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

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Highlights and Market Summary

- This presentation summarizes the outcomes of the NYISO energy, ancillary services, and capacity markets during the third quarter of 2010.
- 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 $63.71/MWh statewide, up 22 percent from the previous quarter and 70 percent from the third quarter of 2009.
  - ✓ Natural gas prices were comparable to the prior quarter but rose 36 percent from the third quarter of 2009.
  - ✓ Average load rose 18 percent from the prior quarter and 8 percent from the third quarter of 2009 due to much hotter weather than the previous summer.
- Convergence between day-ahead and real-time prices improved in the third quarter compared to the previous quarter, particularly in Southeast New York.
  - ✓ However, the day-ahead market did not fully anticipate: real-time congestion associated with TSA events, unplanned generation and transmission outages, and real-time load levels on several days.
  - ✓ Hence, the average day-ahead prices were still 3 to 6 percent lower than average real-time prices in Southeast New York.

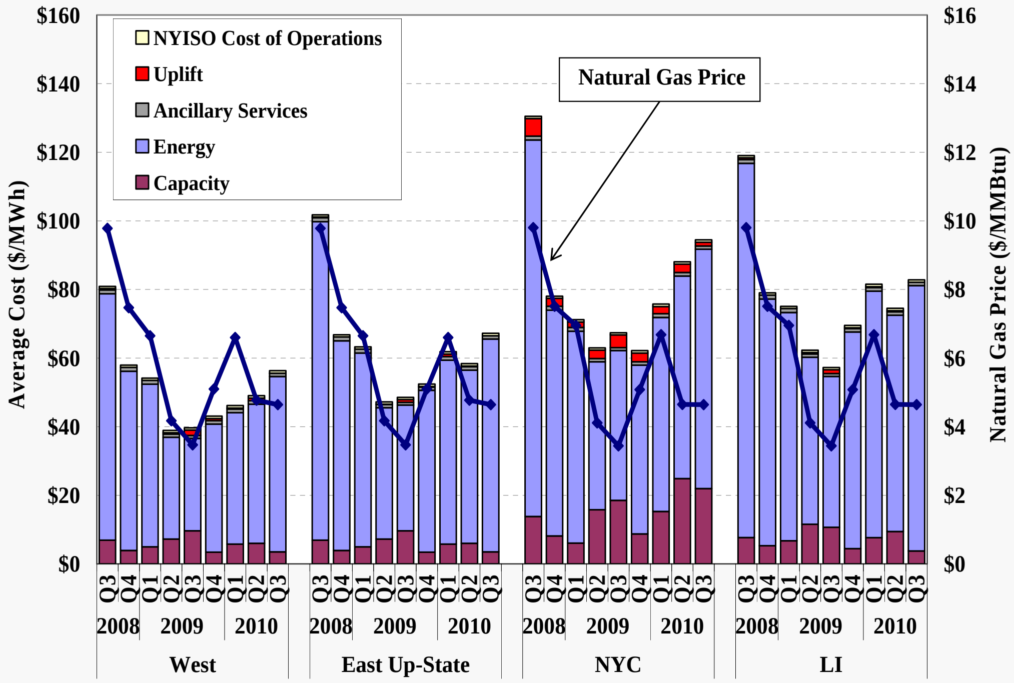
Highlights and Market Summary

- Capacity prices rose substantially in New York City and fell modestly in Long Island and Rest-of-State from the third quarter of 2009.
  - ✓ New York City prices averaged $12.84/kW-month, up 57 percent from the third quarter of 2009, due mainly to the retirement of the Poletti unit and the annual escalation of the demand curve.
  - ✓ The effects of the Poletti retirement were partly offset by capacity additions and reductions in the summer peak load forecast.
- Overall uplift charges in the third quarter fell significantly from the prior quarter and the third quarter of 2009.
  - ✓ Guarantee payments totaled $57 million, up $8 million from the prior quarter and down $26 million from the third quarter of 2009.
  - ✓ Day-ahead and balancing congestion shortfalls fell to a combined $17 million, less than half of the shortfalls in the prior quarter or the third quarter of 2009, due to improved operations during TSAs and reduced congestion over Central-East.
- Day-ahead congestion revenue were $134 million in the third quarter, up 68 percent from the second quarter due to higher load and more frequent TSAs.
  - ✓ However, day-ahead congestion revenue was slightly lower than in the third quarter 2009 – congestion in 2009 was increased by higher hydro production and imports in western New York, and higher clockwise Lake Erie Circulation.

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 38 to 53 percent from the third quarter of 2009, reflecting:
  - ✓ Higher fuel prices and load levels;
  - ✓ Reduced imports and production from hydro and nuclear capacity; and
  - ✓ The effects of the retirement of Poletti on energy and capacity prices.
- All-in prices rose 13 to 17 percent from the second quarter of 2010, primarily reflecting increased load levels.

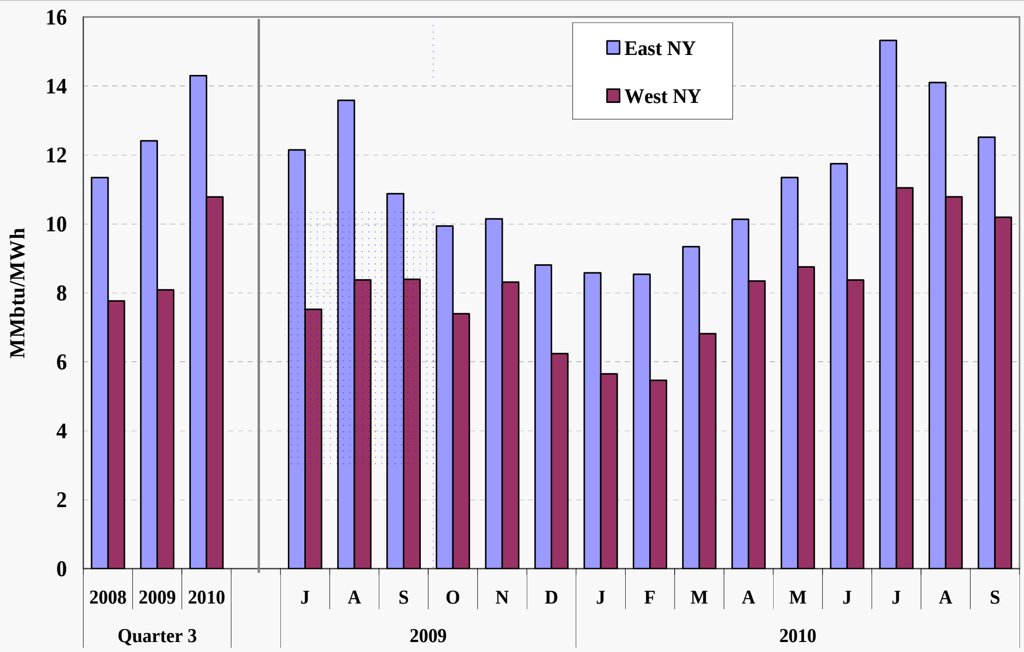
All-In Energy Price by Region



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 average implied heat rate rose 15 percent in East New York and 33 percent in West New York from the third quarter of 2009 to the third quarter of 2010. The following factors contributed to the increases:
  - ✓ Load levels were substantially higher in the third quarter, up 8 percent from a year ago, 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.
  - ✓ Net imports to upstate New York fell 17 percent from the third quarter of 2009. This was driven primarily by a 79 percent reduction of net imports from Quebec, which especially affected implied heat rates in Western New York.
  - ✓ Production by hydro-electric generation and nuclear generation fell by an average of nearly 600 MW from the third quarter of 2009. This contributed to higher implied heat rates, particularly in Western New York.

Implied Heat Rate by Region

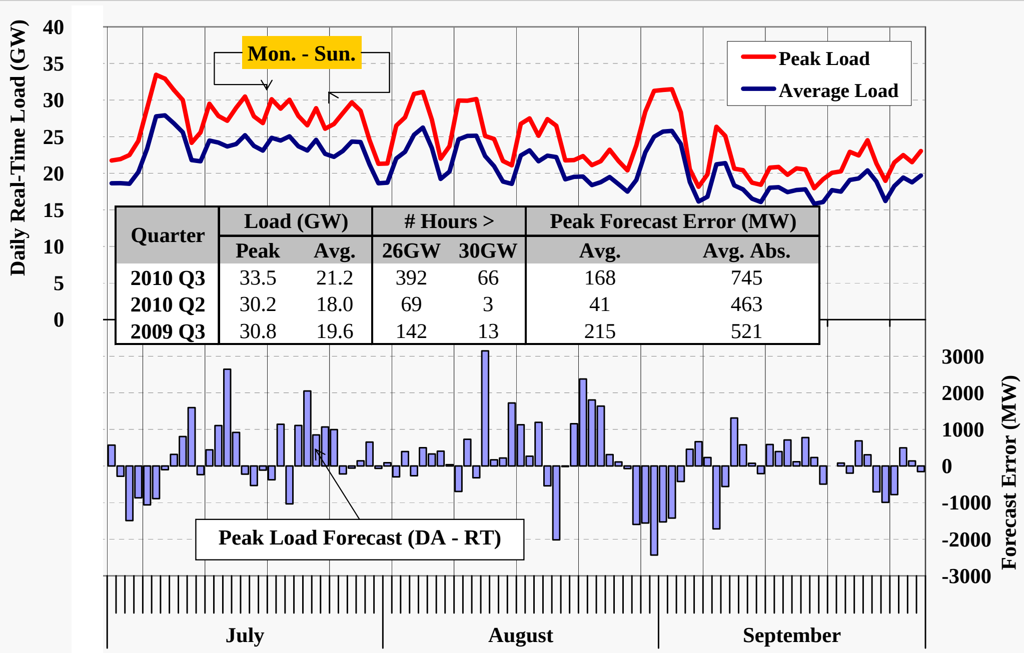


Note: Implied heat rates are for natural gas units and are based on day-ahead prices.

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 third quarter.
  - ✓ The table compares key statistics for the third quarter of 2010 to the previous quarter and the third quarter of 2009.
- Loads increased considerably from the third quarter of 2009 due to summer weather that was hotter than normal.
  - ✓ On average, load was 8 percent higher in the third quarter of 2010.
  - ✓ Load peaked on July 6th at 33.5 GW, which was 1 percent lower than the all-time peak (33.9 GW on August 2, 2006), 1 percent higher than the 2010 peak load forecast (33.0 GW), and 9 percent higher than the 2009 peak.
  - ✓ Load exceeded 26 GW for 392 hours and 30 GW for 66 hours, substantially more than in the third quarter of 2009.
- The daily peak load forecast had an error greater than 2 GW on six days and an error greater than 1 GW on 26 days.
  - ✓ Higher-than-normal temperatures in September likely contributed to the higher number of days with large forecast errors.

Load Forecast and Actual Load

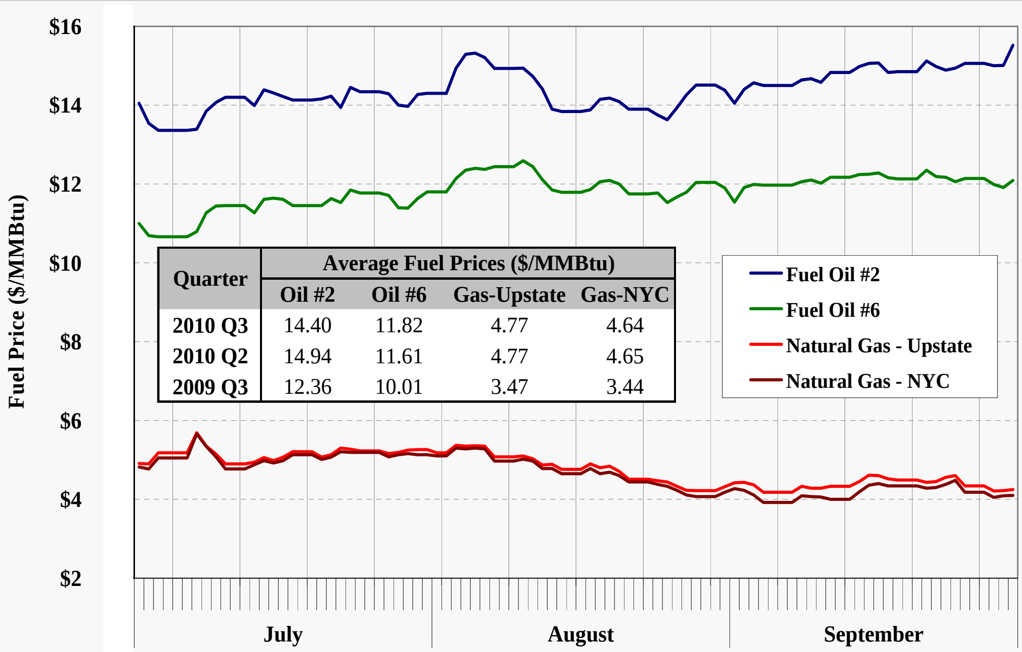


Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2010 Q3	33.5	21.2	392	66	168	745
2010 Q2	30.2	18.0	69	3	41	463
2009 Q3	30.8	19.6	142	13	215	521

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 third quarter, ranging between $4 and $6/MMbtu.
  - ✓ Gas prices were slightly lower in New York City than in other areas. The differential between the two locations shown in the figure averaged $0.13/MMbtu during the third quarter.
- Average natural gas and fuel oil prices were similar to the previous quarter.
  - ✓ However, natural gas prices fell approximately 20% from July to September.
- Average natural gas prices rose 36 percent from the third quarter of 2009, while fuel oil prices rose more moderately over the same period (17 percent for Oil #2 and 18 percent for Oil #6).
  - ✓ Fuel oil prices are much higher than natural gas prices. However, some generators still burn fuel oil for reliability reasons, because they are not connected to the natural gas pipeline system, or due to other difficulties obtaining natural gas.

Natural Gas and Oil Prices



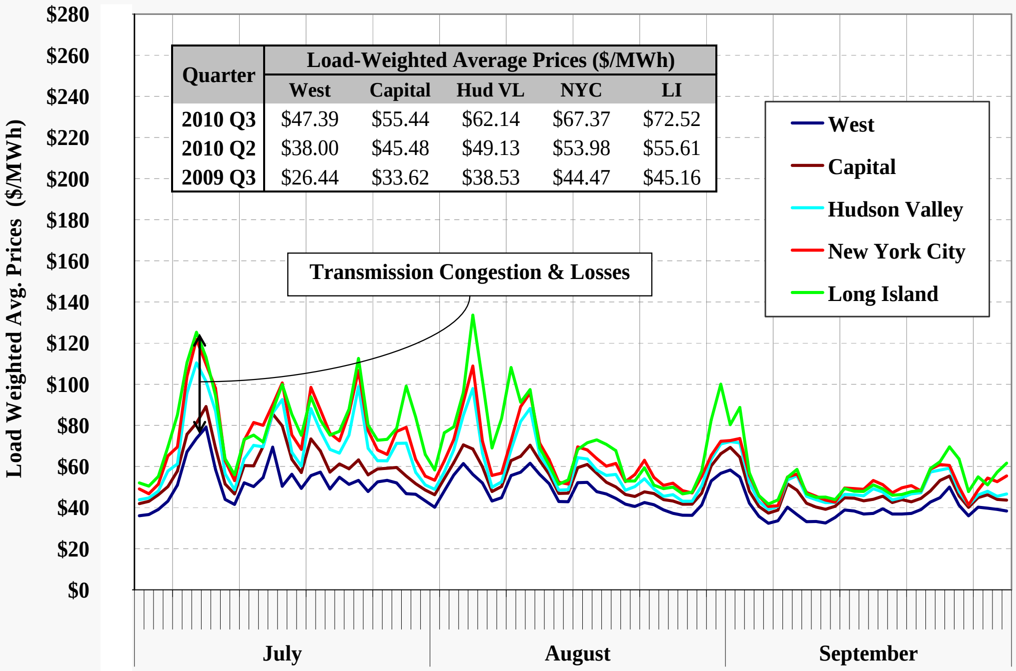
Quarter	Average Fuel Prices ($/MMBtu)			
	Oil #2	Oil #6	Gas-Upstate	Gas-NYC
2010 Q3	14.40	11.82	4.77	4.64
2010 Q2	14.94	11.61	4.77	4.65
2009 Q3	12.36	10.01	3.47	3.44

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 third quarter.
- Prices in the day-ahead market reflect probability-weighted expectations of real-time market conditions.
- Day-ahead prices rose in all zones from the previous quarter, due primarily to increased load levels.
  - ✓ Prices rose substantially on days when load was forecasted to exceed 30 GW.
  - ✓ Average day-ahead prices trended downward from July to September, consistent with the decreases in load and natural gas prices over the quarter.
- Price separation between the West Zone and the Capital Zone decreased (in percentage terms) from the prior periods, reflecting expectations of reduced congestion across the Central-East interface.
- Price differences between Long Island and the rest of New York increased from the prior periods. The following factors contributed to the increase:
  - ✓ The Neptune Cable was out of service for portions of 20 days, up from 11 days in the second quarter and three days in the third quarter of 2009.
  - ✓ Load rose more in Long Island than in other areas from the second quarter to the third quarter (28 percent in Long Island vs. 18 percent statewide).

Day-Ahead Electricity Prices by Zone

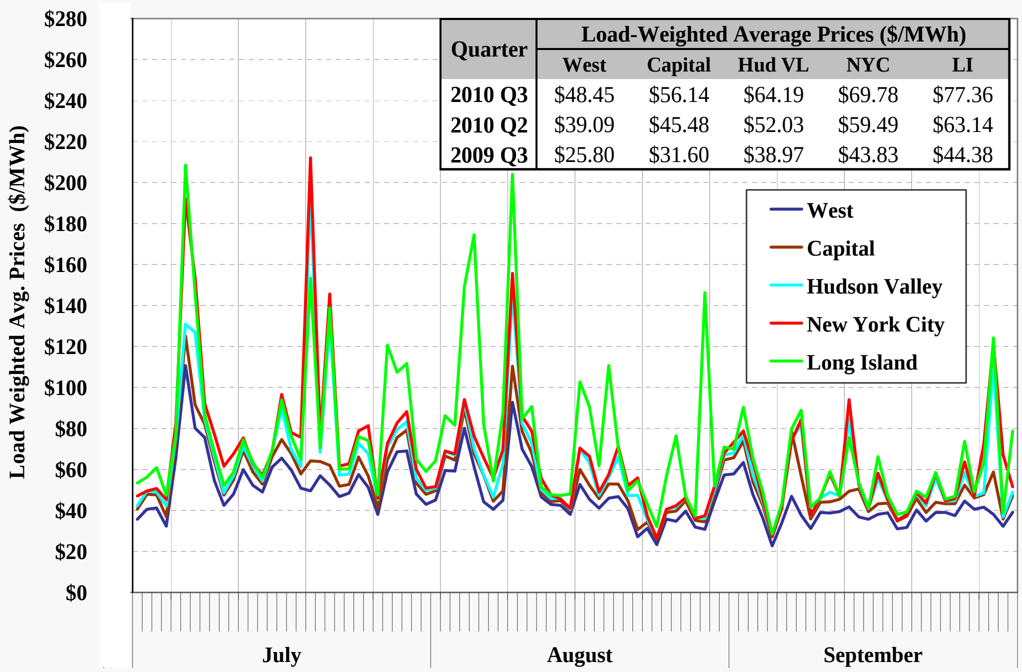


Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2010 Q3	$47.39	$55.44	$62.14	$67.37	$72.52
2010 Q2	$38.00	$45.48	$49.13	$53.98	$55.61
2009 Q3	$26.44	$33.62	$38.53	$44.47	$45.16

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 third quarter.
  - ✓ Prices are more volatile in the real-time market than in the day-ahead market.
- Real-time prices increased from the second quarter, reflecting tighter system conditions primarily due to increased load and more TSA events.
- The average real-time price in the West Zone rose nearly 90 percent from the third quarter of 2009, much more than the increase in natural gas prices.
  - ✓ This partly reflects less congestion across the Central-East interface due to reduced clockwise circulation around Lake Erie, reduced imports to Western New York, and less production from hydro-electric generation.
- Congestion in Southeastern New York increased considerably on many days during the quarter. This was partly due to several factors:
  - ✓ TSAs occurred on 14 days, leading to substantial price spikes in SENY (e.g., July 19, 21 & September 13, 28). However, this was less frequent than in the third quarter of 2009 when there were 19 days with TSAs.
  - ✓ The Neptune Cable was out of service on 20 days, contributing to notable congestion into Long Island (e.g., July 27, 28, 29 & August 4, 5, 9, 29).
  - ✓ High load levels contributed to tight system conditions and high levels of congestion on these and other days during the quarter (e.g., July 6, 7, August 31, & September 1, 2, 3).

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2010 Q3	$48.45	$56.14	$64.19	$69.78	$77.36
2010 Q2	$39.09	$45.48	$52.03	$59.49	$63.14
2009 Q3	$25.80	$31.60	$38.97	$43.83	$44.38

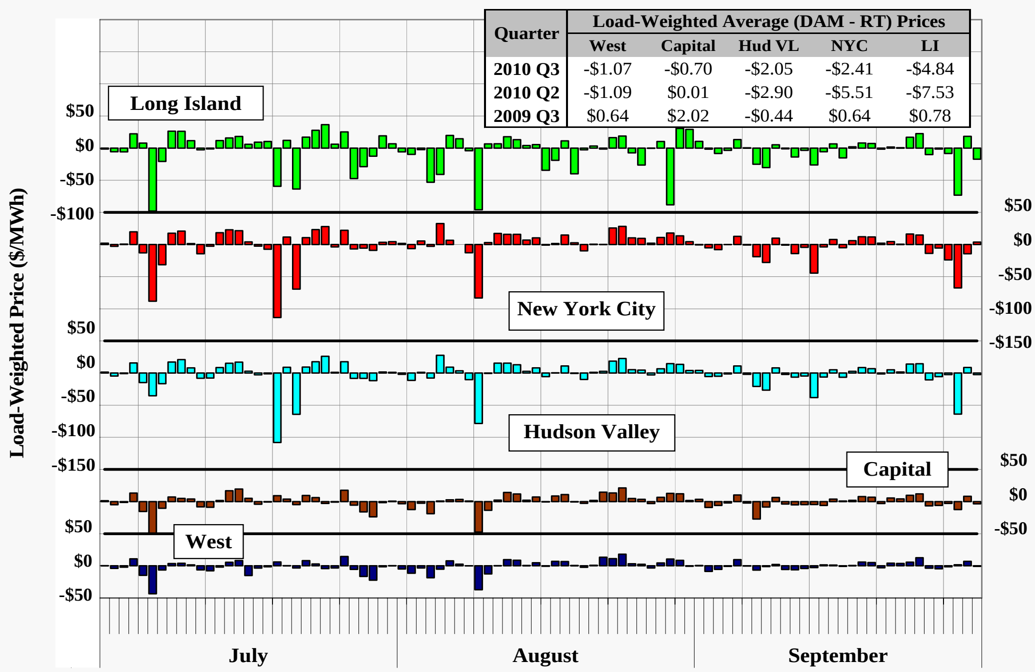
Convergence Between Day-Ahead and Real-Time Prices

- 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 third 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.
- Considerable differences between day-ahead prices and real-time prices occurred on July 6, 19, 21, August 9, 29, & September 28 partly due to unexpected real-time conditions. For example,
  - ✓ On July 6, real-time load approached record levels, exceeding the peak load forecast by nearly 900 MW, and 700 MW of generation tripped offline.
  - ✓ On July 21, a TSA was called with little advanced warning, leading to severe congestion into Southeast New York.
  - ✓ On August 9, the demand for exports to PJM and New England increased in the real-time market relative to day-ahead schedules, and loads ran significantly above the forecast in the early afternoon.

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.
- Average day-ahead prices were generally consistent with average real-time prices in the West Zone and the Capital Zone.
  - ✓ The average day-ahead prices were just 1 to 3 percent lower than the average real-time prices in these areas.
- Convergence in Southeast New York improved in the third quarter compared to the previous quarter.
  - ✓ However, the average day-ahead prices were still 3 to 6 percent lower than average real-time prices in Southeast New York.
  - ✓ Price convergence tends to be worse in Southeast New York during the summer months partly due to the high volatility of real-time prices during TSA events.

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2010 Q3	-$1.07	-$0.70	-$2.05	-$2.41	-$4.84
2010 Q2	-$1.09	$0.01	-$2.90	-$5.51	-$7.53
2009 Q3	$0.64	$2.02	-$0.44	$0.64	$0.78

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

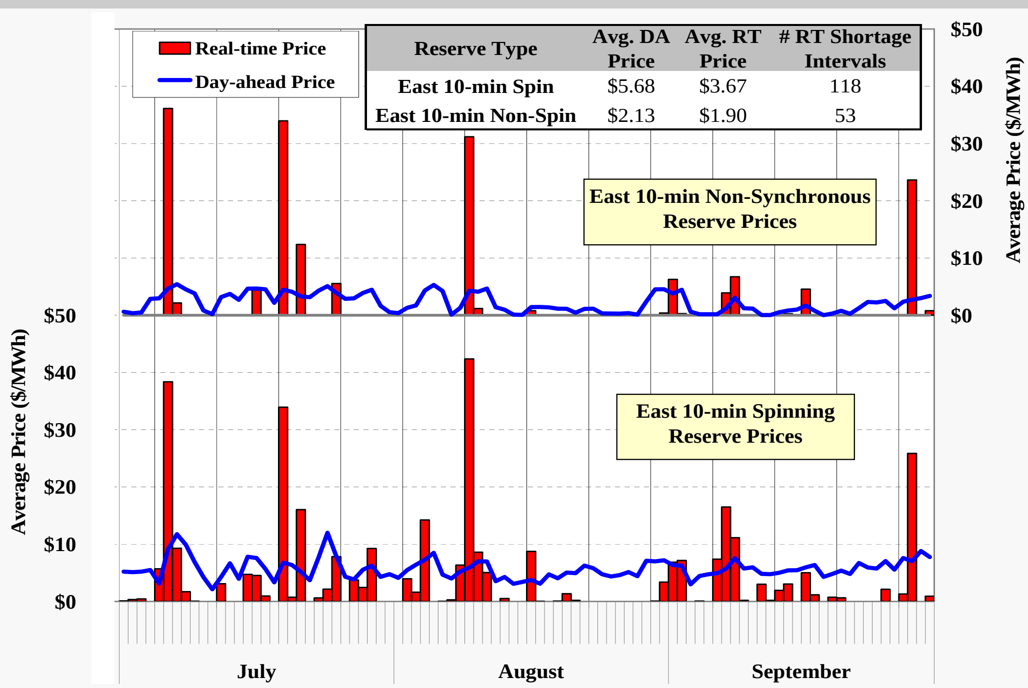
- Reserve prices are relatively consistent from day-to-day in the day-ahead, while reserve prices are much more volatile in the real-time market.
  - ✓ Day-ahead reserves prices are based on suppliers’ offers, which depend on expectations of real-time prices and the risks associated with selling reserves 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 third quarter of 2010.
  - ✓ The day-ahead price premium results partly from the risks that generators perceive from selling in the day-ahead market.
  - ✓ Average day-ahead prices usually rose on high load days when real-time price spikes were more likely.
- Regulation prices decreased in September, partly due to the 10 percent reduction in the average regulation requirement.

Day-Ahead and Real-Time Ancillary Services Prices

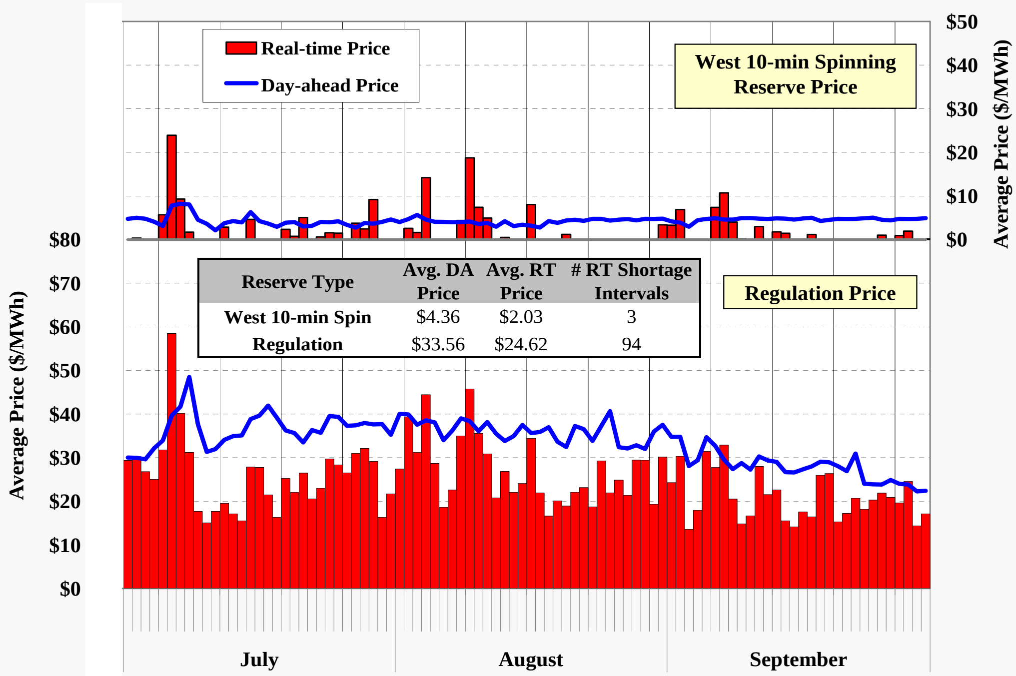
- A shortage occurs when a reserve requirement cannot be satisfied at a marginal cost less than its "demand curve". Shortages occurred in real-time for:
  - ✓ Eastern 10-minute spinning reserves in 62 intervals ($25 demand curve);
  - ✓ Eastern 10-minute total reserves in 53 intervals ($500 demand curve);
  - ✓ State-wide 10-min spinning reserves in 3 intervals ($500 demand curve); and
  - ✓ Regulation in 94 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 118 intervals of shortage pricing: 62 of eastern 10-minute spin, 53 of eastern 10-minute total reserves, and 3 of state-wide 10-minute spin.
- The number of Eastern 10-minute total reserve shortages rose from a year ago, which was attributable to increased load levels and lower day-ahead load scheduling as a share of the actual load in Southeast New York.
  - ✓ The majority of the shortages occurred on the peak load day and on days when TSA events were called.

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	$5.68	$3.67	118
East 10-min Non-Spin	$2.13	$1.90	53



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



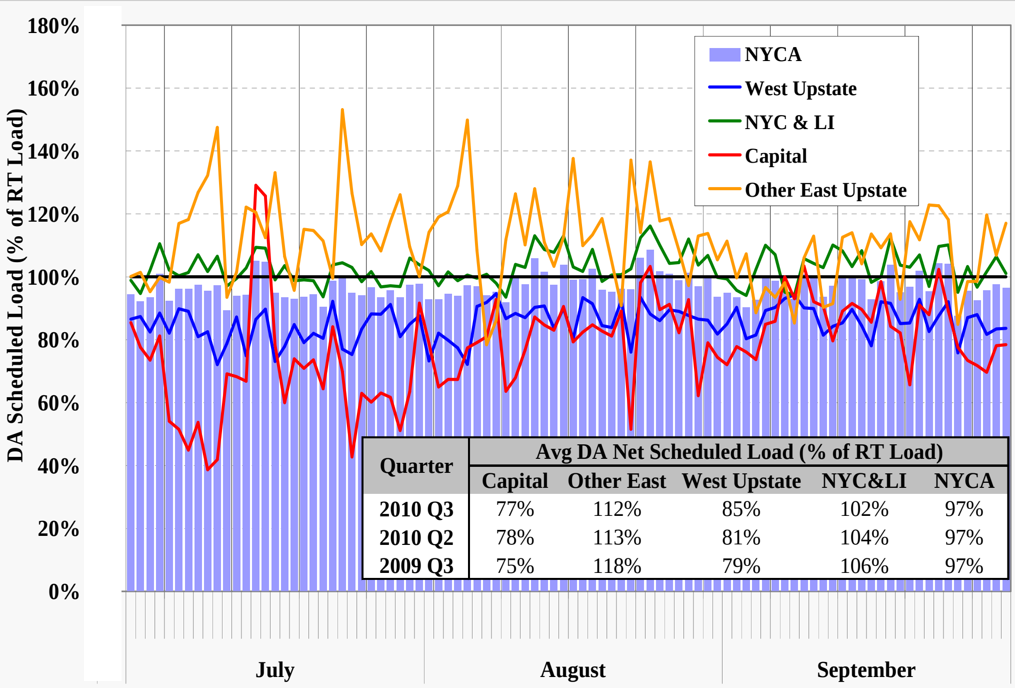
Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
West 10-min Spin	$4.36	$2.03	3
Regulation	$33.56	$24.62	94

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 was scheduled at 97 percent of actual load in NYCA, 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 third quarter.
  - ✓ This was likely in response to frequent congestion into Southeast New York on days when TSAs were likely to be called.
  - ✓ The average amount of day-ahead scheduled load fell as a share of actual load after August, reflecting that TSAs are much less frequent outside the summer months.
- The over- and under-scheduling patterns generally improve convergence between day-ahead and real-time prices in most areas.
  - ✓ Nevertheless, day-ahead prices were noticeably lower on average than real-time prices in Southeast New York in the third quarter. Additional over-scheduling in Southeast New York would have been needed for good convergence.

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour



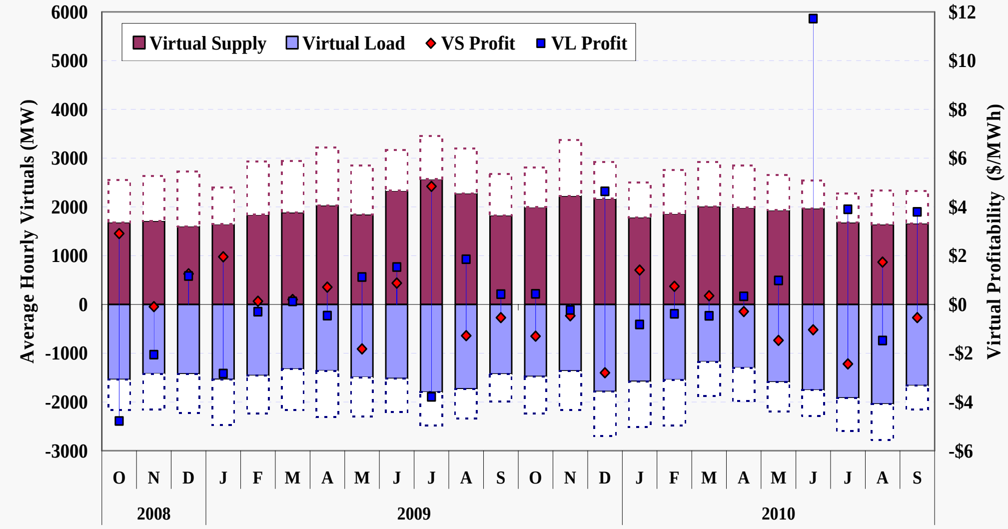
Quarter	Avg DA Net Scheduled Load (% of RT Load)				
	Capital	Other East	West Upstate	NYC&LI	NYCA
2010 Q3	77%	112%	85%	102%	97%
2010 Q2	78%	113%	81%	104%	97%
2009 Q3	75%	118%	79%	106%	97%

Virtual Trading Activity

- The following two figures summarize virtual trading activity in New York.
- The first figure shows monthly average scheduled quantities, unscheduled quantities, and profitability for virtual transactions over the past two years.
  - ✓ In each of the past 24 months, 1.2 to 2.0 GW of virtual load and 1.6 to 2.5 GW of virtual supply have been consistently scheduled in the day-ahead market.
  - ✓ In aggregate, virtual load and supply have been profitable over the period, indicating that they have generally 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.
    - – For example, virtual loads scheduled in Southeast New York earned large profits in June 2010 due to poor price convergence, but they incurred losses in August 2010 due to a reversal in the price differences in New York City.
- The table below the figure shows a screen for relatively large profits or losses.
  - ✓ Large profits may be an indicator of a modeling inconsistency, and large losses may be an indicator of potential manipulation of the day-ahead market.
  - ✓ These levels were modest in the third quarter, and our monitoring of these indicators have not raised potential manipulation concerns.

Virtual Trading Volumes and Profitability

October 2008 to September 2010



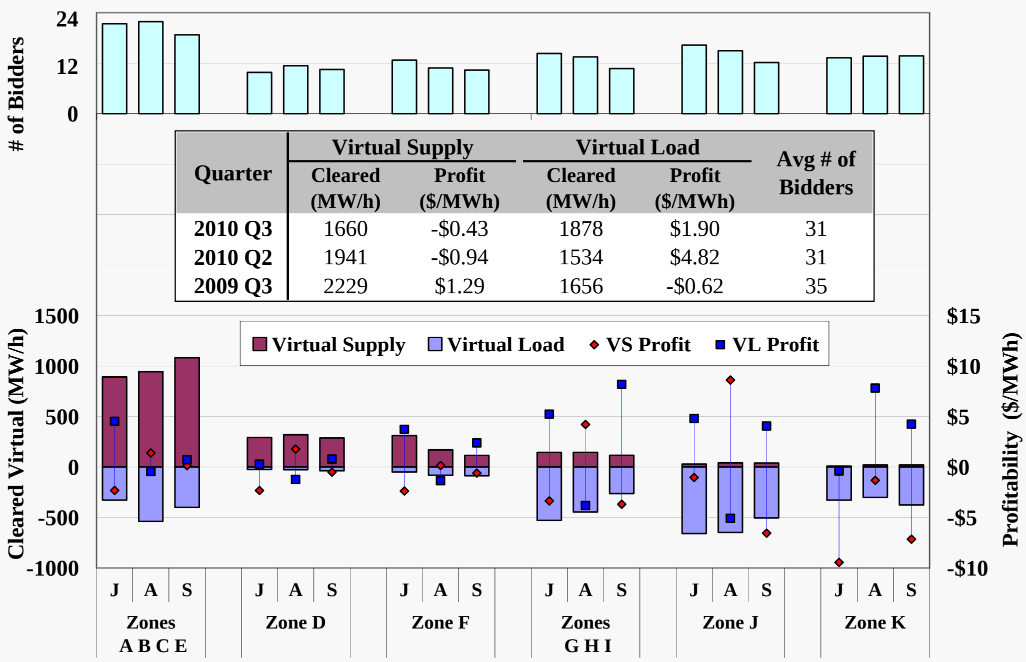
Profit > 50% of Avg. Zone Price	MW	187	71	197	97	105	225	270	271	420	514	293	235	315	239	573	380	324	240	122	181	285	205	176	162
	%	6%	2%	7%	3%	3%	7%	8%	8%	11%	12%	7%	7%	9%	7%	14%	11%	10%	8%	4%	5%	8%	6%	5%	5%
Loss > 50% of Avg. Zone Price	MW	203	107	145	108	102	192	249	281	384	611	441	244	369	253	578	347	284	201	112	211	241	300	205	115
	%	6%	3%	5%	3%	3%	6%	7%	8%	10%	14%	11%	7%	11%	7%	15%	10%	8%	6%	3%	6%	6%	8%	6%	3%

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 bottlenecks frequently limit the amount of power that can flow out of Zone D.
  - ✓ Zone F (the Capital Zone) is shown separately because it is constrained from Western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley.
  - ✓ Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas.
- A large number of market participants regularly submit virtual bids and offers.
  - ✓ On average, 10 or more participants submitted virtual trades in each region and 31 participants submitted virtual trades somewhere in the state.
- There were substantial net virtual load purchases in downstate areas and net virtual supply sales in upstate areas in the third quarter, consistent with prior years.
  - ✓ Almost two-thirds of the virtual trading profits in the third quarter of 2010 came from virtual load scheduling in downstate areas. This is not surprising because real-time congestion was not fully reflected in day-ahead prices in this quarter.

Virtual Trading Activity

By Region

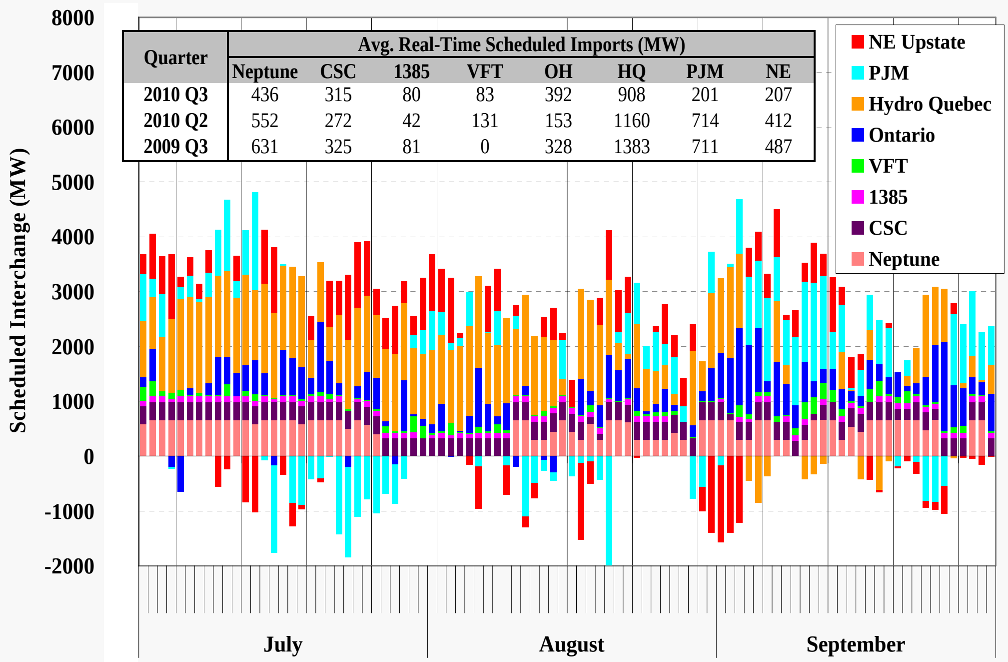


Quarter	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Avg # of Bidders
2010 Q3	1660	-$0.43	1878	$1.90	31
2010 Q2	1941	-$0.94	1534	$4.82	31
2009 Q3	2229	$1.29	1656	-$0.62	35

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 2.6 GW during daily peak hours in the third quarter, down 24 percent from the previous quarter and 34 percent from the third quarter of 2009.
  - ✓ Net imports from HQ, PJM, and New England averaged 1.3 GW in the third quarter, down nearly 1.0 GW from the previous quarter and 1.3 GW from the third quarter of 2009. Supply conditions were tighter in these areas in 2010.
  - ✓ Average imports from the Neptune Cable fell 115 MW from the second quarter due primarily to it being out of service for 20 days in the third quarter.
- Imports on average satisfied 11 percent of the load during daily peak hours in the third quarter, down from the 16 percent in the previous quarter.
  - ✓ The decrease was significant in light of the increased load.
  - ✓ During the quarterly peak load hour on July 6, NYCA imported 3.6 GW that satisfied nearly 11 percent of the peak load.

Net Imports Scheduled Across External Interfaces
Daily Peak Load Hour

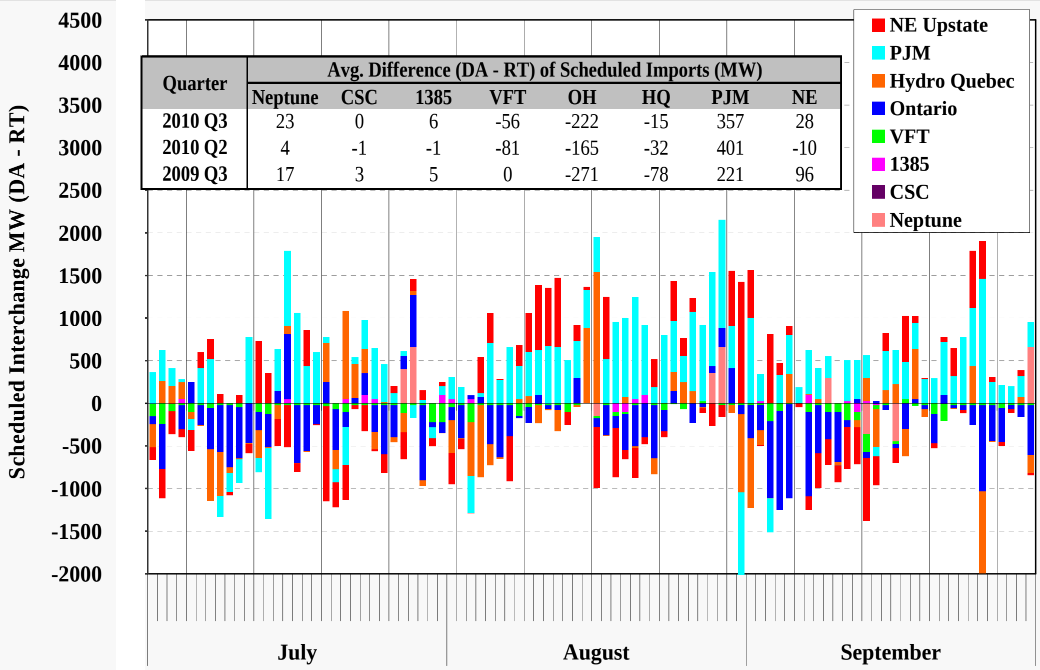


Quarter	Avg. Real-Time Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2010 Q3	436	315	80	83	392	908	201	207
2010 Q2	552	272	42	131	153	1160	714	412
2009 Q3	631	325	81	0	328	1383	711	487

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 or the primary interface with New England;
  - ✓ Did not vary significantly across the primary interface with HQ on most days, although it decreased considerably on some days with TSA-related congestion (e.g., July 19 & 21);
  - ✓ Frequently increased across the Linden VFT;
  - ✓ Decreased across the PJM interface by an average of 357 MW; and
  - ✓ Increased across the Ontario interface by an average of 222 MW.
- Overall, these changes in schedules tend to improve consistency between day-ahead and real-time prices.

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

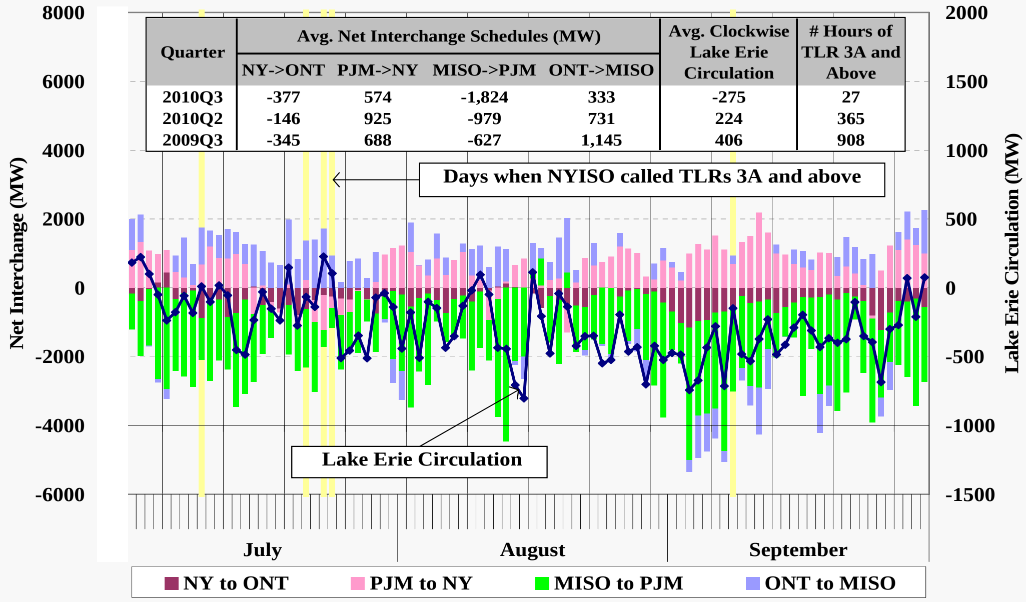


Quarter	Avg. Difference (DA - RT) of Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2010 Q3	23	0	6	-56	-222	-15	357	28
2010 Q2	4	-1	-1	-81	-165	-32	401	-10
2009 Q3	17	3	5	0	-271	-78	221	96

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+) were called by the NYISO are also highlighted.
- Average clockwise circulation fell to *negative* 275 MW in the third quarter, down from 224 MW in the prior quarter and 406 MW in 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 5 days in the third quarter for a total of 27 hours, down 93 percent from the second quarter.
  - ✓ Clockwise circulation averaged 127 MW on days when TLRs were called and -293 MW on days when no TLRs were called.

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		
2010Q3	-377	574	-1,824	333	-275	27
2010Q2	-146	925	-979	731	224	365
2009Q3	-345	688	-627	1,145	406	908

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

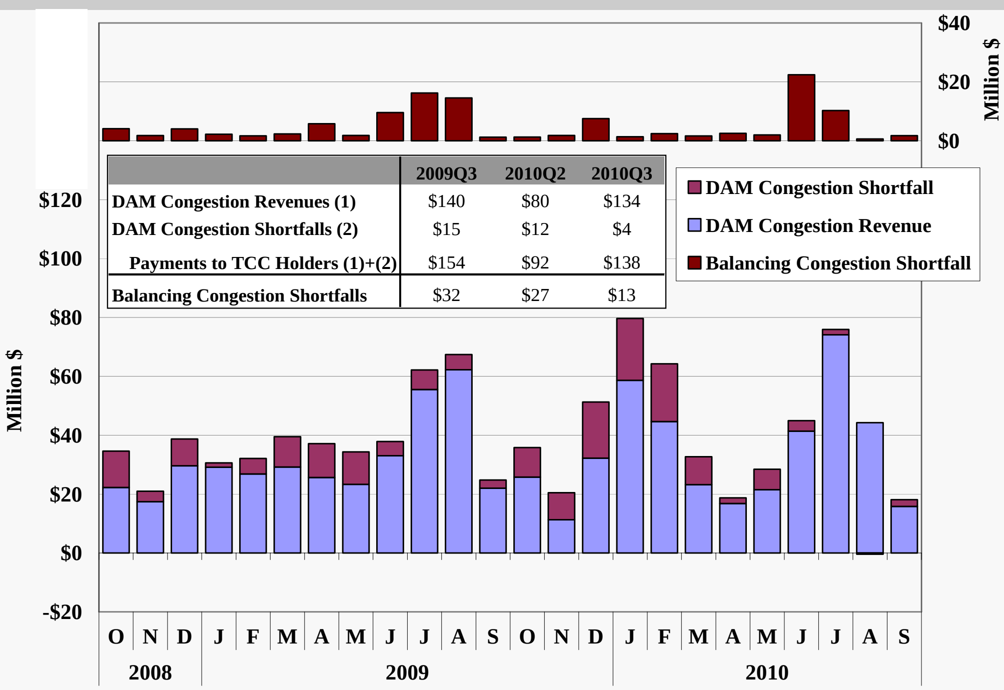
Congestion Revenue and Shortfalls

- 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 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 were $134 million in the third quarter, up 68 percent from the second quarter.
  - ✓ The increase was mostly attributable to the effects on day-ahead scheduling patterns of: (i) increased load levels and (ii) more frequent thunderstorm alerts.
- Day-ahead congestion revenue fell slightly from the third quarter 2009.
  - ✓ Collections declined as a result of reduced hydro production in western New York, imports to western New York, and clockwise Lake Erie Circulation. However, these factors were largely offset by the effects of increased gas prices and loads.
- Day-ahead congestion shortfalls fell substantially in the third quarter, down 70 percent from the second quarter and 75 percent from the third quarter of 2009.
  - ✓ This was primarily due to reduced congestion of the Central-East interface, which has been a significant source of shortfalls in the past, and less frequent transmission maintenance outages in the summer months.
- Balancing congestion shortfalls were $13 million in the third quarter, down from $27 million in the second quarter and $32 million in the third quarter of 2009.
  - ✓ The decreases were primarily due to improved operations during TSA events and less frequent use of simplified interface constraints in New York City.

Congestion Revenue and Shortfalls



	2009Q3	2010Q2	2010Q3
DAM Congestion Revenues (1)	$140	$80	$134
DAM Congestion Shortfalls (2)	$15	$12	$4
Payments to TCC Holders (1)+(2)	$154	$92	$138
Balancing Congestion Shortfalls	$32	$27	$13

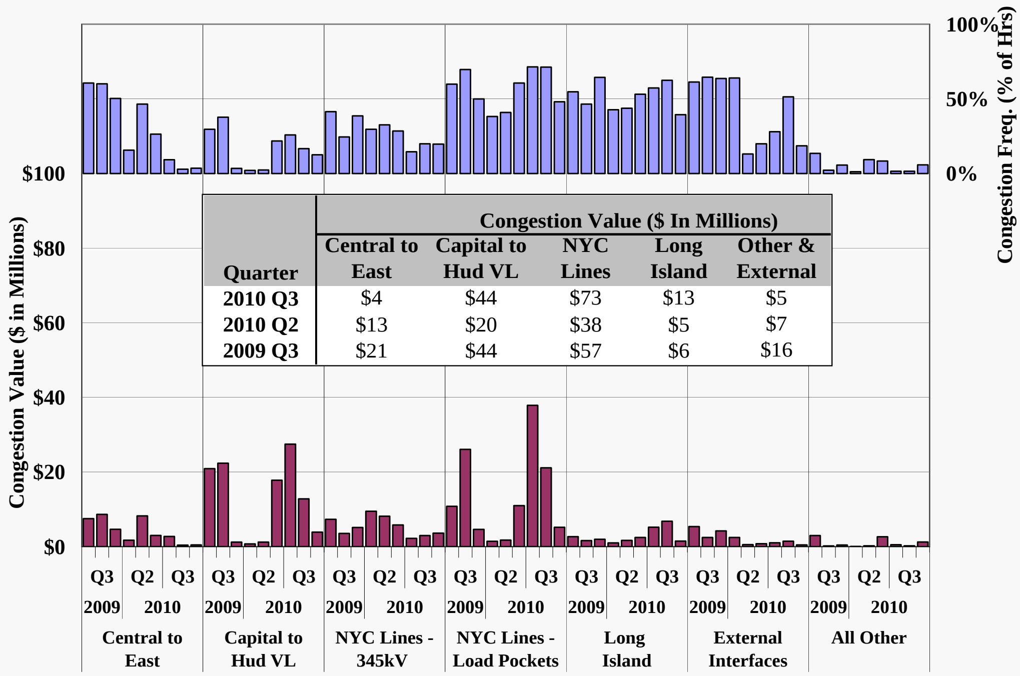
Congestion by Transmission Path

- 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:
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ Capital to Hudson Valley: Primarily the Leeds-to-Pleasant Valley line.
  - ✓ 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 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 third quarter occurred over lines into and within New York City (53 percent), lines from Capital to Hudson Valley (32 percent), and lines into and within Long Island (10 percent).
- Compared to the third quarter of 2009, congestion rose in New York City and Long Island, but fell across Central-East and the external interfaces.
  - ✓ The increase in New York City and Long Island reflects the effects of increased load, higher natural gas prices, the Poletti retirement, and more frequent outages of the Neptune cable.
  - ✓ The decrease across Central-East and the external interfaces reflects reduced imports into western New York, less hydro production, less clockwise circulation around Lake Erie, and new generating supply in the Capital Zone.

Day-Ahead Congestion by Transmission Path

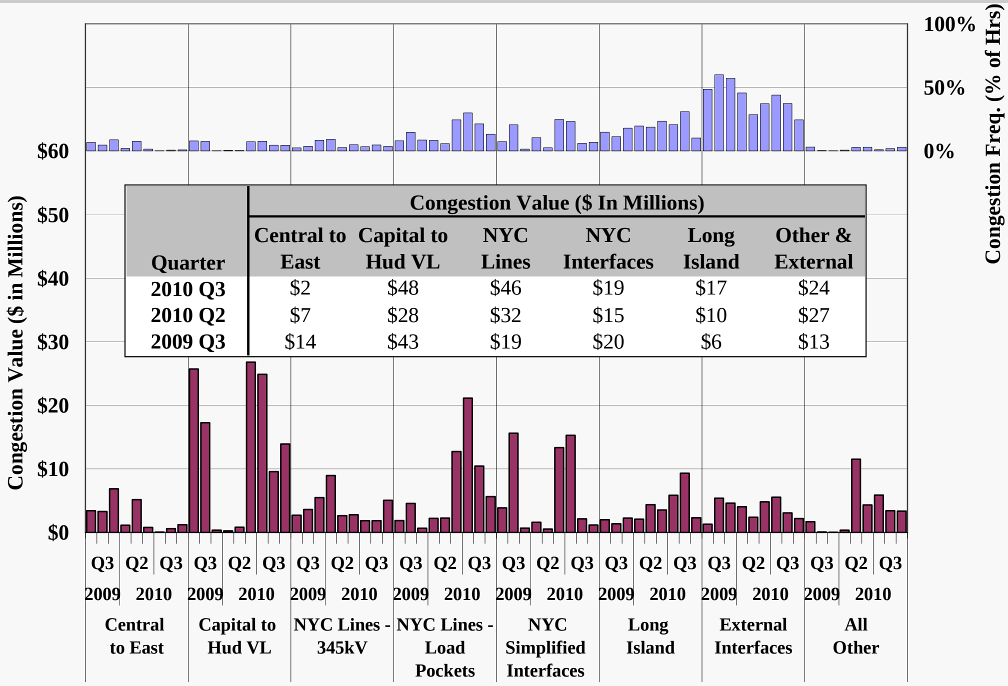


Quarter	Congestion Value ($ In Millions): Central to East	Capital to Hud VL	NYC Lines	Long Island	Other & External
2010 Q3	$4	$44	$73	$13	$5
2010 Q2	$13	$20	$38	$5	$7
2009 Q3	$21	$44	$57	$6	$16

Real-Time Congestion by Transmission Path

- The following figure summarizes the value and frequency of congestion by transmission path in the real-time market.
- Real-time congestion primarily occurred on two paths in the third quarter:
  - ✓ NYC lines and simplified interface constraints (41 percent): Most of these were related to congestion into the Greenwood load pocket in July.
  - ✓ Capital to Hudson Valley (31 percent): This was primarily due to congestion across the Leeds-to-Pleasant Valley line during TSA events.
- Convergence between day-ahead and real-time LBMPs improved from the second quarter to the third quarter, leading to smaller differences in the pattern of congestion between the day-ahead and real-time markets.
  - ✓ In the third quarter, the total value of congestion in the real-time market was $156 million, 12 percent higher than in the day-ahead market. This is an improvement over the second quarter when the total value of congestion in the real-time market was 43 percent higher than in the day-ahead market.
- The use of NYC simplified interface constraints decreased from 2009 to 2010.
  - ✓ Simplified interface constraints accounted for 29 percent of the value of real-time congestion in New York City in the third quarter of 2010, down from 51 percent in the third quarter of 2009.

Real-Time Congestion by Transmission Path

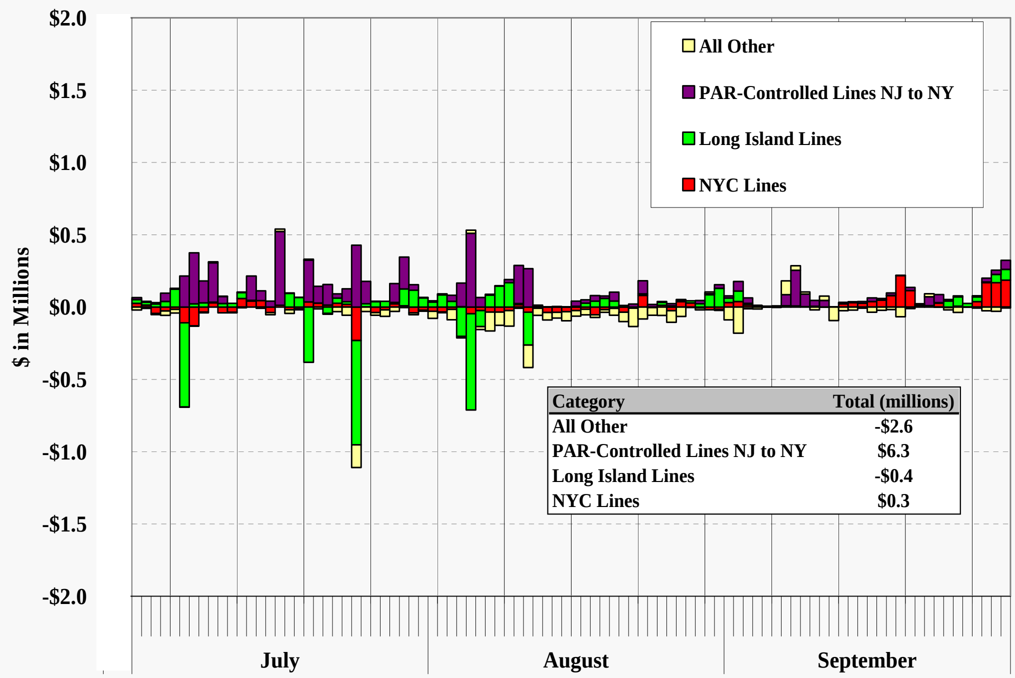


Quarter	Congestion Value ($ In Millions) Central to East	Capital to Hud VL	NYC Lines	NYC Interfaces	Long Island	Other & External
2010 Q3	$2	$48	$46	$19	$17	$24
2010 Q2	$7	$28	$32	$15	$10	$27
2009 Q3	$14	$43	$19	$20	$6	$13

Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily congestion revenue shortfalls by transmission path or facility in the third 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
  - ✓ Transmission outages that are assumed in the day-ahead market but not in the TCC auctions. The NYISO has a process for allocating shortfalls that are attributable to the outages of specific TOs.
- PAR-controlled lines between NJ and NY (i.e., Waldwick, Ramapo, Farragut, and Linden) accounted for the majority of the total shortfalls.
  - ✓ Different modeling assumptions between the TCC auction and the day-ahead market led to consistent day-ahead congestion shortfalls.
- New York City and Long Island lines accounted for $0.1 million of net congestion surpluses.
  - ✓ When the pattern of scheduled flows changes from the TCC auction to the day-ahead market, additional congestion revenues are collected in the day-ahead market.
  - ✓ These surpluses were partly offset by transmission outages in mid- and late-September, which led to several days of shortfalls in New York City.

Day-Ahead Congestion Revenue Shortfalls



Category	Total (millions)
All Other	-$2.6
PAR-Controlled Lines NJ to NY	$6.3
Long Island Lines	-$0.4
NYC Lines	$0.3

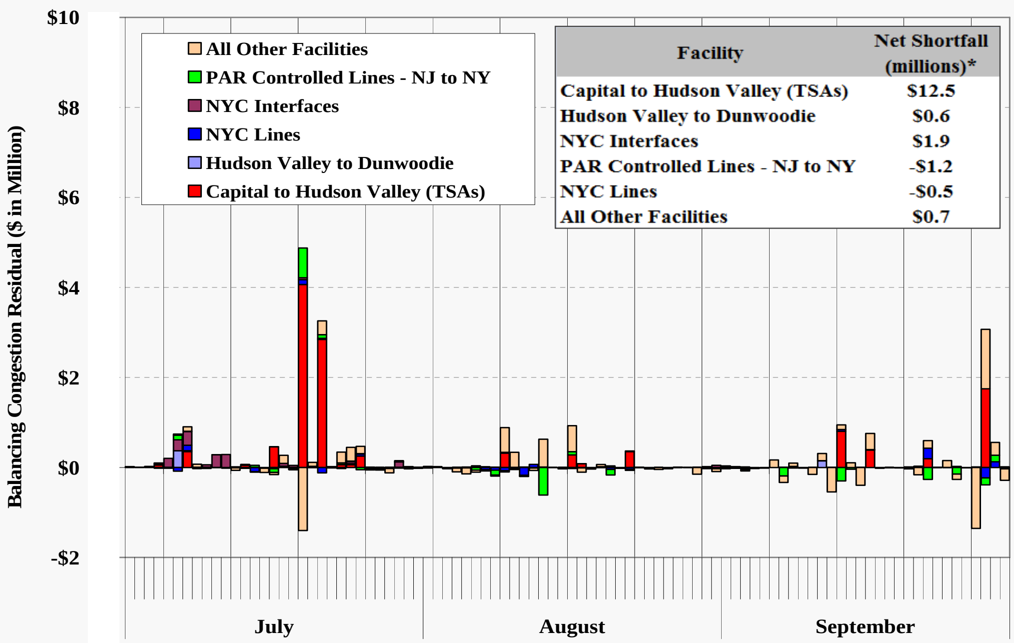
Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the third 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

- Capital to Hudson Valley lines accounted for the majority (90 percent) of balancing congestion shortfalls in the third quarter.
  - ✓ Most occurred on three days (July 19 & 21 and September 28) when TSAs were called.
- Simplified interface constraints in New York City accounted for 14 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 is lower than in prior years when simplified interface constraints were used more frequently to manage real-time congestion in New York City.
- The balancing congestion shortfalls associated with Capital to Hudson Valley lines and PAR-controlled lines between New Jersey and New York fell from the previous quarters. This is partly due to:
  - ✓ Improved operations to better manage reliability during TSA events, including better recognition of the effects of imports on congestion management in the real-time transaction scheduling process; and
  - ✓ Increased circulation around Lake Erie in the counter-clockwise direction.

Balancing Congestion Shortfalls



Facility	Net Shortfall (millions)*
Capital to Hudson Valley (TSAs)	$12.5
Hudson Valley to Dunwoodie	$0.6
NYC Interfaces	$1.9
PAR Controlled Lines - NJ to NY	-$1.2
NYC Lines	-$0.5
All Other Facilities	$0.7

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

Uplift Costs from Guarantee Payments

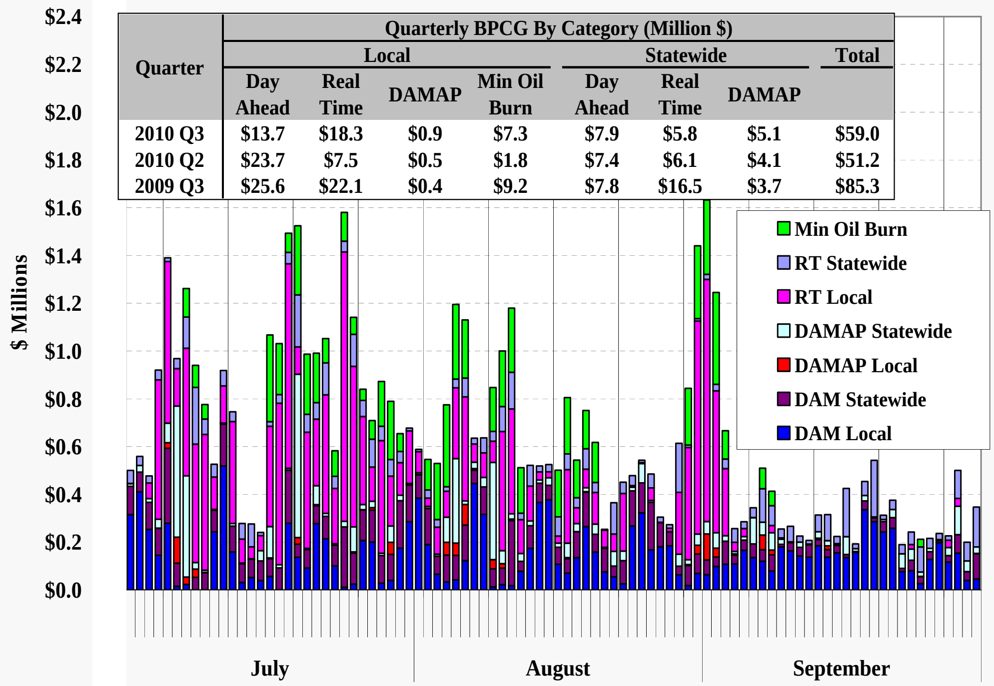
- Three categories of statewide reliability uplift are allocated to all LSEs:
  - ✓ Day Ahead: Primarily for units committed economically that don’t recoup their as-offered start-up and min generation costs across the day from LBMPs.
  - ✓ Real Time: For import transactions and GTs that are scheduled economically but don’t recoup their as-offered costs across the day 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 in margin for generators dispatched by NYISO instruction 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 New York City Local Reliability Requirements (“LRR”) included programmatically in SCUC and Day-Ahead Reliability Unit (“DARU”) commitments requested by TOs for local reliability.
  - ✓ Real Time: From Supplemental Resource Evaluation (“SRE”) commitments and Out-of-Merit (“OOM”) dispatched units requested by TOs for local reliability.
  - ✓ 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 payments to cover losses in margin for generators dispatched OOM for local reliability reasons below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.

Uplift Costs from Guarantee Payments

- The following figure shows the seven categories of uplift charges on a daily basis in the third quarter of 2010.
- Guarantee payment uplift rose to $59 million in the third quarter, up 15 percent from the previous quarter.
  - ✓ Real-time local reliability uplift rose due to more frequent congestion of Long Island facilities that are secured by OOM dispatch by the TO.
  - ✓ Minimum Oil Burn Compensation program costs rose due to more frequent operation on oil for reliability during high load periods.
  - ✓ However, day-ahead local reliability uplift fell because generators that were needed for local reliability were flagged as economic more frequently.
- Guarantee payment uplift decreased 31 percent from the third quarter of 2009 for reasons that are discussed later in this section.
- Guarantee payment uplift rose significantly on high load days during the third quarter, averaging $1.0 million per day on the 25 days when the peak load exceeded 28 GW compared to $0.5 million per day on other days.
  - ✓ Real-time local reliability uplift from Long Island units accounted for 32 percent of the total on high load (>28 GW) days, and Minimum Oil Burn Compensation program costs accounted for another 18 percent.

Uplift Costs from Guarantee Payments

Local and Statewide by Category



Quarterly BPCG By Category (Million $)

Quarter	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2010 Q3	$13.7	$18.3	$0.9	$7.3	$7.9	$5.8	$5.1	$59.0
2010 Q2	$23.7	$7.5	$0.5	$1.8	$7.4	$6.1	$4.1	$51.2
2009 Q3	$25.6	$22.1	$0.4	$9.2	$7.8	$16.5	$3.7	$85.3

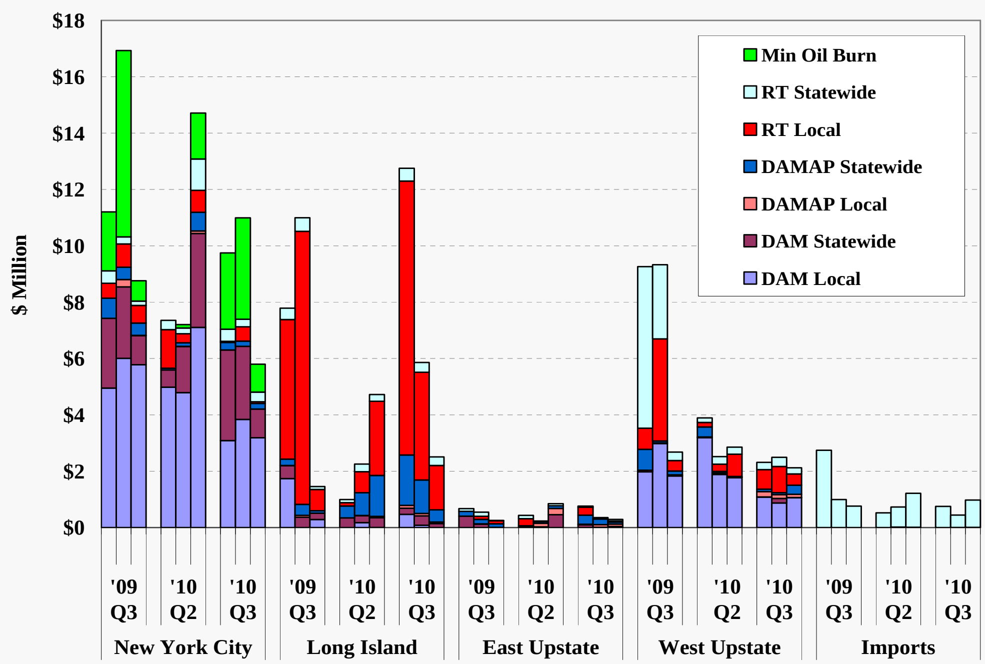
Uplift Costs from Guarantee Payments by Region

- The following figure shows the seven categories of uplift charges on a monthly basis by region.
- Day-ahead local reliability uplift in the third quarter of 2010:
  - ✓ The majority was for New York City (74 percent) and Western New York (22 percent), primarily for DARU- and LRR-commitments.
- Day-ahead statewide reliability uplift in the third quarter of 2010:
  - ✓ 70 percent was paid to NYC generators in hours when they were needed for local reliability but ultimately flagged as economic in the day-ahead market.
    - – If SCUC commits a resource to minimize production costs even when the local reliability rules are removed from the evaluation, it is deemed economic.
- Real-time local reliability uplift in the third quarter of 2010:
  - ✓ 84 percent was for Long Island, primarily to manage transmission facilities on the East End that are secured by OOM dispatch by the TO.
  - ✓ 11 percent was for Western New York, primarily for generators that were SRE-committed by the TO.
- Real-time statewide reliability uplift in the third quarter of 2010:
  - ✓ 41 percent was paid to import transactions that were scheduled by RTC when the real-time LBMP was lower than the offer price.

Uplift Costs from Guarantee Payments by Region

- Guarantee payment uplift decreased 31 percent from the third quarter of 2009. The following accounted for the majority of the year-over-year decline in the third quarter.
  - ✓ In Western New York, day-ahead and real-time local reliability uplift fell from \$11.5 million in 2009 to \$5.0 million in 2010, and real-time statewide reliability uplift fell from \$8.7 million in 2009 to \$0.8 million in 2010. These declines were primarily due to:
    - – Mitigation measures that were instituted in September 2009 to address market power associated with certain reliability commitments outside New York City.
    - – Higher LBMP levels in the third quarter of 2010, which reduced the portion of the cost guarantee that needed to be recouped through guarantee payments.
  - ✓ In New York City, day-ahead local and statewide reliability uplift fell from \$22.8 million in the third quarter of 2009 to \$16.9 million in the third quarter of 2010.
    - – Generators needed for local reliability in the day-ahead market were more economic (i.e., earned less BPCG per unit of output) in the third quarter of 2010.
  - ✓ Guarantee payments to real-time imports fell from \$4.5 million in the third quarter of 2009 to \$2.2 million in the third quarter of 2010 due primarily to less frequent negative price events.

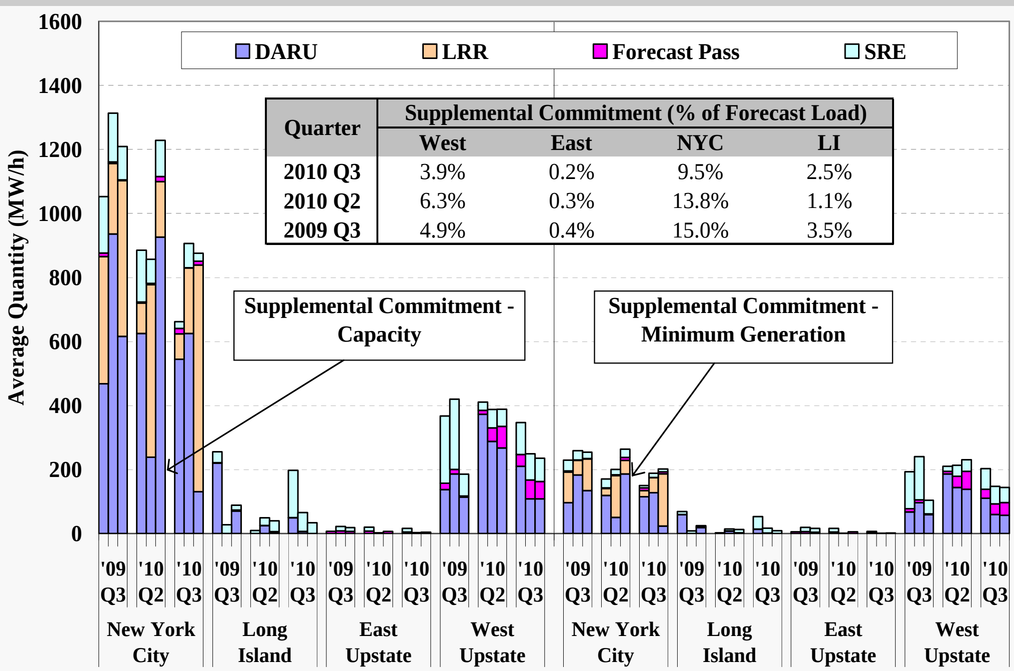
Uplift Costs from Guarantee Payments
By Category and Region



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.
- Local reliability commitment in New York City decreased from prior periods.
  - ✓ Committed capacity in New York City averaged 815 MW, down 18 percent from the prior quarter and 32 percent from the third quarter of 2009.
  - ✓ The minimum generation level of these units averaged 180 MW, down 15 percent from the prior quarter and 27 percent from the third quarter of 2009.
  - ✓ The decline occurred primarily because the generators that were needed for local reliability were flagged as economic more often in the day-ahead market.
- Reliability commitment in western New York also fell from the prior periods.
  - ✓ Committed capacity averaged 277 MW, down 30 percent from the prior quarter and 15 percent from the third quarter of 2009.
  - ✓ The minimum generation level of these units averaged 165 MW, down 24 percent from the prior quarter and 8 percent from the third quarter of 2009.
  - ✓ DARU commitment for local reliability fell partly due to higher LBMP levels, which led the required generators to be flagged as economic more frequently.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2010 Q3	3.9%	0.2%	9.5%	2.5%
2010 Q2	6.3%	0.3%	13.8%	1.1%
2009 Q3	4.9%	0.4%	15.0%	3.5%

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

Automated Mitigation in the Day-Ahead and Real-Time Markets:

- Most mitigation occurred day-ahead for DARU & LRR units (83 percent) and Astoria West/Queens/Vernon congestion (7 percent).
- Mitigation decreased roughly 34 percent from the third quarter of 2009 due primarily to the reduction in DARU- and LRR-committed capacity, which are mitigated whenever their Start-up and/or MinGen offers exceed the reference.

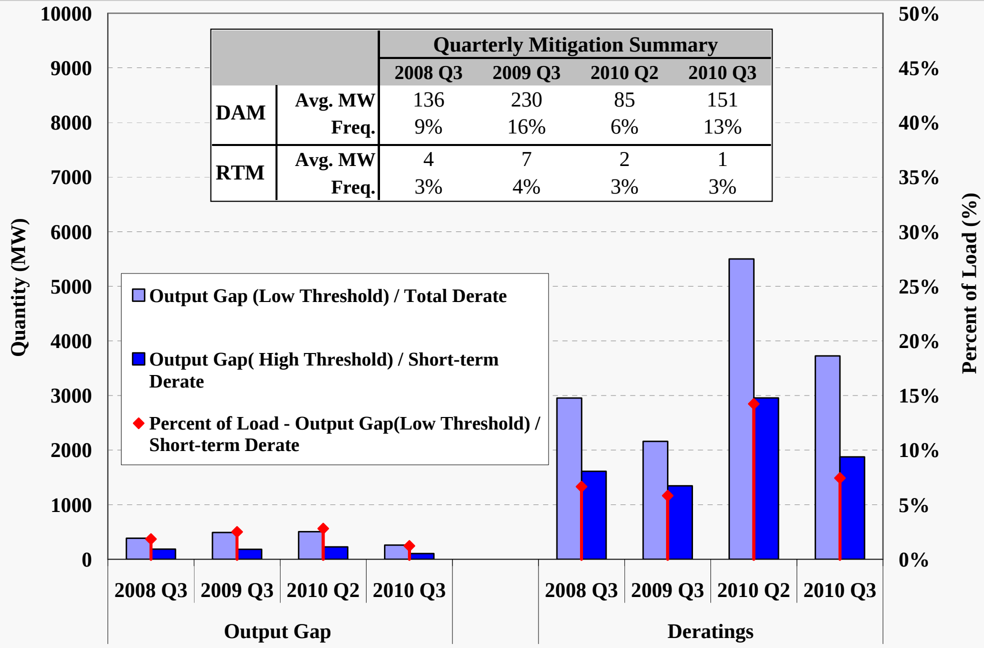
Output Gap at High and Low Thresholds:

- 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.

Long-Term and Short-Term Deratings:

- 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 by the NYISO and no significant concerns arose in the third quarter.

Market Monitoring Screens and Mitigation



		Quarterly Mitigation Summary			
		2008 Q3	2009 Q3	2010 Q2	2010 Q3
DAM	Avg. MW	136	230	85	151
	Freq.	9%	16%	6%	13%
RTM	Avg. MW	4	7	2	1
	Freq.	3%	4%	3%	3%

Note: The deratings are shown for hours 14 to 21, and they exclude the deratings of wind and hydro units.

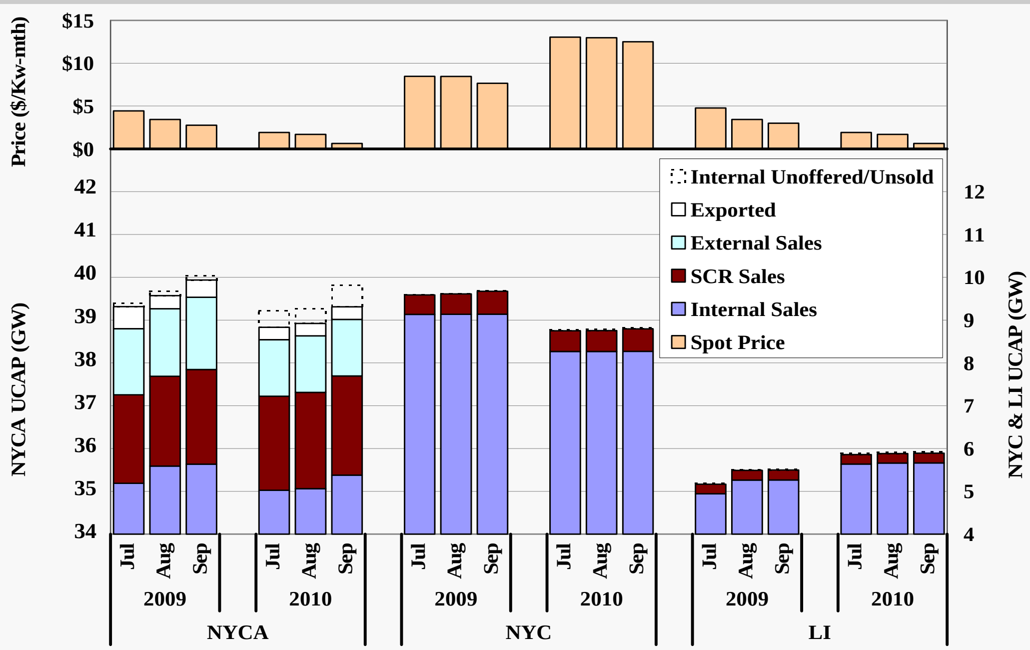
Capacity Market Results

- The following figure summarizes available and scheduled UCAP resources and the clearing prices in each capacity zone.
- In New York City, UCAP spot prices rose to an average of $12.84/kW-month in the third quarter, up 57 percent from the third quarter of 2009 due to:
  - ✓ An 11 percent escalation in the New York City capacity demand curve from the previous capability period; 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, which reduced the capacity requirement.
- In Long Island, UCAP spot prices fell to an average of $1.41/kW-month in the third quarter, down 62 percent from the third quarter of 2009.
  - ✓ The Long Island Local Capacity Requirement (“LCR”) was never binding during the quarter, leading Long Island clearing prices to equal the Rest-Of-State clearing prices.
  - ✓ The excess capacity relative to the Long Island LCR was approximately 17 percent in the third quarter.

Capacity Market Results

- In NYCA, UCAP spot prices fell to an average of $1.41/kW-month in the third quarter of 2010, down 60 percent from the third 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;
  - ✓ An increase of 130 MW in SCR sales from a year ago; and
  - ✓ Several additions to the supply of capacity in the Capital Zone, New York City and Long Island.
- However, these factors were partly offset by:
  - ✓ The retirement of the Poletti unit which reduced supply by nearly 900 MW;
  - ✓ An increase in the Installed Reserve Margin ("IRM") to 118 percent from 116.5 percent in the previous summer capability period;
  - ✓ An 11 percent escalation of the New York Control Area demand curve from the previous capability period; and
  - ✓ A fall in net imports of UCAP from 1.2 GW in the third quarter of 2009 to 1.0 GW in the third quarter of 2010.

Capacity Market Results



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