Quarterly Report on the New York ISO Electricity Markets Third Quarter 2015

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the third quarter of 2015.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- Average all-in prices ranged from roughly $41/MWh in West NY to $68/MWh in NYC, down 7 to 16 percent from the third quarter of 2014. (see slide 9)
  - ✓ In addition to the LBMP reductions mentioned below, capacity costs fell 18 percent (Long Island) to 38 percent (West NY and Capital) from 2014-Q3.
- RT LBMPs averaged $34/MWh statewide, down 5 percent from a year ago.
  - ✓ Gas prices fell 12 to 46 percent across NY primarily because of a 19 percent YoY increase in production from the Marcellus and Utica shales. (see slides 10, 12)
  - ✓ Average nuclear and hydro generation rose 450 MW because of fewer deratings and outages, contributing to the decrease in LBMPs. (see slide 15)
  - ✓ However, the reduction in LBMP was partly offset by:
    - – Transmission outages on UPNY-SENY interface and into Long Is. (see slide 17);
    - – Higher load levels (average load up 6% and peak load up 5%, see slide 11); and
    - – RGGI allowance price increases, which have added ~$0.60/MWh to the cost of a typical CC unit since 2014-Q3.

Highlights and Market Summary: Congestion Patterns

- DAM congestion revenue rose $92 million (or 101 percent) from the third quarter of 2014 partly because of higher load levels (see slides 45-48, 50).
- West Zone 230 kV lines accounted for 31 percent of DA congestion revenue.
  - ✓ These constraints have become more prevalent as coal-fired generation in the West Zone (which relieves these constraints) has been reduced by low natural gas prices.
- Capital to Hudson Valley lines accounted for 22 percent of DA congestion revenue.
  - ✓ Transmission outages reduced transfer capability in late-August and September.
  - ✓ Large natural gas price spreads between Western NY and NYC and Long Island contributed to the congestion (see slide 12).
- Long Island accounted for 22 percent of DA congestion revenue.
  - ✓ Transmission outages reduced transfer capability from upstate NY to Long Island throughout July.
- New York City constraints accounted for 13 percent of DA congestion revenue.
  - ✓ Greenwood/Staten Island congestion was partly driven by outages.
  - ✓ Relatively high gas price spreads in NYC contributed to the congestion.



Highlights and Market Summary:
DA to RT Energy Price Convergence

- Intra-zonal congestion was more severe and volatile in the RT than in the DAM on some paths. (see slides 46, 48, 50)
- In the West Zone, congestion on 230kV facilities often increased in RT because:
  - ✓ Volatile Lake Erie loop flows can cause severe RT congestion (see slide 40);
  - ✓ Incomplete utilization of parallel 115kV lines (to unload 230kV constraints);
  - ✓ Ontario imports and renewable generation in West NY rose from DA to RT; and
  - ✓ Operation of the Ramapo PARs (to relieve Central-East and SENY congestion) increased flows across 230kV lines in the West Zone (see slides 48, 52).
- This pattern led virtual traders to schedule supply (~300 MW) at the Ontario proxy bus and load (~400 MW) at the West Zone in the DAM (see slides 29, 33). These virtual trades contributed to downstream commitments that relieved congestion.
- In the Central Zone, congestion on exports from the Oswego Complex increased in RT as a result of changes in offer patterns between the DAM and RT.
- In New York City, congestion into the Greenwood load pocket was:
  - ✓ Higher in RT because of: (a) offer price changes after the DAM; and (b) brief small transmission constraint violations with very high RT shadow prices; and
  - ✓ Under-stated in the DAM because of uneconomic scheduling of GTs by the SCUC model (units were uneconomically scheduled in approx 100 hours).
    - – NYISO is working on concepts to address this in 2016.

Highlights and Market Summary: Capacity Market

- UCAP spot prices fell notably from the third quarter of 2014. UCAP prices:
  - ✓ In New York City fell 17 percent to an average of $15.28/kW-month;
  - ✓ In the G-J Locality fell 32 percent to an average of $8.32/kW-month;
  - ✓ On Long Island fell 12 percent to an average of $5.72/kW-month;
  - ✓ In Rest of State fell 37 percent to an average of $3.68/kW-month.
- Capacity spot prices fell across the system (see slides 79-81) because:
  - ✓ The return-to-service of multiple units and new wind capacity additions increased internal capacity supply by 850 MW in Zone G, 170 MW in NYC, and 100+ MW in West NY.
  - ✓ Average sales from SCRs rose 70 MW in NYC, 80 MW in the G-J Locality, and 230 MW in NYCA.
  - ✓ The ICAP requirement fell 115 MW (0.3 percent) in NYCA, 54 MW (0.5 percent) in NYC, and 148 MW (3 percent) in Long Island.
    - However, the ICAP requirement rose 451 MW (3 percent) in the G-J Locality, offsetting the decrease of UCAP prices in the G-J Locality.
    - The LCR reductions in NYC and Long Island and the increased LCR in the G-J Locality resulted primarily from recent capacity additions in Zone G.

Highlights and Market Summary:
Uplift and Revenue Shortfalls

- Guarantee payments were $20.3M, up 22 percent primarily because of higher costs for OOM dispatch in Long Island and Western NY. (see slides 62-64, 67, 69-71)
  - ✓ Higher load levels led to increased OOM instructions to dispatch peaking generators to manage voltage constraints on the East End of Long Island.
  - ✓ Lower LBMPs led several coal-fired and gas-fired units to be DARUed and/or OOMed more frequently to manage post-contingency flows on 115kV facilities.
- DAM congestion shortfalls were $7M, down $1M from 2014-Q3. (slides 47, 51)
  - ✓ Transmission outages into SENY and Long Is. accounted for $7M of shortfalls.
  - ✓ West Zone constraints accounted for $3.4M of shortfalls largely because of assumptions related to loop flows and Niagara generator modeling.
  - ✓ The 901 & 903 lines were not used to deliver power from Long Island to NYC in July because the Y50 line was OOS. Typically, these deliveries are uneconomic, so the reduced deliveries generated $5.2M of surpluses.
- Balancing congestion shortfalls totaled $6M, down $1M. (see slides)
  - ✓ $5.0M of shortfalls were associated with congestion in the West Zone primarily because of differences between the DAM and RT regarding loop flows. Although average loop flows are similar between the DA and RT, loop flows can be volatile and lead to severe RT congestion.

Energy Market Outcomes

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All-In Prices

- The first figure summarizes the total cost per MWh of load served in the New York markets by showing the “all-in” price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component based on spot prices multiplied by capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Rate Schedule 1 charges.
- Average all-in prices ranged from roughly $41/MWh in West NY to $68/MWh in NYC, down 7 to 16 percent from the third quarter of 2014.
  - ✓ Energy prices fell roughly 3 percent (NYC) to 8 percent (West NY).
    - – Lower energy prices were due primarily to lower natural gas prices (see slide 12) and increased nuclear and hydro generation (see slide 15).
    - – However, these were largely offset by higher load levels (see slide 11).
  - ✓ Capacity costs fell 18 percent (Long Island) to 38 percent (West NY and Capital).
    - – Capacity spot prices fell across the system primarily because of: (a) increased internal capacity supply; (b) increased SCR sales; and (c) lower ICAP requirements in most capacity zones (see slides 79-81).
    - – However, the reduction of capacity prices in the G-J Locality was partly offset by a significant increase in the ICAP requirement.

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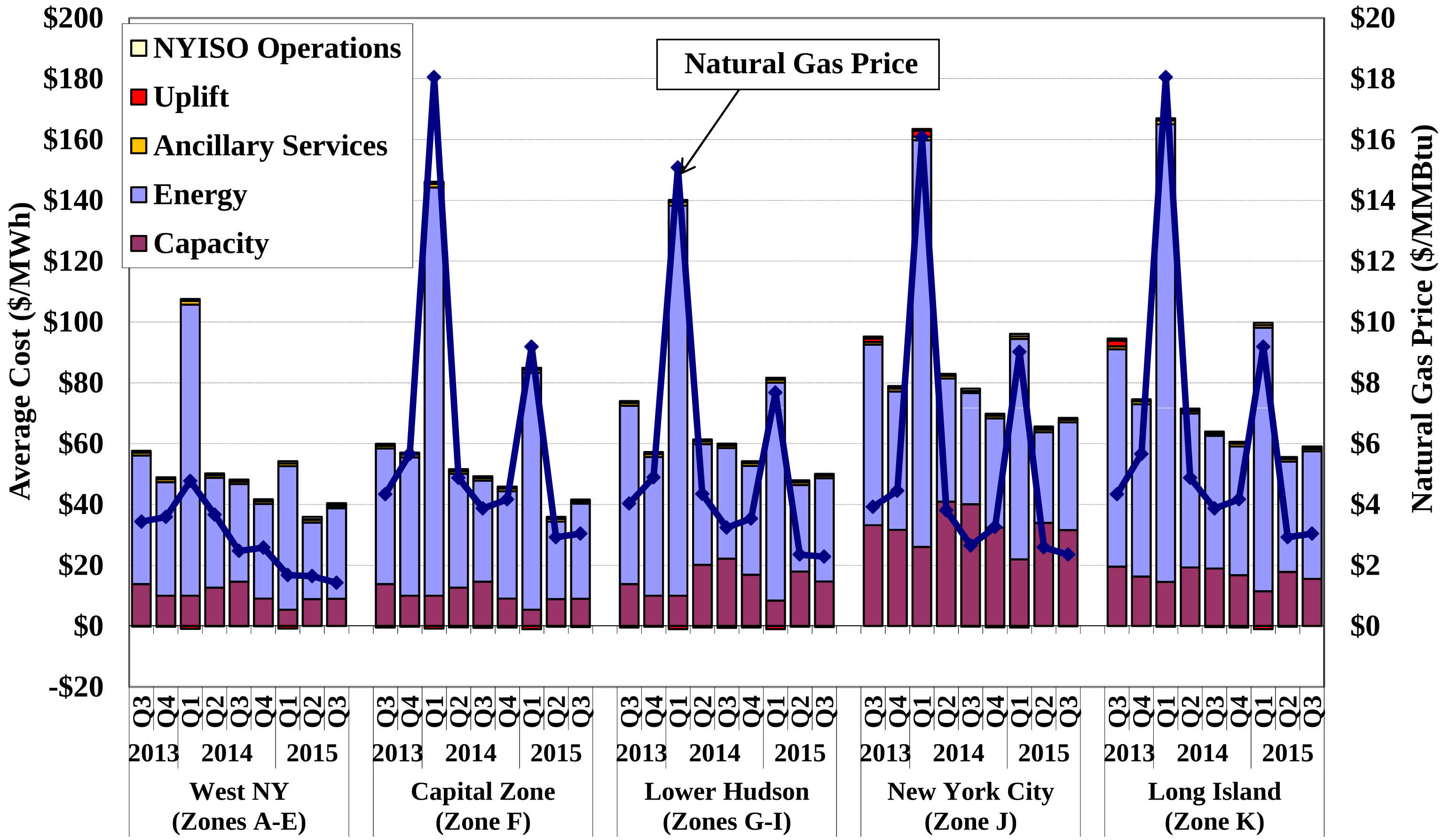
All-In Energy Price by Region

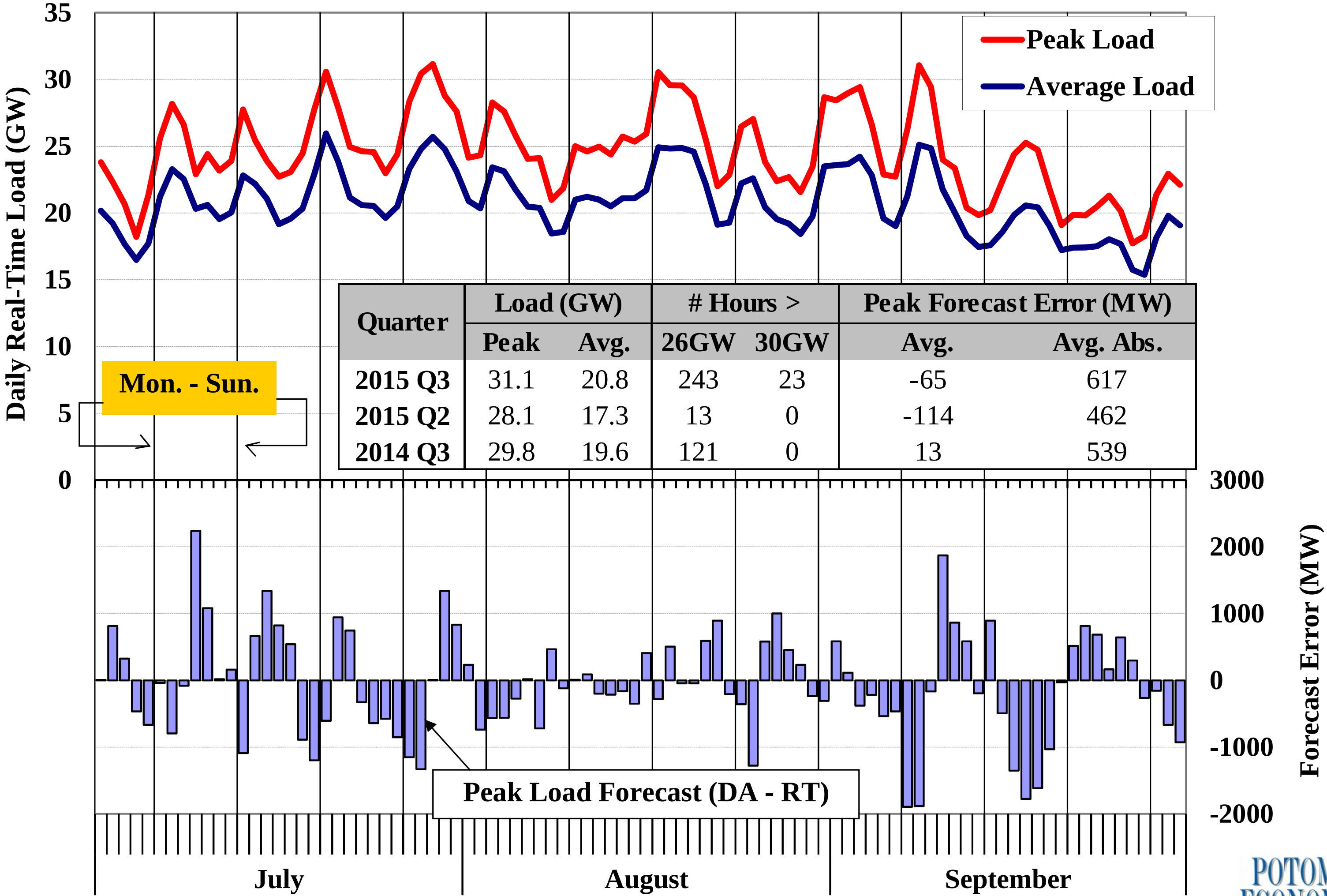


Note: Natural Gas Price is based on the following gas indices (plus a transportation charge of $0.20/MMbtu): the Dominion North index for West NY, the Iroquois Zone 2 index for the Capital Zone, the average of Texas Eastern M3 and Iroquois Zone 2 for Lower Hudson, the Transco Zone 6 (NY) index for New York City, and the Iroquois Zone 2 index for Long Island.

Load Levels and Fuel Prices

- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Load averaged 20.8 GW (up 6% from 2014) and peaked at 31.1 GW (up 5%).
  - ✓ These increases reflected warmer weather than in the previous summer, but load levels in 2015-Q3 were still lower than the same quarter from 2010 to 2013.
  - ✓ Rapid weather changes over a short period led to considerable load variations.
    - – For example, unexpected high temperatures in early September led daily peak load to rise 8 GW from 9/6 to 9/8 and then fall 7 GW over the next two days.
    - – Volatile load levels led to increased forecasting errors, contributing to a large price divergence between DA and RT on several days (e.g., on 9/8, see slides 18, 21).
- Gas prices fell to a multi-year low this summer, down from a year ago (12% in NYC, 23% in LI, and 46% in West NY) primarily because of higher production from the Marcellus and Utica shales (up 3.3 million MMbtu/day from 2014-Q3).
  - ✓ In New York, natural gas traded at a discount to Henry Hub (which averaged $2.74/MMbut) except at Iroquois Z2.
  - ✓ Lower natural gas prices made coal-fired generation in West NY less economic, contributing to increased congestion in this area (see slide 50).

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2015 Q3	31.1	20.8	243	23	-65	617
2015 Q2	28.1	17.3	13	0	-114	462
2014 Q3	29.8	19.6	121	0	13	539

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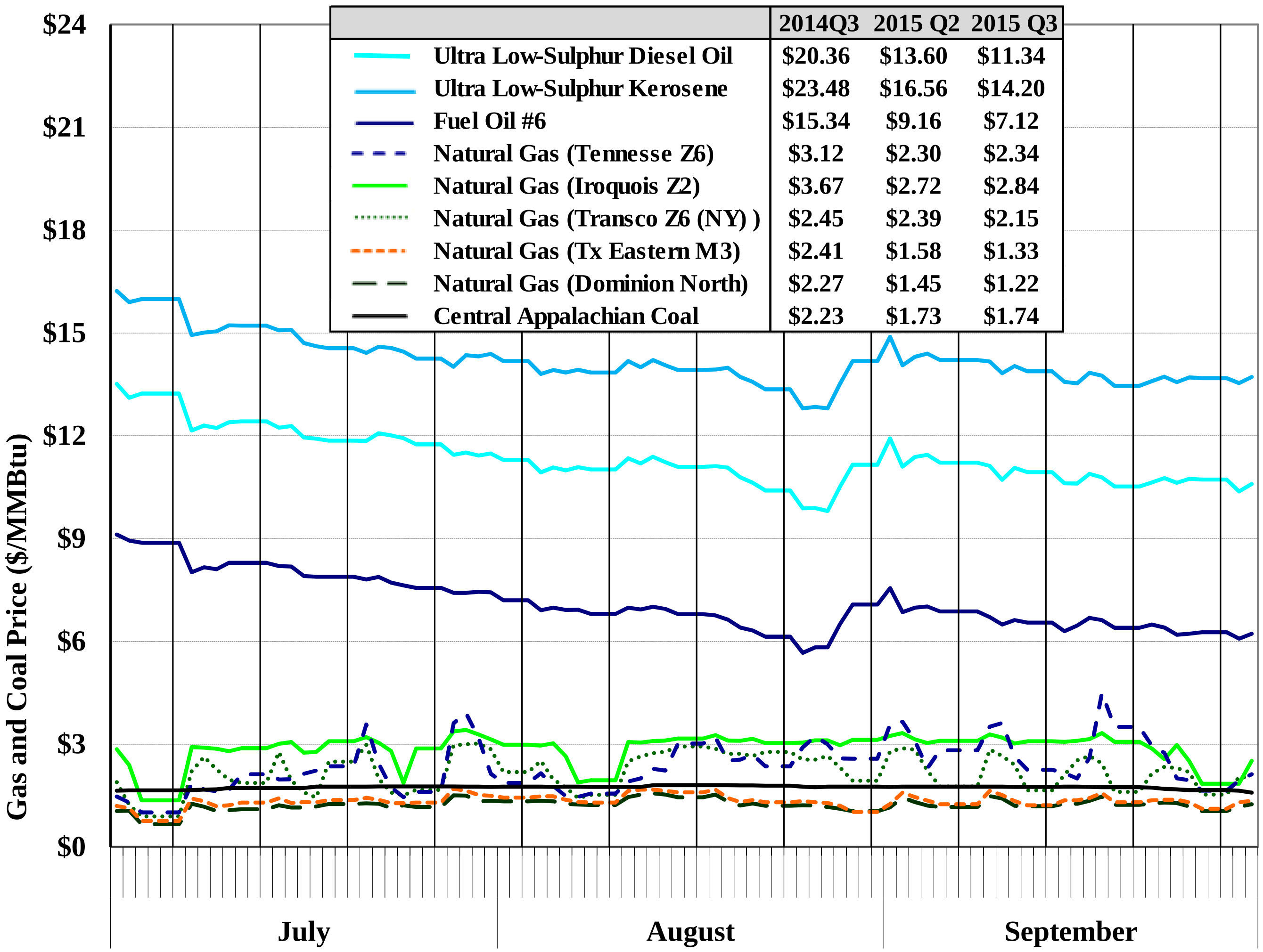
Coal, Natural Gas, and Fuel Oil Prices



	2014Q3	2015 Q2	2015 Q3
Ultra Low-Sulphur Diesel Oil	$20.36	$13.60	$11.34
Ultra Low-Sulphur Kerosene	$23.48	$16.56	$14.20
Fuel Oil #6	$15.34	$9.16	$7.12
Natural Gas (Tennesse Z6)	$3.12	$2.30	$2.34
Natural Gas (Iroquois Z2)	$3.67	$2.72	$2.84
Natural Gas (Transco Z6 (NY))	$2.45	$2.39	$2.15
Natural Gas (Tx Eastern M3)	$2.41	$1.58	$1.33
Natural Gas (Dominion North)	$2.27	$1.45	$1.22
Central Appalachian Coal	$2.23	$1.73	$1.74

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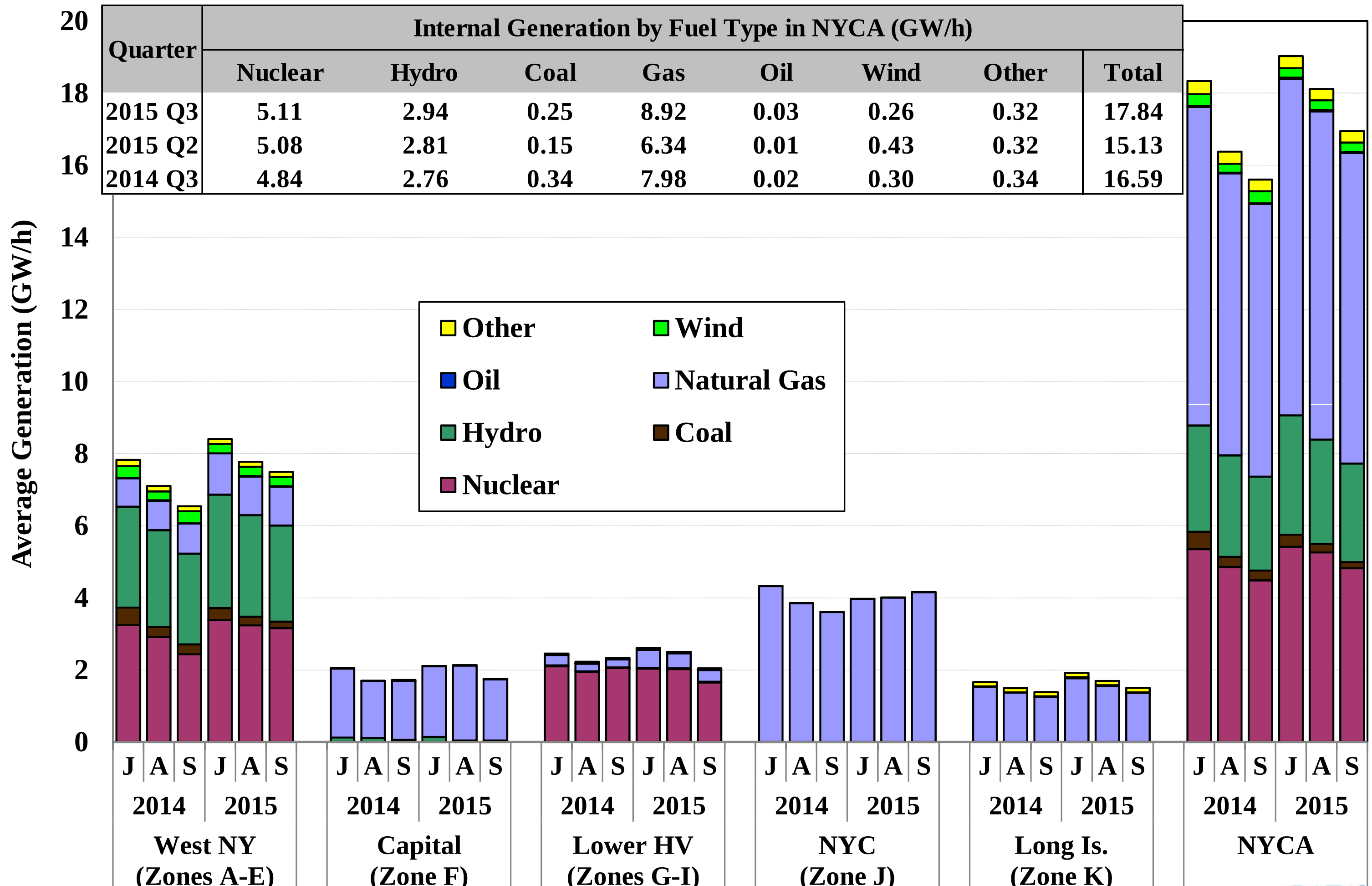
Real-Time Generation by Fuel Type

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the third quarter of 2015.
- The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
- The second figure summarizes how frequently each fuel type is on the margin and setting real-time LBMPs in these regions.
  - ✓ More than one type of generator may be on the margin in an interval, particularly when a transmission constraint is binding. Accordingly, the total for all fuel types may be greater than 100 percent.
    - For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent.
  - ✓ When no generator is on the margin in a particular region, the LBMPs in that region are set by:
    - Generators in other regions in the vast majority of intervals; or
    - Shortage pricing of ancillary services, transmission constraints, and/or energy in a small share of intervals.
- The fuel type for each generator is based on its actual fuel consumption reported to the EPA and the EIA.

Real-Time Generation and Marginal Units by Fuel Type

- Gas-fired (50 percent), nuclear (29 percent), and hydro (17 percent) generation accounted for most of internal generation in the third quarter of 2015.
  - ✓ Average nuclear and hydro generation rose 270 MW and 180 MW from the third quarter of 2014 because of fewer deratings and outages.
    - – The increase was primarily in West NY.
  - ✓ Coal generation fell from a year ago, averaging 250 MW this quarter.
    - – Low natural gas prices in West NY made coal-fired generation less economic.
  - ✓ Gas-fired generation rose from a year ago, picking up most of the load increase.
- Gas-fired and hydro resources were on the margin the vast majority of time in the third quarter of 2015.
  - ✓ Most hydro units on the margin have storage capacity and offer based on the opportunity cost of foregone sales in other hours (i.e., when gas is marginal).
  - ✓ Both gas-fired and hydro units were on the margin slightly more frequently than a year ago, reflecting more frequent congestion.
    - – However, coal units were on the margin less frequently despite increased congestion in the West Zone because most coal-fired generation was dispatched out-of-merit.

Real-Time Generation Output by Fuel Type



Quarter	Internal Generation by Fuel Type in NYCA (GW/h)							
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other	Total
2015 Q3	5.11	2.94	0.25	8.92	0.03	0.26	0.32	17.84
2015 Q2	5.08	2.81	0.15	6.34	0.01	0.43	0.32	15.13
2014 Q3	4.84	2.76	0.34	7.98	0.02	0.30	0.34	16.59

Notes: Pumped-storage resources in pumping mode are treated as negative generation. "Other" includes Methane, Refuse, Solar & Wood.

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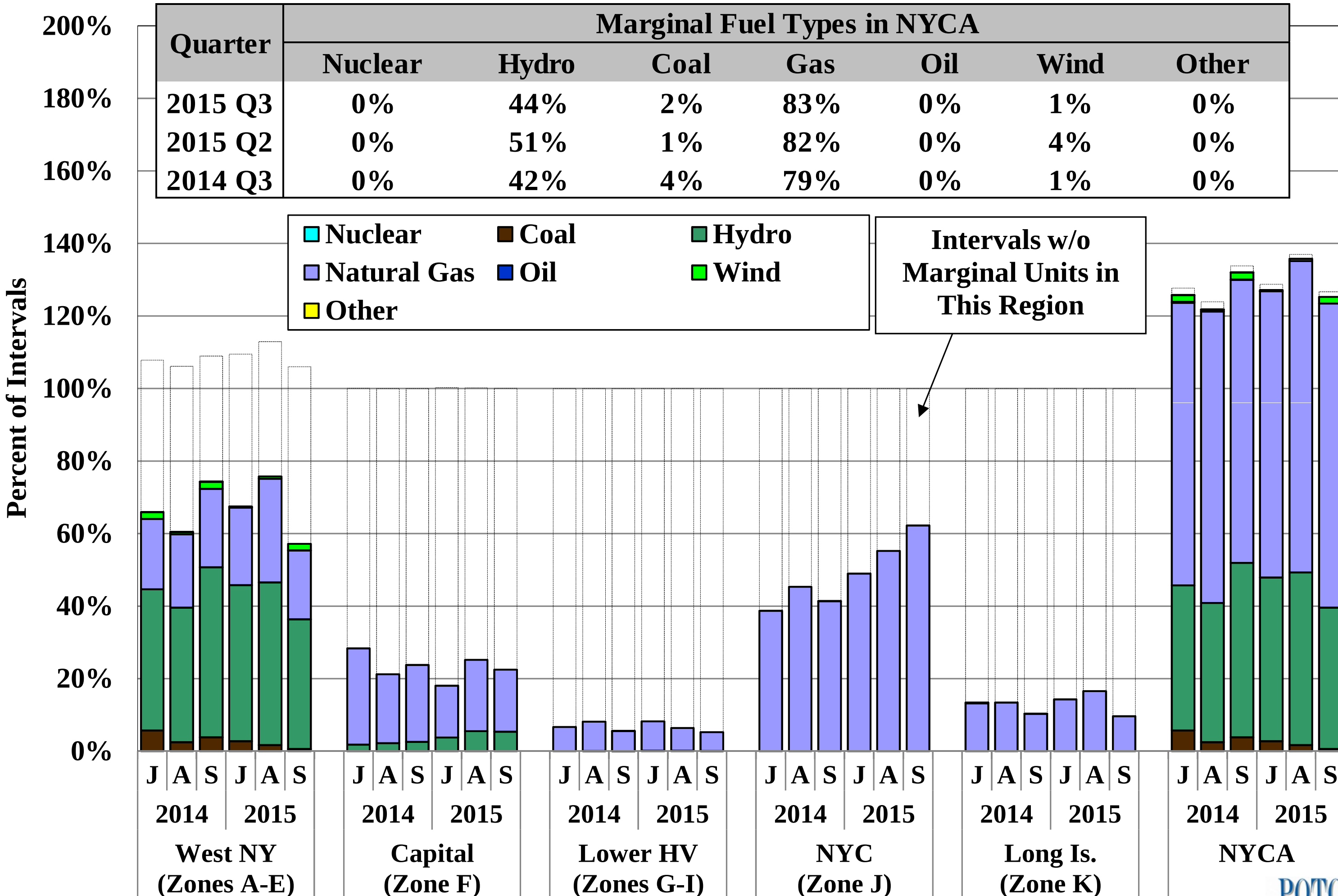
Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other
2015 Q3	0%	44%	2%	83%	0%	1%	0%
2015 Q2	0%	51%	1%	82%	0%	4%	0%
2014 Q3	0%	42%	4%	79%	0%	1%	0%



Note: "Other" includes Methane, Refuse, Solar & Wood.

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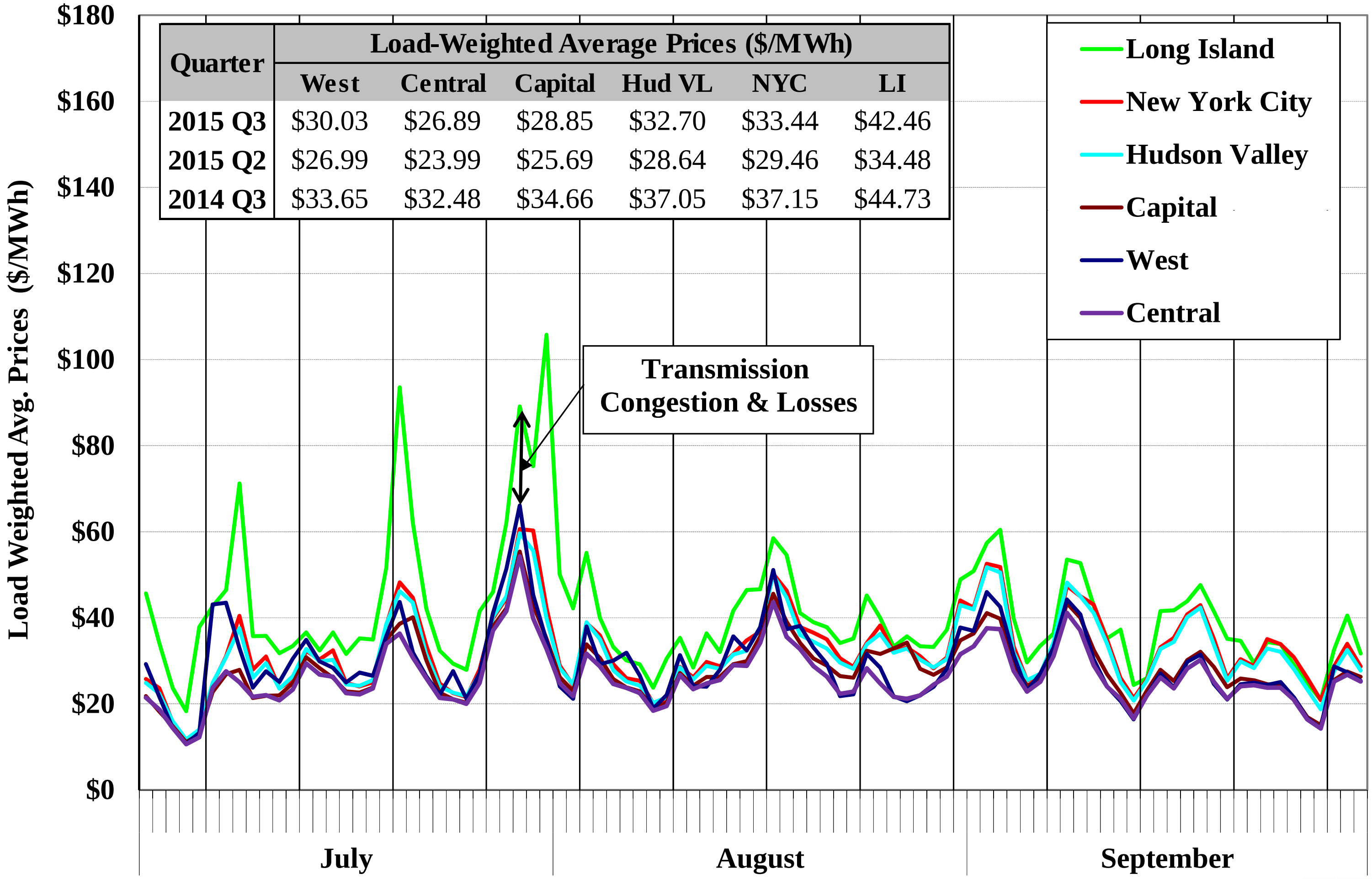
Day-Ahead and Real-Time Electricity Prices

- The following three figures show: 1) load-weighted average DA energy prices; 2) load-weighted average RT energy prices; and 3) convergence between DA and RT prices for six load zones on a daily basis in the third quarter of 2015.
- Average day-ahead prices ranged from $27/MWh in the Central Zone to $42/MWh on Long Island, down 5 to 17 percent from the third quarter of 2014.
  - ✓ The decreases were driven primarily by lower natural gas prices (see slide 12) and higher nuclear and hydro generation (see slide 15).
    - – However, the decreases were partly offset by higher load levels and more frequent peaking conditions (see slide 11).
  - ✓ LBMPs fell the least (5 percent) on Long Island among all regions.
    - – One of the two 345 kV lines from upstate to Long Island (i.e., the Dunwoodie-Shore Rd “Y50” line) was out of service from July to early August, leading to higher LBMPs on Long Island during this period.
  - ✓ LBMPs were elevated frequently in SENY in late August and September.
    - – Planned transmission outages reduced transfer capability from Capital to Hudson Valley (e.g., Leeds-HurleyAve “301” line & Fraser-CooperCorner “33” line).
    - – In addition, unexpected high temperatures led to unexpected high load in early September.

Day-Ahead and Real-Time Electricity Prices

- Prices are generally more volatile in the real-time market than in the day-ahead market because of unexpected events. RT LBMPs rose notably statewide:
  - ✓ On 7/20, due to loss of 850 MW of NYC generation, resulting from: (a) a generator trip and (b) the uneconomic de-commitment of gas turbines by RTC.
  - ✓ On 8/19, due to the effects of: (a) under-scheduling in the DAM, (b) TSA operations (which led to uneconomic de-commitment of units outside SENY), and (c) a sub-optimal balance of generation (between 115kV and 230kV units) in the West Zone reduced the amount that was deliverable.
  - ✓ On 9/8, due to unexpected high load (~2 GW over the NYISO DAM forecast).
  - ✓ On 9/29, due to the effects of significant under-scheduling in the DAM and curtailment of Neptune imports by PJM.
- Average RT prices were 12 percent higher than DA prices in the West Zone. Acute RT congestion often occurred on 230kV lines in the West Zone because of:
  - ✓ Clockwise changes in loop flows around Lake Erie (see slide 40);
  - ✓ Incomplete utilization of parallel 115kV facilities (to unload constrained 230kV facilities); and
  - ✓ Changes in supply offer patterns after the day-ahead market.
- These factors also contributed to RT prices being 3 to 7 percent higher than DA prices in other areas outside Long Island.

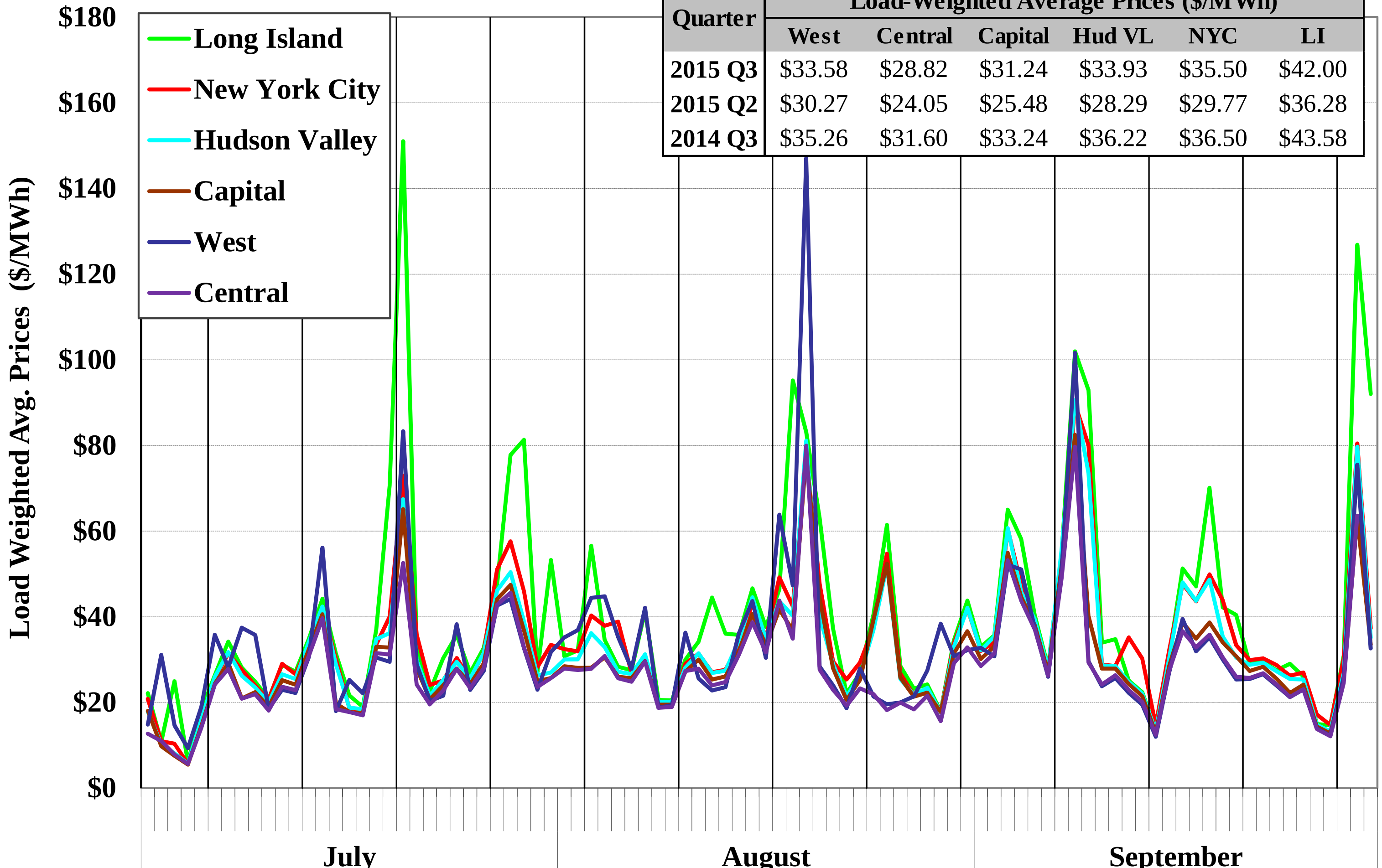
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2015 Q3	$30.03	$26.89	$28.85	$32.70	$33.44	$42.46
2015 Q2	$26.99	$23.99	$25.69	$28.64	$29.46	$34.48
2014 Q3	$33.65	$32.48	$34.66	$37.05	$37.15	$44.73

Real-Time Electricity Prices by Zone

Quarter	Load-Weighted Average Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2015 Q3	$33.58	$28.82	$31.24	$33.93	$35.50	$42.00
2015 Q2	$30.27	$24.05	$25.48	$28.29	$29.77	$36.28
2014 Q3	$35.26	$31.60	$33.24	$36.22	$36.50	$43.58



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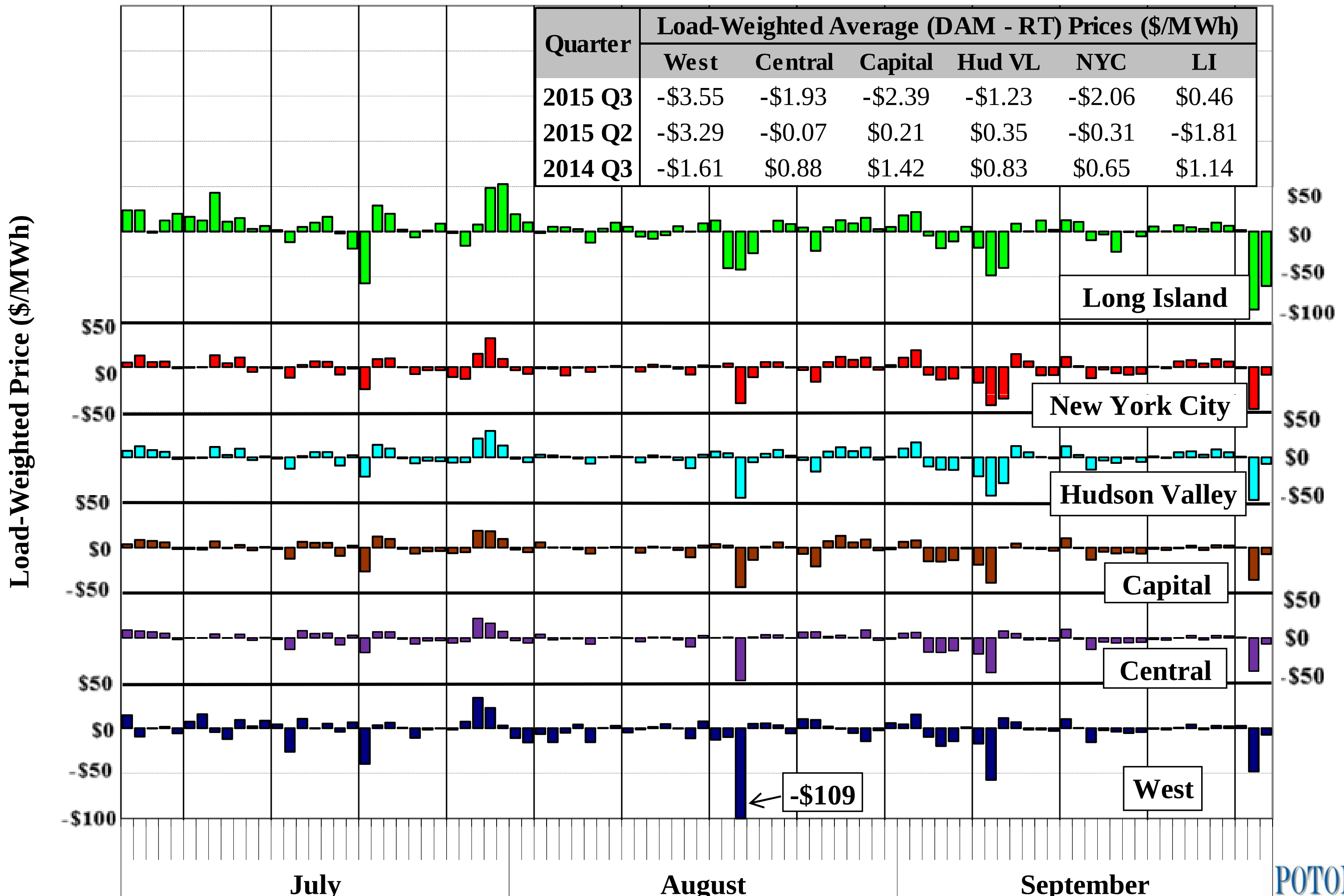
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2015 Q3	-$3.55	-$1.93	-$2.39	-$1.23	-$2.06	$0.46
2015 Q2	-$3.29	-$0.07	$0.21	$0.35	-$0.31	-$1.81
2014 Q3	-$1.61	$0.88	$1.42	$0.83	$0.65	$1.14



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Ancillary Services Market

Ancillary Services Prices

- Two figures summarize DA and RT prices for four ancillary services products:
  - ✓ 10-min spinning reserve prices in eastern NY, which reflect the cost of requiring:
    - 330 MW of 10-minute spinning reserves in eastern NY;
    - 655 MW of 10-minute spinning reserves state-wide; and
    - 1,200 MW of 10-minute total reserves (spin and non-spin) in eastern NY.
  - ✓ 10-min non-spinning reserve prices in eastern NY, which reflect the cost of requiring 1,200 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-min spinning reserve prices in western NY, which reflect the cost of requiring 655 MW of 10-minute spinning reserves statewide.
  - ✓ Regulation prices, which reflect the cost procuring up to 300 MW of regulation, and the cost and uplift charges from moving regulation units up and down.
    - Resources were scheduled assuming a Regulation Movement Multiplier of 13 MW per MW of capability, but they are compensated according to actual movement.
- The figures show the number of shortage intervals -- when a requirement cannot be satisfied at a marginal cost less than its "demand curve", which are:
  - ✓ $25 for eastern 10-minute spinning reserves;
  - ✓ $500 for eastern 10-minute total reserves;
  - ✓ $500 for statewide 10-minute spinning reserves; and
  - ✓ $80 to $400 for regulation.

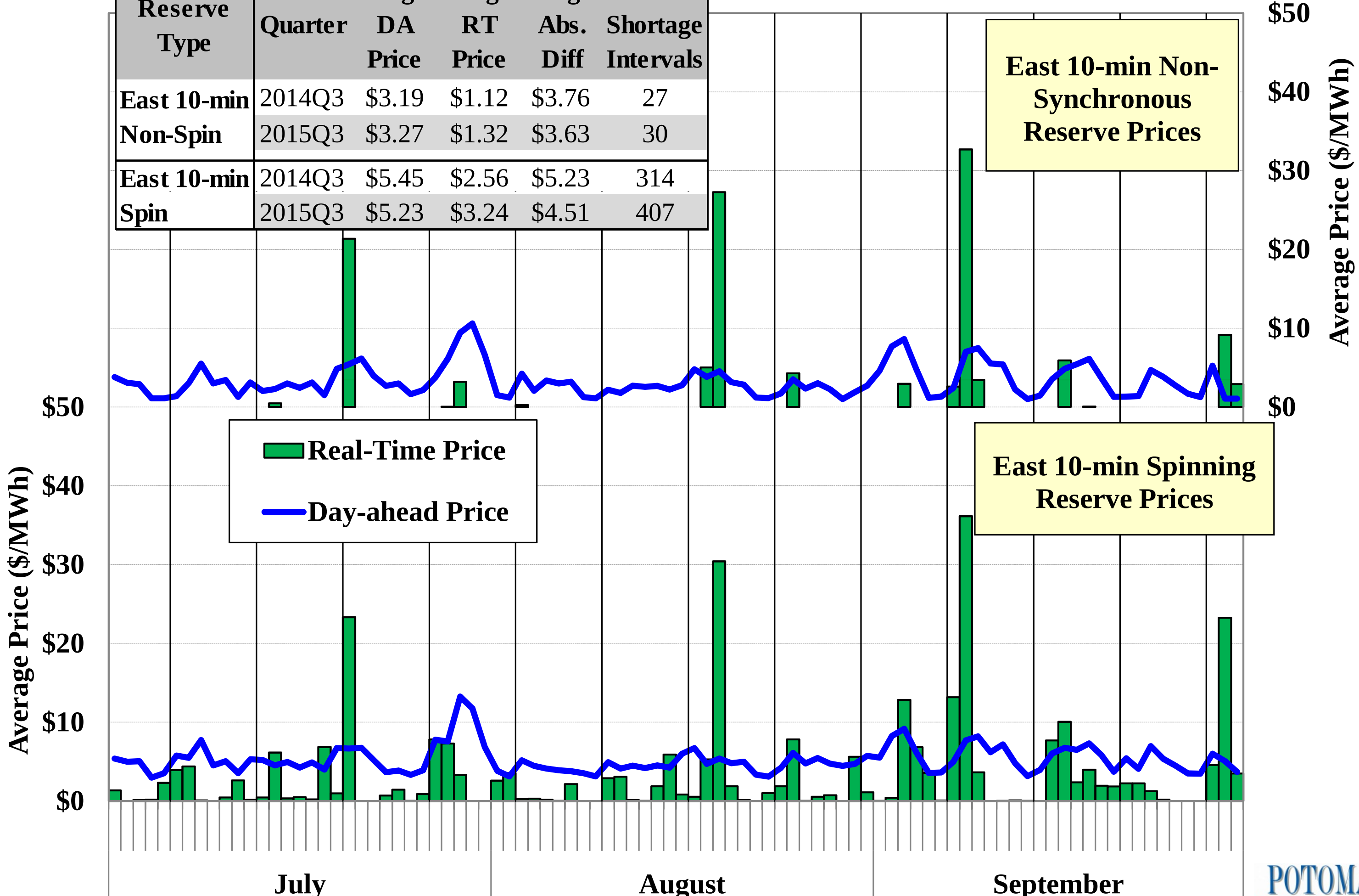
Ancillary Services Prices

- Average prices for ancillary services products were relatively comparable to the third quarter of 2014.
  - ✓ Prices were lower for some ancillary services because of lower opportunity costs associated with lower energy prices.
  - ✓ However, these were offset by moderately increased shortages due to higher load levels and more frequent peaking conditions.
    - – Prices rose notably in real-time on several days when unexpected events resulted in very tight system conditions (which are discussed earlier, see slides 18, 20).
  - ✓ Average DA prices exceeded average RT prices for most reserve products.
    - – DAM price premiums are expected in competitive markets with no virtual trading.
- The NYISO implemented most components in the Comprehensive Shortage Pricing Project on November 3, 2015, including:
  - ✓ Adding a 30-minute reserve requirement for SENY;
  - ✓ Limiting the Zone K reserve contribution to NYCA, East, and SENY requirements;
  - ✓ Raising the NYCA 30-minute reserve requirement; and
  - ✓ Raising the demand curve values for some ancillary services products.
  - ✓ These changes aim to improve the scheduling and pricing of these ancillary services products, which we will continue to monitor.

Day-Ahead and Real-Time Ancillary Services Prices

Eastern 10-Minute Spinning and Non-Spinning Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2014Q3	$3.19	$1.12	$3.76	27
	2015Q3	$3.27	$1.32	$3.63	30
East 10-min Spin	2014Q3	$5.45	$2.56	$5.23	314
	2015Q3	$5.23	$3.24	$4.51	407



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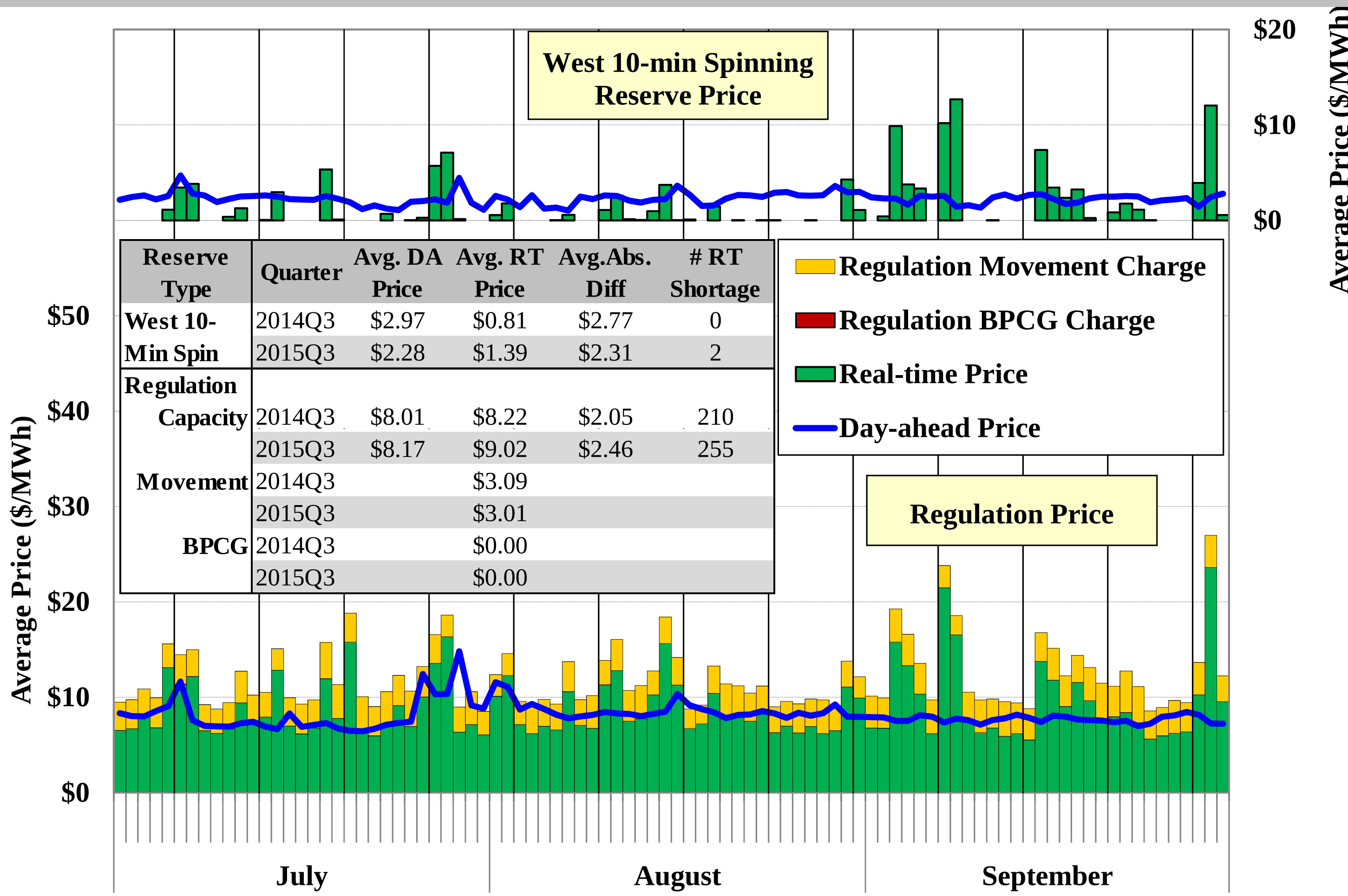
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage
West 10-Min Spin	2014Q3	$2.97	$0.81	$2.77	0
	2015Q3	$2.28	$1.39	$2.31	2
Regulation Capacity	2014Q3	$8.01	$8.22	$2.05	210
	2015Q3	$8.17	$9.02	$2.46	255
Movement	2014Q3		$3.09		
	2015Q3		$3.01		
BPCG	2014Q3		$0.00		
	2015Q3		$0.00		

Note: Regulation Movement Charges and BPCG charges from regulating in real-time are shown in the figure averaged per MWh of RT Scheduled Regulation Capacity.

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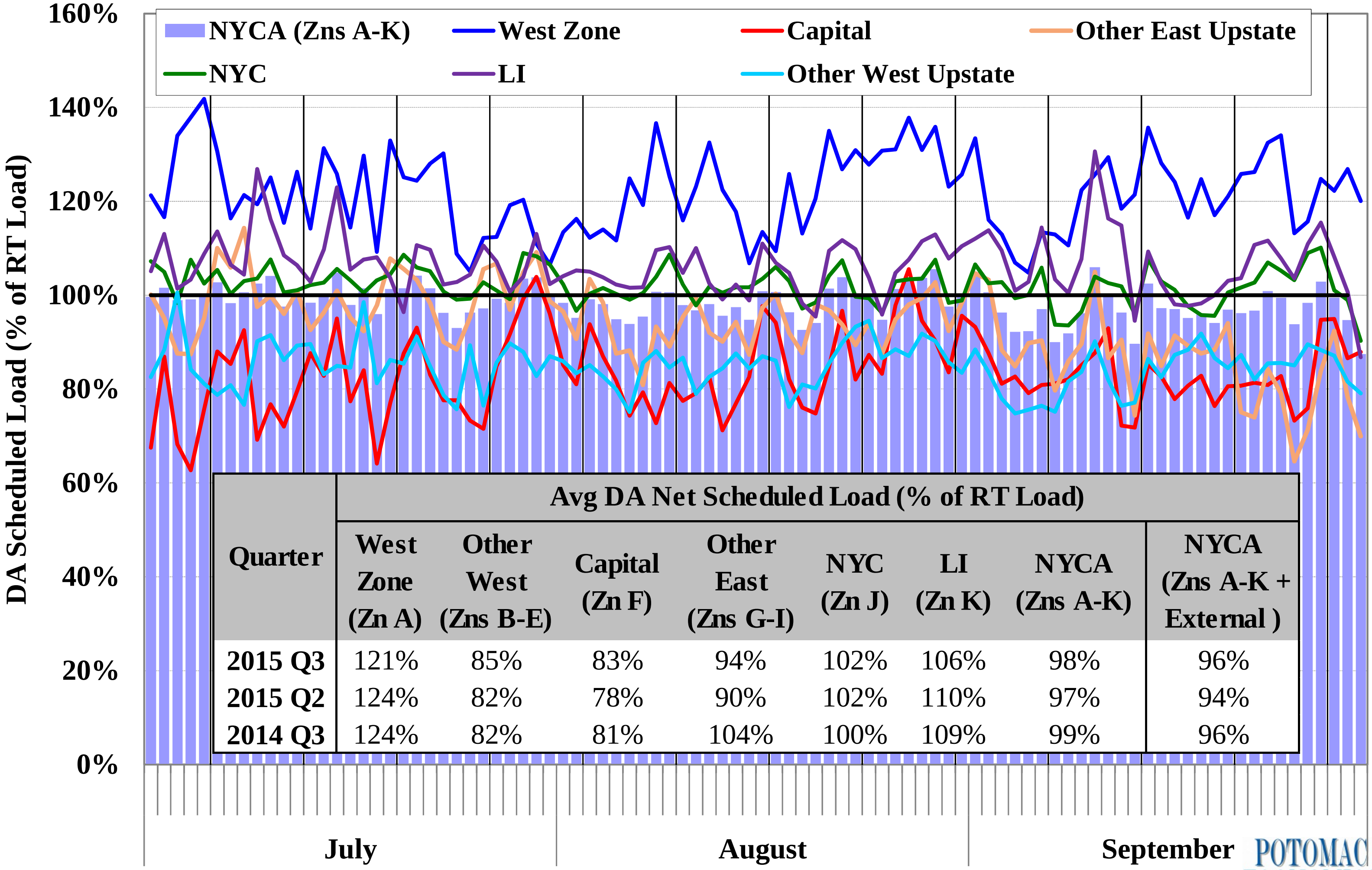
Energy Market Scheduling

Day-ahead Load Scheduling

- The following figure summarizes the quantity of DA load scheduled as a percentage of RT load in each of six regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
  - ✓ The table also summarizes a system-wide net scheduled load that includes virtual imports and virtual exports at the proxy buses.
- For NYCA, 96 percent of actual load was scheduled in the DAM (including virtual imports/exports) in the third quarter of 2015, consistent with the prior year.
- Load scheduling tends to be higher in import-constrained locations, and at times when acute real-time congestion is more likely.
  - ✓ DAM scheduling was the highest in the West Zone and Long Island this quarter, where acute RT congestion occurred most frequently.
    - – Load scheduling in the West Zone rose in recent years due to increased congestion on the 230kV system, averaging 121 percent of actual load this quarter.
  - ✓ Load scheduling rose notably in SENY and fell in the Capital Zone on several days when thunderstorms were likely anticipated (e.g., 7/26, 8/19, 9/3).
- Under-scheduling was still prevalent in West Upstate outside the West Zone.
  - ✓ This is generally consistent with the tendency for renewable generators to increase RT output above DA schedules.

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



Quarter	West Zone (Zn A)	Other West (Zns B-E)	Capital (Zn F)	Other East (Zns G-I)	NYC (Zn J)	LI (Zn K)	NYCA (Zns A-K)	NYCA (Zns A-K + External)
	Avg DA Net Scheduled Load (% of RT Load)							
2015 Q3	121%	85%	83%	94%	102%	106%	98%	96%
2015 Q2	124%	82%	78%	90%	102%	110%	97%	94%
2014 Q3	124%	82%	81%	104%	100%	109%	99%	96%

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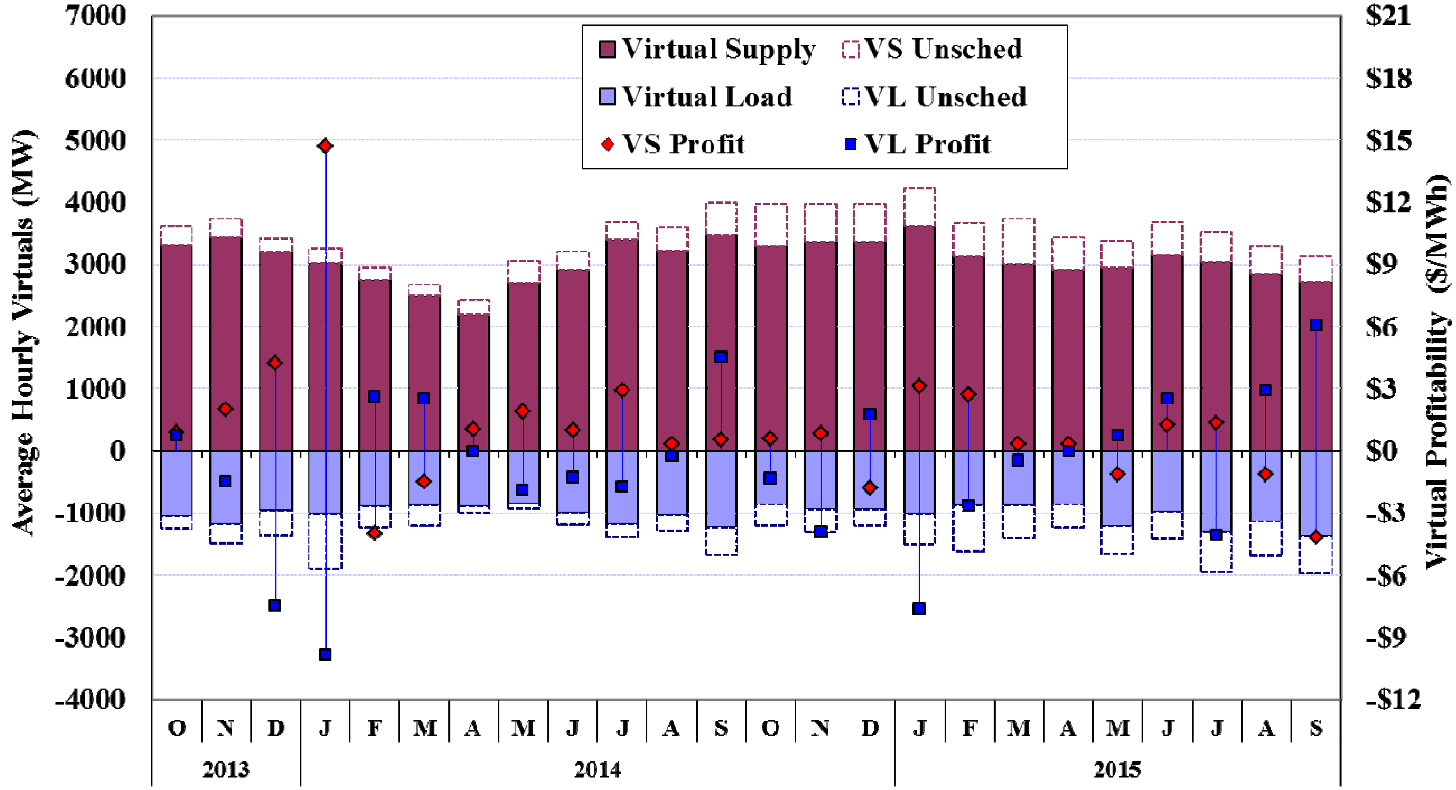
Virtual Trading Activity

- The following two charts summarize recent virtual trading activity in New York.
- The first figure shows monthly average scheduled and unscheduled quantities, and gross profitability for virtual transactions at the load zones in the past 24 months.
  - ✓ The table shows a screen for relatively large profits or losses, which identifies virtual trades with profits or losses larger than 50% of the average zone LBMP.
    - – Large profits may indicate modeling inconsistencies between DA and RT markets, and large losses may indicate manipulation of the day-ahead market.
- The second figure summarizes virtual trading by geographic region.
  - ✓ The load zones are broken into six regions based on typical congestion patterns.
    - – The North Zone is shown separately because transmission constraints frequently affect the value of power in that area.
    - – The Capital Zone is shown separately because it is constrained from West NY by the Central-East Interface and from SENY by constraints in the Hudson Valley.
    - – NYC and Long Island are shown separately because congestion frequently leads to price separation between them and other areas.
  - ✓ Virtual imports and exports are shown as they have similar effects on scheduling.
    - – A transaction is deemed virtual if the DA schedule is greater than the RT schedule, so a portion of these transactions result from forced outages or curtailments by NYISO or another control area (rather than the intent of the participant).

Virtual Trading Activity

- The volume of virtual trading did not change significantly in the third quarter of 2015, generally consistent with prior periods.
  - ✓ The pattern of virtual scheduling was similar as well.
    - – Virtual traders generally scheduled more virtual load in downstate areas and more virtual supply in upstate regions.
    - – This was consistent with typical load scheduling patterns.
- In aggregate, virtual traders netted a gross *loss* of roughly $1.7 million at the load zones and $1.3 million at the proxy buses in the third quarter of 2015.
  - ✓ Virtual load netted a gross *profit* of $4.5 million this quarter, while virtual supply netted a gross *loss* of $7.5 million.
    - – This was consistent with prevailing RT premiums in most areas (see slide 21).
  - ✓ The profits and losses of virtual trades varied widely by time and location, reflecting the difficulty of predicting volatile RT prices.
- Only small quantities of virtual transactions generated substantial profits or losses, consistent with similar periods in prior years.
  - ✓ These trades were primarily associated with high price volatility that resulted from unexpected events, which do not raise significant concerns.

Virtual Trading Activity at Load Zones by Month



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
Profit > 50% of Avg. Zone Price	MW	269	553	417	739	348	345	116	217	187	524	159	333	587	433	380	537	562	313	296	561	765	471	284	239
	%	6%	12%	10%	18%	10%	10%	4%	6%	5%	11%	4%	7%	14%	10%	9%	12%	14%	8%	8%	13%	19%	11%	7%	6%
Loss > 50% of Avg. Zone Price	MW	234	422	310	532	432	351	107	229	234	395	212	333	508	455	370	460	445	375	335	667	680	489	296	336
	%	5%	9%	7%	13%	12%	10%	3%	6%	6%	9%	5%	7%	12%	11%	9%	10%	11%	10%	9%	16%	17%	11%	7%	8%

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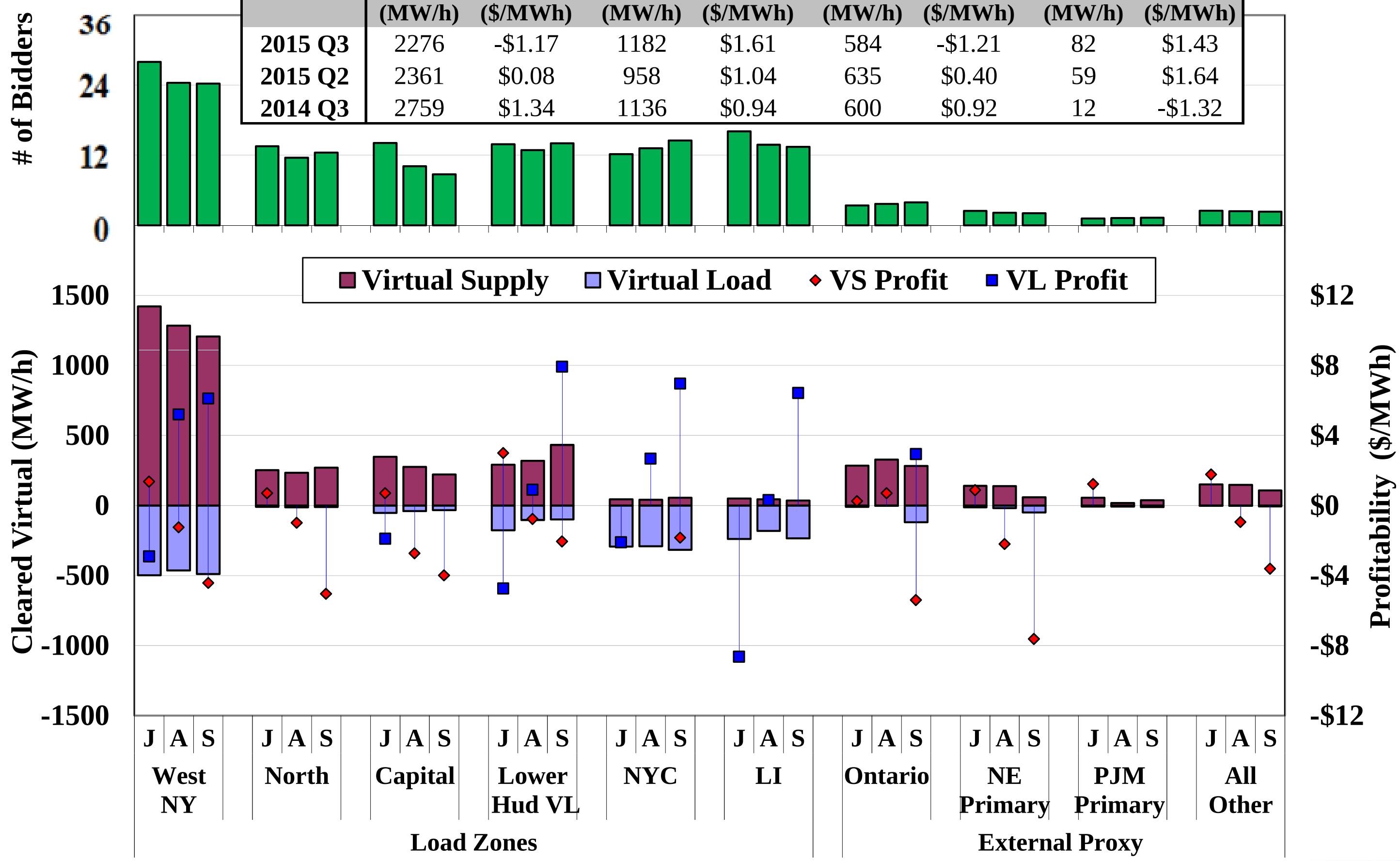
Virtual Trading Activity at Load Zones & Proxy Buses by Location

Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2015 Q3	2276	-$1.17	1182	$1.61	584	-$1.21	82	$1.43
2015 Q2	2361	$0.08	958	$1.04	635	$0.40	59	$1.64
2014 Q3	2759	$1.34	1136	$0.94	600	$0.92	12	-$1.32



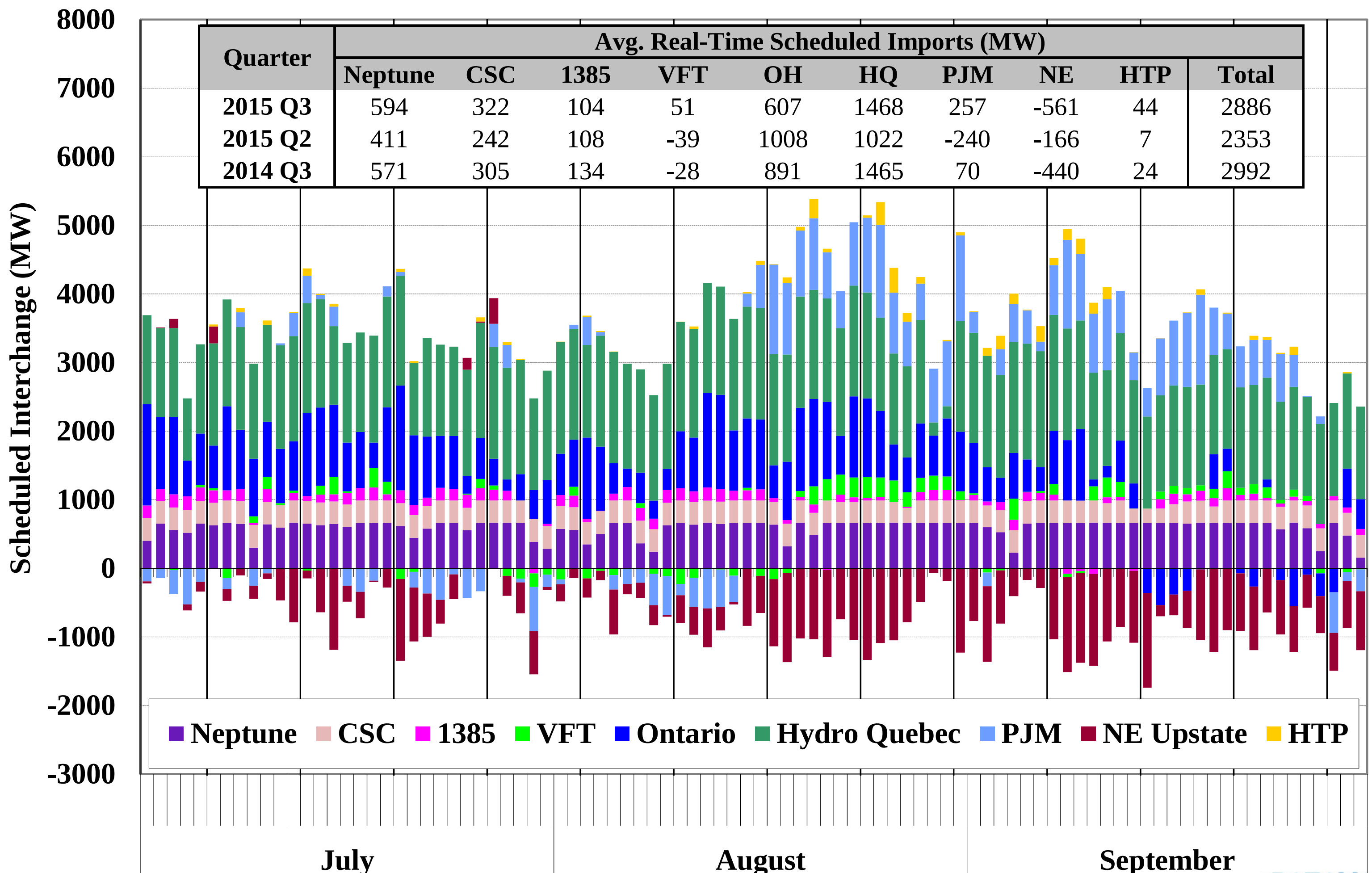
Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.

POTOMAC ECONOMICS

Net Imports Scheduled Across External Interfaces

- The next figure shows average RT scheduled net imports to NYCA across ten external interfaces (two HQ interfaces are combined) in the peak hours (1-9 pm).
- Overall, net imports averaged roughly 2,885 MW (serving roughly 14 percent of the load) during peak hours, down moderately from the third quarter of 2014.
- Net imports from Ontario fell roughly 285 MW on average from a year ago.
  - ✓ The decrease in mid September coincided with nuclear outages (~4 GW OOS) in Ontario, which helped reduce congestion on the 230 kV lines in the West Zone.
- Net exports to NE across the primary interface rose 120 MW from a year ago.
  - ✓ The primary interface was often fully scheduled in the export direction to NE during peak hours from late-August to mid-September when gas spreads between the Algonquin City Gates and Transco Z6 (NY) hubs increased. (see slide 12)
- Net imports from PJM (including VFT, HTP, Neptune, and the primary interface) rose 300 MW from the third quarter of 2014.
  - ✓ Energy prices in SENY were often elevated in late-August and September because import capability into this area was reduced by transmission outages (see slide 19).
    - – This increased the incentives to import power from PJM during this period.

Net Imports Scheduled Across External Interfaces
Daily Peak Hours (1-9pm)



Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2015 Q3	594	322	104	51	607	1468	257	-561	44	2886
2015 Q2	411	242	108	-39	1008	1022	-240	-166	7	2353
2014 Q3	571	305	134	-28	891	1465	70	-440	24	2992

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Intra-Hour Scheduling with PJM
Coordinated Transaction Scheduling ("CTS")

- The next table evaluates the performance of CTS with PJM at its primary interface for each month of the third quarter of 2015 (see Table A-8 in our 2014 SOM report for more detailed description). The table shows:
  - ✓ The percent of quarter-hour intervals during which the interface flows were adjusted (relative to the base schedule) in the scheduling RTC interval.
  - ✓ The average flow adjustment from the base schedule.
  - ✓ The production cost savings that resulted from the CTS, including:
    - Projected savings at scheduling time, which is the expected production cost savings at the time when RTC determines the interchange schedule.
    - Unrealized savings, which are not realized due to: a) New York forecast error; b) PJM forecast error; and c) other factors.
    - Actual savings (= Projected – Unrealized).
  - ✓ Interface prices on both NY and PJM sides that include actual prices (i.e., NY RT prices and PJM RT prices) and forecasted prices at the time of RTC scheduling (i.e., NY RTC prices and PJM IT SCED prices).
  - ✓ Price forecast errors, which show the average difference and the average absolute difference between the actual and forecasted prices on both sides.

POTOMAC ECONOMICS

Intra-Hour Scheduling with PJM
Coordinated Transaction Scheduling ("CTS")

- Interchange between NY and PJM was adjusted relatively evenly under CTS in both the import and export directions. In the third quarter of 2015:
  - ✓ On average, 60 MW of flows were adjusted in the export direction to PJM in 30 percent of intervals, while 65 MW of flows were adjusted in the import direction to NY in 40 percent of intervals.
- Sizable benefits (measured by production cost savings) were projected at the time of scheduling, but a relatively small portion was realized primarily because of price forecast errors in both markets. In the third quarter of 2015:
  - ✓ A total of $1.9 million in production cost savings was estimated at the time when RTC determined final schedules. However, price forecast errors on:
    - The NY side accounted for $0.9 million of unrealized projected savings; and
    - The PJM side accounted for $0.7 million of additional unrealized projected savings.
- Average forecast errors were similar between the New York side and the PJM side.
  - ✓ On the NY side, forecast errors generally increased during periods of RT congestion, particularly in the West Zone where congestion prices were highly volatile.
  - ✓ On the PJM side, forecast errors became smaller in recent months compared to the first several months of CTS implementation.

Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM Interface

			Export (NY to PJM)			Import (PJM to NY)			Average/ Total
			Jul-15	Aug-15	Sep-15	Jul-15	Aug-15	Sep-15	
% of All Intervals			26%	33%	31%	36%	41%	42%	**70%**
Average Flow Adjustment (MW)			-58	-65	-57	62	63	70	**11 (Net) / 63 (Gross)**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.15	$0.15	$0.29	$0.53	$0.47	$0.29	**$1.9**
	Unrealized Savings Due to:	NY Fcst. Err.	-$0.05	-$0.09	-$0.07	-$0.27	-$0.32	-$0.07	**-$0.9**
		PJM Fcst. Err.	-$0.06	-$0.11	-$0.24	-$0.17	$0.00	-$0.09	**-$0.7**
		Other	-$0.01	$0.00	-$0.03	$0.00	-$0.02	$0.00	**-$0.1**
	Actual		$0.03	-$0.06	-$0.05	$0.08	$0.13	$0.13	**$0.3**
Interface Prices ($/MWh)	NY	Actual	$24.30	$28.55	$32.14	$31.76	$33.55	$34.74	**$31.31**
		Forecast	$22.55	$25.77	$29.19	$36.11	$39.87	$34.35	**$32.11**
	PJM	Actual	$26.59	$26.78	$29.17	$32.71	$28.32	$32.10	**$29.50**
		Forecast	$33.40	$32.08	$39.62	$33.07	$28.63	$30.19	**$32.49**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	-$1.84	-$2.78	-$2.98	$4.35	$6.22	-$0.41	**$0.76**
		Abs. Val.	$5.85	$6.29	$8.12	$14.89	$17.04	$11.74	**$11.17**
	PJM	Fcst. - Act.	$6.68	$5.30	$10.41	$0.36	$0.23	-$1.93	**$2.95**
		Abs. Val.	$12.68	$10.25	$18.60	$11.26	$7.87	$13.29	**$12.11**

Lake Erie Circulation

- Loop flows occur when physical flows are inconsistent with the scheduled path of a transaction between control areas or in a control area (from generator to load).
  - ✓ Clockwise Lake Erie Circulation ("LEC") use west-to-east transmission in upstate NY, reducing capacity available for scheduling internal generation to satisfy internal load and increasing congestion (e.g., on the Central-East interface).
- The figure summarizes the frequency of clockwise LEC and the frequency of TLRs (level 3A and above) called by the NYISO in the third quarter of 2015.
- Clockwise LEC was relatively high (average > 200 MW) in 13 percent of all hours.
  - ✓ West-to-east congestion (including congestion in the West Zone, from West-to-Central, and from Central-to-East) occurred in roughly 43 percent of these hours.
    - – In particular, large variations in LEC are a leading contributor of volatile West Zone congestion (see 2014 SOM report, Section IX.E for more details).
- The frequency of TLRs called by the NYISO has been relatively low for the last three years – there were no TLR calls in the third quarter of 2015.
  - ✓ On average (treating counter-clockwise flows as negative clockwise flows), loop flows have fallen since the IESO-MI PARs went in service in April 2012.
  - ✓ However, TLRs cannot be used to manage congestion resulting from loop flows when the IESO-Michigan PARs are in "regulate" mode.

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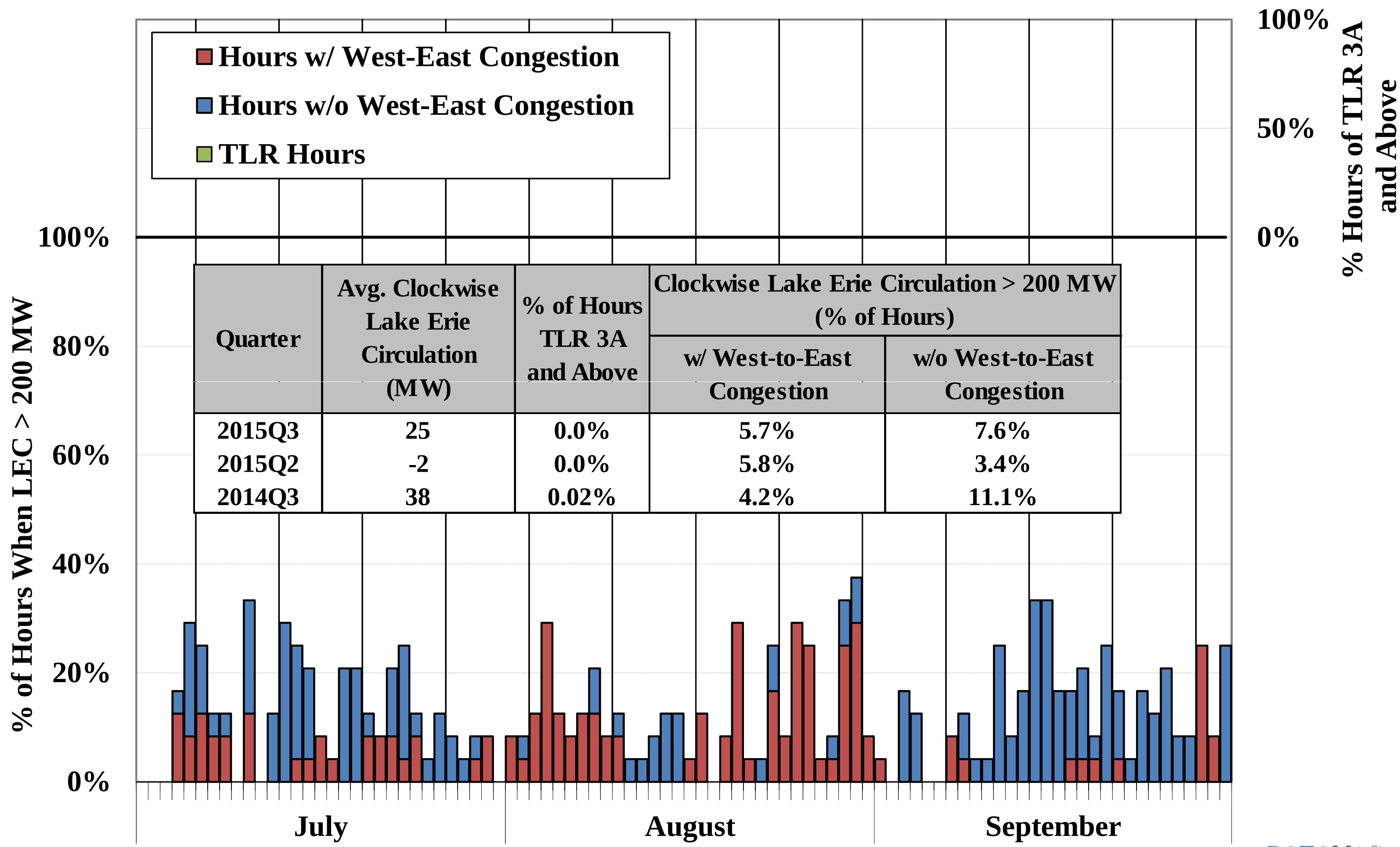
Clockwise Lake Erie Circulation and TLR Calls



Quarter	Avg. Clockwise Lake Erie Circulation (MW)	% of Hours TLR 3A and Above	Clockwise Lake Erie Circulation > 200 MW (% of Hours)	
			w/ West-to-East Congestion	w/o West-to-East Congestion
2015Q3	25	0.0%	5.7%	7.6%
2015Q2	-2	0.0%	5.8%	3.4%
2014Q3	38	0.02%	4.2%	11.1%

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Day-Ahead and Real-Time Transmission Congestion

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Congestion Patterns, Revenues, and Shortfalls

- The next four figures evaluate the congestion patterns in the day-ahead and real-time markets and examine the following categories of resulting congestion costs:
  - ✓ <u>Day-Ahead Congestion Revenues</u> are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market, which is the primary funding source for TCC payments.
  - ✓ <u>Day-Ahead Congestion Shortfalls</u> occur when the net day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - Shortfalls (or surpluses) generally arise when the TCCs on a path exceeds (or is below) the transfer capability of the path modeled in the day-ahead market during periods of congestion.
    - These typically result from modeling assumption differences between the TCC auction and the DA market, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ <u>Balancing Congestion Shortfalls</u> arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.
    - The transfer capability of a constraint falls (or rises) from DA to RT for the similar reasons (e.g., deratings and outages of transmission facilities, inconsistent assumptions regarding PAR schedules and loop flows, etc.).
    - In addition, payments between the NYISO and PJM related to the M2M process also contribute to shortfalls (or surpluses).

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Congestion Patterns, Revenues, and Shortfalls

- The first figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years on a monthly basis.
- The second figure examines in detail the value and frequency of day-ahead and real-time congestion along major transmission paths by quarter.
  - ✓ The value of transfers is equal to the marginal cost of relieving the constraint (i.e., shadow price) multiplied by the scheduled flow across the transmission path.
  - ✓ In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO.
- The third and fourth figures show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.
- Congestion is evaluated along major transmission paths that include:
  - ✓ West Zone Lines: Primarily 230 kV transmission constraints in the West Zone.
  - ✓ West to Central: Including transmission constraints in the Central Zone and interfaces from West to Central.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.

Day-Ahead and Real-Time Congestion

(cont. from prior slide)

- ✓ Capital to Hudson Valley: Primarily lines leading into Southeast New York (e.g., the Leeds-Pleasant Valley Line, the New Scotland-Leeds Line).
- ✓ NYC Lines: Including lines into and within the NYC 345 kV system, lines leading into and within NYC load pockets, and groups of lines into NYC load pockets that are modeled as interface constraints.
- ✓ Long Island: Lines leading into and within Long Island.
- ✓ External Interfaces – Congestion related to the total transmission limits or ramp limits of the external interfaces.
- ✓ All Other – All of other line constraints and interfaces.

- Day-ahead congestion revenue totaled $92 million this quarter, up 101 percent from the third quarter of 2014. The key contributors were:
  - ✓ Increased load levels and more frequent peaking conditions, which generally resulted in more frequent congestion across the system (see slide 50); and
  - ✓ Lengthy transmission outages, which greatly reduced transfer capability from upstate to Long Island and from Capital to Hudson Valley (see slides 47, 51).
  - ✓ However, the increase was partly offset by lower fuel costs, which reduced the re-dispatch cost to manage congestion (in areas other than "West Zone").

Day-Ahead and Real-Time Congestion

- Most congestion (measured as a share of total DA/RT congestion value) occurred in the following areas in the third quarter of 2015:
  - ✓ West Zone (31% DAM, 32% RTM)
    - – This occurred primarily on the Niagara-Packard, Packard-Sawyer, and Sawyer-Huntley 230kV lines.
  - ✓ Long Island (22% DAM, 15% RTM)
    - – Over 60 percent of this congestion occurred in July, when one of the two 345 kV lines from upstate to Long Island was out of service for the entire month.
  - ✓ Capital to Hudson Valley (22% DAM, 10% RTM)
    - – This occurred primarily on the Leeds-Pleasant Valley line.
    - – Over 60 percent of congestion occurred in late-August and September when multiple transmission outages greatly reduced transfer capability on the line.
  - ✓ New York City (13% DAM, 26% RTM)
    - – This occurred primarily on transmission paths into the Greenwood load pocket.

Day-Ahead and Real-Time Congestion

- Congestion was more severe and volatile in RT than DA on some intra-zonal paths.
  - ✓ In the West Zone, congestion on 230kV facilities often increased in RT because:
    - Lake Erie loop flow was volatile, and fluctuations in the clockwise direction contribute to acute congestion price spikes on these facilities;
    - Re-dispatch options were limited sometimes in real-time as a result of congestion on parallel 115 kV facilities.
    - Changes in supply offer patterns between the DAM and RT (that tended to increase flow across these facilities in RT); and
    - Operation of the ABC, JK, and Ramapo PARs (to relieve Central-East and Capital-Hudson VL congestion) increased flows across the constraints in the West Zone.
  - ✓ In the Central Zone (grouped in the "West to Central" category), congestion increased in RT as a result of changes in offer patterns between the DAM and RT.
  - ✓ In New York City, congestion into the Greenwood load pocket:
    - Was under-stated in the DAM because of uneconomic scheduling of GTs by the SCUC model (units were uneconomically scheduled in approx 100 hours); and
    - Often increased in RT because of: (a) changes in offer patterns between the DAM and RT; and (b) the tendency for brief small transmission constraint violations to cause very high (~$4,000) shadow prices in RT.

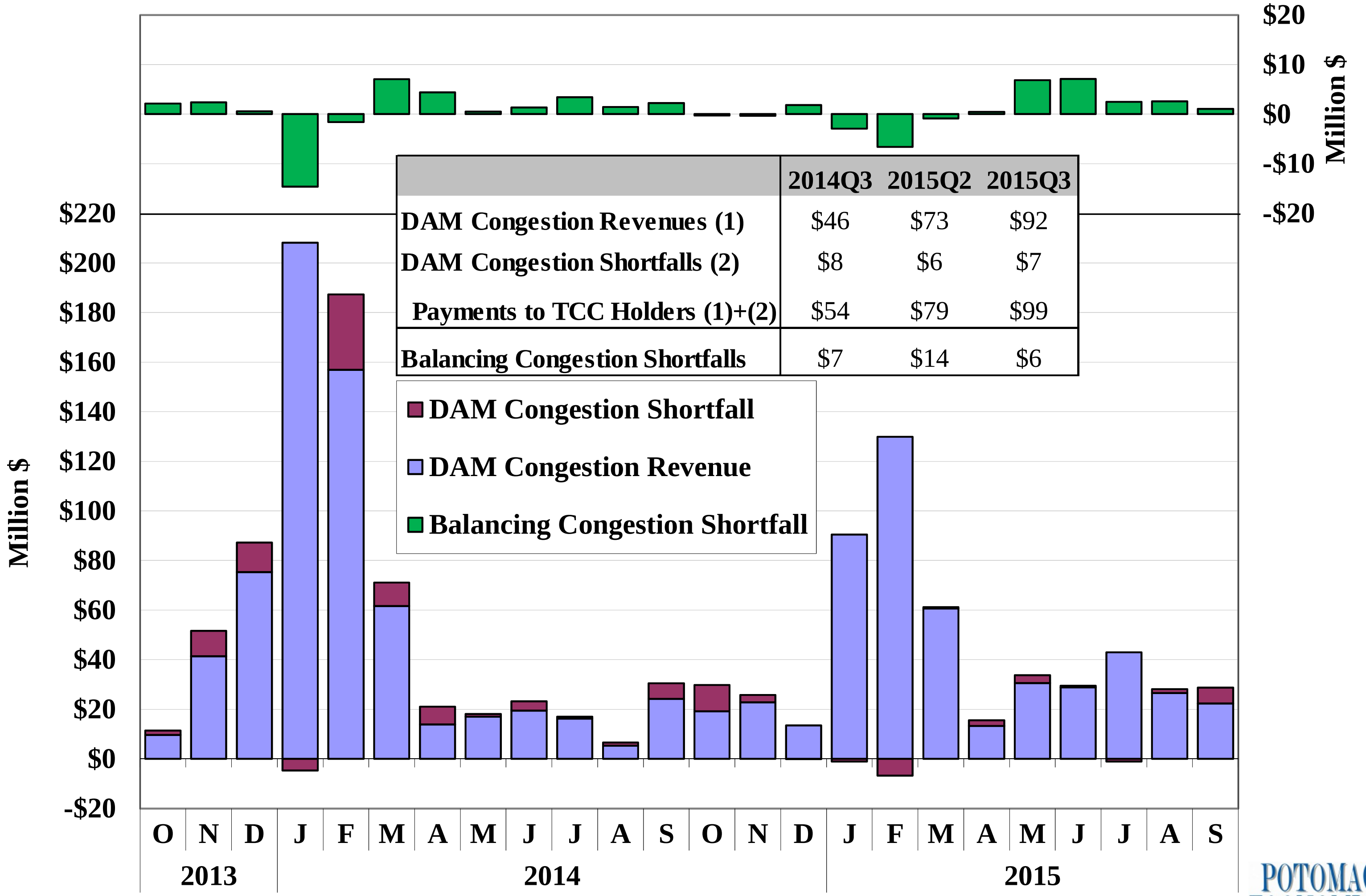
Day-Ahead Congestion Shortfalls

- DA shortfalls totaled $7 million, down $1 million from the third quarter of 2014.
- Transmission outages accounted for a large share of gross shortfalls – roughly $8 million was allocated to the responsible TO in the third quarter of 2015.
  - ✓ $4 million of shortfalls accrued on transmission lines from Capital to Hudson VL.
    - Most occurred from late-August to September, during the outages of the Fraser-to-Coopers Corner (“33”) and Leeds-to-Hurley Avenue (“301”) lines.
  - ✓ Over $2.5 million of shortfalls accrued on Long Island transmission lines.
    - The majority accrued on the transmission lines from upstate into Long Island in July when one of the two 345 kV lines (“Y50”) was out of service.
    - Additional $1.5 million of shortfalls resulted from grandfathered TCCs that exceed the transfer capability of the system from Dunwoodie to Long Island.
    - However, these were offset by $5 million of surpluses generated on the PAR-controlled lines between NYC and Long Island (i.e., the 901/903 lines) in July.
      - The lines were scheduled to flow 0 MW when the Y50 line was OOS.
- West Zone 230 kV lines accounted for $3.4 million of shortfalls.
  - ✓ Differences between the TCC auction and the DAM in the assumed amount of 115 kV Niagara generation contributed $1.4 million to shortfalls.
  - ✓ The primary driver of the remaining $2 million was different assumptions regarding unscheduled loop flows between the TCC auction and DAM.

Balancing Congestion Shortfalls

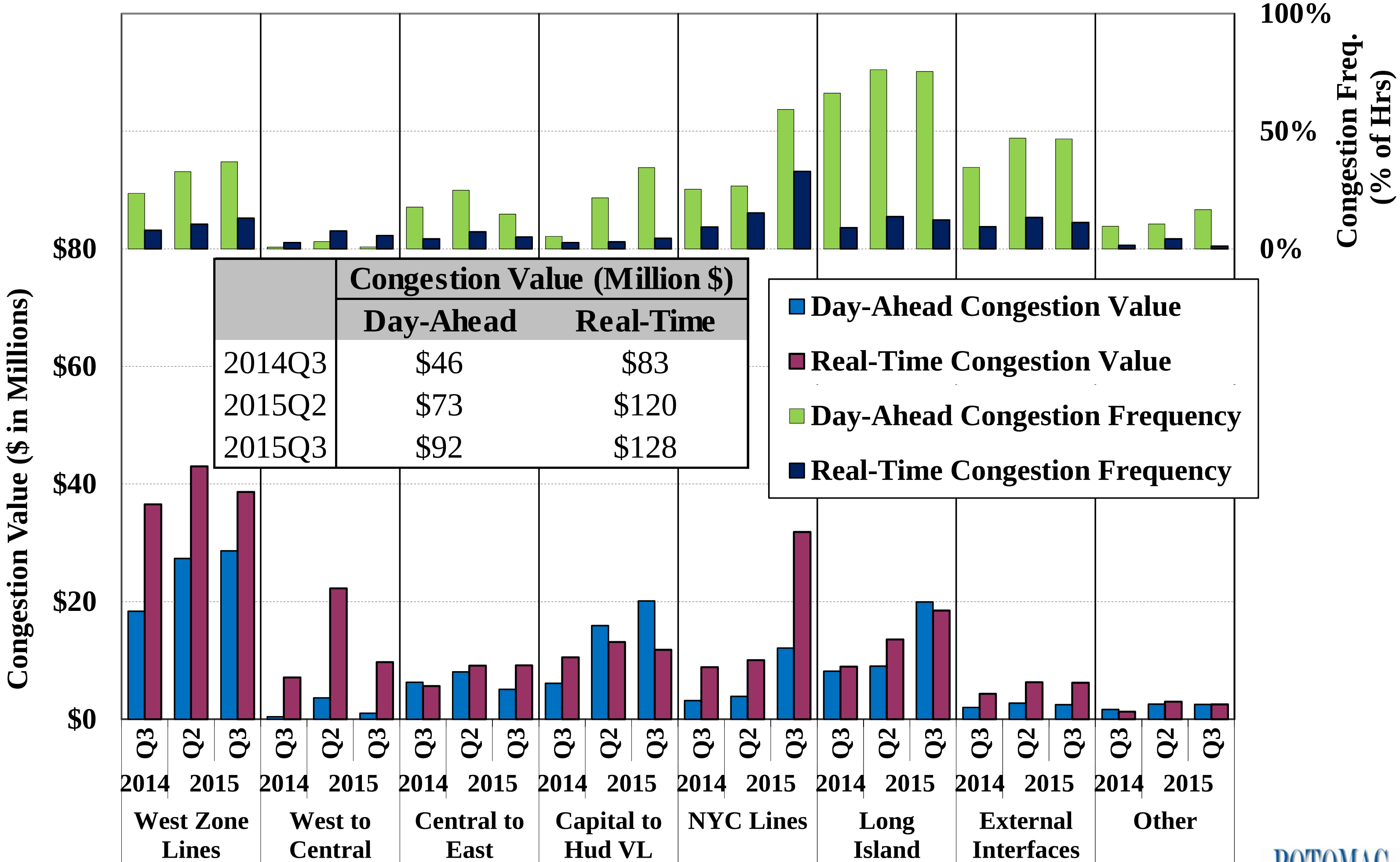
- Balancing congestion shortfalls were $6 million, down $1 million from a year ago.
- Over $5 million of shortfalls were associated with West Zone congestion.
  - ✓ Line deratings, transmission outages, and unexpected changes in loop flows contributed to $3.5 million of shortfalls.
    - – These shortfalls were partly offset by the operation of the Dunkirk-South Ripley and Warren-Falconer lines, which were frequently taken OOS to manage congestion on the 115 kV system (and also help to relieve 230 kV congestion).
  - ✓ Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $1.5 million to shortfalls on the West Zone lines.
    - – However, the additional flows contributed $1.1 million of surpluses on other transmission facilities (e.g., Central-East interface & Leeds-Pleasant Valley).
  - ✓ Differences between the assumed amount of 115 kV Niagara generation in the DAM and the actual amount contributed a net $0.3 million to shortfalls.
- NYC lines accounted for $1.6 million of shortfalls, primarily in the Greenwood load pocket because of: (a) forced transmission outages and (b) difficulty modeling split ring bus contingencies during planned transmission outages.
- TSA events on several days resulted in nearly $1 million of shortfalls.
  - ✓ These events require conservative operation of the transmission system, reducing the available transfer capability in RT on the UPNY-SENY interface.

Congestion Revenues and Shortfalls by Month



	2014Q3	2015Q2	2015Q3
DAM Congestion Revenues (1)	$46	$73	$92
DAM Congestion Shortfalls (2)	$8	$6	$7
Payments to TCC Holders (1)+(2)	$54	$79	$99
Balancing Congestion Shortfalls	$7	$14	$6

DA and RT Congestion Value and Frequency by Transmission Path



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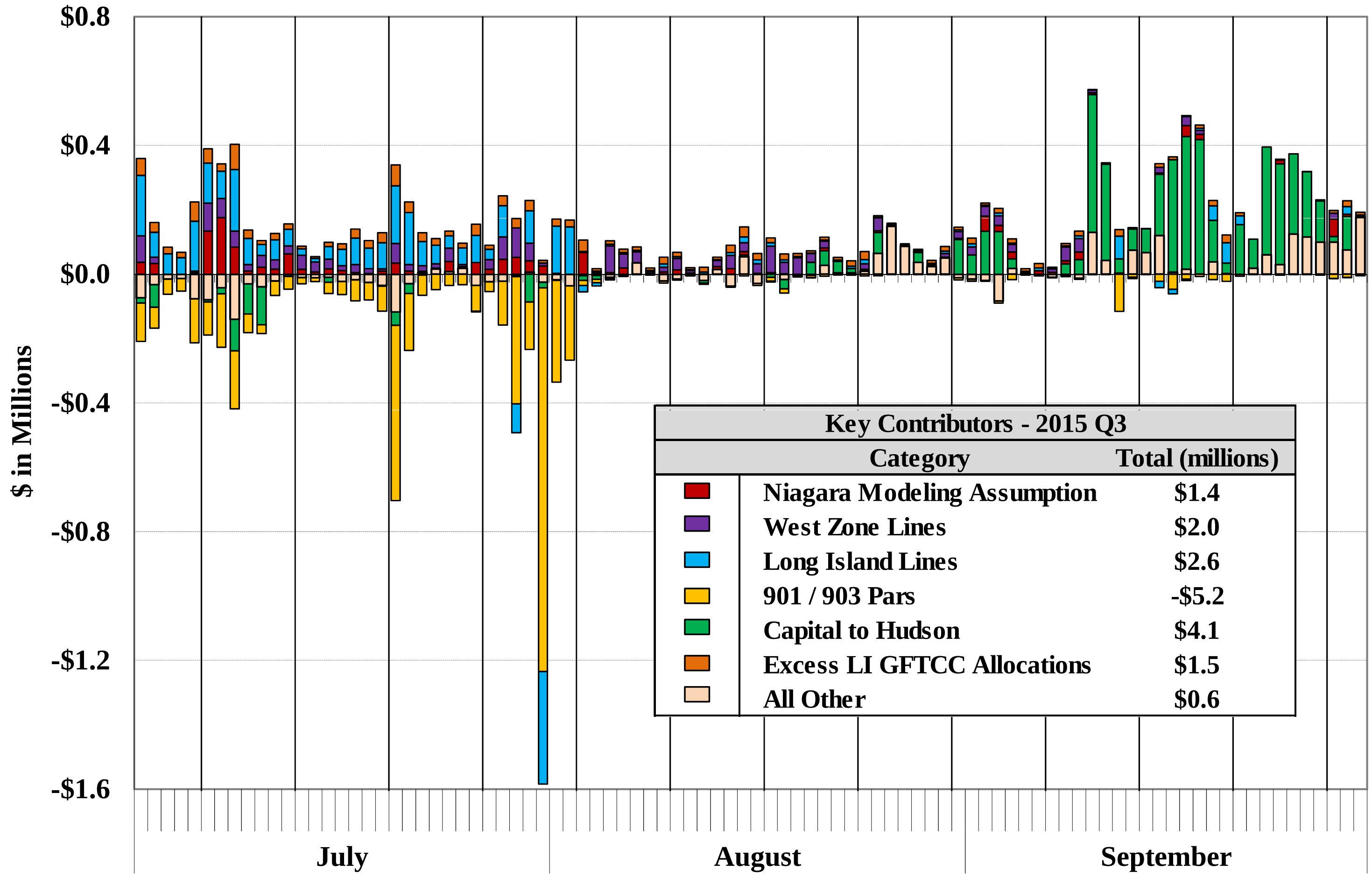
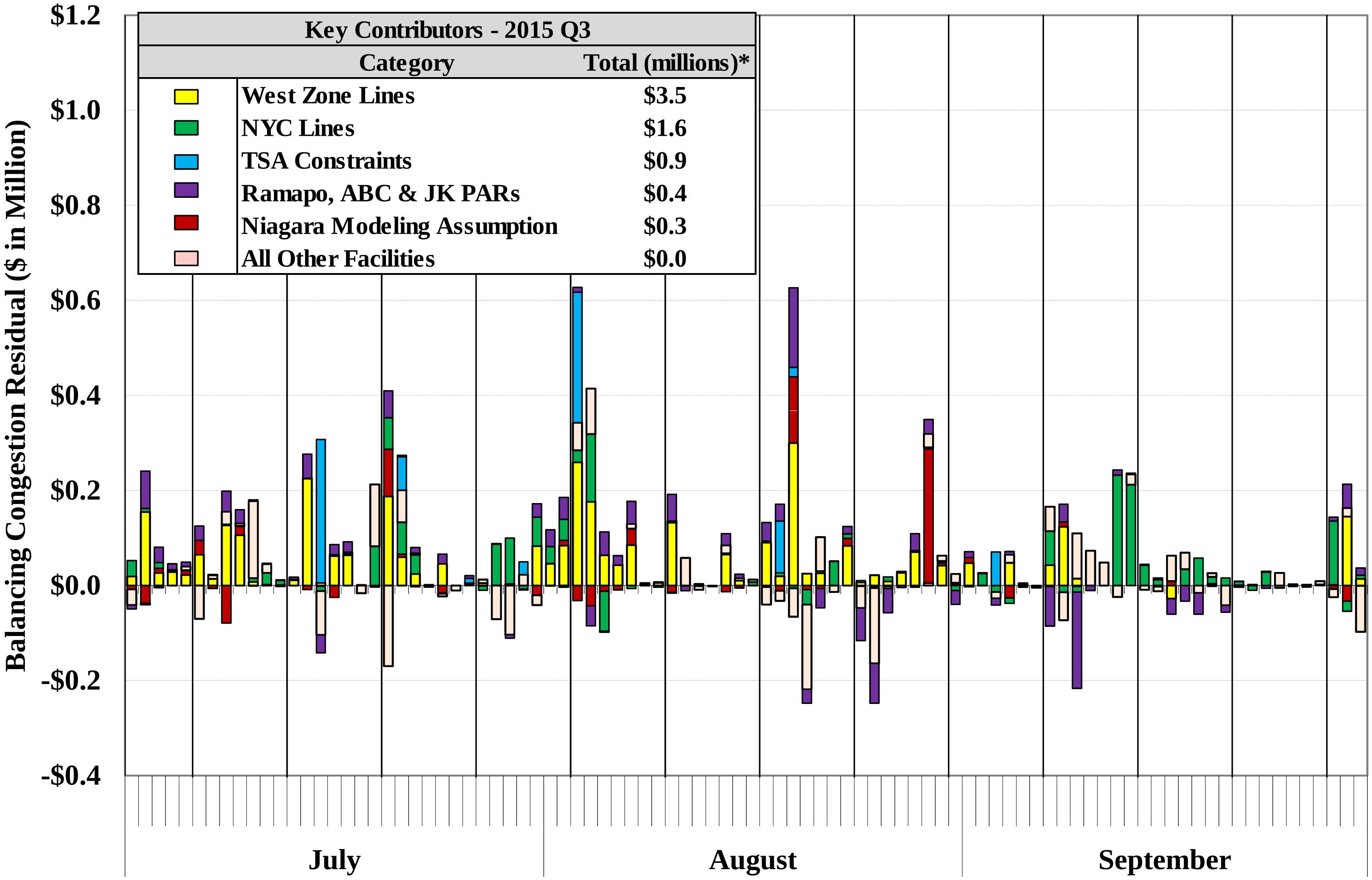
Day-Ahead Congestion Revenue Shortfalls
by Transmission Facility



Note: “Niagara Modeling Assumption” estimates the shortfalls resulted from differences in assumed generation at the Niagara 115 kV Buses between TCC and DAM (for DAMCR) and between DAM and RT actual (for BMCR).

Balancing Congestion Shortfalls by Transmission Facility



Note: The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values.

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Operations under M2M with PJM

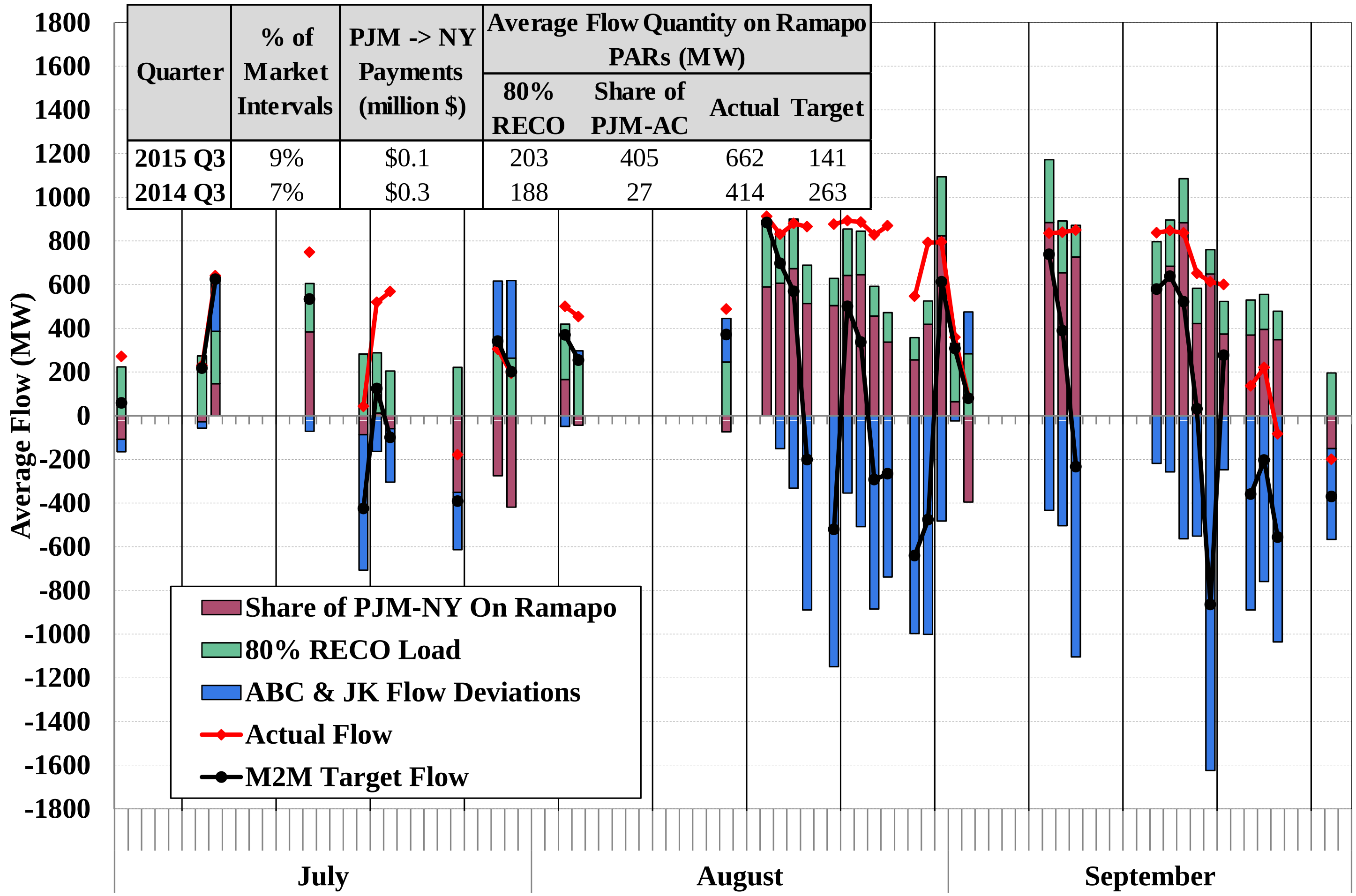
- Coordinated congestion management between NYISO and PJM ("M2M") includes two types of coordination:
  - ✓ Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.
  - ✓ Ramapo PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, the Ramapo PARs are adjusted to reduce overall congestion.
- The following figure evaluates the operation of Ramapo PARs this quarter, which compares the actual flows on Ramapo PARs with their M2M operational targets.
  - ✓ The M2M target flow has the following components:
    - Share of PJM-NY Over Ramapo – Based on the share of PJM-NY flows that were assumed to flow across the Ramapo Line (61% in the third quarter of 2015).
    - 80% RECo Load – 80 percent of telemetered Rockland Electric Company load.
    - ABC & JK Flow Deviations – The total flow deviations on ABC and JK PAR-controlled lines from schedules under the normal wheeling agreement (including "Auto Correction" for deviations on previous days).
  - ✓ The figure shows these average quantities over intervals when M2M constraints for Ramapo Coordination were binding on a daily basis (excluding days with fewer than 12 binding intervals).

Operations under M2M with PJM

- The use of Re-dispatch Coordination is generally very infrequent.
  - ✓ It was activated for the Central-East interface on three days in a total of 24 hours and resulted in a total payment of roughly $27K from PJM to NY this quarter.
- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred in 9 percent of intervals, up modestly from the third quarter of 2014.
  - ✓ The increase was consistent with more frequent congestion on the M2M constraints (e.g., the Central-East interface and transmission paths from Capital to Hudson Valley) than from a year ago.
- Average actual flows across Ramapo exceeded the M2M Target Flow by roughly 520 MW (when M2M constraints were binding) this quarter. Consequently, the resulting M2M payments from PJM to NYISO were small (~$0.1M).
  - ✓ The Target became lower in recent months because of large negative “Auto Correction” on JK flows (which are cumulative of past deviations).
- Although Ramapo PAR Coordination provided congestion relief on key paths from West to East (e.g., the Central-East interface), there were times when additional flows across Ramapo contributed to congestion in the West Zone (see slide 52).

Actual and Target Flows for the Ramapo Line
During the Intervals with Binding M2M Constraints

Quarter	% of Market Intervals	PJM -> NY Payments (million $)	Average Flow Quantity on Ramapo PARs (MW)			
			80% RECO	Share of PJM-AC	Actual	Target
2015 Q3	9%	$0.1	203	405	662	141
2014 Q3	7%	$0.3	188	27	414	263



Note: This chart does not show the days during which M2M constraints were binding in less than 12 intervals. Also, the "ABC & JK Flow Deviations" include cumulative deviations from previous days.

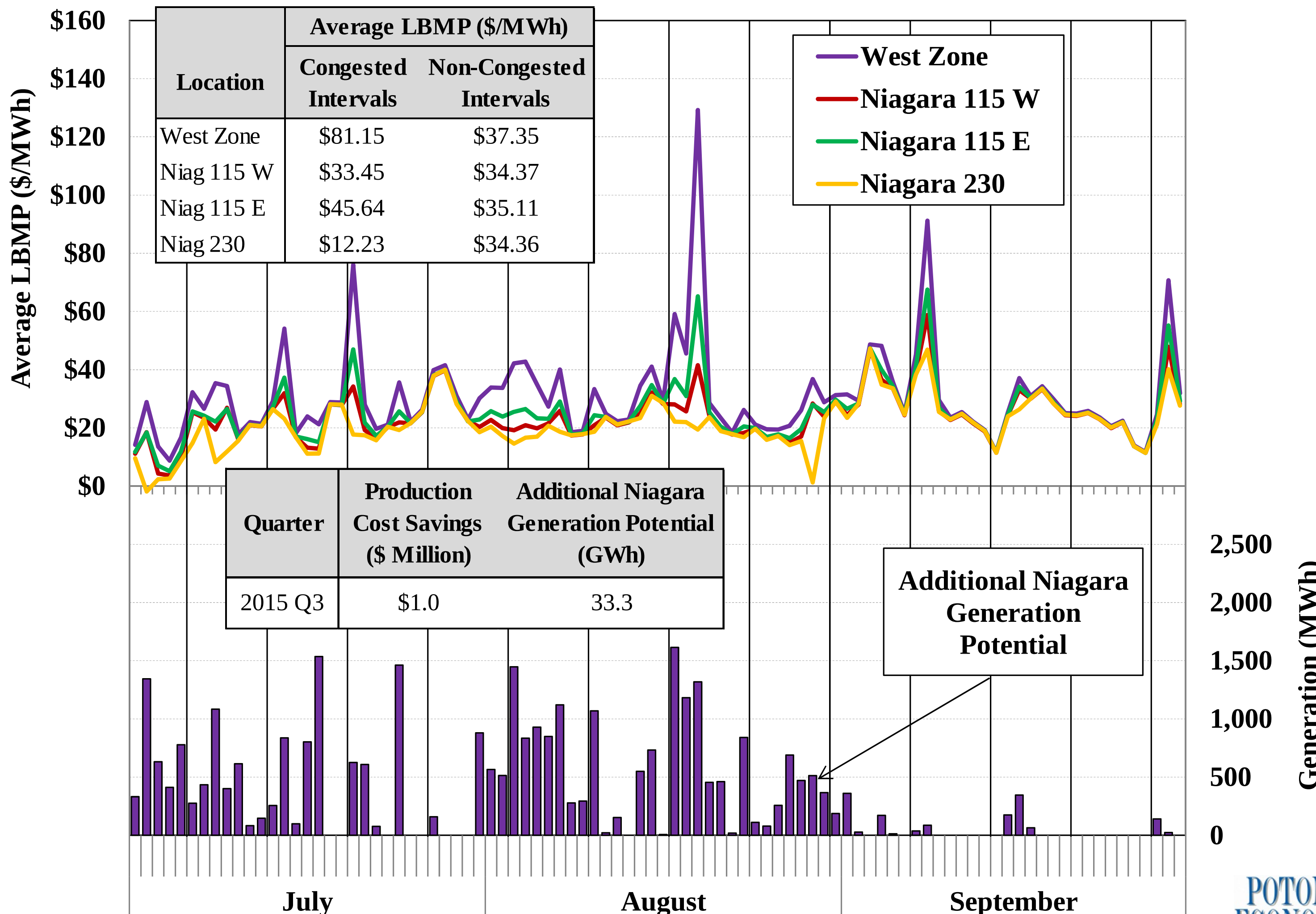
West Zone Congestion and Niagara Generation

- Transmission constraints on the 230kV network in the West Zone have become more frequent in recent years, limiting the flow of power towards Eastern NY.
  - ✓ Niagara units on the 115kV system tend to relieve these constraints, while ones on the 230kV system exacerbate this congestion.
  - ✓ These impacts are not considered by the optimization engine that schedules generation at the Niagara plant.
    - – The optimization treats Niagara as a single bus for pricing and dispatch.
    - – However, NYISO procedures use manual instructions to shift generation among the individual units at the Niagara plant to alleviate congestion (see slides 64, 67).
- The next figure estimates the remaining benefits that might have occurred if the distribution of generation at Niagara was optimized in the third quarter of 2015.
  - ✓ Production Cost Savings – Estimated savings from shifting generation from 230kV units to 115kV units that have available head room at the Niagara plant.
  - ✓ Additional Niagara Generation Potential – Additional Niagara generation (in MWhs) that would be deliverable if output from the 115kV units was maximized.
  - ✓ The figure shows average estimated LBMPs for the West Zone, Niagara 230 kV Bus, Niagara East 115 kV Bus, and Niagara West 115 kV Bus – This illustrates the impact of shifting generation among individual Niagara units.

West Zone Congestion and Niagara Generation

- Although LBMPs at the Niagara 115 kV and 230 kV Buses were very similar when West Zone congestion was not present, LBMP differences were significant during periods of congestion. In the third quarter of 2015:
  - ✓ West Zone 230 kV congestion occurred in roughly 11 percent of all intervals; and
  - ✓ On average, LBMPs were an estimated $21 to $33/MWh higher at the Niagara 115 kV Buses than at the Niagara 230 kV Buses during these intervals.
- We estimate that if the distribution was fully optimized (while considering both 115kV and 230kV constraints in the West Zone):
  - ✓ Production costs would have been reduced by an additional $1 million in the third quarter of 2015 (assuming no changes in the constraint shadow costs).
    - – However, this does not consider the upgrade costs required to fully optimize.
  - ✓ An additional 33 GWh of Niagara generation would have been deliverable. This would have reduced LBMPs in other zones as well, although we have not estimated the effect on statewide average LBMPs.
- These estimates imply that existing NYISO procedures that shift the distribution of generation at the Niagara plant (between 115kV and 230kV units) significantly reduce congestion costs on days when congestion occurs in Western NY.
  - ✓ Thus, the current NYISO procedure captures a large portion of the potential benefits from optimizing the distribution.

West Zone Congestion and Niagara Generation
Third Quarter of 2015



Location	Average LBMP ($/MWh) Congested Intervals	Non-Congested Intervals
West Zone	$81.15	$37.35
Niag 115 W	$33.45	$34.37
Niag 115 E	$45.64	$35.11
Niag 230	$12.23	$34.36

Quarter	Production Cost Savings ($ Million)	Additional Niagara Generation Potential (GWh)
2015 Q3	$1.0	33.3

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Supplemental Commitments, OOM Dispatch, and Uplift Charges

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- The next three figures summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
  - ✓ The first figure shows the quantities of reliability commitment by region in the following categories on a monthly basis:
    - – Day-Ahead Reliability Units (“DARU”) Commitment – occurs before the economic commitment in the DAM at the request of local TO or for NYISO reliability;
    - – Day-Ahead Local Reliability (“LRR”) Commitment – occurs in the economic commitment in the DAM for TO reliability in NYC; and
    - – Supplemental Resource Evaluation (“SRE”) Commitment – occurs after the DAM.
    - – Forecast Pass Commitment – occurs after the economic commitment in the DAM.
  - ✓ The second figure examines the reasons for reliability commitments in NYC where most reliability commitments occur. (This is described on the following slide.)
  - ✓ The third figure summarizes the frequency (measured by the total station-hours) of Out-of-Merit dispatches by region on a monthly basis.
    - – The figure excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.
    - – In each region, the two stations with the highest number of OOM dispatch hours in the current quarter are shown separately.

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- Based on a review of operator logs and LRR constraint information, each New York City commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:
  - ✓ NOx Only – If needed for NOx bubble requirement and no other reason.
  - ✓ Voltage – If needed for ARR 26 and no other reason except NOx.
  - ✓ Thermal – If needed for ARR 37 and no other reason except NOx.
  - ✓ Loss of Gas – If needed for IR-3 and no other reason except NOx.
  - ✓ Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, IR-3. The capacity is shown for each separate reason in the bar chart.
- A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.
- For voltage and thermal constraints, the capacity is shown by the following load pocket that was secured:
  - ✓ (a) AELP = Astoria East; (b) AWLP = Astoria West/Queensbridge; (c) AVLP = Astoria West/Queensbridge/ Vernon; (d) ERLP = East River; (e) FRLP = Freshkills; (f) GSLP = Greenwood/ Staten Island; and (g) SDLP = Sprainbrook/Dunwoodie.

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Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results

- An average of 750 MW of capacity was committed for reliability in the third quarter of 2015, down moderately from the third quarter of 2014.
  - ✓ Of the capacity committed for reliability in the third quarter, 55 percent was in NYC, 39 percent was in Western NY, and only 5 percent was in Long Island.
- Reliability commitments in West NY averaged 290 MW this quarter, up 12 percent from the third quarter of 2014, reflecting higher load levels and lower LBMPs.
  - ✓ Several coal-fired and gas-fired units were often needed for local voltage support and/or to manage post-contingency flows on 115kV facilities.
    - – These units were frequently DARUed because they were not economic as a result of the low LBMPs in this quarter.
  - ✓ Of these commitments, the West Zone accounted for 39 percent and the Central Zone accounted for another 53 percent.
- Reliability commitments rarely occurred in Long Island this quarter.
  - ✓ DARU commitments became less frequent after mid-2014 when transmission upgrades reduced the need to: a) commit generation for voltage constraints on Long Island (see ARR 28); and b) burn oil to protect from a loss of gas (see IR-5).
  - ✓ SRE commitments mainly kept steam units online during overnight hours.

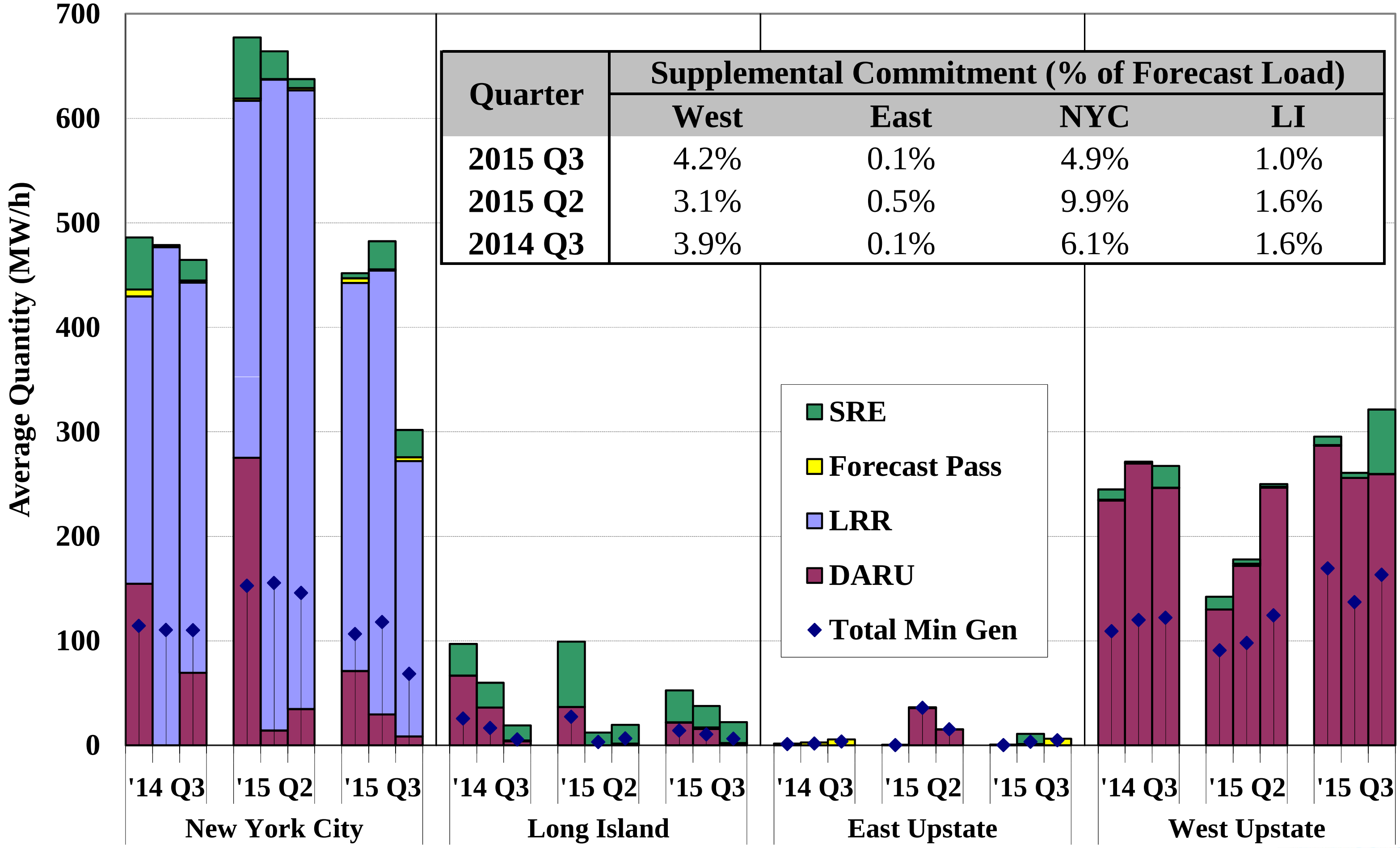
Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results in New York City

- Reliability commitments in New York City averaged 415 MW this quarter, down 12 percent from the third quarter of 2014.
  - ✓ Reliability commitment for the East River load pocket fell from a year ago because of fewer transmission outages.
  - ✓ Reliability commitment in the Freshkills load pocket fell in September of 2015 relative to the previous year.
    - – Although units in this pocket were committed with a frequency similar to the September 2014, they were flagged for reliability less frequently this year.
    - – More frequent economic commitments of these units was attributable to: (a) higher load levels (see slide 11) and (b) planned transmission outages in the Greenwood/ Staten Island load pocket.
  - ✓ Units were flagged less frequently for NOx-Only commitments than in the third quarter of 2014.
    - – The units that are required to satisfy the NOx Bubble requirements were often needed at the same time for local voltage and/or thermal requirements in the Freshkills and Astoria West/Queensbridge load pockets this quarter.
    - – The local needs in these two load pockets rose moderately from last year because of higher load levels.

Supplemental Commitment and OOM Dispatch: OOM Dispatch Results

- The NYISO and local TOs sometimes dispatch generators out-of-merit in order to:
  - ✓ Maintain reliability of the lower-voltage transmission and distribution networks; or
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model.
- Generators were dispatched Out-of-Merit ("OOM") for approximately 3,360 station-hours, up 310 percent from the third quarter of 2014, primarily in Long Island and Western New York.
  - ✓ OOM dispatch in Long Island rose notably in July and August from a year ago because of higher load levels.
    - Over 70 percent of these OOM instructions were to dispatch peaking generators to manage voltage constraints on the East End of Long Island.
  - ✓ OOM dispatch in Western NY also rose significantly this quarter.
    - The Milliken and Dunkirk coal units were frequently OOMed to prevent post-contingency overloading on several 115 kV transmission lines in Western NY.
    - Lower LBMPs led to more frequent OOM dispatch of these units this quarter.
- The Niagara facility was often manually instructed to shift output among its generators to secure certain 115kV and/or 230 kV transmission constraints.
  - ✓ In the third quarter of 2015, this manual shift was required in 118 hours to manage 115 kV constraints and in 742 hours to manage 230 or 345 kV constraints.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2015 Q3	4.2%	0.1%	4.9%	1.0%
2015 Q2	3.1%	0.5%	9.9%	1.6%
2014 Q3	3.9%	0.1%	6.1%	1.6%

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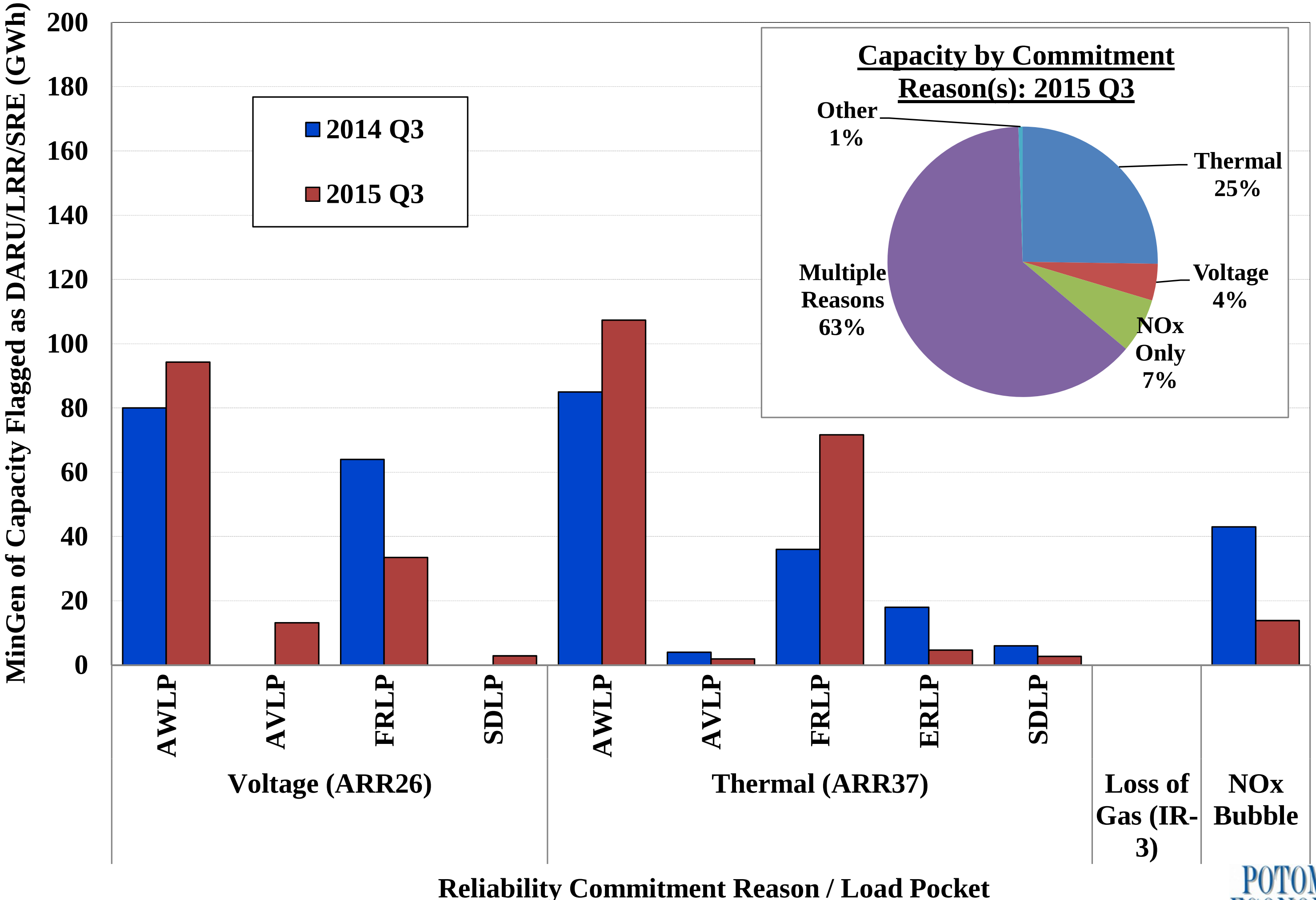
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



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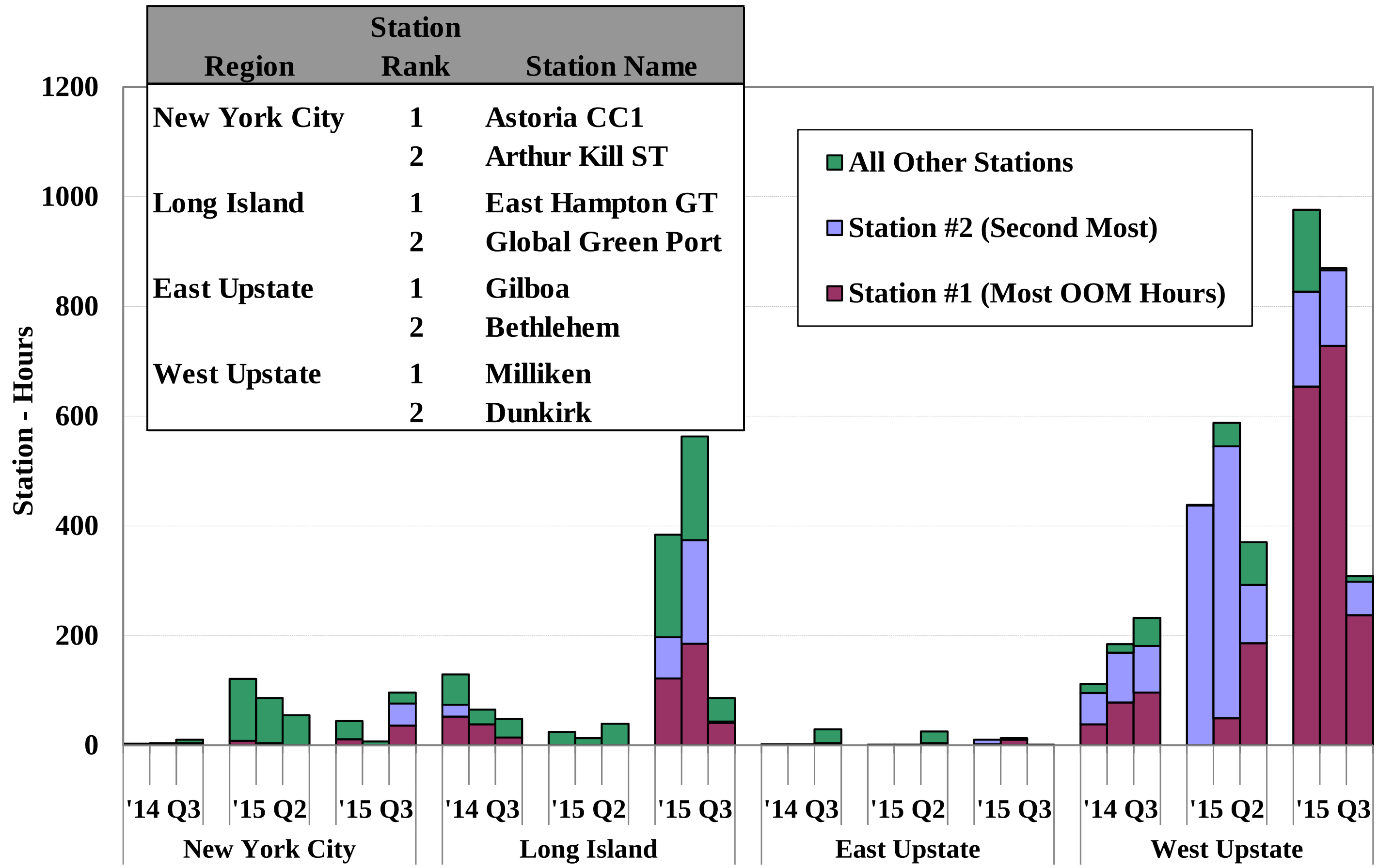
Frequency of Out-of-Merit Dispatch by Region by Month



Note: The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 531 hours in 2014-Q3, 797 hours in 2015-Q2, and 790 hours in 2015-Q3. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

Uplift Costs from Guarantee Payments: Chart Descriptions

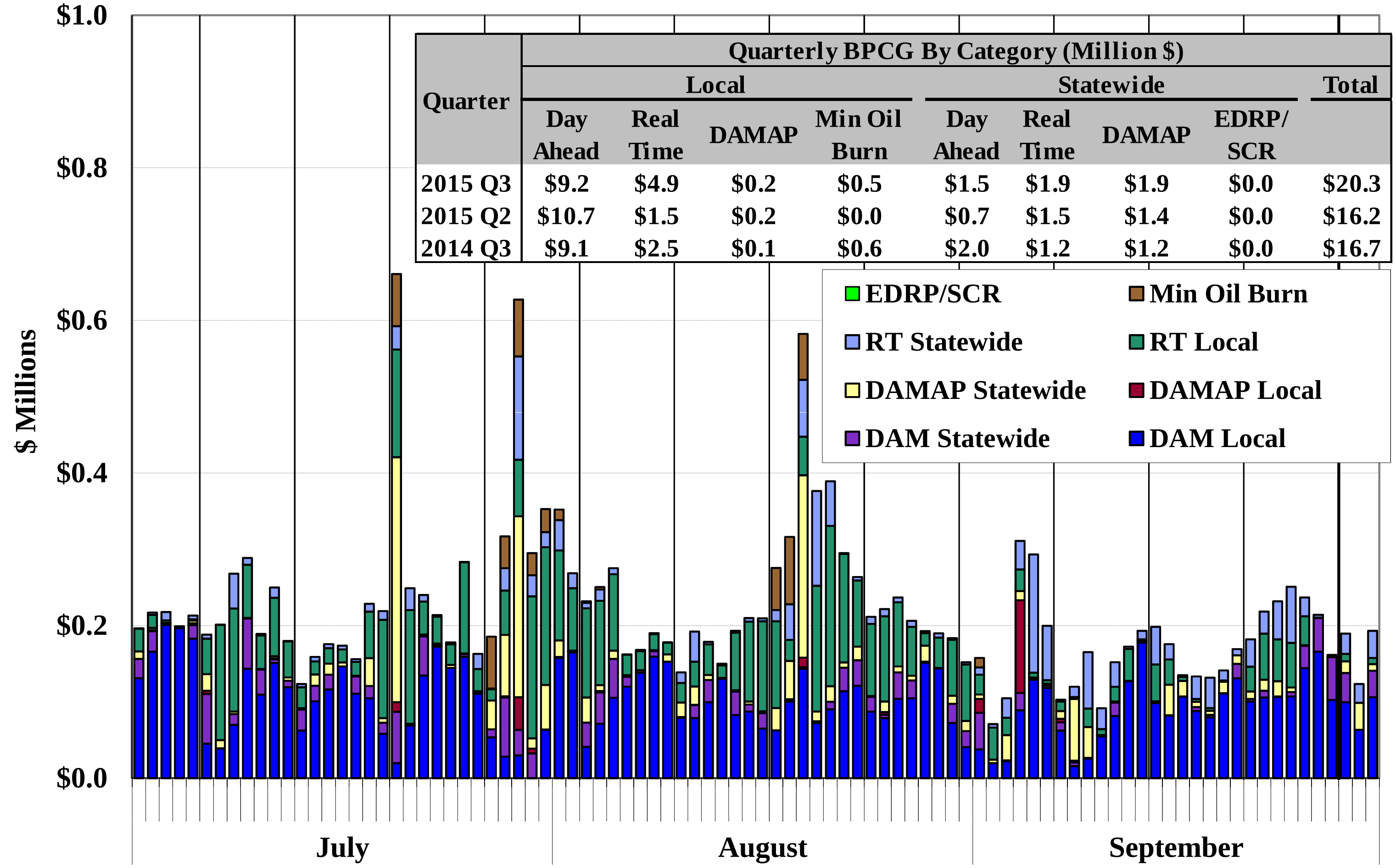
- The next two figures show uplift charges in the following seven categories.
  - ✓ Three categories of non-local reliability uplift are allocated to all LSEs:
    - Day Ahead: For units committed in the day-ahead market (usually economically) whose day-ahead market revenues do not cover their as-offered costs.
    - Real Time: For import transactions (before April 2014) and gas turbines that are scheduled economically, or units committed or dispatched OOM for bulk system reliability whose real-time market revenues do not cover their as-offered costs.
    - Day Ahead Margin Assurance Payment ("DAMAP"): For generators that incur losses because they are dispatched below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.
  - ✓ Four categories of local reliability uplift are allocated to the local TO:
    - Day Ahead: From Local Reliability Requirements ("LRR") and Day-Ahead Reliability Unit ("DARU") commitments.
    - Real Time: From Supplemental Resource Evaluation ("SRE") commitments and Out-of-Merit ("OOM") dispatched units.
    - Minimum Oil Burn Program: Covers spread between oil and gas prices when generators burn oil to satisfy NYC gas pipeline contingency reliability criteria.
    - DAMAP: For units that are dispatched OOM for local reliability reasons.
  - ✓ The first figure shows these seven categories on a daily basis during the quarter.
  - ✓ The second figure summarizes uplift costs by region on a monthly basis.

Uplift Costs from Guarantee Payments: Results

- Guarantee payments totaled $20.3 million this quarter, up $3.6 million from the third quarter of 2014.
  - ✓ RT local uplift rose $2.4 million, accounting for nearly 70 percent of total increase.
    - – This was consistent with the notable increase of OOM dispatch in Long Island and Western NY this quarter (for the reasons discussed earlier, see slides 64, 67).
- Of the total guarantee payment uplift in the third quarter of 2015:
  - ✓ 74 percent was allocated locally, while the remainder was allocated statewide.
  - ✓ Western NY accounted for 47 percent, Long Island accounted 26 percent, and NYC accounted for 23 percent.
- Local uplift in Western NY totaled nearly $9 million, accounting for 43 percent of total guarantee uplift this quarter.
  - ✓ Over 90 percent of the local uplift was paid to several units that were committed for reliability and/or OOMed to manage congestion on the 115 kV system (see slides 62, 64, 65, 67).
- Guarantee payment uplift rose notably on several days this quarter.
  - ✓ DAMAP rose on several days (e.g., 7/20, 7/29, & 8/19) when RTC de-committed units that would have been economic to remain online.

Uplift Costs from Guarantee Payments

Local and Non-Local by Category

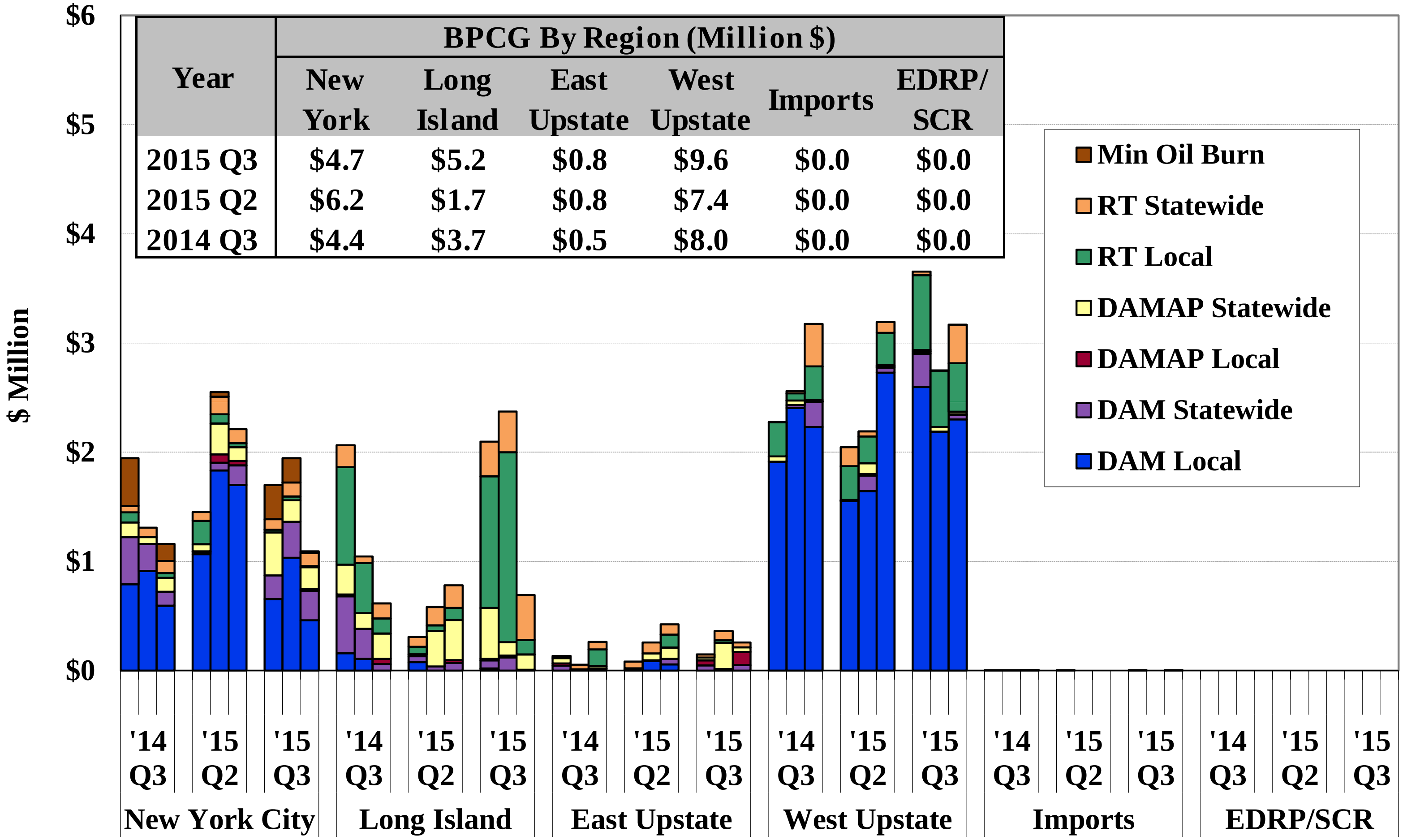


Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2015 Q3	$9.2	$4.9	$0.2	$0.5	$1.5	$1.9	$1.9	$0.0	$20.3
2015 Q2	$10.7	$1.5	$0.2	$0.0	$0.7	$1.5	$1.4	$0.0	$16.2
2014 Q3	$9.1	$2.5	$0.1	$0.6	$2.0	$1.2	$1.2	$0.0	$16.7

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

Uplift Costs from Guarantee Payments
By Category and Region

Year	BPCG By Region (Million $) New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2015 Q3	$4.7	$5.2	$0.8	$9.6	$0.0	$0.0
2015 Q2	$6.2	$1.7	$0.8	$7.4	$0.0	$0.0
2014 Q3	$4.4	$3.7	$0.5	$8.0	$0.0	$0.0



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

Market Power and Mitigation

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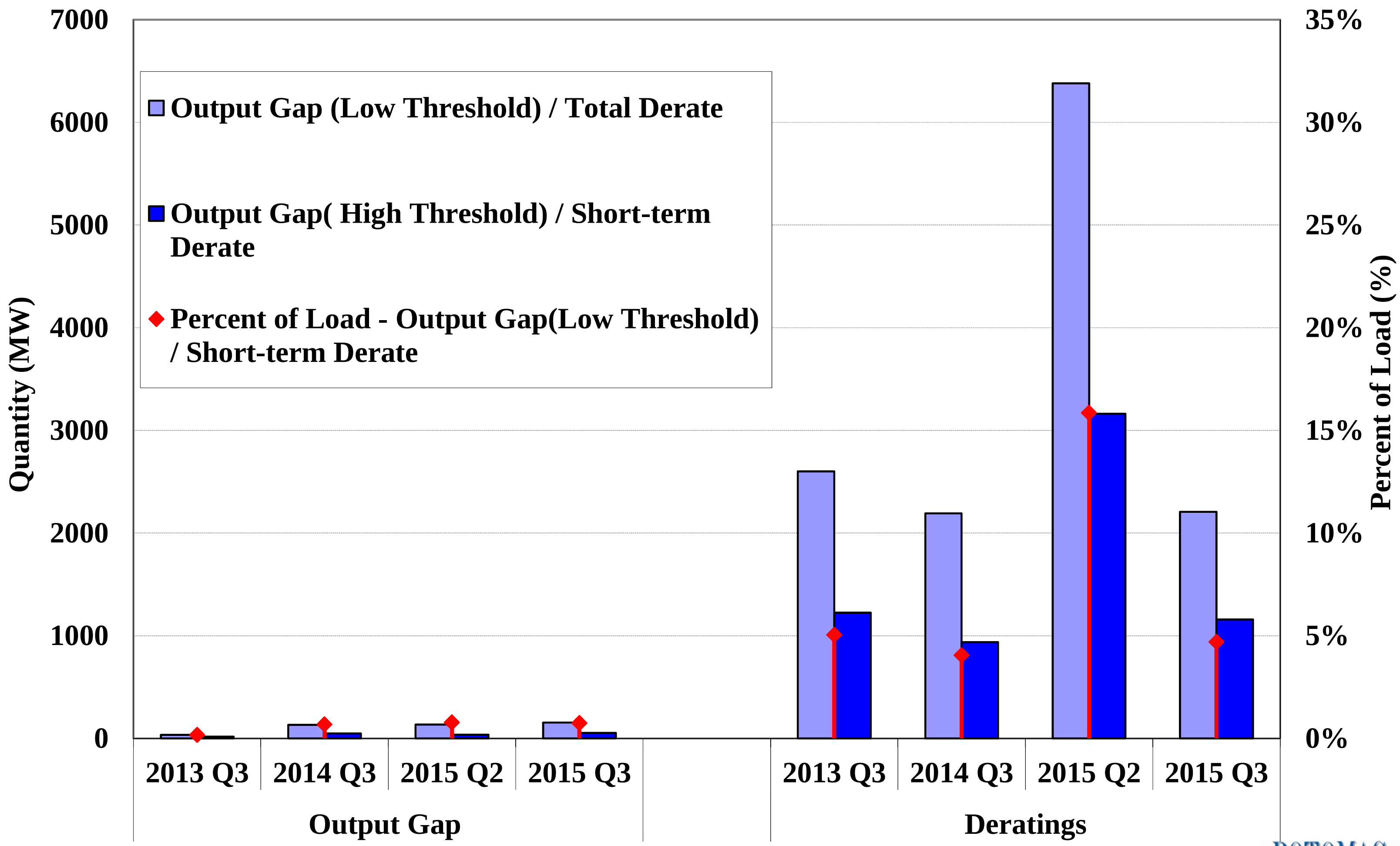
Market Power Screens: Economic Withholding

- The next figure shows the results of our screens for attempts to exercise market power, which may include economic withholding and physical withholding.
- The screen for economic withholding is the "output gap", which is the amount of economic capacity that does not produce energy because a supplier submits an offer price above the unit's reference level by a substantial threshold.
- In the following figure, we show the output gap based on:
  - ✓ A high threshold (the lower of $100/MWh and 300 percent); and
  - ✓ A low threshold (the lower of $50/MWh and 100 percent).
- The output gap was relatively low as a share of load this quarter.
  - ✓ The output gap averaged less than 1 percent of load at the low threshold, comparable to the same quarter in prior years.
  - ✓ The output gap did not raise significant market power concerns because most of the output gap occurred on units that are:
    - – Co-generation resources, most of which operate in a relatively inflexible manner because of the need to divert energy production to non-electric uses; and/or
    - – Owned by suppliers with small portfolios, which generally do not have an incentive to withhold supply.

Market Power Screens: Physical Withholding

- We evaluate generator deratings in the day-ahead market to screen for potential physical withholding. The figure summarizes:
  - ✓ Total deratings, which are measured relative to the DMNC test value; and
  - ✓ Short-term deratings, which exclude deratings lasting more than 30 days.
- Deratings are typically highest in shoulder months when load is lower and lowest in the summer months when load is higher.
  - ✓ Total deratings in the third quarter are normally lower than in the second quarter.
- The amount of total deratings averaged roughly 2.2 GW (11 percent of average load) during peak hours in the third quarter of 2015, consistent with the same quarter in prior years.
  - ✓ Nearly half of these deratings are long-term, which are unlikely to reflect withholding and normally do not raise physical withholding concerns.
    - – However, inefficient outage scheduling (i.e., scheduling an outage when the unit is likely to be economic for a significant portion of the time) may raise concerns.
    - – More capacity was available on Long Island in the third quarter of 2014 and 2015 than in prior years due to less planned outages.

Market Monitoring Screens



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Automated Market Power Mitigation

- The next table summarizes the automated mitigation that was imposed during the quarter (not including BPCG mitigation).
- Energy, minimum generation, and start-up offer mitigation is performed by automated mitigation procedure ("AMP") software in the day-ahead and real-time markets in New York City. The following figure reports:
  - ✓ The frequency of incremental energy offer mitigation; and
  - ✓ The average quantity of mitigated capacity, including capacity below the minimum generation level when the minimum generation offer is mitigated.
- Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled. In the third quarter of 2015,
  - ✓ 97 percent of mitigation occurred in the day-ahead market, of which:
    - – Local reliability (i.e., DARU & LRR) units accounted for 64 percent. These mitigations generally affect guarantee payment uplift but not LBMPs.
    - – Units in the Greenwood/Staten Island load pocket accounted for 28 percent.
- The quantity of mitigation rose modestly from the third quarter of 2014, reflecting more frequent congestion into the Greenwood load pocket.

Automated Market Mitigation

Quarterly Mitigation Summary

		2013 Q3	2014 Q3	2015 Q2	2015 Q3
Day-Ahead Market	**Average Mitigated MW**	141	116	146	141
	Energy Mitigation Frequency	41%	15%	3%	40%
Real-Time Market	**Average Mitigated MW**	7	2	1	4
	Energy Mitigation Frequency	3%	1%	1%	4%

Capacity Market

Capacity Market Results

- The following figure summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices in each capacity zone.
  - ✓ UCAP is a measure of installed capacity that accounts for forced outage rates.
- UCAP spot prices fell in all capacity zones from the third quarter of 2014.
  - ✓ NYC prices averaged $15.28/kW-month, down 17 percent.
  - ✓ Long Island prices averaged $5.72/kW-month, down 12 percent.
  - ✓ G-J Locality prices averaged $8.32/kW-month, down 32 percent.
  - ✓ Rest-of-State prices averaged $3.68/kW-month, down 37 percent.
- The price decreases across the system were primarily because of:
  - ✓ The increase in internal installed capacity supply, which rose:
    - 170 MW in NYC as a result of the return-to-service of Astoria Unit 2 in 2015-Q1;
    - 850 MW in the Hudson Valley as four units at the Danskammer plant returned to service in 2014-Q4 and 2015-Q1 and Bowline Unit 2 returned to full service in July 2015; and
    - Over 100 MW in Western NY as a result of the return-to-service of the Binghamton co-gen unit in 2015-Q1 and additions of new wind capacity.

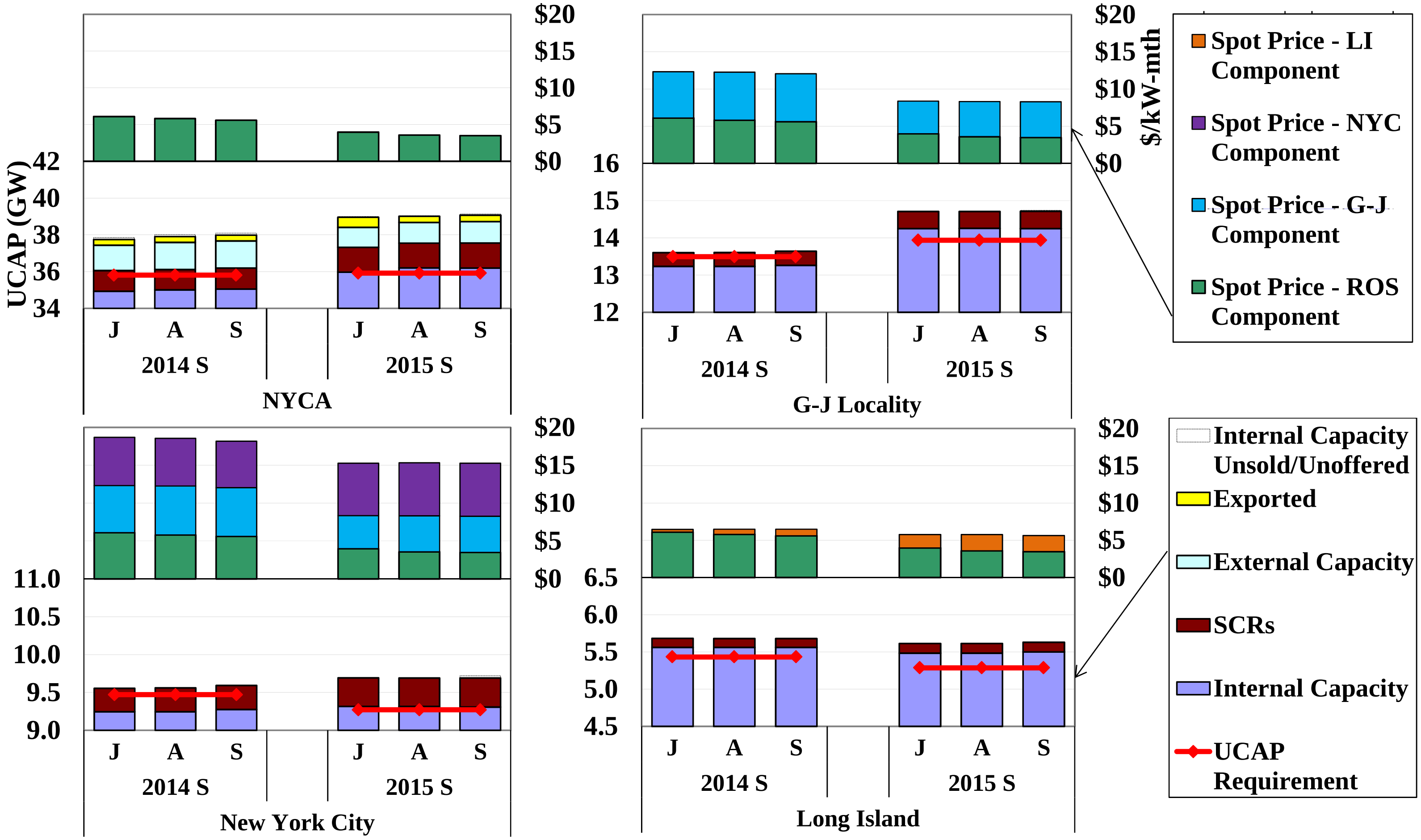
Capacity Market Results

(continued from the prior slide)

- ✓ The increase in the SCR sales, which rose:
  - 70 MW in NYC;
  - 80 MW in the G-J Locality (including 70 MW in NYC); and
  - 230 MW in NYCA (including 80 MW in the G-J Locality).
- ✓ The decrease in the ICAP requirement for most capacity zones, which fell:
  - 54 MW (or 0.5%) in NYC due to a decrease in the LCR from 85% to 83.5% (but this was partly offset by a 147 MW increase in the forecasted peak load);
  - 148 MW (or 3%) in Long Island primarily because of a decrease in the LCR from 107% to 103.5%; and
  - 115 MW (or 0.3%) in NYCA due to a modest decrease in the forecasted peak load.
- ✓ However, the G-J ICAP requirement rose 451 MW (or 3%) due to an increase in the LCR from 88% to 90.5% and a modest increase in forecasted peak load.
  - This partly offset the decrease of UCAP prices in the G-J Locality.

- The recent capacity additions in Zone G was the primary factor that led to: (a) lower LCRs for NYC and Long Island and (b) a higher LCR for the G-J Locality for the period from May 2015 to April 2016.
- Very little capacity was unsold in the G-J Locality, NYC, or Long Island.

Capacity Market Results: Third Quarter 2014 & 2015



Note: Sales associated with Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity," but unsold capacity from resources with UDRs is not shown.