New York City rose notably from the prior year.
  - Lengthy transmission outages were a key contributor, resulting in over $11 million in day-ahead congestion shortfalls. (slide 61)
    - The Astoria Annex-E.13th St. 345 kV Q35L line was OOS throughout the quarter, while the parallel Q35M line was OOS in most of September.

Market Highlights

Congestion Patterns, Revenues, and Shortfalls (cont.)

- Most of North Zone congestion occurred in September.
  - The Moses-Grass River 115 MAL5 line was frequently binding during the period when the parallel MAL4 line was OOS (9/9-9/29) and the congestion-relieving imports from HQ Cedars were limited to 80 MW due to transmission construction work.
    - The current market power mitigation rules for local load pockets outside New York City allow generators in some local areas to raise offers above competitive levels.
- Real-time congestion rose notably above day-ahead congestion on transmission paths from Hudson Valley to Dunwoodie.
  - The increase was largely driven by sharp spikes in real time congestion during high-load periods in July.
  - In addition, TSA events on several days contributed to these spikes, resulting in $22 million in balancing congestion shortfalls. (slide 63)

Market Highlights

Allocation of DAM Congestion Residuals

- 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, $20M of shortfalls were allocated to responsible TOs on a cost causation basis, while $12M of net surpluses were socialized to all TOs.
  - Among socialized residuals, we estimate that: (slides 61 - 62)
    - $6 million of **surpluses** were associated with transmission upgrades from the Segment A & B Public Policy projects.
    - $5 million of **surpluses** accrued on Long Island facilities.
    - $3 million of **shortfalls** were associated with the simultaneous outages of the Q35L and Q35M lines in NYC in September.
      - ✓ However, these were not allocated to the responsible TO, because the current allocation methodology evaluates outages individually, therefore cannot accurately capture the effects of simultaneous outages on parallel lines.
  - 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 for N-1-1 and N-1-1-0 requirements occurred on 30 days in NYC, on 8 days in the North Country load pocket, and on 5 days on Long Island. (slide 65)
  - 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 actions for network reliability were frequent on Long Island. (slides 65– 66)
  - During light-load conditions, OOM actions were often required to alleviate high-voltage risks. Typical actions included:
    - Taking lines out of service to increase reactive power losses, especially Shore Road-Lake Success, Northport-Elwood, and Valley Stream-Stewart Ave 138 kV lines. These actions contributed to higher congestion levels on parallel paths, leading to:
      - ✓ $0.8 million in day-ahead congestion shortfalls allocated to ***local TO***; and
      - ✓ $0.5 million in balancing congestion shortfalls socialized across ***system-wide*** load.
    - Committing generation to provide more voltage control capability - one or more large steam turbines were OOM committed almost daily starting September 9.
      - ✓ These OOM commitments reduced LBMPs and led to $0.6 million in BPCG uplift allocated to ***local*** load.

Market Highlights

OOM Actions to Manage Network Reliability (cont.)

- During high-load conditions, OOM actions were frequent: (slide 66)
  - In the Far Rockaway portion of the Valley Stream load pocket - GTs were needed on 40 days to manage 69 kV transmission constraints involving a contingency not modeled in the market software.
    - ✓ OOM dispatch incentives reward units for having higher variable costs.
    - ✓ We have recommended modeling this congestion in the DA and RT markets.
  - In the East End load pocket - Oil-fired peakers were needed on 52 days to satisfy local transient voltage recovery (TVR) requirements.
    - ✓ The estimated LBMP impact of unmodeled TVR needs was significant in this quarter, averaging roughly $37/MWh in the East End load pocket.
    - ✓ We have recommended the NYISO incorporate this TVR need into the market model. (See Rec #2021-3)
  - These real-time OOM commitments resulted in $4.7 million in BPCG uplift.
    - ✓ Fast start resources that are committed in real time via an OOM (non-SRE) are subject to the high Rest of State mitigation thresholds ($100/300%).
    - ✓ However, the current market power mitigation rules for local load pockets outside New York City allow generators in some local areas to raise offers above competitive levels.

Market Highlights

Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $19.1 million, up 4 percent year-over-year. (slide 77)
- Long Island accounted for most (51 percent) guarantee payment uplift.
  - Approximately $5.5 million was paid to resources that were frequently OOM-committed to address local needs, including high-voltage risks under light-load conditions across Long Island, transient voltage recovery under high-load conditions on the East End, and post-contingency flow violations in the Valley Stream load pocket.
  - DAMAP payments totaled $3.6 million, with 64 percent accrued on the six highest-load days during July heat waves.
    - A key driver was an inconsistency between the scheduling and pricing of reserves—reserve clearing prices do not account for export limitations from Long Island, resulting in inflated reserve clearing prices and DAMAP uplift. We have recommended NYISO address this inconsistency. (see Rec. #2019-1)
- West Upstate accounted for $5.4 million (28 percent) of total BPCG uplift this quarter.
  - Nearly 70 percent was paid to SRE resources during heat waves.
  - Nearly $1 million was paid to resources pivotal for resolving transmission constraints in local areas that were able to raise offer prices significantly above marginal costs.
- BPCG uplift in NYC declined, primarily due to fewer supplemental commitments for N-1-1-0 requirements in local load pockets. (slide 73)

Market Highlights
Regulation Market Performance

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- 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 44); and
  - The average ratio was close to 13 over the past two years. (slide 43)
    - 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 55)
  - In 2025 Q3, LBMPs were below the GTs' as-bid costs in approximately 38 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 \$5 to \$99 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 270 MW in the net import direction during the quarter. (slide 49)
- 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: (Slide 74)
  - 52 percent was “economic” in the DAM; and
  - 26 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 27 percent of total verified MWh was needed for the identified requirement, while the remaining 73 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).
  - 23 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 $15.84/kW-month in NYC and $5.80/kW-month elsewhere. (slides 84-85)
  - Spot prices increased 12 percent in NYC, and 44 to 46 percent elsewhere.
- Price changes were driven by a combination of administrative parameters and supply reductions.
  - In NYC, several peakers entered ICAP Ineligible Forced Outages (IIFOs) and the 2025 demand curve unit CAF dropped, leading to a significant increase in the local Net CONE, driving prices higher.
    - However, the ICAP requirement declined by 340 MW, due to a lower load forecast and a decrease in the LCR from 80.4 to 78.5 percent, partially offsetting the increase in spot prices.
  - Both LI and G-J Locality prices were consistent with ROS prices, reflecting sufficient supply margin against planning requirements 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 94 MW in average capacity imports.

Market Highlights

Performance of Fossil Fuel Generators during Heat Wave

- Generators sell capacity in the NYISO as Unforced Capacity (UCAP), which is equal to Installed Capacity (ICAP) times (1-minus-EFORd). This estimates how much capacity a resource can reliably provide when in demand.
- Our evaluation of generator performance during the July 28-30 heat wave found higher unavailability of fossil-fuel resources than expected based on market EFORds. (slides 86-88) The capacity-weighted unavailability rate during these days:
  - Exceeded the average EFORd for fossil-fuel steam turbine capacity by 1 to 3 percent;
  - Exceeded the average EFORd for combined cycle capacity by 1.5 to 2.5 percent; and
  - Was below the average EFORd for fossil peaking capacity by 1 to 3 percent.
  - Although the quantity of declared forced outages and derates was ~1 percent lower than expected based on market EFORds on July 28-30 (slide 89):
    - An additional 2 to 3 percent of capacity was unavailable due to ambient conditions, forced outages not included in the market EFORd, and other under-performance; and
    - Declared forced outages/derates were significantly higher on other high (>28 GW) load days.
- EFORd measures how frequently a unit is forced out or derated relative to Service Hours (SH). The SH is binary – either the resource is online or offline. Resources that often operate at low output and that experience more problems at higher loads (e.g., fossil-fueled steam turbines) may have EFORds that underestimate unavailability.

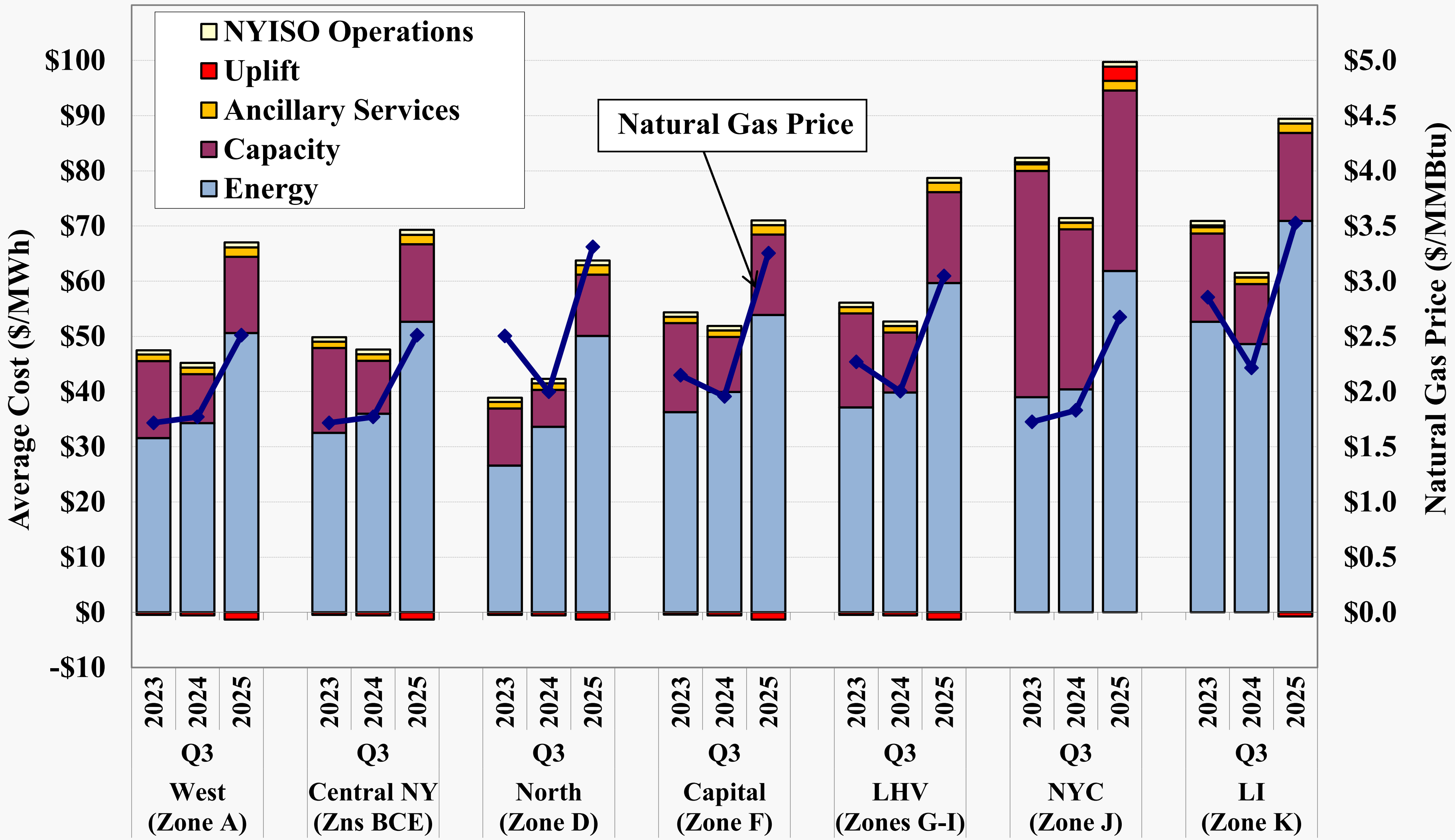
Market Highlights

Performance of Large Curtailable Loads during Heat Wave

- Over 600 MW of large loads participated in SCR+DSASP, DER, and BTM:NG programs. (Slide 90) Some also participate in utility DR programs.
- While ~90 percent of these large loads curtailed in the peak load hour (July 29 HB 18), some curtailable loads were not operated efficiently on the peak days:
  - Over 300 MW of capacity curtailed when reserves would be more efficient. SCR and utility program rules lead to curtailment when 10-minute spin would be more efficient and reliable (for resources qualified to provide reserves).
  - Up to 50 MW of SCR+DSASP capacity did not curtail during SCR calls and was unable to provide reserves due to OOM treatment of SCRs.
  - Most SCR+DSASP resources will transition to the DER model, which (a) makes it mandatory for loads to follow curtailment instructions and (b) provides a mechanism for loads to provide reserves when it would be more efficient (unless curtailed by the utility program).
- Some DSASP and DER resources were able to sell reserves exceeding their actual real time load while ramping up after being curtailed.
  - Resources should update offers to reflect actual capability throughout the operating day.
- 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.

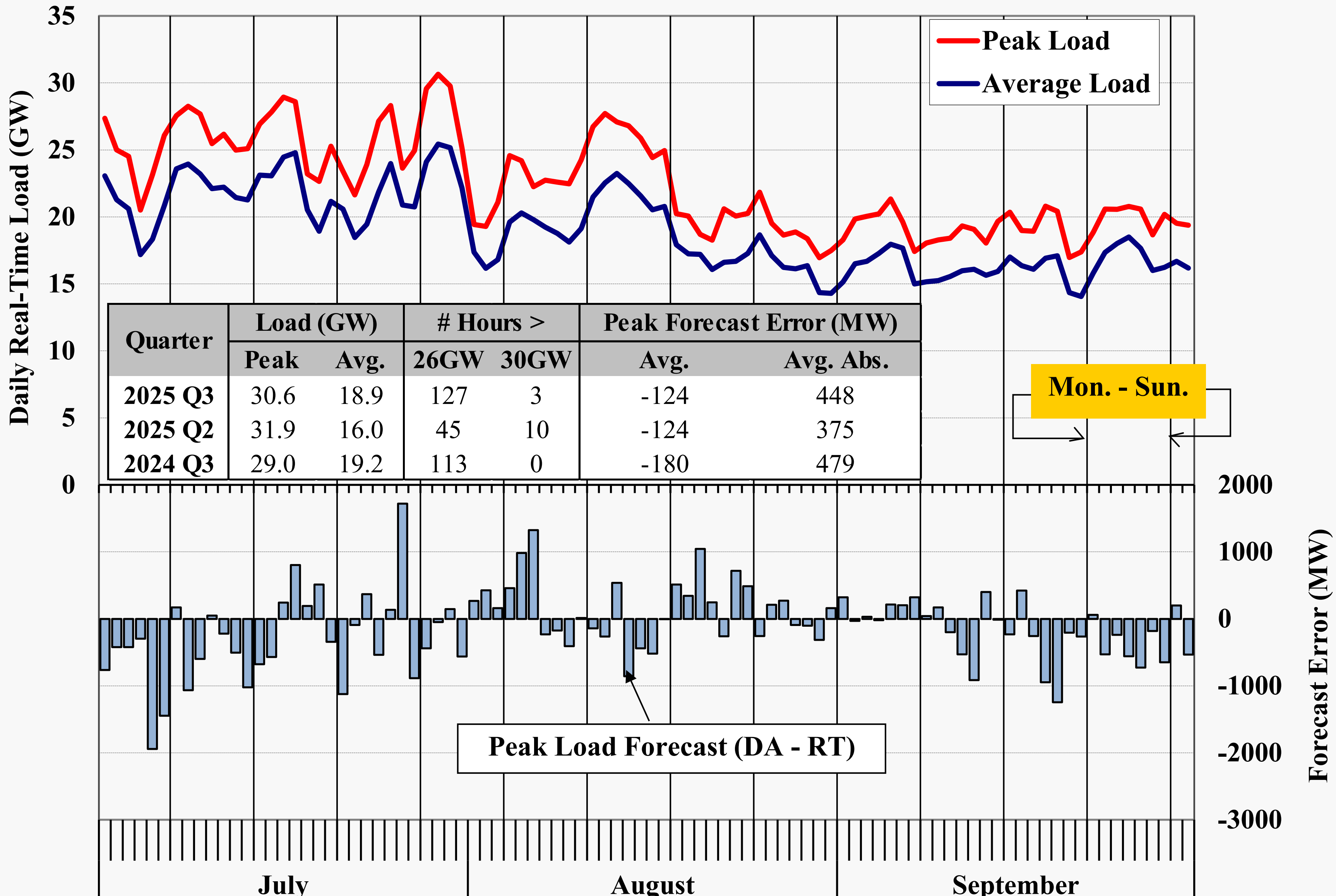
Charts:
Market Outcomes

All-In Prices by Region



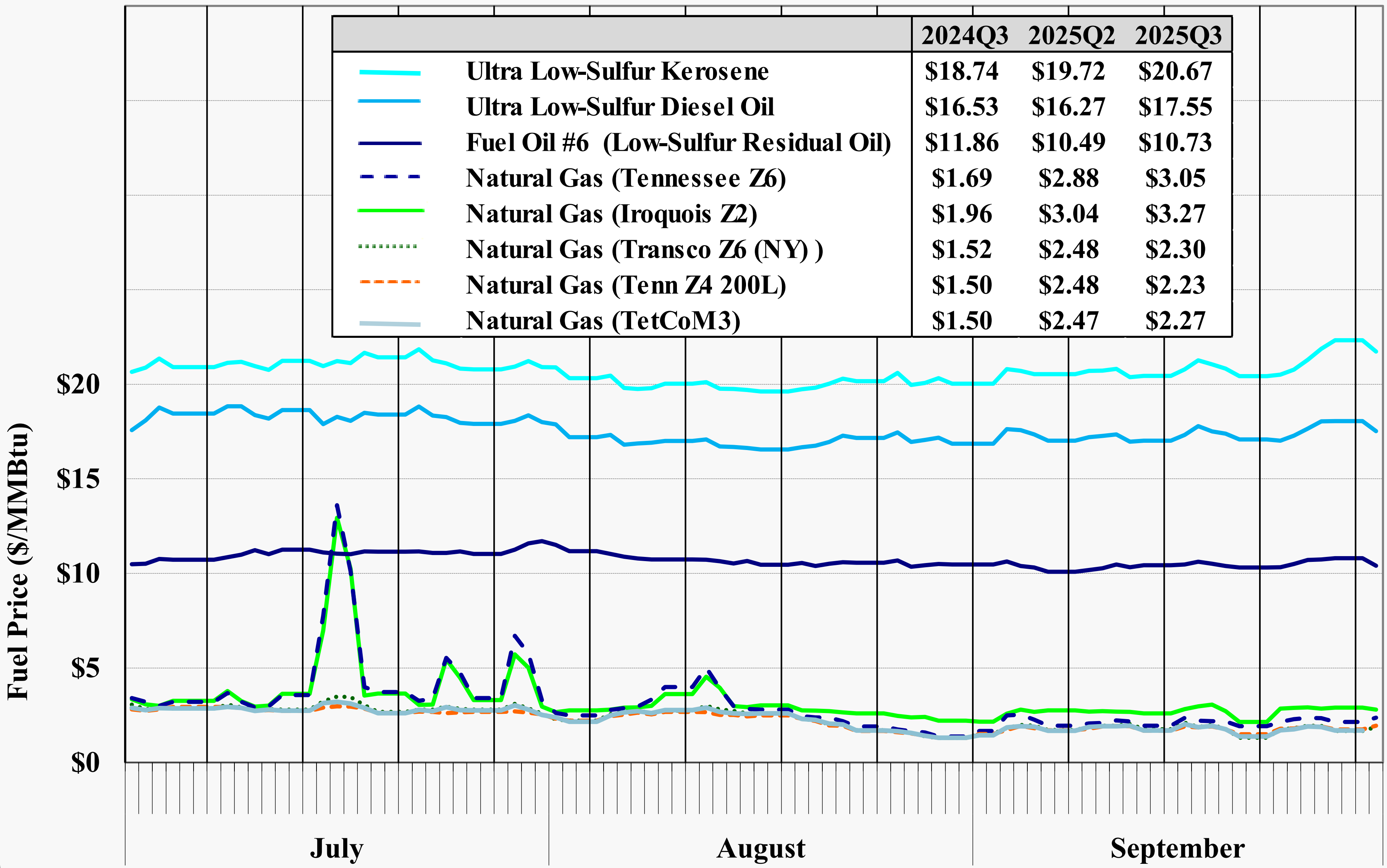
Notes: For chart description, see slide 92.

Load Forecast and Actual Load



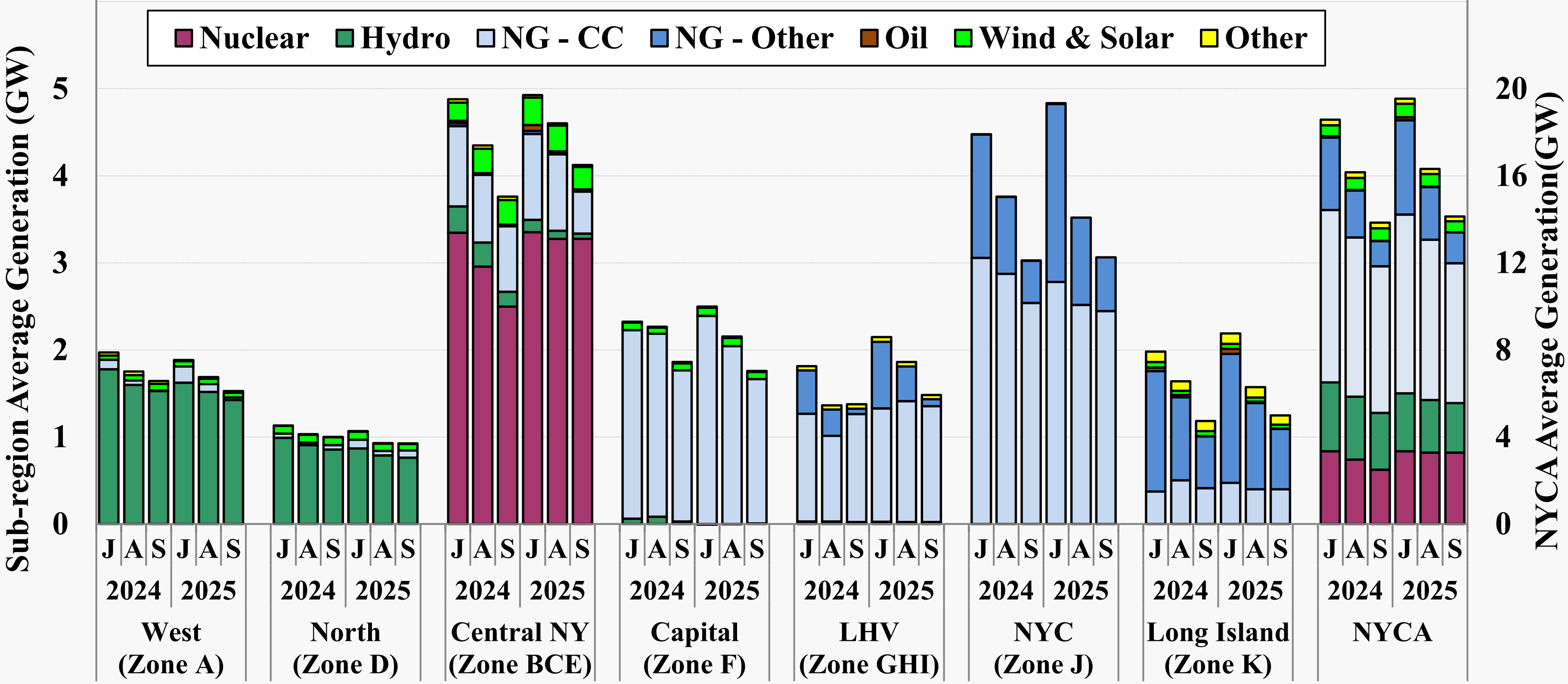
Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2025 Q3	30.6	18.9	127	3	-124	448
2025 Q2	31.9	16.0	45	10	-124	375
2024 Q3	29.0	19.2	113	0	-180	479

Natural Gas and Fuel Oil Prices



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 & Solar	Other	Total
2025 Q3	3.27	2.42	7.26	2.69	0.05	0.57	0.22	16.48
2025 Q2	3.29	2.93	5.47	1.30	0.03	0.94	0.23	14.19
2024 Q3	2.90	2.86	7.25	2.19	0.03	0.54	0.25	16.02

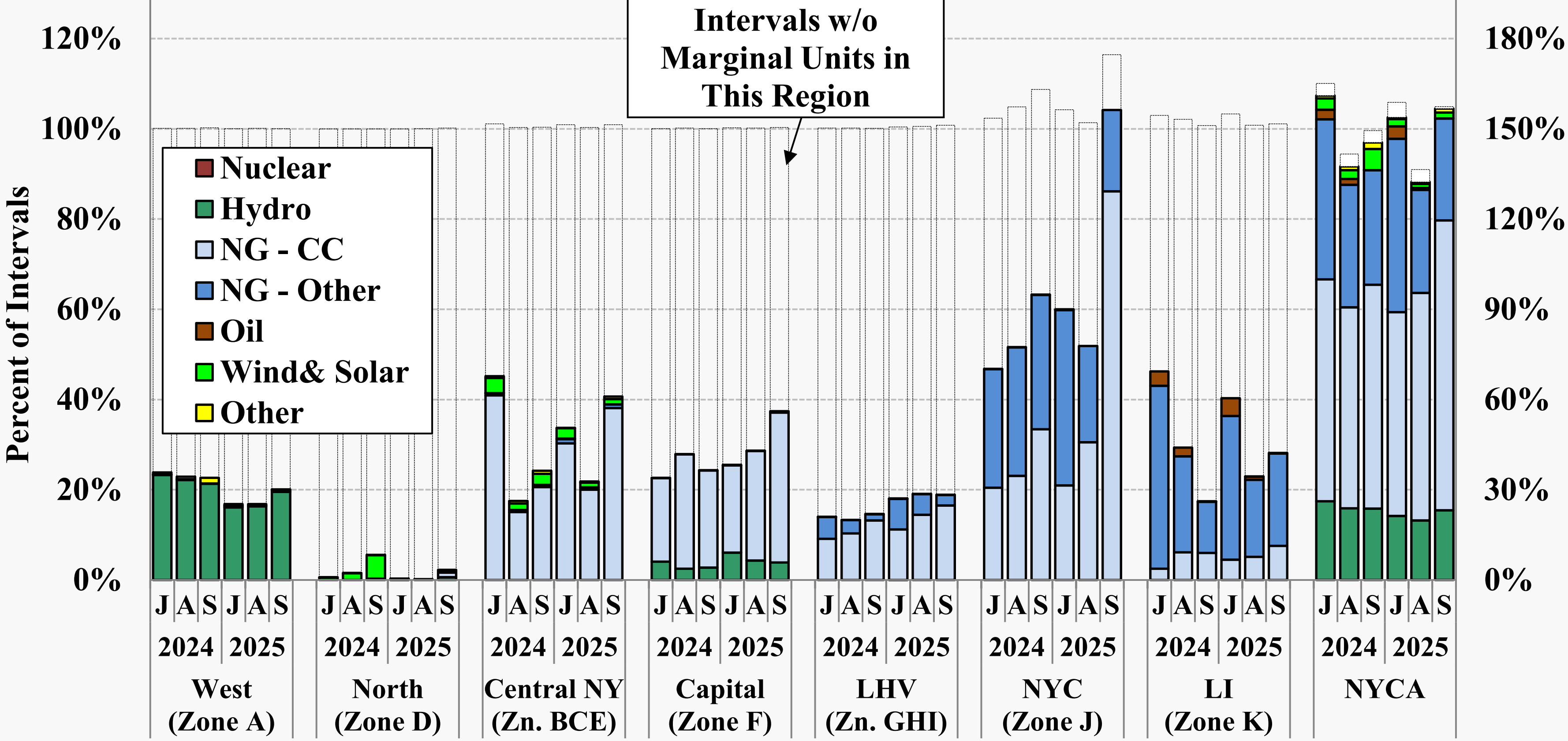


Notes: For chart description, see slide 93.

Fuel Type of Marginal Units

In the Real-Time Market

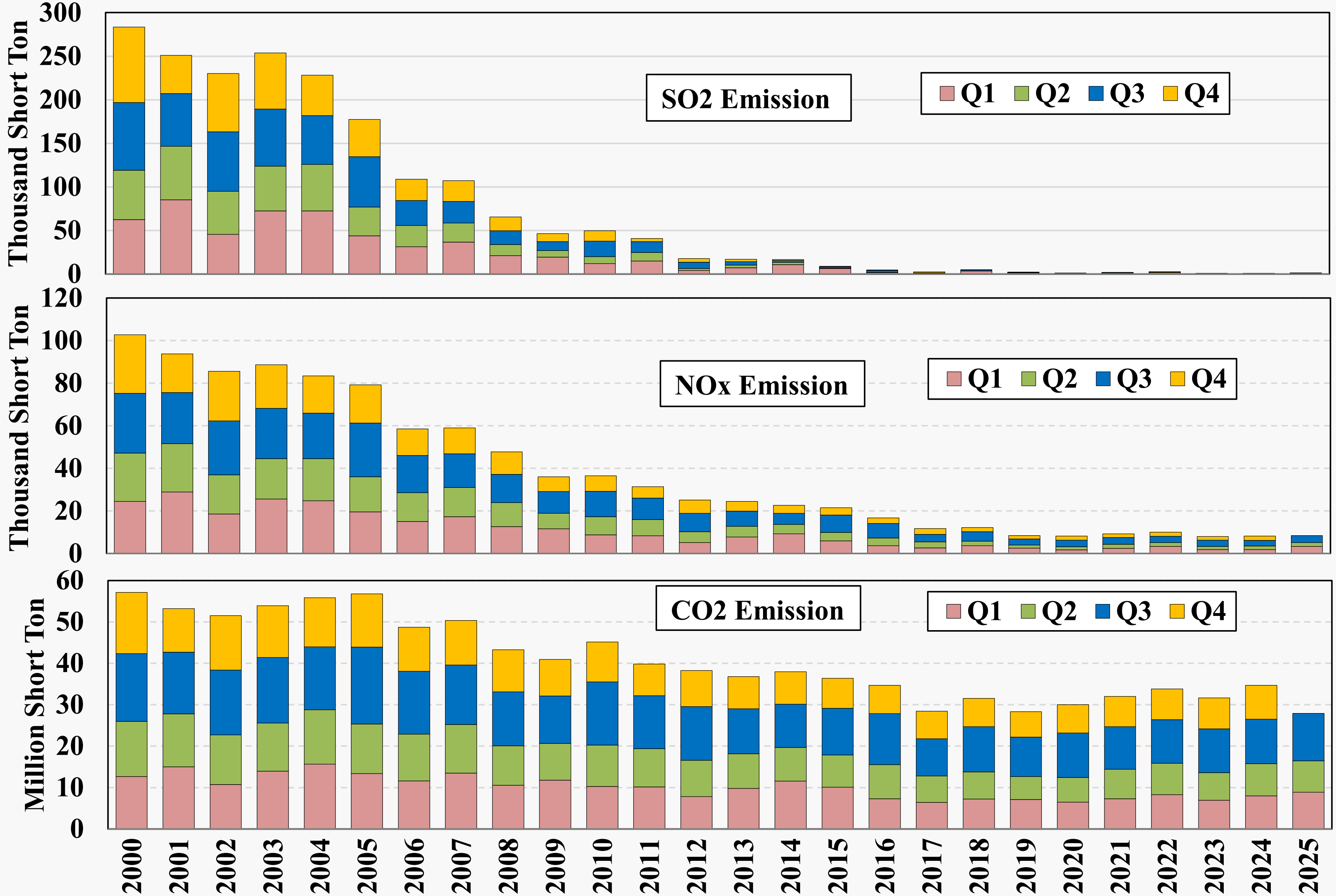
Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind & Solar	Other
2025 Q3	0%	21%	80%	42%	2%	2%	1%
2025 Q2	0%	29%	79%	49%	1%	16%	1%
2024 Q3	0%	25%	72%	44%	2%	5%	1%



Notes: For chart description, see slide 93.

Historical Emissions by Quarter in NYCA

CO_2, SO_2 , and NO_X

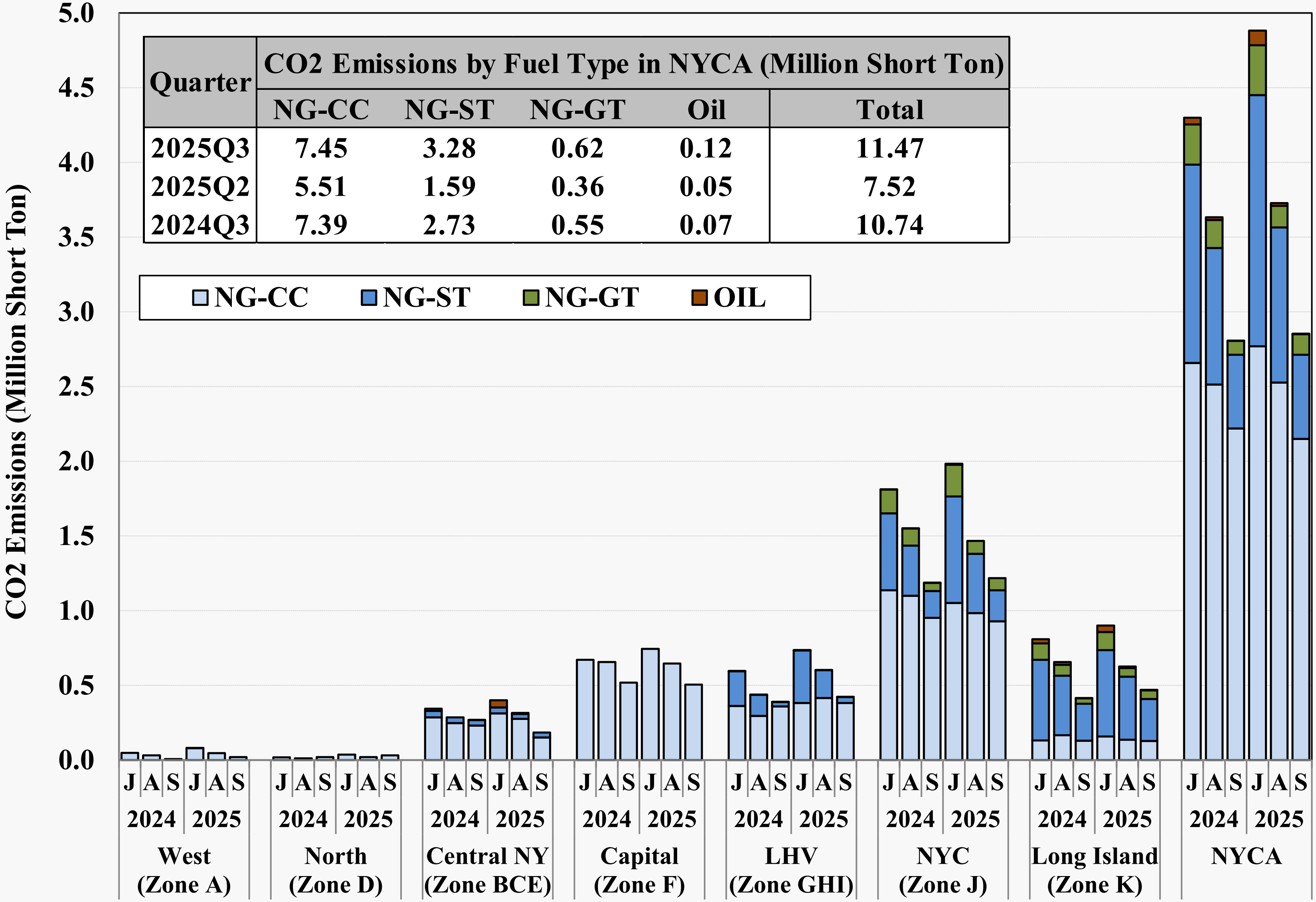


Notes: For chart description, see slide 94.

Emissions by Region by Fuel Type

CO_2 Emissions

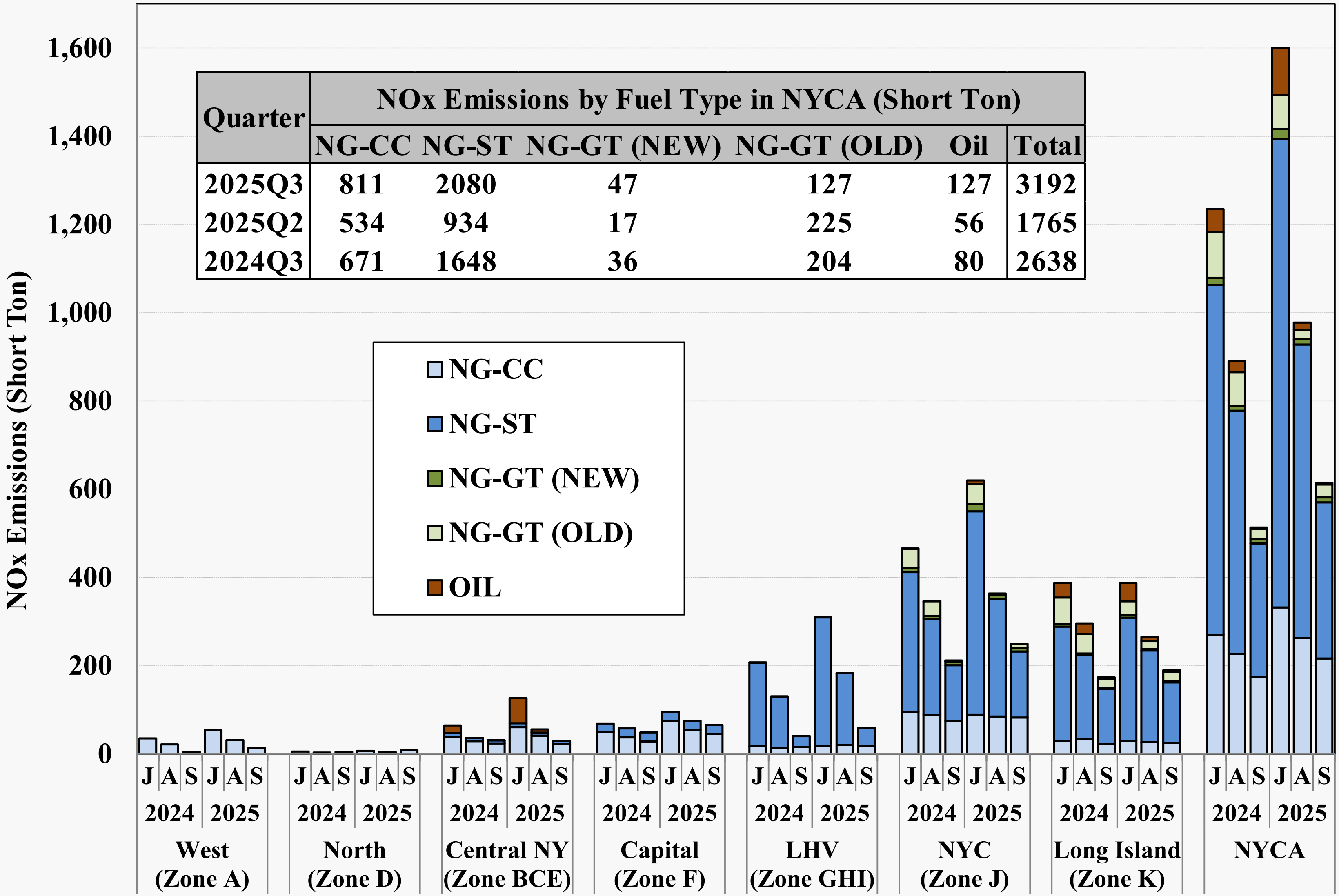
Quarter	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)				
	NG-CC	NG-ST	NG-GT	Oil	Total
2025Q3	7.45	3.28	0.62	0.12	11.47
2025Q2	5.51	1.59	0.36	0.05	7.52
2024Q3	7.39	2.73	0.55	0.07	10.74



Notes: For chart description, see slide 94.

Emissions by Region by Fuel Type

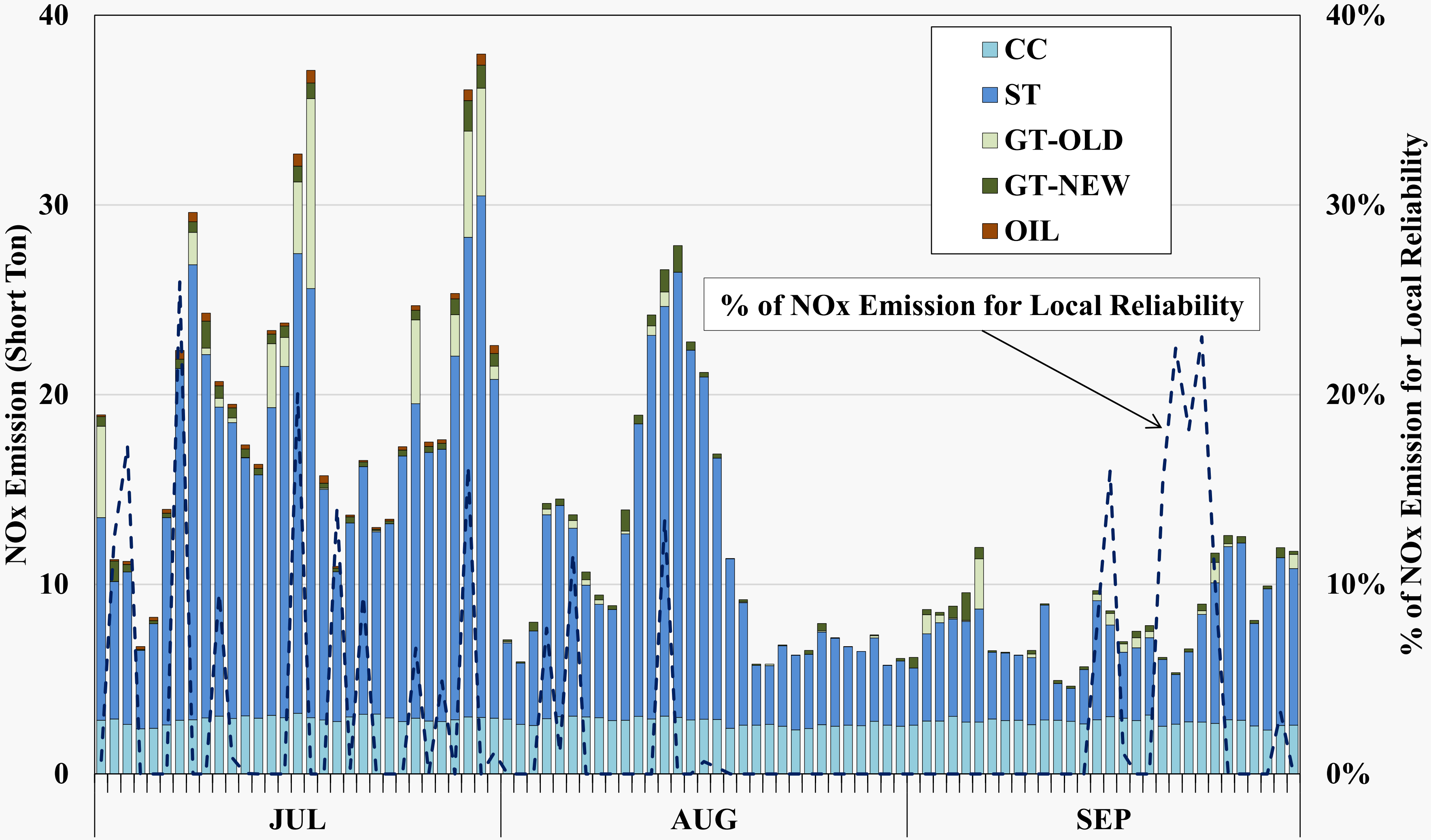
NO_X Emissions



Quarter	NOx Emissions by Fuel Type in NYCA (Short Ton)					
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Total
2025Q3	811	2080	47	127	127	3192
2025Q2	534	934	17	225	56	1765
2024Q3	671	1648	36	204	80	2638

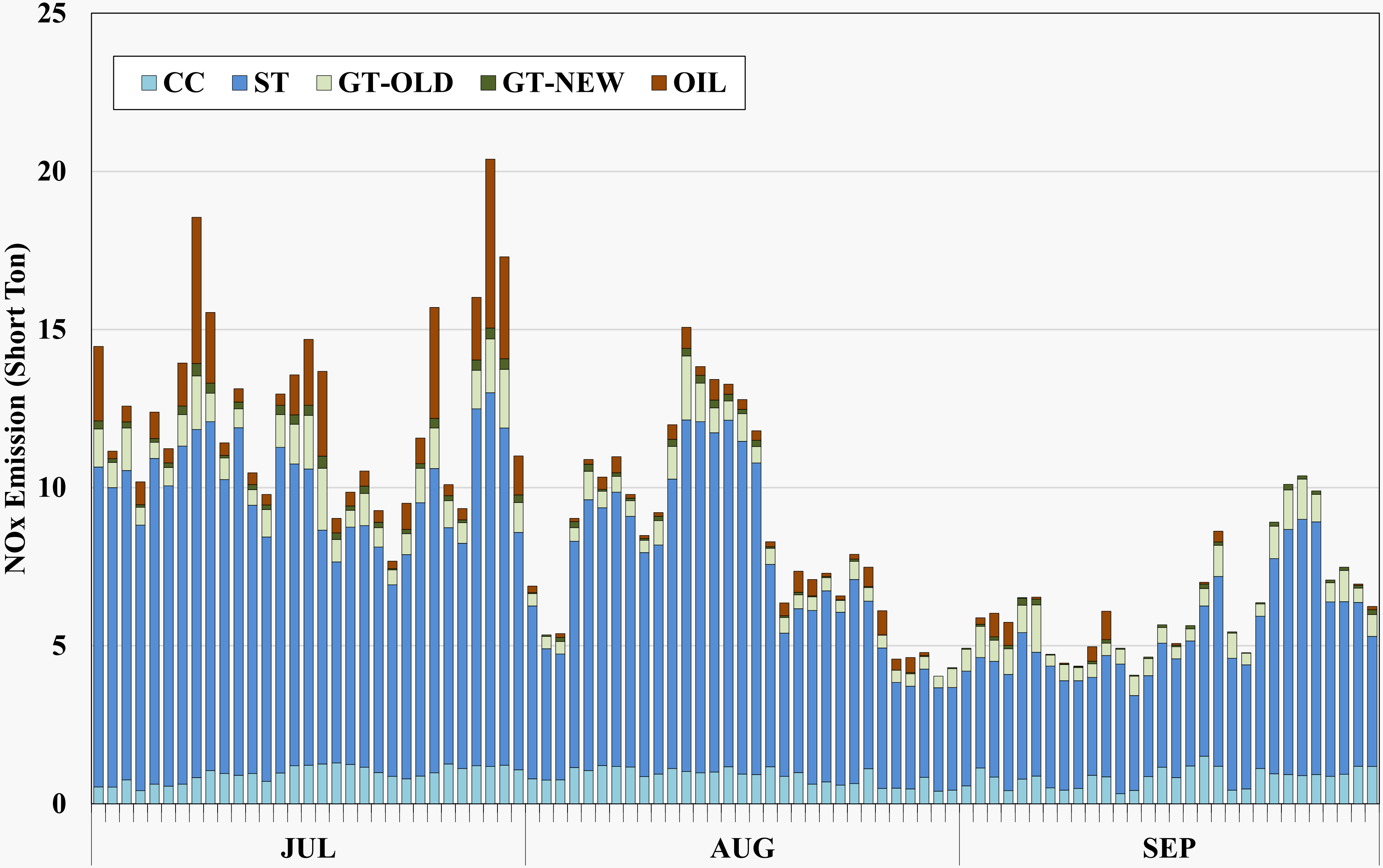
Notes: For chart description, see slide 94.

Daily NO_X Emissions in NYC



Notes: For chart description, see slide 94.

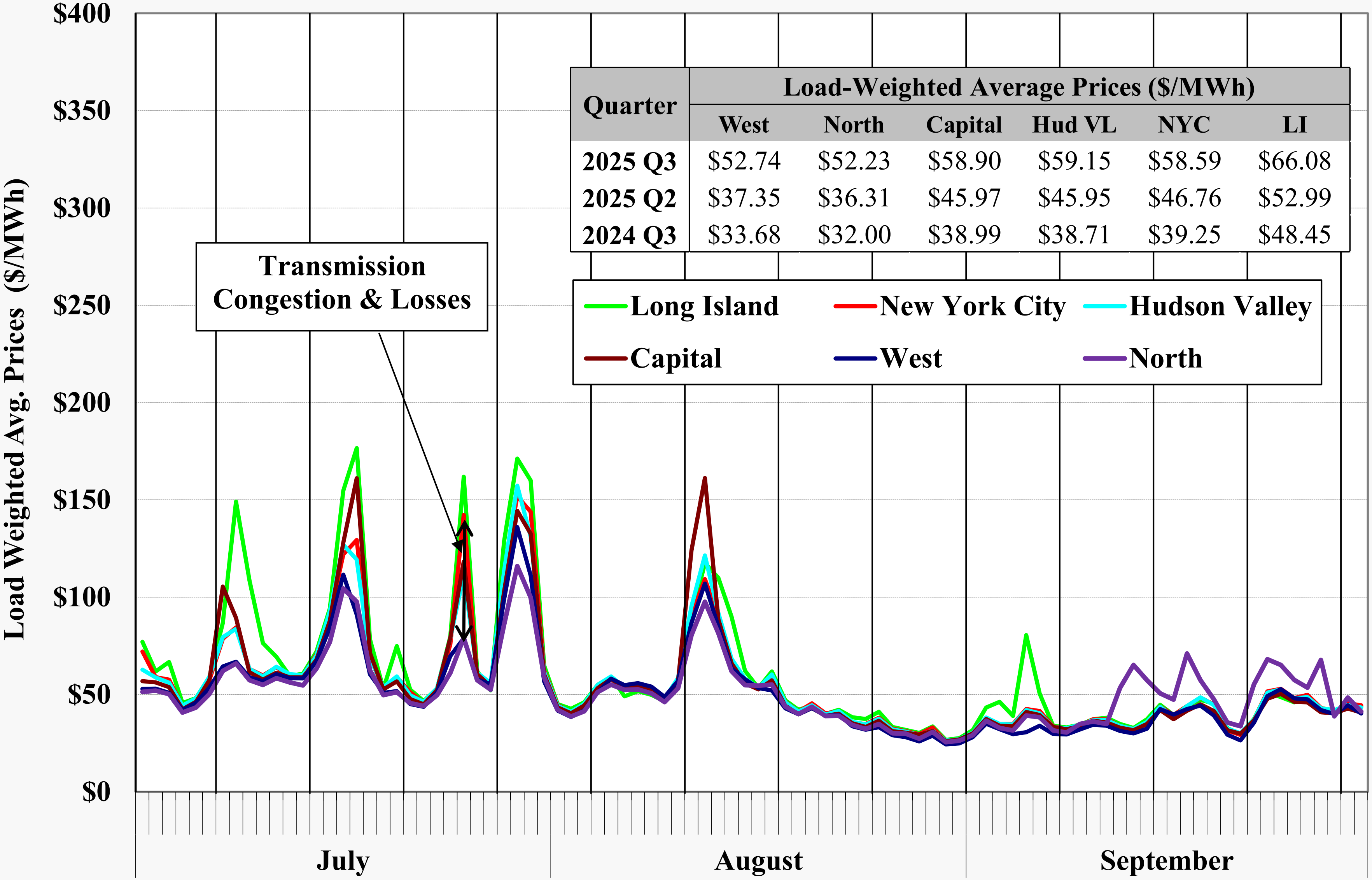
Daily NO_X Emissions in Long Island



Notes: For chart description, see slide 94.

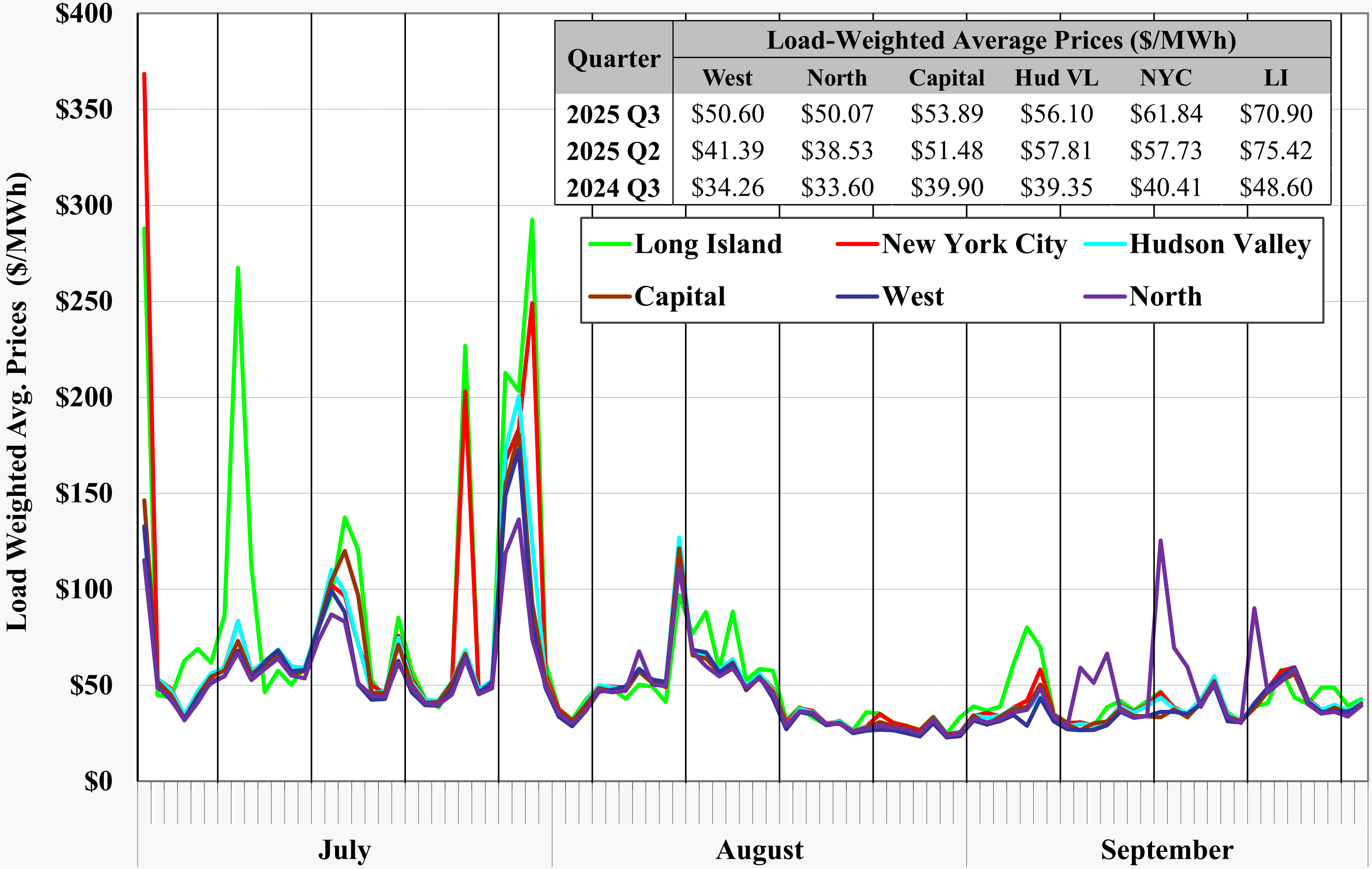
Day-Ahead Electricity Prices by Zone

Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2025 Q3	$52.74	$52.23	$58.90	$59.15	$58.59	$66.08
2025 Q2	$37.35	$36.31	$45.97	$45.95	$46.76	$52.99
2024 Q3	$33.68	$32.00	$38.99	$38.71	$39.25	$48.45



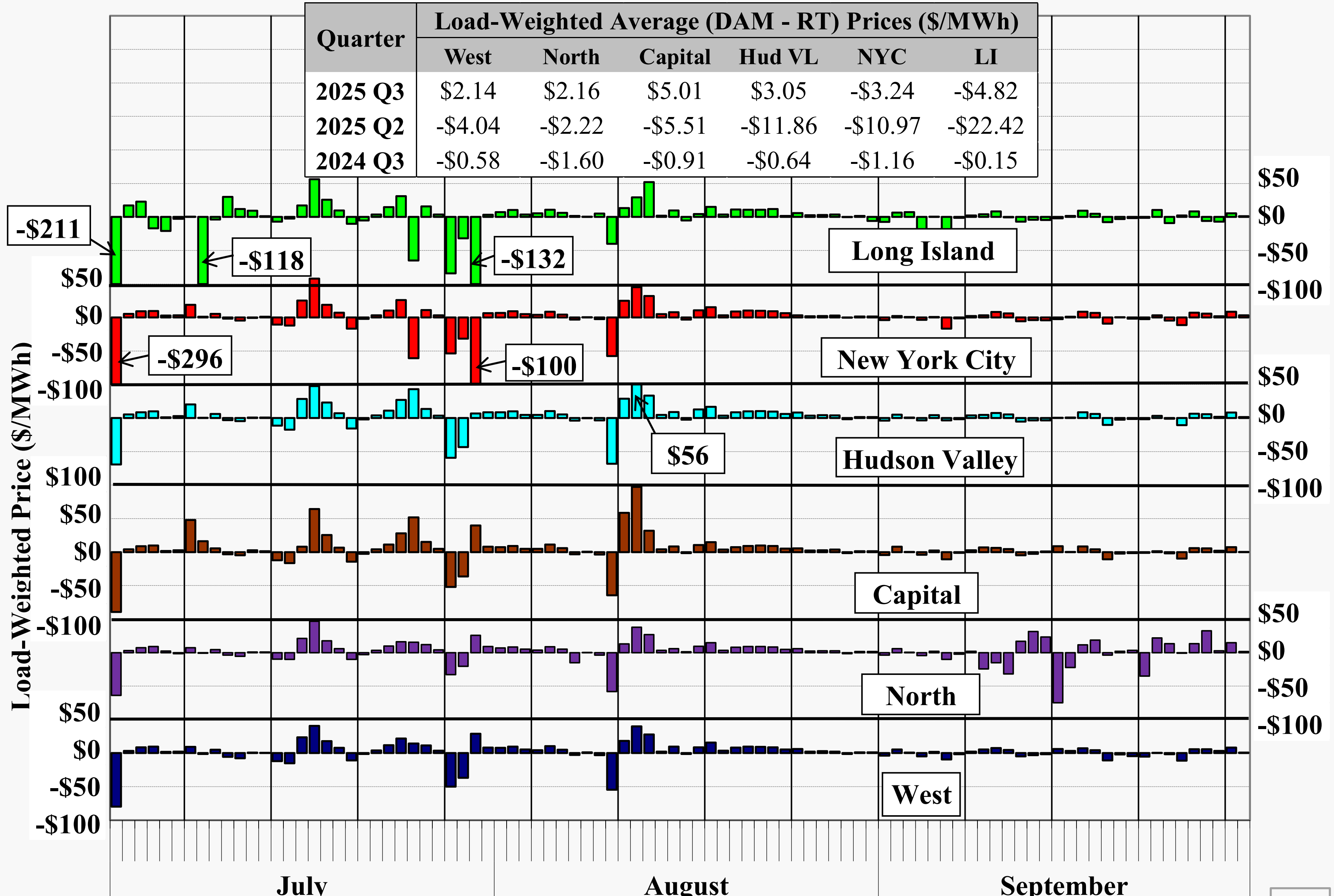
Real-Time Electricity Prices by Zone

Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2025 Q3	$50.60	$50.07	$53.89	$56.10	$61.84	$70.90
2025 Q2	$41.39	$38.53	$51.48	$57.81	$57.73	$75.42
2024 Q3	$34.26	$33.60	$39.90	$39.35	$40.41	$48.60



Convergence of Day-Ahead and Real-Time Prices

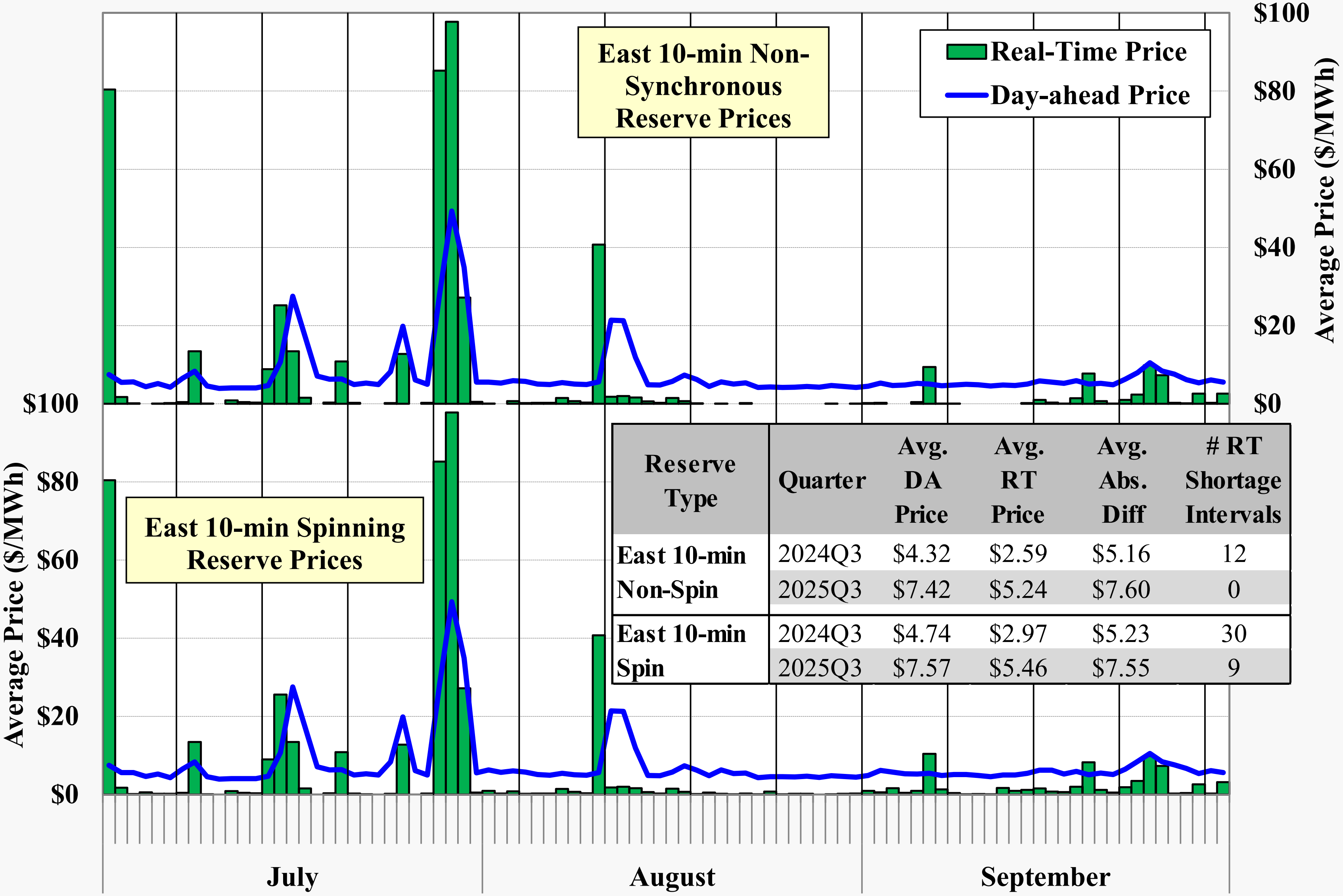
Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2025 Q3	$2.14	$2.16	$5.01	$3.05	-$3.24	-$4.82
2025 Q2	-$4.04	-$2.22	-$5.51	-$11.86	-$10.97	-$22.42
2024 Q3	-$0.58	-$1.60	-$0.91	-$0.64	-$1.16	-$0.15



Charts:
Ancillary Services Market

Day-Ahead and Real-Time Ancillary Services Prices

Eastern 10-Minute Spinning and Non-Spinning Reserves

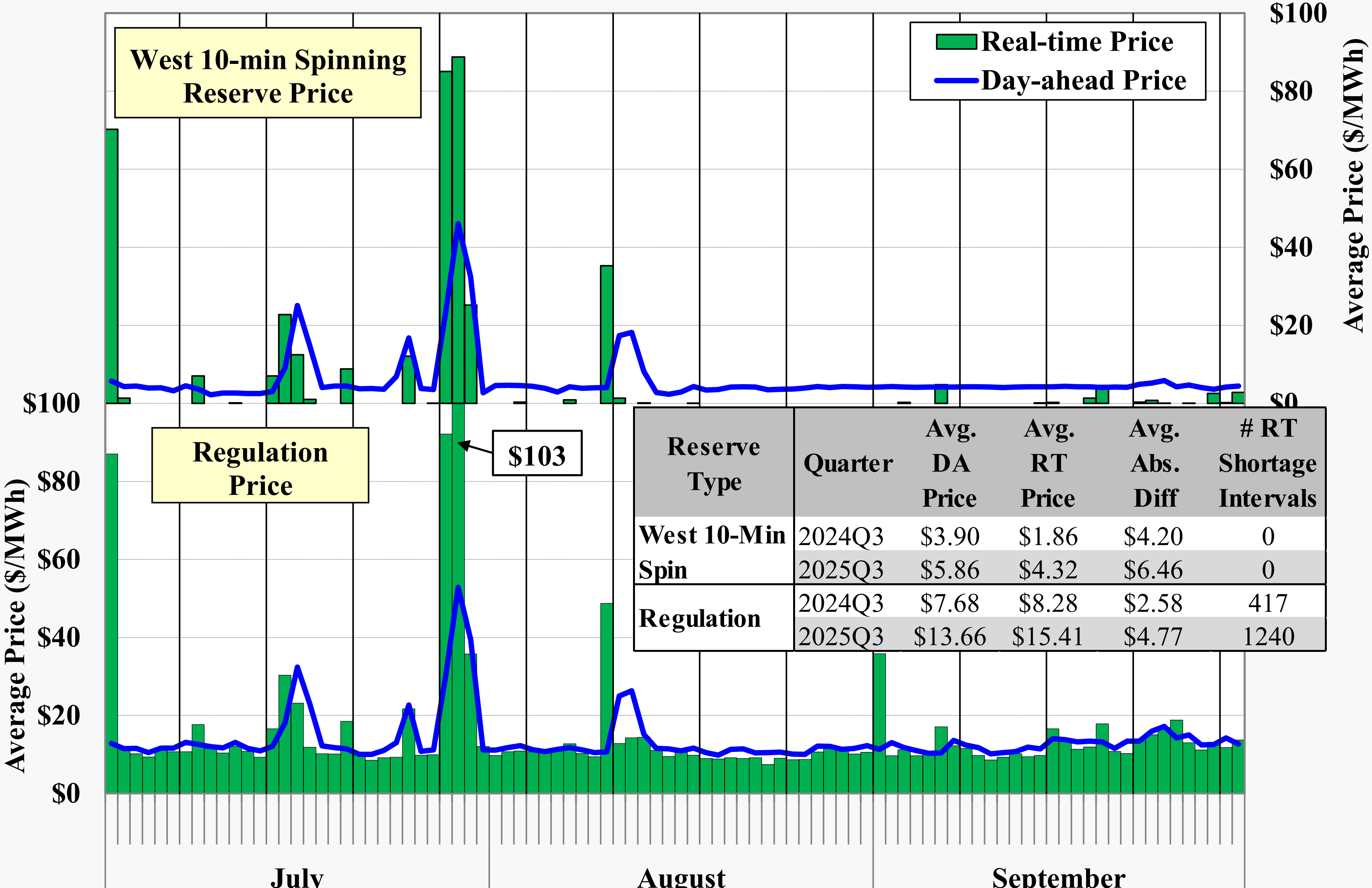


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2024Q3	$4.32	$2.59	$5.16	12
	2025Q3	$7.42	$5.24	$7.60	0
East 10-min Spin	2024Q3	$4.74	$2.97	$5.23	30
	2025Q3	$7.57	$5.46	$7.55	9

Notes: For chart description, see slide 95.

Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation

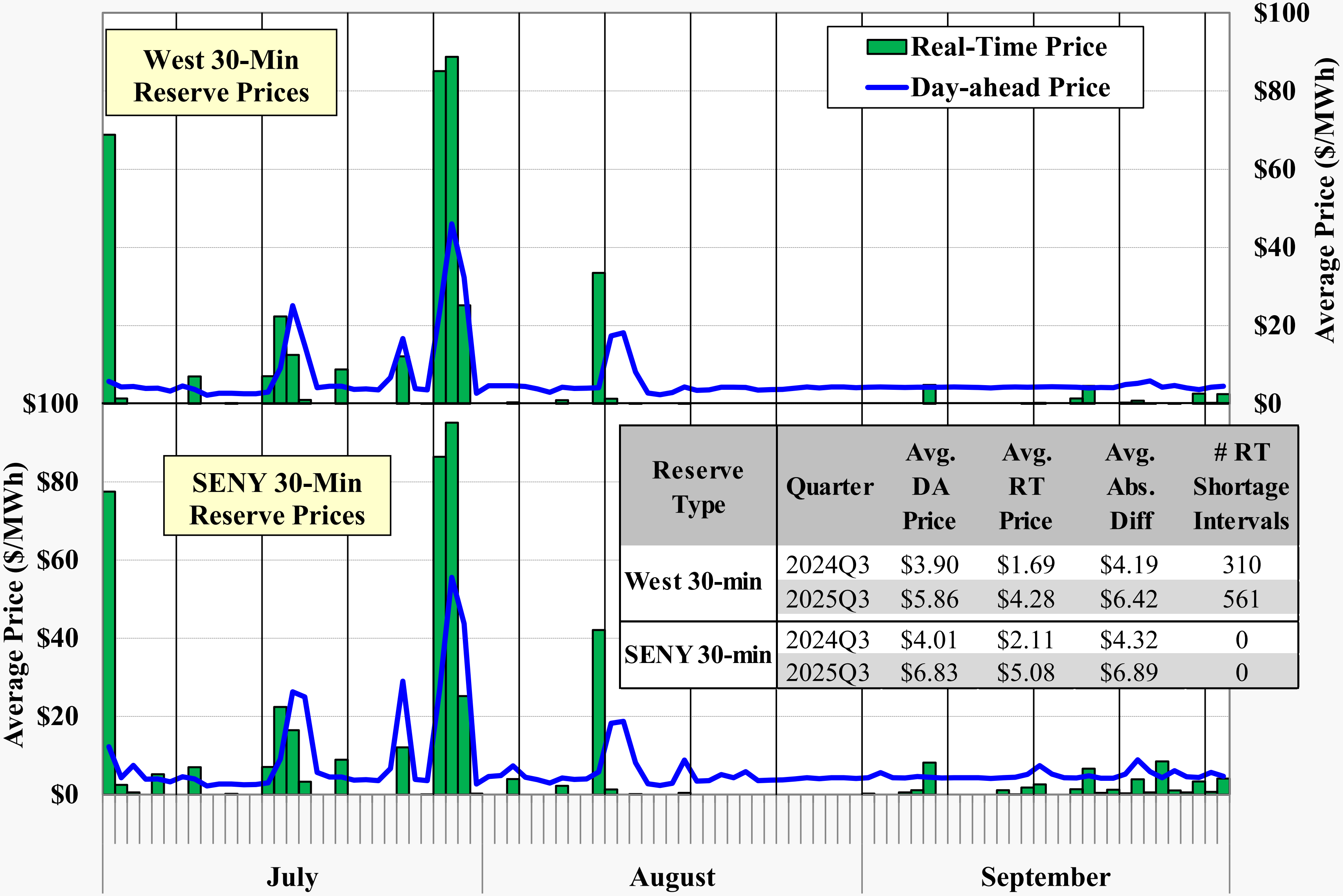


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 10-Min Spin	2024Q3	$3.90	$1.86	$4.20	0
	2025Q3	$5.86	$4.32	$6.46	0
Regulation	2024Q3	$7.68	$8.28	$2.58	417
	2025Q3	$13.66	$15.41	$4.77	1240

Notes: For chart description, see slide 95.

Day-Ahead and Real-Time Ancillary Services Prices

Western and SENY 30-Minute Reserves

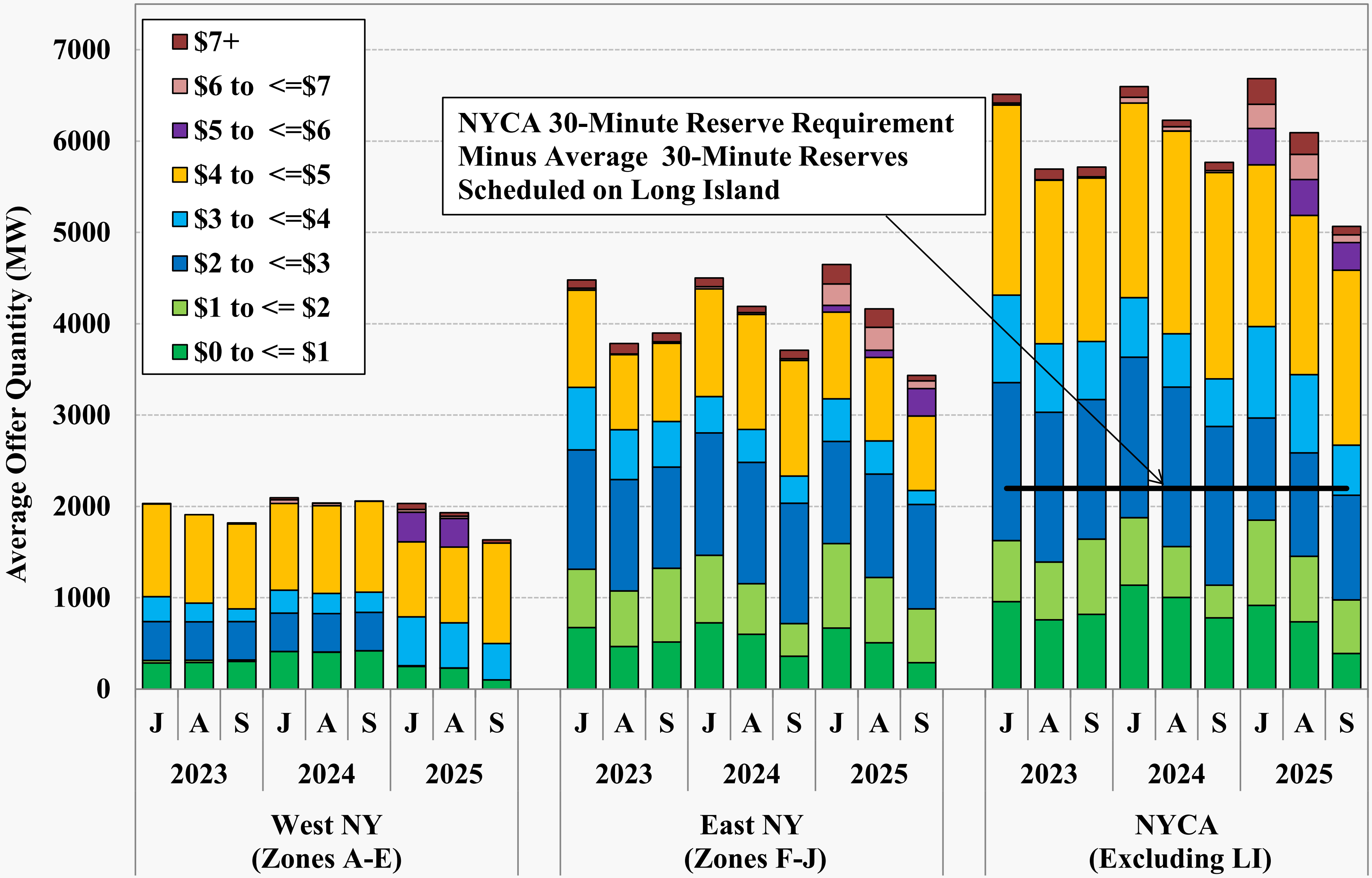


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2024Q3	$3.90	$1.69	$4.19	310
	2025Q3	$5.86	$4.28	$6.42	561
SENY 30-min	2024Q3	$4.01	$2.11	$4.32	0
	2025Q3	$6.83	$5.08	$6.89	0

Notes: For chart description, see slide 95.

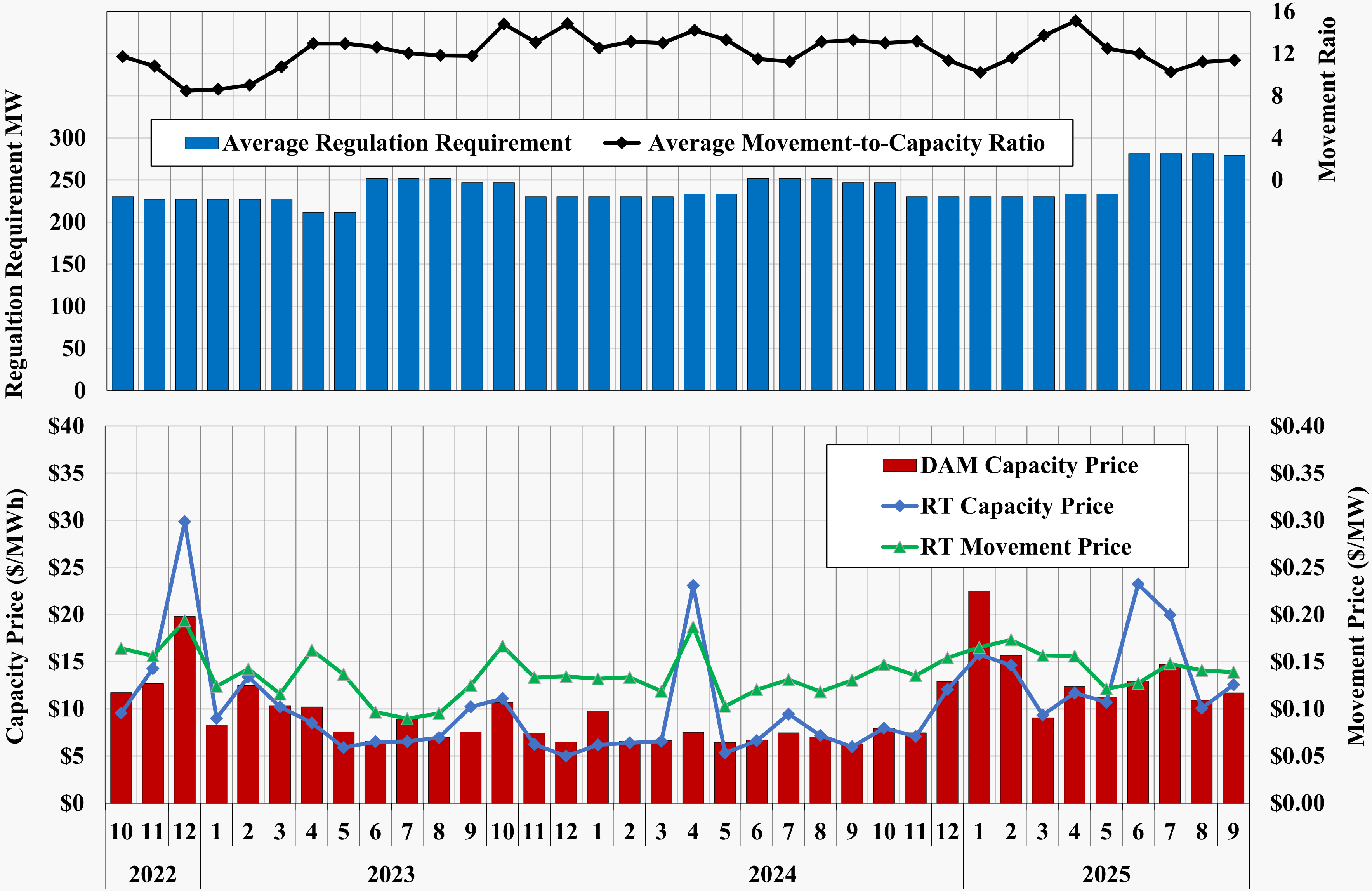
Day-Ahead NYCA 30-Minute Reserve Offers

Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 96.

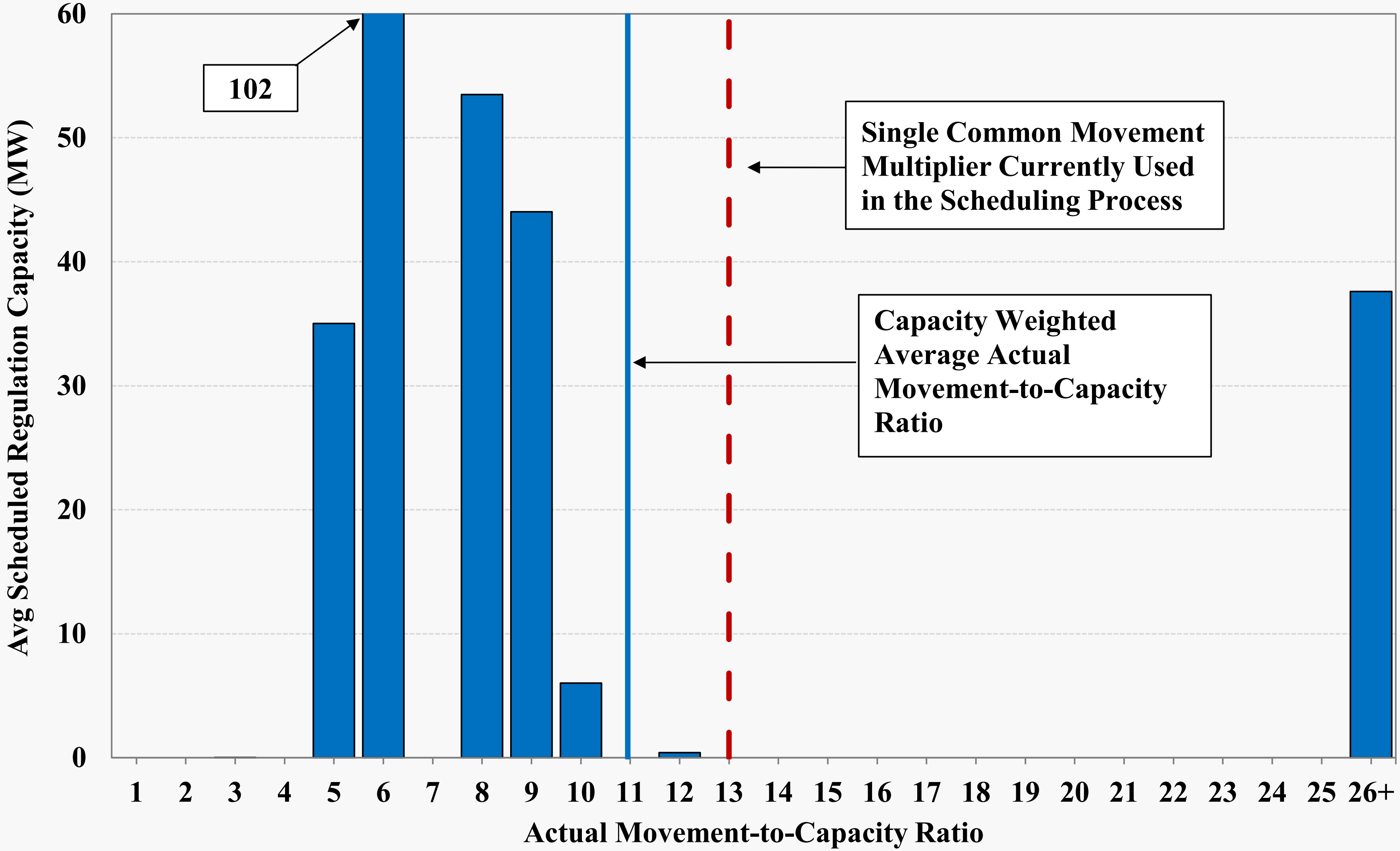
Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month



Notes: For chart description, see slide 97.

Distribution of Actual Regulation Movement

The Third Quarter of 2025

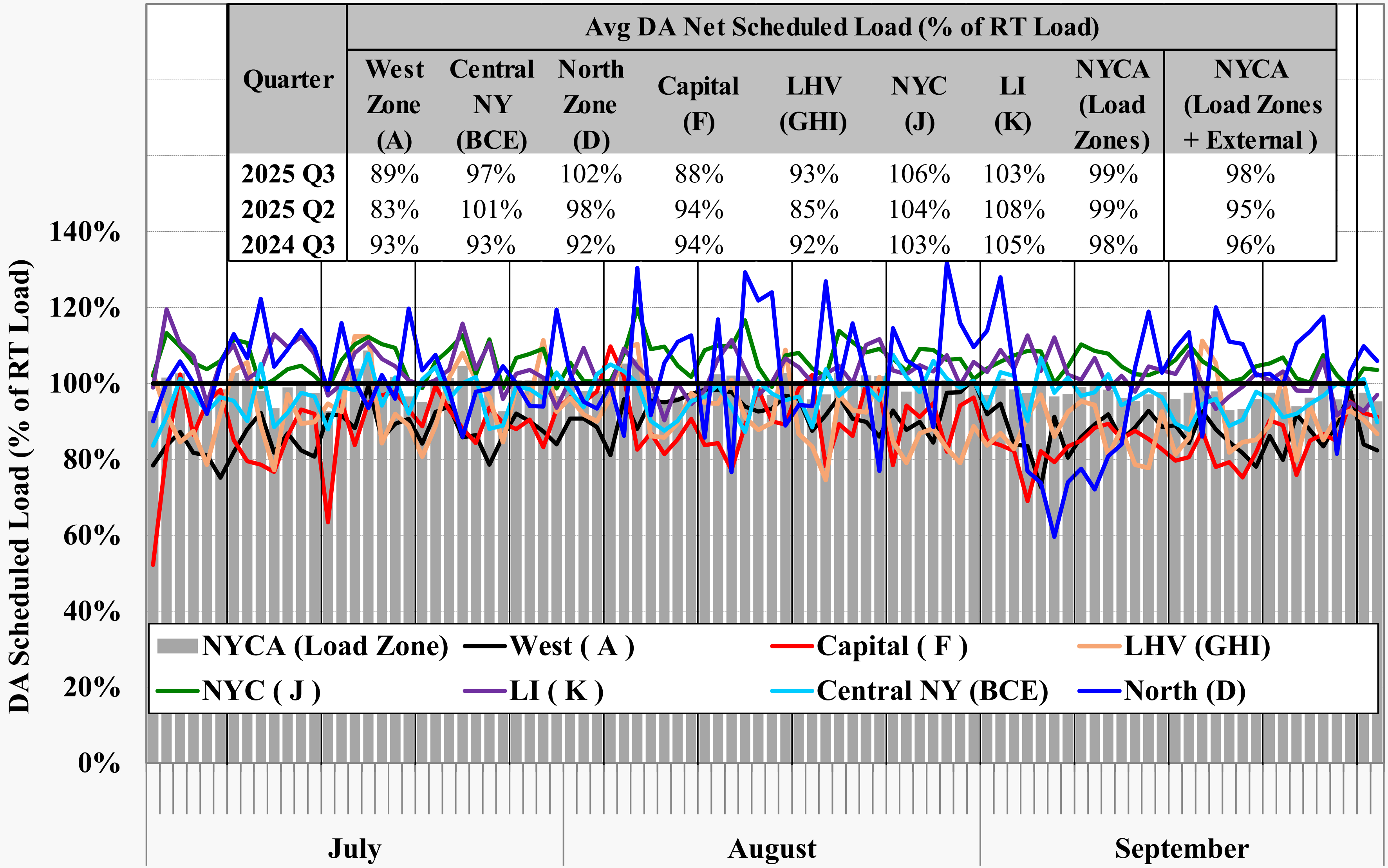


Notes: For chart description, see slide 97.

Charts:
Energy Market Scheduling

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour

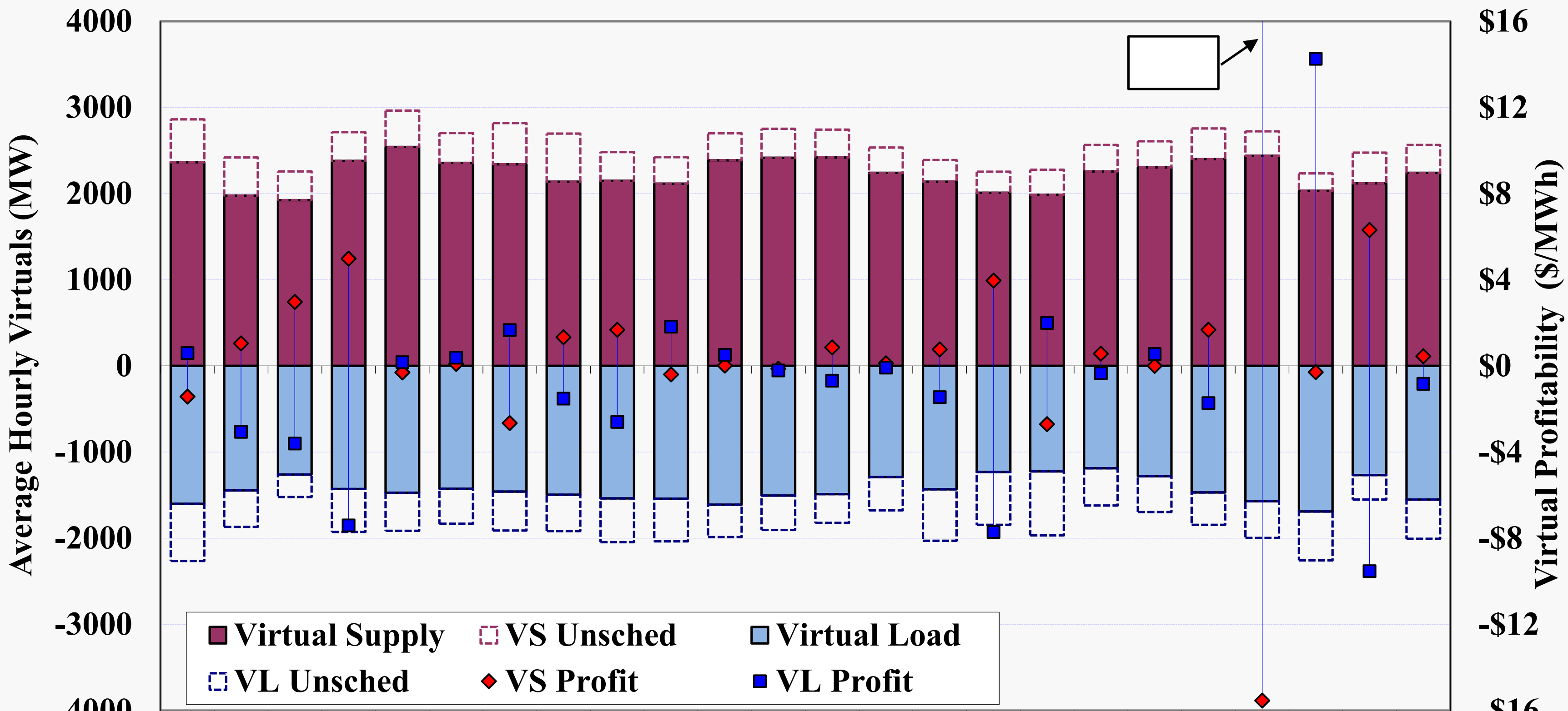


Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2025 Q3	89%	97%	102%	88%	93%	106%	103%	99%	98%
2025 Q2	83%	101%	98%	94%	85%	104%	108%	99%	95%
2024 Q3	93%	93%	92%	94%	92%	103%	105%	98%	96%

Notes: For chart description, see slide 98.

Virtual Trading Activity

by Month

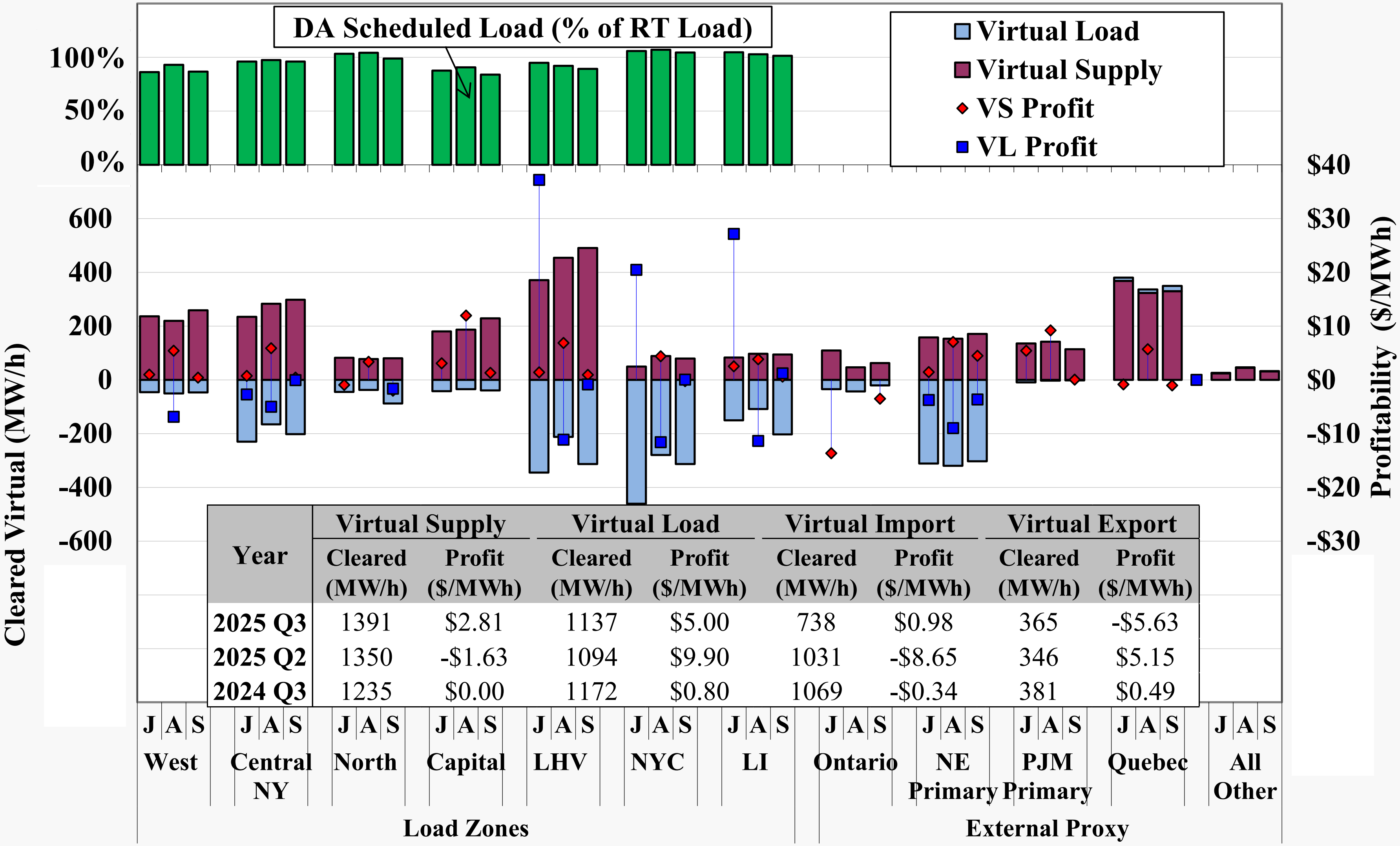


		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
			2023							2024											2025				
Profit > 50% of Avg. Zone Price	MW	166	198	136	334	106	138	81	136	236	249	132	48	104	86	262	287	218	207	147	238	158	300	232	144
	%	4%	6%	4%	9%	3%	4%	2%	4%	6%	7%	3%	1%	3%	2%	7%	9%	7%	6%	4%	6%	4%	8%	7%	4%
Loss > 50% of Avg. Zone Price	MW	213	255	141	283	148	163	93	155	234	252	148	61	110	169	258	284	273	215	150	192	163	323	212	142
	%	5%	7%	4%	7%	4%	4%	2%	4%	6%	7%	4%	2%	3%	5%	7%	9%	9%	6%	4%	5%	4%	9%	6%	4%

Notes: For chart description, see slide 98.

Virtual Trading Activity

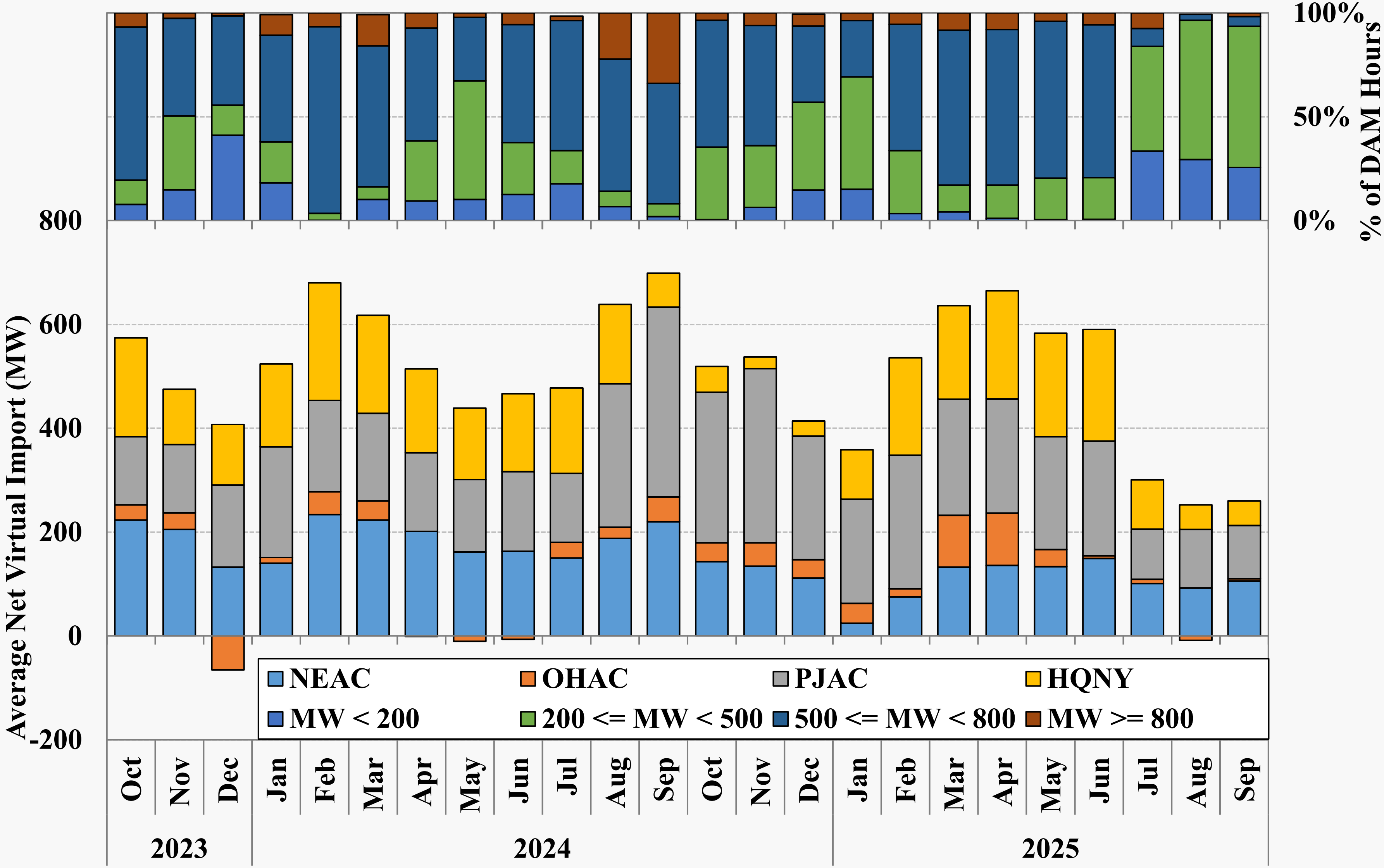
by Location



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)
2025 Q3	1391	$2.81	1137	$5.00	738	$0.98	365	-$5.63
2025 Q2	1350	-$1.63	1094	$9.90	1031	-$8.65	346	$5.15
2024 Q3	1235	$0.00	1172	$0.80	1069	-$0.34	381	$0.49

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 98.

Virtual Imports and Exports in the Day-Ahead Market

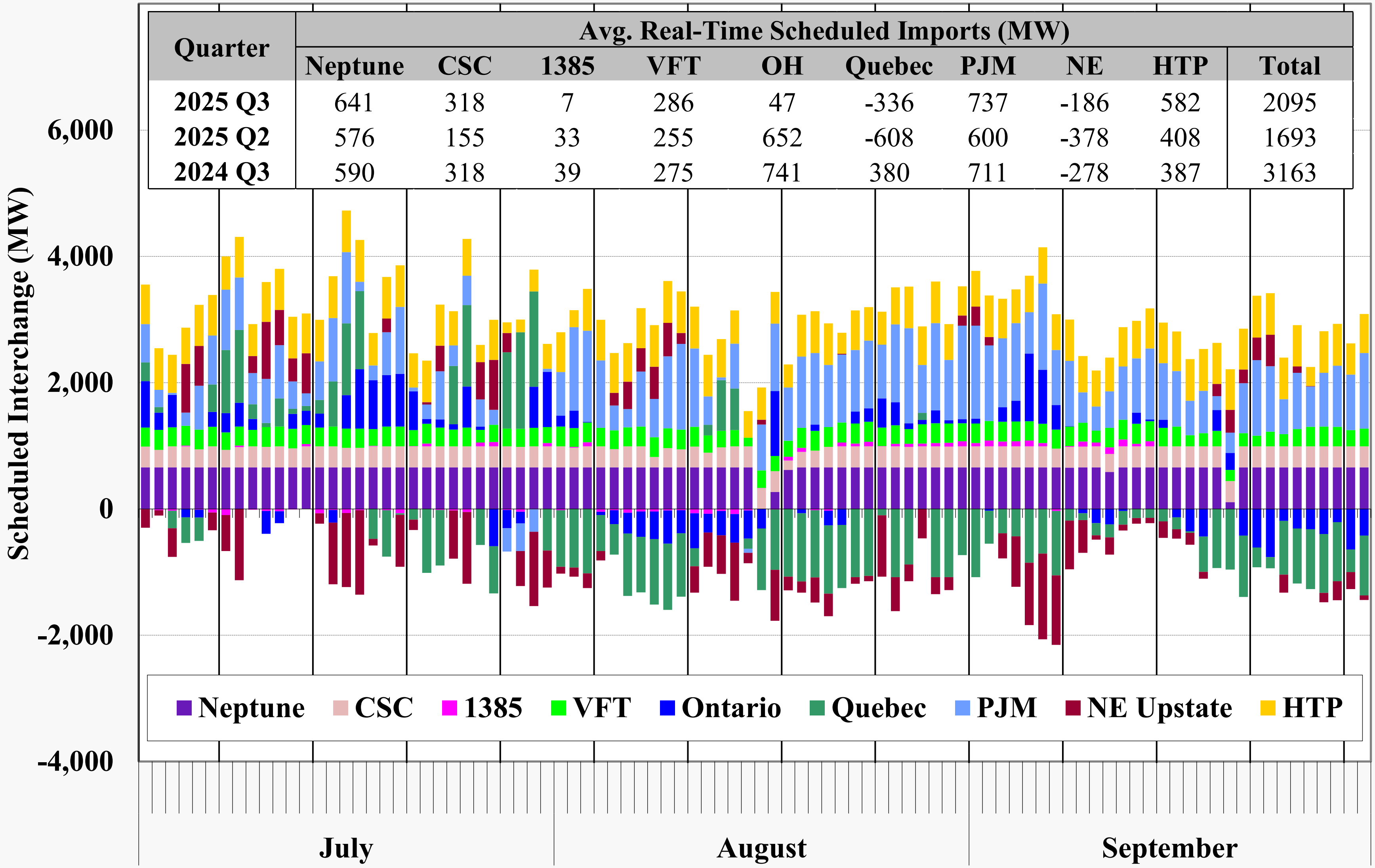


Notes: For chart description, see slide 99.

Net Imports Scheduled Across External Interfaces

Daily Peak Hours (1-9pm)

Quarter	Neptune	CSC	1385	VFT	OH	Quebec	PJM	NE	HTP	Total
	Avg. Real-Time Scheduled Imports (MW)									
2025 Q3	641	318	7	286	47	-336	737	-186	582	2095
2025 Q2	576	155	33	255	652	-608	600	-378	408	1693
2024 Q3	590	318	39	275	741	380	711	-278	387	3163



Notes: Two Quebec interfaces are combined into one.

Efficiency of Intra-Hour Scheduling Under CTS

Primary PJM and NE Interfaces

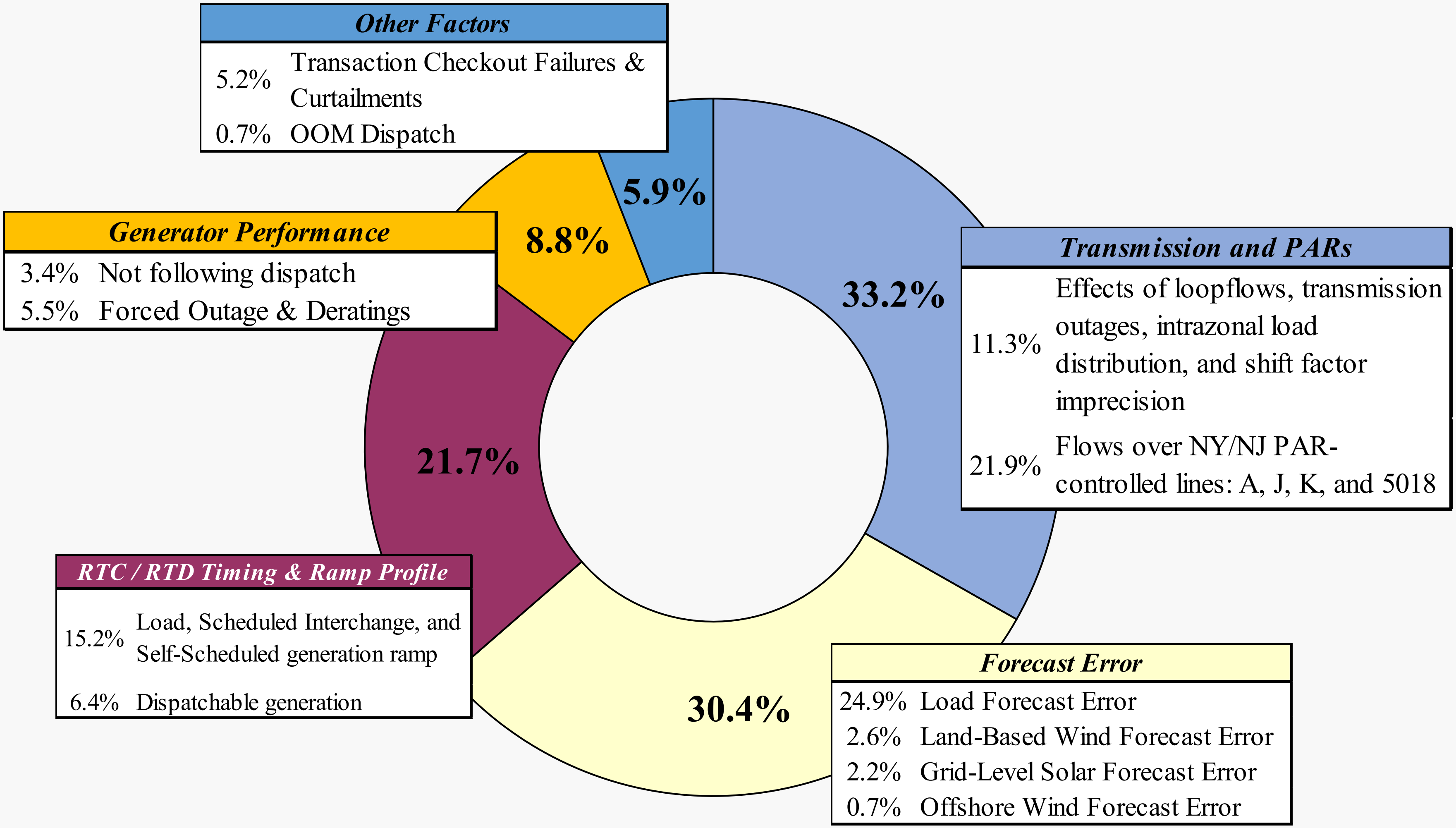
			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total		Both Forecast Errors <= $20	Any Forecast Error > $20	Total	
% of All Intervals w/ Adjustment			80%	11%	**92%**		46%	25%	**71%**	
Average Flow Adjustment (MW)	Net Imports		38	33	**37**		-13	-69	**-33**	
	Gross		117	163	**122**		101	134	**113**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$2.4	$1.5	**$4.0**		$0.8	$3.8	**$4.6**	
	Net Over-Projection by:	NY	-$0.2	-$0.7	**-$0.8**		$0.0	$0.0	**$0.0**	
		NE or PJM	$0.1	-$0.2	**-$0.1**		-$0.3	-$3.5	**-$3.8**	
	Other Unrealized Savings		-$0.1	-$0.5	**-$0.6**		$0.0	$0.0	**$0.0**	
	Actual Savings		$2.3	$0.2	**$2.5**		$0.5	$0.3	**$0.7**	
Interface Prices ($/MWh)	NY	Actual	$40.87	$80.95	**$45.90**	**$45.12**	$39.30	$68.21	**$49.29**	**$46.70**
		Forecast	$41.53	$91.22	**$47.76**	**$46.75**	$39.89	$67.20	**$49.33**	**$46.81**
	NE or PJM	Actual	$39.25	$86.52	**$45.18**	**$44.39**	$36.74	$69.77	**$48.16**	**$44.88**
		Forecast	$39.60	$87.06	**$45.55**	**$44.80**	$38.98	$115.84	**$65.55**	**$59.92**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.66	$10.26	**$1.87**	**$1.63**	$0.59	-$1.02	**$0.03**	**$0.12**
		Abs. Val.	$3.12	$50.48	**$9.06**	**$8.66**	$2.78	$14.39	**$6.79**	**$6.10**
	NE or PJM	Fcst. - Act.	$0.34	$0.53	**$0.37**	**$0.41**	$2.24	$46.07	**$17.39**	**$15.04**
		Abs. Val.	$3.78	$34.69	**$7.66**	**$7.34**	$6.44	$71.20	**$28.83**	**$25.39**

For Adjustment Intervals Only

For All Intervals

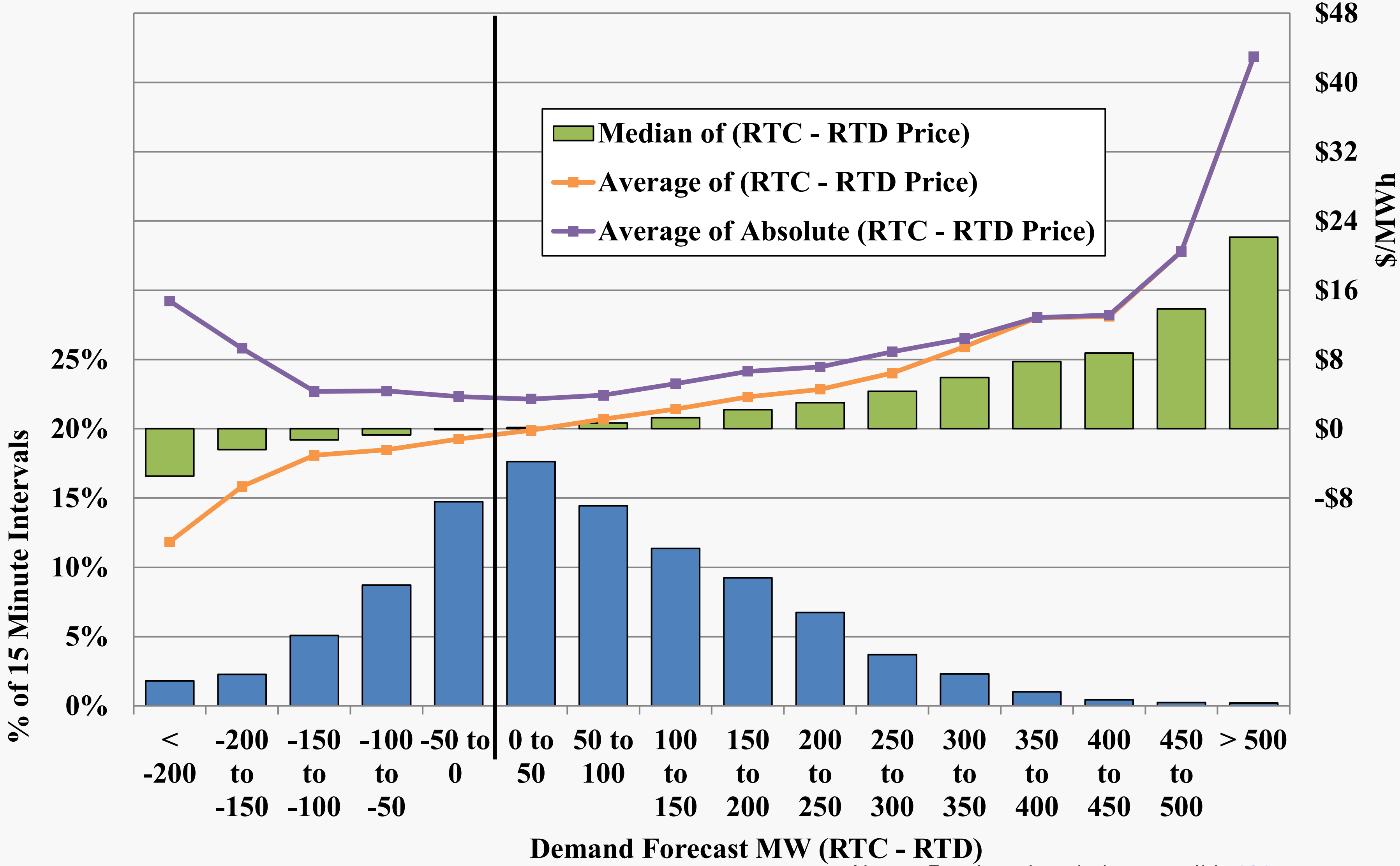
Notes: For chart description, see slide 100.

Detrimental Factors to RTC and RTD Price Divergence



Notes: For chart description, see slide 101.

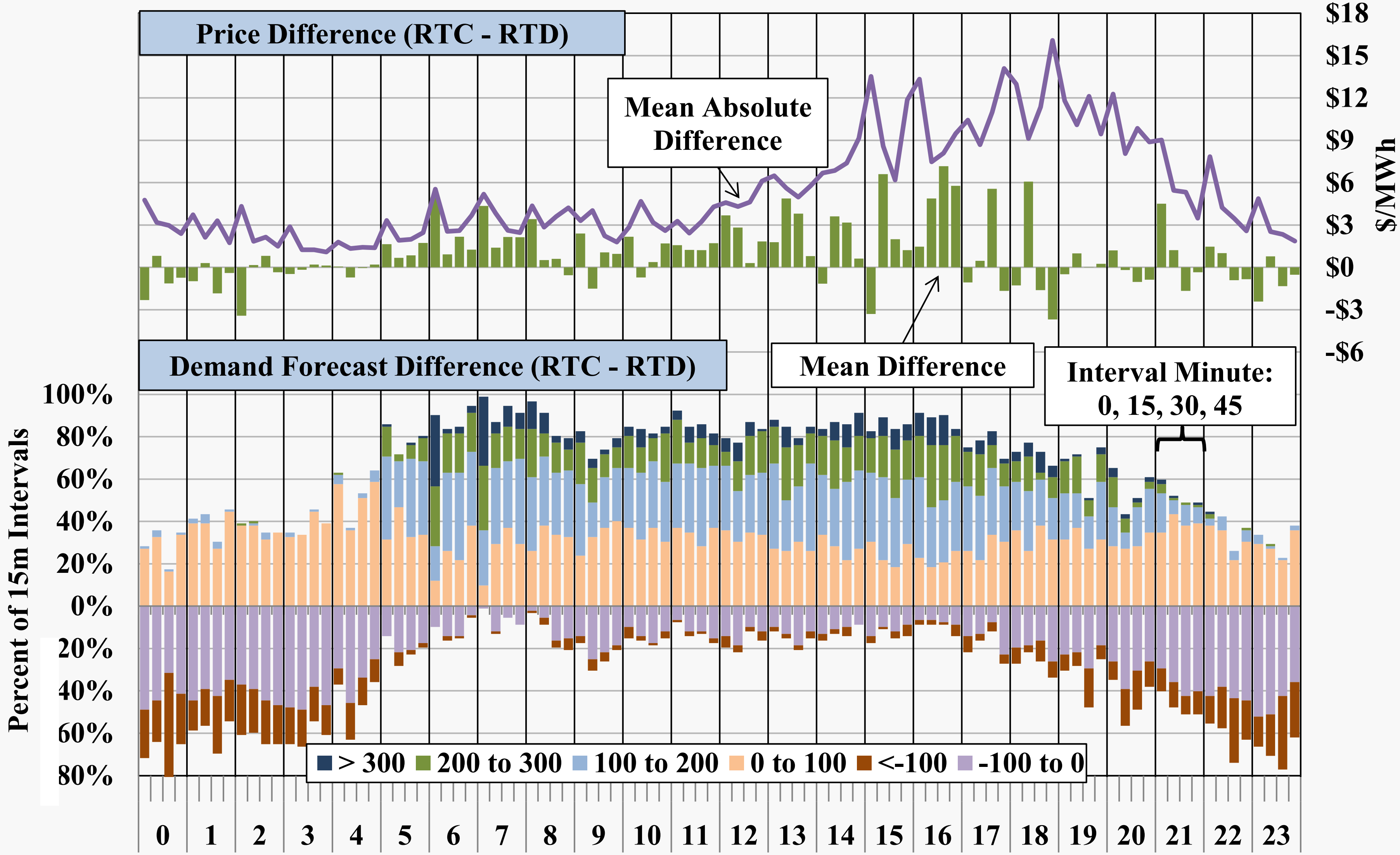
RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide 101.

RTC and RTD Price Difference vs Demand Forecast Difference

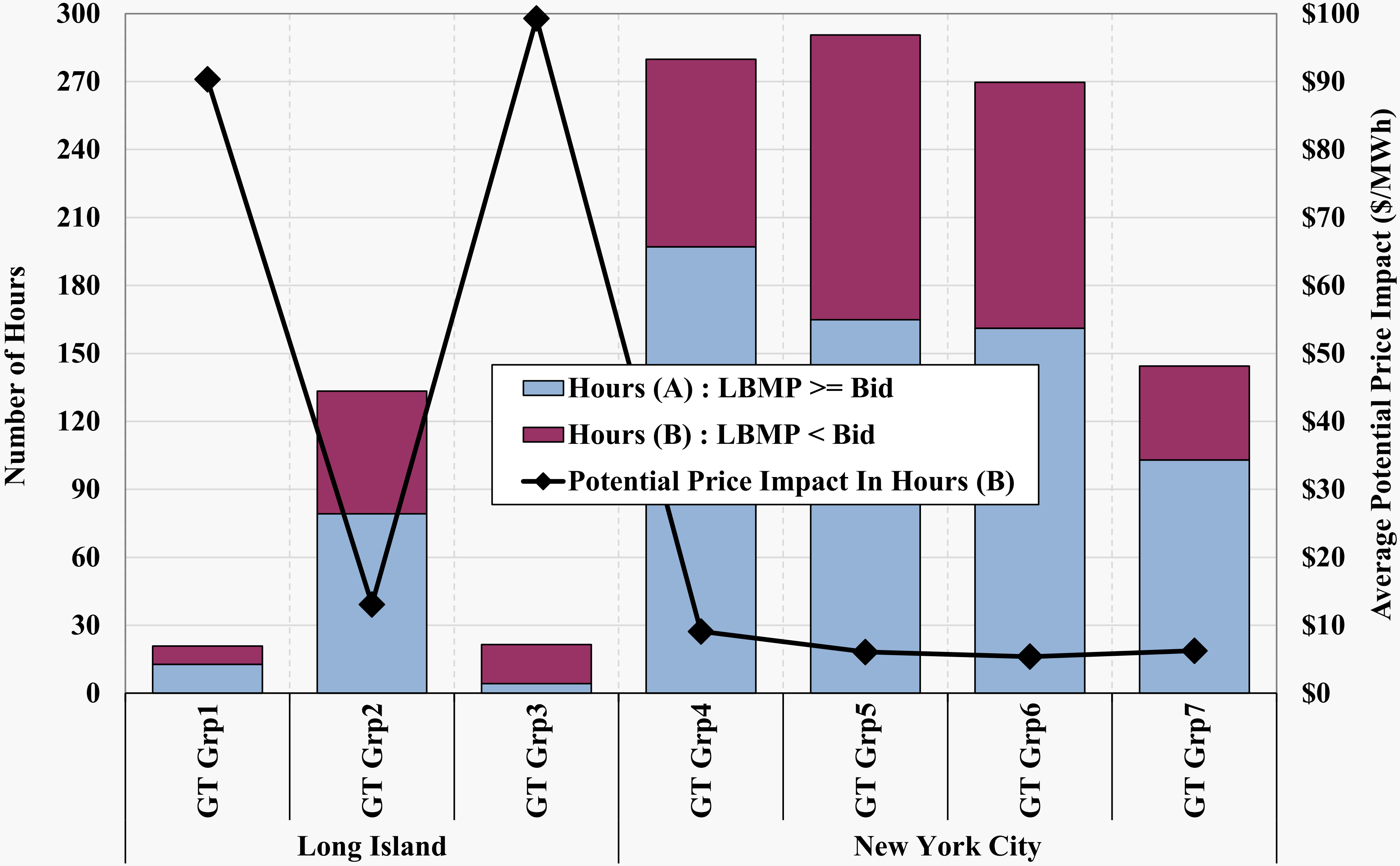
By Time of Day



Notes: For chart description, see slide 102.

Real-Time Prices During Commitments of GTs

Units Offering Multi-Hour Minimum Run Times: 2025 Q3

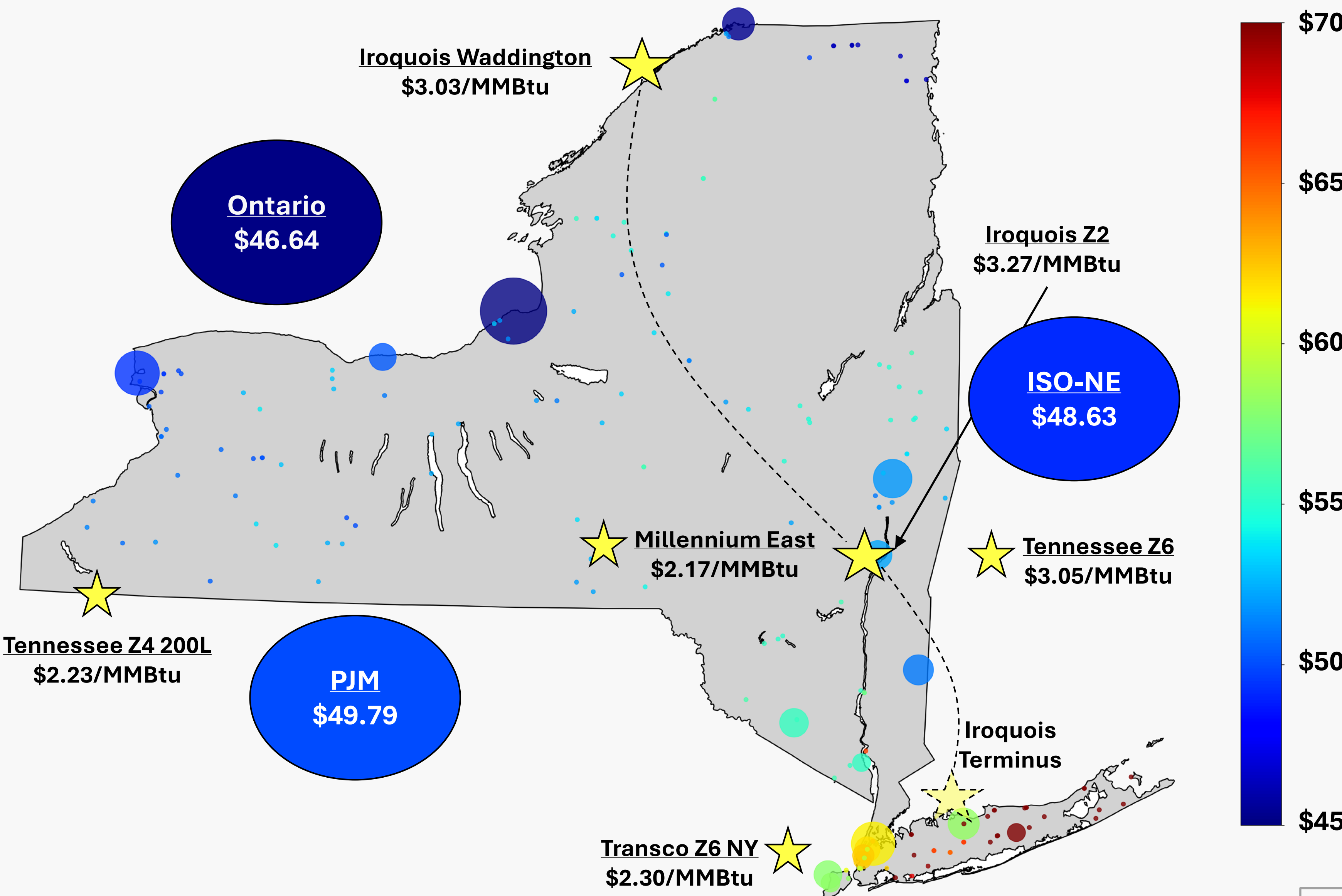


Notes: For chart description, see slide 103.

Charts:
Transmission Congestion Revenues and Shortfalls

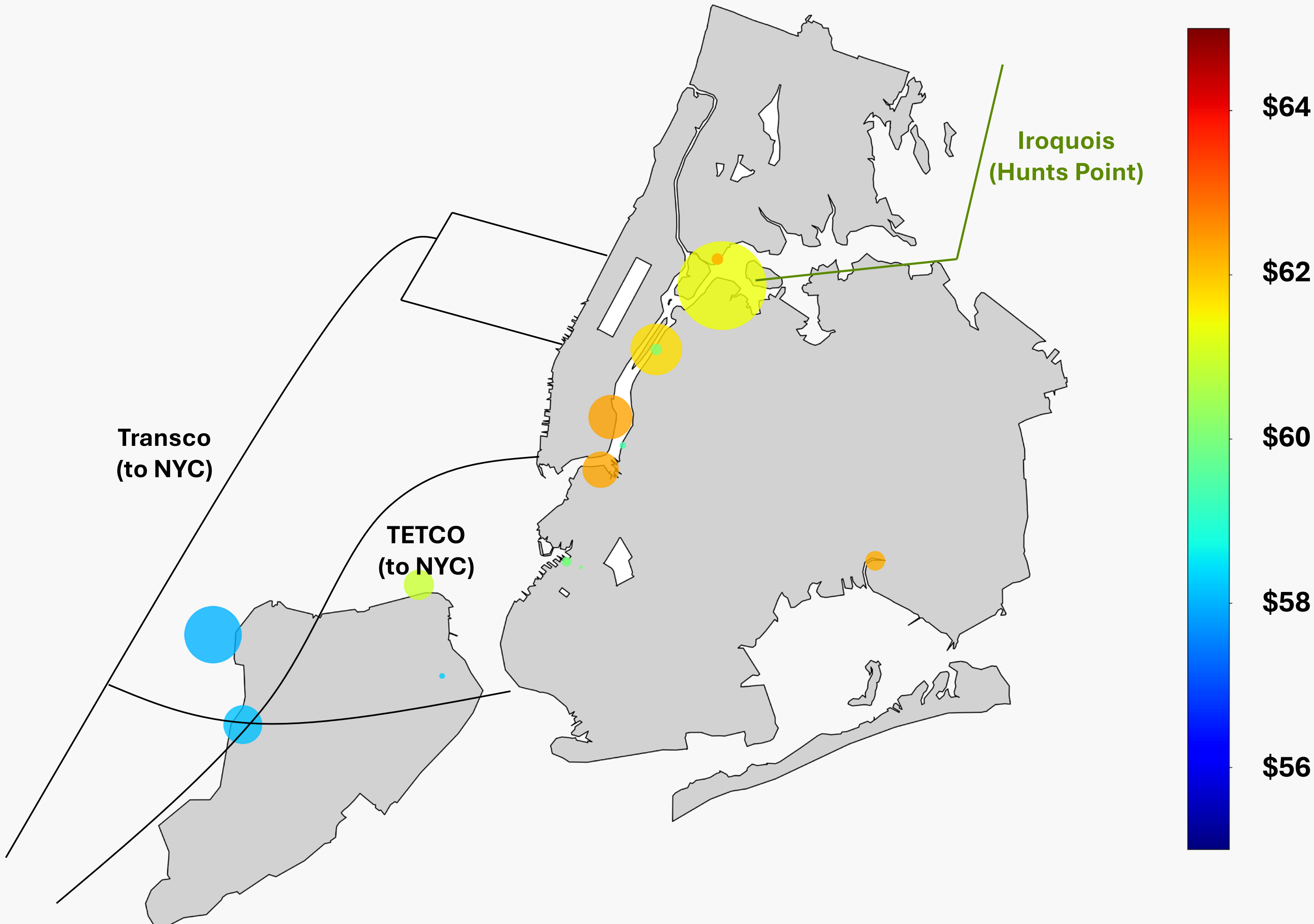
System Congestion

Real-Time Price Map at Generator Nodes



System Congestion

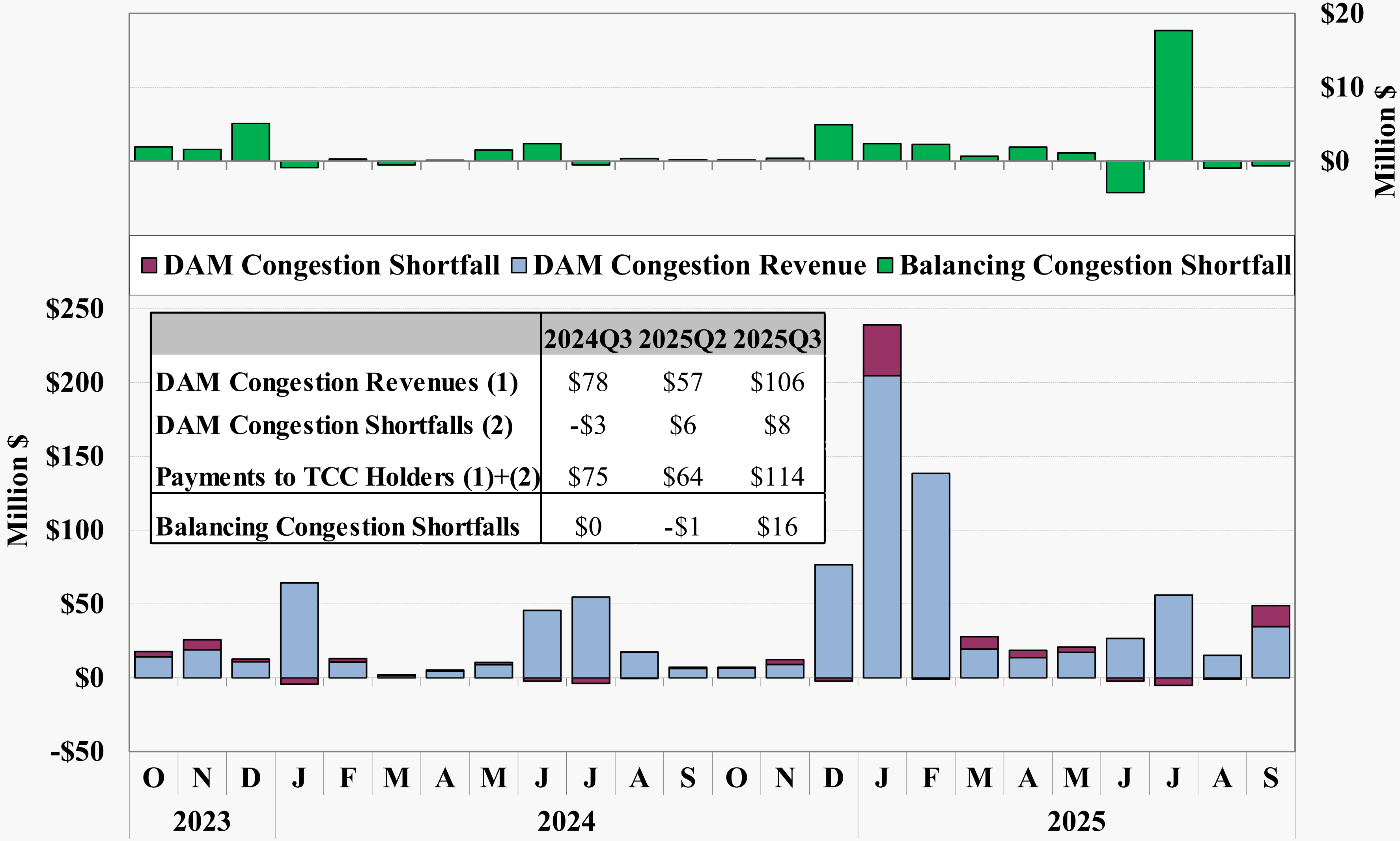
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 104.

Congestion Revenues and Shortfalls

By Month



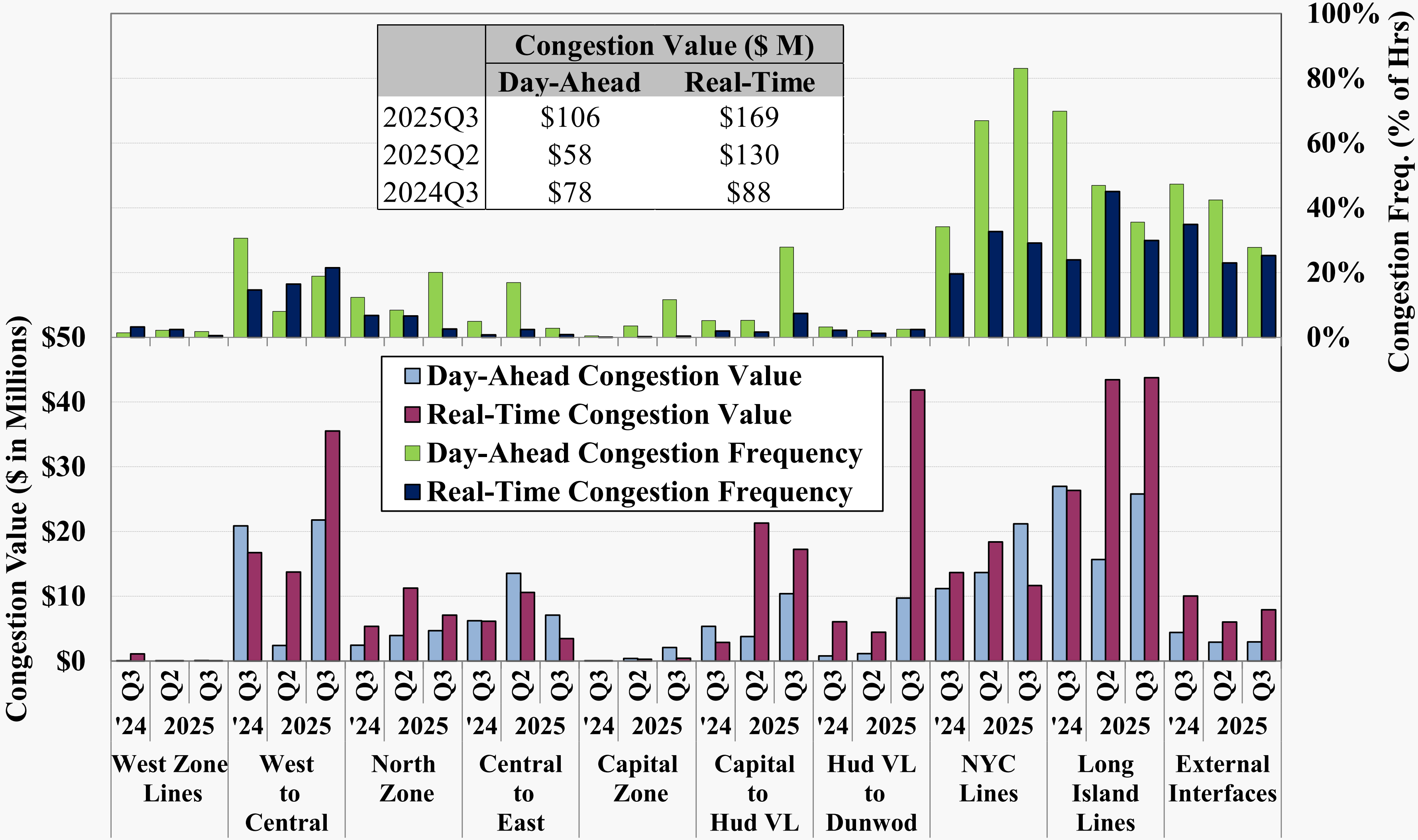
	2024Q3	2025Q2	2025Q3
DAM Congestion Revenues (1)	$78	$57	$106
DAM Congestion Shortfalls (2)	-$3	$6	$8
Payments to TCC Holders (1)+(2)	$75	$64	$114
Balancing Congestion Shortfalls	$0	-$1	$16

Notes: For chart description, see slides 105 and 106.

Day-Ahead and Real-Time Congestion Value

By Transmission Path

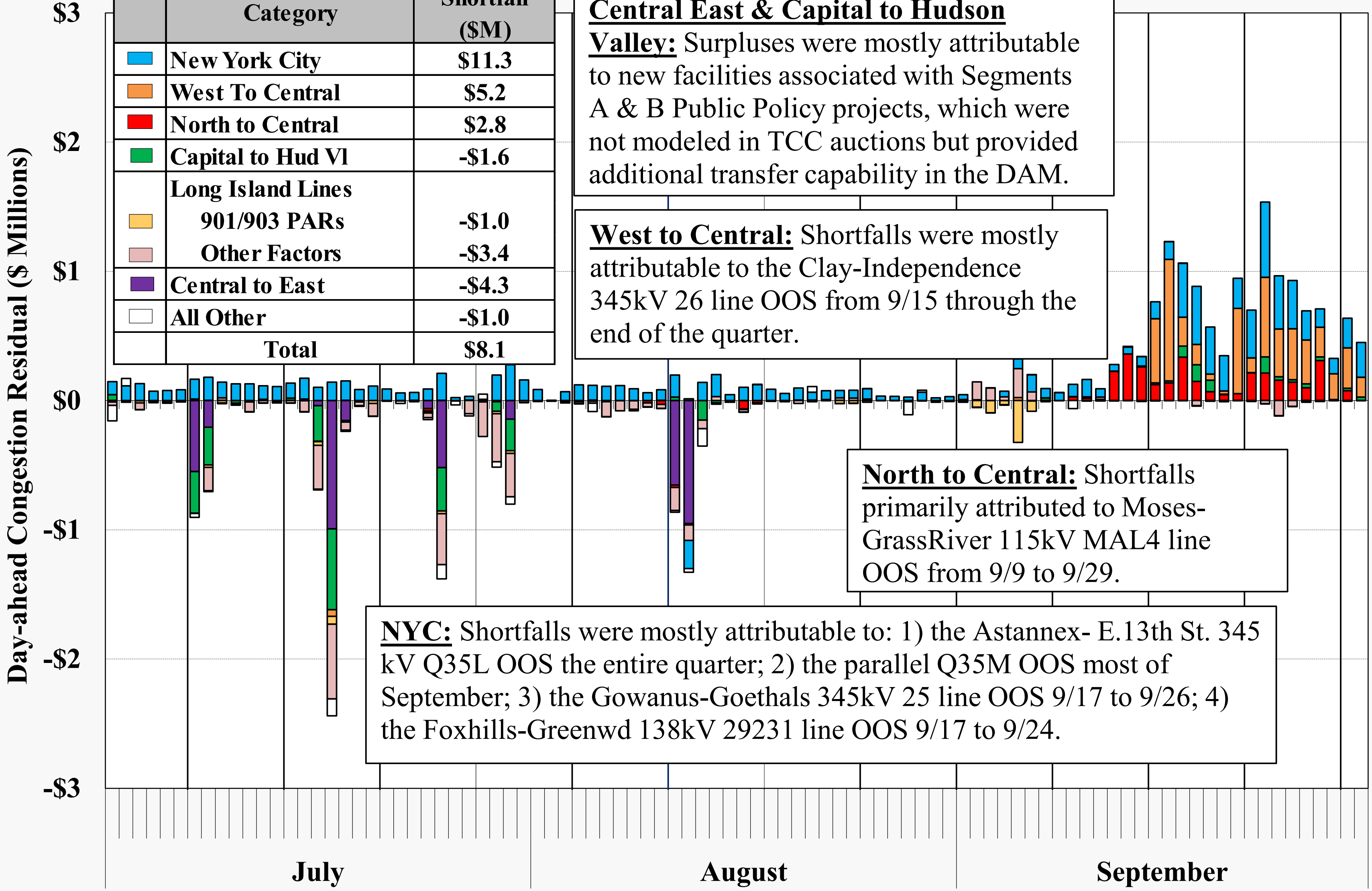
	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2025Q3	$106	$169
2025Q2	$58	$130
2024Q3	$78	$88



Notes: For chart description, see slides 105, 106, and 107.

Day-Ahead Congestion Revenue Shortfalls

By Transmission Facility



	Category	Shortfall ($M)
	New York City	$11.3
	West To Central	$5.2
	North to Central	$2.8
	Capital to Hud Vl	-$1.6
	Long Island Lines	
	901/903 PARs	-$1.0
	Other Factors	-$3.4
	Central to East	-$4.3
	All Other	-$1.0
	Total	$8.1

Central East & Capital to Hudson Valley: Surpluses were mostly attributable to new facilities associated with Segments A & B Public Policy projects, which were not modeled in TCC auctions but provided additional transfer capability in the DAM.

West to Central: Shortfalls were mostly attributable to the Clay-Independence 345kV 26 line OOS from 9/15 through the end of the quarter.

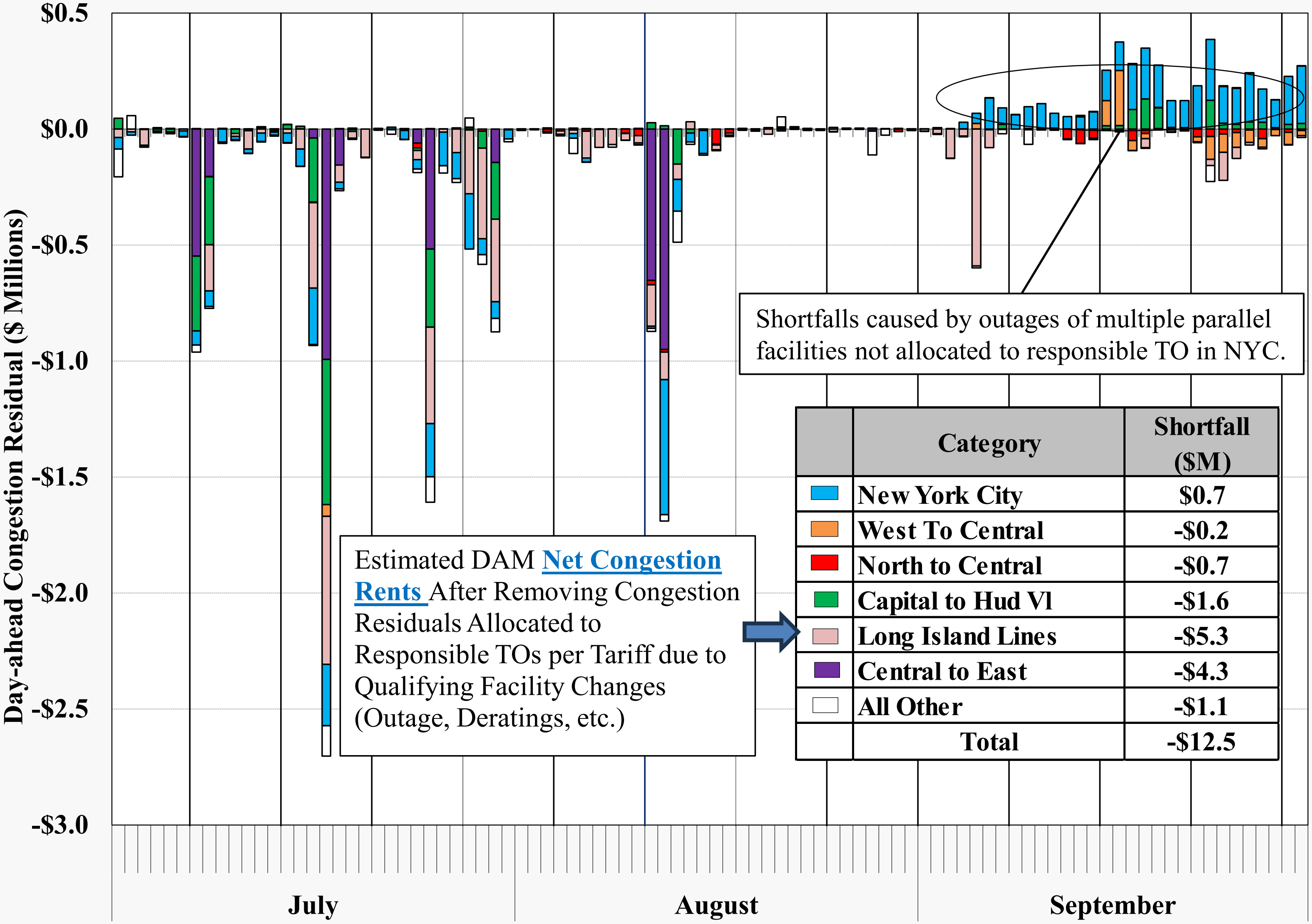
North to Central: Shortfalls primarily attributed to Moses-GrassRiver 115kV MAL4 line OOS from 9/9 to 9/29.

NYC: Shortfalls were mostly attributable to: 1) the Astannex- E.13th St. 345 kV Q35L OOS the entire quarter; 2) the parallel Q35M OOS most of September; 3) the Gowanus-Goethals 345kV 25 line OOS 9/17 to 9/26; 4) the Foxhills-Greenwd 138kV 29231 line OOS 9/17 to 9/24.

Notes: For chart description, see slides 105, 106, and 107.

Estimated DAM Net Congestion Rents

By Transmission Facility

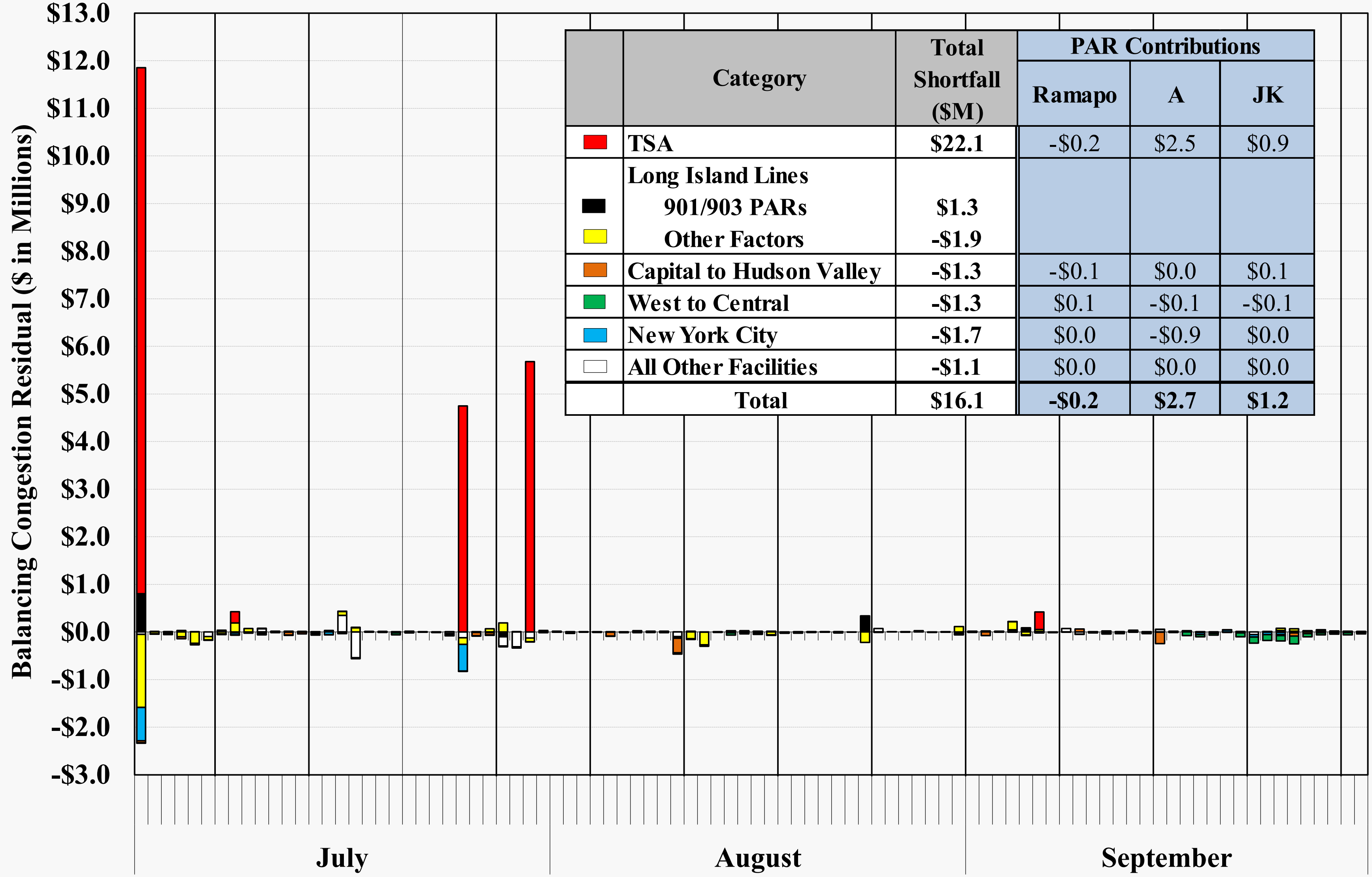


	Category	Shortfall ($M)
	New York City	$0.7
	West To Central	-$0.2
	North to Central	-$0.7
	Capital to Hud Vl	-$1.6
	Long Island Lines	-$5.3
	Central to East	-$4.3
	All Other	-$1.1
	Total	-$12.5

Notes: For chart description, see slides 105, 106, and 107.

Balancing Congestion Shortfalls

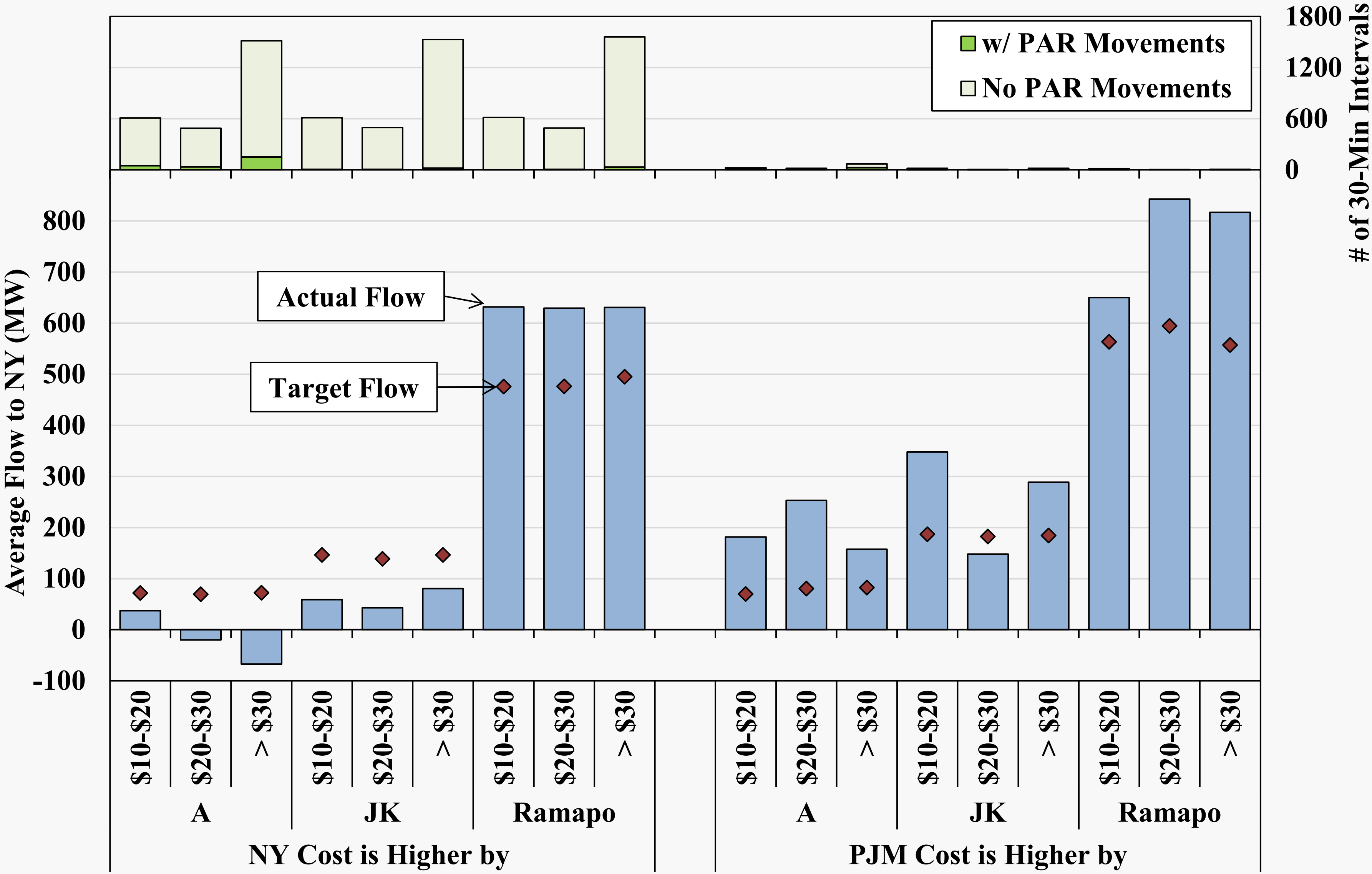
By Transmission Facility



	Category	Total Shortfall ($M)	PAR Contributions		
			Ramapo	A	JK
	TSA	$22.1	-$0.2	$2.5	$0.9
	Long Island Lines				
	901/903 PARs	$1.3			
	Other Factors	-$1.9			
	Capital to Hudson Valley	-$1.3	-$0.1	$0.0	$0.1
	West to Central	-$1.3	$0.1	-$0.1	-$0.1
	New York City	-$1.7	$0.0	-$0.9	$0.0
	All Other Facilities	-$1.1	$0.0	$0.0	$0.0
	Total	$16.1	-$0.2	$2.7	$1.2

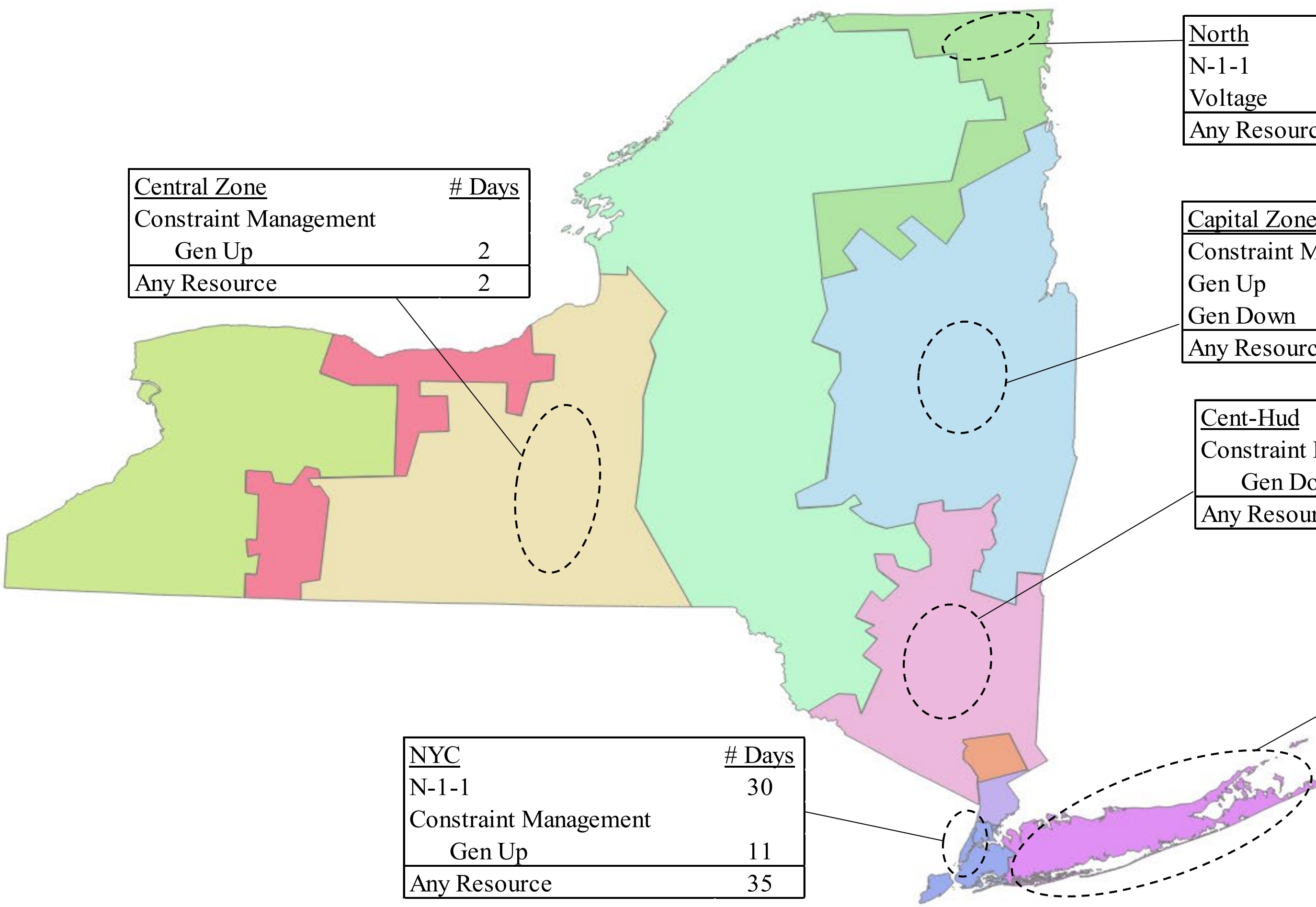
Notes: 1. The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. 2. For chart description, see slides 105, 106, and 107.

PAR Operation under M2M with PJM: 2025 Q3



Notes: For chart description, see slide 108.

OOM Actions to Manage Network Reliability



North	# Days
N-1-1	8
Voltage	3
Any Resource	11

Central Zone	# Days
Constraint Management	
Gen Up	2
Any Resource	2

Capital Zone	# Days
Constraint Management	
Gen Up	2
Gen Down	2
Any Resource	4

Cent-Hud	# Days
Constraint Management	
Gen Down	1
Any Resource	1

Long Island	# Days
N-1-1	5
Voltage	17
Constraint Management	
Gen Up	54
Gen Down	4
Any Resource	70

NYC	# Days
N-1-1	30
Constraint Management	
Gen Up	11
Any Resource	35

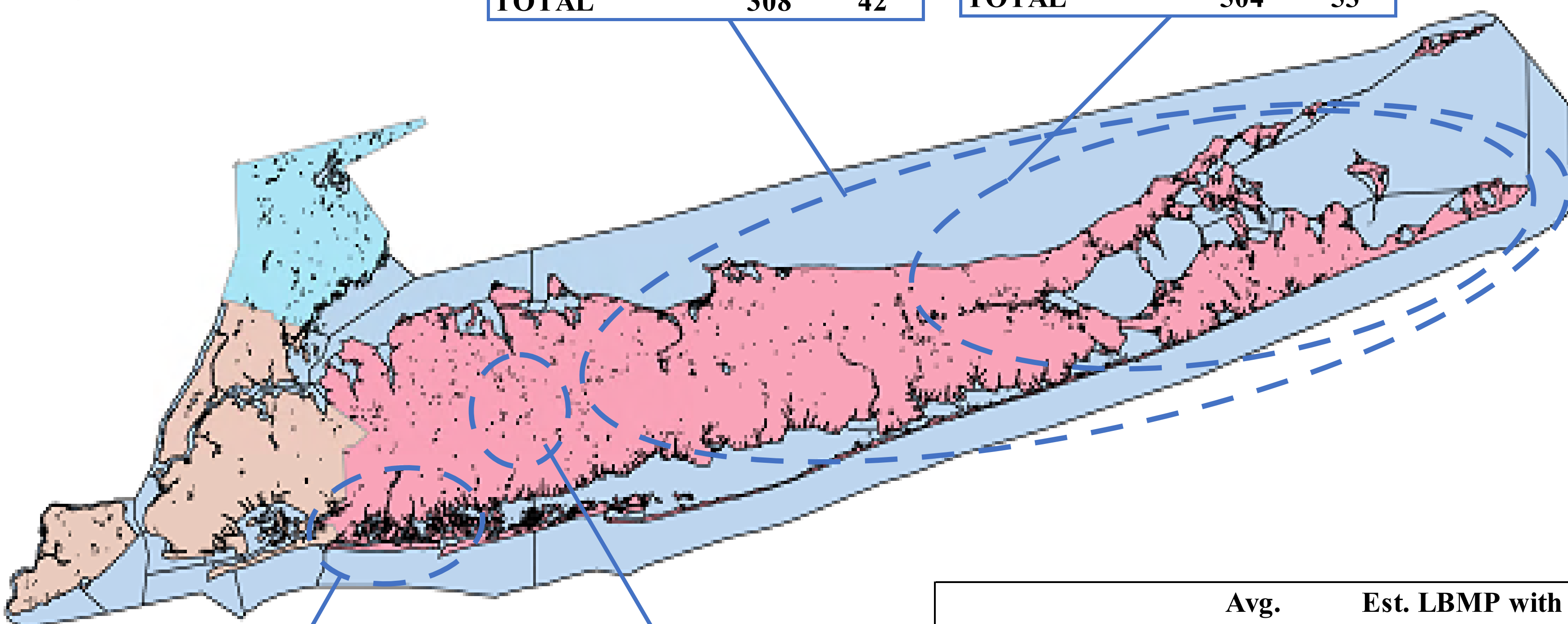
Notes: For chart description, see slide 109

Constraints on the Low Voltage Network

Long Island Load Pockets

East of Northport	#Hours	#Days
69kV OOM	49	5
69kV	268	40
138kV	182	31
TOTAL	308	42

East End	#Hours	#Days
69kV OOM	0	0
138kV	1	1
TVR	503	52
TOTAL	504	53



Valley Stream	#Hours	#Days
69kV OOM	406	40
138kV	761	75
TOTAL	865	76

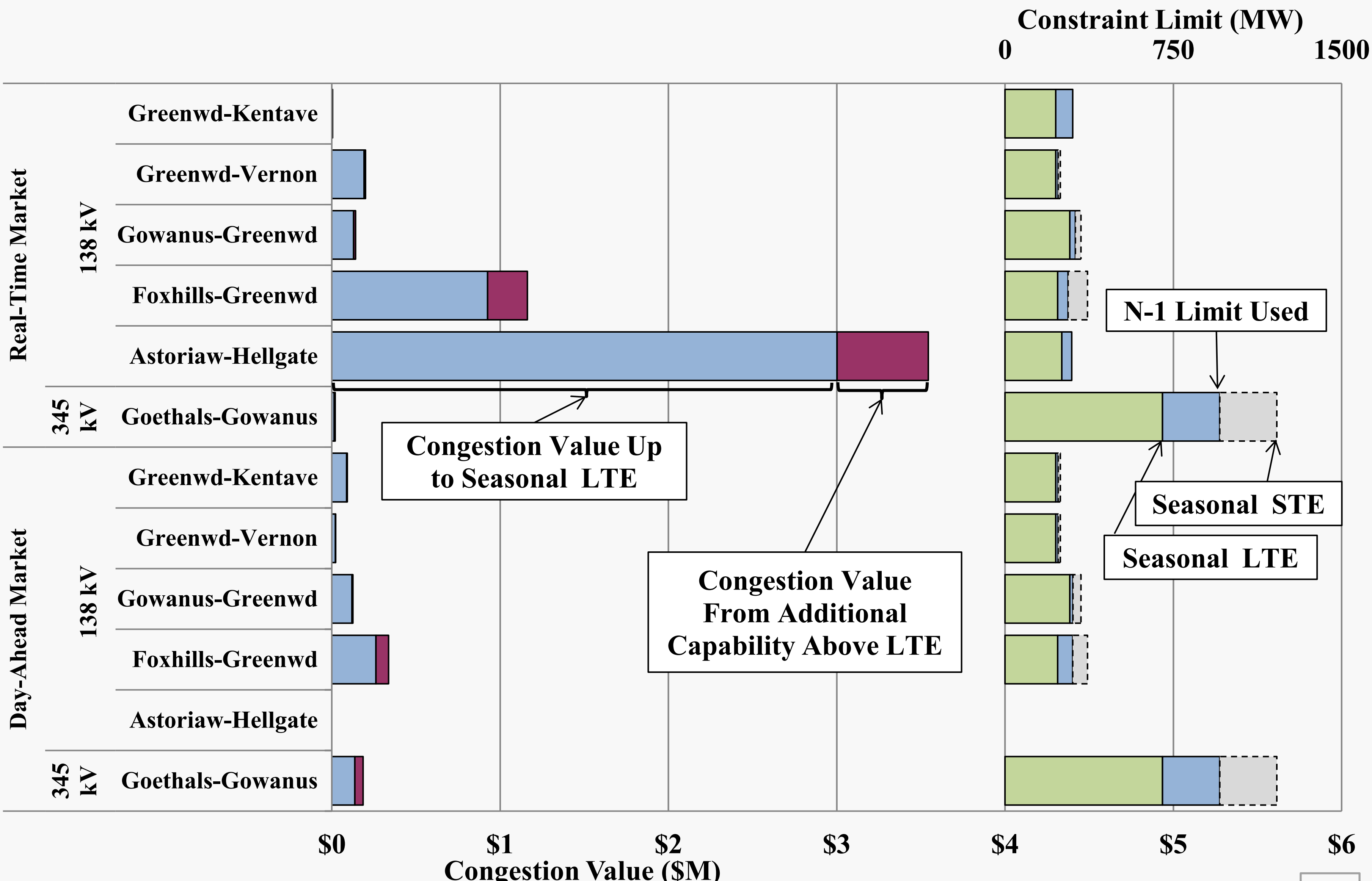
Brentwood	#Hours	#Days
69kV OOM	4	1
69kV	153	29
TOTAL	155	29

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$55.73	$55.80
East End	$60.57	$96.93
East of Northport	$58.92	$59.41
Valley Stream	$61.84	$89.51

Notes: For chart description, see slides 109-110

N-1 Constraints in New York City

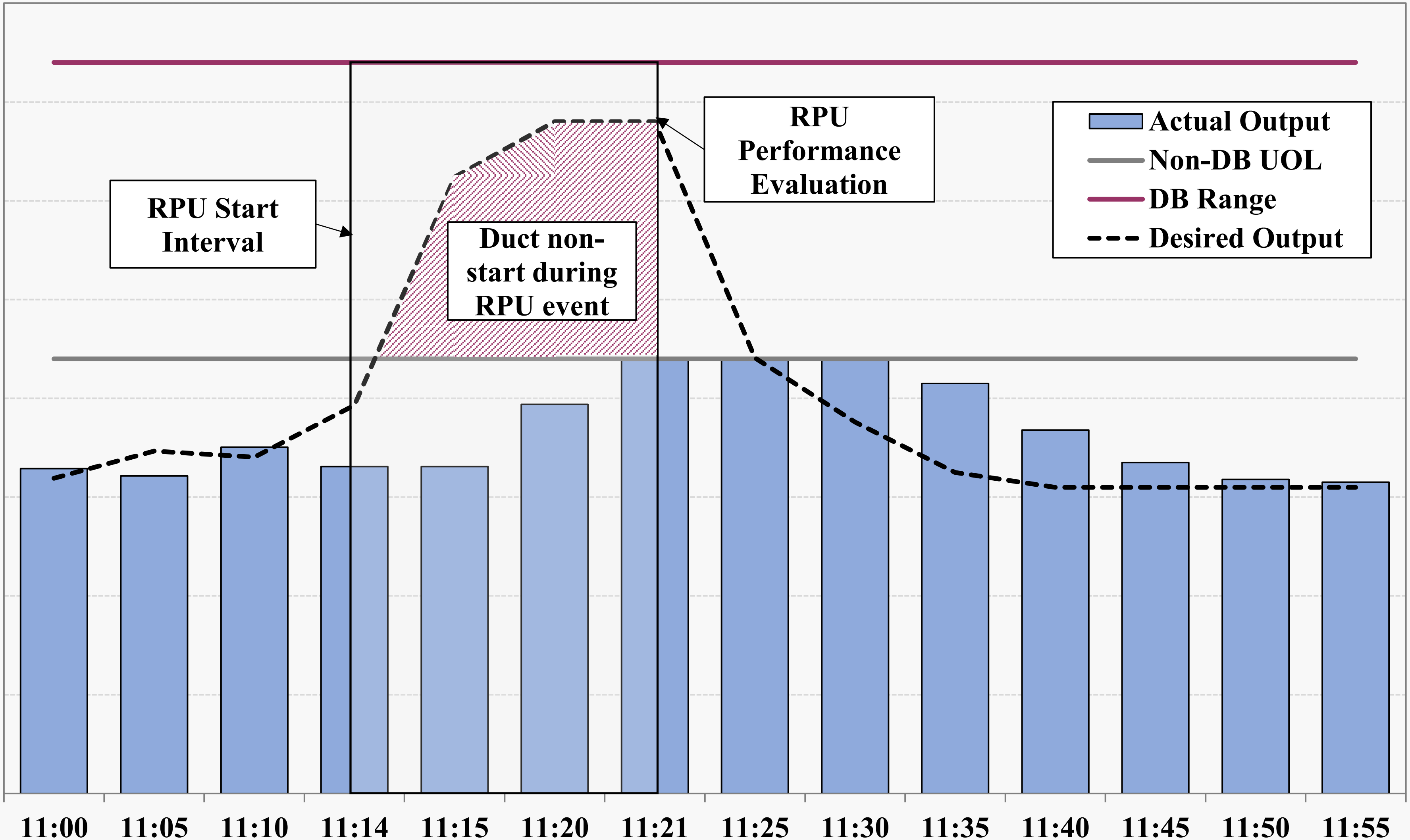
Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide 111

Duct Burner Real-Time Dispatch Issues

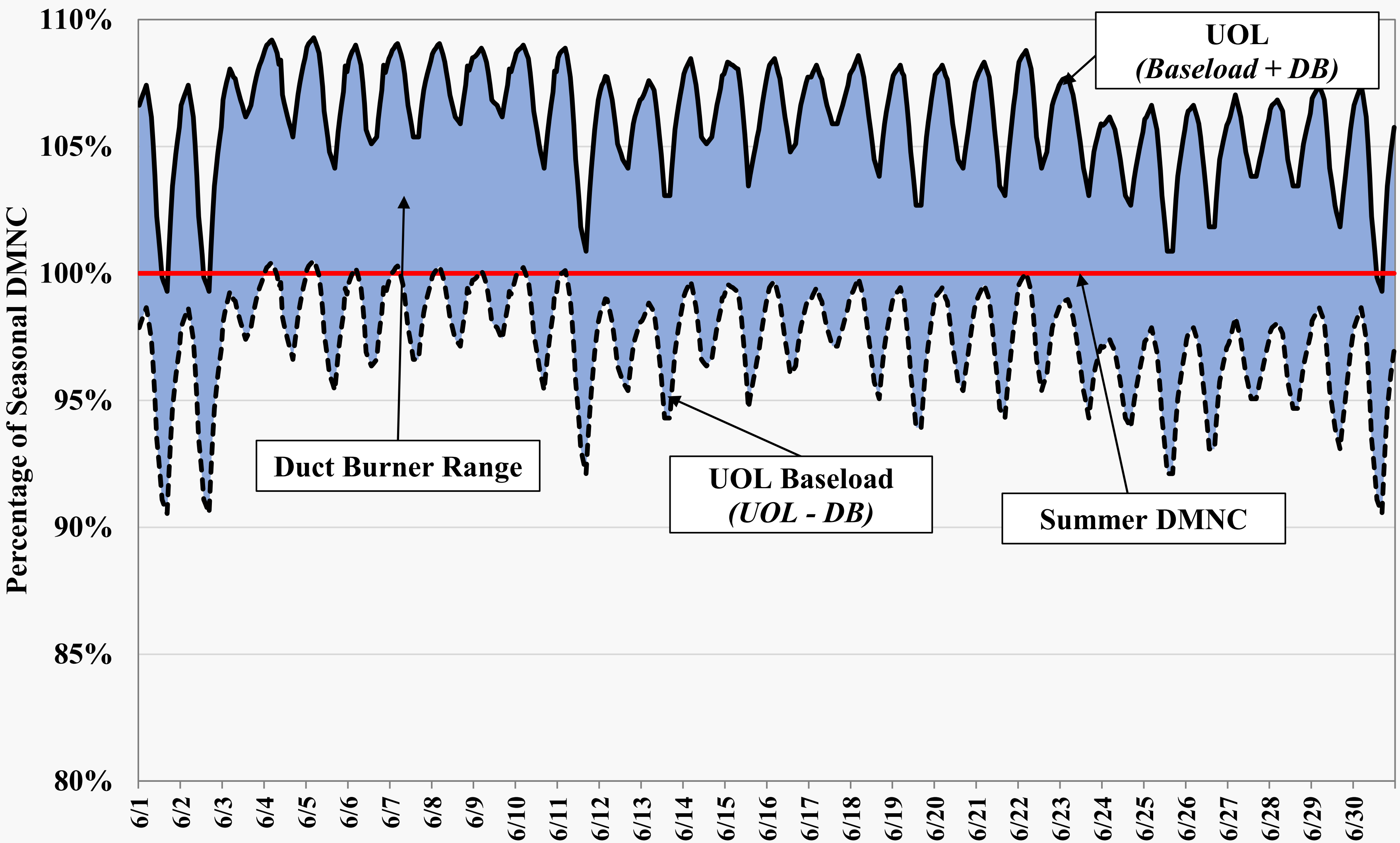
Example of a Failed RPU



Notes: For chart description, see slide 112

Illustration of Duct Burner Range

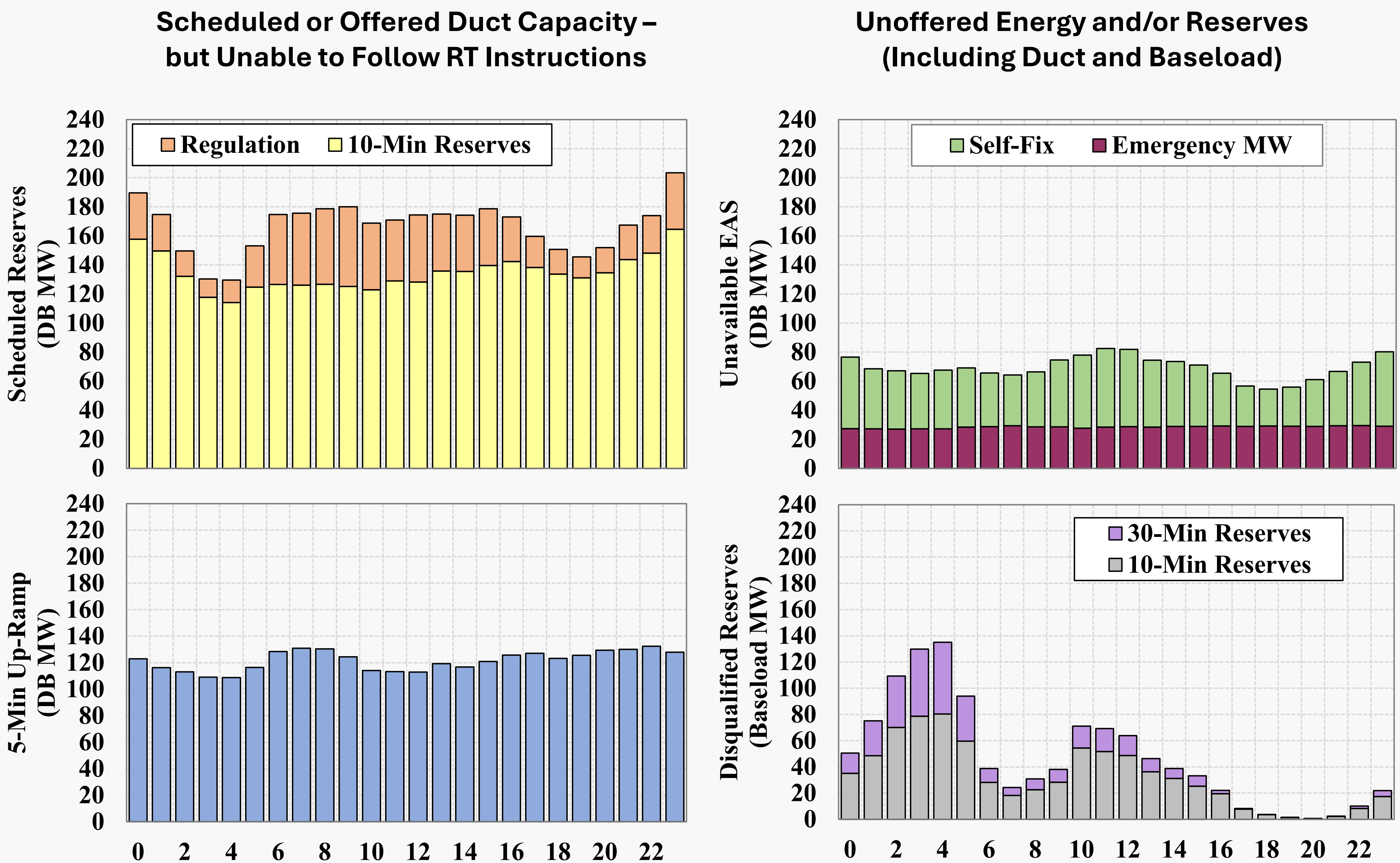
Example Generator Hourly Capability



Notes: For chart description, see slide 113

Duct Burner Schedules and Ramp Expectations

Evaluation of Duct Availability in Real-Time



Notes: For chart description, see slide 112

Gas Turbine Start-up Performance

Economic Starts & Audits

10/30-Minute GT Start Performance - Oct 2024 - Sep 2025						
Performance Category	No. of Units	Total No. of Starts Evaluated	Other Economic Starts and Audits		RPUs + 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%	1	1	0.0%	0.0%		
10% - 20%	0	0				
20% - 30%	0	0				
30% - 40%	0	0				
40% - 50%	3	37	45.1%	61.6%	43.4%	60.0%
50% - 60%	3	61	59.5%	74.8%	53.1%	70.4%
60% - 70%	4	54	69.2%	79.5%	58.6%	69.0%
70% - 80%	4	89	79.8%	86.5%	74.6%	80.1%
80% - 90%	26	4011	86.4%	94.1%	85.9%	94.4%
90% - 100%	60	5609	94.1%	96.1%	93.2%	96.3%
TOTAL	**101**	**9862**				

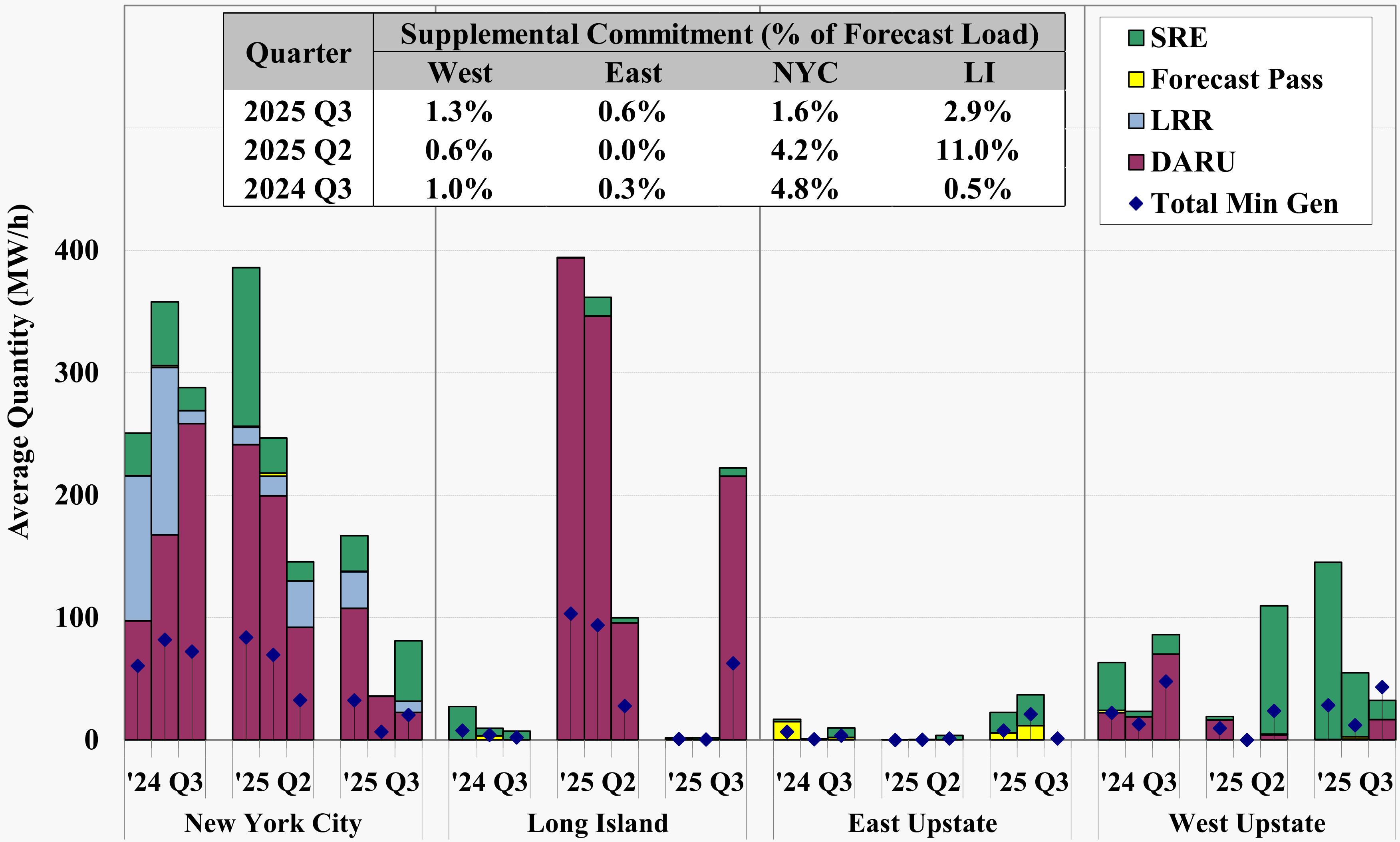
Notes: For chart description, see slide 114

Charts:
Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability

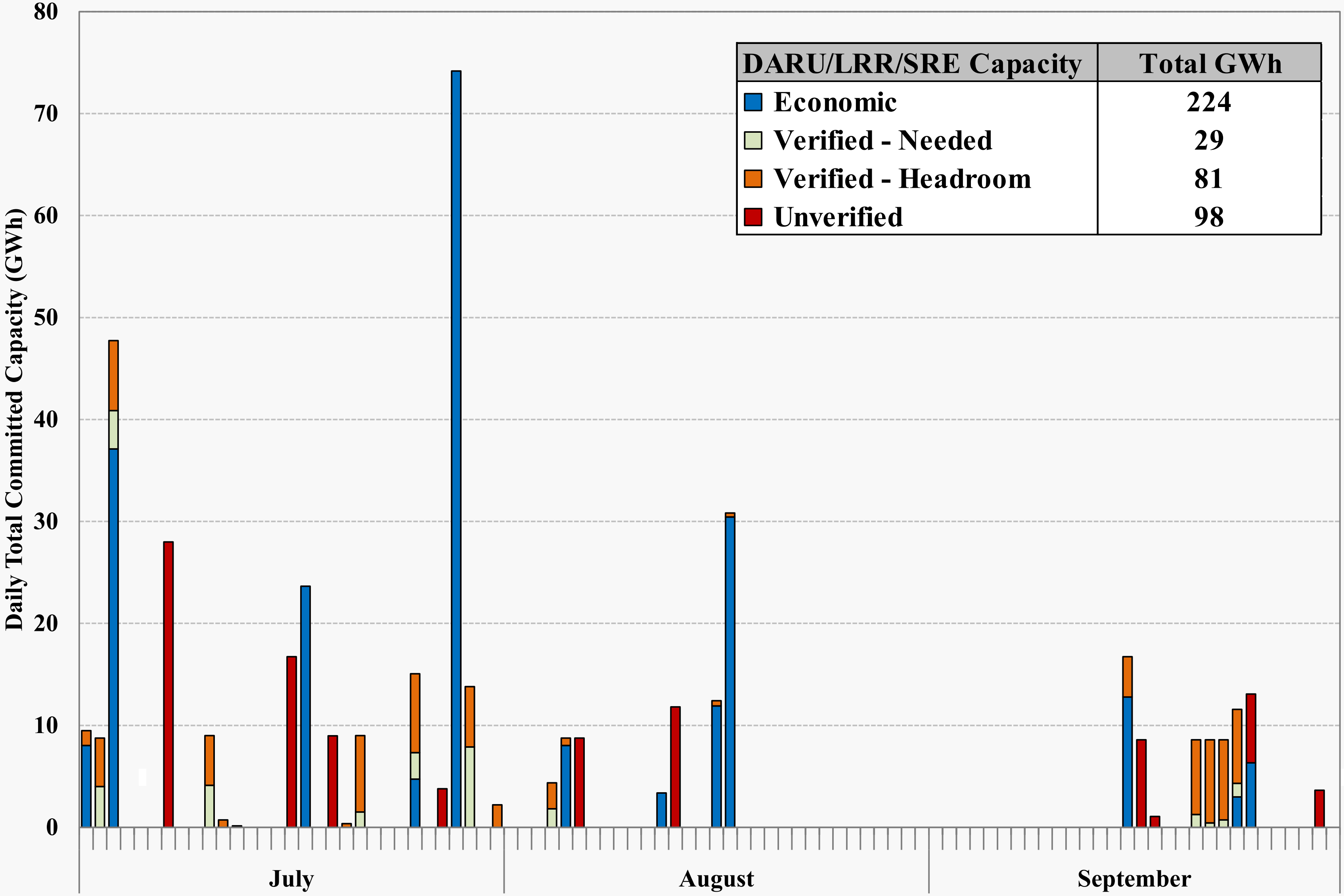
By Category and Region

Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2025 Q3	1.3%	0.6%	1.6%	2.9%
2025 Q2	0.6%	0.0%	4.2%	11.0%
2024 Q3	1.0%	0.3%	4.8%	0.5%



Notes: For chart description, see slides 115.

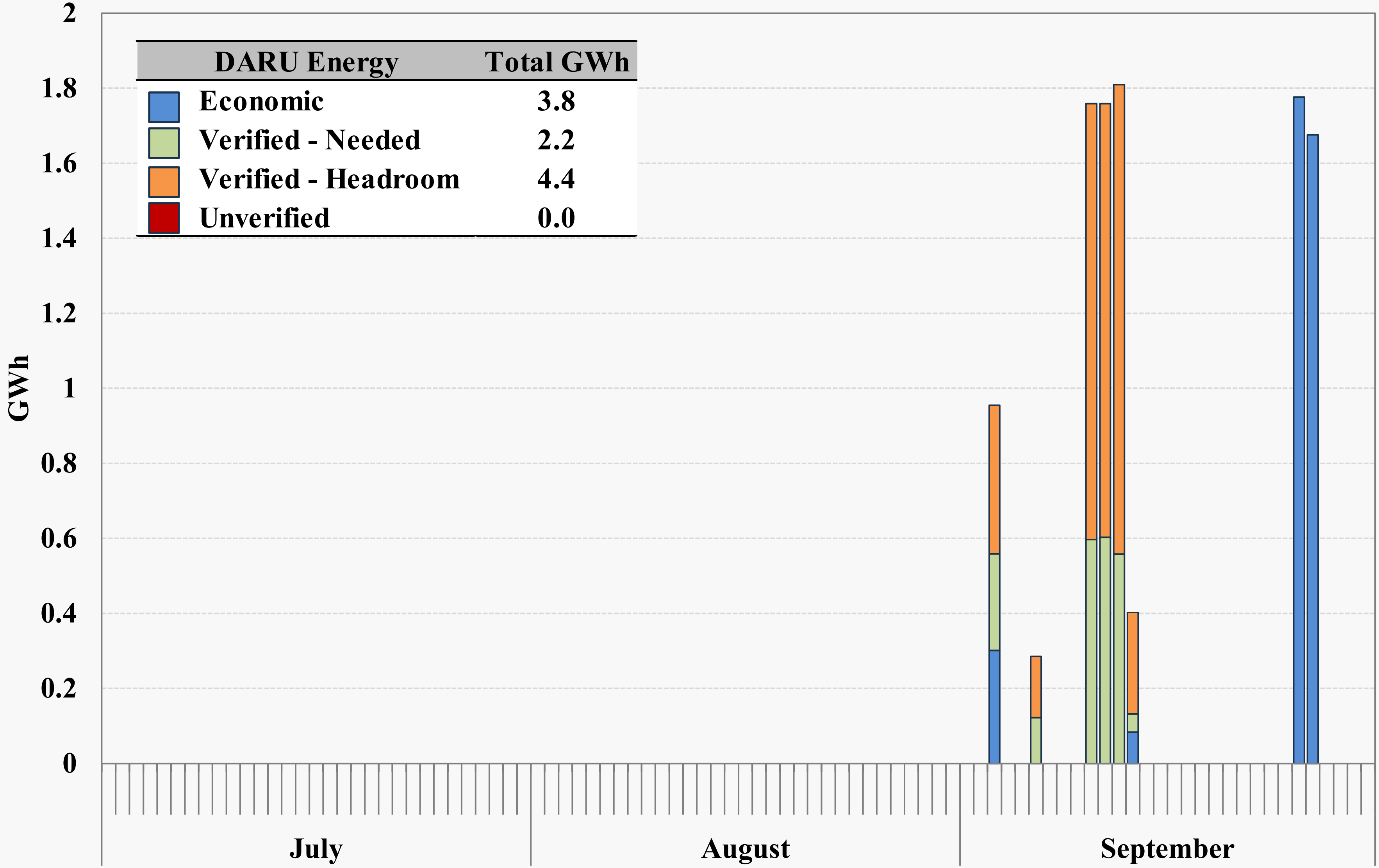
DARU/LRR/SRE Commitments in NYC: 2025 Q3



DARU/LRR/SRE Capacity	Total GWh
Economic	224
Verified - Needed	29
Verified - Headroom	81
Unverified	98

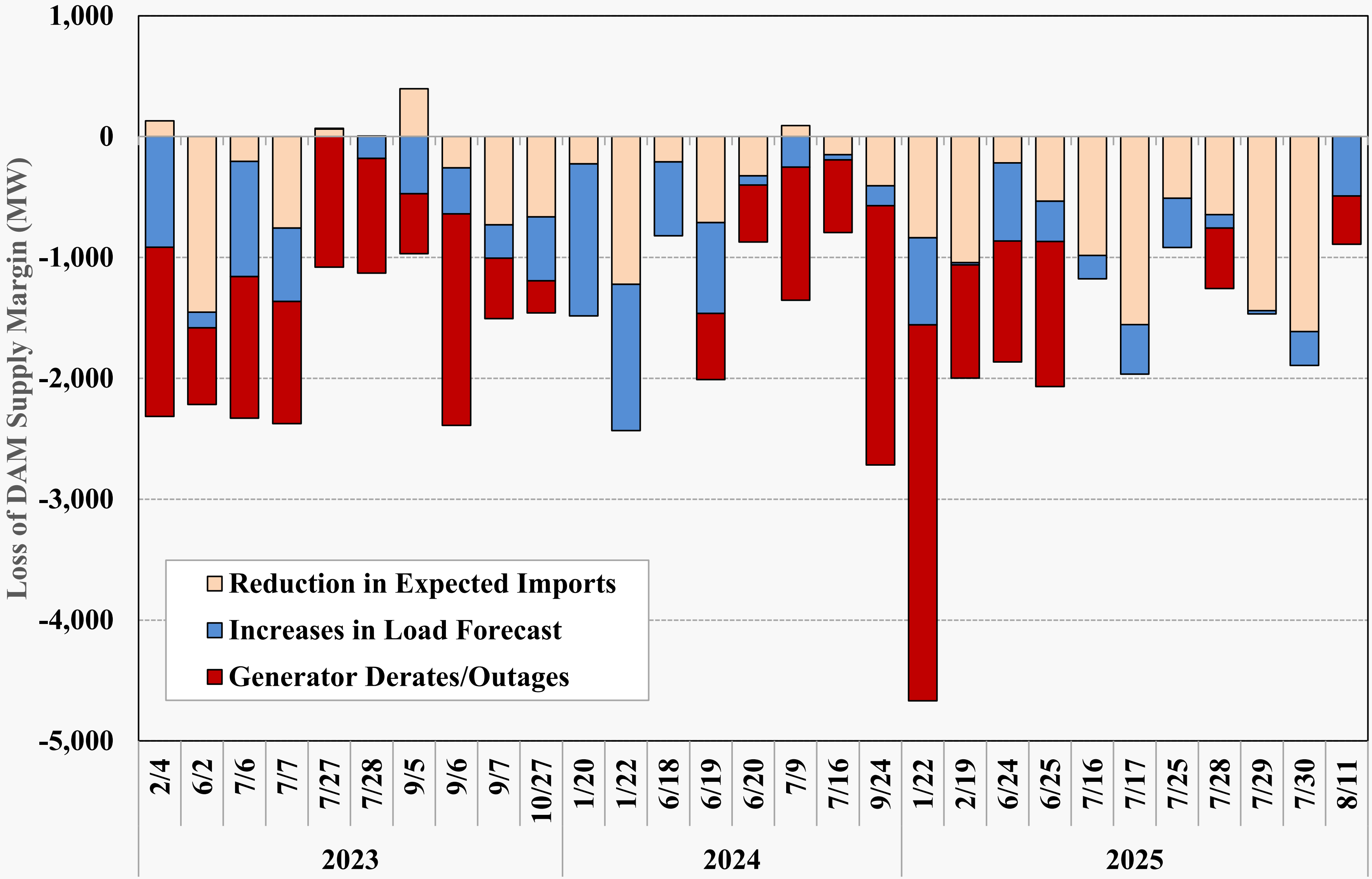
Notes: For chart description, see slide 116.

DARU Commitments in North Country: 2025 Q3



Notes: For chart description, see slide 116.

Key Drivers of SRE Commitments for Systemwide Capacity

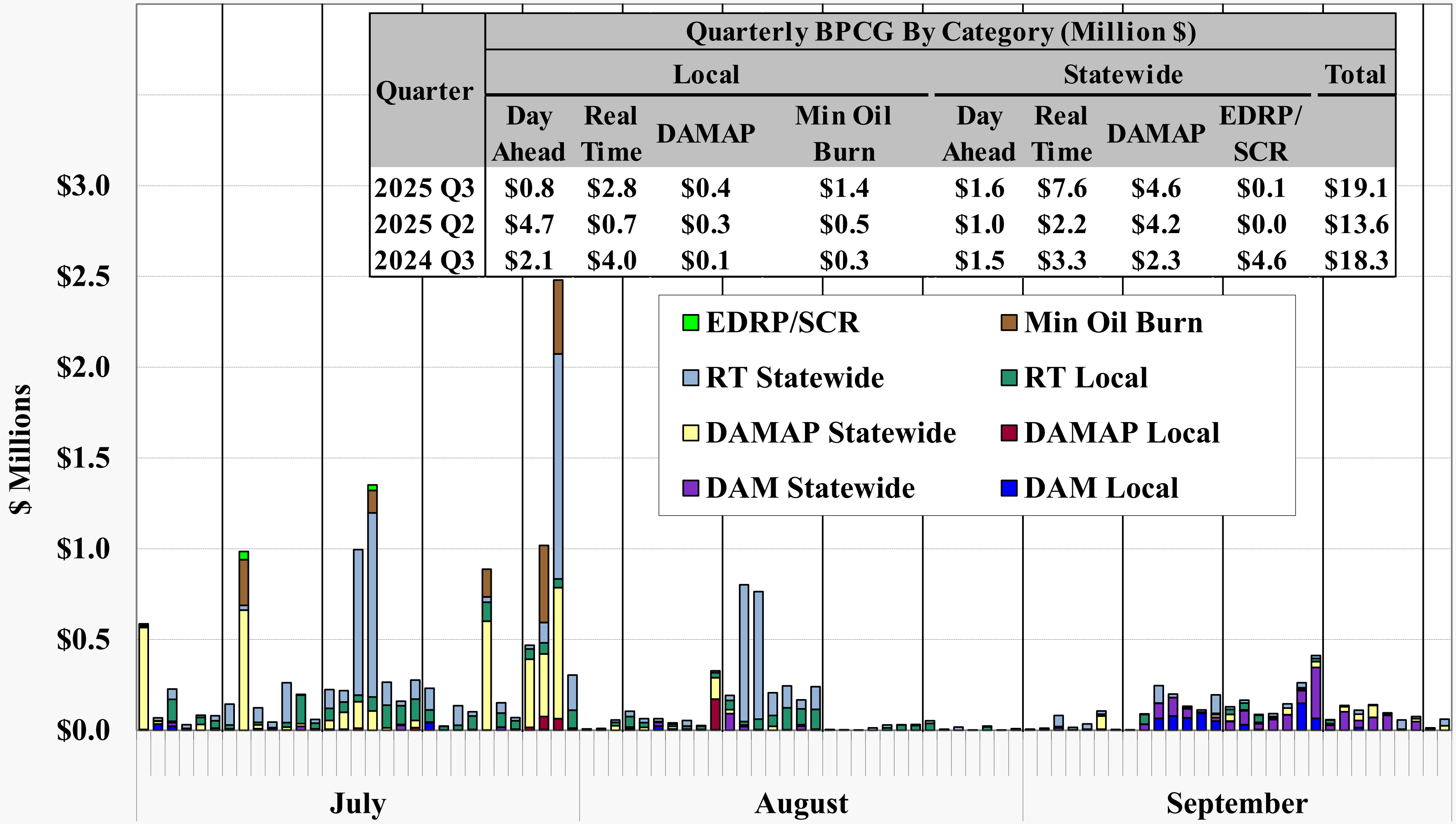


Notes: For chart description, see slide 117.

Uplift Costs from Guarantee Payments

Local and Non-Local by Category

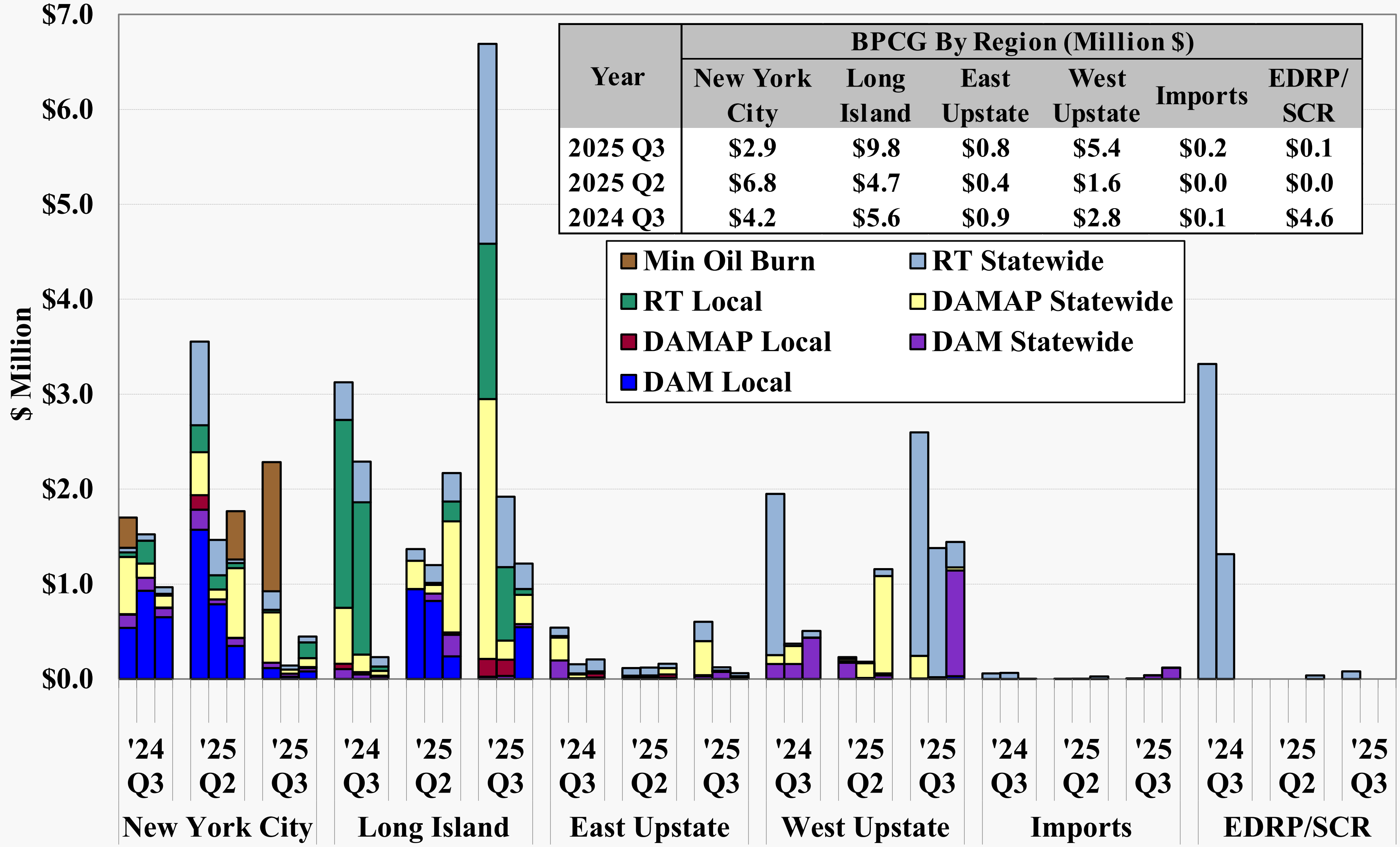
Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2025 Q3	$0.8	$2.8	$0.4	$1.4	$1.6	$7.6	$4.6	$0.1	$19.1
2025 Q2	$4.7	$0.7	$0.3	$0.5	$1.0	$2.2	$4.2	$0.0	$13.6
2024 Q3	$2.1	$4.0	$0.1	$0.3	$1.5	$3.3	$2.3	$4.6	$18.3



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 118.

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
2025 Q3	$2.9	$9.8	$0.8	$5.4	$0.2	$0.1
2025 Q2	$6.8	$4.7	$0.4	$1.6	$0.0	$0.0
2024 Q3	$4.2	$5.6	$0.9	$2.8	$0.1	$4.6

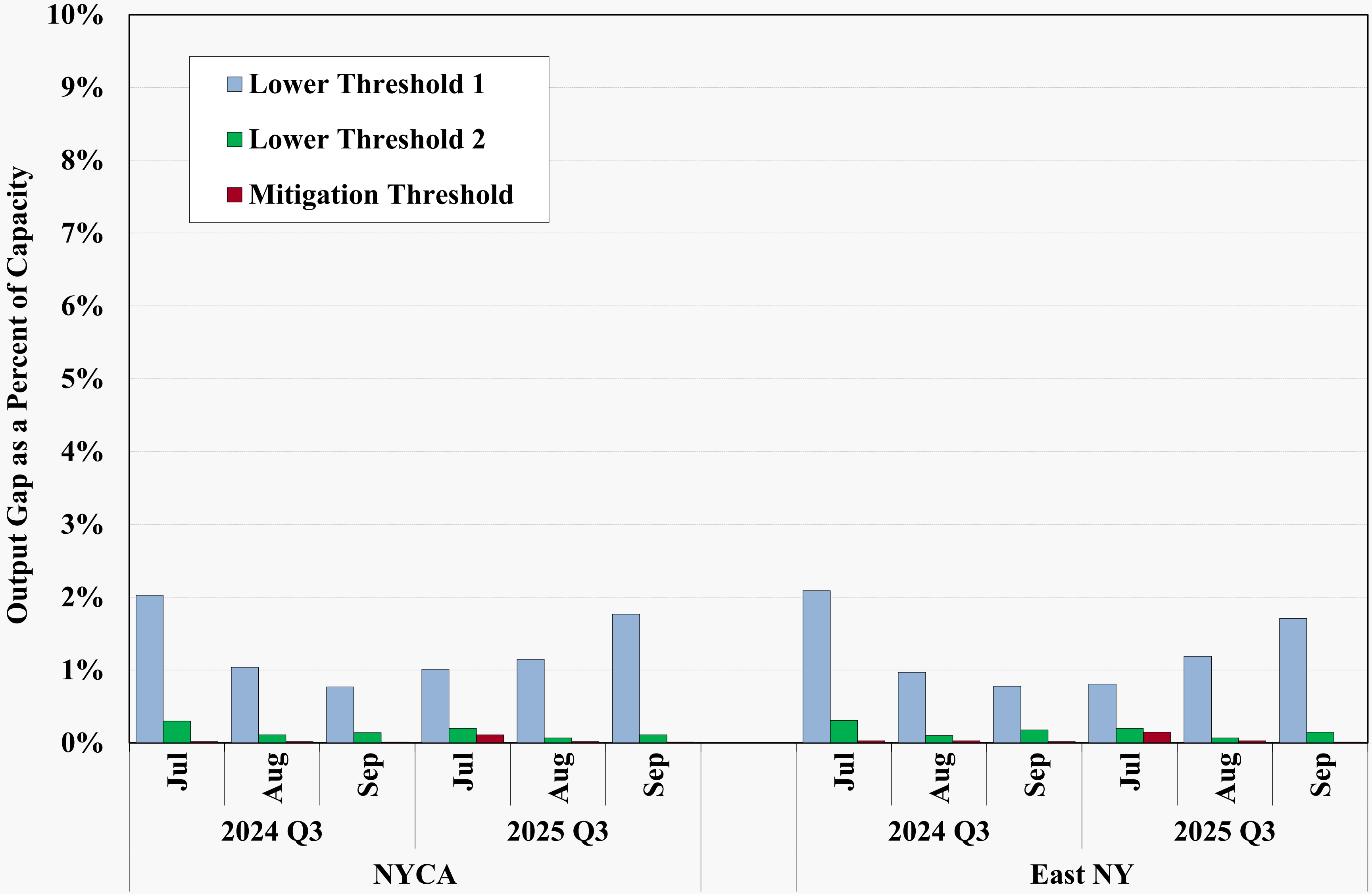
Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.

2. For chart description, see slide 118.

Charts:
Market Power and Mitigation

Output Gap by Month

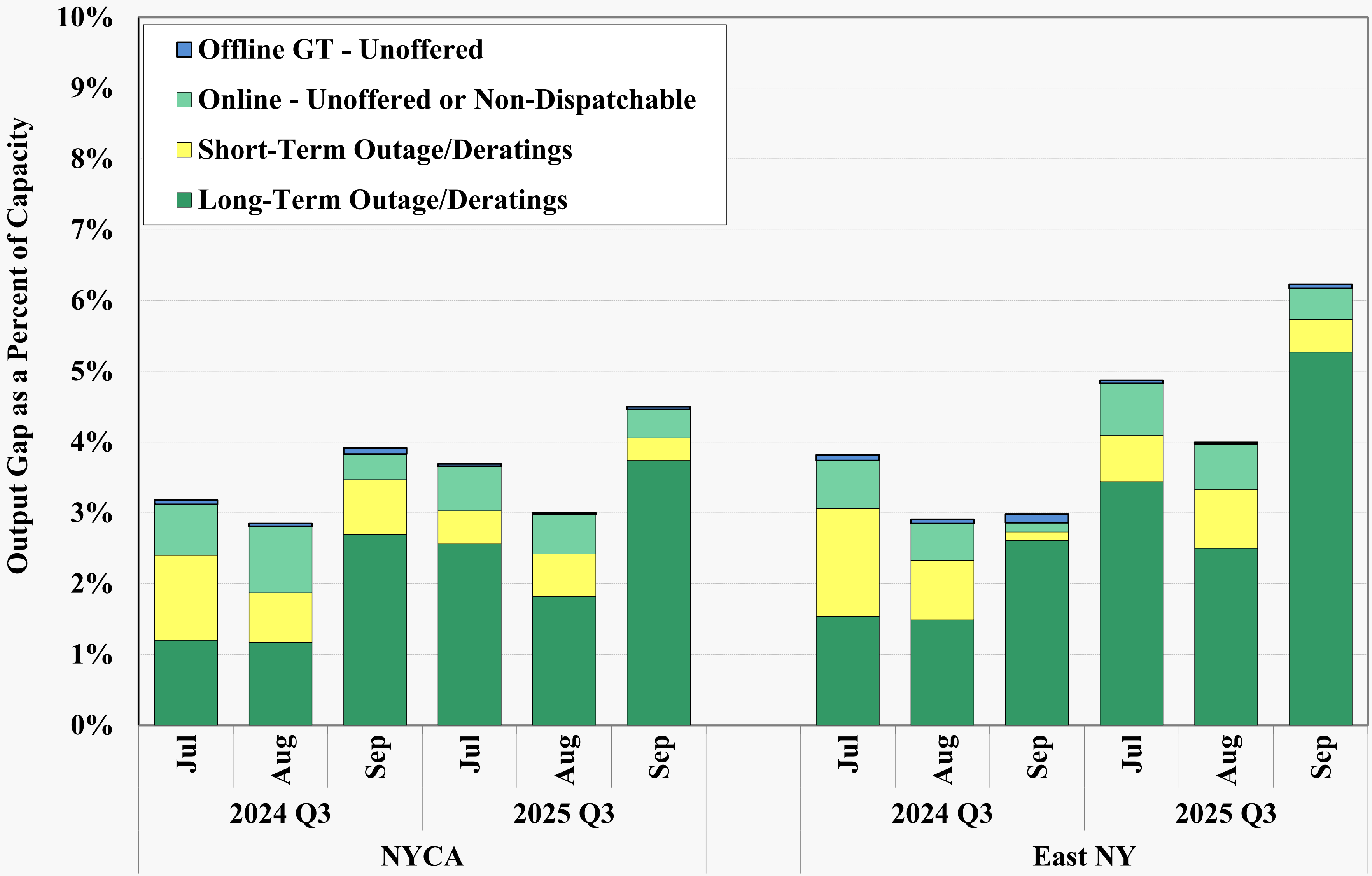
NYCA and East NY



For chart description, see slide 119.

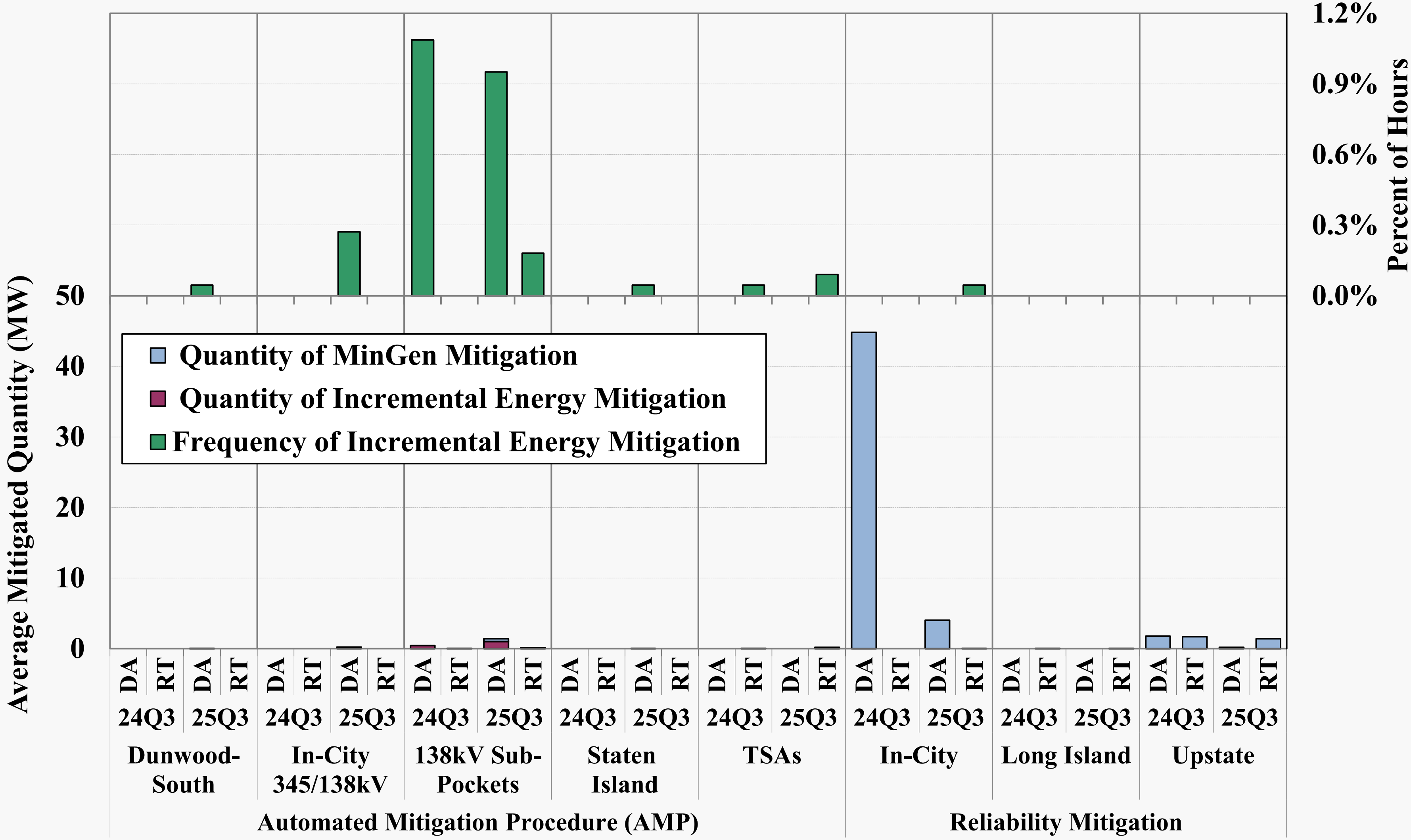
Unoffered Economic Capacity by Month

NYCA and East NY



For chart description, see slide 119.

Automated Market Power Mitigation

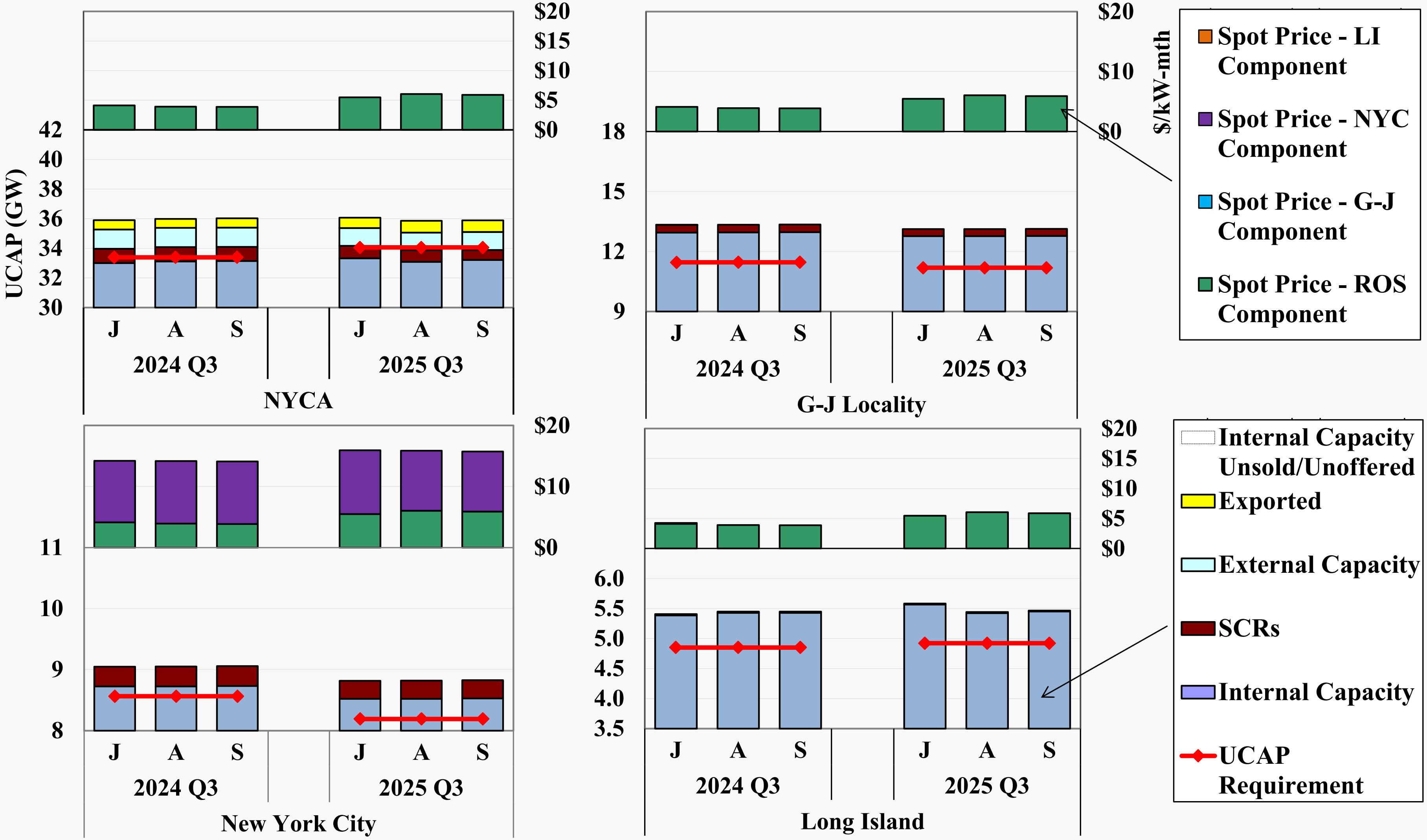


Notes: For chart description, see slide 120.

Charts:
Capacity Market

Spot Capacity Market Results

Monthly Results by Locality



Notes: For chart description, see slide 121.

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2025 Q3 ($/kW-Month)	$5.80	$15.84	$5.80	$5.80
% Change from 2024 Q3	**46%**	**12%**	**44%**	**46%**
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)				
Generation & UDR	**-34**	**-109**	**130**	**-186**
Entry (3)	25	0	0	0
Exit (3)	-199	-92	-43	-110
Other Capacity Changes (1)	141	-17	172	-76
Cleared Import (2)	**-94**			

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

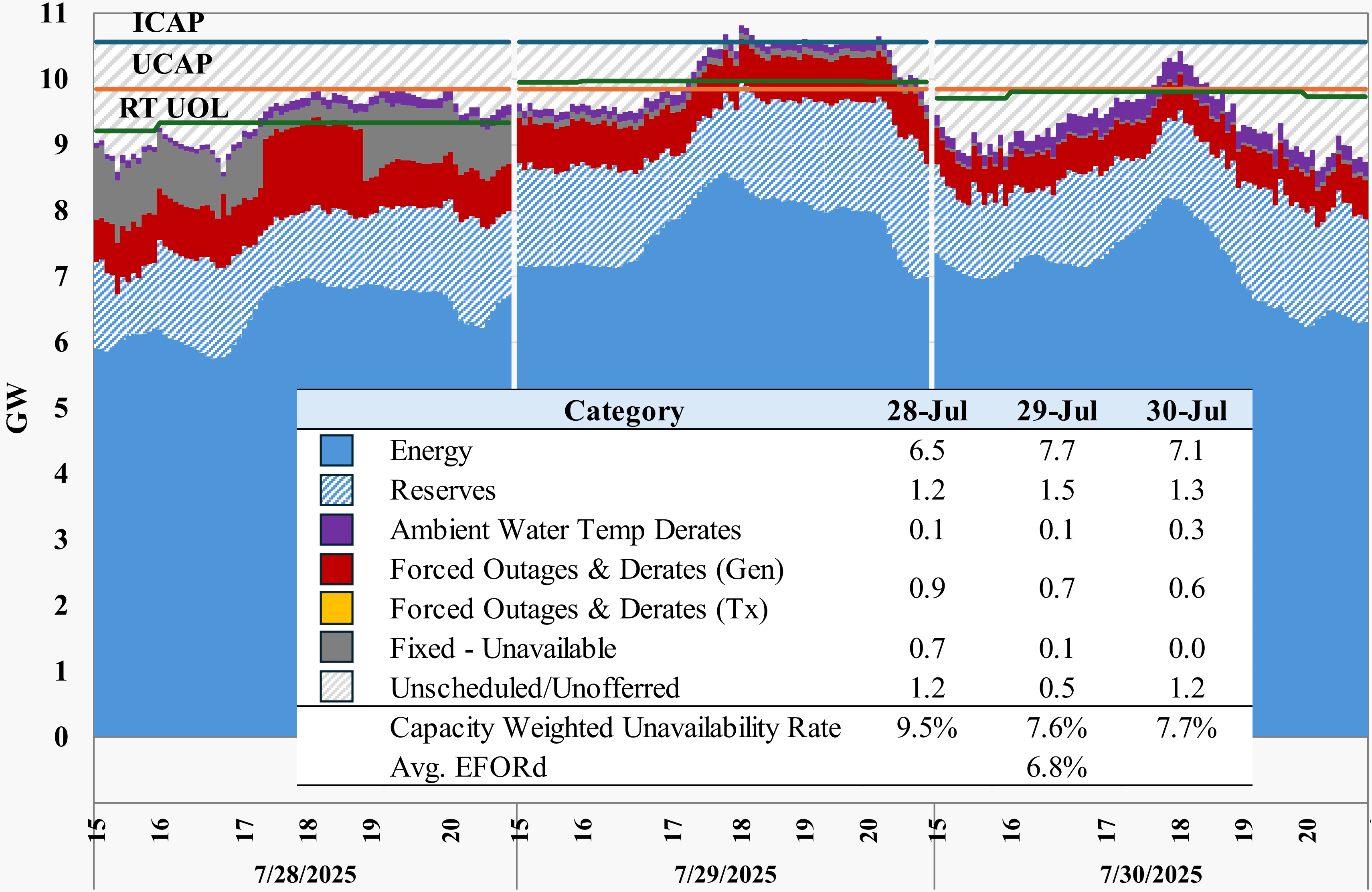
(2) Based on average of quarterly cleared quantity.

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

Notes: For chart description, see slide 121.

Availability Assessment – Fossil Steam Turbines

July 28-30, 2025

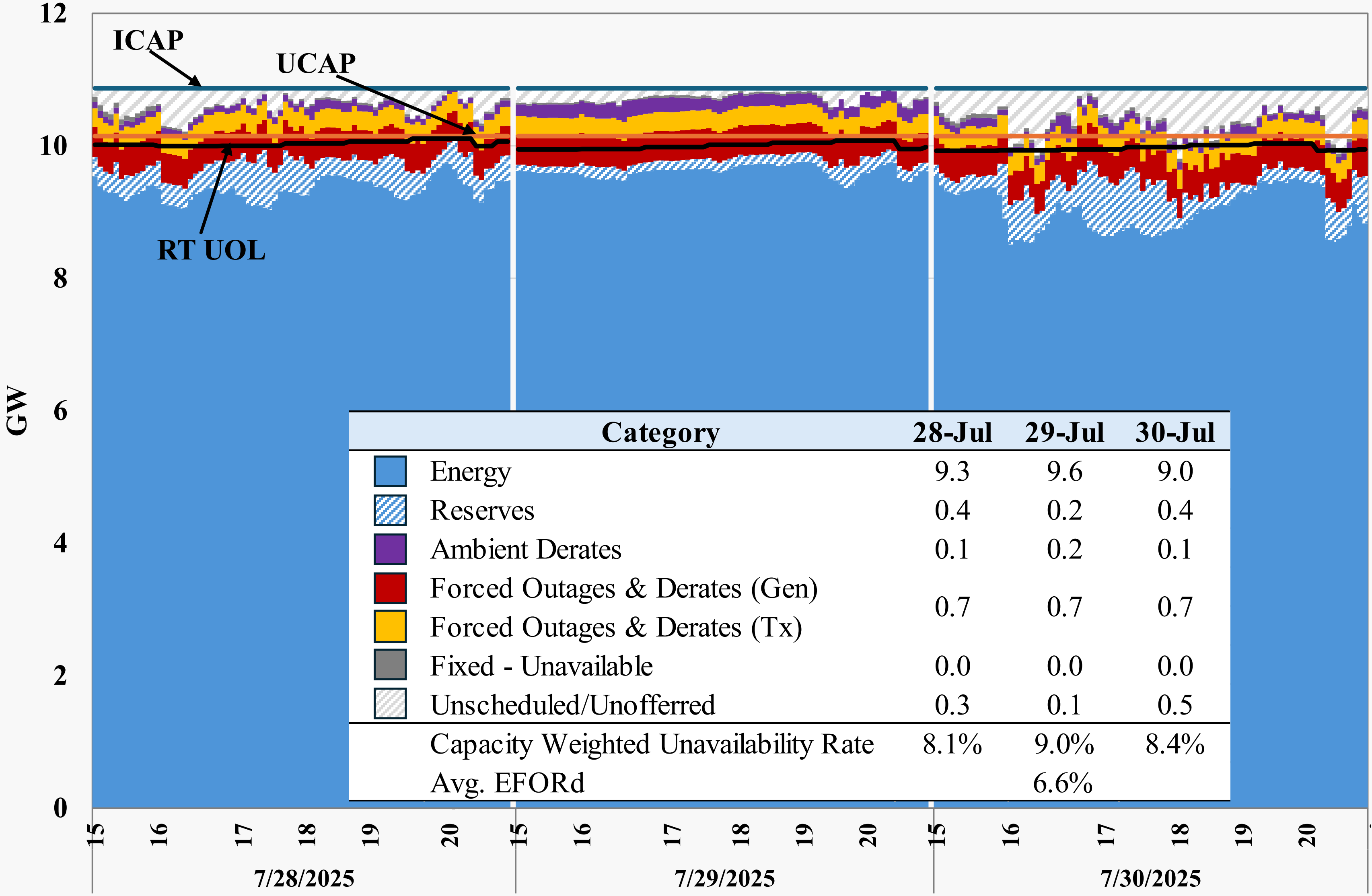


Category	28-Jul	29-Jul	30-Jul
Energy	6.5	7.7	7.1
Reserves	1.2	1.5	1.3
Ambient Water Temp Derates	0.1	0.1	0.3
Forced Outages & Derates (Gen) Forced Outages & Derates (Tx)	0.9	0.7	0.6
Fixed - Unavailable	0.7	0.1	0.0
Unscheduled/Unofferred	1.2	0.5	1.2
Capacity Weighted Unavailability Rate	9.5%	7.6%	7.7%
Avg. EFORd		6.8%	

Notes: For chart description, see slide 122.

Availability Assessment – Combined Cycles

July 28-30, 2025

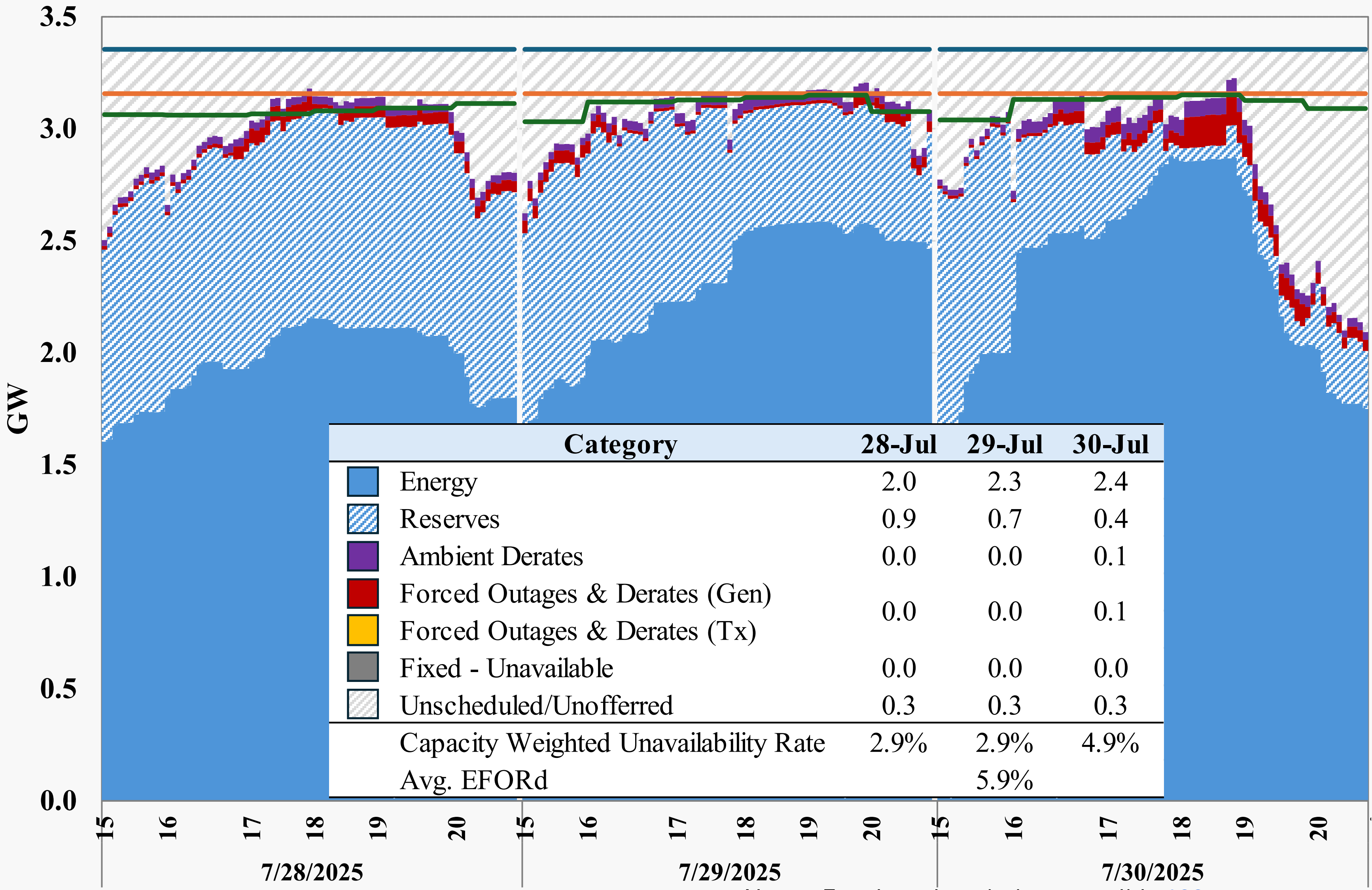


Category	28-Jul	29-Jul	30-Jul
Energy	9.3	9.6	9.0
Reserves	0.4	0.2	0.4
Ambient Derates	0.1	0.2	0.1
Forced Outages & Derates (Gen) / Forced Outages & Derates (Tx)	0.7	0.7	0.7
Fixed - Unavailable	0.0	0.0	0.0
Unscheduled/Unofferred	0.3	0.1	0.5
Capacity Weighted Unavailability Rate	8.1%	9.0%	8.4%
Avg. EFORd		6.6%	

Notes: For chart description, see slide 122.

Availability Assessment – Fossil Peaking Units

July 28-30, 2025

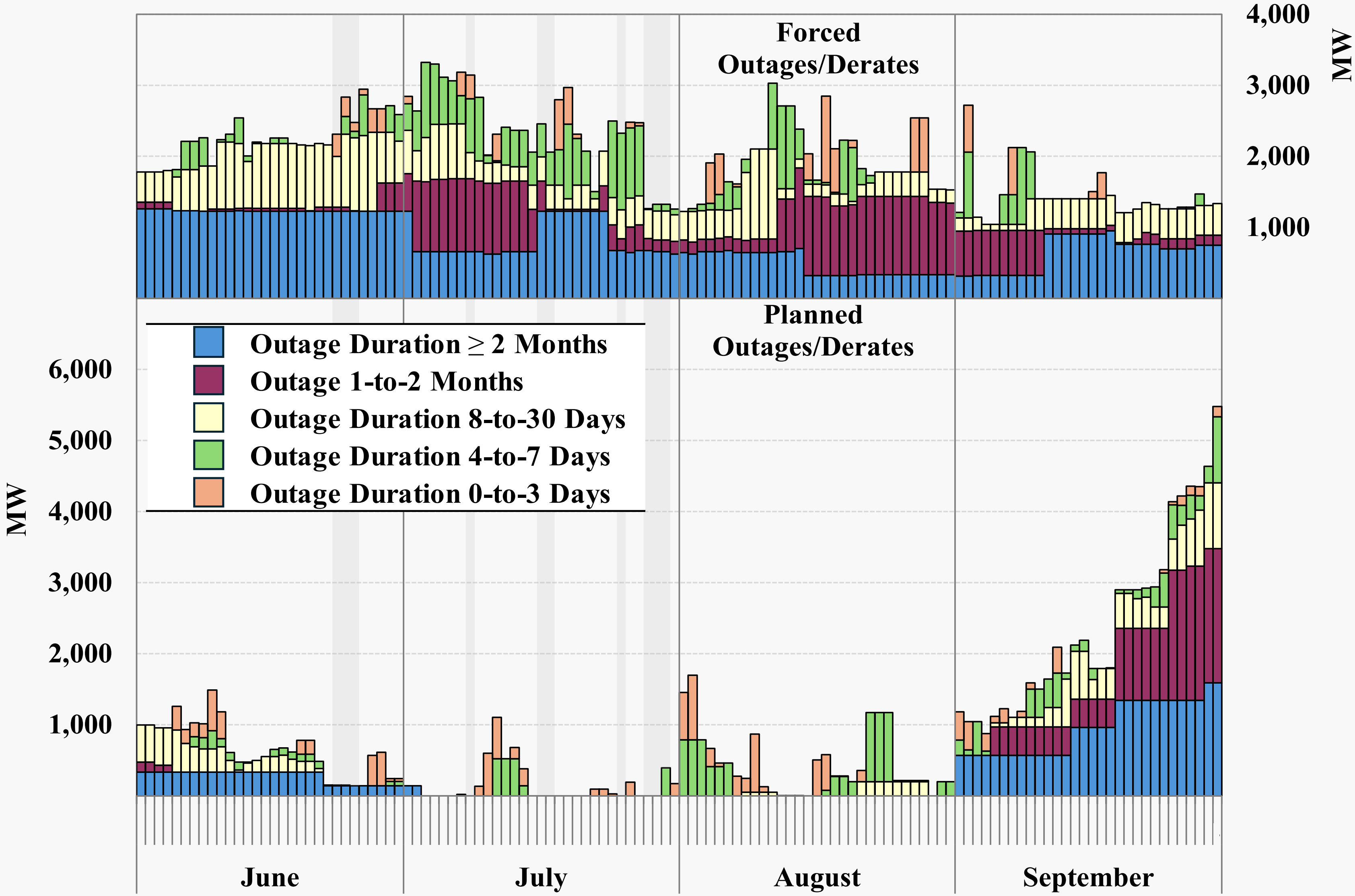


Category	28-Jul	29-Jul	30-Jul
Energy	2.0	2.3	2.4
Reserves	0.9	0.7	0.4
Ambient Derates	0.0	0.0	0.1
Forced Outages & Derates (Gen) Forced Outages & Derates (Tx)	0.0	0.0	0.1
Fixed - Unavailable	0.0	0.0	0.0
Unscheduled/Unofferred	0.3	0.3	0.3
Capacity Weighted Unavailability Rate	2.9%	2.9%	4.9%
Avg. EFORd		5.9%	

Notes: For chart description, see slide 122.

Outage Scheduling of Fossil Resources

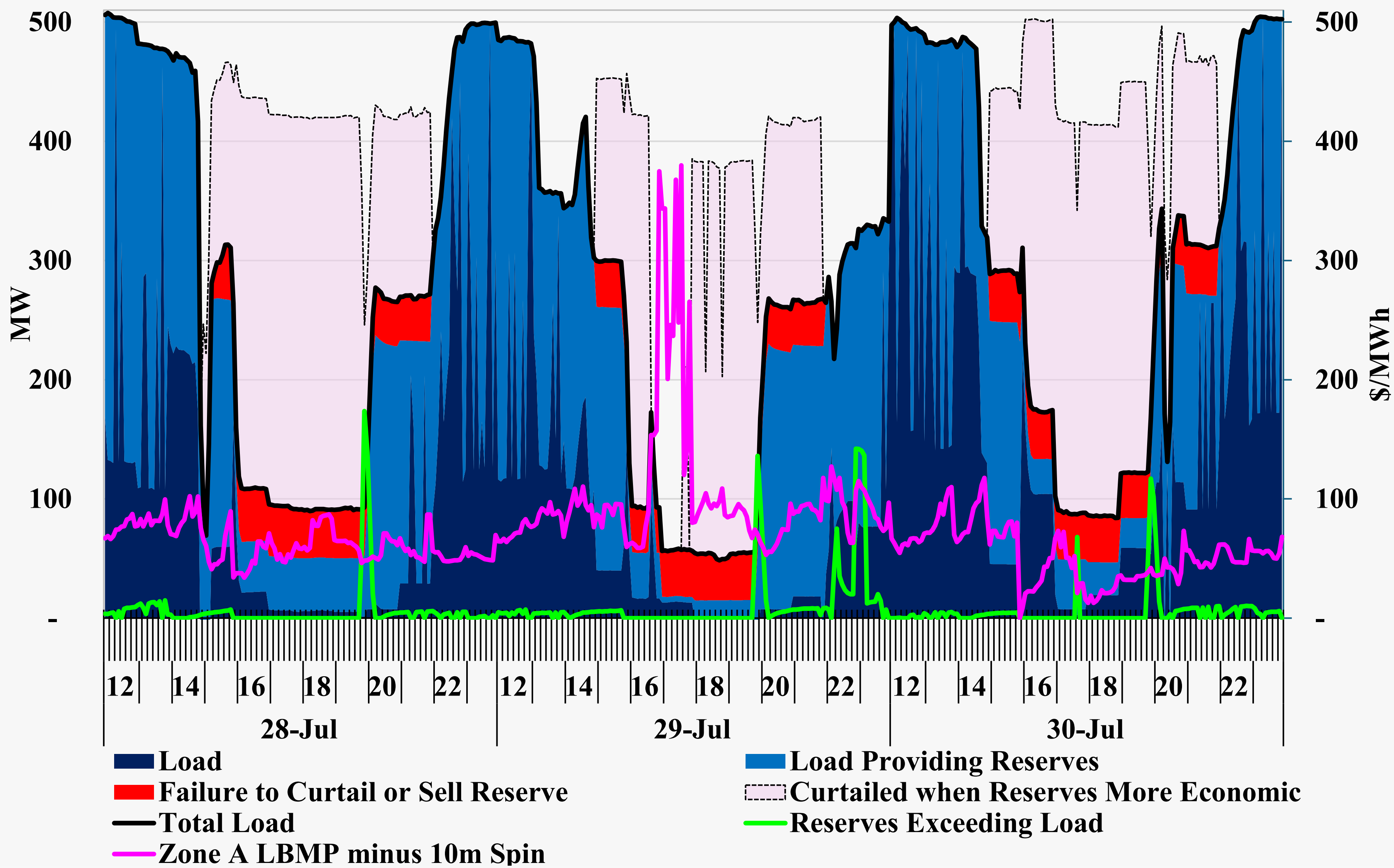
During Peak Hours – 2025 Q3



Notes: For chart description, see slide 123.

Large Curtailable Load Performance During Peak Load

July 28-30, Hours 12 to 23



Notes: For chart description, see slide 124.

Appendix: Chart Descriptions

All-in Price

- Slide 25 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 28 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 29 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 30-34 evaluate emissions from generators in the NYISO market.
  - Slide 30 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_X, and SO_2 .
  - Slides 31-32 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 33-34 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 33 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 39-41 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 40 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 42 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 43 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 44 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

POTOMAC ECONOMICS

- Slide 46 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 47 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 48 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 49 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 51 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 52 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 53 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 54 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

POTOMAC ECONOMICS

- Slide 55 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 57 and 58 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 59, 60, 61, and 63 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 59 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 60 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 61 and 63 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 64 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 65 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 66 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 66 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 67 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 68 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 70 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 69 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 71 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:
  - RPUs + 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 73 summarizes out-of-market commitment, which is one of the primary sources of guarantee payment uplift.
- Slide 73 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 and North Country

- Slides 74 and 75 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 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.
  - ***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*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

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- Slide 76 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 77 and 78 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 77 shows these seven categories on a daily basis during the quarter.
  - Slide 78 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 80 and 81 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

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- Slide 82 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 84 and 85 summarize market results and key drivers in the monthly spot capacity auctions.
  - Slide 84 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 85 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 86, 87, and 88 summarize performance of fossil fuel generators during the peak load window (HB 15-20) of the July Heat Wave (July 28-30).
  - Slide 86 shows performance of the fossil-fired steam turbines in the system.
  - Slide 87 shows performance of the combined cycle resources.
  - 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 on the high side of the generator step-up transformer.
  - Ambient Derates shows the amount of capacity believed to be unavailable due to ambient conditions.
  - Fixed Unavailable shows the amount of capacity unavailable in RT while the resource bid Self-Fixed.
  - Unscheduled/Unoffered shows the amount of capacity that was either unscheduled in DA and, therefore, unavailable in RT or not offered into the market without a reported outage/derate.
- 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 Ambient Derates.

Outage Scheduling of Fossil Resources

- Slide 89 shows the amount of fossil-fuel capacity scheduled out, either planned or unplanned, in the NYISO per each day of June through September 2025.
  - The top portion of the chart shows the amount of capacity listed as forced out or forced derated in the Day-ahead due to unplanned reasons.
    - "9300" outages (i.e., transmission outages making generation unavailable) are shown as forced.
  - The bottom portion of the chart shows the amount of capacity scheduled out and categorized as a planned outage in the NYISO systems.
    - Planned outages in the NYISO system typically map to Planned or Maintenance Outages in the GADS system.
  - The gray-shaded areas denote days where peak load surpassed 28 GW.
- Outages are further classified by forecasted duration at the time of the Day-Ahead Market.
  - 0-to-3 Days: Those outages where the duration of the outage was expected to last no more than 3 days (72 hours).
  - 4-to-7 Days: Those outages where the duration of the outage was expected to last more than 3 days (72 hours) but no more than 7 days.
  - 8-to-30 Days: Those outages where the duration of the outage was expected to last more than 7 days but no more than 30 days.
  - 1-to-2 Months: Those outages where the duration of the outage was expected to last more than 30 days but no more than 60 days.
  - ≥ 2 Months: Those outages where the duration of the outage was expected to last more than 60 days.

Performance of Large Curtailable Loads

- Slide 90 describes the performance of large loads (including DSASP, DER, and BTM:NG resources that sell capacity) in the days including, before and after the July peak load hour (July 28 through 30)
- 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:
  - Failure to Curtail or Sell Reserves: SCR/DSASP loads that did not curtail in response to SCR call and were also unable to sell reserves due to being placed in OOM status as SCRs
  - Curtailed When Reserves More Economic: Loads that curtailed due to SCR and/or TO Demand Respond program participation but could have more economically sold reserves
  - Reserves Exceeding Load: Loads with reserve schedules exceeding their actual real time load