Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2021

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Table of Contents

POTOMAC ECONOMICS

Market Highlights

Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the third quarter of 2021.
- All-in prices ranged from $38 to $117 per MWh, up 62 to 94 percent from 2020-Q3 in all regions but NYC, which saw a decrease of 16 percent. (slide 7)
  - ✓ Energy prices rose 68 to 124 percent primarily because of higher gas prices, which rose 110 to 139 percent across the system. In addition:
    - Nuclear output fell by an average of 820 MW per hour largely because of the Indian Point 3 retirement.
    - Lengthy 345 kV intertie outages increased congestion and prices on Long Island.
  - ✓ Capacity prices: (a) fell sharply in NYC due to a lower LCR; but (b) rose in other areas, reflecting a higher IRM and the Indian Point nuclear retirement. (slide 22)
- Despite several heat waves, load exceeded 30 GW on just one day.
  - ✓ TOs activated utility DR on 10 days, mostly for peak-shaving. (slide 17)
  - ✓ NYISO SRE-committed for statewide capacity needs on three days. (slide 16) Some SREs might not have been necessary if the NYISO considered the effect of utility DR in the load forecast.
- The NYISO was able to substantially reduce the use of OOM dispatch to manage congestion on Long Island by modeling two 69kV facilities, which were constrained on more than 80 percent of days during the quarter. (slide 63)

Market Highlights:
Executive Summary

- Both 345 kV interties from Upstate NY to Long Island were out-of-service for 46 days in the third quarter of 2021, leading to unusually tight operating conditions and volatile pricing. This period highlighted several inefficiencies:
  - ✓ Lack of reserve shortage pricing during Long Island capacity deficiencies;
  - ✓ Understated reserve requirements in the day-ahead and real-time markets;
  - ✓ Inflexible generator scheduling related to gas-balancing charges; and
  - ✓ Over-accreditation of capacity for some conventional Long Island generation.
  - ✓ These issues are discussed further on slides 11-12.
- We identified several categories of conventional generating capacity that may receive excessive accreditation under the current rules, which should be evaluated further. (slide 23)
- We continue to observe large quantities of OOM commitment for operating reserve requirements that are not adequately reflected in the day-ahead and real-time markets. (slides 11, 14, 15, 16, & 20)
  - ✓ Modeling the requirements in the market software would improve scheduling efficiency and incentives for reliable performance and future investment.

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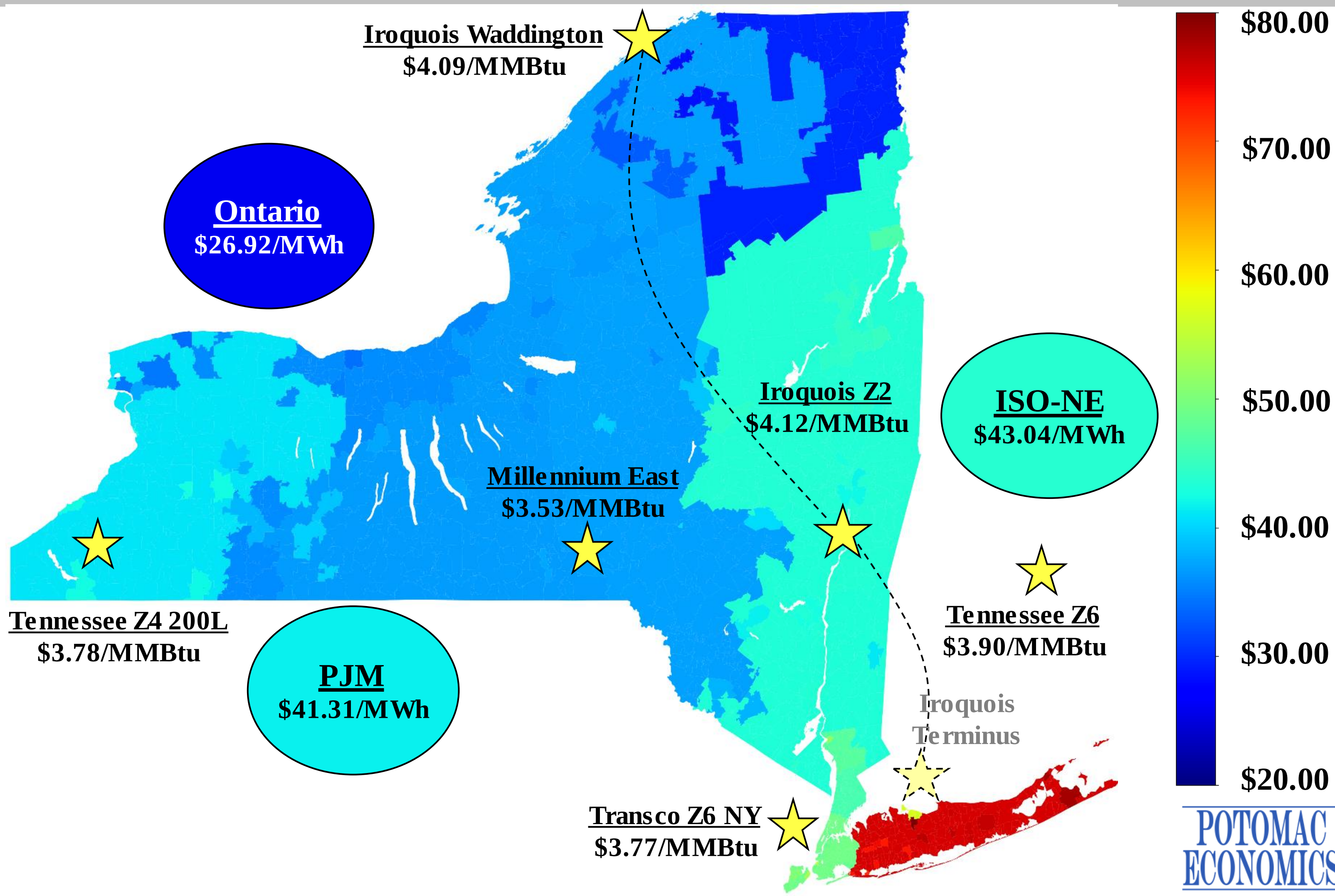
Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the third quarter of 2021.
  - ✓ The amount of output gap (slide 81) and unoffered economic capacity (slide 82) remained modest and reasonably consistent with competitive market expectations.
- All-in prices ranged from $38/MWh in the North Zone to $117/MWh in Long Island, rising 62 to 94 percent from a year ago except for NYC where all-in prices fell by 16 percent. (slide 25)
  - ✓ Energy prices rose substantially in all zones, up by 68 to 74 percent in the Western NY and 94 to 124 percent in Eastern NY. (slides 30-36)
    - – The increase was driven primarily by higher natural gas prices, which rose 110 to 139 percent across the system from a year ago (slide 27).
    - – Other contributing factors include:
      - Lower nuclear generation – the average output fell by roughly 820 MW because of the Indian Point 3 retirement in April 2021; (slide 28) and
      - Lengthy major transmission outages on the Central-East interface and into Long Island, which further elevated prices in Eastern NY. (slide 59)
    - – However, the increase was partially offset by lower load levels because of milder summer weather conditions. (slide 26)
  - ✓ Capacity costs rose in all areas but NYC for the reasons discussed in slide 22.

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Market Highlights:
Generation by Fuel and Emissions

- Average nuclear generation fell by roughly 820 MW from a year ago because of the retirement of the last Indian Point nuclear unit at the end of April 2021.
- Despite the reduction in nuclear output, gas-fired generation fell by about 600 MW on average due to higher gas prices. (slides 27-28)
  - ✓ Gas-fired combined cycle output fell by 590 MW on average and gas-fired steam turbine generation fell by 20 MW on average.
  - ✓ This decrease was offset by higher net imports from PJM and lower net exports to New England. (slide 52)
- Average oil-fired generation rose 70 MW primarily on Long Island.
  - ✓ Both lines from Upstate to Long Island (i.e., Y49 & Y50) were OOS from early August to late September, leading to min oil-burn operation of several STs for loss of gas contingency. This drove higher uplift and emissions. (slides 34, 78-79)
  - ✓ Although these led to increased emissions from 2020-Q3 (slides 31-34), emissions have fallen considerably of the last two decades. (slide 30)
- Steam turbines accounted for 62 percent of NOx emissions in New York City in the third quarter of 2021.
  - ✓ Roughly 34 percent of ST NOx emissions were from STs that were supplementally committed for local reliability. (slide 33)

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Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $152 million, up 81 percent from the third quarter of 2020. (slide 57)
- Long Island accounted for the largest share of congestion (DA 21%, RT 28%).
  - ✓ DA congestion rose 15 percent from a year ago and RT congestion rose 148 percent. (slide 58)
  - ✓ Lengthy outages of the Y49 and Y50 345 kV lines were the primary driver, which contributed to nearly $34 million of DAM congestion shortfalls. (slide 59)
  - ✓ High levels of self scheduling contributed to higher RT congestion on export constraints during low load hours of the day (see more discussion on slide 11).
- The West Zone lines accounted for the second largest share of congestion (DA 23%, RT 14%). (slide 58)
  - ✓ West Zone congestion rose by 48 percent in the DAM and 28 percent in the RTM.
  - ✓ Multiple lengthy 115 kV and 345 kV transmission outages were a key driver, contributing to nearly $13 million of DAM congestion shortfalls. (slide 59)

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

- Central-East congestion rose nearly 10 times from a year ago. (slide 58)
  - ✓ The retirement of Indian Point 3 in April 2021 reduced counterflows from nearly 1 GW of baseload nuclear generation on the interface.
  - ✓ Lengthy outages of the Edic-New Scotland and Porter-Rotterdam transmission lines in September drove much of this congestion.
- The North Zone accounted for $15 million of DA congestion, up from $9 million in 2020-Q3 (i.e., a 69 percent increase).
  - ✓ This congestion led to curtailment of some wind generation in 7 percent of intervals during the quarter.
  - ✓ Approximately 88 percent of this congestion occurred on the Moses-Adirondack 230 kV line when the parallel line was OOS throughout the quarter. (slide 59)
    - – These outages have been primarily related to the Moses-Adirondack Smart Path Reliability Project.
- Congestion from Capital to Hudson Valley and from Hudson Valley to Dunwoodie rose significantly from a year ago.
  - ✓ TSA events were frequent, particularly in July, and led to elevated congestion levels in SENY. (slide 59)
  - ✓ The retirement of the Indian Point plant contributed to increased congestion from the Hudson Valley to Dunwoodie.

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Market Highlights:
Operations and Market Outcomes on Long Island

- Both lines from Upstate NY to Long Island (the Y49 & Y50) were OOS from August 6 to September 20, leading to extraordinary operating conditions and pricing (slide 38) and revealing four significant market inefficiencies:

1) *Lack of reserve shortage pricing* – During moderate and severe reserve deficiencies, prices were often far below levels that would reflect the shortage.
   - ✓ Available reserves fell below the size of the largest contingency (~375 MW) on four days and the largest two contingencies on eight days. (slide 76)
   - ✓ Energy prices only rose above $1,000/MWh when the GTDC was triggered for overloads on the remaining lines into Long Island, but reserve prices never reflected the shortage.
   - ✓ We recommended incorporating Long Island reserve constraints in prices. (See SOM Recommendation #2019-1)
2) *Understated reserve requirements* – OOM commitments to maintain adequate reserves on 31 days revealed that the current 540 MW reserve requirement for Long Island is frequently inadequate to maintain reliability. (slide 76)
   - ✓ When reserve requirements are satisfied with OOM actions, it leads to understated prices and poor incentives for suppliers.
   - ✓ It would be beneficial if operators could satisfy such reserve needs by increasing the market requirements rather than by making OOM commitments.

Market Highlights:
Operations and Market Outcomes on Long Island (cont.)

3) *Inflexible scheduling related to gas balancing charges* – The gas LDC supplying Long Island generally imposes large balancing charges when generators under-burn by more than 2 percent relative to their schedules.
   - ✓ Some generation is offered inflexibly, leading to volatile and sometime negative prices on Long Island.
     - Real-time prices frequently swung from large negative prices in the morning to high positive spikes during the afternoon peak. Average LBMPs ranged from just \$3/MWh in Hour 8 to \$188/MWh in Hour 16 and were negative for 42 hours.
     - Very low prices in the morning resulted from high RT self-schedules (hours 0-9 in particular), which often exceeded DA scheduled generation levels. (slide 38)
     - Generators frequently offered in an overly restrictive manner because balancing charges for under-burn are ~50 percent of the gas index price.

4) *Over-accreditation of conventional capacity* – Large amounts of generating capacity was never utilized even during severe operating reserve deficiencies.
   - ✓ Approximately 420 MW of “emergency” capacity (above the normal UOL) was never offered into the market. (slide 87)
   - ✓ Capacity suppliers are not required to offer this unless instructed by the operator, but operators may be reluctant to activate emergency capacity if it increases the likelihood of a generator trip. (slide 23)

Market Highlights:
OOM Actions to Manage Low-Voltage Network

- The NYISO has greatly reduced the use of OOM actions in the past two years to manage low-voltage transmission constraints by modeling most 115kV constraints in the DA and RT market models.
  - ✓ OOM actions to manage lower-voltage network congestion were most frequent in Long Island (56 days) and North/Mhk VL (15 days) in this quarter. (slide 62)
- The frequency of OOM actions on Long Island fell sharply from the third quarter of 2020 (71 days) for a number of reasons. (slide 63)
  - ✓ Two 69 kV constraints have been secured in the market models since mid-April 2021, allowing resources that were frequently OOMed to manage these constraints to be scheduled economically (on 75 days).
    - – The NYISO has an on-going process to evaluate and incorporate additional 69 kV constraints into the market models.
  - ✓ Lengthy Y49 and Y50 outages required increased operation of internal generators, including oil-fired peakers, thereby reducing the need for OOM actions as well.
  - ✓ Consequently, the estimated LBMP impact of unmodeled local constraints fell to less than $3 per MWh except in the East End load pocket, where OOM actions are still frequently used for TVR needs (on 54 days).

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $26 million, up 20 percent from 2020-Q3 despite fewer NYC reliability commitments. This was driven largely by:
  - ✓ Higher natural gas prices (slide 27);
  - ✓ Frequent oil-burn requirements on Long Island steam units. (slide 77)
- $10.7 million (or 42 percent) of BPCG payments accrued in NYC, 83 percent of which were paid to units that were committed for local reliability. (slide 79)
  - ✓ Despite the increase in uplift to NYC reliability-committed units, the amount of reliability commitments there fell by about 10 percent from 2020-Q3.
    - – The NYISO and ConEd have implemented several procedural changes to reduce N-1-1-0 reliability commitment in NYC load pockets in recent years. For example,
      - Since January 2021, NYC load pocket requirements assume the use of 300-hour ratings rather than normal transfer limits after the second contingency.
- DA Local uplift rose on Long Island due to high DARU commitment and oil-burn requirements for gas contingencies during the Y49 & Y50 outages. (slides 34, 79)
  - ✓ In addition, $1.1 million of RT Statewide occurred because the self-scheduled ST needed to be OOMed down to manage constraints in the generation pocket. NYISO is looking to revise BPCG rules to avoid such payments.

Market Highlights:
Forecast Load Pass Commitments

- When the DAM scheduled bid load is lower than forecast load, it is not uncommon that additional physical resources are supplementally committed (in the Forecast Load Pass of SCUC) to satisfy both forecast load and reserve requirements.
  - ✓ However, this need is not currently priced in the market software, leading units committed for this purpose to often recoup their costs through BPCG uplift.
- We evaluated FCT pass commitments since January 2020: (slide 75)
  - ✓ FCT commitments occurred on 60 days in 2020 and 22 days in 2021 (through Q3), although the amount of FCT-committed capacity was modest on most of these days, implying relatively minor impacts on market schedules and prices.
  - ✓ We found that some quick-start capacity is treated as slow-start capacity in the Forecast Pass.
    - – Consequently, most of the FCT commitments would not have been needed to satisfy the forecasted requirements if these quick-start units were recognized as quick-start by the software (i.e., on days when offline quick-start capacity identified on slide 75 well exceeded FCT-committed capacity).
    - – Software changes would be necessary to correct this issue.
    - – Ultimately, we have recommended the NYISO satisfy the forecasted requirements (currently met in the FCT pass) through the market with the dynamic operating reserve enhancements. (See SOM Recommendation #2015-16)

Market Highlights:
SRE for Capacity on High Load Days

- Despite several heat waves this summer, load exceeded 30 GW on just one day.
  - ✓ Load peaked at 30.3 GW on August 26 below the 50/50 forecast of 32.3 GW.
  - ✓ NYISO activated SCR/EDRP for Long Island (< 40 MW) on six days.
  - ✓ NYISO SREed resources for statewide capacity needs on three days.
  - ✓ See presentation "NYISO Summer 2021 Hot Weather Operations" by Wes Yeomans at 9/29 MC meeting for more details.
- We evaluate the three days with SREs for statewide needs:
  - ✓ SREs were needed to prevent brief NYCA capacity deficiencies (not counting utility DR) on July 20 and August 12 but not on July 8. (slides 72 and 73)
    - SREs are necessary to avoid a capacity deficiency when:

      normal 30-min reserve need > all available capacity (without SRE)
    - It would be beneficial if the expected utility DR activation was incorporated into the load forecast when the NYISO is making SRE commitments.
  - ✓ The BPCG uplift from these SREs was not large, but they were incurred to satisfy reserve needs that are not fully reflected in the day-ahead market.
    - We recommend the NYISO satisfy the forecasted requirements (currently met in the FCT pass and/or with SREs) through the market with the dynamic operating reserve enhancements. (See SOM Recommendation #2015-16)

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Market Highlights:
Utility DR Activations on High Load Days

- Various amounts of Utility DR were activated on 10 days this quarter, and the quantity exceeded 200 MW on eight days.
  - ✓ Most of these utility DR activations were for peak-shaving.
  - ✓ The statewide DR quantity ranged up to nearly 650 MW on August 12 (when NYCA daily peak demand was roughly 29.7 GW).
  - ✓ Utility DR deployments are not considered when NYISO evaluates whether to SRE or deploy emergency DR resources, which can lead to unnecessary OOM actions.
- Utility DR deployments helped avoid brief NYCA capacity deficiencies on three days (August 11, 25, & 26). (slides 72 and 73)
  - ✓ 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 and Availability of Duct Burners

- Most combined cycle generators in the NYISO footprint offer supplemental output from their duct burners, totaling roughly 760 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 65 shows an example of a combined-cycle unit that could not follow dispatch instructions during a Reserve Pickup (RPU) event, due largely to its inability to fire the duct burner within the 10-minute timeframe.
  - ✓ However, this duct burner capacity is considered capable of following 5-minute dispatch signals in the market scheduling and pricing software.
  - ✓ This disconnect presents challenges in real-time operations when the duct-firing capacity becomes more valuable under tight system conditions like an RPU event.
- Slide 66 shows duct-firing capacity that was offered but not physically capable of providing a given service in the required timeframe. In afternoon hours, on average:
  - ✓ 136 MW was offered but not capable of following 5-minute ramping instructions;
  - ✓ 51 MW was scheduled for but not capable of providing 10-minute reserves; and
  - ✓ 33 MW was scheduled for but not capable of providing regulation.
  - ✓ In addition, 65 MW of duct-firing capacity was unavailable because of no offer in this range or non-dispatchable due to self-scheduling.

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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 2020 to September 2021: (slides 67-68)
  - ✓ 212 audits (of 129 unique GTs) were conducted, much higher than in prior years.
  - ✓ Audits are useful in assessing capability but do not adequately incent reliable performance.
    - – For example, a 10-minute GT with a historical 40-50 percent performance rating passed its audit upon retesting after an initial failure.
- Further enhancements to this process could be beneficial such as:
  - ✓ Since units that perform well during audits may still perform poorly during normal market operations, it may be appropriate to suspend or disqualify poor performers.
  - ✓ Using performance during reserve pick-ups or economic starts in lieu of audits would reduce out-of-market actions and uplift costs.
  - ✓ The cost of audits may be born by the participant as a cost to participate in the reserve markets, similar to the DMNC testing process.

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 satisfies the DEC standard.
  - ✓ A steam turbine was LRR-committed solely to satisfy the NOx rule on 27 days in the third quarter of 2021 of which 21 were assessed for necessity of the ST commitment. (slide 74)
    - – 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 21 days.
    - – The supply margin (excluding the committed steam turbine and associated GTs) generally exceeded 230 MW each day. (slide 74)
    - – 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.

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Market Highlights:
Use of Operating Reserves to Manage NYC Congestion

- Transmission facilities in New York City can be operated above their Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) are available to quickly reduce flows to LTE.
  - ✓ The availability of post-contingency actions is important because they allow the NYISO to increase flows into load centers in NYC and reduce congestion costs.
- In 2021-Q3, 74 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 64)
  - ✓ The additional capability above LTE averaged from about 10 to 65 MW for the 138 kV constraints in the Greenwood load pocket to roughly 150 to 290 MW for 345 kV facilities in other NYC load pockets.
    - These increases were largely due to operating reserve providers in NYC, but they are not compensated for this service.
    - This reduces incentives to be available in the short term and to invest in flexible resources in the long term.
    - In addition, when the market dispatches this reserve capacity, it can reduce the transfer capability in NYC.
- We have recommended that the NYISO efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria. (see SOM Recommendation #2016-1)

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Market Highlights:
Capacity Market

- Spot capacity prices averaged $9.72/kW-month in LI, $5.19/kW-month in the G-J Locality and ROS, and $5.34/kW-month in NYC this quarter. (slides 85-86)
  - ✓ Prices increased substantially in all regions (86 to 99 percent) from the prior year except in NYC where prices fell by 72 percent (54 percent).
- The NYC spot price fell 72 percent, driven primarily by a 6.3 percent reduction in the LCR from the prior Capability Year ("CY").
  - ✓ The steep reduction in the LCR year-over-year despite no significant changes in the supply mix in-city highlights some deficiencies in the IRM and LCR-setting process discussed in our 2020 SOM Report.
- The UCAP requirements in the G-J Locality and in NYC were not binding in July and August, leading spot prices in both localities to clear at the same level as in ROS in those two months.
- The ROS prices roughly doubled from the prior year, due partly to an increase of 1.8 percent in the IRM. In addition,
  - ✓ The spot price in each month was influenced by higher spot market offers and resultant unsold capacity.
  - ✓ A few units exited the market, most notably Indian Point 3 in May, which outweighed new entry and increased imports.

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Market Highlights:
Functionally Unavailable Capacity on Highest Load Days

- We examined the availability of procured capacity from certain conventional resources on the 10 highest load days this summer. (slide 87)
- Emergency capacity (i.e., capacity offered above a generator's normal UOL) totaled 187 MW from Steam generators and 290 MW from peakers.
  - ✓ Emergency capacity is only activated under Emergency Operations.
  - ✓ For some units, operating in the emergency range may increase trip risk, but this is risk is not accurately accounted for in the EFORd calculations.
    - Hence, operators may be reluctant to utilize this capacity during an emergency.
- Some steam and nuclear units are classified as ambient-condition dependent units due to ambient water temperature limitations.
  - ✓ An average amount of 112 MW of ambient water related deratings from such units occurred on these 10 days. This type of derating is not considered in EFORd.
  - ✓ In addition, the current DMNC test procedures only require "internal combustion, combustion units and combined cycle units" to be temperature adjusted.
    - Consequently, steam and nuclear units do not adjust DMNC test results, even for predictable ambient water related deratings.
- Steam units averaged 129 MW of drag when instructed to UOL and more than 1 GW of steam capacity never generated on any of the 10-highest load days.

Charts:
Market Outcomes

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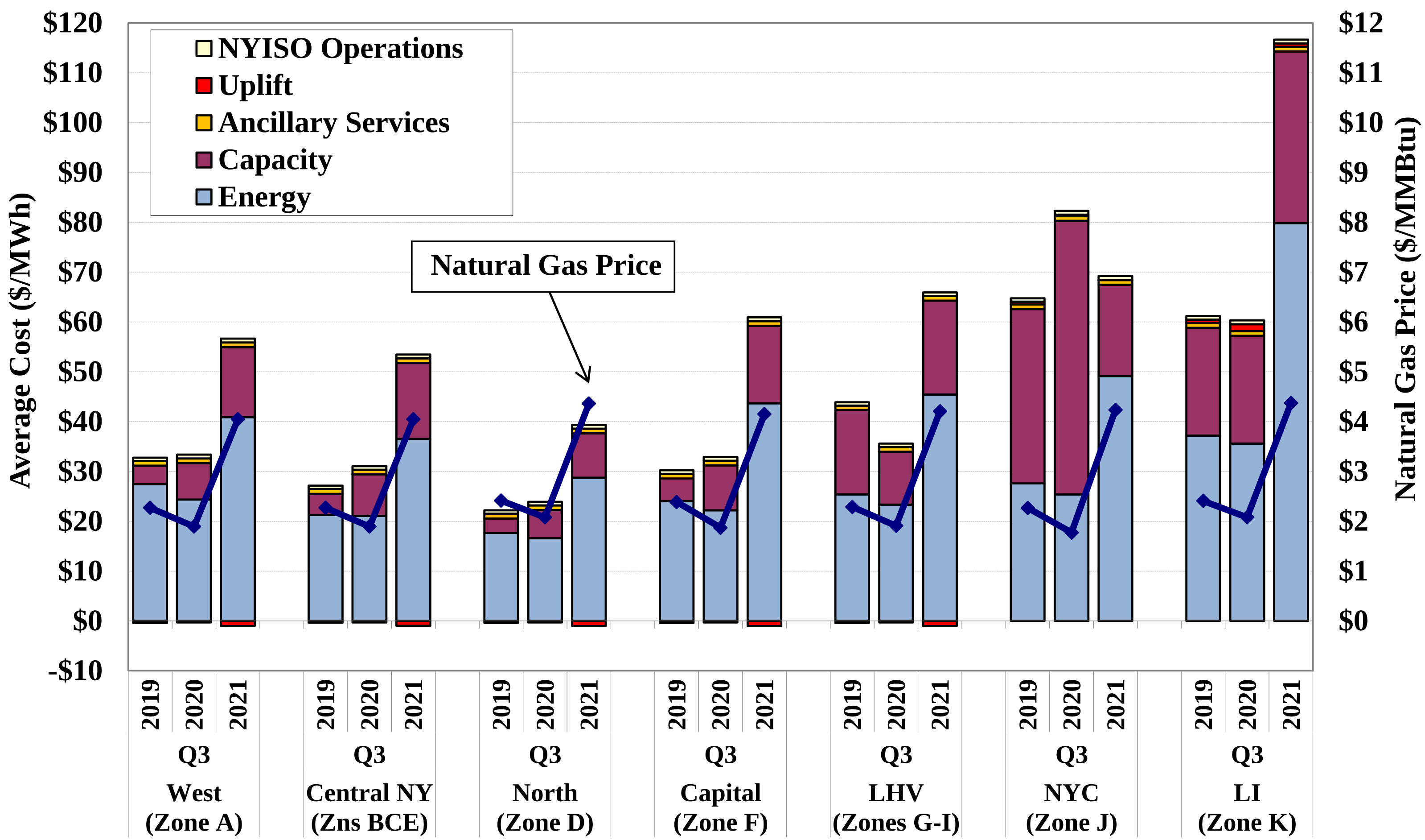
All-In Prices by Region



Notes: For chart description, see slide 89.

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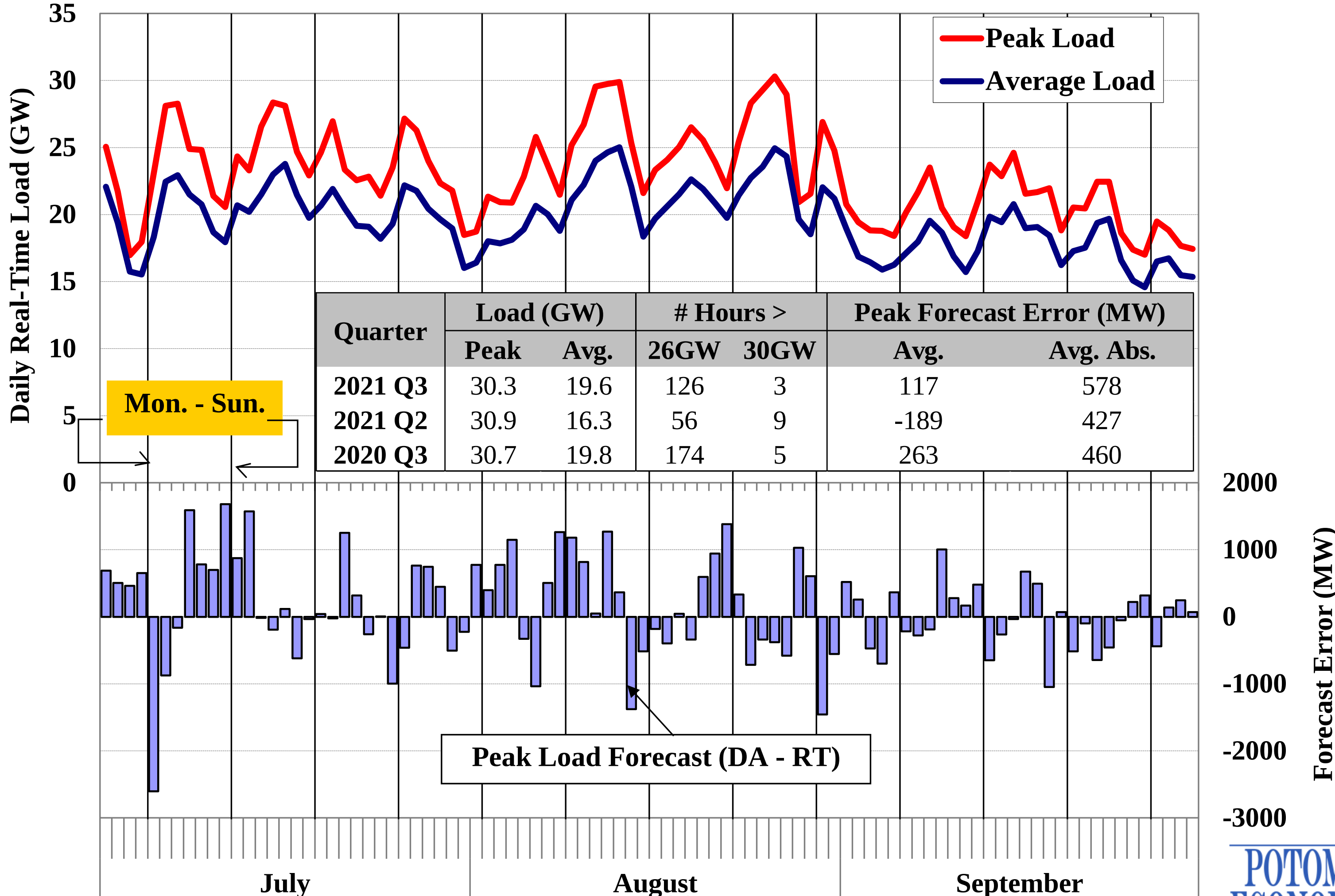
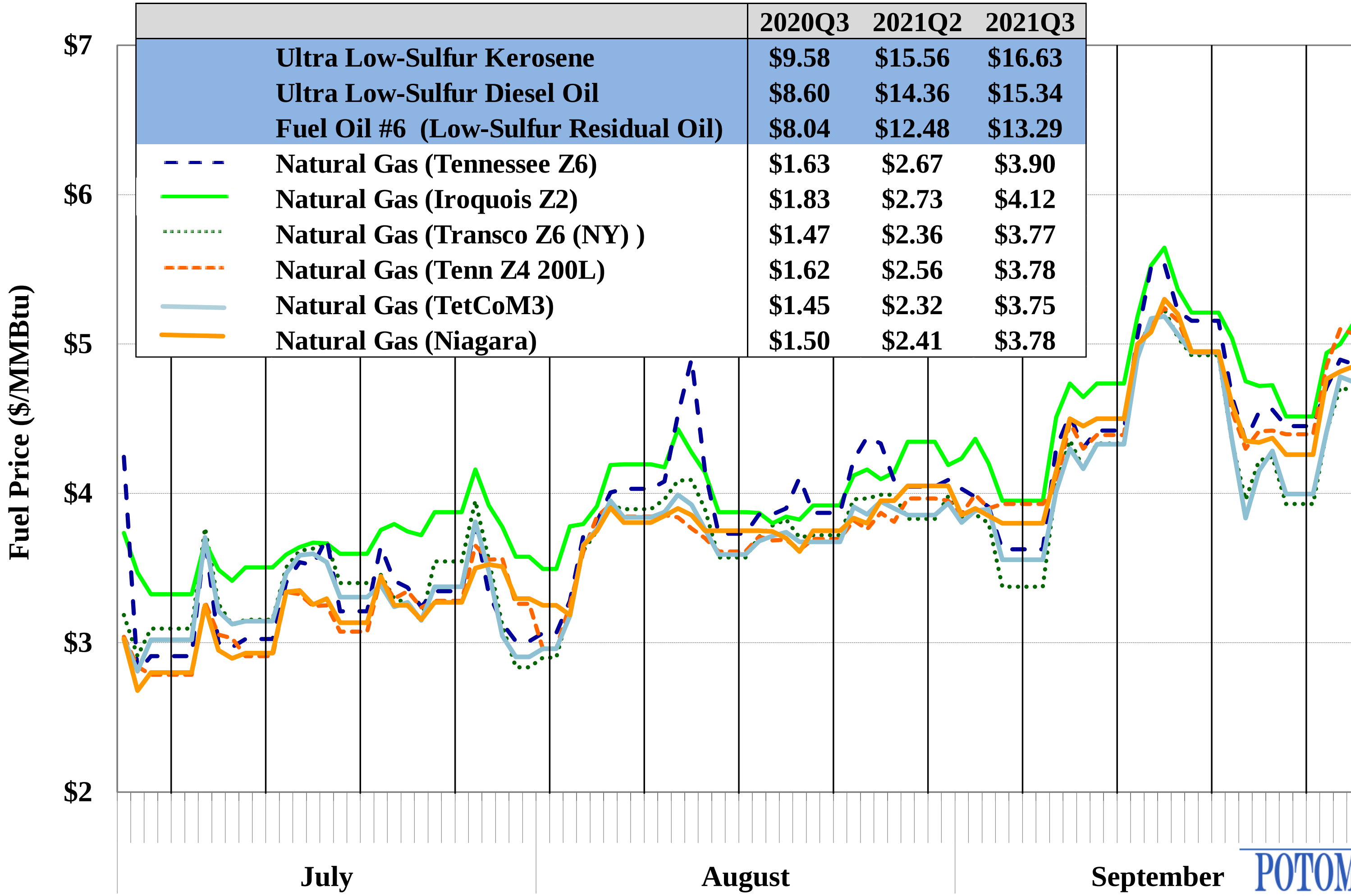
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2021 Q3	30.3	19.6	126	3	117	578
2021 Q2	30.9	16.3	56	9	-189	427
2020 Q3	30.7	19.8	174	5	263	460

Natural Gas and Fuel Oil Prices



	2020Q3	2021Q2	2021Q3
Ultra Low-Sulfur Kerosene	$9.58	$15.56	$16.63
Ultra Low-Sulfur Diesel Oil	$8.60	$14.36	$15.34
Fuel Oil #6 (Low-Sulfur Residual Oil)	$8.04	$12.48	$13.29
Natural Gas (Tennessee Z6)	$1.63	$2.67	$3.90
Natural Gas (Iroquois Z2)	$1.83	$2.73	$4.12
Natural Gas (Transco Z6 (NY))	$1.47	$2.36	$3.77
Natural Gas (Tenn Z4 200L)	$1.62	$2.56	$3.78
Natural Gas (TetCoM3)	$1.45	$2.32	$3.75
Natural Gas (Niagara)	$1.50	$2.41	$3.78

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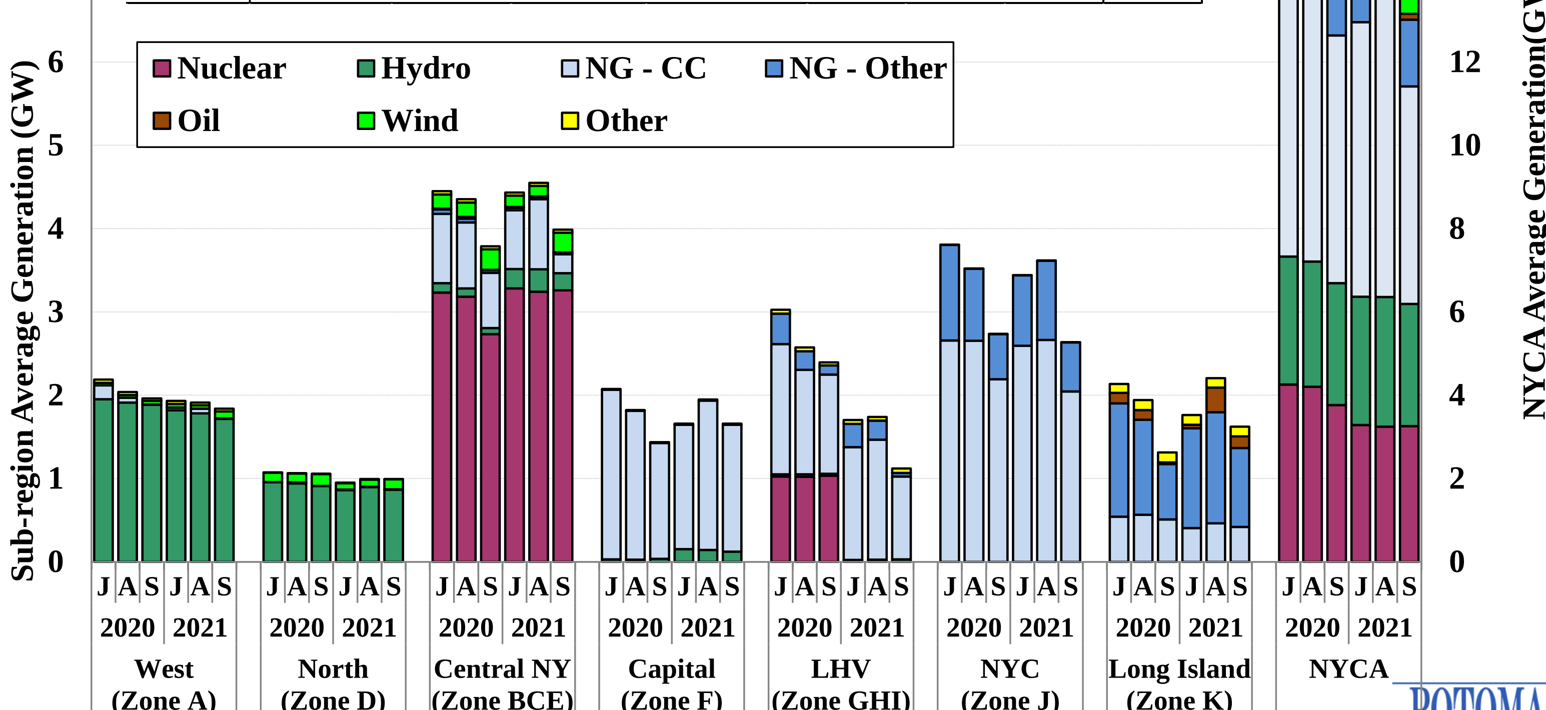
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Total
2021 Q3	3.26	3.05	6.37	2.17	0.17	0.31	0.25	15.58
2021 Q2	3.52	2.99	5.10	1.12	0.02	0.43	0.25	13.44
2020 Q3	4.08	3.00	6.96	2.19	0.10	0.35	0.25	16.94



  Notes: For chart description, see slide 90.

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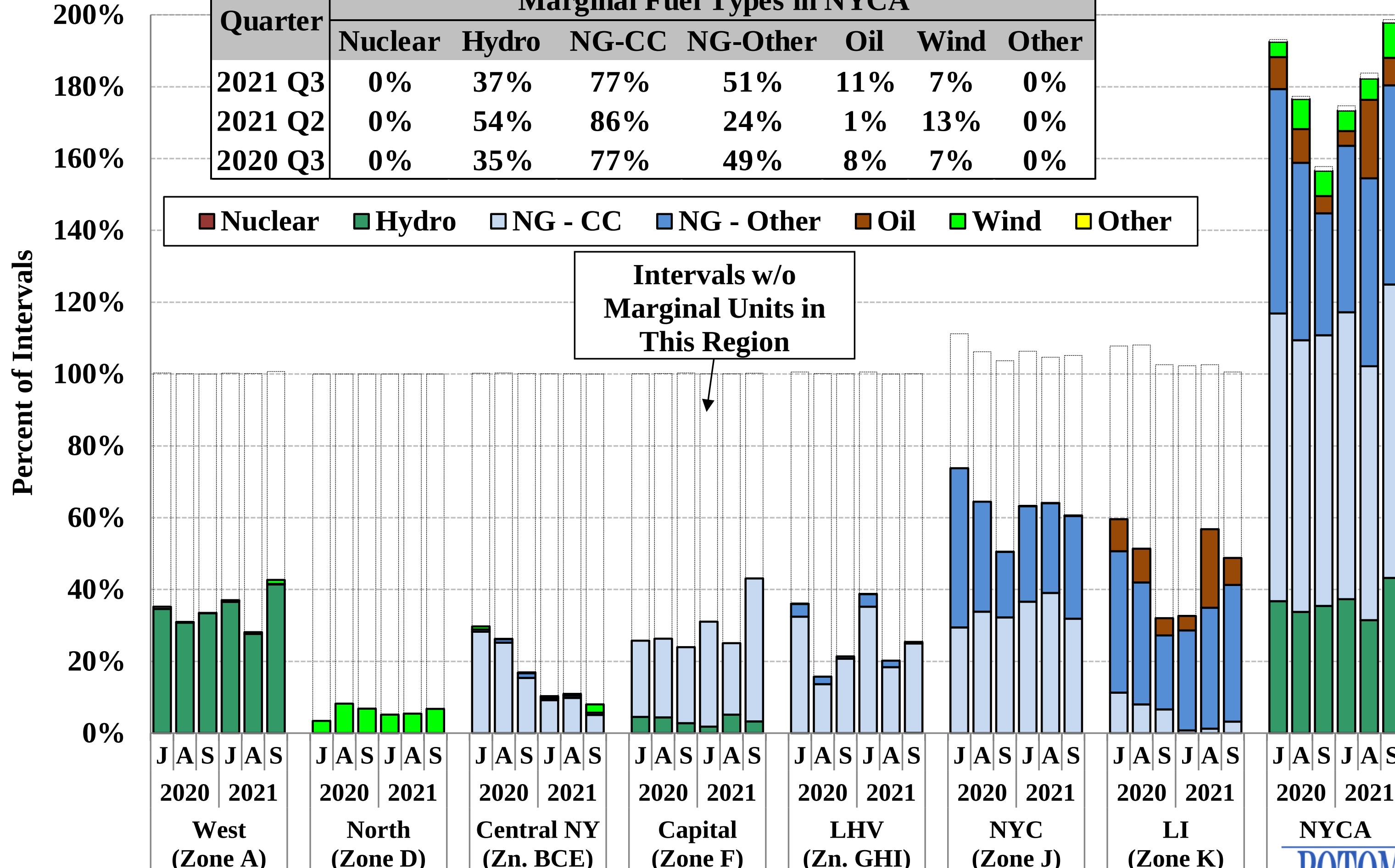
Fuel Type of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other
2021 Q3	0%	37%	77%	51%	11%	7%	0%
2021 Q2	0%	54%	86%	24%	1%	13%	0%
2020 Q3	0%	35%	77%	49%	8%	7%	0%



Notes: For chart description, see slide 90.

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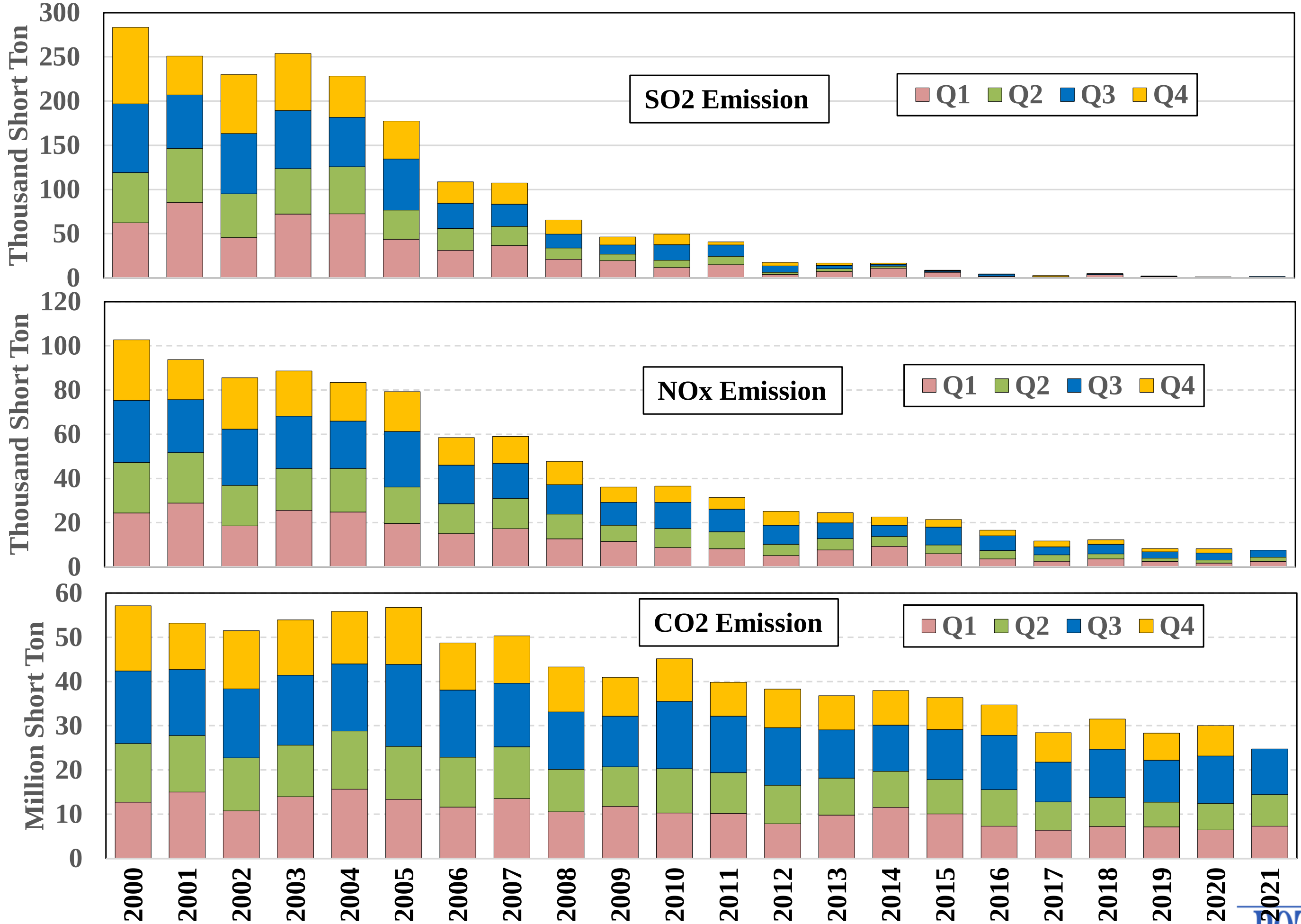
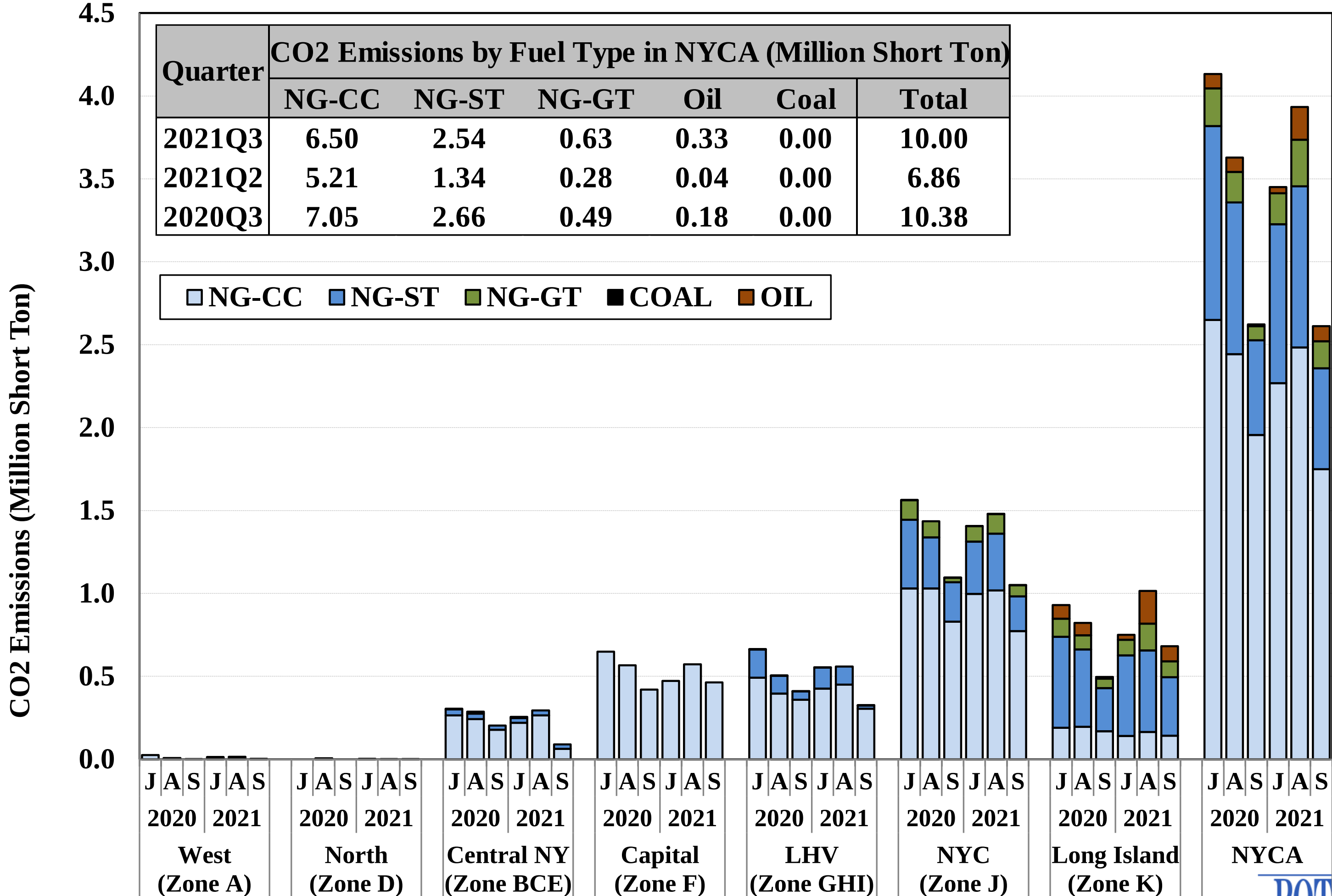
Historical Emissions by Quarter in NYCA
CO_2, SO_2 , and NO_X



Notes: For chart description, see slide 91.

Emissions by Region by Fuel Type
CO_2 Emissions

Quarter	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)					
	NG-CC	NG-ST	NG-GT	Oil	Coal	Total
2021Q3	6.50	2.54	0.63	0.33	0.00	10.00
2021Q2	5.21	1.34	0.28	0.04	0.00	6.86
2020Q3	7.05	2.66	0.49	0.18	0.00	10.38



Notes: For chart description, see slide 91.

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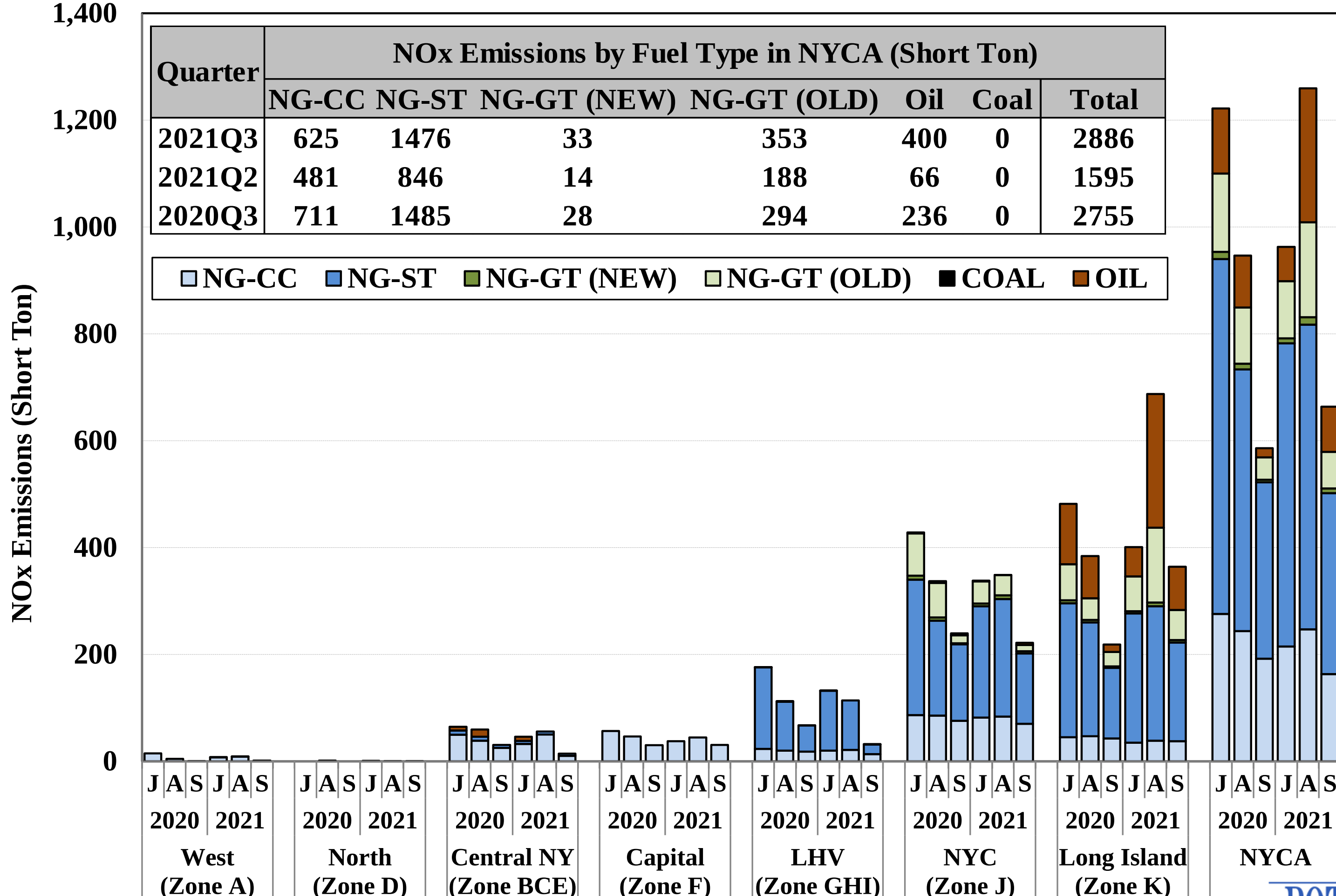
Emissions by Region by Fuel Type
NO_X Emissions

Quarter	NOx Emissions by Fuel Type in NYCA (Short Ton)						
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Coal	Total
2021Q3	625	1476	33	353	400	0	2886
2021Q2	481	846	14	188	66	0	1595
2020Q3	711	1485	28	294	236	0	2755



Notes: For chart description, see slide 91.

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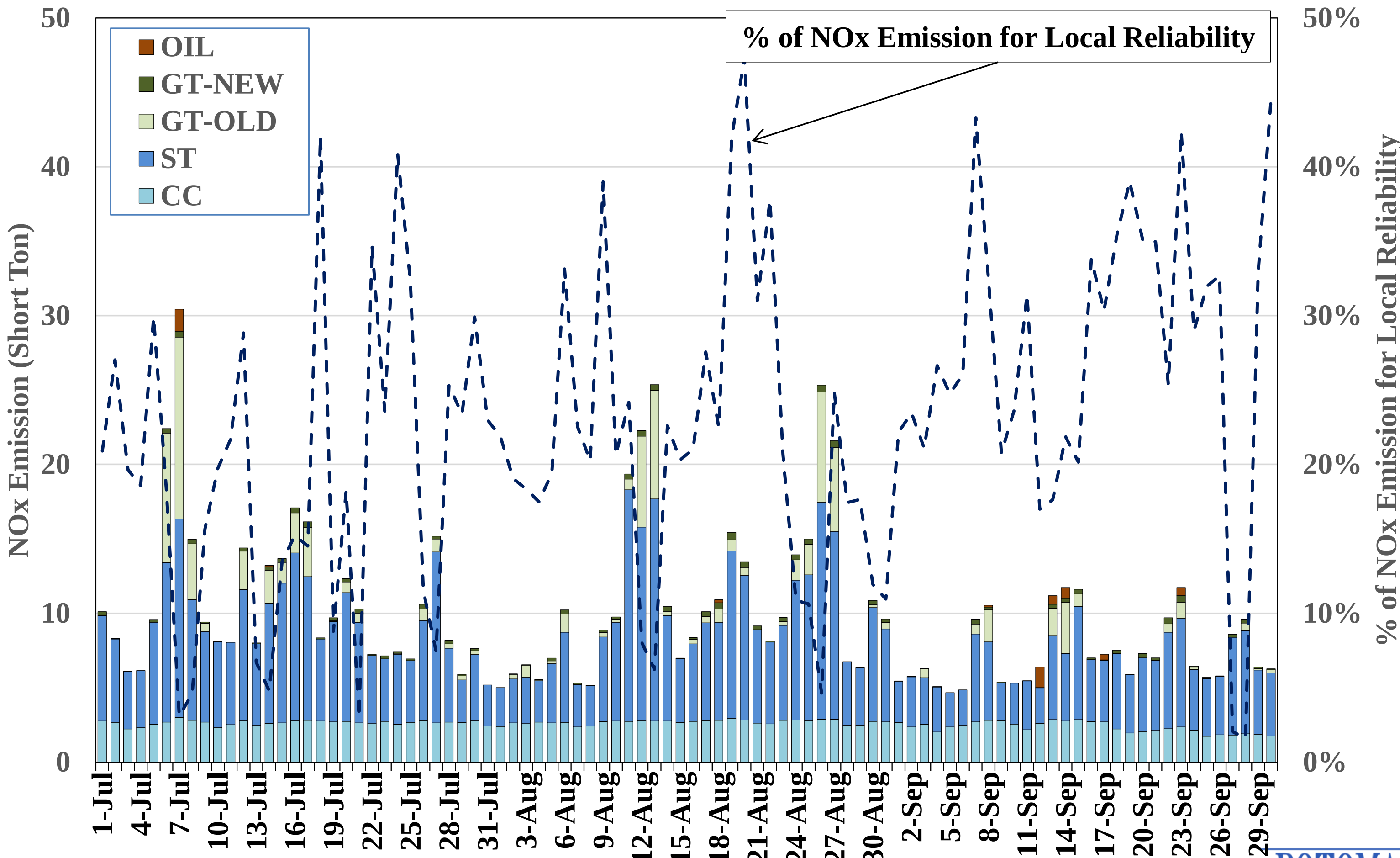
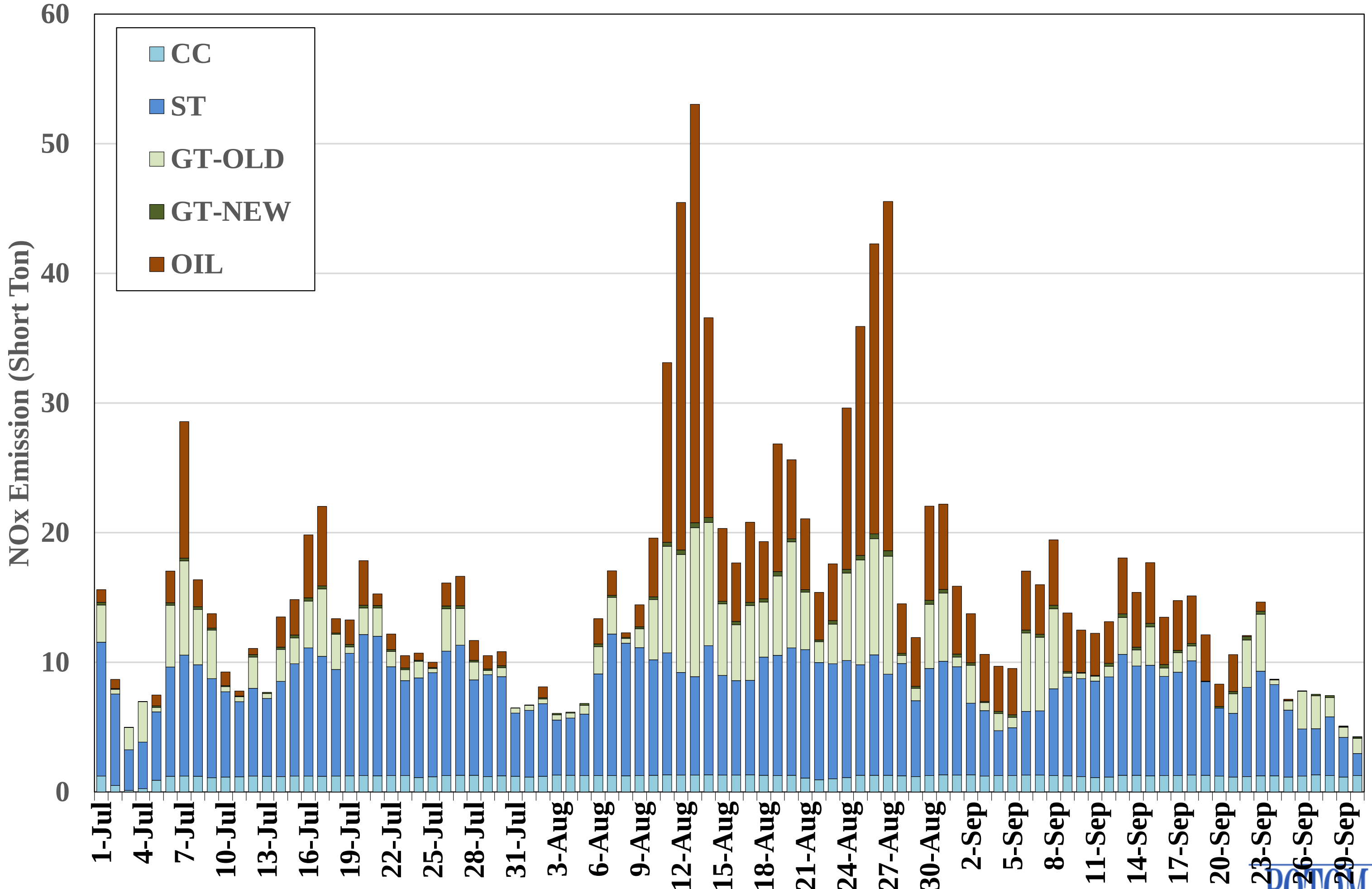
Daily NO_X Emissions in NYC



  Notes: For chart description, see slide 91.

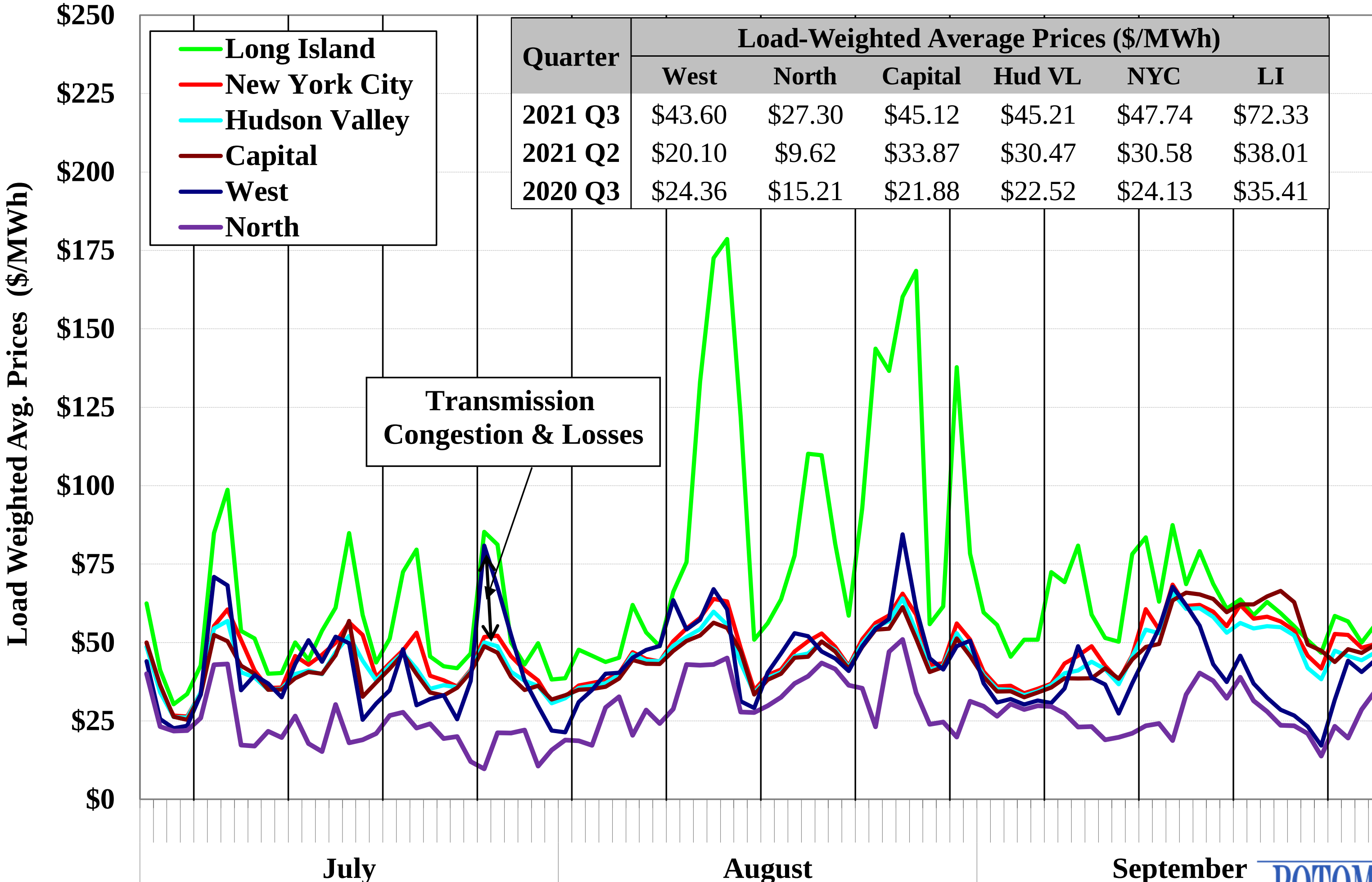
Daily NO_X Emissions in Long Island



  Notes: For chart description, see slide 91.

POTOMAC ECONOMICS

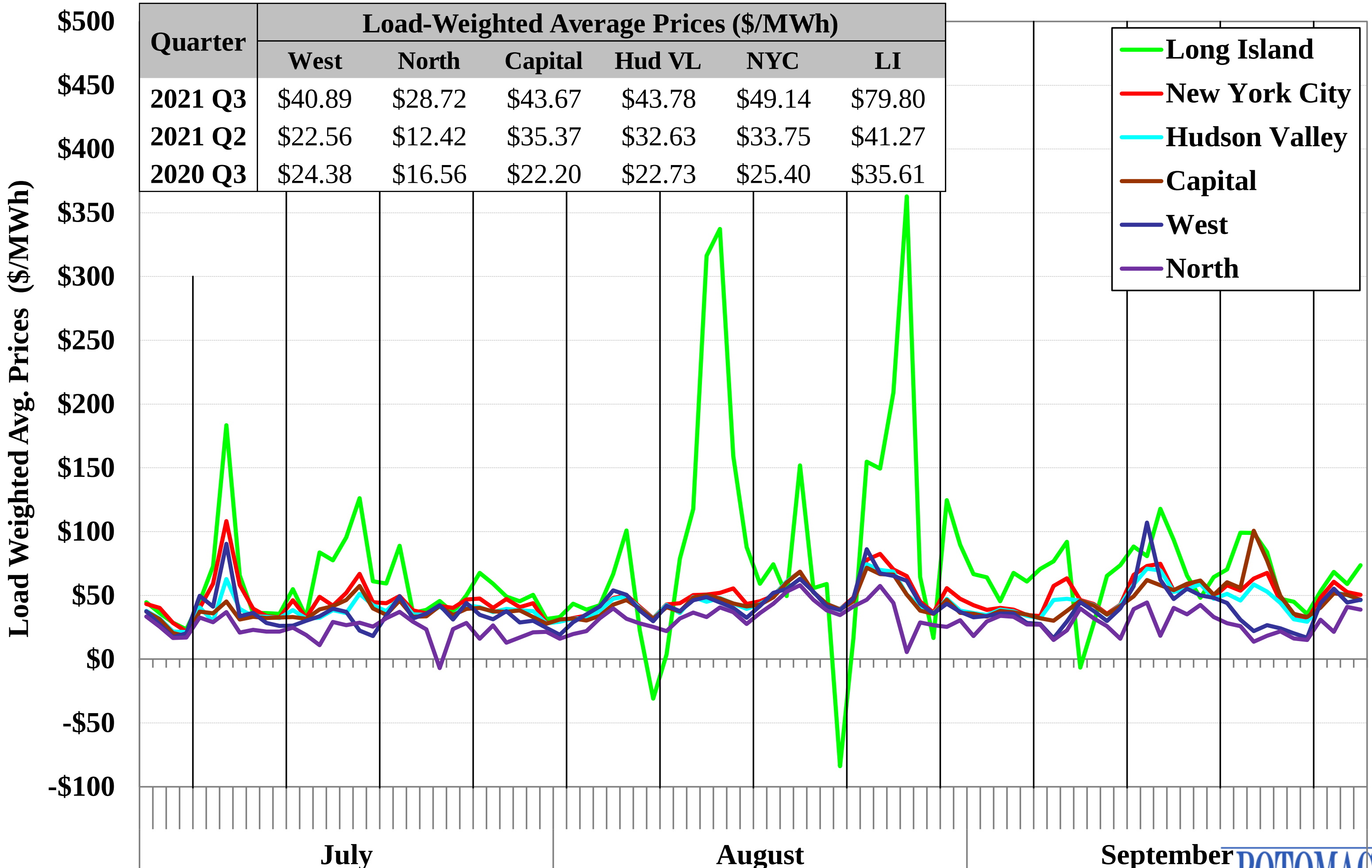
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q3	$43.60	$27.30	$45.12	$45.21	$47.74	$72.33
2021 Q2	$20.10	$9.62	$33.87	$30.47	$30.58	$38.01
2020 Q3	$24.36	$15.21	$21.88	$22.52	$24.13	$35.41

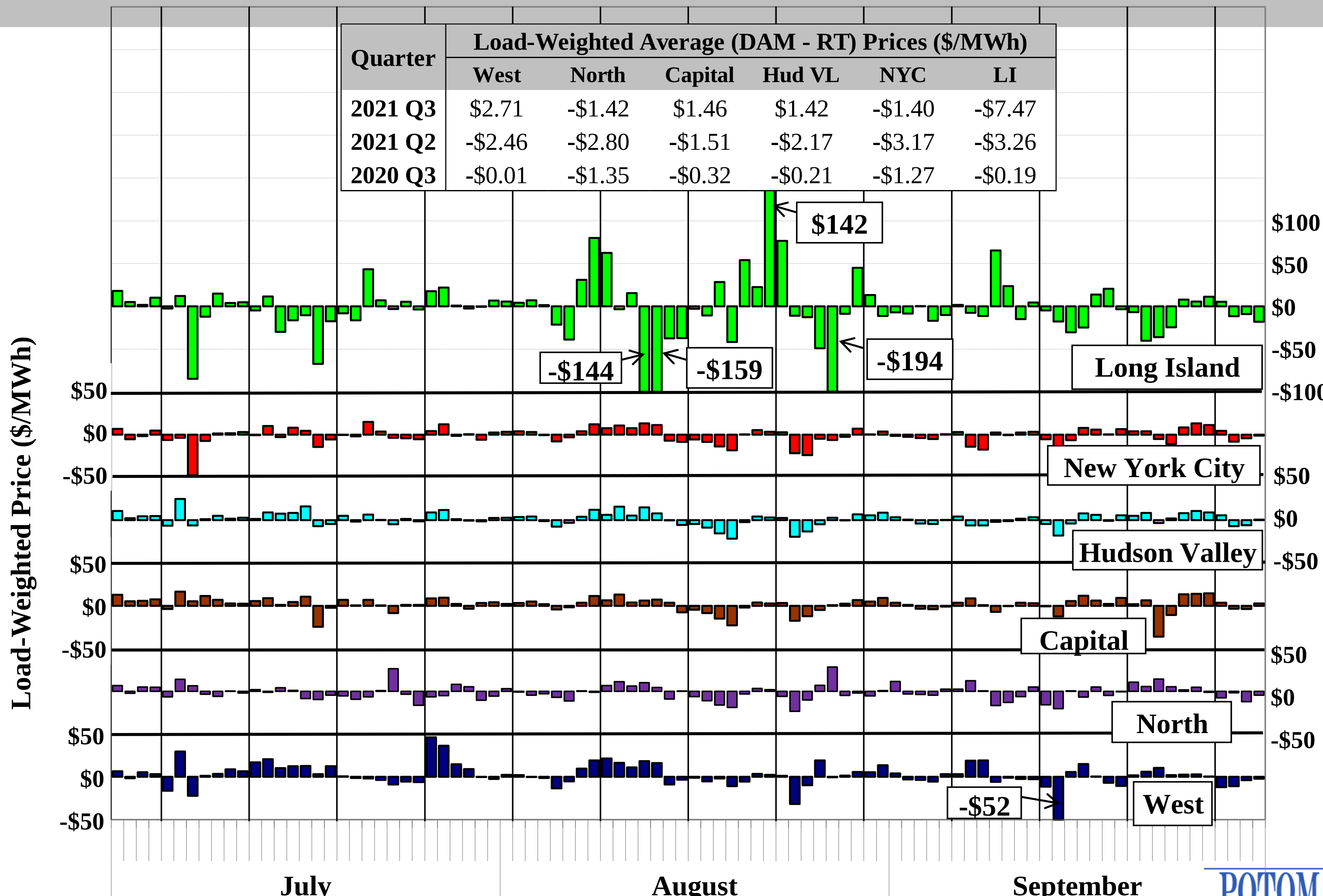
Real-Time Electricity Prices by Zone

Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q3	$40.89	$28.72	$43.67	$43.78	$49.14	$79.80
2021 Q2	$22.56	$12.42	$35.37	$32.63	$33.75	$41.27
2020 Q3	$24.38	$16.56	$22.20	$22.73	$25.40	$35.61

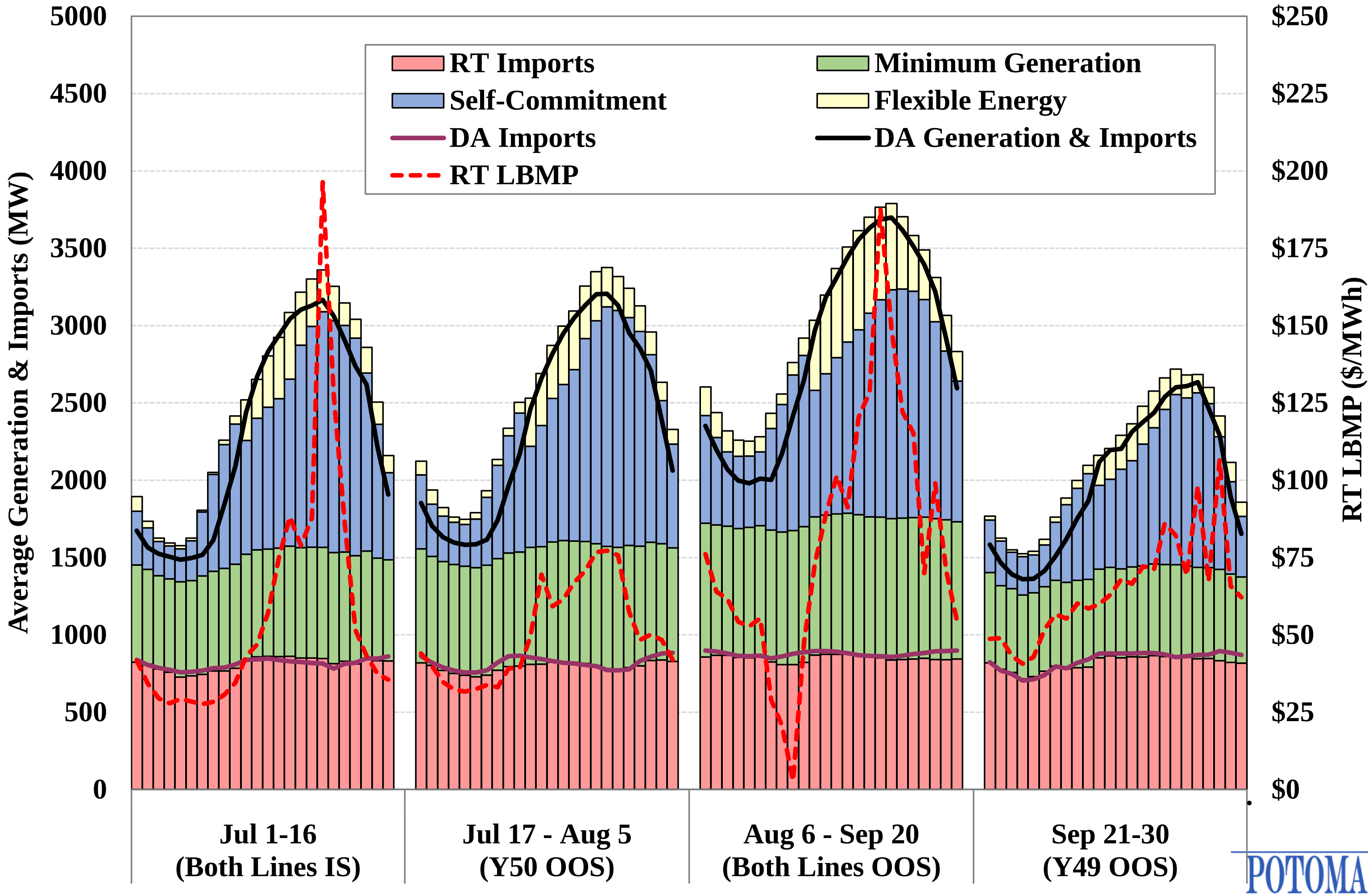


Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q3	$2.71	-$1.42	$1.46	$1.42	-$1.40	-$7.47
2021 Q2	-$2.46	-$2.80	-$1.51	-$2.17	-$3.17	-$3.26
2020 Q3	-$0.01	-$1.35	-$0.32	-$0.21	-$1.27	-$0.19



Real-Time Scheduling on Long Island
Inflexible Supply and LBMPs



Notes: For chart description, see slide 92.

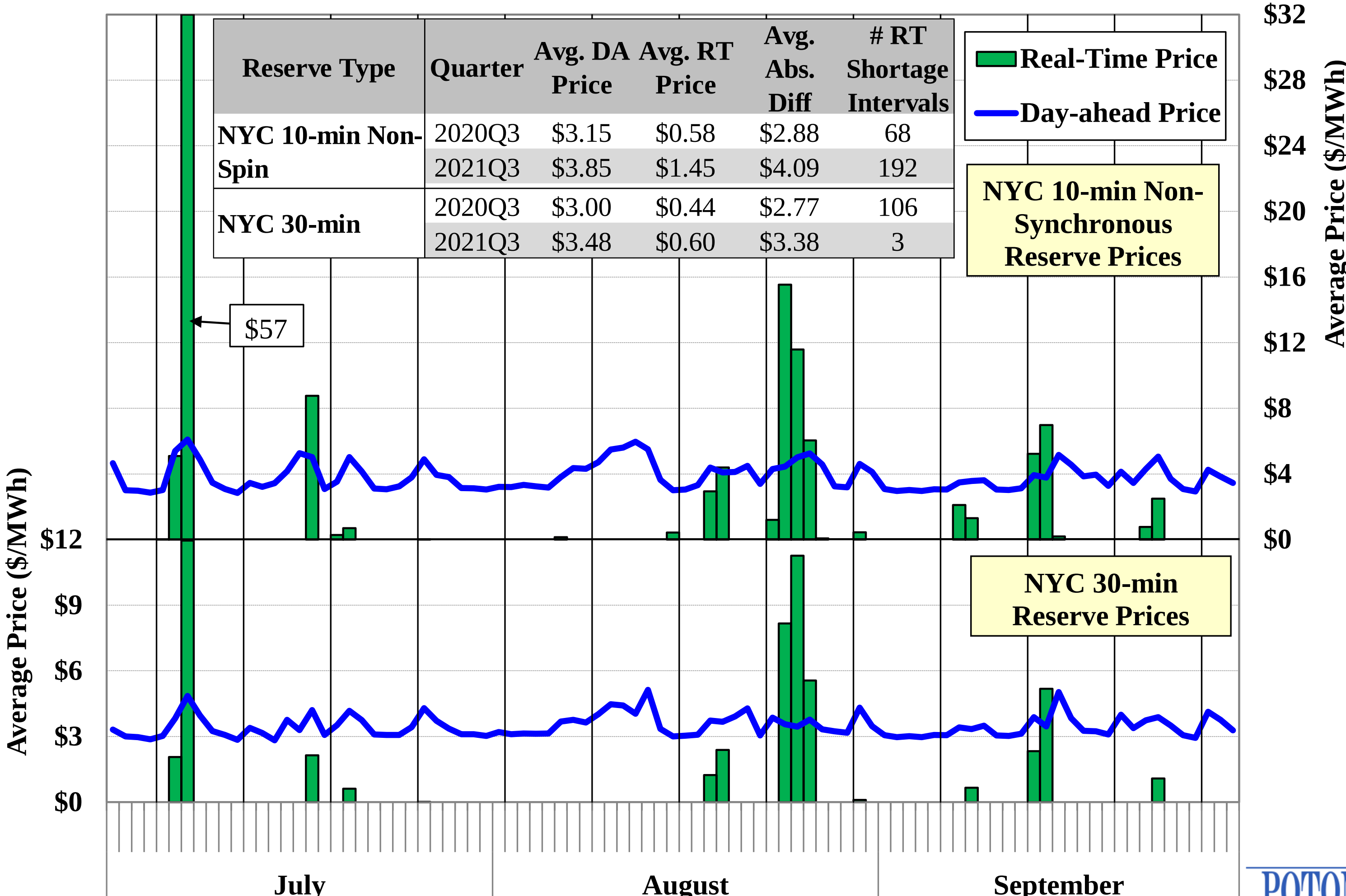
POTOMAC ECONOMICS

Charts:

Ancillary Services Market

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

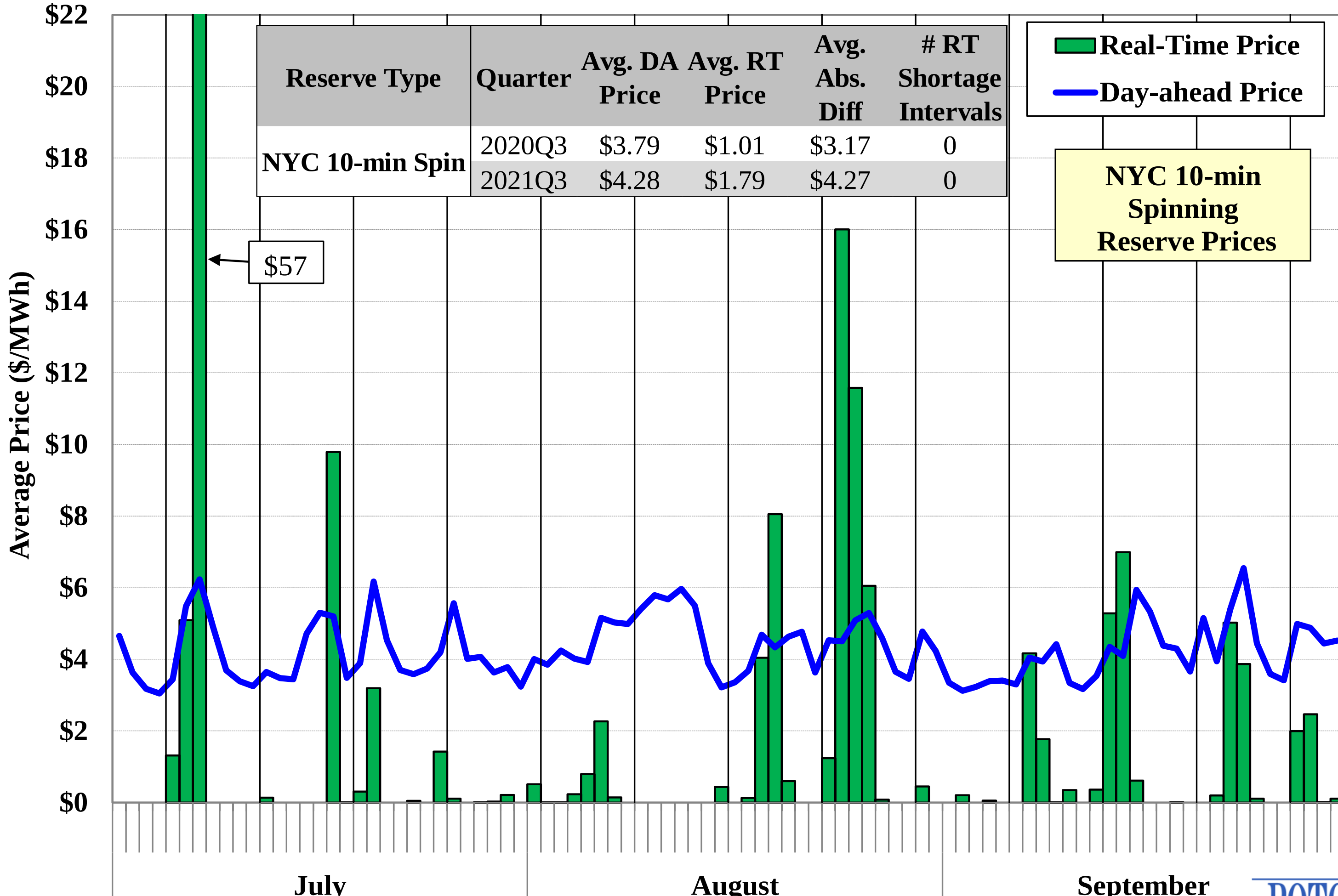
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2020Q3	$3.15	$0.58	$2.88	68
	2021Q3	$3.85	$1.45	$4.09	192
NYC 30-min	2020Q3	$3.00	$0.44	$2.77	106
	2021Q3	$3.48	$0.60	$3.38	3



Notes: For chart description, see slide 93.

POTOMAC ECONOMICS

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

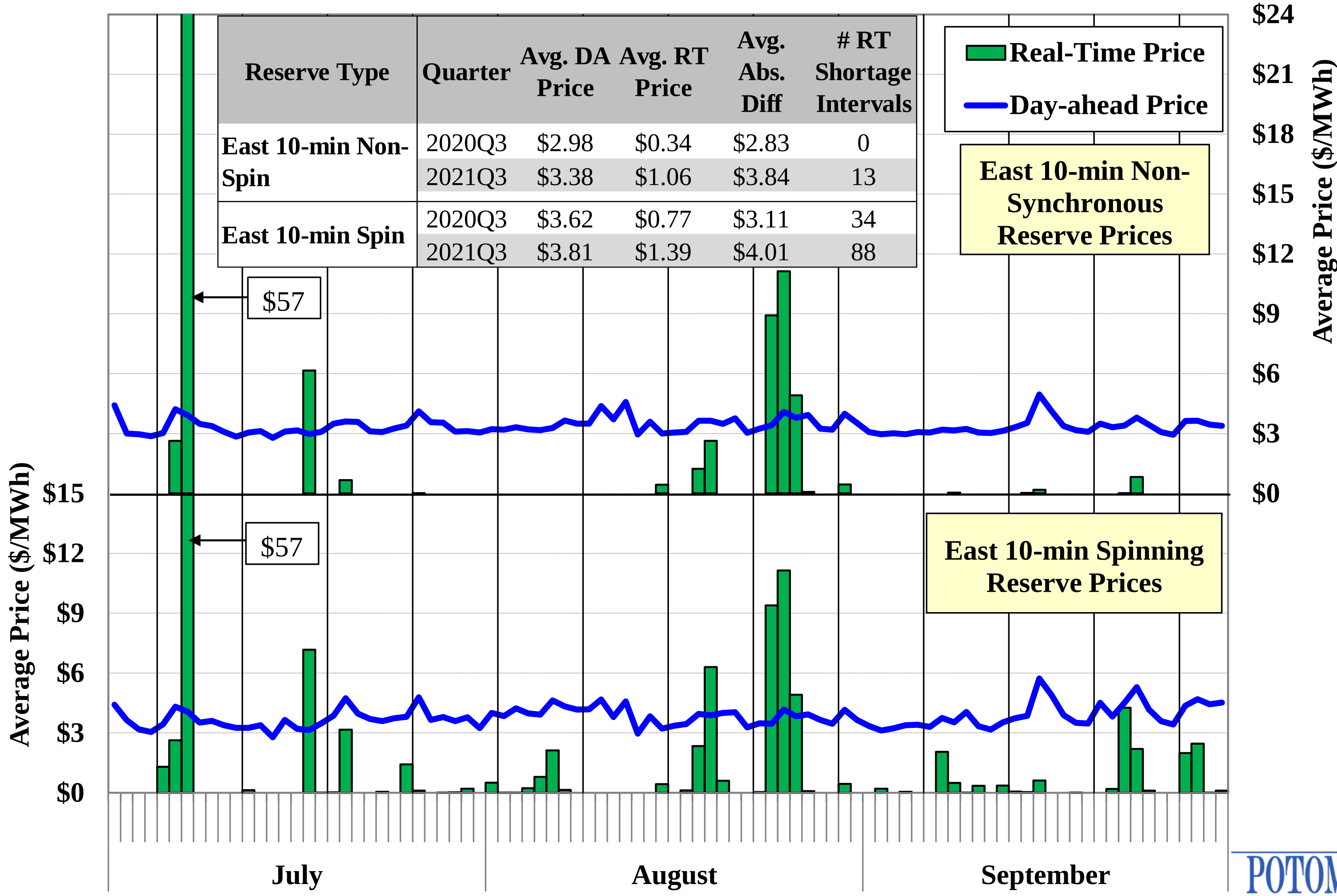


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2020Q3	$3.79	$1.01	$3.17	0
	2021Q3	$4.28	$1.79	$4.27	0

Notes: For chart description, see slide 93.

POTOMAC ECONOMICS

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



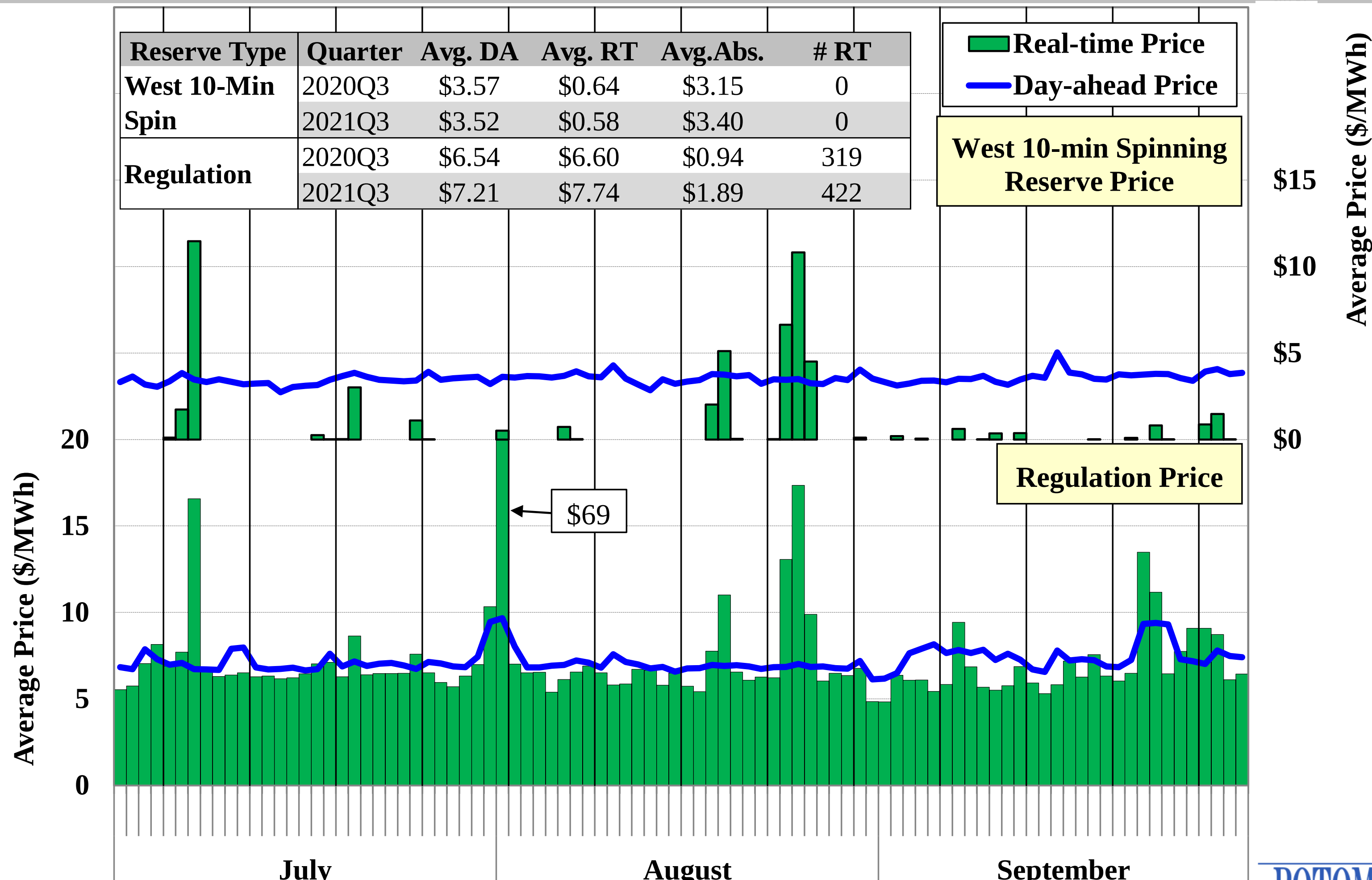
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2020Q3	$2.98	$0.34	$2.83	0
	2021Q3	$3.38	$1.06	$3.84	13
East 10-min Spin	2020Q3	$3.62	$0.77	$3.11	34
	2021Q3	$3.81	$1.39	$4.01	88

Notes: For chart description, see slide 93.

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	2020Q3	$3.57	$0.64	$3.15	0
	2021Q3	$3.52	$0.58	$3.40	0
Regulation	2020Q3	$6.54	$6.60	$0.94	319
	2021Q3	$7.21	$7.74	$1.89	422

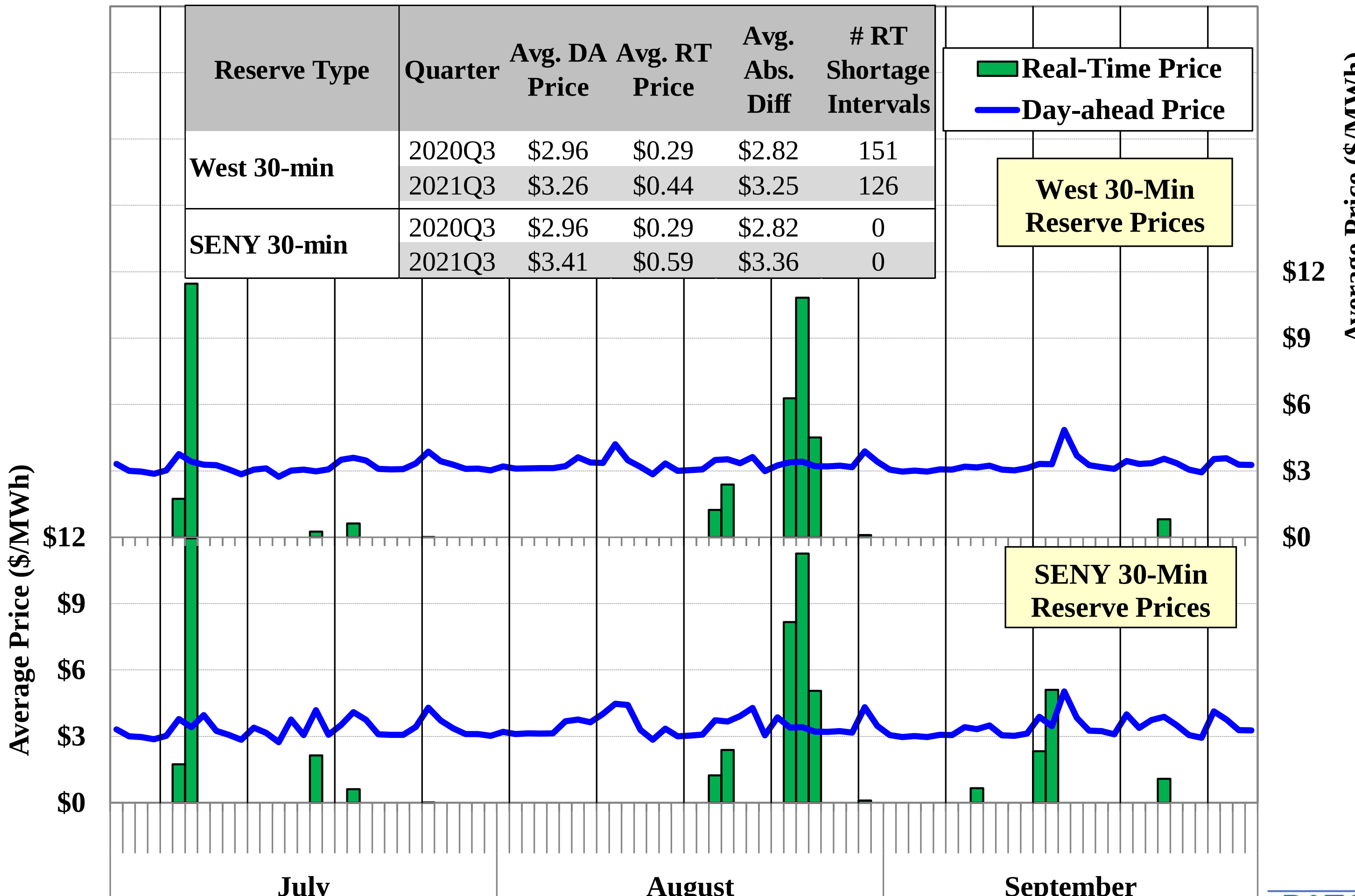


  Notes: For chart description, see slide 93.

POTOMAC ECONOMICS

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

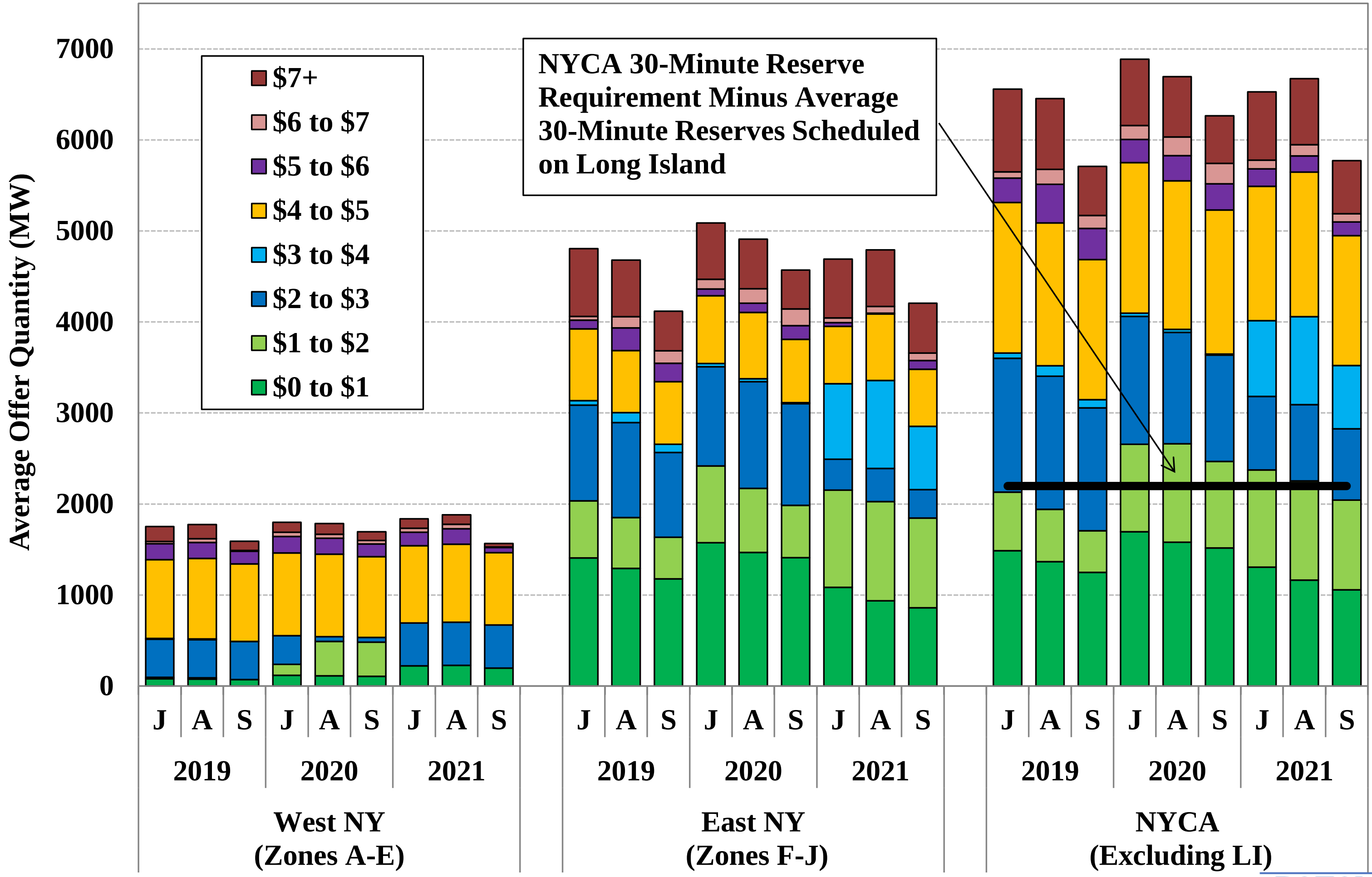
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2020Q3	$2.96	$0.29	$2.82	151
	2021Q3	$3.26	$0.44	$3.25	126
SENY 30-min	2020Q3	$2.96	$0.29	$2.82	0
	2021Q3	$3.41	$0.59	$3.36	0



 Notes: For chart description, see slide 93.

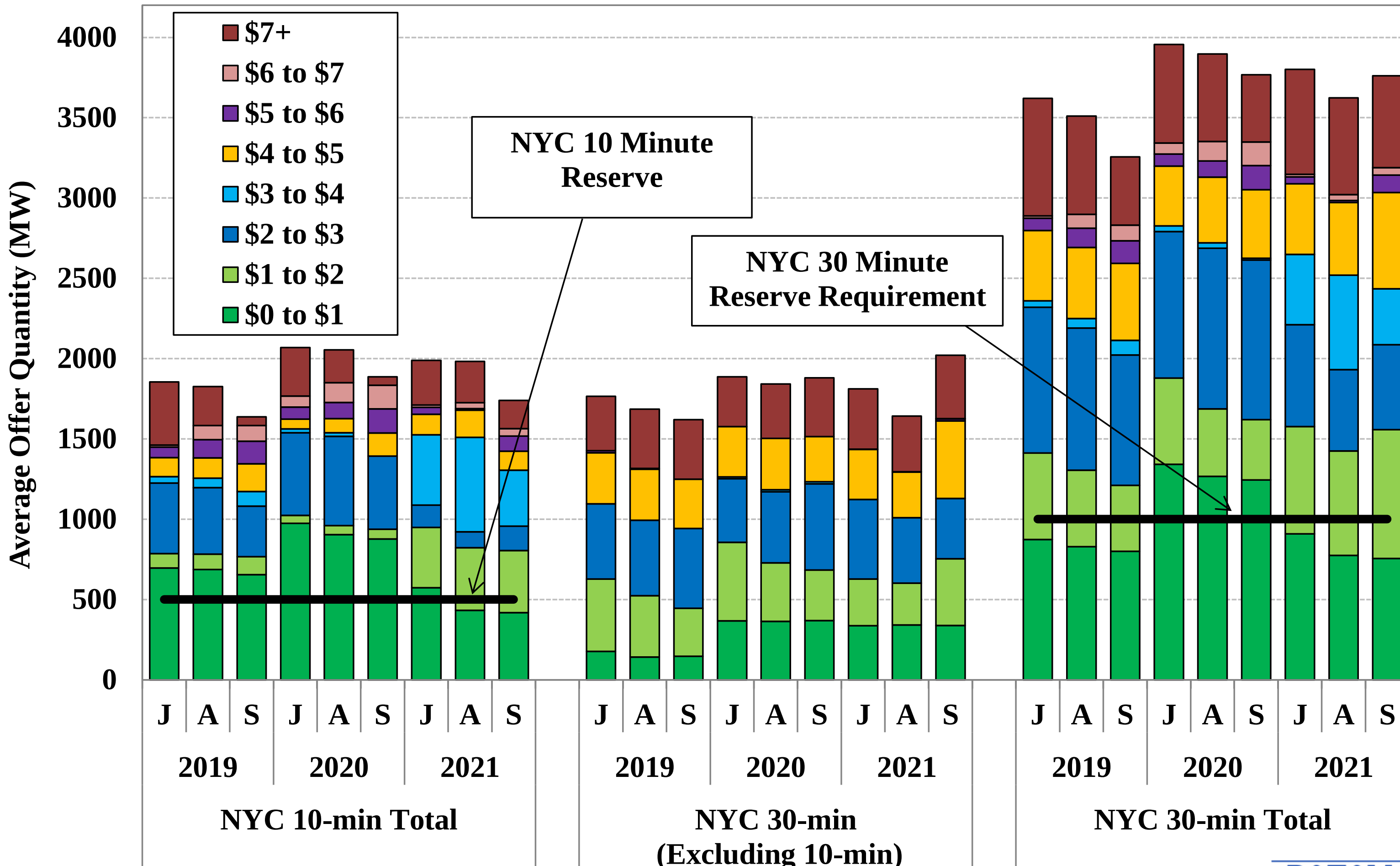
POTOMAC ECONOMICS

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



Notes: For chart description, see slide 94.

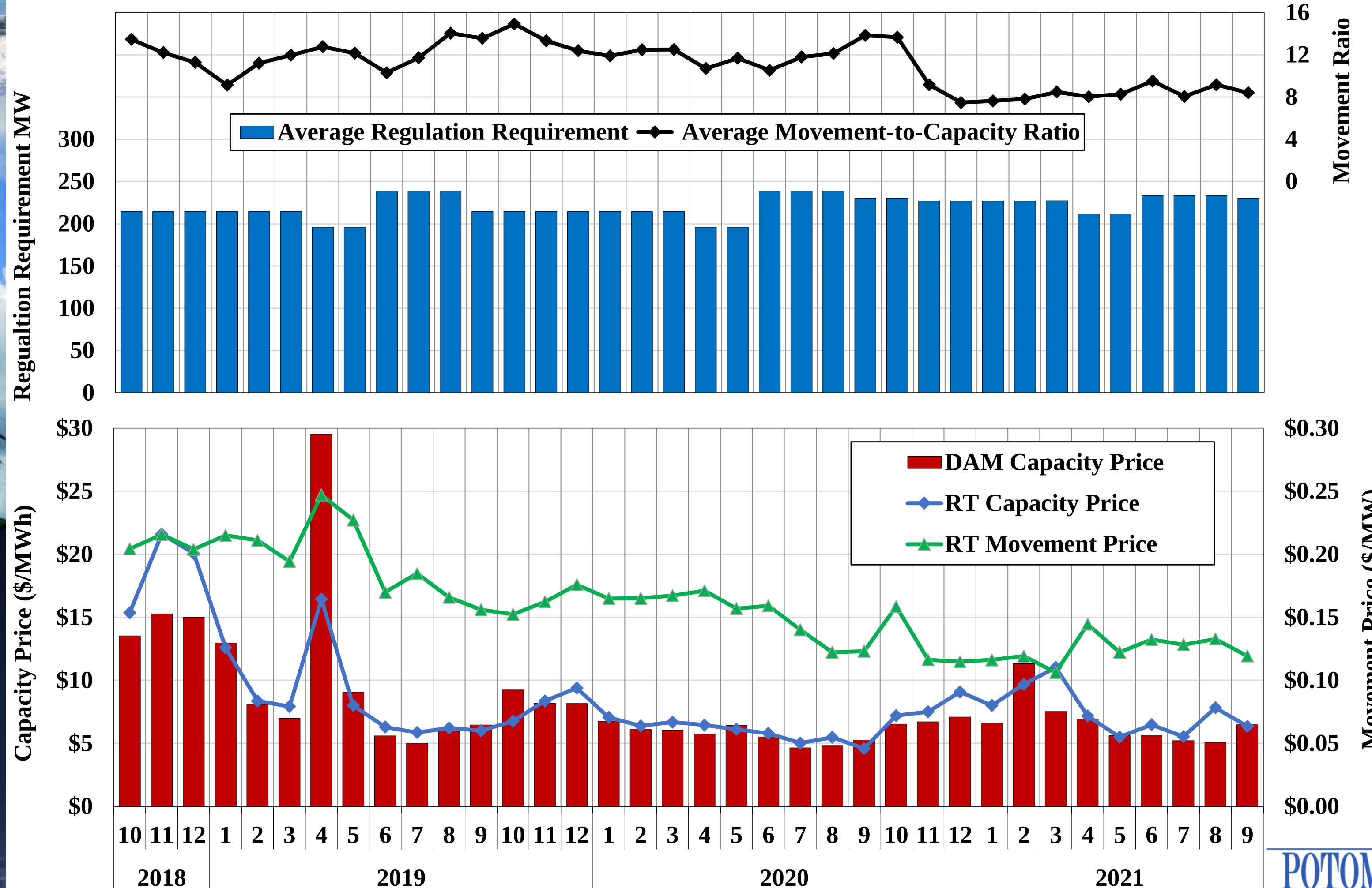
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 94.

POTOMAC ECONOMICS

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



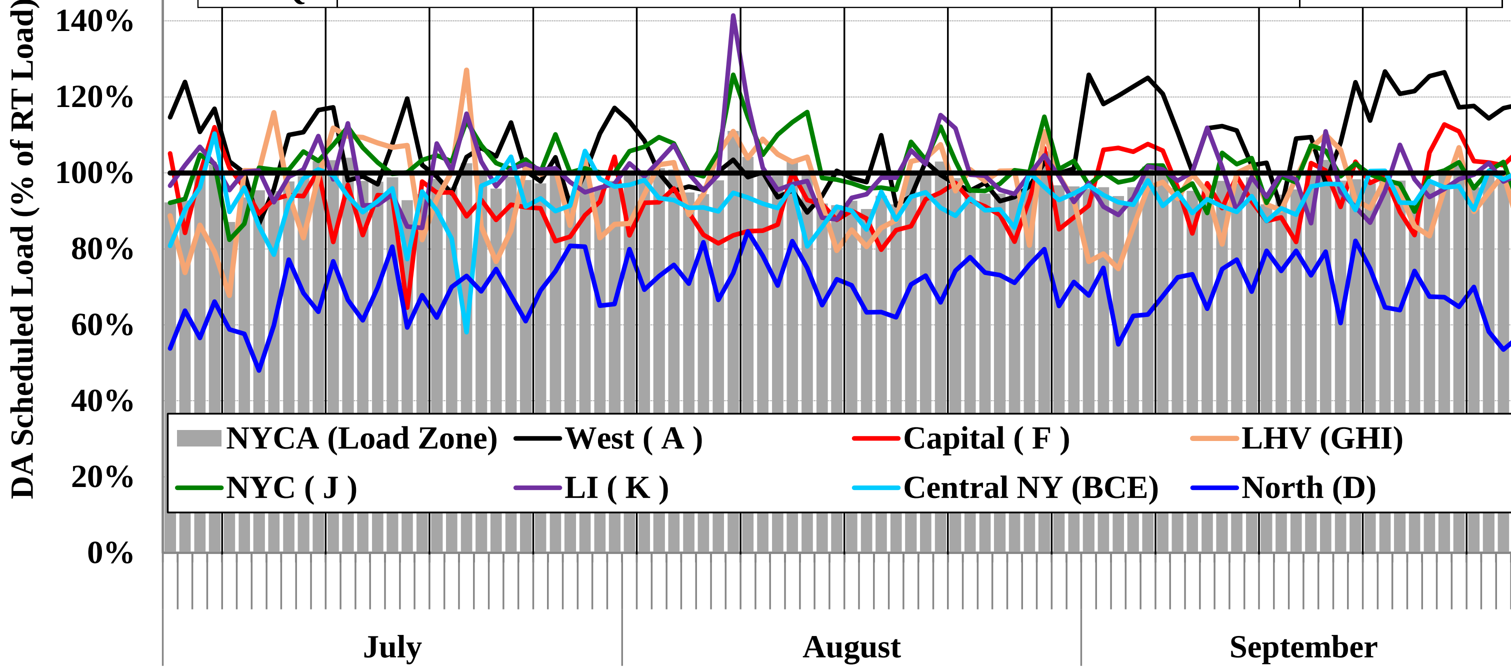
Notes: For chart description, see slide 95.

POTOMAC ECONOMICS

Charts:
Energy Market Scheduling

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

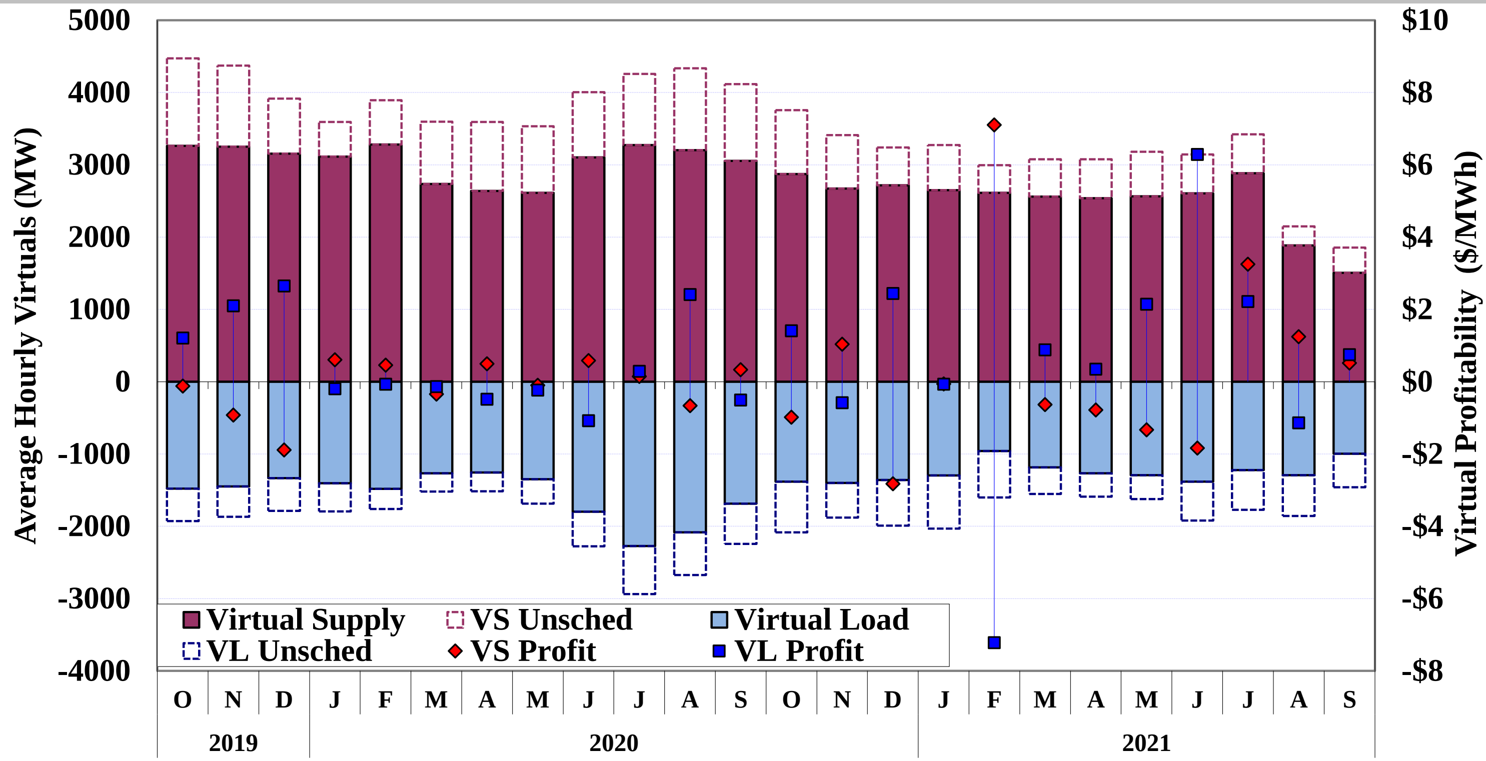
Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2021 Q3	105%	93%	69%	93%	96%	102%	99%	98%	96%
2021 Q2	108%	93%	66%	93%	89%	98%	101%	96%	94%
2020 Q3	108%	89%	64%	83%	88%	100%	101%	95%	94%



Notes: For chart description, see slide 96.

POTOMAC ECONOMICS

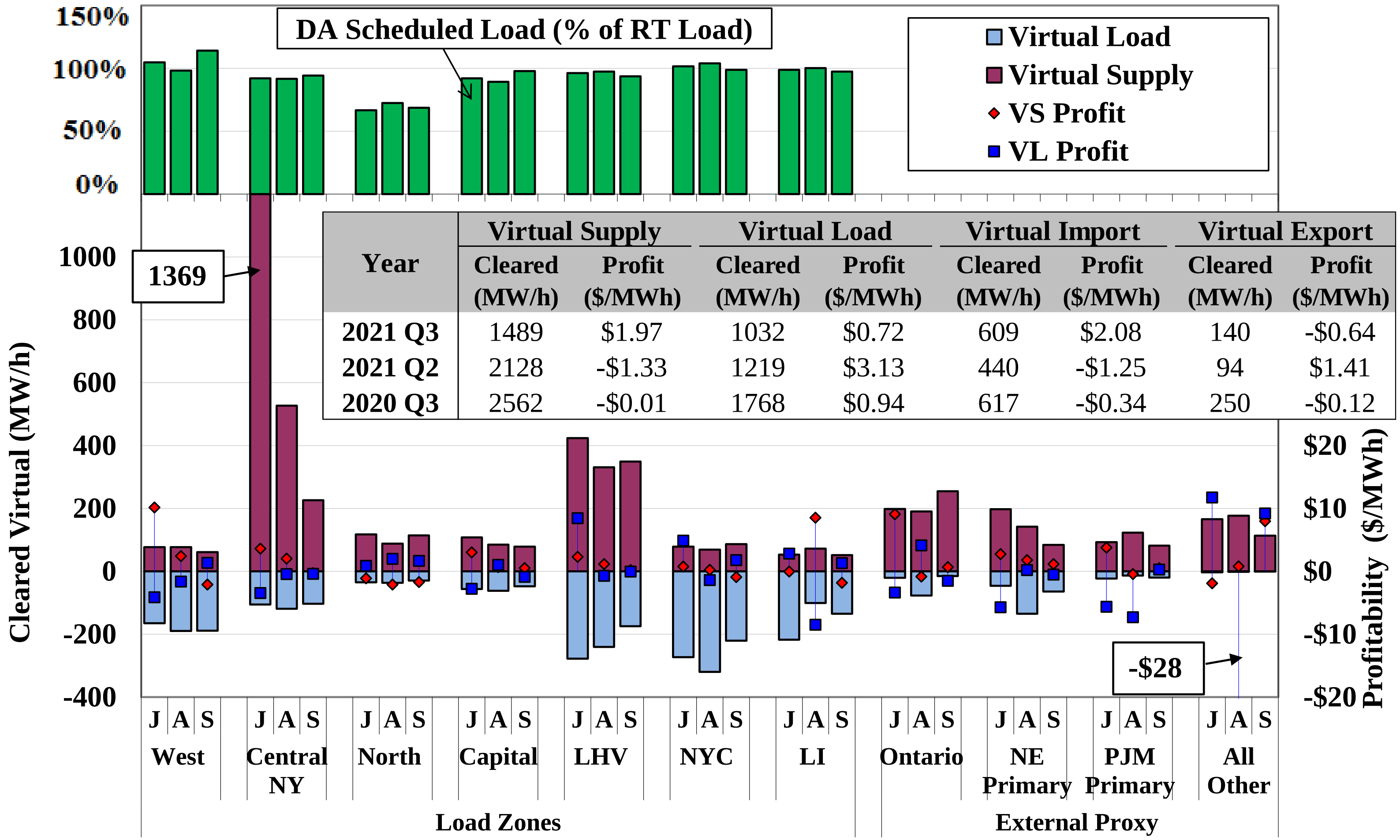
Virtual Trading Activity
by Month



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
Profit > 50% of Avg. Zone Price	MW	312	290	274	421	322	232	370	388	464	416	377	196	235	619	375	320	658	514	549	378	325	413	158	158
	%	7%	6%	6%	9%	7%	6%	10%	10%	9%	8%	7%	4%	6%	15%	9%	8%	18%	14%	14%	10%	8%	10%	5%	6%
Loss > 50% of Avg. Zone Price	MW	376	344	305	338	253	321	298	404	460	377	304	198	312	528	440	283	388	491	688	498	271	234	174	140
	%	8%	7%	7%	7%	5%	8%	8%	10%	9%	7%	6%	4%	7%	13%	11%	7%	11%	13%	18%	13%	7%	6%	5%	6%

Notes: For chart description, see slide 96.

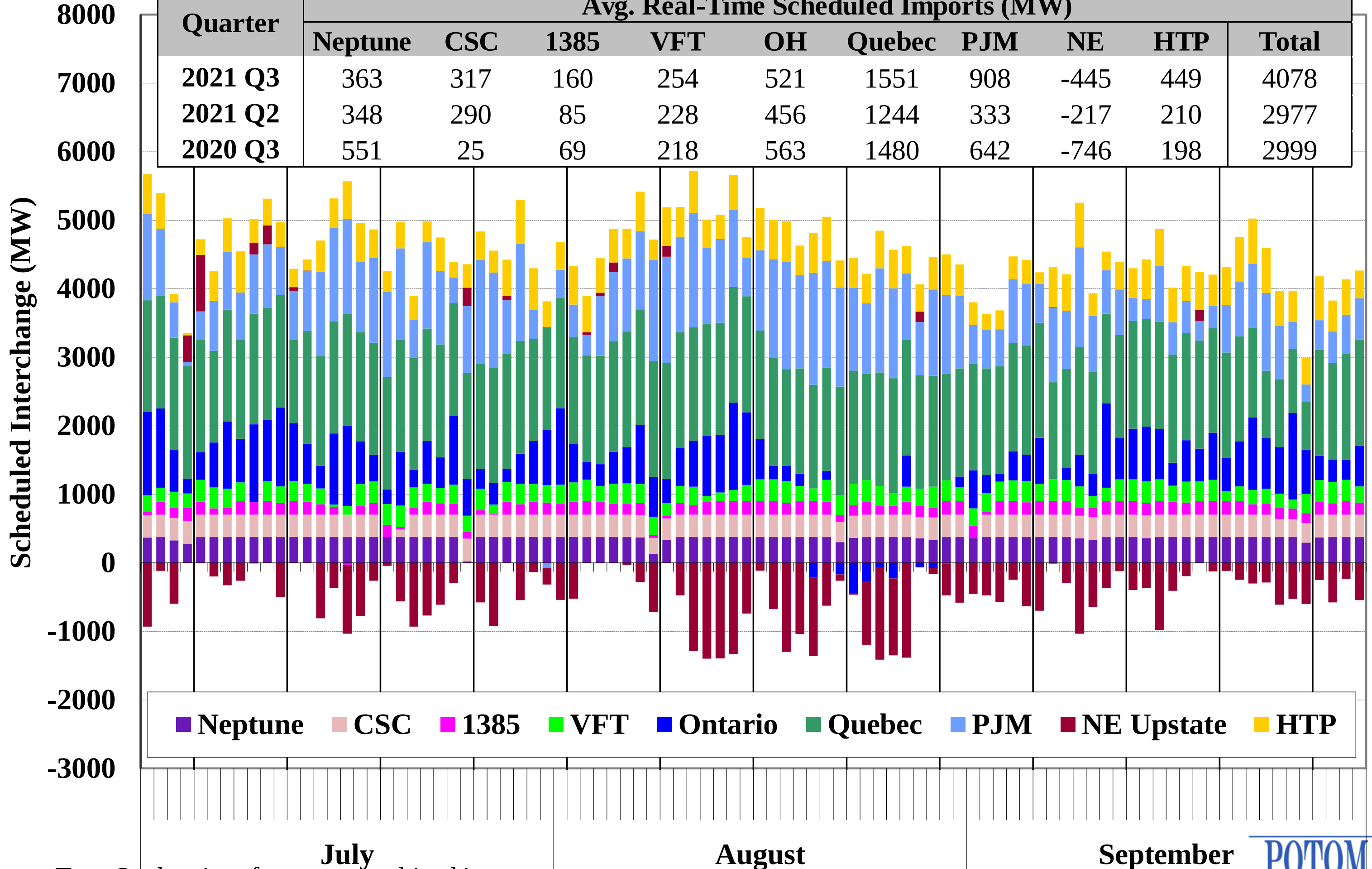
Virtual Trading Activity
by Location



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)
2021 Q3	1489	$1.97	1032	$0.72	609	$2.08	140	-$0.64
2021 Q2	2128	-$1.33	1219	$3.13	440	-$1.25	94	$1.41
2020 Q3	2562	-$0.01	1768	$0.94	617	-$0.34	250	-$0.12

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 96.

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



Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	Quebec	PJM	NE	HTP	Total
2021 Q3	363	317	160	254	521	1551	908	-445	449	4078
2021 Q2	348	290	85	228	456	1244	333	-217	210	2977
2020 Q3	551	25	69	218	563	1480	642	-746	198	2999

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 > $20	Total	
% of All Intervals w/ Adjustment			79%	7%	**86%**		42%	13%	**54%**	
Average Flow Adjustment (MW)	Net Imports		19	9	**19**		2	-35	**-6**	
	Gross		110	154	**114**		62	94	**69**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$1.7	$0.8	**$2.5**		$0.3	$1.1	**$1.5**	
	Net Over-Projection by:	NY	-$0.1	-$0.4	**-$0.5**		-$0.1	-$0.3	**-$0.4**	
		NE or PJM	$0.0	-$0.1	**-$0.1**		-$0.1	-$0.7	**-$0.8**	
	Other Unrealized Savings		$0.0	$0.0	**-$0.1**		$0.0	$0.1	**$0.1**	
	Actual Savings		$1.5	$0.3	**$1.9**		$0.2	$0.2	**$0.5**	
Interface Prices ($/MWh)	NY	Actual	$38.08	$65.96	**$40.30**	**$40.15**	$37.59	$57.65	**$42.25**	**$38.76**
		Forecast	$39.20	$75.68	**$42.10**	**$41.81**	$39.26	$64.06	**$45.02**	**$40.98**
	NE or PJM	Actual	$37.17	$80.13	**$40.59**	**$42.38**	$36.02	$61.43	**$41.92**	**$38.91**
		Forecast	$36.00	$71.42	**$38.82**	**$40.94**	$39.02	$95.17	**$52.07**	**$45.59**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.12	$9.72	**$1.80**	**$1.66**	$1.66	$6.41	**$2.77**	**$2.23**
		Abs. Val.	$3.00	$49.28	**$6.68**	**$6.46**	$3.74	$23.19	**$8.26**	**$6.24**
	NE or PJM	Fcst. - Act.	-$1.17	-$8.71	**-$1.77**	**-$1.44**	$3.00	$33.74	**$10.14**	**$6.68**
		Abs. Val.	$2.96	$32.03	**$5.27**	**$5.74**	$4.89	$58.00	**$17.23**	**$12.99**

For Adjustment Intervals Only

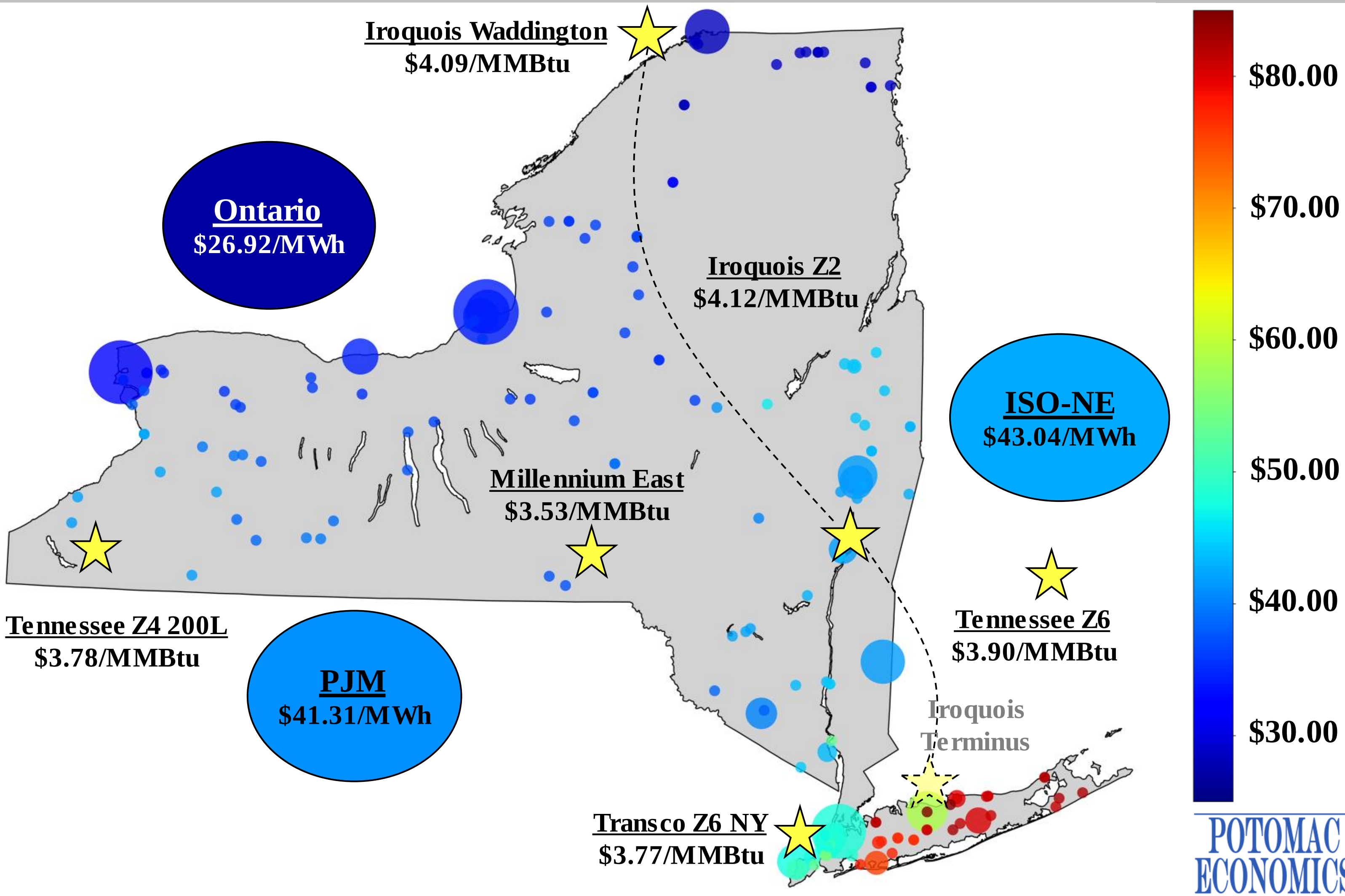
For All Intervals

Notes: For chart description, see slide 97.

Charts:

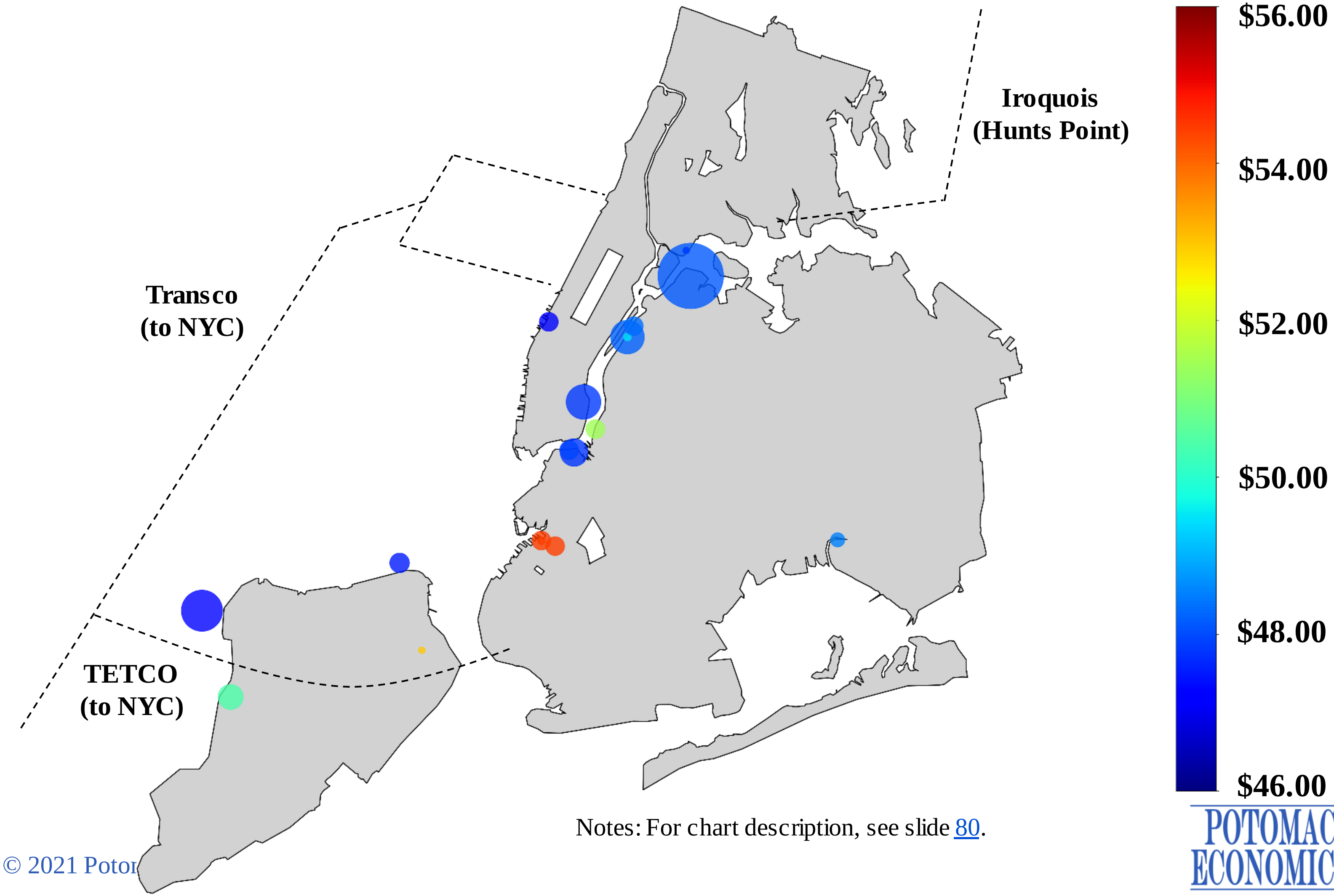
Transmission Congestion Revenues and Shortfalls

System Congestion
Real-Time Price Map at Generator Nodes



POTOMAC ECONOMICS

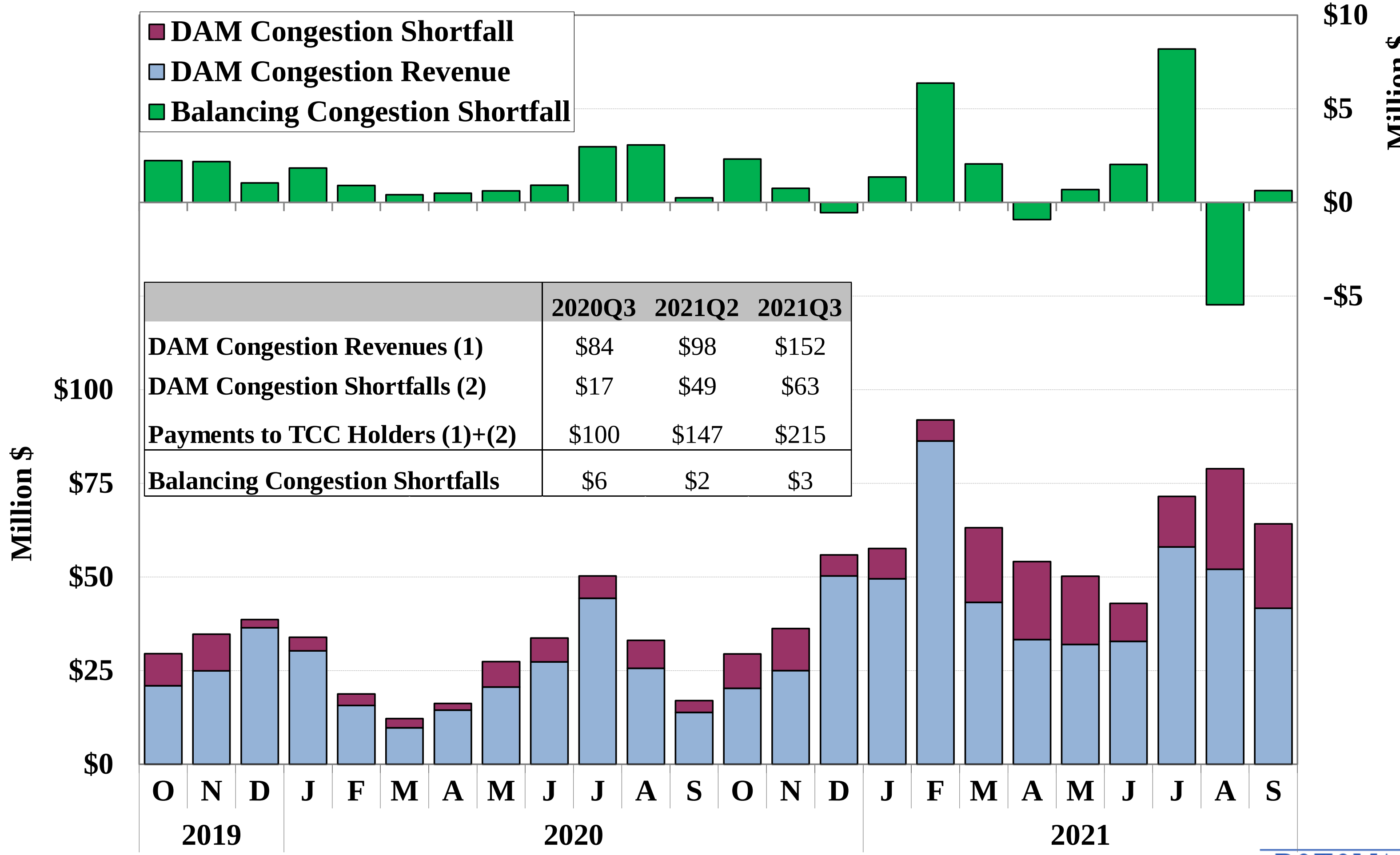
System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

Congestion Revenues and Shortfalls by Month

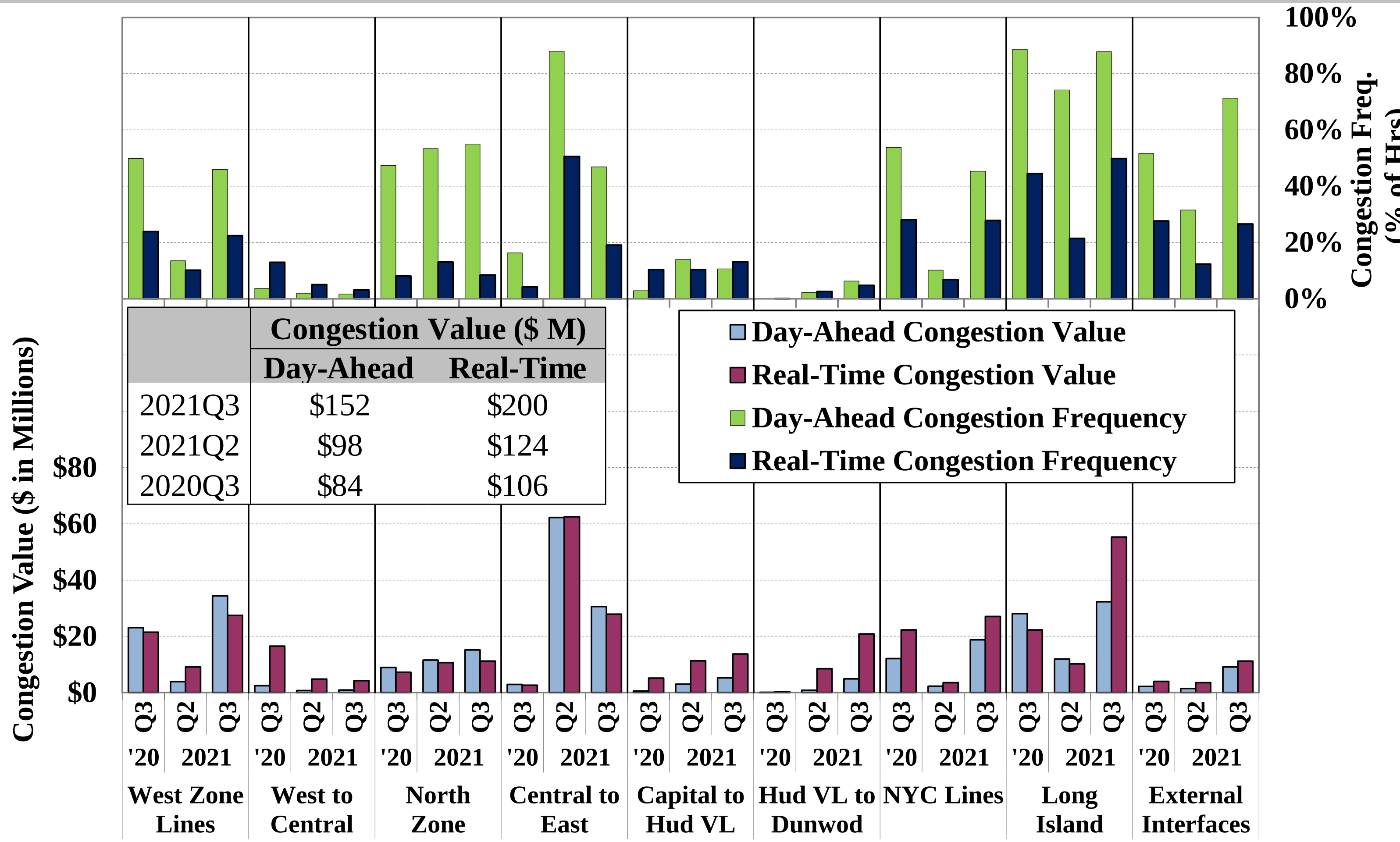


	2020Q3	2021Q2	2021Q3
DAM Congestion Revenues (1)	$84	$98	$152
DAM Congestion Shortfalls (2)	$17	$49	$63
Payments to TCC Holders (1)+(2)	$100	$147	$215
Balancing Congestion Shortfalls	$6	$2	$3

Notes: For chart description, see slides 99 and 100.

POTOMAC ECONOMICS

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

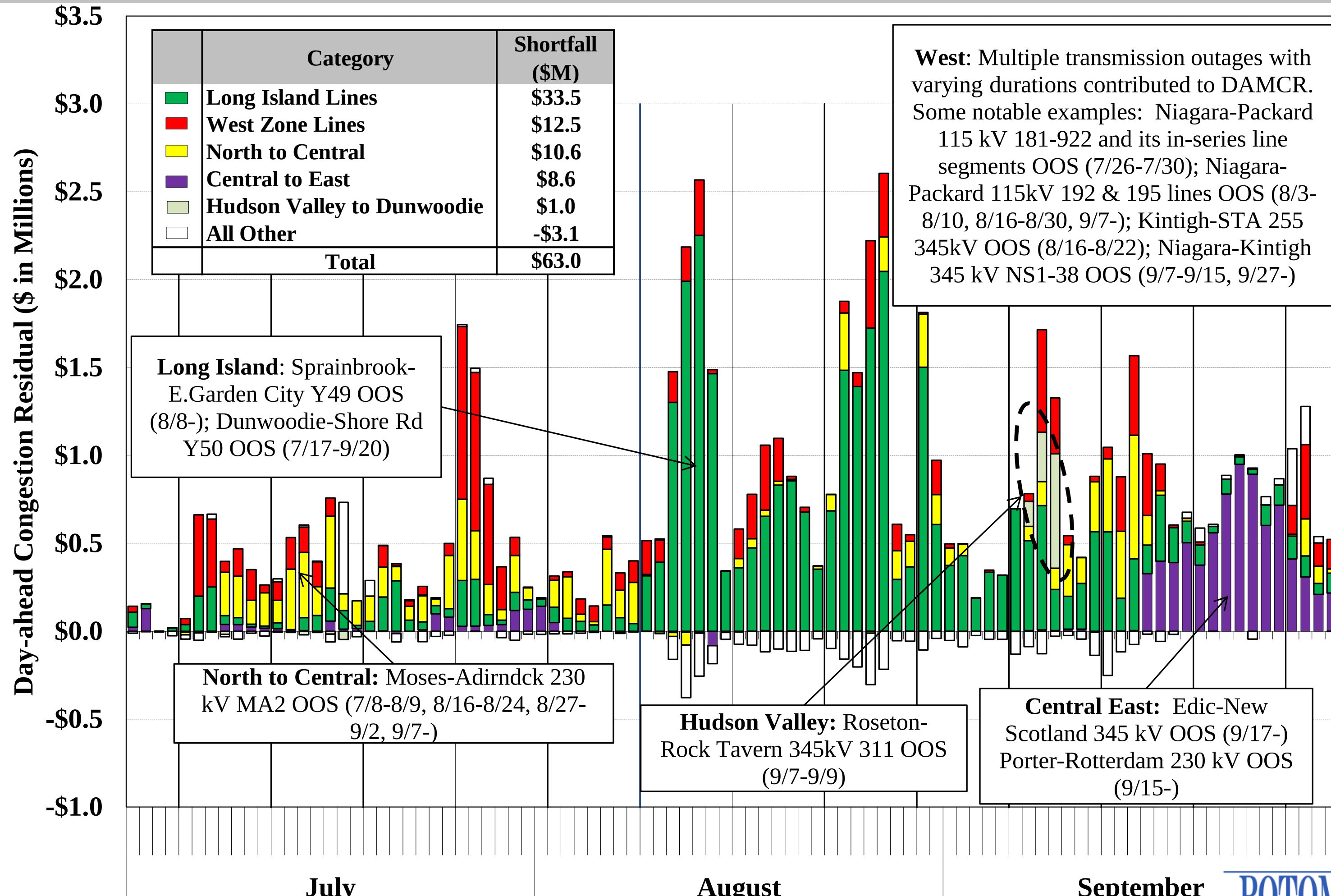


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2021Q3	$152	$200
2021Q2	$98	$124
2020Q3	$84	$106

Notes: For chart description, see slides 99, 100, and 101.

POTOMAC ECONOMICS

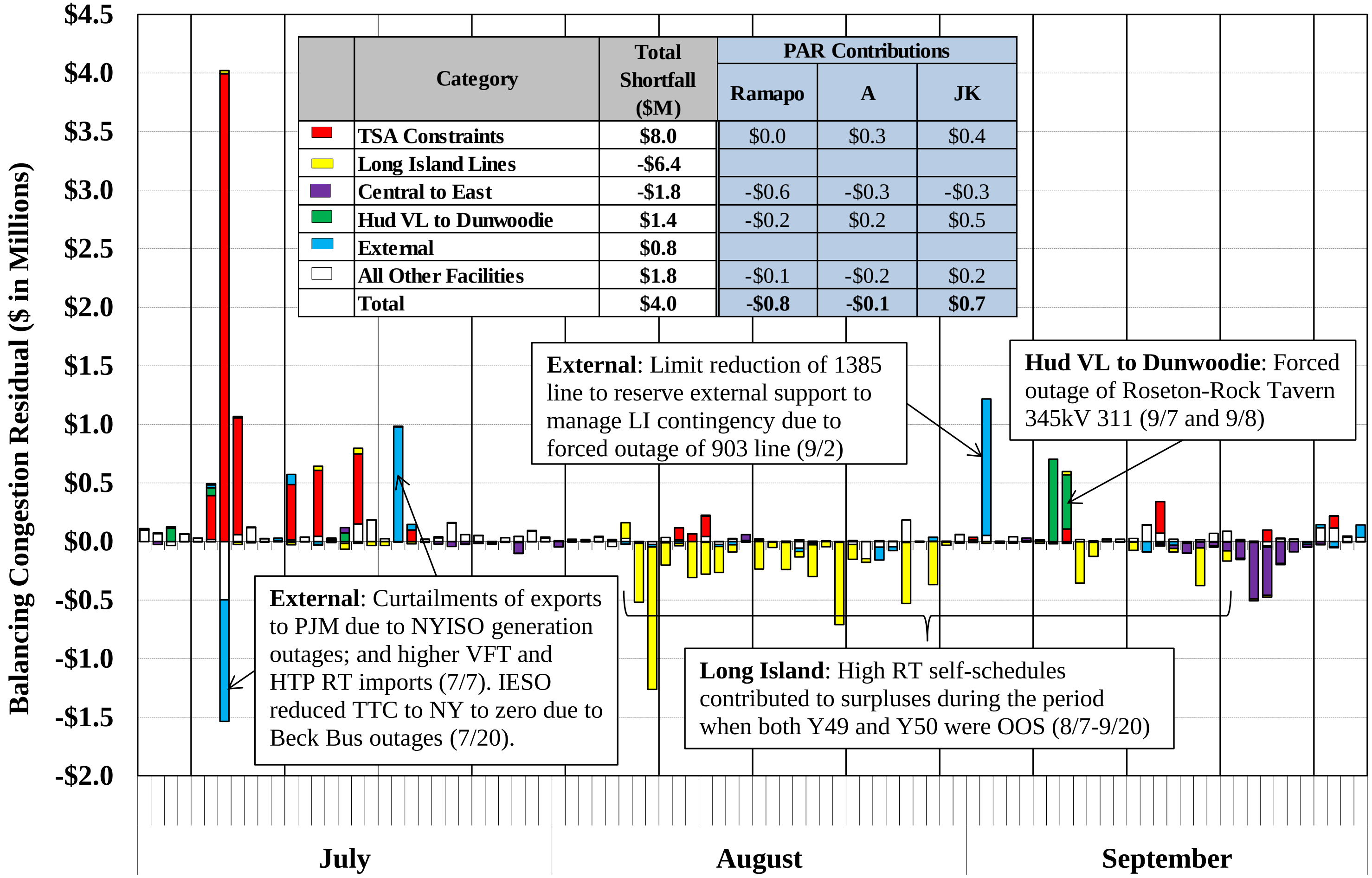
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 99, 100, and 101.

POTOMAC ECONOMICS

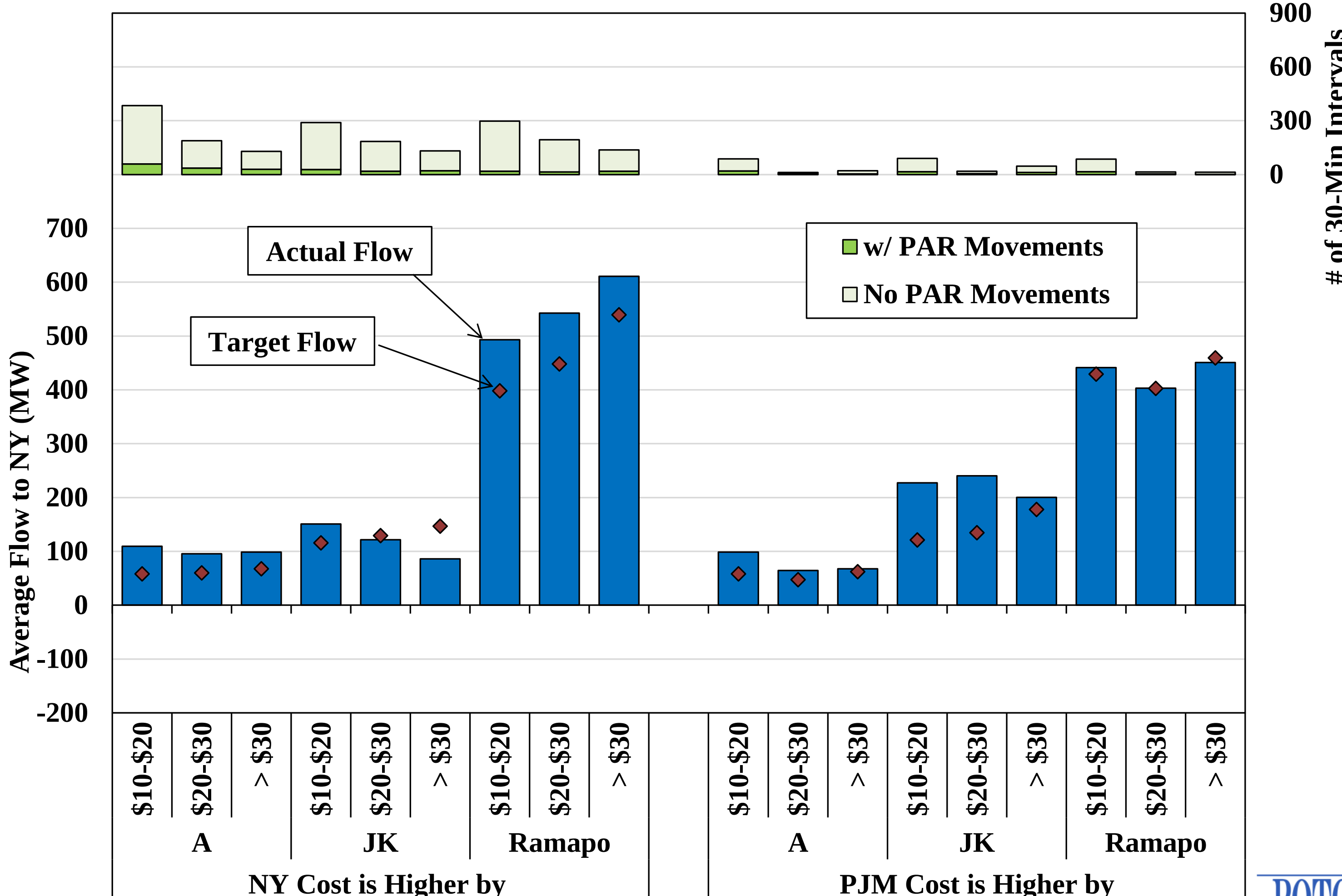
Balancing Congestion Shortfalls by Transmission Facility



Category	Total Shortfall ($M)	PAR Contributions: Ramapo	A	JK
TSA Constraints	$8.0	$0.0	$0.3	$0.4
Long Island Lines	-$6.4			
Central to East	-$1.8	-$0.6	-$0.3	-$0.3
Hud VL to Dunwoodie	$1.4	-$0.2	$0.2	$0.5
External	$0.8			
All Other Facilities	$1.8	-$0.1	-$0.2	$0.2
Total	$4.0	-$0.8	-$0.1	$0.7

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 99, 100, and 101.

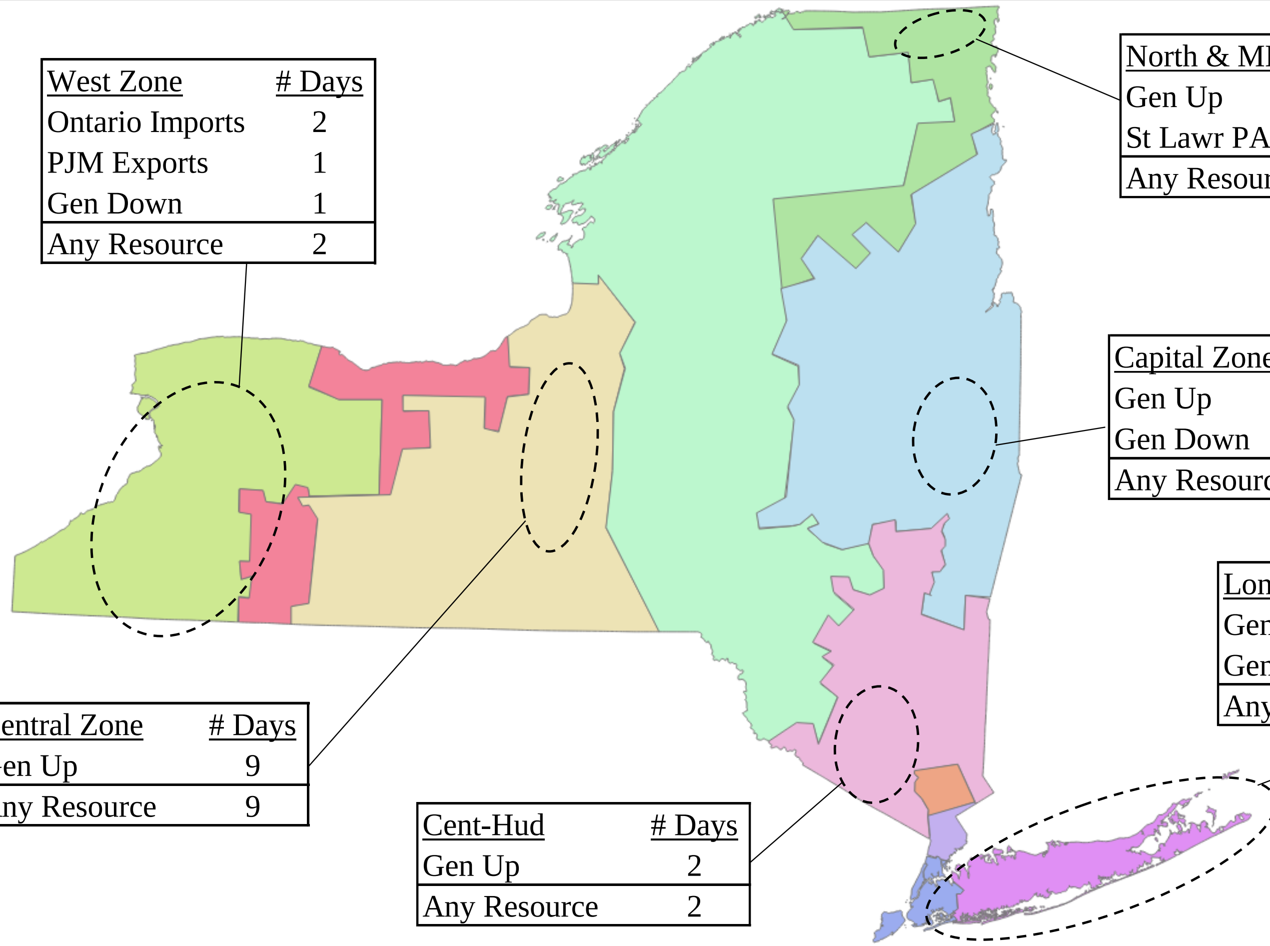
PAR Operation under M2M with PJM
2021 Q3



Notes: For chart description, see slide 102.

POTOMAC ECONOMICS

Constraints on the Low Voltage Network:
Summary of Resources Used to Manage Congestion



West Zone	# Days
Ontario Imports	2
PJM Exports	1
Gen Down	1
Any Resource	2

North & MHK VL Zones	# Days
Gen Up	15
St Lawr PARs	1
Any Resource	15

Capital Zone	# Days
Gen Up	1
Gen Down	3
Any Resource	4

Long Is 69kV	# Days
Gen Up	56
Gen Down	1
Any Resource	56

Central Zone	# Days
Gen Up	9
Any Resource	9

Cent-Hud	# Days
Gen Up	2
Any Resource	2

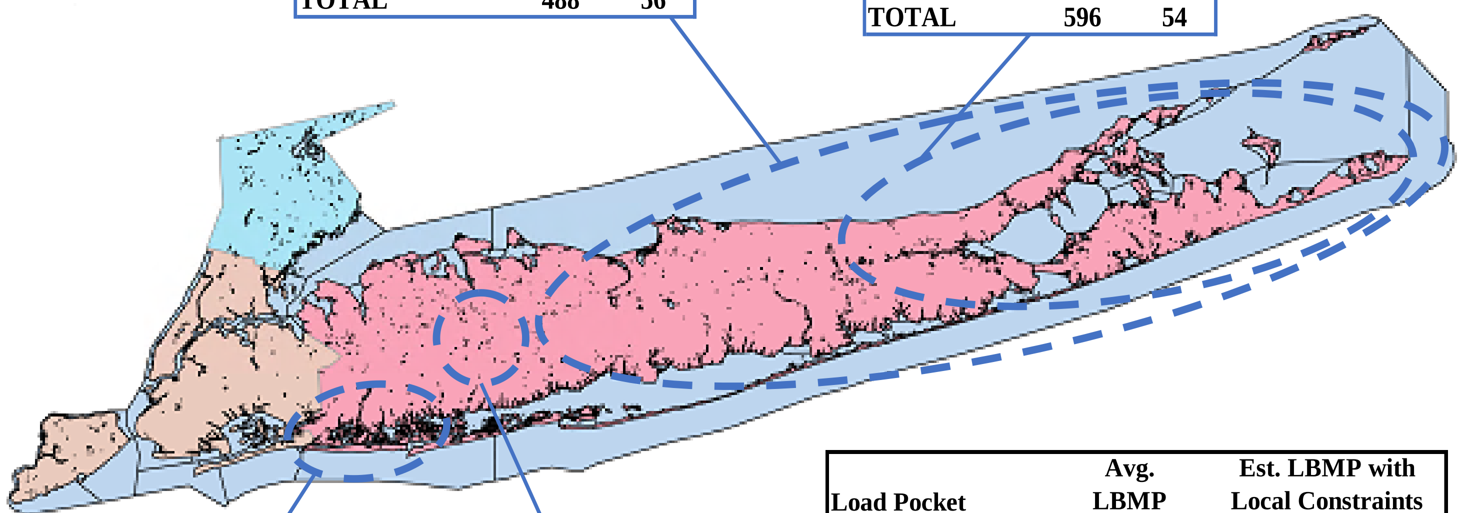
Notes: For chart description, see slides 103-104

POTOMAC ECONOMICS

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV OOM	2	1
69kV	371	50
138kV	374	46
TOTAL	488	56

East End	#Hours	#Days
69kV OOM	16	2
TVR	588	54
138kV	0	0
TOTAL	596	54



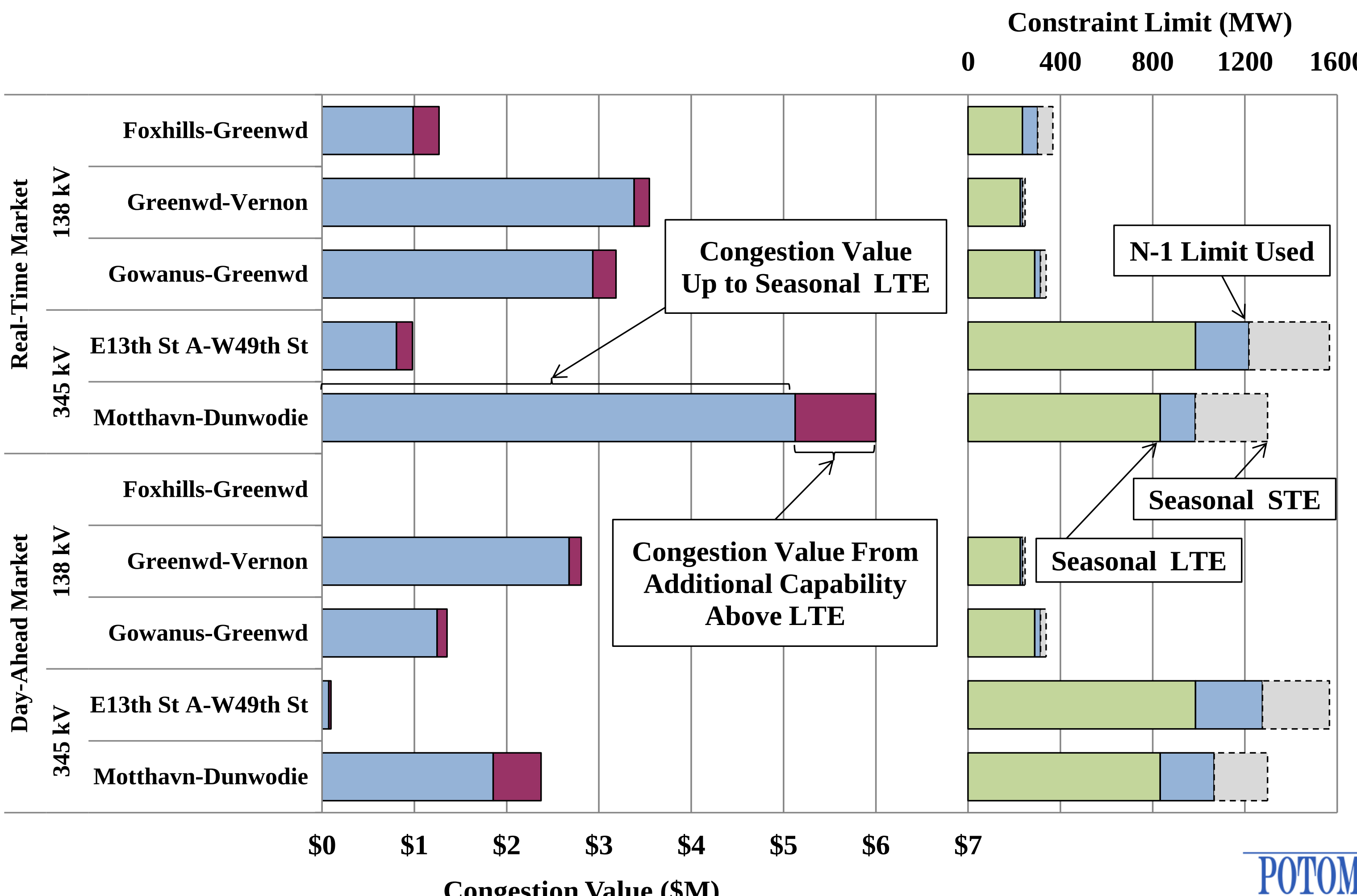
Valley Stream	#Hours	#Days
69kV OOM	237	35
138kV	134	27
TOTAL	356	51

Brentwood	#Hours	#Days
69kV OOM	0	0
69kV	502	75
138kV	0	0
TOTAL	502	75

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$69.99	$69.99
East End	$70.22	$104.15
East of Northport	$68.41	$68.47
Valley Stream	$64.93	$67.04

Notes: For chart description, see slides 103-104

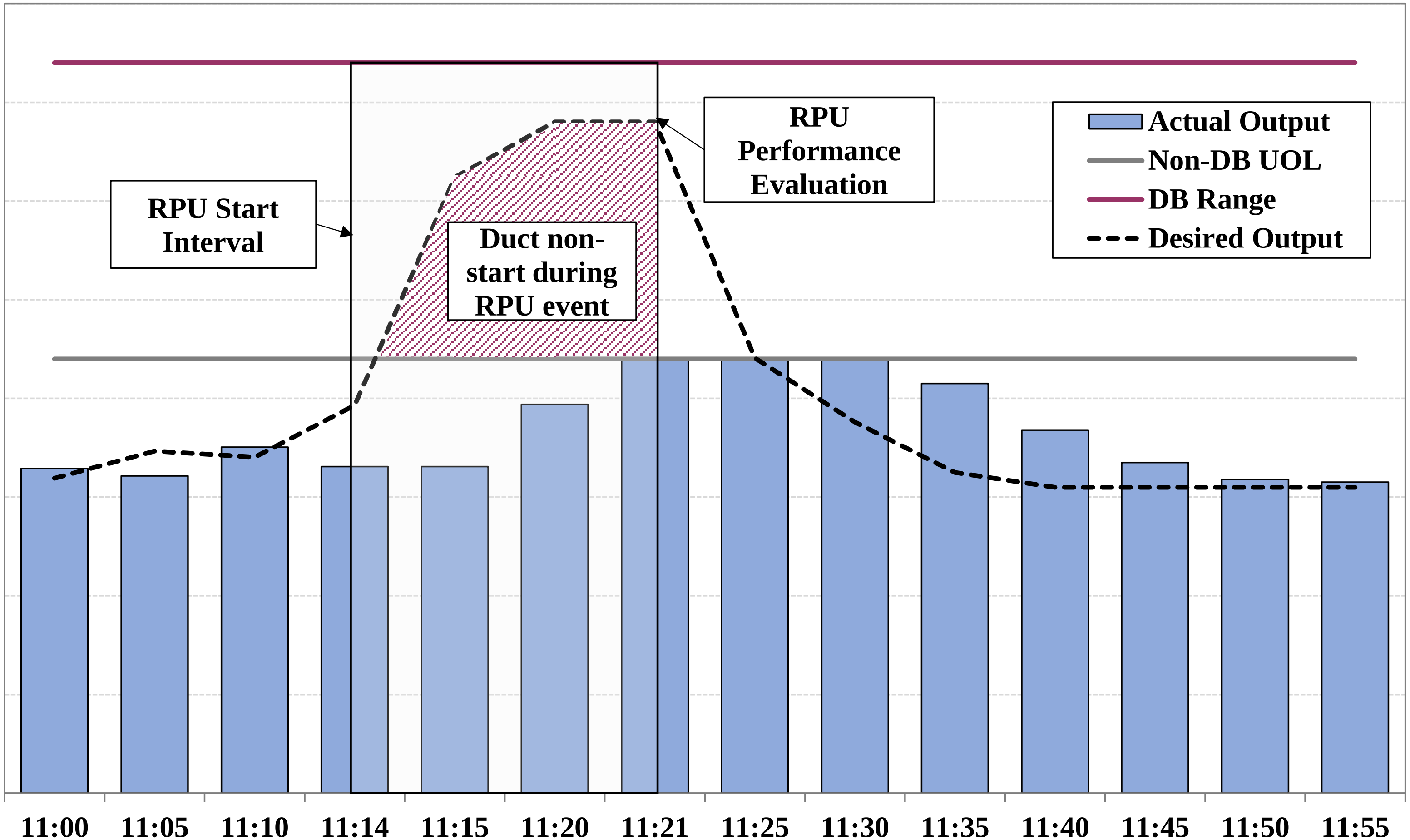
N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide 105.

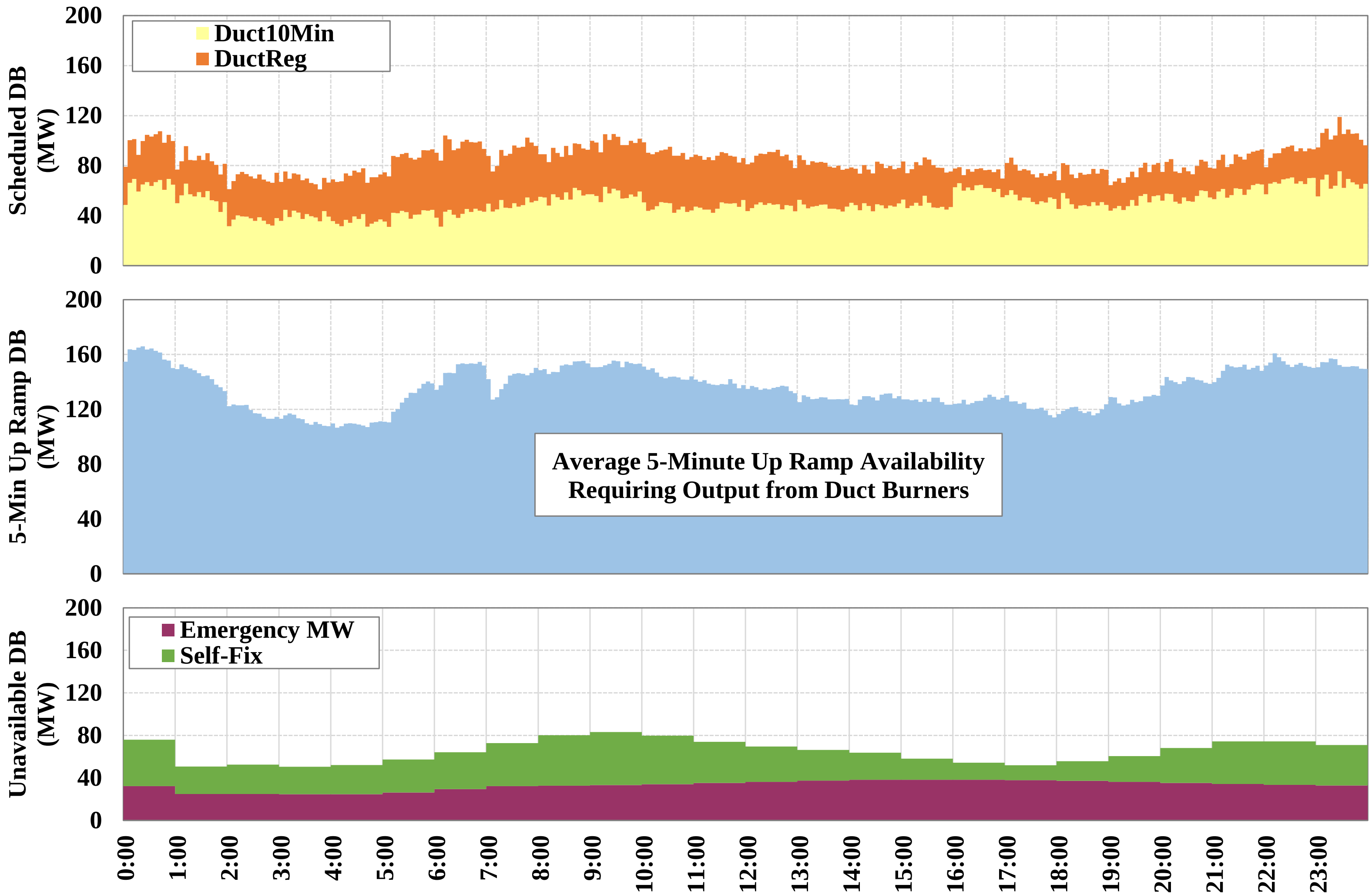
POTOMAC ECONOMICS

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



Notes: For chart description, see slide 106

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



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

10 Minute Economic GT Start Performance vs. Audit Results (October 2020 - September 2021)

Economic GT Starts (RTC, RTD, and RTD-CAM)		GT Audit Results		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Evaluated [1]	0	0	0	0
0% - 10%	0	0	0	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	0	0	0	0
40% - 50%	2	4	2	1
50% - 60%	4	5	4	0
60% - 70%	1	1	1	0
70% - 80%	5	9	5	0
80% - 90%	19	26	17	1
90% - 100%	22	36	22	1
TOTAL	**53**	**81**	**51**	**3**

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 107.

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

30 Minute Economic GT Start Performance vs. Audit Results (October 2020 - September 2021)

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]	14	16	12	1
0% - 10%	2	2	1	1
10% - 20%	0	0	0	0
20% - 30%	2	0	0	0
30% - 40%	0	0	0	0
40% - 50%	0	0	0	0
50% - 60%	0	0	0	0
60% - 70%	1	1	1	0
70% - 80%	7	9	5	2
80% - 90%	16	23	12	8
90% - 100%	50	80	47	3
TOTAL	**92**	**131**	**78**	**15**

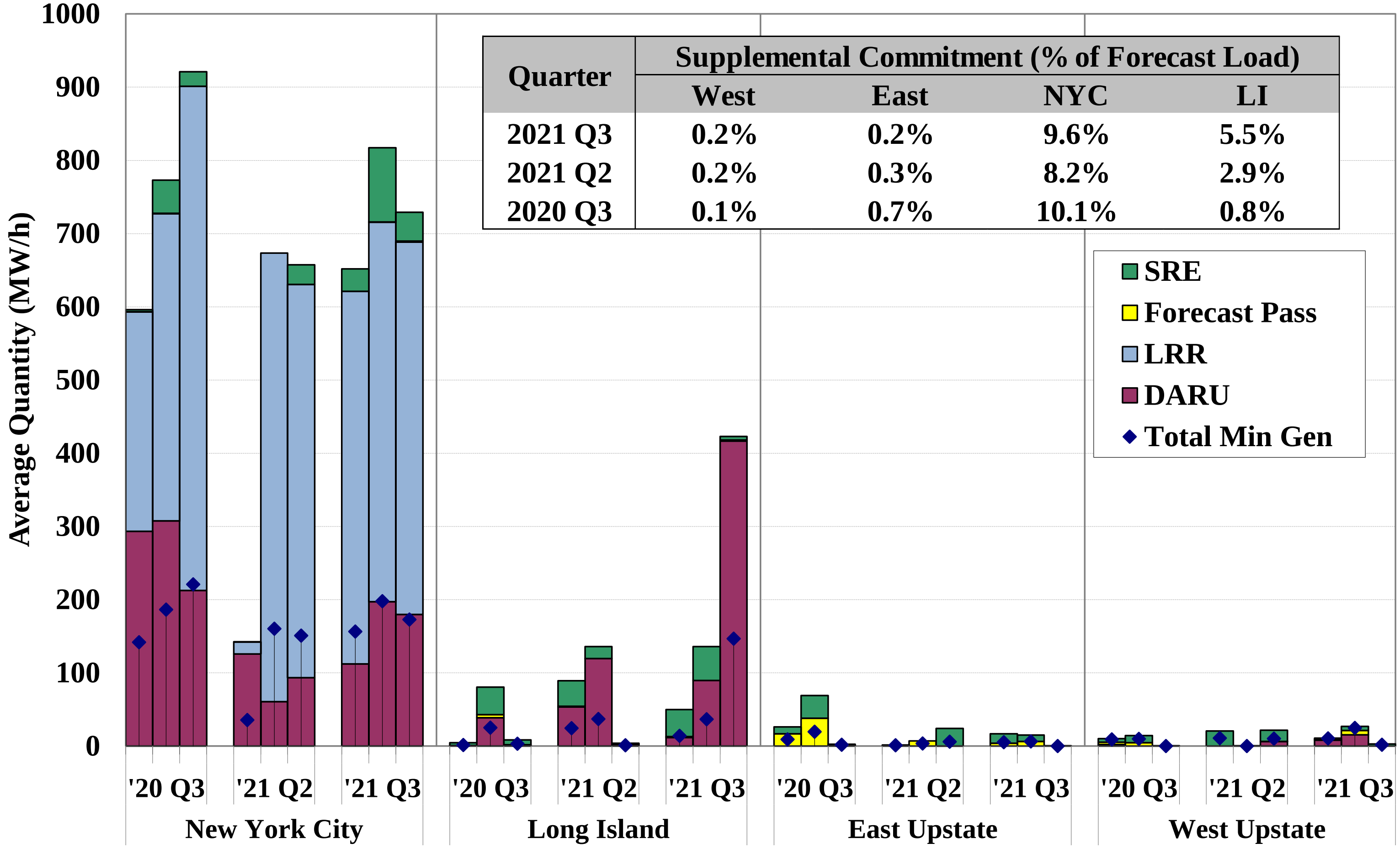
Note: 1. Including units that were OOM- or self-started, units that were never started in the time period, and units that were omitted from the analysis due to certain data issues for reliable performance assessment.

Notes: For chart description, see slide 107.

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability by Category and Region

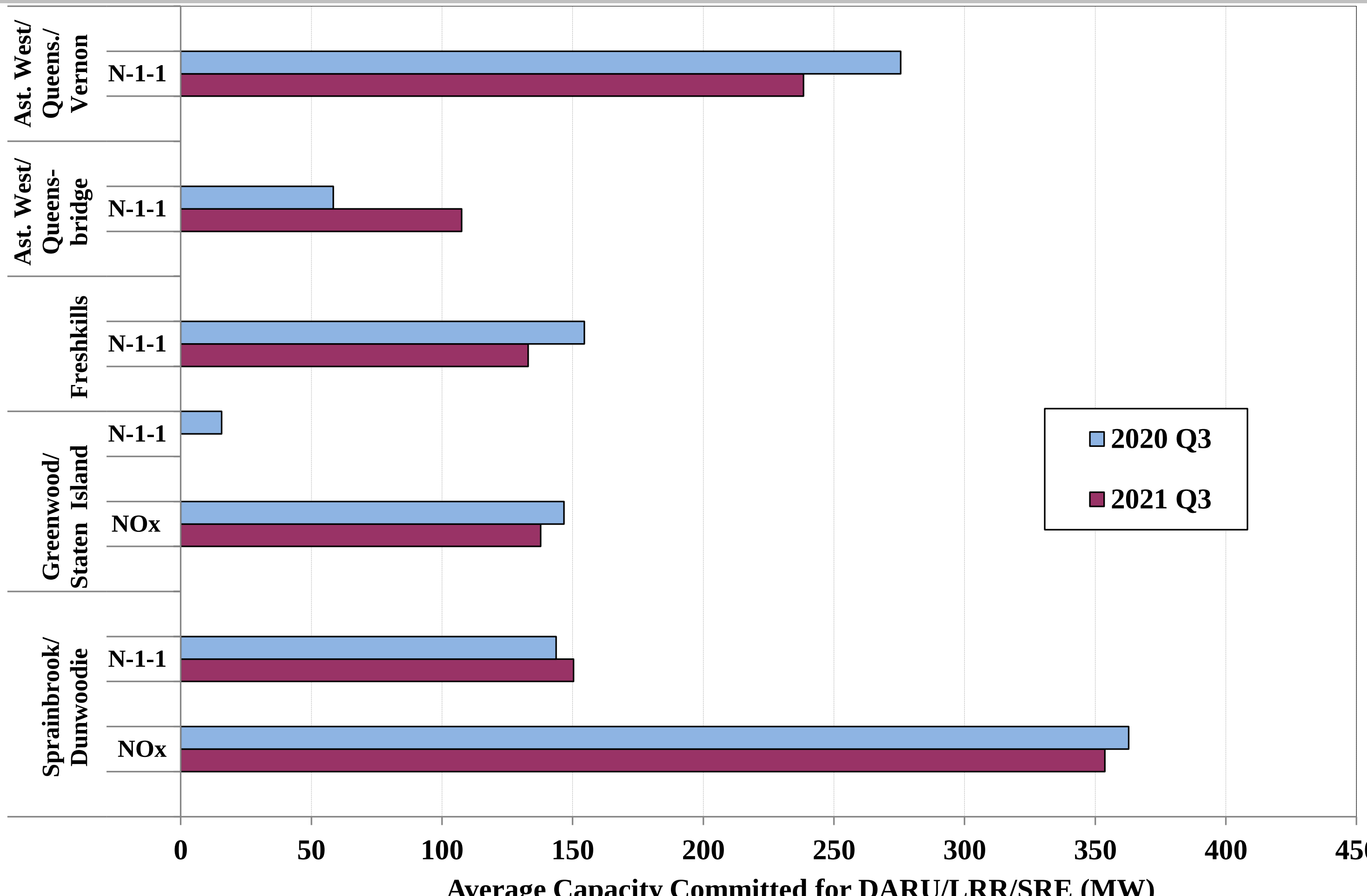


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2021 Q3	0.2%	0.2%	9.6%	5.5%
2021 Q2	0.2%	0.3%	8.2%	2.9%
2020 Q3	0.1%	0.7%	10.1%	0.8%

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

POTOMAC ECONOMICS

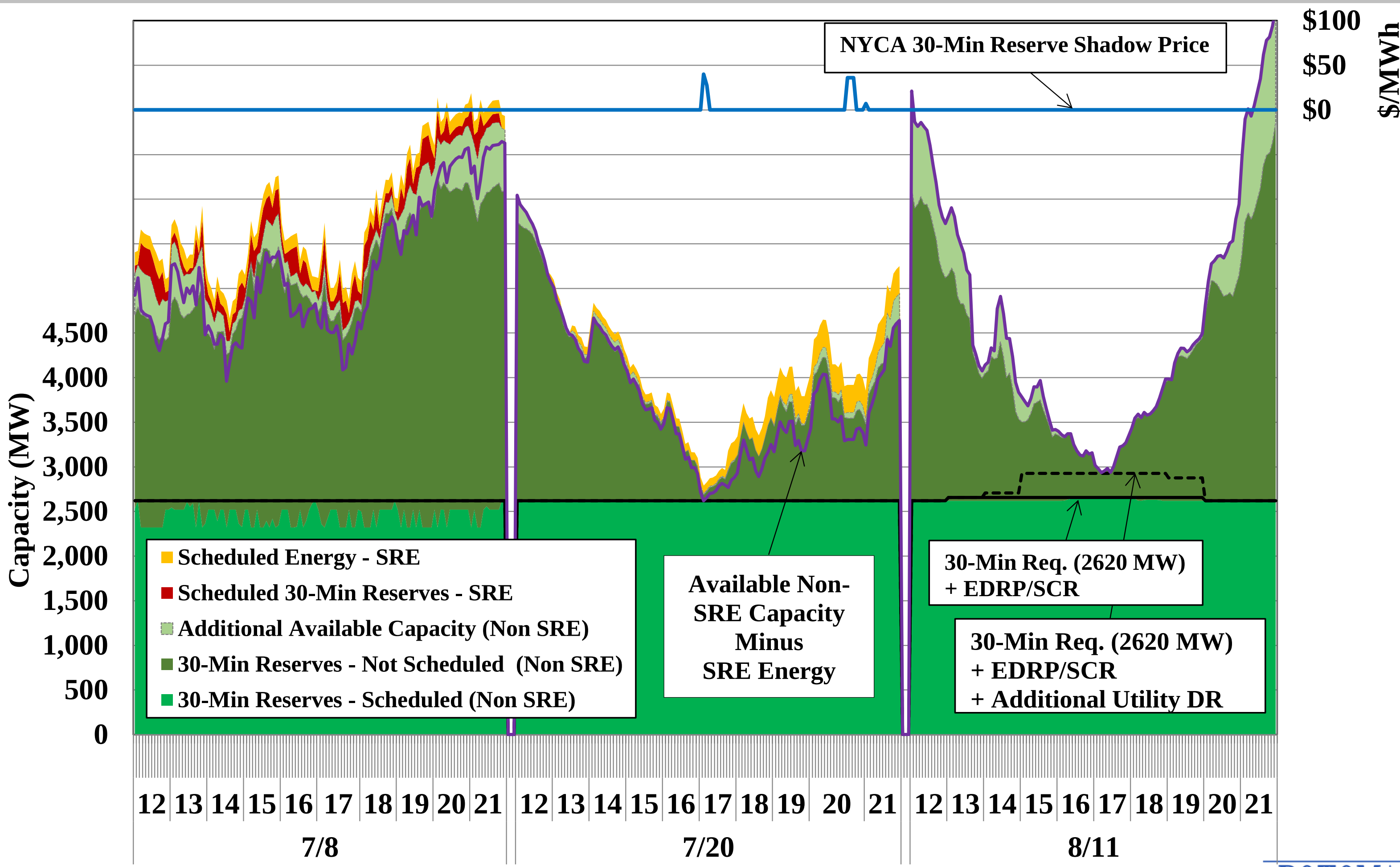
Supplemental Commitment for Reliability in NYC
by Reliability Reason and Load Pocket



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

POTOMAC ECONOMICS

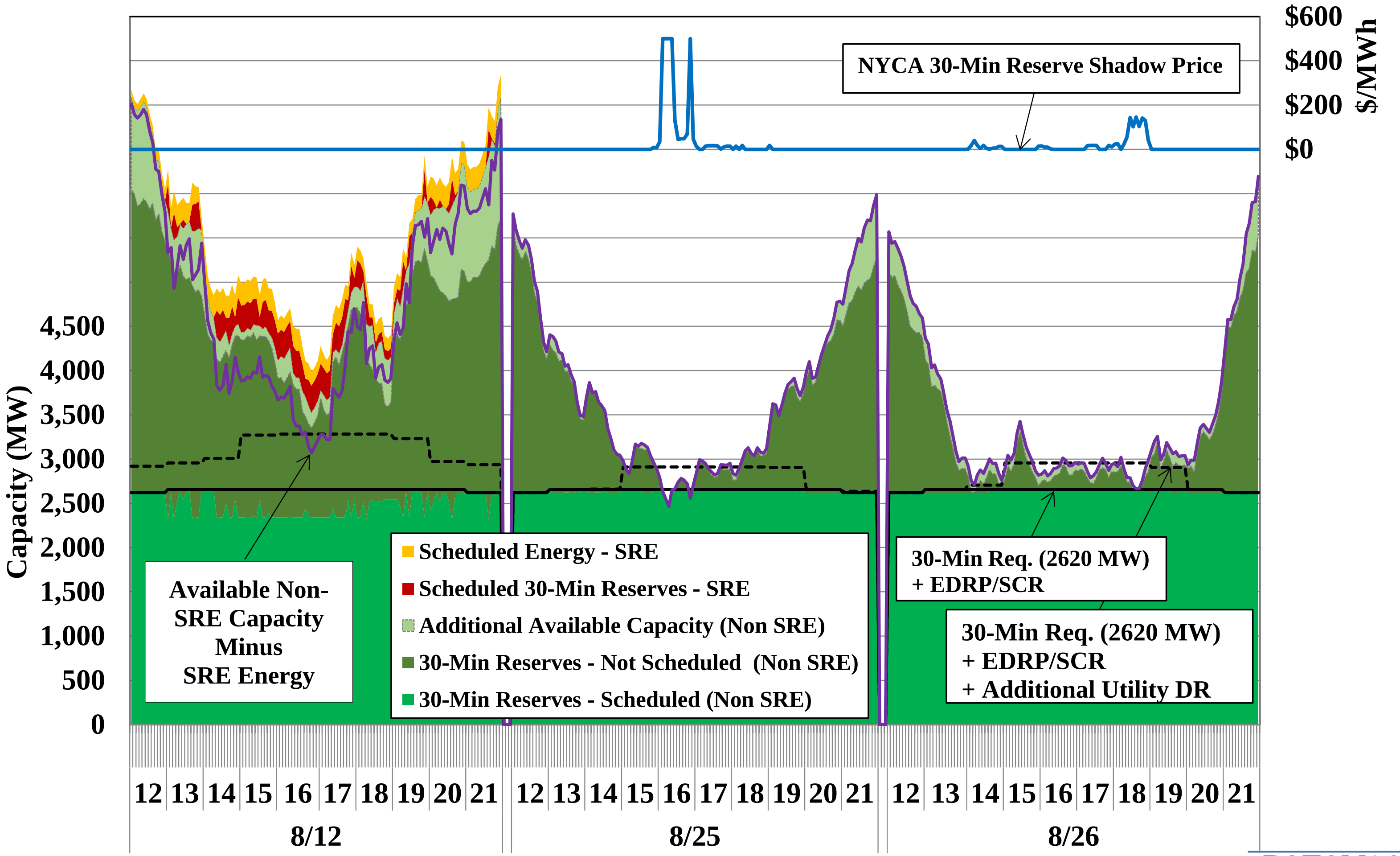
SRE Commitments for Capacity and DR Deployments on High Load Days



Notes: For chart description, see slide 110.

POTOMAC ECONOMICS

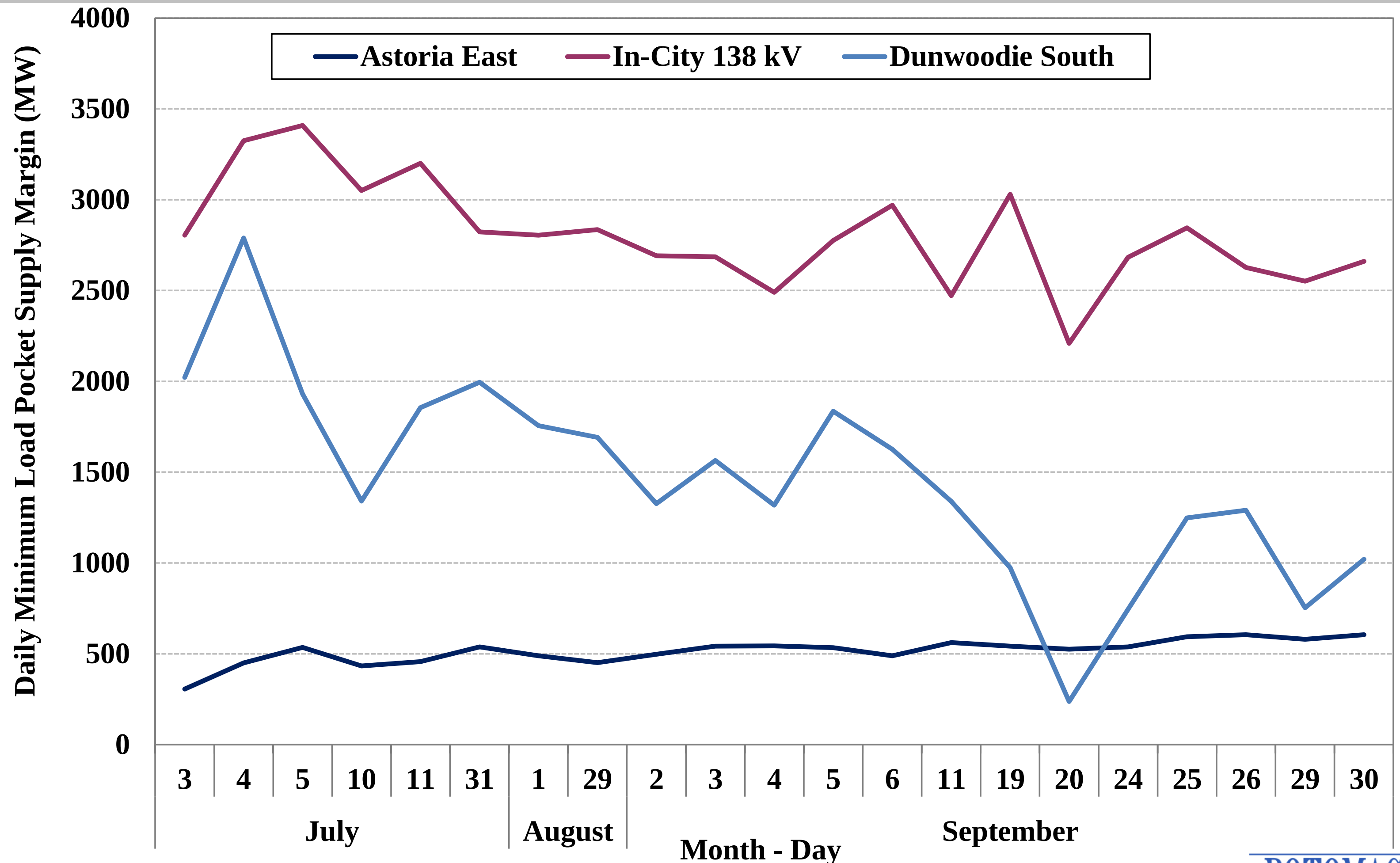
SRE Commitments for Capacity and DR Deployments on High Load Days



Notes: For chart description, see slide 110.

POTOMAC ECONOMICS

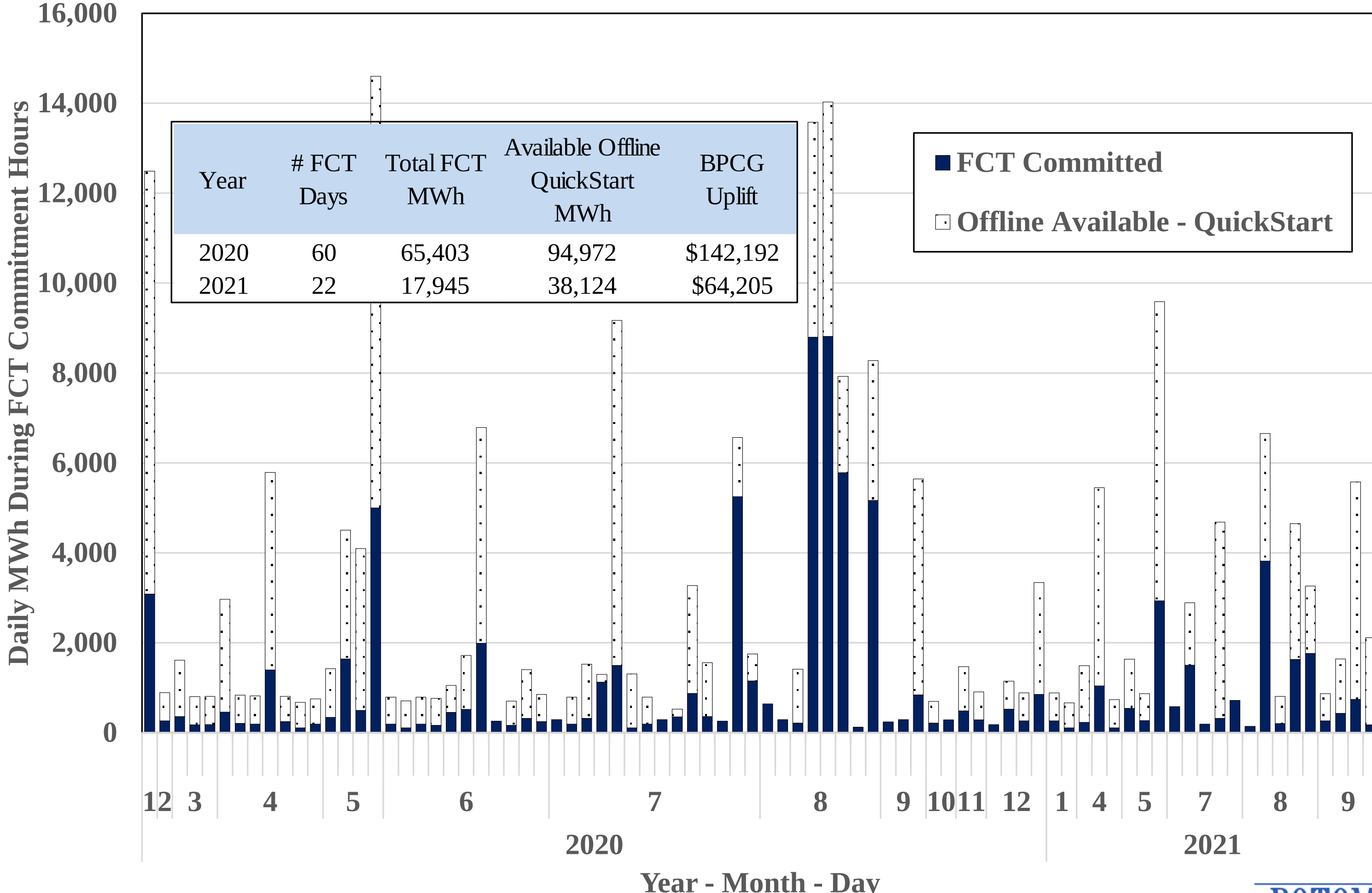
Supply Margin in NYC Load Pockets
After Removing NOx-only Committed ST and GT in the NOx Bubble



For chart description, see slide 111.

POTOMAC ECONOMICS

DAM Forecast Pass Commitment

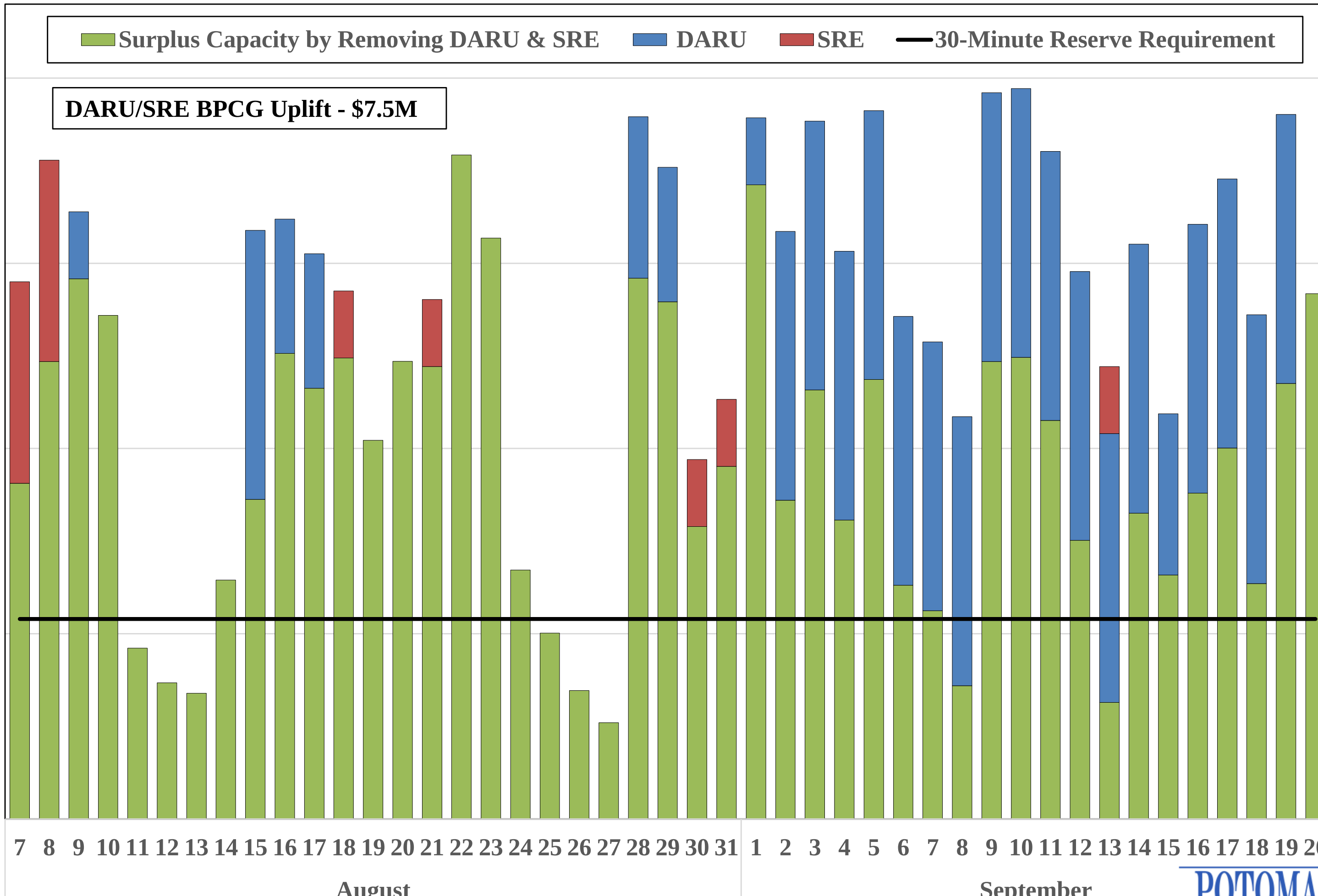


Year	# FCT Days	Total FCT MWh	Available Offline QuickStart MWh	BPCG Uplift
2020	60	65,403	94,972	$142,192
2021	22	17,945	38,124	$64,205

Notes: For chart description, see slide 112.

POTOMAC ECONOMICS

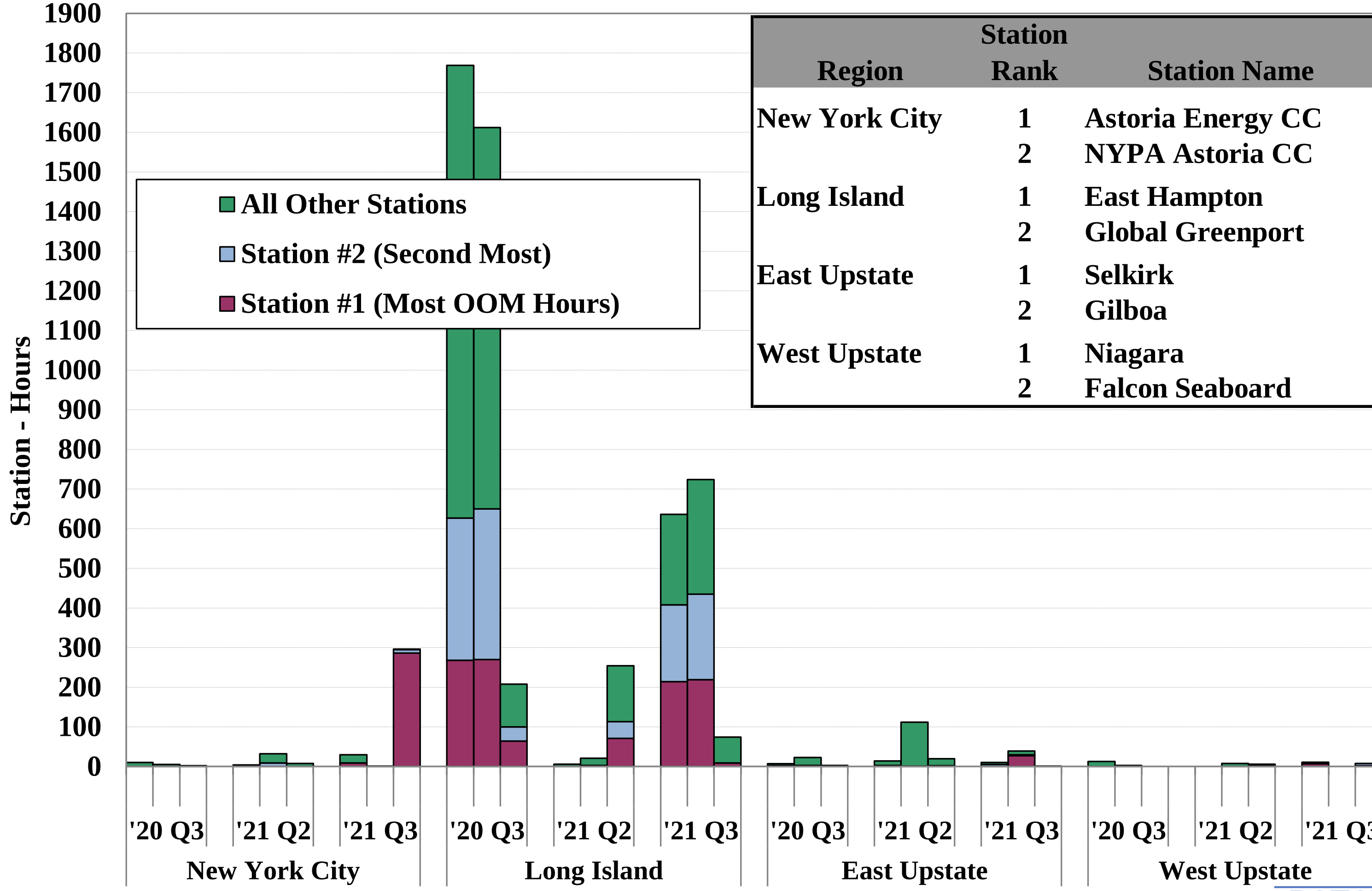
Supplemental Commitment on Long Island
During Y49 & Y50 Outages



Notes: For chart description, see slide 113.

POTOMAC ECONOMICS

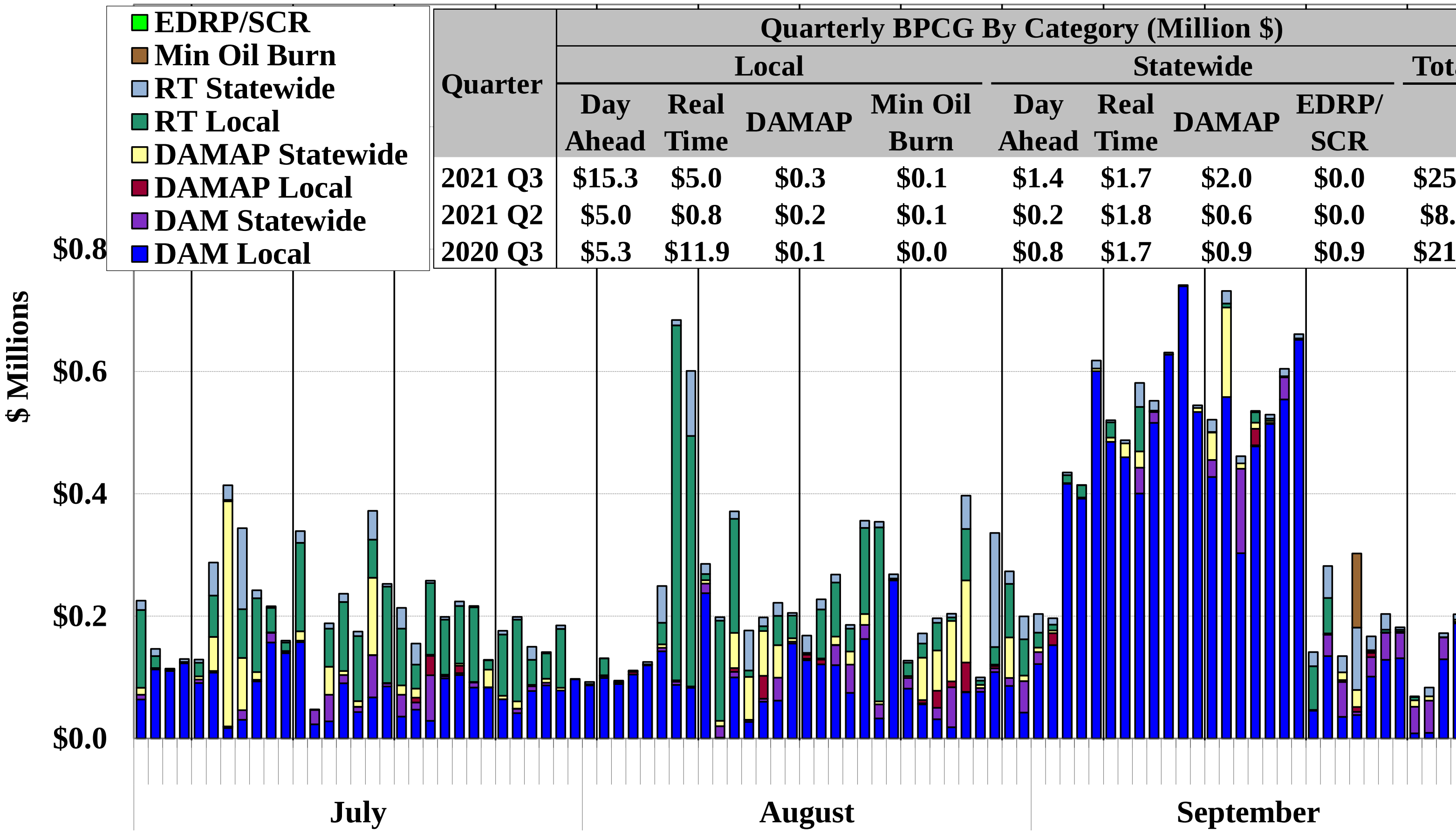
Frequency of Out-of-Merit Dispatch
by Region by Month



Region	Station Rank	Station Name
New York City	1	Astoria Energy CC
	2	NYPA Astoria CC
Long Island	1	East Hampton
	2	Global Greenport
East Upstate	1	Selkirk
	2	Gilboa
West Upstate	1	Niagara
	2	Falcon Seaboard

For chart description, see slides 108 and 109.

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



Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2021 Q3	$15.3	$5.0	$0.3	$0.1	$1.4	$1.7	$2.0	$0.0	$25.9
2021 Q2	$5.0	$0.8	$0.2	$0.1	$0.2	$1.8	$0.6	$0.0	$8.8
2020 Q3	$5.3	$11.9	$0.1	$0.0	$0.8	$1.7	$0.9	$0.9	$21.6

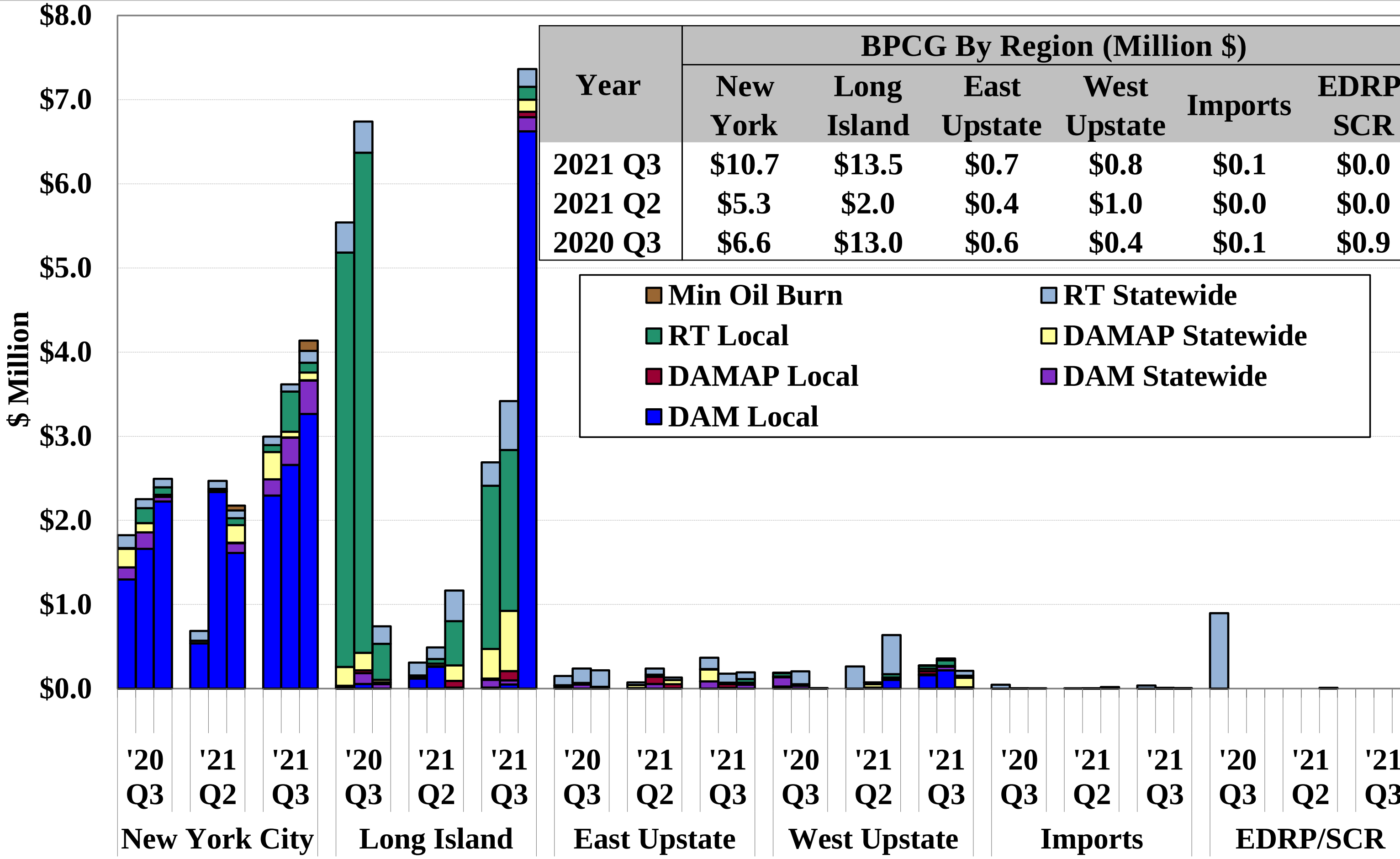
Notes:1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.

2. For chart description, see slide 114.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region

Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2021 Q3	$10.7	$13.5	$0.7	$0.8	$0.1	$0.0
2021 Q2	$5.3	$2.0	$0.4	$1.0	$0.0	$0.0
2020 Q3	$6.6	$13.0	$0.6	$0.4	$0.1	$0.9

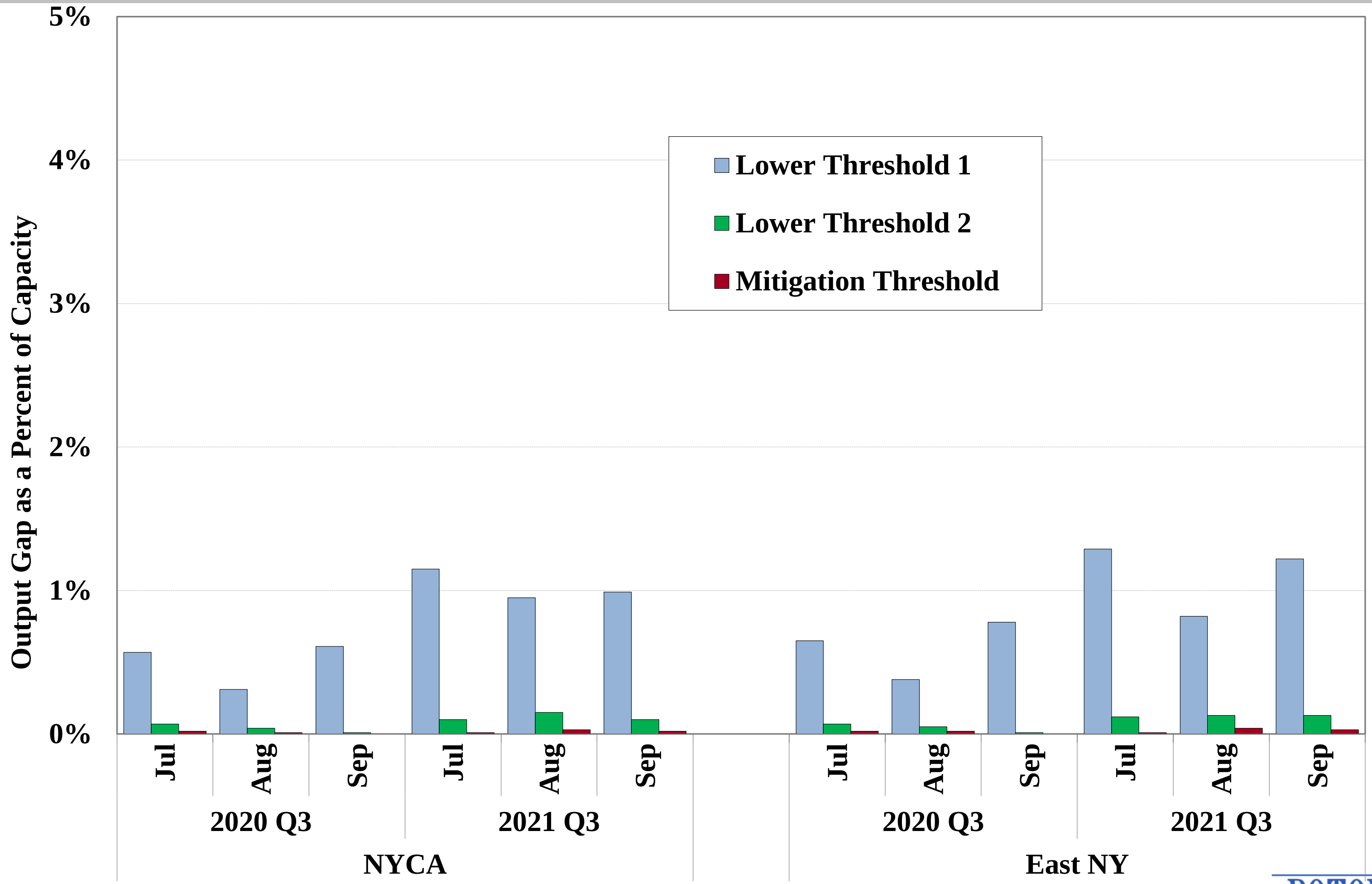


Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.

2. For chart description, see slide 114.

Charts:
Market Power and Mitigation

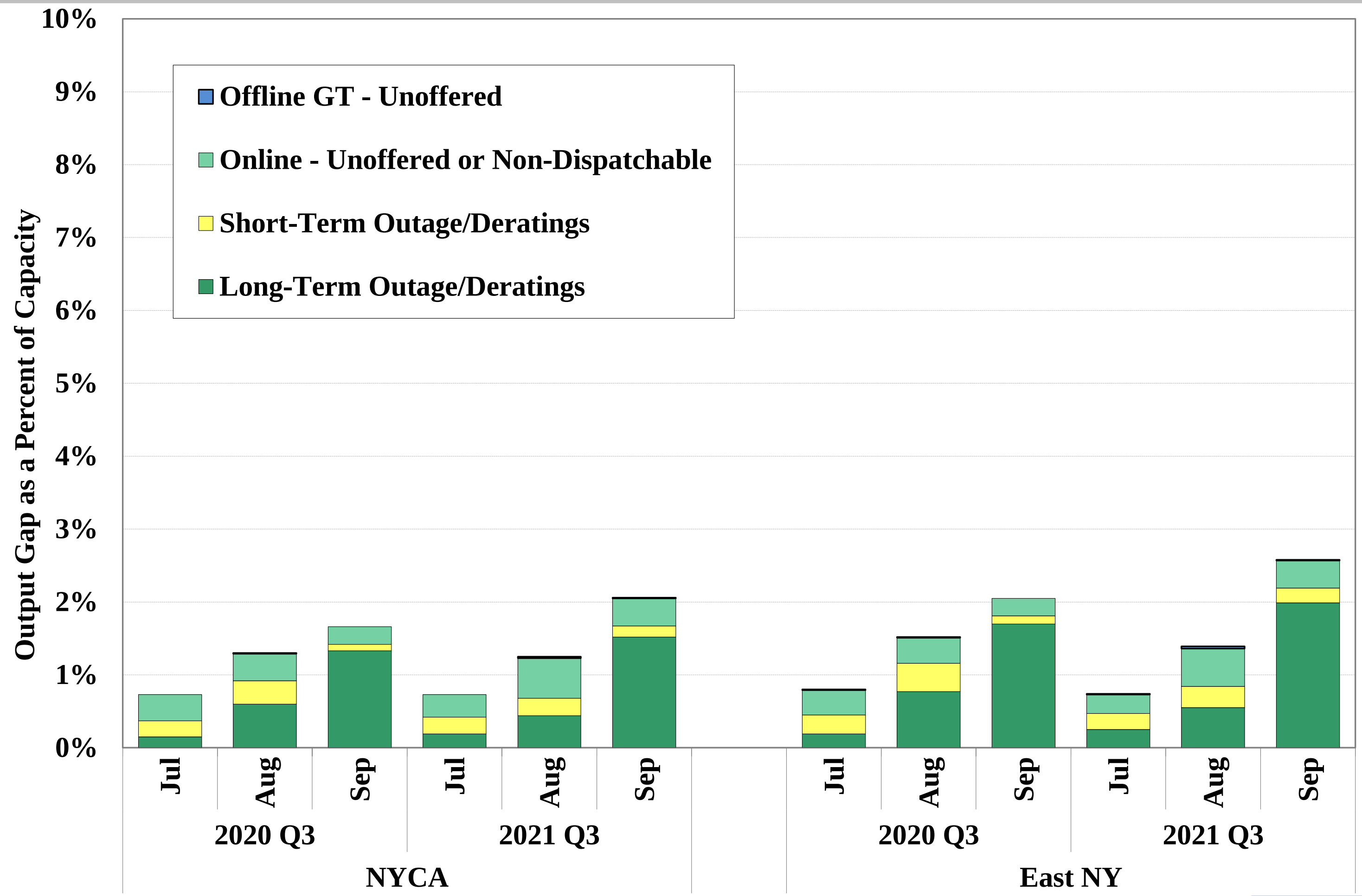
Output Gap by Month
NYCA and East NY



For chart description, see slide 115.

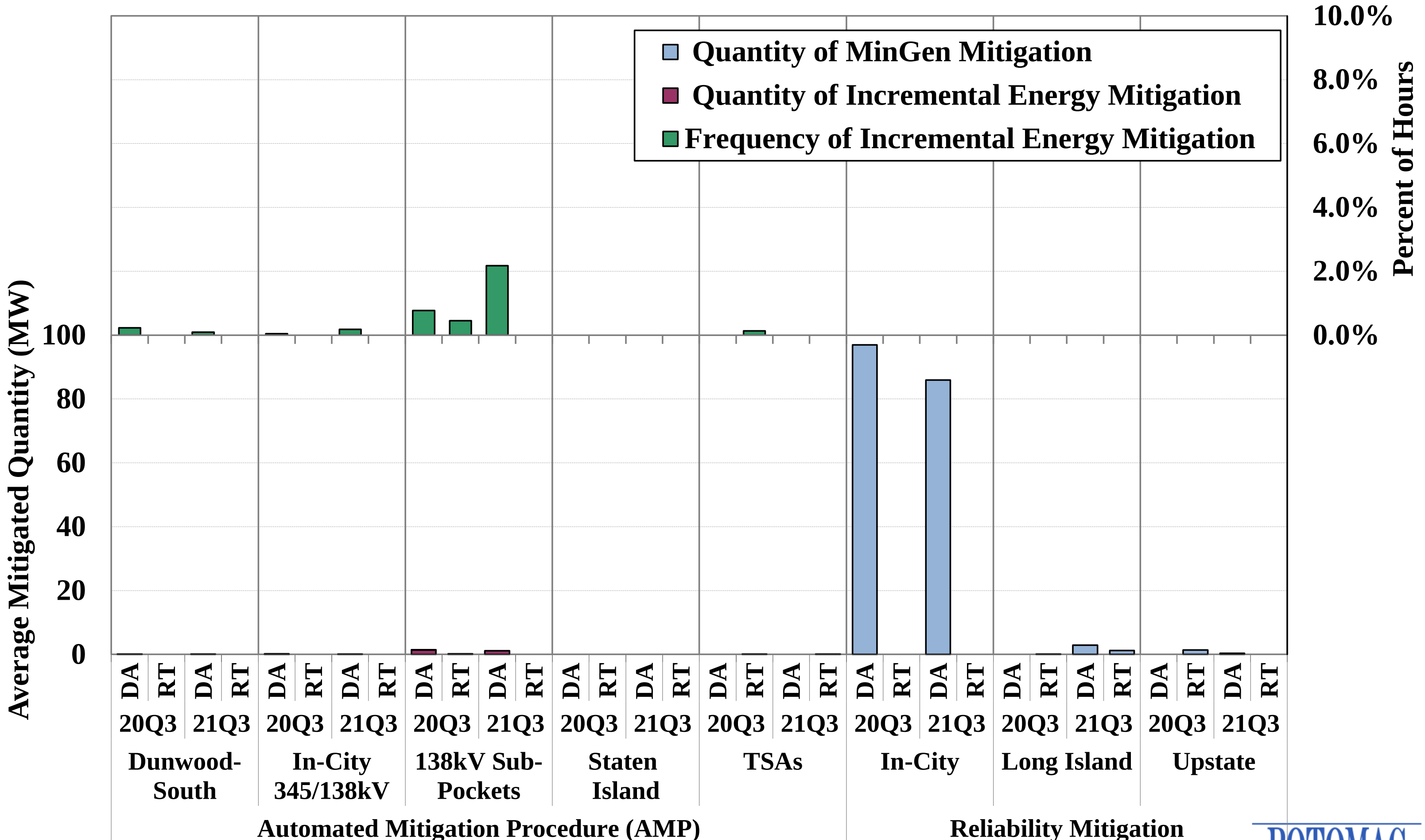
POTOMAC ECONOMICS

Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 115.

Automated Market Power Mitigation

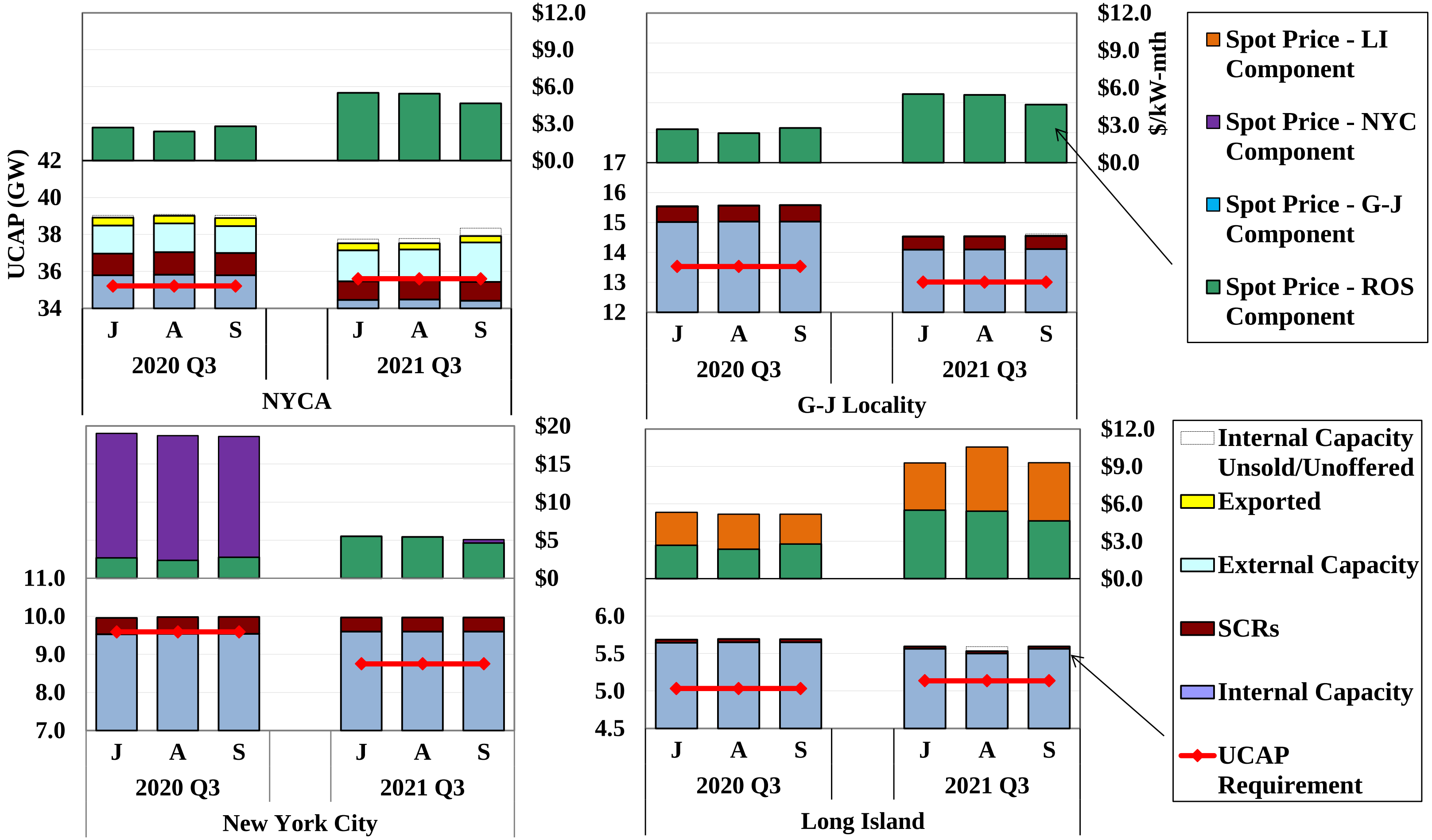
Notes: For chart description, see slide 116.

POTOMAC ECONOMICS

Charts:
Capacity Market

POTOMAC ECONOMICS

Spot Capacity Market Results
Monthly Results by Locality



Notes: For chart description, see slide 117.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2021 Q3 ($/kW-Month)	$5.19	$5.34	$9.72	$5.19
% Change from 2020 Q3	**99%**	**-72%**	**86%**	**99%**
Change in Demand				
Load Forecast (MW)	37	-278	21	-284
IRM/LCR	1.8%	-6.3%	-0.5%	-2.4%
2021/22 Capability Year	*120.7%*	*80.3%*	*102.9%*	*87.6%*
2020/21 Capability Year	*118.9%*	*86.6%*	*103.4%*	*90.0%*
ICAP Requirement (MW)	**626**	**-946**	**-4**	**-626**
Key Changes in ICAP Supply (MW)				
Generation	**-761**	**4**	**-196**	**-1010**
Entry	35	12	0	12
Exit (3)	-1112	-15	-156	-1052
Other Capacity Changes (1)	316	7	-40	30
Cleared Import (2)	**312**			

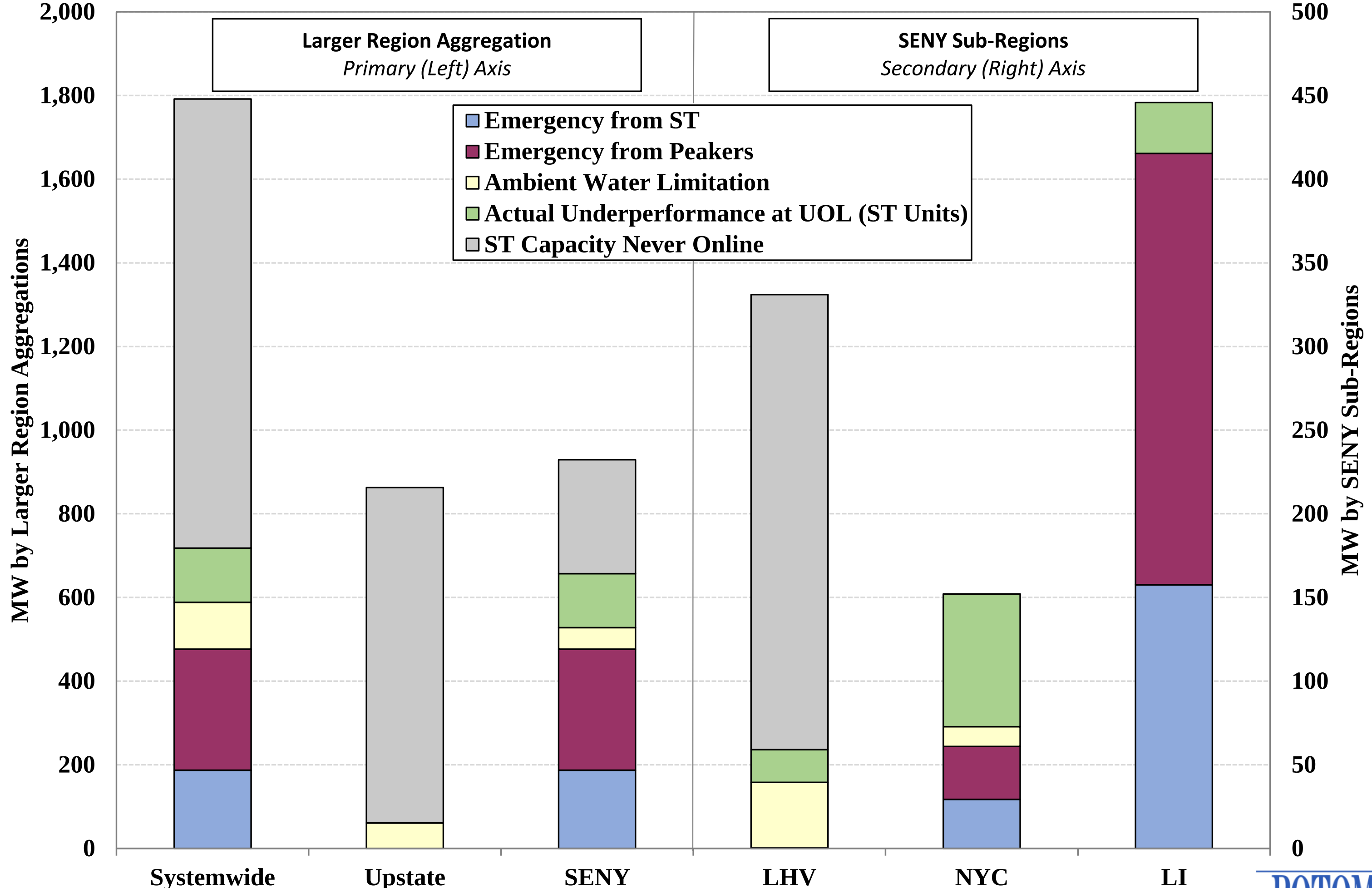
(1) Other changes include DMNC ratings, former exports, unsold capacity, etc.

(2) Based on average of quarterly cleared quantity.

(3) Includes reduced sales from UDR line(s)

Notes: For chart description, see slide 117.

Unavailable Capacity from Steam, Nuclear, and Peakers on Highest Load Days



Notes: For chart description, see slide 118.

POTOMAC ECONOMICS

Appendix: Chart Descriptions

All-in Price

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

POTOMAC ECONOMICS

Real-Time Output and Marginal Units by Fuel

- Slide 28 shows the quantities of real-time generation by fuel type.
  - ✓ Real time generation by fuel type is derived from data reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").
  - ✓ Pumped-storage resources in pumping mode are treated as negative generation. "Other" includes Methane, Refuse, Solar & Wood.
- Slide 29 summarizes how frequently each fuel type was on the margin and setting real-time LBMPs in these regions.
  - ✓ More than one type of generator may be on the margin in an interval, particularly when a transmission constraint is binding. Accordingly, the total for all fuel types may be greater than 100 percent.
    - – For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent.
  - ✓ When no generator is on the margin in a particular region, the LBMPs in that region are set by:
    - – Generators in other regions in the vast majority of intervals; or
    - – Shortage pricing of ancillary services, transmission constraints, and/or energy in a small share of intervals.

POTOMAC ECONOMICS

Emission by Region

- Slides 30-34 evaluate emissions from generators in the NYISO market.
  - ✓ Slide 30 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_X, and SO_2 .
  - ✓ Slides 31-32 show quarterly emissions across the system by generation fuel type for CO_2 and NO_X .
    - – Emission values are given for 7 regions as well as the system as a whole.
    - – The emission tonnage is given by aggregating the total pollution from operations on the various fossil fuel types for each month of the quarter.
    - – The inset tables in each chart provides summary data on the total tonnage of emissions by fuel type for three recent quarters.
  - ✓ Slides 33-34 evaluate NO_X emission during the quarter in the non-attainment areas in New York City and Long Island, respectively, on a daily basis.
    - – The emission tonnage is shown separately for oil-fired units and gas-fired units in stacked bars, where gas-fired units are also grouped based on technology: (a) combined-cycle; (b) steam turbine; (c) gas turbines that were in service before 2000; and (d) gas turbines that were in service since 2000.
    - – The line in slide 33 shows the emission from STs in NYC that were supplementally committed for local reliability as a percent of total emission in NYC.

POTOMAC ECONOMICS

Self-Commitments on Long Island

- The chart on slide 38 shows the real-time production from Long Island generators and imports from NE and PJM during the quarter broken into four time periods:
  - ✓ The period before any outages of either the Y-49 or Y-50 (Jul 1-16);
  - ✓ The period when just the Y-50 was OOS (Jul 17 to Aug 5);
  - ✓ The period when both the Y-49 and Y-50 lines were OOS (Aug 6 to Sep 19); and
  - ✓ The period when just the Y-49 was OOS (Sep 20-30).
- The columns show the real-time output from:
  - ✓ NE & PJM imports (i.e., CSC, 1385, & Neptune);
  - ✓ Minimum generation levels of Long Island generators;
  - ✓ Energy produced above the minimum generation level due to self-commitments; and
  - ✓ Energy produced above minimum generation level offered flexibly.
- The three lines show the total energy scheduled in the day-ahead market from the generation and imports combined (black), and from imports alone (burgundy), and the RT LBMP (red).
- All data is shown as the average hourly values across the four distinct time periods.

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 13 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).

POTOMAC ECONOMICS

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.

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.

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.

POTOMAC ECONOMICS

Real-Time System Price Maps at Generator Nodes

- Slides 55 and 56 show maps of real-time LBMPs at generator nodes across the entire NYISO system and in New York City specifically to illustrate congestion patterns in both areas.
  - ✓ Prices are load-weighted real-time hourly LBMPs.
  - ✓ Generators are marked as circles of various sizes and colors which are determined based on market outcomes:
    - Circle size is developed based on real-time generation from each generator across the quarter.
    - Colors are scaled based on the load-weighted real-time prices at each node.
    - However, both circle sizes and color scales are not necessarily the same at the same generator location in the system map and the NYC map. Because these are independently determined based on the set of generators analyzed in each map.
  - ✓ Natural gas prices for major indices and load-weighted external energy prices are also provided.
    - External LBMPs are not scaled to size in like manner as the generators.
    - Natural gas pipeline connections are given for the NYC price map to illustrate approximate gas delivery points to the city from three major pipelines.

Transmission Congestion and Shortfalls

- Slides 57, 58, 59, and 60 evaluate the congestion patterns in the DAM and RTM and examine the following categories of resulting congestion costs:
  - ✓ Day-Ahead Congestion Revenues are collected by the NYISO when power is scheduled to flow across congested interfaces in the DAM, which is the primary funding source for TCC payments.
  - ✓ Day-Ahead Congestion Shortfalls occur when the net day-ahead congestion revenues are less than the payments to TCC holders.
    - Shortfalls (or surpluses) arise when the TCCs on a path exceed (or is below) its DAM transfer capability in periods of congestion.
    - These typically result from modeling differences between the TCC auction and the DAM, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ Balancing Congestion Shortfalls arise when DAM scheduled flows over a constraint exceed what can flow over the constraint in the RTM.
    - The transfer capability of a constraint falls (or rises) from day-ahead to real-time for the similar reasons (e.g., deratings and outages of transmission facilities, inconsistent assumptions regarding PAR schedules and loop flows, etc.).
    - In addition, payments between the NYISO and PJM related to the M2M process also contribute to shortfalls (or surpluses).

Transmission Congestion and Shortfalls (cont.)

- Slide 57 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 58 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 59 and 60 show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.

Transmission Congestion and Shortfalls (cont.)

- Congestion is evaluated along major transmission paths that include:
  - ✓ West Zone Lines: Primarily 230 kV transmission constraints in the West Zone.
  - ✓ West to Central: Including transmission constraints in the Central Zone and interfaces from West to Central.
  - ✓ North Zone: The Moses-South interface and other lines in the North Zone and leading into Southern New York.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.
  - ✓ Capital to Hudson Valley: Primarily lines leading into SENY (e.g., the New Scotland-Leeds line, the Leeds-Pleasant Valley line, etc.)
  - ✓ NYC Lines: Including lines into and within the NYC 345 kV system, lines leading into and within NYC load pockets, and groups of lines into NYC load pockets that are modeled as interface constraints.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ External Interfaces – Congestion related to the total transmission limits or ramp limits of the external interfaces.
  - ✓ All Other – All of other line constraints and interfaces.

POTOMAC ECONOMICS

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).

Constraints on the Low Voltage Network

- 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 62 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).

Constraints on the Low Voltage Network

- Slide 63 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 63 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 64 shows such select N-1 constraints in New York City. In the figure,
  - ✓ The left panel summarizes their DA and RT congestion values in the quarter.
    - The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities (i.e., constraint shadow cost*seasonal LTE summed over all intervals); and
    - The red bars represent the congestion values measured for the additional transfer capability above LTE (i.e., constraint shadow cost*(modeled constraint limit – seasonal LTE) summed over all intervals).
  - ✓ The bars in the right panel show the seasonal LTE and STE ratings for these facilities, compared to the average N-1 constraint limits used in the market software.

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Duct Burner RPU Performance and Real-Time Availability

- Slide 65 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 66 shows quarterly average real-time duct burner data across all applicable units during this quarter on a 5-minute interval level basis.
  - ✓ The topmost chart shows the average amount of MWs from duct burners scheduled in real-time to provide 10-minute spinning reserves and regulation services.
  - ✓ The middle chart shows the amount of 5-minute up-ramping capability assumed to be available by duct burners (but likely not actually available due to physical operating restrictions) based on real-time output levels and generator offers.
  - ✓ The bottom chart reveals 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.

GT Start-up Performance

- Slides 67-68 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 67): "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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Supplemental Commitments and OOM Dispatch

- Slides 70, 71, and 77 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 70 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 71 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:

Supplemental Commitments and OOM Dispatch (cont.)

  - NOx – If needed for NOx bubble requirement.
  - 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 77 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.

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SRE Commitments for Capacity and DR Deployments On High Load Days

- Slides 72 and 73 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 74 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.

DAM Forecast Pass Commitment

- In the day-ahead market, when the Bid Load Pass does not commit enough physical resources to meet forecast load and reserves requirements, the subsequent Forecast Pass will commit additional physical resources accordingly.
- Slide 75 shows our evaluation of Forecast Pass commitments in 2020 and 2021.
  - ✓ The x-axis shows all days when Forecast Pass commitments occurred during the examined period.
  - ✓ The solid blue bar shows, for each day, the total MWh committed by the Forecast Pass, including capacity from slow-start units and non-blocked quick-start units.
  - ✓ The empty bar shows available offline capacity from non-blocked quick-start units during the hours when FCT commitments occurred. This capacity is currently not treated the same way as blocked quick-start units in the FCT pass to satisfy load and reserve requirements.
  - ✓ The inset table summarizes for 2020 and 2021:
    - Total number of days when FCT commitments occurred;
    - Total MWh committed in the FCT pass;
    - Total available offline capacity from non-blocked quick-start units during FCT commitment hours; and
    - Resulting total BPCG uplift.

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Supplemental Commitments on Long Island

- Slide 76 shows our evaluation of supplemental commitments on Long Island during the period in the third quarter when both Y49 and Y50 345 kV lines were out of service.
  - ✓ The total of the stacked bars represents the minimum hourly surplus capacity on Long Island for each day of the examined period.
    - This is calculated as the total amount of bid UOL from online and offline available quick-start resources minus generation output.
    - Unutilized transfer capability across ties into Long Island (including 901/903, 1385, CSC, and Neptune lines) is not included in this chart.
  - ✓ The red and blue bars represents the bid UOL from resources that are SRE and DARU committed.
  - ✓ The green bar shows the surplus capacity by removing SRE and DARU units.
  - ✓ The black line shows the maximum 30-minute reserve requirement on Long Island, set at 540 MW currently.
    - Long Island is short of reserves when the height of stacked bars is lower than the black line.

Uplift Costs from Guarantee Payments

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

Potential Economic and Physical Withholding

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

Automated Market Power Mitigation

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

Spot Capacity Market Results

- Slides 85 and 86 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 85 summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices that occurred in each capacity zone by month.
    - Sales associated with Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity," but unsold capacity from resources with UDRs is not shown.
  - ✓ Slide 86 compares the year-over-year changes in capacity spot prices by Locality and shows variations in key factors that drove these changes, including:
    - The changes in the UCAP requirements, which are affected by changes in the forecasted peak load, the minimum capacity requirement, and the derating factors;
    - The changes in the UCAP supply, which are affected by changes in new entry, mothballing and retirement, and DMNC test values; and
    - The changes in the demand curves, which are mostly affected by the assumptions used in each demand curve reset process.
      - The most recent reset was done for the Capability Periods from 2017 to 2021.

Unavailable Capacity from Steam, Nuclear, and Peakers on High Load Days

- Slide 87 shows the amount of capacity that was functionally unavailable to the market on the 10 highest load days in the 2021 Summer Capability Period from steam units, nuclear generators, and peakers for a variety of reasons:
  - ✓ ST Capacity Never Online
    - This represents the ICAP from STs that produced zero energy on all 10 of the highest load days this summer.
  - ✓ Actual Underperformance at UOL (ST Units)
    - The average drag MW (i.e., underperformance) of steam units that were online and instructed to operate at their UOLn for at least three five-minute intervals.
  - ✓ Emergency from STs or Peakers
    - The amount of capacity offered by STs or Peakers in their UOLe ranges. This is also called "emergency capacity", which is only dispatchable under emergency circumstances and is unavailable for normal operations.
  - ✓ Ambient Water Limitation
    - The amount of capacity derated either in DA or RT from Steam and Nuclear units and explicitly marked in either the Maintenance or OOM records as related to Ambient Water temperatures.