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

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the first 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.
- High and volatile gas prices, particularly in Eastern NY where gas prices rose 124 to 131 percent from the previous year, were a key driver of market outcomes.
  - ✓ Real-time energy prices averaged $65/MWh statewide, up 95 percent from a year ago. Besides the effects of higher gas prices, LBMPs also increased because:
    - Average load levels rose by 500 MW due to colder weather;
    - Net exports to New England rose by 1 GW due to higher gas prices there; and
    - Several transmission outages increased LBMPs in Long Island.
  - ✓ Day-ahead congestion revenue increased from $52 million to $320 million primarily because gas price spreads between eastern and western NY led to high levels of Central-East congestion.
  - ✓ Production from oil-fired units rose 600 percent because of limited gas supplies. Consequently, oil-fired units were on the margin in 7 percent of intervals, up from 2 percent in the first quarter of 2012.
  - ✓ Convergence between DA and RT energy prices worsened in most areas, particularly during periods of volatile gas prices, extreme weather, and gas pipeline OFOs.

Highlights and Market Summary: Energy Market in Winter Peak Conditions

- Supply of natural gas was tight during the winter due to increased demand for heating, leading to high and volatile gas prices. During the week of January 20-26:
  - ✓ Electricity production from gas in eastern NY fell to an average of just 4.1 GW due to limited supply, down 21 percent from the average for the quarter; and
  - ✓ Electricity demand peaked at the highest level in five winters.
  - ✓ Consequently, production from oil in eastern NY (which normally averages less than 100 MW) rose to an average of 2.8 GW on January 24.
- The liquid gas trading day for January 20-22 occurred on January 18, making it difficult for some generators to obtain gas after being scheduled in the day-ahead and real-time markets.
- Nonetheless, the widespread use of oil during the week indicates that the market performed relatively well in conserving the available supply of natural gas.
  - ✓ However, congestion into NYC was exacerbated on several days when the interface was derated due to uncertainty regarding the fuel supply of some units.
- Substantial amounts of dual-fueled capacity in eastern NY was burning gas or scheduled for operating reserves or not committed (8 GW or more), suggesting that the existing resources are currently sufficient to satisfy system needs under extreme winter operating conditions.

Highlights and Market Summary: Energy Market Enhancements

- The NYISO implemented two market enhancements in January 2013.
- First, coordination of congestion management between PJM and NY ("M2M"):
  - ✓ *Redispatch Coordination* was activated for the Central-East interface for 150 hours and had relatively limited impacts on congestion management.
  - ✓ *Ramapo PAR Coordination* was used to manage high levels of congestion across the Central-East interface on most days during the quarter.
    - – Actual flows across the Ramapo line generally ranged from 500 MW to the limit of 1000 MW to relieve Central-East congestion, but after February 4, flows held close to 500 MW in most hours because of a partial outage of the line.
      - Consequently, the interchange was often shifted to the ABC and JK lines.
    - – Despite the derating, the Ramapo PAR coordination has been valuable in lowering the cost of managing congestion across the Central-East interface.
- Second, two DAM mitigation provisions were revised on January 23, which raised: (a) the reference cap of 10-min non-spin reserves from $2.52 to $5; and (b) the offer cap of 10-min spin reserves for NYC generators from $0 to $5.
  - ✓ The resulting changes in offer patterns did not raise withholding concerns; and
  - ✓ The changes seem to facilitate better price convergence, which improved from last year despite higher and more volatile natural gas prices.

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Highlights and Market Summary: Capacity Market

- In Rest of State, UCAP spot prices averaged $2.74/kW-month in the first quarter of 2013, up substantially from the same quarter of last year because:
  - ✓ 1.8 GW of generation retired or was mothballed since last year.
  - ✓ The NYCA ICAP requirement rose more than 800 MW from the 2011/12 Capability Year to the 2012/13 Capability Year because of:
    - A 1.8 percent increase in the peak load forecast; and
    - An increase in the IRM from 15.5 percent to 16 percent.
  - ✓ Sales from SCRs fell nearly 400 MW following recent changes in the baseline calculation method and auditing of resources.
- In NYC, UCAP spot prices averaged $4.91/kW-month this quarter, comparable to the first quarter of 2012.
  - ✓ From December 2012 to March 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 were equal to Rest of State prices in each month of the two quarters because of the substantial excess capacity on Long Island in the winter.

Highlights and Market Summary: Uplift and Revenue Shortfalls

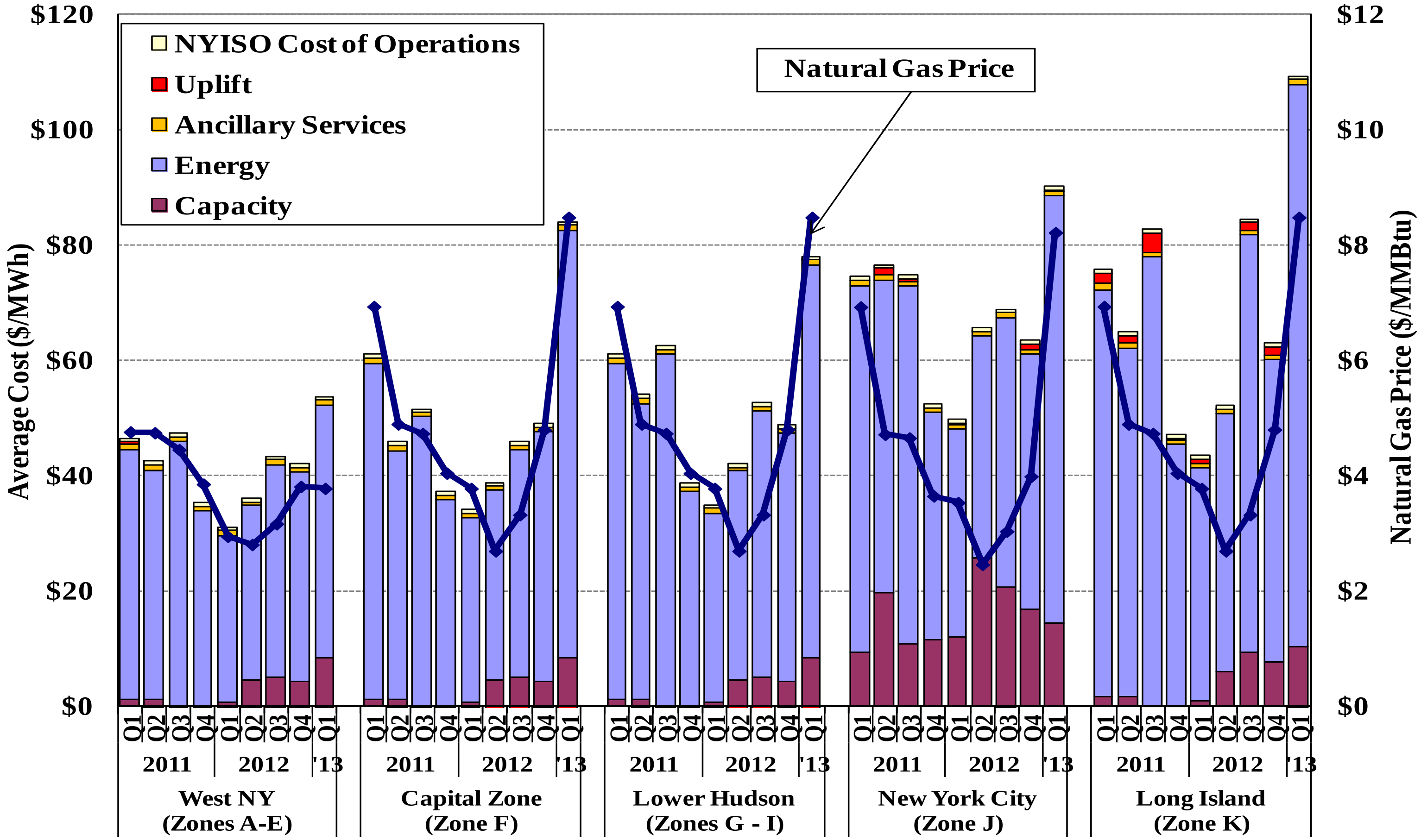
- Higher and volatile natural gas prices were a primary driver of increases for all categories of uplift in the first quarter of 2013 from a year ago.
- The uplift from guarantee payments totaled $50 million, up 78 percent from the first quarter of 2012.
  - ✓ Daily uplift costs were correlated with the variation of natural gas prices -- the highest uplift costs occurred during periods of very high gas prices.
  - ✓ However, the increase was offset by decreased reliability commitment in downstate areas, particularly in Long Island.
- Day-ahead congestion shortfalls were $22 million, up $15 million from a year ago.
  - ✓ Lines into New York City and Long Island accounted for the majority of the shortfalls primarily due to transmission outages.
  - ✓ This was partly offset by $20 million in total surpluses generated at the Central-East interface and the primary NE-NY interface.
- Balancing congestion shortfalls totaled *negative* $10 million (i.e., a surplus), compared to a shortfall of $3 million in the first quarter of 2012.
  - ✓ The surplus resulted primarily from changes in modeling assumptions related to the NY-NJ PAR-controlled lines under M2M and frequent up-rates of the Central-East interface.

Energy and Ancillary Services Markets

All-In Price

- To summarize costs in the New York markets, the following figure shows the "all-in" price that represents the total cost of serving load, including:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component based on spot prices times capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges.
- Average all-in prices ranged from roughly $52/MWh in West NY to $109/MWh on Long Island, up substantially from the first quarter of 2012.
  - ✓ Energy prices rose 51 percent in West NY and 107 to 141 percent in East NY, consistent with the increases in gas prices. LBMPs also increased because:
    - – Average load levels rose by 500 MW due to colder weather;
    - – Net exports to New England rose by 1 GW due to high gas prices there; and
    - – Several transmission outages that increased LBMPs in Long Island.
  - ✓ The capacity component rose moderately in NYC and more substantially elsewhere, primarily because:
    - – ICAP requirements increased in NYC (by 220 MW) and NYCA (by 840 MW);
    - – Sales of internal capacity decreased due to retirements and mothballs (550 MW in NYC, 330 MW on Long Island, 370 MW in Western NY, and 500 MW in Hudson Valley).

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.

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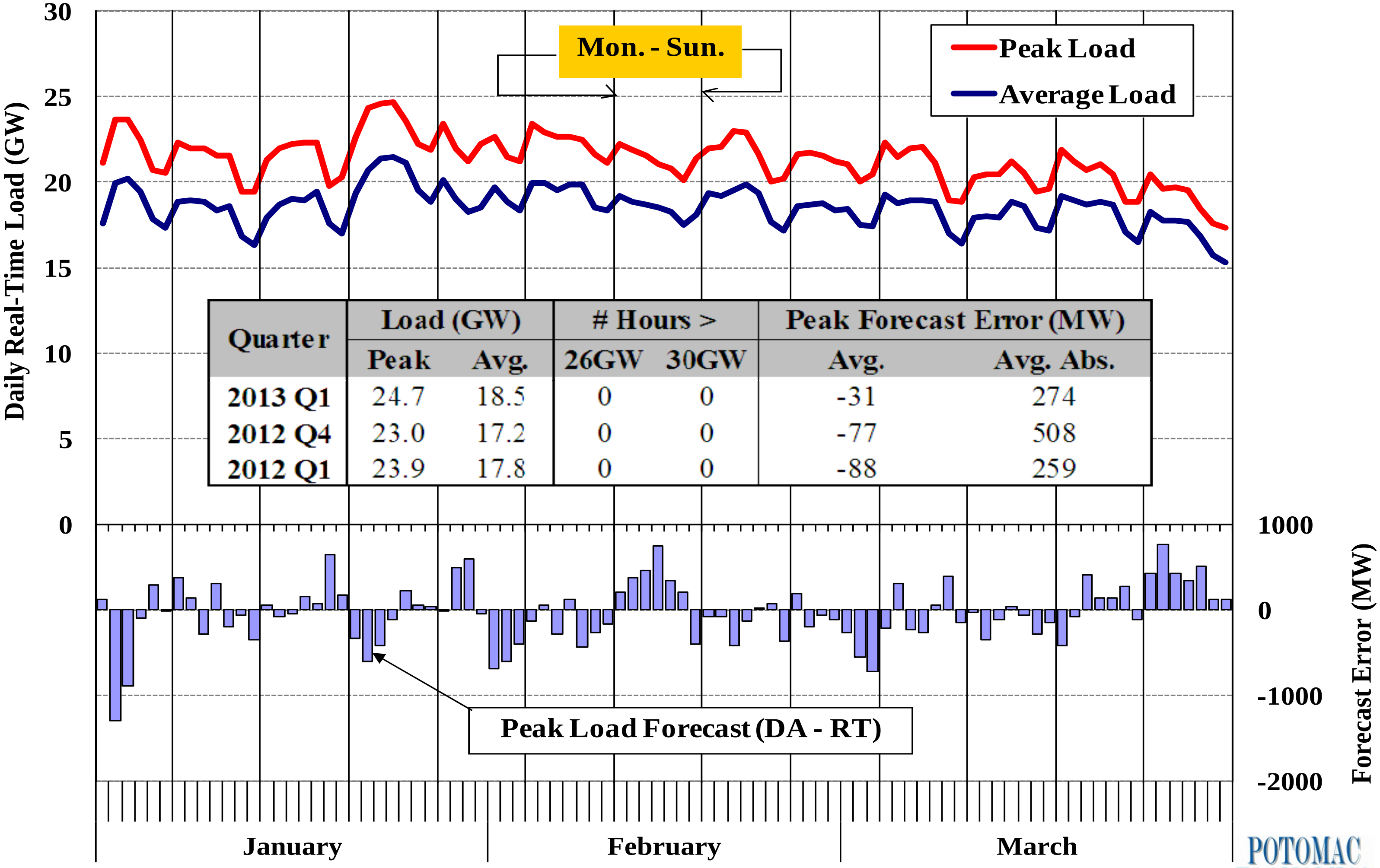
Load Forecast and Actual Load

- The following figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The table compares key statistics for the first quarter of 2013 to the previous quarter and the first quarter of 2012.
- Load rose from the previous quarter, consistent with seasonal patterns, and rose substantially from the first quarter of 2012 when the weather was unusually mild.
  - ✓ Load averaged 18.5 GW in the first quarter of 2013, up 7 percent from the previous quarter and 3 percent from the first quarter of 2012.
  - ✓ Load peaked on January 24 at 24.7 GW, which was up 4 percent from a year ago and was the highest winter peak in the past five years.
  - ✓ Overall, load trended down from January to March as expected.
- Peak load forecasting was generally good during the quarter.
  - ✓ The daily peak load forecast error exceeded 500 MW on 12 days and 1 GW on one day (January 2).
  - ✓ On average, actual daily peak loads were relatively consistent with the daily peak forecasts.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2013 Q1	24.7	18.5	0	0	-31	274
2012 Q4	23.0	17.2	0	0	-77	508
2012 Q1	23.9	17.8	0	0	-88	259

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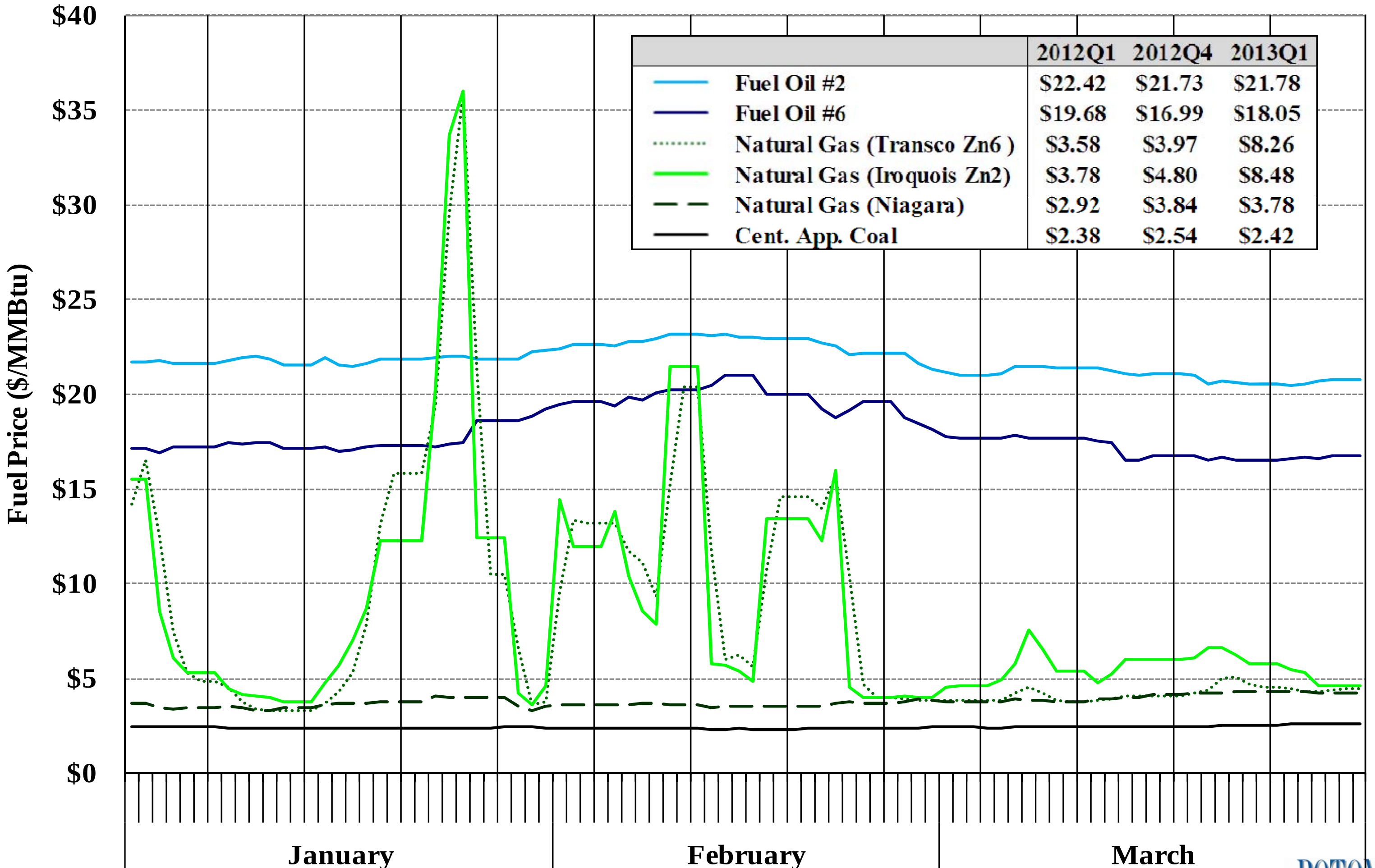
Natural Gas and Oil Prices

- The following figure shows daily natural gas and fuel oil prices, which are key determinants of electricity prices.
- Natural gas prices were high and volatile in the first quarter of 2013, especially in Eastern New York during January and February.
  - ✓ Gas prices rose considerably from the first quarter of 2012 – 30 percent in West NY, 131 percent in NYC, and 124 percent in East upstate and Long Island.
  - ✓ Gas prices were higher and more volatile in Eastern NY, peaking at $36/MMbtu and exceeding #2 oil prices on six days (January 23-25 & February 9-11).
  - ✓ Large price spreads between Eastern and Western NY on many days increased the cost of generation in Eastern NY and led to frequent Central-East congestion.
  - ✓ Large price spreads between Eastern NY and New England led to much higher levels of exports to New England than in previous years.
- Fuel oil prices and coal prices were much more stable than natural gas prices in the first quarter of 2013.
- On the days when natural gas was significantly cheaper than fuel oil, some generators may still burn oil due to: a) reliability reasons, b) difficulties obtaining natural gas, or c) unavailability of pipeline capacity.

Natural Gas and Oil Prices



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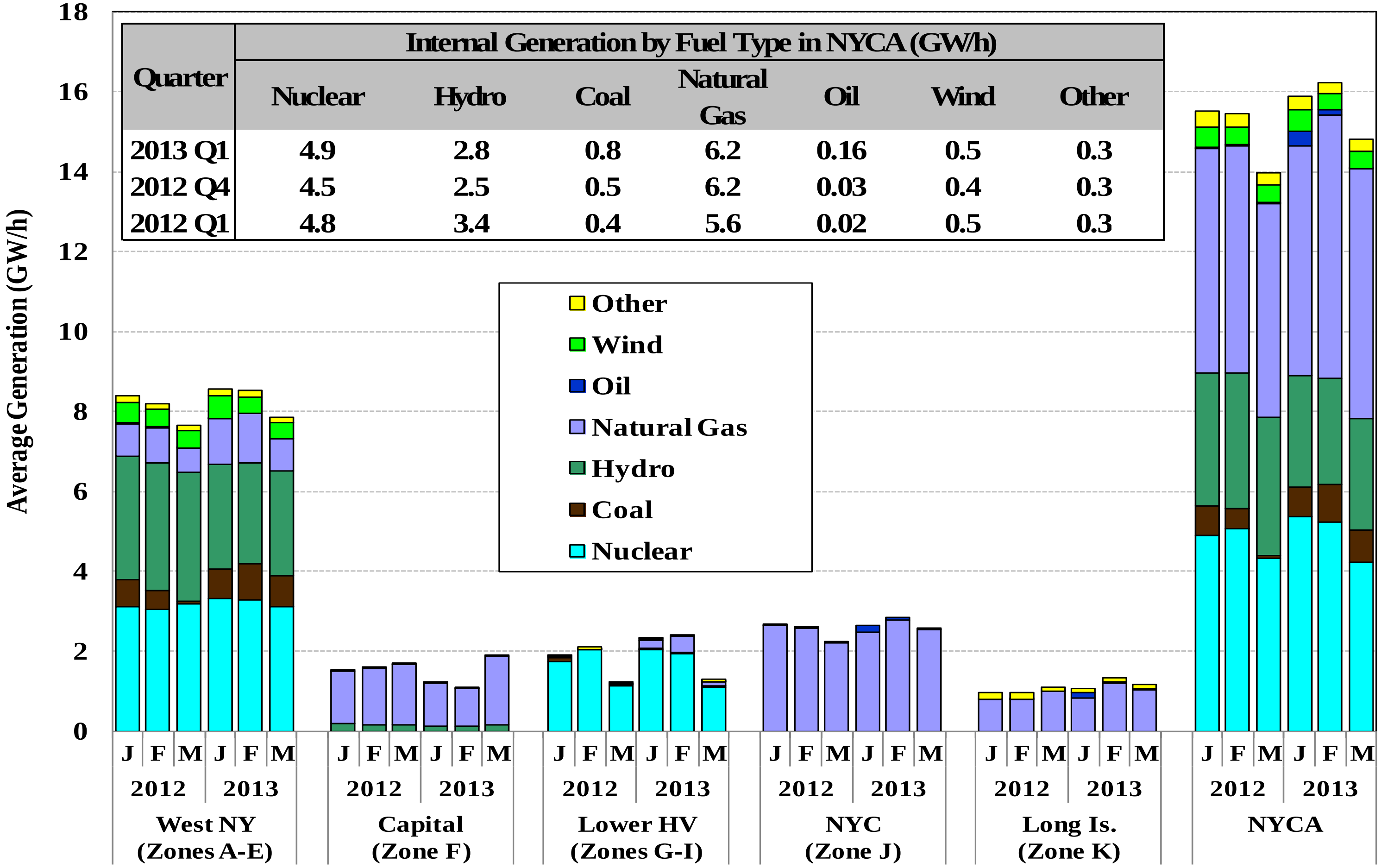
Generation Output by Fuel Type

- The following figure shows the quantities of generation by fuel type in each region of New York in the first quarter of 2013.
- Total generation rose 600 MW from the first quarter of 2012 due to higher loads and increased exports to New England.
- Nuclear units (which account for just 14 percent of total installed capacity) accounted for 32 percent of all production.
- Hydro resources accounted for 18 percent of production, down 600 MW from the previous year.
- Gas-fired generation accounted for 39 percent of production, up from the previous year due to the addition of new capacity in NYC, reduced hydro production, and increased exports to New England.
- Production from coal units and oil-fired resources rose in the first quarter, due to higher gas prices, which led these resources to be economic more frequently.
  - ✓ Coal production averaged roughly 825 MW, up 400MW from a year ago.
  - ✓ Oil production averaged 160 MW, up 140 MW from a year ago.
- Wind units and other renewable resources produced about 5 percent of output in New York, comparable to prior quarters.

Generation Output by Fuel Type

Quarter	Internal Generation by Fuel Type in NYCA (GW/h)						
	Nuclear	Hydro	Coal	Natural Gas	Oil	Wind	Other
2013 Q1	4.9	2.8	0.8	6.2	0.16	0.5	0.3
2012 Q4	4.5	2.5	0.5	6.2	0.03	0.4	0.3
2012 Q1	4.8	3.4	0.4	5.6	0.02	0.5	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

- The following figure summarizes how frequently each fuel type is on the margin and setting real-time energy prices.
  - ✓ The fuel type for each generator is based on actual fuel consumption reported to the EPA and EIA.
- 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.
- The figure shows how frequently each fuel type is on the margin in NYCA and in each region of the state.
  - ✓ When no unit is on the margin in a particular region, the LBMPs in the 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.

Fuel Types of Marginal Units in the Real-Time Market

- Natural gas and hydro resources set prices in large shares of the intervals.
  - ✓ Natural gas fueled resources were on the margin in 81 percent of the intervals, up modestly from the previous year.
  - ✓ Hydro resources (primarily in Western NY) set the prices in 48 percent of the intervals, comparable to a year ago.
    - Some hydro resources have storage capability, allowing them to offer price-sensitively based on the opportunity cost of foregoing sales at another time.
    - Hence, their opportunity costs are heavily dependent on natural gas prices.
- Natural gas prices rose substantially from prior periods, leading other fuel types to set prices more frequently in the first quarter of 2013.
  - ✓ Coal production (primarily in Western NY) was on the margin in 18 percent of the intervals, up from 10 percent a year ago.
  - ✓ Oil production (primarily in NYC and Long Island) was on the margin in 7 percent of the intervals, up substantially from typical levels (~1 to 2 percent).
- Wind units set prices (primarily in the North Zone) much more frequently in the first quarter, largely due to increased export-congestion from the North Zone.
  - ✓ Additional wind capacity was placed in the North Zone in the past year.

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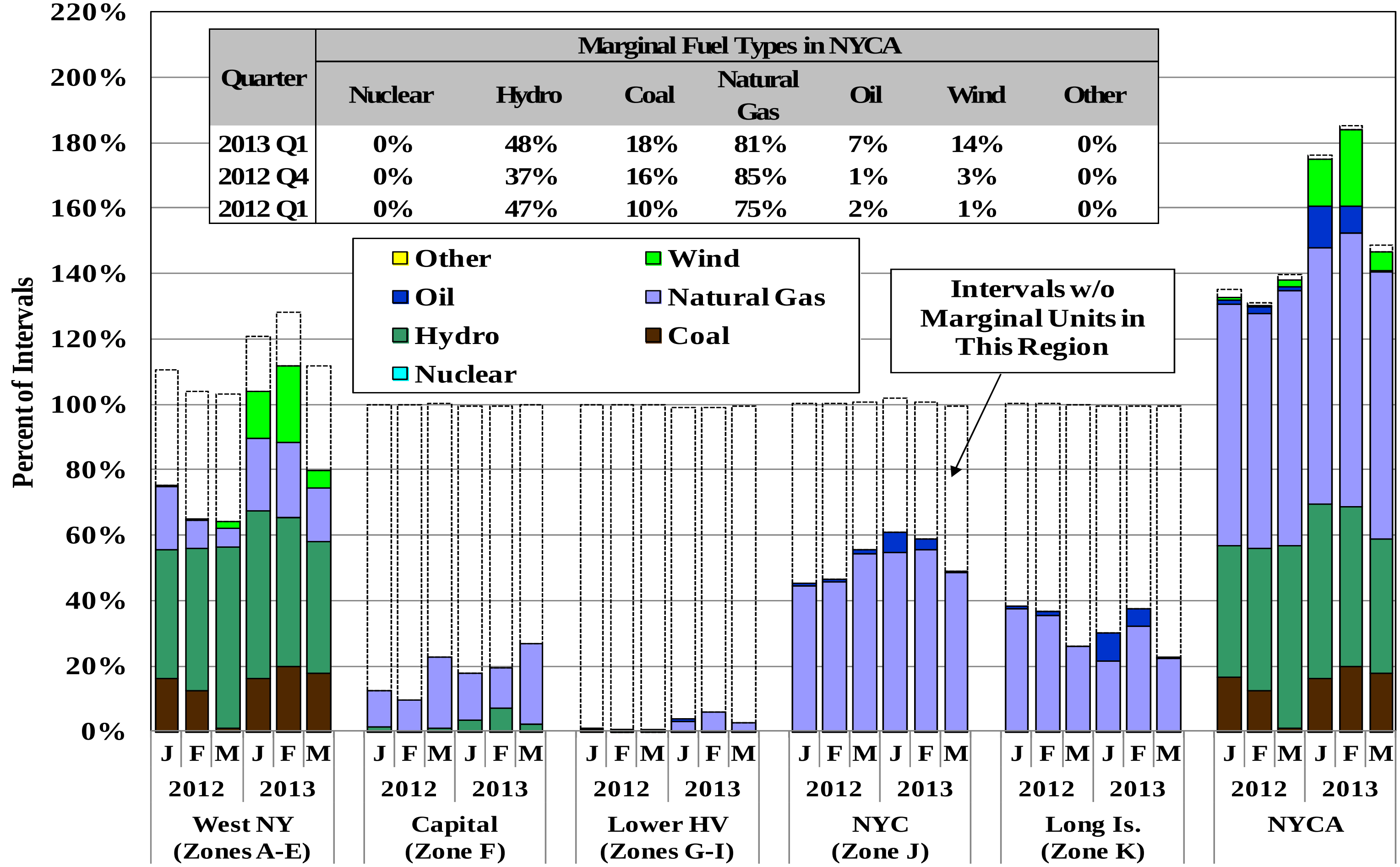
Fuel Types of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Natural Gas	Oil	Wind	Other
2013 Q1	0%	48%	18%	81%	7%	14%	0%
2012 Q4	0%	37%	16%	85%	1%	3%	0%
2012 Q1	0%	47%	10%	75%	2%	1%	0%

Notes: “Other” includes Methane, Refuse, Solar & Wood.

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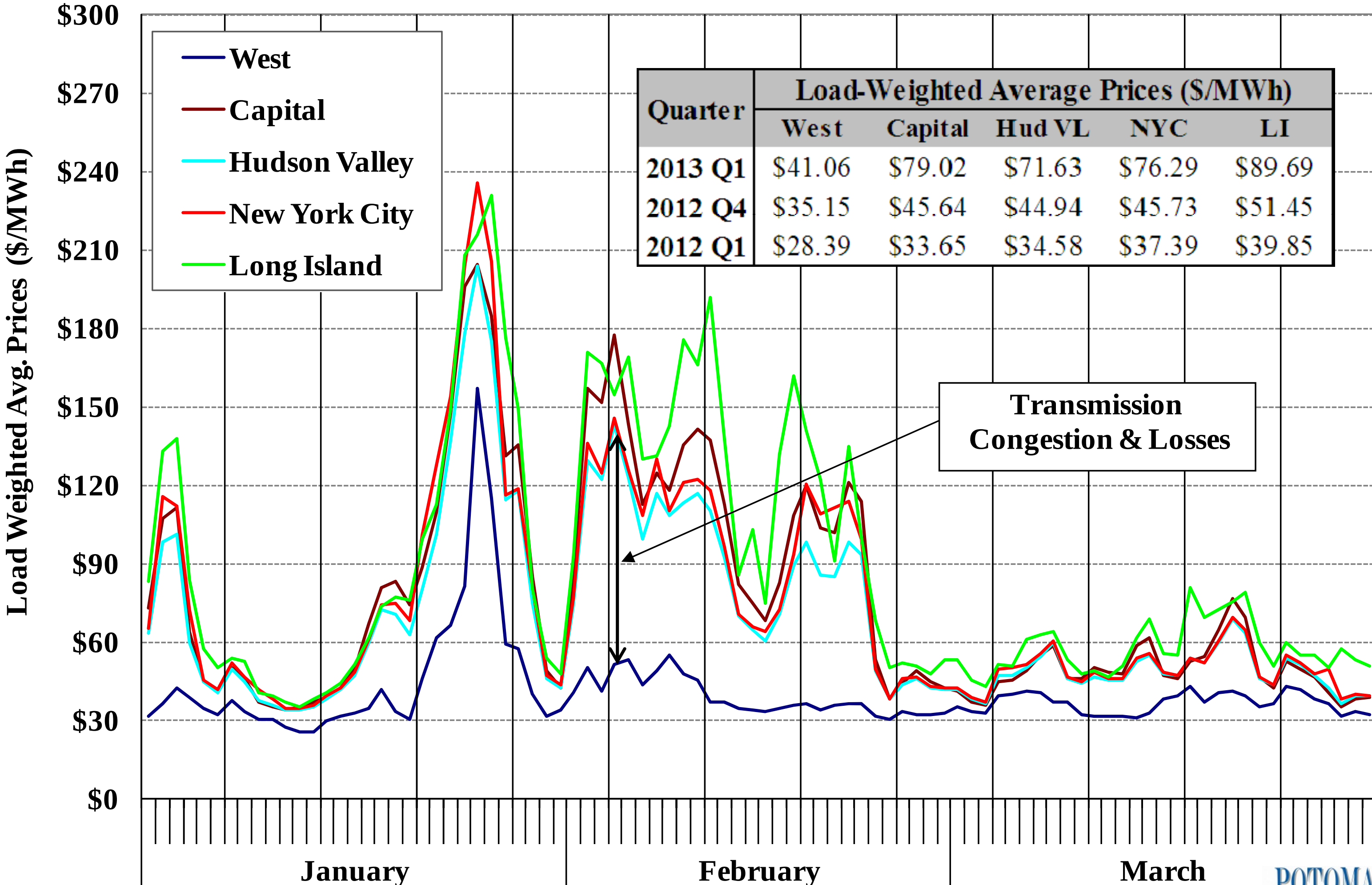
Day-Ahead and Real-Time Electricity Prices by Zone

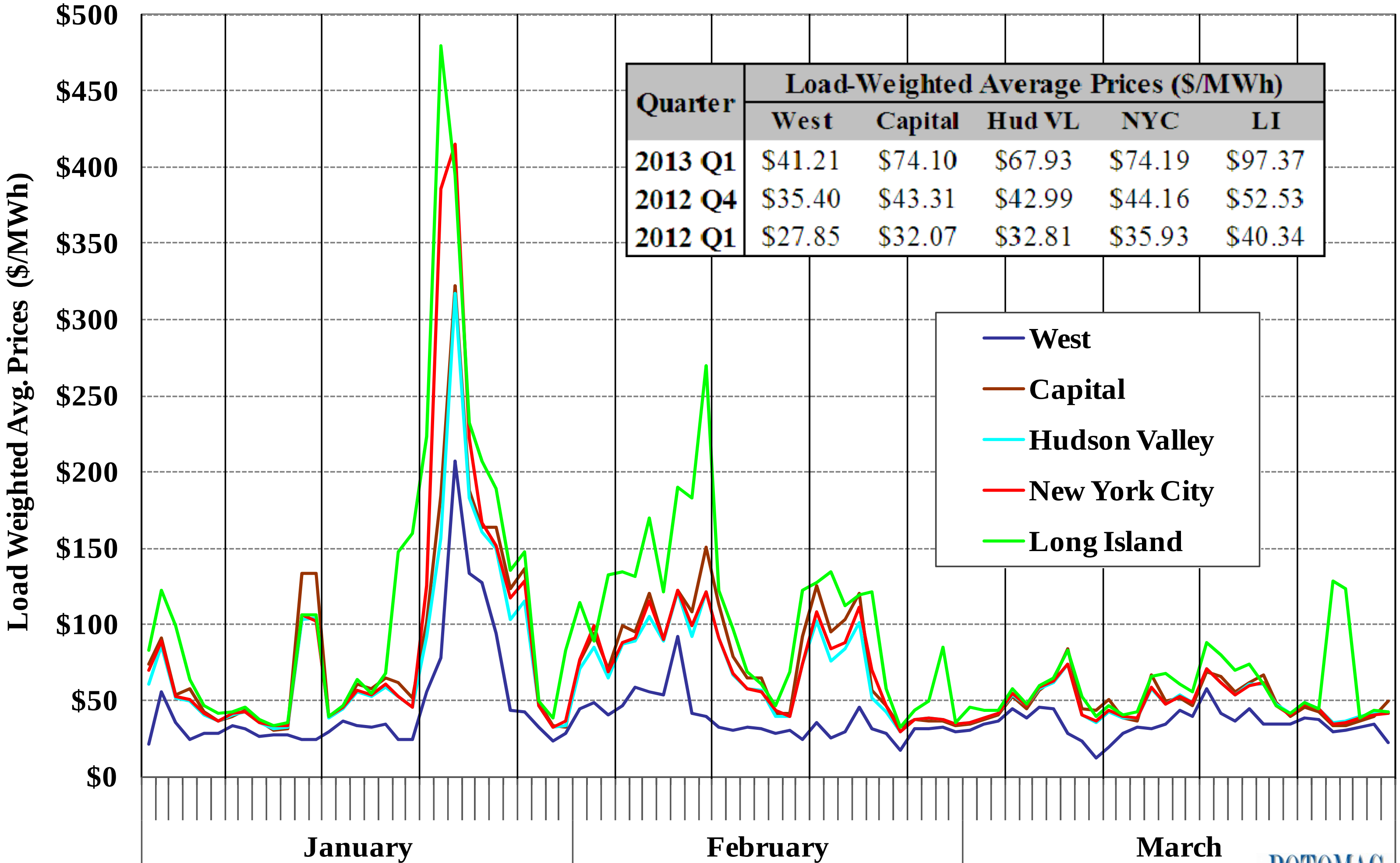
- The following two figures show load-weighted average DA and RT energy prices for five zones on each day in the first quarter of 2013.
  - ✓ DA prices should reflect probability-weighted expectations of RT conditions.
- Average DA prices ranged from $41/MWh in the West Zone to $90/MWh on Long Island, up 45 percent from the first quarter of 2012 in the West Zone and 104 to 135 percent in the other four zones. Higher LBMPs were driven by:
  - ✓ Higher gas prices, which closely tracked DA prices on a daily basis;
  - ✓ Increased exports to New England in January and February, which rose by an average of 1 GW due to higher natural gas prices there.
  - ✓ Increased load levels, which rose 3 percent; and
  - ✓ Lengthy transmission outages in Long Island, especially the partial Neptune outage (since May 2012) and the Dunwoodie-to-Shore Rd outage (February).
- Prices are more volatile in the RT than in the DAM due to unexpected events.
  - ✓ Unexpectedly high natural gas prices combined with significant DA under-scheduling of load led to very high RT prices from January 19-23.
  - ✓ Long Island prices spiked on March 27 & 28 due to an unexpected outage of one 345 kV transmission line into Long Island.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2013 Q1	$41.06	$79.02	$71.63	$76.29	$89.69
2012 Q4	$35.15	$45.64	$44.94	$45.73	$51.45
2012 Q1	$28.39	$33.65	$34.58	$37.39	$39.85

Real-Time Electricity Prices by Zone



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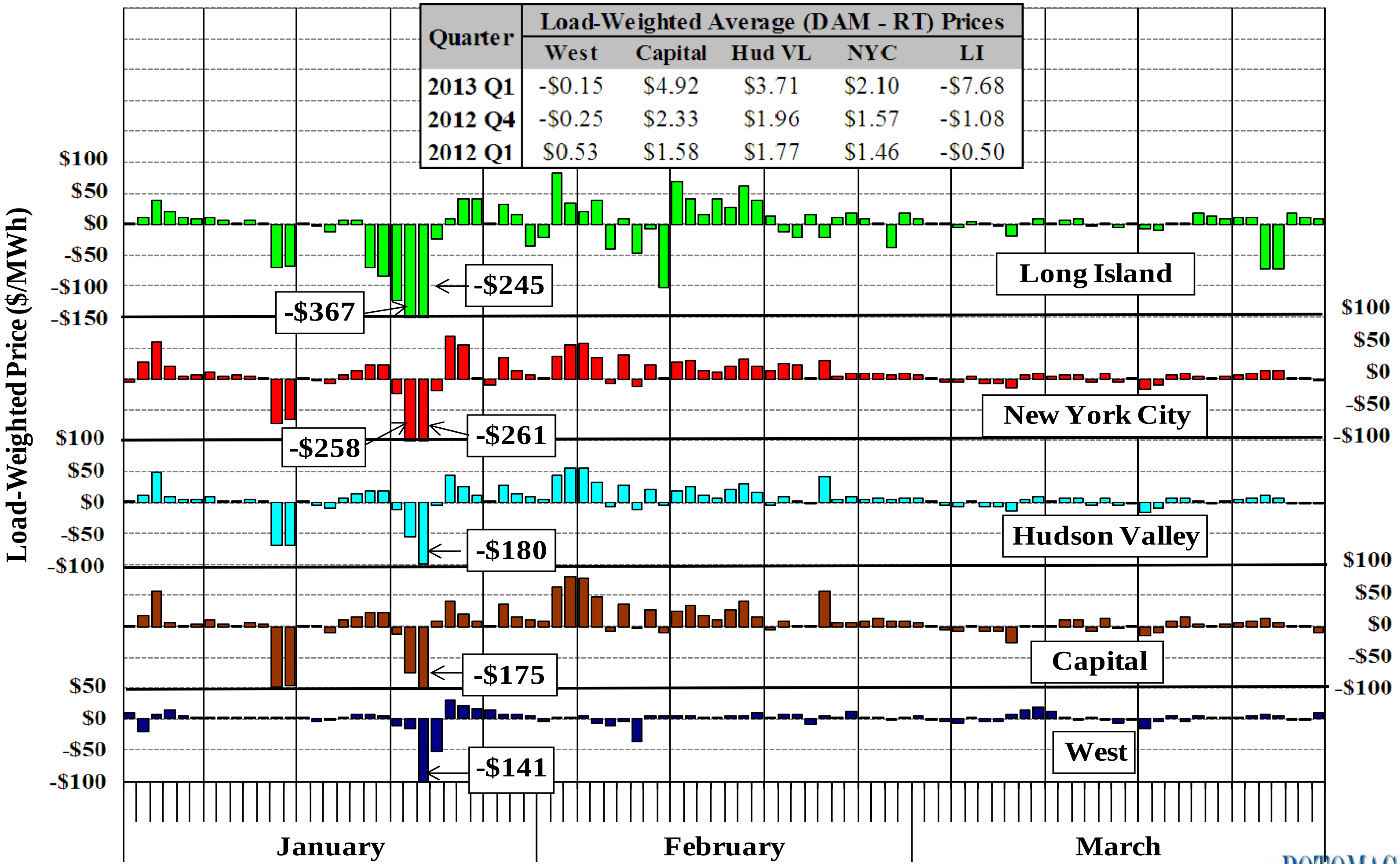
Convergence Between Day-Ahead and Real-Time Prices

- The next analysis evaluates DA and RT price convergence.
  - ✓ 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.
- The figure shows the difference between average DA prices and the average RT prices on each day in the first quarter of 2013.
  - ✓ 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.
- Convergence between DA and RT prices worsened from previous quarters as a result of more volatile natural gas prices. DA-to-RT price differentials were:
  - ✓ Large in Eastern NY in January and February when gas prices were volatile; and
  - ✓ Particularly large from January 19-27 due to volatile gas prices, extreme weather, interstate and LDC pipeline OFOs, and the limited timing of gas market trading.
    - – Differences between the timing of liquid gas trading and the NYISO DAM contribute to cost uncertainty for electricity suppliers.
    - – This was particularly apparent following the holiday weekend (January 19-21). The "day-ahead" gas market for January 22 occurred on January 18.

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2013 Q1	-$0.15	$4.92	$3.71	$2.10	-$7.68
2012 Q4	-$0.25	$2.33	$1.96	$1.57	-$1.08
2012 Q1	$0.53	$1.58	$1.77	$1.46	-$0.50

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Fuel Usage under Tight Gas Supply Conditions

- Supply of natural gas was unusually tight in the winter season due to increased demand for heating, often leading to high and volatile gas prices.
  - ✓ Gas prices were higher and more volatile in the first two months of the quarter due to extreme weather conditions on many days.
  - ✓ This had a big impact on the system operations, especially in eastern New York.
- The following three figures summarize the generation and commitment pattern by fuel type in Long Island, NYC, and east upstate during a one-week period in January when the gas prices were the highest and the most volatile in the quarter.
  - ✓ The figures show the actual generation for the following categories:
    - Oil-fired units (including oil-only and dual-fuel units);
    - Gas-fired dual-fuel units (i.e., units capable of burning oil);
    - Gas-fired gas-only units; and
    - All other fuel types (e.g., hydro, nuclear, and other renewable).
  - ✓ In addition, the figures show excess generating capacity from:
    - Online and offline quick-start capacity (excluding gas-only units); and
    - Slow-start units not committed in the DAM (excluding gas-only units).

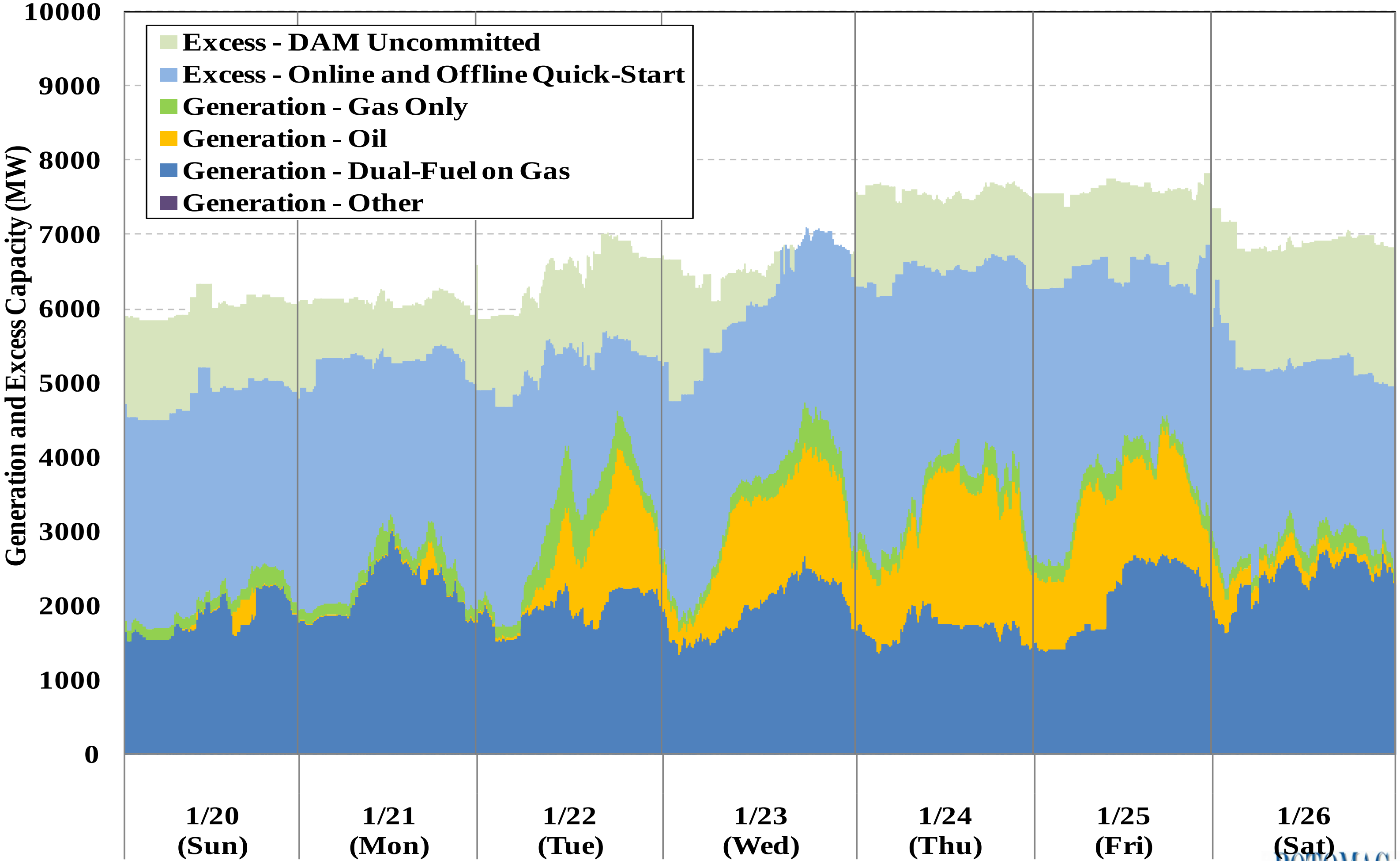
Fuel Usage under Tight Gas Supply Conditions January 20 – 26

- Gas supply to electric generators was limited by high demand of other customers.
  - ✓ Total production from gas in eastern NY averaged 4.1 GW from January 20-26, down 21 percent from the average during the first quarter.
- A large share of generators in eastern NY have dual-fuel capability, allowing them to switch to an alternate fuel when gas becomes expensive or unavailable.
  - ✓ Gas supplies were limited, day-ahead gas prices peaked at $36/MMbtu, and OFOs were in effect on multiple pipelines for most of the week.
  - ✓ Production from oil (which normally averages less than 100 MW) rose significantly during the week. On individual days during the week, production from oil averaged:
    - 50 MW to 1,520 MW in NYC;
    - 10 MW to 990 MW in Long Island; and
    - 0 MW to 330 MW in Eastern Upstate.
- Substantial amounts of dual-fueled capacity in eastern NY was burning gas or scheduled for reserves or not committed, suggesting that existing resources are sufficient to satisfy system needs under extreme winter operating conditions.
  - ✓ However, toward the end of the week, some dual-fueled capacity was derated after their inventory of oil was used from operating earlier in the week.

Fuel Usage under Tight Gas Supply Conditions January 20 – 26

- Substantial amounts of oil was used on three days when “day-ahead” gas prices were lower than oil prices (January 21-22 & 26).
  - ✓ “Day-ahead” gas prices for January 21-22 were determined on January 18 before the 3-day weekend.
  - ✓ The widespread use of oil on these days suggests that the day-ahead gas prices ($12-16/MMbtu in Eastern NY) were lower than the actual cost of gas.
  - ✓ DAM prices were not high enough to recoup the cost of oil-fired generation from January 21-22, which tends to undermine incentives for suppliers to be available.
- Nonetheless, the widespread use of oil indicates that the market performed relatively well in conserving the available supply of natural gas.
  - ✓ However, severe congestion into NYC for 37 hours from January 21-24 was exacerbated when several gas-only generators with spinning reserve and non-spinning reserve capability were derated due to a lack of fuel supply.
    - – Due to the lack of available reserves, the interface into NYC was operated under a tighter criteria that reduced overall imports (to hold reserves on the interface).
    - – Hence, the lack of fuel supply for several units led to an increase in the overall fuel consumption within NYC.

Generation and Excess Capacity by Fuel Type:
New York City, January 20 – 26



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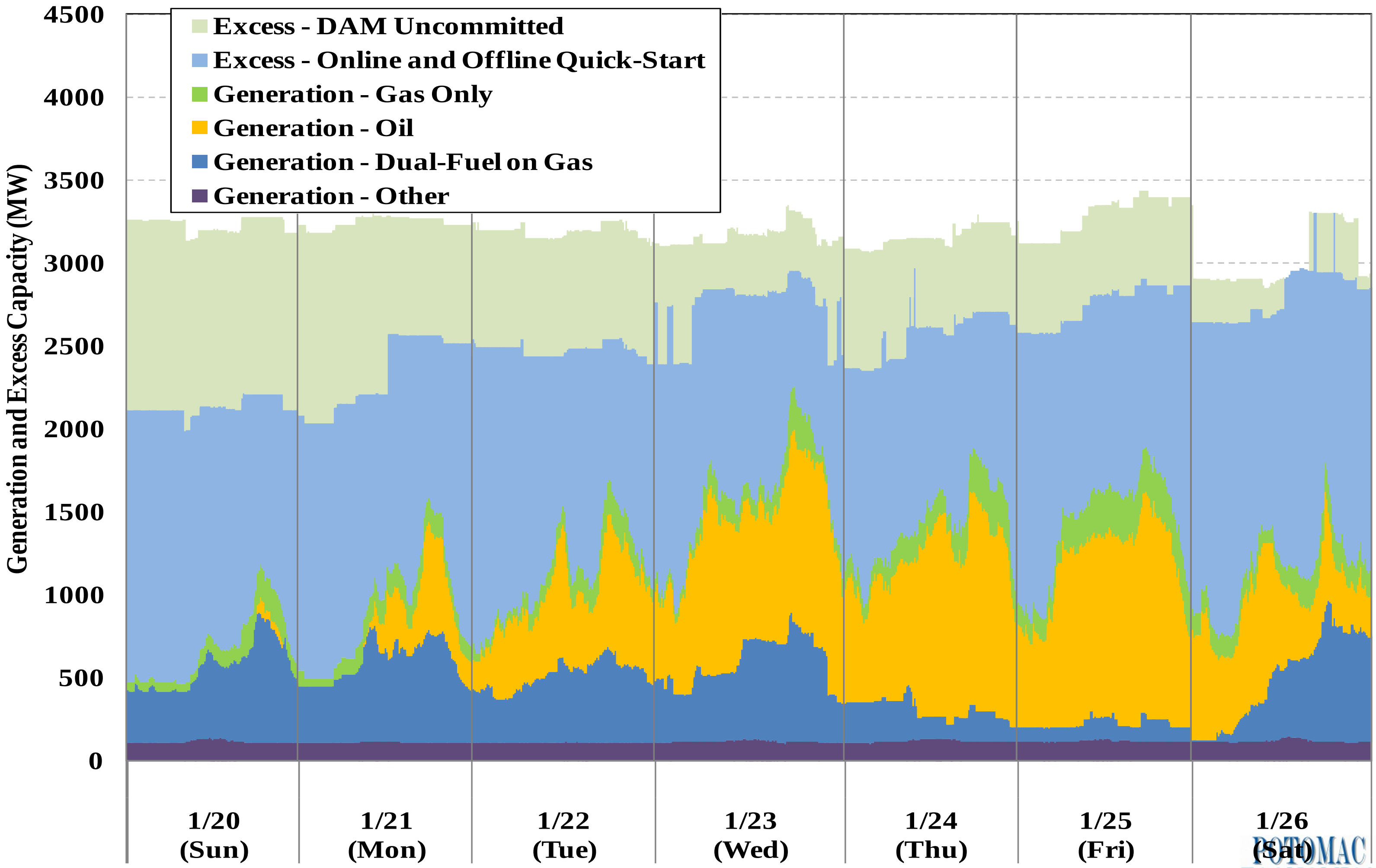
Generation and Excess Capacity by Fuel Type: Long Island, January 20 – 26



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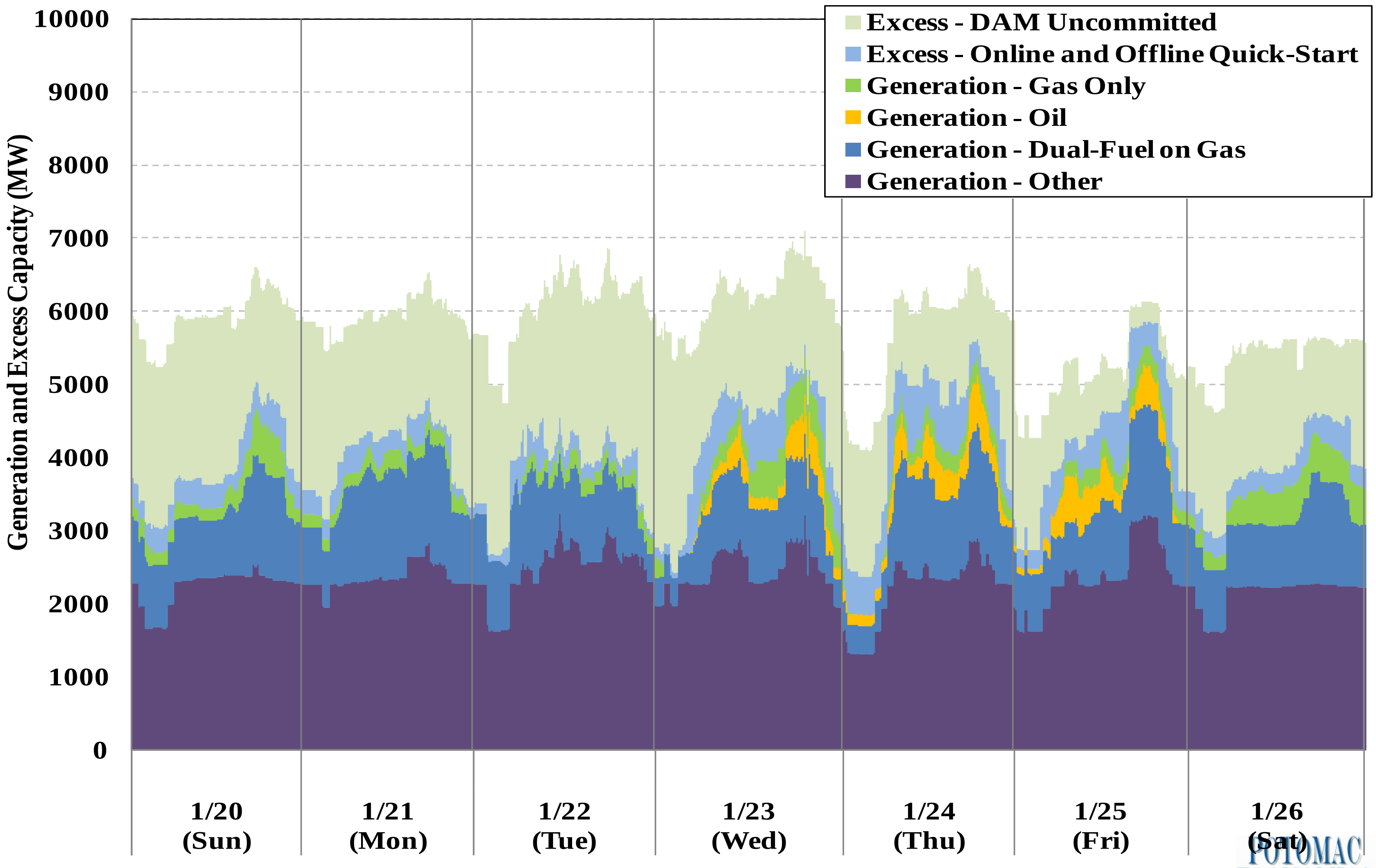
Generation and Excess Capacity by Fuel Type: East Upstate, January 20 – 26



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Day-Ahead and Real-Time Ancillary Services Prices

- The following two figures summarize average day-ahead and real-time clearing prices on a daily basis for four key ancillary services products:
  - ✓ 10-minute 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-minute 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-minute 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 of requiring up to 275 MW of regulation, depending upon season and time of day.
- The table in each figure shows the number of intervals when the real-time reserve price of the product was affected by a shortage of reserves.
  - ✓ During shortages, the prices of products that can satisfy the given requirement will include the "demand curve" value of the requirement.

Day-Ahead and Real-Time Ancillary Services Prices

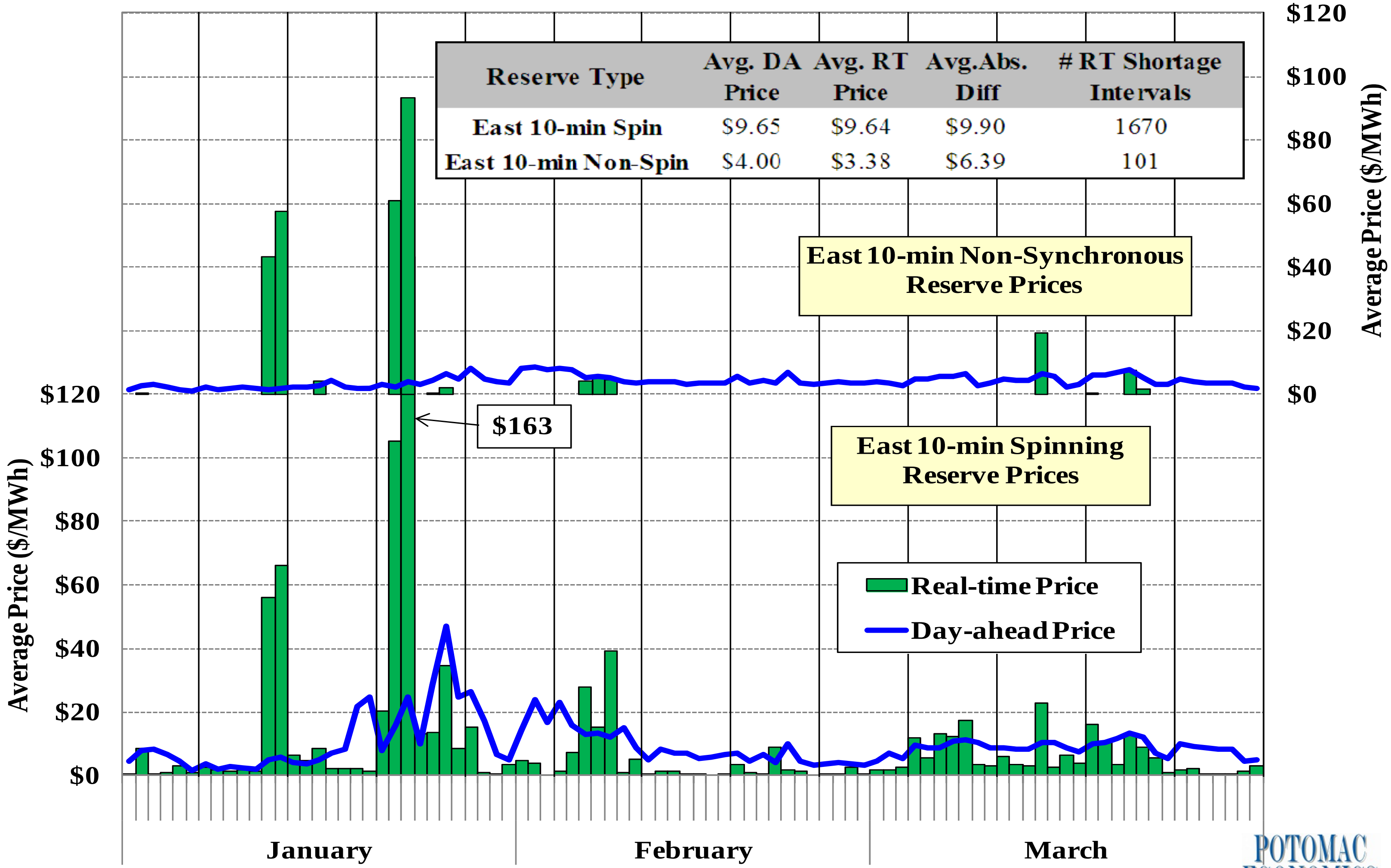
- Reserve prices are relatively consistent in the day-ahead market, but are much more volatile in the real-time market.
  - ✓ DAM reserves prices are based on suppliers' offers, which depend on expectations of real-time prices and the risks associated with selling reserves in the DAM.
  - ✓ Real-time reserves prices are normally close to $0 because of the excess available reserves from online and quick-start units in most hours.
  - ✓ Real-time prices can rise sharply during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Average day-ahead prices were relatively consistent with average real-time prices in eastern NY for 10-minute spinning and non-spinning reserves in the first quarter.
  - ✓ Convergence between day-ahead and real-time prices improved from prior years.
    - Changes in day-ahead operating practices improved the consistency of energy and reserves schedules between the day-ahead and real-time for some units.
    - Changes in mitigation provisions also contributed to the improvement (which are discussed in detail later).
- Average day-ahead prices were higher than average real-time prices for 10-minute spinning reserves in western NY and for regulation in the first quarter of 2013.

Day-Ahead and Real-Time Ancillary Services Prices

- A shortage occurs when a reserve requirement cannot be satisfied at a marginal cost less than its “demand curve”. Shortages occurred in real-time for:
  - ✓ Eastern 10-minute spinning reserves in 1,557 intervals ($25 demand curve), which is approximately 6 percent of all intervals during the quarter;
  - ✓ Eastern 10-minute total reserves in 101 intervals ($500 demand curve);
  - ✓ Statewide 10-minute spinning reserves in 12 intervals ($500 demand curve); and
  - ✓ Regulation in 717 intervals ($80 to $400 demand curve).
- Prices for a product include the demand curve value for all requirements that the product can satisfy.
  - ✓ For example, the 10-minute spinning reserve prices in eastern NY reflect 1,670 intervals of shortage pricing: 1,557 of eastern 10-minute spin, 101 of eastern 10-minute total reserves, and 12 of state-wide 10-minute spin.
- Eastern 10-minute total reserve shortages occurred on ten days in the first quarter of 2013. Roughly 80 percent occurred on four days (January 12-13 & 22-23).
  - ✓ Unexpected congestion across the Central-East interface and restrictions on natural gas supply resulted in very tight operating conditions in eastern NY on these days.

Day-Ahead and Real-Time Ancillary Services Prices

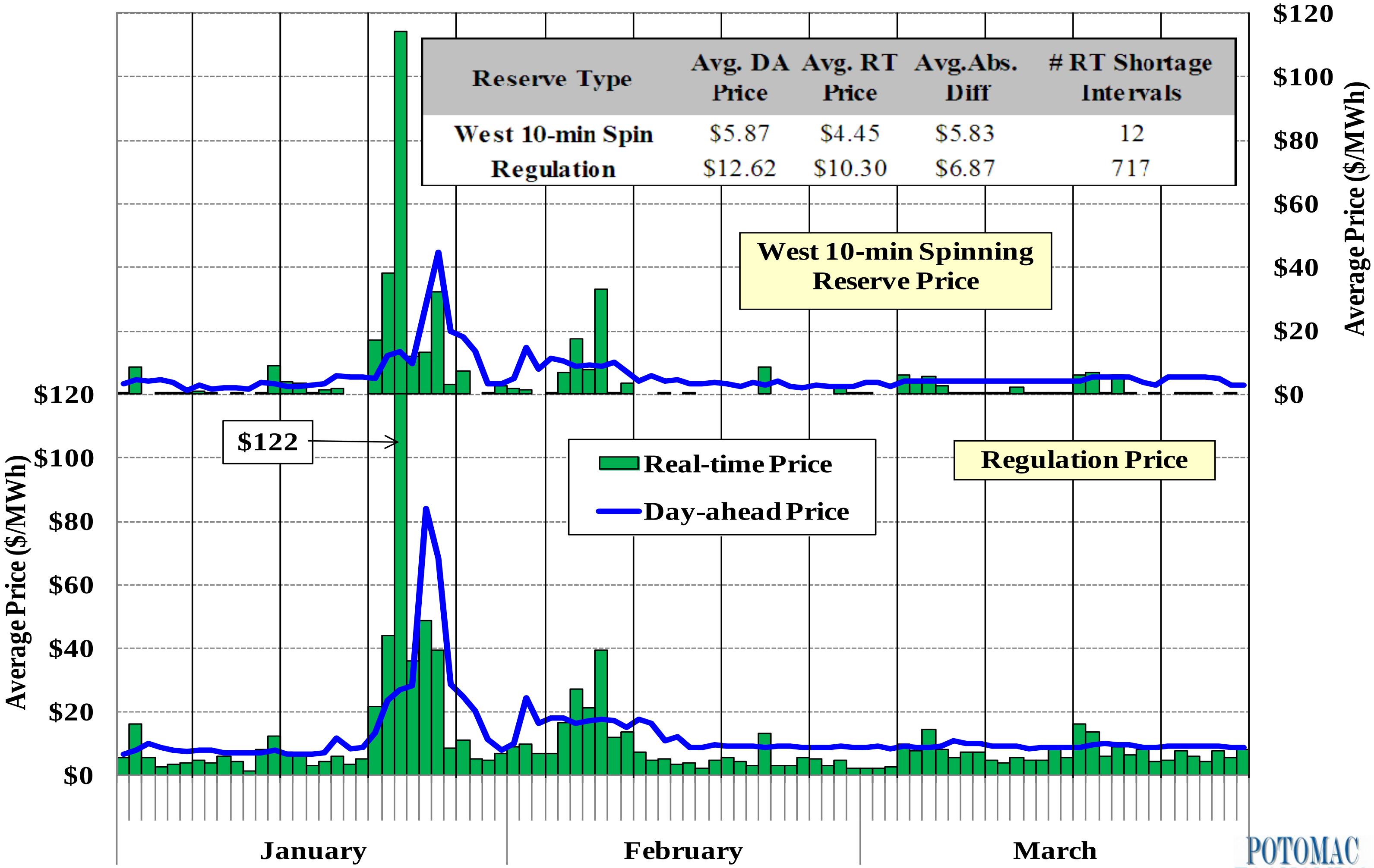
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
East 10-min Spin	$9.65	$9.64	$9.90	1670
East 10-min Non-Spin	$4.00	$3.38	$6.39	101

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	$5.87	$4.45	$5.83	12
Regulation	$12.62	$10.30	$6.87	717



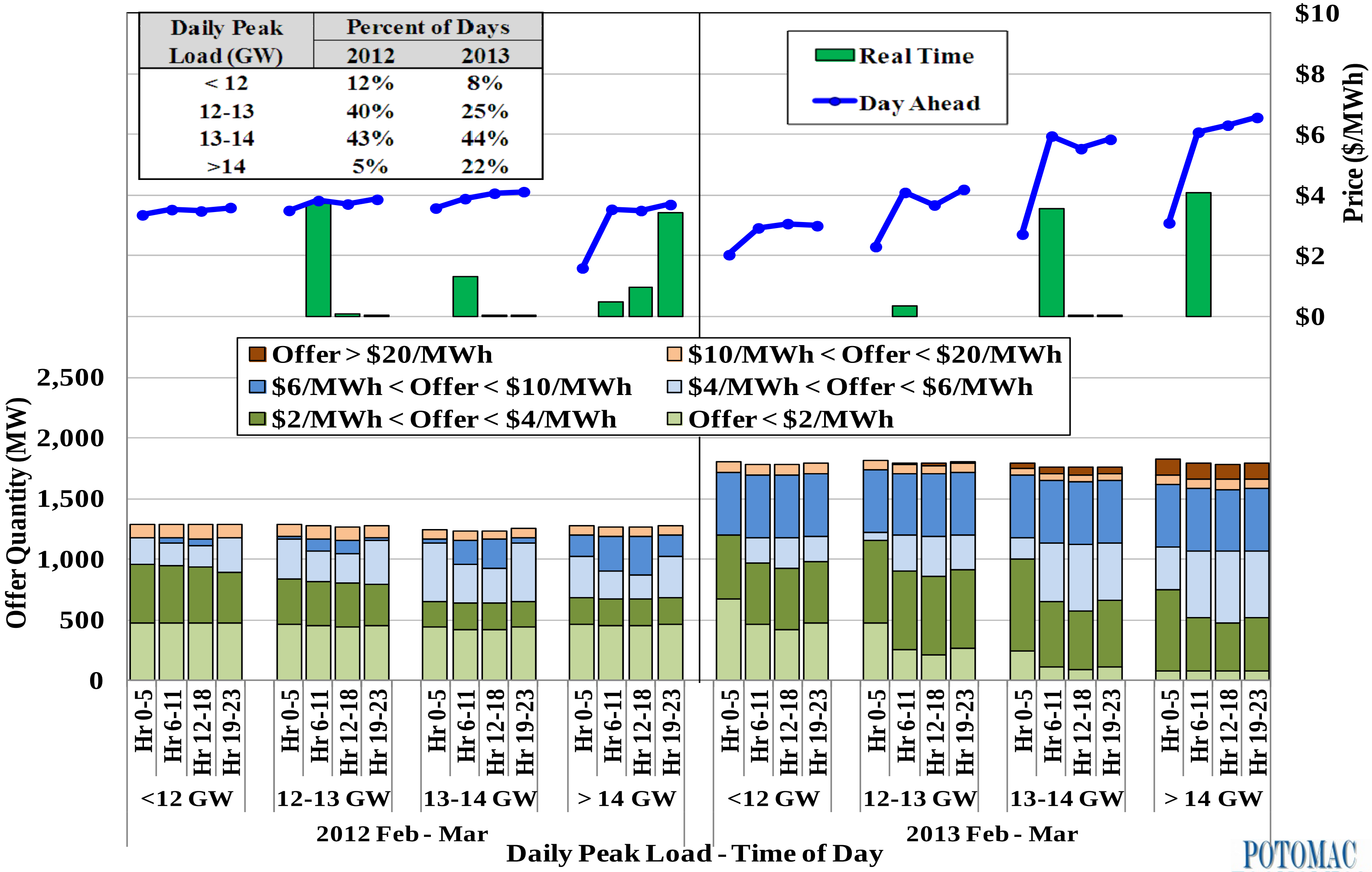
Day-Ahead Reserve Offers and Price Convergence

- On January 23, the NYISO implemented the first phase of a process to modify two DAM ancillary services mitigation provisions. In the first phase, the NYISO:
  - ✓ Raised the reference level cap for 10-minute non-spinning reserves from \$2.52/MWh to \$5/MWh; and
  - ✓ Raised the offer cap of 10-minute spinning reserves for New York City generators from \$0/MWh to \$5/MWh.
- The MMU is required to evaluate the competitiveness of the 10-minute spinning and non-spinning reserves markets and issue recommendations regarding the implementation of subsequent phases.
- The following two figures summarize our evaluation of the first two months following the implementation of the first phase. 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.

Day-Ahead Reserve Offers and Price Convergence

- The increase in eastern 10-minute non-spinning reserves offers in the first quarter of 2013 reflects the entry of new capacity in New York City.
  - ✓ Consequently, the amount of reserves offered under various price levels increased under most conditions even though average offer prices rose.
- Suppliers have generally adjusted their offers consistent with expectations since the mitigation rule changes were implemented.
  - ✓ Offer prices have risen at times of day with higher load levels (e.g., hours 12-17) and on days with higher load levels (e.g., daily peak load in east NY > 14 GW).
  - ✓ This is a positive indicator, since more competing firms have online capacity that is available to sell spinning reserves during higher-load periods.
- Price convergence improved slightly for both products, but prices were higher and more volatile in February and March 2013, so it is premature to draw conclusions.
  - ✓ Average absolute differences between hourly DA and RT prices were 99 and 111 percent (of average DA prices) for spinning and non-spinning reserves, down from 117 and 113 percent in the same months of the previous year.
  - ✓ The variation in DAM prices by time of day is more consistent with RT prices.
- Although we have not found offer patterns that raise significant withholding concerns, we will update our assessment in the next quarterly report.

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



Daily Peak Load (GW)	Percent of Days 2012	Percent of Days 2013
< 12	12%	8%
12-13	40%	25%
13-14	43%	44%
>14	5%	22%

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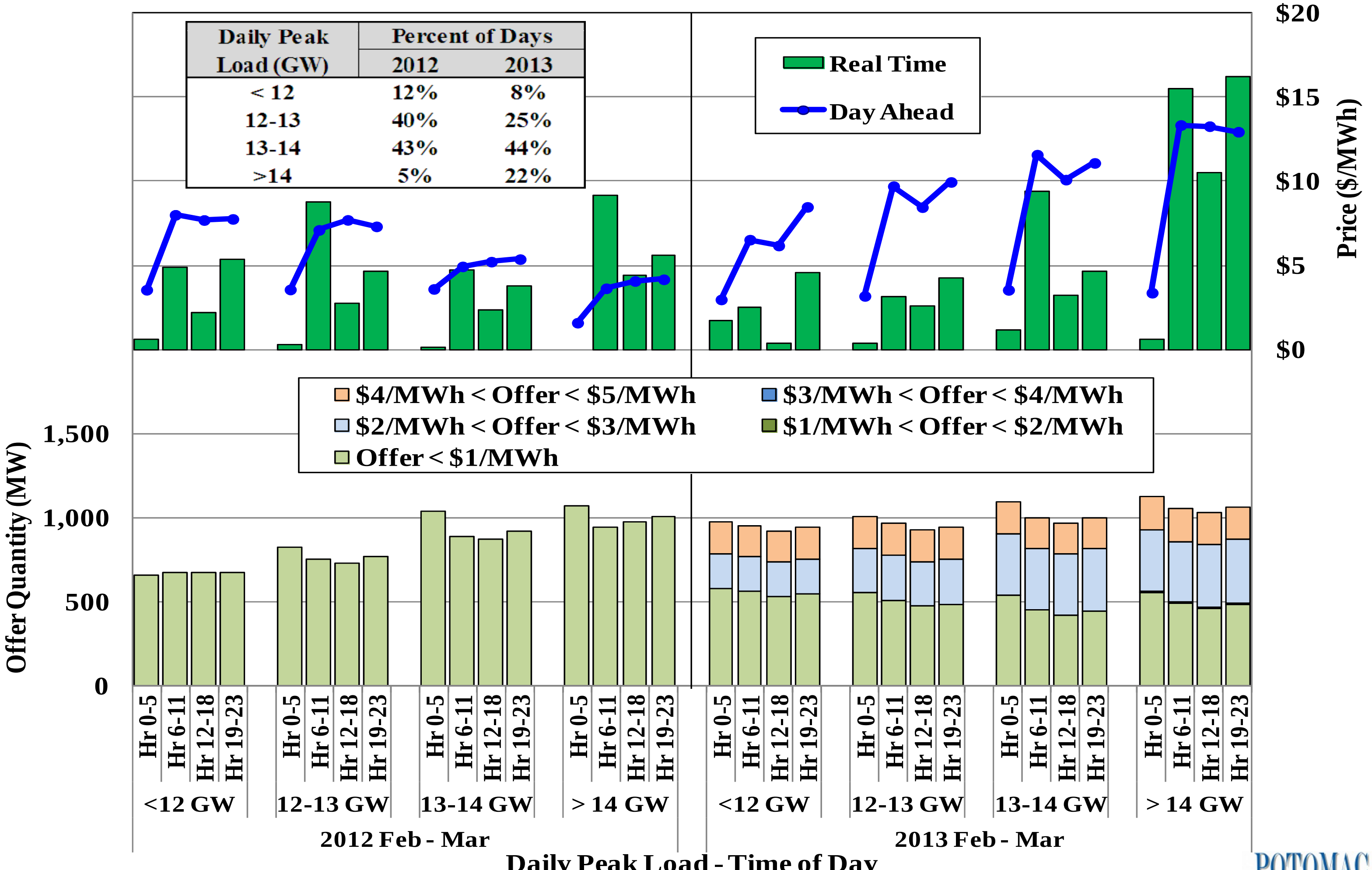
Day-Ahead Reserve Offers and Price Convergence

Eastern 10-Minute Spinning Reserves



Daily Peak Load (GW)	Percent of Days 2012	Percent of Days 2013
< 12	12%	8%
12-13	40%	25%
13-14	43%	44%
>14	5%	22%

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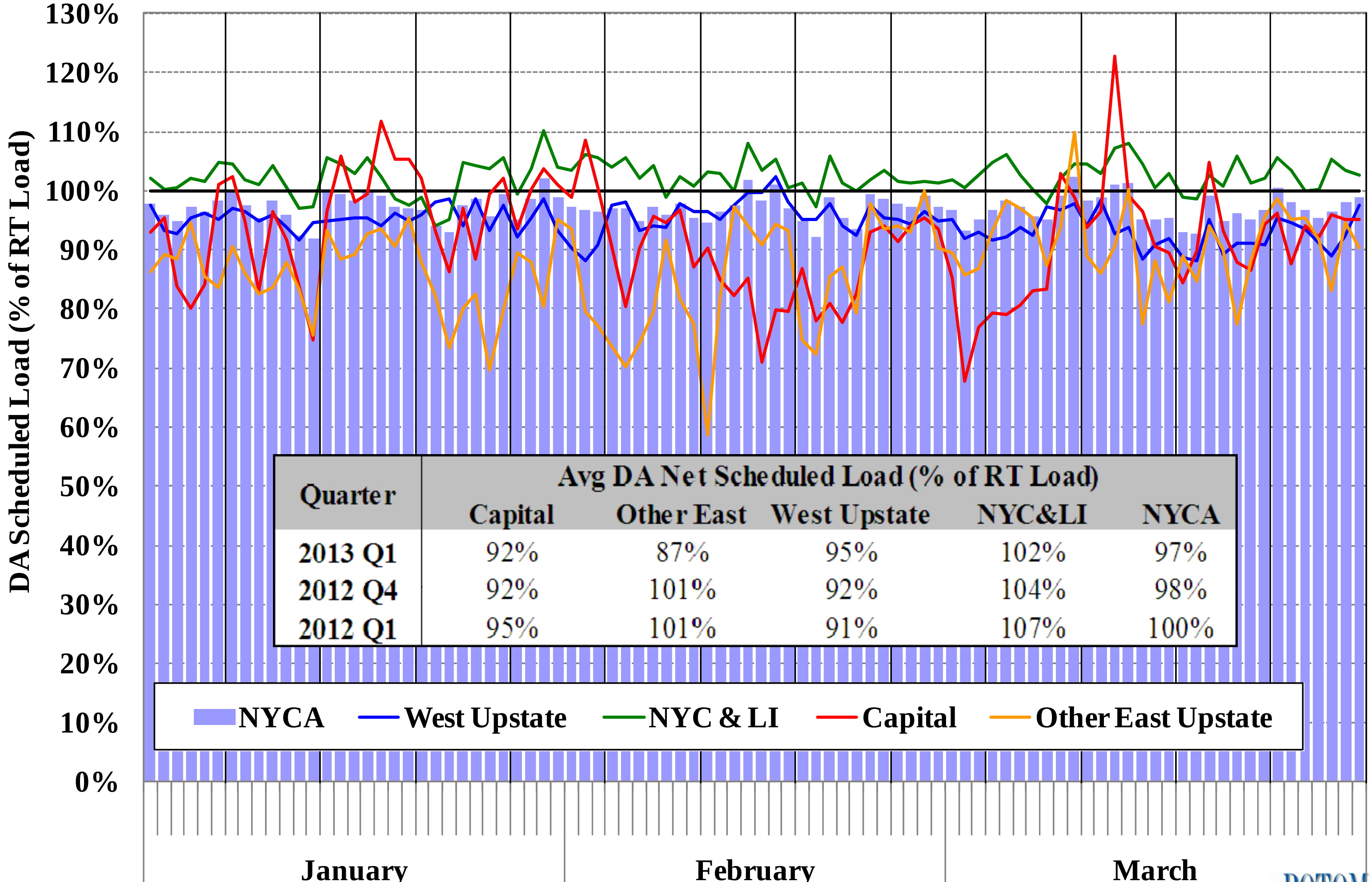
Day-ahead Scheduled Load and Actual Load

- 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 97 percent of actual load in NYCA in the first quarter of 2013, lower than in prior quarters.
  - ✓ The share of load scheduled in the DAM fell in Eastern NY, consistent with the DA price premiums in these areas in the first quarter.
- Substantial over-scheduling or under-scheduling of load in the DAM on individual days can cause significant divergences between the DA and RT markets.
  - ✓ For example, DA load was significantly under-scheduled in Eastern NY on January 22 & 23, contributing to large RT price spikes on the two days.
- Load scheduling patterns vary considerably by region.
  - ✓ Load is typically over-scheduled in NYC and Long Island, which is likely a natural market response to higher RT price volatility in those areas.

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 Q1	92%	87%	95%	102%	97%
2012 Q4	92%	101%	92%	104%	98%
2012 Q1	95%	101%	91%	107%	100%

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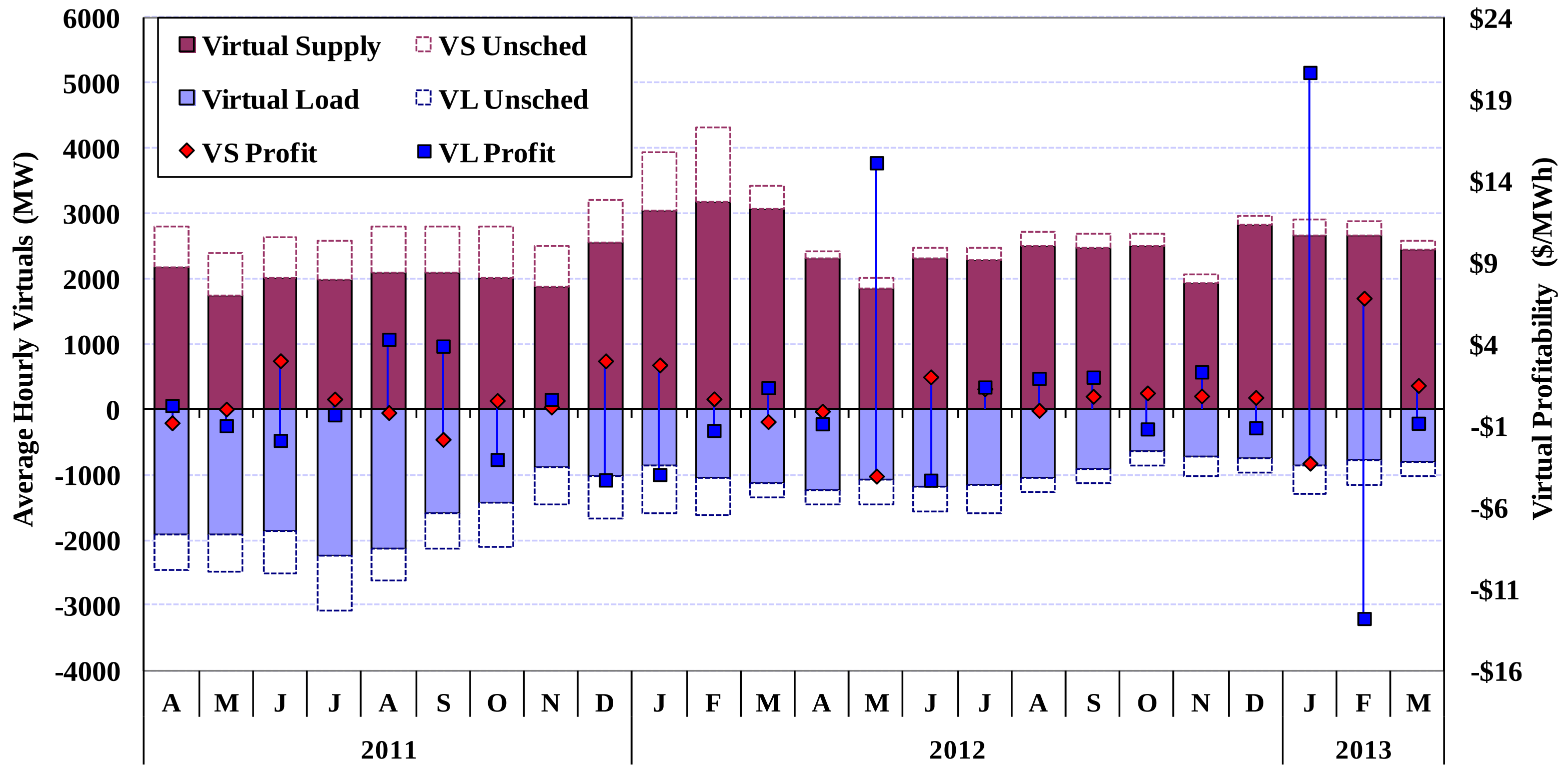
Virtual Trading Activity

- The following figure shows monthly average bids/offers and scheduled quantities, and profitability for virtual transactions in each month over the past two years.
  - ✓ Scheduled virtual supply rose in 2012 and remained relatively high through 2013. The increase reflected that some firms that made bilateral load purchases used virtual supply to sell the energy in the day-ahead market.
  - ✓ Scheduled virtual load fell notably over the two year period due largely to reduced virtual load in SENY, reflecting less congestion into this area in real-time.
  - ✓ In aggregate, virtual load and supply have generally been profitable, indicating that they typically improved convergence between day-ahead and real-time prices.
    - – However, the profits and losses of virtual load and supply have varied widely from month-to-month, reflecting the difficulty of predicting volatile real-time prices.
- The table below the figure shows a screen for relatively large profits (which may indicate modeling inconsistencies) or losses (which may indicate potential manipulation of the day-ahead market).
  - ✓ The table shows that the quantity of transactions generating substantial profits or losses in the first quarter of 2013 increased.
  - ✓ The transactions with notable profits or losses were primarily associated with real-time price volatility, which do not raise manipulation concerns.

Virtual Trading Volumes and Profitability

April 2011 to March 2013

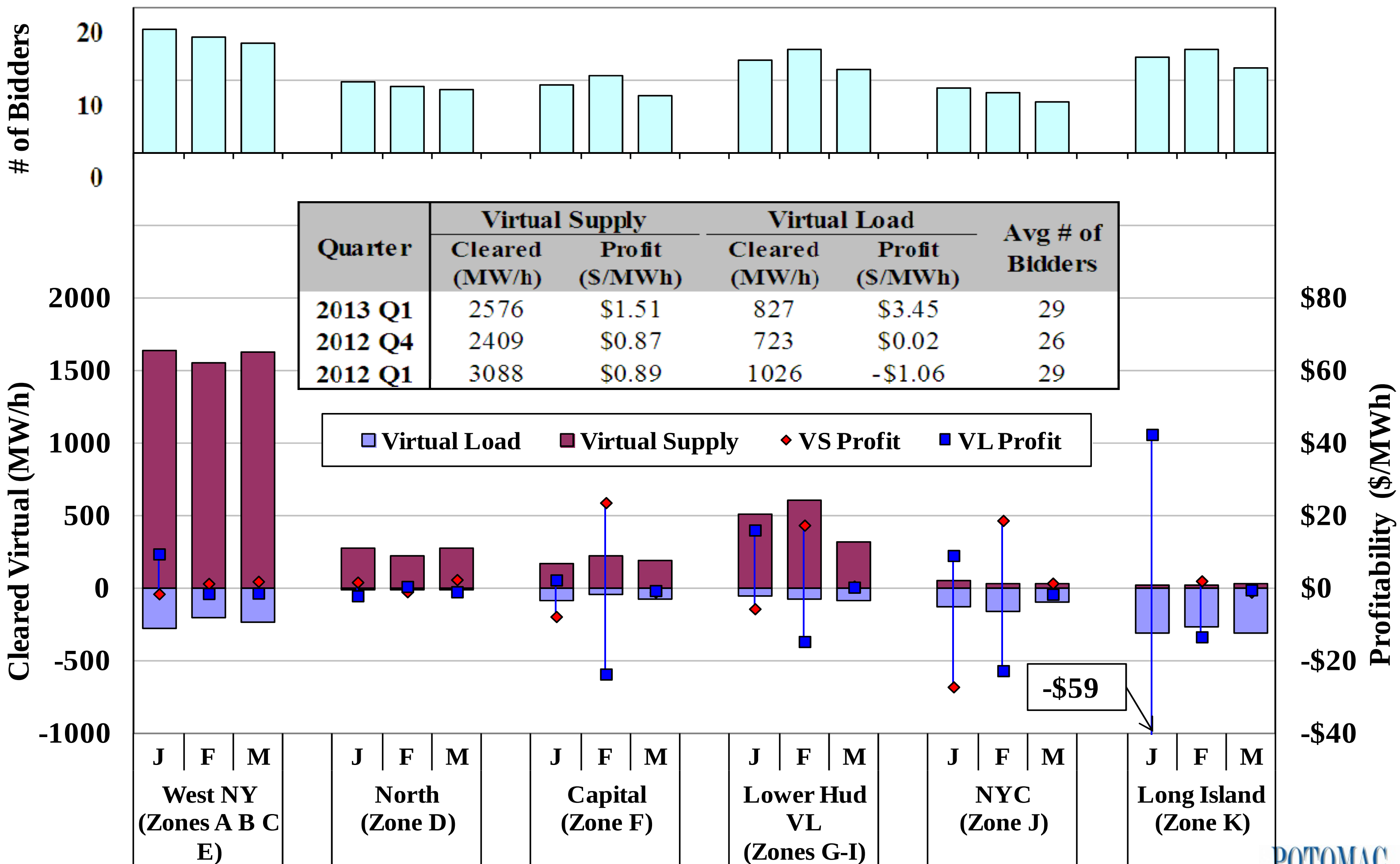


		A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M
		2011									2012												2013		
Profit > 50% of Avg. Zone Price	MW	122	233	350	376	337	186	98	100	208	275	96	224	220	128	345	300	208	158	143	238	202	418	426	191
	%	3%	6%	9%	9%	8%	5%	3%	4%	6%	7%	2%	5%	6%	4%	10%	9%	6%	5%	5%	9%	6%	12%	12%	6%
Loss > 50% of Avg. Zone Price	MW	120	277	381	434	334	122	133	120	193	177	125	283	261	132	377	337	220	129	93	182	195	354	347	125
	%	3%	8%	10%	10%	8%	3%	4%	4%	5%	5%	3%	7%	7%	4%	11%	10%	6%	4%	3%	7%	5%	10%	10%	4%

Virtual Trading Activity

- The next figure summarizes virtual trading by geographic region. The eleven zones are broken into six geographic regions based on typical congestion patterns.
  - ✓ Zone D (the North Zone) is shown separately because transmission constraints frequently affect the value of power in Zone D.
  - ✓ Zone F (the Capital Zone) is shown separately because it is constrained from western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley.
  - ✓ Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas.
- On average, seven or more participants submitted virtual trades in each region and 29 participants submitted virtual trades throughout the state in the first quarter of 2013.
  - ✓ However, the number has fallen since the implementation of new credit requirements in October 2011.
- There were substantial net virtual load purchases downstate and net virtual supply sales upstate in the first quarter of 2013.
  - ✓ Higher LBMPs and RT price volatility have provided additional opportunities for virtual traders to profit from improving DA-RT price convergence.
  - ✓ In the first quarter of 2013, virtual supply netted a profit of $8 million while virtual load netted a profit of $6 million.

Virtual Trading Activity
By Region By Month



Quarter	Virtual Supply		Virtual Load		Avg # of Bidders
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	
2013 Q1	2576	$1.51	827	$3.45	29
2012 Q4	2409	$0.87	723	$0.02	26
2012 Q1	3088	$0.89	1026	-$1.06	29

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Net Imports Scheduled Across External Interfaces

- The following figure summarizes scheduled net imports to NYCA across eight external interfaces during the daily peak load hour in the first quarter of 2013.
- Net imports averaged 2.6 GW (serving 12 percent of the load) in daily peak load hours, down 24 percent from the first quarter of 2012.
- Net exports to New England across its primary interface averaged over 1 GW during daily peak load hours, up 400 MW from the previous quarter and 850 MW from the first quarter of 2012.
  - ✓ The increase was primarily due to the increased spread in natural gas prices between New England and New York over the period.
- Likewise, net imports to Long Island across the 1385 Line and the CSC fell from the previous year for similar reasons.
- Net imports to Long Island across the Neptune Line were fully scheduled during daily peak hours on most days.
  - ✓ However, the Neptune Line has been only partially available (up to 375 MW) since August 2012.
- Net imports from PJM across its primary interface and the VFT Line rose from previous quarters primarily due to the higher natural gas prices in New York.

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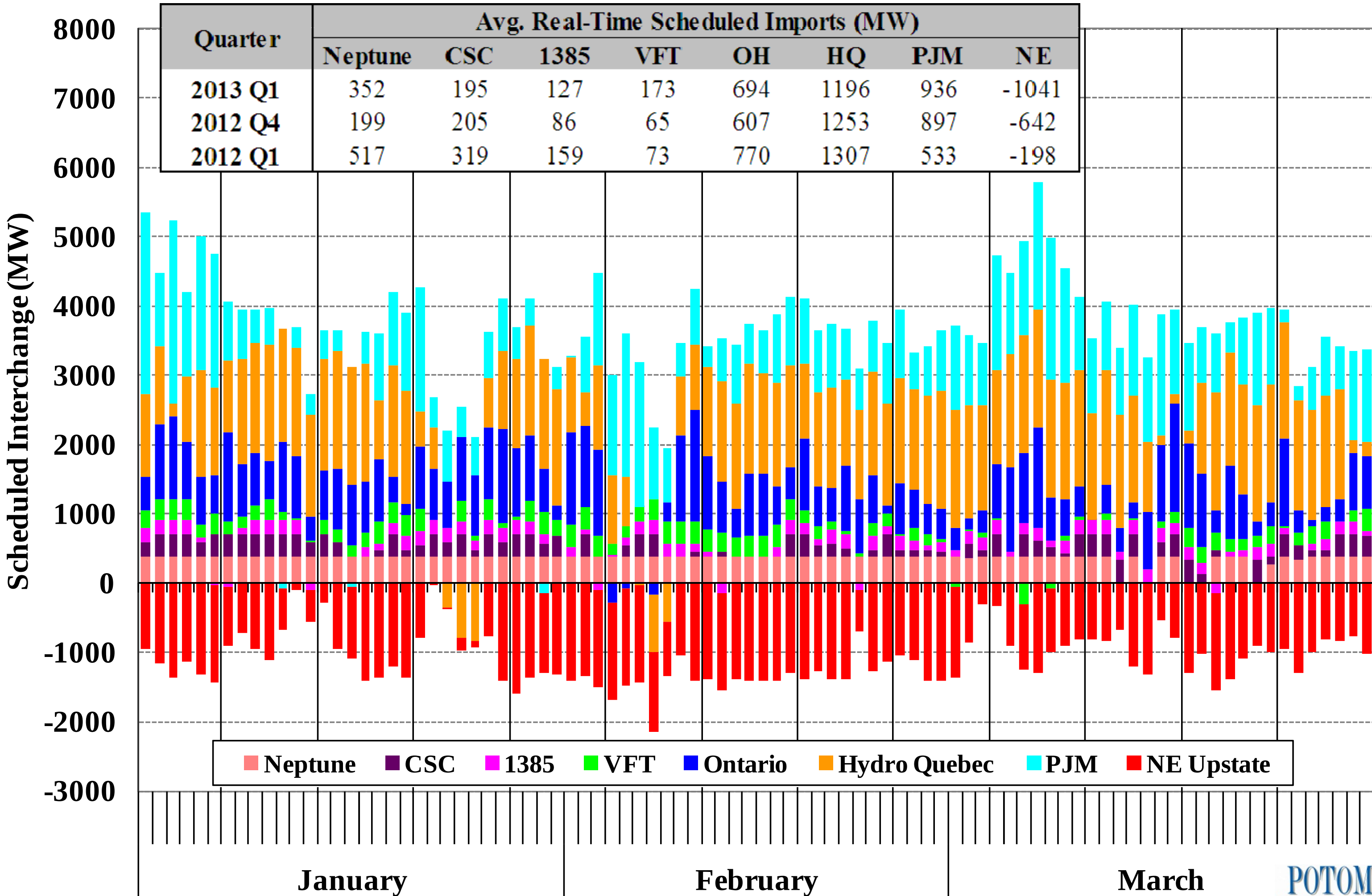
Net Imports Scheduled Across External Interfaces
Daily Peak Load Hour

Quarter	Avg. Real-Time Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2013 Q1	352	195	127	173	694	1196	936	-1041
2012 Q4	199	205	86	65	607	1253	897	-642
2012 Q1	517	319	159	73	770	1307	533	-198



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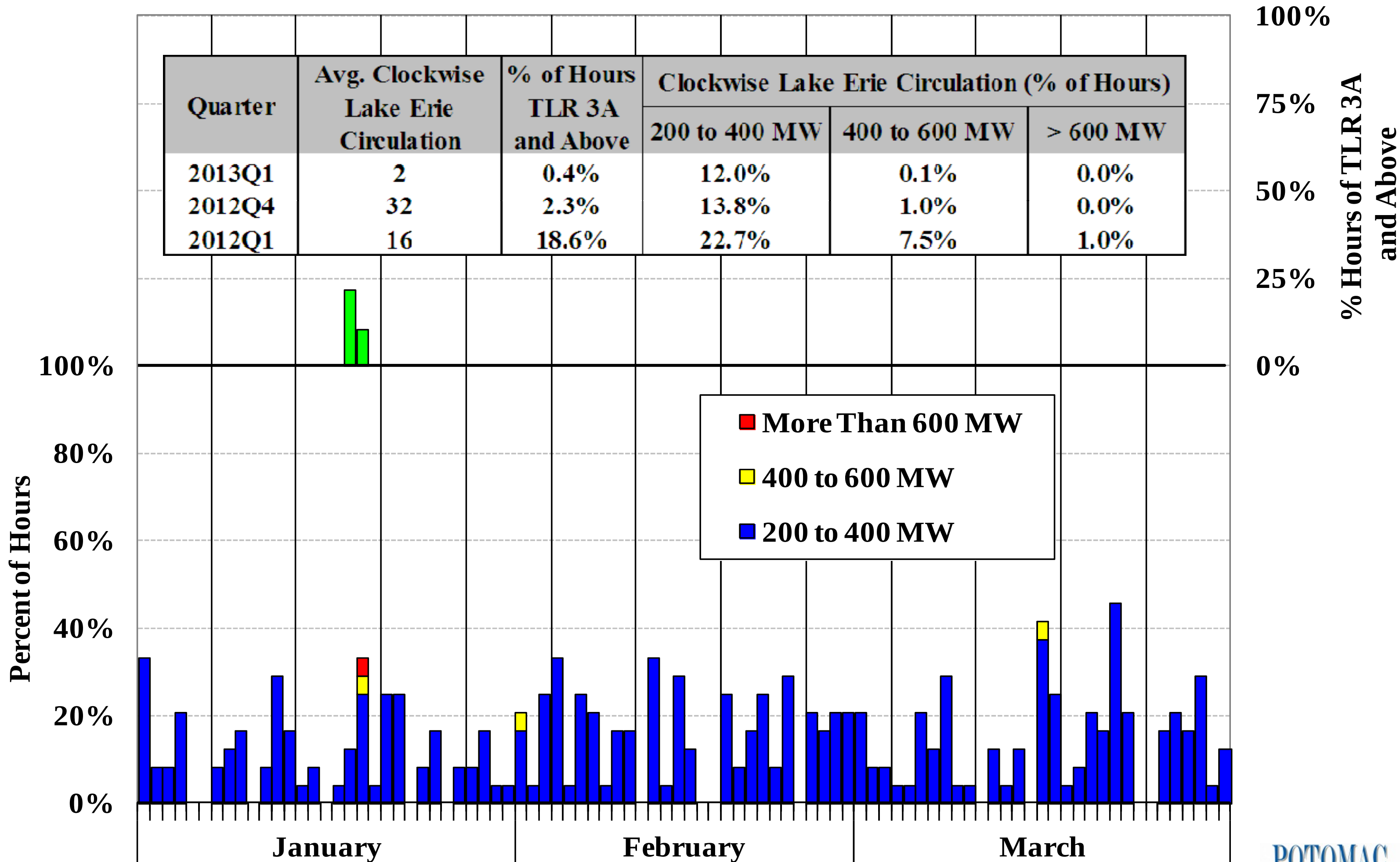
External Interface Scheduling and Lake Erie Circulation

- 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 first quarter.
- Loop flows averaged 2 MW in the clockwise direction in the first quarter of 2013.
  - ✓ The frequency of high (>200MW) clockwise loop flow fell from previous quarters.
  - ✓ IESO-Michigan PARs, which are capable of controlling up to 600 MW of LEC, began operating in April 2012 have generally been used to reduce loop flows.
- The frequency of TLRs called by the NYISO has fallen, consistent with the volume of clockwise loop flows and changes in the TLR process.
  - ✓ Although the frequency of Central-East congestion increased considerably, the NYISO was unable to use TLRs to manage congestion resulting from loop flows when the IESO-Michigan PARs were deemed in “regulate” mode.

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
2013Q1	2	0.4%	12.0%	0.1%	0.0%
2012Q4	32	2.3%	13.8%	1.0%	0.0%
2012Q1	16	18.6%	22.7%	7.5%	1.0%

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 first quarter of 2013.
- The figure reports the seven quantities for four areas of NYC and Long Island:
  - ✓ *Number of Starts* – Excludes self-scheduled and reliability units committed by TOs.
  - ✓ *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.

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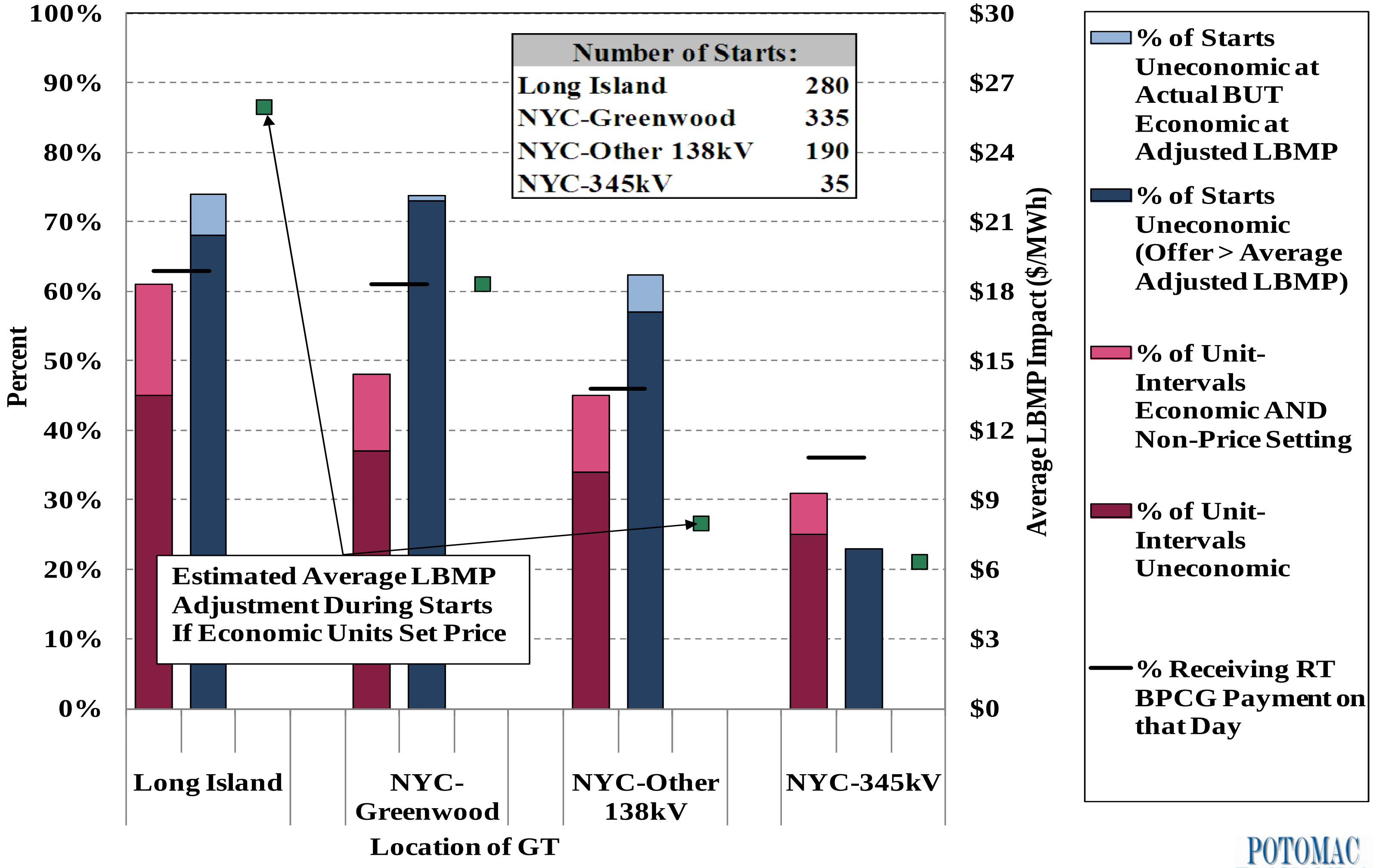
Efficiency of Gas Turbine Commitment and Price Setting

- The figure shows that, in the first quarter of 2013:
  - ✓ Gas turbines were economic in roughly 55 to 75 percent of their initial commitment period (excluding self schedules and local TO commitment).
  - ✓ However, economic gas turbines did not set LBMPs in 6 to 16 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 LI by an average of \$6 to \$25 per MWh in some intervals in the first quarter of 2013.
  - ✓ The higher LBMPs are more efficient, which also help reduce RT BPCG uplift.
- 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 effected, 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



Day-Ahead and Real-Time Transmission Congestion

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Congestion Revenue and Shortfalls

- This section of the report summarizes and evaluates the congestion patterns in New York and quantifies the following categories of 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.
  - ✓ *Day-Ahead Congestion Shortfalls* occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - – Shortfalls generally arise when the TCCs on a path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion.
    - – Payments to TCC holders are equal to the sum of day-ahead congestion revenues and day-ahead congestion shortfalls.
    - – These shortfalls are partly offset by the revenues from selling excess TCCs.
  - ✓ *Balancing Congestion Shortfalls* arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.
    - – This requires the ISO to re-dispatch generation on each side of the constraint in the real-time market, buying additional energy in the high-priced area and selling back energy (that was purchased day-ahead) in the low-priced area.
    - – This re-dispatch results in balancing congestion shortfalls recovered in uplift.
    - – Conversely, increased real-time capability can generate balancing surpluses.

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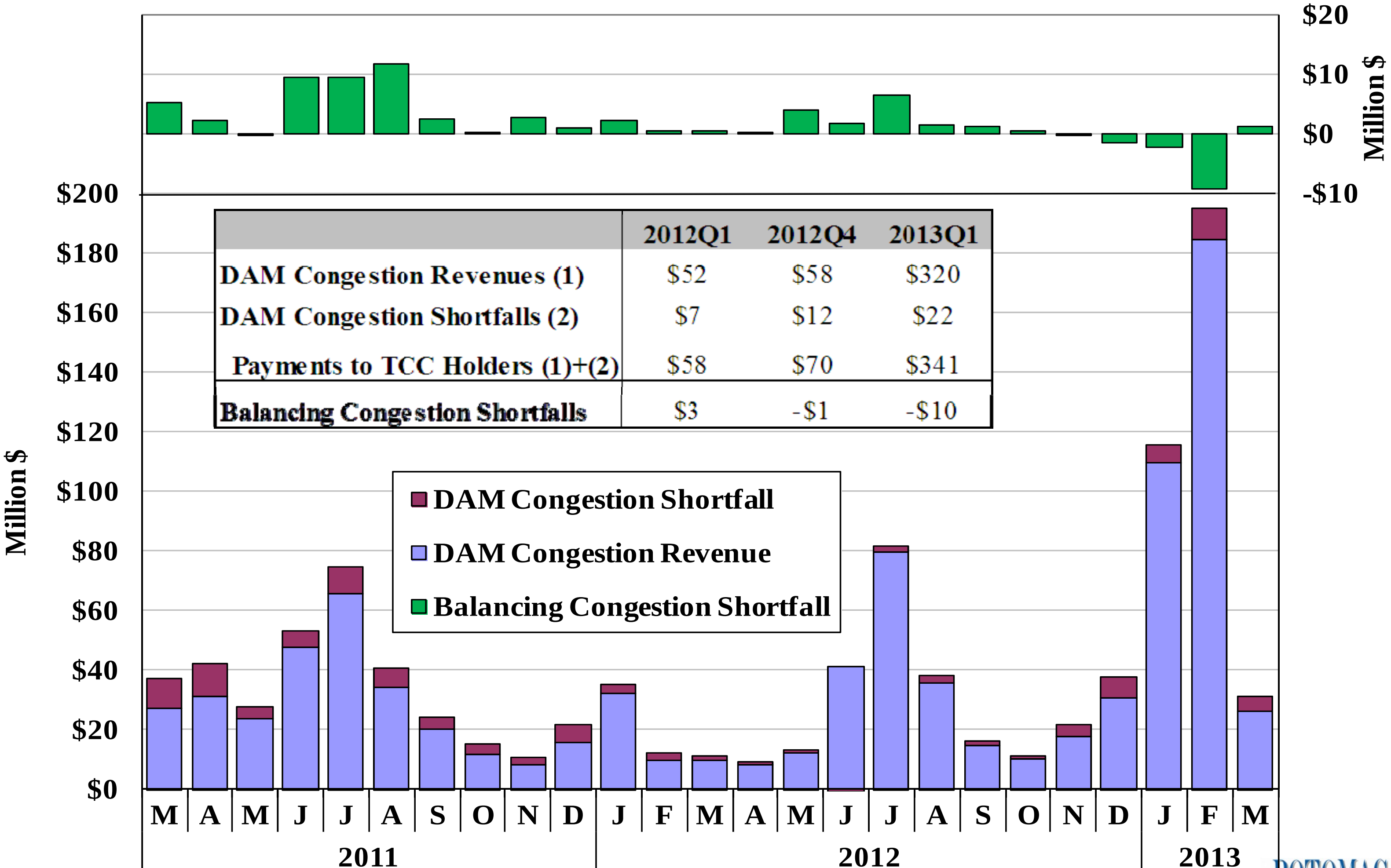
Congestion Revenue and Shortfalls

- The following figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years.
- Day-ahead congestion revenue totaled $320 million in the first quarter of 2013, up 500 percent from the first quarter of 2012. The increase resulted from:
  - ✓ Large gas price spreads between eastern and western NY and between NY and New England. Both factors increase congestion on the Central-East interface.
    - – Central-East accounted for 70 percent of the DAM congestion revenue.
  - ✓ Higher load levels, which increase transfers into constrained load pockets.
- Day-ahead congestion shortfalls totaled roughly $22 million, up $10 and $15 million from the previous quarter and the previous year, respectively.
  - ✓ Lines into New York City and Long Island accounted for the majority of the shortfalls, which was due largely to transmission outages.
  - ✓ This was offset by surpluses generated at the Central-East interface and the primary NE-NY interface.
- Balancing congestion shortfalls totaled *negative* $10 million (i.e., a surplus) in the first quarter of 2013, down from the prior quarters.
  - ✓ The surplus resulted primarily from the operation of PARs from New Jersey to New York under M2M and frequent uprates of the Central-East interface.

Congestion Revenue and Shortfalls



	2012Q1	2012Q4	2013Q1
DAM Congestion Revenues (1)	$52	$58	$320
DAM Congestion Shortfalls (2)	$7	$12	$22
Payments to TCC Holders (1)+(2)	$58	$70	$341
Balancing Congestion Shortfalls	$3	-$1	-$10

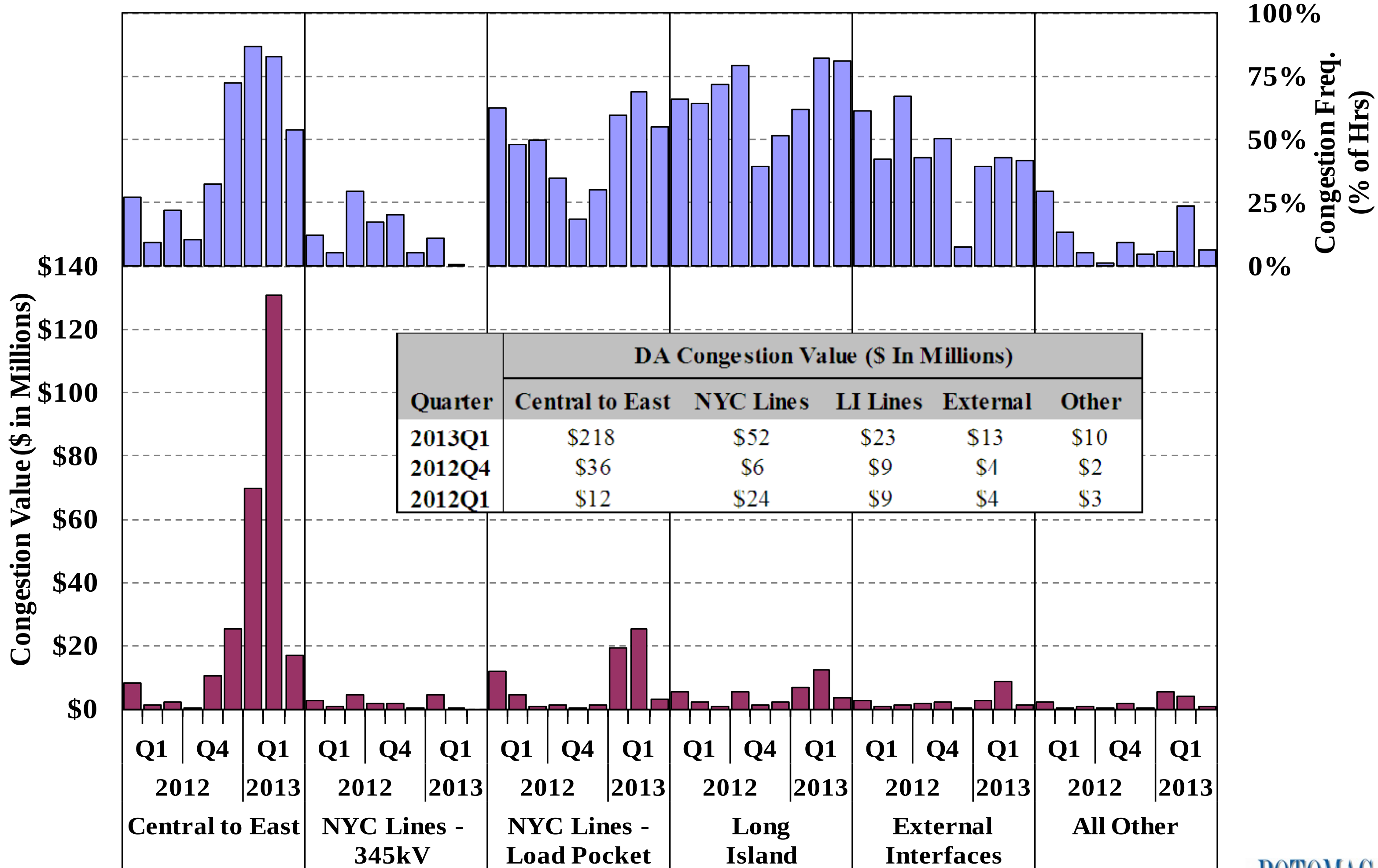
Congestion by Transmission Path

- The following two figures examine the value and frequency of congestion along major transmission paths in the day-ahead and real-time markets.
  - ✓ 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, which is the primary funding source for TCC payments.
- The two figures group congestion into the following transmission paths:
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ NYC Lines – 345kV: Lines leading into and within the NYC 345 kV system.
  - ✓ NYC Lines – Load Pockets: Lines leading into and within NYC load pockets.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ NYC Simplified Interfaces: Groups of lines to NYC load pockets that are modeled as interface constraints.
  - ✓ 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.

Congestion by Transmission Path

- Day-ahead congestion patterns are determined by the market participants' bids and offers, which reflect their expectations of real-time congestion.
  - ✓ Congestion is more frequent in the day-ahead market than in real time, but the shadow prices of constraints are generally lower in the day-ahead market.
- Congestion patterns were relatively consistent in the day-ahead and the real-time markets in the first quarter. Most congestion occurred in the following areas:
  - ✓ Central to East (69% DAM, 58% RTM) – Congestion across the Central East interface rose sharply from prior periods (despite uprates), particularly in January and February.
    - – This was driven primarily by higher natural gas prices and higher spreads in gas prices between West NY and East NY and between NY and NE.
  - ✓ New York City lines (16% DAM, 16% RTM) – 87 percent of DAM congestion was associated with the Vernon/Greenwood load pocket, while 54 percent of RT congestion occurred on paths into the NYC 345 kV system.
    - – Nearly all of RT congestion into the NYC 345 kV system occurred from January 21-24 when the import capability was derated due to gas supply concerns.
  - ✓ Long Island (7% DAM, 12% RTM) – The majority was congestion from upstate into Long Island, driven by high natural gas prices and transmission outages.
  - ✓ External Interfaces (4% DAM, 11% RTM) – Nearly 70 percent was associated with the primary NE interface as exports to NE were often fully scheduled on days when natural gas prices in NE were higher than in New York.

Day-Ahead Congestion by Transmission Path



	DA Congestion Value ($ In Millions)				
Quarter	Central to East	NYC Lines	LI Lines	External	Other
2013Q1	$218	$52	$23	$13	$10
2012Q4	$36	$6	$9	$4	$2
2012Q1	$12	$24	$9	$4	$3

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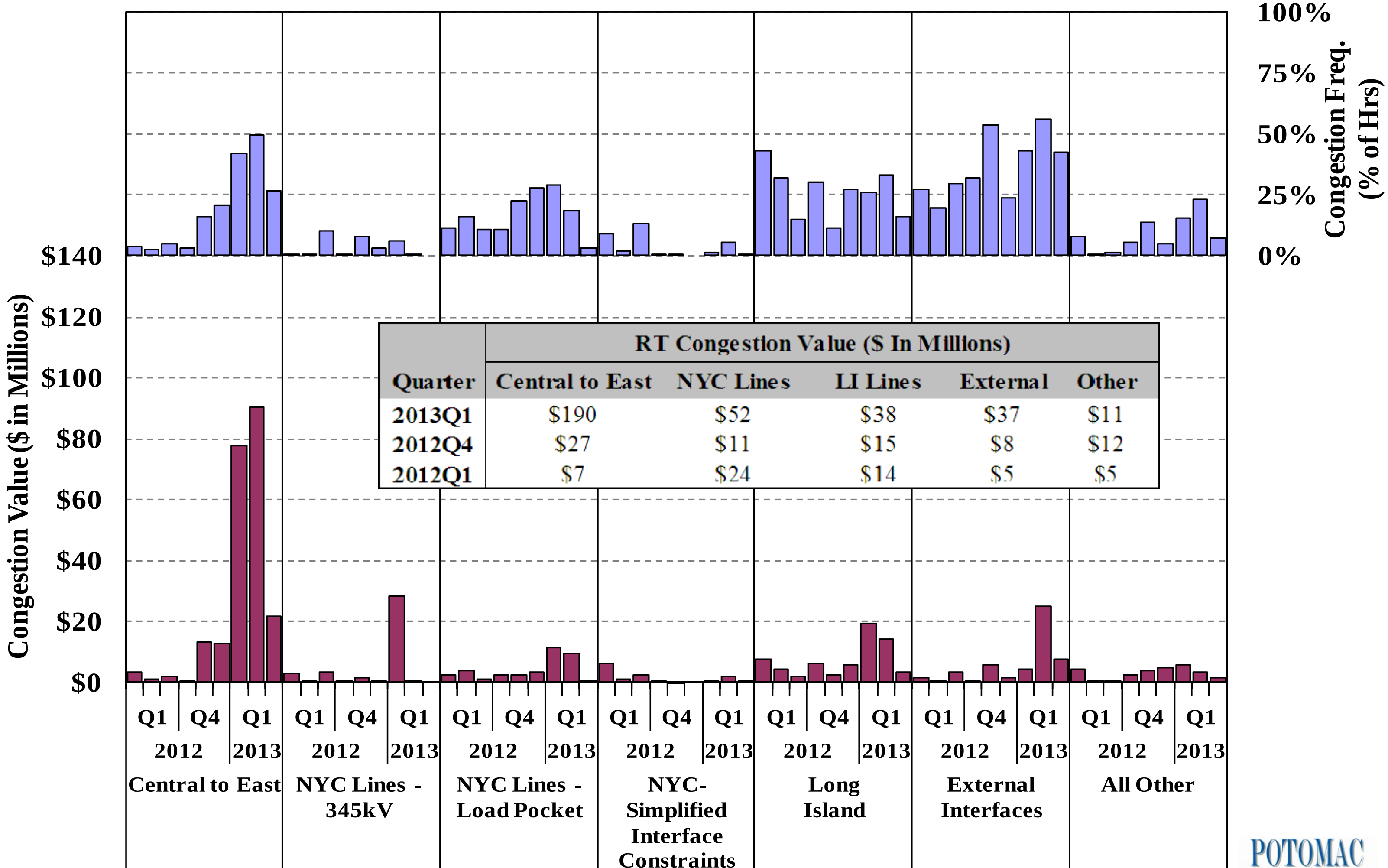
Real-Time Congestion by Transmission Path



	RT Congestion Value ($ In Millions)				
Quarter	Central to East	NYC Lines	LI Lines	External	Other
2013Q1	$190	$52	$38	$37	$11
2012Q4	$27	$11	$15	$8	$12
2012Q1	$7	$24	$14	$5	$5

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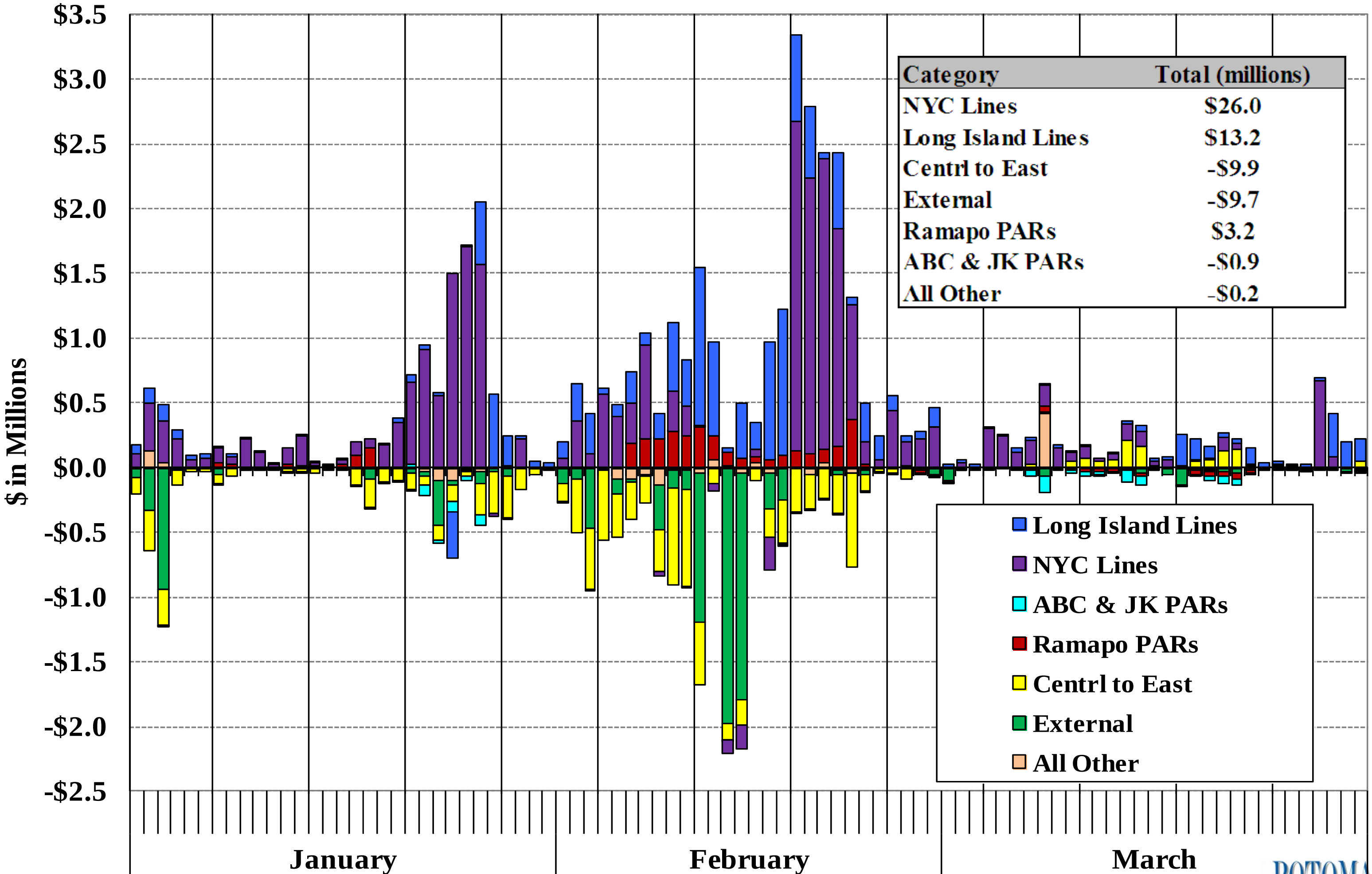
Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily day-ahead congestion revenue shortfalls by transmission path or facility in the first quarter of 2013.
  - ✓ Negative values indicating congestion surpluses that arise from higher day-ahead utilization of interfaces than in the TCC auction.
- Day-ahead congestion revenue shortfalls can result from modeling assumption differences between the TCC auction and the day-ahead market.
  - ✓ This includes assumptions related to PAR schedules, loop flows, and transmission outages. Outage-related shortfalls are allocated to the responsible TO.
- New York City and Long Island lines accounted for the vast majority of shortfalls ($39 million) in the first quarter of 2013, primarily due to transmission outages.
- The Central East voltage interface limit contributed a surplus of $10 million, reflecting higher utilization of voltage regulating equipment (e.g., capacitors and automated voltage regulators, etc.) scheduled in the DAM than in historic periods.
- External interfaces accounted for another $10 million of surplus.
  - ✓ Most of the surplus was from export congestion on the primary NY-NE interface, which was due to natural gas price spreads between NY and New England.
- The PAR-controlled lines between New Jersey and NY accounted for $2 million of shortfalls due to PAR outages and differences between the assumptions used in the DAM and the TCC auctions. These are discussed further in this section.

Day-Ahead Congestion Revenue Shortfalls



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Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the first quarter of 2013.
  - ✓ Negative values indicate balancing congestion surpluses that arise from increased real-time utilization of an interface from the day-ahead market.
- Balancing congestion revenue shortfalls can occur when the transfers across a congested interface fall from day-ahead to real-time due to:
  - ✓ Deratings and outages of the lines that make up the constrained interface;
  - ✓ Unexpected or forced outages of facilities that alter the distribution of flows across other constrained facilities; and
  - ✓ Unutilized transfer capability that can arise from Hybrid Pricing, which treats physically inflexible GTs as flexible in the pricing logic.
- Balancing congestion shortfalls can also occur when modeling assumptions in the day-ahead to real-time markets are inconsistent, including assumptions regarding:
  - ✓ Unscheduled loop flows across constrained interfaces;
  - ✓ Flows across PAR-controlled lines; and
  - ✓ Payments between NYISO and PJM related to the M2M process.

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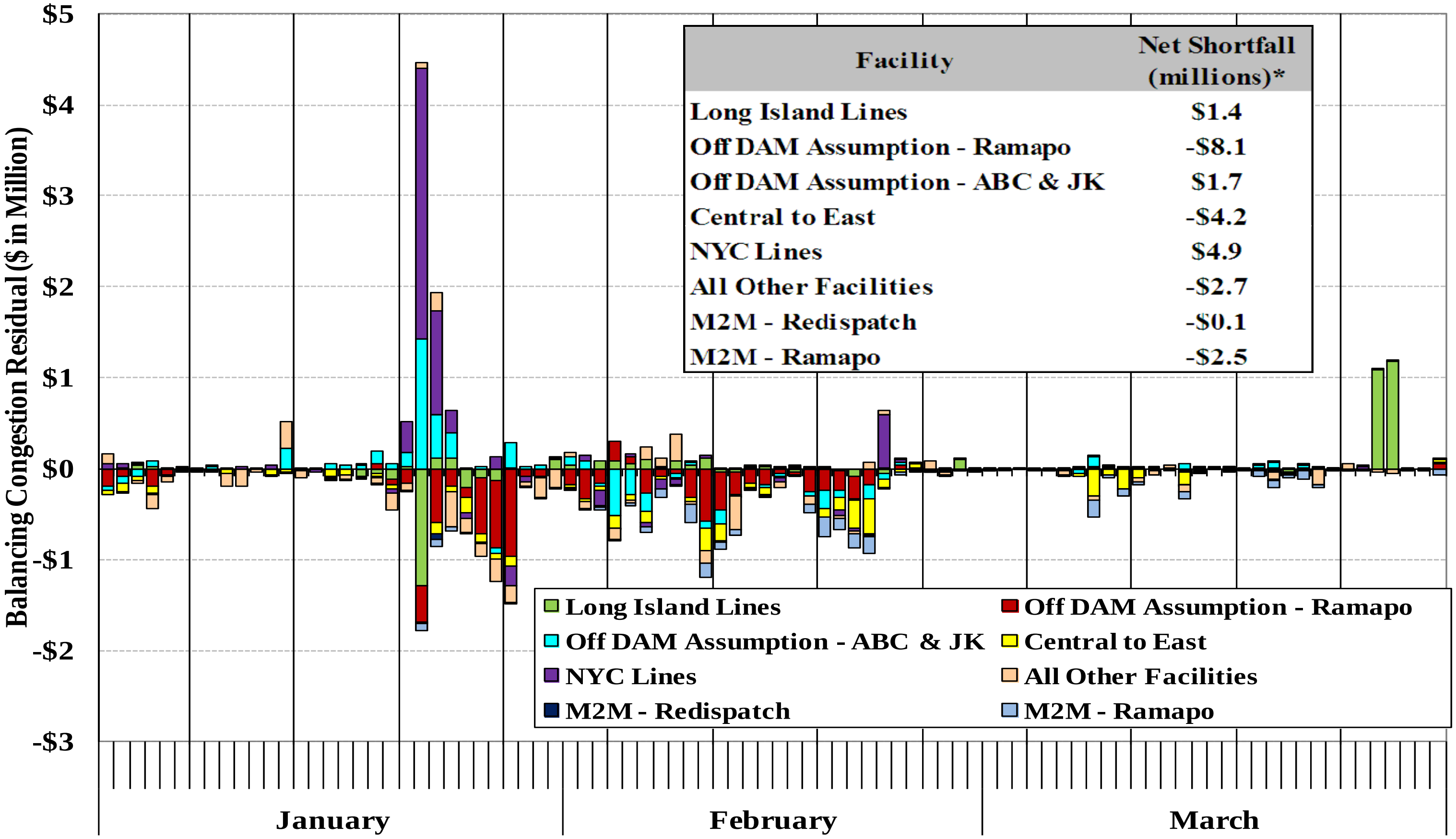
Balancing Congestion Shortfalls

- Balancing shortfalls were small on most days in this quarter but rose notably on several days when unexpected real-time events occurred.
- Lines into NYC accounted for nearly $5 million of shortfalls in the first quarter, most of which occurred on four days in January when the import capability into NYC was reduced due to uncertainty regarding the gas supply to some units.
- Lines into Long Island accumulated over $2 million of shortfalls on two days in March (27 & 28) due to an unexpected transmission outage.
- The Central-East interface accounted for slightly over $4 million of surpluses due to frequent real-time up-rates on the interface.
- Congestion from the North Zone to the rest of NYCA was frequent in January and February during periods of excess wind generation, contributing a surplus of nearly $3 million (included in the “All Other Facilities” category).
- PAR-controlled lines between NY and New Jersey contributed a net surplus of $6.4 million, which resulted primarily from:
  - ✓ Differences between the Ramapo flow assumed in the DAM and the actual operation of the Ramapo line from January 22 to February 26.

Balancing Congestion Shortfalls



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).

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 first quarter of 2013.
  - ✓ It was activated primarily for the Central-East constraint in roughly 150 hours and resulted in a total payment of $0.1 million from PJM to NY for that constraint.
- The use of Ramapo PAR Coordination had considerable impacts on the market in the first quarter of 2013.
  - ✓ Prior to February 4, actual flows across the Ramapo line usually ranged from 500 MW to the limit of 1000 MW to relieve Central-East congestion.
  - ✓ On February 4, one Ramapo phase-angle regulator was forced out. After the outage, actual flows across Ramapo were close to the reduced limit of 580 MW.
    - – Consequently, a portion of the interchange was frequently shifted from Ramapo to the ABC and JK lines.

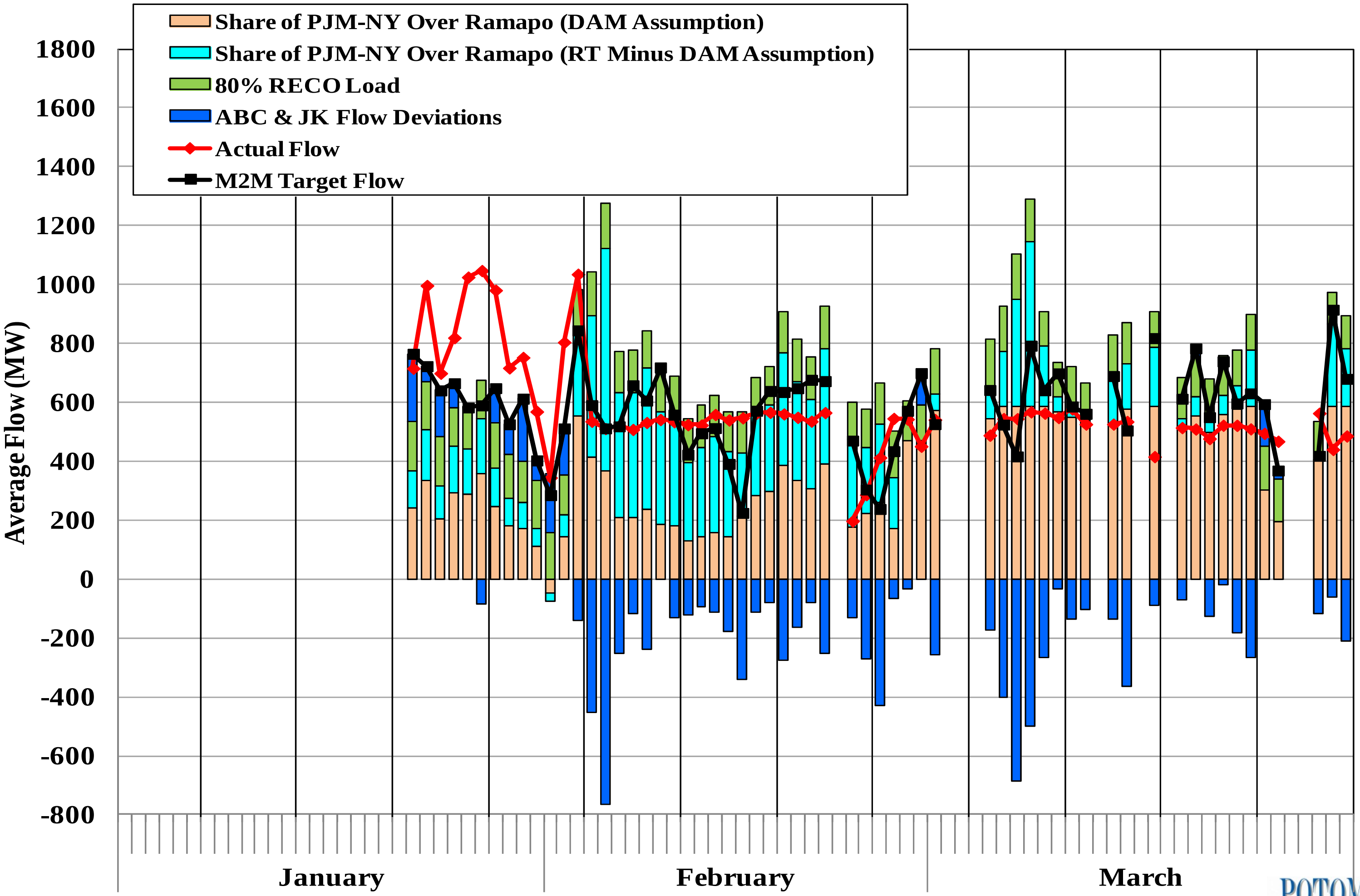
Operations under M2M with PJM
Ramapo PAR Coordination

- The next figure examines the operation of Ramapo PARs by comparing the actual flows with their M2M operational targets on each day in the first quarter of 2013.
  - ✓ RT Target Ramapo Flow = 61% PJM/NY AC-tie interchange + 80% RECo Load + (Actual JK flow – Actual ABC flow + Auto Correction Factors on ABC & JK)
  - ✓ The figure shows the following average quantities over intervals when Ramapo PAR Coordination was in effect on a daily basis:
    - – *Share of PJM-NY Over Ramapo (DAM assumption)* – This is based on the share of PJM-NY flows that were assumed to flow across the Ramapo line in the DAM.
      - This share ranged from 20 to 61 percent during the first quarter of 2013;
    - – *Share of PJM-NY Over Ramapo (RT minus DAM assumption)* – This is based on the difference between the share of interchange targeted to flow over Ramapo in the RT versus in the DAM assumption;
    - – *80% RECo Load* – 80 percent of telemetered Rockland Electric Company load;
    - – *ABC & JK Flow Deviations* – The total flow deviations on ABC and JK PARs from schedules under the normal wheeling agreement. This includes (Actual JK flow – Actual ABC flow + Auto Correction Factors on ABC & JK) from the equation above.

Operations under M2M with PJM Ramapo PAR Coordination

- Before February 4, actual flows across the Ramapo line usually ranged from 500 to 1000 MW to relieve Central-East congestion.
  - ✓ The combination of increased flows across Ramapo and outage conditions led to congestion of a PJM facility that was not a Ramapo coordinated flow gate.
  - ✓ Consequently, PJM used the TLR process to reduce exports to NY in a large number of hours during this period.
  - ✓ Hence, the cost of managing congestion on the PJM facility was not reflected efficiently in the scheduling of the Ramapo line and of PJM-NY transactions. The facility was added as a coordinated flow gate on February 8.
- After February 4, actual flows across Ramapo were close to 500 MW in most hours due to the PAR outage that reduced its limit below 600 MW.
  - ✓ Imports from PJM were relatively high in this period due to high LBMPs in eastern NY (61 percent of the proxy bus price is based on LBMPs in eastern NY).
  - ✓ Due to the PAR outage, the Ramapo line did not have sufficient capability to support 61 percent of imports from PJM.
  - ✓ As scheduled interchange from PJM to NYISO increases, 80 percent of the RECO load is not always deliverable.
  - ✓ Consequently, a substantial portion of the target flows were frequently shifted to the ABC and JK lines, and M2M payments were made by PJM to NYISO during periods of under delivery (i.e., when actual flow < target flow).

Actual and Target Flows on Ramapo PARs
During the Intervals with Binding M2M Constraints



POTOMAC ECONOMICS

Uplift Costs and Supplemental Commitments

Uplift Costs from Guarantee Payments

- The next two figures summarize uplift charges resulting from guarantee payments 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 external 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.

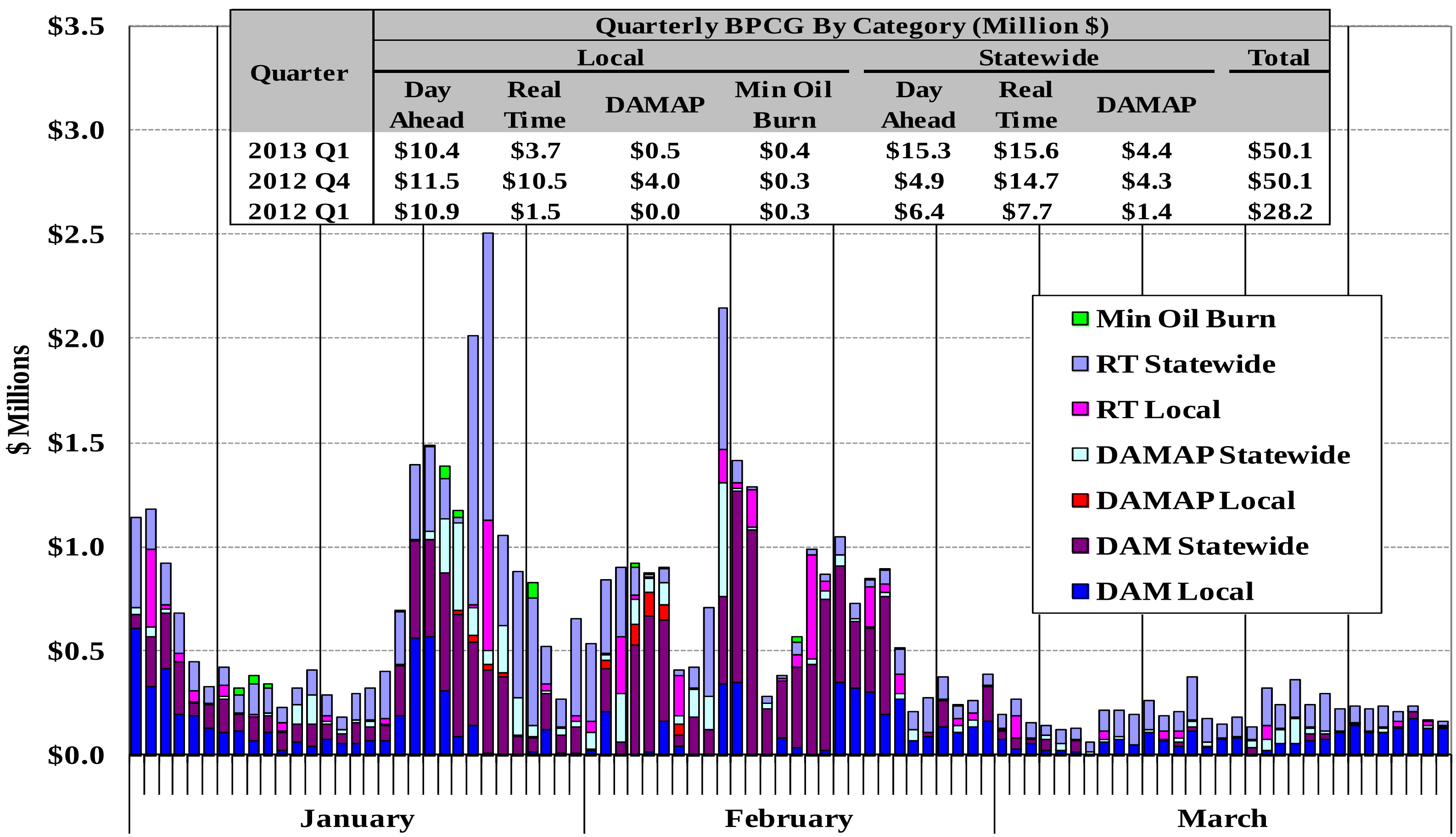
Uplift Costs from Guarantee Payments

- The following figure shows the seven categories of uplift charges on a daily basis in the first quarter of 2013.
- Guarantee payment uplift totaled $50 million in the first quarter, consistent with the fourth quarter of 2012.
  - ✓ Reliability commitment and OOM dispatch in NYC and Long Island fell from the previous quarter, tending to reduce uplift.
    - – Reliability commitment and OOM dispatch rose in the fourth quarter of 2012, which was primarily due to the effects of Hurricane Sandy.
  - ✓ However, the reduction was offset by higher natural gas prices and load levels.
- Guarantee payment uplift rose 78 percent (or $22 million) from the first quarter of 2012, mainly because of the substantial increase in natural gas prices.
  - ✓ Daily uplift costs were correlated with changes in natural gas prices.
  - ✓ The highest uplift costs occurred during periods of very high gas prices (especially January 1-4 & 19-27 and February 1-12 & 16-21).
  - ✓ However, the increase was offset by decreased reliability commitment in downstate areas, particularly in Long Island.

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

Quarterly BPCG By Category (Million $)

Quarter	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2013 Q1	$10.4	$3.7	$0.5	$0.4	$15.3	$15.6	$4.4	$50.1
2012 Q4	$11.5	$10.5	$4.0	$0.3	$4.9	$14.7	$4.3	$50.1
2012 Q1	$10.9	$1.5	$0.0	$0.3	$6.4	$7.7	$1.4	$28.2



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

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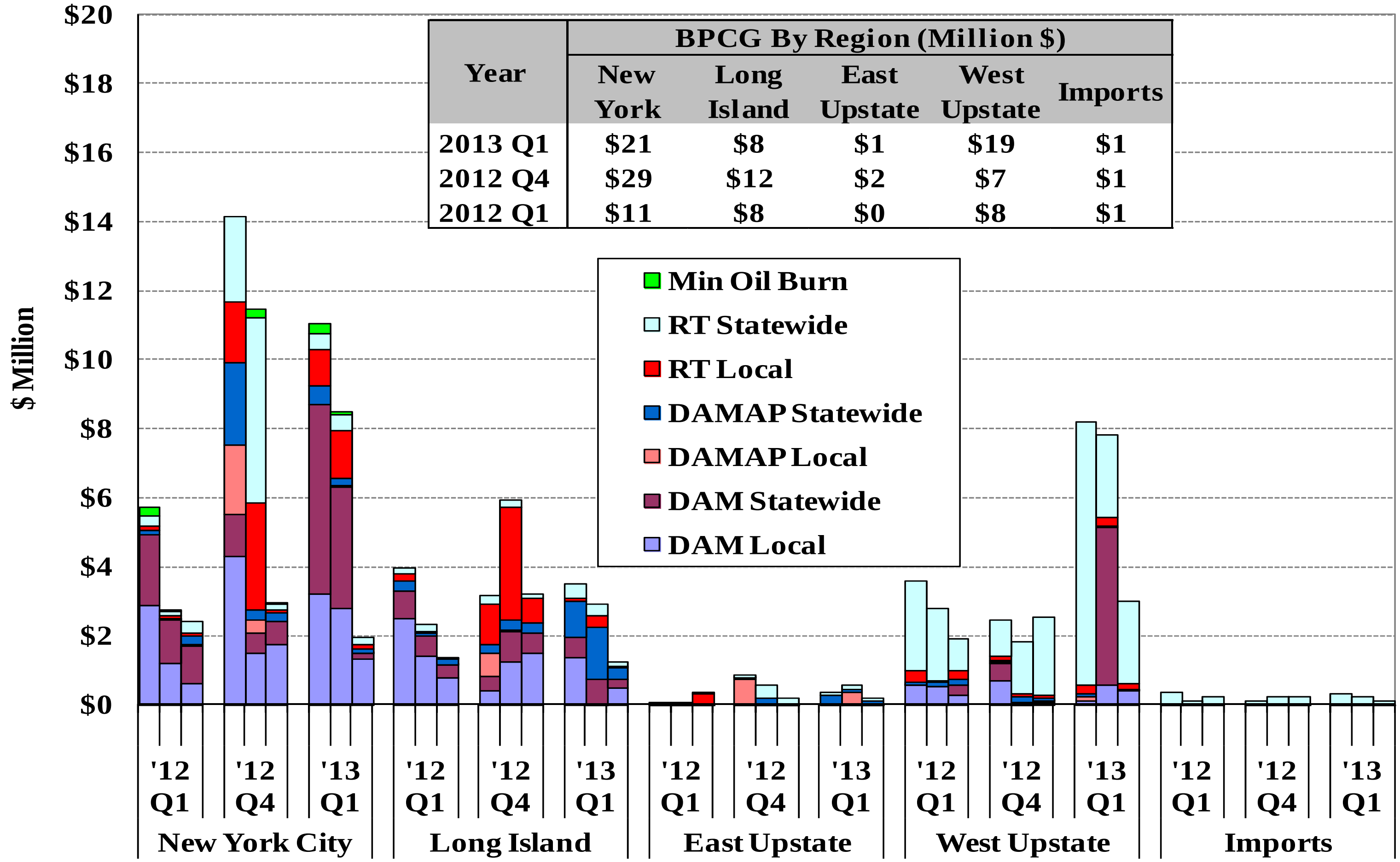
Uplift Costs from Guarantee Payments by Region

- The next figure shows seven categories of uplift on a monthly basis by region.
- <u>Day-ahead local reliability uplift in the first quarter of 2013</u>:
  - ✓ NYC accounted for 71 percent, resulting primarily from DARU commitments for local transmission security.
- <u>Day-ahead statewide uplift in the first quarter of 2013</u>:
  - ✓ 60 percent of these costs were paid to generators in NYC.
  - ✓ 30 percent was paid to generators in western NY that were committed to ensure sufficient capacity would be available to manage transmission security.
    - – Uplift is allocated statewide when the facility being secured is 230kV or higher.
- <u>Real-time local reliability uplift in the first quarter of 2013</u>:
  - ✓ NYC accounted for nearly 70 percent, primarily to manage transmission security in the Greenwood/Staten Island and Astoria West/Queensbridge/Vernon load pockets.
- <u>Real-time statewide uplift in the first quarter of 2013</u>:
  - ✓ 80 percent of these costs were paid to generators in western NY that were SREed to manage transmission security of 230kV facilities.

Uplift Costs from Guarantee Payments by Region

- Guarantee payments rose 78 percent ($22 million) from the first quarter of 2012.
- NYC accounted for a $10 million increase in uplift from the first quarter of 2012.
  - ✓ Nearly all of the increase accrued in the first two months due to higher gas prices.
    - – Gas prices averaged over $10/MMbtu in January and February, compared to around $4/Mmbtu in March.
- Western NY accounted for another $11 million increase in uplift from the first quarter of 2012.
  - ✓ The increase was mostly attributable to increased reliability commitments in the North Zone, as well as higher natural gas prices.
- Overall, uplift fell modestly in Long Island from a year ago due to the reduction in reliability commitment.
  - ✓ Generators needed for local reliability were committed economically more frequently this quarter, reflecting higher LBMPs (relative to natural gas prices) that were driven by transmission outages and unit retirements.
  - ✓ However, DAMAP uplift increased because of more frequent periods when slow-ramping units could not ramp quickly enough to reach their DA energy schedules during transitory high price spikes.

Uplift Costs from Guarantee Payments
By Category and Region



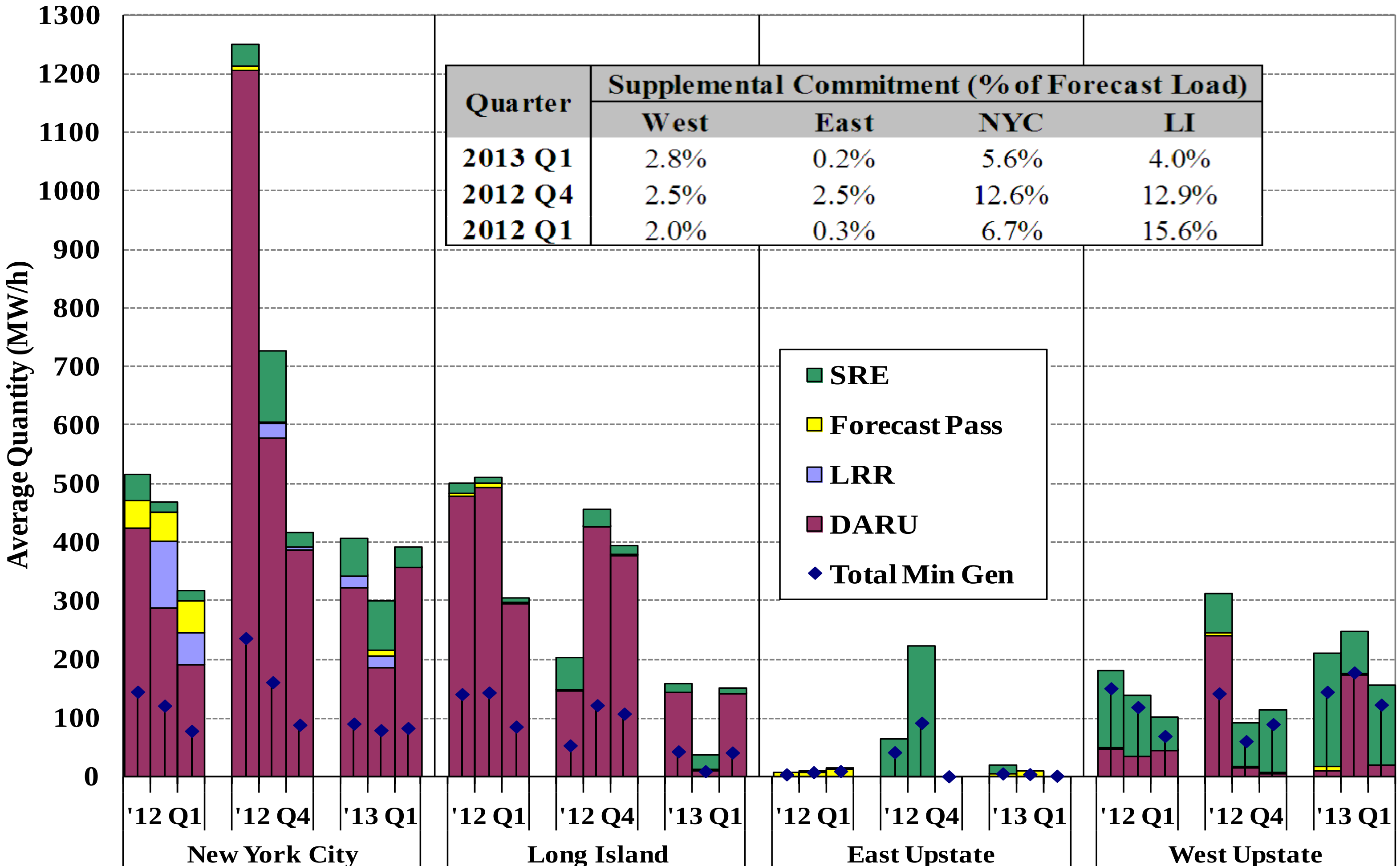
Year	BPCG By Region (Million $)				
	New York	Long Island	East Upstate	West Upstate	Imports
2013 Q1	$21	$8	$1	$19	$1
2012 Q4	$29	$12	$2	$7	$1
2012 Q1	$11	$8	$0	$8	$1

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.

Supplemental Commitment for Reliability

- The following figure shows the monthly quantities of capacity committed for reliability by type of commitment and region.
- In Western NY, reliability commitment averaged 205 MW, up 65 MW from the first quarter of 2012.
  - ✓ The increase was primarily associated with one unit that was needed more frequently for reliability in the North zone because of higher load levels and lower anticipated import capability from Vermont (across the PV-20 line).
- On Long Island, reliability commitment averaged 115 MW, down 74 percent from the first quarter of 2012.
  - ✓ Units frequently needed for local reliability were committed economically more often due to higher price levels resulting from the Neptune derating, unit retirements, and the Dunwoodie-to-Shore Rd outage.
- In NYC, reliability commitment averaged 365 MW, down 16 percent from the first quarter of 2012.
  - ✓ Less reliability commitment has been needed for the 345 kV system, since the entry of new generation and transmission upgrades in the second quarter of 2012.
- Although slow-start units continued to be committed in the Forecast Load Pass when off-line fast-start units are available, the quantity fell substantially after the NYISO deployed a modeling enhancement in late 2012.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2013 Q1	2.8%	0.2%	5.6%	4.0%
2012 Q4	2.5%	2.5%	12.6%	12.9%
2012 Q1	2.0%	0.3%	6.7%	15.6%

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Supplemental Commitment for Reliability in NYC

- The following figure evaluates the reasons for reliability commitments in the first quarter of 2013 in New York City where most occur.
- Based on our review of the reliability commitment logs and LRR constraint information, each hour that was flagged as DARU, LRR, or SRE was categorized according to one of the following reliability reasons:
  - ✓ 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.
- For voltage and thermal constraints, the capacity is shown by the load pocket that was secured: (AELP = Ast East/Corona/Jamaica, AWLP = Ast West/Queensbridge, AVLP = Ast West/Queensbridge/Vernon, ERLP = East River, FRLP = Freshkills, GSLP = Greenwood/Staten Island, & SDLP = Sprainbrook/Dunwoodie).
- A unit is considered to be committed for an LRR constraint if the constraint would be violated without the unit's capacity.

Supplemental Commitment for Reliability in NYC

- NOX environmental constraints are in effect from May to September, therefore no units were committed for this reason during the first quarter of 2013.
- Reliability commitment for thermal constraints in the load pockets accounted for the majority of reliability commitment in NYC during the first quarter of 2013.
  - ✓ Supplemental commitment for thermal constraints in the Astoria West/ Queensbridge/Vernon load pocket accounted for more than 50 percent of all reliability commitment in NYC.
    - – This was to ensure facilities into the pocket will not be overloaded if the largest two contingencies were to occur.
- Supplemental commitments for the Sprainbrook/Dunwoodie thermal and voltage requirements fell substantially from the prior years.
  - ✓ Less capacity has been committed for reliability on the 345kV system following the entry of 500 MW of peaking generation and new transmission facilities.
- Supplemental commitment to protect the system from the sudden loss of gas supply (i.e., IR-3) occurred on several days when the supply of natural gas was limited.

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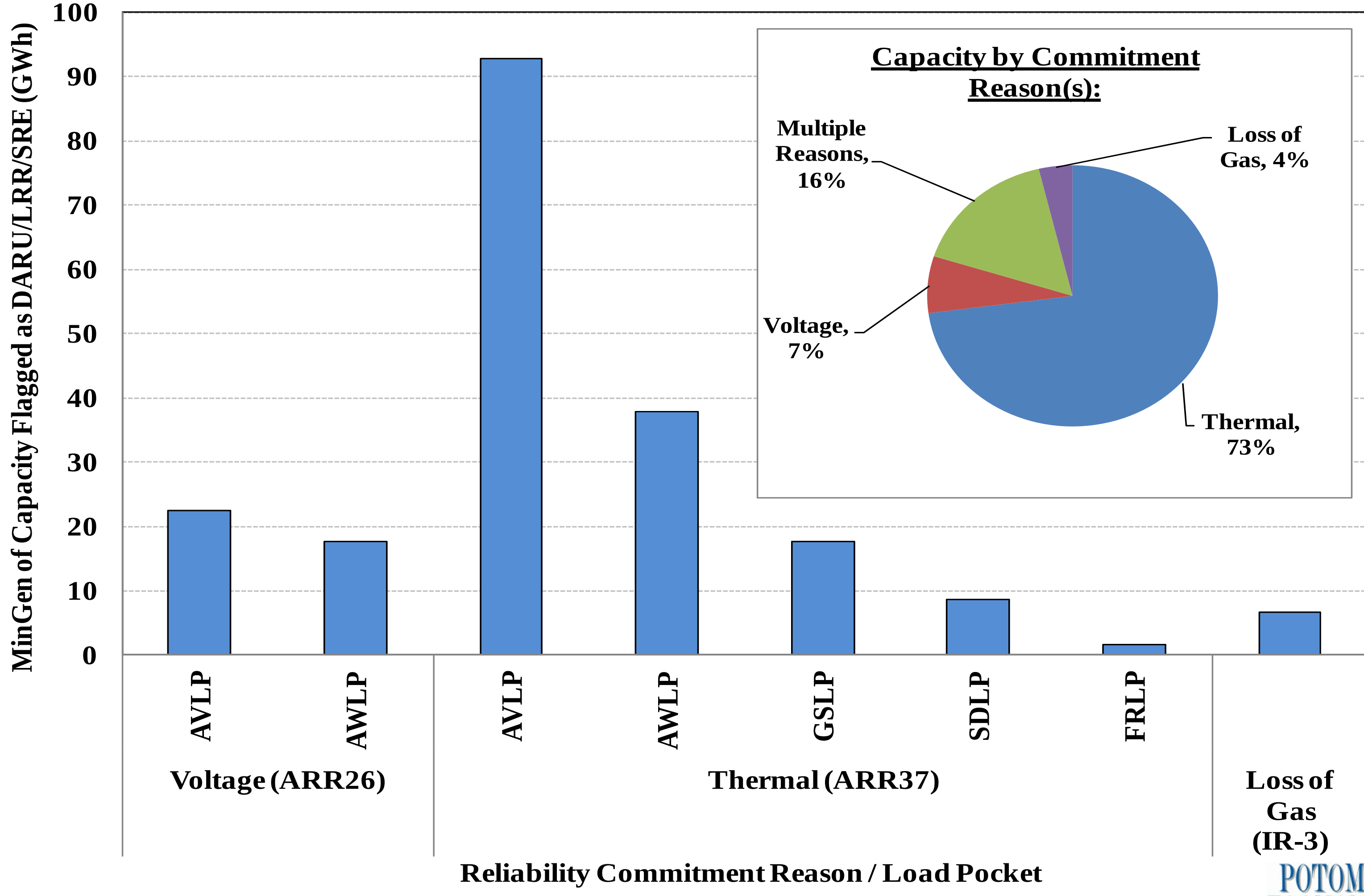
Supplemental Commitment for Reliability in NYC
by Reliability Reason and Load Pocket



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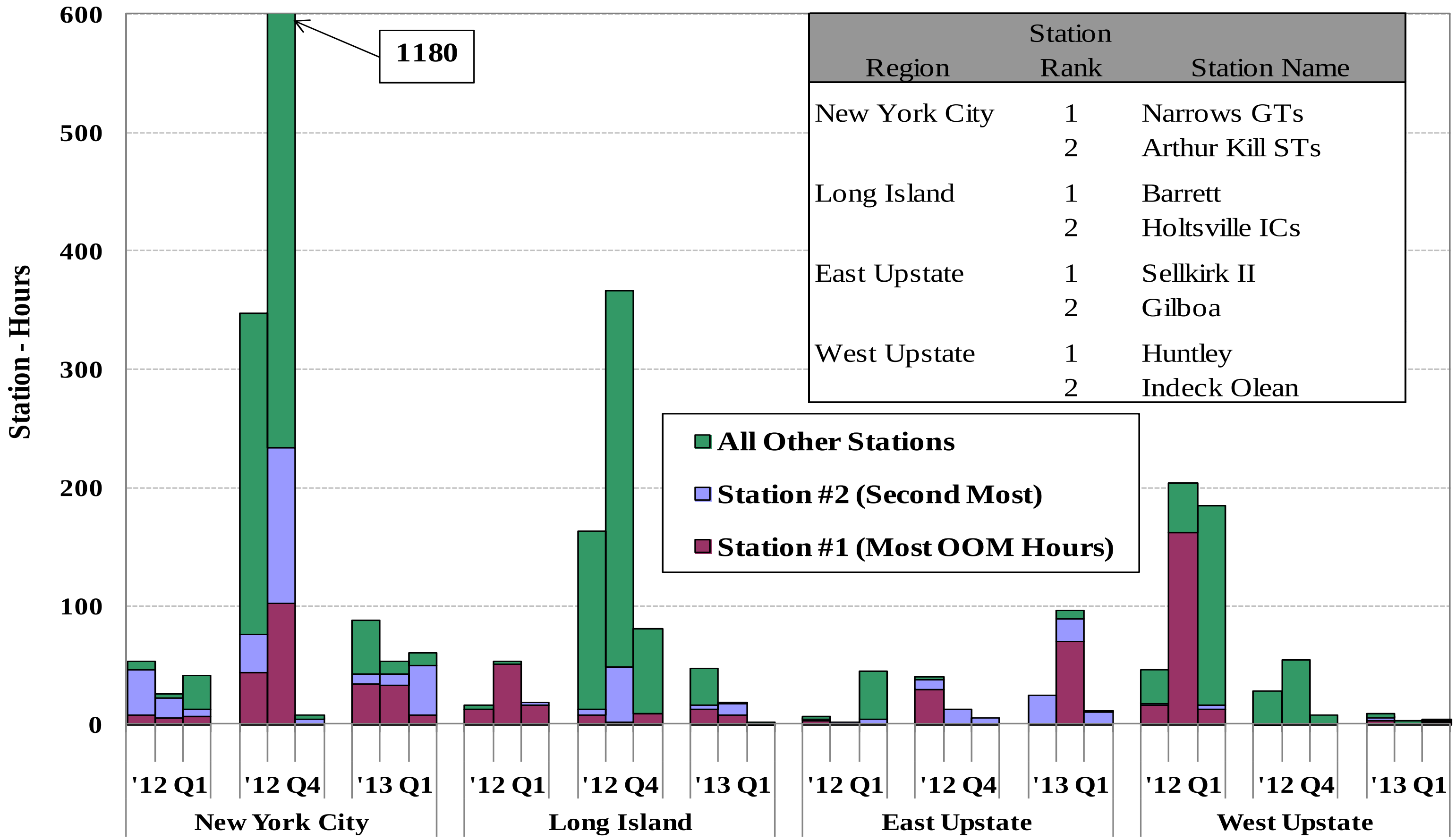
Out-of-Merit Dispatch

- The NYISO and local Transmission Owners sometimes dispatch generators out-of-merit (“OOM”) in order to:
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model; or
  - ✓ Maintain reliability of the lower voltage transmission system and the distribution system.
- The following figure summarizes the frequency (i.e., the total station-hours) of OOM actions on a monthly basis by region in the first quarter of 2013.
  - ✓ In each region, the two stations with the highest number of OOM dispatch hours in the first quarter of 2013 are shown separately.
  - ✓ The figure excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.
- Generators were dispatched OOM for roughly 420 station-hours in the first quarter of 2013, down substantially (1,880 station-hours) from the previous quarter.
  - ✓ The large quantity of OOM in NYC and LI during the fourth quarter of 2012 occurred primarily on the days following Hurricane Sandy.

Out-of-Merit Dispatch

- NYC accounted for 48 percent of OOM station-hours in the first quarter of 2013.
  - ✓ For the Narrows GTs, 52 percent of OOM station-hours were for Greenwood/ Staten Island load pocket security, and the rest were for eastern NY reliability, 138kV load pocket security, or Sprainbrook/Dunwoodie load pocket security.
  - ✓ Arthur Kill units were committed and dispatched OOM to manage security of the Freshkills and Sprainbrook/Dunwoodie load pockets on several days.
- East upstate accounted for 32 percent of OOM station-hours in the first quarter.
  - ✓ Nearly 55 percent was to dispatch Selkirk II for local transmission security on four days (February 4-7) due to a planned transmission outage.
- Long Island accounted for 16 percent of OOM station-hours in the first quarter.
  - ✓ Over 50 percent was for NYISO security and reliability, while most of the rest was called by the local TO to secure 69 kV lines into the Valley Stream load pocket.
- Western NY accounted for only 4 percent of OOM station-hours in this quarter.
  - ✓ OOM dispatch in the West fell more than 95 percent from the first quarter of 2012, accounting for the majority of the reduction of OOM in NYCA over the period.
  - ✓ 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.

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



Region	Station Rank	Station Name
New York City	1	Narrows GTs
	2	Arthur Kill STs
Long Island	1	Barrett
	2	Holtsville ICs
East Upstate	1	Sellkirk II
	2	Gilboa
West Upstate	1	Huntley
	2	Indeck Olean

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.

POTOMAC ECONOMICS

Market Power and Mitigation

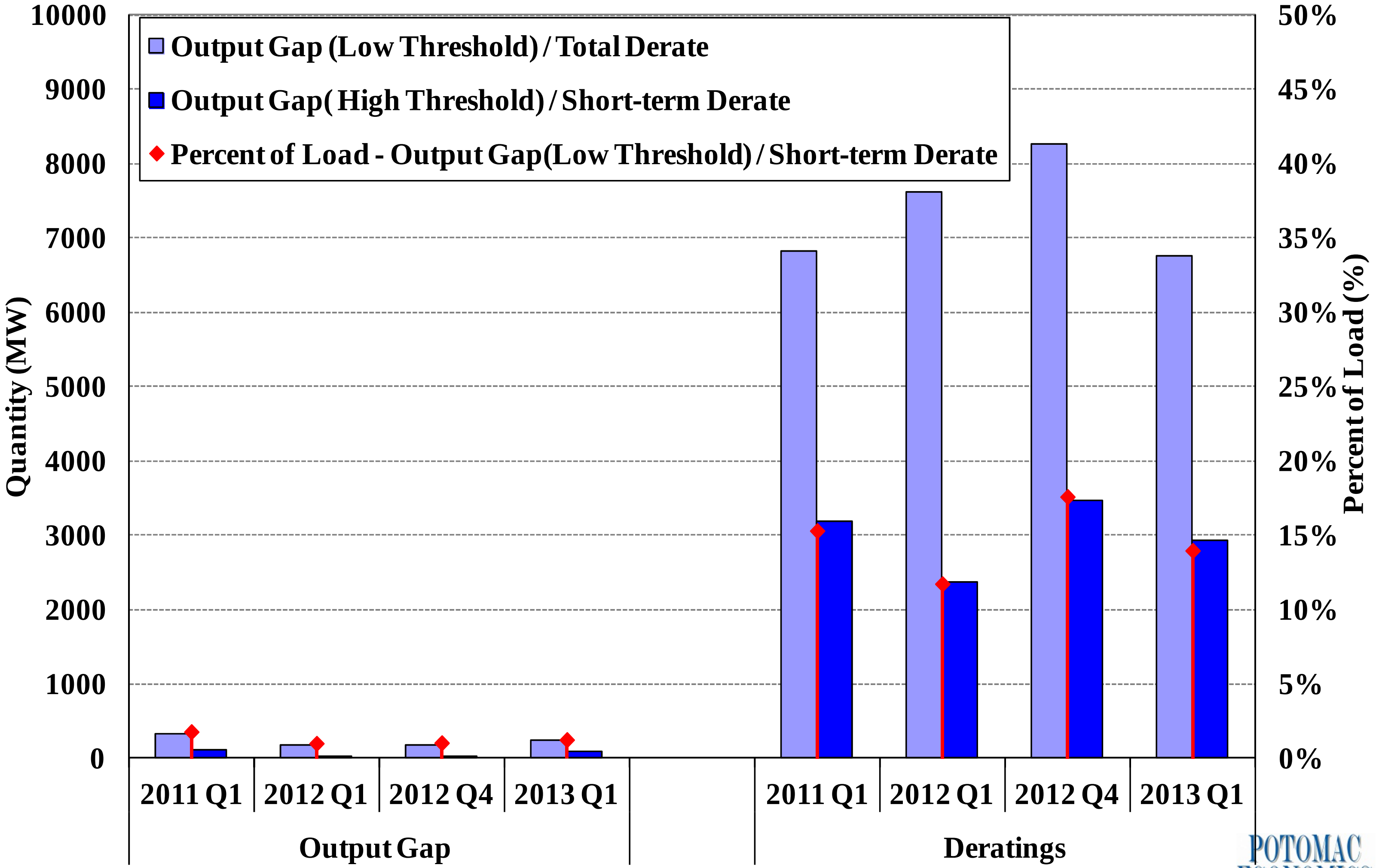
Market Power Screens: Economic Withholding

- 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 slightly more than 1 percent of load based on the low threshold, which is comparable to 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 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 in this quarter versus prior years.
  - ✓ The increase of deratings in the fourth quarter of 2012 resulted from Hurricane Sandy.

Market Monitoring Screens



POTOMAC ECONOMICS

Market Power Mitigation

- This 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 (i.e., the share of hours in which one or more units were mitigated for LBMP impact); 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 Q1	2012 Q1	2012 Q4	2013 Q1
Day-Ahead Market	**Average Mitigated MW**	354	328	129	165
	Energy Mitigation Frequency	43%	39%	2%	30%
Real-Time Market	**Average Mitigated MW**	33	44	43	44
	Energy Mitigation Frequency	7%	5%	4%	8%

POTOMAC ECONOMICS

Automated Market Mitigation

- Most mitigation occurs in the DAM, since that is where most supply is scheduled.
  - ✓ In the first quarter of 2013, nearly 80 percent of mitigation occurred in the DAM primarily for:
    - Local reliability (i.e., DARU & LRR) units (51 percent),
    - The Astoria West Queensbridge/Vernon load pocket (20 percent), and
    - The Greenwood Staten Island load pocket (14 percent).
- DA mitigation fell in recent quarters primarily because:
  - ✓ Less frequent congestion in the 345kV and 138kV areas of NYC than in prior years, resulting from new generation and new transmission.
    - This 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 deratings and outages.

Capacity Market

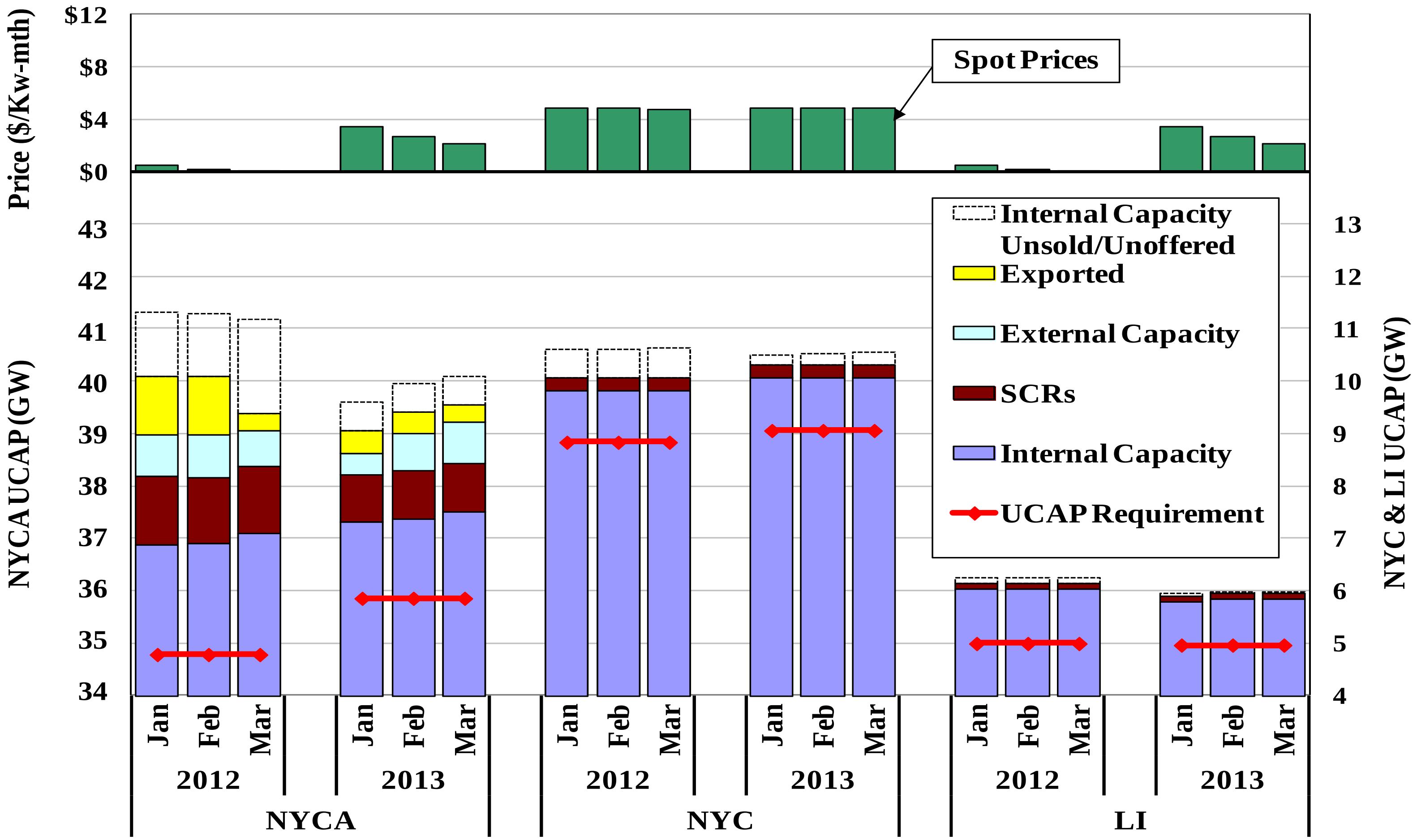
Capacity Market Results

- The following figure summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices in each capacity zone.
  - ✓ UCAP is a measure of installed capacity that accounts for forced outage rates.
- In Rest of State, UCAP spot prices averaged $2.74/kW-month this quarter, up significantly from $0.26/kW-month in the first quarter of 2012 due to:
  - ✓ Internal capacity sales fell 1.8 GW due to the retirement and mothballing of generation, 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; and d) 500 MW in Hudson Valley in January 2013.
  - ✓ The NYCA ICAP requirement rose more than 800 MW from the 2011/12 Capability Year to the 2012/13 Capability Year due to:
    - A 1.8 percent increase in the peak load forecast; and
    - An increase in the IRM from 15.5 percent to 16 percent.
  - ✓ Sales from SCRs fell nearly 400 MW. This may have resulted from increased auditing of resources, more frequent deployments, and low capacity prices.
  - ✓ However, these factors were partly offset by increased sales following the entry of nearly 500 MW of new supply in NYC in June 2012.

Capacity Market Results

- In NYC, UCAP spot prices averaged $4.91/kW-month this quarter, comparable to the first quarter of 2012. However, there were significant offsetting changes in supply and demand over the period, including:
  - ✓ The ICAP requirement rose 219 MW (2.3 percent), which was primarily due to an increase in the LCR from 81 percent to 83 percent.
  - ✓ 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 March 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 were equal to Rest of State prices in each month due to the substantial surplus there during the winter capability period.
  - ✓ However, UCAP sales fell from a year ago due to retirements of 330 MW capacity in July 2012.
  - ✓ The Long Island ICAP requirement fell slightly as a 1.7 percent increase in the peak load forecast was offset by a decrease in the LCR from 101.5 percent to 99 percent.

Capacity Market Results



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

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