

Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2020

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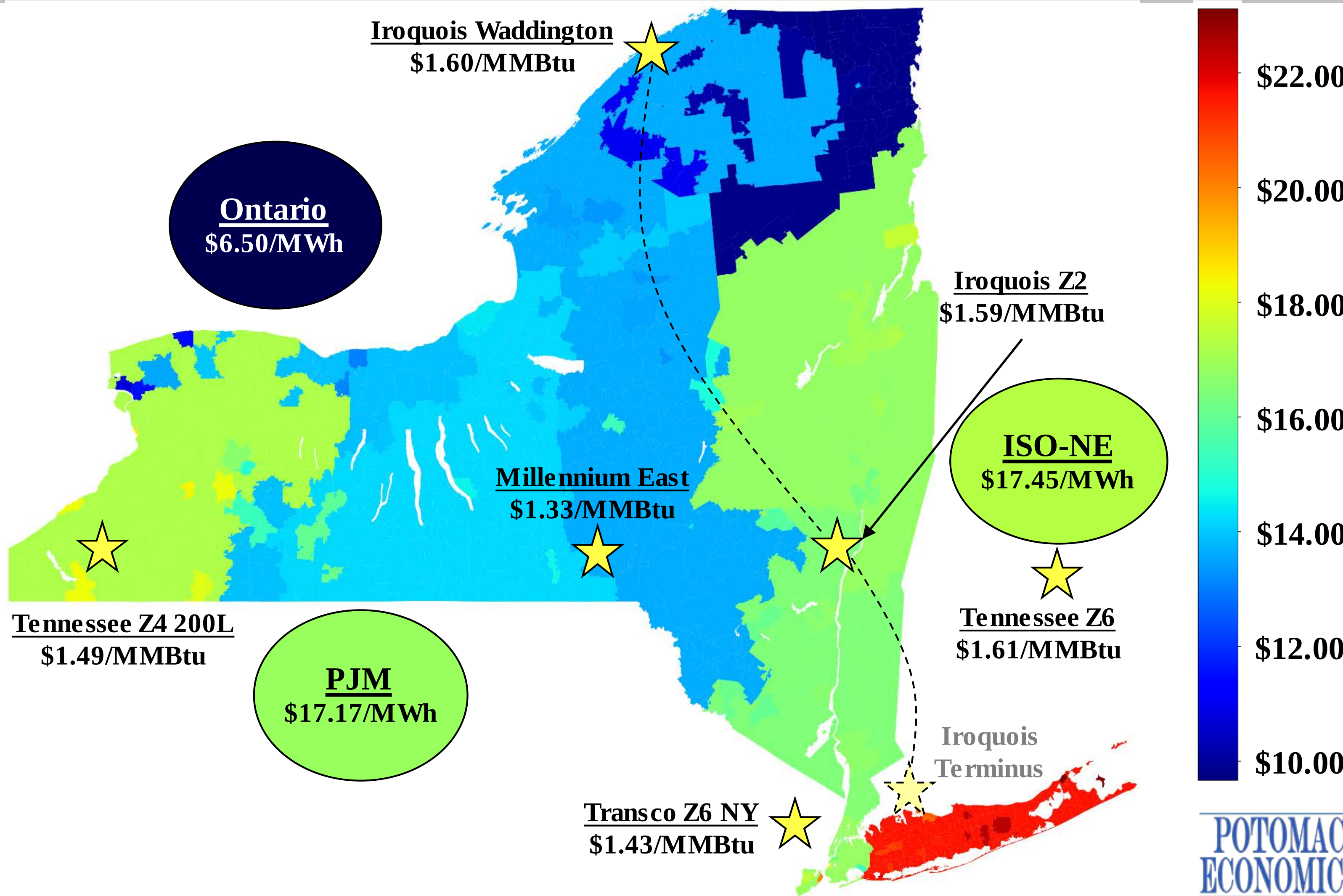
Market Highlights

Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the second quarter of 2020.
- All-in prices ranged from $15 to $61/MWh, down 9 to 31 percent from 2019 in all regions but NYC, which saw an increase of 12 percent. (slide 6)
  - ✓ For the first time in over a decade, capacity costs constituted the majority of NYC all-in prices (71 percent) because of an increased LCR and very low energy prices.
  - ✓ Natural gas prices continued to fall with quarterly averages being the lowest witnessed over the last decade, regardless of season.
  - ✓ Load also fell to the lowest second-quarter level in more than a decade, although peak load levels were consistent with last year because of a heat wave in June.
    - – The Covid-19 pandemic had a significant reductive impact on loads, especially in NYC, and drove most of the reduction from 2019.
- Lower load levels and gas prices led to lower transmission congestion (slides 7-8) and uplift. (slide 11)
- Generation patterns and capacity supply changed with the retirement of the Indian Point 2 nuclear unit, the last two coal plants (Kintigh and Cayuga) and the new entry of the Cricket Valley Energy Center.

Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- The amount of output gap (slide 60) and unoffered economic capacity (slide 61) remained low and reasonably consistent with competitive market expectations.
- Average all-in prices fell in most areas and ranged from roughly $15/MWh in the North Zone to $61/MWh in NYC. (slide 17)
  - ✓ All-in prices fell by as much as 31 percent in LHV but rose 12 percent in NYC.
  - ✓ Energy prices decreased in all regions, falling by 18 to 36 percent from the previous year (slides 22-23), driven primarily by historically low natural gas prices and load levels.
    - – Average natural gas prices fell 31 to 37 percent from a year ago (slide 19), resulting in the lowest quarterly average price seen since at least 2009.
    - – Load levels also fell substantially: average load fell 5 percent due largely to the Covid-19 pandemic (slide 18), contributing to lower prices as well.
      - The 5 percent average load reduction was a decrease against what had previously been the lowest second quarter load in more than a decade.
      - However, the decrease was partly offset by a June heat wave that drove energy demand higher (slide 18).
  - ✓ Capacity costs fell by 5 percent on Long Island and 40 percent in LHV, but capacity costs rose by 64 percent in NYC and doubled in the ROS regions for the reasons discussed later (slide 15).
    - – Capacity costs exceeded energy costs by a large margin in NYC.

Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $62 million, down 46 percent from a year ago, primarily because of lower gas prices and load levels. (slide 42)
  - ✓ Day-ahead congestion fell across the system with most of the decrease occurring on the Central-East interface and in the West Zone. (slide 43)
- The West Zone lines (40 percent) and the Central-East interface (24 percent) accounted for the largest shares of day-ahead congestion revenues in the second quarter of 2020. (slide 43)
  - ✓ West Zone congestion fell 41 percent in DA and 53 percent in RT from a year ago.
    - – Most of this congestion occurred on the transmission facilities in the Niagara area, driven partly by multiple transformer outages (slide 44).
  - ✓ Congestion across the Central-East interface fell 56 percent in DA and 43 percent in RT from a year ago.
    - – Natural gas prices fell more in East NY (particularly in NYC), resulting in much smaller gas price spreads between West NY and East NY. (slide 19)
      - The Millennium hub traded at just a 7 percent discount to Transco Z6 NY.
    - – The frequency of congestion across the Central-East interface fell despite the Indian Point 2 retirement (slides 19-20) and substantially higher exports to NE (slide 37).

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

- New York City constraints accounted for only about 5 percent of congestion in the second quarter of 2020. (slide 43)
  - ✓ Congestion fell by nearly 80 percent in NYC from the prior year.
    - – The Covid-19 pandemic impacted commercial load in NYC more than anywhere else, reducing NYC load by 11 percent (based on weather-normalized values).
    - – NYC generation became more economic as a result of lower gas prices.
- Unlike most other transmission corridors, congestion from the North Zone to central New York rose by more than 100 percent from a year ago. (slide 43)
  - ✓ 90 percent of this congestion occurred on the Moses-Adirondack 230 kV MA1 line when the parallel MA2 line was OOS in most of May and June. (slide 44) These outages have been primarily related to the Moses-Adirondack Smart Path Reliability Project.
- West-to-Central real-time congestion rose substantially from the previous year.
  - ✓ The vast majority of this congestion occurred in the real-time on the Scriba-Volney 345 kV line out of the Oswego generation pocket.
    - – 65 percent of this congestion occurred on two days when parallel 345 kV transmission lines were forced out.

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Market Highlights:
Out of Market Actions to Manage Congestion

- The NYISO has greatly reduced the use of OOM actions over the last two years to manage low-voltage transmission constraints by modeling most 115kV constraints in the DA and RT market models.
  - ✓ The NYISO has an ongoing process to evaluate and add unmodelled 115kV constraints to the market models.
- OOM actions to manage lower-voltage network congestion were most frequent in Long Island (34 days) this quarter. (slide 47)
  - ✓ OOM actions taken to manage 69 kV constraints were most frequent (13 days) in the East of Northport load pocket. (slide 48)
  - ✓ The lack of gas pipeline build on the East End of Long Island requires otherwise uneconomic oil peakers to be OOMed for TVR under high load conditions, which occurred on 14 days in June. (slide 48)
  - ✓ Frequent OOM actions undermine market efficiency, leading to:
    - – Inefficient scheduling (slide 10);
    - – Depressed price signals (slide 48);
    - – Higher BPCG uplift (slides 57-58).

Market Highlights:
Use of Oil-fired Generation in East of Northport

- Oil-fired peakers are often used to manage congestion into the East of Northport load pocket on 69 kV (11 days) and 138 kV (10 days) circuits. (slide 49)
  - ✓ 69 kV constraints are currently not modeled in the market software.
  - ✓ One of the 138 kV lines on the interface into the pocket is PAR-controlled and generally operated to reduce flows over the 69 kV lines into the pocket.
    - – This operation affects flows over the parallel 138 kV lines.
    - – However, this flow variation on the 138 kV lines is not anticipated by SCUC or RTC so the look-ahead model does not have information necessary to secure these lines efficiently.
- Sufficient low-cost resources (e.g., gas-fired units and CSC import capability) were available to manage congestion without oil-fired generation on these days.
  - ✓ A portion of these low-cost resources (e.g., 30-minute gas GTs, CSC imports) were available in real-time but RTC did not schedule them because of lack of information with sufficient lead time.
  - ✓ A portion of these low-cost resources (e.g., gas CCs, CSC imports) would have been available in real-time if they had been committed in the day-ahead market for modeled 69 kV needs.

Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $9.6 million, down 15 percent from the second quarter of 2019 (slides 57-58).
  - ✓ The reduction was driven primarily by lower statewide uplift, which was consistent with lower gas prices and load levels.
  - ✓ However, local uplift increased slightly (by 4 percent), partially offsetting overall decrease.
- $6.2 million (or 65 percent) of BPCG payments were paid to NYC units that were committed for local reliability needs. (slide 58)
  - ✓ Reliability commitments in NYC accounted for nearly 90 percent of all reliability commitments this quarter. (slide 52)
- $1.7 million (or 18 percent) of BPCG payments were paid to Long Island units that were OOMed to manage local reliability on the 69 kV network and TVR needs on the East End of Long Island. (slides 54, 58)
- Modeling the reserve needs in NYC load pockets and Long Island constraints on the 69 kV network would greatly improve market efficiency for resource scheduling and pricing.

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Market Highlights:
Excess N-1-1 LRR Commitments in NYC

- Reliability commitments in NYC often occur because a generator is needed only during the highest load hours of the day.
  - ✓ The actual amount of capacity needed in each load pocket varies by hour based on load and network conditions.
  - ✓ However, during the 2nd quarter the DAM software used a single daily capacity requirement for most load pockets, which is applied to all hours.
  - ✓ This can lead to over-commitment, especially in off-peak hours, raising production costs and depressing market clearing prices.
- We estimated the amount of LRR commitments that would not have occurred if the DAM software used hourly capacity requirements. (slide 55)
  - ✓ If hourly capacity requirements were used, we estimate that LRR Commitments in 151 hours across 20 days would have been avoided (total LRR commitments occurred in 488 hours on 25 days in these load pockets).
  - ✓ The avoidable commitments mostly occurred in off-peak hours (e.g., HB 0-6, 23).
- The NYISO began to apply these capacity requirements on an hourly (rather than daily) basis beginning July 30 for the DA Market.
  - ✓ This should reduce the amount of LRR commitments in off-peak hours and improve overall market efficiency.

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 many days during the Ozone season.
    - – This occurred on 42 days in the second quarter of 2020. (slide 56)
  - ✓ Our evaluation shows that even if the committed steam turbine and the associated GTs were unavailable, all N-1-1 criteria in the associated load pockets could have been satisfied by other resources on each of the 42 days.
    - – The supply margin (excluding the committed steam turbine and associated GTs) exceeded 250 MW each day. (slide 56)
    - – 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).
      - Without the NOx-only steam turbine commitments the GTs would not be available in real time.
  - ✓ These avoidable NOx-only commitments reduce market efficiency by depressing prices and generating uplift and excess production costs.

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Market Highlights:

Use of Operating Reserves to Manage NYC Congestion

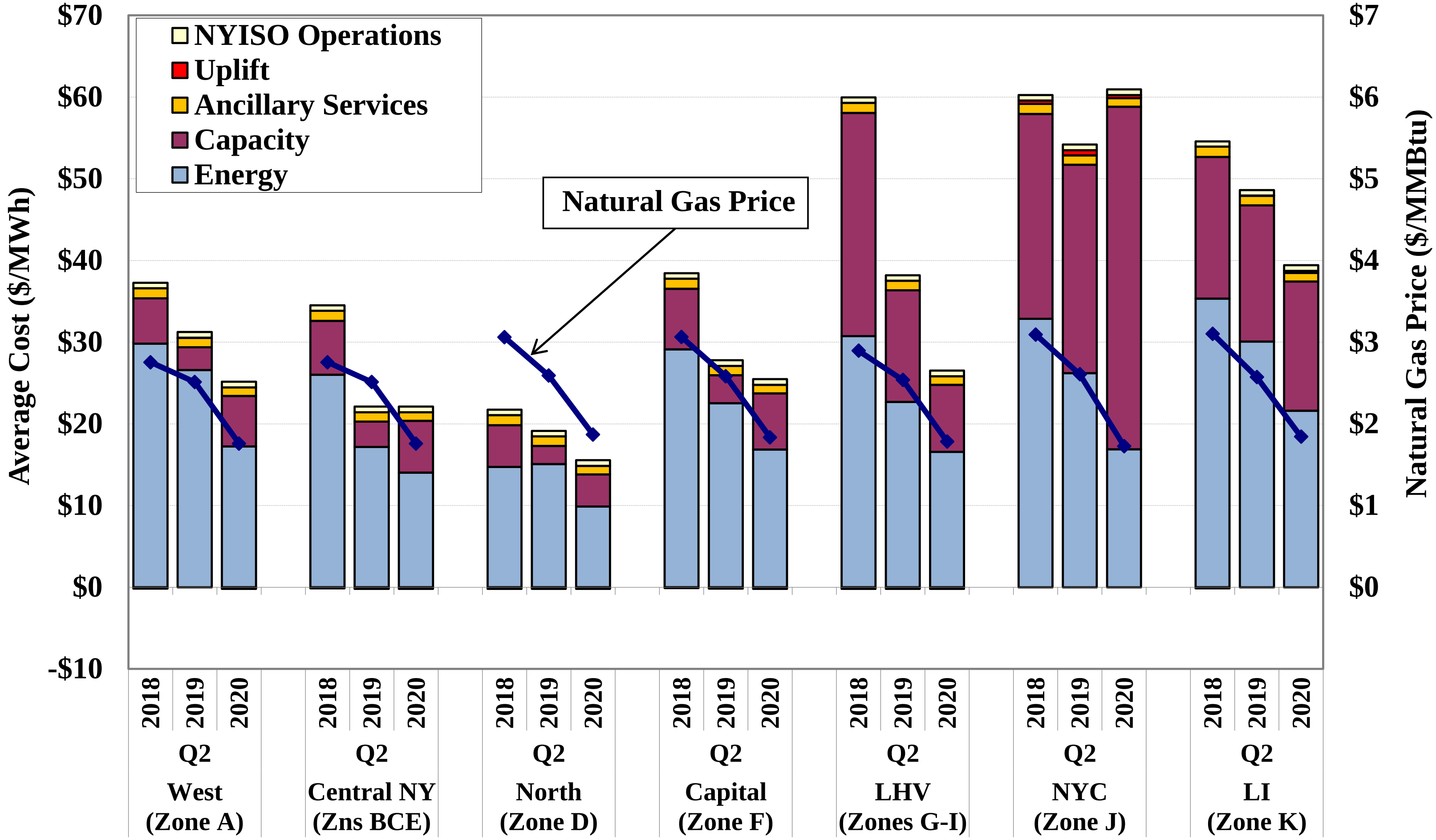
- Transmission facilities in New York City can be operated above their Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) are available to quickly reduce flows to LTE.
  - ✓ The availability of post-contingency actions is important because they allow the NYISO to increase flows into load centers in NYC and reduce congestion costs.
- In 2020-Q2, 57 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 50)
  - ✓ The additional capability above LTE averaged from about 10 to 50 MW for the 138 kV constraints in the Greenwood load pocket to roughly 230 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 should efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria. (see Recommendation #2016-1 in our 2019 SOM report)

Market Highlights:
Capacity Market

- Average spot capacity prices ranged from $2.20/kW-month in ROS and the G-J Locality to $13.94/kW-month in New York City this quarter. (slides 64-65)
- Capacity prices rose in ROS (106 percent), Long Island (3 percent), and NYC (43 percent) but fell the G-J Locality (45 percent) from a year ago.
  - ✓ Changes in demand were one primary driver of these price changes, due largely to changes in IRM and LCRs. Peak load forecast fell slightly in all regions.
    - – The NYCA IRM rose from 117 to 118.9 percent and the LCR rose from 82.8 to 86.6 percent in NYC.
    - – However, the LCR fell from 92.3 to 90.0 percent in the G-J Locality and from 104.1 to 103.4 percent on Long Island.
  - ✓ Changes in supply were also a key driver.
    - – In the G-J Locality, Indian Point 2 retired at the end of April, which was, however, roughly offset by the entry of the Cricket Valley energy center.
    - – In ROS, Kintigh retired at the end of March and both Cayuga units retired in June, marking the end of the coal era in NYISO.
  - ✓ ICAP Reference Prices rose in all Localities, from $0.82 in NYCA to $1.92 per kW-month in Long Island.

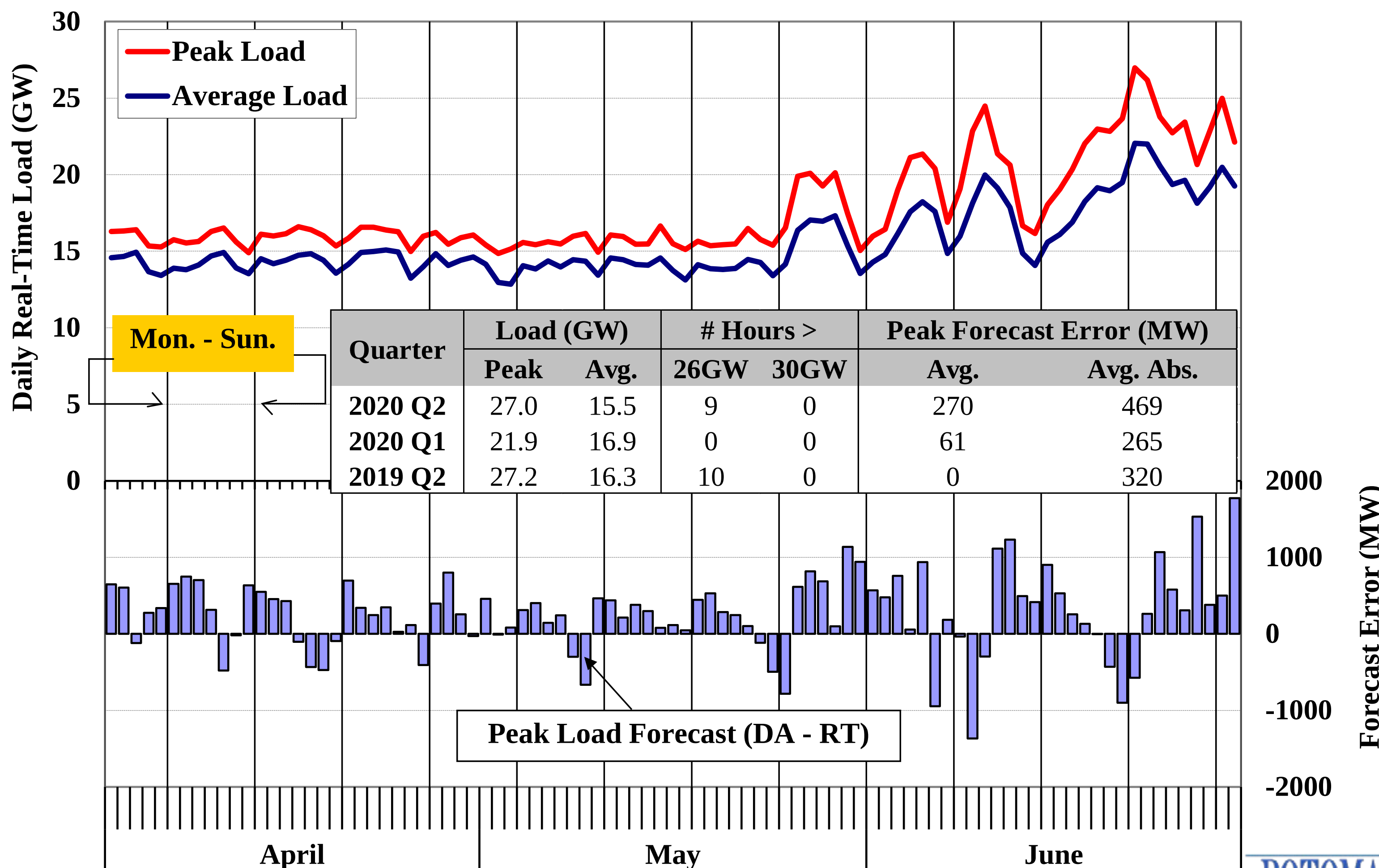
Charts:
Market Outcomes

All-In Prices by Region



Notes: For chart description, see slide 67.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2020 Q2	27.0	15.5	9	0	270	469
2020 Q1	21.9	16.9	0	0	61	265
2019 Q2	27.2	16.3	10	0	0	320

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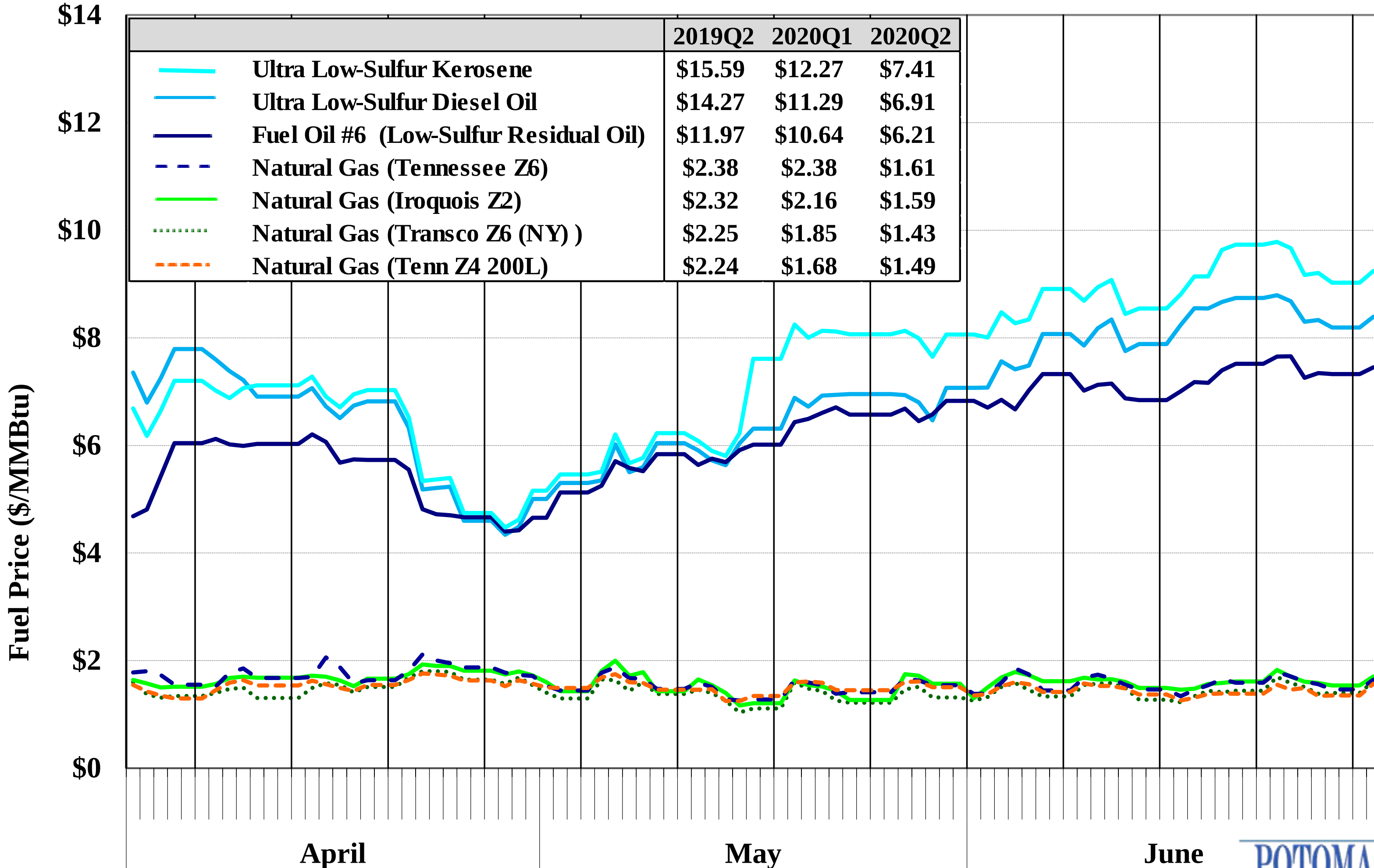
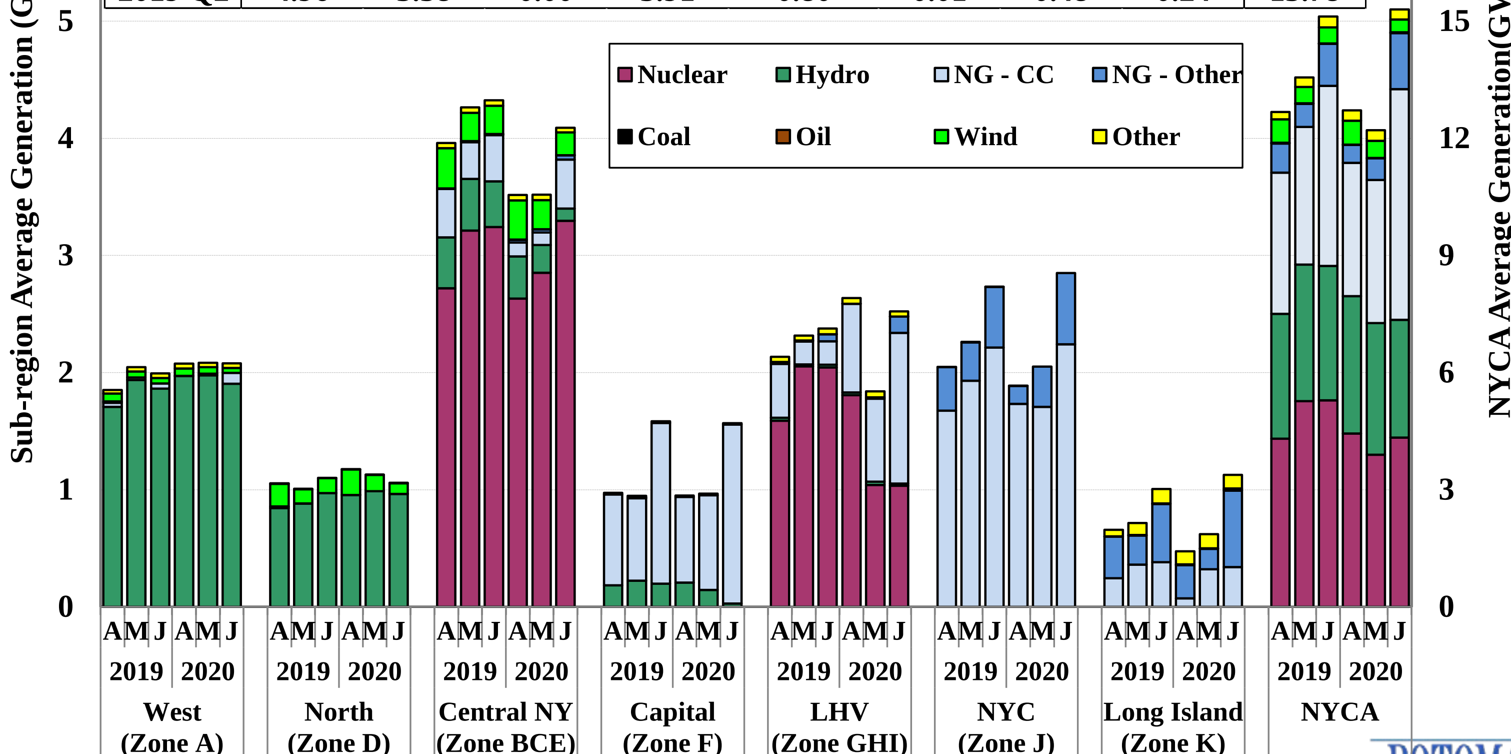
Natural Gas and Fuel Oil Prices



Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2020 Q2	4.22	3.30	0.00	4.32	0.81	0.01	0.46	0.27	13.39
2020 Q1	4.88	3.48	0.07	5.01	0.52	0.02	0.59	0.26	14.82
2019 Q2	4.96	3.38	0.00	3.91	0.80	0.01	0.48	0.24	13.78



  Notes: For chart description, see slide 68.

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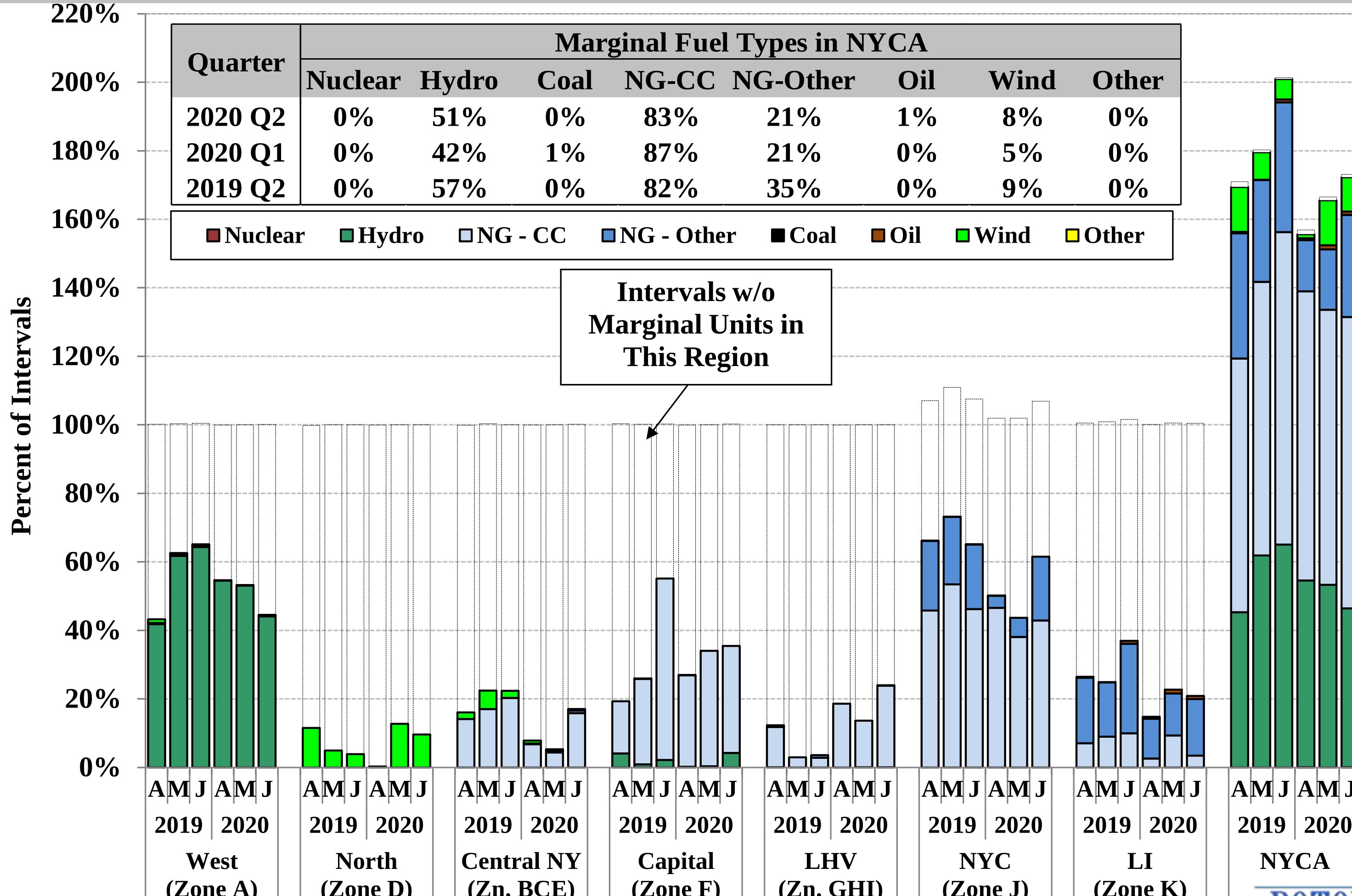
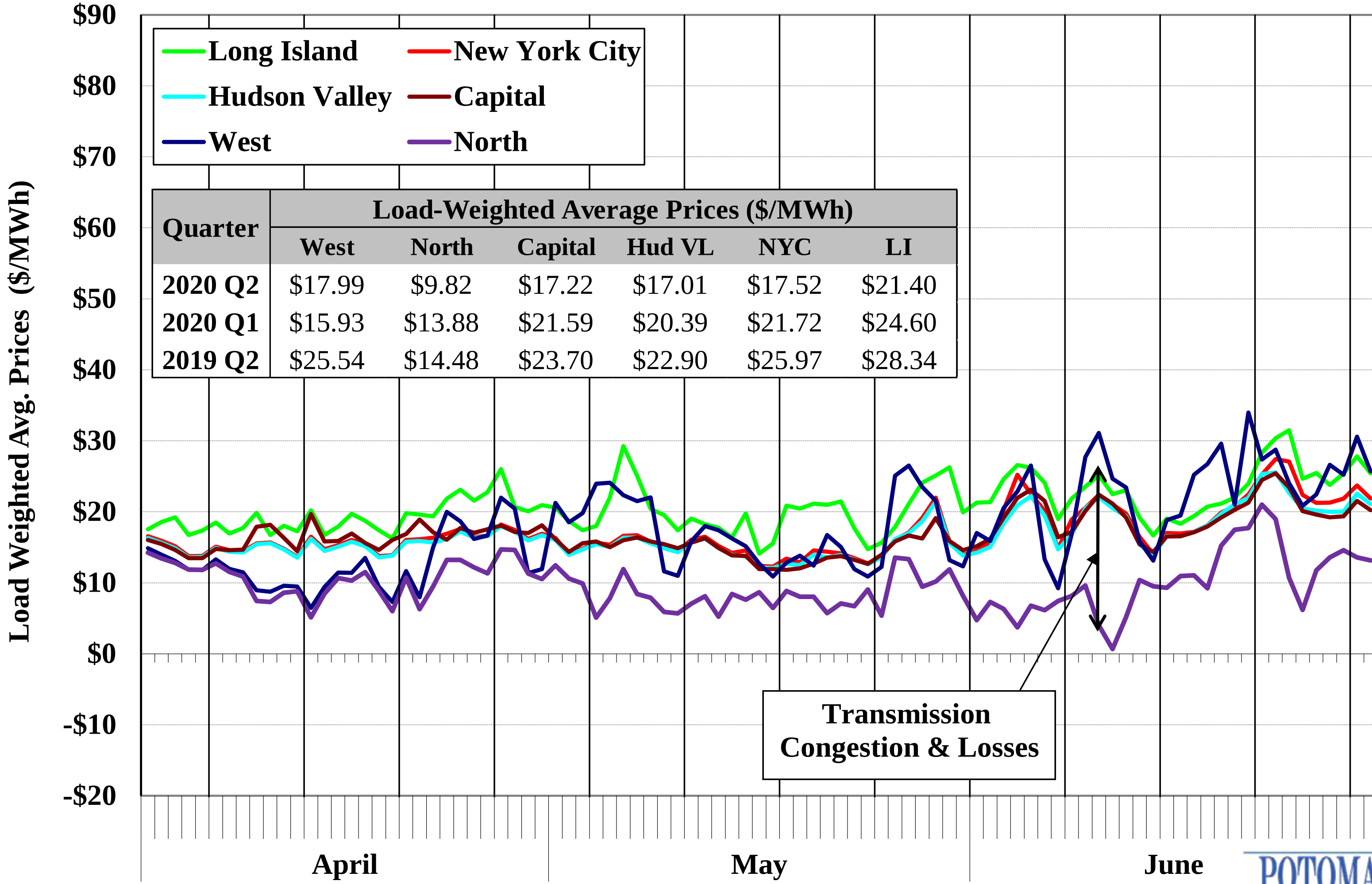
Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2020 Q2	0%	51%	0%	83%	21%	1%	8%	0%
2020 Q1	0%	42%	1%	87%	21%	0%	5%	0%
2019 Q2	0%	57%	0%	82%	35%	0%	9%	0%

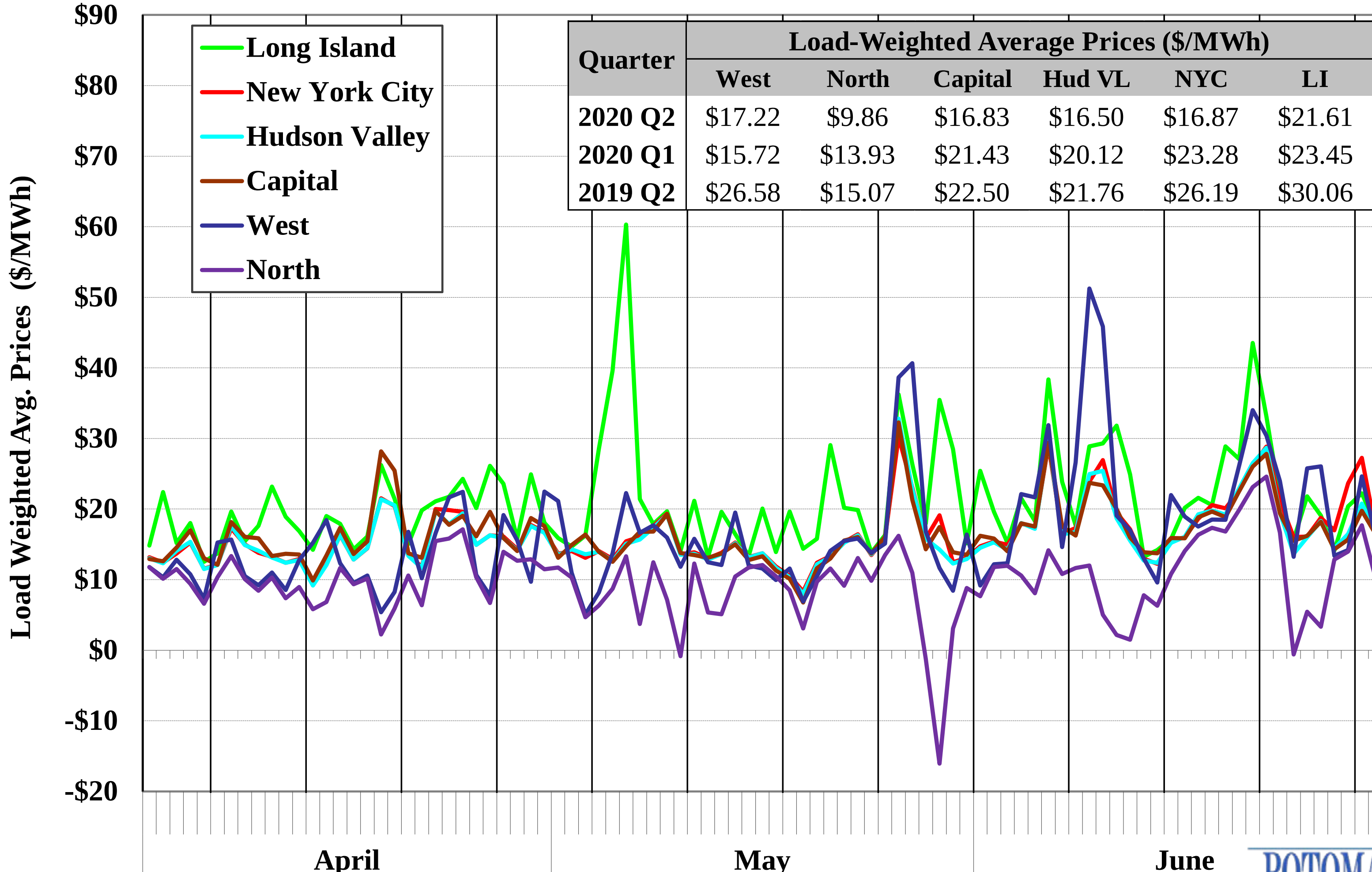
Notes: For chart description, see slide 68.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q2	$17.99	$9.82	$17.22	$17.01	$17.52	$21.40
2020 Q1	$15.93	$13.88	$21.59	$20.39	$21.72	$24.60
2019 Q2	$25.54	$14.48	$23.70	$22.90	$25.97	$28.34

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q2	$17.22	$9.86	$16.83	$16.50	$16.87	$21.61
2020 Q1	$15.72	$13.93	$21.43	$20.12	$23.28	$23.45
2019 Q2	$26.58	$15.07	$22.50	$21.76	$26.19	$30.06

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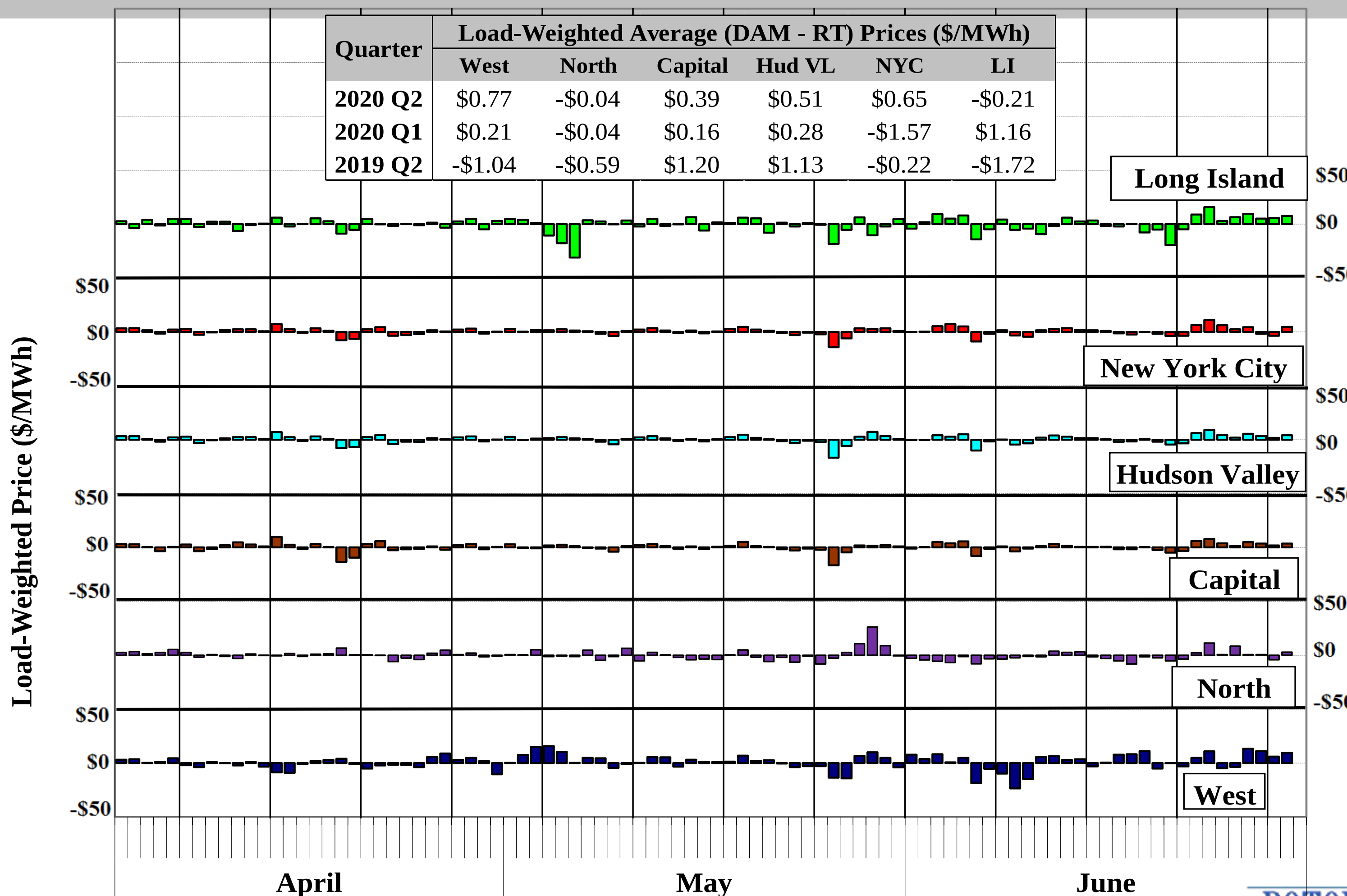
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q2	$0.77	-$0.04	$0.39	$0.51	$0.65	-$0.21
2020 Q1	$0.21	-$0.04	$0.16	$0.28	-$1.57	$1.16
2019 Q2	-$1.04	-$0.59	$1.20	$1.13	-$0.22	-$1.72



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Charts:
Ancillary Services Market

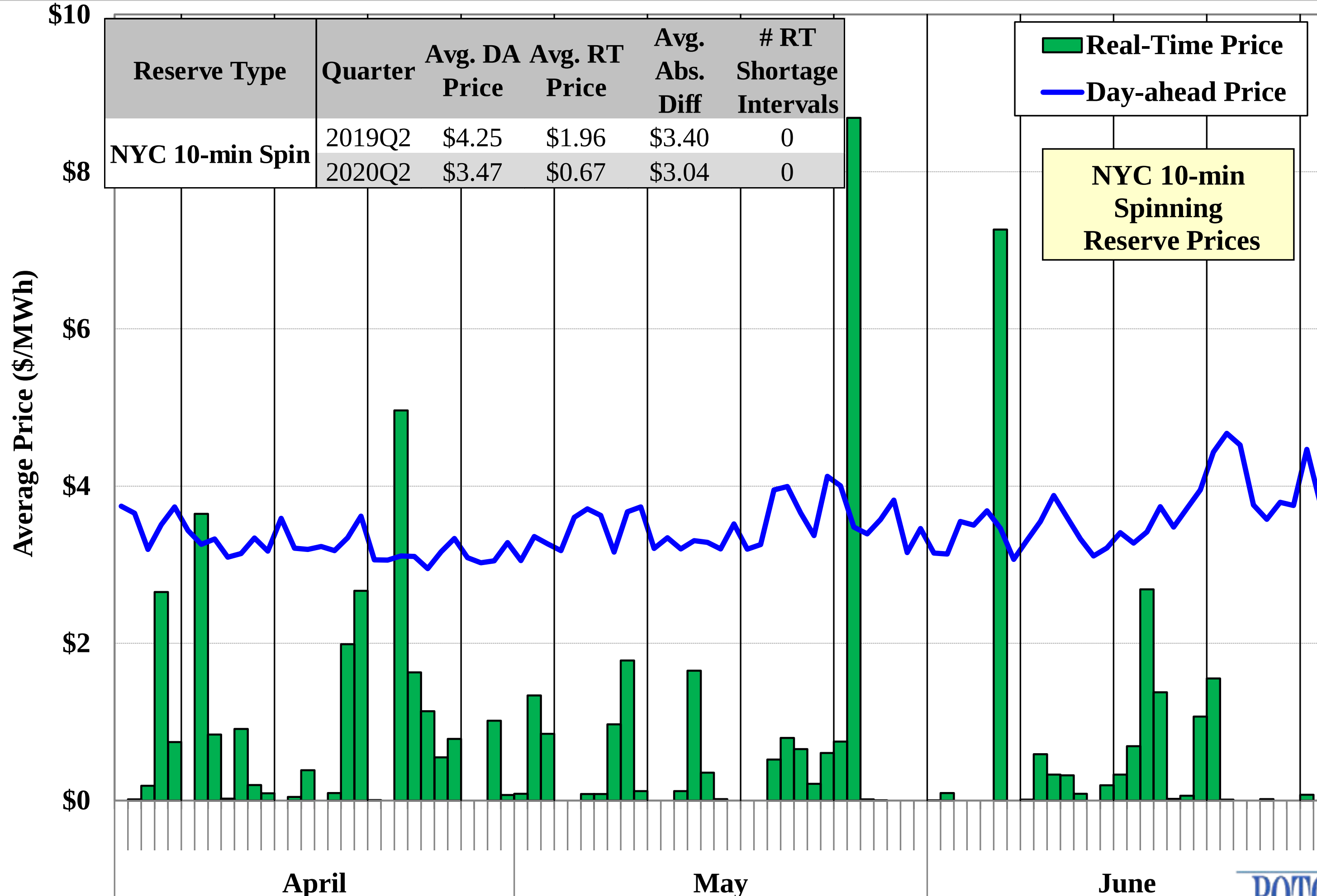
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Non-Spinning and 30-Minute Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2019Q2	$3.89	$0.56	$3.96	0
	2020Q2	$3.02	$0.06	$2.95	4
NYC 30-min	2019Q2	$3.74	$0.08	$3.71	0
	2020Q2	$2.99	$0.05	$2.94	0

Notes: For chart description, see slide 69.

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

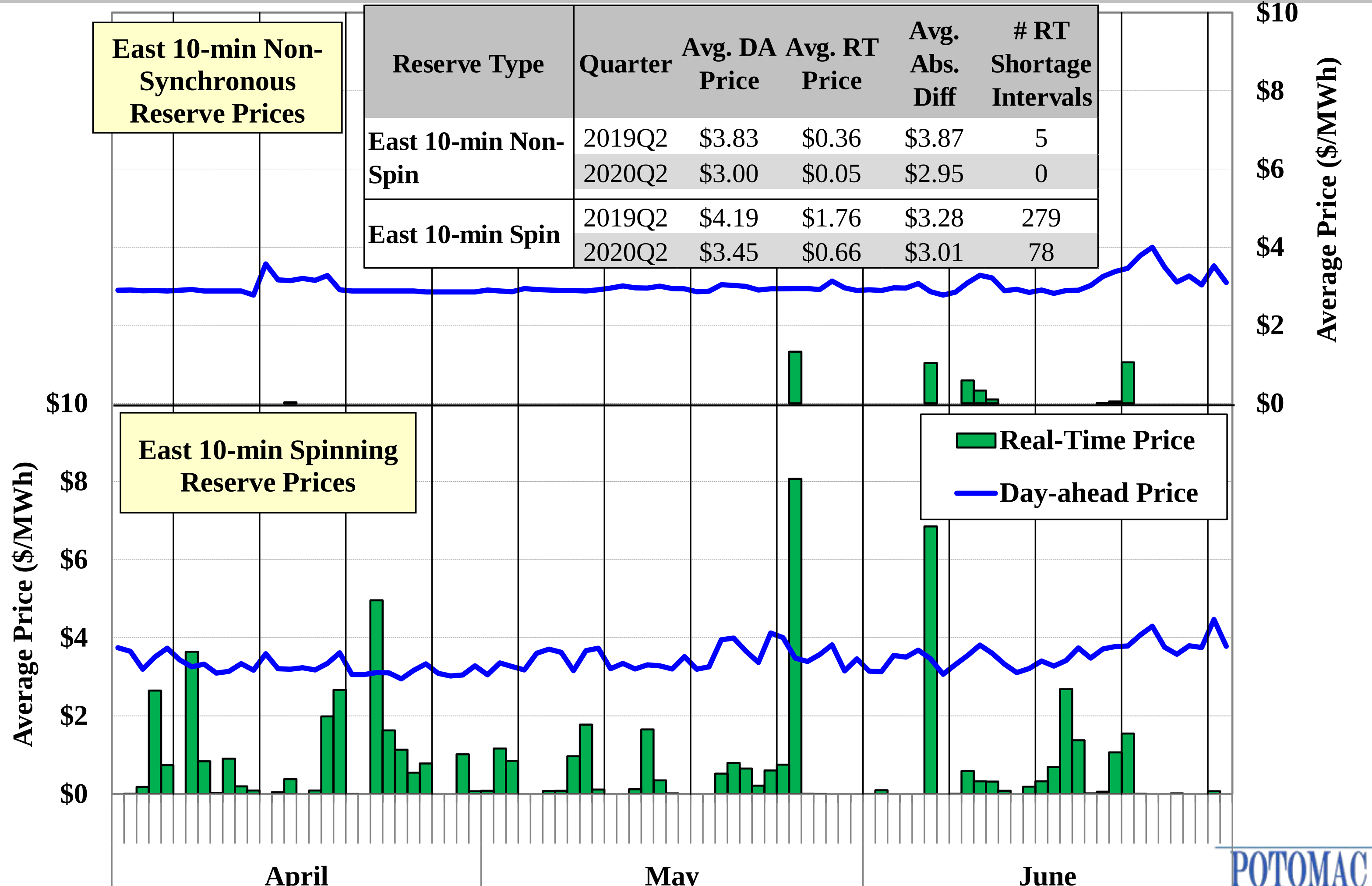
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2019Q2	$4.25	$1.96	$3.40	0
	2020Q2	$3.47	$0.67	$3.04	0



Notes: For chart description, see slide 69.

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

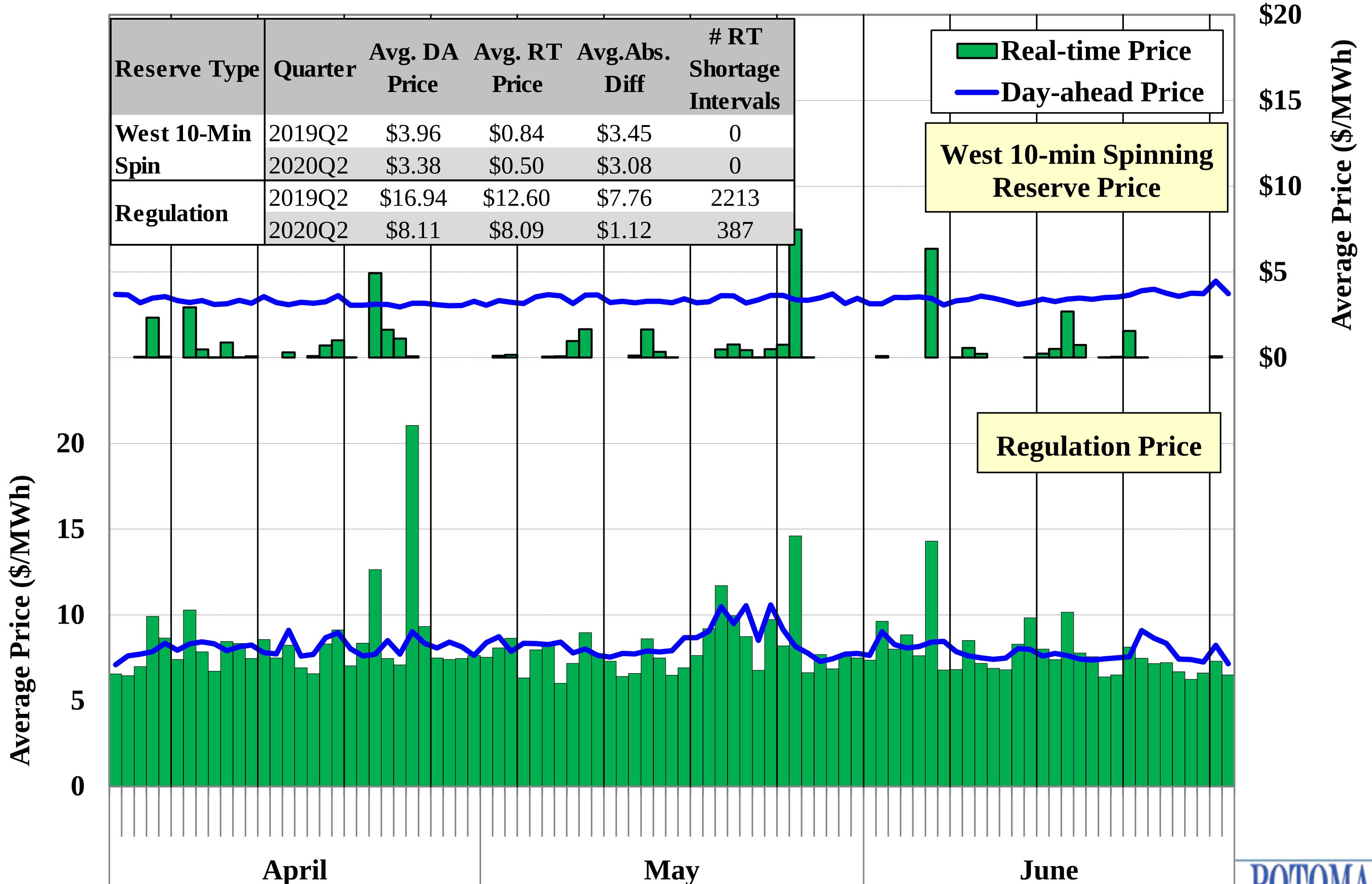
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2019Q2	$3.83	$0.36	$3.87	5
	2020Q2	$3.00	$0.05	$2.95	0
East 10-min Spin	2019Q2	$4.19	$1.76	$3.28	279
	2020Q2	$3.45	$0.66	$3.01	78



Notes: For chart description, see slide 69.

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

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
West 10-Min Spin	2019Q2	$3.96	$0.84	$3.45	0
	2020Q2	$3.38	$0.50	$3.08	0
Regulation	2019Q2	$16.94	$12.60	$7.76	2213
	2020Q2	$8.11	$8.09	$1.12	387



Notes: For chart description, see slide 69.

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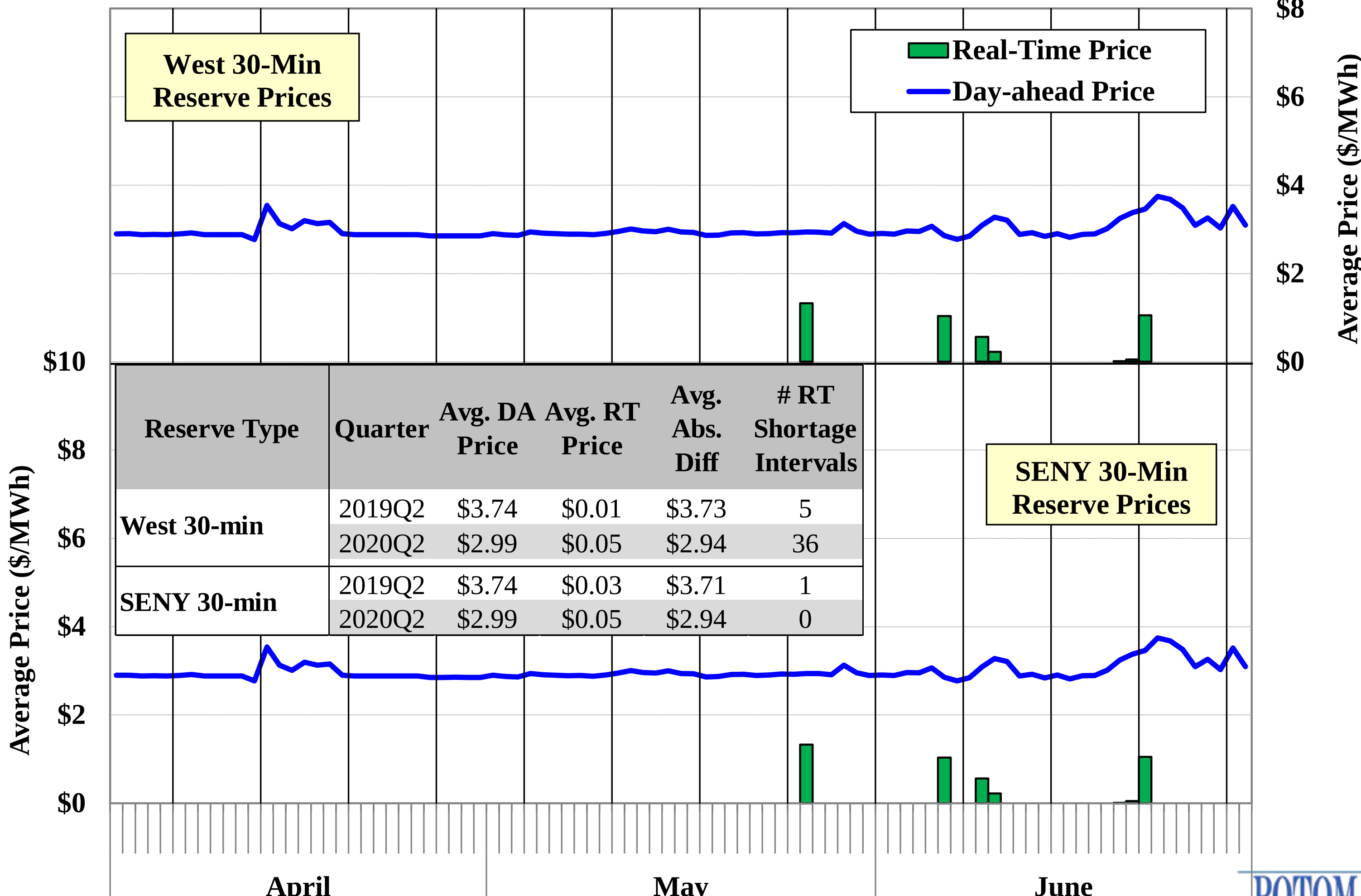
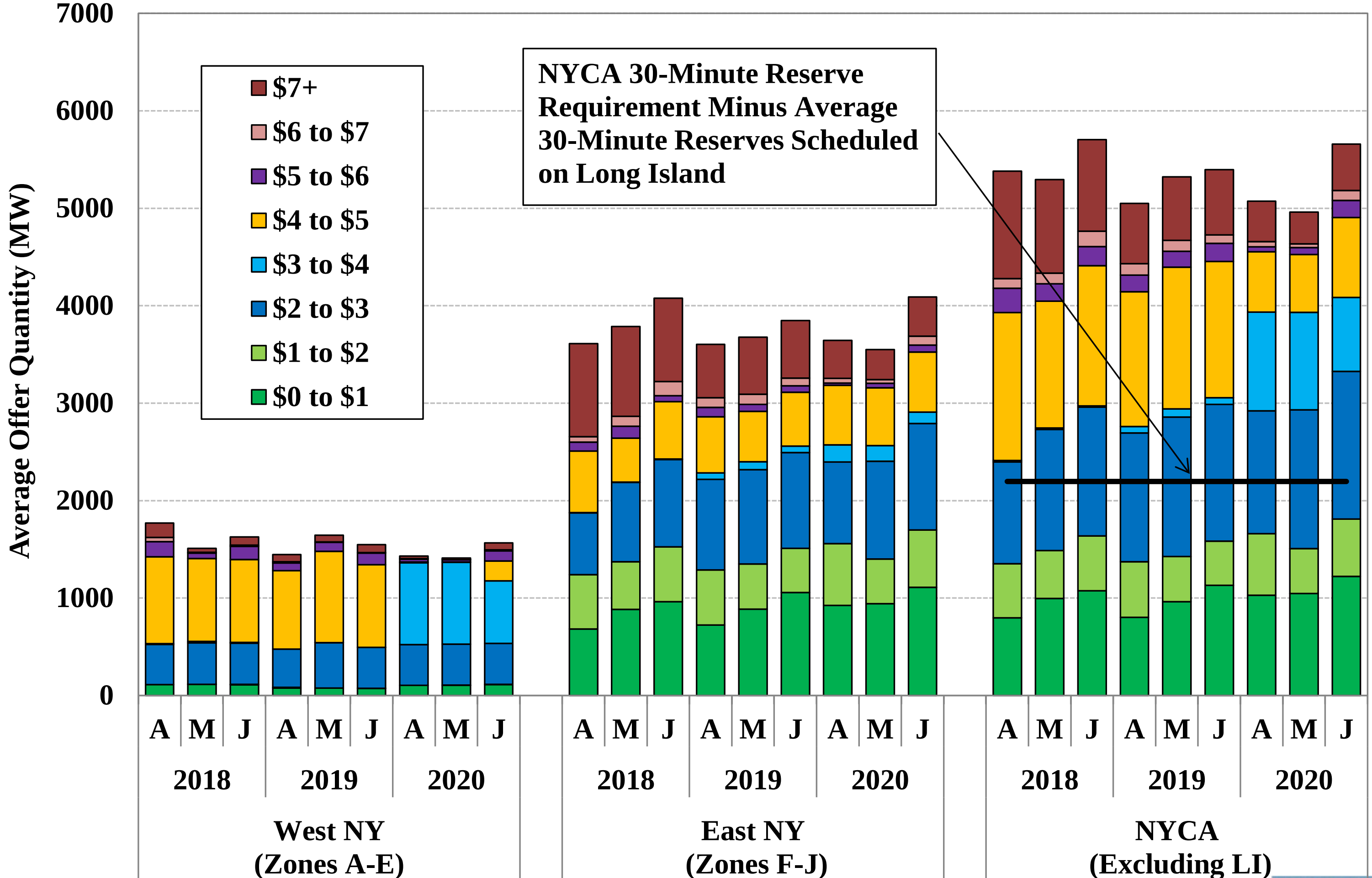
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2019Q2	$3.74	$0.01	$3.73	5
	2020Q2	$2.99	$0.05	$2.94	36
SENY 30-min	2019Q2	$3.74	$0.03	$3.71	1
	2020Q2	$2.99	$0.05	$2.94	0

Notes: For chart description, see slide 69.

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



Notes: For chart description, see slide 70.

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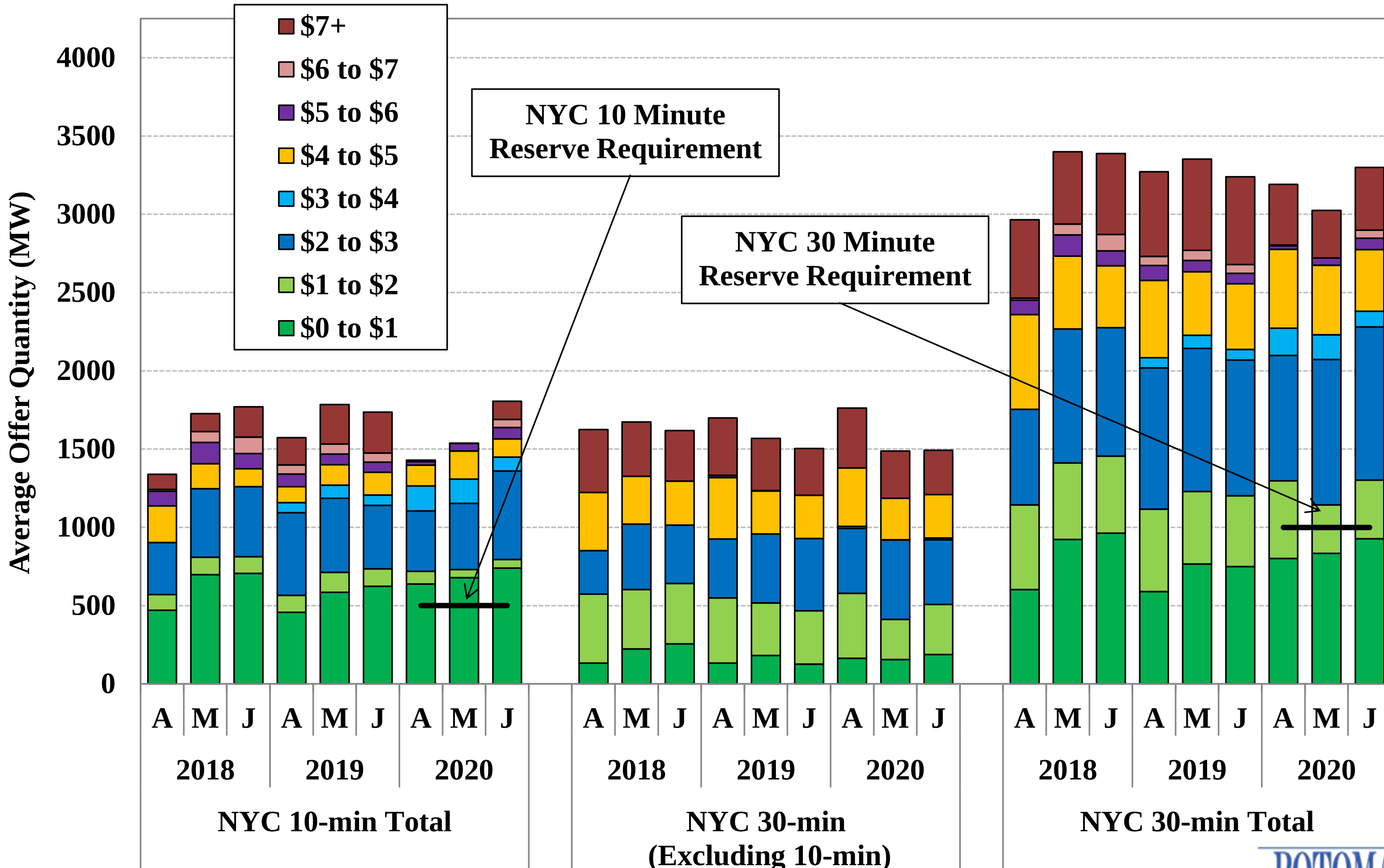
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



  Notes: For chart description, see slide 70.

Charts:

Energy Market Scheduling

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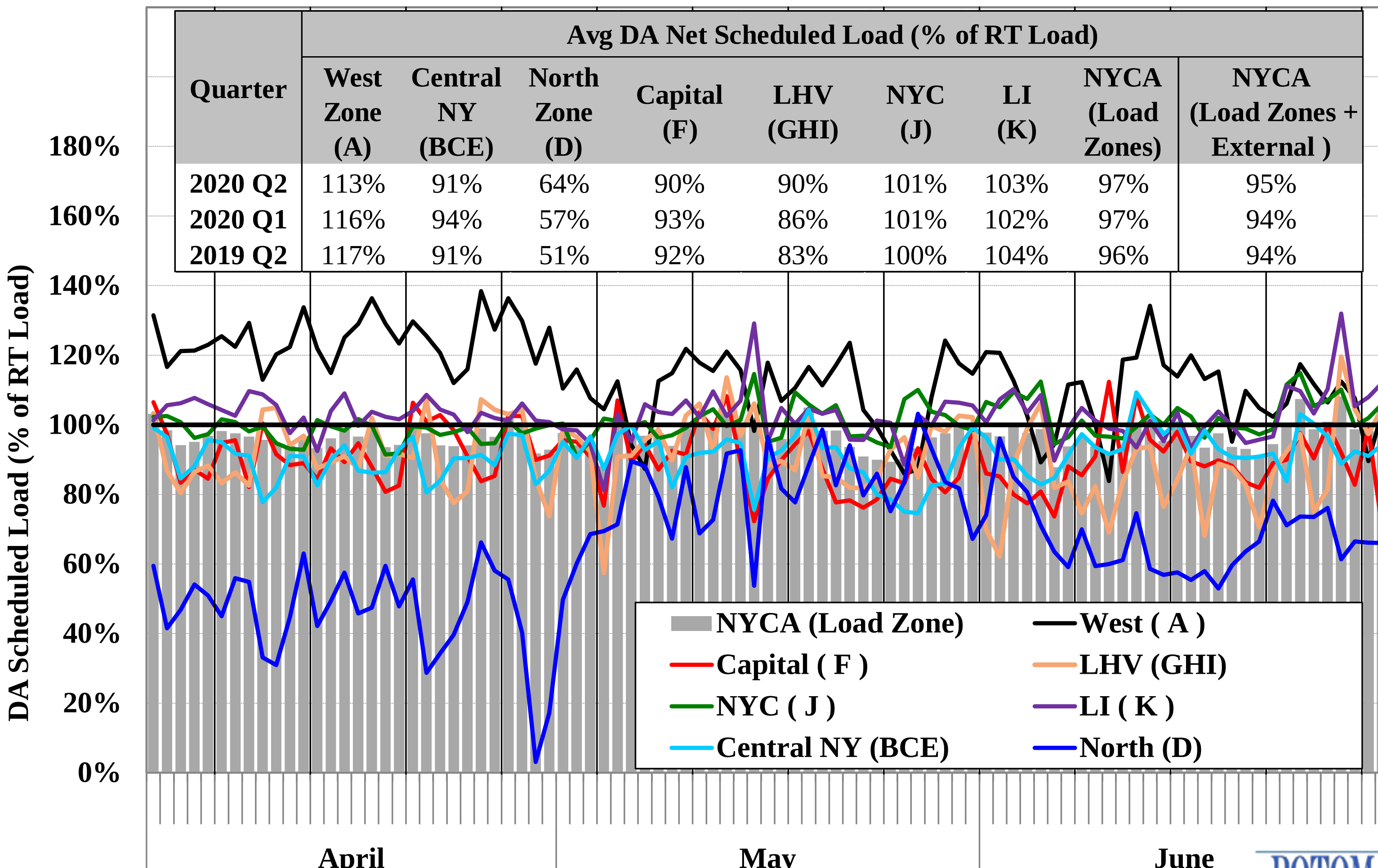
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour



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)
2020 Q2	113%	91%	64%	90%	90%	101%	103%	97%	95%
2020 Q1	116%	94%	57%	93%	86%	101%	102%	97%	94%
2019 Q2	117%	91%	51%	92%	83%	100%	104%	96%	94%

Notes: For chart description, see slide 71.

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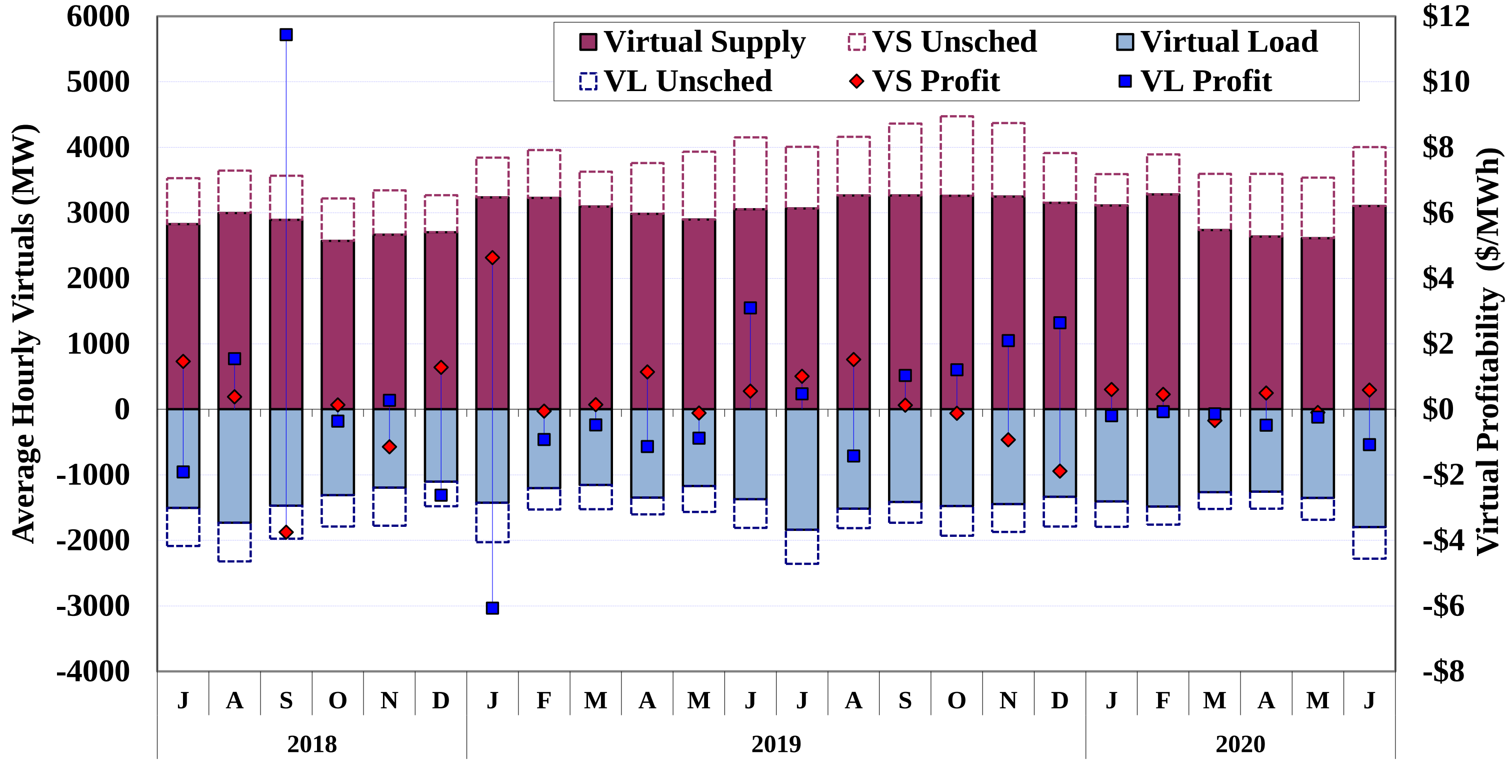
Virtual Trading Activity
by Month



		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	320	299	437	366	312	326	612	279	167	473	477	587	384	396	249	312	290	274	421	322	232	370	388	464
	%	7%	6%	10%	9%	8%	9%	13%	6%	4%	11%	12%	13%	8%	8%	5%	7%	6%	6%	9%	7%	6%	10%	10%	9%
Loss > 50% of Avg. Zone Price	MW	329	328	428	430	345	317	439	331	178	348	591	548	372	321	293	376	344	305	338	253	321	298	404	460
	%	8%	7%	10%	11%	9%	8%	9%	7%	4%	8%	15%	12%	8%	7%	6%	8%	7%	7%	7%	5%	8%	8%	10%	9%

Notes: For chart description, see slide 71.

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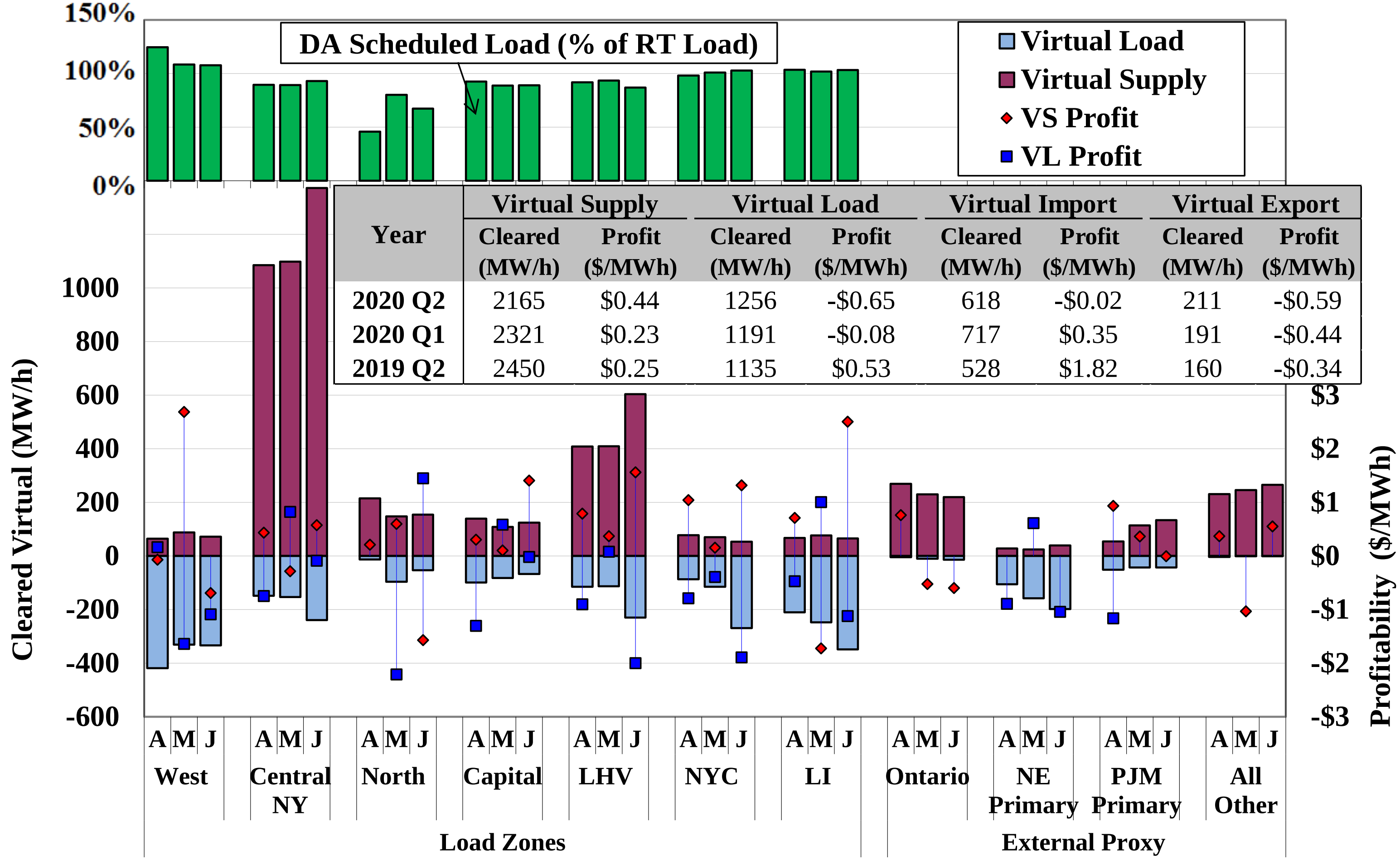
Virtual Trading Activity by Location

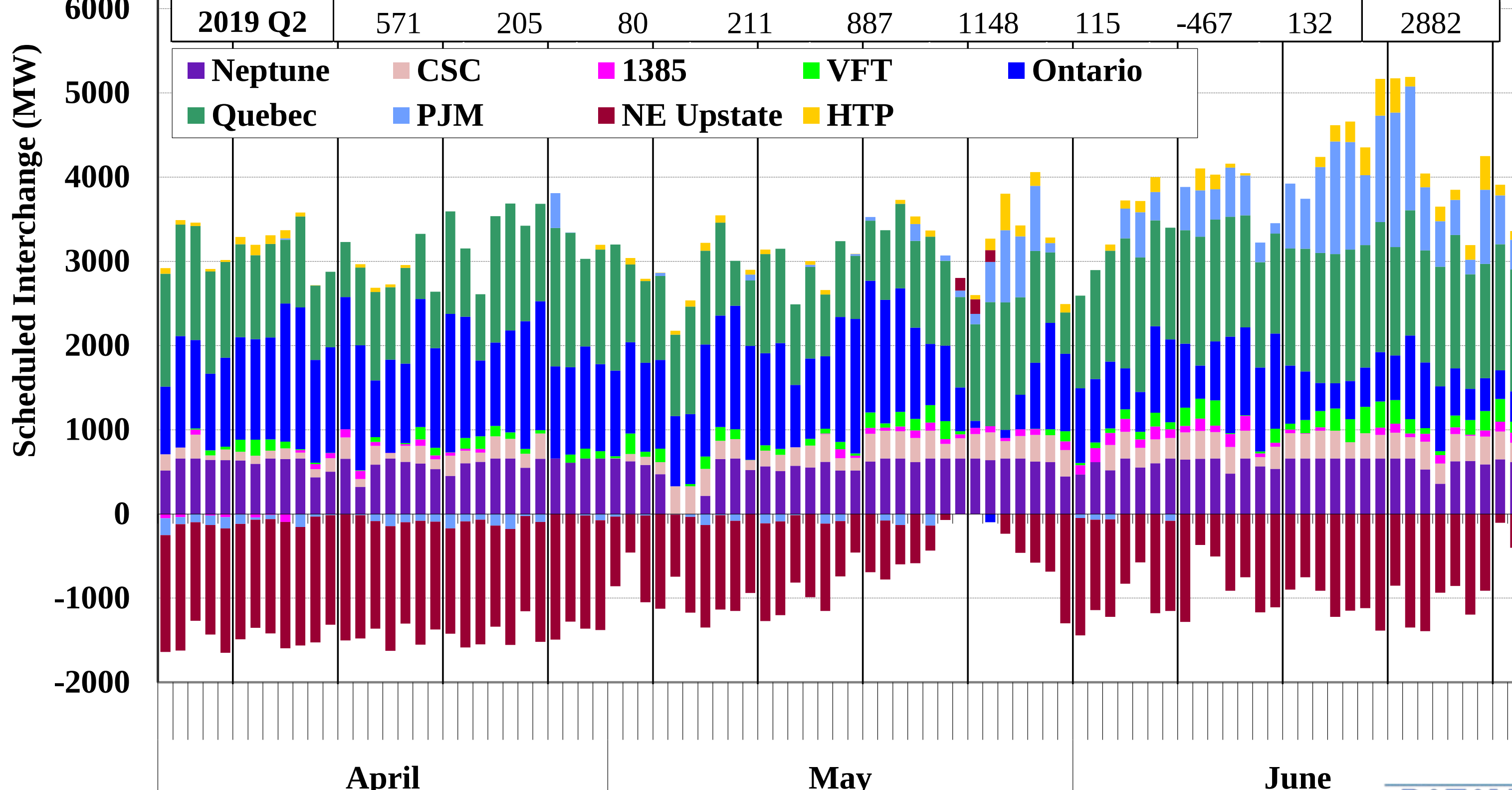


Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2020 Q2	2165	$0.44	1256	-$0.65	618	-$0.02	211	-$0.59
2020 Q1	2321	$0.23	1191	-$0.08	717	$0.35	191	-$0.44
2019 Q2	2450	$0.25	1135	$0.53	528	$1.82	160	-$0.34

Notes: 1. Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.
2. For chart description, see slide 71.

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
2020 Q2	585	215	44	99	959	1175	200	-1003	76	2351
2020 Q1	596	112	30	163	770	1309	117	-1065	194	2226
2019 Q2	571	205	80	211	887	1148	115	-467	132	2882



Notes: Two Quebec interfaces are combined into one.

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

			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			75%	2%	**77%**	22%	3%	**24%**
Average Flow Adjustment (MW)	Net Imports		14	45	**15**	-2	-18	**-4**
	Gross		113	122	**113**	60	108	**65**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.6	$0.1	**$0.6**	$0.1	$0.2	**$0.3**
	Net Over-Projection by:	NY	$0.0	-$0.1	**-$0.1**	$0.0	-$0.2	**-$0.2**
		NE or PJM	$0.0	$0.0	**$0.0**	$0.0	-$0.1	**-$0.1**
	Other Unrealized Savings		$0.0	$0.0	**$0.0**	$0.0	$0.0	**$0.0**
	Actual Savings		$0.6	$0.0	**$0.6**	$0.0	$0.0	**$0.0**
Interface Prices ($/MWh)	NY	Actual	$15.30	$38.24	**$15.77**	$14.95	$33.61	**$17.03**
		Forecast	$17.13	$24.43	**$17.28**	$18.06	$38.34	**$20.32**
	NE or PJM	Actual	$16.68	$29.56	**$16.95**	$16.59	$34.07	**$18.54**
		Forecast	$15.95	$22.14	**$16.08**	$17.57	$37.83	**$19.83**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.83	-$13.81	**$1.50**	$3.11	$4.73	**$3.29**
		Abs. Val.	$2.85	$35.78	**$3.53**	$4.37	$29.92	**$7.22**
	NE or PJM	Fcst. - Act.	-$0.72	-$7.42	**-$0.86**	$0.98	$3.76	**$1.29**
		Abs. Val.	$2.34	$15.59	**$2.62**	$2.50	$27.83	**$5.32**

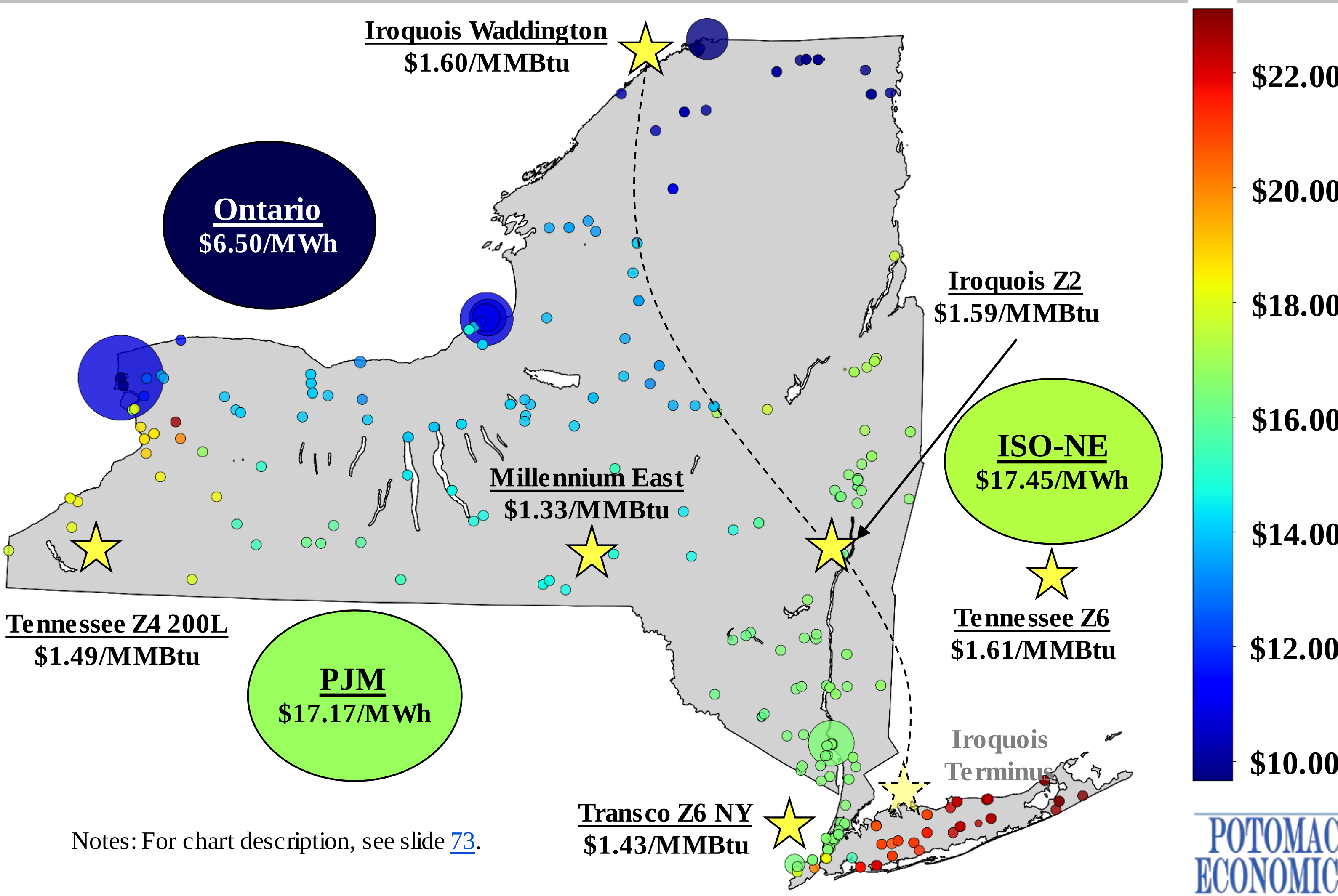
Notes: For chart description, see slide 72.

Charts:

Transmission Congestion Revenues and Shortfalls

POTOMAC ECONOMICS

System Congestion
Real-Time Price Map at Generator Nodes

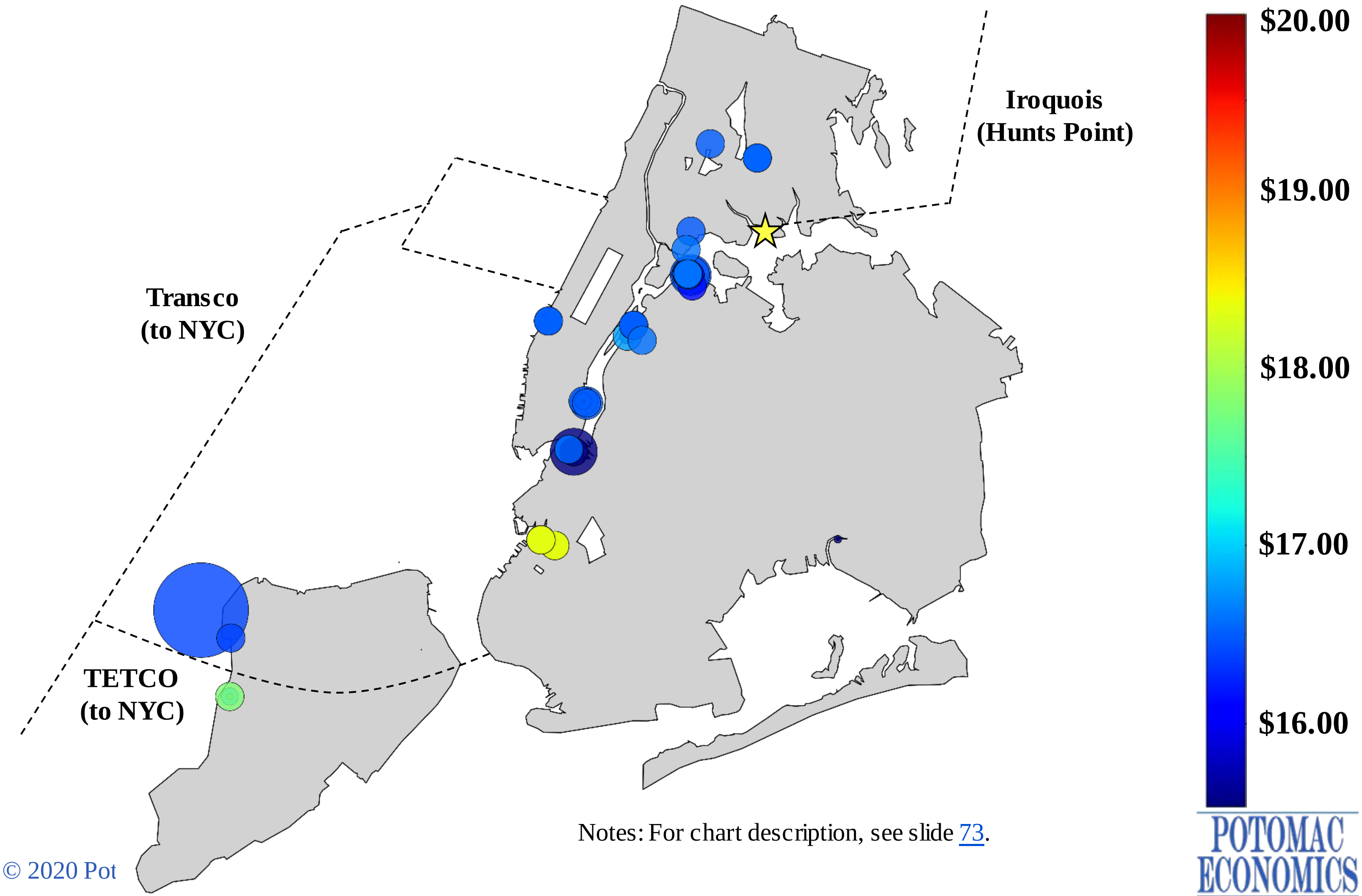


Notes: For chart description, see slide 73.

POTOMAC ECONOMICS

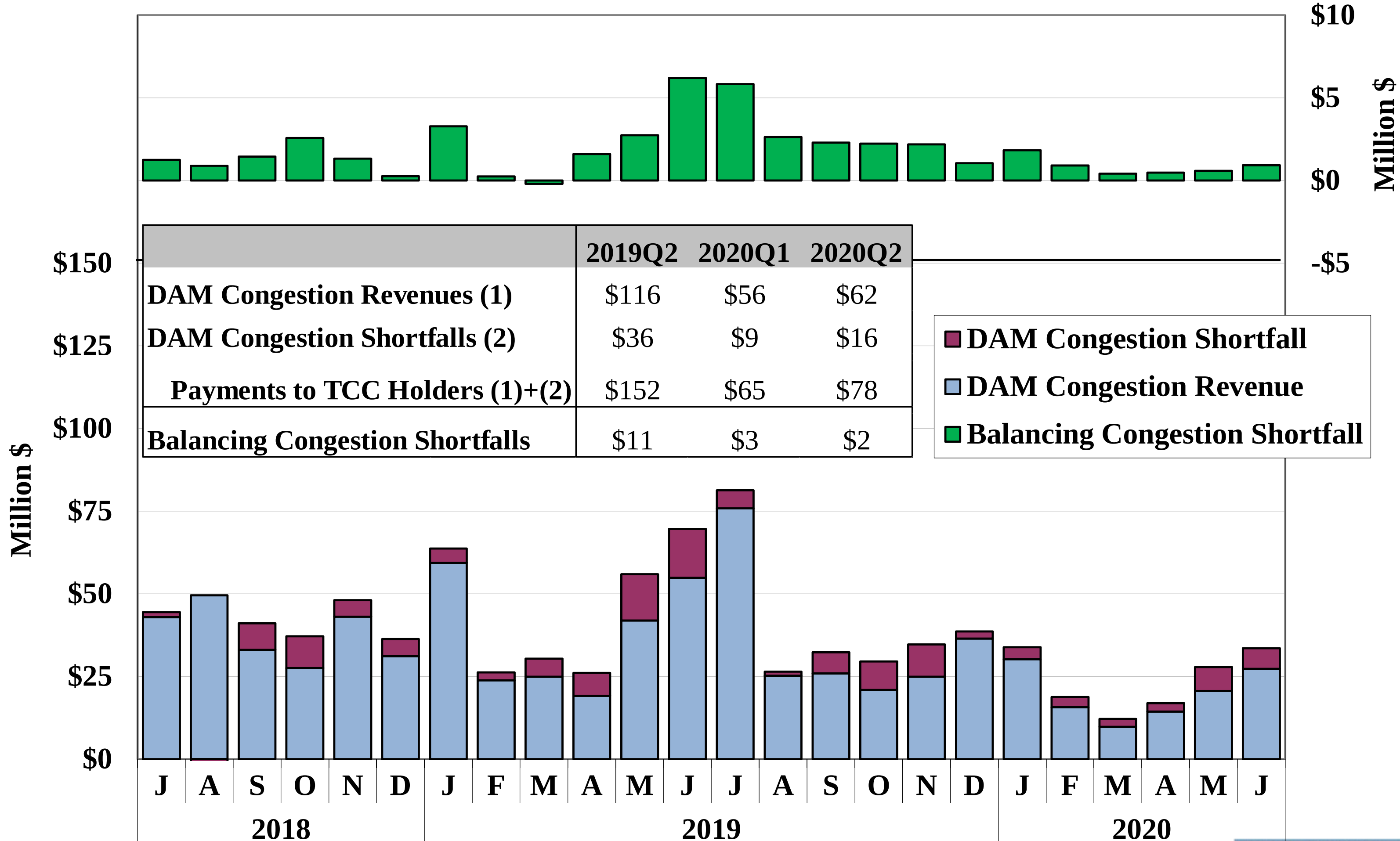
System Congestion

NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 73.

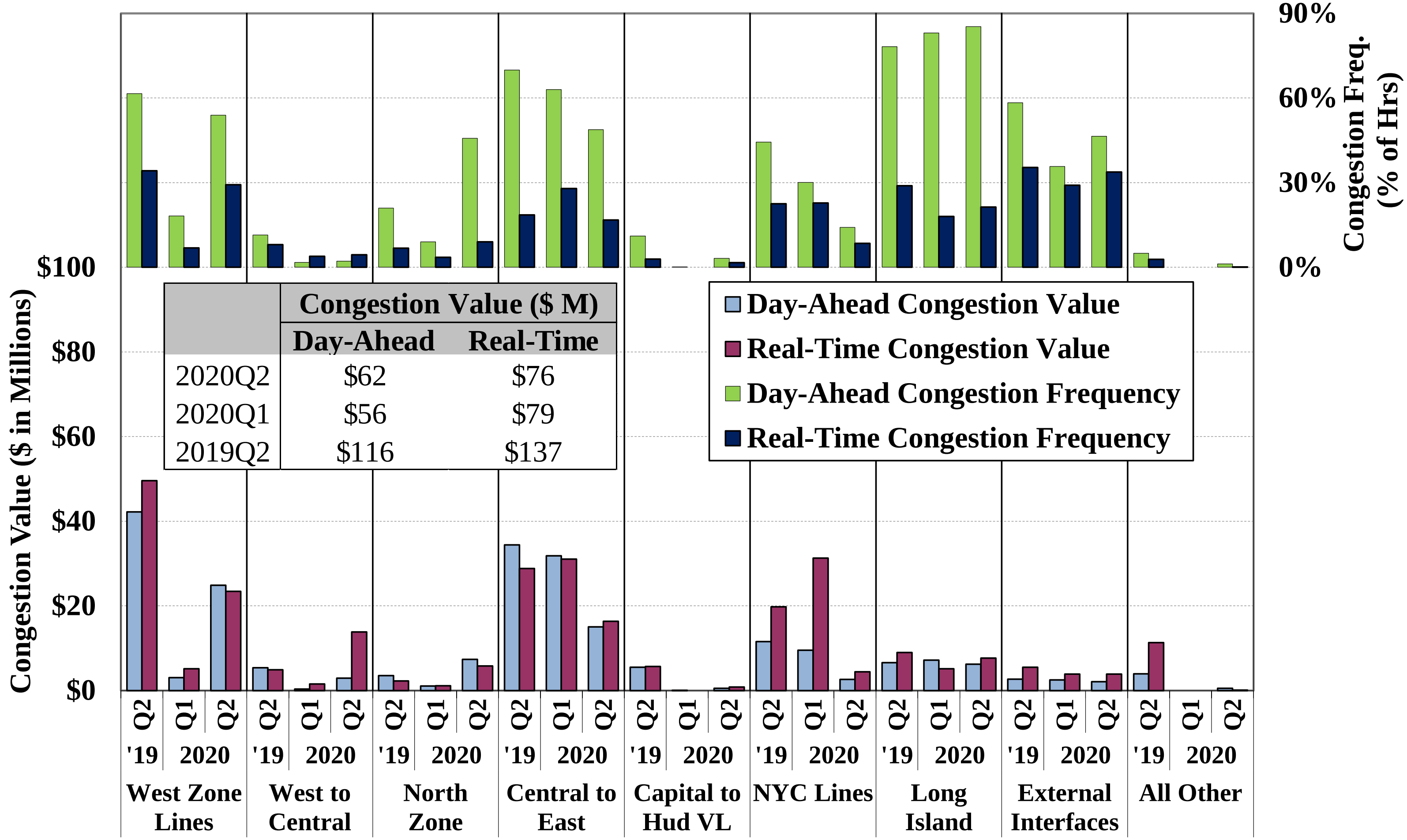
Congestion Revenues and Shortfalls by Month



	2019Q2	2020Q1	2020Q2
DAM Congestion Revenues (1)	$116	$56	$62
DAM Congestion Shortfalls (2)	$36	$9	$16
Payments to TCC Holders (1)+(2)	$152	$65	$78
Balancing Congestion Shortfalls	$11	$3	$2

Notes: For chart description, see slides 74 and 75.

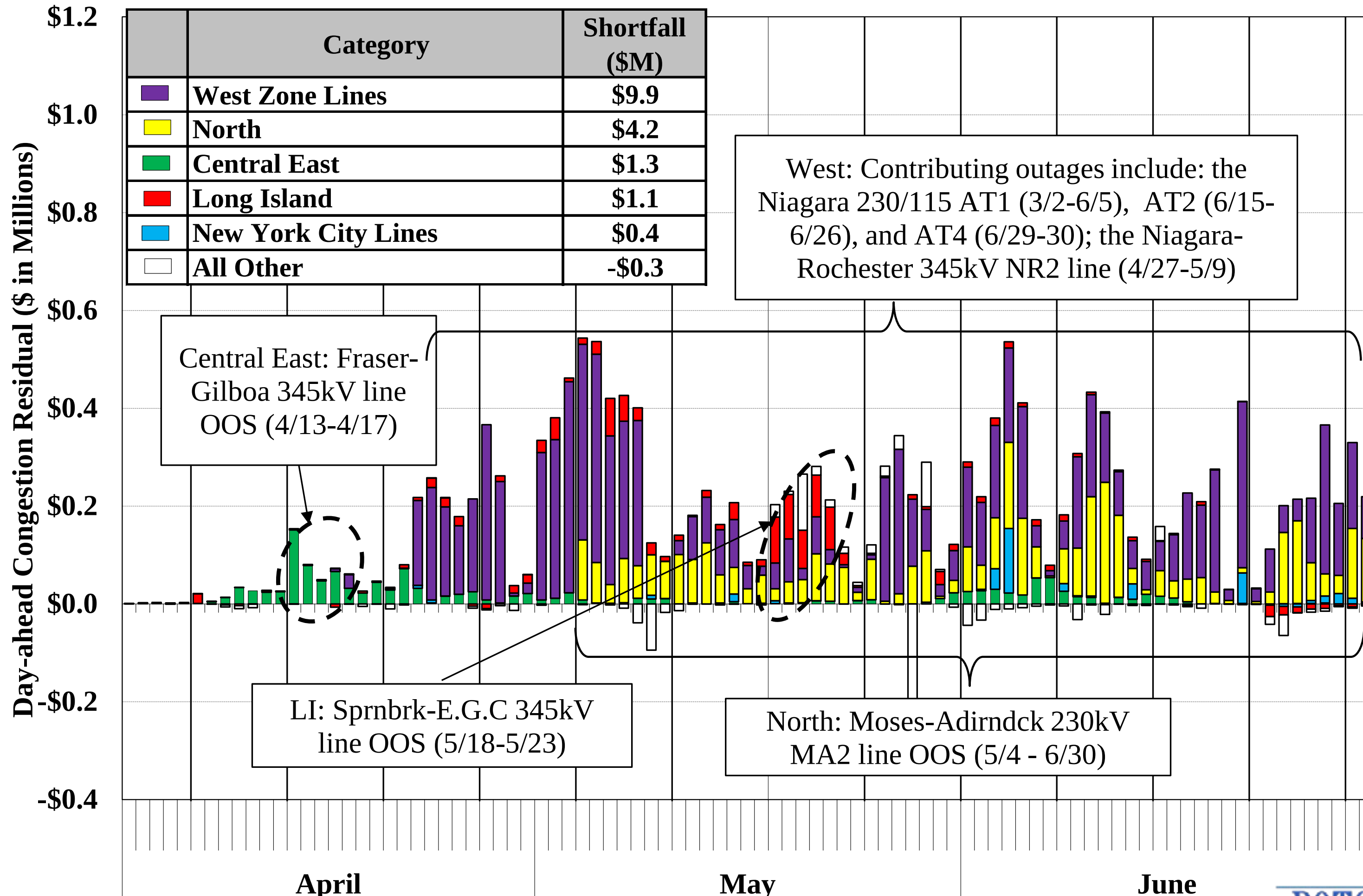
Day-Ahead and Real-Time Congestion Value
by Transmission Path



	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2020Q2	$62	$76
2020Q1	$56	$79
2019Q2	$116	$137

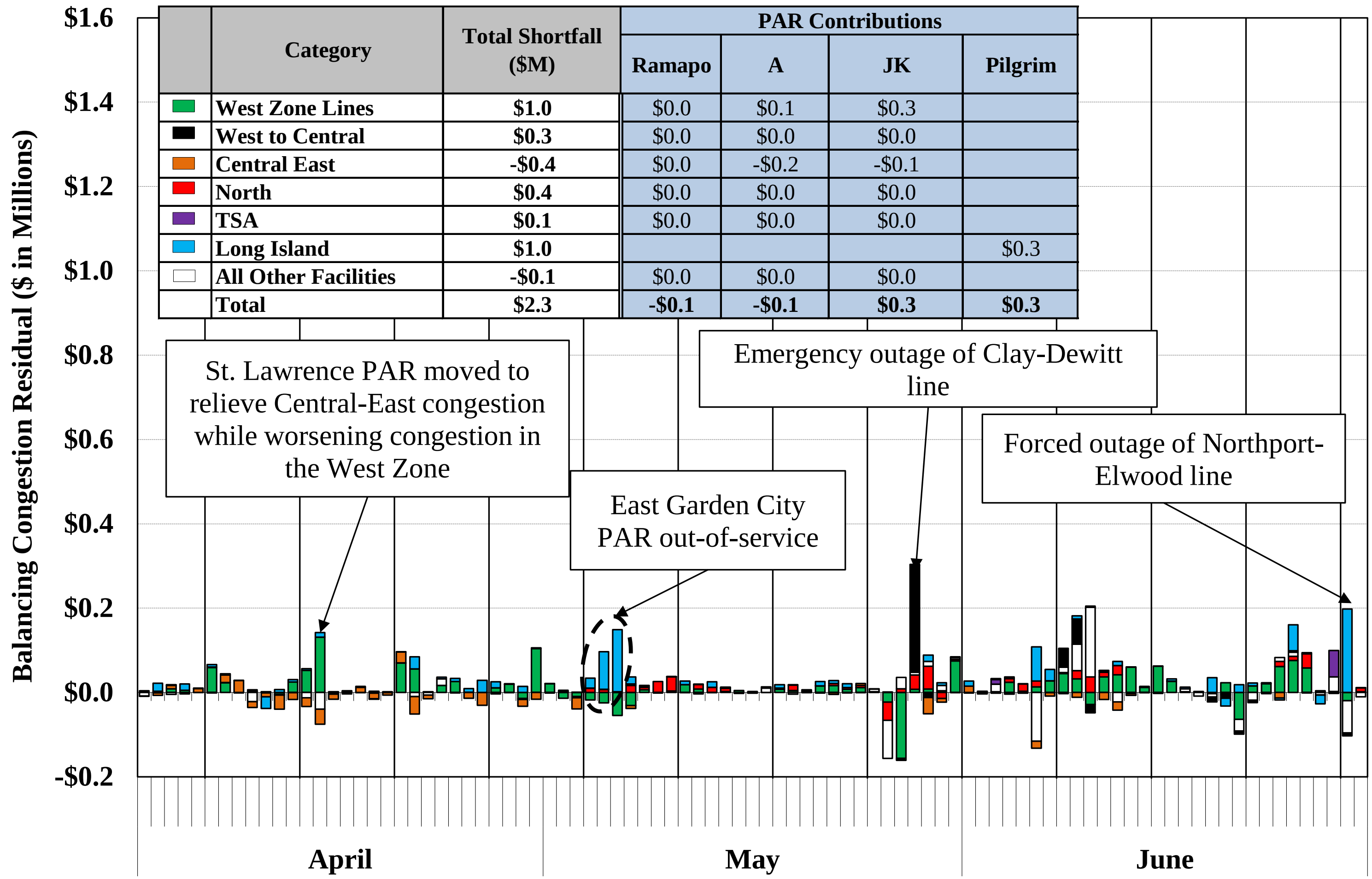
Notes: For chart description, see slides 74, 75, and 76.

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 74, 75, and 76.

Balancing Congestion Shortfalls by Transmission Facility

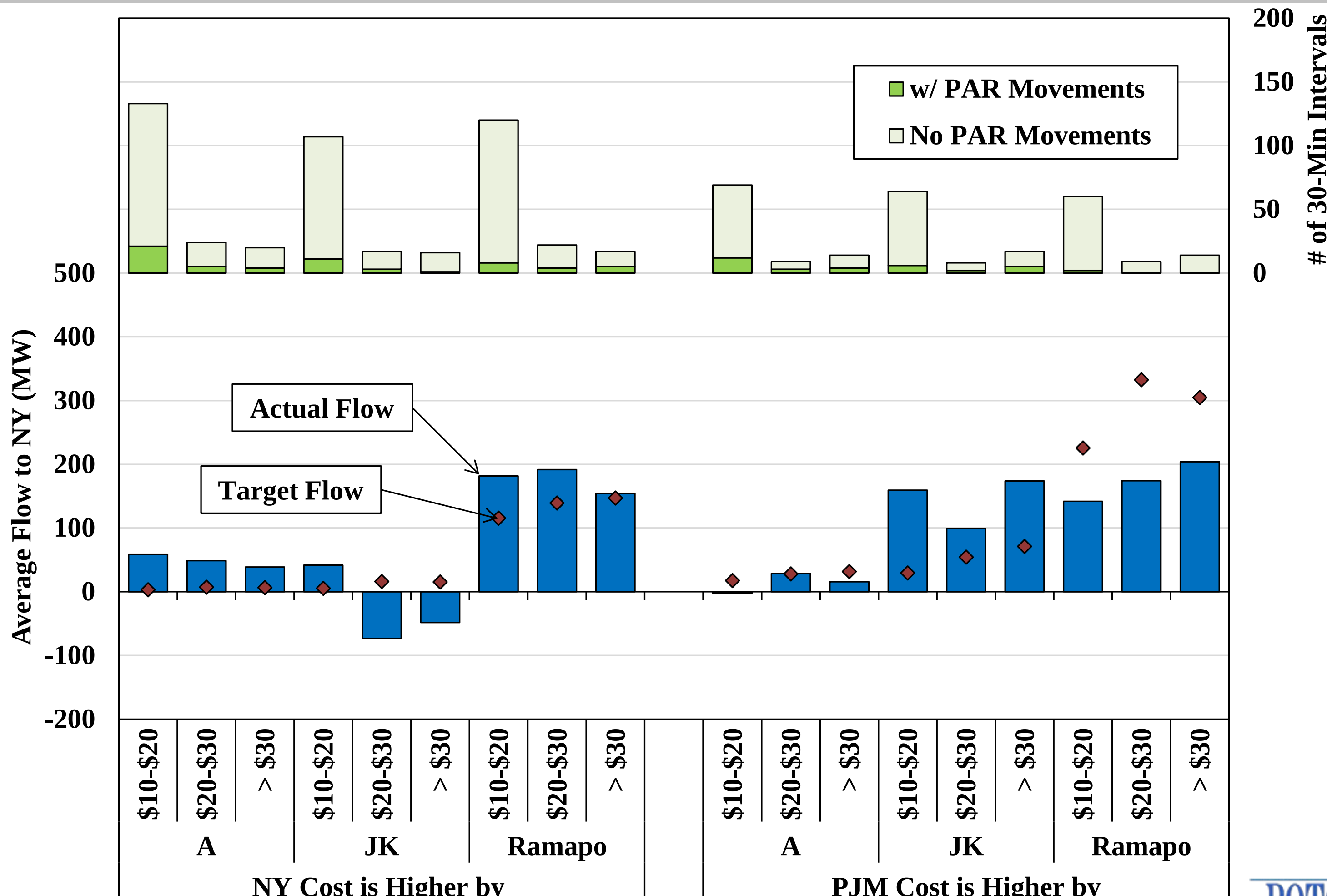


Category	Total Shortfall ($M)	PAR Contributions: Ramapo	A	JK	Pilgrim
West Zone Lines	$1.0	$0.0	$0.1	$0.3	
West to Central	$0.3	$0.0	$0.0	$0.0	
Central East	-$0.4	$0.0	-$0.2	-$0.1	
North	$0.4	$0.0	$0.0	$0.0	
TSA	$0.1	$0.0	$0.0	$0.0	
Long Island	$1.0				$0.3
All Other Facilities	-$0.1	$0.0	$0.0	$0.0	
Total	**$2.3**	**-$0.1**	**-$0.1**	**$0.3**	**$0.3**

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 74, 75, and 76.

POTOMAC ECONOMICS

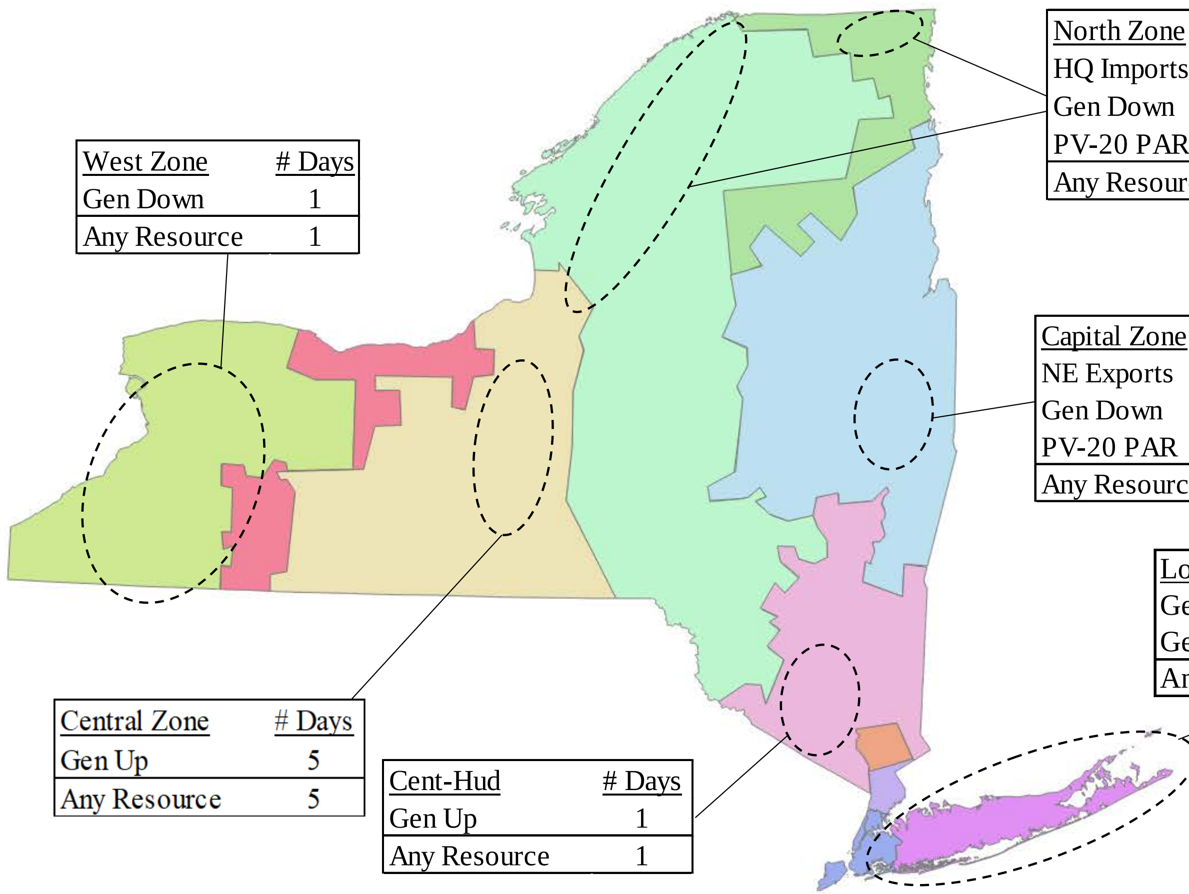
PAR Operation under M2M with PJM
2020 Q2



  Notes: For chart description, see slide 77.

POTOMAC ECONOMICS

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



North Zone	# Days
HQ Imports	1
Gen Down	5
PV-20 PAR	1
Any Resource	7

West Zone	# Days
Gen Down	1
Any Resource	1

Capital Zone	# Days
NE Exports	1
Gen Down	3
PV-20 PAR	1
Any Resource	4

Long Is 69kV	# Days
Gen Up	34
Gen Down	1
Any Resource	34

Central Zone	# Days
Gen Up	5
Any Resource	5

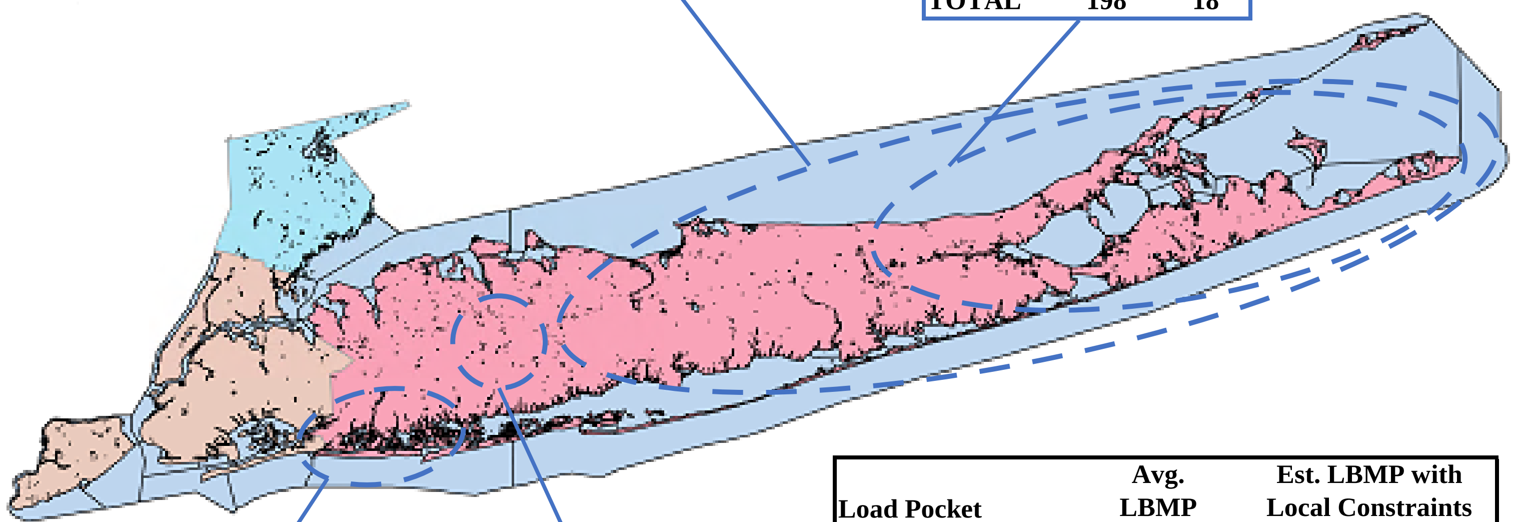
Cent-Hud	# Days
Gen Up	1
Any Resource	1

Notes: For chart description, see slides 78-79

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV	127	13
138kV	162	39
TOTAL	288	46

East End	#Hours	#Days
69kV	60	7
138kV	0	0
TVR	156	14
TOTAL	198	18



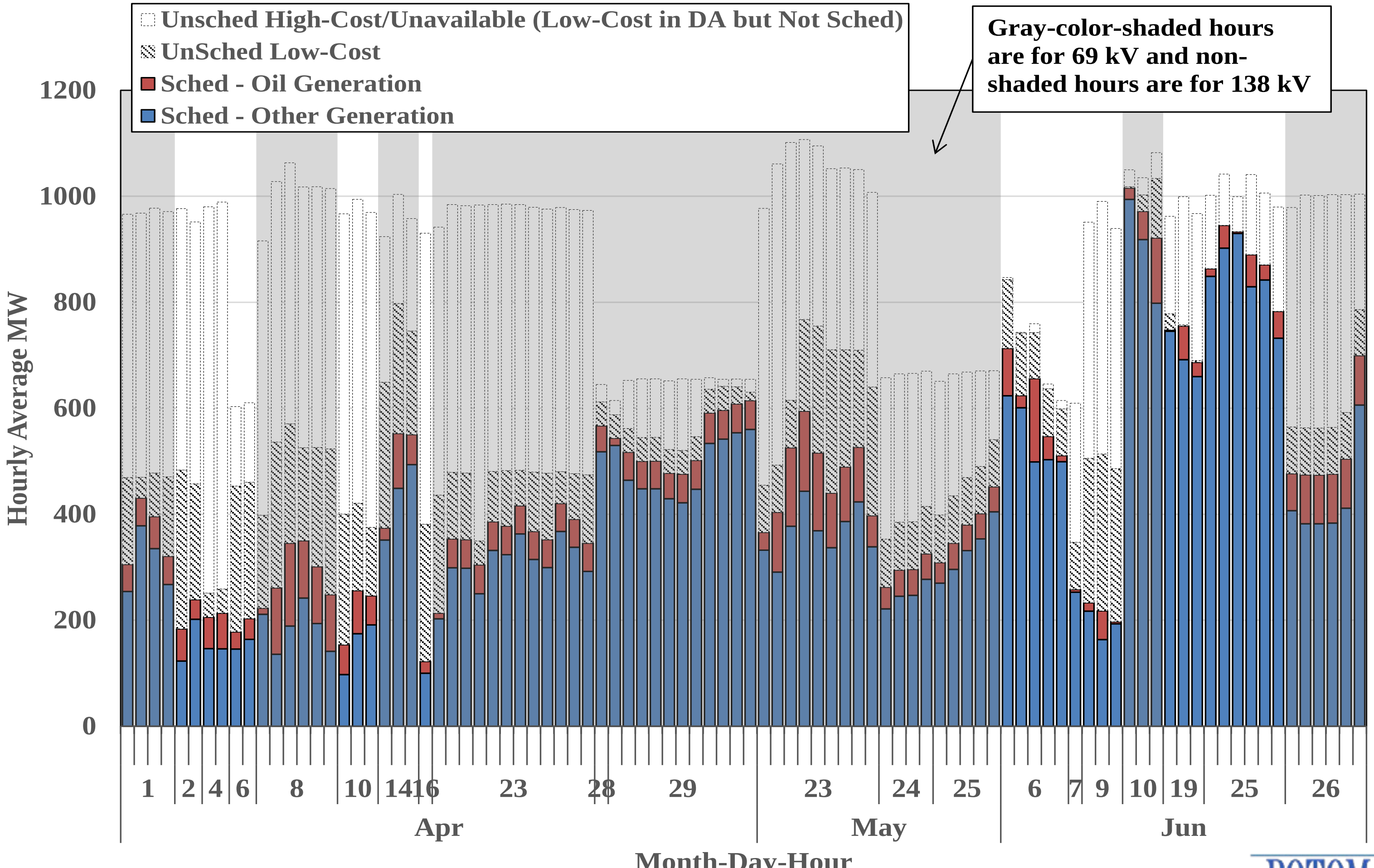
Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$20.34	$20.43
East End	$21.67	$33.48
East of Northport	$21.08	$23.67
Valley Stream	$20.64	$22.92

Brentwood	#Hours	#Days
69kV	22	6
138kV	0	0
TOTAL	22	6

Valley Stream	#Hours	#Days
69kV	116	7
138kV	1458	91
TOTAL	1531	91

Notes: For chart description, see slides 78-79

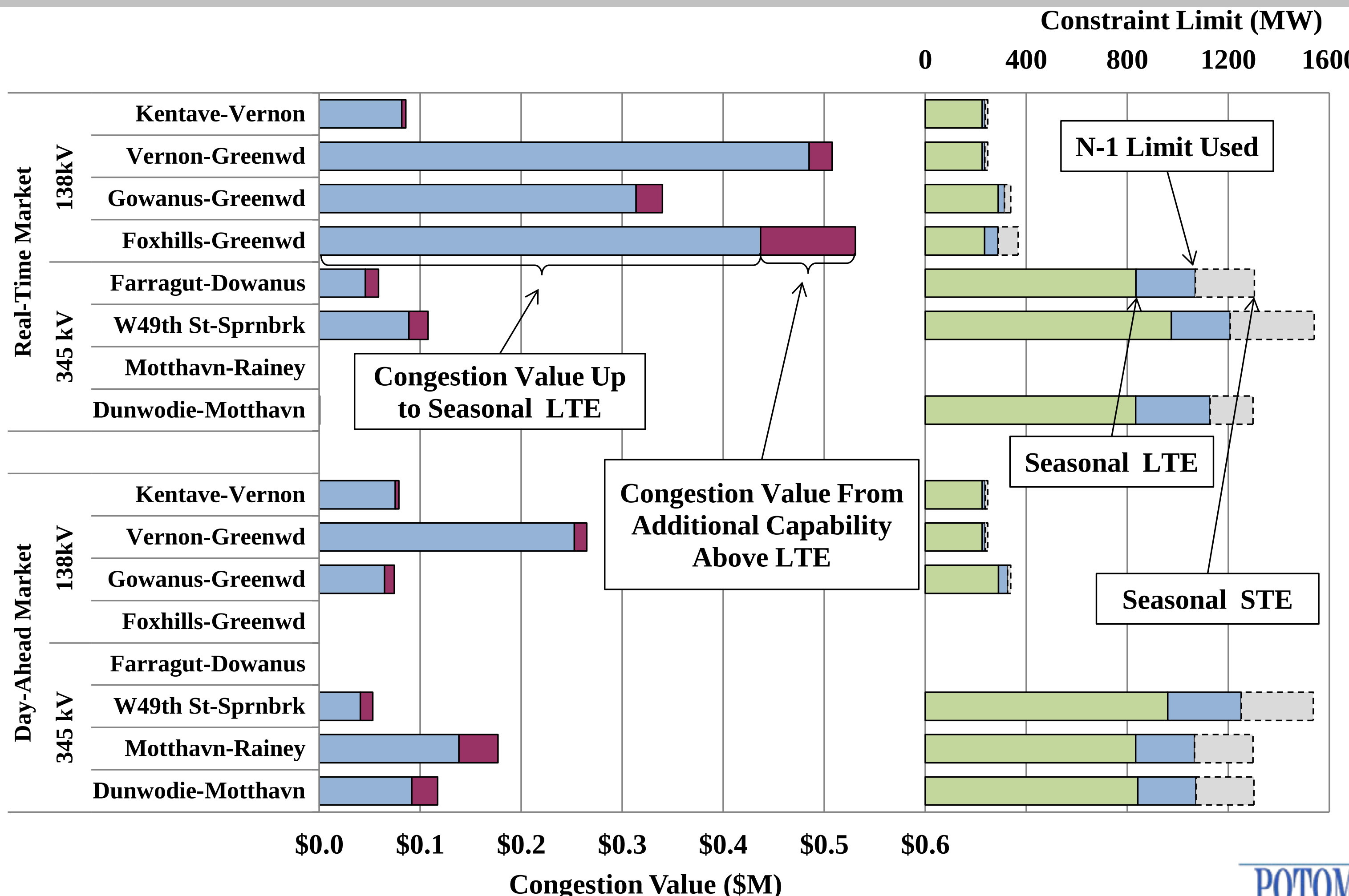
Use of Oil-Fired Generation to Manage Congestion
East of Northport on Long Island



Notes: For chart description, see slide 80

POTOMAC ECONOMICS

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

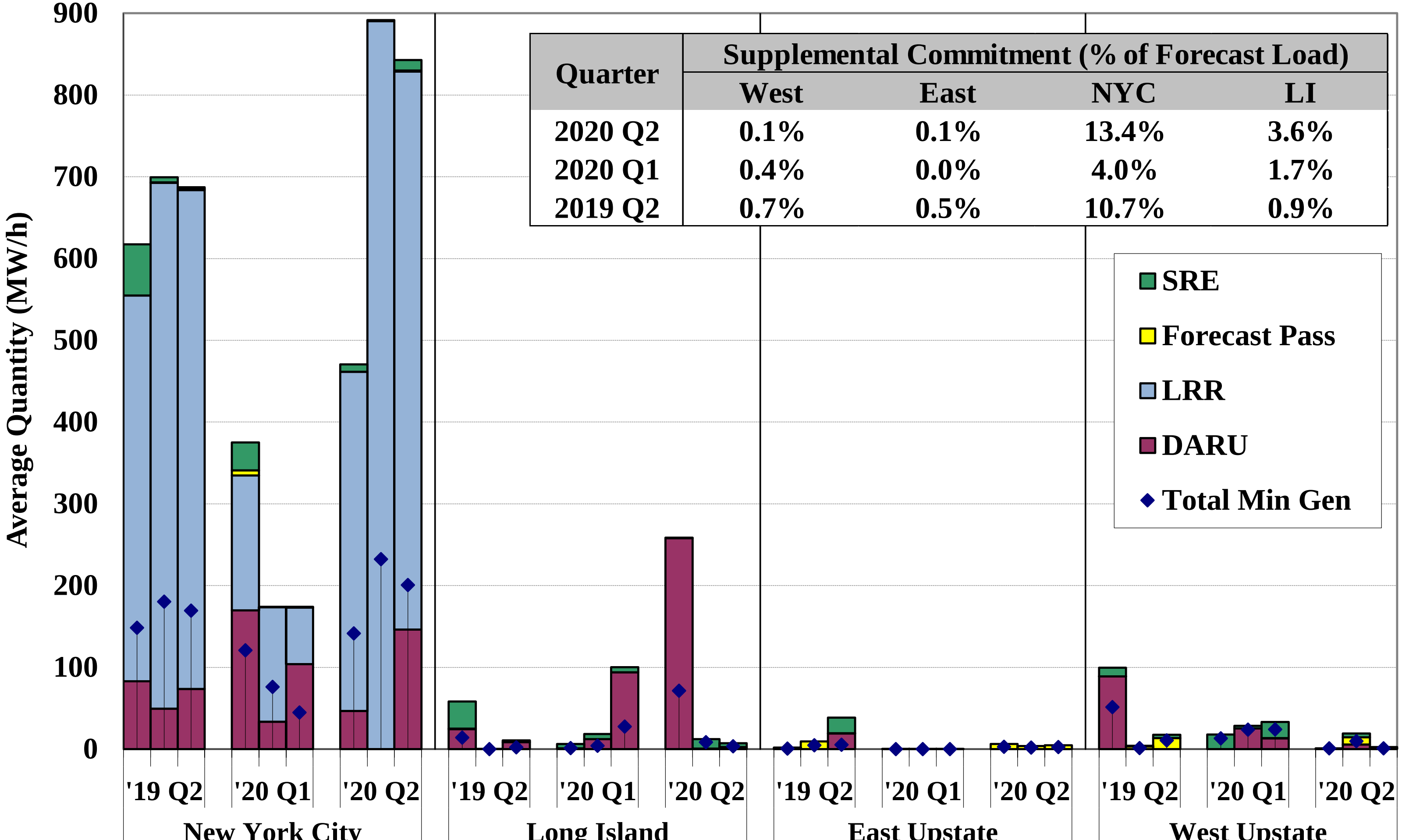


Notes: For chart description, see slide 81.

Charts:
Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

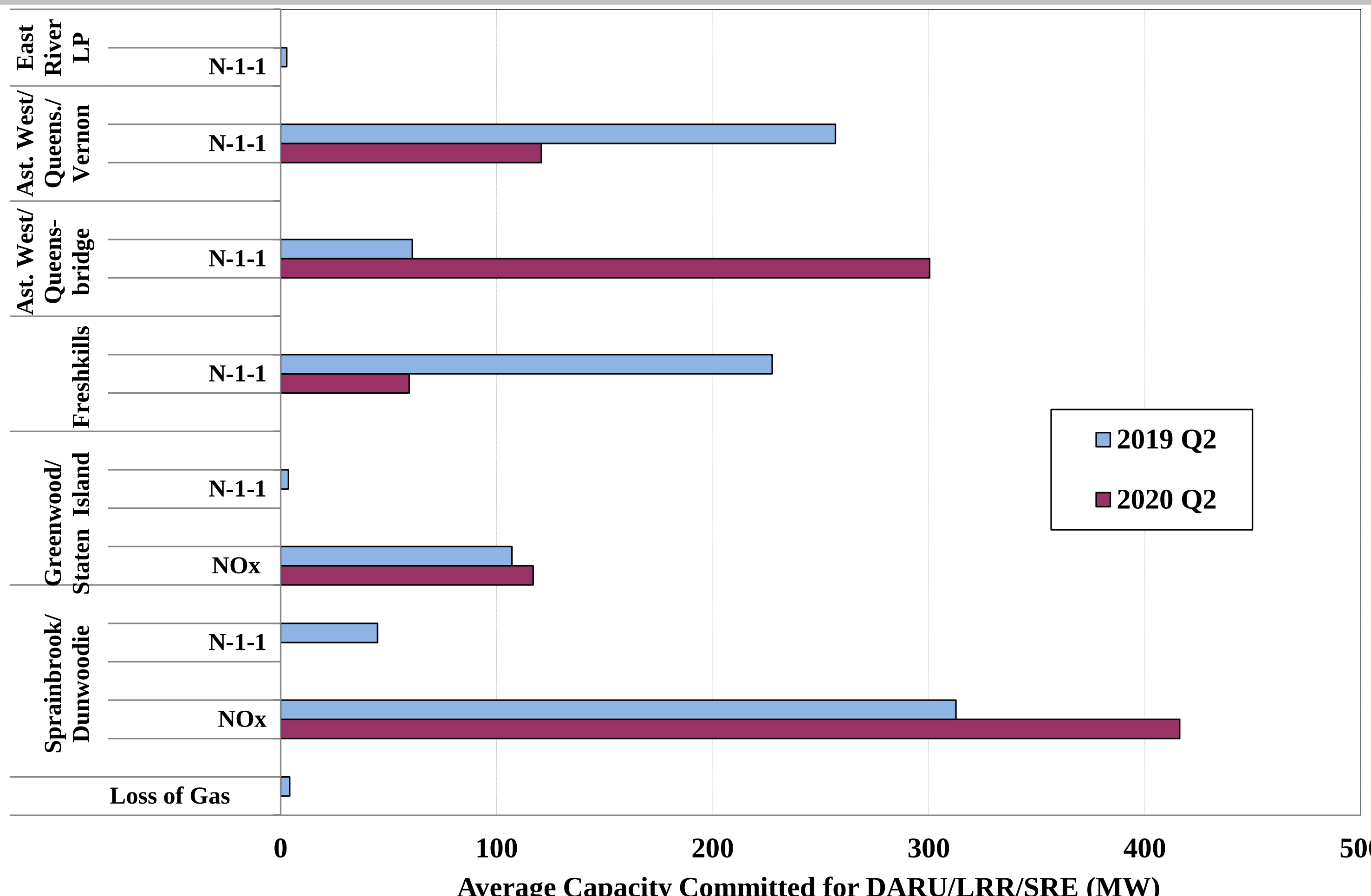
Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2020 Q2	0.1%	0.1%	13.4%	3.6%
2020 Q1	0.4%	0.0%	4.0%	1.7%
2019 Q2	0.7%	0.5%	10.7%	0.9%

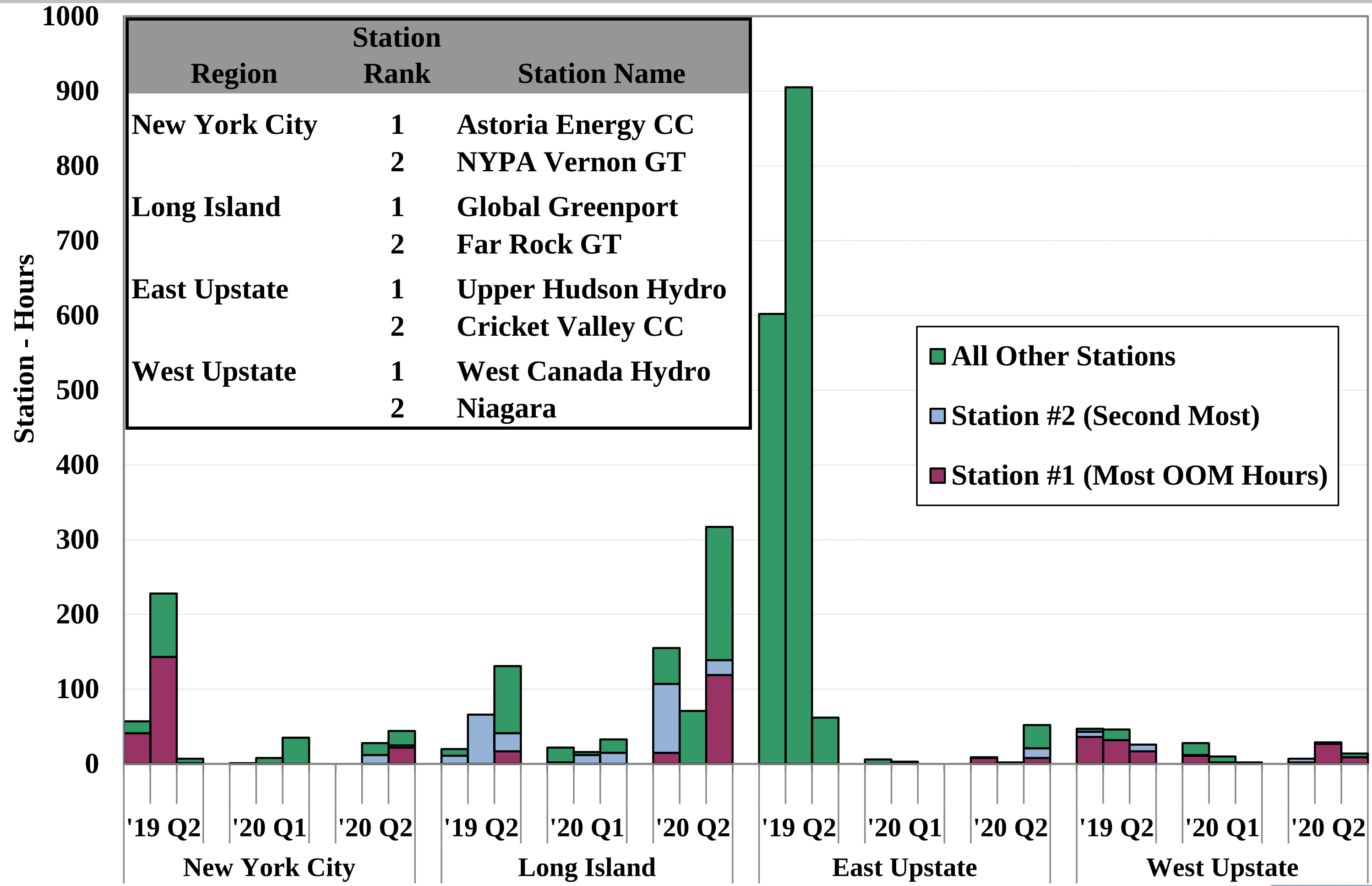
Notes: For chart description, see slides 82 and 83.

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



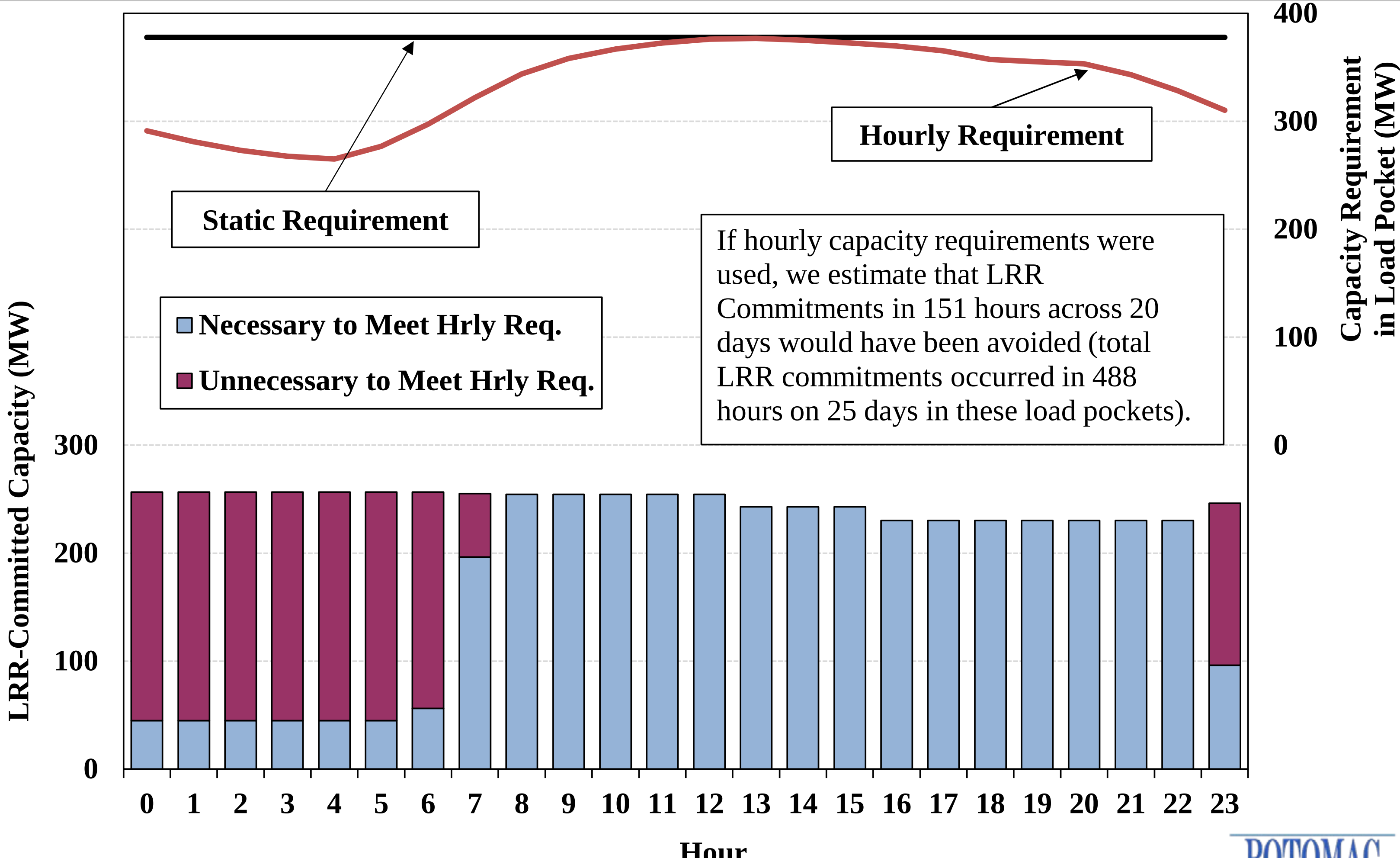
Notes: For chart description, see slides 82 and 83.

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



For chart description, see slides 82 and 83.

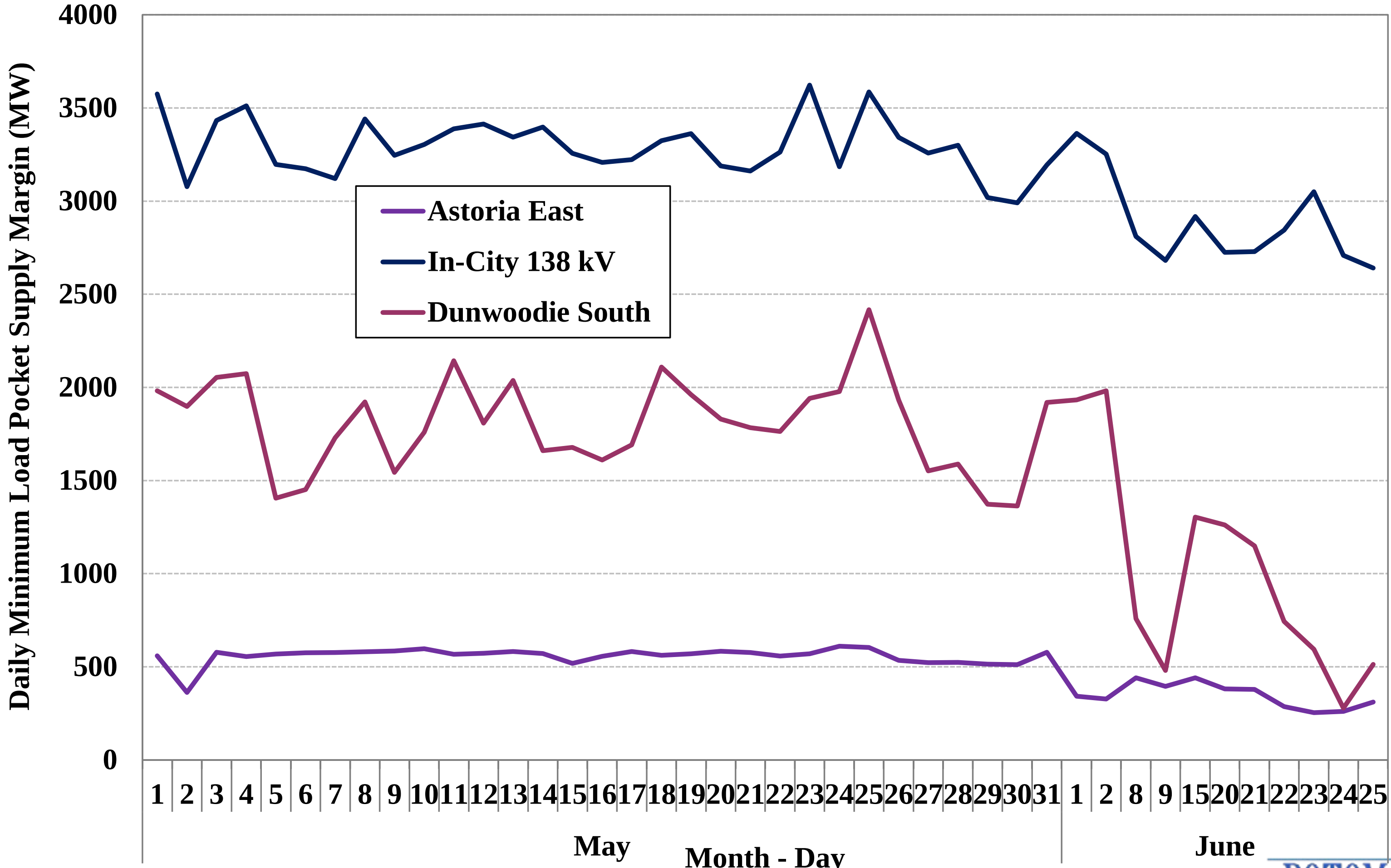
LRR Commitments in New York City
Hourly Requirement vs. Static Daily Requirement



For chart description, see slide 84.

POTOMAC ECONOMICS

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



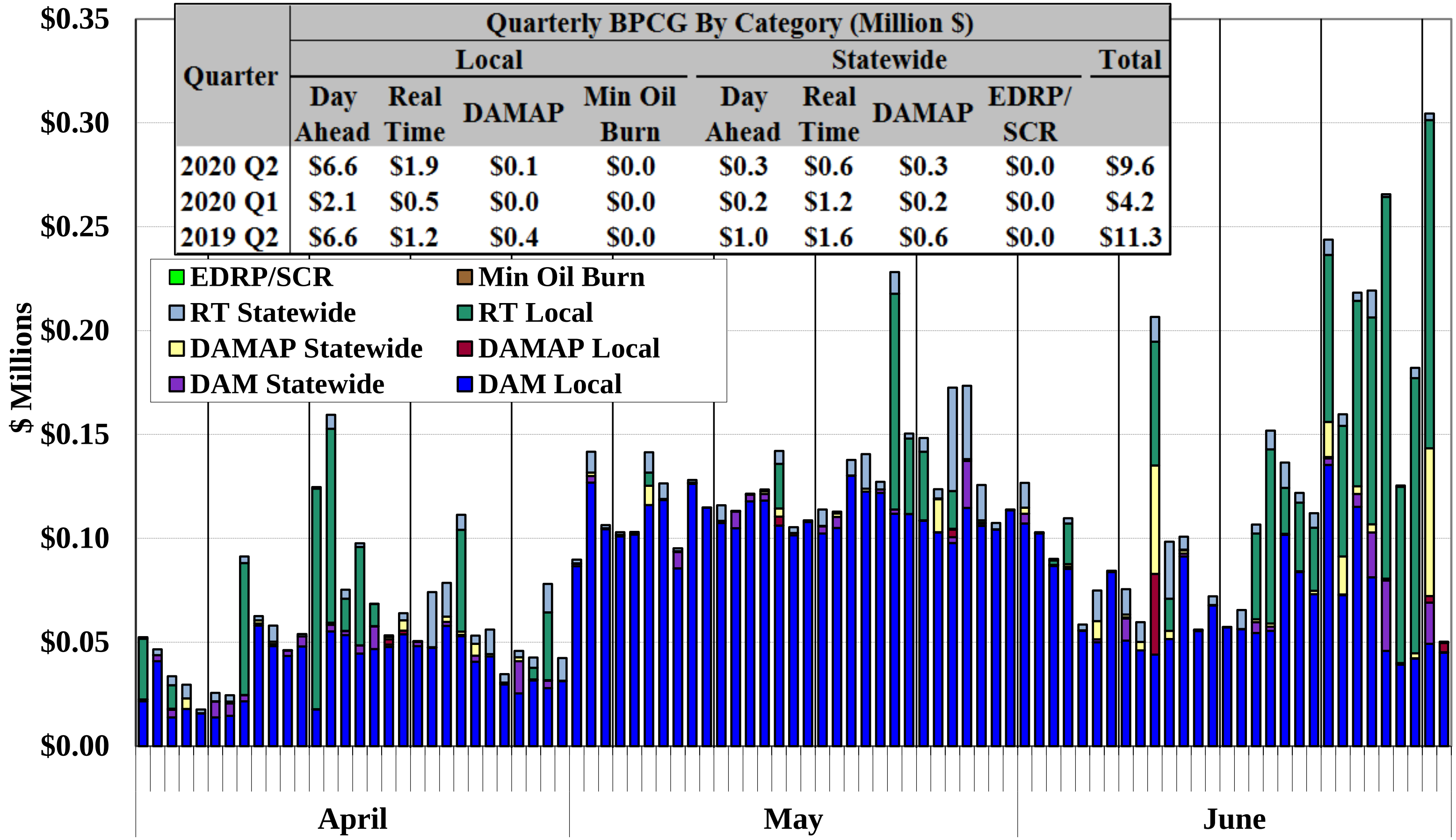
For chart description, see slide 85.

POTOMAC ECONOMICS

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

Quarter	Local: Day Ahead	Local: Real Time	Local: DAMAP	Local: Min Oil Burn	Statewide: Day Ahead	Statewide: Real Time	Statewide: DAMAP	Statewide: EDRP/SCR	Total
2020 Q2	$6.6	$1.9	$0.1	$0.0	$0.3	$0.6	$0.3	$0.0	$9.6
2020 Q1	$2.1	$0.5	$0.0	$0.0	$0.2	$1.2	$0.2	$0.0	$4.2
2019 Q2	$6.6	$1.2	$0.4	$0.0	$1.0	$1.6	$0.6	$0.0	$11.3

Quarterly BPCG By Category (Million $)

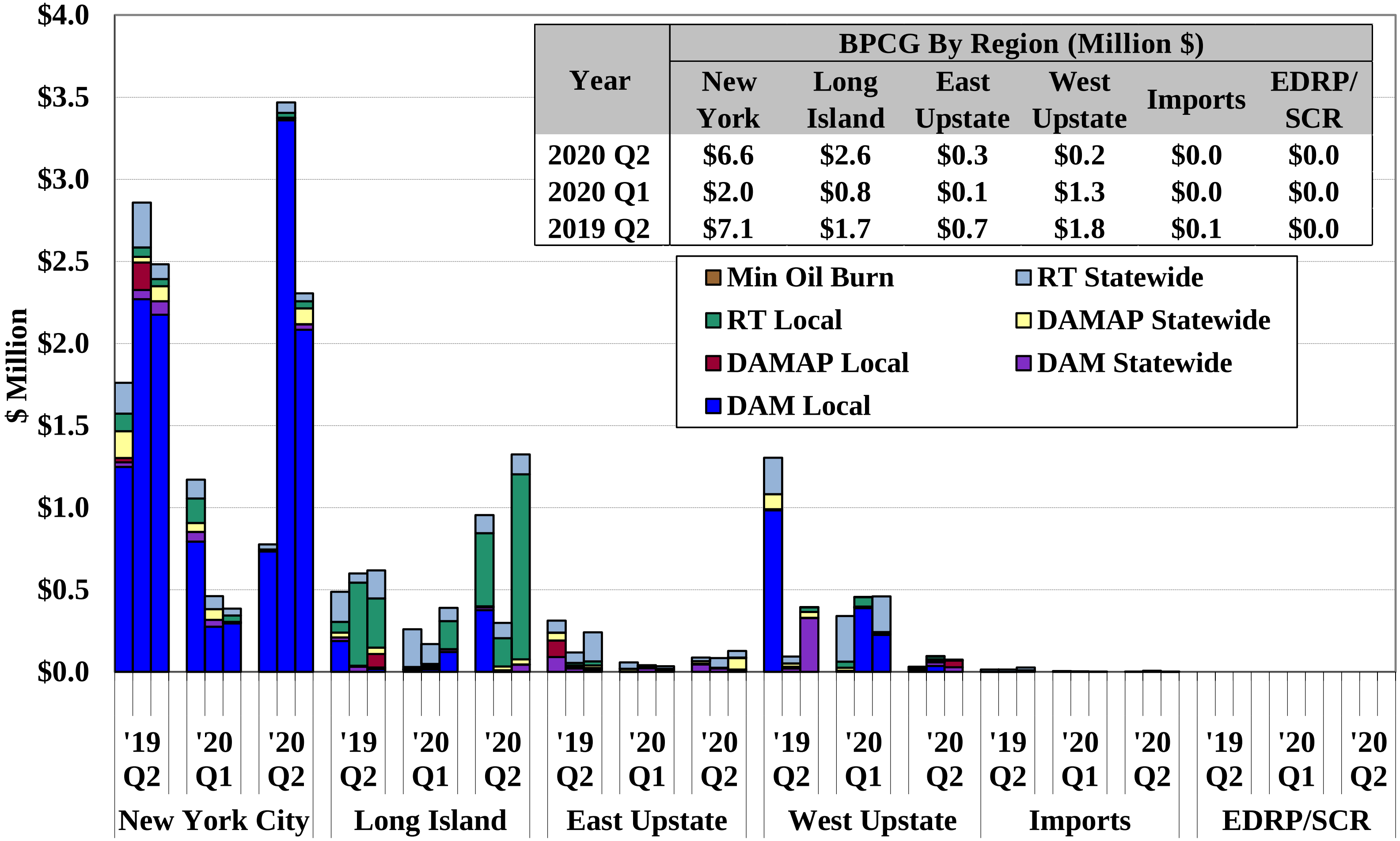


Notes:1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.

2. For chart description, see slide 86.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region



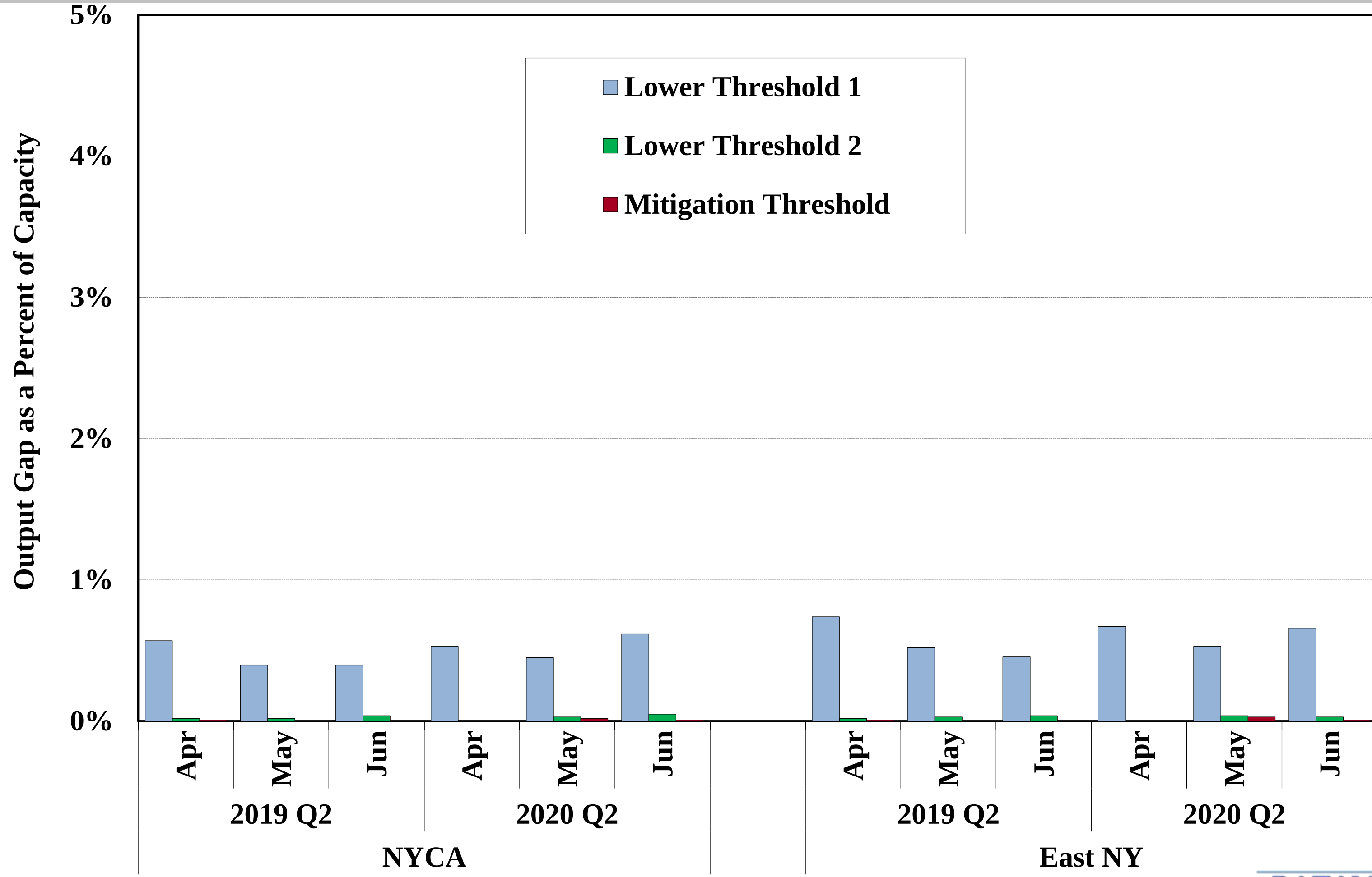
Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2020 Q2	$6.6	$2.6	$0.3	$0.2	$0.0	$0.0
2020 Q1	$2.0	$0.8	$0.1	$1.3	$0.0	$0.0
2019 Q2	$7.1	$1.7	$0.7	$1.8	$0.1	$0.0

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 86.

POTOMAC ECONOMICS

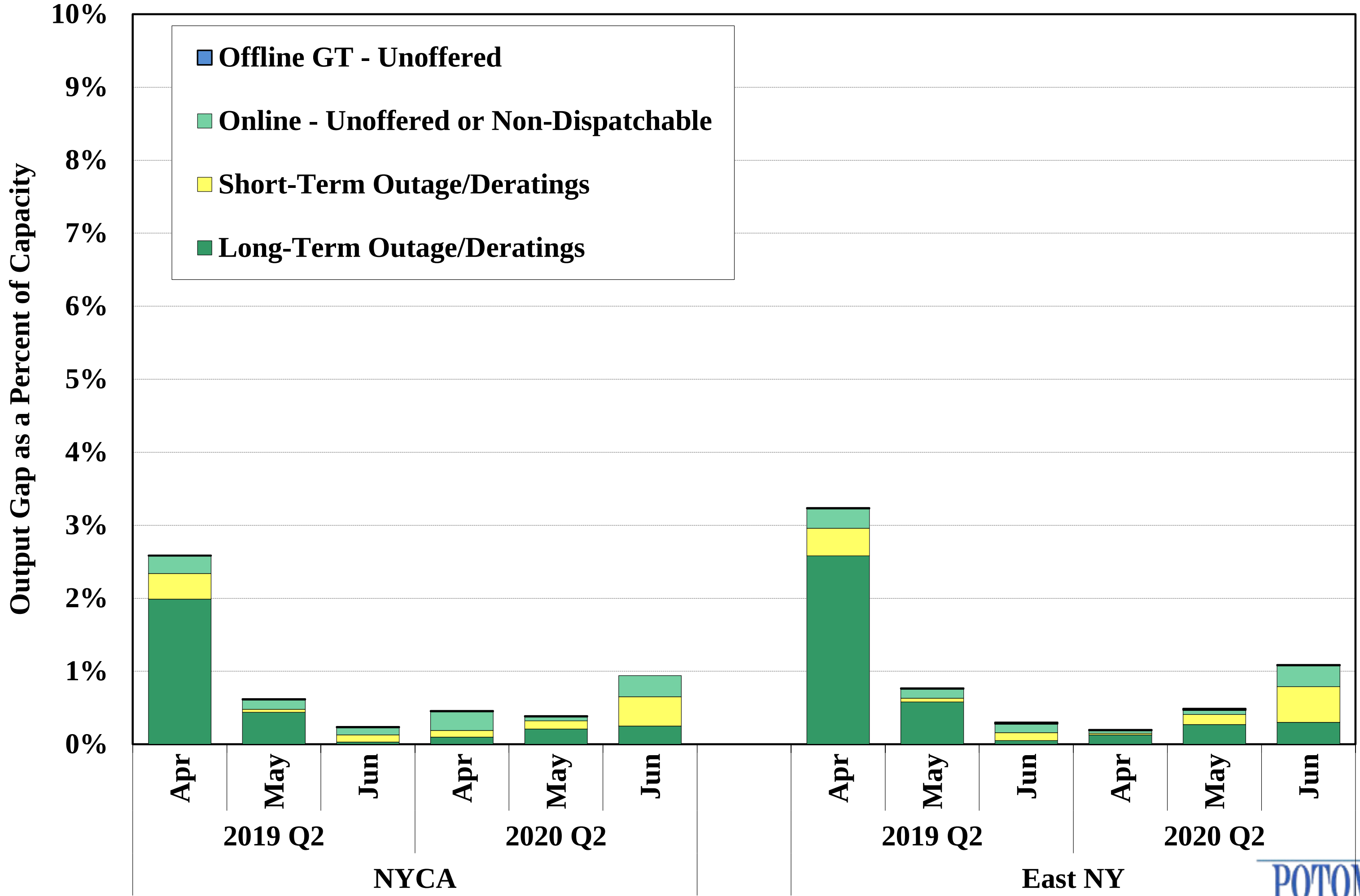
Charts:
Market Power and Mitigation

Output Gap by Month
NYCA and East NY



For chart description, see slide 87.
POTOMAC ECONOMICS

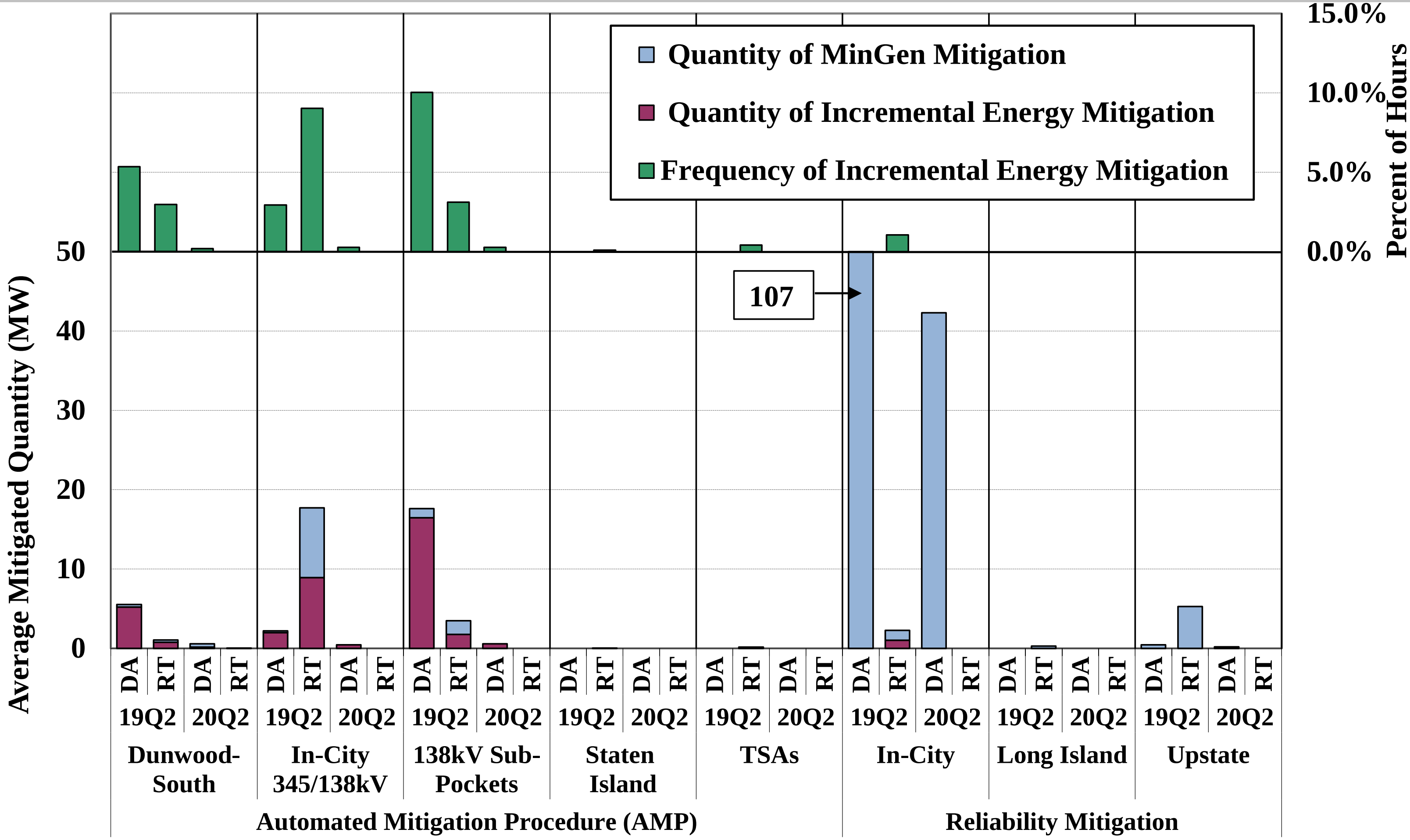
Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 87.

POTOMAC ECONOMICS

Automated Market Power Mitigation

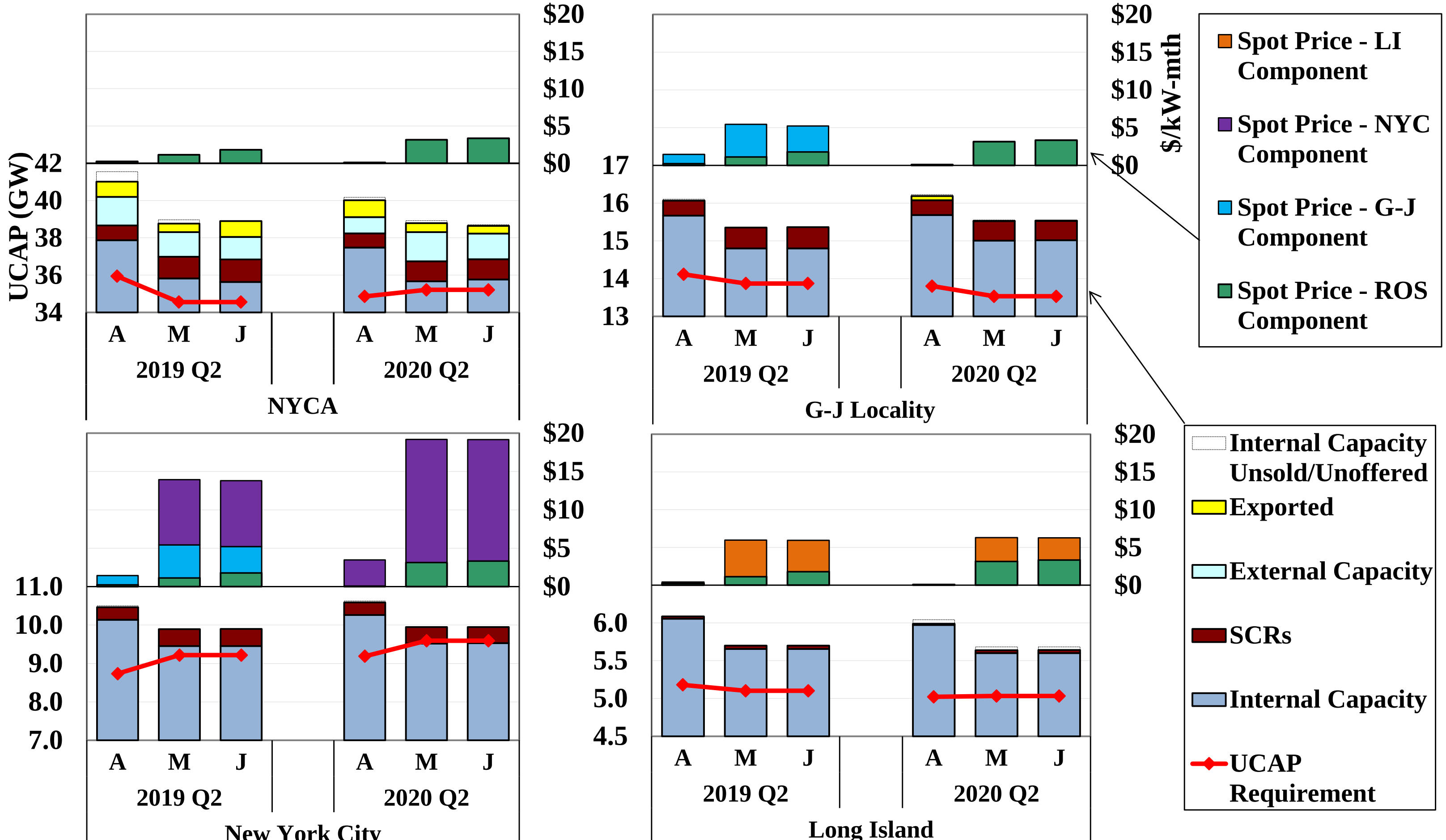


Notes: For chart description, see slide 88.

POTOMAC ECONOMICS

Charts:
Capacity Market

Spot Capacity Market Results
2019-Q2 & 2020-Q2



Notes: For chart description, see slide 89.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2020 Q2 ($/kW-Month)	$2.20	$13.94	$4.23	$2.20
% Change from 2019 Q2	**106%**	**43%**	**3%**	**-45%**
Change in Demand				
Load Forecast (MW)	-87	-130	-13	-150
IRM/LCR	1.9%	3.8%	-0.7%	-2.3%
2020/21 Capability Year	*118.9%*	*86.6%*	*103.4%*	*90.0%*
2019/20 Capability Year	*117.0%*	*82.8%*	*104.1%*	*92.3%*
ICAP Requirement (MW)	**512**	**329**	**-50**	**-501**
Key Changes in ICAP Supply (MW)				
Generation	**-638**	**-10**	**-35**	**-36**
Entry (1)	1310	0	0	1020
Exit (2)	-1919	-32	0	-1059
DMNC & Other	-29	22	-35	3
Cleared Import (3)	**-78**			

(1) Includes capacity returning to service from IIFO designation.

(2) Includes Generators' ICAP associated with BTM load.

(3) Based on average of quarterly cleared quantity.

Notes: For chart description, see slide 89.

Appendix: Chart Descriptions

All-in Price

- Slide 17 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 20 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 21 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.

Ancillary Services Prices

- Slides 26-30 summarize day-ahead and real-time prices for nine 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.
  - ✓ 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 & NYC Reserve Offers

- Slide 31 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).
- Slide 32 summarizes the same quantities for NYC resources only, which also shows 10-minute reserves separately.

Day-Ahead Load Scheduling and Virtual Trading

- Slide 34 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 35 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 36 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 38 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.

Real-Time System Price Maps at Generator Nodes

- Slides 40 and 41 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 42, 43, 44, and 45 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 42 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 43 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 44 and 45 show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.

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Transmission Congestion and Shortfalls (cont.)

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

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NY-NJ PAR Operation Under M2M with PJM

- Slide 46 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 47 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).

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Constraints on the Low Voltage Network

- Slide 48 shows the number of hours and days in the quarter when various resources were used to manage 69 kV 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 138 kV constraint via the market model in the DA and RT markets.
- Slide 48 also shows our estimated price impacts in each LI load pocket that result from explicitly modeling these 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.

Use of Oil-Fired Generation to Manage Congestion
East of Northport on Long Island

- Slide 49 evaluates the efficiency of using oil-fired generation to manage constraints in the East of Northport pocket of Long Island in the real-time market.
- The figure summarizes the following quantities from resources in the East of Northport pocket for each hour when oil-fired generation was used to manage 69 kV (by OOM) or 138 kV (by market model) constraints in this area:
  - ✓ Oil-fired generation - scheduled to manage congestion on the 69 kV network by OOM or on the 138 kV network by the market model.
  - ✓ Other generation – generation scheduled from all other resources in the pocket, including scheduled CSC imports and oil production that is either self-scheduled or OOMed for TVR support on the East End of Long Island.
  - ✓ Unscheduled generation in the pocket, which includes:
    - Low-cost (i.e., offer <= $100/MWh) capacity, which is available but not scheduled when congestion occurs. This include offline gas-fired GT, unscheduled low-cost CSC import, and unscheduled portion of online gas-fired CC and ST.
    - High-cost (i.e., offer > $100/MWh)/Unavailable capacity, which includes unscheduled CSC imports that are offered at a high price level and offline gas-fired CCs that cannot be scheduled by the real-time market software. These capacity are offered at low costs in the day-ahead market but are not scheduled.

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 50 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.

Supplemental Commitments and OOM Dispatch

- Slides 52, 53, and 54 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 52 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 53 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 54 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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LRR Commitments in NYC
Hourly Requirement vs. Daily Static Requirement

- Slide 55 evaluates how much of the capacity committed to satisfy an N-1-1 LRR constraint may have been unnecessary had the daily requirements been calculated hourly instead.
- The slide shows the following quantities as the averages for each hour on days when one or more units were committed to satisfy an LRR constraint:
  - ✓ The static daily requirement vs. the varying hourly requirement (in the top portion of the chart);
  - ✓ LRR-committed capacity (based on the daily requirement) that was:
    - Necessary to satisfy the hourly requirement;
    - Unnecessary to satisfy the hourly requirement.
- This evaluation is done for load pockets that account for most of the LRR-commitments in NYC this quarter.

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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 56 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.

Uplift Costs from Guarantee Payments

- Slides 57 and 58 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 57 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 58 summarizes uplift costs by region on a monthly basis.

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Potential Economic and Physical Withholding

- Slides 60 and 61 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 62 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 64 and 65 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 64 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 65 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.