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

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Market Highlights

Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the first quarter of 2022.
- All-in prices ranged from \$72 to \$130 per MWh, up 69 to 233 percent from 2021-Q1 in all regions. (slide 7)
  - ✓ Energy prices rose 110 to 245 percent across the system primarily because of higher gas prices (up 51 to 138 percent). (slide 19)
  - ✓ Congestion rose substantially across the Central-East interface because of:
    - Increased regional gas price spreads; (slide 20)
    - The retirement of the Indian Point nuclear plant; (slide 24) and
    - Transmission outages that reduced transfer capability by more than 1 GW in March.
  - ✓ 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 16)
- OOM commitments for local operating reserve needs were frequent in the load pockets of: (a) North Country (38 days); (b) 115 kV network in the Capital Zone (23 days); and Long Island (6 days). (slides 13-14)
  - ✓ Modeling these reserve requirements in the market software would improve scheduling and pricing efficiency and provide transparent investment signals for renewable and storage resources.

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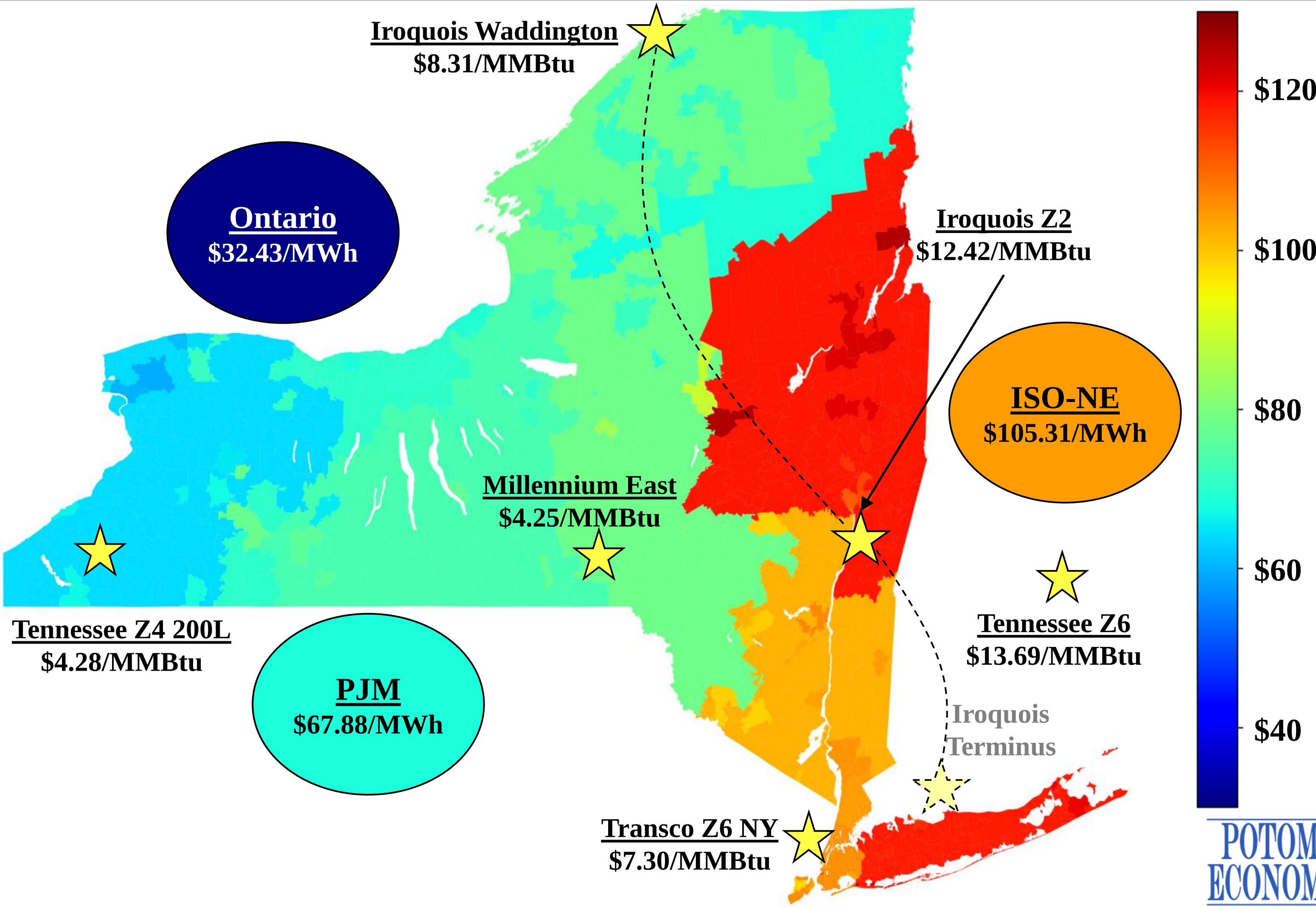
Market Highlights:
Executive Summary

- We evaluated operation of resources in Eastern New York during cold weather conditions from January 7 to 31 when gas supplies were limited. (slides 9-10)
  - ✓ Although oil-fired generation rose substantially during this period, large amounts of gas were available during this period at prices competitive with oil.
  - ✓ However, we estimate that an average of 3.8 GW would have been economic to burn oil but did not operate because:
    - – Oil-firing equipment and/or necessary air permits have not been maintained;
    - – Generator outages and deratings;
    - – Some dual-fuel units have reduced capacity when burning oil; and
    - – Emission and oil-inventory limitations.
  - ✓ Available gas pipeline capacity was insufficient to serve some or all gas-dependent generation on some peak days in Long Island, NYC on both LDC pipelines, and upstate areas served by one LDC.
    - – This reinforces the importance of improving capacity accreditation for resources with winter fuel limitations.

Market Highlights:

System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the first quarter of 2022.
  - ✓ The amount of output gap (slide 71) and unoffered economic capacity (slide 72) remained modest and reasonably consistent with competitive market expectations.
- All-in prices ranged from $72/MWh in the West Zone to $130/MWh in Long Island, rising 69 to 233 percent from a year ago. (slide 18)
  - ✓ Energy prices rose substantially in all zones, up by 167 to 245 percent in the Western NY and 110 to 158 percent in Eastern NY. Increases were by:
    - Primarily higher natural gas prices, which rose 51 to 138 percent across the system from a year ago (slide 20).
    - Lower nuclear generation – the average output fell by roughly 1.35 GW, mainly because of the Indian Point 3 retirement in April 2021; (slide 21)
    - Major transmission outages in March that reduced the transfer capability across the Central-East interface by more than 1,000 MW, leading to further elevated prices in Eastern NY. (slide 54)
    - Higher load levels – peak load rose 3 percent and average load rose 2 percent
    - Higher RGGI allowance prices, up by 68 percent from a year ago.
  - ✓ Capacity costs rose in all areas but NYC for reasons discussed in slide 16.

Market Highlights:
Generation by Fuel and Emissions

- Average nuclear generation fell by roughly 1.35 GW from a year ago because of the retirement of Indian Point 3 in April 2021 and other refueling outages.
- Gas-fired generation rose by about 500 MW on average, picking up part of the nuclear generation loss. (slide 21)
  - ✓ Gas-fired combined cycle output rose by 330 MW on average and other gas-fired generation rose by 170 MW on average.
  - ✓ Gas-fired output increased in regions with lower gas prices (e.g., Central NY and NYC) but fell in the higher cost regions (e.g., Long Island and Capital Zone).
- Oil-fired generation averaged 540 MW, the highest since 2018-Q1.
  - ✓ Nearly 90 percent of oil-fired output occurred during January when natural gas prices were highly volatile and exceeded fuel oil prices on many days. (slide 23)
  - ✓ Despite the increased oil output, oil usage from oil-capable units averaged just 20 percent of the estimated economic level (for reasons discussed in slide 9).
- Emissions rose 37 percent for NOx and 15 percent for CO2 from the prior year.
  - ✓ The increases were driven primarily by higher oil-fired generation in January. (slides 29-30)

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Market Highlights:

Performance of Resources Under Tight Gas Conditions on Cold Days

- January had colder-than-average temperatures and tight gas system conditions, which led natural gas prices to surpass fuel oil prices on many days.
  - ✓ Consequently, oil-fired generation rose substantially on these days. (slides 23-24)
  - ✓ Nonetheless, gas-fired generation was still predominant during this period.
    - – Oil-fired generation in East NY exceeded gas-fired generation on only two days.
    - – Total oil-fired generation in East NY during this period averaged just 20 percent of the capacity that we estimate would have been economic. Much of this capacity was burning natural gas for some reasons discussed below.
- During the cold weather from January 7 to 31, an estimated average of 3.8 GW would have been economic to burn oil but was not operating because:
  - ✓ Some oil-capable units (according to the Gold Book) have not made the requisite investments to maintain oil-burning equipment, necessary air permits, and/or a stock of oil, leading an average of nearly 2 GW to be unavailable;
  - ✓ Many dual-fuel units, have reduced capability when burning oil (e.g., duct burners that are gas-only), leading an average of 370 MW to be unavailable;
    - – Current rules require these units to take forced derates regardless of their energy schedules, which reduce their UCAP capability. While gas-only units are generally not reported as forced derates unless they are scheduled and can't secure gas.
    - – This provides poor incentives for resources to be available during winter peak conditions.

Market Highlights:
Performance of Resources Under Tight Gas Conditions on Cold Days (cont.)

- ✓ Planned and forced outages and derates led 620 MW to be unavailable on average;
- ✓ Inventory limitations became more prevalent in the second half of this period, leading an average of 260 MW to be unavailable;
- ✓ Some portfolios are subject to NOx emission limitations that make operations of all portfolio resources on fuel oil unlikely, leading an average of 340 MW to be unavailable; and
- ✓ Temporary oil equipment outages were most acute during the early and later parts of this period, leading an average of 200 MW to be unavailable.

- We examined the availability of natural gas to gas-only generators during this period and found that:
  - ✓ Estimated natural gas demand for offered gas-only generators in NYC at Hunts Point delivery exceeded: (a) its firm delivery capacity on at least five days; and (b) its operational capacity on at least two days during this period. (slide 25)
    - – Hence, not all of the gas-only capacity would have been available if called on.
  - ✓ National grid LDC issued Tier 1 and 2 interruption of service to non-firm customers on 8 days in NYC, 9 days in Long Island, and 5 days in upstate regions.
    - – Generators on interruptible service contracts had restricted gas service and limited gas availability on these days.

Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $386 million, significantly higher than any first quarter since 2014. (slide 52)
- The Central-East interface accounted for the largest share of congestion this quarter (DA 63%, RT 60%). (slide 56)
  - ✓ DA congestion rose 76 percent from a year ago and RT congestion rose 85 percent.
  - ✓ The high natural gas prices and large regional gas spreads greatly influenced this congestion in January and February.
    - – This was also exacerbated often by large amounts of Lake Erie Circulation as Michigan PARs were frequently not regulating. As a result:
      - NYISO issued TLR 3A cuts to manage this congestion on more than 30 days in January and February.
      - IESO issued TLR 3A cuts affecting PJM→NYISO schedules. This combined with frequent outages of the user-interface for scheduling CTS transactions to increase RT price volatility and worsen RTC/RTD convergence.
      - Transmission outages were taken to facilitate Public Policy Segment A & B construction work in March, reducing interface transfer capability by more than 1,000 MW and leading to high levels of congestion. (slide 54)

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Market Highlights:

Congestion Patterns, Revenues and Shortfalls (cont.)

- The external interfaces were much more congested than usual, accounting for the second largest share of congestion (DA 17%, RT 21%). (slide 56)
  - ✓ The primary interfaces with PJM (58 percent) and ISO-NE (34 percent) drove most of this congestion, driven primarily by large regional gas spreads.
- Most other congestion occurred in NYC, Long Island, and West Zone. (slide 53)
  - ✓ In NYC, most of congestion occurred on transmission paths into the Greenwood load pocket, driven largely by transmission outages on parallel facilities.
    - One Gowanus-Greenwood 138 kV line was OOS in the first half of the quarter.
    - One Gowanus-Goethals and one Goethals-Freshkills 345 kV lines were both OOS in the second half of March.
  - ✓ On Long Island, nearly 90 percent of congestion occurred on the 345 kV inter-ties between upstate regions and Long Island.
    - Long Island generation costs were increased by high gas prices and limited flexibility on the Iroquois and LDC pipelines in January and February.
    - The Y49 345 kV line was OOS in the second half of March.
  - ✓ In the West Zone, more than 60 percent of congestion occurred on the Packard 230/115 kV transformer in January.
    - Several Niagara-Packard 115 kV lines were OOS during this period.

Market Highlights:
OOM Actions to Manage Network Reliability

- OOM actions to manage network reliability were frequent in the Upstate regions this quarter – North and MHK VL Zones (42 days), West Zone (32 days), and Capital Zone (29 days). (slide 57)
- Supplemental commitments to satisfy the N-1-1 requirements in local load pockets were frequent.
  - ✓ Reliability commitments for the N-1-1 requirements in the NCLP and PLP of North Country occurred on 38 days. (slide 59)
    - The NYISO DARUed the needed unit much more frequently rather than using SRE, which helped improve scheduling and pricing efficiency in this area.
    - Nonetheless, commitments occurred on many days with small (< 10 MW) reserve needs, leading to sizable uplift.
    - In addition, wind curtailments occurred on 24 of the 38 days. Wind generation is currently not counted towards satisfying the N-1-1 requirements in the load pockets, so reliability commitments increase generation in the area and often cause additional wind curtailment.
    - Modeling these N-1-1 requirements in the market software would improve scheduling efficiency, send efficient investment signals, and help integrate renewable and storage resources.

Market Highlights:
OOM Actions to Manage Network Reliability (cont.)

- ✓ Reliability commitments for the N-1-1 requirement in the Capital Zone 115 kV network occurred on 23 days. (slide 57)
  - This need arose because of the combined effects of: (1) transmission outages that were taken to facilitate Public Policy-related transmission work, reducing import capability into the 115 kV pocket; and (2) seasonal maintenance of generators, reducing available supply in the 115 kV pocket.
  - All these commitments were SREs, which tend to depress prices and generate uplift in the real-time market, although this uplift was not significant in this quarter.
- ✓ Long Island also had 6 days when supplemental commitments were made for reserve needs either for severe weather and tight gas conditions or for emergency outages of inter-ties.
- ✓ We have recommended the NYISO model full reserve requirements for Long Island in our 2021 SOM report. It would be beneficial to model full reserve requirements in other applicable local areas as well, such as North Country and Capital Zone.

- OOM actions in the West Zone rose modestly this quarter, partly because of non-regulating Michigan PARs not controlling Lake Erie loop flows.
  - ✓ The Dysinger-East interface was used to manage congestion on many days in January.

Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $16.3 million, up 77 percent from 2021-Q1, driven largely by higher natural gas and fuel oil prices. (slide 20)
- $7.6 million (or 46 percent) of BPCG payments accrued in NYC, 58 percent of which were paid to units that were committed for local reliability. (slide 69)
  - ✓ Local reliability commitments fell by 24 percent from the prior year (associated BPCG uplift rose 46 percent though). (slide 66)
    - The reduction occurred mostly when units needed for local reliability became more economic because gas prices were lower in NYC than the rest of East NY.
    - Reliability commitments rose in March as transmission outages in the second half of the month increased the reliability needs for the Fox Hills load pocket.
- West Upstate areas accounted for $3.2 million (or 19 percent) of BPCG uplift.
  - ✓ 60 percent of this uplift accrued on units that were supplementally committed for the N-1-1 requirement in the North Country load pockets. (slide 59)
- East Upstate area had higher BPCG uplift:
  - ✓ In January due partly to system-level reliability commitments of oil-fired generation on peak cold days.
  - ✓ In March due partly to SRE commitments for the N-1-1 needs in the Capital Zone 115 kV system that arose from transmission and generator outages.

Market Highlights:
Capacity Market

- Spot capacity prices averaged $2.86/kW-month in LI and $2.55/kW-month in the G-J Locality, NYC, and ROS this quarter. (slides 75-76)
  - ✓ Prices increased substantially in all regions (316 to 366 percent) from the prior year except in NYC where prices fell by 71 percent.
- The substantial increase in the ROS prices was driven largely by:
  - ✓ Higher ICAP requirement (by 626 MW) due to higher IRM (by 1.8 percent); and
  - ✓ Over 1.3 GW of supply loss from retirement, primarily Indian Point 3 in May 2021.
    - – However, this was partially offset by higher imports and several small new entries.
- The reduction in NYC spot prices was driven primarily by a lower ICAP requirement (by 946 MW) because of lower load forecast and LCR.
  - ✓ The LCR fell from 86.6 percent in the prior Capability Year to 80.3 percent.
    - – The steep reduction in the LCR year-over-year despite no significant changes in the supply mix in NYC highlights some deficiencies in the IRM and LCR-setting process discussed in our 2021 SOM Report.
  - ✓ The UCAP requirements in NYC and the G-J Locality were not binding in any month this quarter, leading spot prices in both localities to clear at the same levels as in ROS.

Charts:

Market Outcomes

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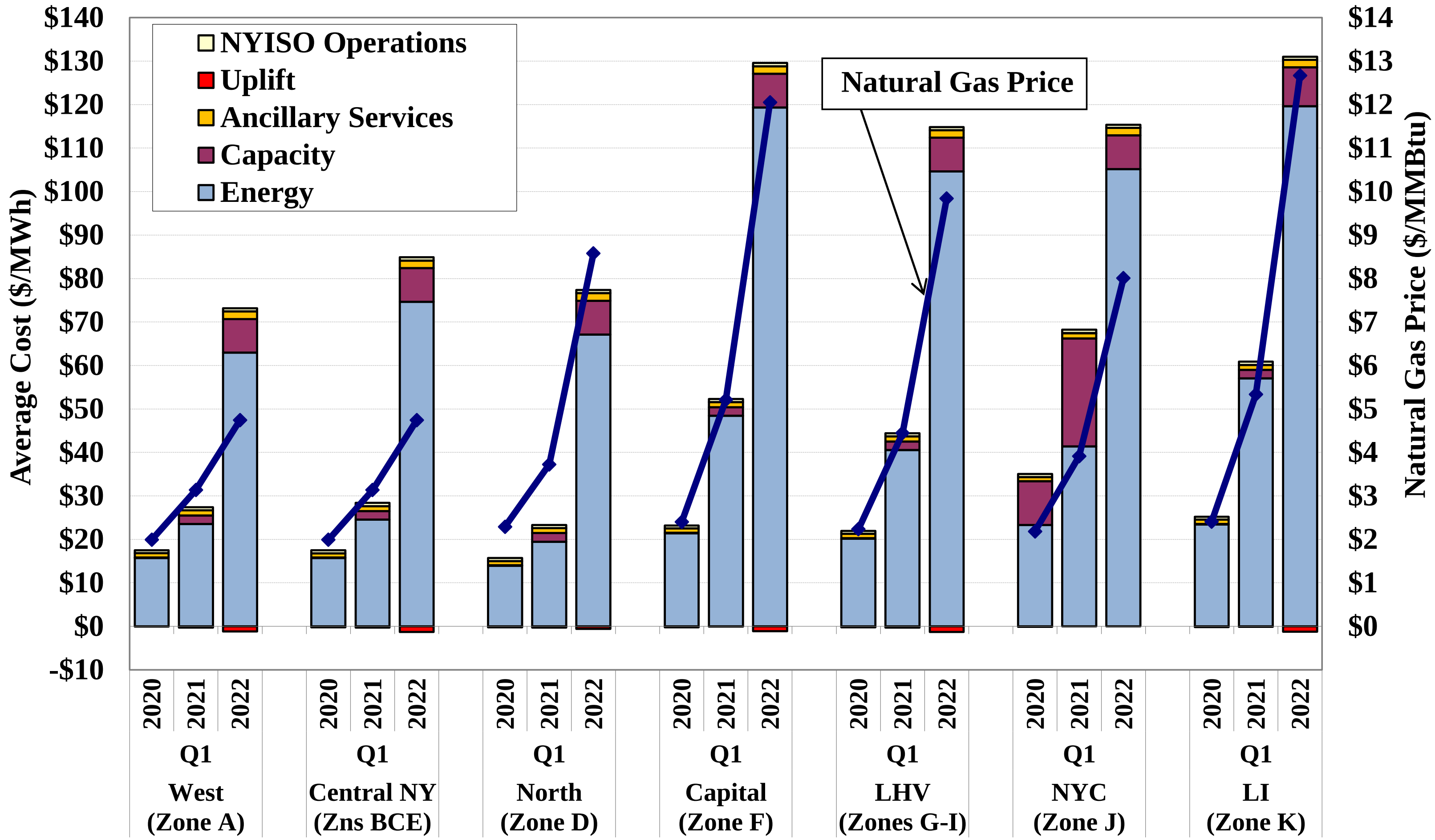
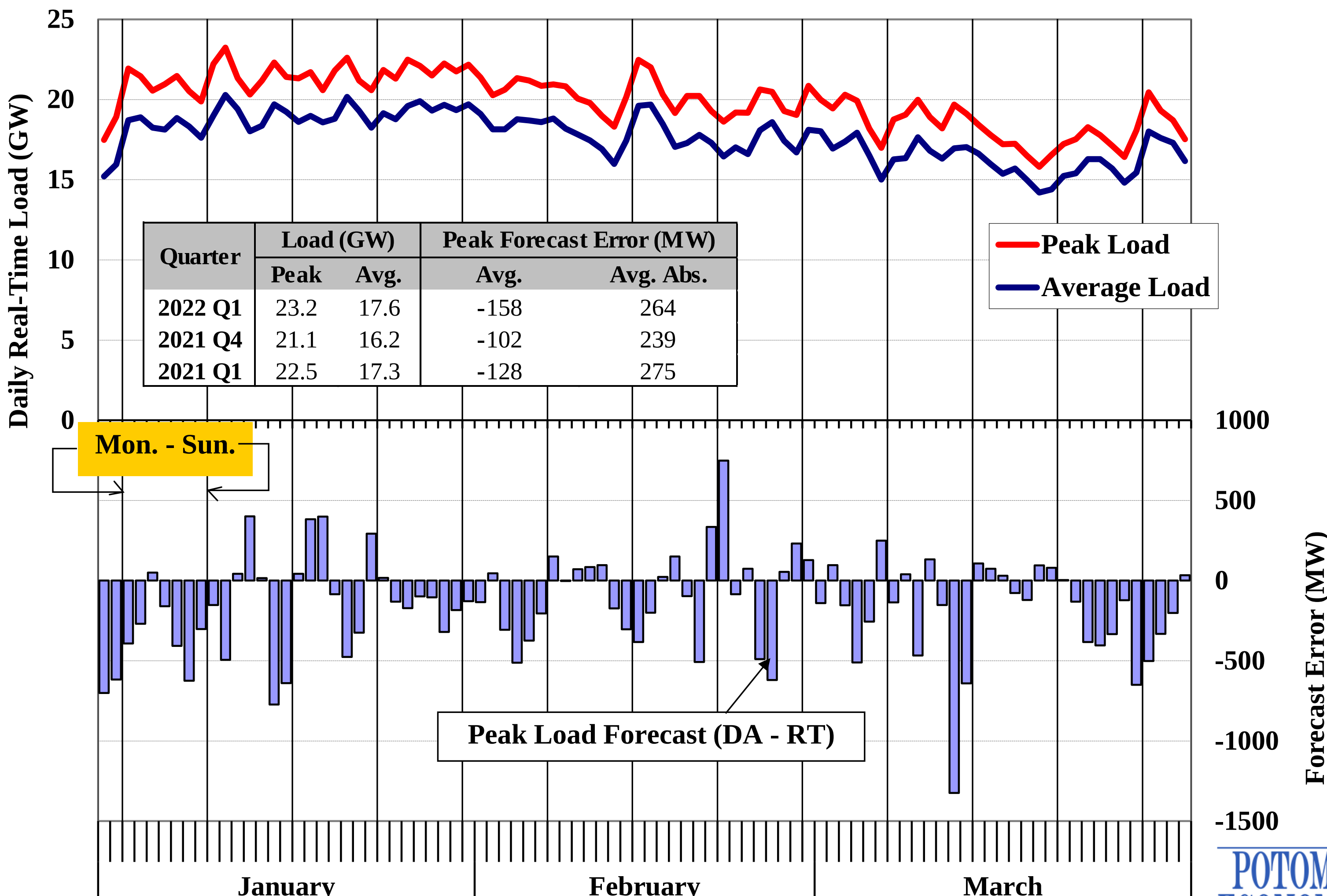
All-In Prices by Region



Notes: For chart description, see slide 78.

Load Forecast and Actual Load



Quarter	Load (GW)		Peak Forecast Error (MW)	
	Peak	Avg.	Avg.	Avg. Abs.
2022 Q1	23.2	17.6	-158	264
2021 Q4	21.1	16.2	-102	239
2021 Q1	22.5	17.3	-128	275

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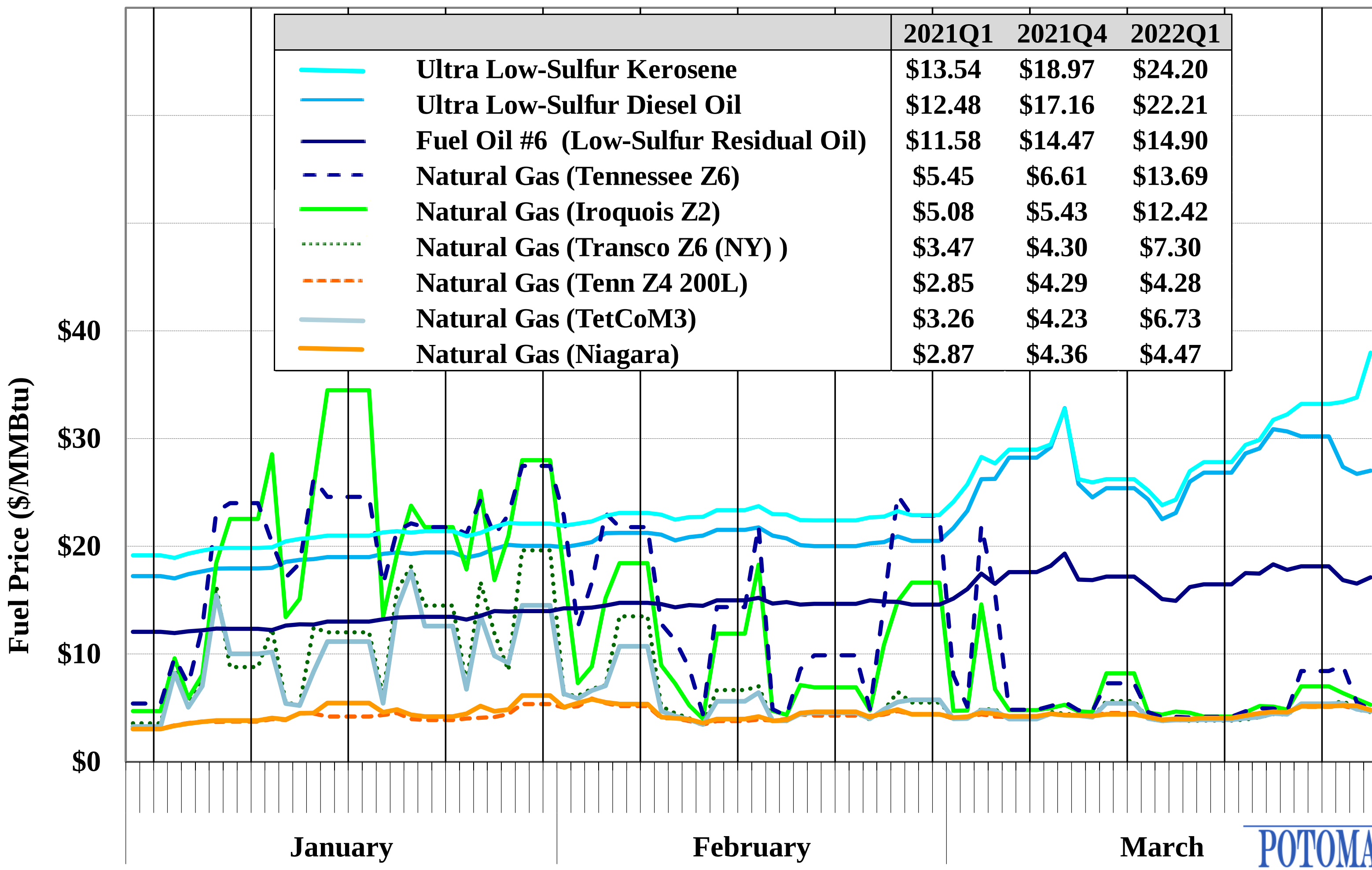
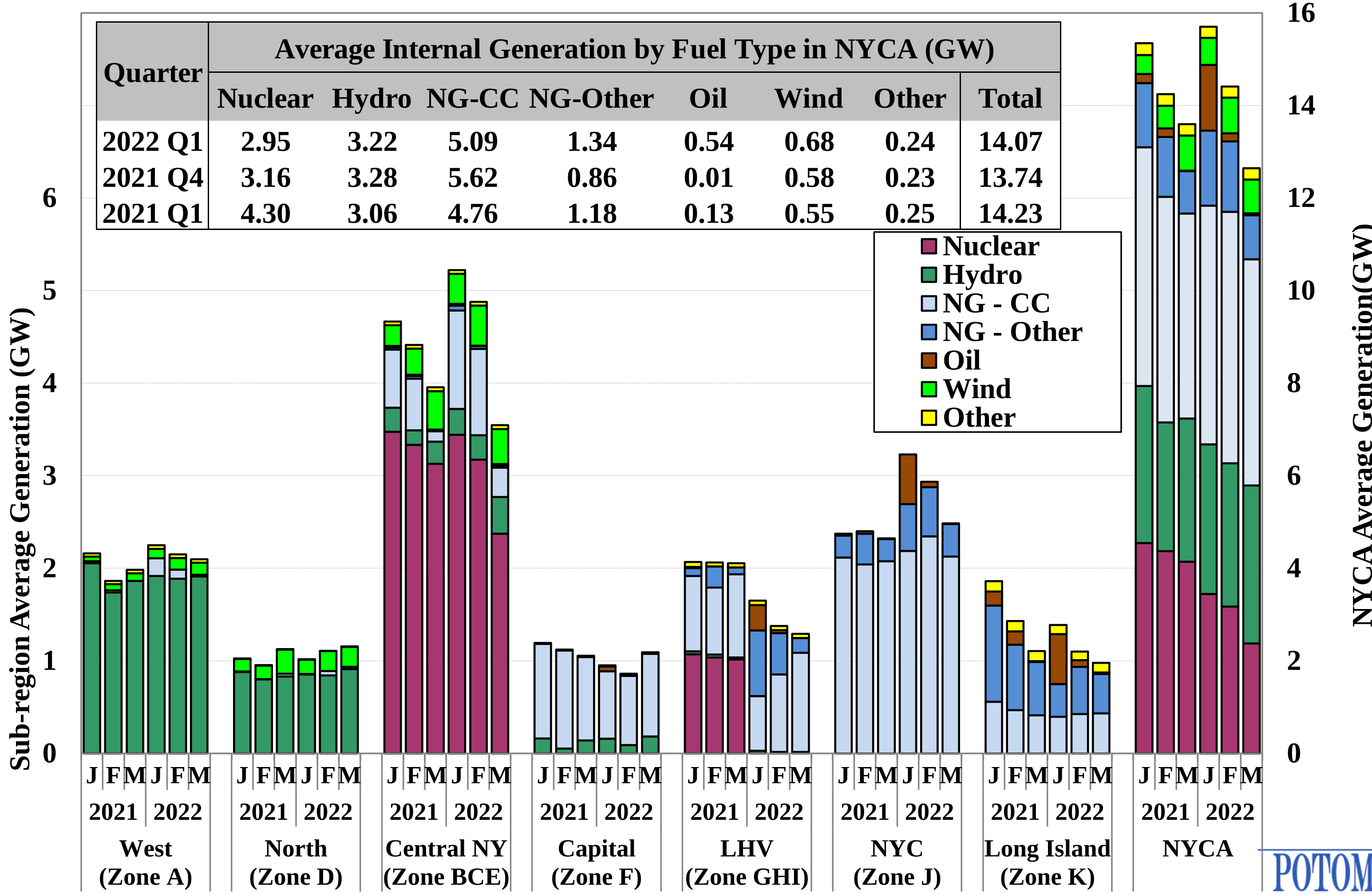
Natural Gas and Fuel Oil Prices



Real-Time Generation Output by Fuel Type

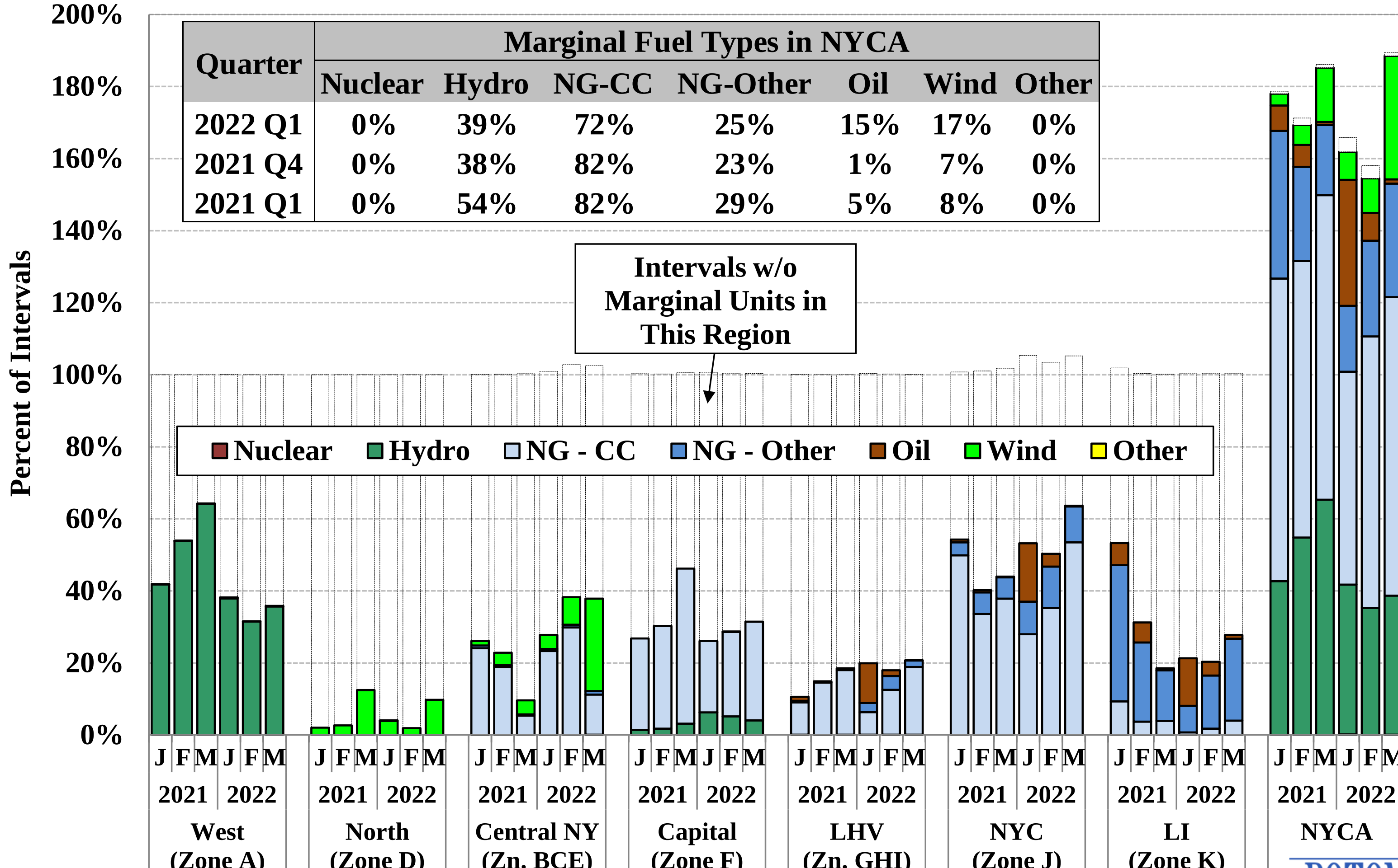


Quarter	Average Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Total
2022 Q1	2.95	3.22	5.09	1.34	0.54	0.68	0.24	14.07
2021 Q4	3.16	3.28	5.62	0.86	0.01	0.58	0.23	13.74
2021 Q1	4.30	3.06	4.76	1.18	0.13	0.55	0.25	14.23

Notes: For chart description, see slide 79.

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 Q1	0%	39%	72%	25%	15%	17%	0%
2021 Q4	0%	38%	82%	23%	1%	7%	0%
2021 Q1	0%	54%	82%	29%	5%	8%	0%



Notes: For chart description, see slide 79.

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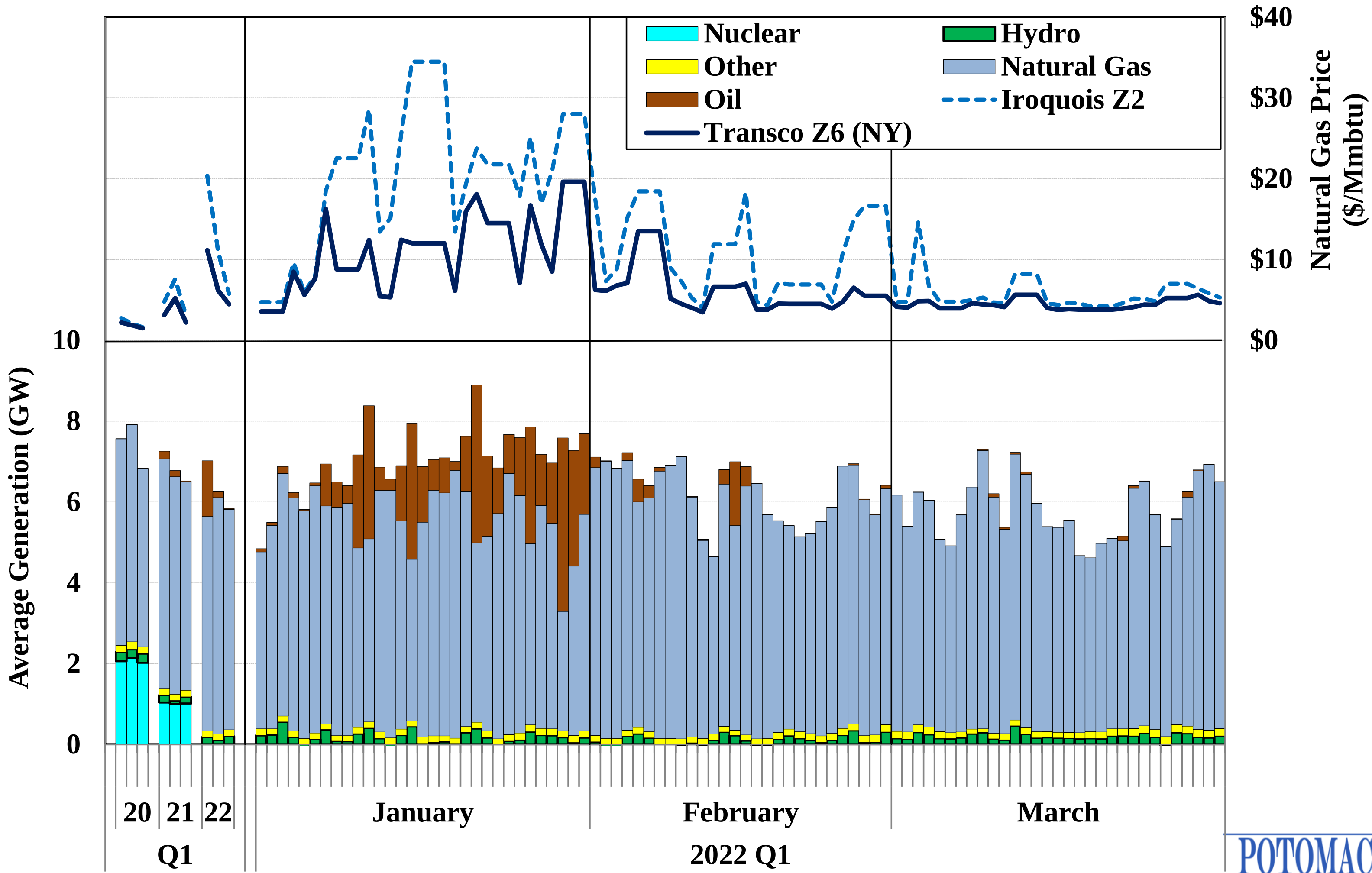
Winter Fuel Usage
Eastern New York



Notes: For chart description, see slide 80.

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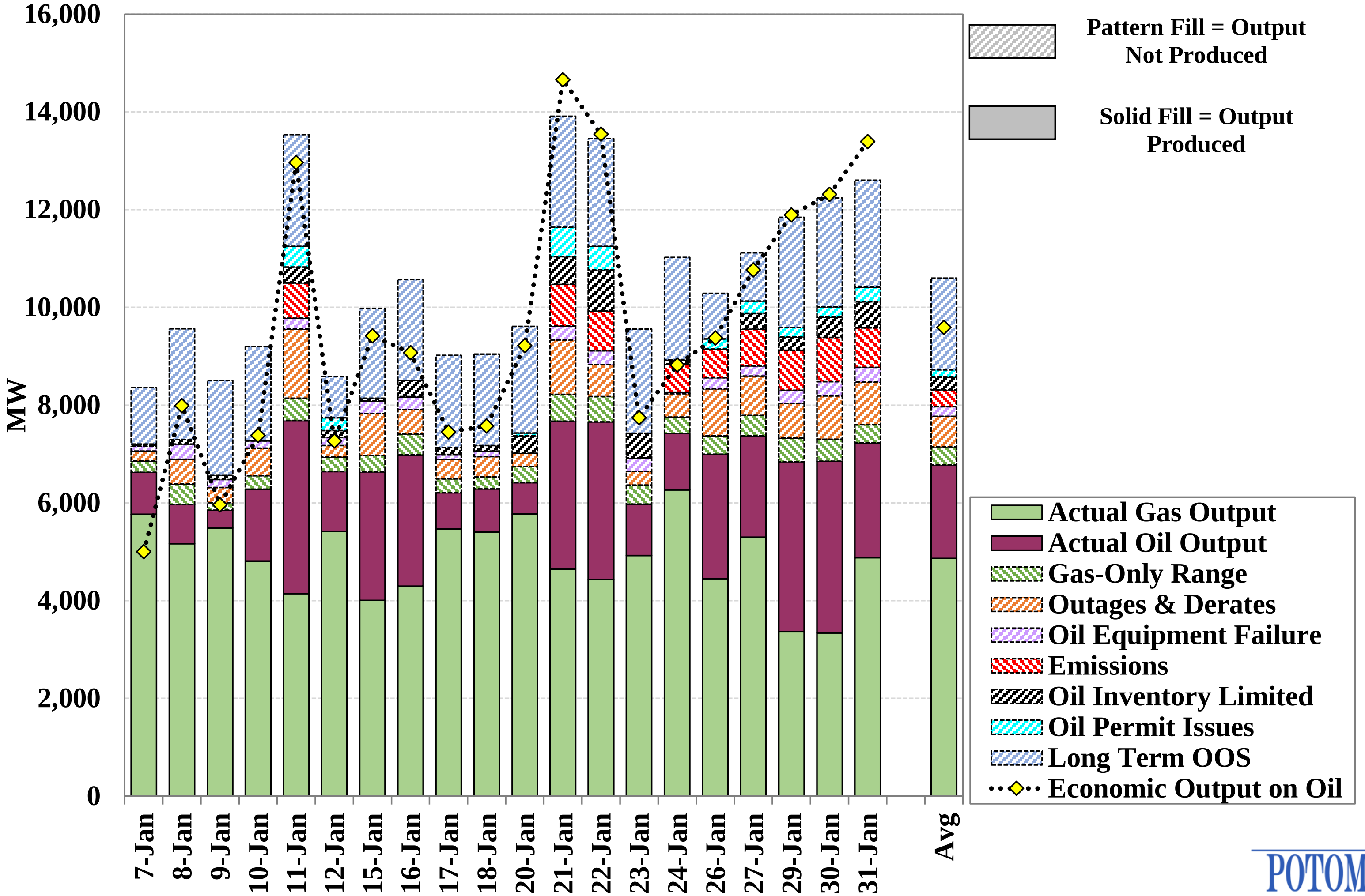
Utilization of Oil-Fired and Dual-Fuel Capacity
Eastern New York During Gas System Congestion



Note: For chart description, see slide 81.

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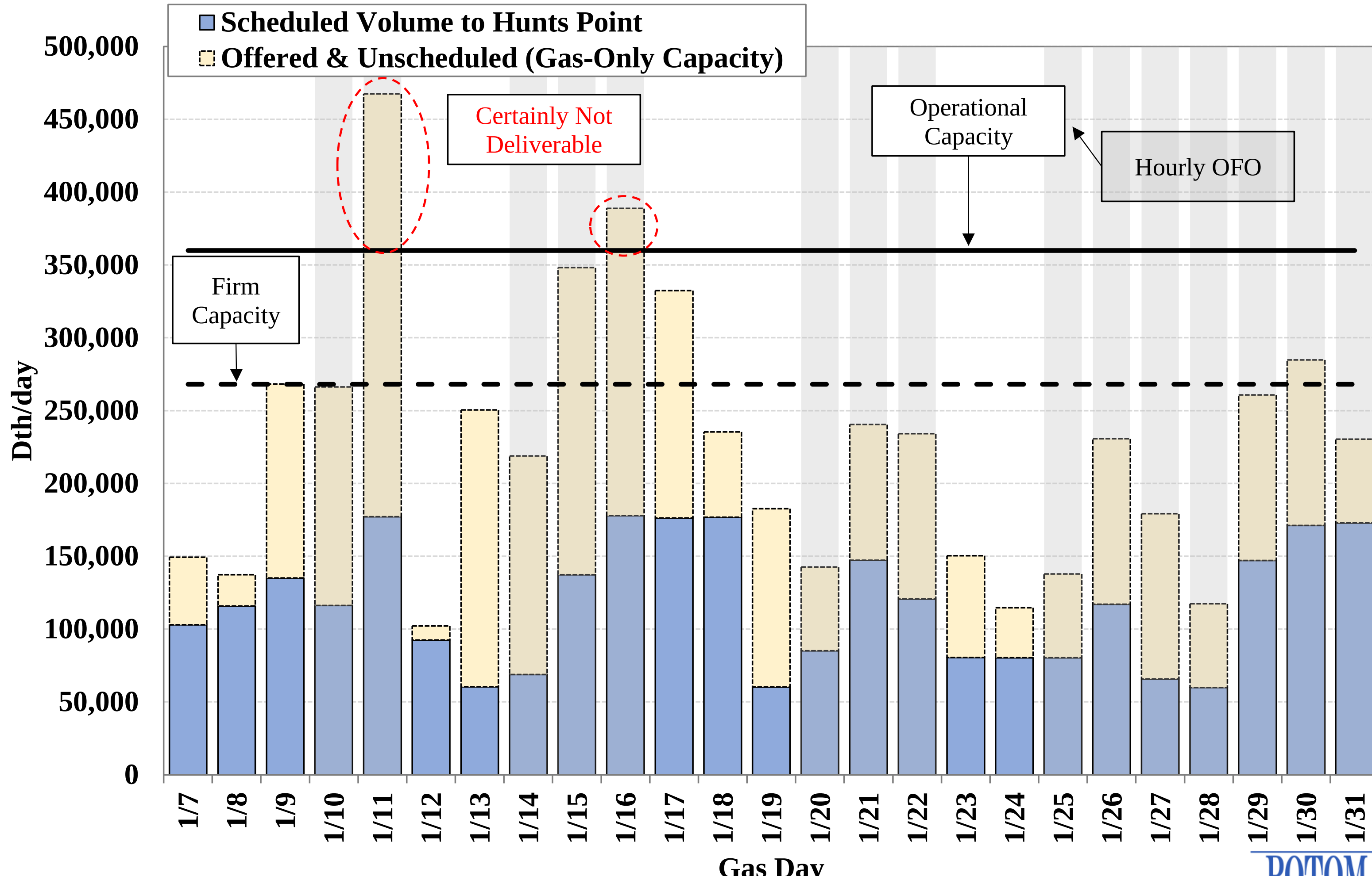
Evaluation of Implied Gas Demand at Hunts Point
NYC Gas-Only Generators on Con Ed System



Notes: For chart description, see slide 82.

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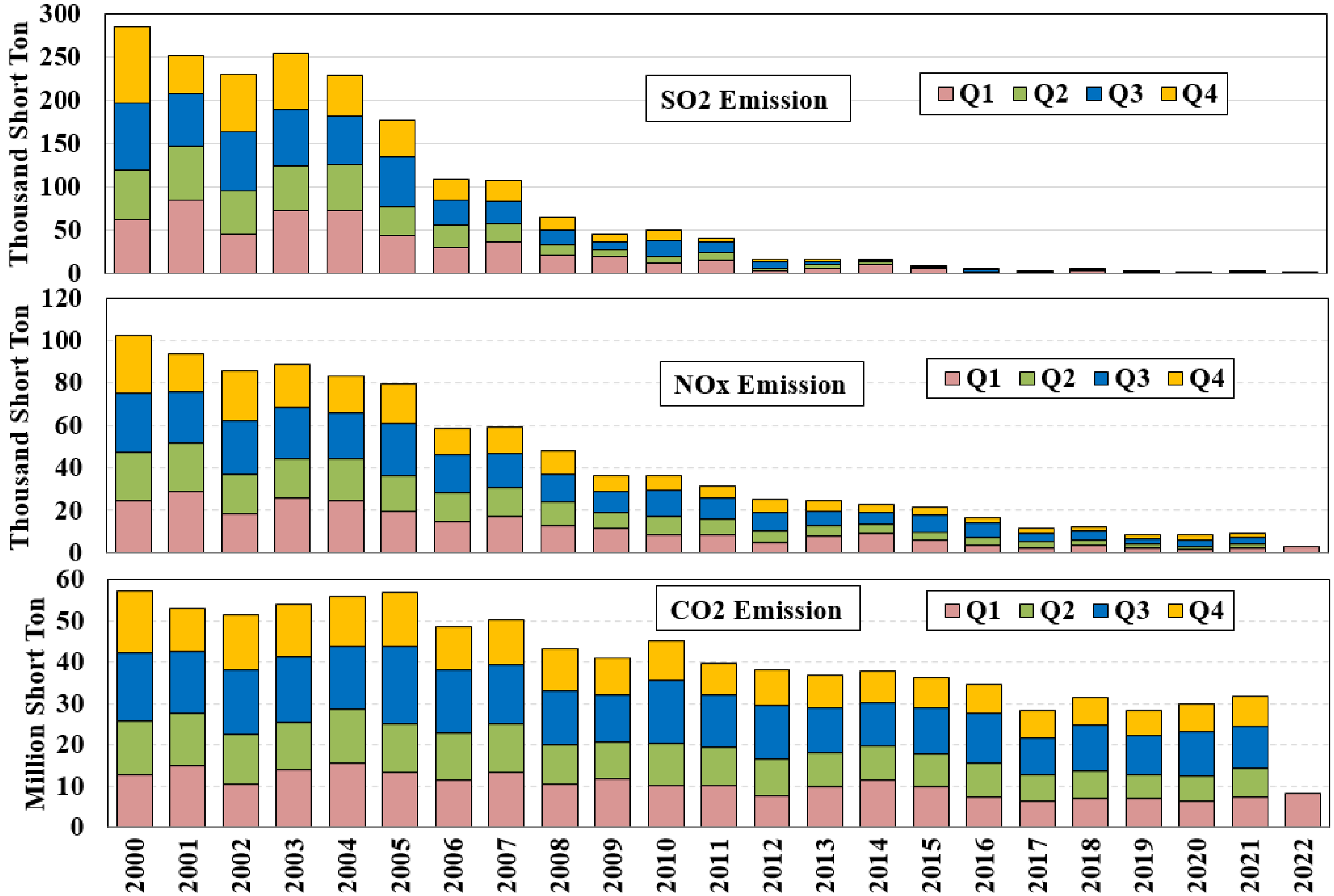
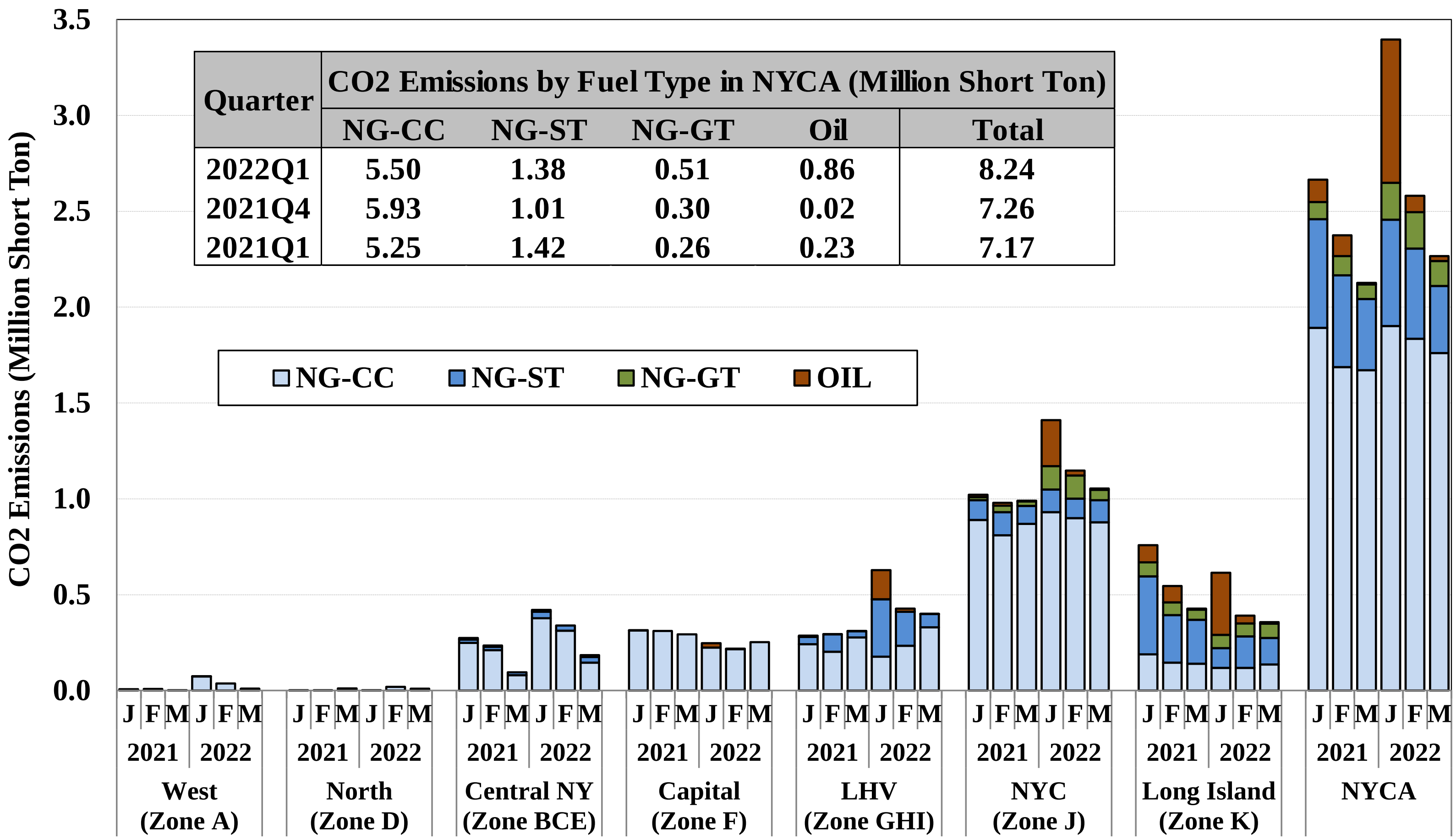
Historical Emissions by Quarter in NYCA
CO_2, SO_2, and NO_X



Notes: For chart description, see slide 83.

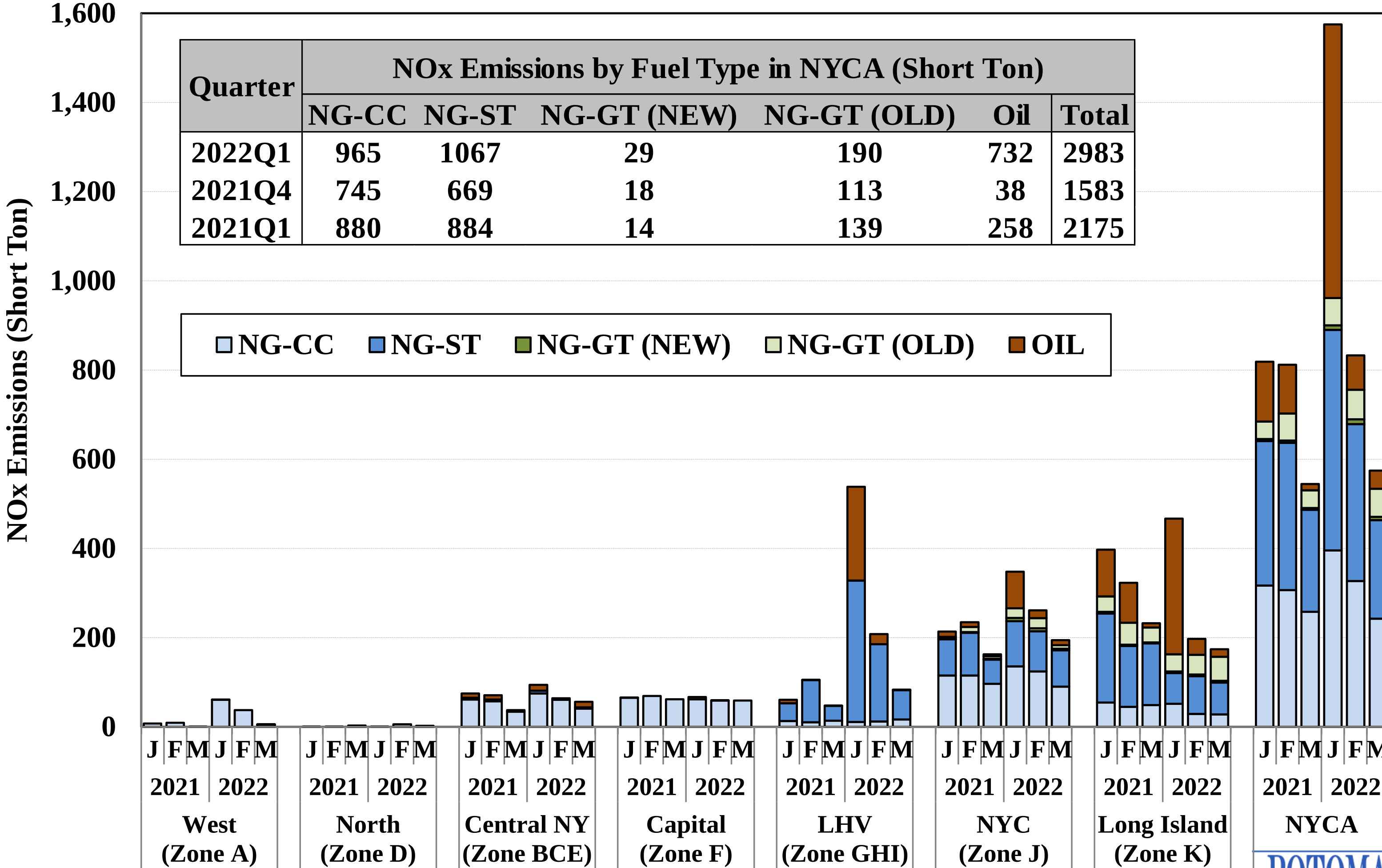
Emissions by Region by Fuel Type
CO_2 Emissions



Quarter	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)				
	NG-CC	NG-ST	NG-GT	Oil	Total
2022Q1	5.50	1.38	0.51	0.86	8.24
2021Q4	5.93	1.01	0.30	0.02	7.26
2021Q1	5.25	1.42	0.26	0.23	7.17

Notes: For chart description, see slide 83.

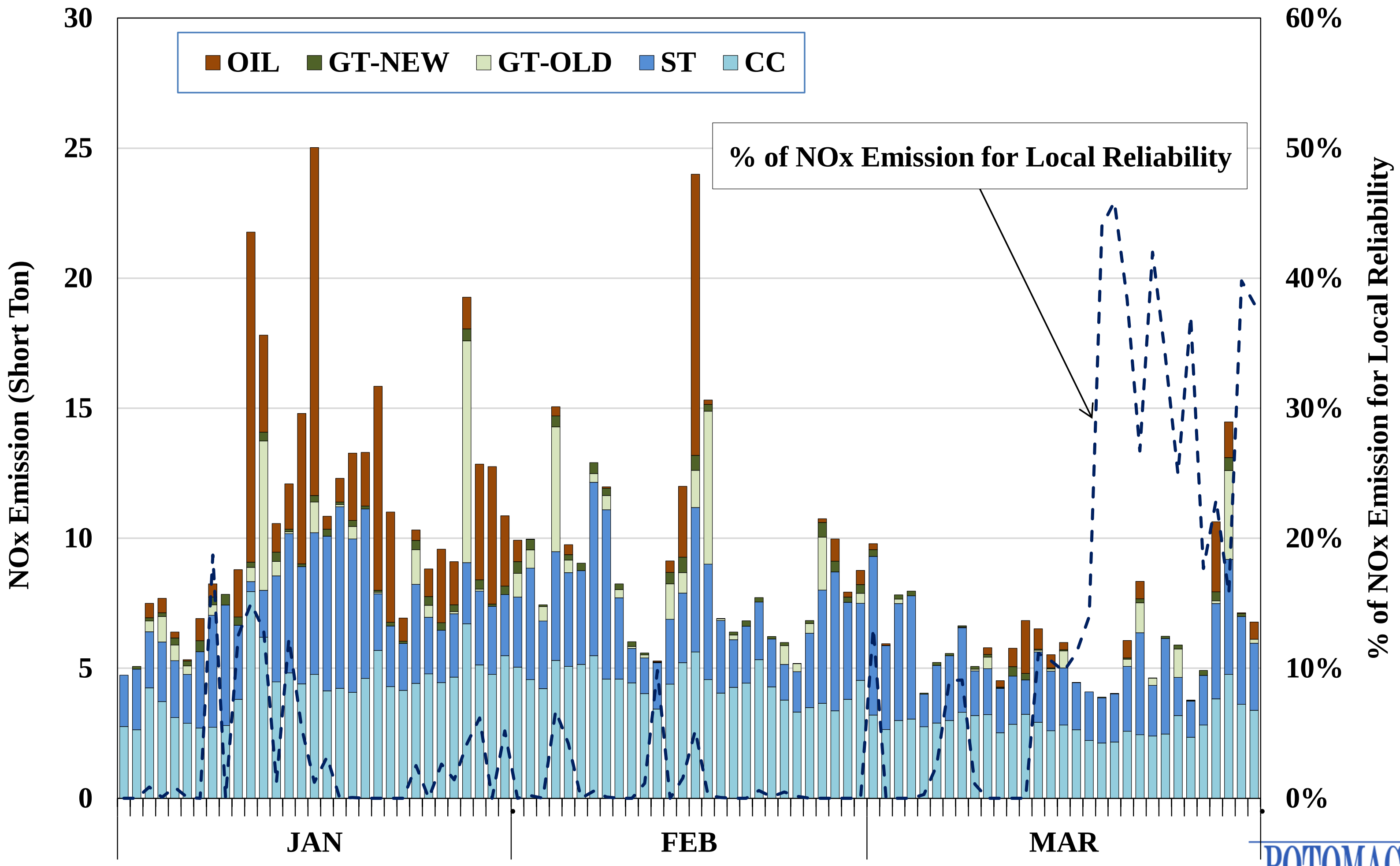
Emissions by Region by Fuel Type
NO_X Emissions



Quarter	NOx Emissions by Fuel Type in NYCA (Short Ton)					
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Total
2022Q1	965	1067	29	190	732	2983
2021Q4	745	669	18	113	38	1583
2021Q1	880	884	14	139	258	2175

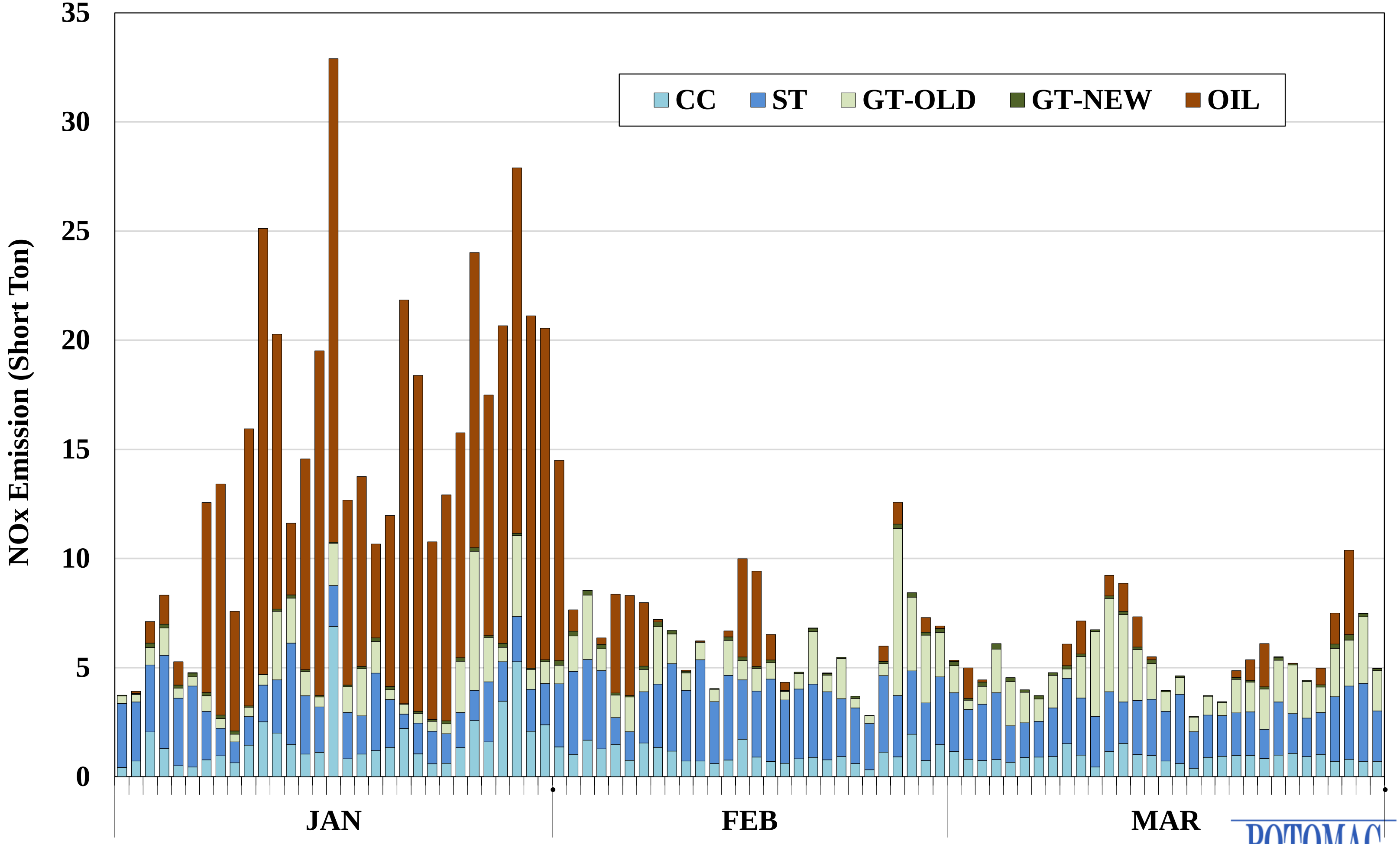
Notes: For chart description, see slide 83.

Daily NO_X Emissions in NYC



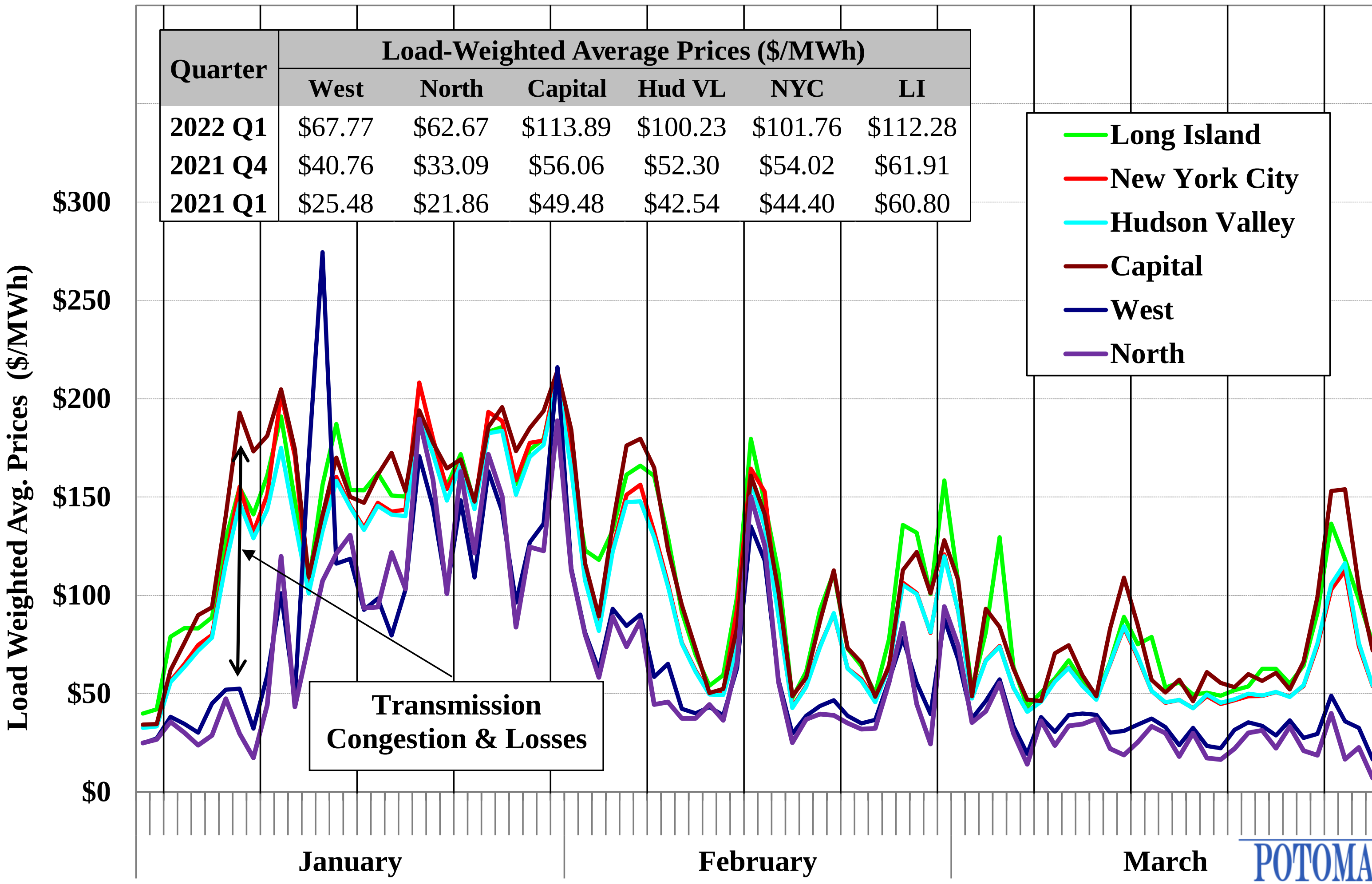
Notes: For chart description, see slide 83.

Daily NO_X Emissions in Long Island



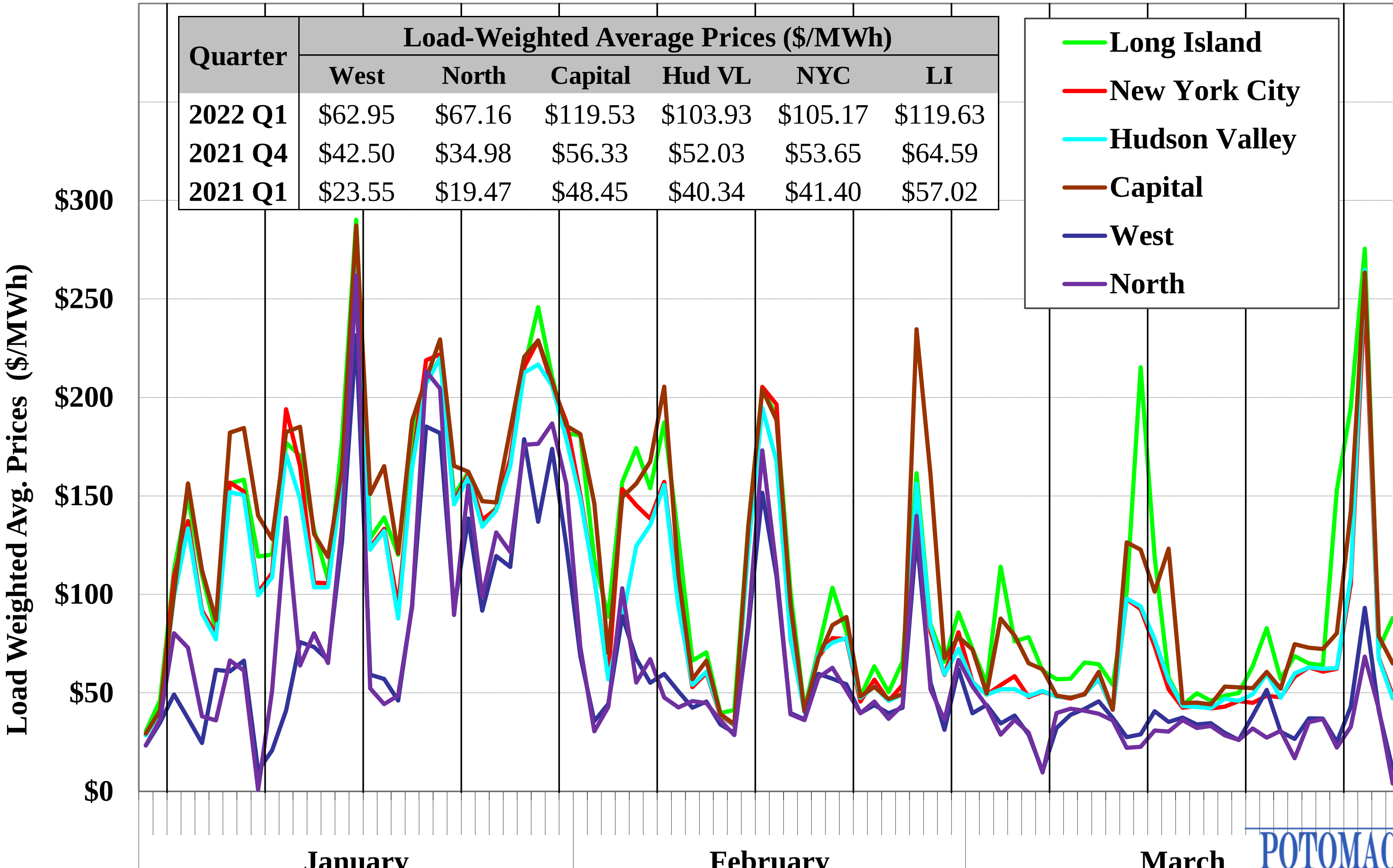
Notes: For chart description, see slide 83.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q1	$67.77	$62.67	$113.89	$100.23	$101.76	$112.28
2021 Q4	$40.76	$33.09	$56.06	$52.30	$54.02	$61.91
2021 Q1	$25.48	$21.86	$49.48	$42.54	$44.40	$60.80

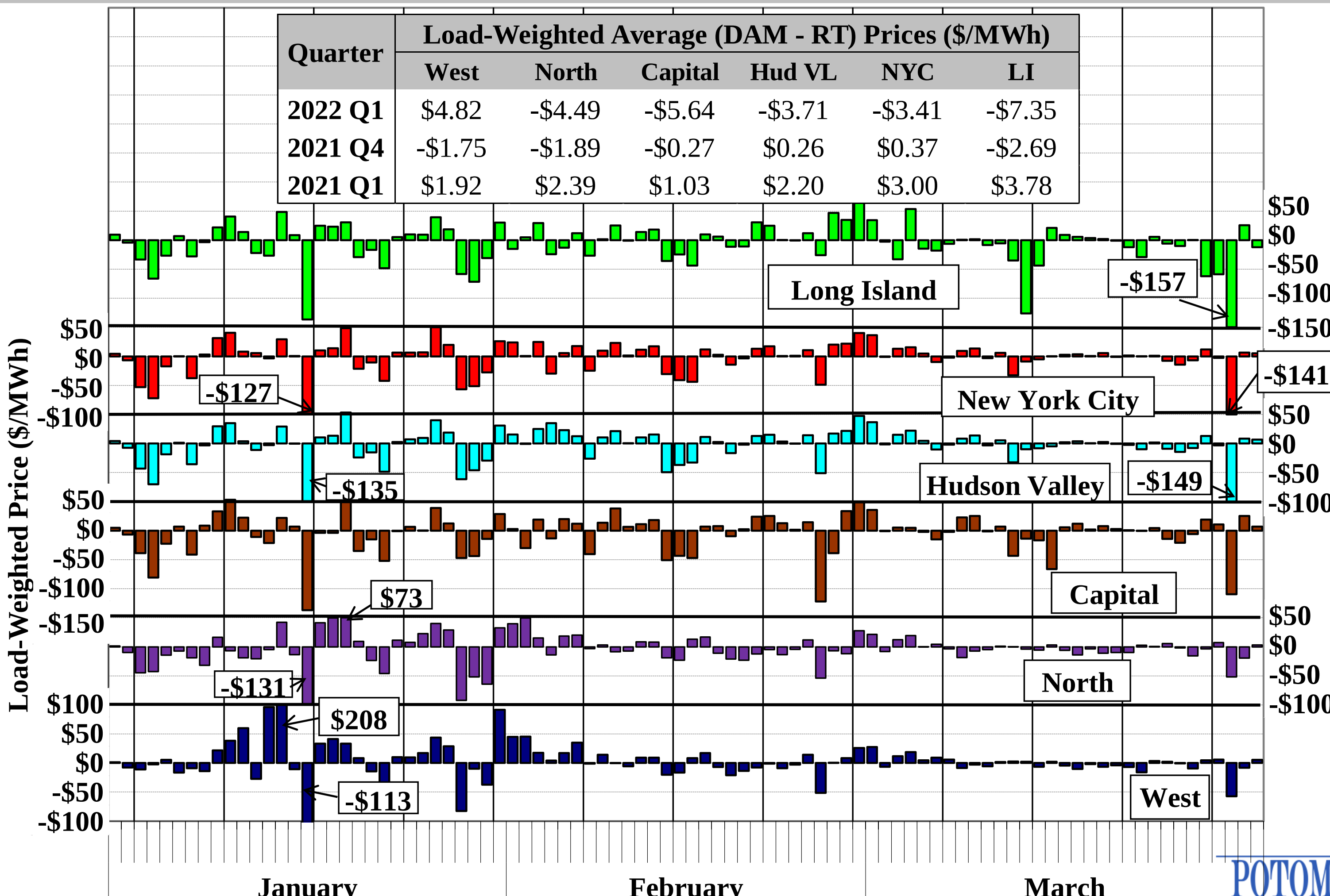
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q1	$62.95	$67.16	$119.53	$103.93	$105.17	$119.63
2021 Q4	$42.50	$34.98	$56.33	$52.03	$53.65	$64.59
2021 Q1	$23.55	$19.47	$48.45	$40.34	$41.40	$57.02

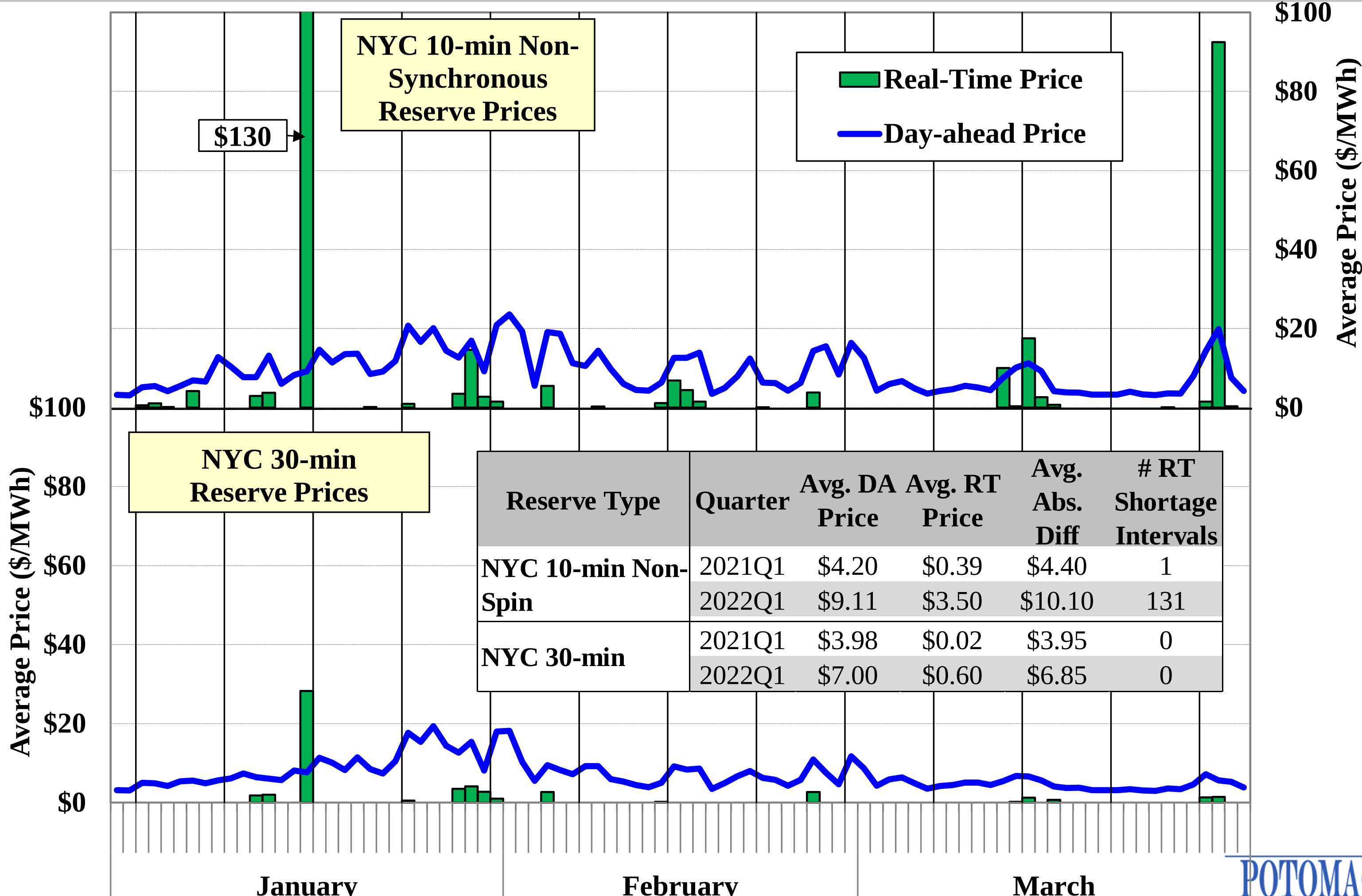
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2022 Q1	$4.82	-$4.49	-$5.64	-$3.71	-$3.41	-$7.35
2021 Q4	-$1.75	-$1.89	-$0.27	$0.26	$0.37	-$2.69
2021 Q1	$1.92	$2.39	$1.03	$2.20	$3.00	$3.78



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	2021Q1	$4.20	$0.39	$4.40	1
	2022Q1	$9.11	$3.50	$10.10	131
NYC 30-min	2021Q1	$3.98	$0.02	$3.95	0
	2022Q1	$7.00	$0.60	$6.85	0

Notes: For chart description, see slide 84.

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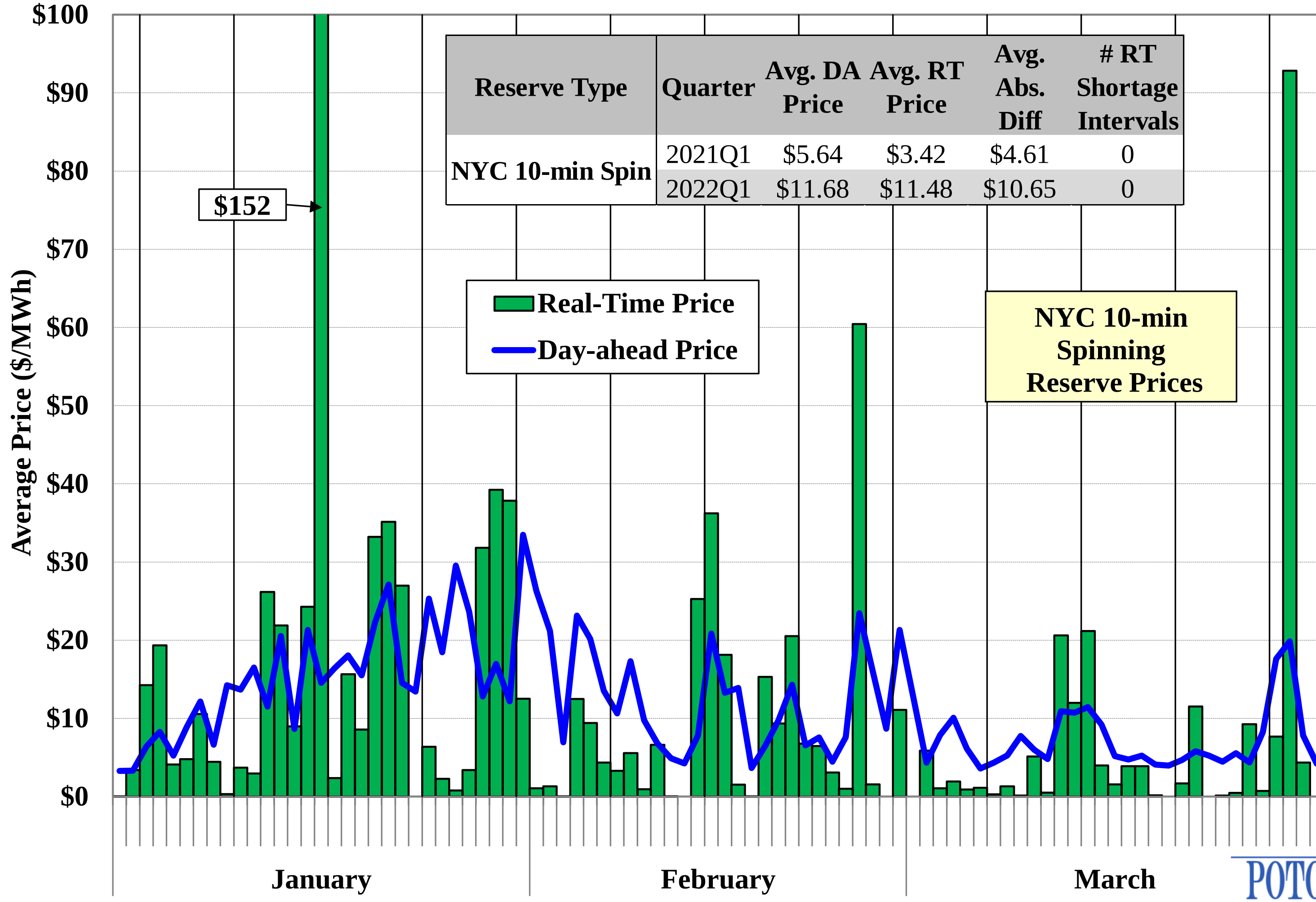
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2021Q1	$5.64	$3.42	$4.61	0
	2022Q1	$11.68	$11.48	$10.65	0

Notes: For chart description, see slide 84.

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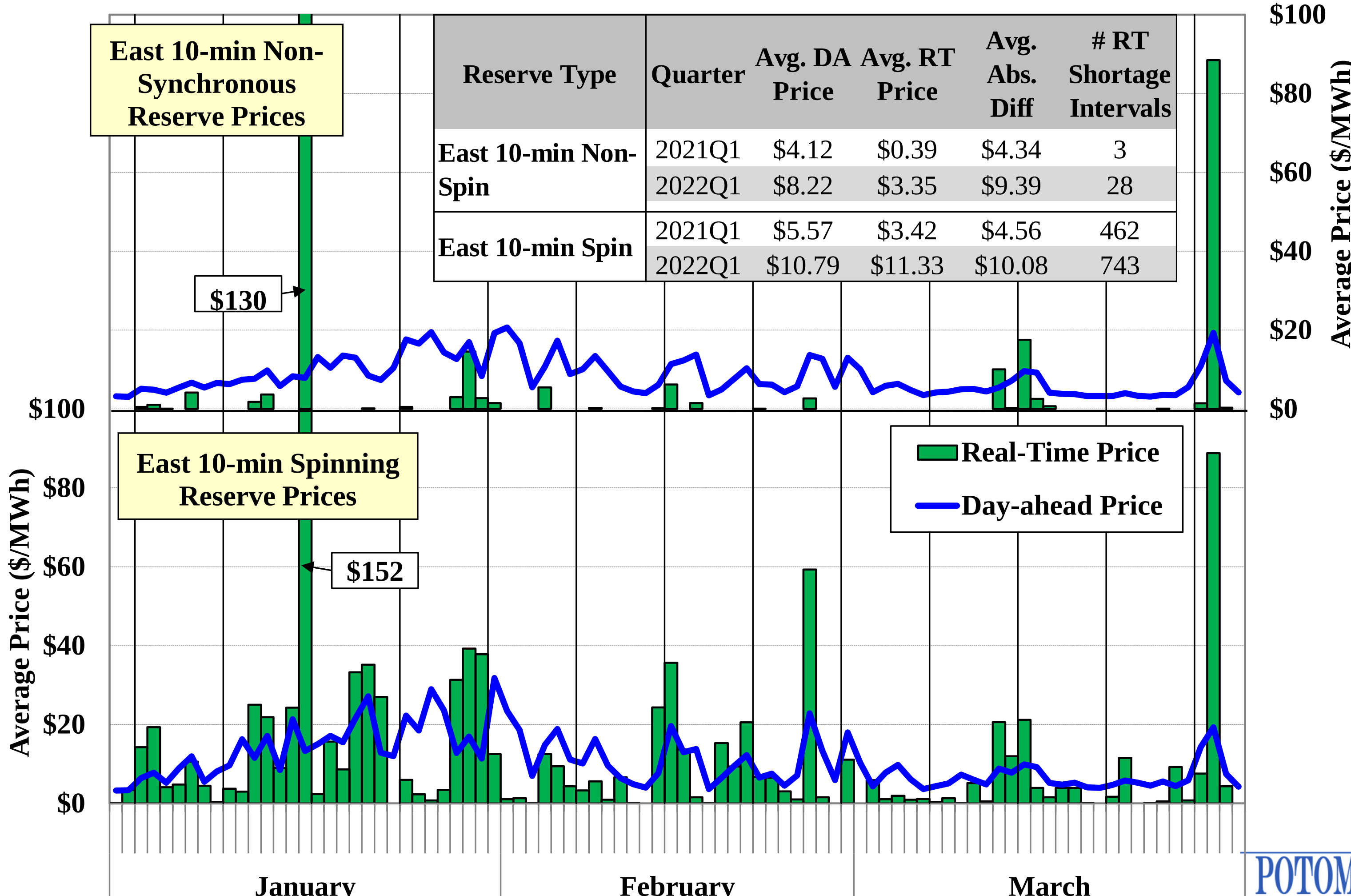
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves

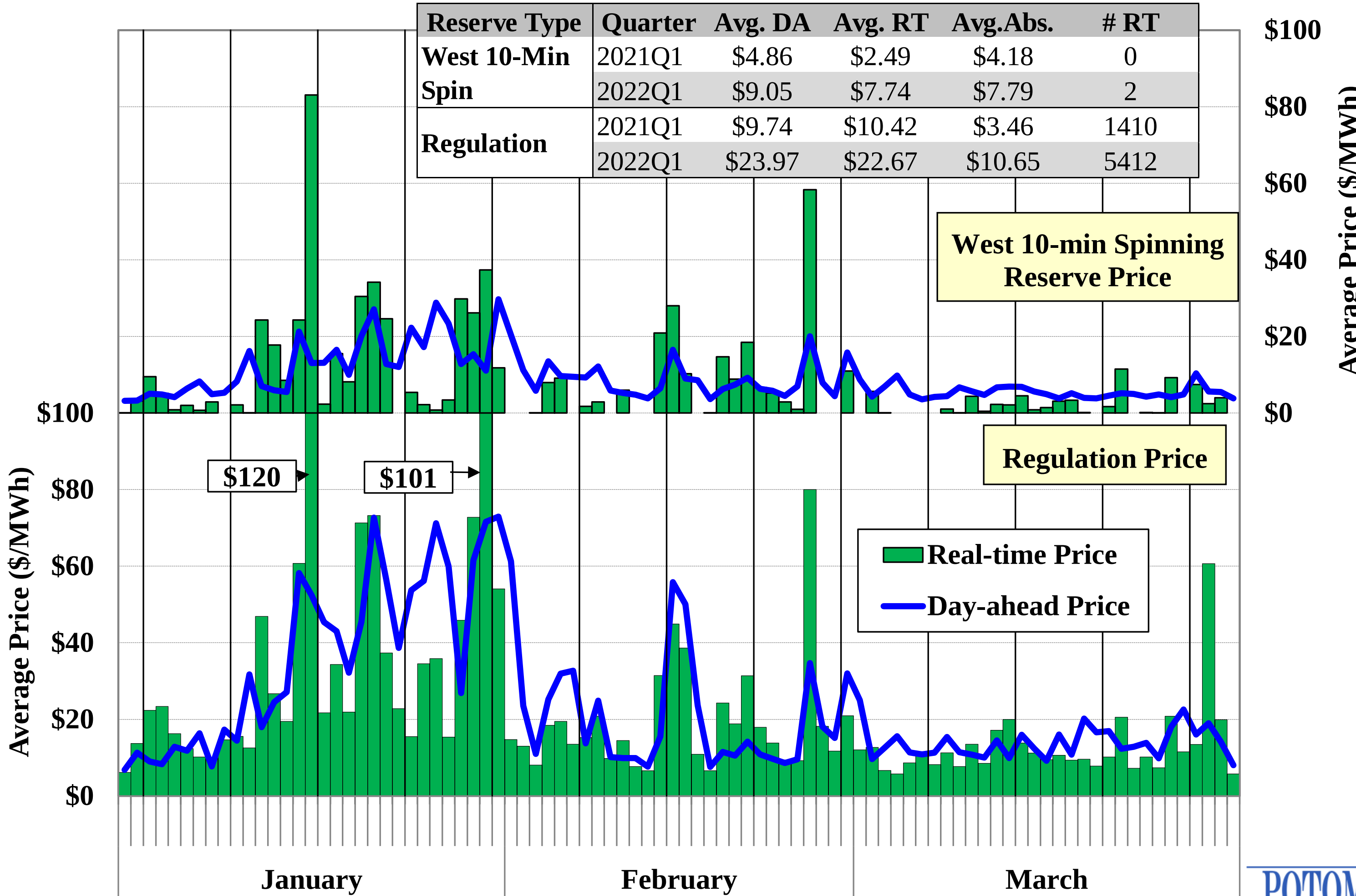


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2021Q1	$4.12	$0.39	$4.34	3
	2022Q1	$8.22	$3.35	$9.39	28
East 10-min Spin	2021Q1	$5.57	$3.42	$4.56	462
	2022Q1	$10.79	$11.33	$10.08	743

Notes: For chart description, see slide 84.

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

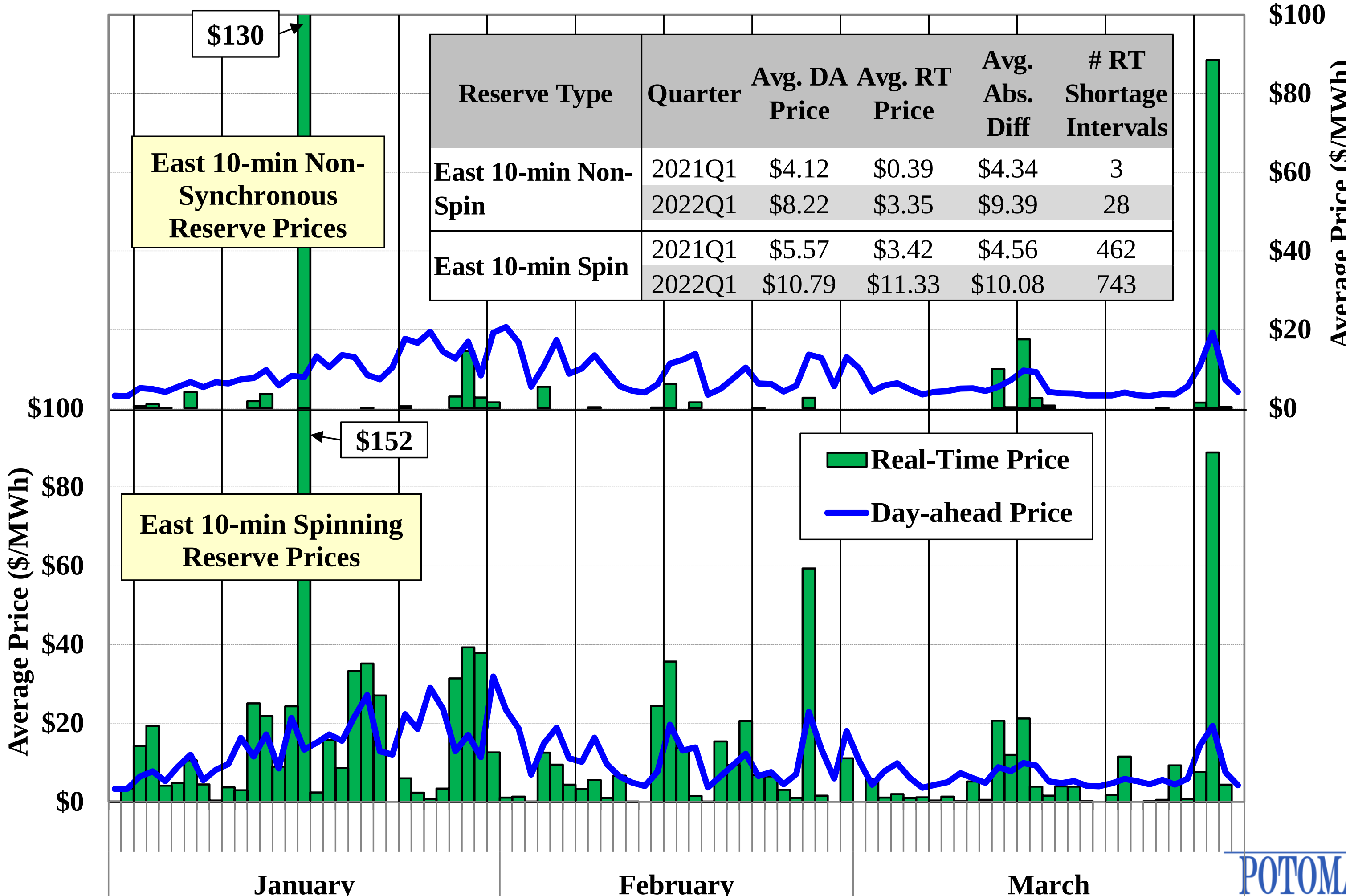
Reserve Type	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2021Q1	$4.86	$2.49	$4.18	0
	2022Q1	$9.05	$7.74	$7.79	2
Regulation	2021Q1	$9.74	$10.42	$3.46	1410
	2022Q1	$23.97	$22.67	$10.65	5412



Notes: For chart description, see slide 84.

POTOMAC ECONOMICS

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

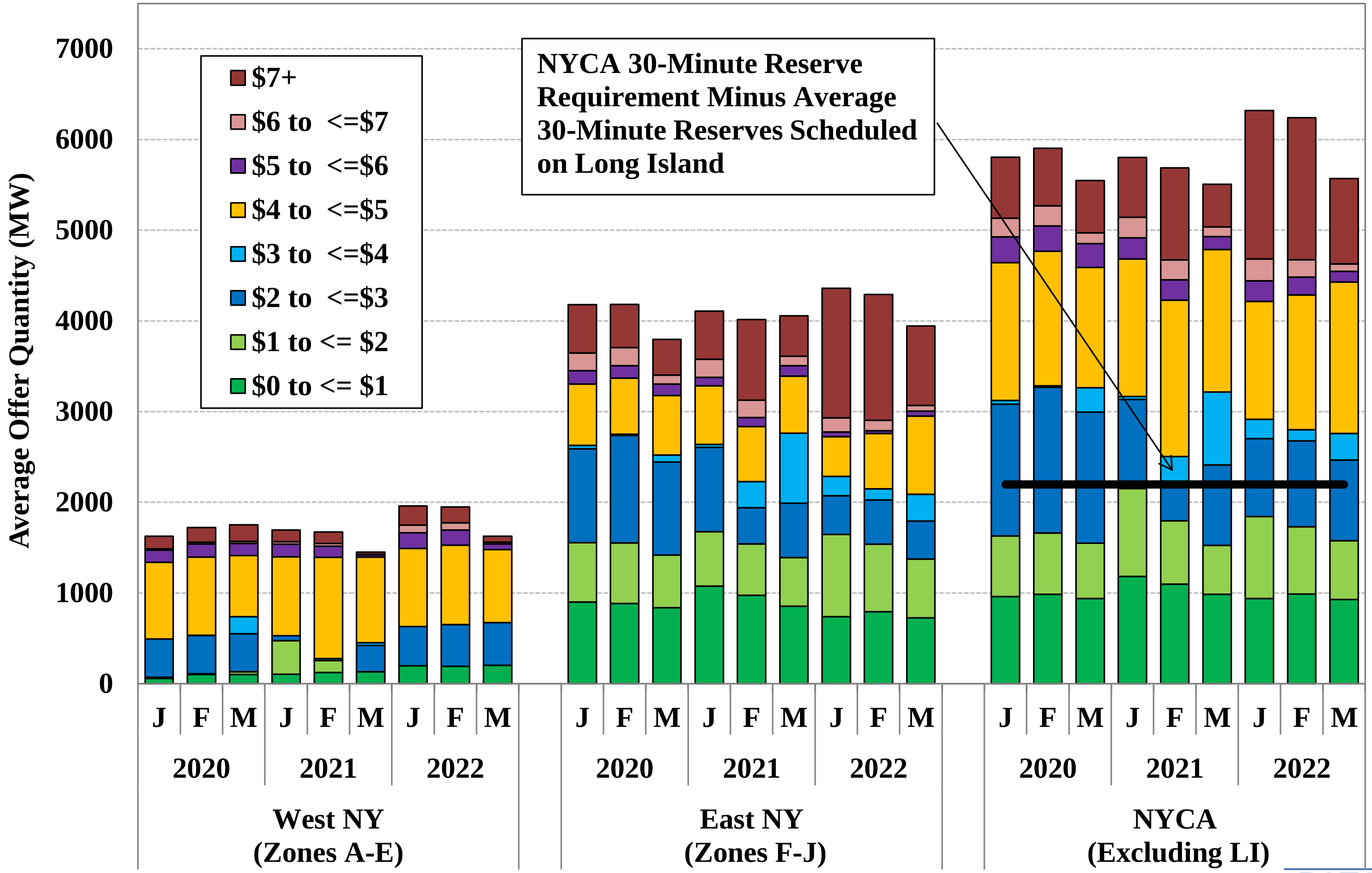


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2021Q1	$4.12	$0.39	$4.34	3
	2022Q1	$8.22	$3.35	$9.39	28
East 10-min Spin	2021Q1	$5.57	$3.42	$4.56	462
	2022Q1	$10.79	$11.33	$10.08	743

Notes: For chart description, see slide 84.

POTOMAC ECONOMICS

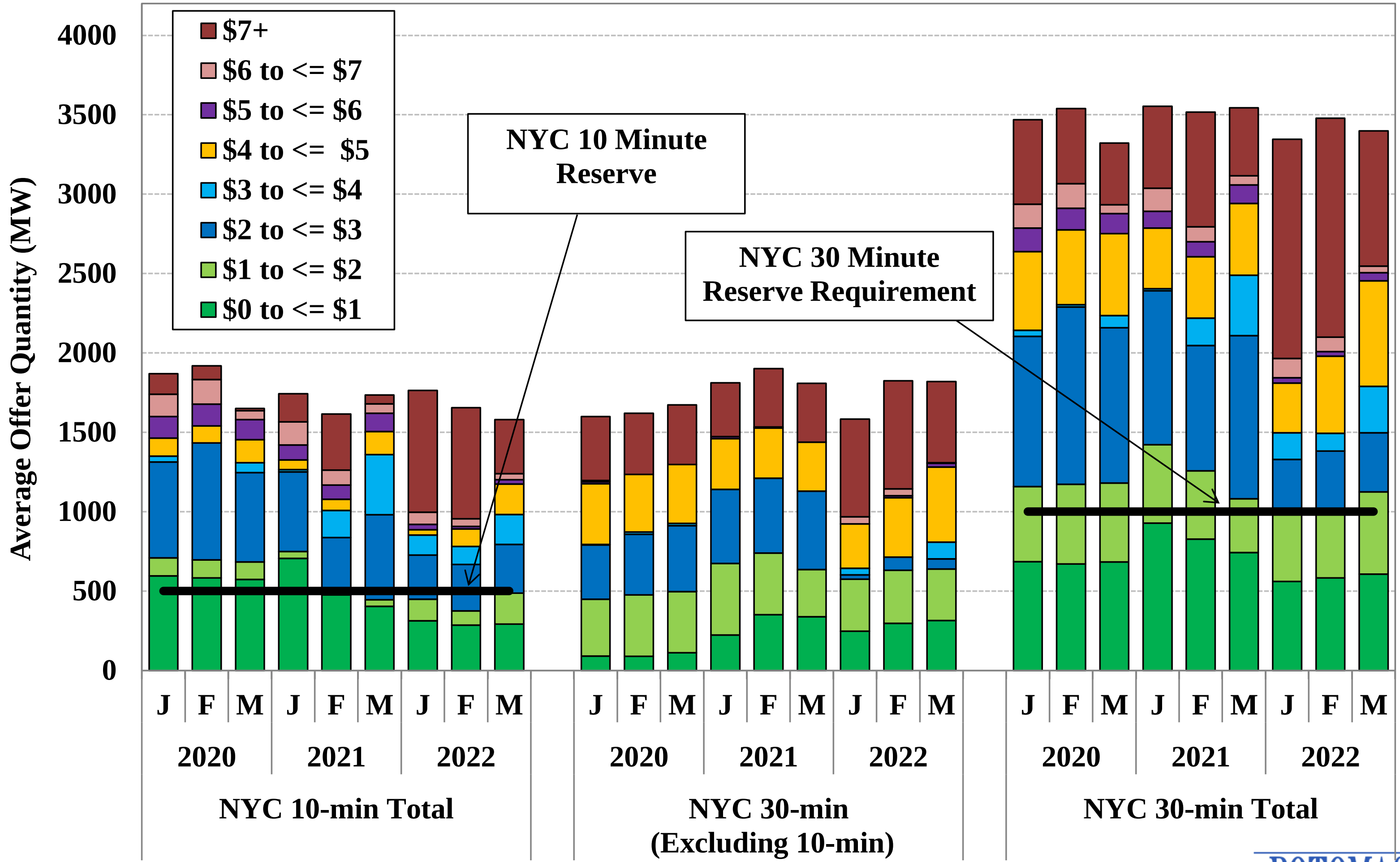
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 85.

POTOMAC ECONOMICS

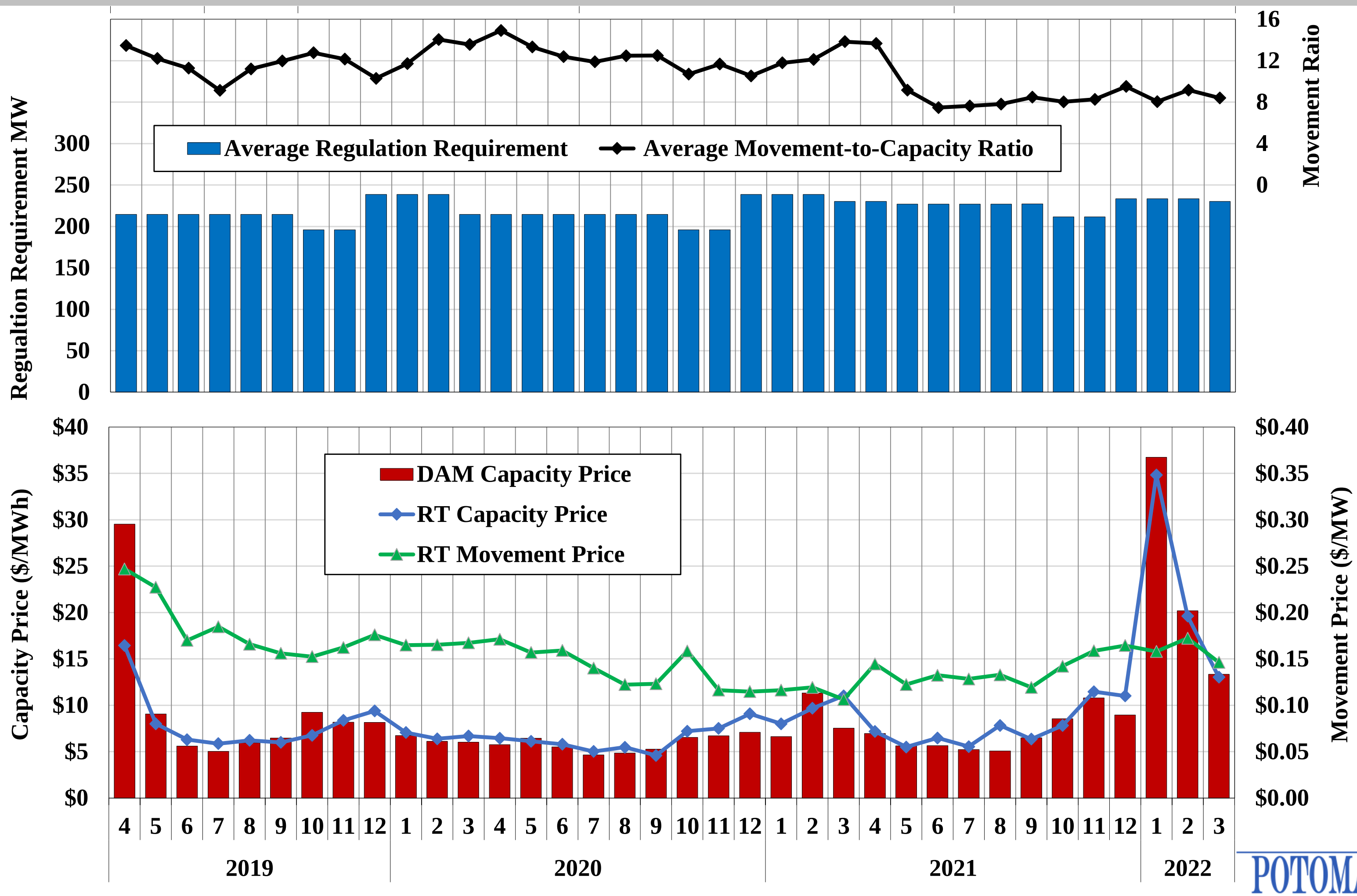
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 85.

POTOMAC ECONOMICS

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

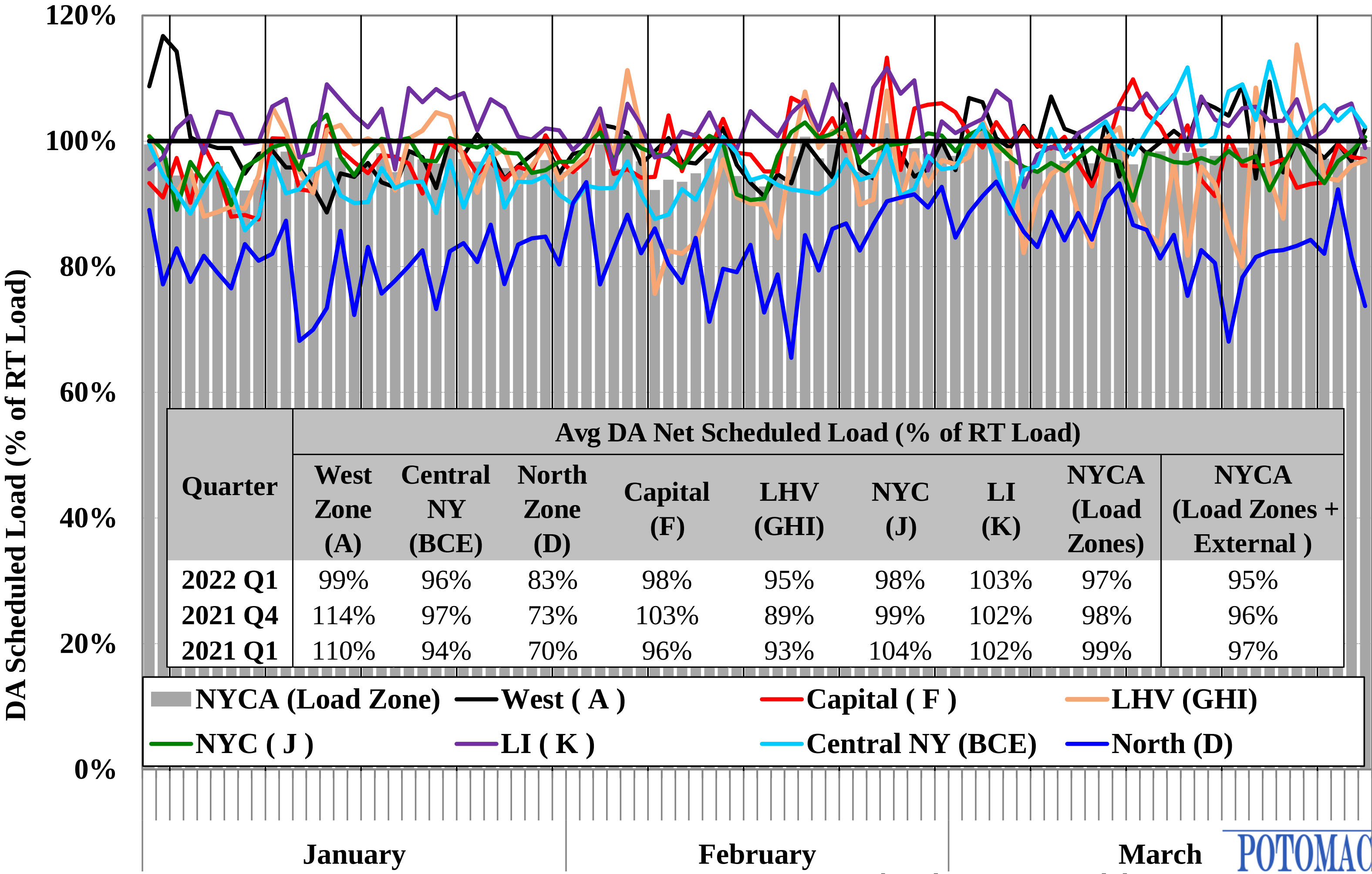


Notes: For chart description, see slide 86.

POTOMAC ECONOMICS

Charts:
Energy Market Scheduling

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

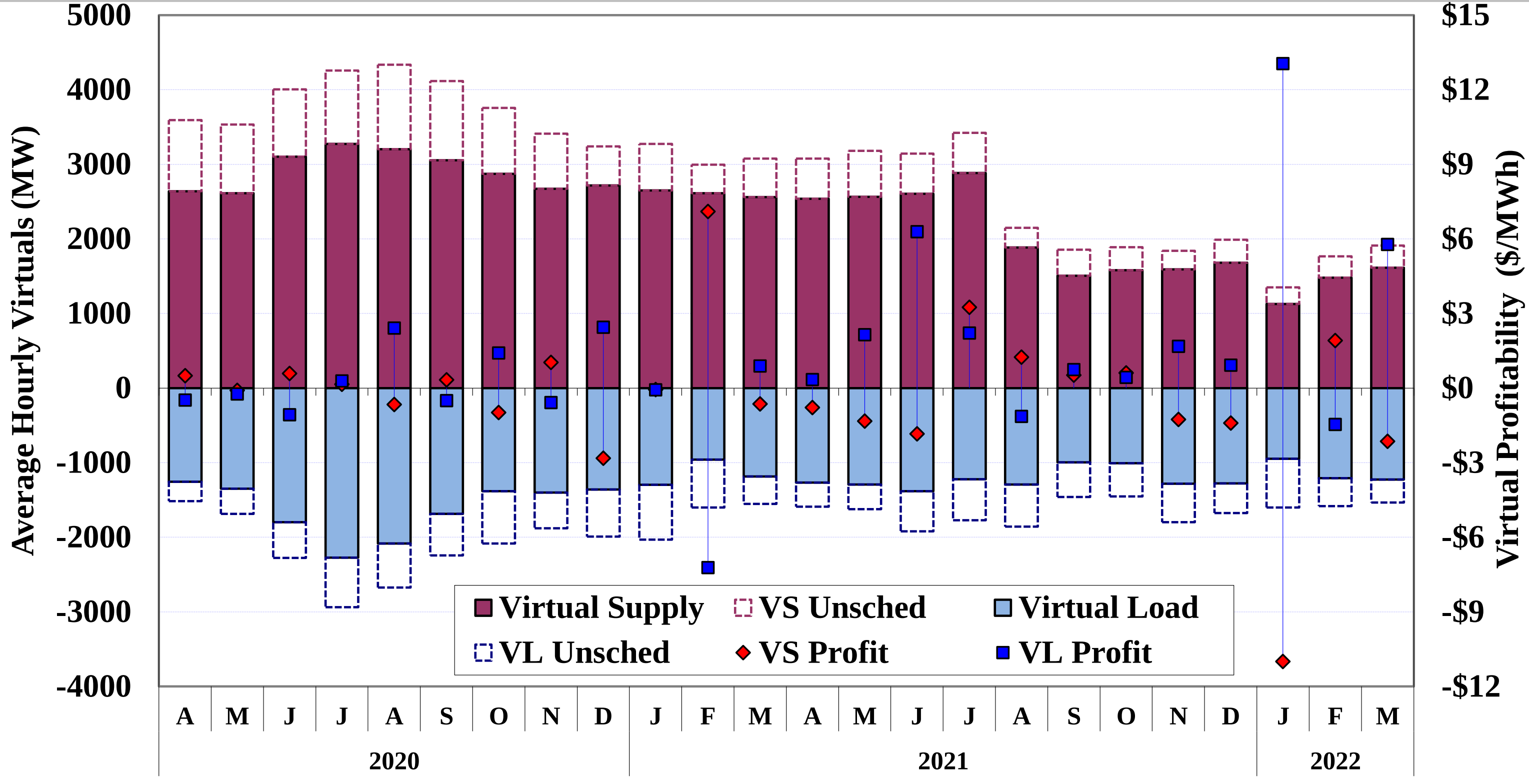


Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2022 Q1	99%	96%	83%	98%	95%	98%	103%	97%	95%
2021 Q4	114%	97%	73%	103%	89%	99%	102%	98%	96%
2021 Q1	110%	94%	70%	96%	93%	104%	102%	99%	97%

Notes: For chart description, see slide 87.

POTOMAC ECONOMICS

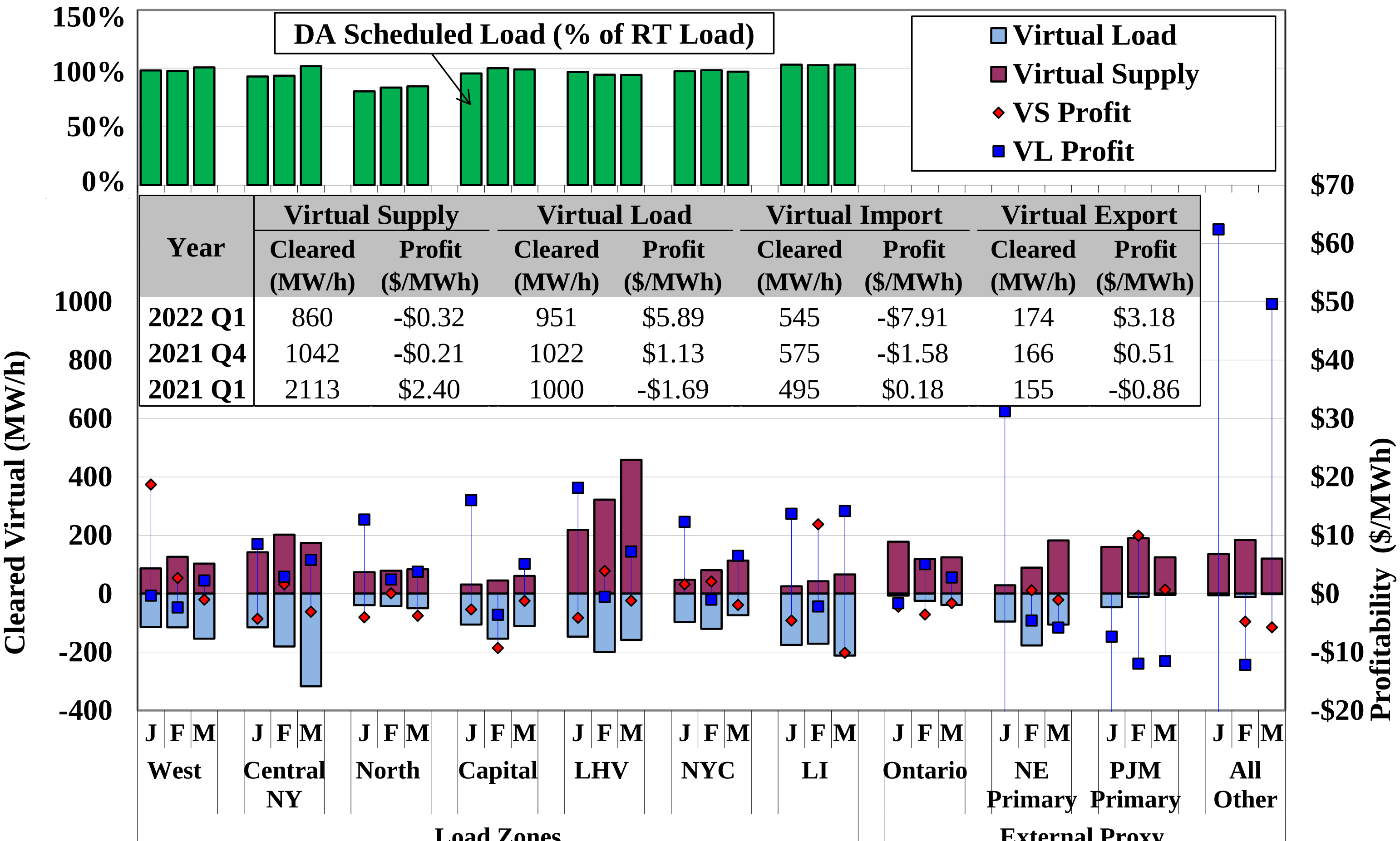
Virtual Trading Activity by Month



		A (2020)	M (2020)	J (2020)	J (2020)	A (2020)	S (2020)	O (2020)	N (2020)	D (2020)	J (2021)	F (2021)	M (2021)	A (2021)	M (2021)	J (2021)	J (2021)	A (2021)	S (2021)	O (2021)	N (2021)	D (2021)	J (2022)	F (2022)	M (2022)
Profit > 50% of Avg. Zone Price	MW	370	388	464	416	377	196	235	619	375	320	658	514	549	378	325	413	158	158	96	182	195	225	307	217
	%	10%	10%	9%	8%	7%	4%	6%	15%	9%	8%	18%	14%	14%	10%	8%	10%	5%	6%	4%	6%	7%	11%	11%	8%
Loss > 50% of Avg. Zone Price	MW	298	404	460	377	304	198	312	528	440	283	388	491	688	498	271	234	174	140	88	197	215	208	278	226
	%	8%	10%	9%	7%	6%	4%	7%	13%	11%	7%	11%	13%	18%	13%	7%	6%	5%	6%	3%	7%	7%	10%	10%	8%

Notes: For chart description, see slide 87.

Virtual Trading Activity by Location

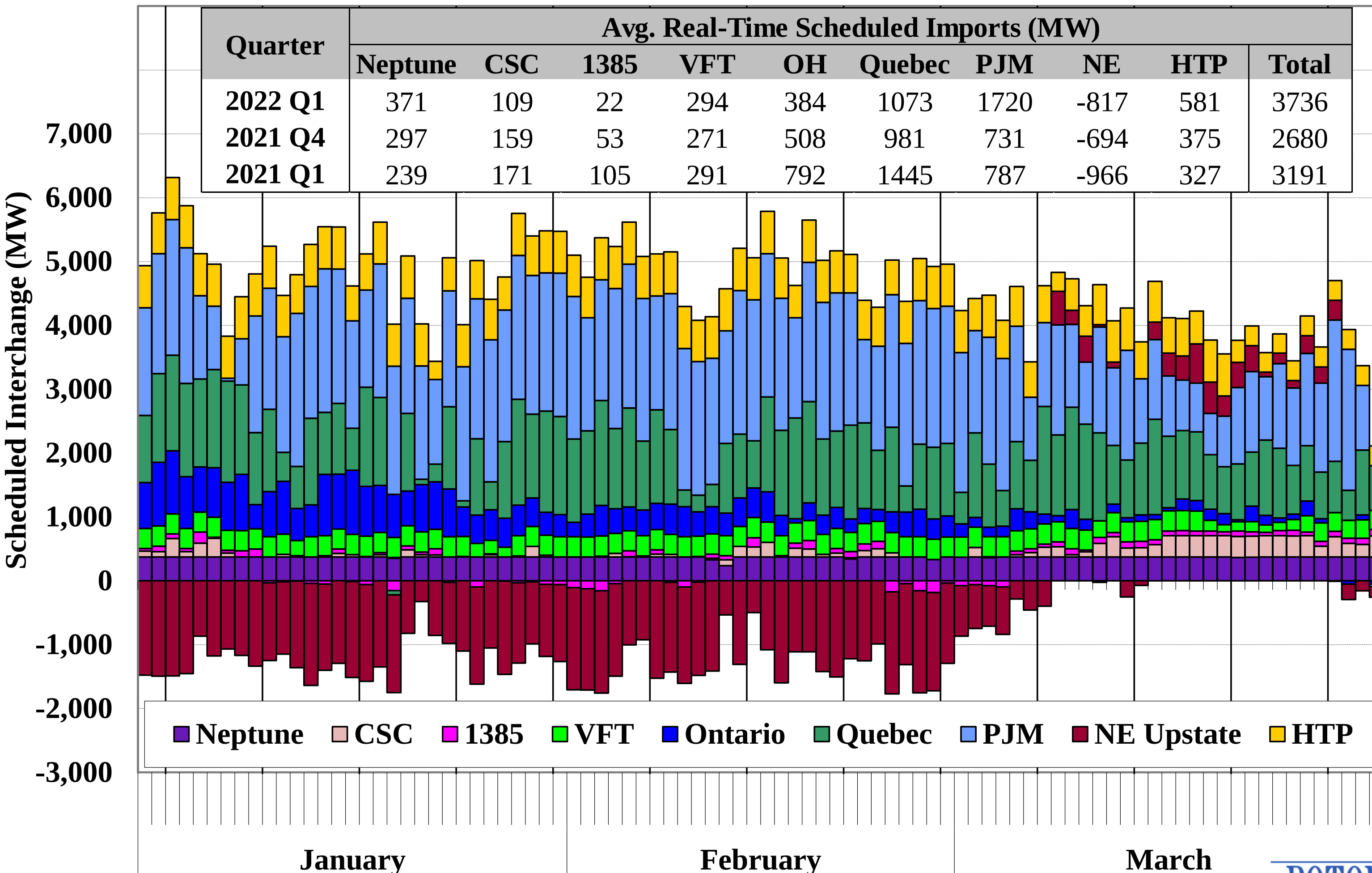


Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2022 Q1	860	-$0.32	951	$5.89	545	-$7.91	174	$3.18
2021 Q4	1042	-$0.21	1022	$1.13	575	-$1.58	166	$0.51
2021 Q1	2113	$2.40	1000	-$1.69	495	$0.18	155	-$0.86

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 87.

POTOMAC ECONOMICS

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 Q1	371	109	22	294	384	1073	1720	-817	581	3736
2021 Q4	297	159	53	271	508	981	731	-694	375	2680
2021 Q1	239	171	105	291	792	1445	787	-966	327	3191

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 > $20	Total	
% of All Intervals w/ Adjustment			49%	33%	**82%**		41%	18%	**59%**	
Average Flow Adjustment (MW)	Net Imports		4	20	**11**		0	-26	**-8**	
	Gross		107	140	**120**		71	116	**85**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$1.8	$6.2	**$8.0**		$0.4	$1.5	**$1.9**	
	Net Over-Projection by:	NY	-$0.1	-$1.8	**-$1.9**		$0.0	$0.3	**$0.3**	
		NE or PJM	$0.0	-$0.3	**-$0.2**		-$0.1	-$2.2	**-$2.3**	
	Other Unrealized Savings		-$0.1	-$0.4	**-$0.5**		$0.0	-$1.6	**-$1.7**	
	Actual Savings		$1.8	$3.7	**$5.5**		$0.2	-$2.0	**-$1.8**	
Interface Prices ($/MWh)	NY	Actual	$75.72	$160.99	**$109.86**	**$105.12**	$50.45	$123.91	**$72.67**	**$79.60**
		Forecast	$78.12	$154.92	**$108.87**	**$103.71**	$52.51	$115.76	**$71.64**	**$78.17**
	NE or PJM	Actual	$73.89	$147.99	**$103.56**	**$104.62**	$42.20	$124.53	**$67.10**	**$64.92**
		Forecast	$72.72	$136.70	**$98.34**	**$99.87**	$43.12	$98.18	**$59.77**	**$57.15**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$2.40	-$6.08	**-$0.99**	**-$1.41**	$2.06	-$8.15	**-$1.03**	**-$1.43**
		Abs. Val.	$5.50	$66.22	**$29.81**	**$27.49**	$4.59	$49.25	**$18.10**	**$18.20**
	NE or PJM	Fcst. - Act.	-$1.17	-$11.29	**-$5.22**	**-$4.75**	$0.92	-$26.35	**-$7.33**	**-$7.77**
		Abs. Val.	$4.85	$27.26	**$13.82**	**$13.70**	$4.43	$80.86	**$27.55**	**$23.77**

For Adjustment Intervals Only

For All Intervals

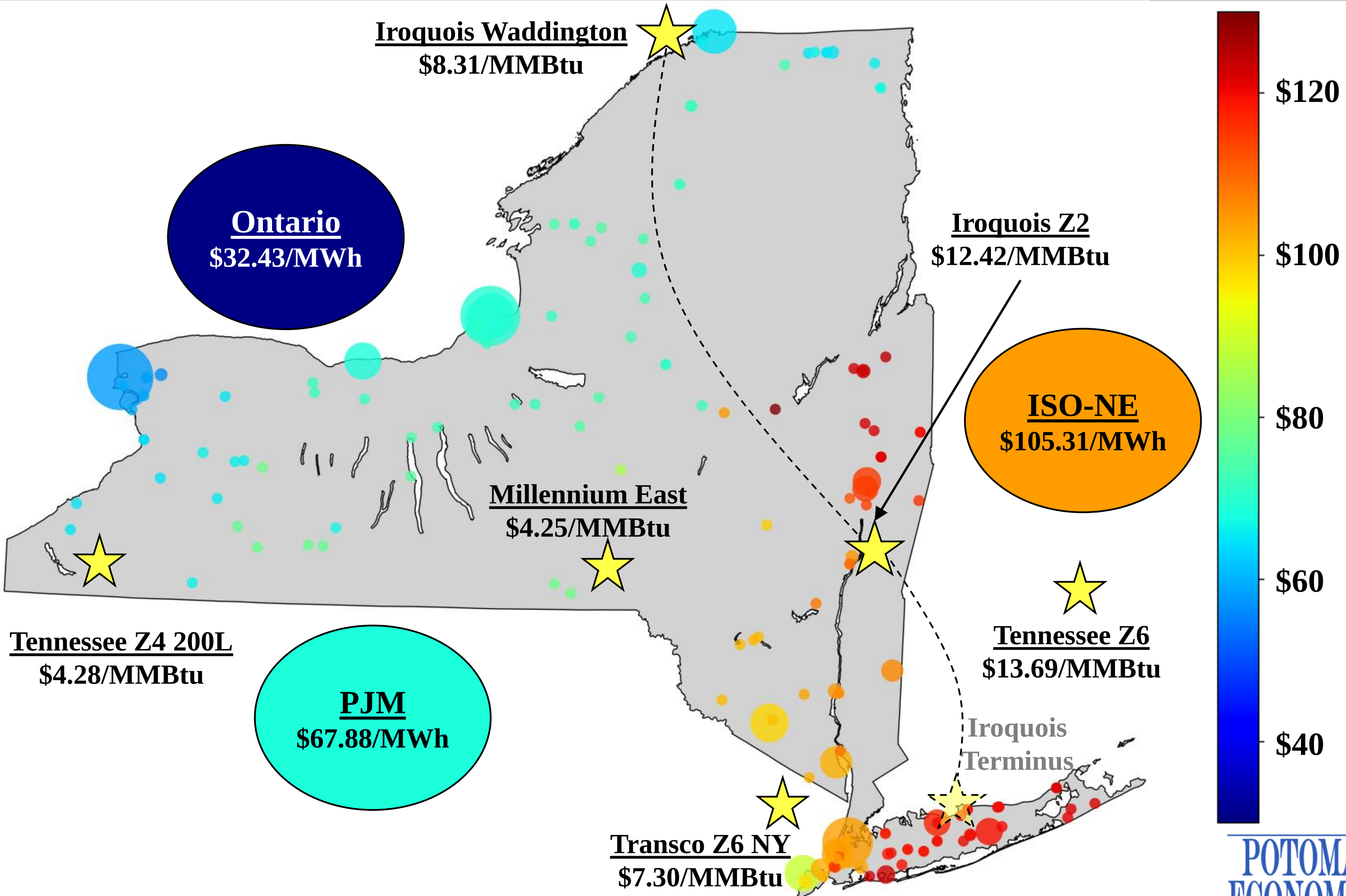
Notes: For chart description, see slide 88.

POTOMAC ECONOMICS

Charts:
Transmission Congestion Revenues and Shortfalls

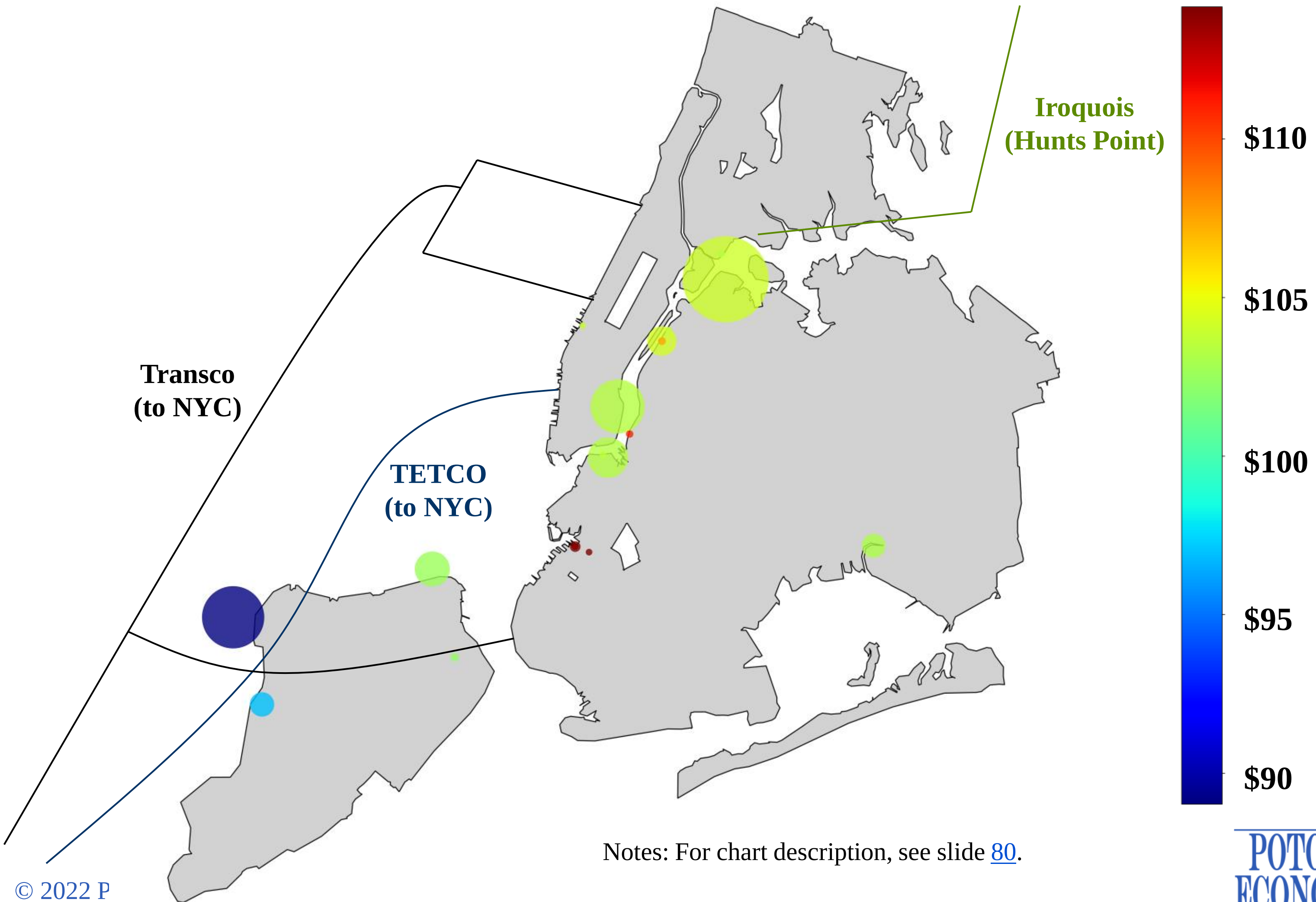
POTOMAC ECONOMICS

System Congestion
Real-Time Price Map at Generator Nodes



POTOMAC ECONOMICS

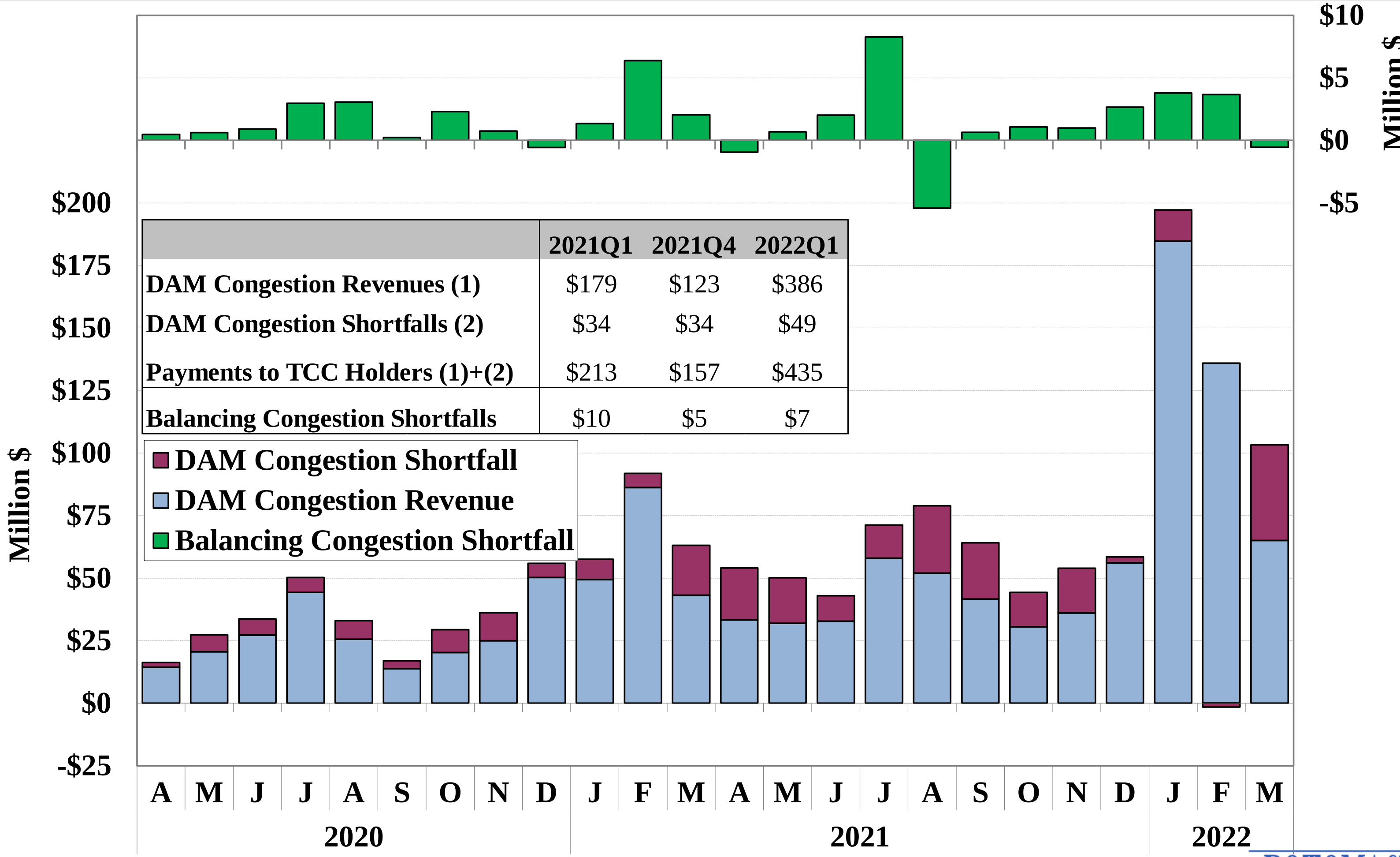
System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

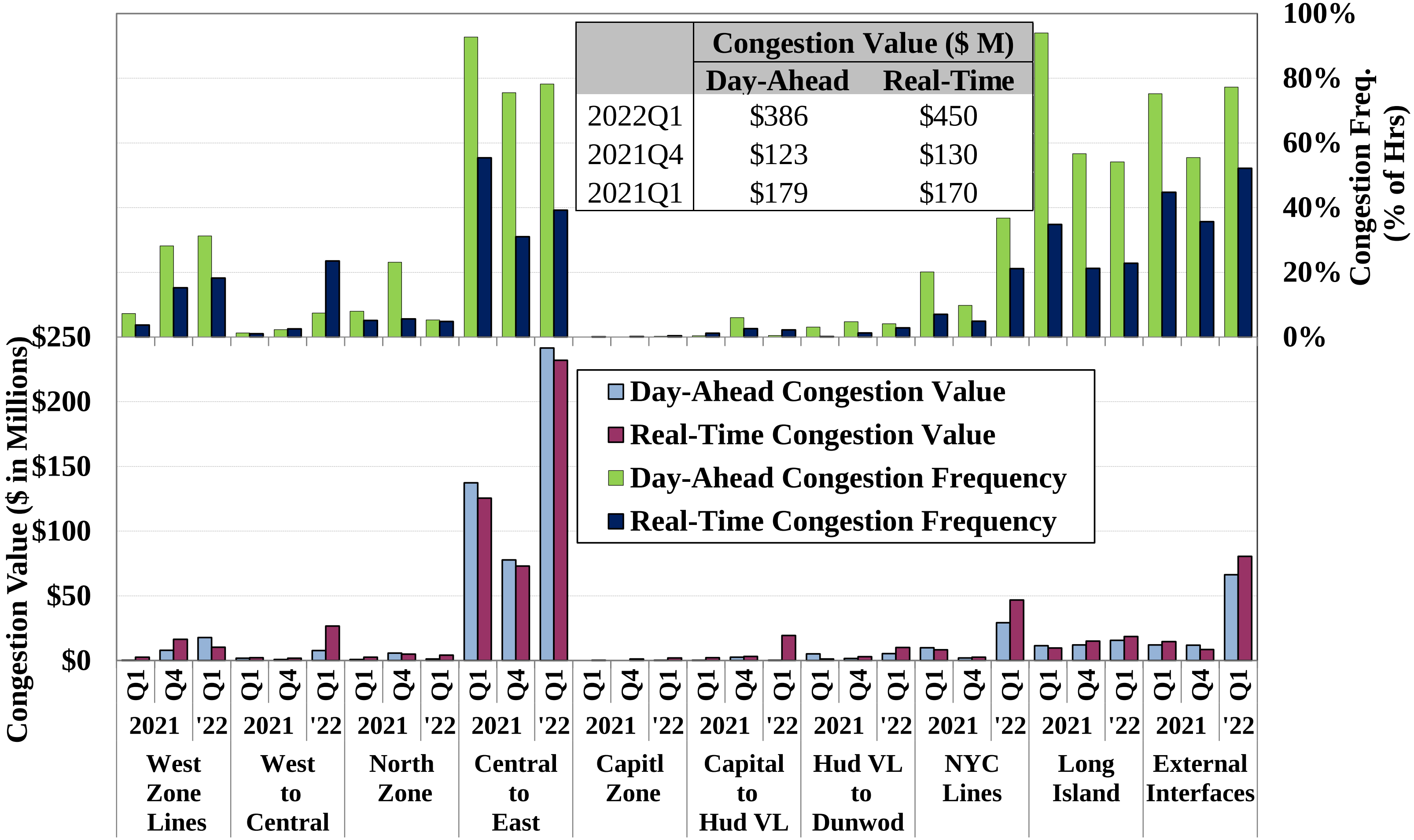
Congestion Revenues and Shortfalls by Month



	2021Q1	2021Q4	2022Q1
DAM Congestion Revenues (1)	$179	$123	$386
DAM Congestion Shortfalls (2)	$34	$34	$49
Payments to TCC Holders (1)+(2)	$213	$157	$435
Balancing Congestion Shortfalls	$10	$5	$7

Notes: For chart description, see slides 90 and 91.

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

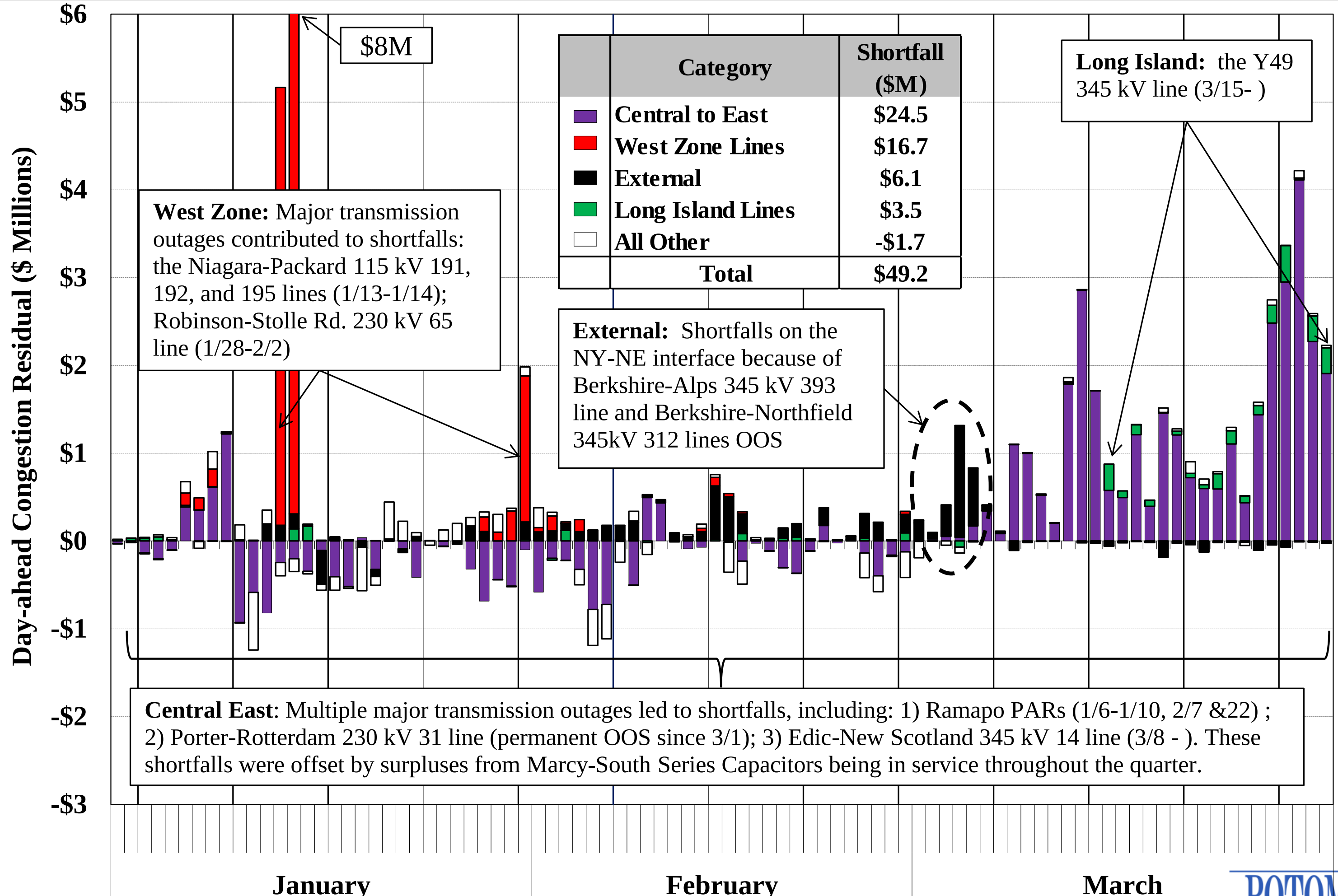


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2022Q1	$386	$450
2021Q4	$123	$130
2021Q1	$179	$170

Notes: For chart description, see slides 90, 91, and 92.

POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility

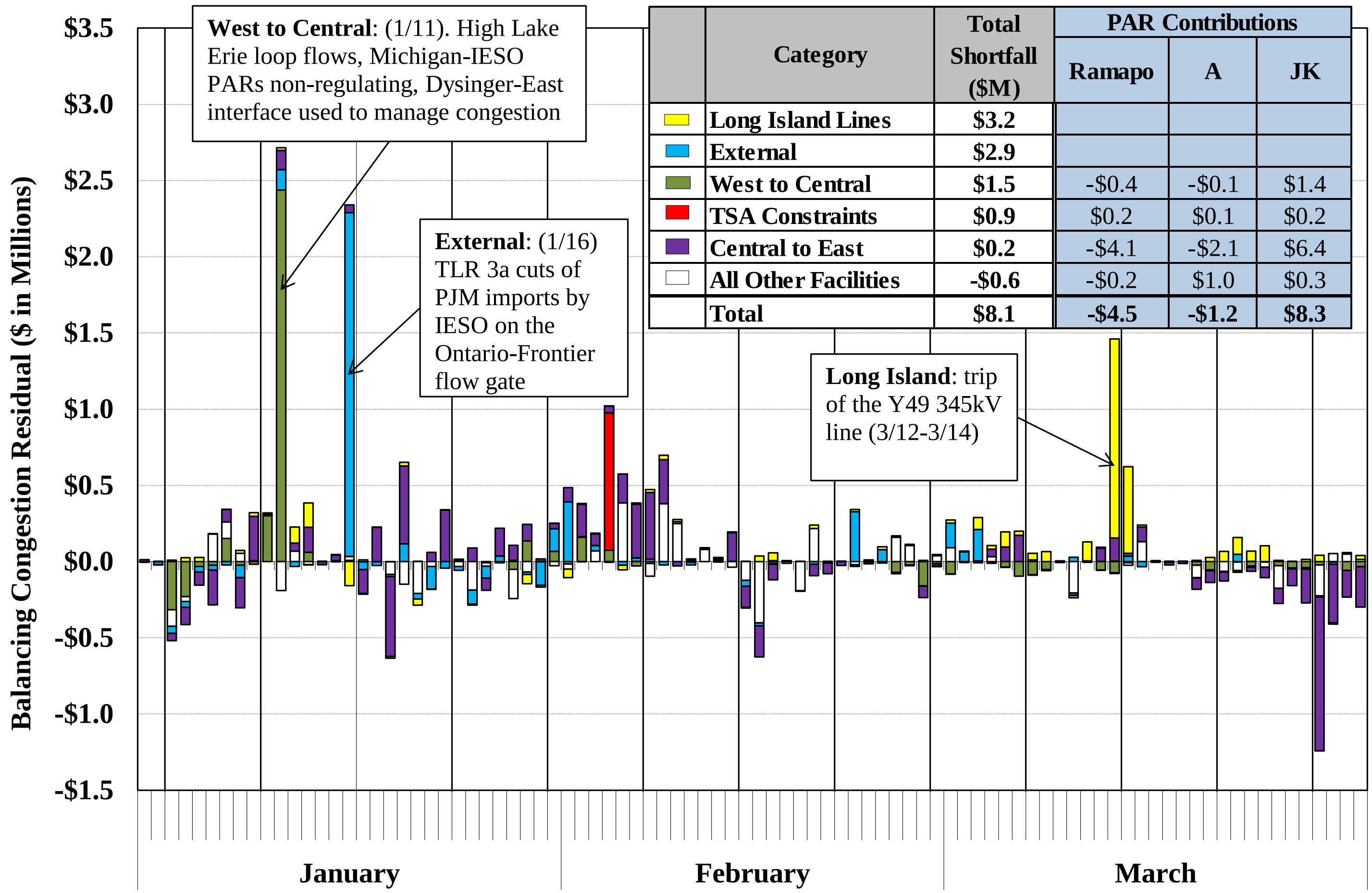


	Category	Shortfall ($M)
	Central to East	$24.5
	West Zone Lines	$16.7
	External	$6.1
	Long Island Lines	$3.5
	All Other	-$1.7
	Total	$49.2

Notes: For chart description, see slides 90, 91, and 92.

POTOMAC ECONOMICS

Balancing Congestion Shortfalls by Transmission Facility

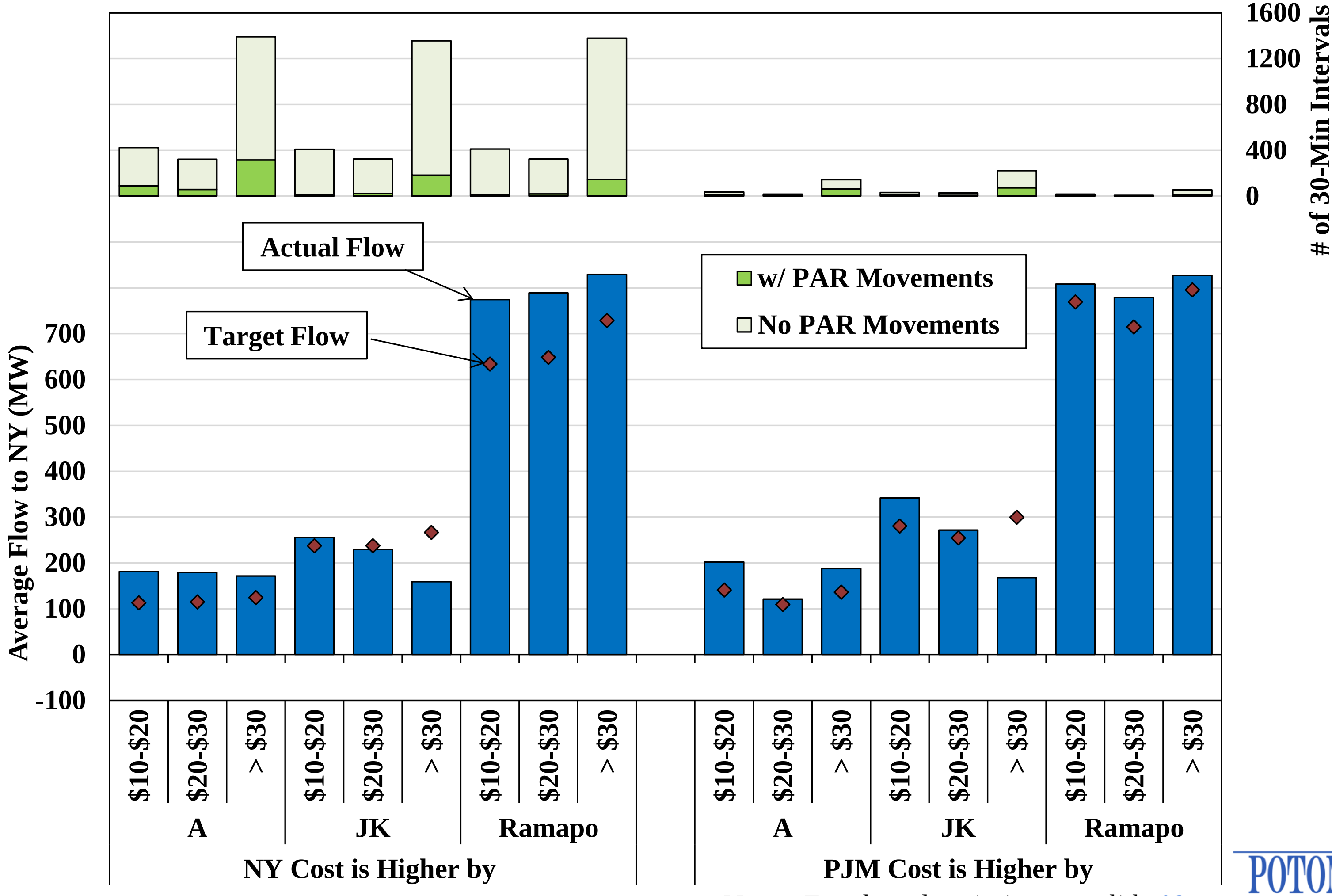


Category	Total Shortfall ($M)	PAR Contributions: Ramapo	PAR Contributions: A	PAR Contributions: JK
Long Island Lines	$3.2			
External	$2.9			
West to Central	$1.5	-$0.4	-$0.1	$1.4
TSA Constraints	$0.9	$0.2	$0.1	$0.2
Central to East	$0.2	-$4.1	-$2.1	$6.4
All Other Facilities	-$0.6	-$0.2	$1.0	$0.3
Total	**$8.1**	**-$4.5**	**-$1.2**	**$8.3**

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 90, 91, and 92.

POTOMAC ECONOMICS

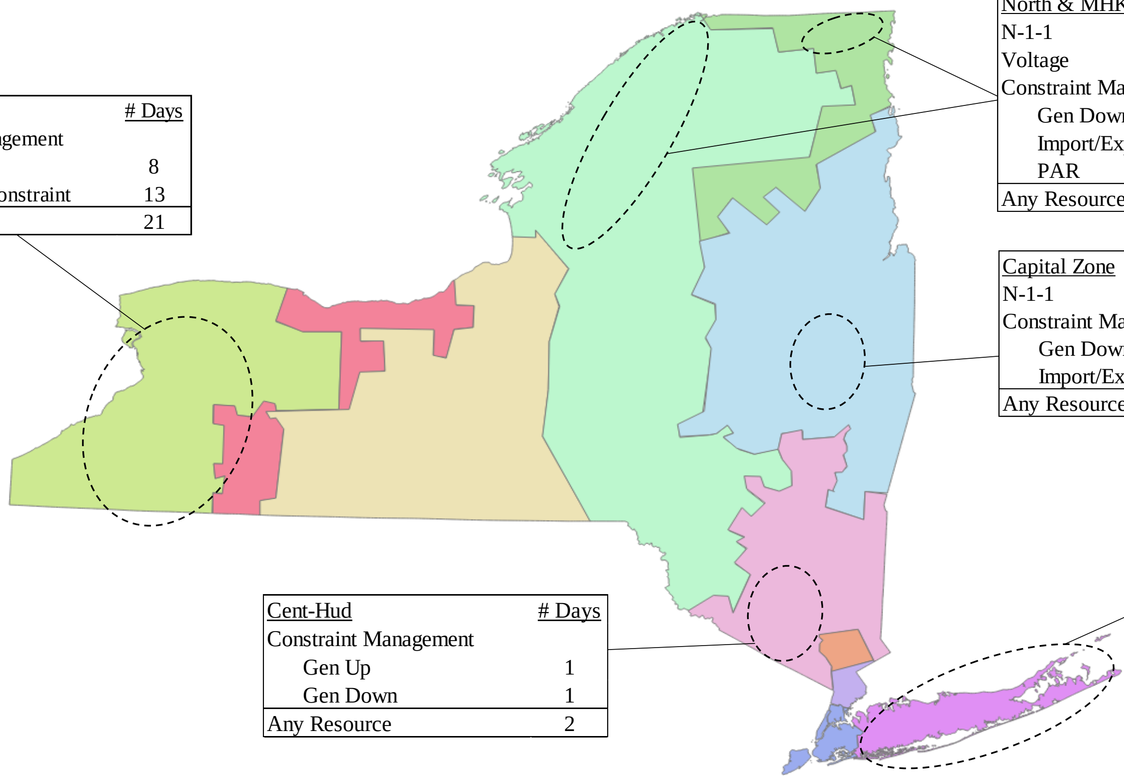
PAR Operation under M2M with PJM
2022 Q1



 Notes: For chart description, see slide 93.

POTOMAC ECONOMICS

OOM Actions to Manage Network Reliability



West Zone	# Days
Constraint Management	
Gen Up	8
Surrogate Constraint	13
Any Resource	21

North & MHK VL Zones	# Days
N-1-1	38
Voltage	1
Constraint Management	
Gen Down	6
Import/Export Limitation	2
PAR	1
Any Resource	42

Capital Zone	# Days
N-1-1	23
Constraint Management	
Gen Down	9
Import/Export Limitation	6
Any Resource	29

Cent-Hud	# Days
Constraint Management	
Gen Up	1
Gen Down	1
Any Resource	2

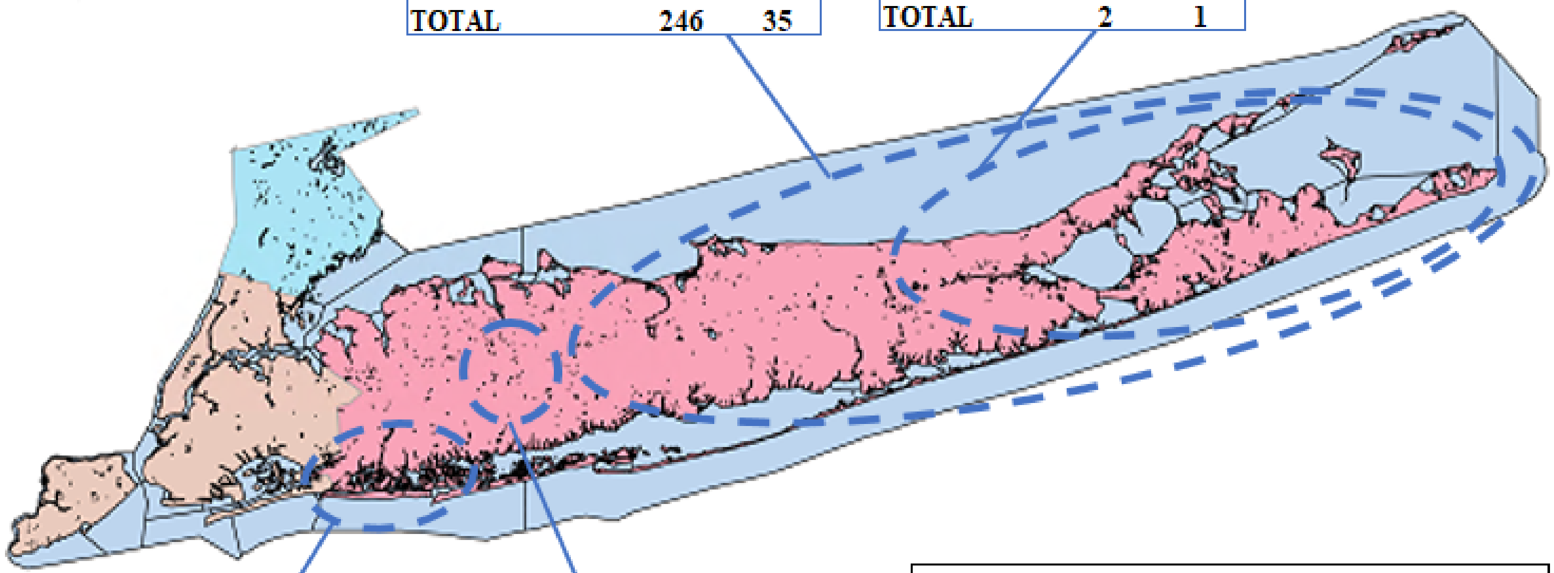
Long Island	# Days
N-1-1	6
Voltage	1
Constraint Management	
Gen Up	11
Gen Down	2
Import/Export Limitation	1
Any Resource	20

Notes: For chart description, see slides 94-95

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV OOM	39	6
69kV	174	31
138kV	81	12
TOTAL	246	35

East End	#Hours	#Days
69kV OOM	2	1
TOTAL	2	1



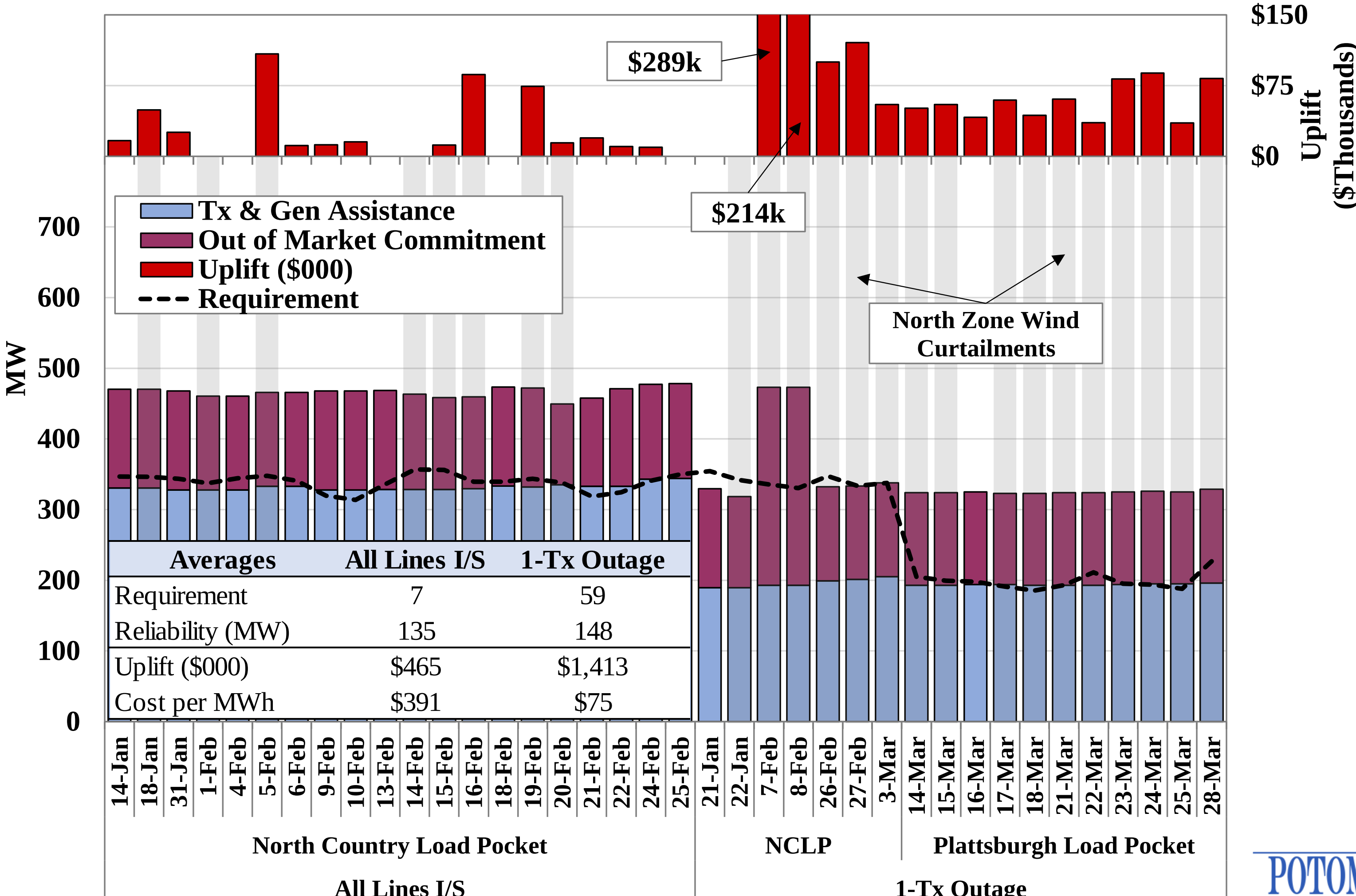
Valley Stream	#Hours	#Days
69kV OOM	71	6
138kV	414	45
TOTAL	472	49

Brentwood	#Hours	#Days
69kV	145	19
TOTAL	145	19

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
East End	$114.65	$115.24
East of Northport	$112.33	$112.73
Valley Stream	$116.37	$117.29

Notes: For chart description, see slides 94-95

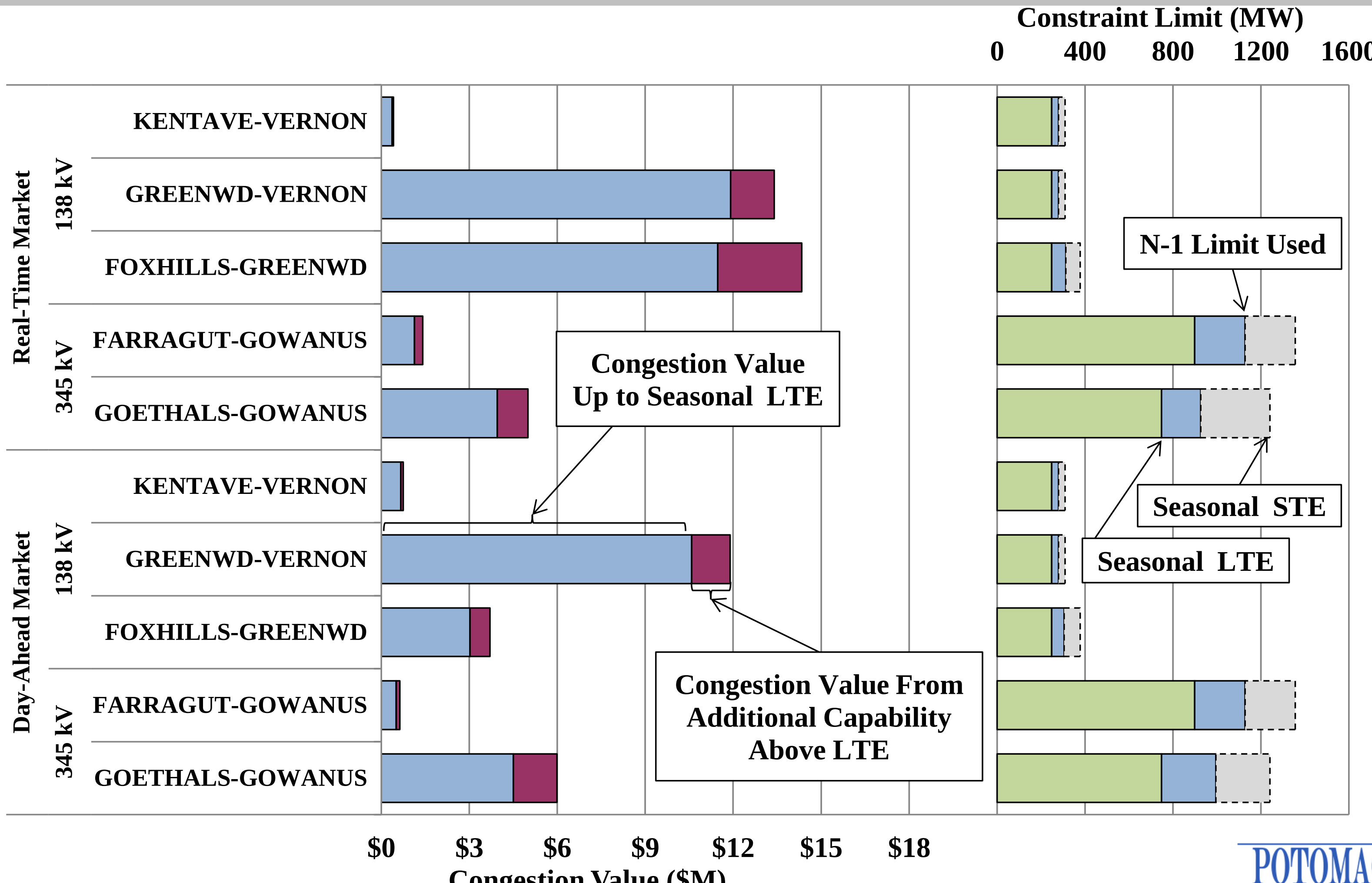
N-1-1 Constraints in North Country Region
Frequency and Magnitude of Capacity Requirements



Averages	All Lines I/S	1-Tx Outage
Requirement	7	59
Reliability (MW)	135	148
Uplift ($000)	$465	$1,413
Cost per MWh	$391	$75

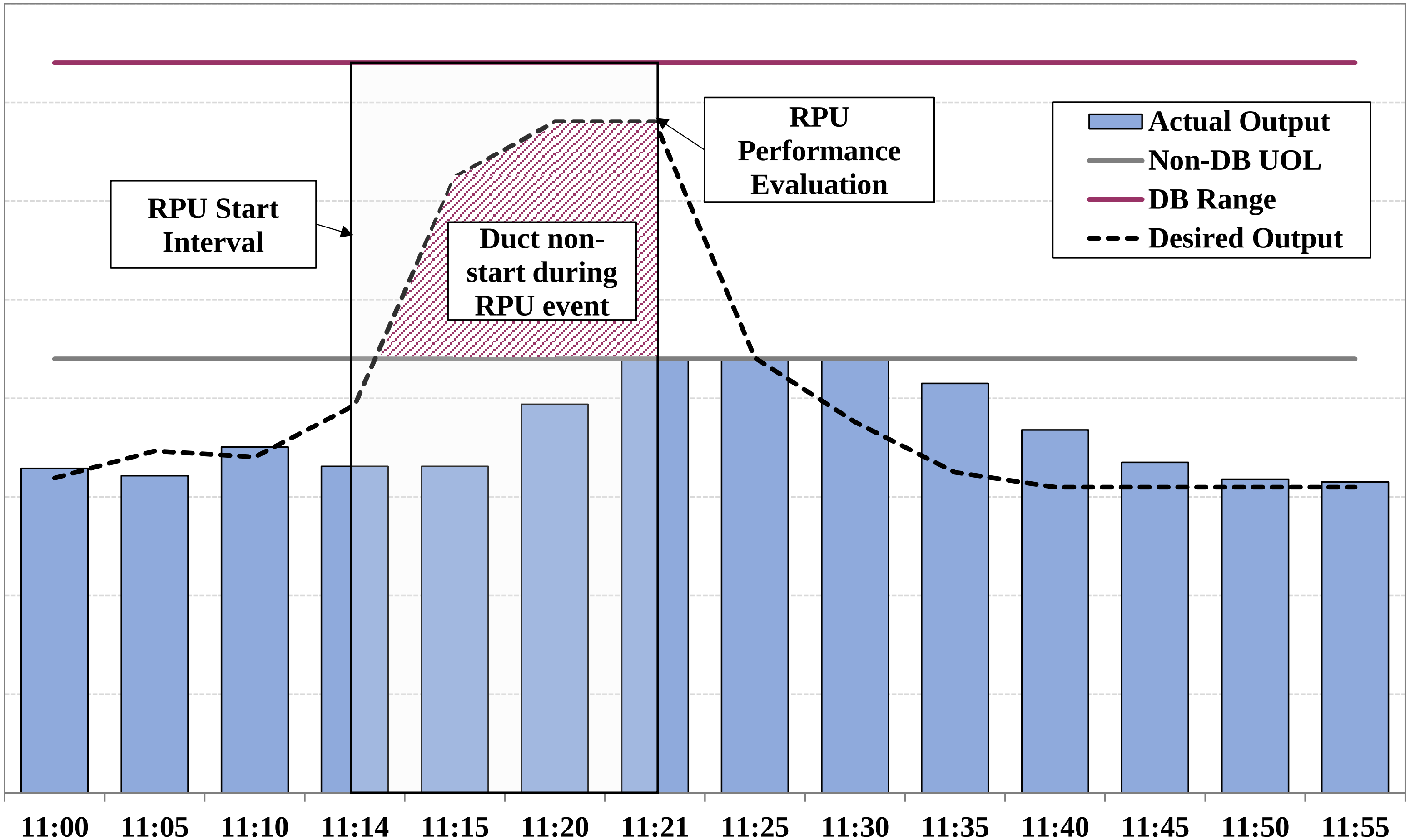
Notes: For chart description, see slide 96

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



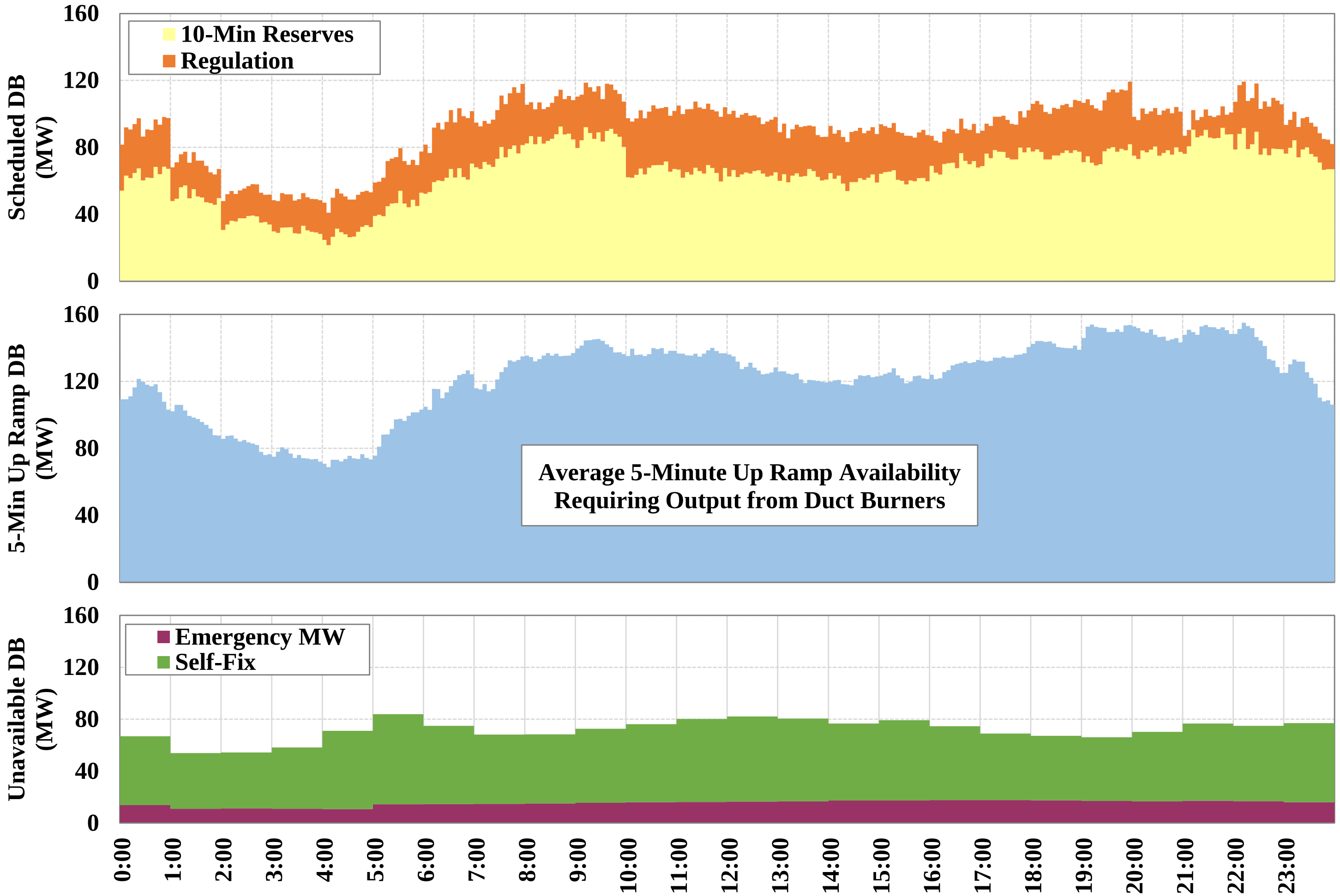
Notes: For chart description, see slide 97.
POTOMAC ECONOMICS

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



Notes: For chart description, see slide 98

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



Notes: For chart description, see slide 98

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

10 Minute Economic GT Start Performance vs. Audit Results (April 2021 - March 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	1	1	1
40% - 50%	2	6	2	3
50% - 60%	3	4	2	1
60% - 70%	0	0	0	0
70% - 80%	1	3	1	1
80% - 90%	23	89	23	19
90% - 100%	22	87	22	10
TOTAL	**53**	**190**	**51**	**35**

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 99.

POTOMAC ECONOMICS

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

30 Minute Economic GT Start Performance vs. Audit Results (April 2021 - March 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]	15	11	6	3
0% - 10%	4	3	3	1
10% - 20%	0	0	0	0
20% - 30%	1	3	1	1
30% - 40%	0	0	0	0
40% - 50%	0	0	0	0
50% - 60%	1	0	0	0
60% - 70%	1	4	1	1
70% - 80%	6	6	5	1
80% - 90%	29	50	27	3
90% - 100%	35	65	33	0
TOTAL	**92**	**142**	**76**	**10**

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 99.

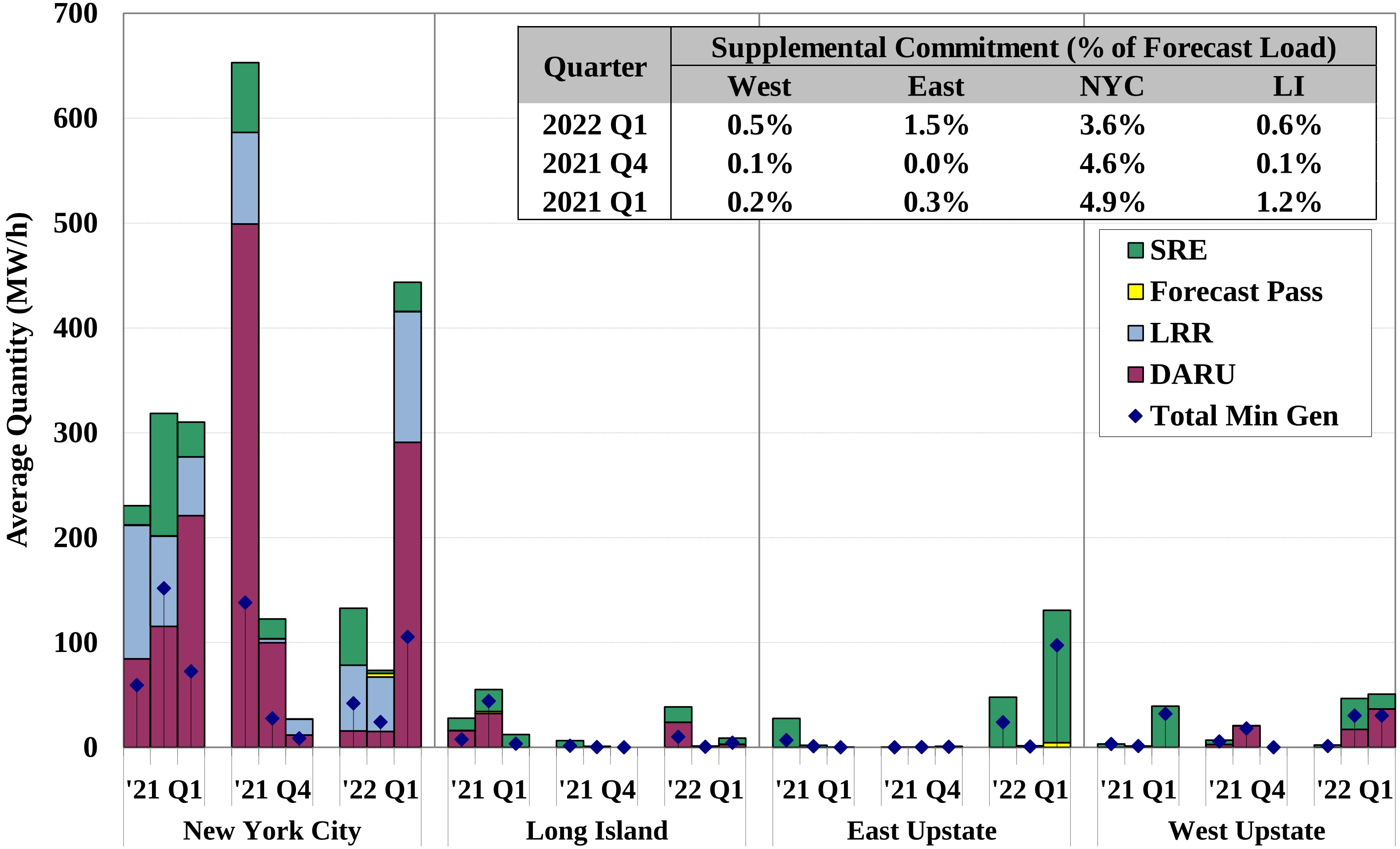
Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

Supplemental Commitment for Reliability
by Category and Region

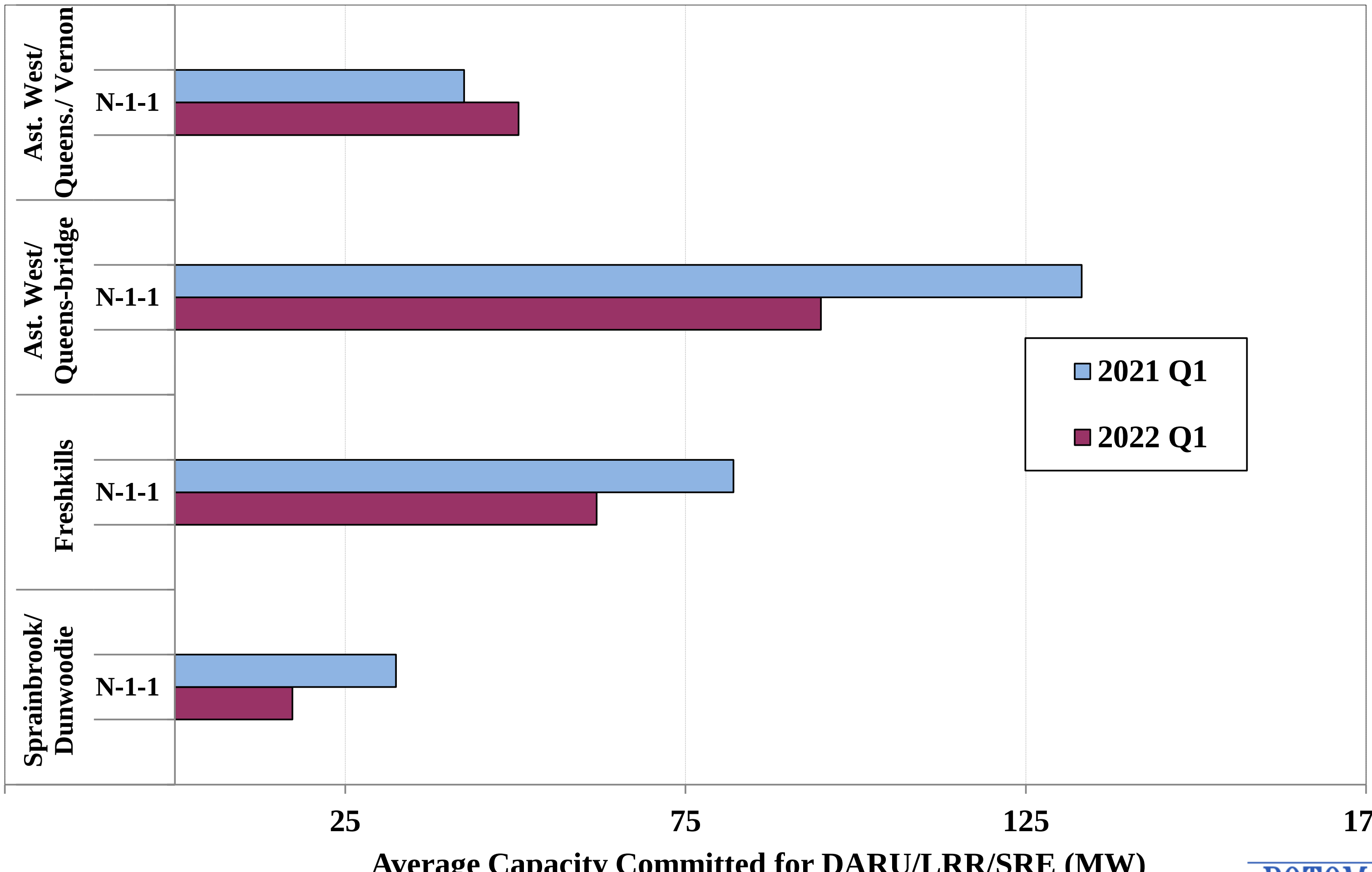
Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2022 Q1	0.5%	1.5%	3.6%	0.6%
2021 Q4	0.1%	0.0%	4.6%	0.1%
2021 Q1	0.2%	0.3%	4.9%	1.2%



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

POTOMAC ECONOMICS

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

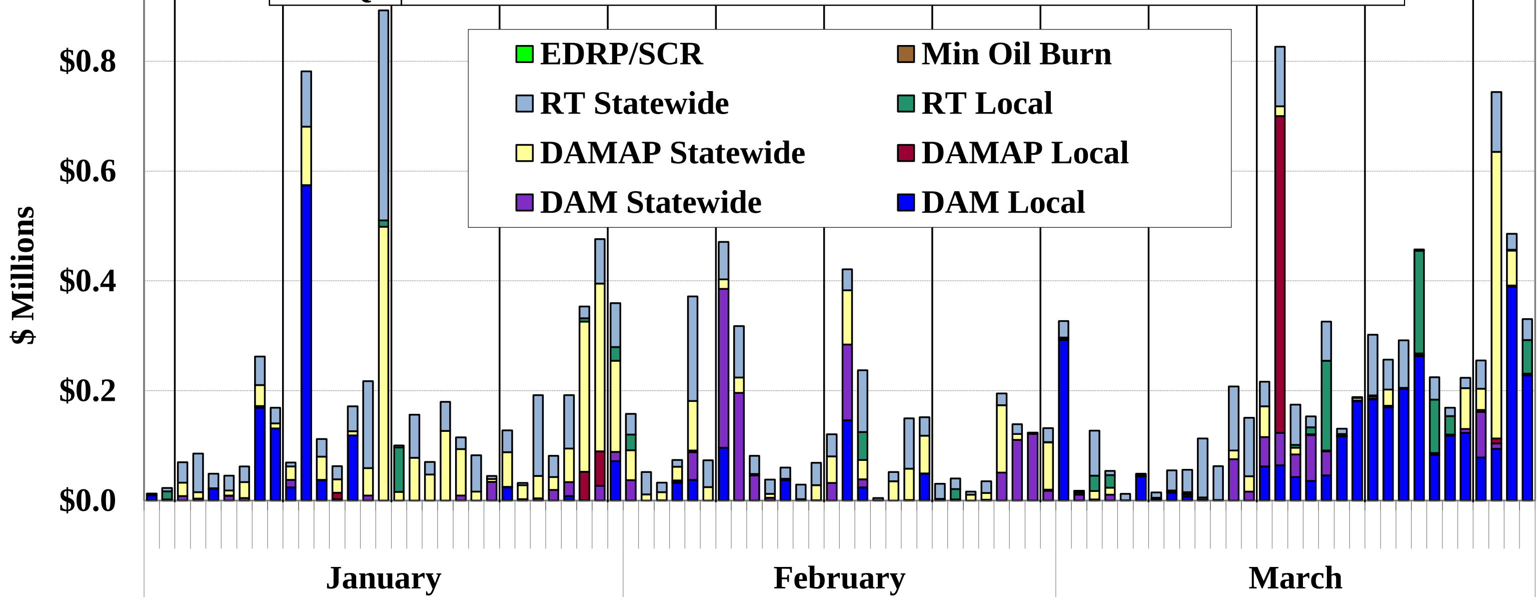


Notes: For chart description, see slides 100 and 101.

POTOMAC ECONOMICS

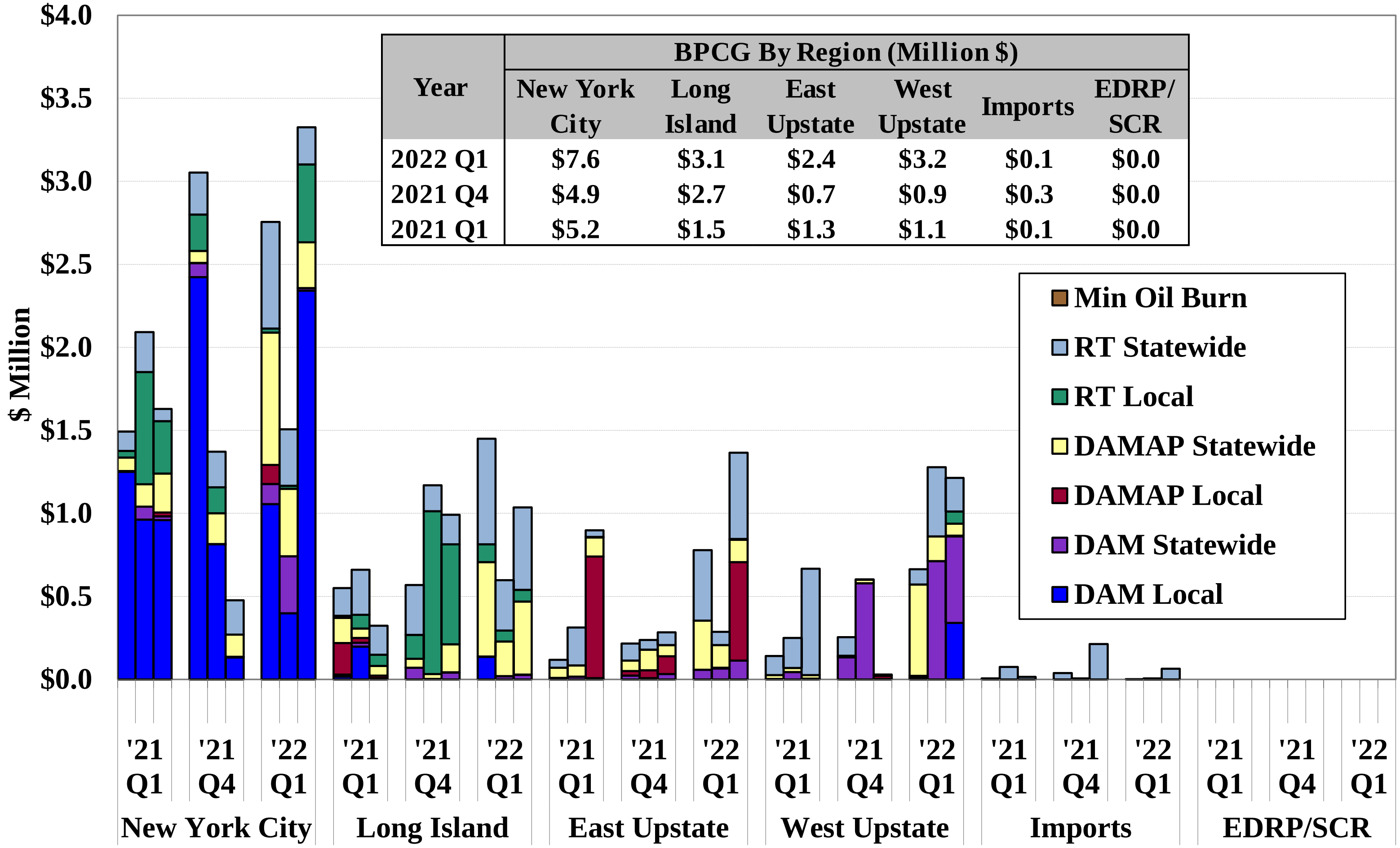
Uplift Costs from Guarantee Payments
Local and Non-Local by Category

Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2022 Q1	$4.5	$0.9	$0.7	$0.0	$1.8	$4.4	$4.0	$0.0	$16.3
2021 Q4	$3.4	$2.2	$0.2	$0.0	$1.0	$1.8	$0.9	$0.0	$9.5
2021 Q1	$3.4	$1.2	$1.0	$0.0	$0.2	$2.4	$1.0	$0.0	$9.2



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 102.

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 Q1	$7.6	$3.1	$2.4	$3.2	$0.1	$0.0
2021 Q4	$4.9	$2.7	$0.7	$0.9	$0.3	$0.0
2021 Q1	$5.2	$1.5	$1.3	$1.1	$0.1	$0.0

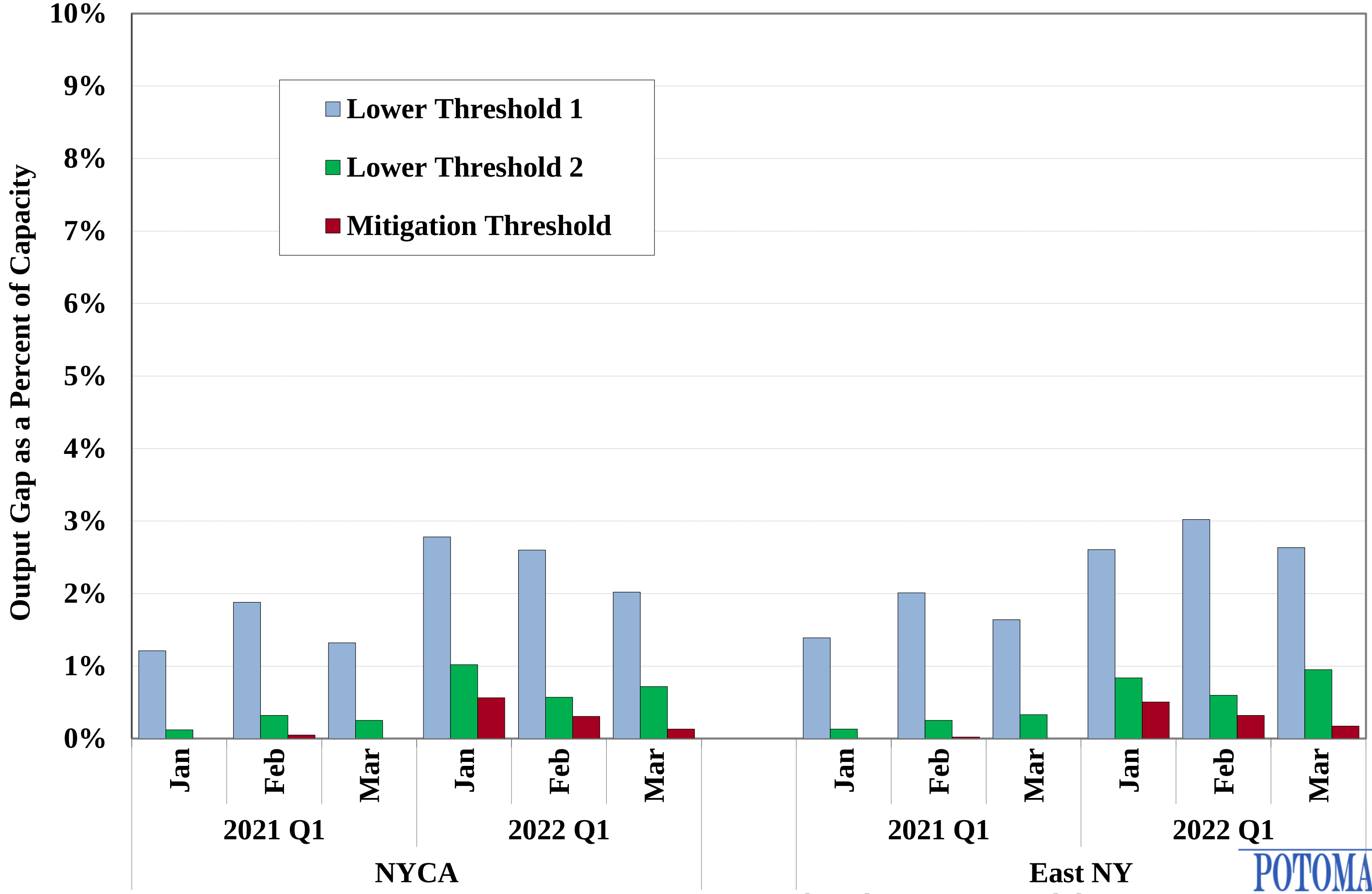
Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 102.

Charts:

Market Power and Mitigation

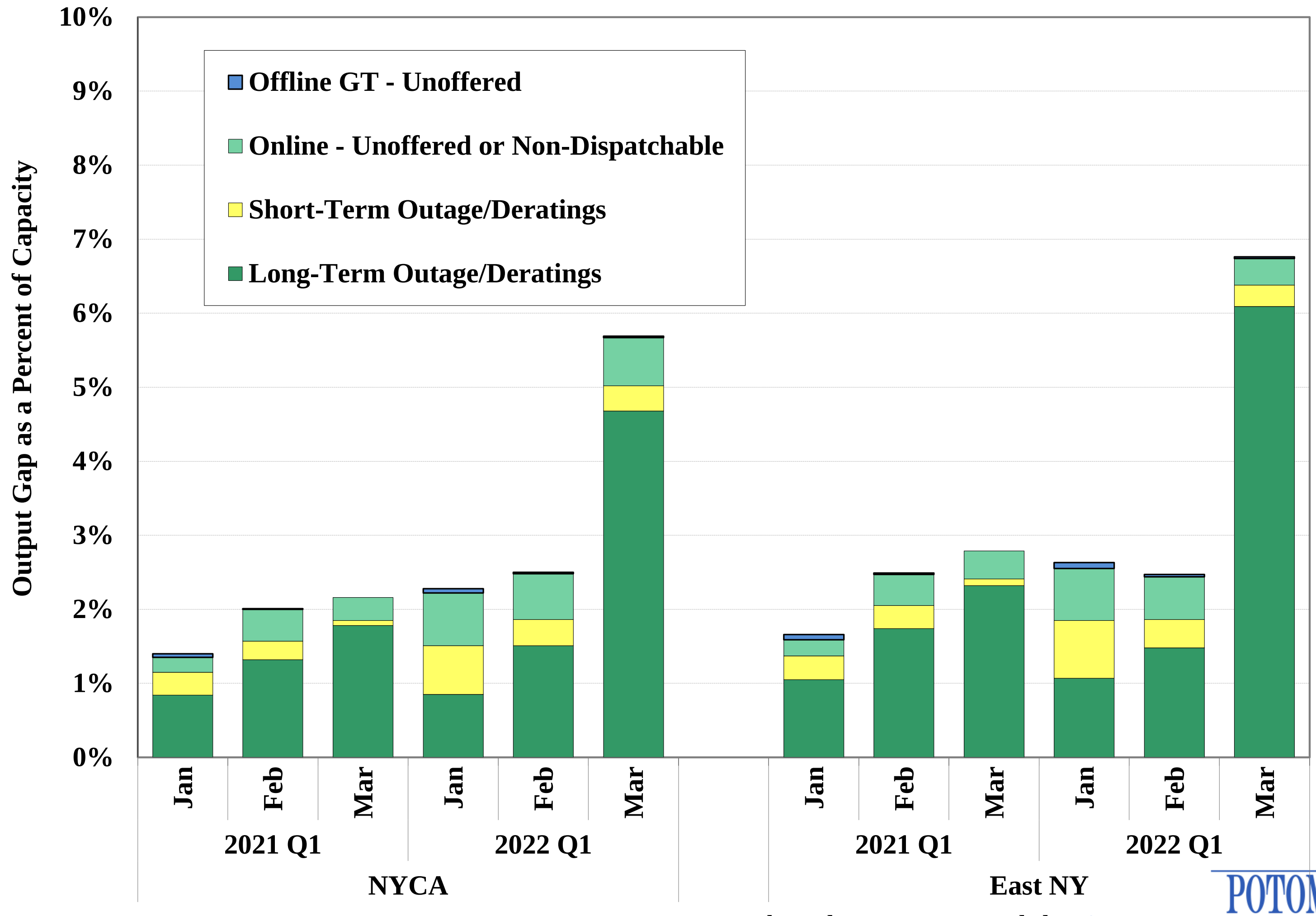
POTOMAC ECONOMICS

Output Gap by Month
NYCA and East NY



For chart description, see slide 103.

Unoffered Economic Capacity by Month
NYCA and East NY



 For chart description, see slide 103.

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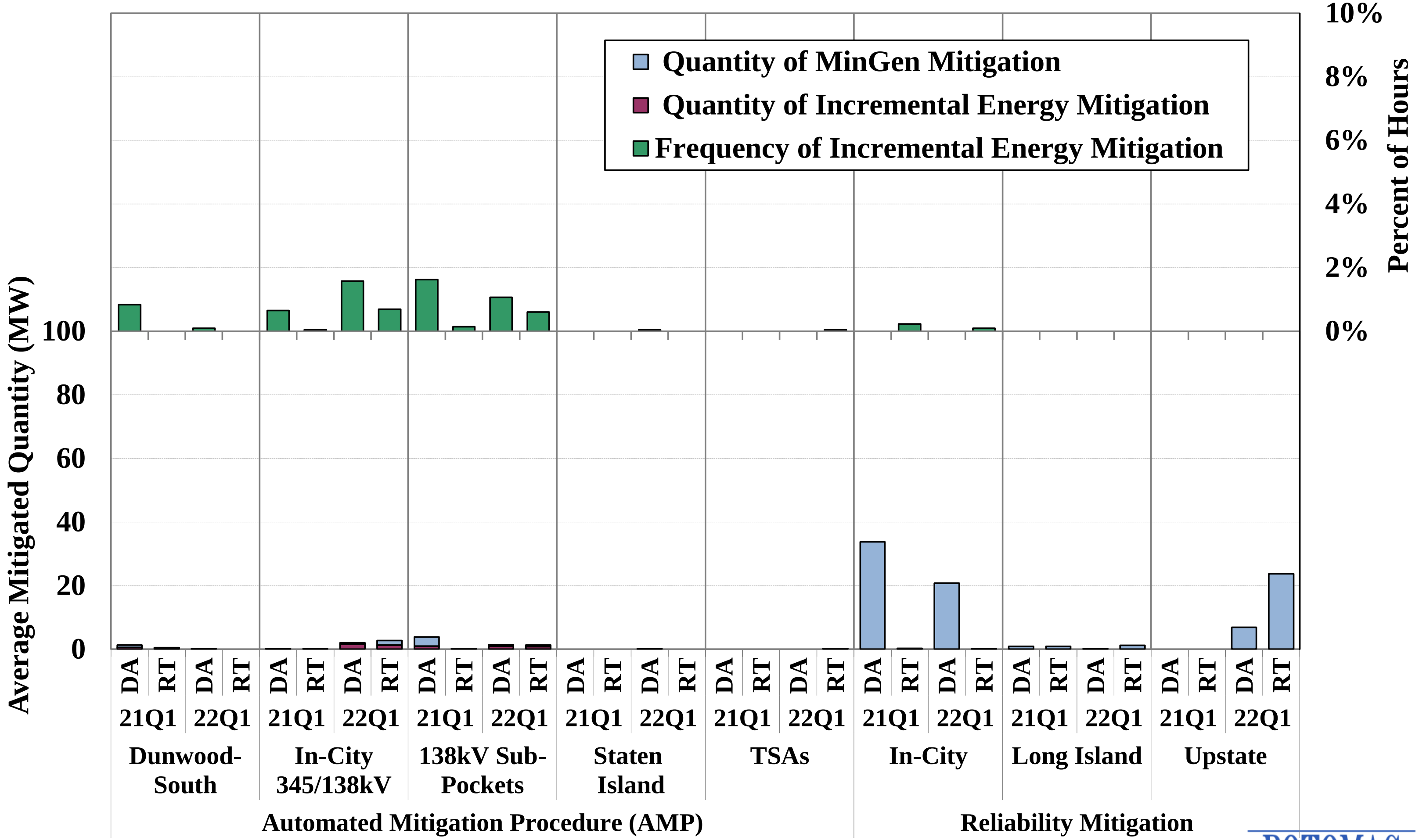
Automated Market Power Mitigation



Notes: For chart description, see slide 104.

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Charts:
Capacity Market

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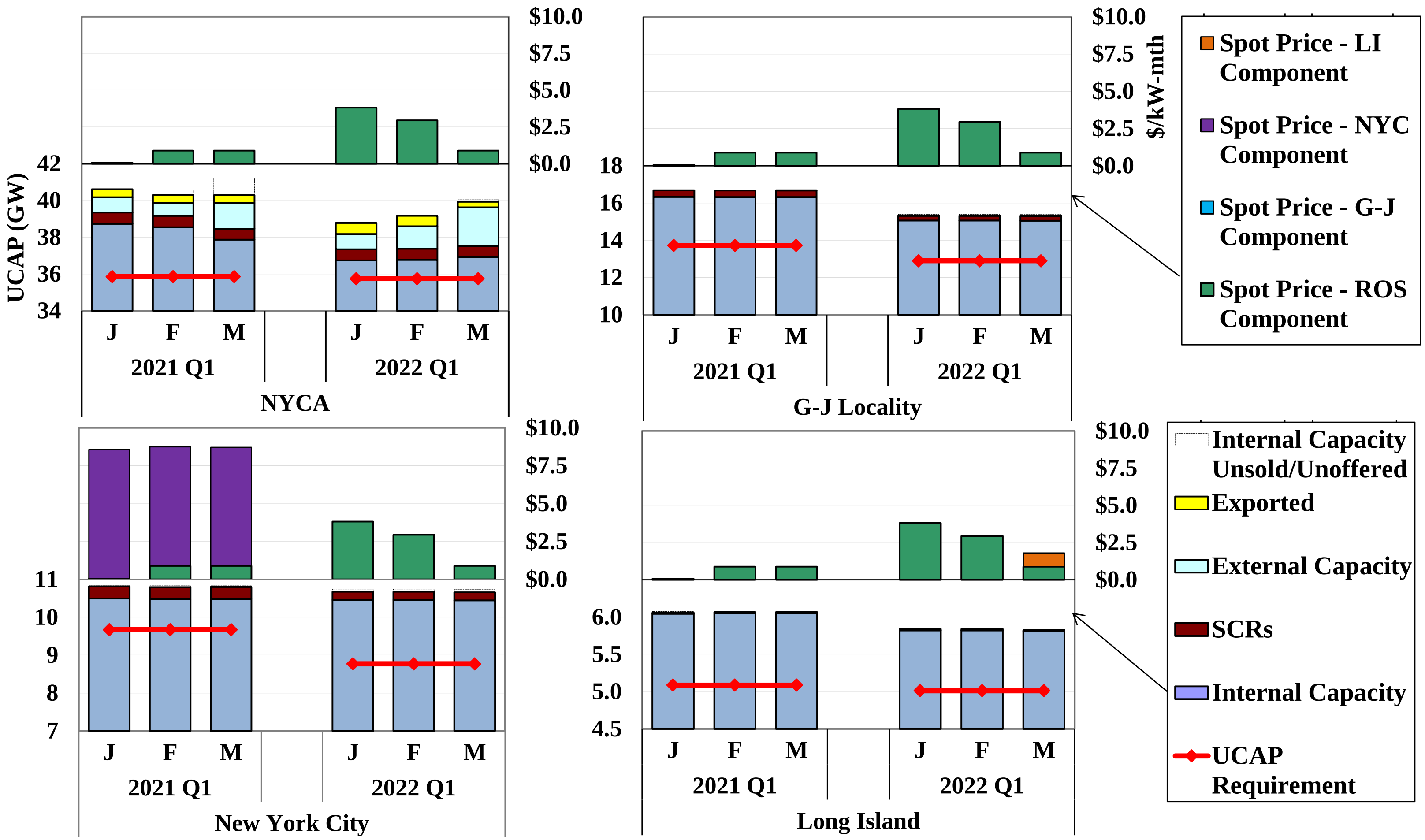
Spot Capacity Market Results
Monthly Results by Locality



Notes: For chart description, see slide 105.

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Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2022 Q1 ($/kW-Month)	$2.55	$2.55	$2.86	$2.55
% Change from 2021 Q1	**316%**	**-71%**	**366%**	**316%**
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	**-1341**	**-36**	**-118**	**-1025**
Entry [(3)]	80	16	0	16
Exit [(3)]	-1198	-53	-104	-1092
Other Capacity Changes [(1)]	-222	2	-14	51
Cleared Import [(2)]	**324**			

(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 105.

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Appendix: Chart Descriptions

All-in Price

- Slide 18 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.

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Real-Time Output and Marginal Units by Fuel

- Slide 21 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 22 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.

Winter Fuel Usage and Emissions by Region

- Slide 23 evaluates the efficiency of fuel usage in Eastern New York in the quarter.
  - ✓ The figure shows the daily averages for:
    - – Internal generation by actual fuel consumed in the lower portion; and
    - – Day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY) in the upper portion.
  - ✓ For a year-over-year comparison, these quantities are also shown by month for the same quarter in the recent three years.

Utilization of Oil-Fired and Dual-Fuel Capacity
Eastern New York During Tight Gas Conditions

- Slide 24 evaluates use of capacity listed as oil-fired or dual-fuel in the Gold Book in Eastern New York during cold weather and tight gas conditions in January 2022.
  - ✓ The figure shows the estimated generation that would have been economic to burn oil based on day-ahead and real-time clearing prices during this period.
- The figure shows the capacity in the following categories:
  - ✓ Actual output, from oil-fired and gas-fired generation separately.
  - ✓ The amount of economic oil-fired generation that was unavailable because of:
    - Long-term OOS – oil capable but with mothballed or decommissioned oil equipment;
    - Oil equipment failure – short-term outages/deratings due to oil equipment failures;
    - Outages and deratings – other outages and deratings;
    - Oil permit issues – oil capable and had inventory but prohibited from burning oil by state regulations;
    - Emission – output that would violate emission requirements, mostly NOx;
    - Gas-only range – the portion of the dispatchable range of dual-fuel combined cycle generators that cannot fire on oil; and
    - Oil inventory limitations.

Evaluation of Implied Gas Demand at Hunts Point
NYC Gas-Only Generators on ConEd System

- Slide 25 analyzes day-ahead implied natural gas demand for gas-only generators in NYC on the ConEd system that fuel-cost-adjusted their bids to source gas from Iroquois Zone 2 (Hunts Point) during gas days from January 7 to 31.
- The stacked columns show:
  - ✓ Scheduled deliveries to Hunts Point from all demand sources (source: Iroquois Pipeline data)
  - ✓ Offered & unscheduled demand from gas-only generators on the ConEd LDC for Hunts Point deliveries.
    - – The portion of gas output scheduled from these generators would not be included in the yellow columns since it is likely that this demand is already counted in the blue columns.
- The dashed and solid black lines show:
  - ✓ Dashed: Contracted maximum daily transportation (Dth) for deliveries to Hunts Point
  - ✓ Solid: Operational capacity for deliveries to Hunts Point, representing the maximum achievable daily deliveries to this point.
- Days impacted by ConEd hourly OFOs are shaded gray.

Emission by Region

- Slides 26-30 evaluate emissions from generators in the NYISO market.
  - ✓ Slide 26 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_X, and SO_2 .
  - ✓ Slides 27-28 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 29-30 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 29 shows the emission from STs in NYC that were supplementally committed for local reliability as a percent of total emission in NYC.

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Ancillary Services Prices

- Slides 35-39 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 38 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.

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Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 40 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 42 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.

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Day-Ahead Load Scheduling and Virtual Trading

- Slide 44 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 45 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 46 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.

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Efficiency of CTS Scheduling with PJM and NE

- Slide 48 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.

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Real-Time System Price Maps at Generator Nodes

- Slides 50 and 51 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 52, 53, 54, and 55 evaluate the congestion patterns in the DAM and RTM and examine the following categories of resulting congestion costs:
  - ✓ Day-Ahead Congestion Revenues are collected by the NYISO when power is scheduled to flow across congested interfaces in the DAM, which is the primary funding source for TCC payments.
  - ✓ Day-Ahead Congestion Shortfalls occur when the net day-ahead congestion revenues are less than the payments to TCC holders.
    - – Shortfalls (or surpluses) arise when the TCCs on a path exceed (or is below) its DAM transfer capability in periods of congestion.
    - – These typically result from modeling differences between the TCC auction and the DAM, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ Balancing Congestion Shortfalls arise when DAM scheduled flows over a constraint exceed what can flow over the constraint in the RTM.
    - – The transfer capability of a constraint falls (or rises) from day-ahead to real-time for the similar reasons (e.g., deratings and outages of transmission facilities, inconsistent assumptions regarding PAR schedules and loop flows, etc.).
    - – In addition, payments between the NYISO and PJM related to the M2M process also contribute to shortfalls (or surpluses).

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Transmission Congestion and Shortfalls (cont.)

- Slide 52 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 53 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 54 and 55 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.

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NY-NJ PAR Operation Under M2M with PJM

- Slide 48 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).

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OOM Actions to Manage Network Reliability

- Unmodeled transmission constraints (mostly on the 115kV and lower voltage network) 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 surrogate for the limiting transmission facility; and
  - ✓ Adjusting PAR-controlled lines on the high voltage network.
- Slide 57 shows the number of days in the quarter when various resources were used to manage transmission constraints in five areas of upstate New York:
  - ✓ West Zone;
  - ✓ Central Zone;
  - ✓ Capital Zone:
  - ✓ North & Mohawk Valley Zones; and
  - ✓ Long Island (mostly constraints on the 69kV system).
- In addition, the figure also reports the number of days when OOM commitments were made to satisfy N-1-1 reserve needs in several local load pockets.

Constraints on the Low Voltage Network on Long Island

- Slide 58 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 58 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-1-1 Constraints in North Country

- Slide 59 shows the size of the N-1-1 requirement in the North Country Load Pocket ("NCLP") and the Plattsburgh Load Pocket ("PLP") on applicable days in the quarter that required supplemental commitments of uneconomic gas units.
  - ✓ The bottom portion of the chart shows details relevant to the calculation of the requirement including:
    - NCLP & PLP portion of day-ahead load forecast of the North Zone;
    - Assistance from available transmission lines and day-ahead scheduled energy from non-wind resources in the pockets;
    - The amount of capacity scheduled from the unit(s) supplementally committed; and
    - The days in which wind generation in the North Zone was curtailed.
  - ✓ The x-axis is delineated between days where capacity was supplementally committed despite all transmission lines being in-service (i.e., due to high loads) and when at least one major transmission line in the pocket was on outage.
  - ✓ The top portion of the chart provides the uplift associated with the reliability commitments for these N-1-1 requirements.
- The inset table provides statistics relevant to the two scenarios that may warrant a supplemental commitment of a generator for reliability in the load pockets.

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 60 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 61 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 62 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 63-64 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 63): "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".

Supplemental Commitments and OOM Dispatch

- Slides 66 and 67summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 66 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 67 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 – 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.

Uplift Costs from Guarantee Payments

- Slides 68 and 69 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 68 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 69 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 71 and 72 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 73 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.

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Spot Capacity Market Results

- Slides 75 and 76 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 75 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 76 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.