Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2024

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Market Highlights

Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the third quarter of 2024.
- All-in prices ranged from $42 in the North Zone to $72 per MWh in New York City, down by 4 to 14 percent from 2023-Q3 in most regions. (slide 8)
  - ✓ Energy costs rose by 4 to 26 percent in most areas, despite comparable natural gas prices and slightly higher load levels.
    - – The primary driver of the increases were higher emission costs: RGGI prices rose by 78 percent year-over-year, adding $4 to $5 per MWh to energy prices.
    - – The lone exception was Long Island, where energy prices decreased 8 percent despite the Y50 line (one of only two 345 kV lines) being OOS the entire quarter.
      - The decrease was driven primarily by smaller gas price differences between Long Island and other areas, additional offshore wind, and higher imports over the Cross Sound Cables which was OOS for much of the previous summer.
  - ✓ Capacity costs fell 29 to 39 percent across all areas primarily due to lower demand curve reference points, reduced LCRs, and lower peak load forecast. (slide 21)
- Congestion rose modestly from the previous year but remained low, marking the second-lowest level for a third quarter since 2014. (slide 9)
  - ✓ Key contributing factors include low gas prices, low load levels, and completed public policy transmission upgrades.

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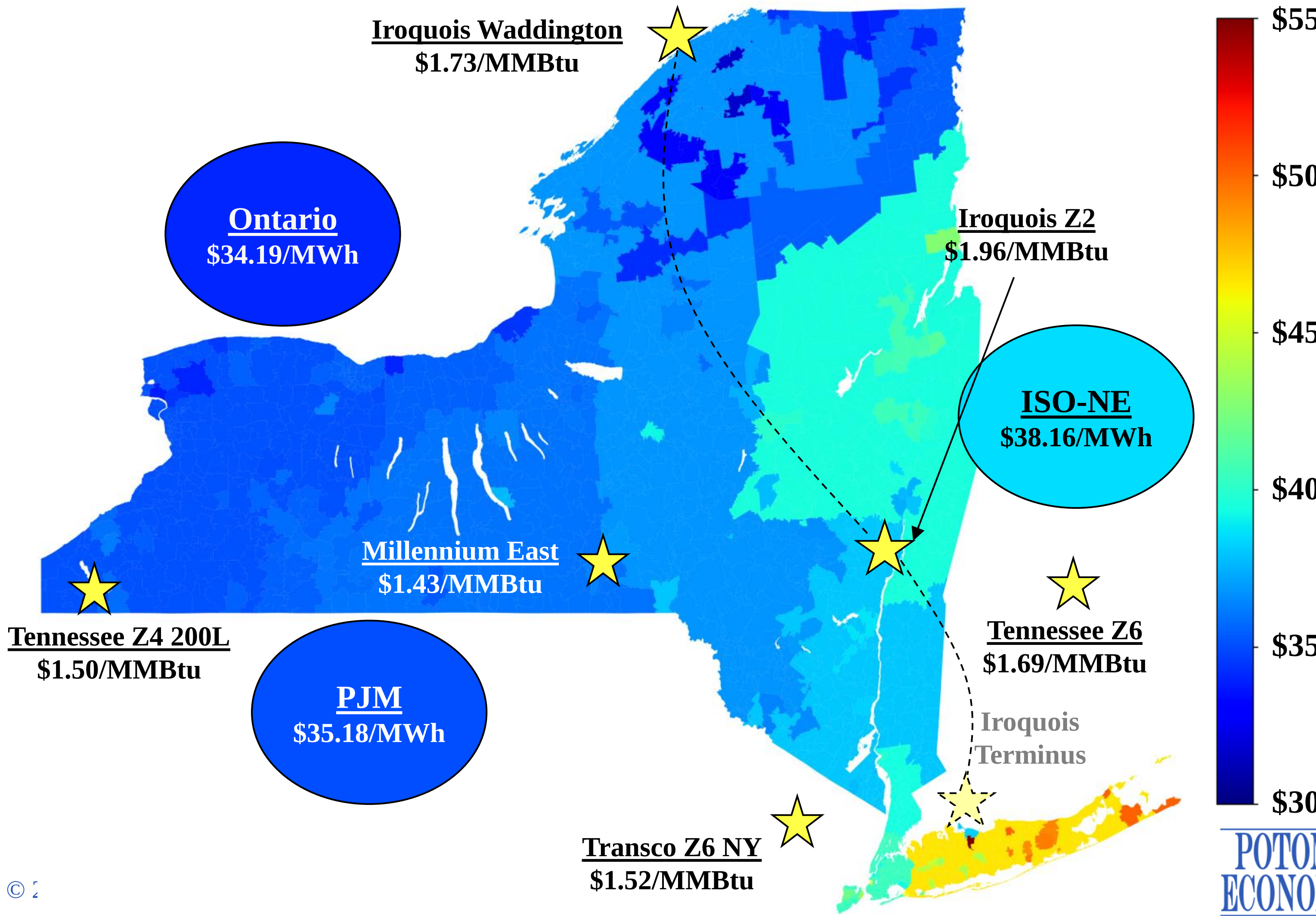
Market Highlights:
Executive Summary

- Supplemental commitments to satisfy reserve requirements occurred on 53 days in the North Country load pocket and 68 days in NYC load pockets. (slides 17-18)
  - ✓ Based on information available to the DAM, the MMU found:
    - – In NYC, 24 percent of the capacity could not be "verified" as needed for reliability, while 48 percent was "verified" as surplus headroom beyond the actual need.
    - – In the North Country, just 4 percent of the capacity could not be "verified", while 46 percent was "verified" as surplus headroom.
  - ✓ We have recommended modeling the underlying N-1-1 and N-1-1-0 requirements as local reserve requirements (Rec #2017-1), which would help attract smaller dispatchable resources (e.g., batteries and DERs) to help satisfy these needs.
- OOM actions occurred on 59 days in two areas of Long Island to manage 69 kV transmission constraints local TVR requirements. (slide 12) We recommend the NYISO incorporate these into the market model. (See Rec #2021-3)
- An average of 605 MW of net virtual imports were scheduled in the DAM, which reduced Forecast Pass commitments and increased SRE commitments. (slide 16)
  - ✓ We recommend distinguishing between firm and non-firm external transactions for scheduling and pricing under Dynamic Reserves. (Rec #2015-16)

Market Highlights:
Executive Summary

- Approximately $7 million of DAM congestion surpluses were socialized to all TOs in proportion to their TCC auction revenues. (slide 11)
  - ✓ This allocation does not align with congestion patterns.
  - ✓ We have recommended revising the allocation methodology based on incremental transfer capability scheduled in the DAM. (Rec #2023-1)
- We estimate 1,470 MW receives excessive accreditation including (slides 22-23):
  - ✓ 540 MW of emergency capacity;
  - ✓ 460 MW affected by ambient humidity and air temperature conditions;
  - ✓ 440 MW from high ambient water temperatures and low tide levels; and
  - ✓ 30 MW of cogeneration capacity with host-steam obligations.
- NYISO approved accreditation rules revising DMNC test requirements that will:
  - ✓ Address the ambient humidity and air temperature issues; and
  - ✓ Place stricter requirements on water-cooled fossil and nuclear steam units using a once through cooling system. We have recommended expanding this to ensure DMNC tests account for the effects of tides and simultaneous operation at multi-unit stations with shared cooling systems. (Rec #2021-4)

Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the third quarter of 2024.
  - ✓ The amounts of output gap (slide 85) and unoffered economic capacity (slide 86) remained reasonably consistent with competitive market expectations.
- All-in prices ranged from $42/MWh in the North Zone to $72/MWh in New York City, falling in most zones by 4 to 14 percent from a year ago. (slide 25)
  - ✓ Energy costs rose in most zones (4 to 26 percent) from a year ago. (slides 35-36)
    - – Increases were driven primarily by higher RGGI CO_2 emissions allowance costs, which averaged ~$25/ton (translating to $11/MWh for a gas unit with a heat rate of 7,500 Btu/kWh), up ~78 percent from last year.
    - – However, energy costs remained relatively low due to:
      - Low natural gas prices – These were driven by continued growth in gas production and high storage levels (slide 27); and
      - Low load levels — Load never exceeded 29 GW (compared to a summer peak load forecast of 31.5 GW), although this was partly because demand response and utility peak shaving program resources provided 1.2 GW of relief. (slide 26)
  - ✓ Capacity costs fell 29 to 39 percent in all areas as discussed in slide 21.

Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $78 million in the third quarter of 2024, up 9 percent from a year ago. (slide 59)
  - ✓ This was the second-lowest congestion revenue collection in third quarter since 2014. Key contributing factors of low congestion levels include:
    - – Low natural gas prices and load levels.
      - Reduced gas pipeline congestion made units in East NY more economic, lowering congestion from West to East and within East NY.
    - – Major transmission upgrades over recent years:
      - The Empire State Line project (completed June 2022), which greatly reduced congestion in the West Zone;
      - The Smart Path project (completed June 2023), which reduced the congestion from North to Central New York; and
      - The AC Transmission Segment A and Segment B projects, which reduced congestion across the Central-East interface and from Capital to Hudson Valley.
    - – Low net imports from Quebec over the last two years – These averaged 300 to 400 MW during peak hours over the last two summers, further reducing congestion across the Central-East interface and from Capital to Hudson Valley.

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

- Long Island lines accounted for the largest share of DAM congestion (34 percent).
  - ✓ This category fell modestly from the previous year despite the outage of the Dunwoodie-Shore Rd 345 kV line (“Y50” Line) throughout the quarter. However, this was offset by:
    - The return to service of the Cross Sound Cable, which was out of service for two months of the third quarter in 2023.
    - Most of this category (60 percent) occurred on 69 kV bottlenecks of west-to-east flows through Elwood and Brentwood during the heat waves in early-July, mid-July, and early-August.
- West-to-Central lines accounted for the second largest share (27 percent).
  - ✓ Nearly all 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.
- New York City facilities accounted for the third largest share (14 percent) of congestion in the day-ahead market.
  - ✓ Half of this congestion occurred on transmission facilities into the Greenwood load pocket.

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.
- The NYISO currently allocates DAM congestion residuals to Transmission Owners using a two-stage process defined in the OATT.
  - ✓ 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, ~$3.5M of shortfalls were allocated to responsible TOs on a cost causation bases, while ~$7M of surpluses were socialized to all TOs. (slide 62)
  - ✓ We estimate that 48 percent of the socialized surpluses accrued on Long Island facilities, 20 percent accrued on transmission paths from central to eastern New York, and 15 percent accrued on facilities from Capital to Hudson Valley.
    - – This allocation does not align with TCC auction revenues.
  - ✓ We have recommended the NYISO revise the residual allocation method based on incremental transfer capability scheduled in the DAM. (see Recommendation #2023-1 in our 2023 SOM report)

Market Highlights:
OOM Actions to Manage Network Reliability

- OOM commitments to satisfy N-1-1 and N-1-1-0 requirements occurred on 53 days in the North Country load pocket and 68 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 #2017-1)
- OOM actions were also frequent on Long Island. (slide 66)
  - ✓ In the Valley Stream load pocket, GTs were needed on 43 days to manage 69 kV transmission constraints involving a contingency not modeled in the market software.
  - ✓ In the East End load pocket, oil-fired peakers were needed on 55 days to satisfy local TVR requirements.
    - The estimated LBMP impact of unmodeled TVR needs was significant in this quarter, averaging roughly \$50/MWh.
    - We have recommended the NYISO incorporate this TVR need into the market model. (See Rec #2021-3)

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $13.6M, down 17 percent from last year. (slide 82)
  - ✓ This was the lowest third quarter total in at least six years primary because of low natural gas prices.
- BPCG uplift was highest on Long Island ($5.6M or 41 percent).
  - ✓ Uplift associated with OOM dispatch to satisfy the East End TVR requirement accounted for 62 percent (or $3.5M).
- NYC accounted for the second largest share with $4.1M or 30 percent of the total.
  - ✓ 59 percent of this category was paid to units committed for N-1-1-0 reliability.
- West Upstate BPCG uplift totaled $2.8 million (or 21 percent of total).
  - ✓ Supplemental commitment of gas and oil-fired steam turbines on high loads days for system reserves incurred $1.7 million of uplift.
  - ✓ Most of the remaining uplift was paid to generators committed for N-1-1 reliability in the North Country load pocket. (slides 18 and 78)

Market Highlights:
Regulation Market Performance

- A single movement-to-capacity ratio, set at 8 since 2021, is used to formulate composite offer prices for resources when scheduling for regulation service.
  - ✓ Composite offer price = capacity offer price + 8*movement offer price
- However, resources are deployed according to their actual ramp capability and compensated based on instructed movement and actual performance. We find that:
  - ✓ Resources exhibited a wide range of movement-to-capacity ratios (slide 44); and
  - ✓ The average ratio has risen above 12 in recent months, due to the entry of new fast-ramping regulation suppliers, primarily battery storage resources. (slide 43)
    - – In the near-term, we recommend NYISO adjust the assumed ratio to a more representative level. NYISO has recommended updating the ratio to 13 and has proposed tariff and manual changes to allow more frequent updates.
  - ✓ Using the same movement-to-capacity ratio for all units underestimates the costs of fast-ramping units for scheduling, leading to inefficient scheduling and incentives.
    - – This has led to 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, although such an enhancement would not be likely cost-effective in the short-term.

Market Highlights:
RT Pricing of GTs Bidding Multi-Hour MRT

- The fast-start pricing rules are currently not applied to fast-start units that submit a minimum run time offer exceeding one hour.
  - ✓ However, the RT scheduling software (RTC and RTD) and market settlement rules ignore the 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 48 percent of the hours when these GTs were committed in the quarter, LBMPs were below the GTs' as-bid costs.
  - ✓ If these GTs were eligible to set prices like other fast start units, the average LBMP during these hours would have increased by $5 per MWh at most affected locations. This issue depresses LBMPs below efficient levels in downstate load pockets when peaking units are used to manage congestion.
- We have recommended the NYISO revise the eligibility for fast-start pricing to be based on the MRT used for scheduling, rather than the value of the offer parameter, which should not require a tariff change. (See Rec #2023-2).

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 605 MW in the net import direction during the quarter. (slide 49)
  - ✓ We identify two issues related to virtual imports and exports in this report.

1) 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.
     - – Net virtual imports averaged ~400 MW in peak load hour on days in 2023 and 2024 when NYISO made SRE commitments for insufficient supply margin. (slide 81)
   - ✓ In the current Dynamic Reserves project proposal, virtual and non-firm imports will satisfy operating reserve requirements, leading to inefficient scheduling.
2) 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 distorts RT prices and schedules in the binding time frame.

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Market Highlights:
DARU and LRR Commitments in NYC

- Our assessment of the NYISO's supplemental commitments to satisfy N-1-1-0 reliability needs in NYC indicated that: (slide 77)
  - ✓ 17 percent was "economic" in the DAM; and
  - ✓ 59 percent was "verified" (by the MMU) as needed to satisfy a specific reliability requirement based on information available in the DAM related to forecasted load, status of generation and transmission equipment, and potential contingencies.
    - Only 20 percent of total verified MWh was necessary to satisfy the identified requirement, while the remaining 80 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 might provide 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 #2017-1).
  - ✓ 24 percent was "not verified" (by the MMU). Some of this capacity was likely committed due to the following factors:
    - DARU requests are typically made at least two days ahead of time for multiple consecutive days. Forecasts tend to be less accurate when the DARUs are requested.
    - The local TO may have operational requirements that are not included in the information available to the MMU.

Market Highlights:
DARU Commitments in North Country

- DARU commitments were made to satisfy N-1-1 reliability requirements in the North Country and Plattsburgh load pockets primarily during transmission outages in support of public policy transmission projects.
- Due to limited flexible generation options, operators frequently relied on a small number of gas-fired units to meet reliability requirements, scheduling over 46 GWh of energy from these resources this quarter. Of this energy: (slide 78)
  - ✓ 7 percent was “economic” in the DAM; and
  - ✓ 96 percent of the remainder was “verified” (by the MMU) as needed to satisfy a specific reliability need based on information available in the DAM on forecasted load, status of generation and transmission equipment, and potential contingencies.
    - – 48 percent of total verified MWh was necessary to satisfy the identified requirement, while the remaining 52 percent was surplus energy generated to satisfy minimum generation and run time requirements for the unit committed.
  - ✓ Just 4 percent was “not verified” (by the MMU). Some of this capacity may have been committed due to differences in load forecasting and assumed transmission support from neighboring control areas.
- Smaller flexible resources such as batteries and DERs might satisfy these needs at lower costs. However, the market does not provide incentives for satisfying these local needs.

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Market Highlights:
SRE Commitment and DR Deployments on Peak Days

- NYISO experienced three heat waves (7/8-10, 7/15-17, and 8/1-2) this quarter.
  - ✓ Load peaked at just 29 GW on July 8, well below the 50/50 forecast of 31.5 GW.
  - ✓ NYISO activated EDRP/SCR resources in all zones on 7/15-16 and 8/1.
    - – Up to 1.2 GW of NYISO & utility DR was activated to reduce peak load.
  - ✓ See presentation "Summer 2024 NYISO Hot Weather Operating Conditions" by Aaron Markham at the October 24 OC meeting for more details.
- The NYISO SREed resources for statewide capacity needs on three days during the three heat waves. (slides 79-80)
  - – Nearly 300 MW of DA scheduled 10- and 30-minutes reserves were identified on July 16 as unavailable among poor-performing fast start resources and from resources flagged with suspected functionally unavailable capacity. (slide [])
  - ✓ These SREs were made for reserve needs not fully represented in the DAM.
    - – The NYISO proposes to satisfy these forecasted requirements (currently met in the FCT pass and/or with SREs) through the market with the Dynamic Reserve enhancements and/or other longer-lead-time reserve products. However, these reserve market enhancements will be undermined by treating virtual imports as firm resources.

Market Highlights:
Performance and Availability of Duct Burners

- Most CCs in the NYISO offer supplemental output from duct burners, totaling ~800 MW of summer capacity. This capacity is difficult to utilize due to inconsistencies between the market design and physical limitations of duct burners.
- Slide 68 shows an example CC that cannot follow dispatch instructions in a Reserve Pickup (RPU) event due to its inability to fire the duct burner within 10 minutes.
  - ✓ Slide 71 shows the performance of CC generators with duct burners during RPU audits in 2024-Q3. All reserve audit failures from these resources involve dispatch in the duct range.
- Slide 69 illustrates the difficulty of offering duct burner capacity given that response rates are not a biddable parameter. Response rates can only be modified through the registration process, which does not accommodate frequent updates.
  - ✓ The 2024 project “Improve Duct-Firing Modeling” partially addresses inconsistencies between the market design and the physical limitations, however, the project will not enable bid response rates to adjust with the duct burner range of the unit.
- Slide 70 shows duct-firing capacity that was offered but not physically able to provide a given service. In afternoon hours, on average: (a) 105 MW was offered but not able to follow 5-minute ramp instructions; (b) 142 MW was scheduled but not able to provide 10-minute reserves; and (c) 16 MW was scheduled but not able to provide regulation.
  - ✓ In addition, (a) 65 MW of duct-firing was unavailable because it was not offered; and (b) 12 MW of 10- and 30-minute reserves were not offered from baseload capacity (i.e., non-duct ranges) due to their inability to perform in the duct burner range.

Market Highlights:
Capacity Market

- Spot capacity prices averaged $14.16/kW-month in NYC, $4.02/kW-month in Long Island, and $3.97/kW-month elsewhere. (slides 89-90)
  - ✓ Spot prices fell by 27 percent in NYC because the ICAP requirement fell by 204 MW due to a lower load forecast and a decrease of 1.3 percent in the LCR.
  - ✓ ROS prices fell by 34 percent, driven primarily by a lower reference point, which fell from $9.39/kW-month in Summer 2023 to $7.74/kW-month in Summer 2024.
    - – Several other factors mitigated the price drop from the lower reference point:
      - The IRM rose from 120 to 122 percent; and
      - Nearly 440 MW reduction in supply from internal generation and UDR lines.
  - ✓ Prices in Long Island and the G-J Locality fell by 33 and 34 percent, respectively.
    - – Lower reference points, driven by higher net Energy and Ancillary Service revenues in recent years, drove most of the declines in prices in these regions.
- The average Derating Factor was just 4.62 percent for New York City during this Summer Capability Period, despite the relatively old age of generating capacity.
  - ✓ This factor, derived from data reported to GADS, may under-estimate the impact of forced outages and deratings on NYC unit availability. The MMU is investigating this and will provide further analyses in future reports.

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Market Highlights:
Functionally Unavailable Capacity

- We examined the availability of capacity procured from conventional resources during peak conditions over the past few summers. (slide 91)
- Roughly 1,470 MW of capacity on fossil-fuel and nuclear units was qualified to sell ICAP but was unavailable under peak conditions for reasons other than reported forced outages, derates, or maintenance outages. Key drivers include:
  - ✓ *Ambient water conditions:* Approximately 440 MW of ICAP from once-through-cooled fossil-fuel and nuclear steam turbine generators is unavailable at peak conditions due to water temperatures and tidal levels.
    - The NYISO proposal to restrict the DMNC testing window (to daytime hours in July and August) for water temperature-affected units does not address most of the 440 MW of capacity identified in our analysis.
    - In addition, some water temperature-related limitations are triggered or exacerbated when multiple generators at the same facility operate simultaneously. *However, none of these facilities conducted DMNC tests under multi-unit conditions.*
  - ✓ *Emergency Capacity:* We estimate that roughly 540 MW of capacity sold was available only in extraordinary configurations or under special procedures.
    - This emergency capacity rarely operates outside of DMNC tests and generally carries a higher outage risk than the baseload portion of the generators.
    - Since EFORd relies on service hours to calculate reliable availability estimates, the UCAP values of these units are over-estimated.

Market Highlights:
Functionally Unavailable Capacity (cont.)

- ✓ *Host Steam Obligations:* Cogeneration units may perform DMNC tests when host steam demand is below the contractual obligation, allowing the unit double-sell capacity.
  - Due to ongoing efforts by the NYISO, this category of capacity has been reduced to approximately 30 MW for 2024-Q3.
  - Some cogeneration units may lack procedures to curtail steam load when their capacity is needed for electric system reliability.
  - Host steam demand for most cogeneration resources generally rises during winter months. Given the emergence of future winter reliability issues, the MMU plans to analyze this issue more closely in future reports.
- ✓ *Low ISO Conditions & Relative Humidity:* Approximately 460 MW of capacity is estimated to be unavailable due to higher air temperatures than those used in the DMNC adjustment procedures and/or other unaccounted-for ambient conditions, primarily relative humidity.
  - The NYISO's "Correlated Derates" project addresses many of these issues by requiring generators with specific evaporative cooling and inlet fogging systems to adjust to wet bulb temperature conditions, and by using dry bulb temperatures that are consistent with the Gold Book for adjusting DMNC results on applicable generators.

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Charts:
Market Outcomes

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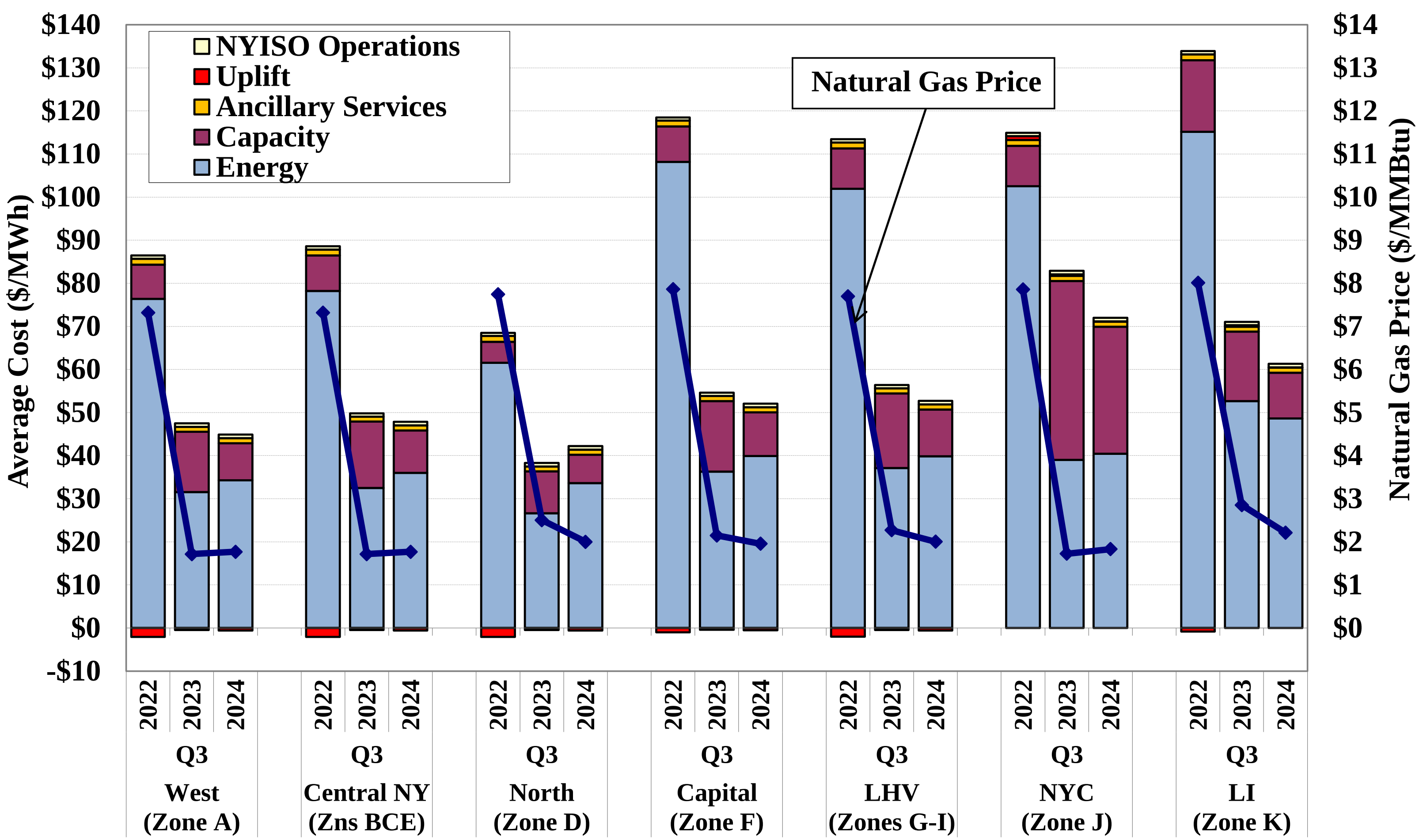
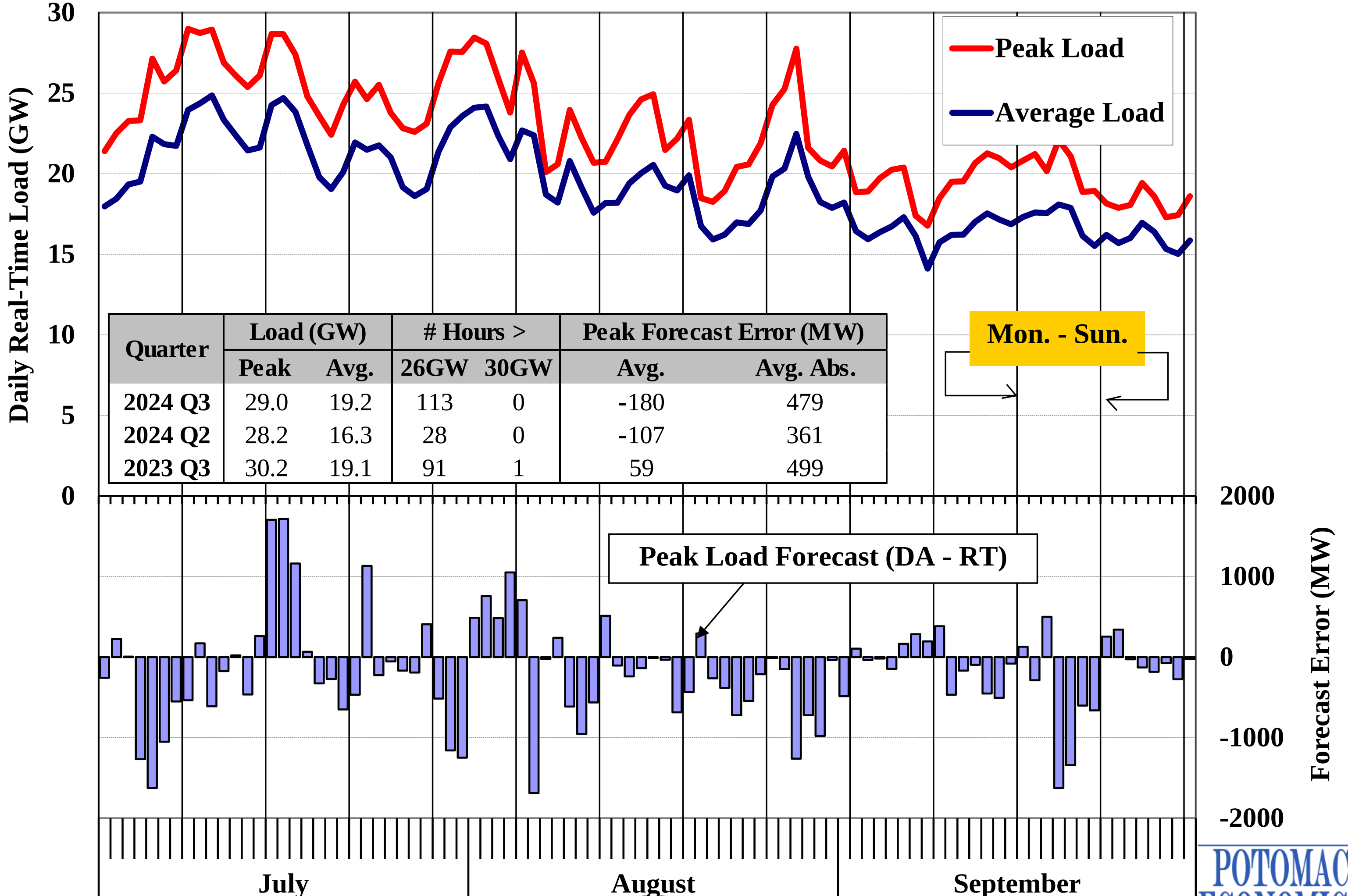
All-In Prices by Region



Notes: For chart description, see slide 93.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2024 Q3	29.0	19.2	113	0	-180	479
2024 Q2	28.2	16.3	28	0	-107	361
2023 Q3	30.2	19.1	91	1	59	499

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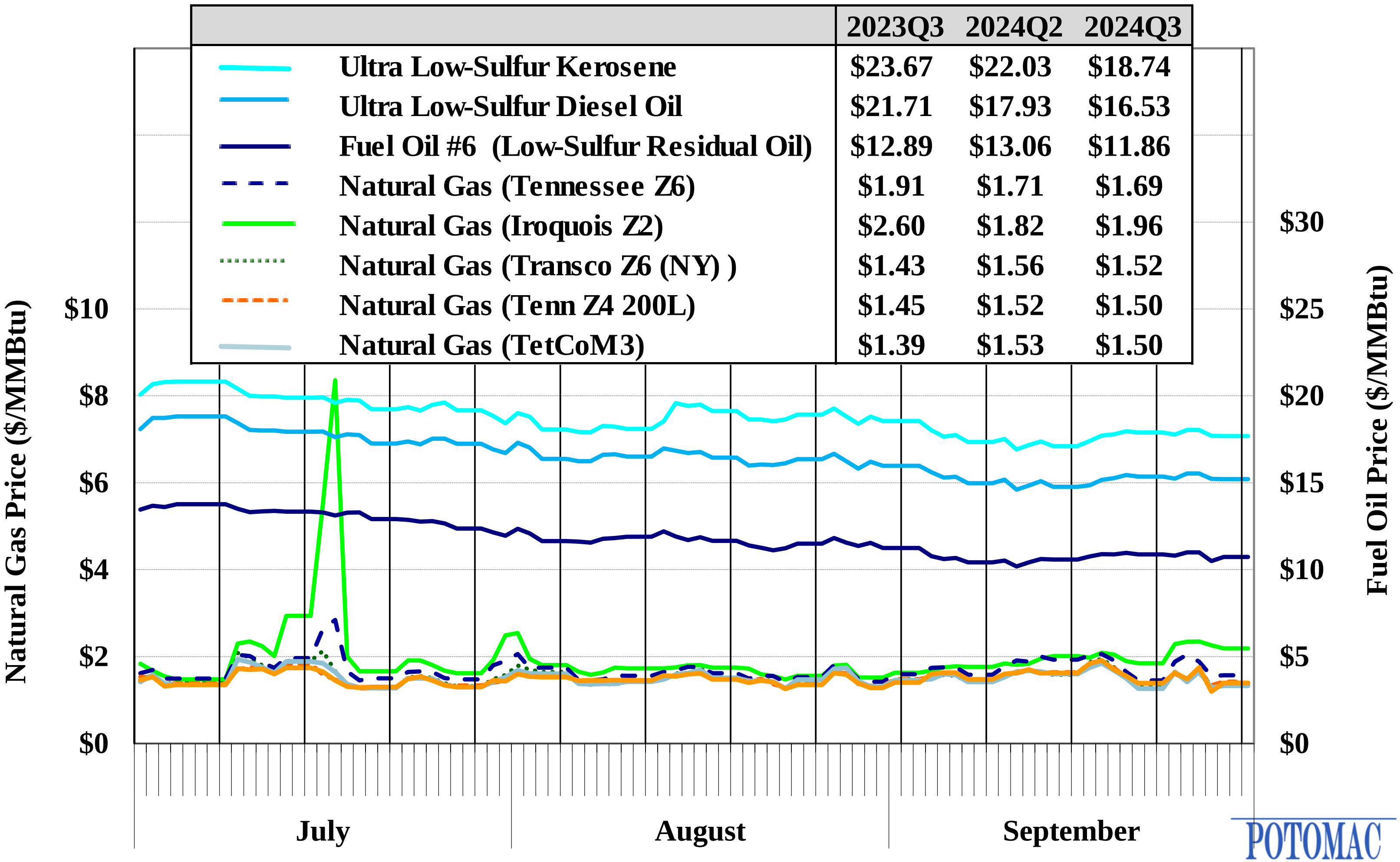
Natural Gas and Fuel Oil Prices



	2023Q3	2024Q2	2024Q3
Ultra Low-Sulfur Kerosene	$23.67	$22.03	$18.74
Ultra Low-Sulfur Diesel Oil	$21.71	$17.93	$16.53
Fuel Oil #6 (Low-Sulfur Residual Oil)	$12.89	$13.06	$11.86
Natural Gas (Tennessee Z6)	$1.91	$1.71	$1.69
Natural Gas (Iroquois Z2)	$2.60	$1.82	$1.96
Natural Gas (Transco Z6 (NY))	$1.43	$1.56	$1.52
Natural Gas (Tenn Z4 200L)	$1.45	$1.52	$1.50
Natural Gas (TetCoM3)	$1.39	$1.53	$1.50

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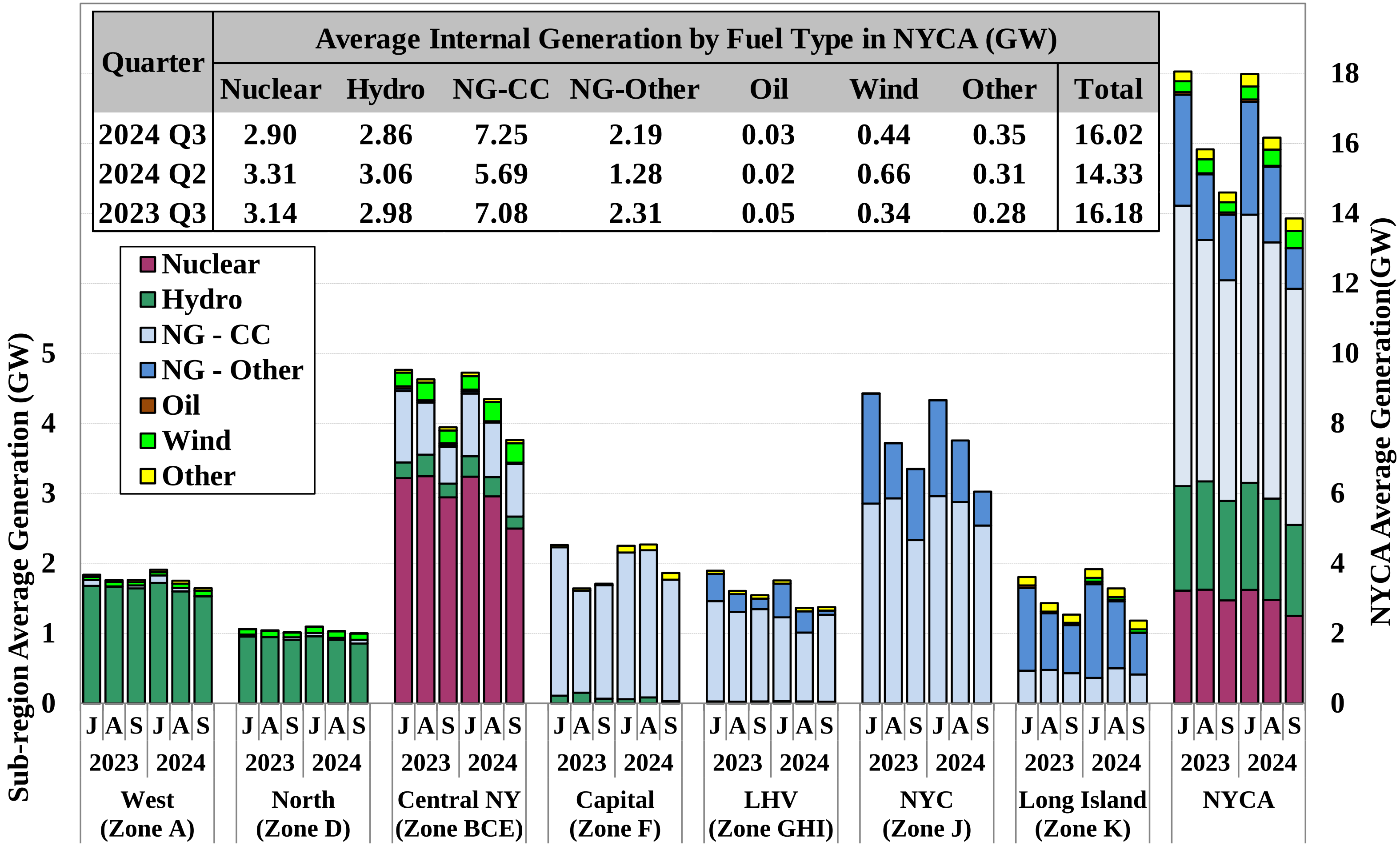
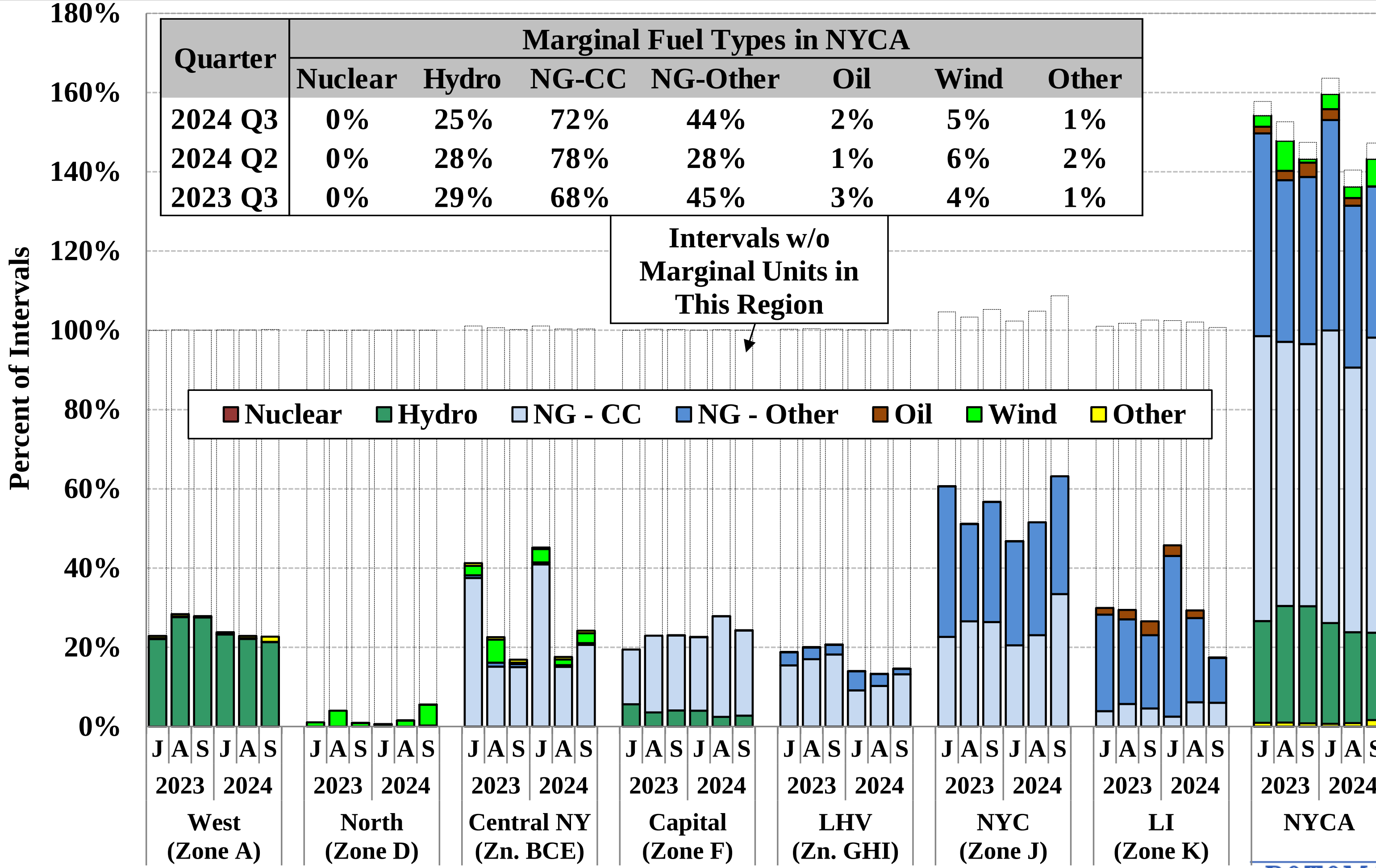
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Total
2024 Q3	2.90	2.86	7.25	2.19	0.03	0.44	0.35	16.02
2024 Q2	3.31	3.06	5.69	1.28	0.02	0.66	0.31	14.33
2023 Q3	3.14	2.98	7.08	2.31	0.05	0.34	0.28	16.18



Notes: For chart description, see slide 95.

Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other
2024 Q3	0%	25%	72%	44%	2%	5%	1%
2024 Q2	0%	28%	78%	28%	1%	6%	2%
2023 Q3	0%	29%	68%	45%	3%	4%	1%

Notes: For chart description, see slide 95.

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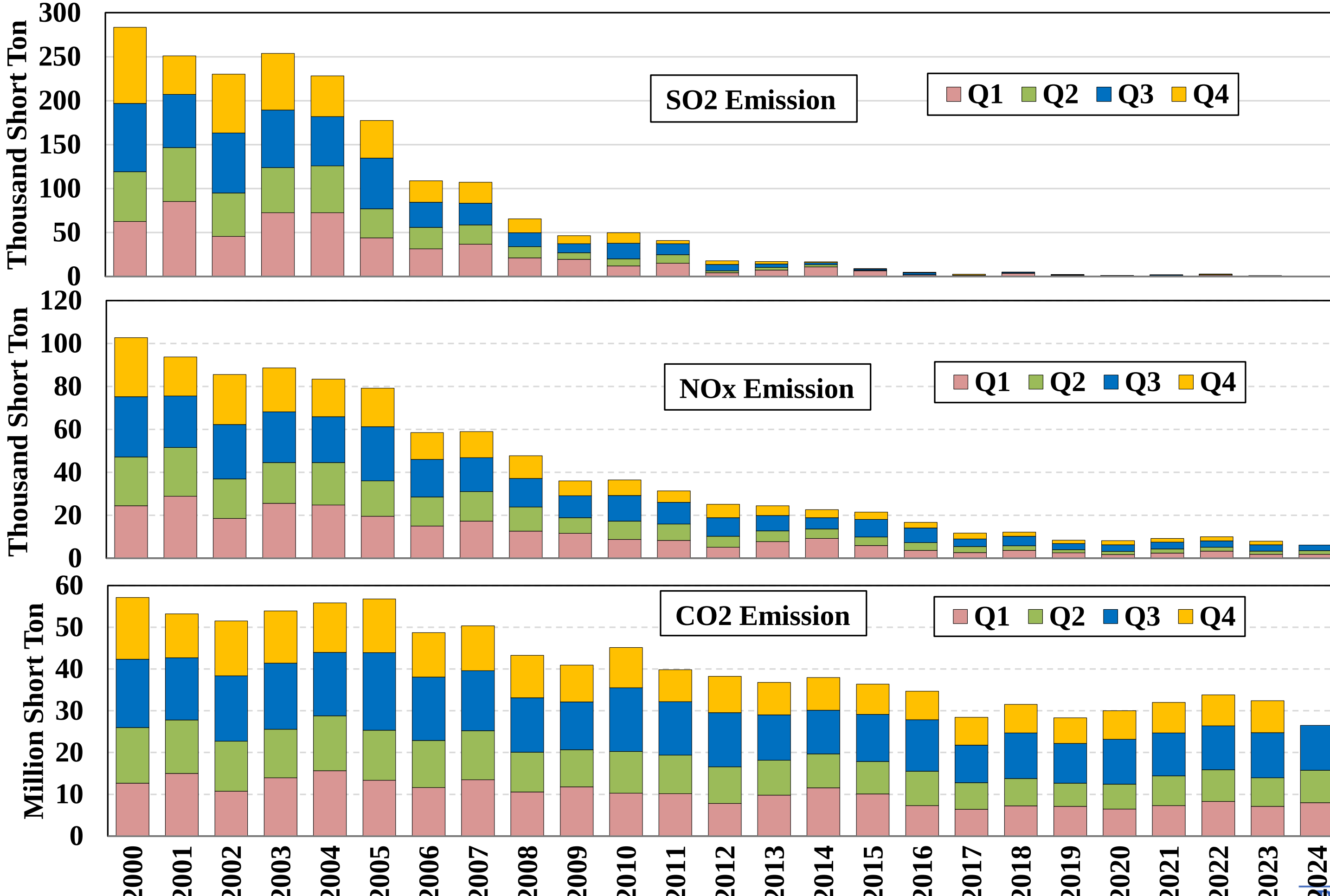
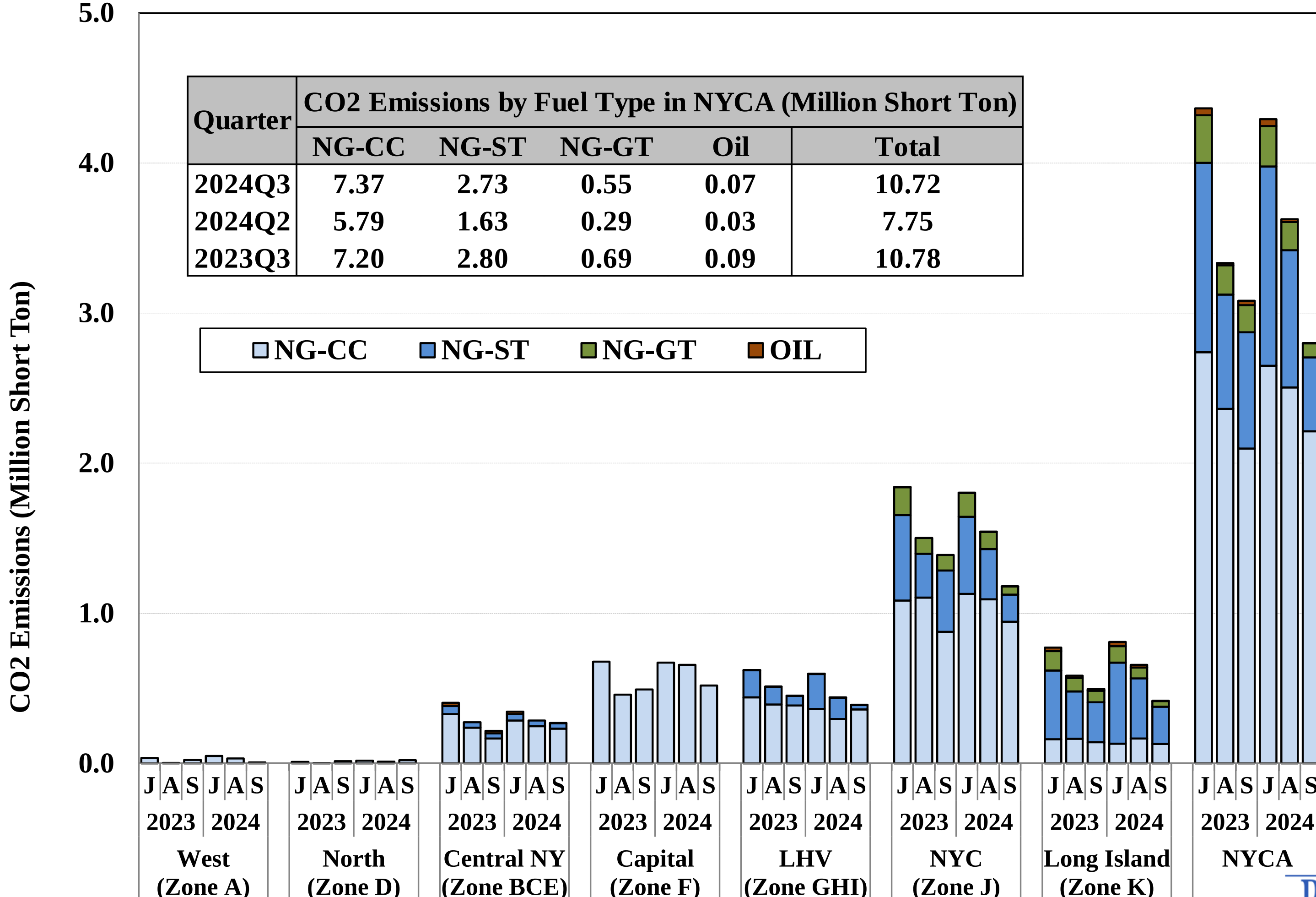
Historical Emissions by Quarter in NYCA
CO_2, SO_2 , and NO_X



Notes: For chart description, see slide 96.

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
2024Q3	7.37	2.73	0.55	0.07	10.72
2024Q2	5.79	1.63	0.29	0.03	7.75
2023Q3	7.20	2.80	0.69	0.09	10.78



Notes: For chart description, see slide 96.

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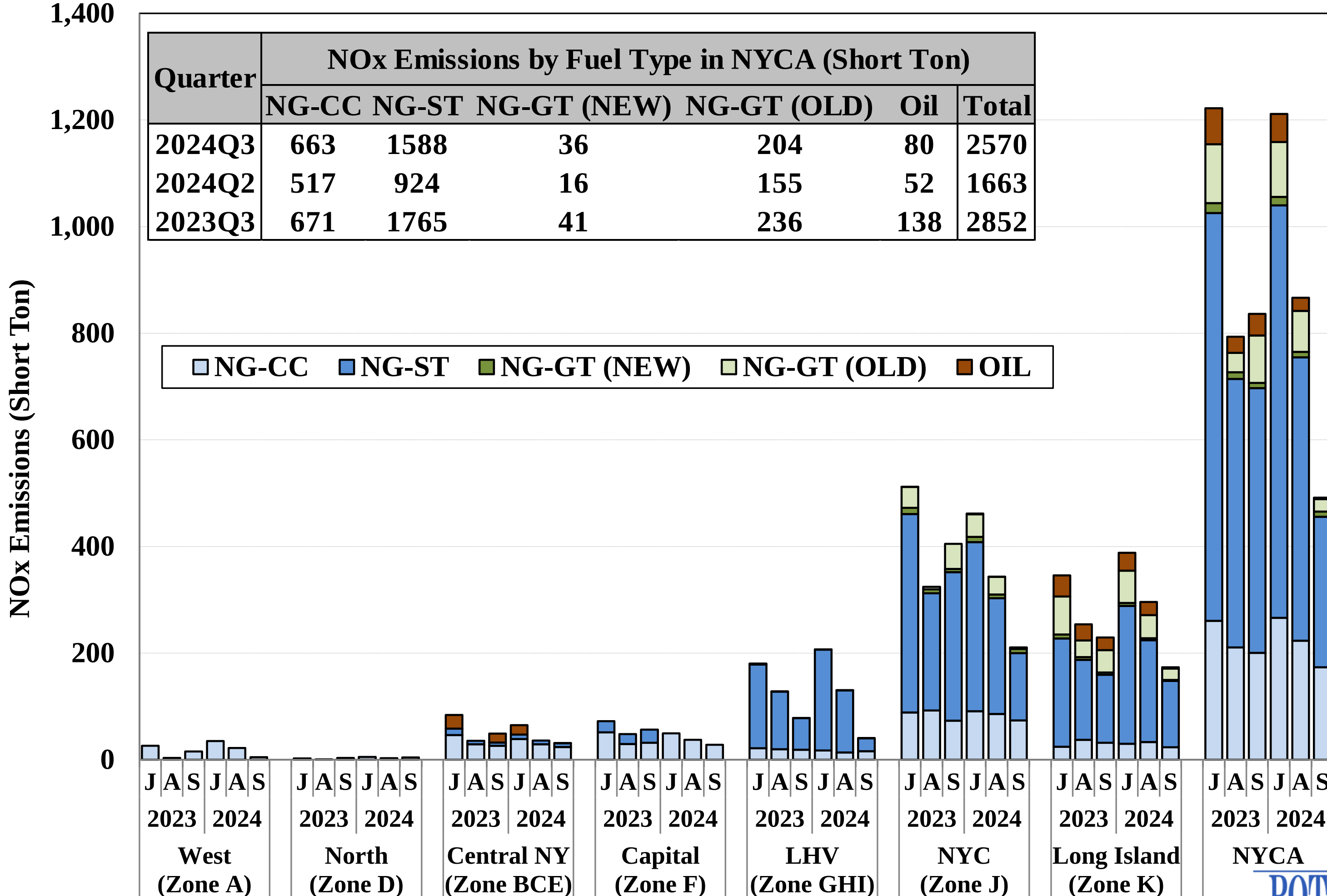
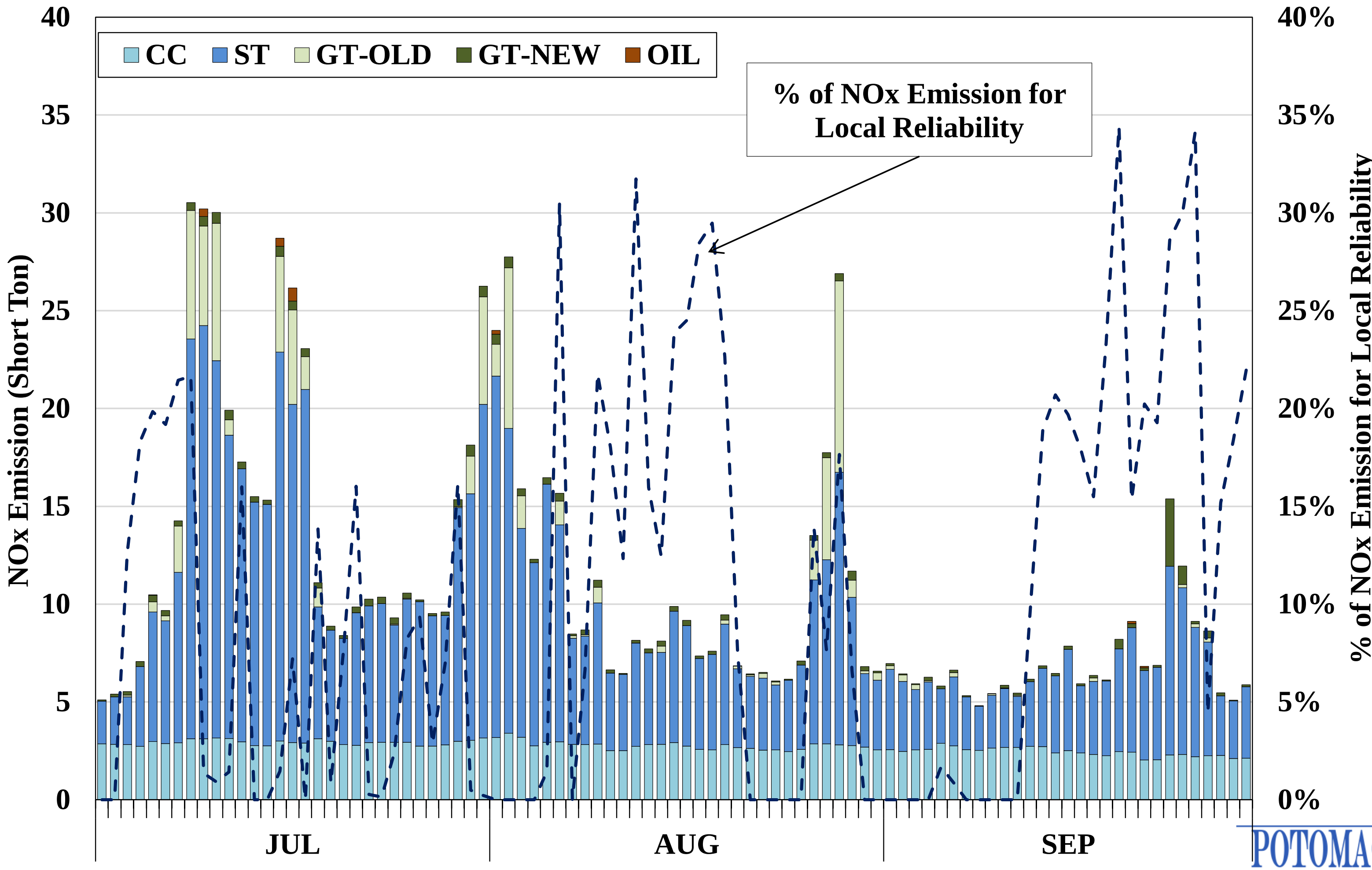
Emissions by Region by Fuel Type
NO_X Emissions



Quarter	NOx Emissions by Fuel Type in NYCA (Short Ton)					
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Total
2024Q3	663	1588	36	204	80	2570
2024Q2	517	924	16	155	52	1663
2023Q3	671	1765	41	236	138	2852

Notes: For chart description, see slide 96.

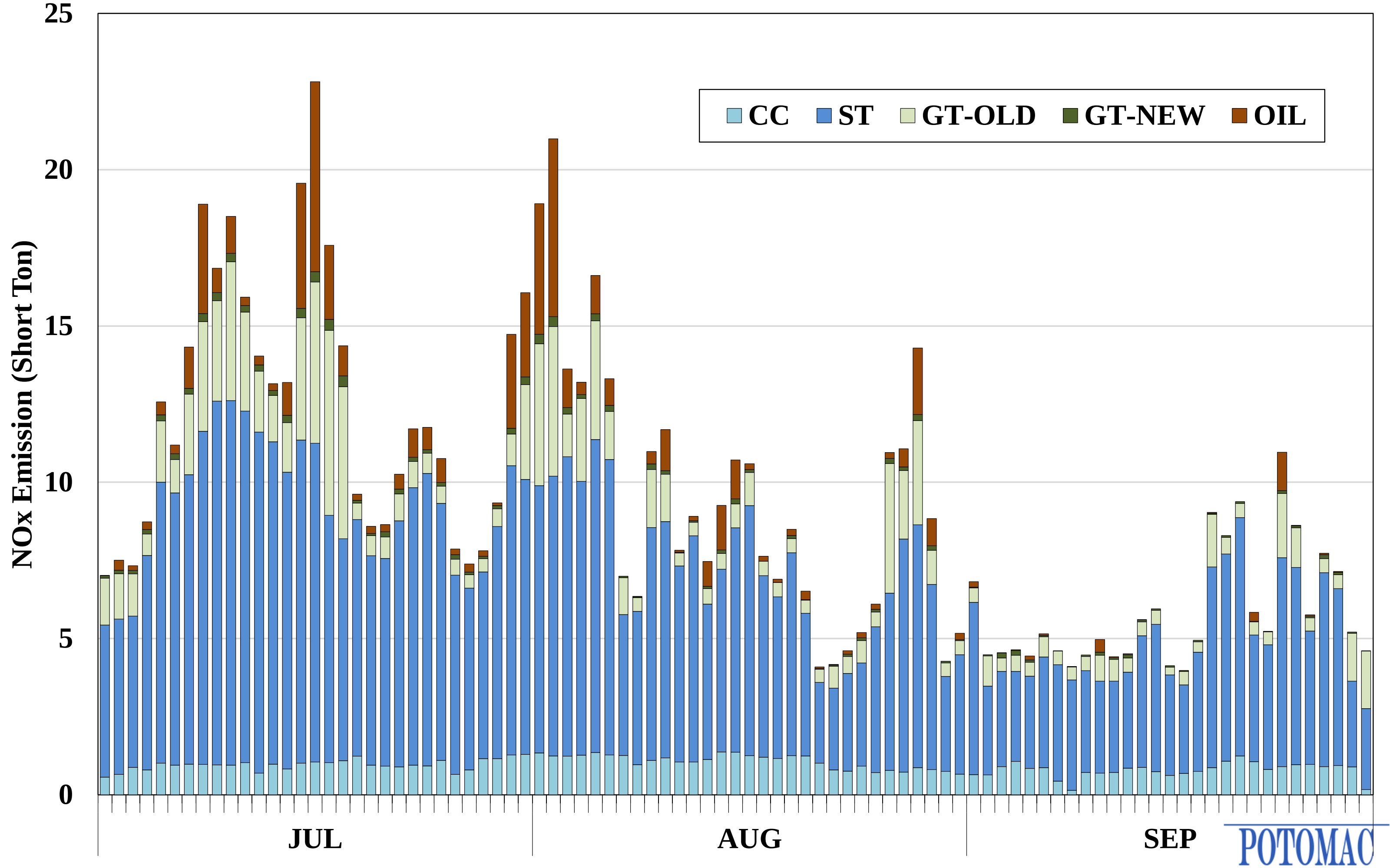
Daily NO_X Emissions in NYC



Notes: For chart description, see slide 96.

POTOMAC ECONOMICS

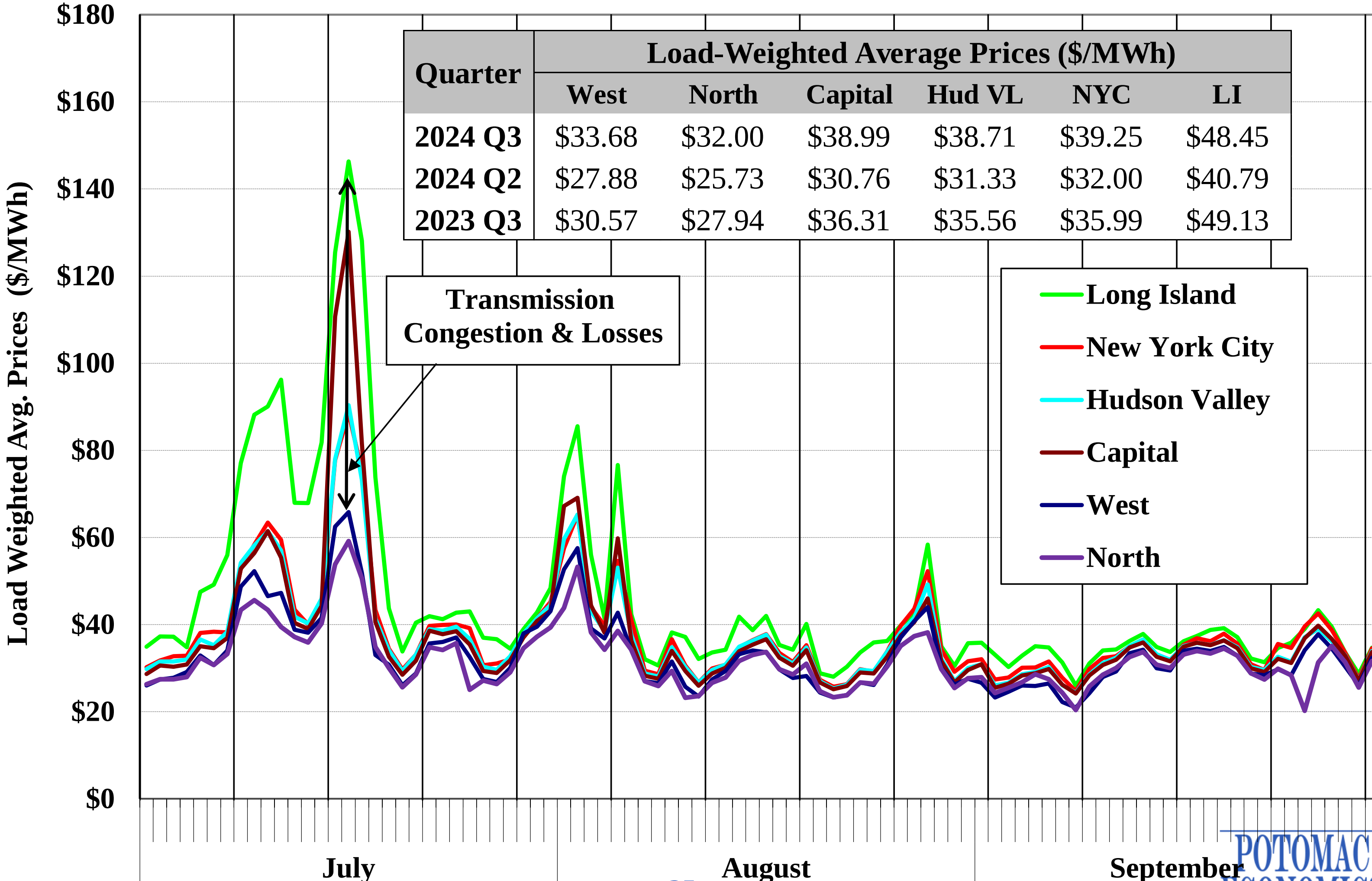
Daily NO_X Emissions in Long Island



Notes: For chart description, see slide 96.

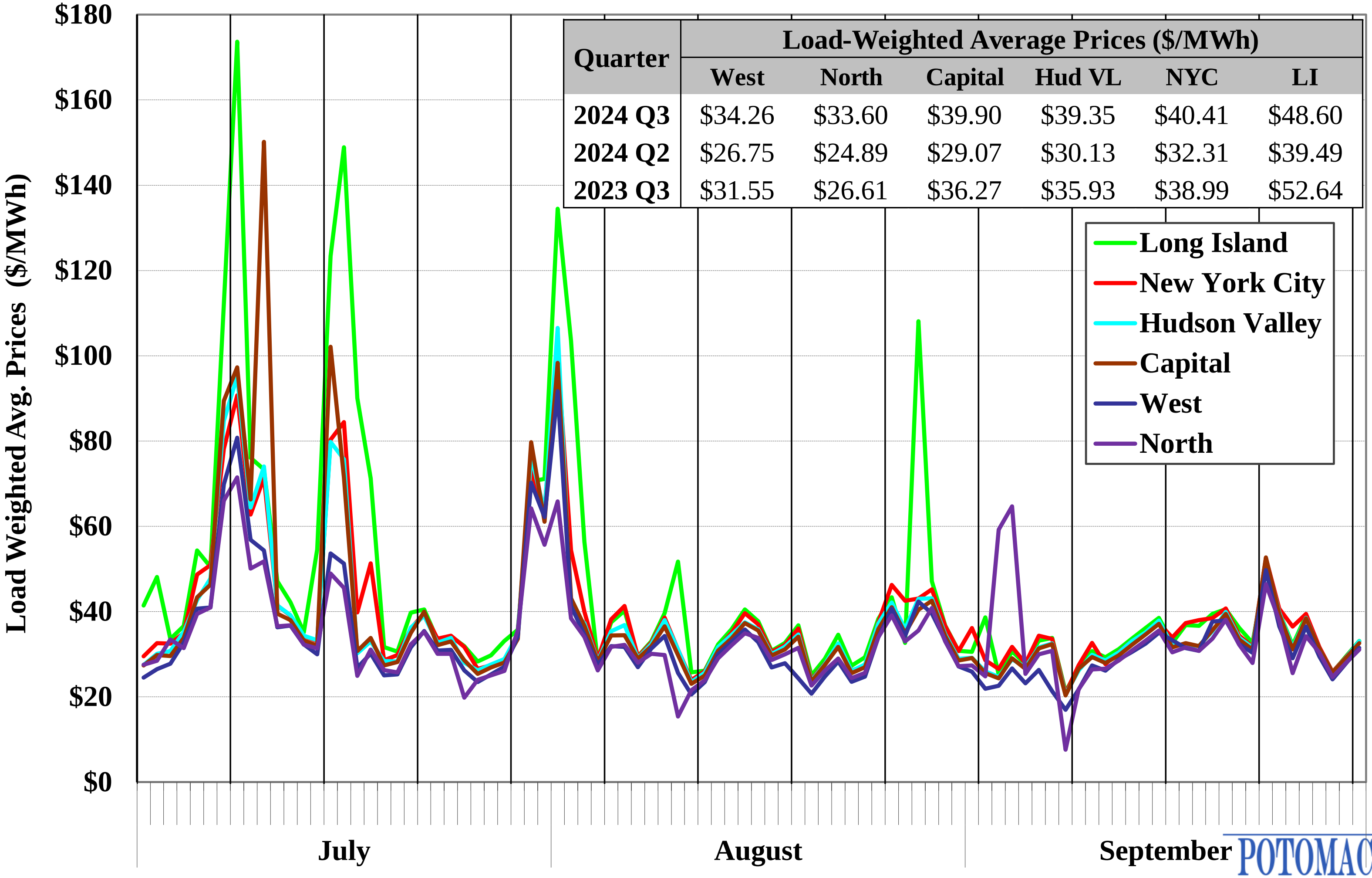
POTOMAC ECONOMICS

Day-Ahead Electricity Prices by Zone



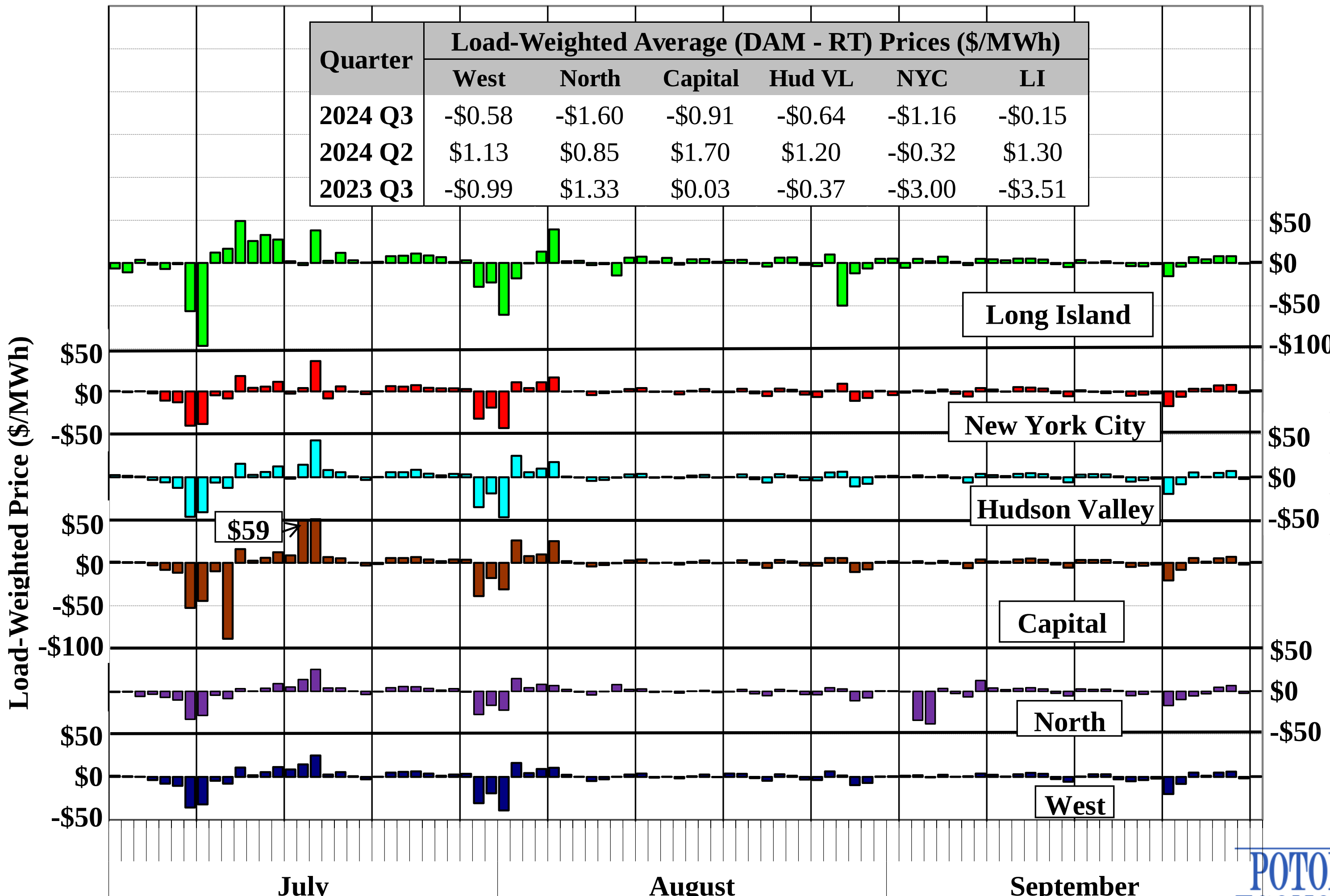
Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2024 Q3	$33.68	$32.00	$38.99	$38.71	$39.25	$48.45
2024 Q2	$27.88	$25.73	$30.76	$31.33	$32.00	$40.79
2023 Q3	$30.57	$27.94	$36.31	$35.56	$35.99	$49.13

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2024 Q3	$34.26	$33.60	$39.90	$39.35	$40.41	$48.60
2024 Q2	$26.75	$24.89	$29.07	$30.13	$32.31	$39.49
2023 Q3	$31.55	$26.61	$36.27	$35.93	$38.99	$52.64

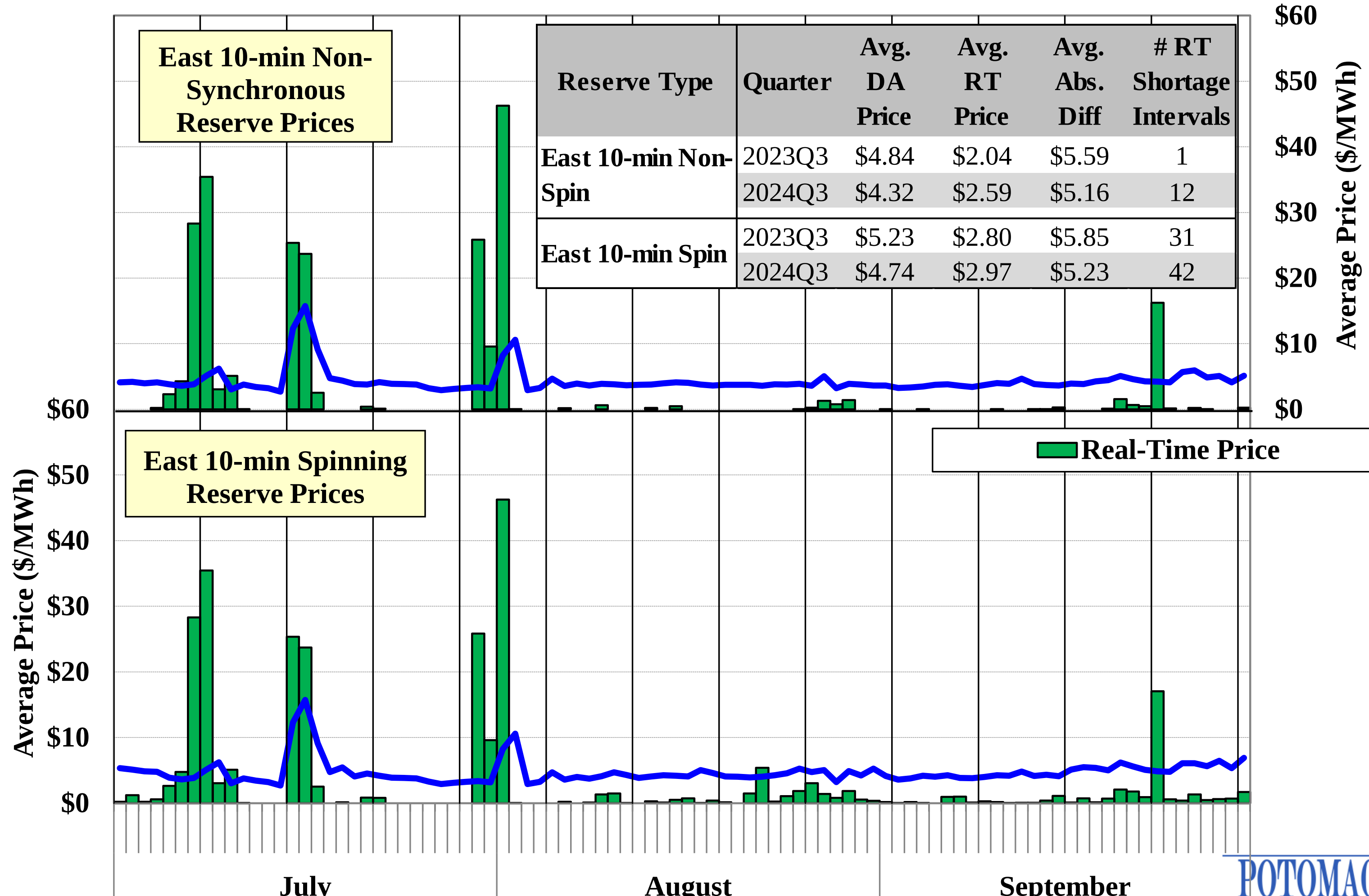
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2024 Q3	-$0.58	-$1.60	-$0.91	-$0.64	-$1.16	-$0.15
2024 Q2	$1.13	$0.85	$1.70	$1.20	-$0.32	$1.30
2023 Q3	-$0.99	$1.33	$0.03	-$0.37	-$3.00	-$3.51

Charts:
Ancillary Services Market

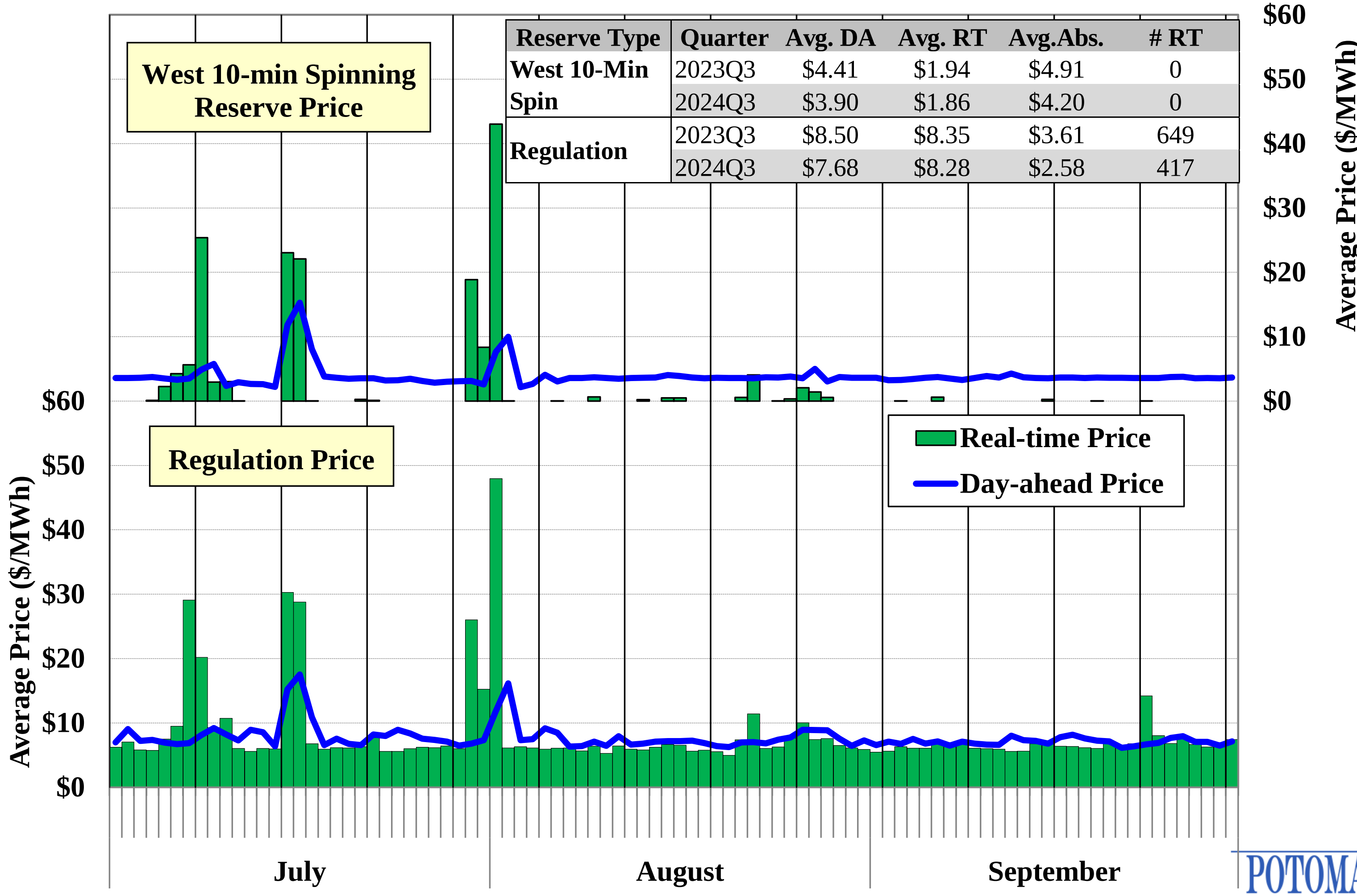
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2023Q3	$4.84	$2.04	$5.59	1
	2024Q3	$4.32	$2.59	$5.16	12
East 10-min Spin	2023Q3	$5.23	$2.80	$5.85	31
	2024Q3	$4.74	$2.97	$5.23	42

Notes: For chart description, see slide 97.

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

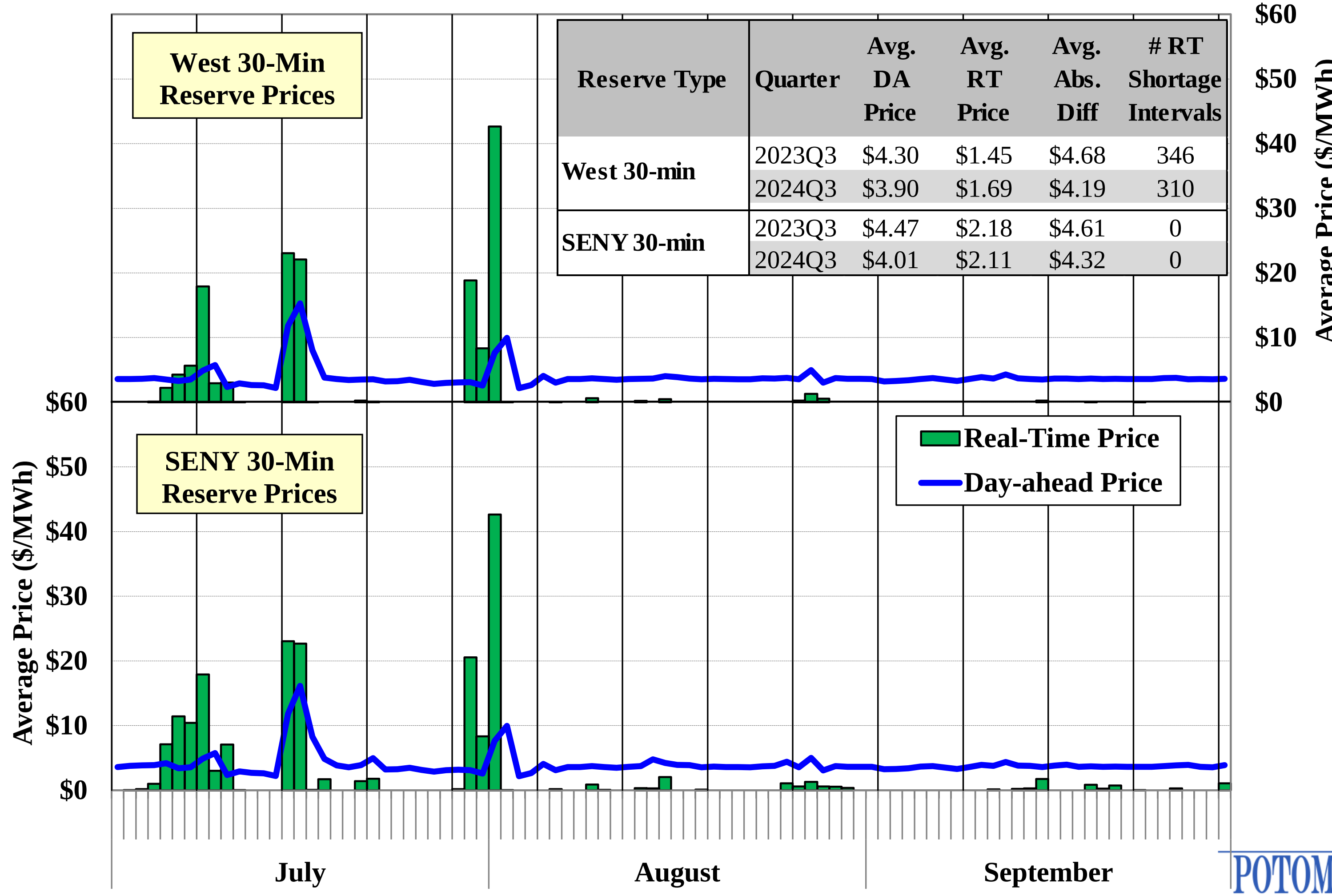


Reserve Type	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2023Q3	$4.41	$1.94	$4.91	0
	2024Q3	$3.90	$1.86	$4.20	0
Regulation	2023Q3	$8.50	$8.35	$3.61	649
	2024Q3	$7.68	$8.28	$2.58	417

Notes: For chart description, see slide 97.

POTOMAC ECONOMICS

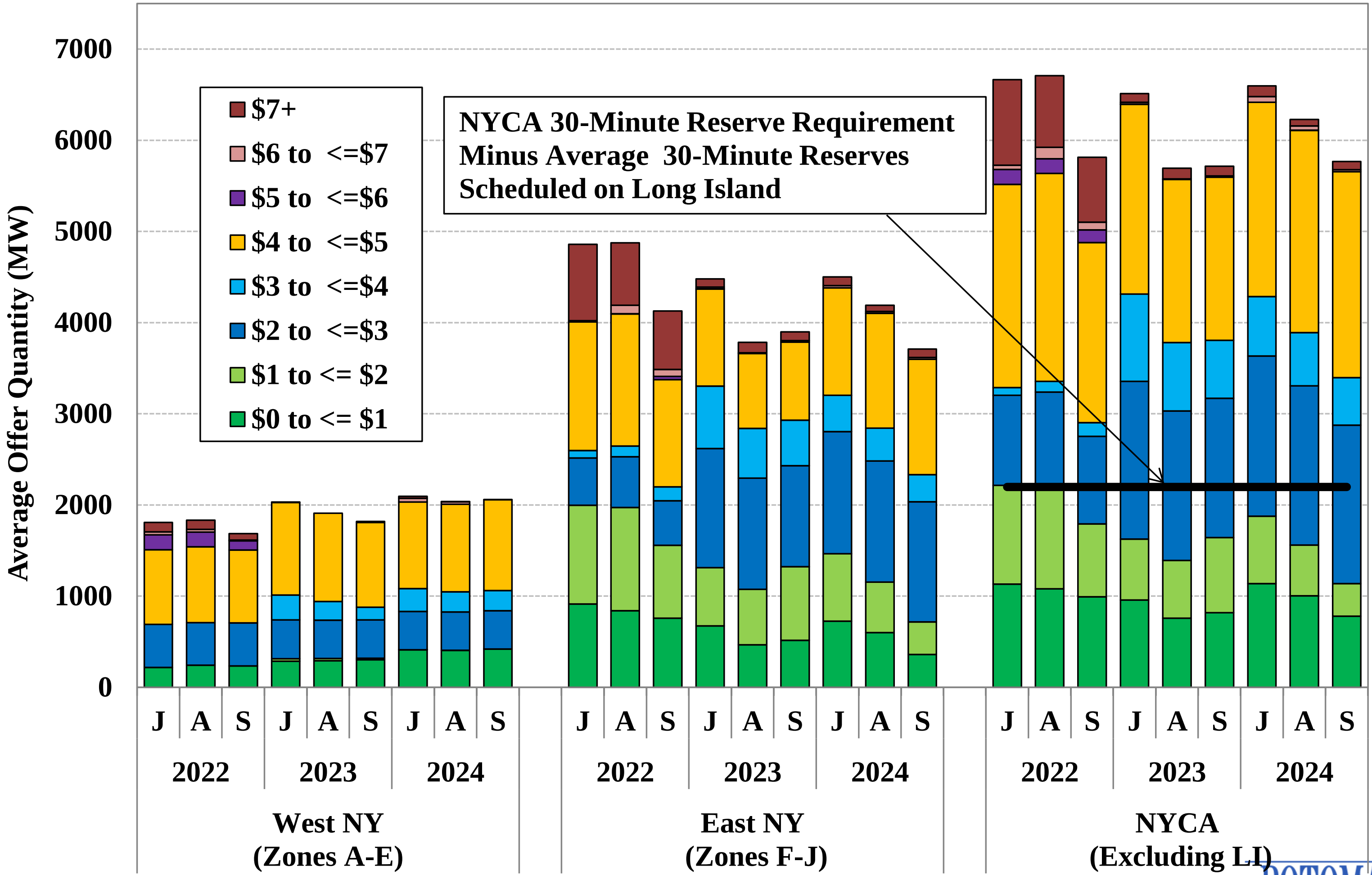
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2023Q3	$4.30	$1.45	$4.68	346
	2024Q3	$3.90	$1.69	$4.19	310
SENY 30-min	2023Q3	$4.47	$2.18	$4.61	0
	2024Q3	$4.01	$2.11	$4.32	0

Notes: For chart description, see slide 97.

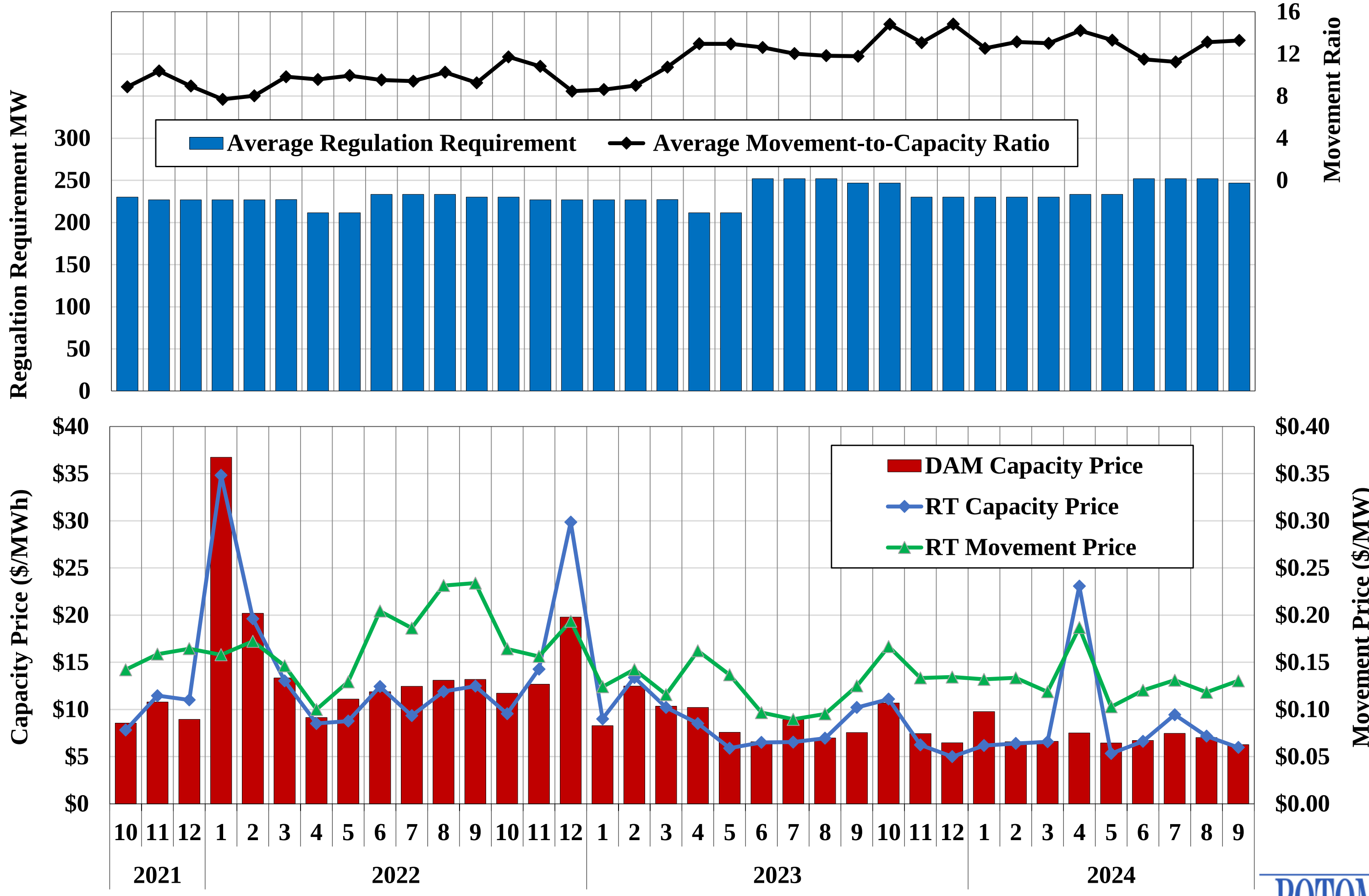
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 98.

POTOMAC ECONOMICS

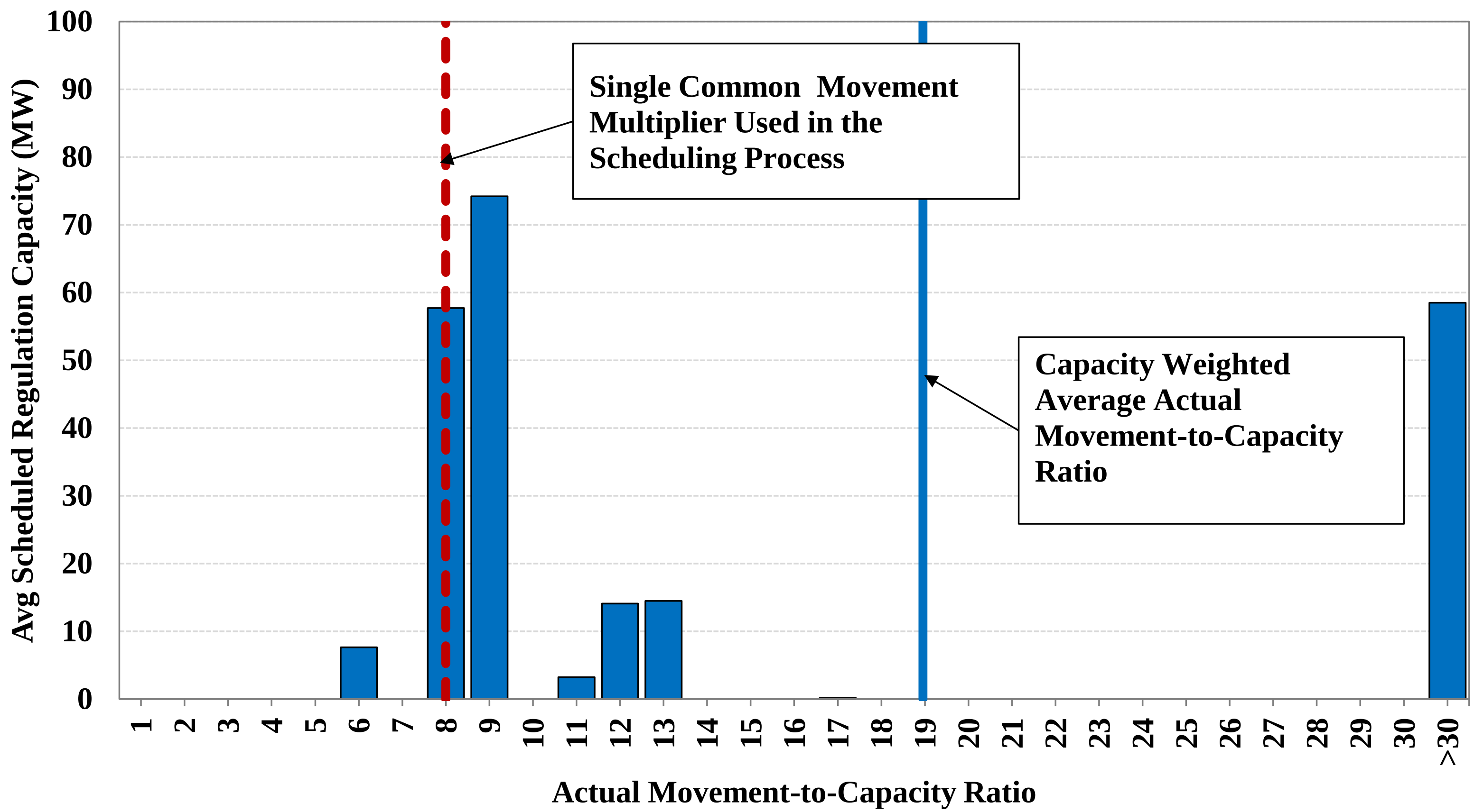
Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month



Notes: For chart description, see slide 99.

POTOMAC ECONOMICS

Distribution of Actual Regulation Movement
from One Sample Day



Notes: For chart description, see slide 99.

POTOMAC ECONOMICS

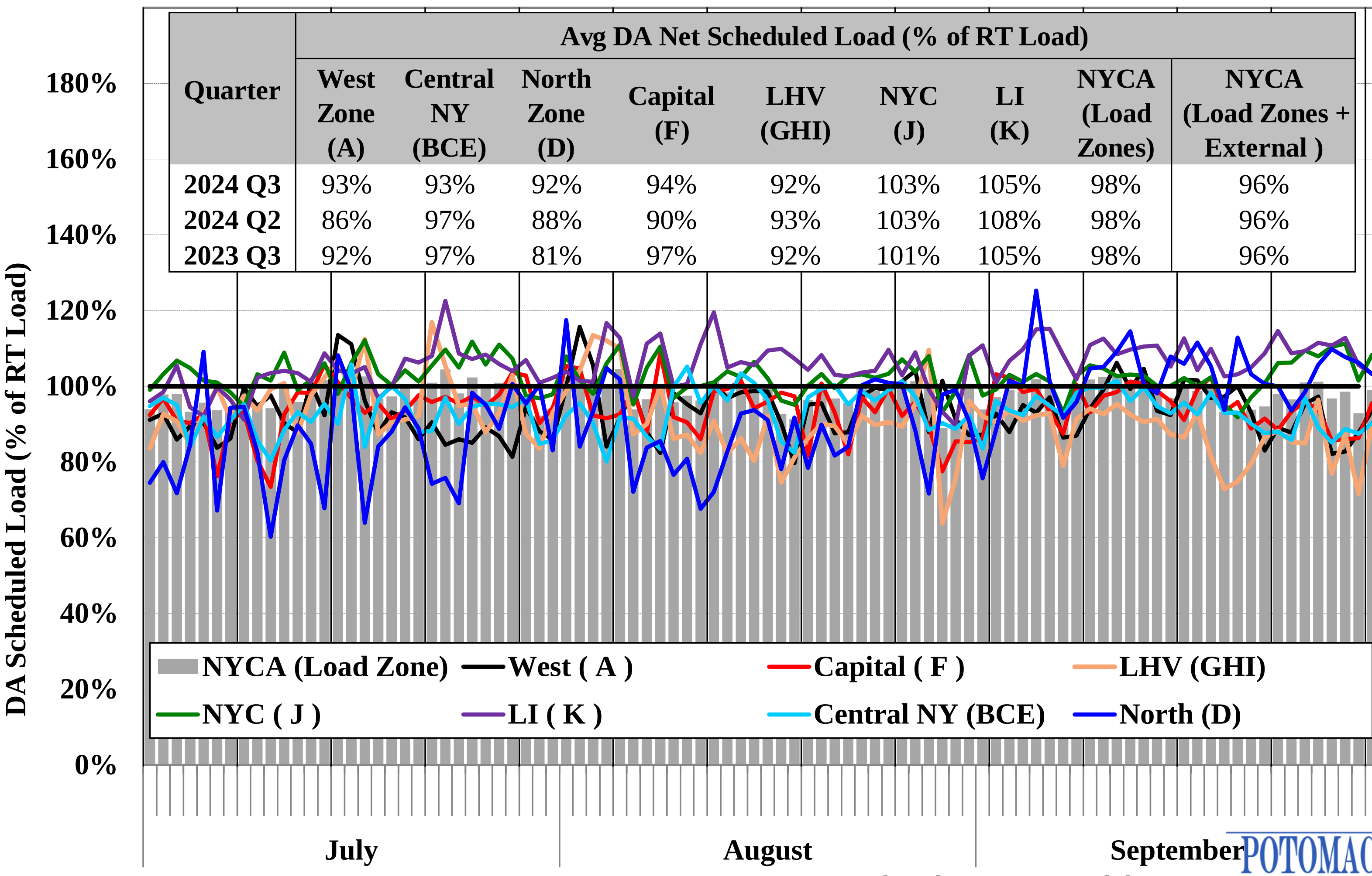
Charts:
Energy Market Scheduling

POTOMAC ECONOMICS

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour

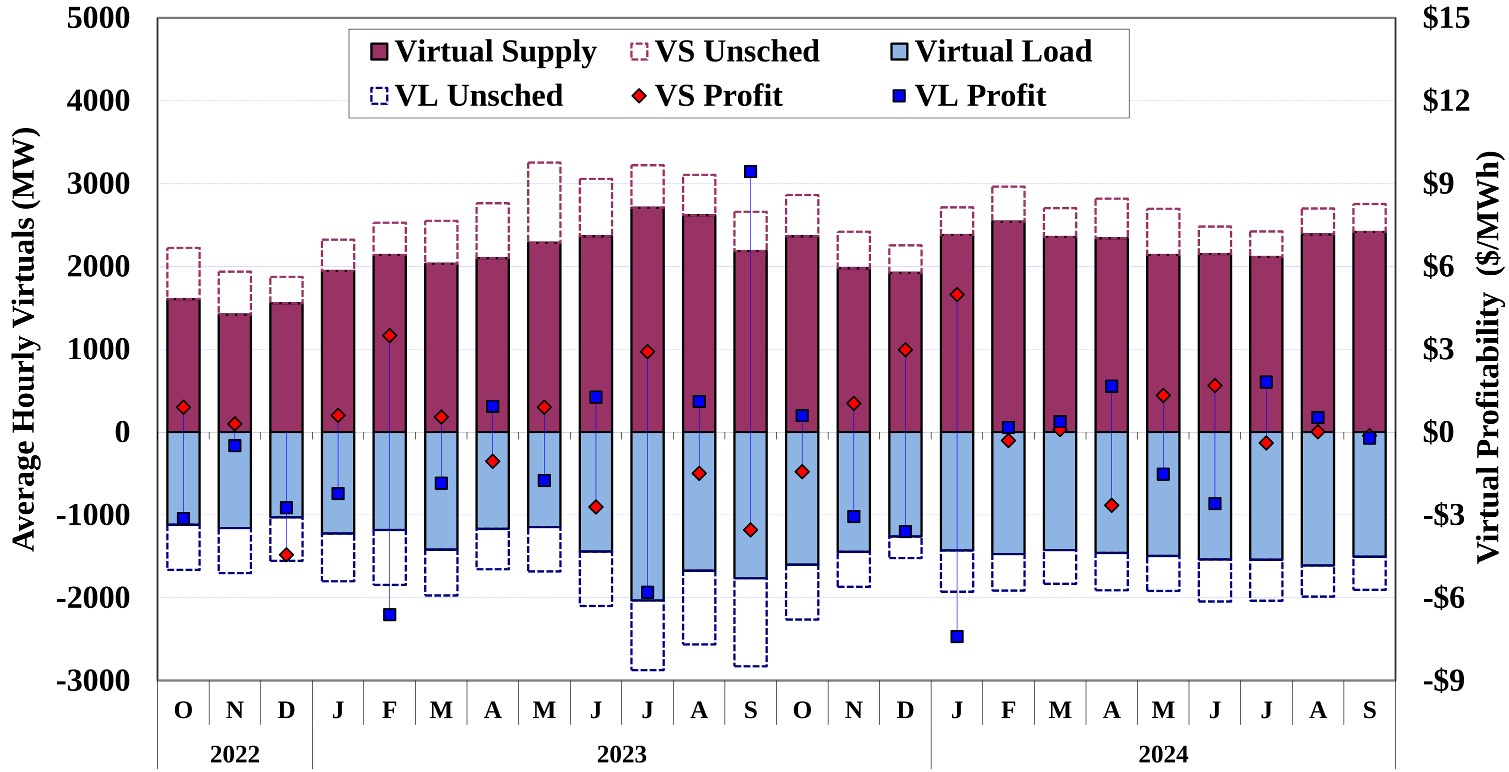
Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2024 Q3	93%	93%	92%	94%	92%	103%	105%	98%	96%
2024 Q2	86%	97%	88%	90%	93%	103%	108%	98%	96%
2023 Q3	92%	97%	81%	97%	92%	101%	105%	98%	96%



Notes: For chart description, see slide 100.

POTOMAC ECONOMICS

Virtual Trading Activity by Month

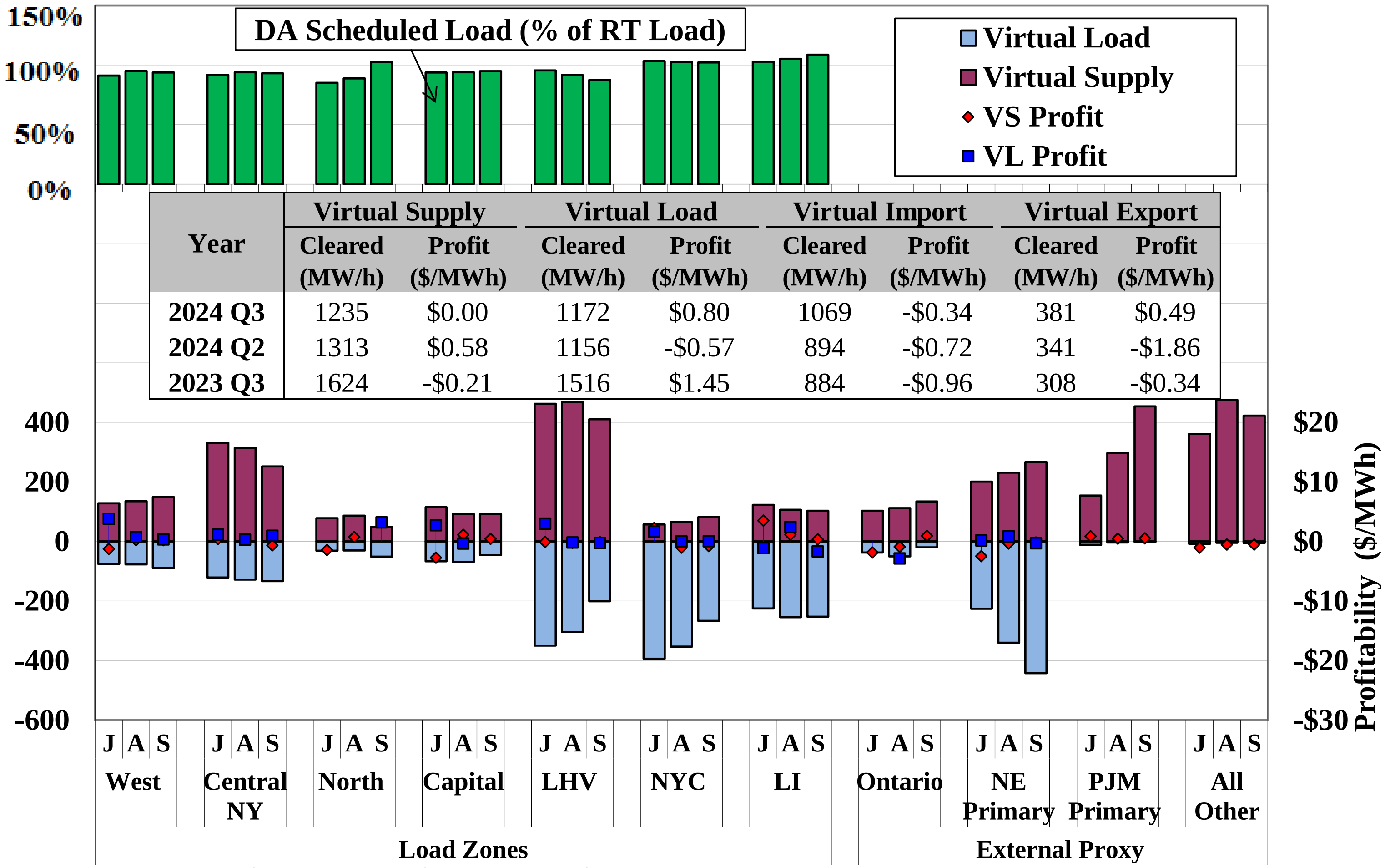


Profit > 50% of Avg. Zone Price	MW	134	250	302	170	455	343	243	275	130	360	243	244	166	198	136	334	106	138	81	136	236	249	132	48
	%	5%	10%	12%	5%	14%	10%	7%	8%	3%	8%	6%	6%	4%	6%	4%	9%	3%	4%	2%	4%	6%	7%	3%	1%
Loss > 50% of Avg. Zone Price	MW	163	289	287	206	412	377	285	296	164	415	322	156	213	255	141	283	148	163	93	155	234	252	148	61
	%	6%	11%	11%	7%	12%	11%	9%	9%	4%	9%	8%	4%	5%	7%	4%	7%	4%	4%	2%	4%	6%	7%	4%	2%

Notes: For chart description, see slide 100.

POTOMAC ECONOMICS

Virtual Trading Activity
by Location

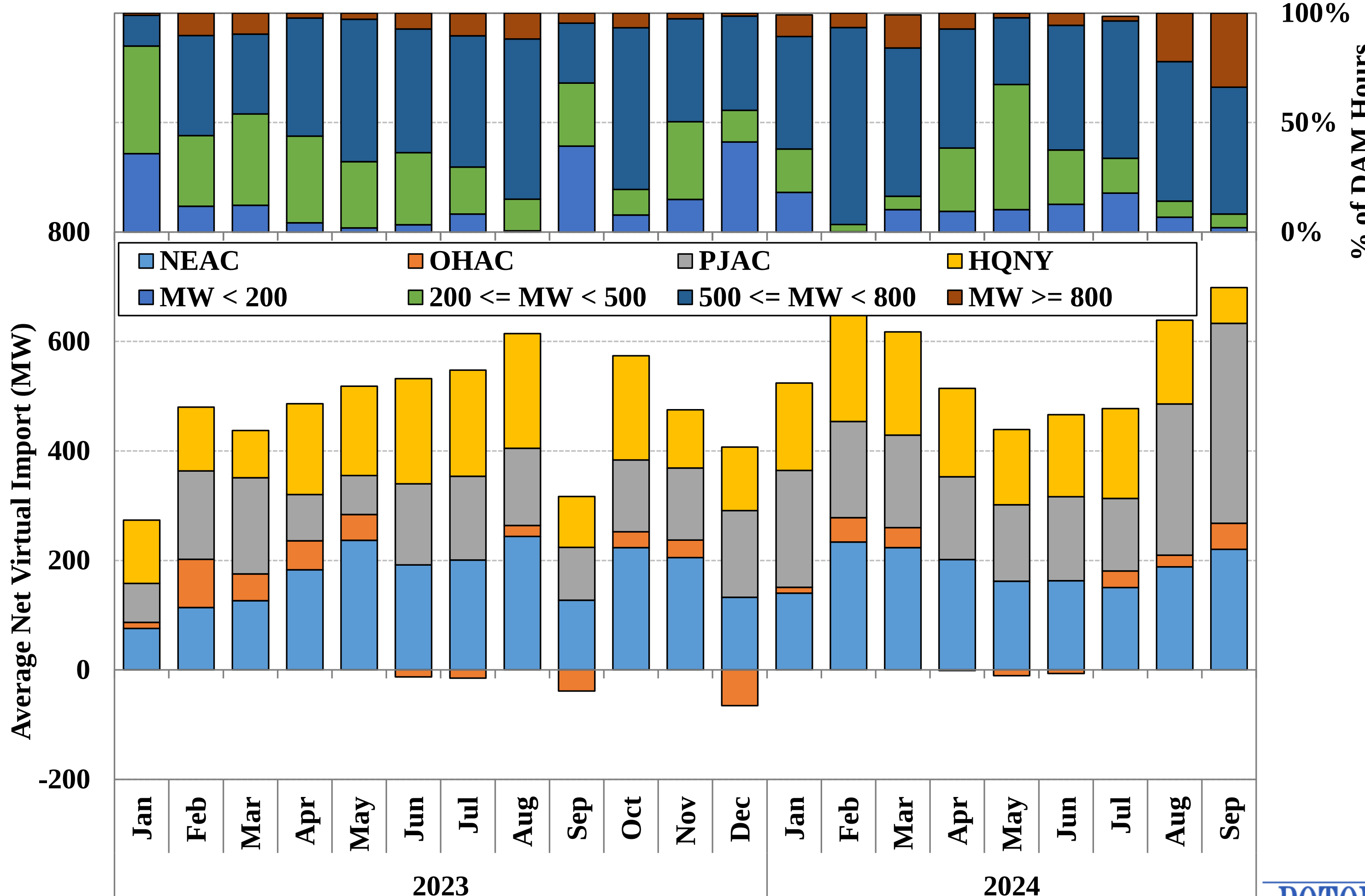


Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2024 Q3	1235	$0.00	1172	$0.80	1069	-$0.34	381	$0.49
2024 Q2	1313	$0.58	1156	-$0.57	894	-$0.72	341	-$1.86
2023 Q3	1624	-$0.21	1516	$1.45	884	-$0.96	308	-$0.34

Notes: 1. Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.
2. For chart description, see slide 100.

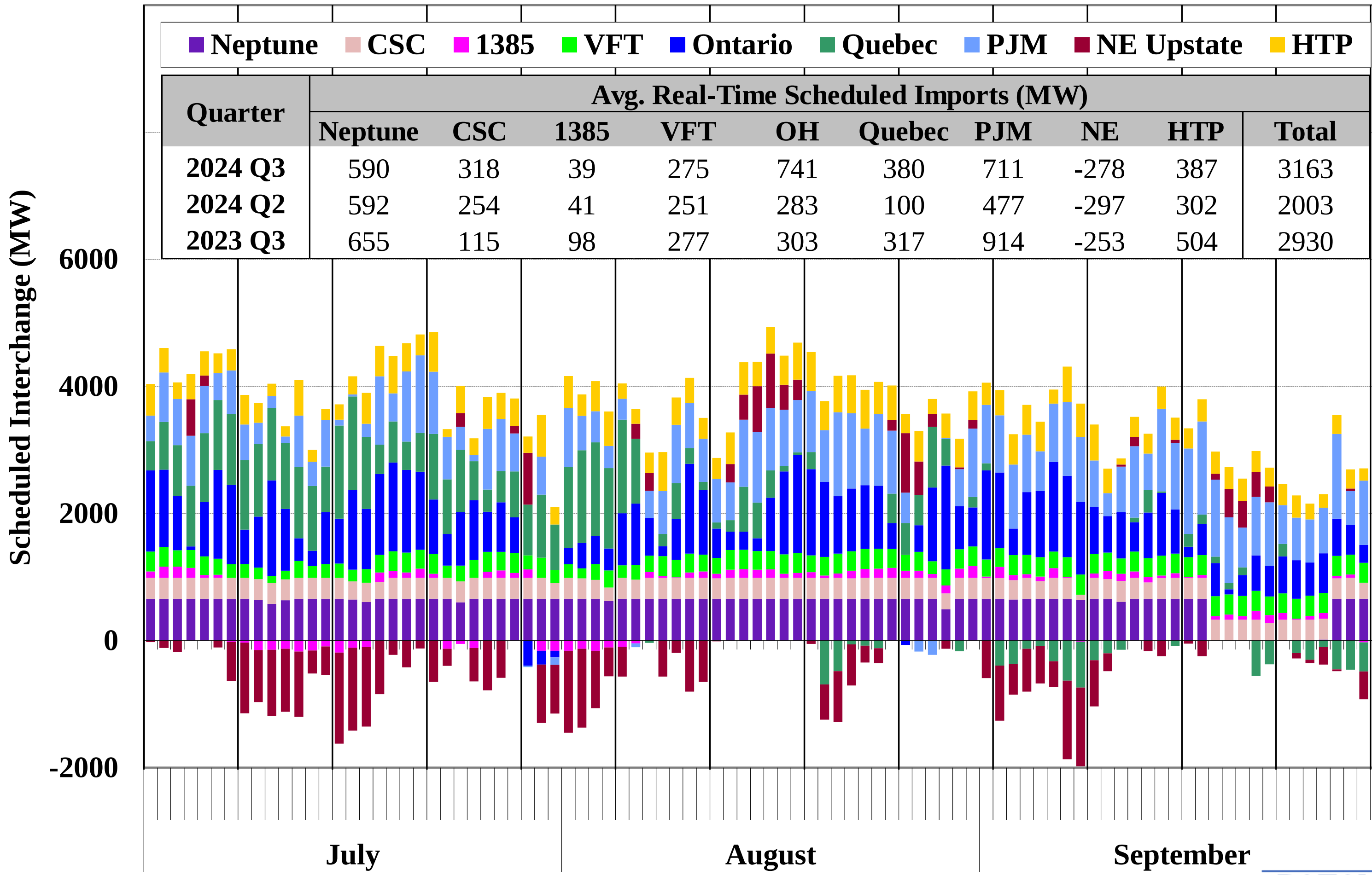
POTOMAC ECONOMICS

Virtual Imports and Exports in the Day-Ahead Market



Notes: For chart description, see slide 101.

Net Imports Scheduled Across External Interfaces
Daily Peak Hours (1-9pm)



Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	Quebec	PJM	NE	HTP	Total
2024 Q3	590	318	39	275	741	380	711	-278	387	3163
2024 Q2	592	254	41	251	283	100	477	-297	302	2003
2023 Q3	655	115	98	277	303	317	914	-253	504	2930

Notes: Two Quebec interfaces are combined into one.

POTOMAC ECONOMICS

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

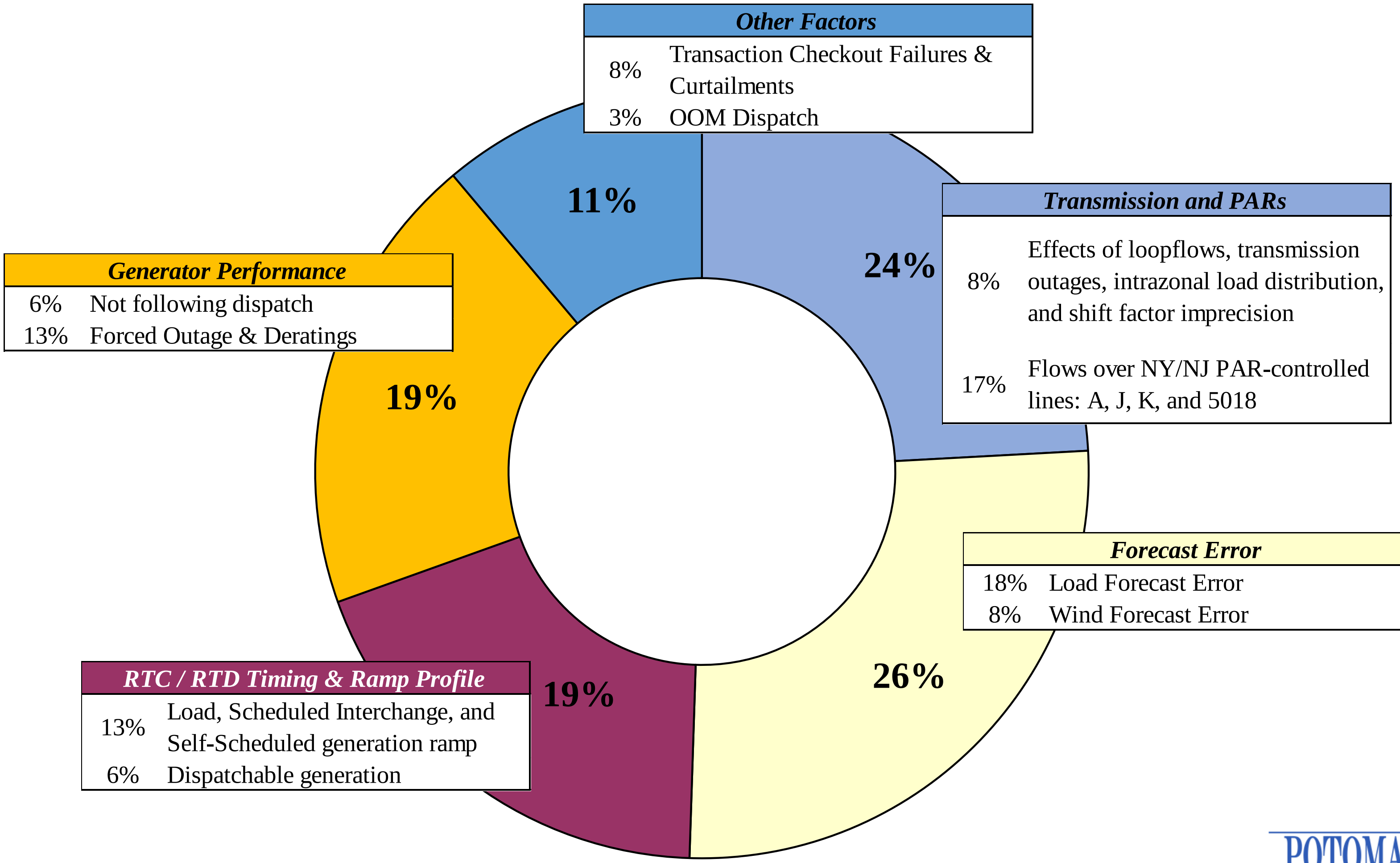
			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total		Both Forecast Errors <= $20	Any Forecast Error > $20	Total	
% of All Intervals w/ Adjustment			81%	8%	**89%**		50%	13%	**63%**	
Average Flow Adjustment (MW)	Net Imports		39	27	**38**		-4	-59	**-15**	
	Gross		138	188	**142**		87	124	**95**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$2.5	$1.7	**$4.2**		$0.6	$1.6	**$2.2**	
	Net Over-Projection by:	NY	-$0.1	$0.0	**-$0.1**		$0.0	$0.1	**$0.0**	
		NE or PJM	$0.0	-$0.6	**-$0.7**		-$0.3	-$1.5	**-$1.8**	
	Other Unrealized Savings		-$0.1	-$0.5	**-$0.6**		$0.0	$0.1	**$0.1**	
	Actual Savings		$2.2	$0.6	**$2.8**		$0.3	$0.3	**$0.6**	
Interface Prices ($/MWh)	NY	Actual	$31.70	$81.20	**$36.15**	**$35.46**	$30.17	$54.07	**$35.03**	**$33.57**
		Forecast	$32.46	$64.69	**$35.36**	**$34.63**	$30.89	$52.20	**$35.22**	**$33.64**
	NE or PJM	Actual	$31.19	$85.09	**$36.04**	**$37.03**	$26.11	$67.33	**$34.49**	**$32.31**
		Forecast	$30.66	$90.80	**$36.07**	**$37.16**	$27.82	$74.18	**$37.24**	**$34.15**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.76	-$16.51	**-$0.79**	**-$0.83**	$0.73	-$1.86	**$0.20**	**$0.07**
		Abs. Val.	$2.25	$42.92	**$5.91**	**$5.88**	$2.20	$21.47	**$6.12**	**$5.19**
	NE or PJM	Fcst. - Act.	-$0.52	$5.72	**$0.04**	**$0.13**	$1.71	$6.85	**$2.76**	**$1.84**
		Abs. Val.	$3.74	$61.14	**$8.91**	**$9.90**	$5.21	$57.45	**$15.83**	**$13.51**

For Adjustment Intervals Only (first Total column)

For All Intervals (second Total column)

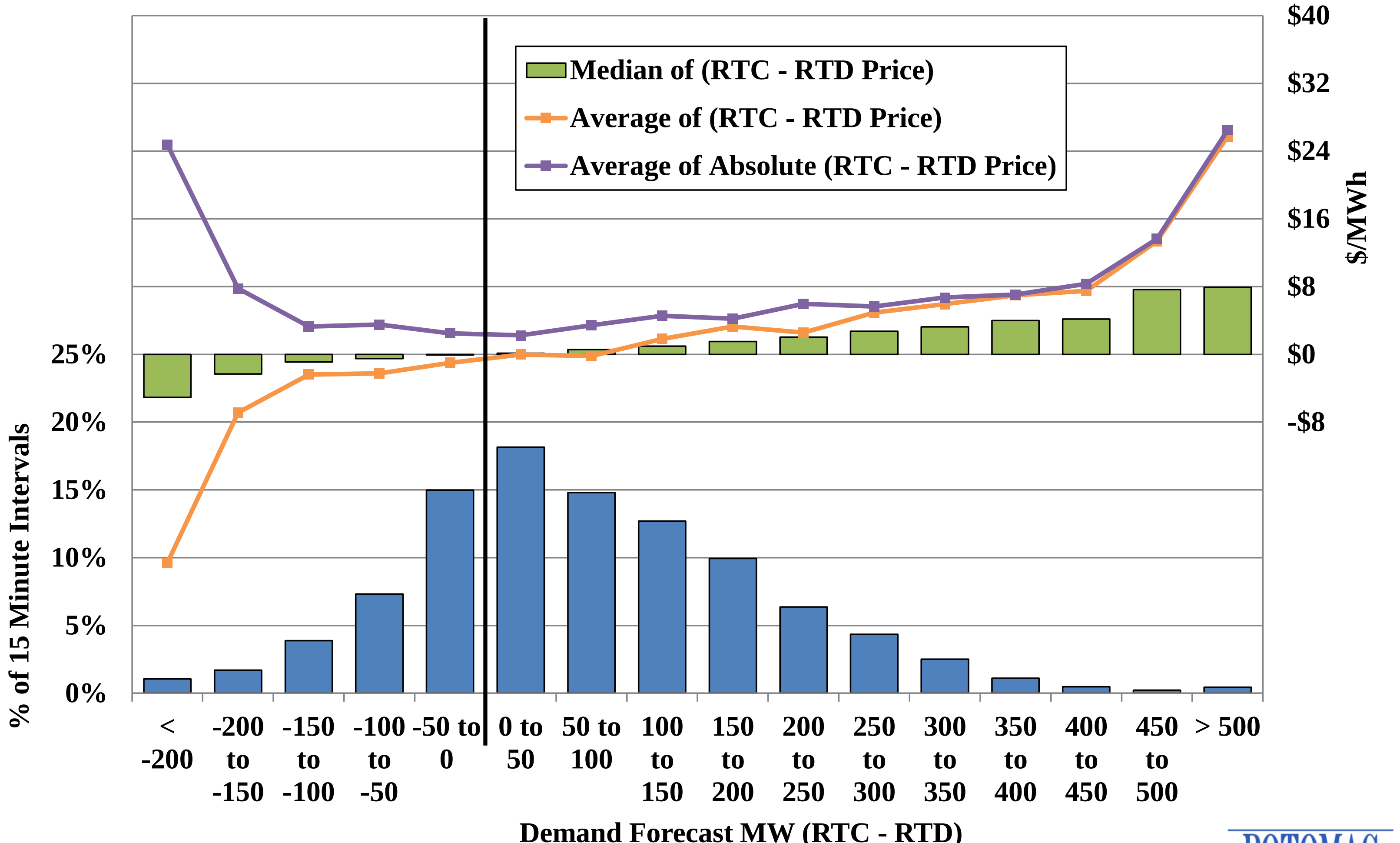
Notes: For chart description, see slide 102.

Detrimental Factors to RTC and RTD Price Divergence



Notes: For chart description, see slide 103.

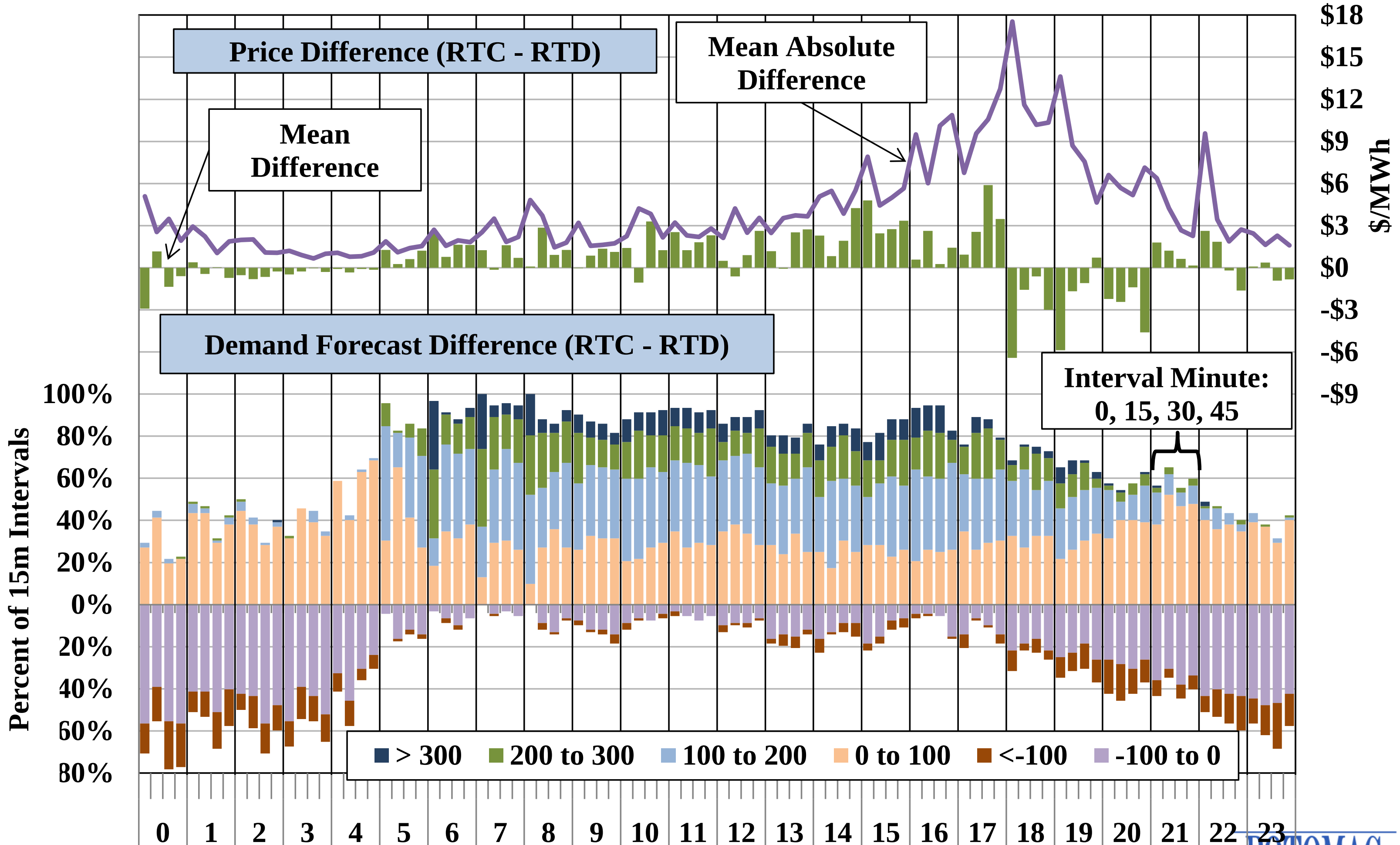
RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide 103.

POTOMAC ECONOMICS

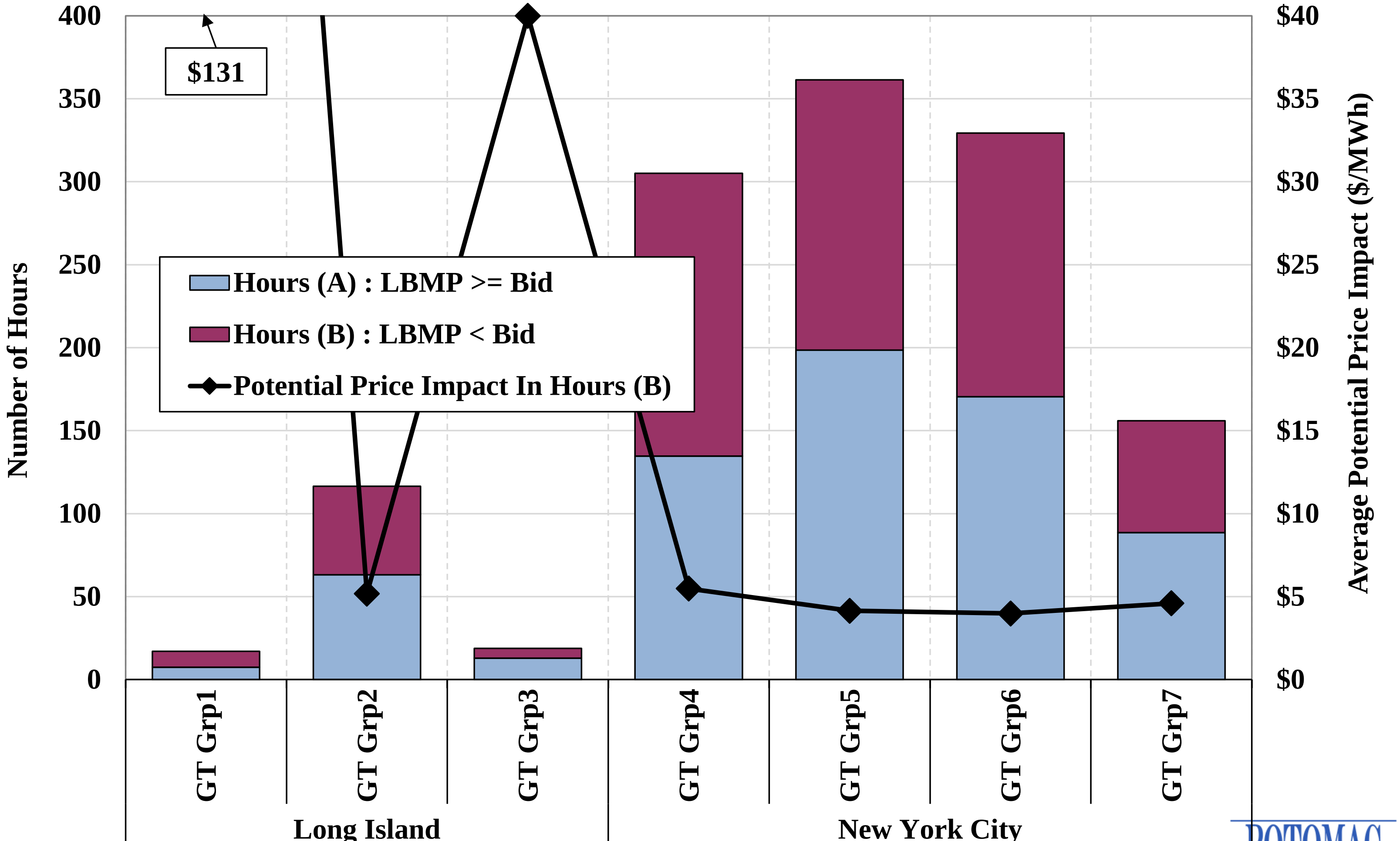
RTC and RTD Price Difference vs Demand Forecast Difference
by Time of Day



Notes: For chart description, see slide 104.

POTOMAC ECONOMICS

Real-Time Prices During Commitments of GTs Offering Multi-Hour Min Run Times: 2024 Q3



Notes: For chart description, see slide 105.

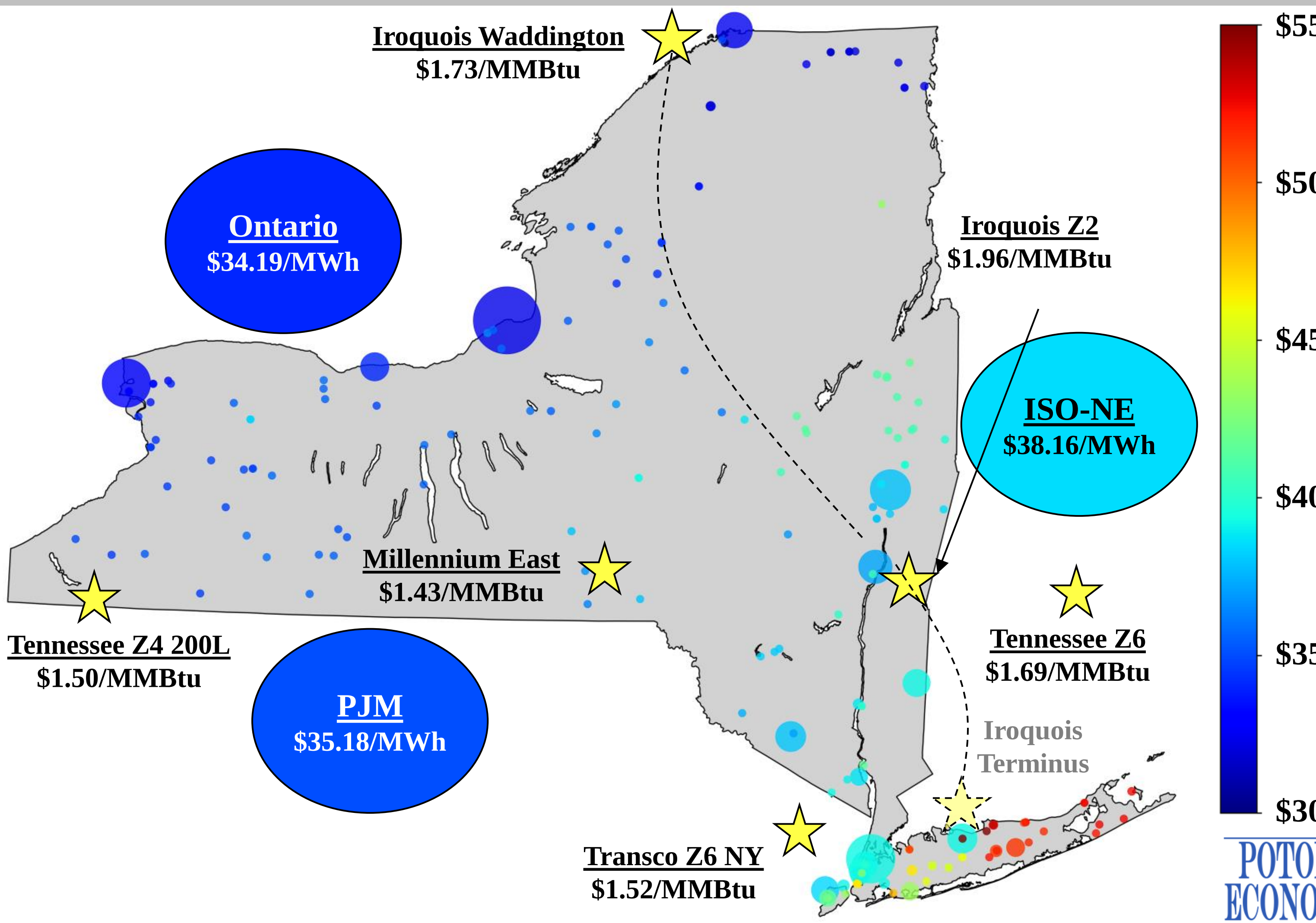
POTOMAC ECONOMICS

Charts:

Transmission Congestion Revenues and Shortfalls

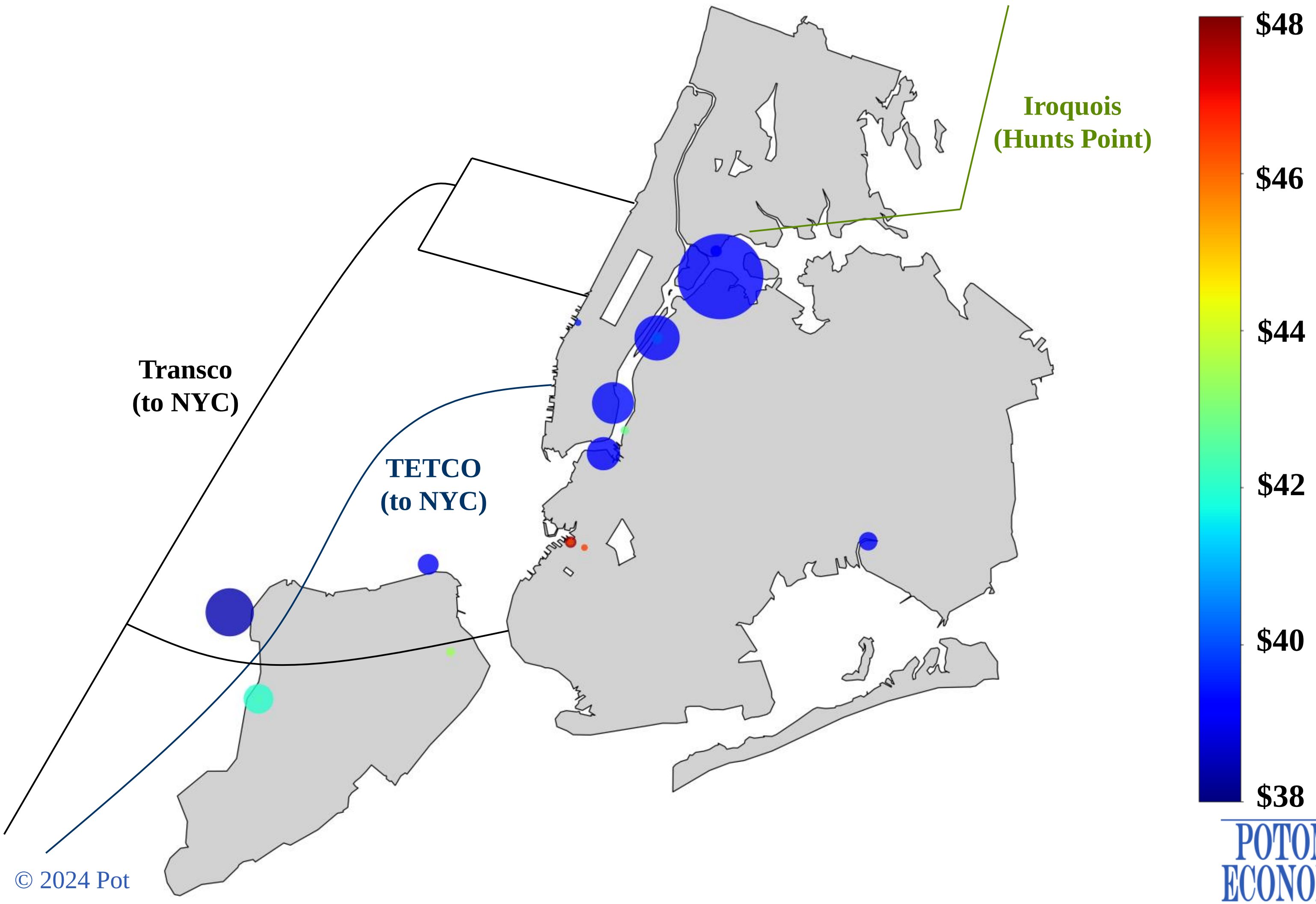
POTOMAC ECONOMICS

System Congestion
Real-Time Price Map at Generator Nodes



POTOMAC ECONOMICS

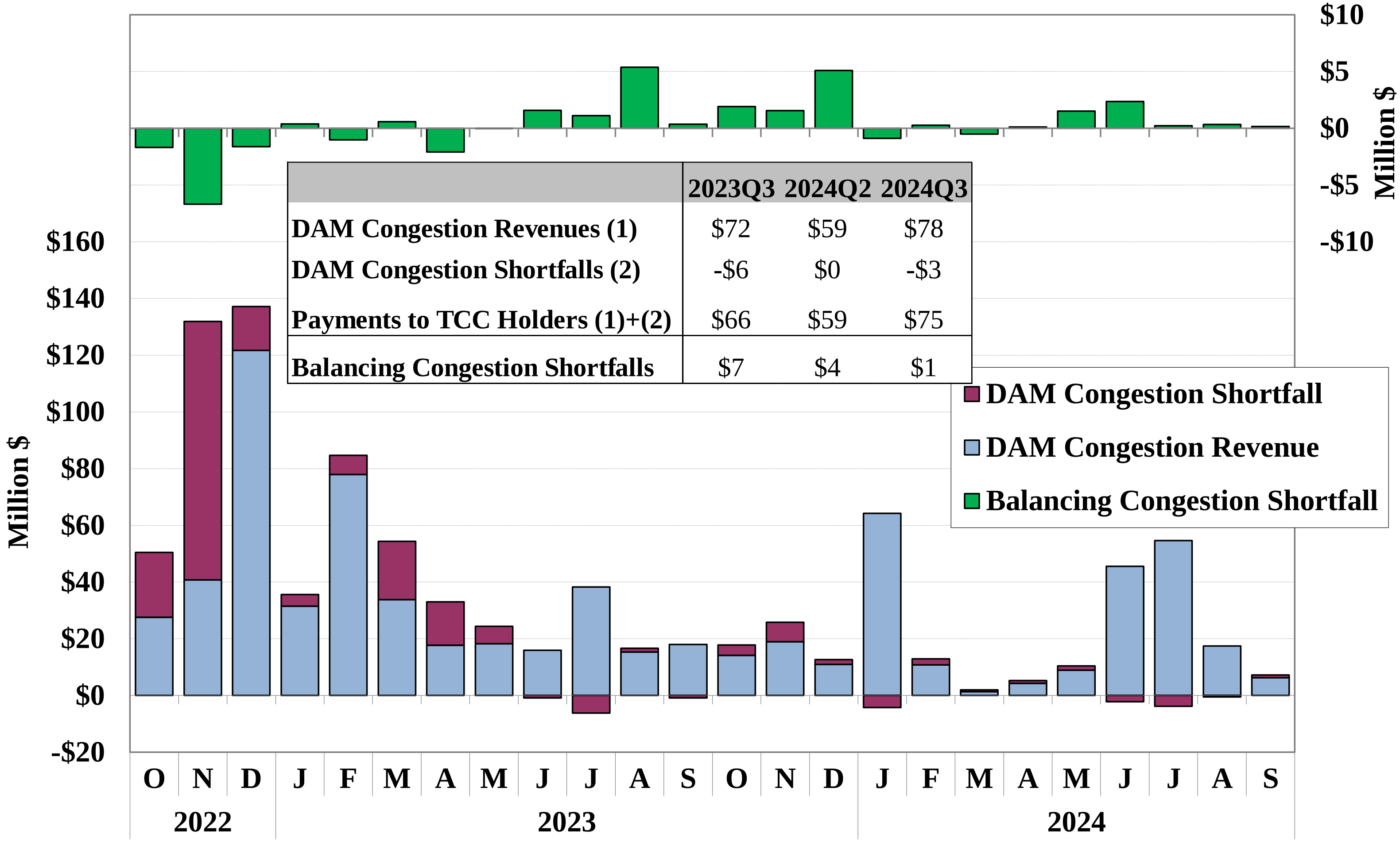
System Congestion
NYC Real-Time Price Map at Generator Nodes



POTOMAC ECONOMICS

Congestion Revenues and Shortfalls by Month

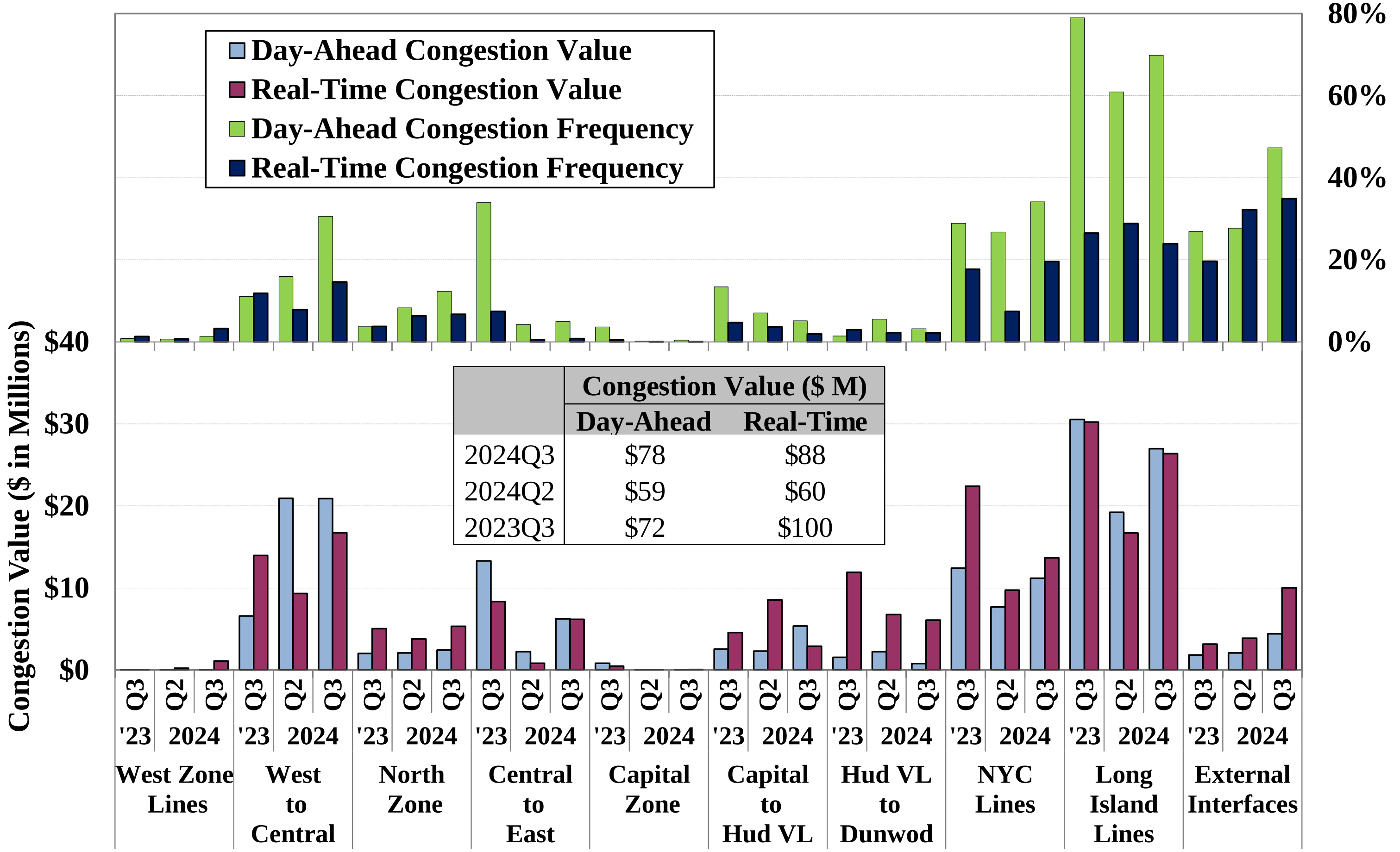
	2023Q3	2024Q2	2024Q3
DAM Congestion Revenues (1)	$72	$59	$78
DAM Congestion Shortfalls (2)	-$6	$0	-$3
Payments to TCC Holders (1)+(2)	$66	$59	$75
Balancing Congestion Shortfalls	$7	$4	$1



Notes: For chart description, see slides 107 and 108.

POTOMAC ECONOMICS

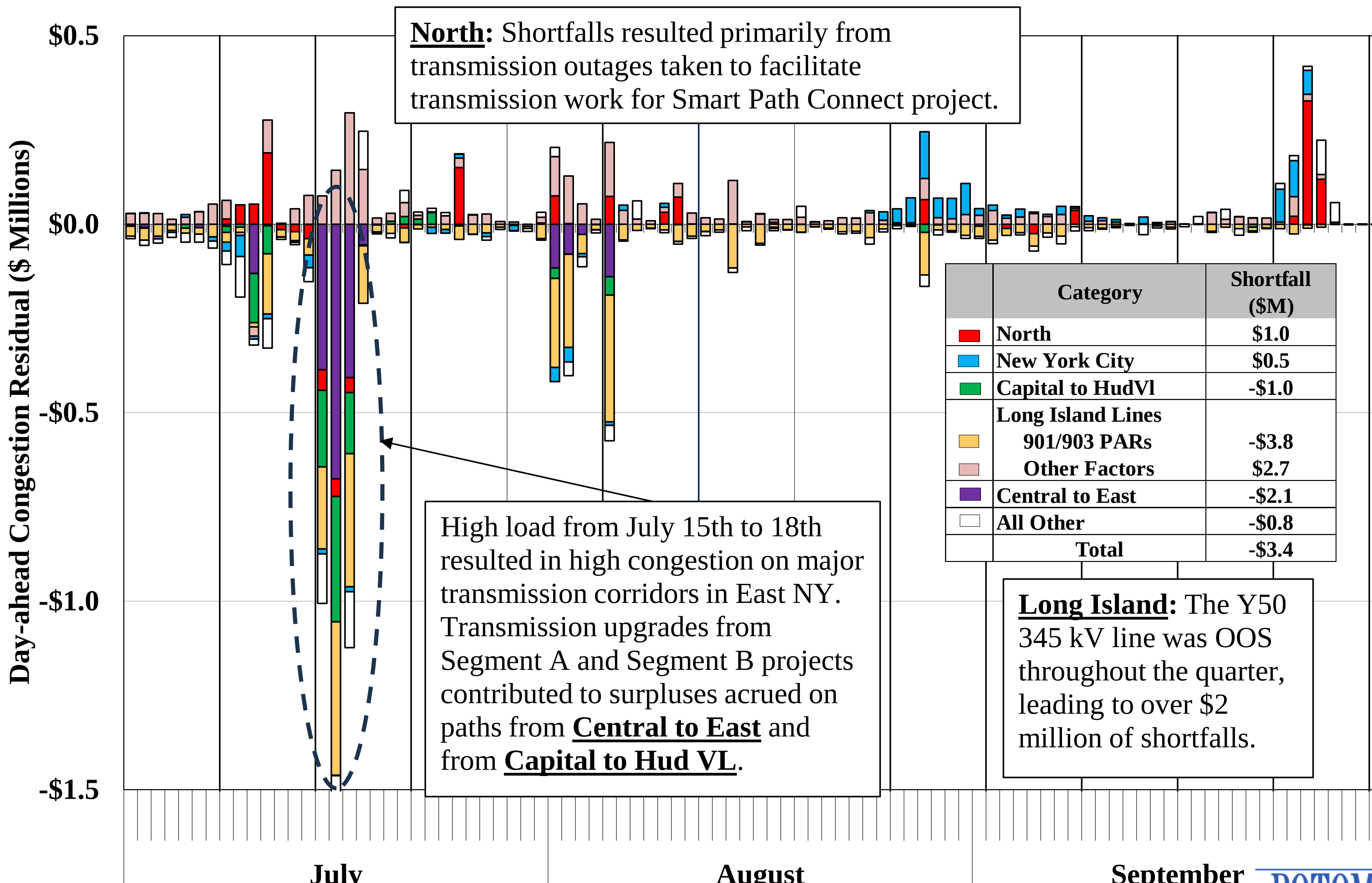
Day-Ahead and Real-Time Congestion Value by Transmission Path



	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2024Q3	$78	$88
2024Q2	$59	$60
2023Q3	$72	$100

Notes: For chart description, see slides 107, 108, and 109.

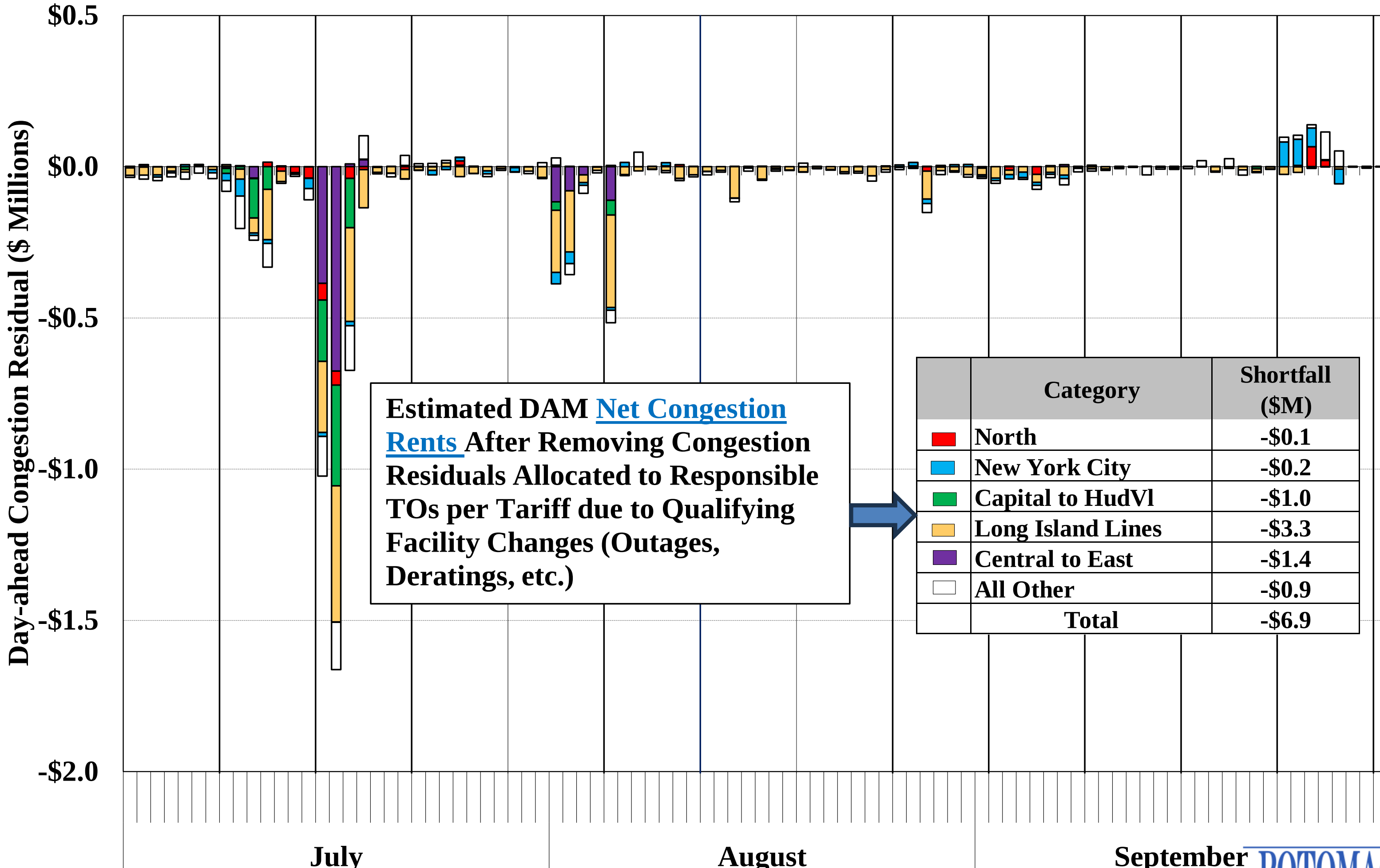
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Category	Shortfall ($M)
North	$1.0
New York City	$0.5
Capital to HudVl	-$1.0
Long Island Lines	
901/903 PARs	-$3.8
Other Factors	$2.7
Central to East	-$2.1
All Other	-$0.8
Total	-$3.4

Notes: For chart description, see slides 107, 108, and 109.

Estimated DAM Net Congestion Rents
by Transmission Facility



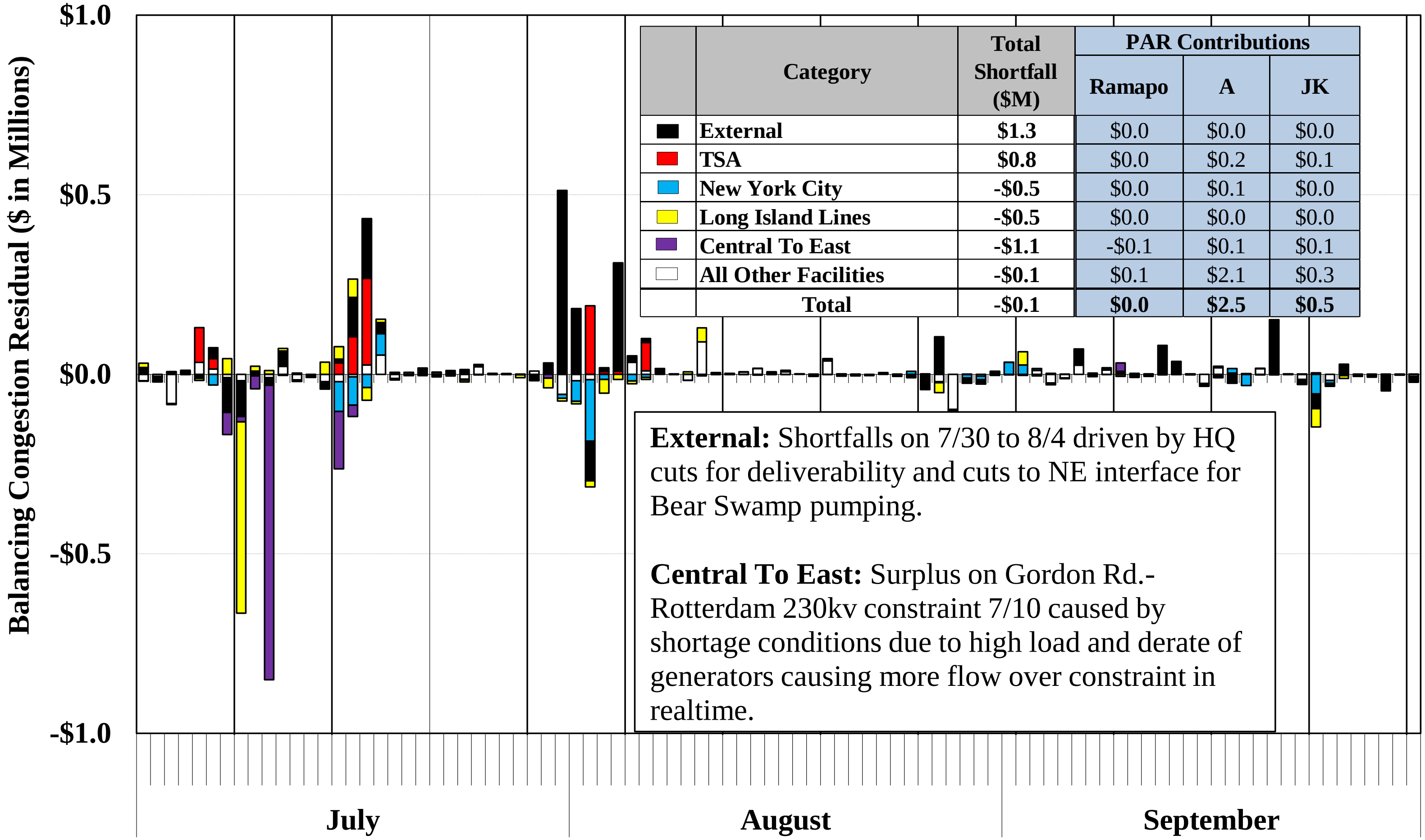
Estimated DAM Net Congestion Rents After Removing Congestion Residuals Allocated to Responsible TOs per Tariff due to Qualifying Facility Changes (Outages, Deratings, etc.)

	Category	Shortfall ($M)
	North	-$0.1
	New York City	-$0.2
	Capital to HudVl	-$1.0
	Long Island Lines	-$3.3
	Central to East	-$1.4
	All Other	-$0.9
	Total	-$6.9

Notes: For chart description, see slides 107, 108, and 109.

POTOMAC ECONOMICS

Balancing Congestion Shortfalls by Transmission Facility



	Category	Total Shortfall ($M)	PAR Contributions		
			Ramapo	A	JK
■	External	$1.3	$0.0	$0.0	$0.0
■	TSA	$0.8	$0.0	$0.2	$0.1
■	New York City	-$0.5	$0.0	$0.1	$0.0
■	Long Island Lines	-$0.5	$0.0	$0.0	$0.0
■	Central To East	-$1.1	-$0.1	$0.1	$0.1
□	All Other Facilities	-$0.1	$0.1	$2.1	$0.3
	Total	-$0.1	$0.0	$2.5	$0.5

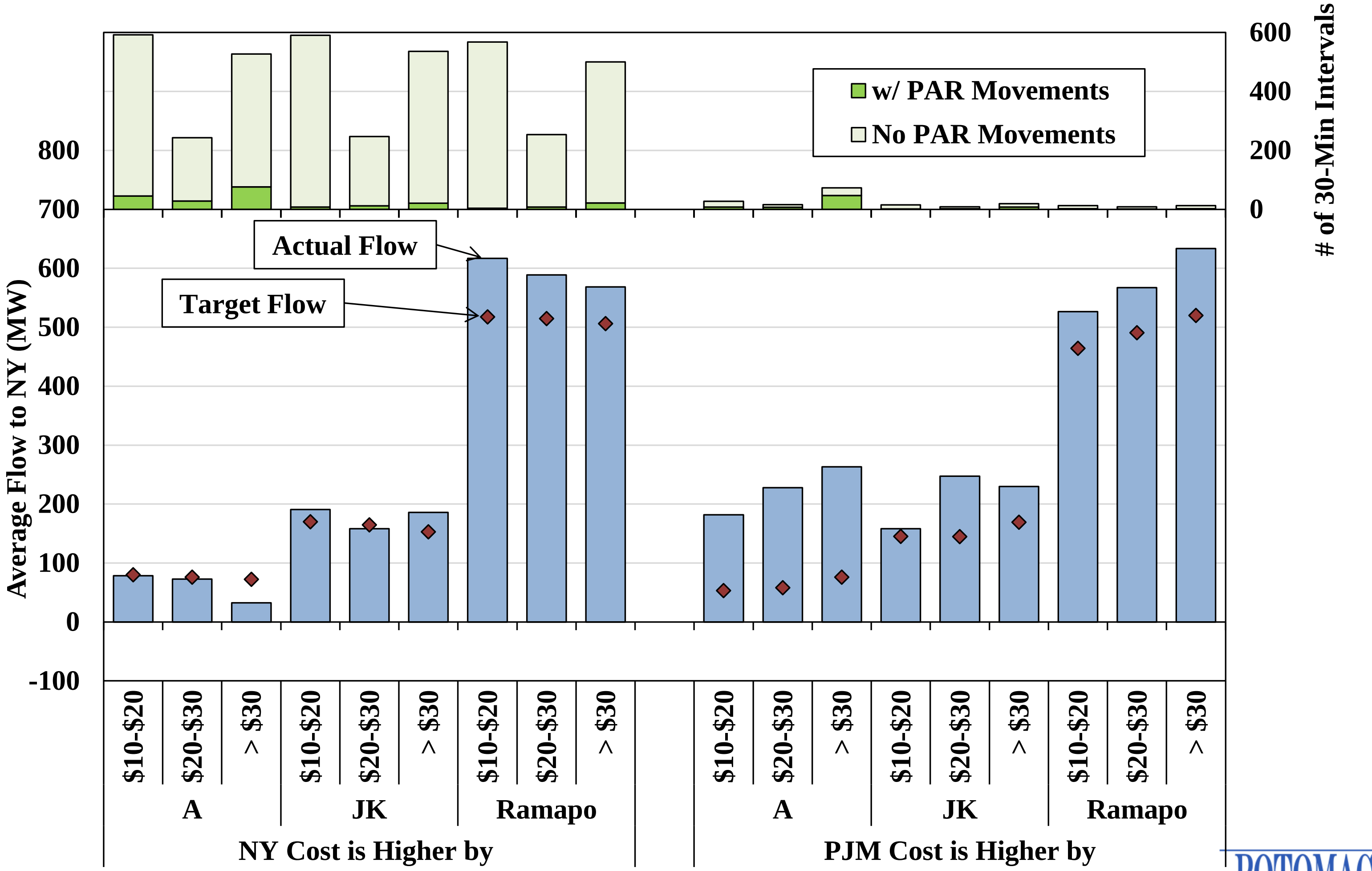
External: Shortfalls on 7/30 to 8/4 driven by HQ cuts for deliverability and cuts to NE interface for Bear Swamp pumping.

Central To East: Surplus on Gordon Rd.-Rotterdam 230kv constraint 7/10 caused by shortage conditions due to high load and derate of generators causing more flow over constraint in realtime.

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

POTOMAC ECONOMICS

PAR Operation under M2M with PJM
2024 Q3



Notes: For chart description, see slide 110.

POTOMAC ECONOMICS

OOM Actions to Manage Network Reliability

North	# Days
N-1-1	53
Constraint Management	
PAR	4
Any Resource	55

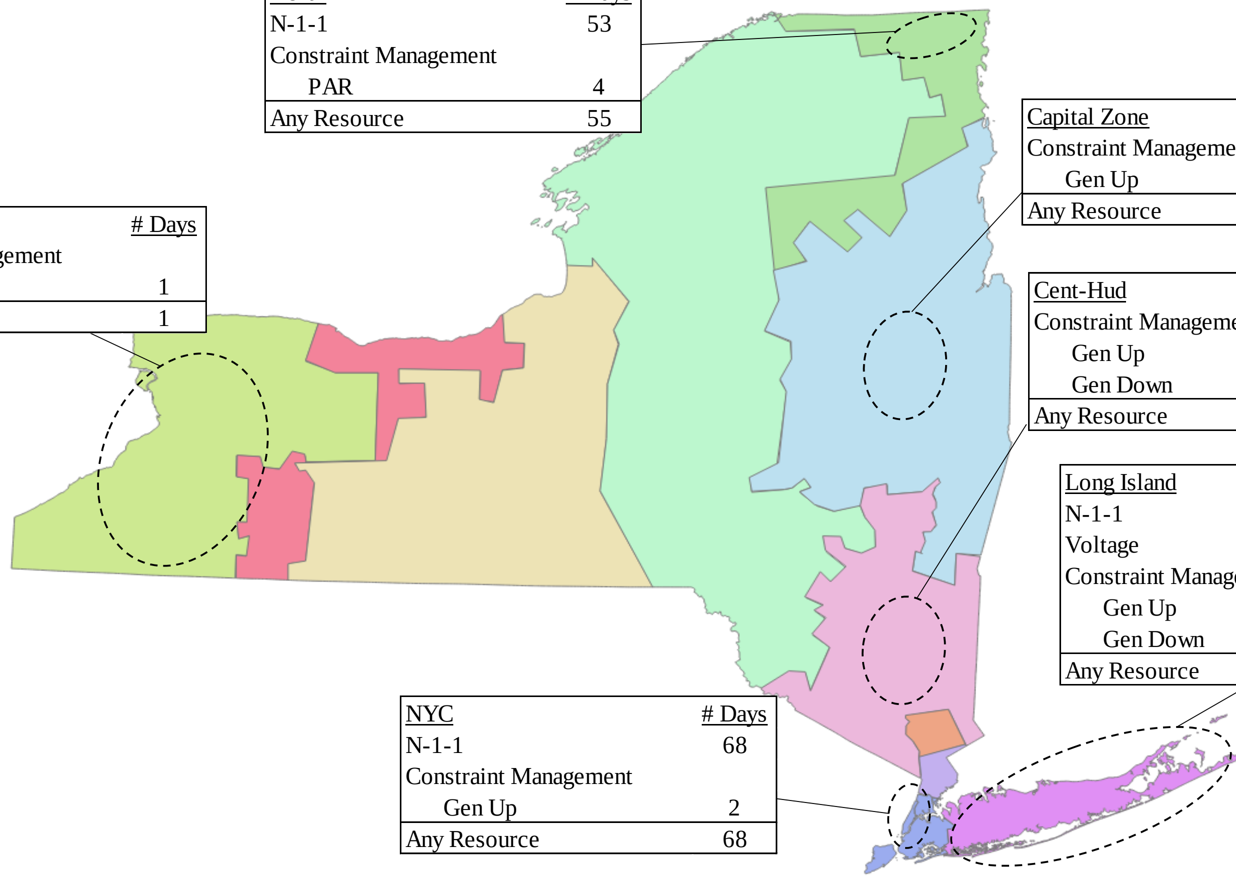
West Zone	# Days
Constraint Management	
PAR	1
Any Resource	1

Capital Zone	# Days
Constraint Management	
Gen Up	1
Any Resource	1

Cent-Hud	# Days
Constraint Management	
Gen Up	1
Gen Down	3
Any Resource	4

Long Island	# Days
N-1-1	2
Voltage	1
Constraint Management	
Gen Up	55
Gen Down	3
Any Resource	59

NYC	# Days
N-1-1	68
Constraint Management	
Gen Up	2
Any Resource	68



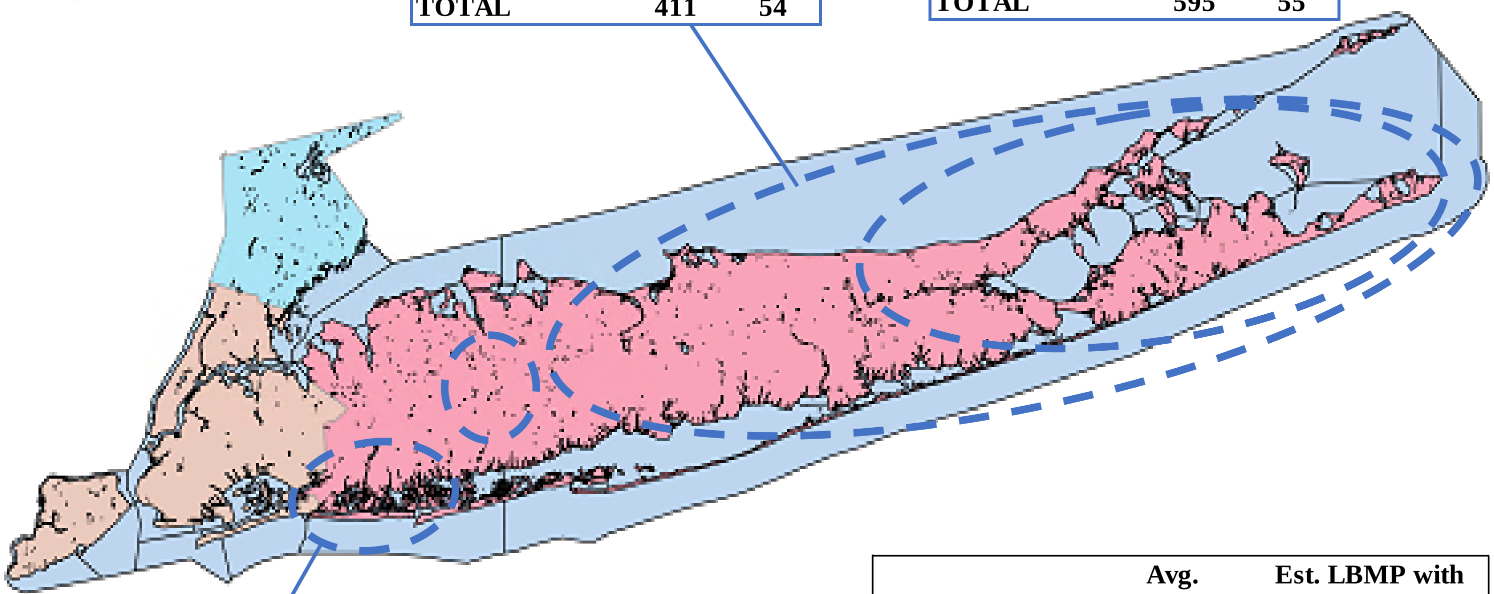
Notes: For chart description, see slides 111-112

POTOMAC ECONOMICS

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV OOM	6	1
69kV	391	53
138kV	259	33
TOTAL	411	54

East End	#Hours	#Days
69kV OOM	11	1
TVR	584	54
TOTAL	595	55



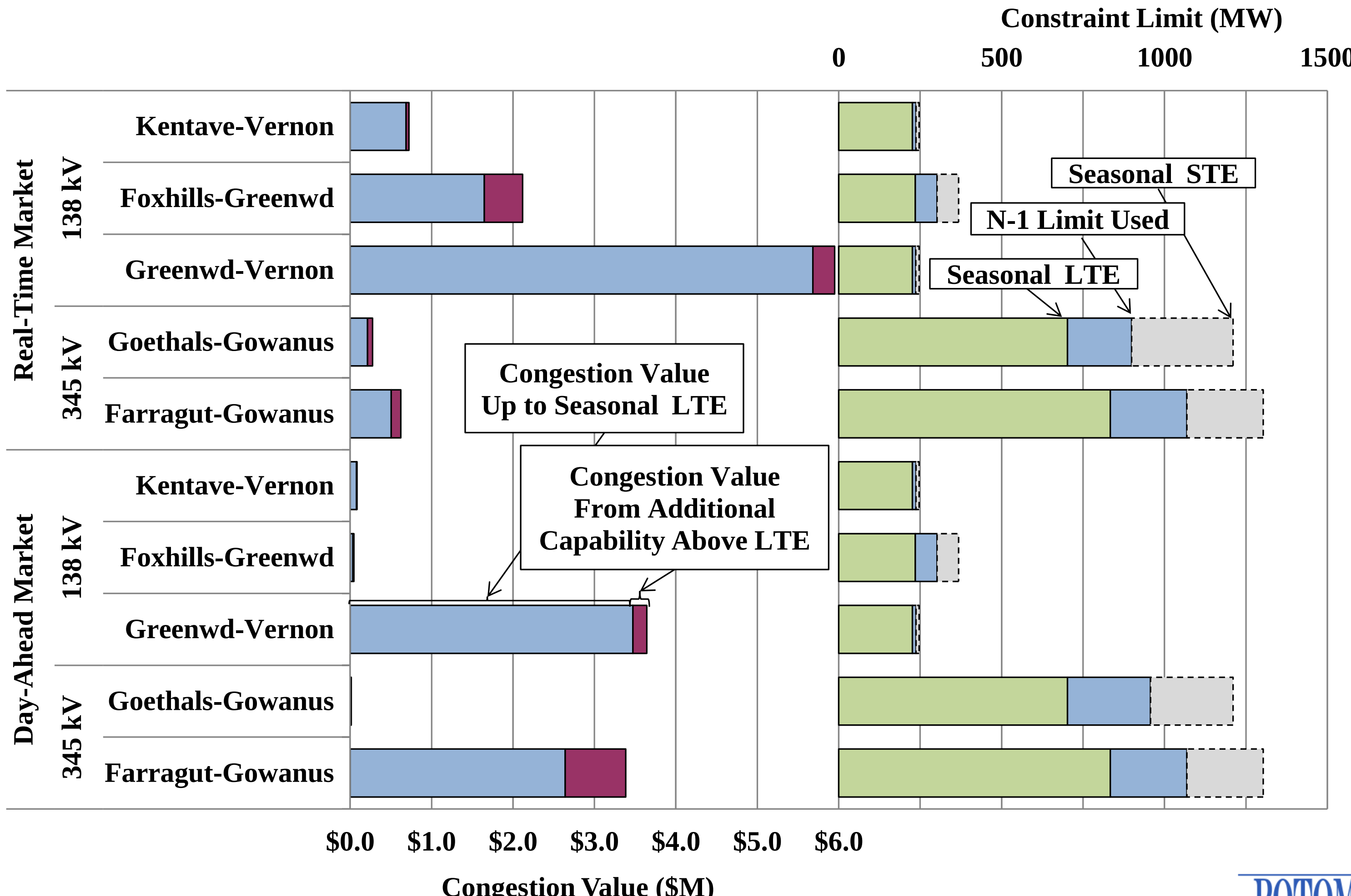
Valley Stream	#Hours	#Days
69kV OOM	179	25
138kV	164	36
TOTAL	296	43

Brentwood	#Hours	#Days
69kV OOM	0	0
69kV	125	42
TOTAL	125	42

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$40.74	$40.74
East End	$45.05	$95.31
East of Northport	$44.05	$44.05
Valley Stream	$39.02	$40.02

Notes: For chart description, see slides 111-112

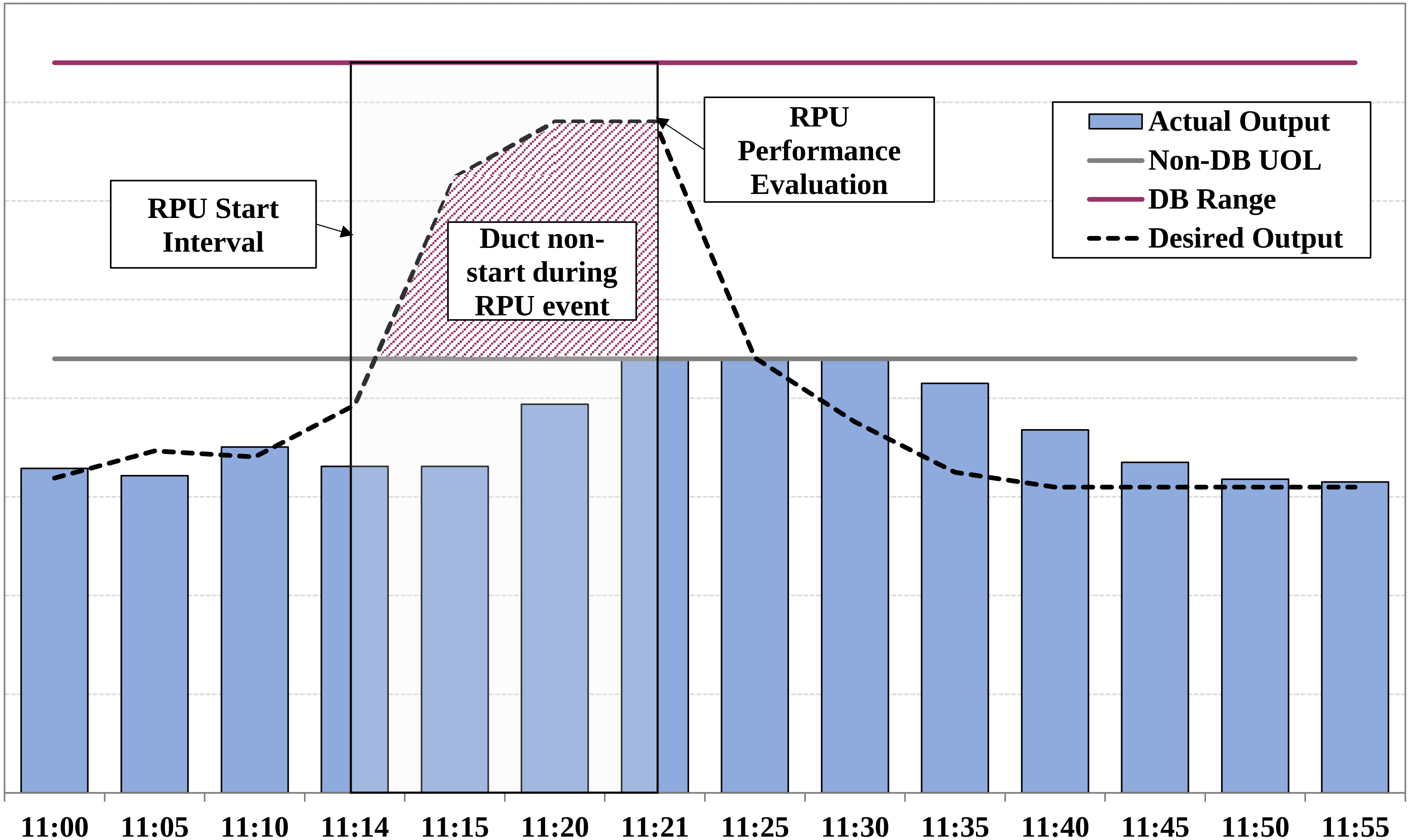
N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide 113.

POTOMAC ECONOMICS

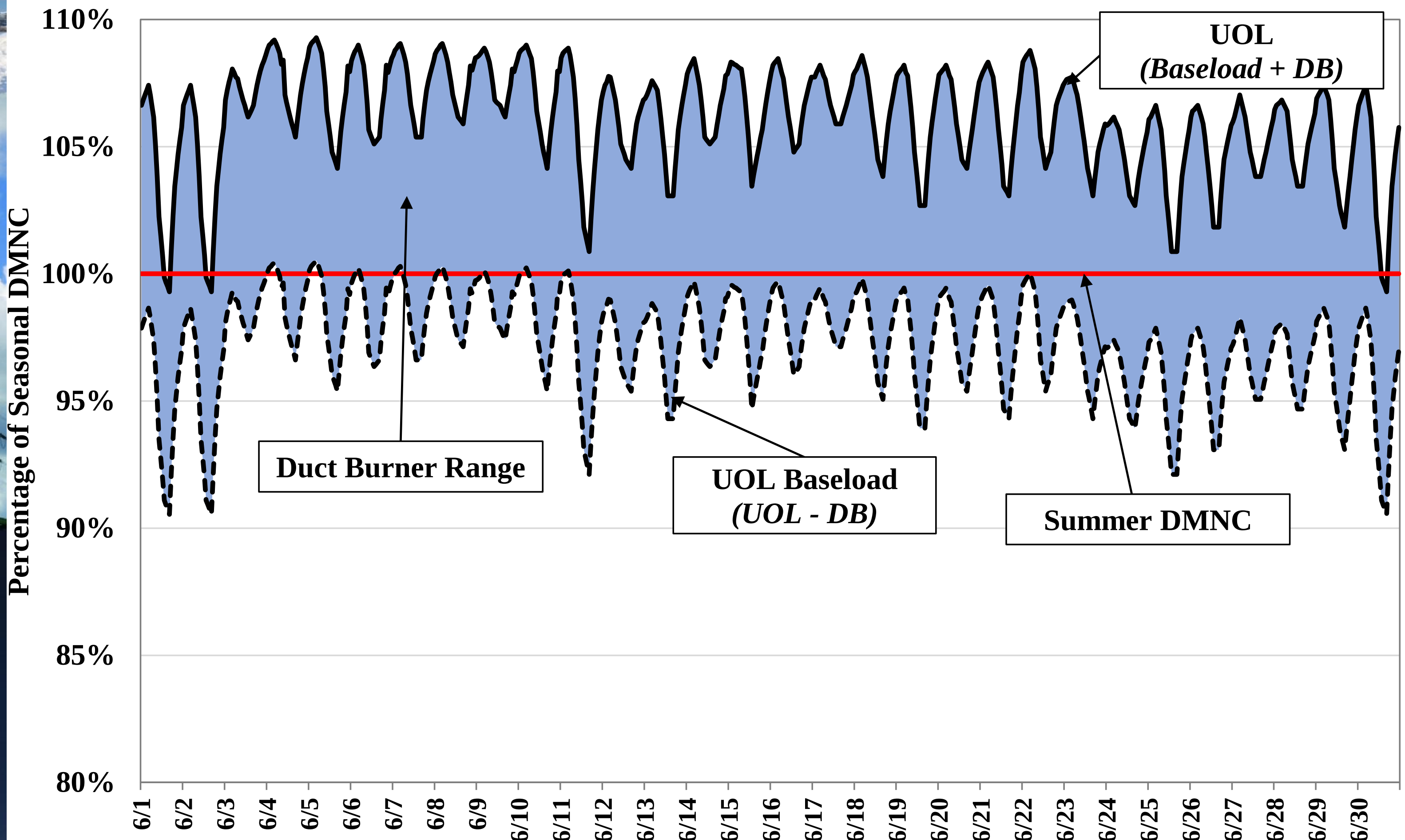
Duct Burner Real-Time Dispatch Issues
Example of a Failed RPU



Notes: For chart description, see slide 114

POTOMAC ECONOMICS

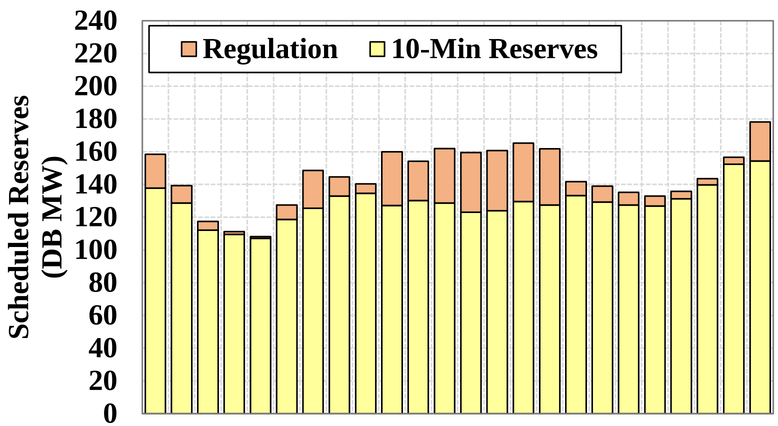
Illustration of Duct Burner Range
Example Generator Hourly Capability

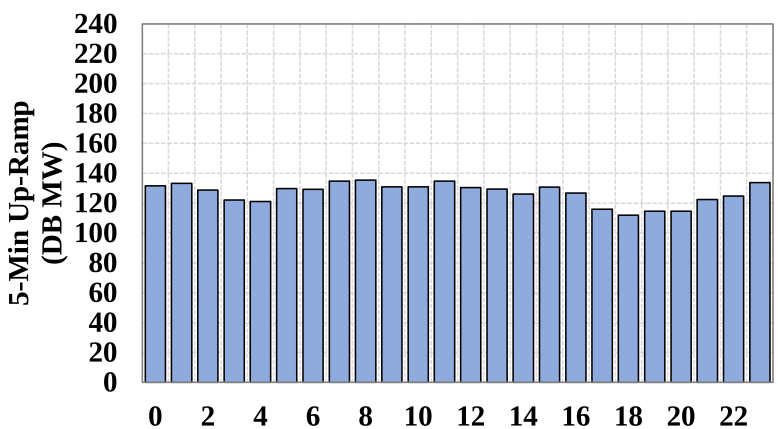


Notes: For chart description, see slide 115

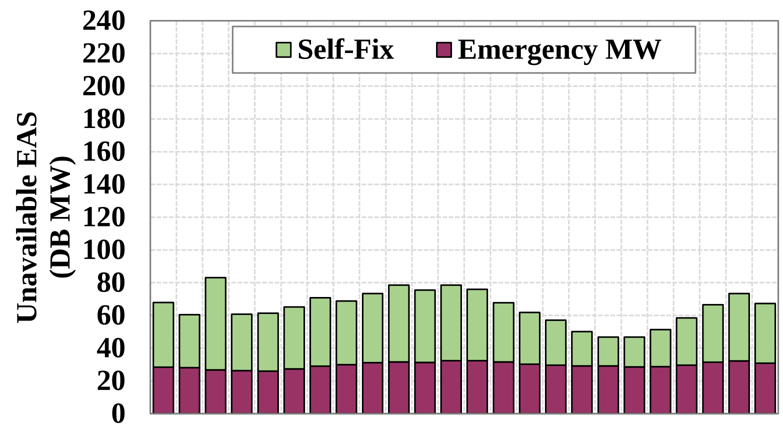
Duct Burner Schedules and Ramp Expectations Evaluation of Duct Availability in Real-Time

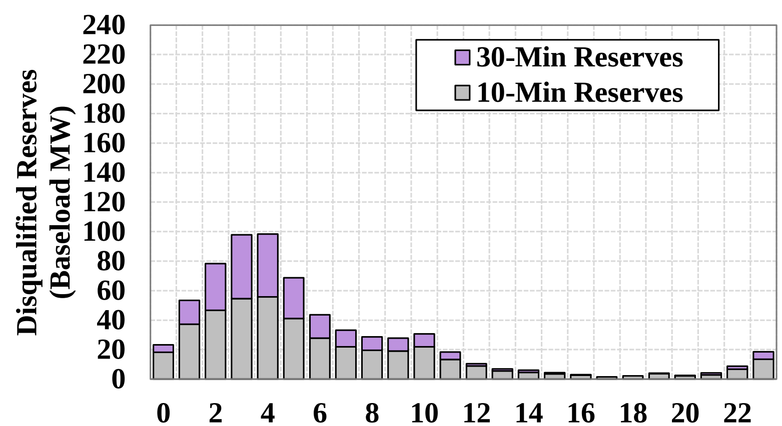
Scheduled or Offered Duct Capacity – but Unable to Follow RT Instructions





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





Notes: For chart description, see slide 114

POTOMAC ECONOMICS

Performance of Spinning Reserve Providers Units with Duct Firing during RPU Events

Spinning Reserve Providers w/Duct Firing Performance during RPU Audits (July - September 2024)				
Category	**No. of Audits**	**Unique CCs Audited**	**No. of Audit Failures**	**No. of Audit Successes**
All Audits	50	8	16	34
Audits Requiring Duct Burners	40	8	16	24
Audits Below Duct Range	10	8	0	10
Performance Rates	**Pass Rate**	**Fail Rate**	**Notes**	
Audits Requiring Duct Burners	60%	40%	79 percent of "Pass" audits involved CCs already operating duct burners at start of RPU	
Audits not Requiring Duct Burners	100%	0%		

Notes: For chart description, see slide 116.

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

10 Minute Economic GT Start Performance vs. Audit Results (October 2023 - September 2024)				
Economic GT Starts (RTC, RTD, and RTD-CAM)		GT Audit Results		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Evaluated [1]	0	0	0	0
0% - 10%	0	0	0	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	2	4	2	2
40% - 50%	0	0	0	0
50% - 60%	1	2	1	1
60% - 70%	1	0	0	0
70% - 80%	2	9	2	5
80% - 90%	9	35	9	6
90% - 100%	23	89	23	9
TOTAL	**38**	**139**	**37**	**23**

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

Notes: For chart description, see slide 117.

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

30 Minute Economic GT Start Performance vs. Audit Results (October 2023 -September 2024)

Economic GT Starts (RTC)		GT Audit Results		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Evaluated [1]	5	3	3	1
0% - 10%	0	0	0	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	0	0	0	0
40% - 50%	0	0	0	0
50% - 60%	0	0	0	0
60% - 70%	3	4	3	0
70% - 80%	4	9	4	0
80% - 90%	15	29	15	3
90% - 100%	39	85	39	5
TOTAL	**66**	**130**	**64**	**9**

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

Notes: For chart description, see slide 117.

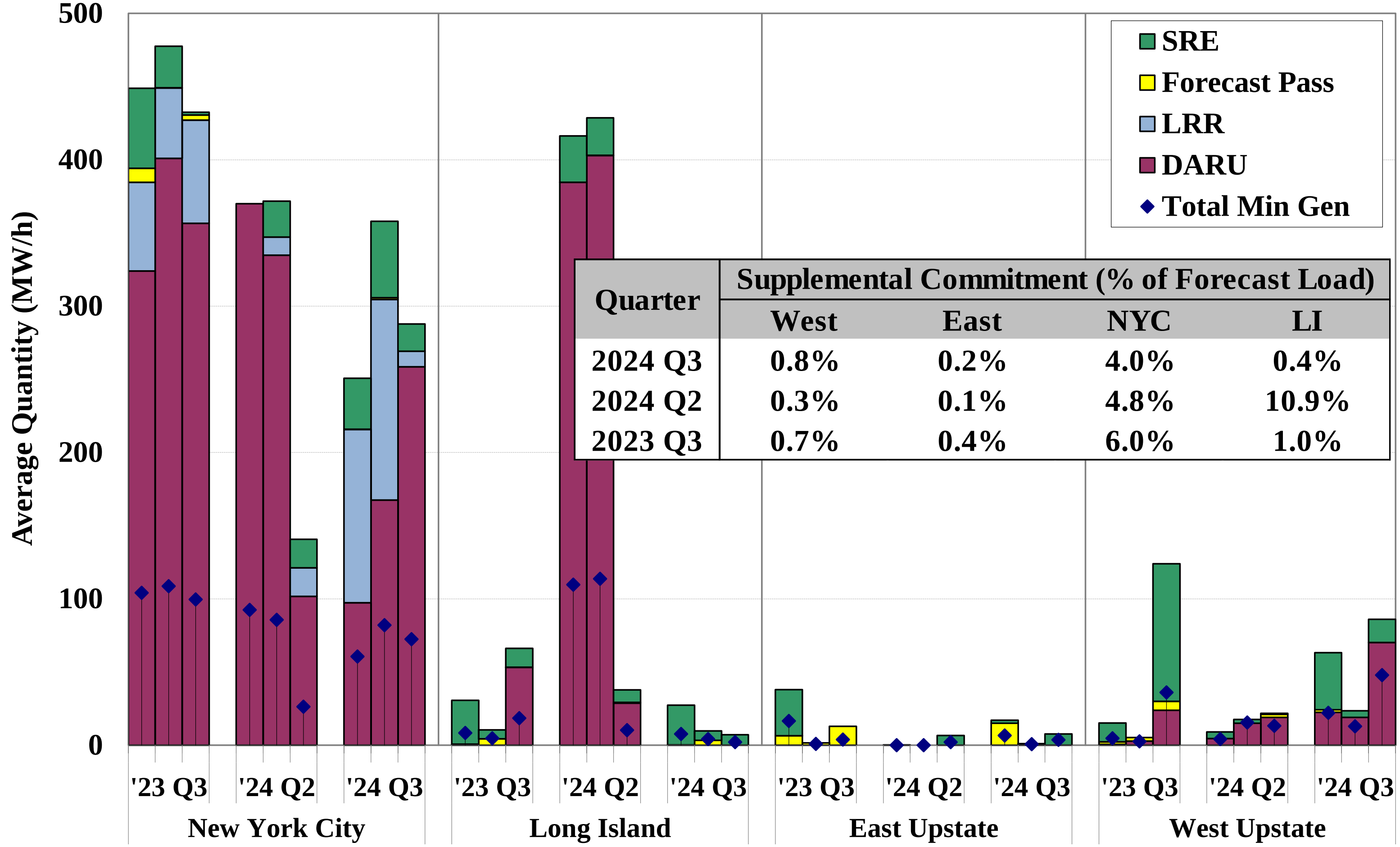
POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

Supplemental Commitment for Reliability
by Category and Region

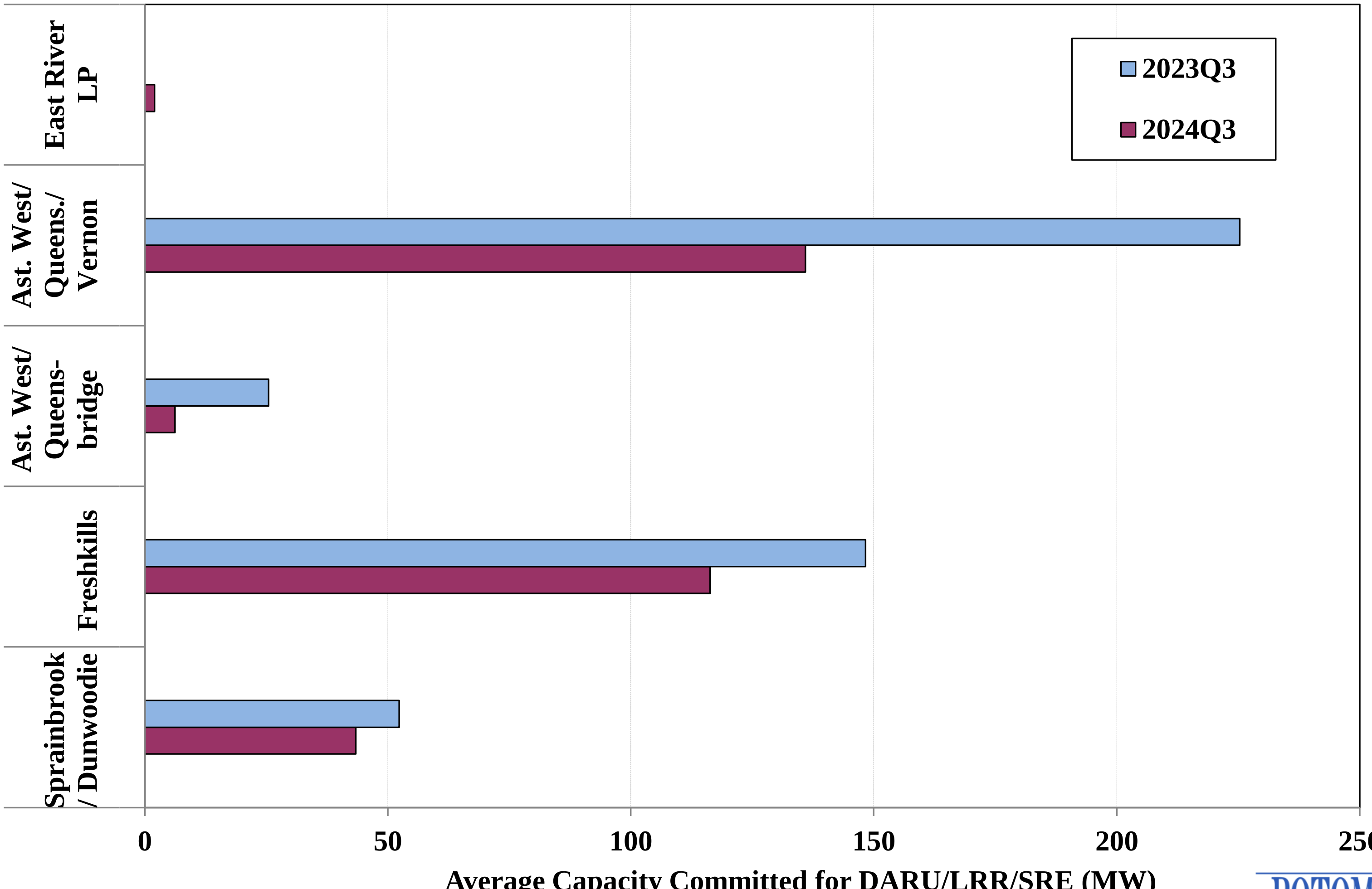


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2024 Q3	0.8%	0.2%	4.0%	0.4%
2024 Q2	0.3%	0.1%	4.8%	10.9%
2023 Q3	0.7%	0.4%	6.0%	1.0%

Notes: For chart description, see slides 118 and 119.

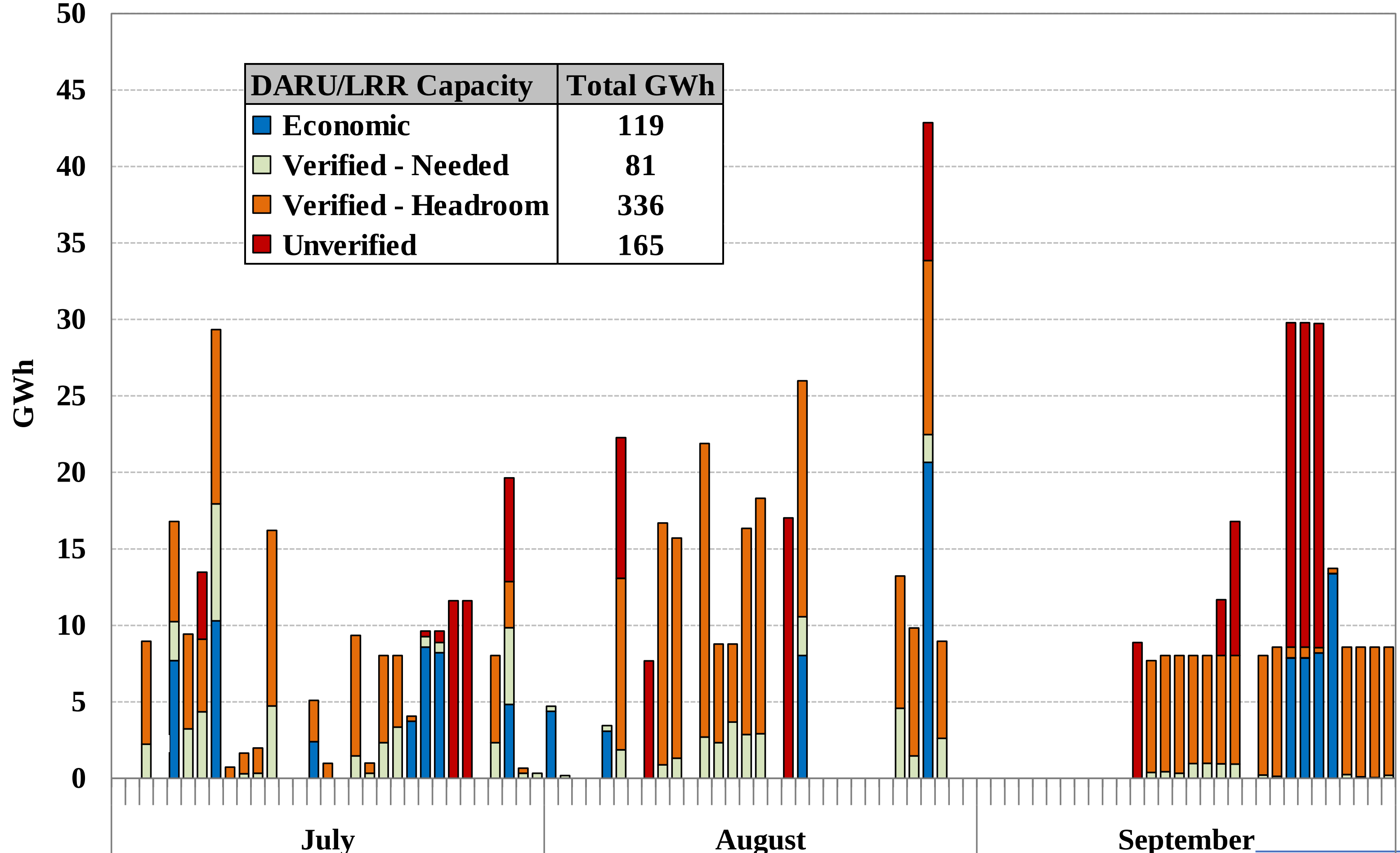
POTOMAC ECONOMICS

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



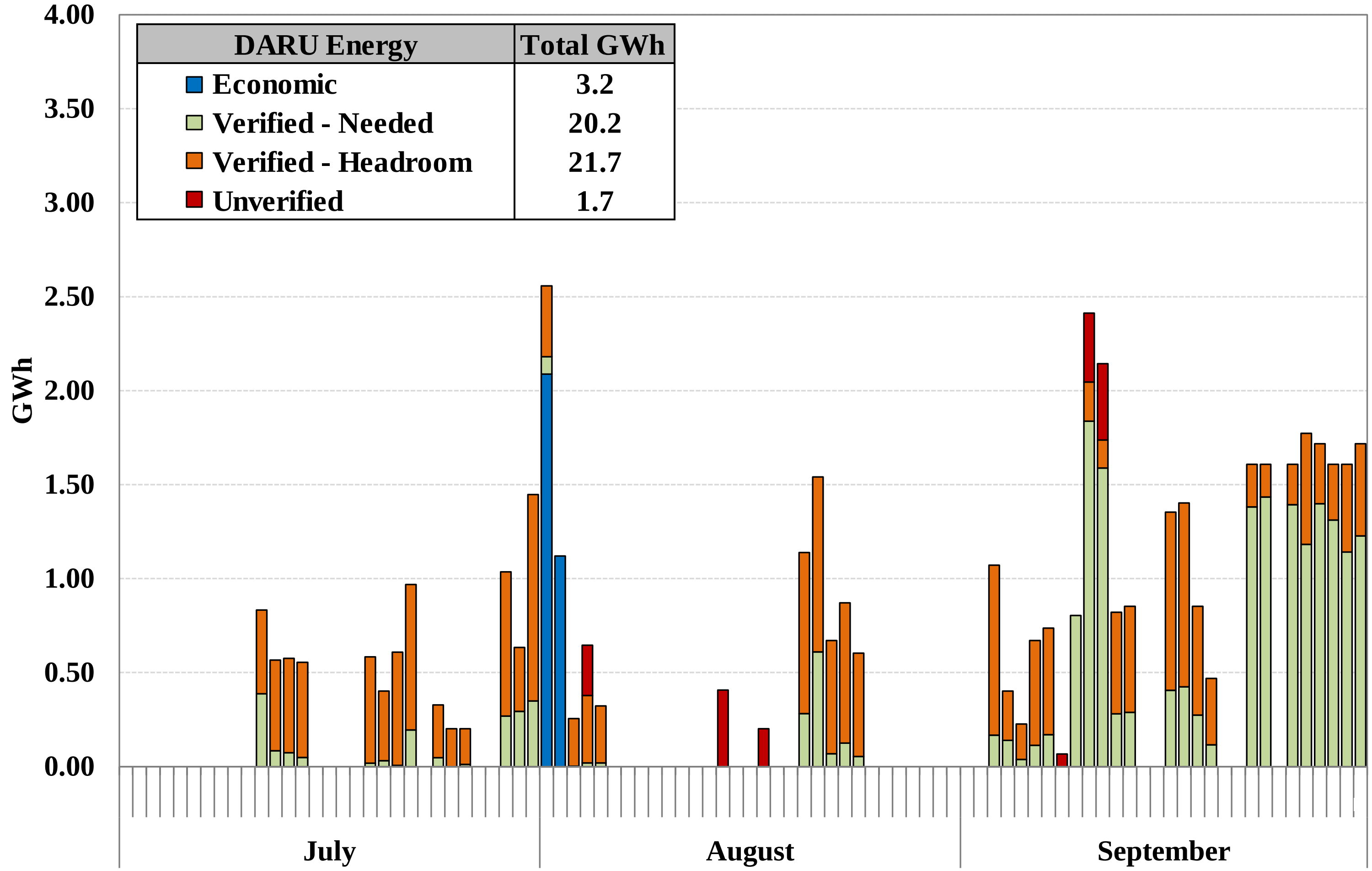
Notes: For chart description, see slides 118 and 119.

DARU and LRR Commitments in NYC
2024 Q3



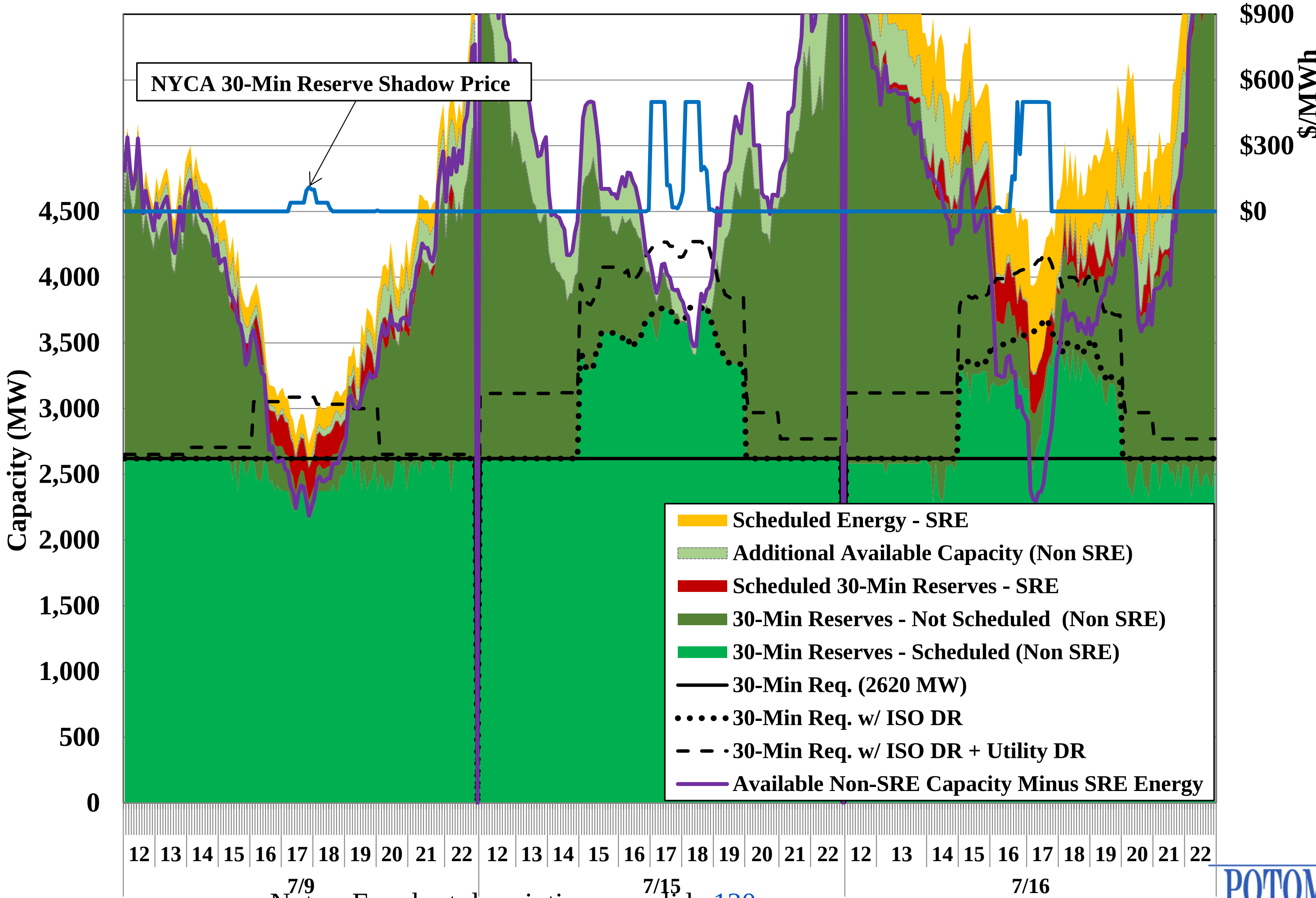
Notes: For chart description, see slide 119.

DARU Commitments in North Country
2024 Q3



Notes: For chart description, see slide 119.

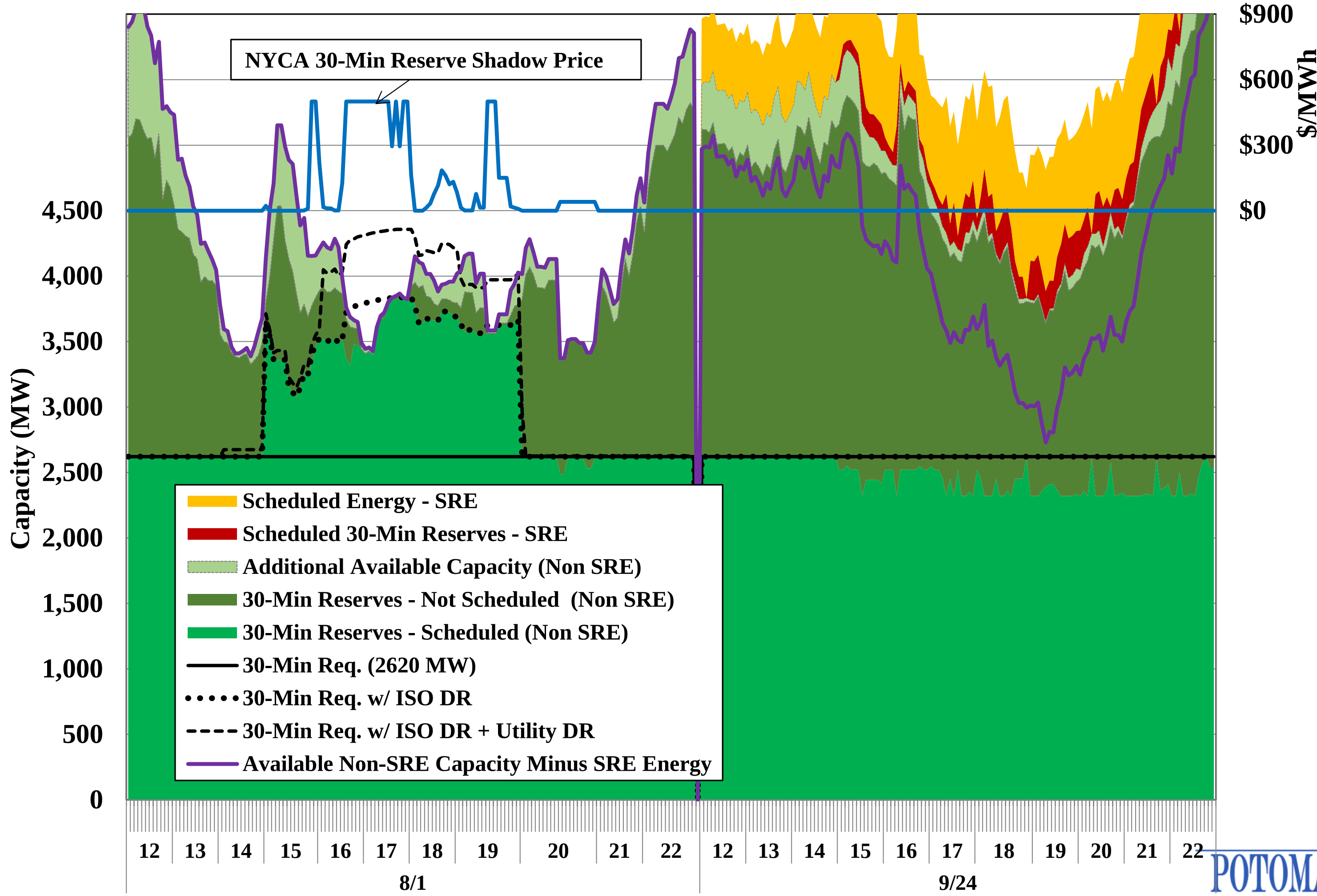
SRE Commitments for Capacity and DR Deployments on High Load Days



Notes: For chart description, see slide 120.

POTOMAC ECONOMICS

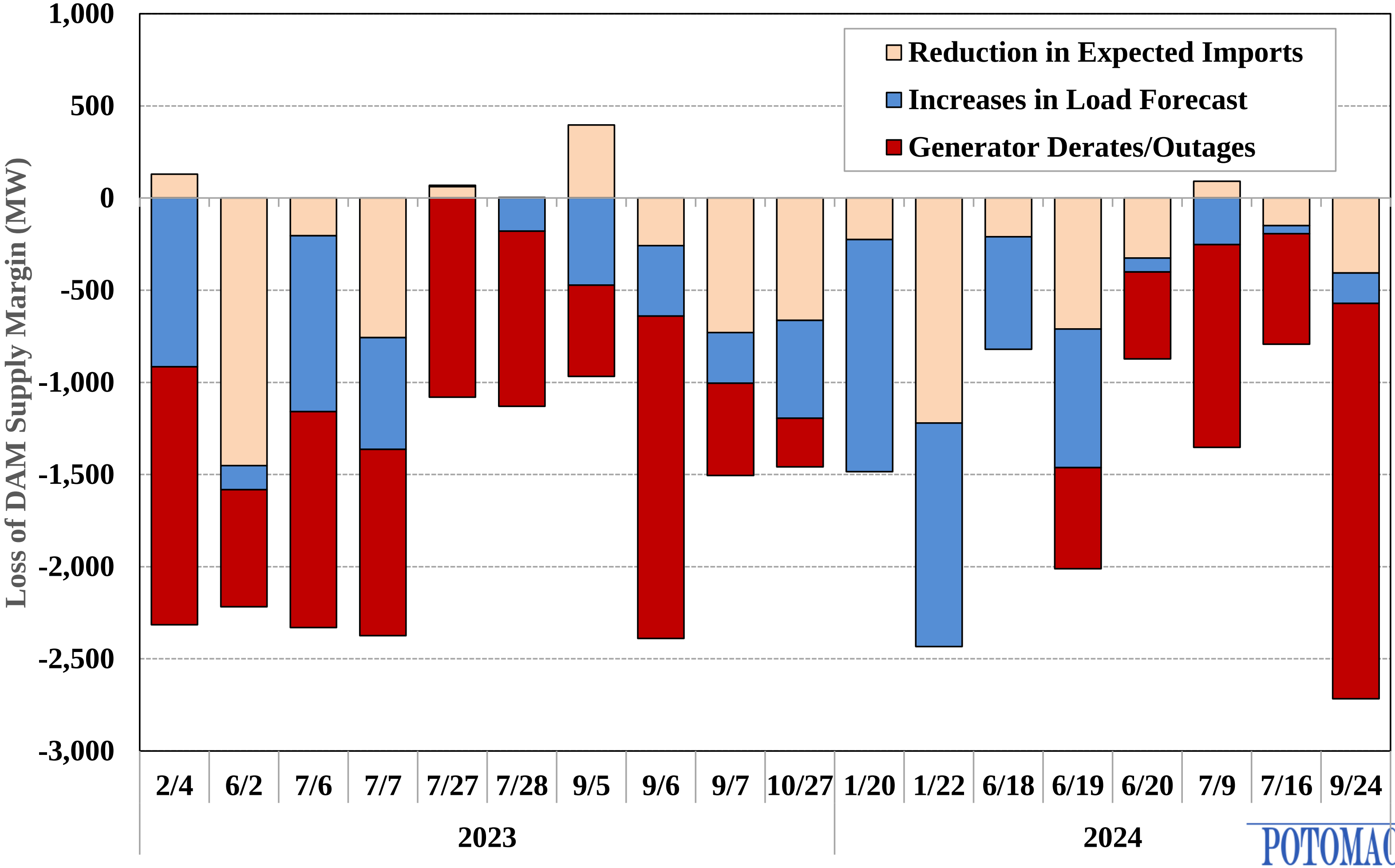
SRE Commitments for Capacity and DR Deployments on High Load Days



 Notes: For chart description, see slide 120.

POTOMAC ECONOMICS

Key Drivers that Lead to SRE Commitments for Systemwide Capacity



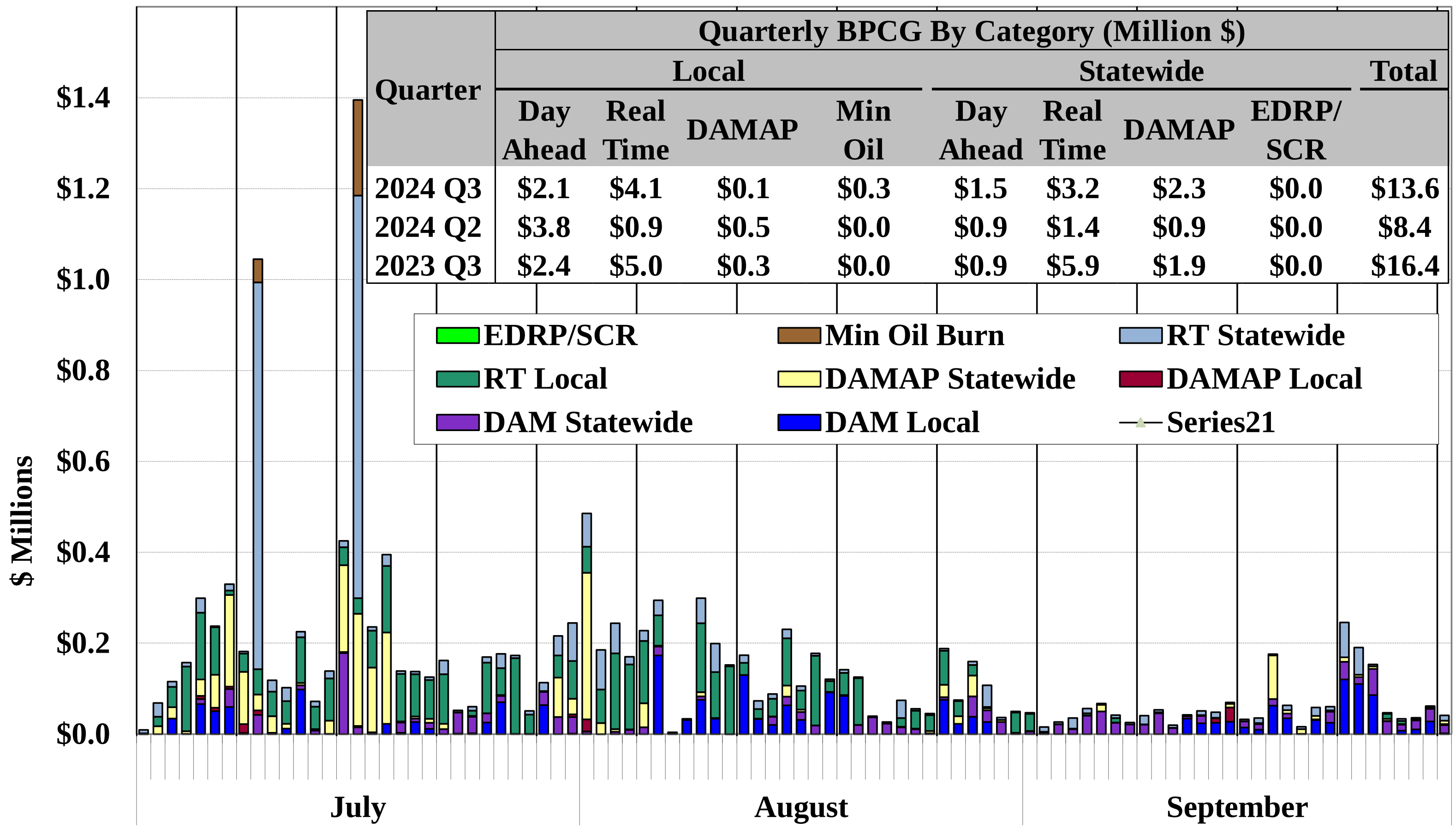
 Notes: For chart description, see slide 121.

POTOMAC ECONOMICS

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

Quarter	Local Day Ahead	Local Real Time	Local DAMAP	Local Min Oil	Statewide Day Ahead	Statewide Real Time	Statewide DAMAP	Statewide EDRP/SCR	Total
2024 Q3	$2.1	$4.1	$0.1	$0.3	$1.5	$3.2	$2.3	$0.0	$13.6
2024 Q2	$3.8	$0.9	$0.5	$0.0	$0.9	$1.4	$0.9	$0.0	$8.4
2023 Q3	$2.4	$5.0	$0.3	$0.0	$0.9	$5.9	$1.9	$0.0	$16.4

Quarterly BPCG By Category (Million $)

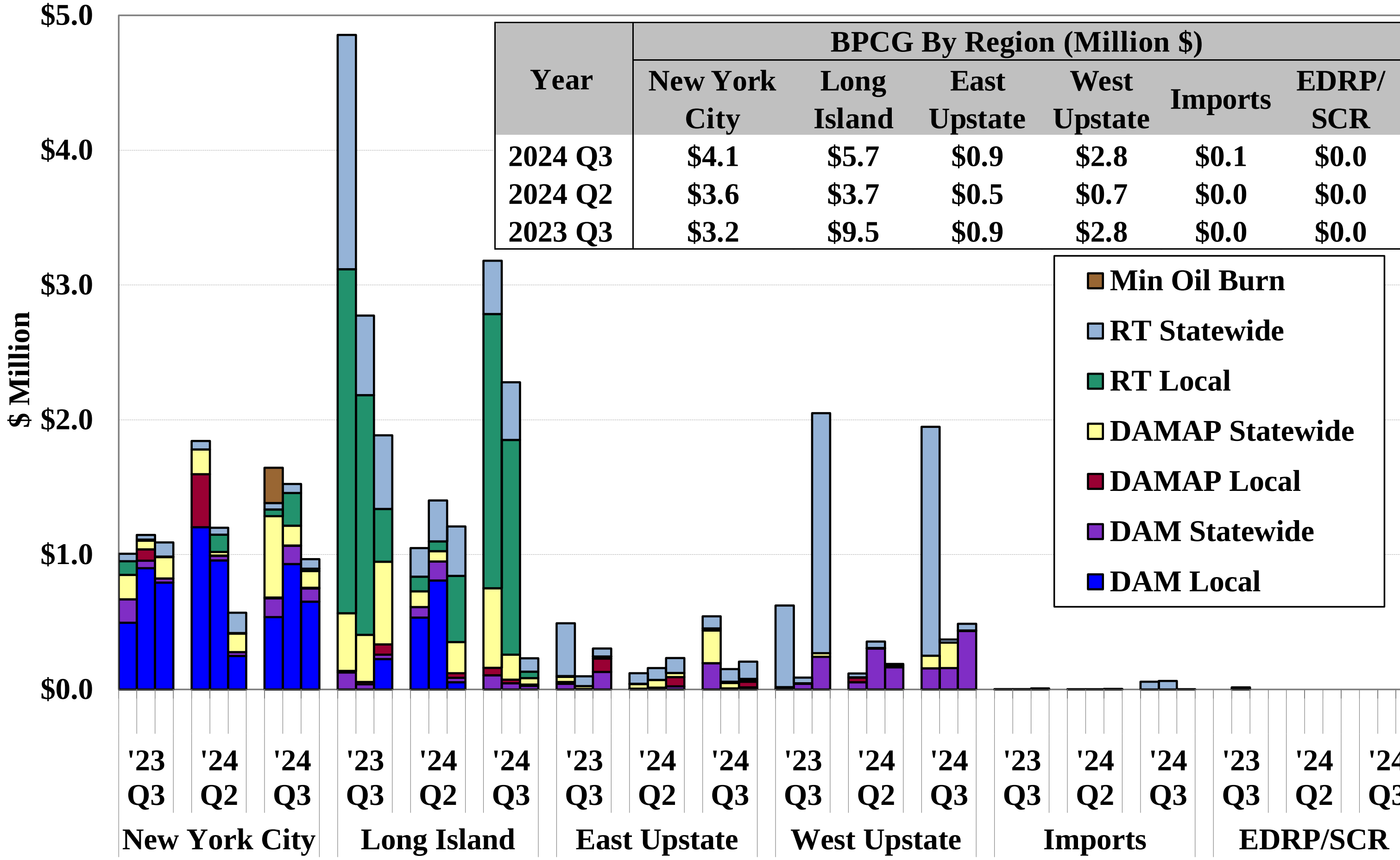


Notes: 1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.
2. For chart description, see slide 122.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region

Year	BPCG By Region (Million $)					
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2024 Q3	$4.1	$5.7	$0.9	$2.8	$0.1	$0.0
2024 Q2	$3.6	$3.7	$0.5	$0.7	$0.0	$0.0
2023 Q3	$3.2	$9.5	$0.9	$2.8	$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 122.

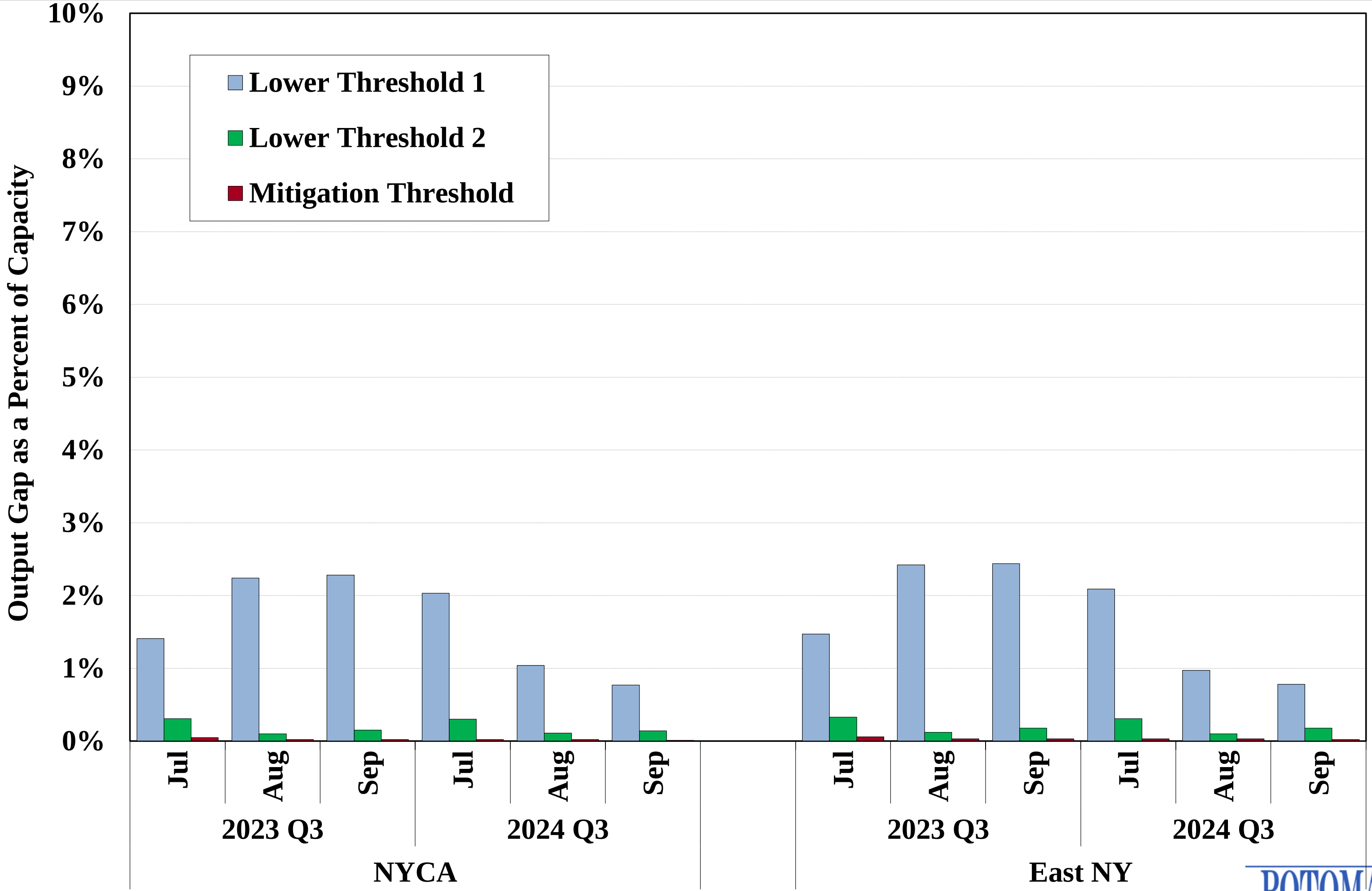
POTOMAC ECONOMICS

Charts:

Market Power and Mitigation

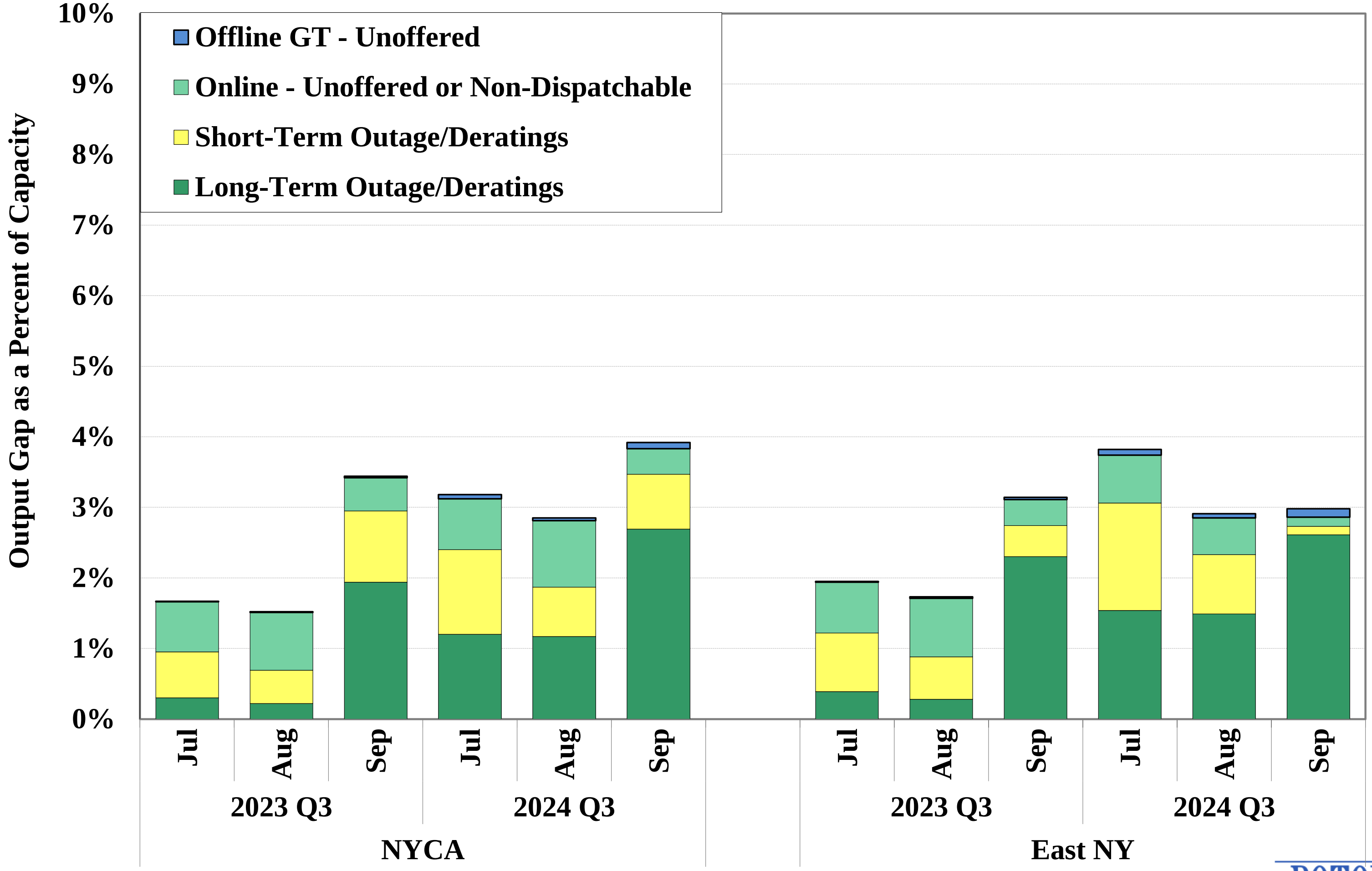
POTOMAC ECONOMICS

Output Gap by Month
NYCA and East NY



For chart description, see slide 123.
POTOMAC ECONOMICS

Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 123.

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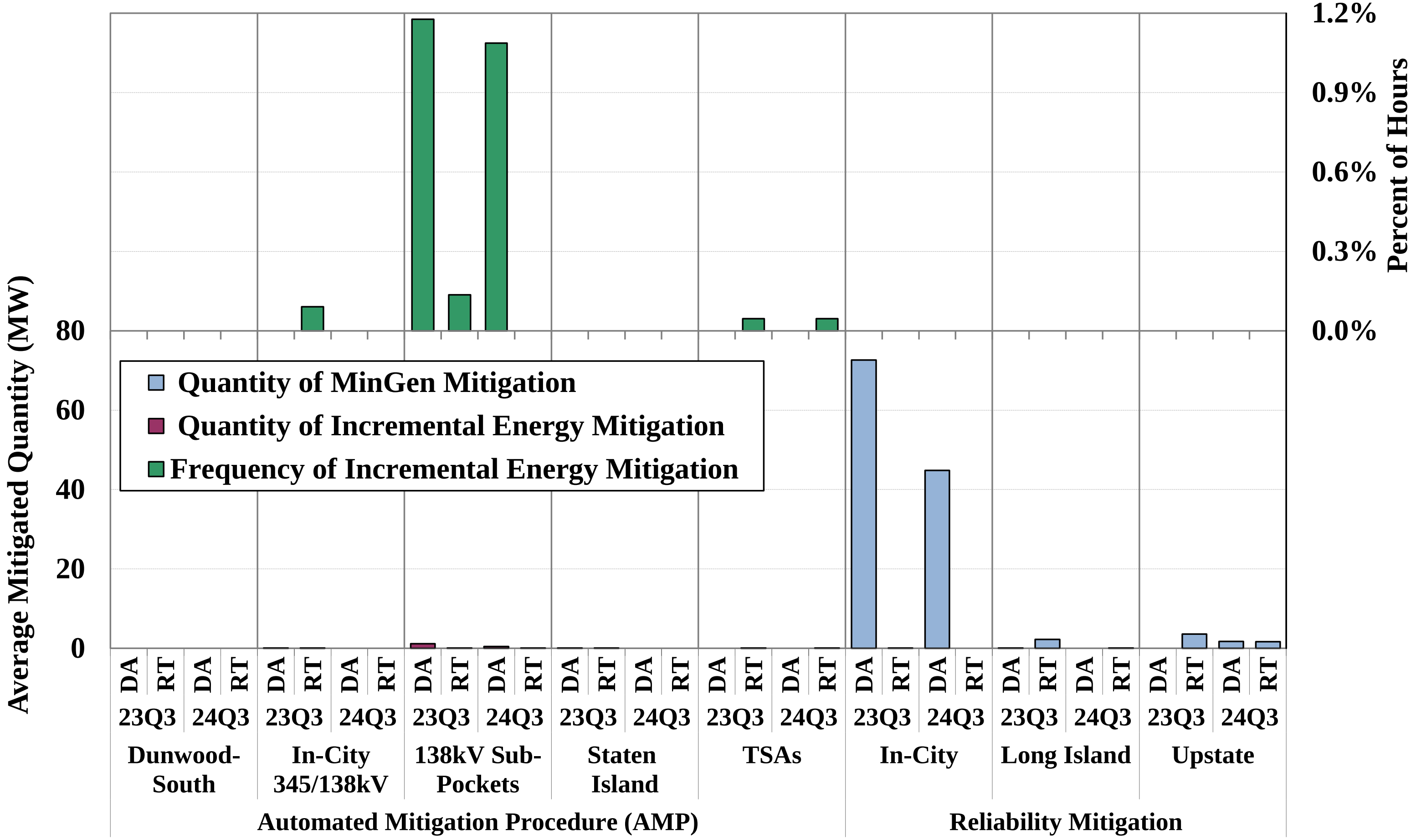
Automated Market Power Mitigation



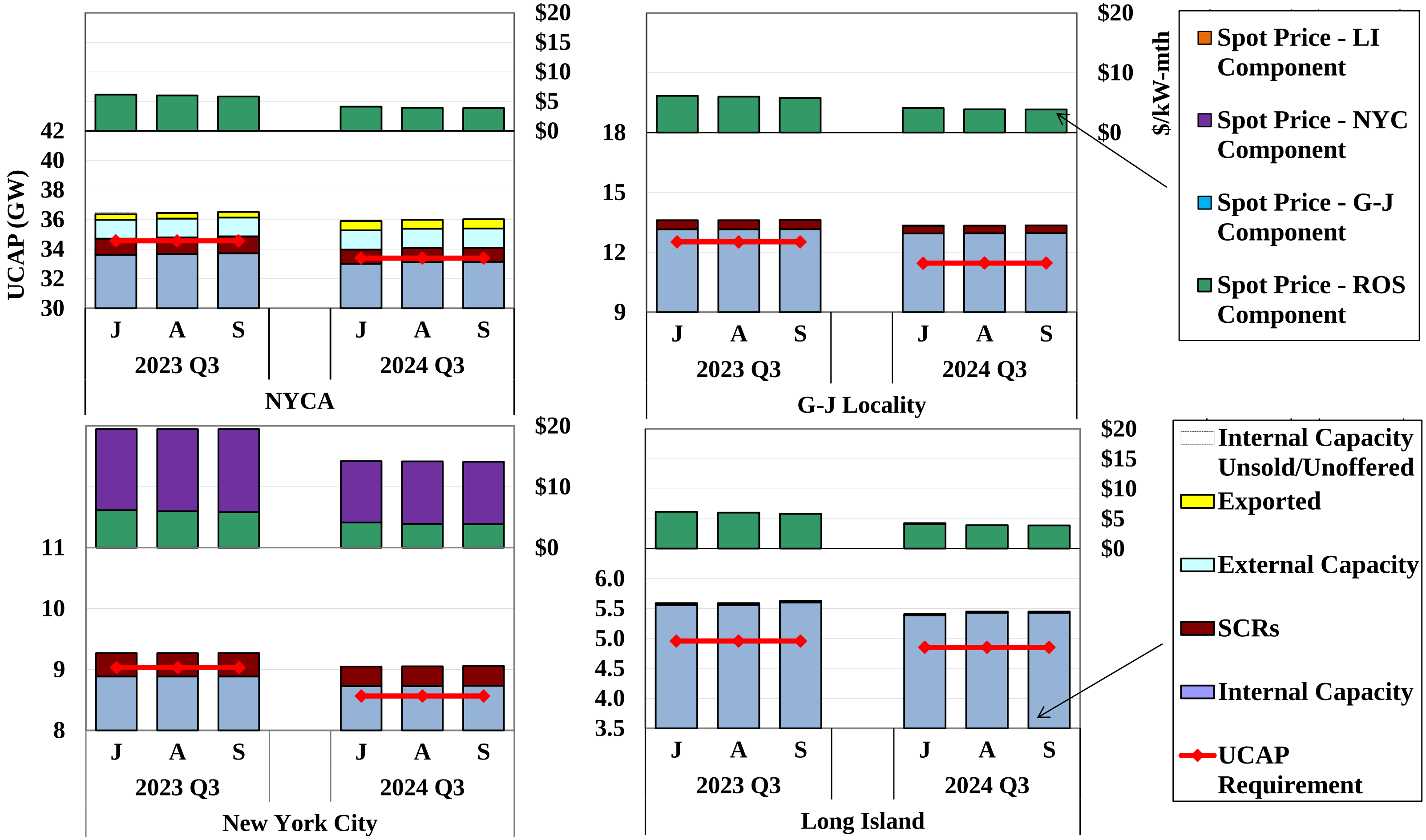
Notes: For chart description, see slide 124.

POTOMAC ECONOMICS

Charts:
Capacity Market

Spot Capacity Market Results

Monthly Results by Locality



Notes: For chart description, see slide 125.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2024 Q3 ($/kW-Month)	$3.97	$14.16	$4.02	$3.97
% Change from 2023 Q3	**-34%**	**-27%**	**-33%**	**-34%**
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	**-437**	**-44**	**-245**	**-78**
Entry[3]	53	13	9	13
Exit[3]	-360	-11	-330	-30
Other Capacity Changes[1]	-131	-46	76	-61
Cleared Import[2]	**23**			

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

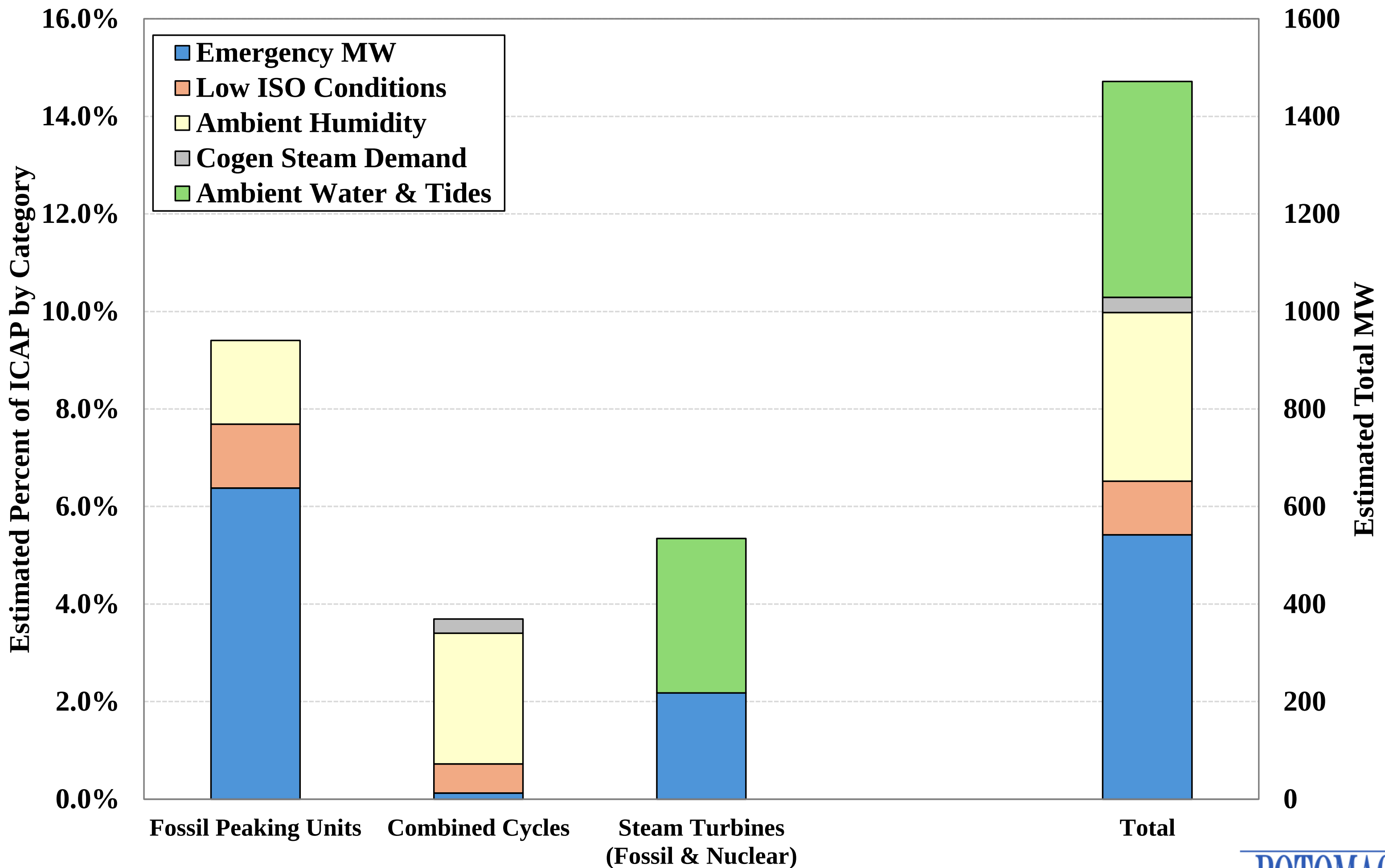
(2) Based on average of quarterly cleared quantity.

(3) Includes change in sales from UDR line(s)

Notes: For chart description, see slide 125.

POTOMAC ECONOMICS

Functionally Unavailable Capacity from Fossil-Fuel and Nuclear Generators



Notes: For chart description, see slide 126.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

Emission Costs by Unit Type
Natural Gas Fired Resources

- Slide 30 shows estimates for the generation-weighted average hourly marginal costs of the two main emissions, CO_2 and NOx, by month for each of the following unit types firing on natural gas:
  - ✓ Combined cycles, Steam Turbines, and Peaking units.
- Emission cost estimates are calculated based on:
  - ✓ Daily price indexes for RGGI (CO_2) and CSAPR Group 3 (NOx) emissions allowances.
  - ✓ CO_2 emission coefficient of 118 Lb/MMBtu for natural gas.
  - ✓ Generation-weighted average hourly NOx emission rates for each unit type based on actual operations during June 2022 from EPA CEMS data.
  - ✓ Heat rate assumptions of 7.5 MMBtu/MWh for combined cycles, 11 MMBtu/MWh for steam turbines, 9.4 MMBtu/MWh for Peakers (post-2000), and 13.25 MMBtu/MWh for Peakers (pre-2000).
- Actual unit-specific emission rates and associated costs may vary substantially for each individual unit based on factors like (a) heat rate efficiency, (b) level of emission control technology at the plant, and (c) typical output factor during operations, etc.

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 eight 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.

POTOMAC ECONOMICS

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).

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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).
- 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.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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.

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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.

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Transmission Congestion and Shortfalls

- Slides 59-63 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).

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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 61-63 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.

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Performance of Spinning Reserve Providers Units with Duct Firing during RPU Events

- Slide 71 show the results of the NYISO's auditing process for 10-minute spinning reserve providers that have duct burners during the quarter. The tables breaks down results by two categories:
  - ✓ The top portion of the table shows total passed and failed audits among the group of evaluated generators.
    - – Additional statistics show the pass/fail statistics based on the MMU evaluation of which audits likely required utilization of the duct burners.
  - ✓ The bottom portion of the table provides greater detail on audit results delineating between tests that likely did or did not require utilization of duct burners.
    - – The Pass Rate shows the number of successful tests divided by the total number of tests per sub-category;
    - – The Fail Rate shows the number of failed tests divided by the total number of tests.
    - – The Notes provide commentary based on the MMU's observations of operations during the tests.
  - ✓ An example read of the table: "8 10-minute spinning reserve provider combined cycle generators with duct burners were audited 40 total times where the audit required an output level unachievable without use of the duct burners. The generators passed 16 of those audits and failed the remaining 24."

GT Start-up Performance

- Slide 72-73 show the results of the NYISO's auditing process for 10- and 30-minute GTs in the past 12-month period, compared to performance measured for economic GT starts by the market model (including starts by RTC, RTD, and RTD-CAM) in the same period. In each table,
  - ✓ The performance is measured as the GT output at 10 or 30 minutes after receiving a start-up instruction as a percent of its UOL.
  - ✓ The rows show the number of units with an average performance in the quarter that falls in each performance range from 0 to 100% with a 10% increment.
    - – The left-hand side of the table shows these numbers based on performance measured during economic starts;
    - – While the right-hand side of the table shows numbers based on audit results.
    - – The units that are in service but were never started by RTC, RTD, or RTD-CAM in the examined period are placed in a separate category of "Not Evaluated", which also includes units that we could not assess their performance reliably because of data issues.
  - ✓ An example read of the table (slide 71): "23 10-minute GTs exhibited a response rate of 90 to 100 percent during economic starts in the examined period, 23 of them were audited 89 times in total with 9 failures".

Supplemental Commitments

- Slides 75 and 76 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 75 shows the quantities of reliability commitment by region in the following categories on a monthly basis:
  - ✓ Day-Ahead Reliability Units (“DARU”) Commitment – occurs before the economic commitment in the DAM at the request of local TO or for NYISO reliability;
  - ✓ Day-Ahead Local Reliability (“LRR”) Commitment – occurs in the economic commitment in the DAM for TO reliability in NYC;
  - ✓ Supplemental Resource Evaluation (“SRE”) Commitment – occurs after the DAM;
  - ✓ Forecast Pass Commitment – occurs after the economic commitment in the DAM.
- Slide 76 examines the reasons for reliability commitments in NYC where most reliability commitments occur.
  - ✓ Based on a review of operator logs and LRR constraint information (where a unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit’s capacity), each NYC commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:

Reliability Commitment in New York City and North Country

- Slides 77 and 78 show the amount of DARU and LRR capacity in New York City and DARU capacity in 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 commitments that do not qualify as ***Economic*** but are verified through our assessment as necessary for maintaining reliability in the applicable load pockets.
    - Our assessment relies on information available in the DAM, 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.

SRE Commitments for Capacity and DR Deployments On High Load Days

- Slides 79 and 80 summarize market outcomes on select high load days when SRE commitments were made for capacity and/or DR were deployed by NYISO and/or TO. The figures report the following quantities in each interval of hours 12-22 for NYCA:
  - ✓ Available capacity from non-SRE resources – including three categories of unloaded capacity of online units and the capacity of offline peaking units up to the Upper Operating Limit:
    - 30-Minute Reserves – Scheduled;
    - 30-Minute Reserves – Unscheduled; and
    - Additional Available Capacity (beyond 30-min rampable).
  - ✓ Schedules from SRE resources – including energy and total 30-minute reserves.
  - ✓ Constraint shadow prices on the NYCA 30-minute reserve requirement.
  - ✓ 30-min reserves requirement, adjusted for SCR/EDRP calls (solid black line).
  - ✓ Utility DR deployed plus 30-minute reserves requirement (dashed black line).
  - ✓ Available capacity from non-SRE resources minus SRE energy schedules (solid purple line).
    - Shortage w/o SRE = solid black line – solid purple line
    - Shortage w/o (Utility DR & SRE) = dashed black line – solid purple line

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Key Drivers that Lead to SRE Commitments for Systemwide Capacity

- Slide 81 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.

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Uplift Costs from Guarantee Payments

- Slides 82 and 83 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 82 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 83 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 85 and 86 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 87 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 89 and 90 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 89 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 90 compares the year-over-year changes in capacity spot prices by Locality and shows variations in key factors that drove these changes, including:
    - – The changes in the UCAP requirements, which are affected by changes in the forecasted peak load, the minimum capacity requirement, and the derating factors;
    - – The changes in the UCAP supply, which are affected by changes in new entry, mothballing and retirement, and DMNC test values; and
    - – The changes in the demand curves, which are mostly affected by the assumptions used in each demand curve reset process.
      - The most recent reset was done for the Capability Periods from 2017 to 2021.

Unavailable Capacity Ambient Conditions Dependent Generators

- Slide 91 shows the estimated ICAP that was functionally unavailable to the market during peak conditions this summer from fossil generators and nuclear units by category:
  - ✓ Emergency Capacity - The amount of capacity offered by units in their UOLe ranges or, after investigation, determined to be comparable to emergency capacity. This is unavailable for normal operations and only dispatchable under emergency or extraordinary circumstances.
  - ✓ Low ISO Conditions - The amount of capacity unavailable due to actual peak summer temperatures exceeding the temperature adjustment values used by various generators in DMNC tests.
  - ✓ Ambient Humidity -The amount of capacity explicitly derated from CCs and Peakers not explained by air temperature conditions.
  - ✓ Cogen Steam Demand -The amount of capacity unavailable from cogeneration resources with active host steam load obligations.
  - ✓ Ambient Water & Tides - The amount of capacity estimated to be unavailable from fossil and nuclear STs due to ambient water temperatures and, where applicable, tidal conditions.
- Values by category are given as percentages of total by unit type on the primary axis with the total ICAP across all resources summed in the secondary axis.