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

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Highlights and Market Summary: Energy Market

- This report summarizes the NYISO market results for the third quarter of 2011.
- The markets performed competitively and variations in wholesale market prices were driven primarily by changes in demand, fuel prices, and supply availability.
- Real-time energy prices averaged $58 per MWh statewide in the third quarter.
  - ✓ This was 19 percent higher than the prior quarter due to higher seasonal loads, but 9 percent lower than the third quarter of 2010 because of higher net imports and new generating capacity in eastern New York.
  - ✓ Convergence between day-ahead and real-time energy prices was relatively good, although convergence of operating reserve prices continues to be relatively poor.
- A heat wave during the quarter in mid-July caused load to exceed 33.4 GW and 33.8 GW on July 21 and 22, respectively, just below peak of 33.9 GW in 2006.
  - ✓ NYISO activated EDRP/SCRs in Southeast NY (“SENY”) both days and statewide on July 22, estimating response of 574 MW on July 21 and 1,396 MW on July 22.
  - ✓ Although real-time energy prices averaged more than $200 per MWh statewide on July 22, the demand response resources needed to resolve the shortage conditions in SENY were not fully reflected in prices on July 21 or July 22.
  - ✓ NYISO is working with stakeholders to develop proposed new pricing provisions.

Highlights and Market Summary: Congestion and Capacity Market

- In the third quarter, day-ahead congestion revenue was $120 million and the value of real-time congestion was $118 million, up 17 and 33 percent from the previous quarter, respectively.
- The increase in congestion this quarter was primarily attributable to:
  - ✓ Increased congestion into Long Island due to transmission outages;
  - ✓ Higher seasonal load levels; and
  - ✓ More frequent Thunder Storm Alerts.
- Most day-ahead congestion this quarter occurred on paths into/within New York City (36%), from Capital to Hudson Valley (33%), and into Long Island (19%).
  - ✓ Congestion in New York City fell significantly from last year due to the effects of new generation in the City and less use of simplified load pocket interfaces.
- In New York City, capacity prices fell to an average of $5.77/kW-month, down 55 percent from the third quarter of 2010 due primarily to entry of a new unit and a reduction in the local capacity requirement.
- In other areas, capacity prices averaged $0.13/kW-month, down from $1.41/kW-month in the third quarter of 2010 due to increased sales from new and existing capacity and a substantial reduction in the NYCA capacity requirement.

Highlights and Market Summary: Uplift and Shortfalls

- Uplift from guarantee payments totaled $48 million, up 50 percent from the last quarter and down 22 percent from the third quarter of 2010.
  - ✓ The increase from the last quarter was due primarily to more frequent congestion over Long Island facilities that are secured by OOM dispatch by the local TO.
  - ✓ The decrease from the third quarter of 2010 was primarily due to: (i) reduced need to commit generation for reliability in NYC and western NY, and (ii) less frequent usage of units in the Minimum Oil Burn programs due to new capacity in NYC.
  - ✓ However, mitigation consultations are on-going for the third quarter, so guarantee payments will increase once these are fully reflected.
- Day-ahead congestion revenue shortfalls were $19 million, down $2 million from the last quarter, but up $15 million from the third quarter of 2010.
  - ✓ Shortfalls fell from the last quarter, since fewer outages are planned in the summer.
  - ✓ Shortfalls rose from the third quarter of 2010 due largely to a lengthy transmission outage into Long Island and several significant outages in New York City.
- Balancing congestion revenue shortfalls rose to $24 million, up $12 million from the previous quarter and up $11 million from the third quarter of 2010.
  - ✓ Most of the shortfalls accrued on several days in July and early August when unexpectedly high load coincided with outages and/or TSA events.

Energy and Ancillary Services Markets

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All-In Energy Price

- The figure summarizes prices and costs in the New York markets. The "all-in" price is the total cost of serving load divided by real-time consumption, including:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component based on spot capacity prices times capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges.
  - ✓ A natural gas price trend is shown because it is a key input to production.
- From the third quarter of 2010, all-in prices fell 3 percent in Long Island and 12 to 20 percent elsewhere.
  - ✓ Energy prices fell 8 to 11 percent in most areas, reflecting significantly higher net imports and new generating capacity.
    - – Energy prices in Long Island did not fall due to several key transmission outages.
  - ✓ Capacity prices fell 51 percent in NYC and over 90 percent elsewhere due to capacity additions in NYC and the Capital Zone and lower capacity requirements.
- From the previous quarter, all-in prices rose 12 to 25 percent outside NYC but fell 2 percent in NYC.
  - ✓ Outside NYC, energy prices rose 14 to 28 percent due to increased load levels.
  - ✓ In NYC, the effect of higher energy prices was offset by the decrease in capacity prices, which fell 46 percent due primarily to capacity additions.

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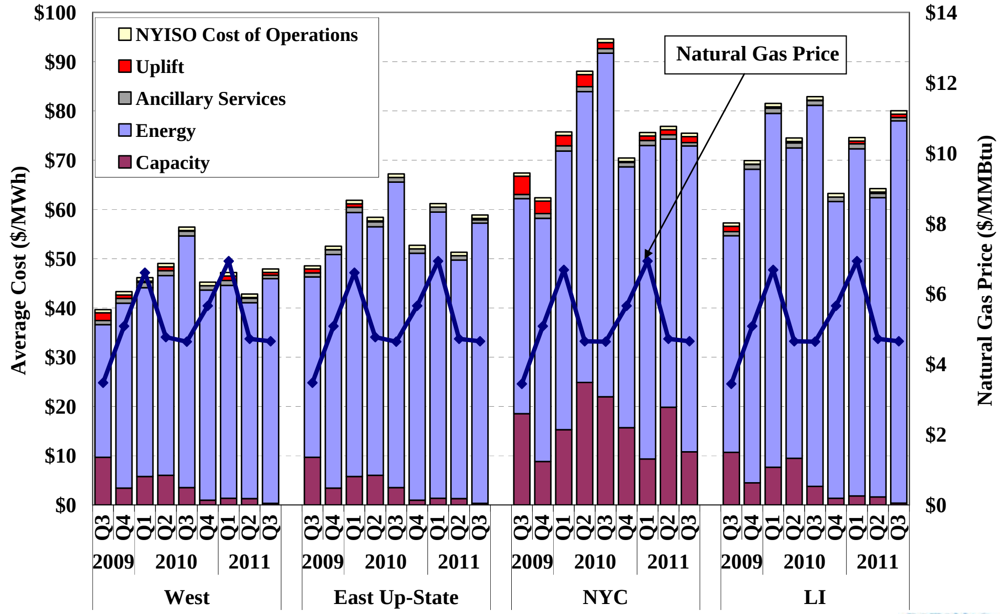
All-In Energy Price by Region



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Implied Heat Rate

- To identify changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows the marginal heat rate that would be implied if natural gas were always the marginal fuel.
  - ✓ Implied Gas Heat Rate = (Day-Ahead Electricity Price) ÷ (Natural Gas Price)
- Prices are higher in eastern New York than in western New York due to transmission losses and congestion across the Central-East interface, into Southeast New York, into New York City load pockets, and into Long Island.
- Average implied heat rates fell 7 and 11 percent from the third quarter of 2010 in eastern and western New York, respectively, due to the following factors:
  - ✓ Net imports to upstate New York rose by over 1 GW from the third quarter of 2010, including an increase from Quebec of 660 MW. This contributed to lower implied heat rates statewide, but particularly in western New York.
  - ✓ New generation facilities have begun operating in the Capital Zone and in New York City, reducing the dispatch of higher cost units in eastern New York.
  - ✓ Load levels fell modestly from a year ago, especially under peak conditions.
    - – Load exceeded 26 GW in 266 hours in this quarter, down from 392 hours in the third quarter of 2010.

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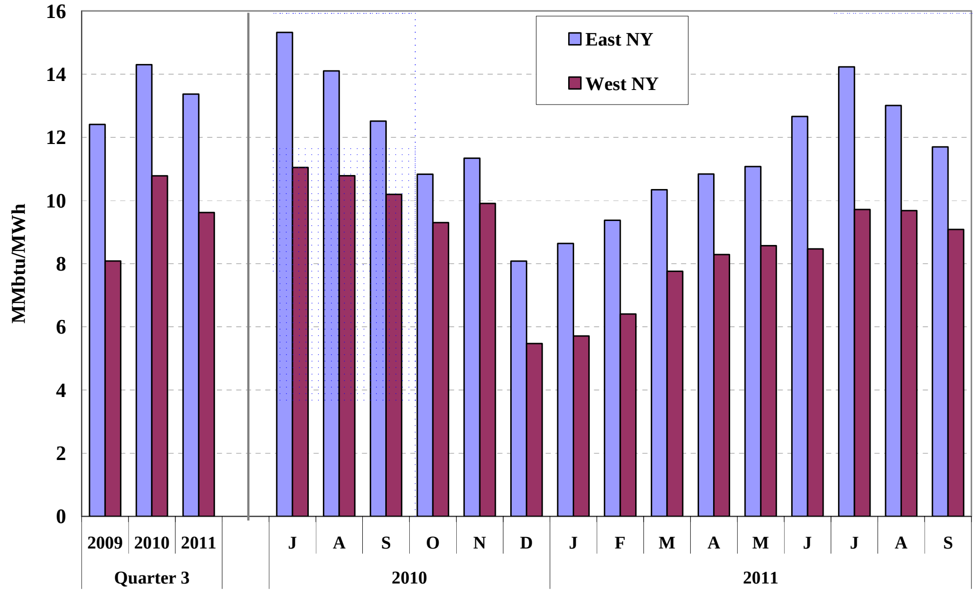
Implied Heat Rate by Region



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

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Load Forecast and Actual Load

- The following figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the third quarter of 2011.
  - ✓ The table compares key statistics for the third quarter of 2011 to the previous quarter and the third quarter of 2010.
- Average load rose considerably from the previous quarter as summer weather resulted in higher seasonal load and was comparable to the same quarter in 2010.
  - ✓ Load averaged 21.1 GW in the third quarter of 2011, up 18 percent from the previous quarter and down slightly (0.5 percent) from the third quarter of 2010.
  - ✓ Load rose considerably in July and peaked on July 22 at 33,865 MW, which was the highest since the all-time peak (33,939 MW) on August 2, 2006.
  - ✓ Load exceeded 30 GW for 60 hours in the third quarter, compared to 8 hours in the previous quarter and 66 hours from the same quarter of 2010.
- Peak load forecast errors rose from the previous quarter due to higher weather-sensitive load levels.
  - ✓ The daily peak load forecast had an error greater than 1 GW on 15 days and an error of over 2 GW on four days (July 3 & 25, August 28 & 29).
  - ✓ Although the NYISO's load forecast is rarely used in day-ahead scheduling decisions, it is used to determine whether to notify emergency demand response resources they may be activated the following day (e.g., July 21 & 22).

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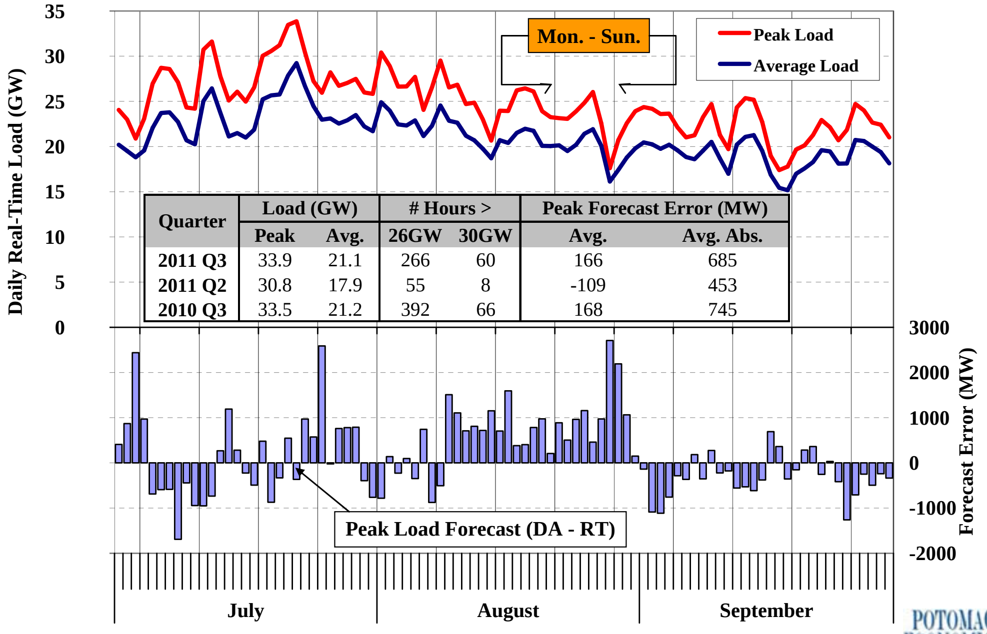
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2011 Q3	33.9	21.1	266	60	166	685
2011 Q2	30.8	17.9	55	8	-109	453
2010 Q3	33.5	21.2	392	66	168	745

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Natural Gas and Oil Prices

- The following figure shows daily natural gas and fuel oil prices, which are key determinants of electricity prices.
- Average natural gas prices fell modestly from the previous quarter and were consistent with prices in the third quarter of 2010.
  - ✓ Gas prices fell steadily from $5 to $4 per MMbtu through the third quarter.
  - ✓ However, gas prices briefly rose above $9 per MMbtu on two days (July 21 & 22) due to high demand.
    - – The price differential was approximately $3.50 per MMbtu between the Transco Zone 6 (New York City) and Iroquois Zone 2 (Upstate NY) on July 22.
- Average fuel oil prices fell slightly from the previous quarter and rose significantly from the third quarter of 2010.
  - ✓ Fuel oil #2 prices fell 2 percent from the previous quarter, but rose 48 percent from the third quarter of 2010.
  - ✓ Fuel oil #6 prices fell 3 percent from the previous quarter, but rose 53 percent from the third quarter of 2010.
- Natural gas was usually much less expensive than fuel oil, but some generators burn oil due to: a) reliability reasons, b) difficulties obtaining natural gas, or c) unavailability of pipeline capacity.

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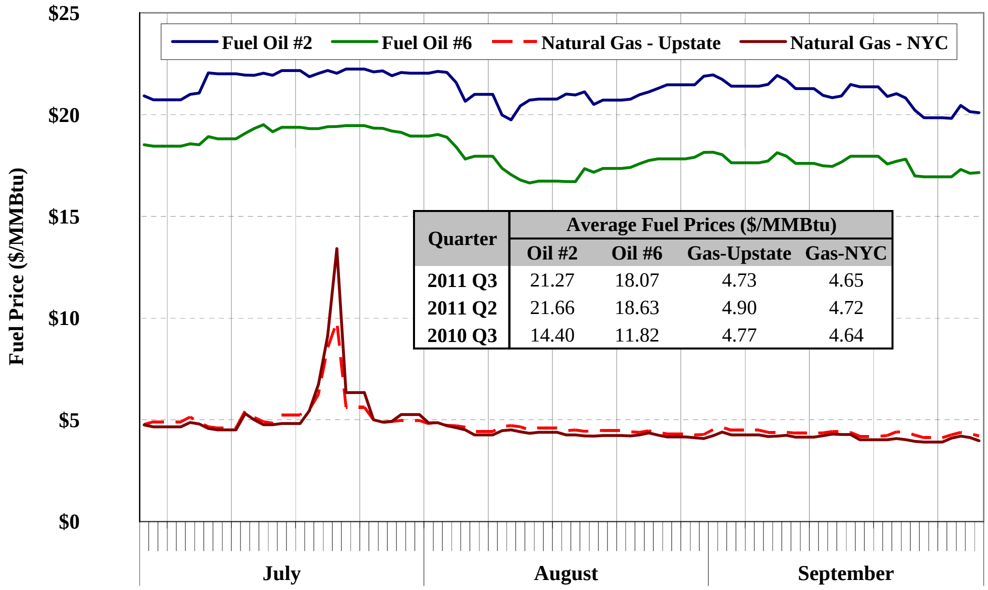
Natural Gas and Oil Prices



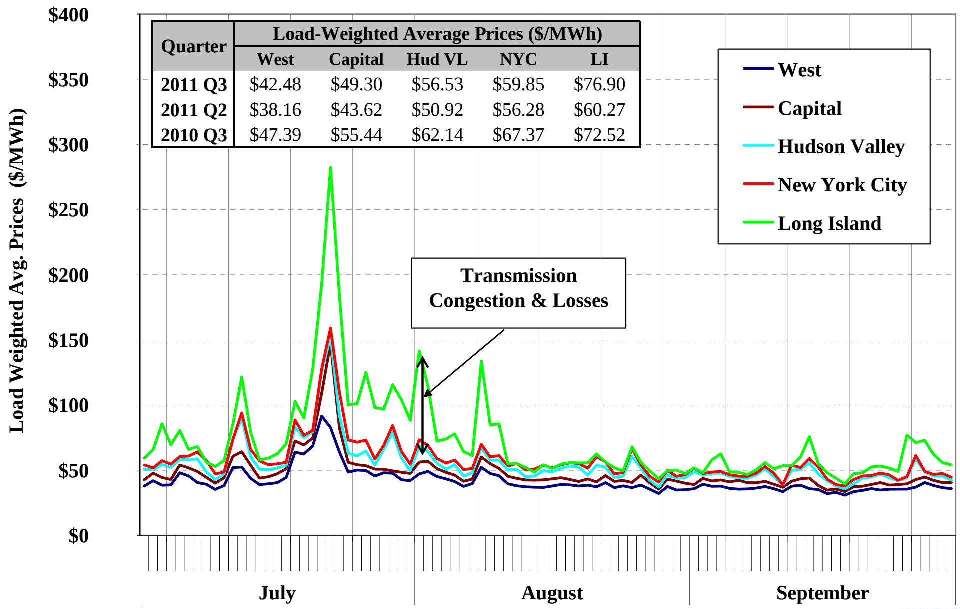
Quarter	Average Fuel Prices ($/MMBtu)			
	Oil #2	Oil #6	Gas-Upstate	Gas-NYC
2011 Q3	21.27	18.07	4.73	4.65
2011 Q2	21.66	18.63	4.90	4.72
2010 Q3	14.40	11.82	4.77	4.64

Note: Natural Gas price for NYC is Transco zone 6 price and for upstate is Iroquois zone 2 price.

Day-Ahead Electricity Prices by Zone

- The following figure shows load-weighted average day-ahead energy prices for five zones on each day in the third quarter of 2011.
- Prices in a well-functioning day-ahead market should reflect probability-weighted expectations of real-time market conditions.
- Average prices rose in all zones by 6 to 28 percent from the second quarter of 2011 but fell 9 to 11 percent (except in Long Island where it rose 6 percent) from the third quarter of 2010.
  - ✓ Average day-ahead prices trended downward from July to September, consistent with the decreases in load and natural gas prices over the quarter.
  - ✓ Prices rose substantially on days when the forecasted load exceeded 30 GW.
- Long Island prices were elevated notably on many days, driven in part by significant transmission outages.
  - ✓ The Neptune Cable was out of service during the first week of July and the last week of September.
  - ✓ One of the major lines carrying power from upstate New York into Long Island (Sprainbrook to East Garden City) was out of service from mid-July to mid-August.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2011 Q3	$42.48	$49.30	$56.53	$59.85	$76.90
2011 Q2	$38.16	$43.62	$50.92	$56.28	$60.27
2010 Q3	$47.39	$55.44	$62.14	$67.37	$72.52

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Real-Time Electricity Prices by Zone

- The following figure shows load-weighted average real-time energy prices for five zones on each day in the third quarter of 2011.
  - ✓ Prices are more volatile in the real-time market than in the day-ahead market.
- Prices rose substantially in the real-time market on several days during the quarter.
  - ✓ On July 22, high loads associated with a heat wave produced average real-time prices ranged from nearly $200/MWh in the West Zone to over $350/MWh in the Long Island Zone. This event is summarized and evaluated after the figure.
  - ✓ On July 8 and August 1 & 7, prices rose sharply in Southeast New York reflecting congestion caused by: under-forecast of load (0.5 to 1.7 GW), TSA events, and multiple outages (Edic-Scotland on August 1 and several generators on August 7).
- Prices averaged below $0 in all zones on August 28. On this day,
  - ✓ A significant share of load was interrupted by the Hurricane Irene;
  - ✓ New York committed enough capacity in anticipation of the hurricane and had no significant generation loss during the event; and
  - ✓ The large amount of excess online capacity led the system to be close to its Minimum Generation State for most of the day, which resulted in significantly lower prices than normal.

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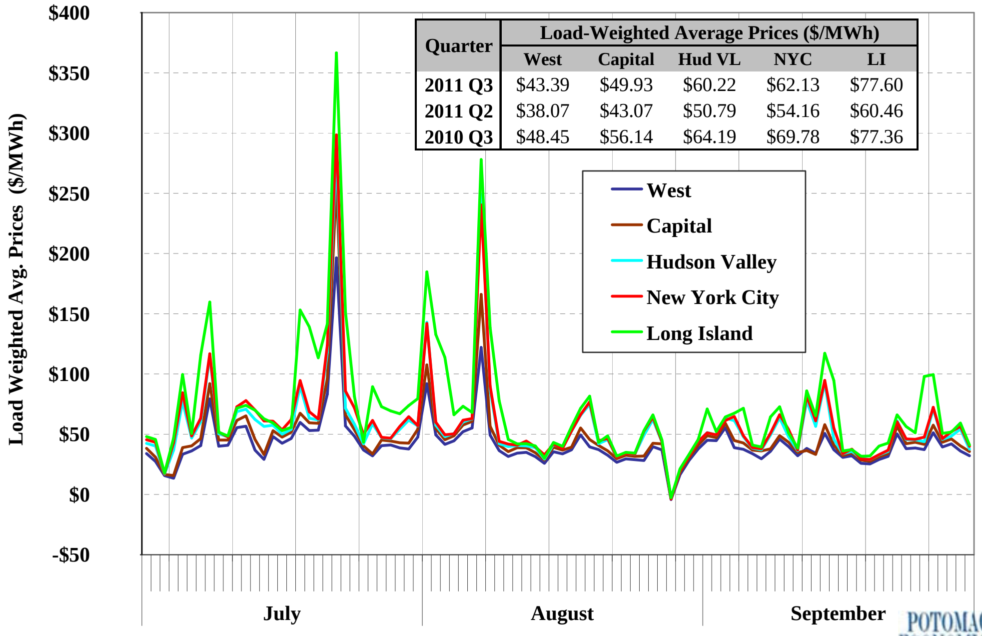
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2011 Q3	$43.39	$49.93	$60.22	$62.13	$77.60
2011 Q2	$38.07	$43.07	$50.79	$54.16	$60.46
2010 Q3	$48.45	$56.14	$64.19	$69.78	$77.36

Heat Wave on July 21 and 22

- Load peaked on July 22 at 33,865 MW, only about 70 MW less than the all-time peak set on August 2, 2006.
  - ✓ Weather conditions on July 22 were well above peak expectations - the Cumulative Temp.-Humidity Index was in the 93 percentile for expected peak conditions.
  - ✓ Load levels on July 21 were only slightly lower, peaking at 33,454.
  - ✓ NYISO called for demand response (EDRP and SCRs) on both days and has estimated total response of 574 MW on July 21 and 1,396 MW on July 22.
    - – On both days, EDRP/SCR resources were activated in Southeast New York (SENY) for transmission security.
    - – EDRP/SCR resources were only activated outside of Southeast New York on July 22 for statewide capacity needs.
- Although energy prices were relatively high on July 22 statewide due to the tight capacity conditions, the demand resources needed to resolve the shortage conditions in SENY were not reflected in prices on July 21 or 22.
  - ✓ We recommended improvements to the NYISO’s shortage pricing provisions to address this issue in the 2010 State of the Market Report.
  - ✓ NYISO is working with stakeholders to develop proposed new pricing provisions.

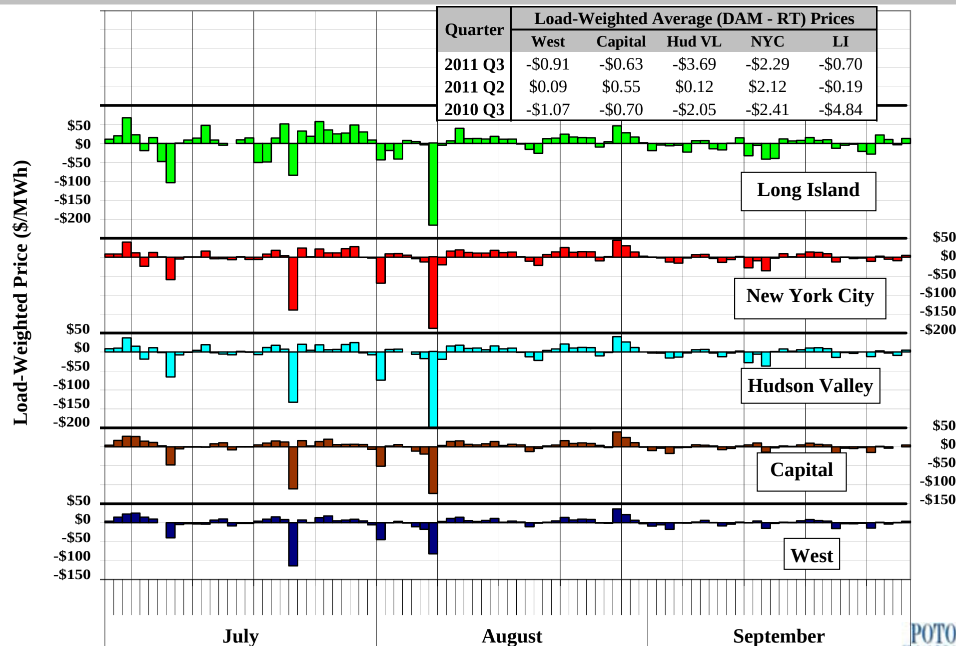
Convergence Between Day-Ahead and Real-Time Prices

- The next analysis evaluates convergence between day-ahead and real-time prices.
  - ✓ Convergence is important because the day-ahead market facilitates the daily commitment of generation and scheduling of natural gas, determines the obligations to TCC holders, and accounts for most energy settlements.
- The figure shows the difference between average day-ahead prices and the average real-time prices on each day in the third quarter of 2011.
  - ✓ This is shown separately for five zones to account for changes in the pattern of congestion from the day-ahead to the real-time.
  - ✓ Convergence should be measured over longer timeframes since random factors can cause large differences in prices on individual days -- the table shows the average price convergence over the entire quarter.
- Convergence between day-ahead and real-time prices was generally good on most days in the third quarter of 2011.
  - ✓ Price differences in most areas ranged from 1 to 4 percent of RT prices in the third quarter, up modestly from last quarter and comparable to the same quarter of 2010.
  - ✓ Price convergence in the summer is normally worse because unexpected events are more likely to result in sharp price movements under tight real-time conditions.

Convergence Between Day-Ahead and Real-Time Prices

- Notable real-time price premiums occurred on several days in July and early August, which was due to severe real-time conditions.
- The largest price differences occurred on August 7 in Southeast New York due to severe real-time conditions, including:
  - ✓ A TSA was called during the afternoon, which greatly reduced transfer capability into Southeast New York;
  - ✓ Clockwise circulation around Lake Erie was up to 500 MW higher than the level assumed in the day-ahead market;
    - – This reduced the amount of transfer capability into Southeast New York that was available to NYISO market;
  - ✓ Real-time load exceeded the peak load forecast by 900 MW; and
  - ✓ Multiple unit outages led to a loss of nearly 1.5 GW of online capacity.

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2011 Q3	-$0.91	-$0.63	-$3.69	-$2.29	-$0.70
2011 Q2	$0.09	$0.55	$0.12	$2.12	-$0.19
2010 Q3	-$1.07	-$0.70	-$2.05	-$2.41	-$4.84

Day-Ahead and Real-Time Ancillary Services Prices

- The following two figures summarize average day-ahead and real-time clearing prices on a daily basis for four key ancillary services products:
  - ✓ 10-minute spinning reserves prices in eastern New York, which reflect the cost of requiring:
    - 300 MW of 10-minute spinning reserves in eastern New York;
    - 600 MW of 10-minute spinning reserves state-wide; and
    - 1,200 MW of 10-minute total reserves (spinning and non-spinning reserves) in eastern New York.
  - ✓ 10-minute non-spinning reserves prices in eastern New York, which reflect the cost of requiring 1,200 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-minute spinning reserves prices in western New York, which reflect the cost of requiring 600 MW of 10-minute spinning reserves state-wide.
  - ✓ Regulation prices, which reflect the cost of requiring up to 275 MW of regulation, depending upon season and time of day.
- The table in each figure shows the number of intervals when the real-time reserve price of the product was affected by a shortage of reserves.
  - ✓ During shortages, the prices of products that can satisfy a given requirement will include the "demand curve" value of that requirement.

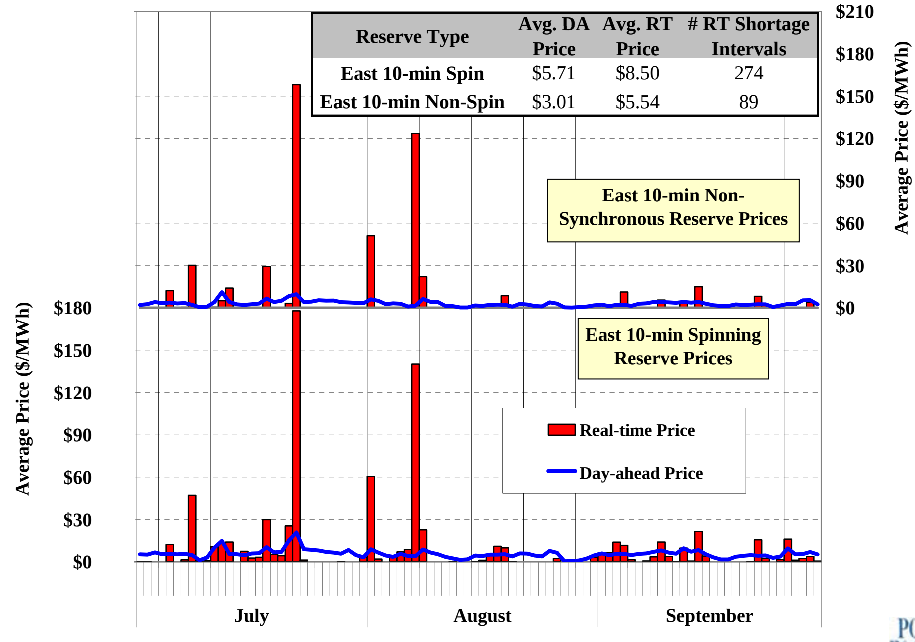
Day-Ahead and Real-Time Ancillary Services Prices

- Reserve prices are relatively consistent from day-to-day in the day-ahead, while reserve prices are much more volatile in the real-time market.
  - ✓ Day-ahead reserves prices are based on suppliers' offers, which depend on expectations of real-time prices and the risks associated with selling reserves in the day-ahead market.
  - ✓ Real-time reserves prices are normally close to $0 due to the excess available reserves from online and quick-start units in most hours.
  - ✓ Real-time prices spike during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Average day-ahead prices were lower than average real-time prices for all four types of reserves in the third quarter of 2011.
  - ✓ These real-time price premiums resulted primarily from high prices on several days (July 7 & 22, August 1 & 7) due to tight system conditions described earlier.
    - The vast majority of reserves shortages in this quarter occurred on these days.
  - ✓ Real-time regulation prices were also notably higher than day-ahead prices on August 28 due to limited downward regulation supply.
    - Generators were dispatched close to their Minimum Generation levels most of the day because Hurricane Irene interrupted a significant share of load.

Real-Time Ancillary Services Shortages

- A shortage occurs when a reserve requirement cannot be satisfied at a marginal cost less than its "demand curve". Shortages occurred in real-time for:
  - ✓ Eastern 10-minute spinning reserves in 172 intervals ($25 demand curve);
  - ✓ Eastern 10-minute total reserves in 89 intervals ($500 demand curve);
  - ✓ State-wide 10-minute spinning reserves in 13 intervals ($500 demand curve); and
  - ✓ Regulation in 566 intervals ($80 to $400 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 274 intervals of shortage pricing: 172 of eastern 10-minute spin, 89 of eastern 10-minute total reserves, and 13 of state-wide 10-minute spin.
- Regulation shortages occurred more frequently in the third quarter of 2011 following the modification of Regulation Demand Curve on May 19, 2011.
  - ✓ The new values more accurately reflect operational actions during shortages.
  - ✓ Regulation shortages occurred more frequently due to the lower value placed on regulation by the new demand curve during small shortages. (There were just 94 regulation shortages in the third quarter of 2010.)

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	$5.71	$8.50	274
East 10-min Non-Spin	$3.01	$5.54	89

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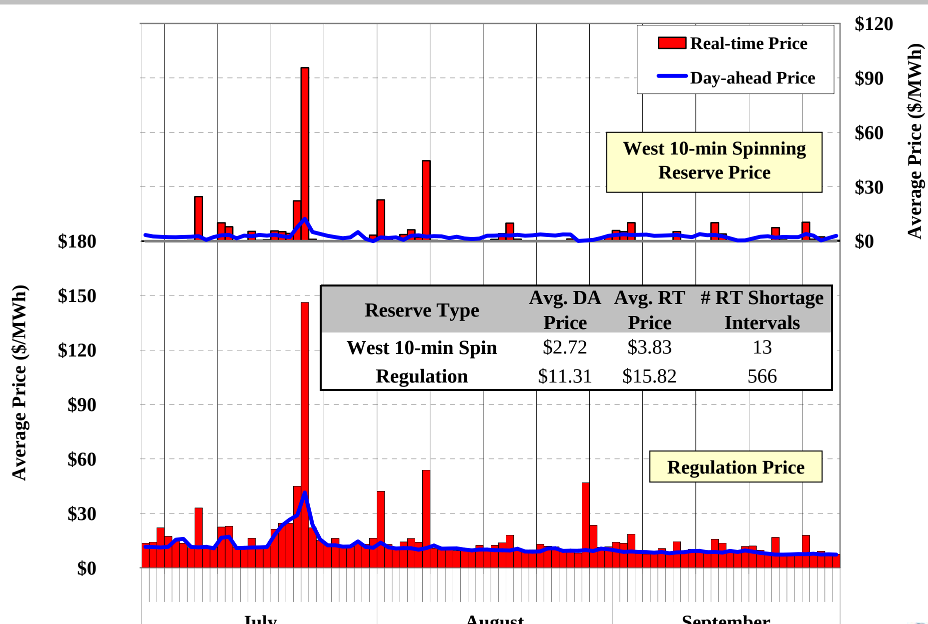
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
West 10-min Spin	$2.72	$3.83	13
Regulation	$11.31	$15.82	566

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Market Monitoring and Mitigation

- The following figure summarizes energy offer mitigation as well as the results of potential withholding screens.
- Energy, minimum generation, and start-up offer mitigation is performed by automated mitigation procedure ("AMP") software in the day-ahead and real-time markets in New York City. The following figure reports:
  - ✓ The frequency of incremental energy offer mitigation; and
  - ✓ The average quantity of mitigated capacity, including capacity below the minimum generation level when the minimum generation offer is mitigated.
- The output gap is the amount of economic capacity that does not produce energy because a supplier submits an offer price above the unit's reference level by a substantial threshold. The following figure shows this using:
  - ✓ A high threshold (the lower of $100/MWh and 300 percent); and
  - ✓ A low threshold (the lower of $50/MWh and 100 percent).
- Generator deratings are reviewed to screen for potential physical withholding. The figure summarizes:
  - ✓ Total deratings, which are measured relative to the DMNC test value; and
  - ✓ Short-term deratings, which exclude deratings lasting more than 30 days.

Market Monitoring and Mitigation

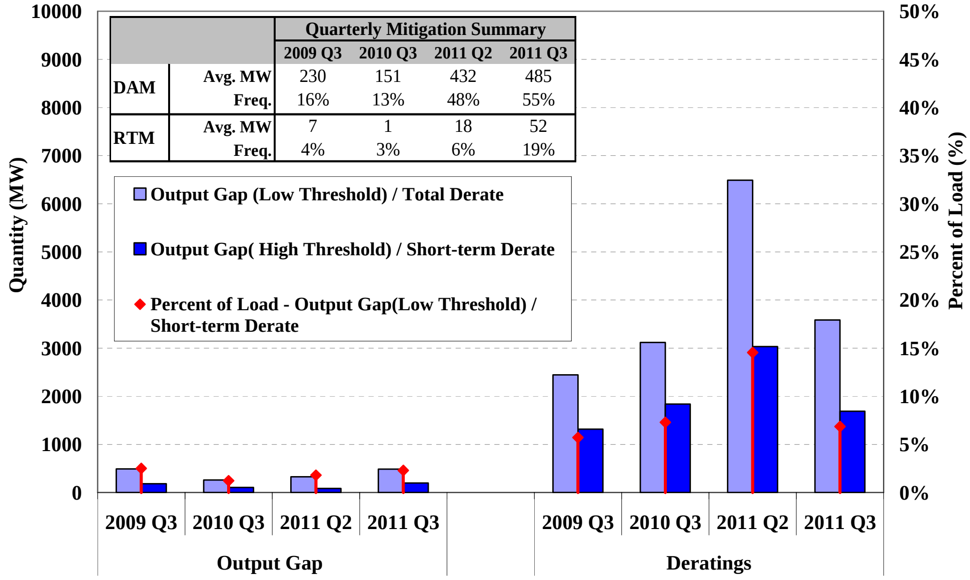
Automated Mitigation in the Day-Ahead and Real-Time Markets:

- Most mitigation occurred day-ahead for DARU & LRR units (33%), Astoria West/Queens/Vernon congestion (32%), and In-City 138 kV congestion (12%).
- Mitigation increased substantially in 2011 from prior years due primarily to the application of the new ROS reliability mitigation rules (since October 2010).
- Mitigation has also increased due to:
  - ✓ Some units having "LBMP-based" reference levels that were below their costs.
  - ✓ Increased mitigation of reliability-committed units whose fuel type varies by time of day as a result of minimum oil-burn reliability rules, since software limitations allow just one fuel type for a particular unit for all hours in the DAM.
  - ✓ Accordingly, mitigation consultations have reversed many of these instances for the 1st and 2nd quarters, and consultations are on-going for the 3rd quarter.

Output Gap at High and Low Thresholds and Long-Term and Short-Term Deratings:

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

Market Monitoring Screens and Mitigation



		Quarterly Mitigation Summary			
		2009 Q3	2010 Q3	2011 Q2	2011 Q3
DAM	Avg. MW	230	151	432	485
	Freq.	16%	13%	48%	55%
RTM	Avg. MW	7	1	18	52
	Freq.	4%	3%	6%	19%

Note: Mitigation summaries for 2011-Q2 are revised from the previous report to reflect the results from mitigation consultations.

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Day-ahead Scheduled Load and Actual Load

- The following figure summarizes the quantity of day-ahead load scheduled as a percent of real-time load in each of four regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Overall, load in the day-ahead market was scheduled at 102 percent of actual load in NYCA, higher than in 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 pattern is typical and is likely in response to real-time congestion across the lines into Southeast New York, New York City, and Long Island.
- The over- and under-scheduling patterns generally improve convergence between day-ahead and real-time prices in most areas.
  - ✓ For example, Southeast New York was consistently over-scheduled but still exhibited a real-time price premium that would have otherwise been much larger.
  - ✓ Over-scheduling is also balanced by differences between the volume of day-ahead and real-time imports, particularly from PJM where day-ahead imports exceeded real-time imports by 685 MW on average.

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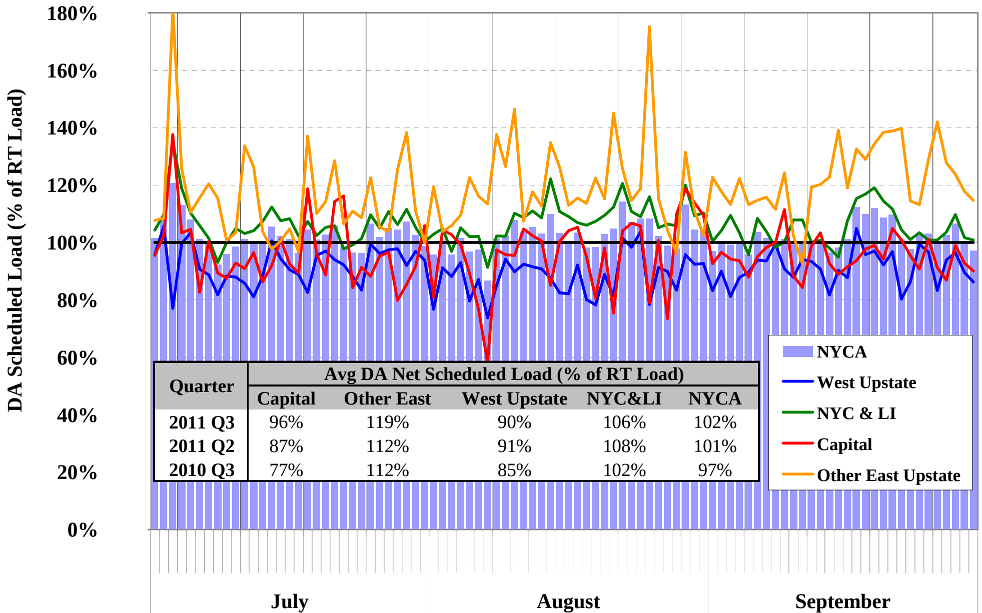
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour



Quarter	Avg DA Net Scheduled Load (% of RT Load)				
	Capital	Other East	West Upstate	NYC&LI	NYCA
2011 Q3	96%	119%	90%	106%	102%
2011 Q2	87%	112%	91%	108%	101%
2010 Q3	77%	112%	85%	102%	97%

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Virtual Trading Activity

- The following two figures summarize virtual trading activity in New York.
- The first figure shows monthly average bids/offers and scheduled quantities, and profitability for virtual transactions in each month over the past two years.
  - ✓ In each of the past 24 months, 1.2 to 2.2 GW of virtual load and 1.5 to 2.2 GW of virtual supply have been scheduled in the day-ahead market.
  - ✓ In aggregate, virtual load and supply have generally been profitable over the period, indicating that they typically improved convergence between day-ahead and real-time prices.
  - ✓ However, the profits and losses of virtual load and supply have varied widely from month-to-month, reflecting the difficulty of predicting volatile real-time prices.
- The table below the figure shows a screen for relatively large profits (which may indicate modeling inconsistencies) or losses (which may indicate potential manipulation of the day-ahead market).
  - ✓ The table shows that the quantity of transactions generating substantial profits or losses rose during the volatile periods in the third quarter of 2011.
  - ✓ The transactions with notable profits or losses were primarily associated with real-time price volatility and did not raise manipulation concerns.

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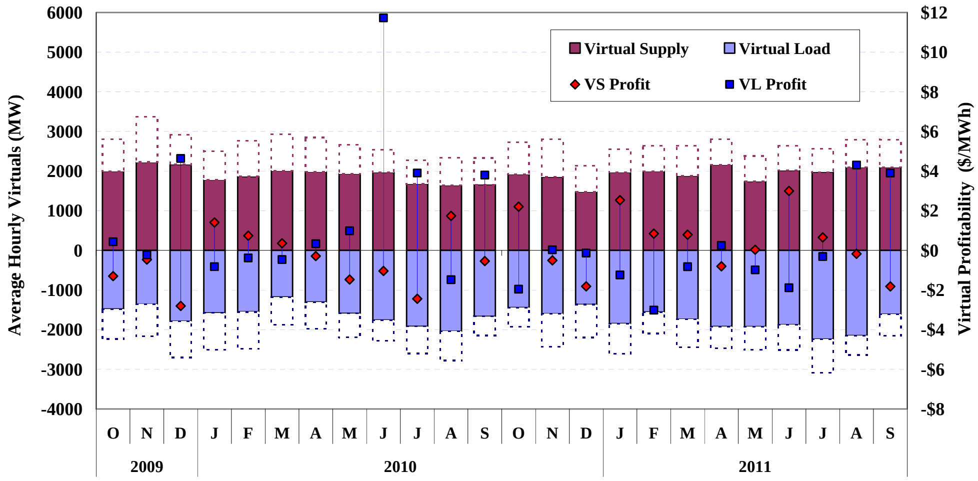
Virtual Trading Volumes and Profitability

October 2009 to September 2011



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
Profit > 50% of Avg. Zone Price	MW	315	239	573	380	324	240	122	181	285	205	176	162	117	135	221	446	193	161	122	233	350	376	337	186
	%	9%	7%	14%	11%	10%	8%	4%	5%	8%	6%	5%	5%	3%	4%	8%	12%	5%	4%	3%	6%	9%	9%	8%	5%
Loss > 50% of Avg. Zone Price	MW	369	253	578	347	284	201	112	211	241	300	205	115	95	131	273	401	244	133	120	277	381	434	334	122
	%	11%	7%	15%	10%	8%	6%	3%	6%	6%	8%	6%	3%	3%	4%	10%	11%	7%	4%	3%	8%	10%	10%	8%	3%

POTOMAC ECONOMICS

Virtual Trading Activity

- The second figure summarizes virtual trading by geographic region. The eleven zones are broken into six geographic regions based on typical congestion patterns.
  - ✓ Zone D (the North Zone) is shown separately because transmission constraints frequently cause the price of power in Zone D to differ from other areas.
  - ✓ Zone F (the Capital Zone) is shown separately because it is constrained from western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley.
  - ✓ Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas.
- A large number of market participants regularly submit virtual bids and offers.
  - ✓ On average, eight or more participants submitted virtual trades in each region and 33 participants submitted virtual trades throughout the state in this quarter.
- There were substantial net virtual load purchases downstate and net virtual supply sales upstate in the third quarter of 2011, consistent with prior periods.
- 86 percent of the virtual trading profits in the third quarter of 2011 came from virtual load scheduling in Zones G to I.
  - ✓ This is because real-time congestion from the Capital Zone to the Hudson Valley Zone was not fully reflected in the day-ahead market in this quarter.

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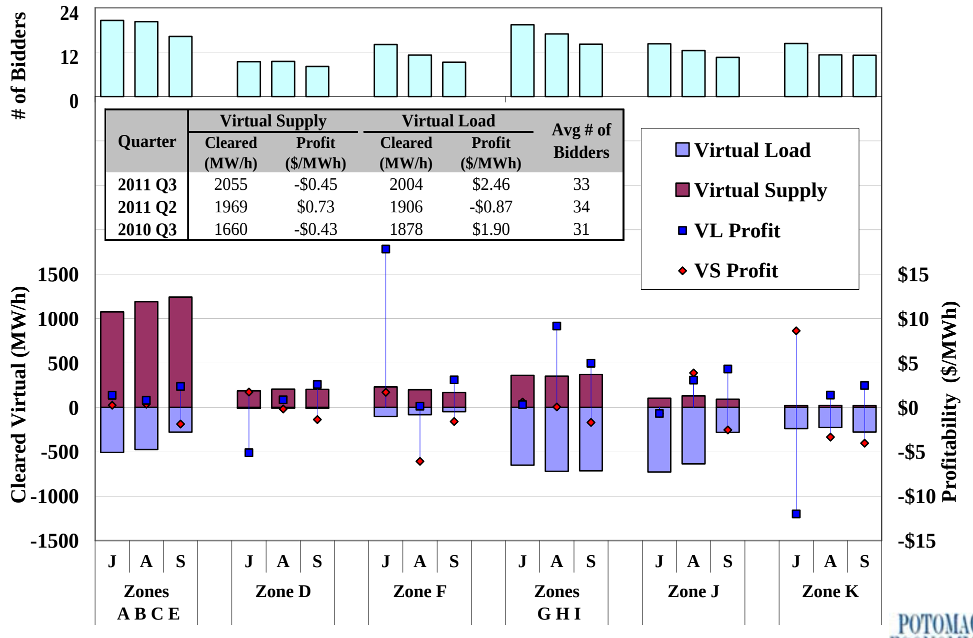
Virtual Trading Activity
By Region By Month

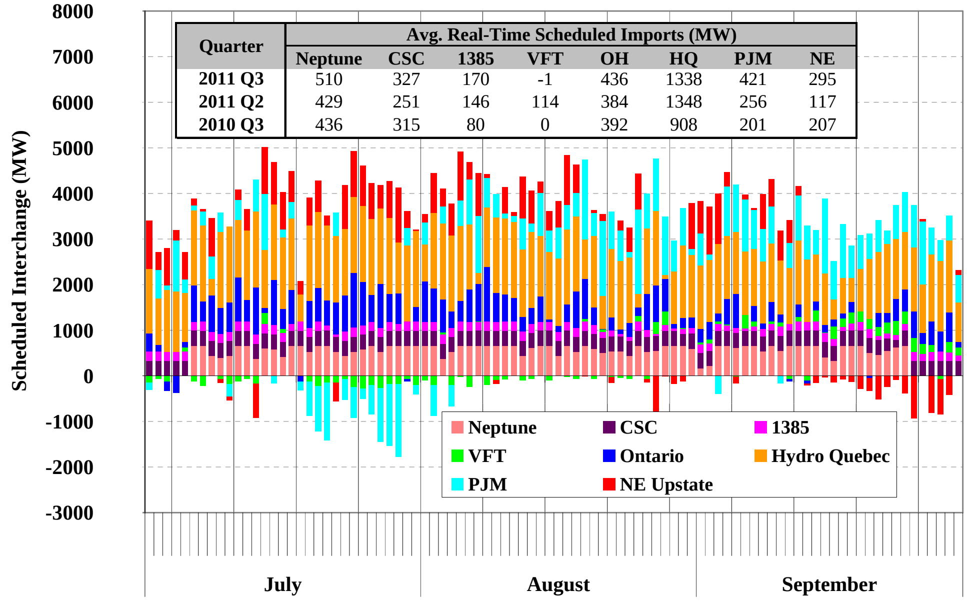


Quarter	Virtual Supply		Virtual Load		Avg # of Bidders
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	
2011 Q3	2055	-$0.45	2004	$2.46	33
2011 Q2	1969	$0.73	1906	-$0.87	34
2010 Q3	1660	-$0.43	1878	$1.90	31

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 nearly 3.5 GW during daily peak hours in the third quarter of 2011, up 450 MW (or 15 percent) from the previous quarter and up 960 MW (or 38 percent) from the third quarter of 2010.
  - ✓ Average net imports from HQ were comparable to the previous quarter and rose 430 MW from the third quarter of 2010.
  - ✓ Average net imports from PJM and NE across their primary interfaces rose 345 MW from the previous quarter and 310 MW from the third quarter of 2010.
    - – These interchanges varied considerably from day to day, reflecting wide variations in prices between these markets.
- Net imports to New York City and Long Island from New England and PJM via four controllable lines increased from the previous quarter due to fewer outages.
- On average, imports satisfied 13 percent of the load during daily peak hours in the third quarter, down from the 15 percent in the previous quarter.
  - ✓ During the peak load hour on July 22, NYCA imported 3.0 GW (satisfying roughly 9 percent of the 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
2011 Q3	510	327	170	-1	436	1338	421	295
2011 Q2	429	251	146	114	384	1348	256	117
2010 Q3	436	315	80	0	392	908	201	207

POTOMAC ECONOMICS

Change in Scheduled Imports from Day Ahead to Real Time

- The following figure summarizes the change in scheduled net imports between the day-ahead market and the real-time market in the daily peak load hour.
  - ✓ As with virtual transactions, these changes generally improve the convergence of day-ahead and real-time prices.
- Net scheduled imports fell 800 MW on average from day-ahead to real-time during daily peak load hours in the third quarter. Net scheduled imports:
  - ✓ Decreased across the PJM interface by an average of 685 MW;
  - ✓ Decreased across the primary interface with NE by an average of 189 MW;
  - ✓ Increased across the Ontario interface by an average of 177 MW; and
  - ✓ Did not vary significantly across the four controllable lines into New York City and Long Island or the interface with Quebec.
- Generally, the changes in schedules between the day-ahead and real-time markets were consistent with the changes in prices.
  - ✓ This was particularly evident at the PJM interface, where the average day-ahead price was consistently higher than the average real-time price.
    - – This inconsistency was partly due to a software issue in the calculation of losses at the PJM proxy bus, which was recently identified and fixed by the NYISO.

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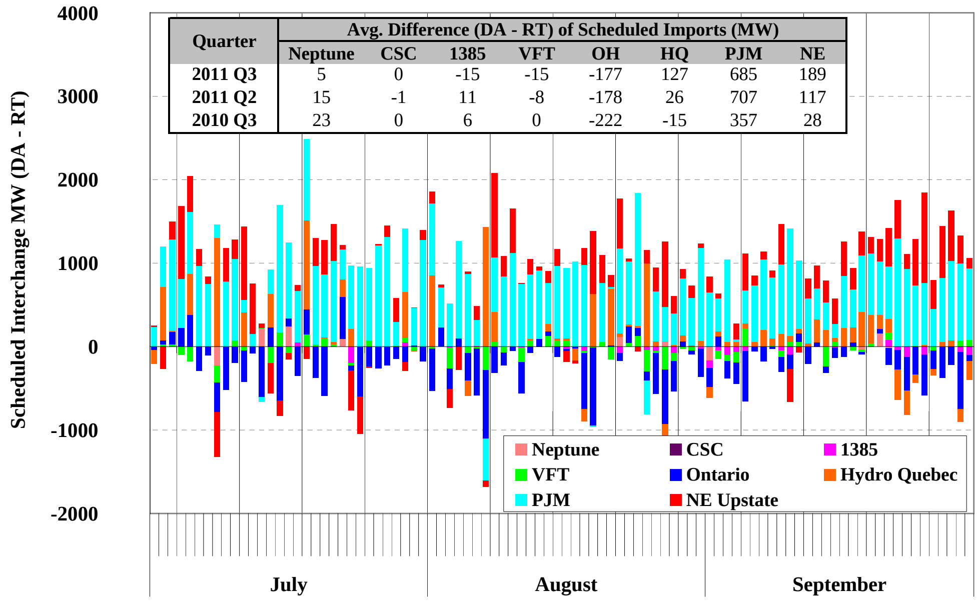
Change in Scheduled Imports from DA to RT
Daily Peak Load Hour



Quarter	Avg. Difference (DA - RT) of Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2011 Q3	5	0	-15	-15	-177	127	685	189
2011 Q2	15	-1	11	-8	-178	26	707	117
2010 Q3	23	0	6	0	-222	-15	357	28

POTOMAC ECONOMICS

External Interface Scheduling and Lake Erie Circulation

- Loop flows occur when physical power flows are not consistent with the scheduled path of the transaction between control areas.
  - ✓ Clockwise loop flows around Lake Erie use valuable west-to-east transmission capacity through upstate New York, reducing the capacity available for scheduling internal generation to satisfy internal load.
  - ✓ Counter-clockwise scheduled transactions tend to increase clockwise loop flows.
  - ✓ Transmission Loading Relief ("TLR") procedure is used by the NYISO when loop flows contribute to congestion on internal flowgates.
- The figure shows the pattern of loop flows and the net scheduled interchange between the four control areas around Lake Erie on each day of the quarter.
  - ✓ Days when TLRs (level 3A+) were called by the NYISO are also highlighted.
- Average clockwise circulation was approximately 65 MW in the third quarter, down from the previous quarter but up from the third quarter of 2010.
  - ✓ The correlation of clockwise circulation and counter-clockwise transactions was weak, suggesting that dispatch by each ISO also significantly affects circulation.
- TLRs were called on 27 days and in 203 hours, down from the previous quarter.
  - ✓ Clockwise circulation averaged 213 MW on days when TLRs were called and only 10 MW on days when no TLRs were called during the third quarter.

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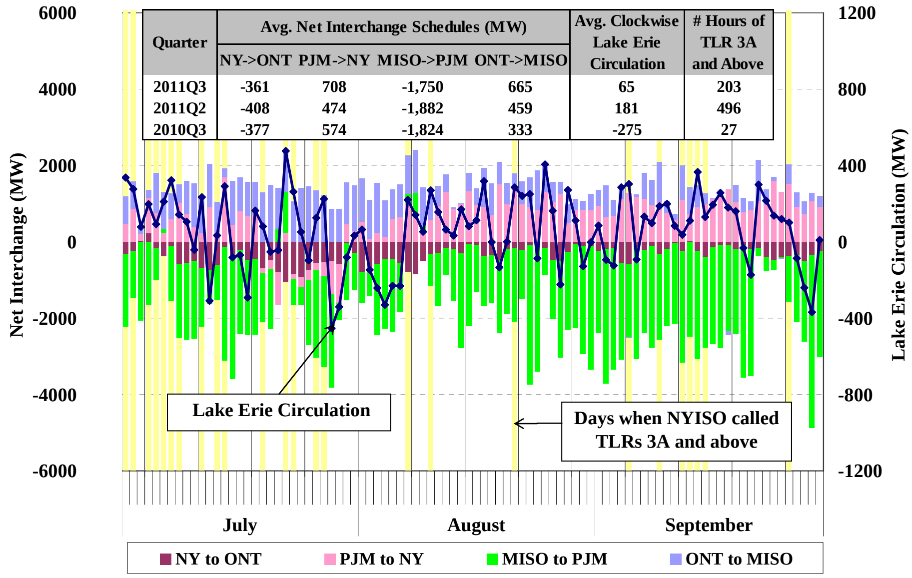
RT Lake Erie Circulation and Interchange Schedules
Daily Peak Hours between 8AM and 8PM



Quarter	Avg. Net Interchange Schedules (MW)				Avg. Clockwise Lake Erie Circulation	# Hours of TLR 3A and Above
	NY->ONT	PJM->NY	MISO->PJM	ONT->MISO		
2011Q3	-361	708	-1,750	665	65	203
2011Q2	-408	474	-1,882	459	181	496
2010Q3	-377	574	-1,824	333	-275	27

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

POTOMAC ECONOMICS

Day-Ahead and Real-Time Transmission Congestion

POTOMAC ECONOMICS

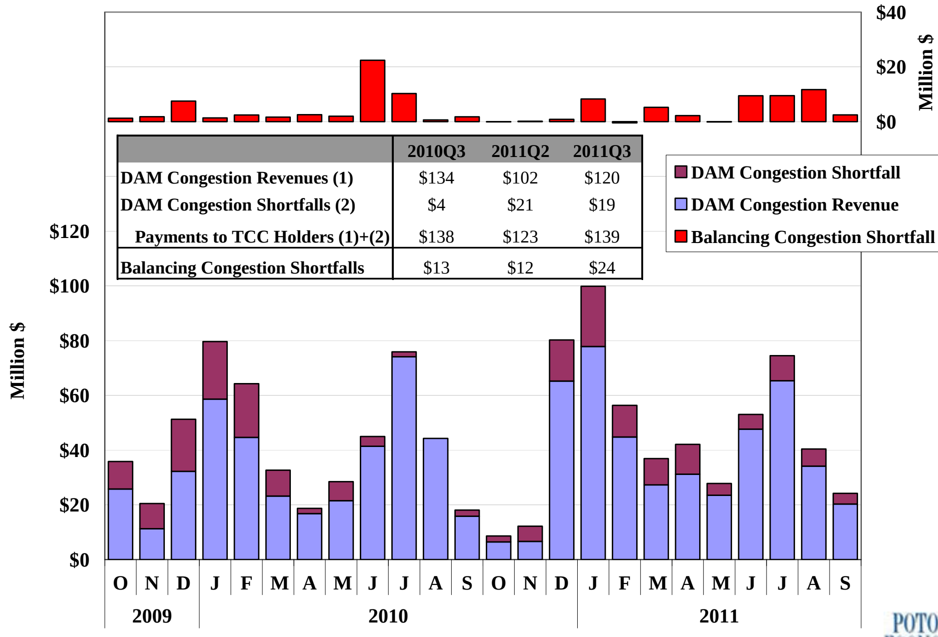
Congestion Revenue and Shortfalls

- 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 was $120 million in the third quarter, up 17 percent from the previous quarter.
  - ✓ The increase was mostly attributable to increased congestion into Long Island due to transmission outages.
  - ✓ The effects on day-ahead scheduling patterns of: (i) increased load levels and (ii) more frequent TSAs also contributed to the increase.
- Day-ahead congestion shortfalls totaled $19 million, down $2 million from the previous quarter and up $15 million from the previous year. In this quarter,
  - ✓ Shortfalls associated with PAR-controlled lines between NJ and NY have been eliminated since May 2011 due to modeling improvement in the TCC auction.
  - ✓ Lines into Long Island and in New York City accounted for the vast majority of total shortfalls, due primarily to transmission outages.
- Balancing congestion shortfalls rose to $24 million in the third quarter of 2011, up $12 million from the previous quarter and $11 million from a year ago.
  - ✓ Most of the shortfalls accrued on several days in July and early August when unexpectedly high load coincided with outages and/or TSA events.

Congestion Revenue and Shortfalls



	2010Q3	2011Q2	2011Q3
DAM Congestion Revenues (1)	$134	$102	$120
DAM Congestion Shortfalls (2)	$4	$21	$19
Payments to TCC Holders (1)+(2)	$138	$123	$139
Balancing Congestion Shortfalls	$13	$12	$24

POTOMAC ECONOMICS

Congestion by Transmission Path

- The following two figures examine the value and frequency of congestion along major transmission paths in the day-ahead and real-time market.
  - ✓ The value of transfers is equal to the marginal cost of relieving the constraint (i.e., shadow price) multiplied by the scheduled flow across the interface.
  - ✓ In the day-ahead market, the value of congestion is equal to the congestion revenue collected by the NYISO, which is the primary funding source for TCC payments.
- The two figures group congestion into the following transmission paths:
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ Capital to Hudson Valley: Primarily the Leeds-to-Pleasant Valley line and the New Scotland-to-Leeds Line.
  - ✓ NYC Lines – 345kV: Lines leading into and within the NYC 345 kV system.
  - ✓ NYC Lines – Load Pockets: Lines leading into and within NYC load pockets.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ NYC Simplified Interfaces: Groups of lines to NYC load pockets that are modeled as interface constraints.
  - ✓ External Interfaces – Congestion related to the total transmission limits or ramp limits of the ten external interfaces.

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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 this quarter was collected for flows over lines into and within New York City (36 percent), lines from Capital to Hudson Valley (33 percent), and lines into Long Island (19 percent).
- Congestion in New York City decreased 38 percent from the third quarter of 2010.
  - ✓ The decrease is partly due to the effects of new generation in New York City.
- Congestion into Long Island increased significantly from the prior quarters.
  - ✓ The increase was mostly attributable to the extended outages of one of the main transmission lines that imports power from upstate New York to Long Island.

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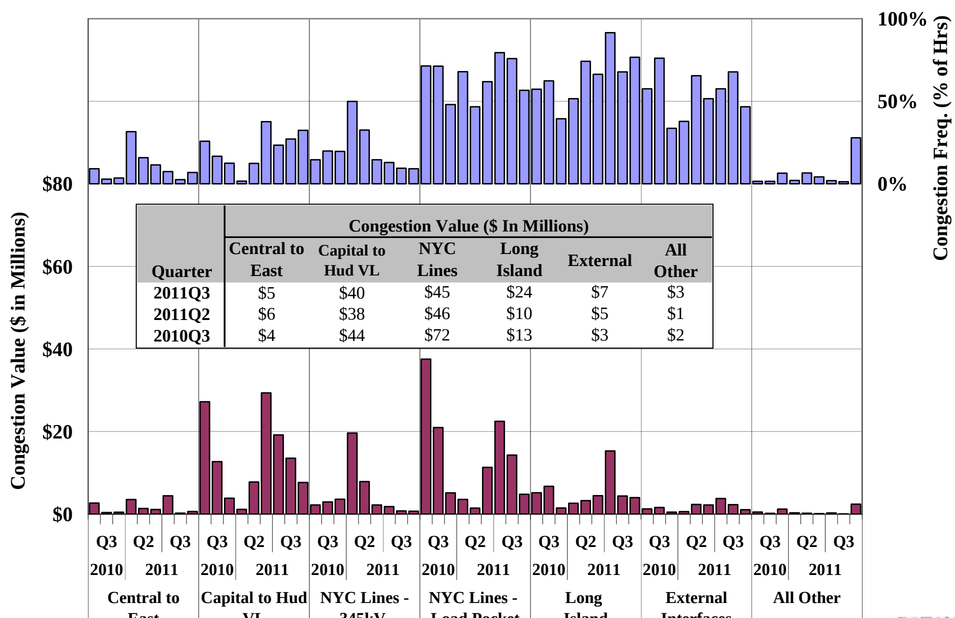
Day-Ahead Congestion by Transmission Path



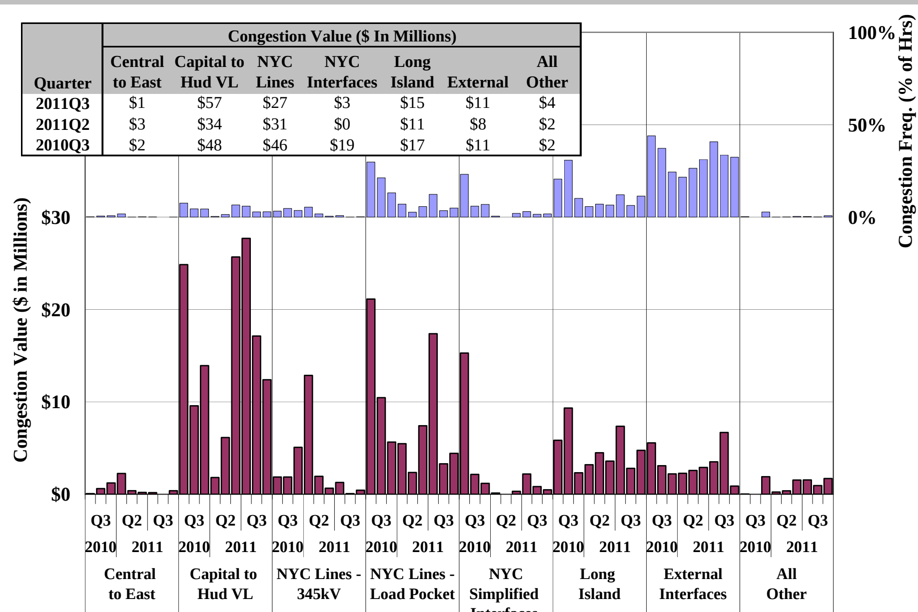
Quarter	Central to East	Capital to Hud VL	NYC Lines	Long Island	External	All Other
	Congestion Value ($ In Millions)					
2011Q3	$5	$40	$45	$24	$7	$3
2011Q2	$6	$38	$46	$10	$5	$1
2010Q3	$4	$44	$72	$13	$3	$2

POTOMAC ECONOMICS

Real-Time Congestion by Transmission Path

- The following figure summarizes the value and frequency of congestion by transmission path in the real-time market.
- The total value of real-time congestion was $118 million in the third quarter, up 33 percent from the previous quarter and down 18 percent from a year ago.
  - ✓ The increase from the previous quarter reflected substantially increased load levels and more frequent TSAs.
  - ✓ The decrease from the previous year was largely due to decreased congestion in NYC that resulted from generation additions and more efficient congestion management (i.e., less frequent use of simplified interface constraints).
- Real-time congestion occurred mostly in the following areas in the third quarter:
  - ✓ *Capital to Hudson Valley* (48 percent):
    - – The majority occurred on days with some combination of TSAs, unexpectedly high load, and multiple transmission or generation outages.
    - – A large New England resource returned to service after a seven-month-long outage in last year, resulting in increased loop flows on transmission paths from Capital to Hudson Valley and contributing to the increased congestion from last year.
  - ✓ *NYC lines and simplified interface constraints* (26 percent):
    - – Congestion into the Greenwood load pocket accounted for 80 percent.

Real-Time Congestion by Transmission Path



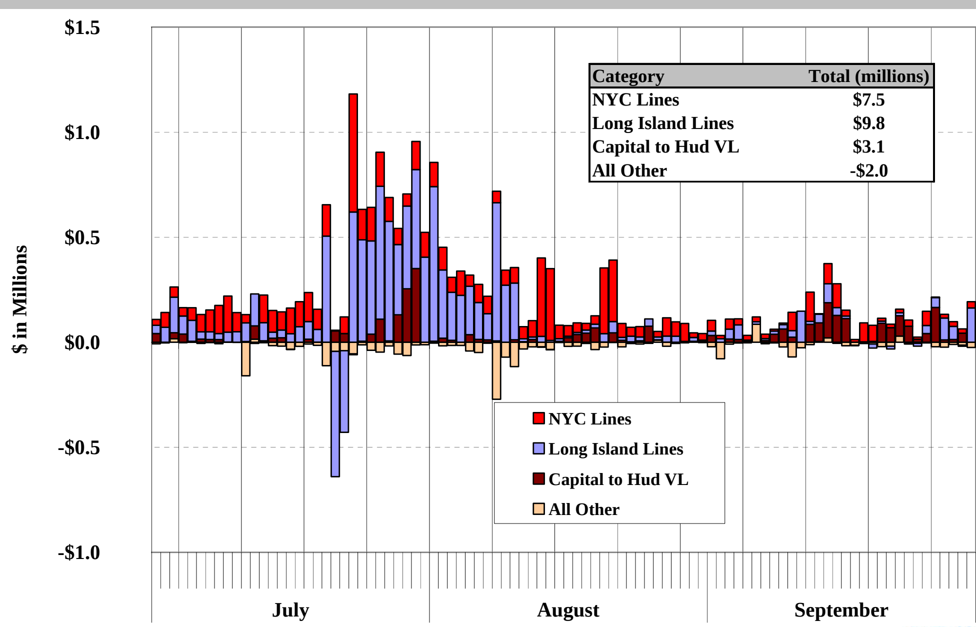
	Congestion Value ($ In Millions)						
Quarter	Central to East	Capital to Hud VL	NYC Lines	NYC Interfaces	Long Island	External	All Other
2011Q3	$1	$57	$27	$3	$15	$11	$4
2011Q2	$3	$34	$31	$0	$11	$8	$2
2010Q3	$2	$48	$46	$19	$17	$11	$2

Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily day-ahead congestion revenue shortfalls by transmission path or facility in the third quarter of 2011.
  - ✓ Negative values indicating congestion surpluses that arise from higher day-ahead utilization of interfaces than in the TCC auction.
- Day-ahead congestion revenue shortfalls can result from modeling assumption differences between the TCC auction and the day-ahead market.
  - ✓ This includes assumptions related to PAR schedules, loop flows, and transmission outages. (Outage-related shortfalls are allocated to the responsible TO.)
- Long Island lines accounted for 53 percent of total shortfalls in the third quarter.
  - ✓ This was due primarily to outages that reduced transfer capability into Long Island from upstate (e.g., Sprainbrook-East Garden City) from mid July to early August.
  - ✓ A surplus of $4 million accrued on three days (July 21 to 23) on two lines (e.g., Elwood-Greenlawn & Northport-Pilgrim), offsetting the shortfalls on other days.
- NYC facilities accounted for 41 percent of shortfalls in the third quarter.
  - ✓ Lines into the Greenwood load pocket accounted for 82 percent of these shortfalls.

POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls



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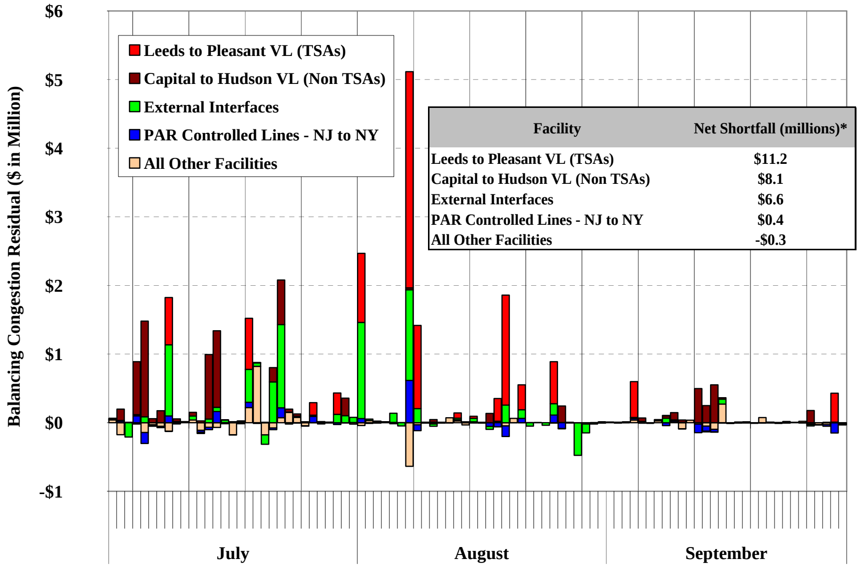
Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the third quarter of 2011.
  - ✓ Negative values indicate balancing congestion surpluses that arise from increased real-time utilization of an interface from the day-ahead market.
- Balancing congestion revenue shortfalls can occur when the transfers across a congested interface fall between day-ahead and real-time due to:
  - ✓ Deratings and outages of the lines that make up the constrained interface;
  - ✓ Unexpected or forced outages of facilities that alter the distribution of flows across other constrained facilities; and
  - ✓ Unutilized transfer capability that can arise from Hybrid Pricing, which treats physically inflexible GTs as flexible in the pricing logic.
- Balancing congestion shortfalls can also occur when modeling assumptions in the day-ahead to real-time markets are inconsistent, including assumptions regarding:
  - ✓ Unscheduled loop flows across constrained interfaces; and
  - ✓ Flows across PAR-controlled lines.

Balancing Congestion Shortfalls

- Capital to Hudson Valley lines accounted for the largest share (74 percent) of the balancing congestion shortfalls in the third quarter.
  - ✓ 58 percent of this share accrued on the Leeds-Pleasant Valley line when TSA events were called.
    - – Transmission and generation outages and unexpected high load levels also contributed to large shortfalls on several days.
  - ✓ 42 percent accrued on several days in July and mid-September when line outages reduced the transfer capability into Southeast New York. For example,
    - – The Roseton-Hurley Avenue line was out of service on July 4 and 5, which led to more than $2 million of shortfalls on the two days.
    - – The Athens-Pleasant Valley line went out of service on July 13 and 14, which also led to over $2 million of shortfalls on the two days.
- External Interfaces accounted for 25 percent of the shortfalls.
  - ✓ The shortfalls often arise when import capability is reduced below the day-ahead scheduled level in order to manage internal congestion.
  - ✓ The majority of these shortfalls in the third quarter were associated with operations during TSAs, since imports are sometimes limited in order to manage congestion on the Leeds-Pleasant Valley line.

Balancing Congestion Shortfalls



Facility	Net Shortfall (millions)*
Leeds to Pleasant VL (TSAs)	$11.2
Capital to Hudson VL (Non TSAs)	$8.1
External Interfaces	$6.6
PAR Controlled Lines - NJ to NY	$0.4
All Other Facilities	-$0.3

Note: These slightly over-estimate shortfalls since they are partly based on real-time schedules rather than metered values and they do not reflect the effects of price corrections.

POTOMAC ECONOMICS

Uplift Costs and Supplemental Commitments

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Uplift Costs from Guarantee Payments

- The next two figures summarize uplift charges resulting from guarantee payments in the following seven categories.
- Three categories of non-local reliability uplift are allocated to all LSEs:
  - ✓ Day Ahead: Primarily for units committed economically that don't recoup their as-offered start-up and min generation costs from LBMPs.
  - ✓ Real Time: For external transactions and gas turbines that are scheduled economically but don't recoup their as-offered costs from LBMPs, for SRE commitments and OOM dispatch that are done for bulk power system reliability.
  - ✓ Day Ahead Margin Assurance Payment ("DAMAP"): For payments to cover losses for generators dispatched below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.
- Four categories of local reliability uplift are allocated to the local TO:
  - ✓ Day Ahead: From Local Reliability Requirements ("LRR") and Day-Ahead Reliability Unit ("DARU") commitments.
  - ✓ Real Time: From Supplemental Resource Evaluation ("SRE") commitments and Out-of-Merit ("OOM") dispatched units.
  - ✓ Minimum Oil Burn Program: Covers spread between oil and gas prices when generators burn oil to satisfy NYC gas pipeline contingency reliability criteria.
  - ✓ DAMAP: For units that are dispatched OOM for local reliability reasons.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments

- The following figure shows the seven categories of uplift charges on a daily basis in the third quarter of 2011.
- Guarantee payment uplift was $48 million in the third quarter, up 50 percent from the previous quarter.
  - ✓ The increase was largely associated with the increase in local real-time uplift, most of which was related to OOM dispatch by the local TO on Long Island to manage congestion on the East End.
  - ✓ NYISO's mitigation consultations are on-going for the third quarter, so guarantee payments may increase further once these are fully reflected.
- Guarantee payment uplift decreased 22 percent from the third quarter of 2010 for reasons that are discussed later in this section.
- Guarantee payment uplift rose notably on high load days, averaging $1.2 million on 14 days when load exceeded 28 GW and just $0.4 million on other days.
  - ✓ Payments were due to: high loads that require OOM dispatch on the East End of Long Island (RT Local), payments to Minimum Oil Burn Compensation program units, and DAMAP payments during transient congestion price spikes.
  - ✓ Uplift also rose substantially on two days (August 27 & 28) when Hurricane Irene moved through the area. Large amounts of supplemental commitment and very low energy prices led to increased uplift.

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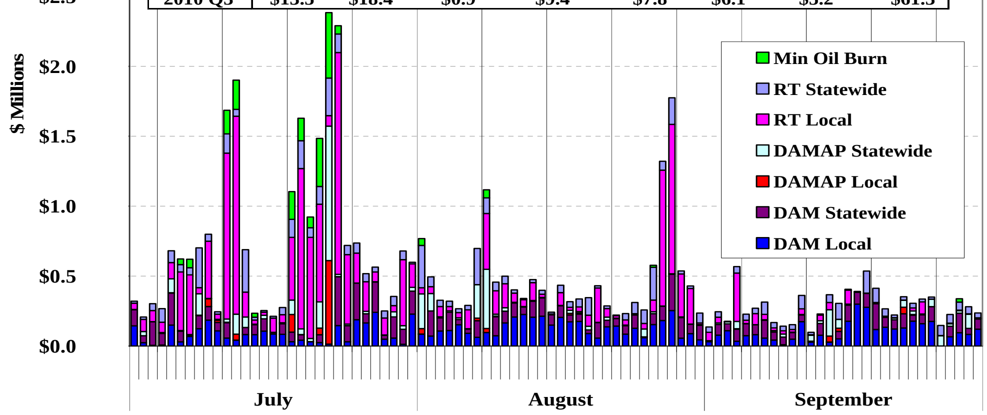
Uplift Costs from Guarantee Payments
Local and Non-Local by Category

Quarter	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2011 Q3	$9.7	$16.9	$1.1	$2.0	$7.7	$6.3	$4.2	$47.9
2011 Q2	$7.7	$6.2	$0.6	$3.9	$6.9	$3.8	$2.8	$31.9
2010 Q3	$13.5	$18.4	$0.9	$9.4	$7.8	$6.1	$5.2	$61.3

Quarterly BPCG By Category (Million $)



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

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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 2011:
  - ✓ The majority was for New York City (51 percent) and West Upstate (28 percent), primarily for DARU and LRR commitments.
- Day-ahead statewide uplift in the third quarter of 2011:
  - ✓ A substantial share (35 percent) went to generators that were committed for local reliability on that day but that were flagged as "economic" in a portion of hours.
  - ✓ The guarantee payments are allocated statewide in hours when the generator is flagged as "economic."
- Real-time local reliability uplift in the third quarter of 2011:
  - ✓ Long Island accounted for 73 percent, primarily to manage local congestion on the East End where some generators do not have a source of natural gas.
- Real-time statewide uplift in the third quarter of 2011:
  - ✓ The majority was for imports (32 percent), Long Island (27 percent), and Western New York (23 percent).

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments by Region

- Overall, guarantee payment uplift fell 22 percent from the third quarter of 2010.
  - ✓ However, mitigation consultations are on-going for the third quarter, so guarantee payments will increase once these are fully reflected.
- New York City accounted for the majority of the reduction in uplift from the third quarter of 2010.
  - ✓ Day-ahead local uplift fell to $5 million from $10 million in third quarter of 2010.
  - ✓ Min Oil Burn Compensation program payments fell to $2 million from $9.5 million.
  - ✓ These reductions were partly the result of the new generating capacity in New York City and improved generator reference level accuracy.
- In Long Island, day-ahead local and statewide uplift increased from $1.2 million in the third quarter of 2010 to $4.3 million in the third quarter of 2011, due to:
  - ✓ More frequent DARU commitments partly due to transmission outages; and
  - ✓ Higher oil prices that led bigger difference in between oil and natural prices.
- In western NY, real-time local uplift decreased from $2 million in the third quarter of 2010 to $1 million in the third quarter of 2011, partly due to improved generator reference level accuracy.

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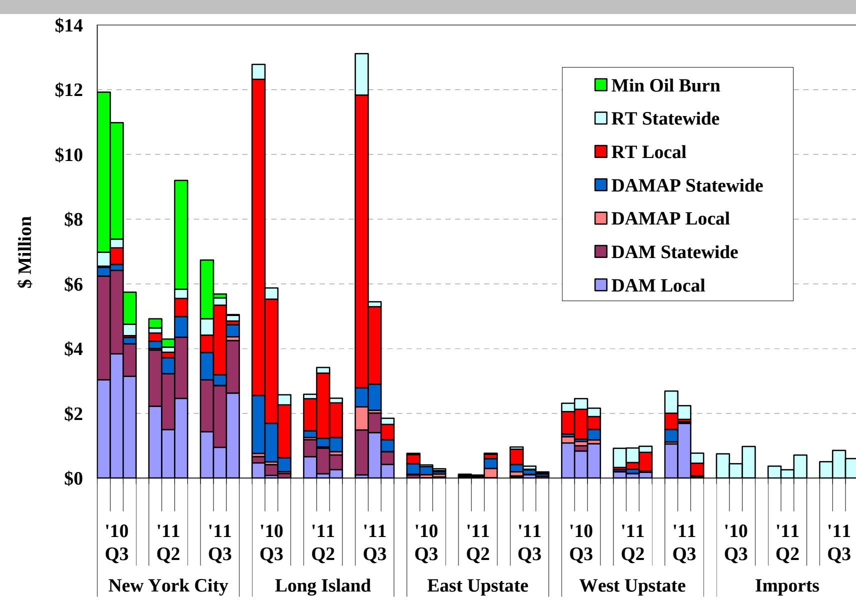
Uplift Costs from Guarantee Payments
By Category and Region



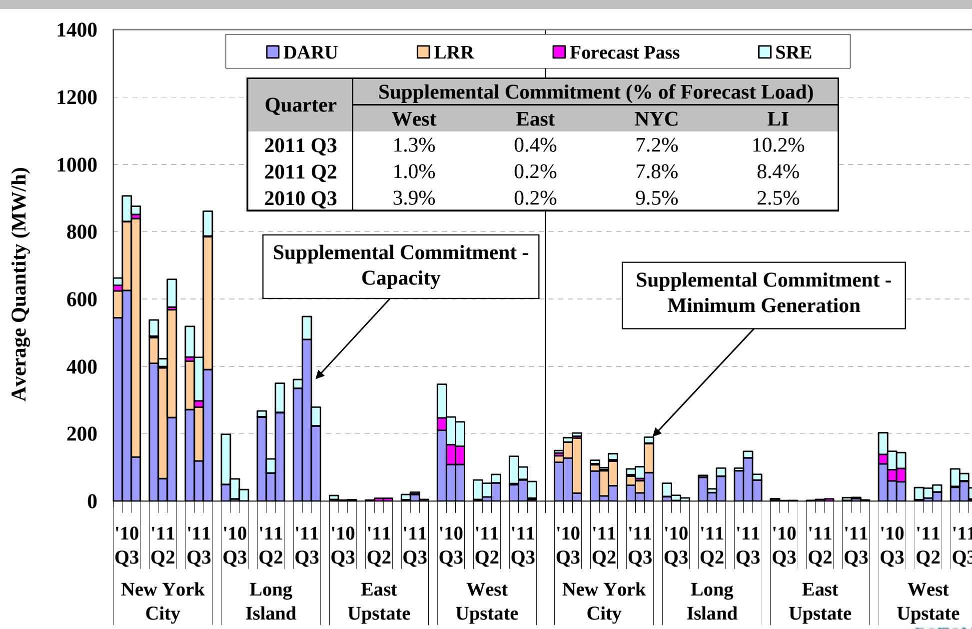
Note: These data are based on information available at the reporting time and do not include some manual adjustments to the mitigation of guarantee payments, hence they can be different from final settlements.

POTOMAC ECONOMICS

Supplemental Commitment for Reliability

- The following figure shows the monthly quantities of capacity (left) and minimum generation (right) committed for reliability by type of commitment and region.
- Reliability commitment in Long Island rose considerably from a year ago.
  - ✓ Committed capacity averaged roughly 395 MW in the third quarter of 2011, up 295 MW from the third quarter of 2010.
  - ✓ The minimum generation level of these units averaged 110 MW, up 80 MW from the third quarter of 2010.
  - ✓ DARU commitment rose from a year ago, partly because units that are required to burn a gas-oil blend for reliability are economic less often due to higher oil prices.
- Reliability commitment in New York City fell from the third quarter of 2010.
  - ✓ Committed capacity averaged 600 MW, down 26 percent from a year ago.
  - ✓ The minimum generation level of these averaged 130 MW, down 28 percent from the third quarter of 2010.
  - ✓ The decrease in reliability commitment was due to new units entering in the City, and to units needed for reliability being committed economically more often.
- DARU commitment in western New York fell from a year ago partly due to fewer transmission outages.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2011 Q3	1.3%	0.4%	7.2%	10.2%
2011 Q2	1.0%	0.2%	7.8%	8.4%
2010 Q3	3.9%	0.2%	9.5%	2.5%

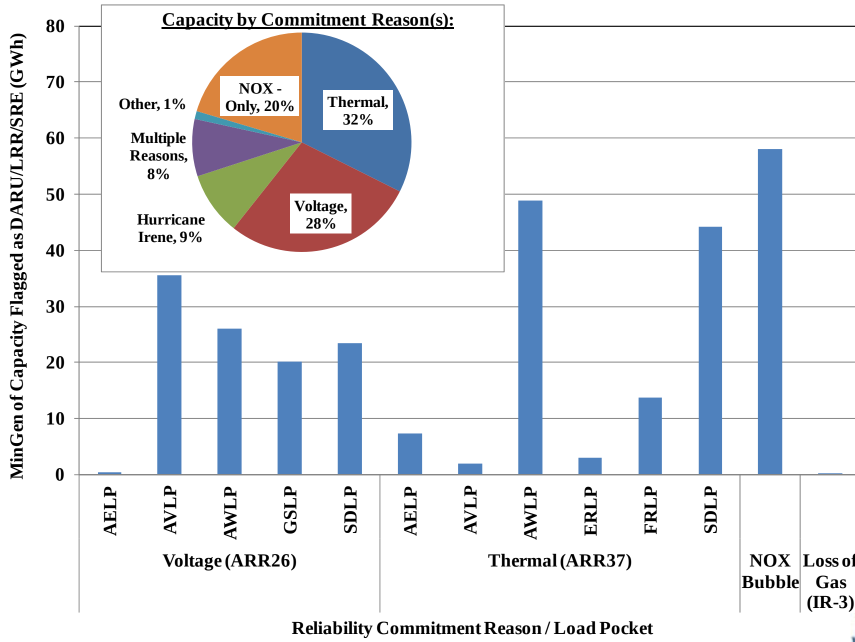
Supplemental Commitment for Reliability in NYC

- The following figure evaluates the reasons for reliability commitments in the third quarter of 2011 in New York City where most occur.
- Based on our review of the reliability commitment logs and LRR constraint information, each hour that was flagged as DARU, LRR, or SRE was categorized according to one of the following reliability reasons:
  - ✓ NOX Only – If needed for NOX bubble and no other reason.
  - ✓ Voltage – If needed for ARR 26 and no other reason except NOX.
  - ✓ Thermal – If needed for ARR 37 and no other reason except NOX.
  - ✓ Loss of Gas – If needed for IR-3 and no other reason except NOX.
  - ✓ Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, IR-3. The capacity is shown for each separate reason in the bar chart.
- For voltage and thermal constraints, the capacity is shown by the load pocket that was secured (AELP = Ast East, AWLP = Ast West/Queens, AVLP = Ast West/ Queens/Vernon, ERLP = East River, FRLP = Freshkills, GSLP = Greenwd/Staten Is, & SDLP = Sprainbr/Dunwoodie).
- A unit is considered to be committed for an LRR constraint if the constraint would be violated without the unit's capacity.

Supplemental Commitment for Reliability in NYC

- The reliability requirements that accounted for the most MWhs of capacity were:
  - ✓ NOX bubble requirements – These require the operation of a steam turbine unit in order to reduce the overall NOX emission rate from a portfolio containing higher-emitting gas turbine units.
  - ✓ Sprainbrook/Dunwoodie thermal requirements – These ensure 345 kV facilities in New York City will not be overloaded if the largest two generation or transmission contingencies were to occur.
  - ✓ Astoria West/Queensbridge thermal and voltage requirements – These ensure facilities into this pocket will not be overloaded if the largest two generation or transmission contingencies were to occur.
- Steam turbine units were flagged for NOX-only in 589 unit-hours during the third quarter.
  - ✓ Unloaded capacity was available on units in close proximity with lower NOX emissions that could have replaced 73 percent of the production from these steam units in these hours.
  - ✓ It is likely that the unloaded capacity on these more efficient and lower NOX-emitting resources would have been scheduled but for the steam turbine commitments needed to satisfy the NOX bubble requirements.

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



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Capacity Market

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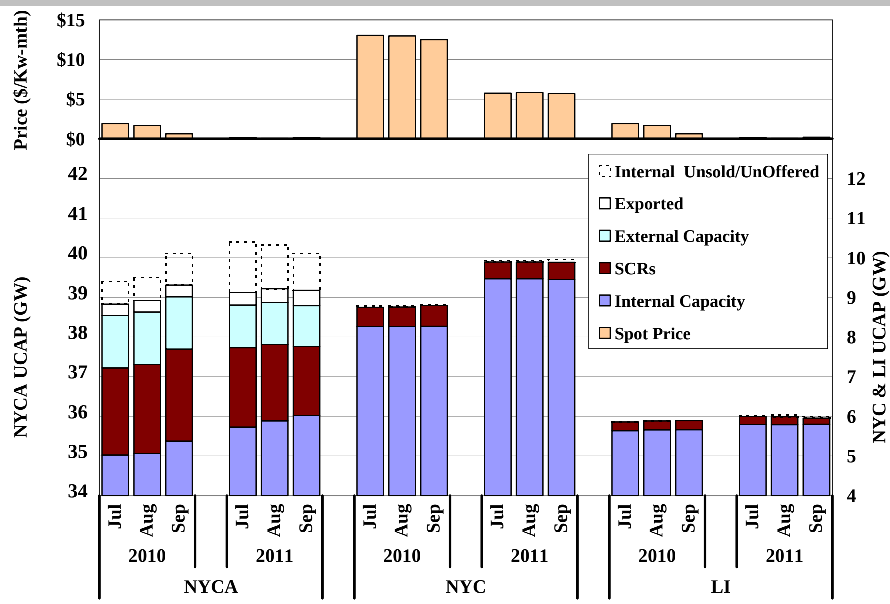
Capacity Market Results

- The following figure summarizes available and scheduled UCAP resources and the clearing prices in each capacity zone.
- In New York City, UCAP spot prices fell to an average of $5.77/kW-month in the this quarter, down 55 percent from the third quarter of 2010, due primarily to:
  - ✓ The addition of a new 550 MW facility; and
  - ✓ The decreased Local Capacity Requirement due to a 211 MW reduction in the peak load forecast for NYC in summer 2011.
    - This was, however, partly offset by an increase in the Local Capacity Requirement from 80 percent to 81 percent over the same period.
- Overall, UCAP sales in NYC rose significantly from last year, due partly to an improvement in forced outage rates from roughly 11 percent to 5 percent.
  - ✓ However, this did not significantly reduce prices because an improvement in forced outage rates triggers an increase in the UCAP requirement.
- The figure shows that virtually all internal capacity has been sold in each month so withholding of supply has not been a concern in New York City.

Capacity Market Results

- In the Rest of State and Long Island, UCAP spot prices fell to an average of $0.13/kW-month in the third quarter, down from $1.41/kW-month in the third quarter of 2010.
  - ✓ A substantial amount of capacity was not sold in the third quarter of 2011, likely due to the relatively large prevailing capacity surplus and the low clearing prices.
  - ✓ Long Island and Rest of State clearing prices have been equal during the two quarters except that in September 2011 Long Island price was slightly higher ($0.02/kW-month) than the ROS price.
- Clearing prices outside New York City were affected by the following factors:
  - ✓ Increased sales from internal capacity from some new and existing facilities, which have contributed to lower clearing prices since the second quarter of 2011.
  - ✓ The ICAP requirement for NYCA fell nearly 1200 MW over the period, because from the 2010/11 capability year to 2011/2012 capability year:
    - The summer peak load forecast for NYCA fell 313 MW; and
    - The installed capacity requirement fell from 118 percent to 115.5 percent.
  - ✓ These factors were partly offset by: (i) a decrease of 360 MW in SCR sales; and (ii) a decrease of 260 MW in net imports of UCAP.

Capacity Market Results



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

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