Quarterly Report on the New York ISO Electricity Markets Second Quarter 2013

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the second quarter of 2013.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- RT energy prices averaged $46/MWh statewide in the second quarter of 2013, up 28 percent from a year ago.
  - ✓ This was primarily driven by higher gas prices, which rose 45 to 70 percent.
    - – However, the increase was offset by lower load levels and increased nuclear generation due to an uprate of one unit and fewer outages.
  - ✓ The increase in Long Island LBMPs was especially large (72 percent), reflecting:
    - – Lengthy transmission deratings and outages associated with one 345 kV line into Long Island and the Neptune Cable; and
    - – Tight supply because of generator outages, unit retirements, and inefficient utilization of some generation resources.
- The DA congestion revenue was $90 million, up 46 percent from the second quarter of 2012. The increase was mostly due to more congestion into Long Island.
- Convergence between DA and RT prices was comparable to prior quarters except in Long Island where average RT prices exceeded DA prices by 9 percent.

Highlights and Market Summary: Energy Market Enhancements

- Two DAM mitigation provisions were revised on January 23, 2013, raising: (a) the reference cap for 10-min non-spinning reserves from $2.52 to $5; and (b) the offer cap for 10-min spinning reserves for NYC generators from $0 to $5.
  - ✓ DA-RT price convergence has improved slightly from the previous year, although convergence was also affected by other significant factors.
  - ✓ Offer patterns following the rule changes do not raise withholding concerns; and
  - ✓ Hence, we recommend the NYISO move to the second phase.
- M2M coordination generally facilitated efficient scheduling of the Ramapo line.
  - ✓ However, the Ramapo line was partly or fully derated throughout the quarter, limiting the benefits of M2M coordination.
  - ✓ Our evaluation of the scheduling efficiency finds that the Ramapo line was:
    - Reasonably efficient in 70 percent of hours with congestion in NY and/or PJM;
    - Not fully utilized in other hours when significant congestion in one or both markets. The evaluation is discussed further in this report.
- The new regulation market (i.e., with the two-part bid and compensation) was implemented in both DA and RT markets on June 26, 2013.
  - ✓ Market operations were smooth and market outcomes were consistent with expectations during the first week of implementation.

Highlights and Market Summary: Capacity Market

- Rest of State UCAP prices averaged $4.44/kW-mth, up 169 percent from last year.
  - ✓ 1.9 GW of generation retired or was mothballed since last April.
  - ✓ The NYCA ICAP requirement rose by over 300 MW from the previous Capability Year because of an increase in the IRM from 16 percent to 17 percent.
  - ✓ Sales from SCRs fell nearly 300 MW due to a combination of increased auditing of resources, attrition, and changing market conditions.
- NYC UCAP prices averaged $12.55/kW-mth, up 13 percent from last year.
  - ✓ The ICAP requirement rose 332 MW because of an increase in the LCR from 83 percent to 86 percent, largely accounting for the increase in UCAP prices.
    - – The LCR increased primarily because of recent reductions in capacity from the Hudson Valley, although this was partially offset by an increase in the potential for emergency assistance following the entry of the HTP line.
  - ✓ From December 2012 to April 2013, some internal capacity has gone unsold following the imposition of buyer-side mitigation on the 550 MW AEII facility.
- Long Island UCAP prices averaged $5.30/kW-mth, separating from Rest of State.
  - ✓ The ICAP requirement increased 320 MW due to an increase in the LCR from 99 percent to 105 percent due to the withdrawal of capacity from the Hudson Valley.
  - ✓ UCAP sales fell by 330 MW from a year ago due to unit retirements.

Highlights and Market Summary: Uplift and Revenue Shortfalls

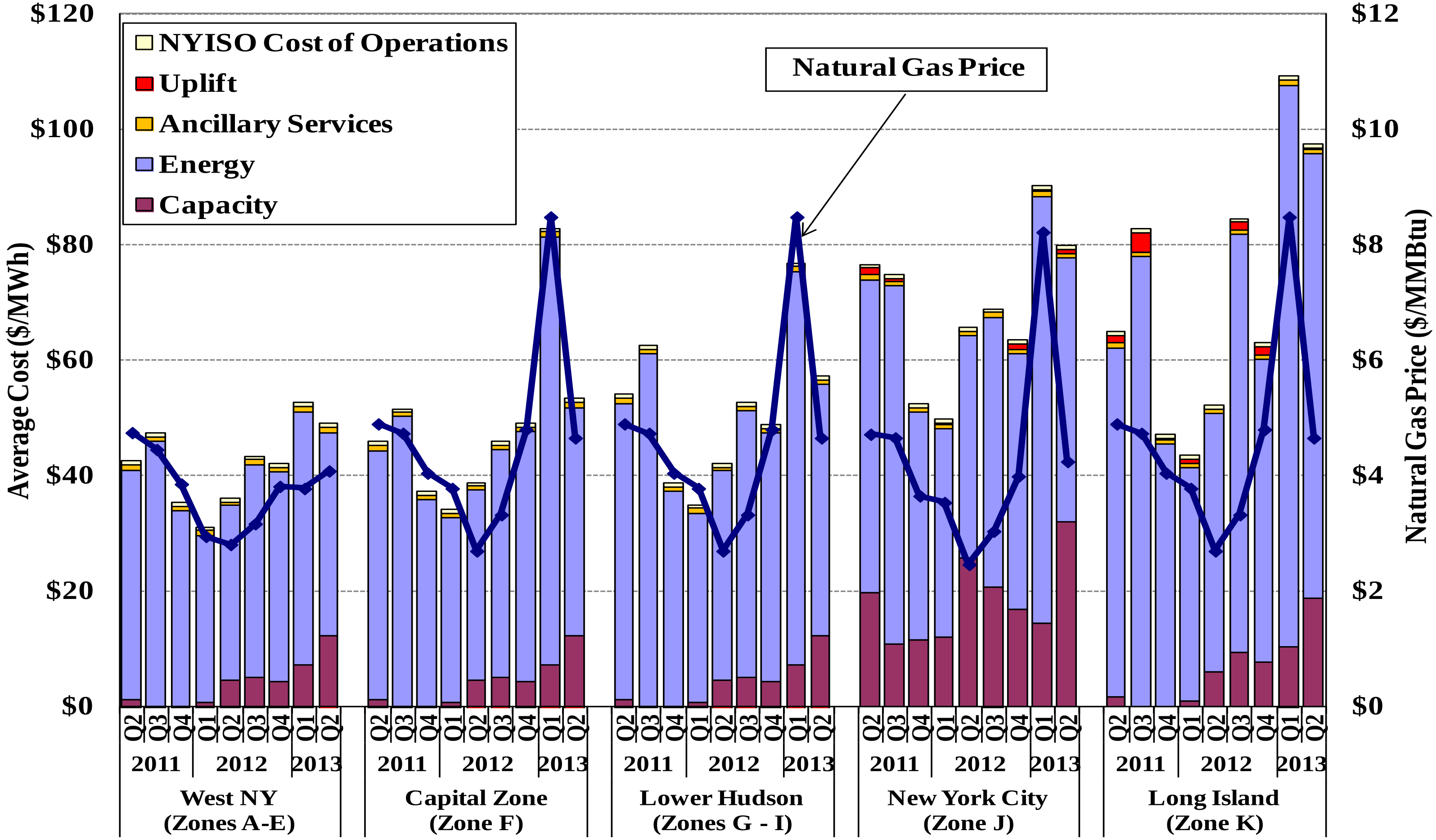
- The uplift from guarantee payments totaled $36 million, up 34 percent from the second quarter of 2012.
  - ✓ Higher natural gas prices increased the commitment costs of gas-fired units that were needed for reliability.
  - ✓ Overall reliability commitments rose 28 percent from a year ago, particularly in New York City because of: (a) transmission and generation outages, and (b) periods when the LRR pass did not select the most economic set of generating resources for NOx constraints due to very long lead times for some units.
- Day-ahead congestion shortfalls totaled roughly $18 million in the second quarter of 2013, up from $1 million in the second quarter of 2012.
  - ✓ The increase was driven primarily by transmission outages into Long Island ($12 million) and by transmission and generation outages affecting the Central-East interface ($4 million).
  - ✓ Outage-related shortfalls are allocated to the responsible TO.
- Balancing congestion shortfalls totaled $8 million, up modestly from the second quarter of 2012.
  - ✓ TSAs were called on 13 days, accounting for nearly all of the shortfall.

Energy Market Outcomes

All-In Prices

- The first figure summarizes the total cost of serving load 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 roughly $49/MWh in Western NY to $97/MWh on Long Island, up substantially from the second quarter of 2012.
  - ✓ Energy prices rose 16 to 20 percent in most areas and 71 percent on Long Island.
    - Higher LBMPs were primarily driven by higher natural gas prices. However, the increase was partly offset by lower load levels and increased nuclear generation.
    - Long Island LBMP increases were particularly large, reflecting high levels of transmission and generation outages, unit retirements, and inefficient utilization of some generating capacity.
  - ✓ The capacity component rose $6 to $13/MWh in all areas primarily because of:
    - Resource retirements and mothballs (330 MW on Long Island, 370 MW in Western NY, and 500 MW in Hudson Valley); and
    - Higher ICAP requirements for the Summer Capability Period in NYC (by 330 MW), Long Island (by 320 MW) and NYCA (by 310 MW).

All-In Energy Price by Region

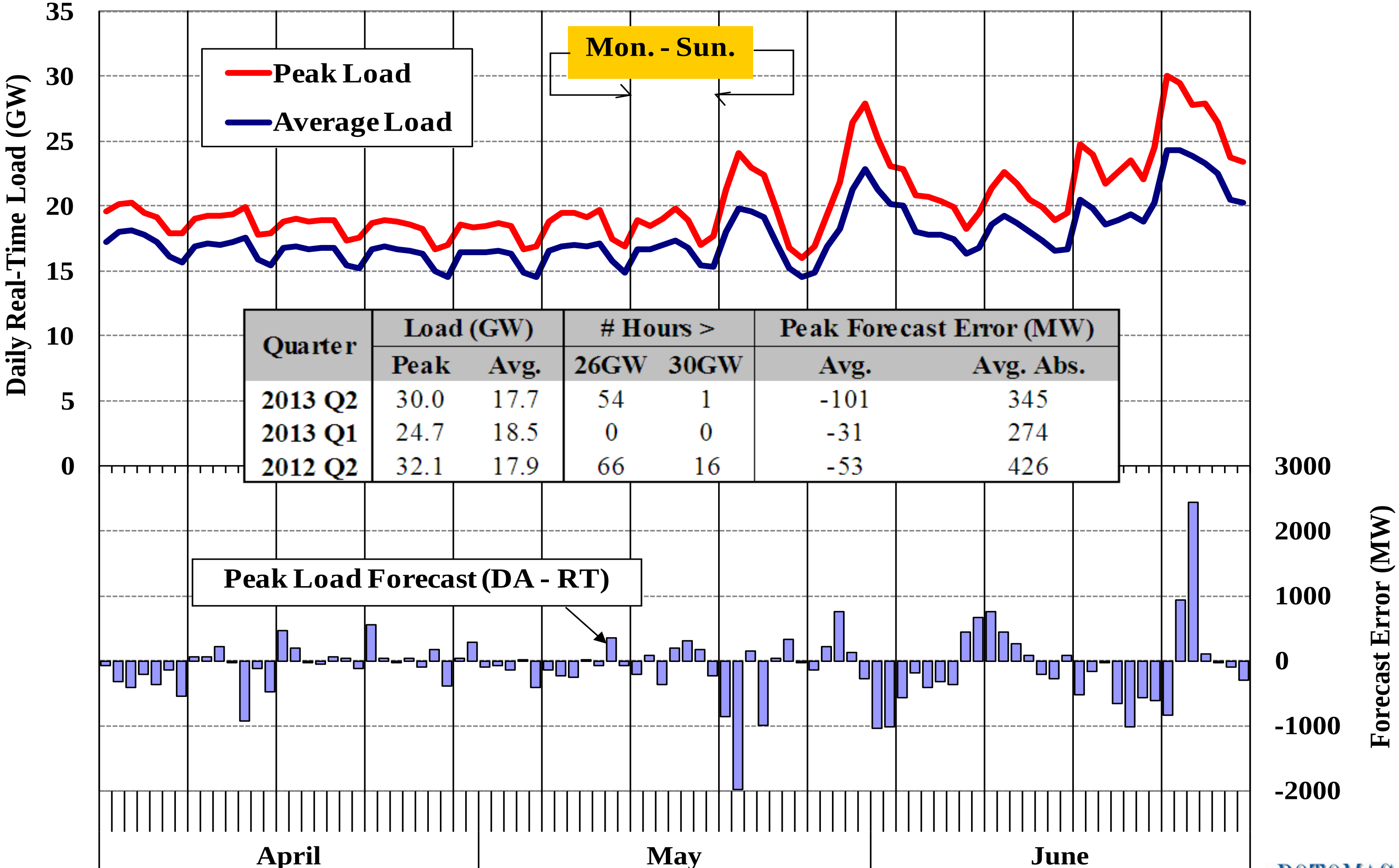


Note: Natural Gas Price based on: Niagara index for West NY, Transco Zone 6 (NY) index for New York City and Iroquois Zone 2 index for other regions.

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.
- Load averaged 17.7 GW, down 5% from last quarter and 1% from last year (Q2).
  - ✓ Load peaked on June 24 at 30.0 GW, down 7 percent from quarter 2 last year.
  - ✓ Daily peak load forecasting was generally good during the quarter, although the magnitude of forecast errors increased at higher load levels.
    - – Large forecast error (by both the NYISO or market participants) may lead to inefficient commitment and/or prices in the day-ahead market.
- Natural gas prices averaged $4.08 at Niagara (in Western NY), $4.25 at Transco Z6 NY (NYC), and $4.65 at Iroquois Z2 (in Eastern NY).
  - ✓ Gas price spreads between western and eastern NY averaged 15 percent, down from 124 percent in the first quarter and *negative* 4 percent last year.
    - – These locational variations affect generation patterns and can lead to comparable variations in electricity prices when transmission congestion occurs.
  - ✓ Although natural gas was significantly cheaper than fuel oil, some generators may still burn oil on some days due to: a) reliability reasons, b) difficulties obtaining natural gas, and c) gas balancing charges.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2013 Q2	30.0	17.7	54	1	-101	345
2013 Q1	24.7	18.5	0	0	-31	274
2012 Q2	32.1	17.9	66	16	-53	426

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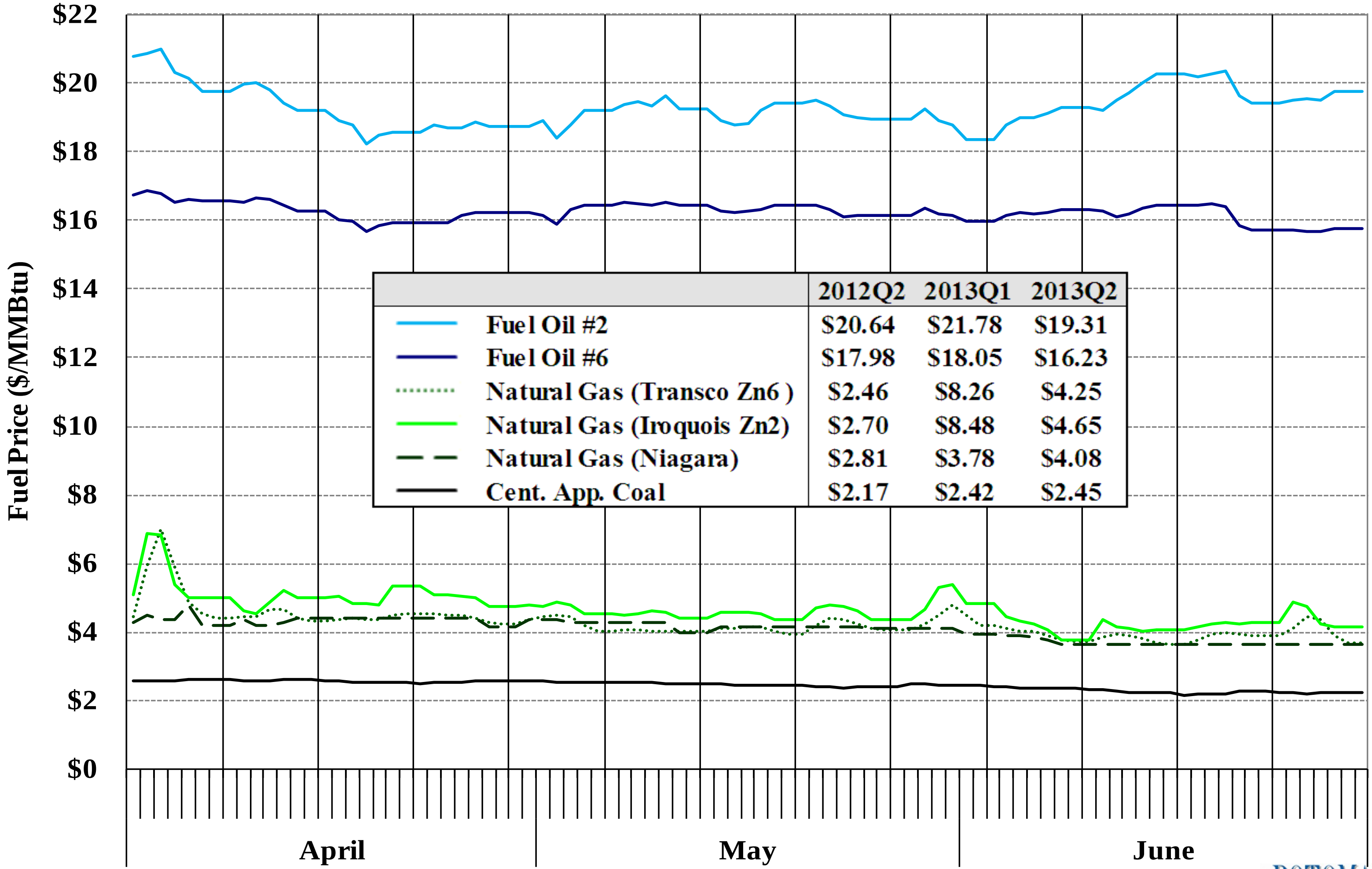
Coal, Natural Gas, and Fuel Oil Prices



	2012Q2	2013Q1	2013Q2
Fuel Oil #2	$20.64	$21.78	$19.31
Fuel Oil #6	$17.98	$18.05	$16.23
Natural Gas (Transco Zn6)	$2.46	$8.26	$4.25
Natural Gas (Iroquois Zn2)	$2.70	$8.48	$4.65
Natural Gas (Niagara)	$2.81	$3.78	$4.08
Cent. App. Coal	$2.17	$2.42	$2.45

Real-Time Generation by Fuel Type

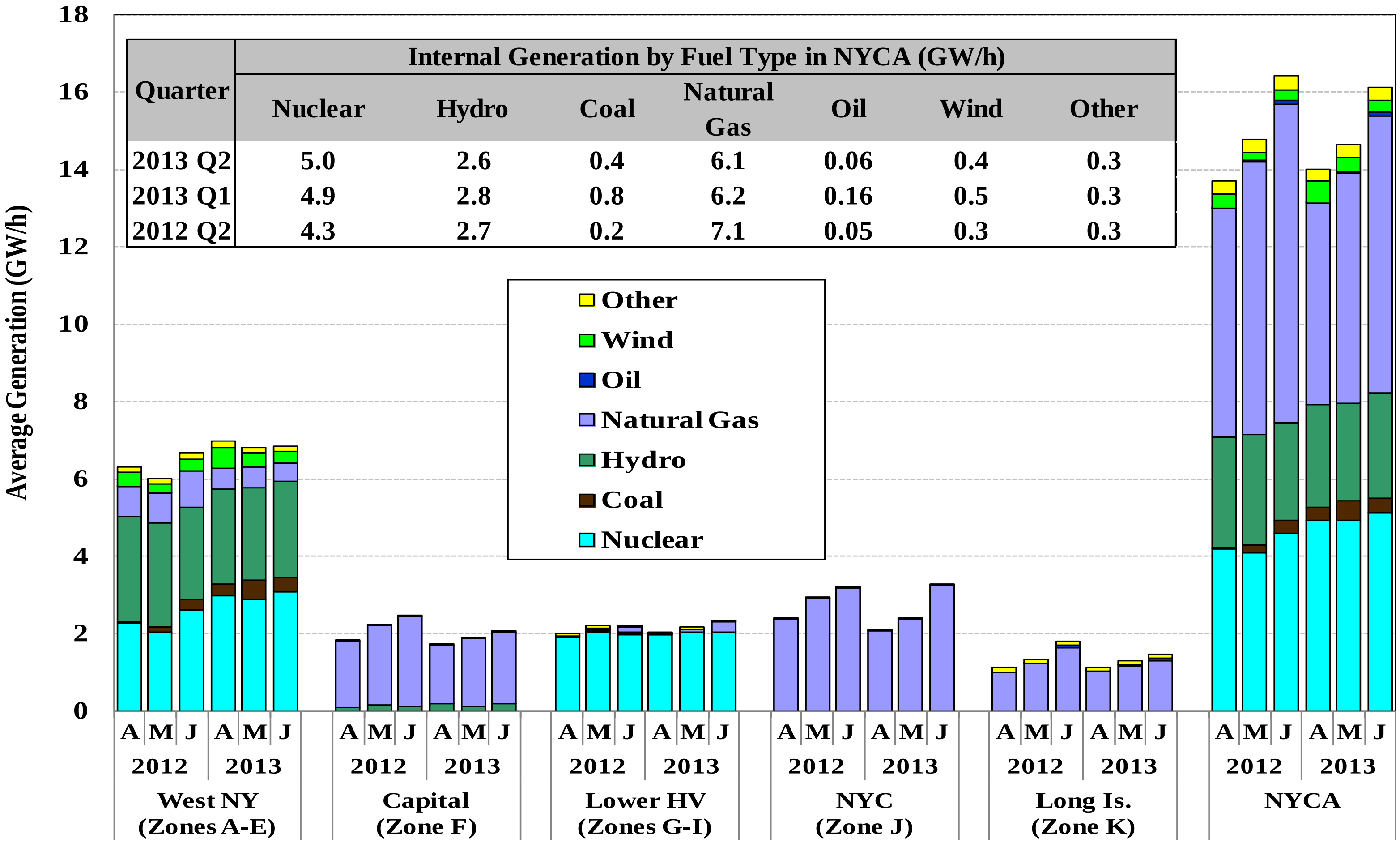
- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the second quarter of 2013.
  - ✓ The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
  - ✓ The second figure summarizes how frequently 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

- Nuclear units were normally base-loaded and accounted for 34 percent of all production in the second quarter of 2013.
  - ✓ Average nuclear generation rose 700 MW from last year following the uprate of one unit and fewer planned and forced outages.
- Hydro resources (primarily in Western NY) accounted for 18 percent of production and set prices in 45 percent of intervals in the second quarter of 2013.
  - ✓ Some hydro resources have storage capability, allowing them to offer price-sensitively based on the opportunity cost of foregoing sales at another time (which are heavily dependent on natural gas prices).
- Natural gas fired resources accounted for roughly 40 percent of all generation and set prices in the majority of intervals.
  - ✓ Gas fired generation fell about 1 GW from last year due to increased nuclear generation and higher natural gas prices.
- Coal production rose 220 MW from a year ago (despite multiple retirements) and was on the margin in 10 percent of the intervals in the second quarter of 2013.
  - ✓ Increased natural gas prices led to more economic production from coal resources.
- Price-setting by wind units in the North Zone has become more frequent over the past year primarily due to new additions of wind capacity.

Real-Time Generation Output by Fuel Type

Quarter	Internal Generation by Fuel Type in NYCA (GW/h)						
	Nuclear	Hydro	Coal	Natural Gas	Oil	Wind	Other
2013 Q2	5.0	2.6	0.4	6.1	0.06	0.4	0.3
2013 Q1	4.9	2.8	0.8	6.2	0.16	0.5	0.3
2012 Q2	4.3	2.7	0.2	7.1	0.05	0.3	0.3



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

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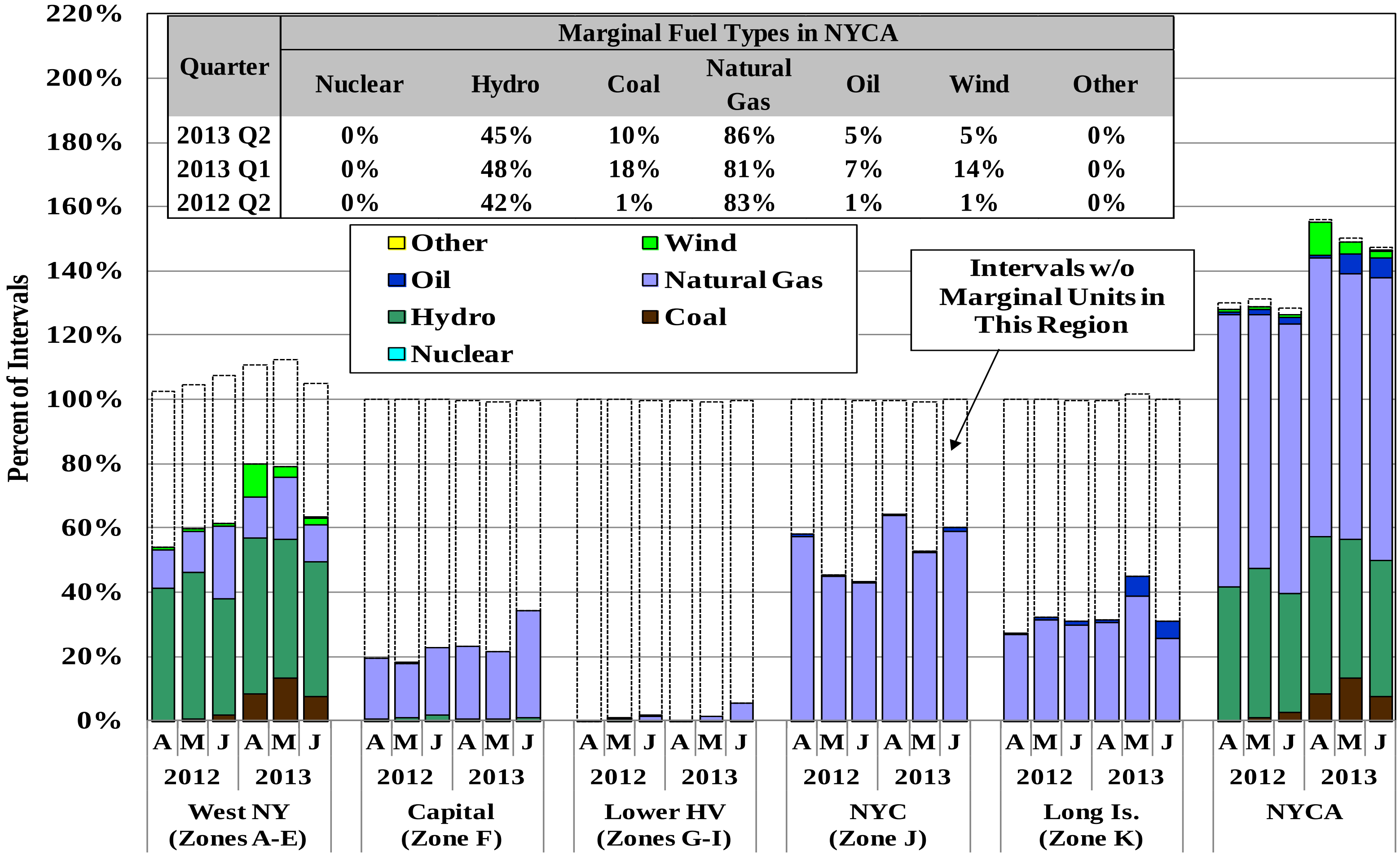
Fuel Types of Marginal Units in the Real-Time Market

Quarter	Nuclear	Hydro	Coal	Natural Gas	Oil	Wind	Other
	Marginal Fuel Types in NYCA						
2013 Q2	0%	45%	10%	86%	5%	5%	0%
2013 Q1	0%	48%	18%	81%	7%	14%	0%
2012 Q2	0%	42%	1%	83%	1%	1%	0%



Notes: "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) DA and RT price convergence for five zones on each day in the second quarter of 2013.
  - ✓ DA prices should reflect probability-weighted expectations of RT conditions.
  - ✓ Convergence is important because the DAM facilitates the daily commitment of generation and scheduling of natural gas, determines the obligations to TCC holders, and accounts for most energy settlements.
- Average DA prices ranged from $37/MWh in the West Zone to $70/MWh on Long Island, up 60 percent on Long Island from the second quarter of 2012 and 26 to 31 percent in the other four zones shown.
  - ✓ Higher LBMPs were primarily driven by higher natural gas prices. However, the increase was offset by lower load levels and increased nuclear generation.
  - ✓ Long Island LBMPs rose to unusually high levels during parts of May and June.
    - – The Neptune Line was fully unavailable from mid-May to early-June and in the last week of June. Otherwise, the line was only 57 percent available until June 30.
    - – One of two 345 kV lines from upstate was out-of-service until late May;
    - – Substantial amounts of gas-fired capacity was planned or forced out in May; and
    - – Several units retired in July 2012, leading to tighter supply conditions.

Day-Ahead and Real-Time Electricity Prices

- Prices are more volatile in the RTM than in the DAM due to unexpected events.
  - ✓ Actual load ran over the DAM forecast by approximately 2 GW on May 21, contributing to high price spikes in the afternoon across the system.
  - ✓ The primary interface with HQ was forced out (flowing 1300 MW of power to NY at the time) on June 17, causing LBMPs to rise above $1000/MWh on many intervals during the outage.
  - ✓ TSAs were called on 13 days (April 10, May 22, 23, & 29, June 2, 13, 17, 18, 24, 25, 27, 28, & 30) during which transfer capability into SENY was greatly reduced, leading LBMPs on several days to rise substantially during the events.
- Convergence should be measured over longer timeframes since random factors can cause large differences in prices on individual days. Hence, the table shows the average price convergence over the entire quarter.
  - ✓ On average, day-ahead prices were 9 percent lower than real-time prices on Long Island and 2 to 6 percent higher than real-time prices in other areas.
  - ✓ Convergence between DA and RT prices was comparable to prior quarters in most regions except Long Island.
    - – Tight supply conditions on Long Island (which are discussed in the previous slide) and inefficient utilization of some generating capacity led to unexpectedly high RT LBMPs on some days.

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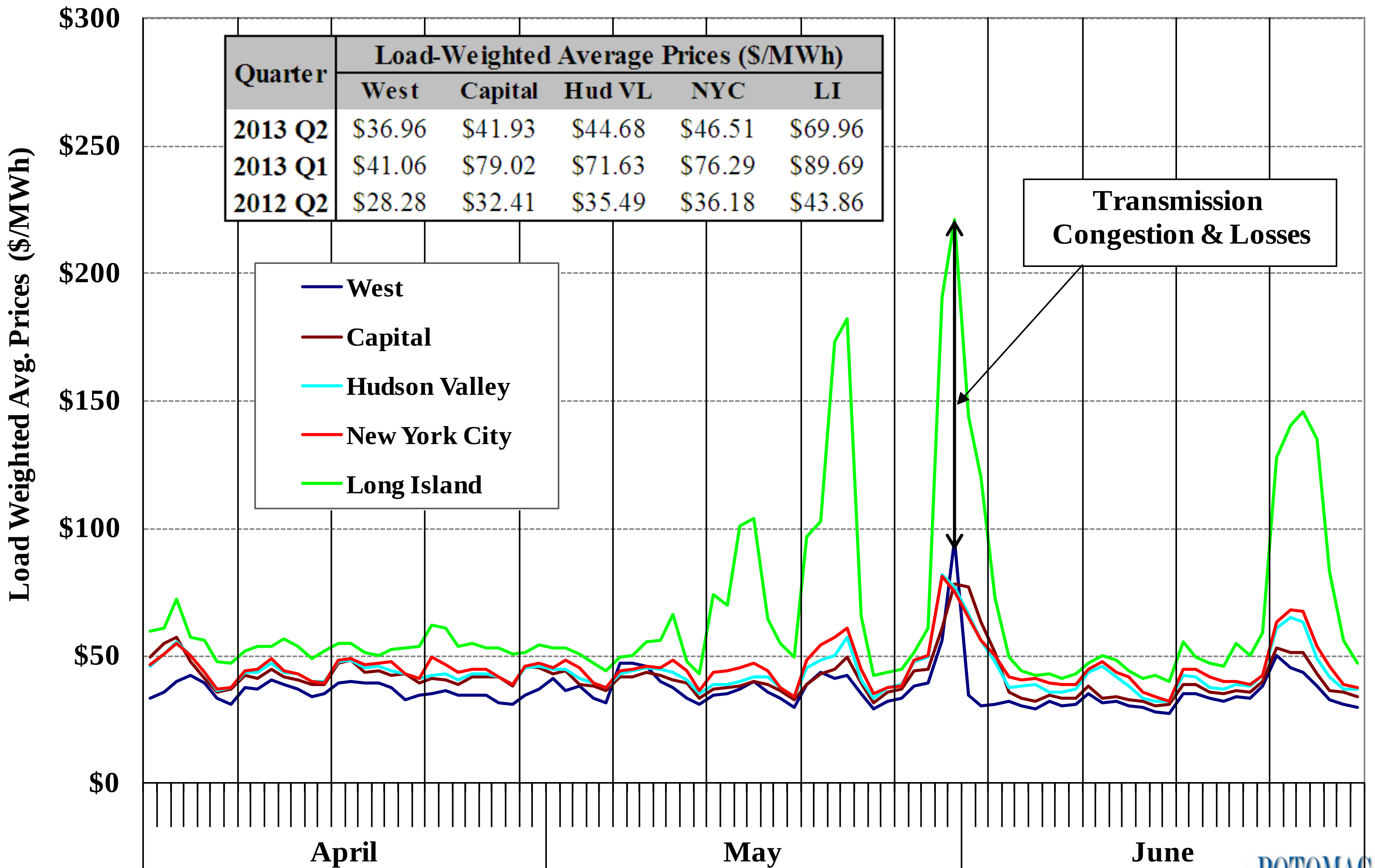
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2013 Q2	$36.96	$41.93	$44.68	$46.51	$69.96
2013 Q1	$41.06	$79.02	$71.63	$76.29	$89.69
2012 Q2	$28.28	$32.41	$35.49	$36.18	$43.86

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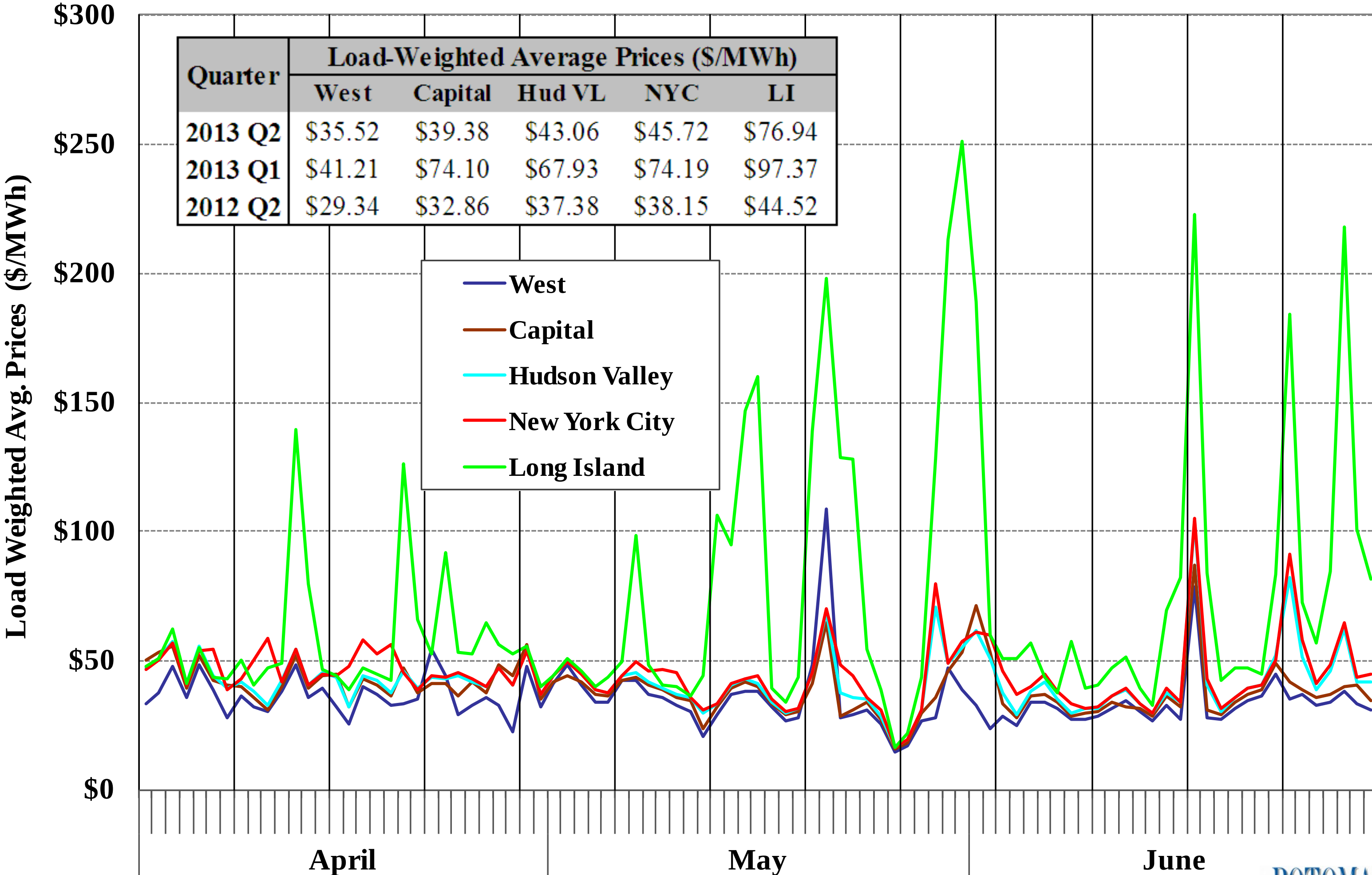
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2013 Q2	$35.52	$39.38	$43.06	$45.72	$76.94
2013 Q1	$41.21	$74.10	$67.93	$74.19	$97.37
2012 Q2	$29.34	$32.86	$37.38	$38.15	$44.52

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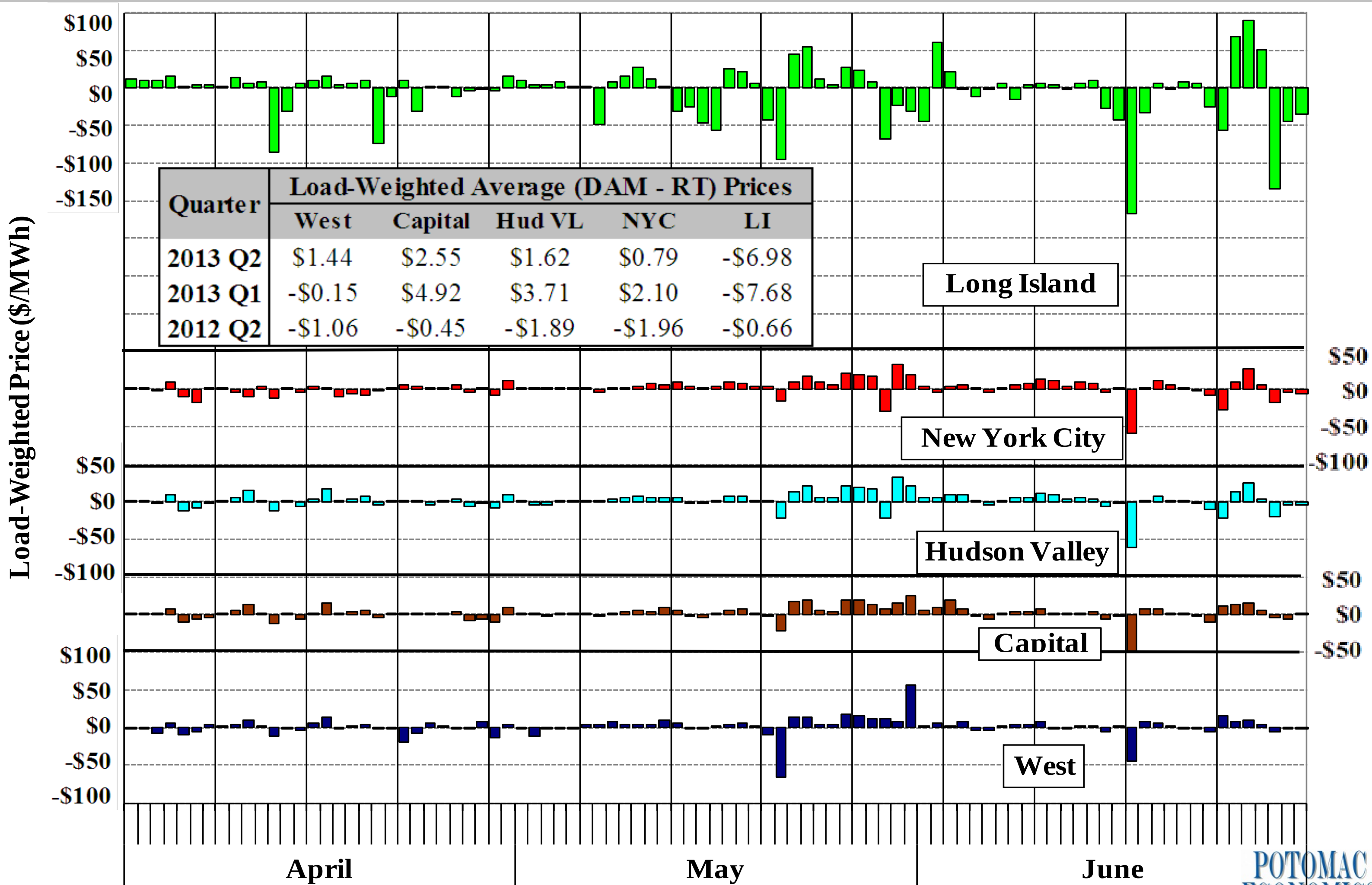
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2013 Q2	$1.44	$2.55	$1.62	$0.79	-$6.98
2013 Q1	-$0.15	$4.92	$3.71	$2.10	-$7.68
2012 Q2	-$1.06	-$0.45	-$1.89	-$1.96	-$0.66

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Ancillary Services Market

Ancillary Services Prices and Offer Patterns

- This part of the report evaluates the outcomes of the ancillary services markets.
- Two figures summarize DA and RT prices for four ancillary services products:
  - ✓ 10-min spinning reserves 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 reserves prices in eastern NY, which reflect the cost of requiring 1,200 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-min spinning reserves prices in western NY, which reflect the cost of requiring 655 MW of 10-minute spinning reserves statewide.
  - ✓ Regulation prices, which reflect:
    - A capacity cost of requiring up to 275 MW of regulation; and
    - A deployment cost from moving regulation units up and down (since June 26).
  - ✓ These figures show the number of intervals when a shortage affected the RT price.
    - A shortage occurs when the requirement cannot be satisfied at a marginal cost less than its "demand curve", which is: a) $25 for eastern 10-minute spinning reserves; b) $500 for eastern 10-minute total reserves; c) $500 for statewide 10-minute spinning reserves; and d) $80 to $400 for regulation.

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Ancillary Services Prices and Offer Patterns

- The last two figures examine price convergence and offer patterns associated with two reserve products in more detail.
  - ✓ On January 23, the NYISO implemented the first phase of a process to modify two DA ancillary services mitigation provisions. In the first phase, the NYISO:
    - – Raised the reference level cap for 10-min non-spin from $2.52/MW to $5/MW; and
    - – Raised the offer cap for 10-min spin for NYC generators from $0/MW to $5/MW.
  - ✓ The MMU is required to evaluate outcomes in the 10-min spin and non-spin reserves markets and recommend whether to proceed to the second phase.
  - ✓ This report provides an update of our evaluation, which was also discussed in the SOM Report for the first quarter.
  - ✓ In order to evaluate these issues, the figures show:
    - – The pattern of DAM reserve offers and DA-RT price convergence in the 10-minute non-spinning reserve market in eastern NY; and
    - – The pattern of DAM 10-minute spinning reserve offers in NYC and DA-RT price convergence of the eastern 10-minute spinning reserves.
    - – The figures show average DA and RT prices for each reserve category in the upper portion and average offer quantities based on offer price level in the lower portion.
      - Quantities are shown by daily peak load level and by time of day.

Ancillary Services Prices and Offer Patterns

- Average RT reserve prices were relatively consistent with DA prices for all four ancillary services products, but RT prices were much more volatile.
  - ✓ DA reserves prices are based on suppliers' offers, which reflect expected DA-RT price differences and the risks associated with selling reserves in the DA.
  - ✓ RT reserves prices are normally close to $0 because of the excess available reserves from online and quick-start units in most hours.
    - – However, RT prices can rise sharply during periods of tight supply and high energy demand, which can be difficult for the DA market to predict.
  - ✓ Average DA prices were higher than average RT prices for all four products.
- The number of shortages fell from last year, reflecting fewer peaking conditions.
  - ✓ Eastern 10-minute reserve shortages occurred in 27 intervals, primarily on May 29 & June 17.
  - ✓ Unexpected RT events and high loads led to tight conditions on these days.
- The new regulation market was implemented on June 26, 2013.
  - ✓ Market operations went smoothly and market outcomes were in line with the expectations during the first week of implementation.
  - ✓ We will continue to monitor the performance of the new market.

Ancillary Services Prices and Offer Patterns: New Mitigation Rules

- In our evaluation of the 10-min spin and non-spin reserves markets, we find:
  - ✓ The total amount of eastern 10-min spinning and non-spinning reserves offers has increased in 2013 due to the entry of new capacity in NYC in mid-2012.
  - ✓ Many suppliers have increased their offer prices consistent with expectations, particularly under conditions when average RT prices tend to exceed DA prices.
    - Offer prices have risen most at times of day with high load levels (e.g., hours 12-18) and on high load days (e.g., east NY peak load > 18 GW).
  - ✓ Although premature to draw strong conclusions, price convergence seemed to improve for both products in 2013.
    - Average absolute differences between hourly DA and RT prices were 107 and 116 percent (of average DA prices) for spin and non-spin reserves in the second quarter of 2013, down from 132 and 165 percent in the same months of 2012.
      - However, these statistics also reflect lower RT price volatility due to less frequent RT peaking conditions in the second quarter of 2013.
    - The variation in DAM prices by time of day and load level was slightly more consistent with RT prices.
    - DAM price premiums are expected in competitive markets with no virtual trading.
- We have not found offer patterns that raise significant withholding concerns. Hence, we will be recommending that the NYISO implement the second phase of the proposed changes to the mitigation rules.

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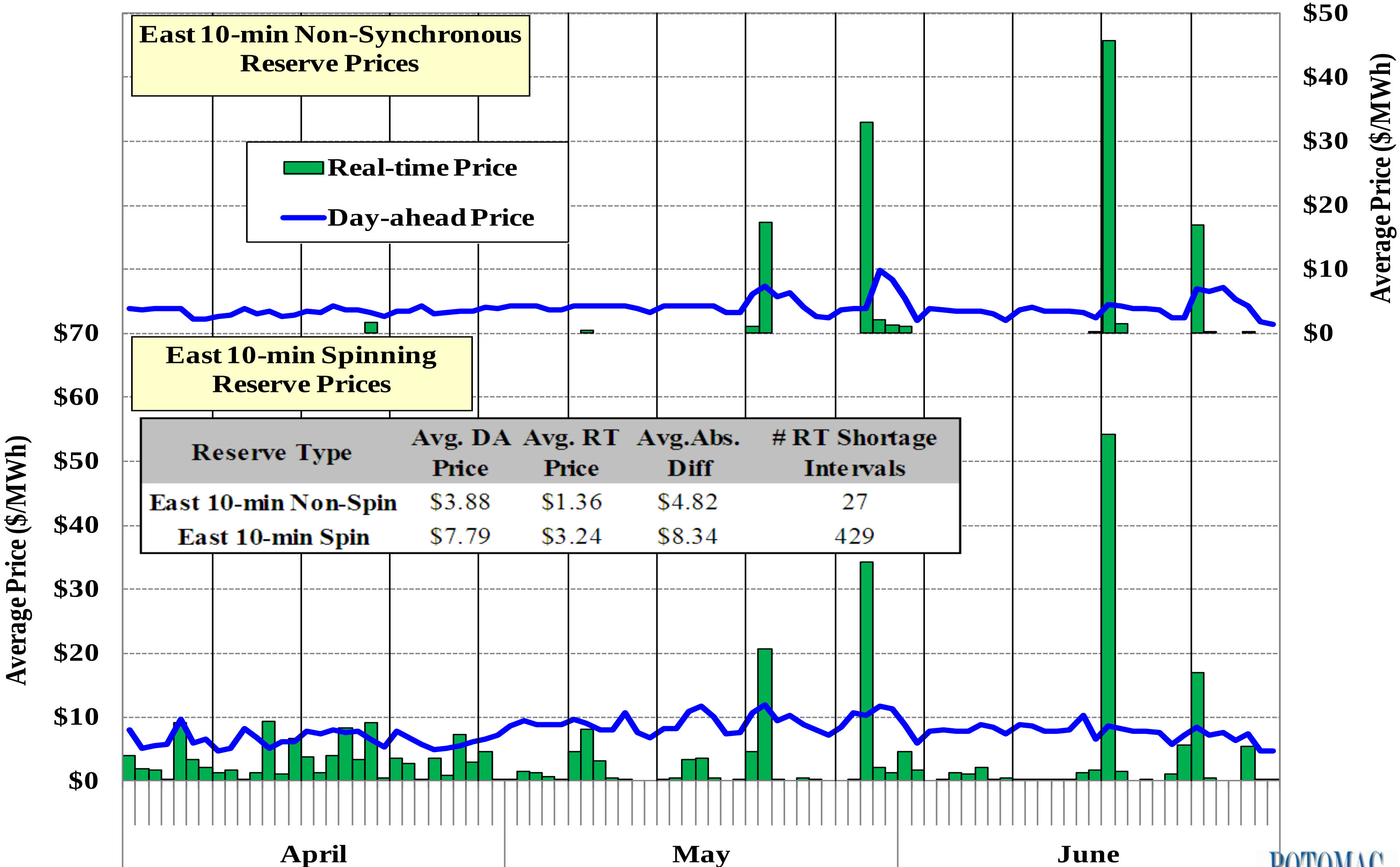
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	$3.88	$1.36	$4.82	27
East 10-min Spin	$7.79	$3.24	$8.34	429

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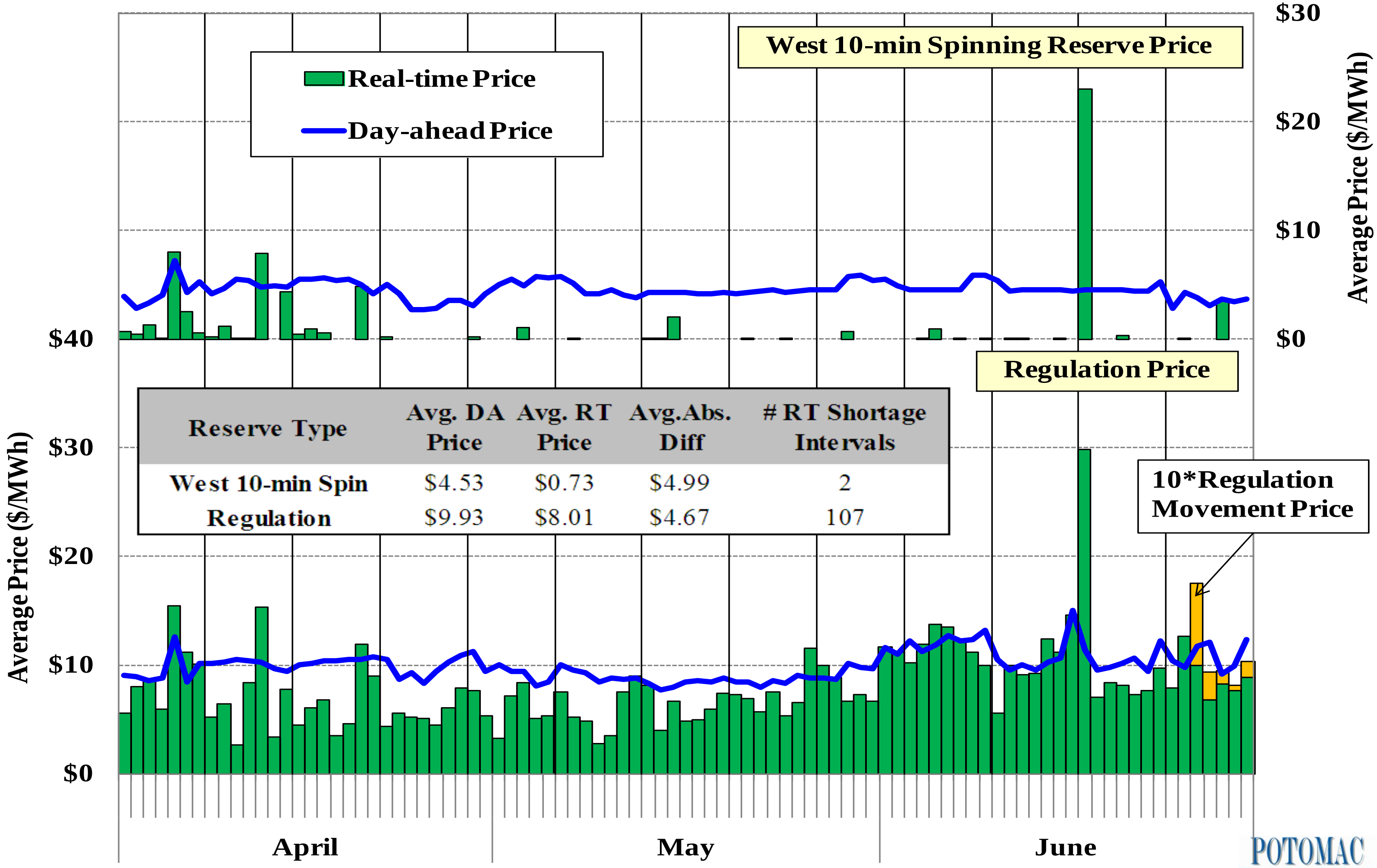
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
West 10-min Spin	$4.53	$0.73	$4.99	2
Regulation	$9.93	$8.01	$4.67	107

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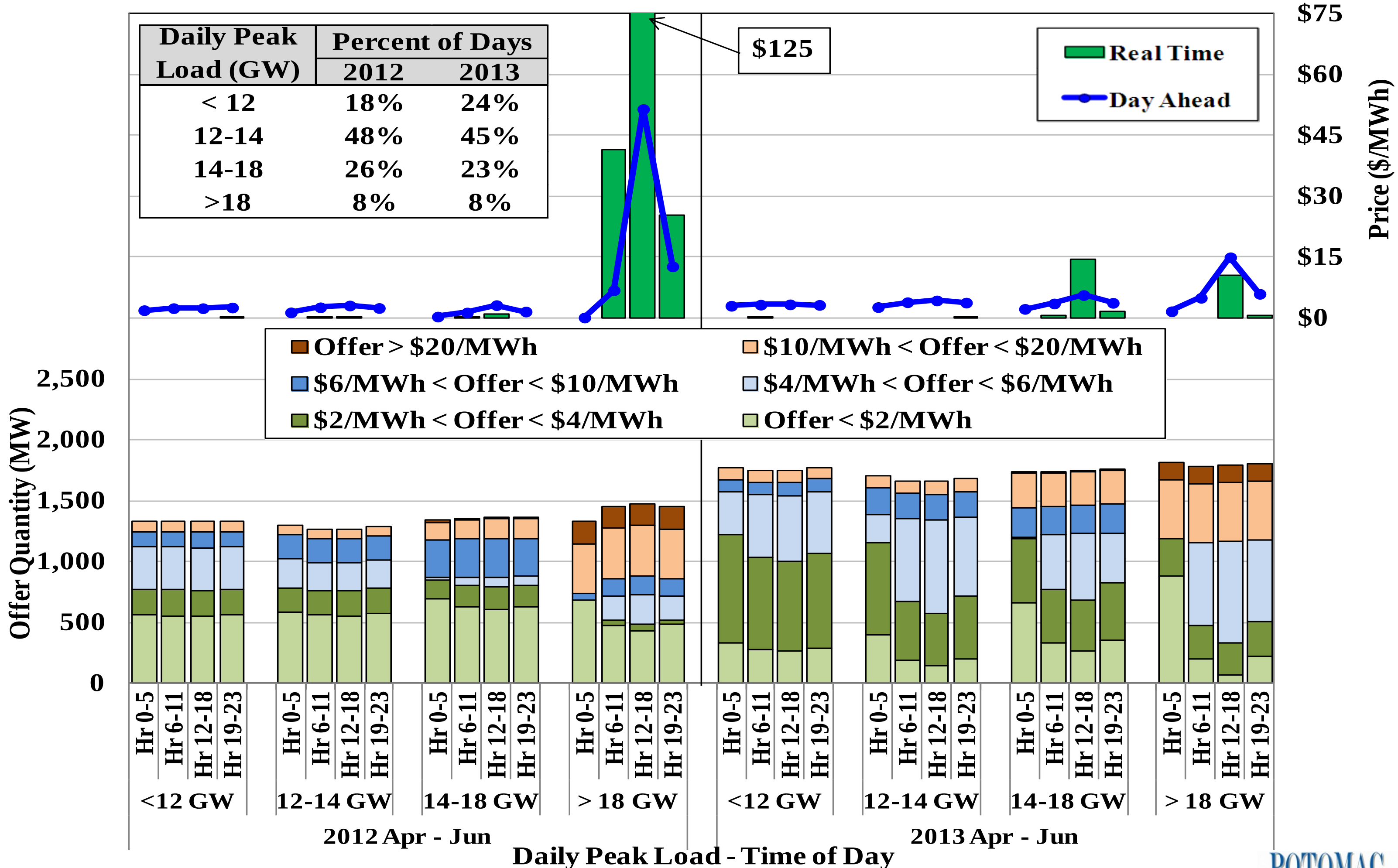
Day-Ahead Reserve Offers and Price Convergence
Eastern 10-Minute Non-Spinning Reserves



Daily Peak Load (GW)	Percent of Days	
	2012	2013
< 12	18%	24%
12-14	48%	45%
14-18	26%	23%
>18	8%	8%

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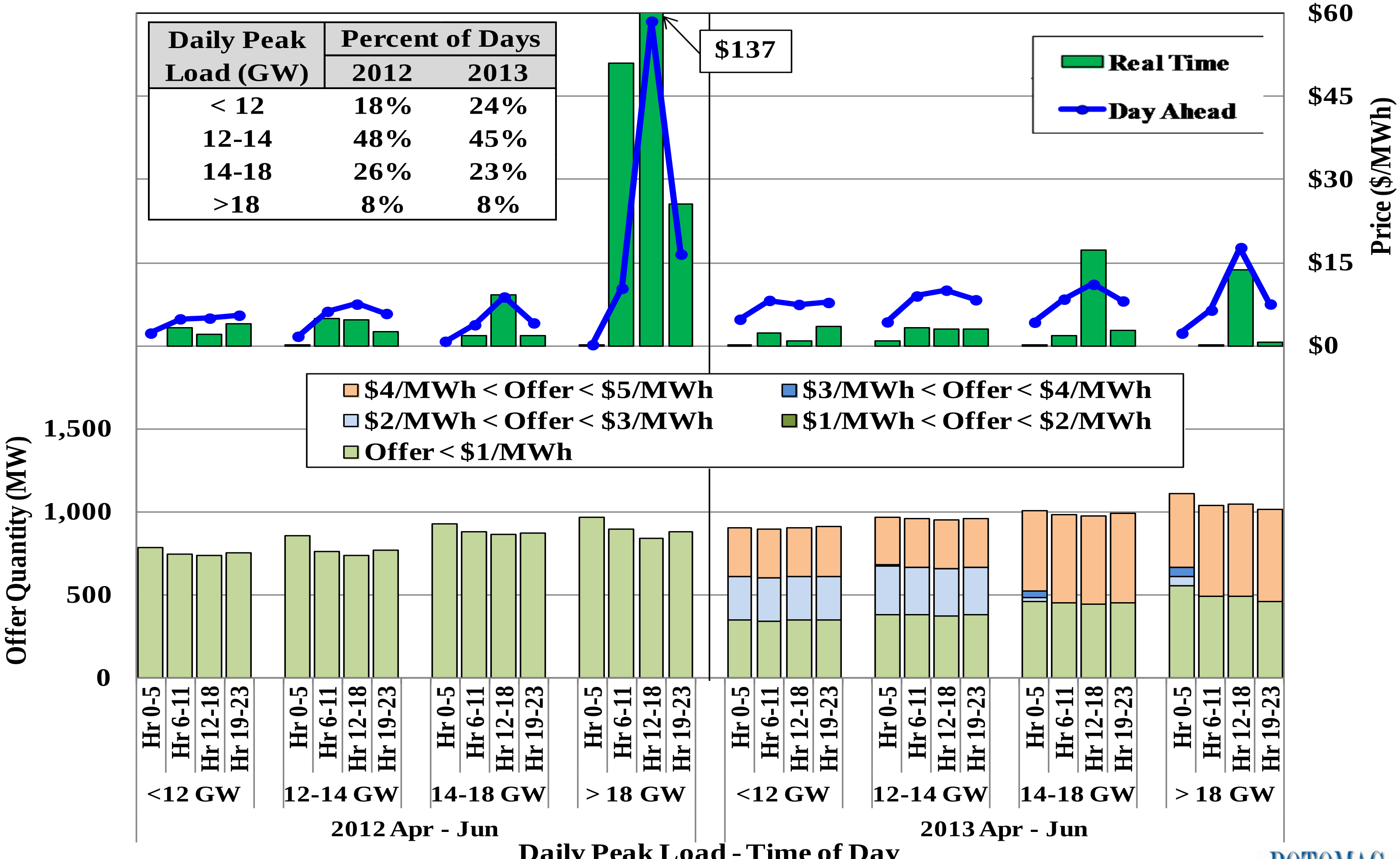
Day-Ahead Reserve Offers and Price Convergence
Eastern 10-Minute Spinning Reserves



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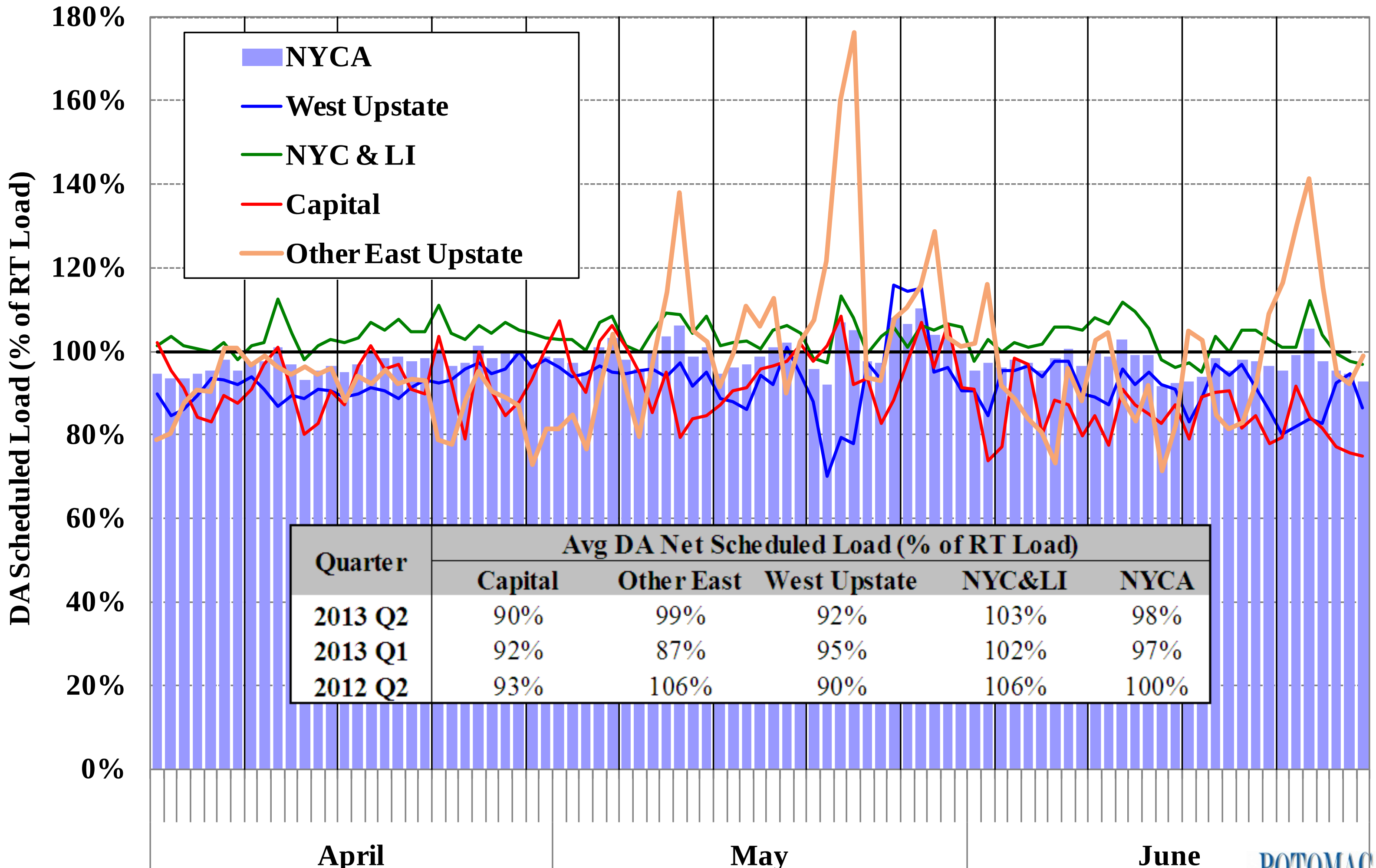
Energy Market Scheduling

Day-ahead Load Scheduling

- The following figure summarizes the quantity of day-ahead load scheduled as a percent of real-time load in each of four regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Overall, load in the DAM was scheduled at 98 percent of actual load in NYCA in the second quarter of 2013. This under-scheduling helped moderate the slight day-ahead premiums in most regions that were shown earlier.
- Load was generally under-scheduled outside SENY (i.e., West Upstate and Capital Zone) and over-scheduled in SENY in the second quarter of 2013.
  - ✓ This pattern has been prevalent in recent years and is likely in response to RT congestion across the lines into SENY, NYC, and Long Island.
    - – For example, load was notably over-scheduled in SENY on several days in May and June when TSA events were well anticipated.
  - ✓ However, the overall amount of over-scheduling in SENY has fallen more recently.
    - – The reduction likely resulted from less acute RT congestion into SENY, due to more efficient use of NY-NJ PARs and the addition of new capacity in NYC.
  - ✓ Under-scheduling outside SENY occurred partly in response to scheduling patterns of some hydro and wind resources in West NY, which normally increased output in RT above their DA schedule level.

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
2013 Q2	90%	99%	92%	103%	98%
2013 Q1	92%	87%	95%	102%	97%
2012 Q2	93%	106%	90%	106%	100%

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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 profit may indicate modeling inconsistencies between DA and RT markets, and large losses may indicate potential manipulation of the DA 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.
    - – An import or export is deemed to be virtual if the DA schedule is greater than the RT schedule, so a portion of these transactions result from curtailments by the NYISO or another control area (rather than the intent of the MP).

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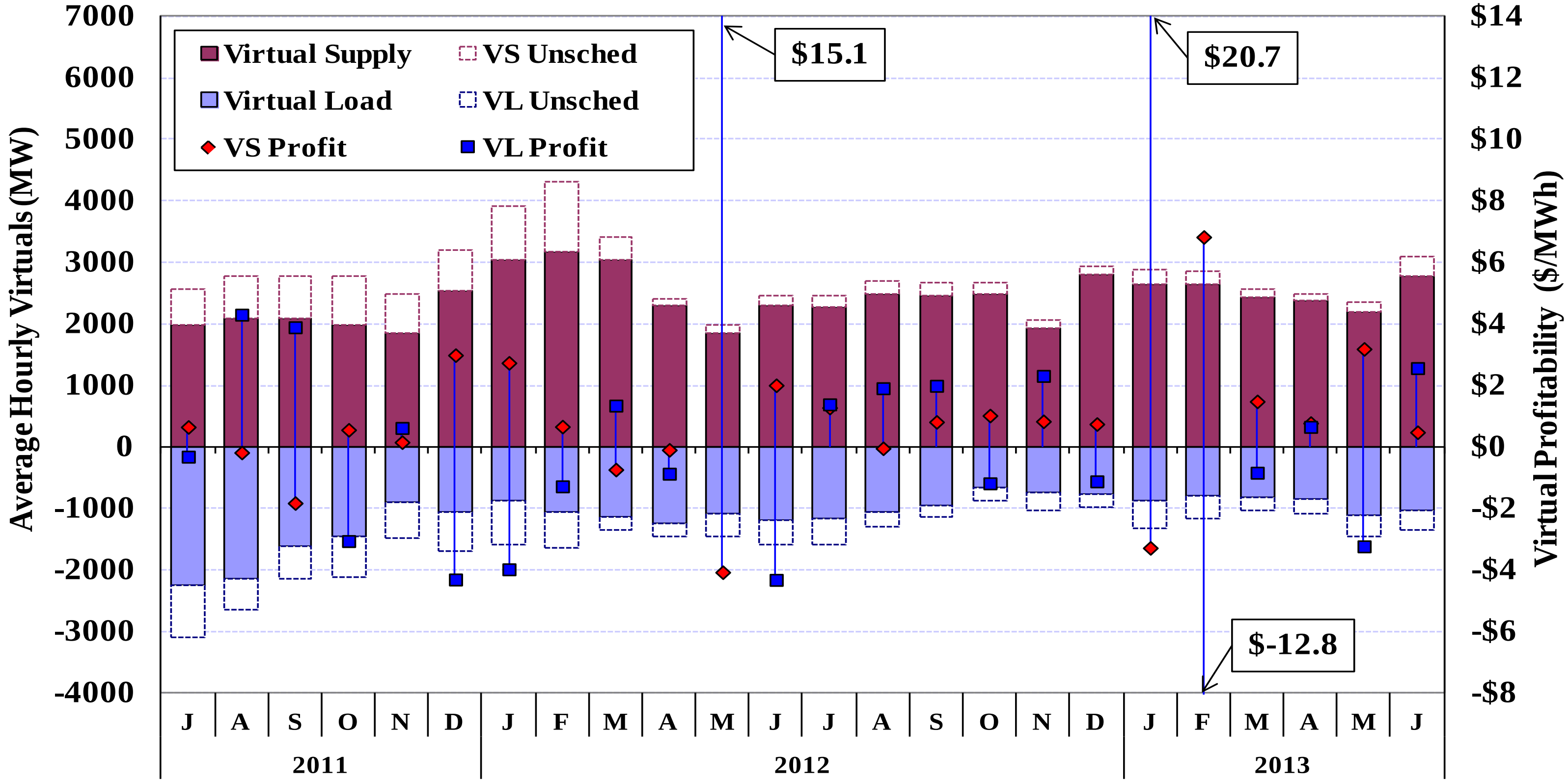
Virtual Trading Activity

- A large number of market participants regularly submit virtual trades, averaging 28 at the load zones and 7 at the proxy buses in the second quarter of 2013.
- Much of the virtual activity was related to the scheduling patterns discussed above.
  - ✓ At the load zones, virtual traders generally scheduled more virtual load in SENY and more virtual supply outside SENY, consistent with prior periods.
  - ✓ At the proxy buses, most of virtual transactions were submitted at the Ontario and primary PJM and NE proxy buses, and nearly 90 percent were virtual imports.
    - – These three proxy buses are primarily interconnected with regions outside SENY, so virtual imports are consistent with the pattern of virtual supply in those regions.
- In aggregate, virtual traders netted a gross profit of $7 million at the load zones and $1 million at the proxy buses in the second quarter of 2013, indicating that they typically improved convergence between DA and RT prices.
  - ✓ However, the profits and losses of virtual trades have varied widely from month-to-month, reflecting the difficulty of predicting volatile real-time prices.
  - ✓ The net profits reported at the proxy buses were partly offset by losses associated with DAM transactions that were curtailed by an ISO rather than by the MP.
- Only small quantities of virtual transactions generated substantial profits or losses.
  - ✓ These were primarily associated with real-time price volatility, which do not raise significant concerns.

Virtual Trading Activity at Load Zones by Month



Profit > 50% of Avg. Zone Price	MW	376	337	186	98	100	208	275	96	224	220	128	345	300	208	158	143	238	202	418	426	191	187	328	253
	%	9%	8%	5%	3%	4%	6%	7%	2%	5%	6%	4%	10%	9%	6%	5%	5%	9%	6%	12%	12%	6%	6%	10%	7%
Loss > 50% of Avg. Zone Price	MW	434	334	122	133	120	193	177	125	283	261	132	377	337	220	129	93	182	195	354	347	125	149	275	165
	%	10%	8%	3%	4%	4%	5%	5%	3%	7%	7%	4%	11%	10%	6%	4%	3%	7%	5%	10%	10%	4%	5%	8%	4%

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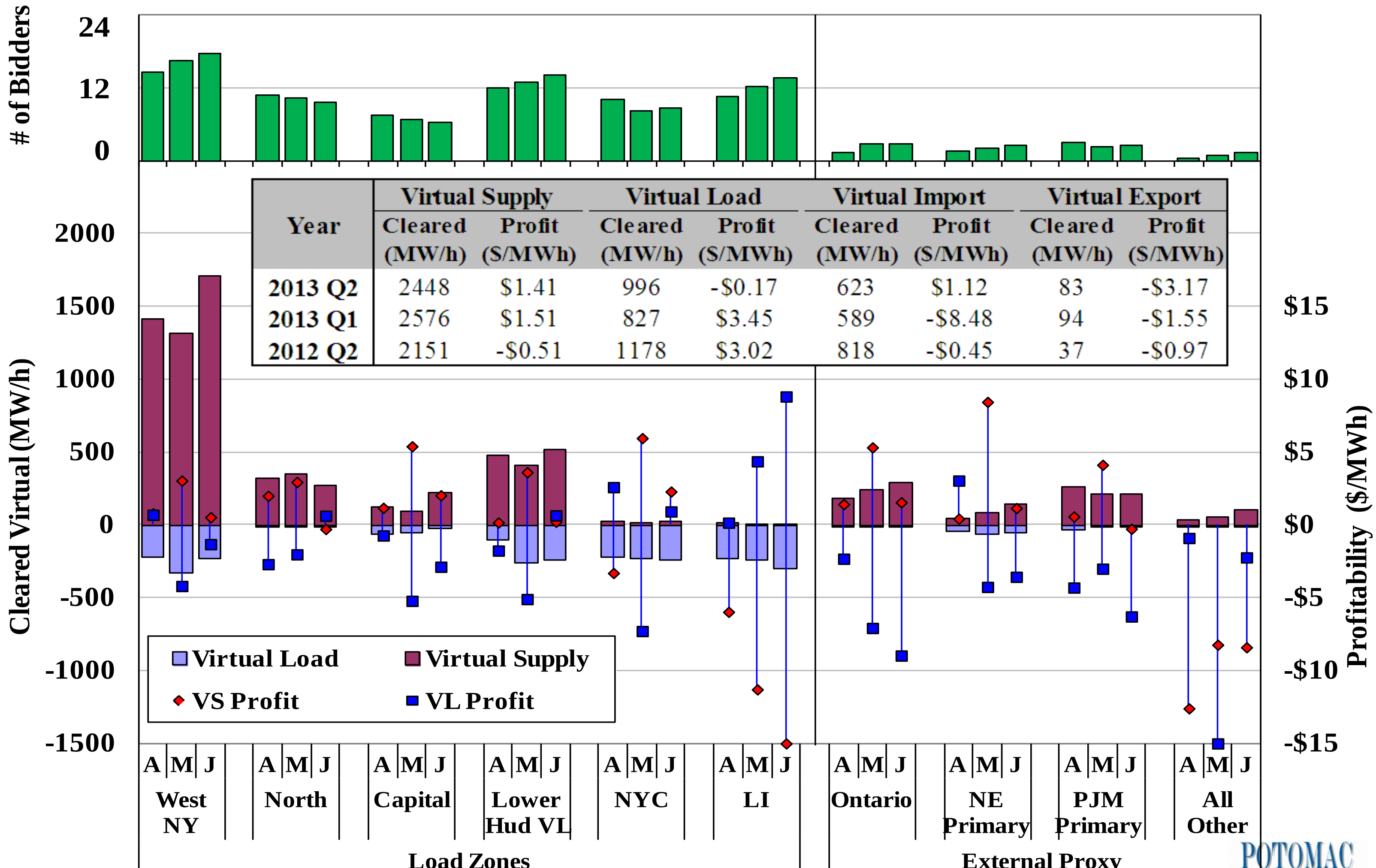
Virtual Trading Activity at Load Zones & Proxy Buses by Location



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)
2013 Q2	2448	$1.41	996	-$0.17	623	$1.12	83	-$3.17
2013 Q1	2576	$1.51	827	$3.45	589	-$8.48	94	-$1.55
2012 Q2	2151	-$0.51	1178	$3.02	818	-$0.45	37	-$0.97

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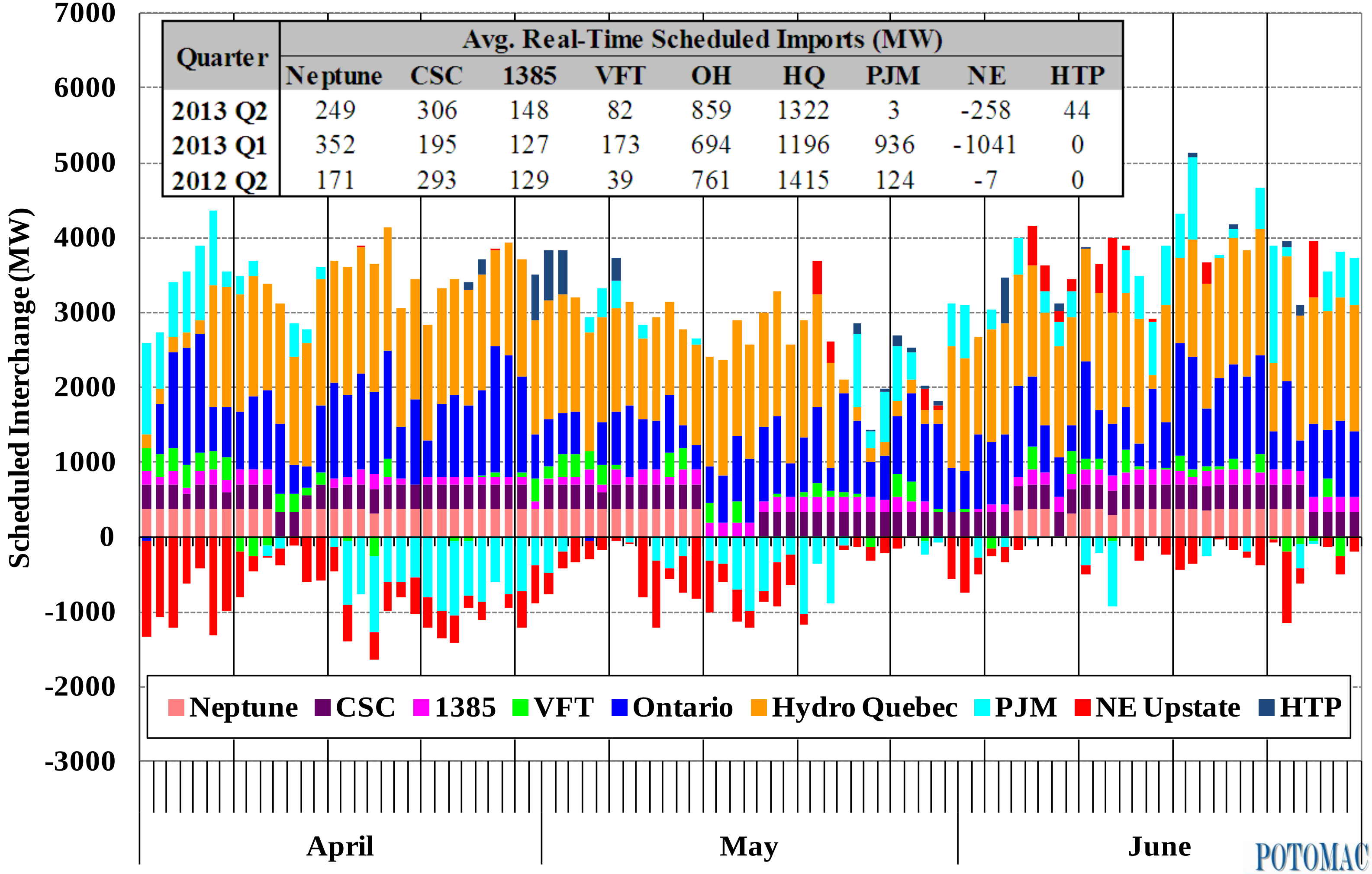
Net Imports Scheduled Across External Interfaces

- The following figure summarizes scheduled net imports to NYCA across ten external interfaces (two HQ interfaces are combined) in the daily peak load hour.
- Overall, net imports averaged 2.8 GW (serving 14 percent of the load) during daily peak load hours, down 170 MW from the second quarter of 2012.
- Net exports to NE across its primary interface averaged 260 MW during daily peak load hours, down 800 MW from last quarter and up 250 MW from last year.
  - ✓ These changes are consistent with the variations in natural gas price spreads between NE and NY over the period.
  - ✓ Imports to Long Island across the 1385 Line and CSC varied for similar reasons.
- Net imports to Long Island across the Neptune Line were usually fully scheduled.
  - ✓ However, the Neptune Line was partially available (up to 375 MW) or fully unavailable throughout the quarter.
- Net imports from PJM across the primary interface fell significantly when both Ramapo PARs were out of service from early-April to mid-May.
  - ✓ These outages shifted power flows to the tie-lines between PJM and Western NY, resulting in lower LBMPs at the PJM proxy (and less incentives to import to NY).
- Although the HTP Scheduled Line began operation on June 3, very little has been scheduled across this interface.

Net Imports Scheduled Across External Interfaces
Daily Peak Load Hour



Quarter	Avg. Real-Time Scheduled Imports (MW)								
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP
2013 Q2	249	306	148	82	859	1322	3	-258	44
2013 Q1	352	195	127	173	694	1196	936	-1041	0
2012 Q2	171	293	129	39	761	1415	124	-7	0

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Lake Erie Circulation

- Loop flows occur when physical power 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 loop flows around Lake Erie 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 Transmission Loading Relief ("TLR") procedure is used by the NYISO when loop flows significantly contribute to congestion on internal flow gates.
- The figure summarizes the frequency of clockwise Lake Erie Circulation ("LEC") and the frequency of TLRs (level 3A) called by the NYISO in the second quarter.
- Loop flows averaged 25 MW in the clockwise direction in the second quarter.
  - ✓ The frequency of high (>200MW) clockwise LEC has been low in recent months.
  - ✓ IESO-Michigan PARs, which are capable of controlling up to 600 MW of LEC, began operating in April 2012 and have generally been used to reduce loop flows.
- The frequency of TLRs called by the NYISO has fallen substantially since the second quarter of 2012 due to changes in the TLR process.
  - ✓ The NYISO was unable to use TLRs to manage congestion resulting from loop flows when the IESO-Michigan PARs were deemed in "regulate" mode.

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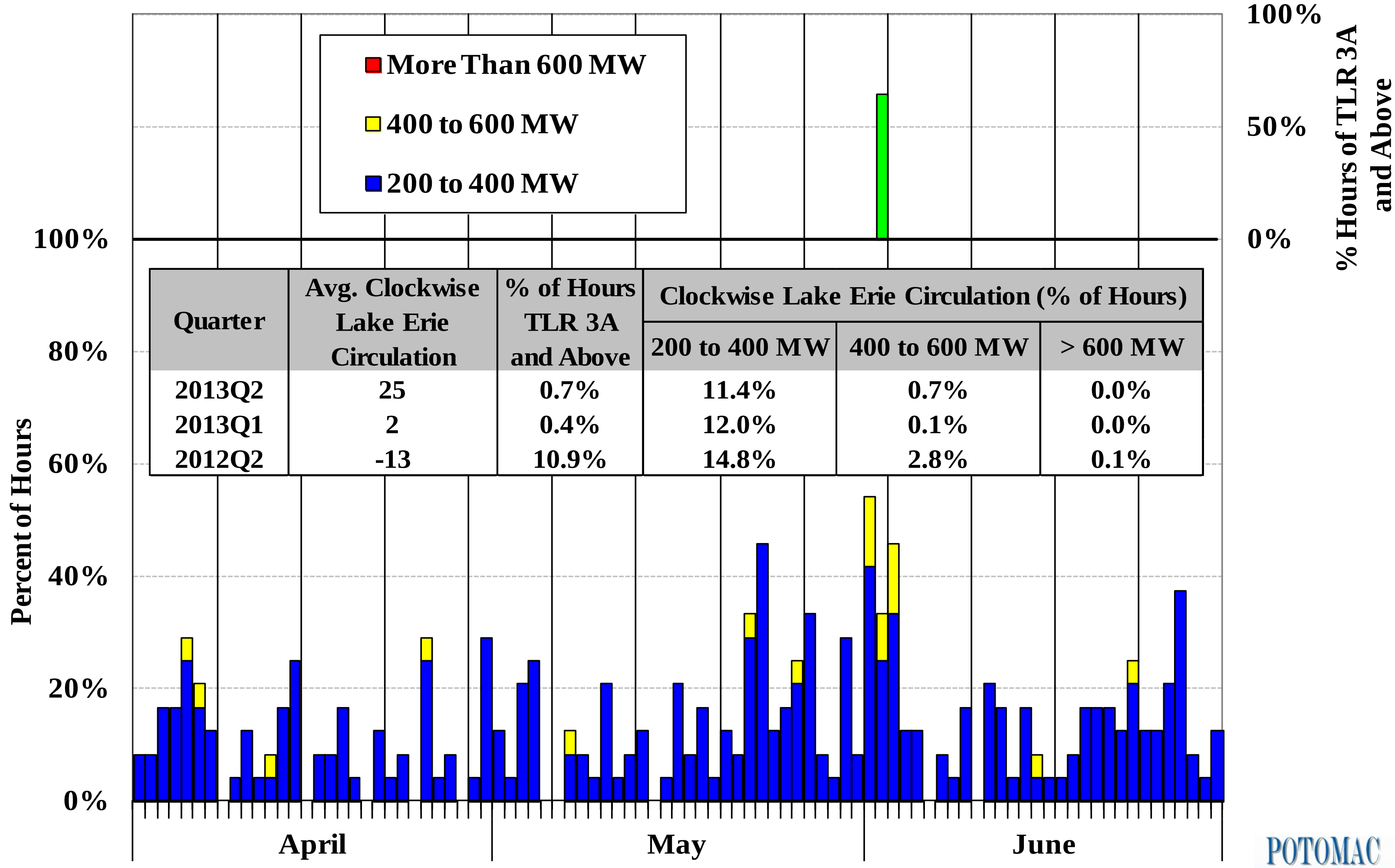
RT Clockwise Lake Erie Circulation and TLR Calls



Quarter	Avg. Clockwise Lake Erie Circulation	% of Hours TLR 3A and Above	Clockwise Lake Erie Circulation (% of Hours)		
			200 to 400 MW	400 to 600 MW	> 600 MW
2013Q2	25	0.7%	11.4%	0.7%	0.0%
2013Q1	2	0.4%	12.0%	0.1%	0.0%
2012Q2	-13	10.9%	14.8%	2.8%	0.1%

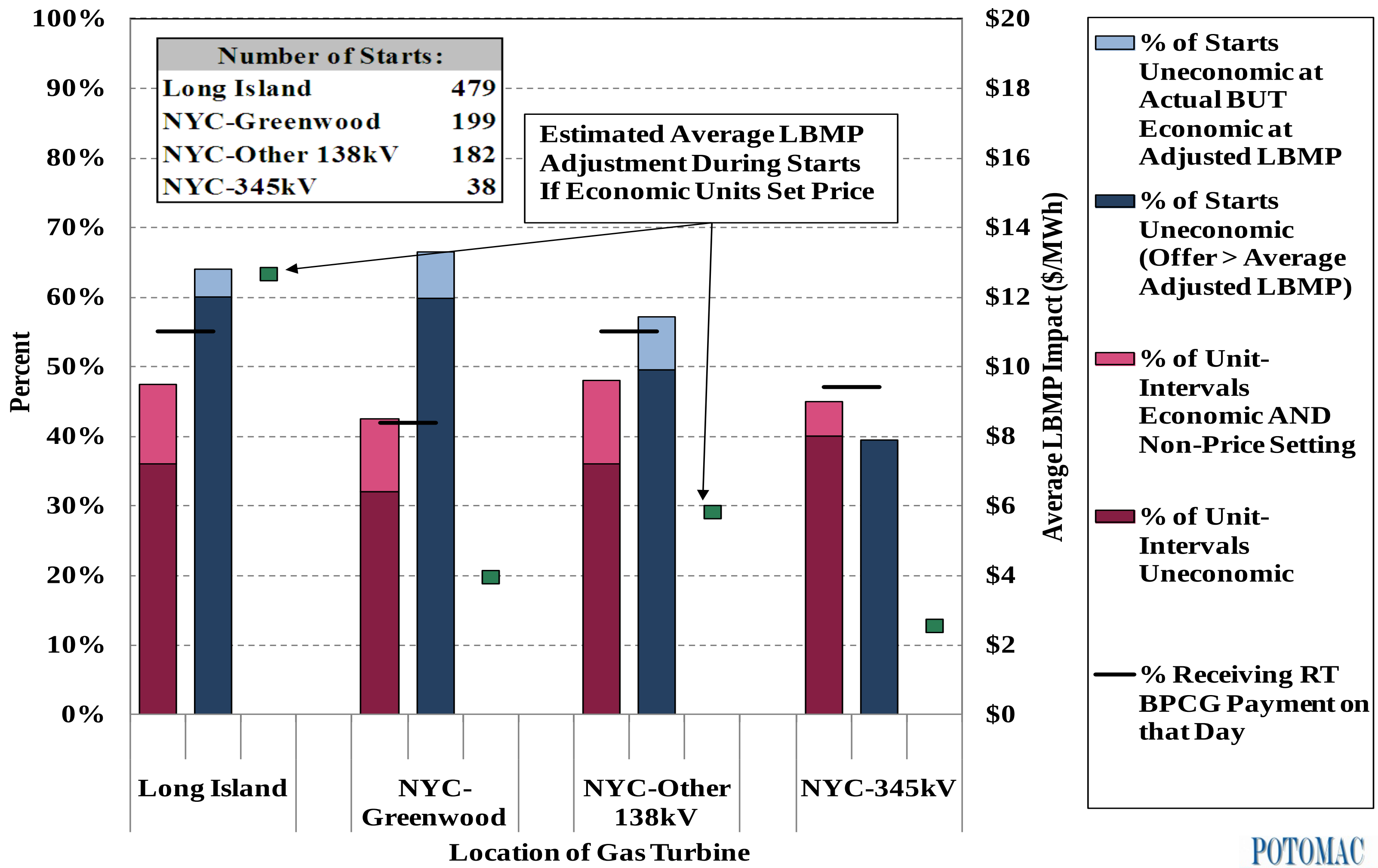
Efficiency of Gas Turbine Commitment and Price Setting

- The next figure evaluates the efficiency of GT commitments and of RT LBMPs during the initial one-hour commitment period in the second quarter of 2013.
- The figure reports the seven quantities for four areas of NYC and Long Island:
  - ✓ Number of Starts – Excludes self-schedules and commitment for TO reliability.
  - ✓ Percent Receiving RT BPCG Payment on that Day – Share of GT commitments that occurred on days when the unit received a RT BPCG payment for the day.
  - ✓ Percent of Unit-Intervals Uneconomic – Share of intervals during the initial commitment period when the unit was displacing less expensive capacity.
  - ✓ Percent of Unit-Intervals Economic AND Non-Price Setting – Share of intervals during the initial commitment period when the unit was displacing more expensive capacity, but not setting the RT LBMP.
  - ✓ Estimated Average LBMP Adjustment During Starts – Average upward adjustment in LBMPs during starts if economic GTs always set the RT LBMP.
  - ✓ Percent of Starts Uneconomic (Offer > Average Adjusted LBMP) – Share of starts when GT's offer was greater than the average "Adjusted LBMP" over the initial commitment period. (The "Adjusted LBMP" is the price that would have been set if economic GTs at the same market location always set the RT LBMP).
  - ✓ Percent of Starts Uneconomic at Actual BUT Economic at Adjusted LBMP – Share of starts when GT's offer was (a) greater than the average actual LBMP but (b) less than the average Adjusted LBMP over the initial commitment period.

Efficiency of Gas Turbine Commitment and Price Setting

- The figure shows that in the second quarter of 2013:
  - ✓ Gas turbines were economic in roughly 60 to 70 percent of intervals during their initial commitment period (excluding self schedules and local TO commitment).
  - ✓ However, economic gas turbines did not set LBMPs in 5 to 12 percent of intervals during their initial commitment period. This is partly due to the effects of NYISO's Hybrid Pricing methodology in the real-time market.
- We estimate that allowing these economic GTs to set prices would have increased the LBMPs in NYC and Long Island by an average of $2 to $13 per MWh when they were started in the second quarter of 2013.
  - ✓ The higher LBMPs would generally be more reflective of the costs of satisfying demand, security, and reliability requirements in the RT market.
- However, the figure under-estimates the effects of allowing GTs to set the RT LBMP in intervals when they are economic because:
  - ✓ It assumes that the RT LBMP impact is limited to nodes in the same area (out of the four areas shown in the figure) that have similar LBMP congestion component. In fact, the LBMPs over a wider area can be affected, depending on congestion.
- The figure also shows some GTs received RT BPCG payments on days when their initial commitment was economic. This can occur when the GT was kept online due to an OOM dispatch instruction after the initial commitment period.

Efficiency of Gas Turbine Commitment and Price Setting



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Day-Ahead and Real-Time Transmission Congestion

Congestion Patterns, Revenues, and Shortfalls

- The next five 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 arises) 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 overall 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 and third figures examine in detail the value and frequency of day-ahead and real-time congestion along major transmission paths by month.
  - ✓ 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 last two 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 to Central: Lines in the West Zone and interfaces from the West Zone to the Central Zone.
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ 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 – 345kV: Lines into and within the NYC 345 kV system.

POTOMAC ECONOMICS

Day-Ahead and Real-Time Congestion

- ✓ NYC Lines – Load Pockets: Lines leading into and within NYC load pockets.
- ✓ NYC Simplified Interfaces: 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 $90 million, up 46 percent from the second quarter of 2012 and down 72 percent from the prior quarter.
  - ✓ The decrease from the prior quarter was driven primarily by greatly reduced gas price spreads between eastern and western NY and between NY and NE.
    - – Congestion across the Central-East interface fell by over $200 million.
  - ✓ The increase from the second quarter of 2012 resulted largely from increased congestion into Long Island, due to factors that were discussed in detail earlier in this report (i.e., transmission and generation outages, unit retirements, and inefficient generation utilization).

Day-Ahead and Real-Time Congestion

- Congestion patterns were relatively consistent between DA and RT markets.
  - ✓ However, congestion was more frequent in the day-ahead market while the shadow prices of constraints were generally higher in the real-time market.
- Most congestion occurred in the following areas in the second quarter of 2013:
  - ✓ Long Island (43% DAM, 36% RTM) – The majority was congestion from upstate into Long Island, due to reasons mentioned earlier.
  - ✓ New York City lines (14% DAM, 17% RTM) – The majority was congestion on paths into the NYC 345 kV system and the Greenwood load pocket.
  - ✓ Central to East (14% DAM, 10% RTM) – Most congestion occurred on the Central-East interface in early April and early June when transmission outages reduced the transfer capability by nearly 1,000 MW.
  - ✓ Capital to Hudson (13% DAM, 11% RTM) – Increased congestion into SENY from the prior quarter was associated with more frequent TSA events.
  - ✓ Congestion in the West Zone and the North Zone has risen since 2012.
    - – The NYISO started to model line constraints (that were previously managed by OOM actions) in the West Zone in mid-2012.
    - – New wind capacity was added in the North Zone in 2012, contributing to more frequent congestion into SENY (included in the “All Other Facilities” category).

Day-Ahead and Balancing Congestion Shortfalls

- Day-ahead congestion shortfalls totaled roughly $18 million in the second quarter of 2013, up from $1 million in the second quarter of 2012.
  - ✓ The increase was driven primarily by transmission outages. Most notably:
    - One of the two major transmission lines from upstate to LI was out of service from late-March to late-May, accounting for roughly $12 million of shortfalls.
    - Transmission outages in early-April and early-June and generation outages in mid-April to mid-May significantly reduced transfer capability on the Central-East interface, contributing an additional $4 million to the total shortfalls.
  - ✓ Outage-related shortfalls are allocated to the responsible TO.
- Balancing congestion shortfalls totaled $8 million, up modestly from the second quarter of 2012.
  - ✓ Balancing shortfalls were small on most days in this quarter but rose notably on several days when unexpected real-time events occurred.
  - ✓ TSAs were the dominant driver of high balancing shortfalls on these days, during which the transfer capability into SENY was greatly reduced in real-time.
    - This led to a total of over $8 million of shortfalls (which reflect re-dispatch costs caused by the reduced transfer limit and performance of NY-NJ PAR-controlled lines during the events).

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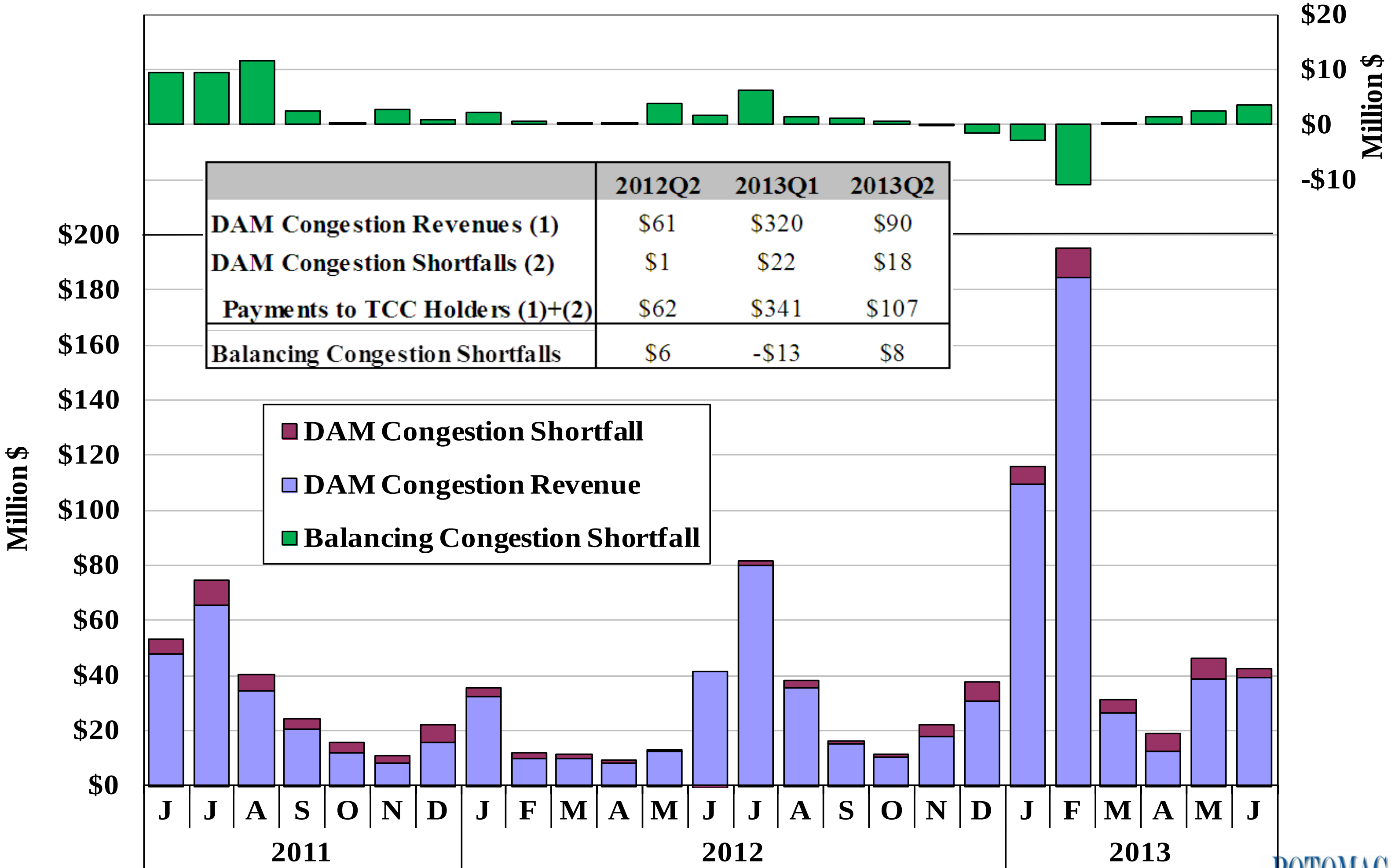
Congestion Revenues and Shortfalls by Month



	2012Q2	2013Q1	2013Q2
DAM Congestion Revenues (1)	$61	$320	$90
DAM Congestion Shortfalls (2)	$1	$22	$18
Payments to TCC Holders (1)+(2)	$62	$341	$107
Balancing Congestion Shortfalls	$6	-$13	$8

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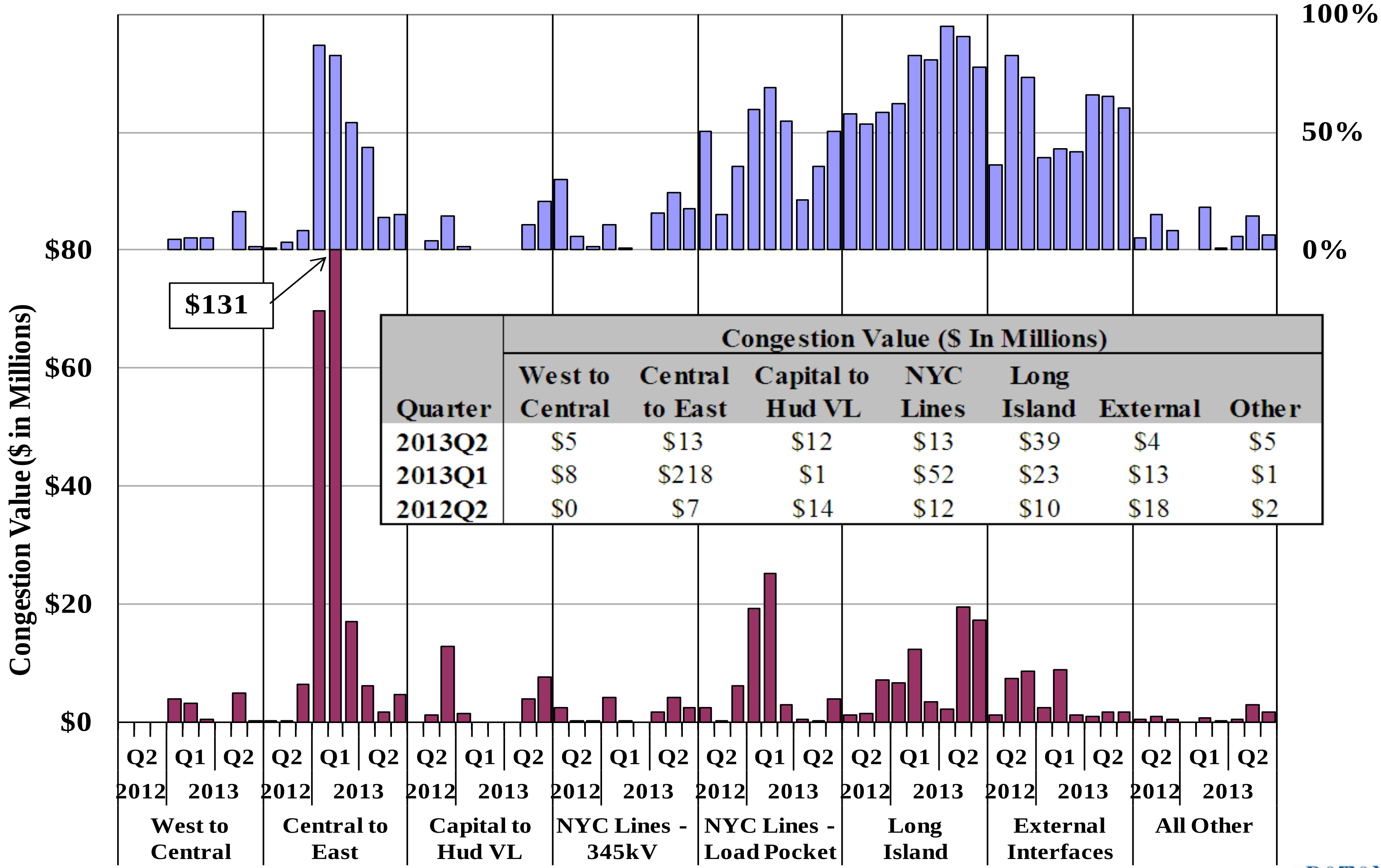
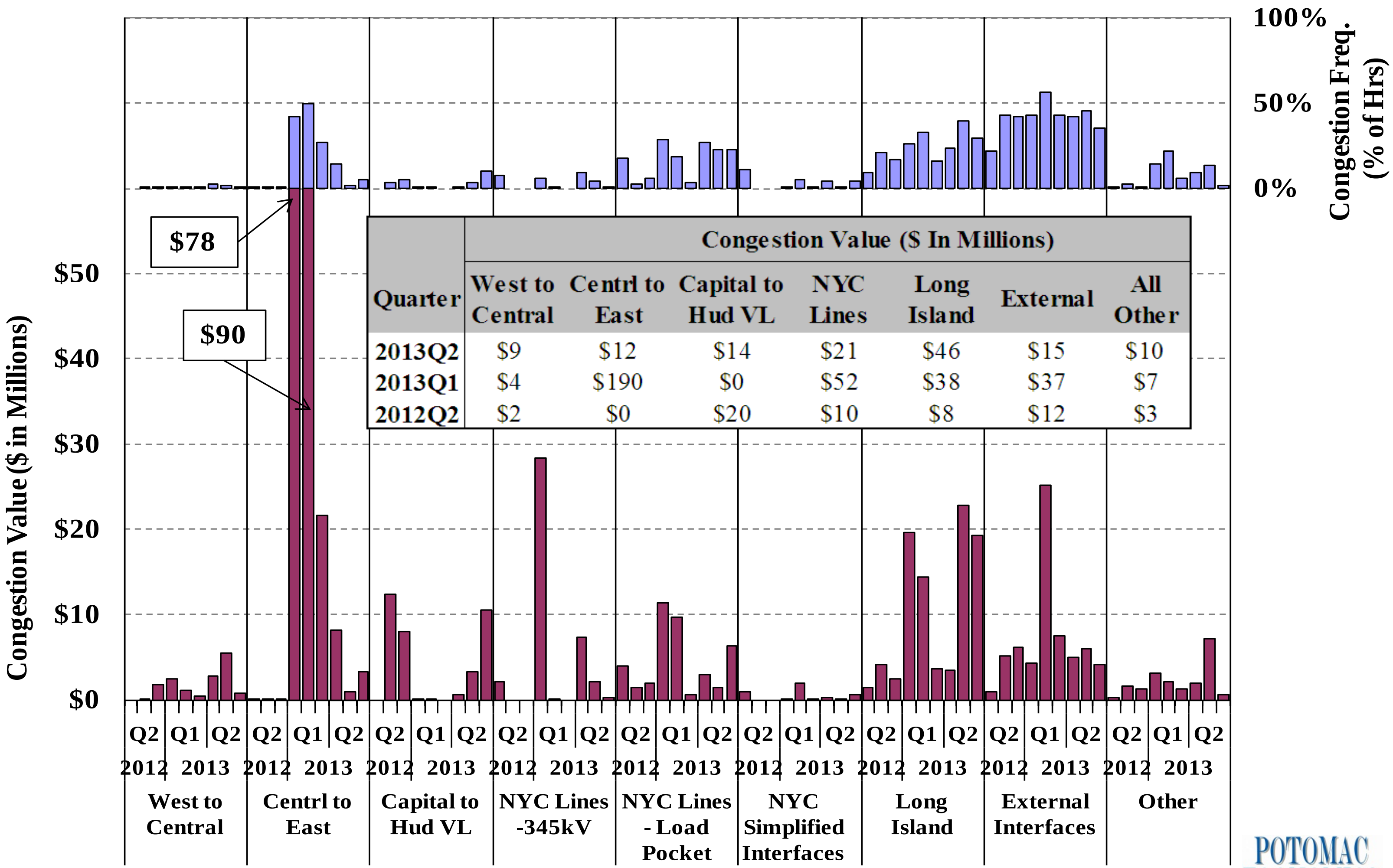
Day-Ahead Congestion Value and Frequency by Transmission Path



	Congestion Value ($ In Millions)						
Quarter	West to Central	Central to East	Capital to Hud VL	NYC Lines	Long Island	External	Other
2013Q2	$5	$13	$12	$13	$39	$4	$5
2013Q1	$8	$218	$1	$52	$23	$13	$1
2012Q2	$0	$7	$14	$12	$10	$18	$2

Real-Time Congestion Value and Frequency by Transmission Path



Quarter	Congestion Value ($ In Millions)						
	West to Central	Centrl to East	Capital to Hud VL	NYC Lines	Long Island	External	All Other
2013Q2	$9	$12	$14	$21	$46	$15	$10
2013Q1	$4	$190	$0	$52	$38	$37	$7
2012Q2	$2	$0	$20	$10	$8	$12	$3

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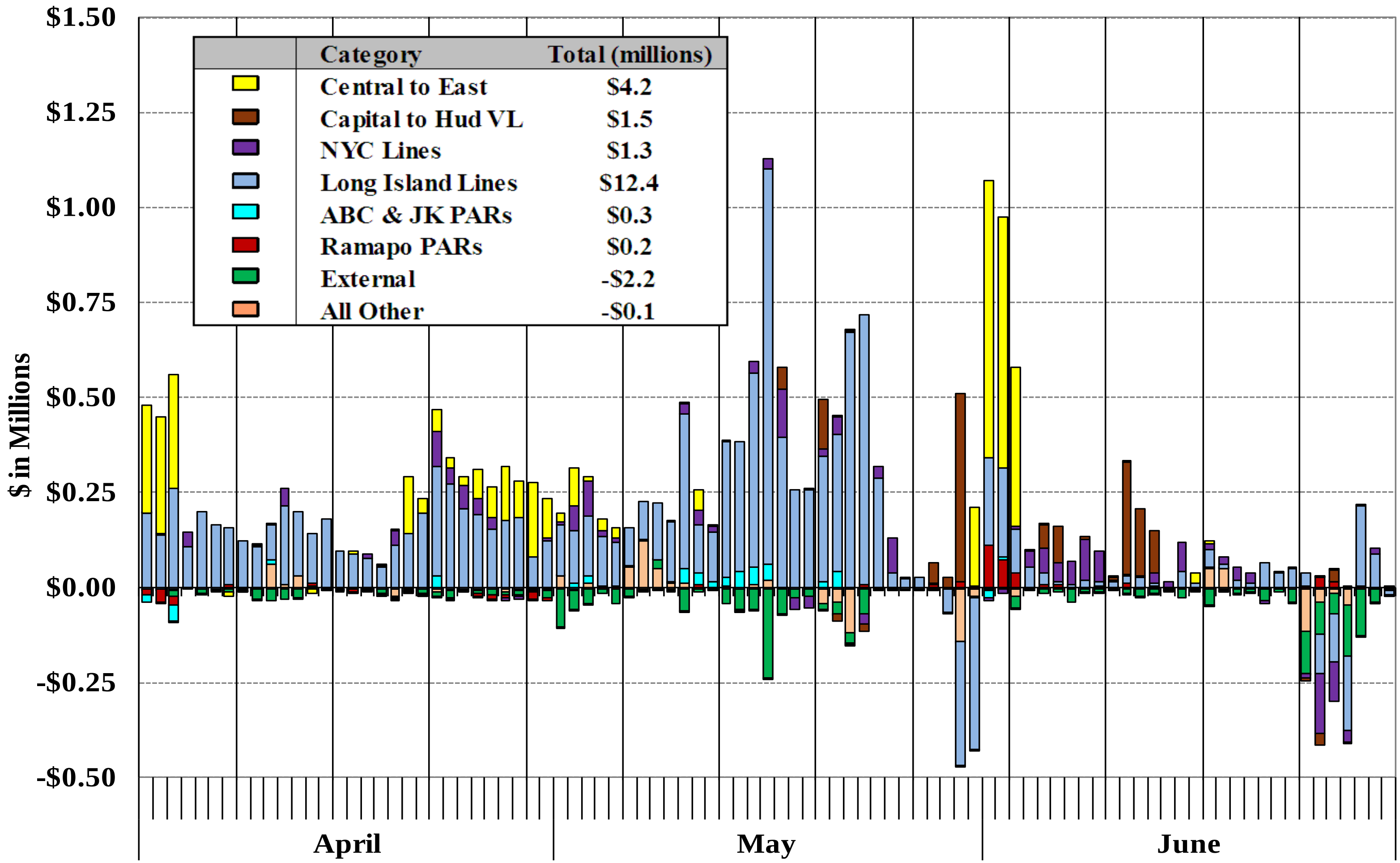
Day-Ahead Congestion Revenue Shortfalls
by Transmission Facility



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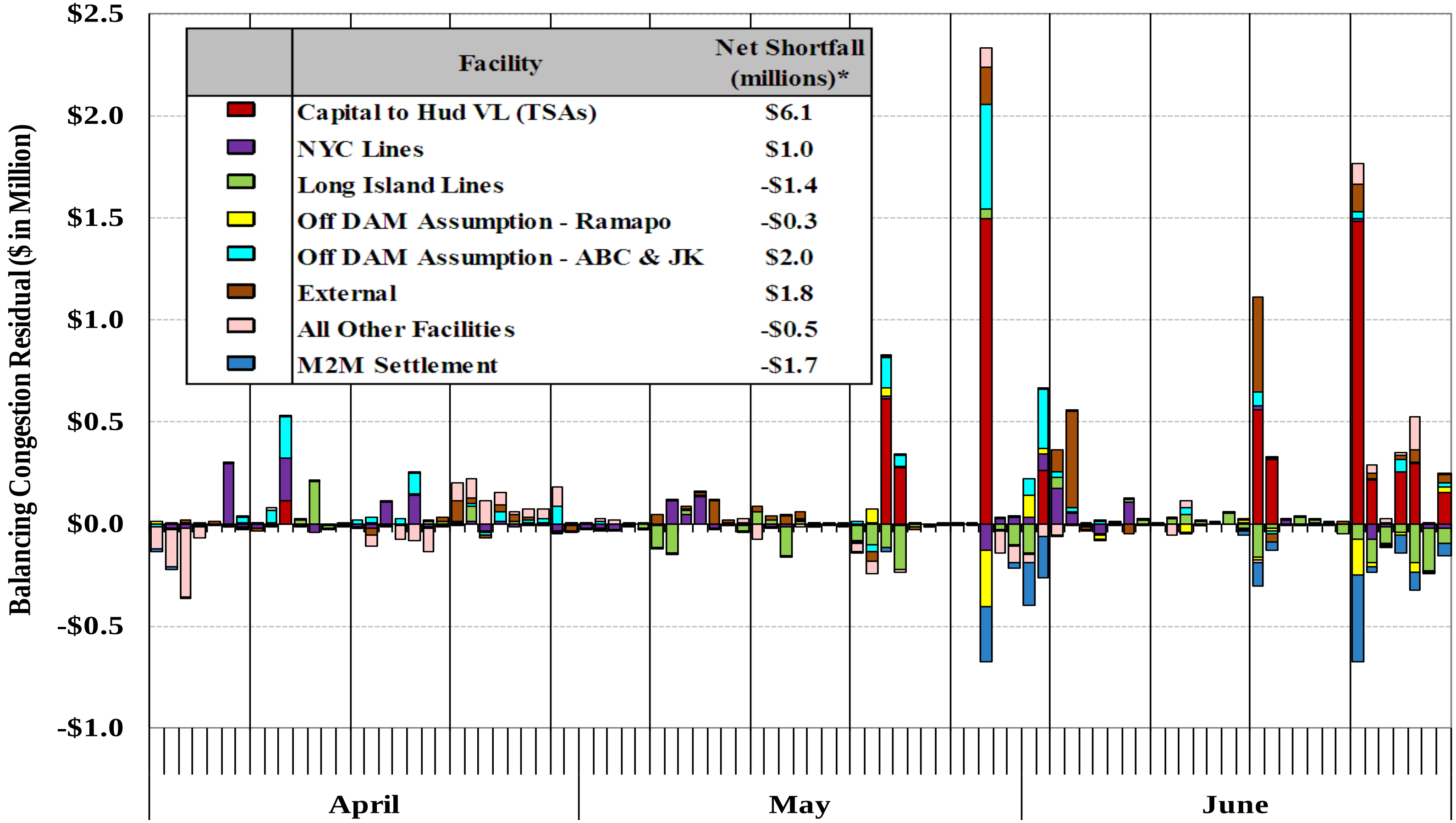
Balancing Congestion Shortfalls by Transmission Facility



Notes: The BMCR estimated above may differ from actual BMCR because the figure: (a) is partly based on real-time schedules rather than metered values and (b) assumes the energy component of the LBMP is the same at all locations including proxy buses (while the actual LBMPs are not calculated this way under all circumstances).

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Operations under M2M with PJM

- Coordinated congestion management between NYISO and PJM ("M2M") commenced in January 2013. 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 use of Re-dispatch Coordination was infrequent in the second quarter of 2013.
  - ✓ It was activated primarily for the Central-East constraint in roughly 7 hours and resulted in only a total payment of $1,700 from PJM to NY for that constraint.
- The use of Ramapo PAR Coordination had more significant impacts on the market in the second quarter of 2013. However, the usage was somewhat limited by facility outages.
  - ✓ One of two Ramapo PARs was out of service during the entire quarter (the outage began on February 4, 2013), reducing Ramapo capability by half.
  - ✓ The second Ramapo PAR was scheduled out of service from April 7 to May 15.
- The next three figures evaluate the operation of Ramapo PARs in the second quarter of 2013.

POTOMAC ECONOMICS

Operations under M2M with PJM Ramapo PAR Coordination

- The first figure compares the actual flows on Ramapo PARs with their M2M operational targets in the second quarter.
  - ✓ 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 (46 percent for most of the quarter).
    - – *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.
- The second figure is a scatter plot of actual Ramapo flow versus the estimated marginal effect of flows across the Ramapo Line on congestion in NY and PJM.
  - ✓ The marginal effect is measured as: (a) its marginal effect on congestion in NY minus (b) its marginal effect on congestion in PJM.
    - – Negative numbers indicate when it is economic to move power from NY to PJM.
    - – This includes congestion on both M2M and non-M2M flow gates.
  - ✓ The figure excludes hours when both markets had very little RT congestion (i.e., marginal effect of Ramapo was less than $2/MWh in both markets).

POTOMAC ECONOMICS

Operations under M2M with PJM Ramapo PAR Coordination

- The inset table provides summary statistics on the efficiency of Ramapo flows.
  - An hour is deemed relatively efficient if: (a) the marginal effect of Ramapo flows between the two markets was within $20/MWh, or (b) if the line was approaching its operational limit (i.e., flow > 450 MW).

- The third figure summarizes these outcomes on afternoons (HB 14-19) on ten days when congestion was greatest (excluding days when the line was out of service).
  - The marginal effect of Ramapo flows are shown separately considering: (a) all binding constraints; and (b) only binding M2M constraints.
  - Hours with binding TSA (Thunderstorm Alert) constraints are shaded.

- Actual flow across Ramapo was lower than Target Flow in most intervals during the second quarter when M2M constraints were binding.
  - Due to PAR outages, the Ramapo line did not have sufficient capability to support 61 percent of PJM imports on top of the other components (e.g., RECo load).
    - As a result, the ratio was changed to 46 percent beginning May 16.
  - M2M constraints in PJM were rarely binding.
  - Consequently, $1.7 million of M2M payments were made by PJM to NYISO during periods of under delivery (i.e., when actual flow < target flow).

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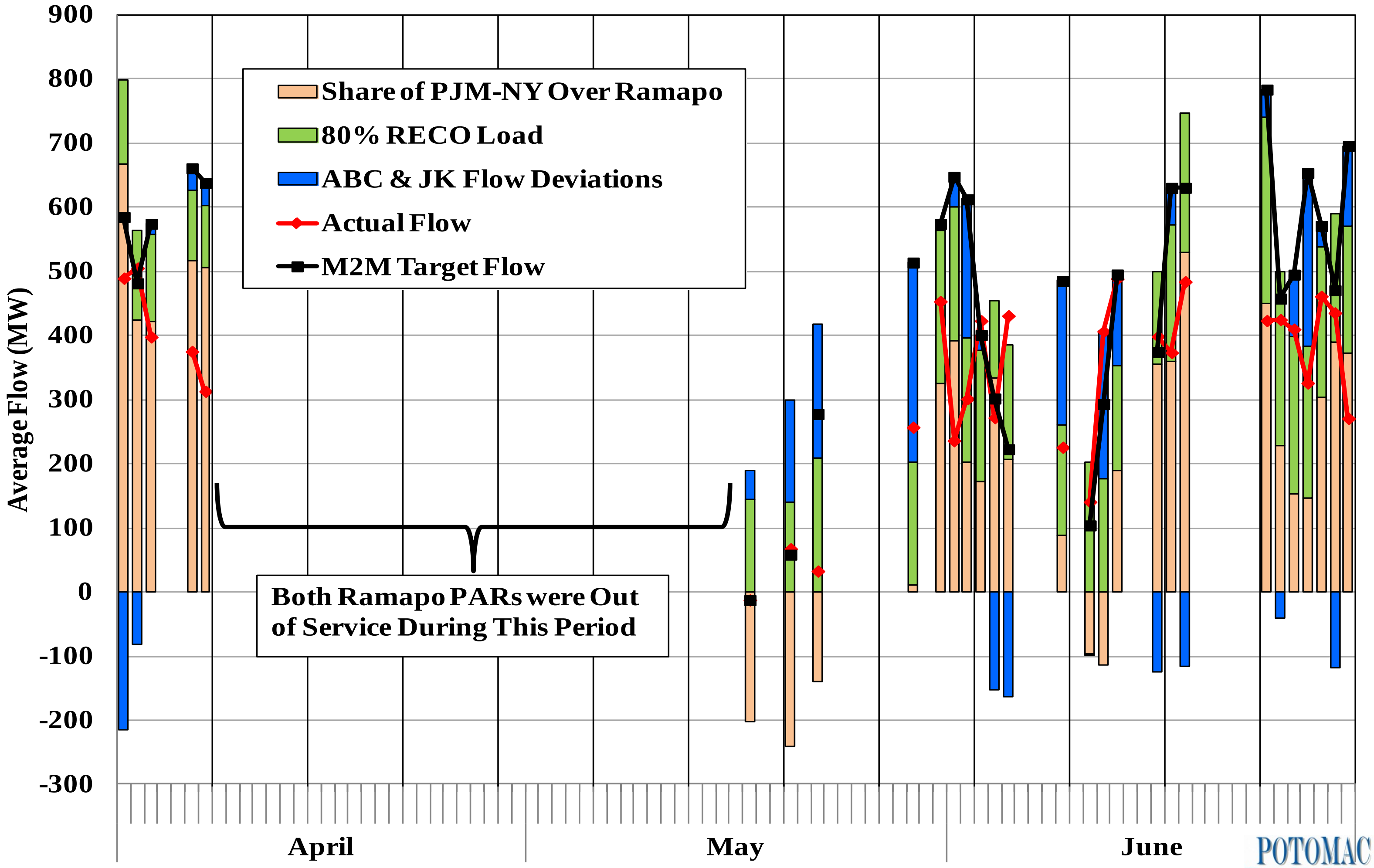
Operations under M2M with PJM Ramapo PAR Coordination

- Of hours with congestion in NY or PJM (i.e., when the marginal effect of Ramapo flow was greater than $2/MWh in one or both markets), Ramapo Line flows were:
  - ✓ Reasonably efficient in 70 percent of the hours.
  - ✓ Not fully optimized while NY congestion minus PJM congestion exceeded $20/MWh in 23 percent of the hours.
    - – The Ramapo Line still provided substantial benefits to NY in most of the hours.
    - – Flows into NY were generally higher in hours with M2M flow gates binding, averaging 293 MW in hours with M2M flow gates binding and 91 MW in other hours.
  - ✓ Not fully optimized while PJM congestion minus NY congestion exceeded $20/MWh in 7 percent of the hours.
    - – M2M flow gates were rarely binding in these hours.
    - – The Ramapo Line usually flowed power out of PJM in these hours, although the magnitude of flows was lower during hours with binding M2M flow gates.
    - – Most of the PJM congestion that was affected by Ramapo Line flows was on non-M2M flow gates.

Operations under M2M with PJM Ramapo PAR Coordination

- On the Top 10 afternoons shown in the third figure, the Ramapo Line affected congestion on both M2M and non-M2M constraints.
  - ✓ On four days shown (June 2, 17, 24, & 28), the Ramapo Line provided relief during periods of significant Leeds-to-Pleasant Valley congestion.
    - This congestion was reflected in the M2M coordination process.
  - ✓ Additional flows into NY would have been economic on two of the days (May 22 & 29) when congestion occurred on a non-M2M flow gate in NY (the Rock Tavern-to-Ramapo line).
  - ✓ Additional flows into PJM would have been economic on several days due to unusual congestion patterns in the NYISO (rather than congestion in PJM).
    - On four days shown (May 20, 21, & 30 and June 12), congestion in the NYISO West Zone could have been reduced by flowing power out of NY across Ramapo.
    - However, the benefit of using the Ramapo Line to relieve West Zone congestion would have been limited because: (a) the effectiveness of Ramapo flow adjustments on West Zone constraints is relatively small, and (b) the congestion was transient except on May 21.

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



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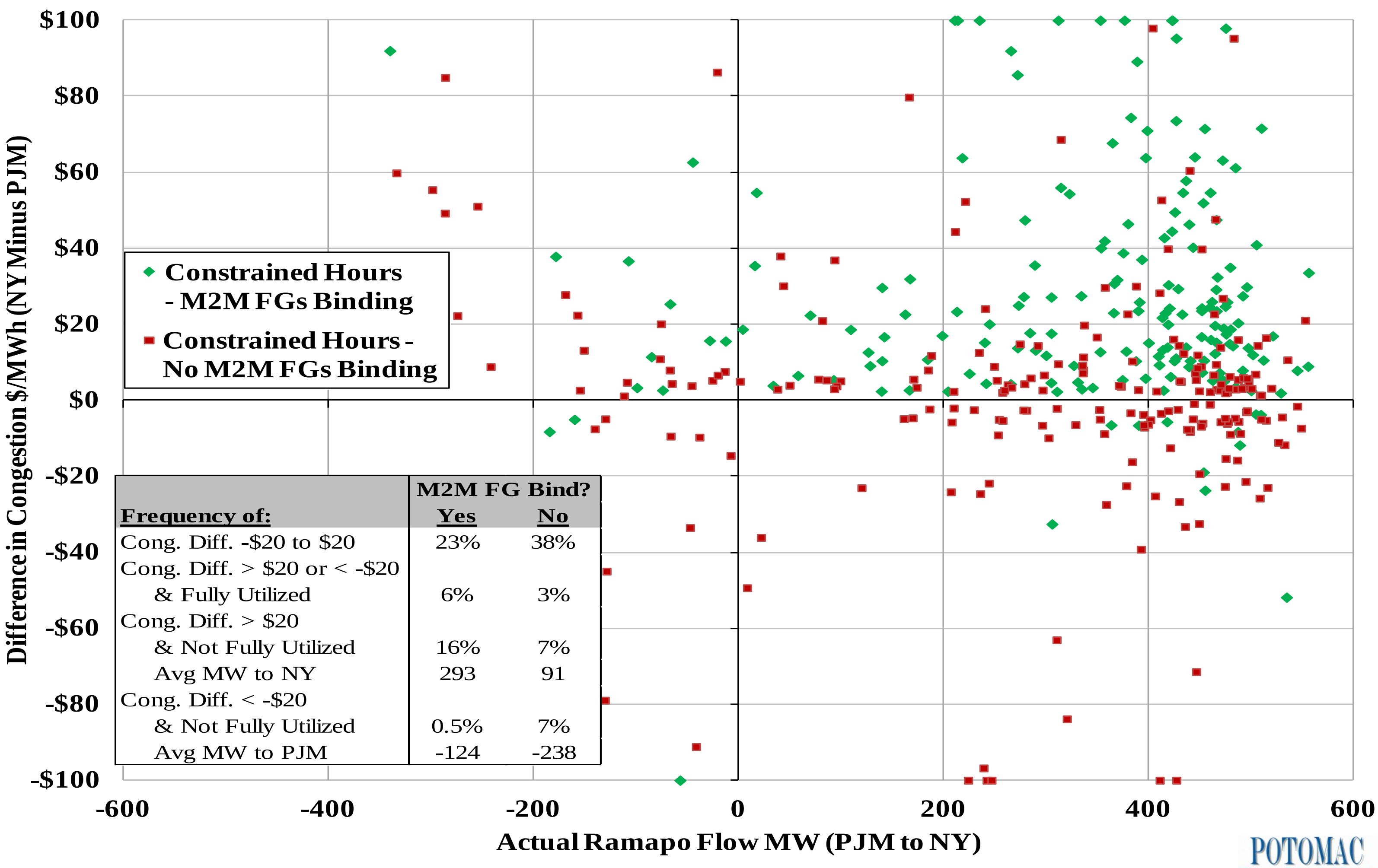
Marginal Effect of Ramapo on NY/PJM Congestion and Actual Ramapo Flow – Hours w/Congestion in NY or PJM



Frequency of:	M2M FG Bind? Yes	M2M FG Bind? No
Cong. Diff. -$20 to $20	23%	38%
Cong. Diff. > $20 or < -$20		
& Fully Utilized	6%	3%
Cong. Diff. > $20		
& Not Fully Utilized	16%	7%
Avg MW to NY	293	91
Cong. Diff. < -$20		
& Not Fully Utilized	0.5%	7%
Avg MW to PJM	-124	-238

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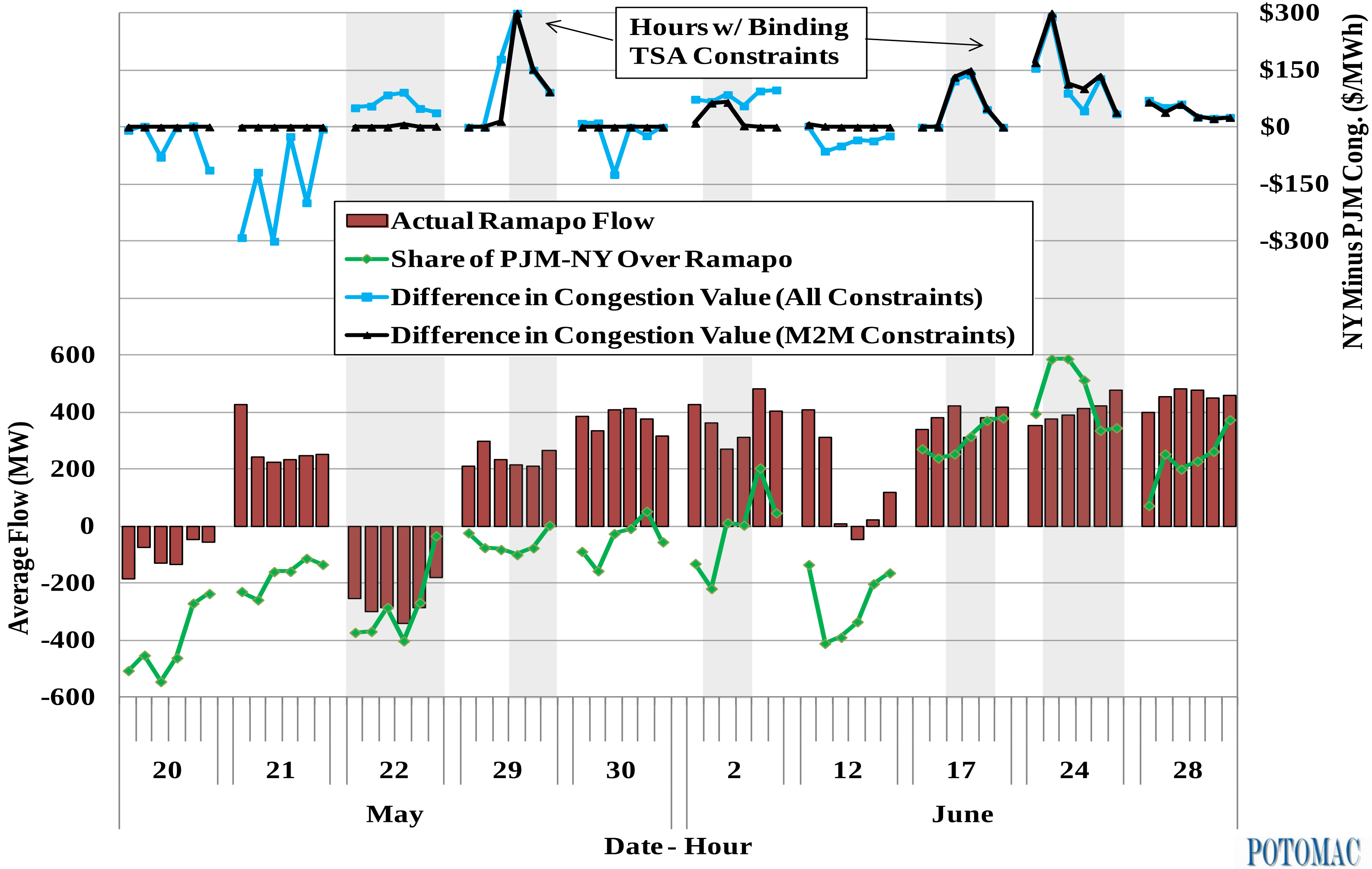
Marginal Effect of Ramapo on NY/PJM Congestion and Actual Ramapo Flow – Top 10 Afternoons



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Supplemental Commitments, OOM Dispatch, and Uplift Charges

Supplemental Commitment and OOM Dispatch

- 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.
  - ✓ 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

- Approximately 1,120 MW of capacity was committed on average for reliability in the second quarter of 2013, up 28 percent from the second quarter of 2012.
  - ✓ Of this total, 79 percent of reliability commitment was in NYC, 13 percent was in Long Island, and 8 percent was in Western NY.
- In western NY, reliability commitment averaged 150 MW, down 35 percent from the second quarter of 2012.
  - ✓ DARU commitments decreased partly because higher gas prices led to coal units being committed economically more frequently.
- On Long Island, reliability commitment averaged 85 MW, down 45 percent from the second quarter of 2012.
  - ✓ Units frequently needed for local reliability were committed economically more often because of higher LBMP levels (which are discussed earlier).
- In NYC, reliability commitment averaged 880 MW, up 92 percent from the second quarter of 2012. The increase was primarily due to:
  - ✓ Increased DARU commitments for the Astoria West/Queens/Vernon load pocket following significant transmission or generation outages; and
  - ✓ Periods when the LRR pass did not select the most economic set of generating resources for NOx constraints due to very long lead times for some units.

Supplemental Commitment in NYC

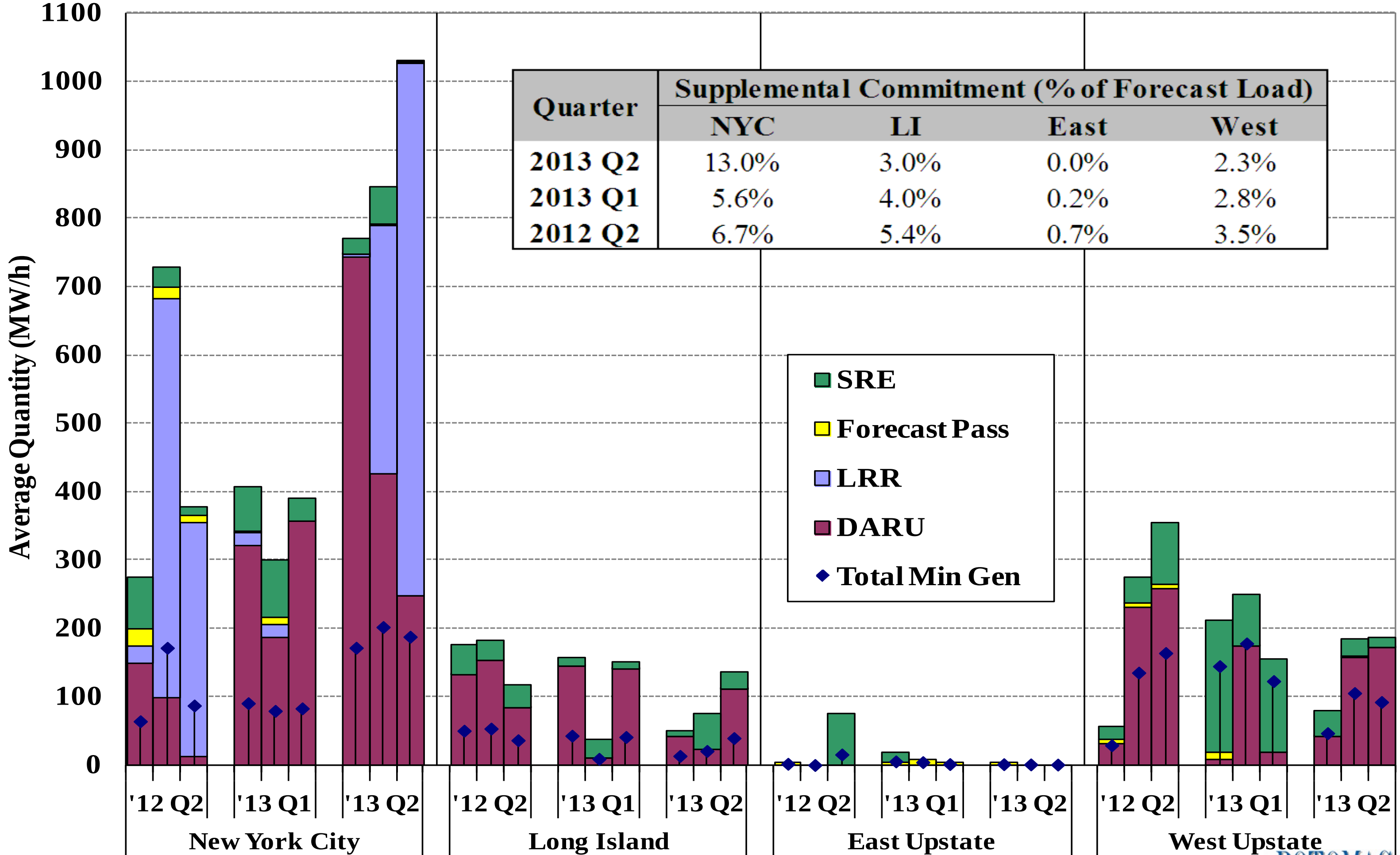
- The reliability criteria that accounted for the most MWhs of capacity in NYC during the second quarter of 2013 were:
  - ✓ Astoria West/Queensbridge/Vernon thermal and voltage requirements, which ensure facilities into the pocket will not be overloaded if the largest two generation or transmission contingencies were to occur.
  - ✓ NOx bubble requirements, which require the operation of a steam turbine unit in order to reduce the overall NOx emission rate from a portfolio containing higher-emitting gas turbine units.
    - These requirements are in effect from May to September each year.
    - On high load days, these requirements were frequently satisfied by economically committed units.
    - On moderate load days, these requirements accounted for a significant portion of reliability commitments.
    - The output from these steam turbine units sometimes displaced output from newer cleaner generation in the city and displaced imports to the city.
- The LRR pass did not select the most economic set of generating resources to satisfy NOx bubble constraints on some days. This is because the most efficient units sometimes had lead times requiring them to be started before the DAM closes, making them unavailable in the LRR pass.

OOM Dispatch

- 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.
- In the second quarter of 2013, generators were dispatched OOM for roughly 1,070 station-hours, up significantly from 420 station-hours in the previous quarter and down moderately from roughly 1,350 station-hours in the second quarter of 2012.
- NYC accounted for 47 percent of OOM station-hours in the second quarter.
  - ✓ An Arthur Kill steam unit accounted for 84 percent of OOM actions as its output was often limited by breaker outages at Freshkills from mid-April to mid-May.
- Long Island accounted for 31 percent of OOM station-hours in the second quarter.
  - ✓ Northport units accounted for 43 percent of OOM actions as the plant generation was limited by transmission outages on several days from late-May to early-June.
- Western NY accounted for 18 percent of OOM station-hours in this quarter.
  - ✓ OOM dispatch in western NY fell 60 percent from the second quarter of 2012.
  - ✓ The reduction was primarily because Huntley and Niagara units are rarely OOMed by the NYISO to manage congestion on 230 kV lines in the West Zone following the transmission constraint modeling improvements in May 2012.

Supplemental Commitment for Reliability
by Category and Region

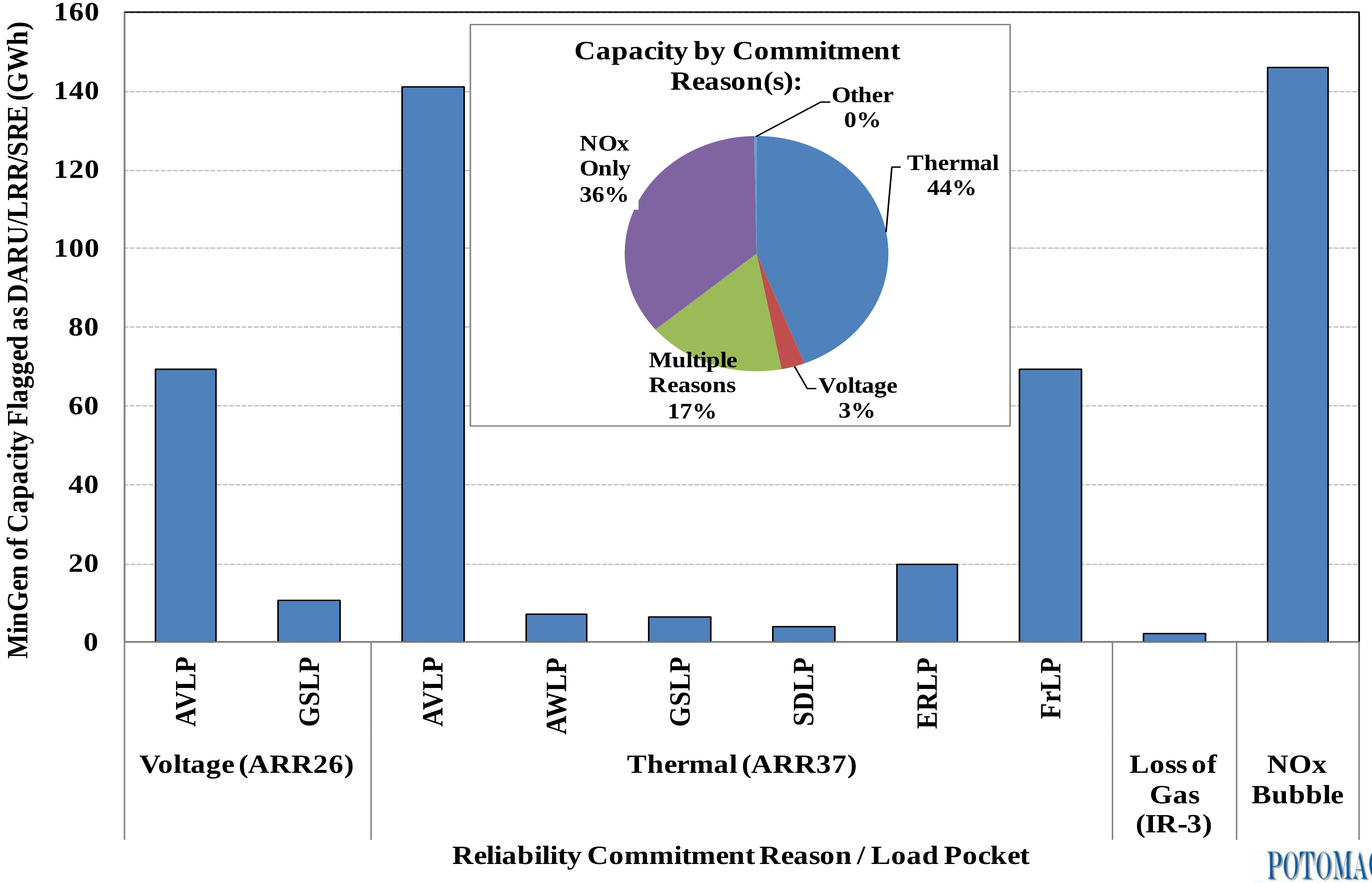
Quarter	Supplemental Commitment (% of Forecast Load)			
	NYC	LI	East	West
2013 Q2	13.0%	3.0%	0.0%	2.3%
2013 Q1	5.6%	4.0%	0.2%	2.8%
2012 Q2	6.7%	5.4%	0.7%	3.5%



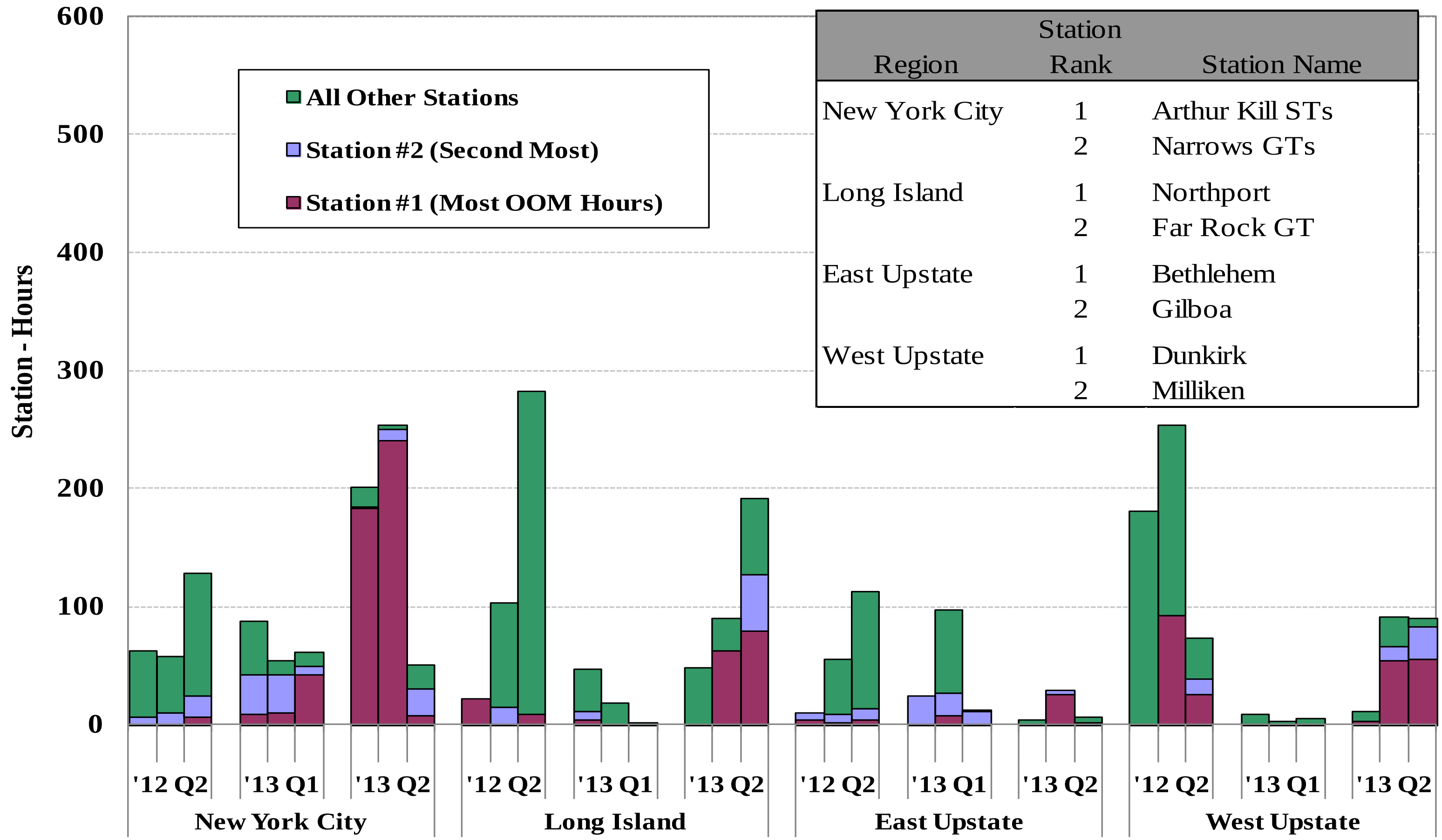
Supplemental Commitment for Reliability in NYC
Chart Description

- Based on our review of reliability recommitment logs and LRR constraint information, each 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) AWLP = Astoria West/Queensbridge; (b) AVLP = Astoria West/Queensbridge/Vernon; (c) ERLP = East River; (d) FRLP = Freshkills; (e) GSLP = Greenwood/Staten Island; and (f) SDLP = Sprainbrook/Dunwoodie.

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



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



Region	Station Rank	Station Name
New York City	1	Arthur Kill STs
	2	Narrows GTs
Long Island	1	Northport
	2	Far Rock GT
East Upstate	1	Bethlehem
	2	Gilboa
West Upstate	1	Dunkirk
	2	Milliken

Note: "Station #1" is the station with the highest number of out-of-merit ("OOM") hours in that region in the current quarter; "Station #2" is that station with the second-highest number of OOM hours in that region in the current quarter.

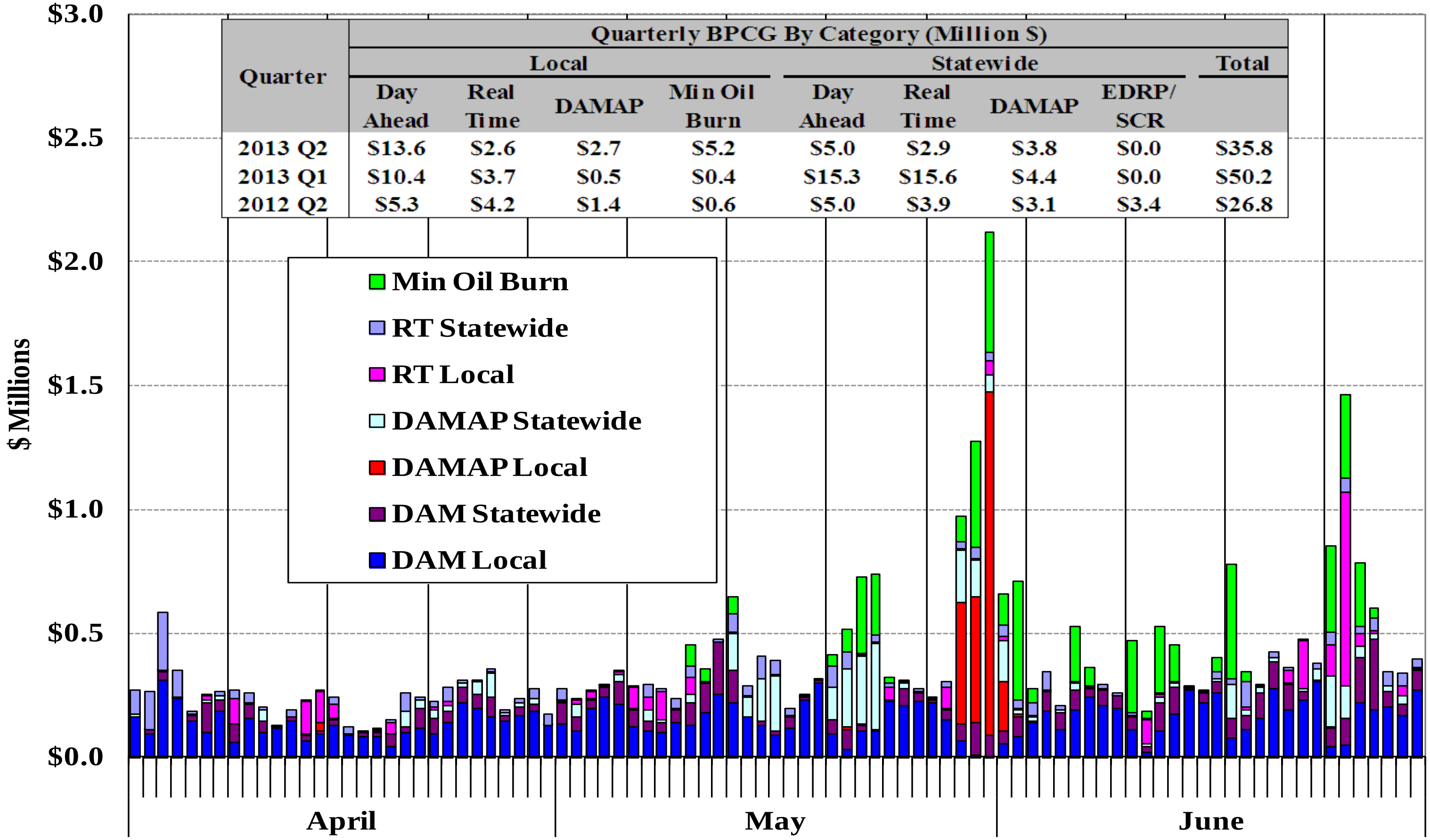
Uplift Costs from Guarantee Payments

- 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 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.

Uplift Costs from Guarantee Payments

- Guarantee payment uplift totaled $36 million in the second quarter of 2013, up 34 percent from the second quarter of 2012.
  - ✓ This is consistent with reliability commitments, which rose 28 percent.
  - ✓ Higher gas prices increased uplift from gas units that were needed for reliability.
- Of the total guarantee payment uplift in the second quarter of 2013:
  - ✓ Local reliability uplift accounted for 67 percent (while non-local was 33 percent).
  - ✓ NYC accounted for 52 percent, Long Island accounted 30 percent, and Western NY accounted for 15 percent.
- Uplift costs rose roughly $12 million in NYC, accounting for the vast majority of the overall increase from a year ago.
  - ✓ Approximately $8 million of the increase was related to the increase in local reliability commitment in NYC, which was discussed in the prior sub-section.
  - ✓ Another $4.6 million of the increase was associated with the Min Oil Burn requirement, which generated charges in late-May and June when some capacity with automatic fuel swapping capability was not available.
- The second figure also shows the estimated charges from out-of-market payment from National Grid under the Dunkirk RSA. These charges are recouped from National Grid customers rather than NYISO customers.

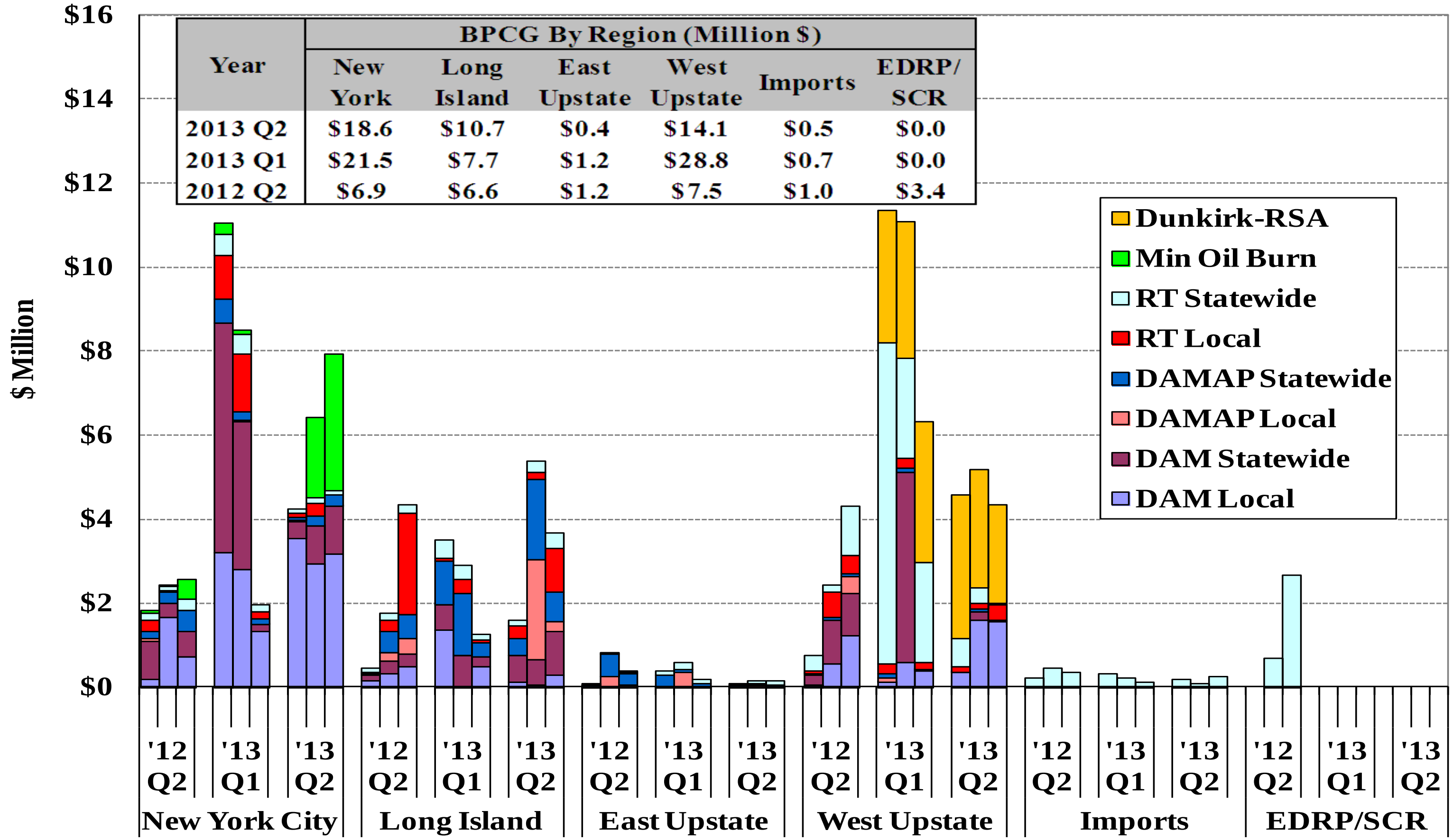
Uplift Costs from Guarantee Payments
Local and Non-Local by Category



Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2013 Q2	$13.6	$2.6	$2.7	$5.2	$5.0	$2.9	$3.8	$0.0	$35.8
2013 Q1	$10.4	$3.7	$0.5	$0.4	$15.3	$15.6	$4.4	$0.0	$50.2
2012 Q2	$5.3	$4.2	$1.4	$0.6	$5.0	$3.9	$3.1	$3.4	$26.8

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.

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
2013 Q2	$18.6	$10.7	$0.4	$14.1	$0.5	$0.0
2013 Q1	$21.5	$7.7	$1.2	$28.8	$0.7	$0.0
2012 Q2	$6.9	$6.6	$1.2	$7.5	$1.0	$3.4

Note: Dunkirk RSA charges are recouped from National Grid customers rather than NYISO customers, but they are shown for discussion purposes. 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.

Market Power and Mitigation

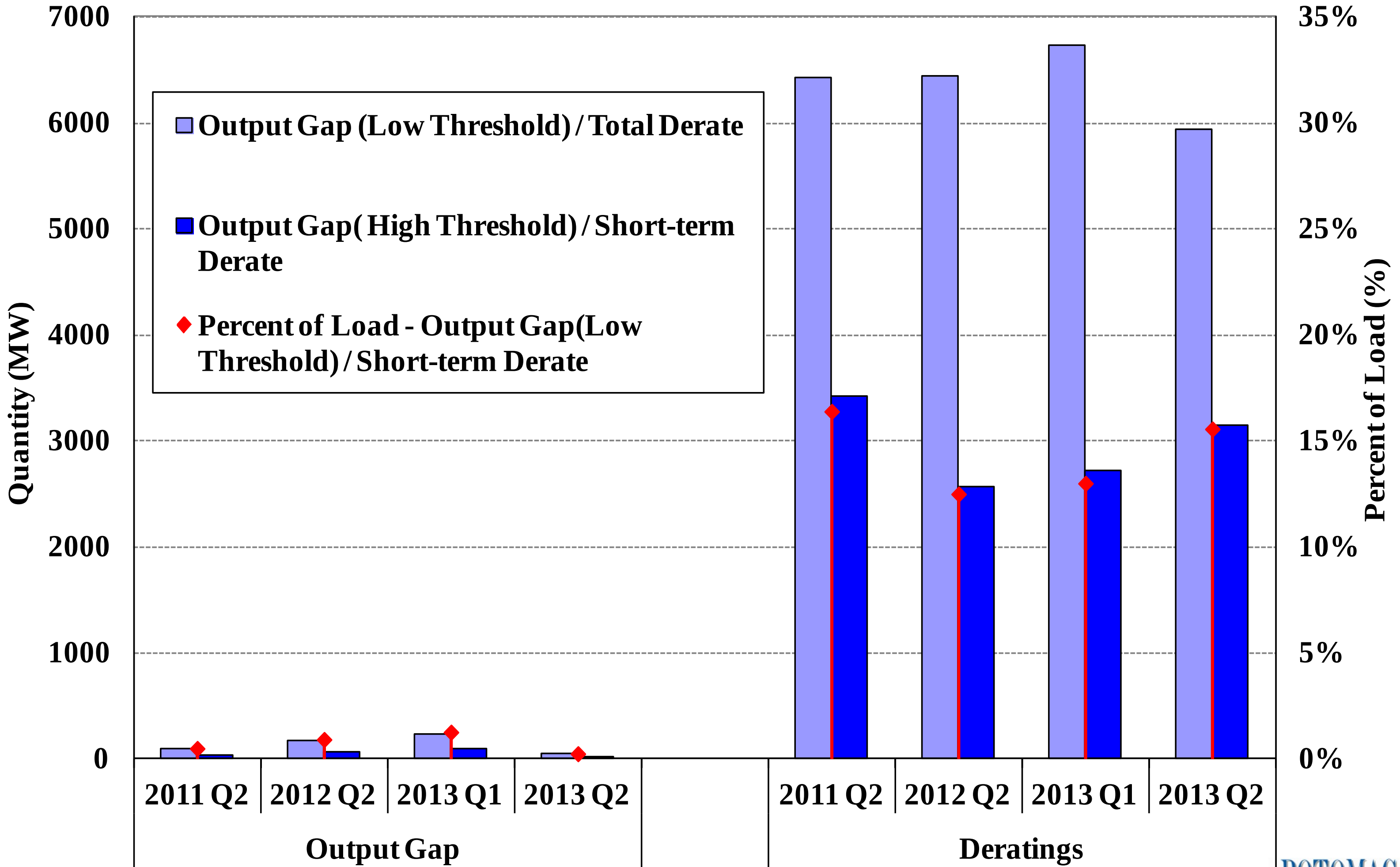
Market Power Screens: Economic Withholding

- 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 in this quarter.
  - ✓ The output gap averaged less than 0.5 percent of load based on the low threshold, which was lower than the same quarter in prior years.
  - ✓ The output gap did not raise market power concerns because it occurred primarily during periods when the prices would not be substantially affected.

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.
- The amount of deratings in this quarter was generally consistent with the same quarters in prior years.
  - ✓ Deratings are typically highest in shoulder months when load is lower and lowest in the summer months when load is higher.
  - ✓ Total deratings are significant, but physical withholding concerns are limited because most deratings are long-term and not likely to reflect withholding.
    - – Mothballing or retirement of several units (which is excluded from the deratings) contributed to the modest reduction of total deratings from 2011.

Market Monitoring Screens



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Market Power Mitigation

- The next table summarizes the mitigation that was imposed during the quarter.
- 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.

Quarterly Mitigation Summary

		2011 Q2	2012 Q2	2013 Q1	2013 Q2
Day-Ahead Market	**Average Mitigated MW**	395	153	165	168
	Energy Mitigation Frequency	47%	18%	30%	14%
Real-Time Market	**Average Mitigated MW**	16	14	44	2
	Energy Mitigation Frequency	6%	3%	8%	1%

Automated Market Mitigation

- Most mitigation occurs in the DAM, since that is where most supply is scheduled.
  - ✓ In the second quarter of 2013, 98 percent of mitigation occurred in the DAM primarily for:
    - – Local reliability (i.e., DARU & LRR) units (87 percent),
    - – The Greenwood/Staten Island load pocket (8 percent), and
    - – The Astoria West Queensbridge/Vernon load pocket (3 percent).
- DA mitigation fell after 2011 primarily because:
  - ✓ Congestion has been less frequent in the 345kV and 138kV areas of NYC than in prior years, resulting from new generation and new transmission.
    - – This has led to reduced mitigation on economically committed units.
  - ✓ DARU commitments fell considerably in Long Island, leading to reduced mitigation in this category.
    - – Units that were frequently DARUed became more economic because of high LBMPs driven by transmission and generation outages, unit retirements, and inefficient utilization of some generation resources.

Capacity Market

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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.
- In Rest of State, UCAP spot prices averaged $4.44/kW-month this quarter, up from $1.65/kW-month in the second quarter of 2012 due to:
  - ✓ Internal capacity sales fell 1.9 GW due to retirement and mothballing, including: a) 550 MW in NYC in May 2012; b) 330 MW on Long Island in July 2012; c) 370 MW in Western NY in September 2012; d) 500 MW in Hudson Valley in January 2013; and e) 150 MW in Western NY in June 2013.
  - ✓ The NYCA ICAP requirement rose more than 300 MW from the 2012/13 Capability Year to the 2013/14 Capability Year due to an increase in the IRM from 16 percent to 17 percent.
  - ✓ Sales from SCRs fell nearly 300 MW due to a combination of increased auditing of resources, attrition, and changing market conditions.
  - ✓ However, these factors were partly offset by increased sales following the entry of nearly 500 MW of new supply in NYC and an uprate of 110 MW on a nuclear unit in Western NY in June 2012.

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Capacity Market Results

- In NYC, UCAP spot prices averaged $12.55/kW-month this quarter, up from $11.10/kW-month in the second quarter of 2012. There were significant offsetting changes in supply and demand over the period, including:
  - ✓ The ICAP requirement rose 332 MW primarily due to a 3% increase in the LCR.
    - – The increased LCR resulted primarily from the loss of generating capacity in the Hudson Valley, which requires more capacity in downstate areas to compensate.
    - – However, this was partly offset by emergency assistance from the new HTP line.
  - ✓ Several generating units were mothballed or retired, which reduced the available installed capacity by more than 500 MW in May 2012.
    - – However, this was offset by the entry of a 500 MW unit in June 2012.
  - ✓ From December 2012 to April 2013, some internal capacity has gone unsold following the imposition of buyer-side mitigation on the 550 MW AEII facility.
- On Long Island, UCAP spot prices averaged $5.30/kW-month this quarter, up from $1.65/kW-month in the second quarter of 2012.
  - ✓ The Long Island ICAP requirement increased 320 MWprimarily due to an increase in the LCR from 99 percent to 105 percent (for reasons discussed above).
  - ✓ UCAP sales fell due to retirements of 330 MW capacity in July 2012.

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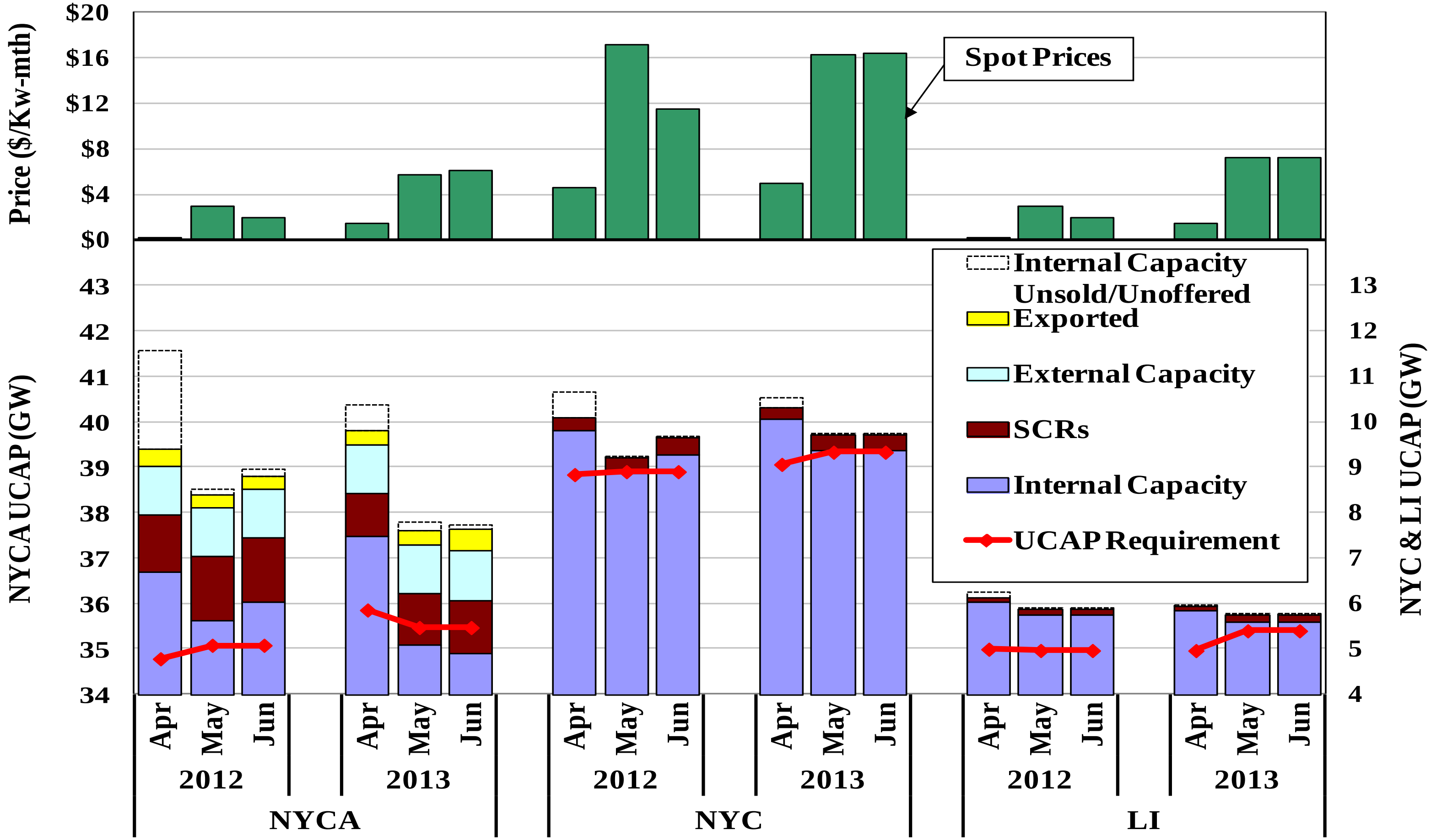
Capacity Market Results



Note: Sales associated with Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity."

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