Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2022

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Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the third quarter of 2022.
- All-in prices ranged from $67 to $133 per MWh, which was up 23 to 101 percent from 2021-Q3 in individual regions. (slide 7)
  - ✓ Energy prices rose dramatically across the system primarily because of:
    - Higher gas prices (which rose 80 to 90 percent); and
    - Lower nuclear and hydro output (which fell ~570 MW on average).
  - ✓ Congestion patterns were greatly affected by: (a) planned transmission outages on the Central-East interface, (b) fewer forced transmission outages into Long Island than in the previous summer, (c) Empire State Line PPT project going into service, and (d) higher emissions costs for fossil-fuel units. Consequently, energy price increases from the previous year varied by region:
    - West, central and northern NY (Zones A-E) prices rose 105 percent,
    - Capital, LHV, and NYC (Zones F-J) prices rose 117 percent, and
    - Long Island (Zone K) prices rose just 44 percent.
  - ✓ Capacity prices fell 30 to 37 percent due to a lower IRM and peak load forecast. (slide 21)

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Market Highlights:
Executive Summary

- The NYISO has increased efforts to audit GTs that provide 10 and 30-minute non-synchronous reserves over the past two years. (slides 17-18) However:
  - ✓ Most audits were conducted on units that regularly demonstrated fast-start capability in normal market operations.
  - ✓ No units that performed poorly in audits and/or normal market operations have been disqualified (despite being scheduled for reserves frequently).
- We identified several categories of conventional generating capacity that may receive excessive accreditation under the current rules. (slides 22-23)
  - ✓ On days when load surpassed 28 GW, an average of ~1,060 MW of ICAP from these resources was functionally unavailable to the market, including:
    - 470 MW offered as emergency capacity with extremely limited availability;
    - 210 MW derated related to ambient water temperature; and
    - 370 MW derated related to humidity or mechanical issues reported as ambient.
  - ✓ These issues are not adequately addressed in the current DMNC test requirements.
    - Clarifications to, improvements in, and better compliance with the relevant DMNC test requirements and GADS reporting rules are needed.

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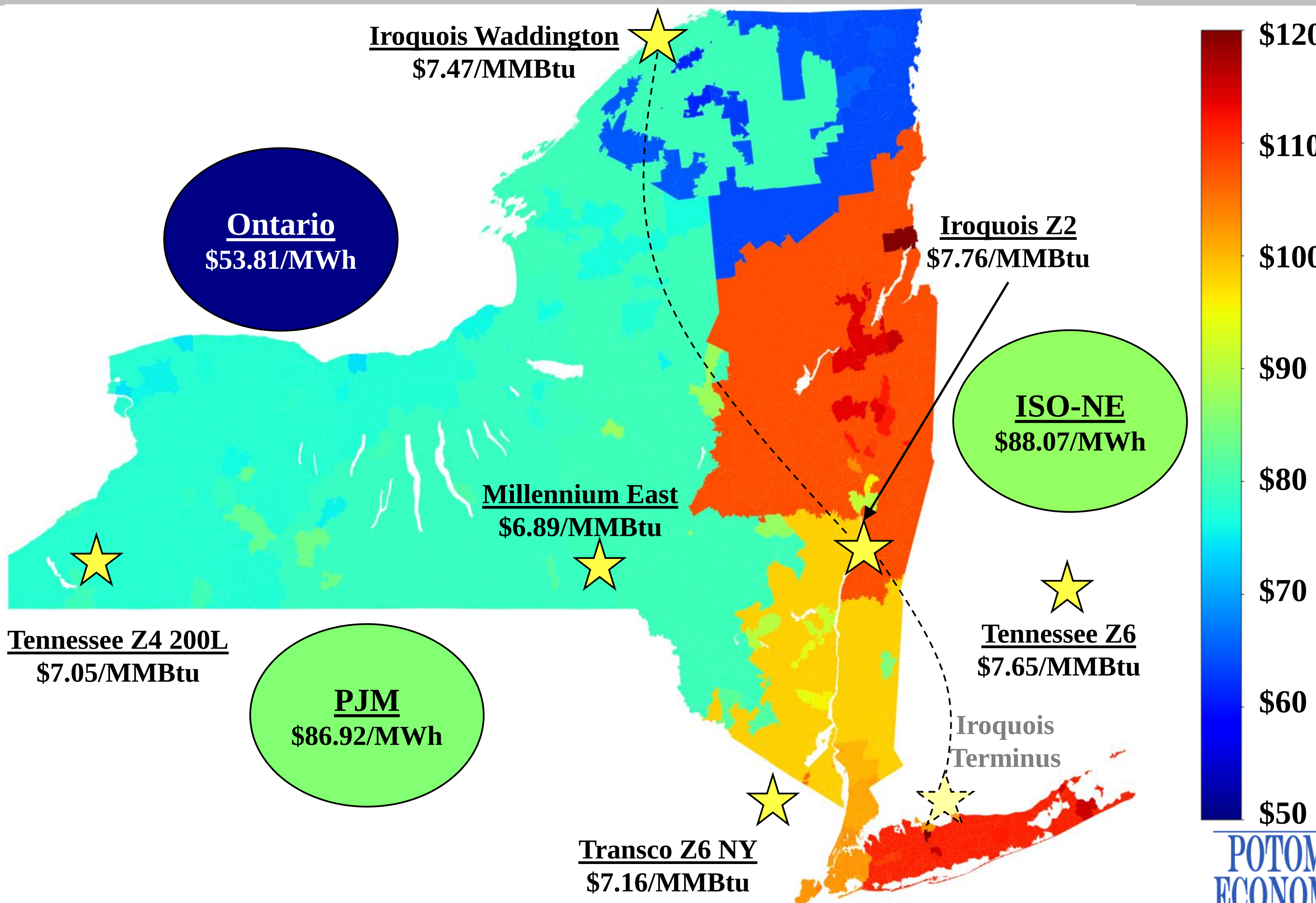
Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the third quarter of 2022.
  - ✓ The amount of output gap (slide 84) and unoffered economic capacity (slide 85) remained modest and reasonably consistent with competitive market expectations.
- All-in prices ranged from $67/MWh in the North Zone to $133/MWh in Long Island, rising 23 to 101 percent from a year ago. (slide 25)
  - ✓ Energy prices rose substantially in all zones, rising 87 to 114 percent in Western NY and 44 to 148 percent in Eastern NY. (slides 31-37)
    - – The primary driver was higher natural gas prices, which rose 80 to 90 percent across the system from a year ago (slide 27).
    - – Other contributing factors include:
      - Lengthy transmission outages due to PPT project work, which led to significant congestion from Central to East and further elevated prices in East NY. (slide 63)
      - Lower nuclear and hydro output (by an average of 620 MW). (slide 29)
      - Higher emission costs (including CO_2, NO_x) which rose 70 to 310 percent for gas-fired CCs, GTs, and STs. (slide 28)
      - Higher load levels – average load rose 2% and peak load rose 1%. (slide 26)
    - – However, the increase of Long Island prices was partially offset because both 345 kV tie lines were in service and the Neptune Line was more fully utilized.
  - ✓ However, capacity costs fell in all areas as discussed in slide 21.

Market Highlights:
Generation by Fuel and Emissions

- Average nuclear generation fell by roughly 350 MW from a year ago due primarily to refueling outages and average hydro generation fell by 270 MW because of drier conditions.
- Gas-fired generation rose by nearly 800 MW on average despite much higher gas prices. (slide 29)
  - ✓ Gas-fired steam output fell on Long Island as a result of the return to full service of the Neptune Line and Y49/Y50 tie lines.
  - ✓ Gas-fired combined cycle output rose by 530 MW on average in the Capital Zone and 170 MW in the Hudson Valley Zone, reflecting:
    - Higher demand for imports from East Upstate to Long Island; and
    - Reduced transfer capability across the Central-East interface.
  - ✓ Although these led to increased emissions from 2021-Q3 (slides 32-33), the emission levels are at historical low levels. (slide 31)
- Steam turbines accounted for 60 percent of NOx emissions in New York City in the third quarter of 2022.
  - ✓ Roughly 32 percent of ST NOx emissions were from STs that were supplementally committed for local reliability. (slide 34)

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Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $206 million, up 36 percent from the third quarter of 2021. (slide 61)
- Transmission paths along the Central to East corridor accounted for the largest share of congestion ($68 million or 33 percent) in the day-ahead market. (slide 63)
  - ✓ The *old* Porter-Rotterdam and *new* Gordon Rd-Rotterdam 230 kV lines accounted for nearly 80 percent of this congestion, while the Central-East interface accounted for the remaining 20 percent.
    - – Transmission outages taken to facilitate the Public Policy Transmission (Segment A) projects were the primary driver, contributing to a total of $21 million of day-ahead congestion shortfalls this quarter for the Central-East interface. (slide 63)
- Congestion from Capital to Hudson Valley was significant this quarter, accounting for 23 percent of day-ahead congestion. (slide 63)
  - ✓ The Cricket VL-Pleasant VL 345 kV lines and the Chestror-Shoemaker 138 kV line accounted for 80 percent of this congestion, driven partly by changes in the pattern of transmission outages from the previous year.
  - ✓ RT congestion more than doubled DA congestion, rising substantially on:
    - – The Chestror-Shoemaker line because of frequent TSA events in July. (slide 64)
    - – The Cricket Valley-Pleasant Valley line because of significant amounts of loop flows between NY and NE on the constraint. (slide 57)

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

- Day-ahead congestion revenues rose 25 percent on Long Island from a year ago.
  - ✓ Nearly 70 percent of congestion occurred on the 69 kV and 138 kV constraints inside Long Island.
    - The Northport-Elwood 138 kV line was OOS during most of the quarter, contributing to higher congestion on the parallel 69 and 138 kV facilities.
  - ✓ Congestion on the tie lines between upstate and Long Island fell substantially as:
    - Both tie lines (Y49 and Y50) were in service this quarter while they were on lengthy outages a year ago.
    - The Neptune Line also returned to full capability starting in mid July.
- The North Zone congestion occurred primarily on the Moses-Adirondack 230 kV line as the parallel facility was OOS throughout the quarter (related to the Moses-Adirondack Smart Path Reliability Project). (slide 63)
- West Zone congestion fell dramatically from a year ago, falling to just $2 million in the day-ahead market from $34 million in 2021-Q3.
  - ✓ Transmission facilities related to the Empire State Line PPT project (including a PAR-controlled Dysinger-East Stolle 345 kV line) were put into service before summer, alleviating congestion and providing additional operational flexibility in this area.

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Market Highlights:
RTC/RTD Divergence - Load Forecast Errors

- RTC schedules non-dispatchable resources with lead times of 15 minutes to one hour (e.g., external transactions and fast-start units).
  - ✓ Inconsistency between RTC and RTD prices is an indicator that some scheduling decisions of RTC may be inefficient.
- We performed a systematic evaluation of factors that led to inconsistent RTC and RTD prices in the third quarter of 2022. (slide 54)
- Load forecasting errors were a significant contributor to price differences between RTC and RTD, accounting for 19 percent of the overall divergence this quarter.
  - ✓ On average, RTC load was higher than RTD load by nearly 90 MW, contributing to higher RTC LBMPs (than RTD LBMPs by an average of $2/MWh). (slide 55)
  - ✓ Operator adjustments to the RTC load forecast were still an important driver, although the frequency and magnitude of these adjustments were notably lower than observed in 2022-Q2. (slide 56)
    - – RTC load forecast adjustments have been more frequent in 2022 because BTM solar forecasting has become less accurate.
  - ✓ Although load forecast adjustments may be justified for many reasons, large changes in adjustment values may contribute to divergences between RTC and RTD prices, inefficient scheduling, and RT price volatility.
  - ✓ Therefore, it would be beneficial to evaluate the current procedure for determining load forecast adjustments in RTC for any potential improvements.

Market Highlights:

RTC/RTD Divergence - Loop Flows on the Cricket-PV Constraint

- Transmission utilization was another significant driver to price differences between RTC and RTD, accounting for 22 percent of the overall divergence this quarter.
  - ✓ Unmodeled flows on the transmission constraints were one of the key contributors.
  - ✓ We examined the differences in unmodeled flows on the Cricket Valley-Pleasant Valley 345 kV constraint between RTC and RTD, which accounted for nearly 30 percent of divergences associated with transmission utilization. (slide 57)
    - – Although the average difference in unmodeled flows between RTC and RTD was close to zero (i.e., approximately symmetric distribution around zero), the overall impact on RTC/RTD price divergence was not.
    - – Congestion occurred in 36 percent of intervals (in either RTC or RTD).
      - At the NY/NE proxy bus, differences in unmodeled flows led RTC prices to be higher than RTD prices by an average of \$4.1/MWh in these intervals (or \$1.50/MWh over the quarter).
      - In other areas, differences in unmodeled flows led RTD prices to be higher than RTC prices.
    - – It would be beneficial to consider enhancing modeling of loop flows between NY and NE to reflect the effects of expected variations more accurately.
    - – However, the installation of the Dover PARs in 2023-Q4 should help reduce the magnitude of loop flows on the NE border.

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Market Highlights:
OOM Actions to Manage Network Reliability

- OOM actions to manage network reliability were frequent in some regions this quarter - Long Island (64 days) and Capital Zone (13 days). (slide 66)
- OOM actions in the Capital Zone occurred primarily from mid- to late-July during the outages of the Greenbush Bus and Greenbush-Calvrton 115 kV line.
  - ✓ Several units were OOMed down frequently to manage congestion on unmodeled 115 kV facilities in the Albany-Greenbush area during this period.
  - ✓ The NYISO is considering the feasibility of modeling these constraints in the market software.
- OOM actions on Long Island were frequent in the Valley Stream load pocket (48 days) and the East End load pocket (63 days). (slide 67)
  - ✓ In the Valley Stream load pocket, one of GTs was often needed to alleviate congestion on the local 69 kV network.
  - ✓ In the East End load pocket, oil-fired peakers were often needed to satisfy the TVR requirement.
    - – The estimated LBMP impact of unmodeled TVR needs was significant in this quarter, averaging nearly $86/MWh.
  - ✓ OOM actions to manage 69 kV network in other load pockets were much less frequent as the market software has incorporated four 69 kV constraints that were previously frequently managed by OOM actions.

Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $33 million, up 25 percent from last year and driven primarily by higher natural gas prices.
  - ✓ Higher supplemental commitments in NYC (slide 75) and more frequent OOM actions in the Capital Zone (slide 79) were also key contributors.
- $16 million (or 50 percent) of BPCG payments accrued in NYC, 82 percent of which were paid to units that were committed for local reliability. (slide 82)
  - ✓ NOx emission costs for gas-fired STs rose to an average of $13/MWh this quarter (slide 28), contributing to higher uplift. However, only a subset of ST-owners have requested to reflect this cost in reference levels.
- Over $3 million of DAMAP accrued in the Capital Zone during a ten-day period in mid-July as several units were OOMed down frequently to manage unmodeled 115 kV constraints during transmission outages.
- BPCG uplift on Long Island fell modestly (by $3 million) from a year ago.
  - ✓ Supplemental commitments to meet the N-1-1 requirements were frequent last year during Y49/Y50 outages, while such needs occurred on only 6 days in this quarter.
  - ✓ However, uplift for local reliability rose modestly as the OOM needs to satisfy the TVR requirements in the East End load pocket increased modestly.

Market Highlights:
SRE for Capacity on High Load Days

- Despite two heat waves (July 17-24, and August 3-9) this summer, load exceeded 30 GW on just two days (i.e., 30.5 GW on July 20, and 30.2 GW on August 8).
  - ✓ Peak loads were below the 50/50 forecast of 31.8 GW on both days.
    - – However, over 700 MW of utility DR programs were activated each day to reduce the peak load.
    - – In addition, NYISO activated SCR/EDRP for Capital Zone (over 100 MW) on July 19 and 20 for Zone F needs due to Greenbush station outage.
  - ✓ See presentation "NYISO Summer 2022 Hot Weather Operations" by Aaron Markham at the September 28 MC meeting for more details.
- NYISO SREed resources for statewide capacity needs on five days during the two heat waves. (slides 77 and 78)
  - ✓ SREs were needed to satisfy NYCA reserve requirements on all days except July 18 (when actual load ran below forecast by more than 1,000 MW).
  - ✓ The BPCG uplift from these SREs was not large, but they were incurred to satisfy reserve needs that are not fully anticipated in the day-ahead market.
    - – The NYISO proposes to satisfy these forecasted requirements (currently met in the FCT pass and/or with SREs) through the market with the dynamic operating reserve enhancements. (See ICAPWG Presentation for November 8)

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Market Highlights:
Utility DR Activations on High Load Days

- Various amounts of Utility DR were activated on 13 days this quarter.
  - ✓ Most of these utility DR activations were for peak-shaving.
  - ✓ The statewide DR quantity reached roughly 750 MW on July 20 (when NYCA daily peak demand was roughly 30.5 GW).
  - ✓ Utility DR deployments are not considered when NYISO evaluates whether to SRE or deploy emergency DR resources.
    - – This can lead to unnecessary OOM actions, although this did not occur this quarter.
  - ✓ Utility DR deployments helped avoid or alleviate brief NYCA capacity deficiencies on four days shown in slides 77 and 78.
    - – Utility DR resources are paid primarily for availability (including capacity).
    - – Utility programs often provide large payments (~$1,000/MWh) for peak-shaving that are far above the value of the load reduction in the real-time market. However, peak-shaving results in lower capacity requirements in future periods.

Market Highlights:
Performance of Non-synchronous Reserve Providers

- The NYISO routinely audits 10- and 30-minute non-synchronous reserve providers to ensure that they are capable of providing the services that they sell.
- We reviewed NYISO audit results and found that in the 12-month period from October 2021 to September 2022: (slides 71-72)
  - ✓ Using performance during reserve pick-ups (RPUs) in lieu of regular audits for 10-minute GTs has been more frequent.
    - More than 70 percent of 10-minute GT audits were RPU audits.
    - This has helped reduce out-of-market actions and associated uplift costs.
  - ✓ The number of audit failures rose notably as a result of more frequent RPU audits.
    - There were a total of 63 audit failures, 42 of which were RPU audit failures.
      - 21 percent of RPU audits failed, compared to just 8 percent of regular audit failures.
    - This demonstrates that units that perform well during regular audits may still perform poorly during normal market operations (including reserve pickups and other RTC and RTD economic starts).

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Market Highlights:
Performance of Non-synchronous Reserve Providers (cont.)

- Audits are useful in assessing capability but do not adequately incent reliable performance. We further reviewed 13 GTs with poor performance (< 70%) in the last 24 months (from October 2020 to September 2022) and found that:
  - ✓ Five GTs had day-ahead reserve schedules in over 90 percent of hours, each receiving $36-$44/kw-year of reserve revenues, while they were rarely started by the market model. (slide 73)
  - ✓ Seven GTs had a below-70-percent audit pass rate, but none of them was either discounted or disqualified from providing reserves.
  - ✓ Two GTs were never audited.
- Since units that perform well during audits may still perform poorly during normal market operations, it would be appropriate to disqualify poor performers and discount reserve revenues based on performance during normal market operations.
  - ✓ Derating poor performers is permitted by the procedures outlined in Technical Bulletin 142.

Market Highlights:
Performance and Availability of Duct Burners

- Most combined cycle generators in the NYISO footprint offer supplemental output from their duct burners, totaling over 800 MW of summer capacity.
  - ✓ This capacity often presents difficulties in real-time due to disconnects between market design and the physical limitation of duct burners.
- Slide 69 shows an example of a CC unit that could not follow dispatch instructions during an RPU event, due to its inability to fire the duct burner within 10 minutes.
  - ✓ However, this duct burner capacity is considered capable of following 5-minute dispatch signals in the market scheduling and pricing software.
- Slide 70 shows duct-firing capacity that was offered but not physically capable of providing a given service in the required timeframe. During afternoon hours, on average: (a) 116 MW was offered but not capable of following 5-minute ramp instructions; (b) 83 MW was scheduled but not capable of providing 10-minute reserves; and (c) 20 MW was scheduled but not capable of providing regulation.
  - ✓ In addition, (a) 62 MW of duct-firing capacity was unavailable because this range was not offered; and (b) 116 MW of 10- and 30-minute reserves were not offered from baseload capacity (i.e., non-duct ranges) due to an inability to perform in audits of the duct burner range.
- A market design project is currently underway to evaluate improvements to modeling of duct-firing that is intended to addresses some of these issues.

Market Highlights:
Excess NOx-Rule LRR Commitments in NYC

- The NOx rule prevents NYC GTs in two portfolios from generating during the Ozone season unless steam turbines in the same portfolios are also producing such that the portfolio-average NOx emission rate satisfies the DEC standard.
  - ✓ A steam turbine was LRR-committed solely to satisfy the NOx rule on 23 days in the third quarter of 2022 of which 15 were assessed for necessity of the ST commitment. (slide 80)
    - These days generally occur when load levels fall during mild weather.
  - ✓ Our evaluation shows that even if the committed steam turbine and the associated GTs were unavailable, all N-1-1-0 criteria in the associated load pockets could have been satisfied by other resources on each of the 15 days.
    - The supply margin (excluding the committed steam turbine and associated GTs) generally exceeded 400 MW each day. (slide 80)
    - This suggests that these NOx-only steam turbine commitments could have been avoided if the market software considered whether the GTs were actually needed for reliability (before committing the associated steam turbine).
      - The GTs would not be available in real time absent a NOx-only ST commitment.
  - ✓ These avoidable NOx-only commitments reduce market efficiency by depressing energy and reserve prices and generating uplift and excess production costs.
    - These inefficient commitments will cease because of GT retirements in summer 2023 due to the DEC Peaker Rule.

Market Highlights:
Capacity Market

- Spot capacity prices fell by 30-37 percent from a year ago, averaging from \$3.25/kW-month in ROS to \$6.62/kW-month in LI this quarter. (slides 88-89)
- The ROS prices fell by 37 percent from the prior year, driven primarily by a lower ICAP requirement for the 2022/23 Capability Year.
  - ✓ The ICAP requirement fell by roughly 1 GW because:
    - Peak load forecast fell by 566 MW; and
    - The IRM fell from 120.7 to 119.6 percent.
- The UCAP requirements in NYC and the G-J Locality were either not or just barely binding, leading spot prices in both localities to be comparable to ROS prices.
  - ✓ Although LCRs rose from the prior Capability Year in both localities, their ICAP requirements were still lower because of lower peak load forecasts.
  - ✓ The high volatility in LCR values year-over-year (despite the lack of significant changes in transmission capability) highlights inefficiencies in the IRM and LCR-setting processes which are discussed in our 2021 SOM Report.

Market Highlights:
Functionally Unavailable Capacity

- We examined the availability of capacity procured from certain conventional resources during daily peak hours this summer. (slide 90)
- Several factors that are not adequately addressed in the current DMNC test requirements have led a significant amount of ICAP from fossil-fuel and nuclear generators to be qualified but unavailable during peak conditions, including:
  - ✓ Fossil-fueled and nuclear steam turbine units that are classified as ambient-condition dependent units due to ambient water temperature limitations.
    - – An average of 210 MW of ambient water-related deratings from such units occurred on peak (>28 GW) load days. This type of derating is not considered in EFORd.
    - – The current DMNC test procedures only require “internal combustion, combustion units and combined cycle units” to be temperature-adjusted.
      - *Consequently, fossil-fueled and nuclear steam turbine units do not adjust DMNC test results, even for predictable ambient water-related deratings*.
  - ✓ Combined cycle units and thermal peakers typically have reduced capability under higher relative humidity. *However, current DMNC test procedures do not require test results to be humidity-adjusted*.
    - – Most fossil-fuel generators (75 percent of ICAP) conduct DMNC tests when humidity conditions are below the seasonal median value. (slide 91)

Market Highlights:
Functionally Unavailable Capacity (cont.)

- ✓ The capability of cogeneration units depends on the host steam demand.
  - – We observed frequent real-time deratings from cogeneration units due to host steam requirements, averaging 26 MW in July and August.
  - – *In some cases, cogeneration units may not have procedures for curtailing steam load when their capacity is needed for electric system reliability*.
- ✓ Emergency capacity (i.e., capacity offered above a generator's normal UOL) averaged roughly 460 MW from fossil-fuel and nuclear units in July and August.
  - – Emergency capacity is only activated under emergency operating procedures.
    - *This may not allow operators to access some emergency capacity in a time frame that can be used to support reliability.*
  - – Operating in the emergency range may increase the risk of tripping for some units. This is risk is not accurately accounted for in the EFORd calculations.
    - *Hence, operators may be reluctant to utilize this capacity during an emergency.*

- Ambient derates are not required to be reported in GADS. Hence, they are not considered in EFORd calculations.
  - ✓ Some instances of mechanical derates have been inappropriately reported as ambient-related.

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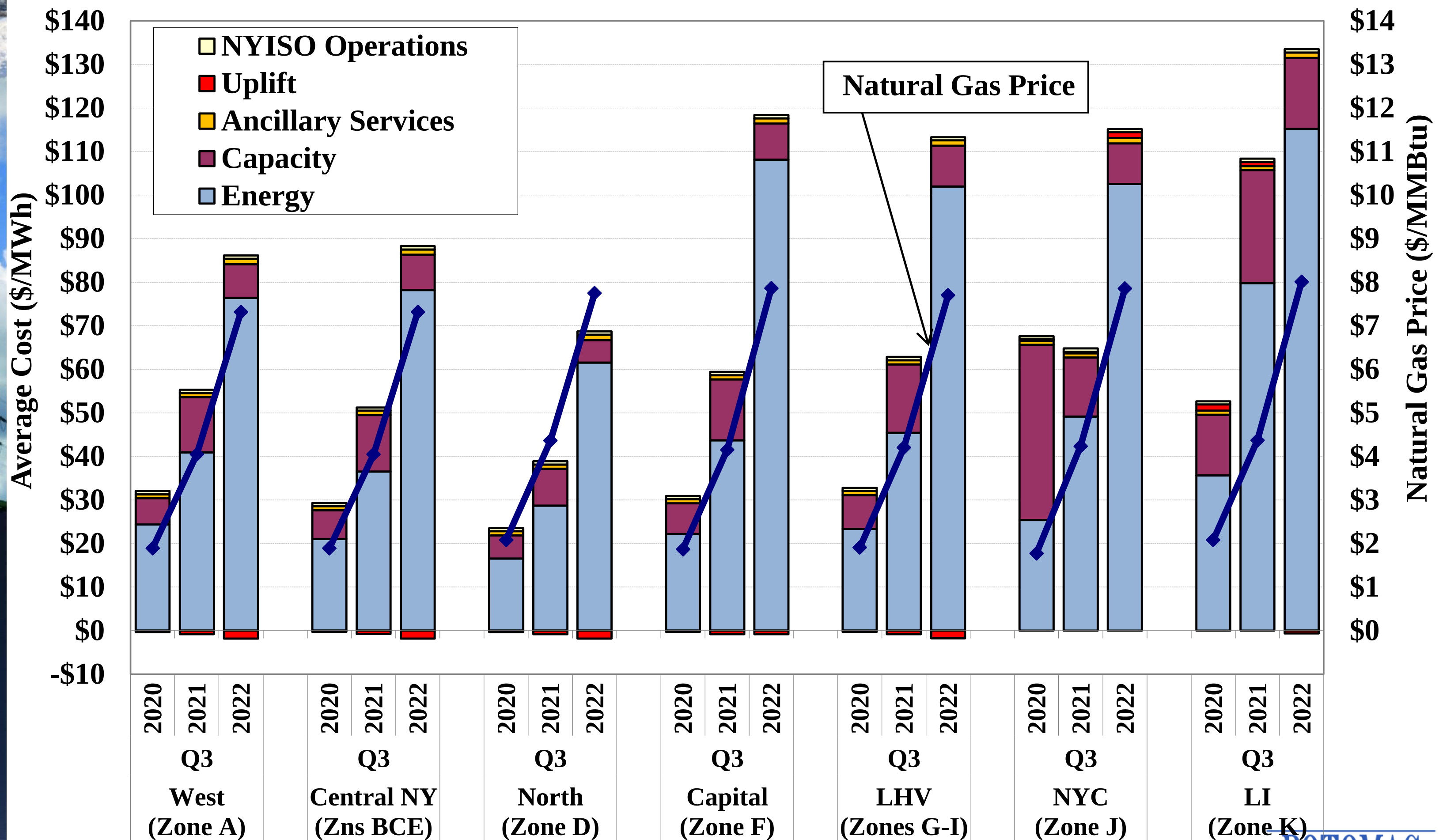
Charts:
Market Outcomes

All-In Prices by Region



Notes: For chart description, see slide 93.

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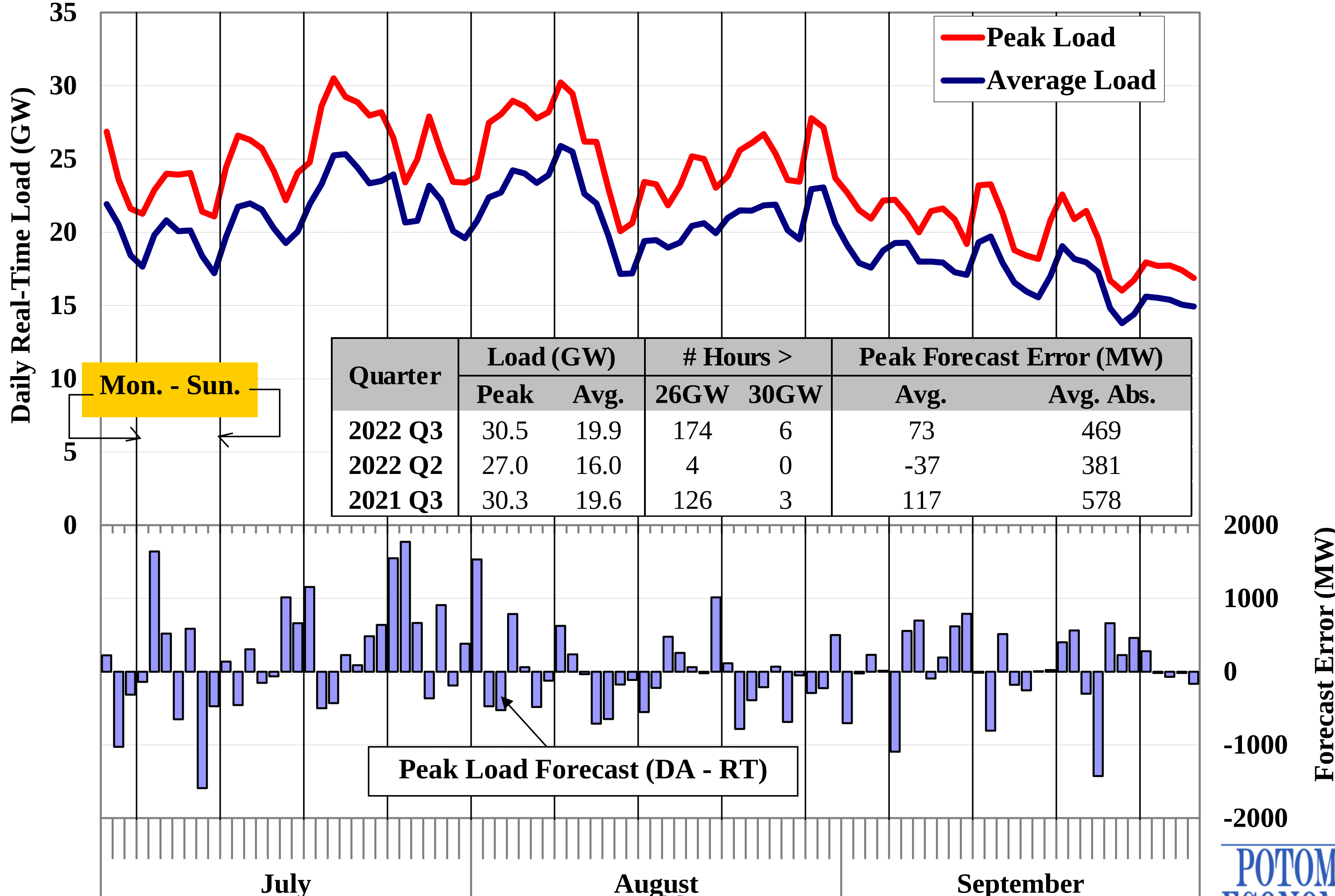
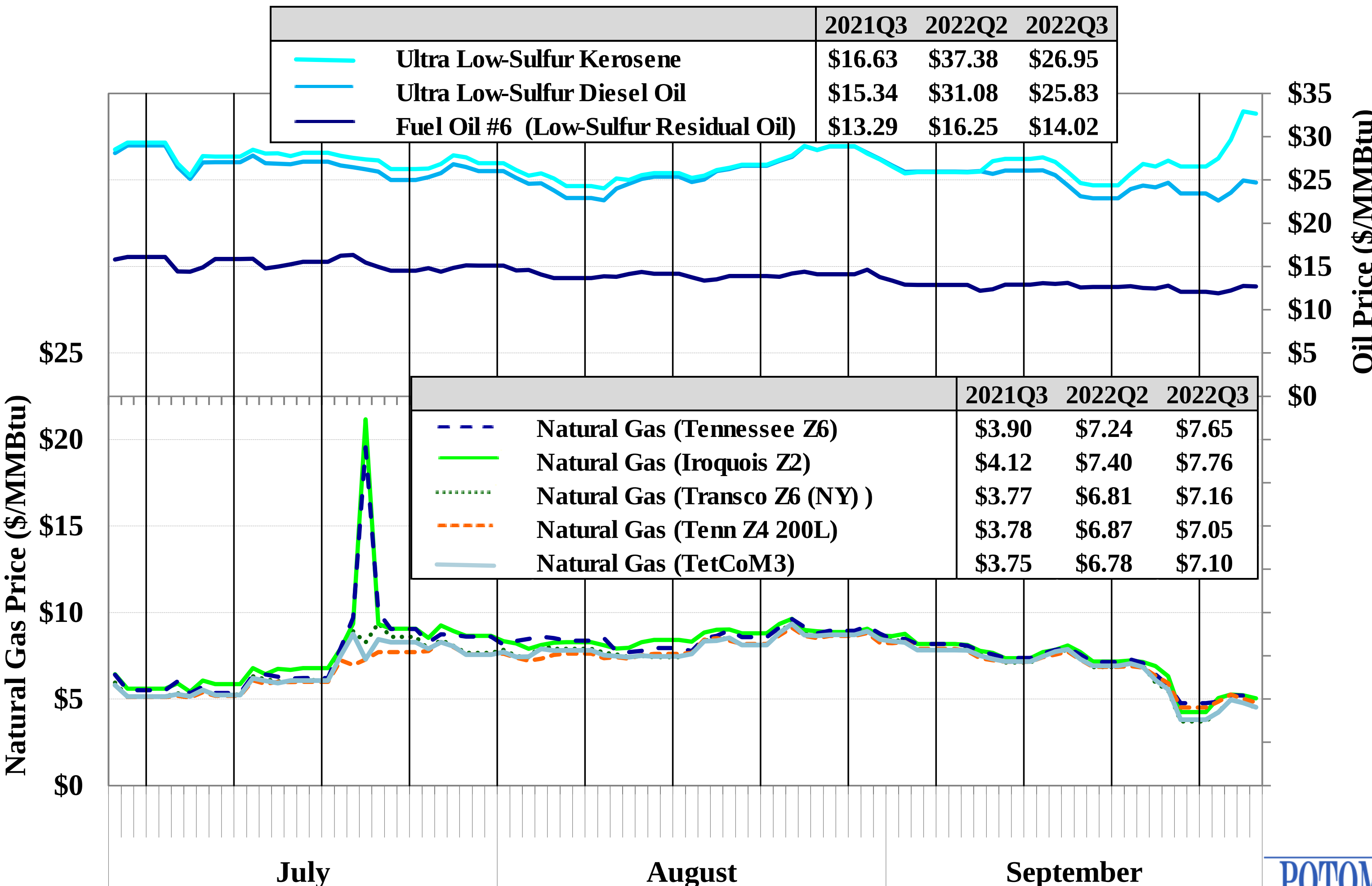
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2022 Q3	30.5	19.9	174	6	73	469
2022 Q2	27.0	16.0	4	0	-37	381
2021 Q3	30.3	19.6	126	3	117	578

Natural Gas and Fuel Oil Prices



	2021Q3	2022Q2	2022Q3
Ultra Low-Sulfur Kerosene	$16.63	$37.38	$26.95
Ultra Low-Sulfur Diesel Oil	$15.34	$31.08	$25.83
Fuel Oil #6 (Low-Sulfur Residual Oil)	$13.29	$16.25	$14.02

	2021Q3	2022Q2	2022Q3
Natural Gas (Tennessee Z6)	$3.90	$7.24	$7.65
Natural Gas (Iroquois Z2)	$4.12	$7.40	$7.76
Natural Gas (Transco Z6 (NY))	$3.77	$6.81	$7.16
Natural Gas (Tenn Z4 200L)	$3.78	$6.87	$7.05
Natural Gas (TetCoM3)	$3.75	$6.78	$7.10

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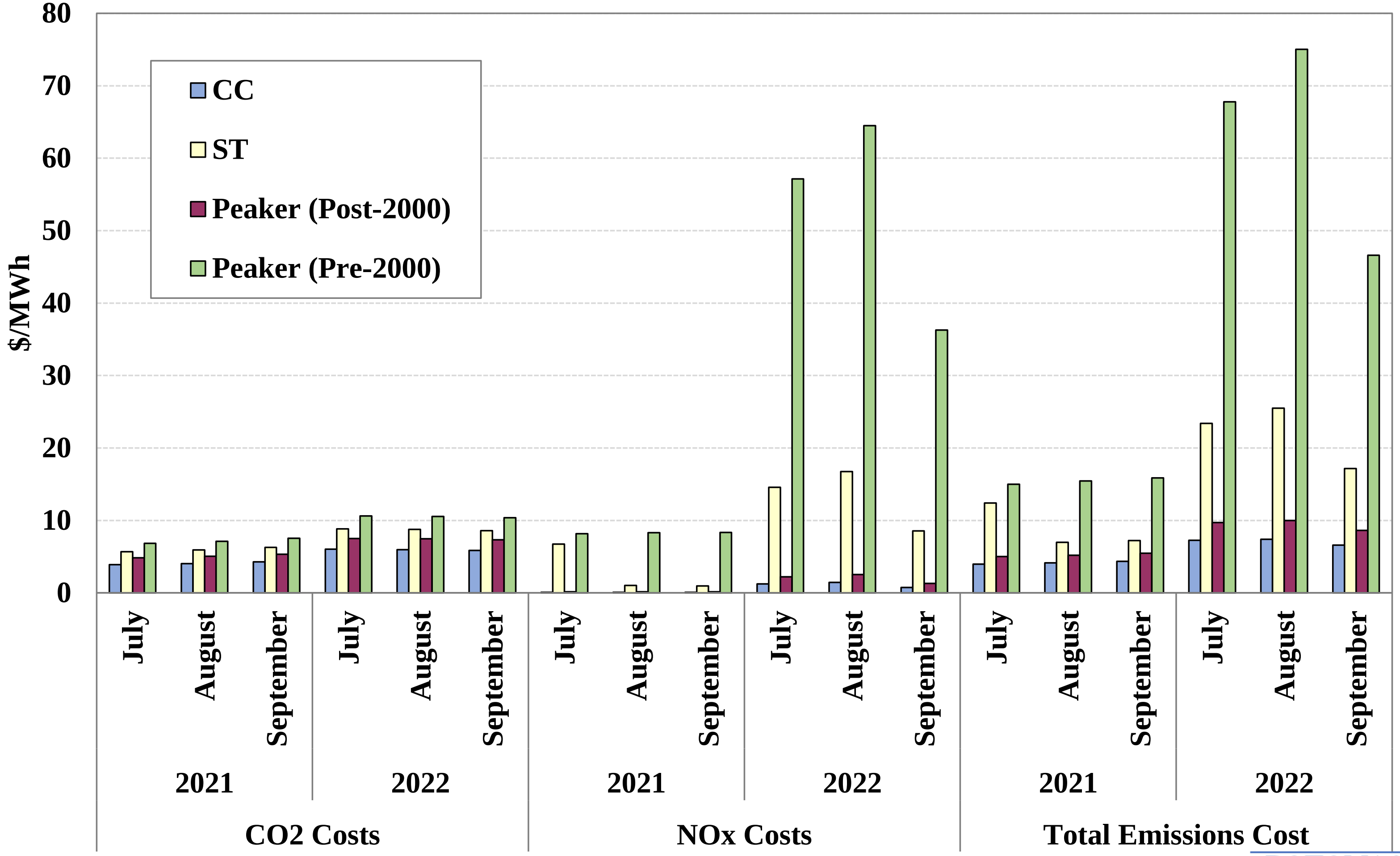
Emissions Costs by Unit Type
Natural Gas Fired Resources



Notes: For chart description, see slide 96

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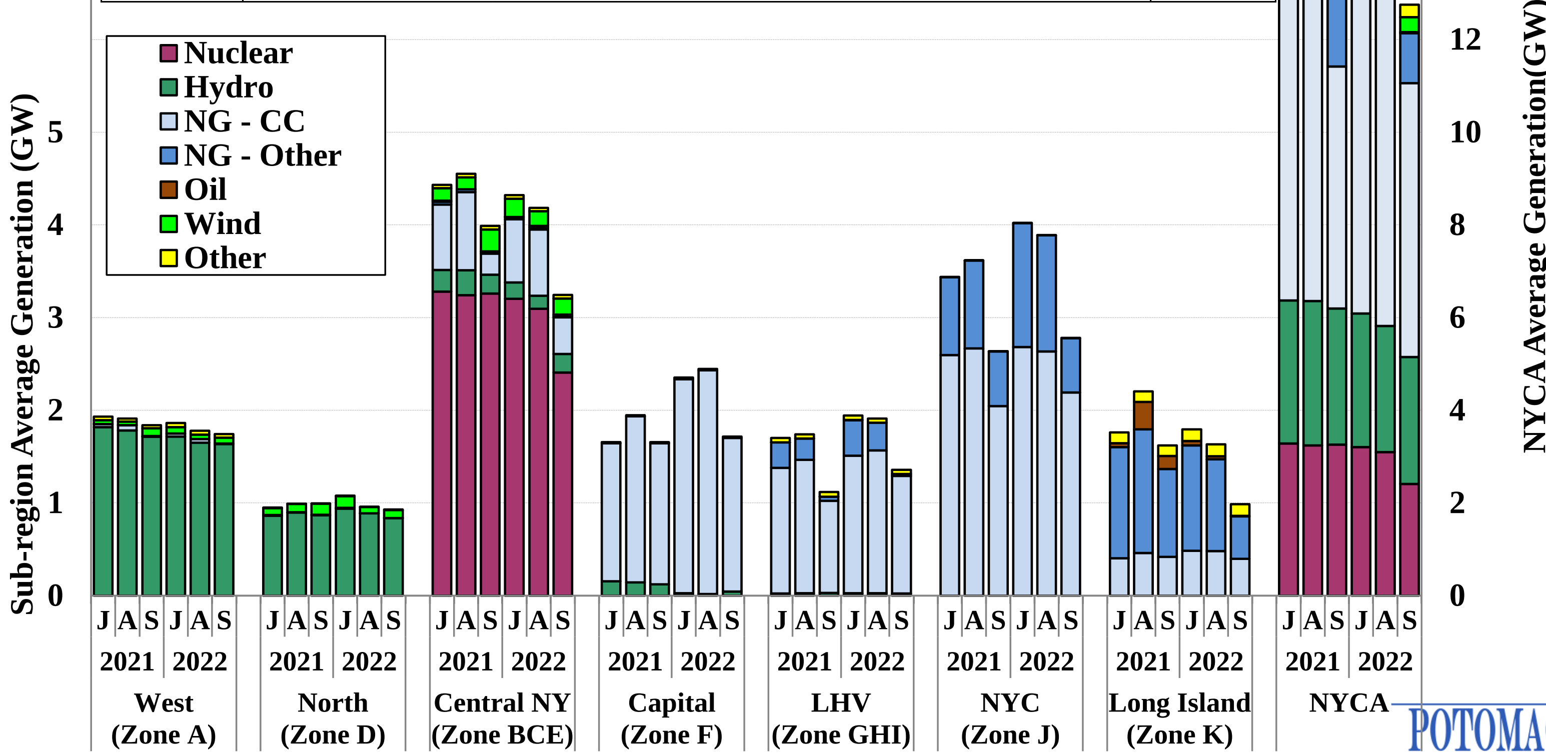
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Total
2022 Q3	2.91	2.78	7.15	2.19	0.04	0.33	0.27	15.67
2022 Q2	3.23	3.04	5.82	1.15	0.01	0.49	0.27	14.01
2021 Q3	3.26	3.05	6.37	2.17	0.17	0.31	0.25	15.58



Notes: For chart description, see slide 94.

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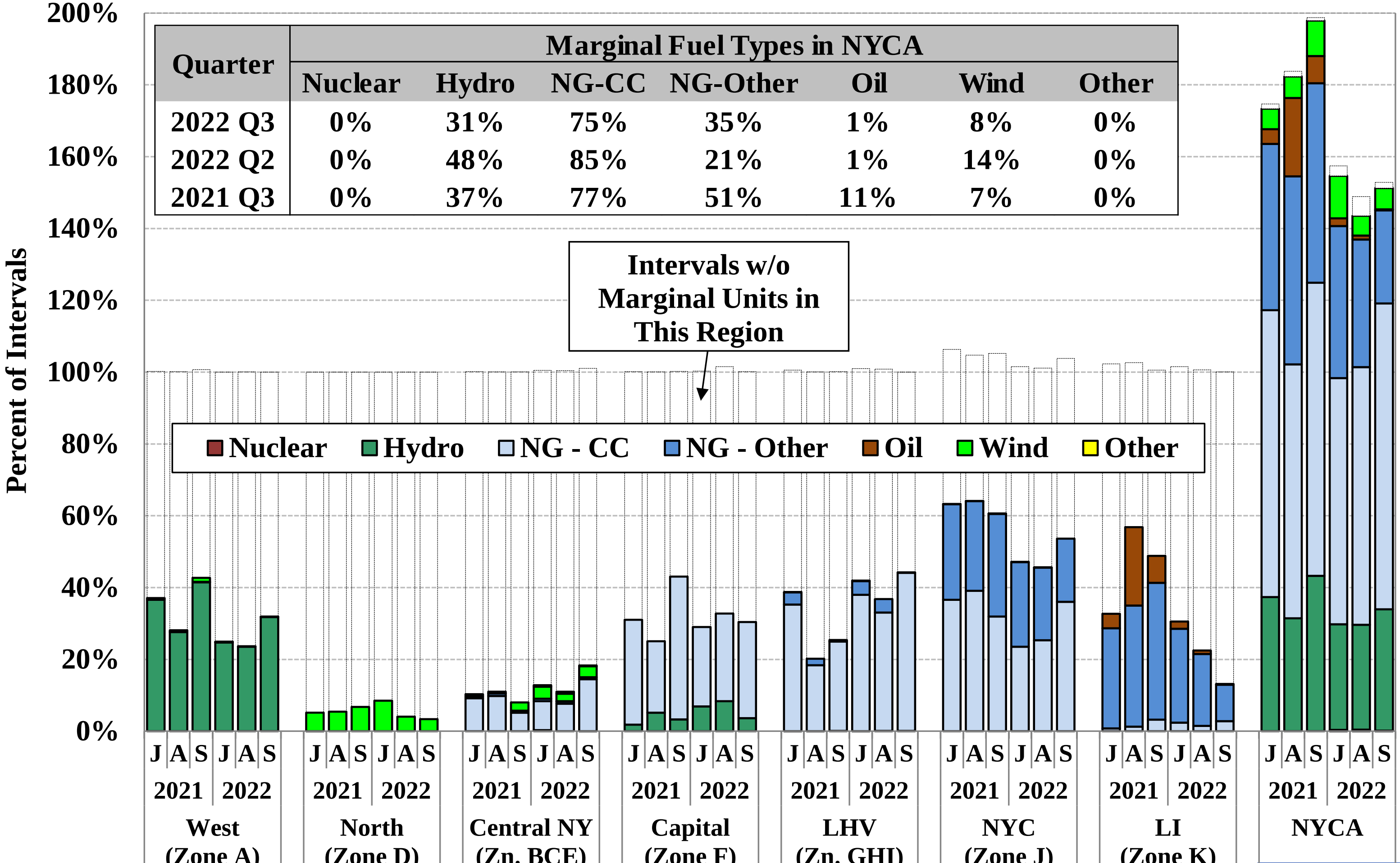
Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other
2022 Q3	0%	31%	75%	35%	1%	8%	0%
2022 Q2	0%	48%	85%	21%	1%	14%	0%
2021 Q3	0%	37%	77%	51%	11%	7%	0%

Notes: For chart description, see slide 94.

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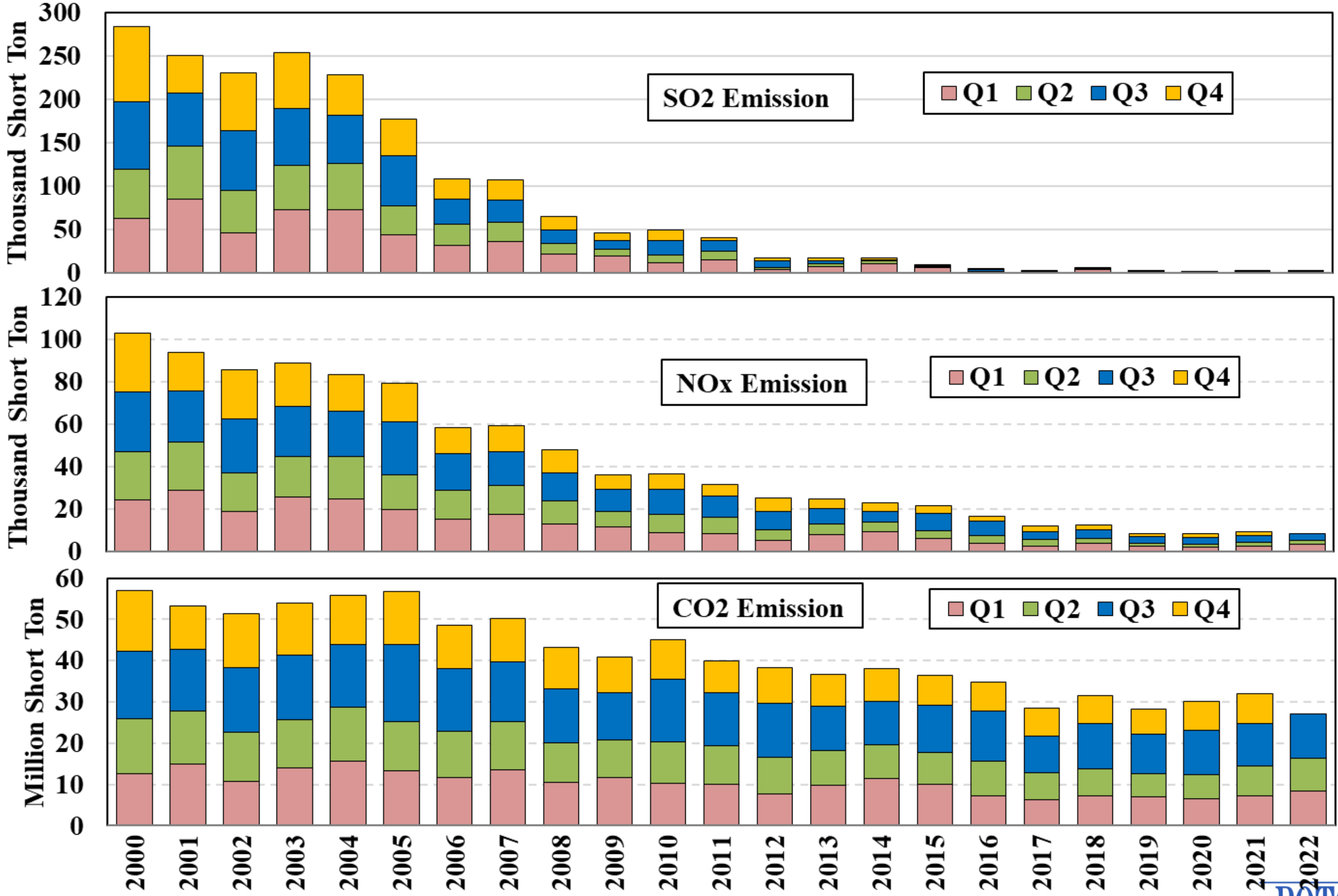
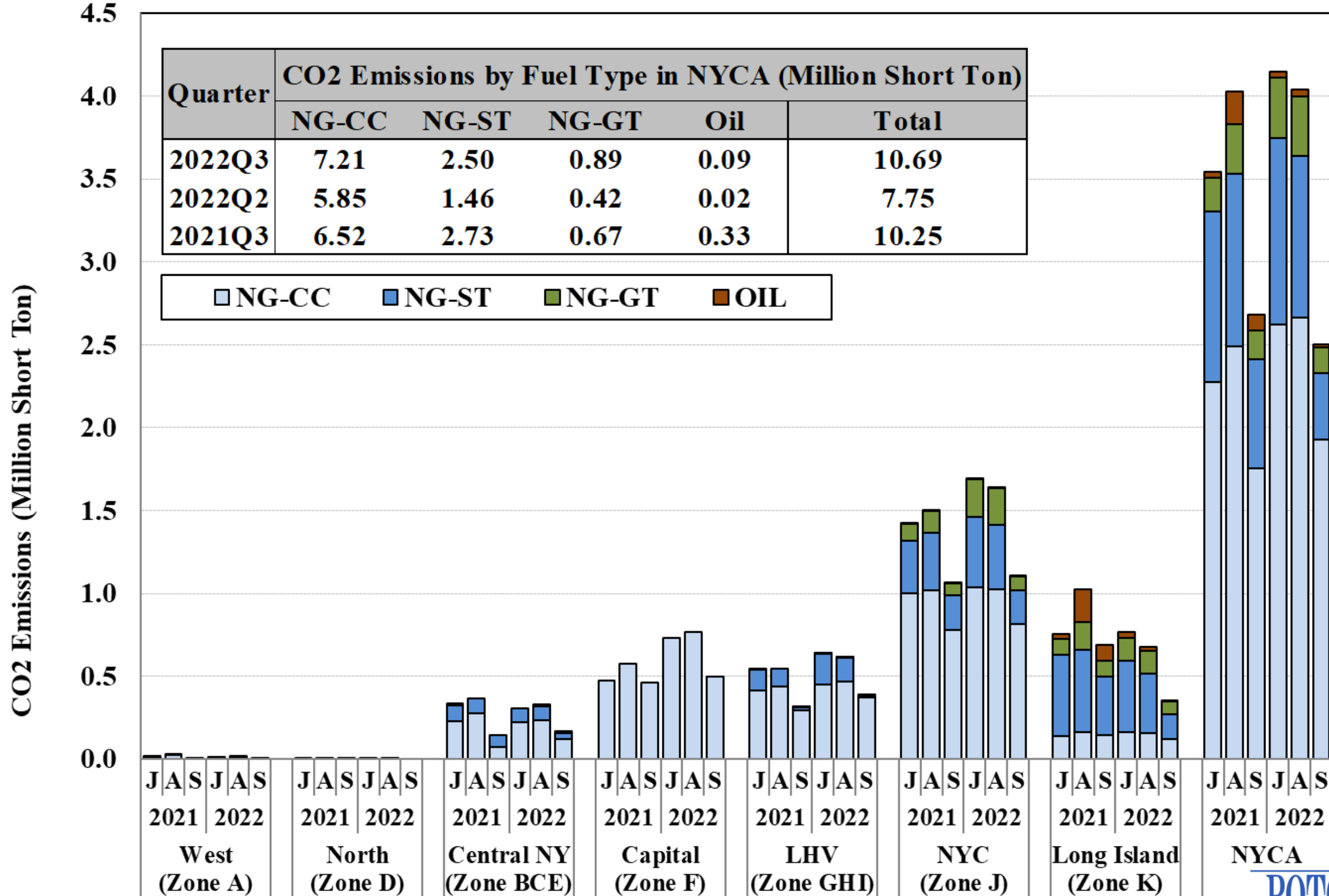
Historical Emissions by Quarter in NYCA
CO_2, SO_2, and NO_X



Notes: For chart description, see slide 95.

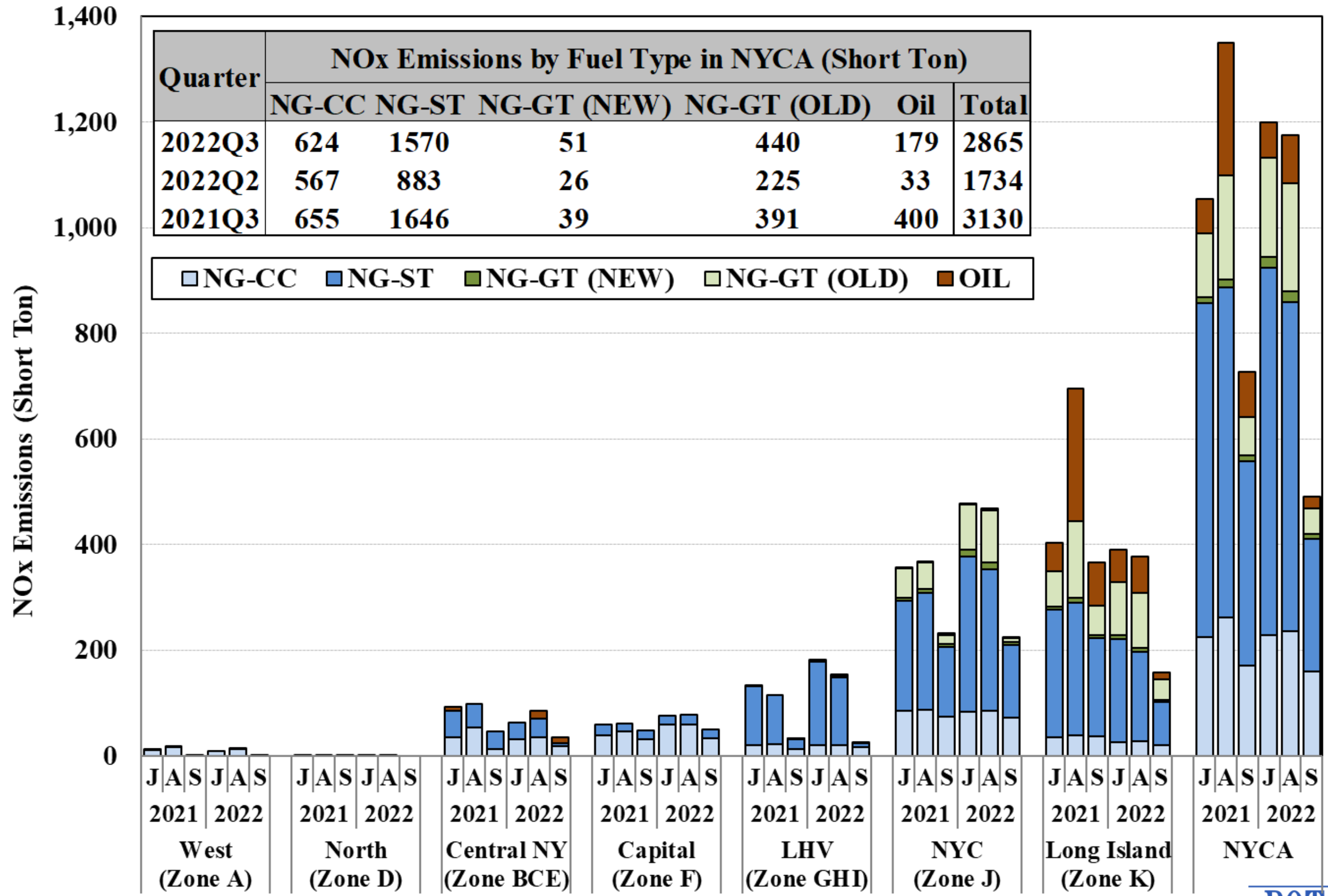
Emissions by Region by Fuel Type
CO_2 Emissions



Quarter	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)				
	NG-CC	NG-ST	NG-GT	Oil	Total
2022Q3	7.21	2.50	0.89	0.09	10.69
2022Q2	5.85	1.46	0.42	0.02	7.75
2021Q3	6.52	2.73	0.67	0.33	10.25

Notes: For chart description, see slide 95.

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
2022Q3	624	1570	51	440	179	2865
2022Q2	567	883	26	225	33	1734
2021Q3	655	1646	39	391	400	3130

Notes: For chart description, see slide 95.

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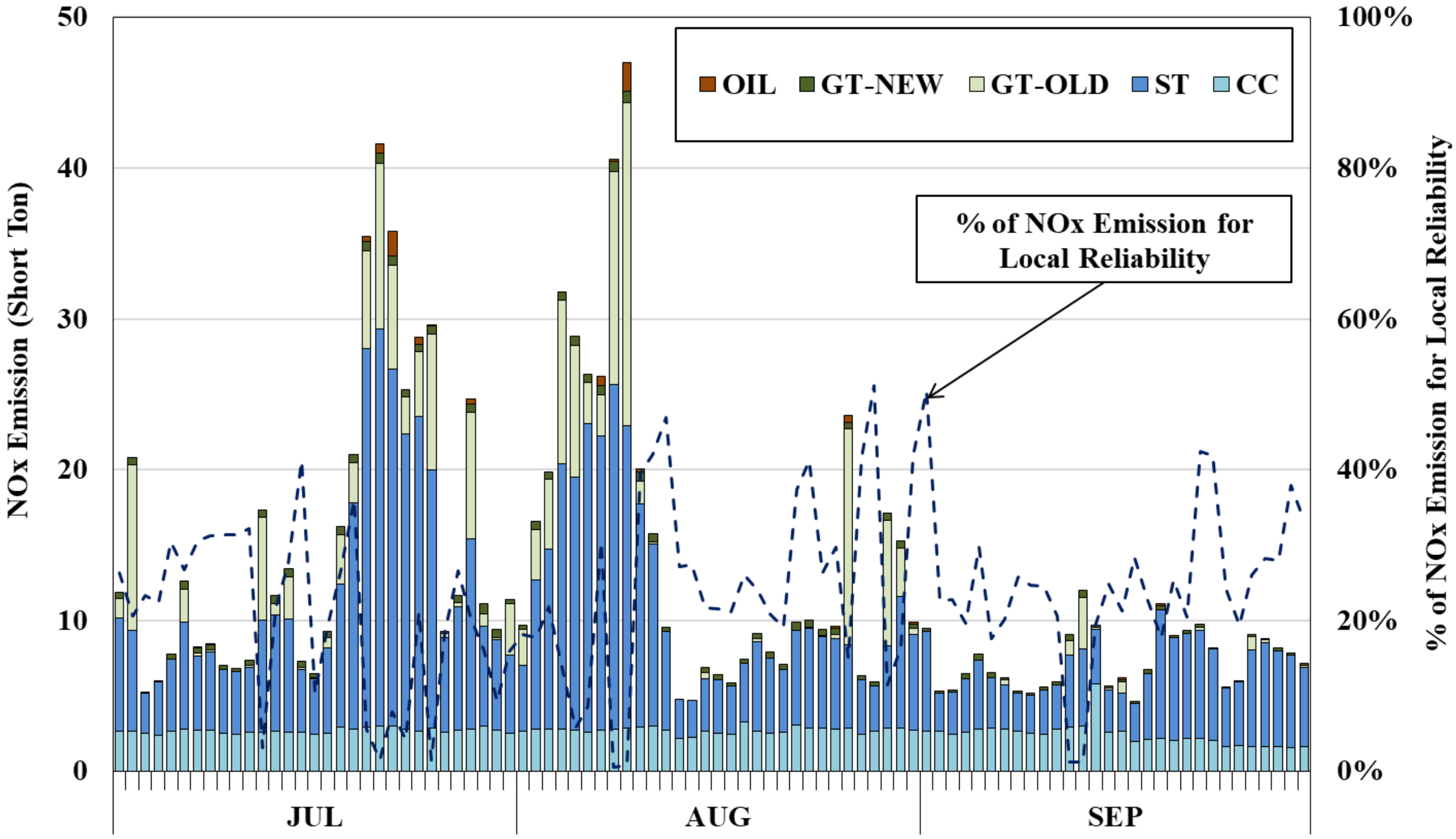
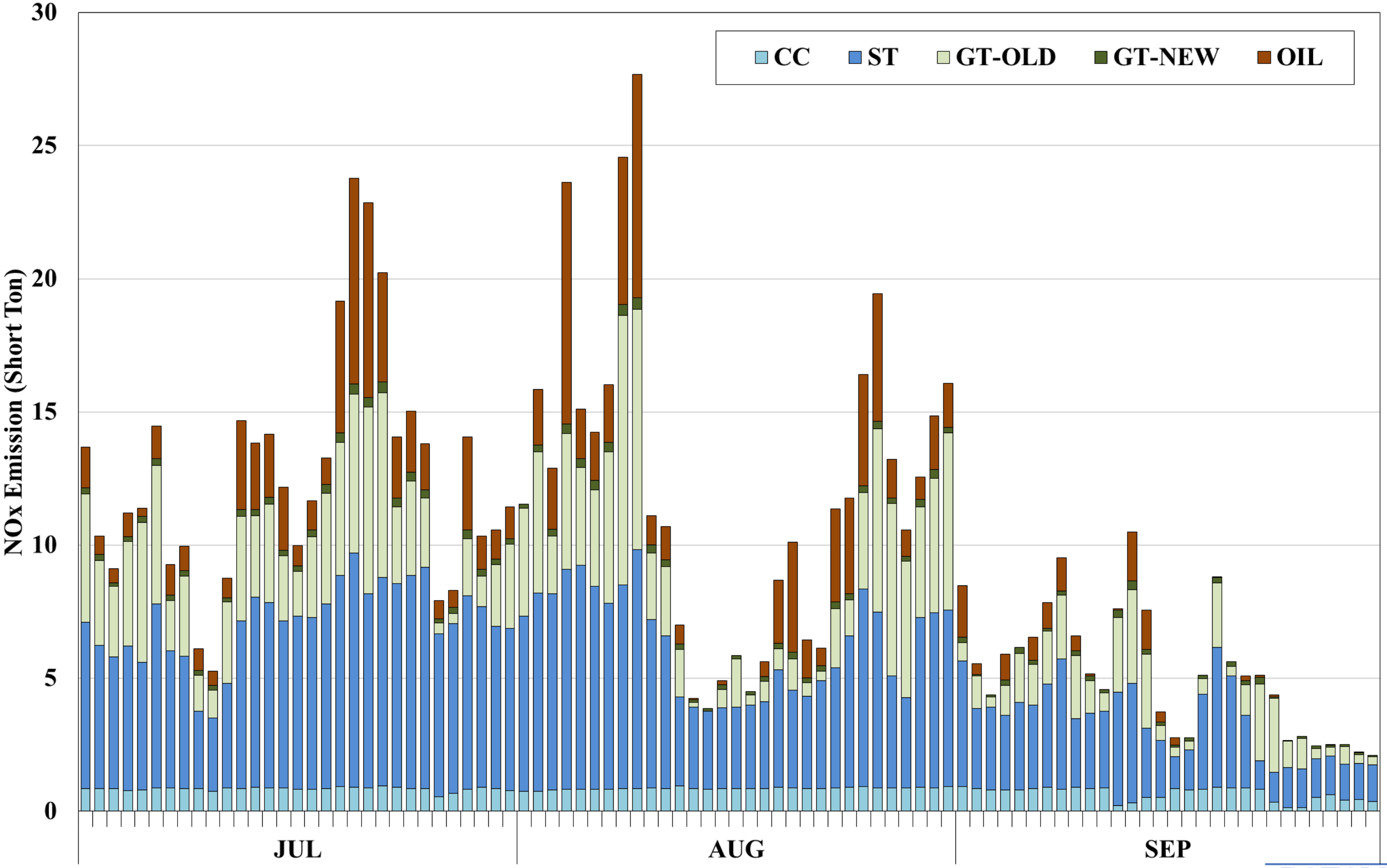
Daily NO_X Emissions in NYC



 Notes: For chart description, see slide 95.

POTOMAC ECONOMICS

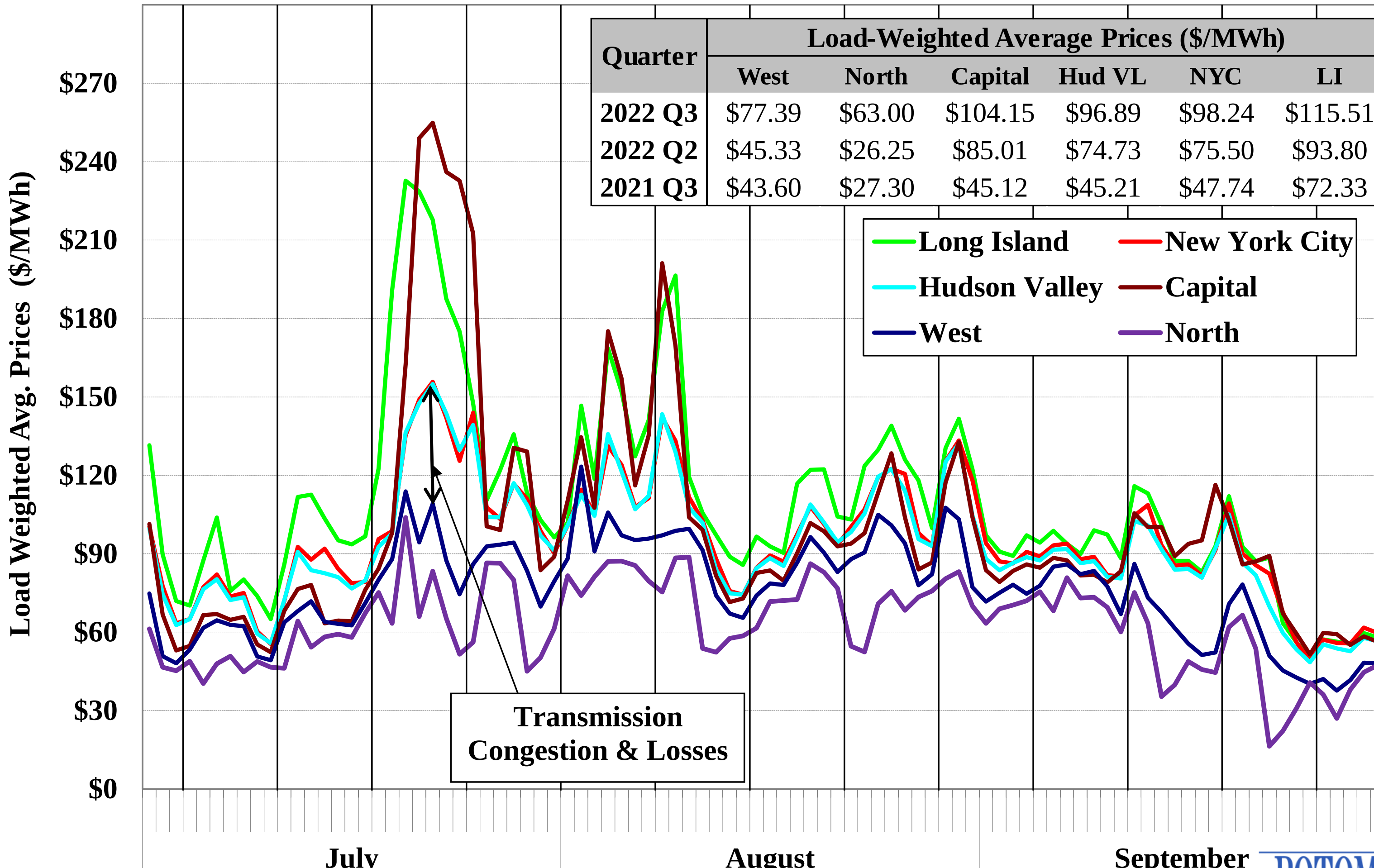
Daily NO_X Emissions in Long Island



Notes: For chart description, see slide 95.

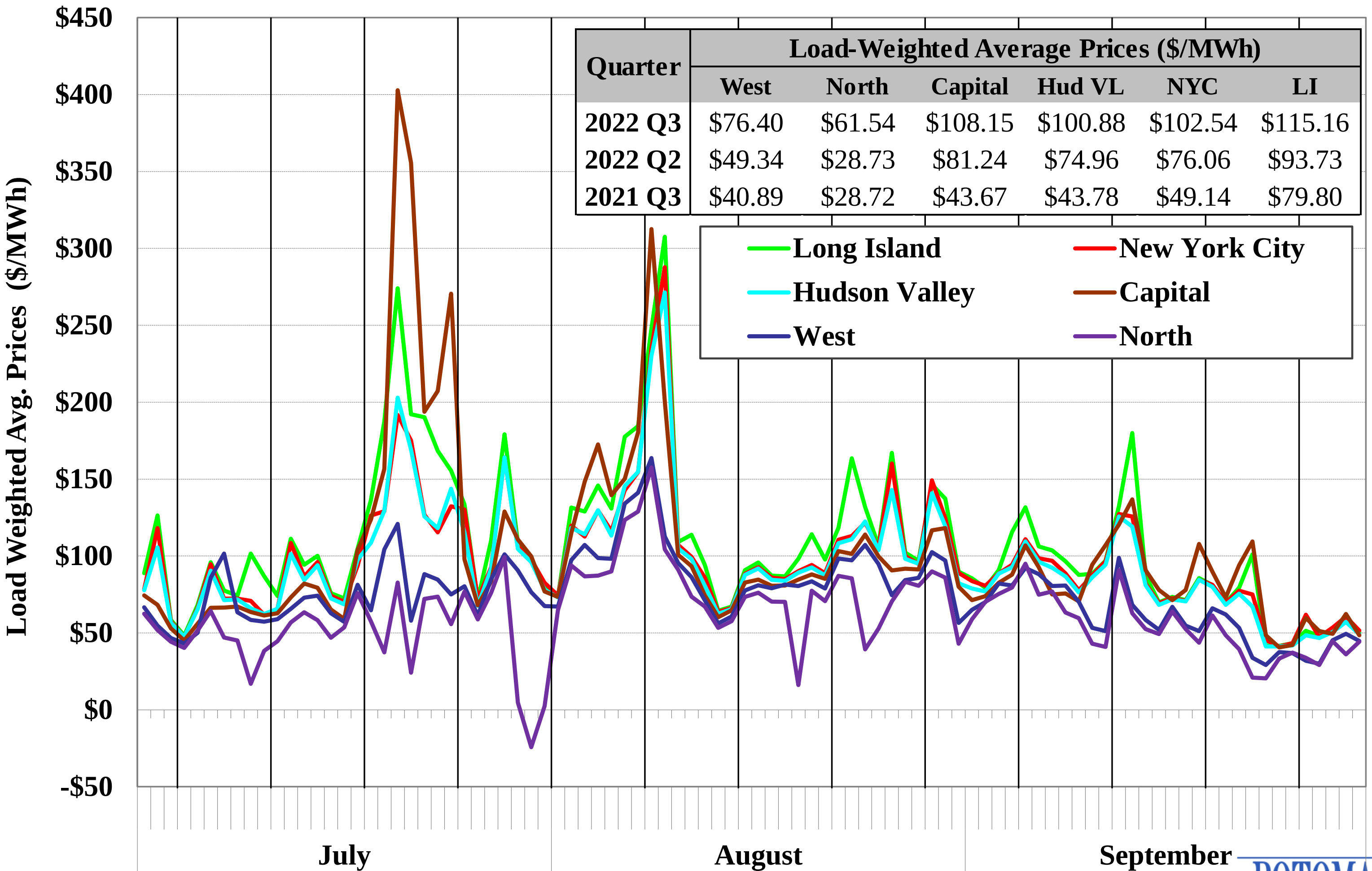
POTOMAC ECONOMICS

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q3	$77.39	$63.00	$104.15	$96.89	$98.24	$115.51
2022 Q2	$45.33	$26.25	$85.01	$74.73	$75.50	$93.80
2021 Q3	$43.60	$27.30	$45.12	$45.21	$47.74	$72.33

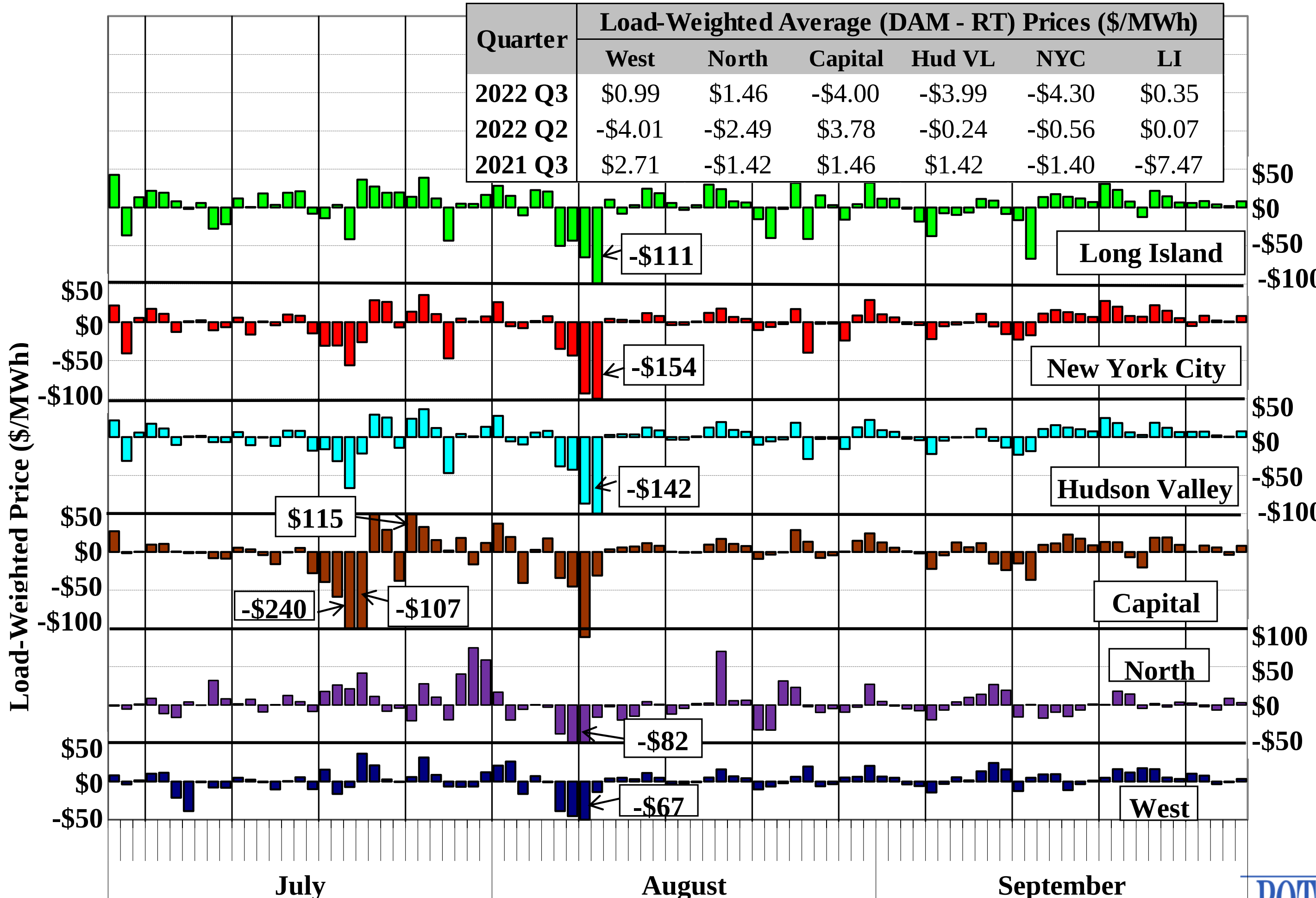
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q3	$76.40	$61.54	$108.15	$100.88	$102.54	$115.16
2022 Q2	$49.34	$28.73	$81.24	$74.96	$76.06	$93.73
2021 Q3	$40.89	$28.72	$43.67	$43.78	$49.14	$79.80

Convergence Between Day-Ahead and Real-Time Prices

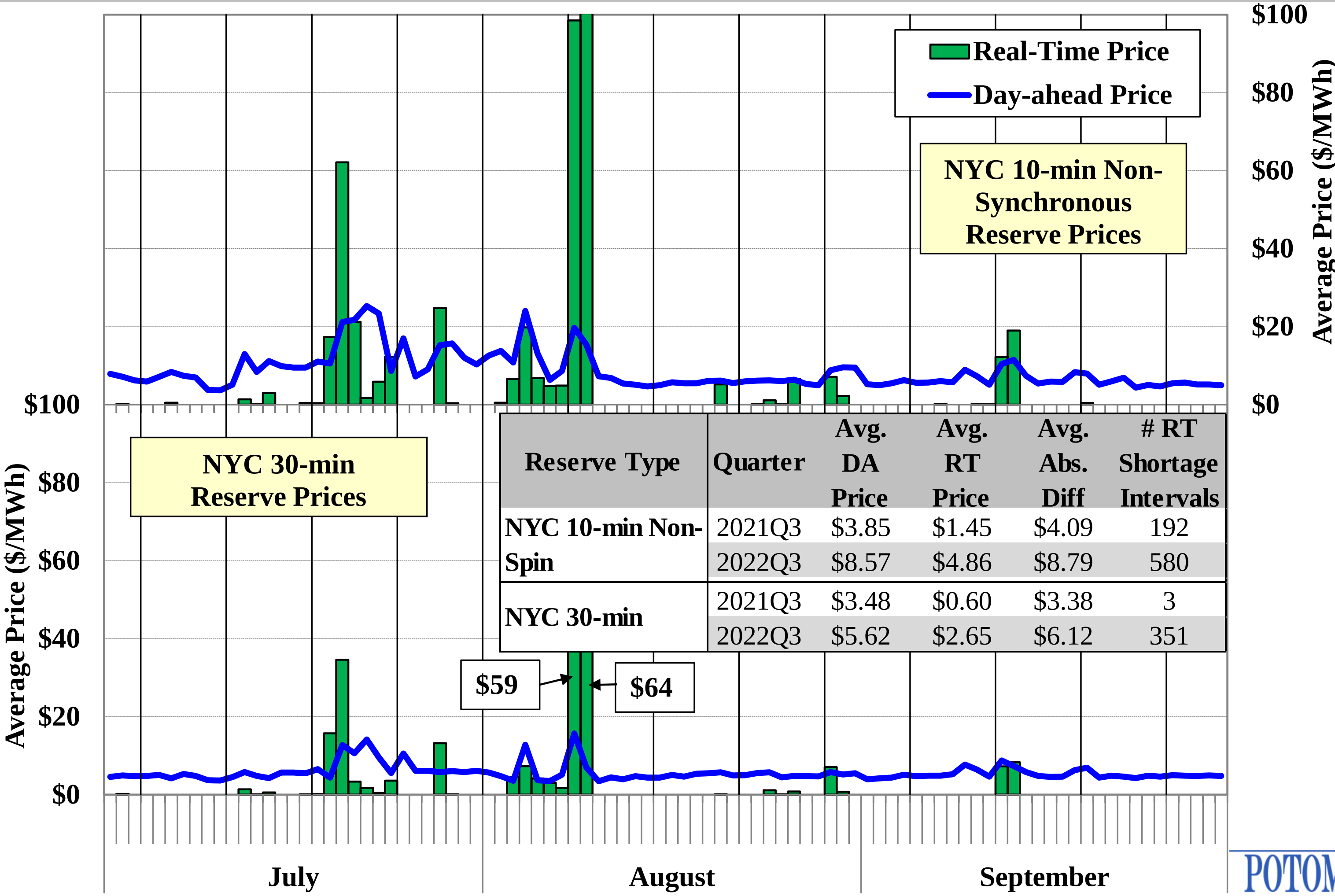
Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q3	$0.99	$1.46	-$4.00	-$3.99	-$4.30	$0.35
2022 Q2	-$4.01	-$2.49	$3.78	-$0.24	-$0.56	$0.07
2021 Q3	$2.71	-$1.42	$1.46	$1.42	-$1.40	-$7.47



Charts:

Ancillary Services Market

Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Non-Spinning and 30-Minute Reserves

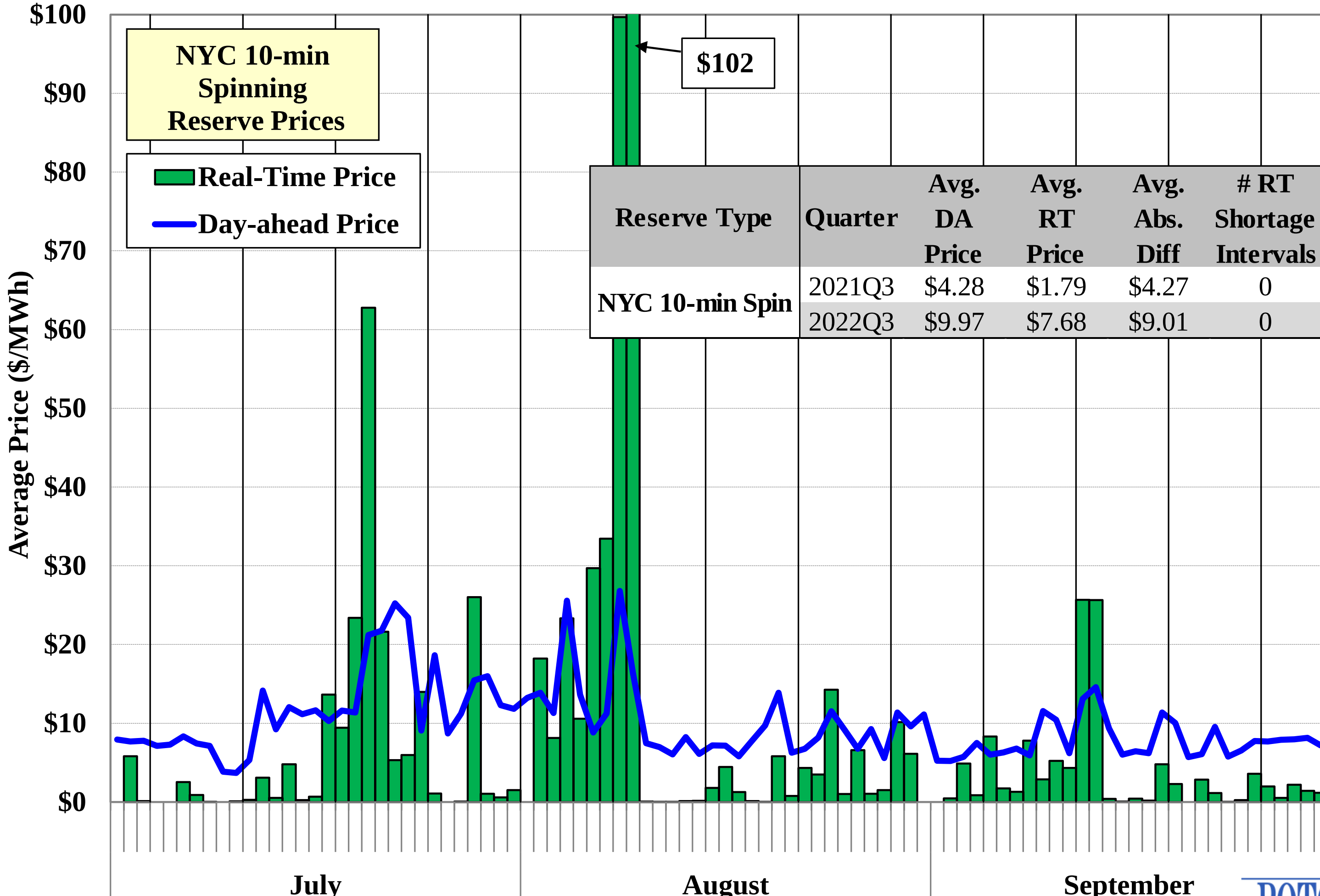


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2021Q3	$3.85	$1.45	$4.09	192
	2022Q3	$8.57	$4.86	$8.79	580
NYC 30-min	2021Q3	$3.48	$0.60	$3.38	3
	2022Q3	$5.62	$2.65	$6.12	351

Notes: For chart description, see slide 97.

POTOMAC ECONOMICS

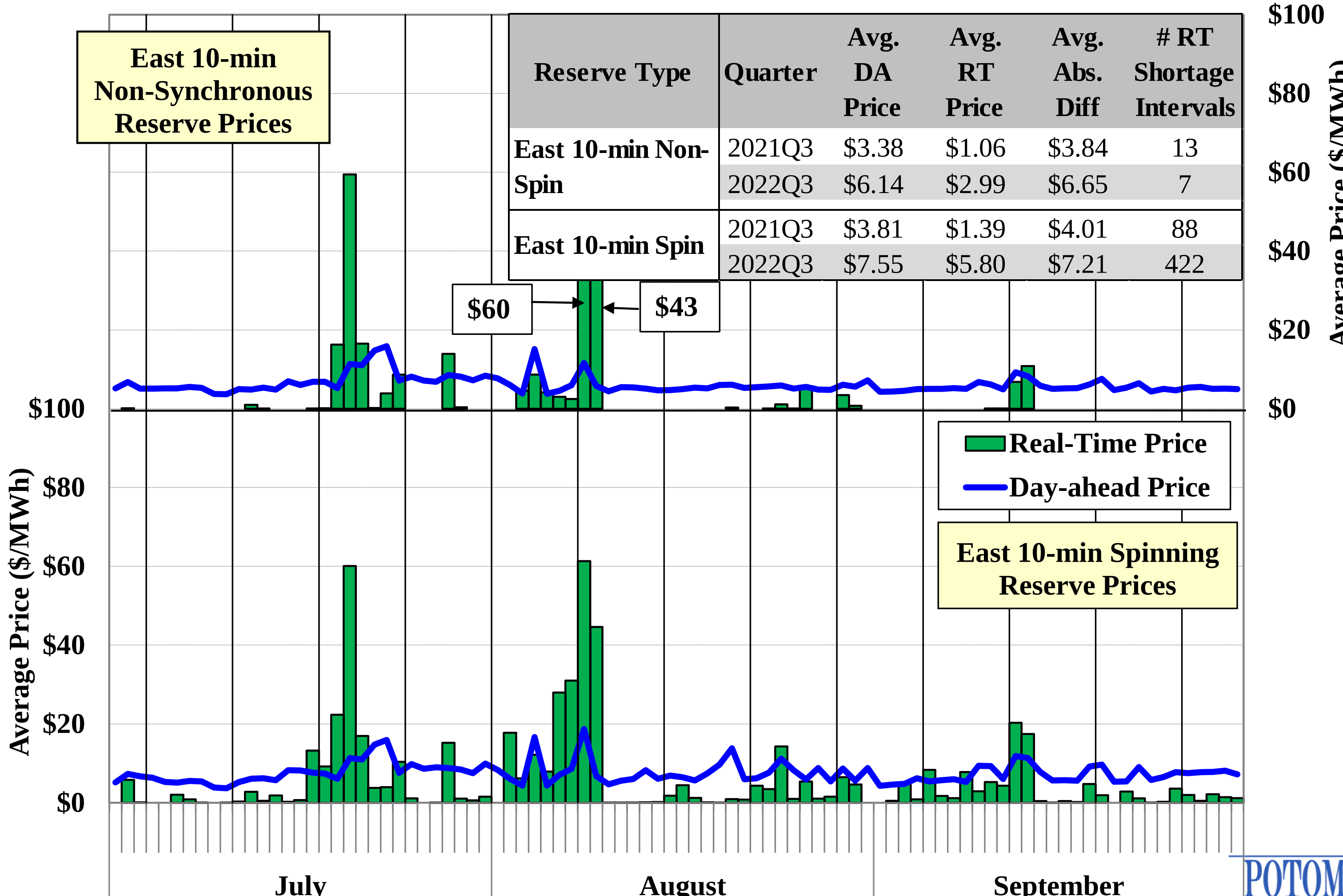
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2021Q3	$4.28	$1.79	$4.27	0
	2022Q3	$9.97	$7.68	$9.01	0

Notes: For chart description, see slide 97.
POTOMAC ECONOMICS

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

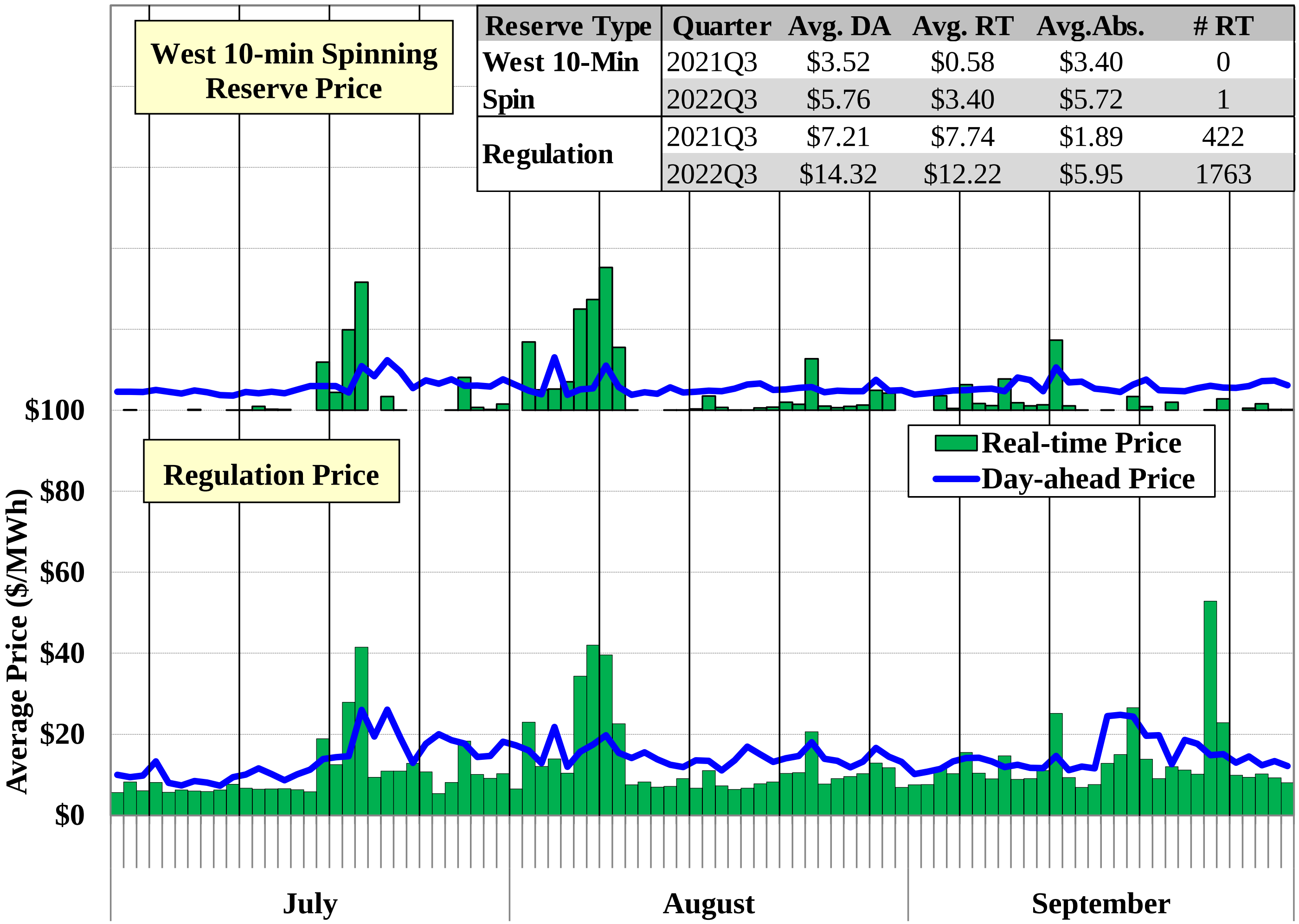


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2021Q3	$3.38	$1.06	$3.84	13
	2022Q3	$6.14	$2.99	$6.65	7
East 10-min Spin	2021Q3	$3.81	$1.39	$4.01	88
	2022Q3	$7.55	$5.80	$7.21	422

Notes: For chart description, see slide 97.

POTOMAC ECONOMICS

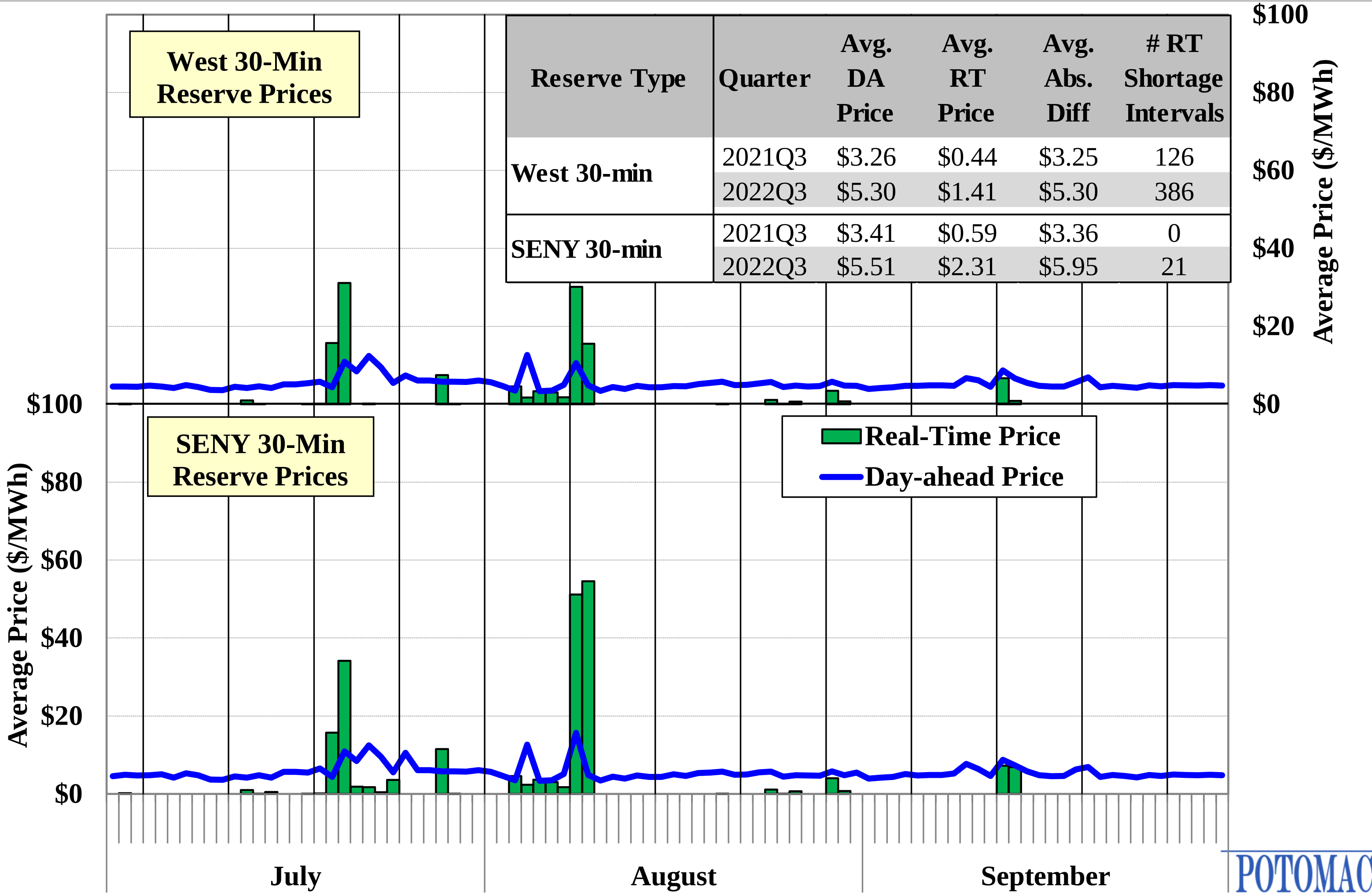
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2021Q3	$3.52	$0.58	$3.40	0
	2022Q3	$5.76	$3.40	$5.72	1
Regulation	2021Q3	$7.21	$7.74	$1.89	422
	2022Q3	$14.32	$12.22	$5.95	1763

Notes: For chart description, see slide 97.

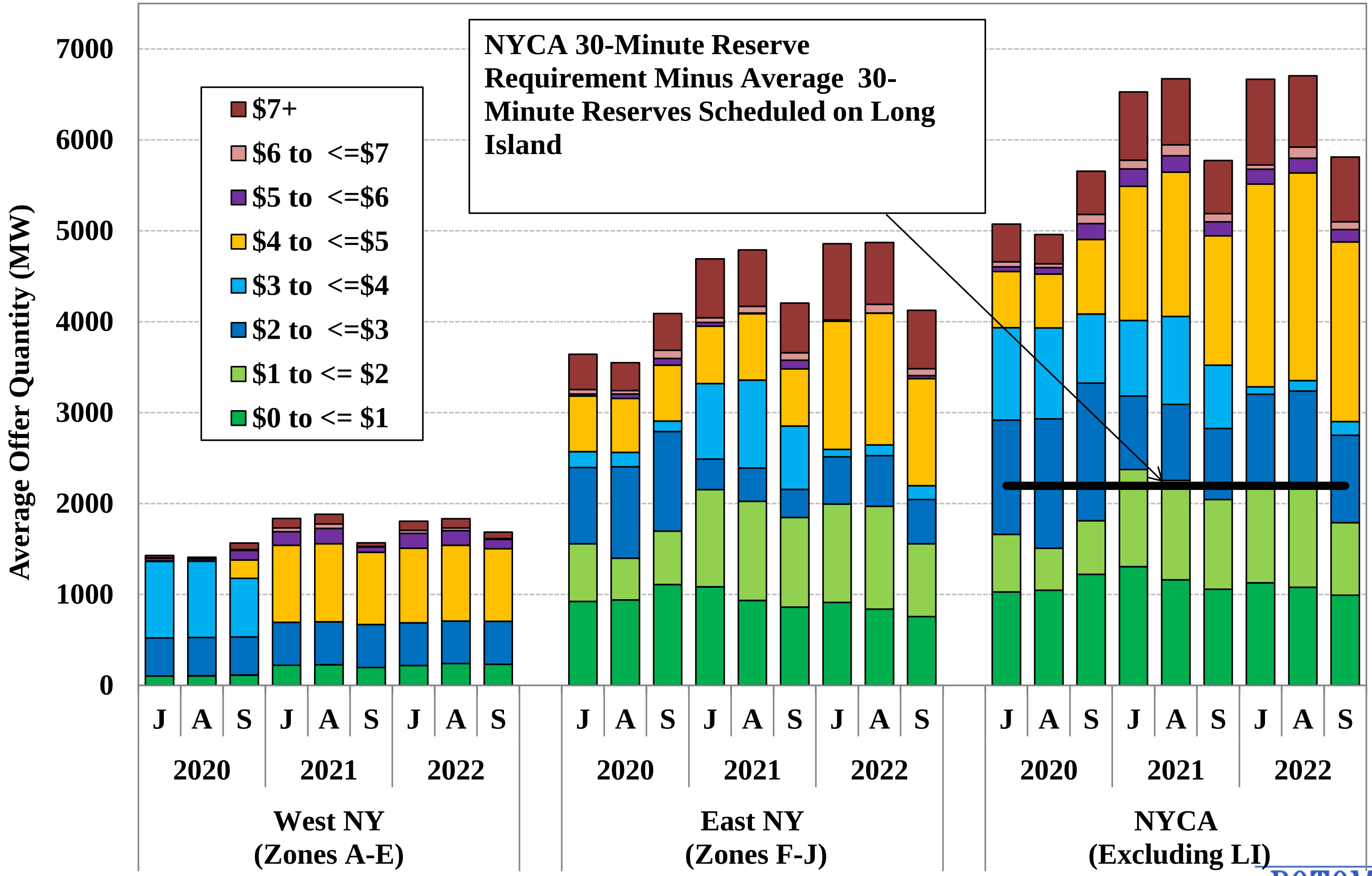
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2021Q3	$3.26	$0.44	$3.25	126
	2022Q3	$5.30	$1.41	$5.30	386
SENY 30-min	2021Q3	$3.41	$0.59	$3.36	0
	2022Q3	$5.51	$2.31	$5.95	21

Notes: For chart description, see slide 97.

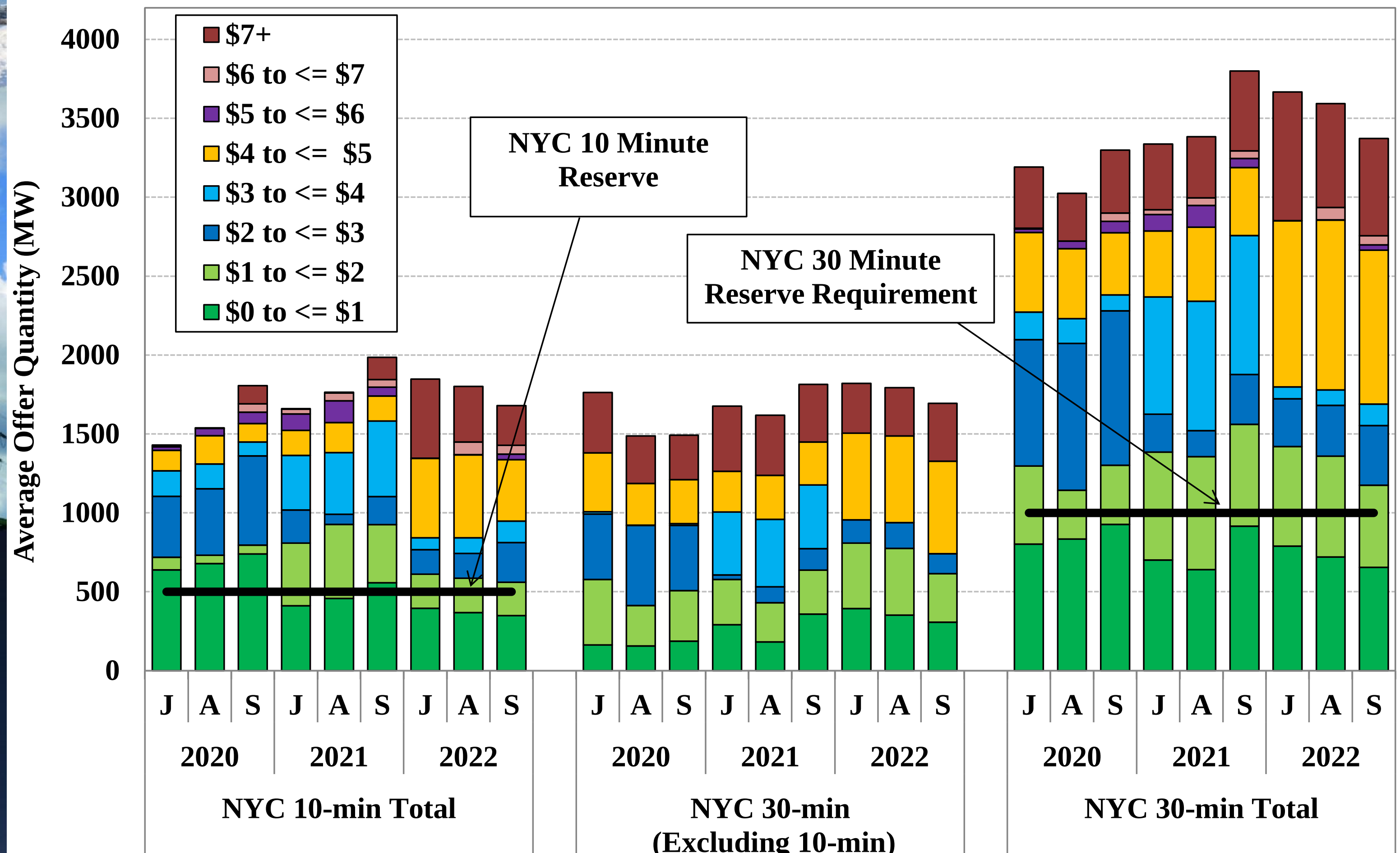
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 98.

POTOMAC ECONOMICS

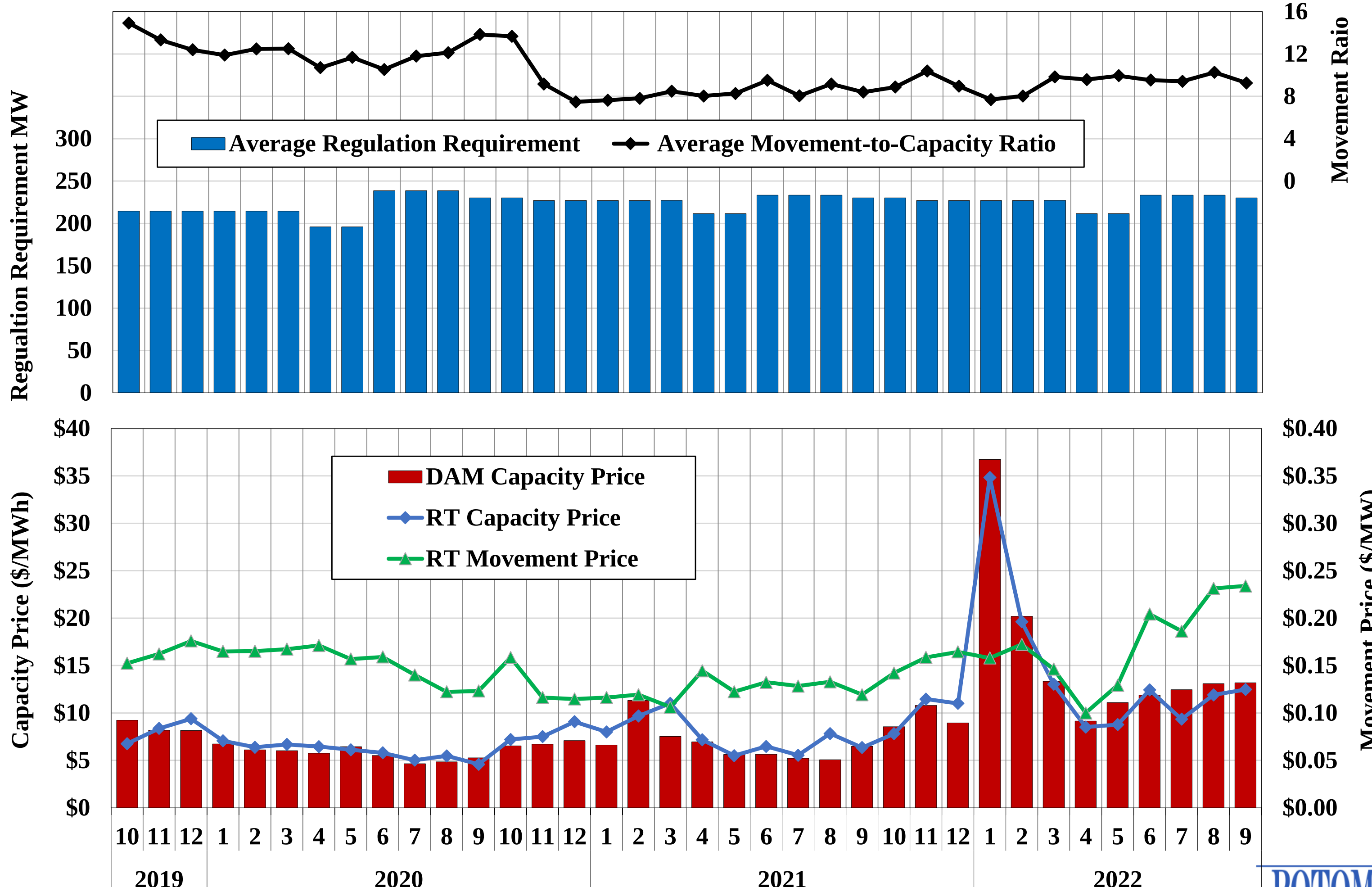
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



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

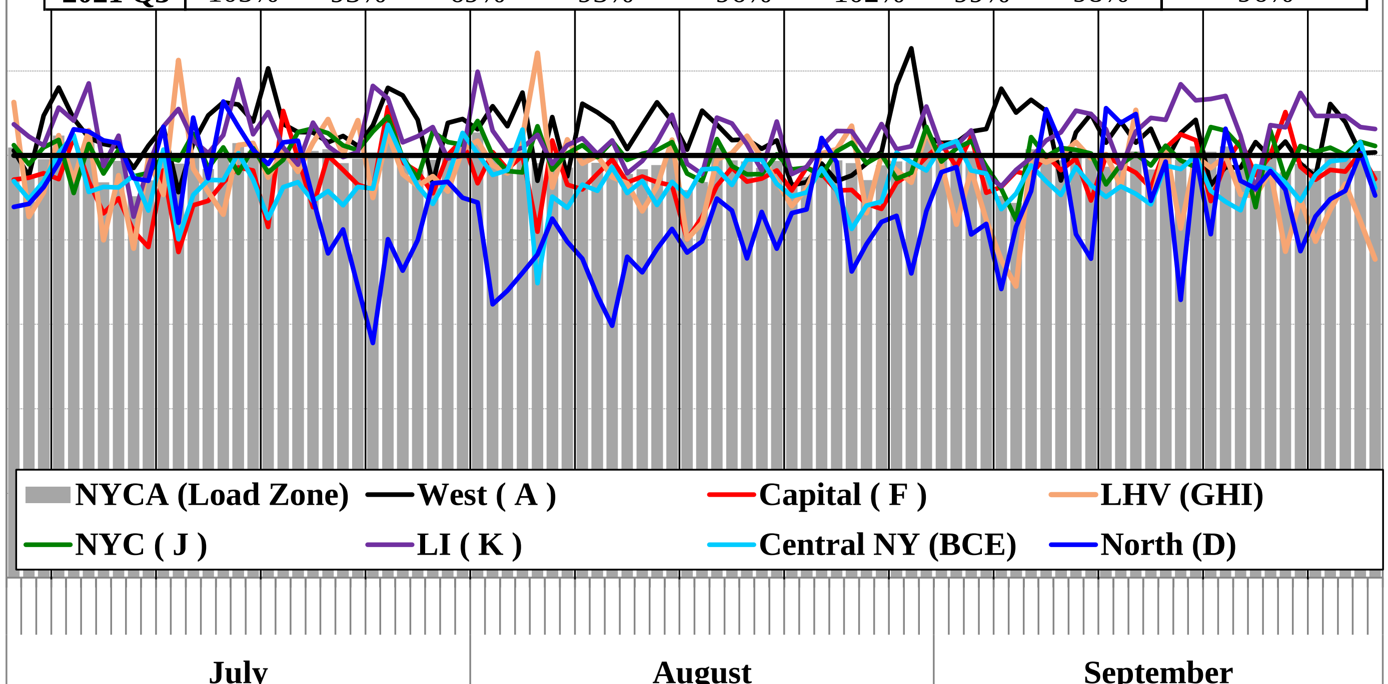
Charts:

Energy Market Scheduling

POTOMAC ECONOMICS

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

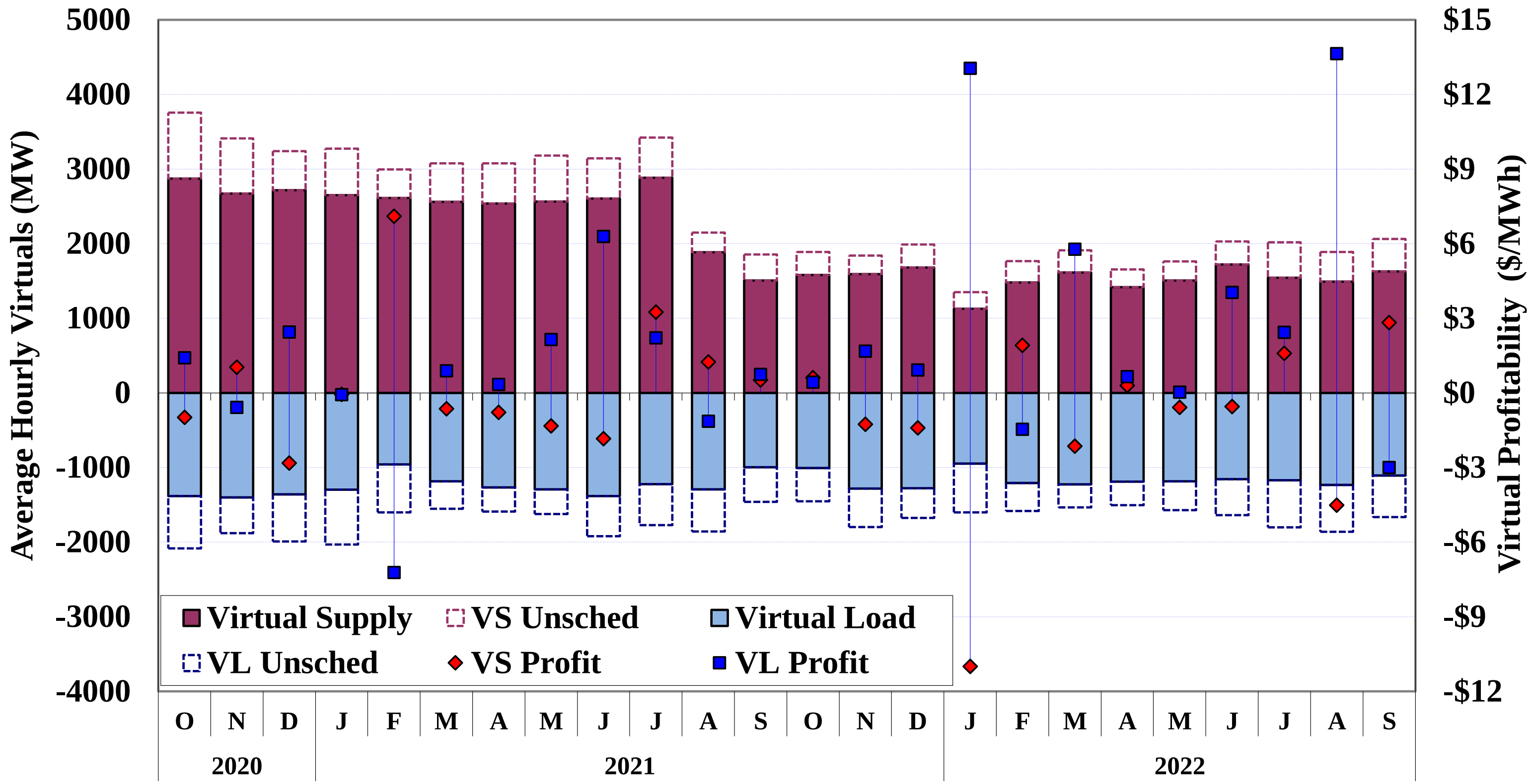
Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2022 Q3	105%	94%	88%	95%	96%	100%	104%	99%	97%
2022 Q2	109%	94%	86%	93%	96%	97%	104%	98%	96%
2021 Q3	105%	93%	69%	93%	96%	102%	99%	98%	96%



Notes: For chart description, see slide 100.

POTOMAC ECONOMICS

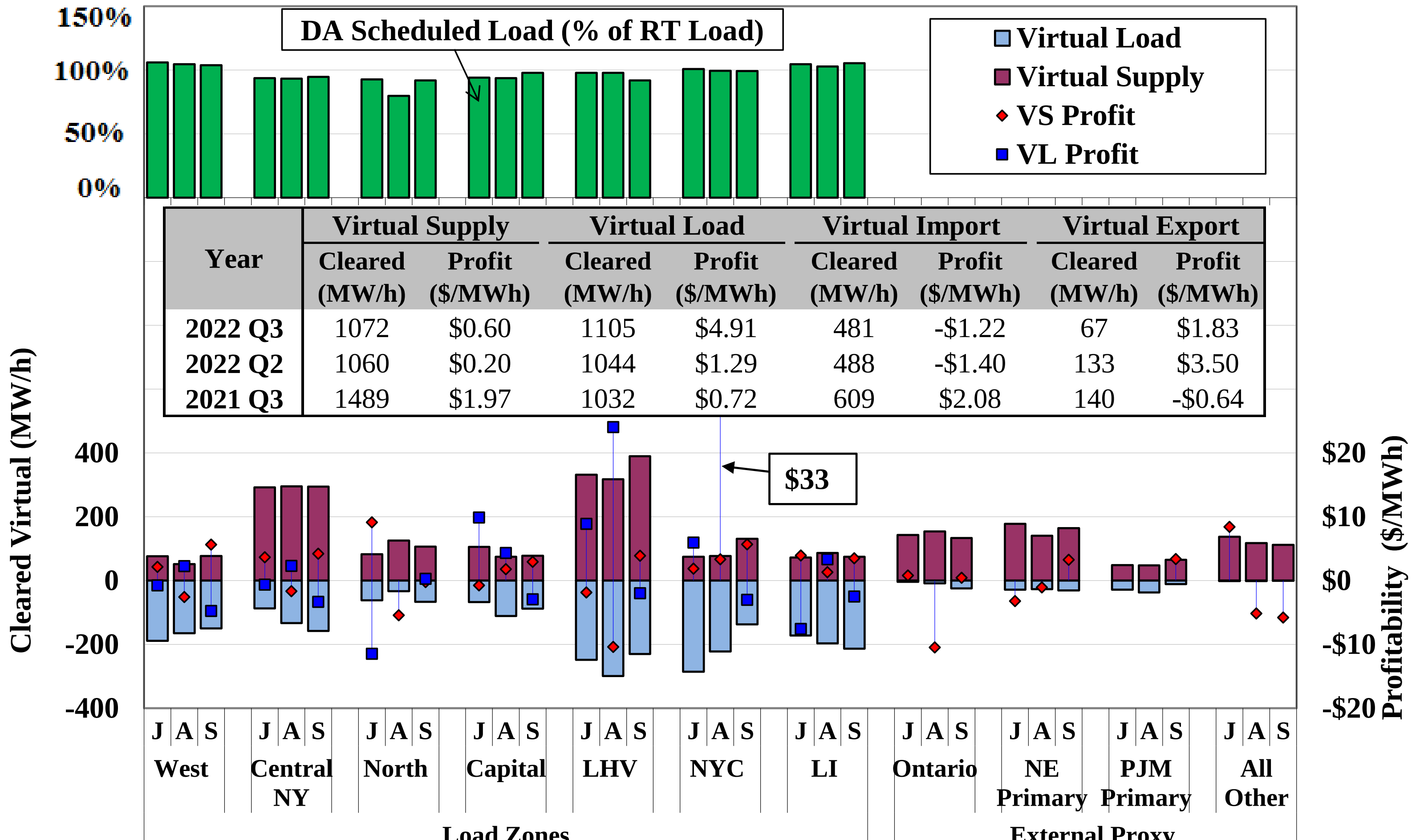
Virtual Trading Activity
by Month



Profit > 50% of Avg. Zone Price	MW	235	619	375	320	658	514	549	378	325	413	158	158	96	182	195	225	307	217	291	324	183	228	153	96
	%	6%	15%	9%	8%	18%	14%	14%	10%	8%	10%	5%	6%	4%	6%	7%	11%	11%	8%	11%	12%	6%	8%	6%	4%
Loss > 50% of Avg. Zone Price	MW	312	528	440	283	388	491	688	498	271	234	174	140	88	197	215	208	278	226	306	304	180	183	124	109
	%	7%	13%	11%	7%	11%	13%	18%	13%	7%	6%	5%	6%	3%	7%	7%	10%	10%	8%	12%	11%	6%	7%	5%	4%

Notes: For chart description, see slide 100.

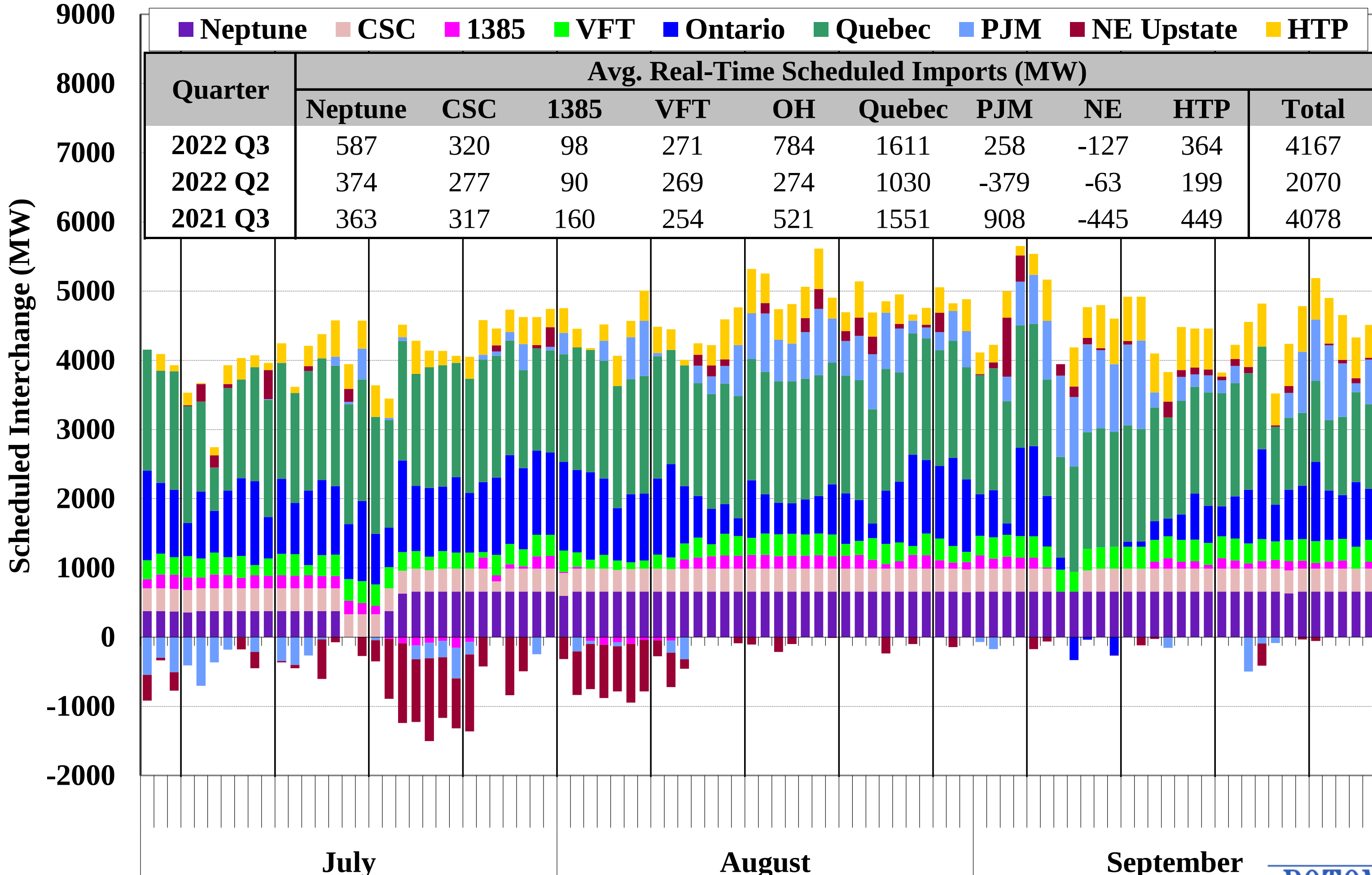
Virtual Trading Activity by Location



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)
2022 Q3	1072	$0.60	1105	$4.91	481	-$1.22	67	$1.83
2022 Q2	1060	$0.20	1044	$1.29	488	-$1.40	133	$3.50
2021 Q3	1489	$1.97	1032	$0.72	609	$2.08	140	-$0.64

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.

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
2022 Q3	587	320	98	271	784	1611	258	-127	364	4167
2022 Q2	374	277	90	269	274	1030	-379	-63	199	2070
2021 Q3	363	317	160	254	521	1551	908	-445	449	4078

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 > $20	Total	
% of All Intervals w/ Adjustment			72%	19%	**91%**		45%	17%	**62%**	
Average Flow Adjustment (MW)	Net Imports		32	41	**34**		19	-6	**12**	
	Gross		105	150	**114**		74	88	**78**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$2.9	$2.8	**$5.7**		$0.7	$1.5	**$2.2**	
	Net Over-Projection by:	NY	-$0.2	-$0.9	**-$1.1**		-$0.1	-$0.4	**-$0.4**	
		NE or PJM	-$0.1	-$0.1	**-$0.2**		-$0.1	-$0.5	**-$0.6**	
	Other Unrealized Savings		-$0.1	-$0.8	**-$0.8**		$0.0	$0.0	**-$0.1**	
	Actual Savings		$2.5	$1.1	**$3.6**		$0.6	$0.6	**$1.1**	
Interface Prices ($/MWh)	NY	Actual	$72.02	$149.34	**$88.11**	**$86.49**	$70.67	$129.51	**$86.86**	**$84.00**
		Forecast	$73.30	$145.34	**$88.29**	**$86.77**	$72.01	$125.37	**$86.69**	**$83.55**
	NE or PJM	Actual	$69.11	$139.78	**$83.81**	**$81.59**	$66.73	$124.61	**$82.65**	**$80.12**
		Forecast	$68.05	$138.21	**$82.65**	**$80.49**	$68.85	$147.39	**$90.46**	**$88.12**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.28	-$4.01	**$0.18**	**$0.28**	$1.34	-$4.14	**-$0.17**	**-$0.44**
		Abs. Val.	$4.29	$65.72	**$17.07**	**$16.33**	$3.79	$34.68	**$12.29**	**$10.63**
	NE or PJM	Fcst. - Act.	-$1.06	-$1.57	**-$1.16**	**-$1.10**	$2.12	$22.78	**$7.80**	**$8.00**
		Abs. Val.	$4.02	$38.60	**$11.21**	**$10.95**	$6.05	$56.21	**$19.85**	**$18.49**

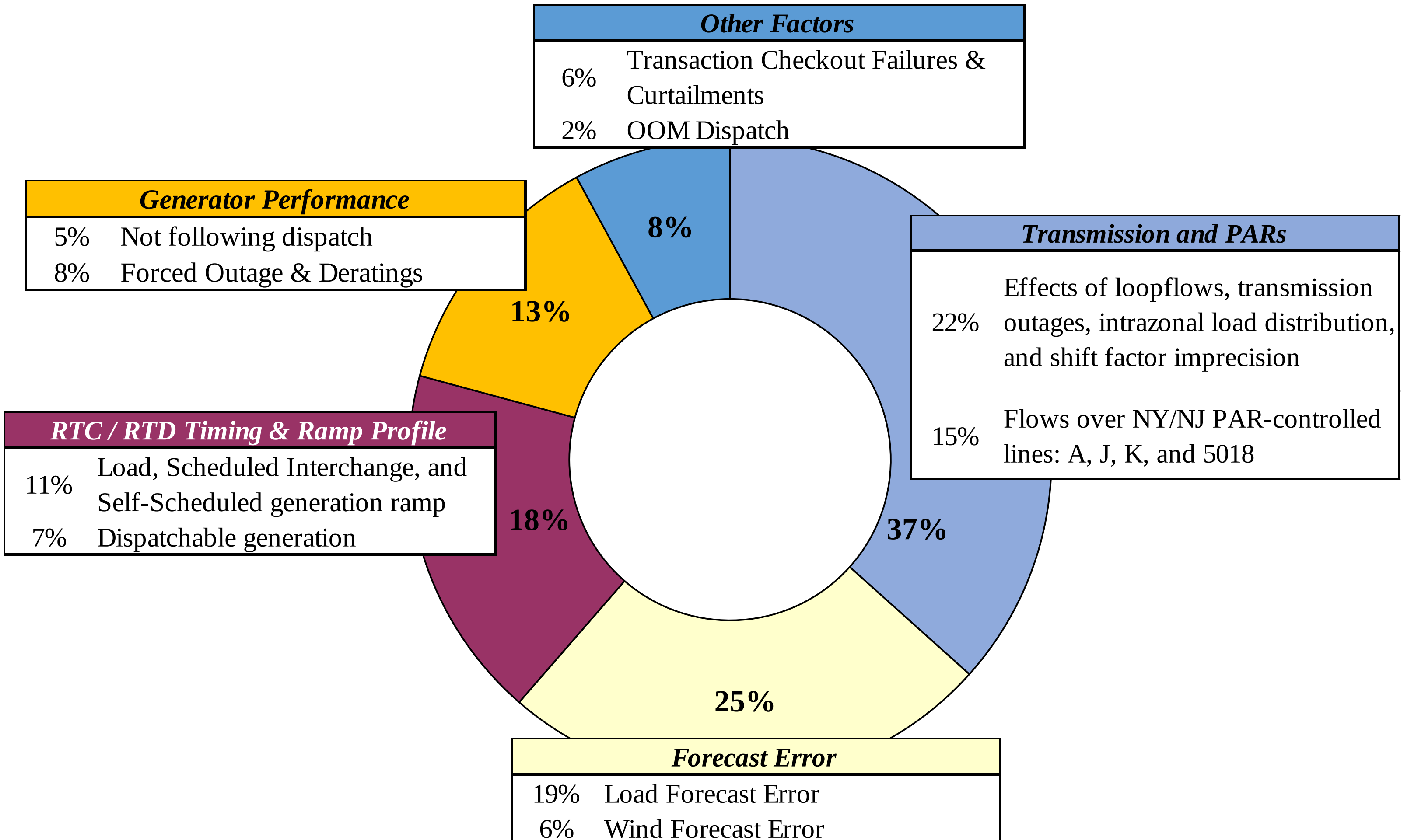
For Adjustment Intervals Only

For All Intervals

Notes: For chart description, see slide 101.

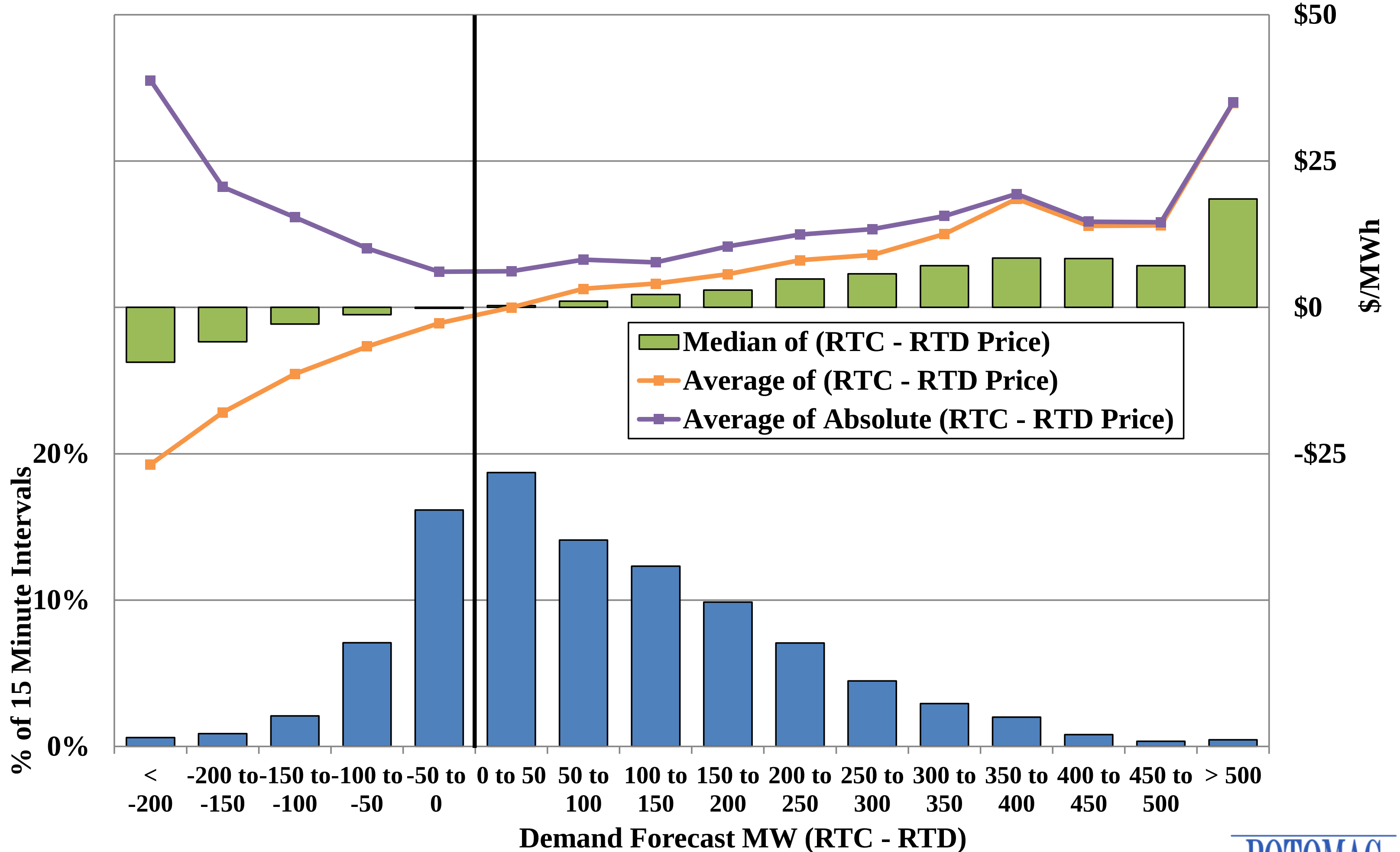
POTOMAC ECONOMICS

Detrimental Factors to RTC and RTD Price Divergence



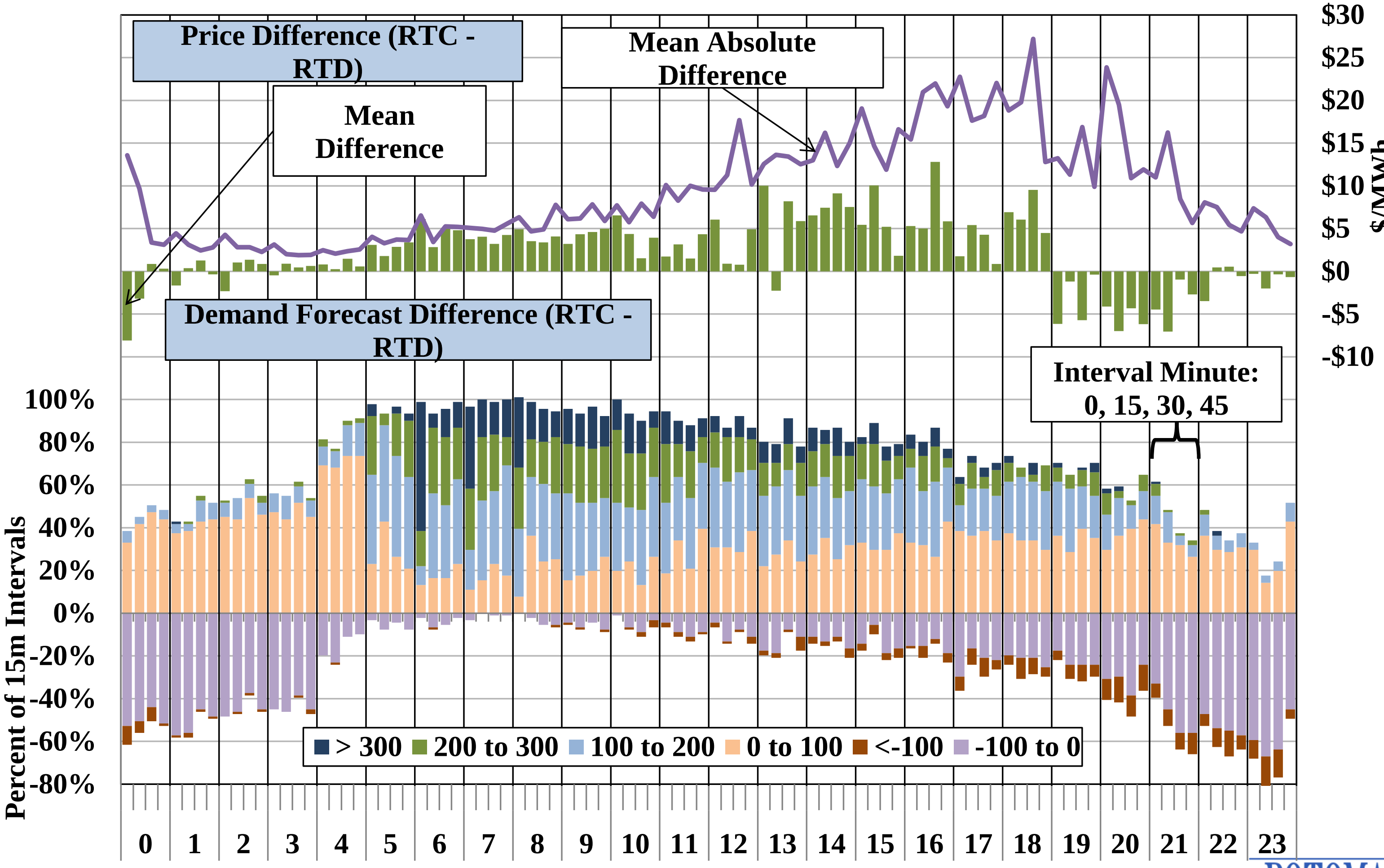
Notes: For chart description, see slide 102.

RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide 102.

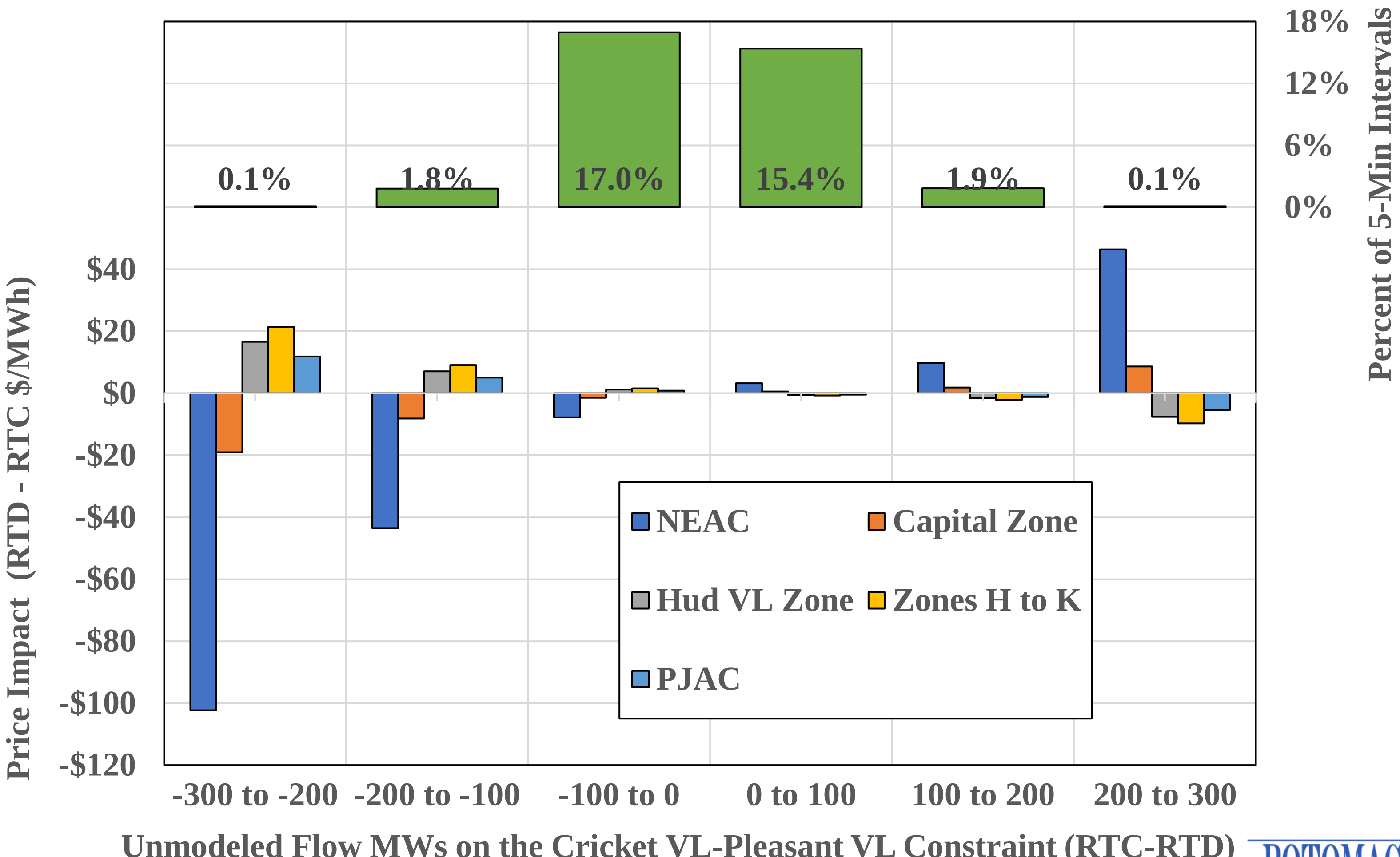
RTC and RTD Price Difference vs Demand Forecast Difference
by Time of Day



Notes: For chart description, see slide 103.

POTOMAC ECONOMICS

RTC and RTD Price Difference vs Unmodeled Flow Difference on the Cricket-PV Constraint



Notes: For chart description, see slide 104.

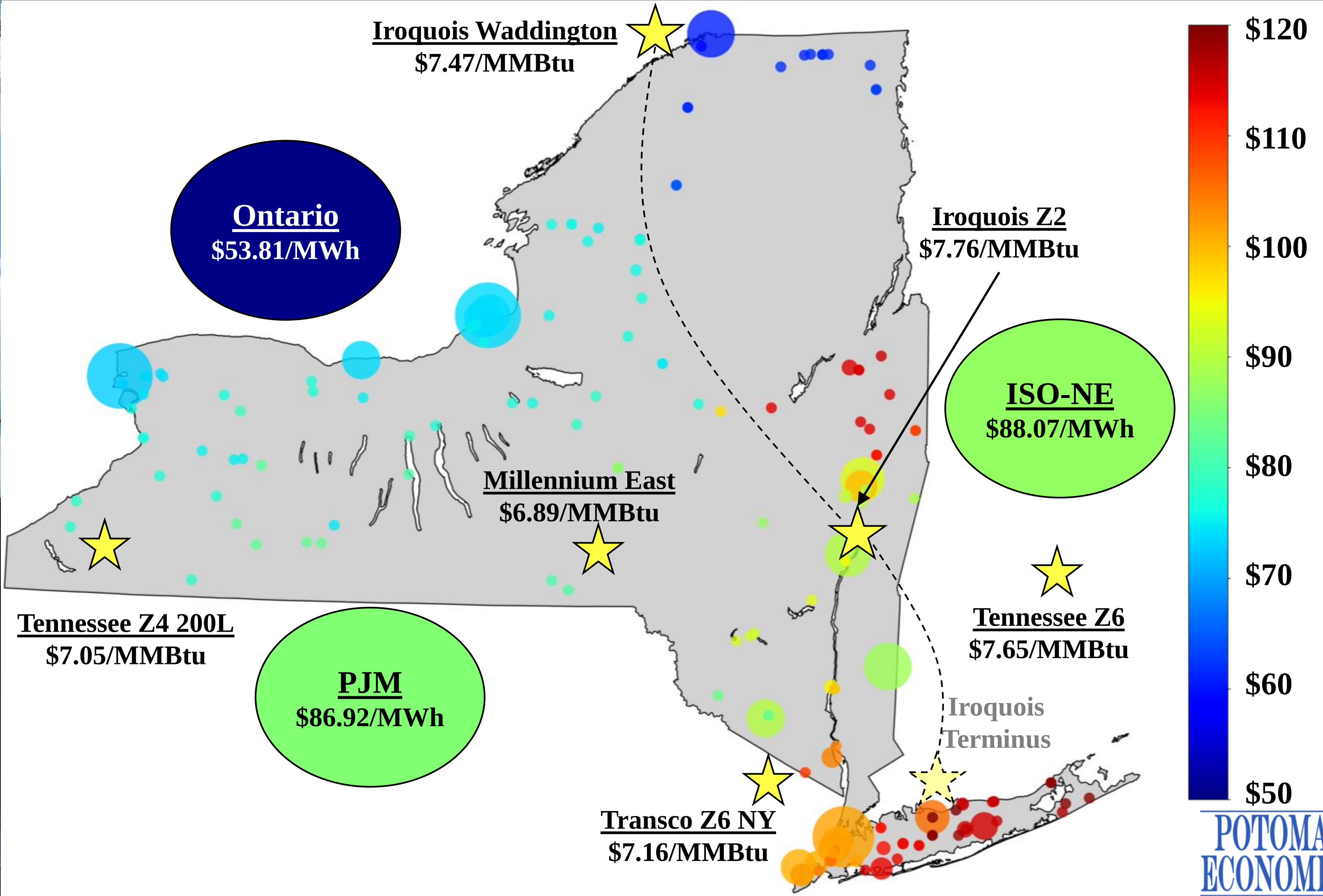
POTOMAC ECONOMICS

Charts:

Transmission Congestion Revenues and Shortfalls

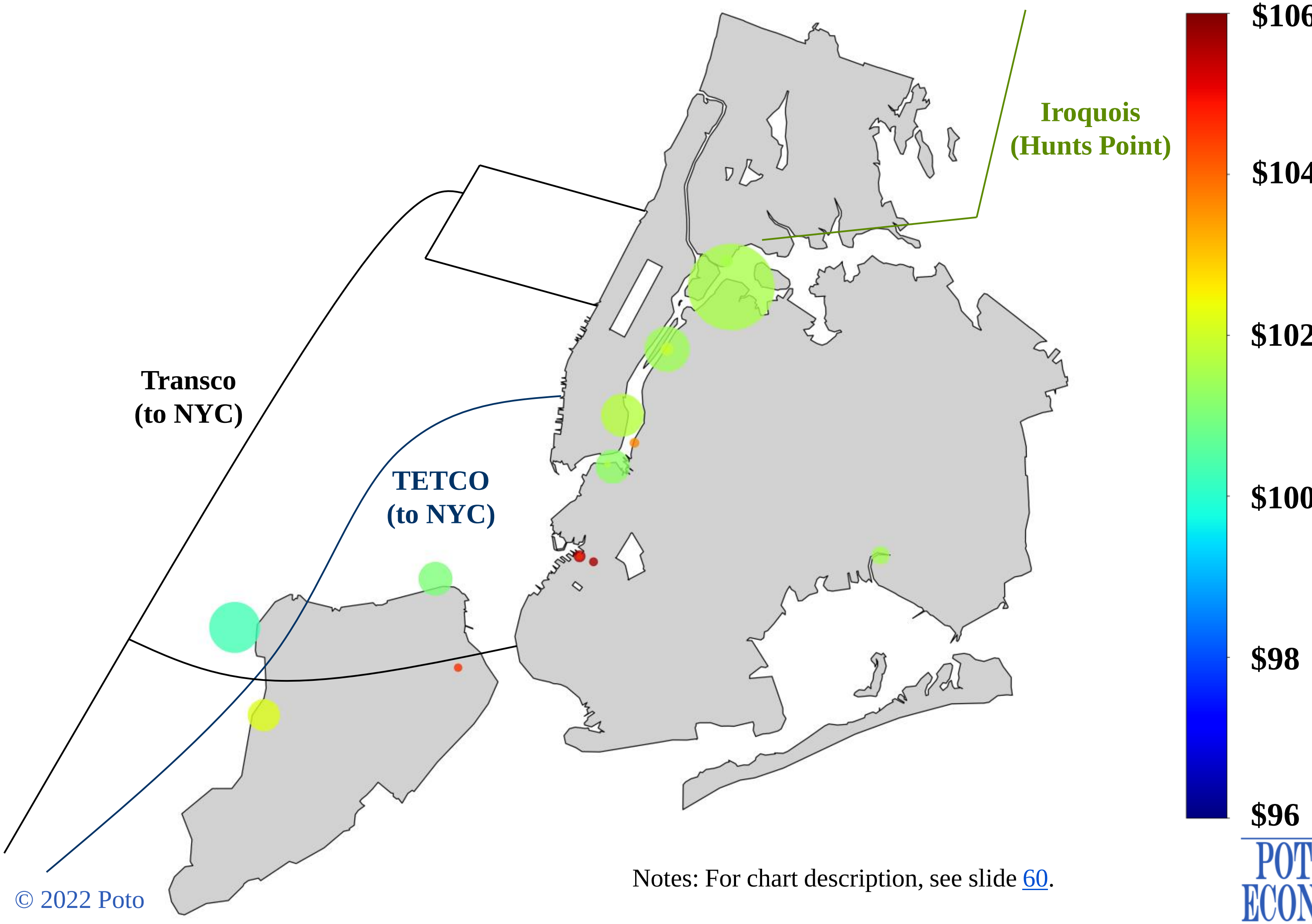
POTOMAC ECONOMICS

System Congestion
Real-Time Price Map at Generator Nodes



POTOMAC
ECONOMICS

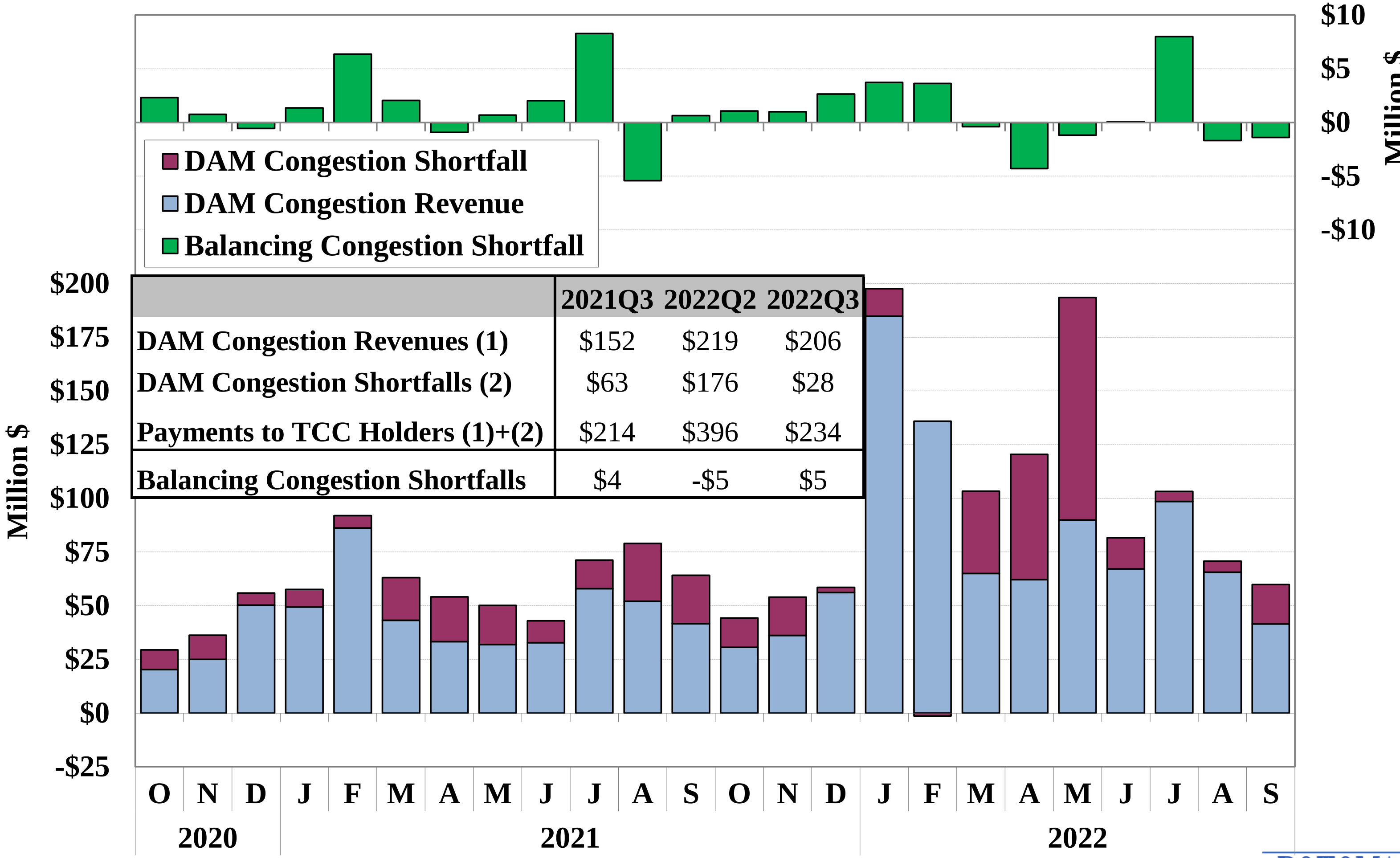
System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 60.

POTOMAC ECONOMICS

Congestion Revenues and Shortfalls by Month

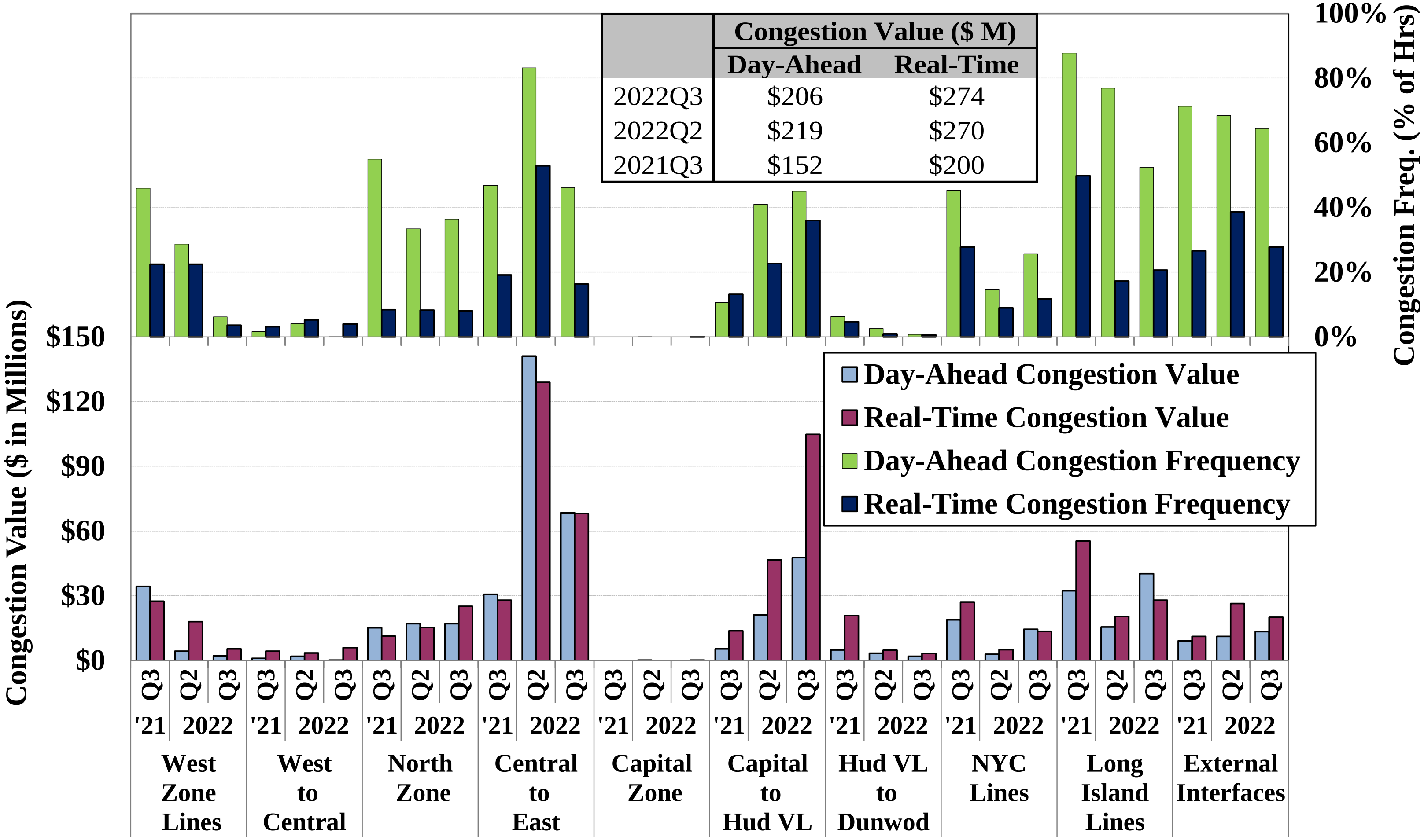


	2021Q3	2022Q2	2022Q3
DAM Congestion Revenues (1)	$152	$219	$206
DAM Congestion Shortfalls (2)	$63	$176	$28
Payments to TCC Holders (1)+(2)	$214	$396	$234
Balancing Congestion Shortfalls	$4	-$5	$5

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

POTOMAC ECONOMICS

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

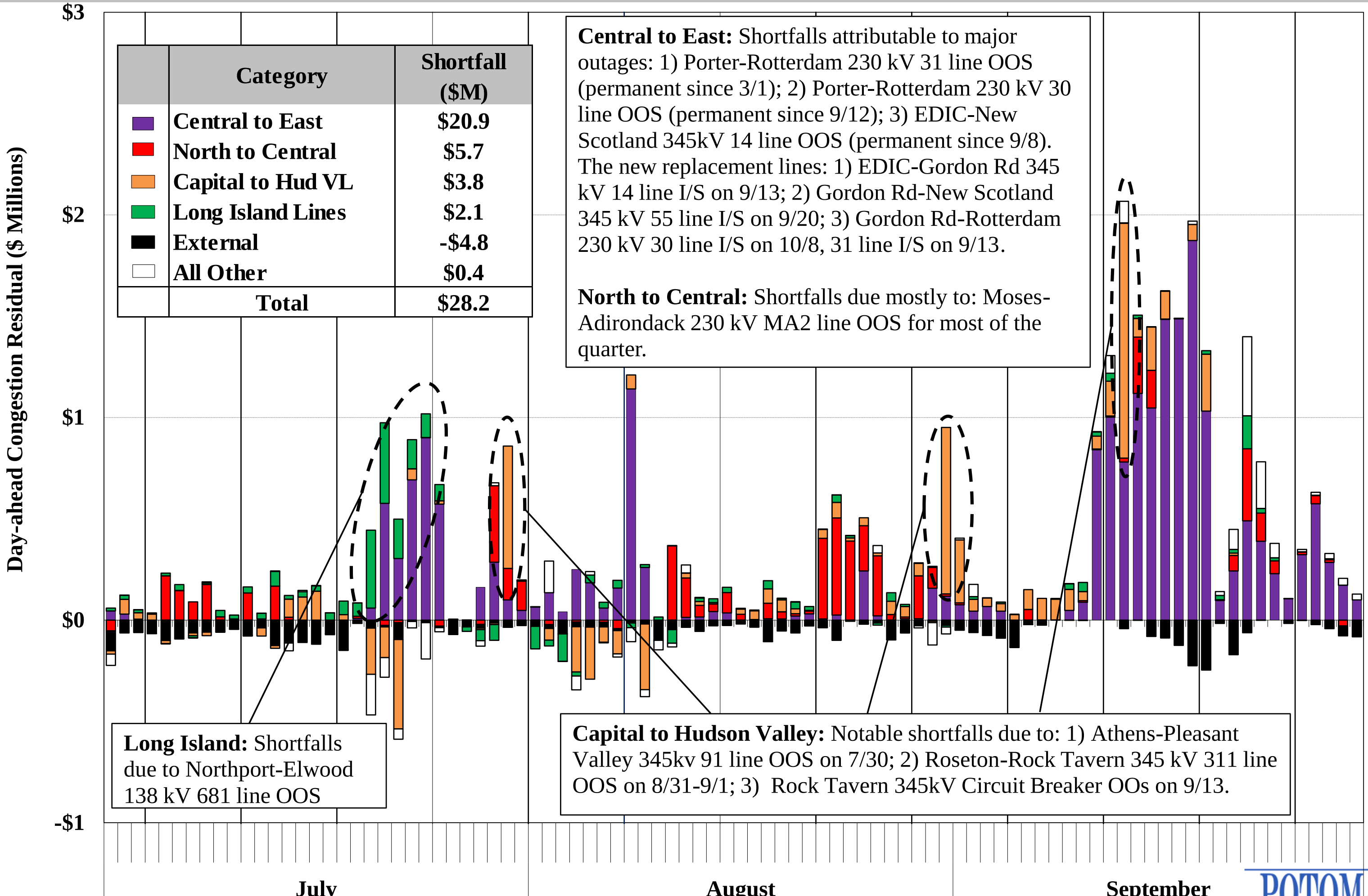


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2022Q3	$206	$274
2022Q2	$219	$270
2021Q3	$152	$200

Notes: For chart description, see slides 106, 107, and 108.

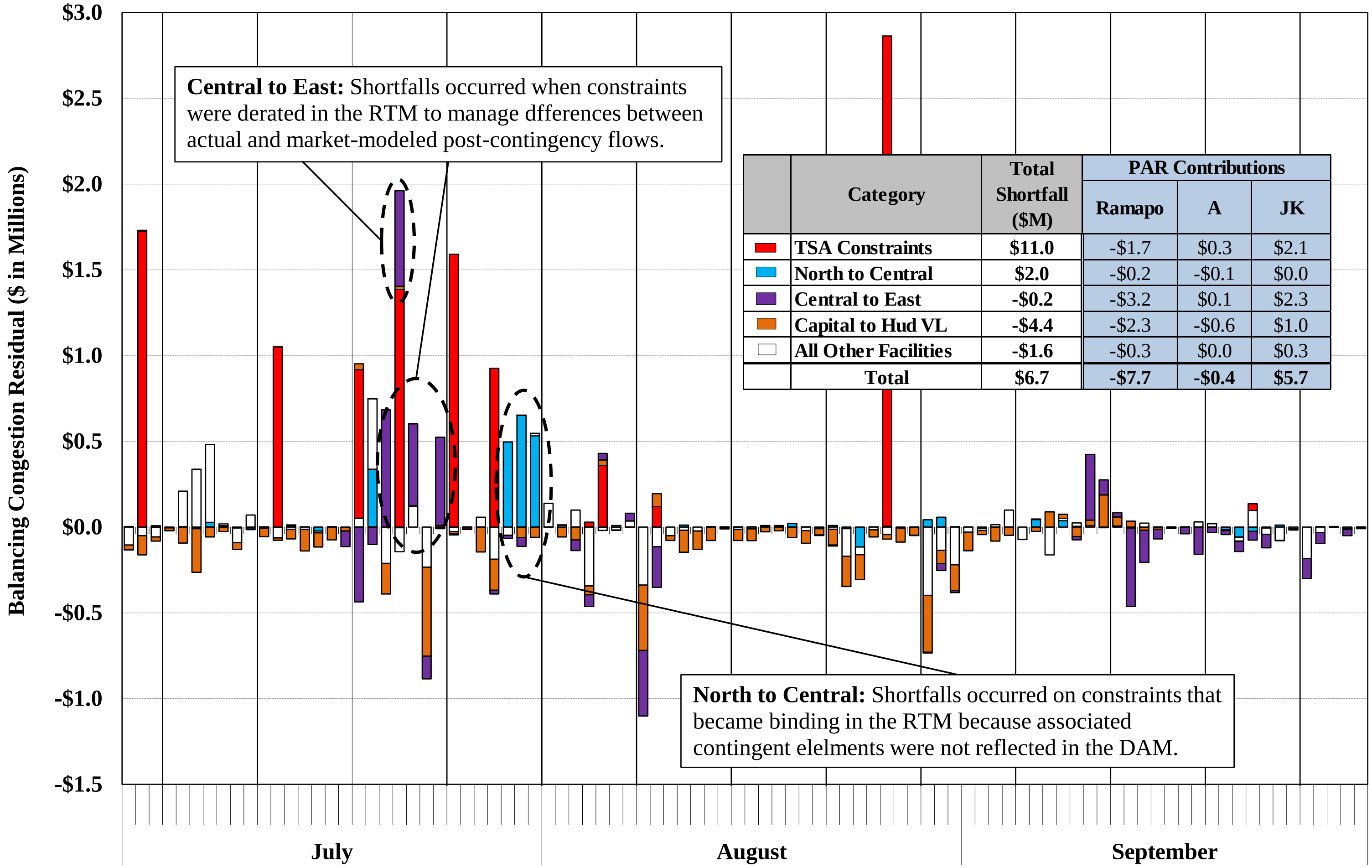
POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 106, 107, and 108.

Balancing Congestion Shortfalls by Transmission Facility

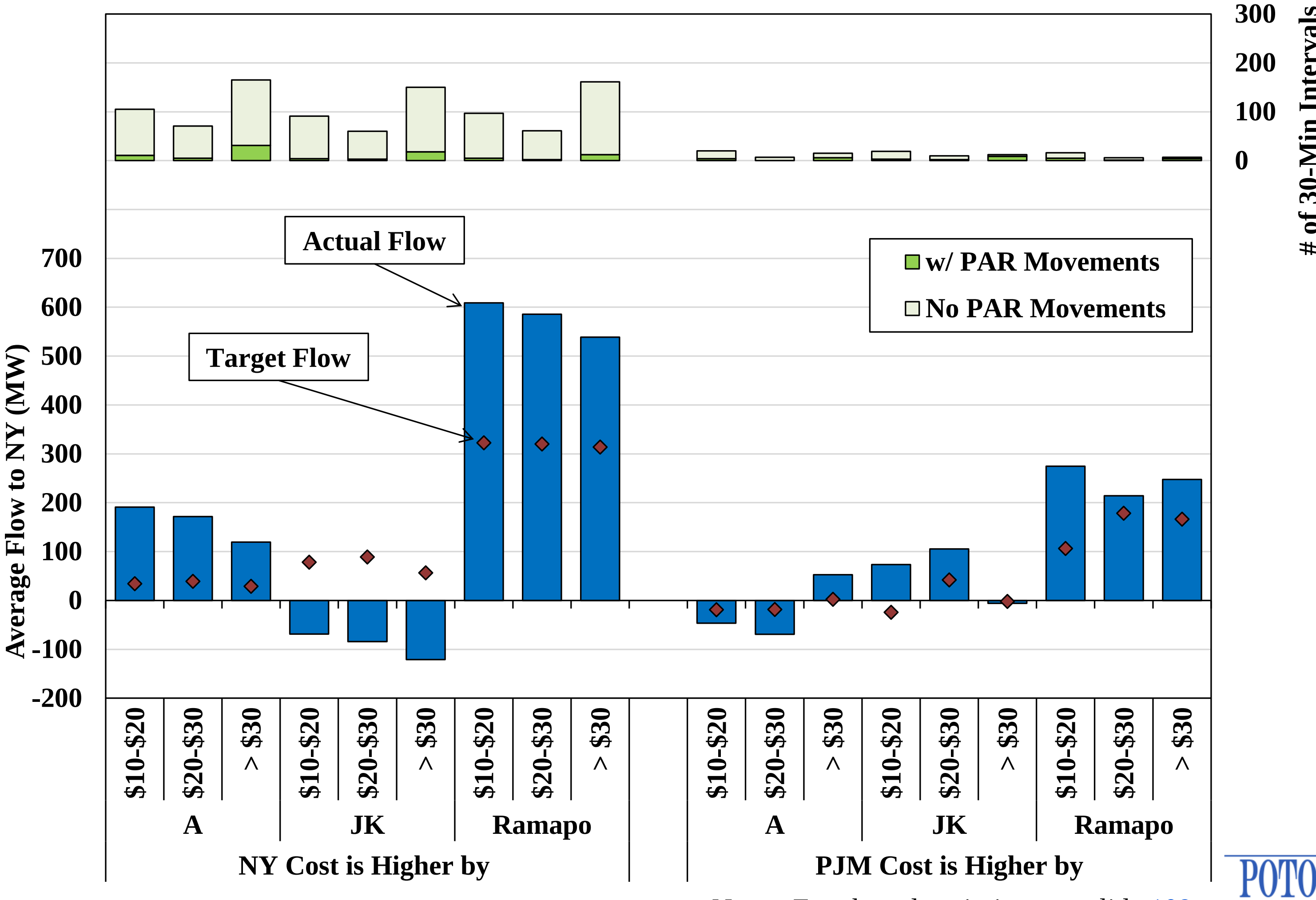


	Category	Total Shortfall ($M)	PAR Contributions		
			Ramapo	A	JK
	TSA Constraints	$11.0	-$1.7	$0.3	$2.1
	North to Central	$2.0	-$0.2	-$0.1	$0.0
	Central to East	-$0.2	-$3.2	$0.1	$2.3
	Capital to Hud VL	-$4.4	-$2.3	-$0.6	$1.0
	All Other Facilities	-$1.6	-$0.3	$0.0	$0.3
	Total	$6.7	-$7.7	-$0.4	$5.7

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 106, 107, and 108.

POTOMAC ECONOMICS

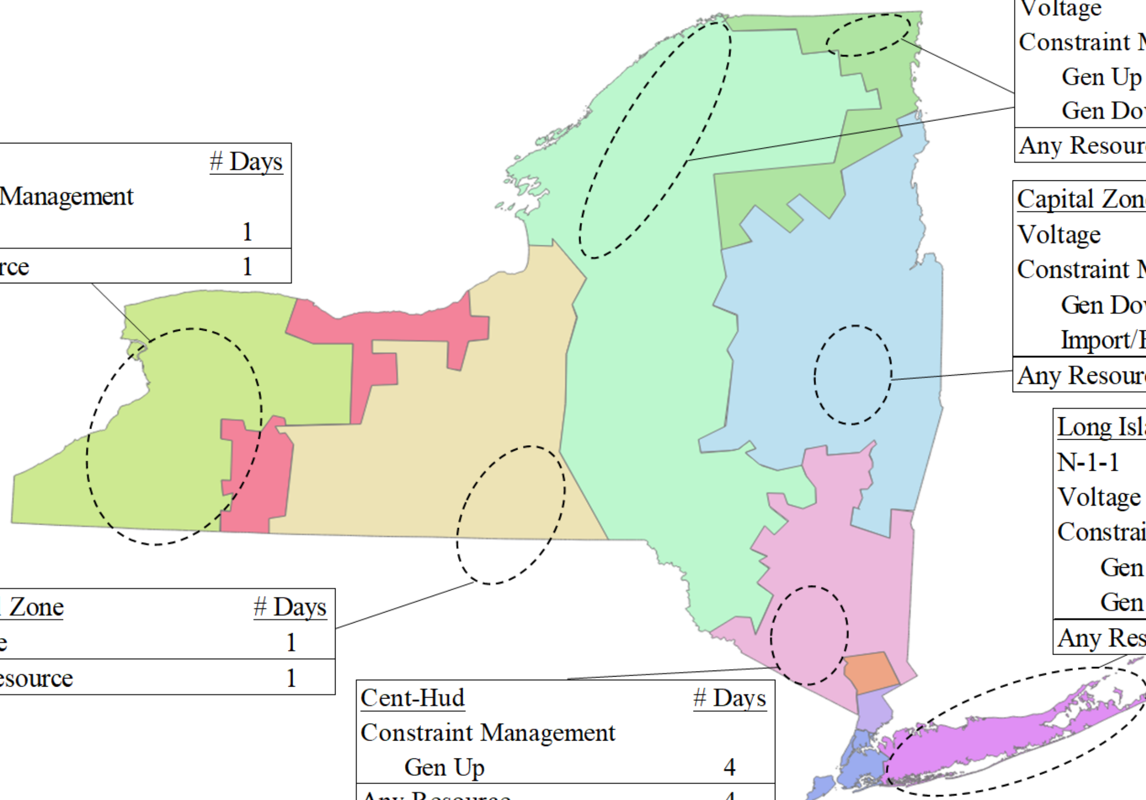
PAR Operation under M2M with PJM
2022 Q3



Notes: For chart description, see slide 109.

POTOMAC ECONOMICS

OOM Actions to Manage Network Reliability



North & MHK VL Zones	# Days
Voltage	1
Constraint Management	
Gen Up	1
Gen Down	1
Any Resource	3

West Zone	# Days
Constraint Management	
PAR	1
Any Resource	1

Capital Zone	# Days
Voltage	4
Constraint Management	
Gen Down	11
Import/Export Limitation	1
Any Resource	13

Long Island	# Days
N-1-1	6
Voltage	1
Constraint Management	
Gen Up	64
Gen Down	7
Any Resource	64

Central Zone	# Days
Voltage	1
Any Resource	1

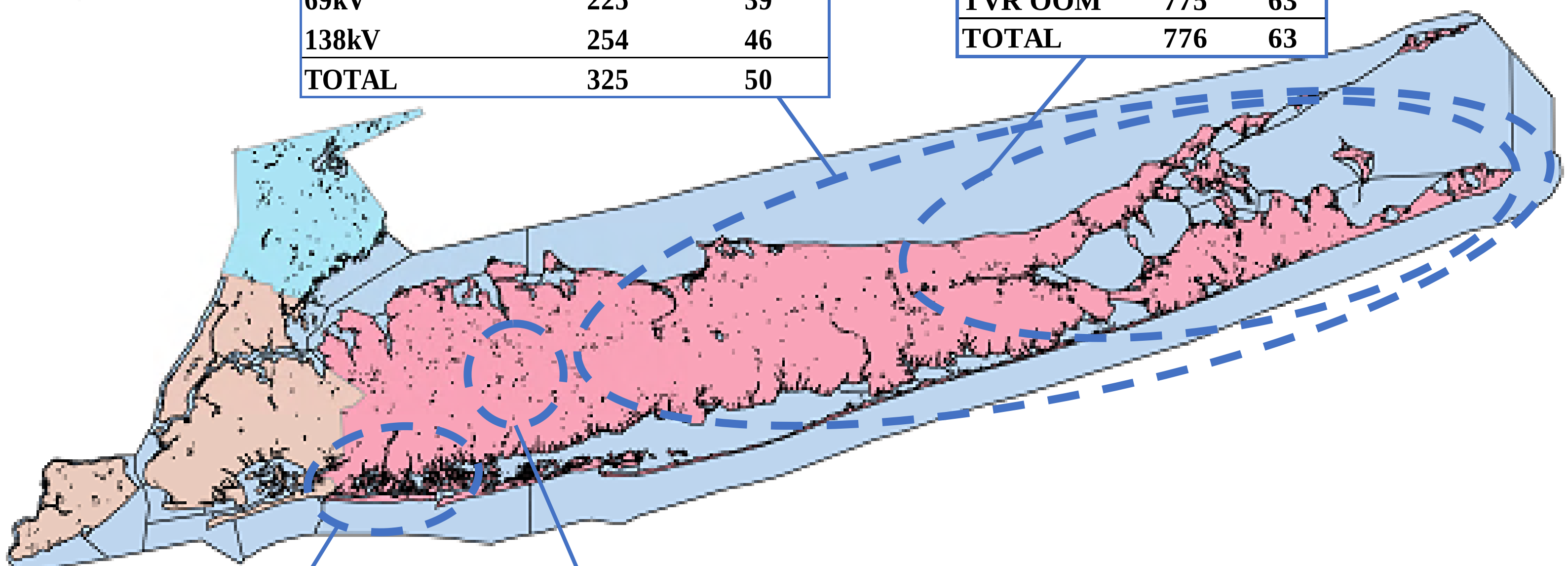
Cent-Hud	# Days
Constraint Management	
Gen Up	4
Any Resource	4

Notes: For chart description, see slides 110-111

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV OOM	36	8
69kV	225	39
138kV	254	46
TOTAL	325	50

East End	#Hours	#Days
69kV OOM	12	1
TVR OOM	775	63
TOTAL	776	63



Valley Stream	#Hours	#Days
69kV OOM	344	48
138kV	115	39
TOTAL	425	60

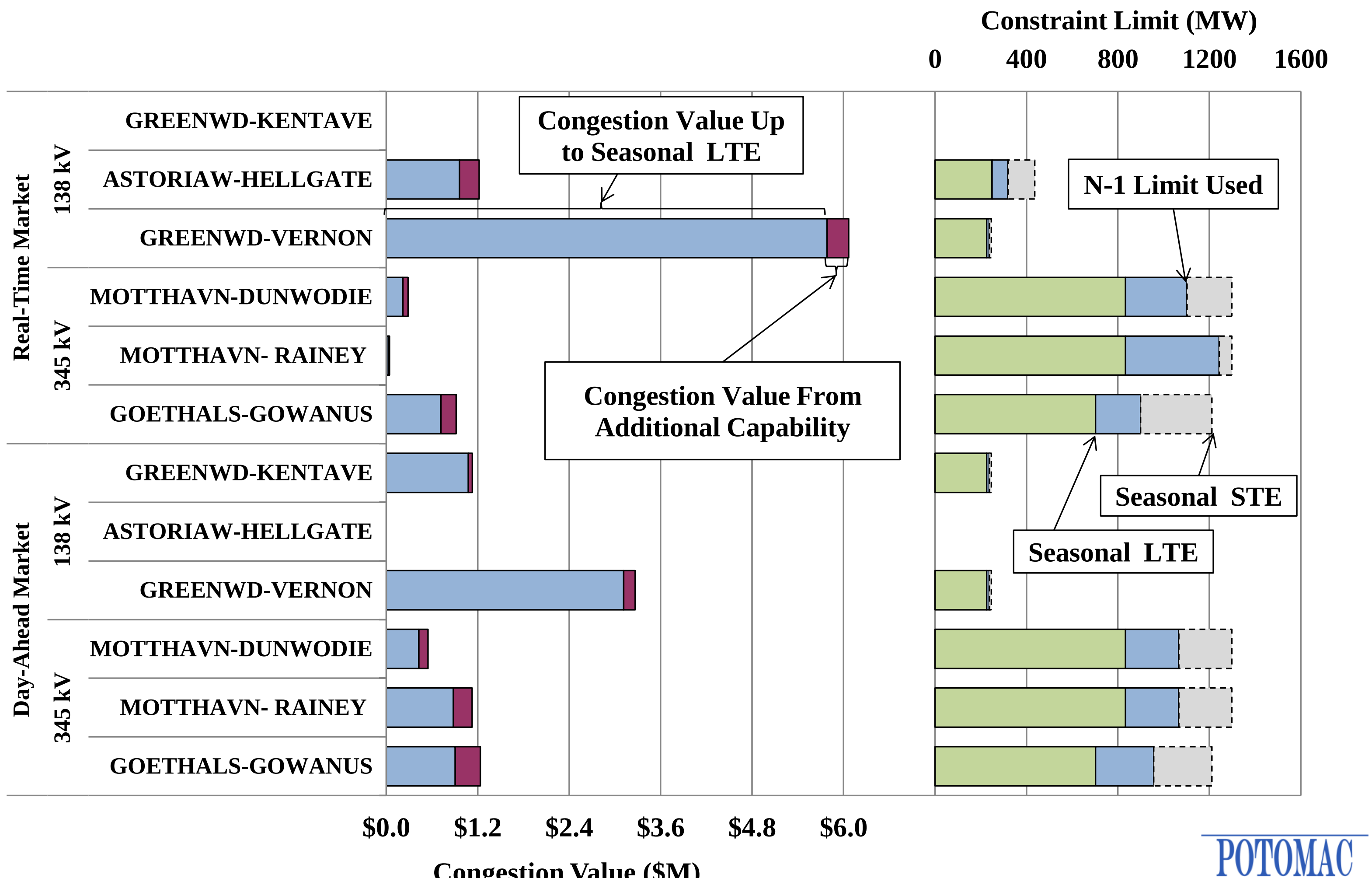
Brentwood	#Hours	#Days
69kV OOM	37	7
69kV	491	74
TOTAL	500	74

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$105.26	$105.33
East End	$105.08	$190.61
East of Northport	$101.58	$104.54
Valley Stream	$100.65	$102.61

Notes: For chart description, see slides 110-111

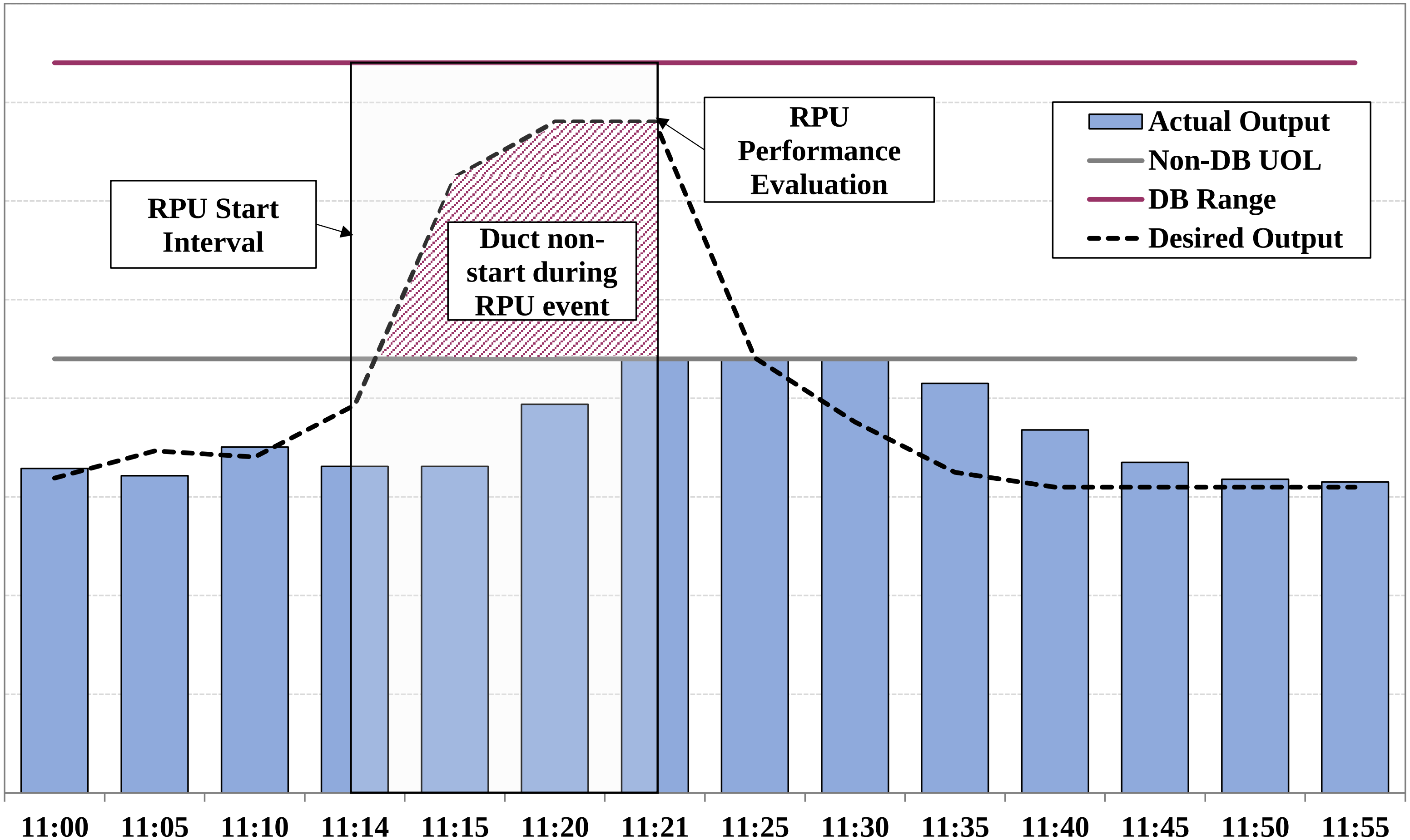
POTOMAC ECONOMICS

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



Notes: For chart description, see slide 112.

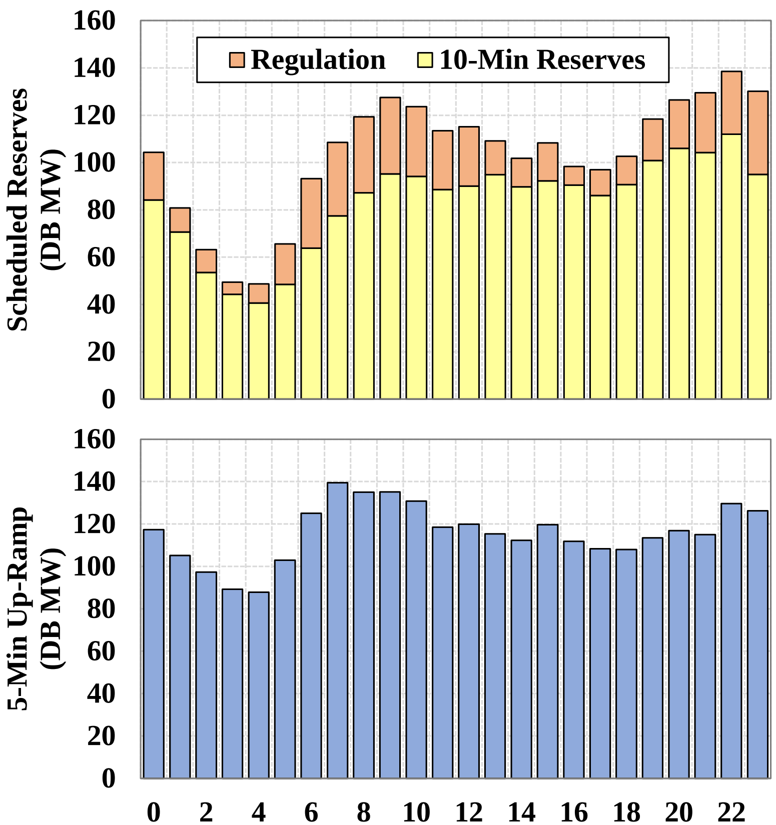
Duct Burner Real-Time Dispatch Issues
Example of a Failed RPU



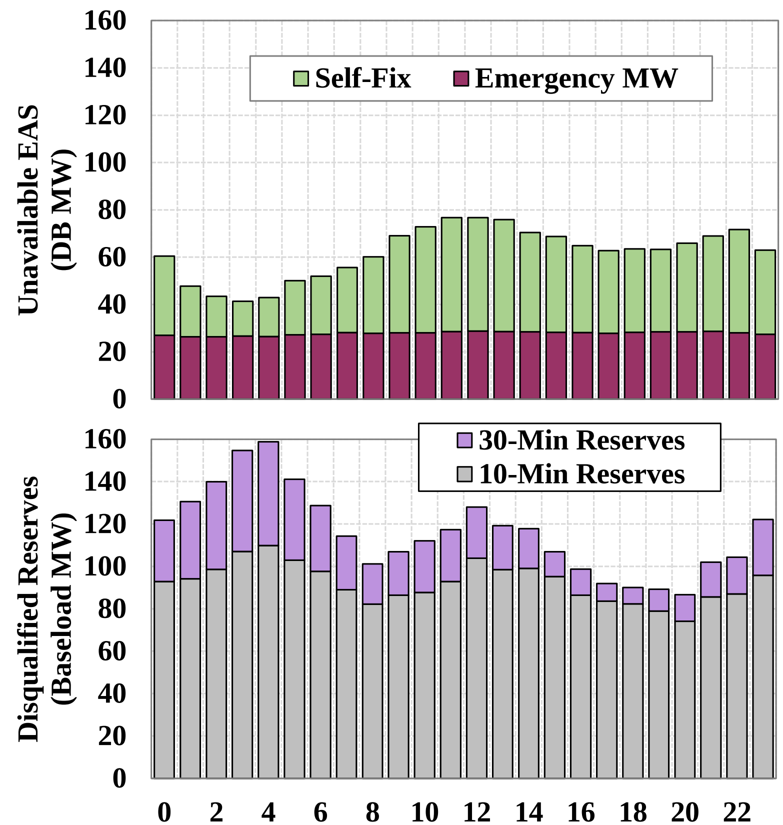
Notes: For chart description, see slide 113

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 113

POTOMAC ECONOMICS

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

10 Minute Economic GT Start Performance vs. Audit Results (October 2021 - September 2022)

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]	1	0	0	0
0% - 10%	0	0	0	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	1	2	1	2
40% - 50%	1	2	1	1
50% - 60%	3	11	3	4
60% - 70%	1	2	1	0
70% - 80%	2	6	2	1
80% - 90%	19	95	19	23
90% - 100%	25	167	25	23
TOTAL	**53**	**285**	**52**	**54**

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 114.

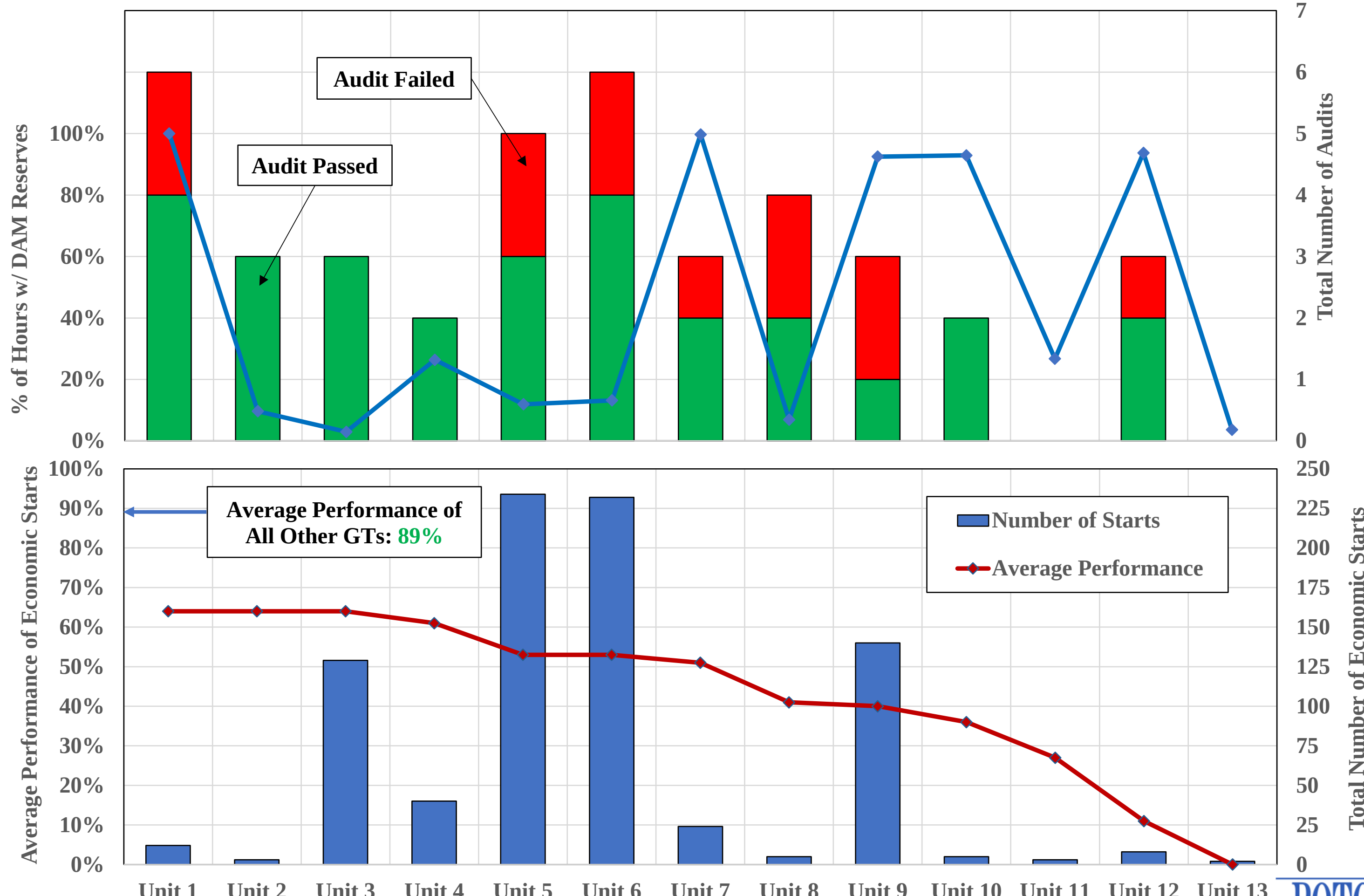
30-Minute Gas Turbine Start-up Performance
Economic Starts vs. Audits

30 Minute Economic GT Start Performance vs. Audit Results (October 2021 - September 2022)				
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]	25	40	22	2
0% - 10%	1	0	0	0
10% - 20%	1	1	1	0
20% - 30%	0	0	0	0
30% - 40%	1	0	0	0
40% - 50%	0	0	0	0
50% - 60%	0	0	0	0
60% - 70%	3	8	3	2
70% - 80%	3	9	3	2
80% - 90%	21	40	19	2
90% - 100%	32	63	30	1
TOTAL	**87**	**161**	**78**	**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 114.

Gas Turbines with Worst Start-up Performance
October 2020 to September 2022



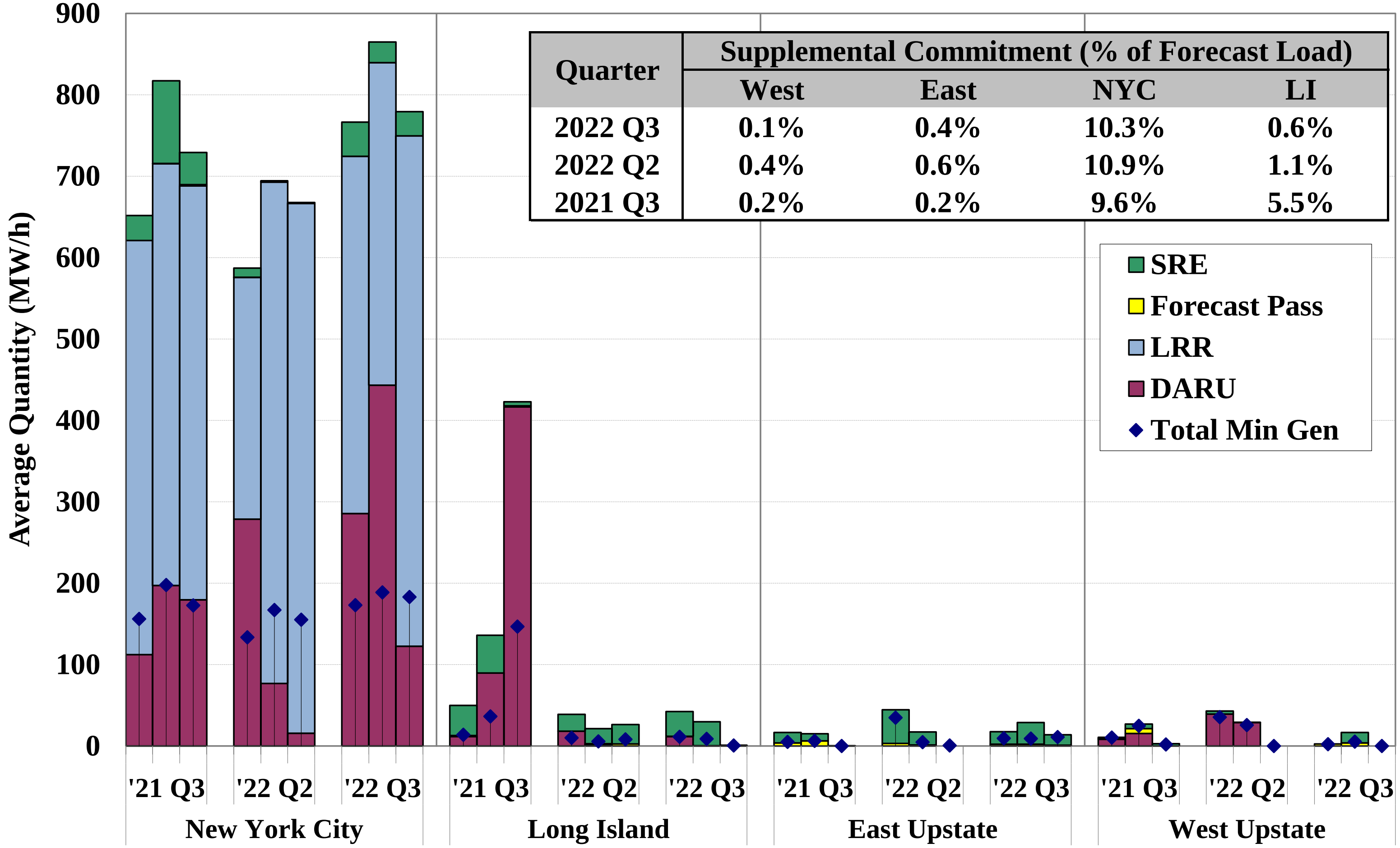
Notes: For chart description, see slide 115.

POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability
by Category and Region

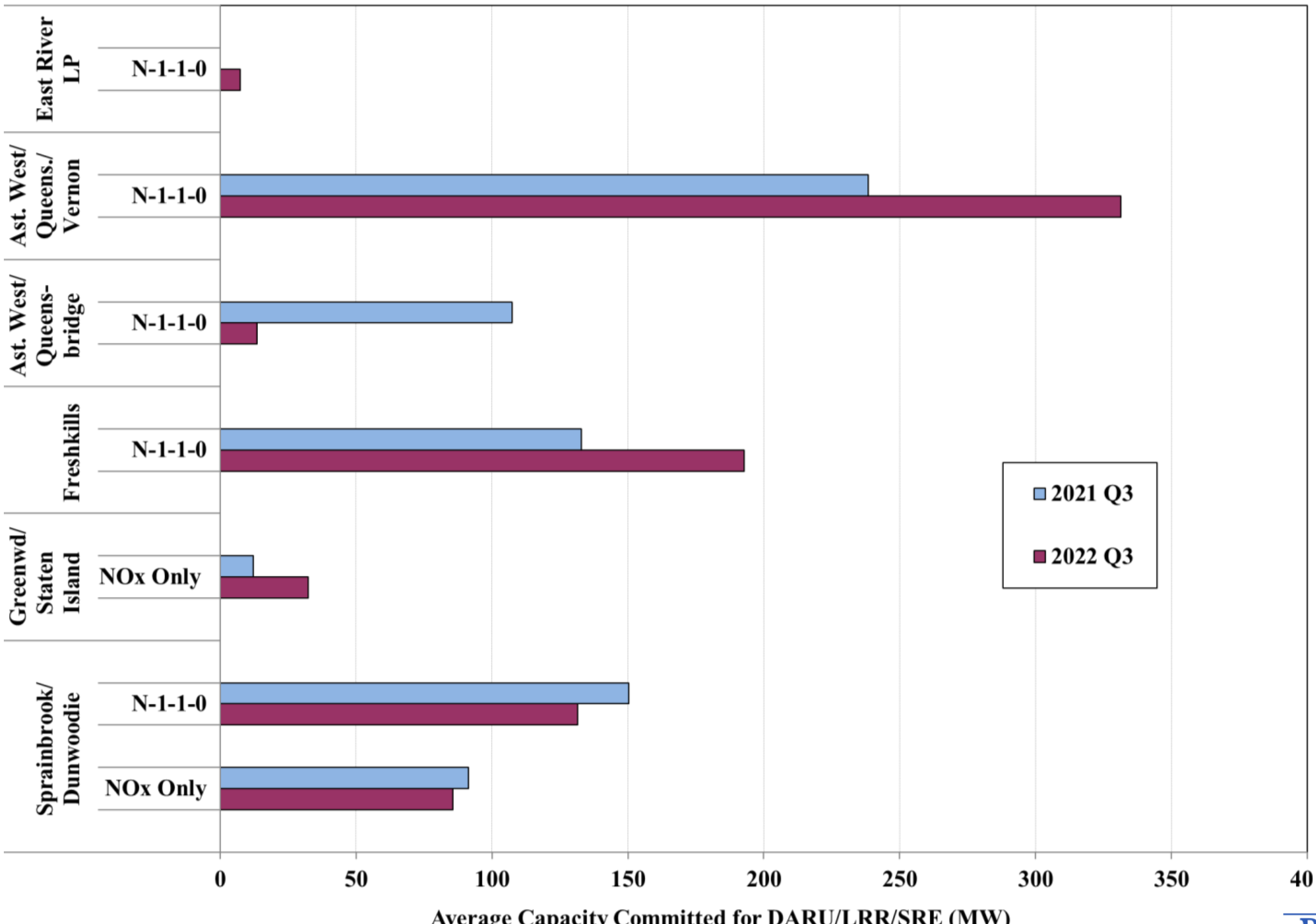


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2022 Q3	0.1%	0.4%	10.3%	0.6%
2022 Q2	0.4%	0.6%	10.9%	1.1%
2021 Q3	0.2%	0.2%	9.6%	5.5%

Notes: For chart description, see slides 116 and 117.

POTOMAC ECONOMICS

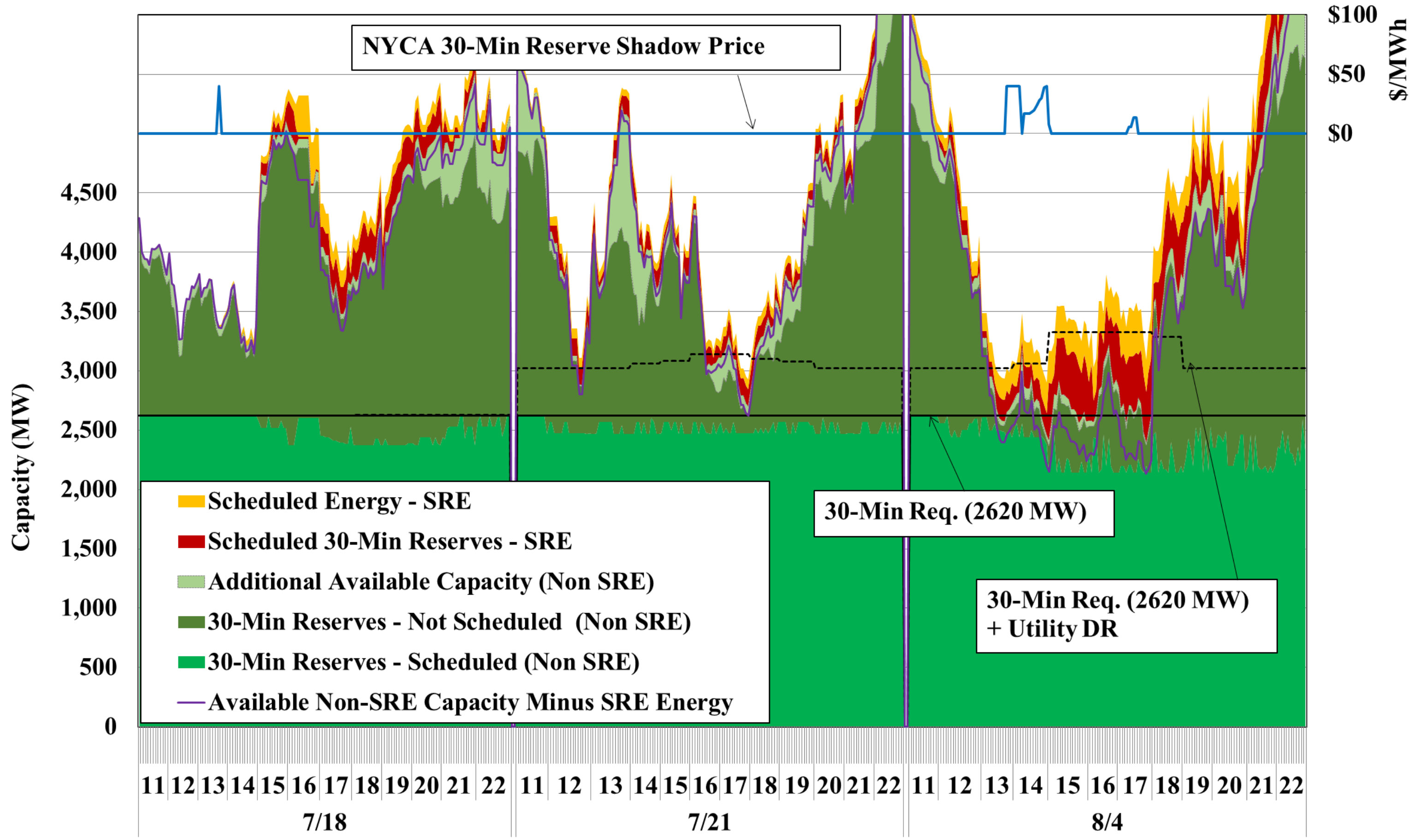
Supplemental Commitment for Reliability in NYC
by Reliability Reason and Load Pocket



Notes: For chart description, see slides 116 and 117.

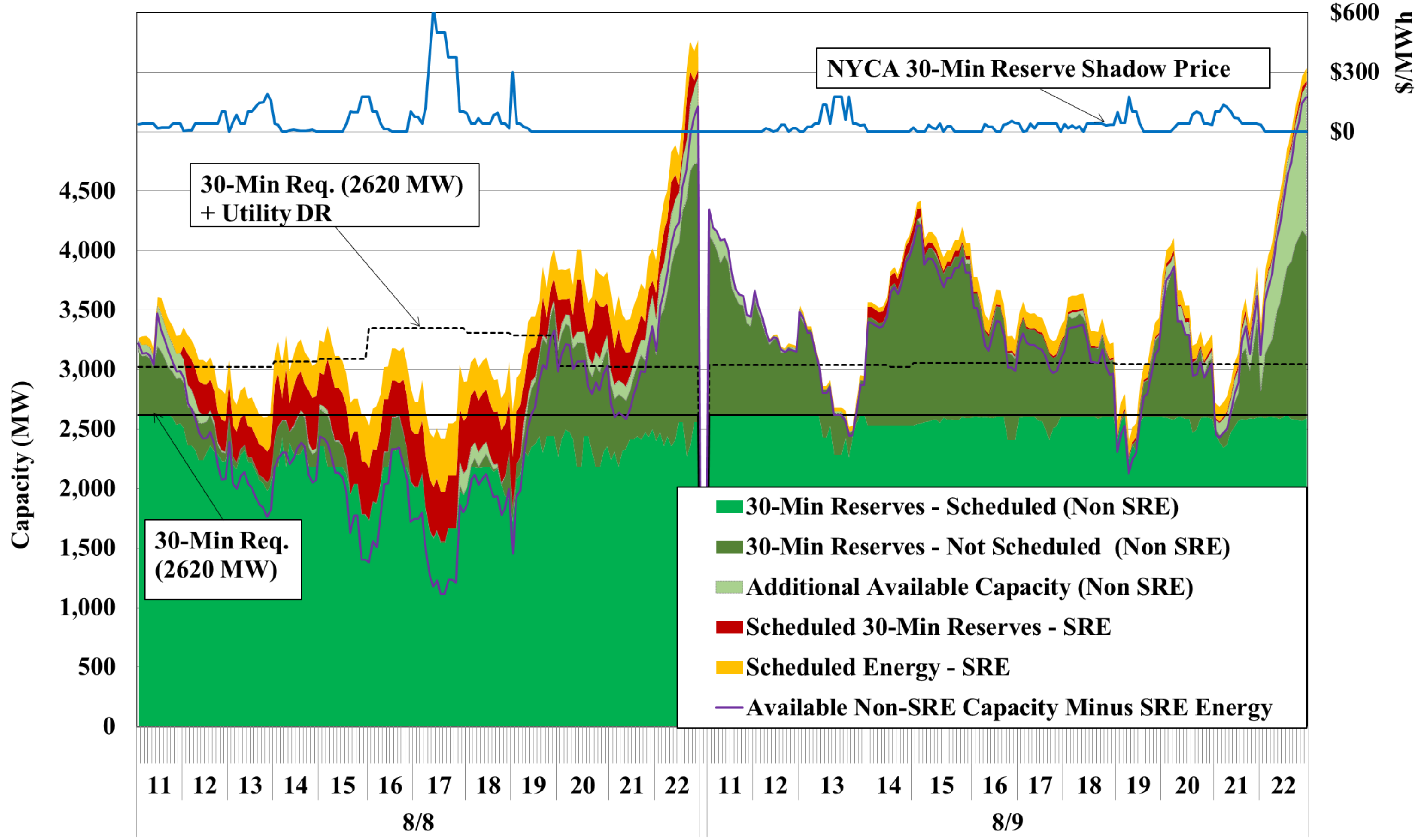
POTOMAC ECONOMICS

SRE Commitments for Capacity and DR Deployments on High Load Days



Notes: For chart description, see slide 118.

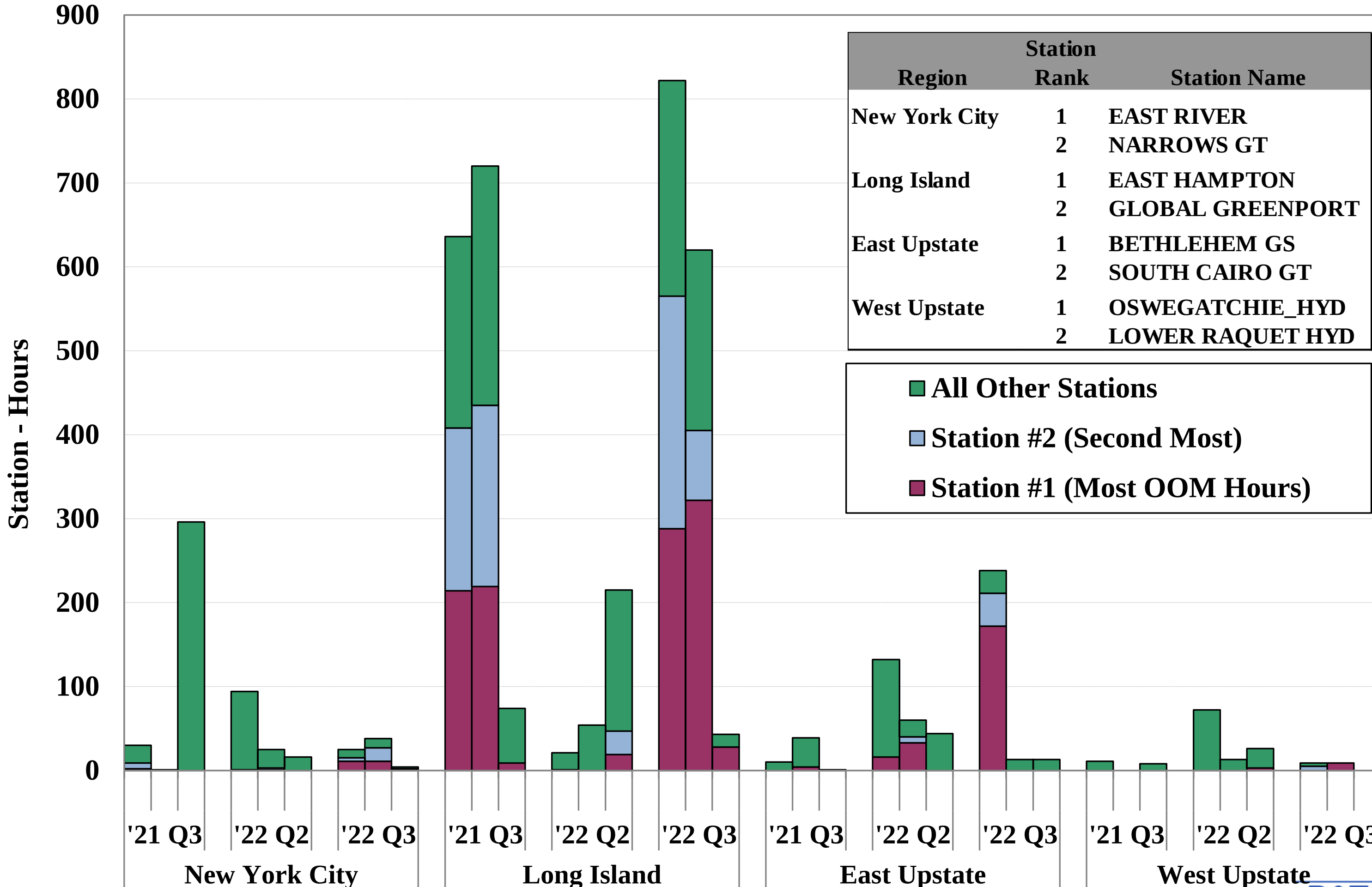
SRE Commitments for Capacity and DR Deployments on High Load Days



Notes: For chart description, see slide 118.

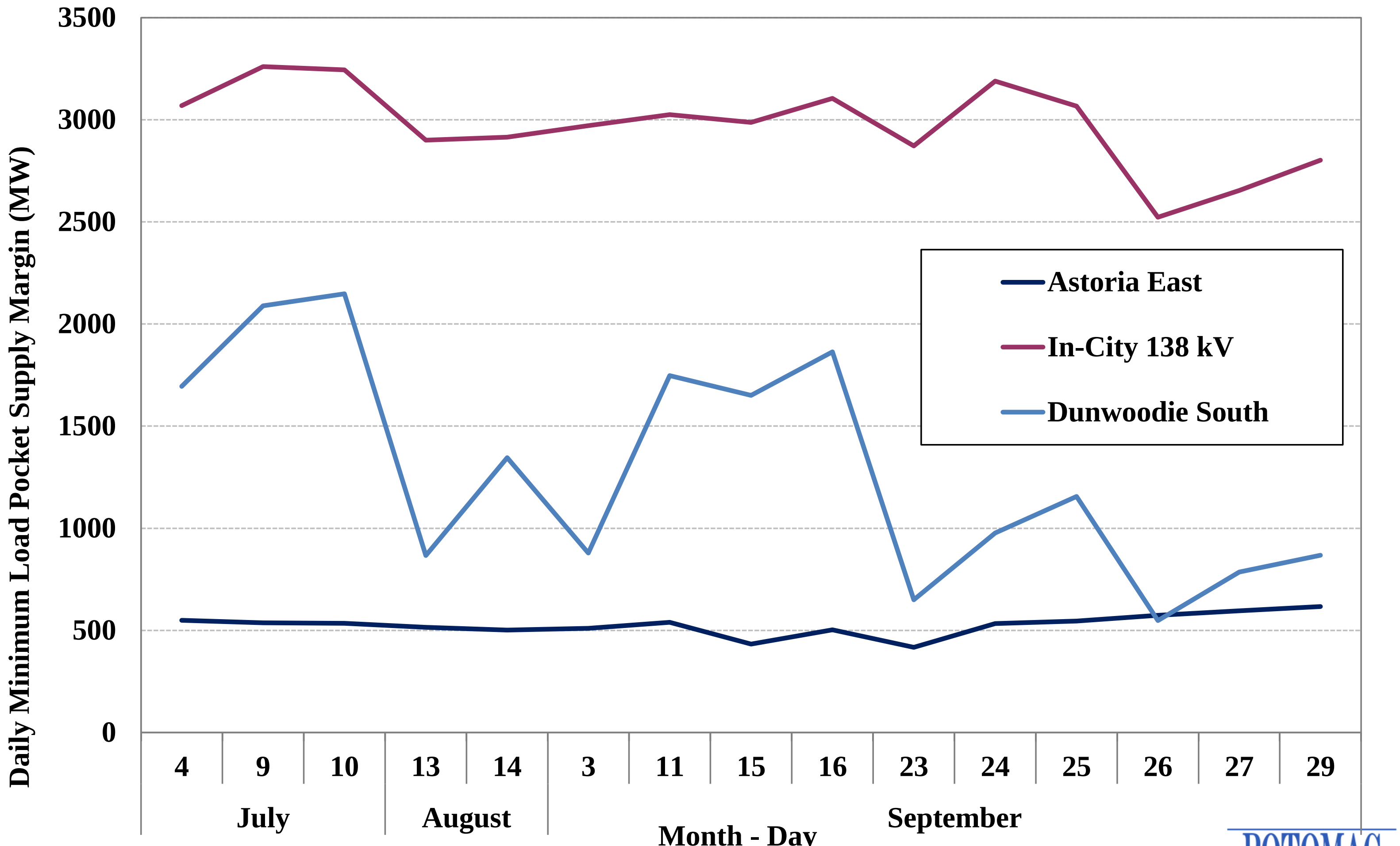
POTOMAC ECONOMICS

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



For chart description, see slides 116 and 117.

Supply Margin in NYC Load Pockets
After Removing NOx-only Committed ST and GT in the NOx Bubble



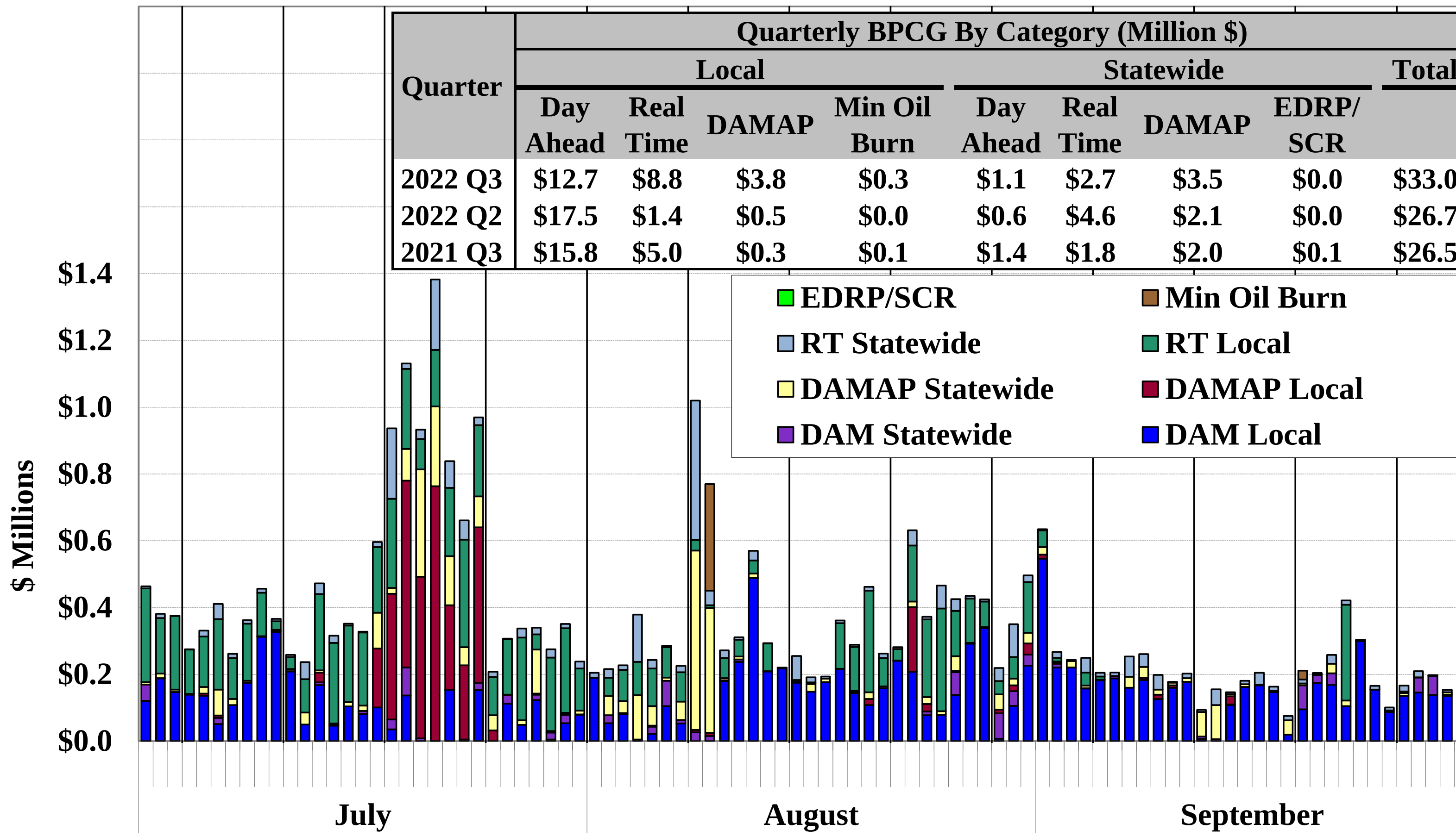
For chart description, see slide 119.

POTOMAC ECONOMICS

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

Quarter	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2022 Q3	$12.7	$8.8	$3.8	$0.3	$1.1	$2.7	$3.5	$0.0	$33.0
2022 Q2	$17.5	$1.4	$0.5	$0.0	$0.6	$4.6	$2.1	$0.0	$26.7
2021 Q3	$15.8	$5.0	$0.3	$0.1	$1.4	$1.8	$2.0	$0.1	$26.5

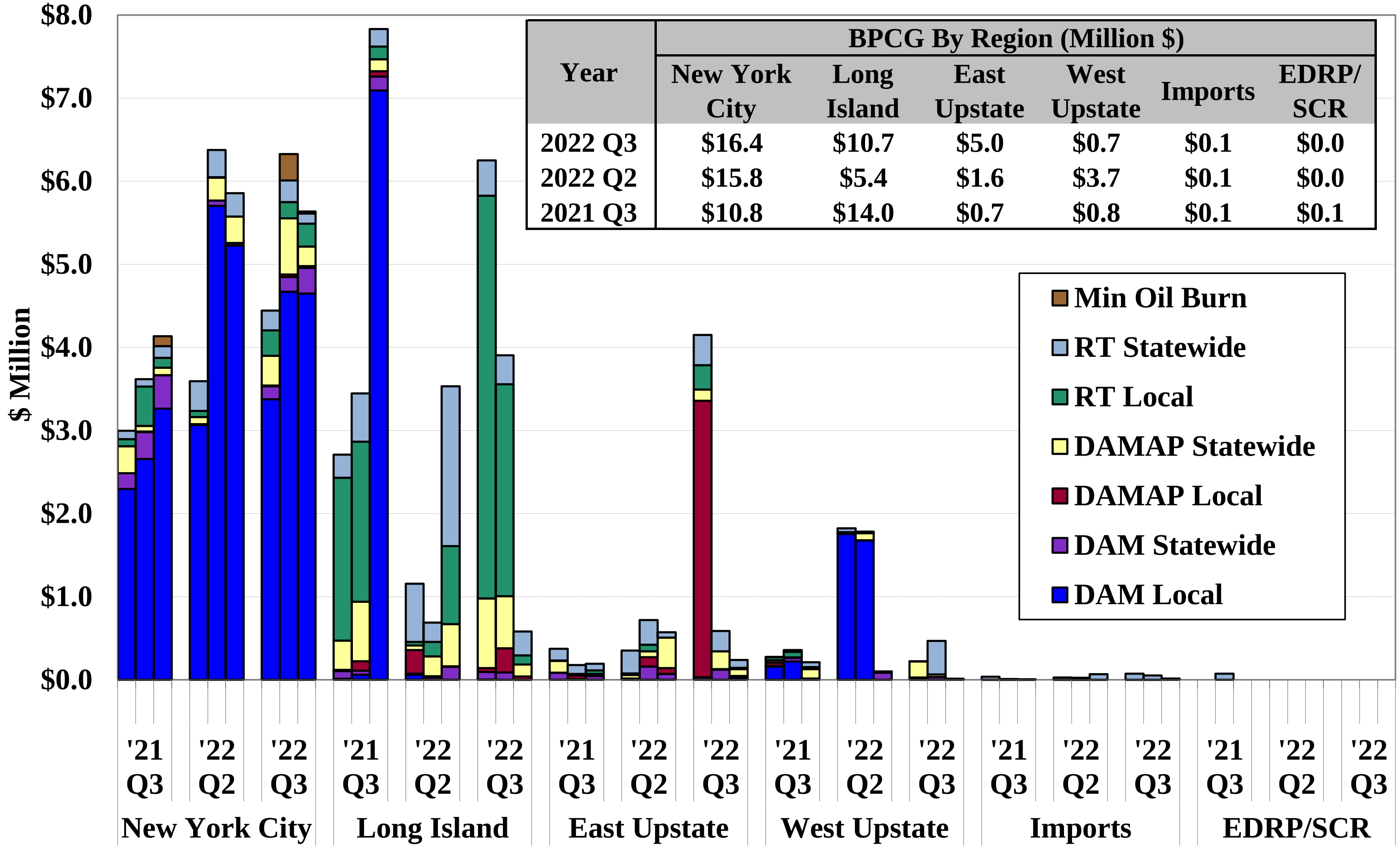
Quarterly BPCG By Category (Million $)



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 120.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region



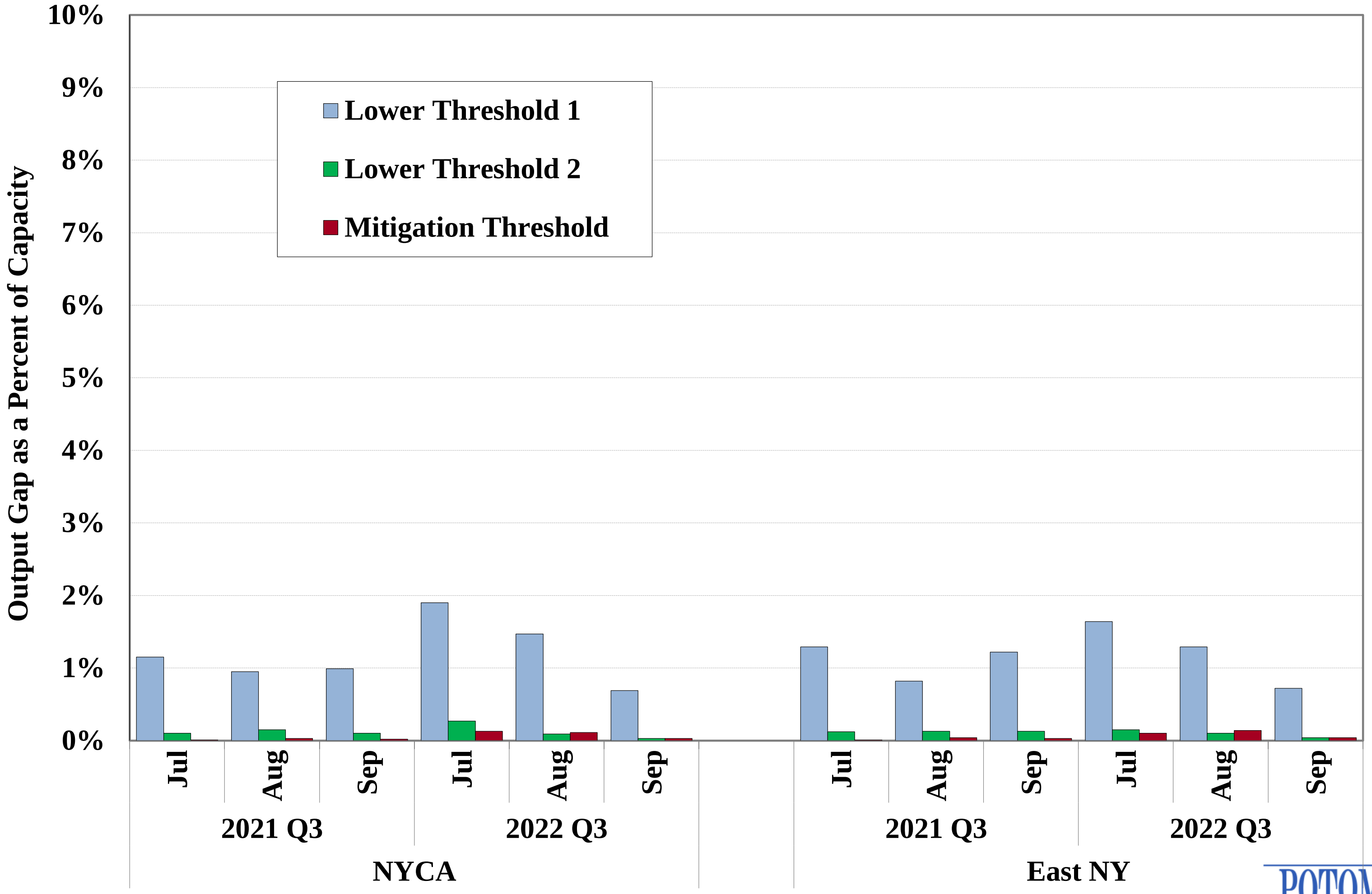
Year	BPCG By Region (Million $)					
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2022 Q3	$16.4	$10.7	$5.0	$0.7	$0.1	$0.0
2022 Q2	$15.8	$5.4	$1.6	$3.7	$0.1	$0.0
2021 Q3	$10.8	$14.0	$0.7	$0.8	$0.1	$0.1

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

Charts:

Market Power and Mitigation

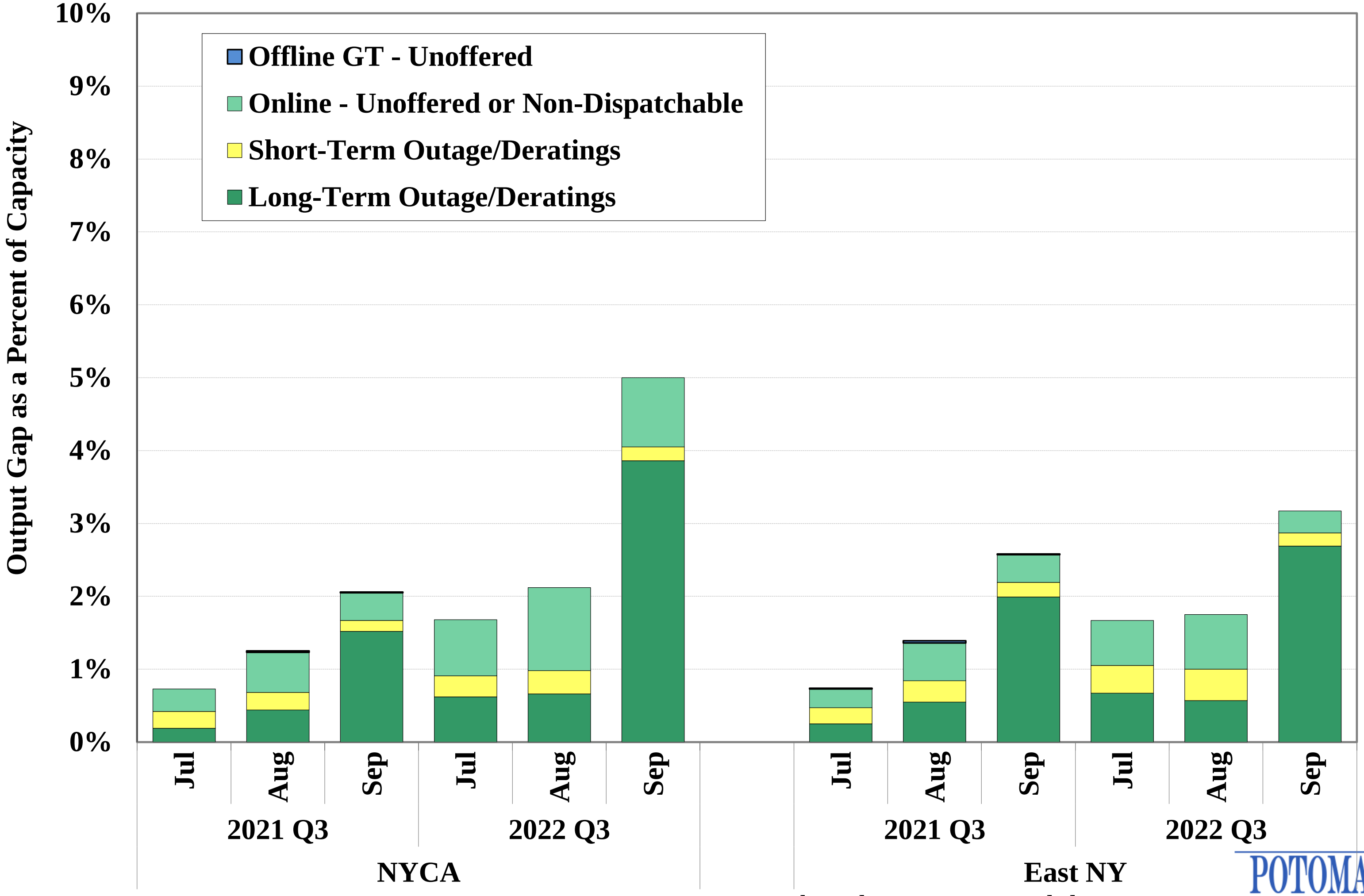
Output Gap by Month
NYCA and East NY



For chart description, see slide 121.

POTOMAC ECONOMICS

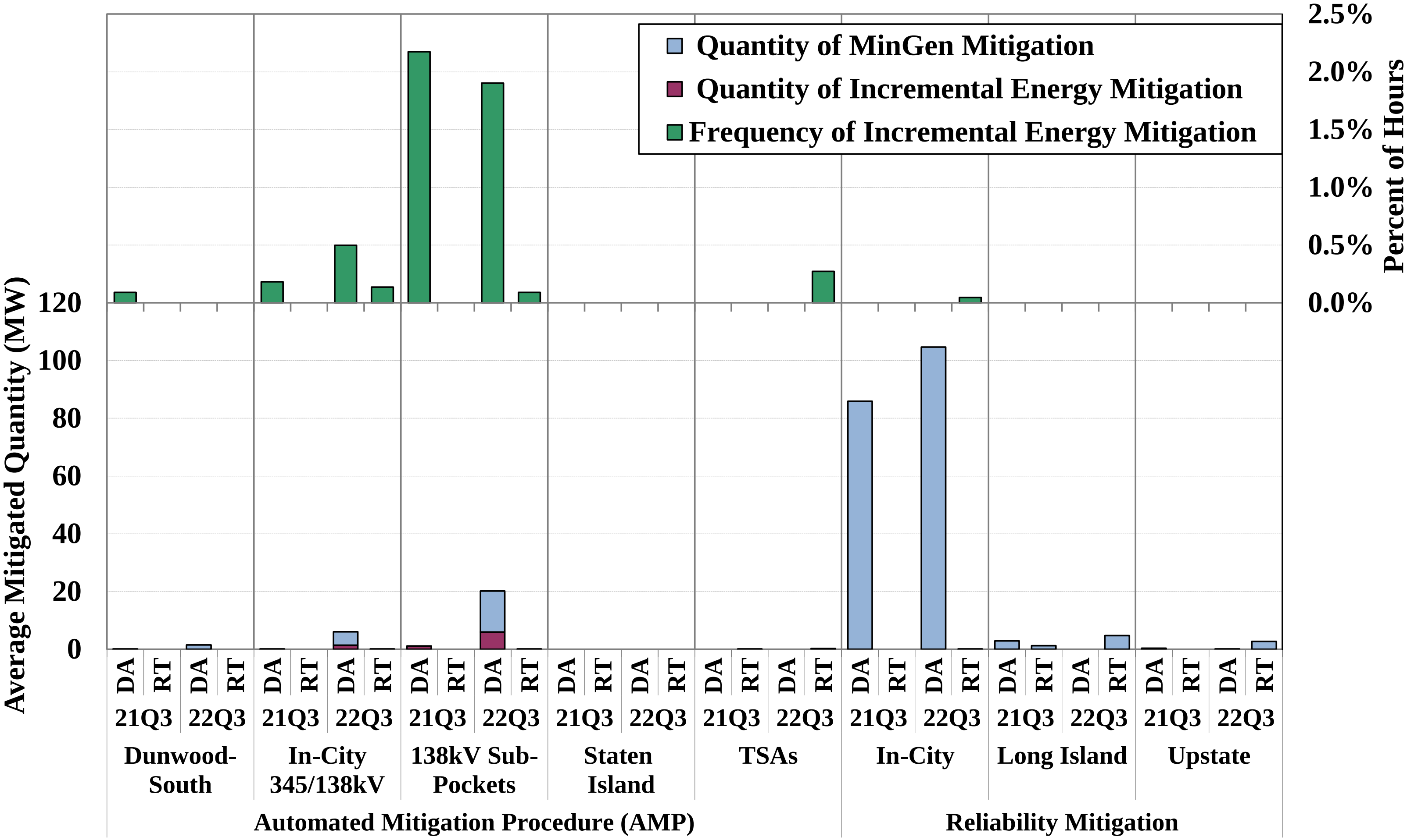
Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 121.

POTOMAC ECONOMICS

Automated Market Power Mitigation

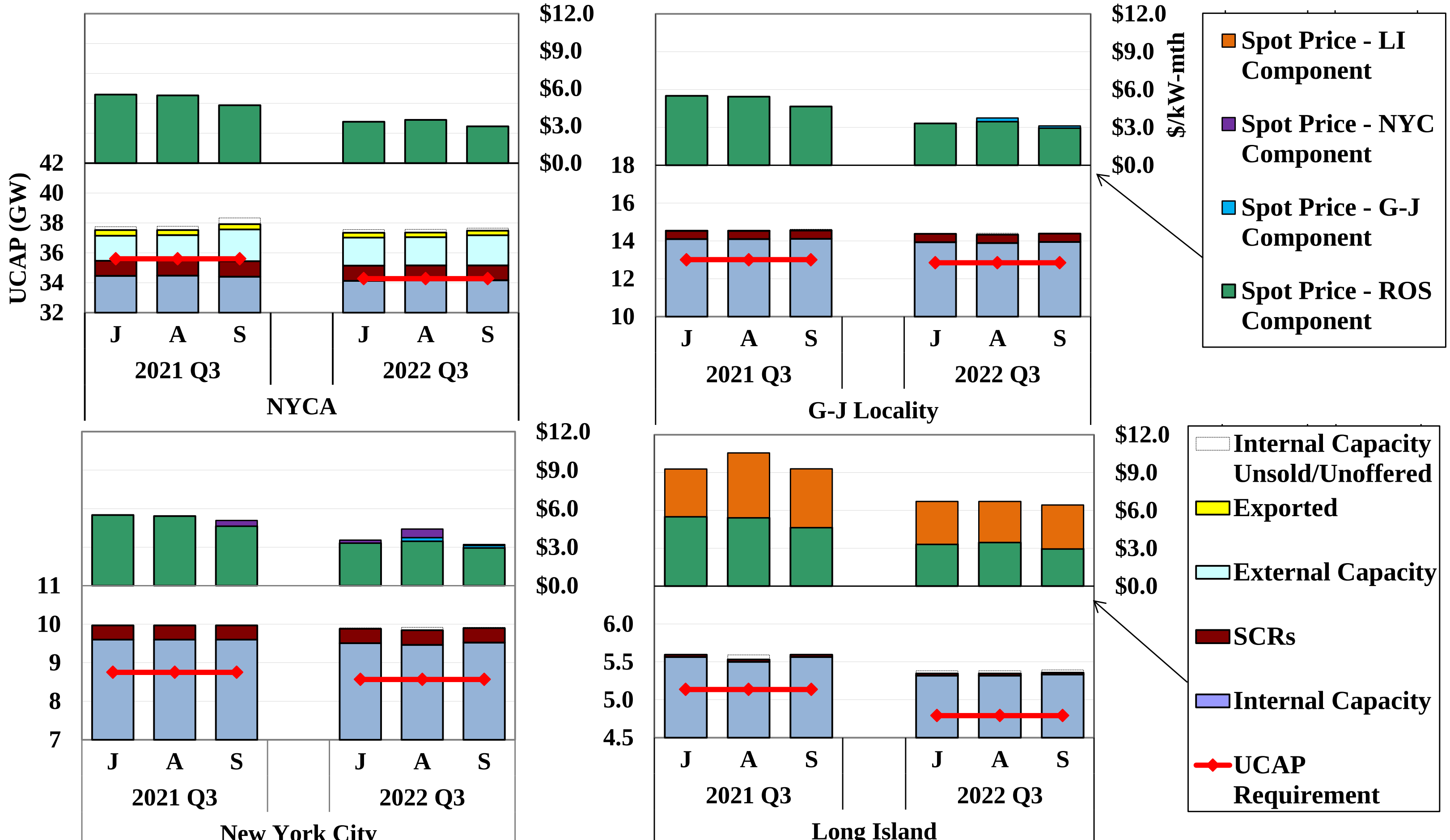


Notes: For chart description, see slide 122.

POTOMAC ECONOMICS

Charts:
Capacity Market

Spot Capacity Market Results
Monthly Results by Locality



Notes: For chart description, see slide 123.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2022 Q3 ($/kW-Month)	$3.25	$3.72	$6.62	$3.39
% Change from 2021 Q3	**-37%**	**-30%**	**-32%**	**-35%**
Change in Demand				
Load Forecast (MW)	-566	-293	-111	-286
IRM/LCR	-1.1%	0.9%	-3.4%	1.6%
2022/23 Capability Year	*119.6%*	*81.2%*	*99.5%*	*89.2%*
2021/22 Capability Year	*120.7%*	*80.3%*	*102.9%*	*87.6%*
ICAP Requirement (MW)	**-1,033**	**-137**	**-289**	**-7**
Key Changes in ICAP Supply (MW)				
Generation	**161**	**-11**	**-104**	**27**
Entry (3)	23	0	23	0
Exit (3)	-66	-24	-42	-24
Other Capacity Changes (1)	204	13	-85	51
Cleared Import (2)	**98**			

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

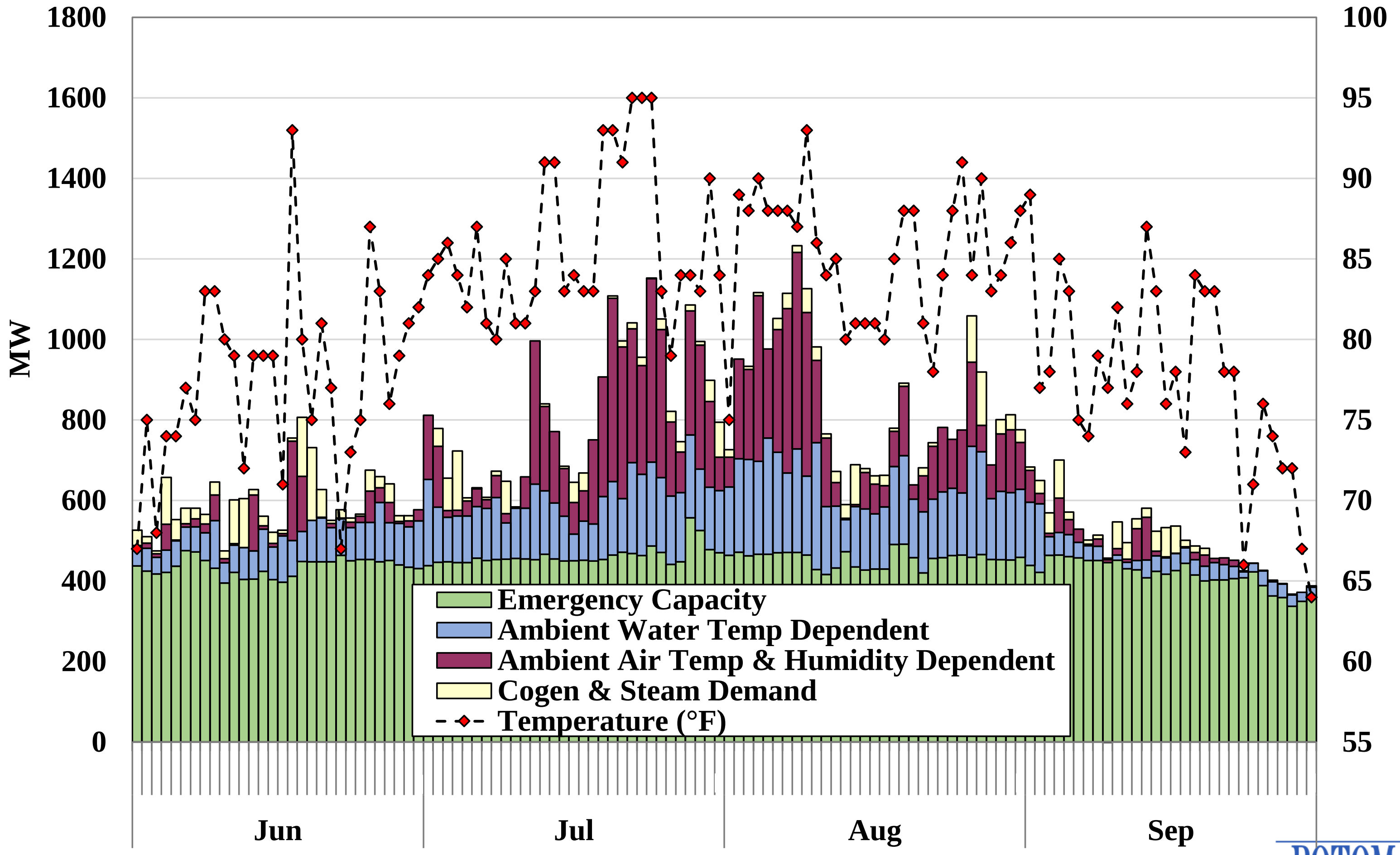
(2) Based on average of quarterly cleared quantity.

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

Notes: For chart description, see slide 123.

POTOMAC ECONOMICS

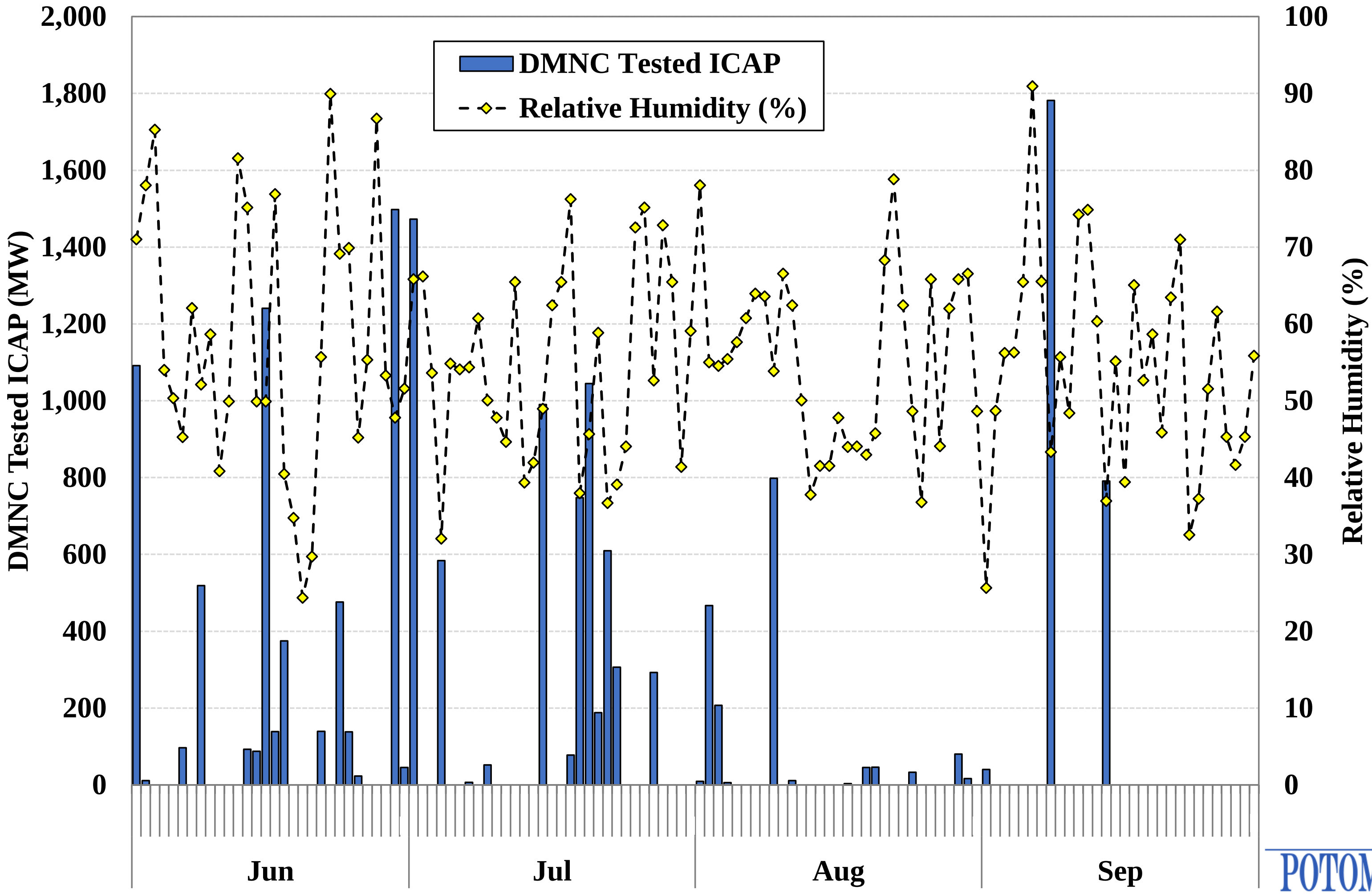
Functionally Unavailable Capacity from Fossil-Fuel and Nuclear Generators



  Notes: For chart description, see slide 124.

POTOMAC ECONOMICS

Timing of Summer DMNC Tests versus Relative Humidity



Notes: For chart description, see slide 125.

POTOMAC ECONOMICS

Appendix: Chart Descriptions

POTOMAC ECONOMICS

All-in Price

- Slide 25 summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component that is calculated based on clearing prices in the monthly spot capacity auctions and capacity obligations in each zone, allocated over the energy consumption in that zone.
  - ✓ An uplift component that is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area.
  - ✓ An ancillary services component that is based on costs associated with operating reserves, regulation, voltage support, and black start.
    - For the purpose of this metric, these costs are distributed evenly across all locations.
  - ✓ The figure also shows representative natural gas prices for each location that is based on the following indices (plus transportation charges equal to $0.27 per MMBtu for Zones A through I, $0.20 per MMBtu for New York City, and $0.25 per MMBtu for Long Island):
    - (a) Tennessee Z4 200L index for the West Zone, (b) the minimum of TN Z6 and Iroquois Zone 2 indices during the months Dec through Feb, and TN Z4 200L index otherwise for Central New York; (c) Iroquois Waddington index for North Zone; (d) the minimum of TN Z6 and Iroquois Z2 indices for the Capital Zone; (e) the average of Iroquois Z2 index and the Tetco M3 index for Lower Hudson Valley; (f) Transco Zone 6 (NY) index for New York City, and (g) the Iroquois Z2 index for Long Island. A 6.9 percent tax rate is also included NYC.

Real-Time Output and Marginal Units by Fuel

- Slide 29 shows the quantities of real-time generation by fuel type.
  - ✓ Real time generation by fuel type is derived from data reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").
  - ✓ Pumped-storage resources in pumping mode are treated as negative generation. "Other" includes Methane, Refuse, Solar & Wood.
- Slide 30 summarizes how frequently each fuel type was on the margin and setting real-time LBMPs in these regions.
  - ✓ More than one type of generator may be on the margin in an interval, particularly when a transmission constraint is binding. Accordingly, the total for all fuel types may be greater than 100 percent.
    - For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent.
  - ✓ When no generator is on the margin in a particular region, the LBMPs in that region are set by:
    - Generators in other regions in the vast majority of intervals; or
    - Shortage pricing of ancillary services, transmission constraints, and/or energy in a small share of intervals.

Emission by Region

- Slides 31-35 evaluate emissions from generators in the NYISO market.
  - ✓ Slide 31 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_X, and SO_2 .
  - ✓ Slides 32-33 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 34-35 evaluate NO_X emission during the quarter in the non-attainment areas in New York City and Long Island, respectively, on a daily basis.
    - The emission tonnage is shown separately for oil-fired units and gas-fired units in stacked bars, where gas-fired units are also grouped based on technology: (a) combined-cycle; (b) steam turbine; (c) gas turbines that were in service before 2000; and (d) gas turbines that were in service since 2000.
    - The line in slide 34 shows the emission from STs in NYC that were supplementally committed for local reliability as a percent of total emission in NYC.

POTOMAC ECONOMICS

Emission Costs by Unit Type
Natural Gas Fired Resources

- Slide 28 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.

Ancillary Services Prices

- Slides 40-44 summarize day-ahead and real-time prices for eight ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices in NYC, eastern NY, and Western NY;
  - ✓ 10-min non-spinning reserve prices in NYC, eastern NY, and Western NY;
  - ✓ Regulation prices, which reflect the cost of procurement, and the cost of moving generation of regulating units up and down.
    - – Resources were scheduled assuming a Regulation Movement Multiplier of 8 per MW of capability, but they are compensated according to actual movement.
    - – Real-time Regulation Movement Charges shown on Slide 43 are estimated by dividing total movement charges by real-time scheduled regulation capacity.
  - ✓ 30-min operating reserve prices in western NY and NYC; and
  - ✓ 30-min operating reserve prices in SENY.
- The number of shortage intervals in real-time for each ancillary service product are also shown.
  - ✓ A shortage occurs when a requirement cannot be satisfied at a marginal cost less than its “demand curve”.
  - ✓ The highest demand curve values are currently set at $775/MW.

Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 45 summarizes the amount of reserve offers in the day-ahead market that can satisfy the statewide 30-minute reserve requirement.
  - ✓ These quantities include both 10-minute and 30-minute and both spinning and non-spin reserve offers. (However, they are not shown separately in the figure.)
  - ✓ Only offers from day-ahead committed (i.e., online) resources and available offline quick-start resources are included, since they directly affect the reserve prices.
  - ✓ The stacked bars show the amount of reserve offers in each select price range for West NY (Zones A to E), East NY (Zones F to J), and NYCA (excluding Zone K).
    - – Long Island is excluded because the current rules limit its reserve contribution to the broader areas (i.e., SENY, East, NYCA).
    - – Thus, Long Island reserve offer prices have little impact on NYCA reserve prices.
  - ✓ The black line represents the equivalent average 30-minute reserve requirements for areas outside Long Island.
    - – The equivalent 30-minute reserve requirement is calculated as NYCA 30-minute reserve requirement minus 30-minute reserves scheduled on Long Island.
    - – Where the lines intersect the bars provides a rough indication of reserve prices (less opportunity costs).

Regulation Market Requirements and Prices

- Slide 47 displays several aspects pertaining to the regulation requirements, prices, and relationship between scheduled regulation capacity and actual regulation movement in the past 36-month period.
- The topmost chart displays information relevant to the regulation requirement and the regulation movement-to-capacity ratio.
  - ✓ The blue column bars show the average monthly regulation requirement.
  - ✓ The secondary y-axis shows the average movement-to-capacity ratio for each month.
- The bottom chart shows the average monthly prices.
  - ✓ The columns show the average monthly regulation capacity prices in the day-ahead market.
  - ✓ The two lines show the real-time capacity prices and movement prices.

POTOMAC ECONOMICS

Day-Ahead Load Scheduling and Virtual Trading

- Slide 49 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 50 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 51 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

Efficiency of CTS Scheduling with PJM and NE

- Slide 53 evaluates the performance of CTS with PJM and NE at their primary interfaces in the quarter. The table shows:
  - ✓ The percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule).
  - ✓ The average flow adjustment from the estimated hourly schedule.
  - ✓ The production cost savings that resulted from CTS, including:
    - Projected savings at scheduling time, which is the expected production cost savings at the time when RTC determines the interchange schedule.
    - Net over-projected savings, which is the portion of savings that was inaccurately projected because of PJM, NYISO, and ISO-NE price forecast errors.
    - Other Unrealized savings, which are not realized due to: a) real-time curtailment; and b) interface ramping.
    - Actual savings (= Projected – Over-projected – Other Unrealized).
  - ✓ Interface prices, which are forecasted prices at the time of RTC scheduling and actual real-time prices.
  - ✓ Price forecast errors, which show the average difference and the average absolute difference between actual and forecasted prices across the interfaces.

RTC and RTD Price Difference vs Load Forecast Difference

- Slide 54 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 55 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.

POTOMAC ECONOMICS

RTC and RTD Price Difference vs Load Forecast Difference

- Slide 56 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.

RTC and RTD Price Difference vs Unmodeled Flow Difference on the CPV Constraint

- Slide 57 summarizes the differences in unmodeled flows between RTD and RTC on the Cricket Valley-Pleasant Valley 345 kV constraint and the resulting price impact on select locations in the quarter.
  - ✓ The x-axis shows the MW tranches of differences in unmodelled flows on the CPV constraint between RTD and RTC.
    - A positive MW tranche indicates a higher level of unmodeled flows in the constraint congested direction in RTC than in RTD, and vice versa for the negative MW tranches.
  - ✓ The top portion of the chart shows the proportion of all 5-minute intervals that fall into each MW tranche on the x-axis.
    - This excludes intervals when the CPV constraint was not binding in both RTC and RTD.
  - ✓ The lower portion of the chart shows the resulting price differences at select locations.
    - Resulting Price Difference = Difference in Constraint Shadow Cost × Location-specific Shift Factor on the Constraint

Real-Time System Price Maps at Generator Nodes

- Slides 59 and 60 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.

POTOMAC ECONOMICS

Transmission Congestion and Shortfalls

- Slides 61, 62, 63, and 64 evaluate the congestion patterns in the DAM and RTM and examine the following categories of resulting congestion costs:
  - ✓ <u>Day-Ahead Congestion Revenues</u> 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.
  - ✓ <u>Day-Ahead Congestion Shortfalls</u> 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.
  - ✓ <u>Balancing Congestion Shortfalls</u> arise when DAM scheduled flows over a constraint exceed what can flow over the constraint in the RTM.
    - The transfer capability of a constraint falls (or rises) from day-ahead to real-time for the similar reasons (e.g., deratings and outages of transmission facilities, inconsistent assumptions regarding PAR schedules and loop flows, etc.).
    - In addition, payments between the NYISO and PJM related to the M2M process also contribute to shortfalls (or surpluses).

Transmission Congestion and Shortfalls (cont.)

- Slide 61 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 62 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 63 and 64 show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.

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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.

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NY-NJ PAR Operation Under M2M with PJM

- Slide 53 evaluates operations of NY-NJ PARs under M2M with PJM during the following periods of noticeable congestion differential between NY and PJM:
  - ✓ When NY costs on relevant M2M constraints exceed PJM costs by: a) \$10/MWh to \$20/MWh; b) \$20/MWh to \$30/MWh; or c) more than \$30/MWh.
  - ✓ When PJM costs on relevant M2M constraints exceed NY costs by: a) \$10/MWh to \$20/MWh; b) \$20/MWh to \$30/MWh; or c) more than \$30/MWh;
  - ✓ The market cost is measured as the constraint shadow price multiplied by the PAR shift factor, summed over relevant M2M constraints in each 5-minute market interval and then averaged over each half-hour period.
  - ✓ The top portion of the figure shows two stacked bars for each evaluation group, representing the total number of 30-minute intervals with and without any PAR tap movements.
  - ✓ The bottom portion of the figure shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).

OOM Actions to Manage Network Reliability

- Transmission constraints on the 115 kV and lower voltage networks in New York are often resolved in ways that include:
  - ✓ Out of merit dispatch and supplemental commitment of generation;
  - ✓ Curtailment of external transactions and limitations on external interface limits;
  - ✓ Use of an internal interface transfer limit that functions as a proxy for the limiting transmission facility; and
  - ✓ Adjusting PAR-controlled lines on the high voltage network.
- Slide 66 shows the number of days in the quarter when various resources were used to manage constraints in five areas of upstate New York:
  - ✓ West Zone;
  - ✓ Central Zone;
  - ✓ Capital Zone:
  - ✓ North & Mohawk Valley Zones; and
  - ✓ Long Island (mostly constraints on the 69kV system).
- In addition, the figure also reports the number of days when OOM commitments were made to satisfy N-1-1 reserve needs in several local load pockets.

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Constraints on the Low Voltage Network

- Slide 67 shows the number of hours and days in the quarter when various resources were used to manage 69 kV ("69 kV OOM") and TVR ("Transient Voltage Recovery") constraints in four local areas of Long Island:
  - ✓ Valley Stream: Mostly constraints around the Valley Stream bus;
  - ✓ Brentwood: Mostly constraints around the Brentwood bus;
  - ✓ East of Northport: Mostly the C._ISLIP-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 67 also shows our estimated LBMP impacts in each LI load pocket that result from explicitly modeling 69 kV and TVR constraints in the market software.
  - ✓ The following generator locations are chosen to represent each load pocket:
    - Barrett ST for the Valley Stream pocket;
    - NYPA Brentwood GT for the Brentwood pocket;
    - Holtsville IC for the East of Northport pocket; and
    - Green Port GT for the East End pocket.

N-1 Constraints in New York City

- The NYISO sometimes operates a facility above its Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE.
  - ✓ The use of post-contingency actions is important because it allows the NYISO to increase flows into load centers and reduce congestion costs.
  - ✓ However, the service provided by these actions are not properly compensated.
- Slide 68 shows such select N-1 constraints in New York City. In the figure,
  - ✓ The left panel summarizes their DA and RT congestion values in the quarter.
    - – The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities (i.e., constraint shadow cost*seasonal LTE summed over all intervals); and
    - – The red bars represent the congestion values measured for the additional transfer capability above LTE (i.e., constraint shadow cost*(modeled constraint limit – seasonal LTE) summed over all intervals).
  - ✓ The bars in the right panel show the seasonal LTE and STE ratings for these facilities, compared to the average N-1 constraint limits used in the market software.

Duct Burner RPU Performance and Real-Time Availability

- Slide 69 shows a case study of real-time performance of a combined-cycle unit that failed to follow 5-minute instructions during an RPU event due to its inability to fire the duct burner within 10-minutes.
  - ✓ The two lines show the levels where resource capacity shifts from baseload without duct burners (gray line) to the duct burner range (red line). Capacity values are not given for confidentiality purposes.
  - ✓ The blue columns show the actual output produced by the resource in each RTD and RTD-CAM interval. The black dotted line shows the 5-minute instructions by the market model.
  - ✓ A faded box highlights the RPU timeframe and the red-patterned area between the columns and the instructed output line outlines the duct burner output that was not delivered by the station.
- Slide 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.

GT Start-up Performance

- Slides 71-72 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): "26 10-minute GTs exhibited a response rate of 90 to 100 percent during economic starts in the examined period, 26 of them were audited 56 times in total with 2 failures".

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GT with Worst Startup Performance

- Slide 73 lists gas turbines that had an average performance below 70 percent for economic starts by the market model (including starts by RTC, RTD, and RTD-CAM but excluding self-schedules) in the 24-month period from October 2020 to September 2022.
  - ✓ The bottom chart shows the average performance (the line) and the total number of economic starts (the bars) for these GTs in this 24-month period.
    - – The average performance of all other GTs is also shown for comparison.
  - ✓ The top chart shows:
    - – The percent of hours each GT was scheduled for reserves in the day-ahead market (the line); and
    - – The number of audits that were done in this 24-month period (in stacked bars for ‘Audit Passed’ and ‘Audit Failed’).
  - ✓ Unit names are removed for confidentiality.

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Supplemental Commitments and OOM Dispatch

- Slides 75, 76, and 79 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:

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Supplemental Commitments and OOM Dispatch (cont.)

- NOx Only – If needed for NOx bubble requirement only.
- N-1-1 – If needed for one or two of the following reasons: voltage support (ARR 26), and thermal support (ARR 37).
- Loss of Gas – If needed for IR-3, a sudden loss of gas supply in NY, and no other reason except NOx.

✓ For N-1-1 constraints, the capacity is shown by the load pocket that was secured.

- Slide 79 summarizes the frequency (measured by the total station-hours) of Out-of-Merit dispatches by region on a monthly basis.
  - ✓ The figure excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.
  - ✓ In each region, “Station #1” is the station with the highest number of OOM hours in its region in the current quarter; “Station #2” is the station with the second-highest number of OOM hours; all other stations are grouped together.

SRE Commitments for Capacity and DR Deployments On High Load Days

- Slides 77 and 78 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 afternoon peak hours (HB 12 - HB 21) 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

Supply Margin in NYC Load Pockets After Removing NOx-only Committed ST and GT in the NOx Bubble

- Steam units in New York City are often LRR-committed solely to satisfy the NOx Bubble requirement in the Ozone season.
  - ✓ On many of these days, even if both the committed ST and its supported GTs were unavailable, all N-1-1 criteria could be satisfied by other resources.
    - – This questions the necessity of such commitments in each day of the Ozone season.
- Slide 80 shows our evaluation of the necessity in the quarter.
  - ✓ The figure shows the daily minimum supply margin in the relevant load pockets after the removal of the NOx-committed STs and their supported GTs in the NOx Bubble.
  - ✓ The evaluation is done on days when the ST is NOx-only committed in the day-ahead market.
  - ✓ A positive minimum supply margin indicates that both the ST and associated GTs were not needed to satisfy any N-1-1 criteria in the load pocket.

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Uplift Costs from Guarantee Payments

- Slides 81 and 82 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 81 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 82 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 84 and 85 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 86 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 88 and 89 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 88 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 89 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 from Fossil and Nuclear Generators during Summer 2022

- Slide 90 shows the amount capacity that was functionally unavailable to the market during the certain peak hours (i.e., HB 10-19) in each day of June through September from fossil generators and nuclear units for a variety of reasons:
  - ✓ Emergency Capacity
    - – The amount of capacity offered by units in their UOLe ranges. This is unavailable for normal operations and only dispatchable under emergency circumstances.
  - ✓ Ambient Water Temp Dependent
    - – The amount of capacity derated from fossil and nuclear STs and marked as related to ambient water temperatures. The drag MW (i.e., underperformance) is also included when the unit is dispatched at UOLn (but no reported derates).
  - ✓ Ambient Air Temp & Humidity Dependent
    - – The amount of capacity derated from CCs and Peakers and marked as related to ambient air conditions. The drag MW (i.e., underperformance) is also included when the unit is dispatched at UOLn (but no reported derates).
  - ✓ Cogen & Steam Demand
    - – The amount of capacity derated from Cogen units related to host steam demand.
- The chart also shows the maximum daily temperature recorded at JFK Airport in New York City as a reference.

DMNC Tests of Fossil and Nuclear Generators versus Relative Humidity

- Slide 91 shows the amount of capacity that conducted DMNC tests in the summer, compared to the relative humidity at peak daily conditions. In the chart,
  - ✓ **DMNC Tested ICAP:** This is the total amount of submitted DMNC values from generators that conducted DMNC tests on each day from June 1 to September 15, 2022.
    - – Only DMNC test submissions from fossil generators and nuclear units are included in these numbers.
  - ✓ **Relative Humidity (%):** This is the calculated value of relative humidity at peak temperature conditions at the JFK Airport for each day of June through September.