2009 State of the Market Report
New York ISO Electricity Markets

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Executive Summary: Introduction

- This presentation provides the results of our assessment of the performance of the New York electricity markets in 2009.
- The New York ISO ("NYISO") operates a complete set of electricity markets, including:
  - ✓ Day-ahead and real-time markets jointly optimize energy, operating reserves and regulation. These markets lead to:
    - Prices that reflect the value of energy at each location on the network;
    - The lowest cost resources being started each day to meet demand;
    - Delivery of the lowest cost energy to New York's consumers to the maximum extent allowed by the transmission network; and
    - Efficient prices when the system is in shortage.
  - ✓ Capacity markets that ensure that the NYISO markets produce efficient long-term economic signals to govern decisions to:
    - Invest in new generation, transmission, and demand response; and
    - Maintain existing resources.
  - ✓ The market for transmission rights allows participants to hedge the congestion costs associated with using the transmission network.

Executive Summary: Unique Aspects of the NYISO Markets

- The performance of the New York markets is enhanced by a number of attributes that are unique to the NYISO:
  - ✓ *A real-time dispatch system that is able to optimize over multiple periods (up to 1 hour)*, which allows the market to anticipate upcoming needs and move resources to efficiently satisfy the needs.
  - ✓ *An optimized real-time commitment system to start gas turbines and schedule external transactions economically* – other RTOs rely on their operators to determine when to start gas turbines.
  - ✓ *A mechanism that allows gas turbines to set energy prices when they are economic* – gas turbines frequently do not set prices in other areas because they are inflexible, which distorts prices.
  - ✓ *A mechanism that allows demand-response resources to set energy prices when they are needed* – this is essential for ensuring that prices signals are efficient during shortages. DR in other RTOs has distorted real-time signals by undermining the shortage pricing.

Executive Summary

<u>Market Performance and Prices</u>

- The energy, capacity, operating reserves, and regulation markets performed competitively in 2009.
  - ✓ We find no evidence that suppliers have withheld a material amount of generation to inflate energy, capacity, or ancillary services prices.
  - ✓ However, the NYISO filed with FERC to address the conduct of three generators in upstate New York that raised their offer prices when committed for reliability, which increased their guarantee payments.
- Energy prices fell 46 percent in western New York and 51 percent in eastern New York from 2008 to 2009. These substantial reductions were due to:
  - ✓ Lower fuel prices in 2009 -- natural gas prices fell an average of 52 percent, while residual fuel oil prices fell 32 percent and diesel oil prices fell 42 percent.
  - ✓ Lower load levels in 2009, particularly during the summer months, due to economic conditions and mild weather.
- Transmission congestion decreased by 61 percent due to lower fuel prices, lower load levels, and the reduced effects of circulation around Lake Erie.

Executive Summary

Market Performance and Prices (cont.)

- Convergence between day-ahead and real-time prices is important because the day-ahead market determines which resources are started-up each day.
  - ✓ Convergence in the energy markets continues to be good in most areas, although large differences sometimes occur on individual days.
  - ✓ Convergence generally improved at the nodal level, which is attributable to:
    - – Better consistency between day-ahead and real-time commitment due to enhancements that lead more reliability units to be committed in the day-ahead market rather than later through the SRE process; and
    - – Less frequent use of simplified interface constraints in New York City load pockets in the real-time market, which are never used in the day-ahead market.
    - – We recommend allowing virtual trading (currently allowed only at the zone level) at a more disaggregated level to further improve convergence.
  - ✓ Convergence generally improved for operating reserves, although day-ahead prices are still lower than would be expected during peak load periods.
    - – We recommend changes in the mitigation provisions in this report that should improve this convergence.

Executive Summary

Long-Term Economic Signals

- The report shows that prices in 2009 would not support investment in new peaking generation in most locations. This is consistent with short-term conditions because:
  - ✓ There is surplus of generation in most areas; and
  - ✓ Load levels were particularly low in 2009.
- Market signals were more favorable for investment in baseload and intermediate resources. Although such resources are more costly to build, they produce electricity at lower cost.
  - ✓ Over time, the markets provide efficient incentives to invest in a diverse array of generating resources, demand response resources, and transmission.
  - ✓ Currently, market conditions appear more favorable for investment in combined cycle generation (which have constituted most of the recent entry) than in gas-fired peaking generation.
  - ✓ However, net revenues in 2009 would not likely support investment in a combined cycle unit at a new site in any areas of New York.

Executive Summary

Market Operations

- Energy prices are highly volatile in the real-time market, particularly at the top-of-the-hour during the morning and evening ramp periods.
  - ✓ This volatility is largely attributable to large schedule changes that occur at the top-of-the-hour rather than being distributed throughout the hour, including:
    - – Changes in schedules of generation that is not offered in a flexible manner;
    - – Commitments and decommitments of generation; and
    - – External transaction schedule changes, including TLRs and other curtailments.
  - ✓ Such changes can create brief shortages as the NYISO dispatch rapidly adjusts the output of flexible generation to compensate for these changes.
  - ✓ We recommend the NYISO implement six proposed market and operational enhancements to reduce the frequency of excess price spikes.
    - – Additionally, the NYISO should identify any rules that would cause schedule changes for generation and pump storage to predominately occur at the top of the hour.

Executive Summary

Market Operations (cont.)

- Shortage pricing should occur during actual physical shortages in order to provide appropriate price signals to market participants.
- Our evaluation of shortage pricing in 2009 indicated that:
  - ✓ The accuracy of shortage pricing generally improved in 2009; and
  - ✓ The frequency of eastern 10-minute reserve shortages fell 82 percent, partly due to lower load levels.
  - ✓ These changes were due to:
    - – Lower peak loads in 2009; and
    - – Changes the NYISO made to its real-time models in March 2009 that improved their recognition of impending shortages resulting from generators not following their dispatch instructions.

Executive Summary

Schedule 1 Uplift Charges

- Schedule 1 uplift charges decreased 53 percent from $599 million in 2008 to $280 million in 2009.
  - ✓ Local allocations fell 43 percent and state-wide allocations fell 65 percent.
- Guarantee payments to generators fell $180 million from 2008 to 2009.
  - ✓ This was primarily due to lower fuel prices in 2009.
  - ✓ Enhancements to the process for committing generation for local reliability also contributed to lower guarantee payments.
- Balancing congestion residuals fell $251 million from 2008 to 2009 due to:
  - ✓ Lower fuel prices, which generally decrease congestion costs;
  - ✓ The end of circuitous transaction scheduling around Lake Erie, which made a significant contribution in 2008;
  - ✓ Better consistency between day-ahead and real-time constraint modeling in New York City; and
  - ✓ Recently implemented NYISO procedures to promptly evaluate the causes of balancing congestion residuals and to adjust market operations accordingly.

Executive Summary

External Transaction Scheduling

- Prices between New York and adjacent markets do not fully converge, which results in market inefficiencies and excess consumer costs.
- Additionally, substantial loop flows caused by dispatch and scheduling by entities outside of New York contribute to congestion in New York.
  - ✓ The loop flows were lower in 2009 than 2008 because circuitous scheduling around Lake Erie (which caused sizable loop flows in early to mid-2008) were prohibited by the NYISO in July 2008.
  - ✓ Additionally, NYISO now uses Transmission Line Loading Relief (“TLR”) procedures more aggressively to curtail schedules outside New York that cause significant congestion.
- NYISO is working with its neighbors to develop a series of market improvements (known as the “Broader Regional Market” initiatives or “BRM”). The BRM will:
  - ✓ Improve the utilization of the interfaces between markets; and
  - ✓ Address unscheduled loop flows from others outside New York that continue to affect the market outcomes.
  - ✓ We have estimated that these initiatives would reduce the production costs (of NYISO’s and its neighbors) by roughly $200 million annually. Consumer savings in the short-term would likely be higher.

Executive Summary

Capacity Market

- The capacity market contributes to the signals that govern investment decisions for generation, transmission, and demand response, as well as retirement decisions for supply resources.
- Spot capacity prices were generally consistent from 2008 to 2009, averaging $4.78/kW-month in NYC, $2.46/kW-month in Long Island, and $2.22/kW-month in Rest-of-State in 2009.
  - ✓ However, spot prices in February 2010 increased $6.13/kW-month in NYC and $1.64/kW-month in Rest-of-State after the retirement of an 800 MW unit in NYC.
- Transmission bottlenecks that limit flows into southeast New York have led new resources (or imports) outside this region to be deemed not “deliverable” under a new test implemented in 2009.
  - ✓ Such new resources or imports must make costly transmission upgrades or procure deliverability rights from an existing supplier to sell capacity.
  - ✓ This presents a significant inefficient barrier to new entry that will lead to higher capacity costs.
  - ✓ In the absence of zones that reflect the transmission bottleneck, the current prices will not be determined efficiently on either side of the bottleneck.
  - ✓ Hence, we recommend that the NYISO work with stakeholders to make the necessary preparations to define a new zone(s) in eastern New York.

Executive Summary

Demand Response Programs

- Demand response resources participate in the NYISO markets, particularly the capacity market where demand resources provide more than 2 GW of supply.
- The most significant barrier to widespread participation by retail loads is that most of them are not exposed to wholesale prices.
  - ✓ Hence, retail electricity rate reform is one means to give retail loads incentives to be price-responsive.
- The NYISO is developing ways to allow price-responsive retail loads to participate in the wholesale market. Specifically, the NYISO is:
  - ✓ Streamlining qualification for the Demand Side Ancillary Services Program, which allows loads to provide reserves and regulation in real-time;
  - ✓ Defining technical requirements to allow Aggregations of Retail Customers (“ARCs”) to participate in these programs the same as larger loads; and
  - ✓ Enabling price-responsive demands to be paid for real-time curtailments.
    - – We support this, but recommend the following settlements on the curtailed load: a) pay the price-responsive customer the LBMP; b) charge the LSE serving the customer the LBMP; and c) the LSE continue to charge the customer the applicable retail rate.
    - – This provides efficient incentives to the customer and avoids uplift costs.

Executive Summary: High Priority Recommendations

1. **We recommend the NYISO prepare to define a new capacity zone(s) in eastern New York to allow the capacity market to efficiently reflect the transmission issues indicated by the new deliverability test.**
   - ✓ The NYISO will be working with stakeholders in 2010 to develop criteria for designating new capacity zones, but we recommend the NYISO work in parallel to develop potential demand curves and other details necessary to implement the new zone(s).
   - ✓ The new zone(s) will provide appropriate price signals in each location for investment in new generation, transmission, or demand response resources.
2. **We recommend the NYISO continue working with adjacent ISOs to better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange and congestion management.**
   - ✓ The NYISO is working with neighboring control areas on several proposals to improve the efficient use of the interfaces.
   - ✓ This change will increase economic efficiency and lower overall costs to consumers.

Executive Summary: High Priority Recommendations

3. **We support the NYISO's development of a real-time demand response program to better align the incentives of retail customers with the needs of the system.**
   - ✓ Retail rate reform is one means to give retail loads incentives to respond to prices. However, there are other ways the ISO may provide these incentives.
   - ✓ The NYISO plans to propose a concept for enabling participation by demand response resources in the real-time market in 2010.
   - ✓ Under such a program, we recommend the following settlements on the curtailed load:
     - pay the price-responsive customer the LBMP;
     - charge the LSE serving the customer the LBMP; and
     - the LSE continue to charge the customer the applicable retail rate.
   - ✓ This provides efficient incentives to the customer and avoids uplift costs.

Executive Summary: Other Recommendations

4. **We recommend addressing several factors that have been shown to contribute to excess real-time price volatility during ramping hours.**
   - ✓ The NYISO has identified six proposed market and operational enhancements that would help reduce unnecessary price volatility.
5. **We recommend NYISO modify two mitigation provisions that may limit competitive 10-minute reserves offers in the day-ahead market.**
   - ✓ This should improve convergence of day-ahead and real-time reserve prices.
6. **We recommend the offer floor for real-time imports and exports be raised from -$1000/MWh to a level more consistent with the avoided costs of curtailment.**
   - ✓ This would limit balancing congestion shortfalls when they must be curtailed.
   - ✓ In March 2010, the NYISO changed the default offer for import transactions with day-ahead priority from -$999.70/MWh to -$0.01/MWh.
   - ✓ Because participants generally do not modify the default offer, this change has mitigated the need to raise the offer floor in the near-term.

Executive Summary: Other Recommendations

7. **We recommend enabling market participants to schedule virtual trades at a more disaggregated level.**
   - ✓ Currently, virtual trading is allowed at only the zonal level. This change would improve day-ahead to real-time price convergence in New York City load pockets.
   - ✓ NYISO has a project to expand the set of locations where virtual trading is allowed.
8. **We recommend the NYISO review the details regarding its uneconomic entry mitigation for the capacity market to ensure that it will be effective without hindering efficient entry.**
9. **We recommend that the NYISO revisit the baseline method and testing procedures for SCRs to ensure their response is accurately measured.**
   - ✓ The NYISO is conducting an evaluation of the baseline methods used for existing SCRs to determine whether they should be revised.

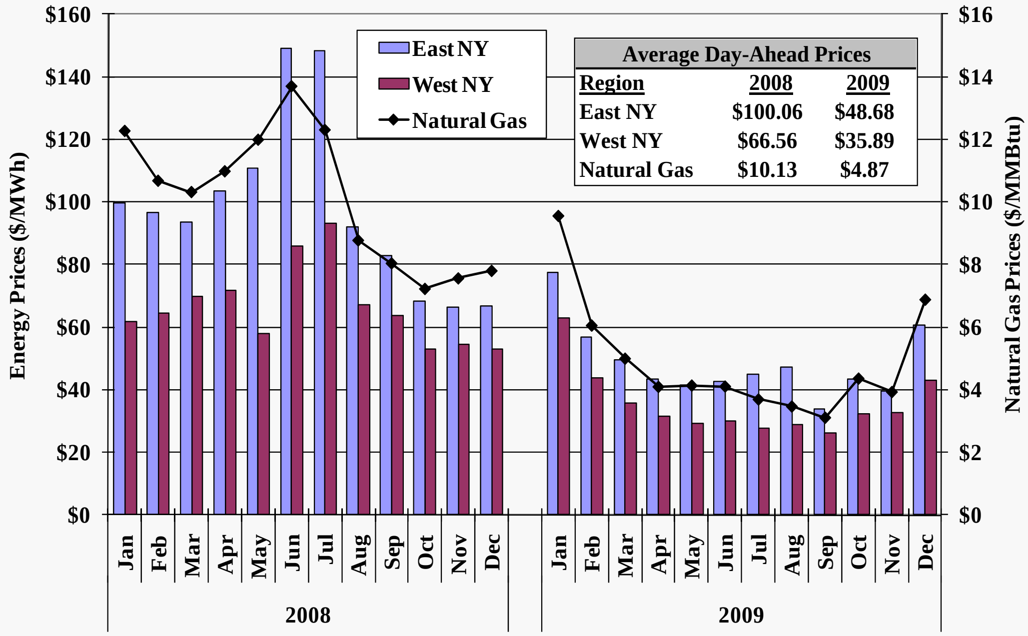
Market Prices and Outcomes: Summary of Prices and Loads

POTOMAC ECONOMICS

Fuel Prices and Energy Prices

- The following figure summarizes day-ahead energy prices in 2008 and 2009.
- Energy prices decreased substantially from 2008 to 2009, due primarily to changes in fuel prices.
  - ✓ Day-ahead energy prices decreased by 51 percent in East NY and by 46 percent in West NY.
  - ✓ Natural gas prices fell by an average of 52 percent, while residual oil (#6) prices fell by 32 percent and diesel oil (#2) prices fell by 42 percent.
  - ✓ The correlation of energy prices with natural gas and oil prices is expected. Fuel costs constitute the majority of variable production costs for most generators, and oil and gas units are on the margin in most hours.
- Transmission congestion became less prevalent in 2009, leading to smaller differences between West and East NY prices:
  - ✓ The average price in East NY was 36 percent higher than the average price in West NY in 2009, down from 50 percent in 2008. This was primarily due to:
    - – Lower gas prices that reduced redispatch costs and coal-fired output in West NY;
    - – Lower loads, which reduced the need for imports to areas in East NY, and
    - – The reduced effects from clockwise loop flows around Lake Erie.

Day-Ahead Electricity and Natural Gas Prices
2008 – 2009

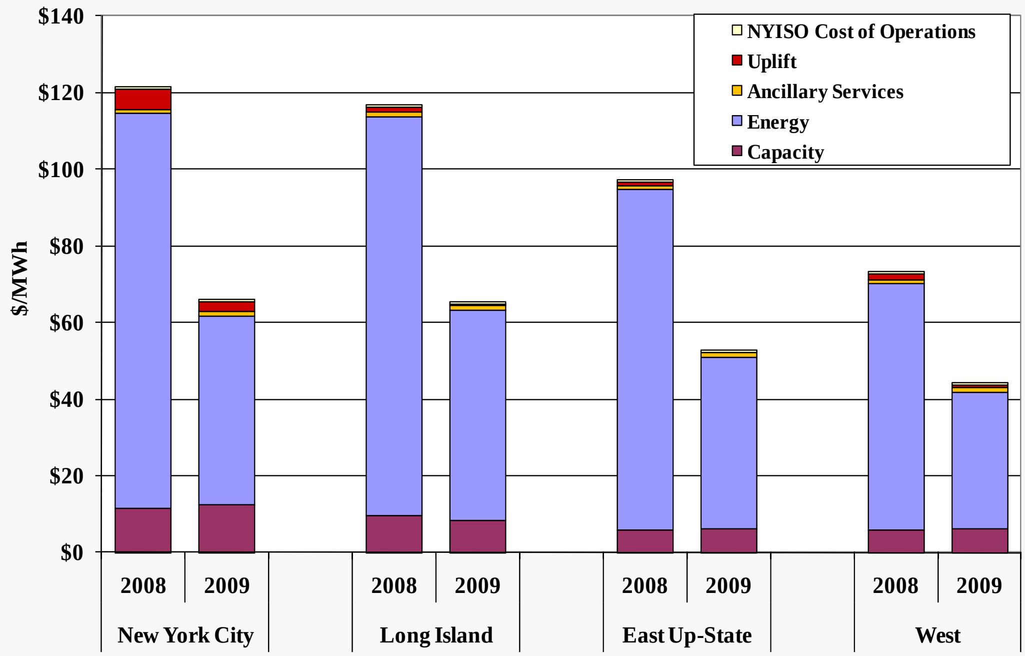


Note: The electricity prices are load-weighted averages.

All-In Energy Prices

- The following figure shows an "all-in" price, which includes the costs of energy, ancillary services, capacity, uplift, and NYISO operating costs.
  - ✓ The capacity component is based on spot capacity prices and load obligations in each area, allocated over the energy consumption in the area.
  - ✓ The energy component is a load-weighted average real-time energy price.
  - ✓ The uplift component is based on local and statewide uplift, allocated over the energy consumption in the area.
- All-in prices decreased by 44 percent from 2008 to 2009 due to:
  - ✓ Lower fuel prices, which contributed to lower:
    - Energy prices,
    - Balancing congestion residual charges, and
    - Guarantee payments to generators;
  - ✓ Improved consistency between day-ahead and real-time scheduling, which reduced balancing congestion residual charges; and
  - ✓ Lower loads, which led to reduced operation of high-cost generation.
  - ✓ However, capacity prices remained relatively constant from 2008 to 2009.

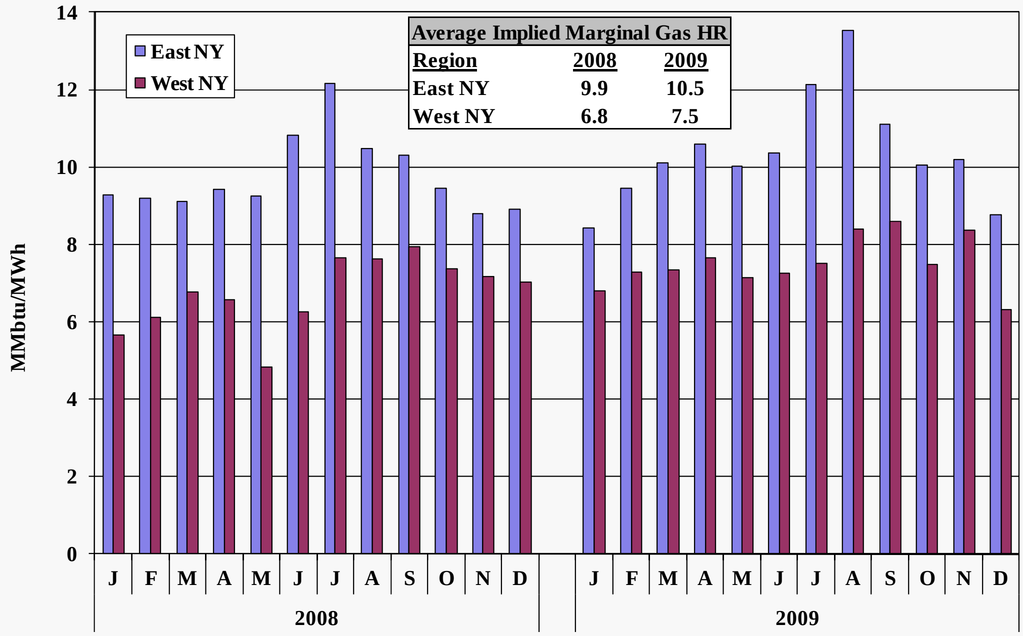
Average All-In Price by Region
2008 – 2009



Fuel Prices and Energy Prices

- To identify changes in energy 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 Elec. Price) ÷ (Natural Gas Price)
- The figure shows that implied heat rates rise in the summer months due to:
  - ✓ Increased demand driven by higher temperatures in the summer; and
  - ✓ Reduced supply resulting from the effects of higher ambient temperatures on the capability of thermal units.
- The implied heat rate rose from 2008 to 2009 due to factors that include:
  - ✓ Substantially lower natural gas prices. Since some of the generation costs are not related to fuel, the implied heat rate rises as fuel prices fall;
  - ✓ The increased disparity between natural gas and oil prices, which increase the effect of periods when oil-fired generation is on the margin; and
  - ✓ RGGI-compliance obligations, which require fossil fuel-fired generators to purchase allowances to cover their emissions since January 2009.

Average Monthly Implied Heat Rate
2008 – 2009



Note: Implied heat rates are load-weighted averages based on day-ahead energy prices and natural gas prices.

Energy Prices

- The next figure shows how hourly price levels have changed in the last three years by showing real-time price duration curves from 2007 to 2009.
  - ✓ These curves show the number of hours when the load-weighted, real-time price for NY State was greater than the level shown on the vertical axis.
- This figure shows that electricity prices rose from 2007 to 2008 and then fell in 2009 across a wide range of hours.
  - ✓ The broad changes in prices over many hours are primarily caused by the variations in natural gas and oil prices.
  - ✓ Natural gas prices increased 19 percent from 2007 to 2008, and decreased 52 percent from 2008 to 2009.
- The figure also shows that the number of extremely high-priced hours (e.g., hours when prices exceed $500/MWh) declined from 2007 to 2009.
  - ✓ The reduced number of peak load hours (>28 GW) contributed to the sharp decline in real-time shortage pricing events.

Price Duration Curves
2007 – 2009

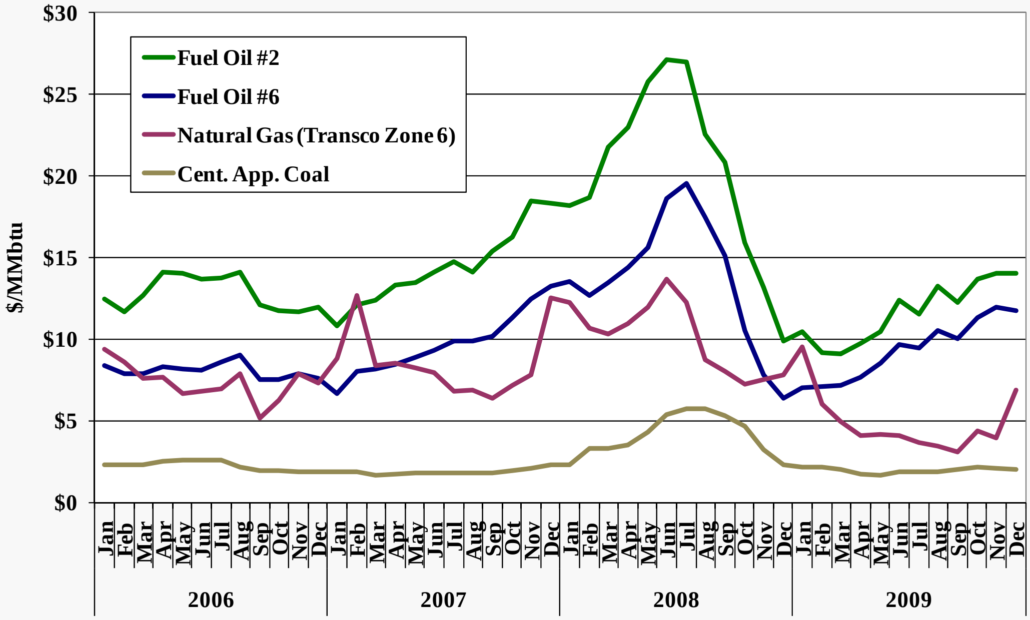
Price Distribution			
Number of Hours	>$500	>$200	>$100
2007	20	100	939
2008	11	119	2371
2009	2	25	280

Note: The pries are load-weighted state-wide average real-time prices.

Prices of Natural Gas and Fuel Oil

- Fuel prices are a key determinant of electricity prices, so the next figure shows monthly average natural gas, fuel oil, and coal prices from 2006 to 2009.
- The ability of many units in New York to burn oil in addition to natural gas mitigates the electricity price effects of transitory spikes in natural gas prices.
  - ✓ Many steam units can burn fuel oil #6, which was priced lower than natural gas on 84 percent of the days in January 2009.
  - ✓ Many gas turbines can burn fuel oil #2, which was priced lower than natural gas on 35 percent of the days in January 2009.
- The "minimum oil burn" procedures require some units in NYC to burn oil to limit exposure to natural gas supply contingencies during high load conditions.
  - ✓ Such units receive out-of-market payments that are not reflected in prices.
  - ✓ These payments fell from $18 million in 2008 to $10 million in 2009 due to reduced fuel oil #6 prices and lower load levels.
- The use of coal has been reduced by several retirements and the decline in natural gas prices relative to coal prices.
  - ✓ When natural gas is close to the price of coal (e.g., April to November 2009), gas-fired combined cycles are more competitive with coal-fired steam units.

Monthly Average Natural Gas, Oil, and Coal Prices 2006 – 2009



Note: These are index prices that do not include transportation charges.

Day-Ahead Energy Prices by Region

- The next figure presents monthly load-weighted average day-ahead energy prices in zones from West New York to Long Island.

West New York to New York City

- Between West NY and Capital Zone, the $8/MWh price difference is primarily due to transmission losses and congestion across the Central East interface.
- Between Capital Zone and the Lower Hudson Valley, the $2/MWh price difference are primarily due to expected congestion from Leeds to Pleasant Valley during Thunderstorm Alerts in the summer months.

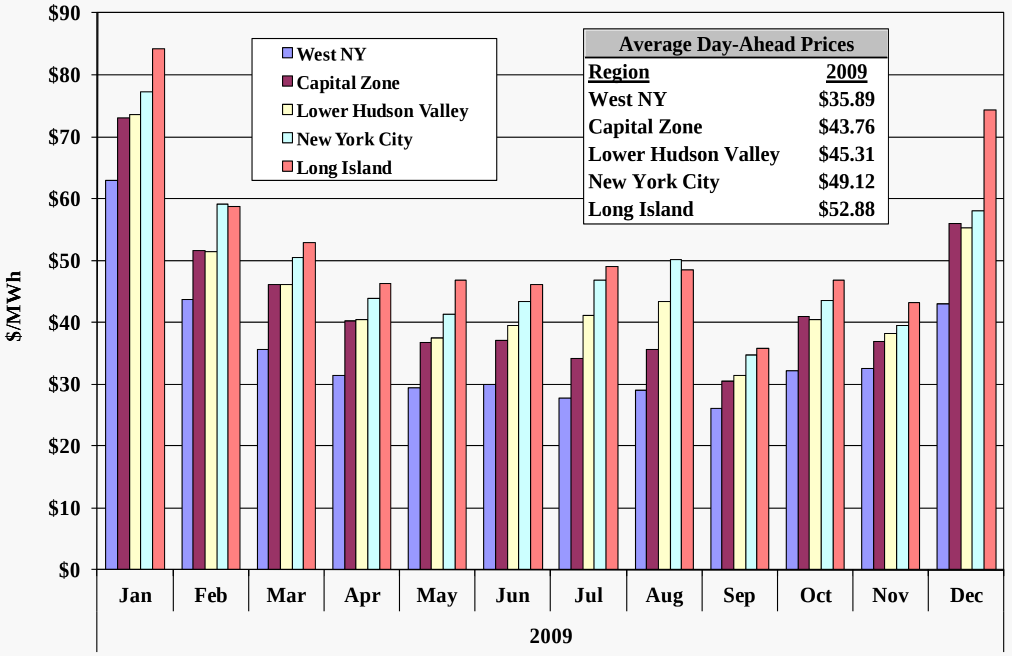
Into New York City

- The $4/MWh price premium in the New York City zone versus the lower Hudson Valley is primarily due to congestion into the Greenwood load pocket.

Into Long Island

- Prices were roughly $7.50 higher Long Island than the Lower Hudson Value due mainly to congestion on the two 345kV lines that bring power from upstate New York to Long Island.
  - ✓ In December, the outage of one of the lines (Sprainbrook-to-East Garden City) led to more frequent congestion into Long Island and particularly high LBMPs.

Day-Ahead Energy Prices by Region
2009

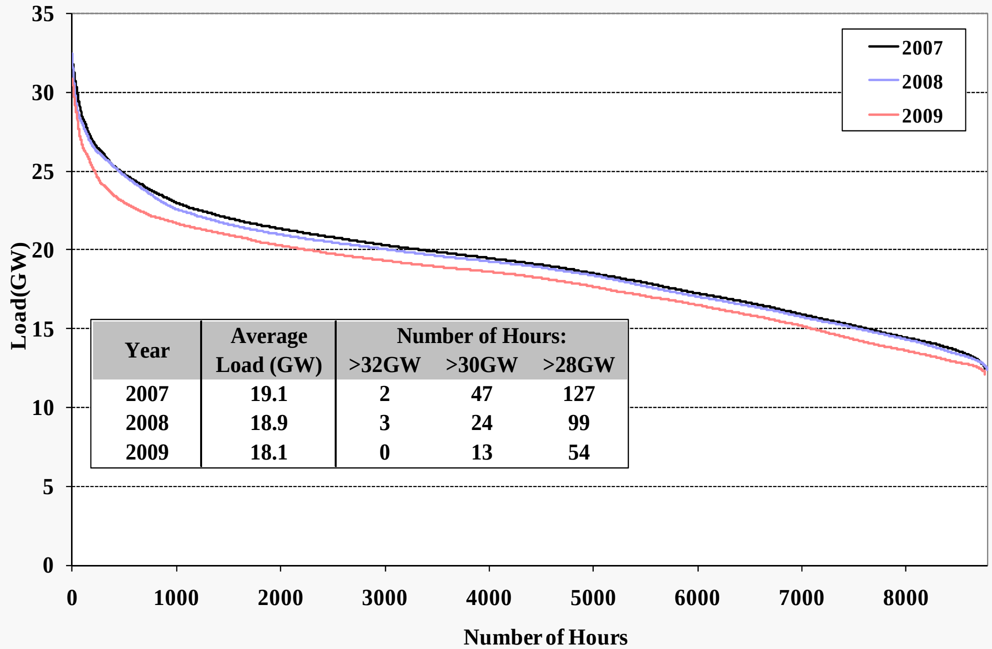


Note: Prices are load-weighted averages. West NY includes Zones A to E, and Lower Hudson Valley includes Zones G to I.

Load Profile

- Load levels are a fundamental determinant of market conditions. The next figure shows load duration curves for 2007 to 2009, which are effective in depicting overall changes in load levels.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- Across a wide range of hours, load decreased slightly from 2007 to 2008 and more substantially from 2008 to 2009.
  - ✓ Average load decreased 1 percent from 2007 to 2008 and 4 percent from 2008 to 2009.
- In the peak demand hours, load declined significantly from 2007 to 2009, resulting in less frequent shortage conditions and associated price spikes.
  - ✓ Load exceeded 30 GW during just 13 hours in 2009 compared to 24 hours in 2008 and 47 hours in 2007.
- The decreased load levels were driven primarily by mild summer weather and by poor economic conditions in 2009 that reduced demand for electricity.

Load Duration Curves for New York State 2007 – 2009

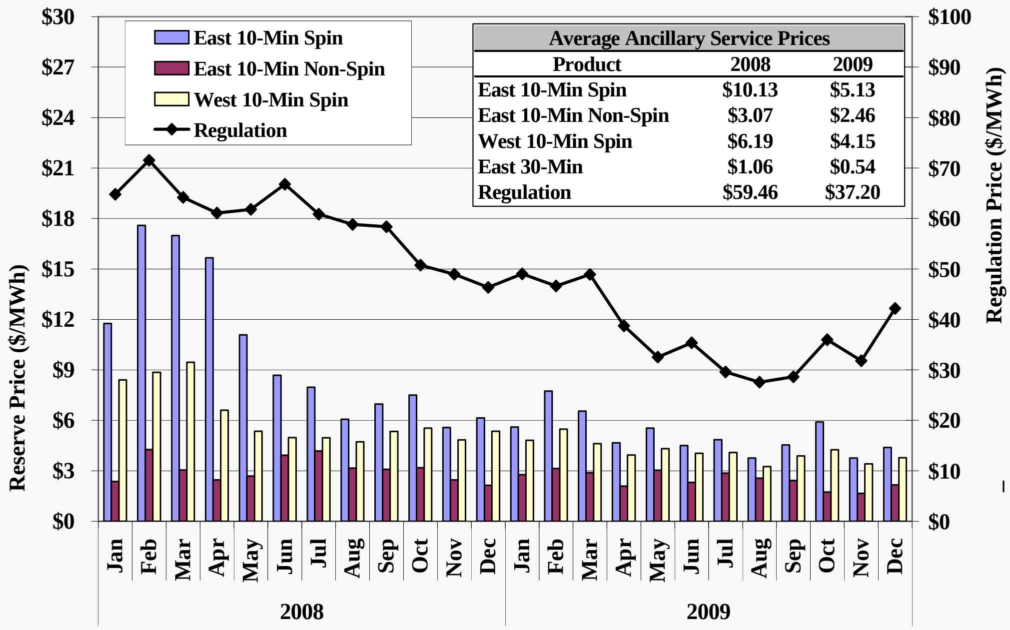


Year	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2007	19.1	2	47	127
2008	18.9	3	24	99
2009	18.1	0	13	54

Ancillary Services Prices

- The following figure summarizes the prices of several key ancillary services products in the day-ahead market in 2008 and 2009.
  - ✓ The NYISO has four ancillary services products: 10-minute spinning reserves, 10-minute total reserves, 30-minute reserves, and regulation.
  - ✓ The NYISO has locational reserve requirements, which result in differences between eastern and western reserve prices.
- To the extent that ancillary services are scheduled on capacity that would otherwise be economic to produce energy, changes in energy prices lead to corresponding changes in the cost of providing ancillary services.
- Regulation prices and 10-minute spinning reserve prices have decreased since early 2008 due to:
  - ✓ The general decline in fuel prices and energy prices; and
  - ✓ Reduced frequency of reserve and regulation shortages that result in transitory price spikes for these products.
- Differences between eastern and western 10-minute spinning reserves prices decreased after the first half of 2008, which is consistent with the reduced congestion from west to east during the same period.

Day-Ahead Ancillary Services Prices
2008 – 2009

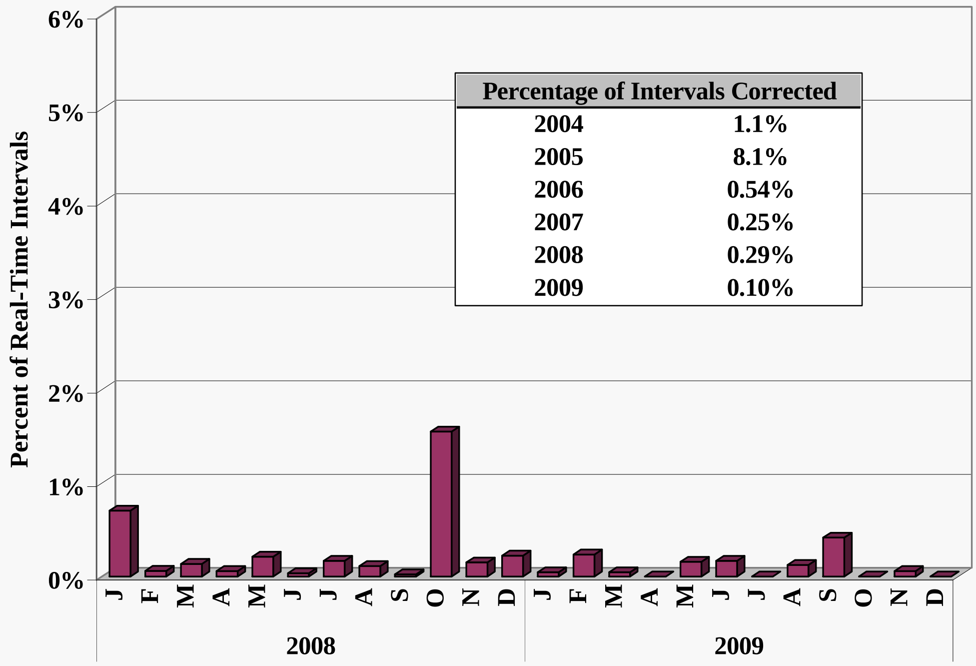


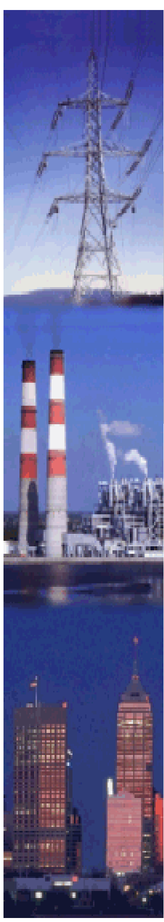
Average Ancillary Service Prices		
Product	2008	2009
East 10-Min Spin	$10.13	$5.13
East 10-Min Non-Spin	$3.07	$2.46
West 10-Min Spin	$6.19	$4.15
East 30-Min	$1.06	$0.54
Regulation	$59.46	$37.20

Price Corrections

- The following figure summarizes the frequency of price corrections in the real-time energy market in 2008 and 2009.
- Price corrections occur in all real-time energy markets due to:
  - ✓ Metering errors and other input data problems; or
  - ✓ Software flaws that cause pricing errors under certain conditions.
- Fewer price corrections reduce administrative burdens and uncertainty for market participants.
- The frequency of price corrections has declined sharply in recent years, and it was particularly low in 2009 at only 0.1 percent of intervals corrected.
  - ✓ Furthermore, the number of pricing locations affected has also decreased.
- Only one month exhibited above average price corrections in 2009.
  - ✓ Corrections in September 2009 were due to an issue that only affected one proxy generator bus.

Frequency of Real-Time Price Corrections 2008 – 2009





Market Prices and Outcomes: Long-Term Market Signals

Long-Term Market Signals – Net Revenue Methodology

- The following two figures show the estimated Net Revenue provided by the NYISO markets over the past four years at several locations.
  - ✓ Net Revenue is the energy, ancillary services, and capacity revenue that a new generator would earn above its variable production costs.
  - ✓ Net Revenue is calculated for a hypothetical gas turbine unit and a hypothetical combined cycle unit using two methods: the Standard Method and the Enhanced Method.
  - ✓ The standard method uses assumptions developed by FERC to standardize the results reported by market monitors.
- The Standard Method assumes the units sell at the day-ahead market prices considering variable O&M costs, forced outage rates, and fuel costs with heat rates of:
  - ✓ 7,000 BTU/kWh for the combined cycle; and
  - ✓ 10,500 BTU/kWh for the combustion turbine.
- The Enhanced Method also considers start-up costs, minimum run-times, other physical limits, and day-ahead and real-time settlement.

Long-Term Market Signals – Net Revenue Methodology

- The enhanced method assumes:
  - ✓ Units are committed based on day-ahead prices, considering start-up costs, and minimum run times and down-times (one hour for combustion turbines).
  - ✓ Combined cycles may sell energy, 10-minute and 30-minute spinning reserves; combustion turbines may sell energy and 30 minute reserves.
  - ✓ Online units respond to real-time prices while offline combustion turbines may be committed based on RTC prices.
  - ✓ The enhanced method also includes RGGI compliance costs and natural gas costs based on an index price for Transco Zone 6, although it does not incorporate additional gas transportation charges or balancing charges.
- The enhanced method uses the following assumptions that reflect our understanding of representative operating and cost parameters for these units:

Characteristics	CC	Upstate CT	Downstate CT
Size	500 MW	165 MW	100 MW
Startup Cost (Dollars)	$8,000	$11,000	$0
Startup Cost (MMBTUs)	5,000	360	0
Incremental Heat Rate (HHV)	8100 to 7,250	10,700	9,100
Min Run Time / Min Down Time	5 hours	1 hour	1 hour
Variable O+M	$0 / MWh	$1 / MWh	$5 / MWh

Long-Term Market Signals – Net Revenue Methodology

- The following figures summarize the results of the enhanced analysis.
  - ✓ A marker shows the standard net revenue analysis results for comparison.
- The results of the enhanced analysis differ from the standard analysis for the following reasons:
  - ✓ Start-up costs and minimum runtime restrictions reduce net revenues in the enhanced analysis;
  - ✓ Online units responding to real-time price signals increases net revenues in the enhanced analysis;
  - ✓ Economic commitment of offline combustion turbines after the day-ahead market by RTC increases net revenues in the enhanced analysis;
  - ✓ Higher heat rate assumptions for combined cycles reduce net revenues in the enhanced analysis; and
  - ✓ Higher heat rate assumptions for combustion turbines outside Southeast New York reduce net revenues in the enhanced analysis, while lower heat rates for combustion turbines in Southeast New York increase net revenues.

Long-Term Market Signals – Net Revenue Analysis

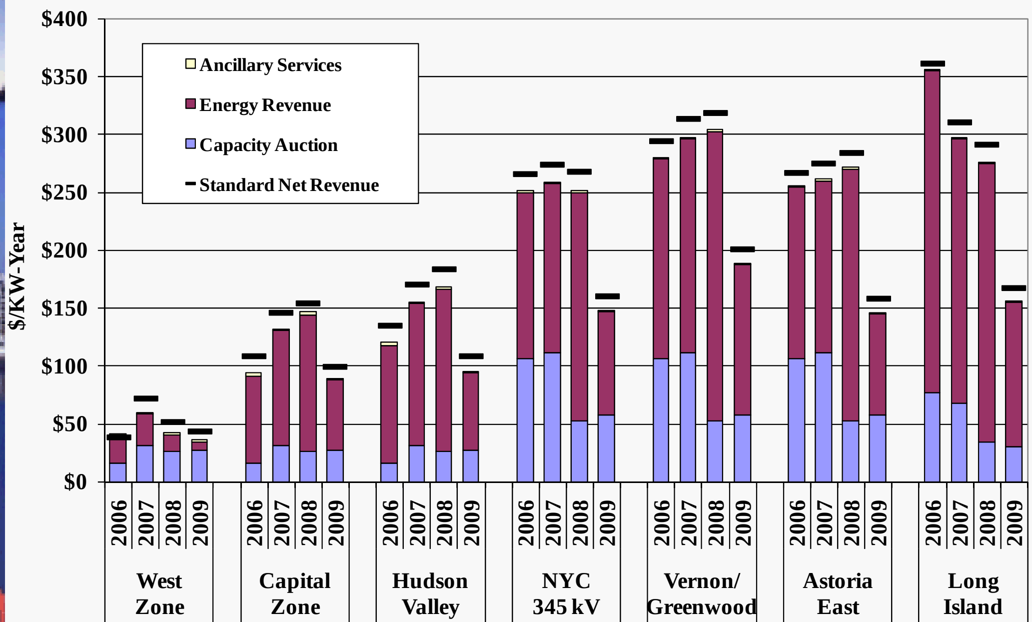
<u>2006 to 2008</u>

- Net revenue levels rose moderately in the Hudson Valley and Capital zones due to:
  - ✓ Additional congestion across the Central-East interface, which was particularly high in 2008 due to circuitous transactions scheduling around Lake Erie.
  - ✓ Increased capacity prices, resulting partly from the introduction of a new capacity market in New England in December 2006, which attracted some capacity that was previously sold into the NYISO market.
- Capacity net revenues declined throughout New York state in 2008 due to:
  - ✓ Increased capacity sales in New York City from previously withheld resources; and
  - ✓ The addition of the Neptune line into Long Island from New Jersey.

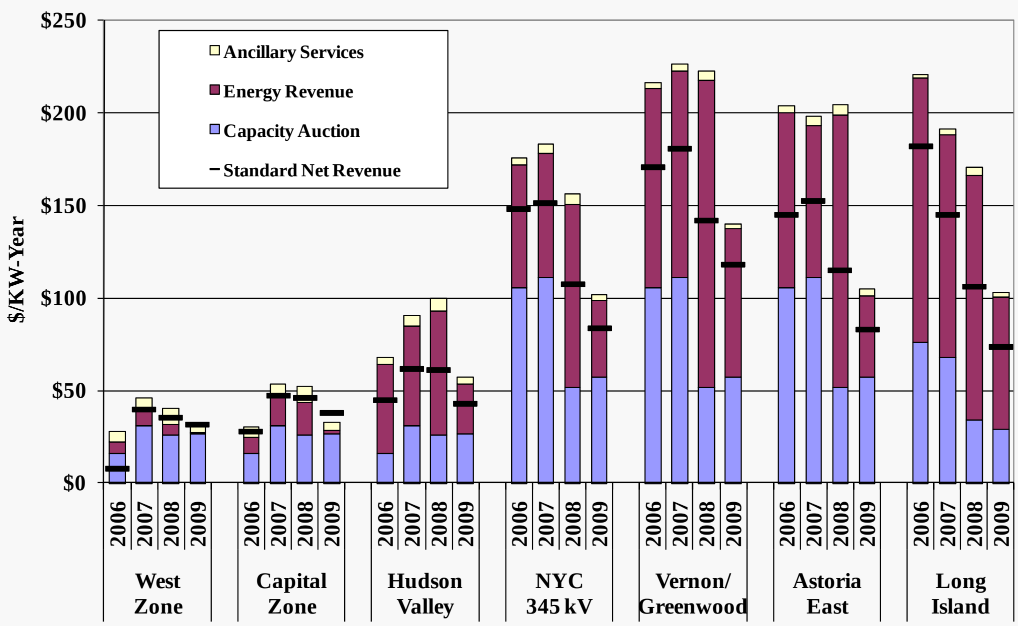
<u>2009</u>

- Fluctuations in fuel prices were the primary driver of variations in energy net revenues throughout New York state from 2008 to 2009.
  - ✓ Energy net revenues and fuel prices are generally correlated because higher fuel prices increase the spreads between energy prices and generators' production costs.
  - ✓ Accordingly, net revenues fell sharply as fuel prices decreased.
- Reductions in load also contributed to lower net revenues in 2009 throughout New York state.

Net Revenue for Combined-Cycle Unit
2006 – 2009



Net Revenue for Combustion Turbine
2006 – 2009



Long-Term Market Signals – Conclusions

- The estimated net revenues decreased substantially in 2009.
  - ✓ The estimated net revenues for a new CC decreased by roughly 40 percent in both New York City and in upstate areas in 2009.
  - ✓ These reductions are larger than those for CTs because fuel price fluctuations have a larger effect on more efficient units.
- Based on the net revenue levels in 2009 for the combustion turbines, we find that there are no areas where new CT investment might have been profitable.
  - ✓ This finding is based on the Cost of New Entry ("CONE") estimates used to determine the NYISO's Capacity Demand Curves:
    - – The estimated CONE for a new CT in New York City and upstate were $203/kW-year and $109/kW-year, respectively, for the 2009/10 Capability Period.
  - ✓ This is not surprising because load levels were relatively low and surplus capacity existed in New York City, in Long Island, and in the rest of the state.
- Although we do not have precise estimates of the CONE for a CC, it is unlikely that investment in a CC could be profitable based on the 2009 net revenues.

Market Prices and Outcomes
Convergence of Day-Ahead and Real-Time Prices

Day-Ahead and Real-Time Prices

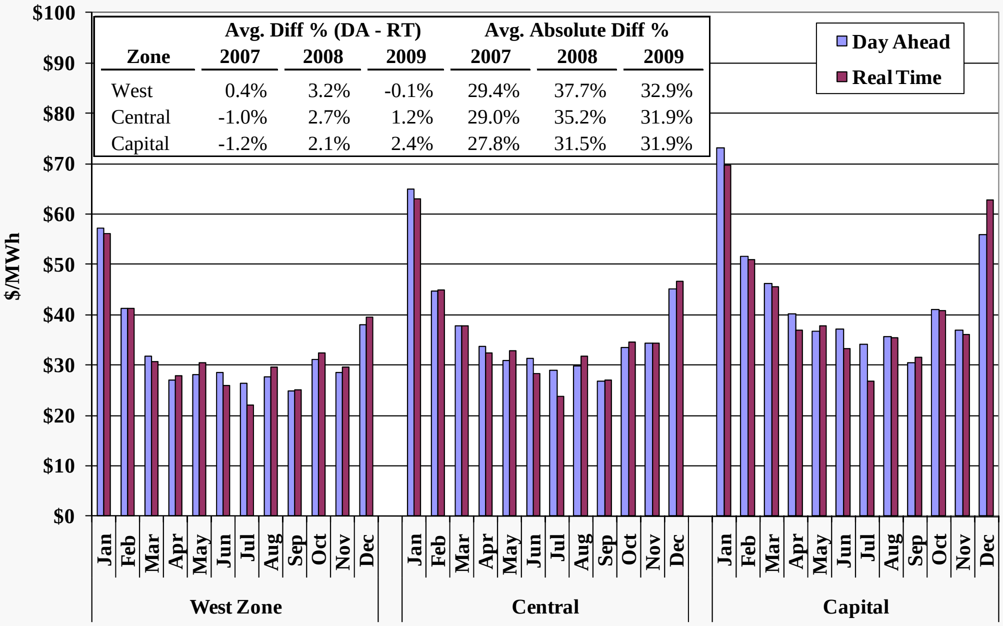
- The next set of analyses examines the convergence between day-ahead and real-time prices.
  - ✓ Price convergence is important because most generation is committed in the day-ahead market -- good price convergence leads to the most economic commitment of resources to serve load in real-time.
  - ✓ Good convergence also helps maintain efficient incentives for generators. Persistent systematic differences between day-ahead and real-time prices undermine incentives of generators to offer at marginal cost.
- There are two kinds of inconsistency between day-ahead and real-time prices:
  - ✓ Random variations between day-ahead and real-time prices due to unanticipated changes in energy supply and load; and
  - ✓ Persistent systematic differences between the average level of day-ahead prices and the average level of real-time prices.
- The analyses in this section of the report look for evidence of persistent systematic differences between day-ahead and real-time prices.

Day-Ahead and Real-Time Energy Prices

- The following two figures show monthly average day-ahead and real-time energy prices in several zones in 2009.
- Substantial day-ahead or real-time price premiums in individual months can occur randomly when real-time prices fluctuate unexpectedly.
  - ✓ Large real-time premiums can arise when real-time scarcity is not anticipated in the day-ahead.
    - – For example, extreme real-time congestion occurred into Long Island on December 16 due to the outage of the Sprainbrook-to-East Garden City line, which led to a large real-time premium in December.
  - ✓ Day-ahead premiums can arise when the day-ahead market anticipates more real-time scarcity than actually occurs (e.g., July 2009).
- Overall, price convergence was very good at the zone level in 2009.
  - ✓ The difference in average prices between the day-ahead and real-time markets was less than one percent in most areas.
  - ✓ The average absolute difference between day-ahead and real-time prices ranged from 30 to 35 percent in the areas shown.
  - ✓ This reflects that real-time energy prices are highly volatile in wholesale markets.

Average Day-Ahead and Real-Time Energy Prices
West, Central, and Capital Zones -- 2009

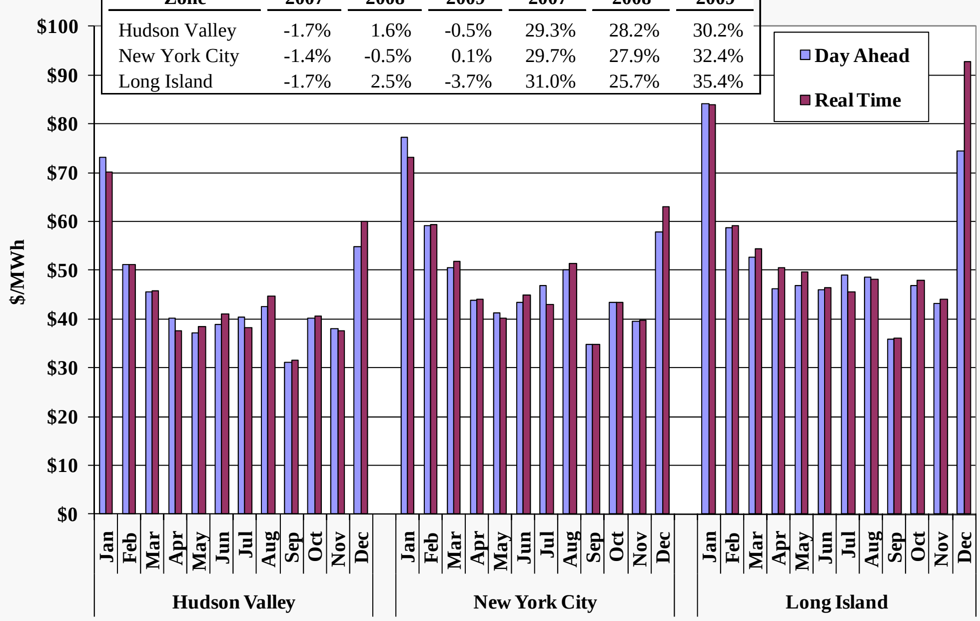
Zone	Avg. Diff % (DA - RT) 2007	2008	2009	Avg. Absolute Diff % 2007	2008	2009
West	0.4%	3.2%	-0.1%	29.4%	37.7%	32.9%
Central	-1.0%	2.7%	1.2%	29.0%	35.2%	31.9%
Capital	-1.2%	2.1%	2.4%	27.8%	31.5%	31.9%



Note: The prices are load-weighted averages.

Average Day-Ahead and Real-Time Energy Prices
Hudson Valley, New York City, and Long Island -- 2009

Zone	Avg. Diff % (DA - RT) 2007	2008	2009	Avg. Absolute Diff % 2007	2008	2009
Hudson Valley	-1.7%	1.6%	-0.5%	29.3%	28.2%	30.2%
New York City	-1.4%	-0.5%	0.1%	29.7%	27.9%	32.4%
Long Island	-1.7%	2.5%	-3.7%	31.0%	25.7%	35.4%



Note: The prices are load-weighted averages.

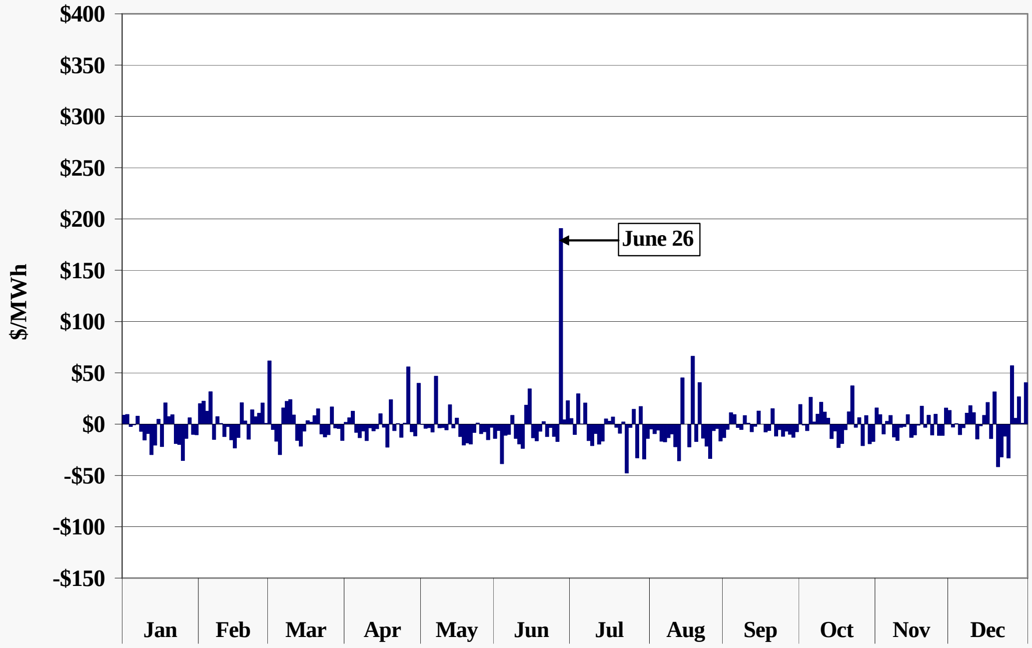
Day-Ahead and Real-Time Energy Prices

- The following two figures show average daily real-time price premiums for weekday afternoon hours for New York City and Long Island.
- Even when average day-ahead and real-time prices are consistent in a month, the figures show substantial differences on individual days.
- Market participants buy and sell in the day-ahead market based in part on their expectations of real-time market outcomes. Day-ahead decisions are influenced by several uncertainties:
  - ✓ Demand can be difficult to forecast with precision; the availability of supply may change due to forced outages or numerous other factors.
  - ✓ Special operating conditions, such as TSAs, may alter the capability of the transmission system in ways difficult to arbitrage in day-ahead markets.
  - ✓ Operators may commit additional generation for reliability after the day-ahead market, increasing the supply available to the real-time market.
- In general, day-ahead prices reflect the probability-weighted expectation of infrequent high-priced events in the real-time market.

Day-Ahead and Real-Time Energy Prices

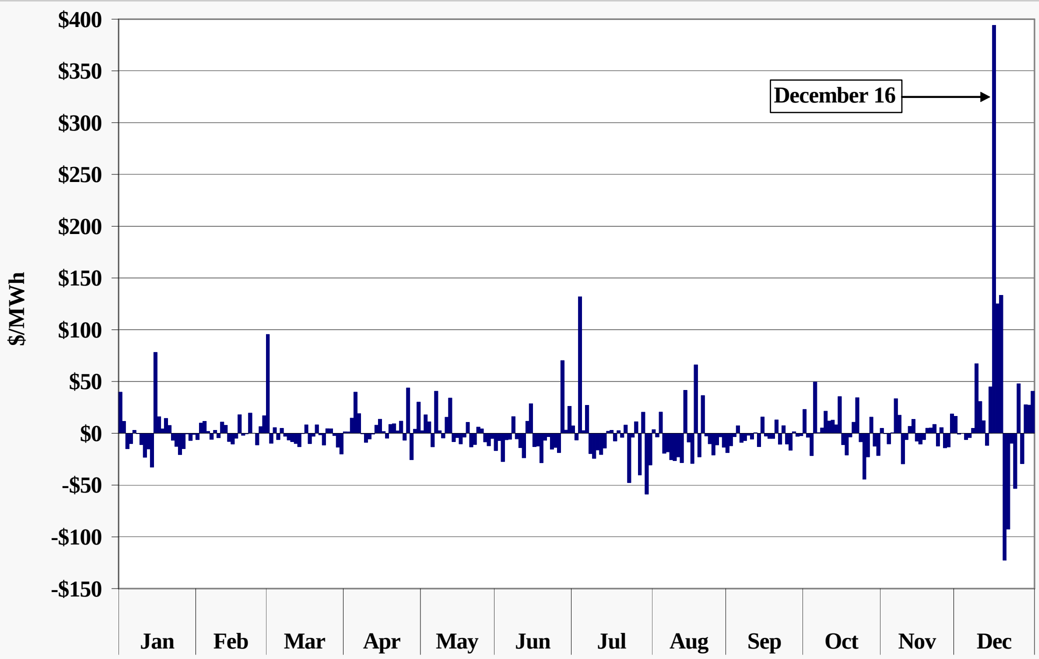
- Average day-ahead prices are higher than average real-time prices on the majority of afternoons shown in the following figures:
  - ✓ Day-ahead prices were higher than real-time prices on 60 percent of afternoons in New York City and 56 percent of afternoons in Long Island.
- However, high-price events are more frequent in the real-time market:
  - ✓ The day-ahead price premium did not exceed $50 per MWh in any afternoon in New York City, but it did in 4 afternoons in Long Island.
  - ✓ The real-time price premium exceeded $50 per MWh on 5 afternoons in New York City and 9 afternoons in Long Island.
- In New York City, the largest real-time price premium occurred on the afternoon of June 26 when the Leeds-to-Pleasant Valley line exhibited acute congestion for four hours during a TSA.
- In Long Island, the largest real-time price premium occurred on the afternoon of December 16 following the outage of one of the two 345 kV lines between upstate New York and Long Island.

Average Daily Real-Time Price Premium
New York City, 1 p.m. to 7 p.m. Weekdays, 2009



Note: The prices are load-weighted averages.

Average Daily Real-Time Price Premium
Long Island, 1 p.m. to 7 p.m. Weekdays, 2009



Note: The prices are load-weighted averages.

Day-Ahead and Real-Time Nodal Prices

- When real-time premiums vary substantially across locations, it indicates that day-ahead congestion patterns are different from real-time patterns.
- Congestion patterns may differ between the day-ahead and real-time for many reasons, including the following:
  - ✓ Differences between constraint limits used in the two markets.
  - ✓ Generators that are not scheduled day-ahead may increase their offers. This is common during periods of fuel price volatility or when gas is more easily procured day-ahead.
  - ✓ Constraints that are sensitive to the load levels may become more or less acute after the day-ahead market due to differences between expected load and load.
  - ✓ Transmission forced outages may occur and transmission maintenance schedules may change unexpectedly.
  - ✓ Generators may be committed or decommitted after the day-ahead market, which changes transmission flows.

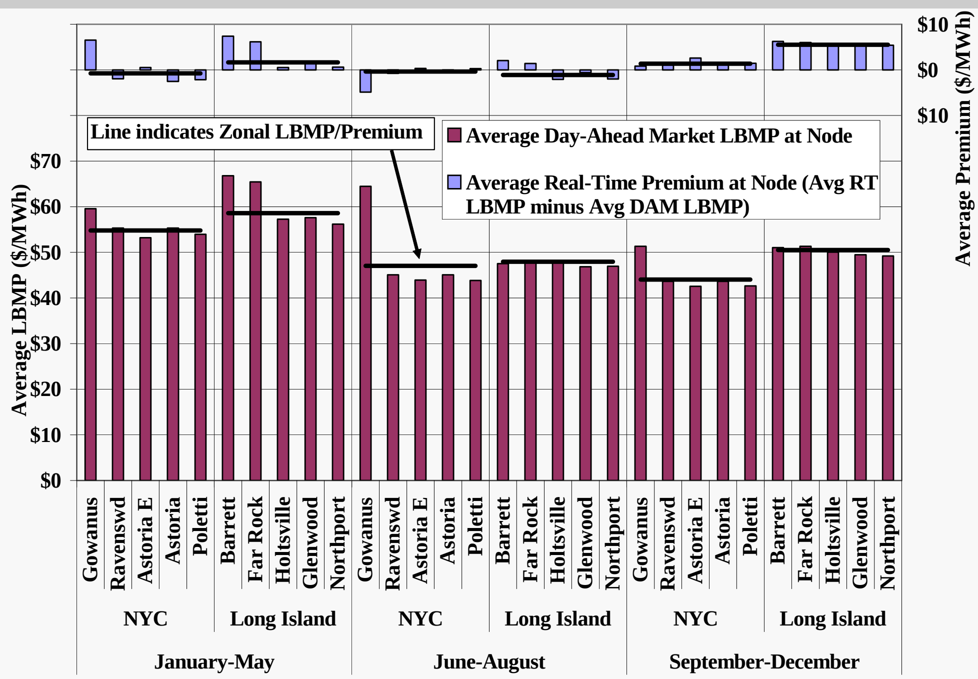
Day-Ahead and Real-Time Nodal Prices

- The following figure shows the average day-ahead LBMP and the average real-time price premium at several nodes in NYC and Long Island in 2009.
  - ✓ The NYC and Long Island zones are shown because they have exhibited the highest levels of intra-zonal congestion historically.
  - ✓ A review of similar data indicates better day-ahead to real-time convergence at the nodal level in up-state areas.
  - ✓ For comparison, the figure also shows the average day-ahead LBMP and the average real-time price premium at the zone level.
- The bottom portion of the figure shows several nodes that exhibit higher average LBMPs than the zone level in the day-ahead market, indicating nodes that are more import-constrained than other areas in the zone.
  - ✓ From January to May, these nodes also exhibited higher average real-time price premiums than the zone, indicating they were more import-constrained in real-time than in the day-ahead market.
  - ✓ Later in the year, this pattern was reversed in NYC at Gowanus due to a change in day-ahead modeling assumptions that was made in July.
    - – This reduced the assumed transfer capability into a NYC load pocket that had sometimes exhibited reduced transfer capability in real-time.

Day-Ahead and Real-Time Nodal Prices

- Convergence generally improved between day-ahead and real-time prices at the nodal level from 2008 to 2009.
  - ✓ For example, the average real-time price premium at the Gowanus location decreased from 45 percent of the average day-ahead LBMP in June to August 2008 to -8 percent in the same months of 2009.
- Several factors contributed to better convergence in 2009:
  - ✓ SRE commitments (which increase commitment after day-ahead market) have been less frequent due to changes that allow TOs to commit units for reliability in the day-ahead market (i.e., DARU commitment).
  - ✓ Simplified NYC interface constraints were used less frequently in real-time to manage congestion. (They are never used in the day-ahead market.)
    - – The share of binding NYC constraints that were interface constraints (rather than line constraints) decreased from 67 percent in 2008 to 43 percent in 2009.
- Currently, virtual trading is allowed at only the zonal level.
  - ✓ The NYISO has developed a concept for allowing virtual trading at a more disaggregated level.
  - ✓ This would improve convergence in NYC load pockets by allowing market participants to arbitrage day-ahead to real-time prices at the nodal level.

Average Real-Time Price Premium at Selected Nodes 2009



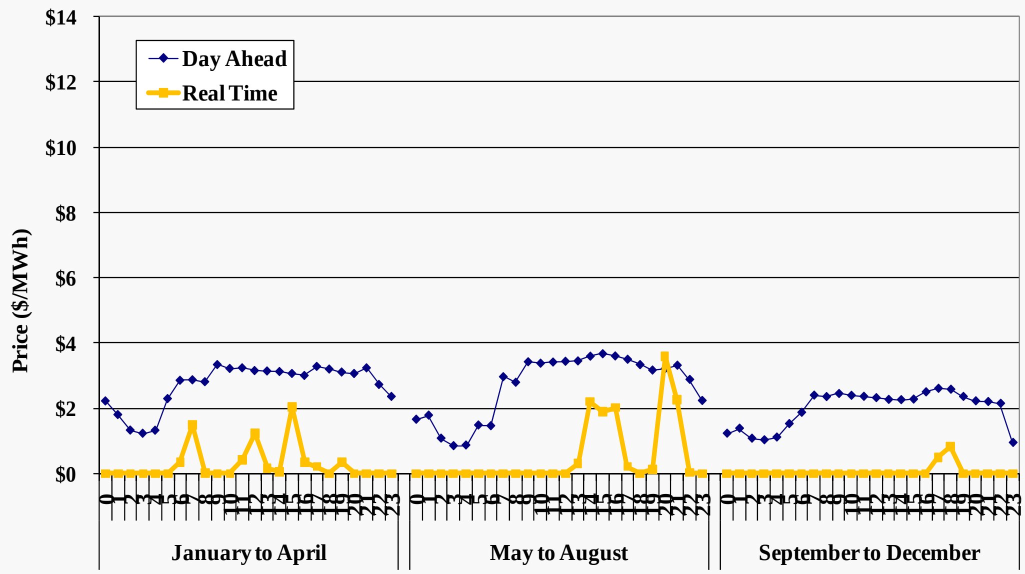
Day-Ahead and Real-Time Ancillary Services Prices

- The following figures summarize day-ahead and real-time clearing prices for the two most important reserve products in NY state.
  - ✓ The first figure shows 10-minute non-spinning reserve prices in eastern New York, which are primarily based on the requirement to hold 1,000 MW of 10-minute reserves east of the Central-East Interface.
  - ✓ The second figure shows 10-minute spinning reserve prices in western New York, which are primarily based on the requirement to hold 600 MW of 10-minute spinning reserves in New York state.
  - ✓ Average prices are shown by season and by hour of day.
- The market models use "demand curves" that place an economic value on meeting each of these requirements.
- Average day-ahead prices are substantially higher than average real-time prices in most hours.
  - ✓ However, average real-time prices are sometimes substantially higher during afternoon hours.

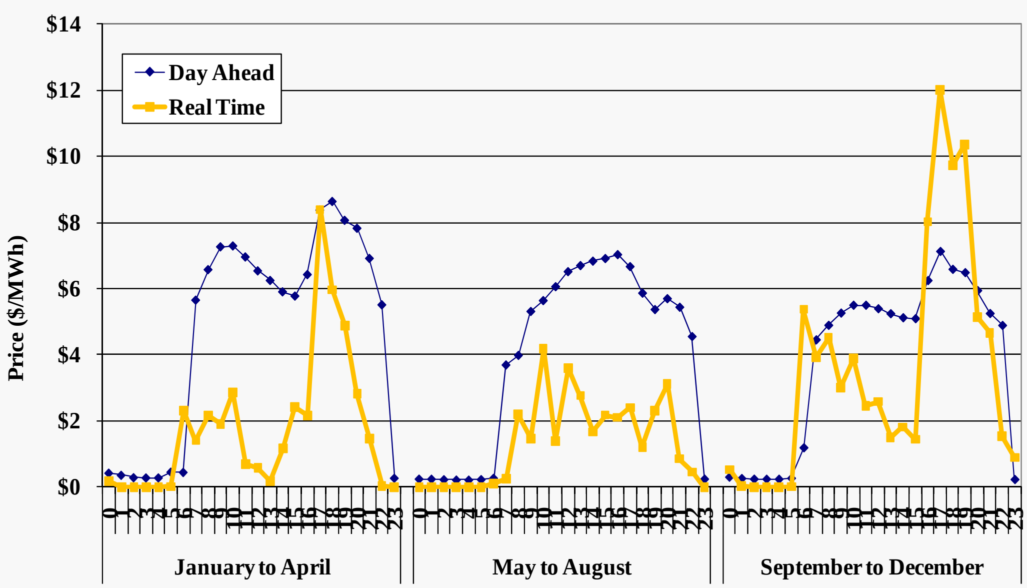
Day-Ahead and Real-Time Ancillary Services Prices

- Real-time reserve prices are generally volatile, making them difficult for market participants to predict in the day-ahead market.
  - ✓ Eastern real-time 10-minute non-spinning reserves prices are normally close to $0, reflecting the excess available reserves from off-line GTs.
    - – However, real-time prices can spike during periods of tight supply.
    - – It can be risky to sell reserves in the day-ahead market. If the real-time price spikes, the supplier can incur substantial losses or foregone profits.
  - ✓ 10-minute spinning reserves prices are less volatile, but still prone to unexpected spikes.
- Day-ahead reserve prices tend to fluctuate based on the expected likelihood of a real-time price spike.
  - ✓ The fact that day-ahead prices were consistently higher than real-time prices in certain periods when real-time price spikes are particularly unlikely suggests that participants over-estimated the frequency of real-time price spikes.
- Average day-ahead reserve prices may be lower than real-time prices in certain periods due to day-ahead offer limitations, which we discuss in the next section.

10-Minute Non-Spinning Reserve Prices in East NY by Season and Hour of Day, 2009



10-Minute Spinning Reserve Prices in West NY by Season and Hour of Day, 2009



Analysis of Bids and Offers: Energy Offer Patterns

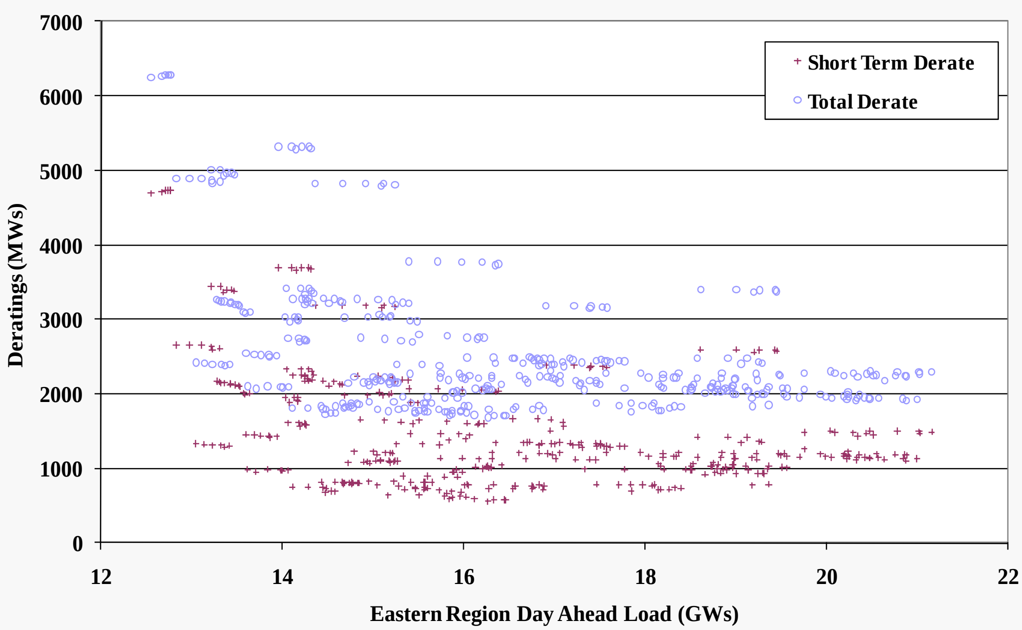
Analysis of Energy Offer Patterns

- This section of the report analyzes patterns of conduct that could indicate physical or economic withholding.
- This analysis evaluates the correlation of quantities of potential withholding to load levels.
  - ✓ Suppliers in a competitive market should increase offer quantities during higher load periods to sell more power at the higher peak prices;
  - ✓ Suppliers in markets that are not workably competitive will have the greatest incentive to withhold at peak load levels when the market impact is the largest.
  - ✓ Hence, this analysis highlights market participant behavior that may reflect attempts to withhold resources to raise prices.
- The first analysis examines potential physical withholding, which includes total generation deratings (including planned outages, forced outages, and partial deratings).

Analysis of Offer Patterns – Deratings

- The following figure plots long-term deratings and short-term deratings versus actual load in eastern New York during peak hours in the summer.
  - ✓ The figures focus on east New York because this area includes two-thirds of the State's load and is more vulnerable to the exercise of market power due to the limited import capability into the area.
  - ✓ The analysis focuses on the summer to exclude the effects of planned outages that typically occur during off-peak seasons, and because market power is most likely during the higher load conditions in the summer.
  - ✓ Long-term deratings are measured relative to the most recent DMNC test value. Short-term deratings exclude quantities lasting more than 30 days.
  - ✓ The short-term deratings are more likely to reflect physical withholding since it is more costly to withhold via long-term deratings or outages.
- The figure shows that long-term deratings and short-term deratings do not increase during the highest load conditions, which is consistent with expectations for a competitive market.

Deratings versus Actual Load in East New York Peak Hours* in Summer 2009



* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

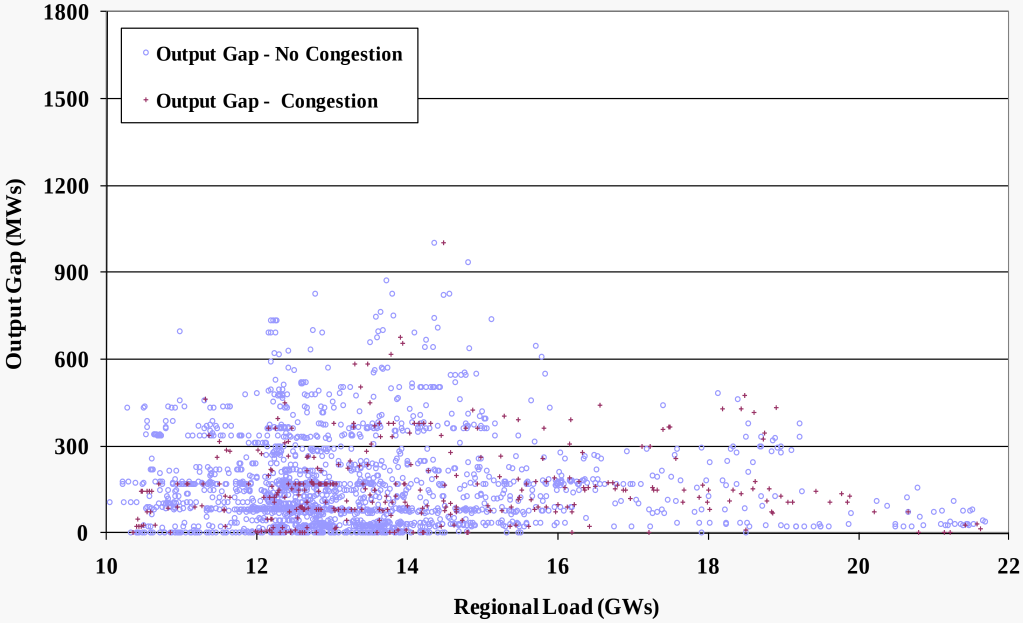
Analysis of Offer Patterns – Output Gap

- The second analysis examines potential economic withholding, employing the "output gap" metric.
- The output gap is the quantity of economic capacity that does not produce energy because a supplier submits an offer price well above a unit's competitive offer price (represented by its reference level in this analysis).
- The output gap:
  - ✓ Addresses all components of a supplier's offer, including start-up, minimum generation, and incremental energy offers.
  - ✓ Excludes capacity that is more economic to provide ancillary services.
- Like the prior analysis of deratings, output gap levels that rise with load would indicate potential competitive concerns, particularly if this occurs during periods of congestion.

Analysis of Offer Patterns – Output Gap

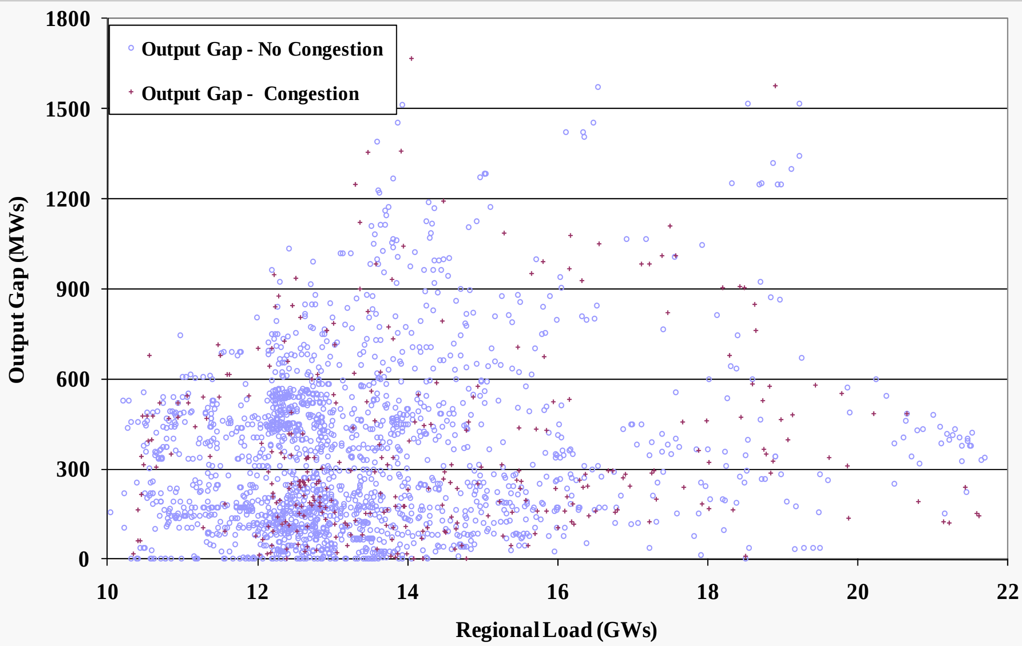
- The following two figures show the real-time output gap in eastern New York during peak hours:
  - ✓ The first chart uses the standard conduct threshold used for mitigation outside New York City, which is the lower of $100/MWh or 300 percent.
  - ✓ The second chart uses a lower conduct threshold of $50/MWh or 100 percent (whichever is lower).
- Congested hours and non-congested hours are indicated separately to show whether the output gap increases during periods of congestion.
- These figures indicate that the average levels of output gap are similar across high and low load conditions for congested and uncongested hours.
  - ✓ These results are consistent with the expectations for a competitive market.
  - ✓ These results are particularly notable for the lower threshold because this conduct is not subject to mitigation.
- We review significant instances of output gap to determine whether they may be an indication of potential withholding.
  - ✓ These reviews have not indicated that these isolated instances raise potential competitive concerns.

Real-Time Output Gap at Mitigation Threshold
East New York -- Peak Hours* of 2009



* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

Real-Time Output Gap at Lower Threshold
East New York -- Peak Hours* of 2009

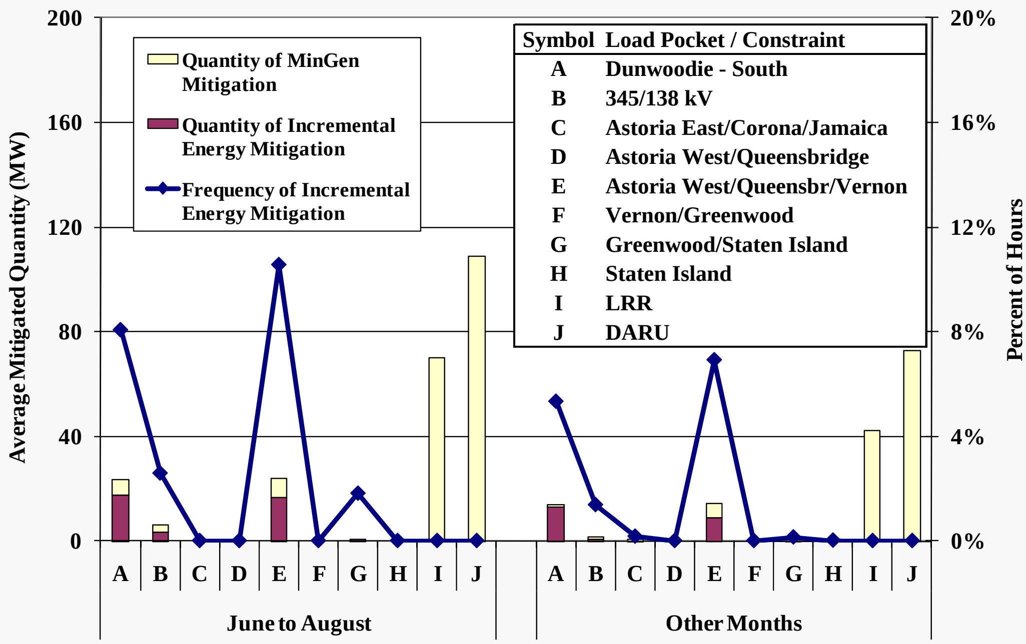


* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

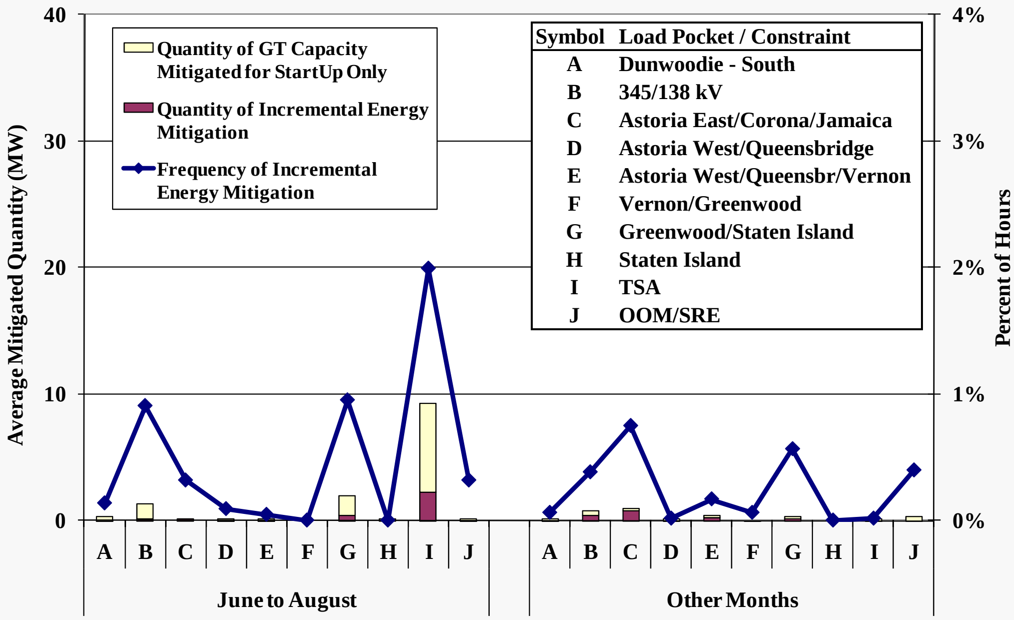
Summary of Mitigation

- The market power mitigation measures are based on the conduct and impact framework, and are triggered when constraints bind into New York City load pockets.
  - ✓ This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.
- The following two figures summarize the amount of mitigation that occurred in New York City in the day-ahead market and in the real-time market (but not guarantee payment mitigation that occurs in settlements).
  - ✓ In the day-ahead market, mitigated quantities are shown separately for (i) the flexible output ranges of units (i.e. incremental energy) and (ii) the non-flexible portions (i.e., MinGen).
  - ✓ In the real-time market, mitigated quantities are shown separately for (i) incremental energy and (ii) the capacity of GTs that is mitigated for start-up.
  - ✓ The bars show the average amount of capacity mitigated in each location across all hours.
  - ✓ The lines show the percent of hours when energy mitigation was imposed.

Summary of Day-Ahead Mitigation
New York City in 2009



Summary of Real-Time Mitigation
New York City in 2009



Symbol	Load Pocket / Constraint
A	Dunwoodie - South
B	345/138 kV
C	Astoria East/Corona/Jamaica
D	Astoria West/Queensbridge
E	Astoria West/Queensbr/Vernon
F	Vernon/Greenwood
G	Greenwood/Staten Island
H	Staten Island
I	TSA
J	OOM/SRE

Summary of Mitigation

- In the day-ahead market, the majority of mitigation is of units that are committed for local reliability (i.e., “LRR” and “DARU”).
  - ✓ These units are mitigated whenever their start-up or MinGen offers exceed the reference level.
- Most of the energy offer mitigation in the day-ahead market is associated with constraints that bind into the Dunwoodie-South and the Astoria West/Queensbridge/Vernon load pockets.
- The majority of the real-time mitigation occurs when constraints bind during TSA operation.
  - ✓ During these periods, the start-up offers of gas turbines may be mitigated at start-up.
- Overall, the majority of energy offer mitigation occurs in the day-ahead market rather than the real-time market due to:
  - ✓ The use of tighter conduct and impact thresholds in the day-ahead market; and
  - ✓ Most energy is initially scheduled in the day-ahead market, and offers scheduled in the day-ahead market cannot be increased in real time.

Analysis of Bids and Offers: Ancillary Services Offer Patterns

Day-Ahead Ancillary Services Offers

- The following figure evaluates day-ahead offers to provide ancillary services in each month of 2009.
  - ✓ The quantities offered are shown for the following categories:
    - 10-minute spinning reserves in western New York;
    - 10-minute spinning reserves in eastern New York;
    - 10-minute non-spinning reserves in eastern New York; and
    - Regulation.
  - ✓ Offer quantities are shown according to offer price level for each category.

10-minute spinning reserve capacity

- Offer quantities decline in the shoulder months when more capacity is out-of-service for planned maintenance.
- Offer prices decreased significantly during 2009.
  - ✓ The quantity offered below \$10/MWh increased from an average of 1,850 MW in January to 2,520 MW in December.
  - ✓ Lower fuel prices and energy prices likely led to the lower offer prices.
- Offer prices are substantially lower in the east than in the west because NYC generators are required to offer at \$0/MWh.

Day-Ahead Ancillary Services Offers

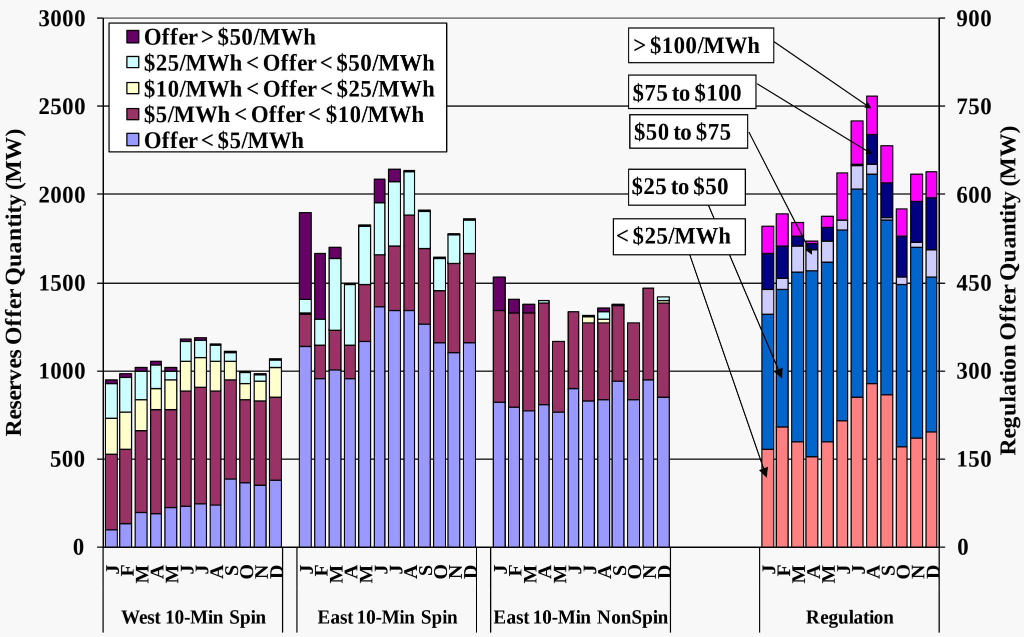
10-minute non-spinning reserves

- Offer quantities decline in the summer due to the reduced capability of GTs (primarily due to higher ambient temperatures) which provide the majority of non-spinning reserves in Eastern New York.
- Suppliers may avoid being scheduled in the day-ahead market by raising their offer prices in periods when:
  - ✓ Day-ahead prices tend to be lower than expected real-time prices; or
  - ✓ There is a risk that a real-time price spike will coincide with the supplier failing to start, leading the supplier to incur substantial losses in the balancing market.
- However, offer price increases are limited by the mitigation rules, which cap the reference levels of 10-minute non-spinning reserve units at \$2.52/MWh.
- Suppliers are likely to continue offering even when the expected cost exceeds their offer price, since non-PURPA ICAP units that have 10-minute non-spinning reserve capability are required to offer it in the day-ahead market.

Regulation

- Regulation offer quantities increased during the summer months when few units are on outage and many steam units offer more frequently.

Summary of Ancillary Services Offers Day-Ahead Market in 2009



Note: Spinning and non-spinning offers are an average of 1pm to 7pm, while regulation includes all hours.

Ancillary Services Offers – Conclusions and Recommendations

- Average day-ahead reserves prices are systematically higher than real-time prices in the majority hours.
  - ✓ This is consistent with the risks suppliers may incur by selling in the day-ahead market.
  - ✓ The day-ahead premium is also likely due to the reduced frequency of real-time price spikes in 2009.
- Average real-time prices are substantially higher than average day-ahead prices during afternoon hours under some conditions.
  - ✓ Systematically low day-ahead prices in these hours increase the opportunity cost of selling reserves in the day-ahead market.
  - ✓ Adjustments in day-ahead offer prices by reserve suppliers are likely to improve convergence between day-ahead and real-time.
- We recommend the NYISO reconsider two provisions in the mitigation measures that may limit competitive offers in the day-ahead market:
  - ✓ Limiting GTs to a 10-minute non-spinning reserve reference of $2.52/MWh.
  - ✓ Requiring NYC steam units to offer 10-minute spinning reserves at $0/MWh.

Analysis of Bids and Offers: Load Bidding and Virtual Trading

POTOMAC ECONOMICS

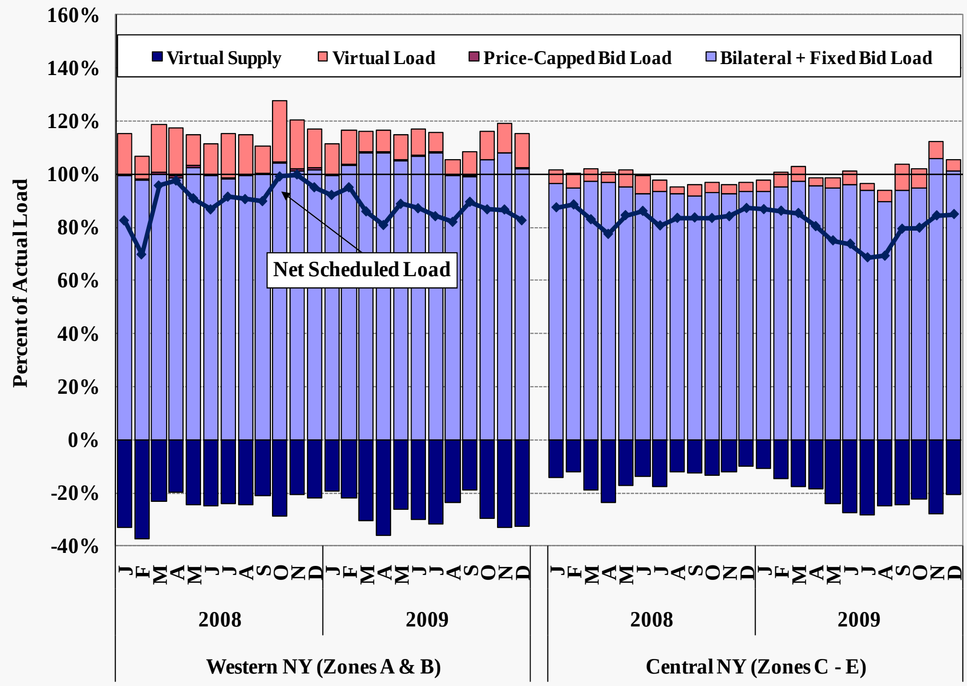
Load Bidding Patterns in the Day-Ahead Market

- The following three figures summarize the quantity of day-ahead load scheduled as a percent of real-time load in 2008 and 2009 in six regions.
  - ✓ Virtual supply nets out an equivalent amount of scheduled load, so it is shown as a negative quantity.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- On a state-wide basis, the average amount of load scheduled in the day-ahead market is slightly lower than the average amount of real-time load.
  - ✓ The ratio of average net load scheduled in the day-ahead market to average real-time load was 97 percent in 2008 and 96 percent in 2009.
  - ✓ Since price convergence was good in 2009, we conclude that the slight under-scheduling does not raise efficiency concerns.
    - – The under-scheduling likely reflects the additional supply that is sometimes committed after the day-ahead market.
- Load is usually over-scheduled in NYC and Long Island and under-scheduled in up-state NY.
  - ✓ This implies that, on average, the day-ahead market schedules more imports into NYC and Long Island than the real-time market.

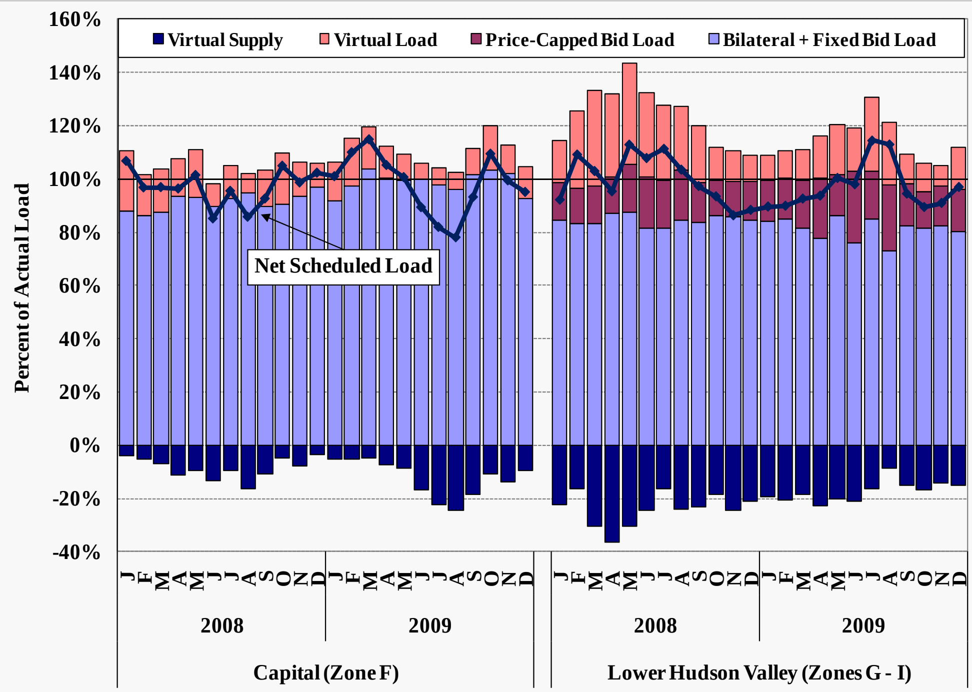
Load Bidding Patterns in the Day-Ahead Market

- The figures show that the market generally responds rationally to differences between congestion patterns in the day-ahead and real-time markets.
  - ✓ Thunderstorm Alerts become more frequent in the summer, resulting in transmission limits from the Capital Zone to the Hudson Valley that are tighter in the real-time market than in the day-ahead.
  - ✓ This provides incentives for market participants to:
    - – Schedule virtual load in Southeast New York (Zones G – K) in anticipation of higher real-time prices; and
    - – To schedule virtual supply outside Southeast New York in anticipation of lower real-time prices.
- Accordingly the ratio of average net scheduled load to average real-time load in 2009 was:
  - ✓ 109 percent in the summer vs. 93 percent in other months in Zones G – I;
  - ✓ 83 percent in the summer vs. 103 percent in other months in the Capital Zone; and
  - ✓ 70 percent in the summer vs. 83 percent in other months in Zones C – E.

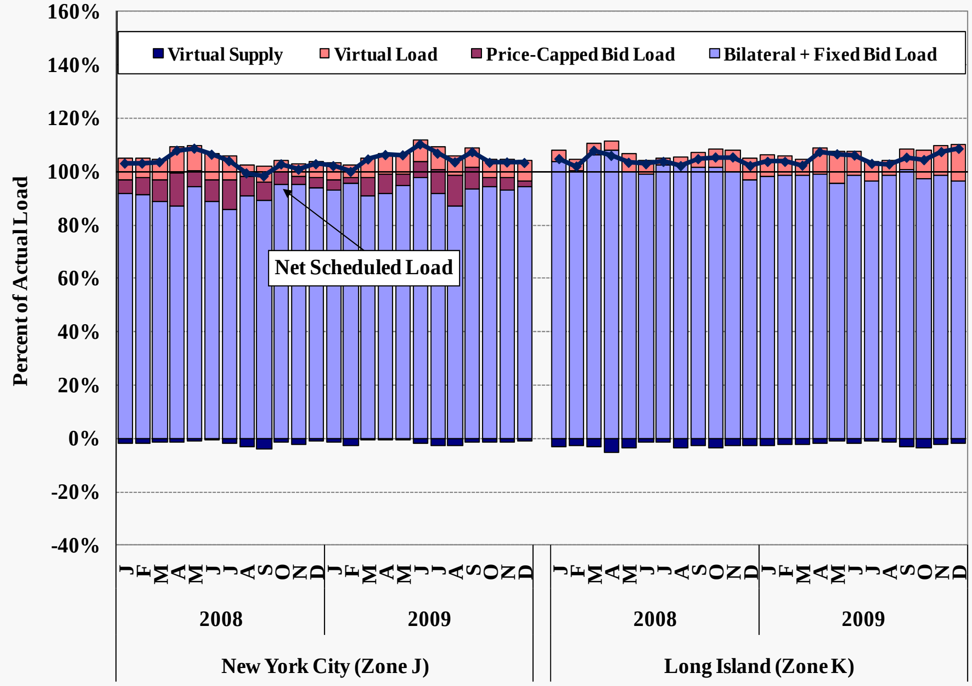
Day Ahead Load Schedules versus Actual Load
West Up-State New York, 2008 – 2009



Day-Ahead Load Schedules versus Actual Load
East Up-State New York, 2008 – 2009



Day-Ahead Load Schedules versus Actual Load
New York City and Long Island, 2008 – 2009



Transmission Congestion

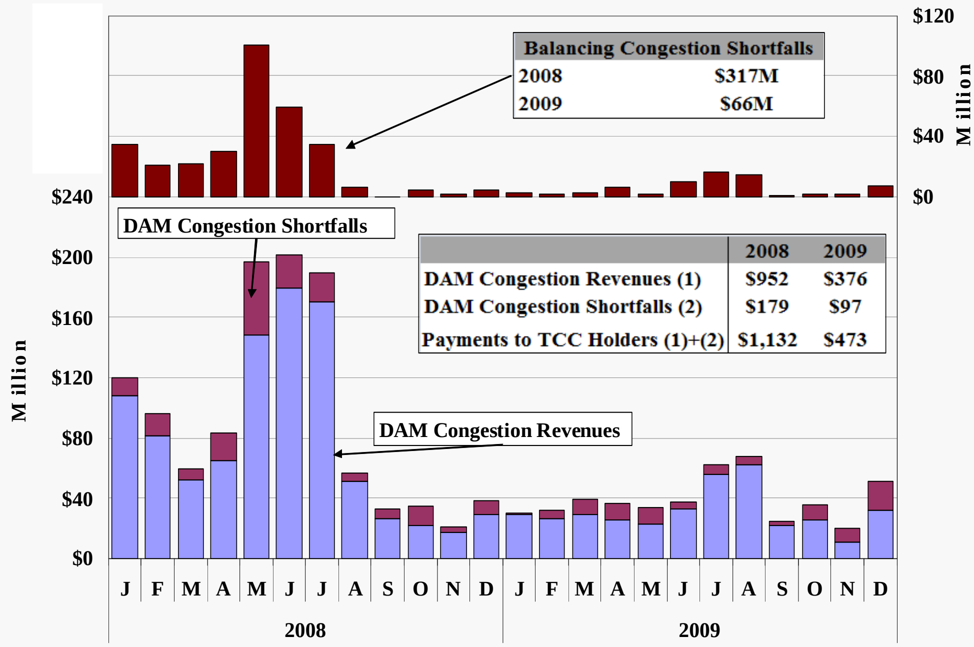
Congestion Revenue Collections and Shortfalls

- The first part of this section evaluates day-ahead and real-time congestion patterns in 2009.
- The first figure shows the following categories of congestion costs:
  - ✓ *Day-Ahead Congestion Revenues* are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market.
  - ✓ *Day-Ahead Congestion Shortfalls* occur when day-ahead congestion revenues collected by the NYISO are less than entitlements of TCC holders.
    - – Shortfalls arise when the quantity of TCCs on a path exceeds the transfer capability of the path modeled in the day-ahead market when it is congestion.
    - – Day-ahead congestion shortfalls are equal to the difference between payments to TCC holders and day-ahead congestion revenues.
  - ✓ *Balancing Congestion Shortfalls* occur when day-ahead scheduled flows over a facility exceed what can flow over the facility in real-time.
    - – This requires the ISO to re-dispatch generation on each side of the facility in the real-time market, which results in balancing congestion shortfalls that are recovered through uplift.

Congestion Revenue Collections and Shortfalls

- The following figure summarizes day-ahead congestion revenue, day-ahead congestion shortfalls, and balancing congestion shortfalls in 2008 and 2009.
- The figure shows that day-ahead congestion revenue fell 61 percent from 2008 to 2009 due primarily to:
  - ✓ Lower fuel costs, which reduced congestion price differences;
  - ✓ Lower load levels, which reduced flows into constrained areas; and
  - ✓ The reduced impact of clockwise Lake Erie circulation.
- Day-ahead congestion revenues and balancing congestion shortfalls rose during the summer months, which is normal due to higher loads and more frequent Thunderstorm Alerts (“TSAs”).
- Day-ahead congestion shortfalls were highest in the spring and fall, which is typical because transmission outages (that are reflected in the day-ahead market but not in the TCC auctions) are more frequent in shoulder months.
  - ✓ 56 percent of the total day-ahead congestion shortfall in 2009 accrued in the shoulder months (i.e., March to May and September to November).
- Balancing congestion shortfalls were much higher in 2008 than in 2009.
  - ✓ This was largely due to loop flows associated with circuitous transaction scheduling, which was prohibited in July 2008.

Congestion Revenue Collections and Shortfalls 2008 – 2009



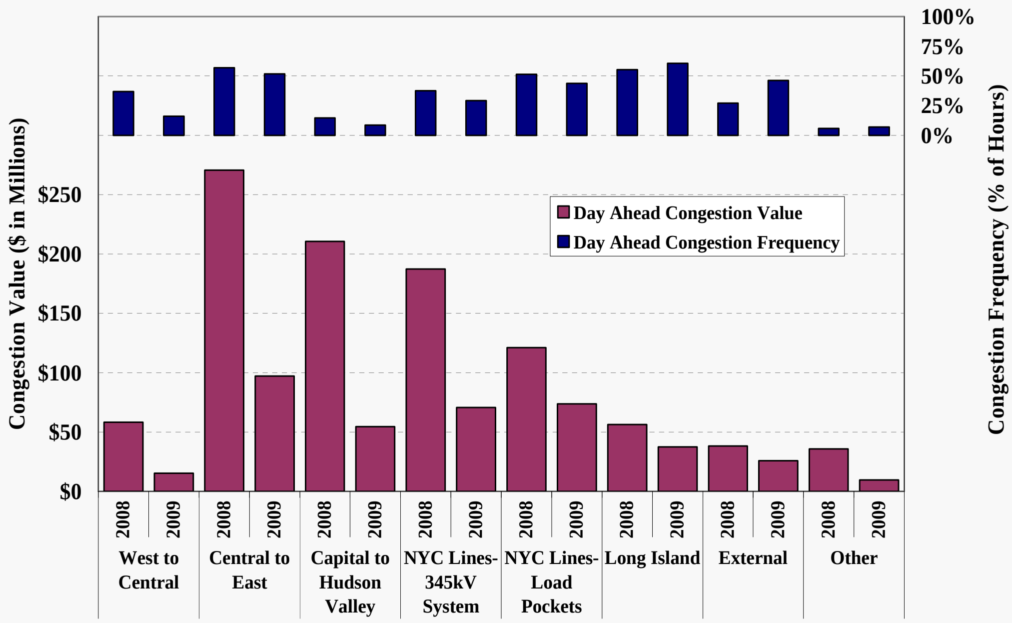
Congestion by Transmission Path

- 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 congestion equals 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 equals the congestion revenue collected by the NYISO.
- The two figures group congestion along the following transmission paths:
  - ✓ West to Central: Primarily Dysinger East, West-Central, and West Export interfaces.
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ Capital to Hudson Valley: Primarily the Leeds-to-Pleasant Valley line during TSAs.
  - ✓ NYC Lines – 345 kV system: Lines leading into and within the NYC 345kV system.
  - ✓ NYC Lines – Load Pockets: Lines leading into and within NYC load pockets.
  - ✓ NYC Simplified Interface Constraints: Groups of lines in NYC that are modeled as interfaces.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ External Interface: Congestion related to the total transmission limits or ramp limits of the nine external interfaces.

Day-Ahead Congestion by Transmission Path

- The next figure summarizes the frequency of congestion and congestion revenue collected by transmission path in the day-ahead market.
- Day-ahead congestion patterns are determined by the market participants' bids and offers, which reflect their expectations of real-time congestion.
  - ✓ Congestion is more frequent in the day-ahead market than in real-time, but shadow prices of constrained interfaces are generally lower in the day-ahead.
- The majority of day-ahead congestion revenue was collected for paths from Capital to Hudson Valley (14 percent), from Central to East (25 percent), and in New York City (38 percent).
  - ✓ The substantial decrease in fuel prices contributed to sharp declines in the value of congestion over each path in 2009.
- The patterns of congestion in the day-ahead and the real-time market were similar for most paths in 2009, except for:
  - ✓ The Capital to Hudson Valley path, which exhibited less congestion in the day-ahead market due to the tighter criteria used in real-time during TSAs.
  - ✓ Lines into the Greenwood/Staten Island load pocket, which exhibited more congestion in the day-ahead market.
    - – This was partly due to day-ahead modeling assumptions that reduced transfer capability into New York City load pockets that sometimes exhibit reduced transfer capability in real-time.

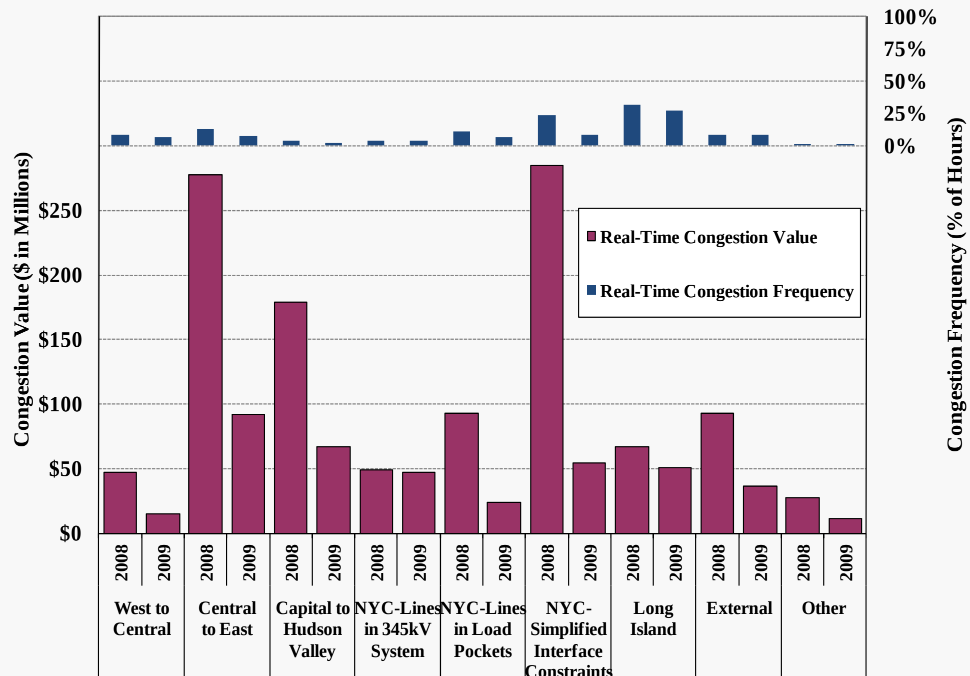
Day-Ahead Congestion by Transmission Path 2008 – 2009



Real-Time Congestion by Transmission Path

- The following figure summarizes the value and frequency of congestion by transmission path in the real-time market for 2008 and 2009.
- Most real-time congestion (71 percent) was in the following areas in 2009:
  - ✓ Central to East: 23 percent
  - ✓ Capital to Hudson Valley: 17 percent
    - – Most of this occurred during TSA events in the summer.
  - ✓ NYC lines and simplified interface constraints: 31 percent
    - – The use of simplified interface constraints decreased from 2008 to 2009, which substantially reduced the share of the real-time congestion value associated with simplified interface constraints.
- December exhibited the most congestion of any month ($52 million) in 2009.
  - ✓ This was primarily associated with the Central-East interface, the Greenwood load pocket in NYC, and lines from upstate to Long Island.
  - ✓ The increase was partly due to higher fuel prices that tend to increase the value of congestion, and an outage of one of the two major lines between upstate and Long Island.

Real-Time Congestion by Transmission Path
2008 – 2009



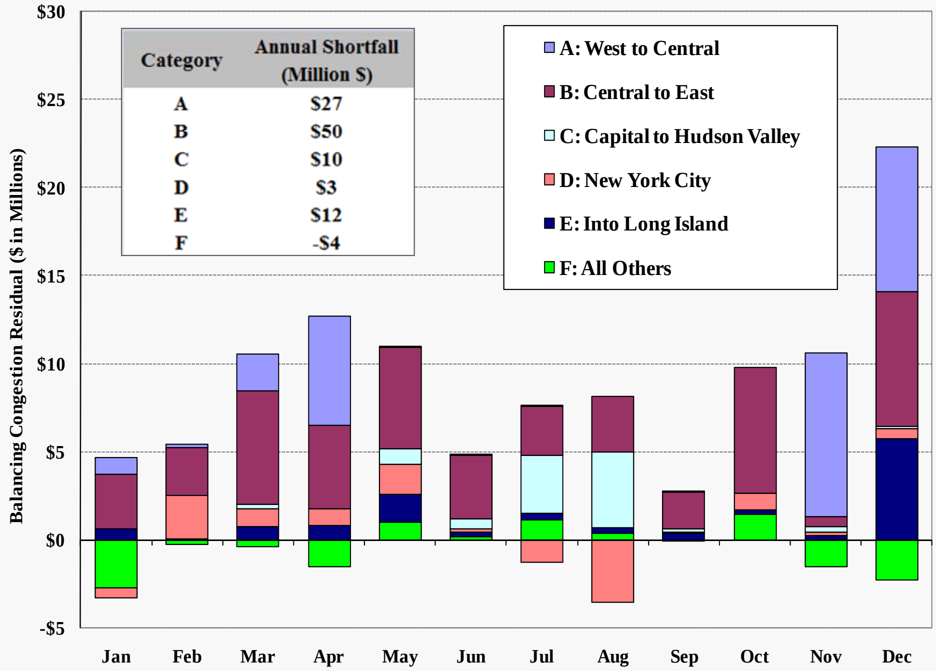
Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the monthly day-ahead congestion revenue shortfalls by transmission path or facility in 2009.
  - ✓ Negative values indicate congestion revenue surpluses.
- Day-ahead congestion revenue shortfalls can result from:
  - ✓ Modeling assumption differences between the TCC auction and the day-ahead market, including PAR schedules and unscheduled loop flows; and
  - ✓ Local TOs not incorporating their transmission outages in the assumptions of the TCC auctions.
- The West to Central and Central to East paths accounted for 79 percent of the total day-ahead congestion revenue shortfall in 2009.
  - ✓ These paths exhibited substantial day-ahead congestion revenue shortfalls in each month when the paths were frequently congested.
  - ✓ This suggests that the transfer capability between regions in the day-ahead market is consistently lower than the amount of TCCs sold between regions.
  - ✓ The west-to-east transfer capability may be reduced in the day-ahead market by outages (that are not incorporated in the TCC auctions) of transmission facilities in New York and in other control areas.

Day-Ahead Congestion Revenue Shortfalls

- Transmission outages reduce the transfer capability of the NYISO network.
  - ✓ When outages are not reflected in the TCC auction assumptions, it may lead to an over-sale of TCCs, contributing to day-ahead congestion revenue shortfalls.
- The NYISO has a process for allocating day-ahead congestion revenue shortfalls to outages that are attributable to specific TOs.
  - ✓ Under this process, the portion of day-ahead congestion revenue shortfalls that were charged to specific TOs for equipment outages and derates was 43 percent in 2008 and 31 percent (based on a preliminary estimate) in 2009.
  - ✓ TOs can avoid allocations of day-ahead congestion revenue shortfalls from specific outages by electing to incorporate them in the TCC auction assumptions.
  - ✓ Although many of the outages were scheduled before the TCC auctions, none of the TOs elected to incorporate them in the TCC auctions in 2008 and in 2009.
- The day-ahead congestion revenue shortfalls not associated with specific outages are charged to all TOs.

Day-Ahead Congestion Revenue Shortfalls 2009



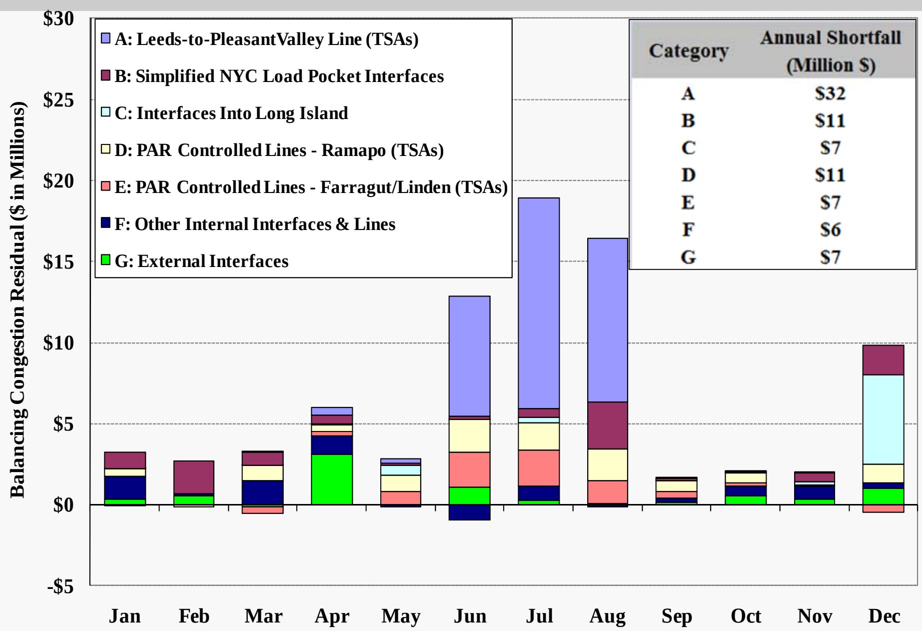
Balancing Congestion Shortfalls

- The following figure shows monthly balancing congestion shortfalls by transmission path or facility in 2009.
  - ✓ Negative values indicate balancing congestion surpluses.
- Balancing congestion shortfalls can occur when the transfer capability of a particular interface changes between day-ahead and real-time due to:
  - ✓ Deratings and outages of the lines that make up the constrained interface;
  - ✓ Unexpected or forced outages of facilities that alter the distribution of flows across other constrained facilities; and
  - ✓ Unutilized transfer capability that can arise from Hybrid Pricing, which treats physically inflexible GTs as flexible in the pricing logic.
- Balancing congestion revenue shortfalls can also occur when assumptions used in the market models change from day-ahead to real-time. This includes the direction and magnitude of:
  - ✓ Unscheduled loop flows across constrained interfaces; and
  - ✓ Flows across PAR-controlled lines.

Balancing Congestion Shortfalls

- Capital to Hudson Valley accounted for 41 percent of balancing congestion shortfalls, primarily during TSAs events.
  - ✓ TSAs require double contingency protection of the Leeds-to-Pleasant Valley line, effectively reducing the transfer capability of the path in real time.
- Several PAR-controlled lines between New Jersey and New York (Ramapo, Farragut, and Linden) accounted for 28 percent of balancing congestion revenue shortfalls, mostly during TSA events.
  - ✓ TSAs may suddenly require generators to increase production in Southeast New York before the PAR-settings can be adjusted accordingly. This reduces net flows into NYCA across the PAR-controlled lines, which results in a revenue shortfall.
- Simplified interface constraints in NYC accounted for 11 percent of congestion revenue shortfalls.
  - ✓ The use of interface constraints in the real-time market (rather than the detailed modeling used in the day-ahead market) generally reduces transfer capability.
  - ✓ This was reduced by assuming reduced transfer capability into certain NYC load pockets in the day-ahead market.
- Long Island accounted for approximately 70 percent of shortfalls in December, primarily due to the Sprainbrook-to-East Garden City line outage.

Balancing Congestion Shortfalls 2009



Category	Annual Shortfall (Million $)
A	$32
B	$11
C	$7
D	$11
E	$7
F	$6
G	$7

Note: Due to differences between real-time schedules and actual metered generation and load, this figure tends to over-estimate shortfalls approximately 20 percent.

Congestion Revenue Shortfalls – Conclusions

- Overall, day-ahead and balancing congestion shortfalls decreased $333 million (or 67 percent) from 2008 to 2009. The decline was partly due to:
  - ✓ The reduction in congestion-related price differences resulting from lower fuel prices and lower load levels.
- Balancing congestion shortfalls were reduced by measures that improved consistency between day-ahead and real-time modeling, including:
  - ✓ Improved interface scheduling procedures when other control areas declare TLRs;
  - ✓ Procedures for promptly evaluating the causes of shortfalls and for adjusting market operations accordingly on a timely basis (e.g., more timely updates to the day-ahead assumptions regarding loop flows);
  - ✓ Prohibiting the scheduling of circuitous transactions; and
  - ✓ Less frequent use of simplified interface constraints in New York City.
- Day-ahead congestion shortfalls accounted for the majority (60 percent) of congestion shortfalls in 2009.
  - ✓ An estimated 31 percent of day-ahead congestion shortfalls were charged to specific TOs for equipment outages and derates in 2009.

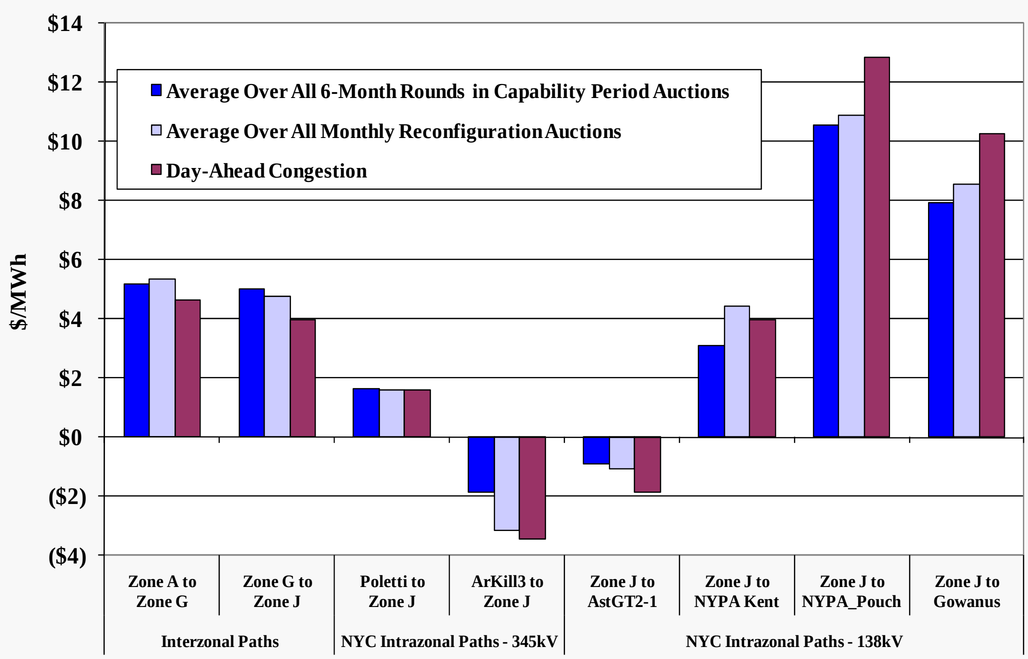
TCC Prices and Day-Ahead Congestion

- The next two analyses evaluate the TCC market. A TCC entitles the holder to the day-ahead congestion price difference between two points.
  - ✓ Hence, TCC prices reflect expectations of congestion in the DAM.
- There are two types of TCC Auctions:
  - ✓ *Capability Period Auctions*: 1-year and 6-month TCC products are offered.
    - – Typically, 33 percent of available transmission capability is auctioned in the form of 1-year TCC products, and 67 percent of available transmission capability is auctioned in the form of 6-month TCC products.
    - – The 1-year and 6-month product auctions consist of a series of rounds. In each round, a portion of the transmission capability is offered, resulting in a set of TCC awards and clearing prices.
  - ✓ *Reconfiguration Auctions:* 1-month TCC products are auctioned following the Capability Period Auctions.
- Auctions occurring closer to the contract start date generally reflect DAM congestion prices more closely than auctions occurring further in advance of the contract start date.

TCC Prices and Day-Ahead Congestion – Summer 2009 Capability Period

- The next figure compares 2009 Summer TCC prices to DAM congestion price differences. The TCC prices are shown averaged over:
  - ✓ The four rounds in the 6-month capability auction; and
  - ✓ The six 1-month reconfiguration auctions.
  - ✓ Prices are shown (i) between three zones commonly used for bilateral trading: Zone A (West), Zone G (Hudson Valley), and Zone J (New York City), and (ii) paths between Zone J and selected nodes inside Zone J.
- The averages of the monthly auction prices were more consistent with DAM congestion than were the averages of the 6-month auction prices.
  - ✓ Although the monthly reconfiguration auctions substantially under or over-valued DAM congestion in individual months.
  - ✓ This is consistent with expectations because participants generally have better information by the time the monthly auction occurs.
- The figure also shows that:
  - ✓ Interzonal TCC prices were generally higher than DAM congestion price differences, suggesting more DAM congestion was expected.
  - ✓ In NYC, intrazonal TCC prices were generally lower than DAM congestion price differences, suggesting less DAM congestion was expected.
  - ✓ However, none of these differences were unusually large or indicate a problem.

TCC Prices and Day-Ahead Congestion Summer 2009 Capability Period



Market Operations

Market Operations – Introduction

- The operation of the real-time market plays a critical role in the efficiency of the market outcomes.
  - ✓ Physical demands and limitations can cause small changes in operations to have a large effect on the market.
- This section of the report evaluates the following four areas of market operations:
  - ✓ Real-time commitment and external transaction scheduling by the real-time commitment model (“RTC”);
  - ✓ Real-time price volatility;
  - ✓ Prices under real-time shortage conditions; and
  - ✓ Supplemental commitment for reliability and the associated uplift charges.

Market Operations:
Real-Time Commitment and Scheduling

POTOMAC ECONOMICS

Market Operations – Real-Time Commitment

- The Real-Time Commitment model ("RTC") commits generators with short lead times such as gas turbines and schedules external transactions.
  - ✓ It re-evaluates just ahead of the real-time market every 15 minutes.
- Convergence between RTC and actual real-time dispatch is important because a lack of convergence can result in:
  - ✓ Uneconomic commitment of generation, particularly gas turbines; and
  - ✓ Inefficient scheduling of external transactions.
- When excess resources are committed or scheduled, the results are increased uplift costs and depressed real-time prices. Alternatively, committing insufficient resources leads to unnecessary scarcity and price spikes.
- This section includes two analyses that evaluate the consistency between RTC and actual real-time outcomes. These analyses evaluate:
  - ✓ The efficiency of gas turbine commitments; and
  - ✓ The efficiency of external transaction scheduling.

Efficiency of Gas Turbine Commitment

- The next figure measures the efficiency of gas turbine commitment by comparing the offer price to the real-time LBMP.
- The figure shows the average volume of gas turbines started whose energy plus start-up costs (amortized over the commitment period) are:

  (a) < LBMP (clearly economic);

  (b) > LBMP by up to 25 percent;

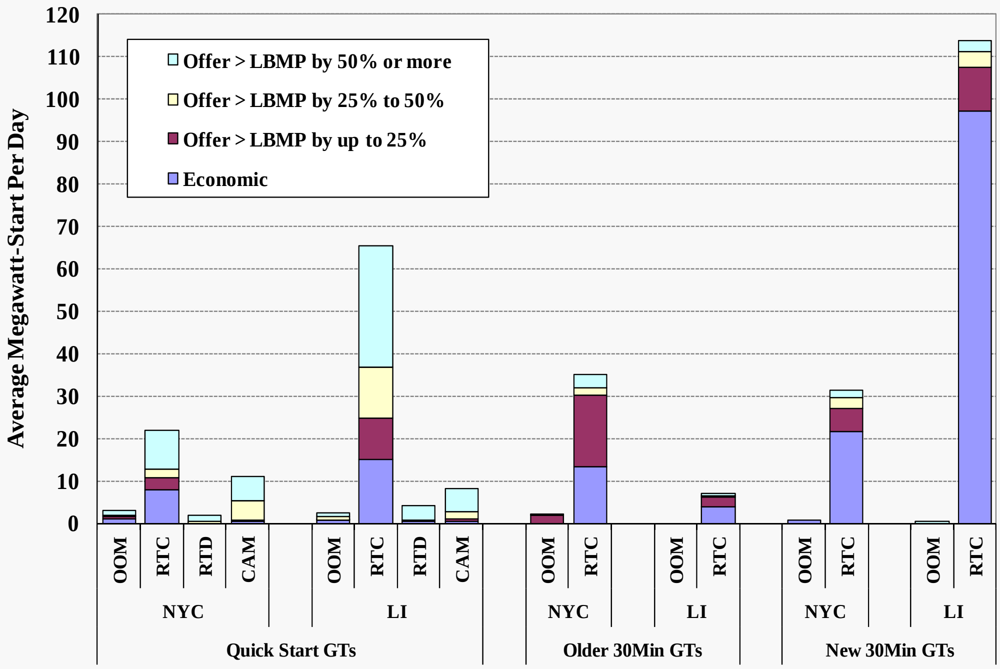
  (c) > LBMP by 25 to 50 percent; or

  (d) > LBMP by more than 50 percent.
- Starts are shown separately by type of unit and location, and whether they were started by RTC, RTD, RTD-CAM, or by an OOM instruction.
- Gas turbines with offers greater than the LBMP can be economic because:
  - ✓ Gas turbines that are started efficiently and set the LBMP at their location do not earn additional revenues needed to recover their start-up offer.
  - ✓ Gas turbines that are started efficiently to address a transient shortage (e.g. transmission constraint violation lasting less than one hour) may lower LBMPs and appear uneconomic over the commitment period.

Efficiency of Gas Turbine Commitment

- New 30-minute gas turbines account for just 28 percent of the gas turbine capacity in New York City.
  - ✓ However, they account for approximately 47 percent of the gas turbine capacity started in 2009 due to their relatively low fuel costs.
- The efficiency of gas turbine commitment was consistent from 2008 to 2009, although the average amount of gas turbine commitment decreased 63 percent in New York City from 2008 to 2009 primarily due to the lower load levels.
- One factor that can reduce the efficiency of gas turbine commitment is the use of simplified interface constraints in New York City load pockets rather than the more detailed model of transmission capability.
  - ✓ To commit gas turbines efficiently, RTD and RTC must forecast congestion patterns in future intervals, and the detailed model allows them to forecast congestion more accurately.
  - ✓ The use of simplified interface constraints decreased substantially from 2008 to 2009 as discussed in the transmission congestion section.

Efficiency of Gas Turbine Commitment 2009



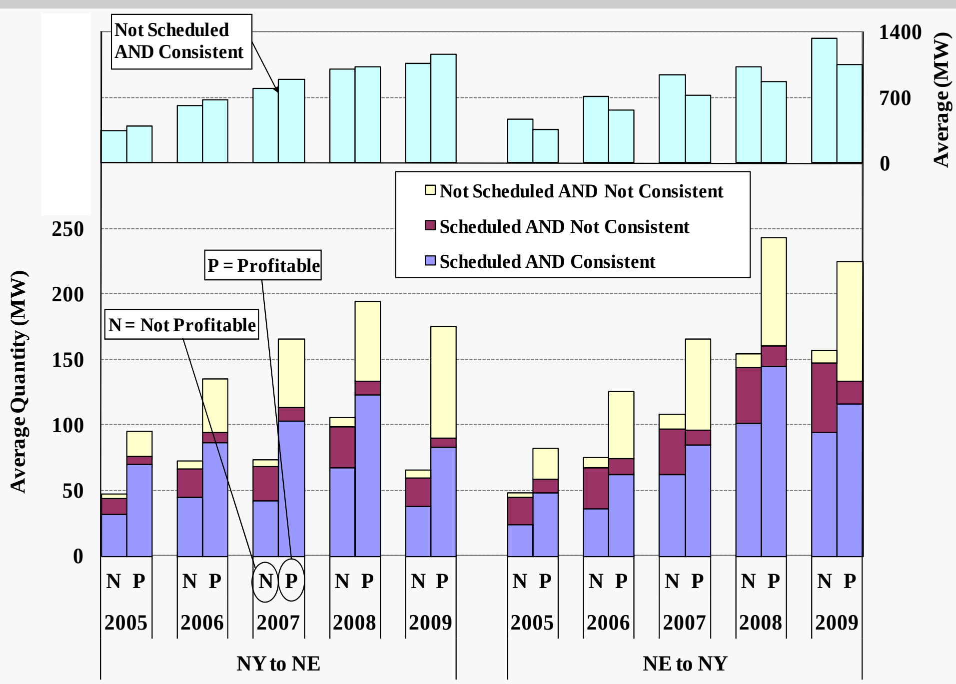
Efficiency of External Transaction Scheduling

- The next figure evaluates the external transaction scheduling by RTC of the primary interface with New England from 2005 to 2009.
  - ✓ It includes transactions that are price-sensitive in real-time (it excludes transactions with DAM priority and bids and offers above $300/MWh and below $0/MWh).
  - ✓ We analyze the New England interface due to its importance in serving eastern areas in New York. We would expect similar results for PJM and Ontario.
- Transactions are shown according to whether they were:
  - ✓ *Scheduled* or *not scheduled*
  - ✓ *Consistent* or *not consistent* – consistent refers to whether the transaction was scheduled in accordance with real-time prices.
    - – For example, if an export is scheduled but the bid is less than the real-time price, it would be considered “not consistent” since exports are scheduled when the bid is greater than or equal to the RTC price.
  - ✓ *Profitable* or *not profitable* – profitable refers to whether the transaction would be profitable if scheduled based on the real-time proxy bus prices on both sides of the border.
    - – Transactions that RTC schedules consistent with real-time prices are not always profitable.

Efficiency of External Transaction Scheduling

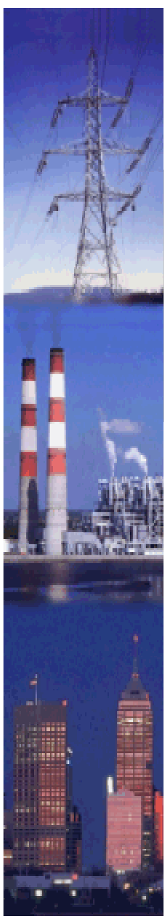
- The volume of price-sensitive offers to transact over the primary interface between NY and New England increased 183 percent from 2005 to 2009.
  - ✓ However, only 8 percent of price-sensitive offers were scheduled in 2009.
- The share of offers that were consistent has not changed significantly since 2005.
  - ✓ 77 percent of scheduled offers were consistent in 2009.
  - ✓ 96 percent of offers not scheduled were consistent in 2009.
- The figure shows that "consistent" scheduling is not the same as efficient scheduling (efficient schedules all profitable). Results for 2009 show:
  - ✓ *Scheduled and consistent* – 60 percent of these transactions were profitable.
  - ✓ *Scheduled and not consistent* – 24 percent of these transactions were still profitable.
  - ✓ *Not scheduled and not consistent* – 92 percent of these transactions would have been profitable if scheduled (i.e., 8% of these outcomes were efficient).
- The efficiency of transaction scheduling depends on *both* the consistency of RTC with RTD *and* the predictability (to market participants) of real-time price differences between New York and adjacent markets.

Efficiency of External Transaction Scheduling
Primary Interface with New England, 2005 – 2009



Efficiency of Commitment and Scheduling – Conclusions

- The volume of price-sensitive real-time transaction bidding at the New England interface grew significantly from 2005 to 2009.
  - ✓ This indicates that participants have increasingly relied on RTC to determine when it will be economic to schedule between adjacent control areas.
- The consistency of RTC with RTD plays a crucial role in both efficient commitment of gas turbines and efficient external transaction scheduling.
- Although the results in this section do not raise significant concerns, there are several potential ways to improve the consistency of RTC and RTD, including:
  - ✓ Improving the assumptions that are used in RTC to be more consistent with RTD, including those related to load forecasting and to the ramping of generators and transactions.
  - ✓ Reducing unnecessary volatility in RTD prices, which is evaluated in the next sub-section. Unnecessary price volatility reduces the efficiency of external transaction scheduling and gas turbine commitment by RTC.



Market Operations:
Real-Time Price Volatility

Real-Time Price Volatility

- The NYISO runs a real-time dispatch usually every five minutes, resulting in a new set of LBMPs every five minutes.
- Changes in LBMPs from one interval to the next depend on how much dispatch flexibility the system has to respond to fluctuations in the following factors:
  - ✓ Electricity demand;
  - ✓ Net export schedules (which are determined by RTC prior to RTD);
  - ✓ Generation schedules of self scheduled and other non-flexible generation; and.
  - ✓ Transmission congestion patterns.
- Hence, large changes in the LBMP from one interval to the next are an indication of substantial fluctuations in at least one of these factors.
- The two figures in this section evaluate factors that contributed to price volatility in real-time in the summer of 2009.

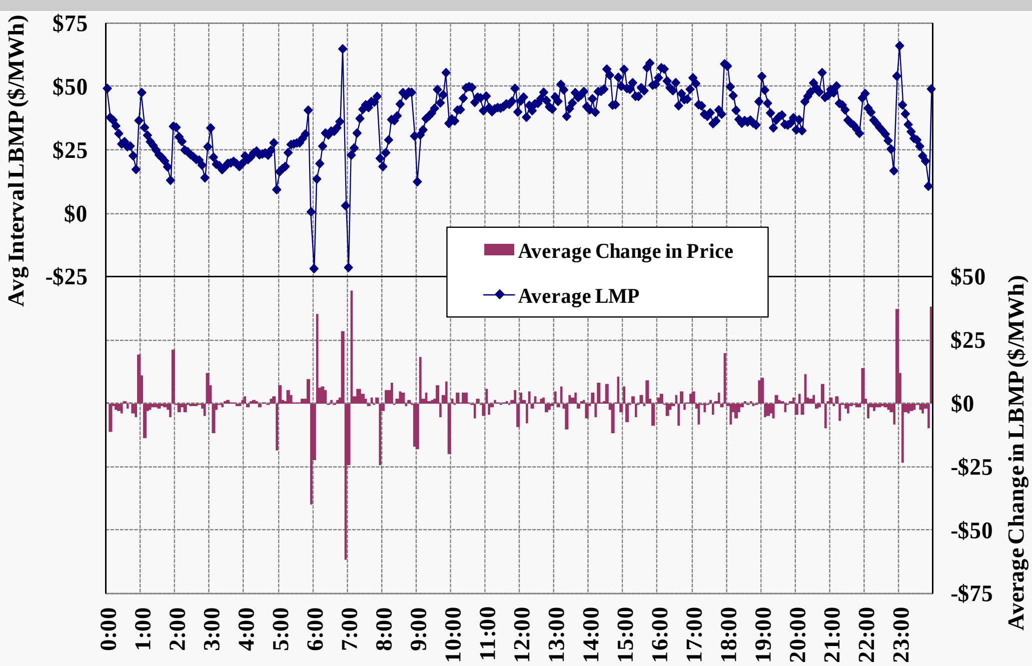
Real-Time Price Volatility

- The first figure shows the average prices in each five minute interval of the day in the summer of 2009.
  - ✓ The figure shows the loaded-weighted average price for New York state.
- The second figure shows how the following categories of inflexible supply change from one interval to the next on average:
  - ✓ Net Imports – Net imports normally ramp at a constant rate from five minutes prior to the top of the hour (:55) to five minutes after the top of the hour (:05). They can change unexpectedly due to curtailments and TLRs before or during the hour.
  - ✓ Switches Between Pumping and Generating – This is when pump storage units switch between consuming electricity and producing electricity.
  - ✓ Fixed Schedule Changes for Online STs – Many units are not dispatchable by the ISO and produce according to their fixed generation schedule.
  - ✓ Start-up and shutdown of Self Scheduled GTs – These GTs are not dispatchable by the ISO, starting-up and shutting-down according to their fixed schedule.
  - ✓ Start-up and shutdown of STs – These non-GTs are not dispatchable during their start-up and shut-down phases of operation.

Real-Time Price Volatility

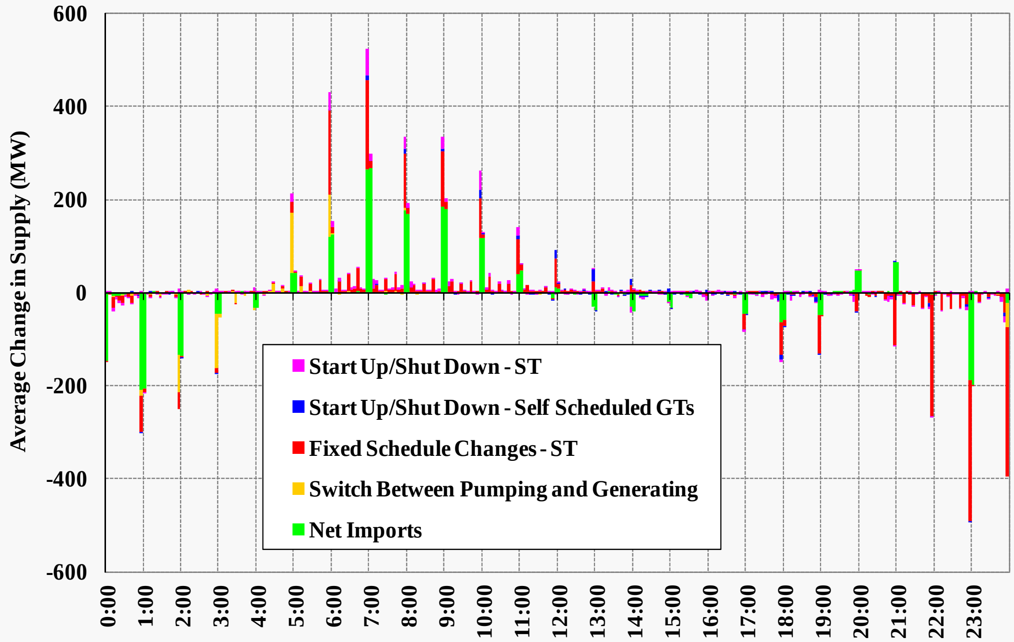
- The first figure shows that prices are generally more volatile at the top of the hour during ramp up and ramp down hours.
  - ✓ The upward and downward price spikes in these hours reflect relatively frequent ramp rate constraints.
  - ✓ In the first interval of the hour, clearing prices drop substantially in ramp-up hours, and clearing prices rise substantially in ramp-down hours.
- The second figure shows the average net changes for five categories of inflexible supply that contribute to:
  - ✓ Adjustments in net imports, pumped storage units switching between pumping and generating, and adjustments in fixed generation schedules account for the most significant changes from hour-to-hour.
  - ✓ For example, from 6:55 am to 7:00 am, the average net increase in inflexible supply from imports and fixed scheduled units was 457 MW, coinciding with an $62/MWh average decrease in the real-time LBMP.

Five-Minute Pricing by Time of Day
June to August 2009



Note: The prices shown are load-weighted system average prices.

Factors Contributing to Real-Time Price Volatility
June to August 2009



Real-Time Price Volatility – Conclusions

- The figures indicate that high price volatility during morning and evening ramp periods is largely caused by changes in inflexible supply at the top of each hour.
- If inflexible supply changes were distributed more evenly throughout each hour, price volatility would be diminished.
- Generators who change fixed schedules or switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour.
  - ✓ For instance, units starting at 6:00 am sold their output at prices ranging from -$20/MWh to $20/MWh on average in the first 15 minutes of operation.
  - ✓ For many units, it would have been more profitable to wait until 6:15 am to start or increase output.
- The NYISO performed an analysis of factors that contribute to unnecessary real-time price volatility (the "Scheduling & Pricing Phase 3" project).
  - ✓ In addition to the factors evaluated in the figure, the NYISO found that two factors were also significant during high-ramping hours:
    - – Changes in the load forecast during the two hours leading up to each real-time interval; and
    - – Adjustments in the amount of regulation capacity required by the ISO.

Real-Time Price Volatility – Conclusions

- The NYISO has identified six projects that are expected to help address the causes of unnecessary real-time price volatility. These include:
  - ✓ Load Forecaster Enhancements – This is intended to correct systematic forecast errors during ramping periods;
  - ✓ Regulation Requirement Changes – This will reduce the size of changes in the amount of regulation scheduled from one hour to the next;
  - ✓ Enhanced Storage Optimization – This would improve the modeling of energy-limited generation such as pumped storage units;
  - ✓ Real-Time Increasing of Bids – This would allow generators facing energy-limitations and/or fuel price changes to offer more flexibly;
  - ✓ Enhanced Shortage Pricing – This would adjust the regulation demand curve to appropriately price small and/or transient shortages of regulation; and
  - ✓ Broader Regional Markets initiative – This is likely to reduce real-time price volatility in two ways:
    - Scheduling the primary interface with Hydro Quebec every five minutes rather than on an hourly basis will greatly increase the amount of flexible supply in western New York; and
    - Better coordination of external transaction scheduling with neighboring areas should reduce the price spikes resulting from curtailments and TLRs.

Market Operations: Prices Under Shortage Conditions

Prices Under Shortage Conditions

- RTD co-optimizes the procurement of energy and ancillary services, which is beneficial in several ways:
  - ✓ The software efficiently allocates resources to provide energy and ancillary services every five minutes.
  - ✓ This incorporates the costs of maintaining adequate ancillary services into the price of energy.
  - ✓ Demand curves rationalize the pricing of energy and reserves during shortage periods by setting limits on the costs that can be incurred to maintain reserves.
- Due to the mechanism that allows gas turbines to set real-time prices, it is possible for inconsistencies to arise between the real-time pricing of reserves and the availability of sufficient reserve capacity in real-time.
- This section evaluates the consistency between the prices of Eastern 10-minute reserves and the actual physical availability of Eastern 10-minute reserves in 2009.
  - ✓ The real-time software maintains 1,000 MW of 10-minute reserves inside Eastern New York up to a cost of $500/MWh.

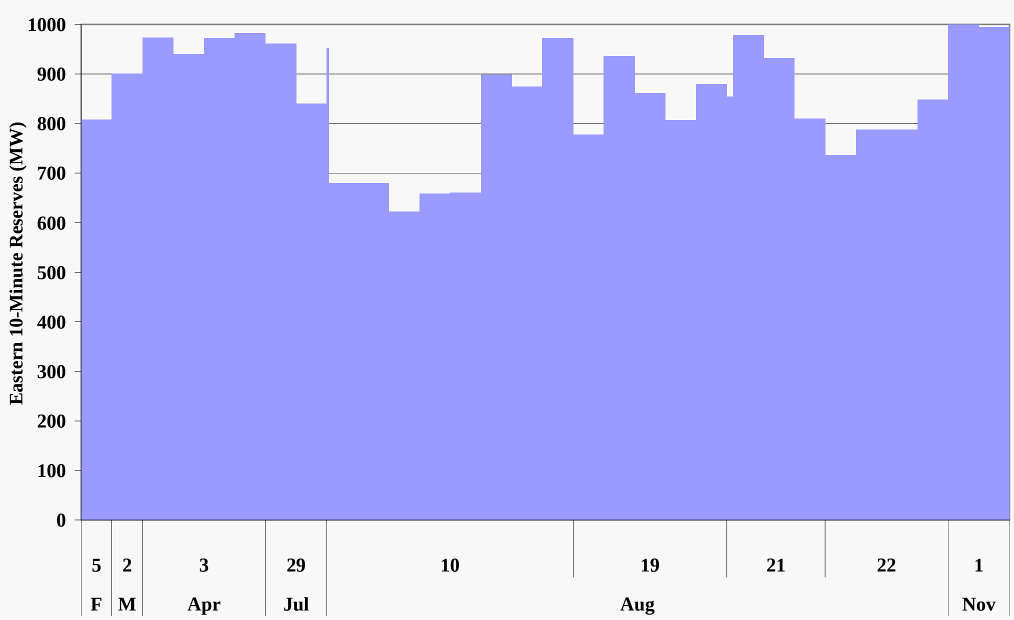
Reserve Shortages and Shortage Pricing

- Co-optimization of energy and reserves is integrated with the Hybrid Pricing approach in the market software. The Hybrid Pricing approach allows gas turbines to set clearing prices.
  - ✓ The inflexibility of gas turbines creates challenges for pricing energy efficiently when the gas turbines are the marginal source of supply.
  - ✓ 28 percent of dispatchable capacity in New York City and 42 percent of the dispatchable capacity in the 138kV load pocket are gas turbines.
  - ✓ Thus, Hybrid Pricing is a particularly important element of setting efficient prices in New York City.
- Hybrid Pricing treats gas turbines as flexible resources for pricing purposes, although gas turbines physically operate close to their maximum output level.
- Hence, Hybrid Pricing results in inconsistencies between the pricing dispatch and the physical dispatch. However, these inconsistencies should be limited such that:
  - ✓ Under physical shortage conditions, prices reflect scarcity; and
  - ✓ Shortage prices are only set when the system is physically in shortage.

Reserve Shortages and Shortage Pricing

- The following figure shows the amount of Eastern 10-minute reserves that was physically scheduled during shortage pricing intervals in 2009.
- Based on the amount of 10-minute reserves that was physically scheduled, Eastern New York was in a physical shortage in all of these intervals.
  - ✓ The pricing and physical dispatch passes of RTD have been very consistent during periods when shortage pricing was invoked.
  - ✓ Hence, shortage pricing in Eastern New York has occurred only during true shortages.
- The frequency of shortage pricing declined from 181 intervals in 2008 to 31 intervals in 2009. The reduction was partly due to:
  - ✓ Mild load conditions which reduced the frequency of tight operating conditions.
  - ✓ Improved recognition by RTC of impending shortages since March 2009 as a result of the modifications to the ramp rate constraints of generators not following dispatch.

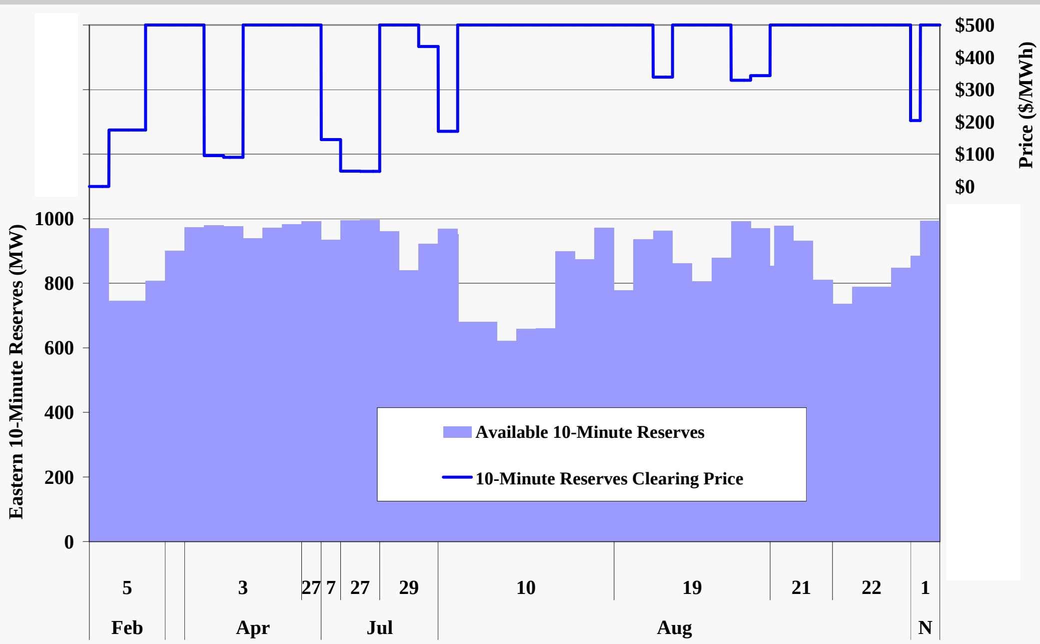
Scheduling of 10-Minute Reserves in the East During Shortage Pricing Intervals, 2009



Reserve Shortages and Shortage Pricing

- The following figure shows the price and quantity of available Eastern 10-minute reserves during physical shortages of Eastern 10-minute reserves.
- 14 of the 45 intervals with physical shortages of Eastern 10-minute reserves did not exhibit shortage pricing in 2009.
  - ✓ In these intervals, the Eastern 10-minute reserve price averaged $204/MWh and the average shortage quantity was only 50 MW.
  - ✓ These periods were brief, lasting for just one or two consecutive intervals.
- The share of physical shortages that exhibited shortage pricing in 2009 was similar to 2008.
  - ✓ However, the consistency between the pricing dispatch and the physical dispatch passes of RTD during eastern 10-minute reserve shortage periods improved from 2008 to 2009 if the duration of the shortage is considered.
  - ✓ Typically, consistency between the pricing dispatch and the physical dispatch is better during shortages of longer duration.
  - ✓ Hence, it is notable that the share of intervals exhibiting shortage pricing did not decrease even though the average duration of physical shortages was substantially shorter in 2009.

Scheduling and Pricing of 10-Minute Reserves in the East During Physical Shortage Intervals, 2009



Note: In cases where the East 10-Minute Non-Spin price exceeds $500/MWh, the figure shows $500/MWh.

Reserves Shortages and Shortage Pricing – Conclusions

- Differences between the pricing dispatch and the physical dispatch are necessary for Hybrid Pricing. However, unnecessary differences generally lead to inaccurate prices and increased uplift.
- We evaluated real-time scheduling in 2009, finding that:
  - ✓ Intervals with real-time eastern 10-minute reserve shortage pricing always occurred during physical shortages, and
  - ✓ Real-time pricing generally improved (over previous years) during intervals with real-time eastern 10-minute shortages.
- In March 2009, NYISO made enhancements to RTD and RTC to reduce divergences between the physical dispatch and pricing dispatch that are caused by units not following dispatch instructions by re-calibrating the ramp limits for such units. These enhancements have led to:
  - ✓ More efficient pricing of energy and ancillary services (particularly during shortages), thereby reducing uplift; and
  - ✓ Fewer physical shortages because RTC will be more likely to start 30-minute gas turbines in anticipation of a shortage.

<u>Market Operations –</u> Uplift and Supplemental Commitment

POTOMAC ECONOMICS

Supplemental Commitment for Reliability

- This section evaluates supplemental commitments during 2009.
- Supplemental commitment occurs when a generator is not committed in the economic pass of the day-ahead market but is needed for reliability. Supplemental commitment primarily occurs in three ways:
  - ✓ Day-Ahead Reliability Units (“DARU”) are committed by the local Transmission Owner prior to the economic commitment in SCUC.
    - Uplift generated from these units goes into day-ahead local reliability uplift.
  - ✓ Day-Ahead Local Reliability (“LRR”) constraints cause generators to be committed within the economic commitment in SCUC.
    - Uplift generated from these units goes into day-ahead local reliability uplift.
  - ✓ The Supplemental Resource Evaluation (“SRE”) process is used to commit generators after the day-ahead market.
    - Uplift generated from units committed for reliability of the local Transmission Owner’s system makes up nearly all of the real-time local reliability uplift.
    - Uplift generated from units committed for reliability of the bulk power system goes into real-time non-local reliability uplift.

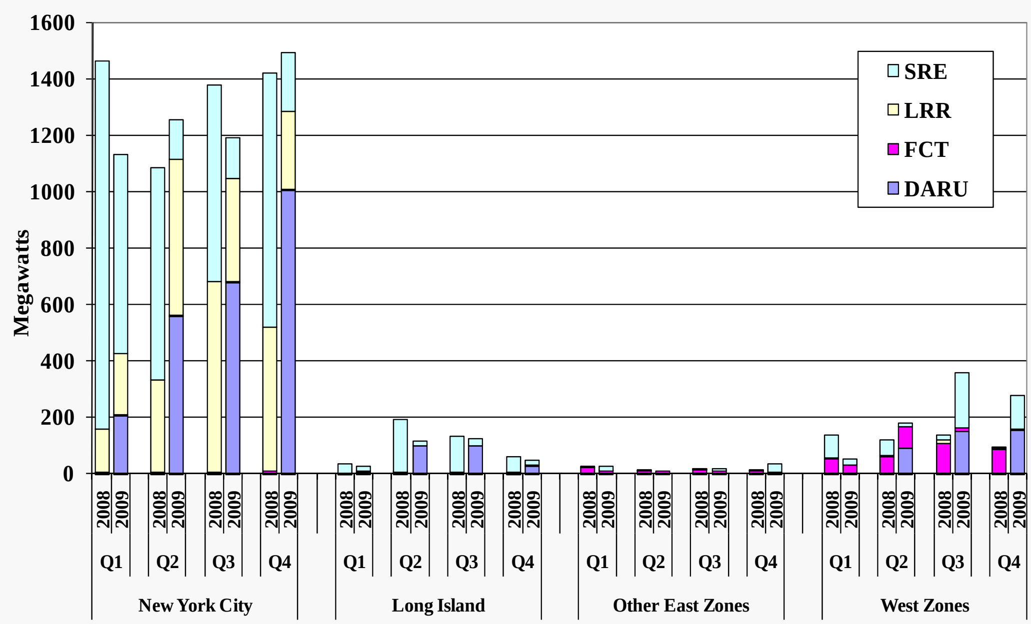
Supplemental Commitment for Reliability

- Generators that are committed for reliability are generally not economic at market prices, but they affect the market by reducing prices from levels that would otherwise result.
  - ✓ Hence, it is important to commit these units efficiently.
- In February 2009, the NYISO made enhancements to improve the efficiency of reliability commitments. These enhancements:
  - ✓ Allow local Transmission Owners to commit units prior to economic commitment of SCUC (i.e., DARU), so that SRE commitments are generally not needed unless there is a change in operating conditions after the day-ahead market.
  - ✓ Commit units for New York City LRR constraints within the economic commitment of SCUC, rather than afterward.
- To the extent LRR constraints in SCUC reflect the reliability requirements in New York City, the local Transmission Owner does not need to commit DARU and SRE units.
  - ✓ LRR commitment is more efficient than DARUs and SREs, which are selected without considering factors in the economic evaluation of SCUC.

Supplemental Commitment for Reliability

- The following figure shows the quarterly quantities of capacity committed for reliability by type of commitment and region in 2008 and 2009.
- Reliability commitment fell 7 percent in New York City and Long Island from 2008 to 2009.
  - ✓ SRE quantities fell the most (700 MW on average), since most local reliability commitment now occurs in the day-ahead market (i.e., DARU & LRR).
- Reliability commitment increased 100 MW on average in western New York from 2008 to 2009 primarily due to:
  - ✓ The emergence of SRE commitments for bulk power system reliability, which had not been necessary for several years; and
  - ✓ More frequent commitment of several other units for local reliability due, in part, to transmission outages and changes in commitment patterns resulting from lower natural gas prices.
- Commitments for forecasted load decreased 50 percent from 2008 to 2009.
  - ✓ This is primarily because the local reliability commitment is now done in the day-ahead market (i.e., DARU and LRR) prior to the commitment for forecasted load.

Supplemental Commitment for Reliability by Category and Region, 2008 & 2009



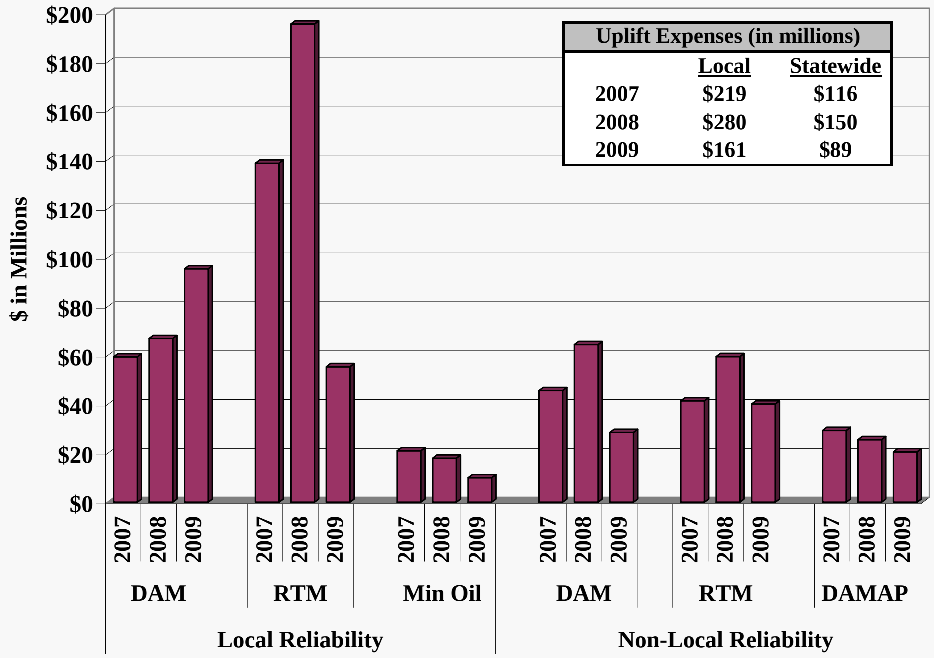
Uplift Charges from Guarantee Payments

- Three categories of uplift charges from guarantee payments are allocated to local Transmission Owners:
  - ✓ Day Ahead: Local Reliability Requirements (“LRR”) and Day-Ahead Reliability Unit (“DARU”) commitments.
  - ✓ Real Time: Supplemental Resource Evaluation (“SRE”) commitments and Out-of-Merit (“OOM”) dispatched units.
  - ✓ Minimum Oil Burn: Covers the spread between oil and gas prices when units burn oil to satisfy New York City gas pipeline contingency reliability criteria.
- Three categories of guarantee payment uplift are allocated to all LSEs:
  - ✓ Day Ahead: Primarily for units committed economically that don’t recoup their as-offered start-up and minimum generation costs from LBMPs.
  - ✓ Real Time: Primarily for gas turbines committed economically that don’t recoup their as-offered costs from LBMPs, and also for SRE commitments and OOM dispatch that are done for bulk power system reliability.
  - ✓ Day Ahead Margin Assurance Payment (“DAMAP”): For payments to cover losses for generators dispatched below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.

Uplift Expenses from Guarantee Payments

- The next figure shows uplift costs associated with guarantee payments over the past three years.
- Total uplift fell from $422 million in 2008 to $250 million in 2009, primarily due to:
  - ✓ Sharp reductions in fuel prices, which generally reduce the payments needed to ensure a generator covers its costs; and
  - ✓ More efficient commitment due to changes in the processes for committing generators for reliability in the day-ahead market.
  - ✓ These effects were was partly offset by more frequent SRE commitments upstate for bulk power system reliability.
- The share of local reliability uplift associated with the real-time market decreased from 70 percent in 2008 to 34 percent in 2009.
  - ✓ This was due to changes that allow Transmission Owners to commit units for reliability in the day-ahead market (i.e., DARU commitment).
  - ✓ This change also explains the corresponding increase in day-ahead local reliability uplift.
- Increases in fuel prices contributed to increases in total uplift, which rose from $331 million in 2007 to $422 million in 2008.

Uplift Expenses from Guarantee Payments 2007 to 2009



External Interface Scheduling

External Interface Scheduling

- Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas.
- Efficient use of transmission interfaces between regions is beneficial in at least two ways by:
  - ✓ Promoting competition in the same way as efficient use of transmission resources within each control area: it allows customers to be served by external resources that are lower-cost than available native resources.
  - ✓ Contributing to reliability in each control area.
- This section examines five areas related to scheduling between regions:
  - ✓ Scheduling patterns between New York and neighboring control areas.
  - ✓ The pattern of loop flow around Lake Erie.
  - ✓ Convergence of prices between New York and neighboring control areas.
  - ✓ Benefits of external interface scheduling by market participants.
  - ✓ Potential benefits from market enhancements associated with the Broader Regional Markets initiative.

External Interface Summary

- The following two figures summarize the interchange with neighboring control areas during the past two years over the primary interfaces.
  - ✓ For each interface, average net imports are shown by month for peak (i.e., 6 am to 10 pm, Monday through Friday) and off-peak hours.
- The three figures show the average net imports across:
  - ✓ The primary interfaces with the Ontario and PJM; and
  - ✓ The primary interfaces with Quebec and New England;

Ontario

- The average net imports from Ontario in peak hours declined from 455 MW in 2008 to 309 MW in 2009.
  - ✓ Imports from Ontario increased after the cessation of circuitous transaction scheduling in July 2008.
  - ✓ Imports from Ontario decreased in early 2009 and averaged between 200 and 300 MW for the remainder of the year.
  - ✓ External transaction scheduling has been affected since January 2008 by the outage of a large transmission line that is part of the interface with Ontario.
  - ✓ Due to additional outages, interface capability was reduced to 0 MW for several weeks in March, April, and November 2009.

External Interface Summary

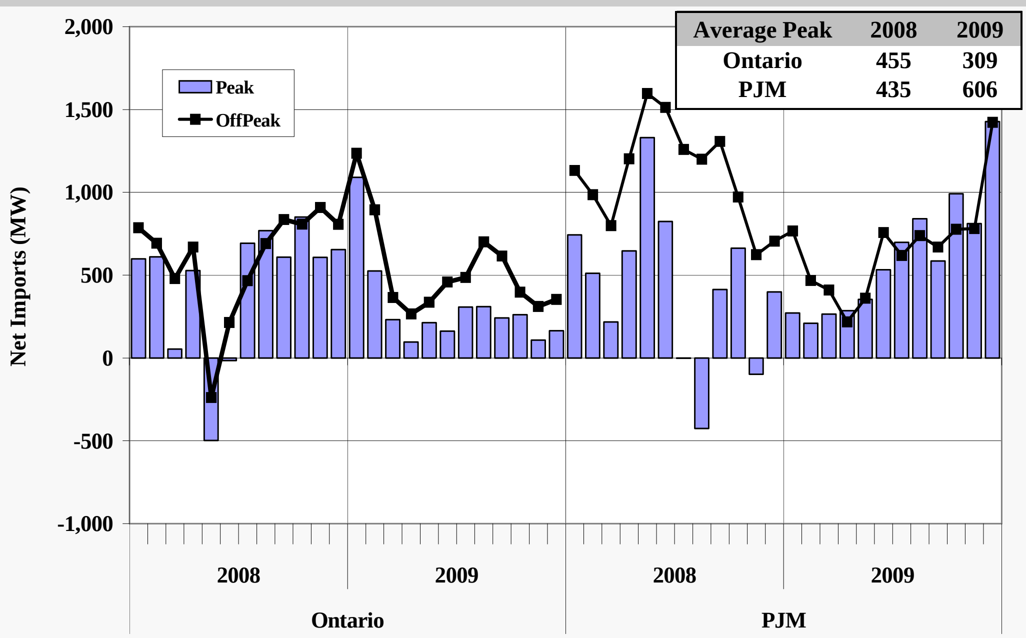
PJM

- The average net imports from PJM in peak hours rose from 435 MW in 2008 to 606 MW in 2009.
  - ✓ The average volume of imports in peak periods steadily increased throughout 2009.

Hydro Quebec and New England

- Significant quantities of imports come across the primary interfaces with Hydro Quebec and New England during peak hours.
  - ✓ Imports from these areas generally increase during peak hours and in the summer, while switching to exports during the winter and in off-peak hours.
    - – Quebec's peak load generally occurs in the winter.
    - – New England is more reliant on natural gas generation, which is more uncertain during the winter months.
  - ✓ Average imports and exports from these areas did not change significantly from 2008 to 2009.

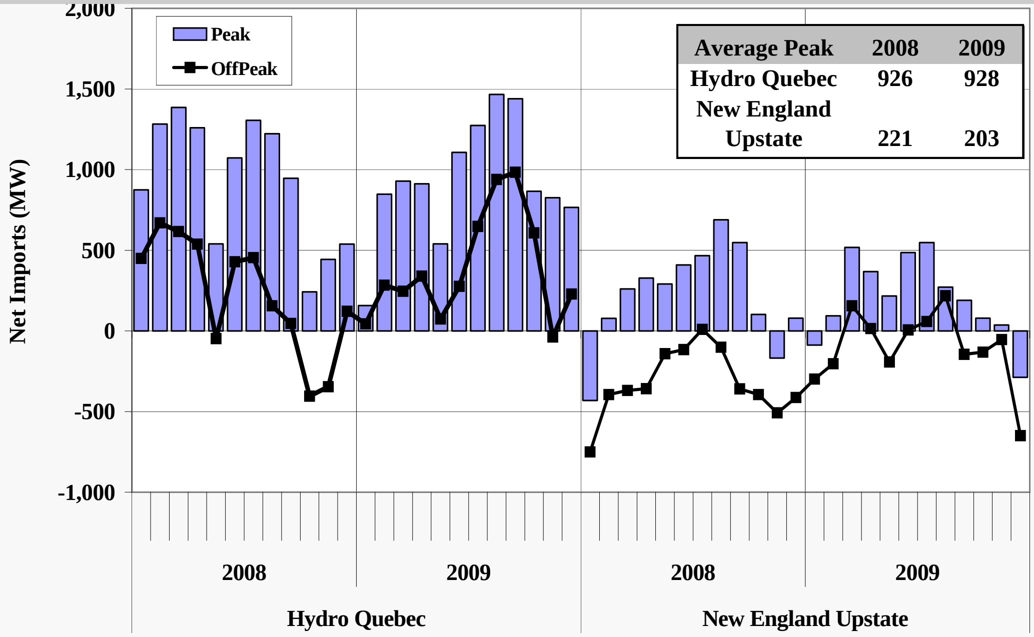
Monthly Average Net Imports from Ontario and PJM* 2008 – 2009



Average Peak	2008	2009
Ontario	455	309
PJM	435	606

Note: Net Imports from PJM include only net imports over the primary interface with PJM. Does not include the Neptune line or Linden VFT shown later.

Monthly Avg Net Imports from Quebec and New England*
2008 – 2009

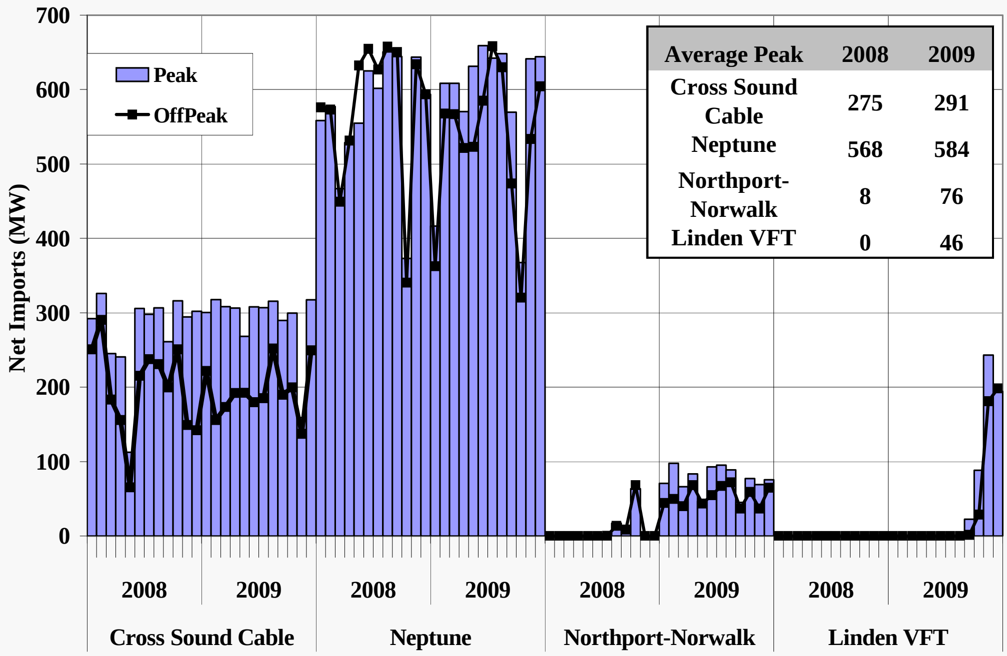


Note: Net Imports from New England include only net imports over the primary free-flowing interface. Does not include the Cross-Sound Cable or the Northport-Norwalk line that are shown later.

External Interface Summary

- A substantial share of the imports to New York state come directly to New York City and Long Island via the:
  - ✓ The Cross Sound Cable (330 MW) and the Northport-to-Norwalk line (100 MW), which usually import power to Long Island from Connecticut.
    - – However, the Northport-to-Norwalk line was out-of-service for most of 2008.
  - ✓ The Neptune Cable (660 MW) usually imports to Long Island from New Jersey.
  - ✓ The Linden VFT line (300 MW) usually imports to New York City from New Jersey.
    - – The Linden VFT line began normal operation in November 2009.
- The Cross Sound Cable, the Northport-to-Norwalk line, and the Neptune Cable satisfied approximately 38 percent of the load in Long Island in 2009.
- The next figure shows the interchange in peak and off-peak hours over these interfaces.
  - ✓ Unlike the primary interfaces, the interchange over these direct interfaces is generally relatively consistent.

Imports into New York City and Long Island
January 2008 – December 2009



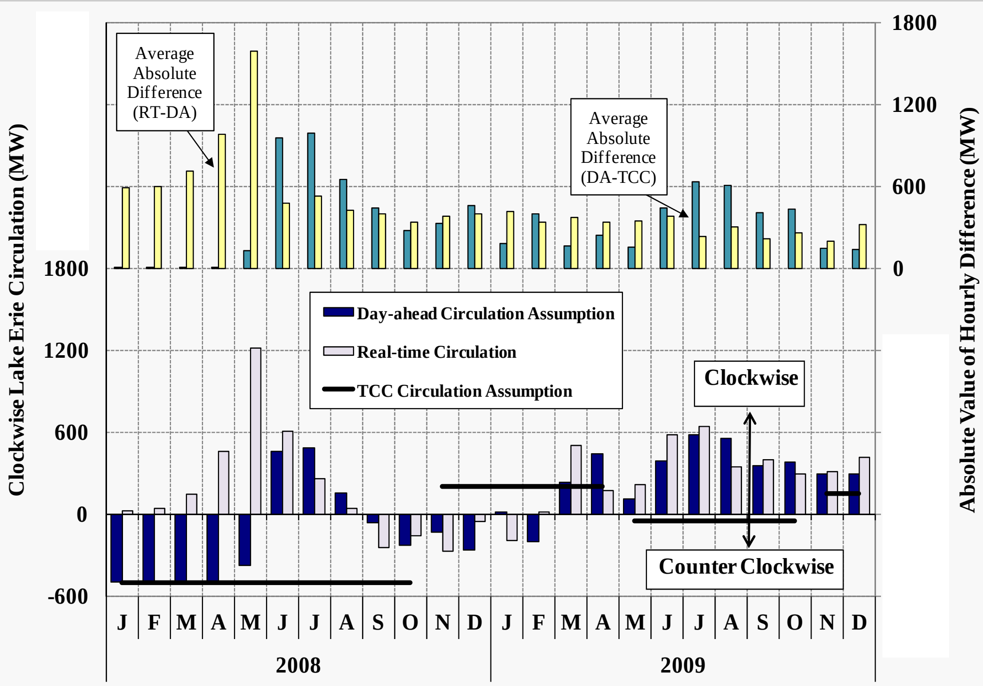
External Interface Scheduling –
Lake Erie Circulation

- 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.
  - ✓ Conversely, counter-clockwise loop flows increase the transmission capacity available for scheduling internal generation.
- Inaccurate assumptions in the day-ahead market regarding the direction and volume of loop flows contributes to inconsistencies between the day-ahead and real-time markets and poor price convergence.
  - ✓ Under-estimating clockwise loop flows leads to day-ahead schedules that are infeasible in real-time, leading to balancing congestion shortfall uplift.
  - ✓ Over-estimating clockwise loop flows leads to day-ahead schedules that under-use transmission capability and are inefficient in real-time.
- Likewise, the loop flow assumption used in the TCC market is important because differences between the TCC and day-ahead market assumptions contribute to:
  - ✓ Poor convergence between TCC prices and day-ahead congestion prices; and
  - ✓ Day-ahead congestion revenue shortfalls or surpluses.

External Interface Scheduling – Lake Erie Circulation

- The following figure summarizes the pattern of loop flows around Lake Erie in each month in 2008 and 2009. The figure shows the monthly averages of:
  - ✓ Actual real-time loop flow in the clockwise (or counter-clockwise, if negative) direction;
  - ✓ Loop flow assumed in the day-ahead market;
  - ✓ Loop flow assumed in the TCC auction; and
  - ✓ The average of the absolute value of the hourly differences in:
    - – The day-ahead market assumption and the actual real-time quantity; and
    - – The TCC market assumption and the day-ahead market assumption.
- The figure shows the increase in loop flows that was associated with circuitous transaction scheduling, which was prohibited in July 2008.
  - ✓ During this period, the difference between the day-ahead market assumption and the actual real-time quantity averaged more than 1500 MW.
- The figure also shows that the NYISO has improved the process of updating the loop flow assumptions since May 2008, particularly in the day-ahead market.
  - ✓ The day-ahead assumptions now track actual loop flows much more closely as indicated by the lower average differences and average absolute differences.
  - ✓ This reduces the market effects of loop flows.

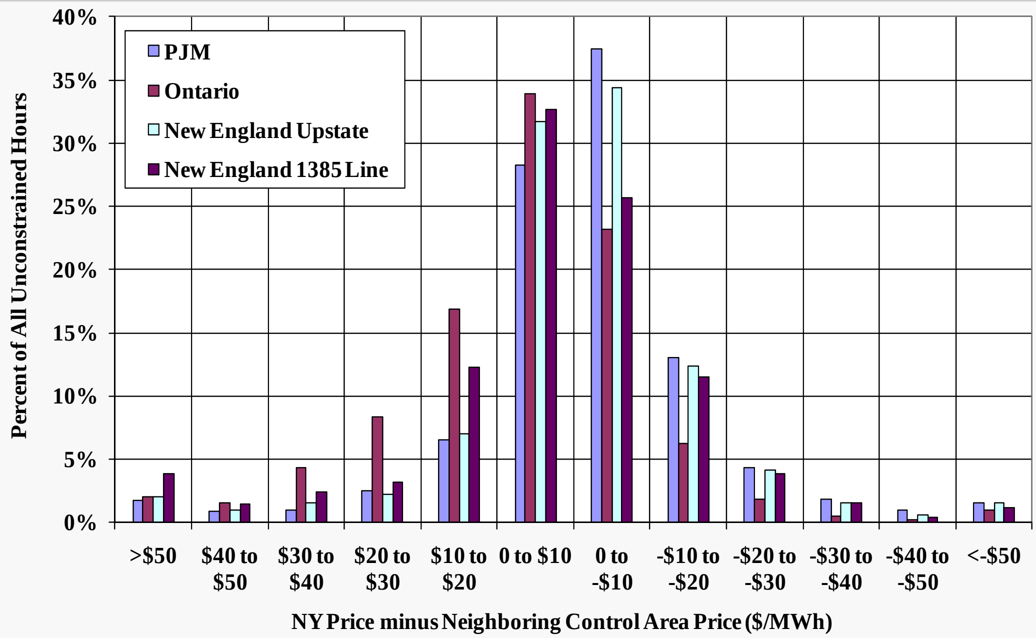
Lake Erie Circulation 2008 – 2009



External Interface Scheduling – Price Convergence Between Control Areas

- When interfaces are used efficiently, prices in adjacent markets and New York should converge unless transmission constraints limit the schedules.
- The following figure summarizes price differences between New York and neighboring markets during unconstrained hours.
  - ✓ The price differences are substantial for every interface.
  - ✓ For example, the price difference exceeded $10/MWh in 34 to 43 percent of the unconstrained hours across each of the interfaces.
  - ✓ The Ontario results were slightly worse that the other interfaces and the price differences were skewed toward higher prices in New York and lower prices in Ontario.
- This reinforces the importance of efforts to improve real-time interchange between New York and adjacent markets.
  - ✓ Efficient scheduling is particularly important during shortages when flows between regions have the largest economic and reliability consequences.
  - ✓ Efficient scheduling can also alleviate over-generation conditions that can otherwise lead to negative price spikes.

Price Convergence Between NY and Adjacent Markets Unconstrained Hours in Real-Time Market, 2009



Note: In these hours, there were no NYISO constraints that prevented scheduling. However, in some of these hours, there may have been constraints that prevented the other ISO from scheduling transactions.

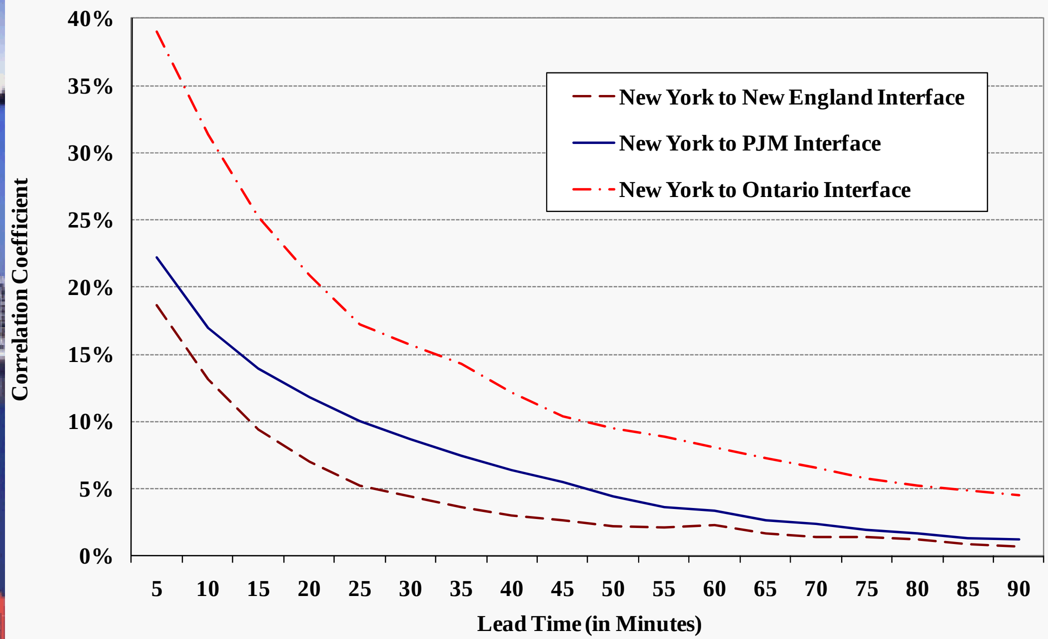
External Interface Scheduling – Market Participant Scheduling

- The prior analyses shows that it has proven difficult to achieve real-time price convergence with adjacent markets through the current process of transaction scheduling by market participants.
  - ✓ Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities.
  - ✓ Furthermore, transaction costs from uplift allocations and export fees reduce or eliminate the expected profits from arbitrage.
- The following two figures evaluate the efficiency of scheduling by market participants between markets.
  - ✓ The first figure illustrates the consistency of real-time price differences between New York and the three adjacent ISO markets in the two hours leading up to each real-time five-minute interval.
  - ✓ The second figure evaluates the consistency of the direction of external transaction scheduling and price differences between New York and the three adjacent ISO markets.

External Interface Scheduling – Market Participant Scheduling

- Currently, market participants submit transactions 75 minutes before the start of an hour, which is 75 to 135 minutes before the power flows.
- This may contribute to participants’ inability to fully arbitrage the difference in prices between adjacent markets.
- To evaluate this, the following figure shows the correlation between the current five-minute price difference between New York and an adjacent market and the actual differences that occurred up to 120 minutes earlier.
  - ✓ The figure shows that the correlation coefficient increases as the lead time is reduced below 120 minutes.
  - ✓ This may under-estimates the predictability of price differences between control areas because participants can use more sophisticated techniques for forecasting and use the RTC’s advisory prices.
  - ✓ Nonetheless, the correlation is still less than 10 percent for a 30 minute lead time at New York’s primary interfaces with PJM and New England. This is the shortest scheduling time used currently by any of the RTOs.
- This analysis suggests that shortening lead times for scheduling would likely capture some of the available benefits from utilizing the external interfaces for efficiently.

Correlation of Price Differences and Lead Time Primary Interfaces with Adjacent Markets -- 2009



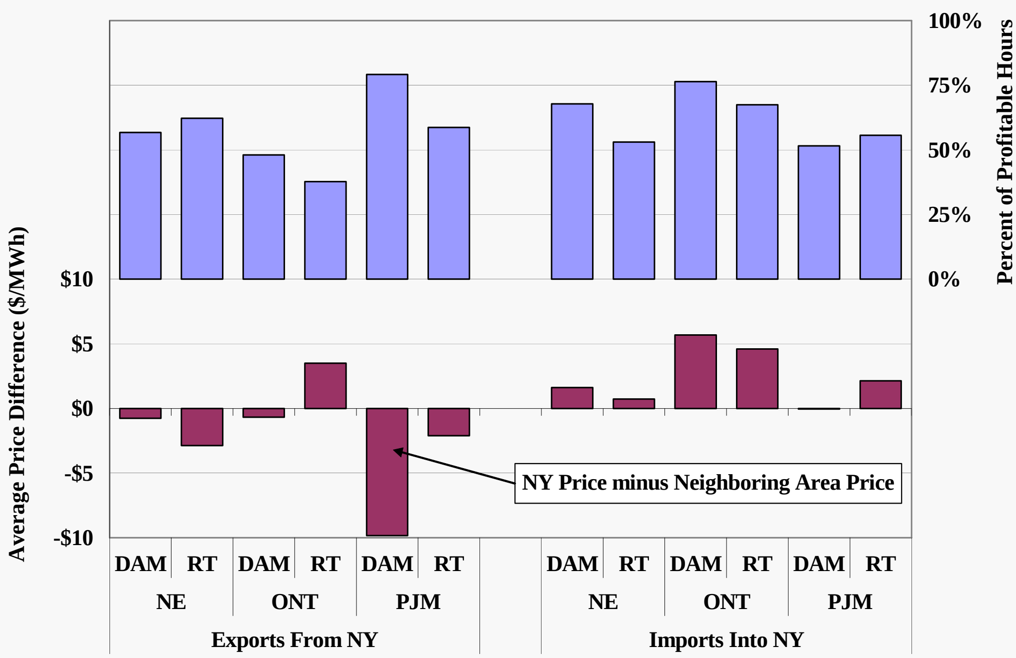
External Interface Scheduling – Market Participant Scheduling

- The following figure summarizes the efficiency of external transaction scheduling across the primary interfaces between New York and New England, PJM, and Ontario.
  - ✓ The left side shows hours when power was scheduled in the export direction.
  - ✓ The right side shows when power was scheduled in the import direction.
  - ✓ The top portion of the figure reports the share of these hours when power was scheduled in the profitable direction (i.e., from the lower-price market to the higher-priced market).
    - – Hence, if more than 50 percent of the hours are profitable, then the market schedules power to flow in the efficient direction in the majority of hours.
  - ✓ The lower portion of the figure summarizes price differences between markets during these hours.
    - – It is efficient for New York to export in hours when the clearing price in New York is lower than in the adjacent area (i.e., the bar is negative), and to import when the clearing price in New York is higher (i.e., the bar is positive).
  - ✓ This analysis evaluates: (i) day-ahead schedules and clearing prices, and (ii) incremental changes in schedules in the real-time market (relative to the day-ahead schedules).

External Interface Scheduling – Market Participant Scheduling

- The figure shows the following:
  - ✓ For most categories of transactions, the average clearing was lower in New York when exports are scheduled and higher in New York when imports are scheduled.
    - – Hence, scheduling by market participants generally improves the efficiency of power flows between markets.
  - ✓ However, power was scheduled in the *unprofitable* direction in a large share of the hours for most the categories of transactions shown in the figure.
    - – 21 to 62 percent hours were unprofitable for all of the categories of transactions.
    - – In the real-time, most of the interfaces and directions showed unprofitable transactions on net in 40 to 50 percent of the hours.
    - – Hence, in almost half of the hours the power physically flows from the high-priced market to the low-priced markets, which is inefficient.
  - ✓ These results indicate that substantial improvement is possible in the utilization of New York's external interfaces.
- Hence, we continue to recommend that the NYISO coordinate its interchange with adjacent markets or otherwise allow real-time intra-hour scheduling to achieve better utilization of the interfaces.

Efficiency of Inter-Market Scheduling Over Primary Interfaces -- 2009



Estimated Benefits of Broader Regional Market Initiatives

- This presentation summarizes our assessment of the potential benefits of some of the Broader Regional Market ("BRM") initiatives.
- In particular, we estimate the production cost savings that may be achieved by:
  - ✓ Coordinating flows around Lake Erie through:
    - – Coordinated congestion management between RTOs; and
    - – The "buy-through congestion" initiative for transaction scheduling); and
  - ✓ Improving the utilization of New York's external interfaces, as well as the interfaces between MISO, PJM and Ontario.
- We report production cost savings because it is the most accurate measure of the improvement in economic efficiency.
  - ✓ In most cases, the short-term consumer savings would be substantially higher (which is based on the price effects of the initiatives).

Inefficient Pricing of Loop Flows

- To estimate the benefits of better coordination of flows around Lake Erie, we first estimate:
  - ✓ The quantity of loop flows across each of the ISOs' flowgates; and
  - ✓ The inefficient pricing of the estimated loop flows;
    - – The inefficiency is reflected in the difference between the value of the flowgate capability and the charges to transactions that cause the loop flows.
    - – This difference provides insight about the potential efficiencies from coordinated congestion management and buy-through congestion provisions.
- For this analysis, we analyzed November 2008 through October 2009.
- The value of flowgate capability used by the loop flows depends on the marginal cost of re-dispatch for the monitoring ISO (the ISO on whose system the flowgate is on).
  - ✓ For example, if a flowgate is constrained with a \$200/MWh shadow price and 150 MW of flowgate capability is used by loop flows in the forward direction, the economic value of capability used by the loop flows is \$30,000/hour.
  - ✓ This is equal to the congestion charges that would be collected if the 150 MW of flow resulted from transactions scheduled internally.

Estimating the Quantity and Pricing of Loop Flows

- We first estimated forward and reverse loop flows resulting from:
  - ✓ Inter-control area transactions where the NYISO is not on the contract path; and
  - ✓ Native generation-to-load impacts from the other three ISOs.
- To identify pricing inefficiencies for the loop flows, the difference between the value of the flowgate and the costs incurred by the source of the loop flows is estimated.
  - ✓ The value of flowgate depends on the marginal redispatch cost to manage the congestion on the flowgate by the NYISO.
- The following tables show these annual pricing inefficiencies for the study period.
  - ✓ It shows the difference between the value of flowgate capability in the NYISO and the charges (or payments) to sources of the loop flows.
  - ✓ These values are likely lower than would otherwise be expected due to the very low fuel prices that prevailed during the study period.

Internal Interfaces (Coordinated Congestion Mgt)	Total
Under-Priced Forward Flows	$ 79
Under-Priced Reverse Flows	$ 61

Conclusions of Loop Flow Analysis

- Forward and reverse loop flows are significant in NYISO.
  - ✓ The total gross value of the loop flows is almost $140 million related to NYISO interfaces and constraints, and over $430 million on all constraints.
  - ✓ The BRM initiatives would capture some portion of this value by providing efficient incentives to schedule transactions and dispatch resources internally to minimize costs throughout the four ISOs' systems.
    - – The portion of the value that would be captured by the BRM is very difficult to estimate. It is based on the ability of other ISOs or schedulers to provide relief on NYISO's constraints at a lower cost than the NYISO real-time dispatch.
    - – We believe a reasonable range for this portion is 10 to 20 percent.
  - ✓ Assuming that coordination would reduce the costs of the constraints affected by loop flows by 10 percent, the production cost reductions for the NYISO would have fallen by $14 million during the study period.
- These results may be understated for the following reasons:
  - ✓ Fuel prices were very low during the period studied, which reduces the value of congestion.
  - ✓ We have no data on TLR-based curtailments and, therefore, have not identified cases where transactions were curtailed whose value exceed the value of the flowgate.
  - ✓ It does not identify the potential efficiency gains of scheduling transactions to relieve a constraint that was not scheduled under current rules.

Analysis of External Interface Utilization

- In addition to the benefits of better coordination of transactions and internal dispatch to lower the costs of managing congestion in the region, the BRM addresses improving scheduling between ISO markets.
- Improved scheduling would more fully utilize the transmission interfaces between the markets and generate significant benefits.
  - ✓ These benefits are best measured as reduced production costs.
  - ✓ Production costs are reduced as lower-cost resources in one market displace higher-cost resources in the adjacent market.
  - ✓ The result of this process is improved price convergence between the markets.
- We performed an econometric analysis estimate the benefits that are available from optimal scheduling of the interfaces between the markets.
- The portion of the savings that are ultimately realized depend on the actions taken by the ISOs.
  - ✓ Real-time coordination of the net scheduled interchange (“NSI”) (or intra-hour scheduling) would likely capture most of the savings.
  - ✓ Simply shortening the scheduling timeframes for participants would capture a much smaller share of the potential benefits.

Analysis of External Interface Utilization

- The largest source of benefits we estimated derives from improving the utilization of the interfaces between markets. The analysis is described below.

<u>Ontario and PJM Interfaces</u>

- We first estimated how prices in each ISO respond to changes in the scheduled interchange (“NSI”) over the interface, recognizing that this price response varies as prices increase or when there is congestion leading to the interface.
  - ✓ Our model also controls for changes in the NSI over other interfaces.
  - ✓ We did not have the congestion component of PJM’s real-time prices so the element was not included for the PJM interfaces.
  - ✓ We then used the estimates to simultaneously optimize the interchange over each of the four inter-ISO interfaces around Lake Erie, given the interface limits.

<u>New England Interface</u>

- For the New England interface, our analysis uses the actual generator offers in both markets, and recognizes the binding constraints leading to the interface, to estimate the optimal interchange each 5-minutes.

<u>HQ Interface</u>

- We have not estimated the benefits from dynamic dispatching the HQ interface.
- However, the BRM would likely reduce or eliminate uplift costs currently incurred when the NYISO lacks the flexibility necessary to manage flows over the interface.

Analysis of External Interface Utilization

- Having calculated the optimal interchange on a five-minute basis for each interface, we then estimated the production costs savings achieved by the NSI adjustments.
  - ✓ Production cost savings result when relatively high-cost resources in one region are displaced by lower cost resources in the adjacent region.
  - ✓ The production costs savings are the total efficiency savings captured by the NYISO and the adjacent RTOs.
- The following table shows the estimated production costs savings by interface:

Coordination of Scheduled Interchange	Estimated Benefits
New York - Ontario	$ 61
New York - PJM	$ 70
New York - New England	$ 10

- The savings for New England are lower in 2009 than estimated in prior years.
  - ✓ In 2006 to 2008, the production cost savings ranged from $17 to $21 million.
  - ✓ Also, coordination over the New England interface may have a larger effect on prices and reliability as it supplies east New York where shortages are more frequent.
- For the HQ interface, the NYISO estimated the following savings:
  - ✓ $8 million less balancing congestion from mitigating the negative prices in west NY.
  - ✓ $11 million in reduced uplift that was paid to HQ to manage flows on the interface.

Summary of Estimated BRM Production Cost Savings

- The potential savings we estimate address two aspects of the BRM initiations.
- Both show significant potential economic efficiencies, although the benefits of improved utilization of the external interfaces is larger.
- The following table summarizes the estimated annual benefits in the two areas. The savings on NYISO interfaces and constraints are shown in blue. It shows:
  - ✓ $174 million in savings for the NYISO interfaces and constraints; and
  - ✓ $303 million in savings on all interfaces and constraints.
- In total, the benefits may be understated due to:
  - ✓ The low load and high surplus capacity that prevailed in 2009; and
  - ✓ The relatively low fuel prices in 2009.
- The low fuel prices in 2009 can be addressed by adjusting the benefits to correspond to a more typical natural gas price.
  - ✓ The benefits should be highly correlated to natural gas prices because gas-fired units are on the margin in most periods in New York and the adjacent markets.
  - ✓ The table shows that at a $6 per MMBTU gas price, the benefits would rise to:
    - – $211 million on the NYISO interfaces and constraints;
    - – $369 million for all interfaces and constraints.

Summary of Estimated BRM Production Cost Savings

Coordination of Scheduled Interchange			Estimated Benefits	Fuel-Price Adj. Benefits*
New York - Ontario			$61	$76
New York - PJM			$70	$86
New York - New England			$10	$12
Ontario - MISO			$57	$70
MISO - PJM			$43	$54
New York - HQ (Balancing Congestion Reduction)			$8	$8
New York - HQ (Uplift Reduction)			$11	$11
			$261	**$317**
Coordinated Congestion Management	**Total**	**Assumed Savings**	**Estimated Benefits**	**Fuel-Price Adj. Benefits***
Under-priced Congestion				
NYISO Forward Loop Flows	$79	10%	$8	$10
NYISO Reverse Loop Flows	$61	10%	$6	$8
PJM Forward Loop Flows	$37	10%	$4	$5
PJM Reverse Loop Flows	$33	10%	$3	$4
MISO Forward Loop Flows	$19	10%	$2	$2
MISO Reverse Loop Flows	$19	10%	$2	$2
Ontario Forward Loop Flows	$30	10%	$3	$4
Ontario Reverse Loop Flows	$32	10%	$3	$4
Over-Priced Congestion				
Ontario Forward Loop Flows	$59	10%	$6	$7
Ontario Reverse Loop Flows	$58	10%	$6	$7
	$427		**$43**	**$53**
Total Estimated Savings - NYISO Interfaces/Constraints			**$174**	**$211**
Total Estimated Savings - All Interfaces/Constraints			**$303**	**$369**

Savings on NYISO's External Interfaces and Internal Constraints

* Adjusted to a $6 per MMBTU Natural Gas Price

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Capacity Market

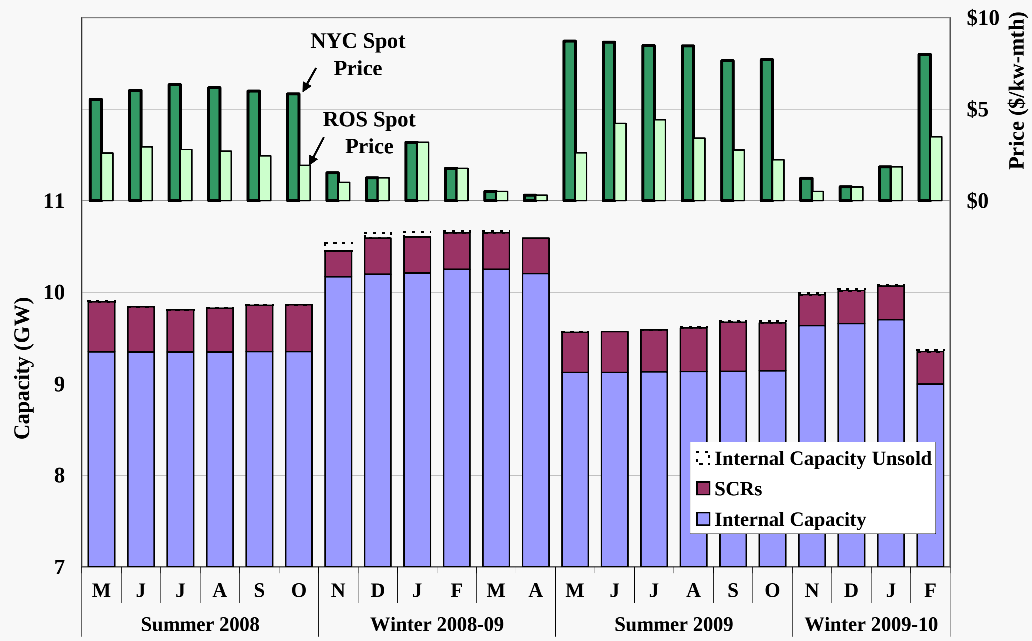
Capacity Market – Background

- The capacity market complements the energy and ancillary services markets in providing efficient economic signals for investment and retirement decisions.
- LSEs have several ways to satisfy their capacity obligations. They can:
  - ✓ “Self-schedule” their own generating capacity;
  - ✓ Purchase capacity through bilateral contracts; or
  - ✓ Participate in voluntary ICAP market auctions run by the NYISO.
- Additional capacity is purchased in the monthly UCAP Spot Auction on behalf of LSEs that have remaining obligations.
  - ✓ LSEs that have purchased more than their obligation prior to the Spot Auction, may sell the excess in the Spot Auction.
- To enhance the competitiveness of the capacity markets, a demand curve is used in the monthly UCAP Spot Auction.
  - ✓ Each LSE’s capacity obligation is determined by the intersection of supply in the Spot Auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions).

Capacity Market – New York City

- The following figure shows the resources available to provide UCAP, the amounts scheduled, and the UCAP prices in the NYISO auctions for NYC.
- The most significant changes in clearing prices result from the seasonal variations in the quantity of capacity supply.
  - ✓ Additional capability is available in the winter capability periods due to lower ambient temperatures, resulting in lower prices in these months.
  - ✓ In six of ten winter months shown, the NYC price fell to the level of the Rest-of-State (“ROS”) price, indicating the local requirement was not binding.
- NYC clearing prices rose from the summer 2008 to the summer 2009 due to:
  - ✓ An increase in the peak load forecast, which raised the NYC requirement;
  - ✓ The scheduled escalation of the NYC capacity demand curve; and
  - ✓ A reduction in UCAP supply due to higher equivalent forced outage rates, although the price effect was mostly offset by a corresponding reduction in the UCAP requirement due to a higher derating factor.
- The retirement of the Poletti steam unit in February 2010 reduced UCAP supply nearly 900 MW, contributing to a $6.13/kW-month increase in the NYC price.
- The figure shows that virtually all internal capacity has been sold in each month so withholding of supply has not been a concern.

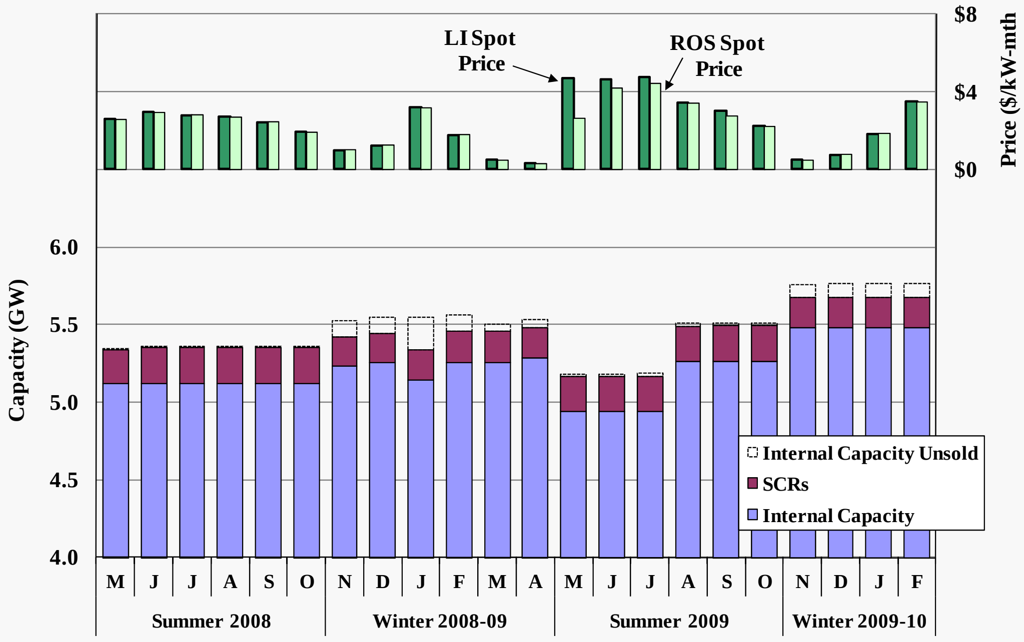
UCAP Sales and Prices in New York City
May 2008 to February 2010



Capacity Market – Long Island

- The following figure shows the resources available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the NYISO-run auctions for Long Island.
- In 19 of the 22 months shown, the Long Island clearing price was equivalent to the ROS clearing price, indicating that the local capacity requirement was not binding.
  - ✓ Long Island had substantial excess capacity—approximately 17 percent more than the amount of capacity needed to satisfy the local capacity requirement.
- Capacity levels increased approximately 300 MW in August 2009 due to the start of operation of the Caithness combined cycle generator.
- Total UCAP supply in Long Island declined in summer 2009 and winter 2009-10 due to an increase in equivalent forced outage rates.
  - ✓ This reduced UCAP supply, but was partly offset by a corresponding reduction in the UCAP requirement due to a higher derating factor.

UCAP Sales and Prices in Long Island
May 2008 to February 2010

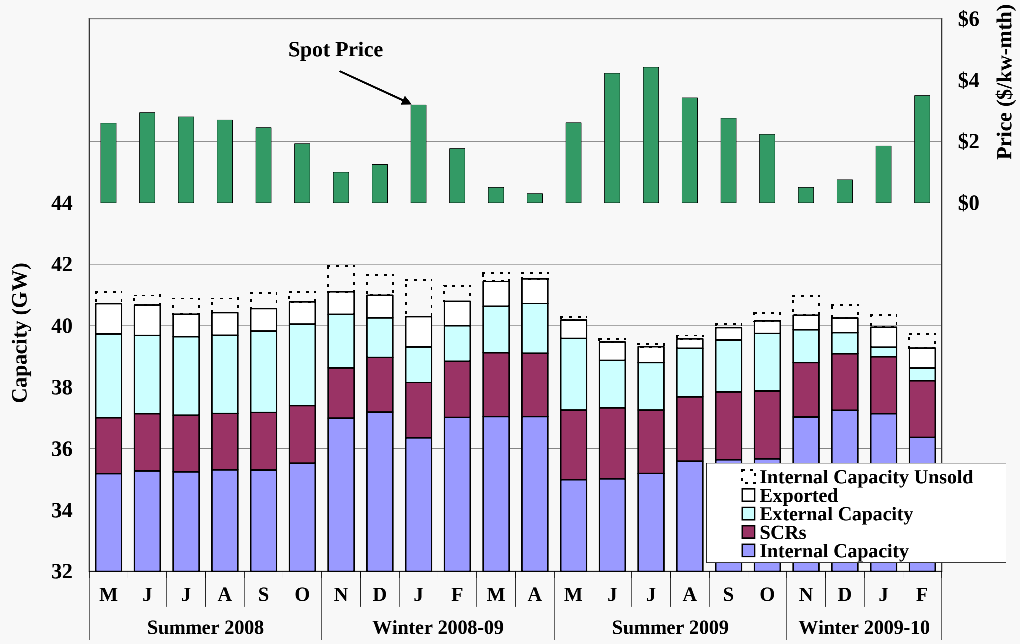


Note: UDRs are included in "Internal Capacity"

Capacity Market – New York State

- The following figure shows the resources available to provide UCAP to New York State, the amounts actually scheduled, and the prices that cleared for the ROS area in the NYISO-run auctions.
- Seasonal variations in capacity led to higher levels of internal capacity in the winter months and correspondingly lower clearing prices.
- Changes in the amount of available internal supply affected clearing prices.
  - ✓ Poletti's retirement in February 2010 reduced UCAP supply nearly 900 MW, contributing to a $1.64/kW-month increase in the clearing price.
  - ✓ New capacity at Caithness increased supply about 300 MW in August 2009, contributing to a $1.00/kW-month decrease in the clearing price.
- The amount of unsold capacity briefly rose by over 500 MW in January 2009, contributing to a $1.94/kW-month increase in the ROS clearing price.
  - ✓ We reviewed the increase and it did not raise competitive concerns.
- Average net imports fell from 1.8 GW in summer 2008 to 1.3 GW in summer 2009 and from 0.6 GW in winter 2008-09 to 0.1 GW in winter 2009-10.
  - ✓ Variations in net imports were driven primarily by a significant increase in PJM capacity prices beginning in June 2009.

UCAP Sales and Prices in New York State
May 2008 to February 2010



Note: UDRs are included in "Internal Capacity"

Capacity Market:
Configuration and Deliverability

- The capacity market should provide price signals that are consistent with the state's planning requirements, allowing the market to facilitate investment that will satisfy these requirements.
- Because transmission constraints limit the ability of the system to deliver supplies from upstate New York to New York City and Long Island, these areas have local planning requirements separate zones in the capacity market.
  - ✓ These local capacity zones allow the clearing prices in these areas to reflect the local conditions and to facilitate investment in local generation and transmission when it is needed.
  - ✓ Outside of these areas, there is only one "rest-of-state" zone ("ROS") where the market sets a single capacity price and all resources are deemed fungible.
  - ✓ To address transmission limitations within the ROS zone, the NYISO has recently implemented a new "deliverability test" to determine resources in one location cannot be fully delivered to another location in the same zone.
  - ✓ New resources or imports deemed undeliverable must either upgrade the transmission network so that it can be fully delivered or acquire deliverability rights from another participant to be able to sell capacity in the market.
  - ✓ Resources may be undeliverable because excess supply on the unconstrained side of a constraint cannot all be transferred across the constraint, even if such transfers would not likely occur in reality and the constraint would not likely bind.

Capacity Market: Configuration and Deliverability

- The new deliverability test has been implemented by NYISO and will apply to class year 2008 (projects that requested interconnection in 2008) and all future class years.
  - ✓ New resources in Class Year 2008 outside Southeast New York were deemed undeliverable.
  - ✓ To sell capacity, these suppliers must pay to upgrade transmission into the Hudson Valley at a cost of over \$170/kW or acquire rights from existing suppliers.
- This raises significant efficiency and competitive concerns because the new deliverability framework:
  - ✓ Does not provide efficient investment incentives for new investment supply resources, demand resources, or transmission facilities, or maintenance or retirement of existing resources;
  - ✓ Creates a substantial barrier to entry for competitive new supplies and imports, reducing the competitiveness of the market;
  - ✓ Does not reflect the marginal reliability value of resources at different locations; and
  - ✓ Will likely raise capacity costs for New York consumers.
- These issues can be resolved by defining a new capacity zone(s) to reflect transmission bottlenecks that legitimately affect the planning needs of the system.
- The following examples illustrate the importance of creating a zone to address deliverability issues.

Capacity Market – Deliverability Examples

- The following two examples show the differences in hypothetical market results under two alternate zonal configurations.
  - ✓ Single zone: the system must be able to deliver 2000 MW of excess capacity to Region 2 to be fully deliverable – 1000 MW is deemed not deliverable in this case.
  - ✓ Multiple zones: the 2000 MW must only be deliverable within Region 1. This is possible so all capacity may be sold.

Example 1: Multiple Zones

- Price in Region 1 is low (determined by the demand curve and surplus in zone).
- Price in Region 2 supports entry because it is needed to meet the reliability needs. (*Price may not rise when entry is not needed, as currently in southeast NY*).

Example 2: Single Zone

- The price in both regions clears at a price based on the single demand curve and the 1000 MW surplus for the aggregate zone.

Region 1

Excess ICAP = 2000 MW

Price = \$4 per KW-mo.

Constrained "Highway"

Headroom = 1000 MW

Region 2

Excess ICAP = 0 MW

Price = \$9 per KW-mo.

Single Zone: Regions 1 & 2

Excess ICAP = 1000

Price = \$7 per KW-mo.

Constrained "Highway"

Headroom = 1000 MW

Capacity Market -- Deliverability Examples

- These differences in market outcomes shown in the prior examples translate to different economic signals and associated investments decisions by participants.
- The next table shows how these changes in market outcomes translate to different investment decisions under four cases that make different assumptions regarding:
  - ✓ The costs expanding the transmission system, and
  - ✓ The costs of building new resources in Region 1 and Region 2.
- For the multi-zone alternative, each of the four cases result in incentives that would be expected to facilitate efficient investment in new resources and transmission.
  - ✓ The locational capacity price accurately reflects the needs and surpluses in each area, providing signals on when and where to build transmission and resources.
- For the single zone alternative, the inefficient incentives produced in this example are generally a barrier to efficient new investment in transmission and resources.
  - ✓ The loss in supply from new resources and imports that are deemed to not be deliverable within the single zone will generally raise costs to consumers.
  - ✓ New investment in Region 2 will only occur when the single zone price rises to the Region 2 net CONE, which imposes unnecessary costs on Region 1.
  - ✓ The single zone does not provide the efficient signal to invest in new transmission that the multiple zone framework does (see Case 3).

Capacity Market -- Deliverability Examples

	Cost Assumptions ($/KW-Mo.)		*Results*		
	Interface Upgrades	**New Resources**	**Zones**	**Expected Outcomes**	**Evaluation**
Case 1	Greater than $5	Region 1: $9 Region 2: $9	Multi-Zone	New resources in Region 2	Efficient
			Single Zone	No investment	Inefficient
Case 2	Greater than $5	Region 1: < $4 Region 2: $9	Multi-Zone	New resources in Region 1	Efficient
			Single Zone	No investment	Inefficient
Case 3	Less than $5	Region 1: $9 Region 2: $9	Multi-Zone	Build transmission	Efficient
			Single Zone	No investment	Inefficient
Case 4	Less than $5	Region 1: < $4 Region 2: $9	Multi-Zone	New resources and transmission in Region 1	Efficient
			Single Zone	Invest if new resources in Region 1 + tx upgrades < $7	Likely Inefficient

Capacity Market Configuration

- FERC has required the NYISO to work with its stakeholders to develop and file criteria for defining new capacity zones by this fall.
  - ✓ The examples above illustrate why a deliverability test failure on a "highway" facility should be the primary criteria for determining new zones.
  - ✓ Given the deliverability test shows that new resources cannot be delivered fully to southeast New York, we recommend that the NYISO make preparations to define a new zone(s) in parallel with developing the criteria in 2010.
  - ✓ These preparations include developing CONE estimates, demand curves, and other details necessary to implement a new zone(s).
- A new capacity zone would distinguish the value of capacity in southeast New York from the value of capacity in other areas. A new zone(s) would:
  - ✓ Allow the capacity market to signal where new capacity would be most beneficial. This may be particularly important in southeast New York because the cost of new entry is likely higher there than in other areas.
  - ✓ Enable more suppliers to sell capacity outside the new zone(s), thereby lowering capacity costs for New York consumers in those areas.
  - ✓ Since new capacity is not currently needed in southeast New York, creating the new zone(s) would likely lower overall capacity costs in New York.

Capacity Market Mitigation

- In early 2008, new market power mitigation measures were implemented for New York City to address:
  - ✓ Withholding of capacity to raise capacity prices (supply-side mitigation); and
  - ✓ Uneconomic investment designed to depress capacity prices (load-side mitigation);
- As the prior figures show, very little capacity remains unsold in New York City, which indicates that the supply-side mitigation measure (i.e., a bid cap) has been effective.
- The load-side mitigation measure is an offer floor that would deter such entry by preventing an uneconomic entrant from selling capacity.
  - ✓ It is too early to conclude whether the offer floor has been effective.
  - ✓ However, we have reviewed the detailed thresholds and testing procedures used to implement the offer floor and find that the tariff is ambiguous in some places and raises potential concerns in others.
  - ✓ Hence, we recommend that the NYISO review the thresholds and procedures used to implement the offer floor, and to identify those that may:
    - – Cause uneconomic entry to be exempted from the floor; or
    - – Erect an inefficient barrier to economic entry.

Demand Response Programs

POTOMAC ECONOMICS

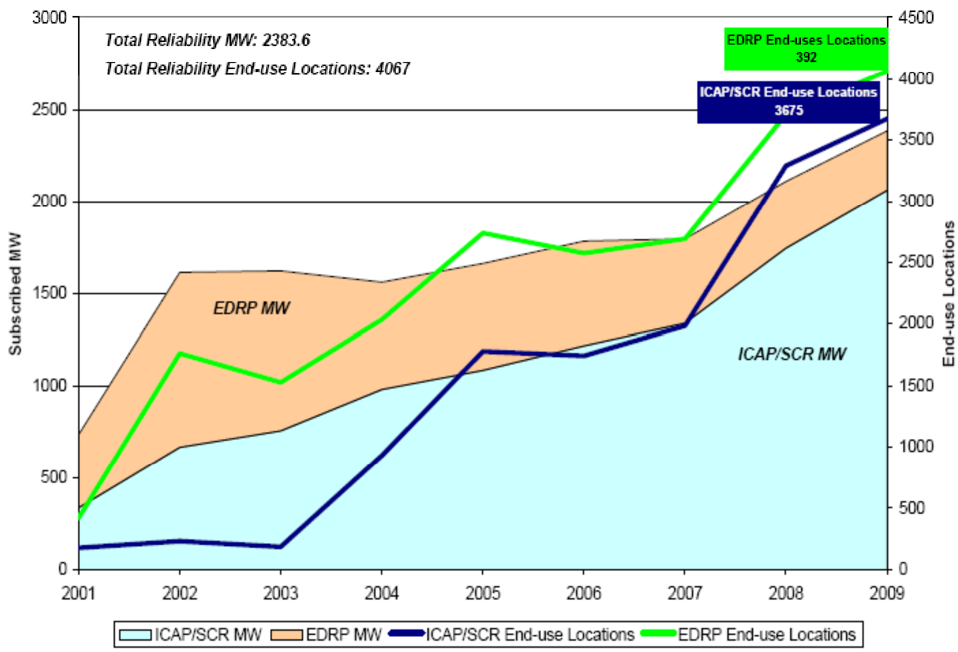
Demand Response Programs – Existing Programs

- The NYISO has five programs that allow retail loads to participate in wholesale market operations:
  - ✓ Three programs curtail loads in real-time for reliability reasons:
    - – Emergency Demand Response Program ("EDRP") resources are paid the higher of $500/MWh or the LBMP when called by the ISO for reliability.
    - – Special Case Resources ("SCRs") are paid the higher of their strike price (usually $500/MWh) or the LBMP when called by the ISO for reliability.
    - – Targeted Demand Response Program ("TDRP") deploys EDRP resources and SCRs to curtail when called by the local TO.
  - ✓ Day-Ahead Demand Response Program ("DADRP") resources offer to curtail in the day-ahead market with a floor price of $75/MWh.
  - ✓ Demand Side Ancillary Services Program ("DSASP") allows resources to offer regulation and reserves in the day-ahead and real-time markets.
- The cost of activating EDRP and SCR resources is reflected in clearing prices when they prevent reserve shortages at the state-level or eastern New York.
  - ✓ Efficient shortage pricing provides price signals that encourage participation in demand response programs.

Demand Response Programs – Existing Programs

- The following figure summarizes the growth in participation in the NYISO's demand response programs from 2001 to 2009.
  - ✓ EDRP resources and SCRs are also able to participate in the TDRP program.
- The SCR resources are more valuable than EDRP resources because SCRs are capacity resources that are obligated to curtail when activated.
  - ✓ SCR registration has grown consistently in each year since 2001 partly because many resources have shifted from the EDRP to the SCR program.
  - ✓ SCR resources provide considerable benefits by reducing the cost of meeting New York's planning reserve margin requirements.
- Since SCRs are needed to satisfy the NYISO's planning reserve requirements, it is important to ensure that the SCRs can perform when activated.
  - ✓ The current SCR baseline methodology is based on the monthly peak loads from the prior year. This may allow loads that have shut down their facilities to make sales as SCRs, so they cannot be activated.
  - ✓ The NYISO is reviewing the methods for calculating baselines for SCR resources to ensure they have the capability to curtail the expected quantity when called in real-time.

Registration in NYISO Demand Response Programs 2001 to 2009



Note: This figure is reproduced from the NYISO's January 15, 2010 Demand Response Compliance Report.

Demand Response Programs – New Developments

- Demand Response Information System ("DRIS") – This IT project will enhance the NYISO's capability to administer demand response programs and reduce the costs of participation.
  - ✓ The project will automate the following: registration, communication during events, settlements, performance monitoring, meter data management, and other functions that currently require manual effort.
- Demand-Side Ancillary Services Program ("DSASP") – Since June 2008, this program allows demand resources to provide regulation and reserves.
  - ✓ However, no DSASP resources have been fully qualified yet. Some resources have experienced delays related to setting up communications with the NYISO through the local Transmission Owner.
  - ✓ The NYISO is exploring ways to communicate directly with resources rather than through the local Transmission Owner.
- Aggregations of Retail Customers ("ARCs") – The NYISO is developing a set of proposed rules and procedures that would allow ARCs to provide ancillary services as DSASP resources.

Demand Response Programs – Real-time Price Responsive Load

- The most significant barrier to widespread participation by retail loads is that most of them are not exposed to wholesale price fluctuations.
  - ✓ Hence, retail electricity rate reform is one means to give retail loads incentives to be price-responsive.
  - ✓ Currently, approximately 6 GW of retail loads are in the Mandatory Hourly Pricing program, which charges loads according to hourly *day-ahead market* LBMPs.
- The NYISO is taking steps to enable demand resources to participate in the real-time energy market.
  - ✓ In consultation with stakeholders, the NYISO plans to develop a concept for a real-time price-responsive demand program in 2010.
  - ✓ Under a price-responsive demand program, the payment to the demand resource and the settlement with the LSE that serves the demand resource should net to zero.
    - – Hence, if the demand resource is paid the real-time LBMP as suggested by the recent FERC Notice of Proposed Rulemaking, the LSE should continue to be charged the real-time LBMP for the increment of load that was curtailed.
    - – Additionally, the retail customer associated with the demand resource should continue to be charged the retail rate.
    - – This will provide efficient incentives to the demand resource and result in a settlement that is comparable to supplying the load from a supply resource.