Quarterly Report on the New York Electricity Market Third Quarter 2009

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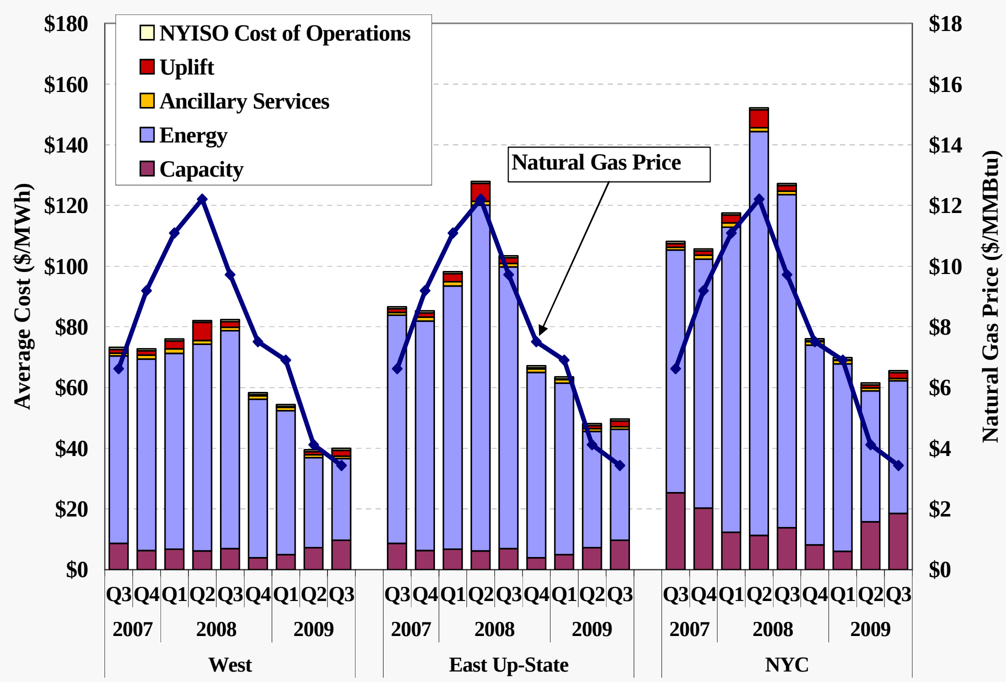
Highlights and Market Summary

- This presentation summarizes the outcomes of the NYISO energy, ancillary services, and capacity markets during the third quarter of 2009.
- Overall, the markets performed competitively and were characterized by substantially lower prices than in prior periods.
  - ✓ Real-time energy prices averaged $37/MWh, down 61 percent from the third quarter of 2008 and 3 percent from the prior quarter. This was primarily due to:
    - Natural gas price reductions of 65 percent from the third quarter 2008 and 15 percent from the second quarter of 2009.
    - Average load decreased 5 percent from the third quarter of 2008. However, load increased from the prior quarter, which partly offset the effects of lower fuel prices.
    - Thunderstorm Alerts ("TSAs"), which are more frequent in July and August, increased congestion-related price differences between Southeast New York and other areas.
  - ✓ Capacity prices increased an average of 33 percent in both New York City and the Rest of State areas in the third quarter 2009 from the same quarter of 2008. This increase was primarily due to reduced supply caused by higher forced outage rates.
  - ✓ Uplift from guarantee payments and congestion revenue shortfalls were down 40 percent from the third quarter of 2008 due largely to lower fuel prices. However, they were up 36 percent from the prior quarter due to more frequent TSAs and SREs.

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 operating costs.
  - ✓ The capacity component is based on spot capacity prices and load obligations in each area, allocated over energy consumption in the area.
  - ✓ The energy component is a load-weighted average real-time energy price.
  - ✓ The uplift and NYISO cost components are shown averaged across all consumption.
- All-in prices rose slightly (1 to 7 percent) from the second to the third quarter. The 15 percent decline in natural gas prices was offset by increased loads and higher capacity prices in the summer season.
- All-in prices fell roughly 50 percent in the third quarter 2009 versus the third quarter 2008 due to the sharp declines fuel prices (e.g., natural gas prices down 65 percent).
  - ✓ The effects of lower fuel prices were partly offset by higher capacity prices in New York City and the rest of state area.
- Lower fuel prices and higher capacity prices have increased the share of the all-in price that is associated with capacity costs, which has increased from 7 to 11 percent in the third quarter of 2008 up to 20 to 28 percent in the third quarter 2009.

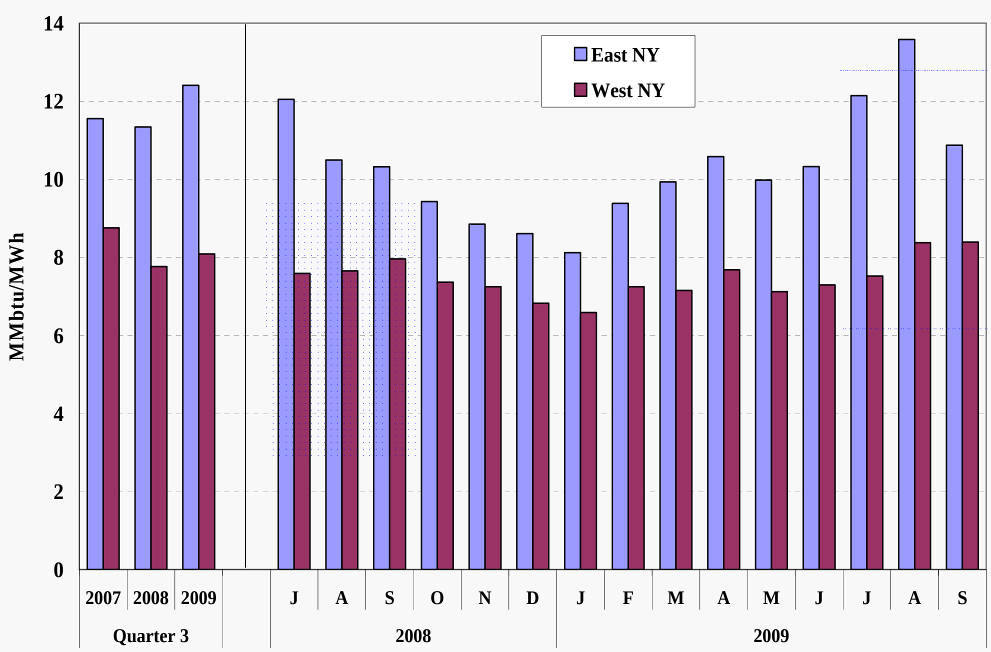
All-In Energy Price by Region



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 heat rate rose from the third quarter of 2008 to the third quarter of 2009, particularly in eastern New York. Factors contributing to this include:
  - ✓ Lower natural gas prices, which increase the non-fuel portion of generation costs;
  - ✓ Congestion in August associated with Thunderstorm Alerts and congestion into load pockets in New York City. Although absolute congestion revenues were lower in 2009, price differences on a percentage basis were relatively high.
  - ✓ The increased disparity between natural gas and oil prices, which increase the effect of periods when oil-fired generation is on the margin; and
  - ✓ RGGI-compliance obligations, which have required fossil fuel-fired generators to purchase allowances to cover their emissions since 2009.
- Prices are higher in East New York than in West New York primarily due to transmission losses and congestion across the Central-East interface, the Leeds-to-Pleasant Valley line, into New York City load pockets, and into Long Island.

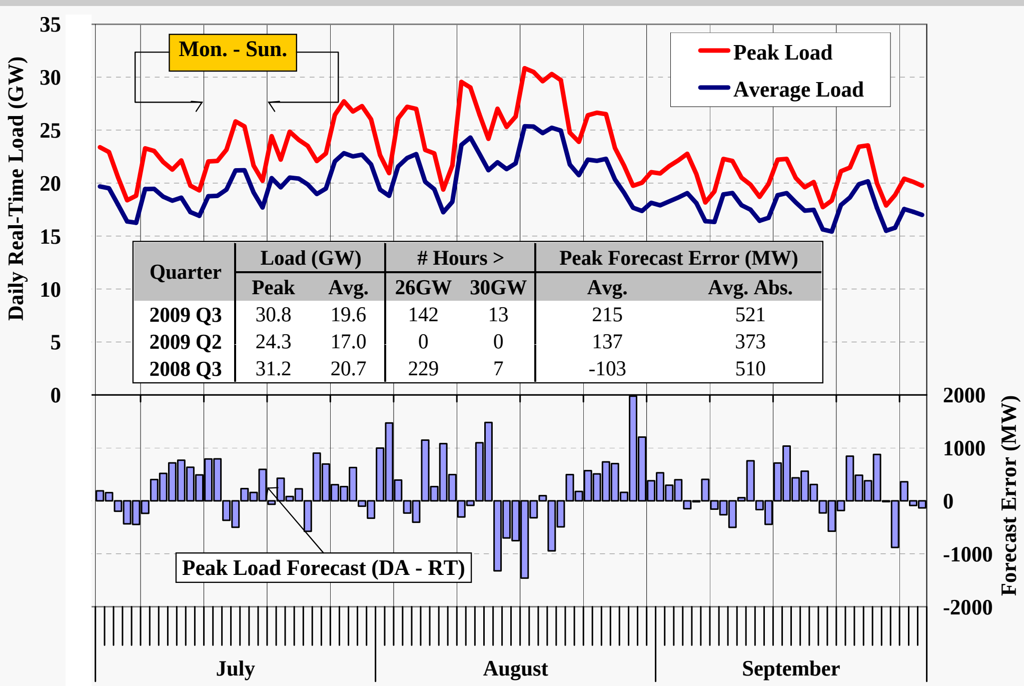
Implied Heat Rate by Region



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 2009 to the previous quarter and the same quarter of the previous year.
- Weather-sensitive load accounted for most of the fluctuations during quarter.
  - ✓ Load trended upward from the beginning of July to the middle of August, peaking at 30.8 GW on August 17. It then began decreasing in late August.
- Load during the third quarter was generally lower in 2009 than in 2008.
  - ✓ Average load declined by 5 percent.
  - ✓ Peak load levels also decreased -- the number of hours when load exceeded 26 GW declined 38 percent.
  - ✓ The decline in load levels was driven primarily by relatively mild weather as well as economic factors.
- The figure also shows that peak load forecasting was generally good, although sustained patterns of errors occurred on a number of days during the quarter.

Load Forecast and Actual Load

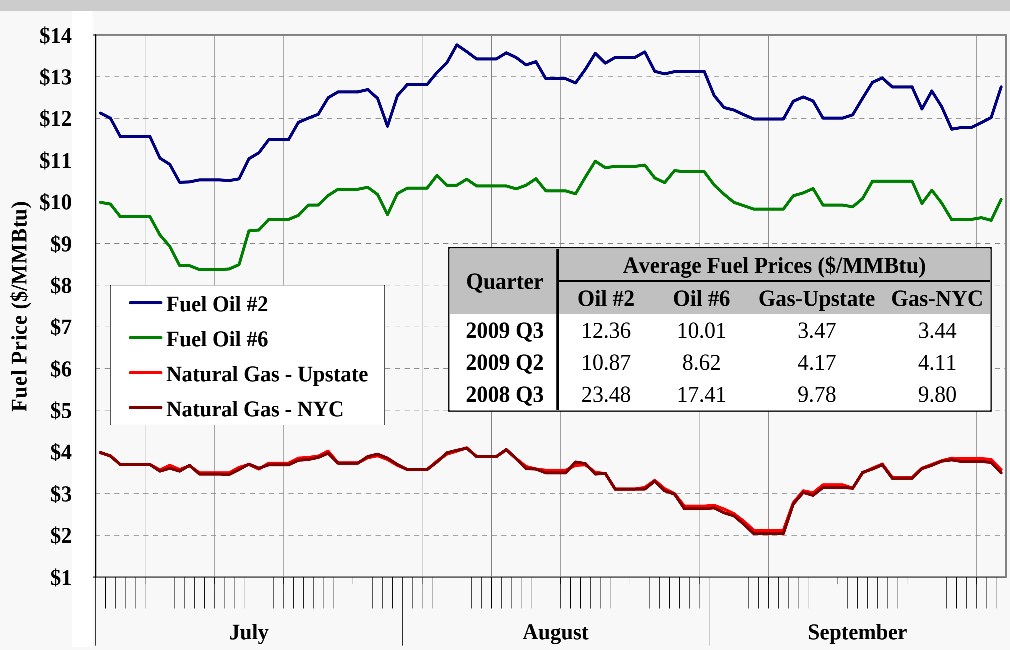


Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2009 Q3	30.8	19.6	142	13	215	521
2009 Q2	24.3	17.0	0	0	137	373
2008 Q3	31.2	20.7	229	7	-103	510

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 ranged between $3 and $4/MMbtu during most of the third quarter, falling below $3/MMbtu for two weeks in late August and early September.
- Natural gas prices declined an average of 15 percent from the second quarter to the third quarter. In contrast, average fuel oil prices rose substantially over the same period (14 percent for Oil #2 and 16 percent for Oil #6).
- The low level of natural gas prices:
  - ✓ Provides incentives for dual-fueled generators to produce energy using natural gas. However, some generators still burn fuel oil for reliability reasons or due to difficulties they face obtaining natural gas.
  - ✓ Has made many gas-fired generators competitive with coal-fired generators, reducing the production of electricity from coal.
- There were no significant deviations in natural gas prices between the major trunk lines in the New York region during the third quarter of 2009.

Natural Gas and Oil Prices



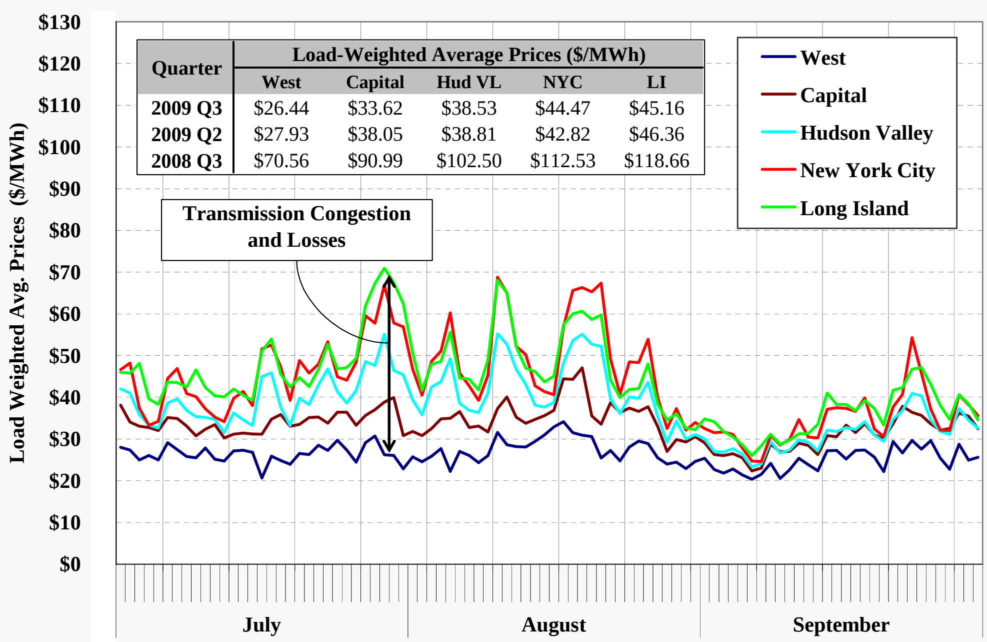
Quarter	Average Fuel Prices ($/MMBtu)			
	Oil #2	Oil #6	Gas-Upstate	Gas-NYC
2009 Q3	12.36	10.01	3.47	3.44
2009 Q2	10.87	8.62	4.17	4.11
2008 Q3	23.48	17.41	9.78	9.80

Note: The gas price shown for NYC is Transco Zone 6 and the price shown for Upstate is Iroquois Zone 2.

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. In particular:
  - ✓ Differences between the West Zone and Capital Zone were driven by both expected congestion across the Central-East interface and expected transmission losses.
  - ✓ Differences between the Capital Zone and Hudson Valley prices were driven by expected congestion over the Leeds-to-Pleasant Valley line and other parallel lines during TSAs.
    - – Expected congestion was particularly high from mid-July to late-August on 25 days when forecasted load exceeded 25 GW and TSAs were likely.
    - – On these days, the average day-ahead price separation between the Hudson Valley and Capital Zones was $16/MWh.
  - ✓ Differences between the Hudson Valley Zone and New York City/Long Island prices were driven by expected congestion into NYC load pockets (for NYC) and across the two lines that run from up-state New York into Long Island (for Long Island).
- The pattern of day-ahead congestion changed from the second to the third quarter, reflecting expectations of less congestion across the Central-East interface and more across the Leeds-to-Pleasant Valley line and into the NYC load pockets.

Day-Ahead Electricity Prices by Zone

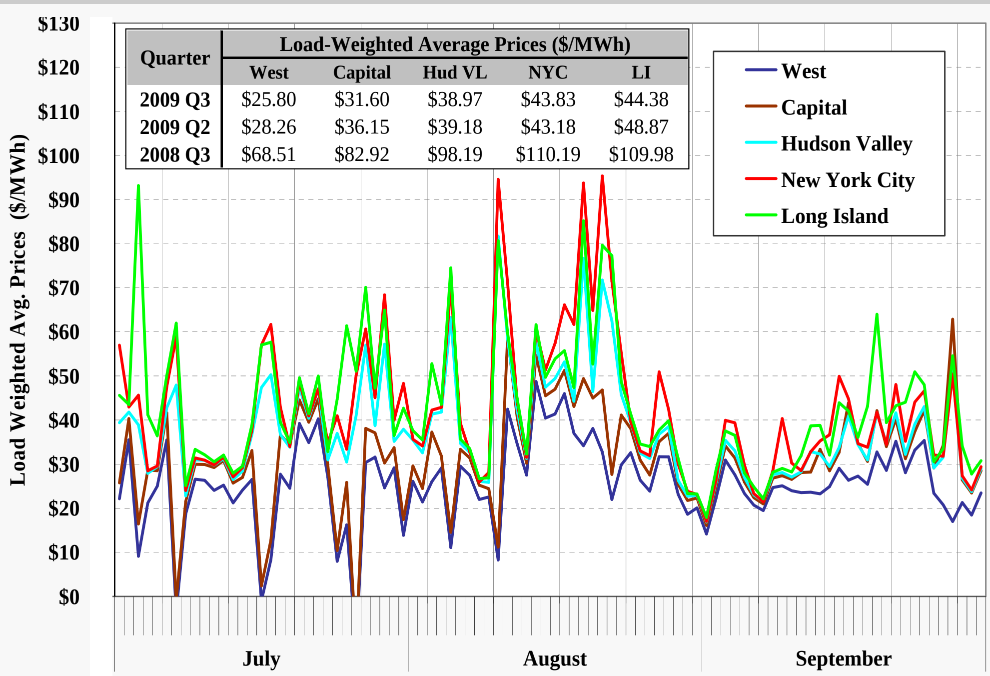


Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2009 Q3	$26.44	$33.62	$38.53	$44.47	$45.16
2009 Q2	$27.93	$38.05	$38.81	$42.82	$46.36
2008 Q3	$70.56	$90.99	$102.50	$112.53	$118.66

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 considerably more volatile in the real-time market than in the day-ahead.
- Most high and low price spikes in July and August occurred as a result of Leeds-to-Pleasant Valley line ("LPV") congestion, which is relieved by increasing generation in Southeast New York ("SENY") and by backing down generation outside SENY.
  - ✓ West Zone and Capital Zone prices dropped to very low levels on six days in July and two days in August when generation available to back down to relieve LPV congestion was limited.
  - ✓ Likewise, prices throughout SENY were substantially elevated on July 27 & 29 and on August 5, 10, 19, 21, & 22 when a limited amount of generation was available to increase output to relieve LPV congestion.
- The Central-East interface accounted for most real-time congestion after August, particularly on September 27.
- The NYC Zone price, which is a weighted average of nodes in NYC, was substantially elevated on August 11 and from August 17 to 23 due to congestion into the Greenwood area.

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2009 Q3	$25.80	$31.60	$38.97	$43.83	$44.38
2009 Q2	$28.26	$36.15	$39.18	$43.18	$48.87
2008 Q3	$68.51	$82.92	$98.19	$110.19	$109.98

Convergence Between Day-Ahead and Real-Time Prices

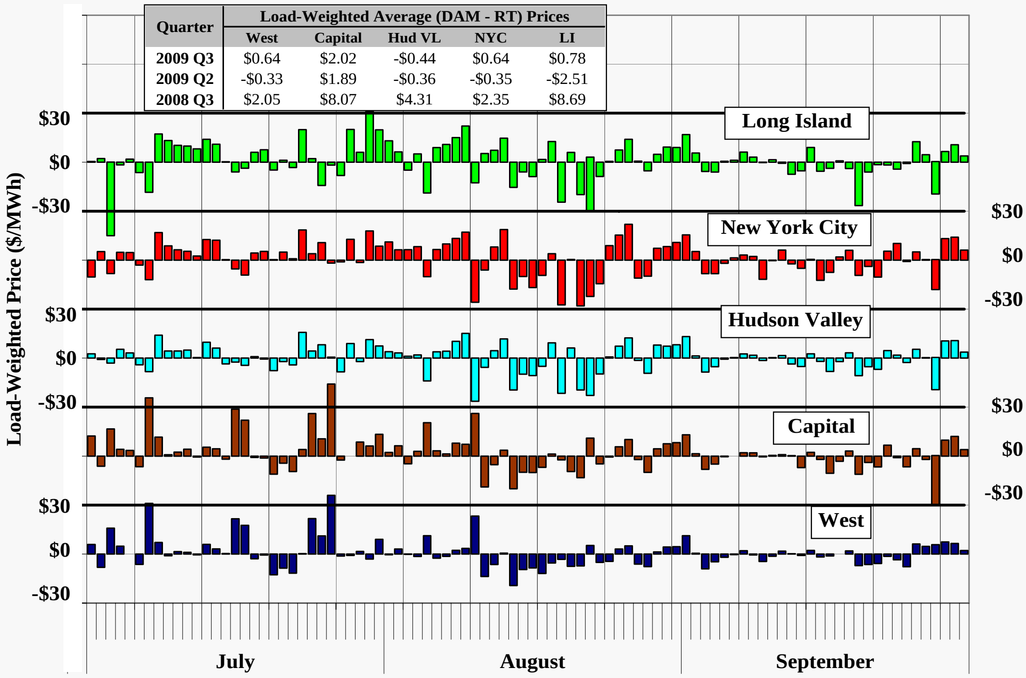
- The following figure shows the difference between the average day-ahead prices and the average real-time prices on each day in the third quarter.
  - ✓ This is shown separately for five zones to account for changes in the pattern of congestion from the day-ahead to the real-time.
  - ✓ For example, convergence was relatively good in the West Zone on September 27, but the four eastern Zones exhibited large real-time premiums due to congestion across Central-East that was not reflected in the day-ahead market.
- Large differences between average day-ahead prices and average real-time prices occurred frequently on individual days.
  - ✓ However, convergence should generally be measured over a longer timeframe since random factors can cause convergence on individual days to be poor.
  - ✓ Therefore, the table shows the average price convergence over the entire quarter. Average day-ahead prices for the quarter were generally consistent with real-time prices, except in the Capital Zone where the day-ahead prices were 6 percent higher.
- Average day-ahead prices were higher than average real-time prices by more than the average difference on most days in SENY (e.g., 61 percent in NYC), since price spike events are more frequent in the real-time market than in the day-ahead market.
  - ✓ Conversely, average day-ahead prices in the West Zone were lower than average real-time prices on most days. This is because low-price spike events are more frequent in the real-time market than in the day-ahead market.

Convergence Between Day-Ahead and Real-Time Prices

- For the NYC Zone, which is a load-weighted average of prices at locations in NYC, day-ahead and real-time prices converged well.
  - ✓ However, convergence was relatively poor in the Greenwood/Staten Island load pocket where the average day-ahead price was 15 percent higher than the average real-time price.
  - ✓ The additional day-ahead congestion was partly due to day-ahead modeling assumptions that reduced transfer capability into New York City load pockets that sometimes exhibit reduced transfer capability in real-time.
- Convergence between day-ahead and real-time prices improved for most locations from the third quarter of 2008 to the same quarter of 2009 .
  - ✓ This was most evident in Long Island where the difference declined from 8 percent in the third quarter of 2008 to 2 percent in the third quarter of 2009.
  - ✓ The frequency of SRE commitments, which usually occur after the day-ahead market, decreased significantly in early 2009 as a result of changes in the day-ahead market process.
    - – This helped improve convergence between day-ahead and real-time prices by reducing the frequency of large changes in commitment after the day-ahead market.

Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2009 Q3	$0.64	$2.02	-$0.44	$0.64	$0.78
2009 Q2	-$0.33	$1.89	-$0.36	-$0.35	-$2.51
2008 Q3	$2.05	$8.07	$4.31	$2.35	$8.69



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 New York.
  - ✓ 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 150 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

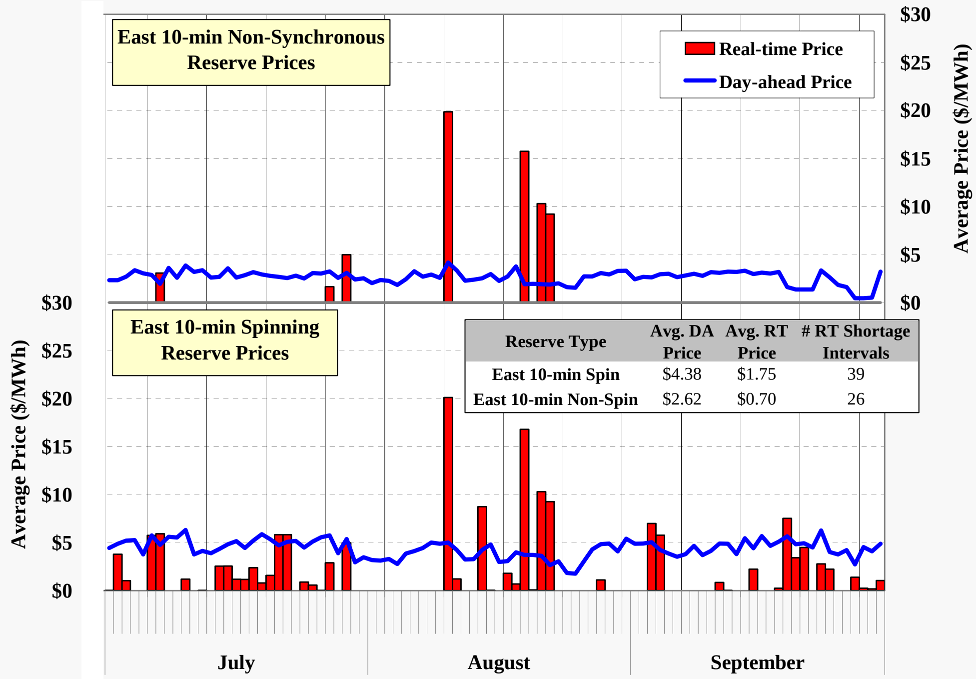
- Reserves prices are relatively consistent in the day-ahead, but are much more volatile in the real-time market.
  - ✓ Day-ahead reserves prices are based on suppliers' offers, which depend expectations of real-time prices and the risks associated with selling reserves in the day-ahead market.
  - ✓ Real-time reserves prices are normally close to $0 due to the excess available reserves from online and quick-start units in most hours.
  - ✓ Real-time prices spike during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Average day-ahead reserves prices were substantially higher than average real-time reserves prices in the third quarter of 2009.
  - ✓ However, average day-ahead reserve prices did not rise substantially on high load days when average real-time prices were high due to tight conditions.
- Day-ahead regulation prices were relatively consistent with real-time regulation prices.

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 13 intervals ($25 demand curve);
  - ✓ Eastern 10-minute total reserves in 26 intervals ($500 demand curve);
  - ✓ State-wide 10-minute spinning reserves in 0 intervals ($500 demand curve); and
  - ✓ Regulation in 65 intervals ($250 to $300 demand curve).
- Reserves prices reflect the levels of the demand curves during shortages.
  - ✓ Eastern 10-minute total reserves were short for one hour on August 10, during which the corresponding reserve prices were $500/MWh.
  - ✓ This shortage was related to TSA operation, which reduced the availability of reserves in Southeast New York as generation there was dispatched up to relieve congestion on the Leeds to Pleasant Valley line.
- 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 39 intervals of shortage pricing – 13 intervals of eastern 10-minute spinning reserve shortages and 26 intervals of eastern 10-minute total reserve shortages.

Day-Ahead and Real-Time Ancillary Services Prices

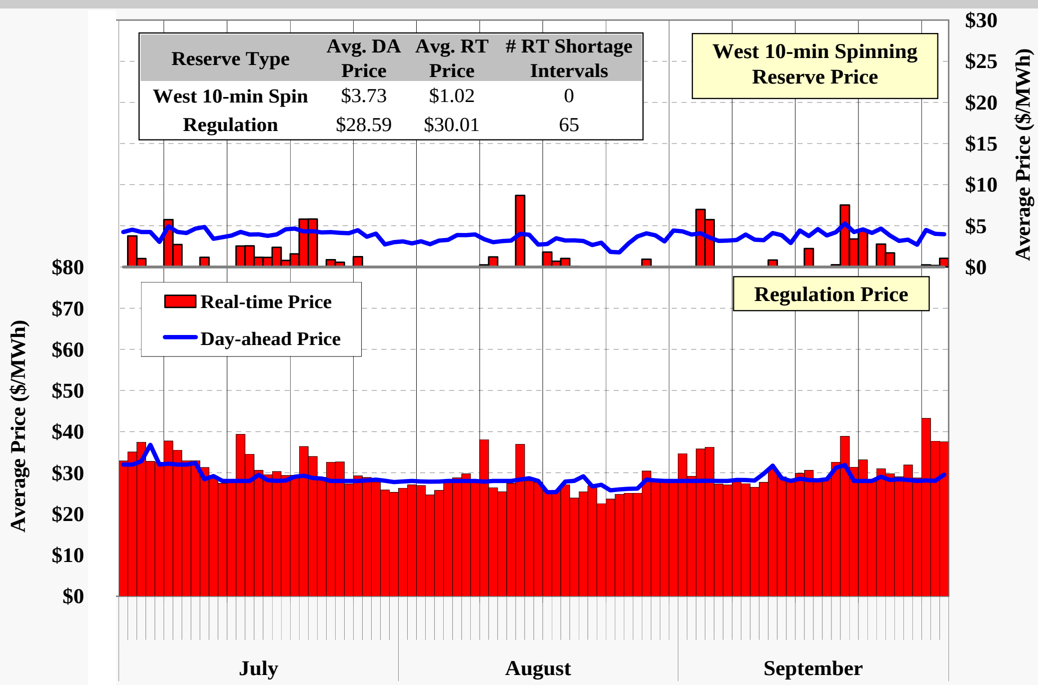
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
East 10-min Spin	$4.38	$1.75	39
East 10-min Non-Spin	$2.62	$0.70	26

Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation

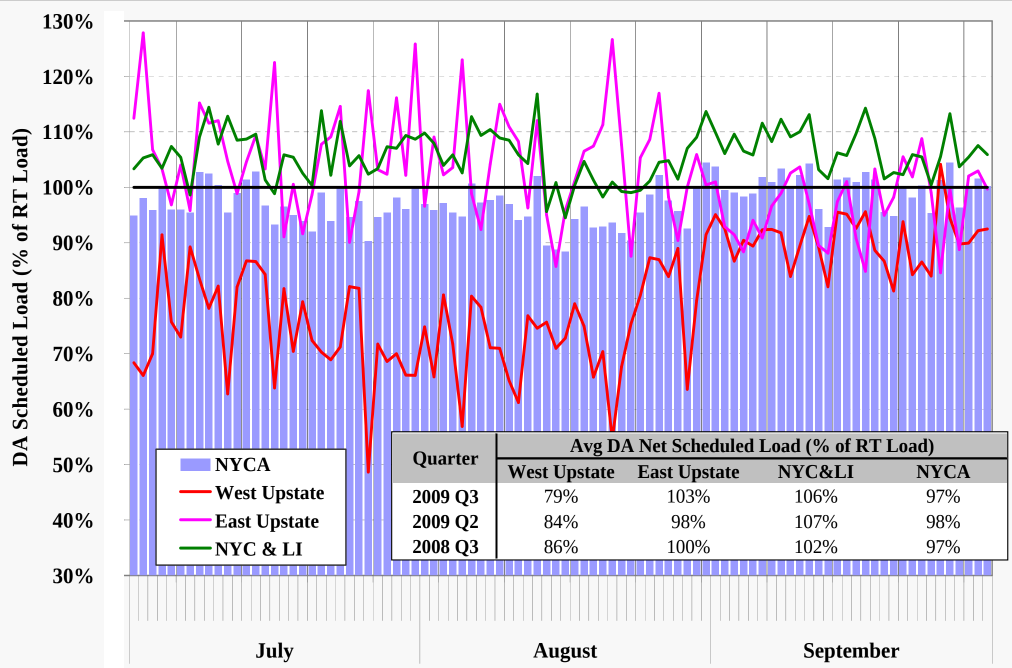


Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
West 10-min Spin	$3.73	$1.02	0
Regulation	$28.59	$30.01	65

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
- The average amount of load scheduled state-wide in the day-ahead market is relatively consistent with the average amount of real-time load.
- Load is generally over-scheduled into New York City and Long Island, partly because transmission capability into these ares is sometimes reduced in real-time. This can occur during:
  - ✓ TSAs, during which the available transmission capability into Southeast New York is reduced below what is available in the day-ahead market; and
  - ✓ Outages and other real-time events that can lead to spikes in real-time prices.
- In western New York, the amount of load scheduled in the day-ahead market was substantially lower than the actual load in the real time market.
  - ✓ This is primarily a response to extreme negative prices that can occur during TSAs.
  - ✓ Under-scheduling increased substantially on several days with extreme negative prices (e.g., July 26), helping to improve convergence between day-ahead and real-time prices.

Day-ahead Scheduled Load and Actual Load

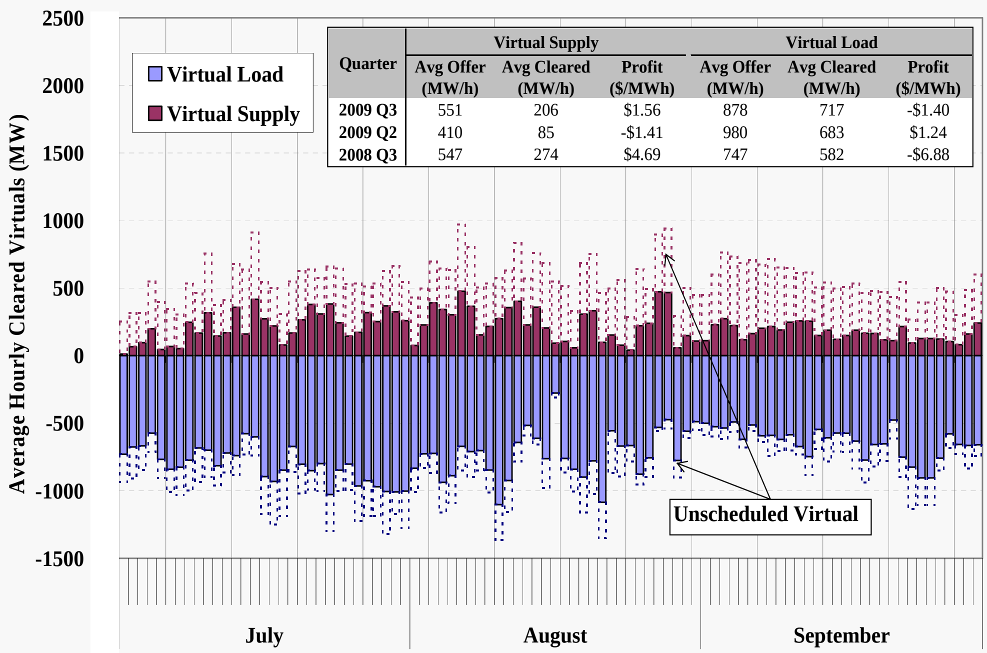


Quarter	Avg DA Net Scheduled Load (% of RT Load)			
	West Upstate	East Upstate	NYC&LI	NYCA
2009 Q3	79%	103%	106%	97%
2009 Q2	84%	98%	107%	98%
2008 Q3	86%	100%	102%	97%

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 supply sales in upstate areas and net virtual load purchases in downstate areas, consistent with the pattern of net scheduled load shown in the previous figure.
  - ✓ This pattern has been persistent for years, although the average amount of net virtual load scheduled downstate increased to 511 MW in the third quarter of 2009 from 308 MW in the third quarter of the previous year.
  - ✓ Likewise, the average amount of net virtual supply scheduled upstate increased to 1,083 MW in the third quarter of 2009 from 527 MW in the third quarter of the previous year.
- Overall profitability from virtual trading was $4.1 million in the third quarter of 2009, up from $2.5 million in the previous quarter and $12.8 million in losses in the third quarter of the previous year.
  - ✓ Virtual trading profits and losses were significantly lower per MWh in the third quarter of 2009 compared to the previous year. This is primarily due to smaller differences between day-ahead and real-time prices, driven by lower fuel prices.

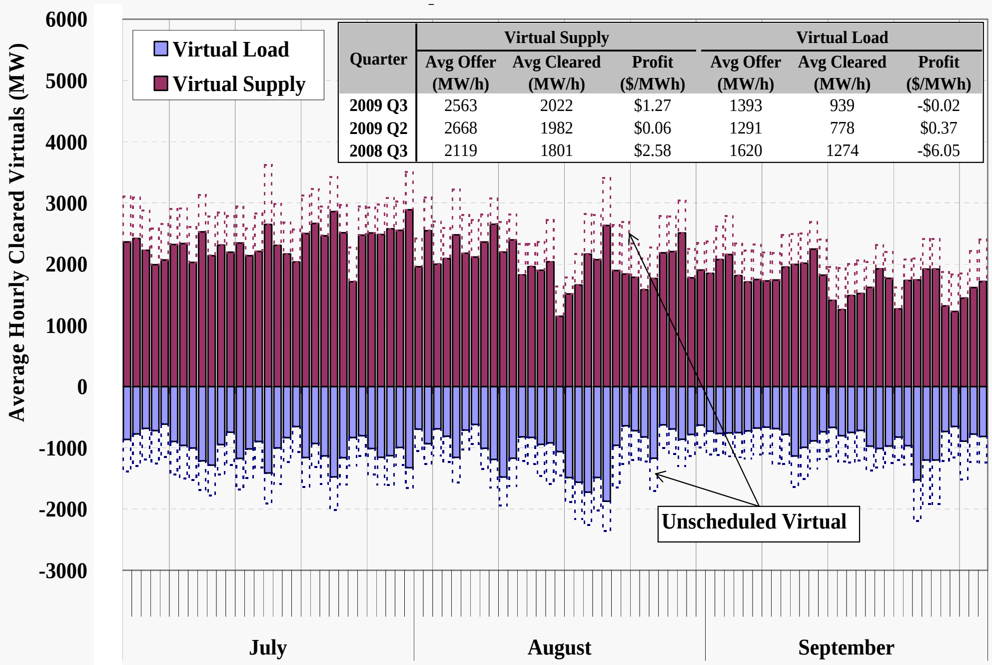
Virtual Load and Supply
New York City and Long Island



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)
2009 Q3	551	206	$1.56	878	717	-$1.40
2009 Q2	410	85	-$1.41	980	683	$1.24
2008 Q3	547	274	$4.69	747	582	-$6.88

Virtual Load and Supply

Upstate New York

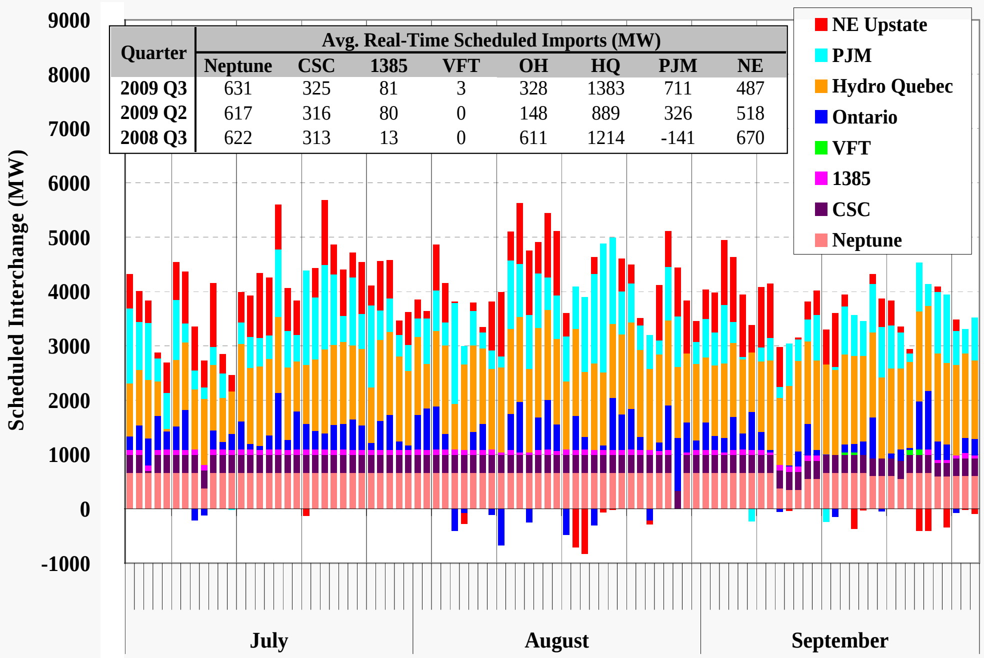


Quarter	Virtual Supply Avg Offer (MW/h)	Virtual Supply Avg Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Avg Offer (MW/h)	Virtual Load Avg Cleared (MW/h)	Virtual Load Profit ($/MWh)
2009 Q3	2563	2022	$1.27	1393	939	-$0.02
2009 Q2	2668	1982	$0.06	1291	778	$0.37
2008 Q3	2119	1801	$2.58	1620	1274	-$6.05

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 3,950 MW during daily peak hours in the third quarter of 2009, up 36 percent from the previous quarter and 20 percent from the same quarter of 2008.
  - The increase in load from the second quarter to the third quarter typically leads to an increase in imports, particularly from Ontario and Quebec.
  - The increase in imports from the third quarter of the previous year was primarily due to additional imports from PJM.
- The Neptune Cable, the Cross Sound Cable, the 1385 Cable, and the Linden VFT Line brought an average of 1,040 MW directly into downstate areas during daily peak hours in the third quarter of 2009.
  - ✓ Imports increased across 1385 cable from the previous year, since the line was out-of-service for most of 2008.
  - ✓ The Linden VFT Line, which has a capability of 300 MW, is scheduled to begin commercial operation in November, so flows were limited in the third quarter.
- ✓ During the annual peak load hour on August 17, NYCA imported 3,120 MW across these interfaces, using imports to satisfy a substantial portion of the peak load.

Net Imports Scheduled Across External Interfaces
Daily Peak Load Hour

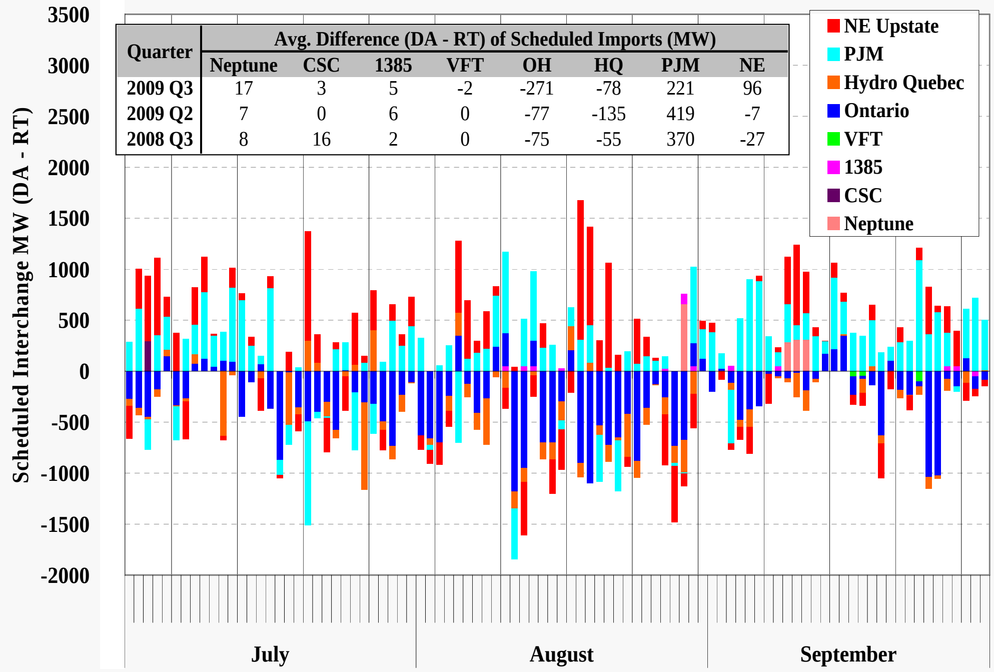


Quarter	Avg. Real-Time Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2009 Q3	631	325	81	3	328	1383	711	487
2009 Q2	617	316	80	0	148	889	326	518
2008 Q3	622	313	13	0	611	1214	-141	670

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 hour.
- From the day-ahead to the real-time, net scheduled imports:
  - Did not vary significantly across the four controllable lines into New York City and Long Island.
  - Usually increased across the Ontario and Hydro Quebec interfaces (349 MW on average), particularly in August.
  - Decreased across the PJM and New England interfaces by an average of 317 MW, although there were many days when imports increased.
- Generally, these changes in schedules help improve consistency between day-ahead and real-time prices.
  - For example, on August 11, when real-time prices in upstate areas averaged $5 to $20/MWh higher than day-ahead prices, importers responded by increasing flows into NYCA by an average of 1,600 MW on that day.
  - However, there were several days when real-time transaction scheduling exacerbated congestion (e.g., on July 26, imports from Ontario and Quebec increased 1,100 MW when real-time prices were negative).

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
2009 Q3	17	3	5	-2	-271	-78	221	96
2009 Q2	7	0	6	0	-77	-135	419	-7
2008 Q3	8	16	2	0	-75	-55	370	-27

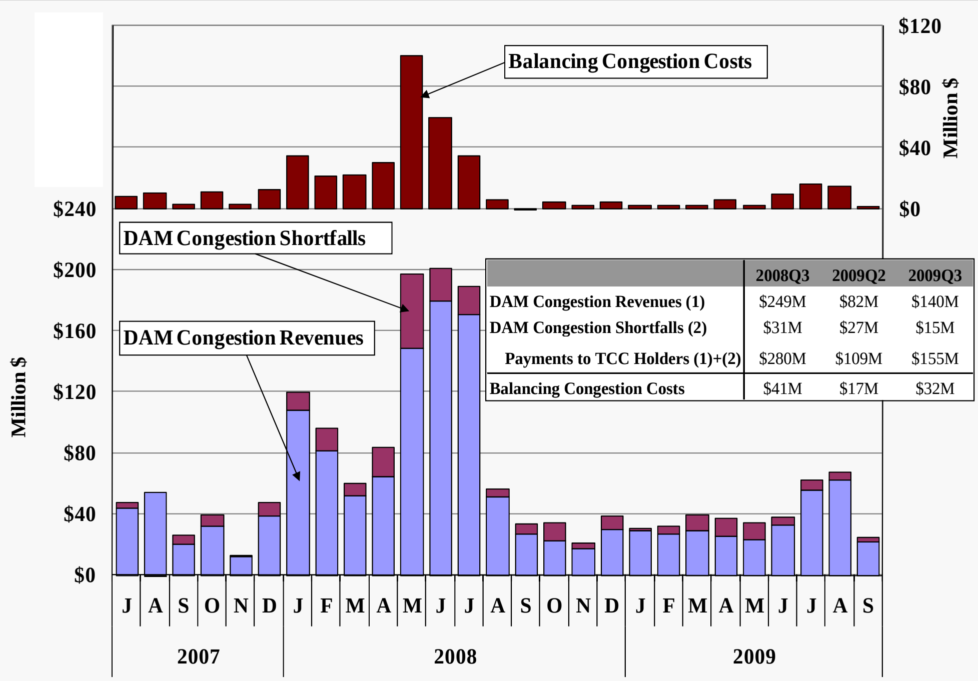
Congestion Revenue Collections and Shortfalls

- This section of the report summarizes and evaluates the congestion patterns in New York during the third quarter.
- The first figure shows 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 entitlements of 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.
  - ✓ *Balancing Congestion Costs* 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, which results in balancing congestion costs that are recovered through uplift.

Congestion Revenue Collections and Shortfalls

- The following figure summarizes day-ahead congestion revenue, day-ahead congestion shortfalls, and balancing congestion costs trends over the past two years.
- The figure shows that day-ahead congestion revenue fell by more than 40 percent from the third quarter of 2008 to the same period in 2009, due primarily to:
  - ✓ Lower fuel costs led to smaller congestion-related price differences between regions.
  - ✓ Lower average load levels in 2009.
- The overall reduction in congestion costs contributed to significant year-over-year reductions in day-ahead congestion shortfalls and balancing congestion costs.
- Day-ahead congestion revenues and balancing congestion costs rose from the second quarter of 2009, which is normal for the summer months due to higher loads and more frequent Thunderstorm Alerts ("TSAs").
- Day-ahead congestion shortfalls decreased almost 50 percent from the second quarter. This is also typical because transmission outages are often highest during the spring and fall (which reduce transmission capability in the day-ahead market).

Congestion Revenue Collections and Shortfalls



	2008Q3	2009Q2	2009Q3
DAM Congestion Revenues (1)	$249M	$82M	$140M
DAM Congestion Shortfalls (2)	$31M	$27M	$15M
Payments to TCC Holders (1)+(2)	$280M	$109M	$155M
Balancing Congestion Costs	$41M	$17M	$32M

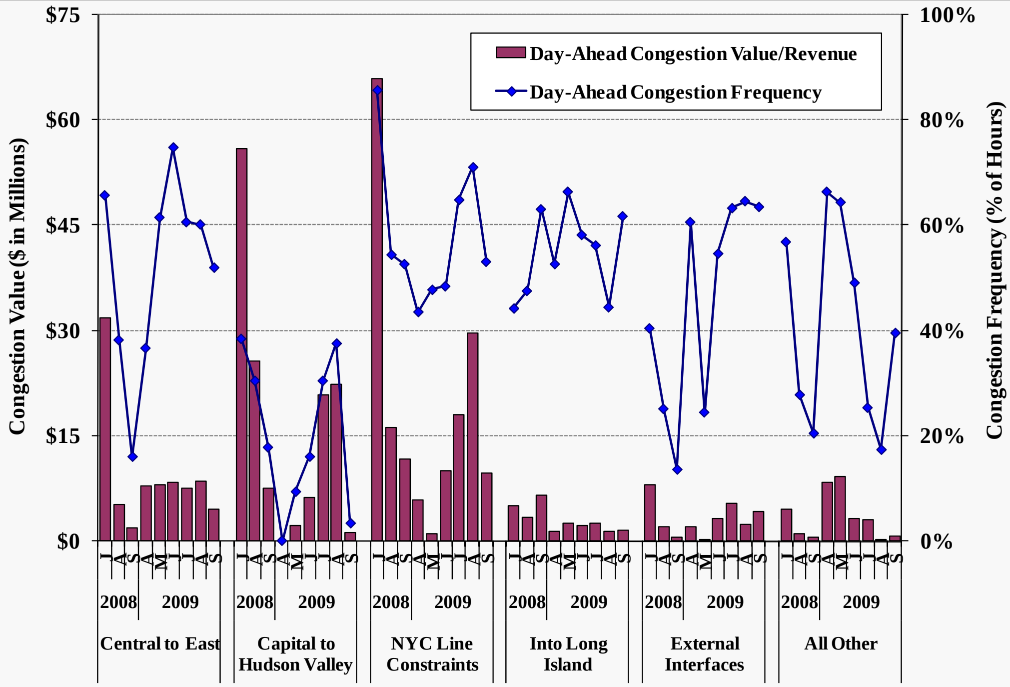
Congestion by Transmission Path

- 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:
  - ✓ Capital to Hudson Valley – Primarily the Leeds-to-Pleasant Valley line during TSAs.
  - ✓ Central to East – Primarily the Central-East interface.
  - ✓ Into Long Island – Primarily the Dunwoodie-to-Shore Road and Sprainbrook-to-East Garden City lines.
  - ✓ NYC Line – Lines in NYC that are modeled as individual facilities.
  - ✓ NYC Load Pockets – Groups of lines to NYC load pockets that are modeled as interfaces.
  - ✓ External Interface – Congestion related to the total transmission limits or ramp limits of the eight 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 constrained interfaces are generally lower in the day-ahead market.
- With a few exceptions, the figure shows that the frequency of congestion has remained in ranges that are comparable to the frequencies in the previous year.
- The majority of day-ahead congestion in the third quarter 2009 occurred over paths from Capital to Hudson Valley (31 percent), Central to East (14 percent), and lines into New York City load pockets (40 percent).
- The patterns of congestion in the day-ahead and the real-time market were similar for most paths, except for:
  - ✓ The Capital to Hudson Valley path, which exhibited less congestion in the day-ahead market due to the tighter criteria used in real-time during TSAs.
  - ✓ Lines into the Greenwood/Staten Island load pocket, which exhibited more congestion in the day-ahead market partly due to day-ahead modeling assumptions that reduced transfer capability into New York City load pockets that sometimes exhibit reduced transfer capability in real-time.

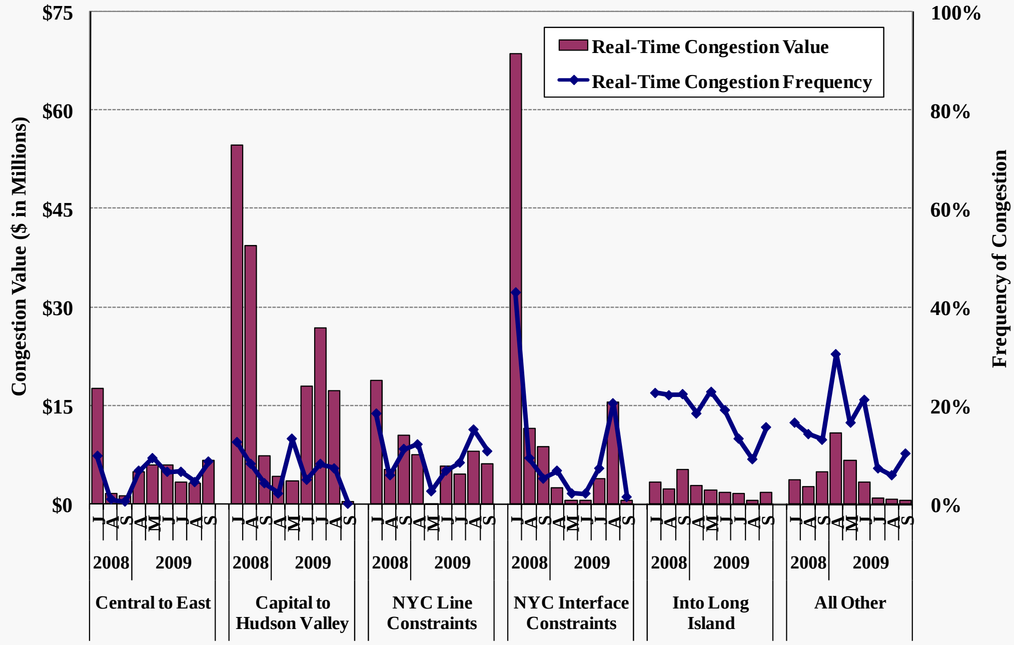
Day-Ahead Congestion by Transmission Path



Real-Time Congestion by Transmission Path

- The following figure summarizes the value and frequency of congestion by transmission path in the real-time market for the third quarter 2008 and the second and third quarters in 2009.
- The value of real-time congestion increased by 18 percent from the second to the third quarter of 2009.
  - ✓ The increase was generally due to higher loads and more frequent TSAs that occur in the summer, although it was partly offset by lower fuel prices.
- Most of real-time congestion occurred on three major transmission paths in the third quarter of 2009 (94 percent):
  - ✓ Capital to Hudson Valley: 43 percent
    - TSAs were a contributor to this congestion -- shadow prices exceeded $1,000/MWh for a total of approximately 8 hours during TSA events in July and August.
  - ✓ Central to East: 13 percent
    - Central-East interface accounted for most of the real-time congestion in September.
  - ✓ NYC load pockets (line and interface constraints together): 38 percent
    - Most of this was congestion into the Greenwood/Staten Island load pocket, which occurred primarily in the middle two weeks of August.

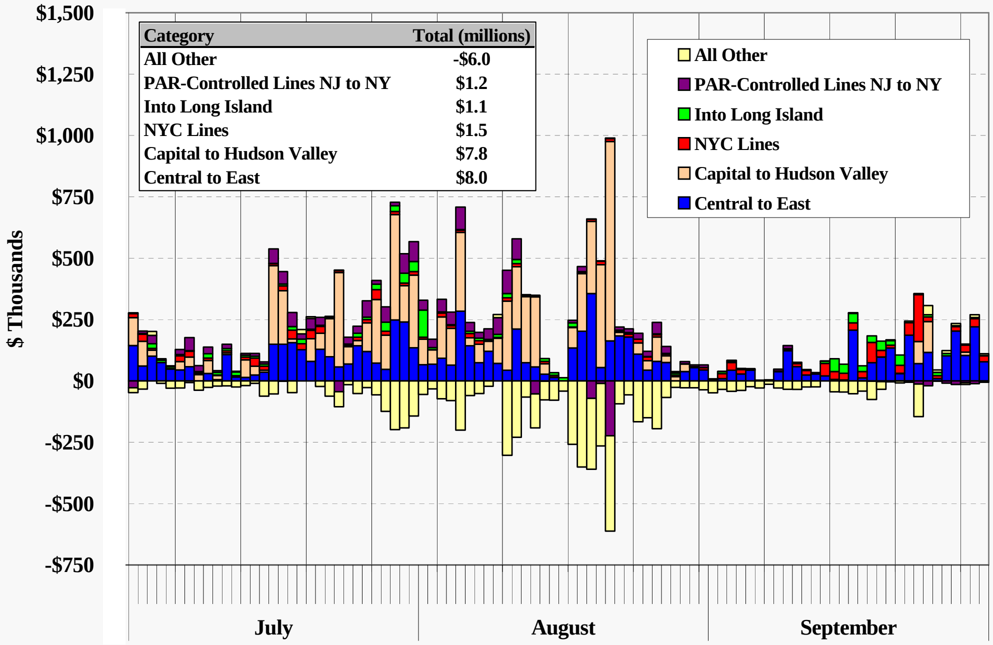
Real-Time Congestion by Transmission Path



Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily congestion revenue shortfalls by transmission path or facility in the third quarter.
  - ✓ Negative values indicate congestion revenue surpluses.
- The Central to East and Capital to Hudson Valley paths consistently generate revenue shortfalls and accounted for most of the total shortfall in the third quarter.
  - ✓ This suggests that the transfer capability between regions is consistently lower than the amount of TCCs sold between regions.
- A significant share of the shortfalls are due to local TOs not incorporating their transmission outages in the assumptions of the TCC auctions.
  - ✓ When outages are not reflected in the TCC auction assumptions, it 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.
- The consistent revenue surplus for the "All Other" category totaling $6 million was primarily due to optimizing the schedules of some PAR-controlled lines in the day-ahead market.
  - ✓ The model determines schedules that effectively increase the volume of transfers in the day-ahead market relative to the assumptions in the TCC auctions.

Day-Ahead Congestion Revenue Shortfalls



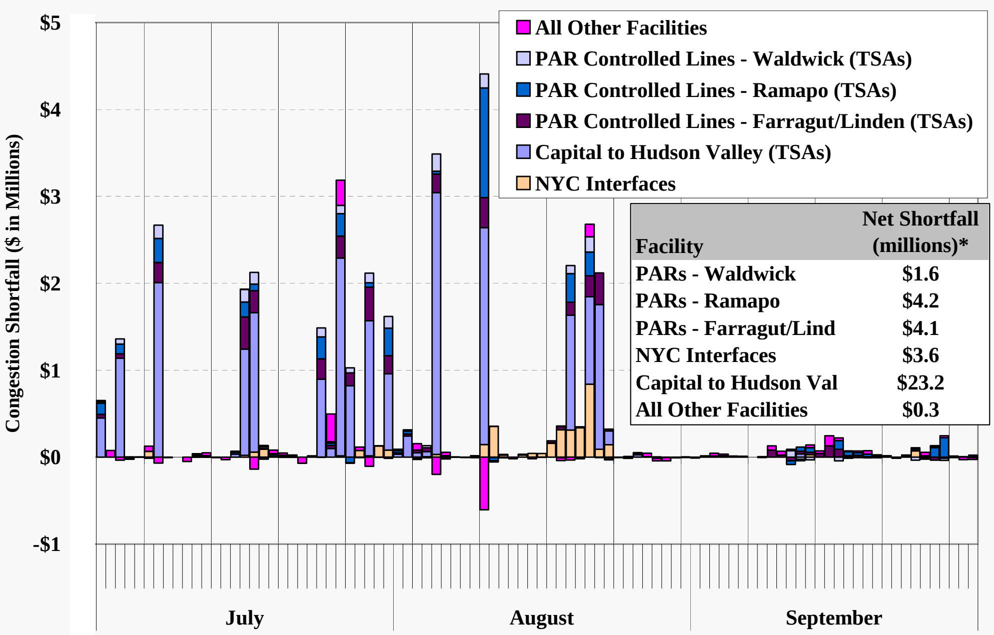
Balancing Congestion Costs

- The following figure shows daily balancing congestion costs by transmission path or facility in the third quarter.
  - ✓ Negative values indicate balancing congestion surpluses.
- Balancing congestion revenue shortfalls can occur when the transfer capability of 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 transmission outages of facilities that reduce the transfer capability of 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. Such assumptions may include:
  - ✓ The direction and magnitude of unscheduled loop flows across constrained interfaces; and
  - ✓ The direction and magnitude of flows across PAR-controlled lines.

Balancing Congestion Costs

- The majority (63 percent) of revenue shortfalls were related to Capital to Hudson Valley congestion, primarily during TSAs events.
  - ✓ TSAs require double contingency protection of the Leeds-to-Pleasant Valley line, effectively reducing the transfer capability of the path in real time.
- 25 percent of revenue shortfalls were associated with differences between the day-ahead scheduled flows and real-time flows on PAR-controlled lines between New Jersey and New York (i.e., Waldwick, Ramapo, Farragut, and Linden), primarily during TSA events.
  - ✓ TSAs may suddenly require generators to increase production in Southeast New York before the PAR-settings can be adjusted accordingly. This reduces net flows into NYCA across the PAR-controlled lines, which results in a revenue shortfall.
- 10 percent of revenue shortfalls were associated with the modeling of interface constraints into New York City load pockets.
  - ✓ The use of interface constraints in the real-time market (rather than the detailed modeling used in the day-ahead market) generally reduces transfer capability.
  - ✓ This category was reduced by assuming reduced transfer capability into NYC load pockets in the day-ahead market when real-time reductions in transfer capability were anticipated.
- September's showed a steep decline in shortfalls due to less congestion that was generally due to lower loads and less frequent Thunder Storm Alerts.

Balancing Congestion Costs



Facility	Net Shortfall (millions)*
PARs - Waldwick	$1.6
PARs - Ramapo	$4.2
PARs - Farragut/Lind	$4.1
NYC Interfaces	$3.6
Capital to Hudson Val	$23.2
All Other Facilities	$0.3

* These slightly over-estimate shortfalls because they are based on real-time schedules rather than actual generation.

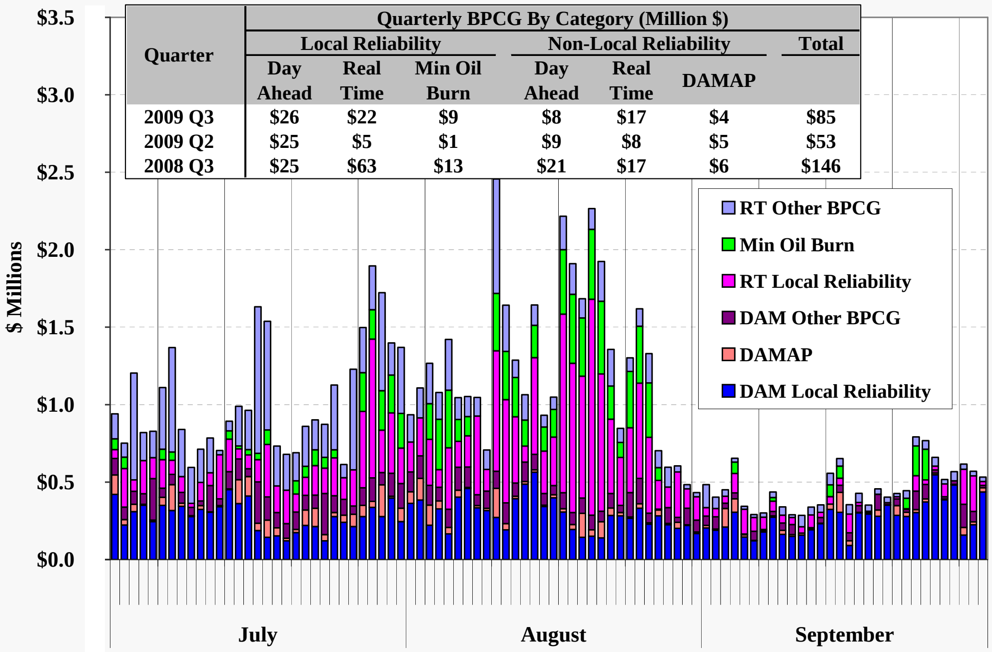
Uplift Costs from Guarantee Payments

- The next figure summarizes uplift charges resulting from guarantee payments ("GP") 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 – Covers the 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

- The figure shows that total uplift in the third quarter increased 62 percent from the second quarter as higher loads:
  - ✓ Required more frequent use of the Min Oil Burn procedure, which is generally invoked in the summer when NYC forecast load exceeds 6.5 GW;
  - ✓ Led to more frequent reliability commitment in upstate New York; and
  - ✓ Resulted in more frequent economic dispatch of gas turbines, which receive uplift when they do not recoup their as-offered costs from LBMPs.
- However, total uplift in the third quarter decreased 42 percent from 2008 to 2009.
  - ✓ The uplift reduction was due primarily to sharp reductions in fuel prices, which generally reduce the payments needed to ensure a generator covers its costs.
  - ✓ This was partly offset by more frequent SRE commitments upstate for bulk system reliability.
- The share of local reliability uplift associated with the real-time market decreased from 62 percent in the third quarter of 2008 to 39 percent in the third quarter of 2009.
  - ✓ This was due to changes that allow TOs to commit units for reliability in the day-ahead market (i.e., DARU commitment).

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

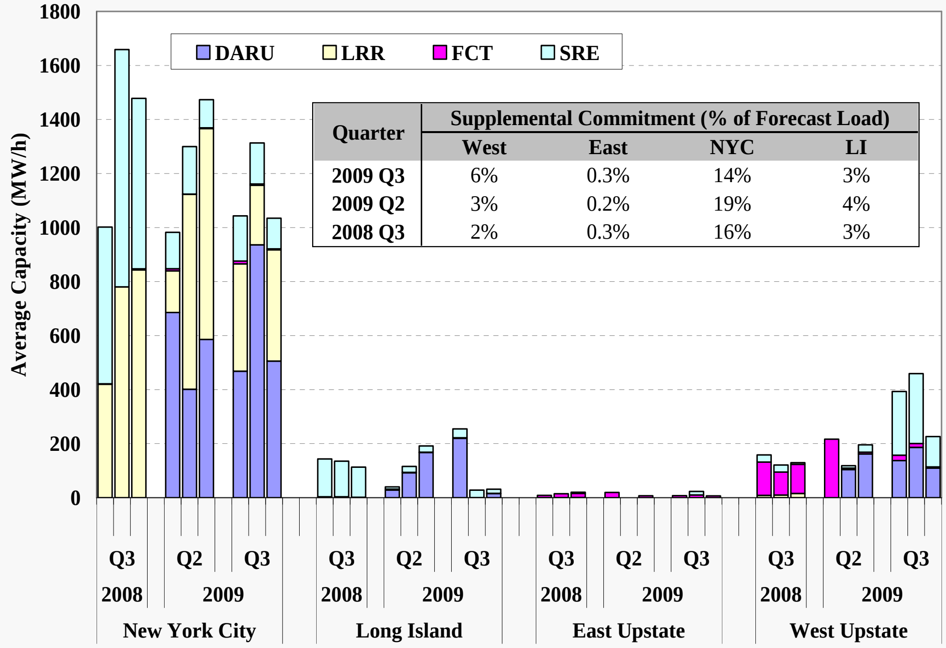


Quarter	Quarterly BPCG By Category (Million $)						
	Local Reliability			Non-Local Reliability			Total
	Day Ahead	Real Time	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2009 Q3	$26	$22	$9	$8	$17	$4	$85
2009 Q2	$25	$5	$1	$9	$8	$5	$53
2008 Q3	$25	$63	$13	$21	$17	$6	$146

Supplemental Commitment for Reliability

- The following figure shows the monthly quantities of capacity committed for reliability by type of commitment and region.
- Local reliability commitment decreased 18 percent in eastern New York from the third quarter of 2008.
  - ✓ SRE commitment after the day ahead decreased the most (650 MW on average), since most local reliability commitment now occurs through the day-ahead market (i.e., DARU and LRR).
- Reliability commitment in the third quarter increased 310 MW on average in western New York from the third quarter of 2008 primarily due to:
  - ✓ The emergence of SRE commitments for bulk power system reliability, which had not been necessary for several years; and
  - ✓ More frequent commitment of several other units for local reliability due, in part, to transmission outages and changes in commitment patterns resulting from lower natural gas prices.
- Commitments for forecasted load decreased 77 percent from 2008.
  - ✓ This is primarily because the local reliability commitment is now done in the day-ahead market (i.e., DARU and LRR) prior to the commitment for forecasted load.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2009 Q3	6%	0.3%	14%	3%
2009 Q2	3%	0.2%	19%	4%
2008 Q3	2%	0.3%	16%	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 procedures ("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 min gen level when the min gen 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:

- Mitigation occurred primarily day-ahead for DARU and LRR units (73 percent), Dunwoodie South congestion (11 percent), and Astoria West/Q/V congestion (12 percent).
- Mitigation increased 69 percent from the previous year due to more DARU- and LRR-committed units, which are mitigated when their Start-up and MinGen offers exceed the reference.

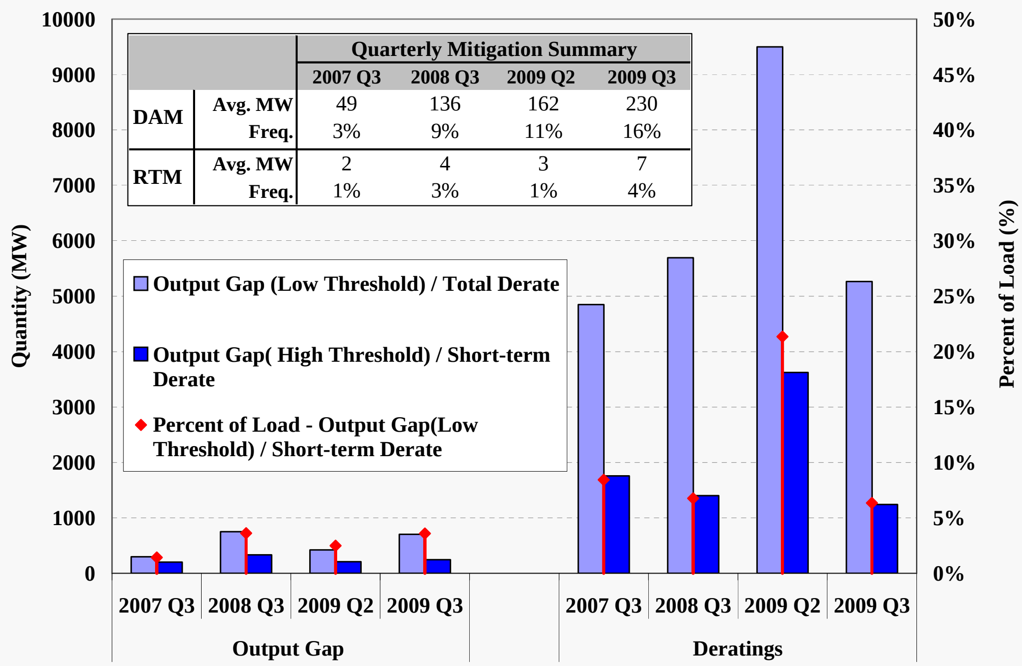
Output Gap at High and Low Thresholds:

- The output gap is low as a share of load (1 to 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.
- On September 4, the NYISO filed to address the offers of three generators that raised their guarantee payments by offering below the High Threshold.

Long-Term and Short-Term Deratings:

- Total deratings are substantial, but concerns about physical withholding are limited because: (i) deratings are typically highest in the shoulder months when demand is lowest, and (ii) most deratings are long-term, which are 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			
		2007 Q3	2008 Q3	2009 Q2	2009 Q3
DAM	Avg. MW	49	136	162	230
	Freq.	3%	9%	11%	16%
RTM	Avg. MW	2	4	3	7
	Freq.	1%	3%	1%	4%

Assertions of "Anomalous Offers" in New York

- A consultant has asserted that the NYISO market is not competitive, citing high offers by some generators as evidence.
  - ✓ While these assertions have generated much publicity, they are highly misleading.
- We monitor all offers in the NYISO market and provide the following information regarding these assertions.
  - ✓ Some generating output is costly and warrants high offers (e.g., intermittent resources, cogeneration, emergency peaking output, etc.).
  - ✓ None of the high-priced offers in any period we have examined set or materially affected the market prices in the NYISO market.
  - ✓ When calculated properly, the portion of the generation offers priced relatively high (e.g., > $900 per MWh) is vanishingly small.
    - The consultant has cited the percent of *units* with at least 1 MW offered at a high price, which overstates the quantity of high-price offers.
    - Further, many of the units the consultant includes are "non-dispatchable" and scheduled at a fixed operating level. Offers from these units are not considered by the real-time market and many would be very costly to dispatch at a different operating level.
    - The *actual* quantity of offers (in MWs) priced above $900/MWh from units that were dispatchable in the real-time market in the third quarter of 2009 was:

      17 MWs on average per hour *or* 0.068% (7/100ths of a percent)
    - These quantities are too small to credibly argue that they have a meaningful effect on NYISO market prices or the competitive performance of the markets.

Capacity Market Results

- The following figure summarizes available and scheduled UCAP resources as well as the clearing prices in each capacity zone.
- UCAP spot prices increased from the third quarter of 2008 to the third quarter of 2009 by:
  - ✓ By 33 percent to $8.19/kW-month in NYC; and
  - ✓ By 33 percent to $3.53/kW-month in ROS (and Long Island).
- The price increase was partly due to lower available UCAP from internal generation.
  - ✓ The lower available UCAP was the result of increased equivalent forced outage rates ("EFORd") associated with:
    - More frequent forced outages over the past year for some generators; and
    - A change in the EFORd methodology to more accurately estimate the available capacity from run of the river hydro units.
- Net imports of UCAP also decreased 660 MW, contributing to the price increase in ROS. This was partly driven by increased capacity prices in neighboring markets.
- The supply reduction in supply were partly offset in ROS and Long Island by:
  - ✓ The entry of a 300 MW generator in August 2009, and
  - ✓ 270 MW of additional sales from SCRs.

Capacity Market Results