Quarterly Report on the New York ISO Electricity Markets Second Quarter 2015

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August 2015

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the second quarter of 2015.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- Lower natural gas prices this quarter were the primary driver of variations in NYISO market outcomes from the same quarter last year.
- RT LBMPs averaged $29/MWh statewide, down 29 percent from a year ago.
  - ✓ Natural gas prices fell 34 to 58 percent across the system due to increased production from the Marcellus and Utica Shales (see slide 11).
  - ✓ Average nuclear generation rose 405 MW because of fewer outages, contributing to the decrease in LBMPs (see slide 14).
  - ✓ However, these LBMP reductions were partly offset by a decrease of 235 MW in average production from hydro units (see slide 14).
- Zonal price convergence between DA and RT was reasonably good in most areas in the second quarter of 2015.
  - ✓ However, in the West Zone, average RT prices were 11 percent higher than DA prices because of frequent acute intra-zonal RT congestion (see slides 19-20). These intra-zonal constraints led to poor price convergence at node-level.

Highlights and Market Summary: Congestion Patterns

- DAM congestion revenue rose 44 percent from a year ago to $73 million.
  - ✓ Larger gas spreads between East NY and West NY led to increased congestion on the Central-East interface and on transmission paths into SENY (see slide 48).
  - ✓ Congestion on the West Zone 230 kV lines increased from a year ago, accounting for nearly 40 percent of total congestion value this quarter (see slide 48).
    - – The increase was partly attributable to lower coal-fired production in the West Zone (see slide 14) and decreased PJM imports (see slide 34).
- Congestion was much more severe in RT than in the DA in the West Zone.
  - ✓ 230 kV lines in the West Zone exhibited $43 million in RT congestion, 60 percent higher than in the DAM (see slides 44-50). This pattern resulted primarily from:
    - – The effects of volatile RT Lake Erie loop flows;
    - – Increased Ontario imports and renewable output in West NY from DAM to RT;
    - – Incomplete utilization of parallel 115kV facilities (to unload 230kV constraints);
    - – Additional flows on the West Zone constraints caused by the operation of the ABC, JK, and Ramapo PARs (to relieve Central-East and SENY congestion).
  - ✓ We estimate that optimizing the distribution of output among the units at the Niagara plant during periods of acute congestion (to fully utilize the parallel 115 kV facilities) would have: (a) reduced production costs by $2.1 million; and (b) allowed an additional 31 GWh of deliverable generation from Niagara. (see slides 54-56).

Highlights and Market Summary: Capacity Market

- UCAP spot prices fell notably from the second quarter of 2014. UCAP prices:
  - ✓ In New York City fell 18 percent to an average of $12.92/kW-month;
  - ✓ In the G-J Locality fell 8 percent to an average of $8.10/kW-month;
  - ✓ On Long Island fell 8 percent to an average of $4.82/kW-month;
  - ✓ In Rest of State fell 34 percent to an average of $3.23/kW-month.
- Capacity spot prices fell across the system (see slides 77-79) because:
  - ✓ The return-to-service of multiple units, new wind capacity additions, and changes in DMNC test results increased internal capacity supply by 480 MW in Zone G, over 300 MW in NYC, and over 100 MW in West NY.
  - ✓ Average sales from SCRs rose 70 MW in NYC, 90 MW in the G-J Locality, and 210 MW in NYCA.
  - ✓ The ICAP requirement fell 115 MW (0.3 percent) in NYCA, 54 MW (0.5 percent) in NYC, and 148 MW (3 percent) in Long Island.
    - – However, the ICAP requirement rose 451 MW (3 percent) in the G-J Locality, offsetting the decrease of UCAP prices in the G-J Locality.
    - – The LCR reductions in NYC and Long Island and the increased LCR in the G-J Locality resulted primarily from recent capacity additions in Zone G.

Highlights and Market Summary: Uplift and Revenue Shortfalls

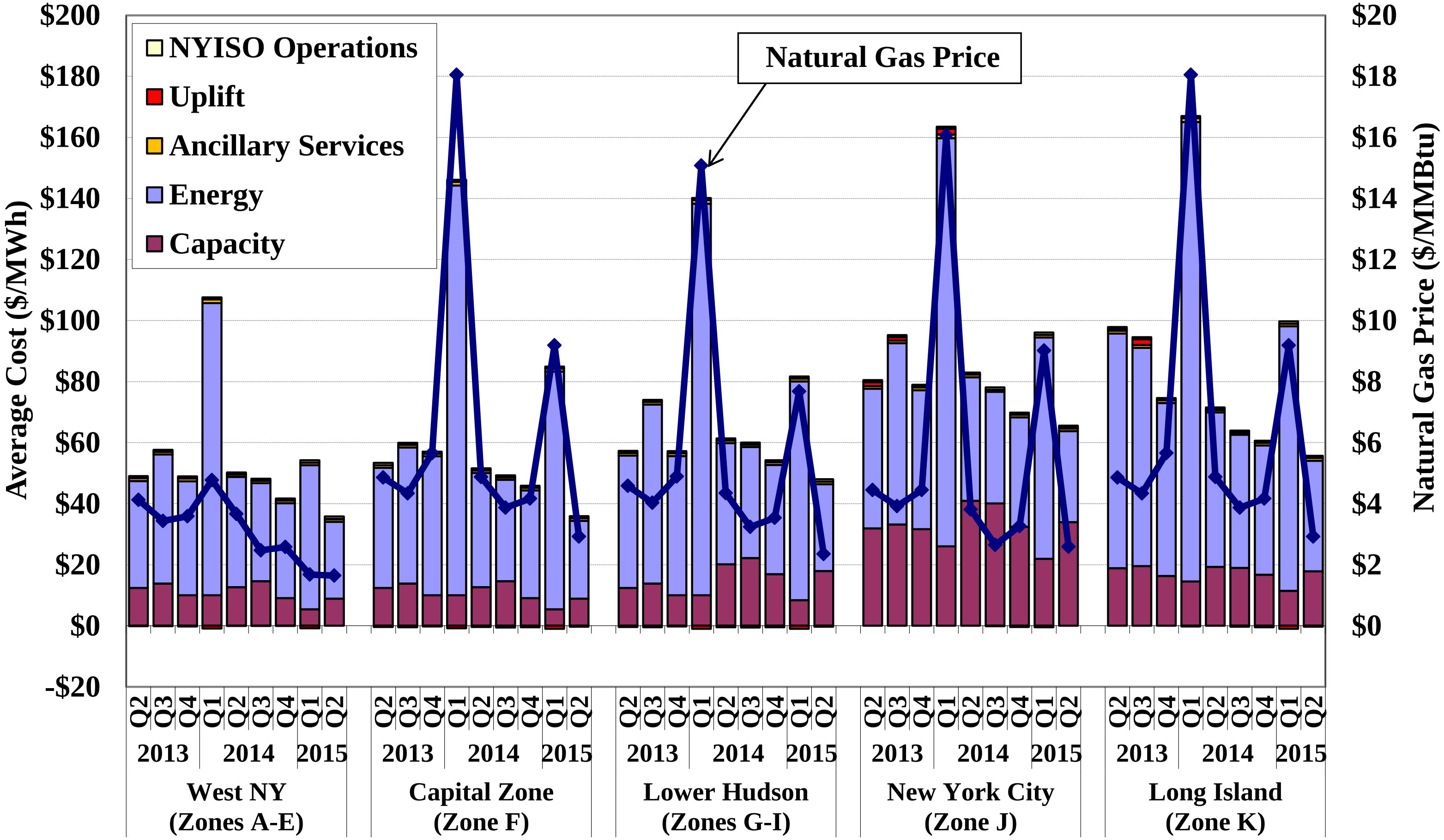
- The uplift from guarantee payments totaled $16.5 million, down 7 percent from the second quarter of 2014. (see slides 67-69)
  - ✓ The reduction was consistent with lower natural gas prices, which decreased the commitment costs of gas-fired units.
  - ✓ However, the reduction was largely offset by increased reliability commitments and OOM dispatch, particularly in Western NY. (see slides 63 & 65)
    - – Several coal-fired and gas-fired units were often DARUed and/or OOMed to manage post-contingency flows on 115kV facilities.
    - – Guarantee payments to these units accounted for over 40 percent of total guarantee uplift this quarter.
- Day-ahead congestion shortfalls were $6 million, down 50 percent from a year ago. (see slides 45 & 49)
  - ✓ West Zone constraints accounted for the majority of shortfalls primarily because of transmission outages and Niagara modeling assumptions.
- Balancing congestion shortfalls totaled $14 million, up $8 million from the second quarter of 2014. (see slides 46 & 50)
  - ✓ Over $9 million of shortfalls were associated with congestion in the West Zone.

Energy Market Outcomes

All-In Prices

- The first figure 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 based on spot prices multiplied by capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Rate Schedule 1 charges.
- Average all-in prices ranged from $36/MWh in West NY and the Capital Zone to $66/MWh in NYC, down 21 to 30 percent from the second quarter of 2014.
  - ✓ Energy prices fell roughly 27 percent (NYC) to 32 percent (Capital Zone).
    - Lower energy prices were due primarily to lower natural gas prices (see slide 11) and increased nuclear generation (see slide 14).
    - However, these were partly offset by higher load levels (see slide 10) and decreased production from hydro units (see slide 14).
  - ✓ Capacity costs fell 8 percent (Long Island) to 30 percent (West NY).
    - Capacity spot prices fell across the system primarily because of: (a) increased internal capacity supply; (b) increased SCR sales; and (c) lower ICAP requirements in most capacity zones (see slides 77-79).
    - However, the reduction of capacity prices in the G-J Locality was partly offset by a significant increase in the ICAP requirement (see slide 79).

All-In Energy Price by Region



Note: Natural Gas Price is based on the following gas indices (plus a transportation charge of $0.20/MMbtu): the Dominion North index for West NY, the Iroquois Zone 2 index for the Capital Zone, the average of Texas Eastern M3 and Iroquois Zone 2 for Lower Hudson, the Transco Zone 6 (NY) index for New York City, and the Iroquois Zone 2 index for Long Island.

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Load Levels and Fuel Prices

- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Average load (17.3 GW) rose slightly (<1 percent) from a year ago, while peak load (28.1 GW) rose more than 3 percent.
  - ✓ Of the last six years, 2014 and 2015 exhibited the lowest load levels during the second quarter of the year.
  - ✓ Loads varied considerably in May and June largely because of changes in weather.
    - – For example, daily peak load rose by more than 9 GW in a four-day period between June 20 and June 23 and then fell by more than 10 GW over the next five days.
    - – Volatile load levels led to increased forecasting errors, contributing to increased price divergence between DA and RT on several days.
- Gas prices fell significantly from a year ago (34% in NYC, 42% in LI, and 58% in West NY) because of increased production from the Marcellus and Utica shales.
  - ✓ Gas traded at a discount to Henry Hub at locations in NY (besides Iroquois Zn 2).
  - ✓ Lower natural gas prices made coal production in West NY less economic, contributing to increased congestion in this area (see slide 48).

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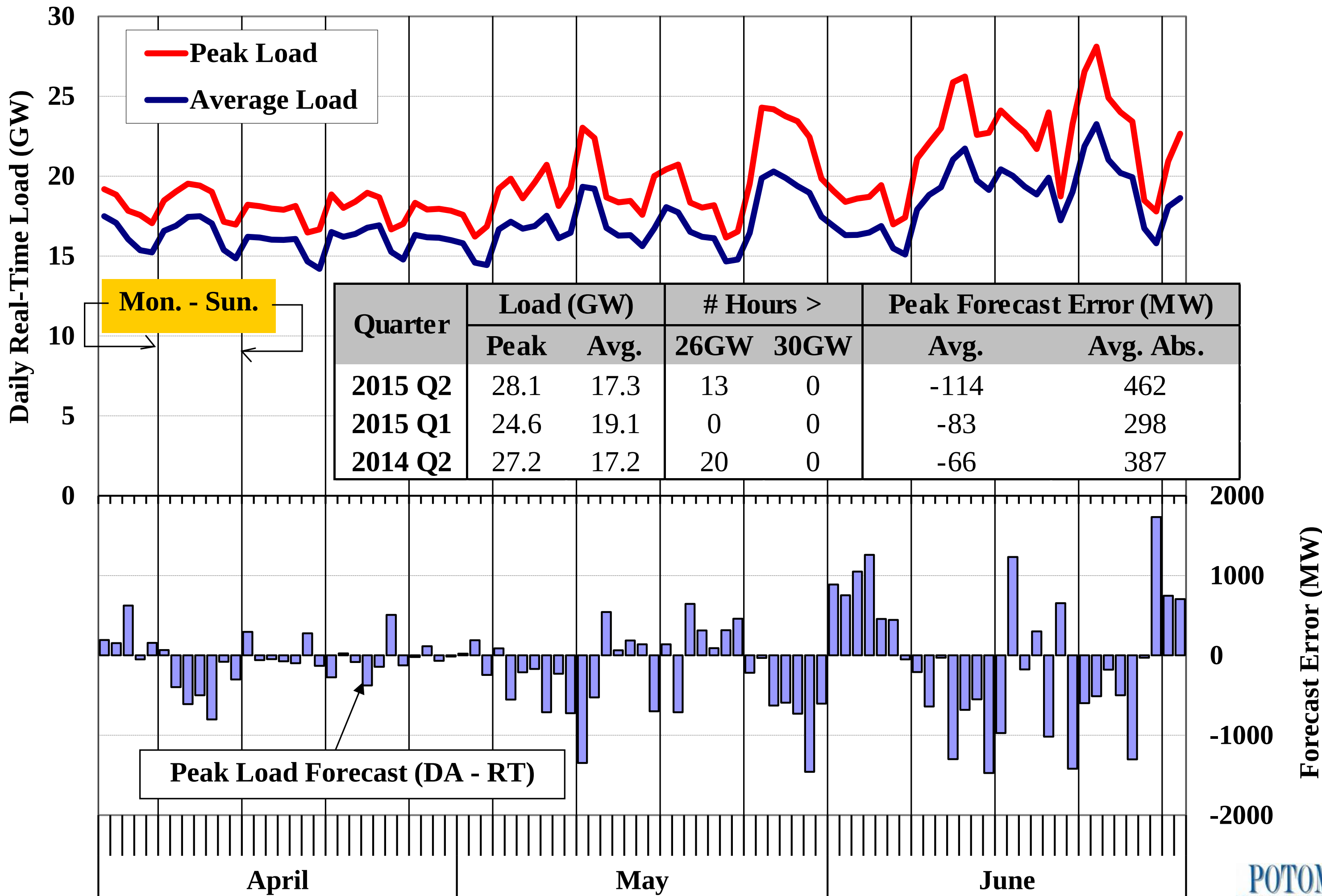
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2015 Q2	28.1	17.3	13	0	-114	462
2015 Q1	24.6	19.1	0	0	-83	298
2014 Q2	27.2	17.2	20	0	-66	387

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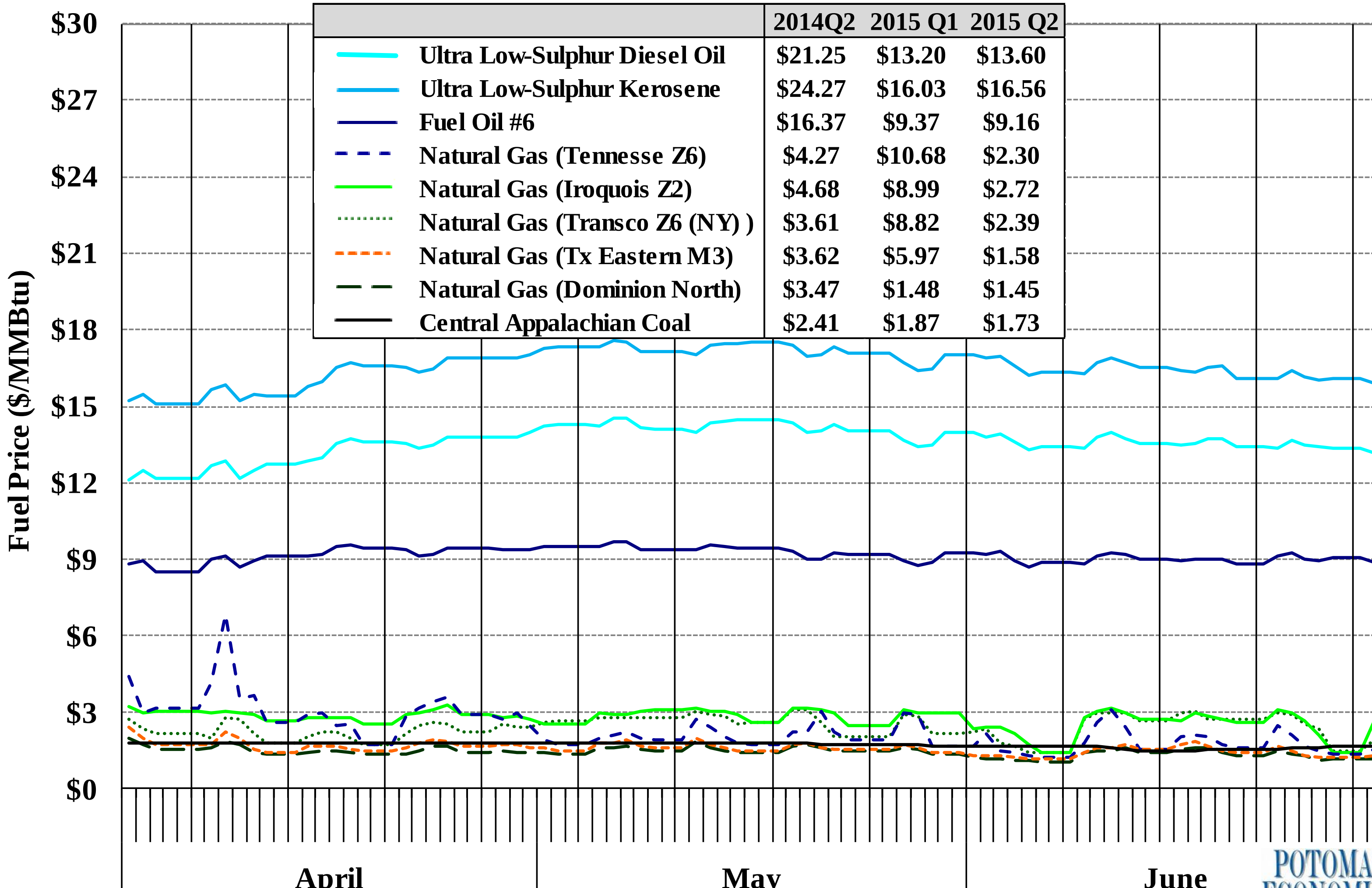
Coal, Natural Gas, and Fuel Oil Prices



	2014Q2	2015 Q1	2015 Q2
Ultra Low-Sulphur Diesel Oil	$21.25	$13.20	$13.60
Ultra Low-Sulphur Kerosene	$24.27	$16.03	$16.56
Fuel Oil #6	$16.37	$9.37	$9.16
Natural Gas (Tennesse Z6)	$4.27	$10.68	$2.30
Natural Gas (Iroquois Z2)	$4.68	$8.99	$2.72
Natural Gas (Transco Z6 (NY))	$3.61	$8.82	$2.39
Natural Gas (Tx Eastern M3)	$3.62	$5.97	$1.58
Natural Gas (Dominion North)	$3.47	$1.48	$1.45
Central Appalachian Coal	$2.41	$1.87	$1.73

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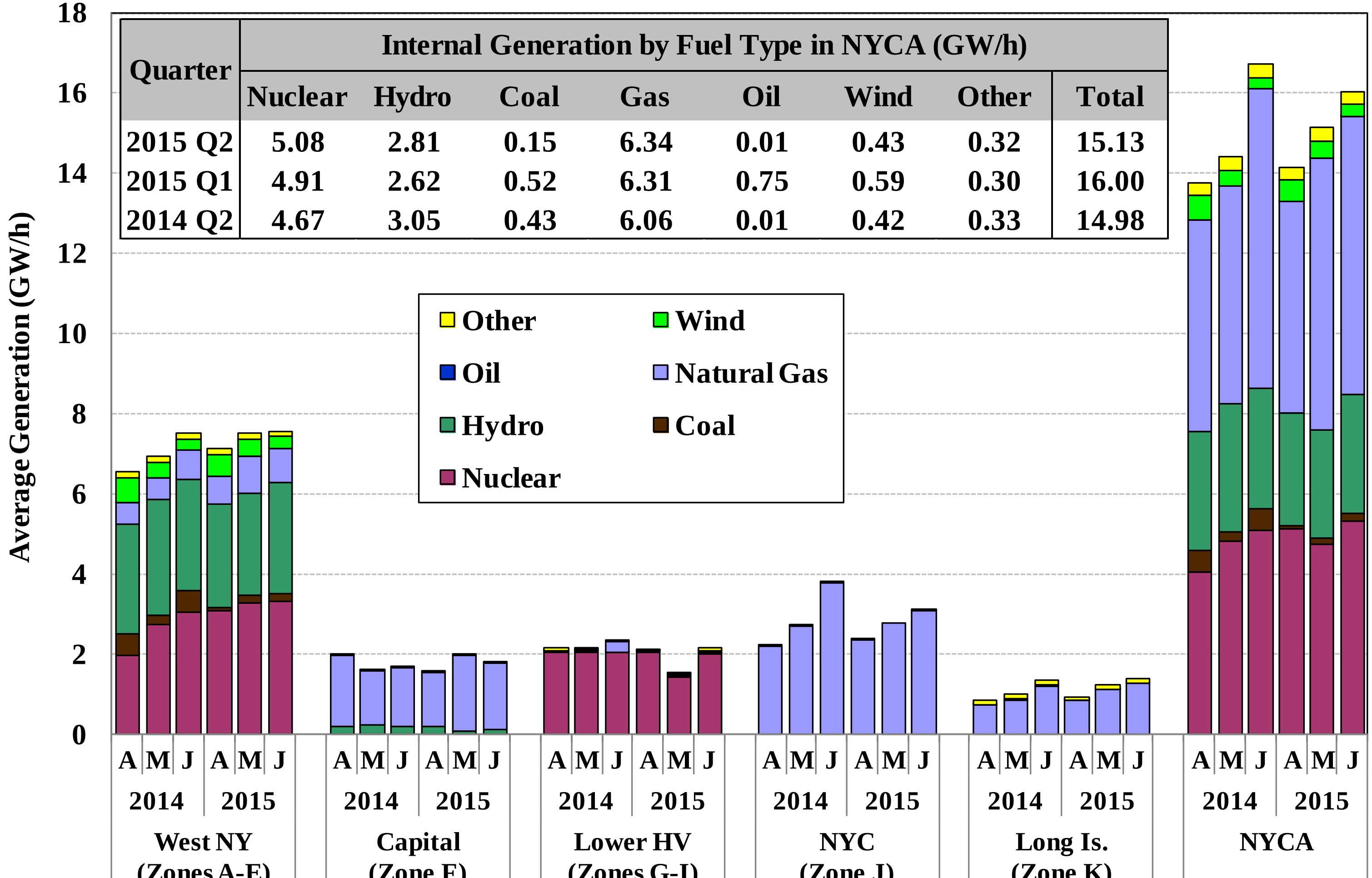
Real-Time Generation by Fuel Type

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the second quarter of 2015.
- The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
- The second figure summarizes how frequently each fuel type is 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.
- The fuel type for each generator is based on its actual fuel consumption reported to the EPA and the EIA.

Real-Time Generation and Marginal Units by Fuel Type

- Gas-fired (42 percent), nuclear (34 percent), and hydro (19 percent) generation accounted for most of internal generation in the second quarter of 2015.
  - ✓ Average nuclear generation rose 405 MW from the second quarter of 2014 because of fewer maintenance outages.
    - The increase was partly offset by the reduction in average hydro generation, which fell 235 MW from a year ago.
  - ✓ Coal generation fell notably from a year ago, averaging 150 MW this quarter.
    - Low natural gas price in West NY made coal production less economic.
  - ✓ Gas-fired generation rose in West NY and fell in NYC from a year ago, reflecting:
    - Increased gas spreads between West NY and East NY; and
    - Decreased gas spreads between NYC and the rest of East NY.
- Gas-fired and hydro resources were on the margin most of time in New York.
  - ✓ Most hydro units on the margin have storage capacity and offer based on the opportunity cost of foregone sales in other hours (i.e., when gas is marginal).
    - Hydro units were on the margin more frequently this quarter because of increased congestion in the West Zone.
  - ✓ Coal units were rarely on the margin this quarter because they were less economic for the reason discussed above.

Real-Time Generation Output by Fuel Type

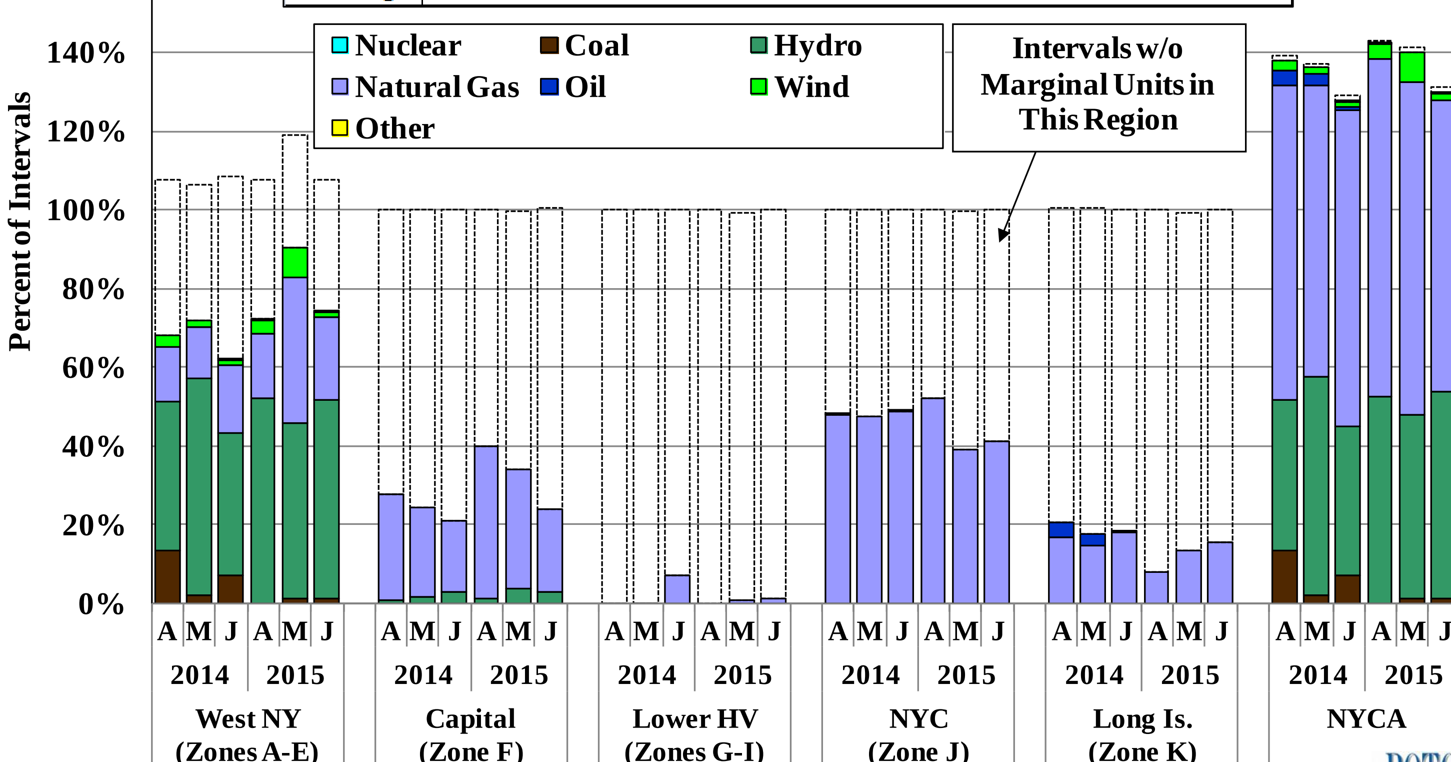


Quarter	Internal Generation by Fuel Type in NYCA (GW/h)							
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other	Total
2015 Q2	5.08	2.81	0.15	6.34	0.01	0.43	0.32	15.13
2015 Q1	4.91	2.62	0.52	6.31	0.75	0.59	0.30	16.00
2014 Q2	4.67	3.05	0.43	6.06	0.01	0.42	0.33	14.98

Notes: Pumped-storage resources in pumping mode are treated as negative generation. “Other” includes Methane, Refuse, Solar & Wood.

Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other
2015 Q2	0%	51%	1%	82%	0%	4%	0%
2015 Q1	0%	49%	7%	71%	17%	3%	0%
2014 Q2	0%	44%	7%	78%	3%	2%	0%



Note: "Other" includes Methane, Refuse, Solar & Wood.

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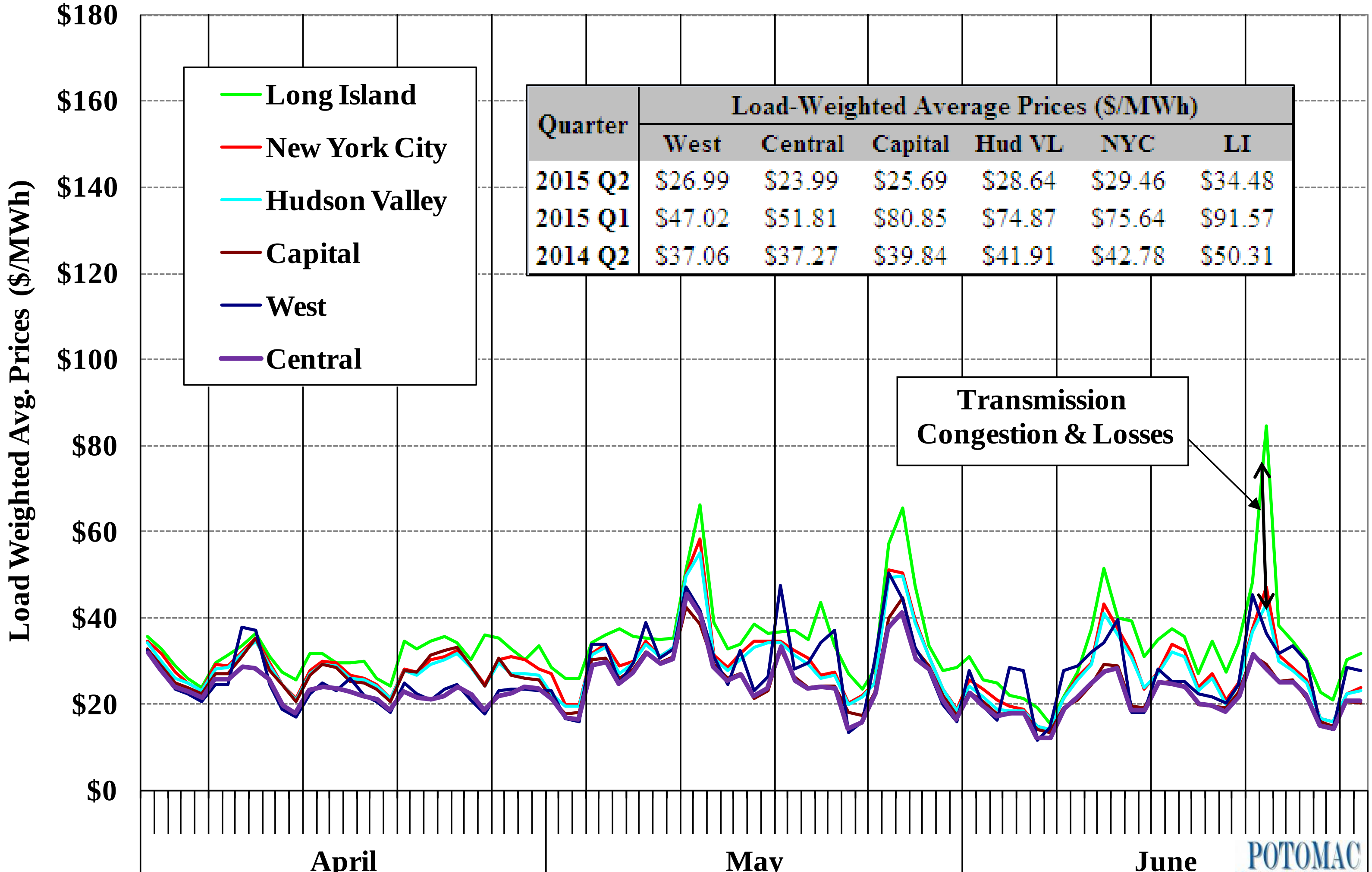
Day-Ahead and Real-Time Electricity Prices

- The following three figures show: 1) load-weighted average DA energy prices; 2) load-weighted average RT energy prices; and 3) convergence between DA and RT prices for six load zones on a daily basis in the second quarter of 2015.
- Average day-ahead prices ranged from $24/MWh in the Central Zone to $34/MWh on Long Island, down 27 to 36 percent from the second quarter of 2014.
  - ✓ The decreases were driven primarily by lower natural gas prices (see slide 11).
  - ✓ Increased nuclear generation also contributed to lower LBMPs (see slide 14).
  - ✓ However, LBMPs rose notably during several days in May and June when load rose considerably from the preceding days (see slide 10).
- Prices are generally more volatile in the real-time market than in the day-ahead market because of unexpected events. Notable examples include:
  - ✓ RT LBMPs rose statewide on 5/11 primarily because loads were higher than anticipated (e.g., 1.3 GW over the NYISO day-ahead forecast).
  - ✓ Long Island RT LBMPs rose substantially:
    - – On 5/31 and 6/14 partly because of significant under-scheduling in the DAM;
    - – On 6/19 partly because of the trip of Dunwoodie-Shore Rd Line.
  - ✓ Southeast NY RT LBMPs rose on 6/22 and 6/23 because of the effects of a solar-magnetic event, TSAs, and unexpectedly high load.

Day-Ahead and Real-Time Electricity Prices

- Random factors can cause large differences between DA and RT prices on individual days, while persistent differences may indicate a systematic issue. The table focuses on persistent differences by averaging over the entire quarter.
  - ✓ Price convergence was relatively good in most areas this quarter.
    - – Average differences between DA and RT prices were small (around 1 percent of average RT prices) in all areas but Long Island and the West Zone.
- Average day-ahead prices were 11 percent lower than real-time prices in the West Zone and 5 percent lower than real-time prices in Long Island this quarter. Acute RT congestion often occurred on:
  - ✓ Paths from upstate to Long Island and into the Valley Stream load pocket.
    - – RT price spikes were driven by fluctuations in flows across PAR-controlled lines combined with the limited flexible dispatch options on Long Island.
  - ✓ 230kV lines in the West Zone, which was driven by:
    - – Clockwise changes in loop flows around Lake Erie that emanate from other areas;
    - – Incomplete utilization of parallel 115kV facilities (to unload constrained 230kV facilities); and
    - – Changes in offer patterns after the day-ahead market.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2015 Q2	$26.99	$23.99	$25.69	$28.64	$29.46	$34.48
2015 Q1	$47.02	$51.81	$80.85	$74.87	$75.64	$91.57
2014 Q2	$37.06	$37.27	$39.84	$41.91	$42.78	$50.31

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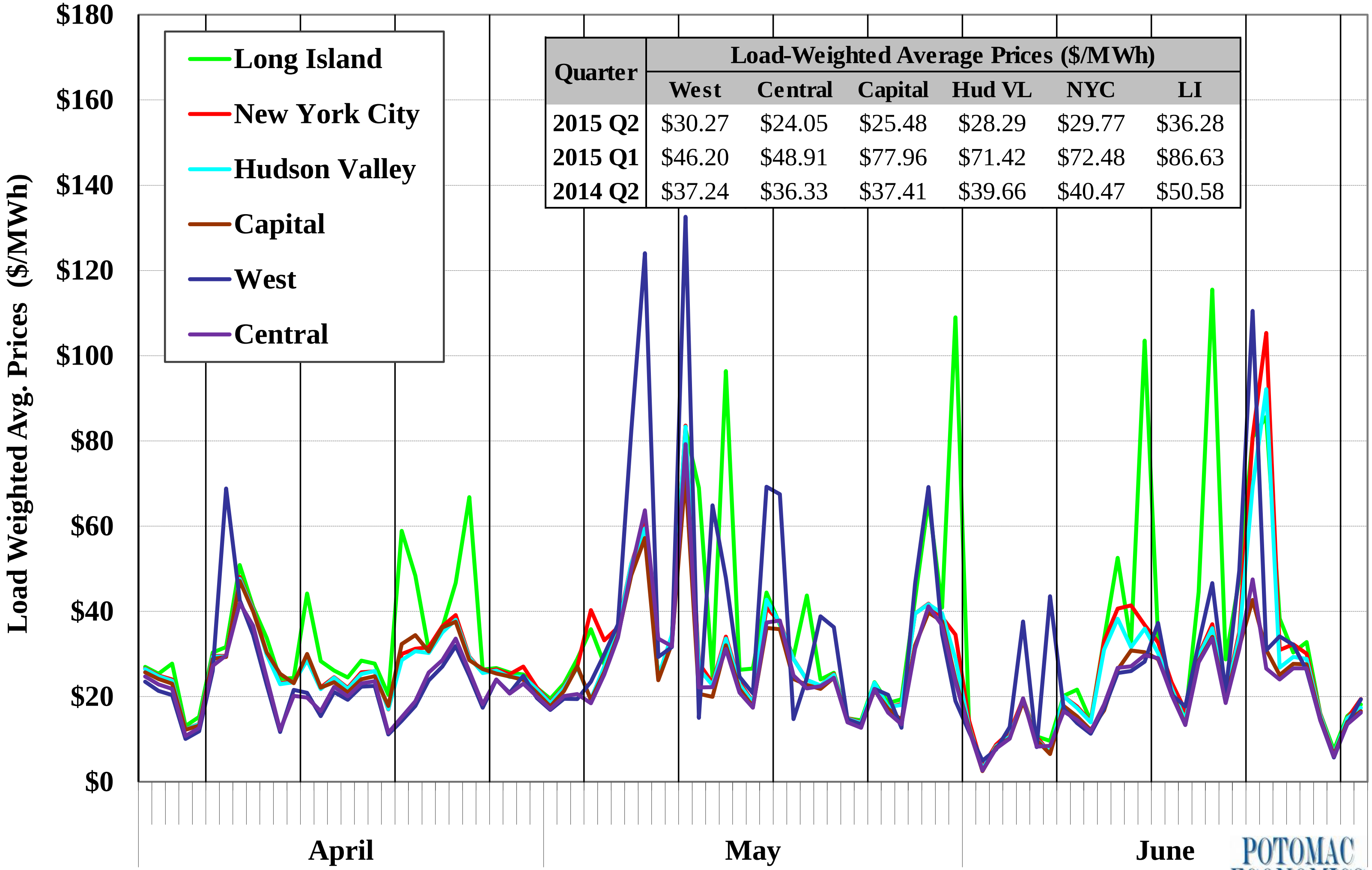
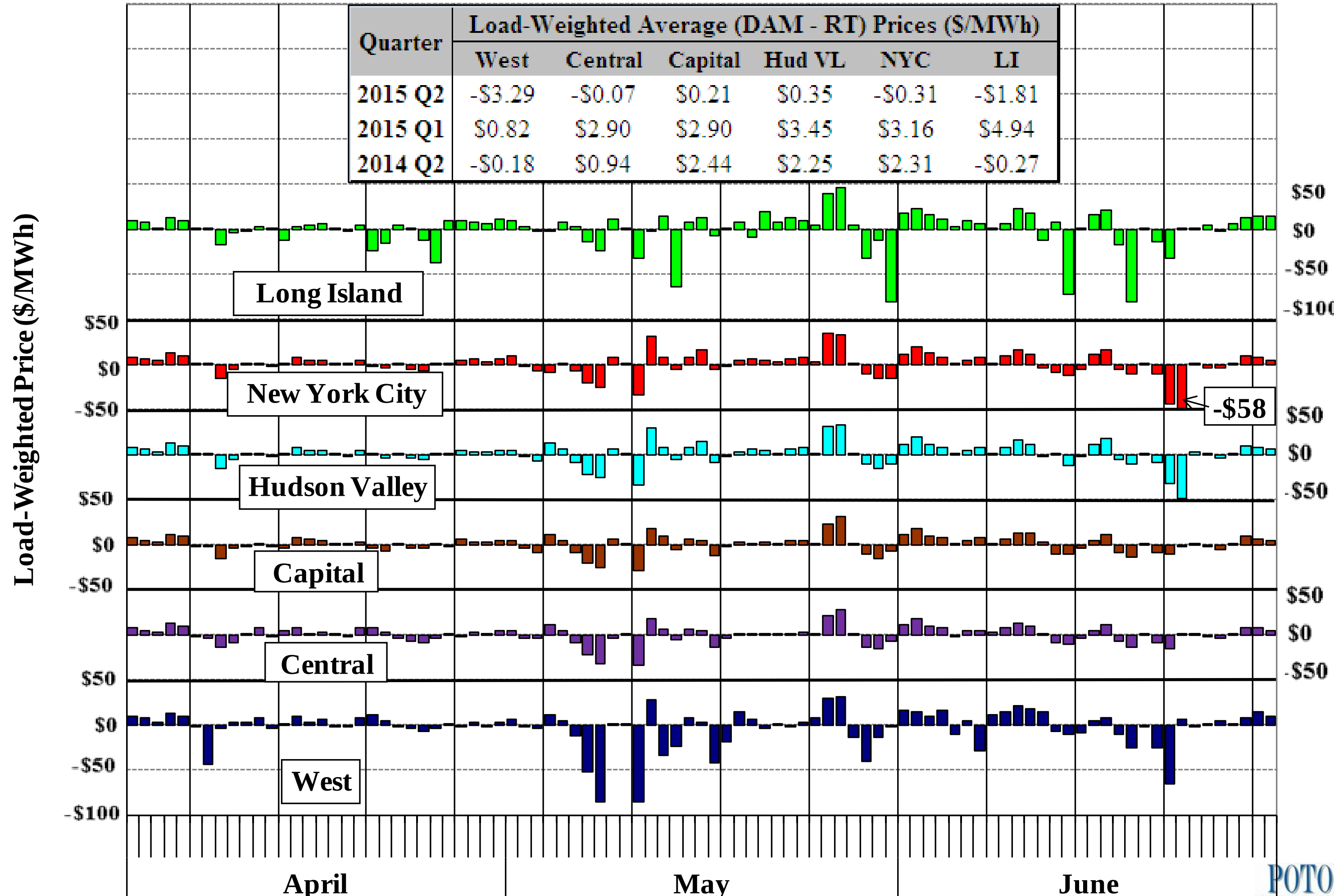
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2015 Q2	$30.27	$24.05	$25.48	$28.29	$29.77	$36.28
2015 Q1	$46.20	$48.91	$77.96	$71.42	$72.48	$86.63
2014 Q2	$37.24	$36.33	$37.41	$39.66	$40.47	$50.58

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2015 Q2	-$3.29	-$0.07	$0.21	$0.35	-$0.31	-$1.81
2015 Q1	$0.82	$2.90	$2.90	$3.45	$3.16	$4.94
2014 Q2	-$0.18	$0.94	$2.44	$2.25	$2.31	-$0.27

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Ancillary Services Market

Ancillary Services Prices

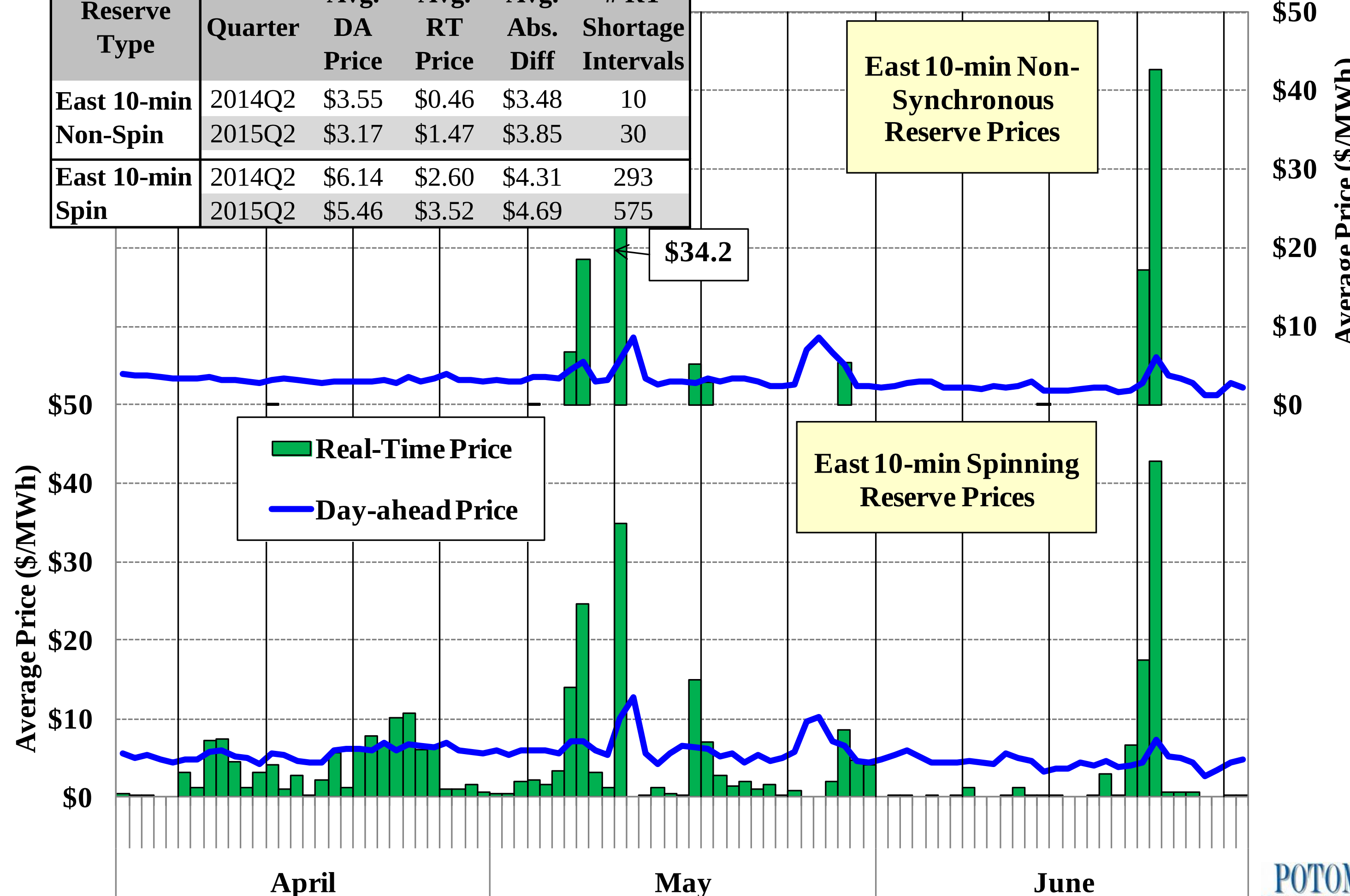
- Two figures summarize DA and RT prices for four ancillary services products:
  - ✓ 10-min spinning reserve prices in eastern NY, which reflect the cost of requiring:
    - 330 MW of 10-minute spinning reserves in eastern NY;
    - 655 MW of 10-minute spinning reserves state-wide; and
    - 1,200 MW of 10-minute total reserves (spin and non-spin) in eastern NY.
  - ✓ 10-min non-spinning reserve prices in eastern NY, which reflect the cost of requiring 1,200 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-min spinning reserve prices in western NY, which reflect the cost of requiring 655 MW of 10-minute spinning reserves statewide.
  - ✓ Regulation prices, which reflect the cost procuring up to 300 MW of regulation, and the cost and uplift charges from moving regulation units up and down.
    - Resources were scheduled assuming a Regulation Movement Multiplier of 10 MW per MW of capability, but they are compensated according to actual movement.
- The figures show the number of shortage intervals -- when a requirement cannot be satisfied at a marginal cost less than its "demand curve", which are:
  - ✓ $25 for eastern 10-minute spinning reserves;
  - ✓ $500 for eastern 10-minute total reserves;
  - ✓ $500 for statewide 10-minute spinning reserves; and
  - ✓ $80 to $400 for regulation.

Ancillary Services Prices

- Average DA prices for most ancillary services products fell from the prior year, consistent with lower opportunity costs from lower energy prices.
  - ✓ Average DA prices exceeded average RT prices for all reserve products.
    - – This is generally expected in competitive markets with no virtual trading.
- Average RT prices for most reserve products rose from the second quarter of 2014, particularly in Eastern New York, partly because of more frequent shortages.
  - ✓ Eastern reserves were short in real-time on several days in May and June:
    - – When load was significantly under-scheduled in the DAM partly because of unexpectedly high RT demand (e.g., 5/11, 6/22, & 6/23); and
    - – During a solar-magnetic event (on 6/22) and TSA events.
      - These events require conservative operation of the transmission system, particularly in Southeast New York, where generating capacity must be ramped up to produce energy, reducing the available 10-minute reserves.
  - ✓ Available 10-minute reserves in SENY were reduced from the previous year.
    - – SENY capacity was less economic because of increased gas spreads between West NY and East NY.
    - – PJM imports to East NY were reduced because of lower LBMPs in New York, driven by lower natural gas prices.

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	2014Q2	$3.55	$0.46	$3.48	10
	2015Q2	$3.17	$1.47	$3.85	30
East 10-min Spin	2014Q2	$6.14	$2.60	$4.31	293
	2015Q2	$5.46	$3.52	$4.69	575



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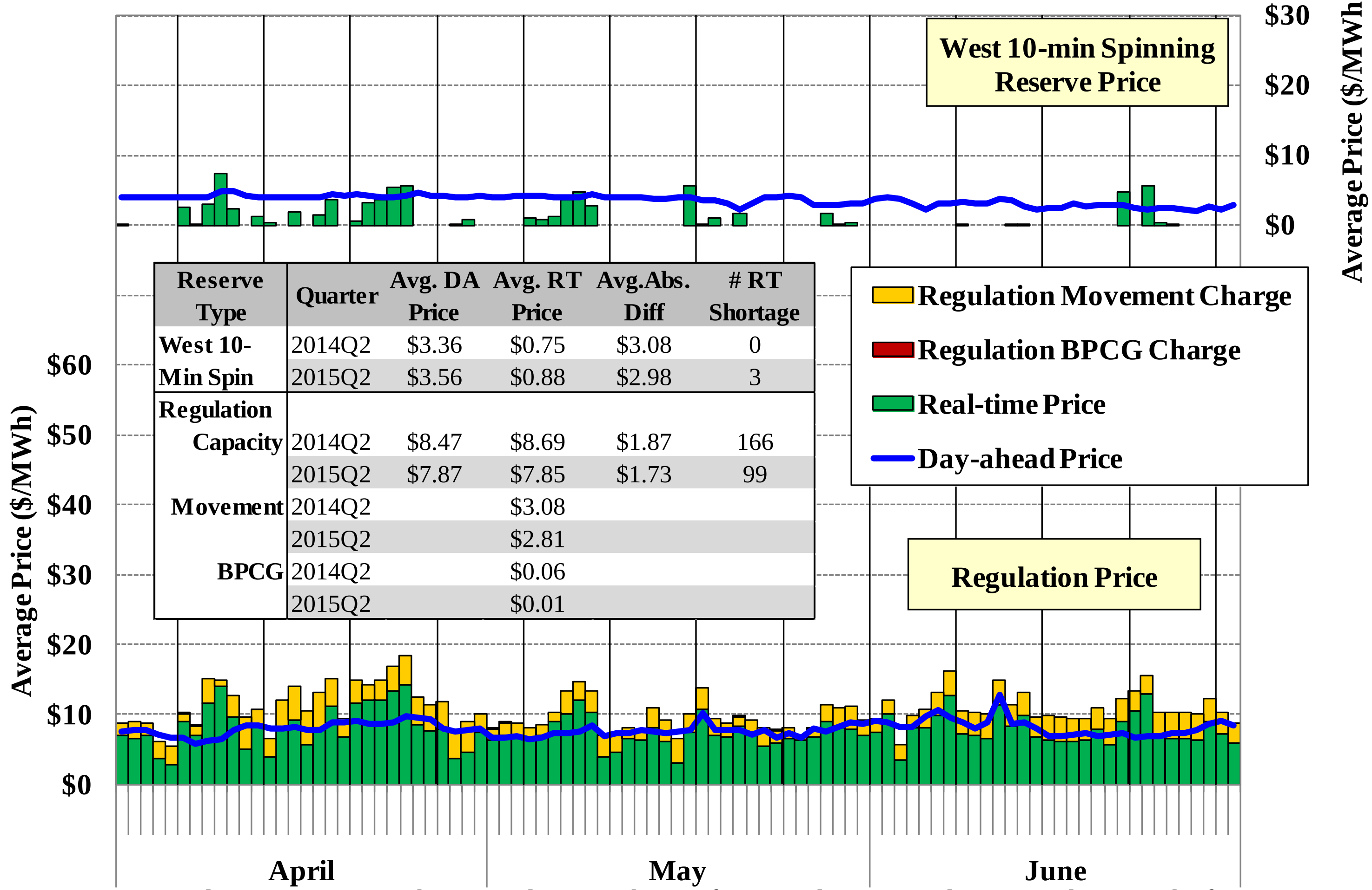
Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage
West 10-Min Spin	2014Q2	$3.36	$0.75	$3.08	0
	2015Q2	$3.56	$0.88	$2.98	3
Regulation Capacity	2014Q2	$8.47	$8.69	$1.87	166
	2015Q2	$7.87	$7.85	$1.73	99
Movement	2014Q2		$3.08		
	2015Q2		$2.81		
BPCG	2014Q2		$0.06		
	2015Q2		$0.01		

Note: Regulation Movement Charges and BPCG charges from regulating in real-time are shown in the figure averaged per MWh of RT Scheduled Regulation Capacity.

Energy Market Scheduling

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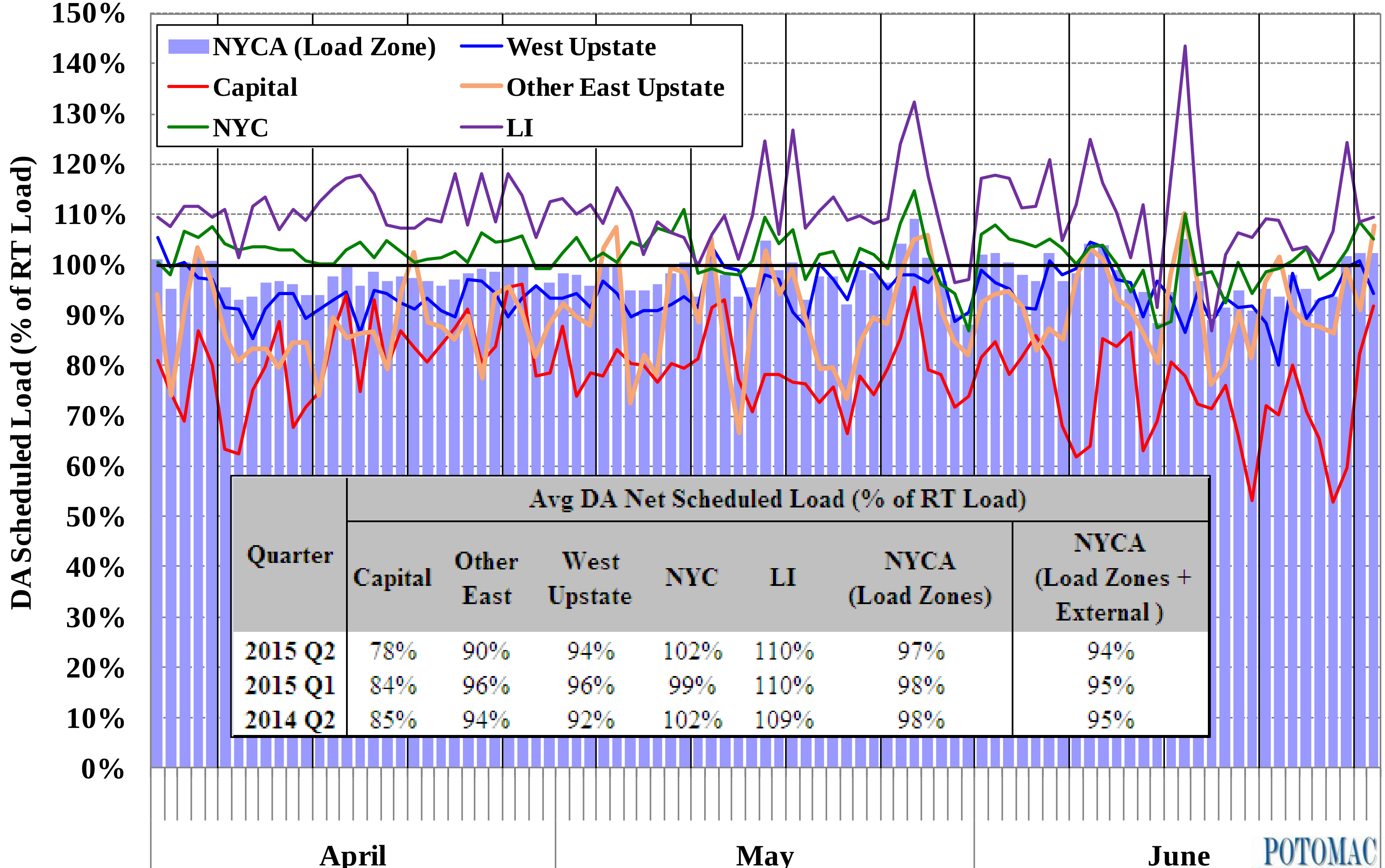
Day-ahead Load Scheduling

- The following figure summarizes the quantity of DA load scheduled as a percentage of RT load in each of five regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
  - ✓ The table also summarizes a system-wide net scheduled load that includes virtual imports and virtual exports at the proxy buses.
- For NYCA, 94 percent of actual load was scheduled in the DAM (including virtual imports/exports) in the second quarter of 2015, down slightly from the prior year.
- Load scheduling tends to be higher in import-constrained locations, and at times when acute real-time congestion is more likely.
  - ✓ For example, load was generally over-scheduled in SENY, particularly on LI.
  - ✓ Load scheduling rose notably in SENY and fell in the Capital Zone on several days in May and June when thunderstorms were likely anticipated.
    - – However, SENY prices were significantly elevated in real-time on several days when TSAs were not well anticipated (e.g., 6/22 & 6/23, see slide 19).
- Under-scheduling was still prevalent outside SENY except in the West Zone.
  - ✓ Load scheduling in the West Zone (which is not shown separately) rose from prior years, averaging 124 percent of actual load this quarter because of increased congestion on the 230kV system.

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour



Quarter	Avg DA Net Scheduled Load (% of RT Load)						
	Capital	Other East	West Upstate	NYC	LI	NYCA (Load Zones)	NYCA (Load Zones + External)
2015 Q2	78%	90%	94%	102%	110%	97%	94%
2015 Q1	84%	96%	96%	99%	110%	98%	95%
2014 Q2	85%	94%	92%	102%	109%	98%	95%

Virtual Trading Activity

- The following two charts summarize recent virtual trading activity in New York.
- The first figure shows monthly average scheduled and unscheduled quantities, and gross profitability for virtual transactions at the load zones in the past 24 months.
  - ✓ The table shows a screen for relatively large profits or losses, which identifies virtual trades with profits or losses larger than 50% of the average zone LBMP.
    - – Large profits may indicate modeling inconsistencies between DA and RT markets, and large losses may indicate manipulation of the day-ahead market.
- The second figure summarizes virtual trading by geographic region.
  - ✓ The load zones are broken into six regions based on typical congestion patterns.
    - – The North Zone is shown separately because transmission constraints frequently affect the value of power in that area.
    - – The Capital Zone is shown separately because it is constrained from West NY by the Central-East Interface and from SENY by constraints in the Hudson Valley.
    - – NYC and Long Island are shown separately because congestion frequently leads to price separation between them and other areas.
  - ✓ Virtual imports and exports are shown as they have similar effects on scheduling.
    - – A transaction is deemed virtual if the DA schedule is greater than the RT schedule, so a portion of these transactions result from forced outages or curtailments by NYISO or another control area (rather than the intent of the participant).

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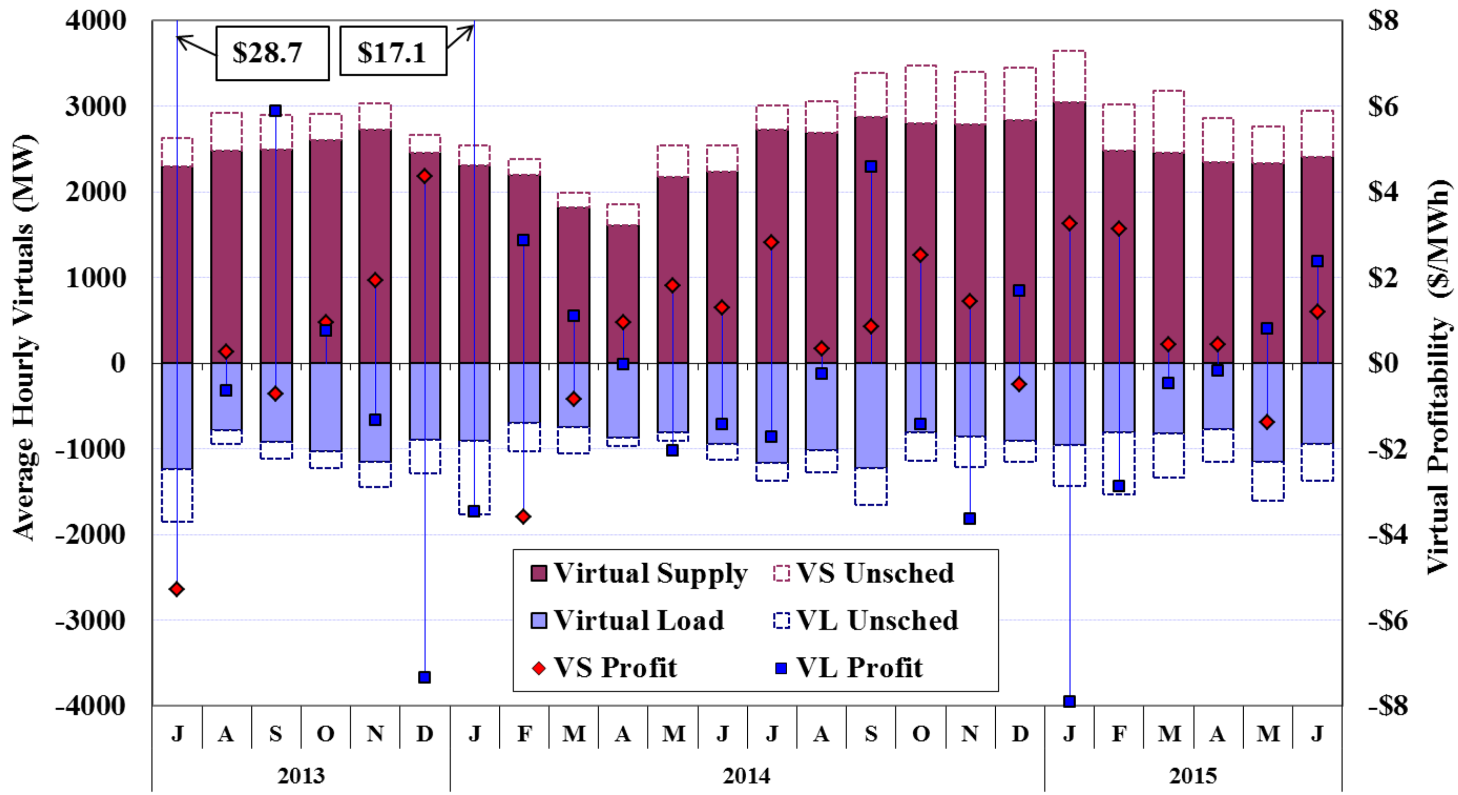
Virtual Trading Activity

- The volume of virtual trading did not change significantly in the second quarter of 2015, generally consistent with prior periods.
  - ✓ The pattern of virtual scheduling was similar as well.
    - Virtual traders generally scheduled more virtual load in downstate areas and more virtual supply in upstate regions.
    - This was consistent with typical load scheduling patterns.
- In aggregate, virtual traders netted a gross profit of roughly $2.6 million at the load zones and $0.8 million at the proxy buses in the second quarter of 2015.
  - ✓ Virtual transactions were profitable, indicating that they have generally improved convergence between DA and RT prices. For example, profitable virtual supply tends to reduce the DA price, bringing it closer to the RT price.
  - ✓ However, the profits and losses of virtual trades have varied widely by time and location, reflecting the difficulty of predicting volatile RT prices.
- The amount of virtual transactions that generated substantial profits and losses rose modestly this quarter.
  - ✓ These trades were primarily associated with high price volatility in May and June that resulted from unexpected events, which do not raise significant concerns.

Virtual Trading Activity at Load Zones by Month



		J 2013	A	S	O	N	D	J 2014	F	M	A	M	J	J	A	S	O	N	D	J 2015	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	345	156	206	230	438	319	590	260	250	83	169	160	421	136	289	522	387	313	460	453	270	244	450	599
	%	10%	5%	6%	6%	11%	10%	18%	9%	10%	3%	6%	5%	11%	4%	7%	15%	11%	8%	11%	14%	8%	8%	13%	18%
Loss > 50% of Avg. Zone Price	MW	252	176	182	201	369	258	395	333	256	70	196	199	346	185	289	428	371	306	412	359	316	278	578	573
	%	7%	5%	5%	6%	10%	8%	12%	12%	10%	3%	7%	6%	9%	5%	7%	12%	10%	8%	10%	11%	10%	9%	17%	17%

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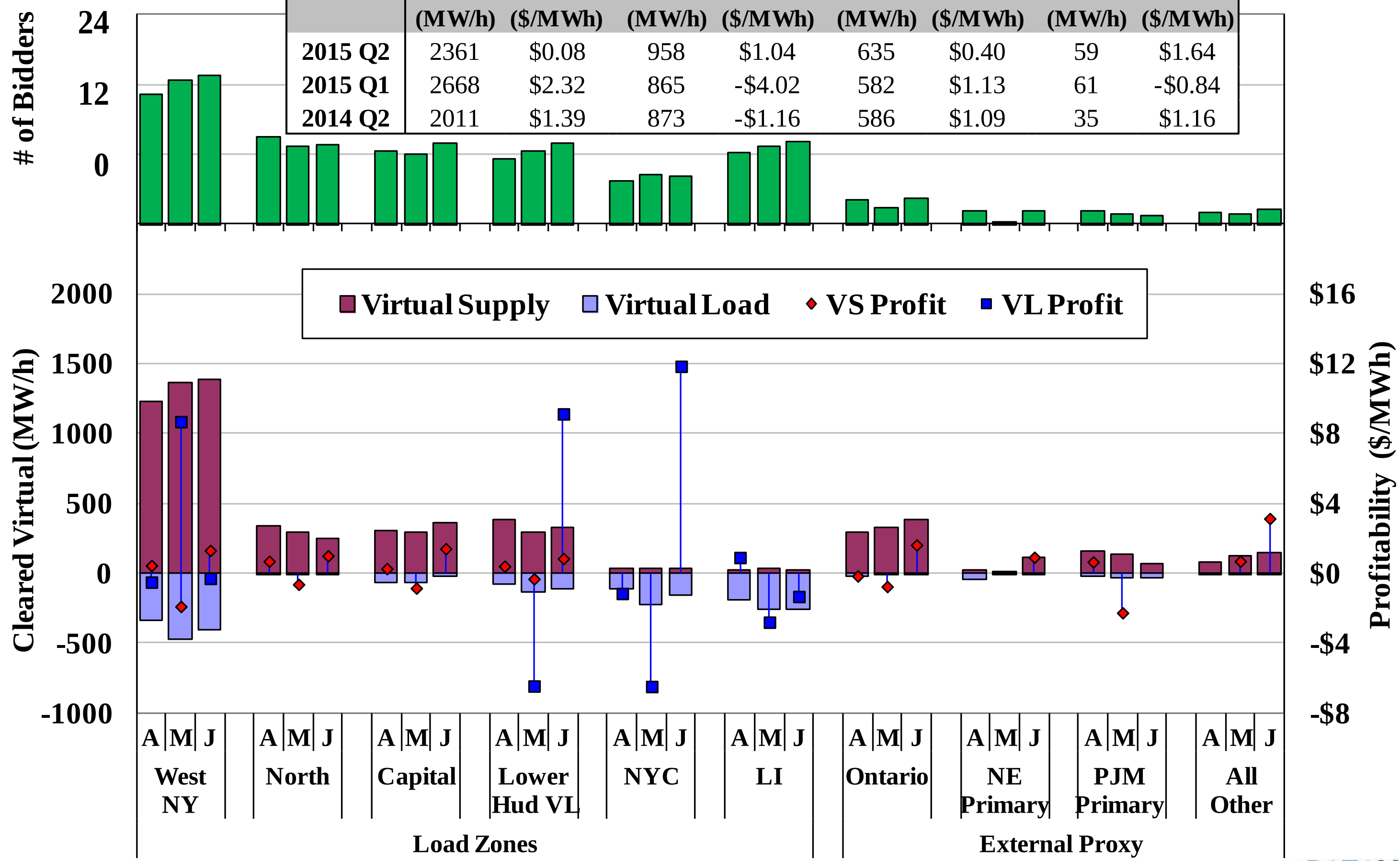
Virtual Trading Activity at Load Zones & Proxy Buses by Location

Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2015 Q2	2361	$0.08	958	$1.04	635	$0.40	59	$1.64
2015 Q1	2668	$2.32	865	-$4.02	582	$1.13	61	-$0.84
2014 Q2	2011	$1.39	873	-$1.16	586	$1.09	35	$1.16



Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.

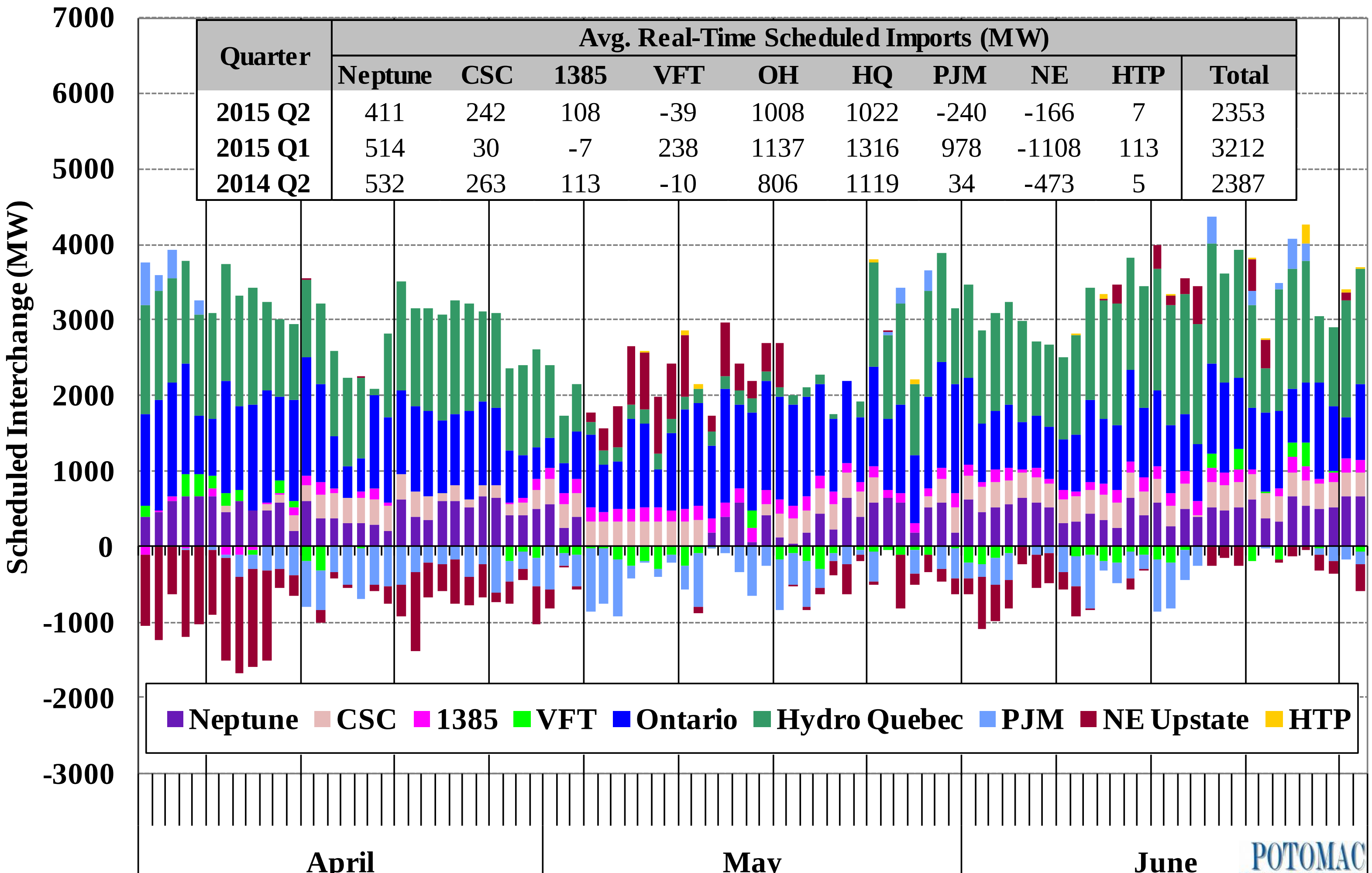
Net Imports Scheduled Across External Interfaces

- The next figure shows average RT scheduled net imports to NYCA across ten external interfaces (two HQ interfaces are combined) in the peak hours (1-9 pm).
- Overall, net imports averaged roughly 2,350 MW (serving roughly 14 percent of the load) during peak hours, comparable to the second quarter of 2014.
- Net exports to NE across the primary interface fell roughly 305 MW from last year.
  - ✓ These changes are consistent with the variations in natural gas price spreads.
    - – NY imported power from NE on many days in May and June when gas prices were cheaper on the NE side.
- Net imports from Ontario rose roughly 200 MW from a year ago.
  - ✓ This was partly offset by lower imports from HQ because the primary HQ interface was out of service during most of May.
  - ✓ The additional imports contributed to 230kV congestion in the West Zone.
- Net imports from PJM fell from the second quarter of 2014.
  - ✓ Natural gas prices in New York were low during most of the quarter compared to the rest of the country, reducing the incentives to import power from PJM.
  - ✓ Imports to Long Island across the Neptune line also fell roughly 120 MW from a year ago because of a nine-day outage in May.

Net Imports Scheduled Across External Interfaces

Daily Peak Hours (1-9pm)

Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2015 Q2	411	242	108	-39	1008	1022	-240	-166	7	2353
2015 Q1	514	30	-7	238	1137	1316	978	-1108	113	3212
2014 Q2	532	263	113	-10	806	1119	34	-473	5	2387



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Intra-Hour Scheduling with PJM
Coordinated Transaction Scheduling (“CTS”)

- The next table evaluates the performance of CTS with PJM at its primary interface for each month of the second quarter of 2015 (see Table A-8 in our 2014 SOM report for more detailed description). The table shows:
  - ✓ The percent of quarter-hour intervals during which the interface flows were adjusted (relative to the base schedule) in the scheduling RTC interval.
  - ✓ The average flow adjustment from the base schedule.
  - ✓ The production cost savings that resulted from the CTS, including:
    - Projected savings at scheduling time, which is the expected production cost savings at the time when RTC determines the interchange schedule.
    - Unrealized savings, which are not realized due to: a) New York forecast error; b) PJM forecast error; and c) other factors.
    - Actual savings (= Projected – Unrealized).
  - ✓ Interface prices on both NY and PJM sides that include actual prices (i.e., NY RT prices and PJM RT prices) and forecasted prices at the time of RTC scheduling (i.e., NY RTC prices and PJM IT SCED prices).
  - ✓ Price forecast errors, which show the average difference and the average absolute difference between the actual and forecasted prices on both sides.

Intra-Hour Scheduling with PJM
Coordinated Transaction Scheduling ("CTS")

- Interchange between NY and PJM was adjusted relatively evenly under CTS in both the import and export directions. In the second quarter of 2015:
  - ✓ On average, 77 MW of flows were adjusted in the export direction to PJM in 32 percent of intervals, while 74 MW of flows were adjusted in the import direction to NY in 36 percent of intervals.
- Sizable benefits (measured by production cost savings) were projected at the time of scheduling, but a relatively small portion was realized primarily because of price forecast errors in both markets. In the second quarter of 2015:
  - ✓ A total of $3.7 million in production cost savings was estimated at the time when RTC determined final schedules. However,
    - – NY price forecast errors accounted for a reduction of $1.6 million in savings; and
    - – PJM price forecast errors accounted for an additional reduction of $1.5 million.
- Average forecast errors were similar between the New York side and the PJM side.
  - ✓ On the NY side, forecast errors generally increased during periods of RT congestion, particularly in the West Zone where congestion prices were highly volatile.
  - ✓ On the PJM side, forecast errors fell significantly in the month of June from previous months.

Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM Interface

			Export (NY to PJM)			Import (PJM to NY)			Average/ Total
			Apr-15	May-15	Jun-15	Apr-15	May-15	Jun-15	
% of All Intervals			35%	35%	27%	34%	41%	35%	**69%**
Average Flow Adjustment (MW)			-80	-87	-63	68	77	78	**3 (Net) / 76 (Gross)**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.90	$1.08	$0.08	$0.11	$1.00	$0.55	**$3.7**
	Unrealized Savings Due to:	NY Fcst. Err.	-$0.05	-$0.26	-$0.05	-$0.07	-$0.80	-$0.34	**-$1.6**
		PJM Fcst. Err.	-$0.73	-$0.85	-$0.02	-$0.04	$0.08	$0.04	**-$1.5**
		Other	-$0.02	-$0.01	$0.00	$0.00	-$0.02	-$0.03	**-$0.1**
	Actual		$0.09	-$0.03	$0.02	-$0.01	$0.27	$0.23	**$0.6**
Interface Prices ($/MWh)	NY	Actual	$25.39	$30.96	$21.60	$23.39	$34.03	$30.28	**$28.03**
		Forecast	$23.83	$24.80	$19.14	$24.38	$47.27	$34.86	**$29.96**
	PJM	Actual	$29.51	$30.70	$24.04	$26.86	$30.28	$24.80	**$27.92**
		Forecast	$40.87	$47.62	$26.71	$25.62	$31.60	$26.28	**$33.35**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	-$1.57	-$6.16	-$2.46	$0.99	$13.23	$4.58	**$1.93**
		Abs. Val.	$5.86	$15.17	$7.76	$7.12	$26.64	$14.34	**$13.42**
	PJM	Fcst. - Act.	$11.36	$16.92	$2.67	-$1.23	$1.33	$1.48	**$5.44**
		Abs. Val.	$18.75	$23.46	$8.31	$7.51	$10.12	$8.19	**$12.84**

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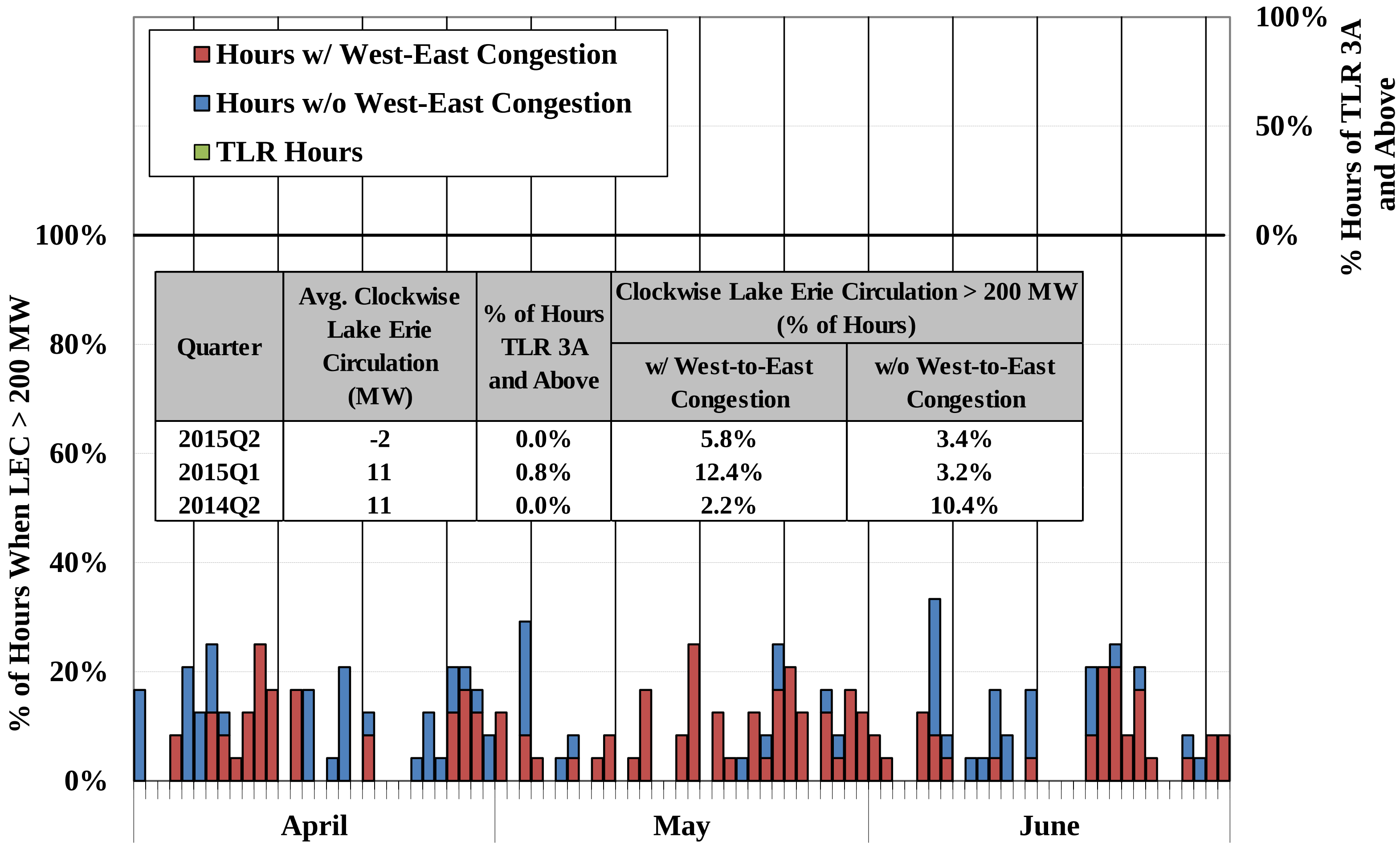
Lake Erie Circulation

- Loop flows occur when physical flows are not consistent with the scheduled path of a transaction between control areas or within a control area (from a generator to a load), so loop flow patterns are affected by many factors.
  - ✓ Clockwise Lake Erie Circulation ("LEC") use west-to-east transmission in upstate NY, reducing capacity available for scheduling internal generation to satisfy internal load and increasing congestion (e.g., on the Central-East interface).
- The figure summarizes the frequency of clockwise LEC and the frequency of TLRs (level 3A and above) called by the NYISO in the second quarter of 2015.
- Clockwise LEC was relatively high (average > 200 MW) in 9 percent of all hours.
  - ✓ West-to-east congestion (including congestion in the West Zone, from West-to-Central, and from Central-to-East) occurred in roughly 63 percent of these hours.
    - – In particular, large variations in LEC are a leading contributor of volatile West Zone congestion (see 2014 SOM report, Section IX.E for more details).
- The frequency of TLRs called by the NYISO has been relatively low for the last three years – there were no TLR calls in the second quarter of 2015.
  - ✓ Loop flows have fallen since the IESO-MI PARs went in service in April 2012.
  - ✓ The NYISO is unable to use TLRs to manage congestion resulting from loop flows when the IESO-Michigan PARs are deemed in "regulate" mode.

Clockwise Lake Erie Circulation and TLR Calls



Quarter	Avg. Clockwise Lake Erie Circulation (MW)	% of Hours TLR 3A and Above	Clockwise Lake Erie Circulation > 200 MW (% of Hours)	
			w/ West-to-East Congestion	w/o West-to-East Congestion
2015Q2	-2	0.0%	5.8%	3.4%
2015Q1	11	0.8%	12.4%	3.2%
2014Q2	11	0.0%	2.2%	10.4%

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Day-Ahead and Real-Time Transmission Congestion

Congestion Patterns, Revenues, and Shortfalls

- The next four figures evaluate the congestion patterns in the day-ahead and real-time markets 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 day-ahead market, which is the primary funding source for TCC payments.
  - ✓ Day-Ahead Congestion Shortfalls occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - Shortfalls (or surpluses) generally arise when the TCCs on a path exceeds (or is below) the transfer capability of the path modeled in the day-ahead market during periods of congestion.
    - These typically result from modeling assumption differences between the TCC auction and the DA market, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ Balancing Congestion Shortfalls arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.
    - The transfer capability of a constraint falls (or rises) from DA to RT 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).

Congestion Patterns, Revenues, and Shortfalls

- The first figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years on a monthly basis.
- The second figure 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.
- The third and fourth figures 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.
- 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.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.

Day-Ahead and Real-Time Congestion

(cont. from prior slide)

- ✓ North Zone Lines: Including transmission lines in the North Zone.
- ✓ Capital to Hudson Valley: Primarily lines leading into Southeast New York (e.g., the Leeds-Pleasant Valley Line, the New Scotland-Leeds Line).
- ✓ 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.

- Day-ahead congestion revenue totaled $73 million this quarter, up 44 percent from the second quarter of 2014.
  - ✓ Larger gas spreads between West NY and East NY led to increased congestion across the Central-East interface and on transmission paths into SENY.
  - ✓ Congestion on the West Zone 230 kV lines increased from a year ago, partly because of lower coal-fired production in the West Zone and decreased PJM imports (coal units and PJM imports help to relieve this congestion).

Day-Ahead and Real-Time Congestion

- West Zone accounted for the largest share (> 35%) of total DA/RT congestion.
  - ✓ This occurred primarily on the Niagara-Packard and Packard-Sawyer 230kV lines.
- Congestion was more severe and volatile in RT than DA on some intra-zonal paths.
  - ✓ In the West Zone, congestion on 230kV facilities often increased in RT because:
    - Lake Erie loop flow was volatile, and fluctuations in the clockwise direction contribute to acute congestion price spikes on these facilities;
    - Re-dispatch options were limited sometimes in real-time as a result of congestion on parallel 115 kV facilities.
    - Changes in offer patterns between the DAM and RT (that tended to increase flow across these facilities); and
    - Operation of the ABC, JK, and Ramapo PARs (to relieve Central-East and Capital-Hudson VL congestion) increased flows across the constraints in the West Zone.
  - ✓ In the Central Zone, congestion increased in RT as a result of changes in offer patterns between the DAM and RT.
  - ✓ In NYC, congestion into the Greenwood load pocket increased in RT because of changes in offer patterns between the DAM and RT and the tendency for brief small transmission constraint violations to cause very high shadow prices in RT.

Day-Ahead Congestion Shortfalls

- DA shortfalls totaled $6 million, down 50 percent from the second quarter of 2014.
- Transmission outages accounted for a large share of shortfalls – roughly $5 million of shortfalls were allocated to the responsible TO in the second quarter of 2015.
  - ✓ Several facilities connected to the Niagara 115 kV buses were OOS during most of the quarter, contributing to transmission bottlenecks on West Zone 230 kV lines.
    - – In addition, differences between the TCC auction and the DAM in the assumed amount of 115 kV Niagara generation contributed a net $3 million to shortfalls.
      - On average, the assumed amount of 115 KV Niagara generation in the TCC auction was higher than in the DAM by more than 300 MW .
  - ✓ The majority of the $2.2 million of shortfalls on Long Island accrued on the transmission lines from upstate into Long Island.
    - – One of the two 345 kV lines was operating at reduced capacity from late April to mid-June because of one PAR outage; the other 345 kV line tripped in mid-June and was forced out of service for the rest of the quarter.
    - – However, the PAR-controlled lines between NYC and LI (i.e., 901/903 lines) generated $1.6 million of surpluses in hours when the lines were scheduled to flow less than the contractual amount assumed in TCC auctions, offsetting the shortfalls.
- $2 million of surpluses accrued on transmission lines from Capital to Hudson Valley, most of which occurred in mid-May and mid-June because of changes in flow patterns between the TCC auction and the DAM.

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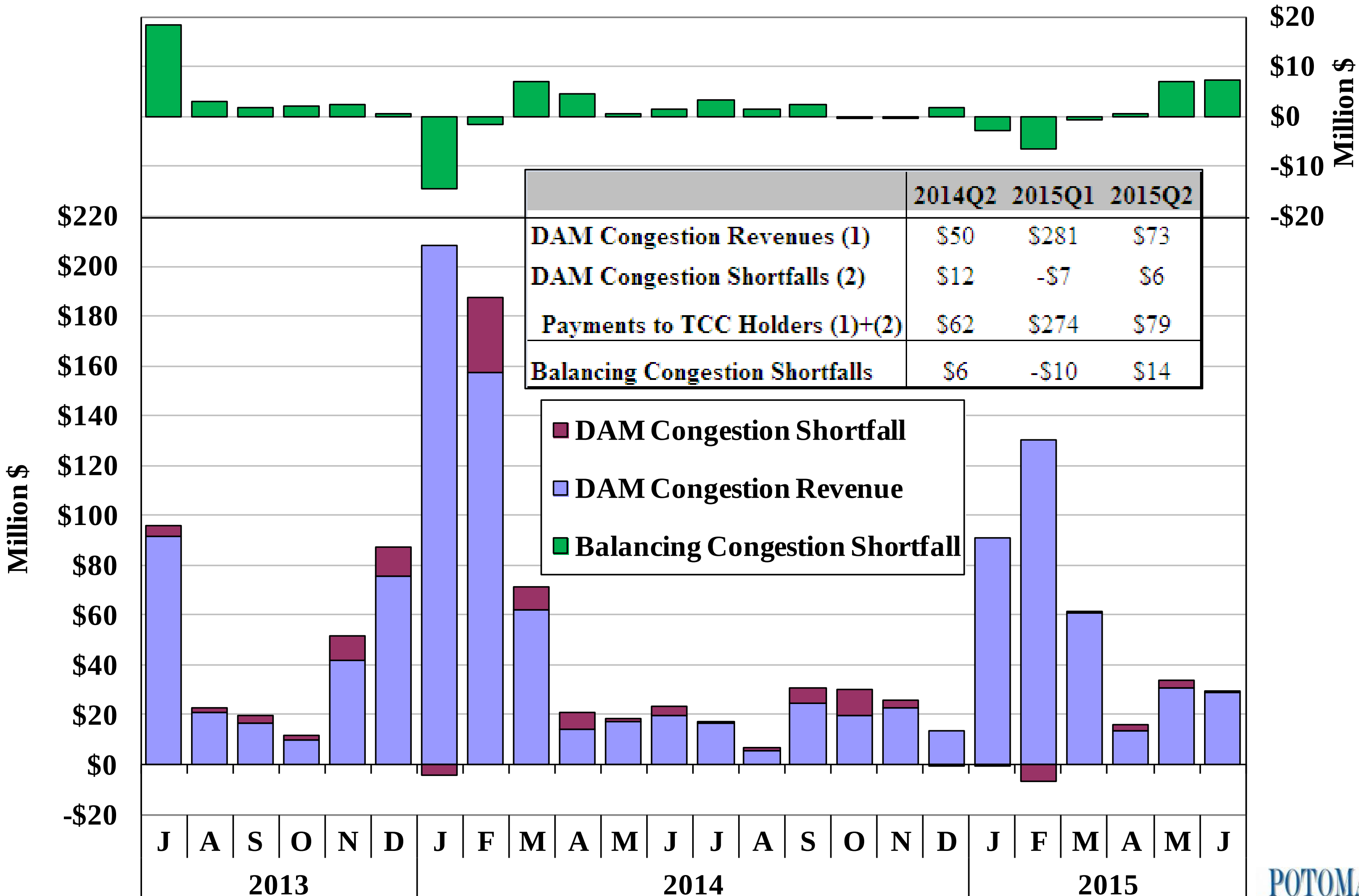
Balancing Congestion Shortfalls

- Balancing congestion shortfalls totaled $14 million, up $8 million from a year ago.
- The majority of shortfalls ($9 million) were associated with West Zone congestion.
  - ✓ Line deratings, transmission outages, and unexpected changes in loop flows contributed to $5.1 million of shortfalls.
    - These shortfalls were partly offset by the operation of the Dunkirk-South Ripley and Warren-Falconer lines, which were frequently taken OOS to manage congestion on the 115 kV system (also help to relieve 230 kV congestion).
  - ✓ Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $2.7 million to shortfalls on the West Zone lines.
    - However, the additional flows contributed $1.2 million of surpluses on other transmission facilities (e.g., Central-East interface & Leeds-to-Pleasant Valley).
  - ✓ Differences between the assumed amount of 115 kV Niagara generation in the DAM and the actual amount contributed a net $1.5 million to shortfalls, primarily on 4/7 and 6/7.
- Other shortfalls were large on a few days with unexpected events. For example:
  - ✓ On June 19, over $1 million of shortfalls accrued on Long Island driven by the trip of the Dunwoodie-Shore Rd Line. This was partly offset by $0.5 million of surplus (see ‘All Other’ category) from 901/903 PAR operations in response to the trip.
  - ✓ On June 22 and 23, the combined effects of a solar-magnetic event and TSAs resulted in $3.2 million of shortfalls. These events require conservative operation of the transmission system, reducing the available transfer capability.

Congestion Revenues and Shortfalls by Month



	2014Q2	2015Q1	2015Q2
DAM Congestion Revenues (1)	$50	$281	$73
DAM Congestion Shortfalls (2)	$12	-$7	$6
Payments to TCC Holders (1)+(2)	$62	$274	$79
Balancing Congestion Shortfalls	$6	-$10	$14

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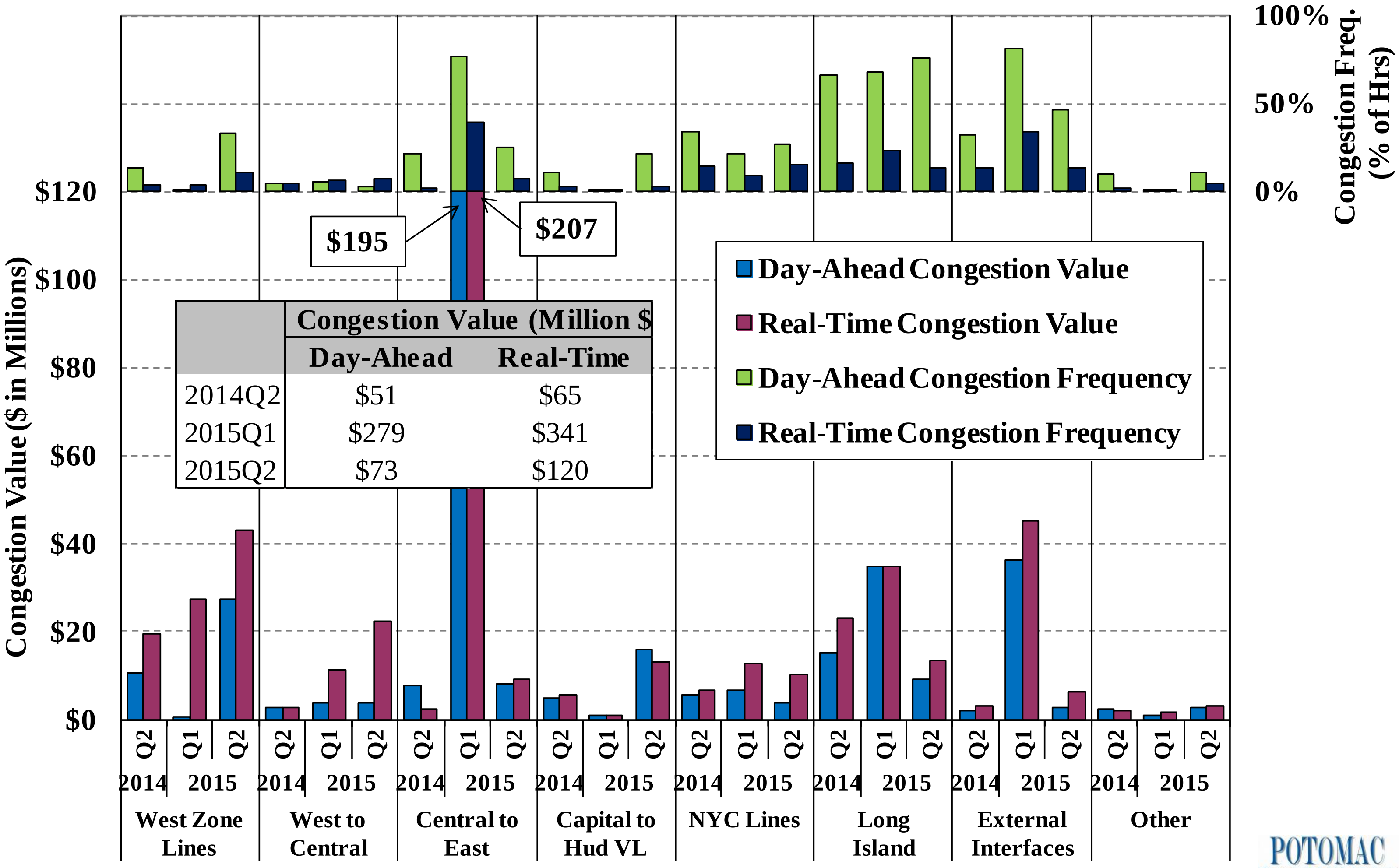
DA and RT Congestion Value and Frequency by Transmission Path



	Congestion Value (Million $	
	Day-Ahead	Real-Time
2014Q2	$51	$65
2015Q1	$279	$341
2015Q2	$73	$120

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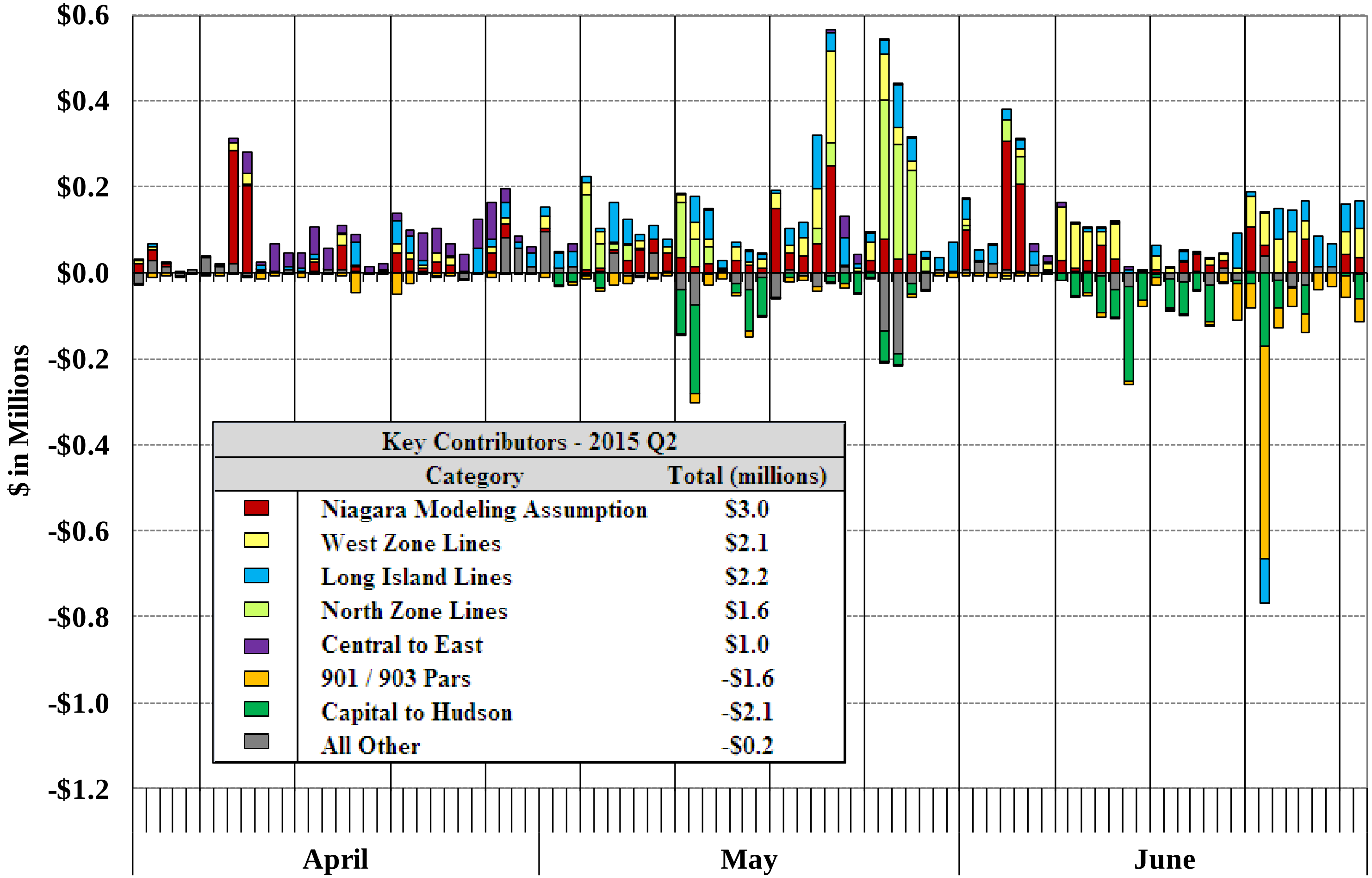
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Key Contributors - 2015 Q2

Category	Total (millions)
Niagara Modeling Assumption	$3.0
West Zone Lines	$2.1
Long Island Lines	$2.2
North Zone Lines	$1.6
Central to East	$1.0
901 / 903 Pars	-$1.6
Capital to Hudson	-$2.1
All Other	-$0.2

Note: "Niagara Modeling Assumption" estimates the shortfalls resulted from differences in assumed generation at the Niagara 115 kV Buses between TCC and DAM (for DAMCR) and between DAM and RT actual (for BMCR).

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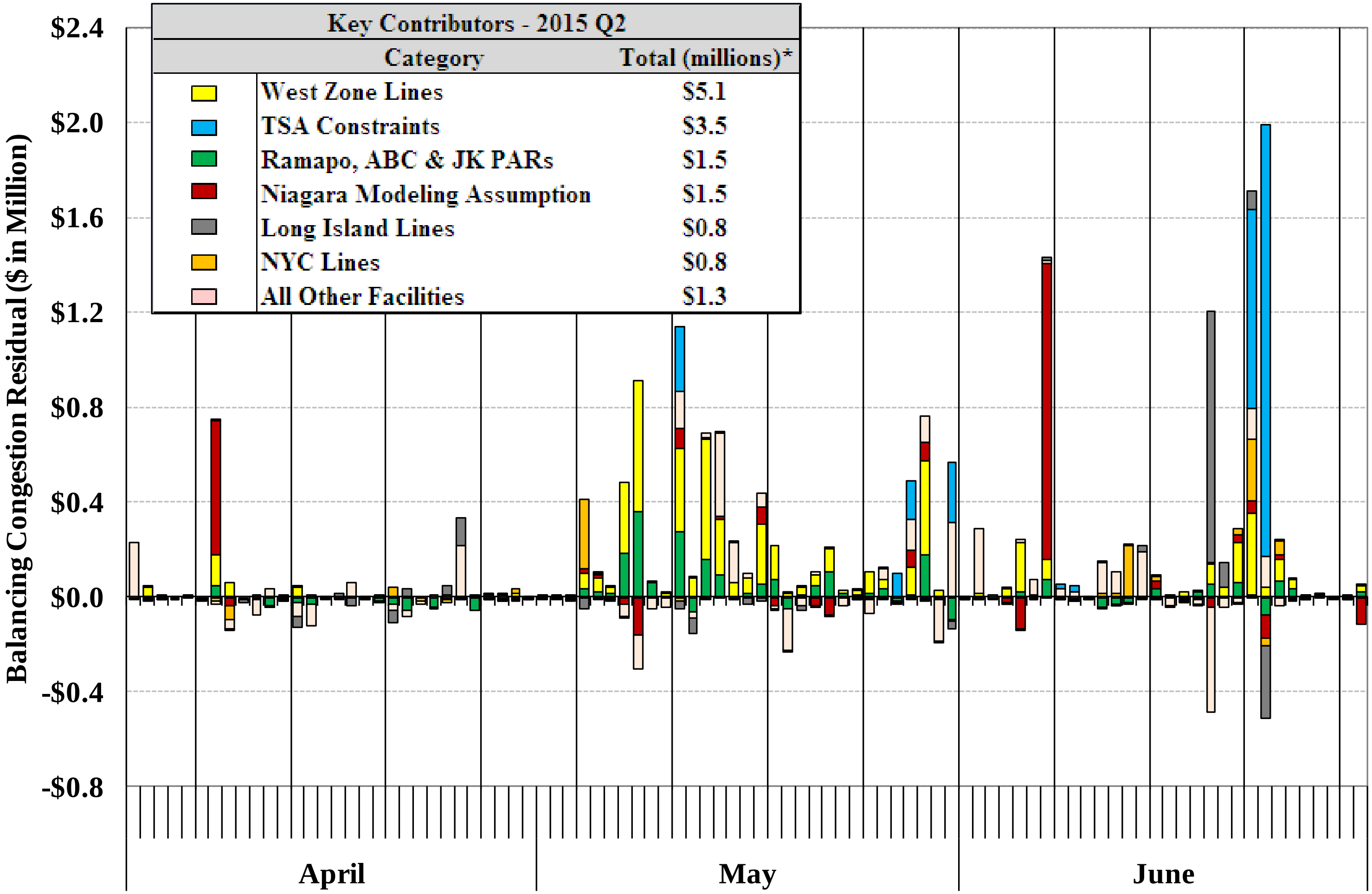
Balancing Congestion Shortfalls by Transmission Facility



Note: The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values.

Operations under M2M with PJM

- Coordinated congestion management between NYISO and PJM (“M2M”) includes two types of coordination:
  - ✓ Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.
  - ✓ Ramapo PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, the Ramapo PARs are adjusted to reduce overall congestion.
- The following figure evaluates the operation of Ramapo PARs this quarter, which compares the actual flows on Ramapo PARs with their M2M operational targets.
  - ✓ The M2M target flow has the following components:
    - Share of PJM-NY Over Ramapo – Based on the share of PJM-NY flows that were assumed to flow across the Ramapo Line (61% in the second quarter of 2015).
    - 80% RECo Load – 80 percent of telemetered Rockland Electric Company load.
    - ABC & JK Flow Deviations – The total flow deviations on ABC and JK PAR-controlled lines from schedules under the normal wheeling agreement.
  - ✓ The figure shows these average quantities over intervals when M2M constraints for Ramapo Coordination were binding on a daily basis (excluding days with fewer than 12 binding intervals).

Operations under M2M with PJM

- The use of Re-dispatch Coordination is generally very infrequent.
  - ✓ It was never activated in the second quarter of 2015.
- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred in 10 percent of intervals this quarter, up from 4 percent in the second quarter of the prior year.
  - ✓ This reflected more frequent congestion on the M2M constraints (e.g., the Central-East interface and transmission paths from Capital to Hudson Valley) than a year ago.
- Average actual flows across Ramapo exceeded the M2M Target Flow by roughly 560 MW in this quarter (when M2M constraints were binding).
  - ✓ The additional flow above the Target helped the NYISO relieve congestion on M2M Flowgates.
  - ✓ They also reduced M2M payments from PJM down close to zero this quarter.
- Although Ramapo PAR Coordination provided congestion relief on key paths from West to East (e.g., the Central-East interface), there were times when additional flows across Ramapo contributed to congestion in the West Zone.

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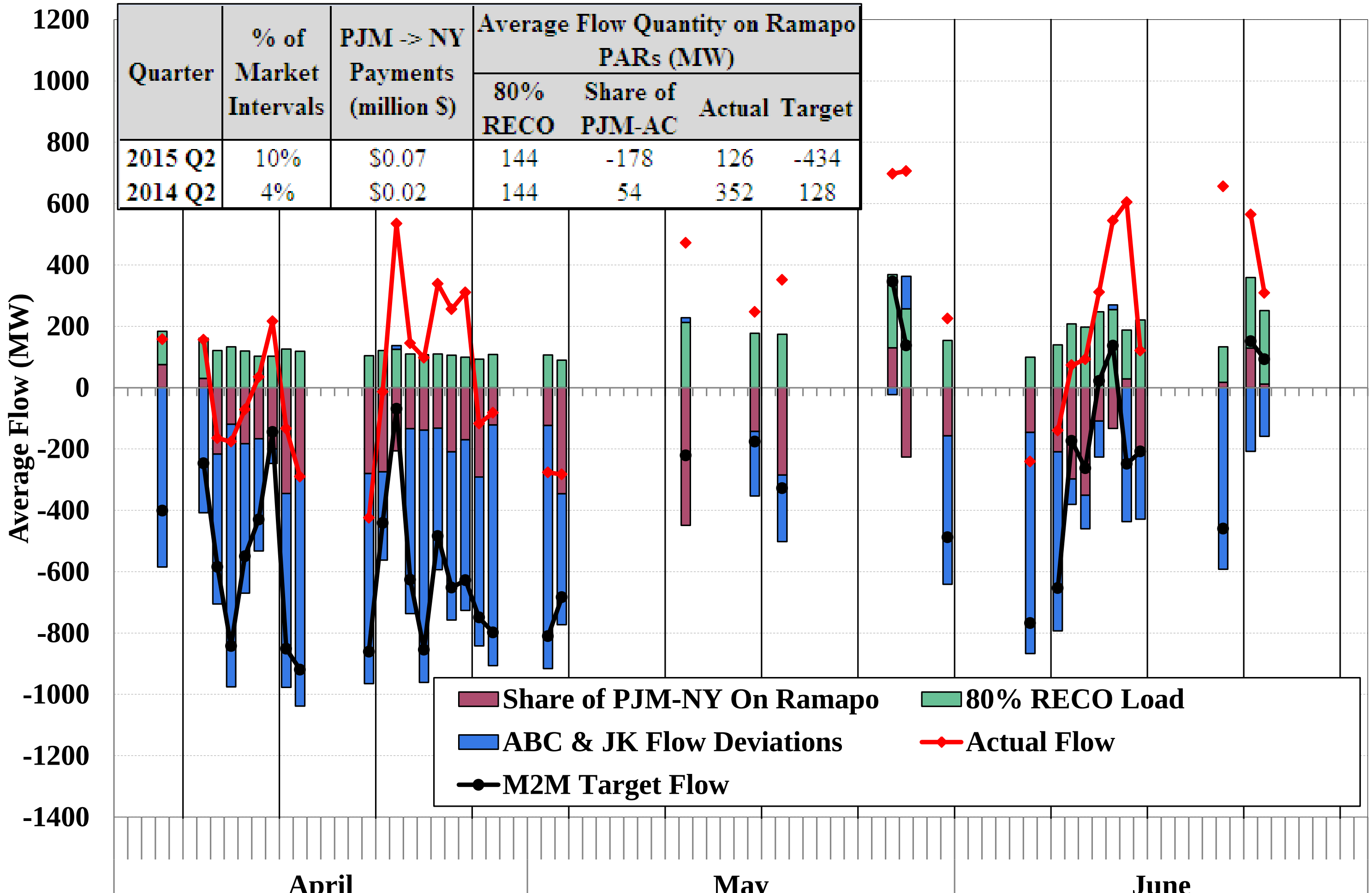
Actual and Target Flows for the Ramapo Line
During the Intervals with Binding M2M Constraints

Quarter	% of Market Intervals	PJM -> NY Payments (million $)	Average Flow Quantity on Ramapo PARs (MW)			
			80% RECO	Share of PJM-AC	Actual	Target
2015 Q2	10%	$0.07	144	-178	126	-434
2014 Q2	4%	$0.02	144	54	352	128



Note: This chart does not show the days during which M2M constraints were binding in less than 12 intervals.

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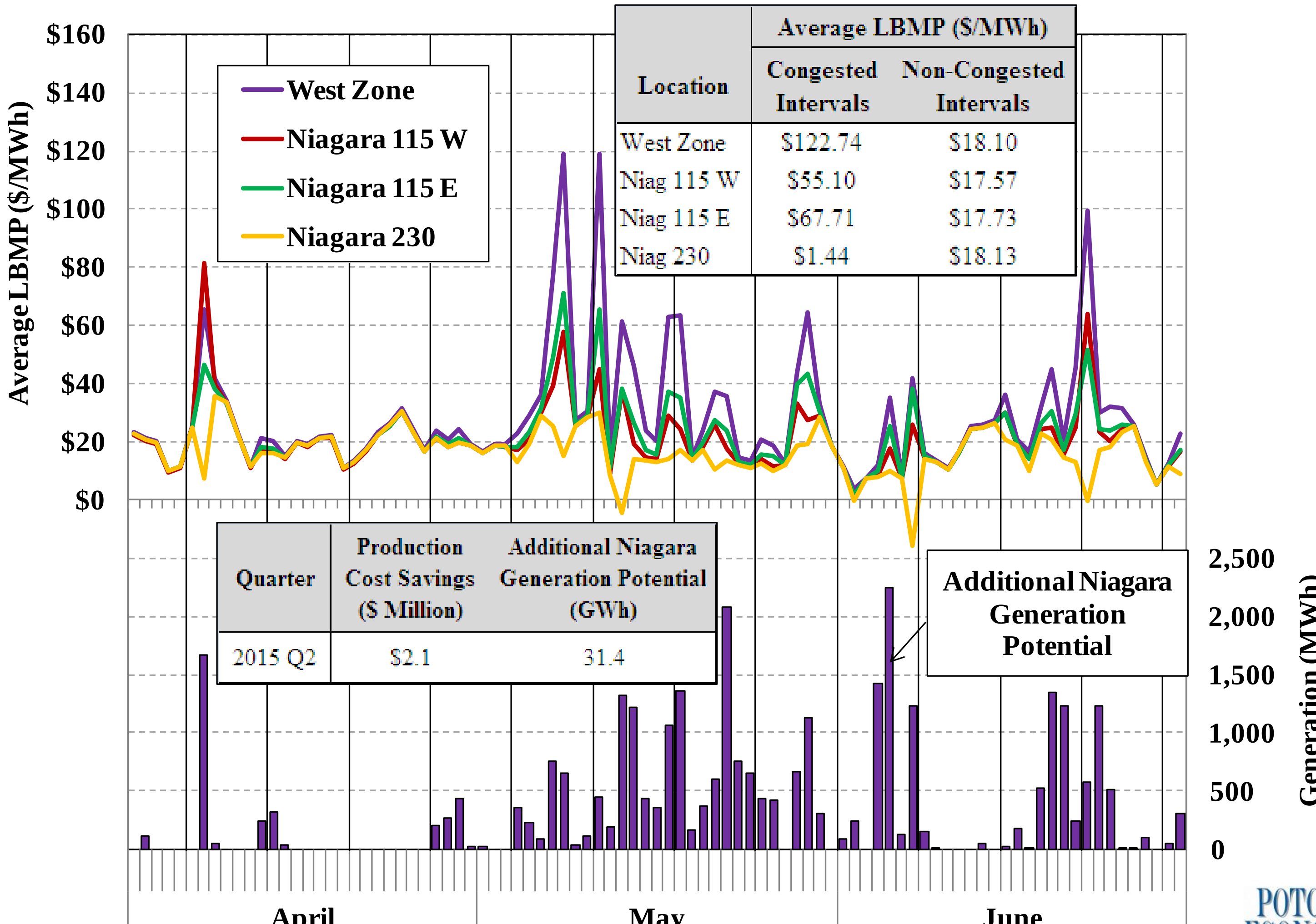
West Zone Congestion and Niagara Generation

- Transmission constraints on the 230kV network in the West Zone have become more frequent in recent years, limiting the flow of power towards Eastern NY.
  - ✓ Niagara units on the 115kV system tend to relieve these constraints, while ones on the 230kV system exacerbate this congestion.
  - ✓ However, these impacts are not considered by the optimization engine that schedules generation at the Niagara plant.
    - – The optimization treats Niagara as a single bus for pricing and dispatch.
    - – Manual instructions are used to shift generation among the individual units at the Niagara plant to alleviate congestion (see slide 65).
- The next figure estimates the potential benefits that might have occurred if the distribution of generation at Niagara was optimized in the second quarter of 2015.
  - ✓ Production Cost Savings – Estimated savings from shifting generation from 230kV units to 115kV units that have available head room at the Niagara plant.
  - ✓ Additional Niagara Generation Potential – Additional Niagara generation (in MWhs) that would be deliverable if output from the 115kV units was maximized.
  - ✓ The figure shows average estimated LBMPs for the West Zone, Niagara 230 kV Bus, Niagara East 115 kV Bus, and Niagara West 115 kV Bus – This illustrates the impact of shifting generation among individual Niagara units.

West Zone Congestion and Niagara Generation

- The LBMPs at the Niagara 115 kV and 230 kV Buses were very similar when West Zone congestion was not present.
  - ✓ However, LBMP differences were significant during periods of congestion. In the second quarter of 2015:
    - – West Zone 230 kV congestion occurred in roughly 10 percent of all intervals; and
    - – On average, LBMPs were an estimated \$55 to \$65/MWh higher at the Niagara 115 kV Buses than at the Niagara 230 kV Buses during these intervals.
- Optimizing the distribution of generation at the Niagara plant would significantly reduce congestion costs on days when congestion occurs in Western NY. We estimate that if the distribution was optimized (while considering both 115 kV and 230 kV constraints in the West Zone):
  - ✓ Production costs would have been reduced by an estimated \$2.1 million in the second quarter of 2015 (assuming no changes in the constraint shadow costs).
  - ✓ An additional 31 GWh of Niagara generation would have been deliverable.
    - – This would have reduced LBMPs in other zones as well, although we have not estimated the effect on statewide average LBMPs.

West Zone Congestion and Niagara Generation
Second Quarter of 2015



Location	Average LBMP ($/MWh)	
	Congested Intervals	Non-Congested Intervals
West Zone	$122.74	$18.10
Niag 115 W	$55.10	$17.57
Niag 115 E	$67.71	$17.73
Niag 230	$1.44	$18.13

Quarter	Production Cost Savings ($ Million)	Additional Niagara Generation Potential (GWh)
2015 Q2	$2.1	31.4

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Supplemental Commitments, OOM Dispatch, and Uplift Charges

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- The next three figures summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
  - ✓ The first figure 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; and
    - – Supplemental Resource Evaluation (“SRE”) Commitment – occurs after the DAM.
    - – Forecast Pass Commitment – occurs after the economic commitment in the DAM.
  - ✓ The second figure examines the reasons for reliability commitments in NYC where most reliability commitments occur. (This is described on the following slide.)
  - ✓ The third figure 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, the two stations with the highest number of OOM dispatch hours in the current quarter are shown separately.

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- Based on a review of operator logs and LRR constraint information, each New York City commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:
  - ✓ NOx Only – If needed for NOx bubble requirement and no other reason.
  - ✓ Voltage – If needed for ARR 26 and no other reason except NOx.
  - ✓ Thermal – If needed for ARR 37 and no other reason except NOx.
  - ✓ Loss of Gas – If needed for IR-3 and no other reason except NOx.
  - ✓ Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, IR-3. The capacity is shown for each separate reason in the bar chart.
- A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.
- For voltage and thermal constraints, the capacity is shown by the following load pocket that was secured:
  - ✓ (a) AELP = Astoria East; (b) AWLP = Astoria West/Queensbridge; (c) AVLP = Astoria West/Queensbridge/ Vernon; (d) ERLP = East River; (e) FRLP = Freshkills; (f) GSLP = Greenwood/ Staten Island; and (g) SDLP = Sprainbrook/Dunwoodie.

Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results

- An average of 910 MW of capacity was committed for reliability in the second quarter of 2015, comparable to the second quarter of 2014.
  - ✓ Of the capacity committed for reliability in the second quarter, 72 percent was in New York City, 21 percent was in Western NY, and only 5 percent was in Long Island.
- Reliability commitments in West NY averaged 190 MW this quarter, up modestly from the second quarter of 2014.
  - ✓ The West Zone accounted for 61 percent of reliability commitment and the Central Zone accounted for another 34 percent.
    - Several coal-fired and gas-fired units were often needed to manage post-contingency flows on 115kV facilities.
    - These units were frequently DARUed because they were often not economic given low LBMPs.
- Reliability commitments rarely occurred in Long Island this quarter.
  - ✓ DARU commitments became less frequent after mid-2014 when transmission upgrades reduced the need to: a) commit generation for voltage constraints on LI (see ARR 28); and b) burn oil to protect LI from a loss of gas (see IR-5).
  - ✓ SRE commitments mainly kept steam units online during overnight hours.

Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results in New York City

- Reliability commitments in New York City averaged roughly 660 MW this quarter, up 23 percent from the second quarter of 2014.
  - ✓ The increase was partly due to decreased gas spreads between NYC and the rest of Eastern NY, which led NYC generators to be committed economically less often.
    - For example, although the Arthur Kill units were not committed more frequently, they were flagged more frequently for Freshkills load pocket reliability this quarter than in the second quarter of 2014.
  - ✓ The increase was partly attributable to transmission and generation outages in some load pockets of New York City.
    - Reliability needs for Greenwood/Staten Island rose in April because of transmission line outages.
    - Generator outages increased the need to commit steam units in the Astoria West/Queensbridge load pocket to satisfy local thermal and voltage requirements.
  - ✓ Units were flagged much less frequently for NOx-Only commitments than in the second quarter of 2014.
    - The units that are required to satisfy the NOx Bubble requirements were often needed at the same time for local voltage and/or thermal requirements this quarter for the reasons discussed above.

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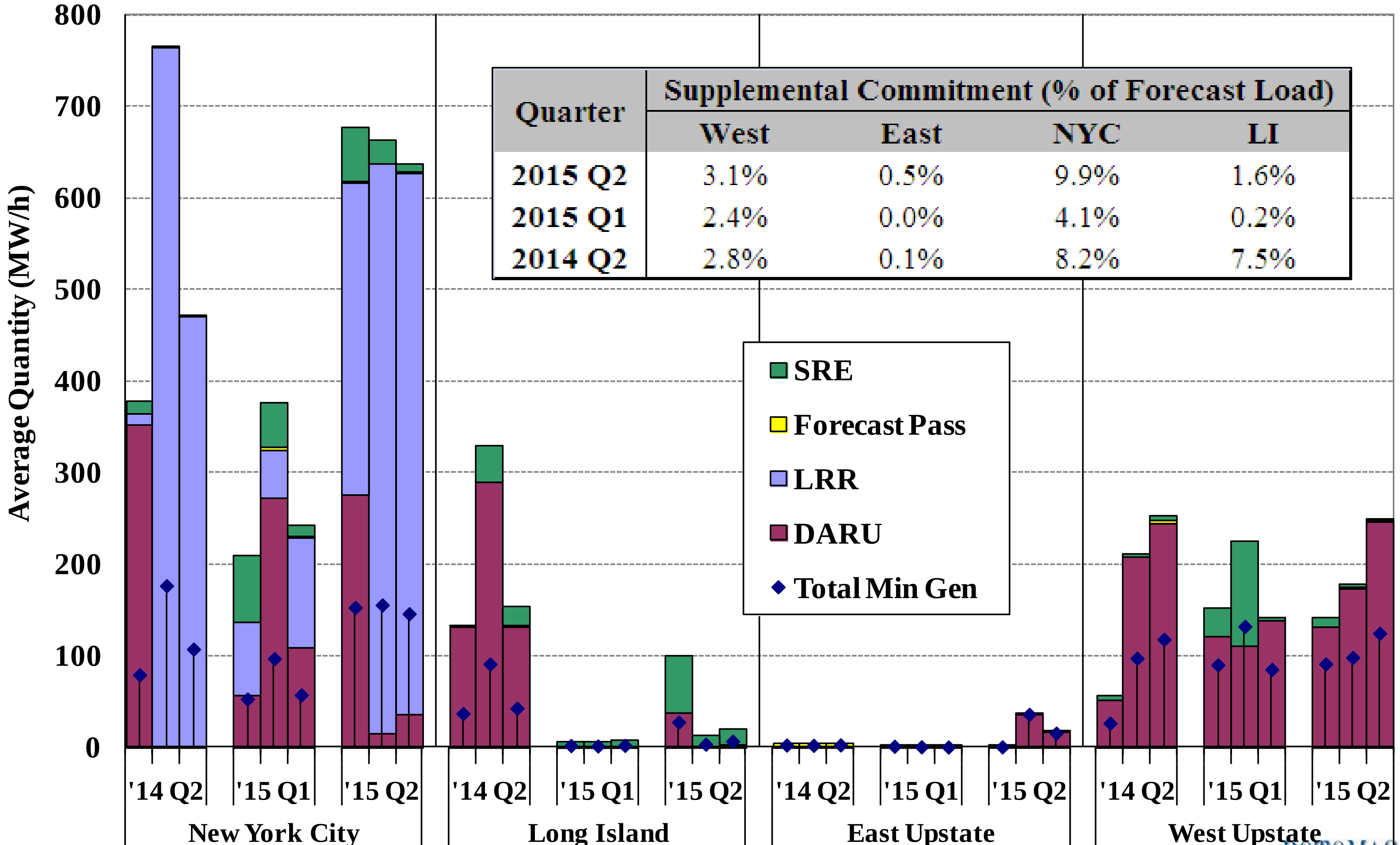
Supplemental Commitment and OOM Dispatch: OOM Dispatch Results

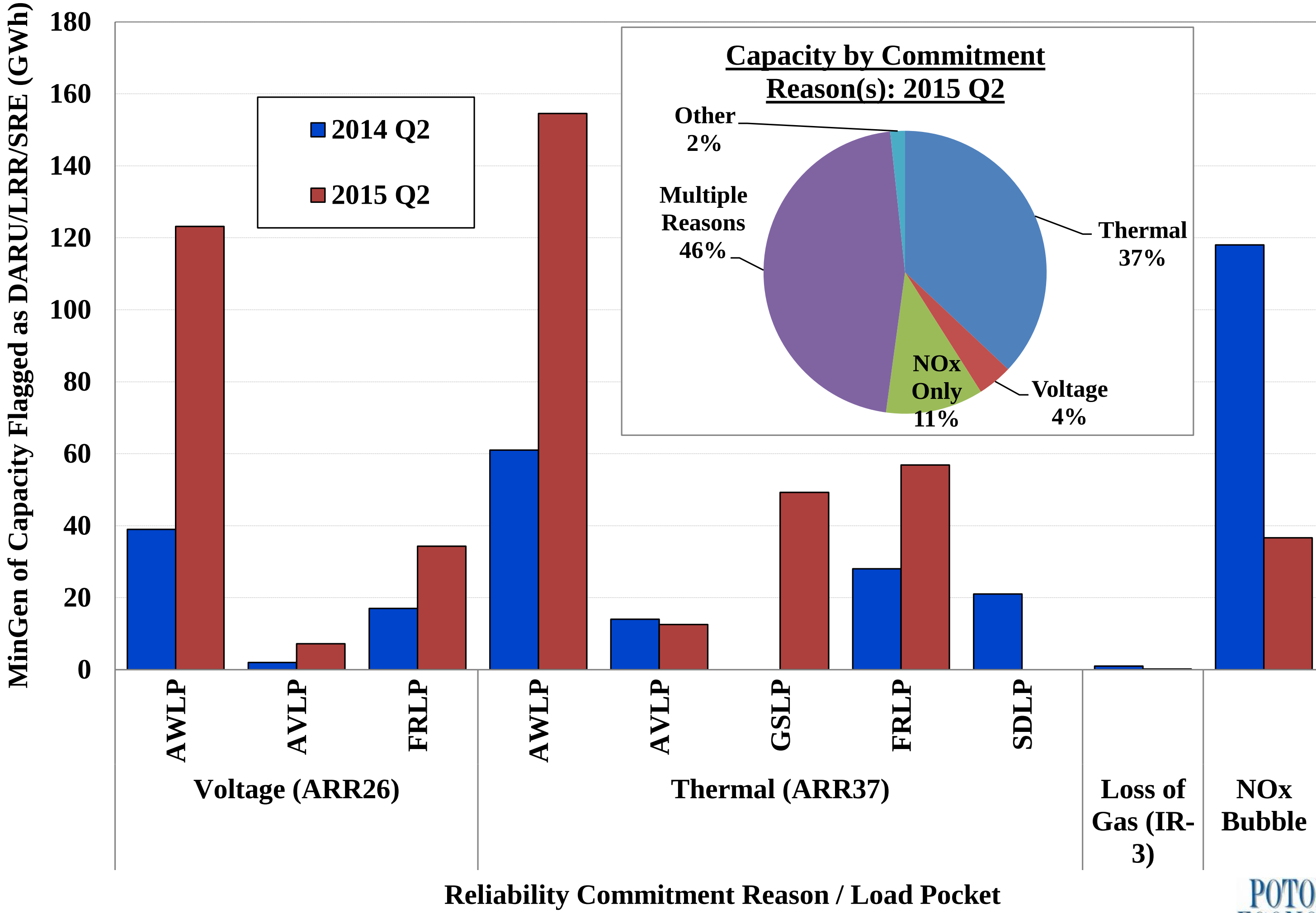
- The NYISO and local TOs sometimes dispatch generators out-of-merit in order to:
  - ✓ Maintain reliability of the lower-voltage transmission and distribution networks; or
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model.
- Generators were dispatched Out-of-Merit ("OOM") for approximately 1,760 station-hours, up 140 percent from the second quarter of 2014.
  - ✓ Of the total OOM station-hours, Western NY accounted for 79 percent, New York City accounted for 15 percent, and Long Island accounted for 4 percent.
- The amount of OOM dispatch in Eastern NY was relatively low this quarter in spite of a modest increase from the second quarter of 2014.
- However, OOM dispatch in Western NY rose significantly this quarter, up 160 percent from a year ago.
  - ✓ The Dunkirk and Milliken coal units were frequently OOMed to prevent post-contingency overloading on several 115 kV transmission lines in Western NY.
- The Niagara facility was often manually instructed to shift output to the 115kV system when 230kV constraints were binding. However, in some hours, output was shifted to the 230kV system to relieve 115kV constraints.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2015 Q2	3.1%	0.5%	9.9%	1.6%
2015 Q1	2.4%	0.0%	4.1%	0.2%
2014 Q2	2.8%	0.1%	8.2%	7.5%

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



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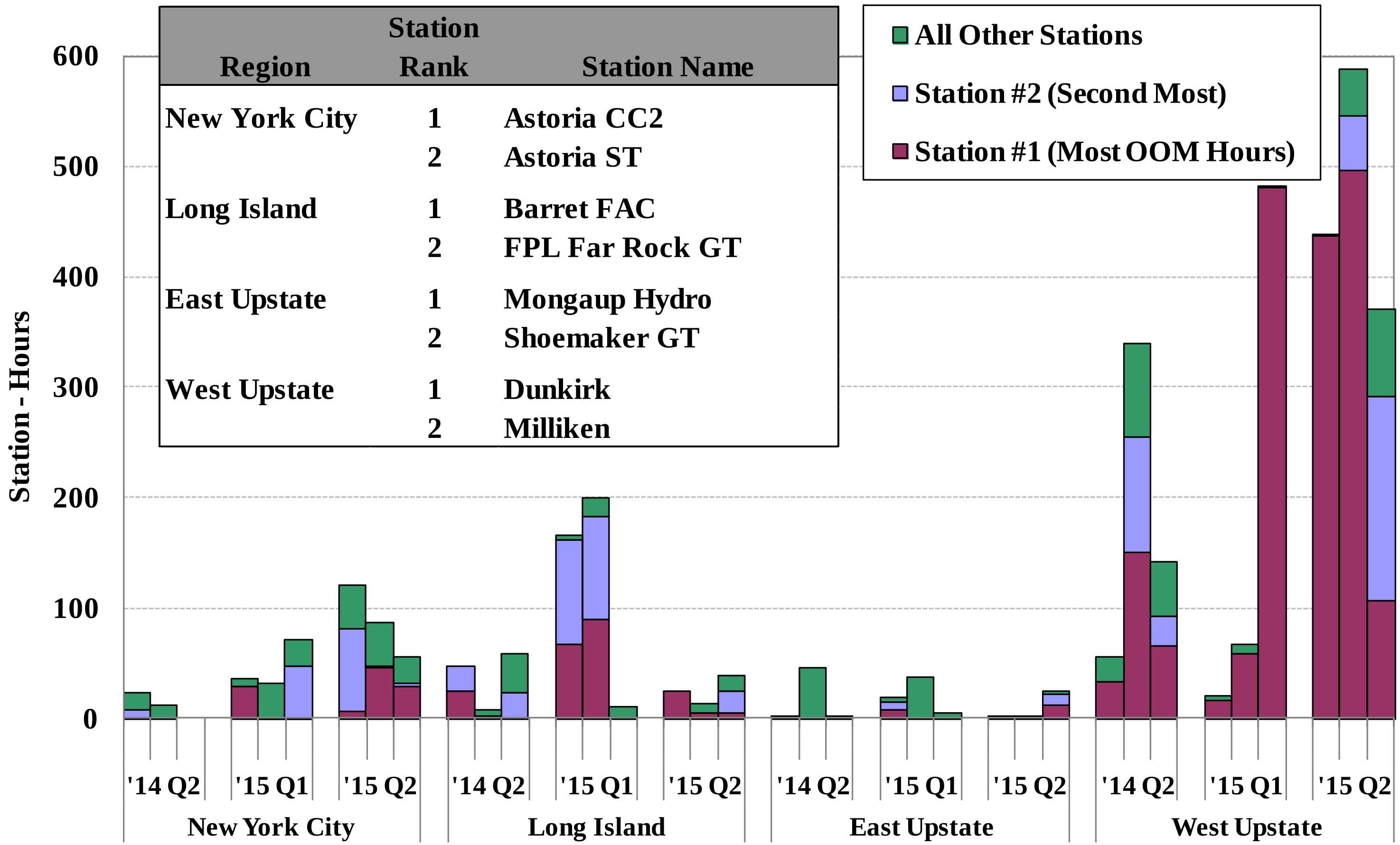
Frequency of Out-of-Merit Dispatch
by Region by Month



Region	Station Rank	Station Name
New York City	1	Astoria CC2
	2	Astoria ST
Long Island	1	Barret FAC
	2	FPL Far Rock GT
East Upstate	1	Mongaup Hydro
	2	Shoemaker GT
West Upstate	1	Dunkirk
	2	Milliken

Note: The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 358 hours in 2014-Q2, 383 hours in 2015-Q1, and 797 hours in 2015-Q2. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

Uplift Costs from Guarantee Payments: Chart Descriptions

- The next two figures 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 day-ahead market (usually economically) whose day-ahead market revenues do not cover their as-offered costs.
    - Real Time: For import transactions (before April 2014) and gas turbines 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.
    - 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.
  - ✓ The first figure shows these seven categories on a daily basis during the quarter.
  - ✓ The second figure summarizes uplift costs by region on a monthly basis.

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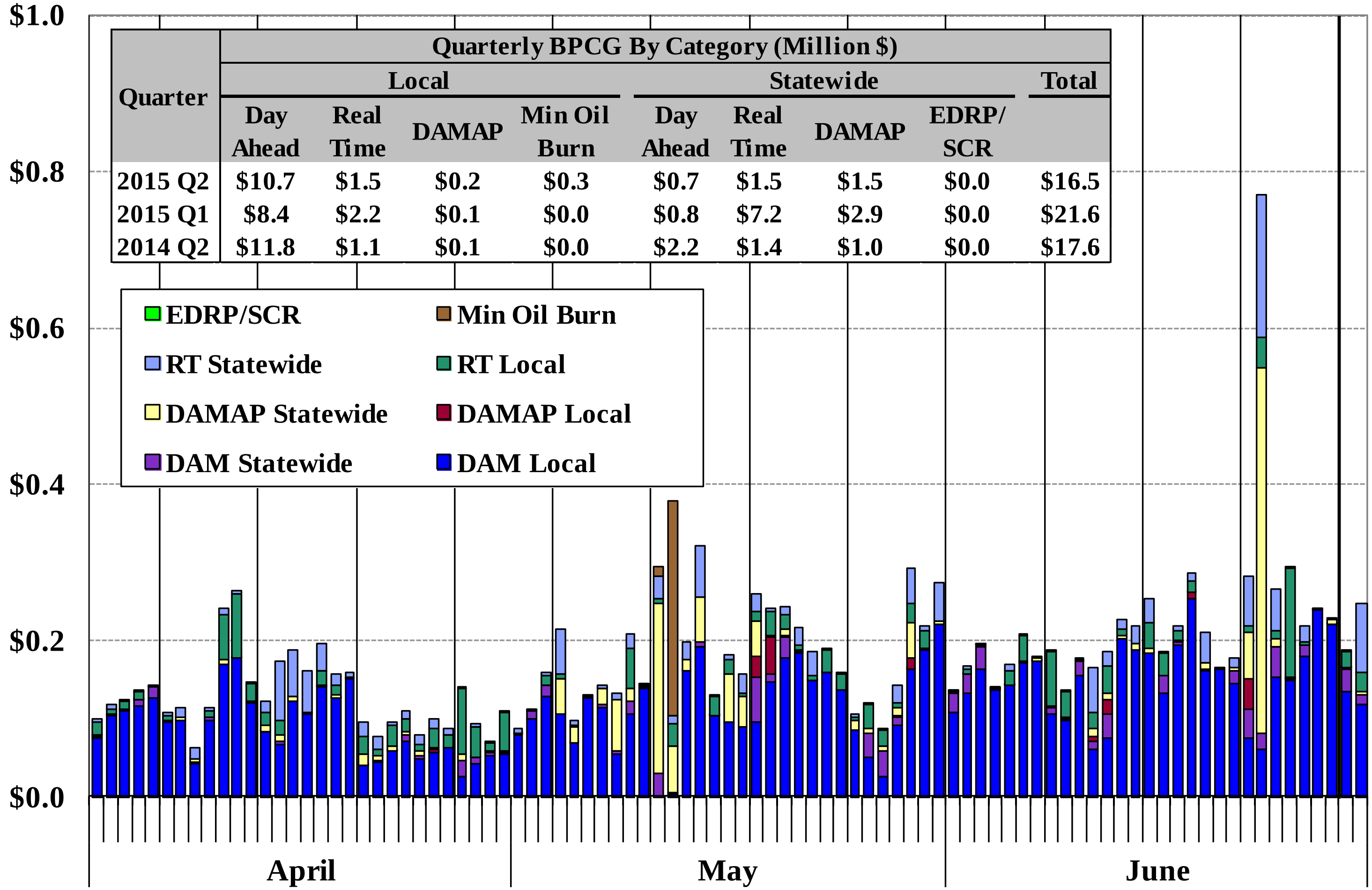
Uplift Costs from Guarantee Payments: Results

- Guarantee payments totaled $16.5 million this quarter, down 7 percent from the second quarter of 2014.
  - ✓ The reduction was consistent with lower natural gas prices, which decreased the commitment costs of gas-fired units.
  - ✓ However, the reduction was largely offset by increased reliability commitments and OOM dispatch, particularly in Western NY.
- Of the total guarantee payment uplift in the second quarter of 2015:
  - ✓ 77 percent was allocated locally, while the remainder was allocated statewide.
  - ✓ Western NY accounted for 46 percent, NYC accounted for 40 percent, and Long Island accounted 10 percent.
- Long Island DAM local uplift fell substantially because of greatly reduced DARU commitments (for the reasons discussed earlier, see slide 60).
- Local uplift in Western NY accounted for over 40 percent of total guarantee uplift this quarter, up nearly 50 percent from a year ago.
  - ✓ The vast majority of the local uplift was paid to several units that were supplementally committed and/or OOMed to manage congestion on the 115 kV system (see slides 60, 62, 63, & 65).

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

Quarterly BPCG By Category (Million $)

Quarter	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2015 Q2	$10.7	$1.5	$0.2	$0.3	$0.7	$1.5	$1.5	$0.0	$16.5
2015 Q1	$8.4	$2.2	$0.1	$0.0	$0.8	$7.2	$2.9	$0.0	$21.6
2014 Q2	$11.8	$1.1	$0.1	$0.0	$2.2	$1.4	$1.0	$0.0	$17.6



Note: These data are based on information available at the reporting time and do not include some manual adjustments to mitigation, so they can be different from final settlements.

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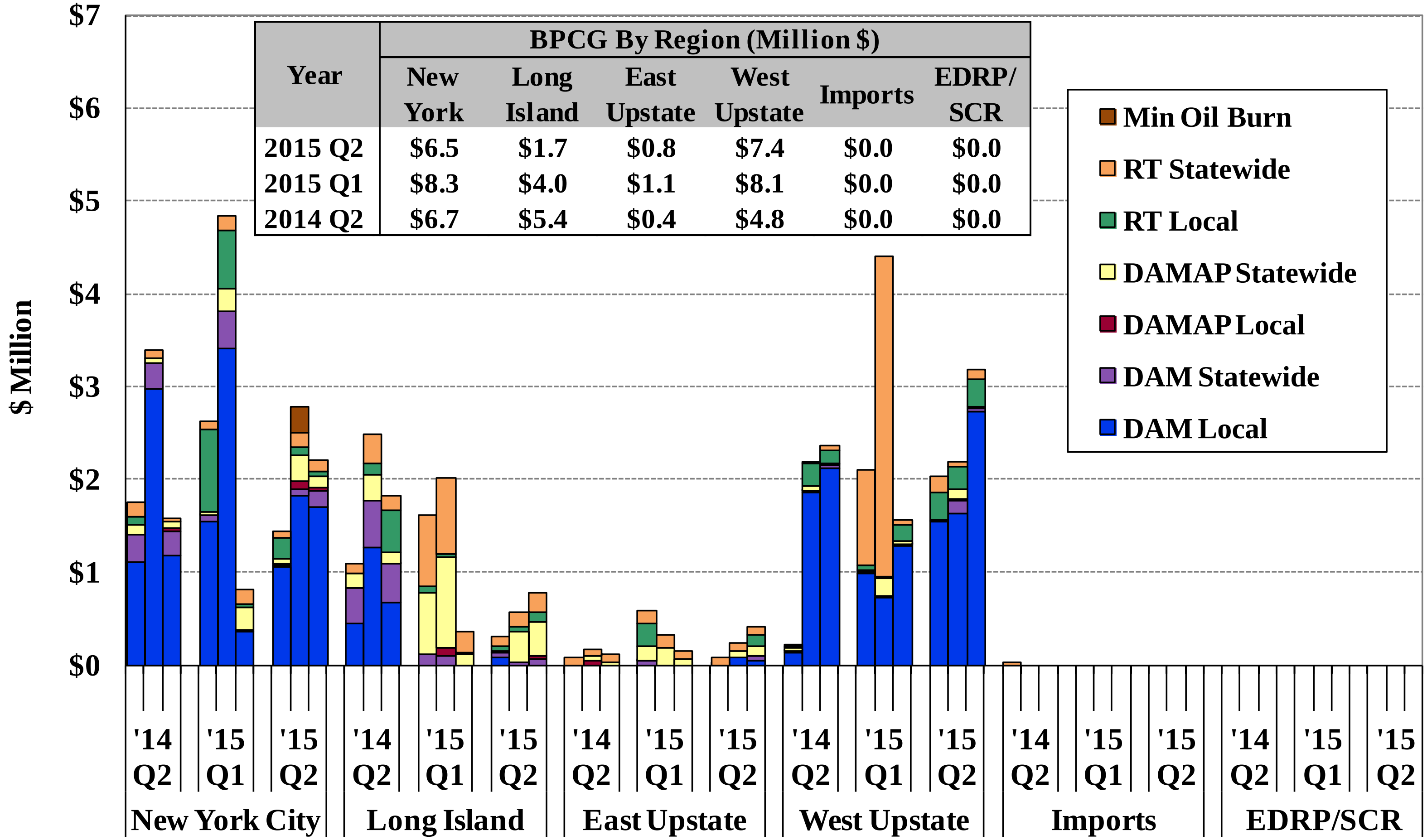
Uplift Costs from Guarantee Payments
By Category and Region



Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2015 Q2	$6.5	$1.7	$0.8	$7.4	$0.0	$0.0
2015 Q1	$8.3	$4.0	$1.1	$8.1	$0.0	$0.0
2014 Q2	$6.7	$5.4	$0.4	$4.8	$0.0	$0.0

Note: BPCG data are based on information available at the reporting time and do not include some manual adjustments to mitigation, so they can be different from final settlements.

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Market Power and Mitigation

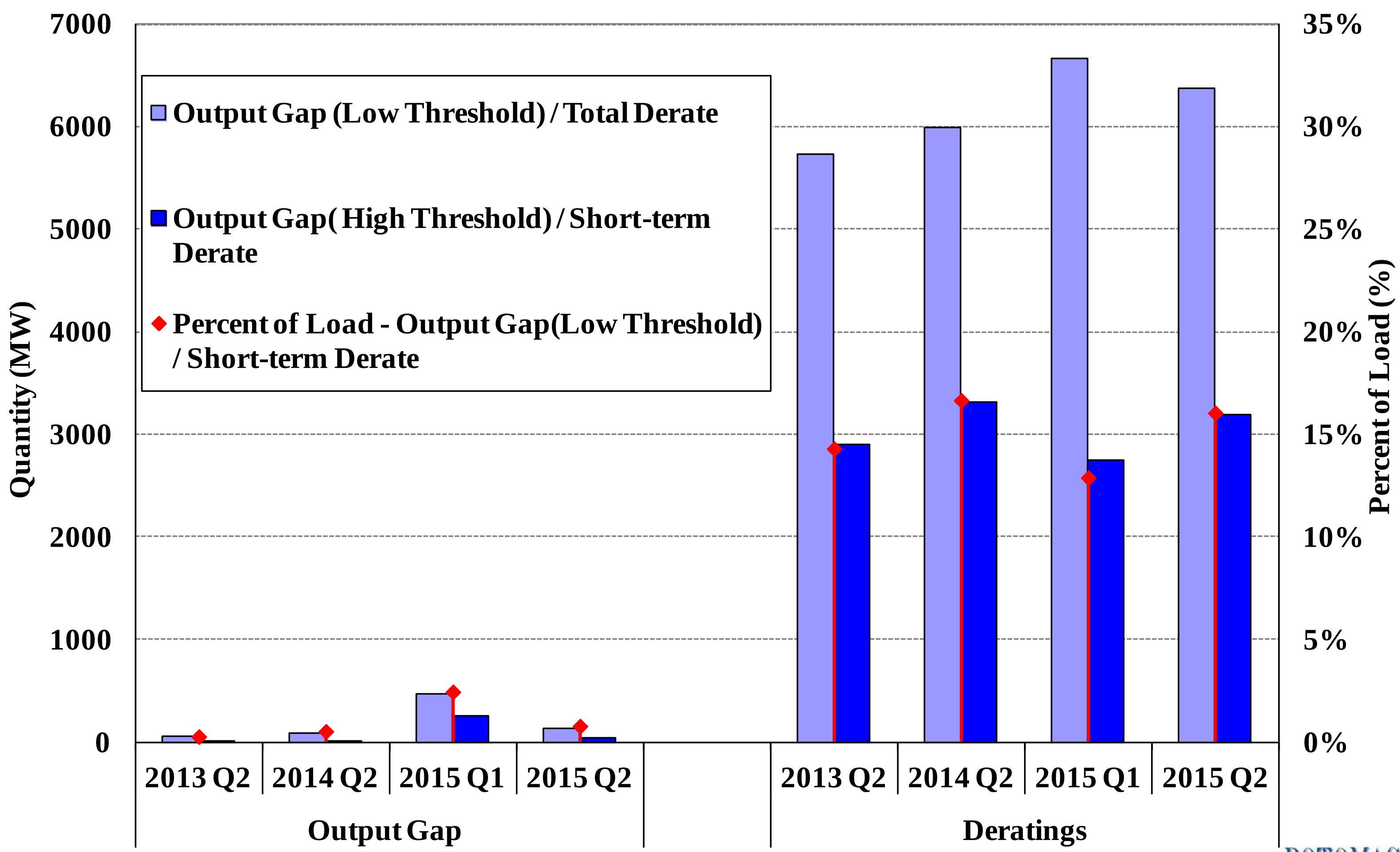
Market Power Screens: Economic Withholding

- The next figure shows the results of our screens for attempts to exercise market power, which may include economic withholding and physical withholding.
- The screen for 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.
- In the following figure, we show the output gap based on:
  - ✓ A high threshold (the lower of $100/MWh and 300 percent); and
  - ✓ A low threshold (the lower of $50/MWh and 100 percent).
- The output gap was relatively low as a share of load this quarter.
  - ✓ The output gap averaged less than 1 percent of load at the low threshold, comparable to the same quarter in prior years.
  - ✓ The output gap did not raise significant market power concerns because most of the output gap occurred on units that are:
    - – Co-generation resources, most of which operate in a relatively inflexible manner because of the need to divert energy production to non-electric uses; and/or
    - – Owned by suppliers with small portfolios, which generally do not have an incentive to withhold supply.

Market Power Screens: Physical Withholding

- We evaluate generator deratings in the day-ahead market to screen for potential physical withholding. The figure summarizes:
  - ✓ Total deratings, which are measured relative to the DMNC test value; and
  - ✓ Short-term deratings, which exclude deratings lasting more than 30 days.
- Deratings are typically highest in shoulder months when load is lower and lowest in the summer months when load is higher.
  - ✓ Total deratings were significant, but physical withholding concerns are limited because most deratings are long-term and unlikely to reflect withholding.
    - – However, inefficient outage scheduling (i.e., scheduling an outage when the unit is likely to be economic for a significant portion of the time) may raise concerns.
- The amount of total deratings rose modestly from the second quarter of 2014.
  - ✓ A large unit in New York City was forced out of service from September 2014 to May 2015 because of equipment issues, accounting for a large portion of the increase in the long-term deratings.
- Short-term deratings fell slightly from a year ago, generally consistent with the same quarter in the prior years.
  - ✓ Most of the short-term deratings resulted from maintenance outages (lasting up to 4 weeks) that were scheduled in March, April, and May.

Market Monitoring Screens



Automated Market Power Mitigation

- The next table summarizes the automated mitigation that was imposed during the quarter (not including BPCG mitigation).
- Energy, minimum generation, and start-up offer mitigation is performed by automated mitigation procedure (“AMP”) software in the day-ahead and real-time markets in New York City. The following figure reports:
  - ✓ The frequency of incremental energy offer mitigation; and
  - ✓ The average quantity of mitigated capacity, including capacity below the minimum generation level when the minimum generation offer is mitigated.
- Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled. In the second quarter of 2015,
  - ✓ 99 percent of mitigation occurred in the day-ahead market; and
  - ✓ 98 percent of day-ahead mitigation occurred on local reliability (i.e., DARU & LRR) units.
- The quantity of mitigation rose from the second quarter of 2014, due largely to more reliability commitments in the day-ahead market (see slide 63).

Automated Market Mitigation

Quarterly Mitigation Summary

		2013 Q2	2014 Q2	2015 Q1	2015 Q2
Day-Ahead Market	**Average Mitigated MW**	167	121	69	147
	Energy Mitigation Frequency	14%	5%	3%	3%
Real-Time Market	**Average Mitigated MW**	2	1	9	1
	Energy Mitigation Frequency	1%	0%	1%	1%

Capacity Market

Capacity Market Results

- The following figure summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices in each capacity zone.
  - ✓ UCAP is a measure of installed capacity that accounts for forced outage rates.
- UCAP spot prices fell in all capacity zones from the second quarter of 2014.
  - ✓ NYC prices averaged $12.92/kW-month, down 18 percent.
  - ✓ Long Island prices averaged $4.82/kW-month, down 8 percent.
  - ✓ G-J Locality prices averaged $8.10/kW-month (based on the ROS spot prices for April), down 8 percent.
  - ✓ Rest-of-State prices averaged $3.23/kW-month, down 34 percent.
- The price decreases across the system were primarily because of:
  - ✓ The increase in internal installed capacity supply, which rose:
    - Over 300 MW in NYC as a result of a change in the ambient temperature conditions assumed for adjusting the generator DMNC test results and the return-to-service of Astoria Unit 20 in 2015-Q1;
    - 480 MW in the Hudson Valley as four units at the Danskammer plant returned to service in 2014-Q4 and 2015-Q1; and
    - Over 100 MW in Western NY as a result of the return-to-service of the Binghamton co-gen unit in 2015-Q1 and additions of new wind capacity.

Capacity Market Results

(continued from the prior slide)

- ✓ The increase in the SCR sales, which rose:
  - 70 MW in NYC;
  - 90 MW in the G-J Locality; and
  - 210 MW in NYCA.
- ✓ The decrease in the ICAP requirement for most capacity zones, which fell:
  - 54 MW (or 0.5%) in NYC due to a decrease in the LCR from 85% to 83.5% (which was partly offset by a 147 MW increase in the forecasted peak load);
  - 148 MW (or 3%) in Long Island primarily because of a decrease in the LCR from 107% to 103.5%; and
  - 115 MW (or 0.3%) in NYCA due to a modest decrease in the forecasted peak load.
  - However, the G-J ICAP requirement rose 451 MW (or 3%) due to an increase in the LCR from 88% to 90.5% and a modest increase in forecasted peak load.
    - This offset the decrease of UCAP prices in the G-J Locality.

- The recent capacity additions in Zone G was the primary factor that led to: (a) lower LCRs for NYC and Long Island and (b) a higher LCR for the G-J Locality starting in May 2015.
- Very little capacity was unsold in the G-J Locality, NYC, or Long Island.

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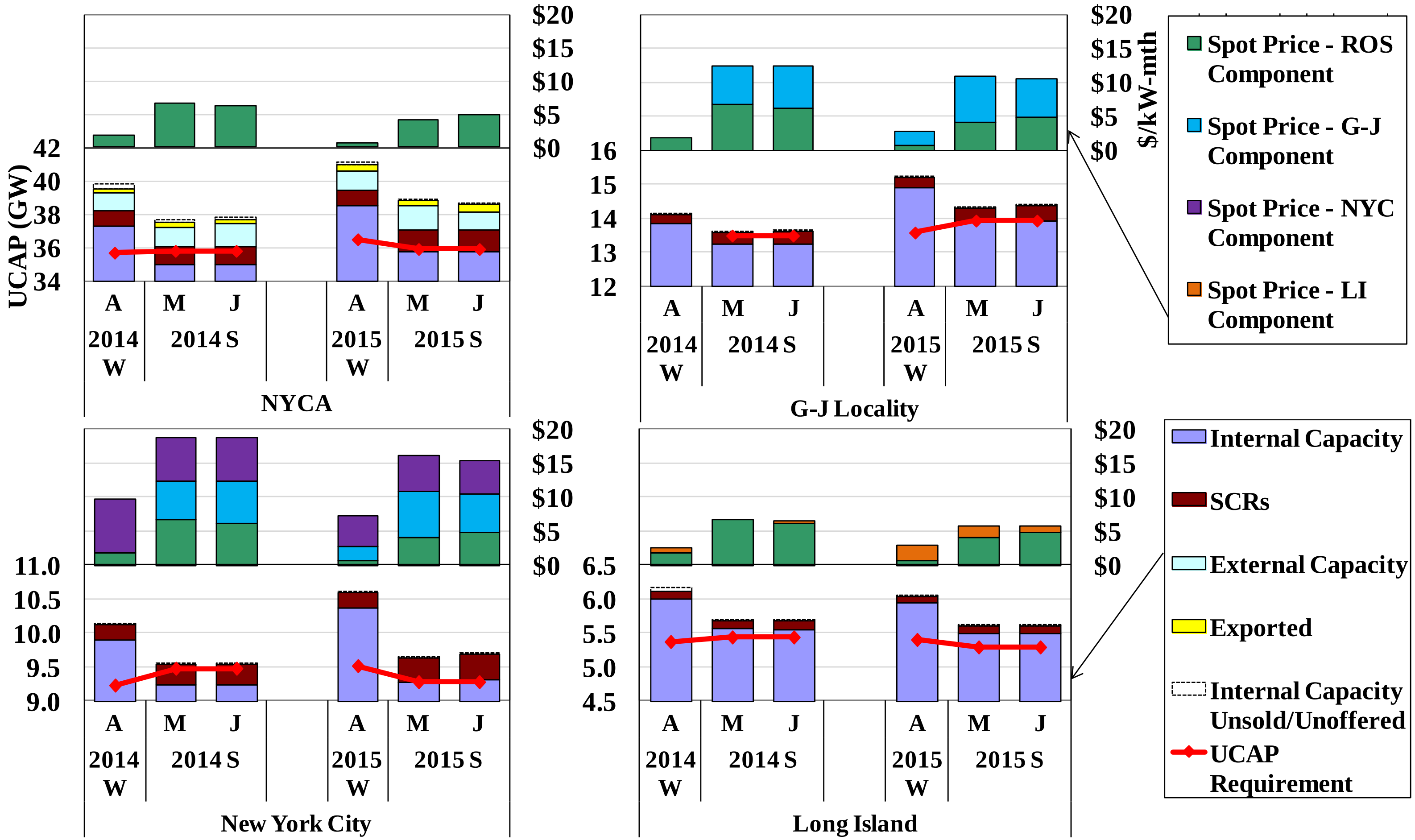
Capacity Market Results: Second Quarter 2014 & 2015



Note: Sales associated with Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity," but unsold capacity from resources with UDRs is not shown.