Highlights from the Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2016

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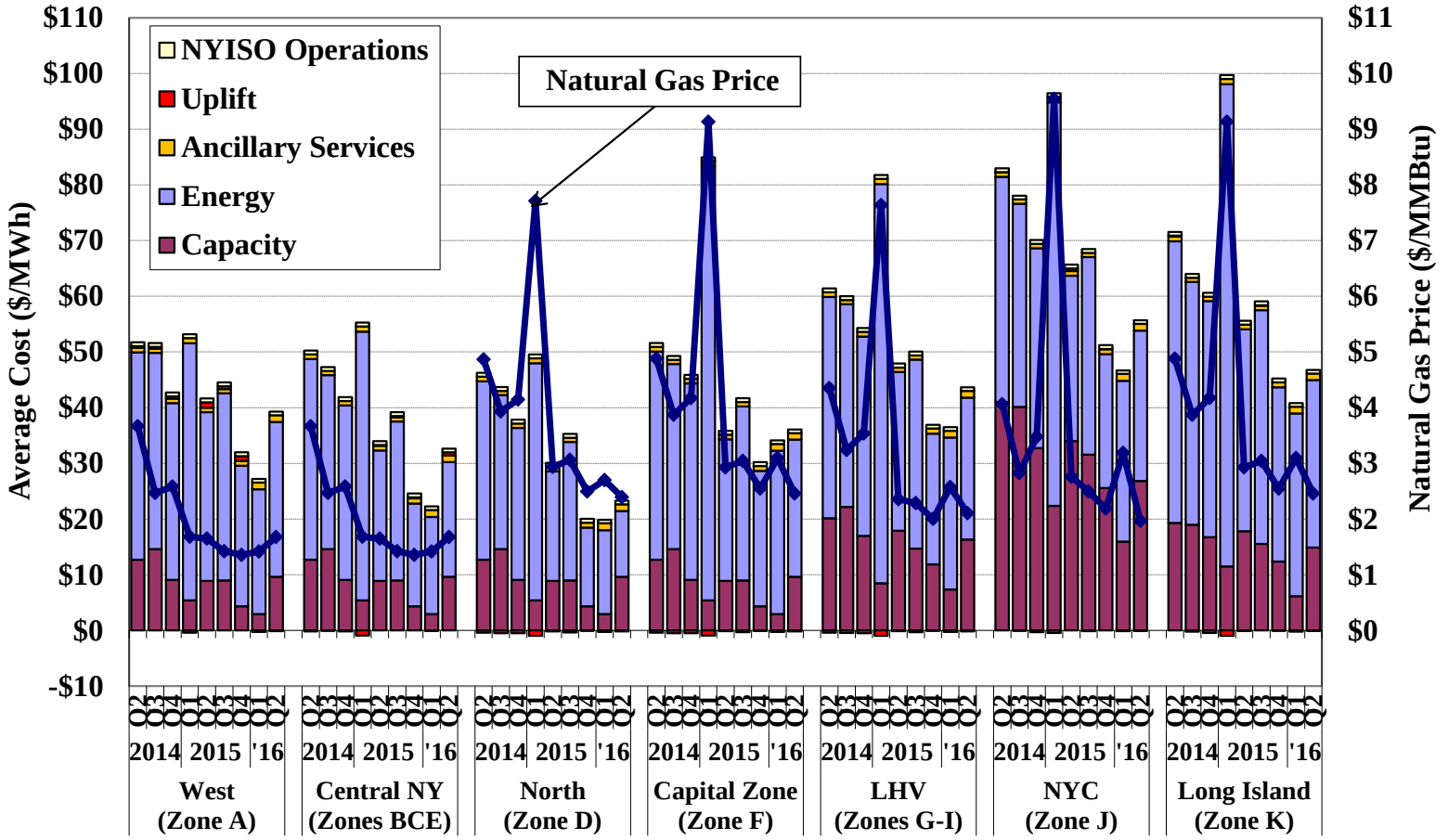
Highlights and Market Summary:
Energy Market

- A copy of the full report on the second quarter of 2016 may be found at: www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp
- 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 $23/MWh in the North Zone to $56/MWh in NYC, down 4 to 23 percent in most regions from a year ago. (see slide 9)
  - ✓ Capacity costs fell 9 to 21 percent in SENY zones but rose 8 percent elsewhere, which offset the reduction in LBMPs mentioned below in these regions.
- RT LBMPs fell 3 percent in the Capital Zone, 40 percent in the North Zone, and 8 to 17 percent in other areas.
  - ✓ The primary driver was lower natural gas prices, which fell 31 percent in NYC and 17 percent in Long Island, resulting largely from increasing production from Marcellus and Utica shales. (see slide 12)
  - ✓ Average load fell only 0.5 percent but peak load fell 7 percent. (see slide 11)
  - ✓ Hydro generation (see slide 15) and net imports from neighboring areas (see slide 39) rose by 550 MW combined, contributing to lower LBMPs as well.
  - ✓ However, these factors were partly offset by lower nuclear generation, which fell by over 1 GW because of lengthy maintenance outages. (see slide 15)

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 Zone and Central NY, the Iroquois Waddington index for North Zone, the Iroquois Zone 2 index for Capital Zone and LI, the average of Texas Eastern M3 and Iroquois Zone 2 for LHV, the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.

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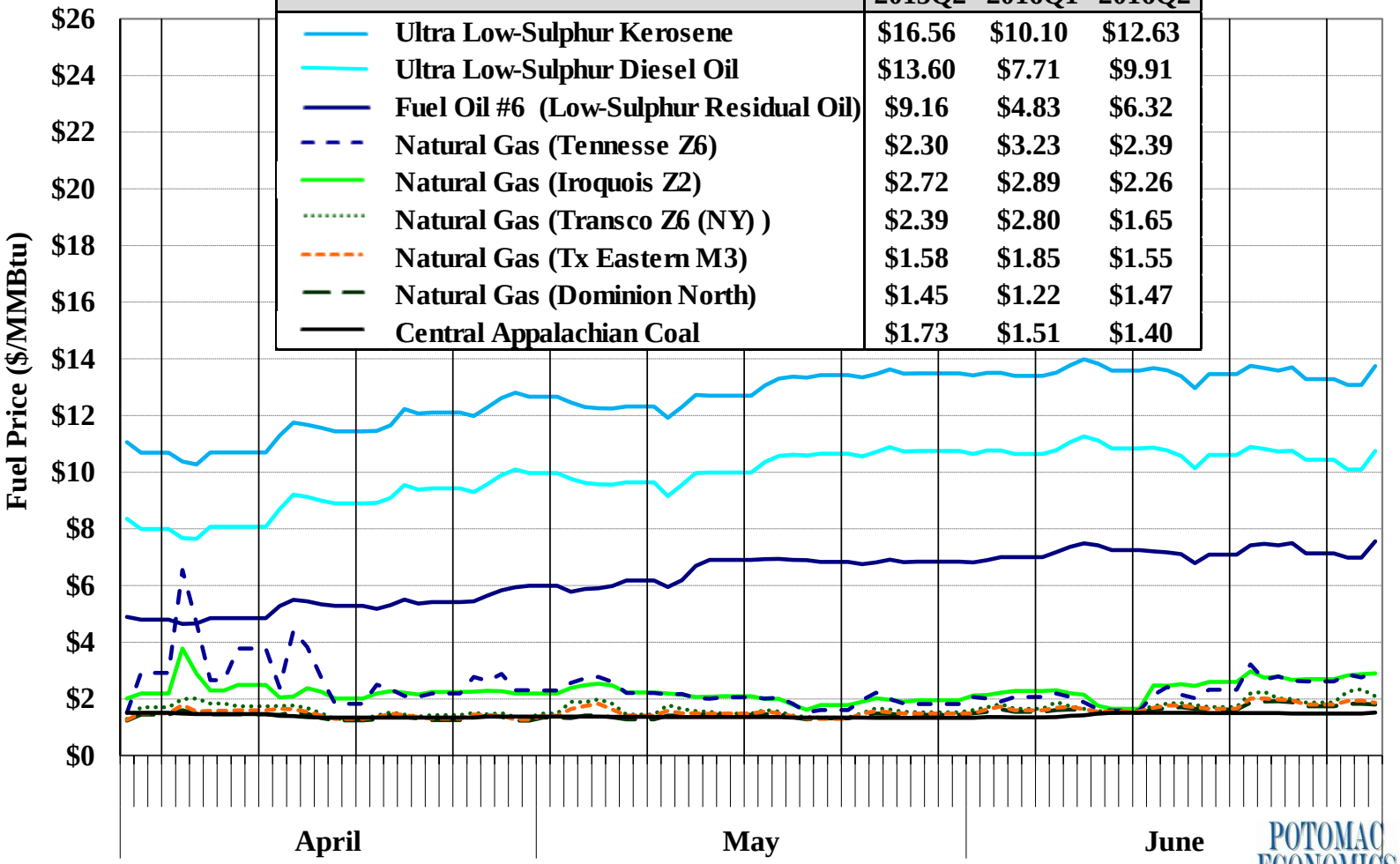
Coal, Natural Gas, and Fuel Oil Prices

	2015Q2	2016Q1	2016Q2
Ultra Low-Sulphur Kerosene	$16.56	$10.10	$12.63
Ultra Low-Sulphur Diesel Oil	$13.60	$7.71	$9.91
Fuel Oil #6 (Low-Sulphur Residual Oil)	$9.16	$4.83	$6.32
Natural Gas (Tennesse Z6)	$2.30	$3.23	$2.39
Natural Gas (Iroquois Z2)	$2.72	$2.89	$2.26
Natural Gas (Transco Z6 (NY))	$2.39	$2.80	$1.65
Natural Gas (Tx Eastern M3)	$1.58	$1.85	$1.55
Natural Gas (Dominion North)	$1.45	$1.22	$1.47
Central Appalachian Coal	$1.73	$1.51	$1.40



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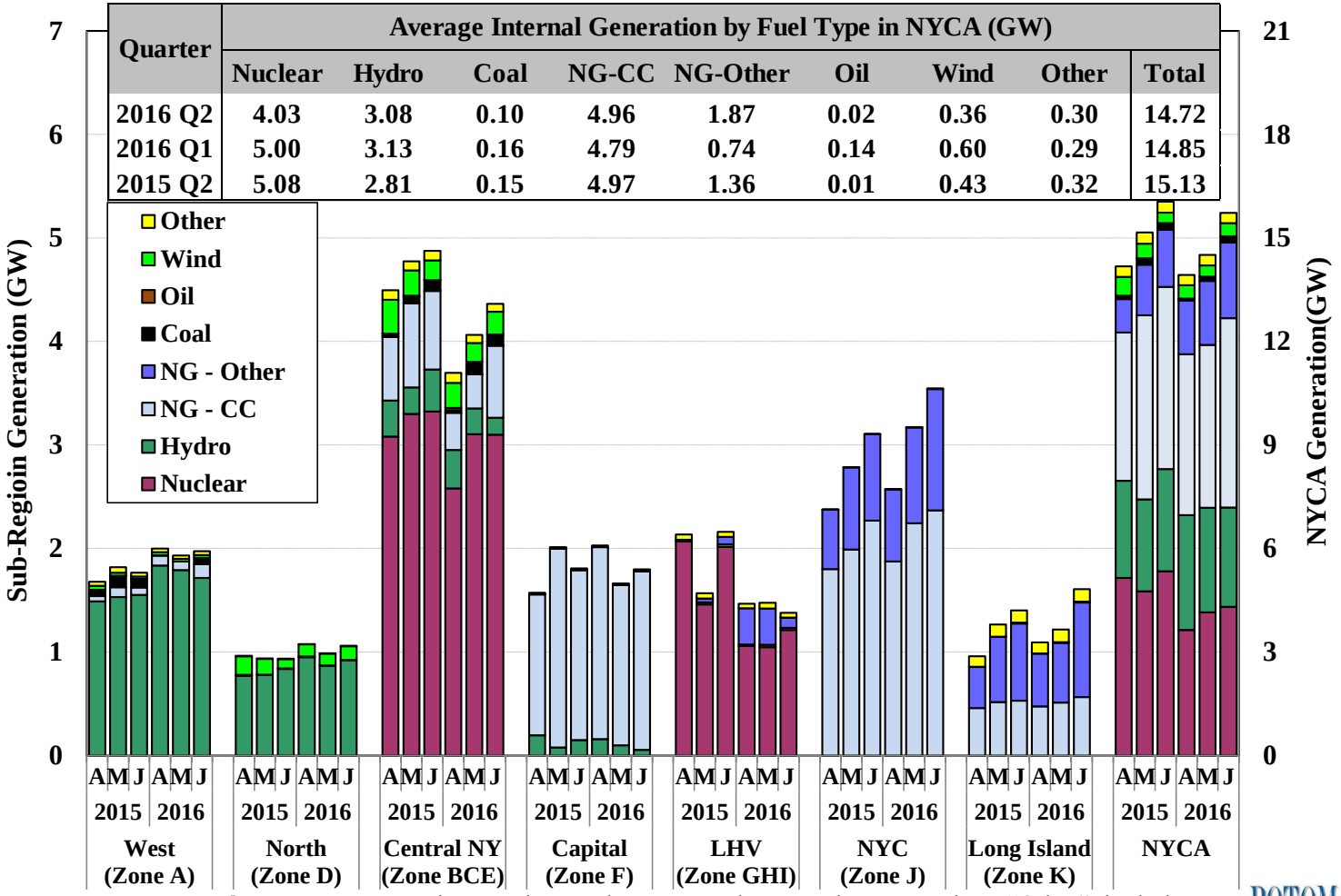
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2016 Q2	4.03	3.08	0.10	4.96	1.87	0.02	0.36	0.30	14.72
2016 Q1	5.00	3.13	0.16	4.79	0.74	0.14	0.60	0.29	14.85
2015 Q2	5.08	2.81	0.15	4.97	1.36	0.01	0.43	0.32	15.13



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

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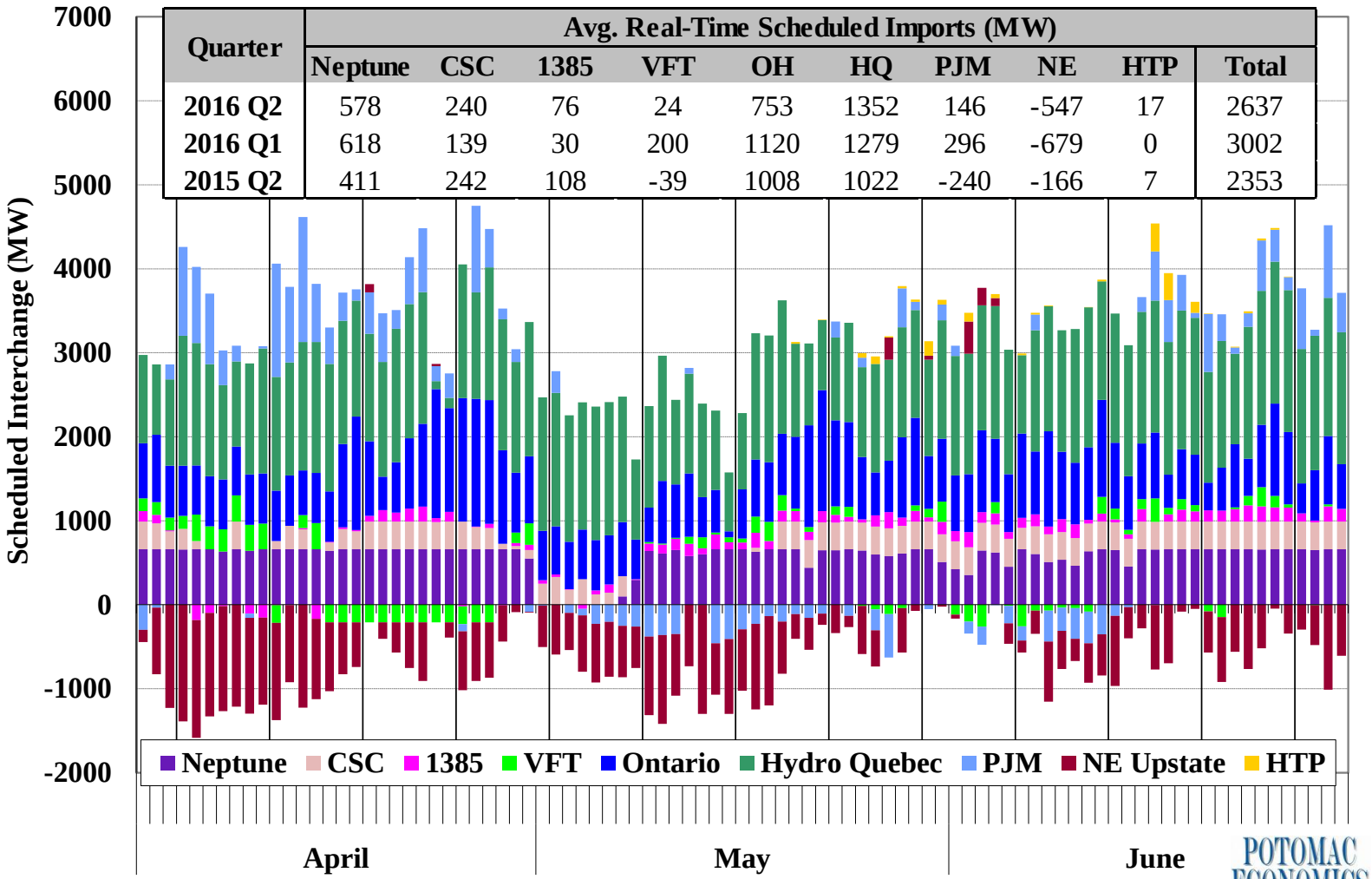
Net Imports Scheduled Across External Interfaces
Daily Peak Hours (1-9pm)

Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2016 Q2	578	240	76	24	753	1352	146	-547	17	2637
2016 Q1	618	139	30	200	1120	1279	296	-679	0	3002
2015 Q2	411	242	108	-39	1008	1022	-240	-166	7	2353



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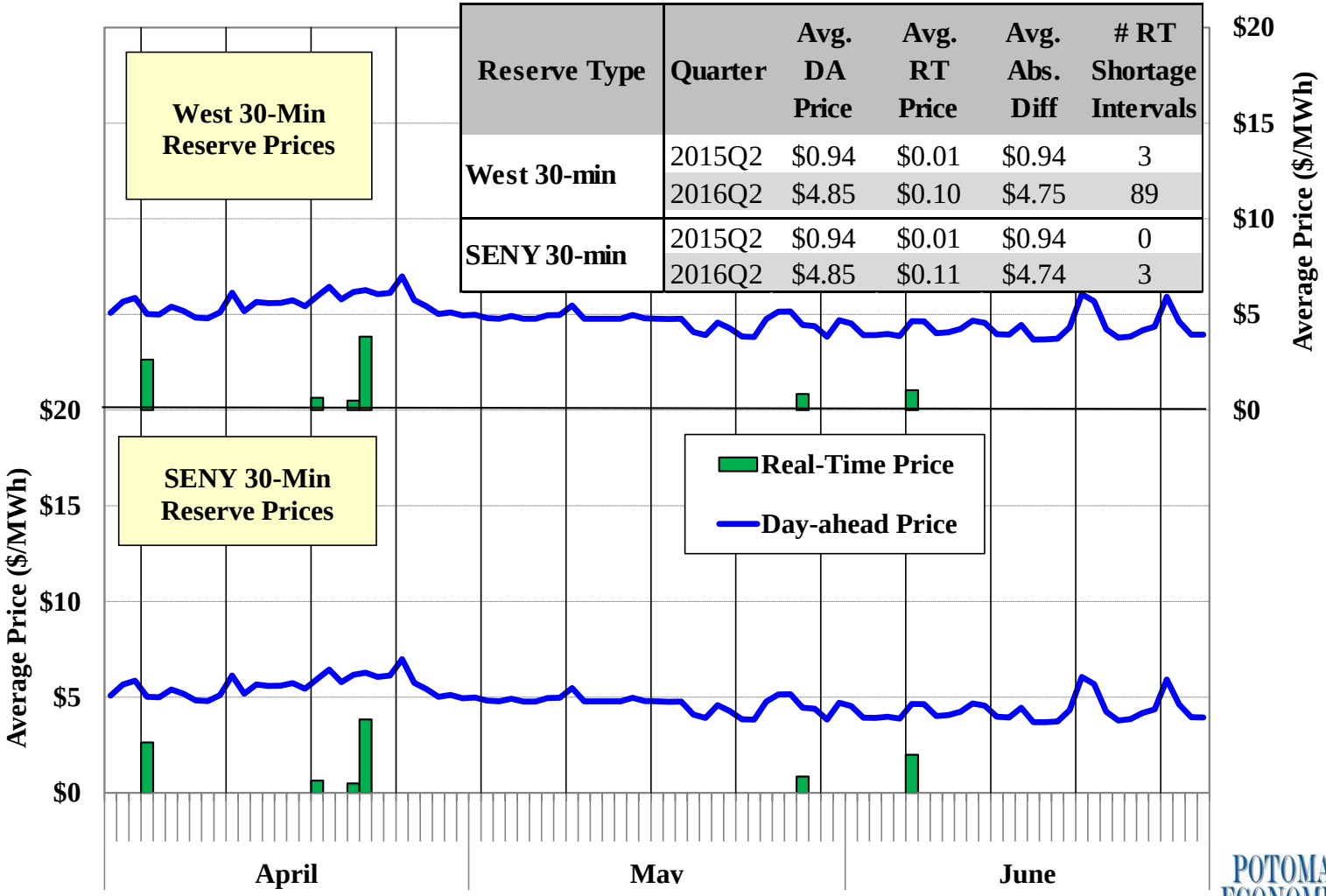
Day-Ahead and Real-Time Ancillary Services Prices

Western and SENY 30-Minute Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2015Q2	$0.94	$0.01	$0.94	3
	2016Q2	$4.85	$0.10	$4.75	89
SENY 30-min	2015Q2	$0.94	$0.01	$0.94	0
	2016Q2	$4.85	$0.11	$4.74	3



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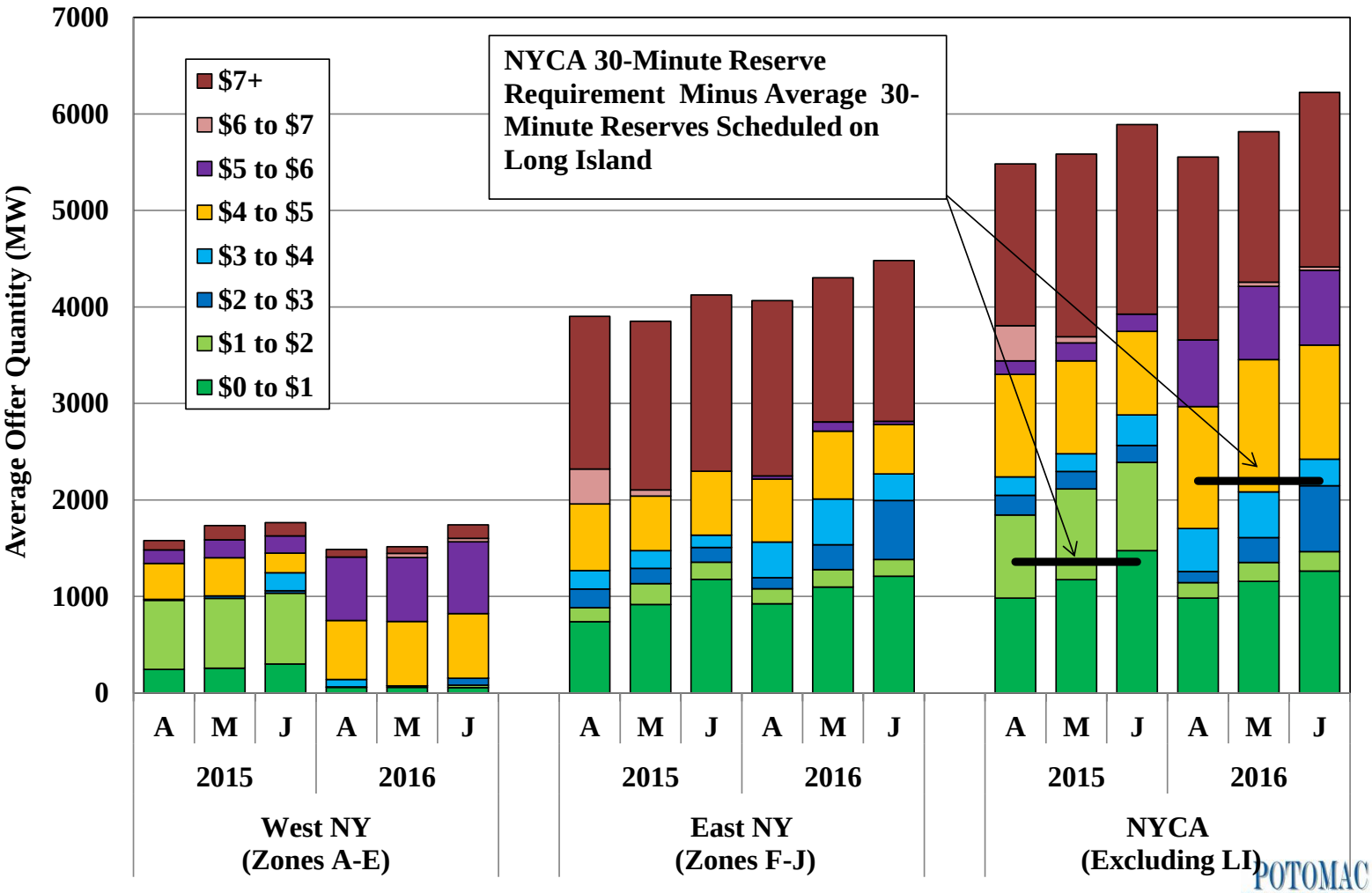
NYCA 30-Minute Reserve Offers in the DAM

- The increase in 30-minute reserve prices from a year ago was primarily driven by the implementation of the Comprehensive Shortage Pricing project.
  - ✓ The increase of the NYCA 30-minute reserve requirement from 1,965 MW to 2,620 MW; and
  - ✓ The limitation on scheduling reserves from Long Island resources.
    - – An average of 423 MW of 30-minute reserves was scheduled on Long Island in the second quarter of 2016, down 183 MW from the second quarter of 2015.
  - ✓ Taken together, these two factors increased the need for 30-minute reserves outside Long Island by 840 MW (compared to a year ago).
- Increased offer prices in West NY was a contributing (yet less significant) factor.
  - ✓ Most reserve offers were priced between $4 and $6/MWh in the second quarter of 2016, while most were between $0 and $2/MWh in the same period of 2015.
  - ✓ We reviewed this offer change and found no significant competitive concerns.
- The amount of low-price offers rose modestly in East NY this quarter, helping to offset the other factors.
- RT 30-minute reserve prices are much lower than DA prices because units that are dispatchable must have availability bids of $0 in RT.

Day-Ahead NYCA 30-Minute Operating Reserve Offers
From Committed and Available Offline Quick-Start Resources



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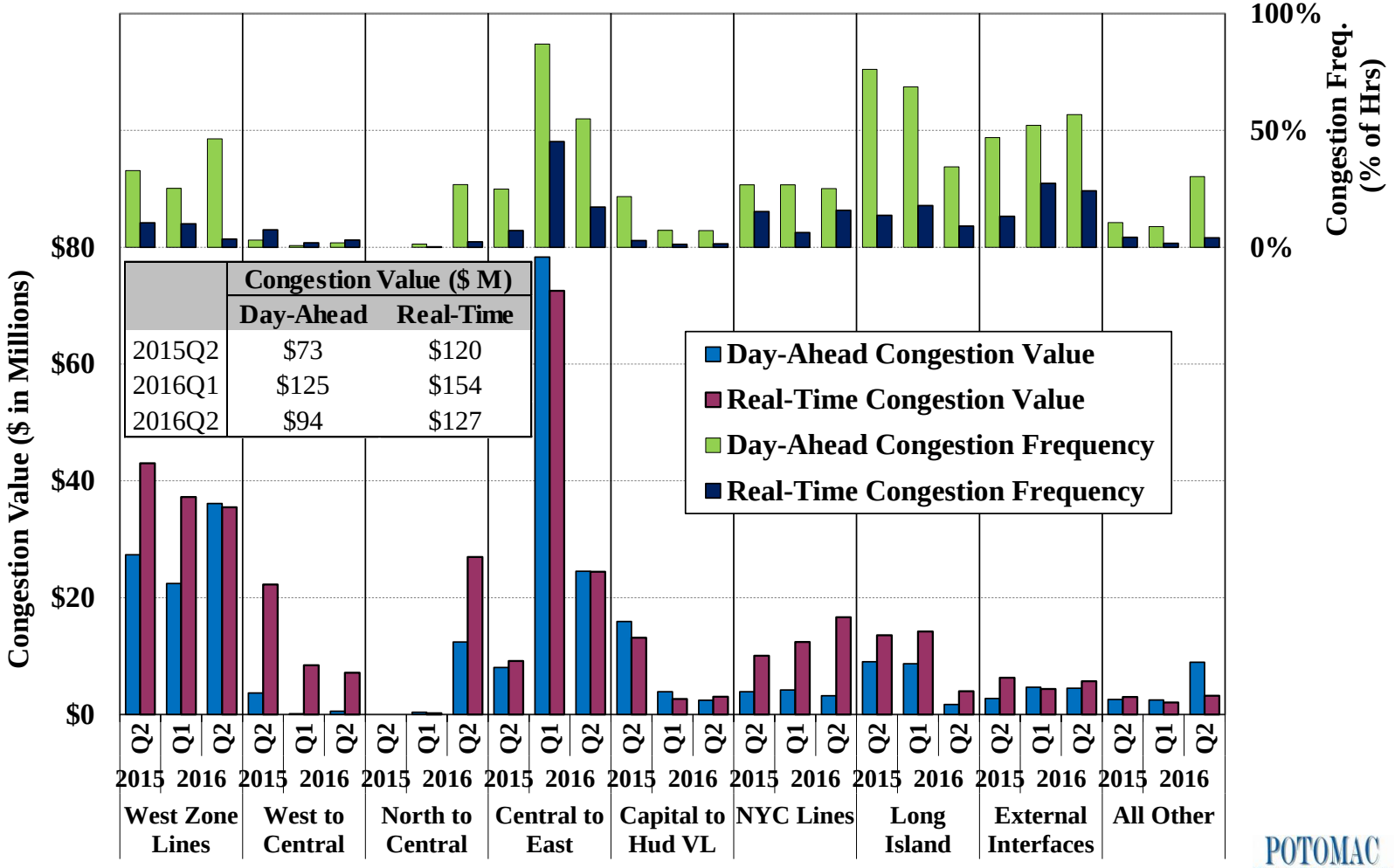
Highlights and Market Summary:
Congestion Patterns

- DAM congestion revenues totaled $94 million (see slides 45-53), up 30 percent from the second quarter of 2015.
  - ✓ Lower natural gas prices and reduced load levels resulted in decreased congestion levels in most areas during the second quarter of 2016.
  - ✓ However, transmission outages reduced transfer capability and led to increased congestion in the following areas:
    - Across the Central-East interface in most of April and May;
    - On the 230 kV system in the West Zone in April;
    - On the transmission paths from North to Central in April and May; and
    - On the transmission paths in LHV in May.
  - ✓ Lower nuclear generation in LHV and higher net exports to ISO-NE also contributed to increased congestion across the Central-East interface.
- Congestion-price differentials increased because of changes in the treatment of transmission shortages following implementation of the Graduated Transmission Demand Curve ("GTDC") project (see slides 65-69).
- In the second quarter of 2016, West Zone constraints accounted for the largest share of DA and RT congestion among all areas.

DA and RT Congestion Value and Frequency
by Transmission Path



	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2015Q2	$73	$120
2016Q1	$125	$154
2016Q2	$94	$127

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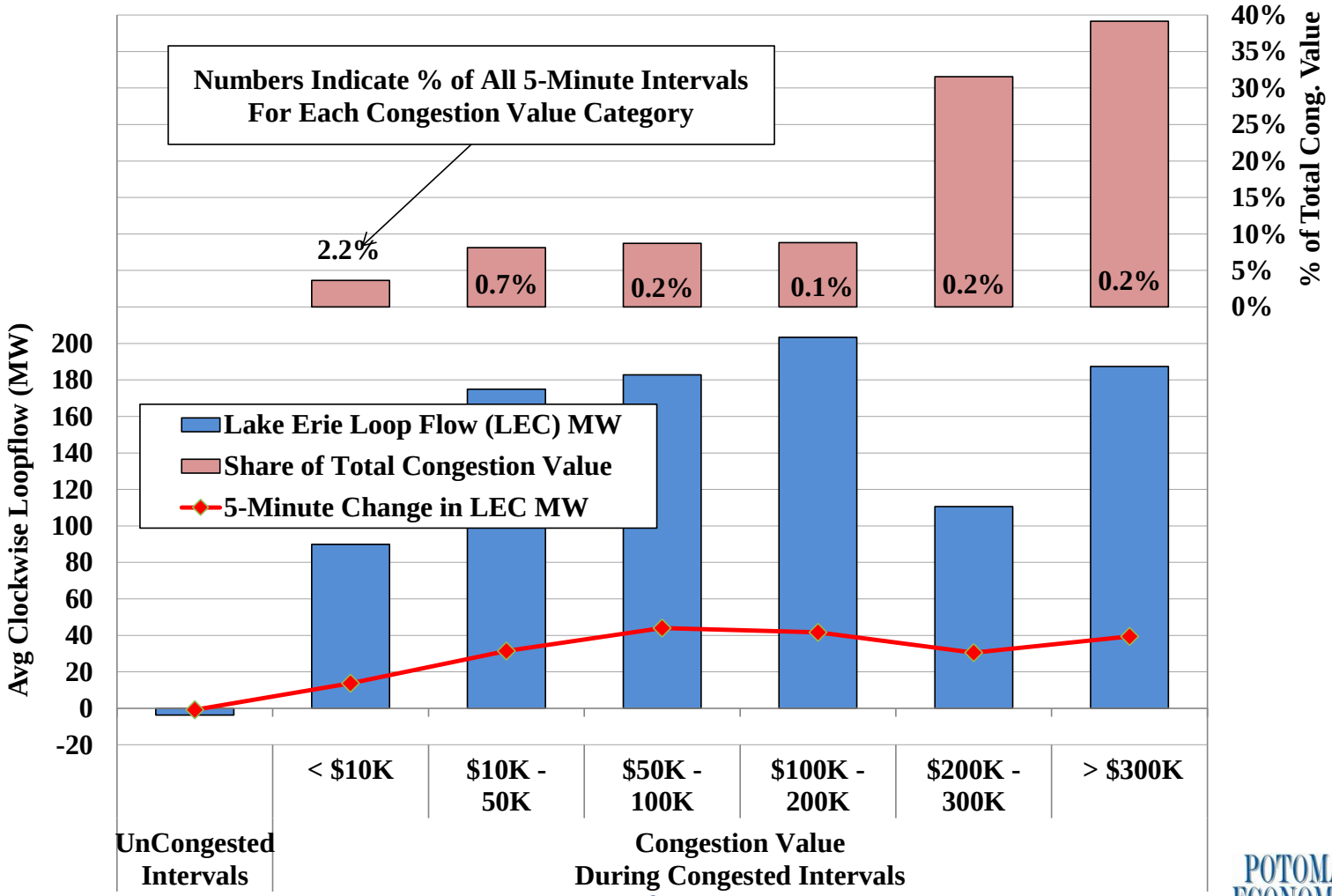
Highlights and Market Summary:
West Zone Congestion

- The pattern of West Zone congestion affected by many significant market changes, including (but not limited to): (see slides 57-70)
  - ✓ (a) the implementation of GTDC in February 2016; (b) the retirements of coal units in December 2015 and in March 2016; (c) the implementation of a composite shift factor at Niagara plant in May 2016; (d) transmission upgrades in May 2016; and (e) the S. Ripley-Dunkirk 230 kV line and Warren-Falconer 115 kV line being taken OOS during most of 2016-Q2.
  - ✓ In addition, volatile loop flows continued to exacerbate congestion.
- These challenges increase the importance of efficient congestion management.
  - ✓ On 6/28, NYISO implemented enhanced loop flow assumptions that are designed to schedule resources more efficiently given uncertainty about loop flows.
  - ✓ Ultimately, efficient congestion management can reduce the need for transmission infrastructure investments. However, we continue to observe:
    - Under-utilization of 115kV circuits that are parallel to congested facilities,
    - Inefficiently-high generation from units that exacerbate 230kV congestion,
    - Under-commitment of West Zone units that relieve 115kV & 230kV congestion,
    - Shadow prices are not well correlated with the severity of congestion during transmission shortages, which undermines scheduling incentives for importers and other non-dispatchable resources.

West Zone Congestion and Clockwise Loop Flows During the Second Quarter of 2016



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West Zone Congestion and Niagara Generation Modeling

LBMPs by Generator & Under-Utilization of 115kV Circuits

Location	Average LBMP ($/MWh)	
	Congested Intervals	Non-Congested Intervals
West Zone	$280.12	$18.23
Niag 115 W	$105.11	$17.29
Niag 115 E	$139.80	$17.35
Niag 230	-$78.39	$17.54

Quarter	Production Cost Savings ($ Million)	Additional Niagara Generation Potential (GWh)
2016 Q2	$1.5	13.1

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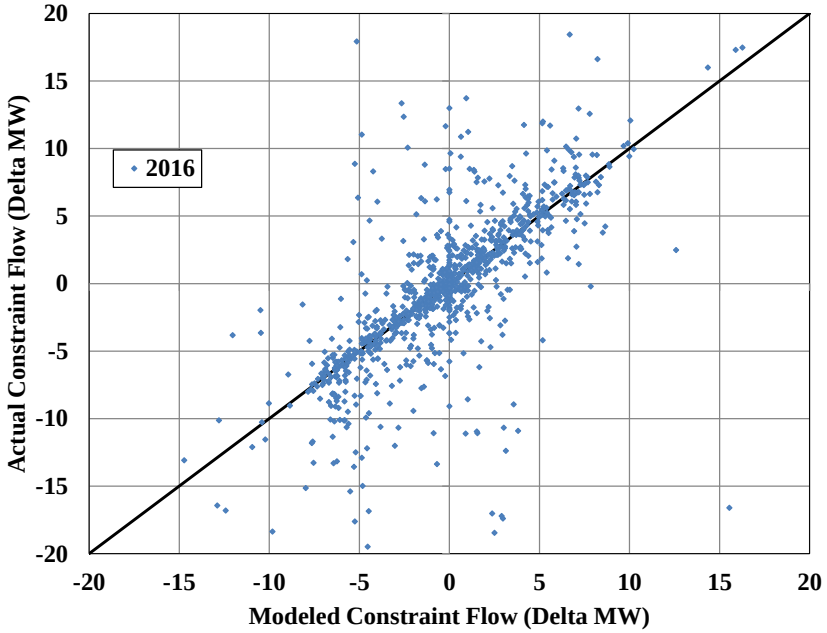
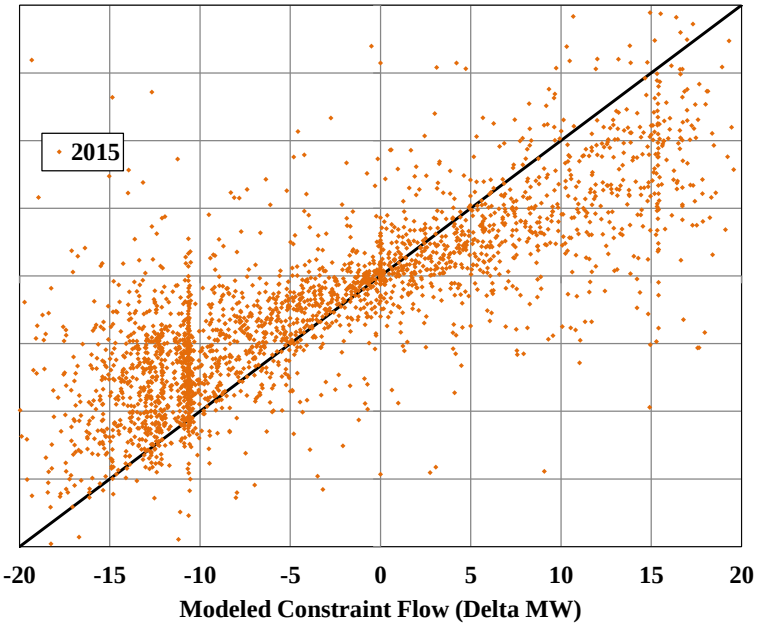
West Zone Congestion and Niagara Generation Modeling

- The second figure illustrates how modeling assumptions related to the system impacts of the Niagara plant differ from the actual impacts of the plant.
  - ✓ The scatter plots show the impact on constrained facilities in the West Zone:
    - The horizontal axis shows the RTD model's assumed impact;
    - The vertical axis reflects where output was actually increased (or decreased) at the plant (assuming perfect dispatch performance relative to the 5-minute signal).
    - Hence, a point on the diagonal line indicates consistency between modeled impact and actual impact.
  - ✓ The table summarizes the average absolute value for both quantities as well as the average differential between the modeled impact and the actual impact.
- Consistency between the modeled and actual impacts was poor in both periods, which contributes to transient price volatility.
  - ✓ The average differential between modeled and actual impacts was large relative to the average modeled impact. (2.3 v 2.8 MW in 2016 & 5.4 v 10.3 MW in 2015.)
  - ✓ Under the old modeling approach, RTD generally over-estimated the impacts from re-dispatching Niagara.
  - ✓ Under the new modeling approach, RTD generally under-estimates the impacts from re-dispatching Niagara.

West Zone Congestion and Niagara Generation Modeling

Modeled Impact vs. Actual Impact





Average Constraint Flow Impact (Delta MW)		
Absolute Value of:	**2016-Q2**	**2015-Q2**
Modeled Impact	2.8	10.3
Actual Impact	4.2	6.9
Modeled v Actual	2.3	5.4

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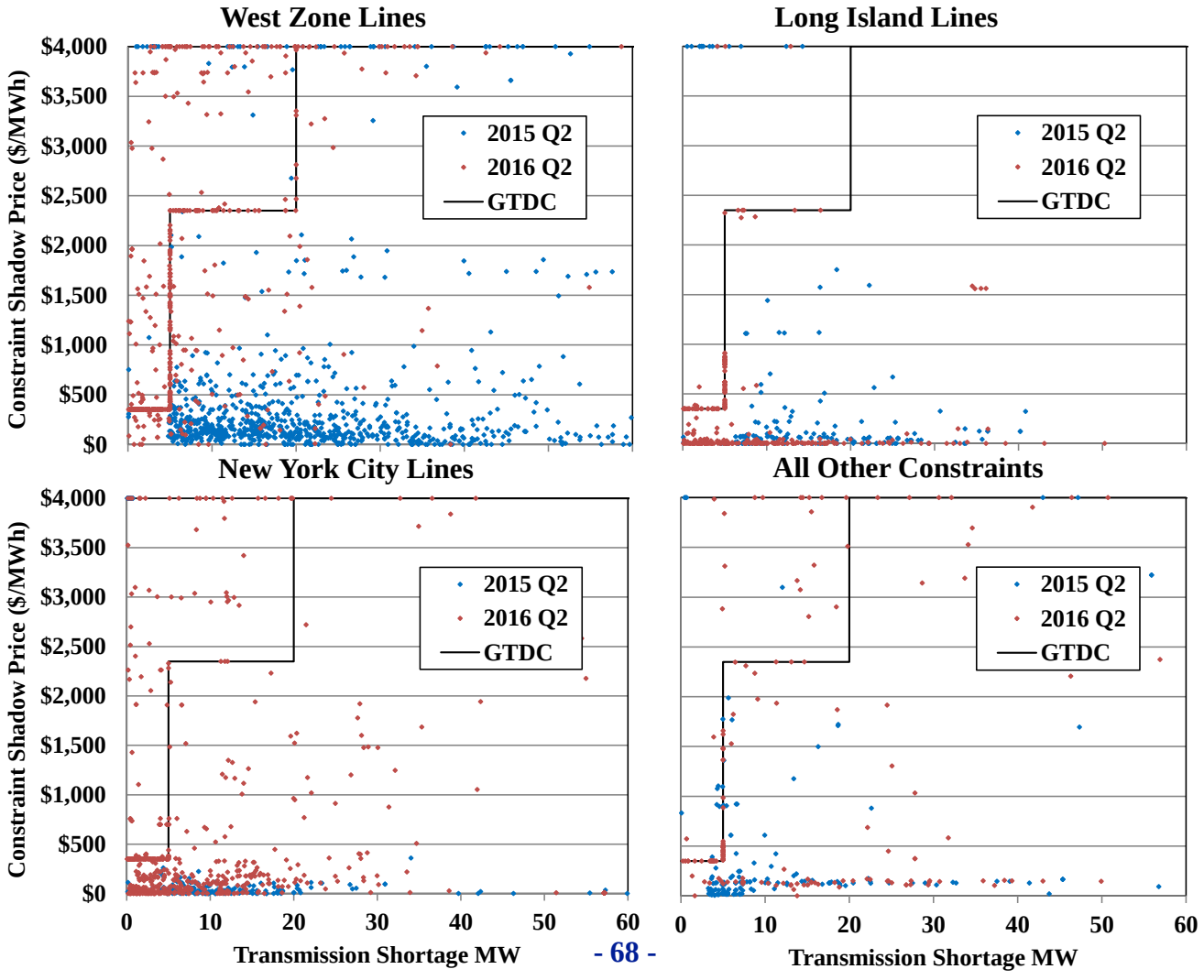
Congestion Management with the GTDC

- The NYISO implemented the Graduated Transmission Demand Curve ("GTDC") on February 12 to improve market efficiency during transmission shortages.
  - ✓ Efficient shadow prices facilitate efficient operations by providing incentives for market participants to schedule generation and external transactions efficiently.
  - ✓ Ideally, constraint shadow prices would reflect the importance and severity of a transmission constraint when flows exceed the BMS limit in RTD.
    - The BMS limit is used by RTD to limit flows in each 5-minute interval.
- The GTDC project changed the scheduling and pricing methodology during shortages. (See *2015 SOM Report*, Appendix Section V.H. for details.)
  - ✓ Key changes include: (a) replacing the $4000 penalty with 3-step GTDC, and (b) reducing the constraint relaxation limit adjustment from +8 MW to +0.2 MW.
- The next three figures compare market performance before and after the change.
  - ✓ The first figure summarizes shadow prices, shortage quantities relative the BMS limit (adjusted for the CRM), and RT congestion value by constraint group.
  - ✓ The second figure shows this information for individual 5-minute intervals.
  - ✓ The third figure shows shadow prices and shortage quantities relative to the seasonal limit (adjusted for the CRM) for West Zone constraints.

Congestion Management with the GTDC

- Shadow prices during shortages have increased since the GTDC was implemented.
  - ✓ This is from the reduced limit adjustment (+0.2MW) since most (~70%) shortages are still resolved using the constraint relaxation method (rather than the GTDC).
  - ✓ Constraint relaxation can lead shadow prices to be higher or lower than the GTDC.
    - In NYC & Long Island, shadow prices were generally lower than the GTDC.
    - In the West Zone, the results were mixed (shadow prices averaged $908 v $350 for shortages of <5 MW and $1957 v $2350 for shortages of 5 to 20 MW).
- Transmission shortage quantities have fallen since the GTDC was implemented.
  - ✓ Higher shadow prices provide stronger incentives for external transactions (and other non-dispatchable resources) to avoid schedules that exacerbate congestion.
    - Efficient prices provide incentives that are neither too strong nor too weak.
  - ✓ However, the shortage frequency increased in NYC & Long Island partly because the GTDC makes RTC less likely to start a GT to manage a brief shortage.
- In the West Zone, volatile loop flows and difficulty managing congestion can lead operators to reduce the BMS limit below the seasonal limit.
  - ✓ BMS limits and modeled flows have been much closer to the seasonal limits (i.e., higher) this year in the West Zone partly because the GTDC project has improved the ability of RTS to manage flows.

Congestion Management with the GTDC
Transmission Shortage Pricing, 2015-Q2 vs. 2016-Q2



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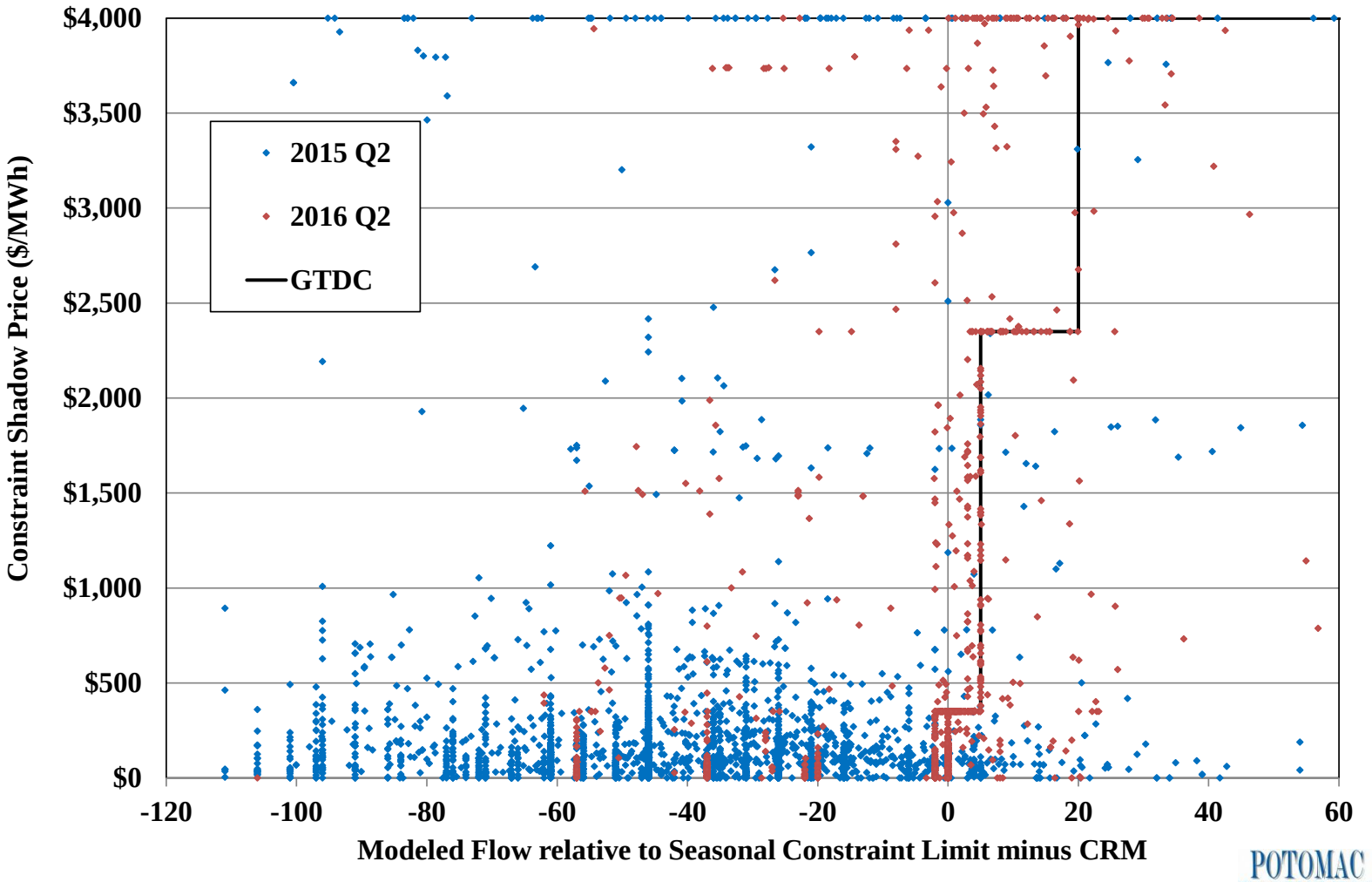
Congestion Management with the GTDC
Constraint Summary, 2015-Q2 vs. 2016-Q2

Location of Constrained Facility	Transmission Shortage	# of Constraint-Intervals		Average Shortage (MW)		Average Shadow Price ($/MWh)		RT Congestion Value ($M)			
								Original		Adjusted Using GTDC Directly	
		2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
West Zone	N	1928	662	0	0	$148	$107	$12	$3	$12	$3
	Y	924	487	27	8	$679	$1,587	$31	$33	$131	$32
New York City	N	11951	11171	0	0	$26	$37	$8	$10	$8	$10
	Y	238	763	17	12	$356	$484	$2	$7	$18	$32
Long Island	N	7198	3222	0	0	$66	$30	$12	$2	$12	$2
	Y	186	302	18	10	$464	$293	$2	$2	$10	$8
All Other	N	6074	7727	0	0	$74	$30	$44	$36	$44	$36
	Y	156	177	15	24	$488	$1,339	$9	$34	$27	$39

Congestion Management with the GTDC
Limit Adjustments & Shortage Pricing, 2015-Q2 vs. 2016-Q2



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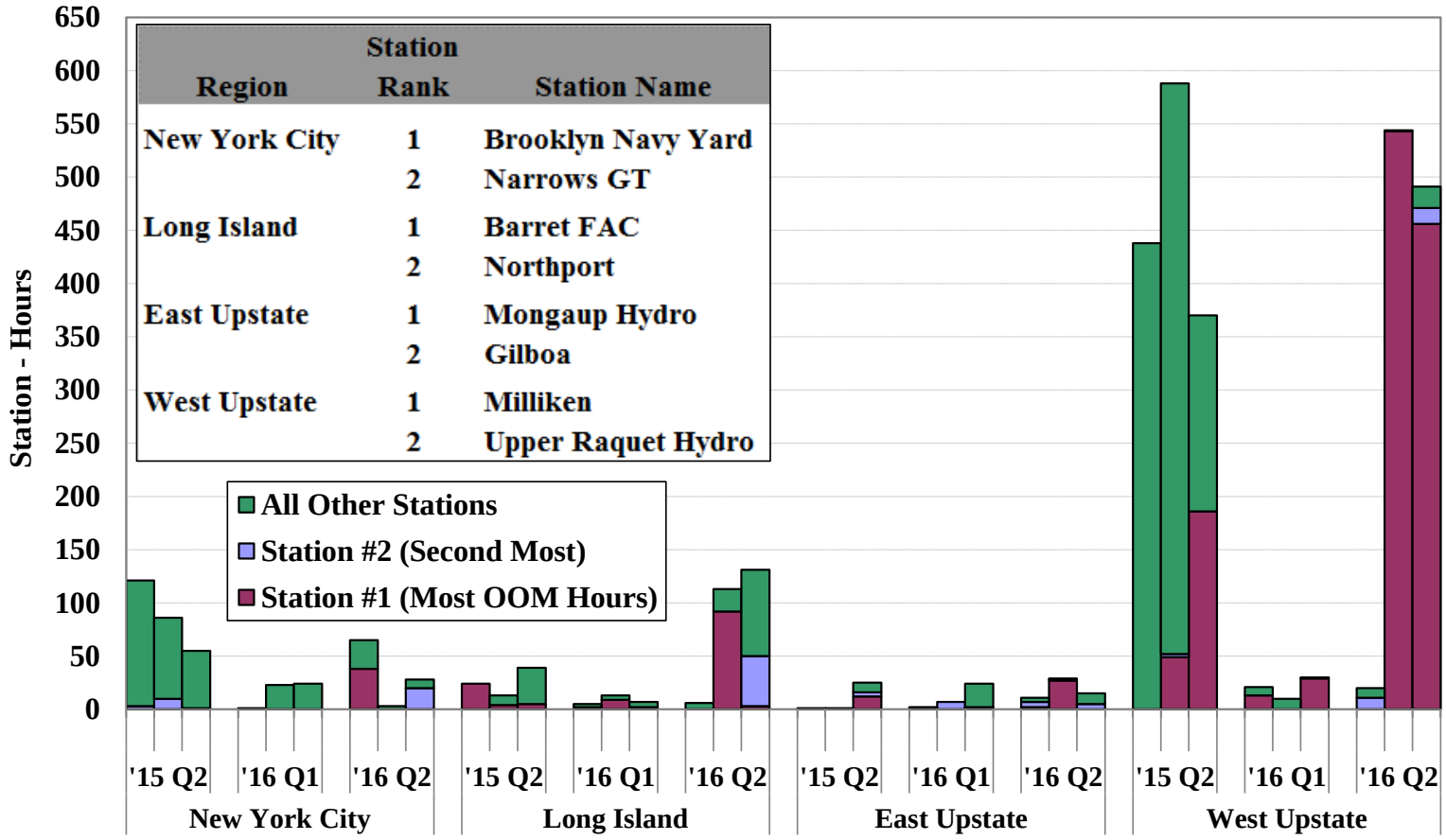
Highlights and Market Summary: Uplift and Revenue Shortfalls

- Guarantee payments were $11M, down 34% from 2015-Q2. (see slides 79-82)
  - ✓ Lower natural gas prices decreased the commitment costs of gas-fired units; and
  - ✓ Supplemental commitments and OOM dispatches fell, attributable to lower load levels, transmission upgrades in Western NY, and NYC generation being more economic (relative to the rest of Eastern NY because of gas market conditions).
- DAM congestion shortfalls were $25M, up $19M from 2015-Q2. (see slides 48,52)
  - ✓ Transmission outages were the primary driver – over $17M of shortfalls were assigned to the responsible transmission owners.
  - ✓ The remaining shortfalls accrued primarily on the West Zone constraints, resulting largely from assumptions related to loop flows.
- Balancing congestion shortfalls were $8M, down $6M from 2015-Q2. (see 49,53)
  - ✓ Changes to the modeling of the 901/903 lines in late-April reduced shortfalls from RT congestion in the Valley Stream load pocket (relative to previous years).
  - ✓ The majority of shortfalls ($7M) accrued on the West Zone 230 kV facilities.
    - – $3M was attributable to the differences between DA assumptions and RT outcomes in: (a) the operation of Ramapo, ABC, & JK PARs ($1.6M); and (b) the distribution of output between 115 and 230 kV units at the Niagara plant ($1.3M).
    - – $4M resulted largely from assumptions related to loop flows.

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

Region	Station Rank	Station Name
New York City	1	Brooklyn Navy Yard
	2	Narrows GT
Long Island	1	Barret FAC
	2	Northport
East Upstate	1	Mongaup Hydro
	2	Gilboa
West Upstate	1	Milliken
	2	Upper Raquet Hydro



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 797 hours in 2015-Q2, 337 hours in 2016-Q1, and 600 hours in 2016-Q2. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

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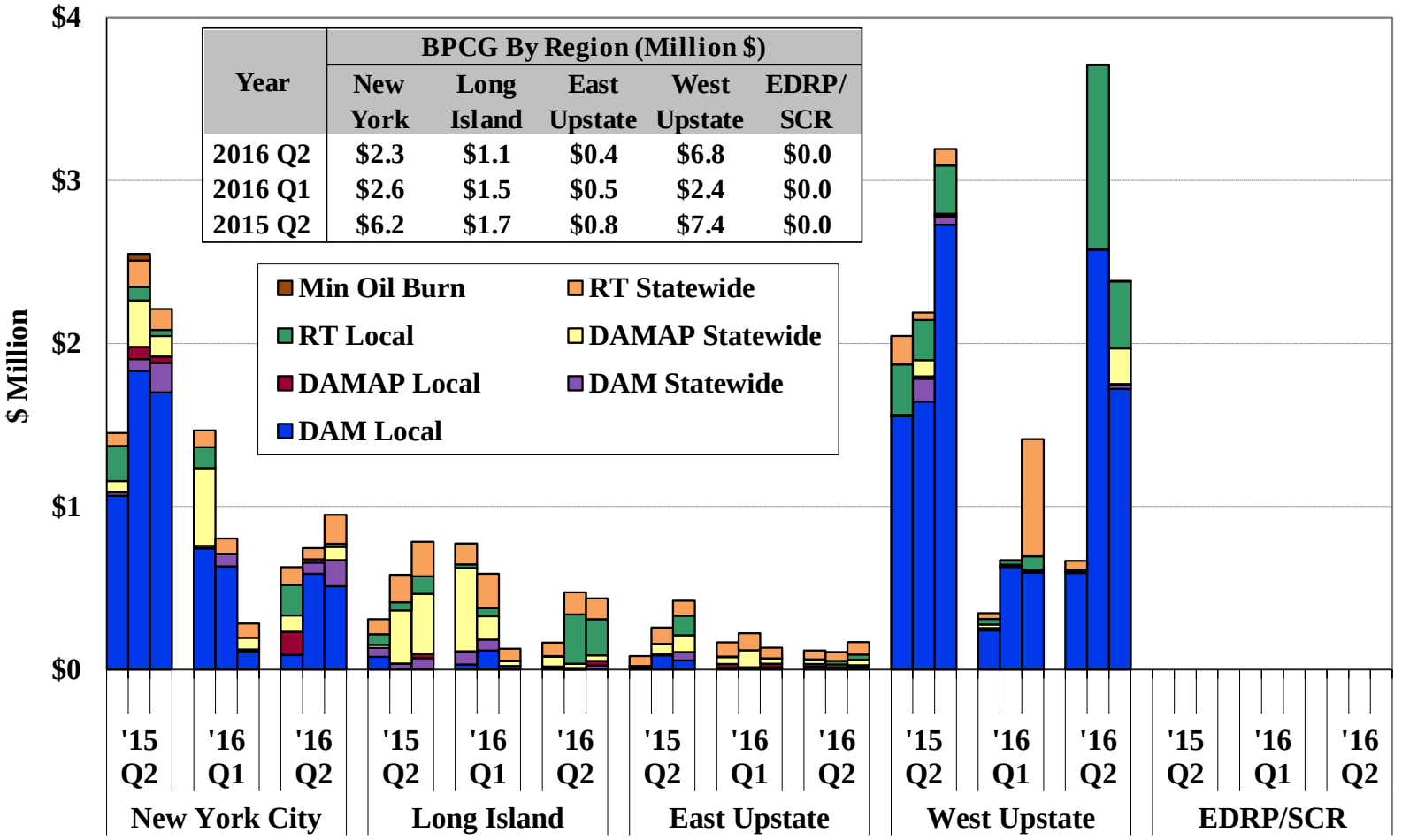
Uplift Costs from Guarantee Payments
By Category and Region

Year	BPCG By Region (Million $)				
	New York	Long Island	East Upstate	West Upstate	EDRP/ SCR
2016 Q2	$2.3	$1.1	$0.4	$6.8	$0.0
2016 Q1	$2.6	$1.5	$0.5	$2.4	$0.0
2015 Q2	$6.2	$1.7	$0.8	$7.4	$0.0



Note: BPCG data are based on information available at the reporting time that can be different from final settlements.

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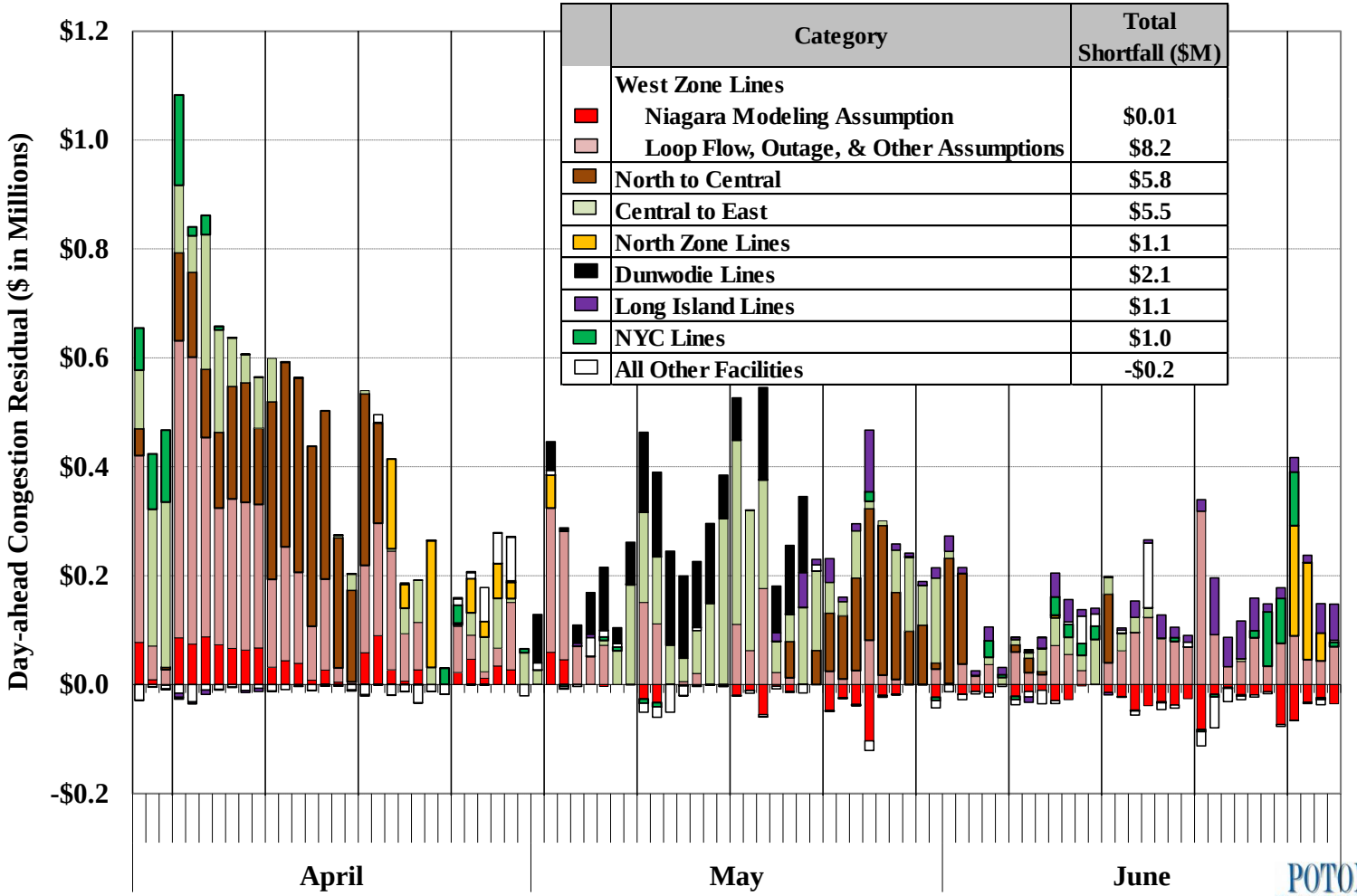
Day-Ahead Congestion Revenue Shortfalls
by Transmission Facility

Category	Total Shortfall ($M)
West Zone Lines	
Niagara Modeling Assumption	$0.01
Loop Flow, Outage, & Other Assumptions	$8.2
North to Central	$5.8
Central to East	$5.5
North Zone Lines	$1.1
Dunwodie Lines	$2.1
Long Island Lines	$1.1
NYC Lines	$1.0
All Other Facilities	-$0.2



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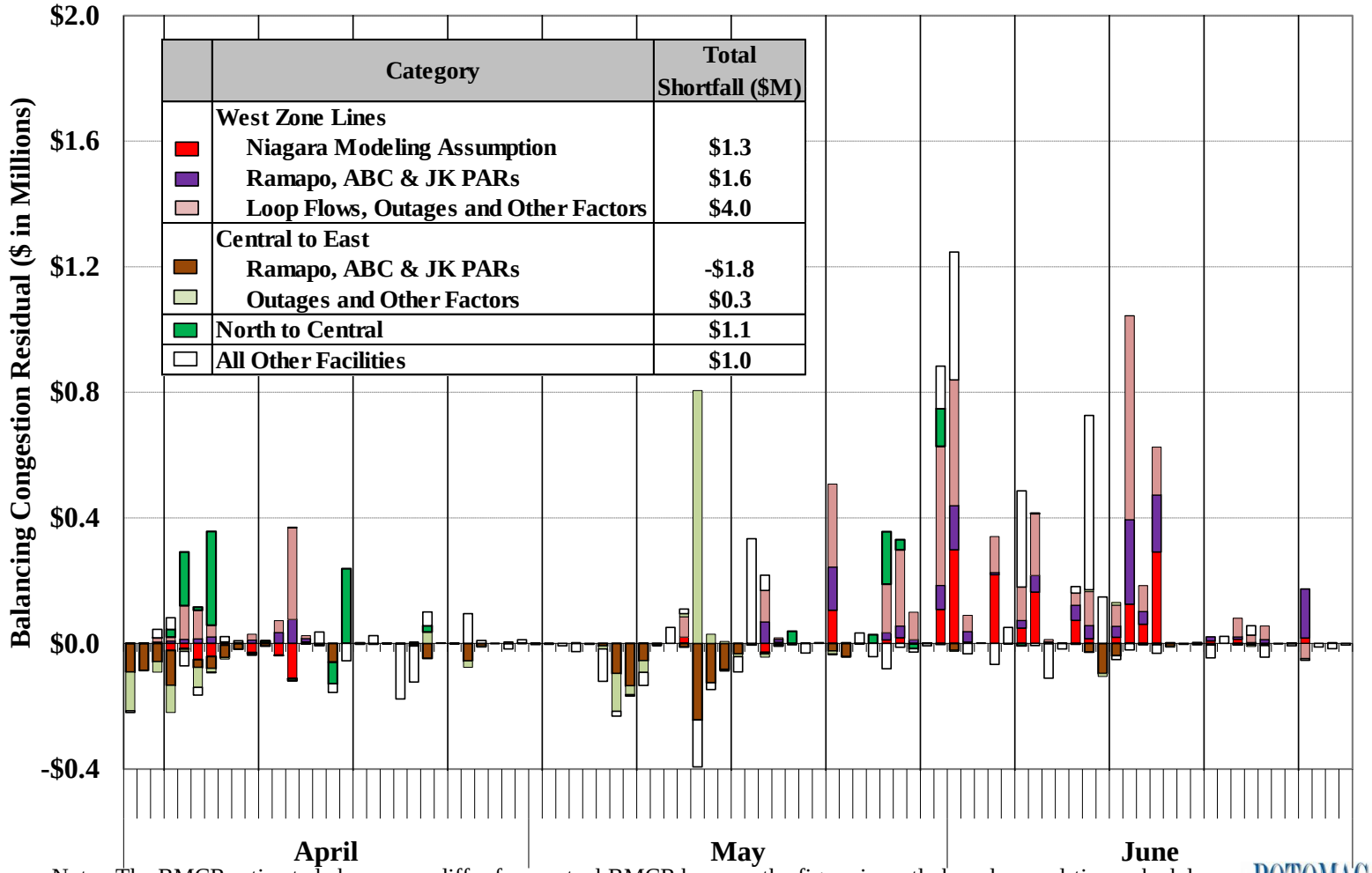
Balancing Congestion Shortfalls
by Transmission Facility

	Category	Total Shortfall ($M)
	West Zone Lines	
	Niagara Modeling Assumption	$1.3
	Ramapo, ABC & JK PARs	$1.6
	Loop Flows, Outages and Other Factors	$4.0
	Central to East	
	Ramapo, ABC & JK PARs	-$1.8
	Outages and Other Factors	$0.3
	North to Central	$1.1
	All Other Facilities	$1.0



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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Highlights and Market Summary: Capacity Market

- UCAP spot prices fell in the zones in SENY but rose elsewhere from the second quarter of 2015. UCAP prices: (see slides 91-93)
  - ✓ In New York City fell 22 percent to an average of $10.12/kW-month;
  - ✓ In the G-J Locality fell 11 percent to an average of $7.22/kW-month;
  - ✓ On Long Island fell 19 percent to an average of $3.92/kW-month;
  - ✓ In Rest of State rose 11 percent to an average of $3.58/kW-month.
- Average capacity spot prices fell in SENY primarily because:
  - ✓ The ICAP requirement fell 467 MW (4.7 percent) in NYC, 117 MW (2.0 percent) in Long Island, and 109 MW (0.7 percent) in the G-J Locality, because of:
    - (a) Lower LCRs due partly to the TOTS projects that increased import capability into SENY; and (b) lower peak load forecast.
  - ✓ An increase of roughly 300 MW of internal ICAP supply in the G-J Locality.
- Average capacity spot prices rose in the ROS primarily because of lower spot prices in May 2015 (which resulted from high sales from NE in this month).
  - ✓ However, spot prices were similar in April and June between 2015 and 2016.
    - The slightly lower ICAP requirement in 2016 Q2 (reflecting the combined effects of lower peak load forecast and a higher IRM) was offset by a similar decrease in total internal ICAP supply.

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2016 Q2 ($/kW-Month)	3.58	10.12	3.92	7.22
% Change from 2015 Q2	11%	-22%	-19%	-11%
Change in Demand				
Load Forecast (MW)	-209	-136	-61	-31
IRM/LCR	0.5%	-3.0%	-1.0%	-0.5%
2016 Summer	*117.5%*	*80.5%*	*102.5%*	*90.0%*
2015 Summer	*117.0%*	*83.5%*	*103.5%*	*90.5%*
ICAP Requirement (MW)	**-77**	**-467**	**-117**	**-109**
Change in ICAP Supply (MW)				
Reductions Due to: Retirement (R), ICAP Inegilible FO (FO), Mothball (M)				
R - Huntley 67 & 68 (Mar-16)	-375			
FO - Astoria GT 05,07,08,12,13 (Jan-16)	-74	-74		-74
R - Dunkirk 2 (Jan-16)	-75			
M - Ravenswood 04,05,06 (May-16)	-49	-49		-49
Additions Due to: Return to Service				
Bowline Unit 2 (Jul-15)	374			374
Changes Due to: DMNC Test	102	73	23	50
Net Changes (MW)	**-97**	**-50**	**23**	**301**

Note: The changes in demand and supply are measured based on the Summer Capability Period.