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

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Highlights and Market Summary

- This report presents the NYISO market outcomes in the first quarter of 2011.
- The markets performed competitively and variations in wholesale market prices were driven primarily by changes in demand, fuel prices, and supply availability.
- Real-time energy prices averaged roughly $56/MWh statewide, up 13 percent from the previous quarter and 8 percent from the first quarter of 2010 primarily because:
  - ✓ Average natural gas prices rose 23 percent from the previous quarter and 5 percent from a year ago; and
  - ✓ Average load rose 6 percent from the prior quarter and 2 percent from a year ago.
- Congestion increased considerably from West to East (primarily across the Dysinger East and the Central-East interfaces) in the first quarter.
  - ✓ This reflects the effects of higher fuel prices (which increased re-dispatch costs particularly in the east) and higher load levels.
  - ✓ Outages in western New York in late-January that substantially reduced the transfer capability from West to East. This also contributed to higher TCC shortfalls and balancing congestion shortfalls.
  - ✓ Clockwise loop flows increased from the previous quarter, but they fell from the first quarter of 2010 due to the expanded use of the TLR procedure.

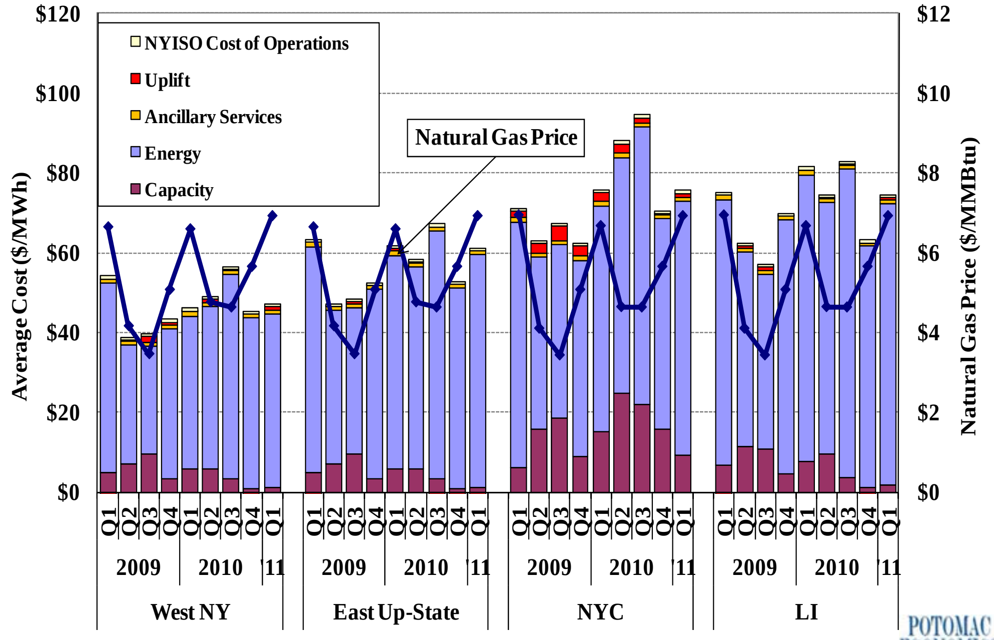
Highlights and Market Summary

- UCAP spot prices averaged $3.71/kW-month in NYC and $0.48/kW-month in the rest of the state in this quarter, down notably from the first quarter of 2010.
  - ✓ The decrease was due largely to increased sales from new resources (including UDRs) and reduced capacity requirements due to a lower peak load forecast.
- Uplift charges rose considerably in the first quarter of 2011 from the previous quarter, but fell modestly from the first quarter of 2010.
  - ✓ It is typical for uplift charges to increase from the fourth quarter to the first quarter due to higher natural gas prices and higher load levels caused by cold weather.
  - ✓ Day-ahead congestion shortfalls were $43 million in the first quarter, partly due to differences in modeling assumptions between the TCC and day-ahead markets for the NJ-to-NY PAR-controlled lines and for the Central East interface.
  - ✓ Real-time congestion shortfalls were $13 million in the first quarter due to differences between the assumptions in the day-ahead market for the NJ-to-NY PAR-controlled lines and their actual real-time operation and to transmission outages on several transmission paths.
  - ✓ Guarantee payment uplift totaled $50 million in the first quarter, down 15 percent from the first quarter of 2010 as less capacity was committed for reliability in NYC and LBMPs were higher relative to the offers of units needed to satisfy the reliability requirements.

All-In Energy Price

- To summarize prices and costs in the New York markets, the following figure shows the “all-in” price that represents the total cost of serving load, including:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component based on spot capacity prices times the capacity obligations in each area, divided by the real-time energy consumption in the area.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges divided by the real-time energy consumption in the relevant area.
  - ✓ The figure also includes a natural gas price trend given its importance as an input.
- All-in prices were generally consistent with the first quarter of 2010.
  - ✓ Energy prices rose more than 10 percent in Upstate and New York City from the first quarter of 2010, reflecting increased fuel prices and increased load levels.
  - ✓ This was largely offset by the decrease in capacity prices, which fell 39 percent in NYC and 77 percent elsewhere, due primarily to several capacity additions.
  - ✓ However, energy prices actual fell slightly in Long Island because the prices in the first quarter of 2010 were affected by the extended outage of a major line into Long Island that was in service in the first quarter of 2011.
- Relative to the prior quarter, all-in prices rose 4 to 18 percent due primarily to increased fuel prices (e.g., gas prices up 23 percent) and load levels.

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 East New York than in West 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.
- The average implied heat rate rose 6 percent in eastern New York and 9 percent in western New York from the first quarter of 2010 to the first quarter of 2011. The following factors contributed to the modest increases:
  - ✓ Load levels increased approximately 2 percent from a year ago, resulting in more frequent dispatch of high-cost generation, especially in the east.
  - ✓ Oil prices rose sharply (37 percent for #2 and 45 percent for #6), raising energy prices more than gas prices when oil units set prices (periods of tight gas supply).
  - ✓ Production by hydro-electric generation and nuclear generation fell by an average of nearly 550 MW, increasing implied heat rates, particularly in the west.
  - ✓ Congestion from West to East across the Dysinger East interface increased substantially from a year ago due to line outages, raising prices in the east.

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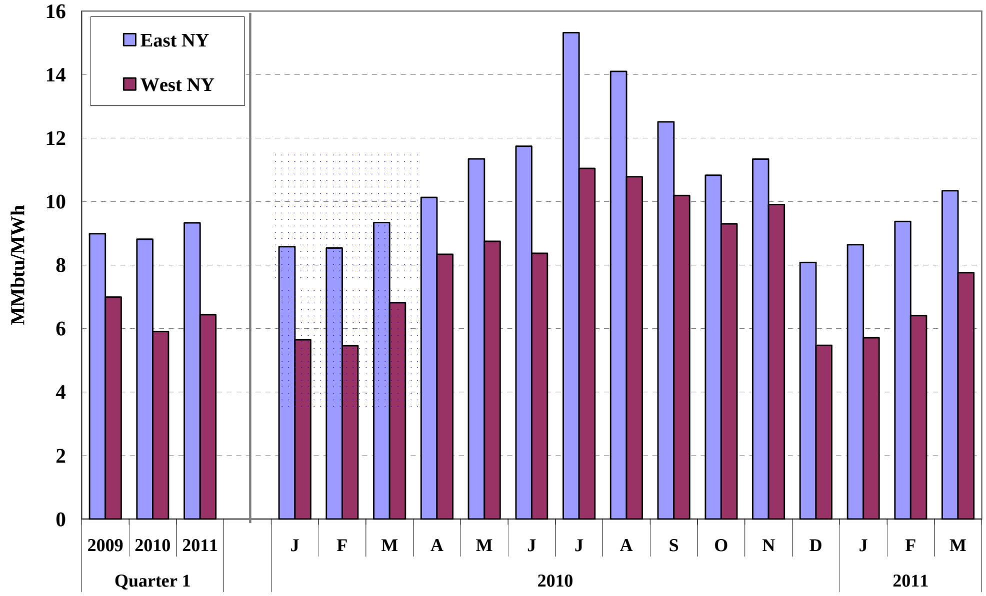
Implied Heat Rate by Region

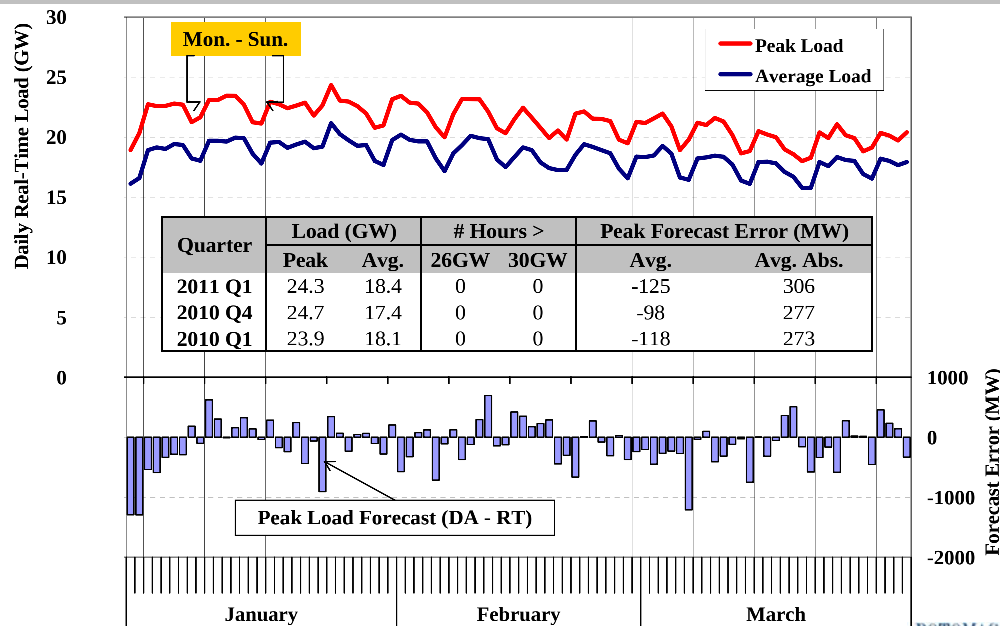


Note: Implied heat rates are for natural gas units and are based on day-ahead prices.

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 first quarter.
  - ✓ The table compares key statistics for the first quarter of 2011 to the previous quarter and the first quarter of 2010.
- On average, load increased 6 percent from the previous quarter and 2 percent from the first quarter of 2010.
  - ✓ Load peaked on January 24th at 24.3 GW, down 2 percent from the peak in the previous quarter and up 2 percent from the peak load in the first quarter of 2010.
  - ✓ Overall, load trended down from January to March as expected.
- The figure also shows that peak load forecasting was generally good, although sustained patterns of errors over a number of days occurred a few times during the quarter.
  - ✓ On average, actual loads ran over the peak forecast by 125 MW, comparable to the average error in prior quarters.
  - ✓ The daily peak load forecast had an error greater than 500 MW on 15 days and an error greater than 1 GW on three days.

Load Forecast and Actual Load

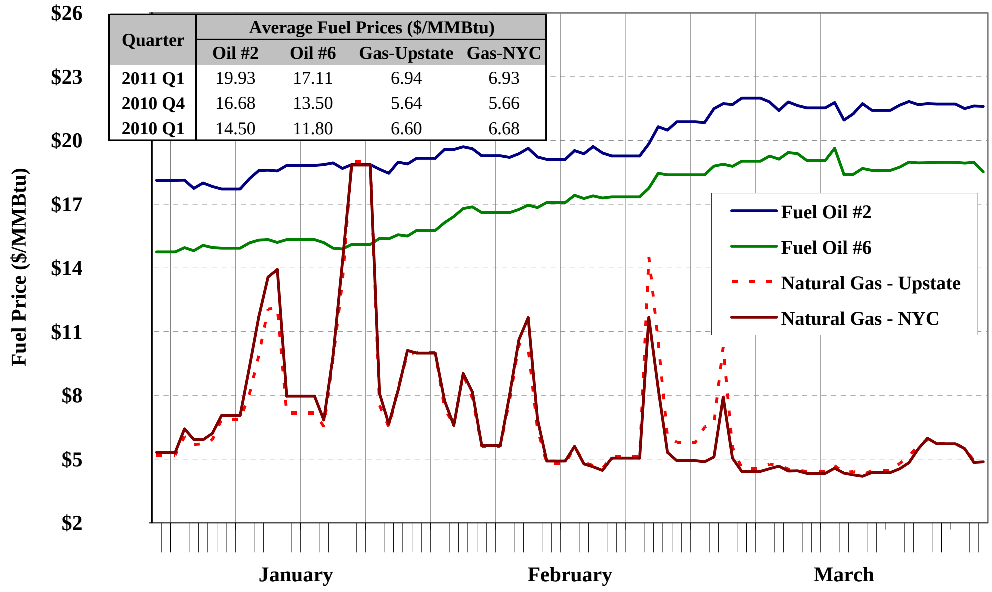


Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2011 Q1	24.3	18.4	0	0	-125	306
2010 Q4	24.7	17.4	0	0	-98	277
2010 Q1	23.9	18.1	0	0	-118	273

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 were volatile, averaging nearly $7/MMbtu -- up approximately 23 percent from the previous quarter and 5 percent from the first quarter of 2010.
  - ✓ Natural gas prices ranged between $4 and $8/MMbtu during most of the quarter but spiked as high as $19/MMBtu on several days due to extreme cold weather in January and following the TransCanada pipeline explosion on February 19.
  - ✓ During these events, there was price separation of up to 19 percent between the Transco Zone 6 (New York City) and Iroquois Zone 2 (Upstate NY).
  - ✓ Natural gas prices trended down during the quarter, falling 43 percent from roughly $9/MMBtu in January to slightly more than $5/MMBtu in March.
- Fuel oil prices rose steadily in the first quarter of 2011.
  - ✓ Prices rose 19 percent for #2 oil and 27 percent for #6 oil from the fourth quarter, making them 37 and 45 percent higher than in first quarter of 2010, respectively.
- Natural gas was usually much less expensive than fuel oil, but some generators still burn oil for reliability reasons or due to difficulties obtaining natural gas.

Natural Gas and Oil Prices



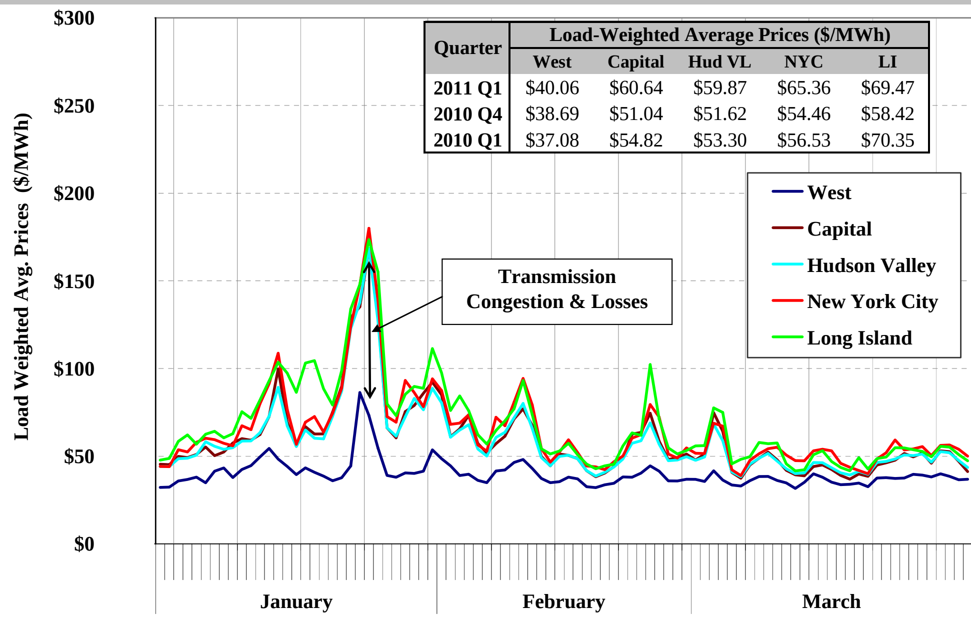
Quarter	Average Fuel Prices ($/MMBtu)			
	Oil #2	Oil #6	Gas-Upstate	Gas-NYC
2011 Q1	19.93	17.11	6.94	6.93
2010 Q4	16.68	13.50	5.64	5.66
2010 Q1	14.50	11.80	6.60	6.68

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 first quarter of 2011.
- Prices in the day-ahead market should reflect probability-weighted expectations of real-time market conditions.
- Price differences between the West Zone and Capital Zone rose considerably from the previous quarter, driven primarily by increased congestion across the Central-East interface and the Dysinger East interface.
  - ✓ This was primarily attributable to the lengthy outages of two Rochester-to-Pannell lines in January and February, which greatly reduced the transfer capability from West to East.
- High natural gas prices contributed to the increased congestion during the quarter.
  - ✓ The largest congestion-related price differences occurred during periods of volatile natural gas prices in January and February.
  - ✓ The decline in natural gas prices in March led to smaller congestion-related price differences between the West Zone and Capital Zone.
- The average day-ahead price was highest in Long Island due to elevated prices there on several days.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2011 Q1	$40.06	$60.64	$59.87	$65.36	$69.47
2010 Q4	$38.69	$51.04	$51.62	$54.46	$58.42
2010 Q1	$37.08	$54.82	$53.30	$56.53	$70.35

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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 first quarter.
  - ✓ Prices are more volatile in the real-time market than in the day-ahead market.
- Real-time prices increased 15 to 20 percent in eastern New York from the previous quarter, due primarily to:
  - ✓ Higher fuel prices and increased load levels; and
  - ✓ Increased congestion across the Central-East interface and the Dysinger East interface, driven largely by reduced transfer capability due to transmission outages.
    - – Daily average real-time price differences between the West Zone and the Capital Zone spiked over $30/MWh on 15 days in this quarter.
- Real-time prices rose modestly (6 to 12 percent) in most areas from the first quarter of 2010, reflecting slightly higher fuel prices and load levels.
  - ✓ The exception was Long Island, where real-time prices fell 2 percent from the previous year because the prices in the first quarter of 2010 were affected by the extended outage of a major line that was in service in the first quarter of 2011.
- Real-time prices spiked on January 24 when load peaked for the quarter at 24.3 GW and day-ahead natural gas prices reach $19/MMbtu.

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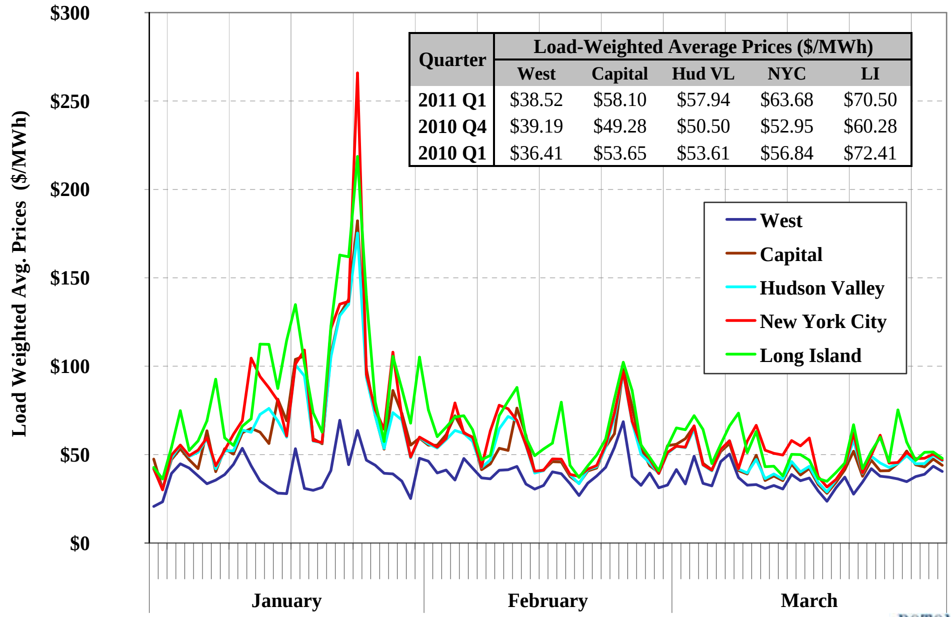
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2011 Q1	$38.52	$58.10	$57.94	$63.68	$70.50
2010 Q4	$39.19	$49.28	$50.50	$52.95	$60.28
2010 Q1	$36.41	$53.65	$53.61	$56.84	$72.41

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Convergence Between Day-Ahead and Real-Time Prices

- The next analysis evaluates day-ahead and real-time price convergence.
  - ✓ Convergence is important because the day-ahead market facilitates the daily commitment of generation and scheduling of natural gas, determines the obligations to TCC holders, and accounts for most energy settlements.
- The figure shows the difference between average day-ahead prices and the average real-time prices on each day in the first quarter of 2011.
  - ✓ This is shown separately for five zones to account for changes in the pattern of congestion from the day-ahead to the real-time.
- The largest price differences occurred on January 24 in New York City and Long Island, due to severe real-time conditions that produced price volatility, including:
  - ✓ Line outages limiting transfers from western New York to eastern areas;
  - ✓ Unusually cold weather that caused several units in downstate areas to have trouble starting up in real-time; and
  - ✓ Short natural gas supplies that limited the availability of fuel to some units and that lead other units to operate of fuel oil.

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Convergence Between Day-Ahead and Real-Time Prices

- Large differences between average day-ahead prices and average real-time prices occurred on individual days due to unexpected factors.
  - ✓ Convergence should be measured over longer timeframes, since random factors can cause convergence on individual days to be poor.
  - ✓ The table shows the average price convergence over the entire quarter.
- Convergence between day-ahead and real-time prices was slightly worse in most locations in the first quarter of 2011 compared to the previous quarter.
  - ✓ This was most evident in the West Zone where the difference rose from -1 percent in the fourth quarter of 2010 to 4 percent in the first quarter of 2011.
  - ✓ The differences in other areas rose from 2 to 3 percent in the fourth quarter of 2010 to 3 to 4 percent in the first quarter of 2011.
  - ✓ The following factors contributed to reduced convergence in this quarter:
    - – Volatile natural gas prices;
    - – Unusually cold weather that caused operational issues for some units on several days; and
    - – Reduced west-to-east transfer capability due to transmission outages. This led to tighter conditions in eastern New York not fully reflected in the day-ahead market.

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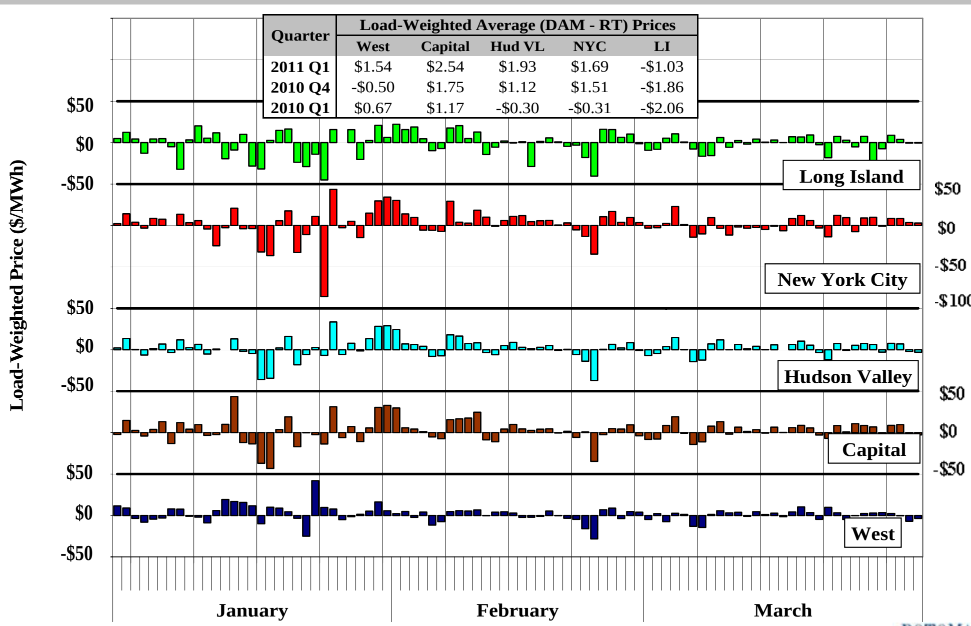
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2011 Q1	$1.54	$2.54	$1.93	$1.69	-$1.03
2010 Q4	-$0.50	$1.75	$1.12	$1.51	-$1.86
2010 Q1	$0.67	$1.17	-$0.30	-$0.31	-$2.06



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Day-Ahead and Real-Time Ancillary Services Prices

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

Day-Ahead and Real-Time Ancillary Services Prices

- Reserve prices are relatively consistent from day-to-day in the day-ahead, while reserve prices are much more volatile in the real-time market.
  - ✓ Day-ahead reserves prices are based on suppliers' offers, which depend on expectations of real-time prices and the risks associated with selling reserves in the day-ahead market.
  - ✓ Real-time reserves prices are normally close to $0 due to the excess available reserves from online and quick-start units in most hours.
  - ✓ Real-time prices spike during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Average day-ahead prices 10-minute non-spin reserves in eastern New York and 10-minute spin in eastern and western New York were substantially higher than average real-time reserves prices in the first quarter of 2011.
  - ✓ The day-ahead price premium results partly from the risks that generators perceive from selling in the day-ahead market.
  - ✓ Average day-ahead prices did not rise very significantly on high load days when real-time price spikes were more likely.
- Average day-ahead regulation prices were relatively consistent with real-time 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 547 intervals ($25 demand curve), 60 percent of which occurred during periods with Central-East congestion;
  - ✓ Eastern 10-minute total reserves in 28 intervals ($500 demand curve);
  - ✓ State-wide 10-minute spinning reserves in one interval ($500 demand curve); and
  - ✓ Regulation in 109 intervals ($250 to $300 demand curve).
- Prices for a product include the demand curve value for all requirements that the product can satisfy.
  - ✓ For example, the 10-minute spinning reserve prices in the East reflect 576 intervals of shortage pricing: 547 of eastern 10-minute spin, 28 of eastern 10-minute total reserves, and one of state-wide 10-minute spin.
- Day-ahead and real-time prices for 10-minute spinning and non-spinning reserves in eastern New York rose significantly from the first quarter of 2010.
  - ✓ The amount of 10-minute total reserves that must be held in eastern New York increased from 1,000 MW to 1,200 MW on December 1, 2010 after a reserve sharing agreement with ISO New England was ended.

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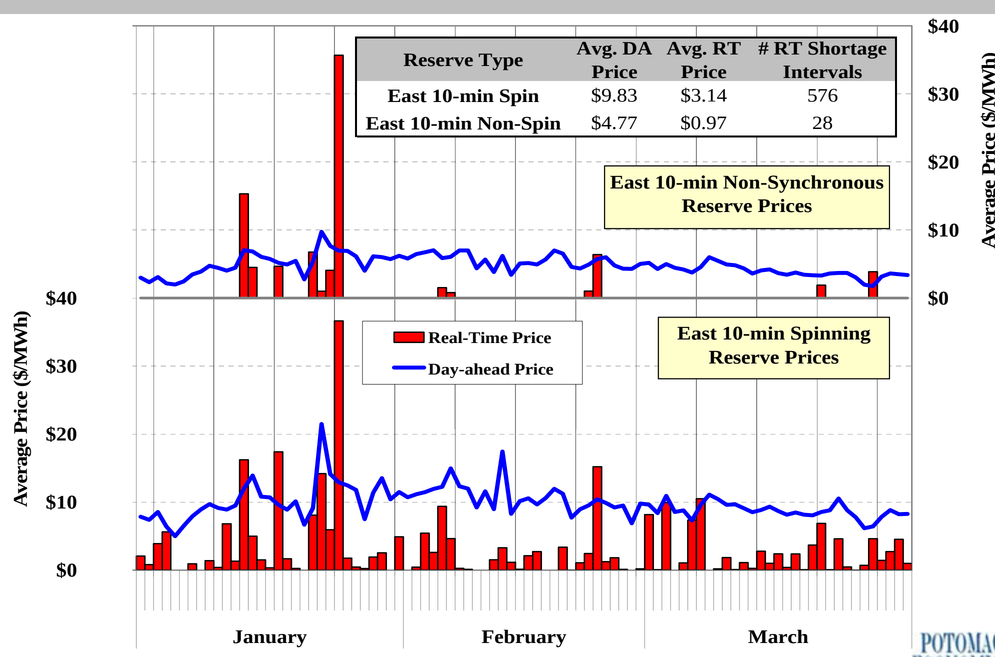
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
East 10-min Spin	$9.83	$3.14	576
East 10-min Non-Spin	$4.77	$0.97	28

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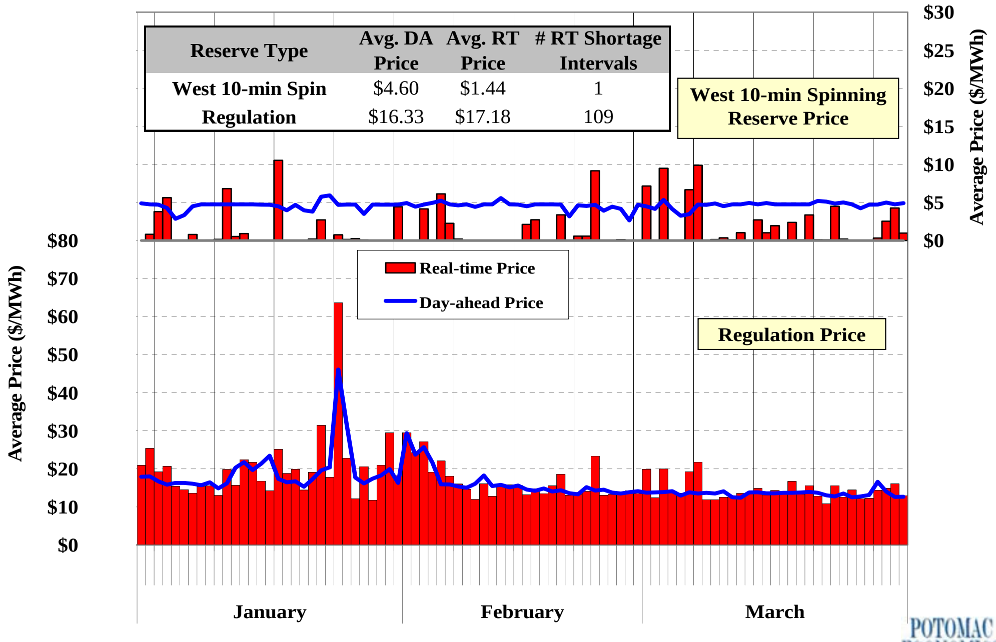
Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



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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 100 percent of actual load in NYCA, slightly higher than in prior quarters.
  - ✓ The increased day-ahead scheduling contributed to the prevailing day-ahead price premiums in the first quarter.
- 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 first quarter.
  - ✓ This pattern was typical and was likely in response to real-time congestion across Central-East, along paths into Southeast NY, and into NYC and Long Island.
- The over- and under-scheduling patterns generally improve convergence between day-ahead and real-time prices in most areas.
  - ✓ For example, Capital zone was the most under-scheduled area and yet it exhibited a large day-ahead price premium that would have been even larger if it were fully scheduled.

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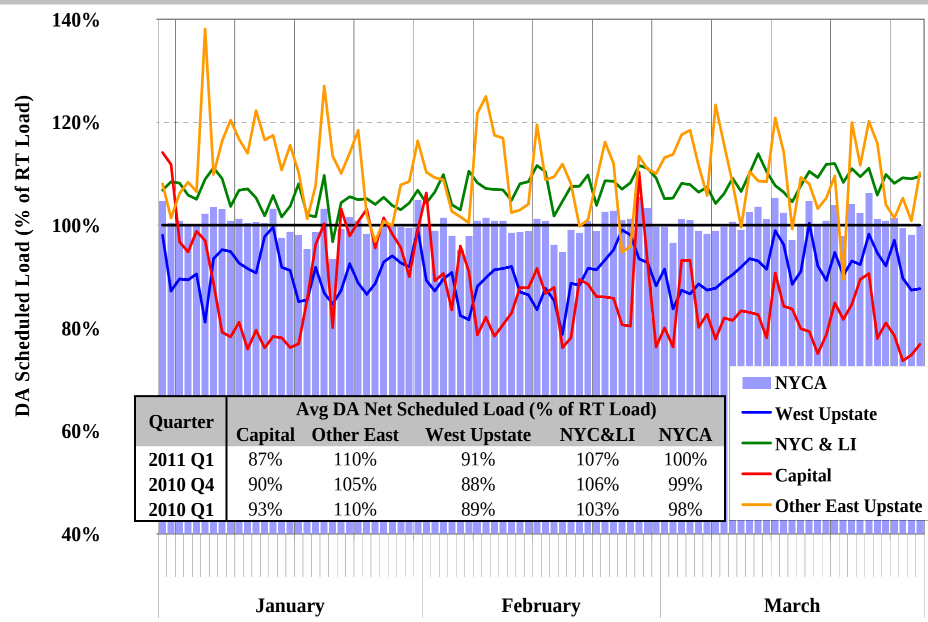
Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour



Quarter	Avg DA Net Scheduled Load (% of RT Load)				
	Capital	Other East	West Upstate	NYC&LI	NYCA
2011 Q1	87%	110%	91%	107%	100%
2010 Q4	90%	105%	88%	106%	99%
2010 Q1	93%	110%	89%	103%	98%

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Virtual Trading Activity

- The following two figures summarize virtual trading activity in New York.
- The first figure shows monthly average bids/offers and scheduled quantities, and profitability for virtual transactions in each month over the past two years.
  - ✓ In each of the past 24 months, 1.2 to 2.0 GW of virtual load and 1.5 to 2.6 GW of virtual supply have been consistently scheduled in the day-ahead market.
  - ✓ In aggregate, virtual load and supply have generally been profitable over the period, indicating that they typically improved convergence between day-ahead and real-time prices.
  - ✓ However, the profits and losses of virtual load and supply have varied widely from month-to-month, reflecting the difficulty of predicting volatile real-time prices.
- The table below the figure shows a screen for relatively large profits (which may indicate modeling inconsistencies) or losses (which may indicate potential manipulation of the day-ahead market).
  - ✓ The table shows that the quantity of transactions generating substantial profits or losses in the first quarter of 2011 was low.
  - ✓ The transactions with notable profits or losses were primarily associated with real-time price volatility and do not raise manipulation concerns.

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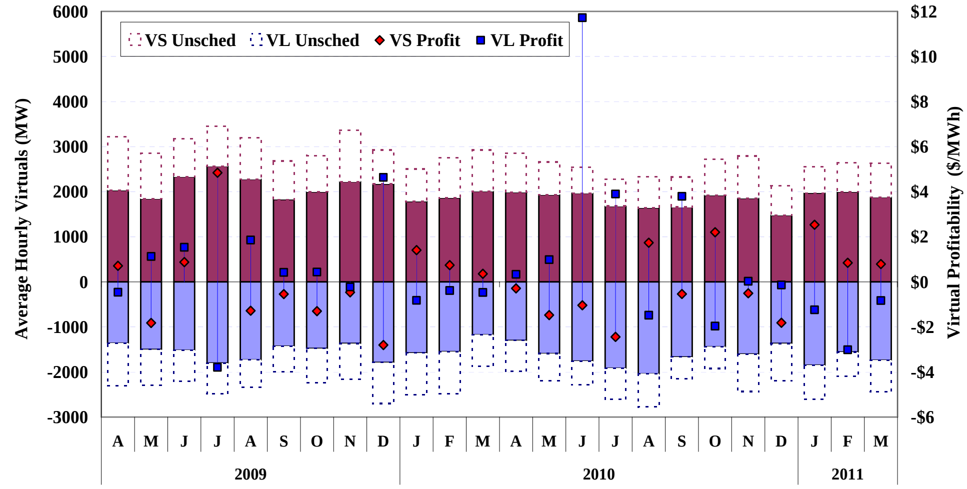
Virtual Trading Volumes and Profitability

April 2009 to March 2011



		A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M
Profit > 50% of Avg. Zone Price	MW	270	271	420	514	293	235	315	239	573	380	324	240	122	181	285	205	176	162	117	135	221	446	193	161
	%	8%	8%	11%	12%	7%	7%	9%	7%	14%	11%	10%	8%	4%	5%	8%	6%	5%	5%	3%	4%	8%	12%	5%	4%
Loss > 50% of Avg. Zone Price	MW	249	281	384	611	441	244	369	253	578	347	284	201	112	211	241	300	205	115	95	131	273	401	244	133
	%	7%	8%	10%	14%	11%	7%	11%	7%	15%	10%	8%	6%	3%	6%	6%	8%	6%	3%	3%	4%	10%	11%	7%	4%

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Virtual Trading Activity

- The second figure summarizes virtual trading by geographic region. The eleven zones are broken into six geographic regions based on typical congestion patterns.
  - ✓ Zone D (the North Zone) is shown separately because transmission constraints frequently affect the value of power in Zone D.
  - ✓ Zone F (the Capital Zone) is shown separately because it is constrained from western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley.
  - ✓ Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas.
- A large number of market participants regularly submit virtual bids and offers.
  - ✓ On average, 11 or more participants submitted virtual trades in each region and 33 participants submitted virtual trades throughout the state.
- There were substantial net virtual load purchases downstate and net virtual supply sales upstate in the first quarter of 2011, consistent with prior periods.
  - ✓ Virtual supply netted a $6 million profit in the first quarter while virtual load netted a loss of a similar amount, due to the prevailing day-ahead price premiums in most regions.

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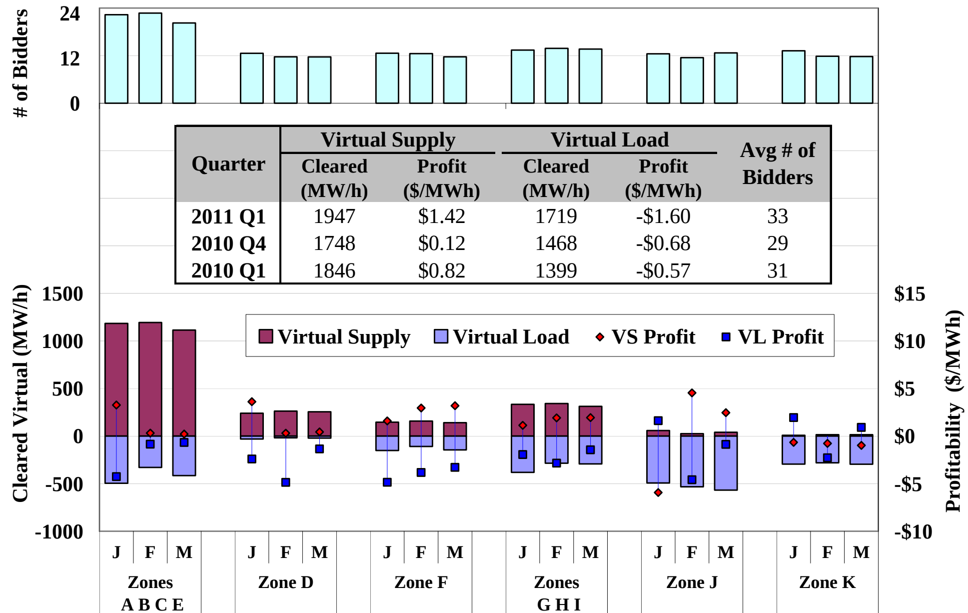
Virtual Trading Activity
By Region By Month



Quarter	Virtual Supply		Virtual Load		Avg # of Bidders
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	
2011 Q1	1947	$1.42	1719	-$1.60	33
2010 Q4	1748	$0.12	1468	-$0.68	29
2010 Q1	1846	$0.82	1399	-$0.57	31

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Net Imports Scheduled Across External Interfaces

- The following figure summarizes scheduled net imports to NYCA across eight external interfaces during the daily peak hour.
- Net imports to NYCA averaged roughly 3.8 GW during daily peak hours in the first quarter of 2011, up 940 MW (or 33 percent) from the previous quarter and down 210 MW (or 5 percent) from the first quarter of 2010.
  - ✓ These changes were consistent with changes in the relative prices between areas.
  - ✓ The increase from the previous quarter resulted primarily from the increases in net imports from HQ and PJM, which rose 735 MW and 250 MW on average.
    - – The increase in hydro-backed imports was consistent with the increase in energy prices, and with the trend observed in the winter months in previous years.
  - ✓ However, the increase was partly offset by the decrease in net imports from New England, which fell 260 MW on average.
  - ✓ New York City and Long Island imported over 1.1 GW from New England and PJM across four controllable lines, which was comparable to prior periods.
- Imports on average satisfied 18 percent of the load during daily peak hours in the first quarter of 2011, up 4 percent from the previous quarter.
  - ✓ During the quarterly peak load hour on January 24, NYCA imported 3.1 GW, which satisfied nearly 13 percent of the peak load.

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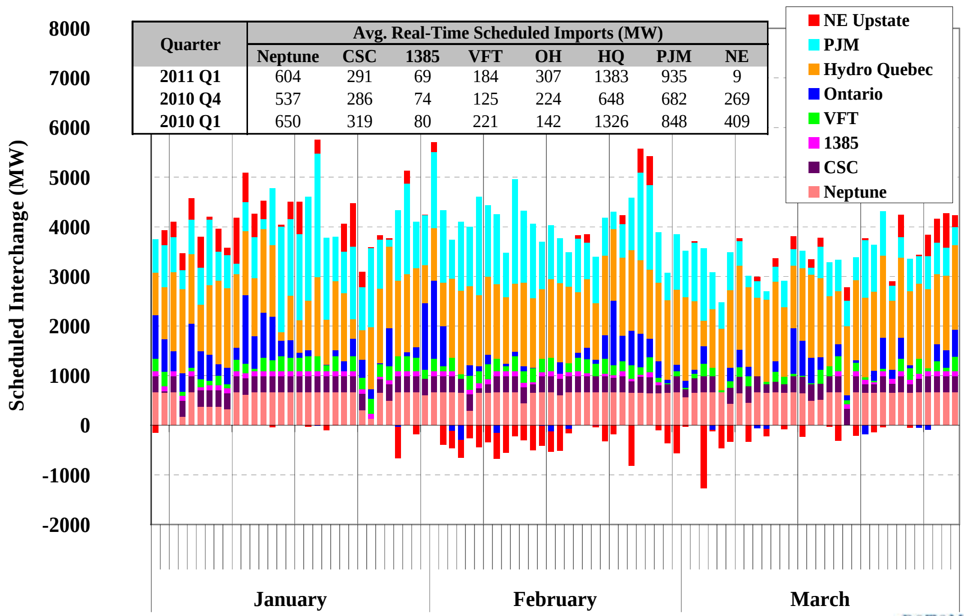
Net Imports Scheduled Across External Interfaces
Daily Peak Load Hour

Quarter	Avg. Real-Time Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2011 Q1	604	291	69	184	307	1383	935	9
2010 Q4	537	286	74	125	224	648	682	269
2010 Q1	650	319	80	221	142	1326	848	409



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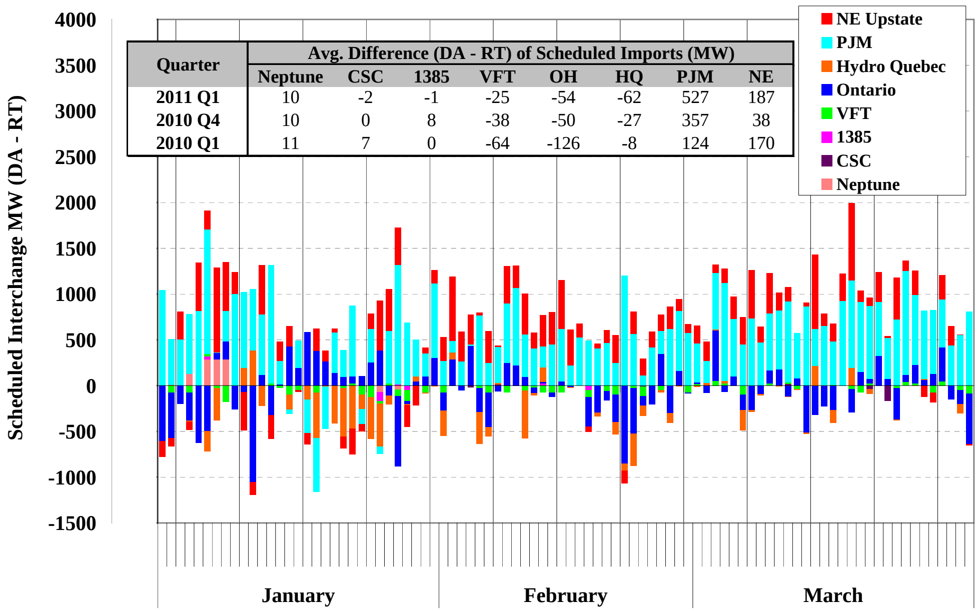
Change in Scheduled Imports from Day Ahead to Real Time

- The following figure summarizes the change in scheduled net imports between the day-ahead market and the real-time market in the daily peak load hour.
  - ✓ As with virtual transactions, these changes should be consistent with the real-time price signals and should improve the convergence of day-ahead and real-time prices.
- Net scheduled imports fell 580 MW on average from day-ahead to real-time during daily peak load hours in the first quarter of 2011. Net scheduled imports:
  - ✓ Decreased across the PJM interface by an average of 527 MW;
  - ✓ Decreased across the primary interface with NE by an average of 187 MW; and
  - ✓ Frequently increased across the Linden VFT and the Ontario interfaces.
- Generally, the changes in schedules between the day-ahead and real-time markets were consistent with the changes in prices.
  - ✓ This was particularly evident at the PJM interface, where the average day-ahead price exceeded the average real-time price by $4/MWh.
  - ✓ Accordingly, at the PJM interface, MPs scheduled substantial quantities of:
    - – "Virtual" imports in the day-ahead market (i.e., day-ahead imports not scheduled in the real-time); and
    - – Exports in the real-time.

POTOMAC ECONOMICS

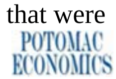
Change in Scheduled Imports from DA to RT
Daily Peak Load Hour



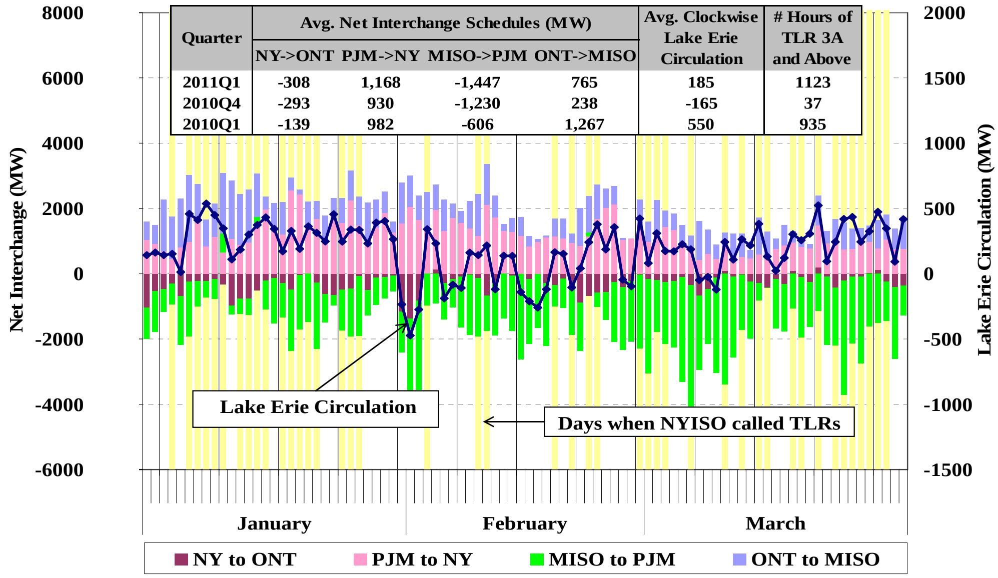
Quarter	Avg. Difference (DA - RT) of Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2011 Q1	10	-2	-1	-25	-54	-62	527	187
2010 Q4	10	0	8	-38	-50	-27	357	38
2010 Q1	11	7	0	-64	-126	-8	124	170

External Interface Scheduling and Lake Erie Circulation

- Loop flows occur when physical power flows are not consistent with the scheduled path of the transaction between control areas.
  - ✓ Clockwise loop flows around Lake Erie use valuable west-to-east transmission capacity through upstate New York, reducing the capacity available for scheduling internal generation to satisfy internal load.
  - ✓ Transmission Loading Relief ("TLR") procedure is used by the NYISO when loop flows contribute to congestion on internal flowgates.
- The figure shows the pattern of loop flows and the net scheduled interchange between the four control areas around Lake Erie on each day of the quarter.
  - ✓ Days when TLRs (level 3A+) were called by the NYISO are also highlighted.
- Average clockwise circulation was 185 MW in the first quarter, up 350 MW from the previous quarter and down 365 MW from the first quarter of 2010.
- TLRs were called on 44 days in the first quarter for a total of 1123 hours, up considerably from the fourth quarter of 2010 due to the increase in loop flows.
  - ✓ Clockwise circulation averaged 300 MW on days when TLRs were called and 75 MW on days when no TLRs were called.
  - ✓ Although clockwise circulation fell from the first quarter of 2010, the frequency of TLRs increased due to changes in the NYISO's criteria for calling a TLR that were implemented in March 2010.



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		
2011Q1	-308	1,168	-1,447	765	185	1123
2010Q4	-293	930	-1,230	238	-165	37
2010Q1	-139	982	-606	1,267	550	935

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

POTOMAC ECONOMICS

Congestion Revenue Collections and Shortfalls

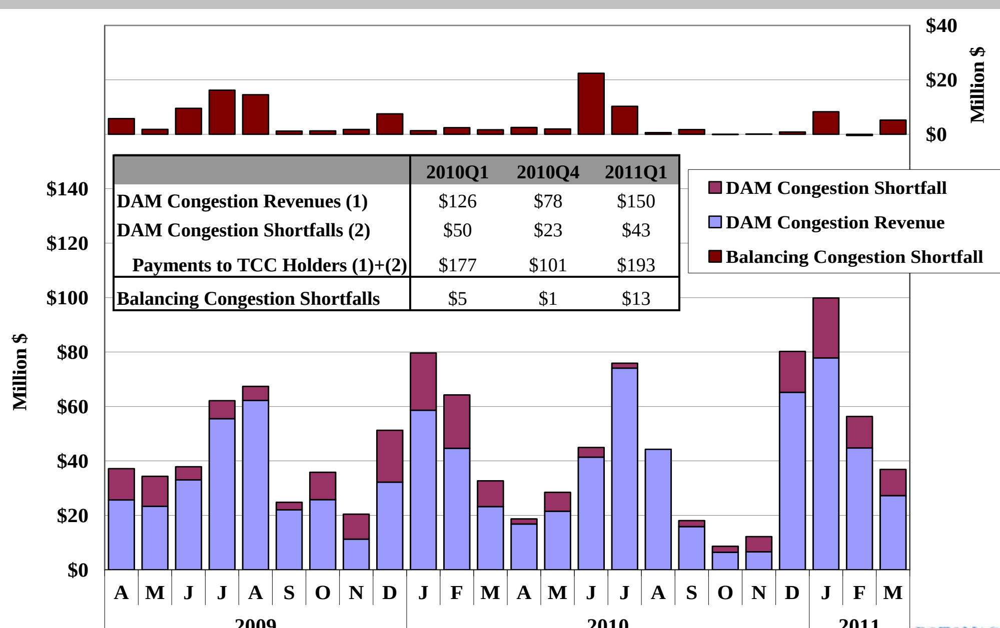
- This section of the report summarizes and evaluates the congestion patterns in New York and quantifies the following categories of congestion costs:
  - ✓ *Day-Ahead Congestion Revenues* are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market.
  - ✓ *Day-Ahead Congestion Shortfalls* occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - – Shortfalls generally arise when the quantity of TCCs on a path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion.
    - – Payments to TCC holders are equal to the sum of day-ahead congestion revenues and day-ahead congestion shortfalls.
    - – These shortfalls are partly offset by the revenues from selling excess TCCs.
  - ✓ *Balancing Congestion Shortfalls* arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.
    - – This requires the ISO to re-dispatch generation on each side of the constraint in the real-time market, buying additional energy in the high-priced area and selling back energy (that was purchased day-ahead) in the low-priced area.
    - – This re-dispatch results in balancing congestion shortfalls, which are recovered through uplift.

POTOMAC ECONOMICS

Congestion Revenue Collections and Shortfalls

- The following figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years.
- Day-ahead congestion revenue was $150 million in the first quarter, up 92 percent from the previous quarter and up 19 percent from a year ago.
  - ✓ The increase from the previous quarter was primarily attributable to increased congestion across the Central-East and Dysinger East interfaces.
  - ✓ Higher natural gas prices and higher load levels also contributed to the increase.
- Day-ahead congestion shortfalls increased 87 percent from the fourth quarter of 2010 and decreased 14 percent from the first quarter of 2010. In this quarter:
  - ✓ PAR-controlled lines between NJ and NY accounted for 34 percent due to different modeling assumptions between the TCC auction and day-ahead market. A market enhancement should begin reducing these shortfalls in May 2011.
  - ✓ Central-East accounted for 29 percent partly due to differences between the TCC auction and the day-ahead market in assumed generator commitments.
- Balancing congestion shortfalls rose to $13 million in the first quarter of 2011, up $12 million from the previous quarter and up $8 million from a year ago.
  - ✓ 34 percent of total shortfalls accrued in mid-March when line outages in NYC led to the frequent use of simplified interface constraints.

Congestion Revenue Collections and Shortfalls



	2010Q1	2010Q4	2011Q1
DAM Congestion Revenues (1)	$126	$78	$150
DAM Congestion Shortfalls (2)	$50	$23	$43
Payments to TCC Holders (1)+(2)	$177	$101	$193
Balancing Congestion Shortfalls	$5	$1	$13

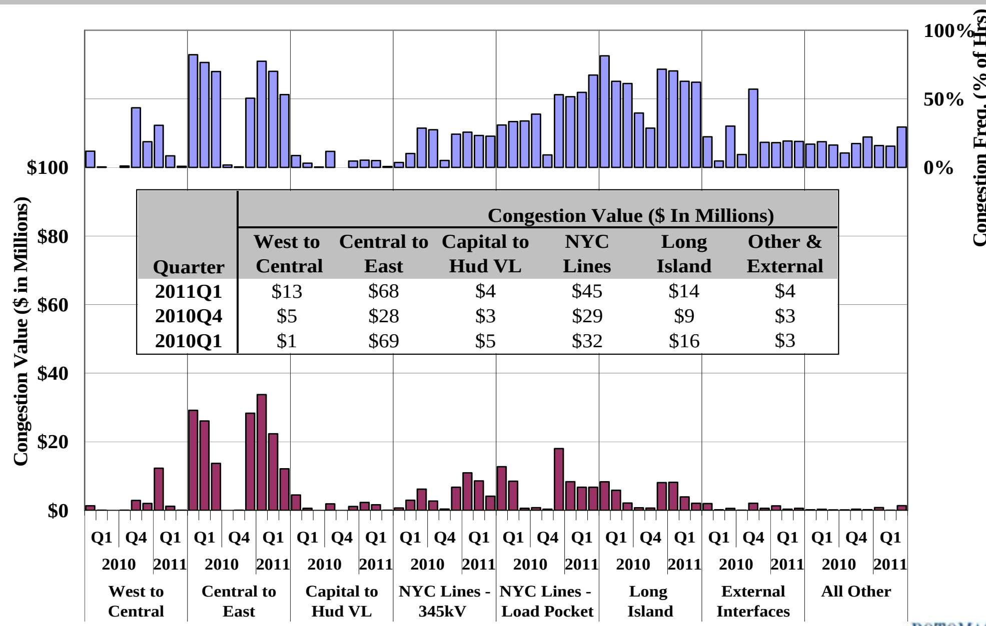
Congestion by Transmission Path

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

Day-Ahead Congestion by Transmission Path

- The next figure summarizes the frequency of congestion and congestion revenue collected by transmission path in the day-ahead market.
- Day-ahead congestion patterns are determined by the market participants' bids and offers, which reflect their expectations of real-time congestion.
  - ✓ Congestion is more frequent in the day-ahead market than in real time, but shadow prices of constraints are generally lower in the day-ahead market.
- Most day-ahead congestion revenue in the first quarter occurred over the Central-East interface (46 percent) and lines into and within New York City (30 percent).
- Congestion from West to Central rose considerably in the first quarter (primarily the Dysinger East interface in January), primarily due to transmission outages (Rochester to Pannell) that reduced the transfer capability of the interface.
- Congestion across the Central-East interface rose notably from the previous quarter but was comparable to the first quarter of 2010.
  - ✓ Central-East constraint tends to bind more frequently in the winter months due to increased imports from Hydro Quebec, increased exports to New England, and higher natural gas prices.
- Congestion into New York City also rose from prior periods with Dunwoodie to Motthaven constraints accounting for 48 percent of NYC congestion.

Day-Ahead Congestion by Transmission Path



Quarter	Congestion Value ($ In Millions) West to Central	Central to East	Capital to Hud VL	NYC Lines	Long Island	Other & External
2011Q1	$13	$68	$4	$45	$14	$4
2010Q4	$5	$28	$3	$29	$9	$3
2010Q1	$1	$69	$5	$32	$16	$3

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 $161 million in the first quarter, up 118 percent from the previous quarter and up 17 percent from a year ago.
  - ✓ The increases reflected higher fuel prices and higher load levels in this quarter.
  - ✓ The substantial increase from the previous quarter was mostly attributable to sharp increases West-to-East congestion on paths affected by line outages.
- Real-time congestion occurred mostly in the following areas in the first quarter:
  - ✓ *West to East* (46 percent): 83 percent of this was on the Central-East interface and 17 percent was on the Dysinger East interface. Transmission outages and higher gas prices that raise redispatch costs contributed to higher west-to-east congestion.
  - ✓ *NYC lines and simplified interface constraints* (26 percent): The majority of this congestion was associated with congestion into the 345 kV system in January (43 percent) and congestion into the Greenwood load pocket in March (22 percent).
  - ✓ *Long Island* (16 percent): Nearly all of congestion occurred along the Dunwoodie to Shore Road line (41 percent) into Long Island and the East Garden City to Valley Stream line (57 percent) within Long Island.

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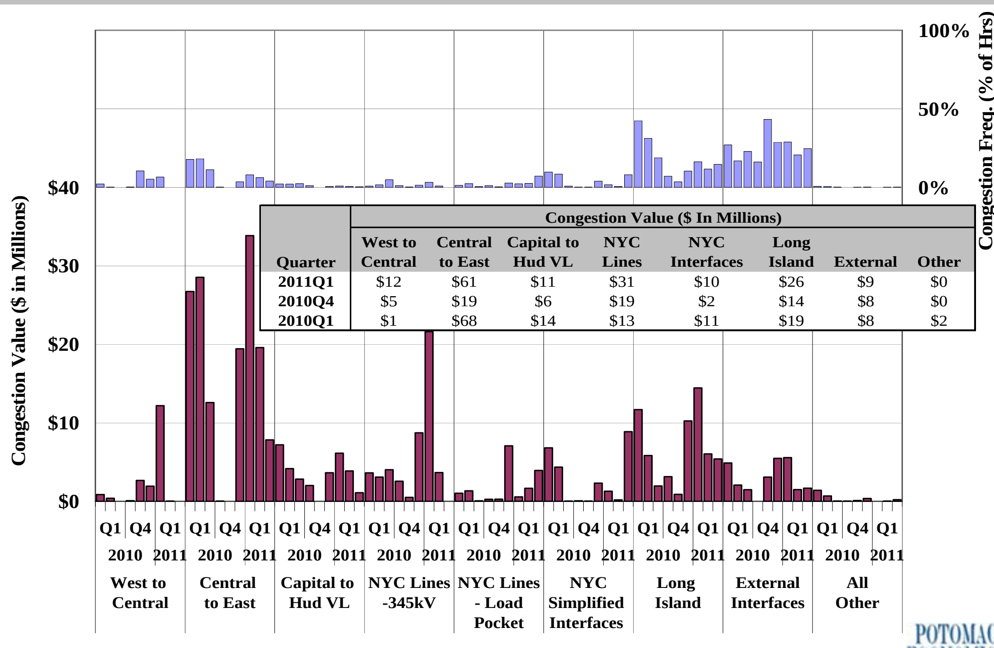
Real-Time Congestion by Transmission Path



	Congestion Value ($ In Millions)							
Quarter	West to Central	Central to East	Capital to Hud VL	NYC Lines	NYC Interfaces	Long Island	External	Other
2011Q1	$12	$61	$11	$31	$10	$26	$9	$0
2010Q4	$5	$19	$6	$19	$2	$14	$8	$0
2010Q1	$1	$68	$14	$13	$11	$19	$8	$2

POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily day-ahead congestion revenue shortfalls by transmission path or facility in the first quarter of 2011.
  - ✓ Negative values indicating congestion surpluses that arise from higher day-ahead utilization of interfaces than in the TCC auction are shown in the "All Other" bar.
- Day-ahead congestion revenue shortfalls can result from modeling assumption differences between the TCC auction and the day-ahead market.
  - ✓ This includes assumptions related to PAR schedules, loop flows, and transmission outages. (Outage-related residuals are allocated to the responsible TO.)
- PAR-controlled lines between NJ and NY accounted for 34 percent due to different modeling assumptions between the TCC auction and day-ahead market.
  - ✓ This issue was addressed by a market enhancement that is expected to begin reducing shortfalls in May 2011.
- Central-East accounted for 29 percent partly due to differences between the commitment assumed in the TCC auction and scheduling in the day-ahead market.
- NYC facilities accounted for 25 percent primarily due to outages affecting transfer capability into the city from upstate and into the Greenwood area.
- West to Central accounted for 18 percent due to line outages that affected the Dysinger East interface in January.

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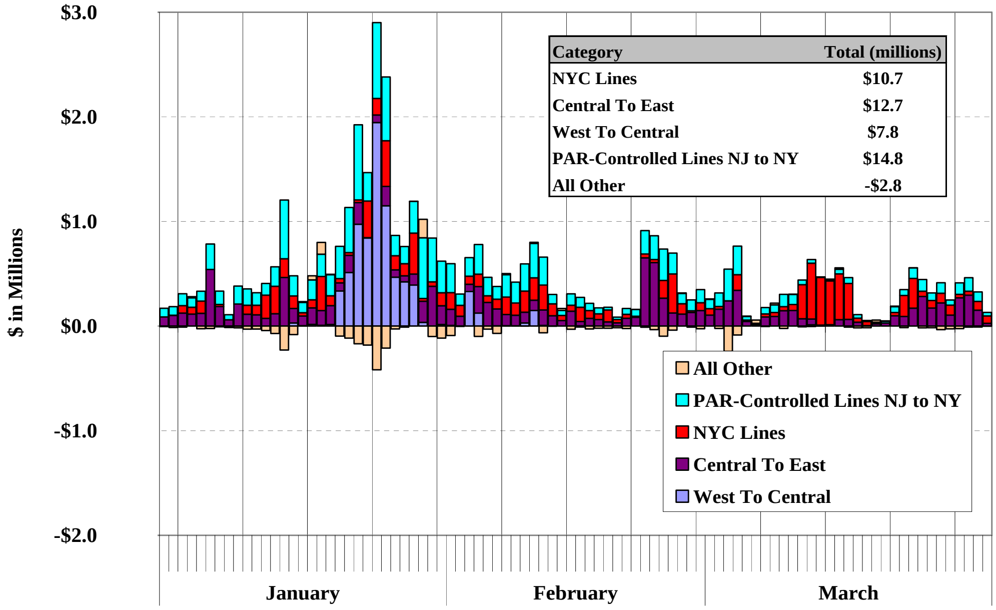
Day-Ahead Congestion Revenue Shortfalls



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Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the first quarter of 2011.
  - ✓ Negative values indicate balancing congestion surpluses. Surpluses that arise from increased real-time utilization of an interface from the day-ahead market, which are shown in the "All Other" category.
- 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.

POTOMAC ECONOMICS

Balancing Congestion Shortfalls

- Simplified interface constraints in New York City accounted for the largest share (34 percent) of balancing congestion shortfalls in the first quarter.
  - ✓ The majority of the shortfalls accrued in mid-March when the simplified interfaces were frequently used to manage congestion in the Greenwood area where transmission capability was reduced by several transmission outages.
  - ✓ Use of simplified interface constraints in the real-time market, rather than the detailed line modeling used in the day-ahead market, generally reduces transfer capability and leads to balancing congestion shortfalls.
- PAR Controlled Lines between New Jersey and New York accounted for 29 percent of shortfalls in the first quarter of 2011.
  - ✓ This fell from the first quarter of 2010, due partly to decreased circulation around Lake Erie in the clockwise direction.
- West to Central paths accounted for 14 percent of shortfalls.
  - ✓ Nearly all of the shortfalls accrued in one week during January when line outages reduced the transfer capability across the Dysinger East interface and the impact was not fully reflected in the day-ahead market.

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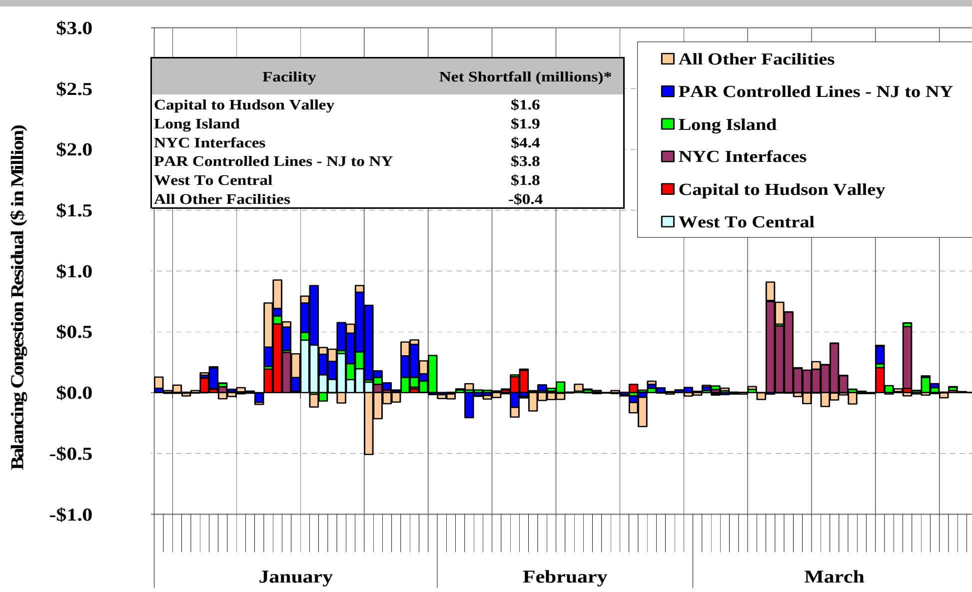
Balancing Congestion Shortfalls



Facility	Net Shortfall (millions)*
Capital to Hudson Valley	$1.6
Long Island	$1.9
NYC Interfaces	$4.4
PAR Controlled Lines - NJ to NY	$3.8
West To Central	$1.8
All Other Facilities	-$0.4

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

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments

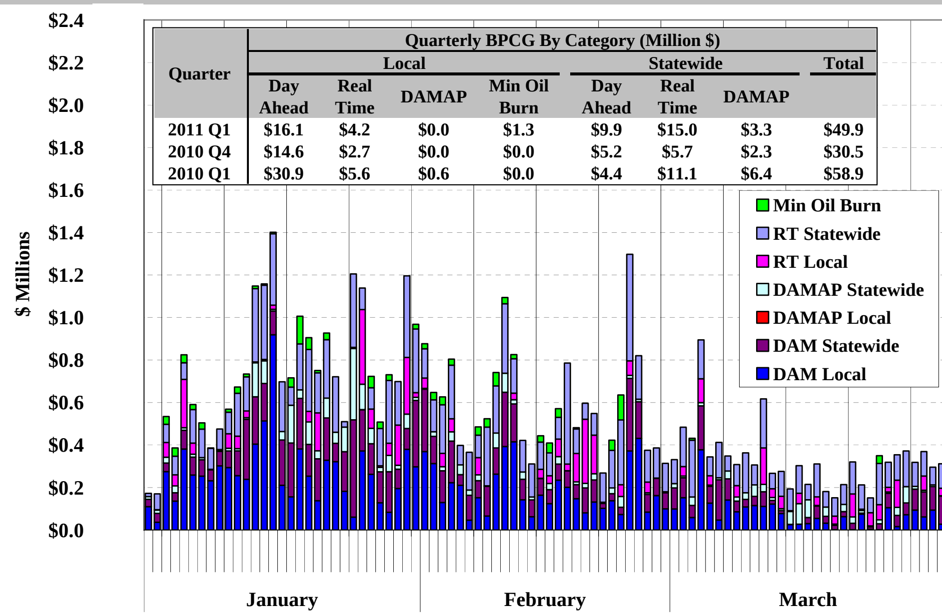
- The next two figures summarize uplift charges resulting from guarantee payments in the following seven categories.
- Three categories of non-local reliability uplift are allocated to all LSEs:
  - ✓ Day Ahead: Primarily for units committed economically that don’t recoup their as-offered start-up and 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.

Uplift Costs from Guarantee Payments

- The following figure shows the seven categories of uplift charges on a daily basis in the first quarter of 2011.
- Fuel prices were strongly correlated with guarantee payment uplift.
  - ✓ Guarantee payments increased considerably on several days in January and February when natural gas prices were elevated, and fell in March as natural gas prices decreased.
- Guarantee payment uplift was $50 million in the first quarter, up 64 percent from the previous quarter and down 15 percent from the first quarter of 2010.
  - ✓ The increase from the previous quarter was associated with an increase in day-ahead and real-time statewide uplift, which increased due to:
    - Higher fuel prices; and
    - Higher load levels that typically increase the number of units that are committed for reliability.
  - ✓ The decrease from the first quarter of 2010 was associated with a decrease in day-ahead local reliability uplift, which fell because:
    - Less capacity was committed for reliability in New York City; and
    - LBMPs were higher relative to the supply offers of the units committed to satisfy reliability requirements, which reduce the guarantee payments needed.

Uplift Costs from Guarantee Payments

Local and Non-Local by Category



Quarterly BPCG By Category (Million $)

Quarter	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2011 Q1	$16.1	$4.2	$0.0	$1.3	$9.9	$15.0	$3.3	$49.9
2010 Q4	$14.6	$2.7	$0.0	$0.0	$5.2	$5.7	$2.3	$30.5
2010 Q1	$30.9	$5.6	$0.6	$0.0	$4.4	$11.1	$6.4	$58.9

Note: These data do not include some manual adjustments to the mitigation of guarantee payments.

Uplift Costs from Guarantee Payments

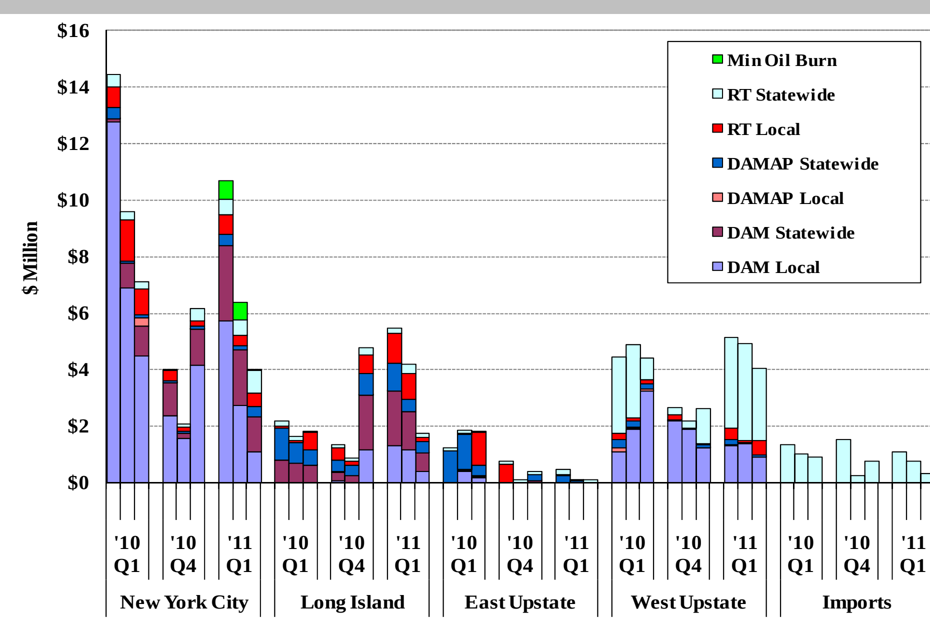
- The following figure shows the seven categories of uplift charges on a monthly basis by region.
- Day-ahead local reliability uplift in the first quarter of 2011:
  - ✓ These costs were primarily for DARU and LRR commitments in New York City (59 percent), western New York (22 percent), and Long Island (18 percent).
- Day-ahead non-local reliability uplift in the first quarter of 2011:
  - ✓ The majority of these costs were paid to generators in New York City and Long Island at several plants where one or more units were required to manage transmission congestion.
  - ✓ The resulting guarantee payments are allocated statewide if the facility being secured is monitored by the NYISO.
- Real-time local reliability uplift in the first quarter of 2011:
  - ✓ Long Island accounted for 45 percent, primarily to manage local congestion on the East End where some generators do not have a source of natural gas.
- Real-time non-local reliability uplift in the first quarter of 2011:
  - ✓ The majority was for western New York (65 percent) associated primarily with SRE commitments.

Uplift Costs from Guarantee Payments

- Overall, guarantee payment uplift fell 15 percent from the first quarter of 2010.
- In Western NY (incl. the North zone which interconnects west of Central-East):
  - ✓ Local reliability uplift fell from $6.7 million in the first quarter of 2010 to $4.7 million in the first quarter of 2011; while
  - ✓ RT non-local reliability uplift rose from $6.0 million to $9.2 million.
- In NYC, DAM local uplift fell from $24.2 million in first quarter 2010 to $9.6 million in first quarter 2011, while DAM non-local uplift rose from $2.0 to $5.9 million.
  - ✓ Less capacity was committed for local reliability in the first quarter of 2011 compared to the previous year, particularly in the month of January.
  - ✓ Generators needed for local reliability in the DAM were more economic (i.e., earned less BPCG per unit of output) in the first quarter of 2011.
- In Long Island, DAM and RT local reliability uplift rose from $0.8 million in the first quarter of 2010 to $5.0 million in this quarter, due to:
  - ✓ Units needed for reliability were less frequently committed economically in the first quarter of 2011. This was partly because Long Island LBMPs fell from the previous year when transmission outages reduced imports from upstate.
  - ✓ Oil-fired units were used more frequently in the first quarter of 2011 to manage local reliability on the East End of Long Island.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region



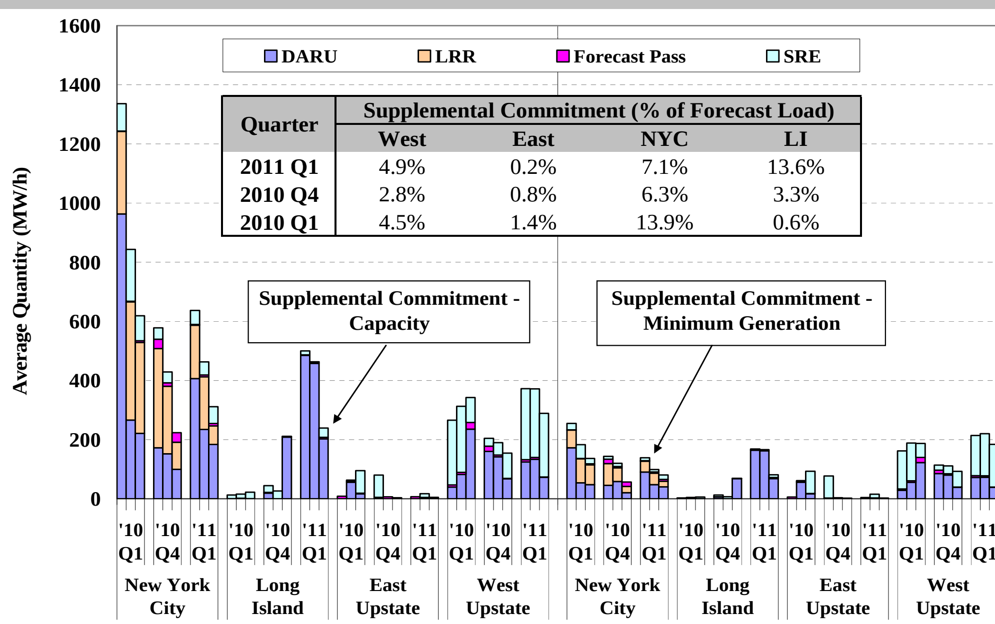
Note: These data do not include some manual adjustments to the mitigation of guarantee payments.

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 increased considerably from prior periods.
  - ✓ Committed capacity averaged roughly 400 MW, up 305 MW from the previous quarter and 385 MW from the first quarter of 2010.
  - ✓ The minimum generation level of these units averaged 140 MW, up 110 MW from the previous quarter and 130 MW from the first quarter of 2010.
  - ✓ DARU commitment increased in the first quarter of 2011 partly because units needed for reliability were committed economically less frequently than in the first quarter of 2010.
- Reliability commitment in New York City decreased substantially from the first quarter of 2010.
  - ✓ Committed capacity averaged 470 MW, down nearly 50 percent from a year ago.
  - ✓ The minimum generation level of these units averaged 105 MW, down 45 percent from the first quarter of 2010.
  - ✓ DARU committed capacity fell after January 2010, coinciding with the retirement of the Poletti unit that had been frequently committed by DARU.
- SRE commitment in western New York rose from the previous quarter due partly to colder weather.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2011 Q1	4.9%	0.2%	7.1%	13.6%
2010 Q4	2.8%	0.8%	6.3%	3.3%
2010 Q1	4.5%	1.4%	13.9%	0.6%

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

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

- Most mitigation occurred day-ahead for Astoria West/Queens/Vernon congestion (37%), DARU & LRR units (35%), and In-City 138 kV congestion (16%).
- Mitigation increased substantially from the prior quarters due primarily to:
  - ✓ The application of tighter mitigation thresholds to units that are DARU-committed outside New York City (since October 2010).
  - ✓ Units having "LBMP-based" reference levels that were below their actual costs. Consultations are ongoing to reverse the mitigation of such units.

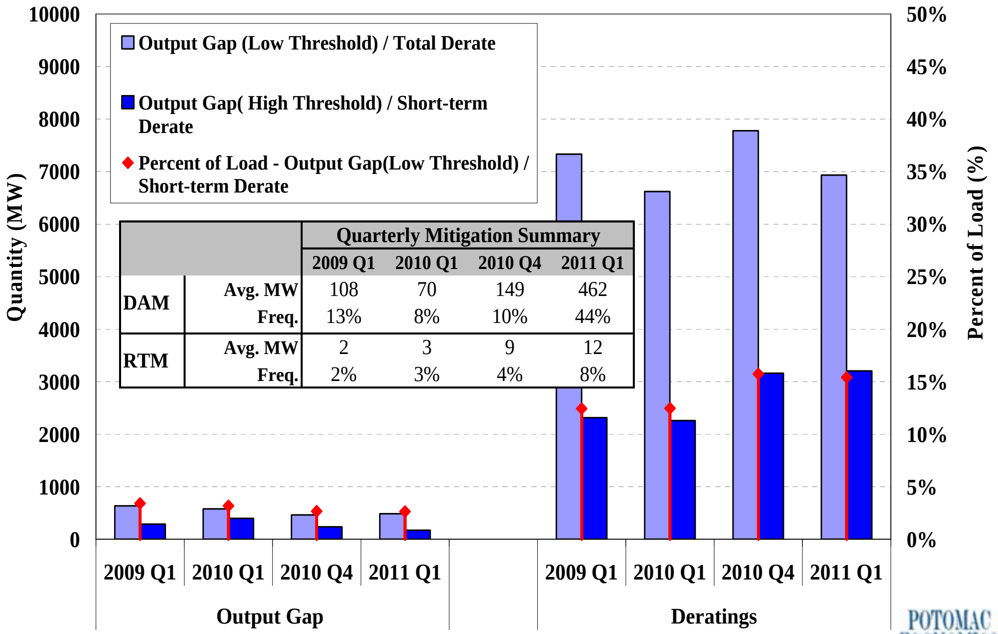
<u>Output Gap at High and Low Thresholds:</u>

- The output gap is low as a share of load (< 3 percent), occurring primarily during periods when the prices would not be substantially affected.

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

- Total deratings are sizable, but physical withholding concerns are limited because: (i) deratings are typically highest in the shoulder months when demand is lowest, and (ii) most deratings are long-term and less likely to reflect withholding.
- The amount of capacity derated in the first quarter of 2011 was higher than in previous years due to several significant outages of large generating units.

Market Monitoring Screens and Mitigation



		Quarterly Mitigation Summary			
		2009 Q1	2010 Q1	2010 Q4	2011 Q1
DAM	Avg. MW	108	70	149	462
	Freq.	13%	8%	10%	44%
RTM	Avg. MW	2	3	9	12
	Freq.	2%	3%	4%	8%

POTOMAC ECONOMICS

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 $3.71/kW-month in the first quarter of 2011, down 37 percent from the first quarter of 2010.
  - ✓ Clearing prices rose to nearly $8/kW-month in Feb and Mar 2010 following the retirement of the Poletti unit, which reduced installed capacity by nearly 900 MW.
  - ✓ Clearing prices fell from the end of the first quarter of 2010 to the first quarter of 2011, primarily due to:
    - – A 325 MW reduction in the peak load forecast for NYC; and
    - – Increased capacity sales from new resources.
- Overall, UCAP sales in NYC rose significantly from the end of the Winter 2009/10 Capability Period to the Winter 2010/11 Capability Period due to an improvement in forced outage rates.
  - ✓ However, this did not significantly reduce prices because an improvement in forced outage rates triggers an increase in the UCAP requirement.
- The figure shows that virtually all internal capacity has been sold in each month so withholding of supply has not been a concern in New York City.

POTOMAC ECONOMICS

Capacity Market Results

- Outside New York City, UCAP spot prices fell to an average of $0.48/kW-month in the first quarter of 2011, down 77 percent from the first quarter of 2010.
  - ✓ A substantial amount of capacity was unsold in the first quarter of 2011 due to the relatively large prevailing capacity surplus and the low prices.
  - ✓ The Long Island Local Capacity Requirement ("LCR") was never binding during the two quarters, so Long Island and Rest of State clearing prices were equal.
- Clearing prices outside New York City were affected by the following factors:
  - ✓ Poletti's retirement in February 2010 reduced UCAP supply by nearly 900 MW, contributing to a $1.64/kW-month increase in the clearing price in February 2010.
  - ✓ Increased sales from Internal Capacity (including UDRs) contributed to lower clearing prices in the first quarter of 2011.
  - ✓ The capacity requirement fell because the peak load forecast for NYCA fell 905 MW from the previous year.
    - – However, this was partly offset by an increase in the installed capacity requirement from 116.5 percent to 118 percent over the same period.
  - ✓ Substantial changes in imports and exports in response to capacity prices in New York also affected prices. For example, imports rose sharply in March 2010 after prices increased in February following the Poletti retirement.

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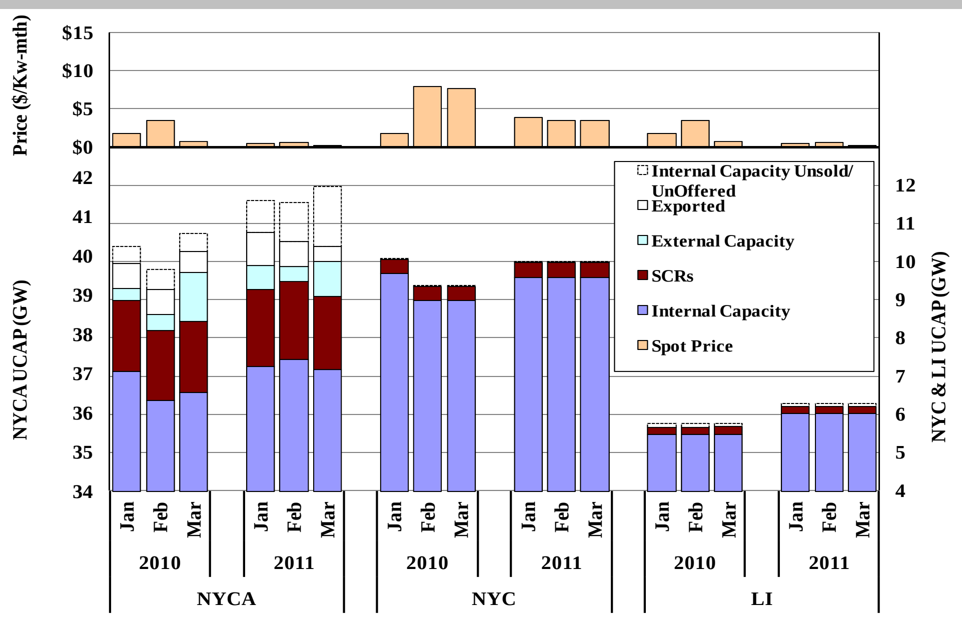
Capacity Market Results



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

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