Quarterly Report on the New York ISO Electricity Markets Second Quarter 2010

Pallas LeeVanSchaick, Ph.D.
David B. Patton, Ph.D.

Potomac Economics
Market Monitoring Unit

July 2010

Highlights and Market Summary

- This presentation summarizes the outcomes of the NYISO energy, ancillary services, and capacity markets during the second quarter of 2010.
- The markets performed competitively and variations in wholesale market prices were driven primarily by changes in fuel prices and installed capacity.
- Real-time energy prices averaged $50/MWh statewide, down 4 percent from the previous quarter and up 28 percent from the second quarter of 2009.
  - ✓ Natural gas prices decreased 29 percent from the prior quarter but rose 14 percent from the second quarter of 2009.
  - ✓ Average load rose 6 percent from the second quarter of 2009, primarily due to much hotter weather in the month of June.
- Convergence between day-ahead and real-time prices was relatively poor as the day-ahead market did not fully anticipate the cost of real-time congestion in Southeast New York.
  - ✓ Average real-time prices were higher than average day-ahead prices by 10 percent in New York City and by 14 percent in Long Island.
  - ✓ Similarly, the value of real-time congestion was $120 million, while day-ahead congestion revenue totaled just $80 million.

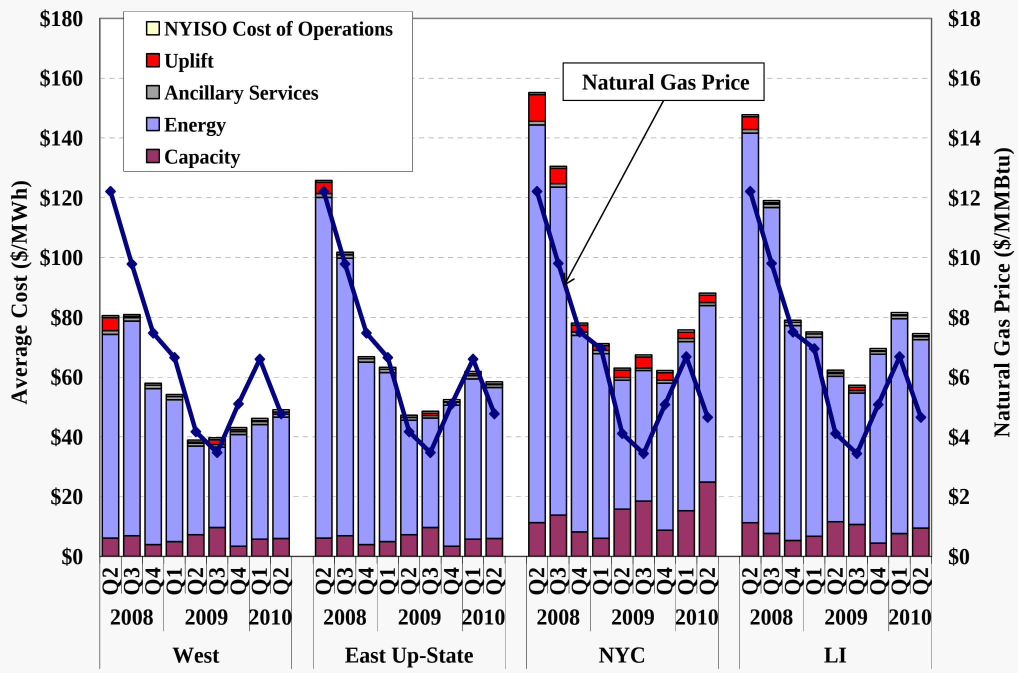
Highlights and Market Summary

- Capacity prices rose substantially in New York City and fell modestly in Long Island and Rest-of-State from the second quarter of 2009.
  - ✓ New York City prices averaged $11.28/kW-month, up 92 percent from the second quarter of 2009 due primarily to the retirement of the Poletti unit.
  - ✓ The effects of the Poletti retirement were offset by capacity additions in New York City and Long Island, as well as by reductions in the summer peak load forecast.
- Uplift charges decreased in the second quarter of 2010 from prior periods.
  - ✓ Guarantee payments allocated locally totaled $34 million, down $3 million from the prior quarter and up $3 million from the second quarter of 2009. These fluctuations are largely due to transitory local reliability issues.
  - ✓ Guarantee payments allocated state-wide totaled $17 million, down $5 million from the prior quarter and the second quarter of 2009.
  - ✓ Balancing congestion revenue shortfalls rose to $27 million, up $22 million from the prior quarter and $10 million from the second quarter of 2009. Most of this occurred during Thunderstorm Alerts.
  - ✓ Day-ahead congestion revenue shortfalls fell to $12 million, down 76 percent from the prior quarter and 56 percent from the second quarter of 2009.

All-In Energy Price

- To summarize overall price trends in the New York markets, the following figure shows the “all-in” price metric, along with a natural gas price trend.
  - ✓ This includes energy, ancillary services, capacity, uplift, and NYISO costs.
  - ✓ The energy component is a load-weighted average real-time energy price.
  - ✓ The capacity component is based on spot capacity prices and capacity obligations in each area, allocated over energy consumption in the area.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges are averaged across all consumption in the relevant area.
- The natural gas price trend is closely correlated with energy prices, which account for most of the All-In Price.
- All-in prices rose 20 to 40 percent from the second quarter of 2009, reflecting higher fuel prices, higher summer demand, and higher New York City capacity prices after the retirement of Poletti.
- Compared to the first quarter of 2010, all-in prices were mixed as the effects of more frequent peak demand conditions, higher capacity prices, and congestion during TSAs were offset by the 29 percent decline in natural gas prices.

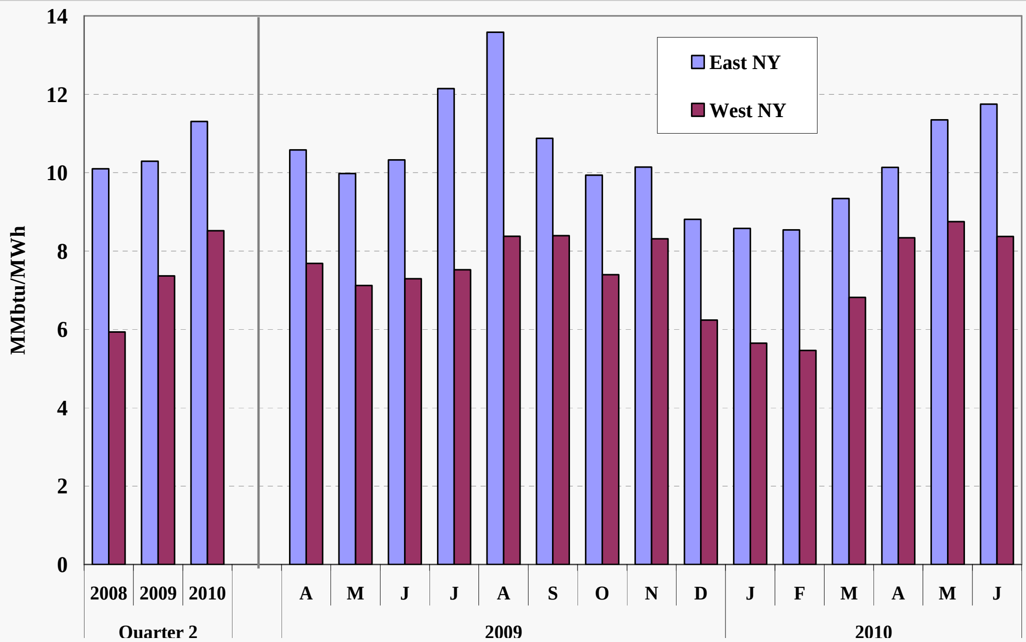
All-In Energy Price by Region



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)
- The implied marginal heat rate rose 10 percent in East New York and 16 percent West New York from the second quarter of 2009 to the second quarter of 2010. The following factors contributed to the increases:
  - ✓ Load levels were substantially higher in the second quarter of 2010, resulting in more frequent dispatch of high-cost generation.
  - ✓ The retirement of the Poletti steam unit reduced supply in New York City, resulting in more frequent use of peaking units during high load conditions.
  - ✓ Fuel oil prices rose significantly, increasing the offers of some oil-fired and dual-fueled generators.
  - ✓ Production from hydro-electric generation fell 20 percent.
- However, these factors were partly offset by new generating capacity in Long Island, lower RGGI allowance prices, and increased imports from Quebec, PJM, and New England.

Implied Heat Rate by Region

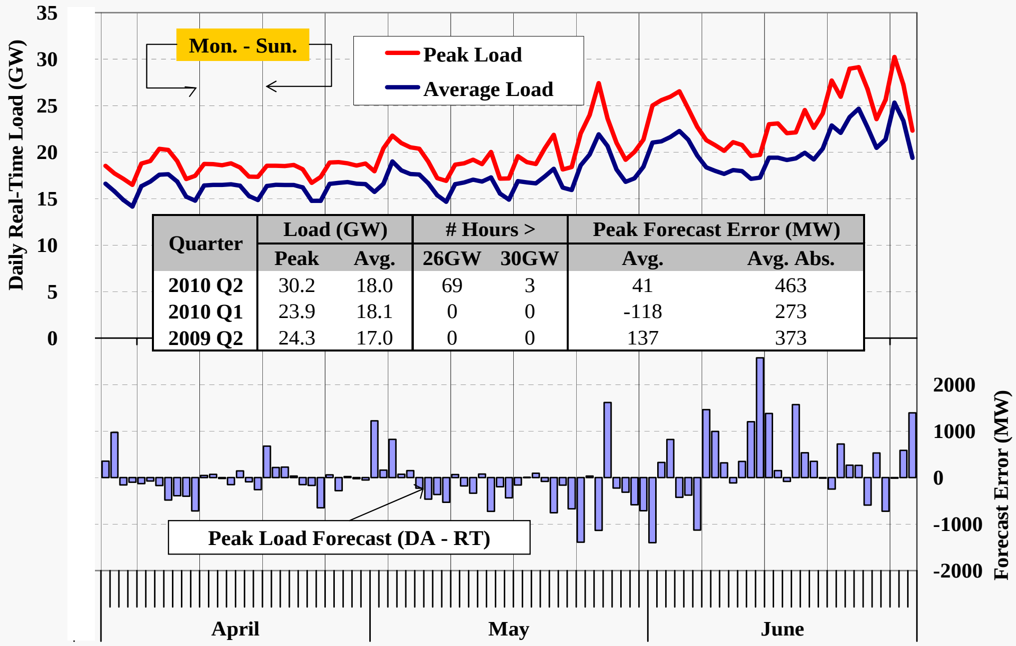


Note: Implied heat rates are for natural gas units and are based on day-ahead prices.

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.
  - ✓ The table compares key statistics for the second quarter of 2010 to the previous quarter and the second quarter of 2009.
- Loads increased considerably from the second quarter of 2009, reversing the recent trend of year-over-year declines in electricity demand.
  - ✓ On average, load was 6 percent higher than in the second quarter of 2009 but approximately equal to the second quarter of 2008.
  - ✓ Load peaked on June 28th at 30.2 GW (not including losses), which was 24 percent higher than the peak in the second quarter of 2009.
  - ✓ Load exceeded 26 GW for 69 hours and 30 GW for 3 hours, while load never reached 26 GW in the second quarter of 2009.
- The figure also shows that peak load forecasting was generally good, although large errors (> 1 GW) occurred on a number of days during the quarter.
  - ✓ Large forecast errors occurred mostly on days when load was below 26 GW. These generally result in less market impact than on days with high loads.

Load Forecast and Actual Load



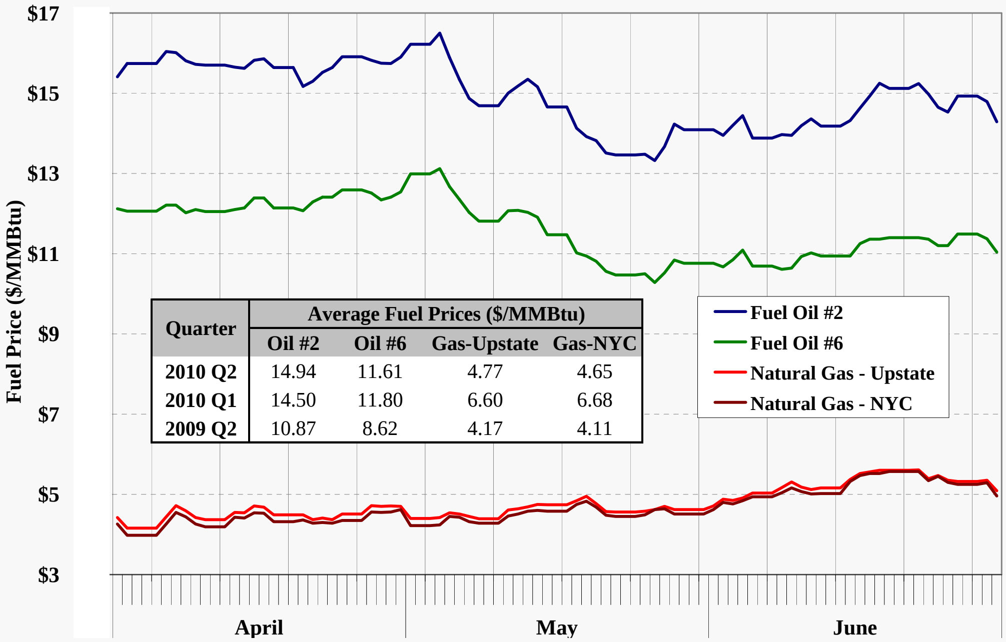
Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2010 Q2	30.2	18.0	69	3	41	463
2010 Q1	23.9	18.1	0	0	-118	273
2009 Q2	24.3	17.0	0	0	137	373

Note: Load does not include transmission losses.

Natural Gas and Oil Prices

- The following figure shows daily natural gas and fuel oil prices, which are key determinants of electricity prices.
- Natural gas prices averaged approximately $4.7/MMbtu during the second quarter, ranging between $4 and $6/MMbtu.
  - ✓ Gas prices were slightly higher upstate than in NYC. The differential between the two locations averaged $0.12/MMbtu during the second quarter.
- Average natural gas prices fell 29 percent from the first quarter of 2010, while fuel oil prices were more consistent.
  - ✓ The decrease in natural gas prices made many gas-fired generators more competitive with coal-fired generators, contributing to the 29 percent decline in production from coal-fired generation from the first quarter.
- Average natural gas prices rose 14 percent from the second quarter of 2009, while fuel oil prices rose considerably over the same period (37 percent for Oil #2 and 35 percent for Oil #6).
  - ✓ The increased margin between fuel oil prices and natural gas prices helped reduce oil-fired generation. However, some generators still burn fuel oil for reliability reasons or due to difficulties they face obtaining natural gas.

Natural Gas and Oil Prices



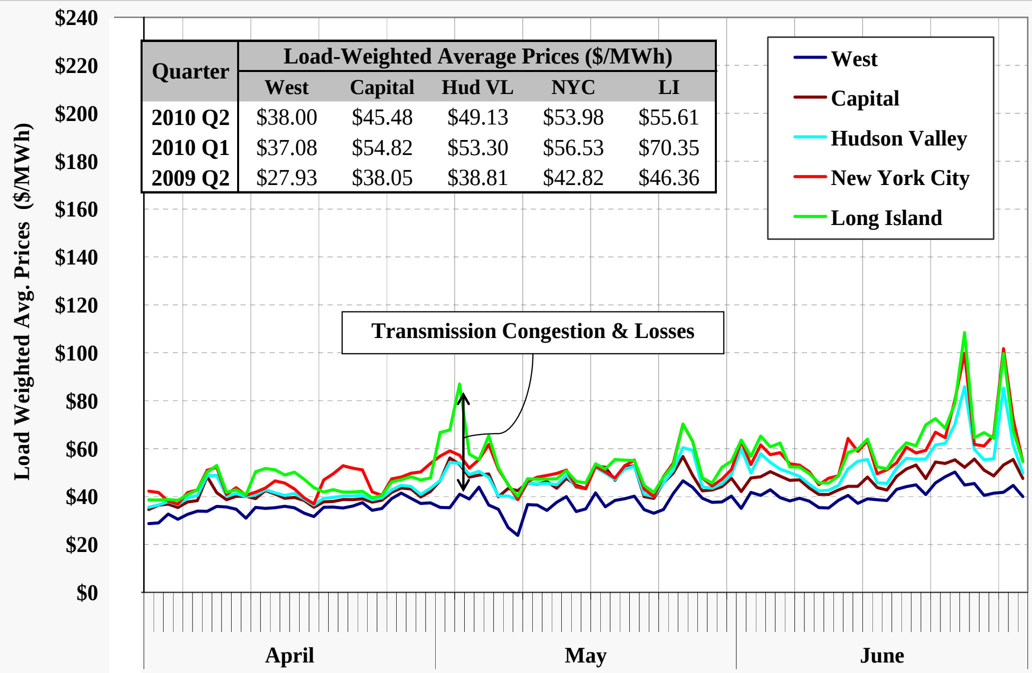
Quarter	Average Fuel Prices ($/MMBtu)			
	Oil #2	Oil #6	Gas-Upstate	Gas-NYC
2010 Q2	14.94	11.61	4.77	4.65
2010 Q1	14.50	11.80	6.60	6.68
2009 Q2	10.87	8.62	4.17	4.11

Note: Natural gas prices 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.
- Prices in the day-ahead market reflect probability-weighted expectations of real-time market conditions.
- Day-ahead prices generally rose from April to June, consistent with the increases in natural gas prices and load during the quarter.
- Price differences between the Capital Zone and Hudson Valley increased from the first quarter, reflecting expectations of increased congestion through the Hudson Valley during TSA events.
  - ✓ On June 24 & 28, prices rose in Southeast New York in anticipation of thunderstorms and high load levels.
- Price differences between Long Island and the rest of New York decreased from the previous quarter because the Sprainbrook-East Garden City line was in-service for the entire quarter.
  - ✓ However, the line was derated for several days in early May, which led to large price differences between Long Island and the rest of New York.

Day-Ahead Electricity Prices by Zone

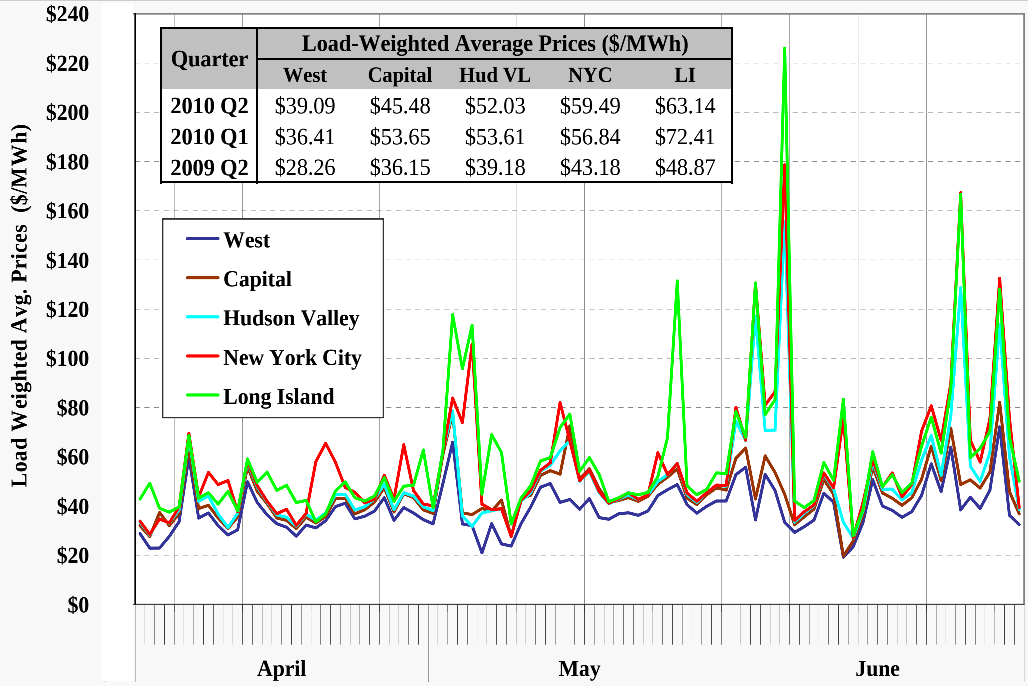


Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2010 Q2	$38.00	$45.48	$49.13	$53.98	$55.61
2010 Q1	$37.08	$54.82	$53.30	$56.53	$70.35
2009 Q2	$27.93	$38.05	$38.81	$42.82	$46.36

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.
  - ✓ Prices are more volatile in the real-time market than in the day-ahead market.
- The average real-time price in the West Zone rose 7 percent from the first quarter, although natural gas prices fell 29 percent.
  - ✓ This reflects less congestion across the Central-East interface as a result of less circulation around Lake Erie, reduced imports to western New York, and less production from hydro-electric generation.
- Congestion in Southeastern New York was modest in April but increased considerably on some days in May and June due to several factors:
  - ✓ TSA events started in early May and led to tight conditions on nine days (May 3, 4, & 14 and June 1, 3, 5, 6, 24, & 28). TSAs reduce the transfer capability into Southeast New York, often leading to local shortages of reserves and associated price spikes in real-time.
  - ✓ Forced outages of major transmission facilities on May 3 & 4 and June 12 also led to real-time shortages and price spikes in New York City and Long Island.
  - ✓ Unusually high load levels in late May when many units in Long Island were on seasonal outages led to real-time shortages and price spikes on May 26.

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2010 Q2	$39.09	$45.48	$52.03	$59.49	$63.14
2010 Q1	$36.41	$53.65	$53.61	$56.84	$72.41
2009 Q2	$28.26	$36.15	$39.18	$43.18	$48.87

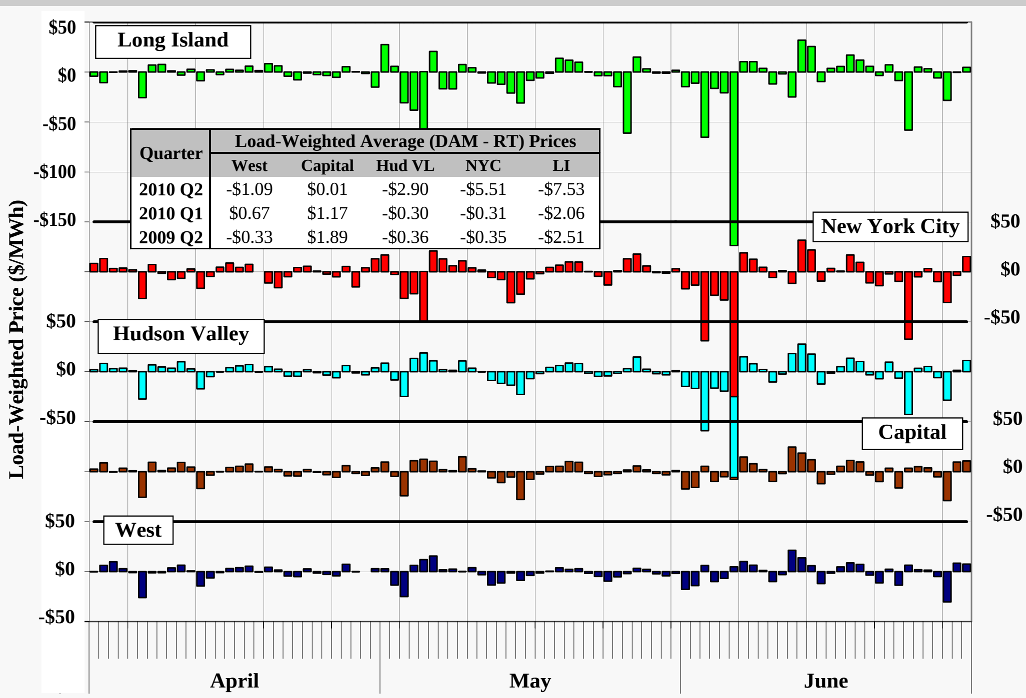
Convergence Between Day-Ahead and Real-Time Prices

- 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, 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 2010.
  - ✓ 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 difference between day-ahead prices and real-time prices occurred on June 6 due to unexpected real-time conditions:
  - ✓ A TSA was called during the afternoon, which substantially reduced transfer capability into Southeast New York, leading to severe congestion into that area.
  - ✓ Clockwise circulation around Lake Erie ranged as high as 900 MW during the TSA event, which further reduced transfer capability into Southeast New York available to the NYISO market.
  - ✓ Real-time load exceeded the peak load forecast by more than 1 GW.

Convergence Between Day-Ahead and Real-Time Prices

- Large differences between average day-ahead prices and average real-time prices occurred frequently 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.
- Average day-ahead prices were generally consistent with average real-time prices in the West Zone and the Capital Zone.
- Average day-ahead prices were considerably lower than average real-time prices in Southeast New York.
  - ✓ This is primarily because the day-ahead market did not fully anticipate the price effects of congestion into Southeast New York during TSA events.
  - ✓ Average real-time prices were higher than average day-ahead prices by:
    - – 6 percent in the Hudson Valley,
    - – 10 percent in New York City, and
    - – 14 percent in Long Island.

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2010 Q2	-$1.09	$0.01	-$2.90	-$5.51	-$7.53
2010 Q1	$0.67	$1.17	-$0.30	-$0.31	-$2.06
2009 Q2	-$0.33	$1.89	-$0.36	-$0.35	-$2.51

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
    - 1,000 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 1,000 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-minute spinning reserves prices in western New York, which reflect the cost of requiring 600 MW of 10-minute spinning reserves state-wide.
  - ✓ Regulation prices, which reflect the cost of requiring up to 275 MW of regulation, depending upon season and time of day.
- The table in each figure shows the number of intervals when the real-time reserve price of the product was affected by a shortage of reserves.
  - ✓ During shortages, the prices of products that can satisfy the given requirement will include the "demand curve" value of the requirement.

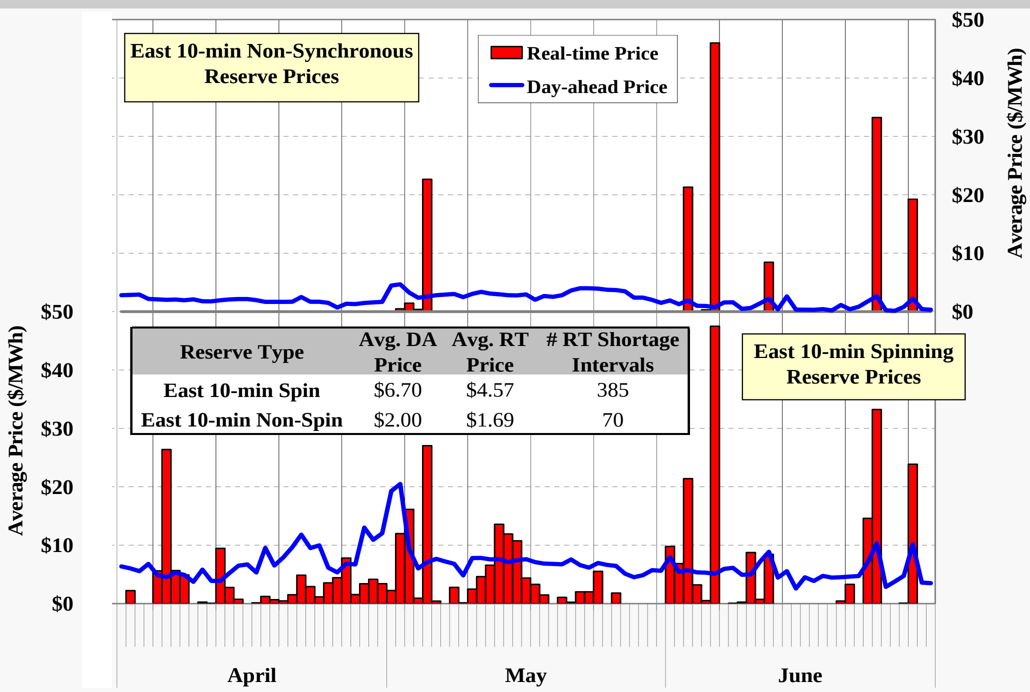
Day-Ahead and Real-Time Ancillary Services Prices

- Reserve prices are relatively consistent from day-to-day in the day-ahead, while reserve prices are much more volatile in the real-time market.
  - ✓ Day-ahead reserves prices are based on suppliers' offers, which depend on expectations of real-time prices and the risks associated with selling reserves in the day-ahead market.
  - ✓ Real-time reserves prices are normally close to $0 due to the excess available reserves from online and quick-start units in most hours.
  - ✓ Real-time prices spike during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Day-ahead regulation and reserves prices were generally higher on average than real-time prices in the second quarter of 2010.
  - ✓ However, day-ahead prices did not rise substantially on days when real-time prices were high due to tight system conditions.
  - ✓ Furthermore, day-ahead eastern 10-minute non-spinning reserve prices fell in June, while real-time price spike events for these reserves became more frequent.

Day-Ahead and Real-Time Ancillary Services Prices

- A shortage occurs when a reserve requirement cannot be satisfied at a marginal cost less than its "demand curve". Shortages occurred in real-time for:
  - ✓ Eastern 10-minute spinning reserves in 313 intervals ($25 demand curve);
  - ✓ Eastern 10-minute total reserves in 70 intervals ($500 demand curve);
  - ✓ State-wide 10-min spinning reserves in 2 intervals ($500 demand curve); and
  - ✓ Regulation in 113 intervals ($250 to $300 demand curve).
- Prices for a product include the demand curve value for all requirements that the product can satisfy.
  - ✓ For example, the 10-minute spinning reserve prices in the East reflect 385 intervals of shortage pricing: 313 of eastern 10-minute spin, 70 of eastern 10-minute total reserves, and 2 of state-wide 10-minute spin.
- The number of Eastern 10-minute total reserve shortages rose from the prior quarter due to higher load levels and congestion into Southeast New York associated with TSA events.
  - ✓ The largest shortages occurred on June 6 & 24 due to congestion during TSA events, leading average daily real-time Eastern 10-minute non-spin prices to exceed $40/MWh and $30/MWh, respectively.

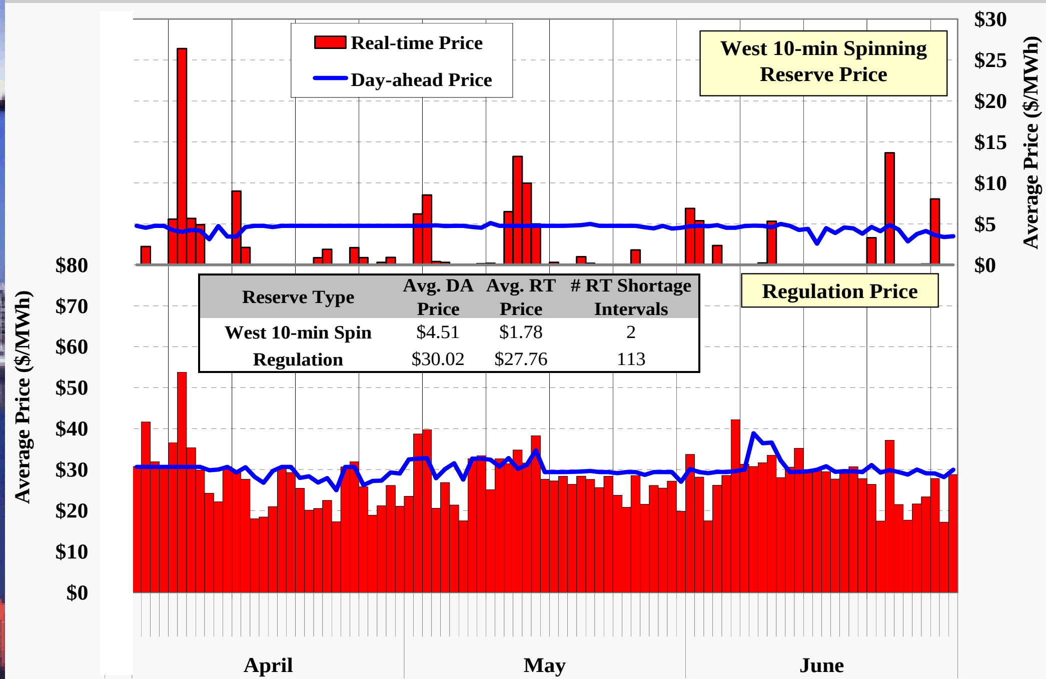
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
East 10-min Spin	$6.70	$4.57	385
East 10-min Non-Spin	$2.00	$1.69	70

Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



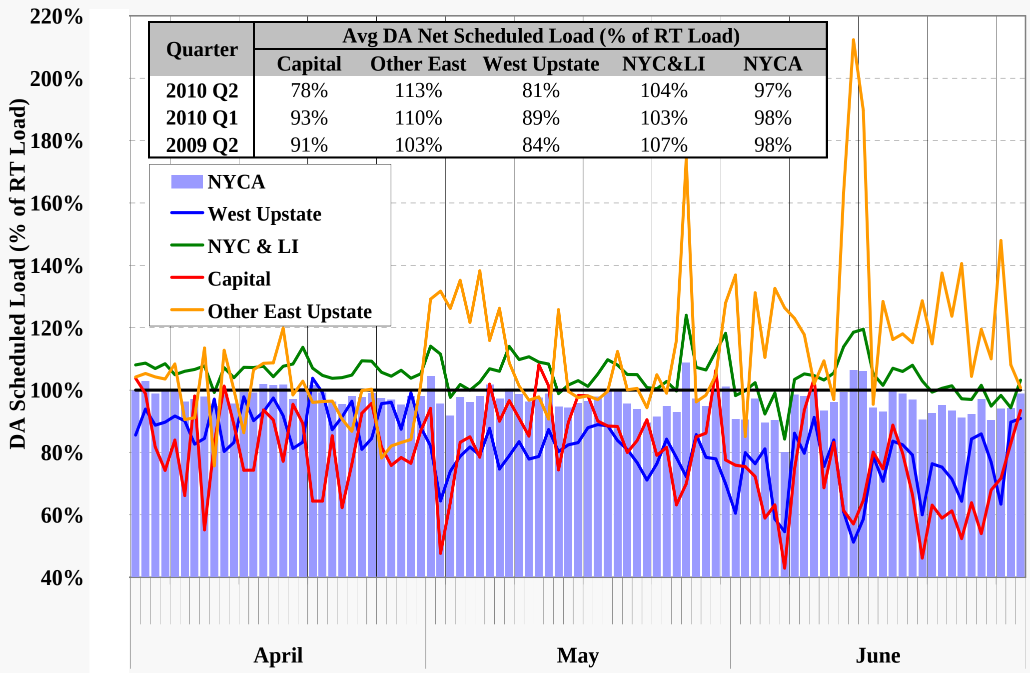
Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
West 10-min Spin	$4.51	$1.78	2
Regulation	$30.02	$27.76	113

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 three regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Overall, load was scheduled at 97 percent of actual load, consistent with prior quarters.
- 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 was likely in response to frequent congestion into Southeast New York on days when TSAs were likely to be called.
  - ✓ TSAs reduce the transfer capability into Southeast New York in the real-time market below the transfer capability modeled in the day-ahead market.
- The over- and under-scheduling patterns generally improve convergence between day-ahead and real-time prices in most areas.
  - ✓ Nevertheless, day-ahead prices were still substantially lower on average than real-time prices in Southeast New York in the second quarter.

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour



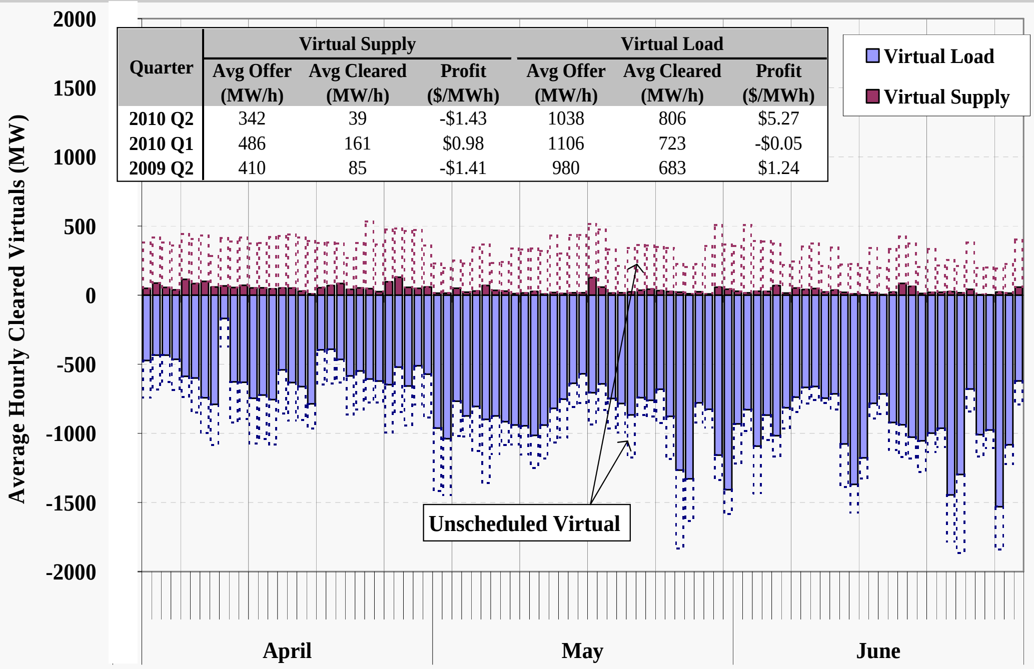
Quarter	Avg DA Net Scheduled Load (% of RT Load)				
	Capital	Other East	West Upstate	NYC&LI	NYCA
2010 Q2	78%	113%	81%	104%	97%
2010 Q1	93%	110%	89%	103%	98%
2009 Q2	91%	103%	84%	107%	98%

Virtual Load and Supply

- The following two figures summarize virtual trading activity on a daily basis in downstate and upstate areas.
- There were substantial net virtual load purchases in downstate areas and net virtual supply sales in upstate areas.
  - ✓ This pattern has persisted for years, although the average net virtual load downstate rose to 767 MW, up 170 MW from the second quarter of 2009. This was likely a response to higher levels of congestion into Southeast New York.
  - ✓ The net virtual supply scheduled upstate averaged 1,178 MW during the quarter, comparable to the second quarter of 2009.
- Overall profitability from virtual trading was $12.3 million in the second quarter of 2010, up substantially from $1.6 million in the previous quarter and $2.5 million in the second quarter of 2009.
  - ✓ Most virtual trading profits in the second quarter of 2010 came from virtual load scheduling in downstate New York. This is not surprising because real-time congestion was not fully reflected in day-ahead prices in this quarter.
  - ✓ The fact that virtual trades have generally been profitable indicates that they have generally improved price convergence.

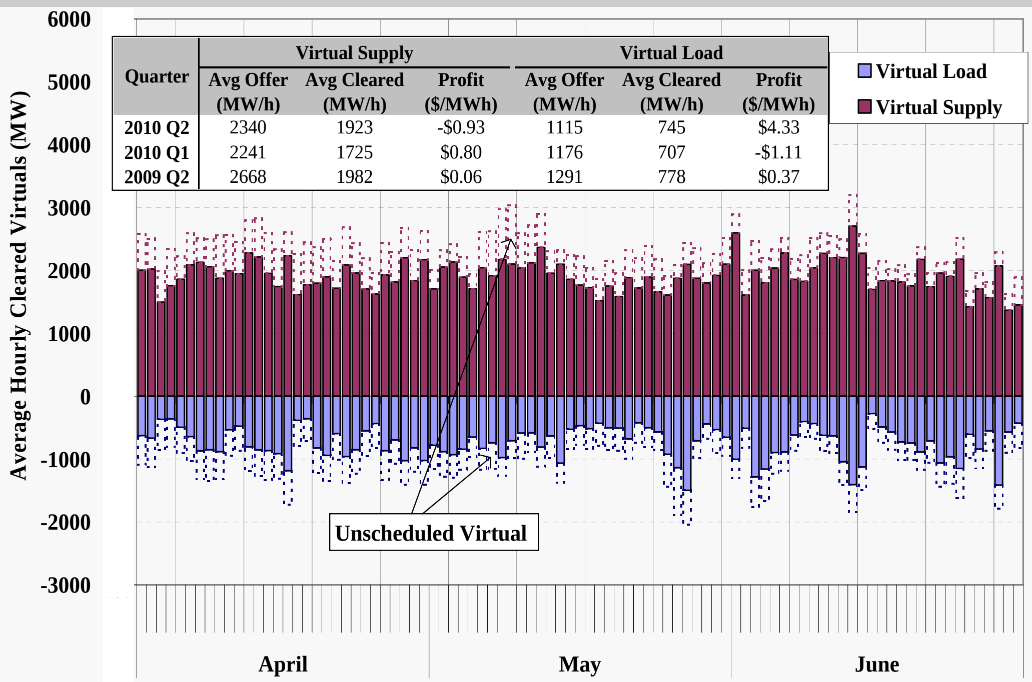
Virtual Load and Supply
New York City and Long Island

Quarter	Virtual Supply Avg Offer (MW/h)	Virtual Supply Avg Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Avg Offer (MW/h)	Virtual Load Avg Cleared (MW/h)	Virtual Load Profit ($/MWh)
2010 Q2	342	39	-$1.43	1038	806	$5.27
2010 Q1	486	161	$0.98	1106	723	-$0.05
2009 Q2	410	85	-$1.41	980	683	$1.24



Virtual Load and Supply
Upstate New York

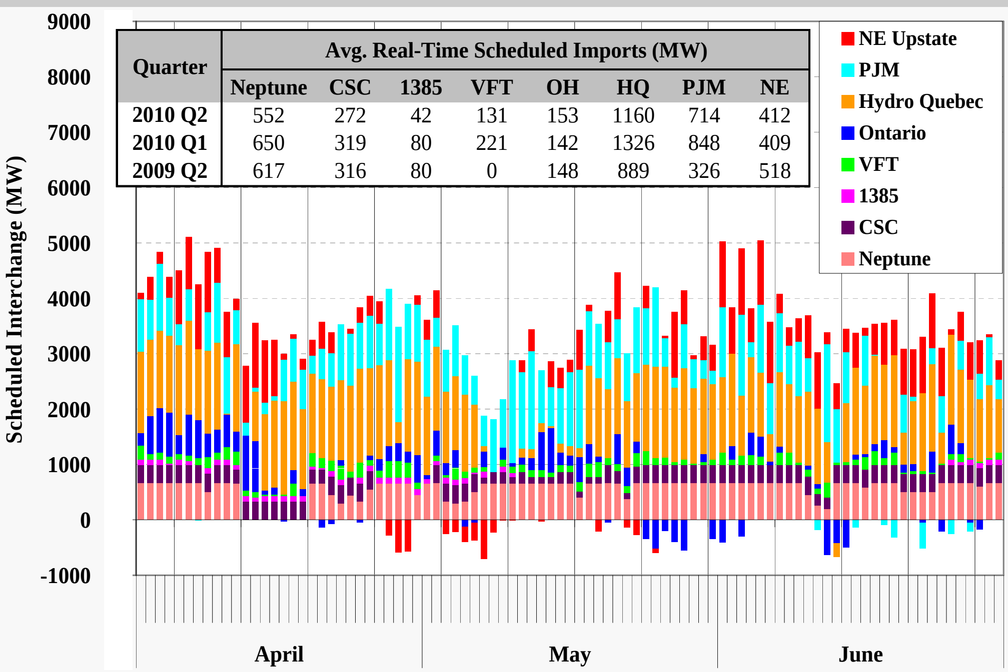
Quarter	Virtual Supply Avg Offer (MW/h)	Virtual Supply Avg Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Avg Offer (MW/h)	Virtual Load Avg Cleared (MW/h)	Virtual Load Profit ($/MWh)
2010 Q2	2340	1923	-$0.93	1115	745	$4.33
2010 Q1	2241	1725	$0.80	1176	707	-$1.11
2009 Q2	2668	1982	$0.06	1291	778	$0.37



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 3.4 GW during daily peak hours in the second quarter, down 14 percent from the first quarter but up 19 percent from the second quarter of 2009.
  - ✓ Imports from HQ and PJM averaged nearly 1.9 GW in the second quarter of 2010, down roughly 300 MW from the previous quarter but up 660 MW from the second quarter of 2009.
  - ✓ Imports over the four controllable lines (Neptune Cable, Cross Sound Cable, 1385 Line, and Linden VFT Line) fell 275 MW from the first quarter to 1 GW. This reduction is attributable to several outages of these lines and is significant because they serve congested areas in Southeast New York.
  - ✓ Imports from New England and Ontario were comparable to prior periods.
- Imports on average satisfied 16 percent of the load during daily peak hours in the second quarter.
  - ✓ During the quarterly peak load hour on June 28, NYCA imported 3.1 GW that satisfied 10 percent of the peak load.

Net Imports Scheduled Across External Interfaces
Daily Peak Load Hour

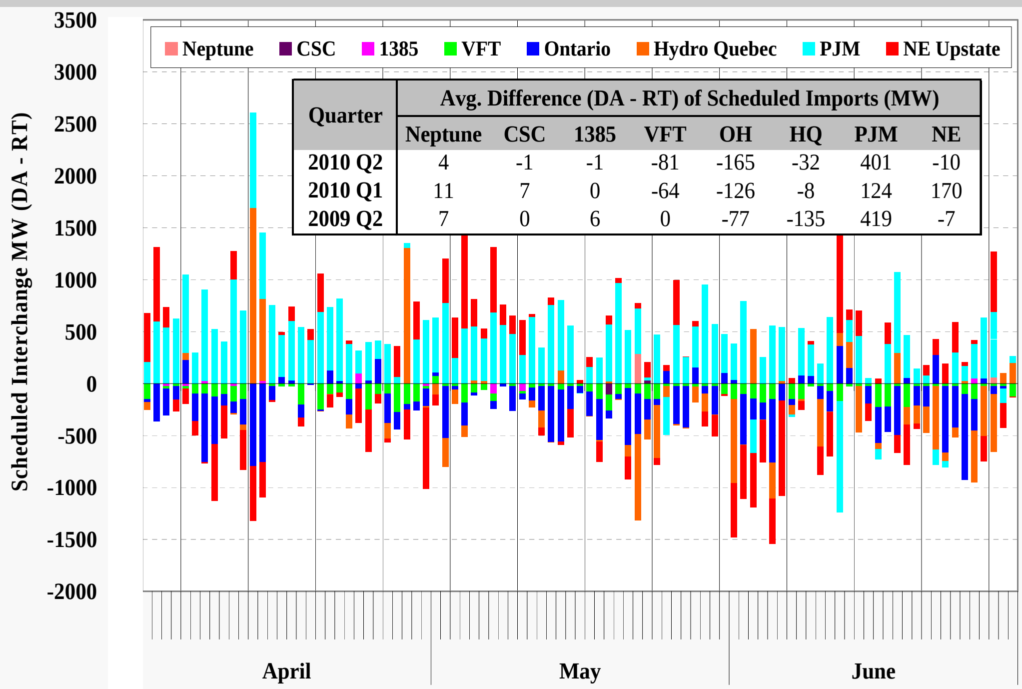


Quarter	Avg. Real-Time Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2010 Q2	552	272	42	131	153	1160	714	412
2010 Q1	650	319	80	221	142	1326	848	409
2009 Q2	617	316	80	0	148	889	326	518

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.
- From the day-ahead to the real-time, net scheduled imports:
  - ✓ Did not vary significantly across the three controllable lines into Long Island;
  - ✓ Frequently increased across the Linden VFT;
  - ✓ Decreased across the PJM interface by an average of 401 MW; and
  - ✓ Increased across the Ontario interface by an average of 165 MW.
- Generally, these changes in schedules improve consistency between day-ahead and real-time prices.
  - ✓ For example, real-time prices were considerably higher than day-ahead prices throughout New York from June 1 to 6.
    - – Importers responded by increasing flows into NYCA by an average of 684 MW in the peak hours on these days.

Change in Scheduled Imports from Day Ahead to Real Time
Daily Peak Load Hour



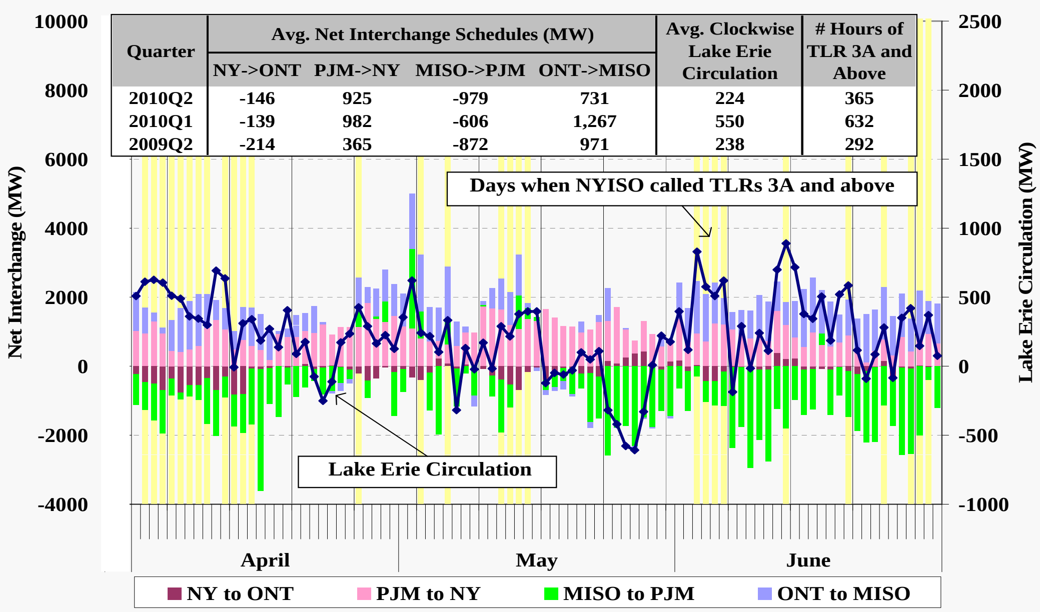
Quarter	Avg. Difference (DA - RT) of Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2010 Q2	4	-1	-1	-81	-165	-32	401	-10
2010 Q1	11	7	0	-64	-126	-8	124	170
2009 Q2	7	0	6	0	-77	-135	419	-7

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.
  - ✓ 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 and above) were called are also highlighted.
- Average clockwise circulation fell to 224 MW in the second quarter, down 59 percent from the prior quarter and 6 percent from the same quarter in 2009.
  - ✓ The decrease was partly driven by reduced scheduling from Ontario to MISO and by increased scheduling from PJM to MISO.
- TLRs were called on 29 days in the second quarter for a total of 365 hours, down 42 percent from the first quarter.
  - ✓ Clockwise circulation averaged 450 MW on days when TLRs were called and 125 MW on days when no TLRs were called.
  - ✓ The Broader Regional Market initiatives developed by the NYISO and other RTOs around Lake Erie will improve the efficiency with which these flows are managed.

Real-Time 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		
2010Q2	-146	925	-979	731	224	365
2010Q1	-139	982	-606	1,267	550	632
2009Q2	-214	365	-872	971	238	292



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

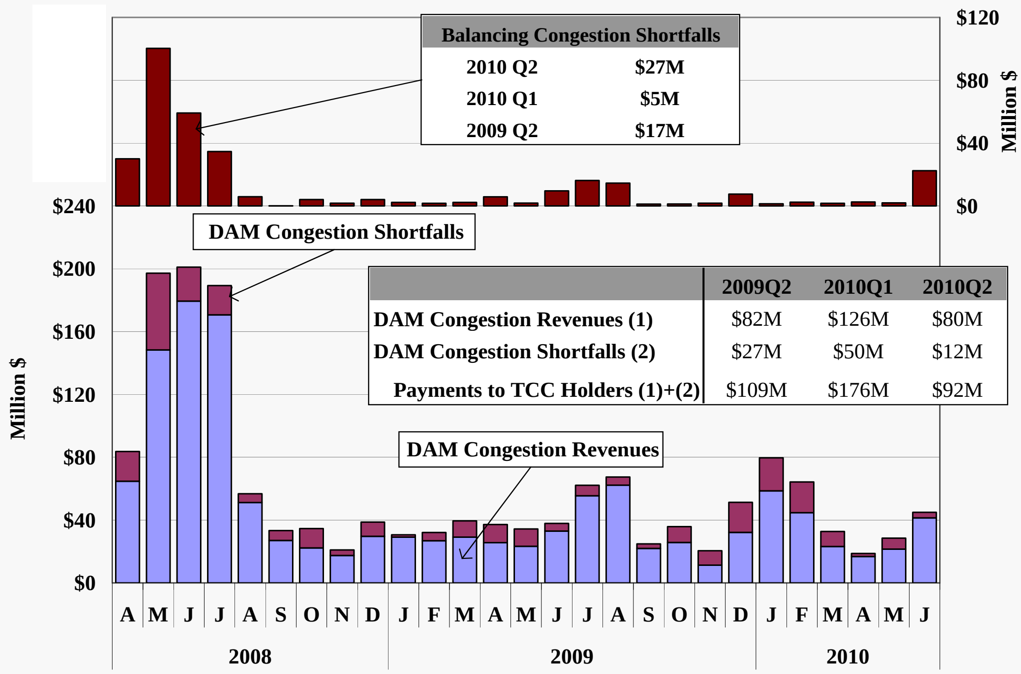
Congestion Revenue Collections and Shortfalls

- 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 collections were $80 million in the second quarter, down 37 percent from the first quarter.
  - ✓ This is partly due to lower natural gas prices, which fell an average of 29 percent from the first quarter.
- Day-ahead congestion shortfalls fell substantially in the second quarter, down 76 percent from the first quarter and 56 percent from the second quarter of 2009.
  - ✓ This was primarily due to reduced congestion of the Central-East interface, which has been a significant source of day-ahead congestion shortfalls.
- Balancing congestion shortfalls were $27 million in the second quarter, up from $5 million in the first quarter and $17 million in the second quarter of 2009. This increase was primarily due to:
  - ✓ More frequent Thunderstorm Alerts ("TSAs") than in the first quarter;
  - ✓ Higher load levels than in the first quarter and in the previous summer, which have increased the need for imports to Southeast New York during TSAs; and
  - ✓ The retirement of the Poletti steam unit, which substantially reduced the amount of capacity available in Southeast New York during TSAs and other peak conditions.

Congestion Revenue Collections and Shortfalls



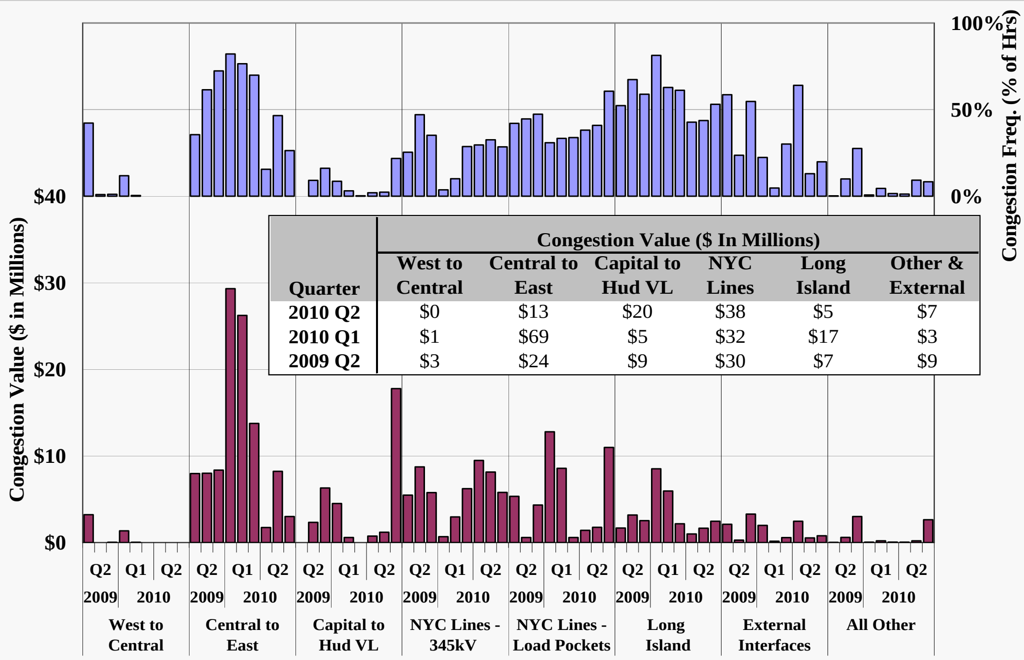
Congestion by Transmission Path

- 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 West Central and the Dysinger East interfaces.
  - ✓ Capital to Hudson Valley: Primarily the Leeds-to-Pleasant Valley line and the Leeds-to-New Scotland line.
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ 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.
  - ✓ 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 nine 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.
- The majority of day-ahead congestion revenue in the second quarter occurred over lines into and within New York City (46 percent), lines from Capital to Hudson Valley (24 percent), and paths from Central to East (16 percent).
- The primary transmission bottlenecks shifted from the Central-East interface in the first quarter to lines through the Hudson Valley (e.g., Leeds-Pleasant Valley) and in New York City in the second quarter.
  - ✓ Committing generation to manage increased congestion into Southeast New York and New York City load pockets helped relieve Central-East congestion.
  - ✓ Central-East congestion also fell due to less clockwise circulation around Lake Erie and the decline in natural gas prices, which reduces generating costs in eastern New York relative to western areas.

Day-Ahead Congestion by Transmission Path

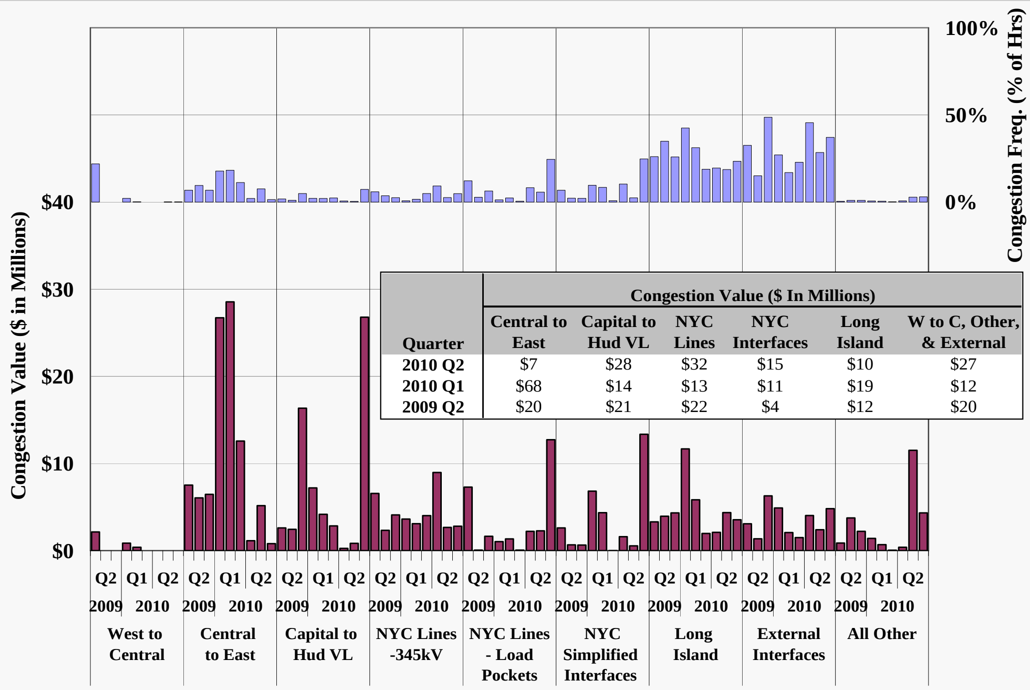


	Congestion Value ($ In Millions)					
Quarter	West to Central	Central to East	Capital to Hud VL	NYC Lines	Long Island	Other & External
2010 Q2	$0	$13	$20	$38	$5	$7
2010 Q1	$1	$69	$5	$32	$17	$3
2009 Q2	$3	$24	$9	$30	$7	$9

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 majority (74 percent) of real-time congestion occurred in three areas in the second quarter:
  - ✓ NYC lines and simplified interface constraints (39 percent): Most of these were related to congestion into the city from upstate and into the Greenwood load pocket in June.
  - ✓ Capital to Hudson Valley (23 percent): This was primarily due to congestion across the Leeds-to-Pleasant Valley line during TSA events.
  - ✓ Millwood to Dunwoodie (11 percent): This was primarily due to congestion across the Millwood to East View lines on May 4 & 5, and June 12 & 24.
- Poor convergence between day-ahead and real-time LBMPs led to differences in the pattern of congestion between the day-ahead and real-time markets.
  - ✓ The total value of congestion in the real-time market was $120 million, which was 50 percent higher than in the day-ahead market.
  - ✓ The real-time market exhibited more congestion into and within Southeast New York than the day-ahead market, although the day-ahead market exhibited more congestion across the Central-East interface.

Real-Time Congestion by Transmission Path

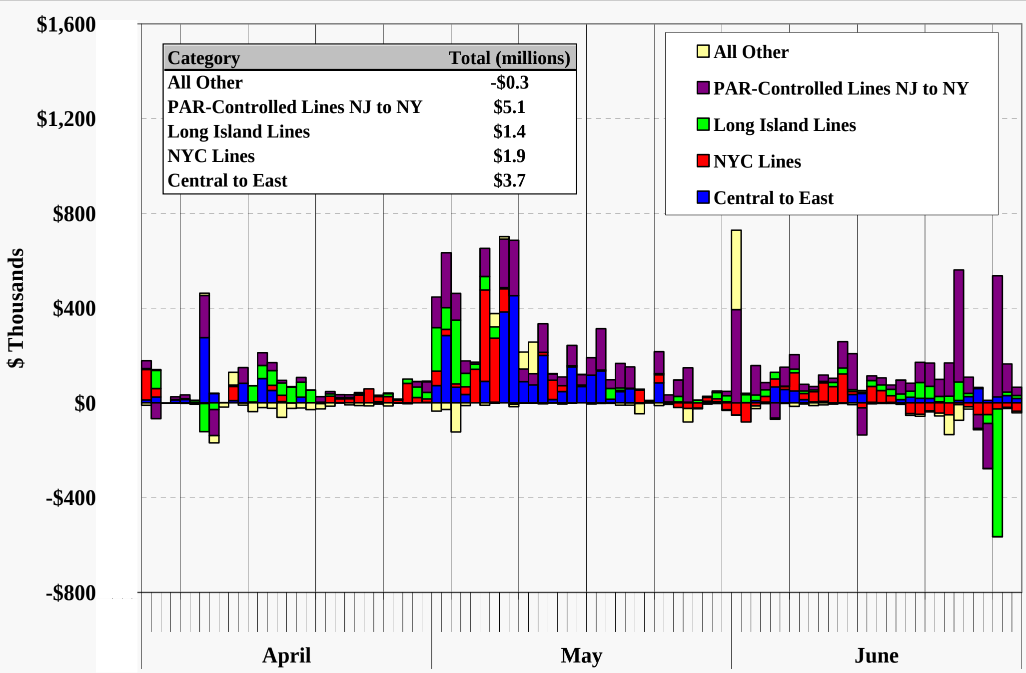


Quarter	Congestion Value ($ In Millions) Central to East	Capital to Hud VL	NYC Lines	NYC Interfaces	Long Island	W to C, Other, & External
2010 Q2	$7	$28	$32	$15	$10	$27
2010 Q1	$68	$14	$13	$11	$19	$12
2009 Q2	$20	$21	$22	$4	$12	$20

Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily congestion revenue shortfalls by transmission path or facility in the second quarter of 2010. Negative values indicate congestion revenue surpluses.
- Day-ahead congestion revenue shortfalls can result from:
  - ✓ Modeling assumption differences between the TCC auction and the day-ahead market, including assumptions related to PAR schedules and loop flows; and
  - ✓ Local TOs not incorporating their planned transmission outages in the assumptions of the TCC auctions, which often leads to over-sale of TCCs and ultimately congestion revenue shortfalls. The NYISO has a process for allocating shortfalls that are attributable to specific TOs.
- PAR-controlled lines between NJ and NY (i.e., Waldwick, Ramapo, Farragut, and Linden) accounted for 43 percent of the total shortfall.
  - ✓ Different modeling assumptions between the TCC auction and the day-ahead market led to consistent day-ahead congestion shortfalls.
- The Central to East interface accounted for 31 percent of the total shortfall.
  - ✓ Day-ahead transfer capability across the interface is consistently lower than the amount of sold TCCs. Central East transfer capability is affected by assumptions regarding transmission outages and generator commitments.
- The primary reason for the fall in day-ahead congestion revenue shortfalls is that the Central-East interface was constrained less frequently in the second quarter.

Day-Ahead Congestion Revenue Shortfalls



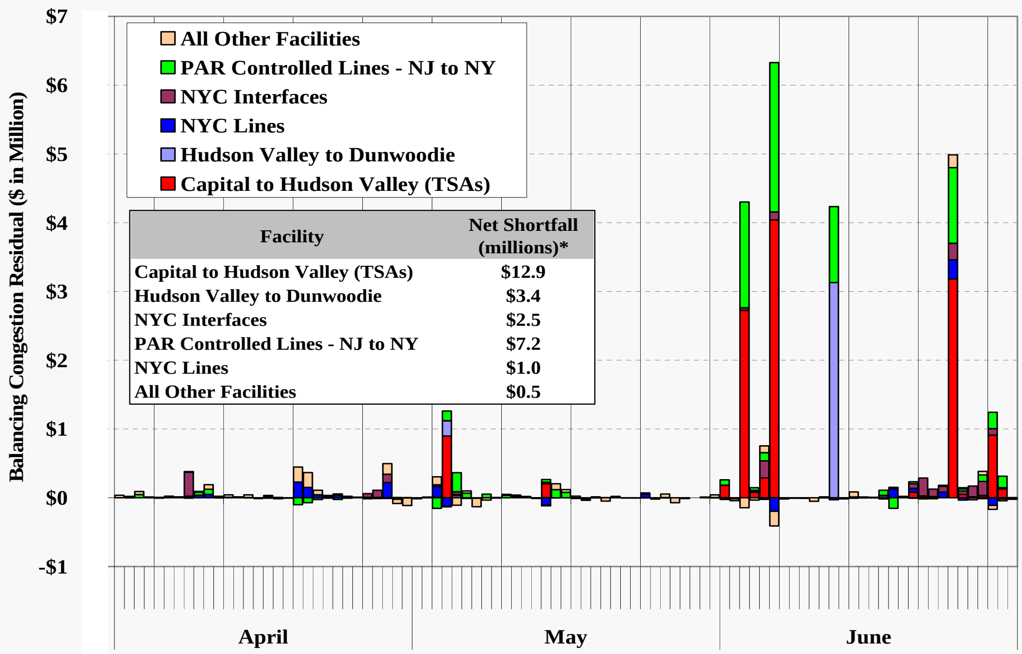
Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the second quarter of 2010.
  - ✓ Negative values indicate balancing congestion surpluses.
- Balancing congestion revenue shortfalls can occur when the transfers across a particular interface changes 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 revenue shortfalls can also occur when assumptions used in the market models change from day-ahead to real-time. This includes the direction and magnitude of:
  - ✓ Unscheduled loop flows across constrained interfaces; and
  - ✓ Flows across PAR-controlled lines.
- Balancing congestion shortfalls rose in the second quarter of 2010 from previous periods due to the effects of more frequent TSAs.

Balancing Congestion Shortfalls

- Two factors accounted for most of balancing congestion shortfalls in the second quarter (73 percent):
  - ✓ Reduced transfer capability from Capital to Hudson Valley (47 percent); and
  - ✓ Flow changes from day-ahead to real-time on PAR-controlled lines between New Jersey and New York (26 percent).
  - ✓ Most occurred on five days (May 4 & June 3, 6, 24, & 28) during TSA events.
- Hudson Valley to Dunwoodie accounted for 12 percent of balancing congestion shortfalls.
  - ✓ The vast majority occurred on June 12 after a fire at the Dunwoodie substation lead to several major line outages.
- Simplified interface constraints in New York City accounted for 9 percent of balancing congestion shortfalls.
  - ✓ Use of interface constraints in the real-time market (rather than the detailed model used in the day-ahead market) generally reduces transfer capability.
  - ✓ This category has been more limited since July 2009 when the NYISO began assuming reduced transfer capability into NYC load pockets in the day-ahead market when real-time reductions in transfer capability were anticipated.

Balancing Congestion Shortfalls



Facility	Net Shortfall (millions)*
Capital to Hudson Valley (TSAs)	$12.9
Hudson Valley to Dunwoodie	$3.4
NYC Interfaces	$2.5
PAR Controlled Lines - NJ to NY	$7.2
NYC Lines	$1.0
All Other Facilities	$0.5

* These slightly over-estimate shortfalls since they are partly based on real-time schedules rather than metered values.

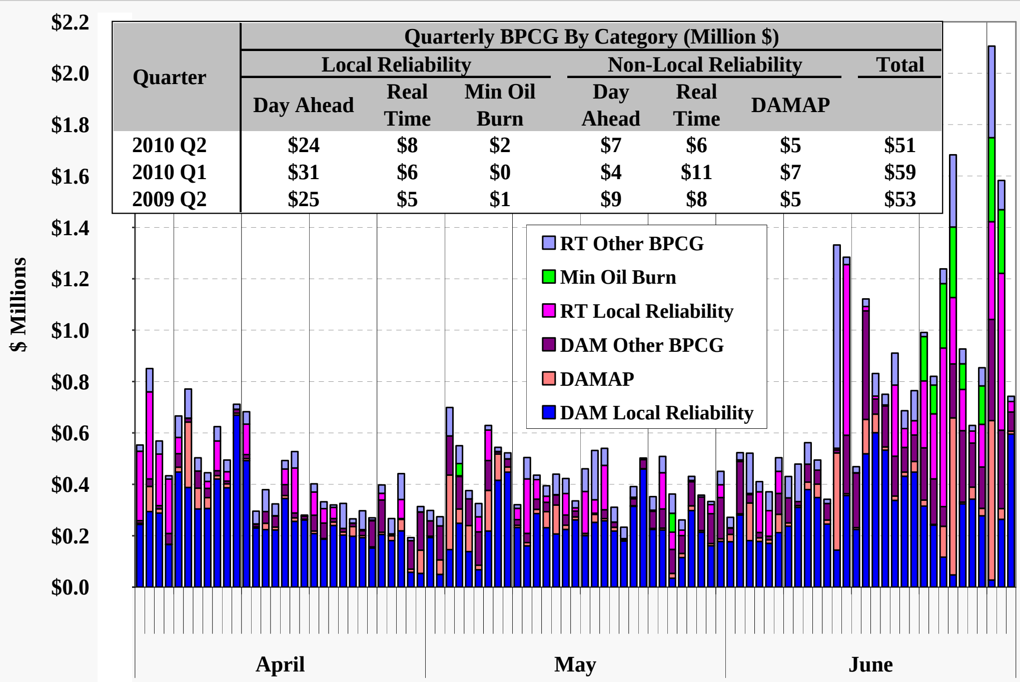
Uplift Costs from Guarantee Payments

- The next figure summarizes uplift charges resulting from guarantee payments in the following six categories.
- Three 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.
- 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: Primarily for gas turbines committed economically that don't recoup their as-offered costs from LBMPs, and also 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.

Uplift Costs from Guarantee Payments

- Guarantee payment uplift fell to $51 million in the second quarter, down 13 percent from the previous quarter.
  - ✓ This was partly due to the 29 percent decrease in natural gas prices, although it was offset by increased reliability commitment in western New York.
- Guarantee payment uplift decreased slightly from the second quarter of 2009.
  - ✓ The average amount of capacity committed for reliability in New York City and Long Island fell from 1370 MW to 1025 MW.
  - ✓ However, this was offset by higher fuel prices and more reliability commitment in western New York.
- Guarantee payments increased substantially during June 2010 due to:
  - ✓ Congestion of facilities on Long Island that are normally secured by OOM dispatch led to RT Local payments;
  - ✓ Frequent TSA operations and the Dunwoodie sub-station fire on June 12 led to increased DAMAP and RT Non-Local payments; and
  - ✓ Increased reliability commitment in New York City and higher costs related to Minimum Oil Burn operation led to increased DAM Local, RT Local, and Minimum Oil Burn Program payments.

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



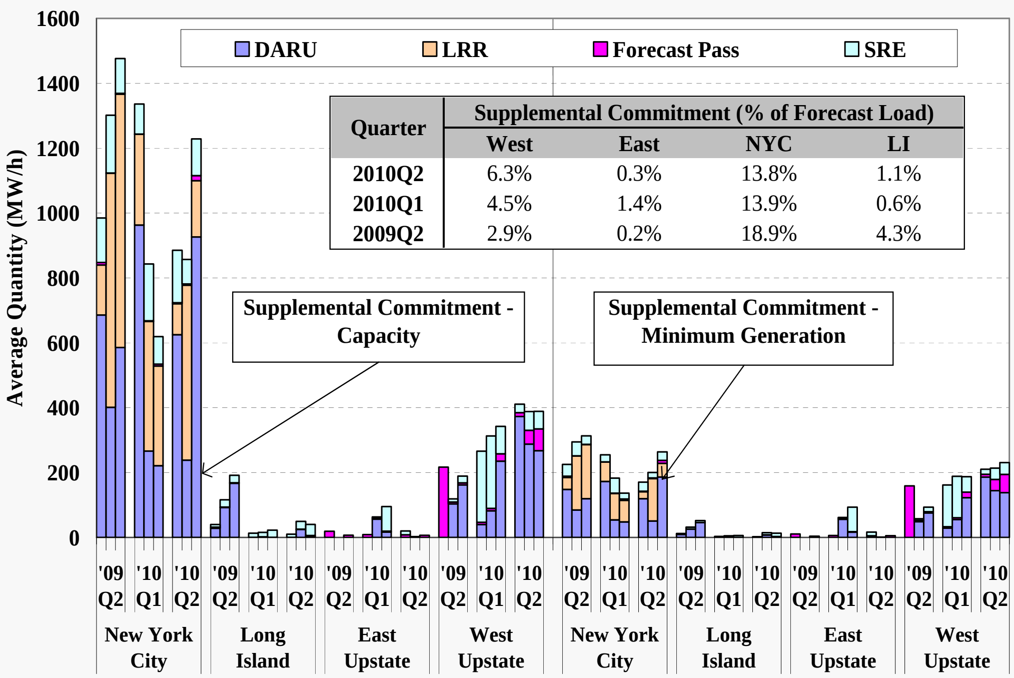
Quarterly BPCG By Category (Million $)

Quarter	Local Reliability: Day Ahead	Local Reliability: Real Time	Local Reliability: Min Oil Burn	Non-Local Reliability: Day Ahead	Non-Local Reliability: Real Time	Non-Local Reliability: DAMAP	Total
2010 Q2	$24	$8	$2	$7	$6	$5	$51
2010 Q1	$31	$6	$0	$4	$11	$7	$59
2009 Q2	$25	$5	$1	$9	$8	$5	$53

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.
  - ✓ The table shows the shares of committed capacity relative to forecast load.
- Local reliability commitment in New York City increased modestly from the previous quarter but declined notably from the second quarter of 2009.
  - ✓ Committed capacity averaged 990 MW, up 6 percent from the prior quarter and down 21 percent from the second quarter of 2009.
  - ✓ The minimum generation level of these units averaged 210 MW, up 10 percent from the prior quarter and down 24 percent from the second quarter of 2009.
- Reliability commitment in western New York rose from the prior periods.
  - ✓ Committed capacity averaged nearly 400 MW, up 29 percent from the prior quarter and 127 percent from the second quarter of 2009.
  - ✓ The minimum generation level of these units averaged 220 MW, up 22 percent from the prior quarter and 111 percent from the second quarter of 2009.
  - ✓ SRE commitments for bulk power system reliability were less frequent than in the previous quarter, while DARU commitment of several coal units for local reliability was more frequent due, in part, to reduced natural gas prices.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2010Q2	6.3%	0.3%	13.8%	1.1%
2010Q1	4.5%	1.4%	13.9%	0.6%
2009Q2	2.9%	0.2%	18.9%	4.3%

Market Monitoring and Mitigation

- The following figure summarizes energy offer mitigation as well as the results of potential withholding screens.
- Energy 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 DARU & LRR units (80 percent) and Astoria West/Queens/Vernon congestion (8 percent).
- Mitigation increased roughly 21 percent from the previous quarter due to more DARU- and LRR-committed capacity, which are mitigated whenever their Start-up and/or MinGen offers exceed a competitive reference.

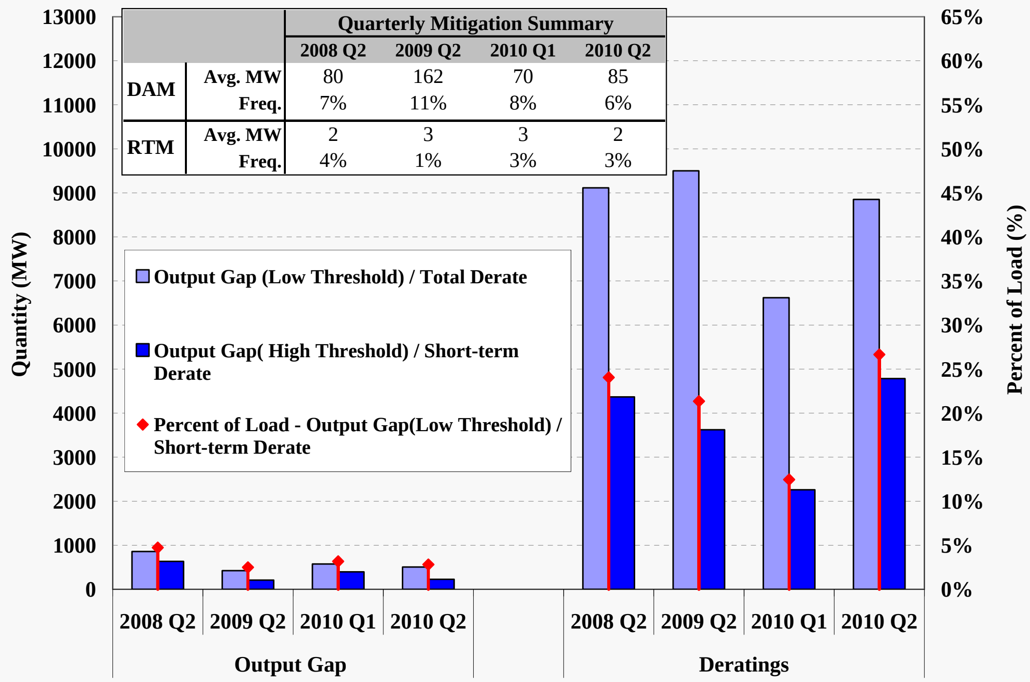
<u>Output Gap at High and Low Thresholds:</u>

- The output gap is low as a share of load (~ 3 percent), occurring primarily during periods when the prices would not be substantially affected.
- We review instances of significant output gap to identify potential competitive concerns.

<u>Long-Term and Short-Term Deratings:</u>

- Total deratings are sizable, but physical withholding concerns are limited because: (i) deratings are typically highest in the shoulder months when demand is lowest, and (ii) most deratings are long-term and less likely to reflect withholding.
- Deratings with significant market effects are reviewed and no significant concerns arose in the second quarter.

Market Monitoring Screens and Mitigation



		Quarterly Mitigation Summary			
		2008 Q2	2009 Q2	2010 Q1	2010 Q2
DAM	Avg. MW	80	162	70	85
	Freq.	7%	11%	8%	6%
RTM	Avg. MW	2	3	3	2
	Freq.	4%	1%	3%	3%

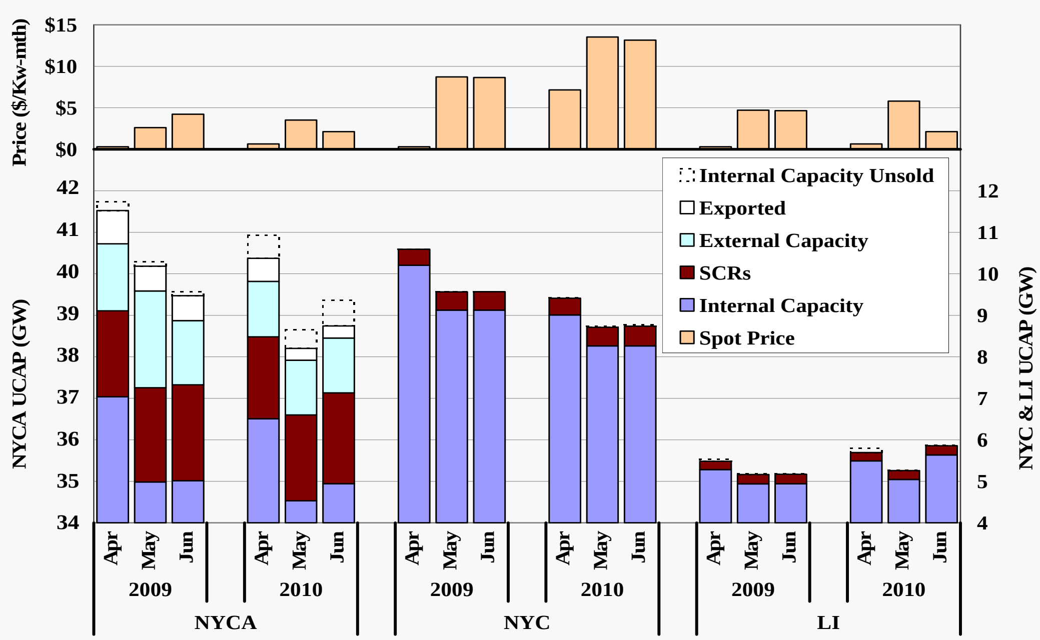
Capacity Market Results

- The following figure summarizes available and scheduled UCAP resources as well as the clearing prices in each capacity zone.
- In New York City, UCAP spot prices rose to an average of $11.28/kW-month in the second quarter, up 92 percent from the second quarter of 2009 due to:
  - ✓ The scheduled escalation of the New York City capacity demand curve; and
  - ✓ The retirement of the Poletti unit which reduced supply by nearly 900 MW.
  - ✓ However, these increases were partly offset by a 325 MW reduction in the summer peak load forecast for New York City.
- In Long Island, UCAP spot prices fell to an average of $2.86/kW-month in the second quarter, down 11 percent from the second quarter of 2009 due to:
  - ✓ The 106 MW reduction in the summer peak load forecast for Long Island; and
  - ✓ The net increase in internal capacity sales from the previous year.
  - ✓ However, these factors were largely offset by the increase in the Long Island Local Capacity Requirement ("LCR") from 97.5 percent in the Summer 2009 capability period to 102 percent in May 2010 and 104.5 percent in June.

Capacity Market Results

- In Rest-Of-State, UCAP spot prices fell to an average of $2.09/kW-month in the second quarter of 2010, down 12 percent from the second quarter of 2009 due to:
  - ✓ The 905 MW reduction in the summer peak load forecast for the New York Control Area from the previous year; and
  - ✓ Several additions to the supply of capacity in New York City and Long Island.
- However, these factors were partly offset by:
  - ✓ An increase in the Installed Reserve Margin (“IRM”) to 118 percent from 116.5 percent in the previous summer capability period;
  - ✓ The retirement of the Poletti steam unit in February 2010, which reduced internal capacity by nearly 900 MW; and
  - ✓ A fall in net imports of UCAP from 1275 MW in the second quarter of 2009 to 915 MW in the second quarter of 2010. This was partly driven by increased capacity prices in neighboring markets.

Capacity Market Results



Note: Sales related to Unforced Deliverability Rights (“UDRs”) are included in “Internal Capacity.”