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

David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.
Jie Chen, Ph.D.

Potomac Economics
Market Monitoring Unit

December 2013

POTOMAC ECONOMICS

Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the third 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.
- Real-time energy prices averaged $54/MWh statewide, up 16 percent from the third quarter of 2012 due to higher (8 to 24 percent) gas prices.
  - ✓ The effects of higher gas prices were offset by a 3 percent drop in average load levels and a 500 MW average increase in nuclear generation and net imports.
  - ✓ On Long Island, LBMPs actually fell slightly because the return of the Neptune Line to normal operation further offset the effects of higher gas prices.
- Despite lower average load levels, loads were very high from July 15 to 19 and a new all-time peak of 33,956 MW was set on July 19.
  - ✓ High load levels led to increased congestion, uplift, and LBMPs across the system and led to demand response activations on all five days.
  - ✓ New scarcity pricing rules were invoked for the first time on these five days.
    - – Our evaluation finds that the Scarcity Pricing outcomes were generally consistent with the occurrence of shortage conditions.
    - – This report discusses potential enhancements to Scarcity Pricing and the operating reserve markets. (See Slide 23)

Highlights and Market Summary: Energy Market

- DA-to-RT price convergence was poor in the third quarter of 2013 as average RT LBMPs exceeded DA LBMPs by 10 to 16 percent in most zones.
  - ✓ These price differences were largest from July 15 to 19 when the incentives for participants to bid up the DA LBMPs was limited by:
    - The unexpectedly high frequency of Scarcity Pricing intervals; and
    - The application of Scarcity Pricing to internal locations only, which is discussed further in this report. (See Slide 23)
  - ✓ Congestion was higher and more volatile in the RT market than in the DA market on the 230kV system in the West Zone and on the interface into Southeast NY.
- Our evaluation of M2M coordination finds that the Ramapo Line was reasonably efficient in 72 percent of the hours with congestion in NY and/or PJM.
  - ✓ However, it was not fully utilized in some hours when significant congestion was in one or both markets. The evaluation is discussed further. (See Slides 64 – 68)
  - ✓ PJM suspended M2M coordination for existing TSA-contingency flow gates on July 12, which has limited the efficiency of congestion management.
- The newly implemented regulation market performed in line with expectations as the new charges for regulation movement and BPCG uplift from regulation resources were a combined 35 percent of the total regulation costs.

Highlights and Market Summary: Capacity Market

- Capacity prices rose sharply from the third quarter of 2012, primarily because of the retirement or mothballing of 1 GW of units in upstate NY, which has:
  - ✓ Reduced the available supply in the NYCA region by almost 3 percent; and
  - ✓ Led to increased Locational Capacity Requirements (“LCRs”) in NYC and on Long Island to compensate for the loss of capacity in the Hudson Valley. However, this was partly offset by emergency energy assistance from the new HTP Line.
- NYCA UCAP prices averaged $5.68/kW-month, up 172 percent due to:
  - ✓ A 300 MW increase in the NYCA ICAP requirement due to an increased IRM;
  - ✓ The 1 GW reduction is supply from the retirement and mothballing of 1 GW of generation; and
  - ✓ SCR sales fell 570 MW from the summer of 2012 due to a combination of increased auditing of resources, attrition, and changing market conditions.
- NYC UCAP prices averaged $15.85/kW-month, up 48 percent from last year.
  - ✓ The LCR change from 83 to 86 percent increased the requirement by 332 MW.
- Long Island UCAP prices averaged $7.10/kW-month, rising above Rest of State.
  - ✓ The LCR change from 99 to 105 percent increased the requirement by 320 MW.

Highlights and Market Summary: Uplift and Revenue Shortfalls

- The uplift from guarantee payments totaled $49 million, up 20 percent from the third quarter of 2012. The most significant contributions were:
  - ✓ More reliability commitment for NOx Bubble constraints in NYC.
  - ✓ High load levels from July 15-19, which accounted for $13 million of uplift.
- Day-ahead congestion shortfalls totaled roughly $9 million in the third quarter of 2013, up 50 percent from the third quarter of 2012.
  - ✓ The majority of shortfalls was driven by transmission outages in NYC from July to early-August, which significantly reduced transfer capability into the Greenwood load pocket and accounted for nearly $10 million of shortfalls.
  - ✓ However, this was offset by a $4 million of surpluses that accrued on several days in mid-July on West Zone constraints.
    - Congestion in the West Zone was not well anticipated in the TCC auction, so the TCCs sold did not capture a large portion of the capability of these lines.
- Balancing congestion shortfalls totaled $23 million, up significantly from $9 million in the third quarter of 2012.
  - ✓ TSAs were called on 17 days, accounting for 80 percent of shortfalls.

POTOMAC ECONOMICS

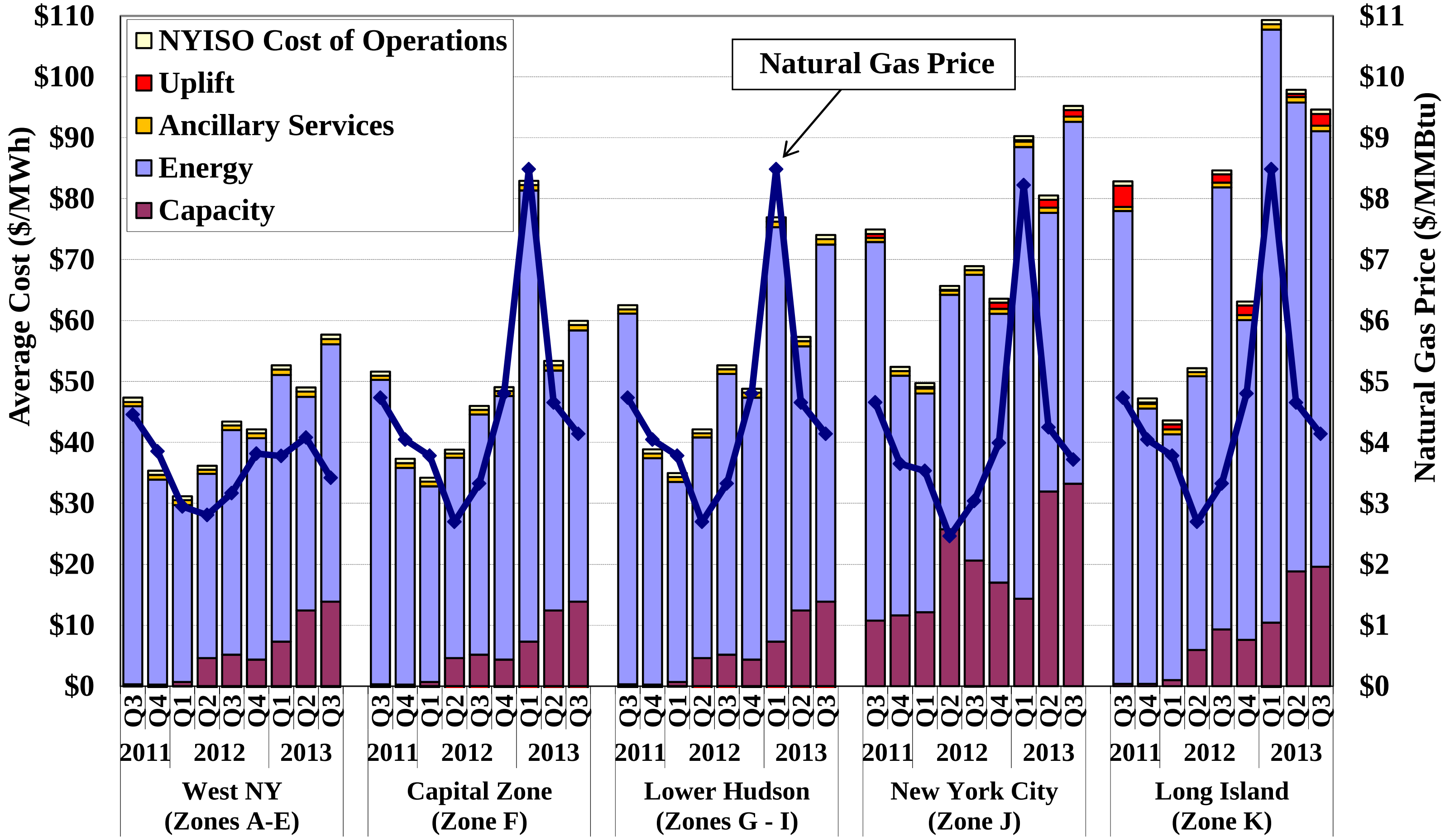
Energy Market Outcomes

POTOMAC
ECONOMICS

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 $58/MWh in Western NY to $95/MWh on Long Island, up 12 percent to 42 percent from the same quarter last year.
  - ✓ Energy prices fell 1 percent on Long Island and rose 13 to 27 percent elsewhere.
    - – Higher LBMPs in most areas were primarily driven by higher natural gas prices. However, the increase was partly offset by higher imports and lower load levels.
    - – On Long Island, the return of the Neptune Line from a year of deratings offset the effects of higher gas prices.
  - ✓ The capacity component rose $9 to $13/MWh in all areas due to retirements and mothballs (520 MW in Western NY and 500 MW in Hudson Valley), which:
    - – Removed substantial amounts of supply from the market; and
    - – Contributed to higher ICAP requirements for NYC and Long Island, which rose 330 MW and 320 MW. (The NYCA requirement also rose 315 MW.)

All-In Energy Price by Region

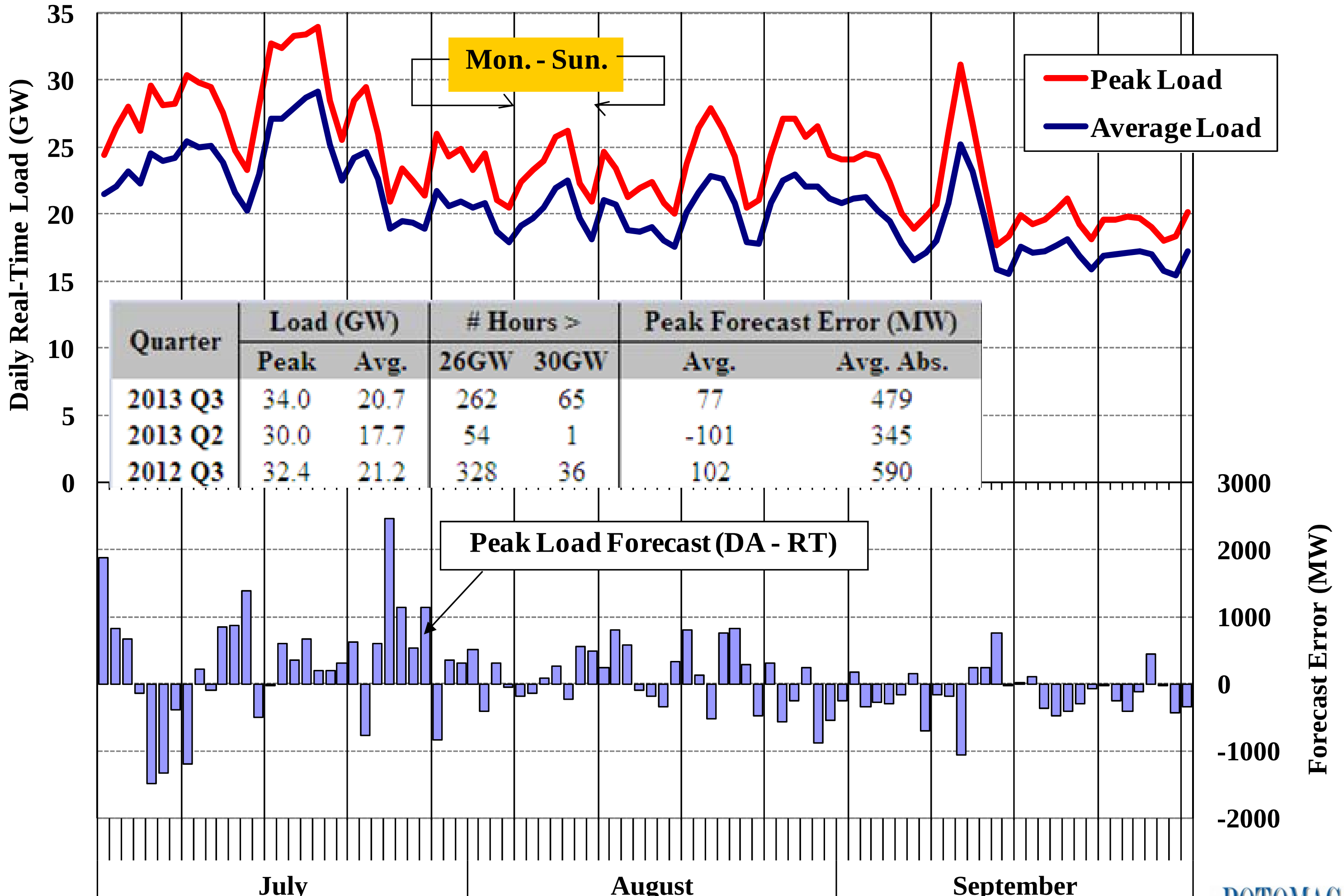


Note: Natural Gas Price based on: Niagara index for West NY, Transco Zone 6 (NY) index for New York City and Iroquois Zone 2 index for other regions.

Load Levels and Fuel Prices

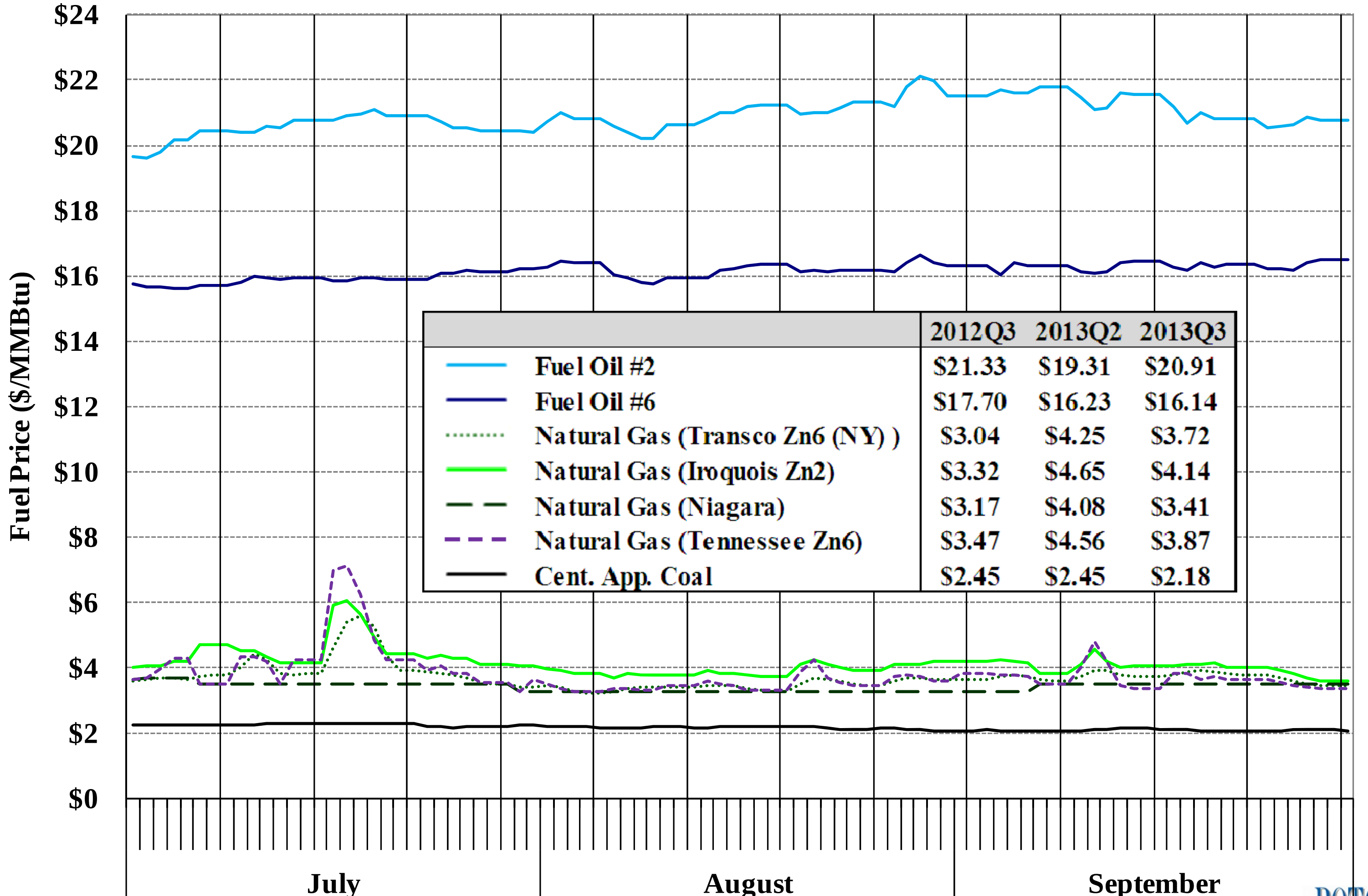
- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Load averaged 20.7 GW, down nearly 3 percent from the third quarter of 2012.
  - ✓ However, NYISO set a new all-time peak of 33,956 MW on July 19, which was up 17 MW from the previous all-time peak in 2006.
  - ✓ Daily peak load forecasting was generally better this quarter than last summer.
    - – Forecast errors (by both NYISO and MPs) tend to rise at higher load levels, which may lead to inefficient commitment and/or prices in the day-ahead market.
- Natural gas prices averaged $3.41 at Niagara (Western NY), $3.72 at Transco Z6 NY (NYC), and $4.14 at Iroquois Z2 (Eastern NY).
  - ✓ Gas prices rose 8% in west NY and more than 20% in east NY from last year.
    - – Increased spreads between western and eastern NY gas prices affect generation patterns and lead to electricity price spreads when transmission congestion occurs.
  - ✓ Although gas was significantly cheaper than fuel oil, some generators still burn oil on some days due to: a) reliability reasons, b) difficulties obtaining gas, and c) high gas balancing charges.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2013 Q3	34.0	20.7	262	65	77	479
2013 Q2	30.0	17.7	54	1	-101	345
2012 Q3	32.4	21.2	328	36	102	590

Coal, Natural Gas, and Fuel Oil Prices



POTOMAC ECONOMICS

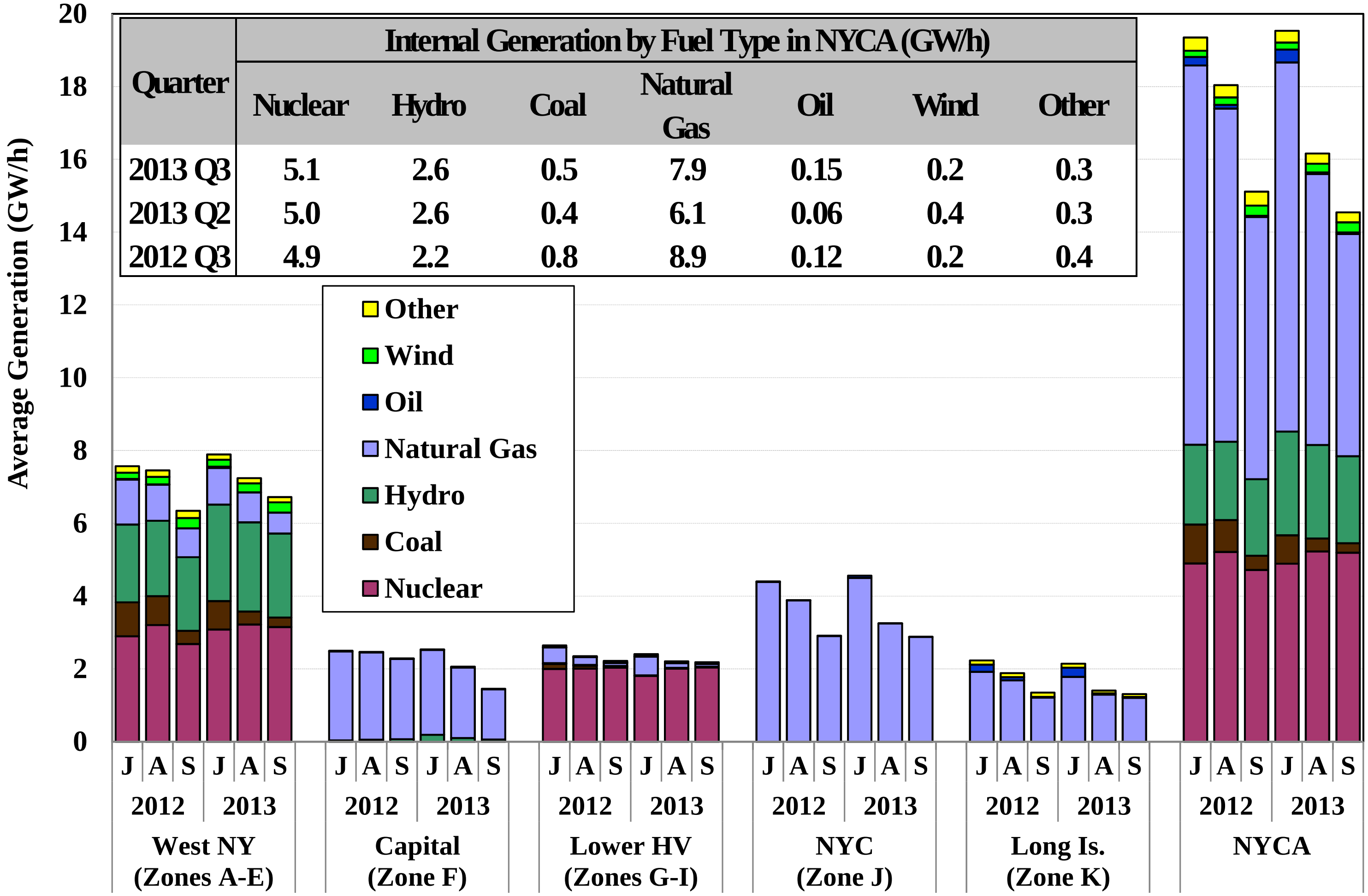
Real-Time Generation by Fuel Type

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the third 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 accounted for 30 percent of production in the third quarter of 2013.
  - ✓ Nuclear output rose 160 MW from last year largely due to the Nine Mile up-rate.
- Hydro units (primarily in western NY) accounted for 16 percent of production and set prices in 37 percent of intervals in the third quarter of 2013.
  - ✓ Most hydro units have storage capacity, leading them to offer based on the opportunity cost of foregoing sales in another hour (when gas units are marginal).
  - ✓ Increased congestion in the West Zone has increased the frequency of price-setting by hydro units.
- Gas-fired units accounted for roughly 48 percent of all generation and set prices in the majority of intervals.
  - ✓ Gas-fired production fell 1 GW from a year ago due to lower load levels, increased imports across the Neptune Line, and higher gas prices (particularly in the Capital Zone).
- Coal-fired output fell 310 MW from a year ago (due to multiple retirements) and was on the margin in 8 percent of the intervals in the third quarter of 2013.
- 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.

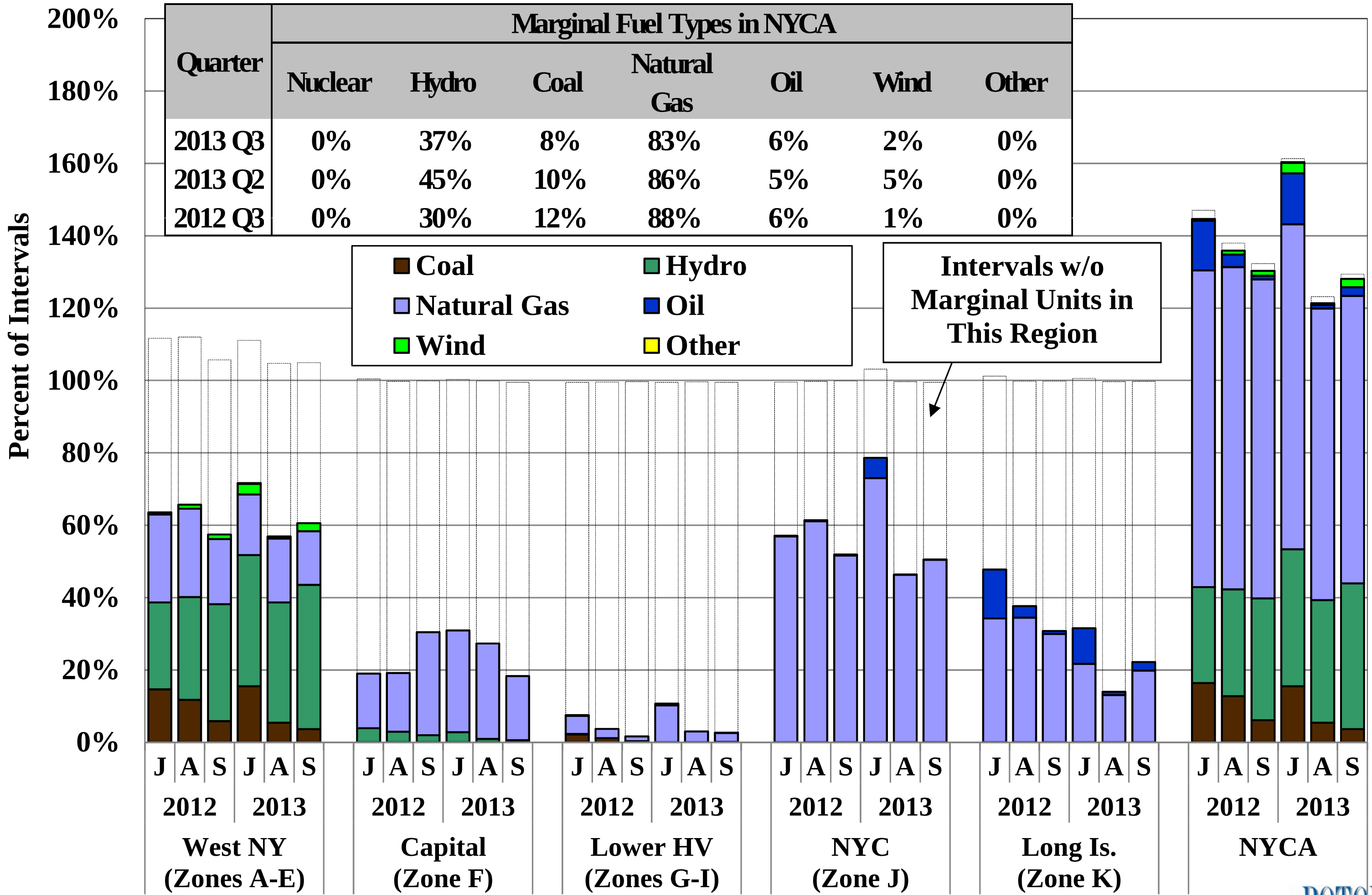
Real-Time Generation Output by Fuel Type



Quarter	Internal Generation by Fuel Type in NYCA (GW/h)						
	Nuclear	Hydro	Coal	Natural Gas	Oil	Wind	Other
2013 Q3	5.1	2.6	0.5	7.9	0.15	0.2	0.3
2013 Q2	5.0	2.6	0.4	6.1	0.06	0.4	0.3
2012 Q3	4.9	2.2	0.8	8.9	0.12	0.2	0.4

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	Natural Gas	Oil	Wind	Other
2013 Q3	0%	37%	8%	83%	6%	2%	0%
2013 Q2	0%	45%	10%	86%	5%	5%	0%
2012 Q3	0%	30%	12%	88%	6%	1%	0%

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

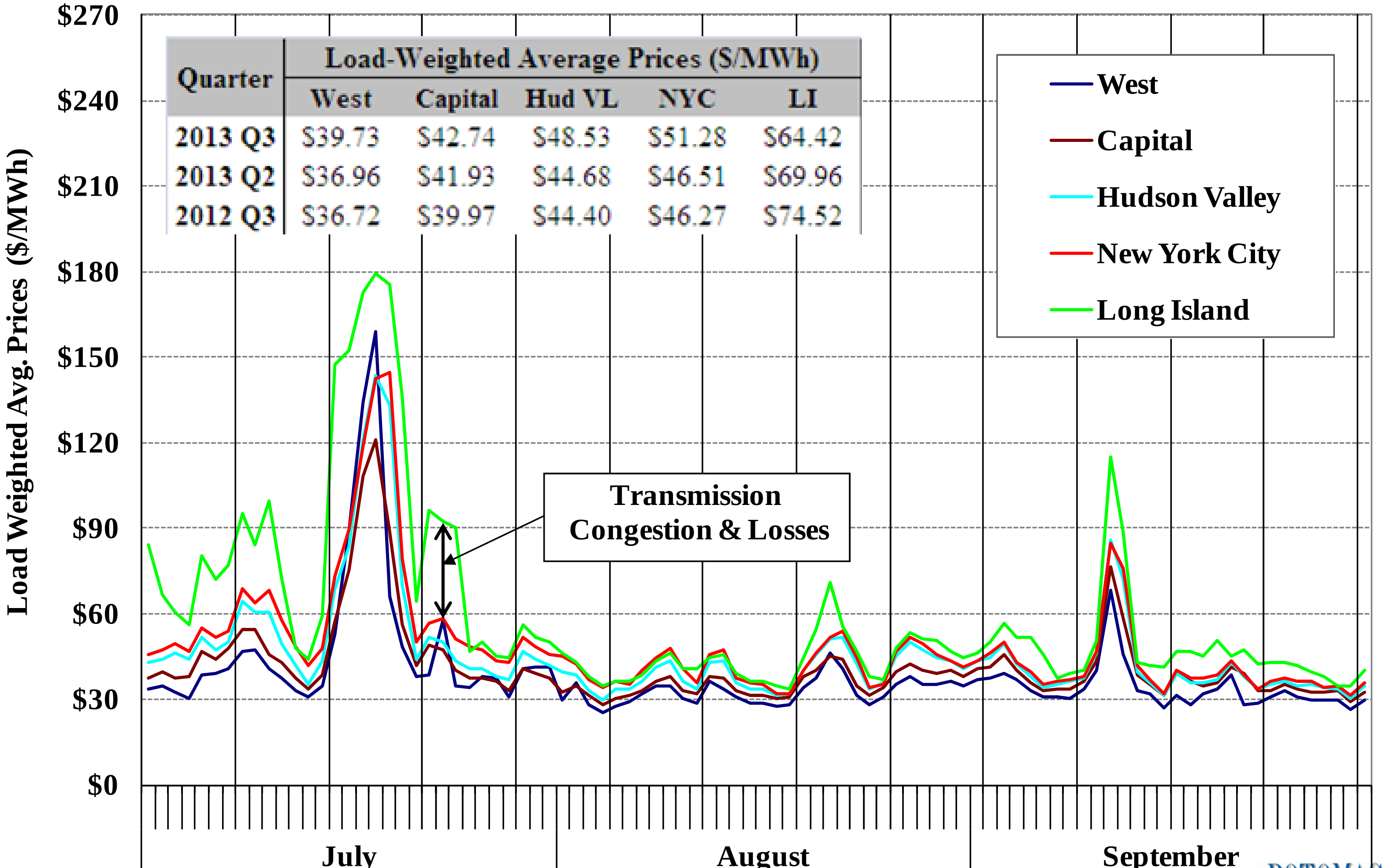
Day-Ahead and Real-Time Electricity Prices

- The following three figures show: 1) load-weighted average day-ahead energy prices; 2) load-weighted average real-time energy prices; and 3) day-ahead and real-time price convergence for five zones on each day in the third quarter of 2013.
  - ✓ Day-ahead prices should reflect expectations of real-time conditions.
  - ✓ Convergence is important because the day-ahead market facilitates the daily commitment of generation and scheduling of natural gas, determines the obligations to TCC holders, and accounts for most energy settlements.
- Average day-ahead prices ranged from $40/MWh in the West Zone to $64/MWh on Long Island, up 7 to 11 percent from the third quarter of 2012 in all areas but Long Island, where LBMPs fell nearly 14 percent.
  - ✓ Higher LBMPs in most areas were primarily driven by higher natural gas prices (8 to 24 percent increase from last summer).
    - – However, the increase was offset by a 3 percent decrease in load levels and a combined 500 MW increase in nuclear generation and imports.
  - ✓ On Long Island, the effects of higher gas prices were also offset by the return of the Neptune Line to normal operation in early July.
  - ✓ LBMPs rose to very high levels on days with high forecasted demand in early and mid July as well as on September 11, leading to increased commitment.

Day-Ahead and Real-Time Electricity Prices

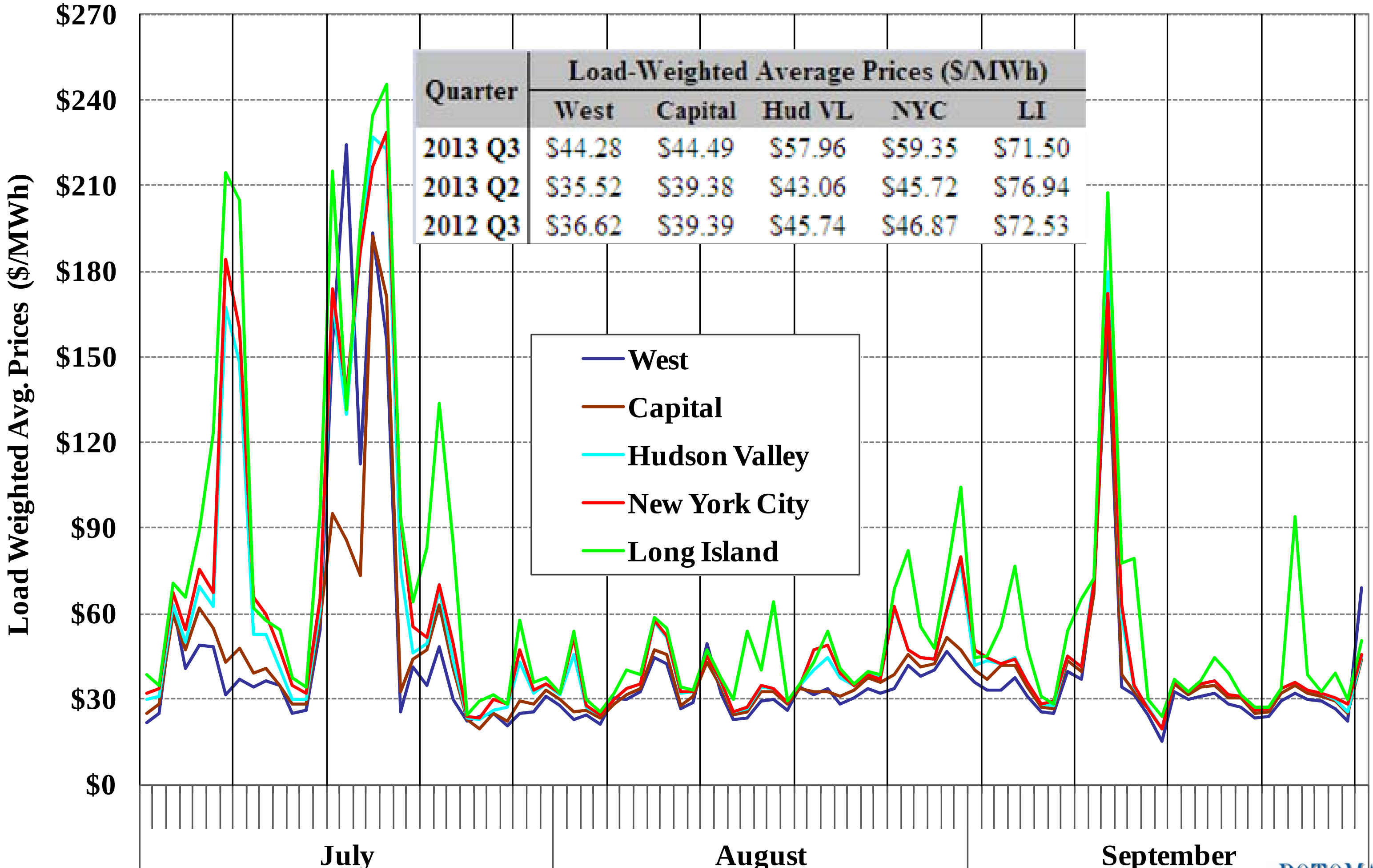
- Prices are more volatile in the real-time market than in the day-ahead market due to unexpected events.
  - ✓ TSAs were called on 18 days (July 1, 7-11, 20, 28; August 8-9, 26, 28, & 31; and September 2, 10-12) during which transfer capability into SENY was greatly reduced, leading to very high LBMPs on several days (e.g., July 7-8).
  - ✓ New scarcity pricing rules were invoked in SENY on July 15-19 and in NYCA on July 18-19 during DR activations. The new rules made scarcity pricing far more frequent than during DR activations in previous years.
  - ✓ Actual load was unseasonably high and ran over the day-ahead forecast by over 1 GW on September 11, contributing to price spikes across the system.
  - ✓ West Zone LBMPs rose as real-time congestion became more volatile there.
- 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.
  - ✓ Average day-ahead prices were 4 percent lower than real-time prices in the Capital Zone and were 10 to 16 percent lower than real-time prices in other areas.
    - – The vast majority of the real-time premiums accrued on eight days (July 7-8, 15-19; & September 11) due to the unexpected events discussed above.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2013 Q3	$39.73	$42.74	$48.53	$51.28	$64.42
2013 Q2	$36.96	$41.93	$44.68	$46.51	$69.96
2012 Q3	$36.72	$39.97	$44.40	$46.27	$74.52

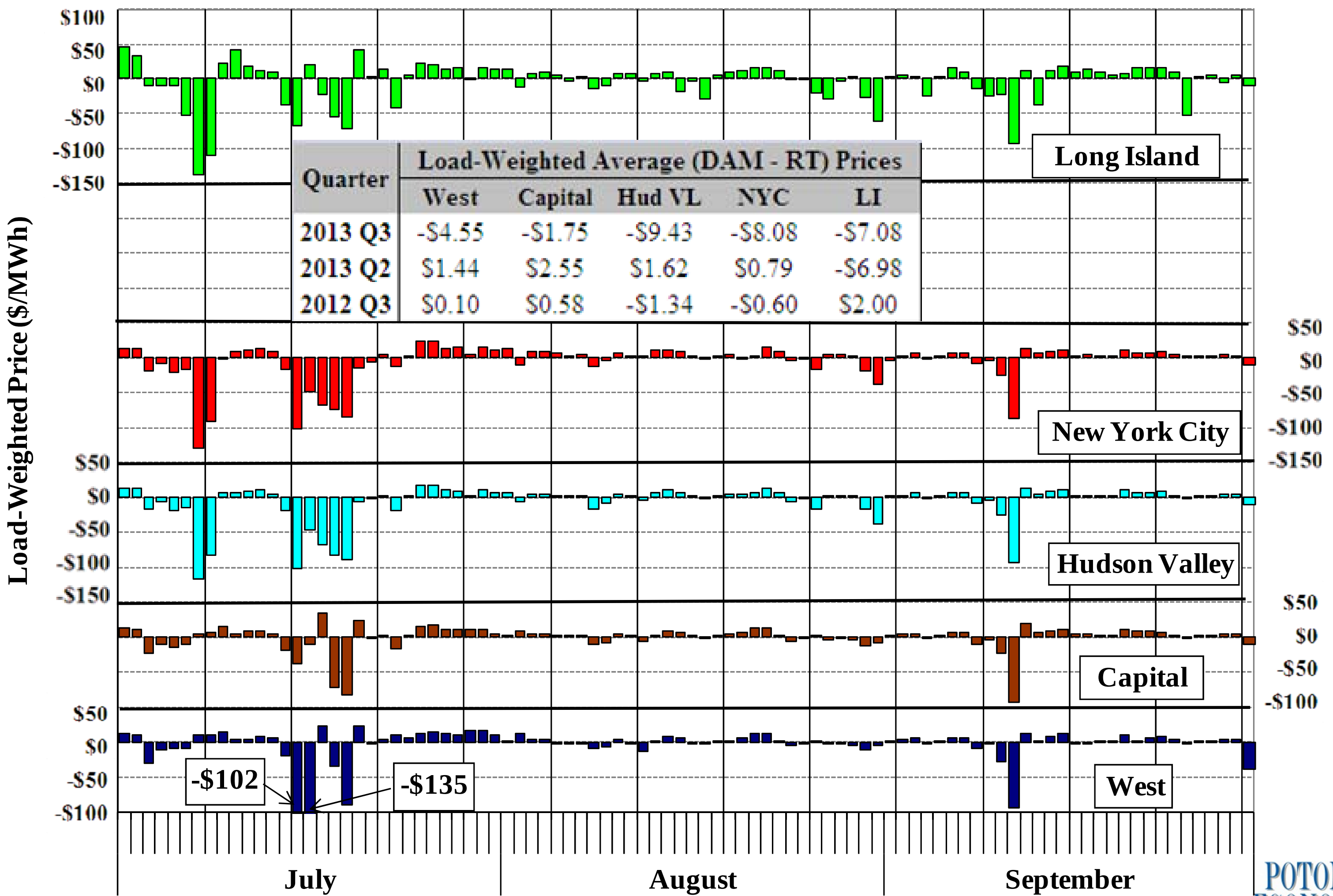
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2013 Q3	$44.28	$44.49	$57.96	$59.35	$71.50
2013 Q2	$35.52	$39.38	$43.06	$45.72	$76.94
2012 Q3	$36.62	$39.39	$45.74	$46.87	$72.53

POTOMAC ECONOMICS

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2013 Q3	-$4.55	-$1.75	-$9.43	-$8.08	-$7.08
2013 Q2	$1.44	$2.55	$1.62	$0.79	-$6.98
2012 Q3	$0.10	$0.58	-$1.34	-$0.60	$2.00

Demand Response Deployments – Introduction

- NYISO activated DR on five days when load ranged from 32.4 to 34.0 GW.
  - ✓ On July 15, 16, & 17, 556 MW of DR was activated in Zones G to K for SENY reliability (i.e., to enable re-preparation of system after largest SENY contingency).
  - ✓ On July 18 & 19, 1,269 MW of DR was activated in all zones for NYCA reliability (i.e., to enable restoration of 10-minute reserves after largest NYCA contingency).
- The use of DR resources is complicated by scheduling lead times and other inflexibilities, which have significant implications:
  - ✓ The NYISO must determine how much DR to activate when there is still considerable uncertainty about the needs of the system; and
  - ✓ The DR may not be needed for the entire duration of the DR activation period.
  - ✓ Hence, there may be substantial surplus capacity during portions of the event.
- The newly implemented Scarcity Pricing rule was designed to ensure that real-time prices better reflect actual real-time shortages. The figures in this section evaluate:
  - ✓ Whether DR deployments were necessary in retrospect to maintain adequate capacity; and
  - ✓ Whether real-time prices efficiently reflected system conditions in each interval.

Demand Response Deployments – Description of Evaluation

- The two figures report the following in each interval for the relevant region:
  - ✓ Available capacity – Includes three categories of unloaded capacity of online units and the capacity of offline peaking units up to the Upper Operating Limit:
    - 30-Minute Reserves – Unscheduled (see dark blue area);
    - 30-Minute Reserves – Scheduled (see green area); and
    - Additional Available Capacity (see light blue area).
  - ✓ DR deployed plus market requirement for 30-minute reserves (see black line).
  - ✓ DR deployed plus actual need for 30-minute reserves (see red line).
  - ✓ LBMP of the least import-constrained zone in the relevant region (see blue line).
- Scarcity Pricing is invoked under the Tarff when:

  DR deployment > unscheduled 30-minute reserves (i.e., "Available Reserves")

  (shown in the figure when the black line is higher than the dark blue area).
- DR was likely necessary to avoid a capacity deficiency when:

  DR deployment + actual 30-minute reserve need > all available capacity

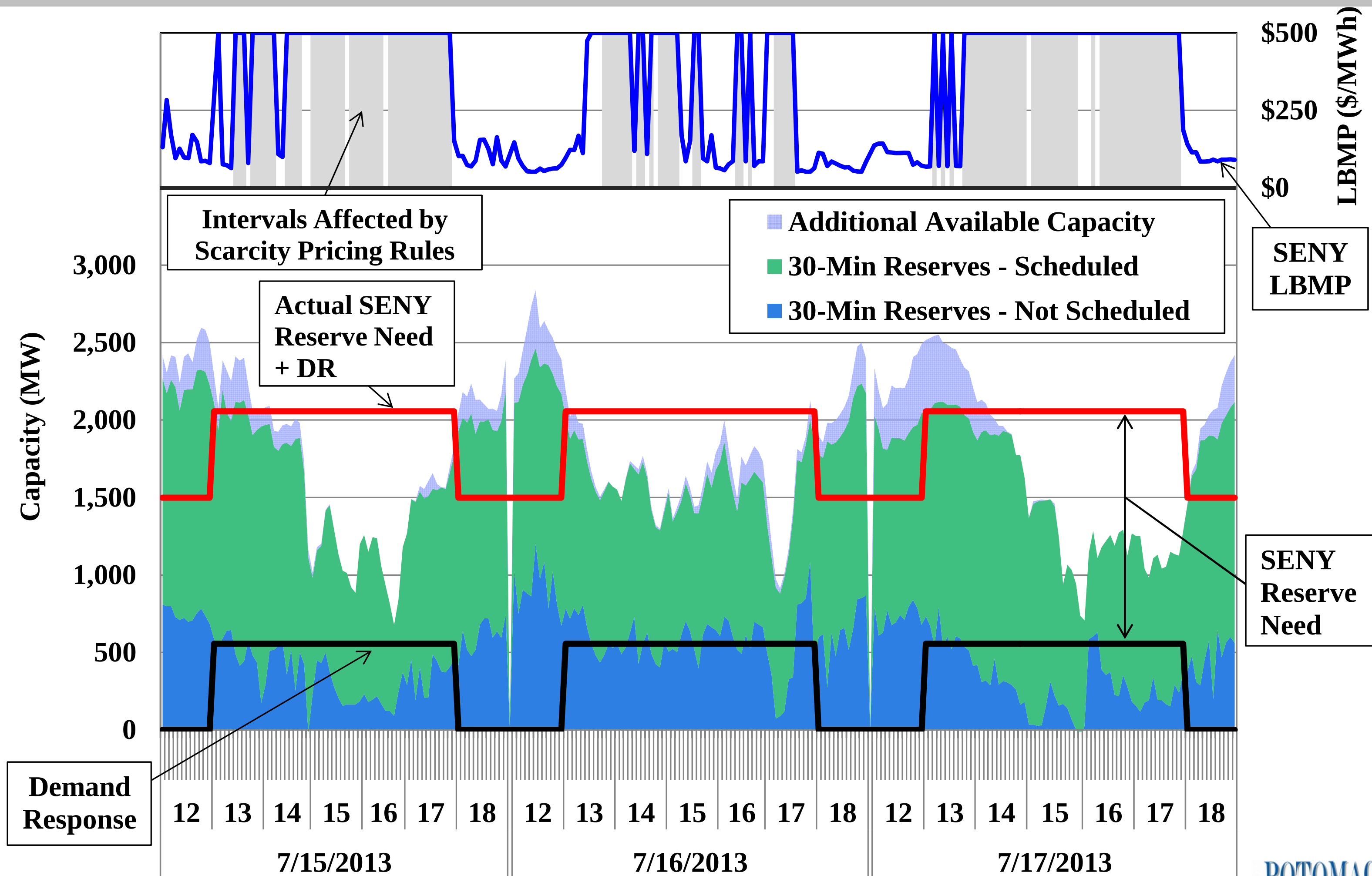
  (shown in the figure when the red line is higher than all areas).
- These tests differ when the market requirement is not equal to the actual need, which occurs because: (a) SENY has no market requirement and (b) NYCA requirement assumes a reasonable level of average external support.

Demand Response Deployments – Scarcity Pricing

- The evaluation suggests that Scarcity Pricing generally occurred when DR was actually needed, a significant improvement under the new Scarcity Pricing Rule.
  - ✓ Scarcity Pricing was triggered for 118 intervals in SENY of the 145 intervals in which it was needed to satisfy capacity needs (i.e., red line > height of all areas).
  - ✓ In NYCA, it was triggered in 116 intervals and DR was needed in 111 intervals.
- However, Scarcity Pricing only applies to internal locations, resulting in large differences at real-time prices at internal versus external interfaces (proxy buses).
  - ✓ When DR calls are likely, participants have inefficient incentives to import day ahead and buy back at non-scarcity real-time prices, leading to under commitment.
  - ✓ Hence, we support NYISO's evaluation of extending Scarcity Pricing to external interfaces, which should include considering how this will affect real-time imports.
- We also support improving the consistency between NYISO's reserve needs and its market requirements, which include:
  - ✓ Defining a market requirement to reflect SENY's 30-minute reserve needs; and
  - ✓ Ensuring that the NYCA 30-minute reserve demand curve fully reflects NYISO's reserve needs on high load days.
- It may improve pricing and lower uplift if NYISO developed more flexibility in calling DR, including varying quantities and staggering times if possible.

Available Capacity and Real-Time Prices During DR Activations

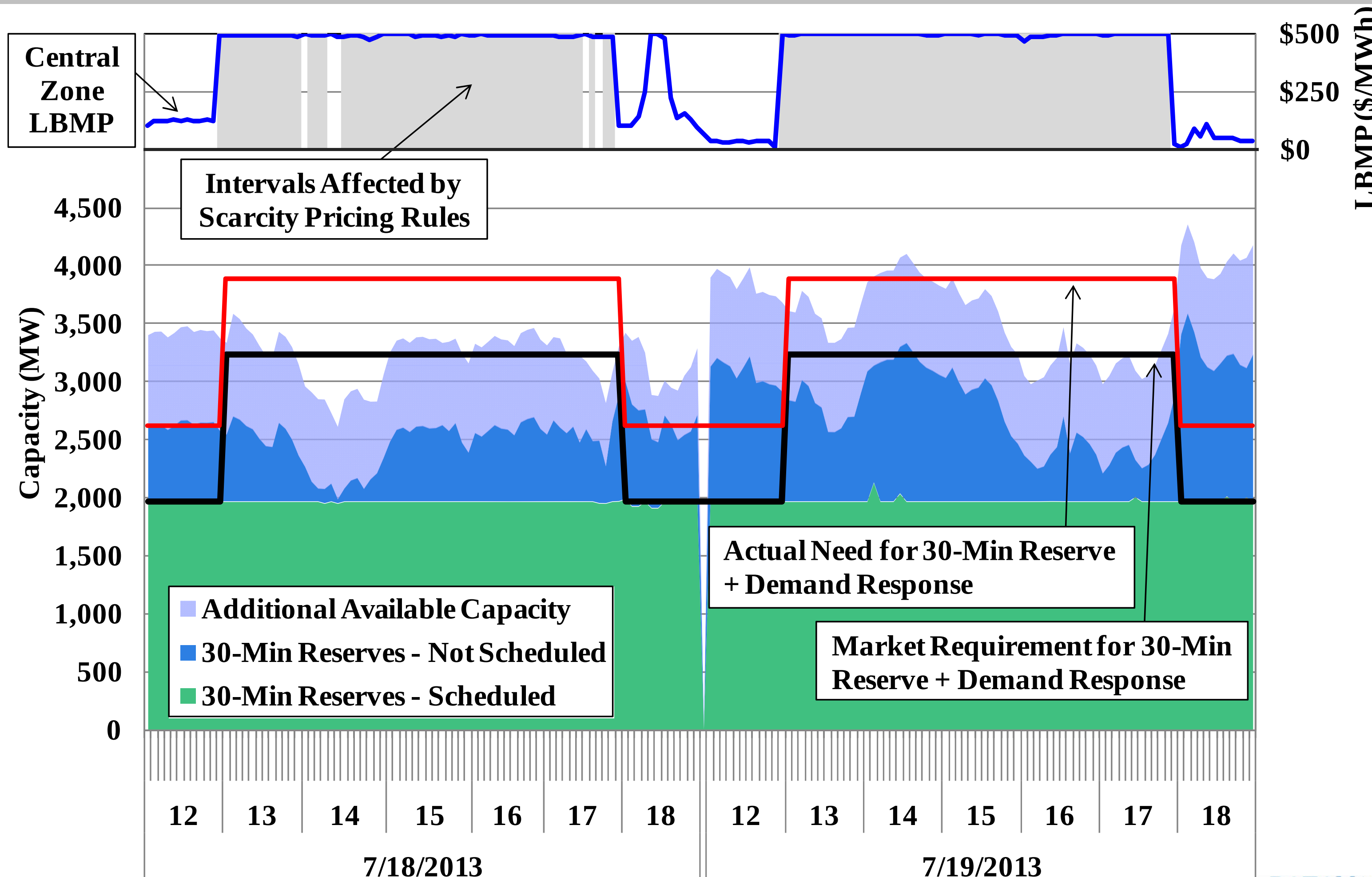
SENY, July 15 to 17



POTOMAC ECONOMICS

Available Capacity and Real-Time Prices During DR Activations

NYCA, July 18 & 19



Note: SENY-only DR activations occurred in HB 12 on both days, but these are not shown.

POTOMAC ECONOMICS

Ancillary Services Market

POTOMAC ECONOMICS

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 the cost procuring up to 275 MW of regulation, and the cost and uplift charges from moving regulation units up and down.
- 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 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 to $5/MW; and
  - ✓ Raised the offer cap for 10-min spin for NYC generators from $0/MW to $5/MW.
- Near the end of the third quarter on September 25, the NYISO implemented the second phase of the process, which:
  - ✓ Raised the reference level cap for 10-min non-spin from $5/MW to $10/MW; and
  - ✓ Raised the offer cap for 10-min spin for NYC generators from $5/MW to $10/MW.
- We evaluate the market effects of these changes. Accordingly, 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.

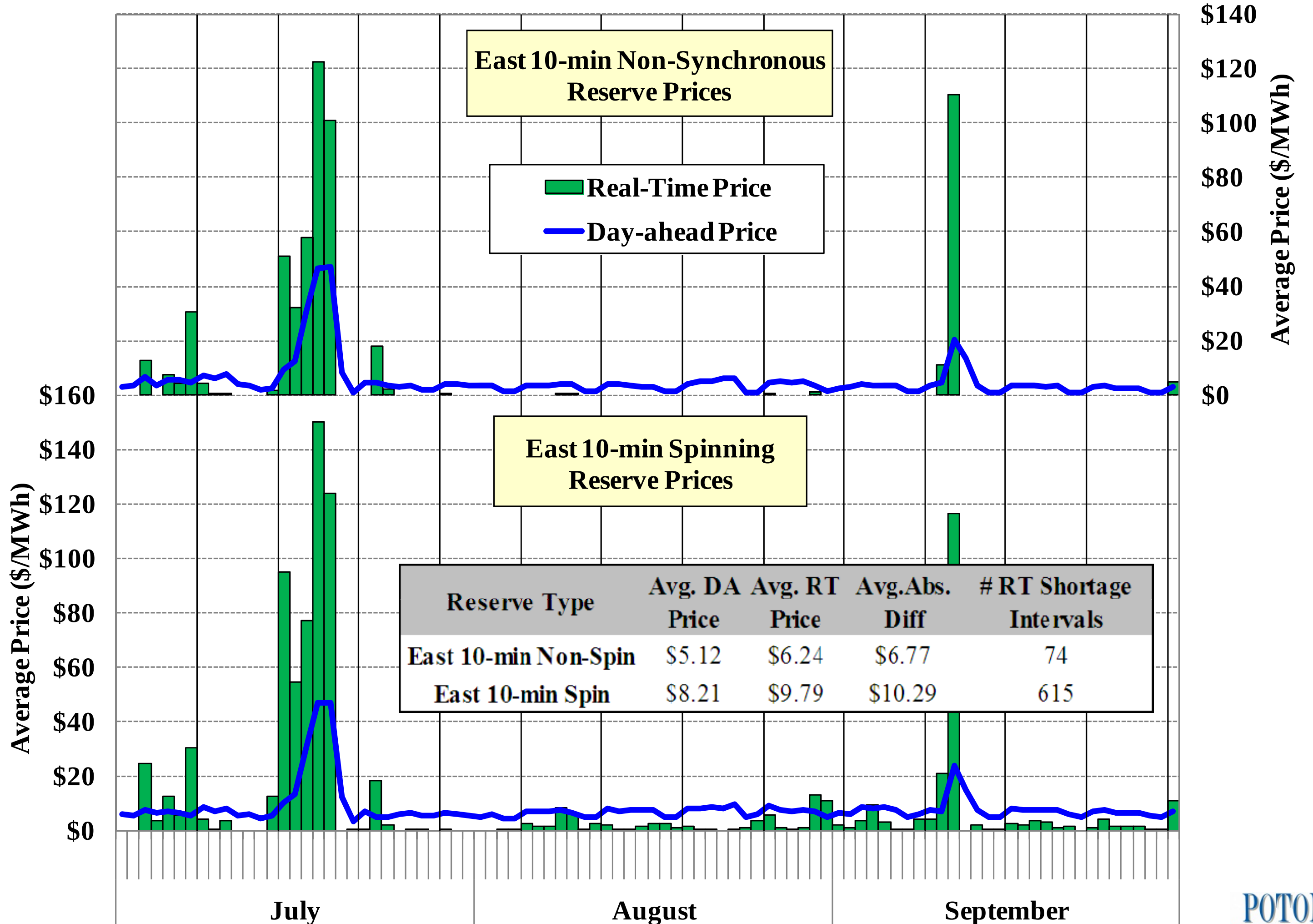
Ancillary Services Prices and Offer Patterns

- 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 load (e.g., July 15-19 & September 11), which can be difficult for the DAM to predict.
- Average DA prices were lower than average RT prices for most products in the third quarter of 2013, partly because RT shortages rose considerably due to more frequent peaking conditions.
  - ✓ Shortages occurred primarily on July 15-19 and September 11 when load levels were particularly high due to extreme weather conditions.
  - ✓ Scarcity pricing rules were invoked on July 15-19.
- The new regulation market was implemented on June 26, 2013. In this quarter,
  - ✓ Market operations and outcomes were generally in line with the expectations.
  - ✓ On average, movement charges and uplift charges were roughly 35 percent of the overall regulation cost.

Ancillary Services Prices and Offer Patterns: New Mitigation Rules

- In our evaluation of the 10-min spin and non-spin reserves markets, we have not found offer patterns that raise significant withholding concerns.
  - ✓ 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 > 19 GW).
- Although still premature to draw strong conclusions, price convergence seemed to improve slightly for both products in 2013.
  - ✓ The variation in DAM prices was slightly more consistent with RT prices, particularly during high load periods.
  - ✓ Average absolute differences between hourly DA and RT prices for spin and non-spin reserves have generally fallen (as a percent of DA prices) since 2012.
    - – However, the differences for spinning reserves rose in the third quarter (146% vs. 128% In 2012 Q3), reflecting higher RT price volatility during SCR activations.
- The NYISO implemented the second phase of the proposed changes (i.e., raised the two caps to $10) to the mitigation rules on September 25.
  - ✓ We will continue to monitor the performance of the reserve market.

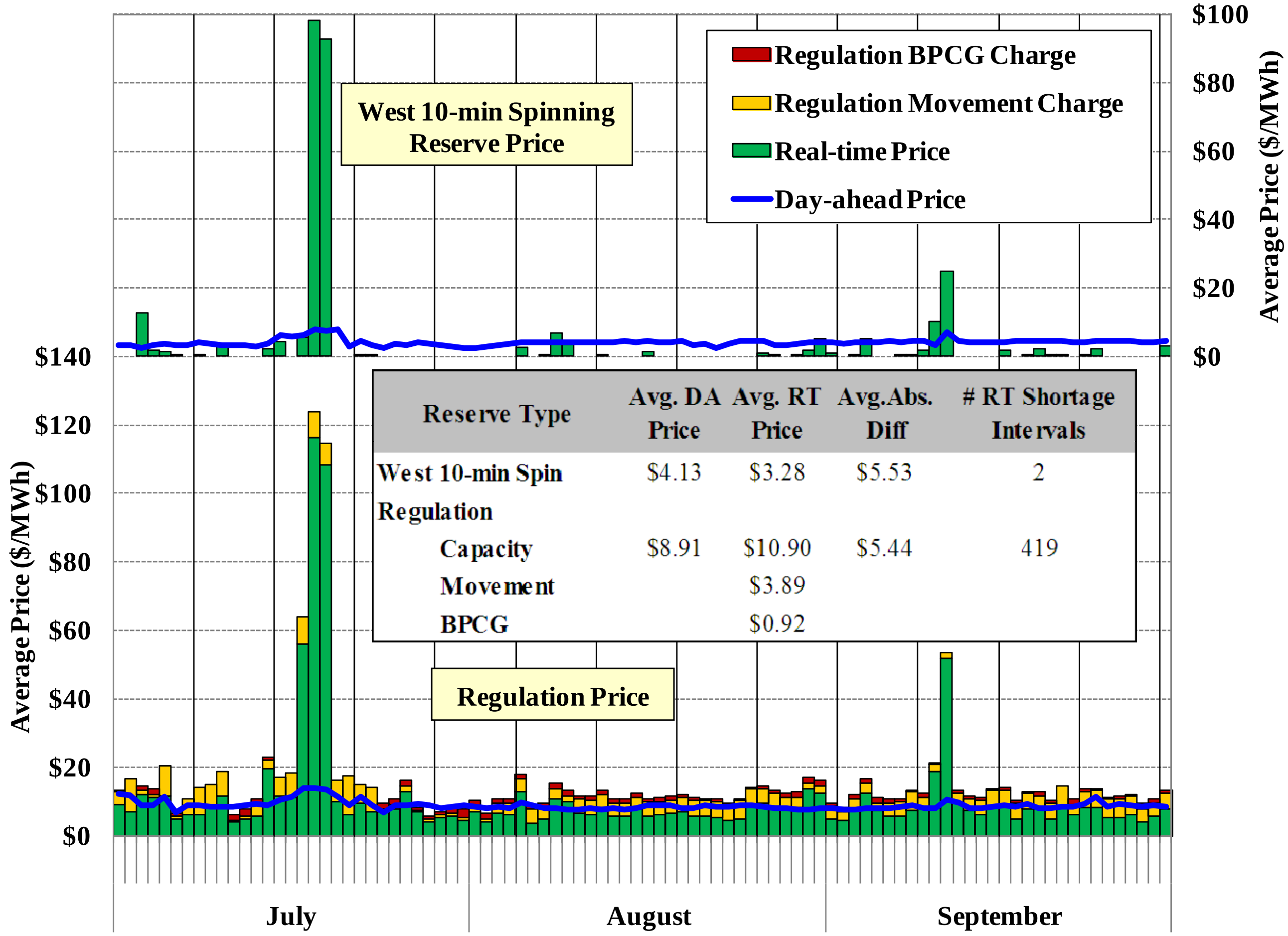
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	$5.12	$6.24	$6.77	74
East 10-min Spin	$8.21	$9.79	$10.29	615

POTOMAC ECONOMICS

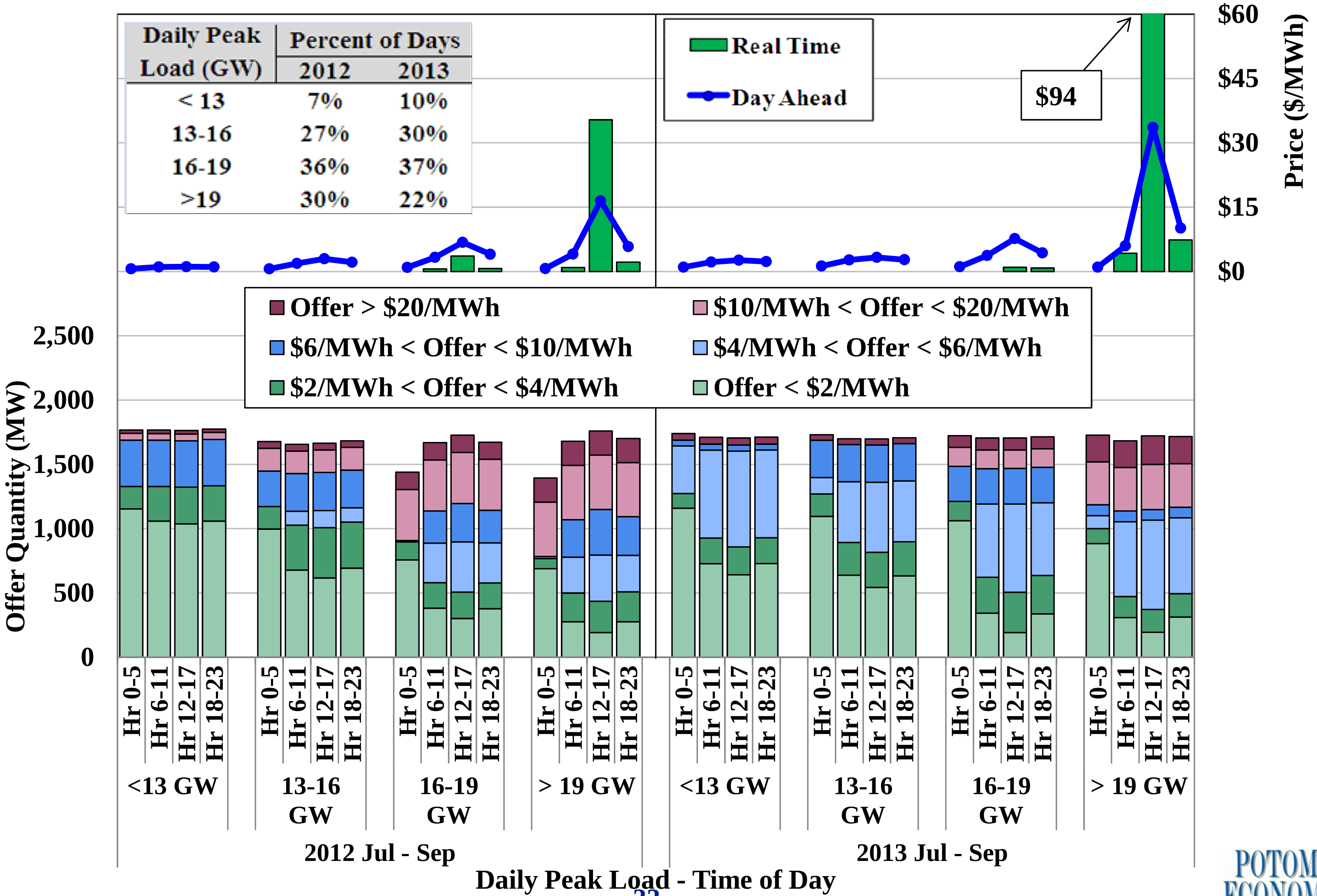
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
West 10-min Spin	$4.13	$3.28	$5.53	2
Regulation				
Capacity	$8.91	$10.90	$5.44	419
Movement		$3.89		
BPCG		$0.92		

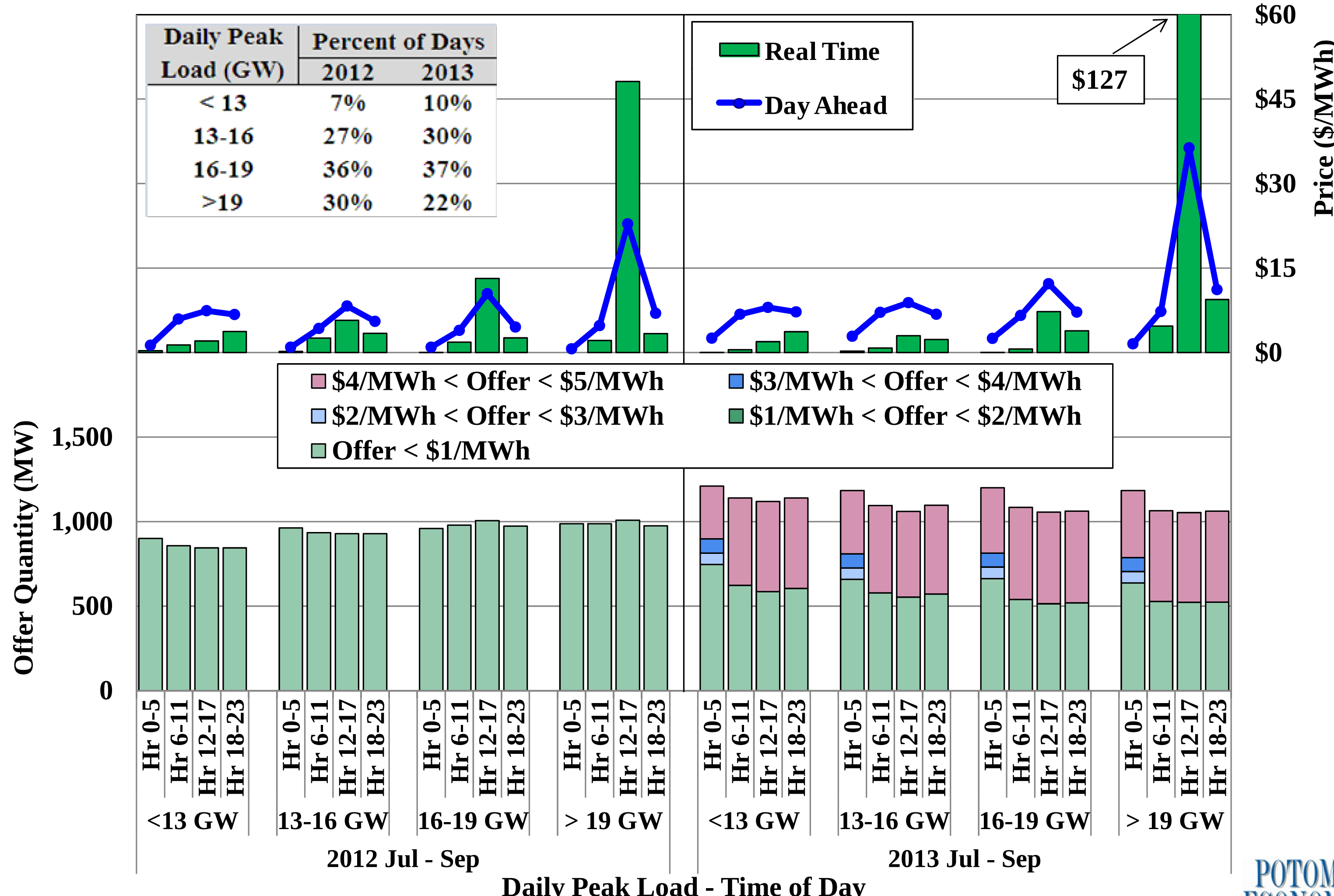
Note: Regulation Movement Charges and BPCG charges from regulating in real-time are shown in the figure averaged per MWh of RT Scheduled Regulation Capacity.

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



POTOMAC ECONOMICS

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



Daily Peak Load (GW)	Percent of Days 2012	Percent of Days 2013
< 13	7%	10%
13-16	27%	30%
16-19	36%	37%
>19	30%	22%

POTOMAC ECONOMICS

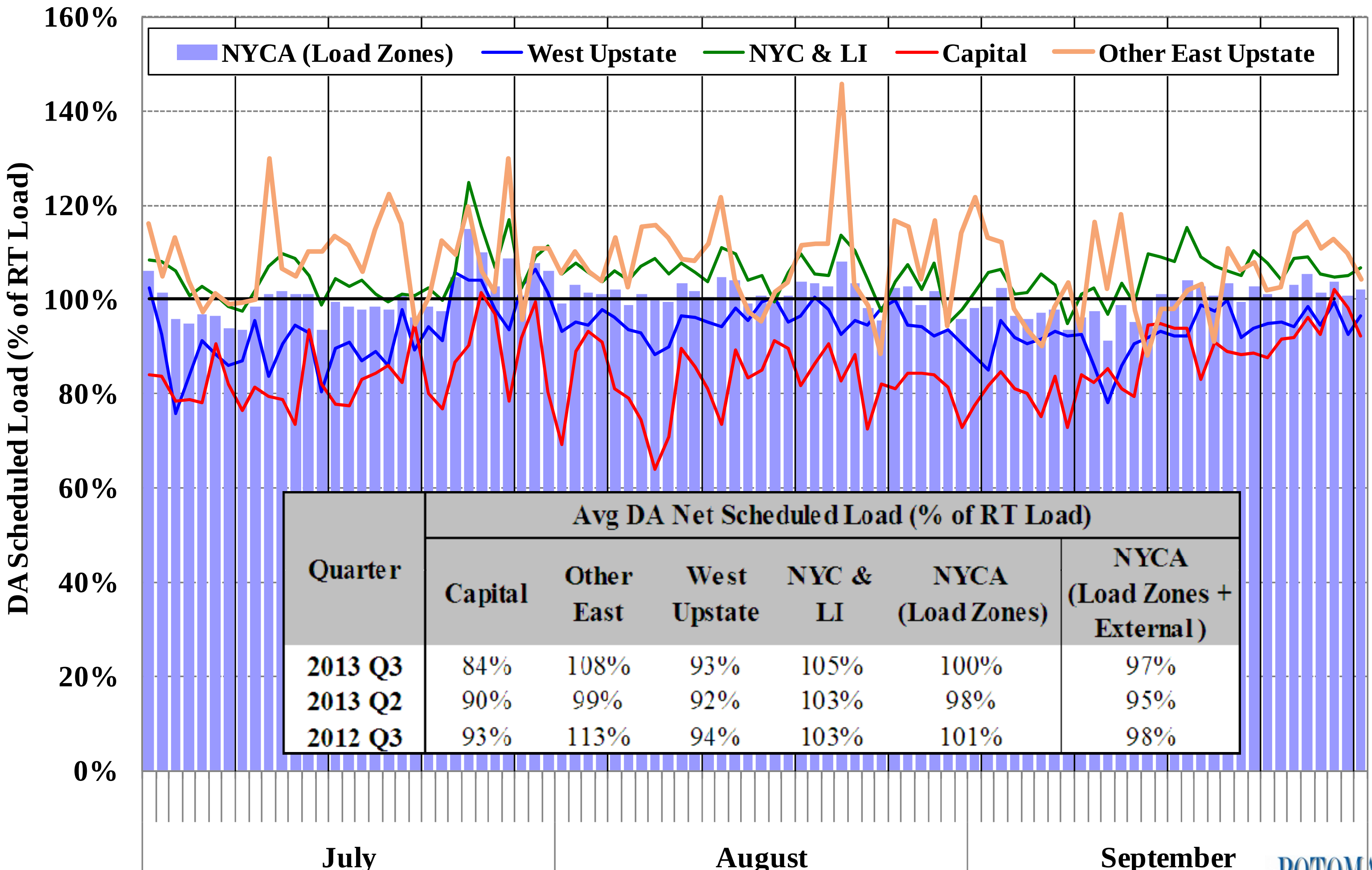
Energy Market Scheduling

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
  - ✓ The table also summarizes a system-wide net scheduled load that includes virtual imports and virtual exports at the proxy buses.
- Overall, load in the day-ahead market was scheduled at 100% (97% when virtual imports and exports are taken into account) of actual load in NYCA in the third quarter of 2013.
- Load was generally under-scheduled outside SENY (i.e., West Upstate and Capital Zone) and over-scheduled in SENY in the third quarter of 2013.
  - ✓ This pattern has been prevalent in recent years and is likely in response to real-time congestion across the lines into SENY, NYC, and Long Island.
    - – For example, load tended to schedule notably more in SENY on days when TSA events were well anticipated.
  - ✓ 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 real-time above their day-ahead 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 (Load Zones)	NYCA (Load Zones + External)
2013 Q3	84%	108%	93%	105%	100%	97%
2013 Q2	90%	99%	92%	103%	98%	95%
2012 Q3	93%	113%	94%	103%	101%	98%

POTOMAC ECONOMICS

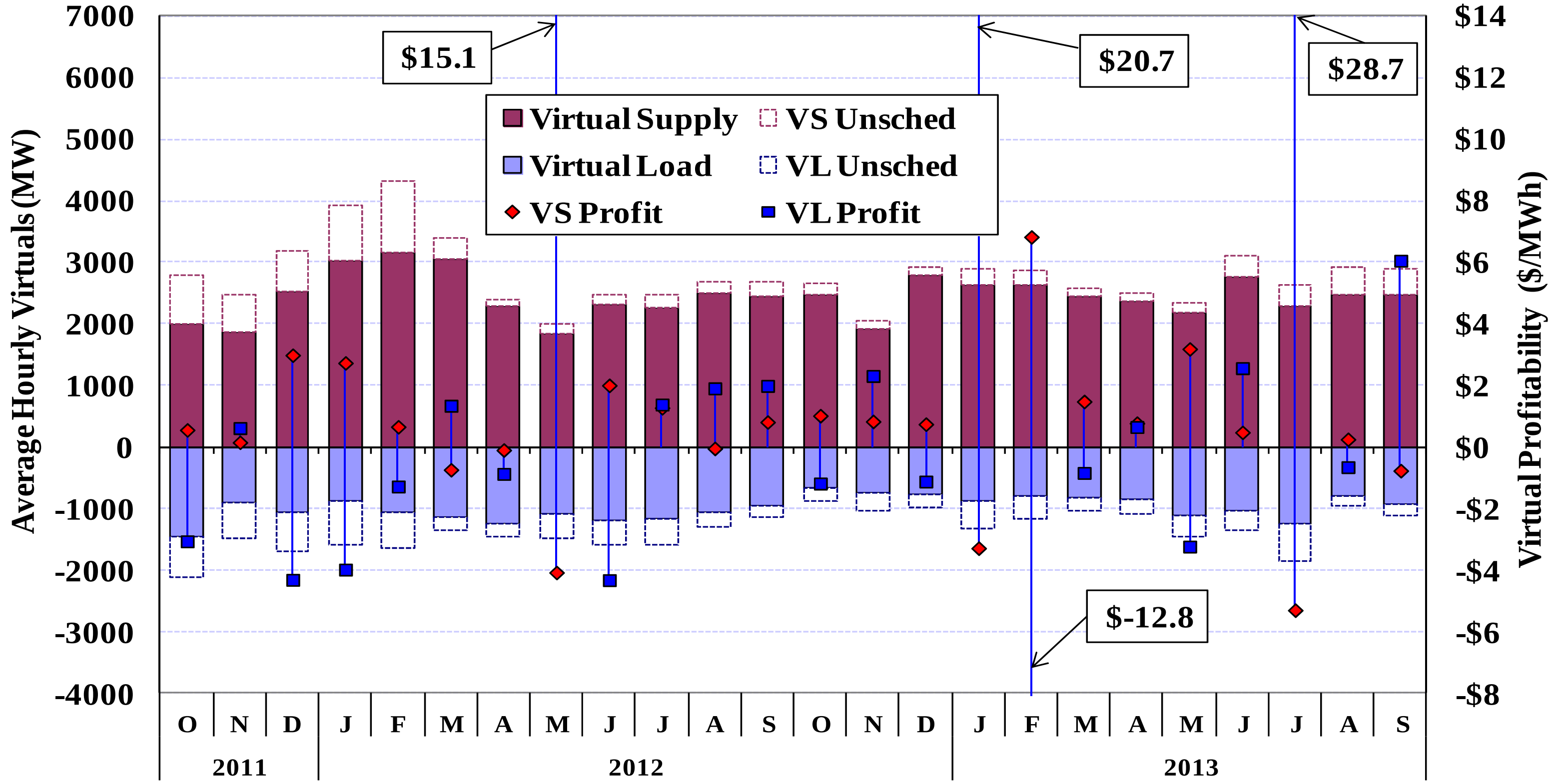
Virtual Trading Activity

- 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 day-ahead and real-time 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.
    - – An import or export is deemed to be virtual if the day-ahead schedule is greater than the real-time schedule, so a portion of these transactions result from curtailments by NYISO or another control area (rather than the intent of the participant).

Virtual Trading Activity

- A large number of market participants regularly submit virtual trades, averaging 28 bidders at the load zones and 7 at the proxy buses in the third quarter of 2013.
  - ✓ 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 93 percent were virtual imports.
- In aggregate, virtual traders netted a gross profit of $20 million at the load zones and over $1 million at the proxy buses in the third quarter of 2013.
  - ✓ The profits and losses of virtual trades have varied widely from month-to-month, reflecting the difficulty of predicting volatile real-time prices.
    - – Notable increases in load zone gross profit (180% from second quarter of 2013 & 164% from third quarter of 2012) were attributable to real-time price spikes on several days when SCRs were activated or TSAs were called, particularly in July.
  - ✓ The net profits at the proxy buses were partly offset by losses associated with day-ahead market 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 and did not raise significant concerns.

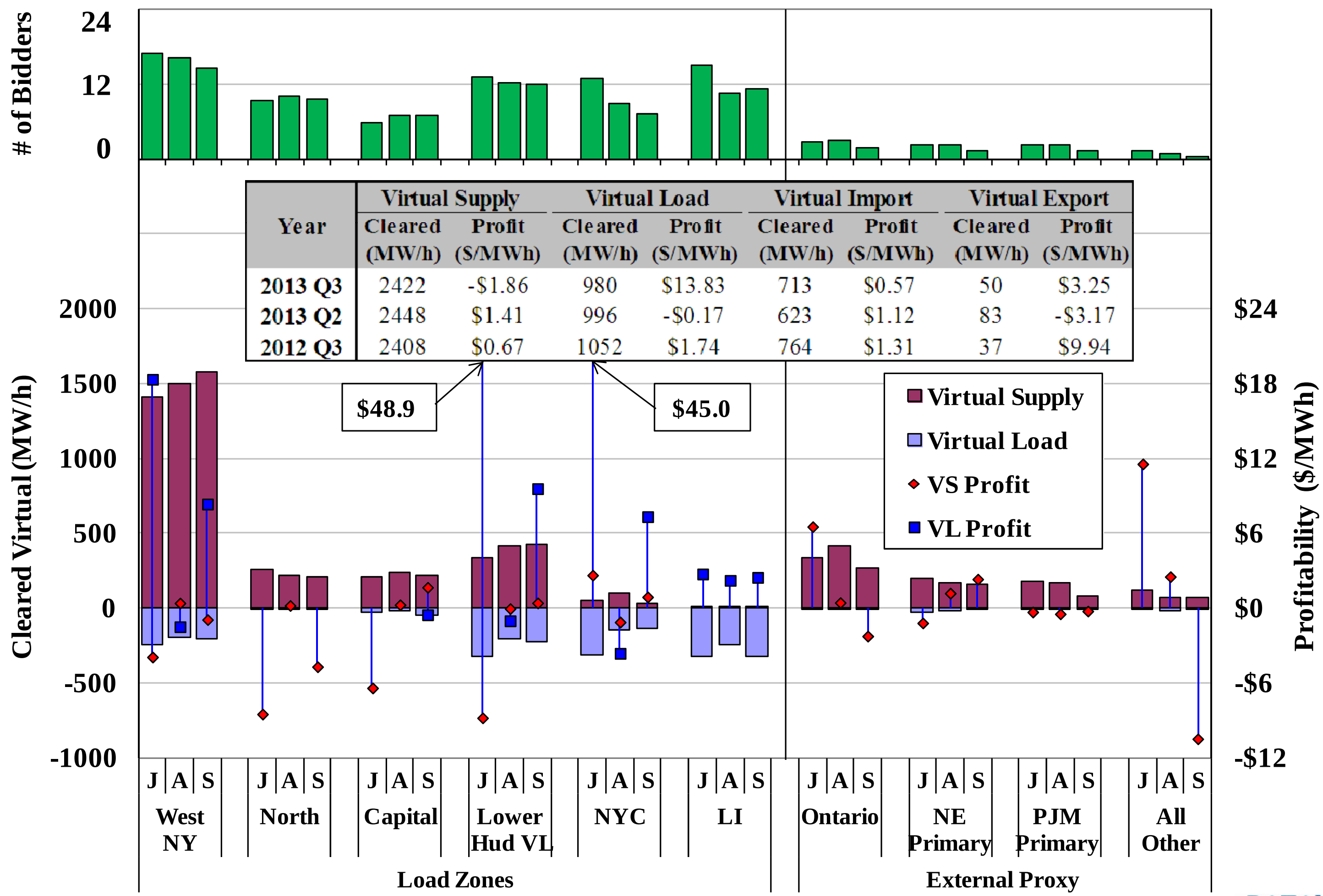
Virtual Trading Activity at Load Zones by Month



		O 2011	N 2011	D 2011	J 2012	F 2012	M 2012	A 2012	M 2012	J 2012	J 2012	A 2012	S 2012	O 2012	N 2012	D 2012	J 2013	F 2013	M 2013	A 2013	M 2013	J 2013	J 2013	A 2013	S 2013
Profit > 50% of Avg. Zone Price	MW	98	100	208	275	96	224	220	128	345	300	208	158	143	238	202	418	426	191	187	328	253	345	156	209
	%	3%	4%	6%	7%	2%	5%	6%	4%	10%	9%	6%	5%	5%	9%	6%	12%	12%	6%	6%	10%	7%	10%	5%	6%
Loss > 50% of Avg. Zone Price	MW	133	120	193	177	125	283	261	132	377	337	220	129	93	182	195	354	347	125	149	275	165	252	176	185
	%	4%	4%	5%	5%	3%	7%	7%	4%	11%	10%	6%	4%	3%	7%	5%	10%	10%	4%	5%	8%	4%	7%	5%	5%

POTOMAC ECONOMICS

Virtual Trading Activity at Load Zones & Proxy Buses by Location



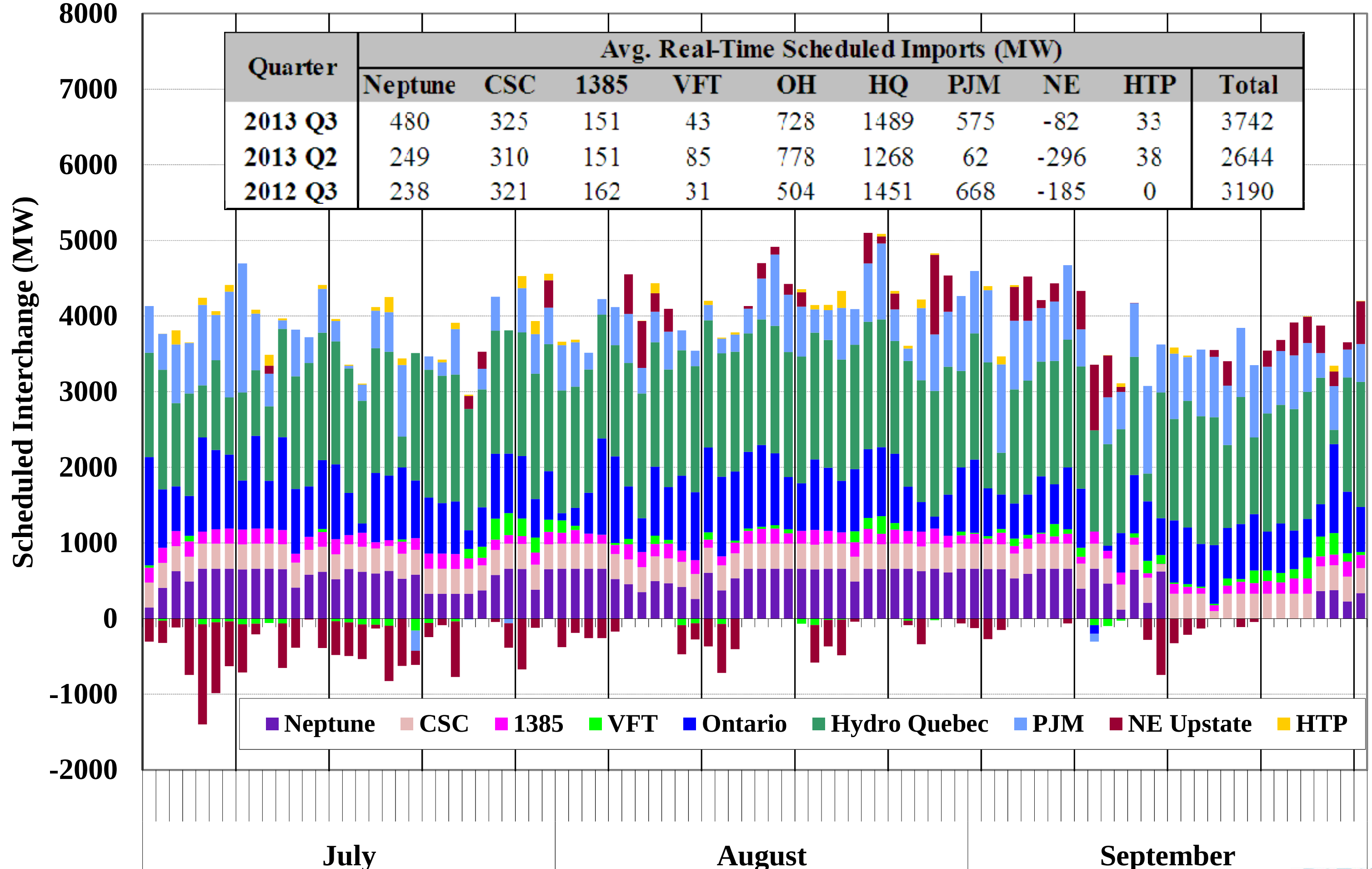
Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2013 Q3	2422	-$1.86	980	$13.83	713	$0.57	50	$3.25
2013 Q2	2448	$1.41	996	-$0.17	623	$1.12	83	-$3.17
2012 Q3	2408	$0.67	1052	$1.74	764	$1.31	37	$9.94

Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 30 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 nearly 3.8 GW (serving roughly 17 percent of the load) during peak hours, up 550 MW from the third quarter of 2012.
- Net exports to NE across its primary interface averaged 82 MW during peak hours, down 214 MW from last quarter and 103 MW from the same quarter of last year.
  - ✓ During the summer months, exports to ISO-NE tend to rise on high demand days.
- Net imports to LI across the controllable interfaces (i.e., CSC, 1385, and Neptune) were often fully scheduled when in service, especially during peak hours.
  - ✓ Imports across the Neptune Line rose 240 MW from prior quarters as the line fully returned to service in early July after 13 months of frequent outages and deratings.
- Net imports from PJM across the primary interface increased over 500 MW from last quarter and fell about 95 MW from the same quarter of last year.
  - ✓ These were primarily associated with the changing status of the Ramapo Line (one PAR out since February 2013 and second PAR out in April and May 2013).
  - ✓ These outages shifted power flows to the tie-lines between PJM and Western NY, resulting in lower LBMPs at the PJM proxy (and less incentive to import to NY).
- The HTP Scheduled Line was used very little (~5 percent of capability).

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



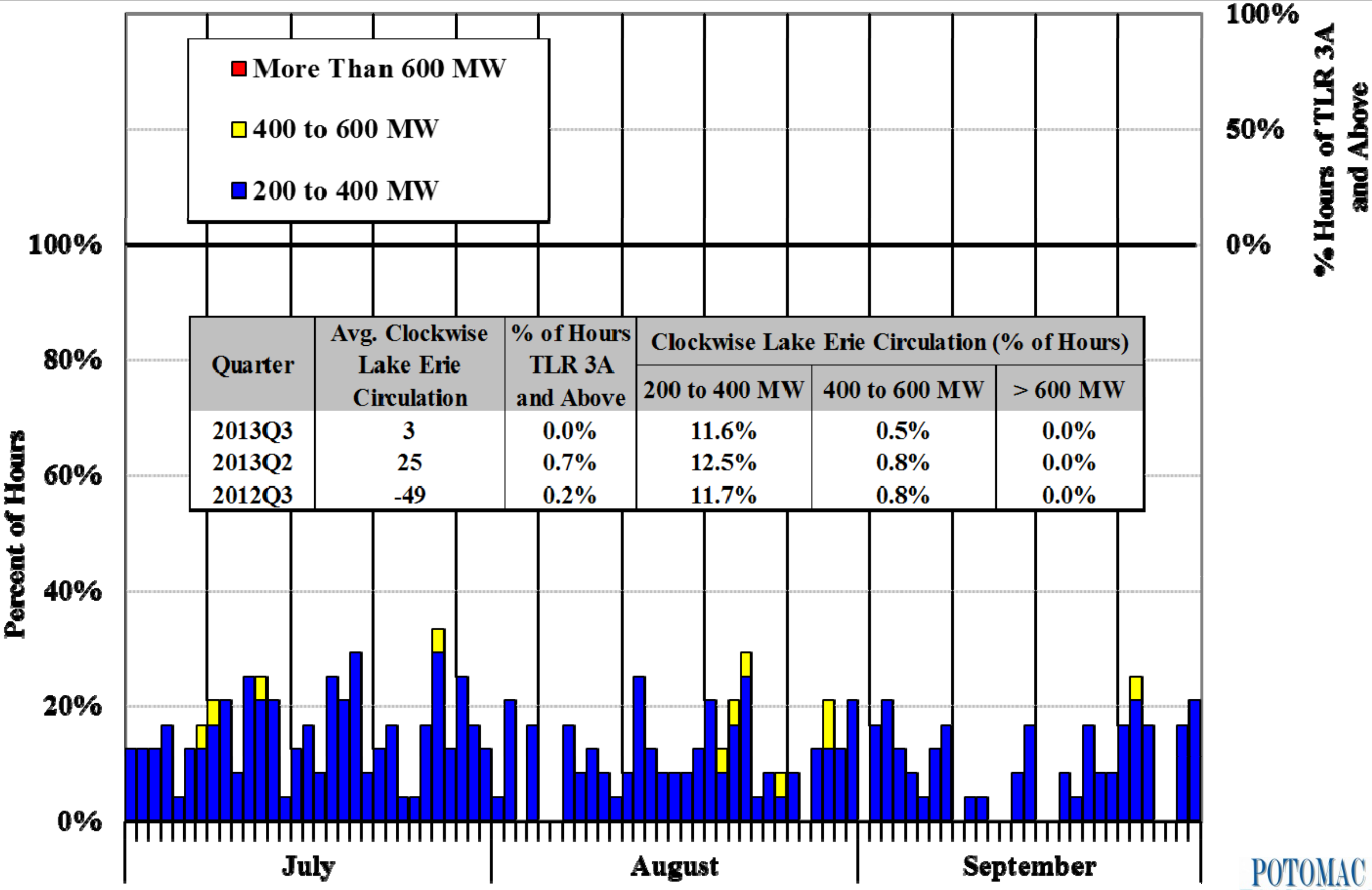
Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2013 Q3	480	325	151	43	728	1489	575	-82	33	3742
2013 Q2	249	310	151	85	778	1268	62	-296	38	2644
2012 Q3	238	321	162	31	504	1451	668	-185	0	3190

POTOMAC ECONOMICS

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 third quarter.
- LEC averaged 3 MW in the clockwise direction in the third quarter.
  - ✓ Clockwise LEC was high (>200 MW hourly average) in 12 percent of hours.
  - ✓ 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.
  - ✓ In the third quarter of 2013, the NYISO did not call any TLRs.

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
2013Q3	3	0.0%	11.6%	0.5%	0.0%
2013Q2	25	0.7%	12.5%	0.8%	0.0%
2012Q3	-49	0.2%	11.7%	0.8%	0.0%

POTOMAC ECONOMICS

Efficiency of Gas Turbine Commitment and Price Setting

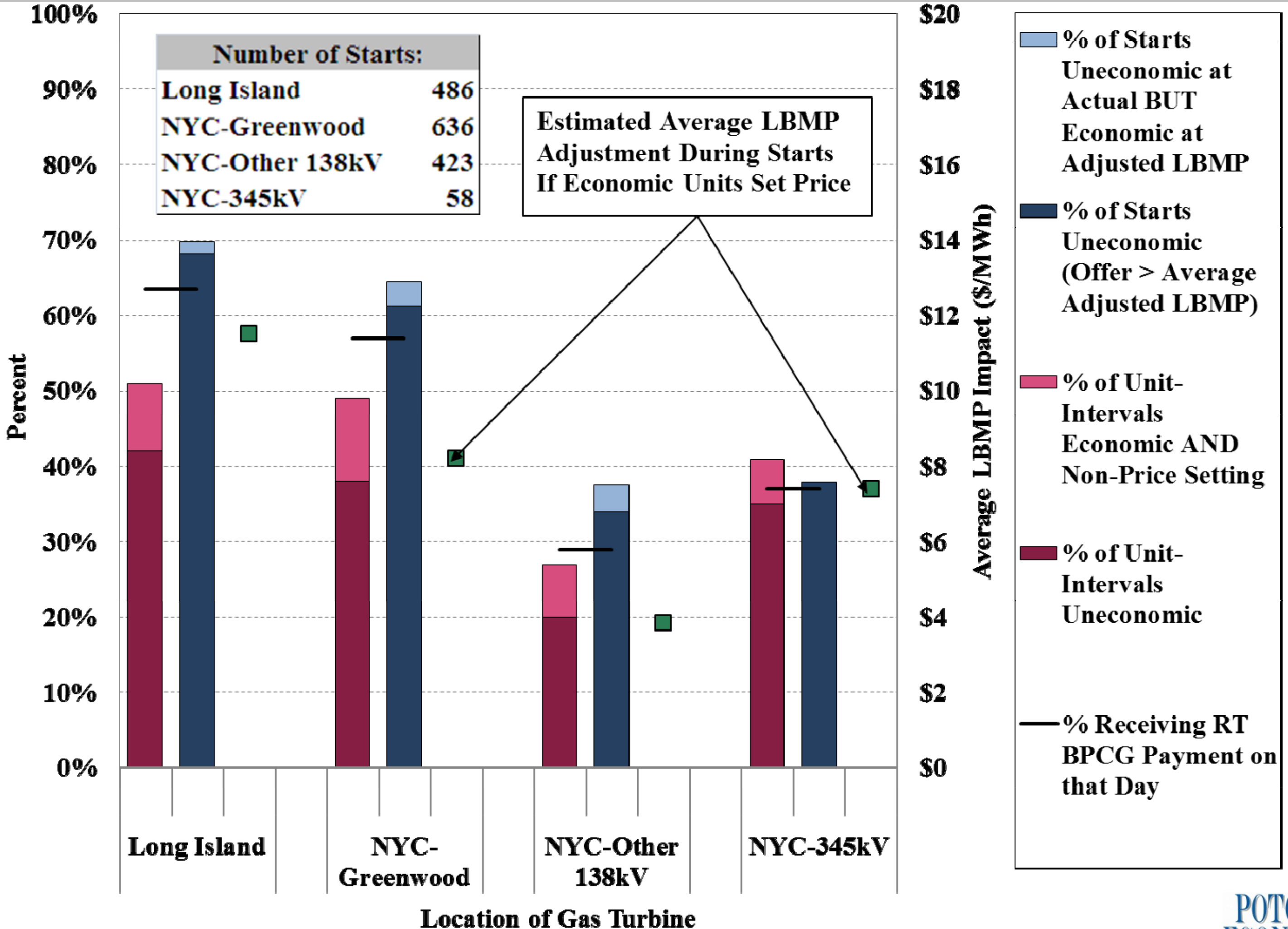
- The next figure evaluates the efficiency of GT commitments and of real-time LBMPs during the initial one-hour commitment period in the third quarter of 2013.
- The figure reports the seven quantities for four areas of NYC and Long Island:
  - ✓ Number of Starts – Excludes self-schedules and commitment for TO reliability.
  - ✓ Percent Receiving Real-Time BPCG on that Day – Share of GT commitments that occurred on days when the unit received a real-time 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 real-time LBMP.
  - ✓ Estimated Average LBMP Adjustment During Starts – Average upward adjustment in LBMPs during starts if economic GTs always set the real-time 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 real-time LBMP).
  - ✓ Percent of Starts Uneconomic at Actual BUT Economic at Adjusted LBMP – Share of starts when GT's offer was (a) greater than average actual LBMP but (b) less than average Adjusted LBMP over the initial commitment period.

POTOMAC ECONOMICS

Efficiency of Gas Turbine Commitment and Price Setting

- The figure shows that in the third quarter of 2013:
  - ✓ Gas turbines were economic in roughly 60 to 80 percent of intervals during their initial commitment period (excluding self schedules and local TO commitment).
  - ✓ However, economic gas turbines did not set LBMPs in 6 to 11 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 $4 to $12 per MWh during their initial commitment period in the third quarter of 2013.
  - ✓ The higher LBMPs would generally be more reflective of the costs of satisfying demand, security, and reliability requirements in the real-time market.
- However, the figure under-estimates the effects of allowing GTs to set the real-time LBMP in intervals when they are economic because:
  - ✓ It assumes that the real-time LBMP impact is limited to nodes in the same area (out of the four areas shown) that have similar LBMP congestion component. In fact, the LBMPs over a wider area can be affected, depending on congestion.

Efficiency of Gas Turbine Commitment and Price Setting



POTOMAC ECONOMICS

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 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 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 fourth and fifth 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: Lines in the West Zone.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.
  - ✓ Capital to Hudson Valley: Primarily lines leading into 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.

Day-Ahead and Real-Time Congestion

(cont. from prior slide)

- ✓ 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 $128 million, down 1 percent from last year.
  - ✓ Congestion increased in the West Zone, from West to East, and into SENY, while congestion decreased into Long Island and across the HQ interface.
  - ✓ $91 million (or 71 percent) of third-quarter congestion revenues accrued in July.
    - High load levels generally led to increased congestion across the system.
    - Frequent TSA events contributed to higher congestion into SENY.
    - Congestion into the Greenwood area of NYC rose due to transmission outages and difficulties with modeling ring bus separation contingencies.
    - Congestion rose notably in the West Zone, due to reasons discussed later.

POTOMAC ECONOMICS

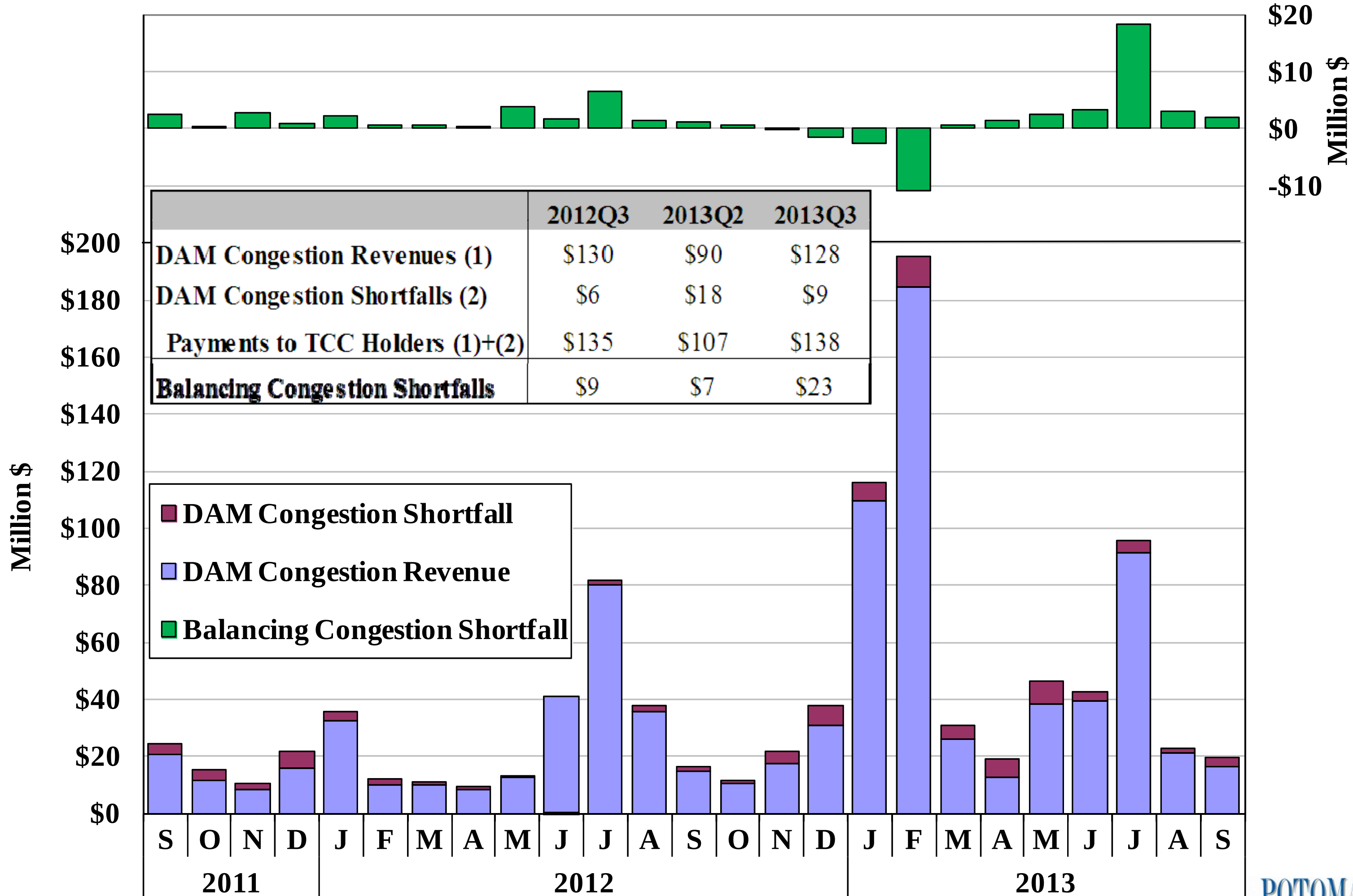
Day-Ahead and Real-Time Congestion

- Most congestion (measured as a % of total DA/RT congestion value) occurred in the following areas in the third quarter of 2013:
  - ✓ Capital to Hudson (24% DAM, 31% RTM) – Severe congestion into SENY was mostly associated with TSA events and/or high load levels.
  - ✓ New York City lines (29% DAM, 20% RTM) – Most was congestion on paths into the Greenwood load pocket, which were exacerbated by transmission outages.
  - ✓ Long Island (19% DAM, 19% RTM) – Most congestion was from upstate-to-Long Island. This fell from prior quarters primarily due to increased Neptune imports.
  - ✓ West Zone Lines (13% DAM, 18% RTM) – The NYISO started to model these 230kV line constraints in May 2012. This has increased in 2013 due to:
    - The retirement of several Dunkirk units, which had helped relieve this congestion;
    - Transmission outages, which reduced transfer limits on in-service lines;
    - Generation outages of units that are effective in managing this congestion; and
    - Aggregated modeling of a large plant in the market software, which does not calculate LBMPs and dispatch signals for individual units at the plant.
- There were significant inconsistencies in the magnitude of congestion from the DAM to the RTM on several interfaces, which led to poor price convergence.
  - ✓ RT congestion was more volatile for West Zone lines, lines in SENY, and lines into Long Island and the Valley Stream load pocket (inside Long Island).

Day-Ahead and Balancing Congestion Shortfalls

- Day-ahead congestion shortfalls totaled roughly $9 million in the third quarter of 2013, up from $6 million in the third quarter of 2012.
  - ✓ The majority of shortfalls was driven by transmission outages.
    - – In July and early-August, nearly $10 million resulted from outages that reduced capability in the Greenwood load pocket in NYC. These were exacerbated because the market software's pricing and dispatch logic does not accurately model certain contingencies at ring buses.
    - – Outage-related shortfalls are allocated to the responsible TO.
  - ✓ This was offset by $4 million of surpluses that accrued on several days in mid-July on West Zone constraints.
    - – Flows on these lines were much higher in the DAM than in the TCC auction, reflecting that these constraints were not well anticipated in the TCC auction.
- Balancing congestion shortfalls were $23 million, much higher than prior quarters.
  - ✓ 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 $18 million (or 80 percent) of shortfalls.

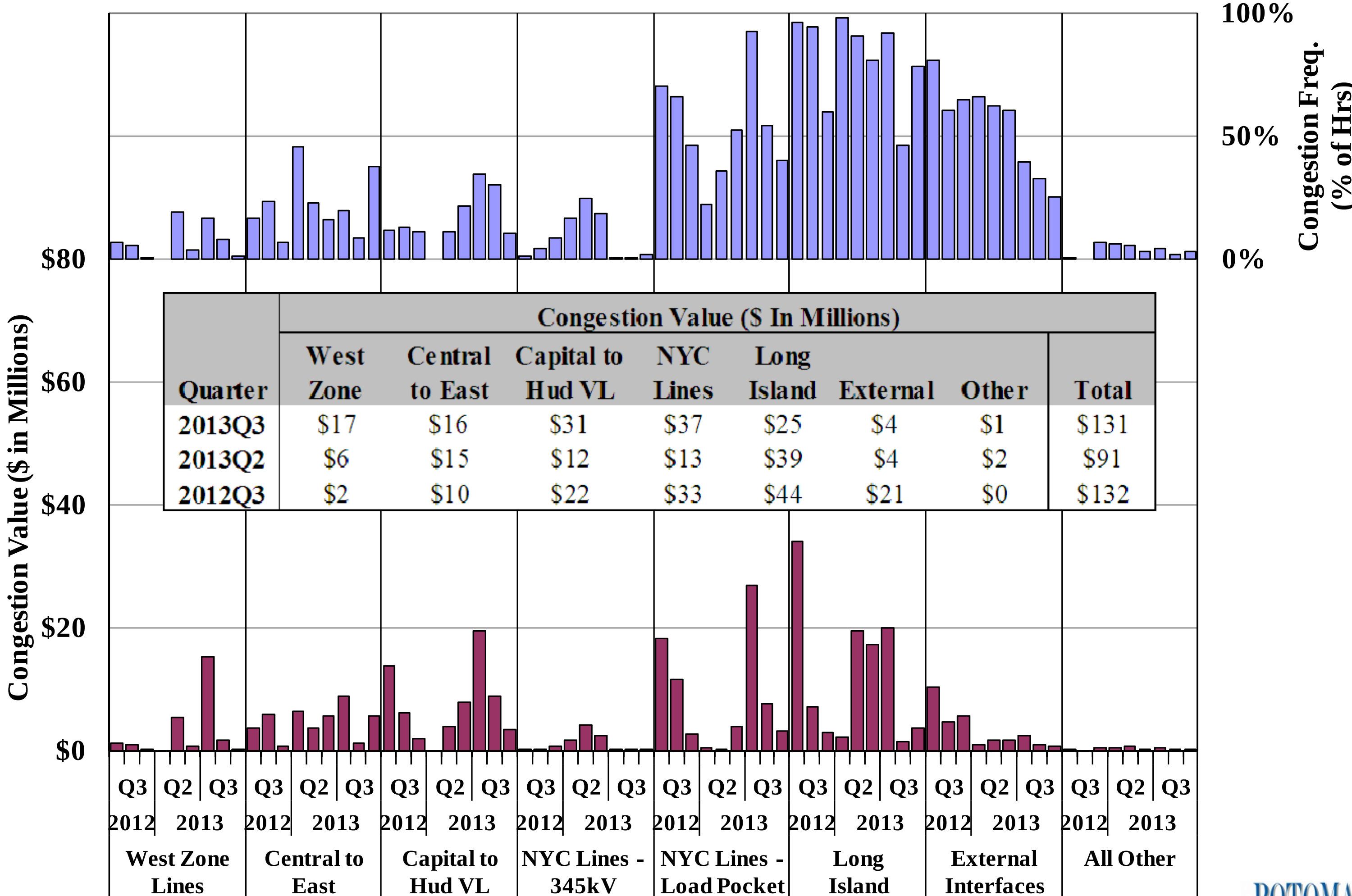
Congestion Revenues and Shortfalls by Month



	2012Q3	2013Q2	2013Q3
DAM Congestion Revenues (1)	$130	$90	$128
DAM Congestion Shortfalls (2)	$6	$18	$9
Payments to TCC Holders (1)+(2)	$135	$107	$138
Balancing Congestion Shortfalls	$9	$7	$23

POTOMAC ECONOMICS

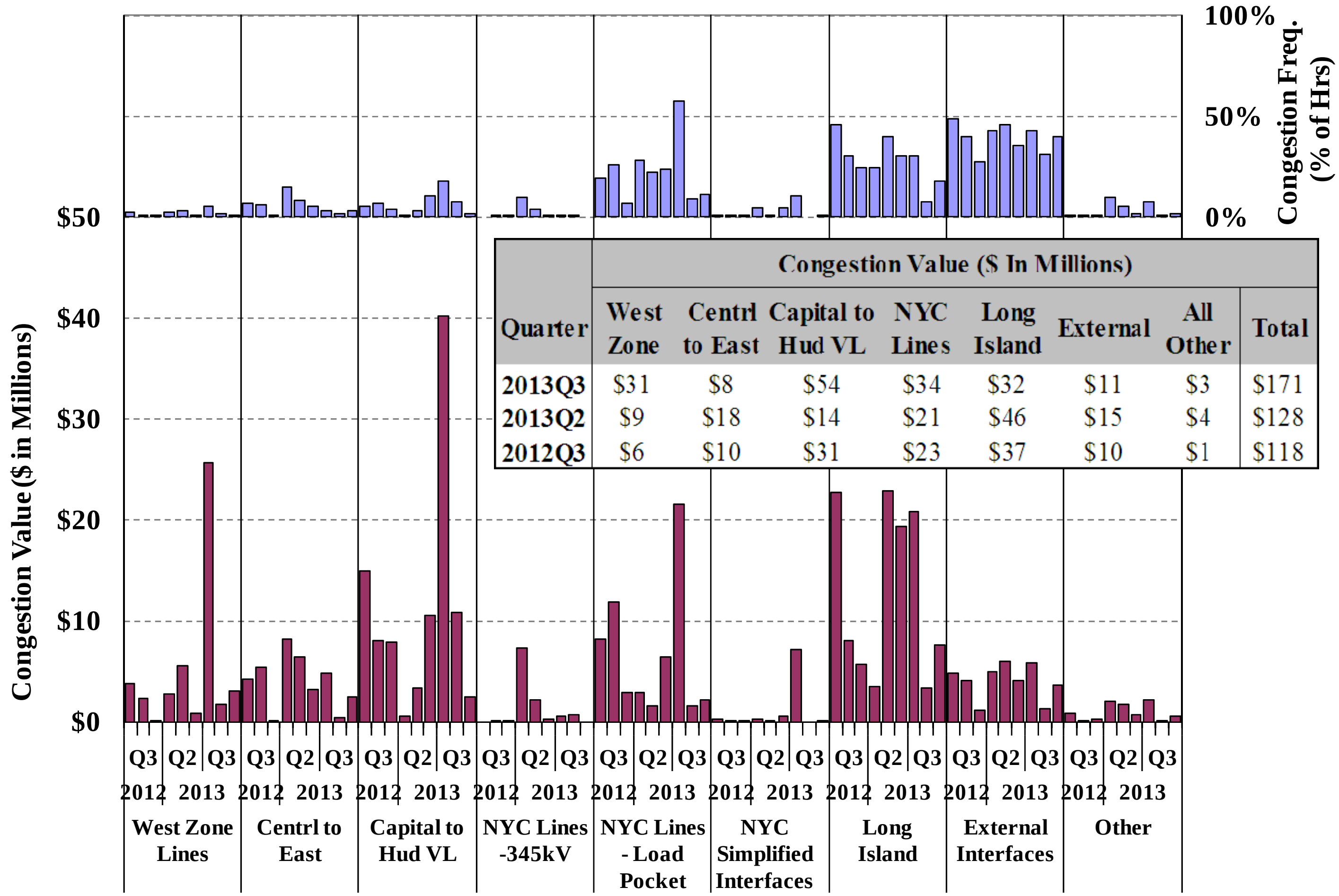
Day-Ahead Congestion Value and Frequency
by Transmission Path



	Congestion Value ($ In Millions)							
Quarter	West Zone	Central to East	Capital to Hud VL	NYC Lines	Long Island	External	Other	Total
2013Q3	$17	$16	$31	$37	$25	$4	$1	$131
2013Q2	$6	$15	$12	$13	$39	$4	$2	$91
2012Q3	$2	$10	$22	$33	$44	$21	$0	$132

POTOMAC ECONOMICS

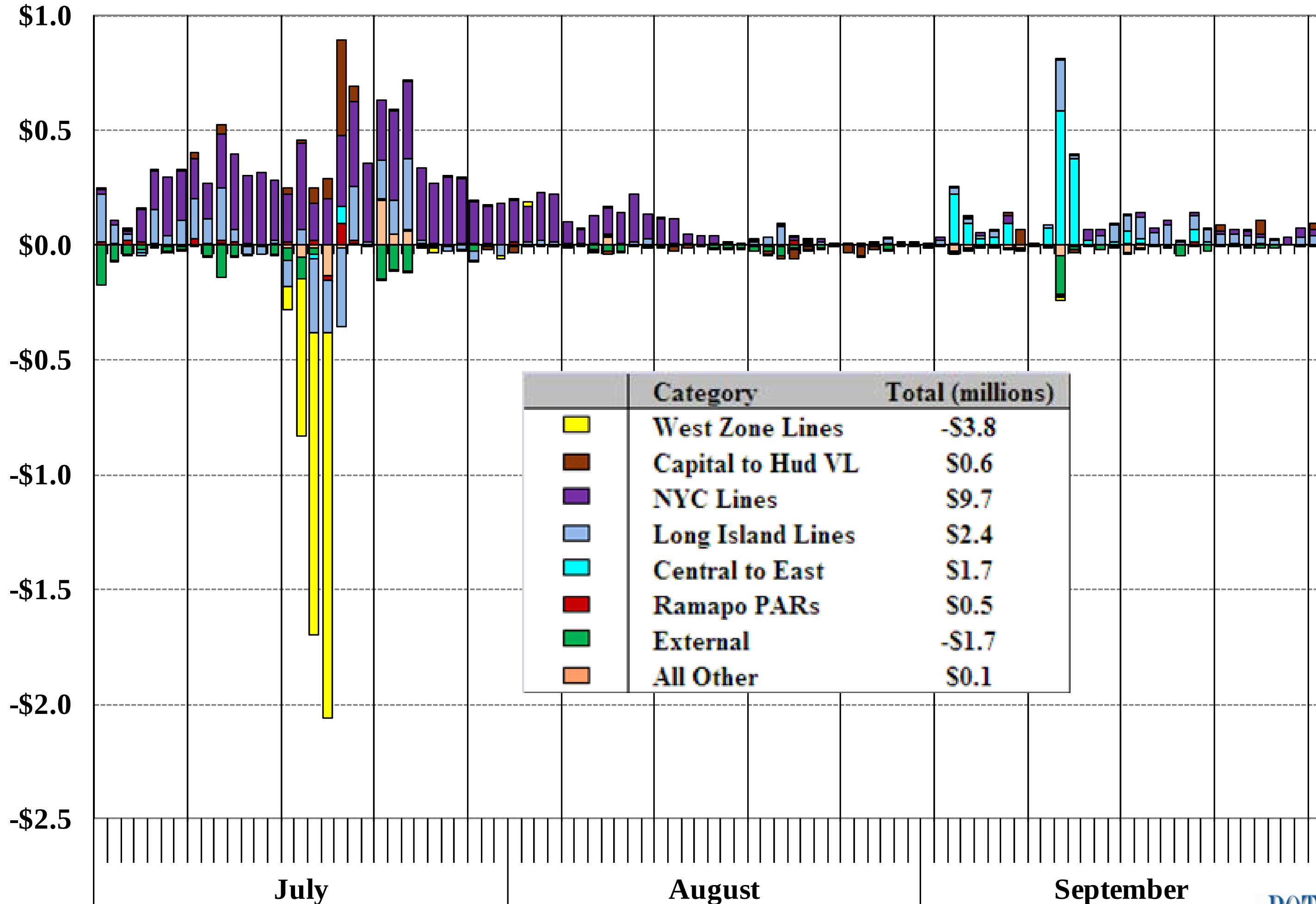
Real-Time Congestion Value and Frequency by Transmission Path



Quarter	Congestion Value ($ In Millions)							
	West Zone	Centrl to East	Capital to Hud VL	NYC Lines	Long Island	External	All Other	Total
2013Q3	$31	$8	$54	$34	$32	$11	$3	$171
2013Q2	$9	$18	$14	$21	$46	$15	$4	$128
2012Q3	$6	$10	$31	$23	$37	$10	$1	$118

Notes: The effects of the Scarcity Pricing rules are not included in this chart, which will increase the total congestion value by $2.5 million in the third quarter of 2013.

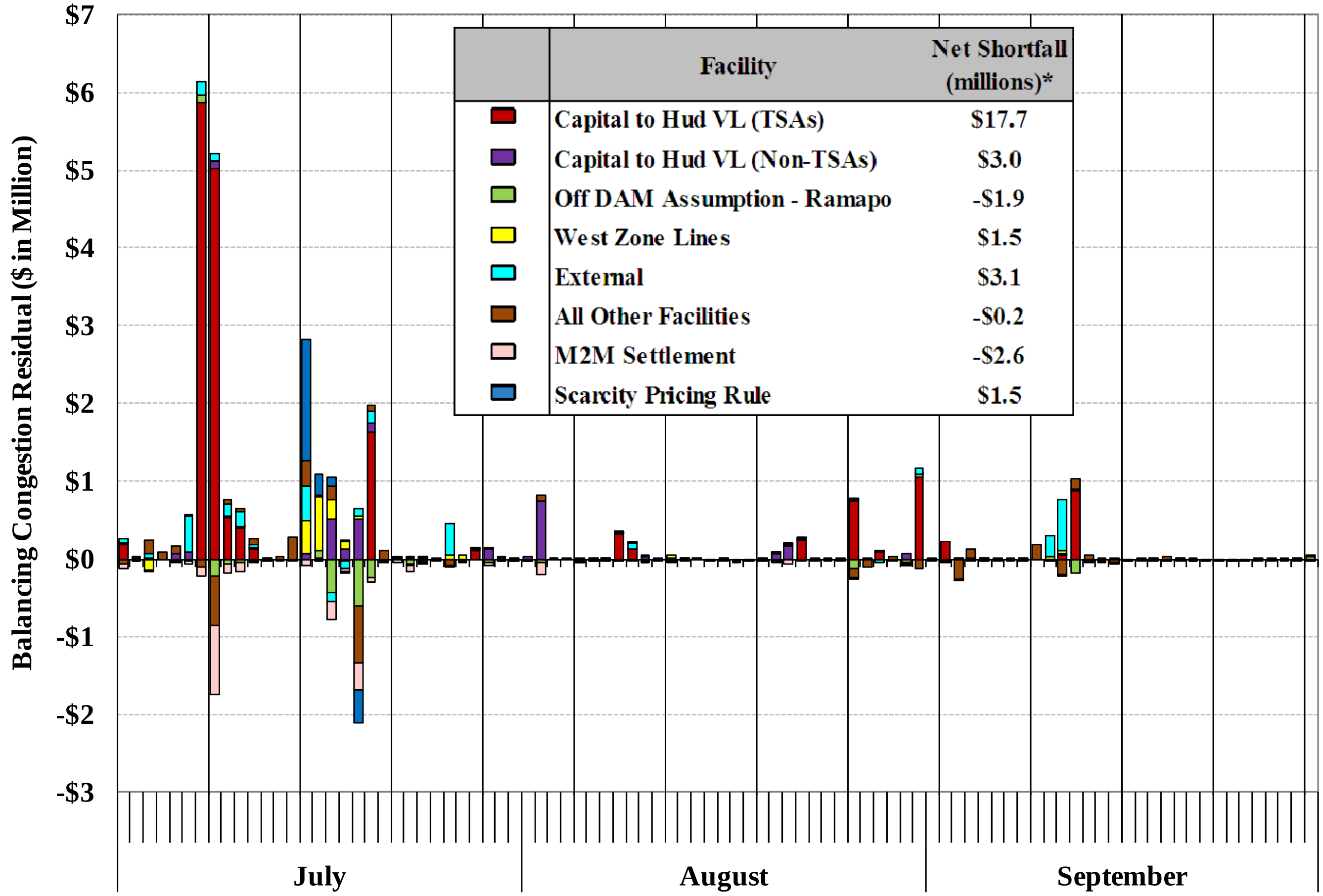
Day-Ahead Congestion Revenue Shortfalls
by Transmission Facility



Category	Total (millions)
West Zone Lines	-$3.8
Capital to Hud VL	$0.6
NYC Lines	$9.7
Long Island Lines	$2.4
Central to East	$1.7
Ramapo PARs	$0.5
External	-$1.7
All Other	$0.1

POTOMAC ECONOMICS

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).

POTOMAC ECONOMICS

Congestion in the West Zone

- Congestion in the West Zone has risen significantly as constraints on the 230kV network have more frequently limited the flow of power towards Eastern NY.
  - ✓ These constraints are affected by: (a) clockwise Lake Erie circulation, (b) the retirement of three Dunkirk units, and (c) outages (tx. and gen.) in the West Zone.
- As these factors have led to increased flows on the 230kV constraints, NYISO's current modeling of a large plant in the West Zone has become significant.
  - ✓ Some NYISO plants are modeled as a single bus (rather than as separate units).
  - ✓ The plant in question has units on the 115kV system that relieve the 230kV constraints, while those on the 230kV system increase flows over the constraints.
  - ✓ NYISO's aggregated modeling of the plant affects the market's ability to manage the 230kV constraints and reduces the deliverability of the plant and other sources.
- Possible benefits of enhanced modeling (if feasible) in the past 2 quarters include:
  - ✓ Lower congestion that may have reduced the average West Zone LBMP by as much as $2.34/MWh and the daily LBMP on July 16 by more than $100/MWh.
  - ✓ Lower production costs under the existing transmission demand curve by as much as $1.7 million ($1.0 million lower under the proposed demand curve).
  - ✓ 19 GWh more generation would have been deliverable in the 120 congested hours.
- Although the benefits are modest on most days, the feasibility of enhanced modeling of the plant in question should be evaluated.

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 third quarter of 2013.
  - ✓ It was activated for the Dysinger East constraint in roughly 20 hours and resulted in only a total payment of $9,700 from PJM to NY for that constraint.
- The use of Ramapo PAR Coordination had more significant impacts on the market in the third quarter of 2013. However, usage of this process was limited by:
  - ✓ The outage of one of two Ramapo PARs during the entire quarter (the outage began on February 4, 2013), reducing Ramapo capability in half; and
  - ✓ PJM's suspension of coordination for TSA flow gates starting July 15.
- The next three figures evaluate the operation of Ramapo PARs in the third quarter of 2013.

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% for the third quarter of 2013).
    - 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.
    - This excludes the LBMP effects of Scarcity Pricing during DR activations.

POTOMAC ECONOMICS

Operations under M2M with PJM
Ramapo PAR Coordination

- ✓ 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).
- ✓ 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 third quarter of 2013 when M2M constraints were binding.
  - ✓ The sum of the components of the Ramapo Target Flow exceeded the capability of the Ramapo Line to support RECo deliveries, 46 percent of PJM-NY interchange, and any wheel imbalance on may days.
  - ✓ M2M constraints in PJM were rarely binding.
  - ✓ Consequently, $2.6 million of M2M payments were made by PJM to NYISO during periods of under delivery (i.e., when actual flow < target flow).

Operations under M2M with PJM Ramapo PAR Coordination

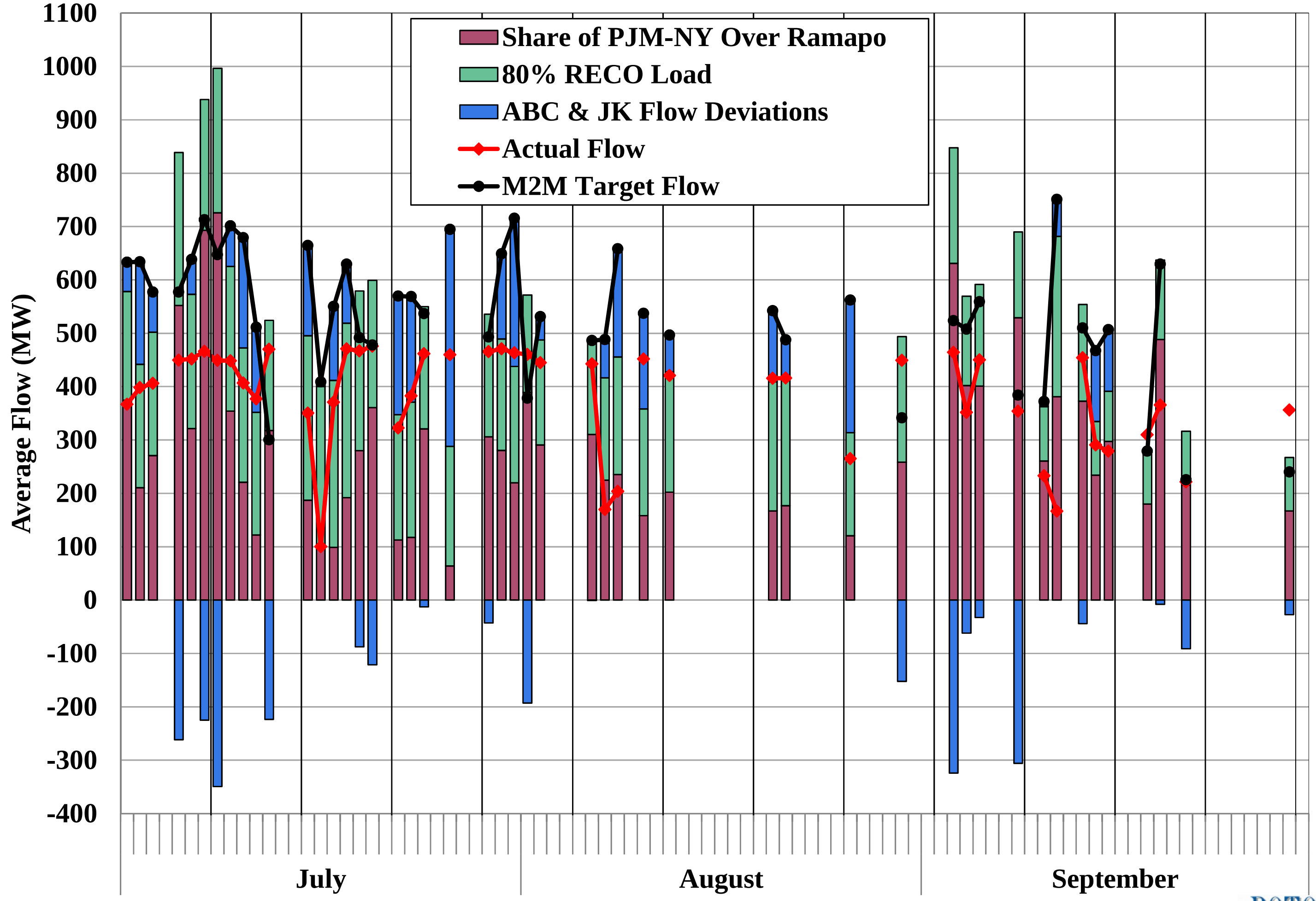
- Of hours with congestion in NY or PJM (i.e., when the marginal effect of Ramapo flow was greater than $2/MWh in one or both markets), Ramapo Line flows were:
  - ✓ Reasonably efficient in 72 percent of the hours.
  - ✓ Not fully optimized while NY congestion > PJM congestion (by $20/MWh or more) in 15 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 378 MW in hours with M2M flow gates binding and 307 MW in other hours.
  - ✓ Not fully optimized while PJM congestion > NY congestion (by $20/MWh or more) in 13 percent of the hours. In these hours:
    - – M2M flow gates were rarely binding;
    - – The PJM congestion was generally on non-M2M flow gates;
    - – The NY congestion was sometimes negative due to West Zone constraints, which can lead LBMPs in the West Zone to exceed those in the Hudson Valley; and
    - – The Ramapo Line usually flowed power out of PJM in these hours (averaging 300+ MW).

Operations under M2M with PJM Ramapo PAR Coordination

- On the Top 10 afternoons in the third figure, Ramapo had significant impacts.
  - ✓ On three days shown (July 8, 17, & 19), the Ramapo Line provided relief to the NYISO during periods of significant Leeds-to-Pleasant Valley congestion.
    - – This congestion was reflected in the M2M coordination process.
  - ✓ On three days shown (July 15, 16, & 18), additional flows into PJM would have been economic due to unusual congestion patterns in the West Zone of the NYISO (rather than congestion in PJM).
    - – However, the benefit of using the Ramapo Line to relieve West Zone congestion would have been limited because the effectiveness of Ramapo flow adjustments on West Zone constraints is relatively small.
  - ✓ On two days (July 20 & August 31), additional flows into NY would have been economic due to congestion on TSA constraints. However,
    - – On July 8, charges to PJM from NYISO exceeded $800k.
    - – On July 12, PJM suspended M2M coordination for existing TSA flow gates.
    - – PJM’s suspension of TSA flow gates will diminish the efficiency of congestion management across the two markets.
  - ✓ On two days shown (July 23 & August 21), the benefit of flow adjustments would have been more limited.

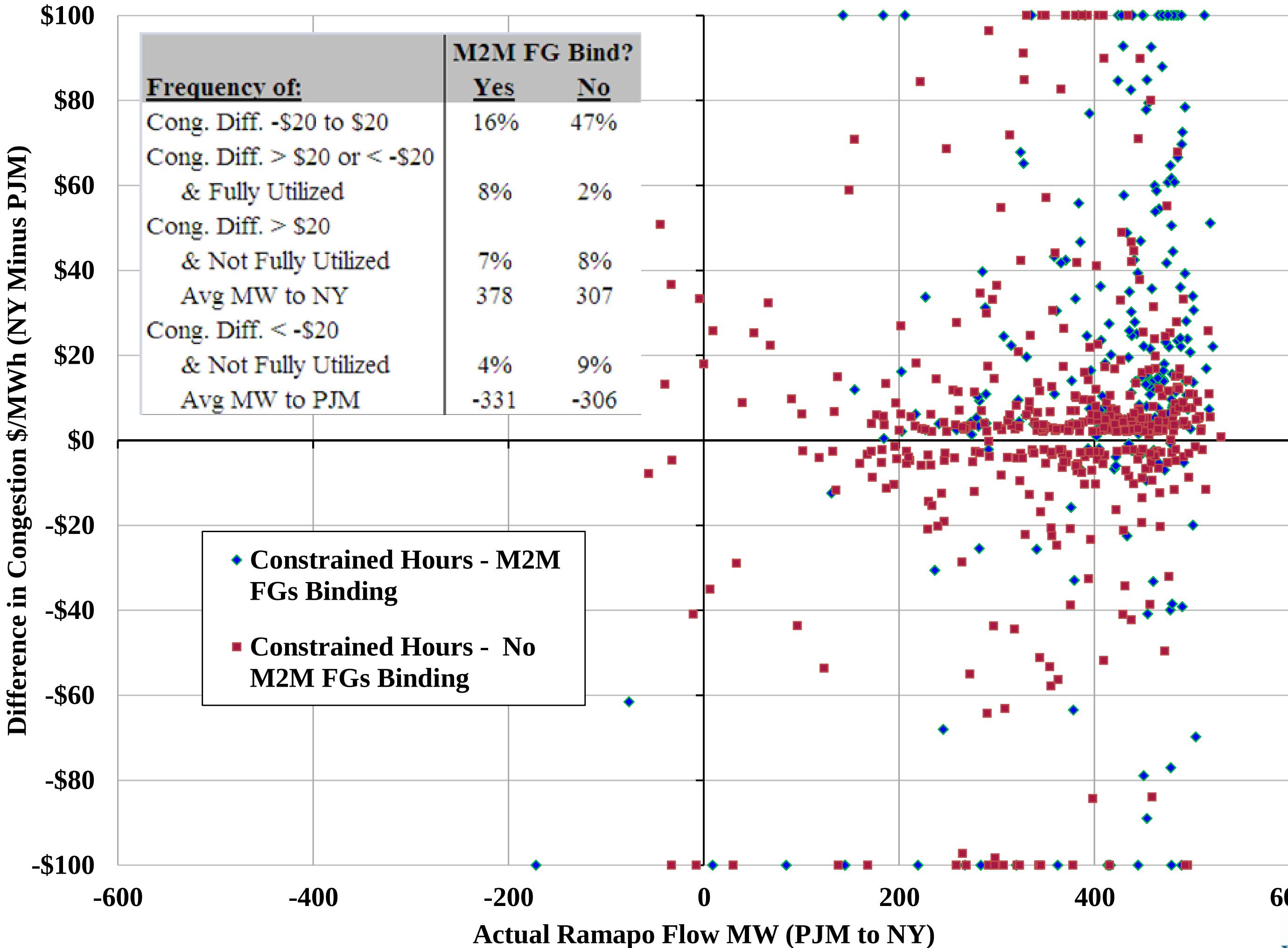
Actual and Target Flows for the Ramapo Line

During the Intervals with Binding M2M Constraints



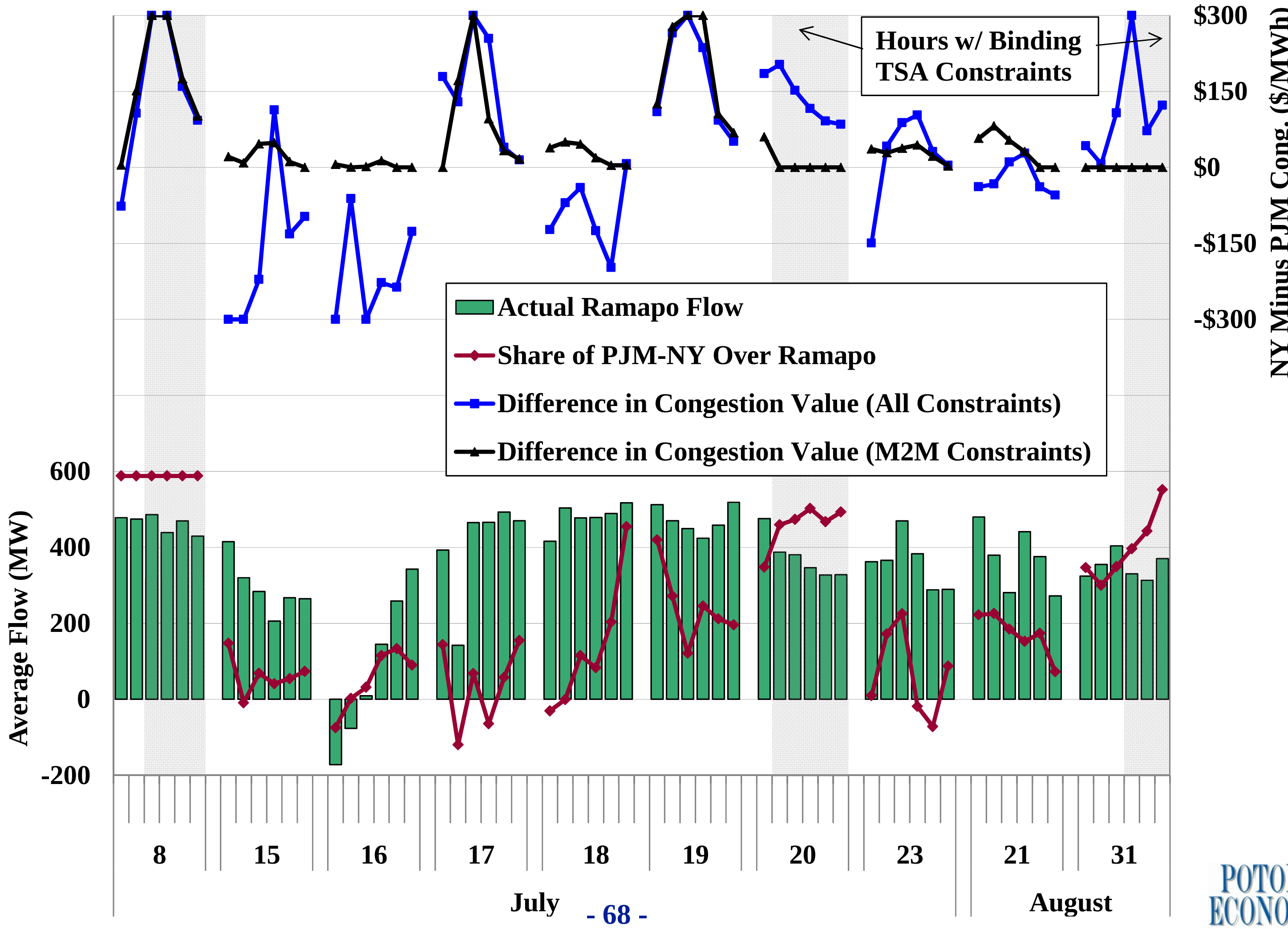
POTOMAC ECONOMICS

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



	M2M FG Bind?	
Frequency of:	**Yes**	**No**
Cong. Diff. -$20 to $20	16%	47%
Cong. Diff. > $20 or < -$20		
& Fully Utilized	8%	2%
Cong. Diff. > $20		
& Not Fully Utilized	7%	8%
Avg MW to NY	378	307
Cong. Diff. < -$20		
& Not Fully Utilized	4%	9%
Avg MW to PJM	-331	-306

Marginal Effect of Ramapo on NY/PJM Congestion and Actual Ramapo Flow – Top 10 Afternoons (HB 14-19)



POTOMAC ECONOMICS

Supplemental Commitments, OOM Dispatch, and Uplift Charges

POTOMAC ECONOMICS

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. (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 for Reliability in NYC

- 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 Results

- An average of 1,065 MW of capacity was committed for reliability in the third quarter of 2013, up 16 percent from the third quarter of 2012.
  - ✓ Of this total, 49 percent of reliability commitment was in NYC, 26 percent was in Long Island, and 25 percent was in Western NY.
- In western NY, reliability commitment averaged 267 MW, down 41 percent from the third quarter of 2012. DARU commitments decreased because:
  - ✓ Several coal units retired that had often been DARUed for local reliability; and
  - ✓ Higher gas prices and increased West Zone congestion led the remaining coal units to be committed economically more often.
- On Long Island, reliability commitment averaged 275 MW, up 66 percent from the third quarter of 2012.
  - ✓ Units needed for local reliability were committed economically less often because of reduced LBMP levels (following the return to normal operation of Neptune).
- In NYC, reliability commitment averaged 520 MW, up 78 percent from the third quarter of 2012.
  - ✓ Steam units that satisfy NOx Bubble constraints were committed economically less often due to lower DAM LBMPs (relative to fuel prices) in NYC. Hence, these units had to be committed for reliability more often.

Supplemental Commitment Results in NYC

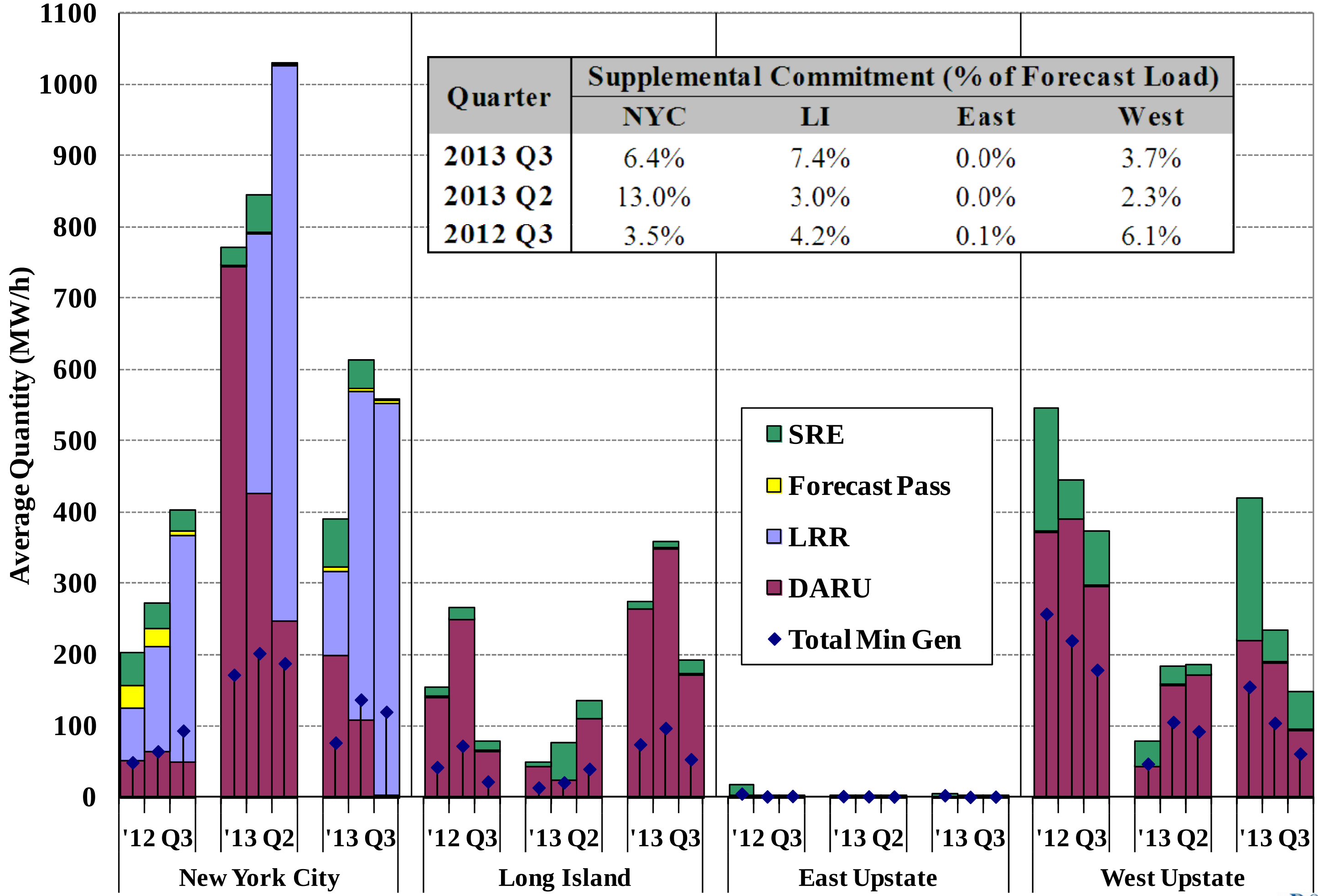
- NOx bubble requirements accounted for most MWhs of reliability commitment (57 percent) in NYC during the third quarter of 2013.
  - ✓ This reliability criteria requires the operation of a steam turbine unit in order to reduce the overall NOx emission rate from a portfolio containing higher-emitting 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 most reliability commitments in NYC.
    - The output from these steam turbine units frequently displaces output from newer cleaner generation in the city and imports to the city.
- The majority of the remaining reliability commitment occurred in the two Astoria West load pockets for both thermal and voltage needs driven partly by high loads and transmission outages.
  - ✓ These reliability requirements ensure that transmission into the pockets will not be overloaded if the largest two contingencies (generation or transmission) occur.

POTOMAC ECONOMICS

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 OOM for 3,090 station-hours, up from 1,070 station-hours in the previous quarter and 1,750 station-hours in the third quarter of 2012.
- NYC accounted for 27 percent of OOM station-hours in the third quarter.
  - ✓ The Narrows and Gowanus GTs accounted for 81 percent of NYC OOM actions.
    - – These occurred primarily in July when the market software was not able to properly model a ring bus split during a transmission outage in the Greenwood area.
    - – A project to correct this problem was not approved for the 2014 Project Plan.
- Long Island accounted for 63 percent of OOM station-hours in the third quarter.
  - ✓ 90 percent of OOM actions occurred in July when high load levels led more units to be called to manage local reliability on the East End of Long Island.
  - ✓ Such units were dispatched economically more often in 2012 (so less OOM dispatch was required then).
- Western NY accounted for 9 percent of OOM station-hours in the third quarter.
  - ✓ This rose modestly in July during high loads and transmission outages.

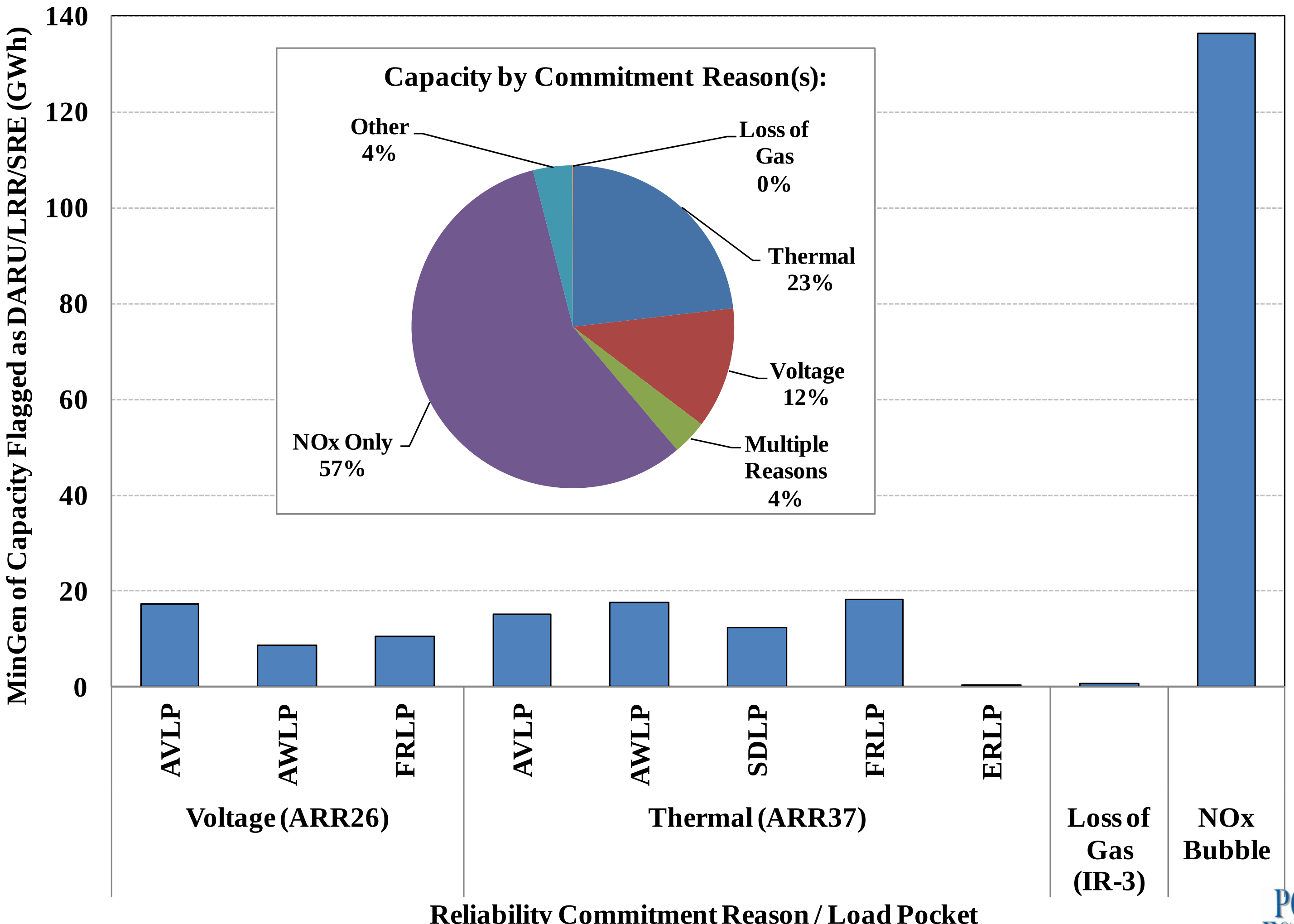
Supplemental Commitment for Reliability
by Category and Region



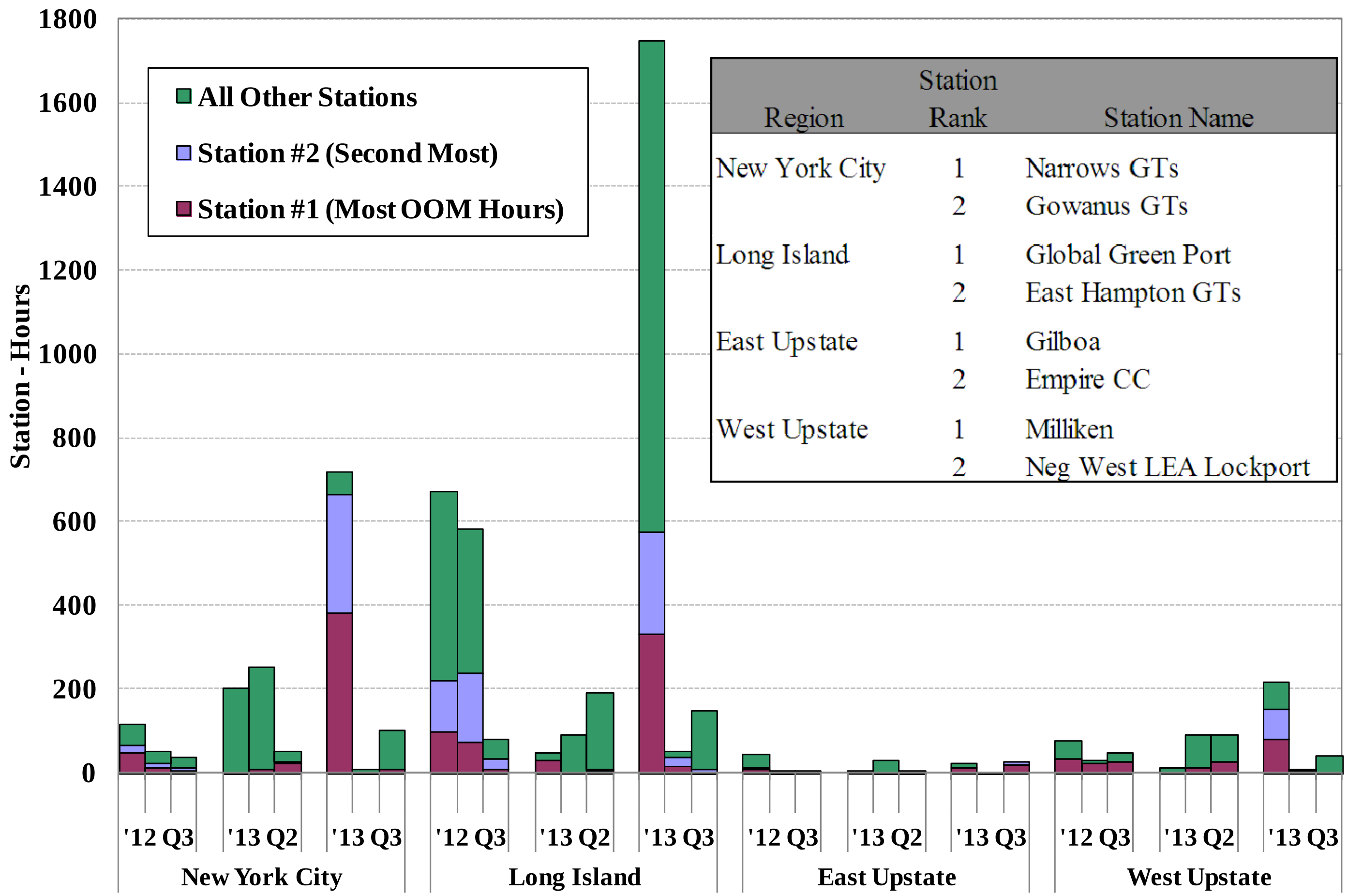
Quarter	Supplemental Commitment (% of Forecast Load)			
	NYC	LI	East	West
2013 Q3	6.4%	7.4%	0.0%	3.7%
2013 Q2	13.0%	3.0%	0.0%	2.3%
2012 Q3	3.5%	4.2%	0.1%	6.1%

POTOMAC ECONOMICS

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



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



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.

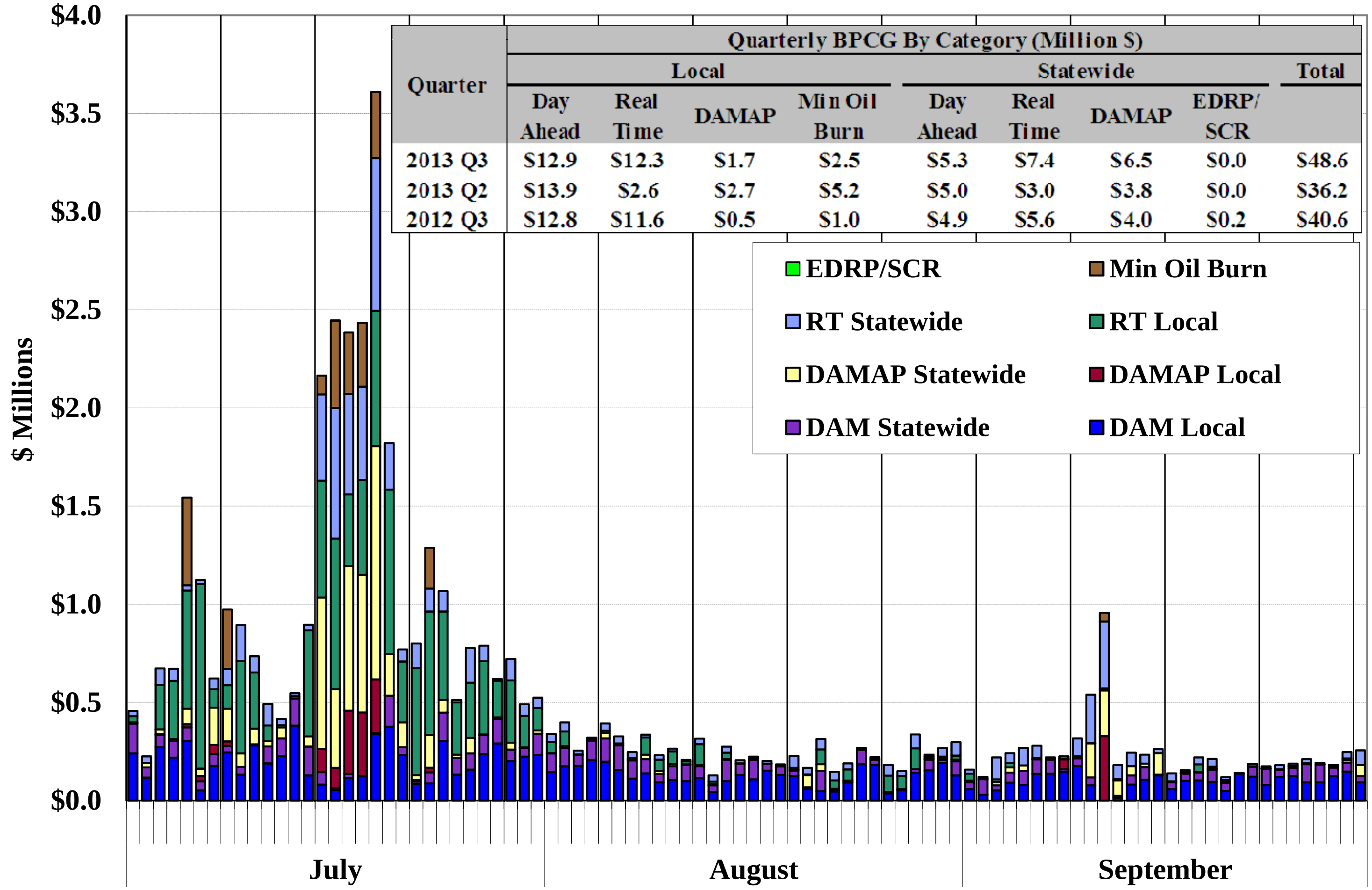
Uplift Costs from Guarantee Payments
Chart Descriptions

- 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 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 $49 million in the third quarter of 2013, up 20 percent from the third quarter of 2012. The most significant contributions were:
  - ✓ More reliability commitment for NOx Bubble constraints in NYC where commitment-related uplift rose by $5.5 million from the third quarter of 2012.
  - ✓ Increased OOM dispatch in Long Island where RT local uplift rose $1.5 million.
  - ✓ Increased OOM dispatch in the Greenwood load pocket (due to the ring bus modeling issue) accounted for $1.0 million of RT statewide uplift.
  - ✓ During high loads from July 15-19, $4.9 million of DAMAP and $5.8 million of RT BPCG uplift accrued. The new Scarcity Pricing rules increased DAMAP and reduced RT BPCG uplift.
- Of the total guarantee payment uplift in the third quarter of 2013:
  - ✓ Local reliability uplift accounted for 60 percent (while non-local was 40 percent).
  - ✓ Long Island accounted for 43 percent, NYC accounted for 32 percent, and Western NY accounted for 18 percent.
- The second figure shows the estimated $10 million in charges from out-of-market payments from National Grid and NYSEG under the Dunkirk and Cayuga RSAs.
  - ✓ These charges are recouped from National Grid and NYSEG customers rather than NYISO customers.

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



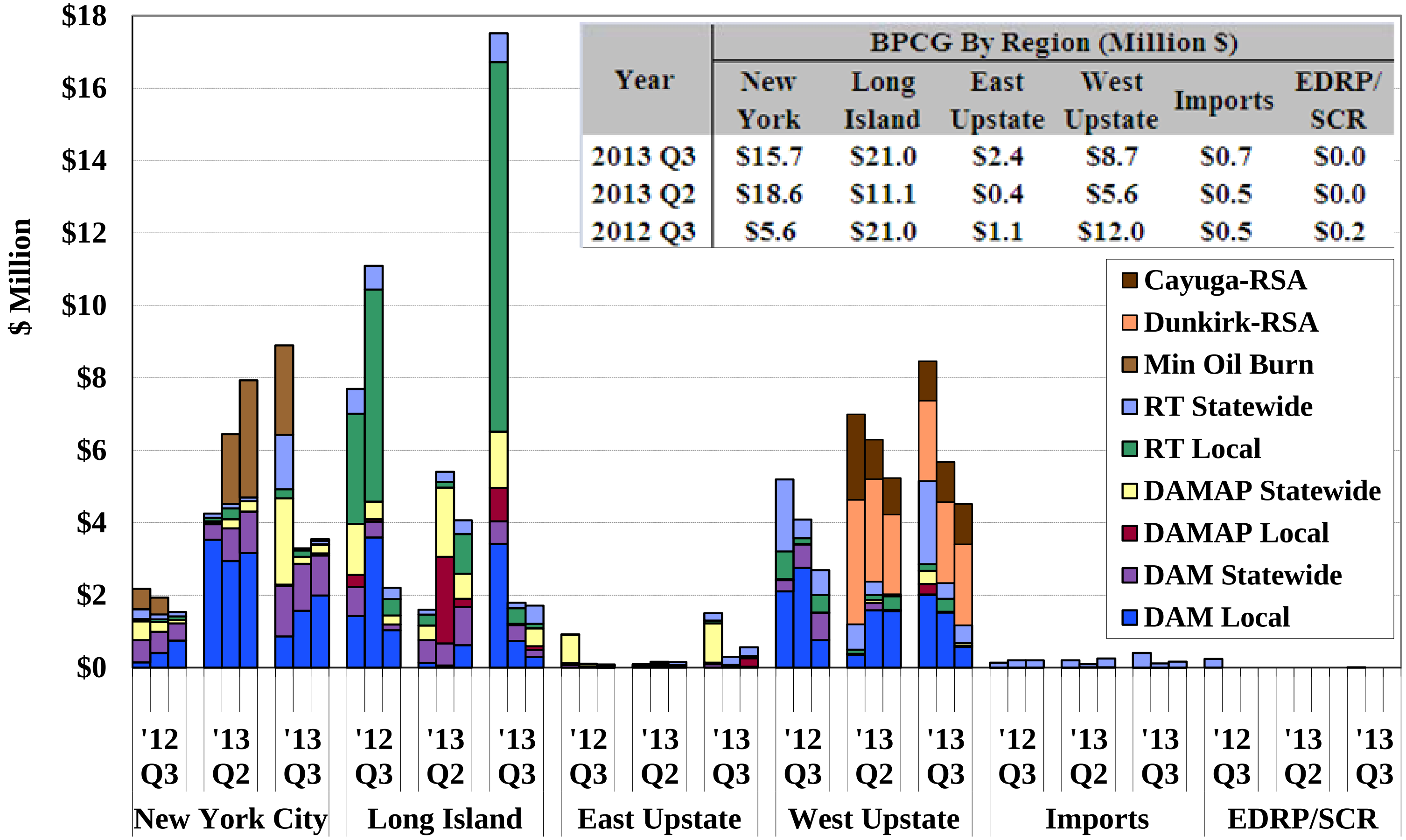
Quarterly BPCG By Category (Million $)

Quarter	Local: Day Ahead	Local: Real Time	Local: DAMAP	Local: Min Oil Burn	Statewide: Day Ahead	Statewide: Real Time	Statewide: DAMAP	Statewide: EDRP/SCR	Total
2013 Q3	$12.9	$12.3	$1.7	$2.5	$5.3	$7.4	$6.5	$0.0	$48.6
2013 Q2	$13.9	$2.6	$2.7	$5.2	$5.0	$3.0	$3.8	$0.0	$36.2
2012 Q3	$12.8	$11.6	$0.5	$1.0	$4.9	$5.6	$4.0	$0.2	$40.6

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.

Uplift Costs from Guarantee Payments & RSAs

By Category and Region



Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2013 Q3	$15.7	$21.0	$2.4	$8.7	$0.7	$0.0
2013 Q2	$18.6	$11.1	$0.4	$5.6	$0.5	$0.0
2012 Q3	$5.6	$21.0	$1.1	$12.0	$0.5	$0.2

Note: 1. Dunkirk and Cayuga RSA charges are recouped from National Grid and NYSEG customers rather than NYISO customers, but they are shown for discussion purposes.
2. 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.

POTOMAC ECONOMICS

Market Power and Mitigation

Market Power Screens: Economic Withholding

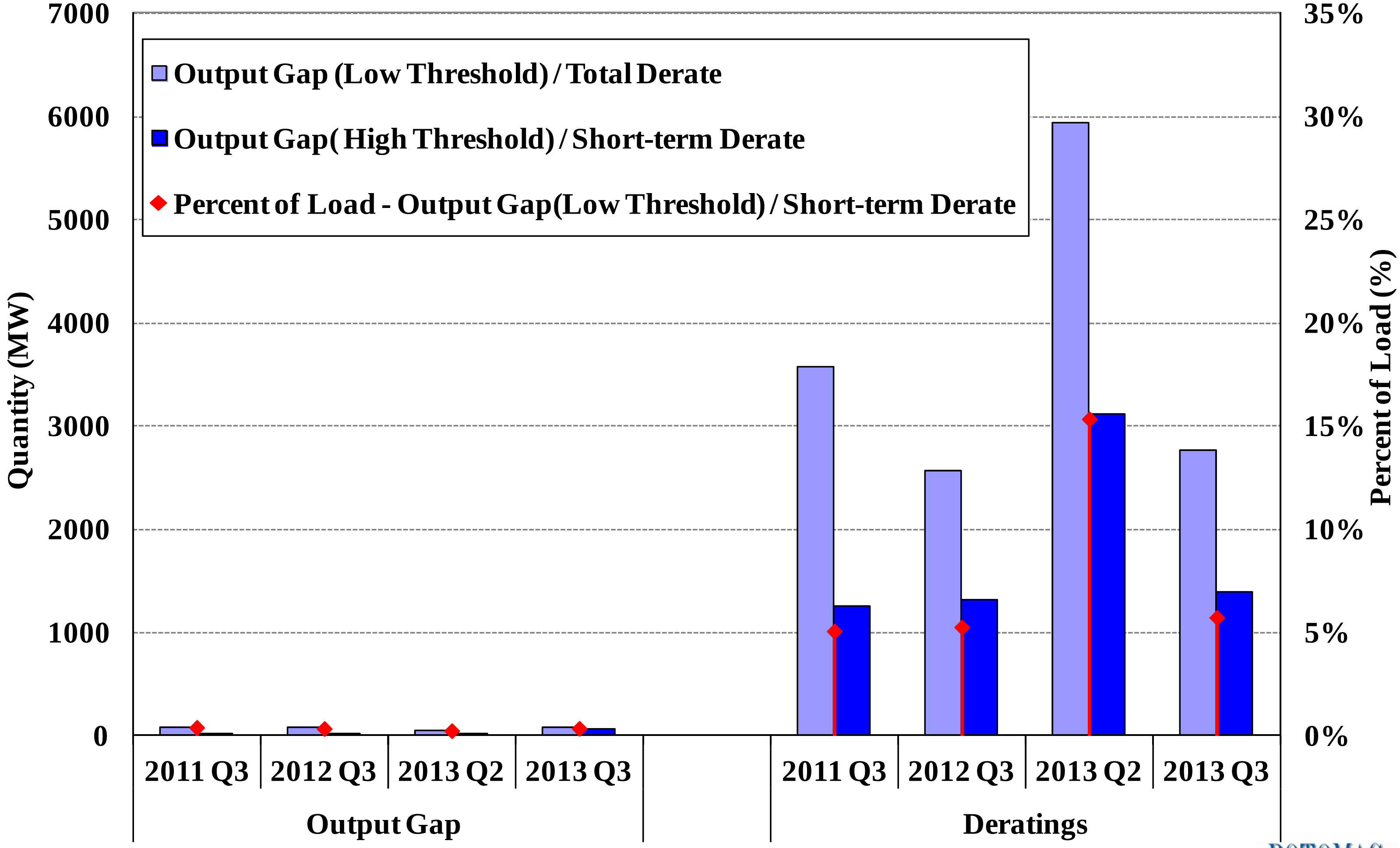
- The next figure shows the results of our screens for attempts to exercise market power, which may include economic withholding and physical withholding.
- The screen for economic withholding is the "output gap", which is the amount of economic capacity that does not produce energy because a supplier 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 consistent with prior quarters.
  - ✓ 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.
  - ✓ The amount of short-term deratings across the state in the third quarter of 2013 were consistent with the same quarters in the prior years.

POTOMAC ECONOMICS

Market Monitoring Screens



POTOMAC ECONOMICS

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.

		2011 Q3	2012 Q3	2013 Q2	2013 Q3
Day-Ahead Market	**Average Mitigated MW**	417	64	167	152
	Energy Mitigation Frequency	54%	12%	14%	41%
Real-Time Market	**Average Mitigated MW**	48	19	2	7
	Energy Mitigation Frequency	19%	7%	1%	3%

Automated Market Mitigation

- Most mitigation occurs in the DAM, since that is where most supply is scheduled.
  - ✓ In the third quarter of 2013, 96 percent of mitigation occurred in the DAM primarily for:
    - – Local reliability (i.e., DARU & LRR) units (56 percent), and
    - – The Greenwood/Staten Island load pocket (22 percent).
- DA mitigation rose from the third quarter of 2012 primarily because:
  - ✓ Congestion into the Greenwood/Staten Island load pocket rose in the third quarter of 2013 because of transmission outages, leading to more frequent mitigation in that area.
  - ✓ Reliability commitment for NOx Bubble constraints rose in New York City, leading to more frequent mitigation of local reliability commitments.
  - ✓ The Neptune Cable fully returned to service in early July 2013, contributing to lower LBMPs. This reduced the economic commitment of generation and increased the need to DARU commitment in the third quarter.

Capacity Market

POTOMAC ECONOMICS

Capacity Market Results

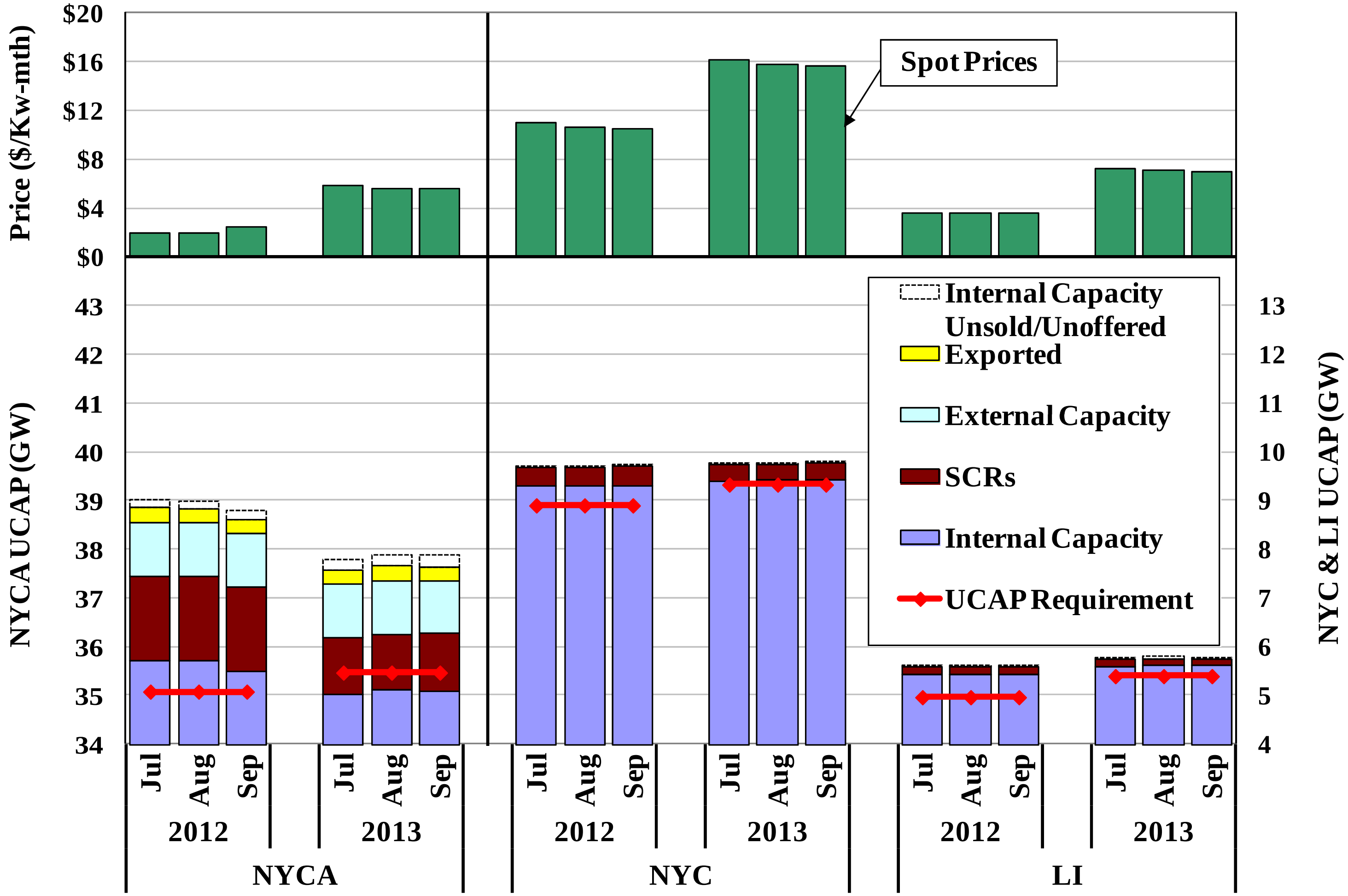
- The following figure summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices in each capacity zone.
  - ✓ UCAP is a measure of installed capacity that accounts for forced outage rates.
- NYCA UCAP spot prices averaged \$5.68/kW-month this quarter, up from \$2.09/kW-month in the third quarter of 2012 because:
  - ✓ Internal capacity sales fell 1 GW following the retirement and mothballing of:
    - 370 MW in Western NY in September 2012;
    - 500 MW in Hudson Valley in January 2013; and
    - 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 570 MW from the summer of 2012 due to a combination of increased auditing of resources, attrition, and changing market conditions.

Capacity Market Results

- In NYC, UCAP spot prices averaged $15.85/kW-month this quarter, up from $10.69/kW-month in the third quarter of 2012.
  - ✓ The ICAP requirement rose 332 MW primarily due to a 3 percent increase in the Local Capacity Requirement ("LCR").
    - – The increased LCR resulted primarily from the loss of generating capacity in the Hudson Valley, which requires more capacity in downstate areas for the UPNY-SENY interface.
    - – However, this was partly offset by increased emergency energy assistance from the new HTP Line.
- On Long Island, UCAP spot prices averaged $7.10/kW-month this quarter, up from $3.57/kW-month in the third quarter of 2012.
  - ✓ The Long Island ICAP requirement increased 320 MW primarily because the LCR rose from 99 percent to 105 percent (for reasons discussed above).

POTOMAC ECONOMICS

Capacity Market Results



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