Quarterly Report on the New York ISO Electricity Markets First Quarter 2014

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June 2014

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the first quarter of 2014.
- 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 natural gas prices and congestion on the gas pipeline system were the primary drivers of variations in NYISO market outcomes.
  - ✓ RT energy prices averaged $121/MWh statewide, an increase of 86 percent from the first quarter of 2013 primarily because natural gas index prices rose 31 to 185 percent across the system. Other important drivers were:
    - Load levels rose by 560 MW on average because of colder weather;
    - Net imports from Ontario and Quebec fell especially during periods of high electricity demand and high gas prices. Net imports fell by 570 MW on average and by 1,015 MW on the 27 days when natural gas prices exceeded $20/MMbtu.
    - However, these factors were partly offset by increased imports from PJM across the Neptune Line, the HTP Line, and the Ramapo Line (collectively 470 MW).
  - ✓ Production from oil-fired units rose 469 percent from a year ago because high natural gas prices led oil-fired generation to be economic on nearly 30 days.
    - Consequently, oil-fired units were on the margin in 23 percent of intervals, up from 7 percent in the first quarter of 2013.

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Highlights and Market Summary: Congestion Patterns and DA-RT Price Convergence

- Day-ahead congestion revenue increased to $427 million from $320 million in the first quarter of 2013 as a result of larger natural gas price spreads between East NY and West NY.
  - ✓ The Central-East Interface accounted for 64 percent of day-ahead congestion.
  - ✓ However, congestion was less frequent than in the first quarter of 2013 because there were many periods when energy prices in West NY rose to the levels of prices in East NY as a result of:
    - The reduced imports to West NY from Ontario and Quebec; and
    - The increased imports to East NY from PJM across Neptune, HTP, and Ramapo.
  - ✓ Consequently, average real-time energy prices in West NY rose more (118 percent) than in East NY (55 to 88 percent).
- Convergence between day-ahead and real-time energy prices worsened in most areas, particularly during periods of volatile gas prices, extreme weather, and gas pipeline OFOs.
  - ✓ Average day-ahead prices were 1 percent higher than real-time prices in the West Zone and were 4 to 9 percent higher than real-time prices in other areas.
  - ✓ January 22 to 29 (which exhibited the most gas price volatility) accounted for most of the day-ahead premiums.

Highlights and Market Summary:
Energy Market in Winter Peak Conditions

- Hourly production from oil-fired generation rose significantly on 27 days when natural gas prices in Eastern NY exceeded $20/MMbtu, averaging 2.4 GW during these periods and reaching a maximum of 5.7 GW on January 23.
  - ✓ On most of these days, pipeline capability into East NY was not fully utilized because the import-constrained area (for natural gas) encompassed East NY and portions of neighboring systems.
  - ✓ The majority of oil was used on days when gas pipeline constraints led to high gas prices up and down the Atlantic coast, leading generators in East NY to use fuel oil when gas was available.
    - Our simulations indicate that dual-fueled CCs and steam turbines in East NY could have earned an additional $34 to $43/kW-year from dual-fuel capability.
    - However, actual use of oil was limited by planned and forced generator outages, low oil inventories, and air permit restrictions.
- Nonetheless, the widespread use of oil during high gas price conditions reflects that the market performed relatively well in guiding the fuel consumption decisions of generators.
- Large amounts of dual-fueled capacity in East NY burned gas, was scheduled for operating reserves, or not committed, suggesting that existing installed resources more than adequate to satisfy system needs in extreme winter conditions.

Highlights and Market Summary: Capacity Market

- UCAP spot prices rose notably in the first quarter of 2014.
  - ✓ In Rest of State and Long Island, UCAP spot prices averaged $3.91/kW-month, up 43 percent from the first quarter of 2013.
  - ✓ In New York City, UCAP spot prices averaged $9.64/kW-month this quarter, up 96 percent from the first quarter of 2013.
- Higher UCAP prices were primarily driven by increased ICAP requirements from the 2012/13 Capability Year to the 2013/14 Capability Year, which rose:
  - ✓ 314 MW (0.8%) in NYCA due to an increase in the IRM from 16% to 17%;
  - ✓ 332 MW (3.5%) in NYC due to an increase in the LCR from 83% to 86%; and
  - ✓ 320 MW (5.8% in LI due to an increase in the LCR from 99% to 105%.
- The increased LCRs in NYC and LI (in the 2013/14 Capability Year) resulted primarily from the loss of generating capacity in the Hudson Valley, since this requires more capacity in downstate areas to secure the UPNY-SENY interface.
  - ✓ However, this is less efficient than modeling a capacity Locality that includes the Hudson Valley and setting the LCR in the new Locality at a level that accurately reflects the reliability benefits of placing capacity there.
  - ✓ Hence, modeling the new G-J Locality starting in the 2014/15 Capability Year better enables the market to provide efficient investment signals.

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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 2014 from a year ago.
- The uplift from guarantee payments totaled $98 million, up 95 percent from the first quarter of 2013.
  - ✓ Daily uplift costs were correlated with the variation of natural gas prices
    - – 31 percent of all guarantee payment uplift accrued from January 22 to 28 when natural gas prices averaged over $50/MMbtu in Eastern NY.
  - ✓ Increased supplemental commitment and OOM dispatch also contributed to the increase in guarantee payment uplift.
- Day-ahead congestion shortfalls were $35 million, up $13 million from a year ago.
  - ✓ Transmission outages in NYC, Long Island, and on the Ramapo PARs accounted for the majority of the shortfalls.
    - – This was offset by $13 million surpluses generated at the Central-East and Oswego Export interfaces due to changes in commitment and generation patterns.
- Balancing congestion shortfalls totaled *negative* $9 million (i.e., a surplus), comparable to the first quarter of 2013.
  - ✓ The surplus resulted primarily from changes in generation patterns after the DAM because of changing weather patterns, natural gas prices, generation forced outages, and SRE commitments.

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Energy Market Outcomes

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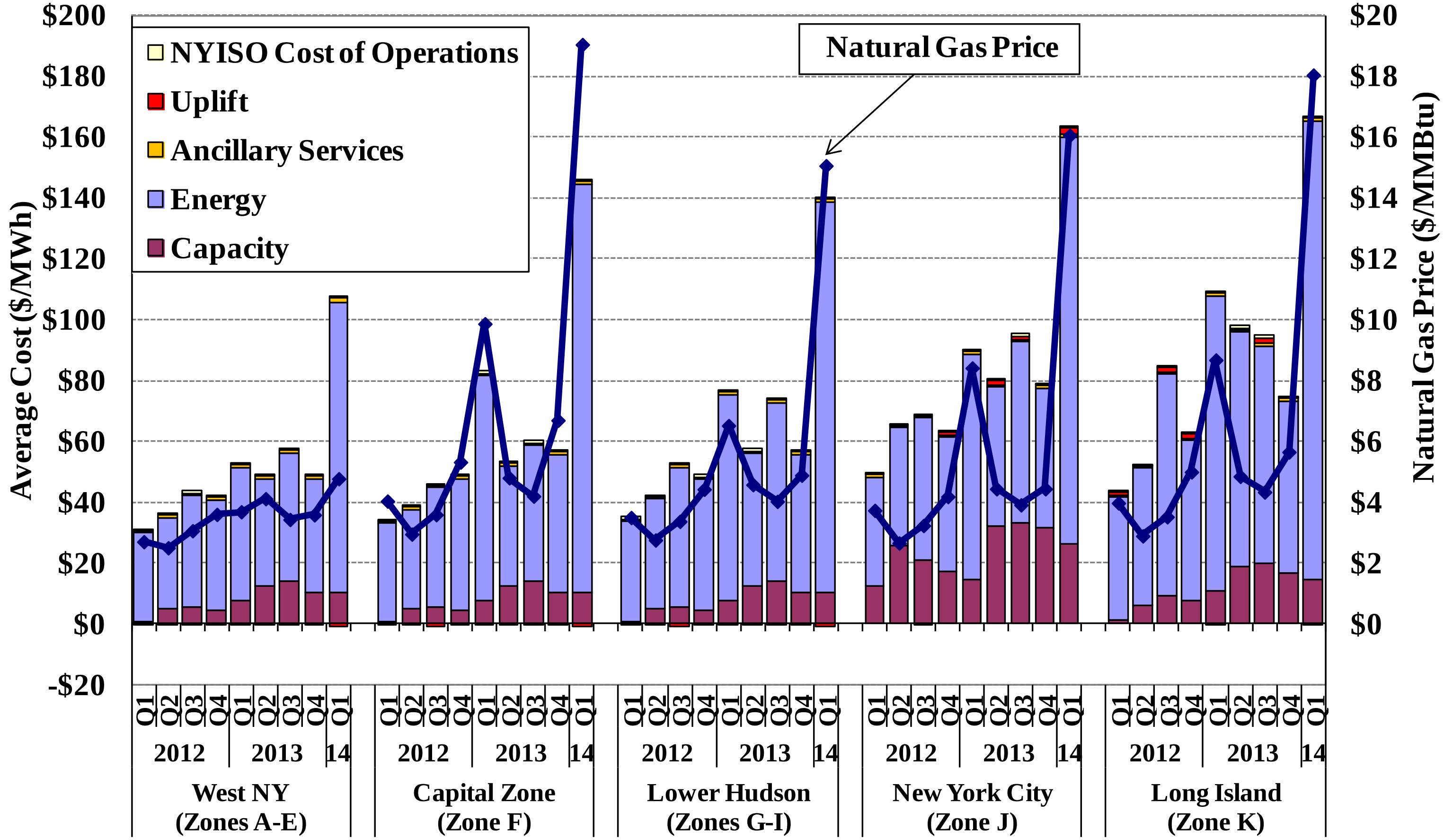
All-In Prices

- The first figure summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component based on spot prices multiplied by capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Rate Schedule 1 charges.
- Average all-in prices ranged from \$107/MWh in West NY to \$167/MWh on Long Island, up 53 percent (Long Island) to 104 percent (West NY) from a year ago.
  - ✓ Energy prices rose from 55 percent (Long Island) to 119 percent (West NY).
    - – In East NY, higher LBMPs were driven by higher gas prices and load levels.
    - – In West NY, LBMPs rose considerably when the Central-East interface was uncongested.
      - High gas prices in East NY frequently coincided with low imports from Quebec, Ontario, and PJM, resulting in high LBMPs in West NY.
    - – The Neptune Line returned to full operation, offsetting the effects of higher gas prices on Long Island.
  - ✓ Capacity costs rose \$12/MWh in NYC and \$3 to \$4/MWh elsewhere primarily because of higher ICAP requirements (330 MW in NYC, 320 MW in Long Island, and 315 MW in NYCA).

All-In Energy Price by Region



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

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Load Levels and Fuel Prices

- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Load averaged 19.1 GW, up 3 percent from the first quarter of 2013.
  - ✓ NYISO set a new winter peak of 25,738 MW on January 7, 2014, up 1,080 MW from 2013 winter peak and 197 MW from the prior all-time winter peak in 2004.
    - Demand response was activated statewide on a voluntary basis.
  - ✓ Load exceeded 22 GW in 138 hours this quarter, compared to 43 such hours in the first quarter of 2013.
- Natural gas prices averaged $4.58 at Dominion North (West NY), $15.87 at Transco Z6 (NY) (NYC), and $17.85 at Iroquois Z2 (most other East NY).
  - ✓ Average gas prices rose substantially from last winter, up 31 percent in West NY and up around 100 percent in most of East NY.
    - Increased spreads between West NY and East NY gas prices affect generation patterns and lead to electricity price spreads when transmission congestion occurs.
  - ✓ Gas prices exceeded oil prices on 20 to 30 days, leading to substantial increases in LBMP, congestion, and uplift.

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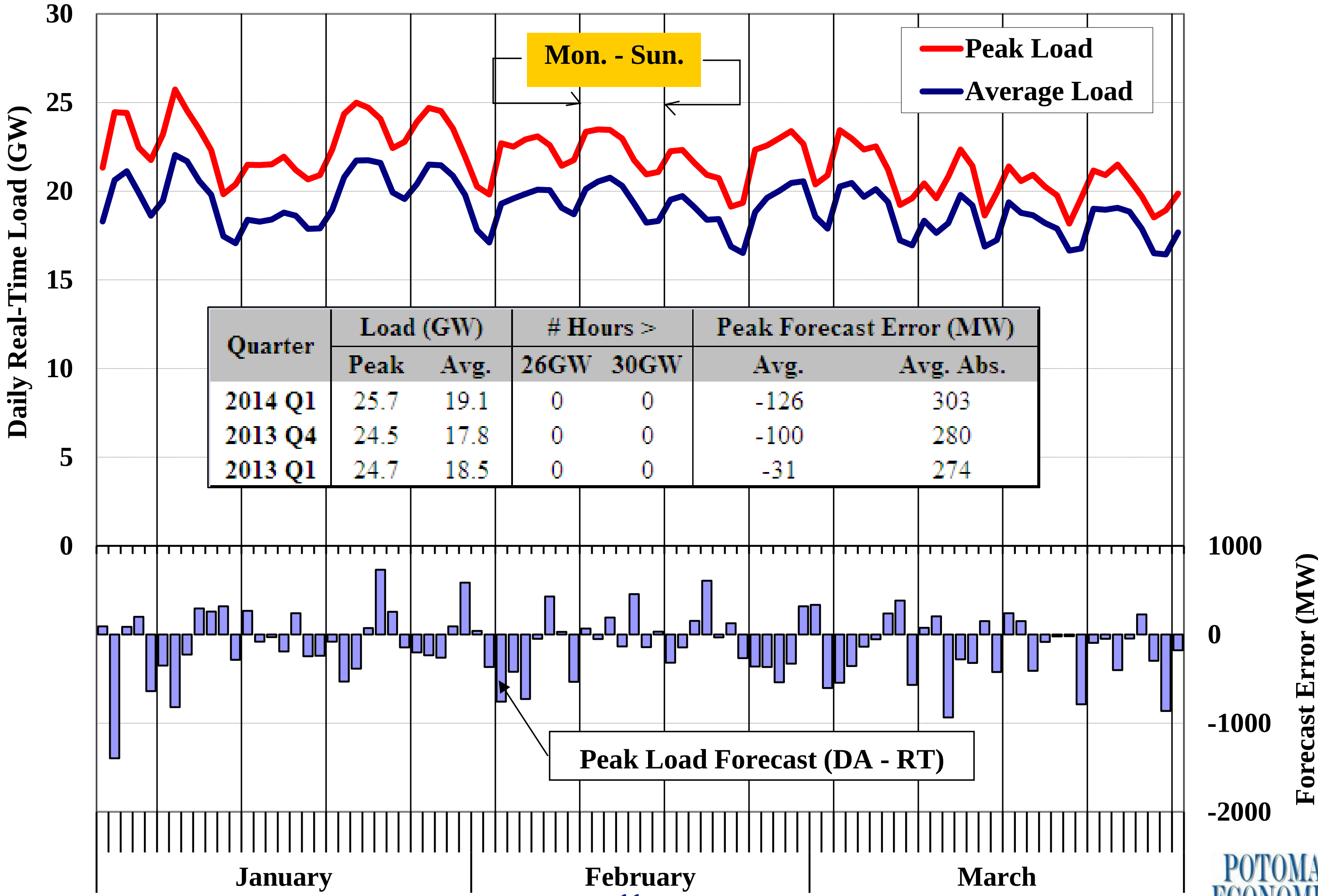
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2014 Q1	25.7	19.1	0	0	-126	303
2013 Q4	24.5	17.8	0	0	-100	280
2013 Q1	24.7	18.5	0	0	-31	274

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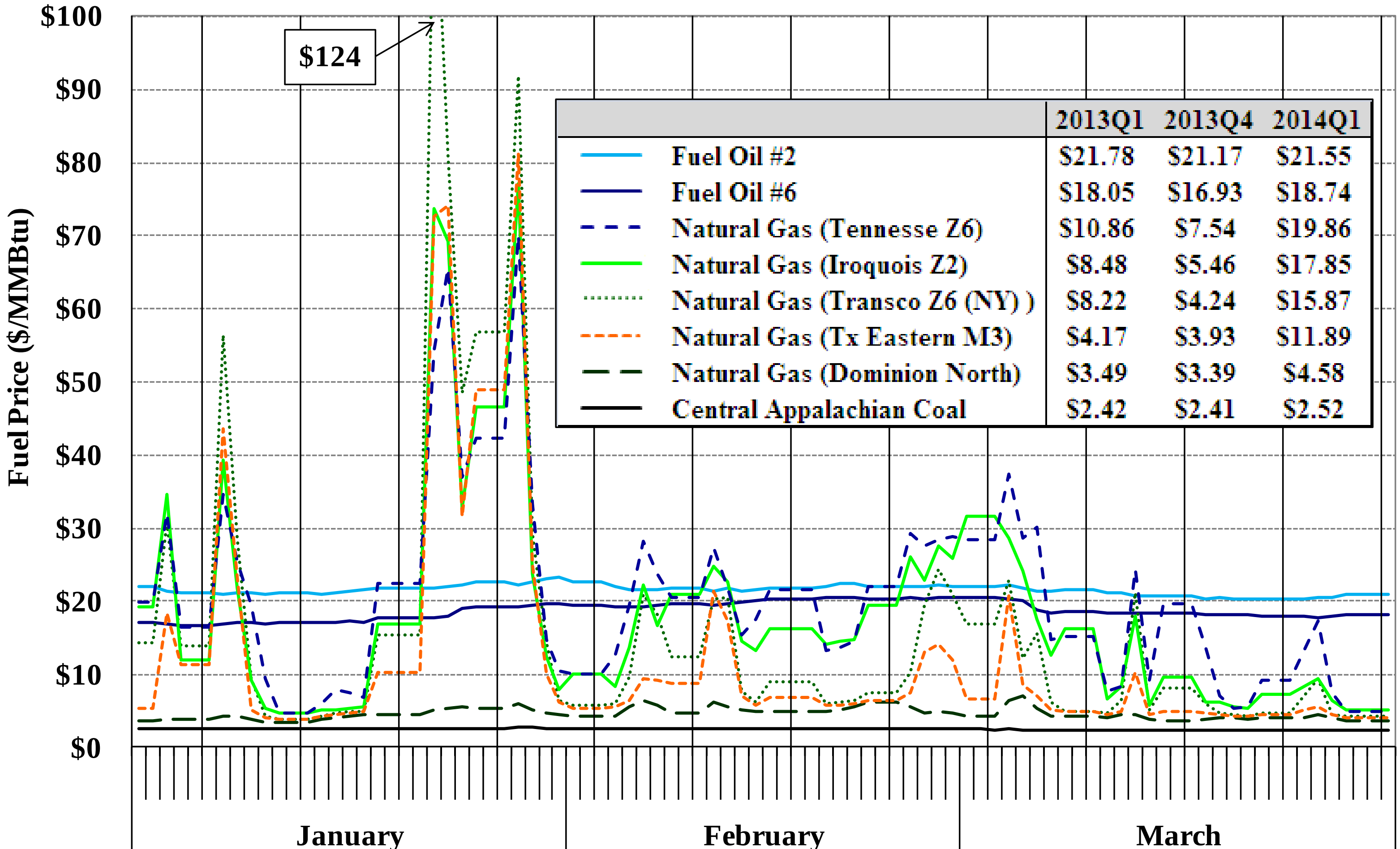
Coal, Natural Gas, and Fuel Oil Prices



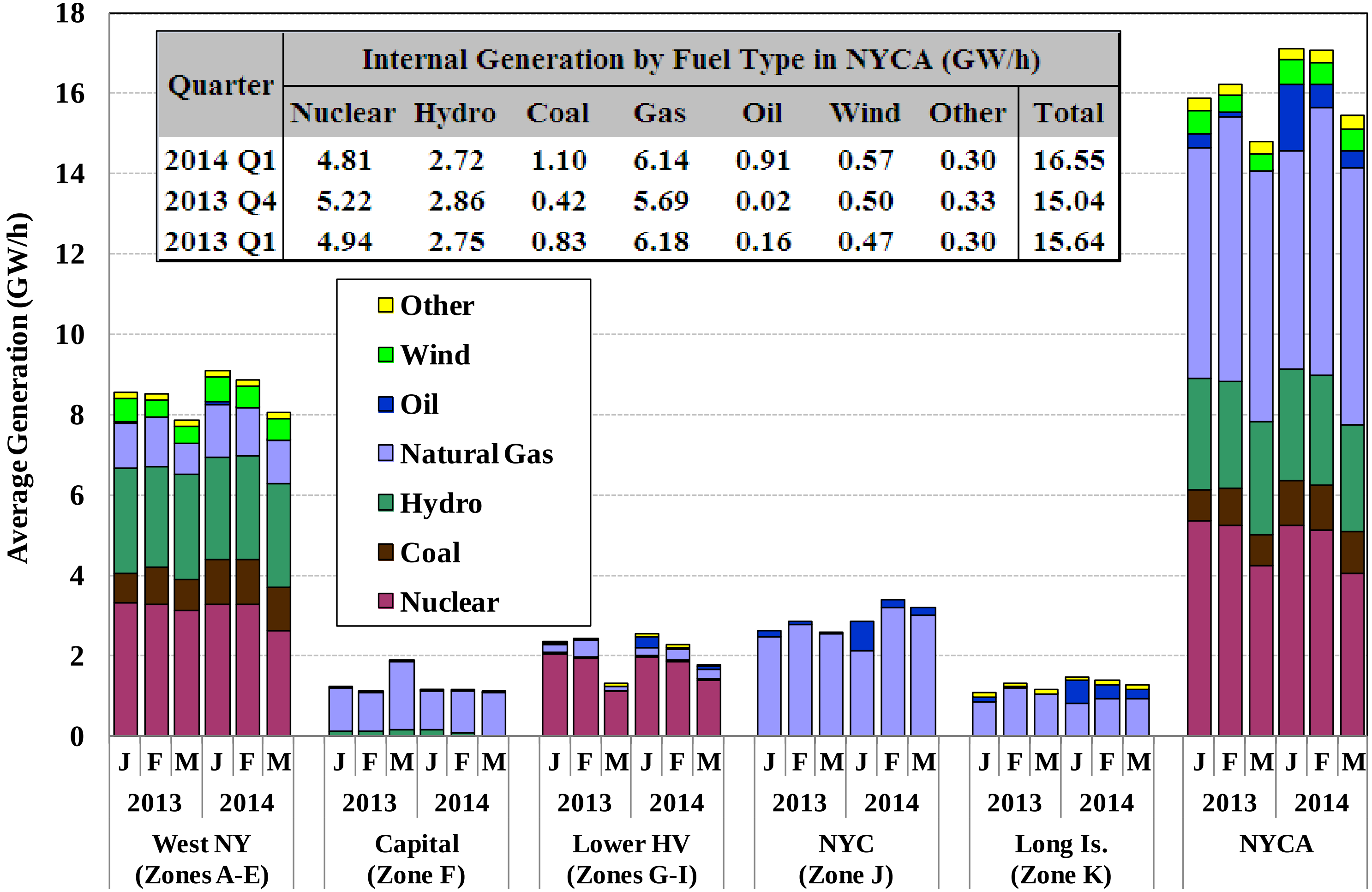
Real-Time Generation by Fuel Type

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the first quarter of 2014.
  - ✓ The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
  - ✓ The second figure summarizes how frequently each fuel type is on the margin and setting real-time LBMPs in these regions.
    - – More than one type of generator may be on the margin in an interval, particularly when a transmission constraint is binding. Accordingly, the total for all fuel types may be greater than 100 percent.
      - For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent.
    - – When no generator is on the margin in a particular region, the LBMPs in that region are set by:
      - Generators in other regions in the vast majority of intervals; or
      - Shortage pricing of ancillary services, transmission constraints, and/or energy in a small share of intervals.
  - ✓ The fuel type for each generator is based on its actual fuel consumption reported to the EPA and the EIA.

Real-Time Generation and Marginal Units by Fuel Type

- Gas-fired (37 percent), nuclear (29 percent), and hydro (16 percent) generation accounted for most of internal generation in the first quarter of 2014.
  - ✓ Average nuclear generation fell 400 MW from the prior quarter and 130 MW from the first quarter of 2013 mainly because of planned outages of two units.
  - ✓ Coal-fired and oil-fired generation rose notably from prior quarters because of higher natural gas prices. Compared to the first quarter of 2013,
    - Average coal-fired generation rose 270 MW despite retirements and mothballs at several plants; and
    - Average oil-fired generation rose 750 MW.
  - ✓ Wind generation also increased due to additional installed wind capacity.
  - ✓ However, gas-fired generation did not fall much, reflecting increased load levels (average 560 MW) and lower net imports (average 180 MW).
- Gas-fired and hydro resources were on the margin most of time in New York.
  - ✓ 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).
  - ✓ Oil-fired resources were on the margin in 23 percent of intervals this quarter due to substantially higher natural gas prices, especially in January.

Real-Time Generation Output by Fuel Type



Quarter	Internal Generation by Fuel Type in NYCA (GW/h)							
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other	Total
2014 Q1	4.81	2.72	1.10	6.14	0.91	0.57	0.30	16.55
2013 Q4	5.22	2.86	0.42	5.69	0.02	0.50	0.33	15.04
2013 Q1	4.94	2.75	0.83	6.18	0.16	0.47	0.30	15.64

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

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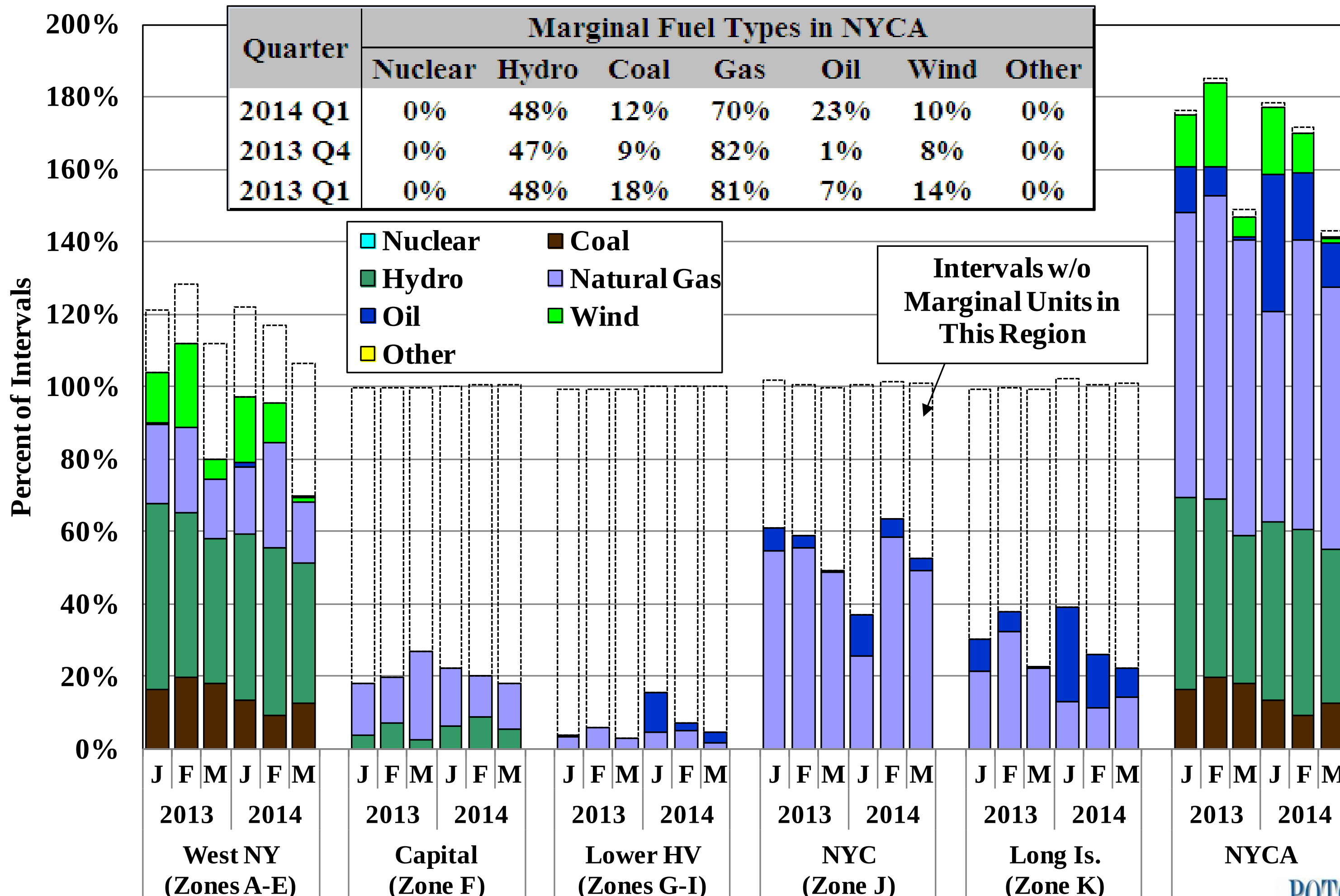
Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other
2014 Q1	0%	48%	12%	70%	23%	10%	0%
2013 Q4	0%	47%	9%	82%	1%	8%	0%
2013 Q1	0%	48%	18%	81%	7%	14%	0%



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

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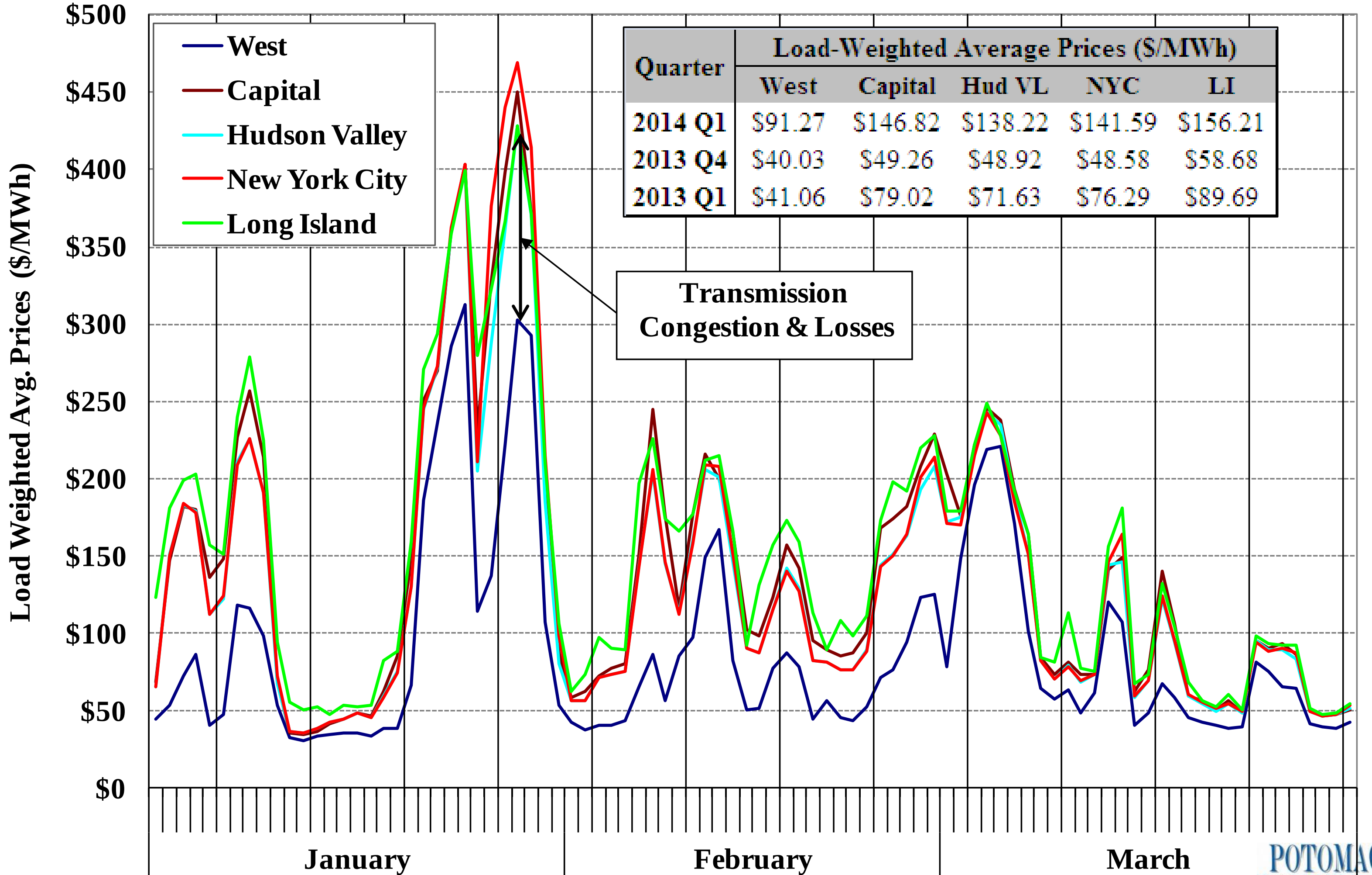
Day-Ahead and Real-Time Electricity Prices

- The following three figures show: 1) load-weighted average 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 first quarter of 2014.
  - ✓ 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 $91/MWh in the West Zone to $156/MWh on Long Island, up considerably from the first quarter of 2013 because of:
  - ✓ Higher gas prices, which were the primary driver; and
  - ✓ Increased winter peaking conditions due to extreme cold weather.
  - ✓ West Zone exhibited the largest increase (122 percent) among these regions.
    - – Central-East congestion was less frequent than a year ago partly because of increased imports across the Ramapo line and decreased exports to NE.
    - – Nuclear generation in West NY and imports from Ontario and Quebec combined fell by over 700 MW, leading to the dispatch of more expensive generation.
  - ✓ Long Island exhibited the smallest increase (74 percent) in LBMPs partly because of increased Neptune imports (since it fully returned in mid-2013).

Day-Ahead and Real-Time Electricity Prices

- Prices are generally more volatile in the real-time market than in the day-ahead market due to unexpected events. Some notable examples were:
  - ✓ On January 7, RT prices were substantially elevated in most areas when:
    - A very large unit in East NY tripped the previous evening; and
    - A Force Majeure event on the Tx Eastern pipeline in Pennsylvania reduced the available gas supply to NYISO generators and led PJM imports to fall 1.5 GW from the DAM in peak hours.
  - ✓ From January 22 to 29, spreads between DA and RT LBMPs varied considerably, often driven by changes in weather patterns, natural gas prices, and supplemental commitments after the DAM.
  - ✓ On March 4, RT prices rose considerably across the system when one nuclear unit in Western NY tripped in the early morning.
- 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 1 percent higher than real-time prices in the West Zone and were 4 to 9 percent higher than real-time prices in other areas.
  - ✓ January 22 to 29 accounted for most of the day-ahead premiums.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2014 Q1	$91.27	$146.82	$138.22	$141.59	$156.21
2013 Q4	$40.03	$49.26	$48.92	$48.58	$58.68
2013 Q1	$41.06	$79.02	$71.63	$76.29	$89.69

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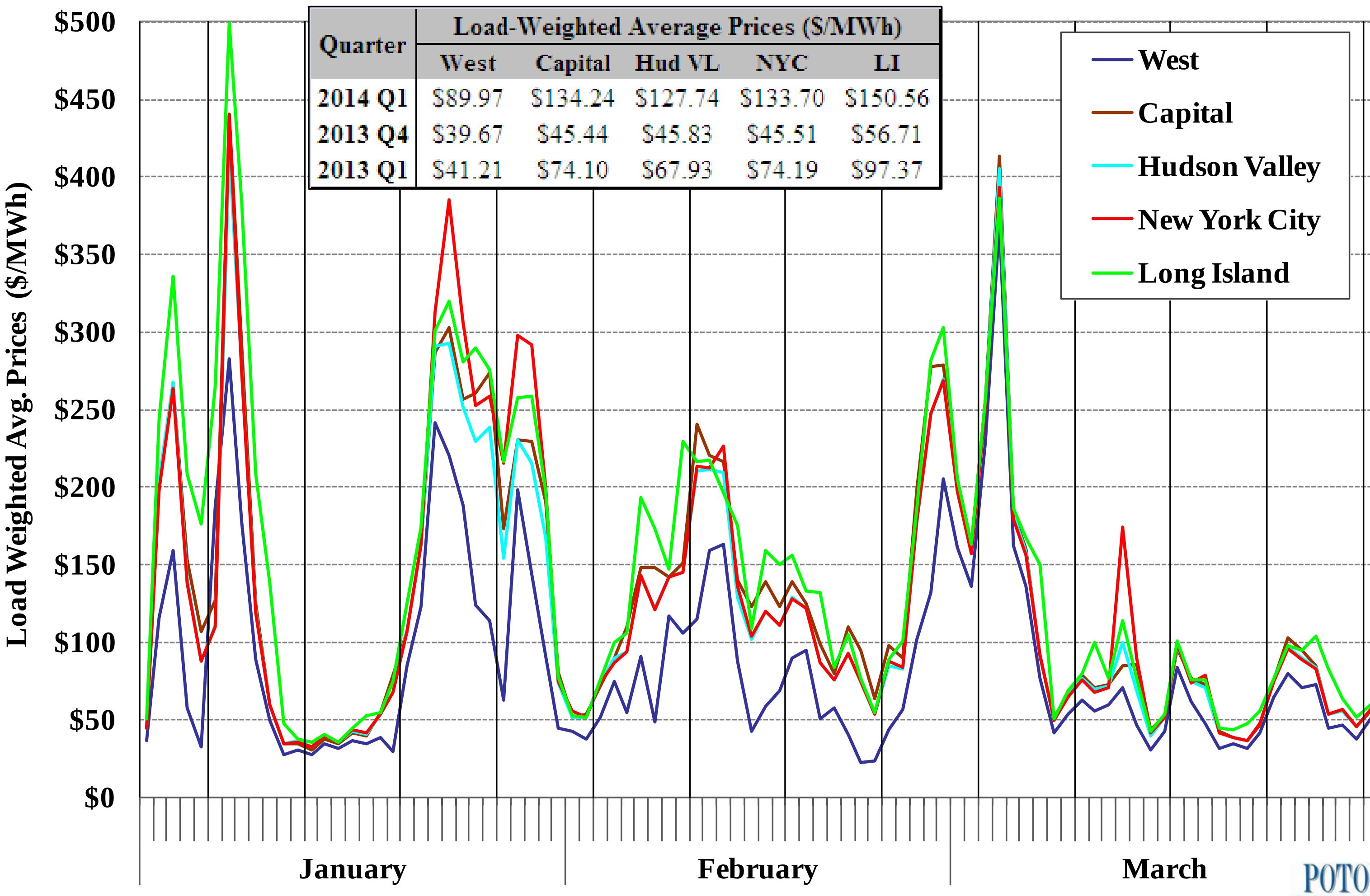
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2014 Q1	$89.97	$134.24	$127.74	$133.70	$150.56
2013 Q4	$39.67	$45.44	$45.83	$45.51	$56.71
2013 Q1	$41.21	$74.10	$67.93	$74.19	$97.37

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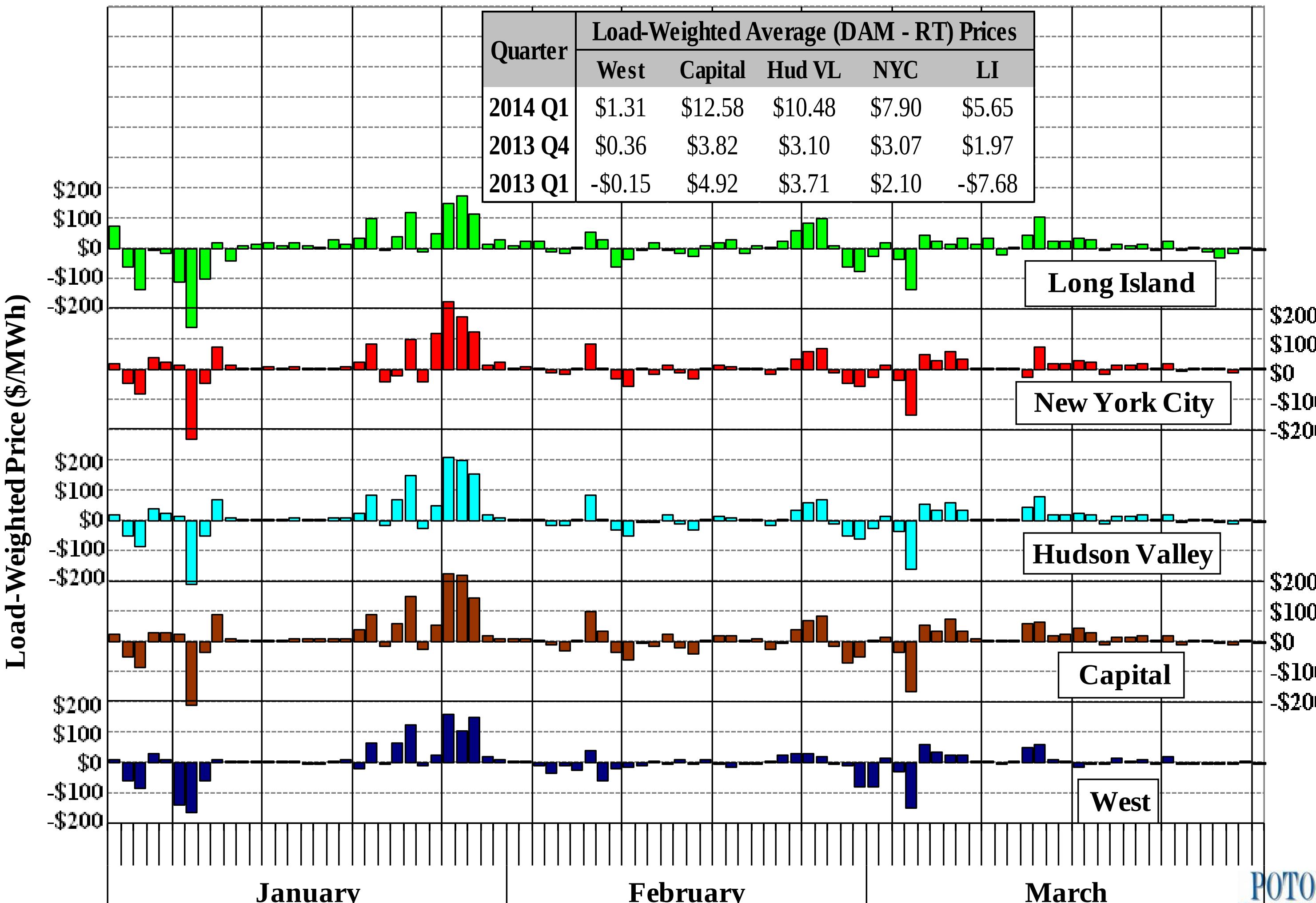
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2014 Q1	$1.31	$12.58	$10.48	$7.90	$5.65
2013 Q4	$0.36	$3.82	$3.10	$3.07	$1.97
2013 Q1	-$0.15	$4.92	$3.71	$2.10	-$7.68



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Fuel Use during Winter Operations

Fuel Usage under Tight Gas Supply Conditions

- The following two figures evaluate the efficiency of fuel usage in Eastern New York in the first quarter of 2014, focusing on periods with tight natural gas supply.
  - ✓ The first figure provides daily averages for:
    - Internal generation by actual fuel consumed; and
    - Day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY).
  - ✓ The second figure compares actual oil usage for dual-fueled units in NYC with the optimal level based on simulations.
    - The comparison was done for a typical CC and a typical ST (see net revenue analysis in the 2013 SOM for the assumptions used in the simulations).
    - The simulated optimal level assumes: 1) no planned generation outages; 2) sufficient oil inventories; and 3) no air permit limitations.
    - The figure shows on a daily basis:
      - The actual capacity factor on oil vs. optimal capacity factor on oil (in the bottom portion of the figure); and
      - The additional net revenues a unit could earn from dual-fuel capability based on the simulations (in the upper portion of the figure).
    - The table in the figure summarizes these quantities for the quarter.

Fuel Usage under Tight Gas Supply Conditions Eastern New York

- Gas supply to electric generators was limited by high heating demand on many days in the first quarter of 2014 due to extreme cold weather.
  - ✓ As a result, natural gas prices exceeded \$20/MMbtu on 27 days in Eastern NY.
- 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.
  - ✓ Hourly production from oil rose significantly on the 27 days, averaging 2.4 GW and reaching a maximum of 5.7 GW on January 23.
  - ✓ Production from oil was particularly high from January 21 to 29 when natural gas prices averaged over \$60/MMbtu, accounting for 40 percent of total oil-fired generation during the quarter.
    - – The large amount of oil use in a single 9-day period illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.
- The widespread use of oil indicates that the market performed reasonably well in conserving the available supply of natural gas under tight gas supply conditions.
  - ✓ The NYISO’s DAM helps coordinate decisions by generators about whether to operate on natural gas, oil, or a blend.

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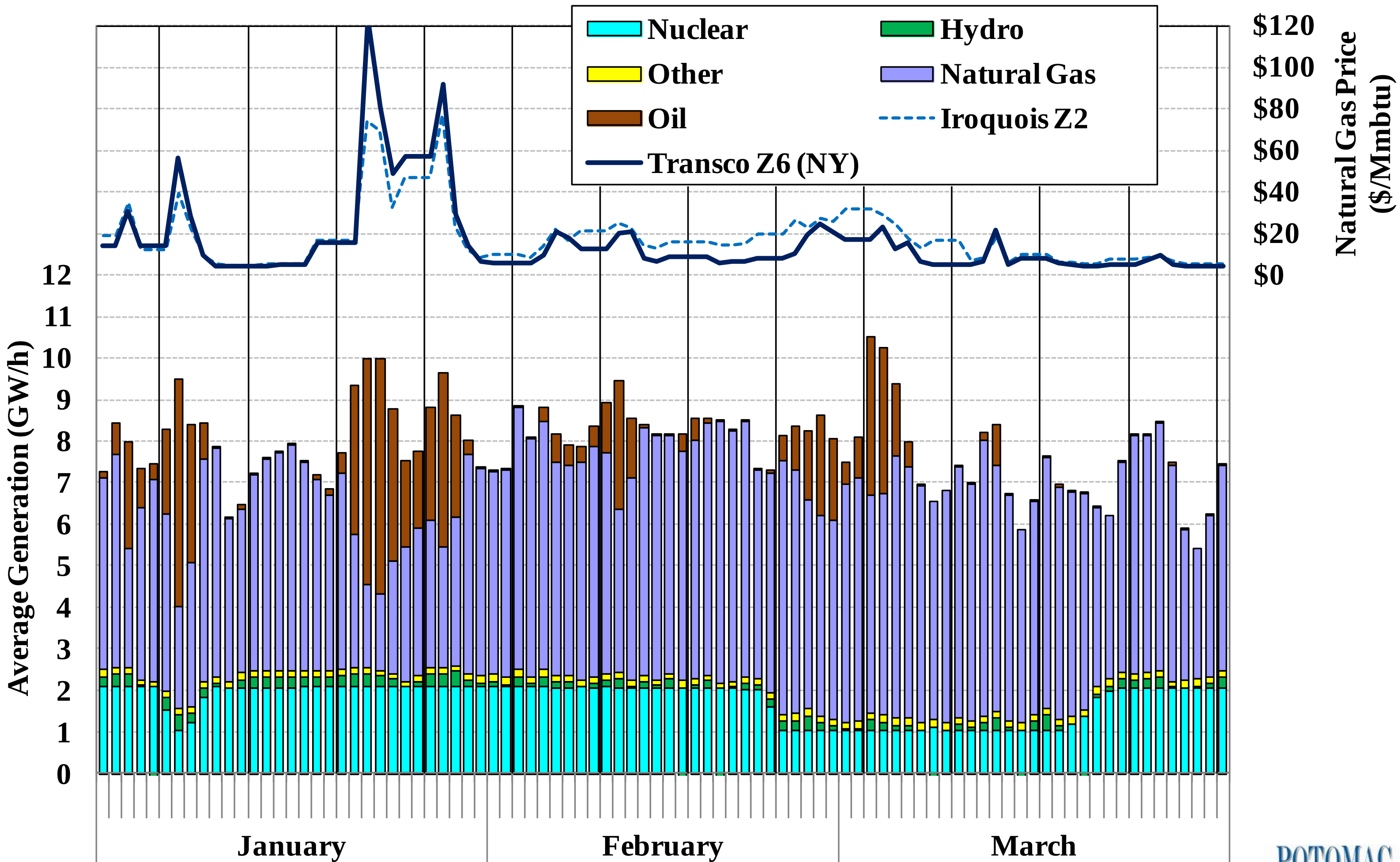
Fuel Usage under Tight Gas Supply Conditions
Eastern New York

- On a few days, oil was only used after the available pipeline capability into East NY and New England was fully utilized. For example:
  - ✓ On January 2, gas pipeline flows into East NY reached nearly 7 million MMbtus.
    - 44 percent flowed into New England;
    - 40 percent went to serve core gas demand in East NY; and
    - 16 percent was consumed by generators in East NY.
  - ✓ This illustrates how moderate variations in gas demand have large effects on the availability of fuel to generators.
- On most days when oil was used, pipeline capability into East NY was not fully utilized because the import-constrained area (for gas) was larger than East NY.
  - ✓ January 6-8 & 21-29 – Gas pipeline constraints occurred into the entire Atlantic coastal region, resulting in high gas prices in a multi-state region and providing incentives for generators in East NY to use fuel oil when gas was available.
  - ✓ March 1-3 – Gas flows into East NY was reduced because of high demand in Canada, leading generators in East NY to use fuel oil as the NYISO exported power to Ontario and Quebec in many hours.

Fuel Usage under Tight Gas Supply Conditions
Potential Net Revenues for Dual-Fueled Units in NYC

- However, our simulations indicate that actual production from oil was significantly lower than would have been optimal based on gas prices and LBMPs.
  - ✓ The average actual capacity factors on oil were about one-third of the optimal levels for steam turbines and combined-cycle units in NYC. Although not shown, the ratios were similar in the rest of East NY.
  - ✓ Potentially, \$34-\$43/kW-year of additional net revenue could have been earned from dual-fuel capability.
    - – Most of this would have been in a 9-day period from January 21 to 29, reinforcing the difficulty of predicting and maintaining optimal oil inventories.
- Several factors reduced the use of oil by generators in the first quarter.
  - ✓ Timing differences between gas and electric markets sometimes lead generators to commit to burning natural gas when oil would have been economic in retrospect.
  - ✓ Oil-fired generation availability was reduced by:
    - – Planned and forced outages – Major maintenance outages led several units to be unavailable throughout the first quarter;
    - – Low oil inventories – Given the cost of working capital, the risk of holding excess oil after the winter limits the inventory of most generators; and
    - – Air permit restrictions – These limit the run hours and/or grades of fuel that may be used.

Actual Fuel Usage and Natural Gas Price
Eastern New York



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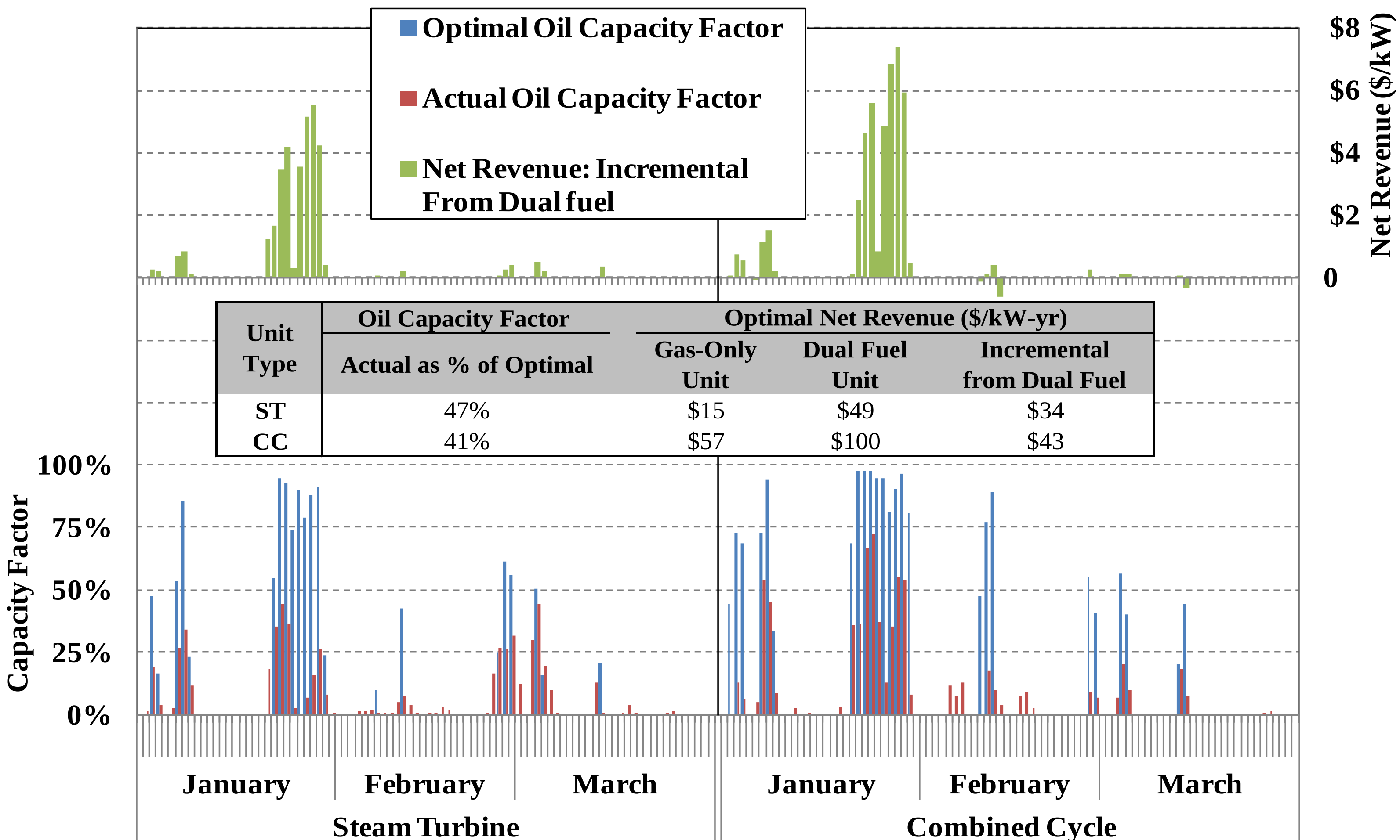
Actual Oil Production vs Optimal Oil Production
New York City



Unit Type	Oil Capacity Factor	Optimal Net Revenue ($/kW-yr)		
	Actual as % of Optimal	Gas-Only Unit	Dual Fuel Unit	Incremental from Dual Fuel
ST	47%	$15	$49	$34
CC	41%	$57	$100	$43

Ancillary Services Market

Ancillary Services Prices and Offer Patterns

- This part of the report evaluates the outcomes of the ancillary services markets.
- Two figures summarize DA and RT prices for four ancillary services products:
  - ✓ 10-min spinning reserves prices in eastern NY, which reflect the cost of requiring:
    - 330 MW of 10-minute spinning reserves in eastern NY;
    - 655 MW of 10-minute spinning reserves state-wide; and
    - 1,200 MW of 10-minute total reserves (spin and non-spin) in eastern NY.
  - ✓ 10-min non-spinning reserves prices in eastern NY, which reflect the cost of requiring 1,200 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-min spinning reserves prices in western NY, which reflect the cost of requiring 655 MW of 10-minute spinning reserves statewide.
  - ✓ Regulation prices, which reflect the cost procuring up to 300 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.

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Ancillary Services Prices and Offer Patterns

- The last two figures examine price convergence and offer patterns associated with two reserve products in more detail.
- The NYISO implemented a process in phases to modify two DA ancillary services mitigation provisions.
  - ✓ In the first phase, the NYISO raised on January 23, 2013:
    - – The reference level cap for 10-min non-spin from $2.52 to $5/MWh; and
    - – The offer cap for 10-min spin for NYC generators from $0 to $5/MWh.
  - ✓ In the second phase, the NYISO raised both caps from $5 to $10/MWh on September 25, 2013.
- 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.

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Ancillary Services Prices and Offer Patterns

- Average prices for all four ancillary services products increased notably from the first quarter of 2013, largely driven by higher opportunity costs associated with higher energy prices.
- Differences between DA and RT prices increased for most ancillary services products, similar to the patterns for LBMPs and natural gas prices.
  - ✓ However, price convergence was better for regulation service than other products.
    - – The new regulation market was implemented in June 2013, allowing participants to offer regulation movement costs separately from regulation capacity costs.
    - – DA regulation capacity prices were generally more consistent with RT capacity prices following the implementation.
- The number of reserve shortages in Eastern NY fell modestly from the first quarter of 2013 despite increased winter peaking conditions and substantially higher and more volatile natural gas prices.
  - ✓ This reflects that the system generally faced energy limitations (from limited fuel) rather than capacity limitations in Eastern NY in this quarter.
  - ✓ However, system-wide reserve and regulation shortages rose notably, reflecting tighter system conditions from lower imports and increased loads.

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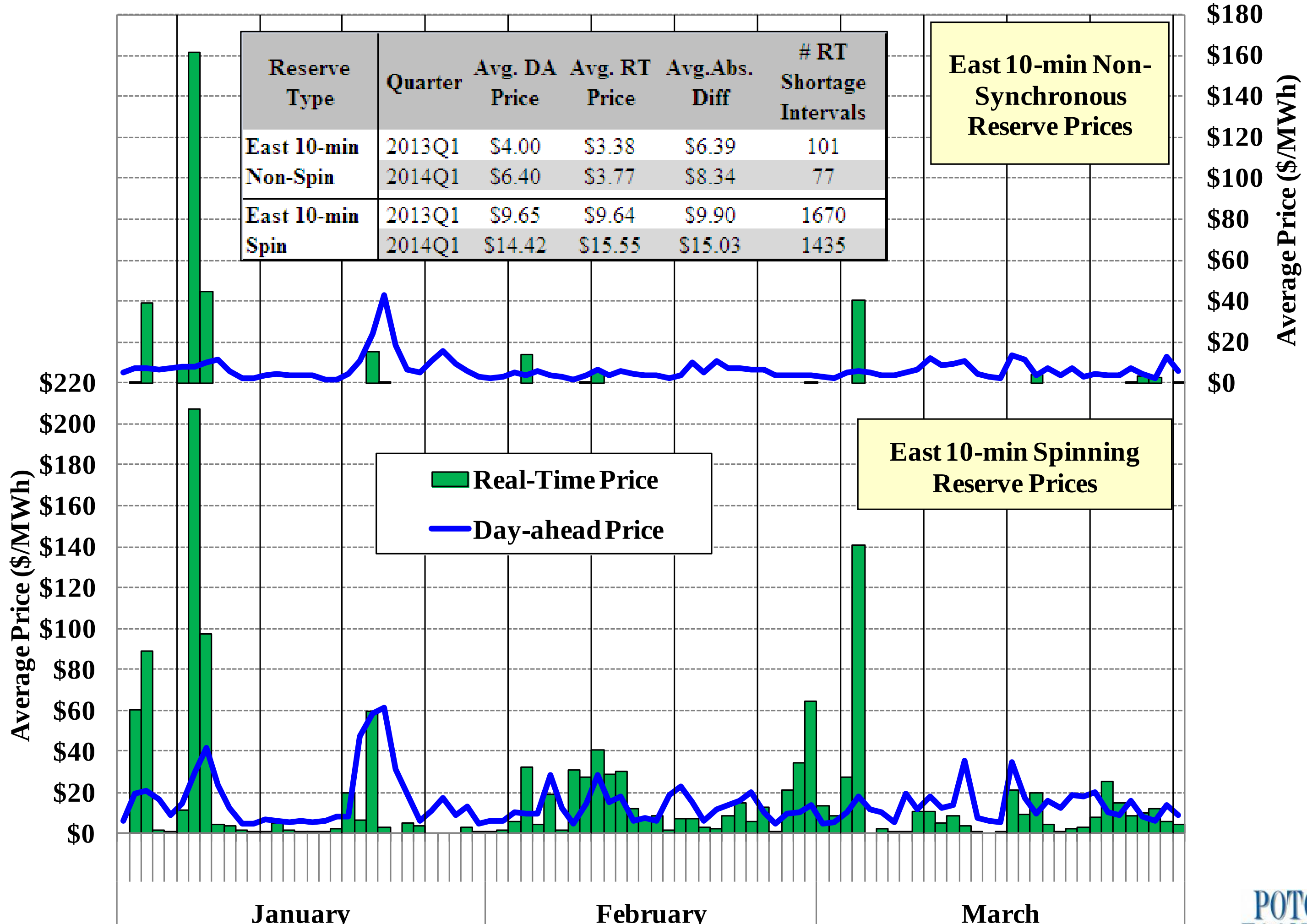
Ancillary Services Prices and Offer Patterns: New Mitigation Rules

- 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 when RT prices are more likely to reach very high levels (e.g., hours 12-17 and when Eastern NY peak load > 15 GW).
    - – Such increases are consistent with competitive behavior when the RT clearing price is expected to be higher than the DA clearing price.
    - – Furthermore, such increases improve convergence between DA and RT prices.
- Price convergence has improved for both products during high load periods following the revisions of mitigation rules.
  - ✓ On days when the daily peak load in Eastern NY exceeded 15 GW, DA prices were more consistent with RT prices in the first quarter of 2014 (Phase 2) than in the first quarter of 2013 (Phase 1).
- During low and moderate load periods, reserve prices have always been higher in the DAM than in the RT market. This pattern:
  - ✓ Is reasonable given the risk profile for a day-ahead reserve seller; and
  - ✓ Has continued since the recent modifications to the mitigation rules.

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



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2013Q1	$4.00	$3.38	$6.39	101
	2014Q1	$6.40	$3.77	$8.34	77
East 10-min Spin	2013Q1	$9.65	$9.64	$9.90	1670
	2014Q1	$14.42	$15.55	$15.03	1435

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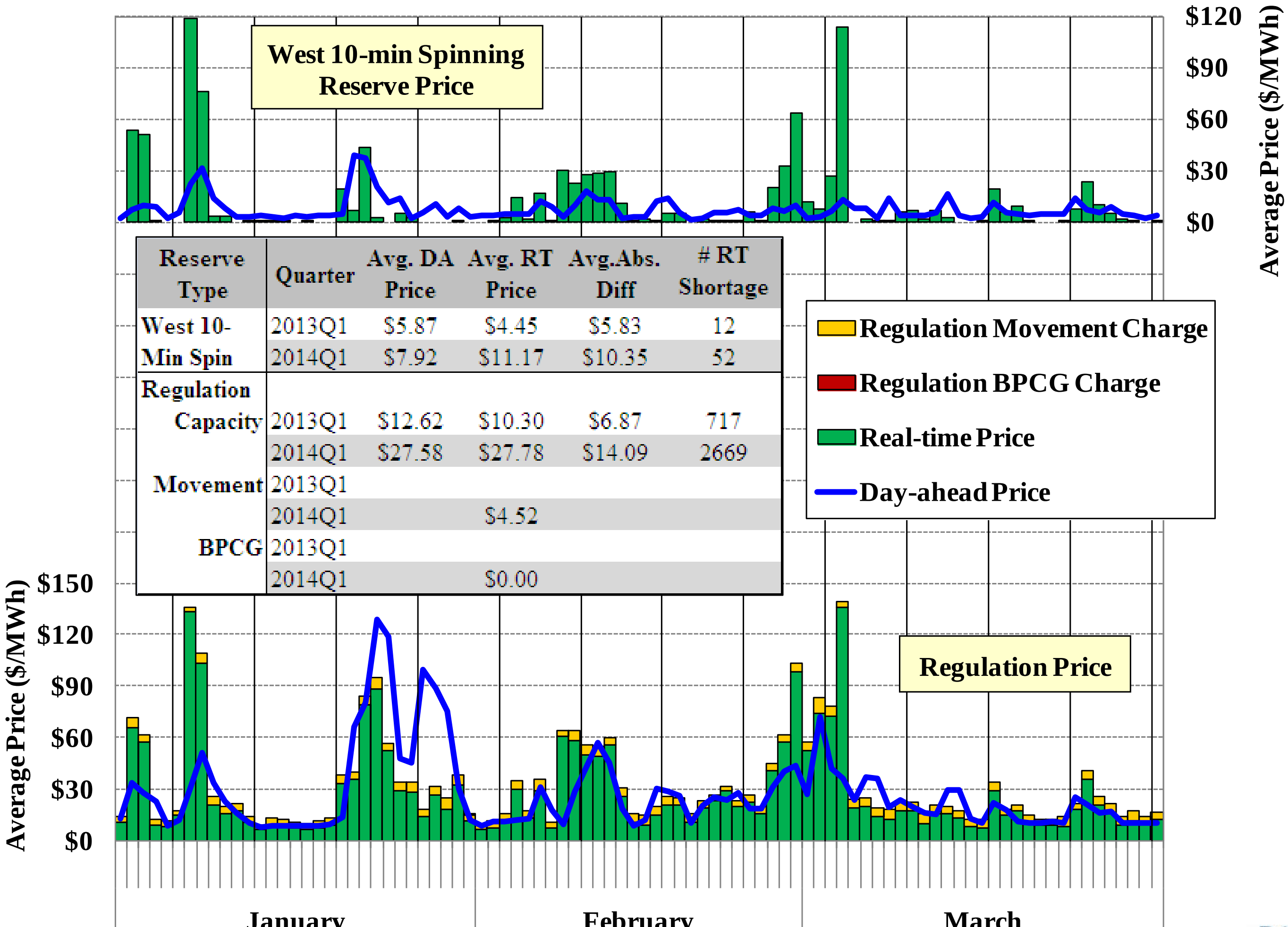
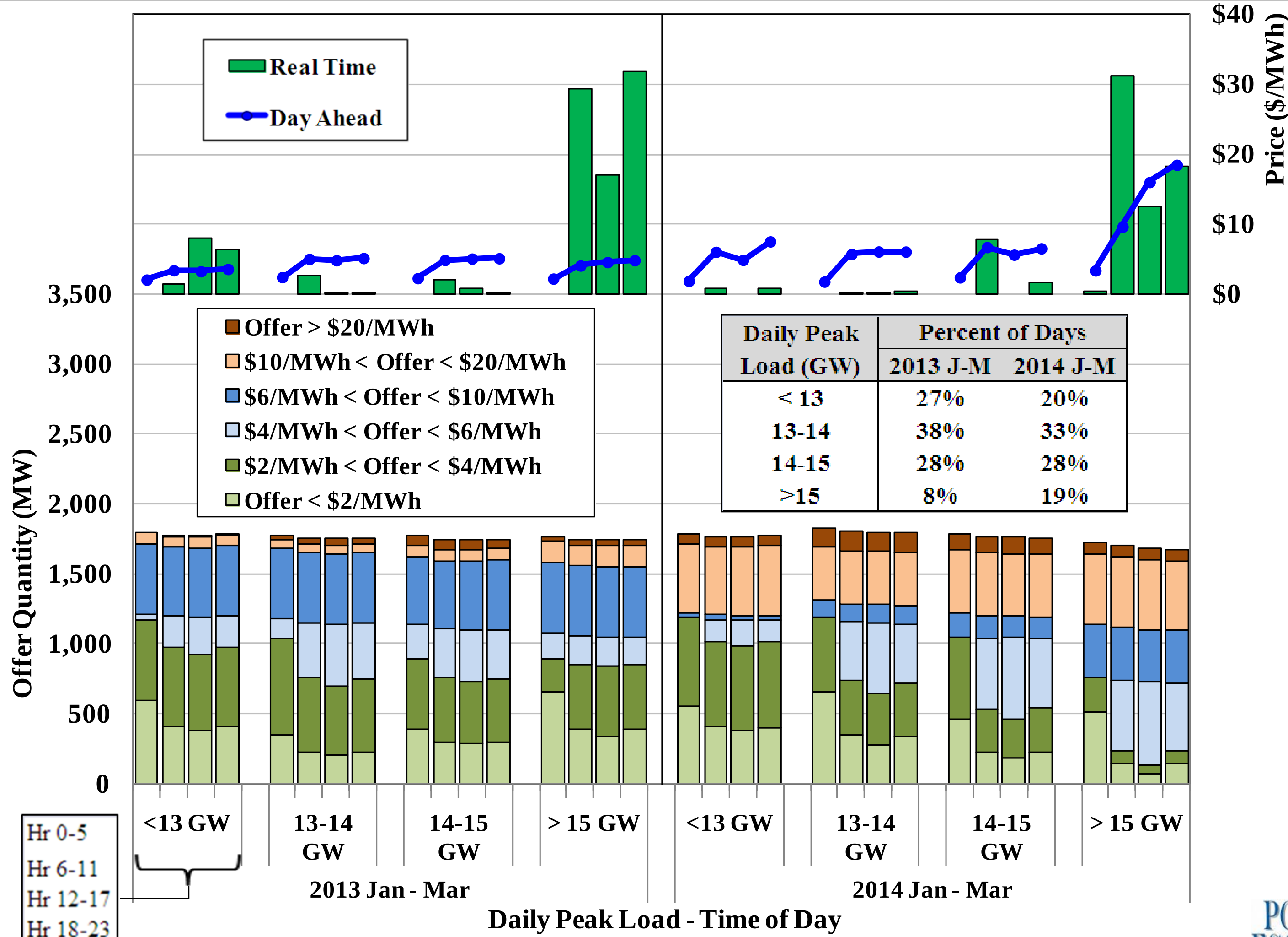
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage
West 10-Min Spin	2013Q1	$5.87	$4.45	$5.83	12
	2014Q1	$7.92	$11.17	$10.35	52
Regulation Capacity	2013Q1	$12.62	$10.30	$6.87	717
	2014Q1	$27.58	$27.78	$14.09	2669
Movement	2013Q1				
	2014Q1		$4.52		
BPCG	2013Q1				
	2014Q1		$0.00		

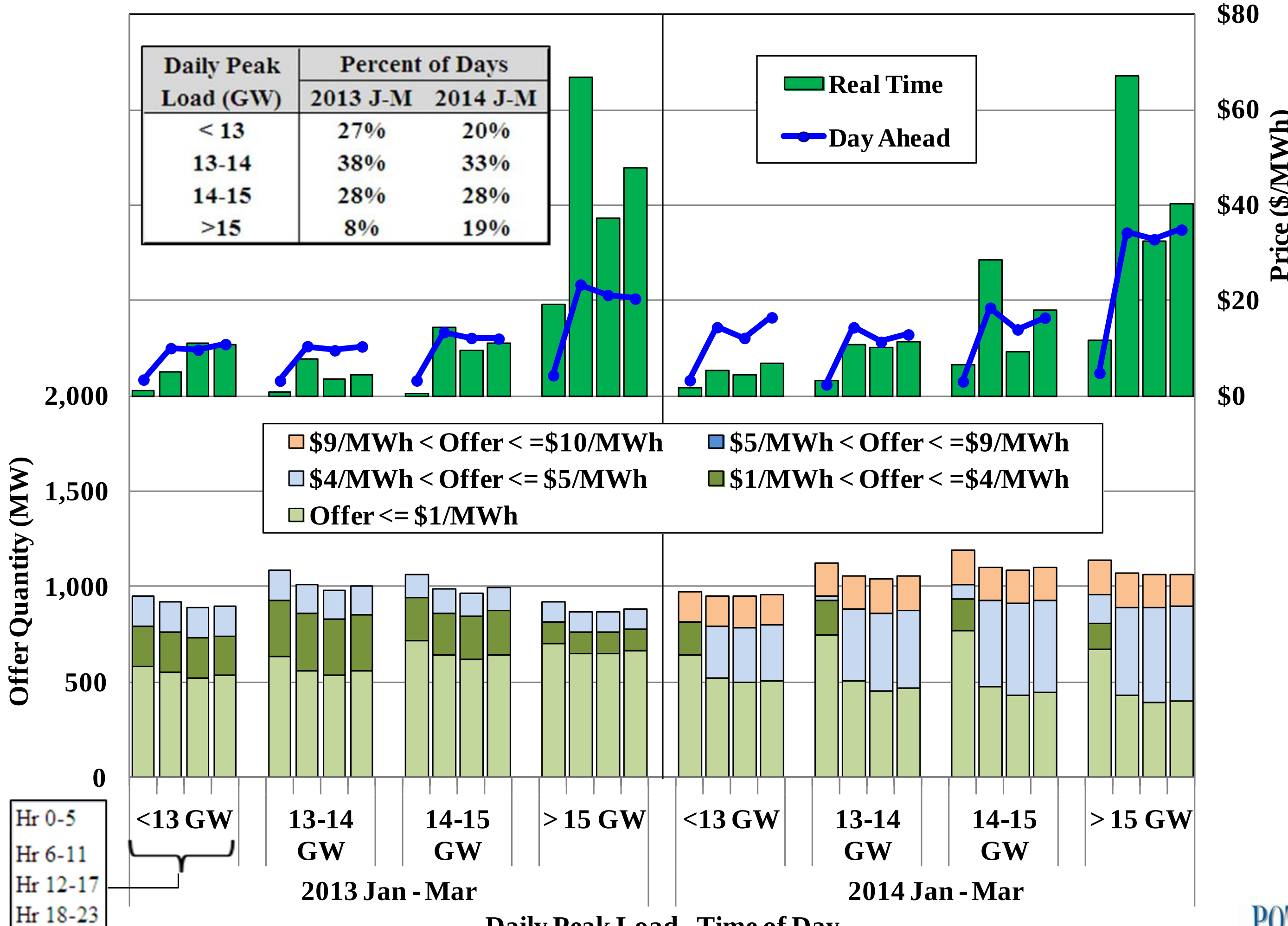
Note: Regulation Movement Charges and BPCG charges from regulating in real-time are shown in the figure averaged per MWh of RT Scheduled Regulation Capacity.

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



Daily Peak Load (GW)	Percent of Days	
	2013 J-M	2014 J-M
< 13	27%	20%
13-14	38%	33%
14-15	28%	28%
>15	8%	19%

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



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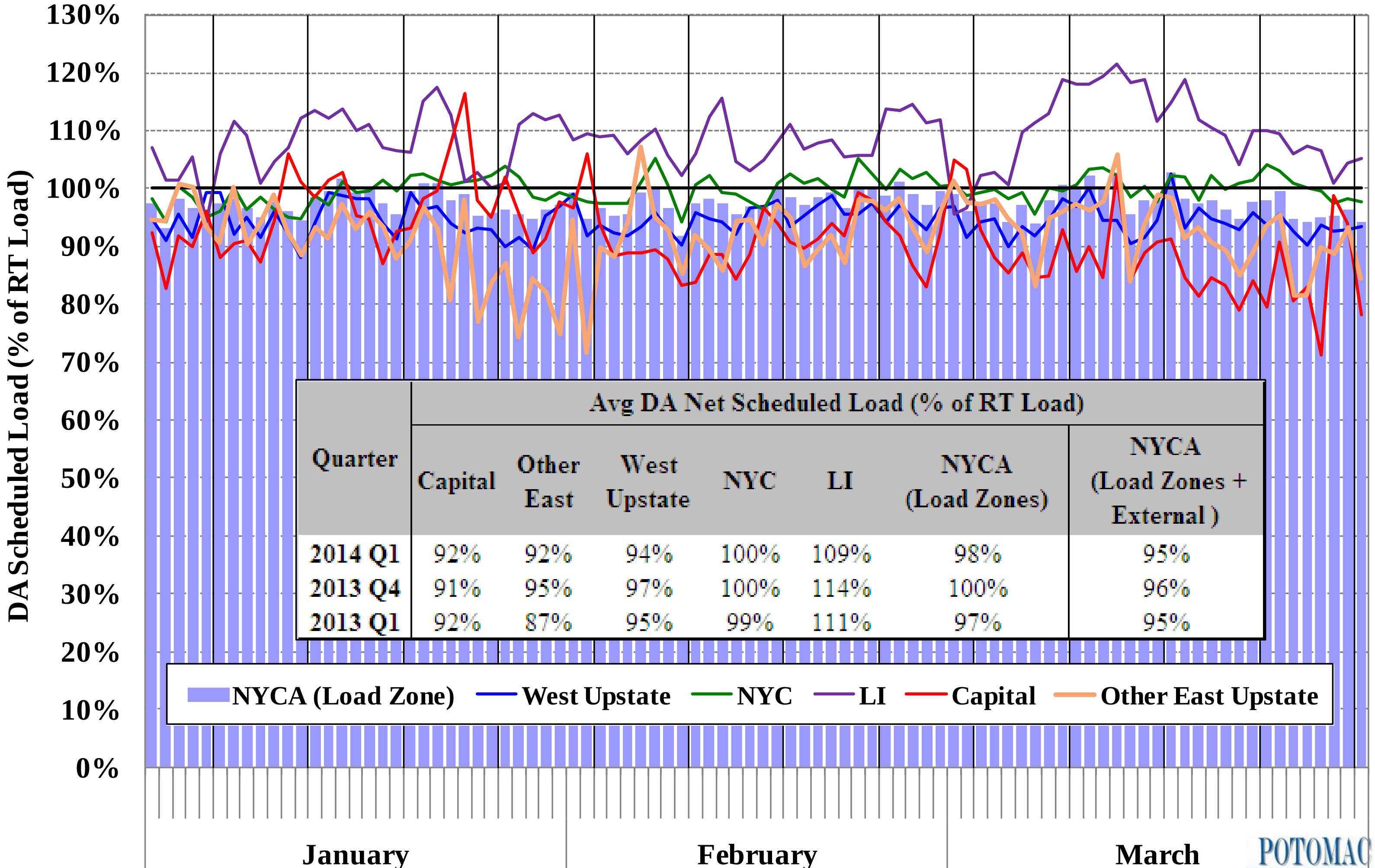
Energy Market Scheduling

Day-ahead Load Scheduling

- The following figure summarizes the quantity of DA load scheduled as a percent of RT load in each of five regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
  - ✓ The table also summarizes a system-wide net scheduled load that includes virtual imports and virtual exports at the proxy buses.
- For NYCA, 95 percent of actual load was scheduled in the DAM (including virtual imports/exports) in the first quarter of 2014, consistent to prior quarters.
- The historic pattern of DAM over-scheduling in SENY (i.e., Other East Upstate, NYC, & Long Island) has been less evident in 2013 and 2014.
  - ✓ The reduction has coincided with less frequent periods of acute RT congestion into SENY and NYC, reflecting: (a) the more effective use of Ramapo PAR-controlled lines; and (b) generation and transmission additions in NYC.
  - ✓ Long Island is the only zone that was consistently over-scheduled in this quarter.
- Under-scheduling continues to be prevalent outside SENY, likely in response to the tendency for hydro and wind units to increase RT output above DA schedules.
- Under-scheduling in most areas improved convergence between DA and RT prices given prevailing day-ahead premiums.

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)
2014 Q1	92%	92%	94%	100%	109%	98%	95%
2013 Q4	91%	95%	97%	100%	114%	100%	96%
2013 Q1	92%	87%	95%	99%	111%	97%	95%

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Virtual Trading Activity

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

Virtual Trading Activity

- Scheduled virtual supply in Western NY fell notably in March.
  - ✓ This coincided with decreased bilateral load scheduling in Western NY during the same period because some firms that made bilateral load purchases used virtual supply to sell energy in the DAM.
- Scheduled virtual load fell from prior quarters, reflecting prevailing DA price premiums across the system in the first quarter of 2014.
  - ✓ The reduction was greatest in SENY, consistent with the reduction in DA load scheduling in this area for similar reasons.
- In aggregate, virtual traders netted a gross profit of roughly $23 million at the load zones and a gross loss of $11 million at the proxy buses in the first quarter of 2014.
  - ✓ Virtual transactions have been profitable over the period, indicating that they have generally improved convergence between DA and RT prices.
  - ✓ However, the profits and losses of virtual trades have varied widely by time and location, reflecting the difficulty of predicting volatile RT prices.
- Virtual supply netted profits of $40 million in a ten-day period in late January.
  - ✓ This was caused by persistent and high DA premiums across the system on these days (for the reasons discussed earlier).

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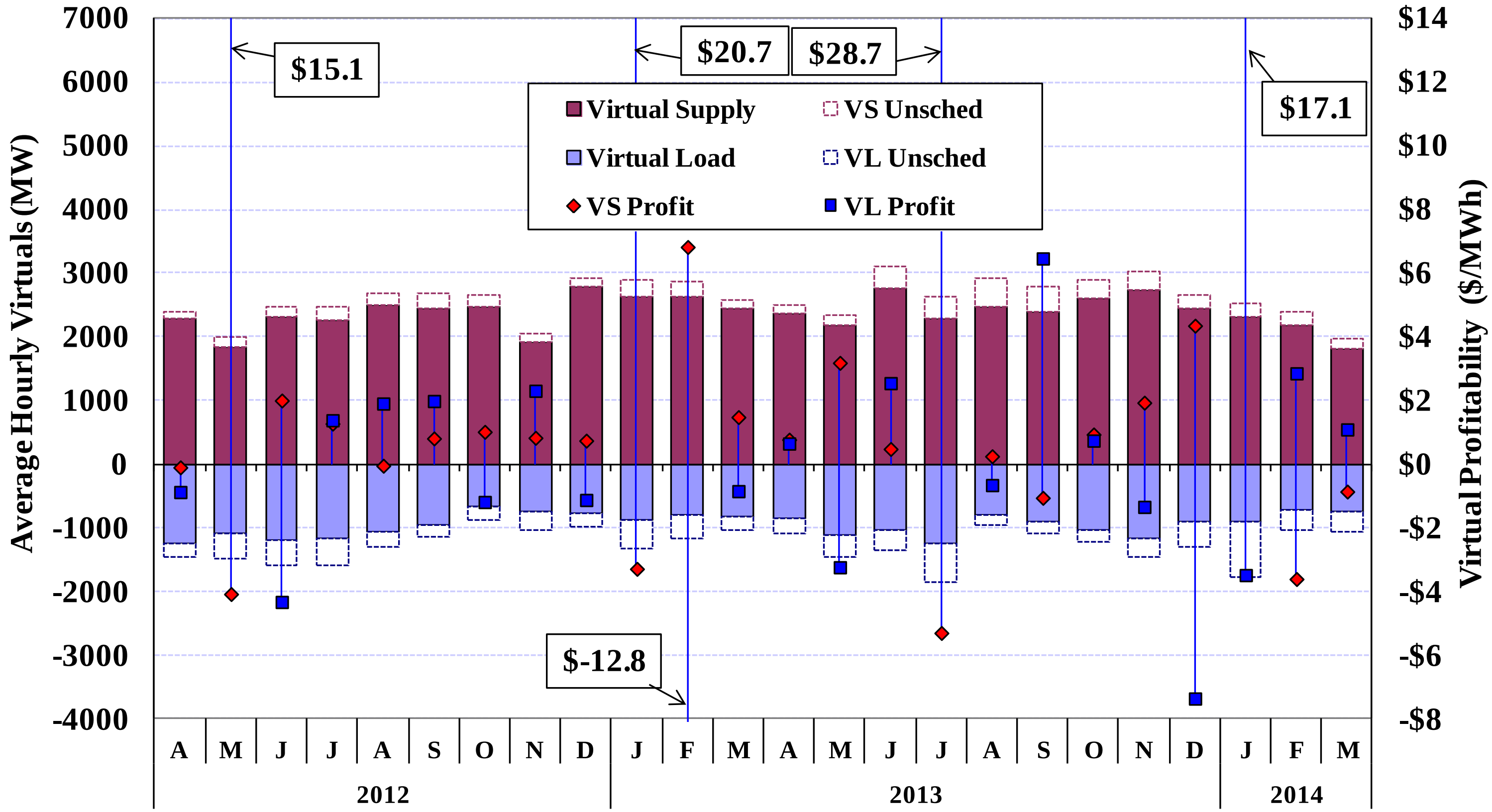
Virtual Trading Activity at Load Zones by Month



Profit > 50% of Avg. Zone Price	MW	220	128	345	300	208	158	143	238	202	418	426	191	187	328	253	345	156	193	230	438	319	590	260	250
	%	6%	4%	10%	9%	6%	5%	5%	9%	6%	12%	12%	6%	6%	10%	7%	10%	5%	6%	6%	11%	10%	18%	9%	10%
Loss > 50% of Avg. Zone Price	MW	261	132	377	337	220	129	93	182	195	354	347	125	149	275	166	252	176	177	201	369	258	395	333	256
	%	7%	4%	11%	10%	6%	4%	3%	7%	5%	10%	10%	4%	5%	8%	4%	7%	5%	5%	6%	10%	8%	12%	12%	10%

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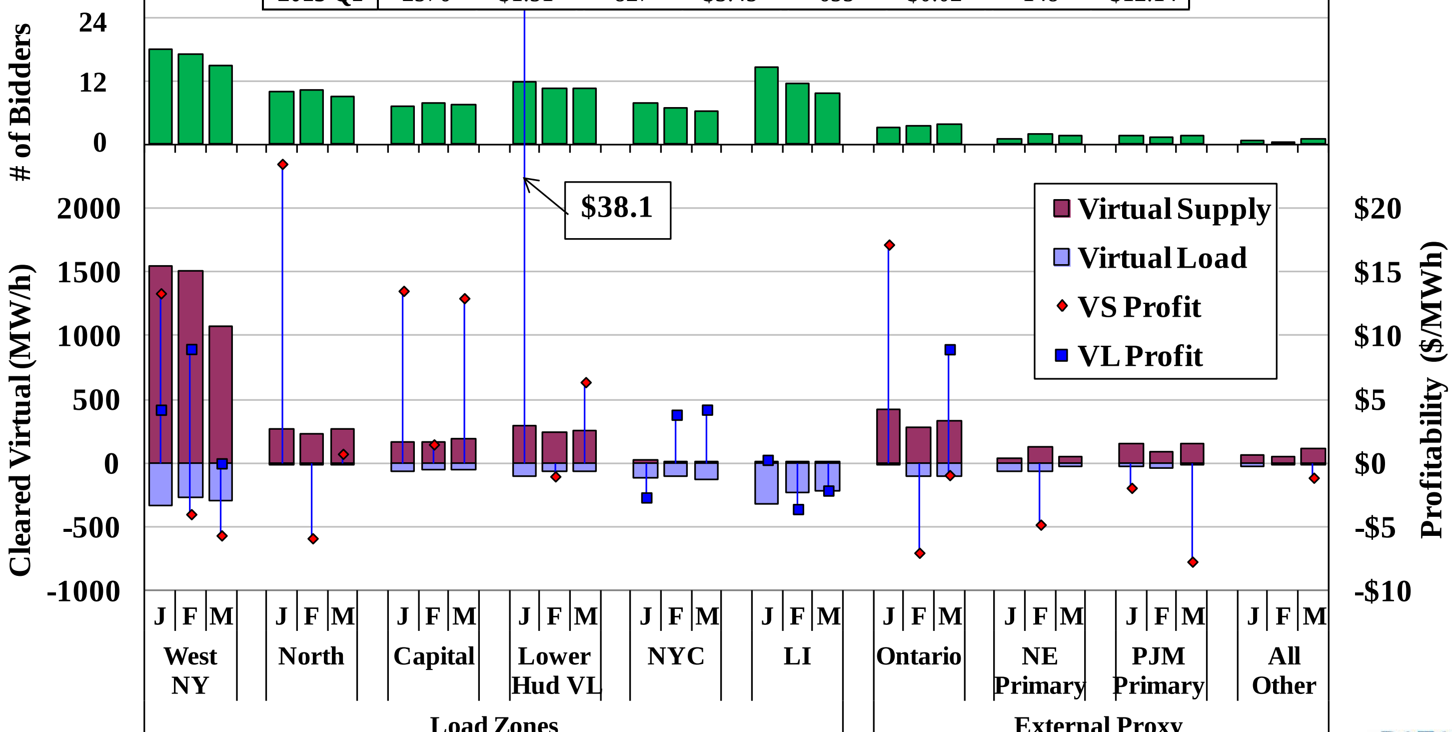
Virtual Trading Activity at Load Zones & Proxy Buses by Location

Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2014 Q1	2102	$5.07	786	-$0.22	596	-$8.48	95	-$1.55
2013 Q4	2596	$2.37	1024	-$2.39	712	$2.32	39	-$7.40
2013 Q1	2576	$1.51	827	$3.45	655	$0.02	148	-$12.14



Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 100 MW.

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Net Imports Scheduled Across External Interfaces

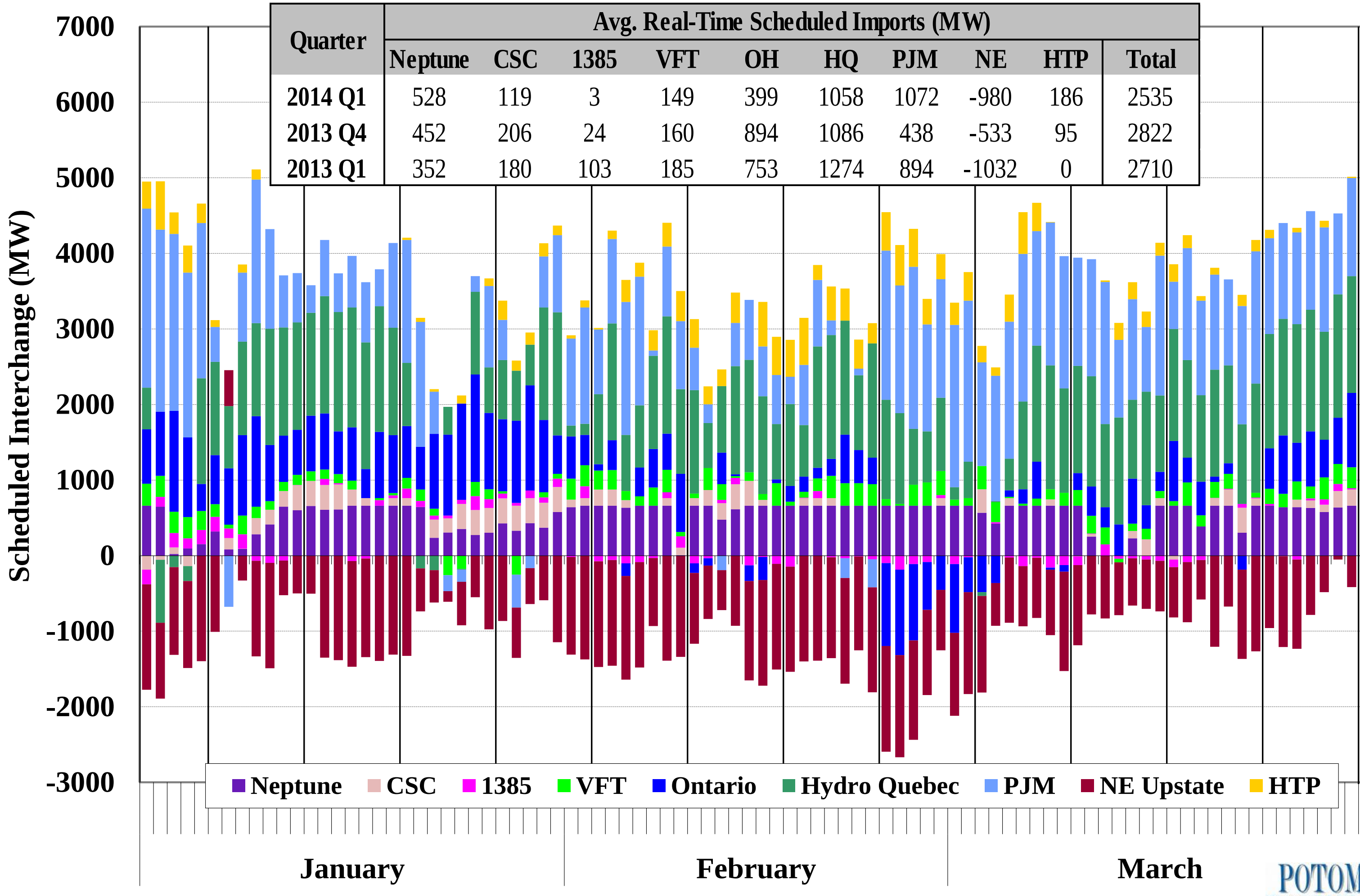
- The next figure shows average RT scheduled net imports to NYCA across ten external interfaces (two HQ interfaces are combined) in the peak hours (1-9 pm).
- Overall, net imports averaged 2,535 MW (serving roughly 13 percent of the load) during peak hours, down 175 MW from the first quarter of 2013.
- Net imports to Long Island averaged 650 MW during peak hours.
  - ✓ Net imports across the CSC and the 1385 Scheduled Lines fell from the previous year because of higher natural gas prices (and power prices) in Connecticut.
  - ✓ This was offset by increased imports across the Neptune Line following its return to full operation in the summer 2013.
- Net imports from PJM also rose notably from prior quarters because:
  - ✓ LBMPs were generally higher on the NY side of the interface due to higher natural gas prices on most days;
  - ✓ The start of operation of the HTP Line in the summer of 2013 increased import capability from PJM to NYISO; and
  - ✓ The Ramapo PARs were in service during a larger share of the first quarter of 2014 as compared with the same quarter in 2013. Both PARs were out of service in mid-February, reducing imports during this period.

Net Imports Scheduled Across External Interfaces

- Average net imports from HQ fell from the first quarter of 2013.
  - ✓ The reduction was mostly associated with more frequent extreme cold weather conditions this winter that led to limited hydro production and increased winter peaking load in HQ during these periods.
  - ✓ HQ had to import power from NY on several days.
  - ✓ These reductions had significant price effects in West NY.
- Net imports from Ontario fell by an average of 455 MW during peak hours from the first quarter of 2013, reflecting more frequent winter peaking conditions, the retirement of some coal capacity, and rising natural gas prices in Ontario.
  - ✓ Ontario imported a substantial amount of power from New York in late February to early March when natural gas prices in Ontario were notably higher than in Western NY.
- New York normally exported power to New England across its primary interface in the winter season.
  - ✓ This pattern was consistent with higher natural gas prices in New England than in Eastern NY in the winter.

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
2014 Q1	528	119	3	149	399	1058	1072	-980	186	2535
2013 Q4	452	206	24	160	894	1086	438	-533	95	2822
2013 Q1	352	180	103	185	753	1274	894	-1032	0	2710



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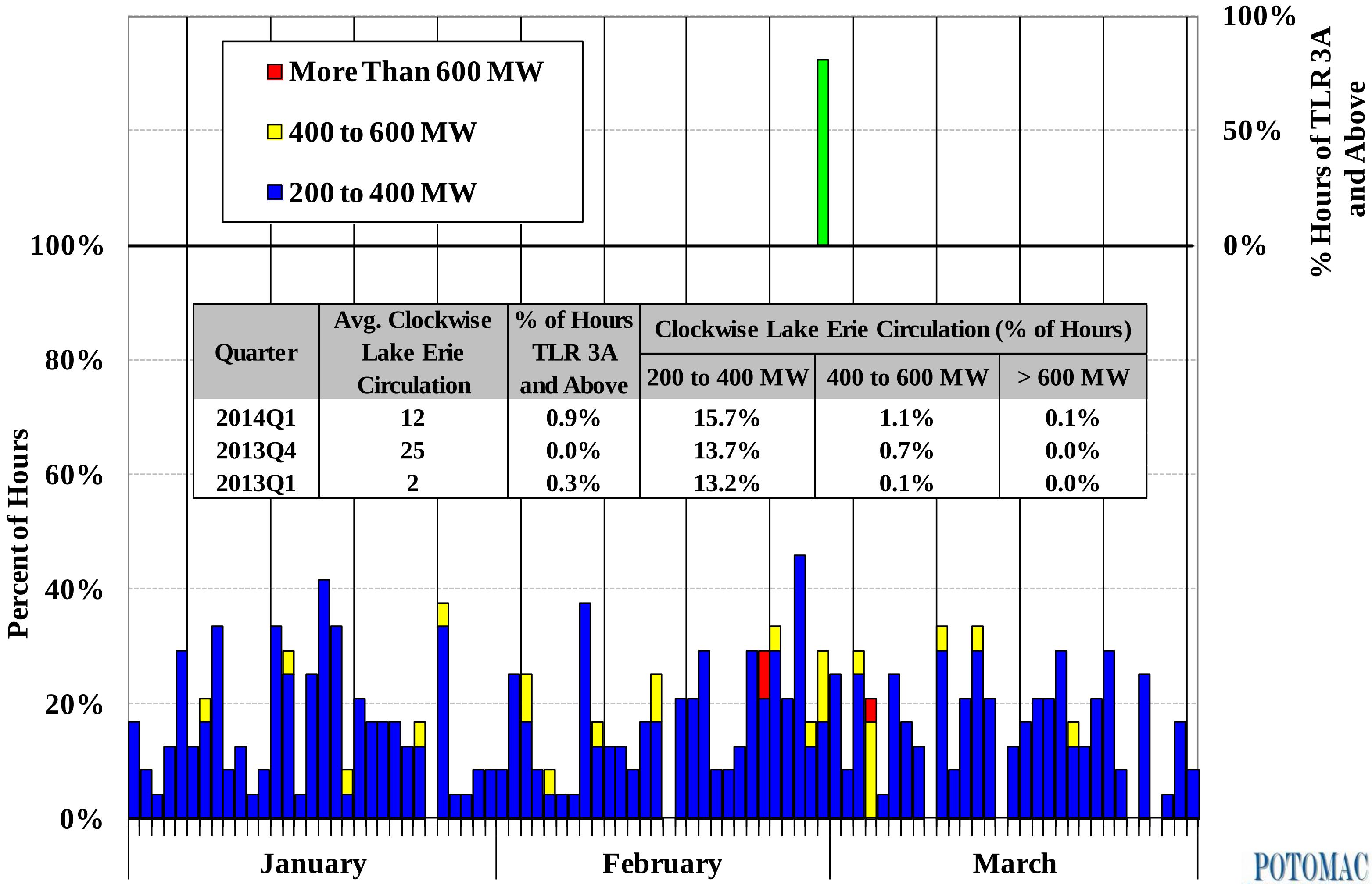
Lake Erie Circulation

- Loop flows occur when physical flows are not consistent with the scheduled path of a transaction between control areas or within a control area (from a generator to a load), so loop flow patterns are affected by many factors.
  - ✓ Clockwise Lake Erie Circulation ("LEC") use west-to-east transmission in upstate NY, reducing capacity available for scheduling internal generation to satisfy internal load and increasing congestion (e.g., on the Central-East interface).
- The figure summarizes the frequency of clockwise LEC and the frequency of TLRs (level 3A) called by the NYISO in the first quarter of 2014.
- Clockwise LEC was relatively high (> 200 MW) in 17 percent of all hours.
  - ✓ However, west-to-east congestion occurred in only 35 percent of these 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 NYISO called only one TLR (level 3A) for the Central-East interface on February 28 during this quarter.
  - ✓ 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.

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
2014Q1	12	0.9%	15.7%	1.1%	0.1%
2013Q4	25	0.0%	13.7%	0.7%	0.0%
2013Q1	2	0.3%	13.2%	0.1%	0.0%

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 to Central: Lines and interfaces in the West Zone through Central 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 $427 million, up 237 percent from the prior quarter and up 33 percent from the first quarter of 2013.
  - ✓ The increases were consistent with: 1) higher natural gas prices; and 2) larger gas price spreads between Western NY and Eastern NY.
    - These led to higher net imports to Eastern NY (where gas is the primary input fuel) and increased the redispatch costs incurred to manage congestion.
  - ✓ More frequent winter peaking conditions also contributed to increased levels of congestion across the system.

Day-Ahead and Real-Time Congestion

- Most congestion (measured as a share of total DA/RT congestion value) occurred in the following areas in the first quarter of 2014:
  - ✓ Central to East (64% DAM, 50% RTM) – More than half of congestion occurred across the Central East interface, 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 East NY and New England.
  - ✓ New York City (13% DAM, 14% RTM)
    - The NYC 345 kV system accounted for most (54% DAM, 77% RTM) of the NYC category. Most occurred in late January as a result of multiple 345 kV transmission outages and large gas price spreads between NYC and eastern upstate NY.
    - Paths into the Vernon/Greenwood load pocket accounted for most (36% DAM, 17% RTM) other NYC congestion.
  - ✓ External Interfaces (10% DAM, 17% RTM) – Roughly 65 percent was associated with the primary interface with New England, which was often fully utilized to export on days when natural gas prices were higher in New England than in NY.
  - ✓ Long Island (7% DAM, 10% RTM) – The majority was congestion from upstate into Long Island driven by high natural gas prices and transmission outages.

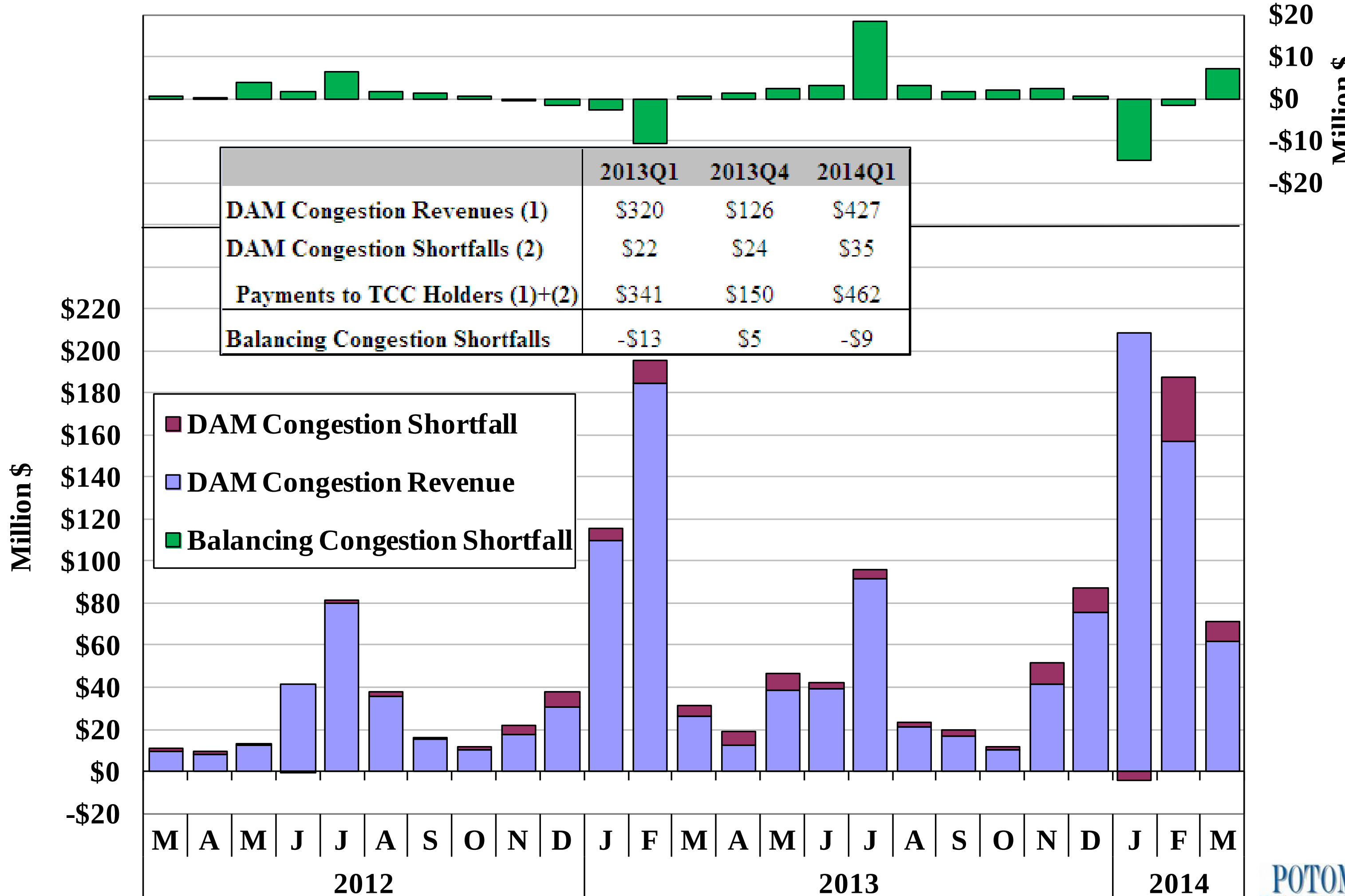
Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled roughly $35 million in the first quarter of 2014, up from $22 million in the first quarter of 2013.
  - ✓ The majority of shortfalls was driven by transmission outages.
    - – Transfer capacity into the NYC 345 kV system and in the Greenwood load pocket were reduced during most of the quarter because of multiple transmission outages in these areas, accounting for $15 million of the overall shortfall.
    - – Transmission outages from upstate to Long Island in early January and the entire February contributed an additional $9 million shortfalls.
    - – The two Ramapo PARs were out of service from February 7 to 23, which led to substantial reductions in PJM imports and higher internal flows from west to east and contributed a $16 million shortfalls on the Central-East interface .
  - ✓ However, this was offset by surpluses that accrued in January.
    - – Nearly $6 million surplus accrued on the Oswego export interface in three days during January because flows out of the generation pocket were much higher in the DAM than in the TCC auction, reflecting that these constraints were not generally anticipated in the TCC auction.
    - – Another $7 million surplus accrued on the Central-East interface on several extreme cold days in early and late January because changes in the commitment pattern led to increased voltage transfer limits for the Central-East interface.

Balancing Congestion Shortfalls

- Balancing congestion shortfalls totaled *negative* $9 million (i.e, a $9 million surplus), comparable to the first quarter of 2013.
  - ✓ When the transmission system is operated efficiently, balancing congestion surpluses are to be expected as a result of changes in generation and load patterns between the DA and RT markets.
- The Central-East interface accounted for a $7 million surplus, nearly all of which accrued on several days in early and late January. This was largely driven by:
  - ✓ Changes in generation patterns after the DAM because of changing weather patterns, natural gas prices, and SRE commitments.
- External interfaces accounted for $9 million of shortfalls in the first quarter.
  - ✓ Most of accrued on several days in March when the primary NY-NE interface was frequently de-rated in real-time due to transmission outages in New England.
- Congestion from the North Zone to the rest of NYCA was frequent in January during periods of excess wind generation, adding $4 million to the surplus.
- January 7 accounted for $6 million of the surplus related to the following constraints: (a) $1.8M on East Garden City-Valley Stream; (b) $1.7M on Central-East ($0.9M due to Ramapo operation); and (c) $2.6M on the primary PJM-NY interface.
  - ✓ These surpluses were driven by changes in generation patterns after a unit in East NY tripped and tight conditions in PJM reduced imports by 1500 MW after the DAM.

Congestion Revenues and Shortfalls by Month



	2013Q1	2013Q4	2014Q1
DAM Congestion Revenues (1)	$320	$126	$427
DAM Congestion Shortfalls (2)	$22	$24	$35
Payments to TCC Holders (1)+(2)	$341	$150	$462
Balancing Congestion Shortfalls	-$13	$5	-$9

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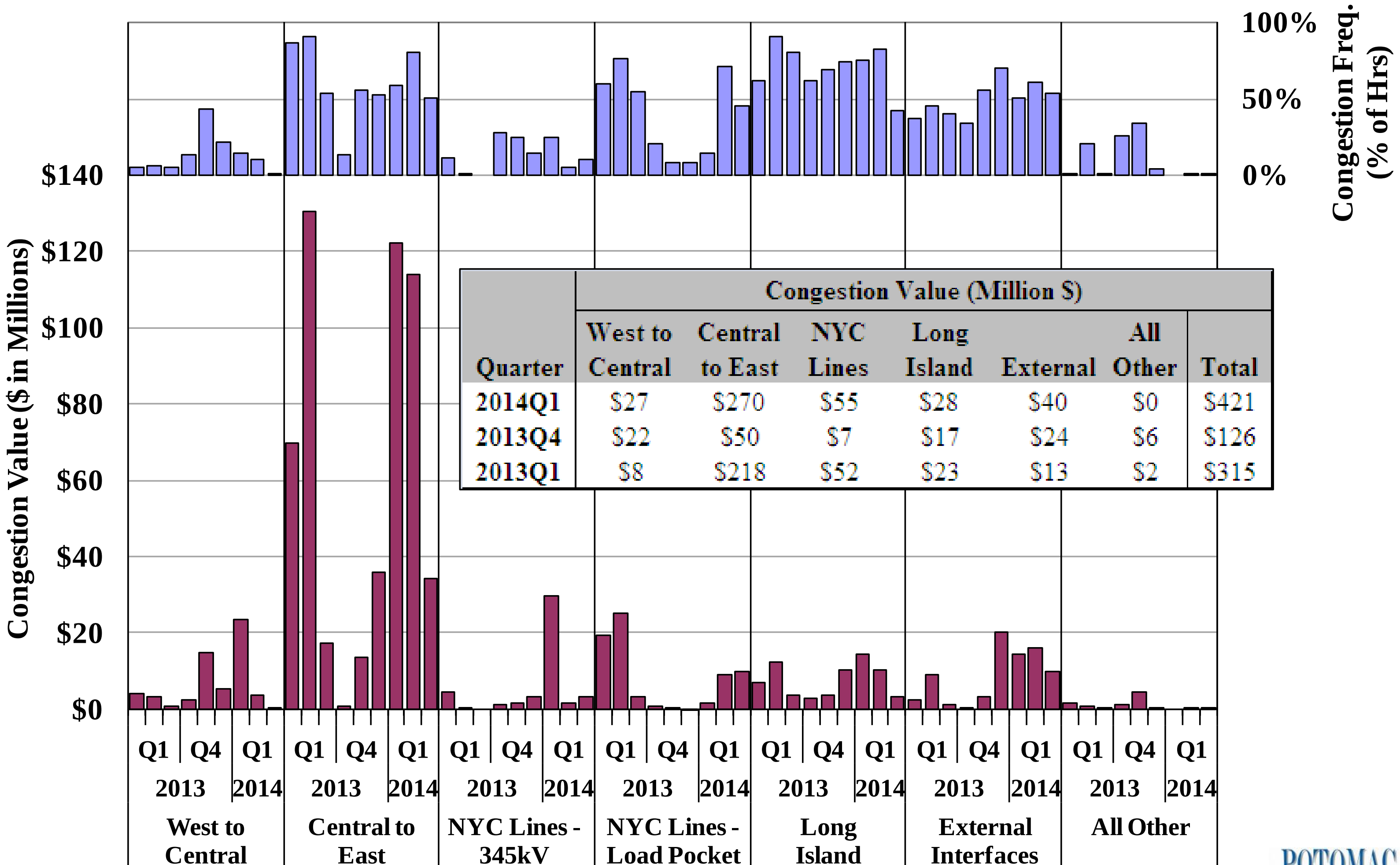
Day-Ahead Congestion Value and Frequency by Transmission Path



Quarter	Congestion Value (Million $)						
	West to Central	Central to East	NYC Lines	Long Island	External	All Other	Total
2014Q1	$27	$270	$55	$28	$40	$0	$421
2013Q4	$22	$50	$7	$17	$24	$6	$126
2013Q1	$8	$218	$52	$23	$13	$2	$315

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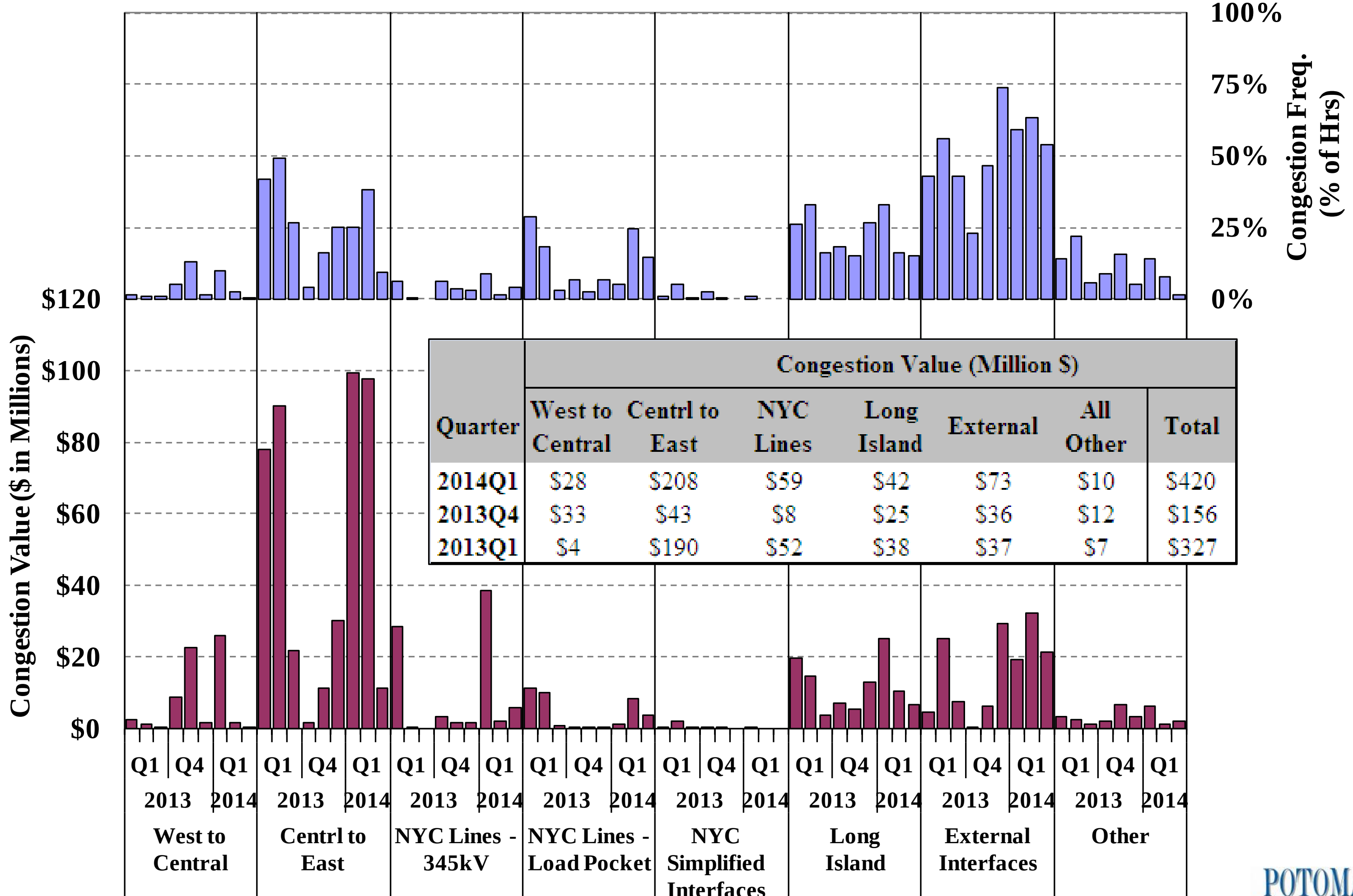
Real-Time Congestion Value and Frequency by Transmission Path



Quarter	Congestion Value (Million $)						
	West to Central	Centrl to East	NYC Lines	Long Island	External	All Other	Total
2014Q1	$28	$208	$59	$42	$73	$10	$420
2013Q4	$33	$43	$8	$25	$36	$12	$156
2013Q1	$4	$190	$52	$38	$37	$7	$327

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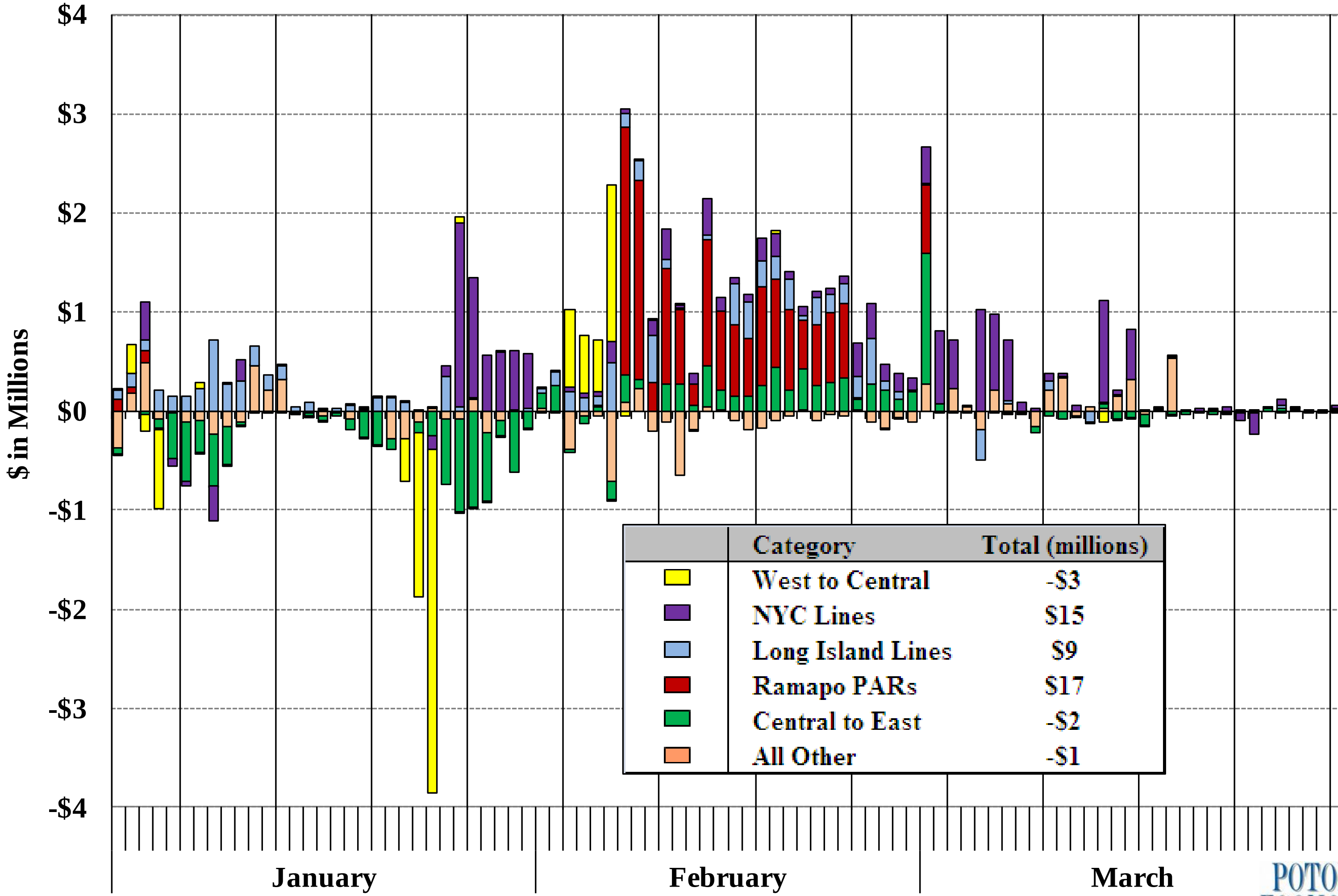
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



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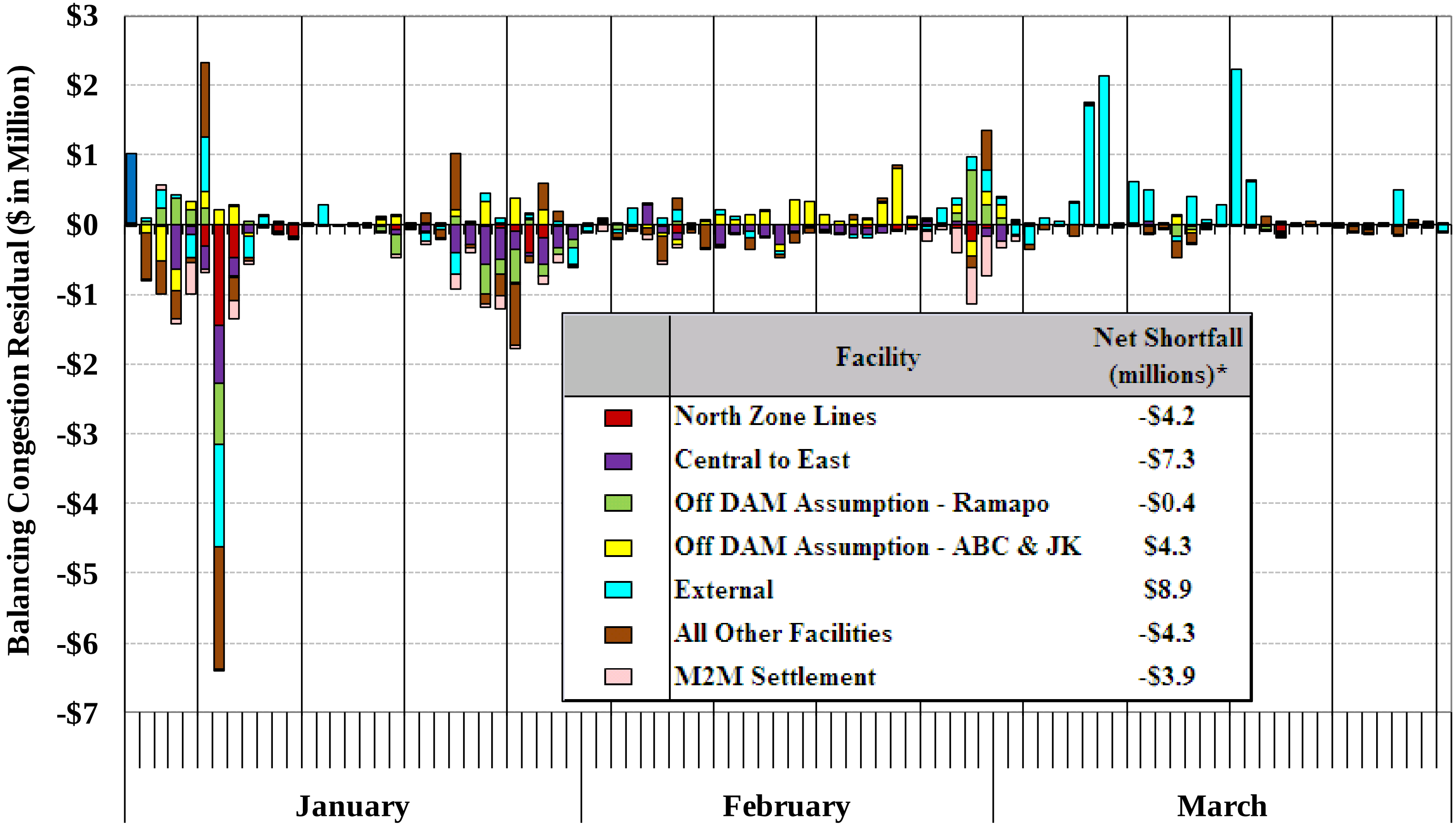
Balancing Congestion Shortfalls by Transmission Facility



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

POTOMAC ECONOMICS

Operations under M2M with PJM

- Coordinated congestion management between NYISO and PJM ("M2M") includes two types of coordination:
  - ✓ Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.
  - ✓ Ramapo PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, the Ramapo PARs are adjusted to reduce overall congestion.
- The use of Re-dispatch Coordination was still relatively infrequent in the first quarter of 2014.
  - ✓ It was activated in roughly 116 hours and resulted in a total payment of roughly $31,000 from PJM to NY.
- The use of Ramapo PAR Coordination continued to have significant impacts on the market in the first quarter of 2014.
  - ✓ However, usage of this process was limited by the outage of both Ramapo PARs from February 7 to February 23.
- The next two figures evaluate the operation of Ramapo PARs in the first quarter of 2014.

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 first quarter of 2014.
  - ✓ The M2M target flow has the following components:
    - Share of PJM-NY Over Ramapo – Based on the share of PJM-NY flows that were assumed to flow across the Ramapo Line (61% in the first quarter of 2014).
    - 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.

Operations under M2M with PJM Ramapo PAR Coordination

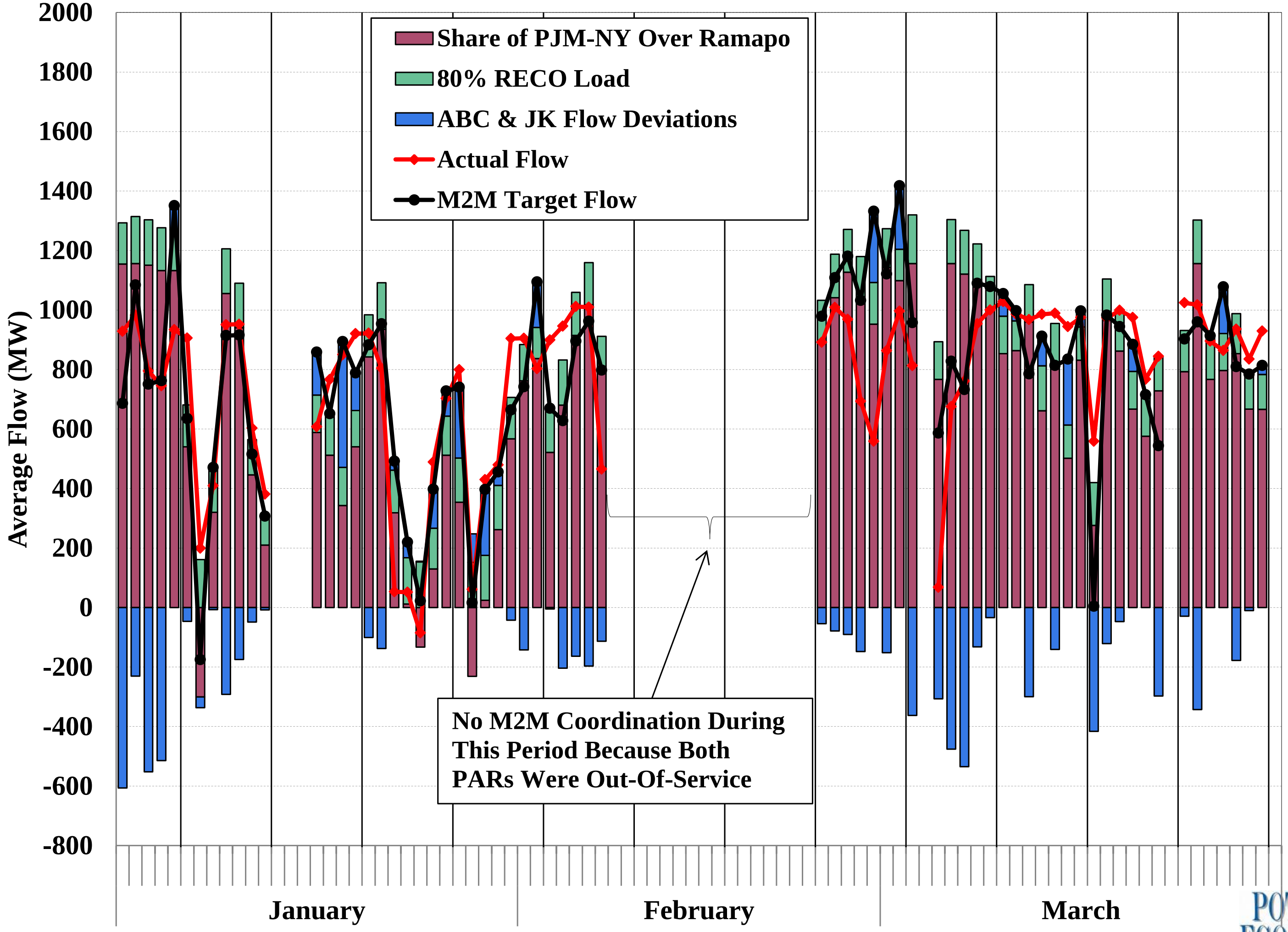
- ✓ The figure excludes hours when both markets had very little RT congestion (i.e., marginal effect of Ramapo was less than $10/MWh in both markets).
- ✓ The inset table provides summary statistics on the efficiency of Ramapo flows.
  - An hour is deemed relatively efficient if: (a) the marginal effect 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 when one PAR was in service and flow > 900 MW when two PARs were in service).

- Actual flows across Ramapo were more consistent with target flows during the first quarter of 2014 (when M2M constraints were binding) more than in 2013.
  - ✓ One of two PARs that was out of service during most of 2013 returned to service at the beginning of 2014.
    - This doubled the capability of the Ramapo Line (compared to 2013) so that it was able to fully support RECo deliveries, 61 percent of PJM-NY interchange, and any wheel imbalance on most days.
  - ✓ A total of nearly $4 million of M2M payments were made by PJM to NYISO.
    - Most of the payments accrued on several days in late January, late February, and early March 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 > $10/MWh in one or both markets), Ramapo Line flows were:
  - ✓ Reasonably efficient in 49 percent of the hours.
  - ✓ Not fully optimized while NY congestion > PJM congestion (by $20/MWh or more) in 16 percent of the hours.
    - – The Ramapo Line still provided substantial benefits to NY in most of the hours.
    - – Average flows to NY were higher when M2M flow gates were binding – 577 MW when M2M flow gates were binding and 540 MW in other hours.
  - ✓ Not fully optimized while PJM congestion > NY congestion (by $20/MWh or more) in 36% of the hours (including hours without binding M2M constraints).
    - – Flows into NY across the Ramapo Line were generally lower in these hours.
    - – Most of these hours occurred in January during periods when statewide LBMPs were very high while congestion was mild in New York.
      - In such hours, the analysis appears to suggest that power is flowing inefficiently across Ramapo, however, the results are also an indication that the PJM-NYISO ties in western NY were under-utilized.
  - ✓ Although the Ramapo Line is not always fully utilized, the figure exhibits an appropriate correlation between the flows across Ramapo and the relative congestion in the two markets.

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



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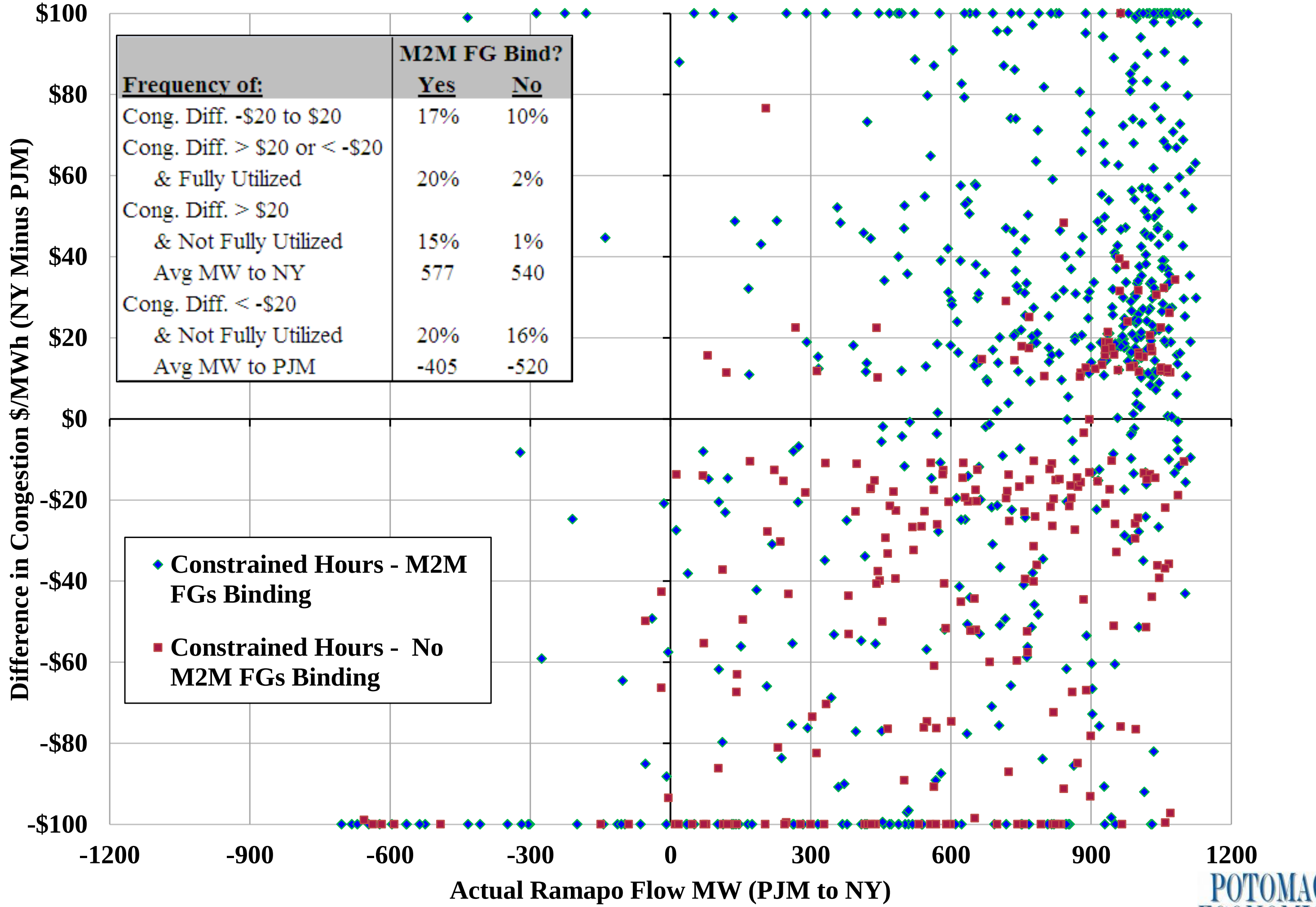
Marginal Effect of Ramapo on NY/PJM Congestion and Actual Ramapo Flow – Hours w/Congestion in NY or PJM



Frequency of:	M2M FG Bind? Yes	No
Cong. Diff. -$20 to $20	17%	10%
Cong. Diff. > $20 or < -$20		
& Fully Utilized	20%	2%
Cong. Diff. > $20		
& Not Fully Utilized	15%	1%
Avg MW to NY	577	540
Cong. Diff. < -$20		
& Not Fully Utilized	20%	16%
Avg MW to PJM	-405	-520

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Supplemental Commitments, OOM Dispatch, and Uplift Charges

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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 roughly 990 MW of capacity was committed for reliability in the first quarter of 2014, up 42 percent from the first quarter of 2013.
  - ✓ Of this total, 66 percent of reliability commitment was in NYC, 15 percent was in Long Island, and 15 percent was in Western NY.
- Outside New York City, reliability commitments did not change significantly from the first quarter of 2013, which was lower than in prior years.
  - ✓ DARU commitments decreased because several units that had often been DARUed in Long Island and Western NY for local reliability were committed economically more often because of higher gas prices.
  - ✓ SRE commitments in Western NY decreased in March because transmission upgrades in the North Zone greatly reduced such needs.
  - ✓ SRE commitments in Eastern Upstate NY rose because the NYISO committed the Empire combined cycle units (on gas) frequently during the last week of January for capacity needs in East NY.
- In New York City, reliability commitment averaged 650 MW, up 78 percent from the first quarter of 2013.
  - ✓ A large portion of this capacity was committed for local reliability because of transmission work in the Freshkills load pocket.

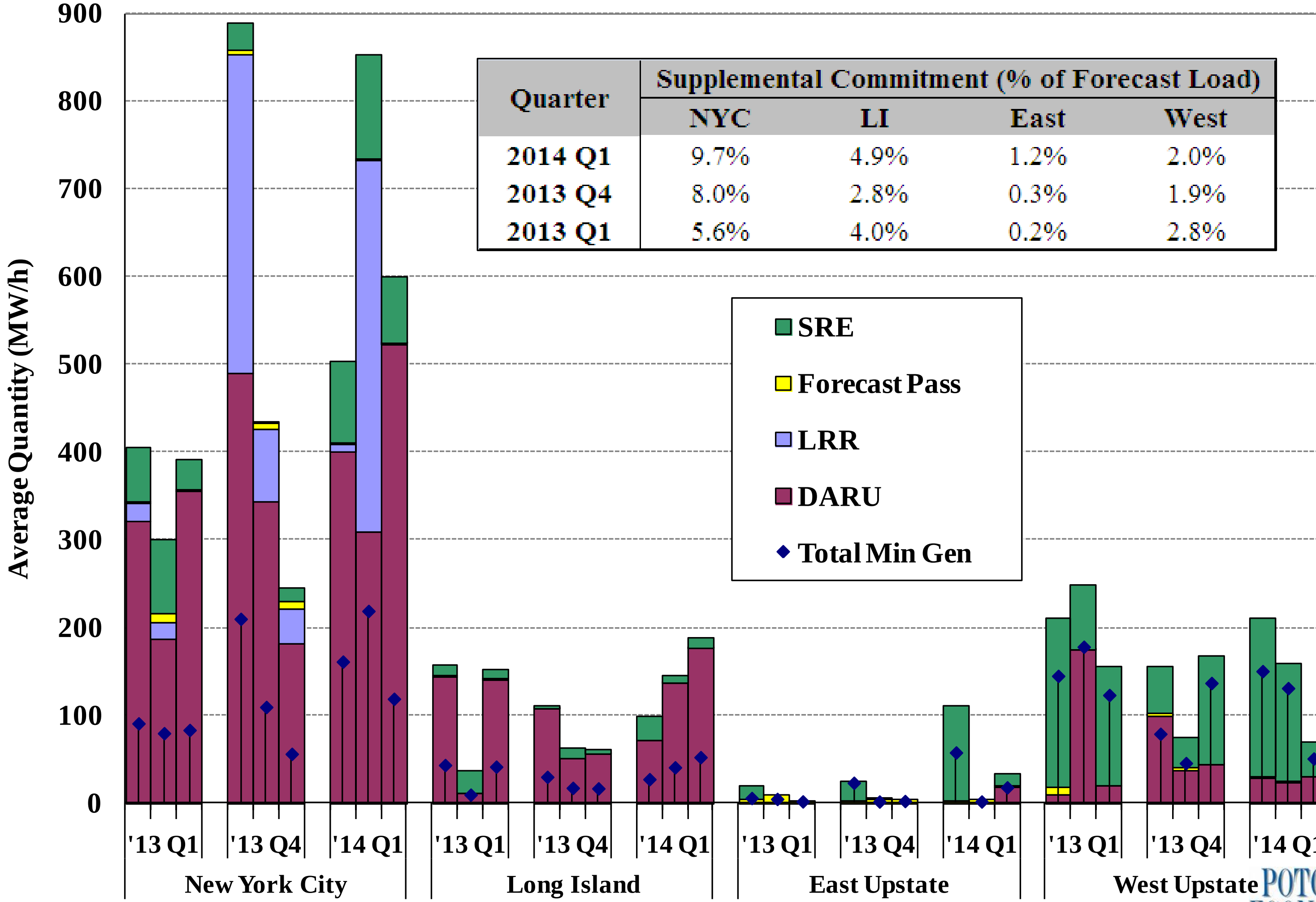
Supplemental Commitment Results in NYC

- Thermal requirements accounted for most MWhs of reliability commitment in New York City during the first quarter of 2014.
  - ✓ Most reliability commitment was for the Freshkills load pocket on Staten Island.
    - – Increased local needs were largely driven by multiple transmission outages related to transmission work at the Goethals Bus from early January throughout the quarter.
  - ✓ Most of the remaining reliability commitment was made for the Sprainbrook/Dunwoodie and the Astoria West/Queensbridge load pockets.
    - – Multiple 345 kV transmission lines from upstate to NYC were out of service for a significant portion of the quarter, resulting in increased thermal and voltage needs in the two pockets.
    - – These reliability requirements ensure that transmission into the pockets will not be overloaded if the largest two contingencies (generation or transmission) occur.
- Supplemental commitment was also made on several days because of contingencies associated with low availability of natural gas.
  - ✓ Units tripped in real-time when switching to oil on several extreme cold days.
  - ✓ Capacity deratings were also taken in real-time on several units because of limited natural gas and/or fuel oil supply.

OOM Dispatch Results

- The NYISO and local TOs sometimes dispatch generators out-of-merit in order to:
  - ✓ Maintain reliability of the lower-voltage transmission and distribution networks; or
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model.
- Generators were dispatched out-of-merit (“OOM”) for 644 station-hours, up 53 percent from the first quarter of 2013.
  - ✓ However, the use of OOM actions was relatively low compared to periods before 2013.
  - ✓ Of the total OOM station-hours, Long Island accounted for 41 percent, Western NY accounted for 26 percent, and New York City accounted for 22 percent.
- Most OOM dispatches (72 percent) occurred in January.
  - ✓ Units in Eastern NY were frequently OOMed for NYISO reliability and security, driven partly by unexpected system conditions that resulted from forced generation outages and deratings due to extreme cold weather and natural gas availability.
- Local TO reliability accounted for 33 percent of all OOM dispatch in the first quarter.
  - ✓ 56 percent of these occurred in the West Zone to manage congestion on 115 kV lines.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	NYC	LI	East	West
2014 Q1	9.7%	4.9%	1.2%	2.0%
2013 Q4	8.0%	2.8%	0.3%	1.9%
2013 Q1	5.6%	4.0%	0.2%	2.8%

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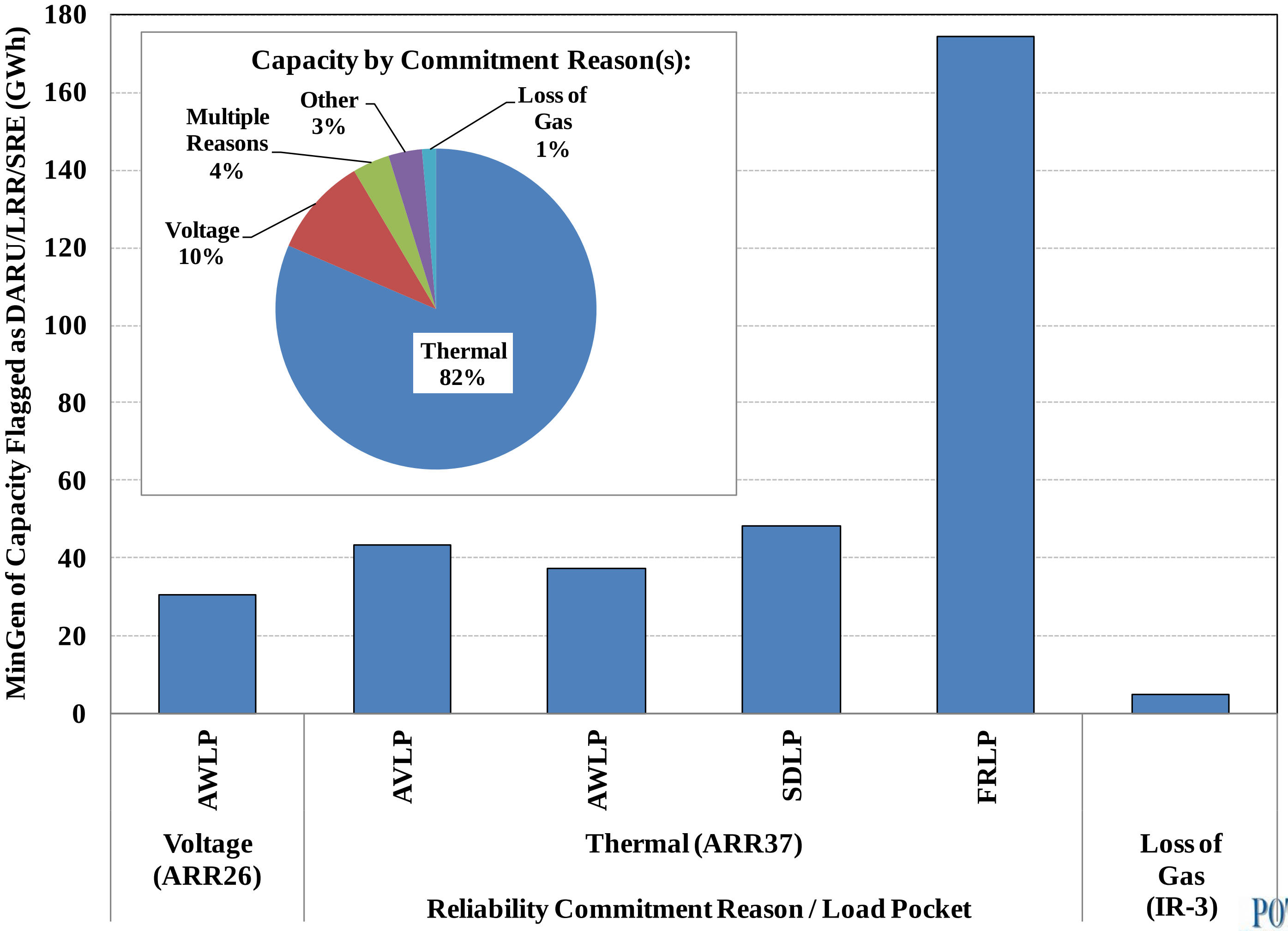
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



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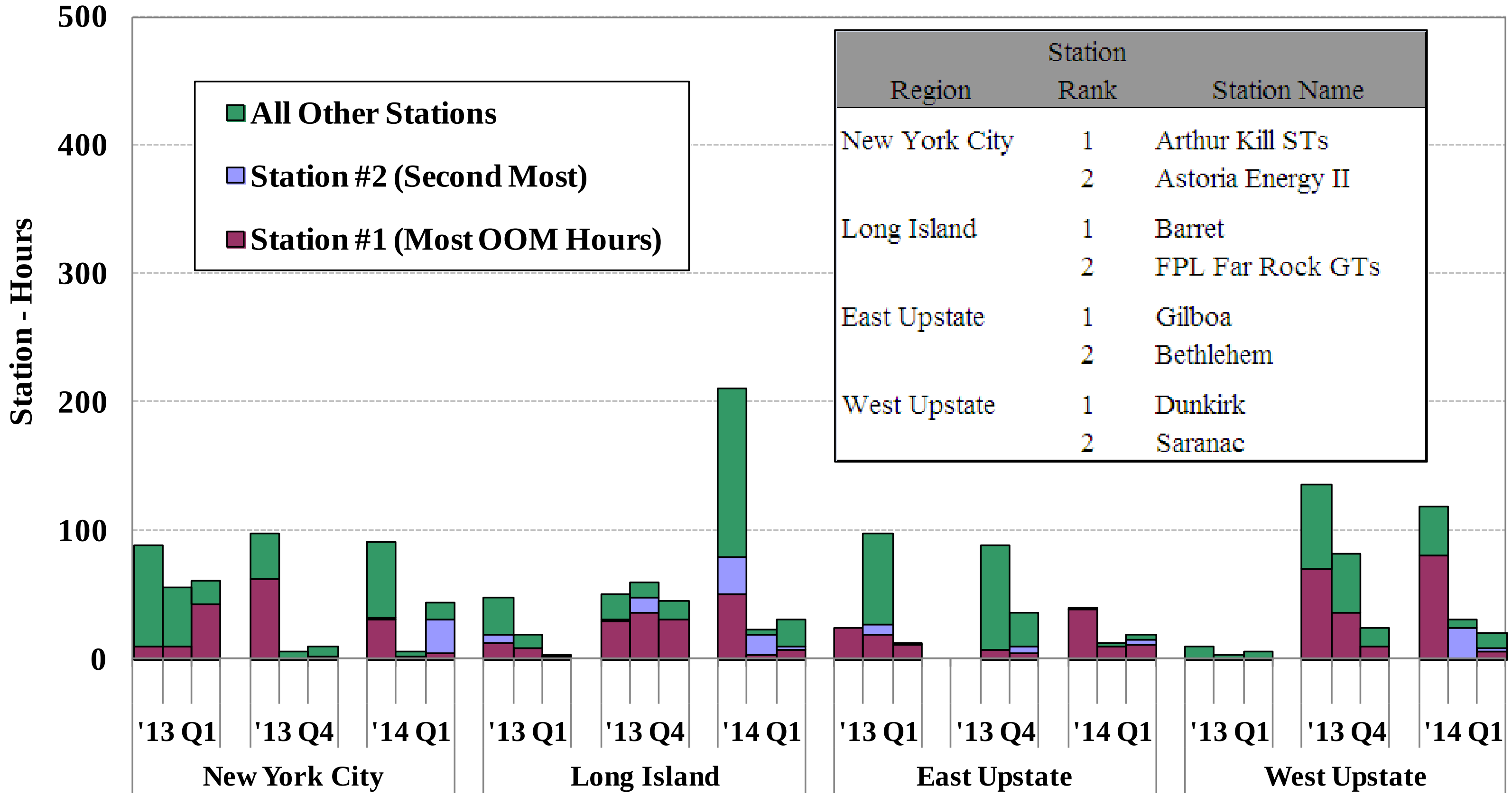
Frequency of Out-of-Merit Dispatch
by Region by Month



Region	Station Rank	Station Name
New York City	1	Arthur Kill STs
	2	Astoria Energy II
Long Island	1	Barret
	2	FPL Far Rock GTs
East Upstate	1	Gilboa
	2	Bethlehem
West Upstate	1	Dunkirk
	2	Saranac

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.

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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.

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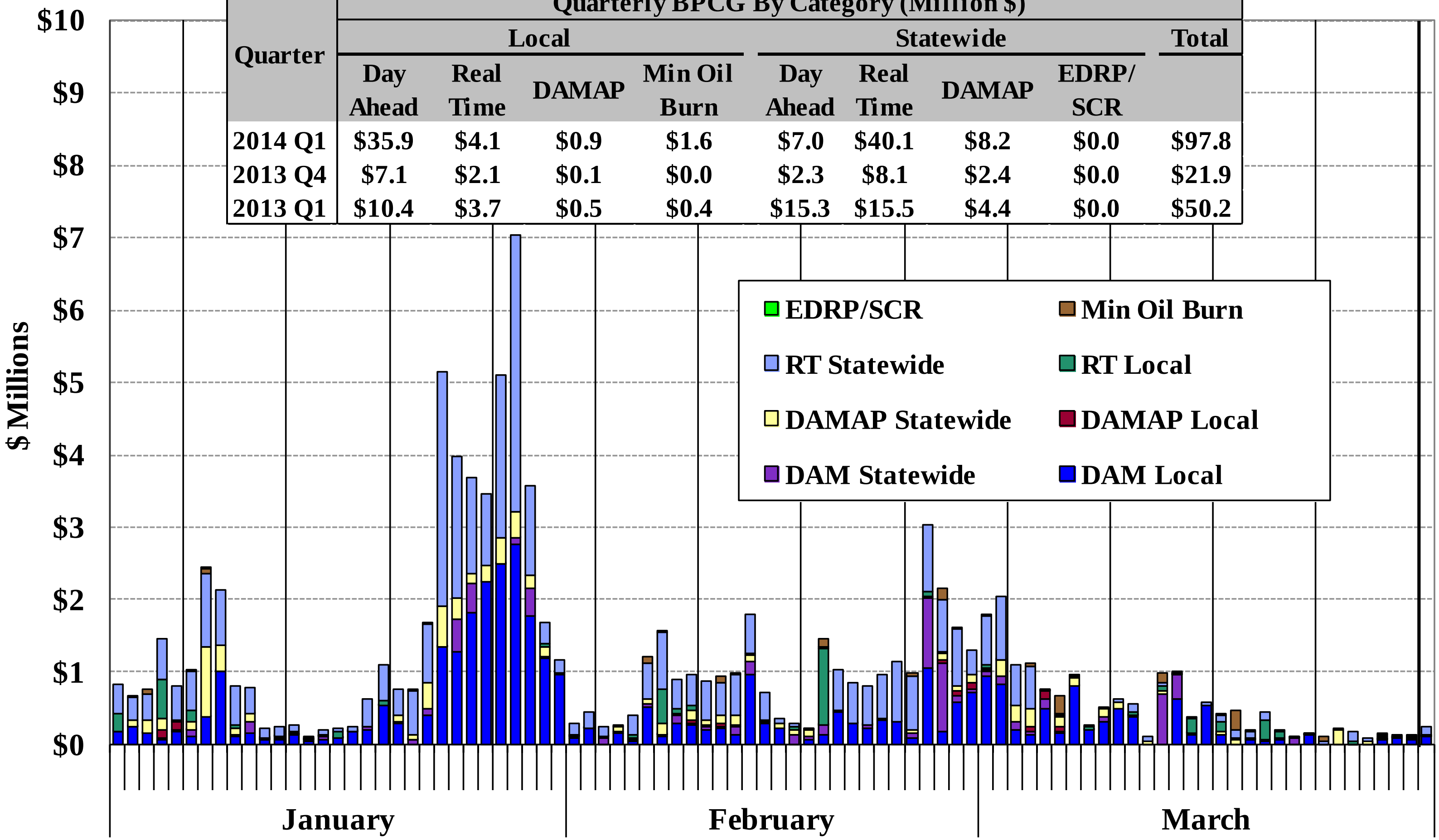
Uplift Costs from Guarantee Payments

- Guarantee payment uplift totaled $98 million in the first quarter of 2014, up 95 percent from the first quarter of 2013.
  - ✓ Higher natural gas prices increased the commitment costs of gas-fired units.
    - – 31 percent of all guarantee payment uplift accrued from January 22 to 28 when natural gas prices averaged over $50/MMbtu in Eastern NY.
  - ✓ Increased supplemental commitment and OOM dispatch (as discussed earlier) also contributed to the increase in guarantee payment uplift.
- Most of guarantee payment uplift in Western NY accrued on one gas-fired unit that was frequently needed for reliability. However, transmission upgrades completed in February greatly reduced the need for this unit.
- Nearly half of guarantee payment uplift in New York City was related to transmission work in the Freshkills load pocket.

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

Quarter	Local Day Ahead	Local Real Time	Local DAMAP	Local Min Oil Burn	Statewide Day Ahead	Statewide Real Time	Statewide DAMAP	Statewide EDRP/SCR	Total
2014 Q1	$35.9	$4.1	$0.9	$1.6	$7.0	$40.1	$8.2	$0.0	$97.8
2013 Q4	$7.1	$2.1	$0.1	$0.0	$2.3	$8.1	$2.4	$0.0	$21.9
2013 Q1	$10.4	$3.7	$0.5	$0.4	$15.3	$15.5	$4.4	$0.0	$50.2

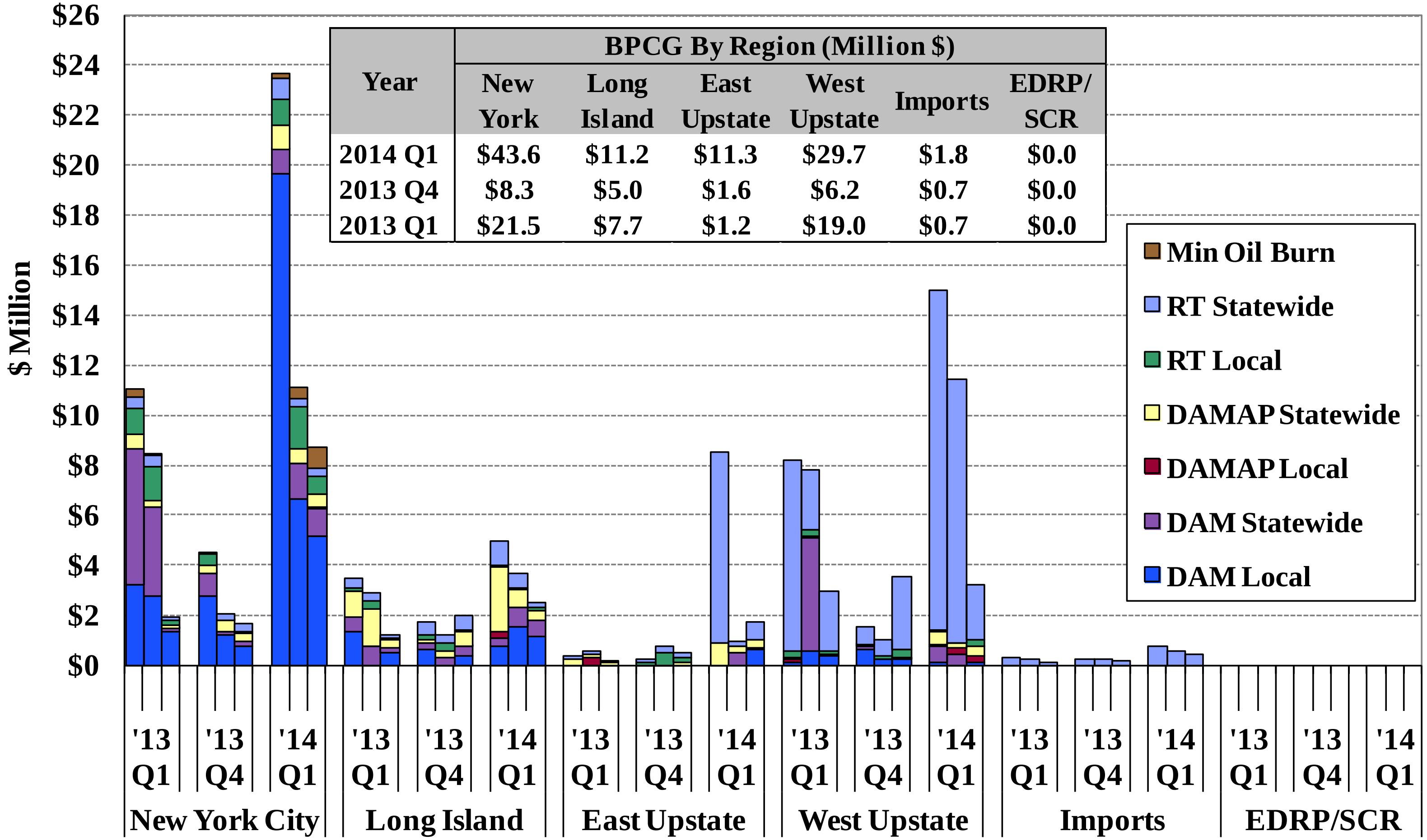
Quarterly BPCG By Category (Million $)



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
2014 Q1	$43.6	$11.2	$11.3	$29.7	$1.8	$0.0
2013 Q4	$8.3	$5.0	$1.6	$6.2	$0.7	$0.0
2013 Q1	$21.5	$7.7	$1.2	$19.0	$0.7	$0.0

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

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 rose modestly in this quarter but was still low as a share of load.
  - ✓ The rise in output gap was due partly to high and volatile natural gas prices that:
    - Made the dollar-threshold a tighter threshold (relative to offers and LBMPs); and
    - Increased the difficulty of reflecting actual costs in the reference prices.
  - ✓ However, the output gap did not raise significant market power concerns because:
    - NYC accounted for 26 percent of all output gap at the low threshold, which occurred primarily during periods when the prices would not be substantially affected (would be AMP-mitigated otherwise).
    - The Capital Zone accounted for another 33 percent, most of which occurred on several units that are owned by suppliers with small portfolios.

Market Power Screens: Physical Withholding

- We evaluate generator deratings in the day-ahead market to screen for potential physical withholding. The figure summarizes:
  - ✓ Total deratings, which are measured relative to the DMNC test value; and
  - ✓ Short-term deratings, which exclude deratings lasting more than 30 days.
- Deratings are typically highest in shoulder months when load is lower and lowest in the summer months when load is higher.
  - ✓ Total deratings are significant, but physical withholding concerns are limited because most deratings are long-term and not likely to reflect withholding.
    - However, inefficient long-term outage scheduling (i.e., to schedule an outage during a period that the capacity is likely economic in a significant portion of the time) may raise concerns.
  - ✓ Long-term deratings fell from 2012 to 2013 because several units were mothballed or retired over the period (out-of-service units are excluded from the figure).
    - Average long-term deratings fell by an additional 1.3 GW in the first quarter of 2014, because market participants scheduled fewer outages. This is consistent with the increased need for supply compared to prior winters.
    - The amount of short-term deratings in the first quarter of 2014 was consistent with previous years.

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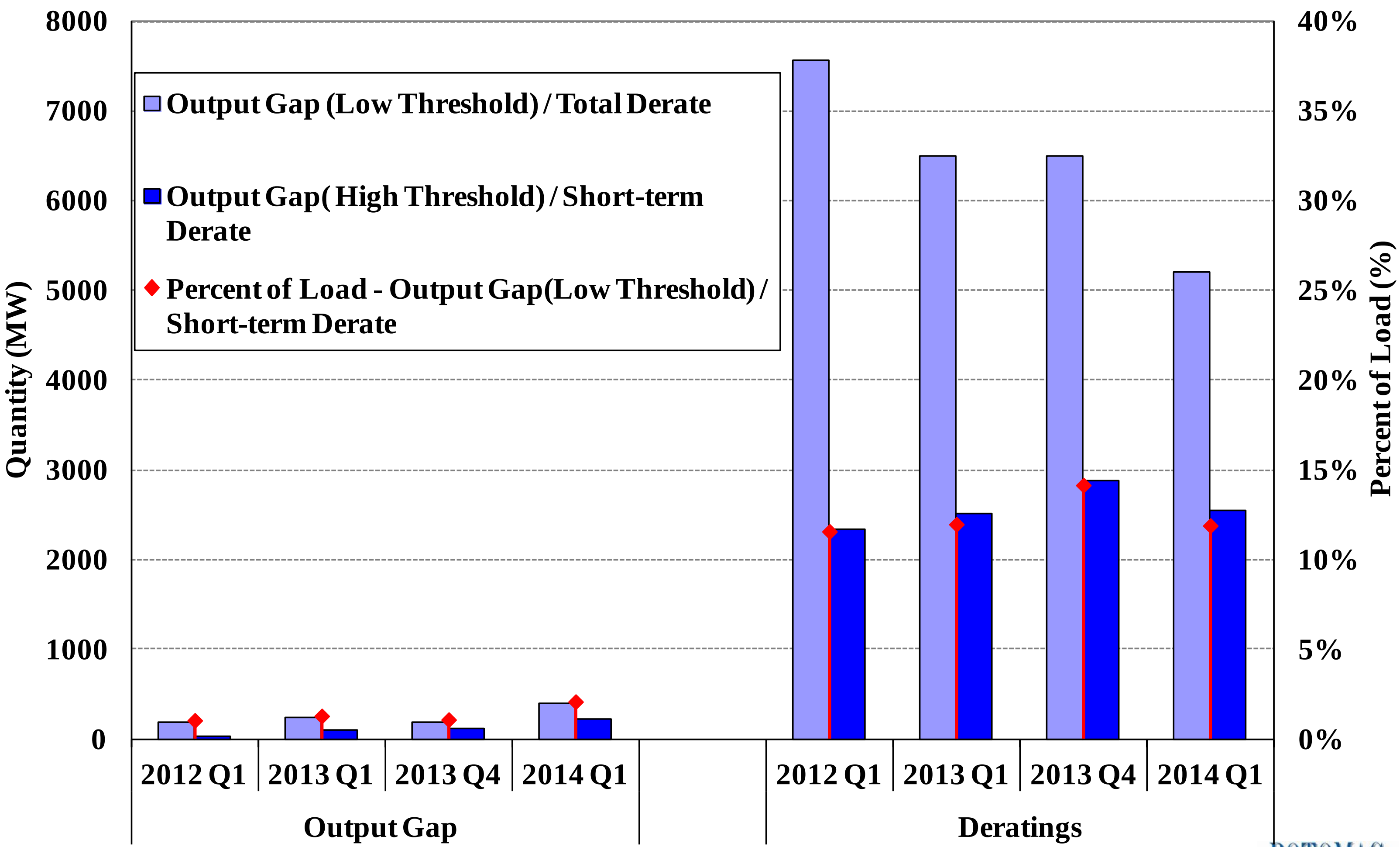
Market Monitoring Screens



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Market Power Mitigation

- The next table summarizes the mitigation that was imposed during the quarter.
- Energy, minimum generation, and start-up offer mitigation is performed by automated mitigation procedure ("AMP") software in the day-ahead and real-time markets in New York City. The following figure reports:
  - ✓ The frequency of incremental energy offer mitigation; and
  - ✓ The average quantity of mitigated capacity, including capacity below the minimum generation level when the minimum generation offer is mitigated.

Quarterly Mitigation Summary

		2012 Q1	2013 Q1	2013 Q4	2014 Q1
Day-Ahead Market	Average Mitigated MW	328	165	146	203
	Energy Mitigation Frequency	39%	30%	4%	7%
Real-Time Market	Average Mitigated MW	44	44	5	41
	Energy Mitigation Frequency	5%	8%	1%	4%

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Automated Market Mitigation

- Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled.
  - ✓ In the first quarter of 2014, 83 percent of mitigation occurred in the day-ahead market primarily for:
    - Local reliability (i.e., DARU & LRR) units (63 percent);
    - The Dunwoodie South interface (12 percent); and
    - The Astoria West Queensbridge/Vernon load pocket (11 percent).
- The amount of day-ahead mitigation rose modestly from the first quarter of 2013.
  - ✓ The increase was primarily because more reliability commitment occurred in New York City, leading to more frequent mitigation of local reliability committed units.
- However, the frequency of incremental energy mitigation fell from the first quarter of 2013.
  - ✓ Congestion occurred less frequently in the Greenwood/Vernon load pocket, leading to reduced mitigation on economically committed units in this area.

Capacity Market

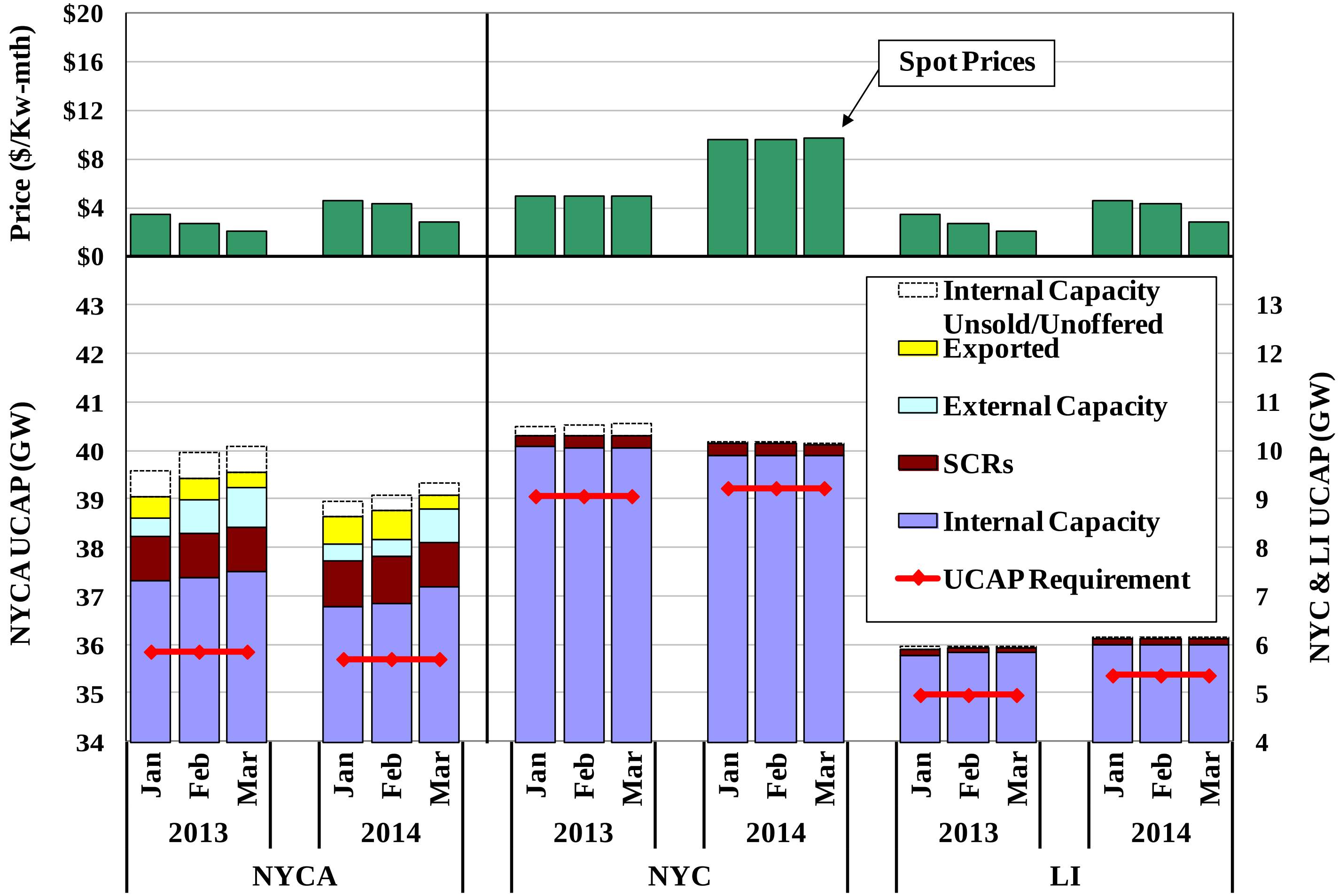
Capacity Market Results

- 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.
- Rest-of-State UCAP spot prices averaged $3.91/kW-month this quarter, up from $2.74/kW-month in the first quarter of 2013, because:
  - ✓ The NYCA ICAP requirement rose 314 MW (or 0.8 percent) from the 2012/13 Capability Year to the 2013/14 Capability Year because of an increase in the IRM from 16 percent to 17 percent.
  - ✓ Internal capacity supply fell 170 MW following the retirement and mothballing of several units in Western NY in June 2013 and September 2013.
  - ✓ Sales from external resources fell by an average of 193 MW, driven by variations in conditions in neighboring areas.
- Long Island UCAP spot prices were equal to Rest-of-State prices in both quarters, reflecting that Long Island had far more capacity than needed to satisfy its LCR.
  - ✓ However, the Long Island ICAP requirement rose 320 MW (or 5.8 percent) from the 2012/13 Capability Year to the 2013/14 Capability Year because the LCR increased from 99 percent to 105 percent. The increase resulted in more frequent binding LCRs in the Summer Capability months (but not in this quarter).

Capacity Market Results

- In NYC, UCAP spot prices averaged $9.64/kW-month this quarter, up from $4.91/kW-month in the first quarter of 2013.
  - ✓ The ICAP requirement rose 332 MW (or 3.5 percent), primarily due to an increase in the LCR from 83 percent to 86 percent.
  - ✓ Buyer-side mitigation was initially imposed on the 550 MW AEII facility in December 2012 (i.e., an Offer Floor was imposed).
    - During the first quarter of 2013, the amount of unsold NYC capacity rose and the spot clearing price was $4.91/kW-month in each month.
    - During the first quarter of 2014, there was virtually no unsold NYC capacity , implying that the capacity from AEII facility was sold.
- The increased LCRs in NYC and Long Island resulted primarily from the loss of generating capacity in the Hudson Valley, since this requires more capacity in downstate areas to secure the UPNY-SENY interface.
  - ✓ However, this is less efficient than modeling a capacity Locality that includes the Hudson Valley and setting the LCR in the new Locality at a level that accurately reflects the reliability benefits of placing capacity there.
  - ✓ Hence, modeling the new G-J Locality starting in May 2014 better enables the market to provide efficient investment signals.

Capacity Market Results



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

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