Quarterly Report on the New York ISO Electricity Markets First Quarter of 2016

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the first quarter of 2016.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- Average all-in prices ranged from $20/MWh in the North Zone to $47/MWh in NYC, down 49 to 60 percent from the first quarter of 2015. (see slide 9)
  - ✓ In addition to the LBMP reductions mentioned below, capacity costs fell 13 percent (Lower Hudson Valley) to 47 percent (Long Island) from 2015-Q1.
- RT LBMPs averaged from $18/MWh in the North Zone to $33/MWh in Long Island, down 57 to 65 percent from 2015-Q1, primarily because:
  - ✓ Average load fell 8 percent and peak load fell 5 percent. (see slides 10-11)
  - ✓ Gas prices fell 18 percent in West NY and nearly 70 percent in East NY because of the combined effects of milder weather conditions, increased LNG deliveries to the region, falling oil prices, and higher production from the Marcellus and Utica shales. (see slide 12)
  - ✓ Average nuclear and hydro generation rose a combined 600 MW (see slide 15), which, however, was partly offset by lower net imports from neighboring areas (see slide 42).

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Highlights and Market Summary: Congestion Patterns

- DAM congestion revenues totaled $125 million (see slides 55-56, 59-60), down 55 percent from 2015-Q1 primarily because of lower load levels and gas prices.
  - ✓ The Central-East interface accounted for the largest share (over 50 percent).
    - Consistent natural gas price spreads between West NY and East NY lead to frequent congestion across the Central-East Interface.
    - Although DAM congestion revenue decreased 60 percent from the first quarter of 2015, the frequency of congestion increased because Central-East transfer capability was reduced more by transmission outages (to support the TOTS projects).
  - ✓ West Zone lines accounted for the next largest share (~20 percent) of congestion.
    - Unlike other areas, congestion in the West Zone actually rose from the first quarter of 2015.
    - Over 90 percent of this congestion occurred in March because of significant transmission outages after the Huntley units retired at the end of February. The outages were necessary to install new transmission facilities that will help relieve congestion on the 230 kV lines, but this work was not completed until May.
    - Severe West Zone congestion is often associated with high clockwise loop flows and sudden clockwise changes from the prior interval. (See slide 68)

Highlights and Market Summary: Operating Reserve Market and CTS Performance

- The average DA clearing price for 30-min operating reserves was $5.42/MWh, up 301 percent from the same quarter of 2015 despite milder weather. (see slide 30)
  - ✓ The resulted primarily from rule changes (under the Comprehensive Shortage Pricing Project in November 2015). (see slides 27 & 31-33)
    - – The NYCA 30-minute reserve requirement increased 655 MW to 2,620 MW;
    - – Reserve scheduling from Long Island generators was limited to an average of 423 MW, down 310 MW from the first quarter of 2015.
    - – These factors increased the need for reserves outside Long Island by 970 MW.
  - ✓ The rise in offer prices in West NY was a less important factor. (see slide 33)
- In our review of the operation of CTS (see slides 43-51), we find that:
  - ✓ High transaction fees greatly reduce participation and liquidity at the PJM border;
  - ✓ Performance is diminished by errors in short-term forecasting of RT conditions;
  - ✓ Price forecasting by PJM and ISO-NE was generally more accurate than forecasting by the NYISO, consistent with the overall pattern of higher RT price volatility in New York; and
  - ✓ Forecasting by PJM improved considerably from the previous year and is slightly more accurate than forecasting at the ISO-NE interface.

Highlights and Market Summary: Capacity Market

- UCAP spot prices fell notably from the first quarter of 2015. UCAP prices:
  - ✓ In New York City fell 30 percent to an average of \$5.83/kW-month;
  - ✓ In the G-J Locality fell 13 percent to an average of \$3.15/kW-month;
  - ✓ On Long Island fell 51 percent to an average of \$1.53/kW-month;
  - ✓ In Rest of State fell 48 percent to an average of \$1.12/kW-month.
- Capacity spot prices fell across the system primarily because: (see slides 93-95)
  - ✓ Internal ICAP supply rose by 135 MW in NYC, 527 MW in the G-J Locality, and 50 MW in NYCA because of the net effects of:
    - (a) the retirement of Dunkirk 2 and Huntley 67 & 68 (in West NY); (b) the return-to-service of Bowline 2 at full capability (in LHV) and Astoria 2 (in NYC); (c) the ICAP Ineligible Forced Outages of Astoria GT 5, 7, 12 & 13 (in NYC); and (d) increases in DMNC test results across the fleet.
  - ✓ The ICAP requirement fell 54 MW (0.5 percent) in NYC, 148 MW (3 percent) in Long Island, and 115 MW (0.3 percent) in NYCA.
    - However, the ICAP requirement rose 451 MW (3 percent) in the G-J Locality, partly offsetting the decrease of UCAP prices in the G-J Locality.
    - The LCR reductions in NYC and Long Island and the increased LCR in the G-J Locality resulted primarily from recent capacity additions in LHV.

Highlights and Market Summary: Uplift and Revenue Shortfalls

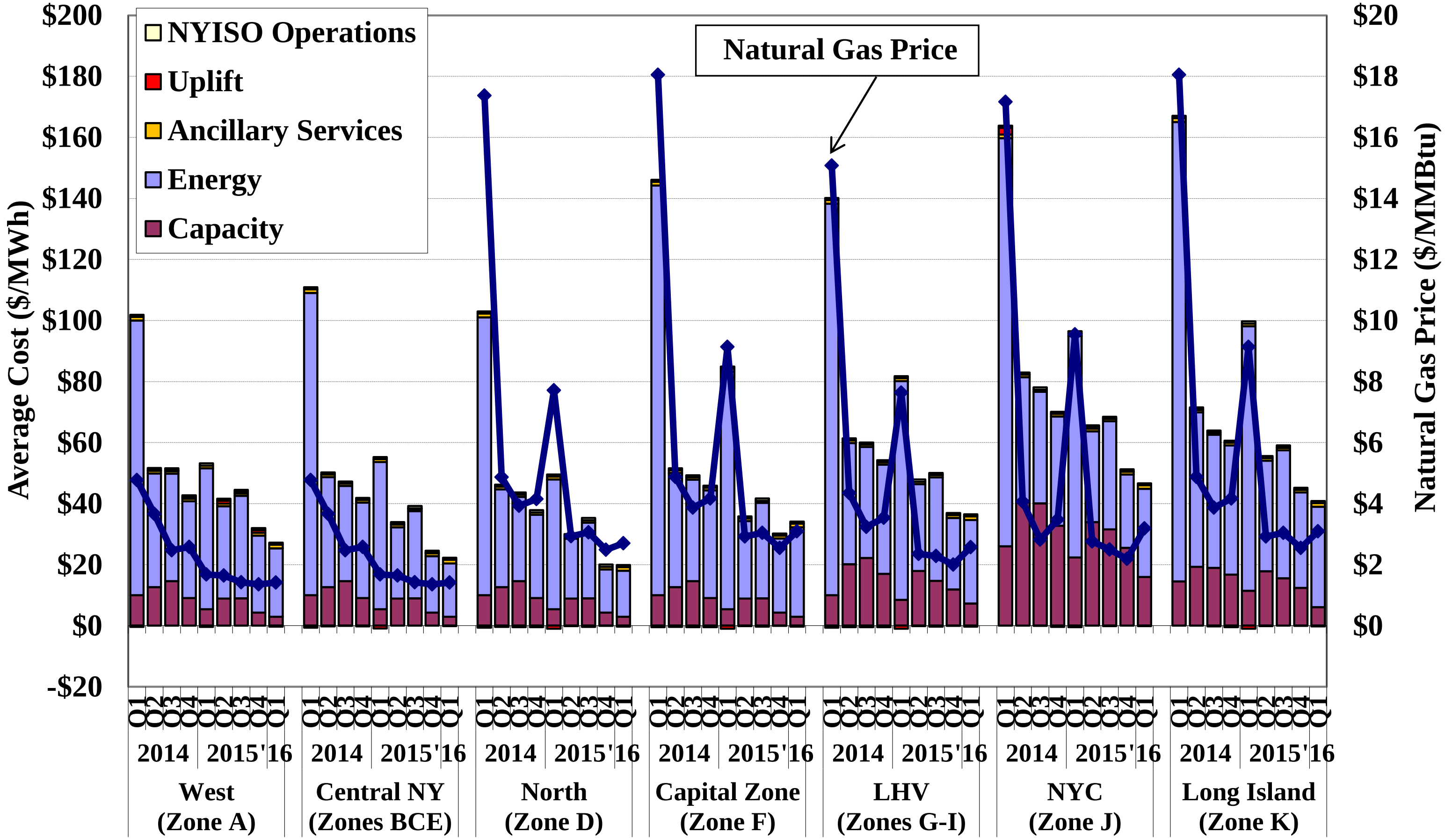
- Guarantee payments were $7M, down 68 percent from 2015-Q1. (see slides 83-84)
  - ✓ Lower natural gas prices decreased the commitment costs of gas-fired units; and
  - ✓ Lower load levels and transmission upgrades in Western NY (required by the retirement of Dunkirk 2) reduced supplemental commitment and OOM dispatch.
- DAM congestion shortfalls were $24M. (see slides 57, 61)
  - ✓ Transmission outages were the primary driver of shortfalls, contributing to: (a) $11M on the Central-East interface; (b) $5M on the West Zone constraints; and (c) $2.6M in NYC.
  - ✓ The remaining shortfalls accrued primarily on the West Zone constraints, resulting from assumptions related to loop flows and Niagara generator modeling.
- Balancing congestion shortfalls were low overall ($2M), although large shortfalls were offset by substantial surplus contributions. (see slides 58, 62)
  - ✓ The primary shortfalls were from differences between DA assumptions and RT flows for the ConEd-LIPA wheel ($2M), the ConEd-PSEG wheel ($3M), and loop flow around Lake Erie ($2.5M).
  - ✓ Significant surpluses resulted from differences between DA assumptions and RT outcomes in the operation of the Ramapo line ($5M) and the distribution of generation between 115 and 230 kV units at the Niagara plant ($3M).

Energy Market Outcomes

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 roughly \$19.60/MWh in the North Zone to \$46.60/MWh in NYC, down 49 to 60 percent from the first quarter of 2015.
  - ✓ LBMPs fell 52 percent in the West Zone and 60 to 65 percent in other areas.
    - The reductions were due primarily to: a) lower gas prices (see slide 12); b) lower load levels (see slide 11); and c) higher nuclear and hydro production (see slide 15).
    - LBMPs fell the least in the West Zone, partly because of higher congestion levels.
  - ✓ Capacity costs fell 13 percent (G-J Locality) to 47 percent (Long Island).
    - Capacity spot prices fell across the system primarily because of: (a) increased internal capacity supply; and (b) lower ICAP requirements in most capacity zones (see slides 94-95).
    - However, the reduction of capacity prices in the G-J Locality was partly offset by a significant increase in the ICAP requirement.

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 Zone and Central NY, the Iroquois Waddington index for North Zone, the Iroquois Zone 2 index for Capital Zone and LI, the average of Texas Eastern M3 and Iroquois Zone 2 for LHV, the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.

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.
- Average load (17.7 GW) fell 8 percent and peak load (23.3 GW) fell 5 percent from the first quarter of 2015.
  - ✓ Both were close to the lowest levels over the last ten winters.
  - ✓ These were due largely to overall mild winter weather conditions this quarter (although February was colder than 10- and 30-year averages).
- Average natural gas prices fell significantly in all locations from a year ago (18 percent in West NY and nearly 70 percent in East NY).
  - ✓ Gas prices in East NY exceeded $8/MMbtu for just one weekend in mid-February.
    - – Gas price increases were limited during this weekend even though the February 14 NYCA composite temperature index was within one degree of the all-time low (February 18, 1979).
    - – The combined effects of increased LNG deliveries to the region, higher production from the Marcellus and Utica shales, and very low oil prices limited the increase in natural gas prices.

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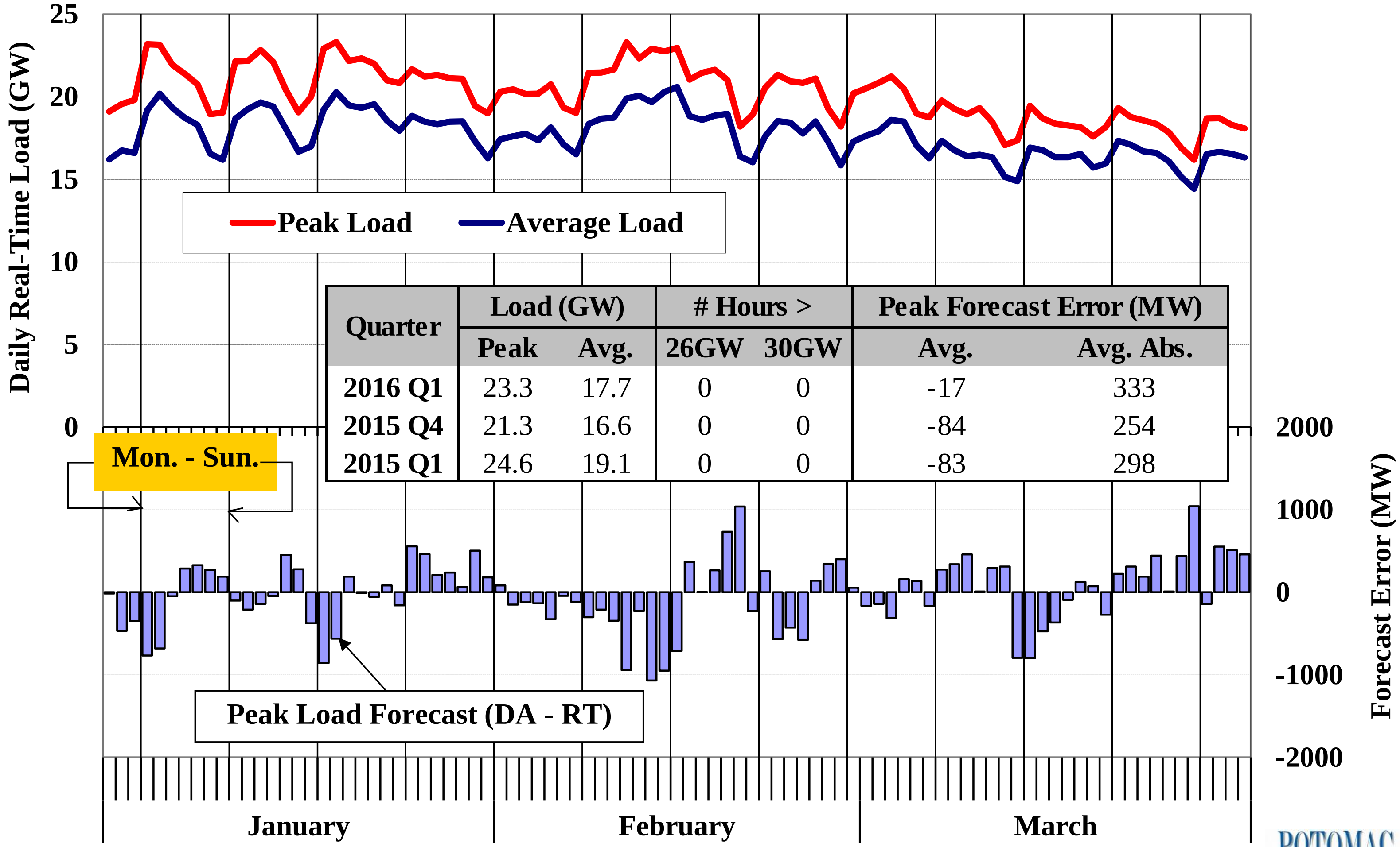
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2016 Q1	23.3	17.7	0	0	-17	333
2015 Q4	21.3	16.6	0	0	-84	254
2015 Q1	24.6	19.1	0	0	-83	298

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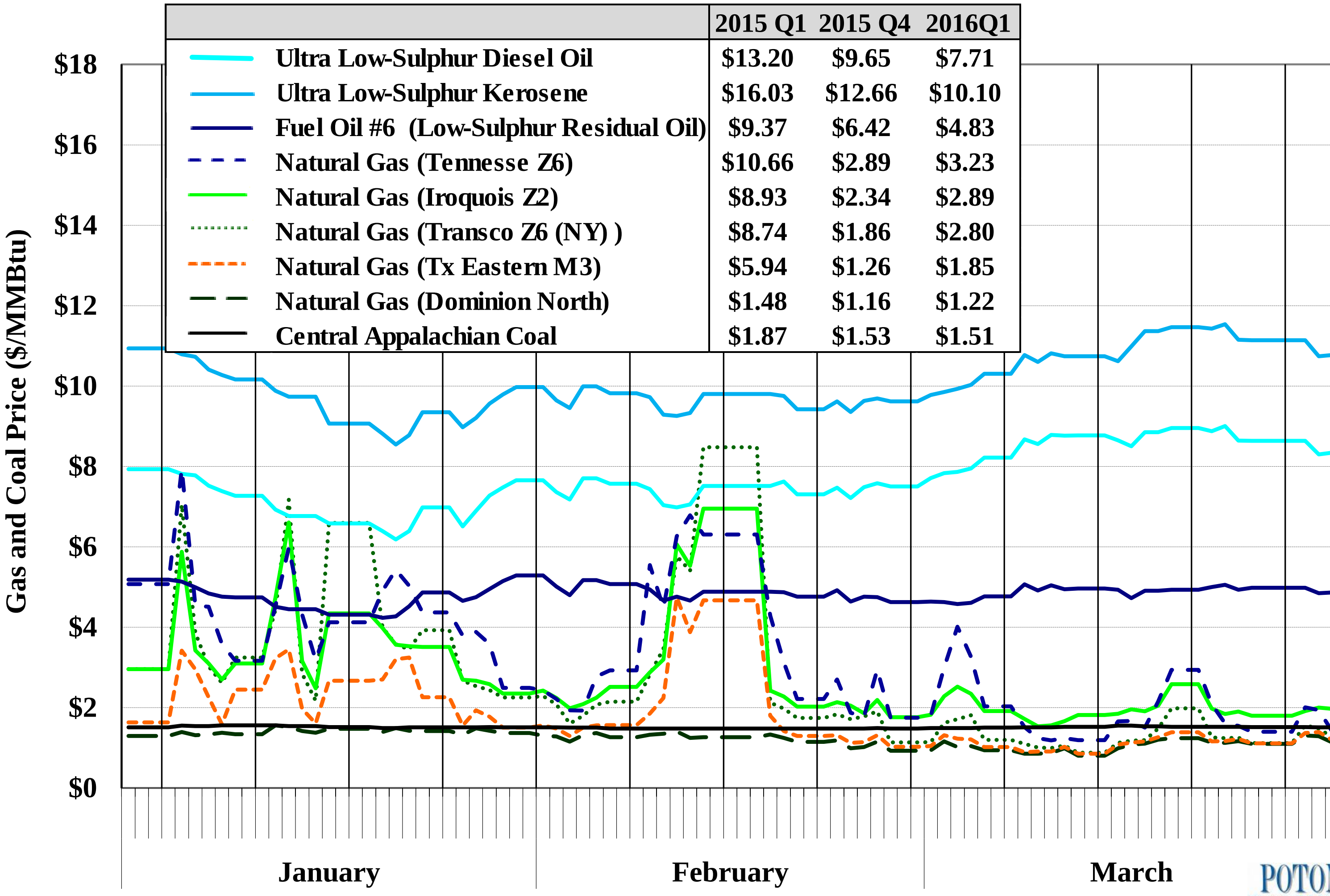
Coal, Natural Gas, and Fuel Oil Prices



	2015 Q1	2015 Q4	2016Q1
Ultra Low-Sulphur Diesel Oil	$13.20	$9.65	$7.71
Ultra Low-Sulphur Kerosene	$16.03	$12.66	$10.10
Fuel Oil #6 (Low-Sulphur Residual Oil)	$9.37	$6.42	$4.83
Natural Gas (Tennesse Z6)	$10.66	$2.89	$3.23
Natural Gas (Iroquois Z2)	$8.93	$2.34	$2.89
Natural Gas (Transco Z6 (NY))	$8.74	$1.86	$2.80
Natural Gas (Tx Eastern M3)	$5.94	$1.26	$1.85
Natural Gas (Dominion North)	$1.48	$1.16	$1.22
Central Appalachian Coal	$1.87	$1.53	$1.51

Real-Time Generation by Fuel Type

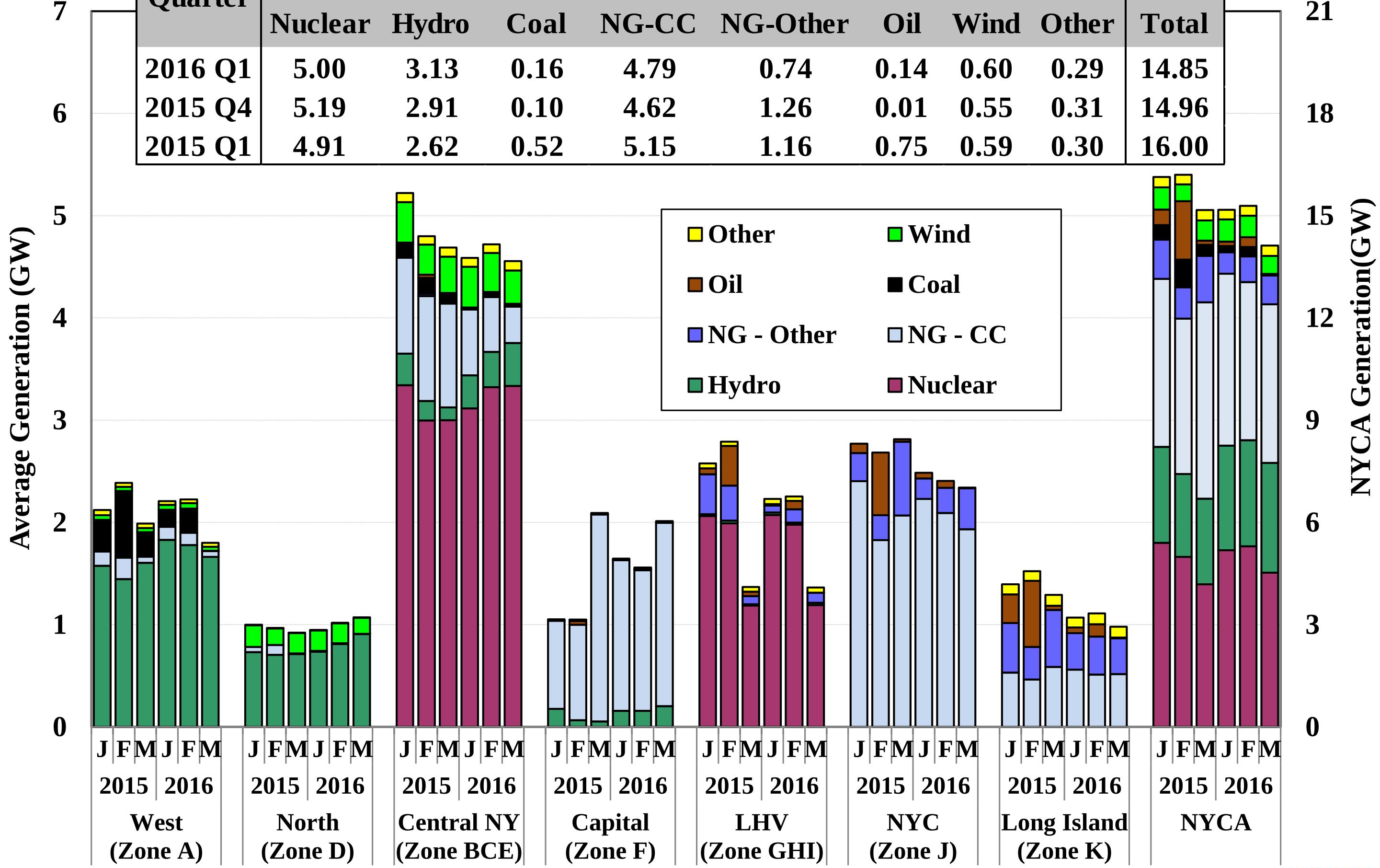
- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the first quarter of 2016.
- The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
- The second figure summarizes how frequently each fuel 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 (33 percent), and hydro (21 percent) generation accounted for most of the internal generation in the first quarter of 2016.
  - ✓ Average nuclear generation rose 90 MW from the first quarter of 2015 because of fewer deratings and outages.
  - ✓ Average coal and oil-fired generation fell by a total of 970 MW from a year ago, primarily because lower natural gas prices made these fuels less economic.
  - ✓ Average hydro generation rose 510 MW from a year ago, partly because:
    - Milder weather conditions led to increased supply of water (compared to frequent icy conditions in the prior year); and
    - Increased output from the Niagara facility in January and February due to limited congestion in the West Zone.
  - ✓ Gas-fired generation fell from a year ago due primarily to lower load levels.
- Gas-fired and hydro resources were on the margin the vast majority of time in the first quarter of 2016.
  - ✓ Most hydro units on the margin have storage capacity and offer based on the opportunity cost of foregone sales in other hours (i.e., when gas is marginal).
  - ✓ Hydro units in the West Zone were on the margin more frequently in March, reflecting increased congestion in the West Zone.

Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2016 Q1	5.00	3.13	0.16	4.79	0.74	0.14	0.60	0.29	14.85
2015 Q4	5.19	2.91	0.10	4.62	1.26	0.01	0.55	0.31	14.96
2015 Q1	4.91	2.62	0.52	5.15	1.16	0.75	0.59	0.30	16.00



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

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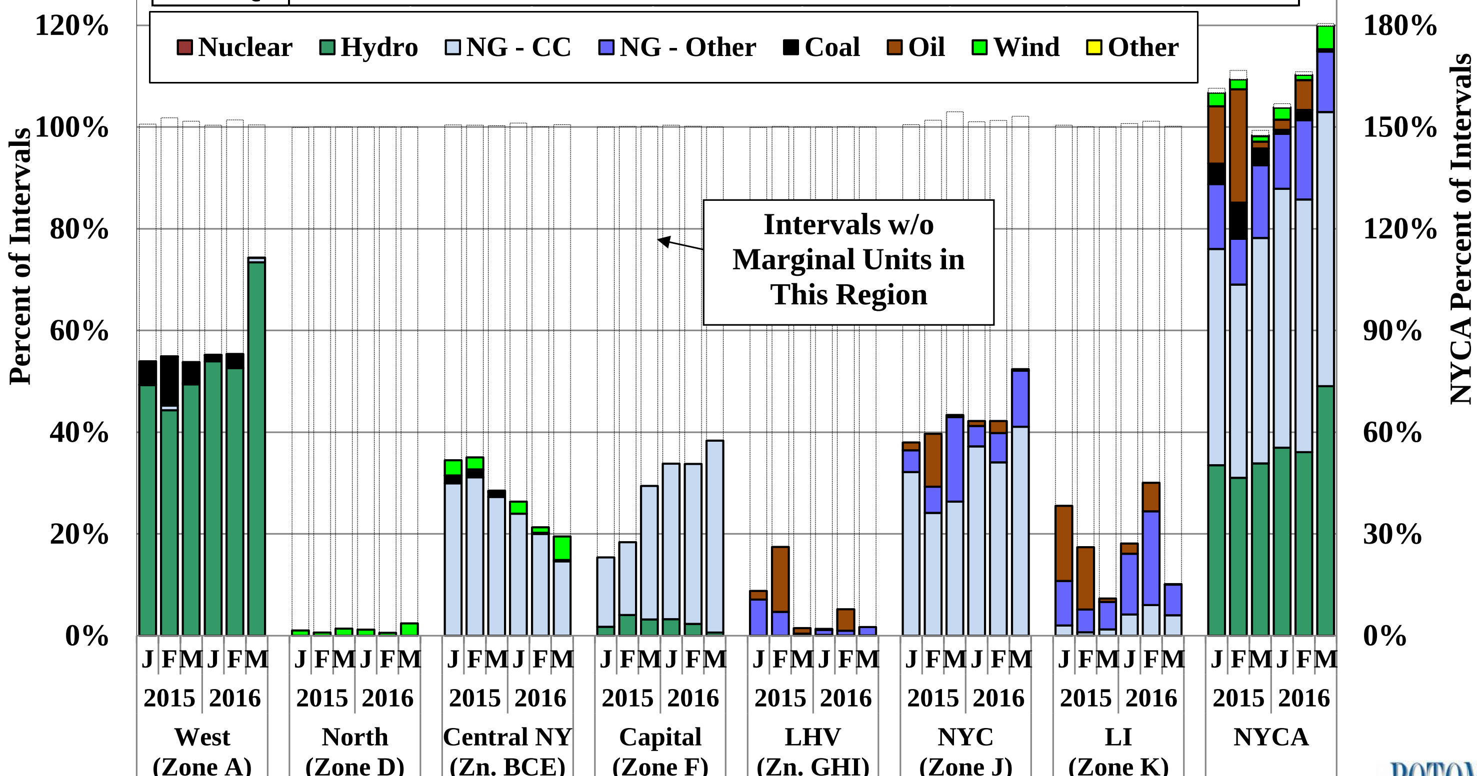
Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2016 Q1	0%	61%	1%	77%	19%	4%	4%	0%
2015 Q4	0%	53%	0%	72%	22%	1%	11%	0%
2015 Q1	0%	49%	7%	63%	18%	17%	3%	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 DA energy prices; 2) load-weighted average RT energy prices; and 3) convergence between DA and RT prices for five zones on a daily basis in the first quarter of 2016.
- Average day-ahead prices ranged from $18/MWh in the Central Zone to $34/MWh on Long Island, down 57 to 65 percent from the first quarter of 2015.
  - ✓ The decreases were driven primarily by:
    - – Lower natural gas prices (see slide 12);
    - – Lower load levels and less frequent winter peaking conditions (see slide 11); and
    - – Higher nuclear and hydro production (see slide 15), which were partly offset by lower net imports from neighboring areas (see slide 42).
  - ✓ The West Zone exhibited the smallest reduction in LBMPs (57 percent), reflecting higher levels of congestion than the previous year (see slide 60).
    - – The 230 kV constraints in the West Zone were binding more frequently in March as a result of multiple transmission outages and retirement of several coal units.
  - ✓ Separations in LBMPs between most areas in West NY and East NY were persistent throughout the quarter as the Central-East interface was frequently congested, driven partly by lengthy transmission outages (see slide 60).

Day-Ahead and Real-Time Electricity Prices

- Prices are generally more volatile in the real-time market than in the day-ahead market because of unexpected events. Notable examples include:
  - ✓ On January 5, statewide prices were elevated significantly during several hours in the morning because of a series of unexpected events (which are described in more detail in the next slide).
  - ✓ On March 28-30, RT prices in the West Zone rose notably because of severe congestion on the Packard-Sawyer and Gardenville-Stolle Road lines, driven by:
    - Transmission outages;
    - Large deviations on the JK PARs (below scheduled from NY to PJM);
    - Loop flows from PJM flowing out to Western PA; and
    - The early return of the Dunkirk-S. Ripley line on the 28th at the request of PJM for reliability in Western PA (which increases congestion in the West Zone).
- Random factors can cause large differences between DA and RT prices on individual days, while persistent differences may indicate a systematic issue. The table focuses on persistent differences by averaging over the entire quarter.
  - ✓ Average DA prices were roughly 3 to 7 percent higher than RT prices in most areas this quarter except the West Zone, which exhibited a 10 percent RT premium for the quarter largely because of higher RT prices on last days of March (for the reasons mentioned above).

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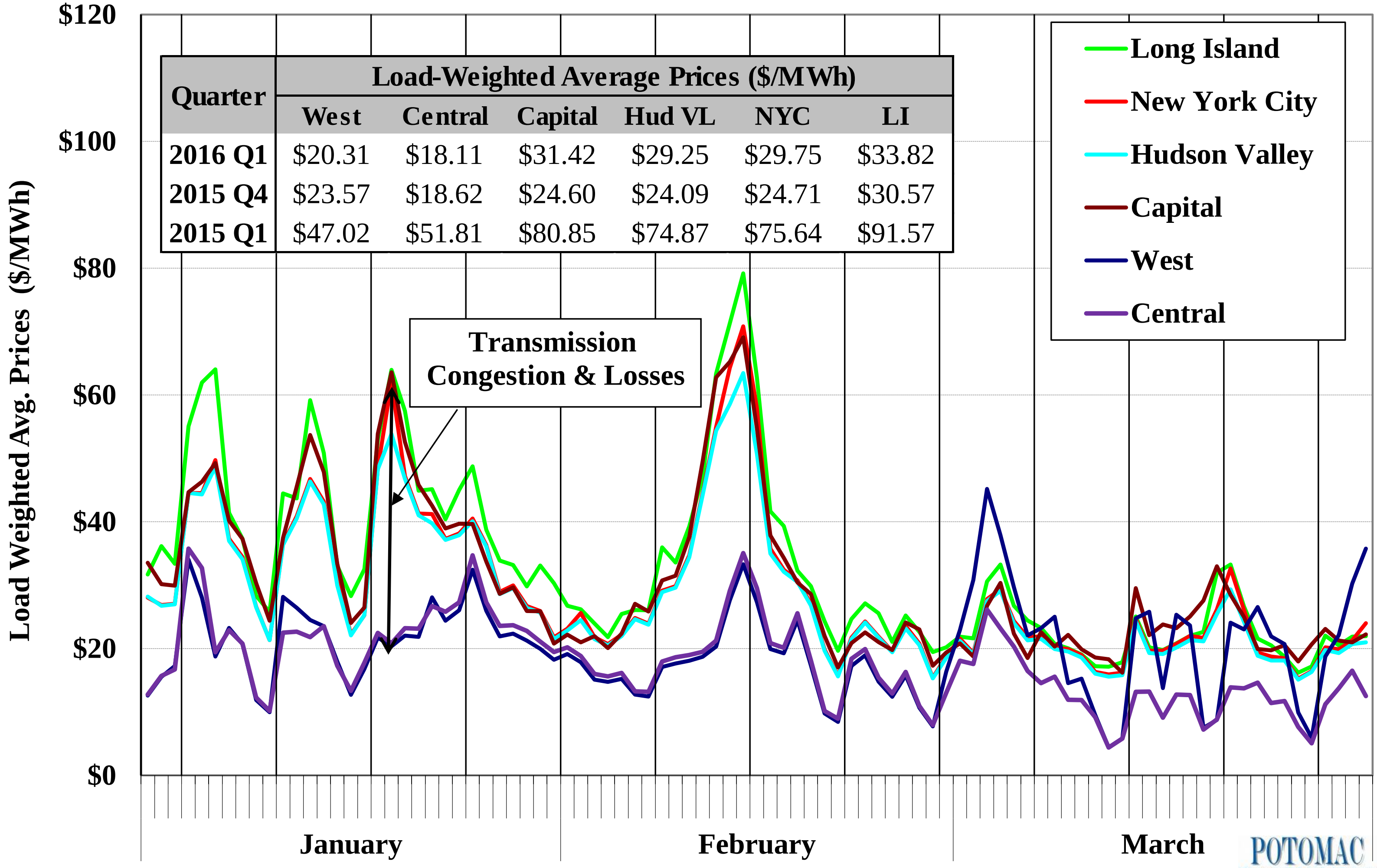
Real-Time Electricity Prices
January 5th Real-Time Event

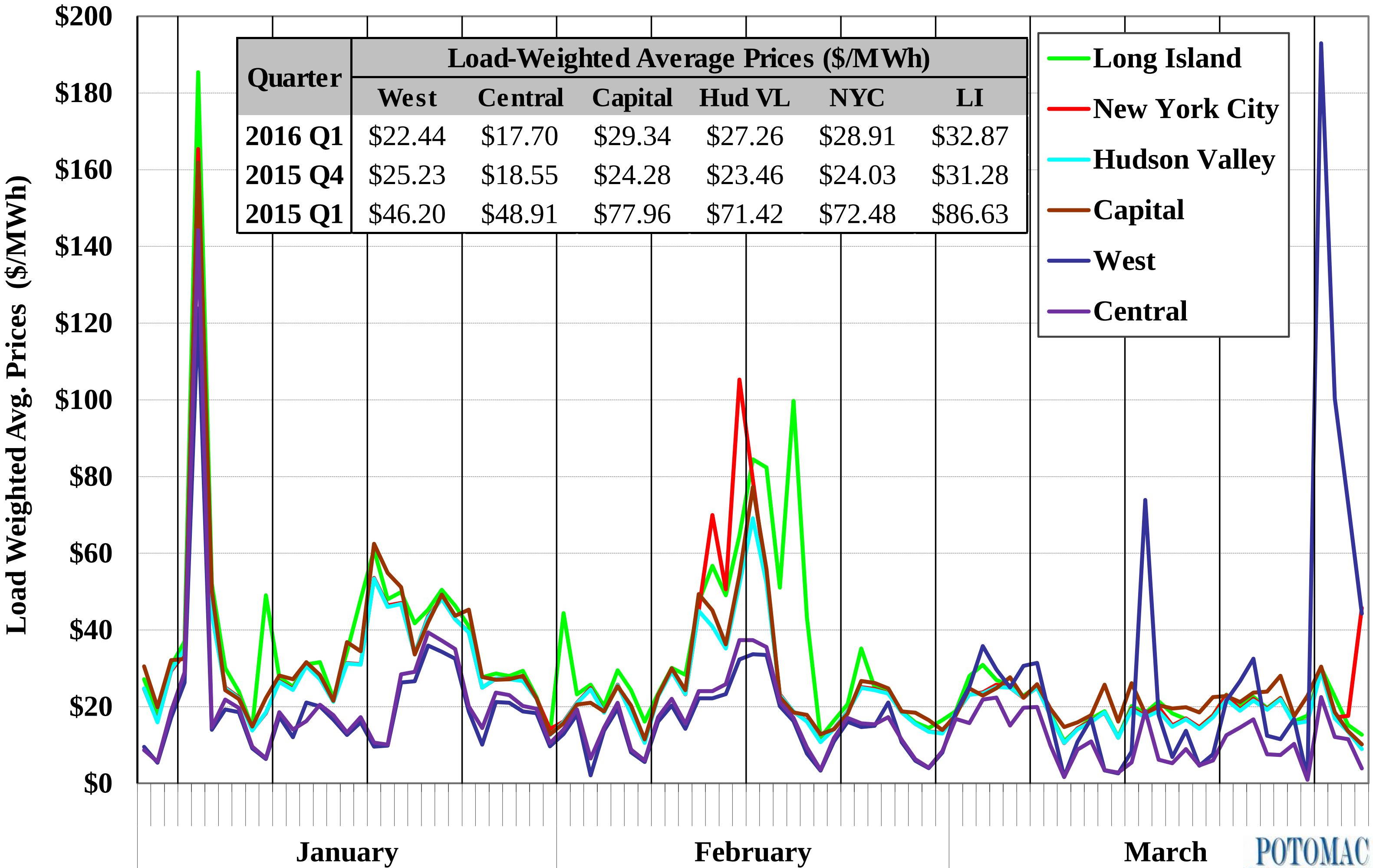
- On January 5, energy and reserve price spikes occurred from 8:35 to 10:40:
  - ✓ A TLR3b was issued by PJM at 8:07 am, resulting in the net loss of 1.3 GW of imports starting at 8:30.
    - – When a TLR is issued, NYISO operators do not have a way to reflect transaction cuts in RTC until the TLR process identifies specific transactions to be cut. Thus, no cuts were included until ~700 MW were included in the RTC that initialized at 9:00, which schedules CTS transactions for 9:35 and 30-minute GTs for 9:45.
    - – Consequently, RTC prices were below $150 while RTD prices generally exceeded $1,000, reflecting that RTC did not perceive the value of importing CTS transactions from ISO-NE and starting 30-min GTs.
  - ✓ A large generator (600 MW) tripped off at 8:33.
  - ✓ 1.4 GW of offline 10-minute units were started in reserve pick-ups.
    - – This quantity was increased by poor generator performance. Approximately 450 MW failed to start, including 260 MW offering without apparent gas supply.
      - NYISO is working with generators to clarify their obligations in such cases.
    - – This led to Eastern 10-minute reserve shortages from 8:45 to 10:40.
  - ✓ RTC shut down 1 GW of 10-minute units at 9:45 (at the end of their minimum run times), leading to statewide 10-minute reserve shortages (since GTs cannot provide reserves immediately after being shut down).

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2016 Q1	$20.31	$18.11	$31.42	$29.25	$29.75	$33.82
2015 Q4	$23.57	$18.62	$24.60	$24.09	$24.71	$30.57
2015 Q1	$47.02	$51.81	$80.85	$74.87	$75.64	$91.57

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2016 Q1	$22.44	$17.70	$29.34	$27.26	$28.91	$32.87
2015 Q4	$25.23	$18.55	$24.28	$23.46	$24.03	$31.28
2015 Q1	$46.20	$48.91	$77.96	$71.42	$72.48	$86.63

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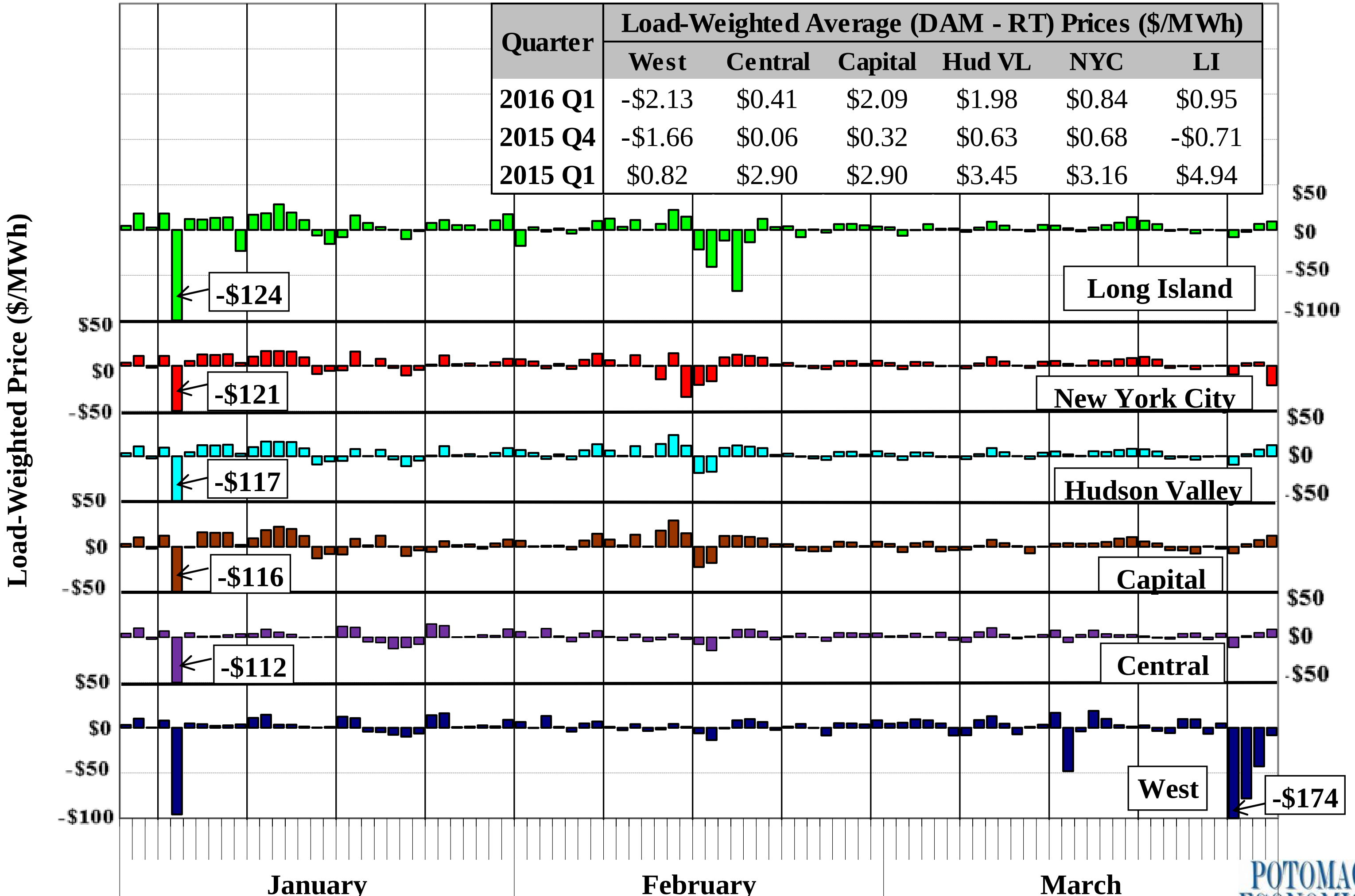
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2016 Q1	-$2.13	$0.41	$2.09	$1.98	$0.84	$0.95
2015 Q4	-$1.66	$0.06	$0.32	$0.63	$0.68	-$0.71
2015 Q1	$0.82	$2.90	$2.90	$3.45	$3.16	$4.94

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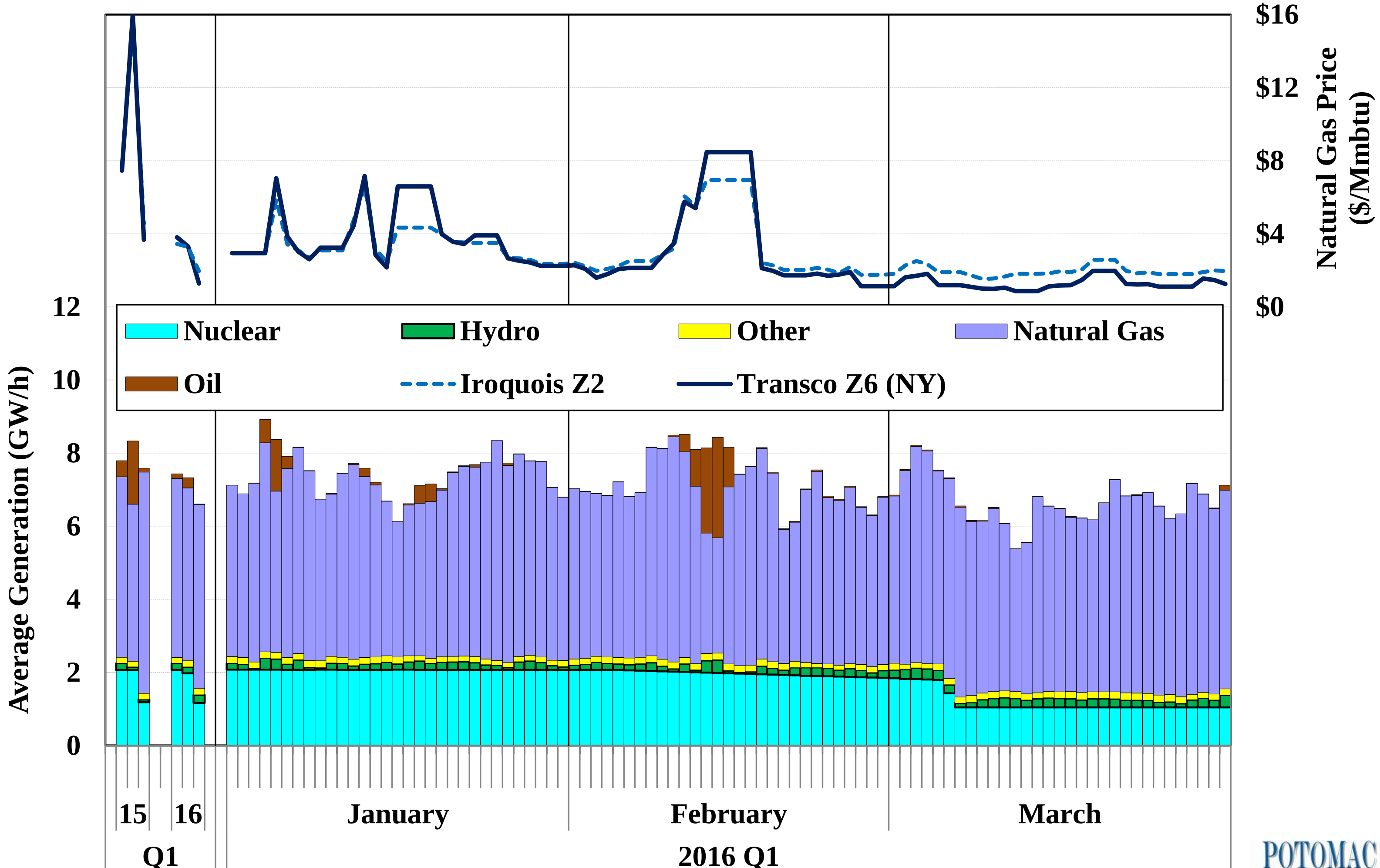
Market Performance Under Tight Gas Supply Conditions
Eastern New York

- The following figure evaluates the efficiency of fuel usage in Eastern New York in the first quarter of 2016, showing 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).
  - ✓ These quantities are also shown by month for the first quarter of 2015 and 2016.
- Oil-fired generation in East NY totaled roughly 0.3 million MWh in the first quarter of 2016, down notably from 1.6 million MWh in the first quarter of 2015.
  - ✓ Gas supply constraints were much less frequent and severe in the first quarter of 2016 than the previous year because of factors discussed earlier.
  - ✓ As a result, natural gas prices in Eastern NY exceeded $8/MMbtu only for one weekend in February (while gas prices exceeded $15/MMbtu on 22 days last year).
  - ✓ During the weekend in mid-February, oil-fired generation rose sharply, averaging nearly 1.8 GW.

Fuel Usage and Natural Gas Price
Eastern New York



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Ancillary Services Market

Ancillary Services Prices

- The following three figures summarize DA and RT prices for six ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices in eastern NY;
  - ✓ 10-min non-spinning reserve prices in eastern NY;
  - ✓ 10-min spinning reserve prices in western NY;
  - ✓ Regulation prices, which reflect the cost procuring regulation, and the cost from moving regulation units up and down.
    - – Resources were scheduled assuming a Regulation Movement Multiplier of 13 MW per MW of capability, but they are compensated according to actual movement.
  - ✓ 30-min operating reserve prices in western NY; and
  - ✓ 30-min operating reserve prices in SENY.
- The figures also show the number of shortage intervals in real-time for each ancillary service product.
  - ✓ A shortage occurs when a requirement cannot be satisfied at a marginal cost less than its "demand curve".
  - ✓ The highest demand curve values are currently set at $775/MW.

Ancillary Services Prices

- The differences in day-ahead prices between various reserve products became much smaller in the first quarter of 2016.
  - ✓ The largest average difference was only $0.43/MWh (between eastern 10-min spinning prices and western 30-min total prices) this quarter, much lower than the $6.90/MWh from a year ago.
    - – This indicates that all reserve requirements except the statewide 30-minute requirement were binding much less frequently this quarter.
  - ✓ In the day-ahead market, average western 30-minute reserve prices rose notably from $1.35/MWh in the first quarter of 2015 to $5.42/MWh this quarter despite lower natural gas prices and lower load levels.
    - – This was due primarily to the rule changes (Comprehensive Shortage Pricing Project) made in November 2015. (see slides 31-33 for more detailed discussion)
- Ancillary services prices rose substantially in real-time on January 5th because of unexpected events. (see slide 19)
- The number of regulation shortages in real-time rose 76 percent from a year ago despite milder winter weather and lower load levels this quarter.
  - ✓ The increase was also due to the rule changes in November 2015, which reduced the lowest demand curve value from $80 to $25.

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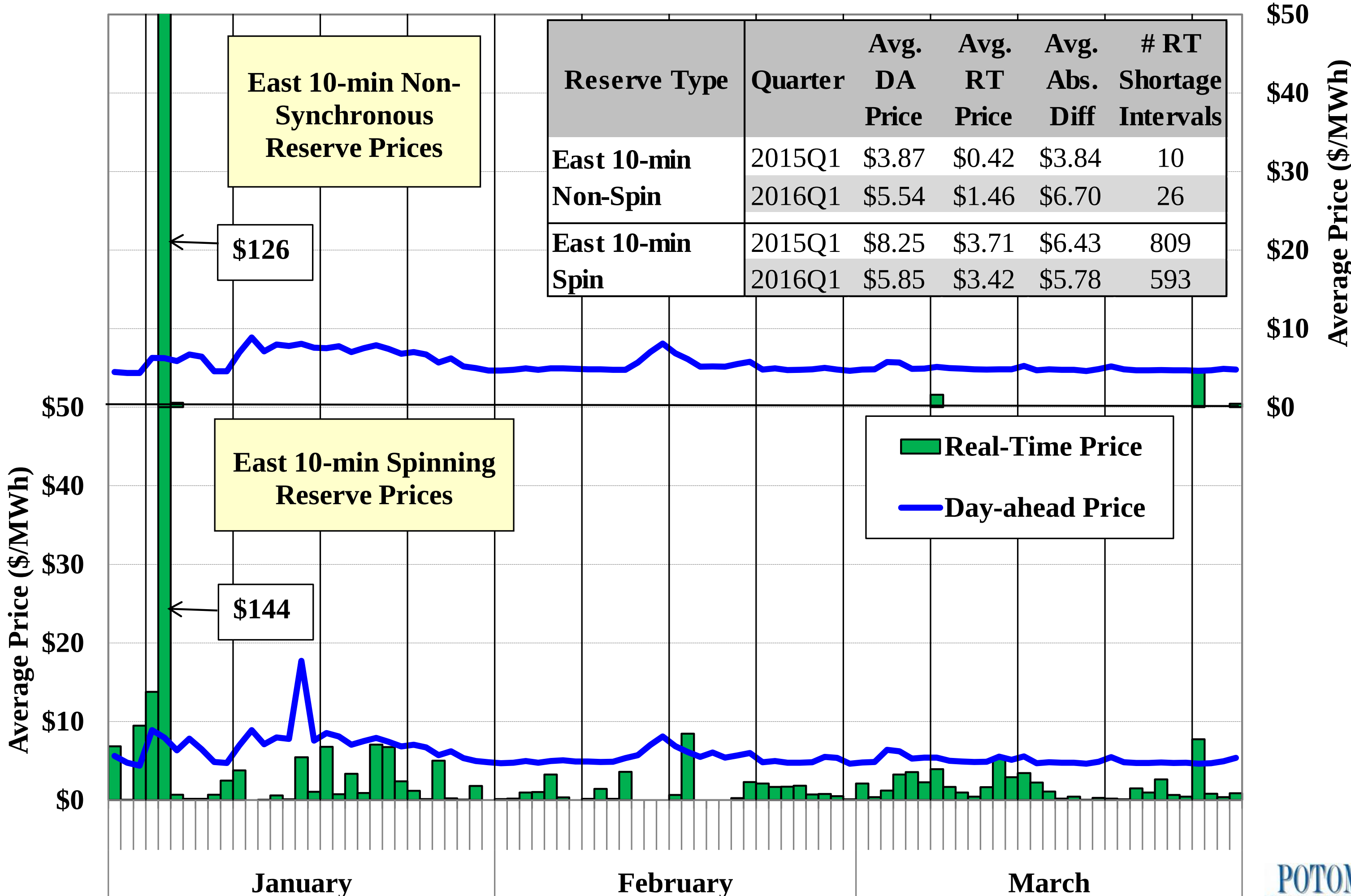
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2015Q1	$3.87	$0.42	$3.84	10
	2016Q1	$5.54	$1.46	$6.70	26
East 10-min Spin	2015Q1	$8.25	$3.71	$6.43	809
	2016Q1	$5.85	$3.42	$5.78	593

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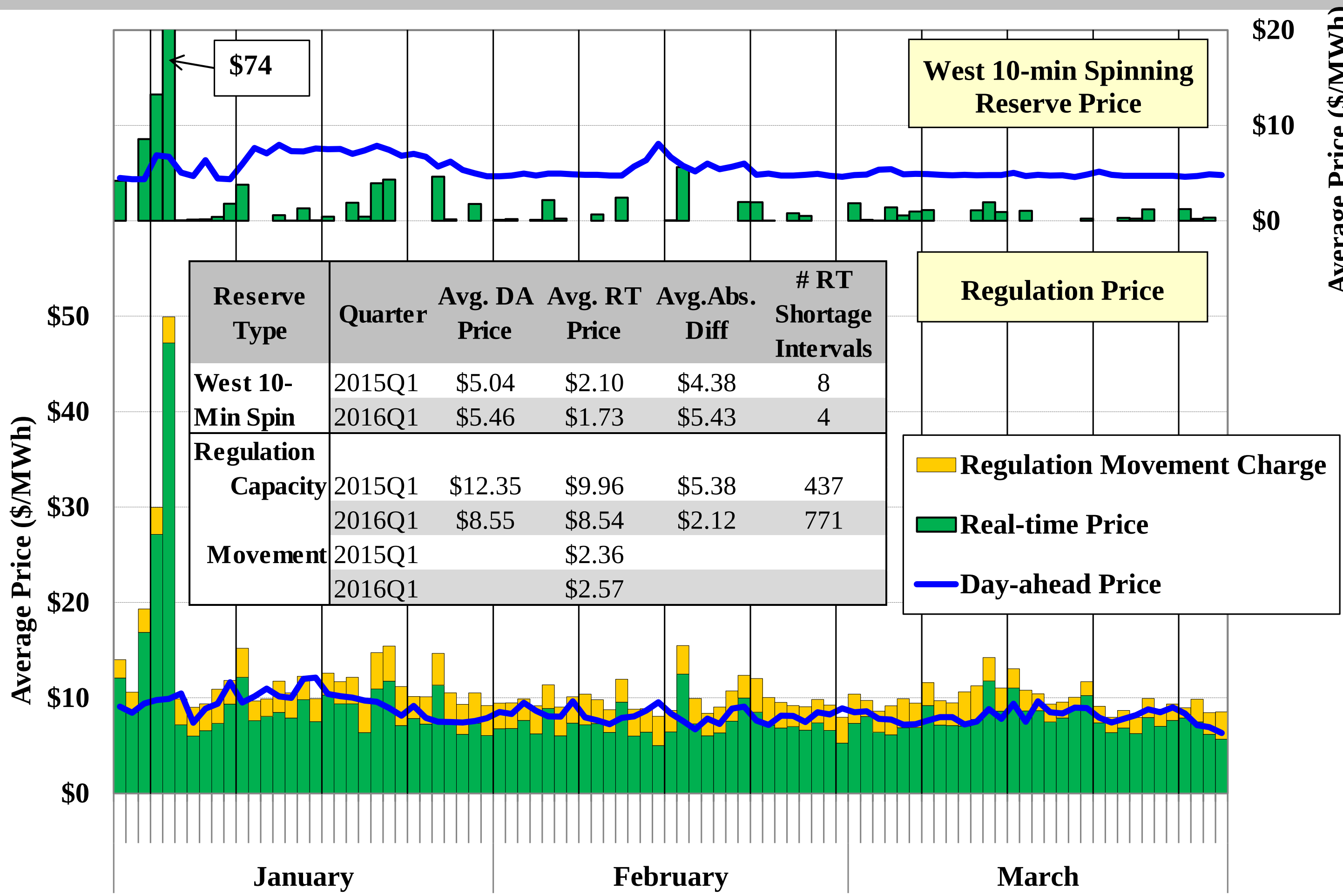
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
West 10-Min Spin	2015Q1	$5.04	$2.10	$4.38	8
	2016Q1	$5.46	$1.73	$5.43	4
Regulation Capacity	2015Q1	$12.35	$9.96	$5.38	437
	2016Q1	$8.55	$8.54	$2.12	771
Movement	2015Q1		$2.36		
	2016Q1		$2.57		

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

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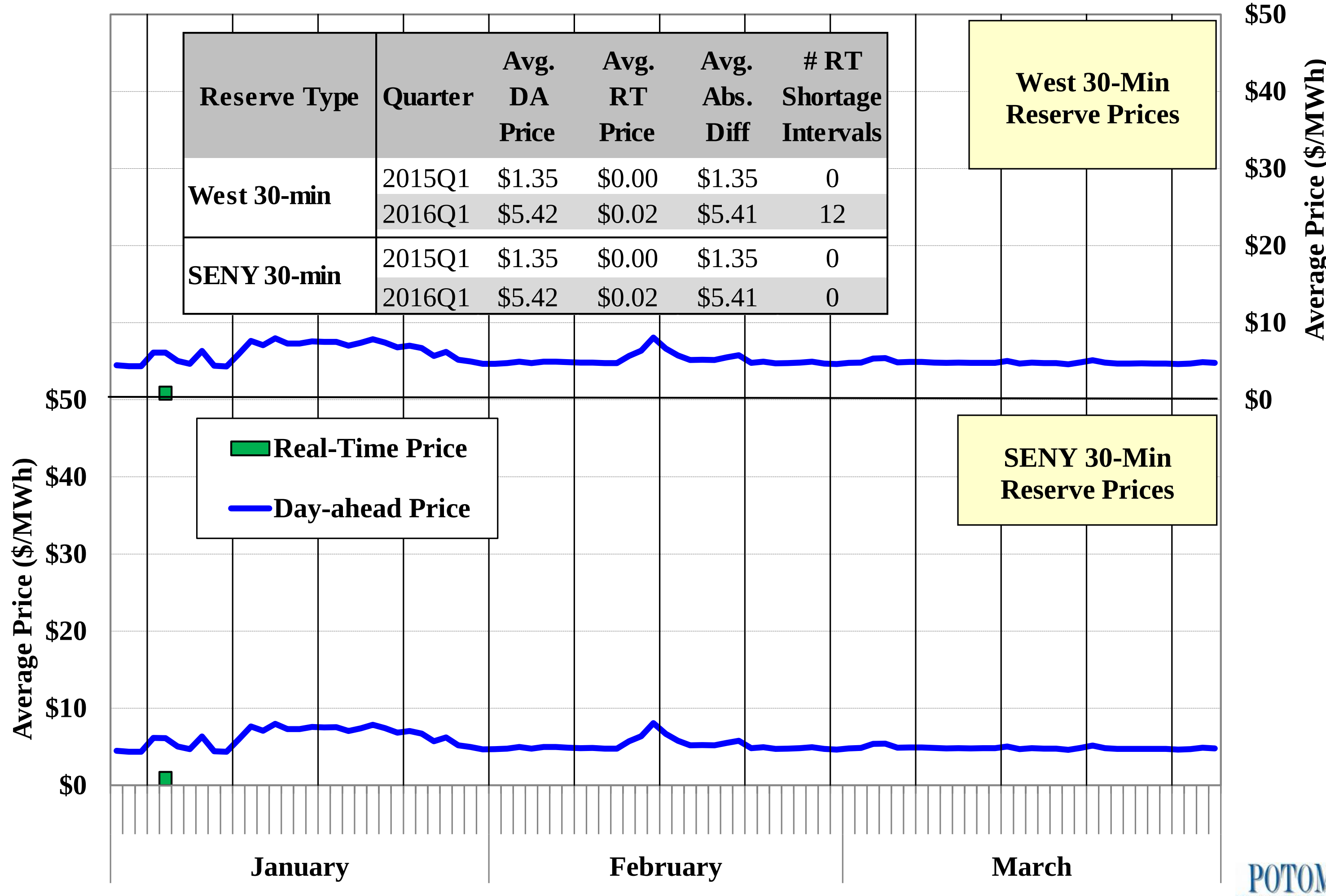
Day-Ahead and Real-Time Ancillary Services Prices

Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2015Q1	$1.35	$0.00	$1.35	0
	2016Q1	$5.42	$0.02	$5.41	12
SENY 30-min	2015Q1	$1.35	$0.00	$1.35	0
	2016Q1	$5.42	$0.02	$5.41	0

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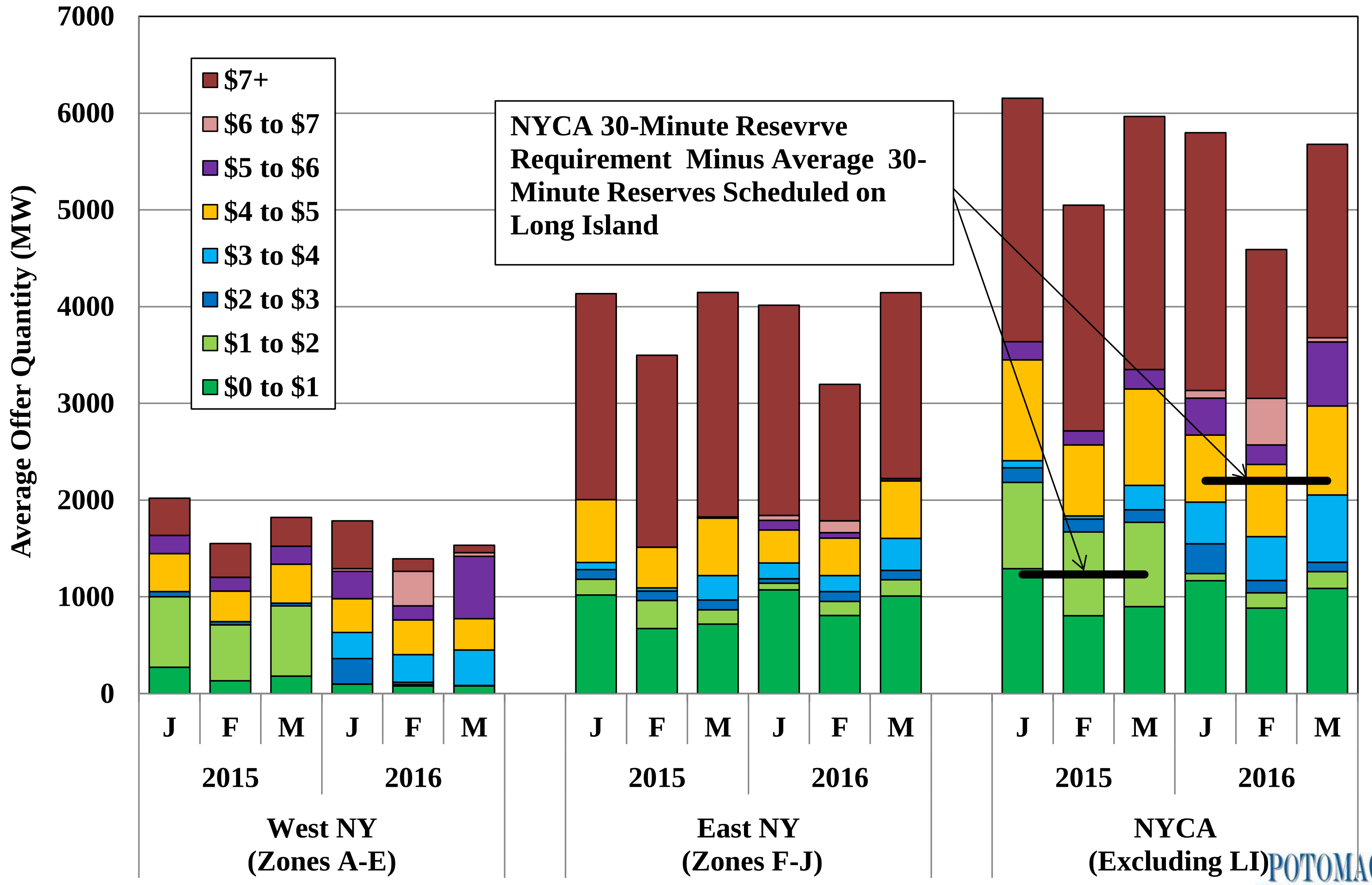
NYCA 30-Minute Reserve Offers in the DAM

- The next figure summarizes the amount of reserve offers in the day-ahead market that can satisfy the statewide 30-minute reserve requirement.
  - ✓ These quantities include both 10-minute and 30-minute and both spinning and non-spin reserve offers (However, they are not shown separately in the figure).
  - ✓ Only offers from day-ahead committed (i.e., online) resources and available offline quick-start resources are included in this evaluation, because they directly affect the reserve prices.
  - ✓ The stacked bars show the amount of reserve offers in each select price range for West NY (Zones A to E), East NY (Zones F to J), and NYCA (excluding Zone K).
    - – Long Island is excluded because the current rules limit its reserve contribution to the broader areas (i.e., SENY, East, NYCA) to its 30-minute reserve requirement.
    - – As a result, Long Island reserve offers have little impact on NYCA reserve prices.
  - ✓ The two black lines represent the equivalent average 30-minute reserve requirements for areas outside Long Island in the first quarter of 2015 and 2016.
    - – The equivalent 30-minute reserve requirement is calculated as NYCA 30-minute reserve requirement *minus* 30-minute reserves scheduled on Long Island.
    - – Where the lines intersect the bars provides a rough indication of reserve prices (however, opportunity costs are not reflected here).

NYCA 30-Minute Reserve Offers in the DAM

- The amount of cheaper offers rose modestly in East NY in the first quarter of 2016.
  - ✓ However, the amount of cheaper offers fell notably in West NY, largely because one supplier increased its offer prices.
  - ✓ We reviewed this offer change and found no significant competitive concerns.
- The observed increase in statewide 30-minute reserve prices from a year ago was largely due to:
  - ✓ The NYCA 30-minute reserve requirement increased from 1,965 MW to 2,620 MW; and
  - ✓ The limitation on scheduling reserves from Long Island resources.
    - An average of 423 MW of 30-minute reserves was scheduled on Long Island in the first quarter of 2016, down 310 MW from the first quarter of 2015.
  - ✓ Taken together, these two factors increased the need for 30-minute reserves outside Long Island by 970 MW.
  - ✓ The rise of offer prices in West NY was a less important factor because the equivalent 30-minute reserve requirement from 2016 Q1 would intersect the 2015 Q1 offer bars at similar price ranges.
- RT 30-minute reserve prices are much lower than DA prices because units that avoid being scheduled in the DAM must have availability bids of $0 in RT.

Day-Ahead NYCA 30-Minute Operating Reserve Offers
From Committed and Available Offline Quick-Start Resources



POTOMAC ECONOMICS

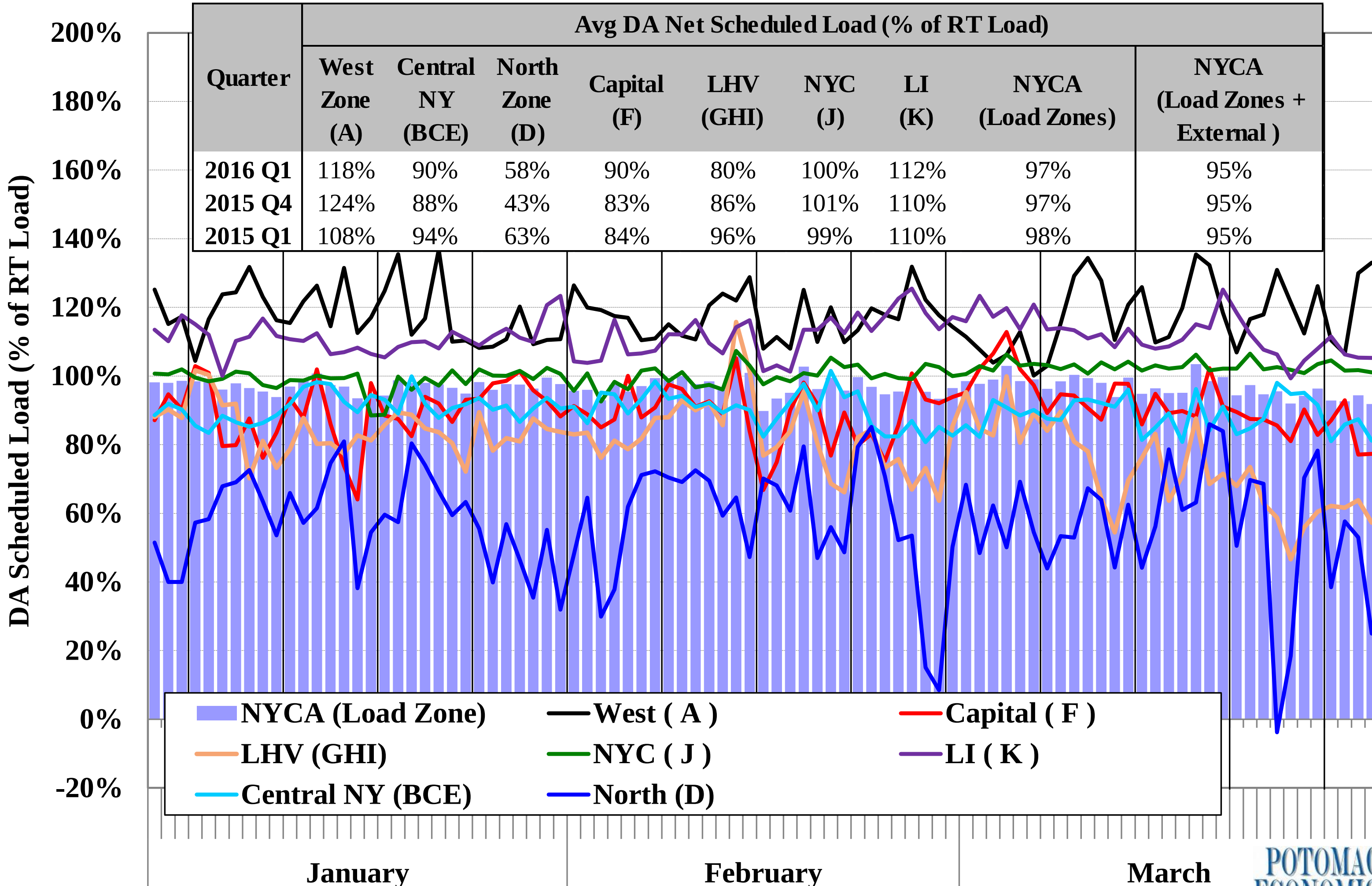
Energy Market Scheduling

Day-ahead Load Scheduling

- The following figure summarizes the quantity of DA load scheduled as a percentage of RT load in each of seven 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) during peak load hours in 2016 Q1, comparable to 2015 Q1.
  - ✓ DA load scheduling pattern in each sub-region was generally consistent as well.
- Average net load scheduling tends to be higher in locations where volatile real-time congestion is more common.
  - ✓ Net load scheduling was generally higher in NYC and Long Island because they were downstream of most congested interfaces.
  - ✓ Net load scheduling was highest in the West Zone partly because of volatile RT congestion on the West Zone 230kV system.
- Load was typically under-scheduled in the North Zone by a large margin primarily in response to the scheduling patterns of wind resources in the zone and imports from Canada.

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour



Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2016 Q1	118%	90%	58%	90%	80%	100%	112%	97%	95%
2015 Q4	124%	88%	43%	83%	86%	101%	110%	97%	95%
2015 Q1	108%	94%	63%	84%	96%	99%	110%	98%	95%

POTOMAC ECONOMICS

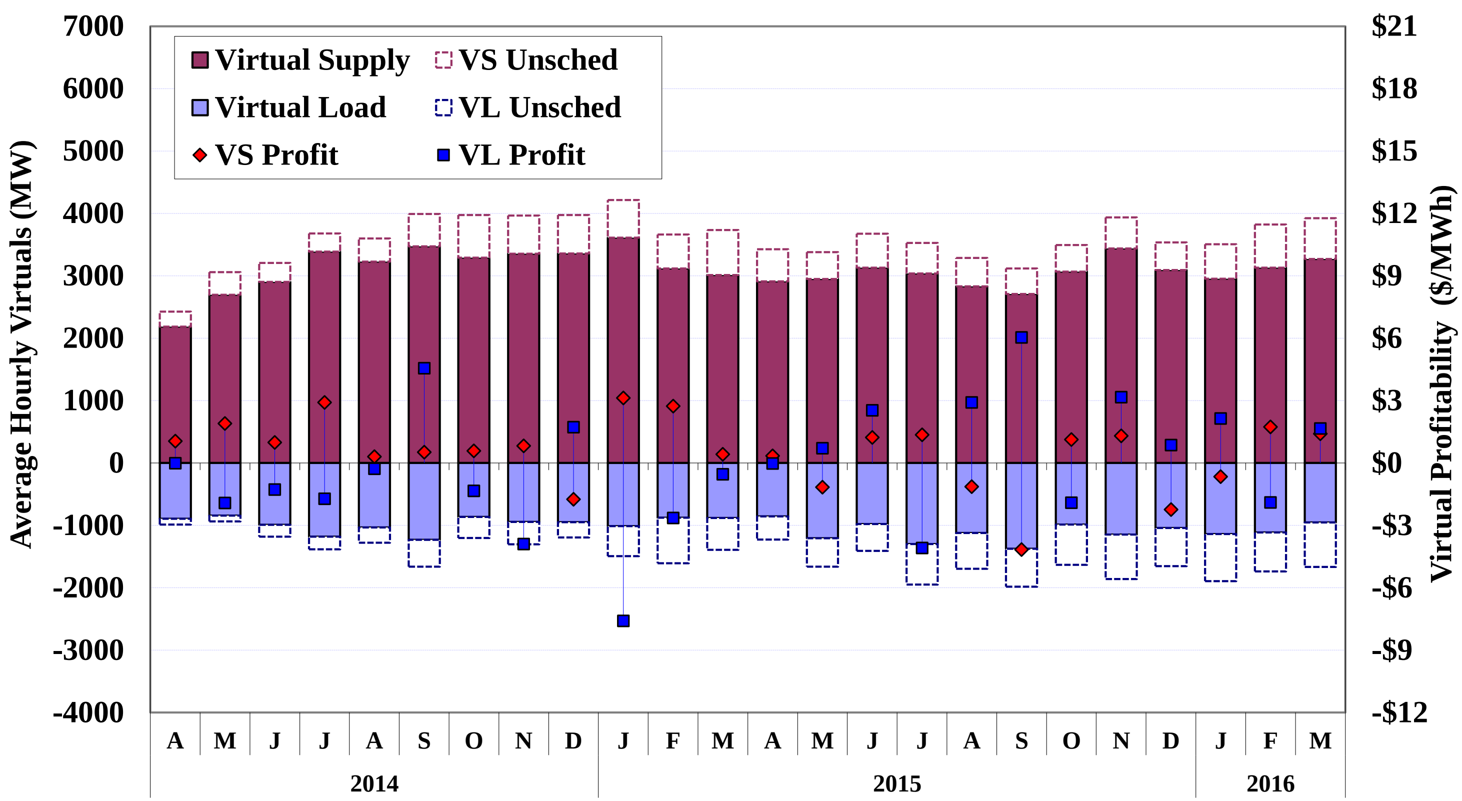
Virtual Trading Activity

- The following two charts summarize recent virtual trading activity in New York.
- The first figure shows monthly average scheduled and unscheduled quantities, and gross profitability for virtual transactions at the load zones in the past 24 months.
  - ✓ The table shows a screen for relatively large profits or losses, which identifies virtual trades with profits or losses larger than 50% of the average zone LBMP.
    - – Large profits may indicate modeling inconsistencies between DA and RT markets, and large losses may indicate manipulation of the day-ahead market.
- The second figure summarizes virtual trading by geographic region.
  - ✓ The load zones are broken into seven regions based on typical congestion patterns.
  - ✓ 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).
  - ✓ The top portion of the chart also shows average day-ahead scheduled load (as a percent of real-time load) at each geographic region.

Virtual Trading Activity

- The volume of virtual trading did not change significantly in the first quarter of 2016, generally consistent with prior periods.
  - ✓ The pattern of virtual scheduling was similar as well.
    - – Virtual traders generally scheduled more virtual load in the West Zone and downstate areas (i.e., NYC and LI) and more virtual supply in other regions.
    - – This was consistent with typical DA load scheduling patterns discussed earlier for similar reasons.
- Overall, virtual traders netted a profit of $7.1 million in the first quarter of 2016.
  - ✓ Virtual transactions were profitable, suggesting that they have generally improved convergence between DA and RT prices. (For example, profitable virtual supply tends to reduce the DA price, bringing it closer to the RT price.)
  - ✓ However, the profits and losses of virtual trades varied widely by time and location, reflecting the difficulty of predicting volatile RT prices.
- The quantities of virtual transactions that generated substantial profits or losses rose modestly from prior periods.
  - ✓ These trades were primarily associated with high price volatility that resulted from unexpected events, which do not raise significant concerns.

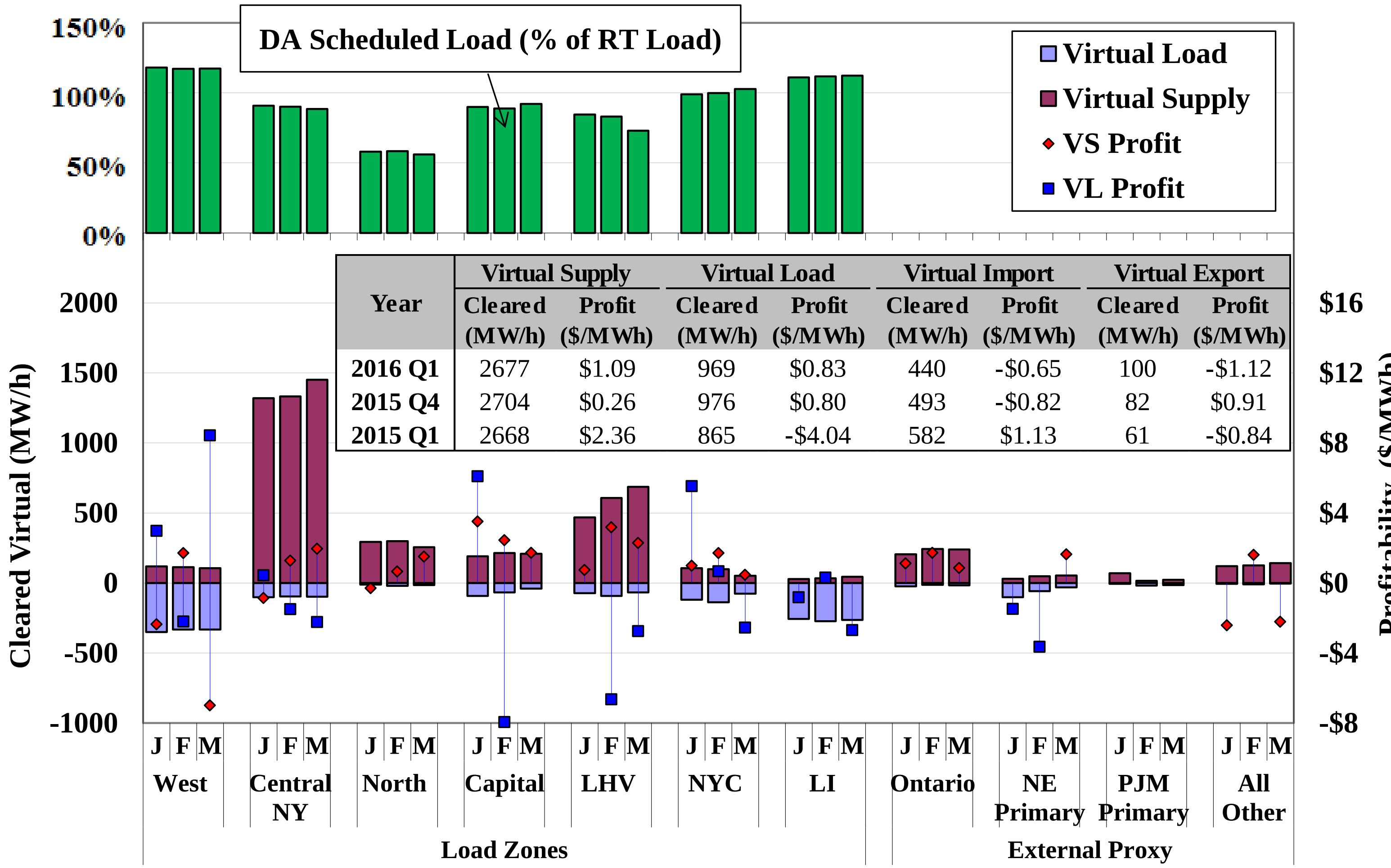
Virtual Trading Activity at Load Zones by Month



		A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M
Profit > 50% of Avg. Zone Price	MW	116	217	187	524	159	333	587	433	381	537	562	315	296	561	763	471	284	239	375	1078	627	680	626	991
	%	4%	6%	5%	11%	4%	7%	14%	10%	9%	12%	14%	8%	8%	13%	19%	11%	7%	6%	9%	23%	15%	17%	15%	23%
Loss > 50% of Avg. Zone Price	MW	107	229	234	395	212	333	508	455	370	460	445	373	335	667	680	489	296	336	368	698	752	547	538	666
	%	3%	6%	6%	9%	5%	7%	12%	11%	9%	10%	11%	10%	9%	16%	17%	11%	7%	8%	9%	15%	18%	13%	13%	16%

POTOMAC ECONOMICS

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)
2016 Q1	2677	$1.09	969	$0.83	440	-$0.65	100	-$1.12
2015 Q4	2704	$0.26	976	$0.80	493	-$0.82	82	$0.91
2015 Q1	2668	$2.36	865	-$4.04	582	$1.13	61	-$0.84

Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.

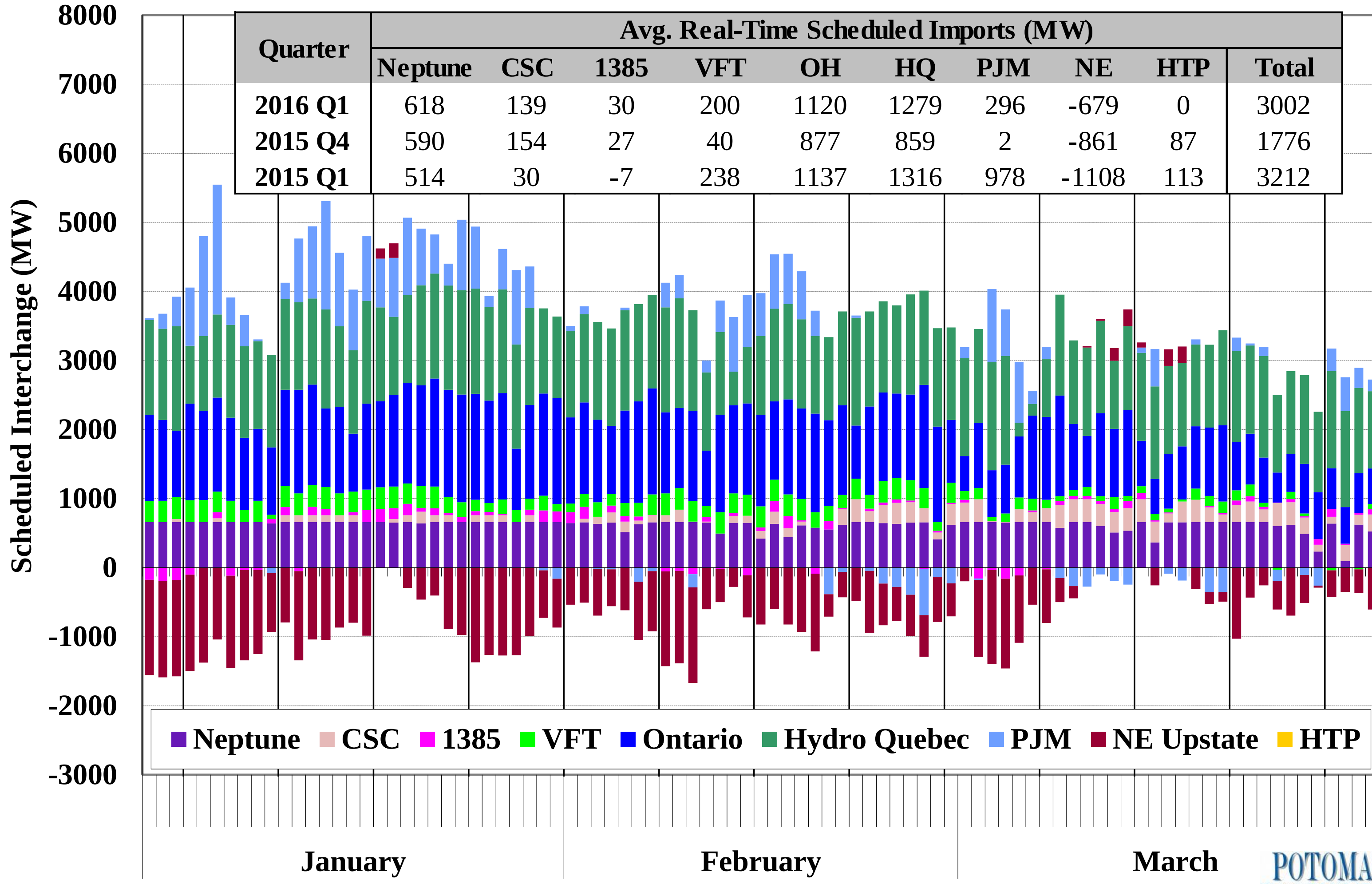
POTOMAC ECONOMICS

Net Imports Scheduled Across External Interfaces

- The next figure shows average RT net imports to NYCA across ten external interfaces (two HQ interfaces are combined) in peak hours (1-9 pm).
- Overall, net imports averaged roughly 3.0 GW (serving nearly 17 percent of the load) during peak hours, down 200 MW from the first quarter of 2015.
- Imports from Hydro Quebec and Ontario accounted for 80 percent of total imports in the first quarter of 2016, comparable to the first quarter of 2015.
  - ✓ However, net imports from Ontario fell in March because of increased congestion in the West Zone throughout the month.
- New York normally imported power from PJM and exported power to New England across their primary interfaces in the winter season.
  - ✓ This pattern was consistent with the spreads in natural gas prices between these markets in the winter (i.e., NE > NY > PJM).
  - ✓ However, reduced PJM imports and NE exports this quarter reflected lower natural gas spreads between these markets.
- Average net imports to Long Island rose by 250 MW from a year ago partly because of fewer transmission outages on the CSC and Neptune lines.
- Average net imports to NYC fell by 150 MW from a year ago, largely because the HTP interface was out of service for the entire quarter.

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
2016 Q1	618	139	30	200	1120	1279	296	-679	0	3002
2015 Q4	590	154	27	40	877	859	2	-861	87	1776
2015 Q1	514	30	-7	238	1137	1316	978	-1108	113	3212



POTOMAC ECONOMICS

Intra-Hour Scheduling with PJM and NE Coordinated Transaction Scheduling ("CTS")

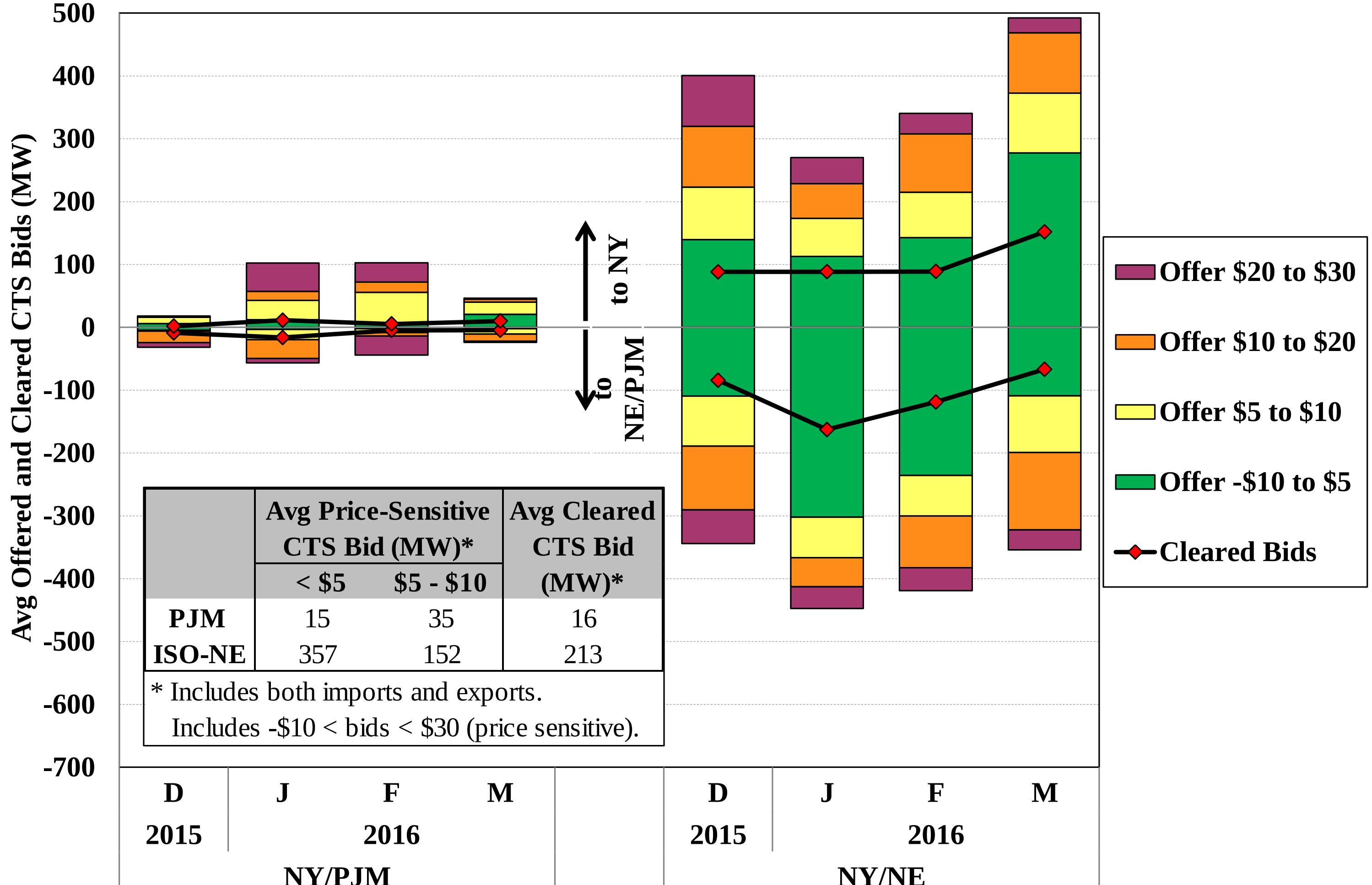
- The following three analyses evaluate the performance of CTS with PJM and NE at their primary interfaces during the first quarter of 2016.
- The following figure shows the average amount of CTS transactions at the two primary interfaces during peak hours (i.e., HE 8 to 23) by month.
  - ✓ Stacked bars show the average quantities of price-sensitive CTS bids for four select price ranges between -$10 and $30/MWh.
    - Bids that are offered below -$10/MWh or above $30/MWh are considered price insensitive for this analysis.
  - ✓ The two black lines in the figure indicate the average scheduled price-sensitive CTS imports and exports in each month during the examined period.
  - ✓ The table in the figure summarizes for the two CTS-enabled interfaces:
    - The average amount of CTS bids with offer prices between -$10 and $5/MWh or between $5 and $10/MWh; and
    - The average MW of cleared CTS bids that were priced between -$10 and $30/MWh. Both imports and exports are included in these numbers.

POTOMAC ECONOMICS

Intra-Hour Scheduling with PJM and NE
Average CTS Transactions

- The average amount of price-sensitive CTS bids submitted at the primary New England interface was much higher than at the PJM border, even though CTS with ISO-NE is relatively new.
  - ✓ During the examined period, an average of 510 MW of CTS bids (including both imports and exports) were offered between -$10 and $10/MWh at the NE/NY interface, while only 50 MW were offered at the primary PJM/NY interface.
  - ✓ Likewise, the amount of cleared price-sensitive CTS bids was 10 times higher at the NE/NY interface.
  - ✓ These results indicate much more active CTS participation at the NE/NY interface.
- These differences between the two CTS processes are largely attributable to the large fees that are imposed on CTS transactions with PJM, while no substantial fees are imposed on CTS transactions with NE.
- These results suggest that:
  - ✓ Imposing substantial charges on low-margin trading activity has a dramatic effect on liquidity at the interface; and
  - ✓ The policy of not assessing uplift charges to transactions at the NY/NE interface will lead to more efficient scheduling outcomes.

Average CTS Transactions by Month
During Peak Hours, Primary PJM and NE Interfaces



	Avg Price-Sensitive CTS Bid (MW)*		Avg Cleared CTS Bid (MW)*
	< $5	$5 - $10	
PJM	15	35	16
ISO-NE	357	152	213

* Includes both imports and exports.
Includes -$10 < bids < $30 (price sensitive).

Note: the quantities reported for December 2015 are based on data from December 15 to December 31 and are averaged over these 17 days.

POTOMAC ECONOMICS

Efficiency of CTS Scheduling with PJM and NE

- The next table examines the efficiency of CTS and shows the following quantities:
  - ✓ The percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule).
  - ✓ The average flow adjustment from the estimated hourly schedule.
  - ✓ The production cost savings that resulted from CTS, including:
    - Projected savings at scheduling time, which is the expected production cost savings at the time when RTC determines the interchange schedule.
    - Net over-projected savings, which is the portion of savings that was inaccurately projected because of PJM, NYISO, and ISO-NE price forecast errors.
    - Unrealized savings, which are not realized due to: a) real-time curtailment ; b) interface ramping; and c) price curve approximation (which applies only to the NY/NE CTS as NYISO transfers the 7-point supply curve forecasted by ISO-NE into a step-function curve for use in the CTS process).
    - Actual savings (= Projected – Over-projected - Unrealized).
  - ✓ Interface prices, which are forecasted prices at the time of RTC scheduling and actual real-time prices.
  - ✓ Price forecast errors, which show the average difference and the average absolute difference between actual and forecasted prices across the interfaces.

Efficiency of CTS Scheduling with PJM and NE

- The interchange schedules were adjusted during 91 percent of all quarter-hour intervals (from our estimated hourly schedule) at the NE/NY interface, higher than the 70 percent at the PJM/NY interface.
  - ✓ This was partly attributable to the fact that the amount of low-price CTS bids was substantially higher at the NE/NY interface than at the PJM/NY interface.
- Our analyses show that $1.6 million and $1.3 million of production cost savings were projected at the time of scheduling at the NE/NY and PJM/NY interfaces.
  - ✓ However, an estimated $0.6 million of savings were realized at the NE/NY interface and savings were estimated to be negative $0.3 million at the PJM/NY interface largely because of price forecast errors.
    - – It is important to note that our evaluation may under-estimate both projected and actual savings, because the estimated hourly schedules (by using actual CTS bids) may include some of the efficiencies that result from the CTS process.
    - – Nonetheless, the results of our analysis are still useful for identifying some of the sources of inefficiency in the CTS process.
- Projected savings were relatively consistent with actual savings when the forecast errors were moderate (e.g., less than $20/MWh), while the CTS process produced much more inefficient results when forecast errors were larger.
  - ✓ Therefore, improvements in the CTS process should focus on identifying sources of forecast errors.

Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM and NE Interfaces

			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			76%	14%	**91%**	62%	8%	**70%**
Average Flow Adjustment (MW)			-16 (Net) / 81 (Gross)	-18 (Net) / 104 (Gross)	**-17 (Net) / 85 (Gross)**	20 (Net) / 64 (Gross)	6 (Net) / 104 (Gross)	**18 (Net) / 69 (Gross)**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.9	$0.7	**$1.6**	$0.4	$0.9	**$1.3**
	Net Over-Projection by:	NY Market	-$0.02	-$0.2	**-$0.2**	-$0.1	-$0.6	**-$0.7**
		Neighbor Market	-$0.01	-$0.3	**-$0.3**	$0.001	-$0.3	**-$0.3**
	Unrealized Savings Due to:	Ramping	-$0.05	-$0.1	**-$0.1**	-$0.02	-$0.02	**-$0.04**
		Curtailment	-$0.01	-$0.01	**-$0.02**	-$0.002	-$0.5	**-$0.5**
		Price Curve	-$0.1	-$0.3	**-$0.4**	N/A	N/A	**N/A**
	Actual Savings		$0.7	-$0.1	**$0.6**	$0.3	-$0.6	**-$0.3**
Interface Prices ($/MWh)	NY Market	Actual	$21.64	$49.94	**$26.09**	$18.25	$54.06	**$22.41**
		Forecast	$22.40	$35.49	**$24.46**	$18.45	$35.63	**$20.45**
	Neighbor Market	Actual	$22.60	$34.63	**$24.49**	$20.84	$35.64	**$22.56**
		Forecast	$23.05	$29.47	**$24.06**	$21.21	$36.56	**$23.00**
Price Forecast Errors ($/MWh)	NY Market	Fcst. - Act.	$0.76	-$14.45	**-$1.63**	$0.20	-$18.43	**-$1.97**
		Abs. Val.	$4.67	$43.72	**$10.81**	$3.80	$48.59	**$9.01**
	Neighbor Market	Fcst. - Act.	$0.46	-$5.16	**-$0.43**	$0.38	$0.92	**$0.44**
		Abs. Val.	$4.26	$35.90	**$9.23**	$2.88	$38.94	**$7.07**

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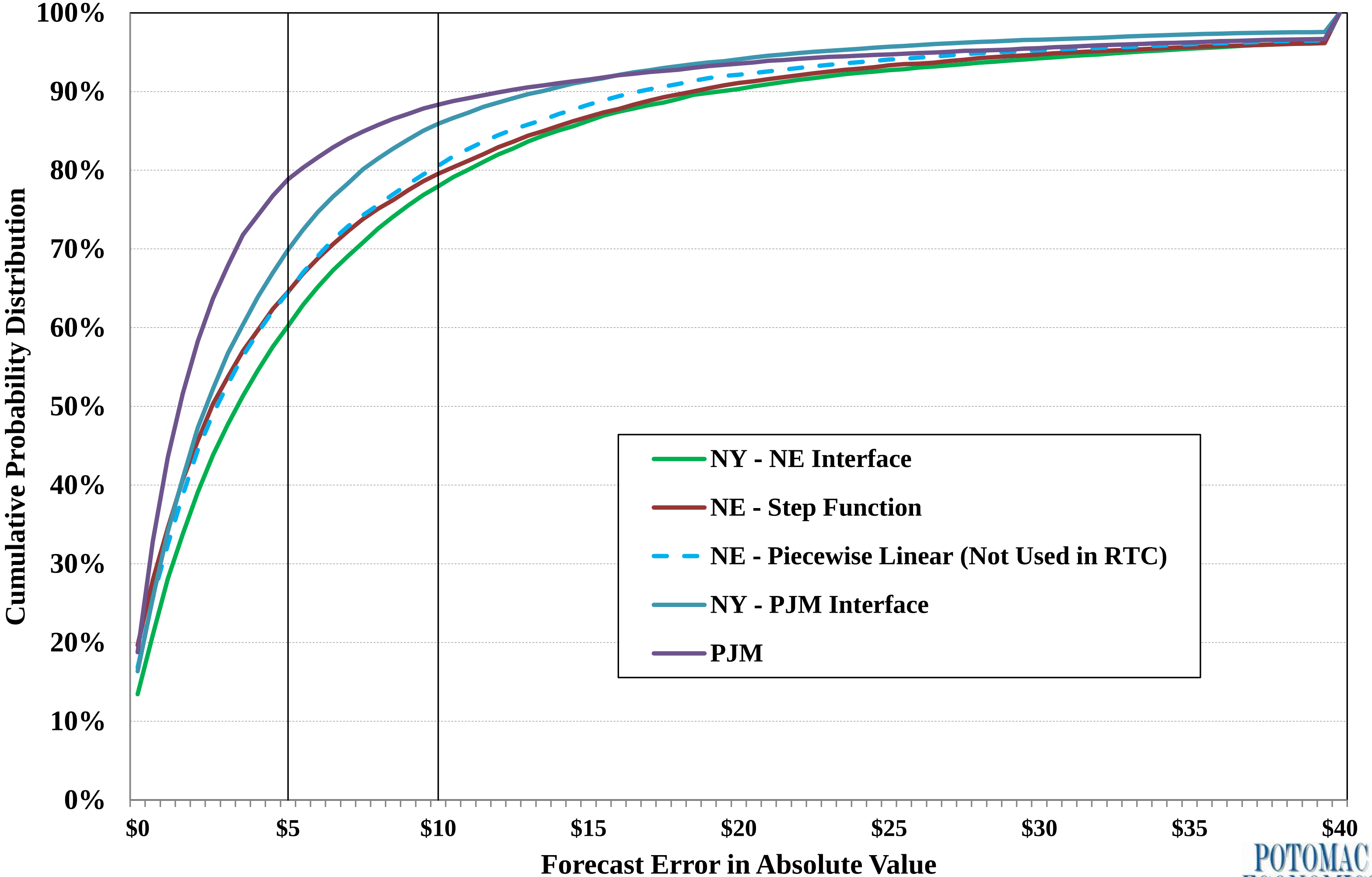
Price Forecast Errors Under CTS

- The next figure examines the performance of price forecasting in the CTS by the three ISOs by comparing the cumulative distributions of their forecasting errors.
  - ✓ The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast price and actual price.
  - ✓ The figure shows the ISO-NE forecast error in two ways:
    - Based on the piece-wise linear curve that is produced by its forecasting model; and
    - Based on the step-function curve that the NYISO model uses to approximate the piece-wise linear curve.
- The performance of the price forecast was generally better at the PJM/NY interface than at the NE/NY interface during the first quarter of 2016. In particular:
  - ✓ Price forecast errors were less than $5/MWh in 70 to 80 percent of intervals at the PJM/NY interface compared to 60 to 65 percent at the NE/NY interface; and
  - ✓ Price forecast errors were less than $10/MWh in 86 to 88 percent of intervals at the PJM/NY interface compared to around 80 percent at the NE/NY interface.
  - ✓ The price-elasticity of supply is normally greater at the PJM/NY interface than at the NE/NY interface because of the larger size of the PJM market.

Price Forecast Errors Under CTS

- Price forecasting by PJM and ISO-NE was generally more accurate than forecasting by the NYISO at each interface.
  - ✓ This is consistent with the general pattern of RT price volatility, which is higher in New York than the neighboring markets (and which we evaluate in the annual State of the Market Reports).
- In addition, price forecasting accuracy based on NYISO's approximation of ISO-NE's supply curve was similar to the accuracy of the piecewise linear curve in the 80 percent of intervals when the forecast error was less than \$10/MWh.
  - ✓ However, the step-function approximation leads to more frequent large (i.e., >\$20/MWh) forecast errors.
- Price forecasting was generally better at the PJM border than at the NE border.
  - ✓ This also reflects the generally lower price levels at the PJM border.
  - ✓ However, we estimated higher production cost savings at the NE/NY interface because intra-hour interchange adjustments were more frequent and larger.
    - – This was due in part to more low-priced CTS bids that were available to respond to moderate price differentials between NE and NY.

Distribution of Price Forecast Errors Under CTS
Primary PJM and NE Interfaces



POTOMAC ECONOMICS

Day-Ahead and Real-Time Transmission Congestion

Congestion Patterns, Revenues, and Shortfalls

- The next four 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 net day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - – Shortfalls (or surpluses) arise when the TCCs on a path exceed (or is below) the transfer capability of the path modeled in the DA market in 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 figure examines in detail the value and frequency of day-ahead and real-time congestion along major transmission paths by quarter.
  - ✓ 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 third and fourth figures show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.
- Congestion is evaluated along major transmission paths that include:
  - ✓ West Zone Lines: Primarily 230 kV transmission constraints in the West Zone.
  - ✓ West to Central: Including transmission constraints in the Central Zone and interfaces from West to Central.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.

Day-Ahead and Real-Time Congestion

(cont. from prior slide)

- ✓ NYC Lines: Including lines into and within the NYC 345 kV system, lines leading into and within NYC load pockets, and 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 $125 million this quarter, down 55 percent from the first quarter of 2015. Key contributors to the reduction were:
  - ✓ Decreased fuel costs, which reduced re-dispatch costs to manage congestion (in areas other than “West Zone”) (see slide 12); and
  - ✓ Lower load levels and less frequent peaking conditions, which generally resulted in less frequent congestion across the system (see slide 11);
  - ✓ However, transmission outages greatly reduced transfer capability: a) across the Central-East interface throughout the quarter; and b) on the 230 kV system in the West Zone in March (see slide 57).

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 2016:
  - ✓ Central to East (63% DAM, 47% RTM)
    - This congestion rose during cold weather as a result of higher natural gas prices and higher gas spreads between regions.
    - Although congestion value decreased more than 60 percent from the first quarter of 2015, the frequency of congestion increased, reflecting reduced transfer capability because of more transmission outages this quarter.
  - ✓ West Zone (18% DAM, 24% RTM)
    - Unlike other areas, congestion in the West Zone rose from the first quarter of 2015.
    - Over 90 percent of this occurred in March because of significant transmission outages after the Huntley units retired. The outages were necessary to install new transmission facilities that will help relieve congestion on the 230 kV lines, but this work was not completed until May.
- Congestion into Long Island and across the primary NE interface fell substantially from the first quarter of 2015.
  - ✓ These changes resulted from lower exports to ISO-NE and higher imports into Long Island from ISO-NE (see slide 42).

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Day-Ahead Congestion Shortfalls

- Transmission outages accounted for a large share of shortfalls – roughly $18 million (out of $24 million) was allocated to the responsible TO in 2016-Q1.
  - ✓ Nearly $11 million of shortfalls accrued on the Central-East interface, most of which was attributable to the following transmission outages:
    - – The Fraser-Coopers 345 line was out of service from early January to early March.
    - – The Edic-New Scotland 345 line was out of service in most of March.
    - – The Ramapo PARs were out of service in the last week of February.
  - ✓ Another $11 million of shortfalls accrued on the 230 kV lines in the West Zone.
    - – Multiple 230 kV lines along the Niagara-Packard-Sawyer-Huntley path were out of service in March, accounting for roughly $5 million of shortfalls.
    - – Inconsistencies between the TCC auctions and the DAM in the assumed amount of 115 kV Niagara generation accounted for $3.6 million of shortfalls.
    - – A large portion of the remaining nearly $3 million of shortfalls was attributable to different loop flow assumptions between the TCC auction and the DAM.
  - ✓ Roughly $1 million of shortfalls accrued on the Moses-South interface on two days in March because multiple lines at the Massena Bus were out of service, which greatly reduced the interface transfer capability.
  - ✓ An additional $2.6 million of shortfalls accrued in NYC, primarily in the Freshkills load pocket during March because of Goethels 345 kV breaker outages.

Balancing Congestion Shortfalls

- Long Island lines accounted for $3.5 million of shortfalls, most of which accrued on the E. Garden City-Valley Stream 138 kV line on three days (Feb. 1, 16, & 18).
  - ✓ The line was scheduled to be OOS on these days. Under this outage condition:
    - – The only free-flowing lines into the Valley stream load pocket are secured by the TO rather than the NYISO, so the DAM does not identify a binding constraint and schedules infeasible amounts of power to flow into the pocket.
    - – Consequently, the line was retained in service in RT on these days (but the DA scheduled flows into the pocket were still infeasible).
  - ✓ The differences between the DA scheduled assumptions on the 901/903 lines and their actual flows in RT contributed $2 million of shortfalls as well.
- West Zone lines accounted for a total of nearly $2.5 million of shortfalls, most of which accrued on the last four days in March.
  - ✓ Large deviations on ABC/JK wheel (particularly under-delivery from NY to PJM on the JK lines) contributed an estimated $3 million to shortfalls (see slide 65).
  - ✓ Differences between the assumed amount of 115 kV Niagara generation in the DAM and the actual amount contributed $3 million to surpluses (see slide 71).
  - ✓ Among the other factors that accounted for an additional $2.5 million of shortfalls, unexpected changes in loop flows was a key contributor (see slide 68).
- The operation of Ramapo PARs contributed over $5 million of surpluses on the Central-East interface (see slide 65).

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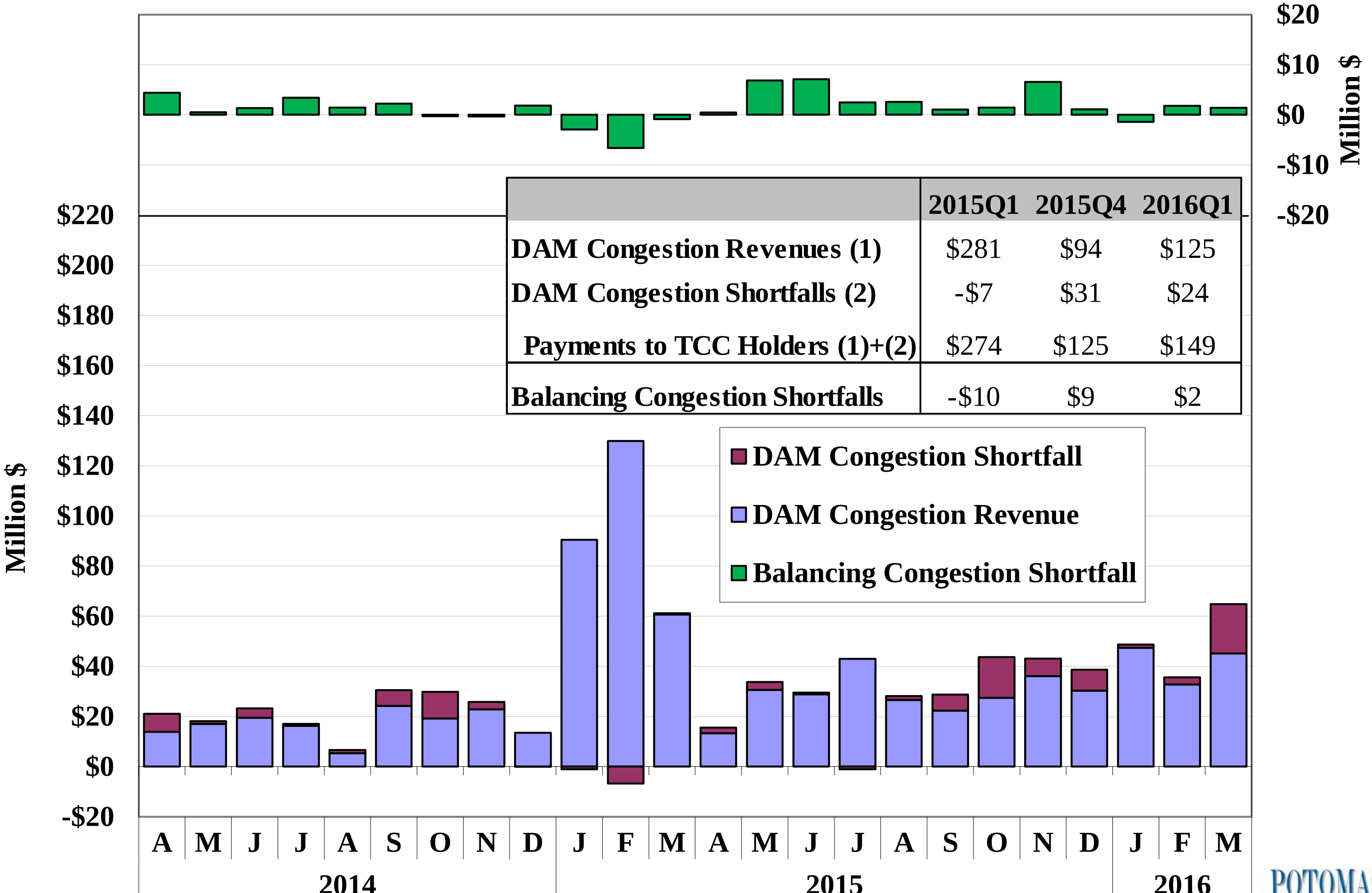
Congestion Revenues and Shortfalls by Month



	2015Q1	2015Q4	2016Q1
DAM Congestion Revenues (1)	$281	$94	$125
DAM Congestion Shortfalls (2)	-$7	$31	$24
Payments to TCC Holders (1)+(2)	$274	$125	$149
Balancing Congestion Shortfalls	-$10	$9	$2

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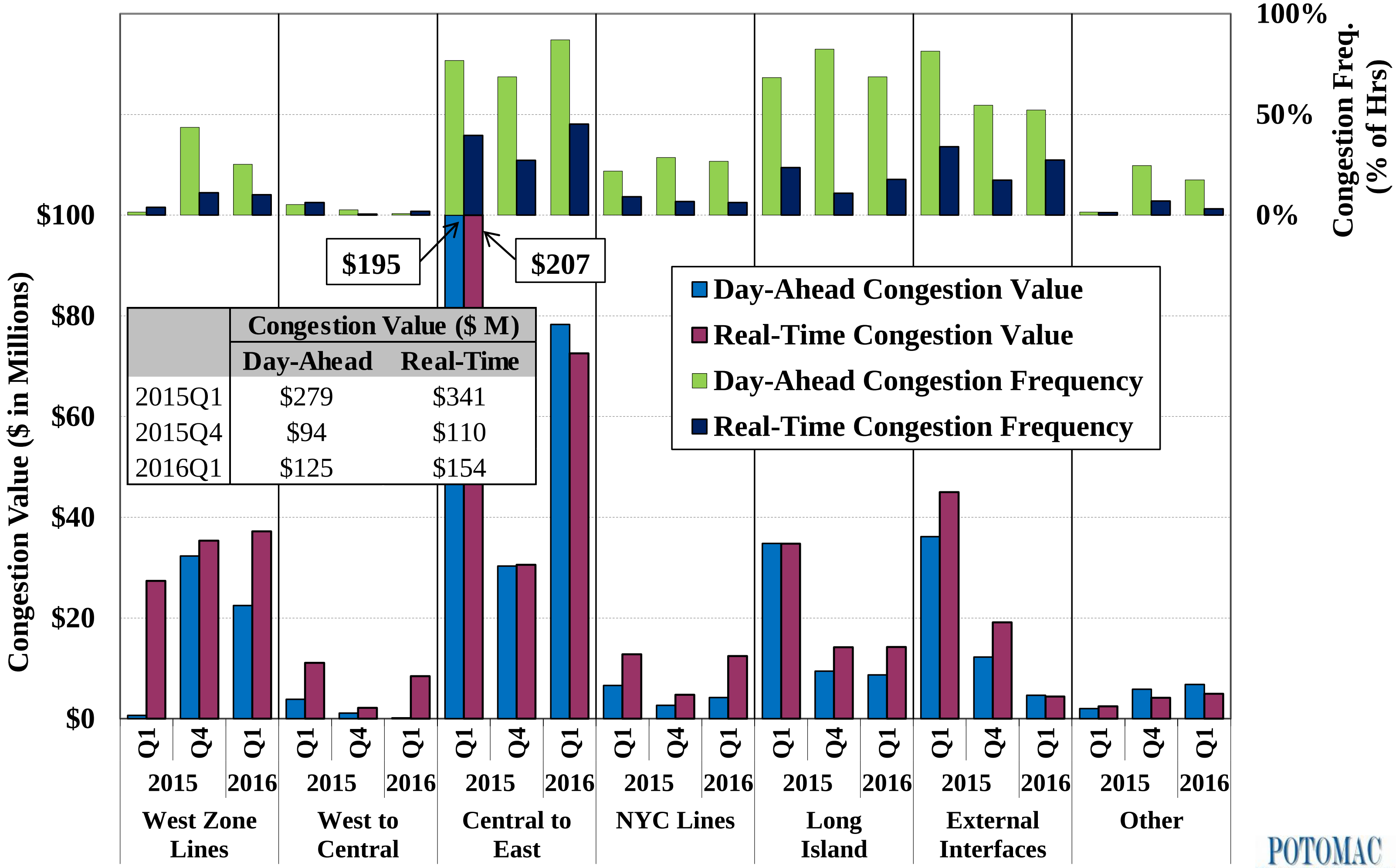
DA and RT Congestion Value and Frequency by Transmission Path



	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2015Q1	$279	$341
2015Q4	$94	$110
2016Q1	$125	$154

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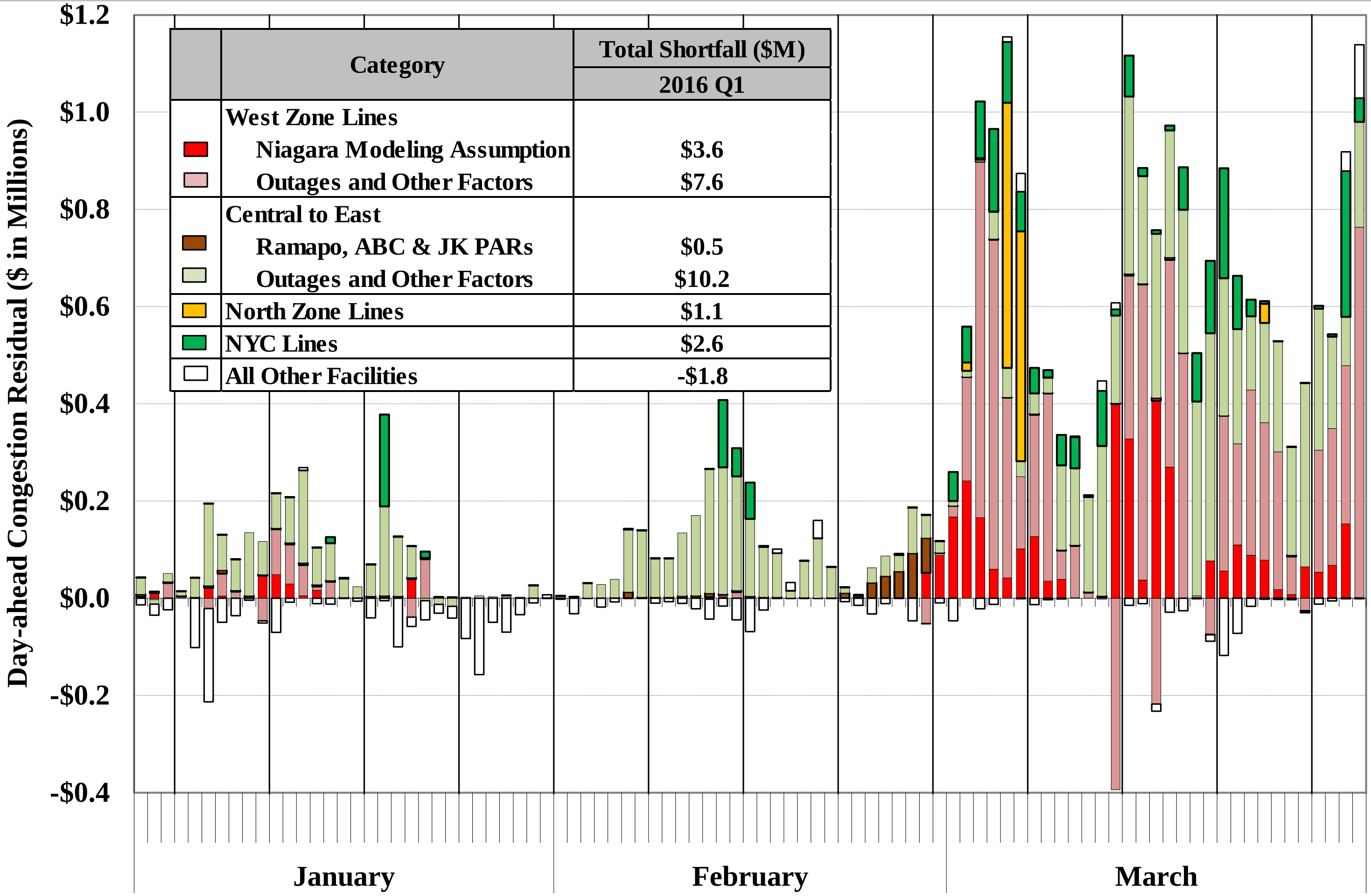
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Note: "Niagara Modeling Assumption" estimates the shortfalls resulted from differences in assumed generation at the Niagara 115 kV Buses between TCC and DAM (for DAMCR) and between DAM and RT actual (for BMCR).

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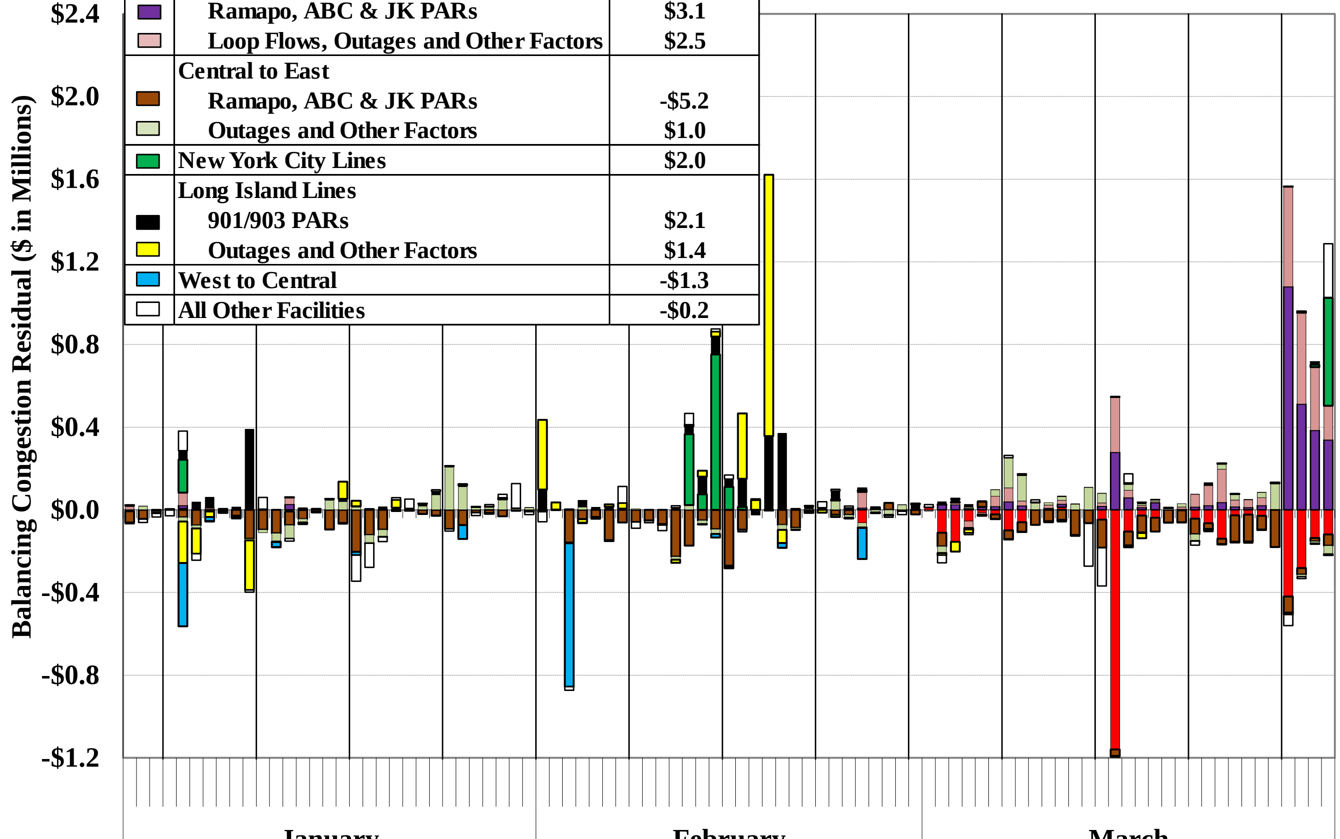
Balancing Congestion Shortfalls by Transmission Facility

	Category	Total Shortfall ($M)
	West Zone Lines	
red	Niagara Modeling Assumption	-$3.2
purple	Ramapo, ABC & JK PARs	$3.1
pink	Loop Flows, Outages and Other Factors	$2.5
	Central to East	
brown	Ramapo, ABC & JK PARs	-$5.2
light green	Outages and Other Factors	$1.0
green	New York City Lines	$2.0
	Long Island Lines	
black	901/903 PARs	$2.1
yellow	Outages and Other Factors	$1.4
blue	West to Central	-$1.3
white	All Other Facilities	-$0.2



Note: The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values.

Operations under M2M with PJM

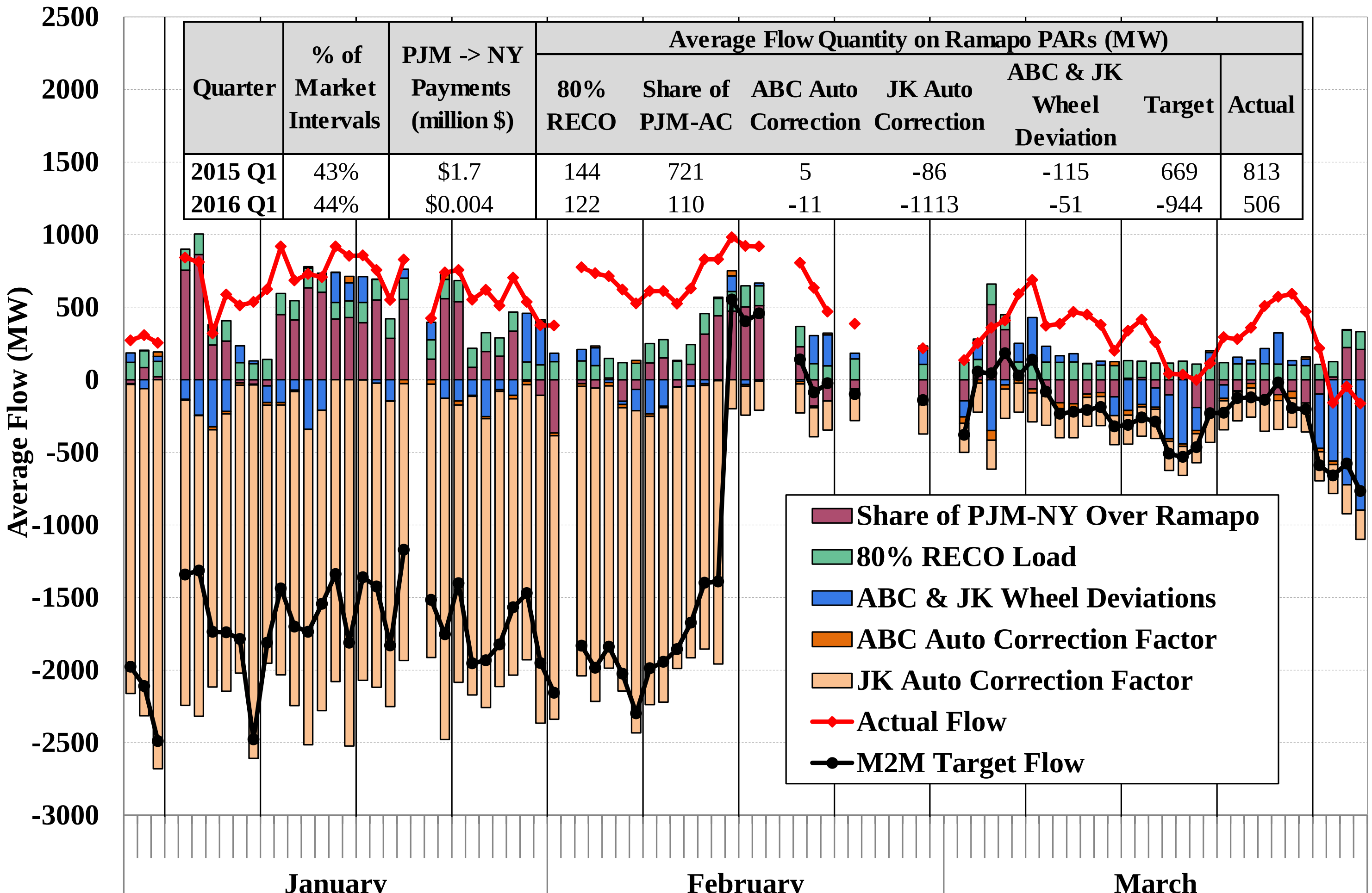
- Coordinated congestion management between NYISO and PJM ("M2M") includes two types of coordination:
  - ✓ Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.
  - ✓ 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 following figure evaluates the operation of Ramapo PARs this quarter, which compares the actual flows on Ramapo PARs with their M2M operational targets.
  - ✓ 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.
    - 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.
    - ABC & JK Auto Correction Factors – These represent "pay-back" MW generated from cumulative deviations on the ABC or JK interface from prior days.
- The figure shows these average quantities over intervals when M2M constraints for Ramapo Coordination were binding on a daily basis (excluding days with fewer than 12 binding intervals).

Operations under M2M with PJM

- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred in 44 percent of intervals, comparable to the first quarter of 2015.
  - ✓ However, the M2M Target Flows were greatly reduced from a year ago, causing average actual flows to exceed the Target Flow by 1,450 MW and resulting in a very small amount of M2M payments (~$4K) from PJM to NY this quarter.
  - ✓ This was due primarily to large cumulative negative deviations on the JK PARs, which reached thousands of MWs before they were reset in mid-February.
- The operation of the Ramapo PARs under M2M with PJM has provided significant benefit to the NYISO in managing congestion on coordinated flow gates.
  - ✓ The balancing congestion surpluses resulted from this operation on the Central-East interface indicate that it reduced production costs and congestion.
  - ✓ However, these were partly offset by shortfalls, an indication of PAR operations that increase production costs and congestion on the West Zone lines, which are currently not under the M2M JOA.
    - – The NYISO improved its operating practice in November 2015 to limit the use of Ramapo Coordination process to periods when the NYISO does not expect constraints in Western New York to be active.
    - – Nonetheless, it will be difficult to optimize the operation of the Ramapo line without a model to forecast the impacts of tap adjustments in RT.

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

Quarter	% of Market Intervals	PJM -> NY Payments (million $)	Average Flow Quantity on Ramapo PARs (MW): 80% RECO	Share of PJM-AC	ABC Auto Correction	JK Auto Correction	ABC & JK Wheel Deviation	Target	Actual
2015 Q1	43%	$1.7	144	721	5	-86	-115	669	813
2016 Q1	44%	$0.004	122	110	-11	-1113	-51	-944	506



Note: This chart does not show the days during which M2M constraints were binding in less than 12 intervals.

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West Zone Congestion and Clockwise Loop Flows

- Unscheduled clockwise loop flows contribute to congestion on transmission paths in Western New York, particularly in the West Zone.
- The following figure illustrates how and to what extent unscheduled loop flows affected congestion on West Zone 230 kV constraints in the first quarter of 2016.
  - ✓ The bottom portion of the chart shows the average amount of:
    - Unscheduled loop flows (the blue bar); and
    - Changes in unscheduled loop flows from the prior 5-minute interval (the red line) during congested intervals in real-time. The congested intervals are grouped based on different ranges of congestion values.
    - For comparison, these numbers are also shown for the intervals with no West Zone congestion.
  - ✓ In the top portion of the chart,
    - The bar shows the portion of total congestion values that each congestion value group accounted for during the quarter; and
    - The number in each bar indicates how frequently each congestion value group occurred during the quarter.

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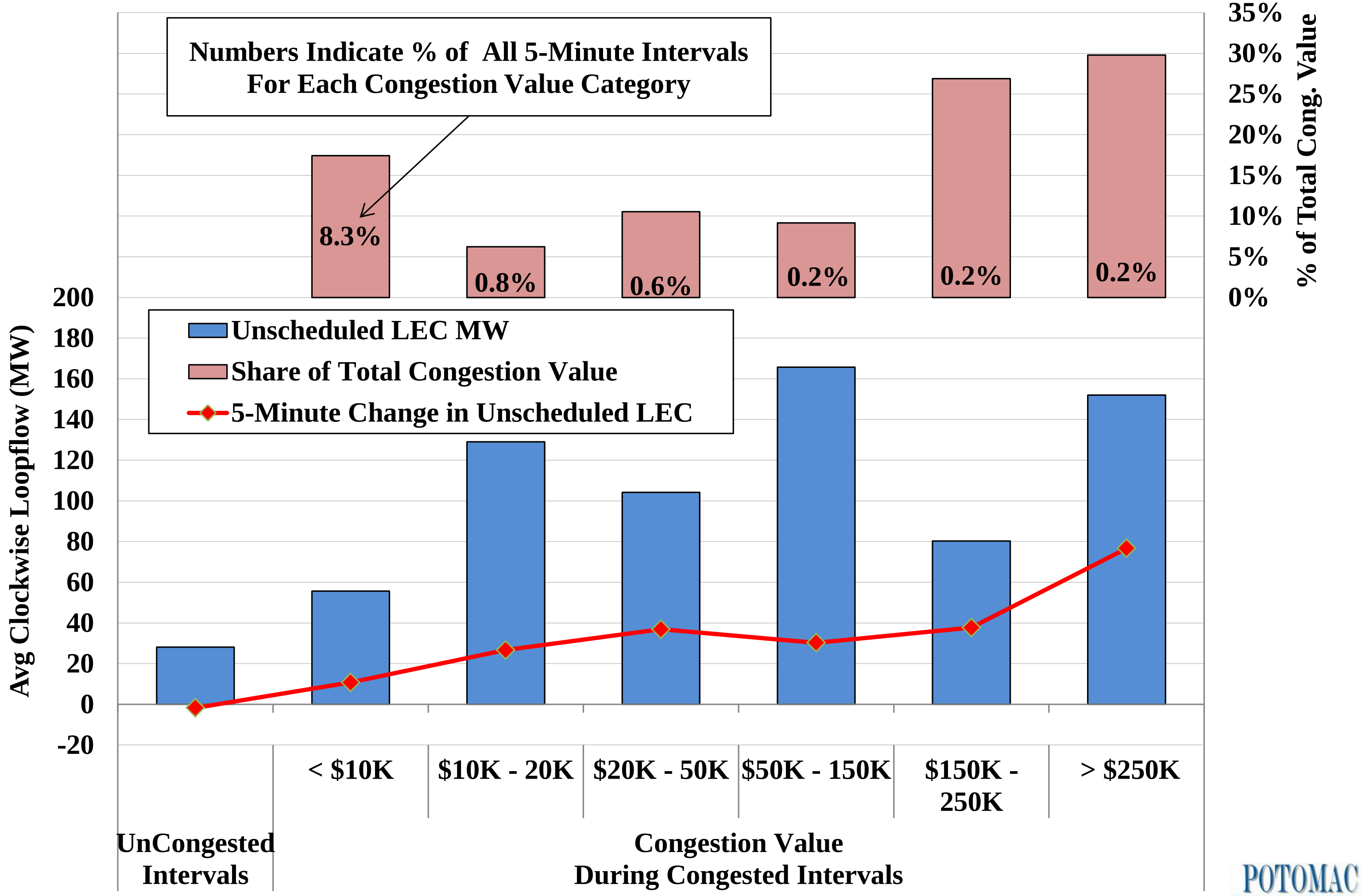
West Zone Congestion and Clockwise Loop Flows

- A correlation was apparent between the severity of West Zone congestion (measured by congestion value) and the magnitude of unscheduled loop flows and the occurrence of sudden changes from the prior interval.
- There was no West Zone congestion in 90 percent of intervals in the quarter.
  - ✓ Both the amount of clockwise loop flows and the change from the prior interval were low in these intervals.
- However, West Zone congestion was more prevalent when loop flows arose or happened to swing rapidly in the clockwise direction.
  - ✓ The congestion value on the West Zone constraints exceeded $20,000:
    - This included just 1.2 percent of all intervals, but these intervals accounted for 76 percent of the total congestion value in the West Zone.
    - In these intervals, unscheduled clockwise loop flows averaged nearly 120 MW and clockwise changes in unscheduled loop flows averaged 45 MW.
  - ✓ The congestion value on the West Zone constraints exceeded $250,000:
    - This included just 0.2 percent of all intervals, but these intervals accounted for 30 percent of the total congestion value in the West Zone.
    - In these intervals, unscheduled clockwise loop flows averaged over 150 MW and clockwise changes in unscheduled loop flows averaged nearly 80 MW.

West Zone Congestion and Clockwise Loop Flows



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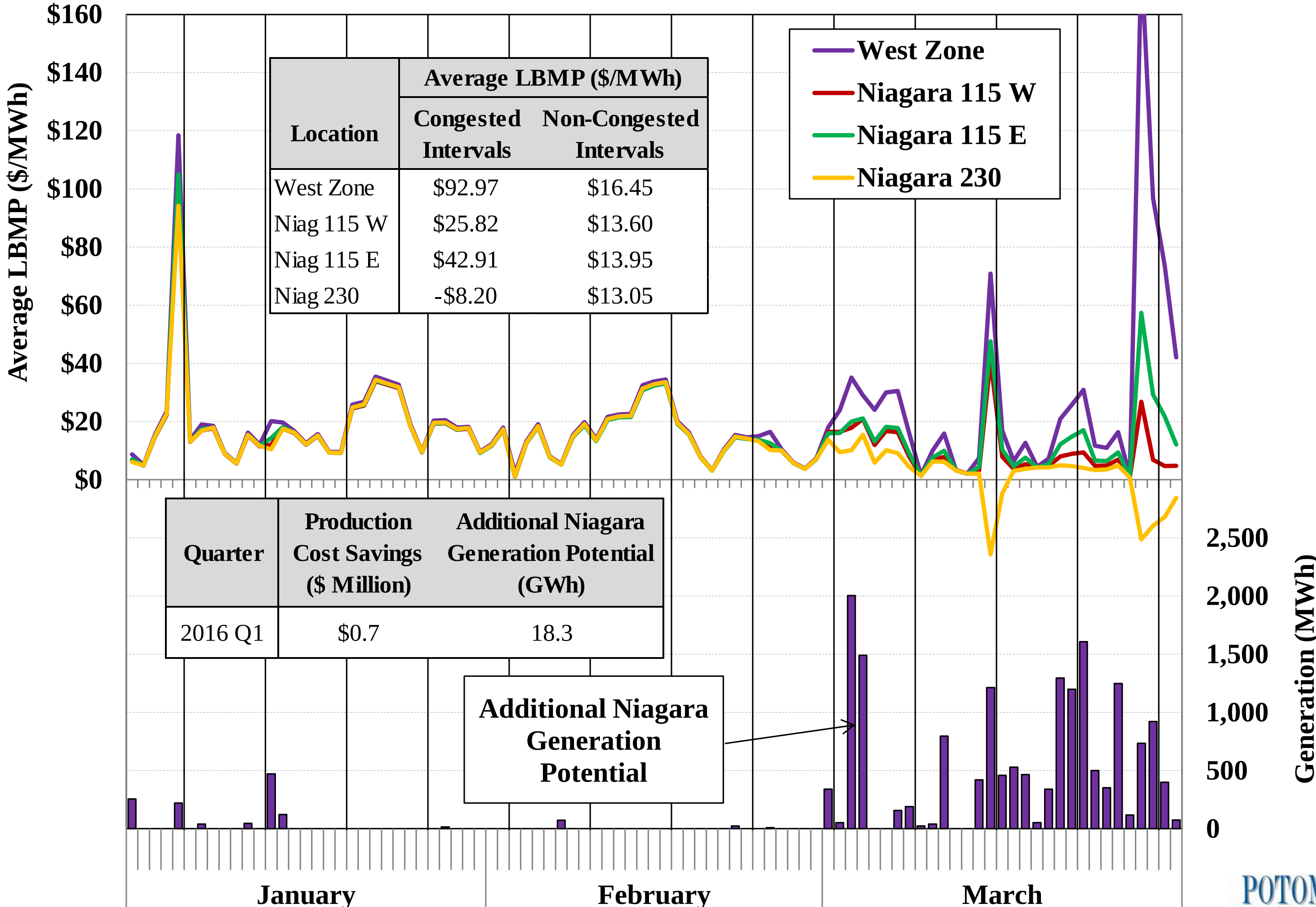
West Zone Congestion and Niagara Generation

- Transmission constraints on the 230kV network in the West Zone have become more frequent in recent years, limiting the flow of power towards Eastern NY.
  - ✓ Niagara units on the 115kV system tend to relieve these constraints, while ones on the 230kV system exacerbate this congestion.
  - ✓ These impacts are not considered by the optimization engine that schedules generation at the Niagara plant.
    - – The optimization treats Niagara as a single bus for pricing and dispatch.
    - – However, NYISO procedures use manual instructions to shift generation among the individual units at the Niagara plant to alleviate congestion.
- The next figure estimates the remaining benefits that might have occurred if the distribution of generation at Niagara was optimized in congested intervals.
  - ✓ Production Cost Savings – Estimated savings from shifting generation from 230kV units to 115kV units that have available head room at the Niagara plant.
  - ✓ Additional Niagara Generation Potential – Additional Niagara generation (in MWhs) that would be deliverable if output from the 115kV units was maximized.
  - ✓ The figure shows average estimated LBMPs for the West Zone, Niagara 230 kV Bus, Niagara East 115 kV Bus, and Niagara West 115 kV Bus – This illustrates the impact of shifting generation among individual Niagara units.

West Zone Congestion and Niagara Generation

- Although LBMPs at the Niagara 115 kV and 230 kV Buses were very similar when West Zone congestion was not present, LBMP differences were significant during periods of congestion. In the first quarter of 2016:
  - ✓ West Zone 230 kV congestion occurred in roughly 7 percent of all intervals; and
  - ✓ On average, LBMPs were \$34 to \$51/MWh higher at the Niagara 115 kV Buses than at the Niagara 230 kV Buses during these intervals.
- We estimate that if the distribution was fully optimized in congested intervals (while considering both 115kV and 230kV constraints in the West Zone):
  - ✓ Production costs would have been reduced by an additional \$0.7 million in the first quarter of 2016 (assuming no changes in the constraint shadow costs).
    - However, this does not consider the upgrade costs required to fully optimize.
  - ✓ An additional 18 GWh (or 120 MW on average) of Niagara generation would have been deliverable. This would have had significant LBMP effects outside the west zone, since sudden reductions in Niagara output sometimes require expensive generation to be dispatched in Eastern New York.
- In May 2016, the ISO implemented a modeling change for Niagara. A composite (i.e., generation-weighted) shift factor is now used for pricing and scheduling.
  - ✓ Previously, the Niagara shift factor was based on the location of the 230 kV units.
  - ✓ We will evaluate the effects of this change in future reports.

West Zone Congestion and Niagara Generation
First Quarter of 2016



Location	Average LBMP ($/MWh) Congested Intervals	Average LBMP ($/MWh) Non-Congested Intervals
West Zone	$92.97	$16.45
Niag 115 W	$25.82	$13.60
Niag 115 E	$42.91	$13.95
Niag 230	-$8.20	$13.05

Quarter	Production Cost Savings ($ Million)	Additional Niagara Generation Potential (GWh)
2016 Q1	$0.7	18.3

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Supplemental Commitments, OOM Dispatch, and Uplift Charges

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- 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.

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Supplemental Commitment and OOM Dispatch: Chart Descriptions

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

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Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results

- An average of 273 MW of capacity was committed for reliability in the first quarter of 2016, down 40 percent from the first quarter of 2015.
  - ✓ The decrease reflected reduced local needs due to lower load levels in 2016 Q1.
  - ✓ Of the capacity committed for reliability in this quarter, 70 percent was in NYC, 21 percent was in Western NY, and 8 percent was in Long Island.
- Reliability commitments in West NY averaged 60 MW this quarter, down 66 percent from the first quarter of 2015.
  - ✓ SRE commitments in the North Zone have occurred much less frequently since March 2014 because transmission upgrades greatly reduced the need to commit generation to maintain reliability in this region.
    - SRE commitments still occur when certain transmission outages are present.
  - ✓ Several coal-fired and gas-fired units were often needed for local voltage support and/or to manage post-contingency flows on 115kV facilities.
    - These commitments were reduced by transmission upgrades in Western NY, which allowed the last Dunkirk unit to retire at the end of December.
    - In the first quarter of 2016, the vast majority of DARU commitments occurred in the Central Zone at the Cayuga (Milliken) plant.

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Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results

- Reliability commitments rarely occurred in Long Island this quarter.
  - ✓ However, some DARU commitments occurred in January and February to maintain reliability of the 69 kV system in the Valley Stream load pocket and near the Holtsville station.
  - ✓ SRE commitments were mainly done to keep steam units online during overnight hours.
- Reliability commitments in New York City averaged 192 MW this quarter, down 30 percent from the first quarter of 2015.
  - ✓ Reliability commitments in NYC are frequently driven by transmission and generation outages. Fewer transmission and generation outages led to fewer DARU commitments this quarter.
  - ✓ Most reliability commitments were made to satisfy the N-1-1 thermal requirements in the Astoria West/Queensbridge load pocket.
  - ✓ Supplemental commitment for contingencies associated with a loss of gas on cold days fell from the first quarter of 2015 as weather conditions moderated relative to the prior year.

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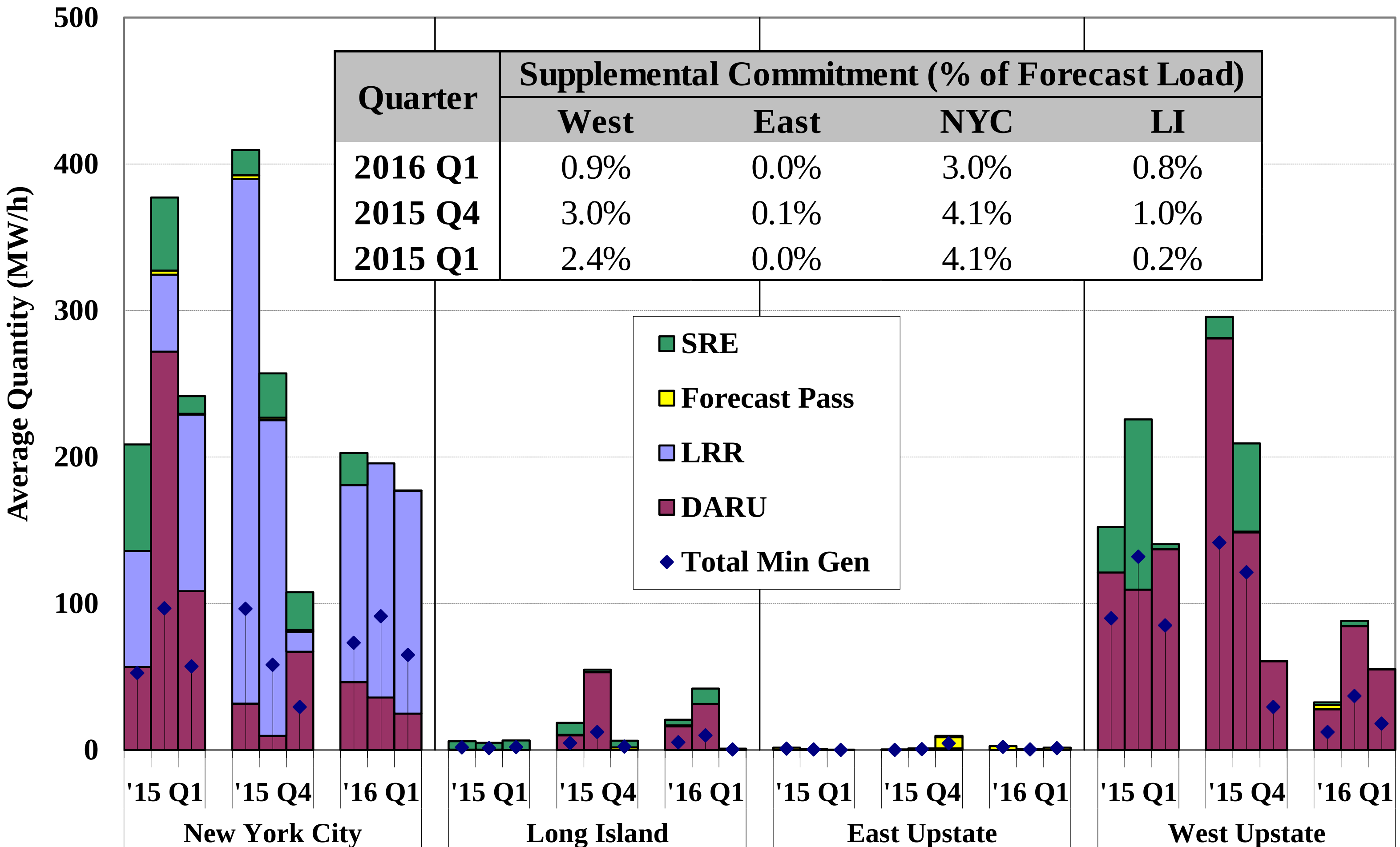
Supplemental Commitment and OOM Dispatch: OOM Dispatch Results

- 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 167 station-hours, down 85 percent from the first quarter of 2015 partly because of reduced load levels.
- The reduction in Western NY was primarily attributable to transmission upgrades that allowed the retirement of the last Dunkirk unit at the end of December, which was frequently OOMed in the past for local reliability needs.
  - ✓ High OOM levels in March 2015 were from frequent OOM dispatch of the Dunkirk unit to manage congestion on the Gardenville-to-Dunkirk 115kV line.
- Nonetheless, the Niagara facility was often manually instructed to shift output among its units to secure certain 115kV and/or 230 kV transmission constraints.
  - ✓ In the first quarter of 2016, this manual shift was required in 178 hours to manage 115 kV constraints and in 293 hours to manage 230 or 345 kV constraints.
  - ✓ OOM dispatch may increase because of transmission upgrades made in May 2016 (to allow the Huntley units to retire). The new facilities tend to shift flows from certain 230kV lines to other parallel facilities, including 115kV facilities.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2016 Q1	0.9%	0.0%	3.0%	0.8%
2015 Q4	3.0%	0.1%	4.1%	1.0%
2015 Q1	2.4%	0.0%	4.1%	0.2%

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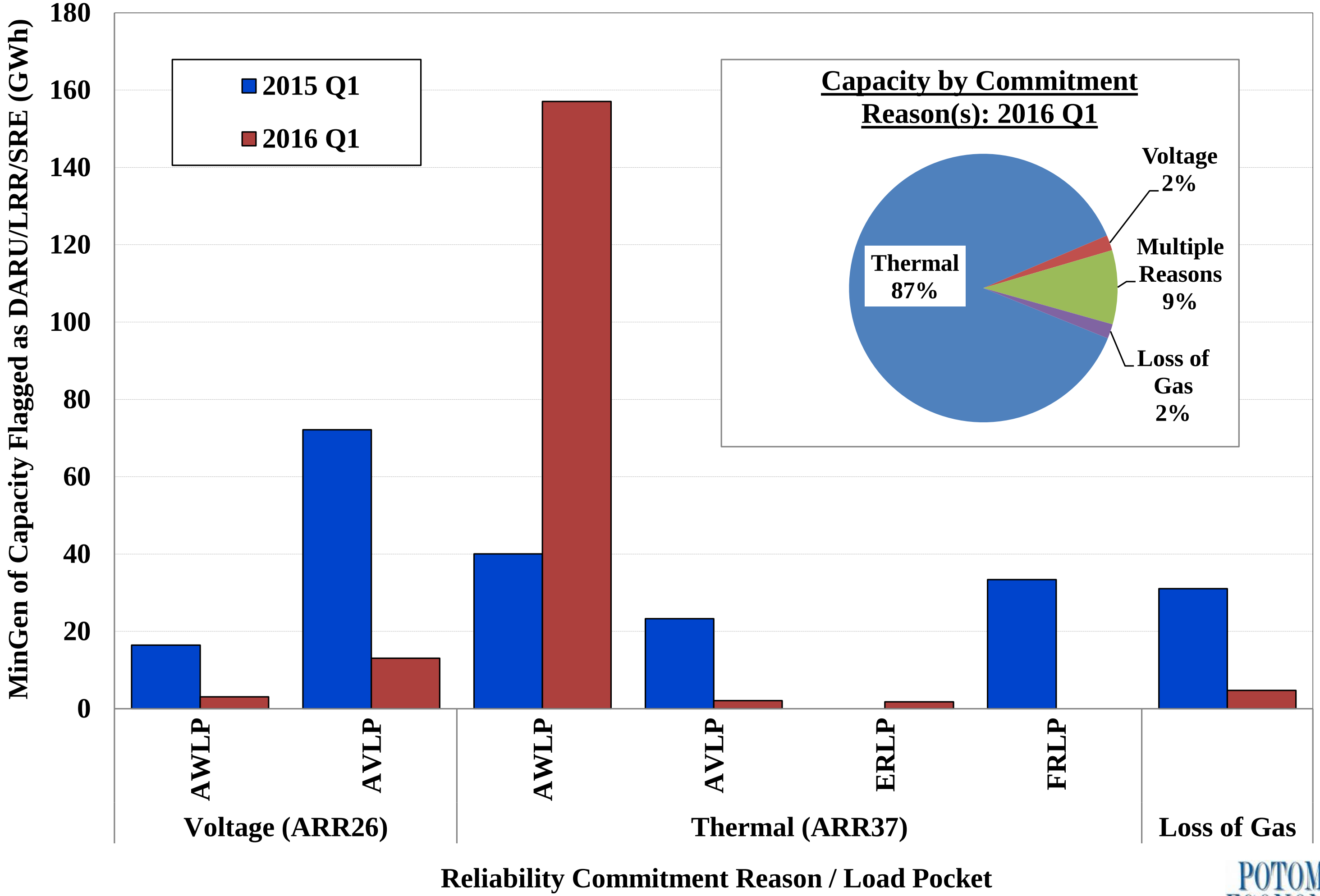
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



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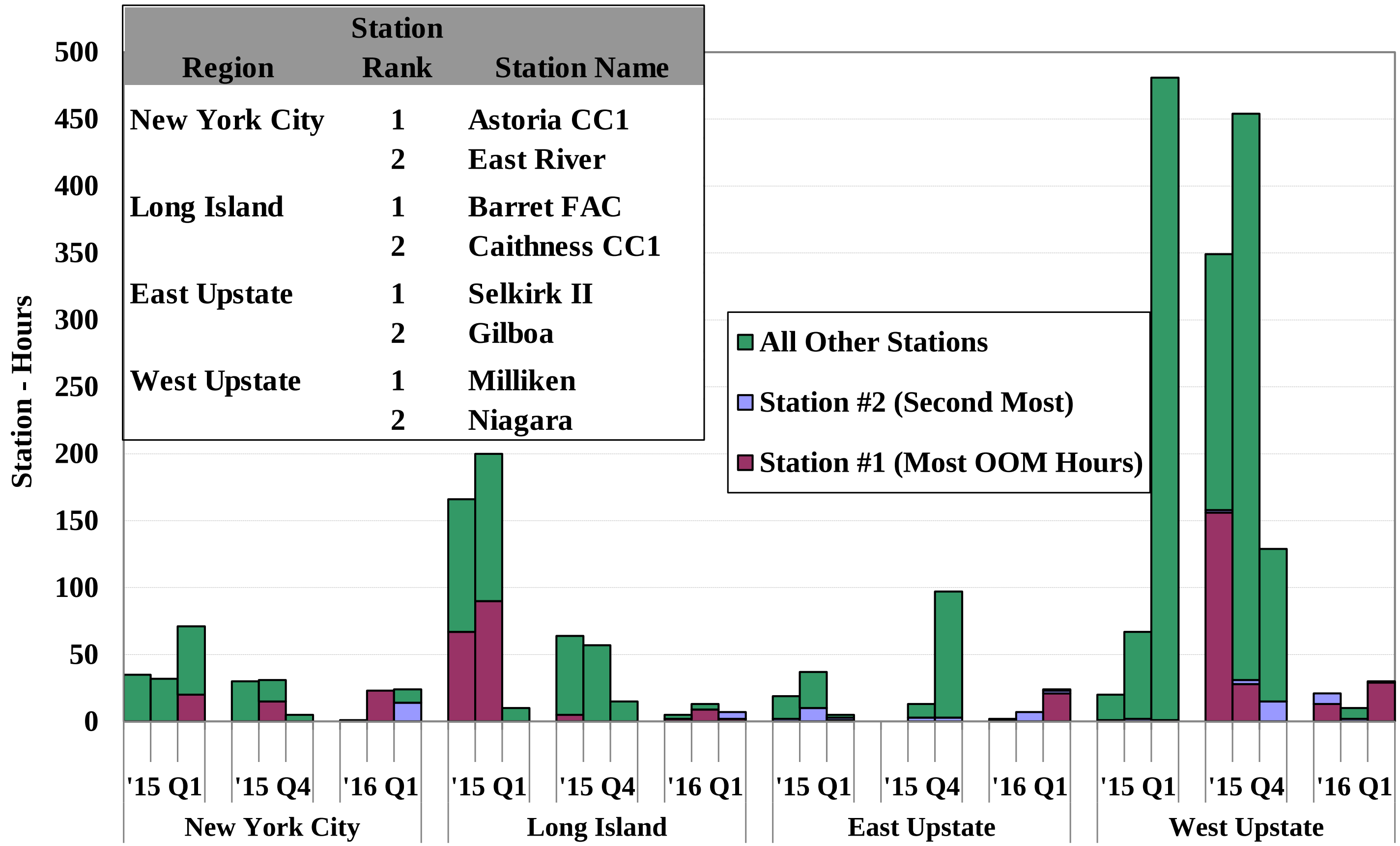
Frequency of Out-of-Merit Dispatch by Region by Month

Region	Station Rank	Station Name
New York City	1	Astoria CC1
	2	East River
Long Island	1	Barret FAC
	2	Caithness CC1
East Upstate	1	Selkirk II
	2	Gilboa
West Upstate	1	Milliken
	2	Niagara



Note: The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 383 hours in 2015-Q1, 840 hours in 2015-Q4, and 337 hours in 2016-Q1. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

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 gas turbines that are scheduled economically, or units committed or dispatched OOM for bulk system reliability whose real-time market revenues do not cover their as-offered costs.
    - Day Ahead Margin Assurance Payment ("DAMAP"): For generators that incur losses because they are dispatched below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.
  - ✓ Four categories of local reliability uplift are allocated to the local TO:
    - Day Ahead: From Local Reliability Requirements ("LRR") and Day-Ahead Reliability Unit ("DARU") commitments.
    - Real Time: From Supplemental Resource Evaluation ("SRE") commitments and Out-of-Merit ("OOM") dispatched units.
    - Minimum Oil Burn Program: Covers spread between oil and gas prices when generators burn oil to satisfy NYC gas pipeline contingency reliability criteria.
    - DAMAP: For units that are dispatched OOM for local reliability reasons.
  - ✓ The first figure shows these seven categories on a daily basis during the quarter.
  - ✓ The second figure summarizes uplift costs by region on a monthly basis.

Uplift Costs from Guarantee Payments: Results

- Guarantee payments totaled $7 million this quarter, down 68 percent from the first quarter of 2015. The reduction was consistent with:
  - ✓ Decreased supplemental commitment and OOM dispatches; and
  - ✓ Lower natural gas prices, which decreased the commitment costs of gas-fired units.
- Local uplift in Western NY totaled $1.4 million, accounting for 20 percent of total guarantee uplift this quarter.
  - ✓ Nearly all of the local uplift was paid to several units that were committed and/or OOMed to manage congestion on the 115 kV system (see slide 80).
- DAMAP uplift rose to $1 million on January 5 when GTs scheduled for 10-minute reserves in the DAM had to buy out during RT reserve shortages because they were started to provide energy. (see slide 19 for more discussion)
  - ✓ Over 1 GW of 10-minute GTs were started following import curtailments and a large generator trip, leading to 10-minute reserve shortages in Eastern NY. DAMAP was high in intervals when 10-minute reserve prices exceeded LBMPs.
  - ✓ Most were decommitted by RTC at the end of their minimum run time, leading to statewide 10-minute reserve shortages. DAMAP was high because most GTs cannot provide reserves immediately after being shut down.

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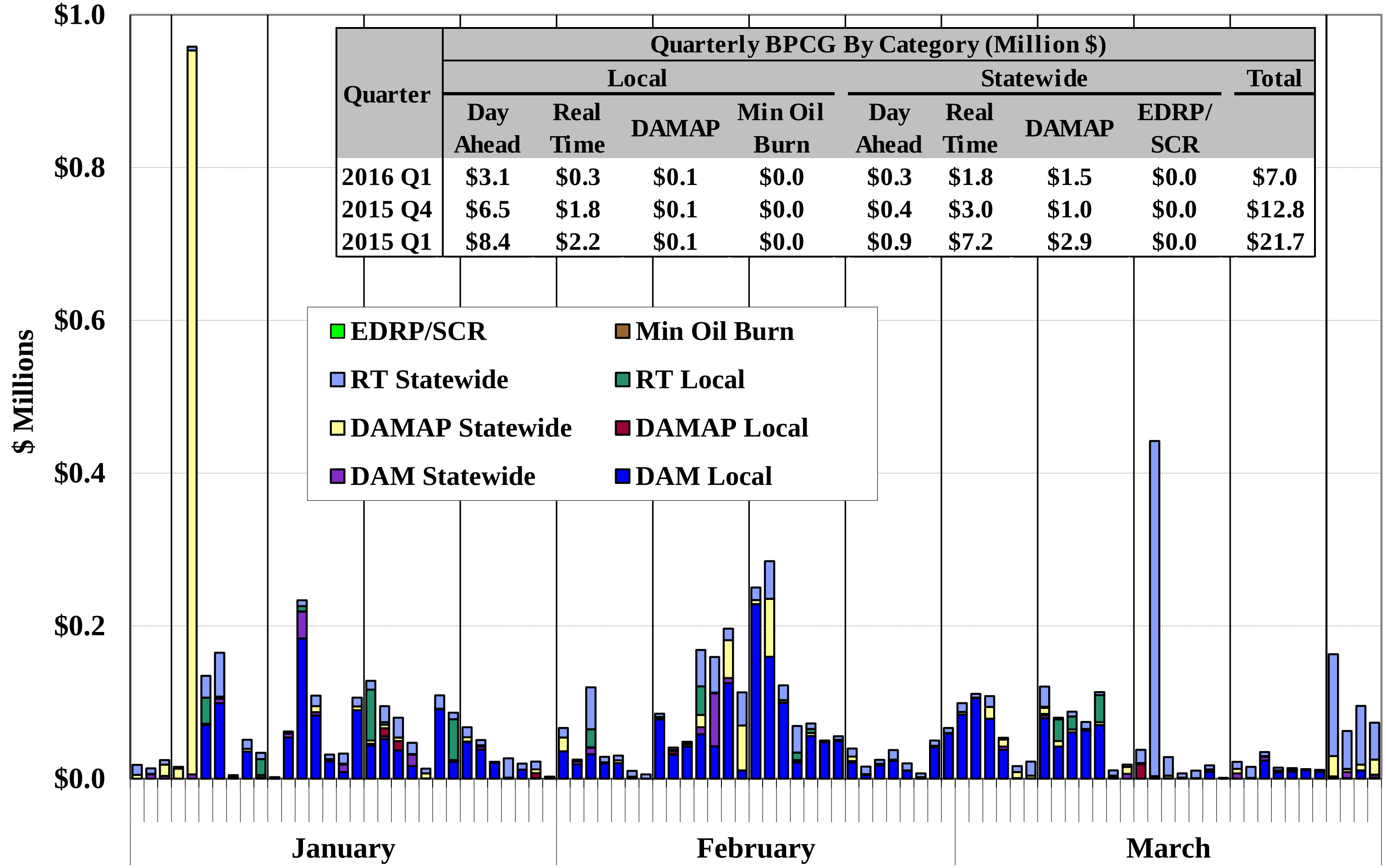
Uplift Costs from Guarantee Payments
Local and Non-Local by Category



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
2016 Q1	$3.1	$0.3	$0.1	$0.0	$0.3	$1.8	$1.5	$0.0	$7.0
2015 Q4	$6.5	$1.8	$0.1	$0.0	$0.4	$3.0	$1.0	$0.0	$12.8
2015 Q1	$8.4	$2.2	$0.1	$0.0	$0.9	$7.2	$2.9	$0.0	$21.7

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.

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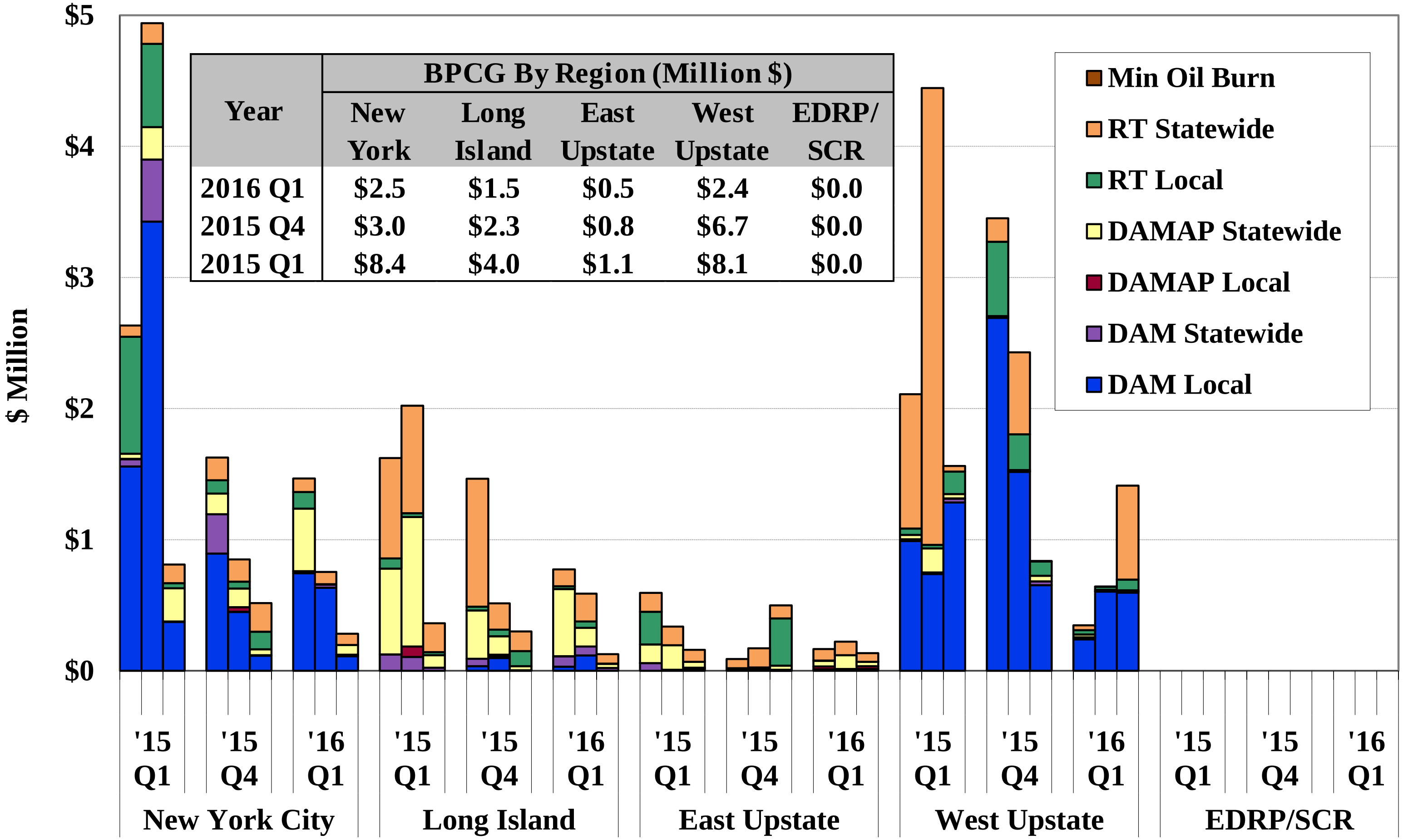
Uplift Costs from Guarantee Payments
By Category and Region



Year	BPCG By Region (Million $)				
	New York	Long Island	East Upstate	West Upstate	EDRP/ SCR
2016 Q1	$2.5	$1.5	$0.5	$2.4	$0.0
2015 Q4	$3.0	$2.3	$0.8	$6.7	$0.0
2015 Q1	$8.4	$4.0	$1.1	$8.1	$0.0

Note: BPCG data are based on information available at the reporting time that can be different from final settlements.

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Market Power and Mitigation

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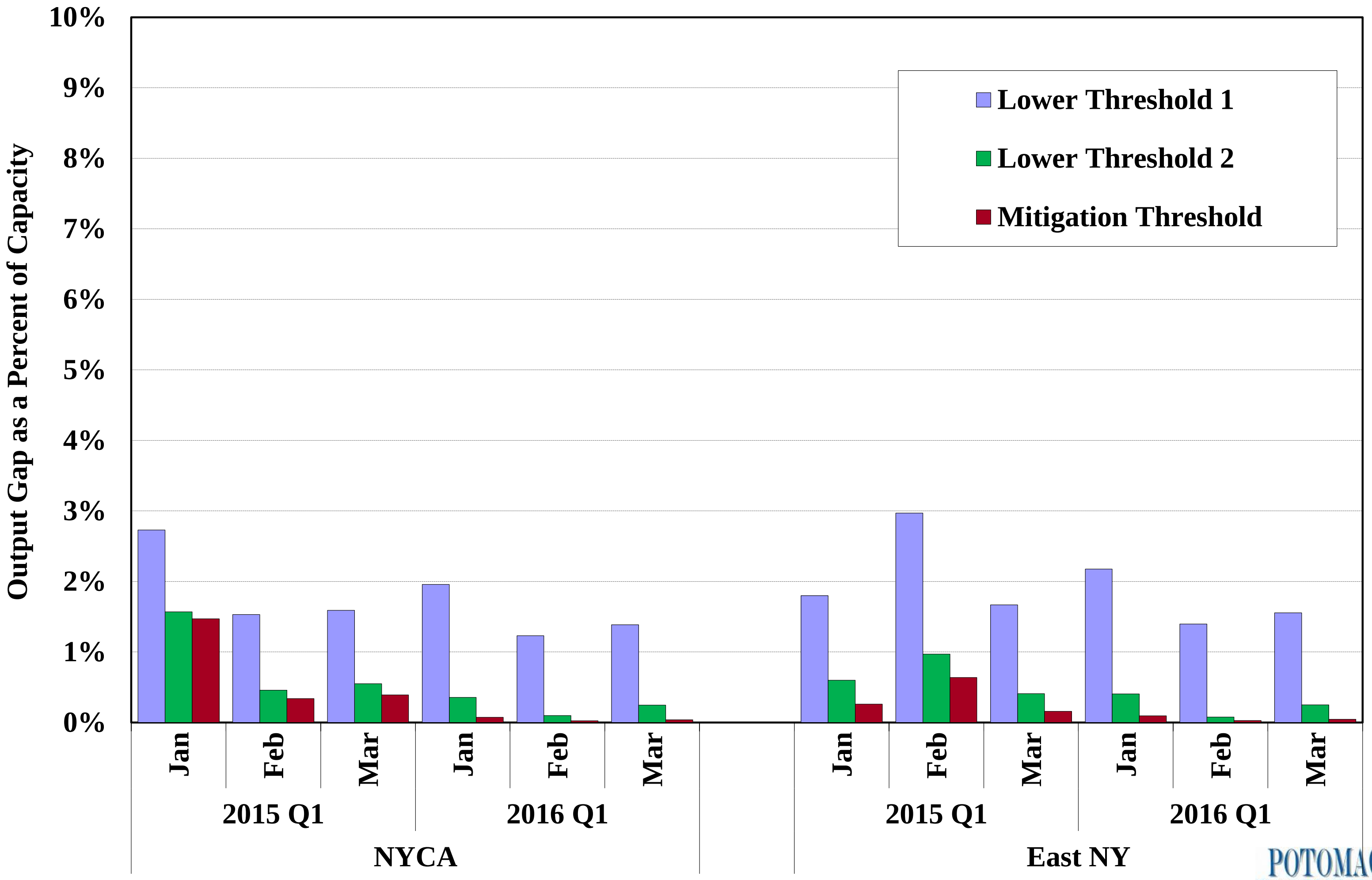
Market Power Screens:
Potential Economic and Physical Withholding

- The next two figures show the results of our screens for attempts to exercise market power, which may include economic and physical withholding.
- The screen for potential 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.
  - ✓ We show output gap in NYCA and East NY, based on:
    - The state-wide mitigation threshold (the lower of $100/MWh and 300 percent); and
    - Two other lower thresholds (100 percent and 25 percent).
- The screen for potential physical withholding is the "unoffered economic capacity", which is the amount of economic capacity that is not available to the market because a supplier does not offer, claims a derating, or offers in an inflexible way.
  - ✓ We show the unoffered economic capacity in NYCA and East NY from:
    - Long-term outages/deratings (at least 7 days);
    - Short-term outages/deratings (less than 7 days);
    - Online capacity that is not offered or offered inflexibly; and
    - Offline GT capacity that is not offered in the real-time market.

Market Power Screens:
Potential Economic and Physical Withholding

- The amount of output gap was relatively low as a share of capacity.
  - ✓ During the first quarter of 2016, the average amount of output gap averaged:
    - – Less than 0.1 percent of total capacity at the mitigation threshold; and
    - – Roughly 1.5 to 1.7 percent at the lowest threshold evaluated (i.e., 25 percent).
  - ✓ The amount of output gap fell modestly from a year ago, reflecting much lower and less volatile natural gas prices and lower load levels.
  - ✓ Overall, the output gap raised no significant market power concerns this quarter.
- The amount of unoffered (including outages/deratings) economic capacity was reasonably consistent with expectations for a competitive market.
  - ✓ Economic capacity on short-term outages/deratings was higher in the colder months of 2015-Q1 than in 2016-Q1, reflecting that cold temperatures tend to increase outage risks, particularly for oil-fired units.
  - ✓ Economic capacity on long-term outages/deratings rose in March as suppliers scheduled more maintenance expecting milder conditions.
    - – In some cases, it would have been efficient to postpone the some of these outages because it would have been economic to operate given actual market conditions.
    - – However, some generators will be economic whenever they take an outage because they have very low operating costs (e.g., nuclear units).

Output Gap in NYCA and East NY



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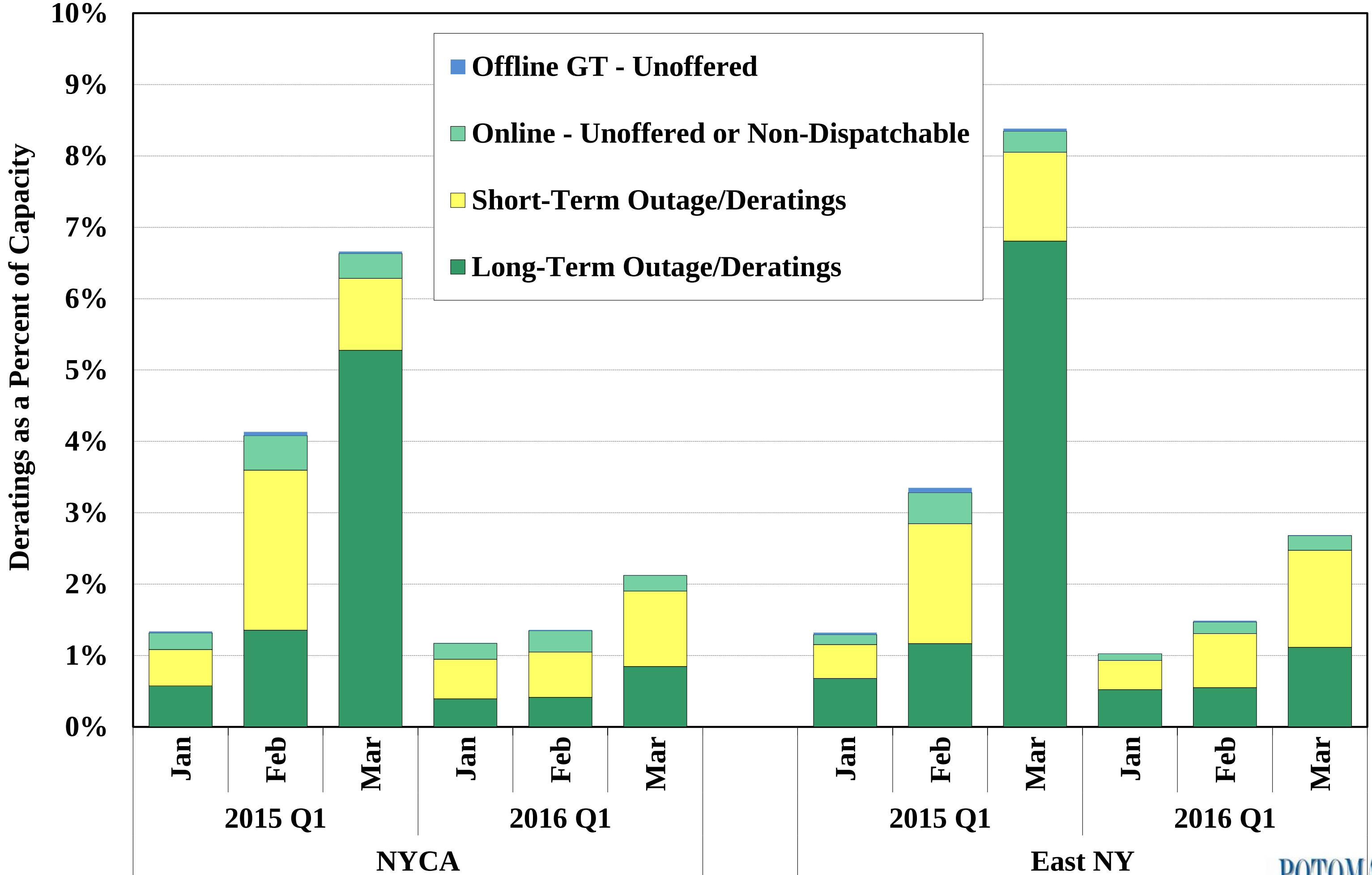
Unoffered Economic Capacity in NYCA and East NY



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Automated Market Power Mitigation

- The next table summarizes the automated mitigation that was imposed during the quarter (not including BPCG mitigation).
- 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.
- Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled. In the first quarter of 2016,
  - ✓ Nearly all of mitigation occurred in the day-ahead market, of which:
    - – Local reliability (i.e., DARU & LRR) units accounted for 83 percent. These mitigations generally affect guarantee payment uplift but not LBMPs.
    - – Units in the Astoria West and Astoria East load pockets accounted for 15 percent.
- The quantity of mitigation declined modestly from the first quarter of 2015 primarily because of reduced DARU and LRR commitments in New York City (see slides 78-79).

Automated Market Mitigation

Quarterly Mitigation Summary

		2014 Q1	2015 Q1	2015 Q4	2016 Q1
Day-Ahead Market	**Average Mitigated MW**	197	69	55	55
	Energy Mitigation Frequency	7%	3%	7%	1%
Real-Time Market	**Average Mitigated MW**	30	9	0.2	0.3
	Energy Mitigation Frequency	4%	1%	0.4%	0.0%

Capacity Market

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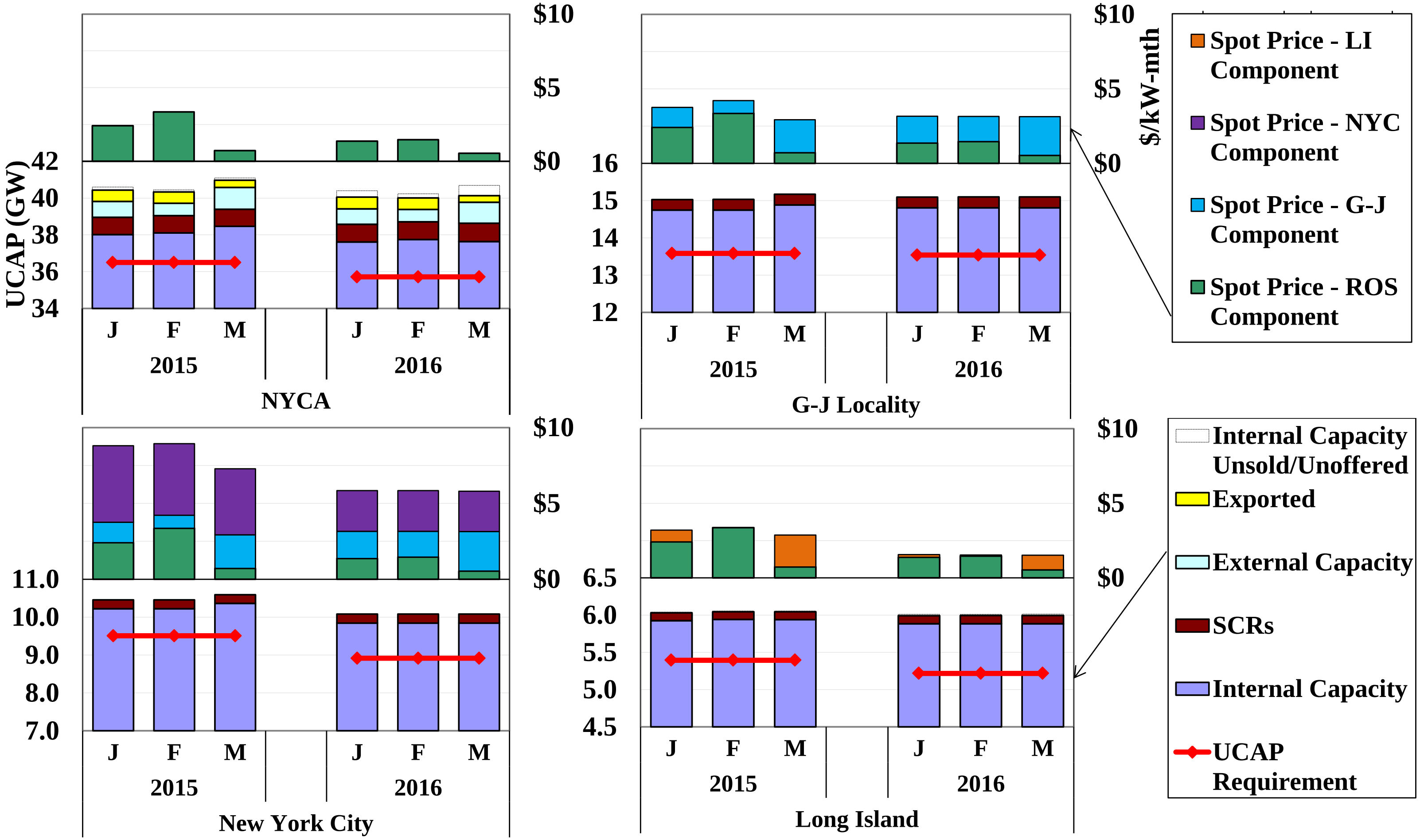
Capacity Market Results

- The following two figures summarize capacity market results and key market drivers in the first quarter of 2016.
  - ✓ The first figure summarizes available and scheduled Unforced Capacity (“UCAP”), UCAP requirements, and spot prices that occurred in each capacity zone by month (also compared to those from a year ago).
  - ✓ The next table shows: (a) the year-over-year changes in spot prices by locality; and (b) variations in key factors that drove these changes.
- The average spot prices fell 13 to 51 percent from a year ago primarily because:
  - ✓ On the supply side, internal ICAP supply rose in every capacity zone; and
  - ✓ On the demand side, the ICAP requirements fell in all capacity zones except the G-J Locality.
    - – The spot prices in the G-J Locality fell because the amount of increased ICAP supply exceeded the amount of increased ICAP requirement.
    - – Increased capacity in the Hudson Valley Zone was the primary factor that led to: (a) lower LCRs for New York City and Long Island; and (b) a higher LCR for the G-J Locality.
- There was little unsold capacity in New York City, Long Island, and the G-J Locality.

Capacity Market Results: First Quarter 2015 & 2016



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

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2016 Q1 ($/kW-Month)	1.12	5.83	1.53	3.15
% Change from 2015 Q1	-48%	-30%	-51%	-13%
Change in Demand				
Load Forecast (MW)	-98	147	43	49
IRM/LCR	0%	-1.5%	-3.5%	2.5%
2016 Q1	*117%*	*83.5%*	*103.5%*	*90.5%*
2015 Q1	*117%*	*85.0%*	*107.0%*	*88.0%*
ICAP Requirement (MW)	**-115**	**-54**	**-148**	**451**
Change in ICAP Supply (MW)				
Reductions Due to: Retirement (R), ICAP Inegilible FO (FO)				
R - Huntley 67 & 68 (Mar-16)	-375			
FO - Astoria GT 05,07,12,13 (Jan-16)	-74	-74		-74
R - Dunkirk 2 (Jan-16)	-75			
Additions Due to: Return to Service				
Astoria Unit 2 (Mar-15)	167	167		167
Bowline Unit 2 (Jul-15)	374			374
Changes Due to: DMNC Test	33	42	11	60
Net Changes (MW)	**50**	**135**	**11**	**527**

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