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

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Executive Summary

- NYISO energy markets performed competitively in the first quarter of 2025.
- All-in prices ranged from $75/MWh in the West Zone to $128/MWh in New York City, up 59 to 119 percent across all regions from a year ago. (slide 8)
  - Energy prices rose by 120 to 158 percent across the system, primarily due to higher gas prices which rose by 67 to 188 percent.
    - Higher load levels were also a key contributor - average load rose by 4.5 percent and peak load increased by 3.4 percent.
  - In contrast, capacity costs fell by 13 to 37 percent across the system, with the largest decrease in New York City, primarily due to lower demand curve reference points, reduced LCRs, and lower peak load forecast. (slide 21)
- Congestion costs rose significantly from the previous year, especially along the Central-East interface, within New York City, and on the primary PJM-NYISO interface. (slides 9 - 10)
  - Key contributing factors include high gas prices, lengthy major transmission outages in New York City, and the need to secure upstate transmission for a large generator contingency.

Market Highlights

Executive Summary

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- OOM actions were used frequently to maintain reliability. (slides 12-14)
  - From late-December to February 1, NYISO reduced the primary PJM interface by up to 700 MW to secure the Watercure-to-Oakdale 345kV line for a large generation contingency, resulting in $26 million in congestion shortfalls.
  - From mid-February to late-April, OOM actions were used to secure NYC transmission for unmodeled ring bus configurations in the Greenwood pocket, leading to ~$8 million in BPCG uplift and ~$4 of balancing congestion residuals.
  - It would be beneficial for NYISO to incorporate these constraints into the market models, which leads to an allocation of costs more consistent with cost causation principles and provides more efficient incentives to market participants.
- $34 million of DAM congestion surpluses and $21 million of DAM shortfalls were socialized to all TOs in proportion to their TCC auction revenues. (slide 11)
  - Surpluses were largely generated by the new AC transmission projects and reduced deliveries on the ConEd-LIPA wheel, while shortfalls were largely driven by the limits on PJM imports to secure the Watercure-Oakdale line.
  - We have recommended revising the allocation methodology based on incremental transfer capability scheduled in the DAM. (Rec #2023-1)

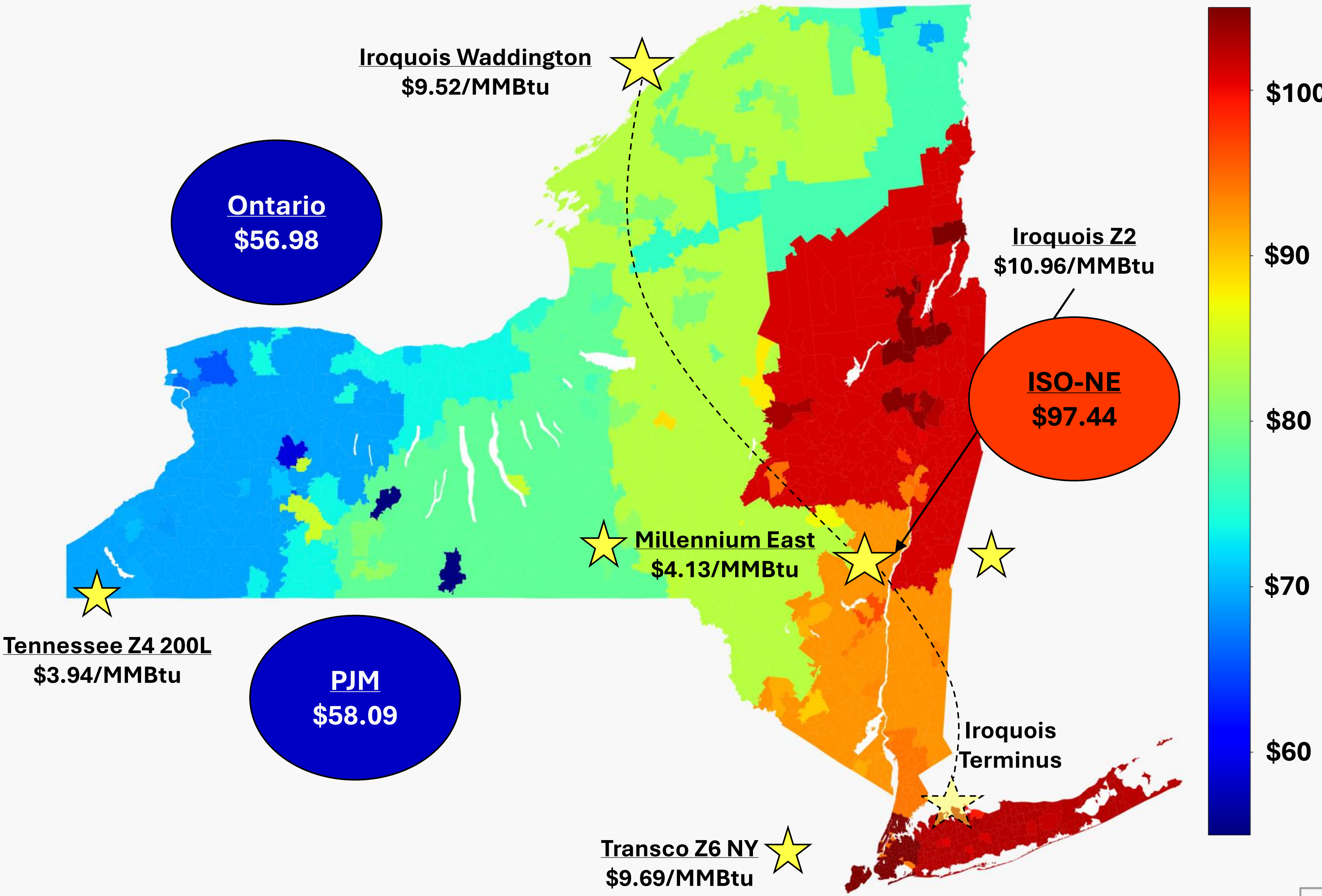
Market Highlights

Executive Summary

- Wind curtailments increased significantly, totaling 75 GWh and including 27 GWh from manual instructions for: (a) unmodeled transmission constraints, or (b) after units did not receive/respond to initial economic curtailment instructions. (slide 20)
- During the coldest winter period (January 20–24), nearly 1.75 GW of oil-capable generation was on planned outages. (slide 22)
  - As NYISO implements firm-fuel capacity accreditation in 2026/27 and designs a seasonal capacity market, it will be important to consider reasonable limits on planned outage scheduling under peak conditions and incentives for availability.
- Supplemental commitments to satisfy reserve requirements occurred on 75 days in the North Country load pocket and 28 days in NYC load pockets. (slide 12)
  - In NYC, we found that 45 percent of the capacity could not be "verified" as needed for reliability based on information made available to NYISO. (slide 19)
  - Of the portion of NYC commitments that we "verified", ~83 percent was surplus headroom or committed to satisfy minimum runtime requirements.
    - We have recommended modeling the underlying N-1-1 and N-1-1-0 requirements as local reserve requirements (Rec #2024-1), which would help attract smaller dispatchable resources (e.g., batteries and DERs) to help satisfy these needs through the market.

Market Highlights

System Price Diagram



Market Highlights

Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the first quarter of 2025.
  - The amount of output gap (slide 81) and unoffered economic capacity (slide 82) remained reasonably consistent with competitive market expectations.
- All-in prices ranged from $75/MWh in the West Zone to $128/MWh in New York City, up 59 to 119 percent across all regions from a year ago. (slide 24)
  - The increases were driven largely by higher energy prices, which rose by 120 to 158 percent across the system (slides 35-36), primarily due to higher gas prices.
    - Gas prices rose by 67 percent in most of West NY and up to 188 percent in East NY, driven by cold weather in January and February. (slide 26)
      - ✓ Gas prices exceeded $10/MMBtu in East NY on 55 days, up from 10 days in 2024 Q1. Prices spiked to roughly $94/MMBtu over the President's Day weekend.
    - Load levels were up significantly as average load rose 4.5 percent and peak load increased 3.4 percent. (slide 25)
      - ✓ Load peaked at 23.5 GW on January 21 and 22 (after all-zone SCR/EDRP calls on both days). Reconstituted loads exceeded the 2024/25 winter baseline forecast.
  - In contrast, capacity costs fell by 13 to 37 percent across the system, with the largest decrease in New York City. (see slide 20 for further discussion).

Market Highlights

Congestion Patterns, Revenues, and Shortfalls

- Day-ahead congestion revenues totaled $363 million in the first quarter of 2025, up 375 percent from a year ago (slide 59). Key drivers of the increase include:
  - Higher natural gas prices and regional gas spreads in January and February, coinciding with 95 percent of total quarterly congestion.
  - Prolonged transmission outages of the Gowanus-Greenwood 138 kV lines, which significantly increased congestion into the Greenwood load pocket in NYC.
  - Operator-imposed limit reductions of several hundred MWs on the primary PJM interface in January to secure the Watercure-Oakdale 345 kV line led to congestion on the PJM interface.
- Congestion across the Central-East interface accounted for the largest share (32 percent) of day-ahead congestion in 2025 Q1.
  - Congestion revenues increased by 217 percent from a year ago, driven primarily by elevated regional gas spreads.
  - Congestion frequency rose to roughly 44 percent of all hours, though this remains relatively low compared to levels observed prior to the public policy transmission upgrades.

Market Highlights

Congestion Patterns, Revenues, and Shortfalls (cont.)

- NYC facilities accounted for the second largest share (30%) of DAM congestion.
  - New York City congestion increased ~450 percent year-over-year.
  - In addition to higher gas prices, transmission outages were a major contributor.
    - The Gowanus-Greenwood 138 kV 42231 line was out of service throughout the quarter, and the parallel 42232 line was OOS starting in mid-February. As a result:
      - ✓ 75 percent of NYC congestion occurred on adjacent facilities – specifically the Goethals-Gowanus 345 kV line (38%) and the Greenwood-Vernon 138 kV line (37%)
      - ✓ Over $30 million in congestion shortfalls were incurred. (slide 61)
    - The situation was further exacerbated by fuel oil inventory restrictions affecting the few non-gas generators within the constrained load pocket.
- External interfaces accounted for another 26 percent of DAM congestion.
  - Elevated regional gas spreads drove substantial energy flows along the typical winter path, from PJM to NYISO to ISO-NE, leading to high congestion on those interfaces.
  - In addition, operators imposed several hundred MWs of limit reductions on the primary PJM interface in January to manage a specific contingency on the Watercure-Oakdale 345 kV line, further exacerbating congestion on the PJM interface.

Market Highlights

Allocation of DAM Congestion Residuals

- Day-ahead congestion shortfalls and surpluses ("residuals") occur when day-ahead network capability differs from the modeled capability in the TCC auctions.
- NYISO allocates DAM congestion residuals to NYTOs using a two-stage process:
  - First, congestion residuals resulted from Qualifying facility changes (e.g., outages, return-to-services, and uprate/derate) are allocated to responsible TOs on a "cost causation" basis. (see OATT 20.2.4 Formula N-5 through N-14)
  - Second, remaining congestion residuals ("Net Congestion Rents") are socialized to all TOs in proportion to their TCC revenues rather than DAM congestion patterns. (see OATT 20.2.5 Formula N-15)
- In this quarter, ~$52M of shortfalls were allocated to responsible TOs on a cost causation basis, while ~$14M of net surpluses were socialized to all TOs.
  - Among socialized residuals, we estimate that: (slides 61 - 62)
    - $20.9 million of **shortfalls** accrued on the primary PJM interface;
    - $28.6 million of **surpluses** were associated with transmission upgrades from the Segment A & B Public Policy projects.
    - $5.3 million of **surpluses** resulted from schedule changes on 901/903 PARs.
  - We have recommended the NYISO revise the residual allocation method based on incremental transfer capability scheduled in the DAM. (see Rec. #2023-1)

Market Highlights

OOM Actions to Manage Network Reliability

- OOM commitments to satisfy N-1-1 and N-1-1-0 requirements occurred on 75 days in the North Country load pocket and 28 days in NYC load pockets. (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 commitments to address high voltage risks during light load conditions occurred on 19 days on Long Island. (slide 65)
  - The frequency of OOM commitment for high voltage has increased since 2024 because of changing operating practices by the local TO. Previously, high voltage conditions were more frequently addressed by taking lines out of service (to increase reactive power losses).
  - Large steam turbines were supplementally committed for this need, which reduced LBMPs and led to BPCG uplift.

Market Highlights

OOM Actions to Manage Network Reliability (cont.)

- Operators imposed several hundred MWs of limit reductions on the primary PJM interface throughout January to manage a large generation contingency on the Watercure-Oakdale 345 kV line. (slide 65)
  - Starting in late-December, NYISO identified a large generation contingency for the Watercure-Oakdale 345 kV line, which was not represented in the DAM and RT market models.
  - To manage this constraint, NYISO imposed limit reductions of up to 700 MW on the primary PJM interface, which remained in effect until February 1, when an enhanced operational procedure was implemented to mitigate the security risk.
  - These OOM actions resulted in total congestion shortfalls of $26 million in the day-ahead and real-time markets over the 40-day period, which were uplifted to ratepayers rather than being allocated to the responsible party. (slides 61, 63)
- When N-1 transmission constraints for generation contingencies are secured in the DAM and RT market models and the TCC auctions, congestion costs are allocated on a cost causation basis through nodal prices.
  - This provides efficient incentives for generators to help mitigate the issue.

Market Highlights

OOM Actions to Manage Network Reliability (cont.)

- OOM actions occurred on 47 days in the first quarter of 2025 to manage transmission constraints in New York City. (slide 65)
  - In mid-February, when both Gowanus-Greenwood 138 kV lines were out of service, a circuit breaker contingency within the Greenwood ring bus configuration emerged as the most severe contingency for adjacent facilities.
    - This contingency shifted load within the Greenwood load pocket in a manner not represented in the NYISO market model.
  - To manage this constraint, peaking resources within the load pocket were OOM committed – beginning in the real-time market in mid-February and extending to the day-ahead market starting in early March.
  - These OOM actions resulted in nearly $8 million in BPCG uplift payments.
    - This includes BPCG payments in April, as the OOM commitments continued until late April, when one of the Gowanus-Greenwood 138 kV lines returned to service.
    - The DAM BPCG uplift (~$1.7M) was allocated to ***local*** load, while the remaining RT BPCG was socialized across ***system-wide*** load.
  - It would be beneficial for NYISO to enhance modeling of ring bus configurations in the NYISO market models.

Market Highlights

Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $30 million, up 297 percent year-over-year, driven primarily by elevated natural gas prices. (slide 78)
- New York City accounted for the largest share (57 percent).
  - Nearly $5 million was paid to generators committed for N-1-1-0 reliability. (slide 75)
  - $6 million was paid to units OOM dispatched to manage congestion into the Greenwood pocket for contingencies not modeled in the RT market model during Gowanus-Greenwood 138 kV line outages. (slide 14)
  - Most of the remaining uplift was attributable to OOM actions by operators to manage fuel oil inventories in constrained pockets on cold days.
- Long Island accrued $6 million (or 21 percent) of BPCG uplift this quarter.
  - DAMAP payments accounted for $4 million largely due to an inconsistency between the scheduling and pricing of reserves—reserve clearing prices do not account for the costs of satisfying the Long Island reserve requirements. We have recommended NYISO address this inconsistency. (see Rec. #2019-1)
- West upstate accounted for $5.5 million of BPCG uplift, 85 percent of which was paid to units OOM committed for North Country reliability.

Market Highlights

Regulation Market Performance

- A single movement-to-capacity ratio is used to formulate composite offer prices for all resources when scheduled for providing regulation.

  Composite offer price = *capacity offer price* + *movement ratio* * *movement offer price*

- However, resources are deployed according to their actual ramp capability and compensated based on instructed movement and actual performance.
  - Resources exhibited a wide range of movement-to-capacity ratios (slide 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 in May 2025.
    - Nonetheless, using a single movement-to-capacity ratio for all units significantly underestimates the costs of fast-ramping resources in the scheduling process, which leads to inefficient scheduling and market incentives.
      - ✓ This has led to relatively high uplift (e.g., uplift $/movement MW of up to 150 percent of movement clearing price) for some fast-ramping resources. Such resources have incentives to raise their movement offers above marginal cost.
      - ✓ An enhanced regulation scheduling and pricing model would be needed to address this inefficiency.

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 Q1, LBMPs were below the GTs' as-bid costs in approximately 32 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 $15 to $71 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 510 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 75)
  - 29 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 17 percent of total verified MWh was needed for the identified requirement, while the remaining 83 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).
  - 45 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

Curtailments of Wind Generation

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- More than 28 GWh of curtailment resulted from manual instructions issued by NYISO or the local TO. (Slide 72) Manual curtailments were used for:
  - Unmodeled transmission constraints, or
  - When resources did not receive/respond to economic curtailment instructions.
- *Unmodeled transmission constraints* – Manual curtailments were used frequently in January to secure the Watercure-Oakdale 345 kV line, which was not secured in the RT market model.
- *Generators not receiving/responding to instructions* – Most of the manual curtailments this quarter were attributable to resources that did not reduce output following initial economic curtailment instructions.
  - In many of these instances, TO-controlled communications equipment was not properly maintained and failed to automatically transmit curtailment signals from NYISO to the plant's control center.
  - To address instances of failure of generator equipment, we have recommended that NYISO implement stronger penalties when units with negative incremental cost fail to comply with curtailment instructions. (See Recommendation #2023-3)

Market Highlights

Capacity Market Outcomes

- Spot capacity prices averaged $8.12/kW-month in NYC and $2.59/kW-month elsewhere. (slides 85-86)
  - Spot prices declined across all regions – falling by 36 percent in NYC and by 20 to 21 percent elsewhere.
    - These declines were primarily driven by lower reference points, which reflect higher net energy and ancillary service revenues in recent years.
  - The reduction in NYC prices was further influenced by a 204 MW reduction in the ICAP requirement, due to a lower load forecast and a 1.3 percent decrease in the LCR.
  - LI and G-J Locality prices were consistent with ROS prices, reflecting sufficient supply margin in these local areas.
  - Several other factors mitigated the ROS price drop from the lower reference point:
    - An increase in the IRM from 120 to 122 percent;
    - A reduction of approximately 240 MW in internal generation supply; and
    - A decline of 125 MW in average capacity imports.
      - ✓ The system was a net exporter of capacity to Quebec during January and February.

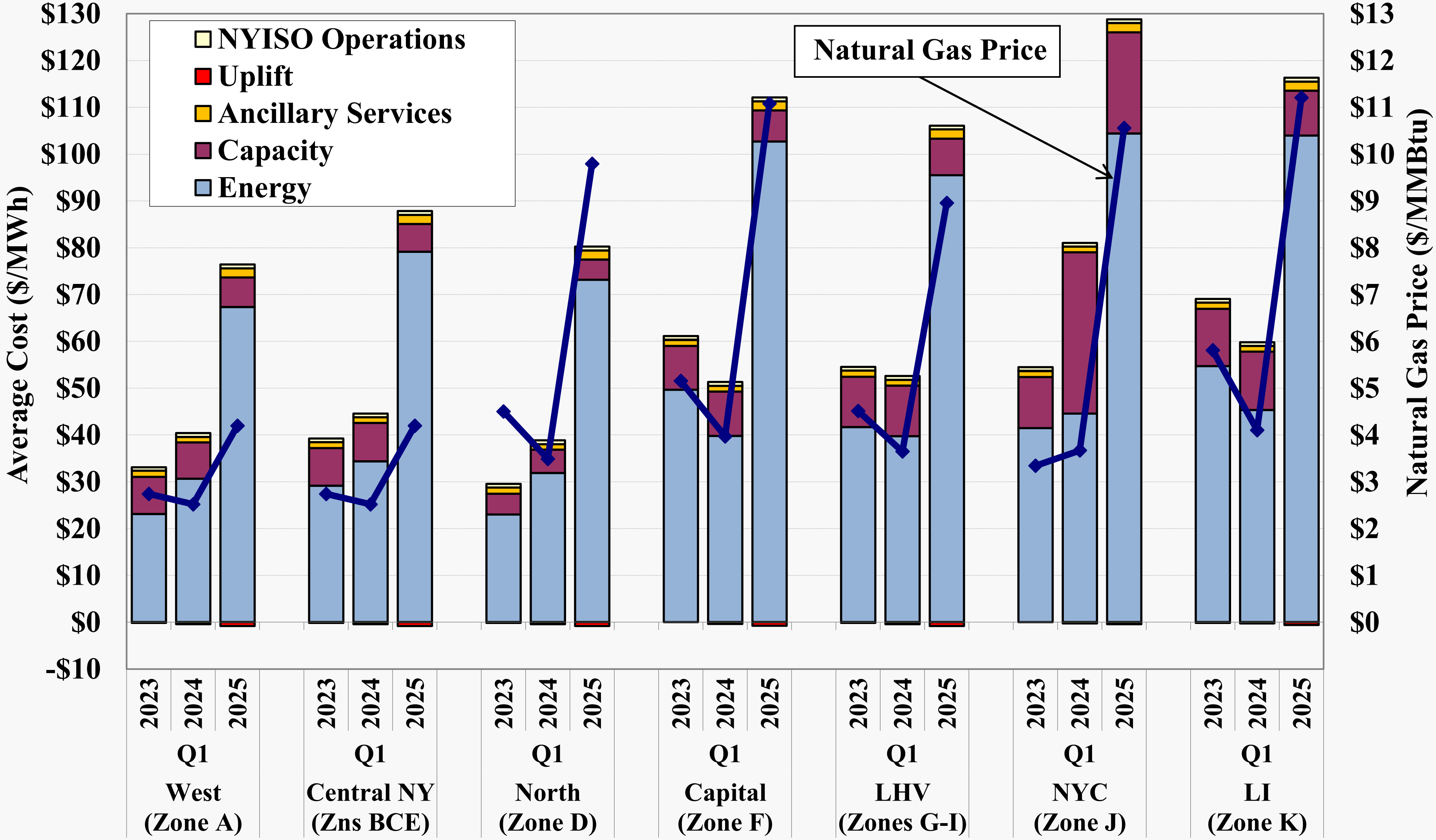
Market Highlights

Outage Scheduling of Oil-Capable Generators

- A significant amount of oil-capable resources were on planned outages during periods of peak winter load and gas restriction. (slide 87)
  - During the coldest period, January 20-24, when NYISO was most reliant on oil-capable generation, an average of 1.75 GW (~10 percent) was on planned outages.
  - These outages were often long-term and involved complex coordination with multiple external vendors, requiring significant lead time.
- EFORd metrics only reflect forced outages and do not consider planned outages.
  - This allows resources to schedule planned outages during critical reliability periods without affecting their EFORd values, effectively contributing nothing to reliability during winter peak conditions.
  - NYISO reviews and approves planned outages based on forecasted reserve margins, so the amount of fuel-secure capacity taking such outages is limited.
- As NYISO implements firm-fuel capacity accreditation in 2026/27 and designs a seasonal capacity market, it will be important to consider reasonable limits on planned outage scheduling under peak conditions and incentives for availability.

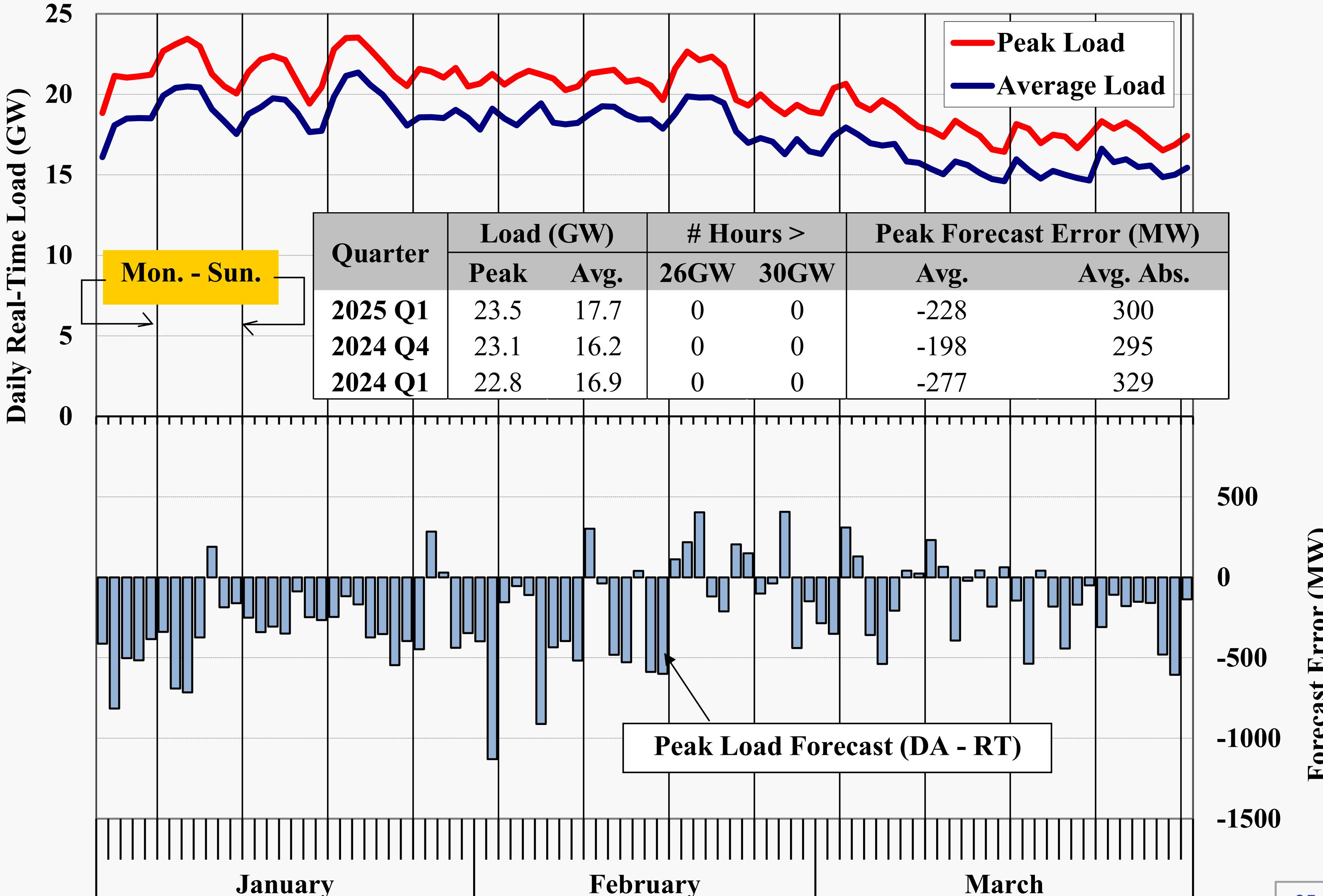
Charts: Market Outcomes

All-In Prices by Region



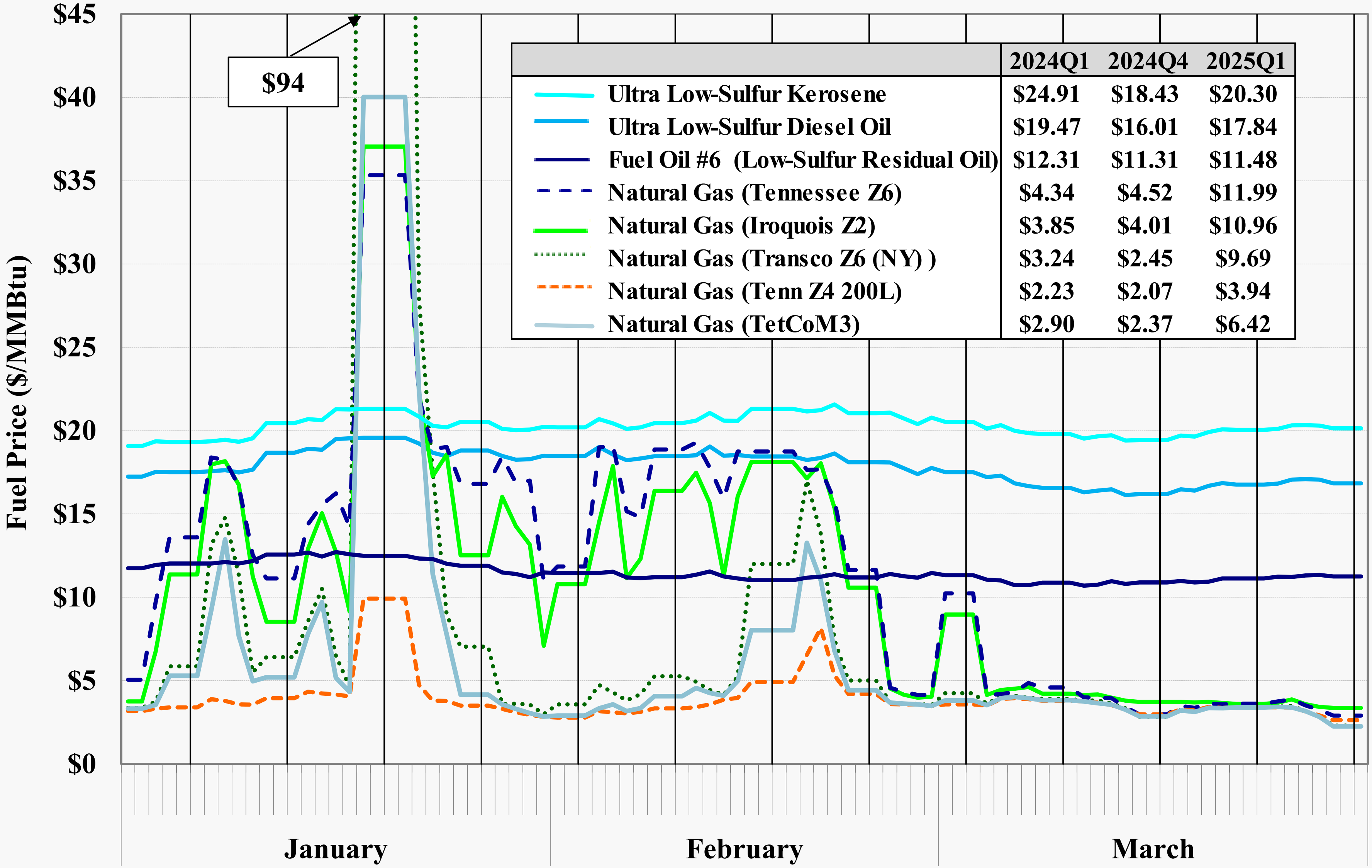
Notes: For chart description, see slide 89.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2025 Q1	23.5	17.7	0	0	-228	300
2024 Q4	23.1	16.2	0	0	-198	295
2024 Q1	22.8	16.9	0	0	-277	329

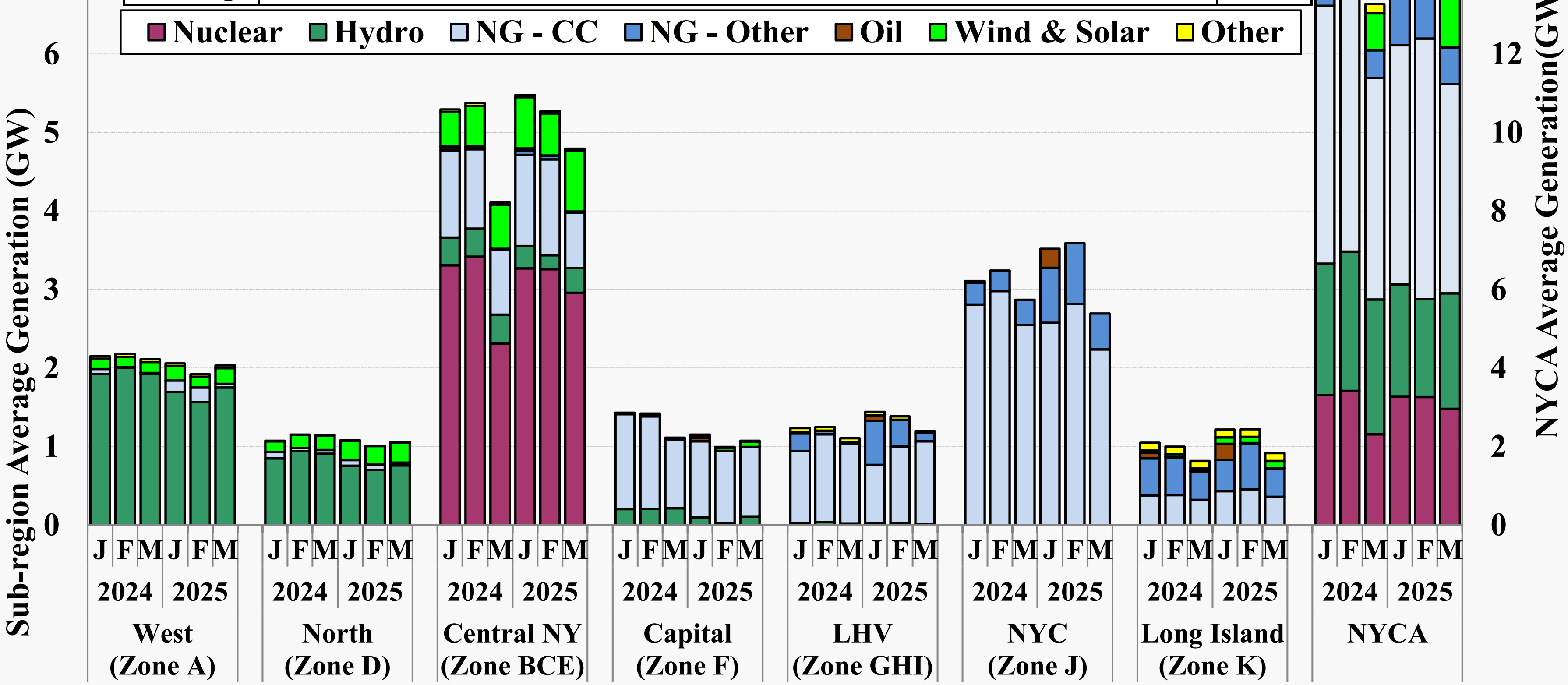
Natural Gas and Fuel Oil Prices



	2024Q1	2024Q4	2025Q1
Ultra Low-Sulfur Kerosene	$24.91	$18.43	$20.30
Ultra Low-Sulfur Diesel Oil	$19.47	$16.01	$17.84
Fuel Oil #6 (Low-Sulfur Residual Oil)	$12.31	$11.31	$11.48
Natural Gas (Tennessee Z6)	$4.34	$4.52	$11.99
Natural Gas (Iroquois Z2)	$3.85	$4.01	$10.96
Natural Gas (Transco Z6 (NY))	$3.24	$2.45	$9.69
Natural Gas (Tenn Z4 200L)	$2.23	$2.07	$3.94
Natural Gas (TetCoM3)	$2.90	$2.37	$6.42

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 Q1	3.16	2.78	6.00	1.46	0.21	1.20	0.22	15.02
2024 Q4	3.17	2.70	5.94	1.28	0.04	0.95	0.25	14.33
2024 Q1	2.96	3.40	6.22	0.84	0.06	0.83	0.23	14.55

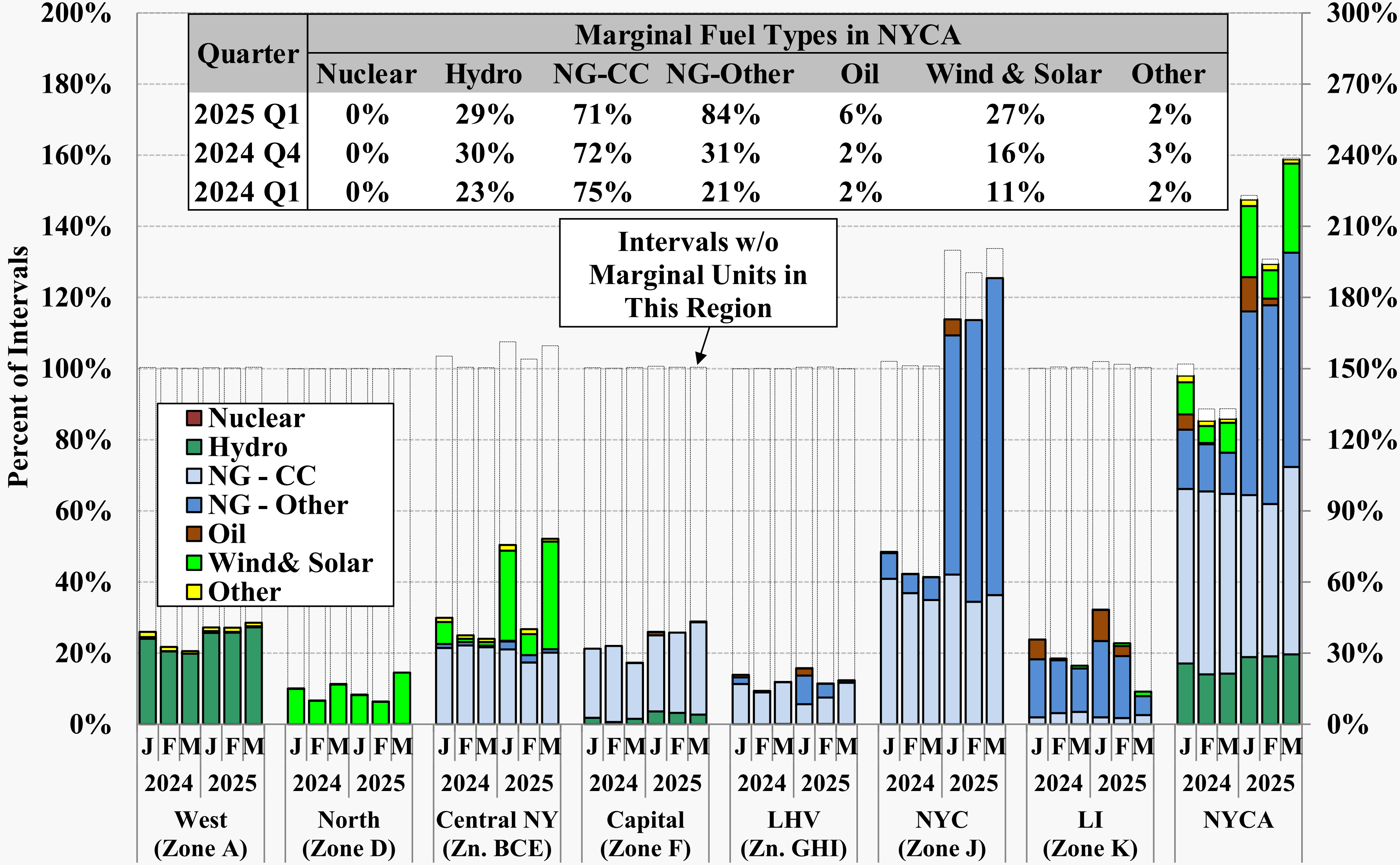


Notes: For chart description, see slide 90.

Fuel Type of Marginal Units

In the Real-Time Market

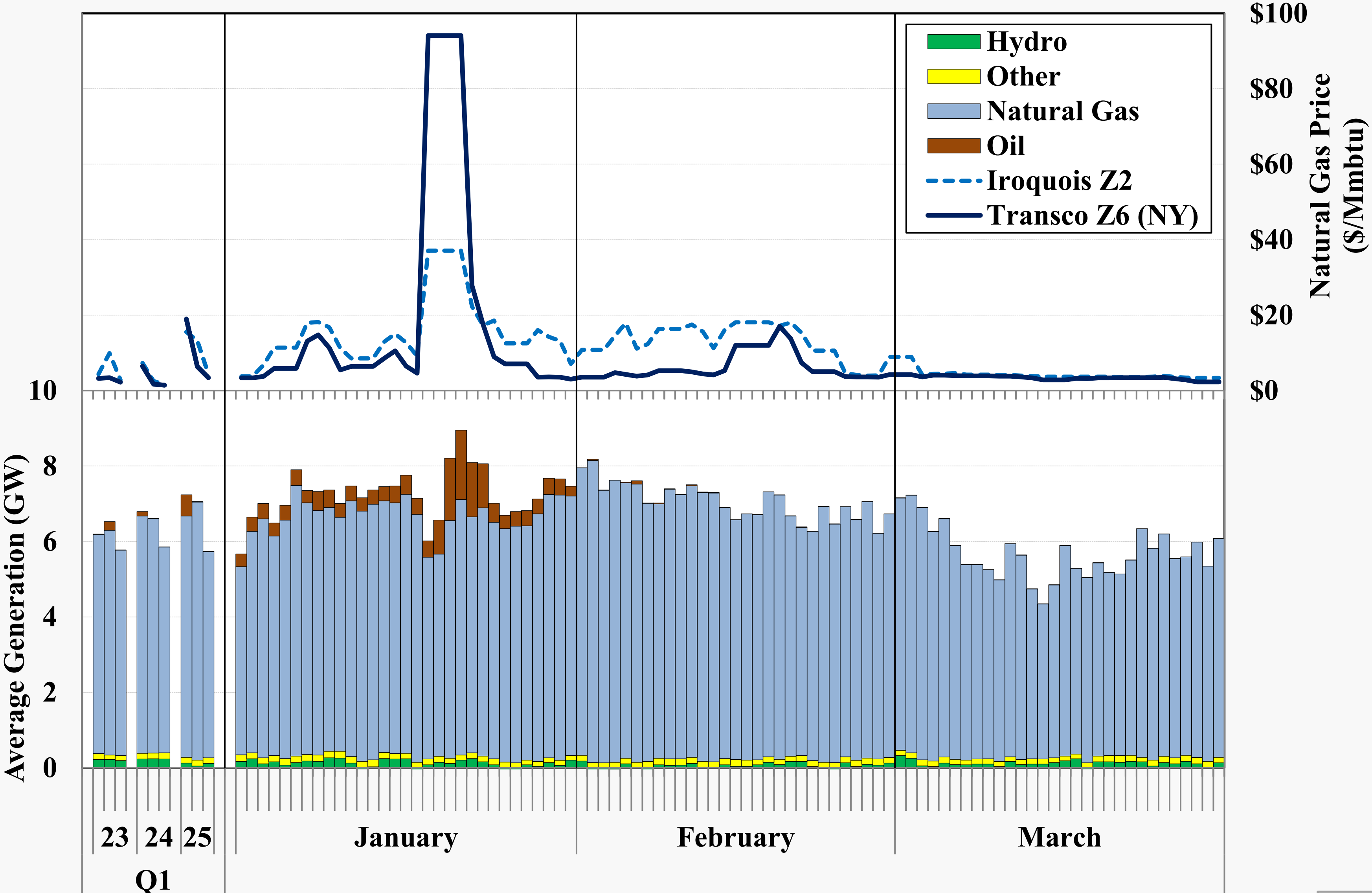
Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind & Solar	Other
2025 Q1	0%	29%	71%	84%	6%	27%	2%
2024 Q4	0%	30%	72%	31%	2%	16%	3%
2024 Q1	0%	23%	75%	21%	2%	11%	2%



Notes: For chart description, see slide 90.

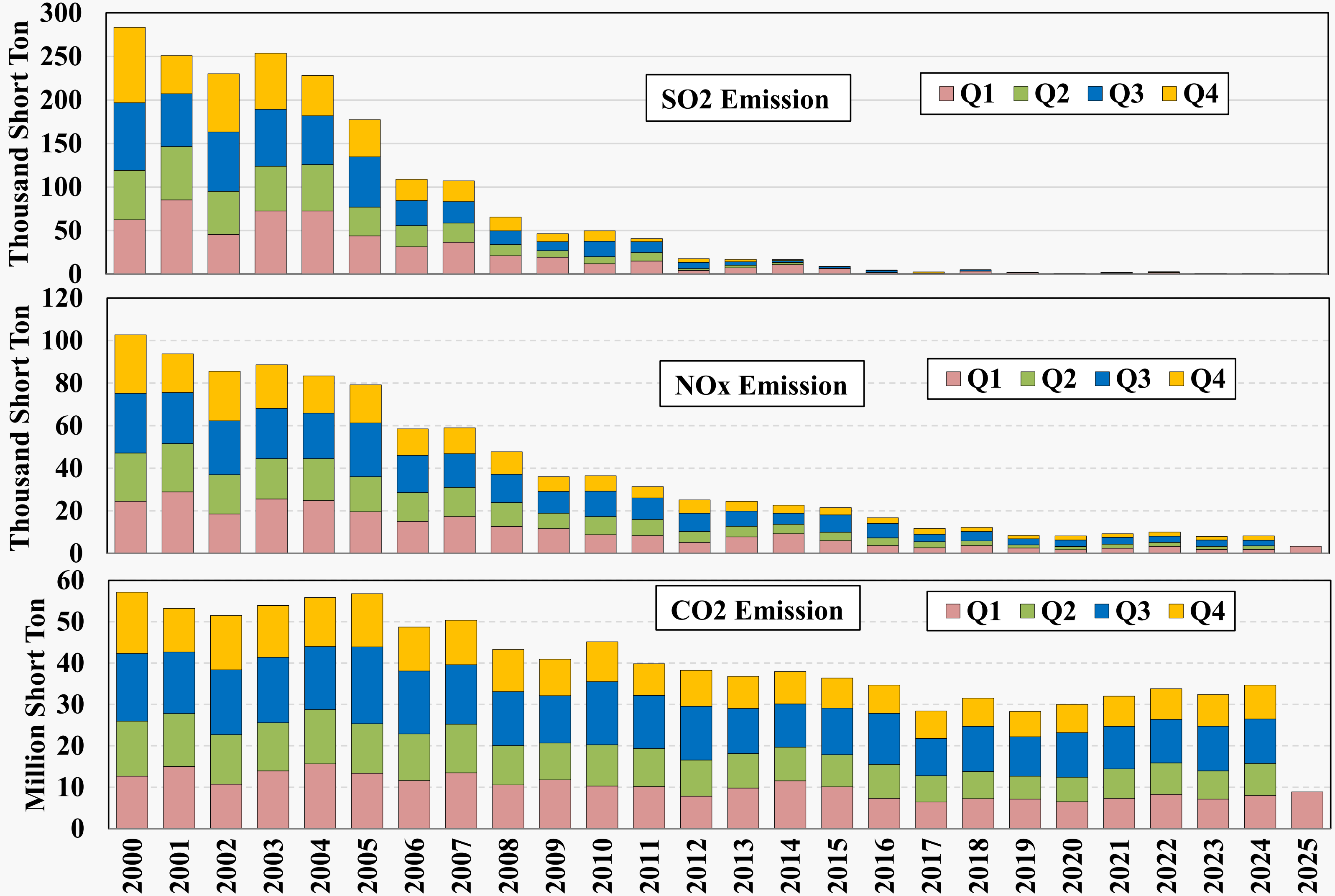
Winter Fuel Usage

Eastern New York



Historical Emissions by Quarter in NYCA

CO_2, SO_2, and NO_X

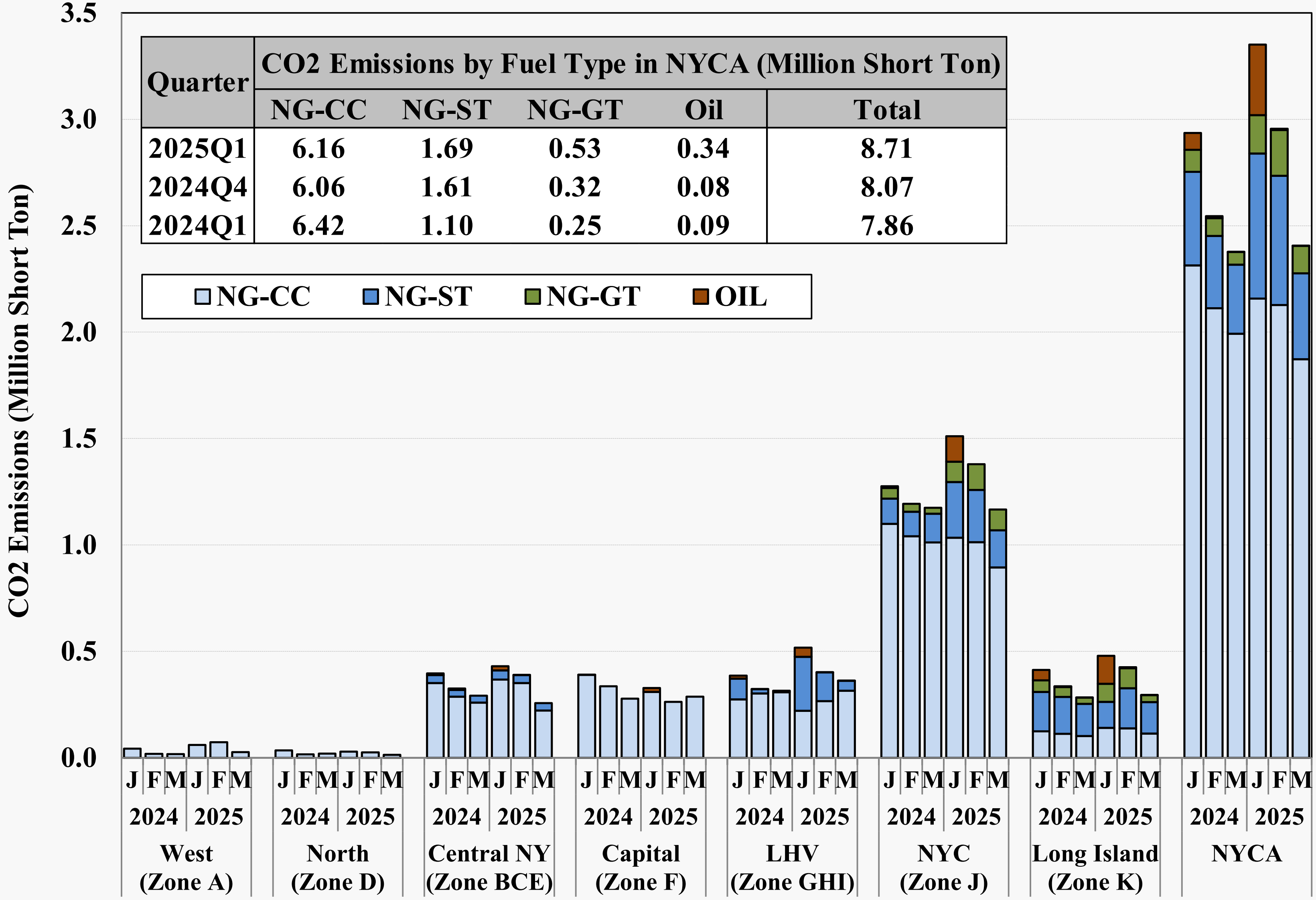


Notes: For chart description, see slide 91.

Emissions by Region by Fuel Type

CO_2 Emissions

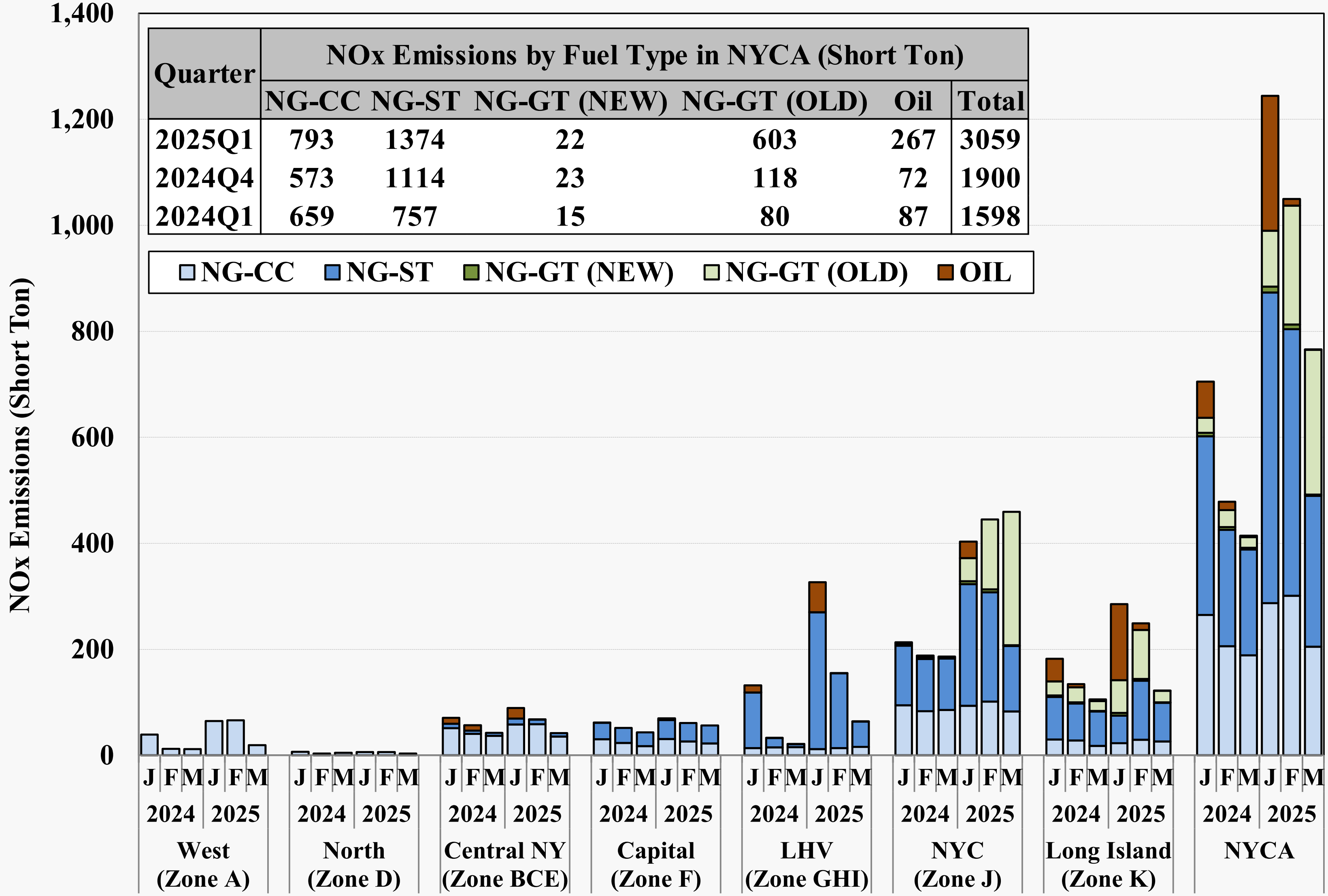
Quarter	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)				
	NG-CC	NG-ST	NG-GT	Oil	Total
2025Q1	6.16	1.69	0.53	0.34	8.71
2024Q4	6.06	1.61	0.32	0.08	8.07
2024Q1	6.42	1.10	0.25	0.09	7.86



Notes: For chart description, see slide 91.

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
2025Q1	793	1374	22	603	267	3059
2024Q4	573	1114	23	118	72	1900
2024Q1	659	757	15	80	87	1598

Notes: For chart description, see slide 91.

Daily NO_X Emissions in NYC

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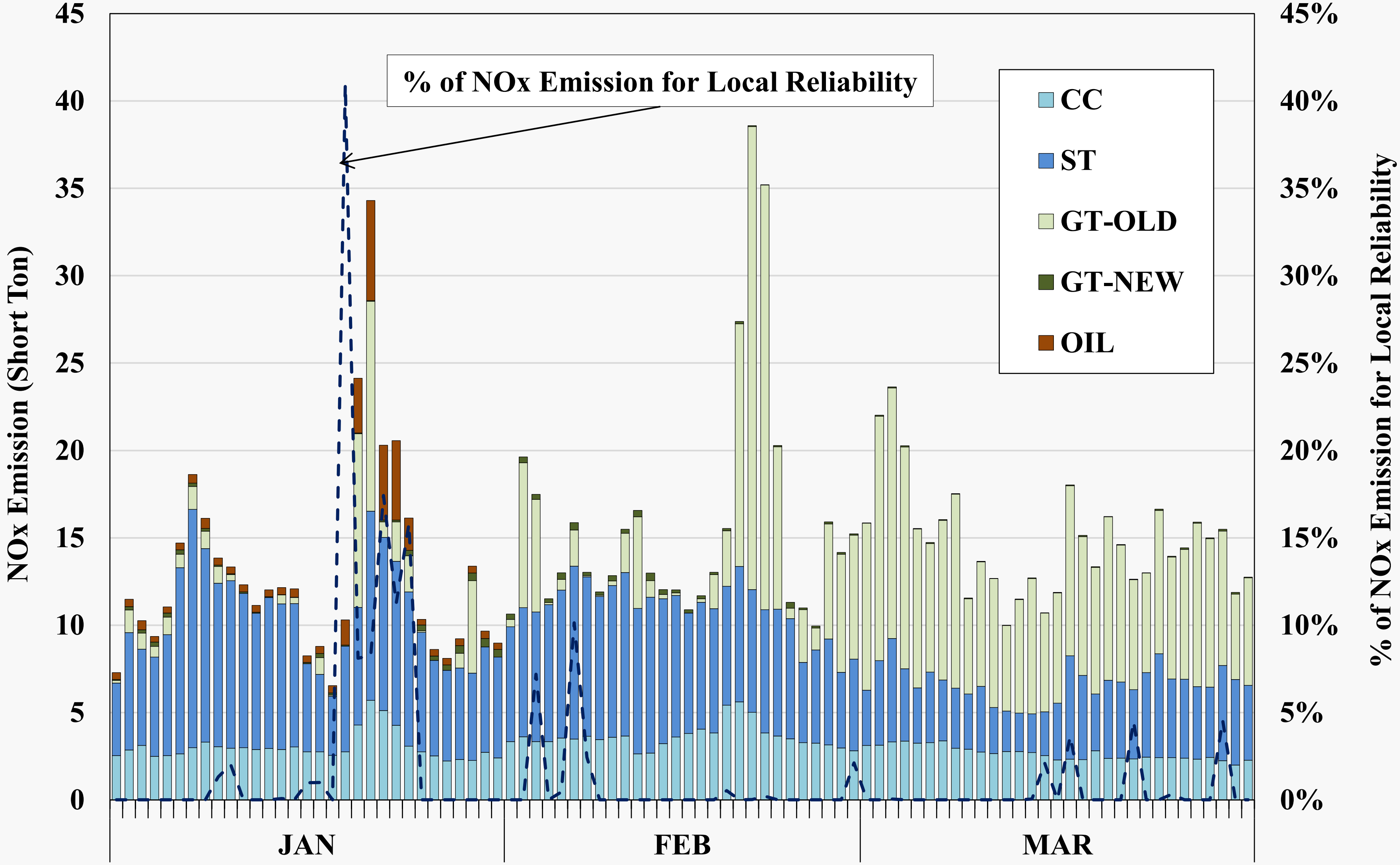
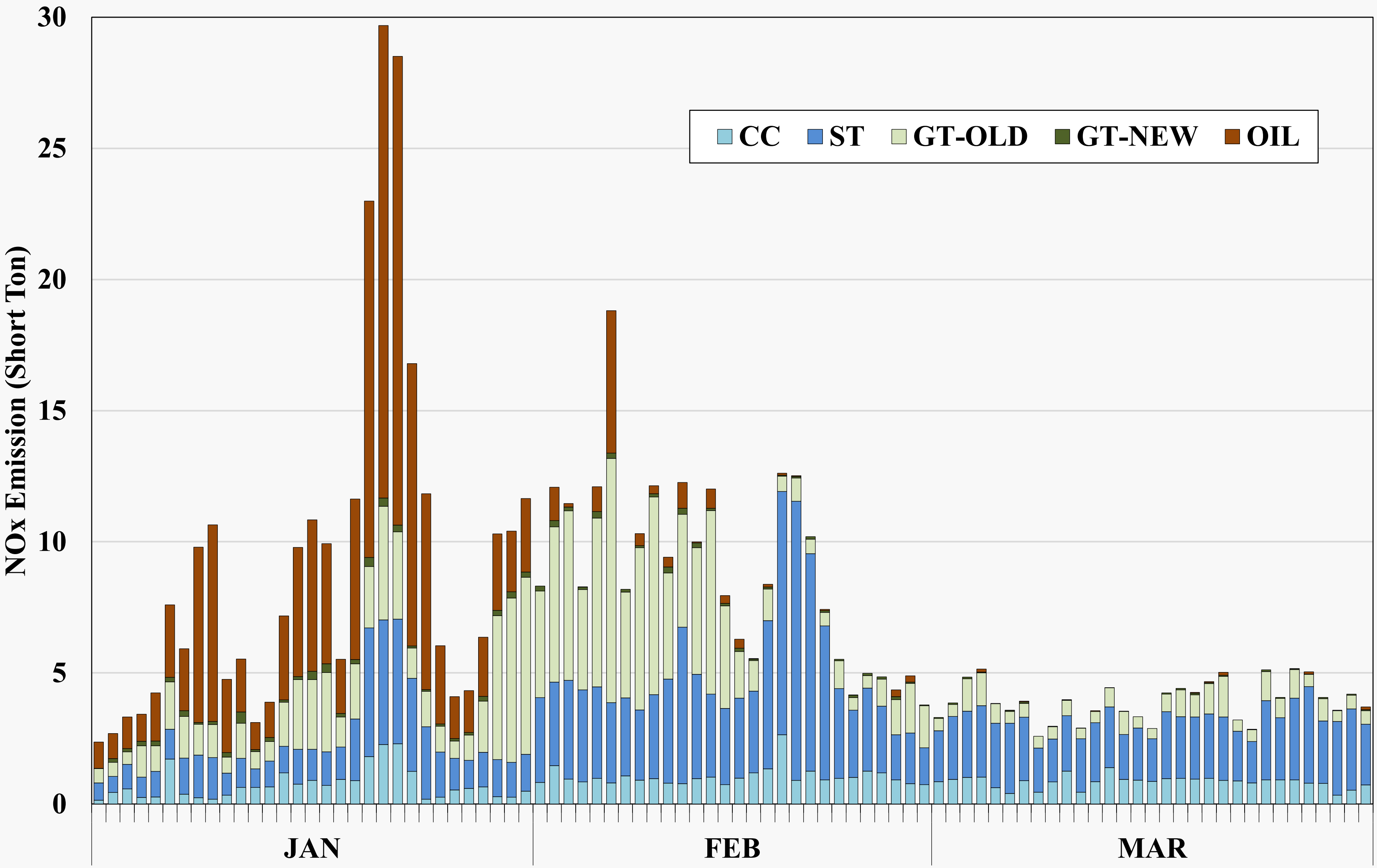


Notes: For chart description, see slide 91.

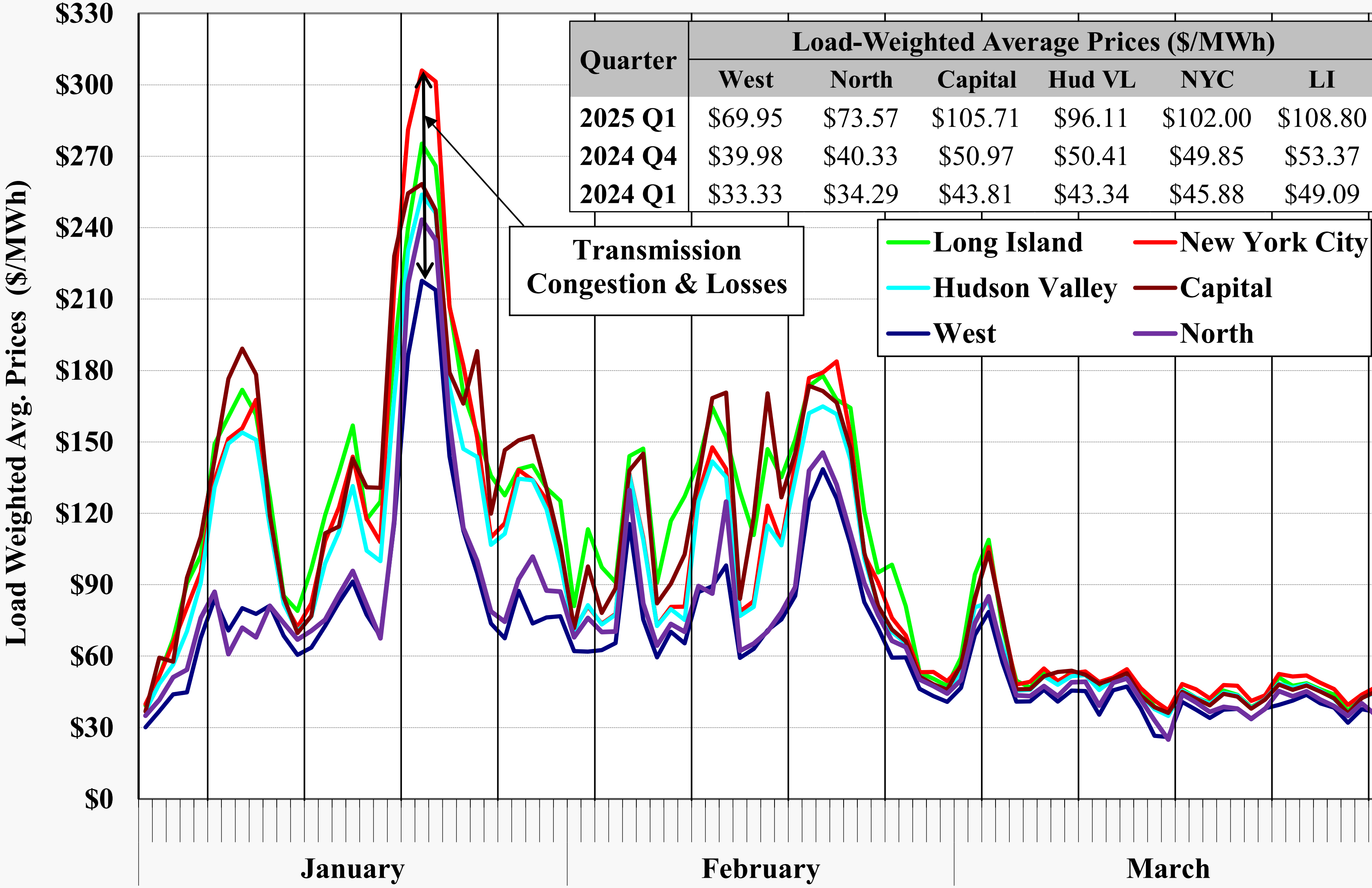
Daily NO_X Emissions in Long Island



Notes: For chart description, see slide 91.

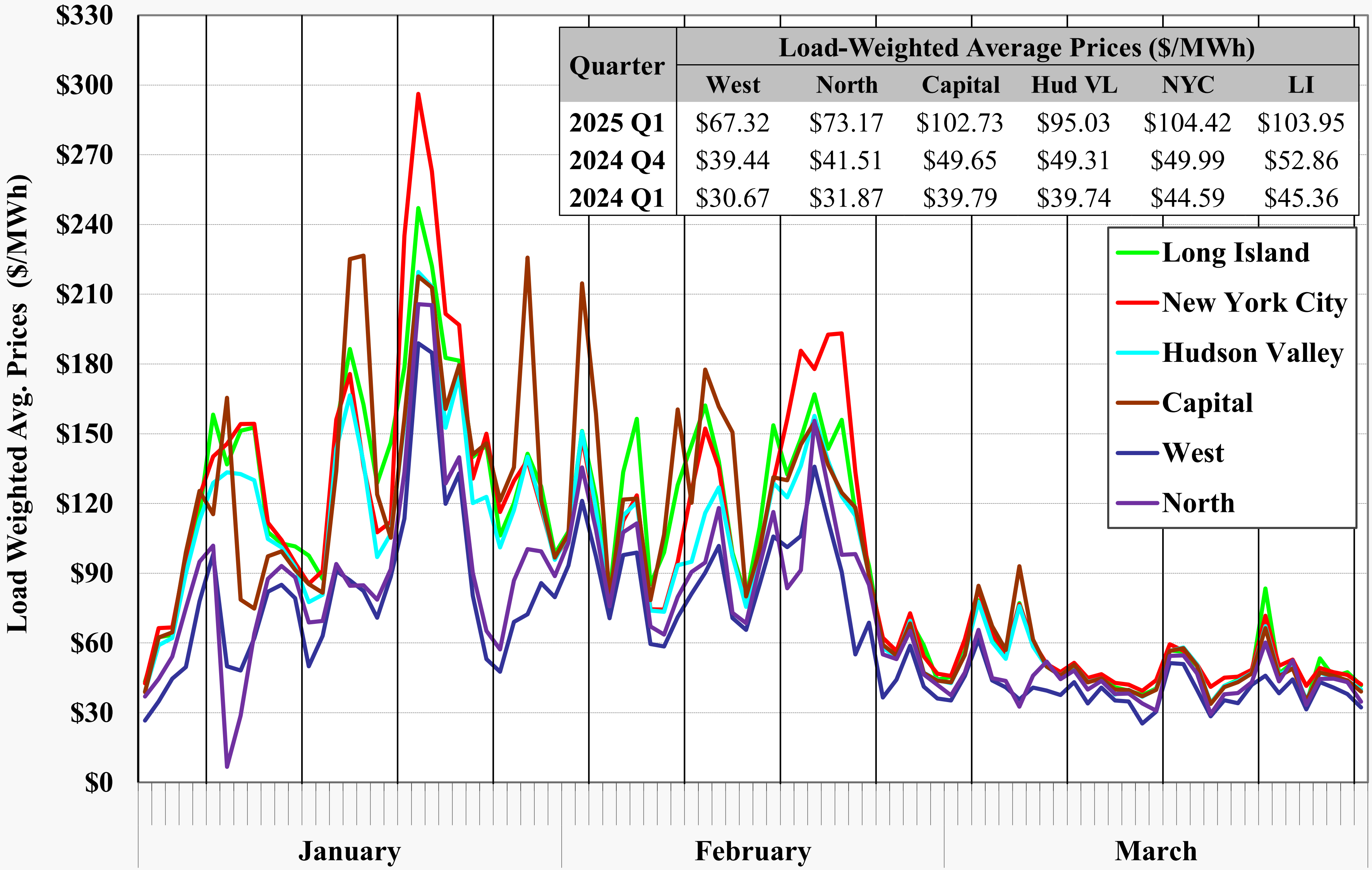
Day-Ahead Electricity Prices by Zone

POTOMAC ECONOMICS



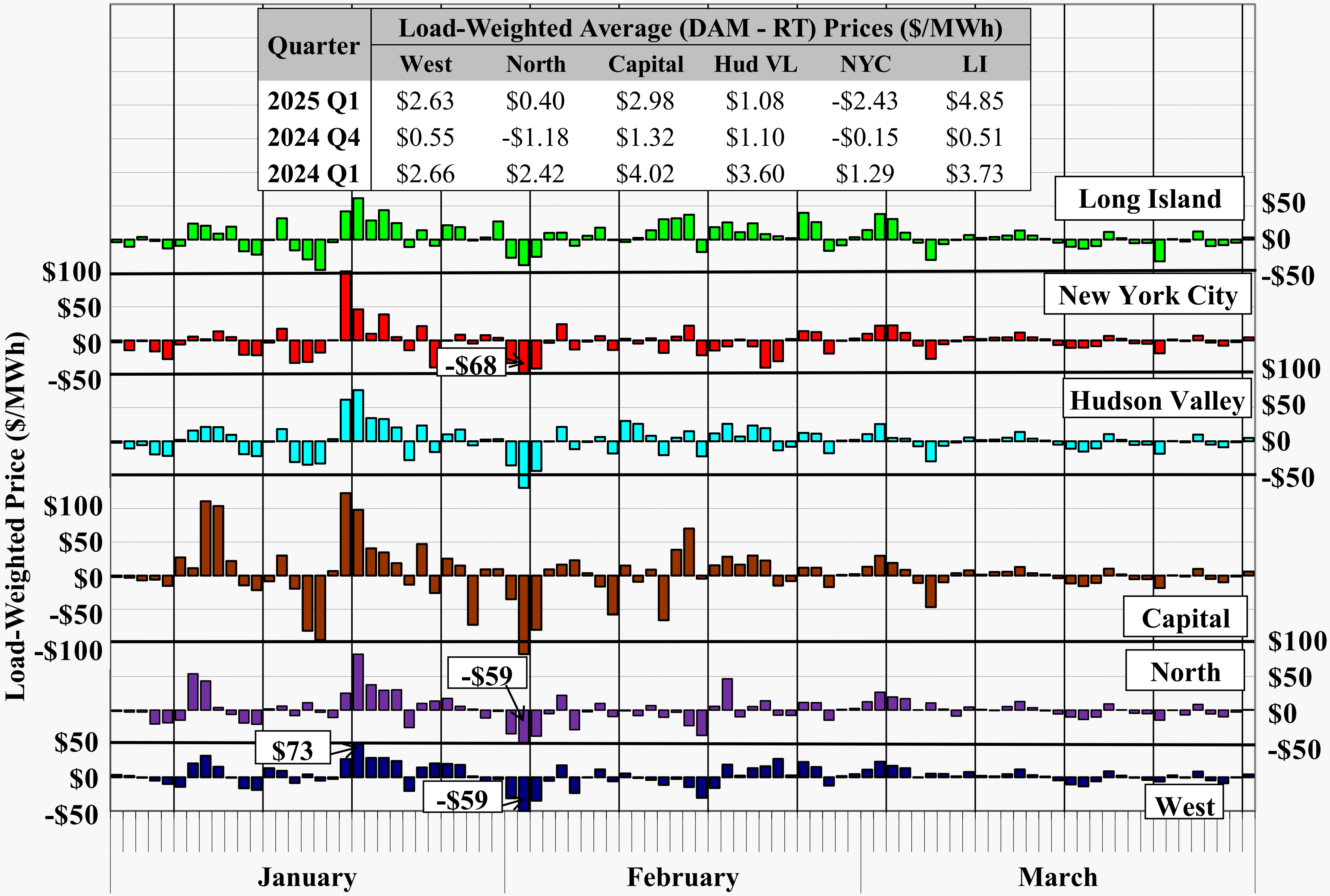
Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2025 Q1	$69.95	$73.57	$105.71	$96.11	$102.00	$108.80
2024 Q4	$39.98	$40.33	$50.97	$50.41	$49.85	$53.37
2024 Q1	$33.33	$34.29	$43.81	$43.34	$45.88	$49.09

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2025 Q1	$67.32	$73.17	$102.73	$95.03	$104.42	$103.95
2024 Q4	$39.44	$41.51	$49.65	$49.31	$49.99	$52.86
2024 Q1	$30.67	$31.87	$39.79	$39.74	$44.59	$45.36

Convergence of Day-Ahead and Real-Time Prices

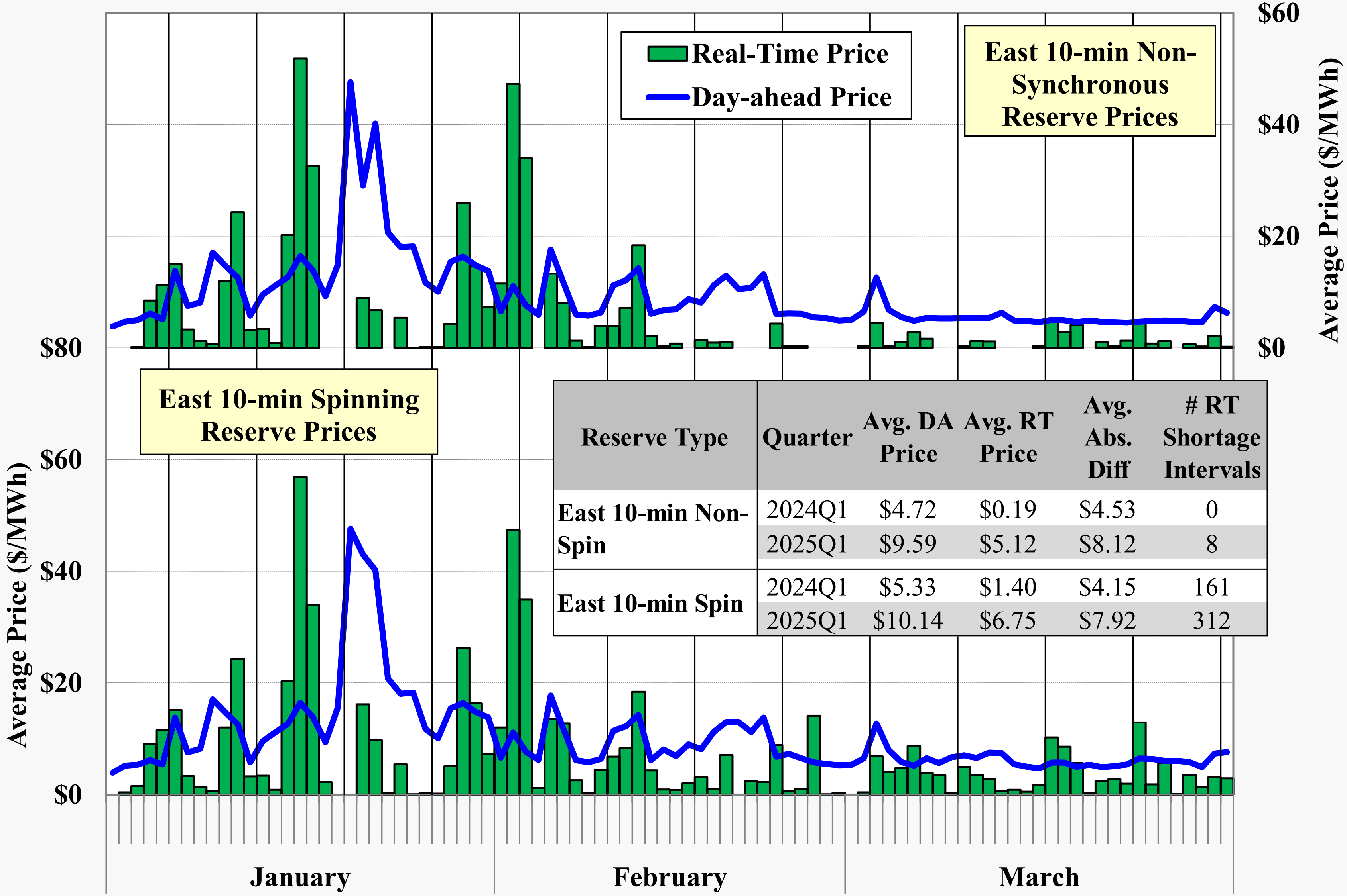


Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2025 Q1	$2.63	$0.40	$2.98	$1.08	-$2.43	$4.85
2024 Q4	$0.55	-$1.18	$1.32	$1.10	-$0.15	$0.51
2024 Q1	$2.66	$2.42	$4.02	$3.60	$1.29	$3.73

Charts:
Ancillary Services Market

Day-Ahead and Real-Time Ancillary Services Prices

Eastern 10-Minute Spinning and Non-Spinning Reserves

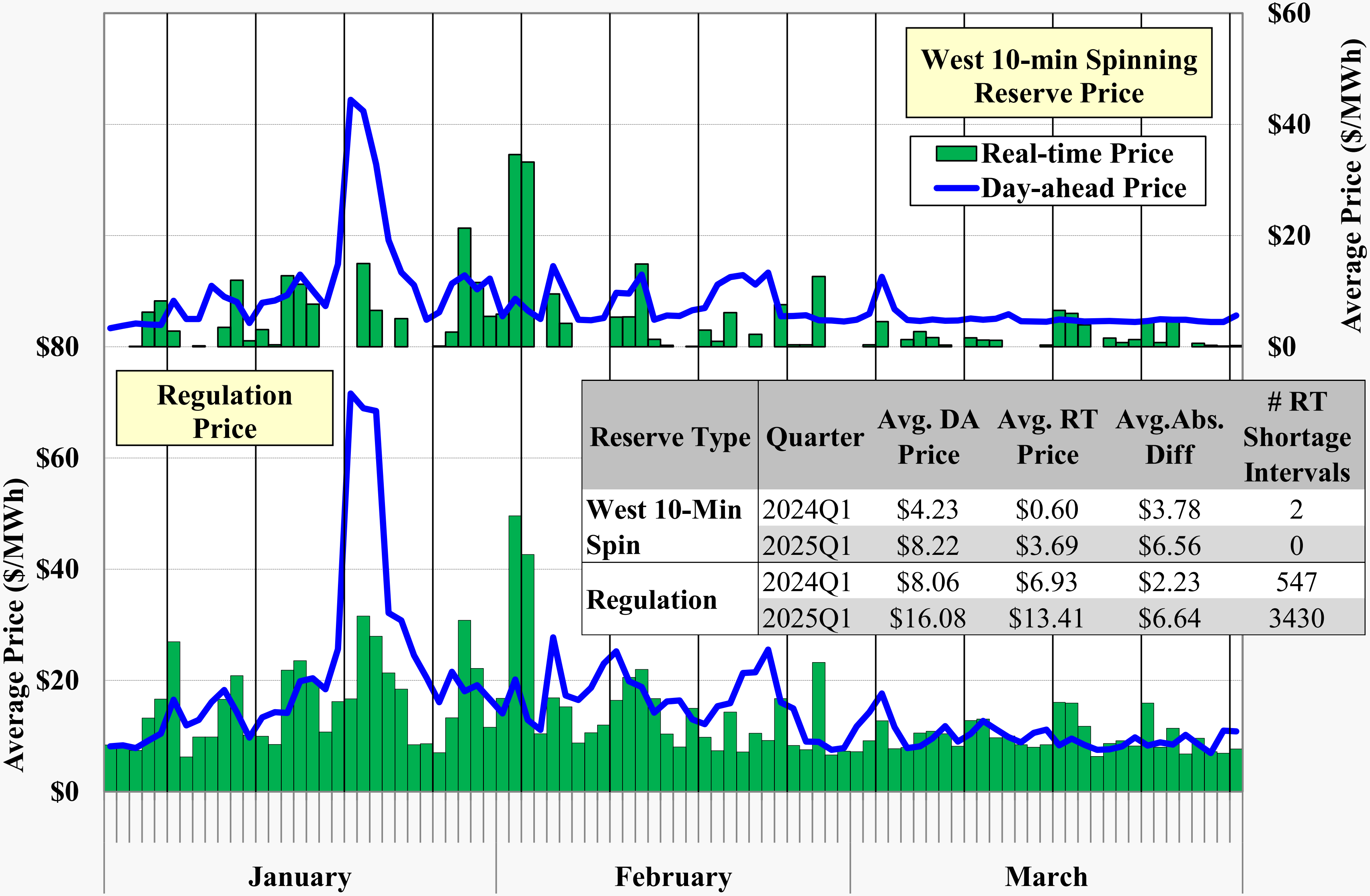


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2024Q1	$4.72	$0.19	$4.53	0
	2025Q1	$9.59	$5.12	$8.12	8
East 10-min Spin	2024Q1	$5.33	$1.40	$4.15	161
	2025Q1	$10.14	$6.75	$7.92	312

Notes: For chart description, see slide 92.

Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



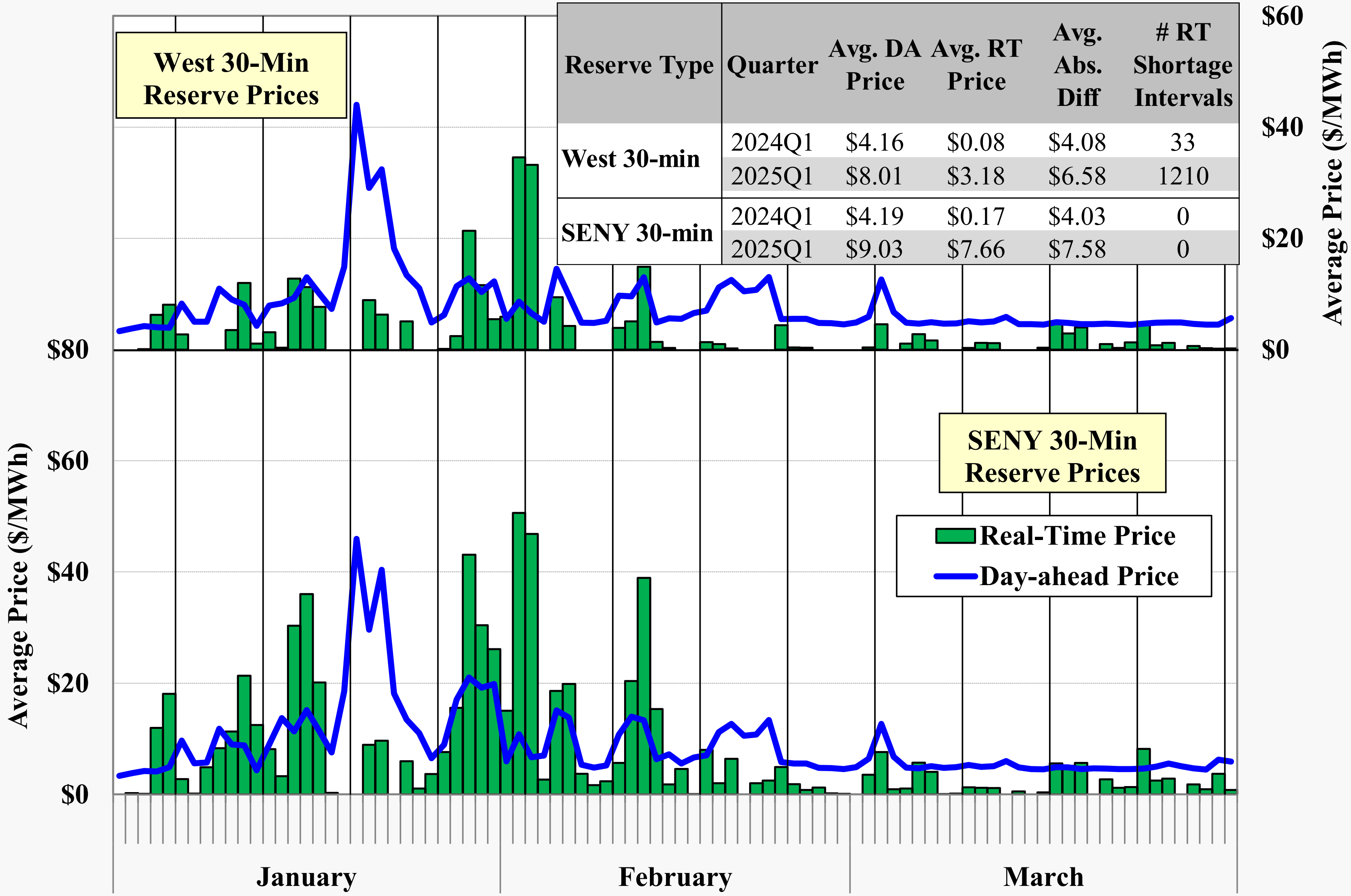
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
West 10-Min Spin	2024Q1	$4.23	$0.60	$3.78	2
	2025Q1	$8.22	$3.69	$6.56	0
Regulation	2024Q1	$8.06	$6.93	$2.23	547
	2025Q1	$16.08	$13.41	$6.64	3430

Notes: For chart description, see slide 92.

Day-Ahead and Real-Time Ancillary Services Prices

Western and SENY 30-Minute Reserves

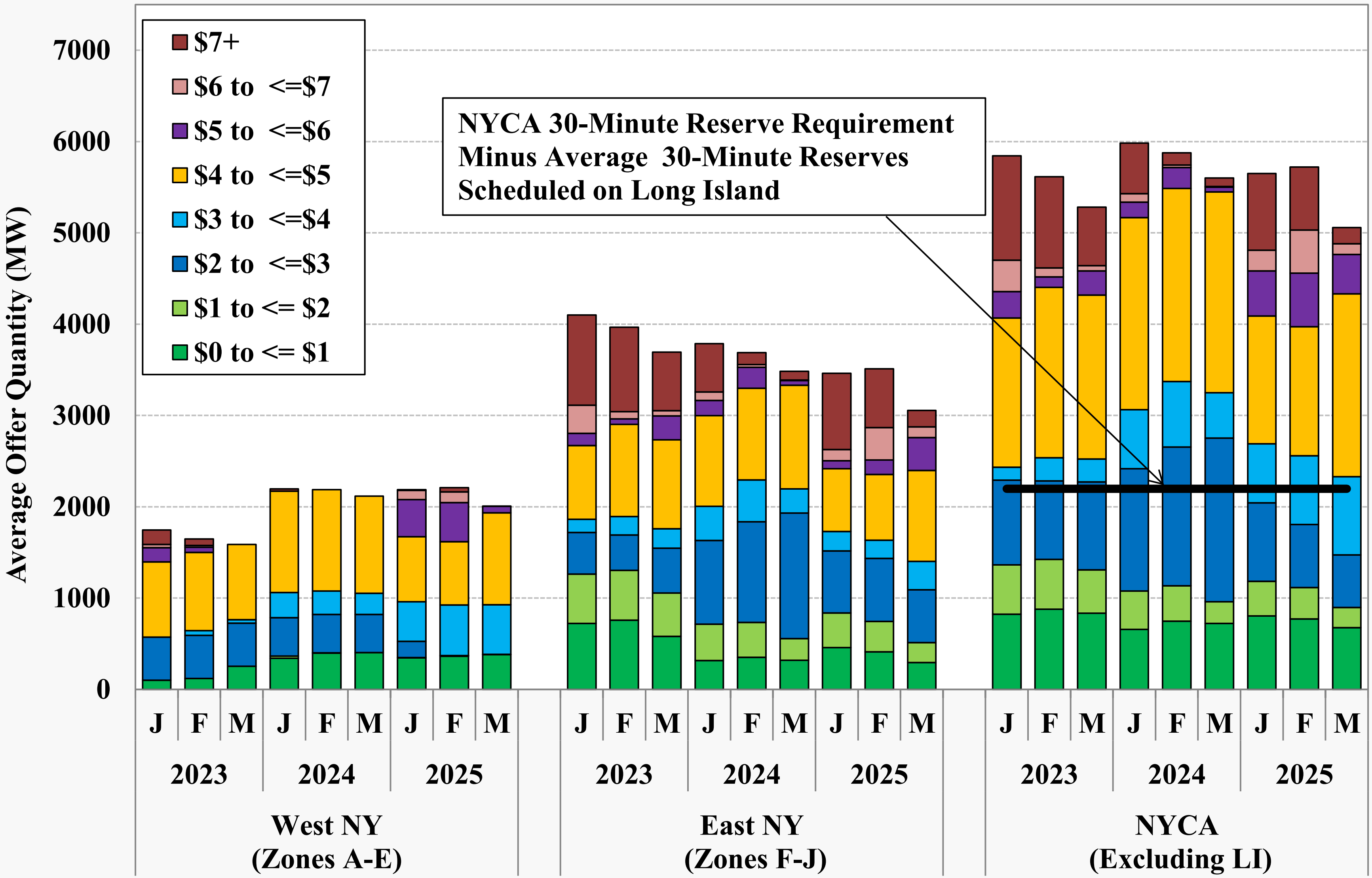
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2024Q1	$4.16	$0.08	$4.08	33
	2025Q1	$8.01	$3.18	$6.58	1210
SENY 30-min	2024Q1	$4.19	$0.17	$4.03	0
	2025Q1	$9.03	$7.66	$7.58	0



Notes: For chart description, see slide 92.

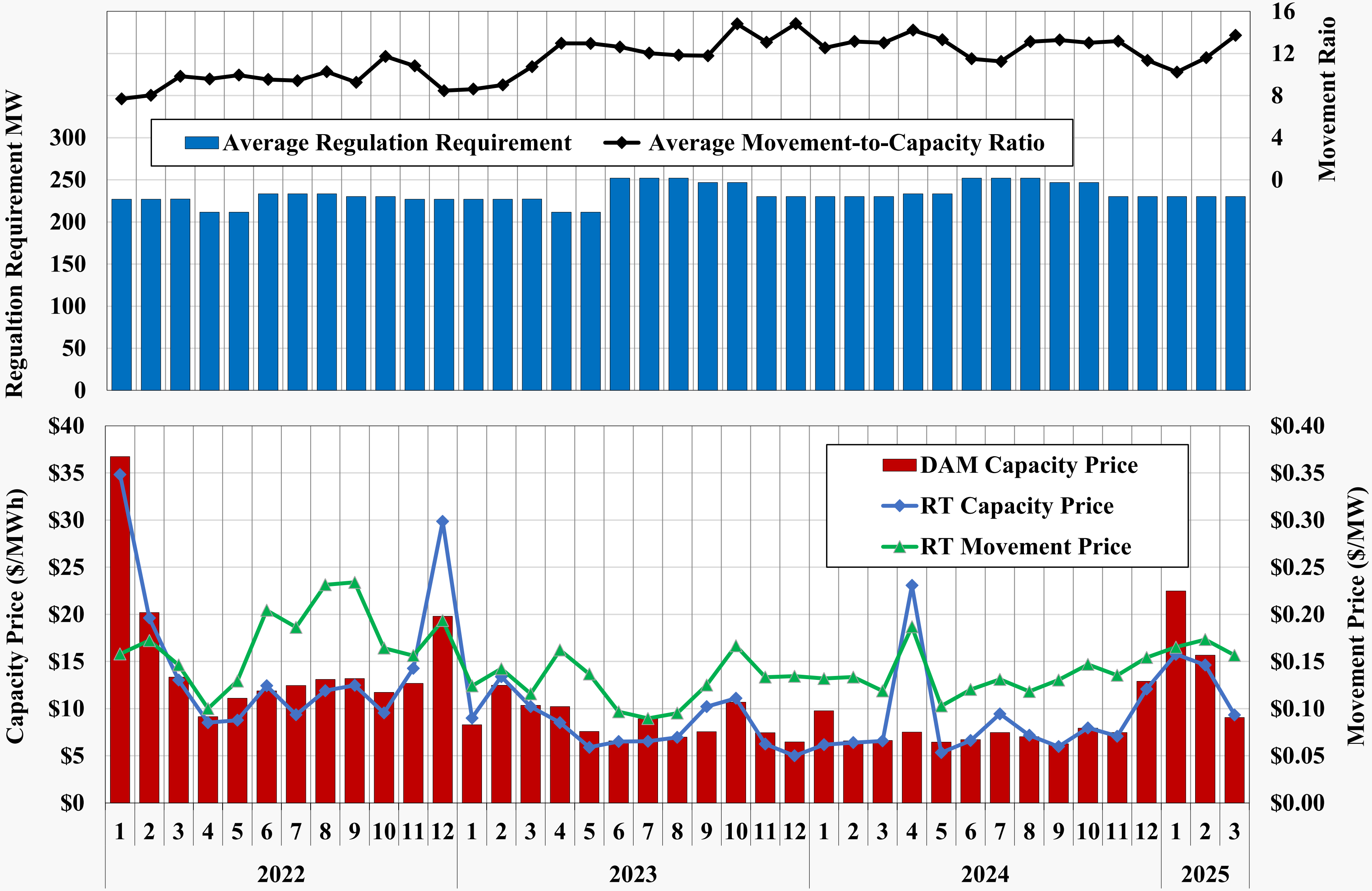
Day-Ahead NYCA 30-Minute Reserve Offers

Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 93.

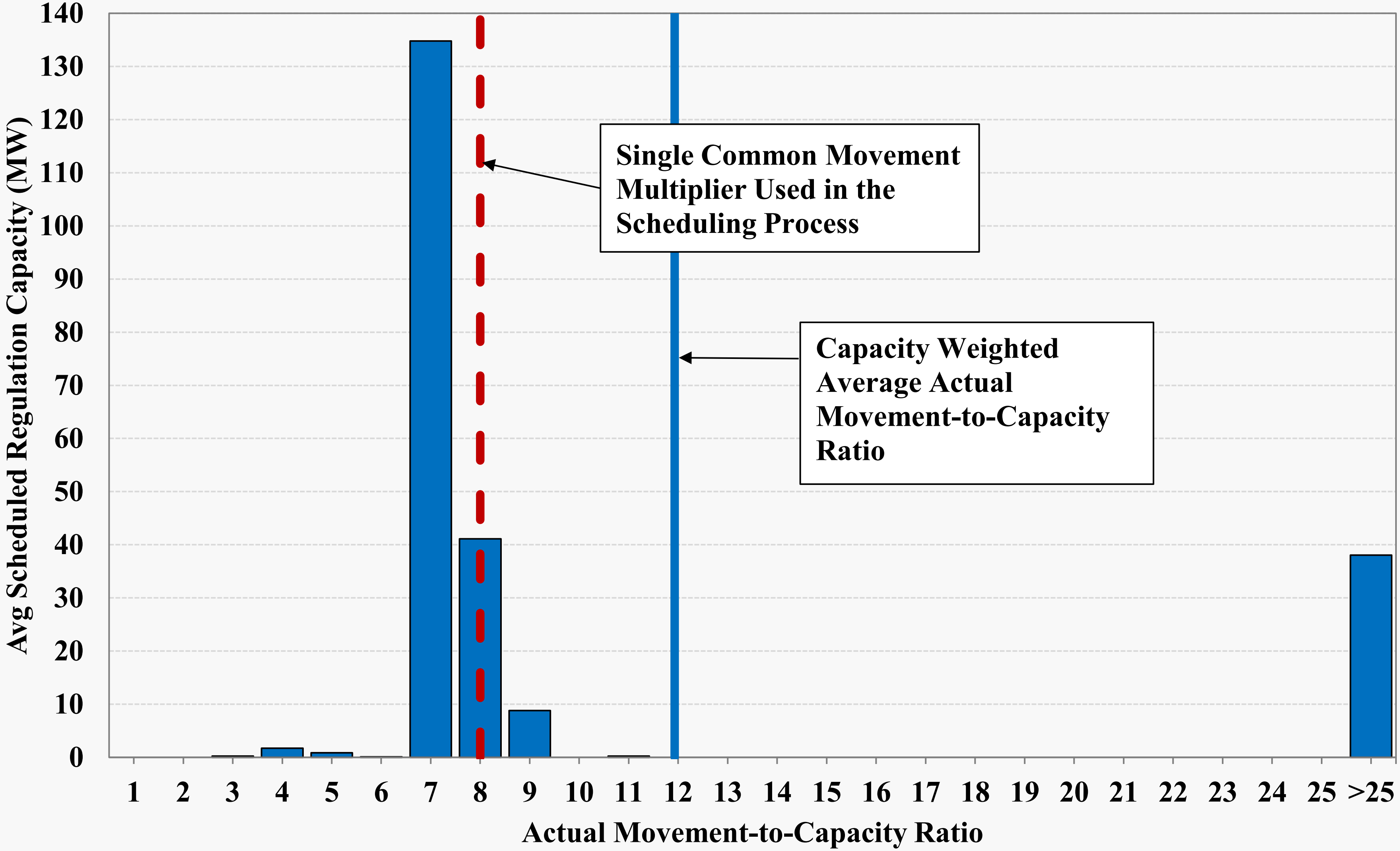
Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month



Notes: For chart description, see slide 94.

Distribution of Actual Regulation Movement

The First Quarter of 2025

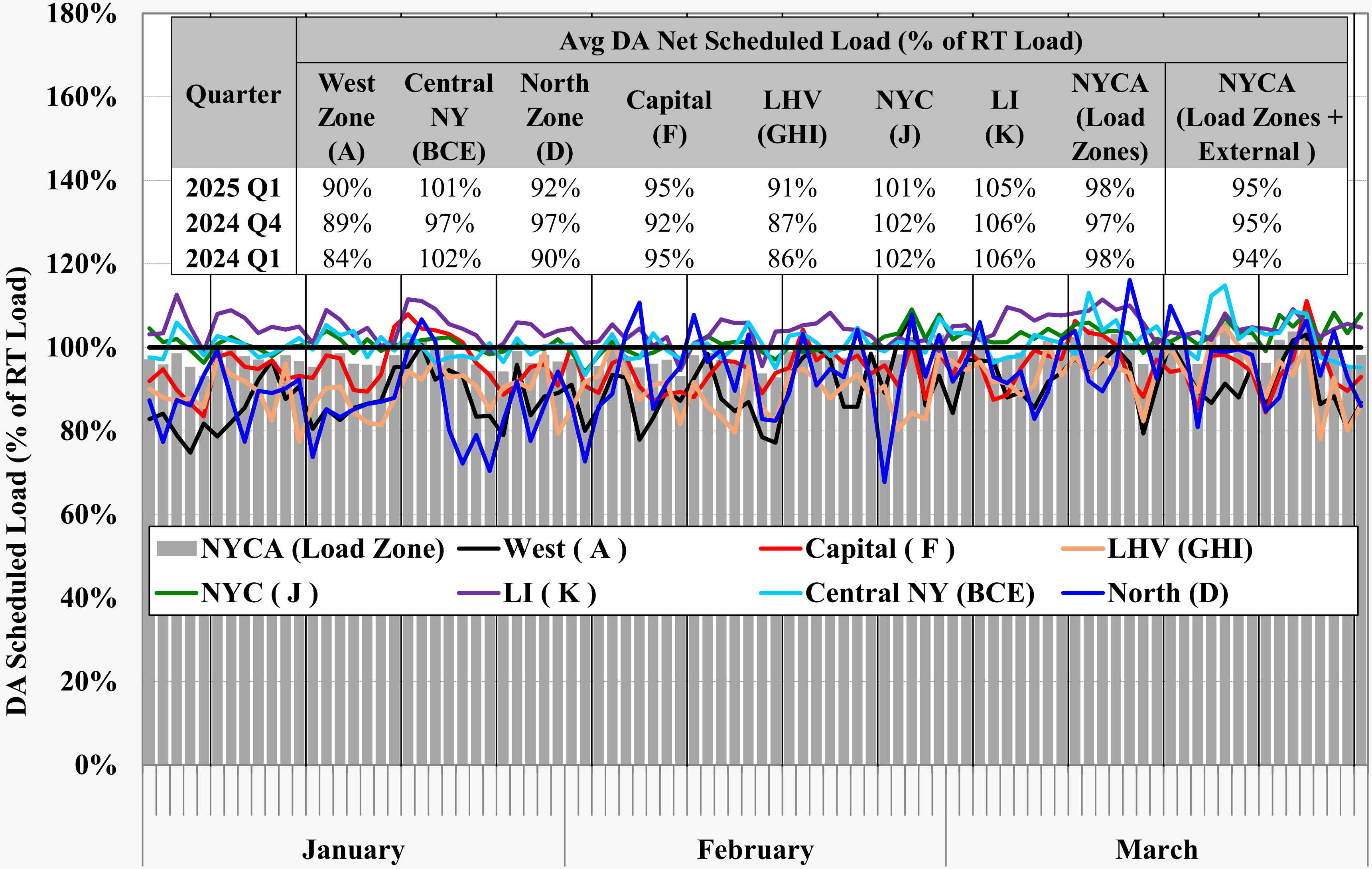


Notes: For chart description, see slide 94.

Charts: Energy Market Scheduling

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour

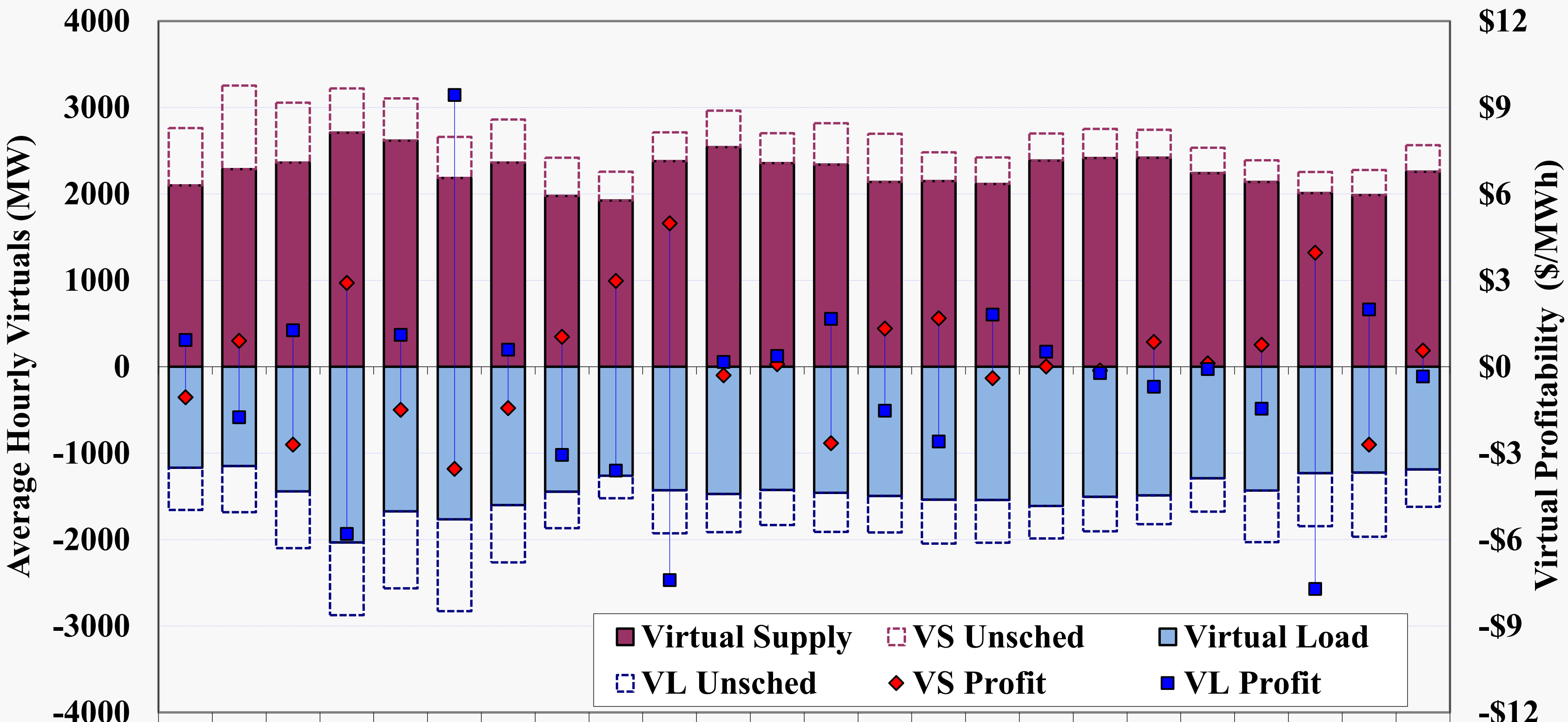


Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2025 Q1	90%	101%	92%	95%	91%	101%	105%	98%	95%
2024 Q4	89%	97%	97%	92%	87%	102%	106%	97%	95%
2024 Q1	84%	102%	90%	95%	86%	102%	106%	98%	94%

Notes: For chart description, see slide 95.

Virtual Trading Activity

by Month

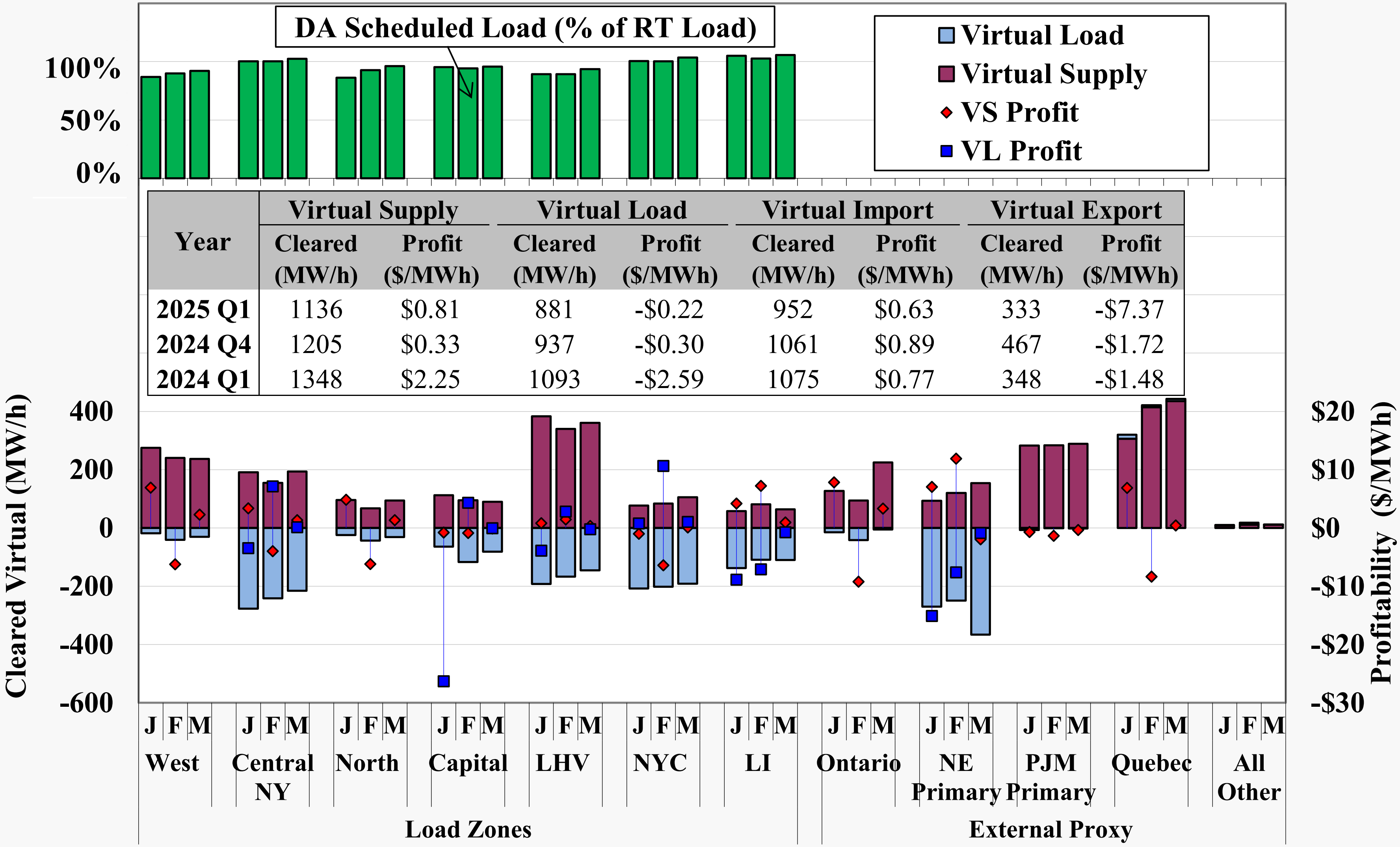


		A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M
		2023									2024												2025		
Profit > 50% of Avg. Zone Price	MW	243	275	130	360	243	244	166	198	136	334	106	138	81	136	236	249	132	48	104	86	262	287	218	207
	%	7%	8%	3%	8%	6%	6%	4%	6%	4%	9%	3%	4%	2%	4%	6%	7%	3%	1%	3%	2%	7%	9%	7%	6%
Loss > 50% of Avg. Zone Price	MW	285	296	164	415	322	156	213	255	141	283	148	163	93	155	234	252	148	61	110	169	258	284	273	215
	%	9%	9%	4%	9%	8%	4%	5%	7%	4%	7%	4%	4%	2%	4%	6%	7%	4%	2%	3%	5%	7%	9%	9%	6%

Notes: For chart description, see slide 95.

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 Q1	1136	$0.81	881	-$0.22	952	$0.63	333	-$7.37
2024 Q4	1205	$0.33	937	-$0.30	1061	$0.89	467	-$1.72
2024 Q1	1348	$2.25	1093	-$2.59	1075	$0.77	348	-$1.48

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 95.

Virtual Imports and Exports in the Day-Ahead Market

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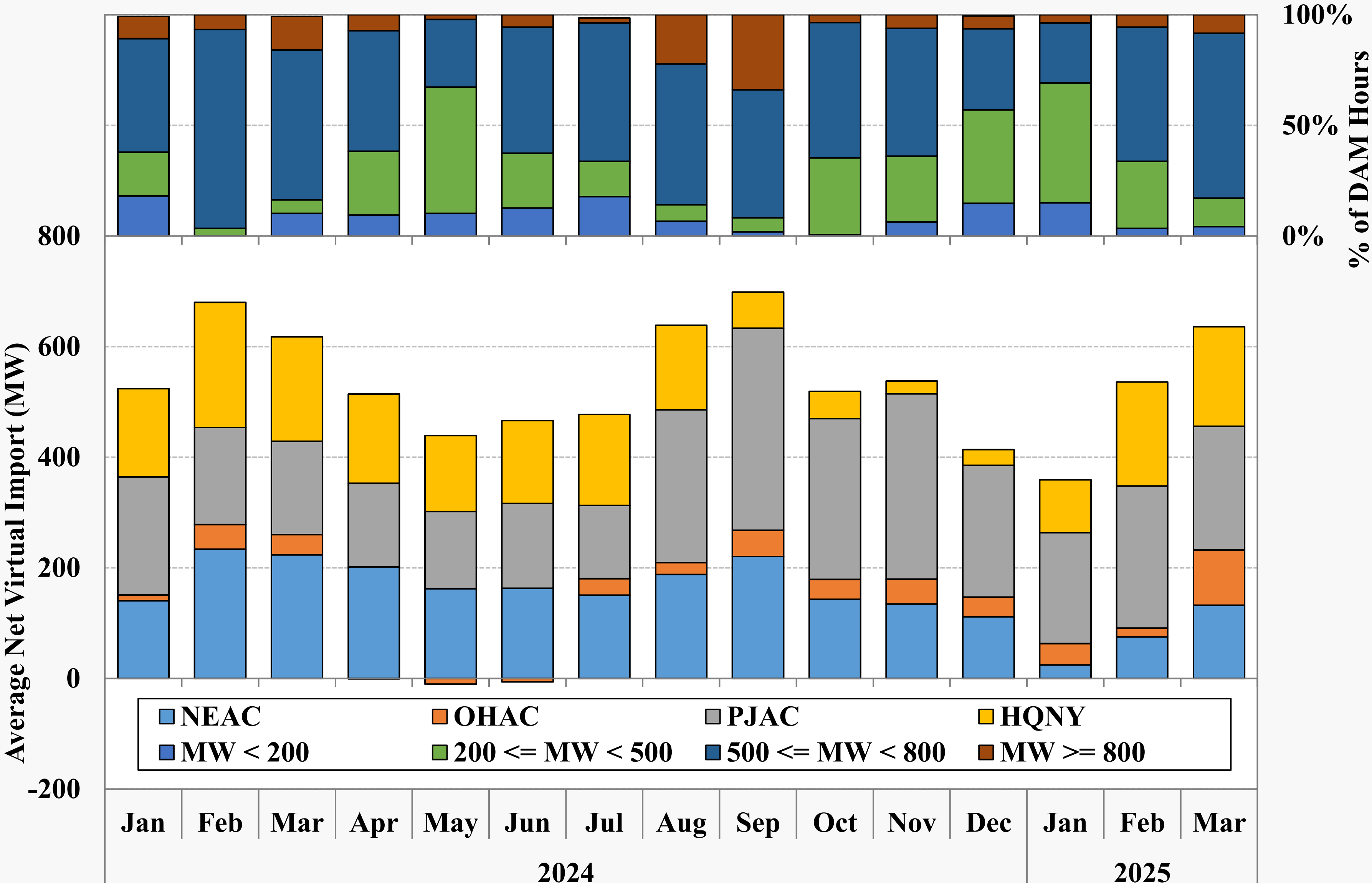
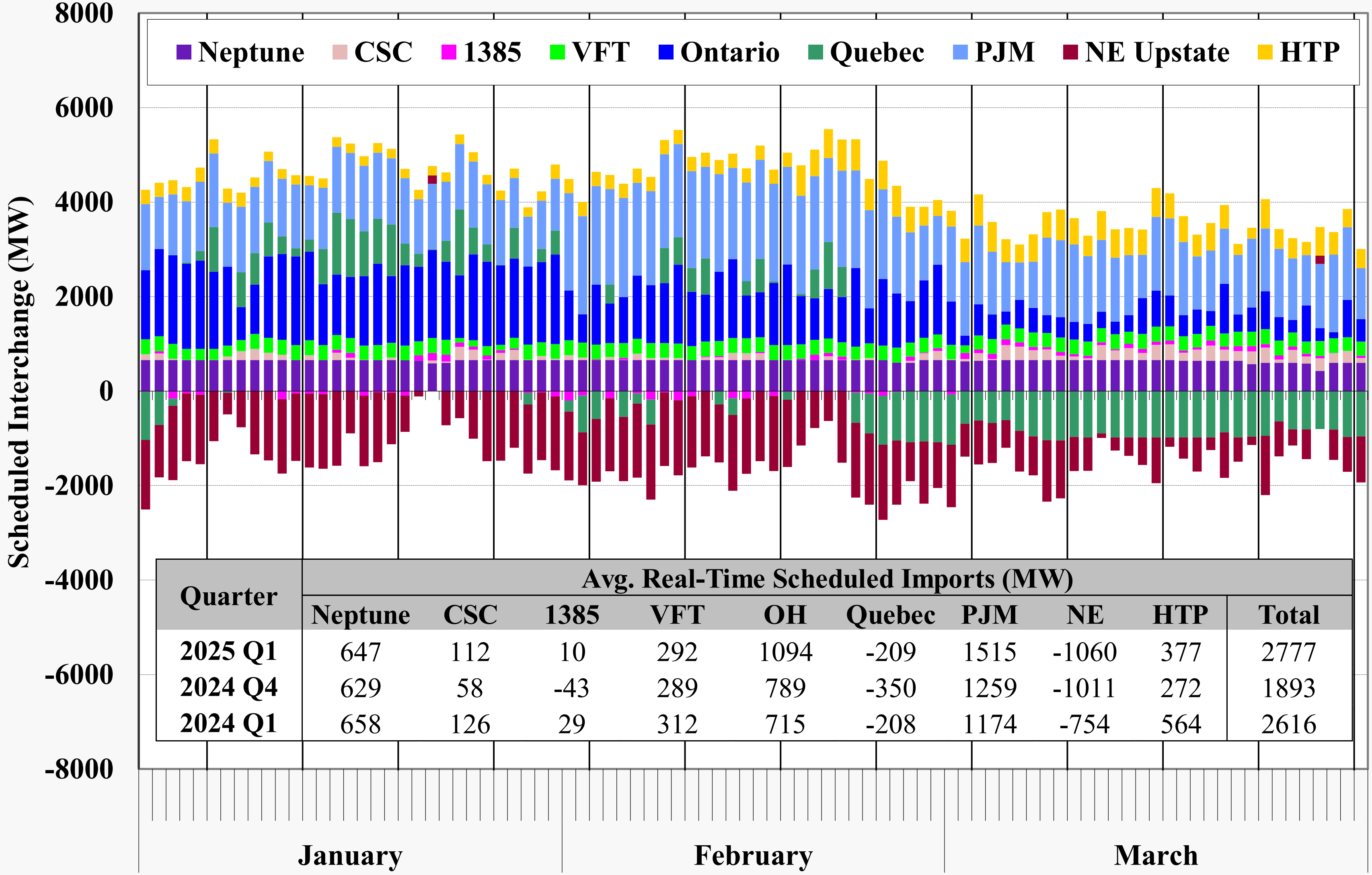


Notes: For chart description, see slide 96.

Net Imports Scheduled Across External Interfaces

Daily Peak Hours (1-9pm)



Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	Quebec	PJM	NE	HTP	Total
2025 Q1	647	112	10	292	1094	-209	1515	-1060	377	2777
2024 Q4	629	58	-43	289	789	-350	1259	-1011	272	1893
2024 Q1	658	126	29	312	715	-208	1174	-754	564	2616

Notes: Two Quebec interfaces are combined into one.

Efficiency of Intra-Hour Scheduling Under CTS

Primary PJM and NE Interfaces

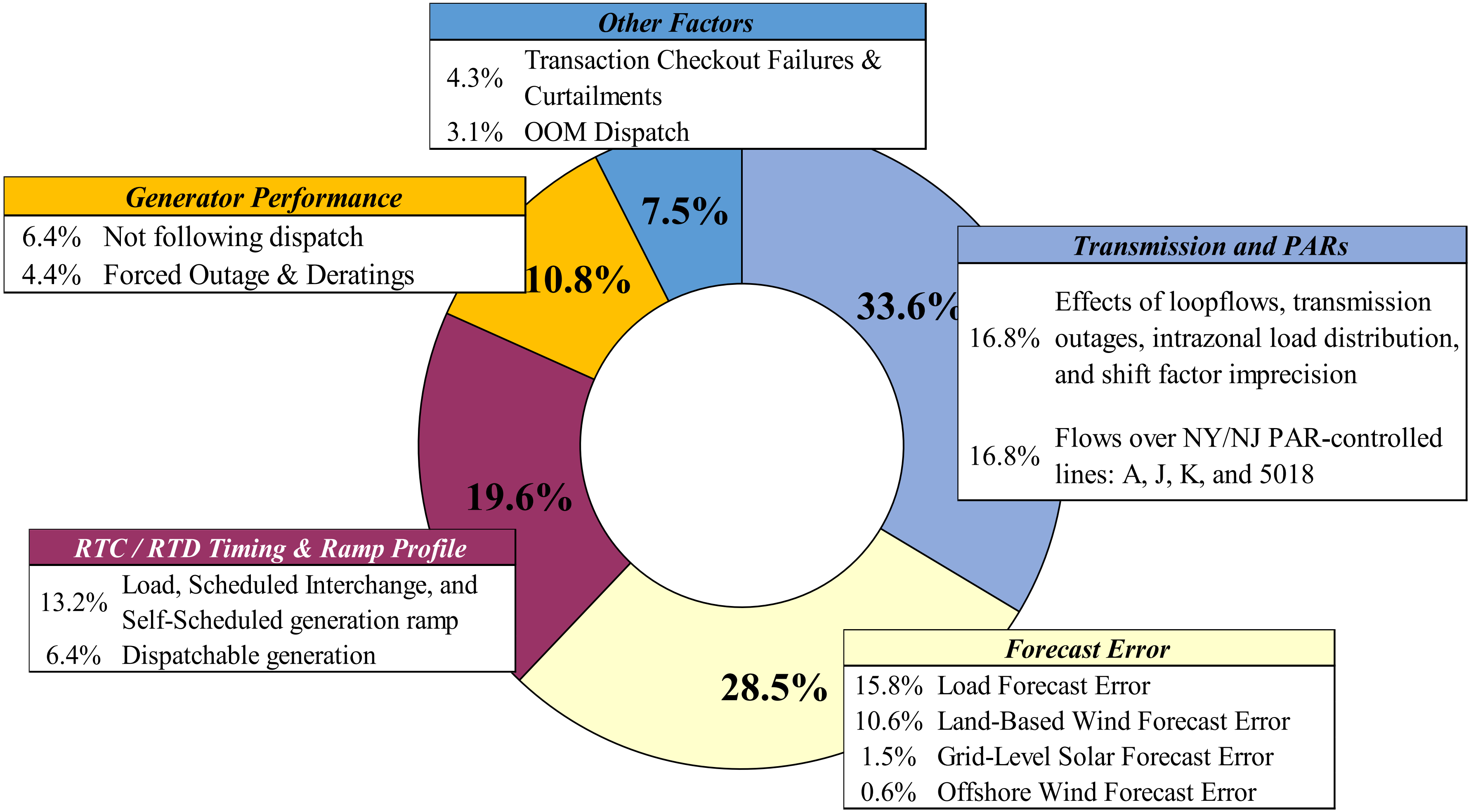
			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total		Both Forecast Errors <= $20	Any Forecast Error > $20	Total	
% of All Intervals w/ Adjustment			50%	27%	**77%**		29%	24%	**54%**	
Average Flow Adjustment (MW)	Net Imports		43	64	**50**		19	-5	**8**	
	Gross		120	150	**130**		75	86	**80**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$2.5	$3.1	**$5.7**		$0.7	$3.2	**$3.9**	
	Net Over-Projection by:	NY	-$0.1	-$0.3	**-$0.4**		$0.0	$0.1	**$0.0**	
		NE or PJM	$0.0	-$0.4	**-$0.3**		$0.0	-$2.7	**-$2.8**	
	Other Unrealized Savings		-$0.1	-$0.3	**-$0.4**		$0.0	$0.0	**$0.0**	
	Actual Savings		$2.4	$2.1	**$4.6**		$0.6	$0.5	**$1.1**	
Interface Prices ($/MWh)	NY	Actual	$73.79	$124.55	**$91.61**	**$89.32**	$56.39	$92.34	**$72.65**	**$76.35**
		Forecast	$74.90	$125.36	**$92.61**	**$90.19**	$57.32	$91.35	**$72.71**	**$77.14**
	NE or PJM	Actual	$73.15	$125.35	**$91.48**	**$96.98**	$44.46	$74.99	**$58.27**	**$55.21**
		Forecast	$73.22	$122.73	**$90.60**	**$97.27**	$46.13	$121.12	**$80.06**	**$68.60**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.11	$0.81	**$1.00**	**$0.87**	$0.93	-$0.99	**$0.06**	**$0.78**
		Abs. Val.	$5.00	$32.07	**$14.50**	**$13.97**	$4.50	$19.46	**$11.27**	**$11.01**
	NE or PJM	Fcst. - Act.	$0.07	-$2.62	**-$0.88**	**$0.29**	$1.68	$46.13	**$21.79**	**$13.39**
		Abs. Val.	$4.77	$30.74	**$13.89**	**$14.02**	$6.61	$73.53	**$36.89**	**$28.71**

For Adjustment Intervals Only

For All Intervals

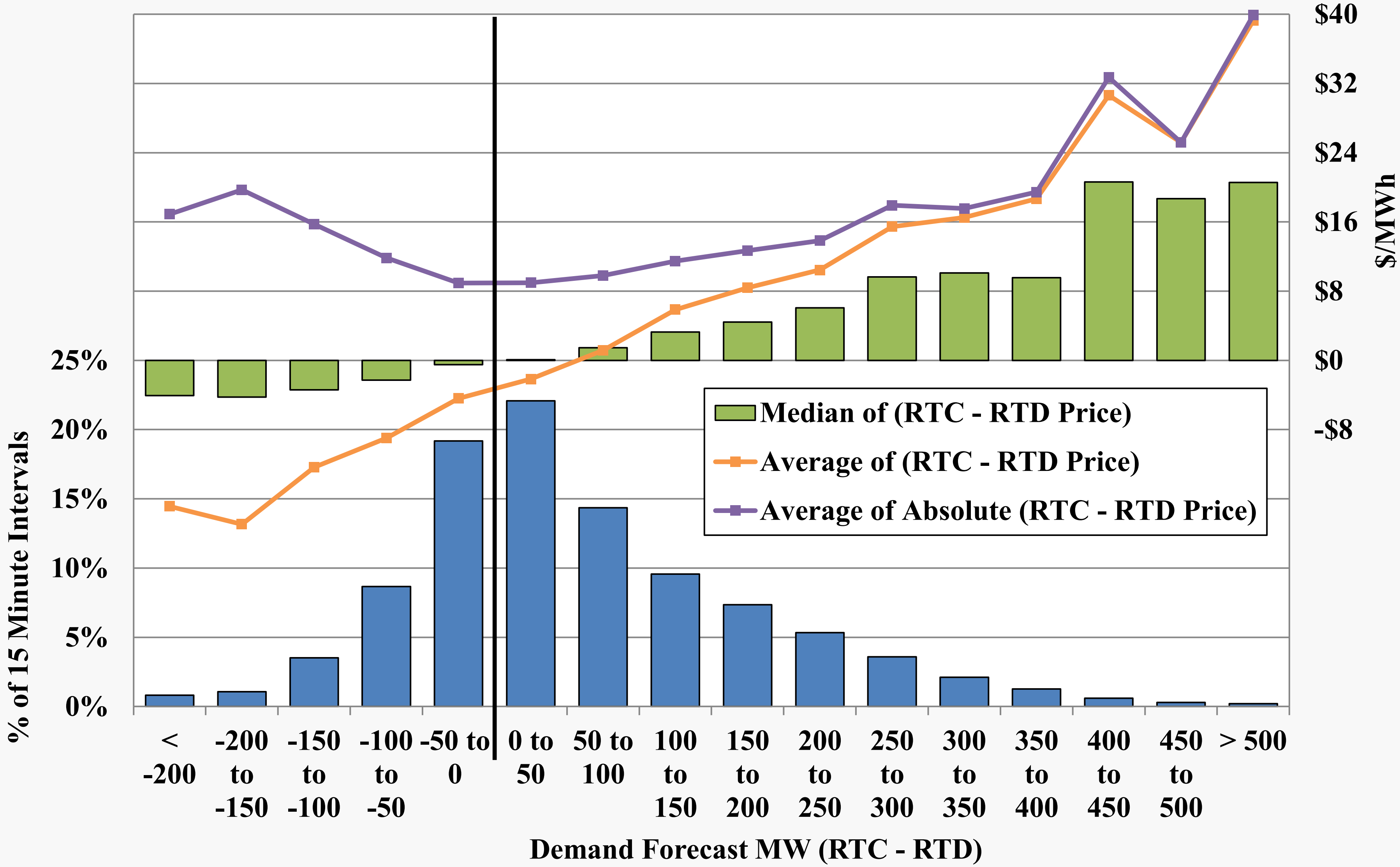
Notes: For chart description, see slide 97.

Detrimental Factors to RTC and RTD Price Divergence



Notes: For chart description, see slide 98.

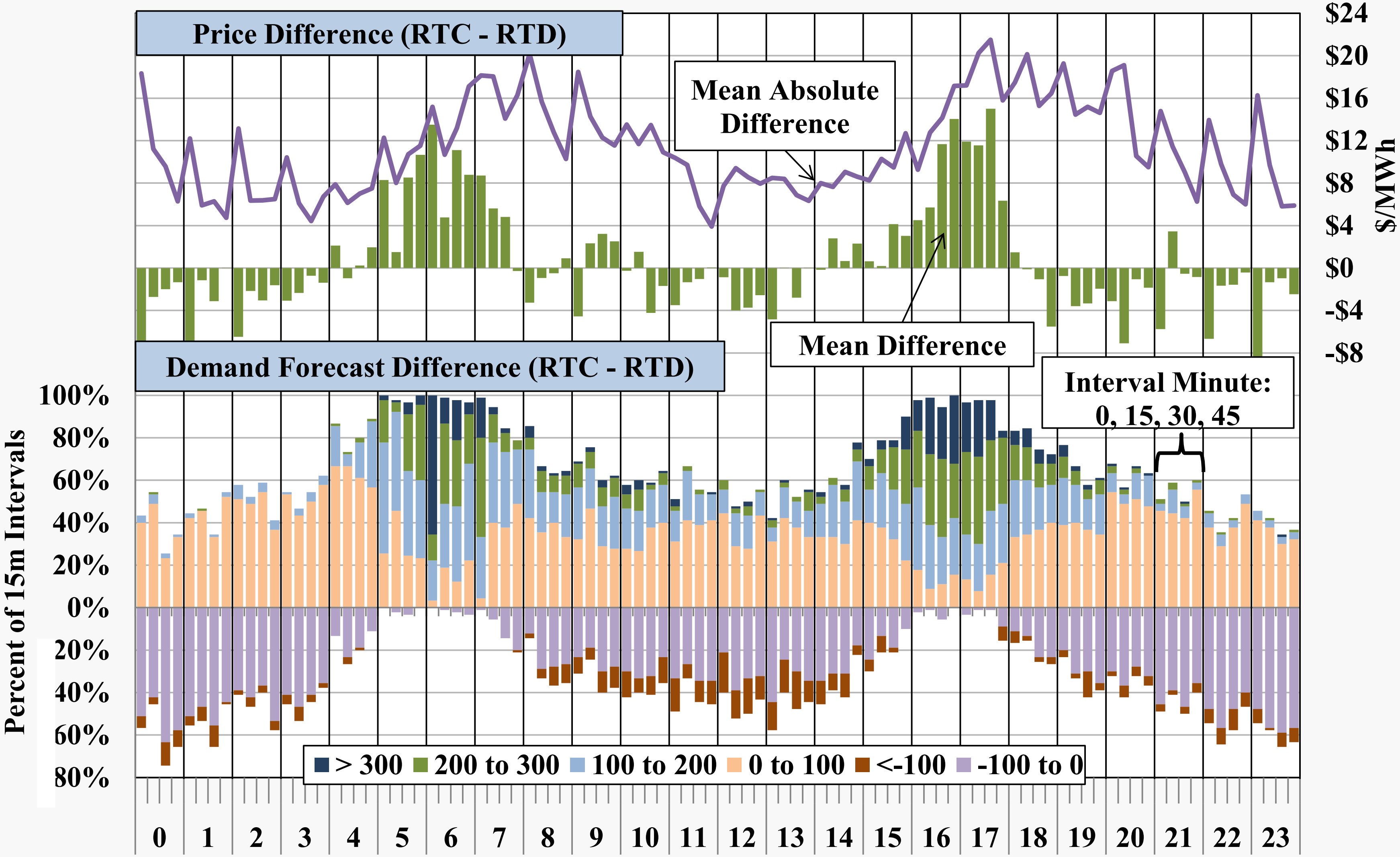
RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide 98.

RTC and RTD Price Difference vs Demand Forecast Difference

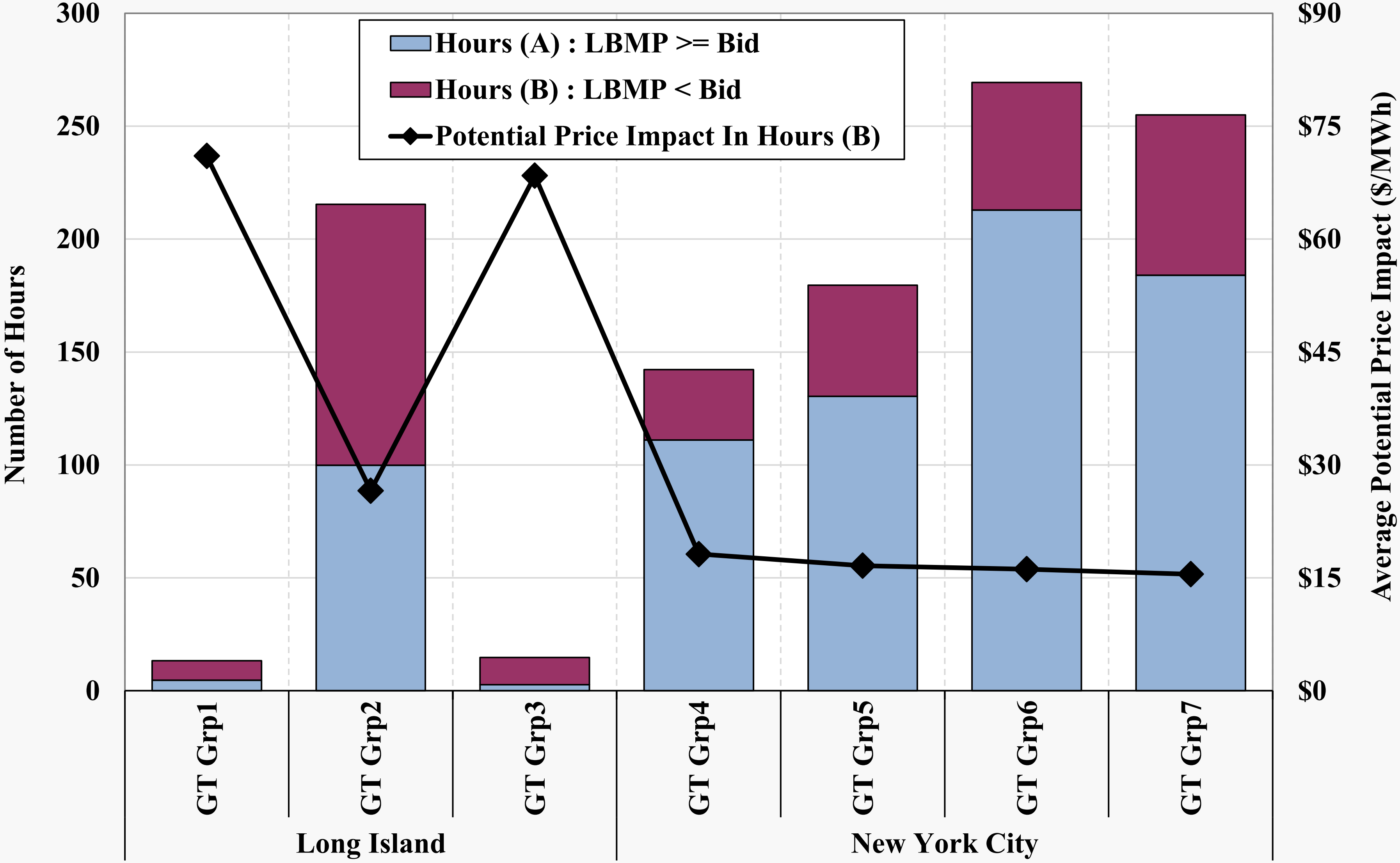
By Time of Day



Notes: For chart description, see slide 99.

Real-Time Prices During Commitments of GTs

Units Offering Multi-Hour Minimum Run Times: 2025 Q1

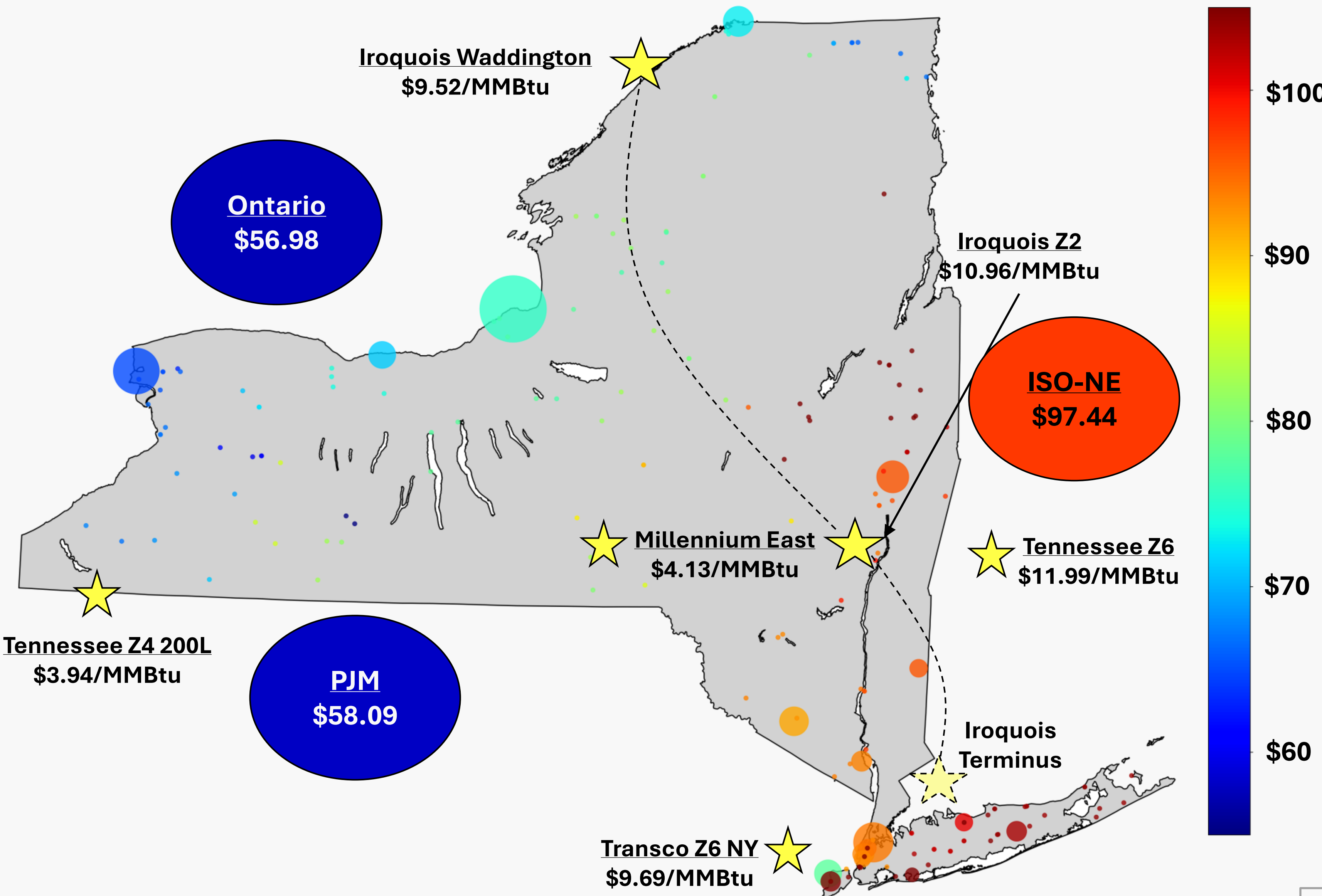


Notes: For chart description, see slide 100.

Charts:
Transmission Congestion Revenues and Shortfalls

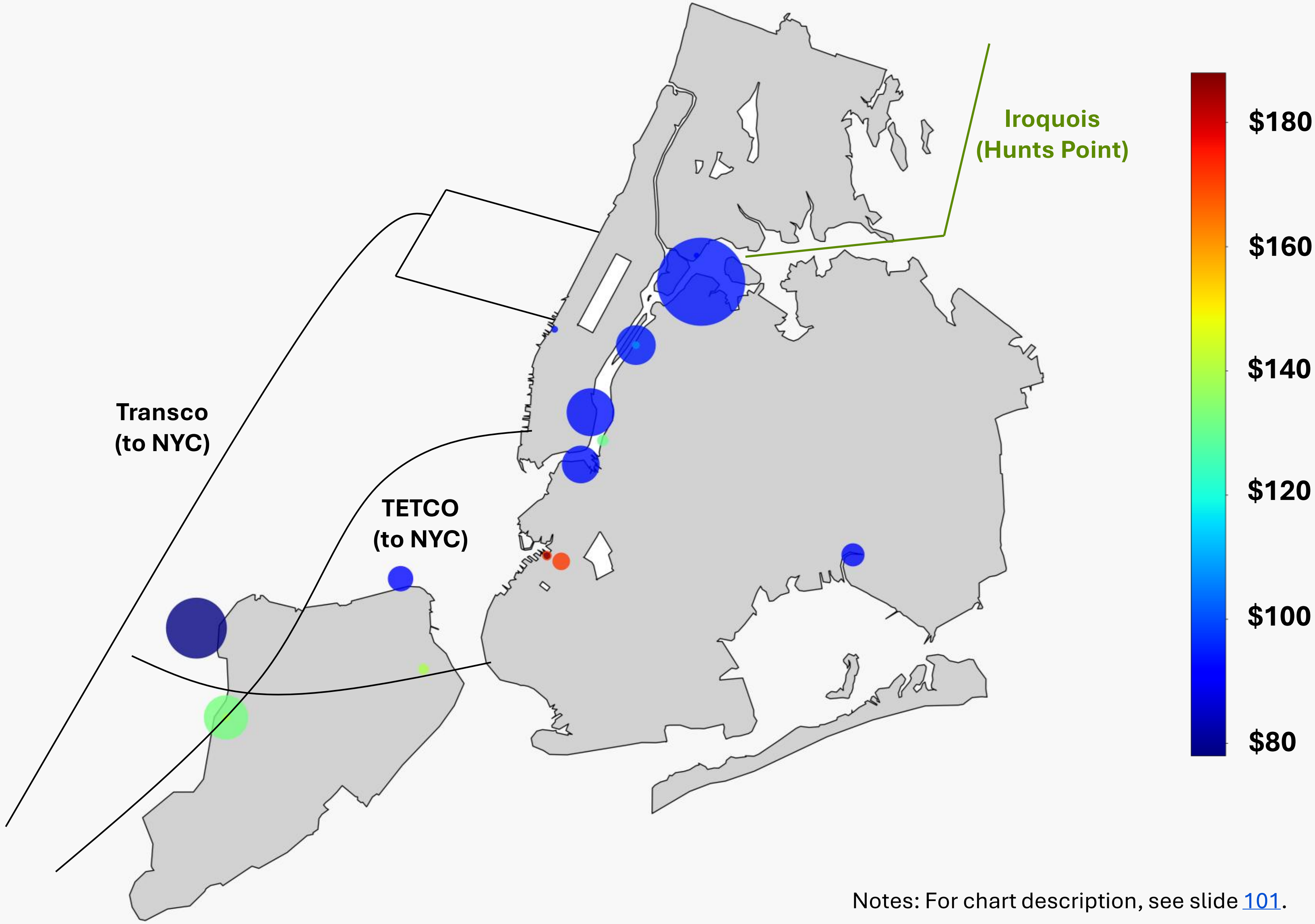
System Congestion

Real-Time Price Map at Generator Nodes



System Congestion

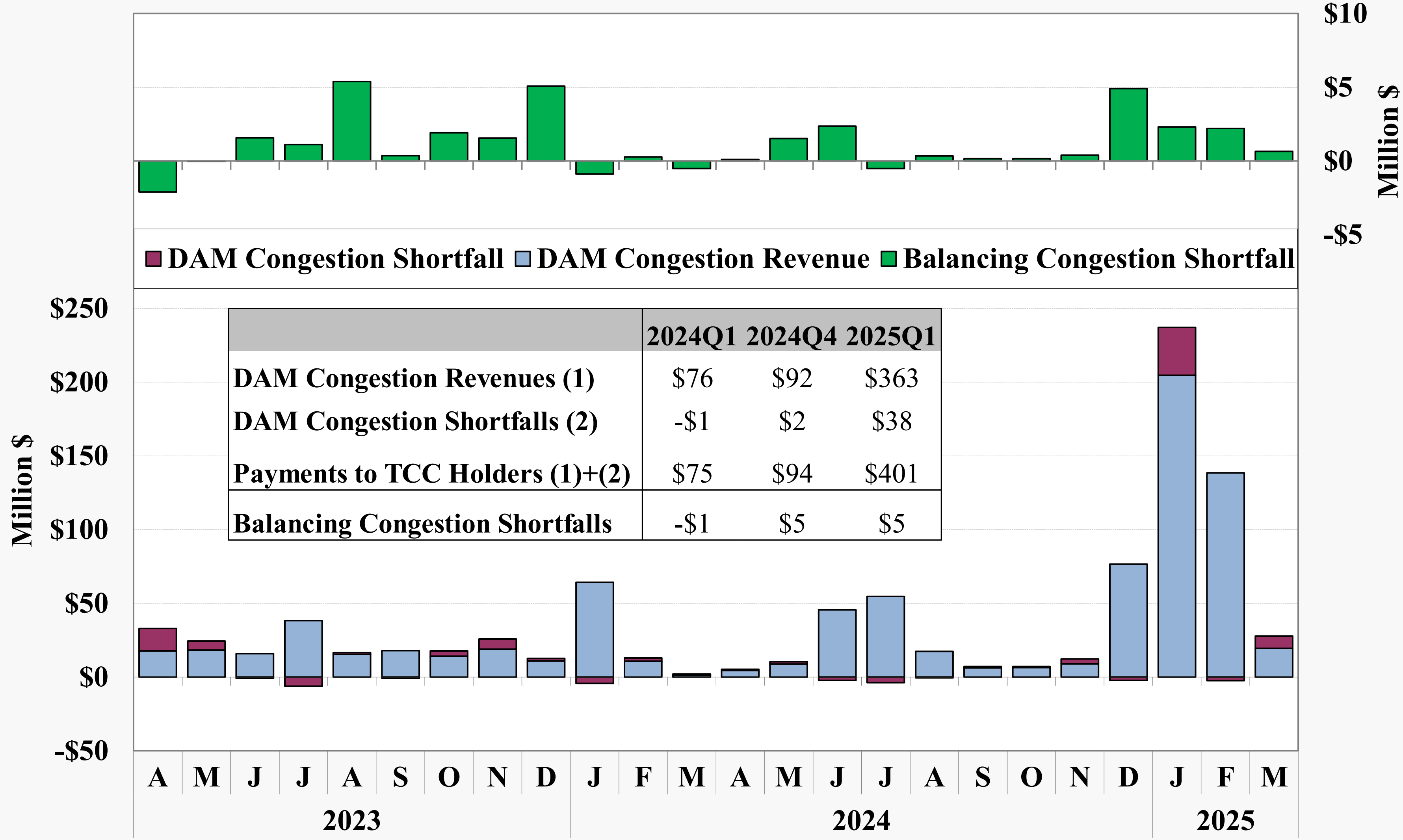
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 101.

Congestion Revenues and Shortfalls

By Month

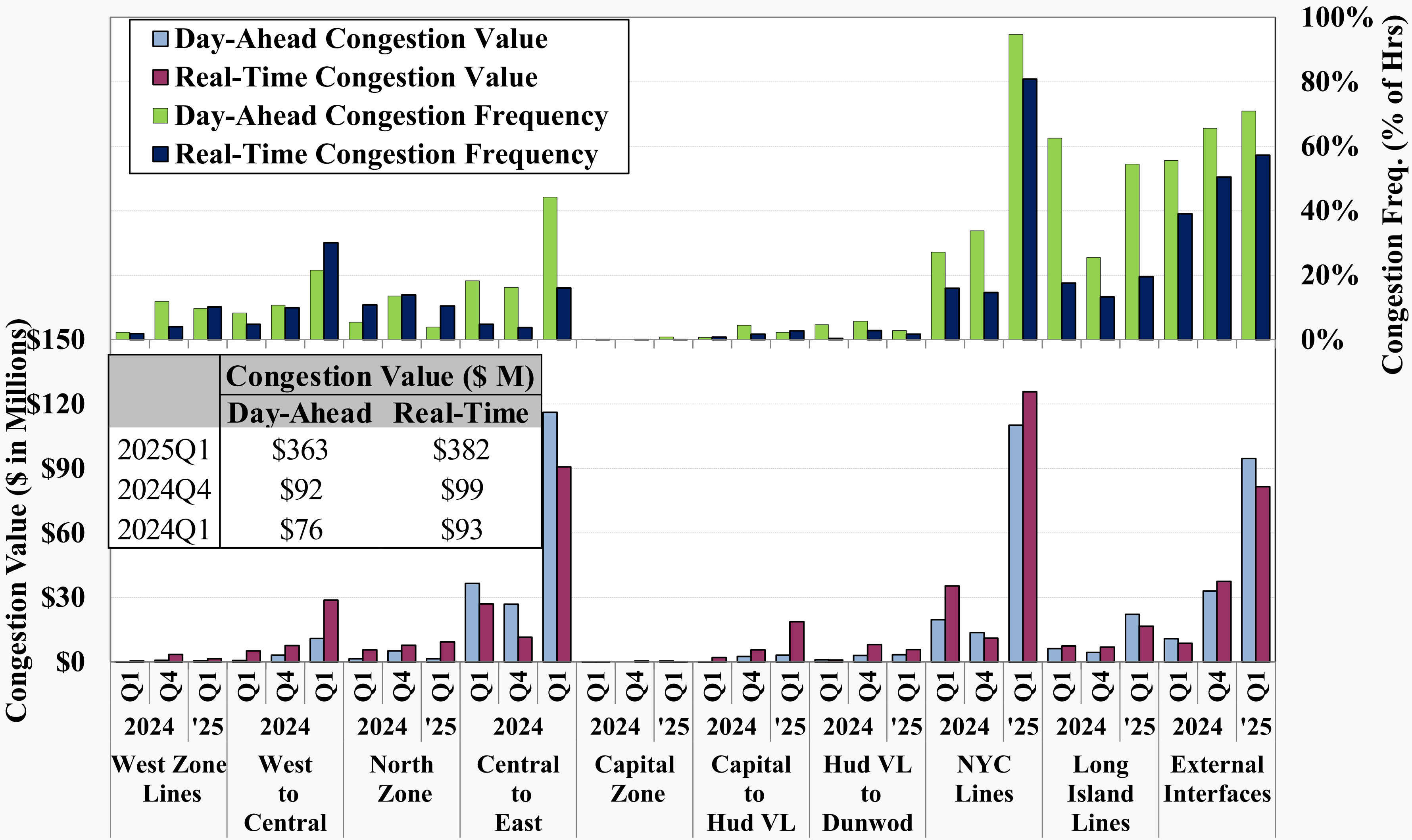


	2024Q1	2024Q4	2025Q1
DAM Congestion Revenues (1)	$76	$92	$363
DAM Congestion Shortfalls (2)	-$1	$2	$38
Payments to TCC Holders (1)+(2)	$75	$94	$401
Balancing Congestion Shortfalls	-$1	$5	$5

Notes: For chart description, see slides 102 and 103.

Day-Ahead and Real-Time Congestion Value

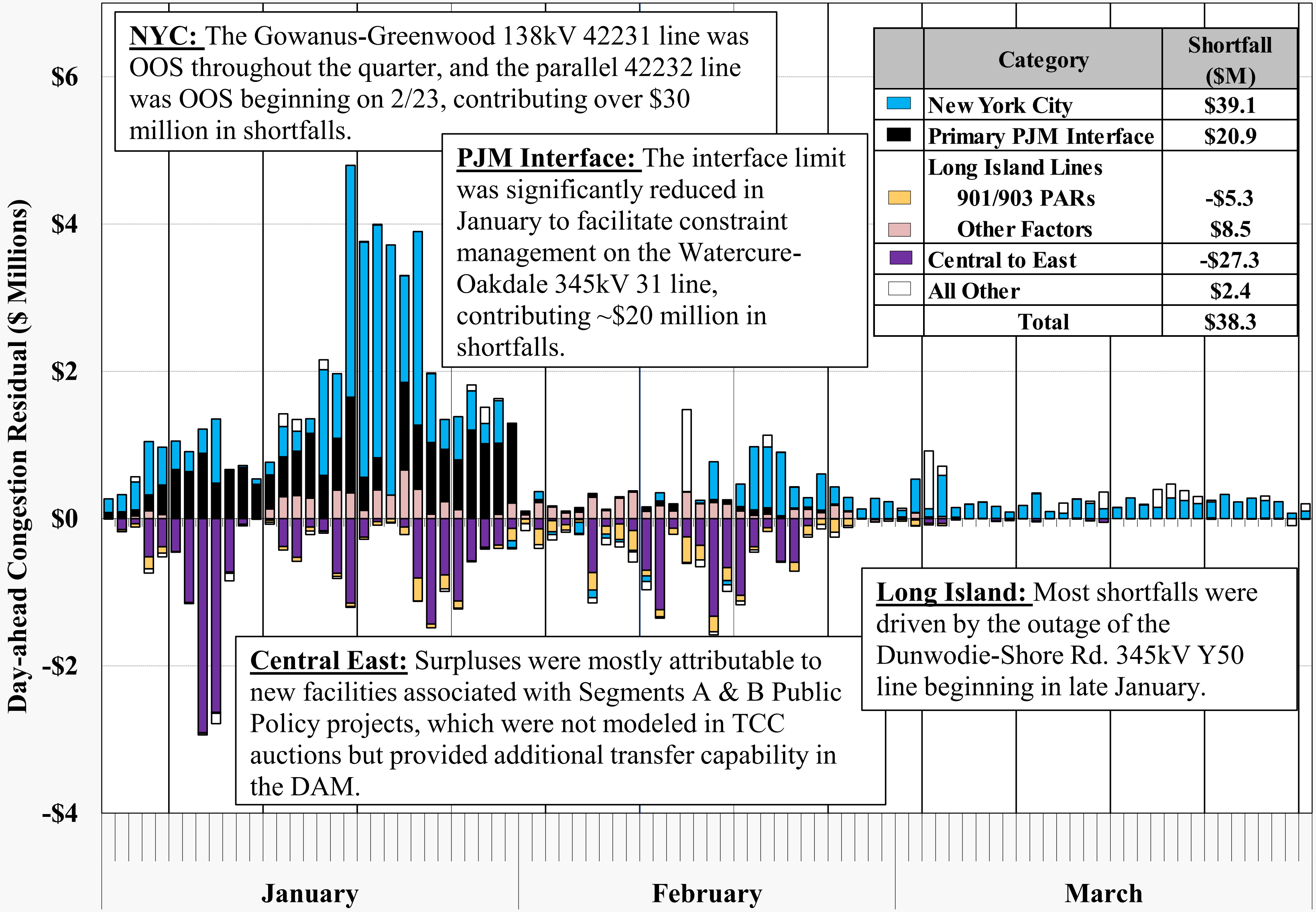
By Transmission Path



Notes: For chart description, see slides 102, 103, and 104.

Day-Ahead Congestion Revenue Shortfalls

By Transmission Facility

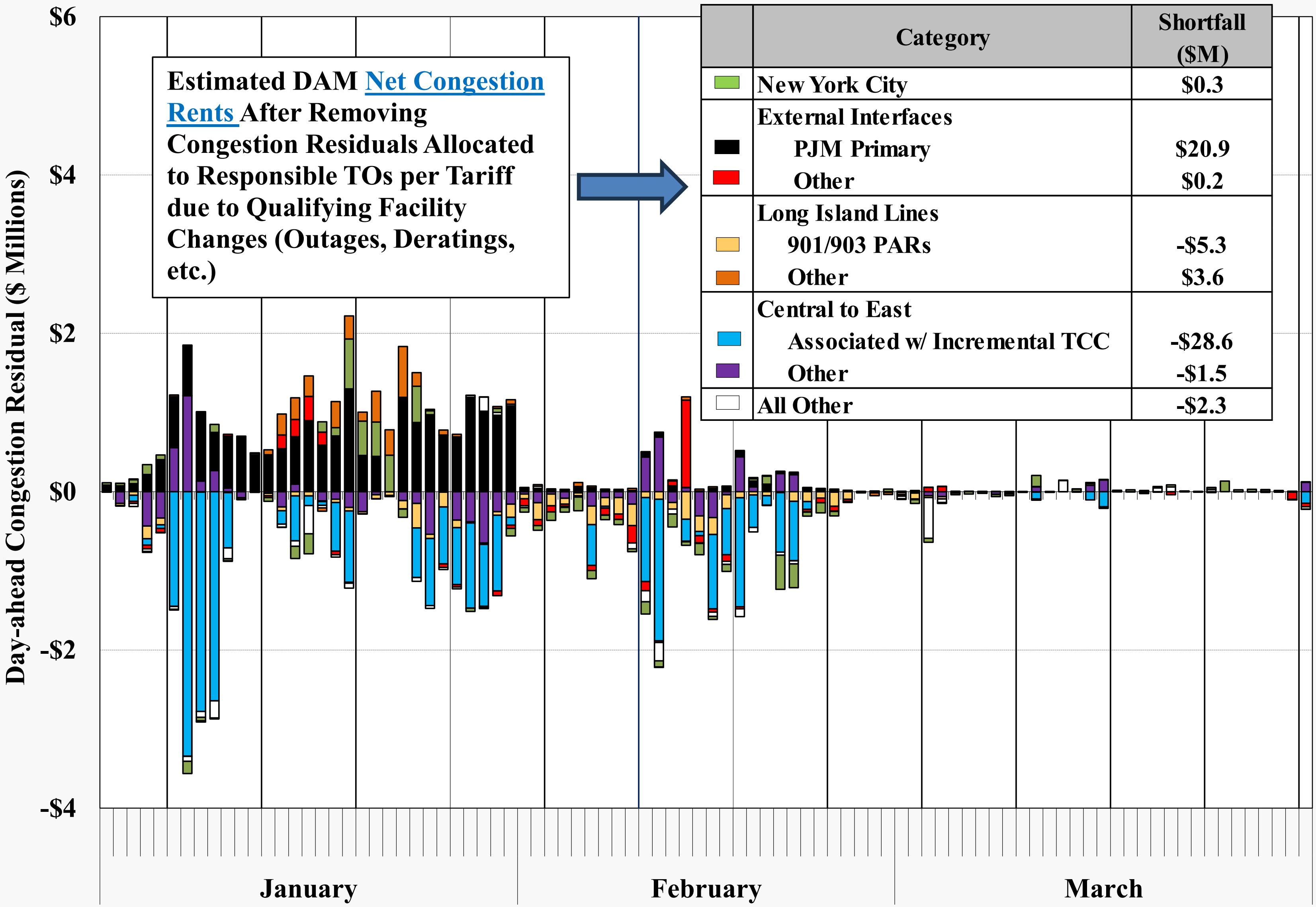


Category	Shortfall ($M)
New York City	$39.1
Primary PJM Interface	$20.9
Long Island Lines	
901/903 PARs	-$5.3
Other Factors	$8.5
Central to East	-$27.3
All Other	$2.4
Total	$38.3

Notes: For chart description, see slides 102, 103, and 104.

Estimated DAM Net Congestion Rents

By Transmission Facility

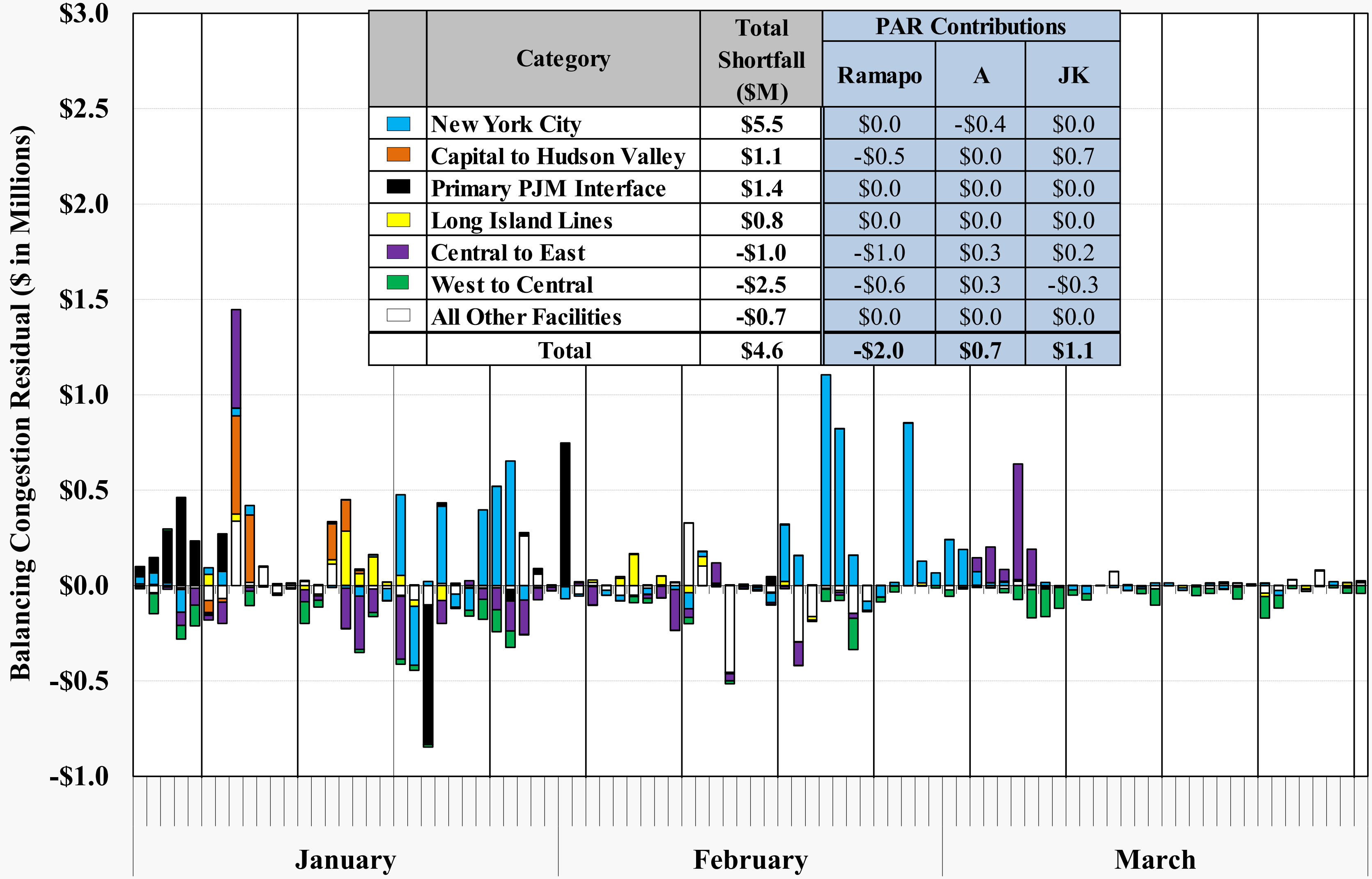


Category	Shortfall ($M)
New York City	$0.3
External Interfaces	
PJM Primary	$20.9
Other	$0.2
Long Island Lines	
901/903 PARs	-$5.3
Other	$3.6
Central to East	
Associated w/ Incremental TCC	-$28.6
Other	-$1.5
All Other	-$2.3

Notes: For chart description, see slides 102, 103, and 104.

Balancing Congestion Shortfalls

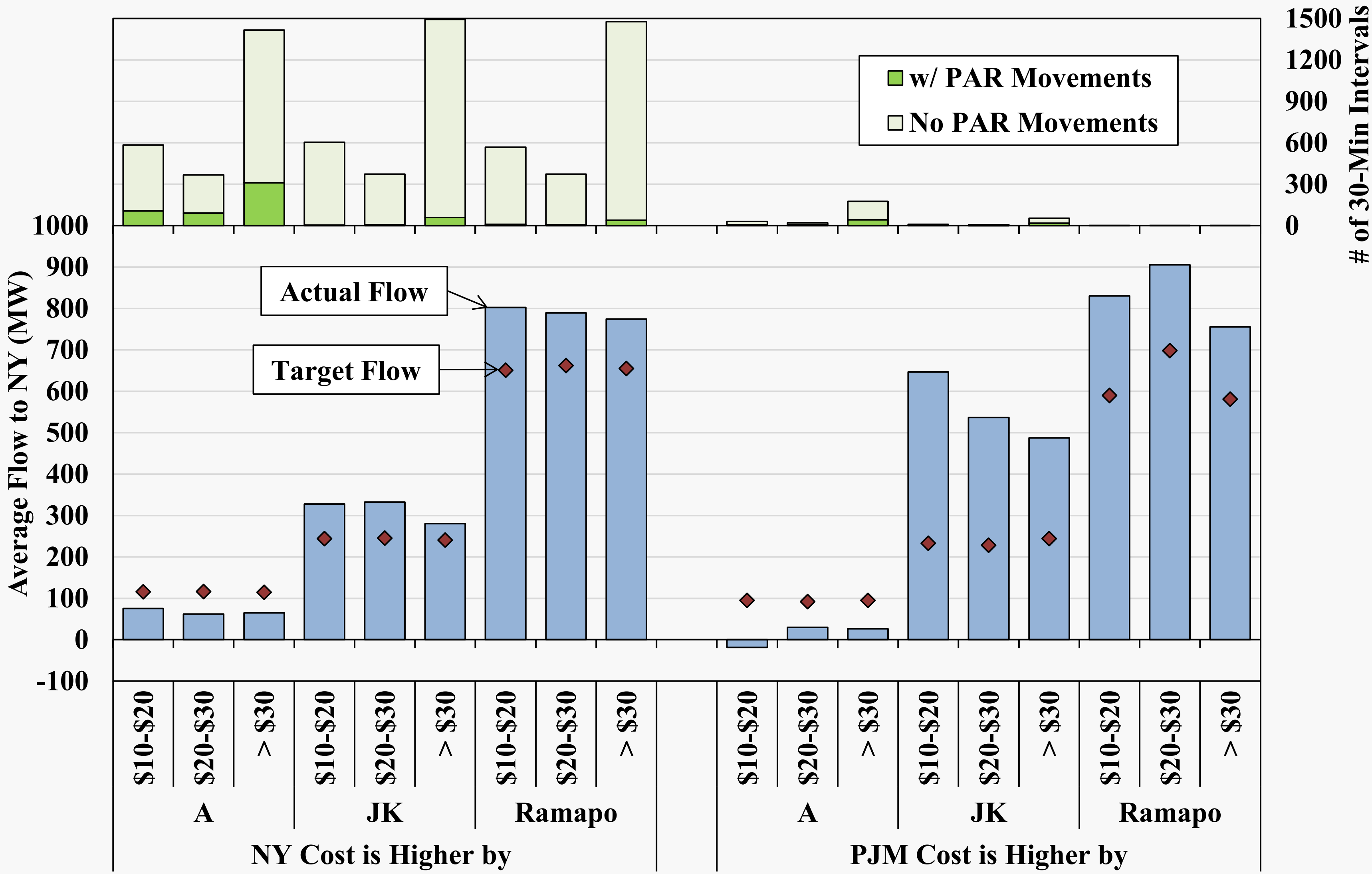
By Transmission Facility



	Category	Total Shortfall ($M)	PAR Contributions		
			Ramapo	A	JK
New York City	New York City	$5.5	$0.0	-$0.4	$0.0
Capital to Hudson Valley	Capital to Hudson Valley	$1.1	-$0.5	$0.0	$0.7
Primary PJM Interface	Primary PJM Interface	$1.4	$0.0	$0.0	$0.0
Long Island Lines	Long Island Lines	$0.8	$0.0	$0.0	$0.0
Central to East	Central to East	-$1.0	-$1.0	$0.3	$0.2
West to Central	West to Central	-$2.5	-$0.6	$0.3	-$0.3
All Other Facilities	All Other Facilities	-$0.7	$0.0	$0.0	$0.0
	Total	$4.6	-$2.0	$0.7	$1.1

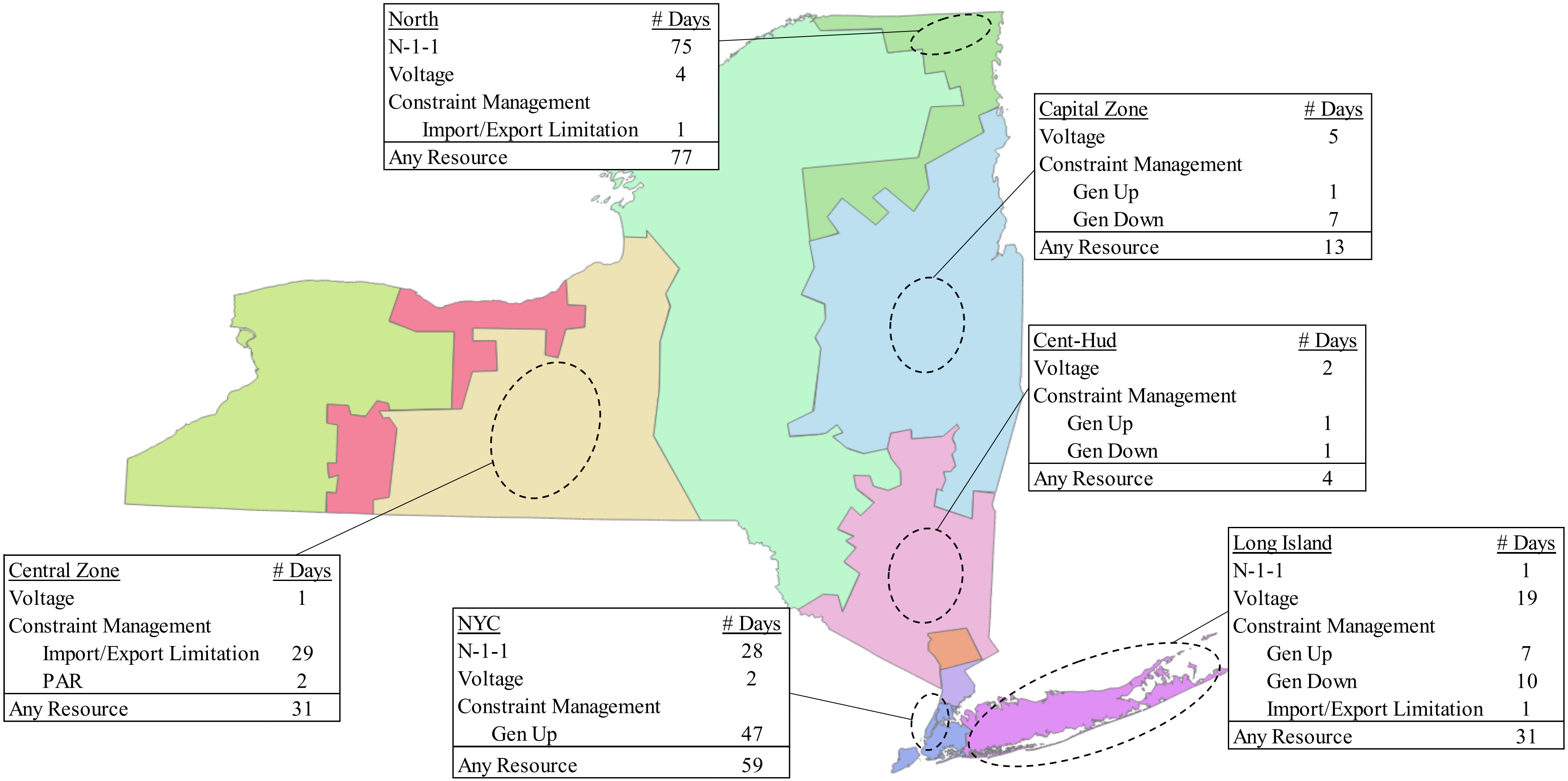
Notes: 1. The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. 2. For chart description, see slides 102, 103, and 104.

PAR Operation under M2M with PJM: 2025 Q1



Notes: For chart description, see slide 105.

OOM Actions to Manage Network Reliability



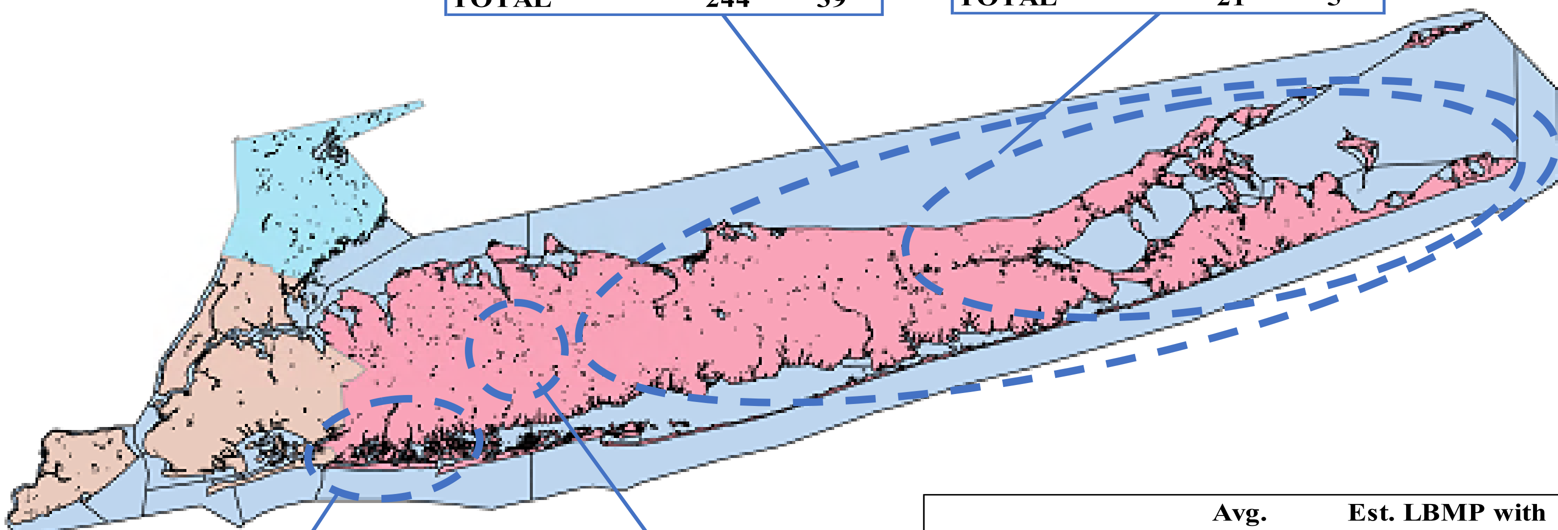
Notes: For chart description, see slide 106

Constraints on the Low Voltage Network

Long Island Load Pockets

East of Northport	#Hours	#Days
69kV OOM	61	12
69kV	197	31
138kV	39	7
TOTAL	244	39

East End	#Hours	#Days
69kV OOM	21	5
69kV	0	0
TOTAL	21	5



Valley Stream	#Hours	#Days
69kV OOM	13	2
138kV	529	52
TOTAL	539	53

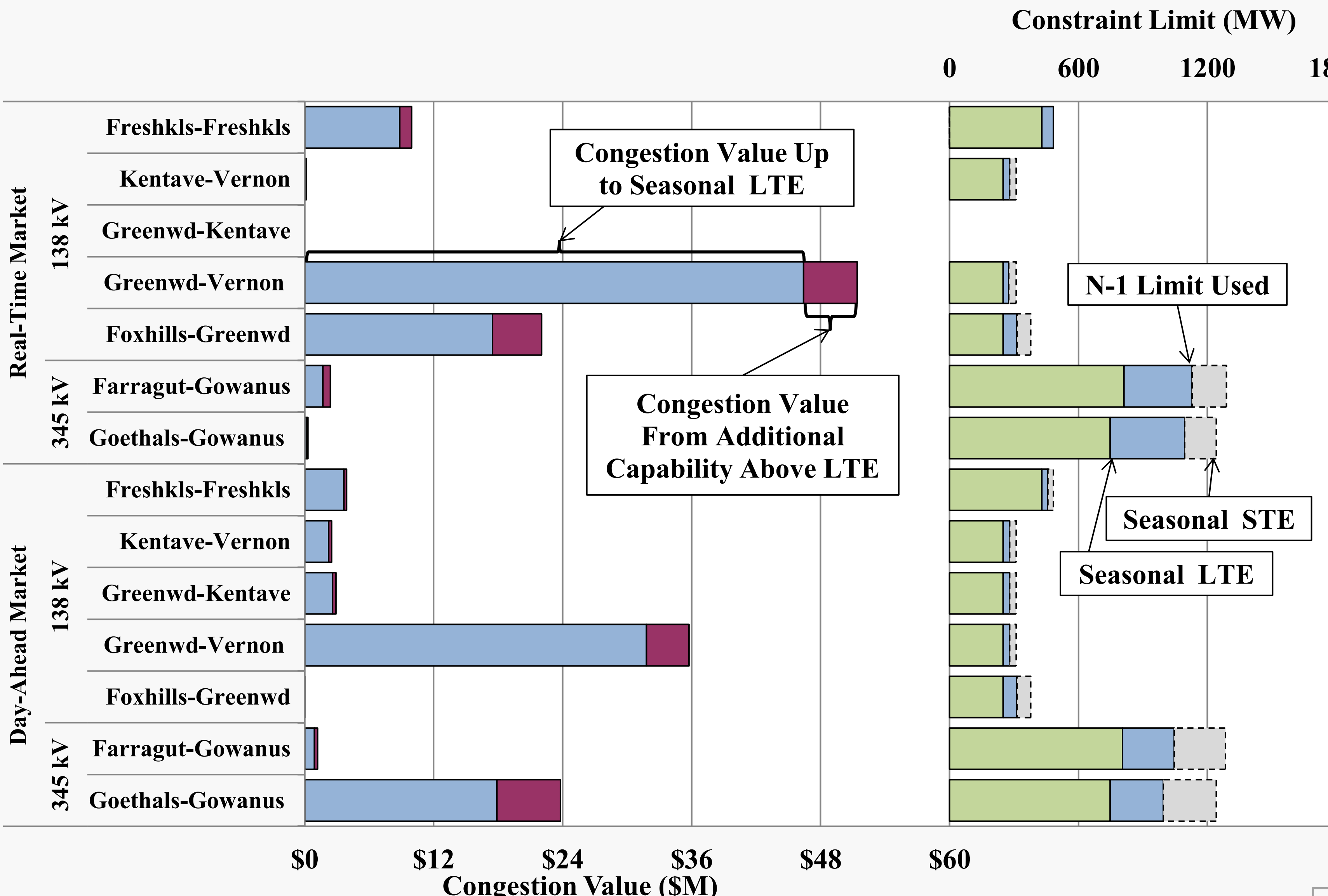
Brentwood	#Hours	#Days
69kV OOM	0	0
69kV	0	0
TOTAL	0	0

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$95.26	$95.26
East End	$96.79	$98.05
East of Northport	$96.24	$96.68
Valley Stream	$105.37	$106.78

Notes: For chart description, see slides 106-107

N-1 Constraints in New York City

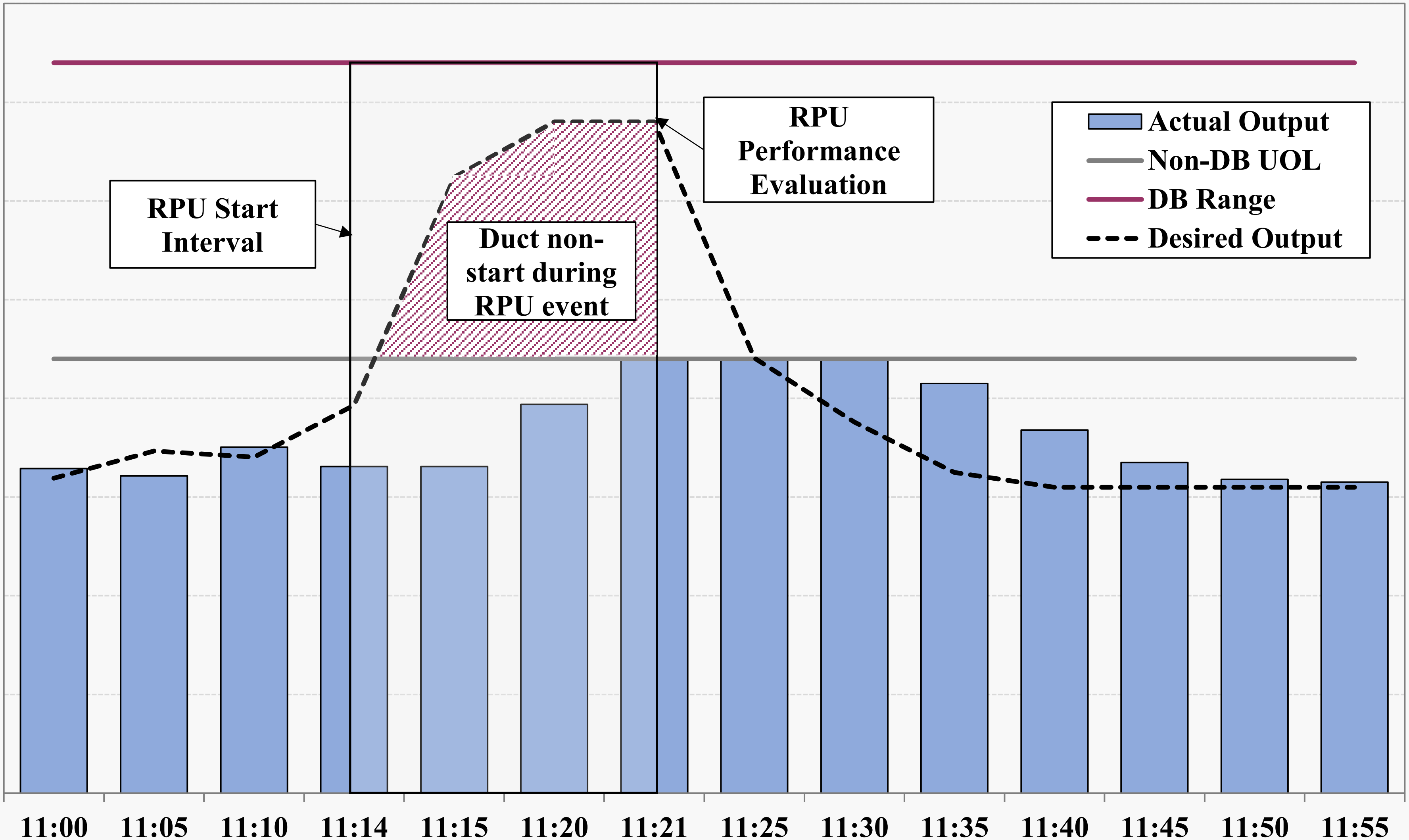
Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide 108

Duct Burner Real-Time Dispatch Issues

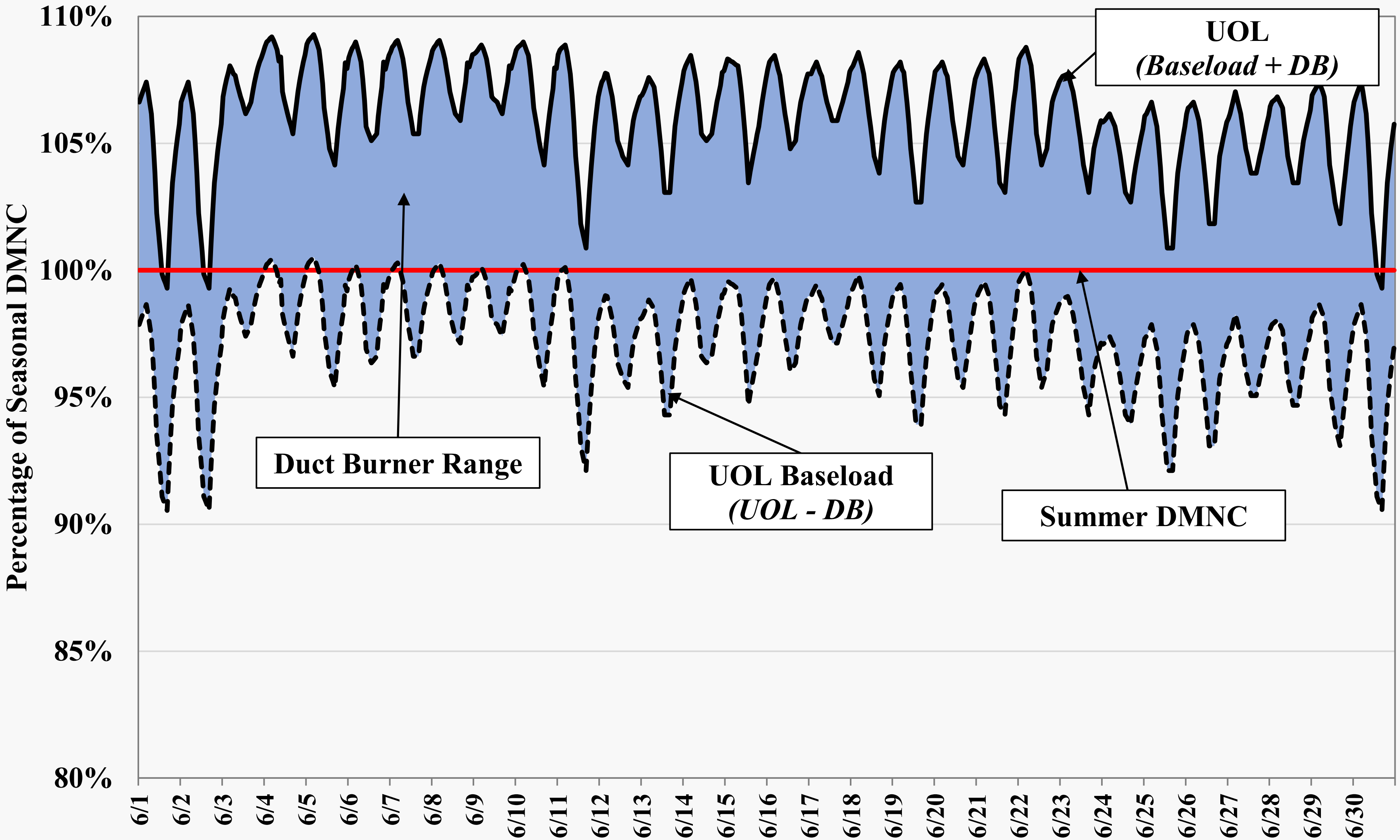
Example of a Failed RPU



Notes: For chart description, see slide 109

Illustration of Duct Burner Range

Example Generator Hourly Capability

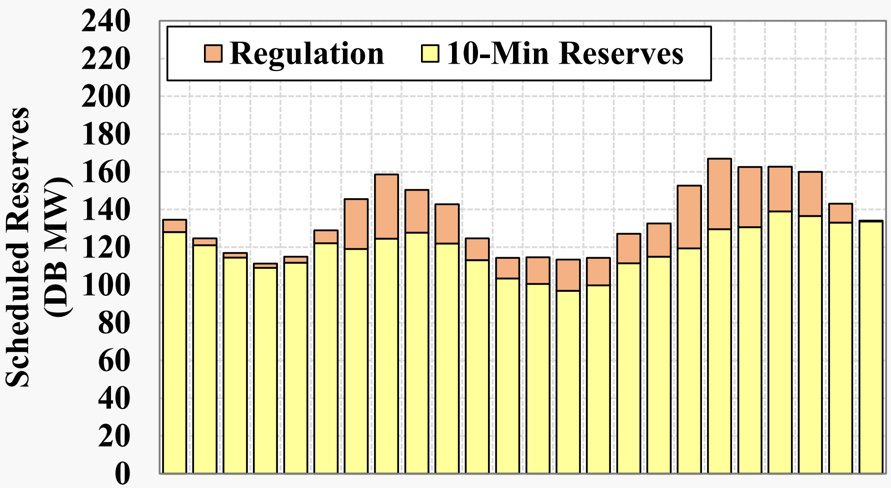


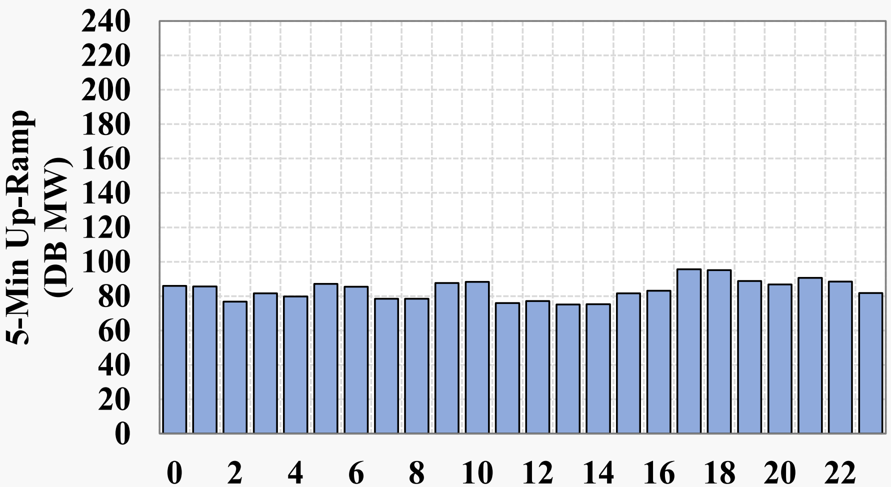
Notes: For chart description, see slide 110

Duct Burner Schedules and Ramp Expectations

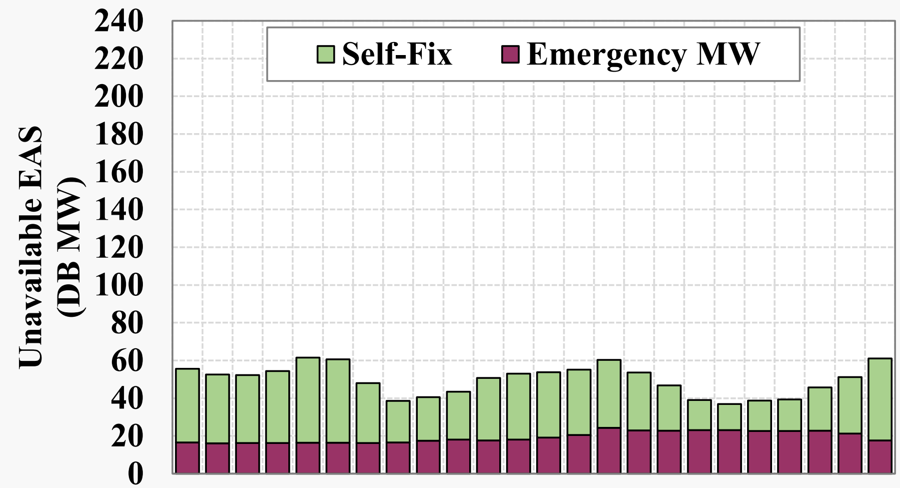
Evaluation of Duct Availability in Real-Time

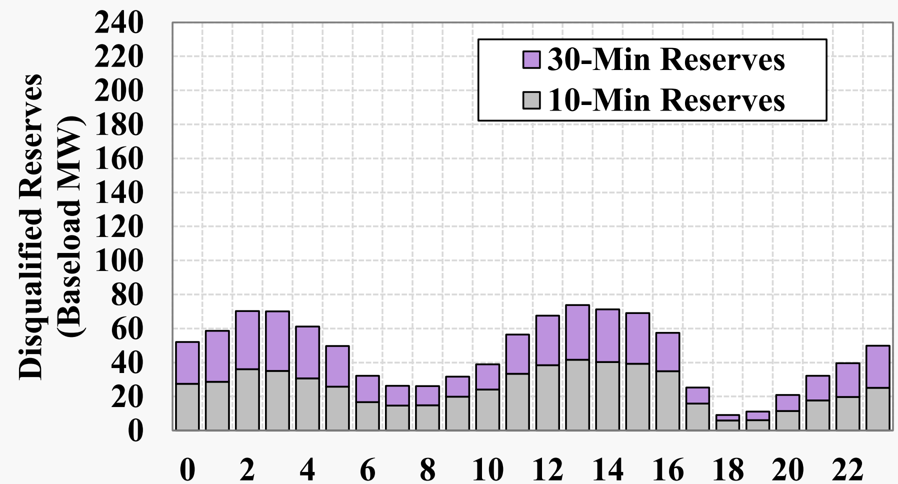
Scheduled or Offered Duct Capacity – but Unable to Follow RT Instructions





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





Notes: For chart description, see slide 109

Gas Turbine Start-up Performance

Economic Starts & Audits

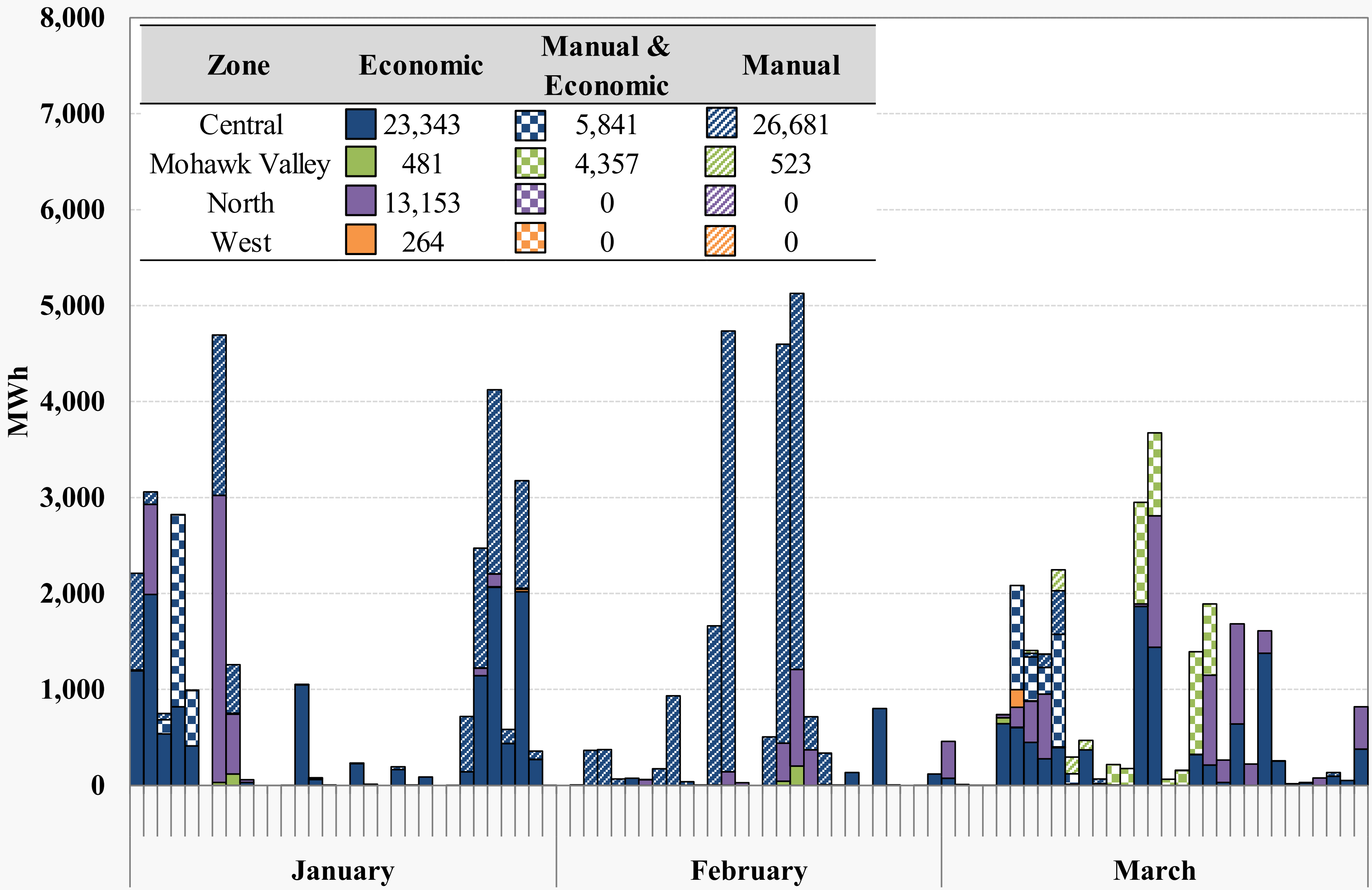
POTOMAC ECONOMICS

10/30-Minute GT Start Performance - Apr 2024 - Mar 2025						
Performance Category	No. of Units	Total No. of Starts Evaluated	RPUs + Unforeseen Economic Starts and Audits		Remaining Economic Starts and Audits	
			Performance On Time	Performance 10 Min Later	Performance On Time	Performance 10 Min Later
0% - 10%	0	0				
10% - 20%	0	0				
20% - 30%	1	14	25.1%	51.6%		
30% - 40%	1	8	35.9%	37.5%		
40% - 50%	1	4			46.0%	70.0%
50% - 60%	0	0				
60% - 70%	3	48	48.4%	88.0%	71.1%	80.3%
70% - 80%	3	100	65.4%	66.2%	84.5%	87.1%
80% - 90%	29	3831	85.1%	94.7%	86.9%	94.2%
90% - 100%	66	6130	95.1%	97.7%	94.5%	97.5%

Notes: For chart description, see slide 111

Daily Wind Curtailments

Economic and Manual Curtailments by Zone



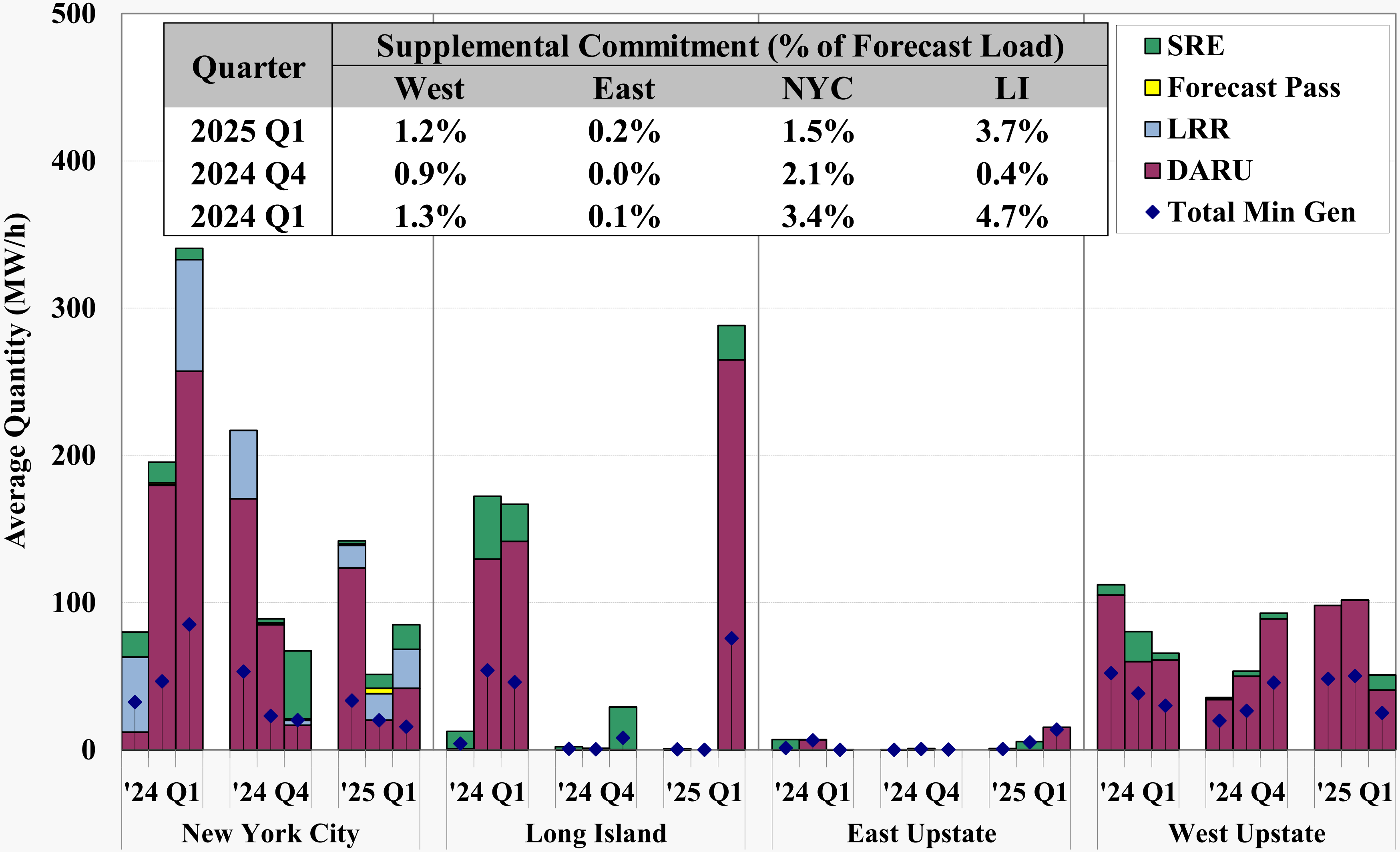
Notes: For chart description, see slide 112.

Charts:
Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability

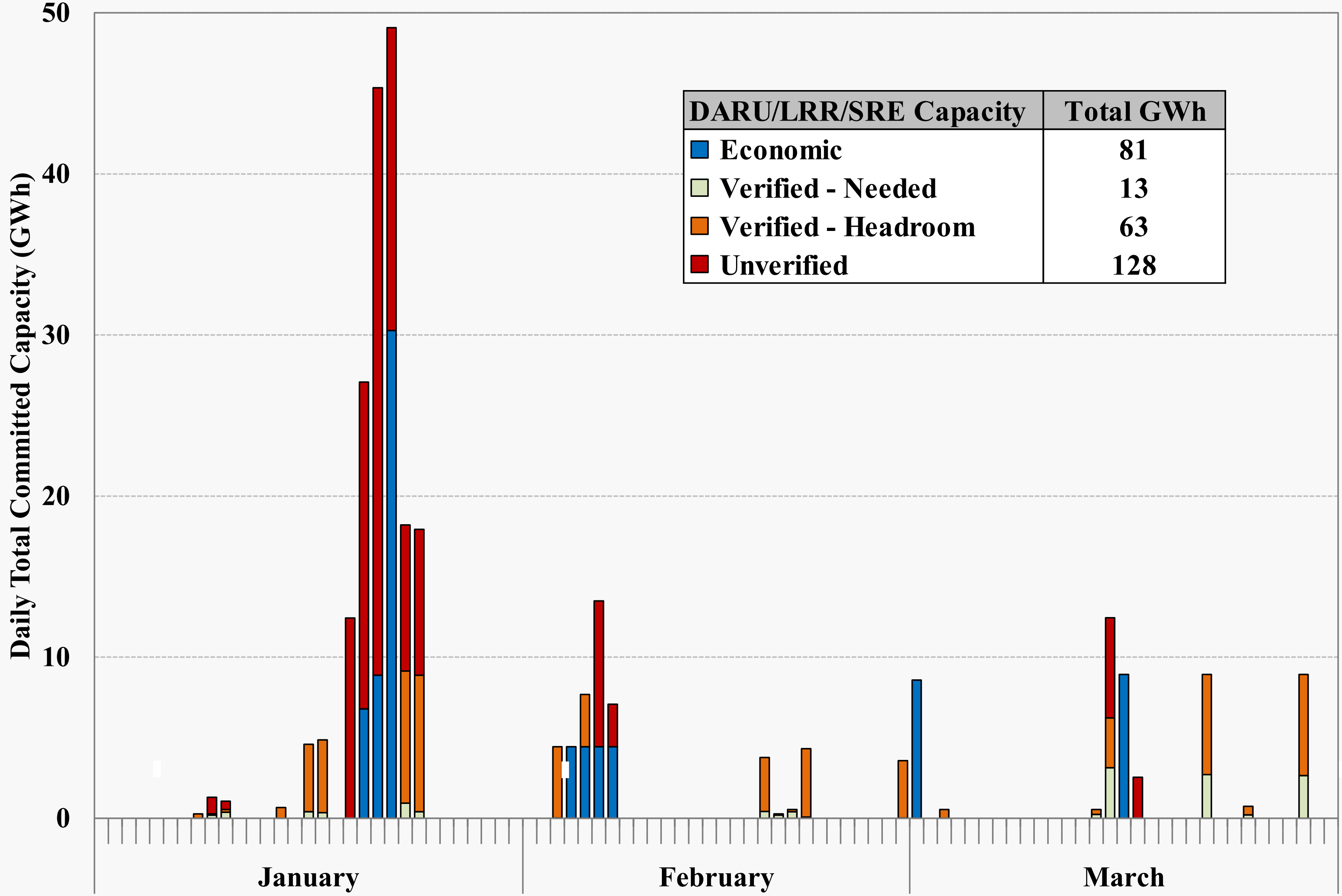
By Category and Region

Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2025 Q1	1.2%	0.2%	1.5%	3.7%
2024 Q4	0.9%	0.0%	2.1%	0.4%
2024 Q1	1.3%	0.1%	3.4%	4.7%



Notes: For chart description, see slides 113.

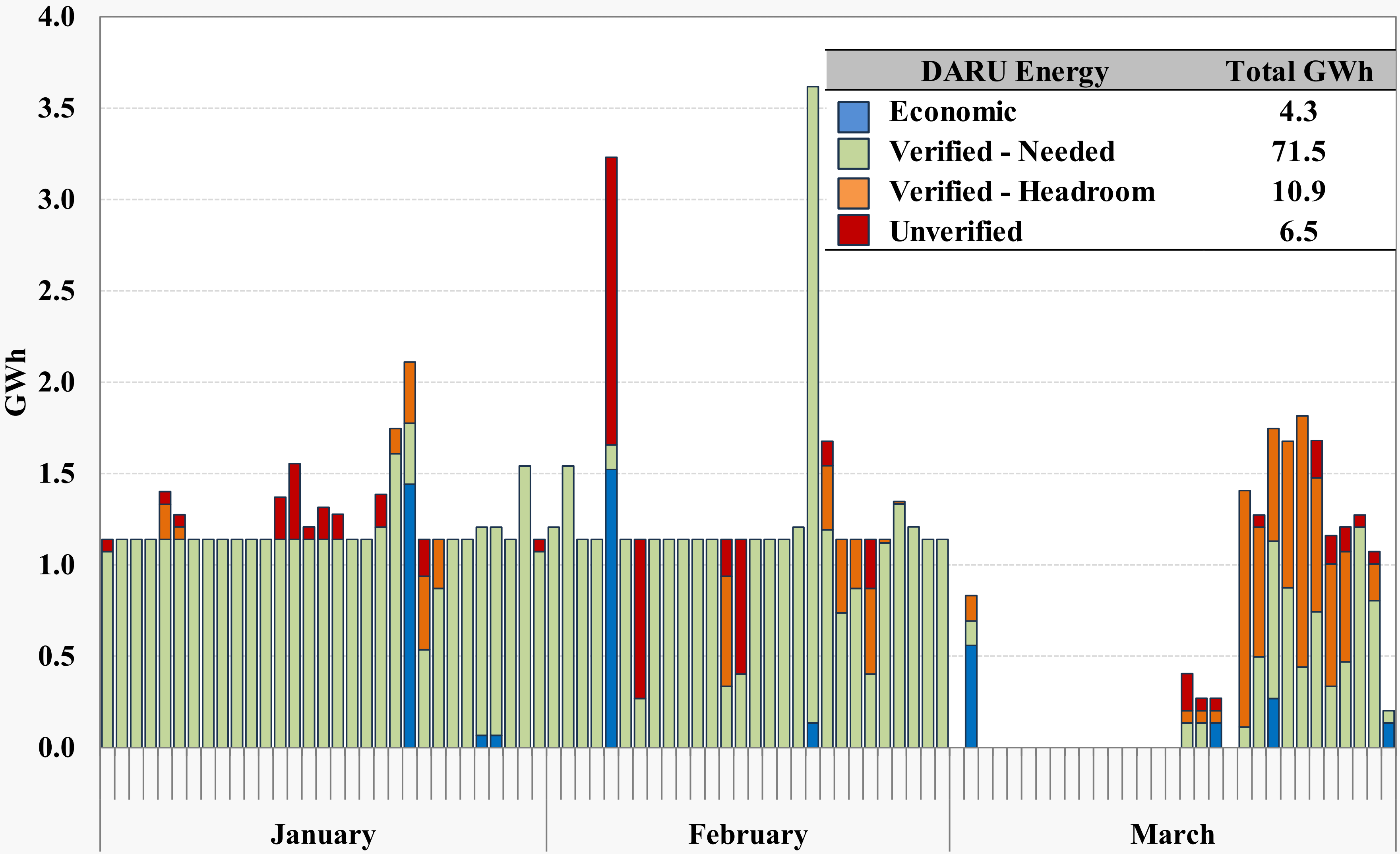
DARU/LRR/SRE Commitments in NYC: 2025 Q1



DARU/LRR/SRE Capacity	Total GWh
Economic	81
Verified - Needed	13
Verified - Headroom	63
Unverified	128

Notes: For chart description, see slide 114.

DARU Commitments in North Country: 2025 Q1



Notes: For chart description, see slide 114.

Key Drivers of SRE Commitments for Systemwide Capacity

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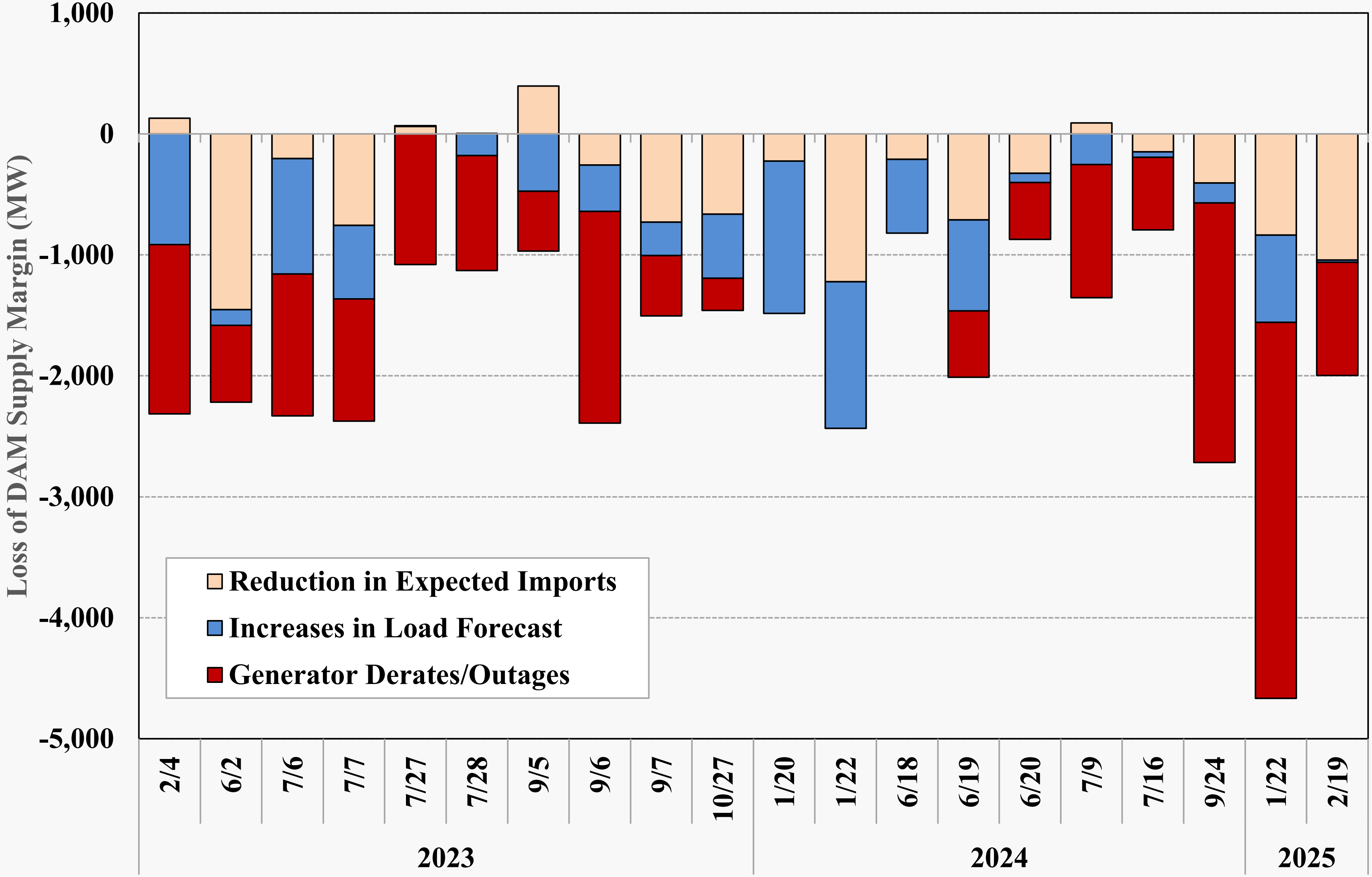
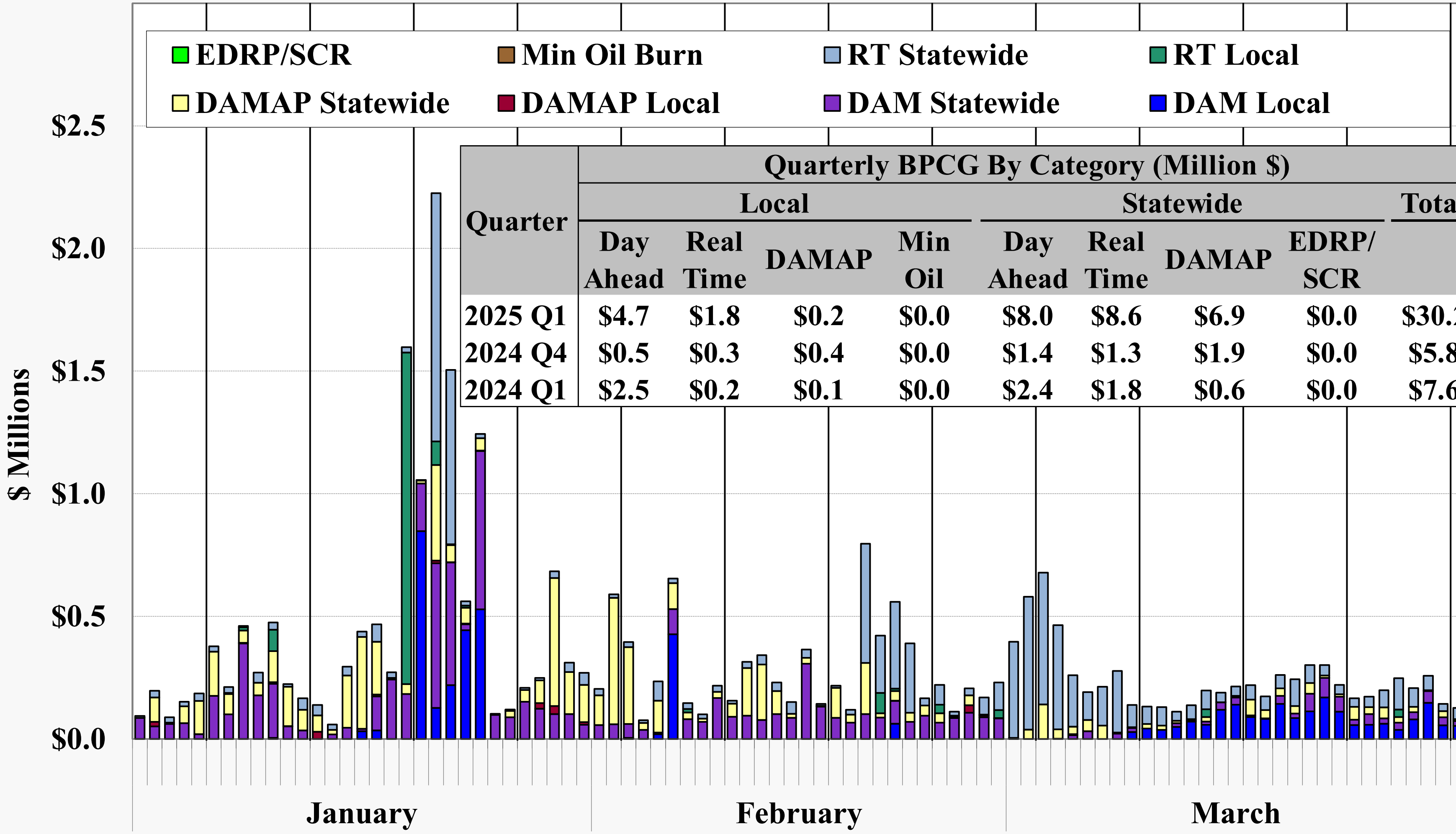


Notes: For chart description, see slide 115.

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	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2025 Q1	$4.7	$1.8	$0.2	$0.0	$8.0	$8.6	$6.9	$0.0	$30.2
2024 Q4	$0.5	$0.3	$0.4	$0.0	$1.4	$1.3	$1.9	$0.0	$5.8
2024 Q1	$2.5	$0.2	$0.1	$0.0	$2.4	$1.8	$0.6	$0.0	$7.6

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 116.

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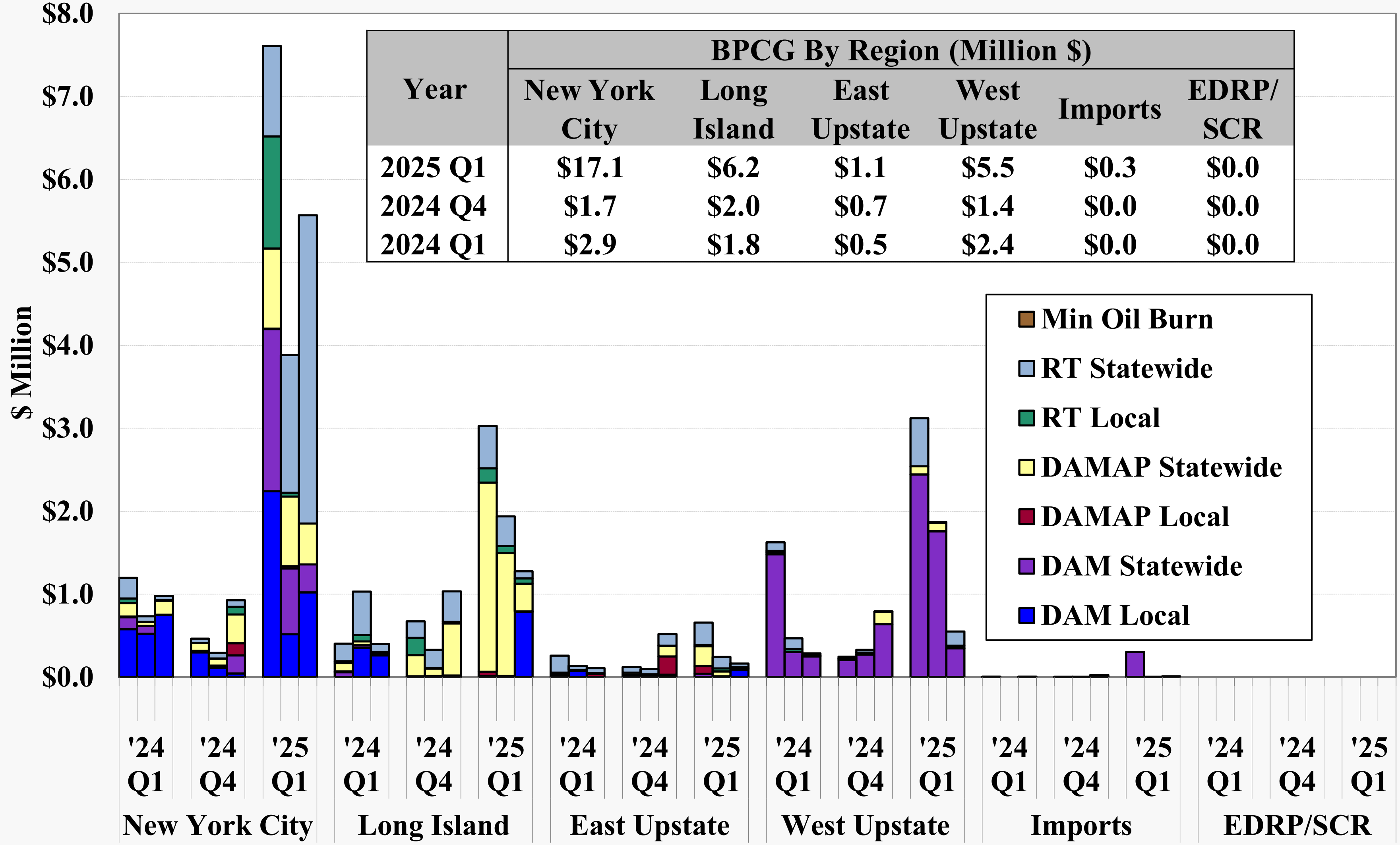
Uplift Costs from Guarantee Payments

By Category and Region



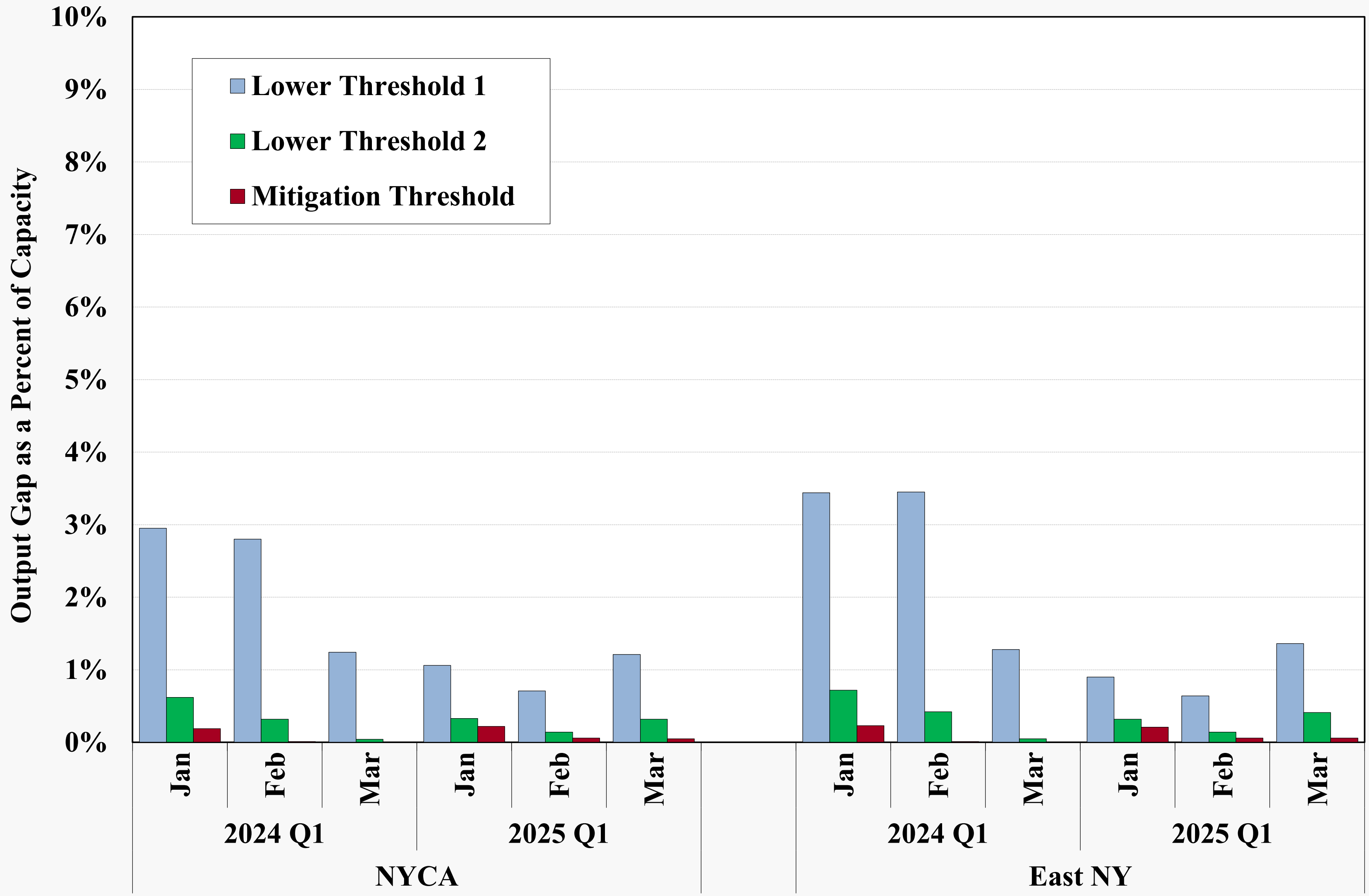
Year	BPCG By Region (Million $)					
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2025 Q1	$17.1	$6.2	$1.1	$5.5	$0.3	$0.0
2024 Q4	$1.7	$2.0	$0.7	$1.4	$0.0	$0.0
2024 Q1	$2.9	$1.8	$0.5	$2.4	$0.0	$0.0

Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 116.

Charts:
Market Power and Mitigation

Output Gap by Month

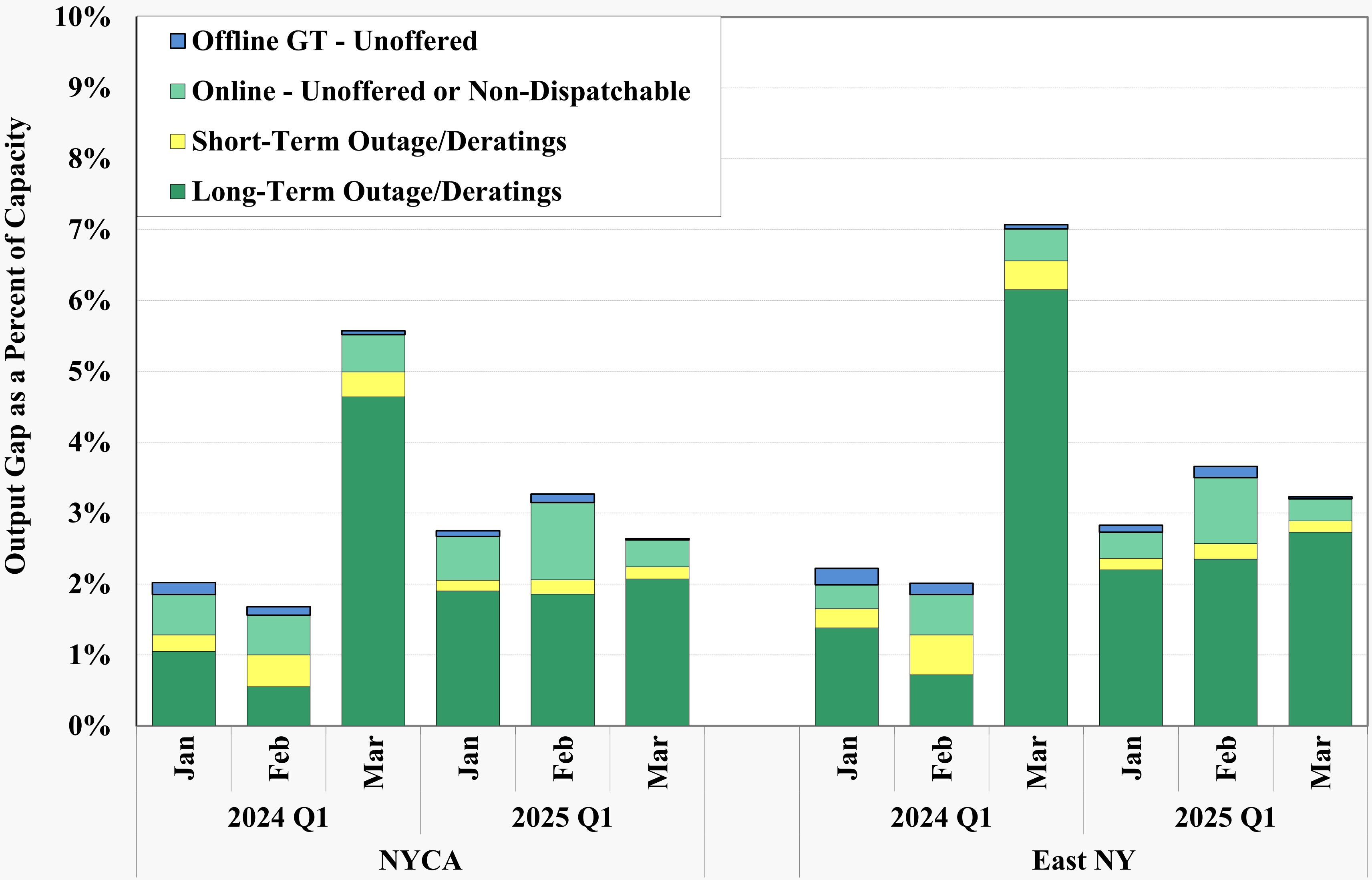
NYCA and East NY



For chart description, see slide 117.

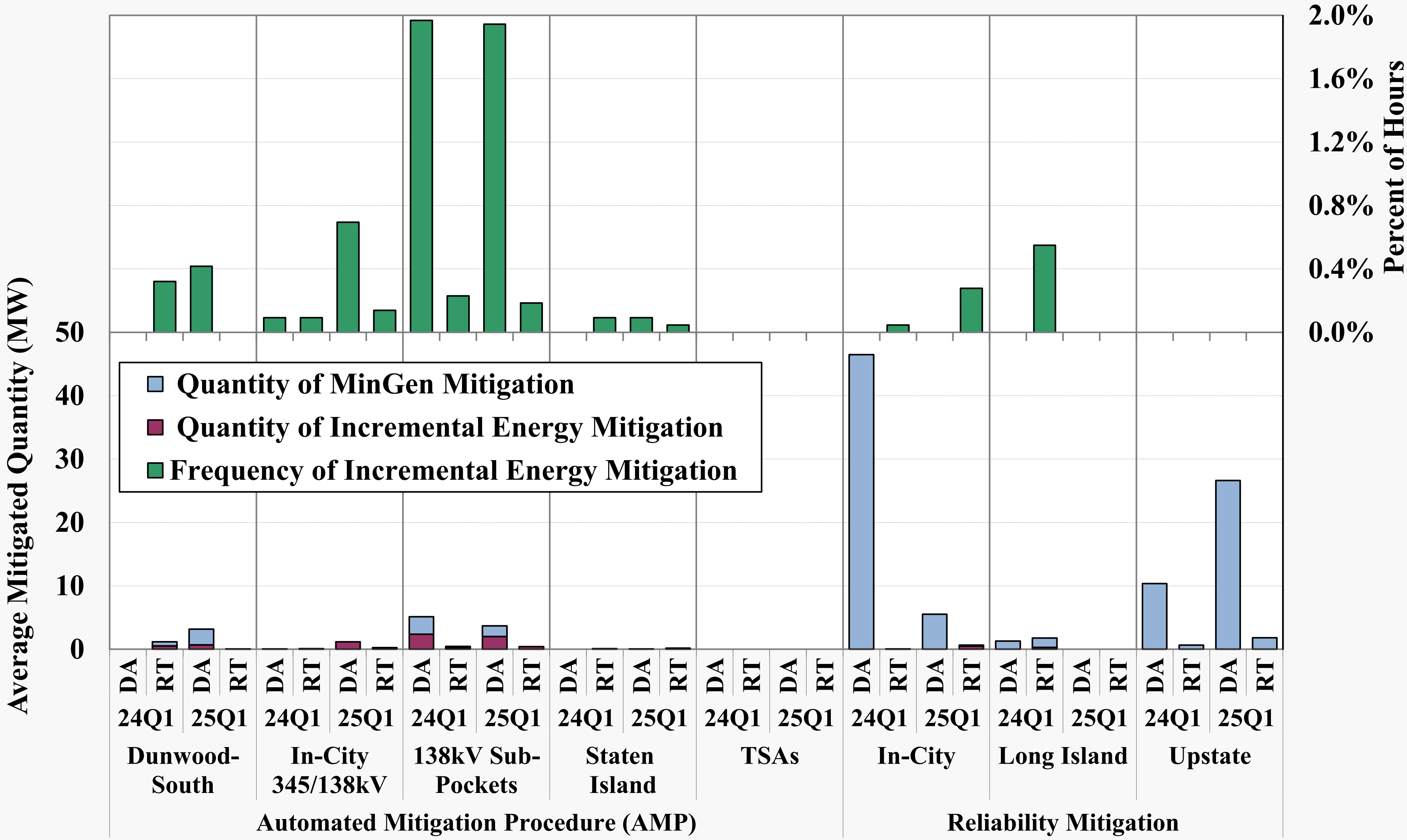
Unoffered Economic Capacity by Month

NYCA and East NY



For chart description, see slide 117.

Automated Market Power Mitigation

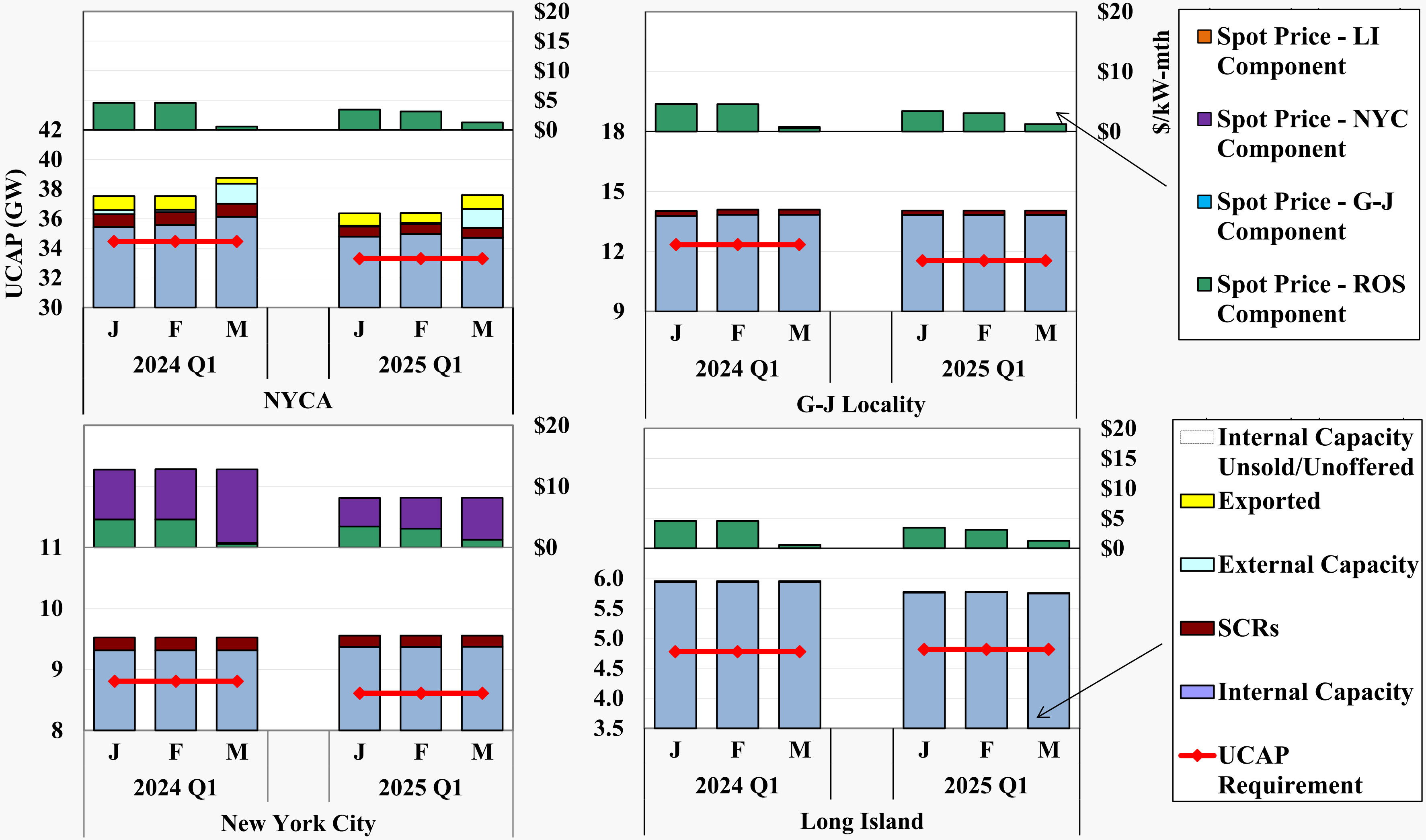


Notes: For chart description, see slide 118.

Charts:
Capacity Market

Spot Capacity Market Results

Monthly Results by Locality



Notes: For chart description, see slide 119.

Key Drivers of Capacity Market Results

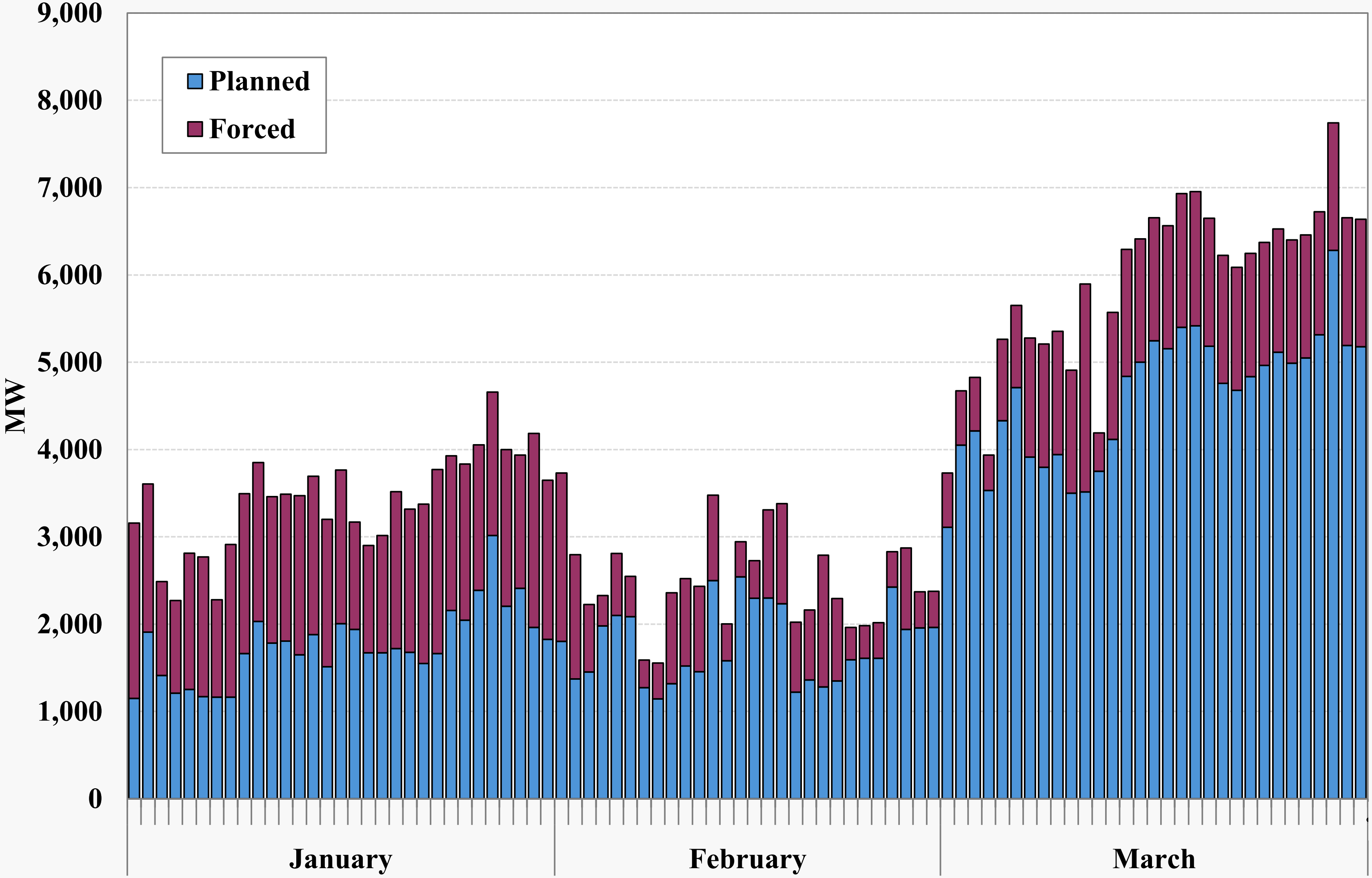
	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2025 Q1 ($/kW-Month)	$2.59	$8.12	$2.59	$2.59
% Change from 2024 Q1	**-20%**	**-36%**	**-20%**	**-21%**
Change in Demand				
Load Forecast (MW)	-507	-72	-38	-172
IRM/LCR	2.0%	-1.3%	0.1%	-4.4%
2024/25 Capability Year	*122.0%*	*80.4%*	*105.3%*	*81.0%*
2023/24 Capability Year	*120.0%*	*81.7%*	*105.2%*	*85.4%*
ICAP Requirement (MW)	**22**	**-204**	**-35**	**-817**
Key Changes in ICAP Supply (MW)				
Generation	**-238**	**-29**	**1**	**-41**
Entry (3)	13	0	13	0
Exit (3)	0	0	0	0
Other Capacity Changes (1)	-251	-29	-13	-41
Cleared Import (2)	**-125**			

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

Notes: For chart description, see slide 119.

Outages of Oil-Capable Generators

Planned and Forced Outages



Notes: For chart description, see slide 120.

Appendix: Chart Descriptions

All-in Price

- Slide 24 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 27 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 28 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 8 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

- 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

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- 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

- 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

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- 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.

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.

Daily Wind Curtailments

- Slide 72 shows the frequency of wind curtailments in the NYISO by load zone this quarter, divided into three different types of curtailments:
  - **Economic curtailments:** These represent dispatch instructions to reduce output issued via the market model.
  - **Economic and Manual curtailments:** These include resources that the MMU flagged as operating under a manual curtailment instruction but also received economic curtailments signals to further reduce output.
  - **Manual Curtailments:** These include instances where telemetry suggests that the wind resource is under a curtailment instruction and no economic curtailment instruction was issued in RTD.
- The amount of output curtailed is calculated based on the difference between the economic basepoint and the RTD Forecasted output for the wind resources.
  - We limit these to intervals where an RTD "Curtail Flag" exists for the economic curtailments.
  - There are no flags in the market data to signify a manual curtailment. Manual curtailments are flagged based on a combination of:
    - Abrupt, persistent reductions in actual output the precede a corresponding drop in the economic basepoint.
    - Operator notes indicating a manual curtailment.

Supplemental Commitments

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- Slide 74 summarizes out-of-market commitment, which is one of the primary sources of guarantee payment uplift.
- Slide 74 shows the quantities of reliability commitment by region in the following categories on a monthly basis:
  - Day-Ahead Reliability Units (“DARU”) Commitment – occurs before the economic commitment in the DAM at the request of local TO or for NYISO reliability;
  - Day-Ahead Local Reliability (“LRR”) Commitment – occurs in the economic commitment in the DAM for TO reliability in NYC;
  - Supplemental Resource Evaluation (“SRE”) Commitment – occurs after the DAM;
  - Forecast Pass Commitment – occurs after the economic commitment in the DAM.

Reliability Commitment in New York City and North Country

- Slides 75 and 76 show the amount of reliability commitments in New York City and North Country, respectively, for each day of the quarter.
- The chart shows these quantities in stacked bars in four distinct categories:
  - ***Economic MWh***: This category represents the total MWh of the initial DARU commitments that eventually qualify as economic capacity 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

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

Uplift Costs from Guarantee Payments

- Slides 78 and 79 show uplift charges in the following seven categories.
  - Three categories of non-local reliability uplift are allocated to all LSEs:
    - Day Ahead: For units committed in the DAM (usually economically) whose day-ahead market revenues do not cover their as-offered costs.
    - Real Time: Typically for quick-start resources that are scheduled economically, or units committed or dispatched OOM for bulk system reliability whose real-time market revenues do not cover their as-offered costs.
    - Day Ahead Margin Assurance Payment ("DAMAP"): For generators that incur losses because they are dispatched below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.
  - Four categories of local reliability uplift are allocated to the local TO:
    - Day Ahead: From Local Reliability Requirements ("LRR") and Day-Ahead Reliability Unit ("DARU") commitments.
    - Real Time: From Supplemental Resource Evaluation ("SRE") commitments and Out-of-Merit ("OOM") dispatched units for local reliability.
    - Minimum Oil Burn Program: Covers spread between oil and gas prices when generators burn oil to satisfy NYC gas pipeline contingency reliability criteria.
    - DAMAP: For units that are dispatched OOM for local reliability reasons.
  - Slide 78 shows these seven categories on a daily basis during the quarter.
  - Slide 79 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 81 and 82 show the results of our screens for attempts to exercise market power, which may include economic and physical withholding.
- The screen for potential economic withholding is the Output Gap, which is the amount of economic capacity that does not produce energy because a supplier submits an offer price above the unit's reference level by a substantial threshold.
  - We show output gap in NYCA and East NY, based on:
    - The state-wide mitigation threshold (the lower of $100/MWh and 300 percent); and
    - Two other lower thresholds (100 percent and 25 percent).
- The screen for potential physical withholding is the Unoffered Economic Capacity, which is the amount of economic capacity that is not available to the market because a supplier does not offer, claims a derating, or offers in an inflexible way.
  - We show the unoffered economic capacity in NYCA and East NY, from:
    - Long-term outages/deratings (at least 7 days);
    - Short-term outages/deratings (less than 7 days);
    - Online capacity that is not offered or offered inflexibly; and
    - Offline GT capacity that is not offered in the real-time market.
  - Long-term nuclear outages/deratings are excluded from this analysis.

Automated Market Power Mitigation

- Slide 83 summarizes the automated mitigation that was imposed in the day-ahead and real-time markets (not including BPCG mitigation) in the quarter.
  - The bars in the upper panel shows the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category.
  - The bars in the lower panel shows the average mitigated capacity.
    - Mitigated quantities are shown separately for flexible output range of units (i.e., Incremental Energy) and the non-flexible portion (i.e., MinGen).
  - The left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on economically committed units in NYC load pockets.
  - The right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.
  - Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

Spot Capacity Market Results

- Slides 85 and 86 summarize market results and key drivers in the monthly spot capacity auctions.
  - Slide 85 summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices that occurred in each capacity zone by month.
    - Sales associated with Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity," but unsold capacity from resources with UDRs is not shown.
  - Slide 86 compares the year-over-year changes in capacity spot prices by Locality and shows variations in key factors that drove these changes, including:
    - The changes in the UCAP requirements, which are affected by changes in the forecasted peak load, the minimum capacity requirement, and the derating factors;
    - The changes in the UCAP supply, which are affected by changes in new entry, mothballing and retirement, and DMNC test values; and
    - The changes in the demand curves, which are mostly affected by the assumptions used in each demand curve reset process.

Outages of Oil-Capable Generators

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- Slide 87 summarizes outage and derate records recorded in the generator maintenance logs among resources capable of operating on fuel oil.
- The data is displayed in two categories:
  - **Planned:** These include outages and derates that are reported to the NYISO and approved as planned outages.
    - These are generally also reported as planned outages and derates in the generator GADS submissions.
  - **Forced:** These include forced outages and derates.
- Since ICAP to UCAP translation is performed based on EFORd and EFORd values rise due to forced outages (and not due to planned outages), a resource that can schedule a planned outage during the peak reliability windows effectively provides no reliability value while avoiding a hit to its EFORd rating.
  - This can lead to inefficient incentives where units that operate during peak load hours carry a higher risk of UCAP reductions (via increased EFORds) than resources that schedule planned outages over the large stretches of the capability period.