

# Quarterly Report on the New York ISO Electricity Markets First Quarter 2012


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# Highlights and Market Summary: Energy Market

- This report summarizes the NYISO market outcomes in the first quarter of 2012.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in demand, fuel prices, and supply availability.
- Real-time energy prices averaged roughly $33/MWh statewide in the first quarter of 2012, down 41 percent from the first quarter of 2011. The following factors contributed to the significant reduction:
  - ✓ Natural gas prices fell nearly 50 percent from a year ago;
  - ✓ Load levels were 3 percent lower than a year ago; and
  - ✓ A new 550 MW combined-cycle facility entered in eastern New York.
- Convergence between day-ahead and real-time energy prices was relatively good.
- Day-ahead congestion revenue fell 65 percent from last year to $52 million as lower natural gas prices reduced redispatch costs and new generation entered in eastern New York.
  - ✓ Most day-ahead congestion occurred on paths into and within New York City (47%), the Central-East interface (22%), and lines into Long Island (17%).
  - ✓ Congestion across the Central-East interface fell significantly from last year.

# Highlights and Market Summary: Capacity Market

- UCAP spot prices rose in NYC and fell in the rest of the state in the first quarter of 2012 relative to the first quarter of 2011.
- In New York City, spot prices averaged $4.83/kW-month, up 30 percent from last year.
  - ✓ The increase was due to the deployment of a higher demand curve and an increase in the amount of unsold capacity, although it was mostly offset by sales from new generation in New York City.
  - ✓ Some capacity in the New York City market continued to go unsold in the first quarter of 2012. We made several recommendations in the 2011 State of the Market Report to address issues related to the unsold capacity.
- Outside New York City, spot prices averaged $0.26/kW-month, down from $0.48/kW-month in the first quarter of 2011.
  - ✓ The decrease was primarily due to reduced capacity requirements, which was due to a lower peak load forecast and a reduction in the installed capacity requirement.

# Highlights and Market Summary: Uplift and Revenue Shortfalls

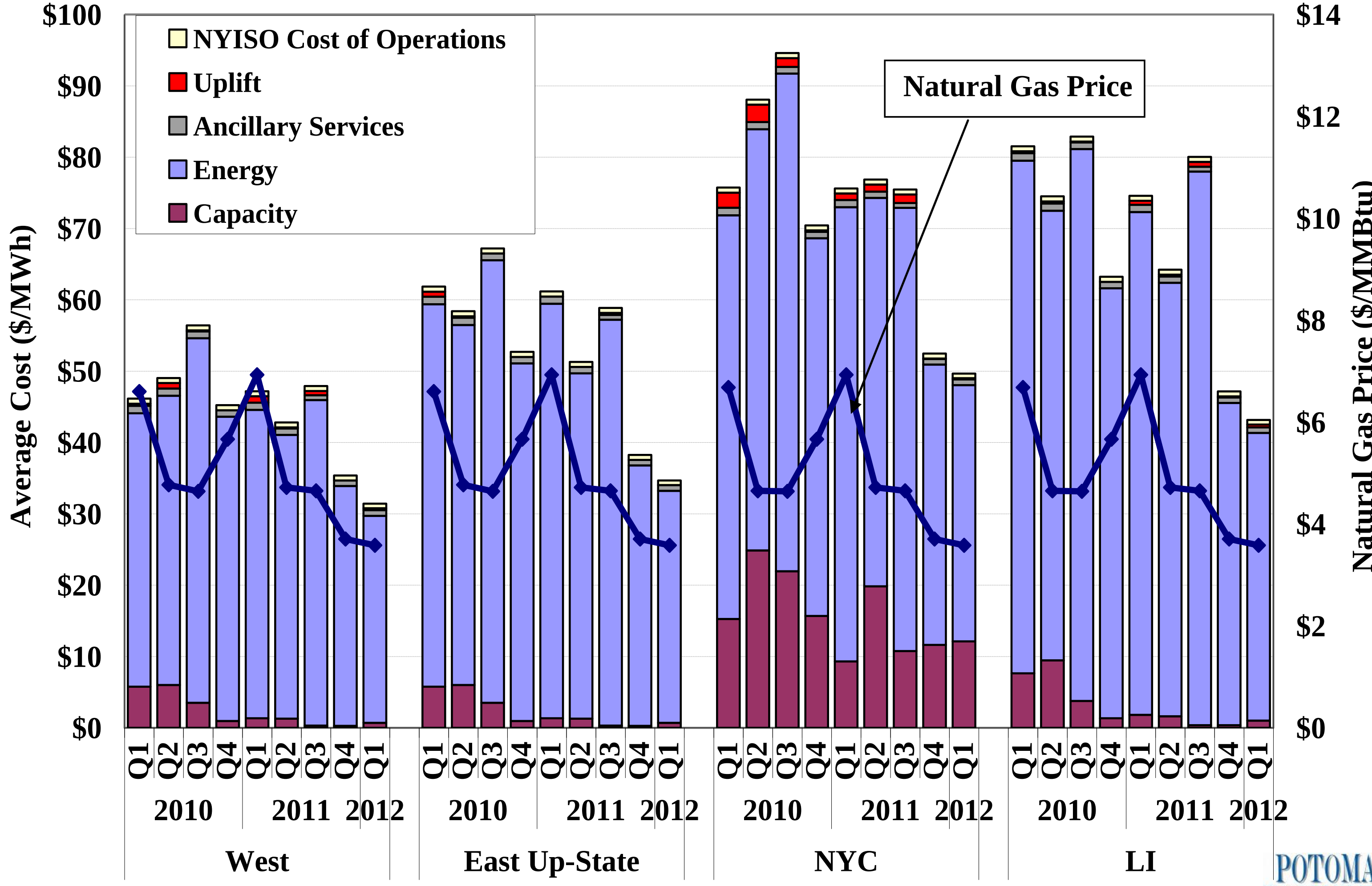
- Uplift charges and revenue shortfalls fell considerably in the first quarter of 2012.
  - ✓ The reduction in natural gas prices was the primary driver of reductions for all categories of uplift discussed below.
- Uplift from guarantee payments totaled $26 million, down 54 percent from the first quarter of 2011.
  - ✓ Guarantee payments were also reduced because lower load levels reduced the need for reliability commitments.
- Day-ahead congestion shortfalls totaled $7 million, down $5 and $36 million from the previous quarter and the previous year, respectively.
  - ✓ Shortfalls fell from a year ago due to lower overall congestion, TCC auction modeling improvements implemented in May 2011, and lower shortfalls related to transmission outages in western NY than in 2011.
- Balancing congestion shortfalls were $3 million in the first quarter of 2012, down slightly from the previous quarter and down from $13 million from a year ago.
  - ✓ These reductions were due to lower overall congestion and improved real-time operations related to the NY-PJM PAR controlled lines.

# Energy and Ancillary Services Markets

# All-In Energy Price

- To summarize prices and 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 capacity prices times the capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges.
  - ✓ A natural gas price trend, which is a key input to production.
- Average all-in prices ranged from $31/MWh in western NY to $50/MWh in NYC, down 33 to 44 percent from the first quarter of 2011.
  - ✓ The reductions were mostly attributable to the significant decreases in energy prices, which were driven primarily by:
    - 50 percent lower natural gas prices, and
    - 3 percent lower load levels due to unseasonably warm weather.
  - ✓ Capacity costs changed only modestly from the first quarter of 2011.
    - In NYC, capacity prices rose 30 percent as the effects of new supply were offset by the effects of unsold capacity and an increase in the capacity demand curve.
    - Outside NYC, capacity prices fell slightly, reflecting a reduced capacity requirement due to a lower peak load forecast.

# All-In Energy Price by Region



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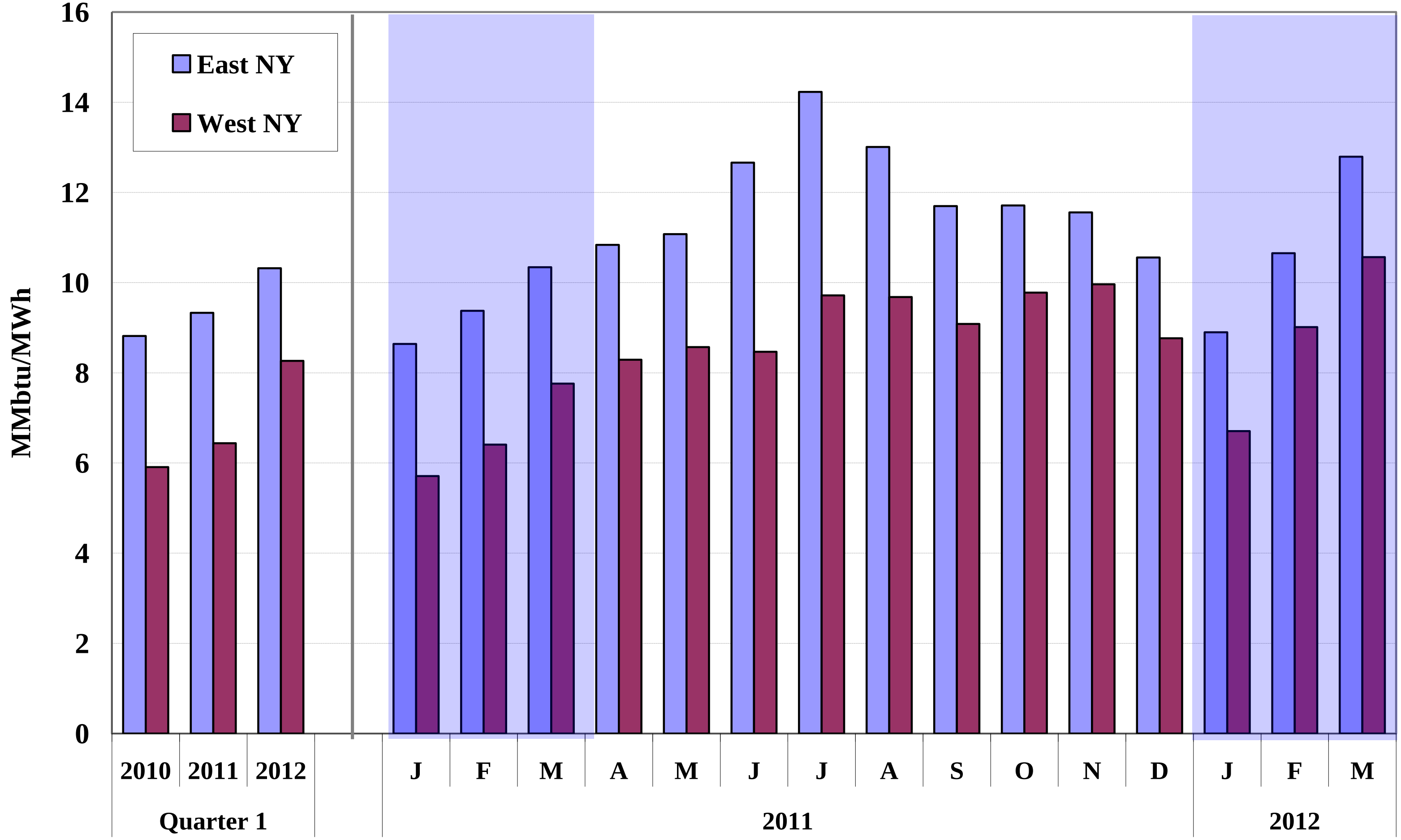
# Implied Heat Rate

- To identify changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows the marginal heat rate that would be implied if natural gas were always the marginal fuel.
  - ✓ Implied Gas Heat Rate = (Day-Ahead Electricity Price) ÷ (Natural Gas Price)
- Prices are higher in East New York than in West New York due to transmission losses and congestion across the Central-East interface, into Southeast New York, into New York City load pockets, and into Long Island.
- The average implied heat rate rose 28 and 11 percent in western NY and eastern NY from the first quarter of 2011 due primarily to the following factors:
  - ✓ Some generation costs (e.g., variable O&M) are not related to fuel prices, leading the implied heat rate to rise when natural gas prices fall to very low levels.
  - ✓ The differential between natural gas prices and oil prices has increased, increasing the effect on the implied heat rate of periods when oil-fired capacity is on the margin.
  - ✓ Energy prices fell less in percentage terms in western NY where less of the generation capacity operates on natural gas.
  - ✓ However, the lower load levels offset a portion of the increases in the implied heat rates.

# Implied Heat Rate by Region




Note: Implied heat rates are for natural gas units and are based on day-ahead prices.

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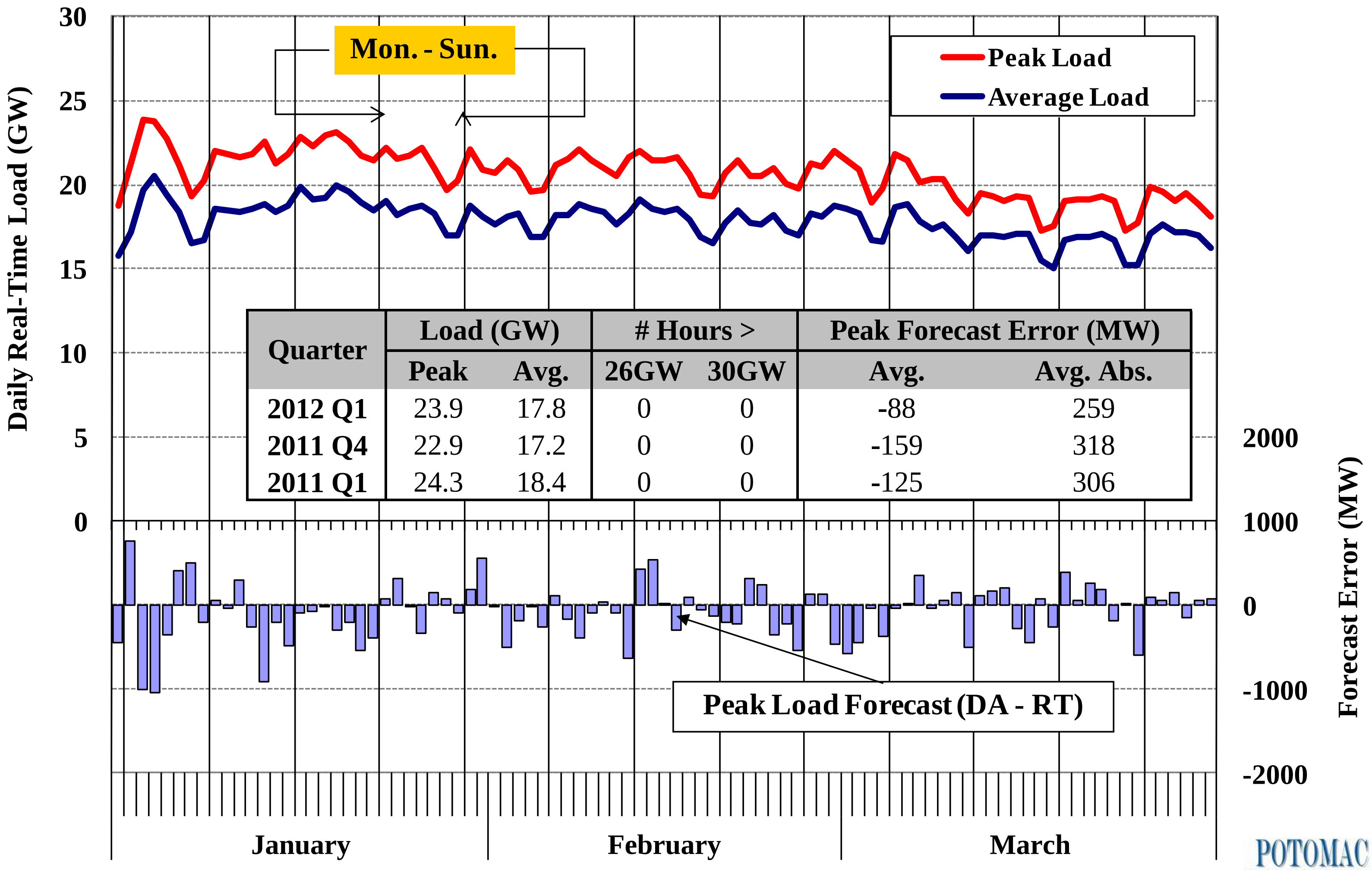
# Load Forecast and Actual Load

- The following figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the first quarter.
  - ✓ The table compares key statistics for the first quarter of 2012 to the previous quarter and the first quarter of 2011.
- Load increased from the previous quarter as winter weather resulted in higher seasonal load.  However, load fell from the first quarter of 2011 as the weather was unseasonably warm in the first quarter of 2012.
  - ✓ Load averaged 17.8 GW, up 3 percent from the prior quarter and down 3 percent from a year ago.
  - ✓ Load peaked on January 3rd at 23.9 GW, up 4 percent from the previous quarter and down 2 percent from the first quarter of 2011.
  - ✓ Overall, load trended down from January to March as usual.
- Peak load forecasting was generally good during the first quarter of 2012.
  - ✓ The daily peak load forecast had an error greater than 500 MW on 13 days and an error greater than 1 GW on one day.
  - ✓ On average, actual loads ran over the peak forecast by 88 MW, lower than the averages in prior quarters.

# Load Forecast and Actual Load




| Quarter | Load (GW) | | # Hours > | | Peak Forecast Error (MW) | |
|---|---|---|---|---|---|---|
| | Peak | Avg. | 26GW | 30GW | Avg. | Avg. Abs. |
| 2012 Q1 | 23.9 | 17.8 | 0 | 0 | -88 | 259 |
| 2011 Q4 | 22.9 | 17.2 | 0 | 0 | -159 | 318 |
| 2011 Q1 | 24.3 | 18.4 | 0 | 0 | -125 | 306 |



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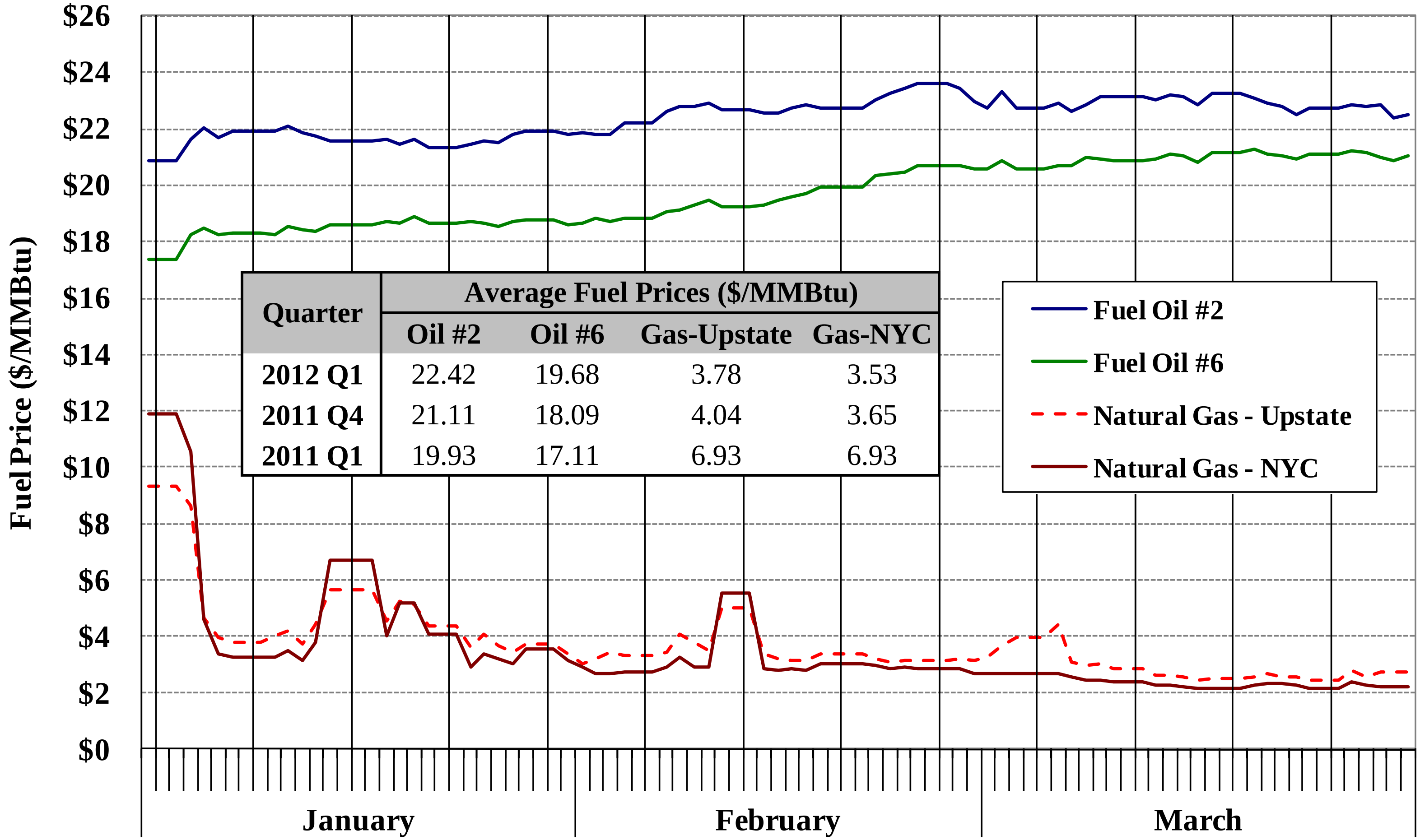
# Natural Gas and Oil Prices

- The following figure shows daily natural gas and fuel oil prices, which are key determinants of electricity prices.
- Natural gas prices averaged roughly $3.50/MMbtu in NYC and $3.80/MMbtu in upstate NY – down 5 percent from the previous quarter and nearly 50 percent from the first quarter of 2011.
  - ✓ Natural gas prices exhibited their lowest quarterly average since 2002.
  - ✓ Natural gas prices generally ranged from $2 to $4/MMbtu, spiking (as high as $12/MMbtu) on several days due to pipeline constraints during cold weather.
  - ✓ Gas prices trended down during the quarter, falling 42 percent from an average of roughly $5/MMbtu in January to $2.60/MMbtu in March.
- Fuel oil prices rose steadily in the first quarter of 2012.
  - ✓ Prices rose 6 percent for #2 oil and 9 percent for #6 oil from the fourth quarter, and prices rose 12 percent and 15 percent from the first quarter of 2011, respectively.
- Natural gas was much less expensive than fuel oil, but some generators still burn oil due to: a) reliability reasons, b) difficulties obtaining natural gas, or c) unavailability of pipeline capacity.

# Natural Gas and Oil Prices



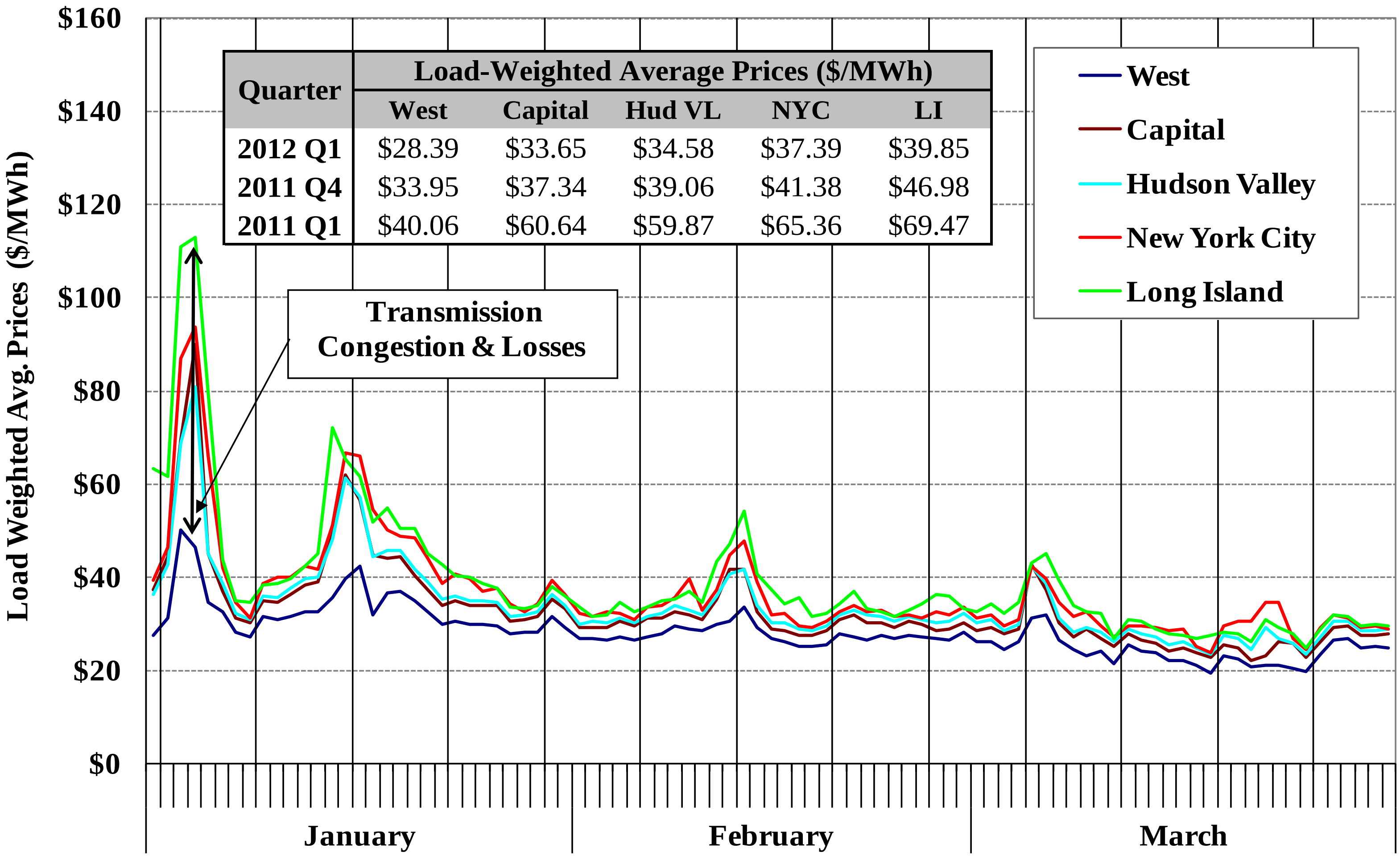

| Quarter | Average Fuel Prices ($/MMBtu) | | | |
|---|---|---|---|---|
| | Oil #2 | Oil #6 | Gas-Upstate | Gas-NYC |
| 2012 Q1 | 22.42 | 19.68 | 3.78 | 3.53 |
| 2011 Q4 | 21.11 | 18.09 | 4.04 | 3.65 |
| 2011 Q1 | 19.93 | 17.11 | 6.93 | 6.93 |

**Note: Natural Gas price for NYC is Transco zone 6 price and for upstate is Iroquois zone 2 price.**

# Day-Ahead Electricity Prices by Zone

- The following figure shows load-weighted average day-ahead energy prices for five zones on each day in the first quarter of 2012.
  - ✓ Prices in the day-ahead market should reflect probability-weighted expectations of real-time market conditions.
- Average day-ahead prices ranged from roughly $28/MWh in the West Zone to $40/MWh in Long Island in the first quarter of 2012.
  - ✓ Average day-ahead prices trended downward from January to March, consistent with the decreases in load and natural gas prices over the quarter.
- Average prices fell 10 to 16 percent from the fourth quarter of 2011 and 29 to 45 percent from the first quarter of 2011.
- Low natural gas prices contributed to the decreased congestion during the quarter, since generating capacity is more reliant on gas in eastern NY than in western NY.
  - ✓ The decline in natural gas prices led to smaller congestion-related price differences between the West Zone and Capital Zone.
  - ✓ However, the congestion-related price differences  between western NY and eastern NY rose considerably during periods of volatile natural gas prices, particularly in early January.

# Day-Ahead Electricity Prices by Zone




| Quarter | Load-Weighted Average Prices ($/MWh) | | | | |
|---|---|---|---|---|---|
| | West | Capital | Hud VL | NYC | LI |
| 2012 Q1 | $28.39 | $33.65 | $34.58 | $37.39 | $39.85 |
| 2011 Q4 | $33.95 | $37.34 | $39.06 | $41.38 | $46.98 |
| 2011 Q1 | $40.06 | $60.64 | $59.87 | $65.36 | $69.47 |

# Real-Time Electricity Prices by Zone

- The following figure shows load-weighted average real-time energy prices for five zones on each day in the first quarter of 2012.
  - ✓ Prices are more volatile in the real-time market than in the day-ahead market.
- Average real-time prices decreased significantly from previous quarters due to lower natural gas prices and load levels.
  - ✓ This is consistent with the pattern of lower day-ahead prices.
- In the first week of January, real-time prices rose, particularly in New York City and Long Island due to:
  - ✓ A sharp rise in gas prices and gas limitations for some generators; and
  - ✓ Unexpected outages of several generators.
- Significant real-time prices spikes occurred on Long Island on several days:
  - ✓ On January 19, February 29, and March 14, the Neptune Line was out unexpectedly, leading to increased real-time prices.
- Real-time prices spiked in New York City on March 23 after multiple generator outages.



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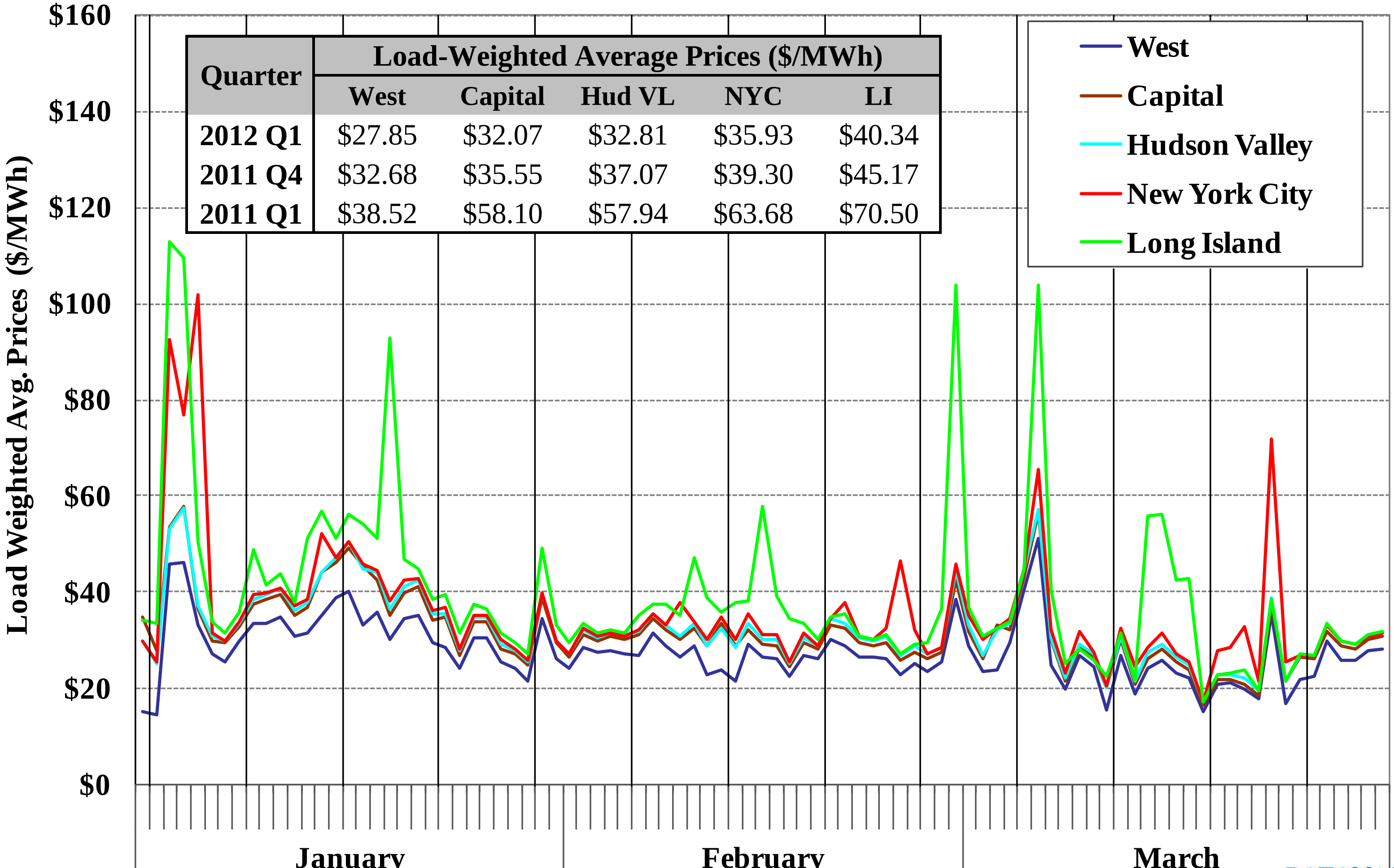
# Real-Time Electricity Prices by Zone

| Quarter | Load-Weighted Average Prices ($/MWh) | | | | |
|---|---|---|---|---|---|
| | West | Capital | Hud VL | NYC | LI |
| 2012 Q1 | $27.85 | $32.07 | $32.81 | $35.93 | $40.34 |
| 2011 Q4 | $32.68 | $35.55 | $37.07 | $39.30 | $45.17 |
| 2011 Q1 | $38.52 | $58.10 | $57.94 | $63.68 | $70.50 |



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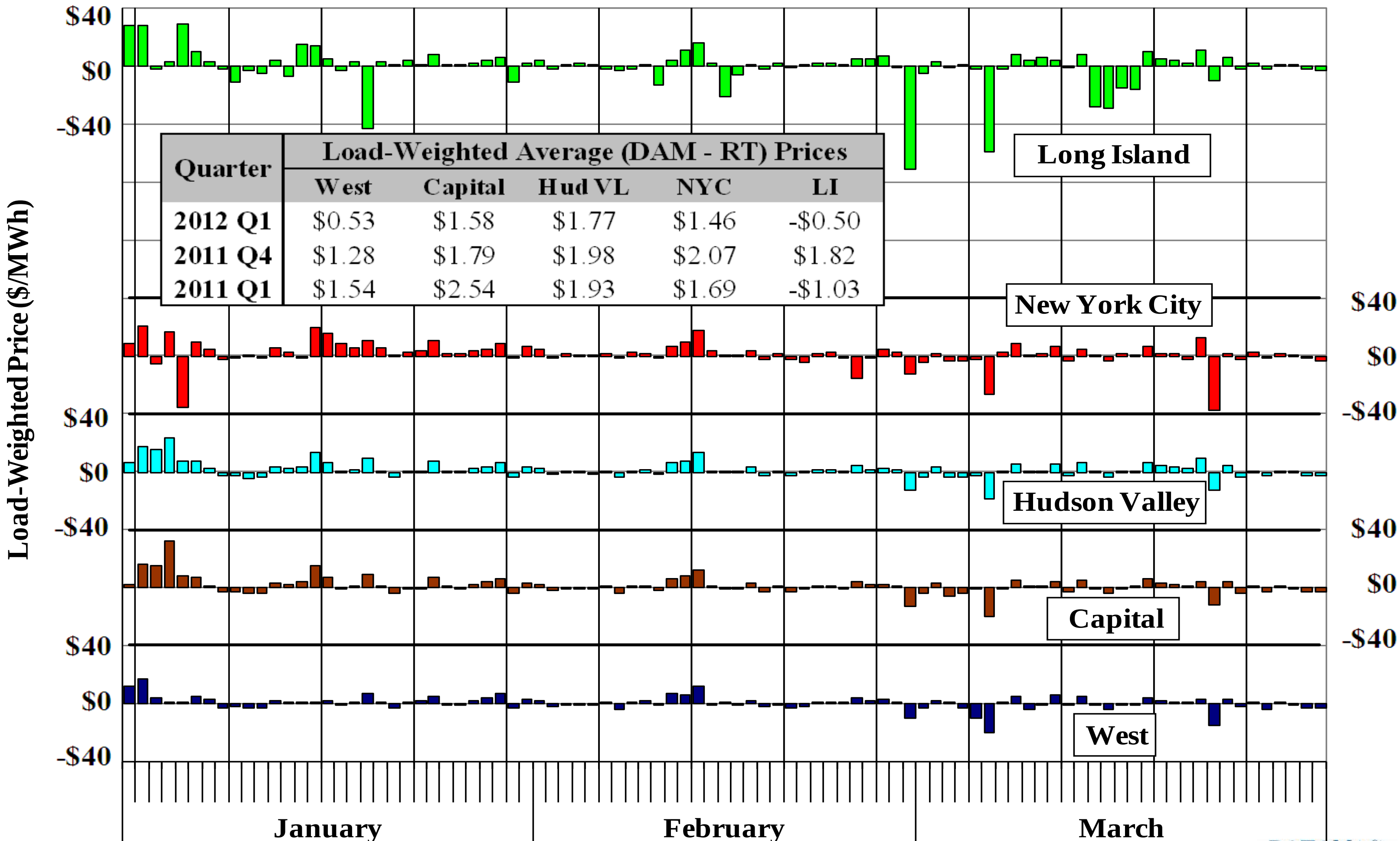
# Convergence Between Day-Ahead and Real-Time Prices

- The next analysis evaluates day-ahead and real-time price convergence.
  - ✓ 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.
- The figure shows the difference between average day-ahead prices and the average real-time prices on each day in the first quarter of 2012.
  - ✓ This is shown separately for five zones to account for changes in the pattern of congestion from the day-ahead to the real-time.
  - ✓ Convergence should be measured over longer timeframes since random factors can cause large differences in prices on individual days -- the table shows the average price convergence over the entire quarter.
- Convergence between day-ahead and real-time prices was generally good on most days in the first quarter of 2012.
  - ✓ Price differences in most areas ranged from 1 to 5 percent of RT prices in the first quarter, down from last quarter and comparable to the same quarter of 2011.

# Convergence Between Day-Ahead and Real-Time Prices




| Quarter | Load-Weighted Average (DAM - RT) Prices | | | | |
|---|---|---|---|---|---|
| | West | Capital | Hud VL | NYC | LI |
| 2012 Q1 | $0.53 | $1.58 | $1.77 | $1.46 | -$0.50 |
| 2011 Q4 | $1.28 | $1.79 | $1.98 | $2.07 | $1.82 |
| 2011 Q1 | $1.54 | $2.54 | $1.93 | $1.69 | -$1.03 |



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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 New York, which reflect the cost of requiring:
    - 300 MW of 10-minute spinning reserves in eastern New York;
    - 600 MW of 10-minute spinning reserves state-wide; and
    - 1,200 MW of 10-minute total reserves (spinning and non-spinning reserves) in eastern New York.
  - ✓ 10-minute non-spinning reserves prices in eastern New York, which reflect the cost of requiring 1,200 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-minute spinning reserves prices in western New York, which reflect the cost of requiring 600 MW of 10-minute spinning reserves state-wide.
  - ✓ 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.

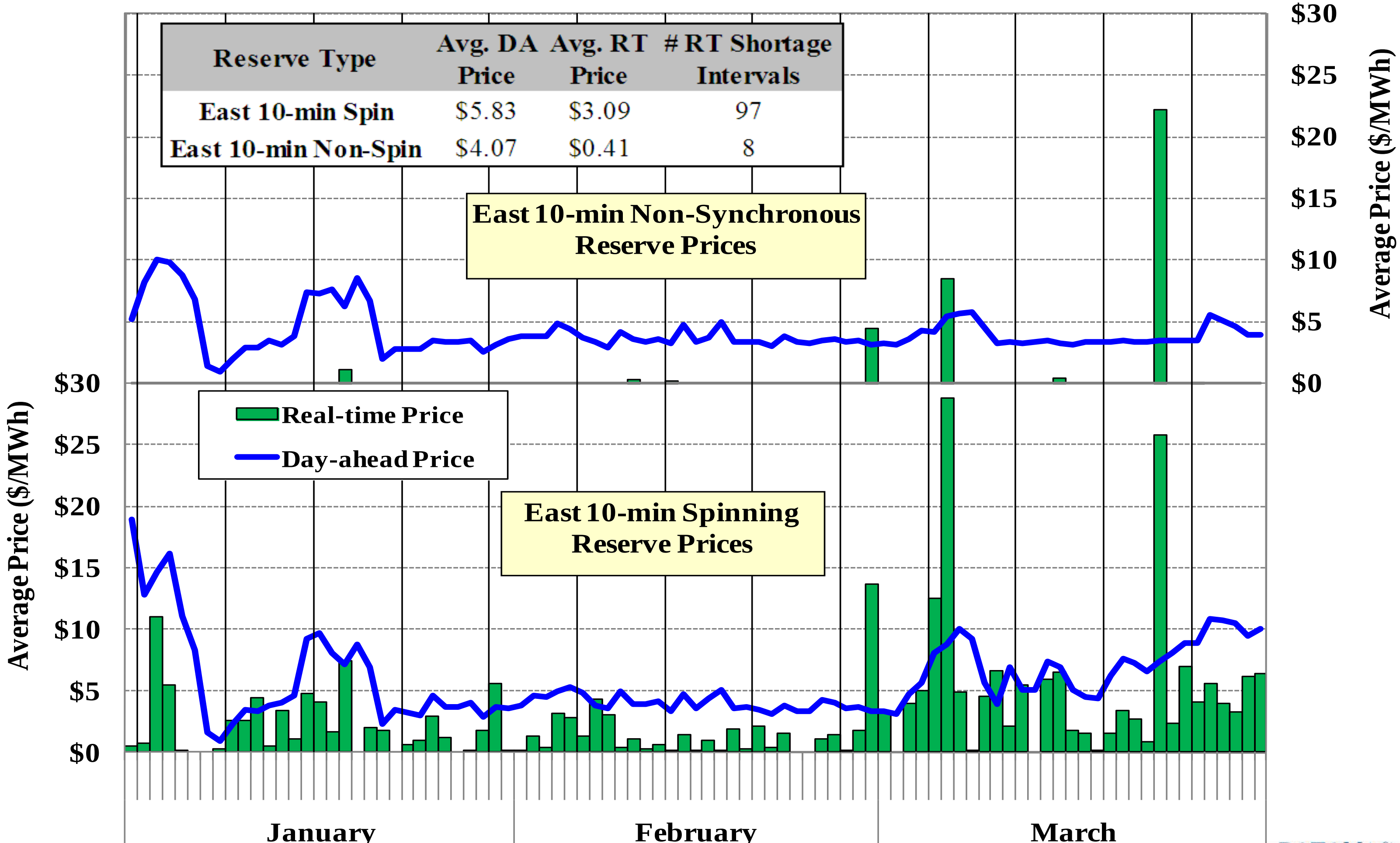
# Day-Ahead and Real-Time Ancillary Services Prices

- Reserve prices are relatively consistent from day-to-day in the day-ahead, while reserve prices are much more volatile in the real-time market.
  - ✓ Day-ahead reserves prices are based on suppliers' offers, which depend on expectations of real-time prices and the risks associated with selling reserves in the day-ahead market.
  - ✓ Real-time reserves prices are normally close to $0 due to the excess available reserves from online and quick-start units in most hours.
  - ✓ Real-time prices spike during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Average day-ahead prices in eastern New York for 10-minute spinning and non-spinning reserves were substantially higher than average real-time reserves prices in the first quarter of 2012.
  - ✓ Day-ahead and real-time prices were more closely correlated for eastern 10-minute spinning reserve prices than in previous years.
- Average day-ahead prices were lower than average real-time prices for 10-minute spinning reserves in western New York and for regulation.

# 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 89 intervals ($25 demand curve);
  - ✓ Eastern 10-minute total reserves in 8 intervals ($500 demand curve);
  - ✓ State-wide 10-minute spinning reserves in 0 intervals ($500 demand curve); and
  - ✓ Regulation in 355 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 the East reflect 97 intervals of shortage pricing: 89 of eastern 10-minute spin, 8 of eastern 10-minute total reserves, and 0 of state-wide 10-minute spin.
- Regulation shortages occurred more frequently than the same quarter of 2011 following the modification of Regulation Demand Curve on May 19, 2011.
  - ✓ The new values more accurately reflect operational actions during shortages.
  - ✓ Regulation shortages occurred more frequently due to the lower value placed on regulation by the new demand curve during small shortages. (There were just 109 regulation shortages in the first quarter of 2011.)

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

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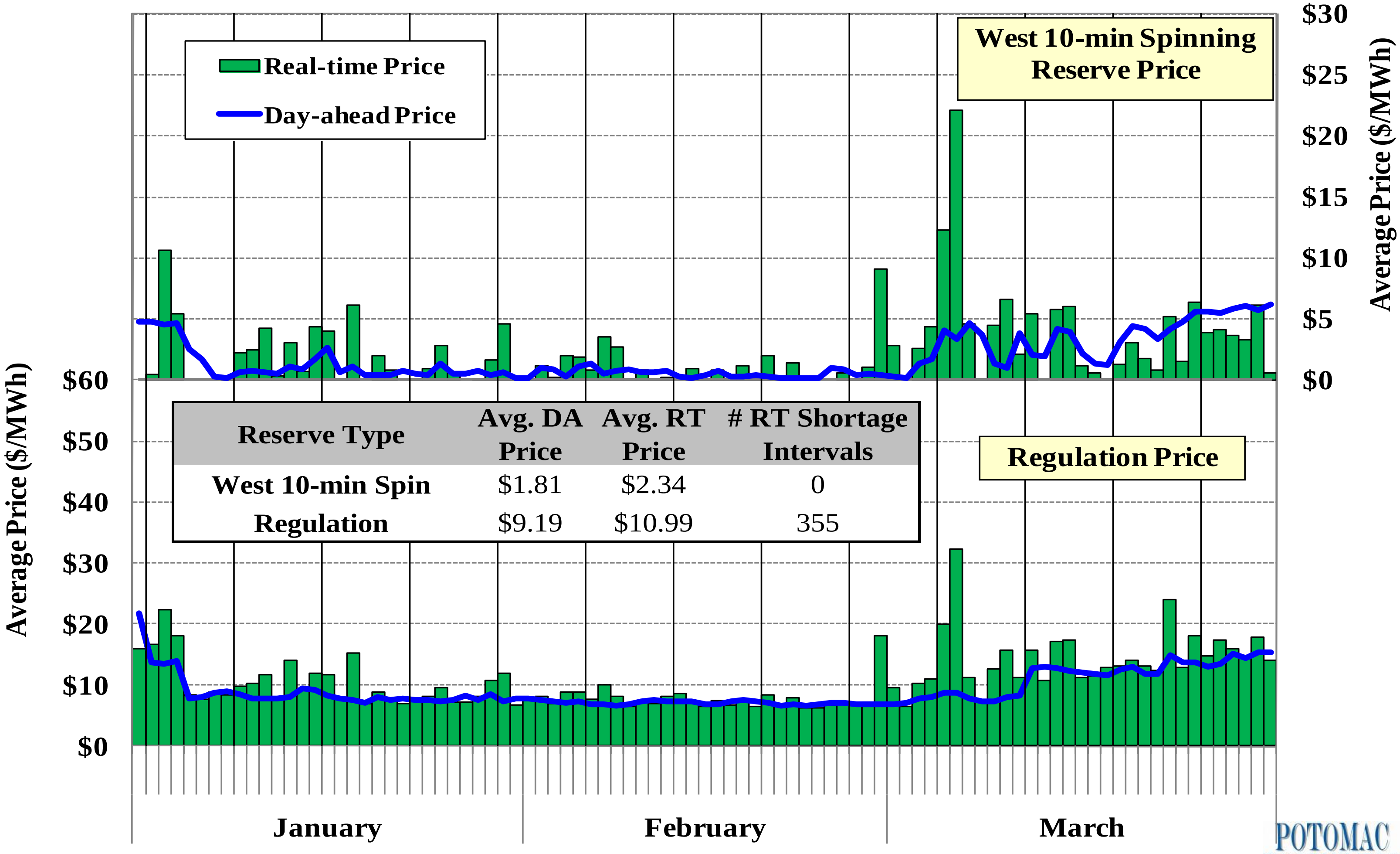
# Day-Ahead and Real-Time Ancillary Services Prices
## Western 10-Minute Spinning Reserves and Regulation




| Reserve Type | Avg. DA Price | Avg. RT Price | # RT Shortage Intervals |
|---|---|---|---|
| West 10-min Spin | $1.81 | $2.34 | 0 |
| Regulation | $9.19 | $10.99 | 355 |



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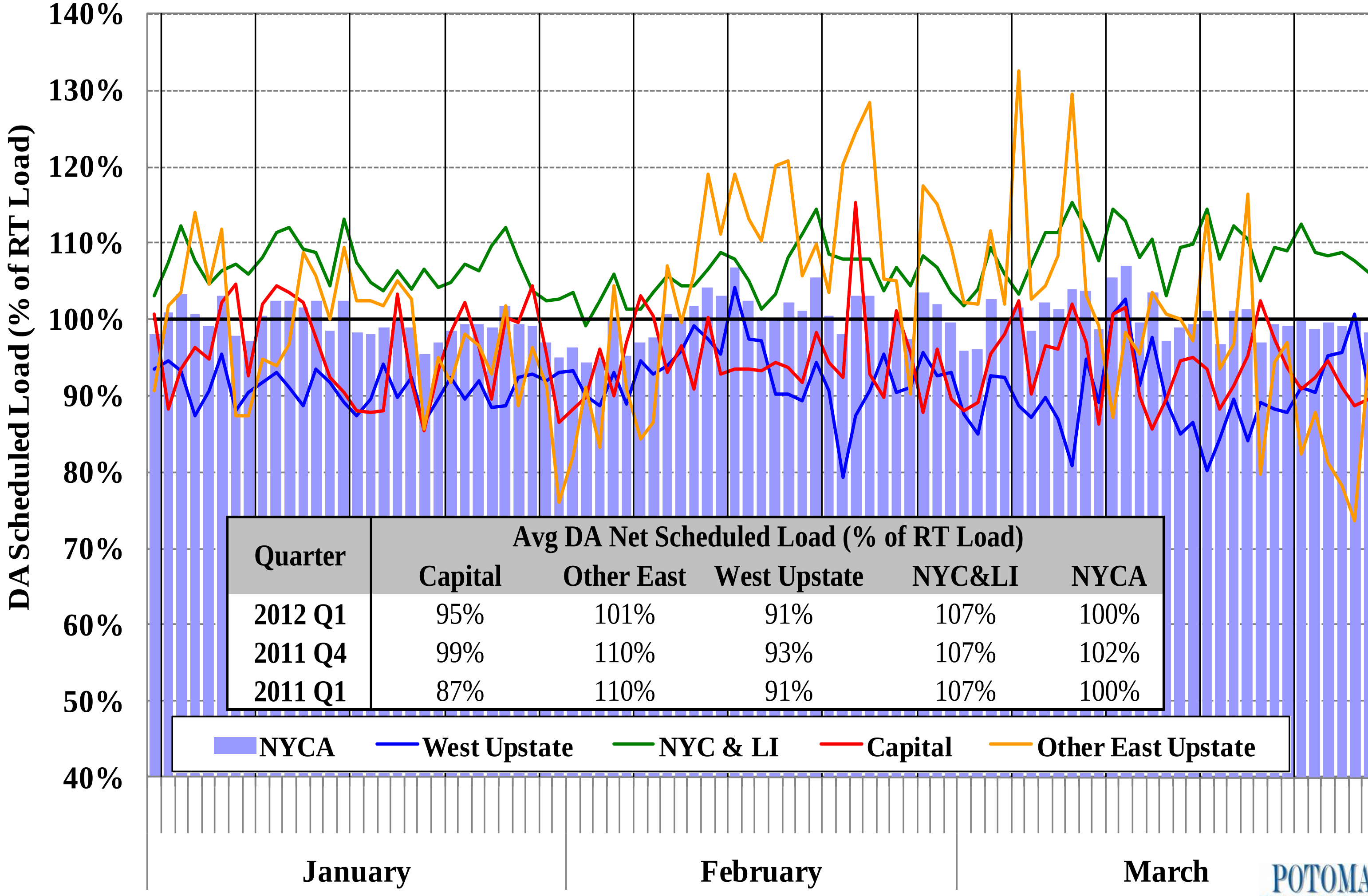
# Day-ahead Scheduled Load and Actual Load

- 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 day-ahead market was scheduled at 100 percent of actual load in NYCA, lower than the previous quarter but comparable to the first quarter of 2011.
- Load was generally under-scheduled outside Southeast New York (i.e., West Upstate and Capital Zone) and over-scheduled in Southeast New York (i.e., Other East Upstate, New York City and Long Island) in the first quarter.
  - ✓ This pattern is typical, and it is likely a natural market response to real-time congestion on paths into Southeast NY, and into NYC and Long Island.
- The over- and under-scheduling patterns generally improve convergence between day-ahead and real-time prices in most areas.
  - ✓ For example, West Upstate NY was the most under-scheduled area and yet it exhibited a day-ahead price premium that would have been even larger if it were fully scheduled.

# 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 |
| 2012 Q1 | 95% | 101% | 91% | 107% | 100% |
| 2011 Q4 | 99% | 110% | 93% | 107% | 102% |
| 2011 Q1 | 87% | 110% | 91% | 107% | 100% |



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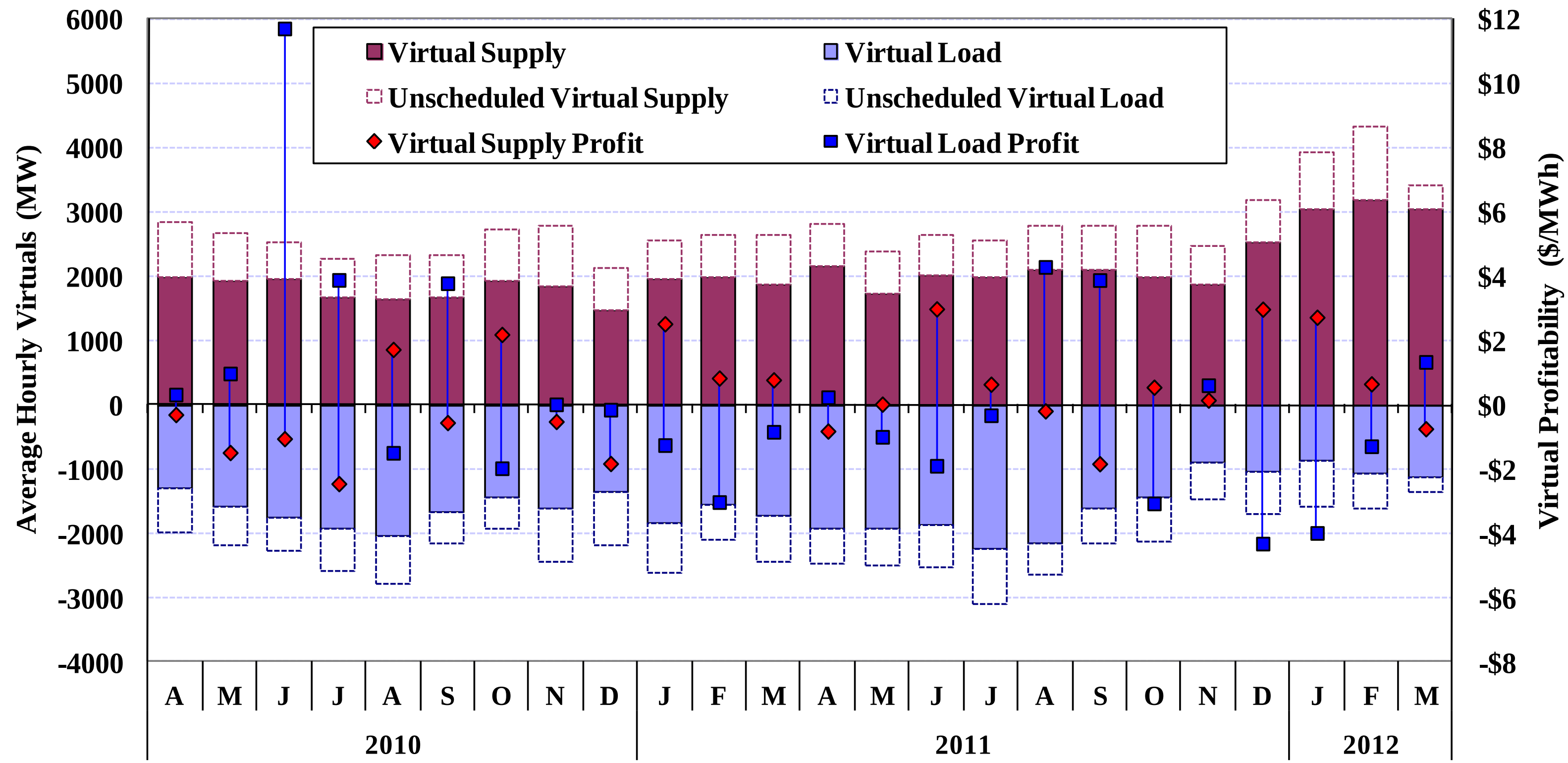
# Virtual Trading Activity

- The following two figures summarize virtual trading activity in New York.
- The first figure shows monthly average bids/offers and scheduled quantities, and profitability for virtual transactions in each month over the past two years.
  - ✓ In each of the past 24 months, 0.8 to 2.2 GW of virtual load and 1.5 to 3.2 GW of virtual supply have been consistently scheduled in the day-ahead market.
  - ✓ The increased virtual supply in the first quarter of 2012 coincided with increased physical load scheduling, so the Net Scheduled Load did not change significantly.
  - ✓ In aggregate, virtual load and supply have generally been profitable over the period, 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 2012 was low.
  - ✓ The transactions with notable profits or losses were primarily associated with real-time price volatility and do not raise manipulation concerns.

# Virtual Trading Volumes and Profitability

## April 2010 to March 2012




| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Profit > 50% of Avg. Zone Price | MW | 122 | 181 | 285 | 205 | 176 | 162 | 117 | 135 | 221 | 446 | 193 | 161 | 122 | 233 | 350 | 376 | 337 | 186 | 98 | 100 | 208 | 275 | 96 | 224 |
| | % | 4% | 5% | 8% | 6% | 5% | 5% | 3% | 4% | 8% | 12% | 5% | 4% | 3% | 6% | 9% | 9% | 8% | 5% | 3% | 4% | 6% | 7% | 2% | 5% |
| Loss > 50% of Avg. Zone Price | MW | 112 | 211 | 241 | 300 | 205 | 115 | 95 | 131 | 273 | 401 | 244 | 133 | 120 | 277 | 381 | 434 | 334 | 122 | 133 | 120 | 193 | 177 | 125 | 283 |
| | % | 3% | 6% | 6% | 8% | 6% | 3% | 3% | 4% | 10% | 11% | 7% | 4% | 3% | 8% | 10% | 10% | 8% | 3% | 4% | 4% | 5% | 5% | 3% | 7% |



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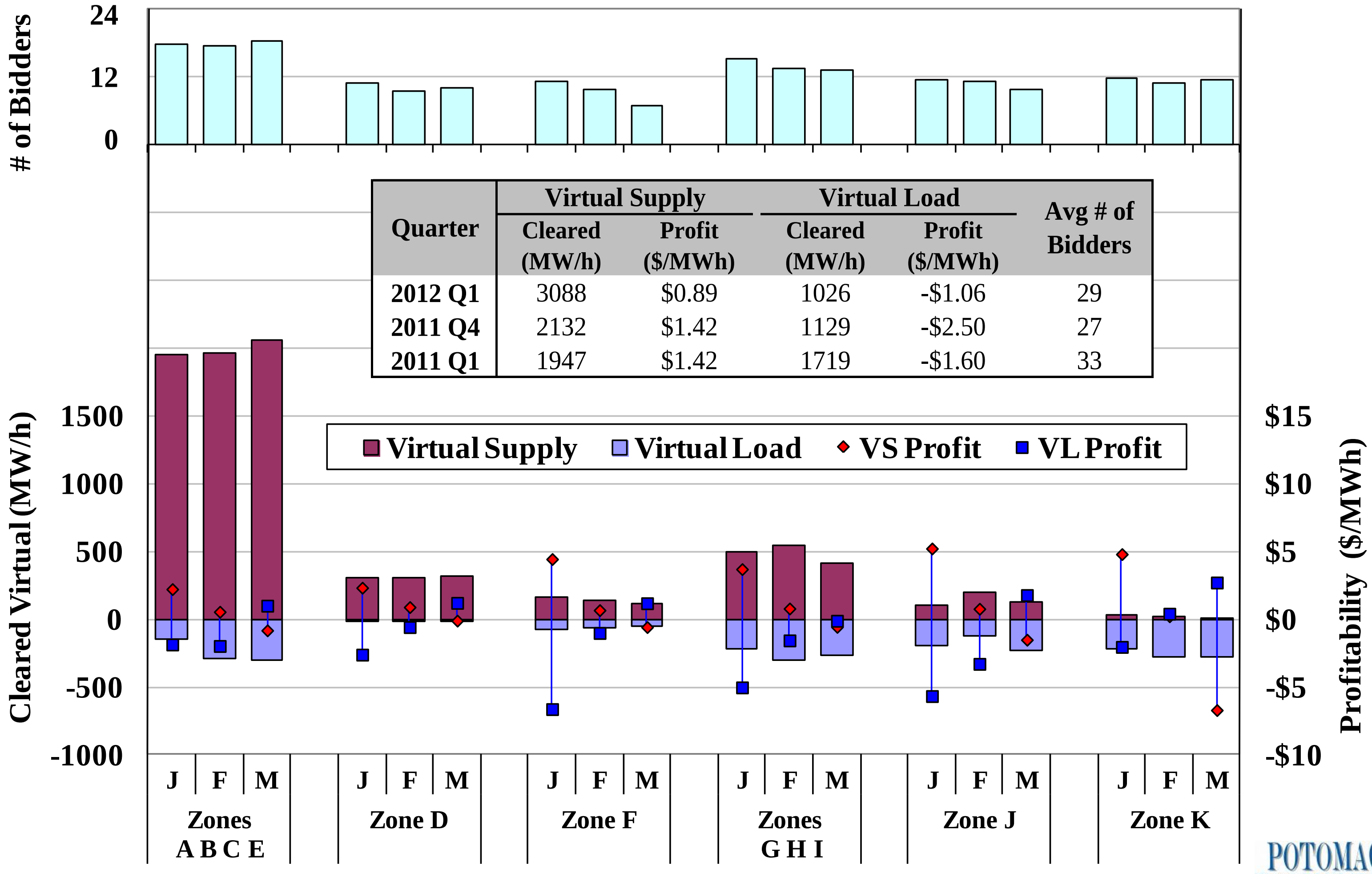
# Virtual Trading Activity

- The second 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.
- A large number of market participants regularly submit virtual bids and offers, although the number has fallen since the implementation of new credit requirements in October 2011.
  - ✓ On average, seven or more participants submitted virtual trades in each region and 29 participants submitted virtual trades throughout the state.
- There were substantial net virtual load purchases downstate and net virtual supply sales upstate in the first quarter of 2012, consistent with prior periods.
  - ✓ Virtual supply netted a $6 million profit in the first quarter while virtual load netted a loss of about $2 million, due to the prevailing day-ahead price premiums in most regions.

# 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) | |
| **2012 Q1** | 3088 | $0.89 | 1026 | -$1.06 | 29 |
| **2011 Q4** | 2132 | $1.42 | 1129 | -$2.50 | 27 |
| **2011 Q1** | 1947 | $1.42 | 1719 | -$1.60 | 33 |



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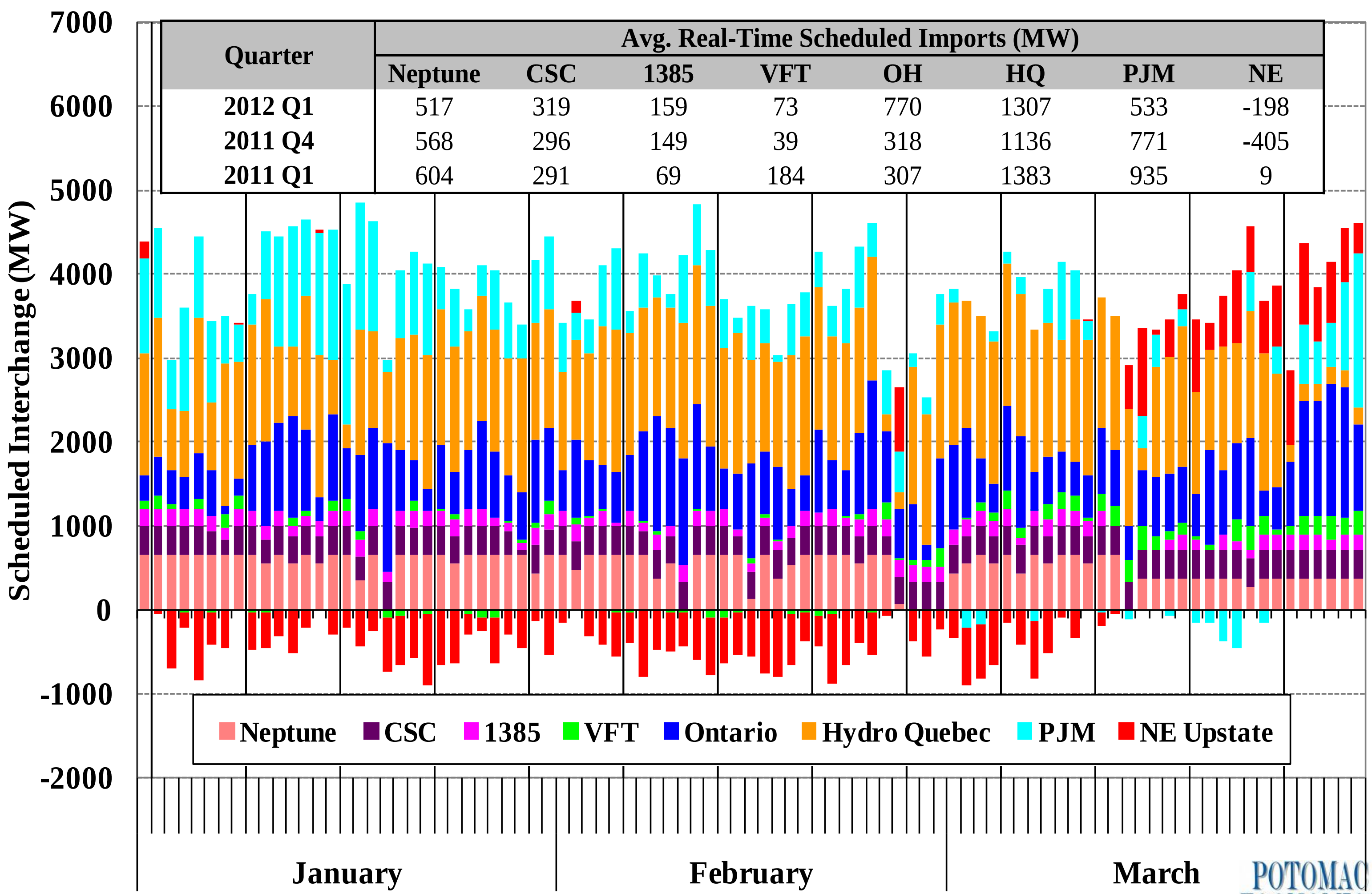
# Net Imports Scheduled Across External Interfaces

- The following figure summarizes scheduled net imports to NYCA across eight external interfaces during the daily peak hour.
- Net imports to NYCA averaged roughly 3.5 GW during daily peak hours in the first quarter of 2012, up 600 MW (or 21 percent) from the previous quarter and down 300 MW (or 8 percent ) from the first quarter of 2011.
  - ✓ Net imports from HQ rose 170 MW from the previous quarter and was consistent with the first quarter of 2011.
    - – The hydro-backed imports typically rise in the winter months.
  - ✓ Net imports from Ontario increased over 450 MW from the prior periods due in part to fewer transmission outages that affected the transfer capability between the two regions.
  - ✓ Net imports from PJM fell 240 MW from the previous quarter and 400 MW from a year ago due in part to the effects of lower natural gas prices.
- On average, imports satisfied 17 percent of the load during daily peak hours in the first quarter of 2012, up from 14 percent in the previous quarter.
  - ✓ During the quarterly peak load hour on January 3, NYCA imported 2.3 GW, satisfying nearly 10 percent of the peak load.

# 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 |
| 2012 Q1 | 517 | 319 | 159 | 73 | 770 | 1307 | 533 | -198 |
| 2011 Q4 | 568 | 296 | 149 | 39 | 318 | 1136 | 771 | -405 |
| 2011 Q1 | 604 | 291 | 69 | 184 | 307 | 1383 | 935 | 9 |



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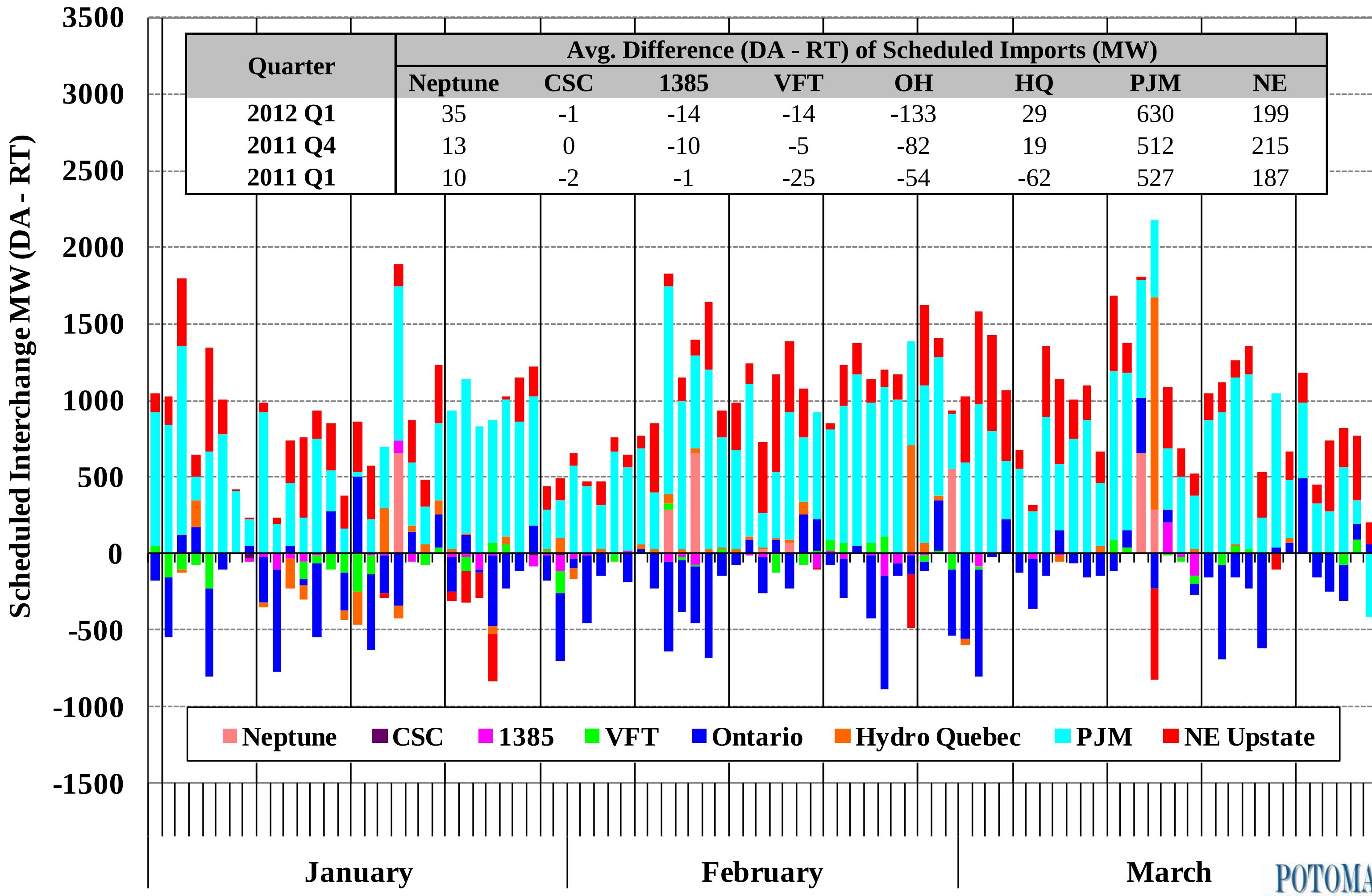
# Change in Scheduled Imports from Day Ahead to Real Time

- The following figure summarizes the change in scheduled net imports between the day-ahead market and the real-time market in the daily peak load hour.
  - ✓ As with virtual transactions, these changes should be consistent with the RT price signals and should improve the convergence of DA and RT prices.
- Net scheduled imports fell 730 MW on average from day-ahead to real-time during daily peak load hours in the first quarter of 2012. Net scheduled imports:
  - ✓ Decreased across the PJM interface by an average of 630 MW;
  - ✓ Decreased across the primary interface with NE by an average of 199 MW; and
  - ✓ Increased across the Ontario interfaces by an average of 133 MW.
- On average, the changes in schedules between the day-ahead and real-time markets were consistent with the differences in prices.
  - ✓ However, power was still scheduled in the inefficient direction (i.e., from the high-priced area to the low-priced area) in a large share of hours.
  - ✓ The NYISO is working on market enhancements to improve the efficiency of the interchange (e.g., 15-minute scheduling with PJM and CTS with ISO-NE).

# Change in Scheduled Imports from DA to RT
## Daily Peak Load Hour

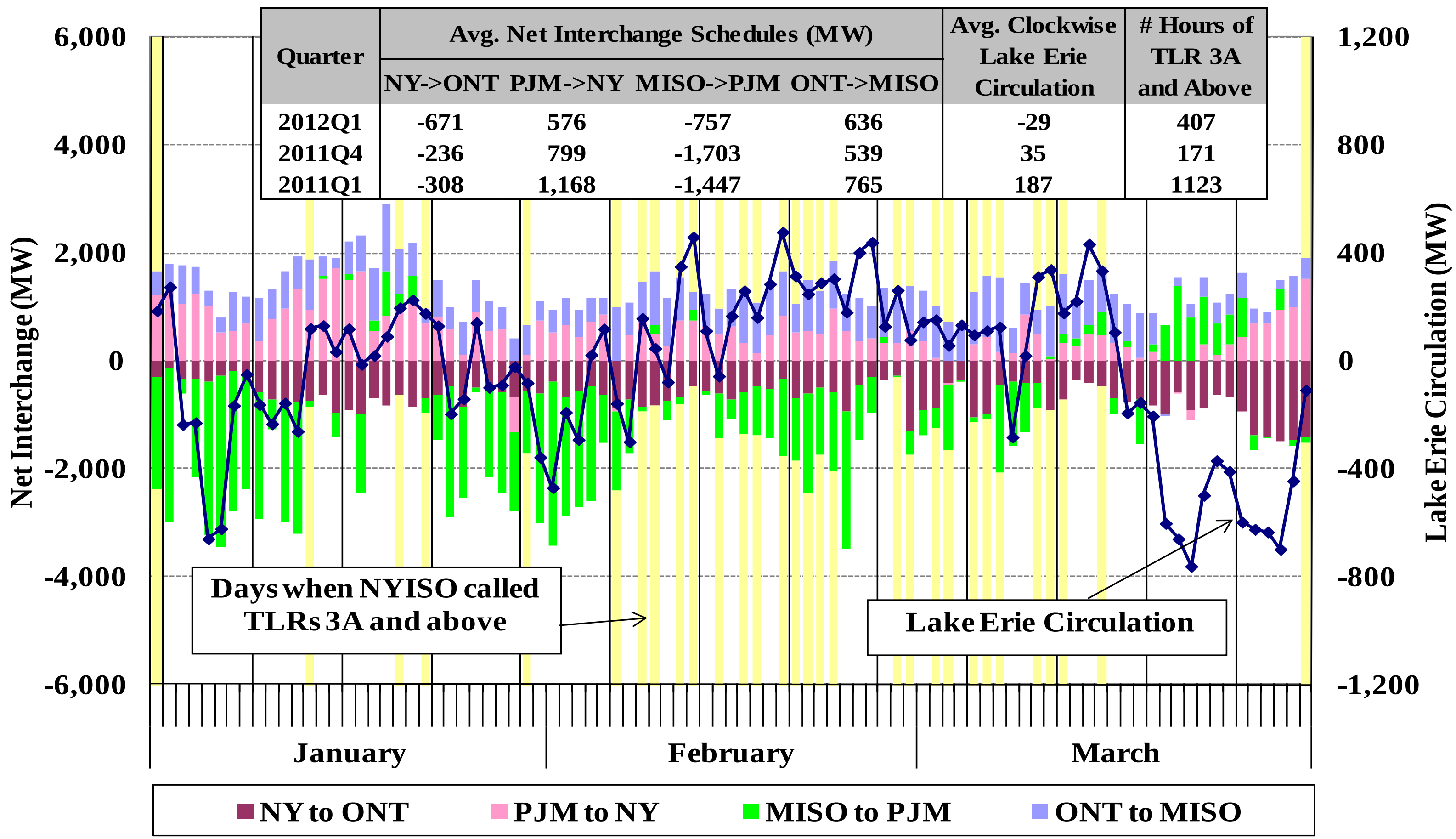



| Quarter | Avg. Difference (DA - RT) of Scheduled Imports (MW) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Neptune | CSC | 1385 | VFT | OH | HQ | PJM | NE |
| 2012 Q1 | 35 | -1 | -14 | -14 | -133 | 29 | 630 | 199 |
| 2011 Q4 | 13 | 0 | -10 | -5 | -82 | 19 | 512 | 215 |
| 2011 Q1 | 10 | -2 | -1 | -25 | -54 | -62 | 527 | 187 |

# External Interface Scheduling and Lake Erie Circulation

- Loop flows occur when physical power flows are not consistent with the scheduled path of the transaction between control areas.
  - ✓ Clockwise loop flows around Lake Erie use valuable west-to-east transmission capacity through upstate New York, reducing the capacity available for scheduling internal generation to satisfy internal load.
  - ✓ The Transmission Loading Relief (“TLR”) procedure is used by the NYISO when loop flows contribute to congestion on internal flow gates.
- The figure shows the pattern of loop flows and the net scheduled interchange between the four control areas around Lake Erie on each day of the quarter.
  - ✓ Days when TLRs (level 3A) were called by the NYISO are also highlighted.
- Average clockwise circulation was *negative* 29 MW in the first quarter, down 64 MW from the previous quarter and down 216 MW from the first quarter of 2011.
  - ✓ The correlation of clockwise circulation and counter-clockwise transactions was weak, suggesting that dispatch by each ISO also significantly affects loop flows.
- TLRs were called on 30 days in 407 hours, down from the first quarter of 2011.
  - ✓ Some of the IESO-Michigan PARs began operating in April 2012. We will evaluate their effects on the frequency of TLR calls and volume of loop flows in future reports.

# RT Lake Erie Circulation and Interchange Schedules
## Daily Peak Hours between 8AM and 8PM



| Quarter | Avg. Net Interchange Schedules (MW) | | | | Avg. Clockwise Lake Erie Circulation | # Hours of TLR 3A and Above |
|---|---|---|---|---|---|---|
| | NY->ONT | PJM->NY | MISO->PJM | ONT->MISO | | |
| 2012Q1 | -671 | 576 | -757 | 636 | -29 | 407 |
| 2011Q4 | -236 | 799 | -1,703 | 539 | 35 | 171 |
| 2011Q1 | -308 | 1,168 | -1,447 | 765 | 187 | 1123 |



Note: Positive circulation MW indicates clockwise circulation. Reported TLR hours include all hours, while other quantities are averaged over hours between 8AM and 8PM.



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# Day-Ahead and Real-Time Transmission Congestion

# 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 quantity of 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, which are recovered through uplift.



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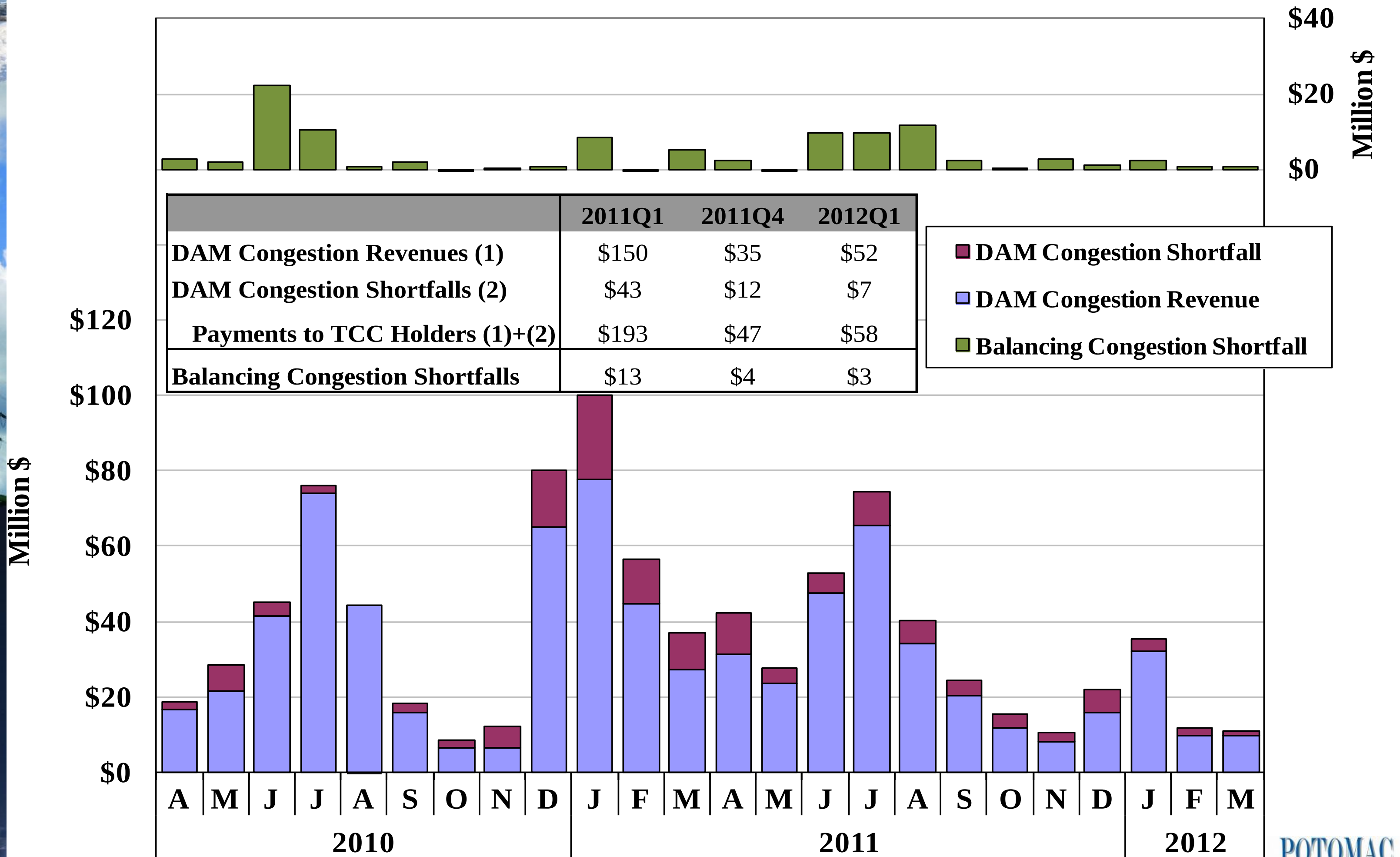
# Congestion Revenue and Shortfalls

- The following figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years.
- Day-ahead congestion revenue was $52 million in the first quarter, up nearly 50 percent from the previous quarter but down 65 percent from a year ago.
  - ✓ The reduction from a year ago primarily reflects the effects of lower natural gas prices, which reduce imports to eastern NY and which reduce congestion-related price differences.
  - ✓ Lower load levels, fewer transmission outages in western NY, and new generation in NYC also contributed to the decline in congestion.
- Day-ahead congestion shortfalls totaled $7 million, down $5 and $36 million from the previous quarter and the previous year, respectively.
  - ✓ The reduction from a year ago was due to less overall congestion, TCC auction modeling improvements implemented in May 2011, and lower shortfalls related to transmission outages in Western NY (which were more significant last year).
- Balancing congestion shortfalls were $3 million in the first quarter of 2012, down slightly from the previous quarter and down from $13 million from a year ago.
  - ✓ Shortfalls fell primarily due to the overall reduction in congestion and improved real-time operations related to the NY-PJM PAR controlled lines.

# Congestion Revenue and Shortfalls

| | 2011Q1 | 2011Q4 | 2012Q1 |
|---|---|---|---|
| DAM Congestion Revenues (1) | $150 | $35 | $52 |
| DAM Congestion Shortfalls (2) | $43 | $12 | $7 |
| Payments to TCC Holders (1)+(2) | $193 | $47 | $58 |
| Balancing Congestion Shortfalls | $13 | $4 | $3 |



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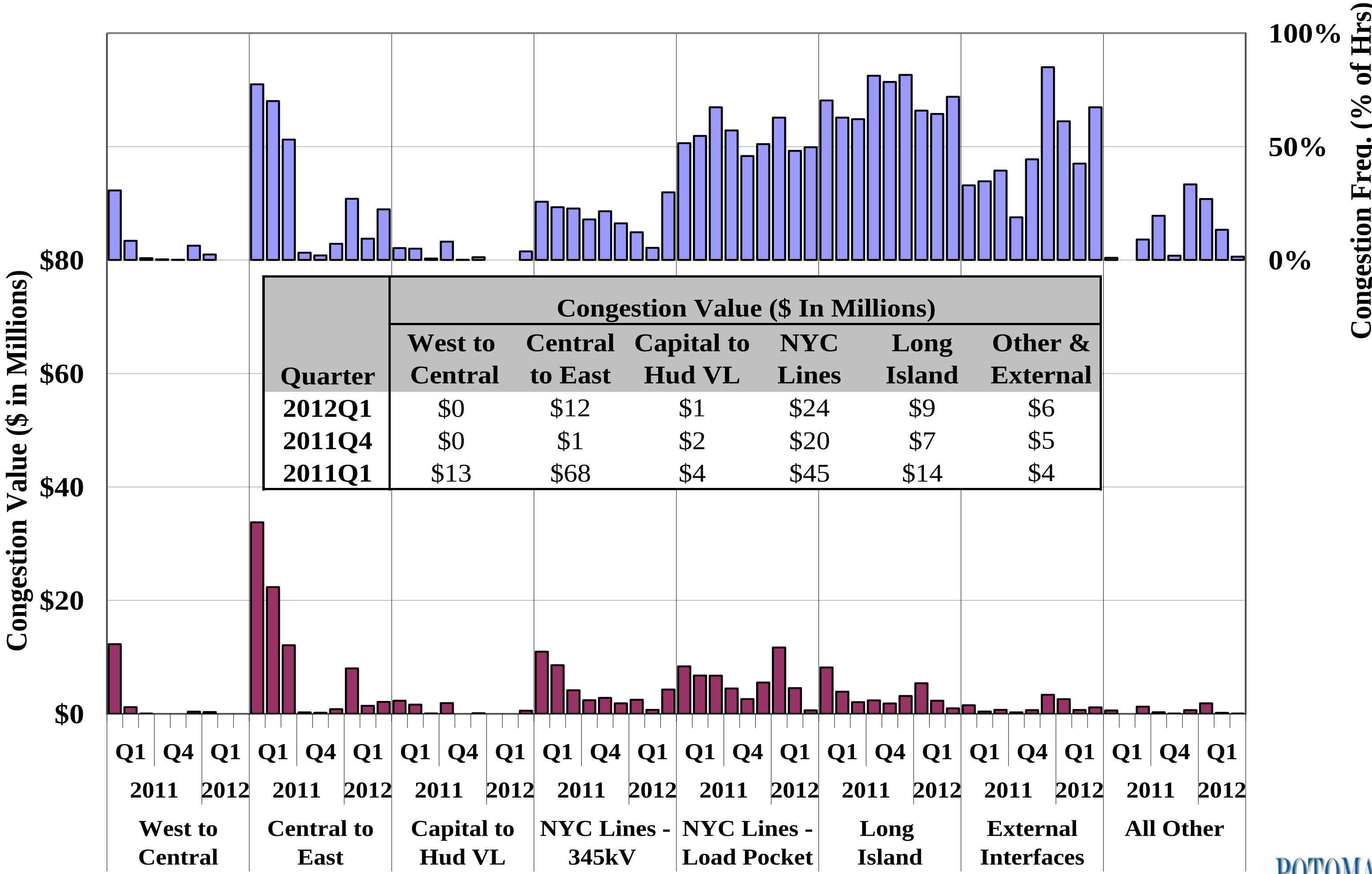
# Congestion by Transmission Path

- The following two figures examine the value and frequency of congestion along major transmission paths in the day-ahead and real-time market.
  - ✓ 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 interface.
  - ✓ In the day-ahead market, the value of congestion is equal to 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:
  - ✓ West to Central: Primarily the Dysinger East interface.
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ Capital to Hudson Valley: Primarily the New Scotland-to-Leeds Line.
  - ✓ 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 ten external interfaces.

# Day-Ahead Congestion by Transmission Path

- The next figure summarizes the frequency of congestion and congestion revenue collected by transmission path in the day-ahead market.
- 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 shadow prices of constraints are generally lower in the day-ahead market.
- Most day-ahead congestion revenue in this quarter was collected for flows over lines into and within New York City (47 percent), the Central-East interface (22 percent), and lines into Long Island (17 percent).
- Lines into the Vernon/Greenwood area were binding frequently in this quarter, which were affected by planned transmission outages, accounting for 76 percent of total congestion in New York City.
- Congestion across the Central-East interface decreased 83 percent from the first quarter of 2011.
  - ✓ The decrease was due largely to the combined effects of new generation in NYC, significantly lower gas prices,  lower load levels, and reduced clockwise Lake Erie Circulation.

# Day-Ahead Congestion by Transmission Path




| Quarter | Congestion Value ($ In Millions) | | | | | |
|---|---|---|---|---|---|---|
| | West to Central | Central to East | Capital to Hud VL | NYC Lines | Long Island | Other & External |
| 2012Q1 | $0 | $12 | $1 | $24 | $9 | $6 |
| 2011Q4 | $0 | $1 | $2 | $20 | $7 | $5 |
| 2011Q1 | $13 | $68 | $4 | $45 | $14 | $4 |



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# Real-Time Congestion by Transmission Path

- The following figure summarizes the value and frequency of congestion by transmission path in the real-time market.
- The total value of real-time congestion was $55 million in the first quarter of 2012, consistent with the congestion revenue in the day-ahead market.
  - ✓ Compared to the previous quarter, real-time congestion value rose 67 percent, reflecting increased congestion across the Central-East interface, in New York City, and in Long Island.
  - ✓ Compared to a year ago, real-time congestion value fell 66 percent, largely due to fewer line outages affecting West to East transmission, significantly lower gas prices, and lower load levels.
- Real-time congestion occurred mostly in the following areas in the first quarter:
  - ✓ *NYC lines and simplified interface constraints* (44 percent): The majority of this congestion was associated with congestion into the Greenwood load pocket (51 percent) and congestion into the 345 kV system in early-January and late-March (44 percent). These patterns were affected by planned transmission outages.
  - ✓ *Long Island* (26 percent): Nearly all of the congestion occurred along the Dunwoodie-to-Shore Road line (44 percent) into Long Island and the East Garden City-to-Valley Stream line (55 percent) within Long Island.



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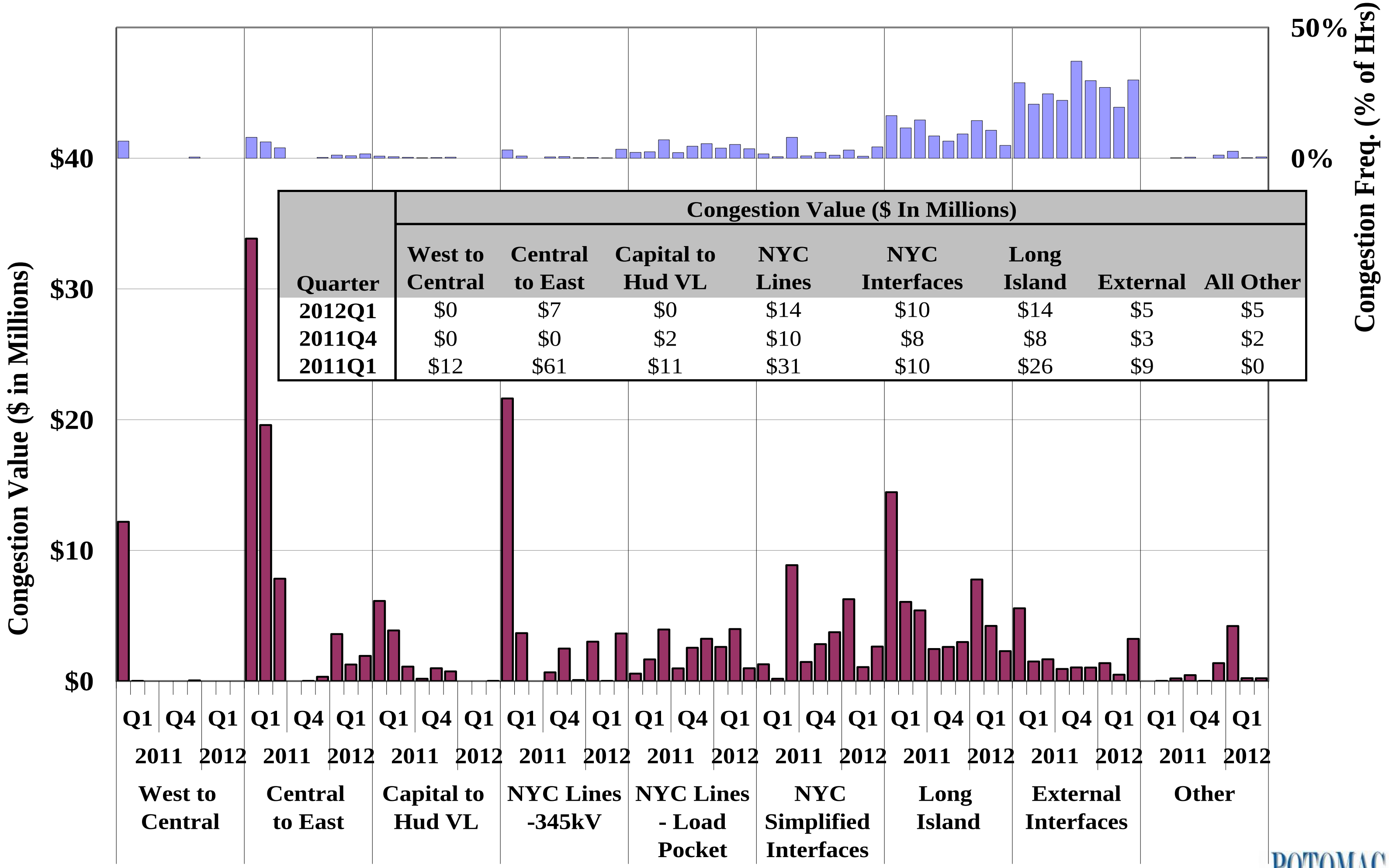
# Real-Time Congestion by Transmission Path




| Quarter | Congestion Value ($ In Millions) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | West to Central | Central to East | Capital to Hud VL | NYC Lines | NYC Interfaces | Long Island | External | All Other |
| 2012Q1 | $0 | $7 | $0 | $14 | $10 | $14 | $5 | $5 |
| 2011Q4 | $0 | $0 | $2 | $10 | $8 | $8 | $3 | $2 |
| 2011Q1 | $12 | $61 | $11 | $31 | $10 | $26 | $9 | $0 |



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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 2012.
  - ✓ 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 lines accounted for the vast majority of the total shortfalls in the first quarter of 2012.
  - ✓ This was primarily due to transmission outages that were taken to support the installation of new transmission lines in the Greenwood/Vernon area, which reduced transfer capability in New York City during this period.
- Long Island facilities accounted for roughly $1.5 million of shortfalls in the first quarter of 2012.
  - ✓ One of the major transmission lines into Long Island was out of service, generating significant shortfalls in early January and early March.



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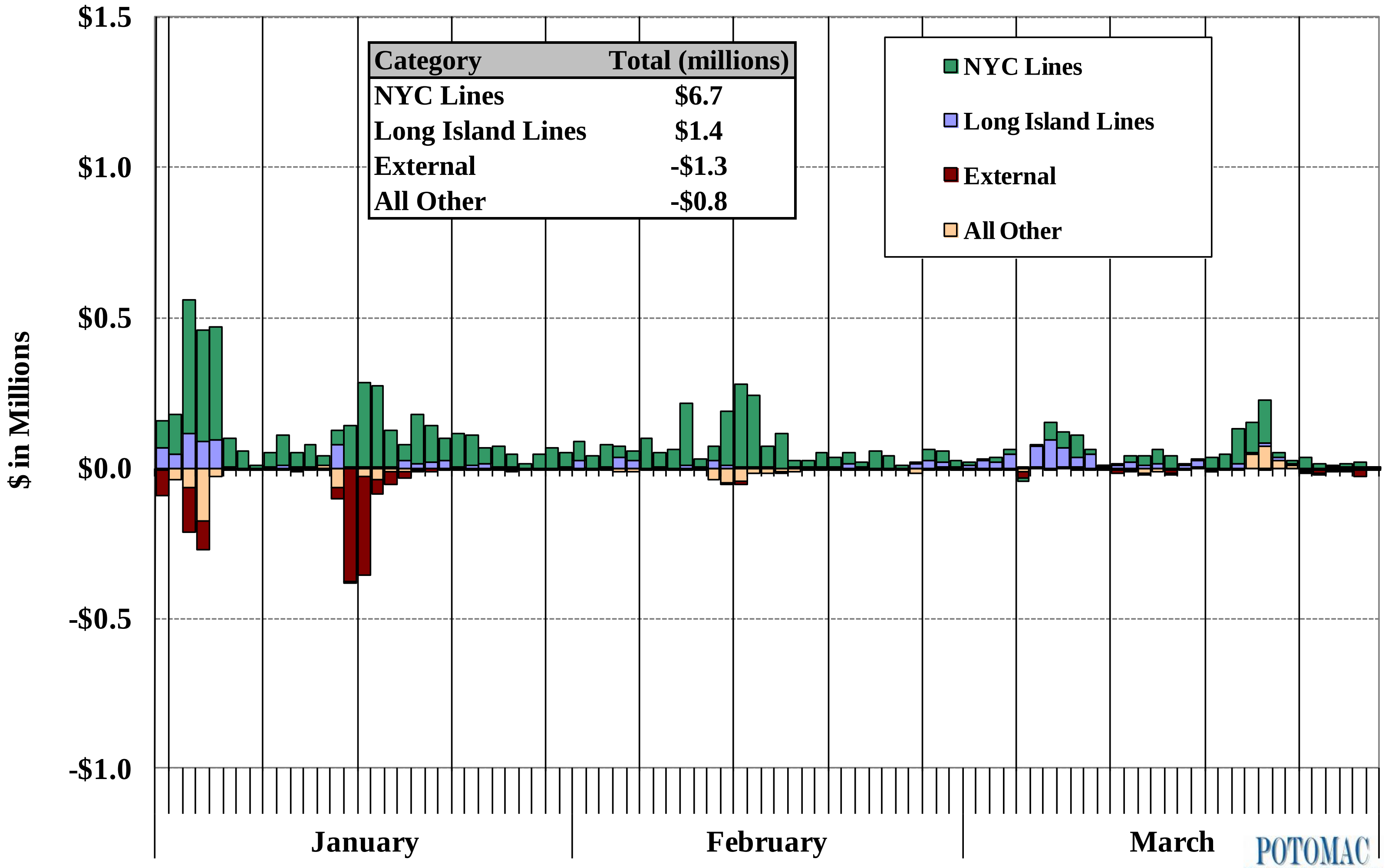
# Day-Ahead Congestion Revenue Shortfalls




| Category | Total (millions) |
|---|---|
| NYC Lines | $6.7 |
| Long Island Lines | $1.4 |
| External | -$1.3 |
| All Other | -$0.8 |

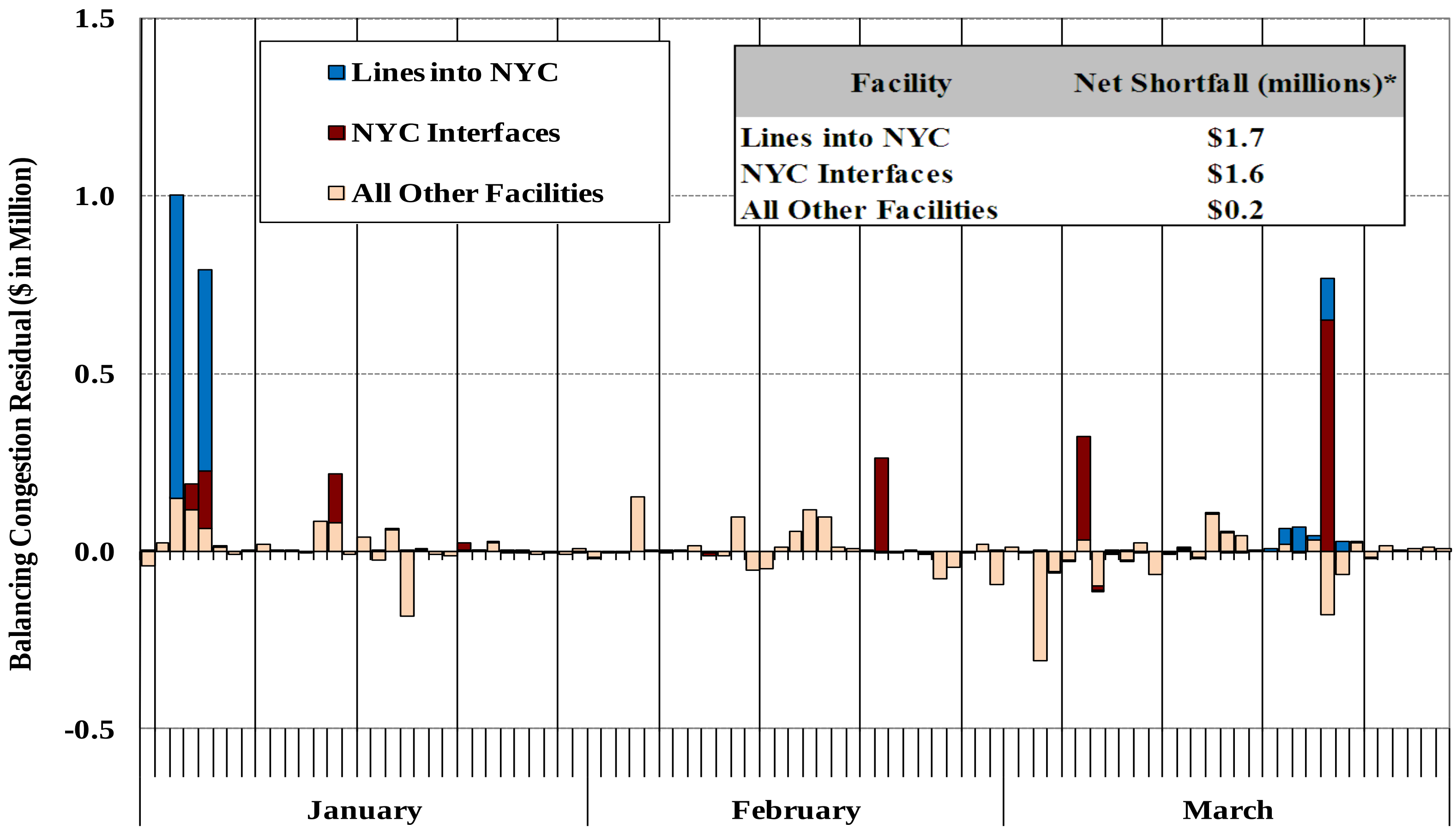
# Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the first quarter of 2012.
  - ✓ 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 between day-ahead and 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; and
  - ✓ Flows across PAR-controlled lines.

# Balancing Congestion Shortfalls

- Balancing congestion shortfalls were approximately $3.5 million in the first quarter of 2012, which is lower than in similar periods in recent years.
  - ✓ Balancing congestion shortfalls exceeded $0.5 million on three days (January 3, 5 & March 23), which accounted for 70 percent of total shortfalls in the quarter.
- Lines into New York City accounted for the largest share (49 percent) of the balancing congestion shortfalls in the first quarter.
  - ✓ In the first week of January, unexpected issues with some of the PAR-controlled lines between PJM and NY led to reduced import capability into the 345 kV system in New York City.
  - ✓ The remaining occurred primarily on a few days in March when there were multiple in-city outages that affected the transfer capability into New York City in real-time.
- Congestion on NYC simplified interfaces accounted for 46 percent of the shortfalls.
  - ✓ The majority of the shortfalls occurred three days in February and March.
  - ✓ Load pocket interface constraints were activated to manage local congestion on these days when unexpected in-city generation trip occurred.

# Balancing Congestion Shortfalls




**Note: These slightly over-estimate shortfalls since they are partly based on real-time schedules rather than metered values and they do not reflect the effects of price corrections.**



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# Uplift Costs and Supplemental Commitments

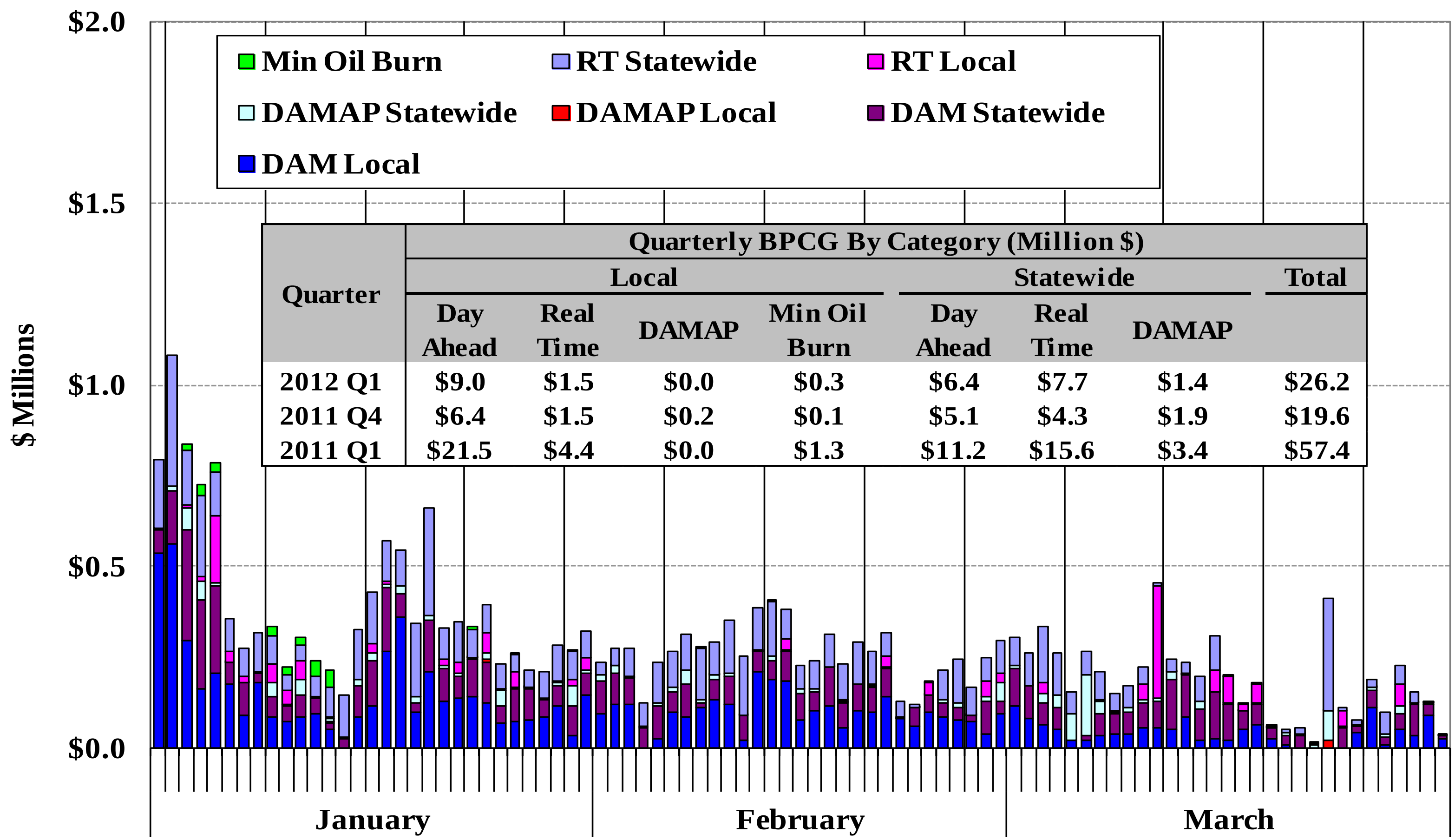
# Uplift Costs from Guarantee Payments

- 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: Primarily for units committed economically that don’t recoup their as-offered start-up and min generation costs from LBMPs.
  - ✓ Real Time: For external transactions and gas turbines that are scheduled economically but don’t recoup their as-offered costs from LBMPs, for SRE commitments and OOM dispatch that are done for bulk power system reliability.
  - ✓ Day Ahead Margin Assurance Payment (“DAMAP”): For payments to cover losses for generators 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 2012.
- Guarantee payment uplift was $26 million in the first quarter, up 34 percent from the previous quarter.
  - ✓ The increase was partly due to higher load levels and more days with volatile gas prices in the first quarter of 2012.
  - ✓ Guarantee payments rose significantly on several days of cold weather in January and February when gas supply constraints led to increased commitment of oil units for reliability.
- Guarantee payment uplift decreased 54 percent from the first quarter of 2011, due primarily to:
  - ✓ Lower natural gas prices, which decreased the commitment costs of gas-fired units that were needed for reliability; and
  - ✓ Lower load levels, which reduced the overall amount of reliability commitment, particularly the need for units to burn oil to satisfy reliability requirements.
- NYISO's mitigation consultations are on-going for the first quarter, so guarantee payments may increase further once these are fully reflected.

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




| Quarterly BPCG By Category (Million $) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Local | | | | Statewide | | | Total |
| Quarter | Day Ahead | Real Time | DAMAP | Min Oil Burn | Day Ahead | Real Time | DAMAP | |
| 2012 Q1 | $9.0 | $1.5 | $0.0 | $0.3 | $6.4 | $7.7 | $1.4 | $26.2 |
| 2011 Q4 | $6.4 | $1.5 | $0.2 | $0.1 | $5.1 | $4.3 | $1.9 | $19.6 |
| 2011 Q1 | $21.5 | $4.4 | $0.0 | $1.3 | $11.2 | $15.6 | $3.4 | $57.4 |

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

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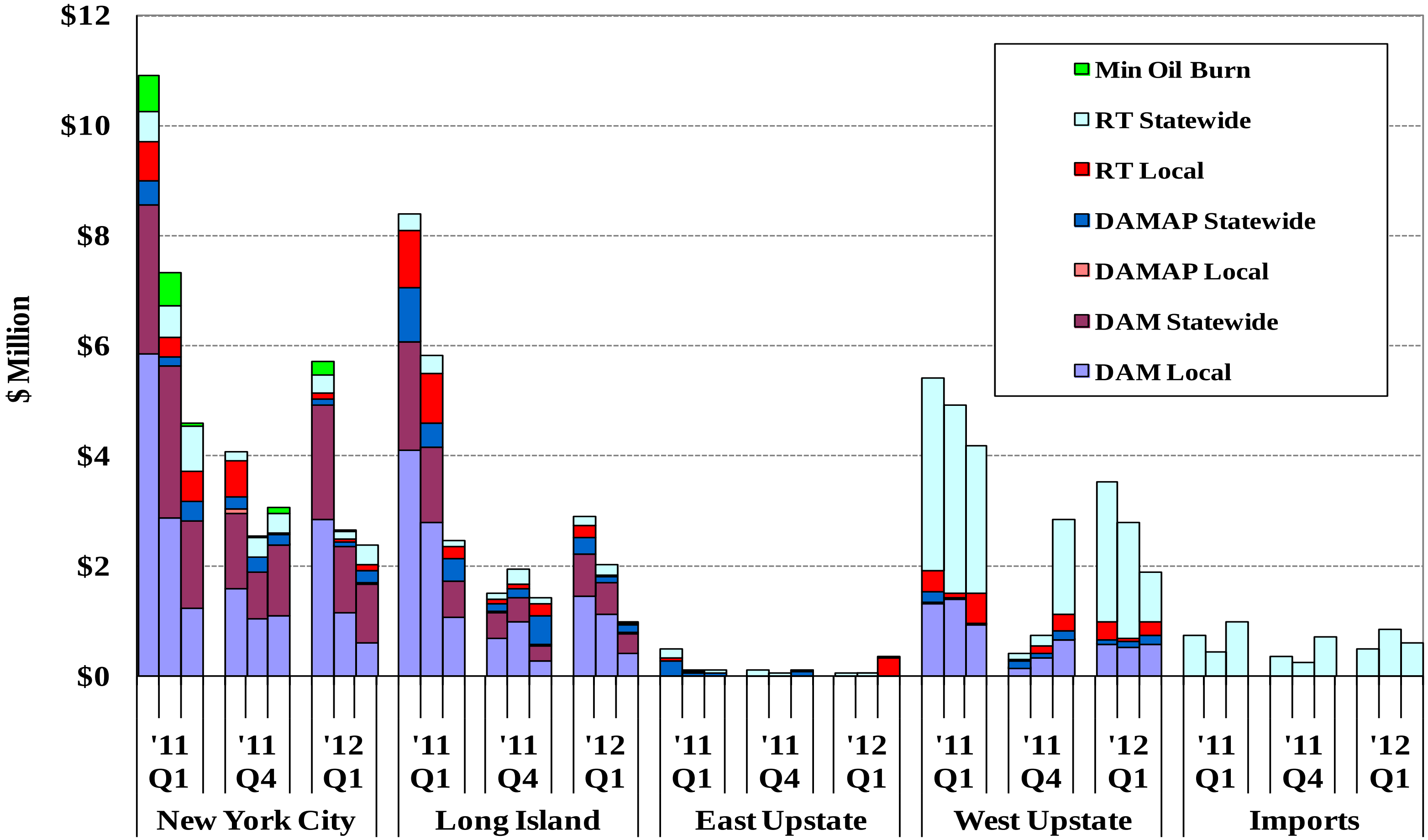
# Uplift Costs from Guarantee Payments by Region

- The next figure shows seven categories of uplift on a monthly basis by region.
- Day-ahead local reliability uplift in the first quarter of 2012:
  - ✓ The majority was for New York City (50 percent) and Long Island (32 percent), primarily for DARU and LRR commitments.
- Day-ahead statewide uplift in the first quarter of 2012:
  - ✓ The majority of these costs were paid to generators in New York City and Long Island at several plants where one or more units were required to manage transmission congestion.
  - ✓ The resulting guarantee payments are allocated statewide if the facility being secured is monitored by the NYISO.
- Real-time local reliability uplift in the first quarter of 2012:
  - ✓ The need to commit units in real-time for local reliability declined considerably in this quarter due to unseasonably warm weather and low loads, leading to greatly reduced uplift in this category.
- Real-time statewide uplift in the first quarter of 2012:
  - ✓ The majority was for Western New York (63 percent) associated primarily with SRE commitments.

# Uplift Costs from Guarantee Payments by Region

- Guarantee payment uplift decreased 54 percent from the first quarter of 2011.
  - ✓ However, mitigation consultations are on-going for the first quarter, so guarantee payments will increase once these are fully reflected.
- New York City accounted for the majority of the reduction in uplift from the first quarter of 2011.
  - ✓ Day-ahead uplift fell to $9 million from $17 million in first quarter of 2011.
  - ✓ Real-time uplift also decreased significantly, down 70 percent to just $1 million.
  - ✓ These reductions were partly the result of less reliability commitment and improved accuracy of generator reference levels.
- On Long Island, day-ahead local and statewide uplift decreased from $12 million in the first quarter of 2011 to roughly $5 million in the first quarter of 2012, due to:
  - ✓ Oil-fired units being used less frequently to manage local reliability on the East End of Long Island.
- In western NY, real-time statewide uplift decreased by over $4 million from the first quarter of 2011, partly due to less reliability commitment.

# Uplift Costs from Guarantee Payments
## By Category and Region



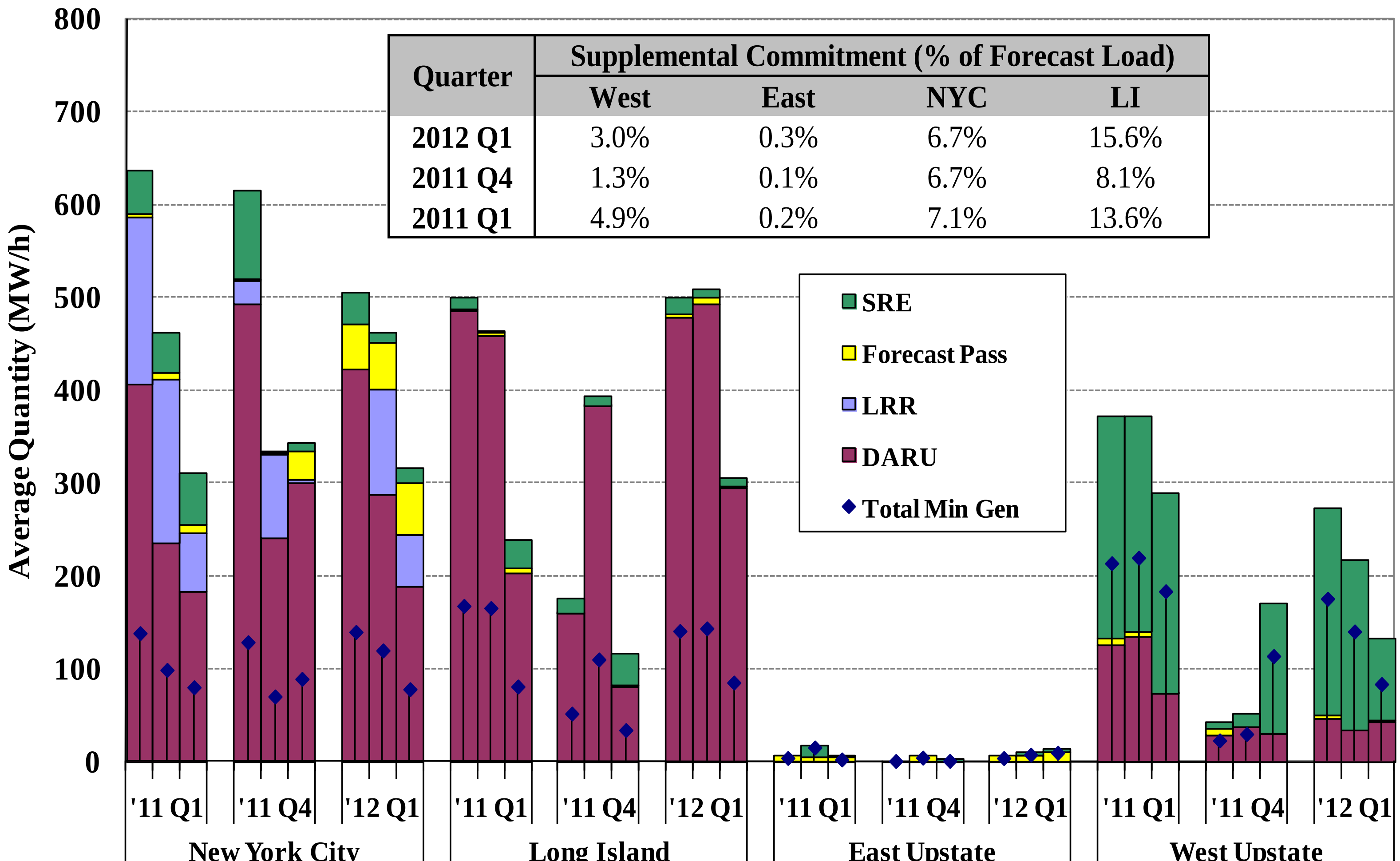

Note: These data are based on information available at the reporting time and do not include some manual adjustments to the mitigation of guarantee payments, hence they can be different from final settlements.

# Supplemental Commitment for Reliability

- The following figure shows the monthly quantities of capacity committed for reliability by type of commitment and region.
- Reliability commitment in West Upstate declined considerably from a year ago.
  - ✓ Committed capacity averaged 210 MW in the first quarter of 2012, down from 340 MW in the first quarter of 2011.
  - ✓ DARU commitment decreased from a year ago, partly because there were fewer transmission outages that required the commitment of units to secure the system.
  - ✓ SRE commitment fell from the a year ago due partly to warmer weather and lower load levels.
- Reliability commitment in New York City fell from the first quarter of 2011.
  - ✓ Committed capacity averaged 470 MW, down 9 percent from 2011 as many units frequently needed for local reliability were instead committed economically.
  - ✓ However, slow-start generators were committed in the Forecast Load Pass in some hours when off-line fast-start units were available and unscheduled. These generators were very close to being economic in the Bid Load Pass, so relatively little uplift was generated by these commitments.
- Reliability commitment in Long Island was relatively consistent with the first quarter of 2011.

# Supplemental Commitment for Reliability
## by Category and Region

| Quarter | Supplemental Commitment (% of Forecast Load) | | | |
|---|---|---|---|---|
| | West | East | NYC | LI |
| 2012 Q1 | 3.0% | 0.3% | 6.7% | 15.6% |
| 2011 Q4 | 1.3% | 0.1% | 6.7% | 8.1% |
| 2011 Q1 | 4.9% | 0.2% | 7.1% | 13.6% |



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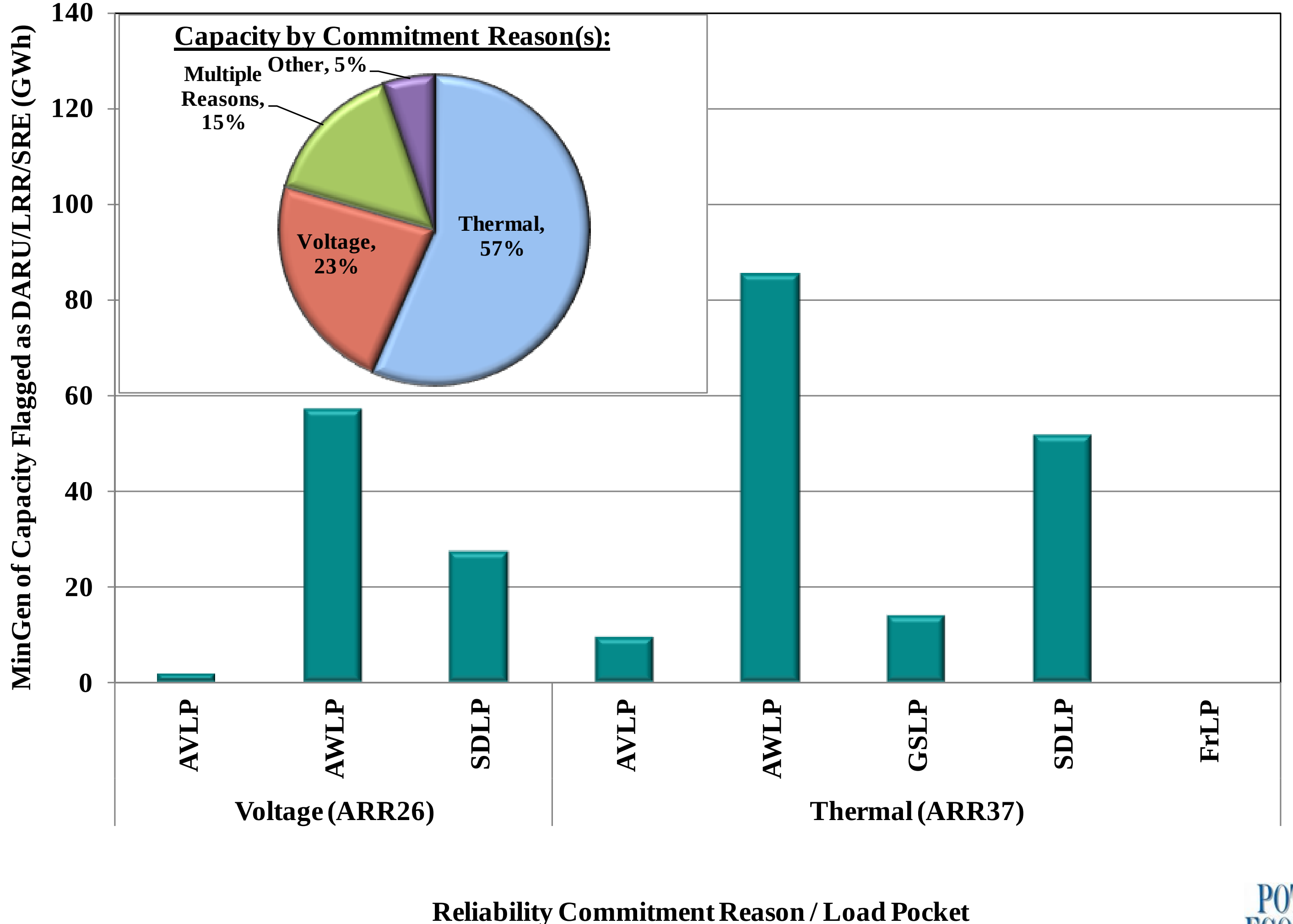
# Supplemental Commitment for Reliability in NYC

- The following figure evaluates the reasons for reliability commitments in the first quarter of 2012 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, AWLP = Ast West/Queens, AVLP = Ast West/ Queens/Vernon, ERLP = East River, FRLP = Freshkills, GSLP = Greenwd/Staten Is, & SDLP = Sprainbr/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 effective from May to September, therefore no units were committed for this reason during the first quarter of 2012.
- The reliability requirements that accounted for the most MWhs of capacity in the first quarter of 2012 were:
  - ✓ Astoria West/Queensbridge thermal and voltage requirements (57 percent) –
    - These ensure facilities into this pocket will not be overloaded if the largest two generation or transmission contingencies were to occur.
    - Higher-than-normal levels of generation and transmission line outages in the load pocket accounted for a significant share of the commitment in the first quarter of 2012.
  - ✓ Sprainbrook/Dunwoodie thermal and voltage requirements (32 percent) –
    - These ensure 345 kV facilities in New York City will not be overloaded if the largest two generation or transmission contingencies were to occur.
    - Extended transmission outages of the Sprainbrook-to-W49th St. line, one of the PAR-controlled lines supporting the ConEd-PSEG wheel, and at the Gowanus 345kV substations were significant drivers of the commitment in the first quarter of 2012.

# 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 units 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 number of total station-hours) of the OOM actions on a monthly basis by region for the first quarter of 2012.
  - ✓ In each region, the two stations with the highest number of OOM dispatch hours in the current quarter are shown separately.
- Overall, units were OOMed for over 1,000 station-hours in the first quarter of 2012, comparable to the previous quarter but down considerably from the first quarter of 2011.
  - ✓ The reduction from a year ago was generally attributable to lower load levels and unseasonably warm weather.

# Out-of-Merit Dispatch

- OOM dispatch in West Upstate accounted for more than 50 percent of total OOM station-hours in the first quarter of 2012.
  - ✓ Huntley and Niagara units accounted for 76 percent of all OOM station-hours in West Upstate.
    - These units were often OOMed by the NYISO to manage congestion on 230 kV lines in the West Zone.
    - The NYISO will implement improved constraint modeling of these lines in the day-ahead and real-time markets in May 2012, which should:
      - Reduce OOM dispatch and the related uplift charges; and
      - Result in market signals that lead to more efficient commitment of generation in the West Zone and more efficient scheduling of imports from Ontario and PJM.
- On Long Island, units were primarily OOMed by the local TO to secure 69 kV lines into the Valley Stream load pocket.
- In New York City, units were primarily OOMed by the local TO to secure lines on the 138 kV system, typically following significant unit or transmission outages.



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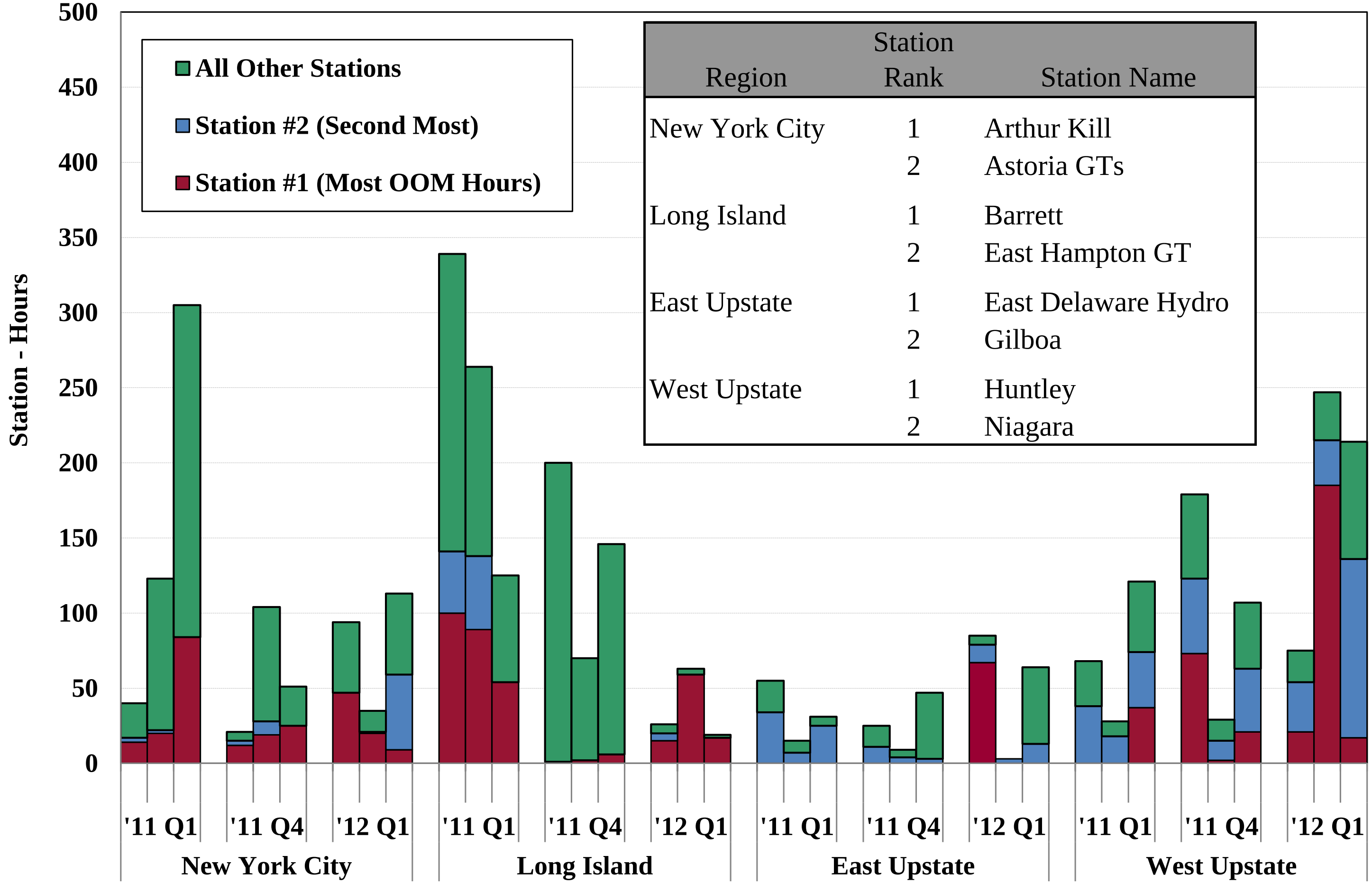
# Frequency of Out-of-Merit Dispatch by Region by Month




| Region | Station Rank | Station Name |
|---|---|---|
| New York City | 1 | Arthur Kill |
| | 2 | Astoria GTs |
| Long Island | 1 | Barrett |
| | 2 | East Hampton GT |
| East Upstate | 1 | East Delaware Hydro |
| | 2 | Gilboa |
| West Upstate | 1 | Huntley |
| | 2 | Niagara |

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.

# Market Monitoring and Mitigation

- The following figure summarizes energy offer mitigation as well as the results of potential withholding screens.
- 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.
- The output gap 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. The following figure shows this using:
  - ✓ A high threshold (the lower of $100/MWh and 300 percent); and
  - ✓ A low threshold (the lower of $50/MWh and 100 percent).
- Generator deratings are reviewed 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.

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# Automated Market Mitigation

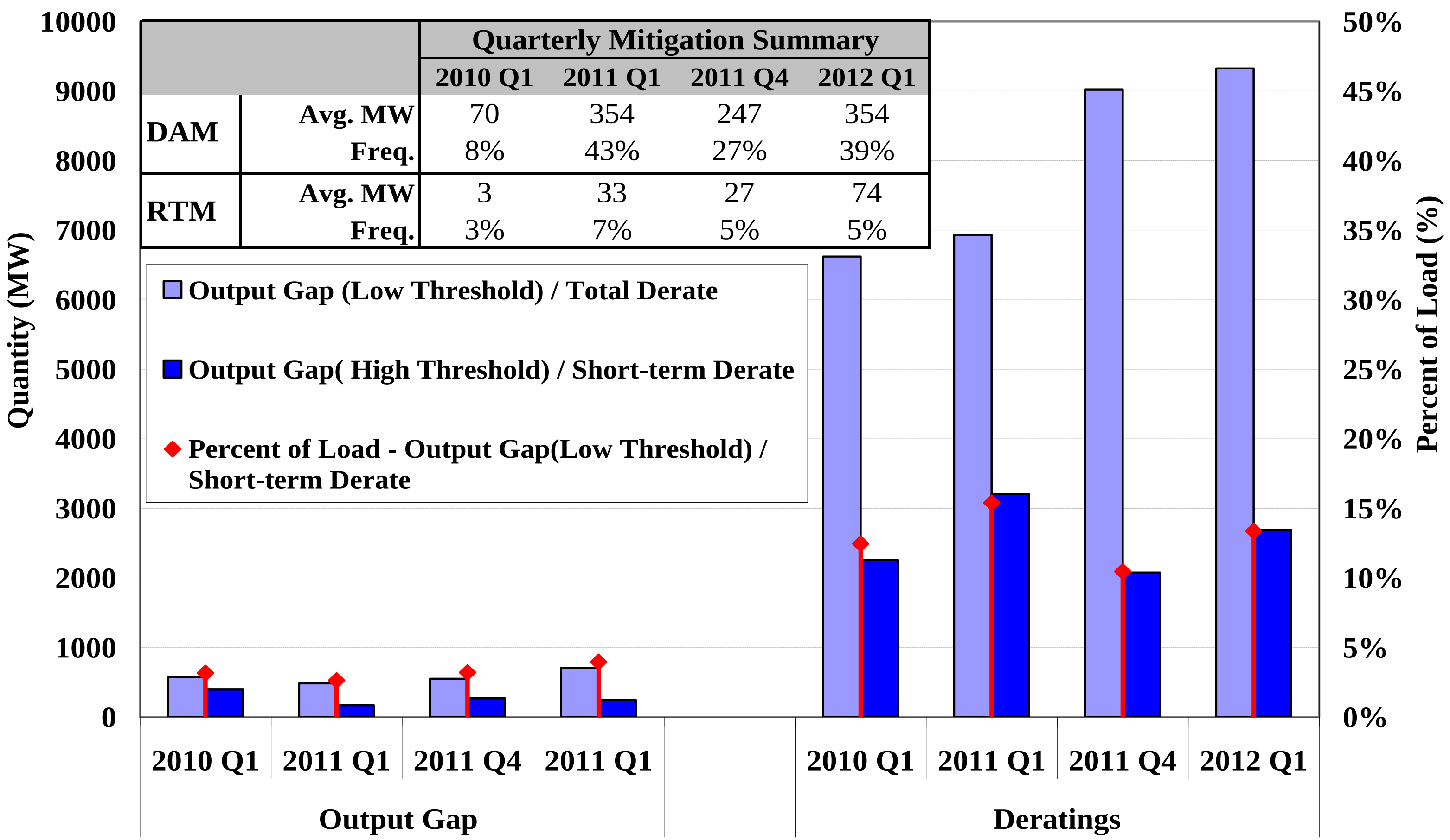
- The vast majority of mitigation occurred in the day-ahead market.
  - ✓ In the first quarter of 2012, day-ahead mitigation occurred primarily for the Astoria West/Queens/Vernon load pocket (44%), for DARU & LRR units (28%), and for the 345/138kV interface (18%).
- Mitigation increased substantially in Long Island and in Upstate New York in 2011 and 2012, due primarily to the application of the new ROS reliability mitigation rules (since October 2010).
  - ✓ However, the quantities mitigated were still much smaller than in New York City.
- Mitigation increased substantially in New York City in 2011 and 2012, due to changes in offer patterns by some suppliers and improvements in the accuracy of reference levels for some generators.
  - ✓ Several units consistently offered well above marginal cost and were accordingly mitigated frequently.
- NYISO began unmitigating generators more frequently in 2011.
  - ✓ The majority of unmitigation occurred outside New York City.
  - ✓ Some mitigation consultations are still on-going for the first quarter of 2012, so the amount of mitigation may decrease.

# Market Monitoring of Withholding

- The output gap was relatively low as a share of load in the first quarter of 2012.
  - ✓ The amount of output gap averaged 245 MW at the high threshold and 700 MW at the low threshold in this quarter (< 4% of load), consistent with the same periods from previous years.
  - ✓ The output gap did not raise significant market power concerns because they occurred primarily during periods when the prices would not be substantially affected.
- Total deratings increased in the most recent two quarters, while short-term deratings (< 30 days) were consistent with prior periods.
  - ✓ Total deratings are significant, but physical withholding concerns are limited because:
    - – Deratings are highest in shoulder months when demand is lowest; and
    - – Most deratings are long-term and less likely to reflect withholding.

# Market Monitoring Screens and Mitigation

| | | Quarterly Mitigation Summary | | | |
|---|---|---|---|---|---|
| | | 2010 Q1 | 2011 Q1 | 2011 Q4 | 2012 Q1 |
| DAM | Avg. MW | 70 | 354 | 247 | 354 |
| | Freq. | 8% | 43% | 27% | 39% |
| RTM | Avg. MW | 3 | 33 | 27 | 74 |
| | Freq. | 3% | 7% | 5% | 5% |




Note: Mitigation summaries for 2011-Q1 are revised from the previous report to reflect the results from mitigation consultations.



POTOMAC ECONOMICS

# Capacity Market

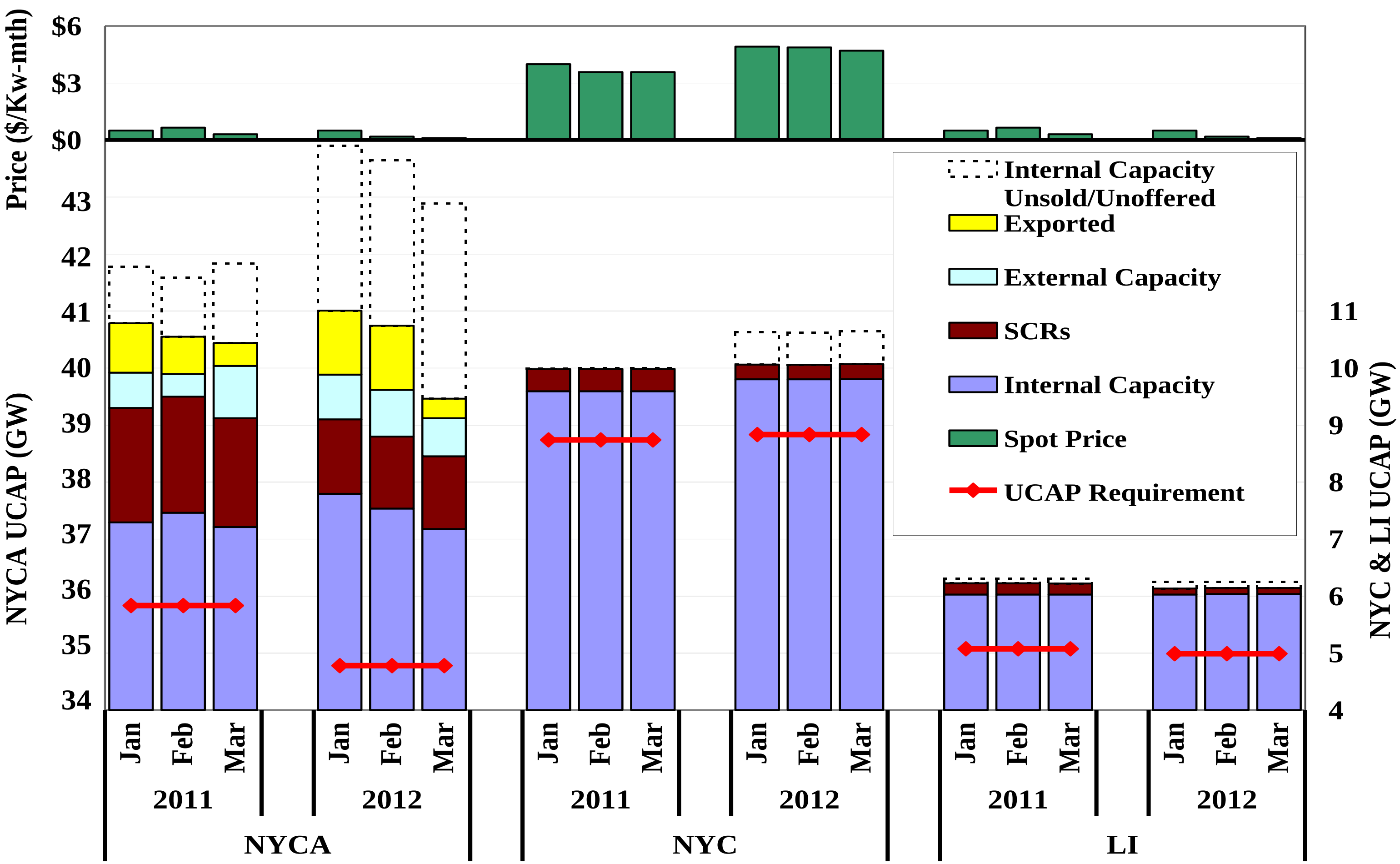
# Capacity Market Results

- The following figure summarizes available and scheduled UCAP resources, UCAP requirement, and the spot clearing prices in each capacity zone.
- In New York City, UCAP spot prices rose to an average of $4.83/kW-month in the first quarter of 2012, up 30 percent from the first quarter of 2011. The increase was primarily due to:
  - ✓ The deployment of the new demand curve, which was higher than the previous curve; and
  - ✓ The substantial increase in the amount of  unsold capacity.
  - ✓ However, the increase was offset by sales from the new 550 MW generating facility starting in July 2011.
- The figure shows that nearly 600 MW (or 5.5 percent) of internal capacity in New York City was not sold in each month during the first quarter of 2012.
  - ✓ This is similar to the pattern that was observed at the end of 2011 in our annual State of the Market Report.
  - ✓ We made several recommendations that are intended to address issues related to the unsold capacity.

# Capacity Market Results

- In Rest of State and Long Island, UCAP spot prices averaged $0.26/kW-month in the first quarter of 2012, down from $0.48/kW-month in the first quarter of 2011.
  - ✓ A substantial amount of capacity was not sold in the first quarter of 2012 due to the relatively large prevailing capacity surplus and the low clearing prices.
  - ✓ Long Island and Rest of State clearing prices were equal during the two quarters.
    - – The local capacity requirement was not binding during the period, reflecting that Long Island had far more capacity than needed to satisfy the local capacity requirement.
- Clearing prices outside New York City were affected by the following factors:
  - ✓ Increased sales of internal capacity following the entry of new supply in July 2011.
  - ✓ The ICAP requirement for NYCA fell nearly 1200 MW over the period, because from the 2010/11 capability year to 2011/2012 capability year:
    - – The summer peak load forecast for NYCA fell 313 MW; and
    - – The installed capacity requirement fell from 118 percent to 115.5 percent.
  - ✓ These factors were partly offset by a decrease of 800 MW in SCR sales.

# Capacity Market Results




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