Quarterly Report on the New York ISO Electricity Markets Second Quarter 2011

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Highlights and Market Summary

- This report presents the NYISO market outcomes in the second quarter of 2011.
- The markets performed competitively and variations in wholesale market prices were driven primarily by changes in demand, fuel prices, and supply availability.
- Real-time energy prices averaged roughly $49/MWh statewide.
  - ✓ This was down 13 percent from the previous quarter, primarily because natural gas prices fell 30 percent, reducing the cost of supply in the east.
  - ✓ This was down 6 percent from the second quarter of 2010 for reasons that include the effects of new supply in eastern New York and improved TSA operations.
- Convergence between day-ahead and real-time prices improved considerably from the second quarter of 2010.
  - ✓ The differential between average day-ahead and real-time prices improved to:
    - 4 percent in 2011-Q2 from 9 percent in 2010-Q2 in New York City; and
    - 0 percent in 2011-Q2 from 12 percent in 2010-Q2 in Long Island.
  - ✓ Since average day-ahead prices were understated in the second quarter of 2010, the improved convergence led average day-ahead prices to rise 3 percent from the second quarter of 2010 (even as real-time prices fell 6 percent).

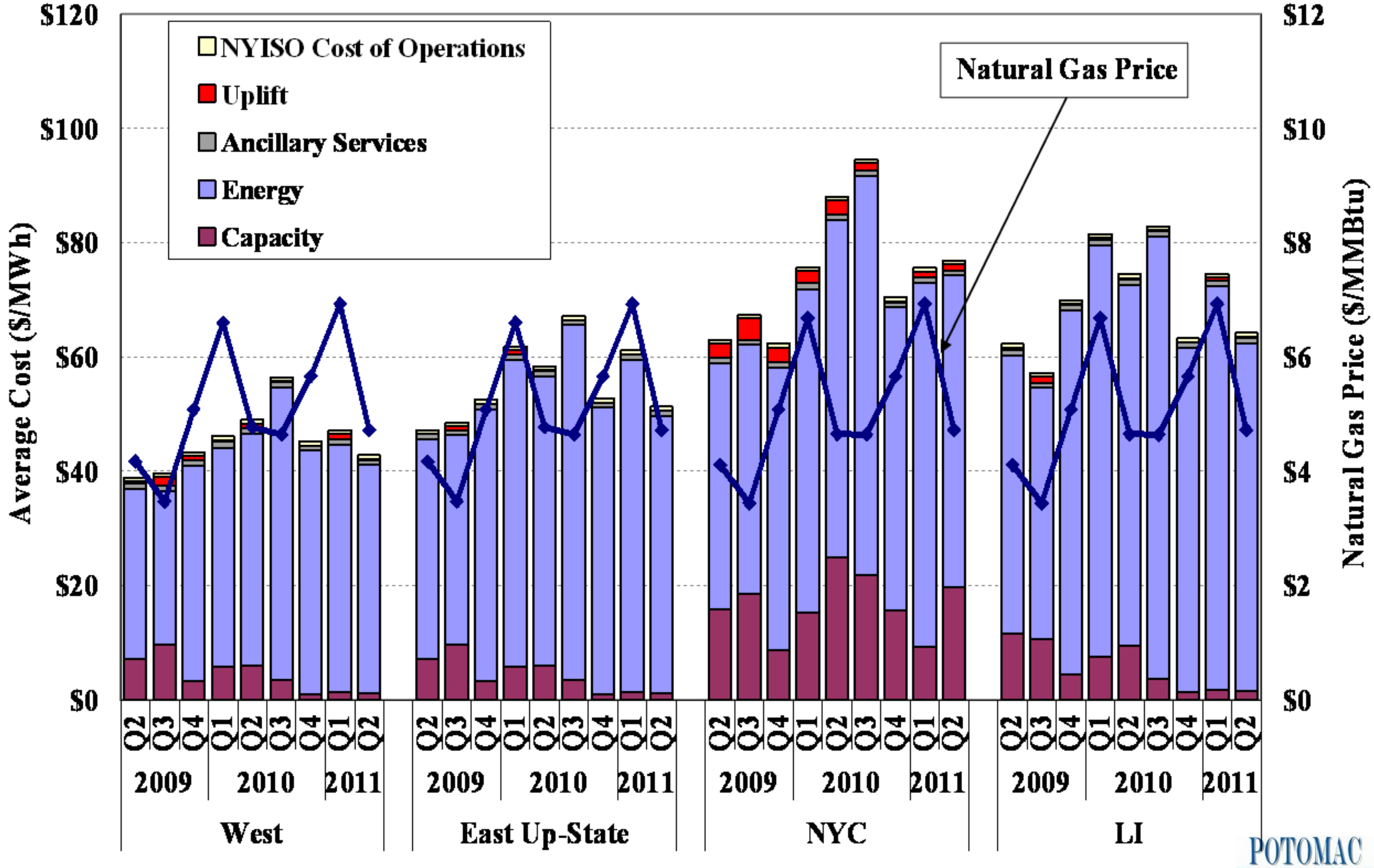
Highlights and Market Summary

- UCAP spot prices averaged $9.02/kW-month in NYC and $0.45/kW-month in the rest of the state, down 20 percent and 78 percent from the second quarter of 2010.
  - ✓ The decreases were due largely to: a) more sales from new and existing resources, and b) reduced capacity requirements associated with lower peak load forecasts.
- Uplift from guarantee payments and balancing congestion shortfalls totaled $43 million, down 35 percent from the last quarter and 45 percent from the second quarter of 2010.
  - ✓ Uplift fell from the first quarter due largely to the reduction in gas prices.
  - ✓ Uplift fell from the second quarter of 2010 primarily due to: (i) improved TSA operations, (ii) reduced need to commit generation for reliability in NYC and western NY, and (iii) some units needed for reliability were more economic.
  - ✓ However, mitigation consultations are on-going for the second quarter, so guarantee payments will increase once these are fully reflected.
- Day-ahead congestion revenue shortfalls were $21 million this quarter -- 51 percent less than last quarter, but up 75 percent from the second quarter of 2010.
  - ✓ Shortfalls fell from the first quarter, since fewer transmission outages were planned in the second quarter.
  - ✓ Shortfalls rose from the second quarter of 2010 due to several significant outages in New York City and into the Hudson Valley.

All-In Energy Price

- The first figure summarizes prices and costs in the New York markets. It shows the “all-in” price that represents the total cost of serving load, which includes:
  - ✓ 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 in each area, divided by the real-time energy consumption in the area.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges divided by the real-time energy consumption in the relevant area.
- A natural gas price trend is shown because it is a key input to production.
- Compared to the second quarter of 2010, all-in prices fell 12 to 14 percent.
  - ✓ Energy prices fell 2 to 8 percent partly due to improved TSA operations, increased output from hydro resources, and generation and transmission additions.
  - ✓ Capacity prices fell 20 percent in NYC and over 75 percent elsewhere because of capacity additions and reduced capacity requirements from the previous year.
- Compared to last quarter, all-in prices fell 9 to 16 percent outside NYC and rose 2 percent in NYC.
  - ✓ Energy prices fell in all areas due to lower natural gas prices, which fell 30 percent.
  - ✓ However, capacity prices rose 113 percent in NYC as the market transitioned from the winter to summer capability period.

All-In Energy Price by Region



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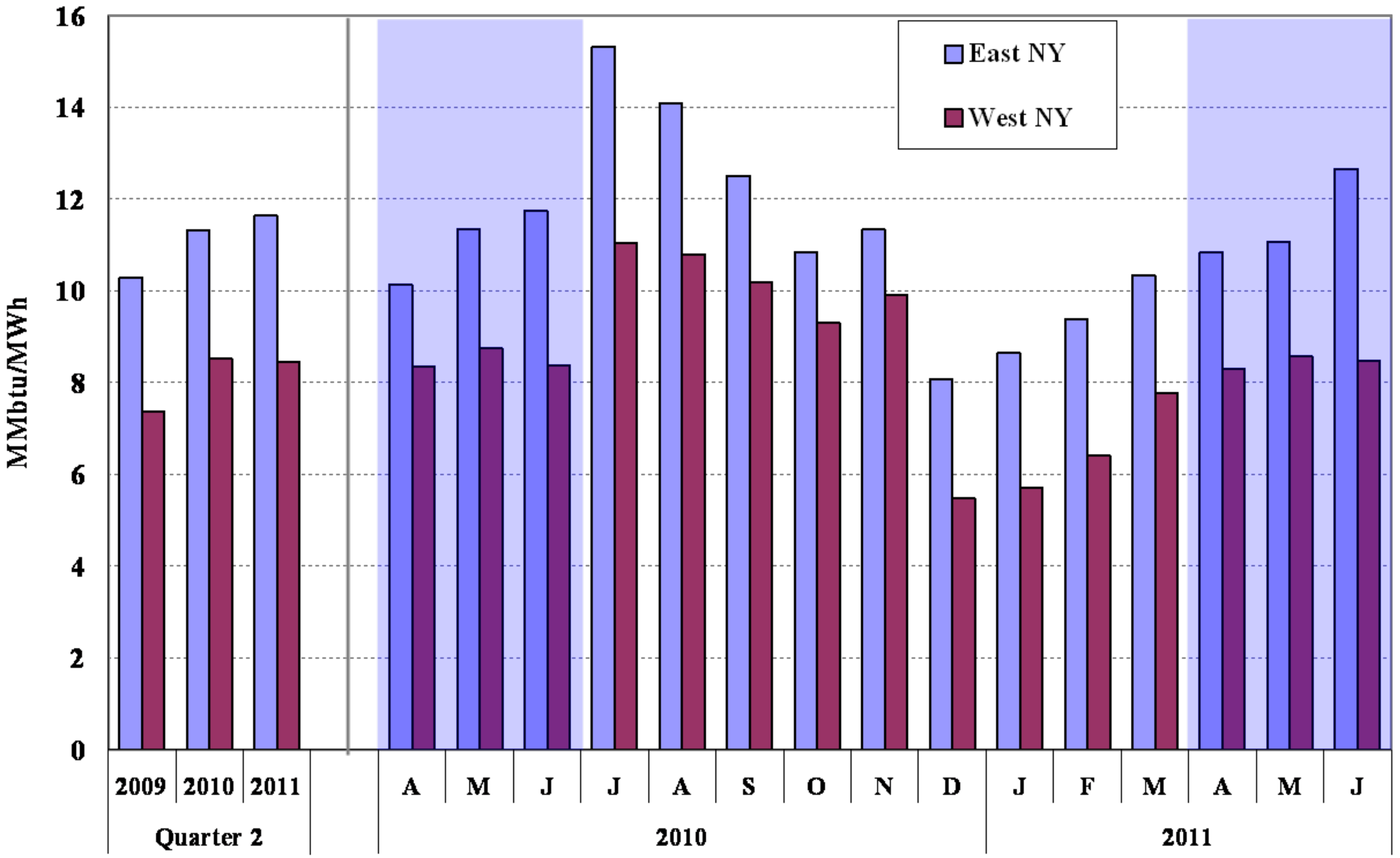
Implied Heat Rate

- 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 eastern New York than in western 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.
- Average implied heat rates rose 3 percent in eastern New York and fell 1 percent in western New York from the second quarter of 2010. The following factors contributed to these modest changes:
  - ✓ Oil prices rose sharply (45 percent for #2 and 60 percent for #6), raising energy prices when oil-fired units set prices.
  - ✓ Imports fell from PJM and New England by 800 MW combined.
  - ✓ Convergence between day-ahead and real-time prices improved -- day-ahead prices were low relative to real-time prices in the second quarter of 2010.
  - ✓ However, these were partly offset by new capacity in the Capital Zone and a 410 MW increase in average output from hydro-electric generation.

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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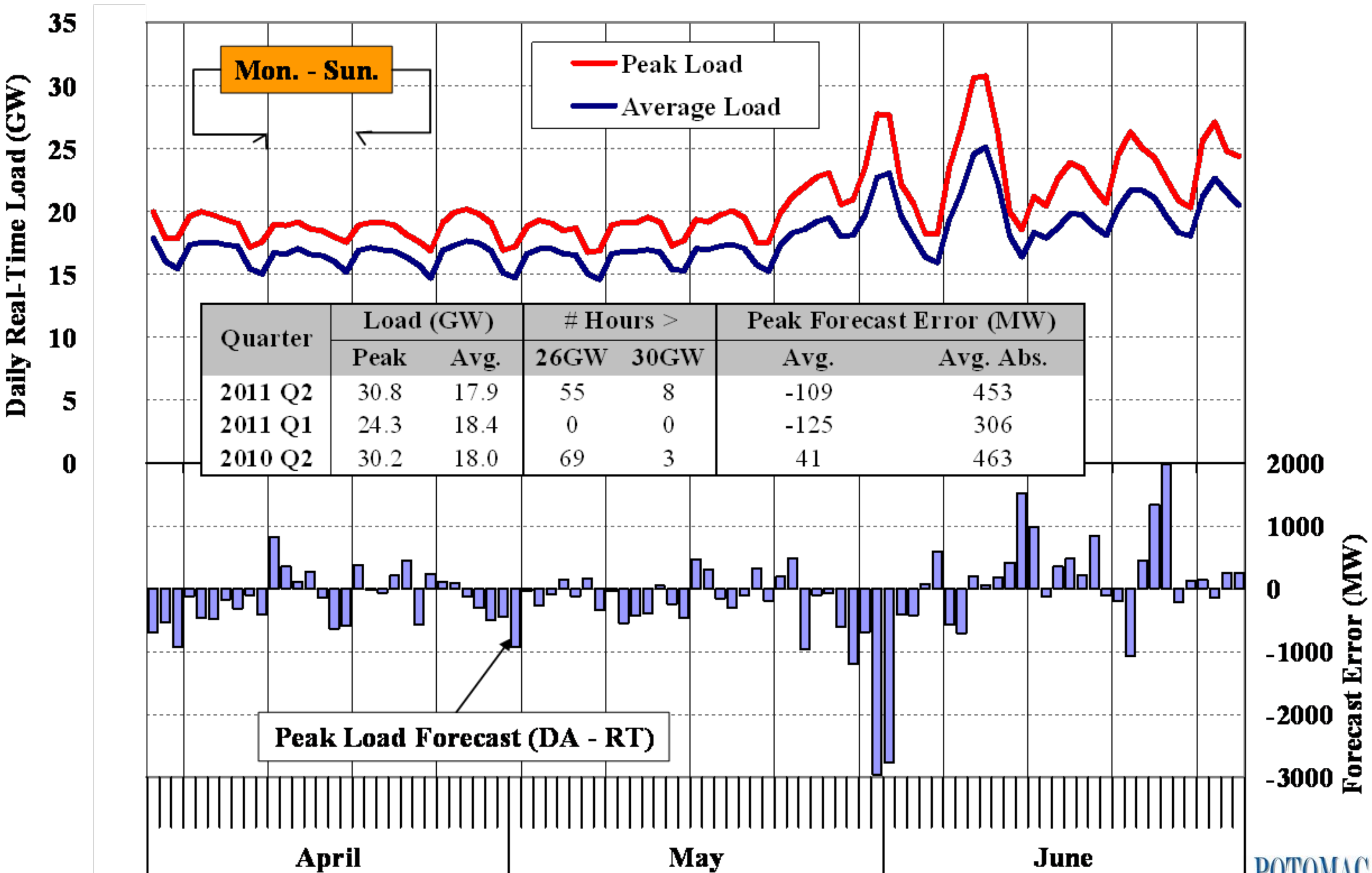
Load Forecast and Actual Load

- The following figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the second quarter of 2011.
  - ✓ The table compares key statistics for the second quarter of 2011 to the previous quarter and the second quarter of 2010.
- Average load fell from prior quarters but peak load levels increased.
  - ✓ Load averaged 17.9 GW in the second quarter of 2011, down 3 percent from the previous quarter and slightly lower than the second quarter of 2010.
  - ✓ Load rose considerably at the end of May and peaked on June 9 at 30.8 GW, up 26 percent from the first quarter and 2 percent from the second quarter of 2010.
  - ✓ Load exceeded 30 GW for 8 hours on two days (June 8 & 9), compared to 0 hours in the previous quarter and only 3 hours from the same quarter of 2010.
- Peak load forecasting was generally good, although sustained patterns of errors for several days occurred a few times during the quarter.
  - ✓ The daily peak load forecast had an error greater than 1 GW on 7 days and an error of nearly 3 GW on two days (May 31 & June 1).
  - ✓ Although participants are responsible for day-ahead market scheduling, NYISO’s forecast errors are generally correlated with those of market participants.

Load Forecast and Actual Load

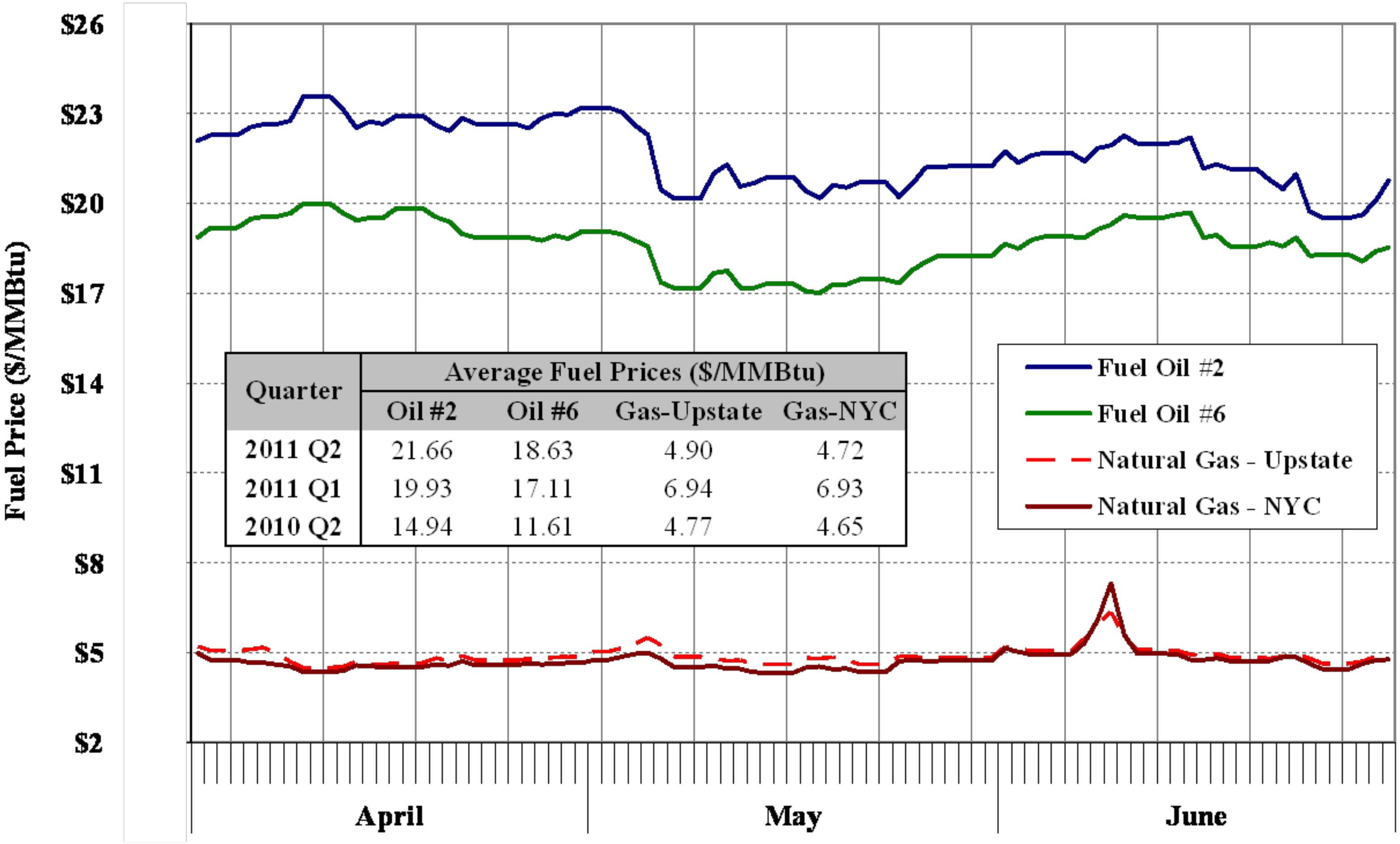


Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2011 Q2	30.8	17.9	55	8	-109	453
2011 Q1	24.3	18.4	0	0	-125	306
2010 Q2	30.2	18.0	69	3	41	463

Natural Gas and Oil Prices

- The following figure shows daily natural gas and fuel oil prices, which are key determinants of electricity prices.
- Average natural gas prices fell approximately 30 percent from the previous quarter and were slightly higher (2 percent) than the second quarter of 2010.
  - ✓ Gas prices remained close to $5/MMBtu on nearly every day of the quarter.
  - ✓ However, gas prices briefly rose above $7/MMBtu on June 9, just before a two-week scheduled Transco pipeline outage.
    - – The price differential was approximately $1/MMBtu between the Transco Zone 6 (New York City) and Iroquois Zone 2 (Upstate NY) on this day.
- Average fuel oil prices have risen.
  - ✓ Fuel oil #2 prices rose 9 percent from the previous quarter and 45 percent from the second quarter of 2010.
  - ✓ Fuel oil #6 prices rose 9 percent from the previous quarter and 60 percent from the second quarter of 2010.
- Natural gas was usually much less expensive than fuel oil, but some generators 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
2011 Q2	21.66	18.63	4.90	4.72
2011 Q1	19.93	17.11	6.94	6.93
2010 Q2	14.94	11.61	4.77	4.65

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 second quarter of 2011.
- Prices in a well-functioning day-ahead market should reflect probability-weighted expectations of real-time market conditions.
- Average prices in Southeast New York fell 13 to 15 percent from the previous quarter but rose 4 to 8 percent from the second quarter of 2010.
  - ✓ The decrease from the prior quarter was mainly due to the reduction in natural gas prices, although this was partly offset by much higher peak load conditions.
  - ✓ The increase from 2010 was due primarily to higher oil prices, reduced imports from PJM and New England, and better consistency between DAM and RT prices.
- Price differences between the Capital Zone and Hudson Valley have increased since late May as a function of increased day-ahead congestion on the New Scotland-Leeds and Leeds-Pleasant Valley lines since late May caused by:
  - ✓ Peak load conditions, anticipation of more frequent TSAs, and a significant transmission line outage from New Scotland-Leeds (June 17 to 28).
- New York City and Long Island prices were elevated on many days caused in part by significant transmission outages (e.g., Sprainbrook-W49th: April 9-May 6; Dunwoodie-Shore Road: May 1-25; Neptune: April 25-29 & June 21-30).

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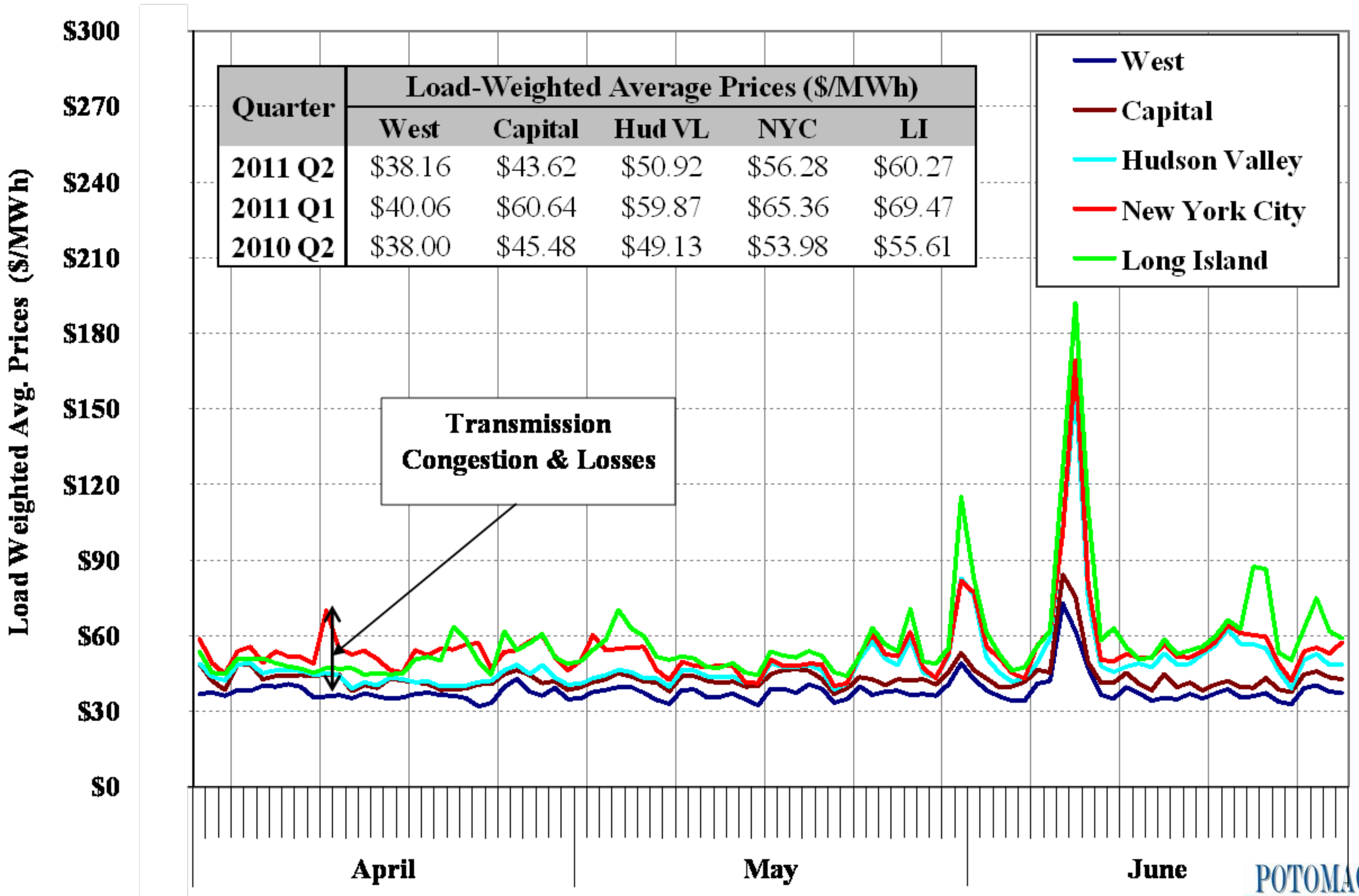
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2011 Q2	$38.16	$43.62	$50.92	$56.28	$60.27
2011 Q1	$40.06	$60.64	$59.87	$65.36	$69.47
2010 Q2	$38.00	$45.48	$49.13	$53.98	$55.61

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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 second quarter of 2011.
  - ✓ Prices are more volatile in the real-time market than in the day-ahead market.
- Congestion into Southeast New York was particularly acute in the real-time market on several days during the quarter.
  - ✓ On May 31 & June 1, congestion increased due to unexpectedly high load levels, a sharp increase in clockwise loop flows around Lake Erie (June 1 only), reduced imports from PJM, and TSA operations (June 1 only).
  - ✓ On June 9, congestion increased due to particularly high load levels, generator derates, increased demand for exports to PJM, and TSA operations.
  - ✓ On June 17, congestion increased due to multiple outages of major lines into Southeast New York (New Scotland-Leeds and Leeds-Hurley Avenue) and TSA operations.
- Congestion into Long Island was particularly acute in the real-time market on several days (particularly May 25) because of several generator outages, unexpectedly high load levels, and the on-going outage of a major line from upstate New York (Dunwoodie-Shore Road).

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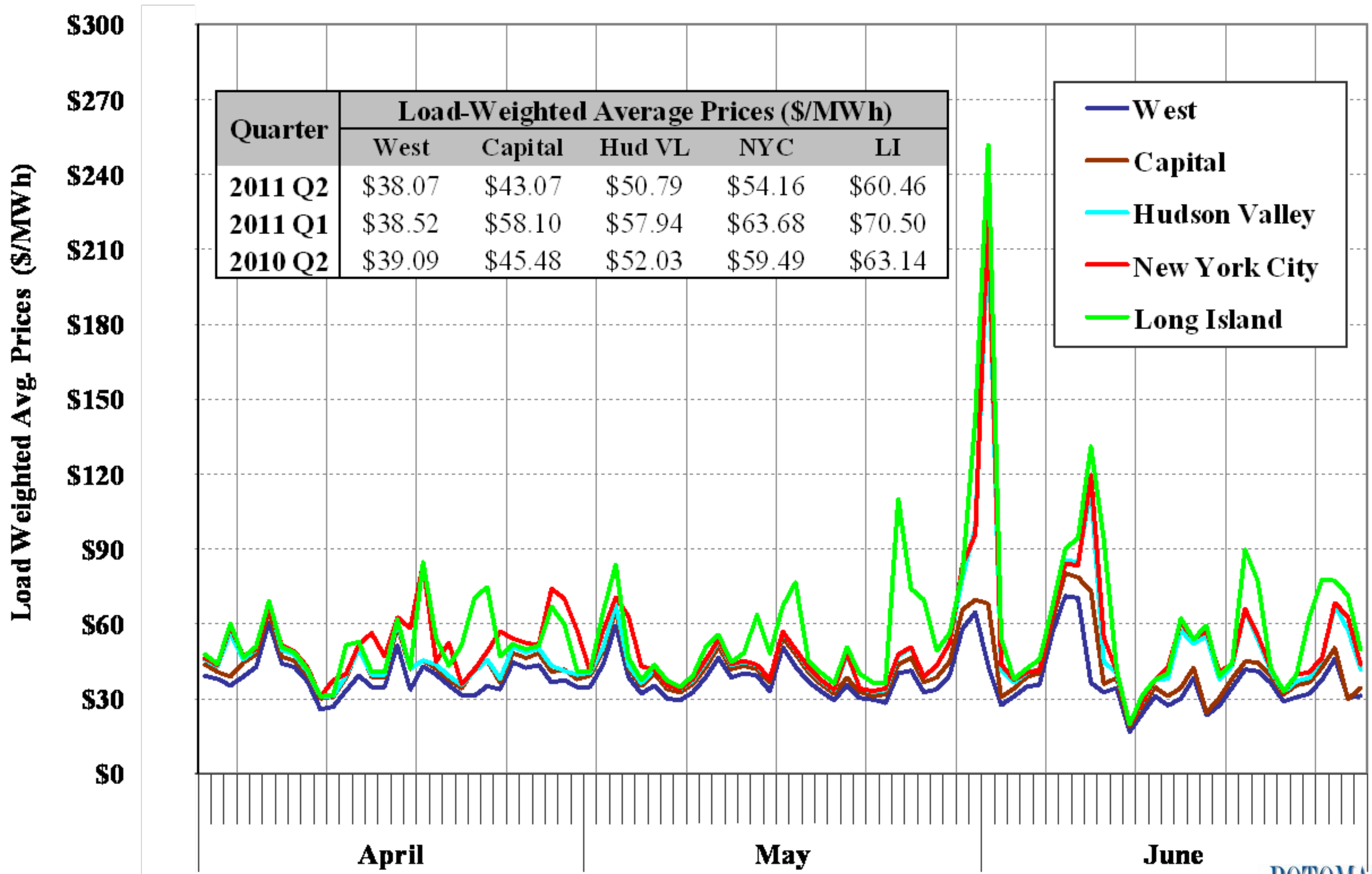
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2011 Q2	$38.07	$43.07	$50.79	$54.16	$60.46
2011 Q1	$38.52	$58.10	$57.94	$63.68	$70.50
2010 Q2	$39.09	$45.48	$52.03	$59.49	$63.14

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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 second quarter of 2011.
  - ✓ This is shown separately for five zones to account for changes in the pattern of congestion from the day-ahead to the real-time.
- The largest price differences occurred on June 1 in Southeast New York due to severe real-time conditions, including:
  - ✓ A TSA was called during the afternoon, which reduced transfer capability into Southeast New York, increasing congestion on the Leeds-to-Pleasant Valley line.
  - ✓ Clockwise circulation around Lake Erie rose to a level 700 MW higher in real-time than in the day-ahead during the TSA event (despite the use of TLR procedures).
    - – This reduced the amount of transfer capability into Southeast New York that was available to NYISO market participants.
  - ✓ Real-time load exceeded the peak load forecast by almost 3 GW.

Convergence Between Day-Ahead and Real-Time Prices

- Large differences between average day-ahead prices and average real-time prices occurred on individual days due to unexpected factors.
  - ✓ Convergence should be measured over longer timeframes, since random factors can cause convergence on individual days to be poor.
  - ✓ The table shows the average price convergence over the entire quarter.
- Convergence between day-ahead and real-time prices was much better in most locations in the second quarter of 2011 compared to the previous quarter.
  - ✓ The price differences in most areas ranged from 0.3 to 1.2 percent (of RT prices) in the second quarter of 2011, down from 3 to 4 percent in the previous quarter.
  - ✓ The following factors likely contributed to improved convergence from the previous quarter:
    - Much less volatile natural gas prices;
    - Modification of the 30-Minute Long Island Reserve Demand Curve in May, reducing the frequency and severity of transient price spikes in Long Island;
    - Modification of the Regulation Demand Curve in May, preventing small brief shortages of regulation from causing very high statewide prices; and
    - Increased load scheduling in the day-ahead market in Southeast New York.

Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2011 Q2	$0.09	$0.55	$0.12	$2.12	-$0.19
2011 Q1	$1.54	$2.54	$1.93	$1.69	-$1.03
2010 Q2	-$1.09	$0.01	-$2.90	-$5.51	-$7.53

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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 a given requirement will include the “demand curve” value of that requirement.

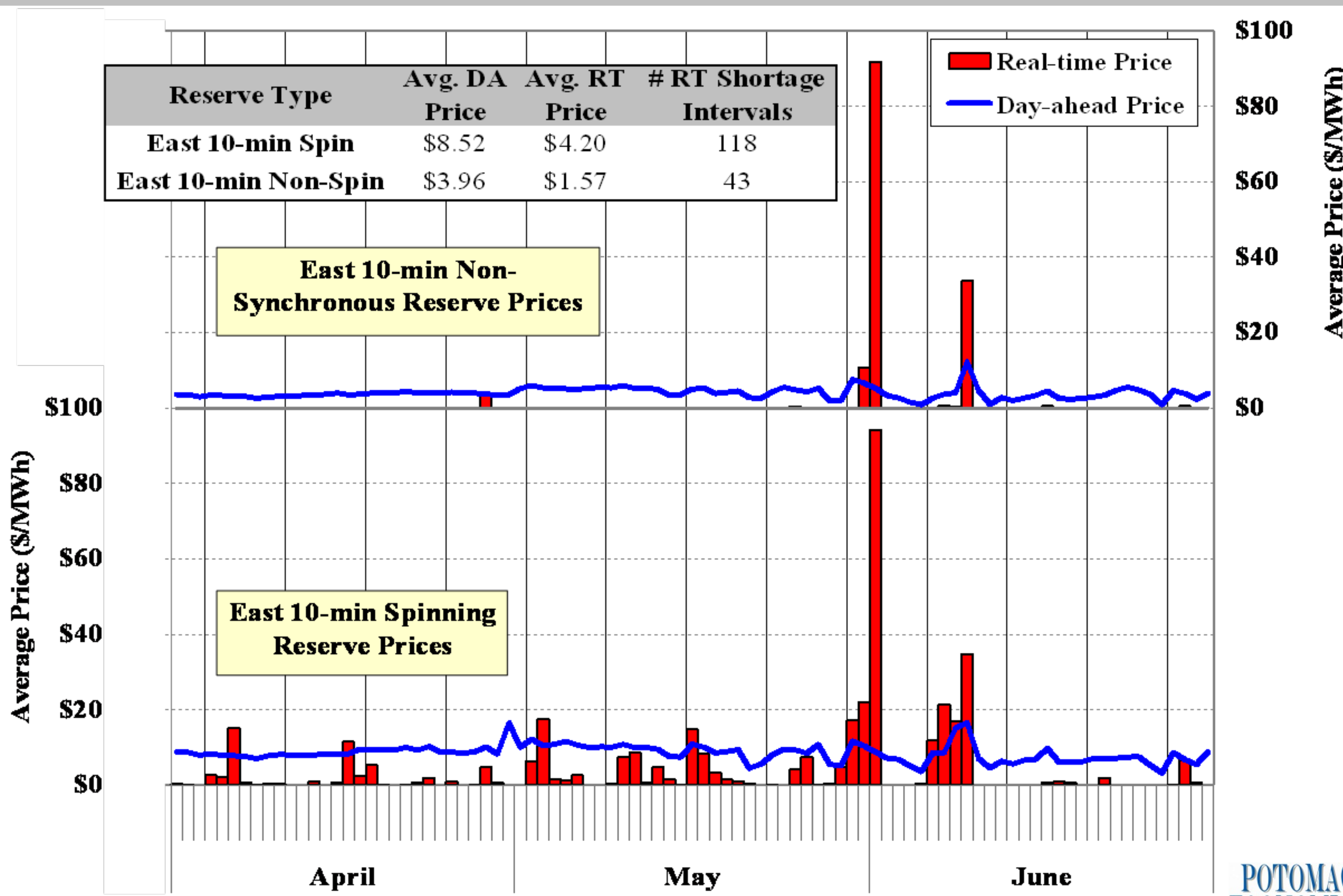
Day-Ahead and Real-Time Ancillary Services Prices

- 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 for 10-minute non-spin reserves in eastern New York and 10-minute spin in eastern and western New York were substantially higher than average real-time reserves prices in the second quarter of 2011.
  - ✓ The day-ahead price premium results partly from the risks that generators perceive from selling in the day-ahead market.
  - ✓ Real-time prices in the eastern NY spiked on June 1 due to unexpectedly high loads and TSA conditions, and on June 9 due to peak load and TSA conditions.
- Average day-ahead regulation prices were relatively consistent with real-time prices. Real-time prices were only moderately higher due to more frequent shortages in real-time.

Real-Time Ancillary Services Shortages

- 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 75 intervals ($25 demand curve), 36 percent of which occurred during periods with Central-East congestion;
  - ✓ Eastern 10-minute total reserves in 43 intervals ($500 demand curve);
  - ✓ State-wide 10-minute spinning reserves in 0 intervals ($500 demand curve); and
  - ✓ Regulation in 362 intervals ($250 to $300 demand curve before May 19, and $80 to $400 demand curve afterwards).
- 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 118 intervals of shortage pricing: 75 of eastern 10-minute spin, 43 of eastern 10-minute total reserves, and 0 of state-wide 10-minute spin.
- Regulation shortages occurred more frequently in the second quarter of 2011 following the modification of Regulation Demand Curve on May 19.
  - ✓ 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.

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



Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
East 10-min Spin	$8.52	$4.20	118
East 10-min Non-Spin	$3.96	$1.57	43

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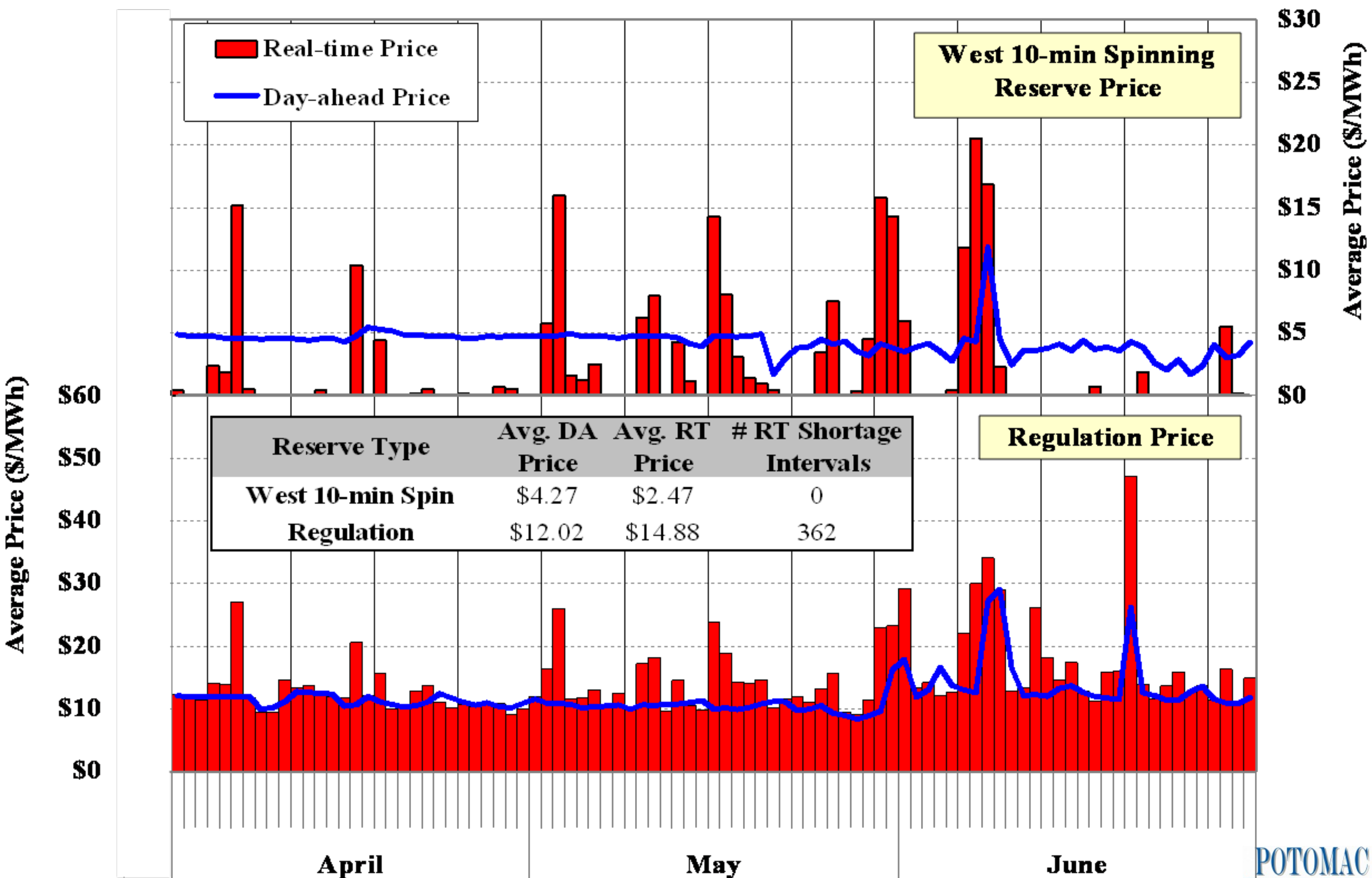
Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
West 10-min Spin	$4.27	$2.47	0
Regulation	$12.02	$14.88	362

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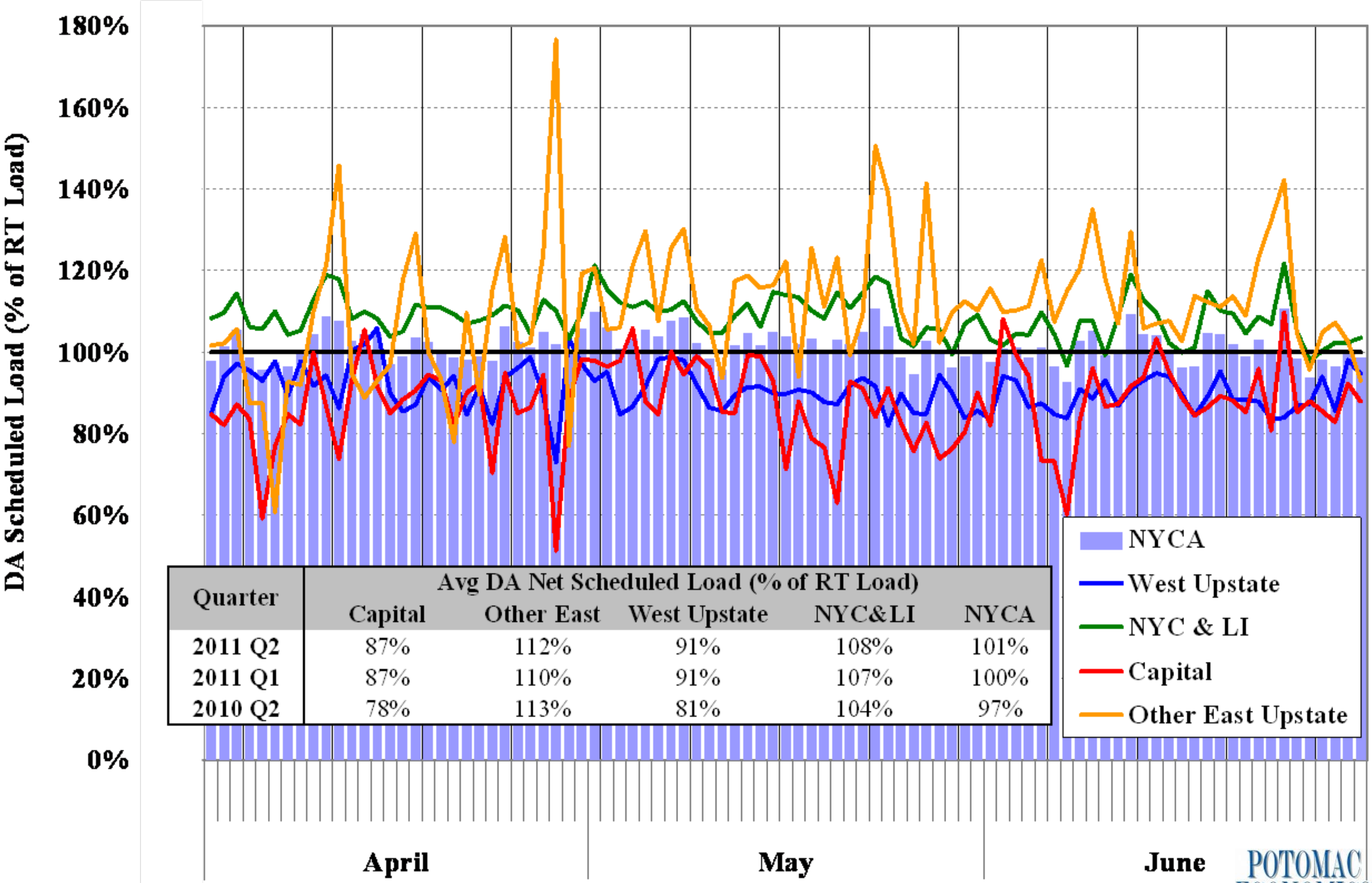
Day-ahead Scheduled Load and Actual Load

- 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 101 percent of actual load in NYCA, slightly higher than in prior quarters.
  - ✓ Higher day-ahead load scheduling in New York City and Long Island contributed to the improvement in consistency between day-ahead and real-time prices from the second quarter of 2010.
- 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 second quarter.
  - ✓ This pattern is typical and is likely in response to real-time congestion across on lines into Southeast New York, New York City, and Long Island.
- The over- and under-scheduling patterns generally improve convergence between day-ahead and real-time prices in most areas.
  - ✓ For example, Capital zone was consistently under-scheduled but still exhibited a day-ahead price premium that would have otherwise been much larger.

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
2011 Q2	87%	112%	91%	108%	101%
2011 Q1	87%	110%	91%	107%	100%
2010 Q2	78%	113%	81%	104%	97%

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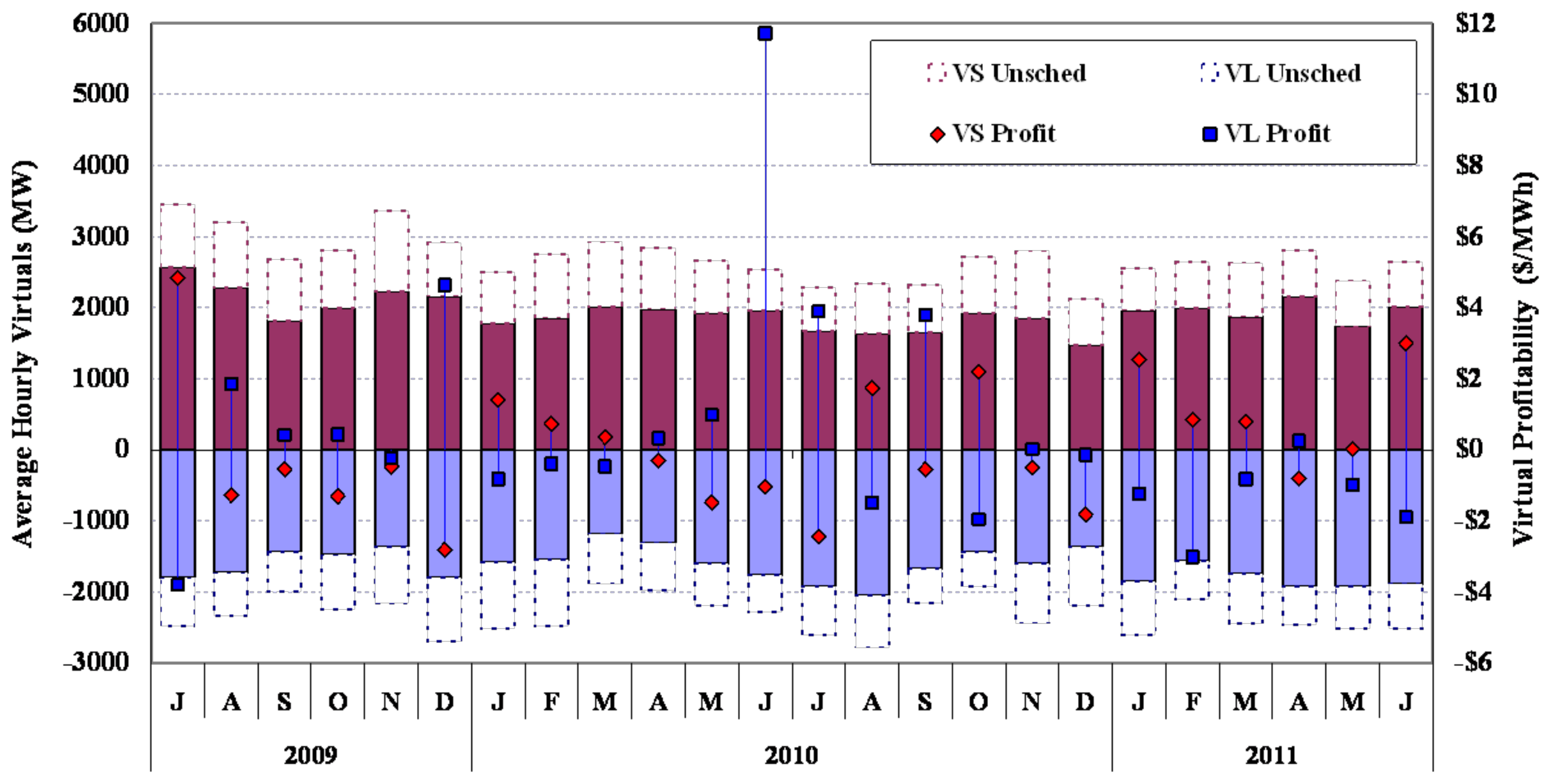
Virtual Trading Activity

- 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, 1.2 to 2.0 GW of virtual load and 1.5 to 2.6 GW of virtual supply have been consistently scheduled in the day-ahead market.
  - ✓ 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 rose during the volatile periods in the second quarter of 2011.
  - ✓ The transactions with notable profits or losses were primarily associated with real-time price volatility and did not raise manipulation concerns.

Virtual Trading Volumes and Profitability

July 2009 to June 2011



		J 2009	A	S	O	N	D
Profit > 50% of Avg. Zone Price	MW	514	293	235	315	239	573
	%	12%	7%	7%	9%	7%	14%
Loss > 50% of Avg. Zone Price	MW	611	441	244	369	253	578
	%	14%	11%	7%	11%	7%	15%

		J 2010	F	M	A	M	J	J	A	S	O	N	D
Profit > 50% of Avg. Zone Price	MW	380	324	240	122	181	285	205	176	162	117	135	221
	%	11%	10%	8%	4%	5%	8%	6%	5%	5%	3%	4%	8%
Loss > 50% of Avg. Zone Price	MW	347	284	201	112	211	241	300	205	115	95	131	273
	%	10%	8%	6%	3%	6%	6%	8%	6%	3%	3%	4%	10%

		J 2011	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	446	193	161	122	233	350
	%	12%	5%	4%	3%	6%	9%
Loss > 50% of Avg. Zone Price	MW	401	244	133	120	277	381
	%	11%	7%	4%	3%	8%	10%

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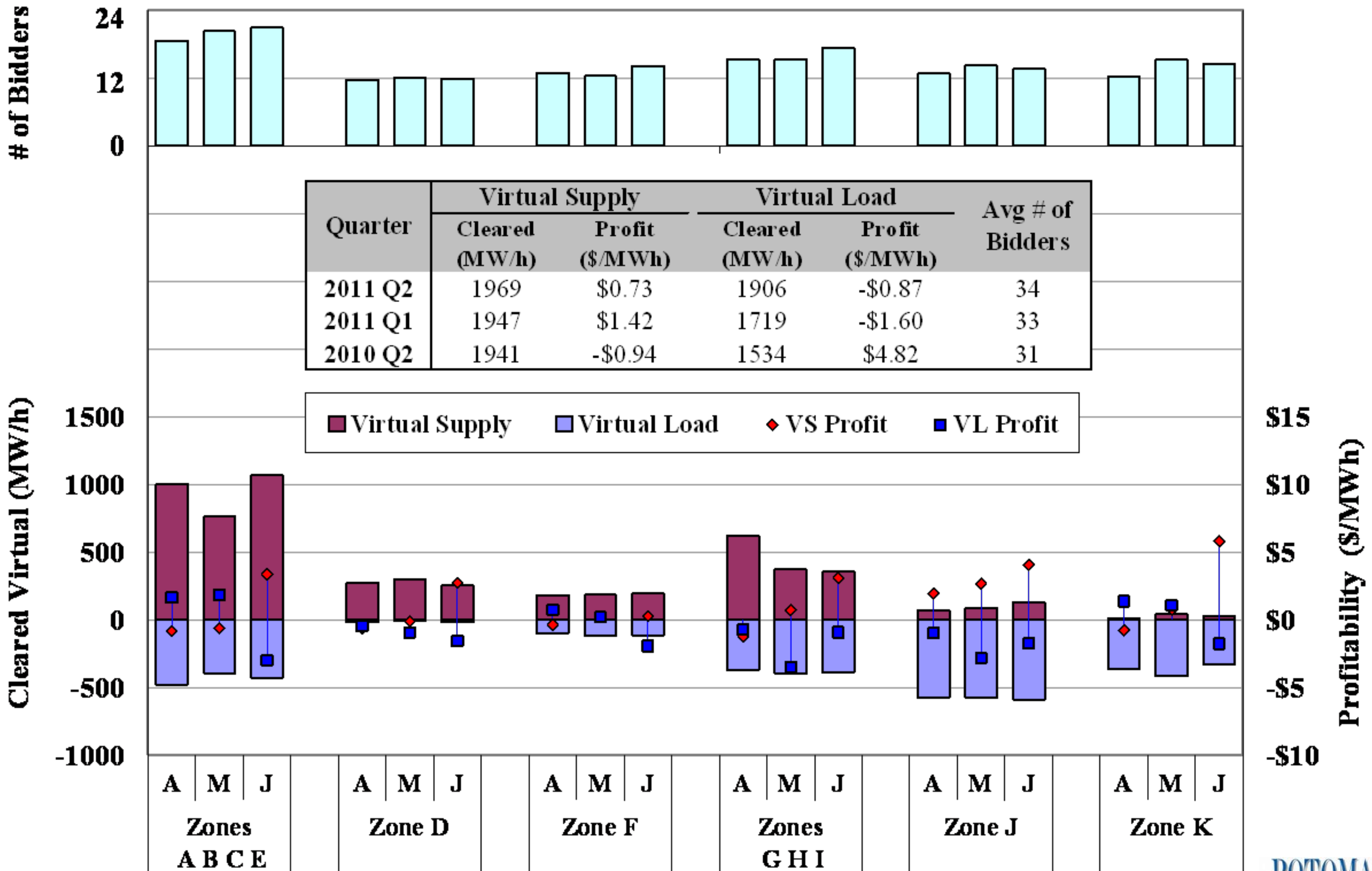
Virtual Trading Activity

- 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 cause the price of power in Zone D to differ from other areas.
  - ✓ 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.
  - ✓ On average, 12 or more participants submitted virtual trades in each region and 34 participants submitted virtual trades throughout the state.
- There were substantial net virtual load purchases downstate and net virtual supply sales upstate in the second quarter of 2011, consistent with prior periods.
- Virtual supply netted a \$3.1 million profit in the second quarter while virtual load netted a \$3.6 million loss, due to the day-ahead price premiums in most regions.

Virtual Trading Activity
By Region By Month



Quarter	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Avg # of Bidders
2011 Q2	1969	$0.73	1906	-$0.87	34
2011 Q1	1947	$1.42	1719	-$1.60	33
2010 Q2	1941	-$0.94	1534	$4.82	31

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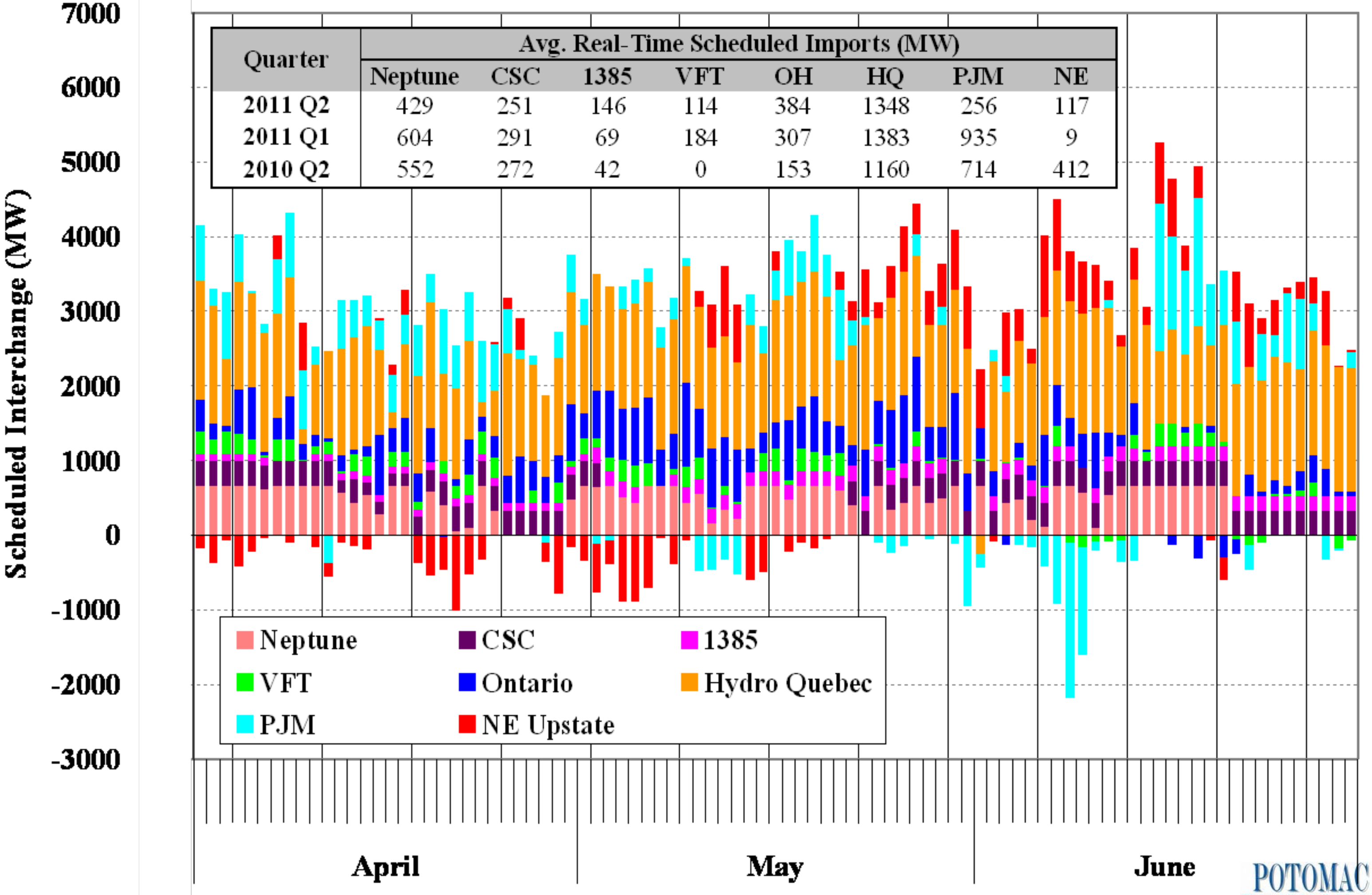
Net Imports Scheduled Across External Interfaces

- The following figure summarizes scheduled net imports to NYCA across eight external interfaces during the daily peak hour.
- Net imports to NYCA averaged slightly over 3 GW during daily peak hours in the second quarter of 2011, down 740 MW (or 20 percent) from the previous quarter and down 260MW (or 8 percent) from the second quarter of 2010.
  - ✓ Net imports from PJM fell an average of 680 MW from the previous quarter and 460 MW from the second quarter of 2010.
  - ✓ Interchange with PJM and New England across their primary interfaces varied considerably from day to day, reflecting wide variations in prices between these markets.
- Net imports to New York City and Long Island from New England and PJM via four controllable lines decreased from the previous quarter, due to:
  - ✓ The Cross Sound Cable was out of service on 19 days from May 3 to 21.
  - ✓ The Neptune Cable was out of service on 17 days, mostly in late April and late June.
  - ✓ Participants started to schedule bi-directionally via Linden VFT in June.
  - ✓ However, these factors were partly offset by increased imports via the 1385 Line following an upgrade to the facility from 100 MW to 200 MW in May.

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
2011 Q2	429	251	146	114	384	1348	256	117
2011 Q1	604	291	69	184	307	1383	935	9
2010 Q2	552	272	42	0	153	1160	714	412

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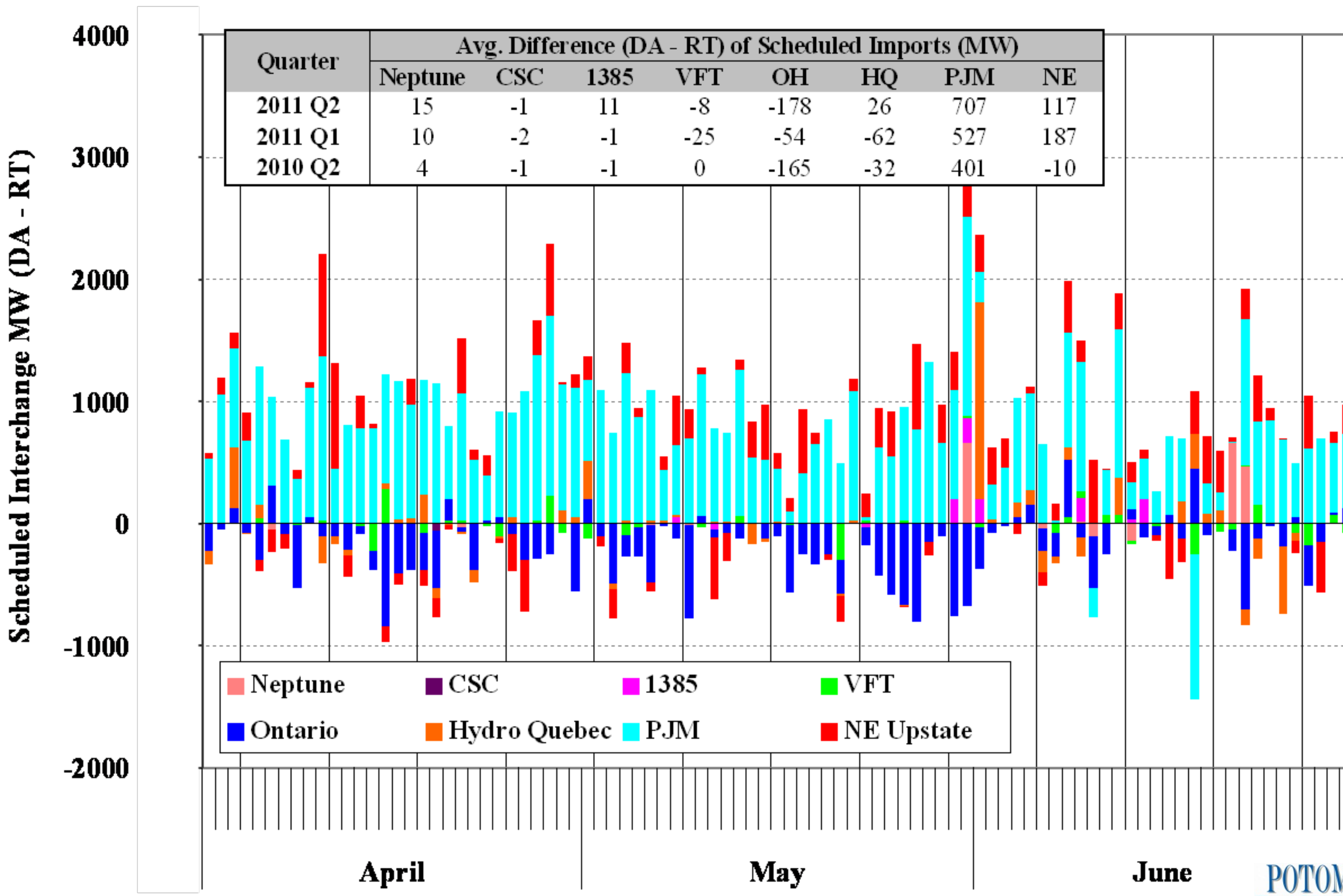
Change in Scheduled Imports from Day Ahead to Real Time

- 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 generally improve the convergence of day-ahead and real-time prices.
- Net scheduled imports fell 690 MW on average from day-ahead to real-time during daily peak load hours in the second quarter. Net scheduled imports:
  - ✓ Decreased across the PJM interface by an average of 707 MW;
  - ✓ Decreased across the primary interface with NE by an average of 117 MW; and
  - ✓ Frequently increased across the Ontario interface.
- Generally, the changes in schedules between the day-ahead and real-time markets were consistent with the changes in prices.
  - ✓ This was particularly evident at the PJM interface, where the average day-ahead price exceeded the average real-time price by more than $2/MWh in the quarter.
  - ✓ Accordingly, at the PJM interface, MPs scheduled substantial quantities of:
    - – "Virtual" imports in the day-ahead market (i.e., day-ahead imports not scheduled in the real-time); and
    - – Exports in the real-time.

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
2011 Q2	15	-1	11	-8	-178	26	707	117
2011 Q1	10	-2	-1	-25	-54	-62	527	187
2010 Q2	4	-1	-1	0	-165	-32	401	-10

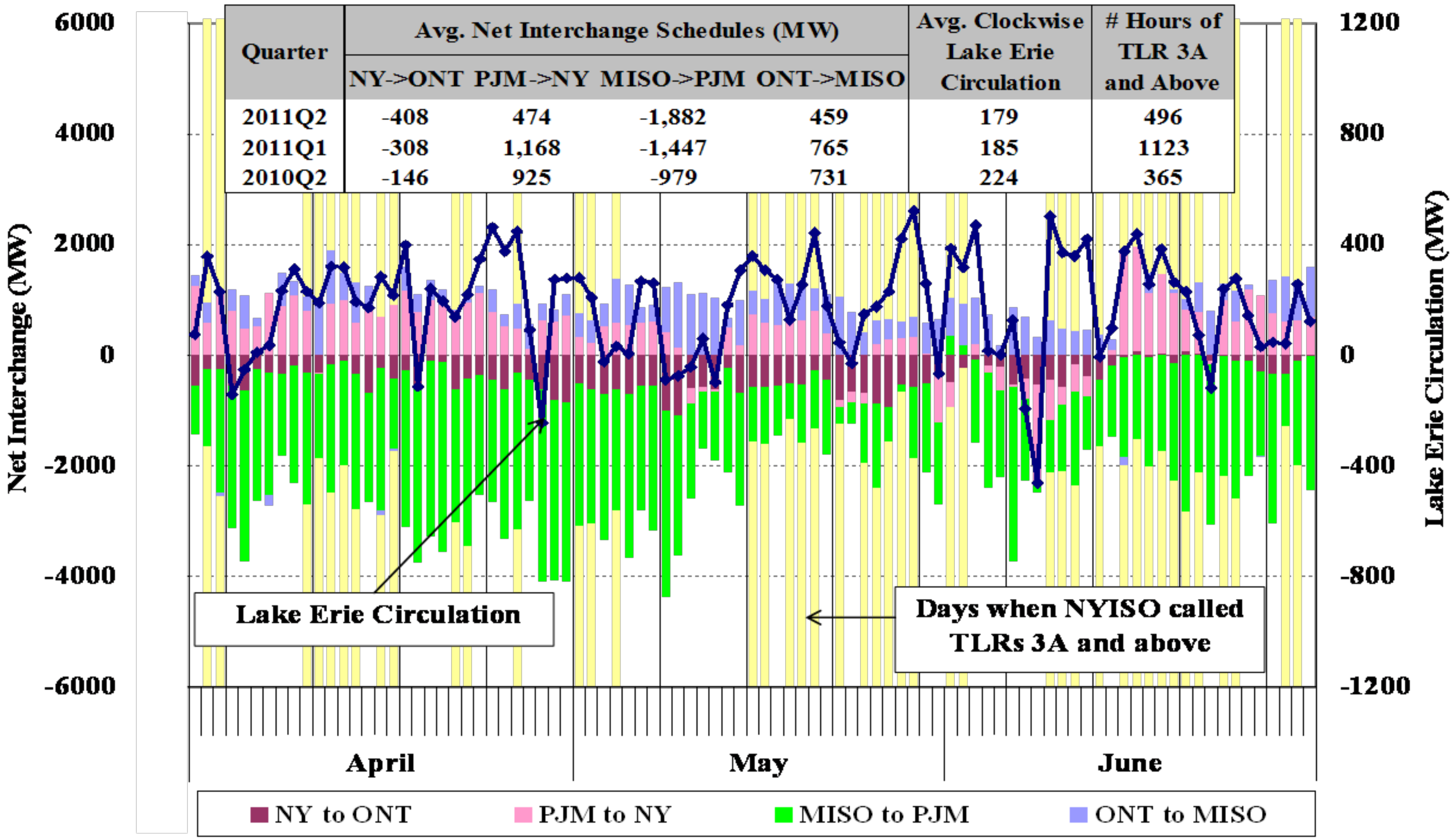
POTOMAC ECONOMICS

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.
  - ✓ Counter-clockwise scheduled transactions tend to increase clockwise loop flows.
  - ✓ Transmission Loading Relief ("TLR") procedure is used by the NYISO when loop flows contribute to congestion on internal flowgates.
- 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 approximately 180 MW in the second quarter, slightly lower than in the previous quarter and the second quarter of 2010.
  - ✓ The correlation of clockwise circulation and counter-clockwise transactions was weak, suggesting that internal dispatch by each ISO also affects circulation.
- TLRs were called on 43 days and in 496 hours, down from the previous quarter.
  - ✓ Clockwise circulation averaged 267 MW on days when TLRs were called and 104 MW on days when no TLRs were called during the second quarter.

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		
2011Q2	-408	474	-1,882	459	179	496
2011Q1	-308	1,168	-1,447	765	185	1123
2010Q2	-146	925	-979	731	224	365

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

POTOMAC ECONOMICS

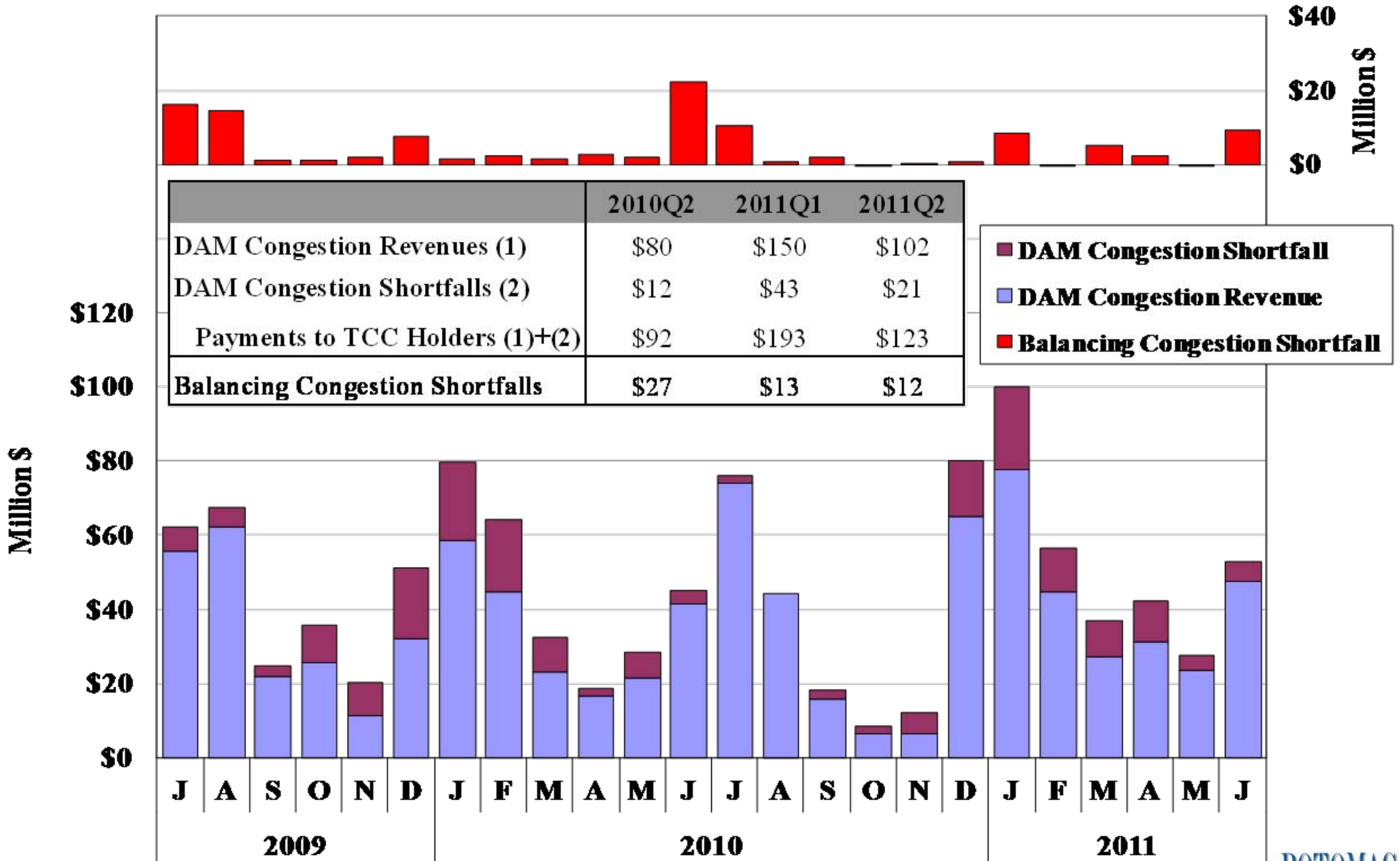
Congestion Revenue Collections and Shortfalls

- 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.

Congestion Revenue Collections 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 $102 million in the second quarter, down 32 percent from the previous quarter.
  - ✓ The decrease was primarily attributable to decreased congestion across the Central-East and Dysinger East interfaces.
  - ✓ Natural gas prices fell 30 percent in the second quarter, contributing to the decrease as well.
- Day-ahead congestion shortfalls decreased 52 percent from the first quarter of 2011 and rose 66 percent from the second quarter of 2010. In this quarter:
  - ✓ Shortfalls associated with the PAR-controlled lines between NJ and NY fell due to modeling improvements in the TCC auction for May 2011.
  - ✓ Lines in Hudson Valley and New York City accounted for the vast majority of total shortfalls, due primarily to transmission outages.
- Balancing congestion decreased to $12 million in the second quarter of 2011, down $1 million from the previous quarter and $15 million from a year ago.
  - ✓ Improved TSA operations have contributed to reduced shortfalls since July 2010.

Congestion Revenue Collections and Shortfalls



	2010Q2	2011Q1	2011Q2
DAM Congestion Revenues (1)	$80	$150	$102
DAM Congestion Shortfalls (2)	$12	$43	$21
Payments to TCC Holders (1)+(2)	$92	$193	$123
Balancing Congestion Shortfalls	$27	$13	$12

POTOMAC ECONOMICS

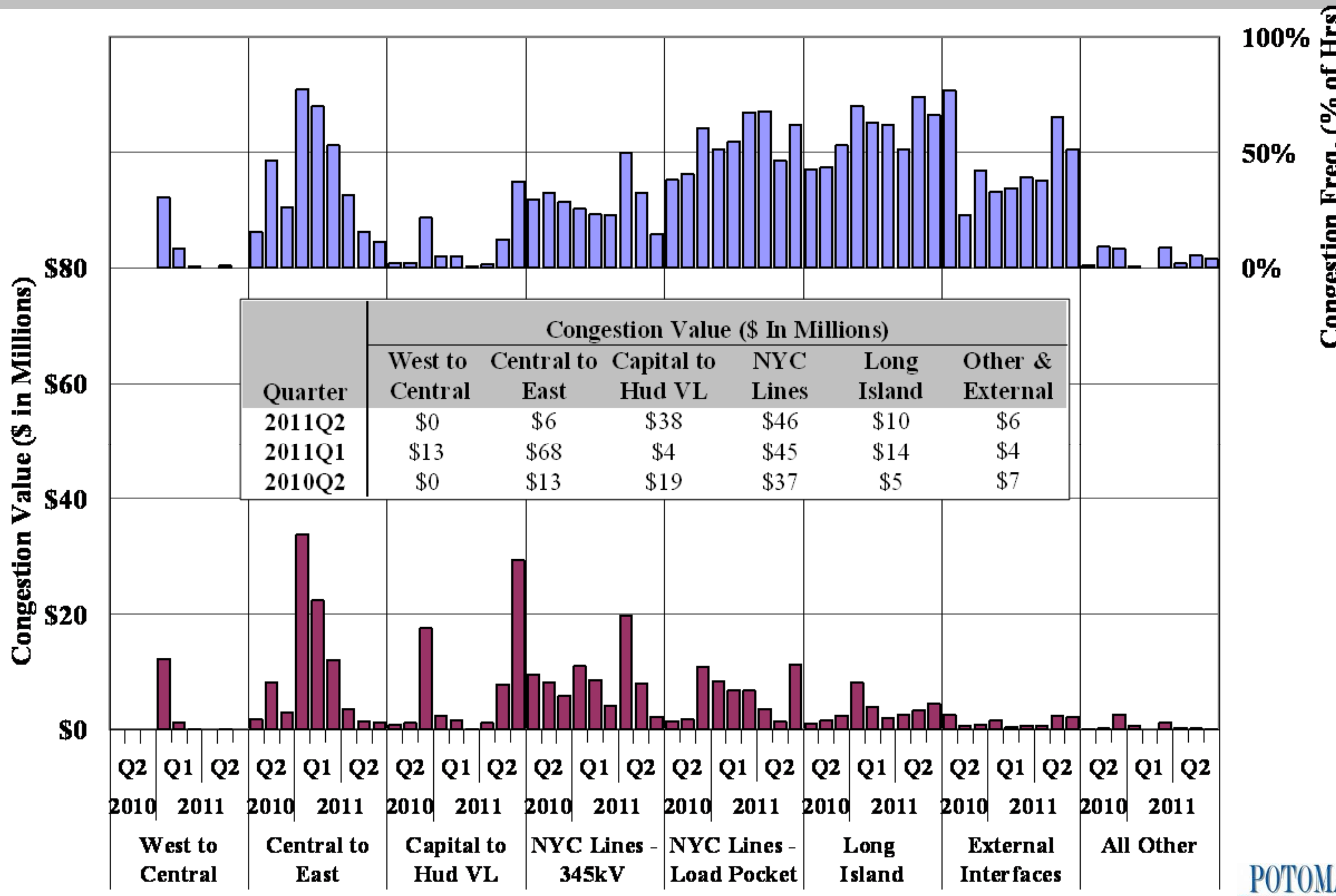
Congestion by Transmission Path

- 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 Leeds-to-Pleasant Valley line and the Leeds-to-New Scotland 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 the second quarter was collected for flows over lines into and within New York City (43 percent), lines from Capital to Hudson Valley (36 percent), and lines into Long Island (9 percent).
  - ✓ This pattern is similar to the second quarter of 2010, reflecting increased imports to these areas during high load periods, expectations of TSA-related congestion, and the effects of several transmission outages.
- The primary transmission bottlenecks shifted from the Dysinger East and Central-East interfaces in the first quarter to lines through the Hudson Valley (e.g., Leeds-Pleasant Valley) and in New York City in the second quarter.
  - ✓ Central-East congestion fell due to increased imports from New England, lower natural gas prices, and increased generation to manage congestion into SENY, which also helps relieve Central-East congestion.

Day-Ahead Congestion by Transmission Path



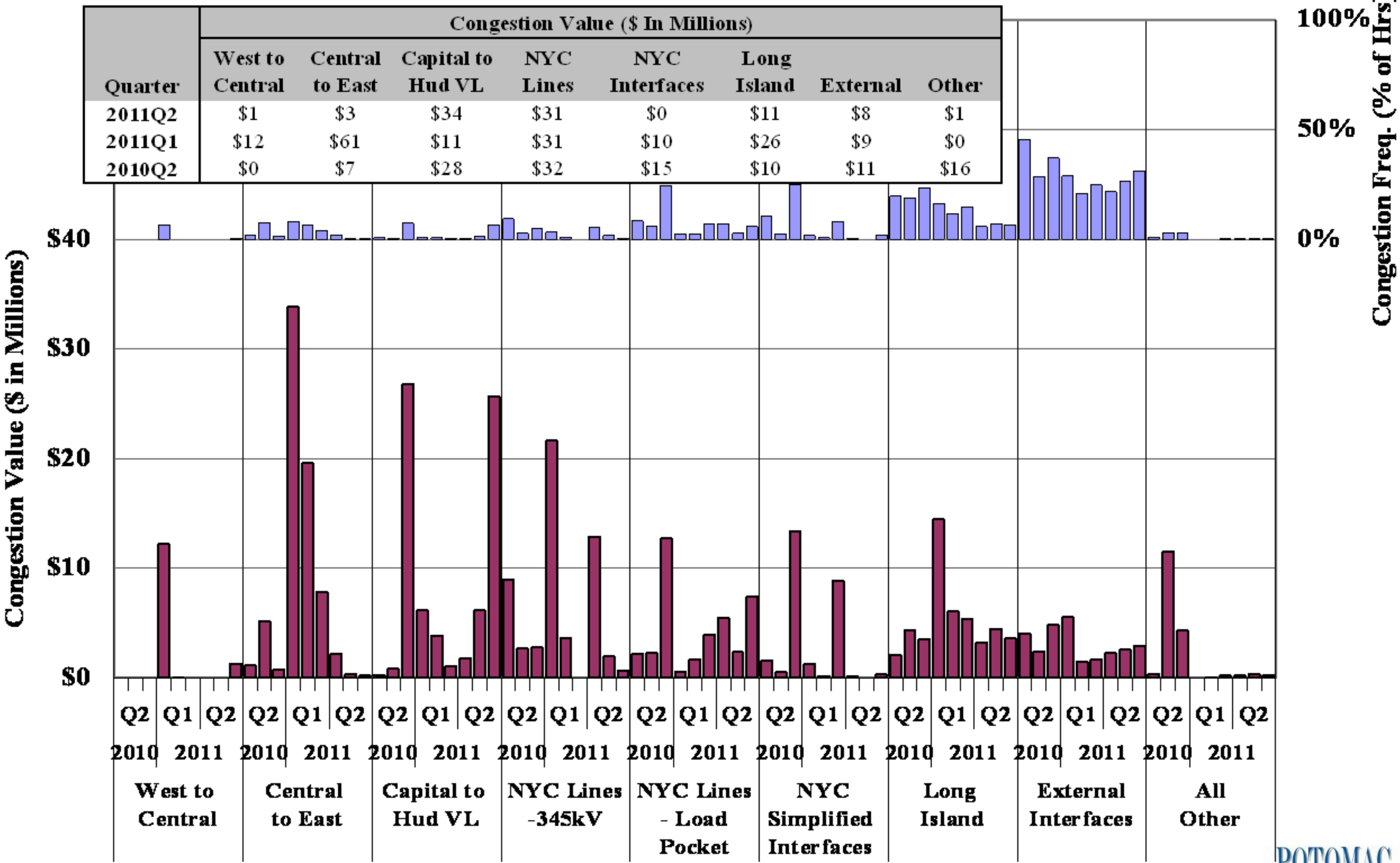
Quarter	Congestion Value ($ In Millions) West to Central	Central to East	Capital to Hud VL	NYC Lines	Long Island	Other & External
2011Q2	$0	$6	$38	$46	$10	$6
2011Q1	$13	$68	$4	$45	$14	$4
2010Q2	$0	$13	$19	$37	$5	$7

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 $89 million in the second quarter, down 45 percent from the previous quarter and down 32 percent from a year ago.
  - ✓ The substantial decrease from the previous quarter reflected the 30 percent decrease in natural gas prices.
  - ✓ The decrease from the previous year was partly due to more efficient congestion management in New York City load pockets and more efficient commitment resulting from better consistency between day-ahead and real-time prices.
- Real-time congestion occurred mostly in the following areas in the second quarter:
  - ✓ *Capital to Hudson Valley* (38 percent):
    - 76 percent of this accrued in June, reflecting increased load, reduced transfer capability due to line outages, and more frequent TSAs in this month.
  - ✓ *NYC lines and simplified interface constraints* (35 percent):
    - Congestion into the 345 kV system from April to early May accounted for 47 percent of this total, during which a major line into the 345 kV system was out.
    - Congestion into the Greenwood load pocket accounted for 44 percent.

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	Other
2011Q2	$1	$3	$34	$31	$0	$11	$8	$1
2011Q1	$12	$61	$11	$31	$10	$26	$9	$0
2010Q2	$0	$7	$28	$32	$15	$10	$11	$16



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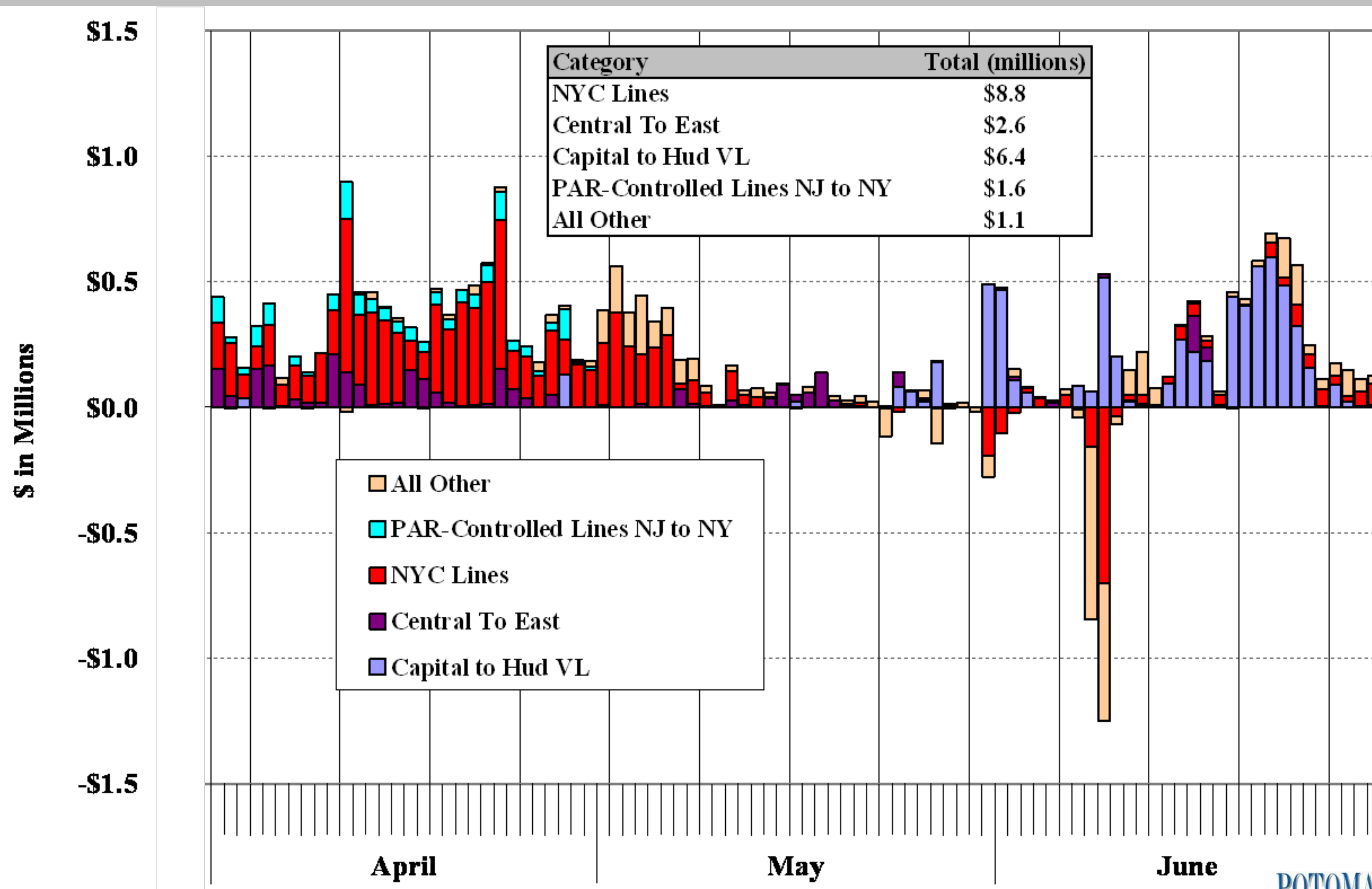
Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily day-ahead congestion revenue shortfalls by transmission path or facility in the second quarter of 2011.
  - ✓ 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 residuals are allocated to the responsible TO.)
- NYC facilities accounted for 43 percent of shortfalls due to outages that reduced transfer capability into the city from upstate (e.g., Sprainbrook-W49th) and into the Greenwood load pocket (e.g., Gowanus-Greenwood) in April and early May.
- Capital to Hudson Valley accounted for 31 percent of shortfalls, mostly due to transmission outages in late May and in June (e.g., New Scotland-Leeds).
- PAR-controlled lines between NJ and NY accounted for only 8 percent of shortfalls in the second quarter, much less than in the past.
  - ✓ A modeling improvement was implemented in May 2011 that virtually eliminated these shortfalls.

Day-Ahead Congestion Revenue Shortfalls



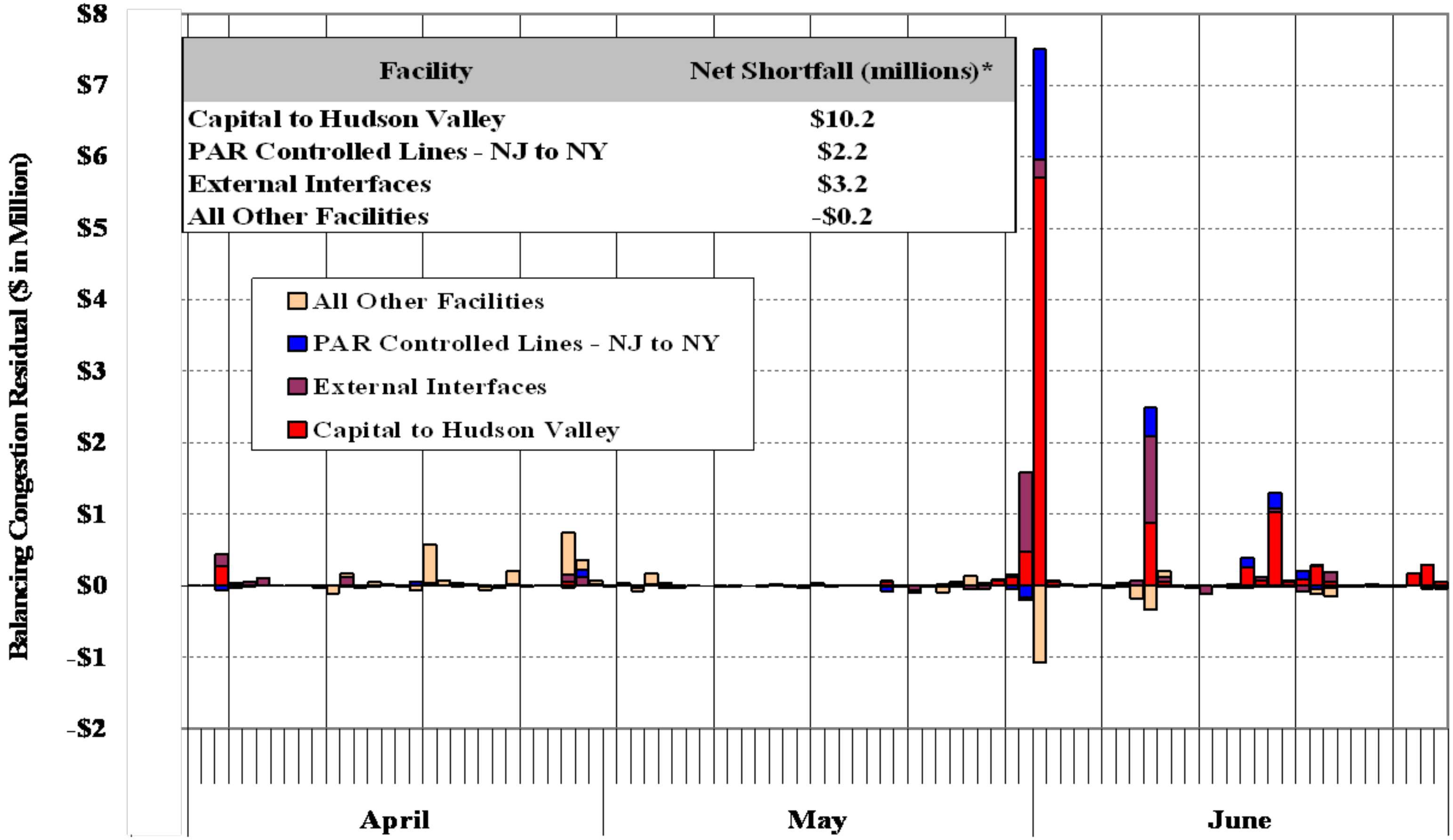
Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the second quarter of 2011.
  - ✓ 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

- Capital to Hudson Valley accounted for the largest share (66 percent) of balancing congestion shortfalls. These primarily accrued on three days (June 1, 9, & 18).
  - ✓ TSAs were called on June 1 and 9, which greatly reduced the transfer capability on the Leeds-Pleasant Valley line.
  - ✓ One New Scotland-Leeds line was forced out on June 17, leading to high shortfalls on June 18.
  - ✓ On these days, loop flows from New England (which are not explicitly modeled in the day-ahead market) also reduced available transfer capability into SENY in real-time, contributing to the shortfalls.
- External Interfaces accounted for 21 percent of the shortfalls.
  - ✓ These often result when transactions are scheduled by RTC and subsequently curtailed in real-time to manage congestion.
- PAR Controlled Lines between New Jersey and New York accounted for 14 percent of shortfalls.
  - ✓ These generally coincide with TSAs, reflecting that it can be difficult to maintain the scheduled flow on these lines during TSA operations.
- Simplified interface constraints were rarely used to manage congestion in New York City load pockets. This contributed to lower shortfalls.

Balancing Congestion Shortfalls



Note: These slightly over-estimate shortfalls since they are partly based on real-time schedules rather than metered values. The estimates exclude 49 price-corrected intervals in the second quarter.

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.

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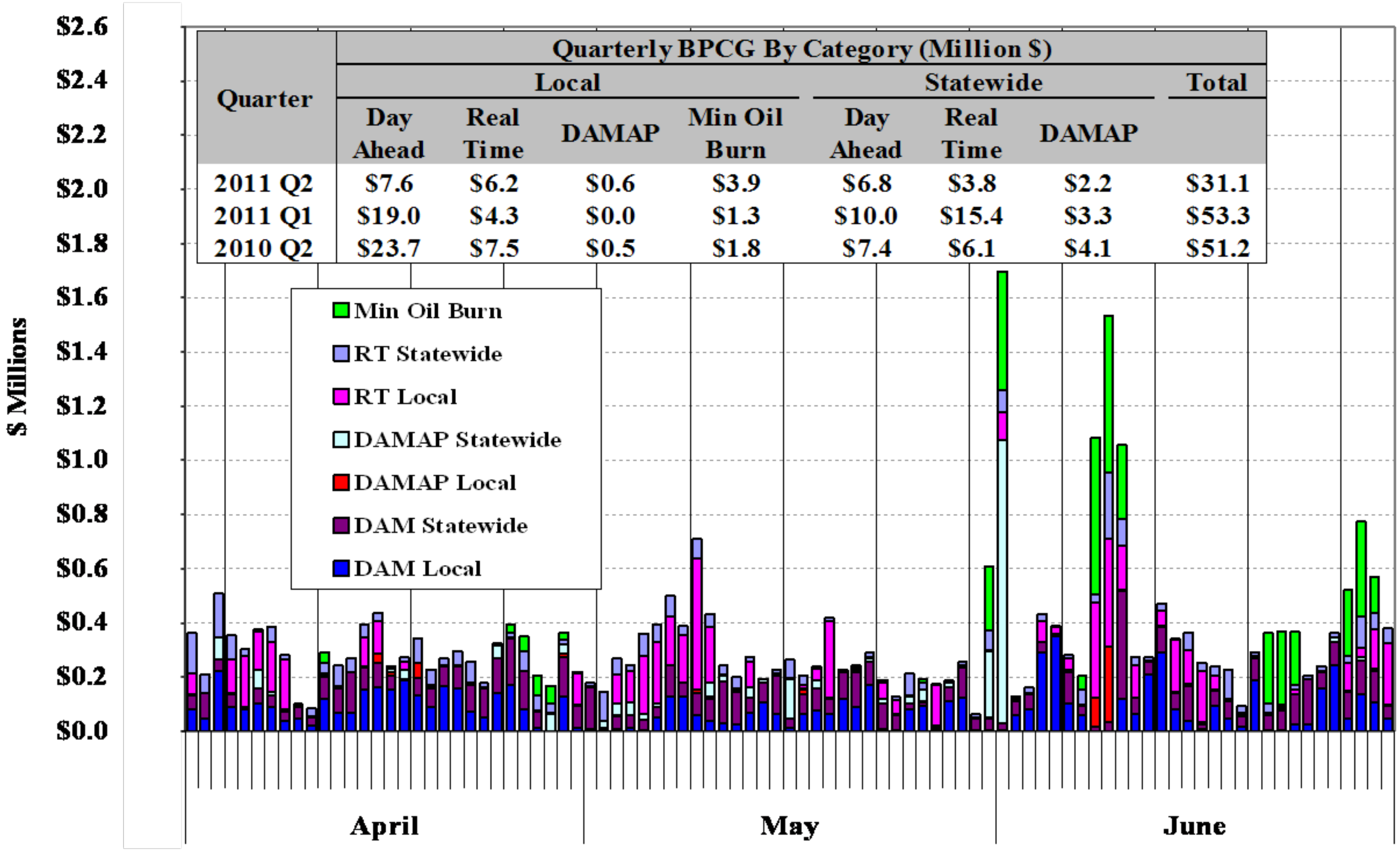
Uplift Costs from Guarantee Payments

- The following figure shows the seven categories of uplift charges on a daily basis in the second quarter of 2011.
- Guarantee payment uplift was $31 million, down significantly from the previous quarter (42 percent) and the second quarter of 2010 (39 percent).
  - ✓ The decrease from the previous quarter was mostly associated with decreases in day-ahead local and real-time statewide uplift, driven largely by:
    - – Lower natural gas prices; and
    - – Fewer DARUs in Long Island and fewer SREs in western NY.
  - ✓ The decrease from the second quarter of 2010 was mostly associated with:
    - – Less uplift from day-ahead reliability commitment in western NY and in NYC.
    - – Lower DAMAP uplift as a result of improved TSA operations.
  - ✓ However, mitigation consultations are on-going for the second quarter, so guarantee payments will increase once these are fully reflected.
- Guarantee payment uplift rose significantly on high load days, averaging $0.9 million on days when load reached 26 GW and just $0.3 million on other days.
  - ✓ High loads frequently require OOM dispatch on the East End of Long Island (RT Local), payments to Minimum Oil Burn Compensation program units, and DAMAP payments during transient congestion price spikes.

Uplift Costs from Guarantee Payments

Local and Non-Local by Category



Quarterly BPCG By Category (Million $)

Quarter	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2011 Q2	$7.6	$6.2	$0.6	$3.9	$6.8	$3.8	$2.2	$31.1
2011 Q1	$19.0	$4.3	$0.0	$1.3	$10.0	$15.4	$3.3	$53.3
2010 Q2	$23.7	$7.5	$0.5	$1.8	$7.4	$6.1	$4.1	$51.2

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.

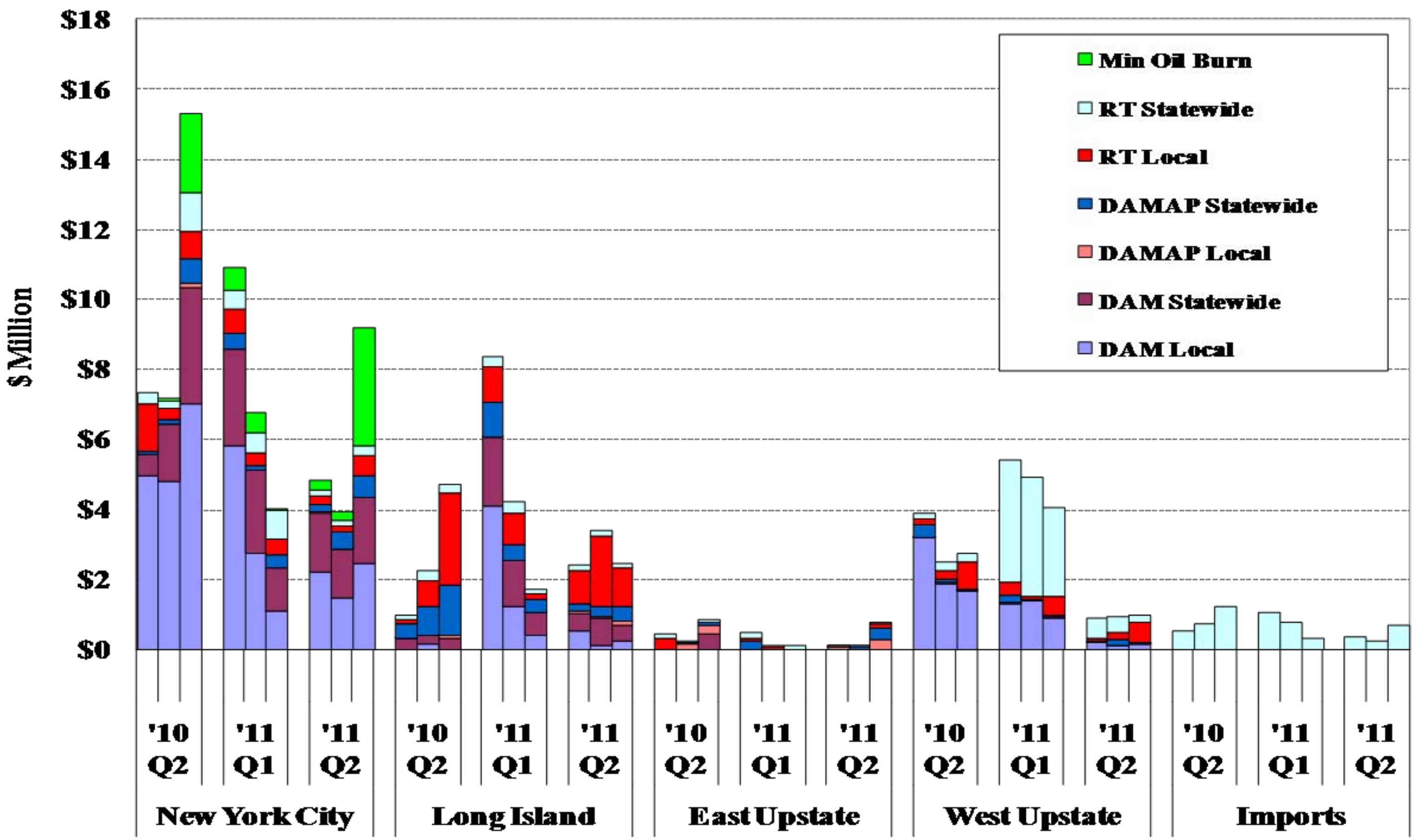
Uplift Costs from Guarantee Payments

- The following figure shows the seven categories of uplift charges on a monthly basis by region.
- Day-ahead local reliability uplift in the second quarter of 2011:
  - ✓ The majority was for New York City (82 percent) and Long Island (12 percent), primarily for DARU and LRR commitments.
- Day-ahead statewide uplift in the second quarter of 2011:
  - ✓ The majority was paid to generators in New York City and Long Island at several locations 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 second quarter of 2011:
  - ✓ Long Island accounted for 67 percent, primarily to manage local congestion on the East End where some generators do not have a source of natural gas.
- Real-time statewide uplift in the second quarter of 2011:
  - ✓ The majority was for imports (40 percent) and Western New York (33 percent).

Uplift Costs from Guarantee Payments

- Overall, guarantee payment uplift fell 39 percent from the second quarter of 2010.
  - ✓ However, mitigation consultations are on-going for the second quarter, so guarantee payments will increase once these are fully reflected.
- In western NY (including the North Zone), day-ahead local reliability uplift fell 93 percent from $6.7 million in the second quarter of 2010.
  - ✓ In 2010, there were local transmission outages that required units that would not otherwise have been economic to be online for reliability.
- In New York City, day-ahead local uplift fell from $16.8 million in second quarter 2010 to $6.2 million in second quarter 2011.
  - ✓ Less capacity was needed for local reliability than in the previous year, partly due to the new transmission line (Dunwoodie-Academy) into the City.
  - ✓ Generators needed for local reliability in the DAM were economically committed more frequently and/or earned less BPCG per unit of output, partly due to:
    - Increased participation in the Min Oil Burn Compensation program; and
    - Improved convergence between day-ahead and real-time prices and generator reference level accuracy.
- In Long Island, day-ahead local and statewide uplift rose from $1.1 million in the second quarter of 2010 to $2.7 million, partly due to higher oil prices.

Uplift Costs from Guarantee Payments
By Category and Region



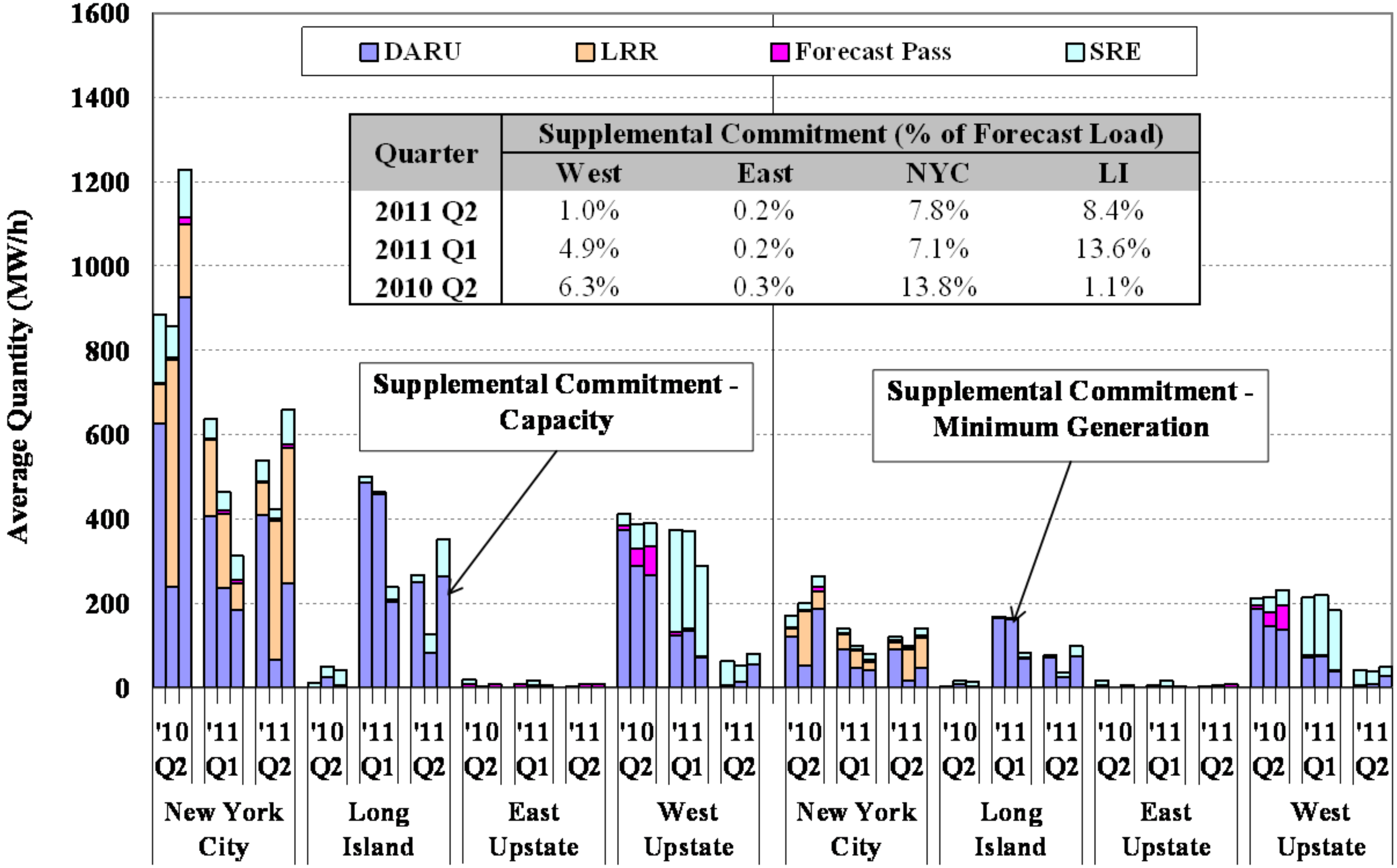
Note: These data are based on information available at the reporting time and do not include some manual adjustments to the mitigation of guarantee payments, hence they can be different from final settlements.

POTOMAC ECONOMICS

Supplemental Commitment for Reliability

- The following figure shows the monthly quantities of capacity (left) and minimum generation (right) committed for reliability by type of commitment and region.
- Reliability commitment in Long Island rose considerably from a year ago.
  - ✓ Committed capacity averaged roughly 250 MW in the second quarter of 2011, up 215 MW from the second quarter of 2010.
  - ✓ The minimum generation level of these units averaged 70 MW, up 60 MW from the second quarter of 2010.
  - ✓ DARU commitment rose from a year ago, partly because units that are required to burn a gas-oil blend for reliability are economic less often due to higher oil prices.
- Reliability commitment in New York City decreased substantially from the second quarter of 2010.
  - ✓ Committed capacity averaged 540 MW, down nearly 45 percent from a year ago.
  - ✓ The minimum generation level of these units averaged 120 MW, down 43 percent from the second quarter of 2010.
  - ✓ The decrease in reliability commitment was driven partly by the new transmission line into the City and partly because units needed for reliability are more frequently economic.
- DARU commitment in western New York fell from a year ago partly due to fewer transmission outages.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2011 Q2	1.0%	0.2%	7.8%	8.4%
2011 Q1	4.9%	0.2%	7.1%	13.6%
2010 Q2	6.3%	0.3%	13.8%	1.1%

POTOMAC ECONOMICS

Supplemental Commitment for Reliability in NYC

- The following figure evaluates the reasons for reliability commitments in the second quarter of 2011 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:
  - ✓ NOX Only – If needed for NOX bubble 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 and no other reason except NOX. 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 (AWLP = Ast West/Queens, AVLP = Ast West/Queens/Vernon, ERLP = East River, 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.

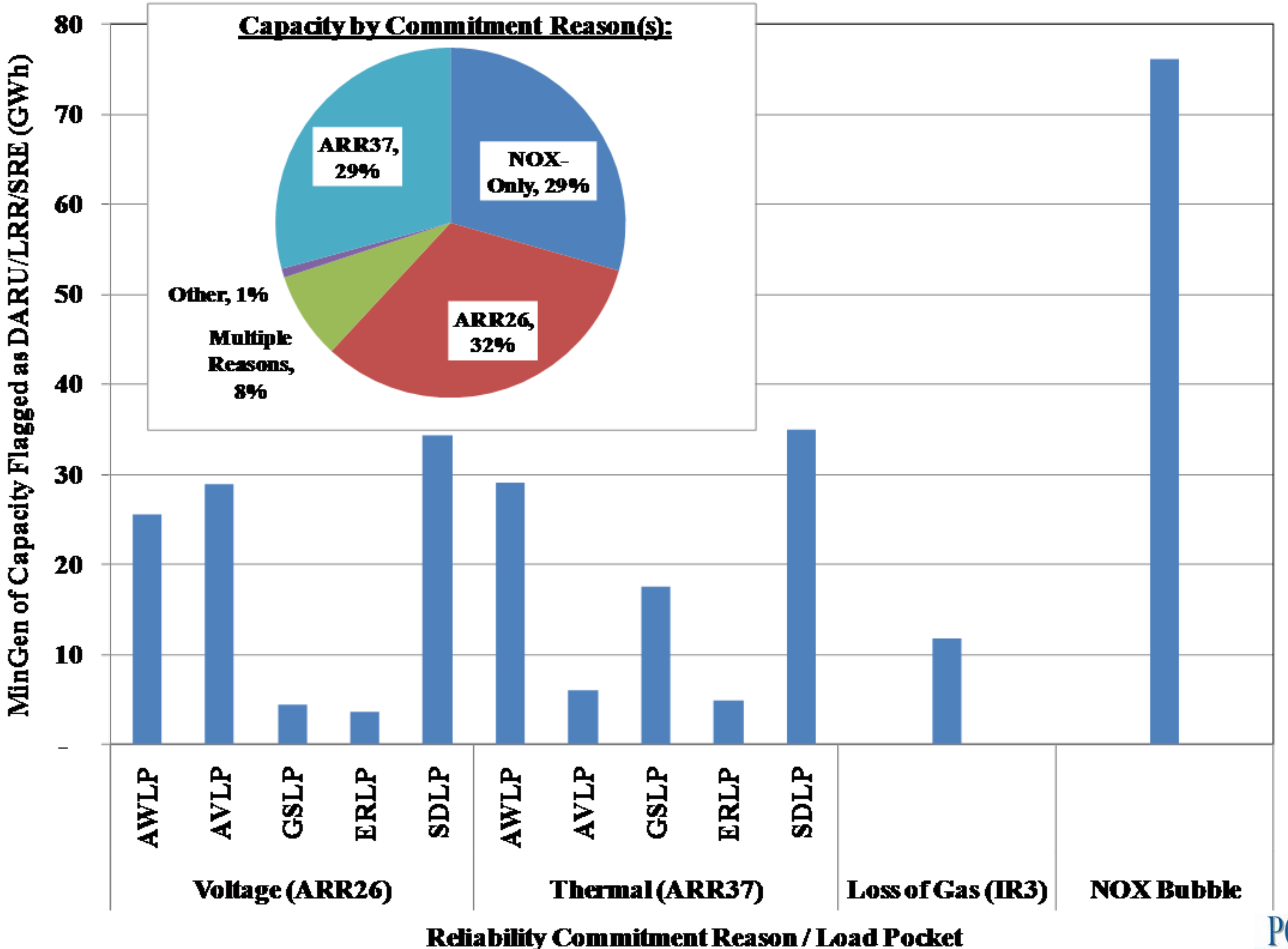
Supplemental Commitment for Reliability in NYC

- The reliability requirements that accounted for the most MWhs of capacity were:
  - ✓ NOX bubble requirements – These require the operation of a steam turbine unit in order to reduce the overall NOX emission rate from a portfolio containing higher-emitting gas turbine units.
  - ✓ Sprainbrook/Dunwoodie thermal and voltage requirements – These ensure 345 kV facilities in New York City will not be overloaded if the largest two generation or transmission contingencies were to occur.
  - ✓ Astoria West/Queensbridge/Vernon thermal and voltage requirements – These ensure facilities into this pocket will not be overloaded if the largest two generation or transmission contingencies were to occur.
- Steam turbine units were flagged for NOX-only in 801 unit-hours during the second quarter.
  - ✓ The estimated weighted-average heat rate of these units was 12 MMbtus per MWh in these hours, reflecting that they usually ran at a relatively low (and less fuel-efficient) operating level.
  - ✓ In 77 percent of these hours, unloaded capacity was available on more fuel-efficient and lower-NOX-emitting gas-fired units that would have been sufficient to displace the production from the steam unit flagged for NOX.

POTOMAC ECONOMICS

Supplemental Commitment for Reliability in NYC

by Reliability Reason and Load Pocket



POTOMAC ECONOMICS

Market Monitoring and Mitigation

- The following figure summarizes energy offer mitigation as well as the results of potential withholding screens from hours-beginning 14 to 19, Monday to Friday.
- 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.

Market Monitoring and Mitigation

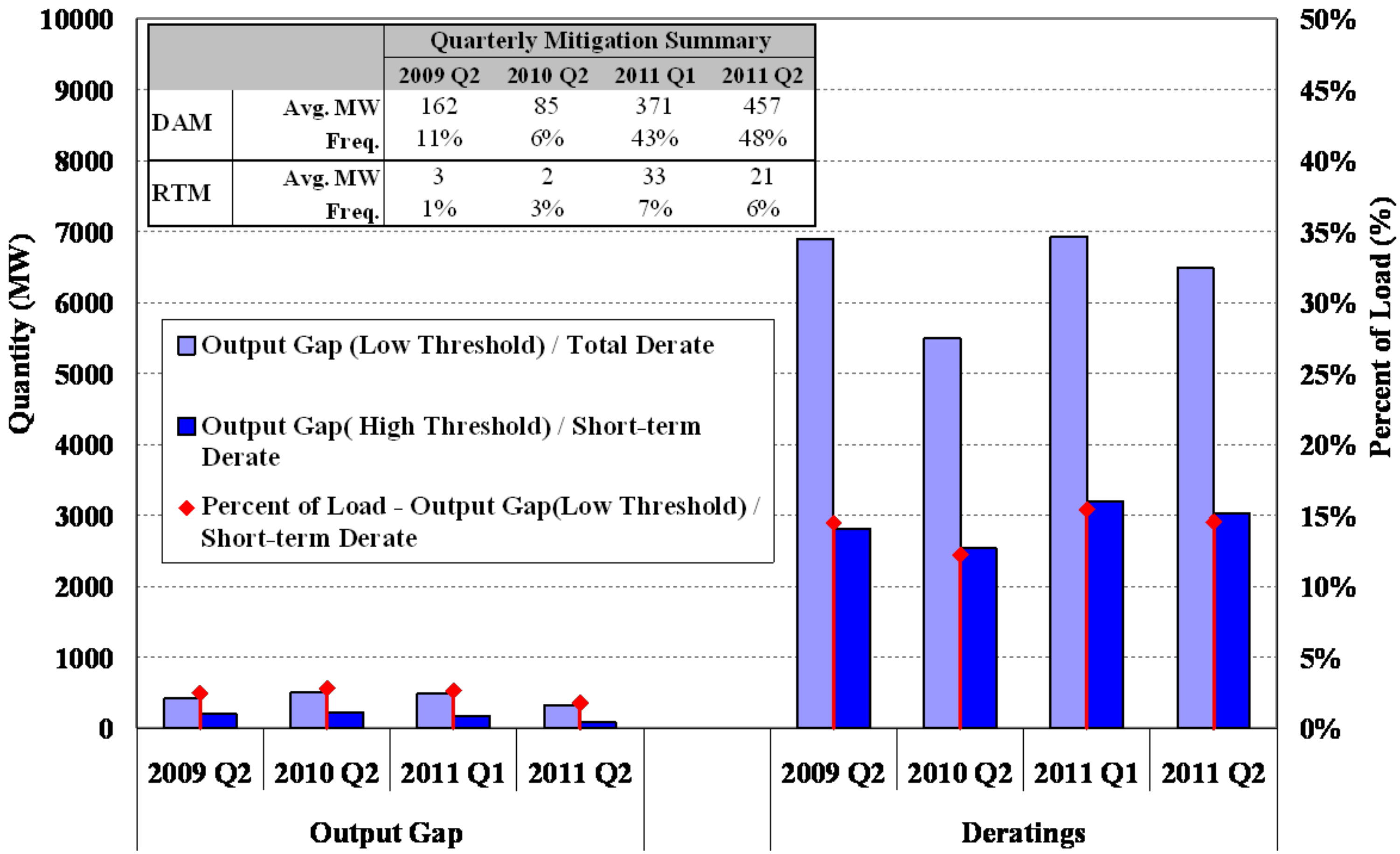
<u>Automated Mitigation in the Day-Ahead and Real-Time Markets:</u>

- Most mitigation occurred day-ahead for Astoria West/Queens/Vernon congestion (35%), DARU & LRR units (24%), and In-City 138 kV congestion (19%).
- Mitigation increased substantially from 2010 due primarily to the application of the new ROS reliability mitigation rules (since October 2010).
- Mitigation has also increased due to:
  - ✓ Some units having "LBMP-based" reference levels that were below their costs.
  - ✓ Increased mitigation of reliability-committed units whose fuel type varies by time of day as a result of minimum oil-burn reliability rules, since software limitations allow just one fuel type for a particular unit for all hours in the DAM.
  - ✓ Accordingly, mitigation consultations have reversed many of these instances for the first quarter, and consultations are on-going for the second quarter.

<u>Output Gap at High and Low Thresholds and Long-Term and Short-Term Deratings:</u>

- The output gap was low as a share of load in this quarter (< 2 percent), occurring primarily during periods when the prices would not be substantially affected.
- Total deratings are significant, but physical withholding concerns are limited because: (i) deratings are highest in shoulder months when demand is lowest, and (ii) most deratings are long-term and less likely to reflect withholding.

Market Monitoring Screens and Mitigation



		Quarterly Mitigation Summary			
		2009 Q2	2010 Q2	2011 Q1	2011 Q2
DAM	Avg. MW	162	85	371	457
	Freq.	11%	6%	43%	48%
RTM	Avg. MW	3	2	33	21
	Freq.	1%	3%	7%	6%

Note: Mitigation summaries for 2011-Q1 are revised from the previous report to: (1) reflect the results from mitigation consultations, and (2) include ROS SREs, which were previously omitted.

Capacity Market Results

- The following figure summarizes available and scheduled UCAP resources and the clearing prices in each capacity zone.
- Due to seasonal variations, there are higher levels of internal capacity and lower demand curves in the Winter Capability Period (e.g., April) than in the Summer (e.g., May and June), and correspondingly lower clearing prices.
- In New York City, UCAP spot prices fell to an average of $9.02/kW-month in the this quarter, down 20 percent from the second quarter of 2010 due to:
  - ✓ Increased capacity sales from new and existing facilities; and
  - ✓ A 211 MW reduction in the peak load forecast for NYC in summer 2011.
  - ✓ However, this was partly offset by an increase in the Local Capacity Requirement from 80 percent to 81 percent over the same period.
- Overall, UCAP sales in NYC rose significantly from last year, due partly to an improvement in forced outage rates.
  - ✓ However, this did not significantly reduce prices because an improvement in forced outage rates triggers an increase in the UCAP requirement.
- The figure shows that virtually all internal capacity has been sold in each month so withholding of supply has not been a concern in New York City.

Capacity Market Results

- In the Rest of State and Long Island, UCAP spot prices fell to an average of \$0.45/kW-month in this quarter, down from \$2.09/kW-month and \$2.86/kW-month in the second quarter of 2010, respectively.
  - ✓ A substantial amount of capacity was unoffered/unsold in the second quarter of 2011, primarily due to the relatively large prevailing capacity surplus and the low clearing prices.
  - ✓ The Long Island Local Capacity Requirement was binding only in May 2010 (when sales under UDRs fell for one month). Otherwise, Long Island and Rest of State clearing prices have been equal during the two quarters.
- Clearing prices outside New York City were affected by the following factors:
  - ✓ Increased sales from internal capacity at some new and existing facilities, which have contributed to lower clearing prices in the second quarter of 2011.
  - ✓ The capacity requirement for NYCA fell 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.

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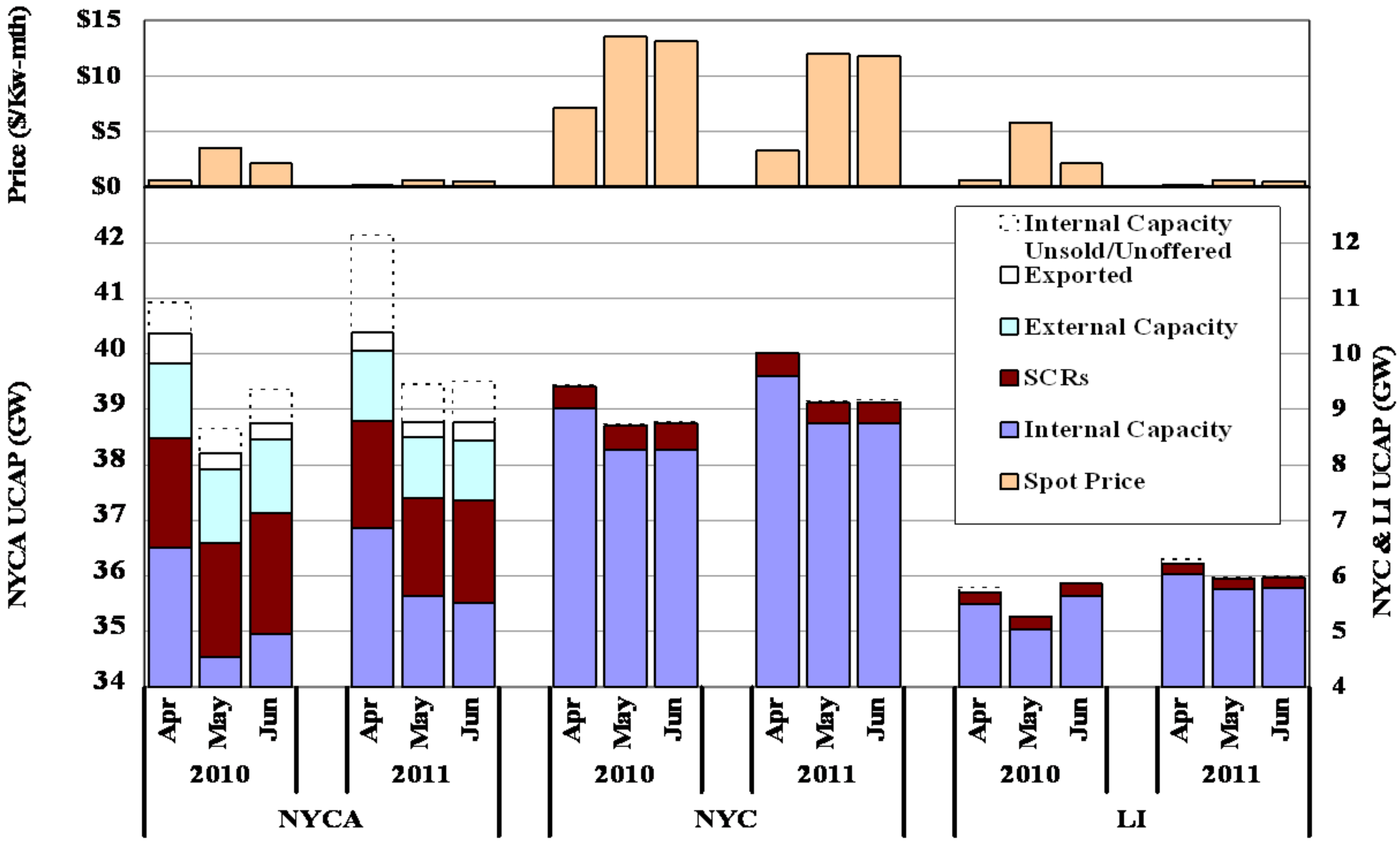
Capacity Market Results



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

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