

Market Surveillance Panel Report (May to October 2007)

Presented to the MPWG Feb 07, 2008



Chapter 1 of Market Surveillance Panel Report (May to October 2007)

Presented by: Anthony Clemente (IESO Market Assessment Unit)

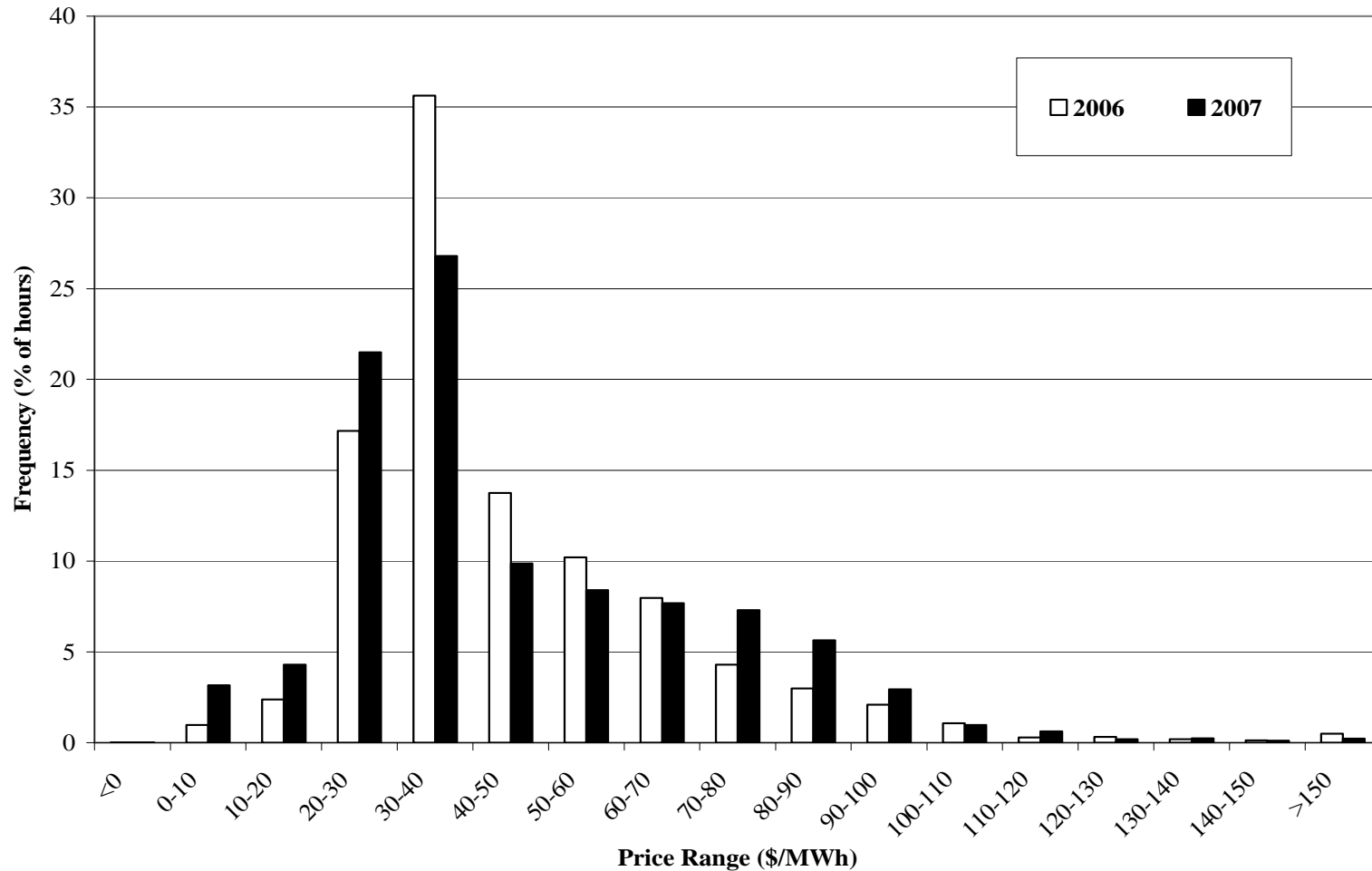


- Pricing
- Demand
- Supply
- Imports and Exports

- Average HOEP higher than a year ago by \$0.45/MWh (1 percent)
- Energy Prices more dispersed:
 - more hours with prices and above \$70/MWh, and;
 - more hours with prices below \$20/MWh.

Frequency Distribution of HOEP

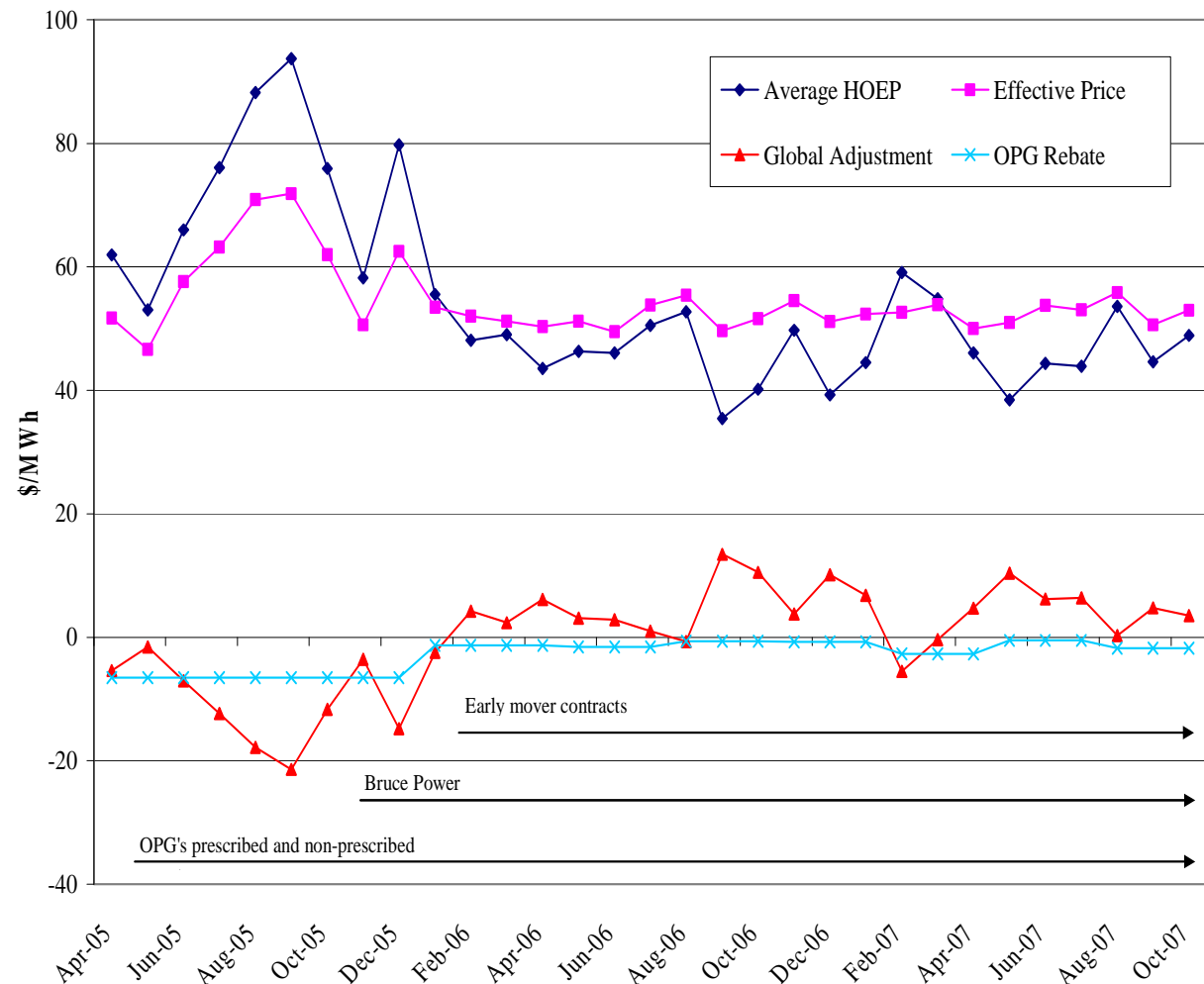
May – October 2006 & 2007
(% of Total Hours in \$10/MWh price ranges)



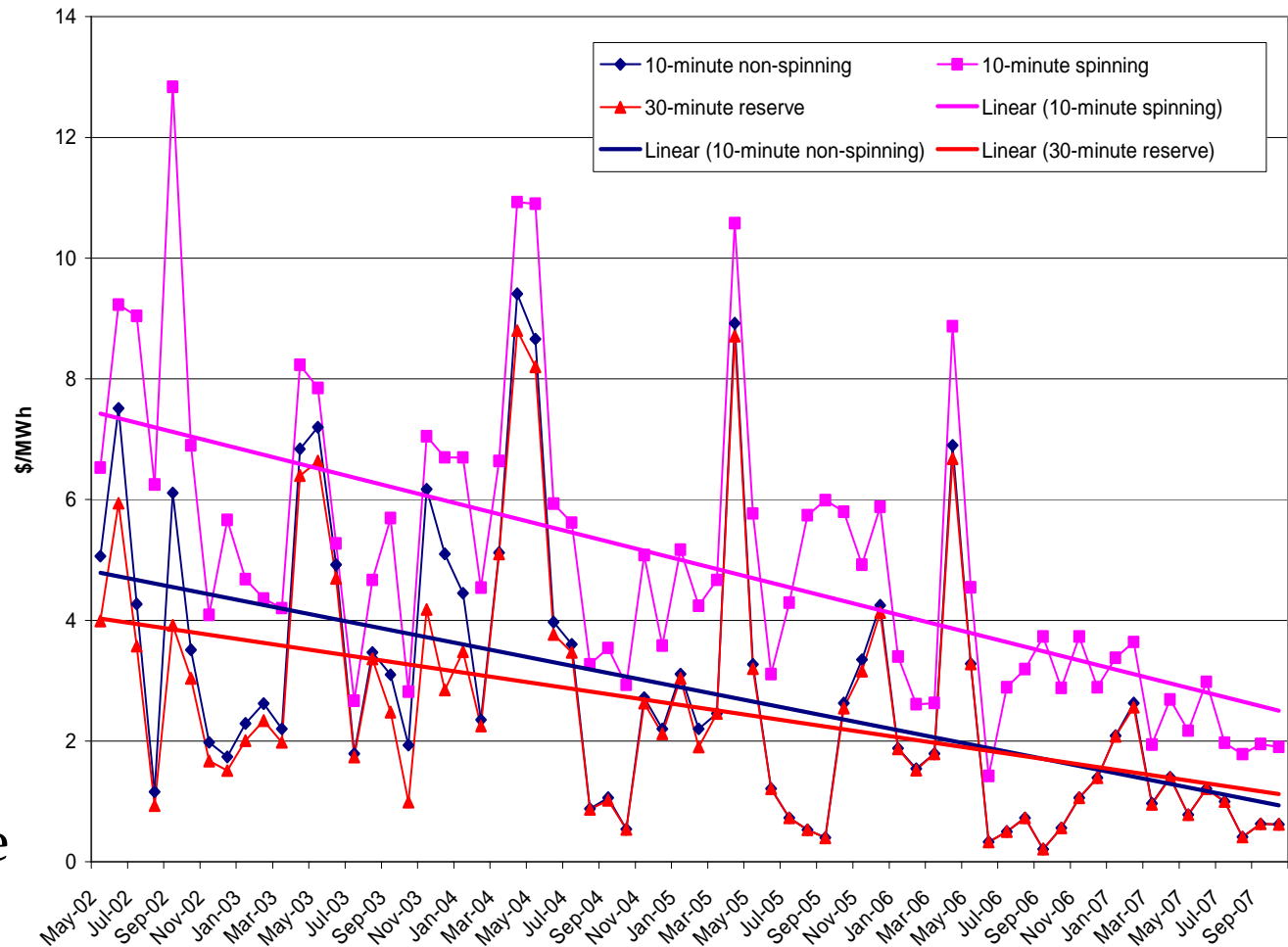
Monthly HOEP versus Effective HOEP

April 2005 – October 2007
(\$/MWh)

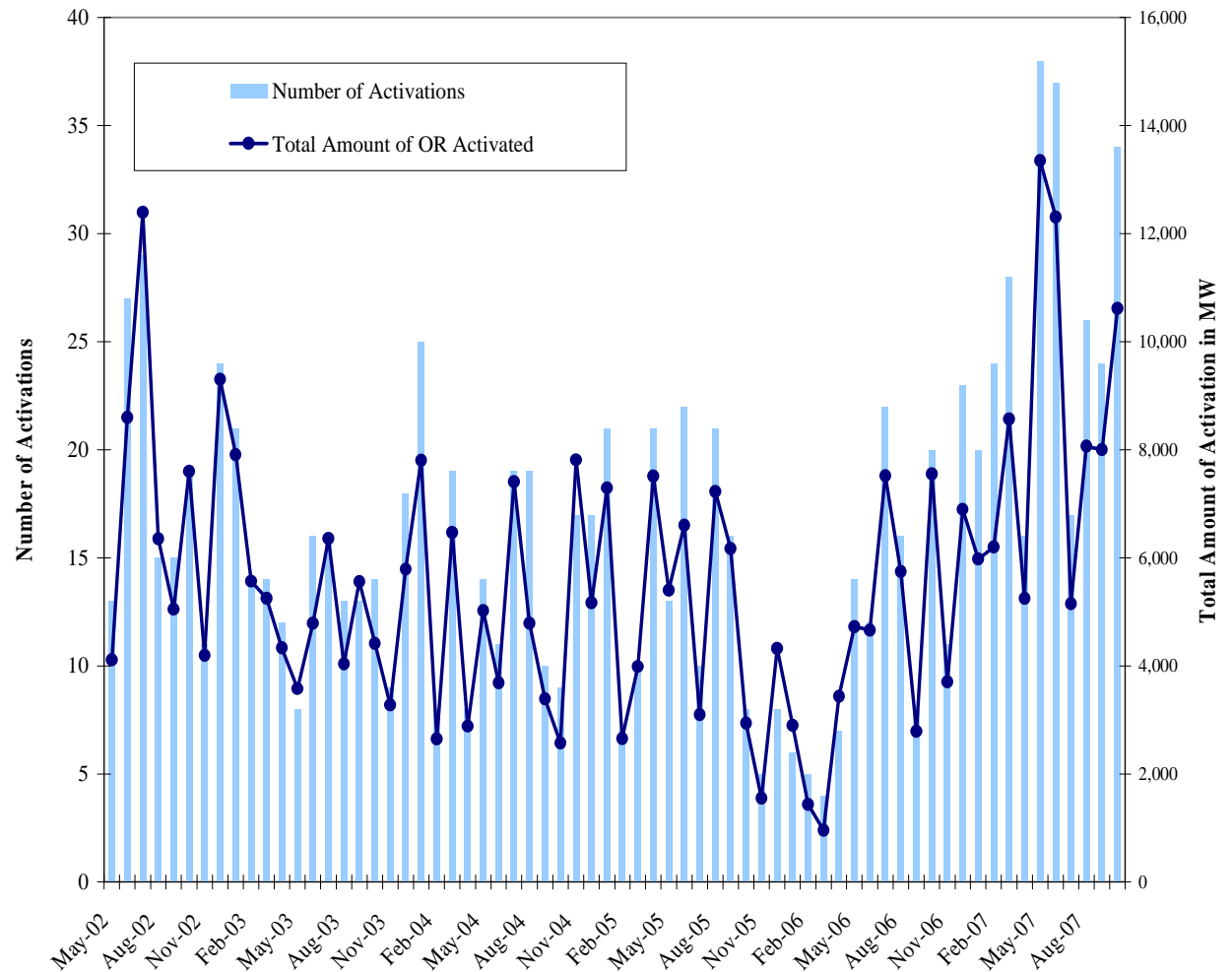
- Effective price to consumers after the Global Adjustments and OPG Rebate is higher by \$1.20/MWh (2.3 percent)
- Upward pressure on the effective price is due to increased OPA uplifts. Panel has recommended more transparency on the OPA programs generating uplifts

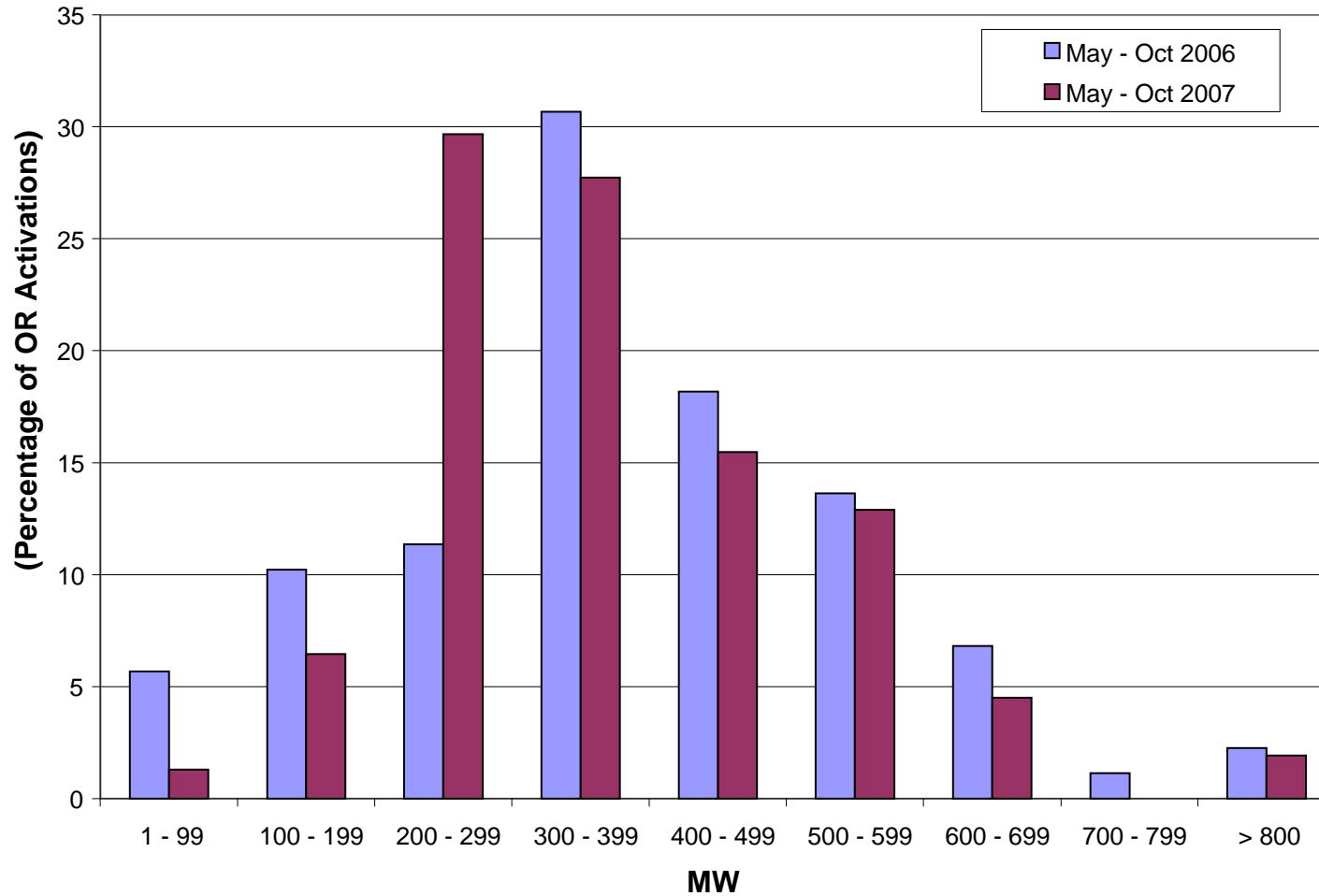


- OR prices continue to fall
- Off-peak OR prices fell by 50 percent over all categories compared to summer 2006
- On-peak OR prices declined in May and increased in June



- Frequency and magnitude of OR activations reached record highs during the 2007 summer month
- Increase in lower MW activations and decrease in higher MW activations





- Coal-fired generators continue to set the MCP most frequently in Ontario
- Small observed shift from Coal to Oil/Gas
 - higher demand and/or a lower baseload generation supply in August, September, and October 2007

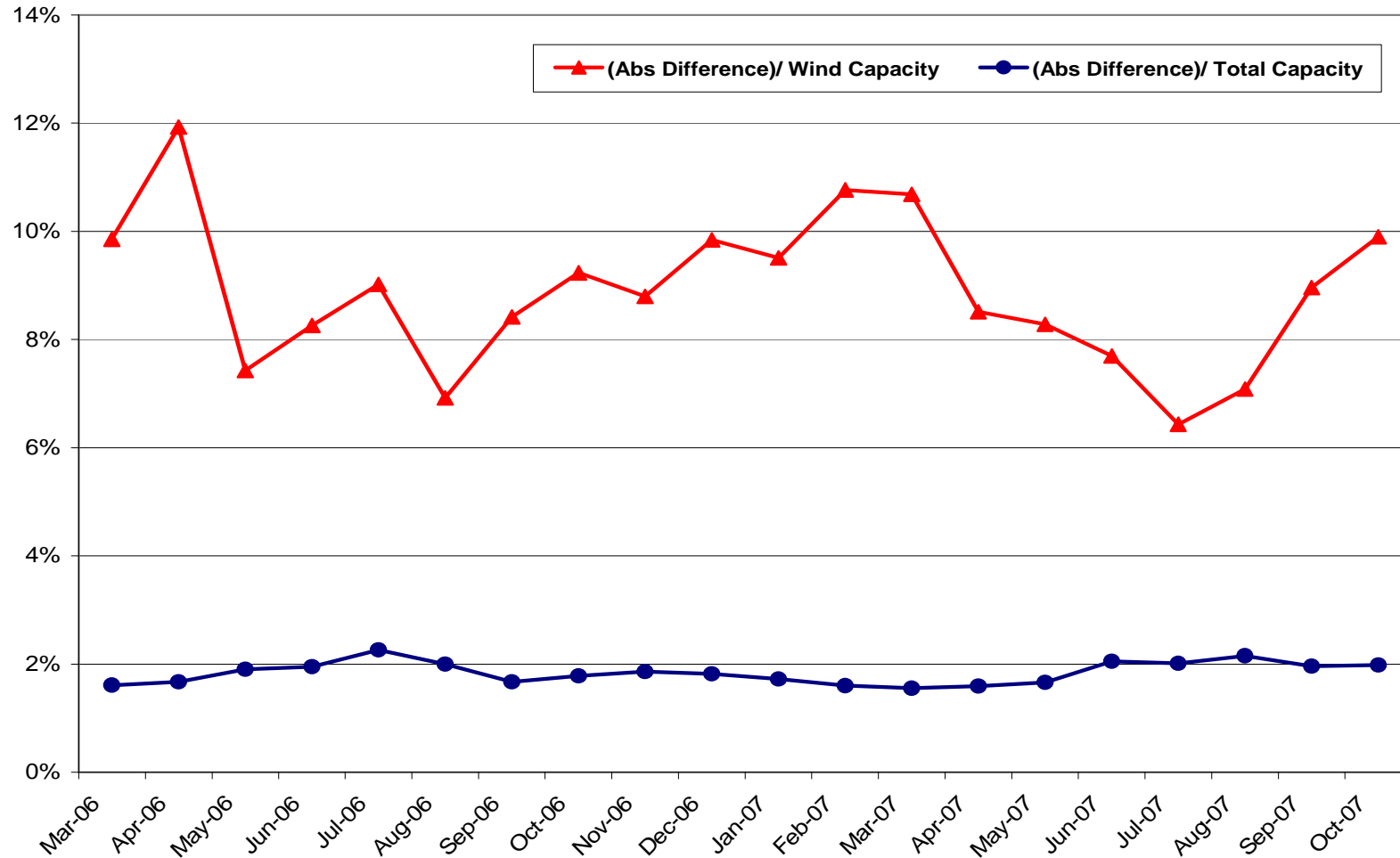
	May – Oct 2006	May – Oct 2007	Difference
Coal	59	54	(5)
Nuclear	0	0	0
Oil/Gas	20	24	4
Hydro	21	22	1

- Average difference between one and three-hour ahead pre-dispatch prices and HOEP similar to last summer
- As a percentage of HOEP:
 - 4% higher for one-hour ahead, and;
 - 6% higher for three-hour ahead vs. HOEP

Factors that lead to discrepancies between pre-dispatch and real-time prices include:

1. Demand forecast error;
2. Performance of self-schedulers and intermittent generators;
3. Failure of scheduled imports and exports; and
4. Frequency that imports set the pre-dispatch price.

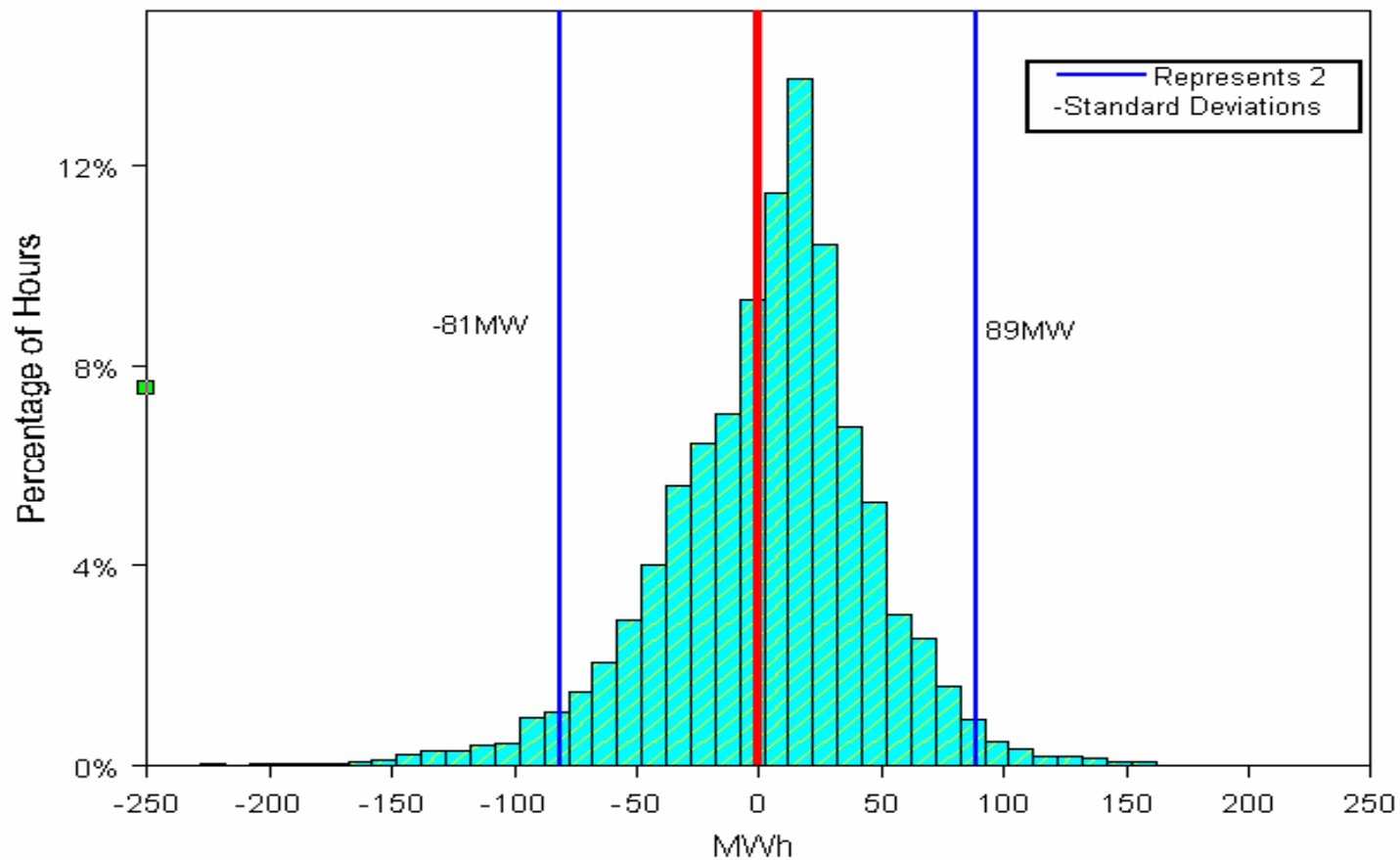
One Hour Ahead Demand Forecast Error (Wind vs. Total Demand) *(% of Capacity)*



Wind Generation Forecast Error Distribution

One-hour Ahead Pre-dispatch vs. Real-time,
(May – October 2007)

- Forecast error on 400 MW of wind capacity



Recommendation 1-1:

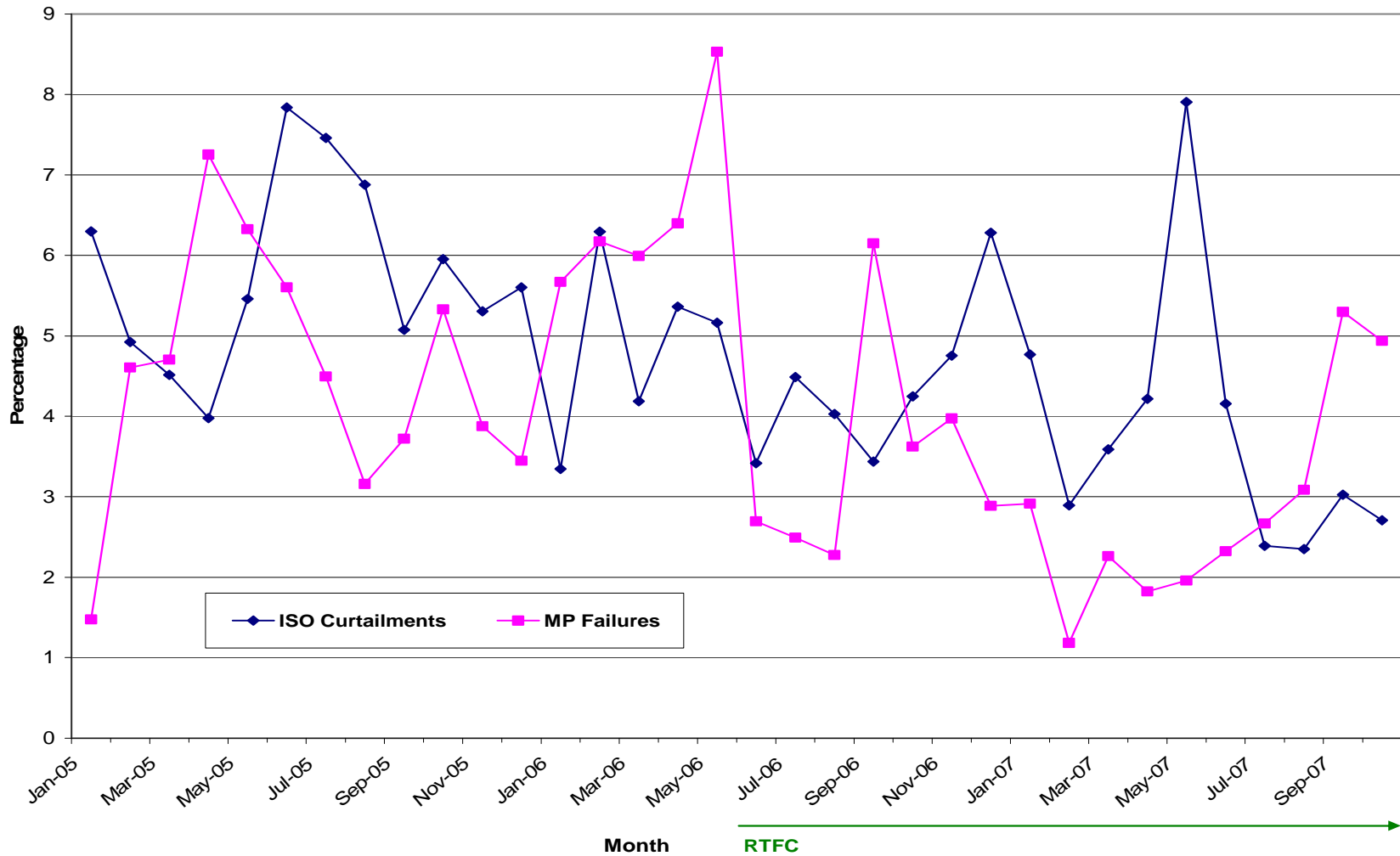
The Panel encourages the IESO to continue to review the forecasting process with wind generators and determine methods to reduce forecast errors. Such generators should have incentives (positive or negative) to encourage accurate forecasting.

Import and Export Failures

- Import and export failures lead to errors between pre-dispatch and real-time prices
- Import failure rate increased by 4 percent compared to same period one year ago.
- Export failure rate declined from 7.9 percent to 6.7 percent.
- Implementation of the Intertie Failure Charge (IFC) in June 2006 appears to have had an impact of the number of export failures

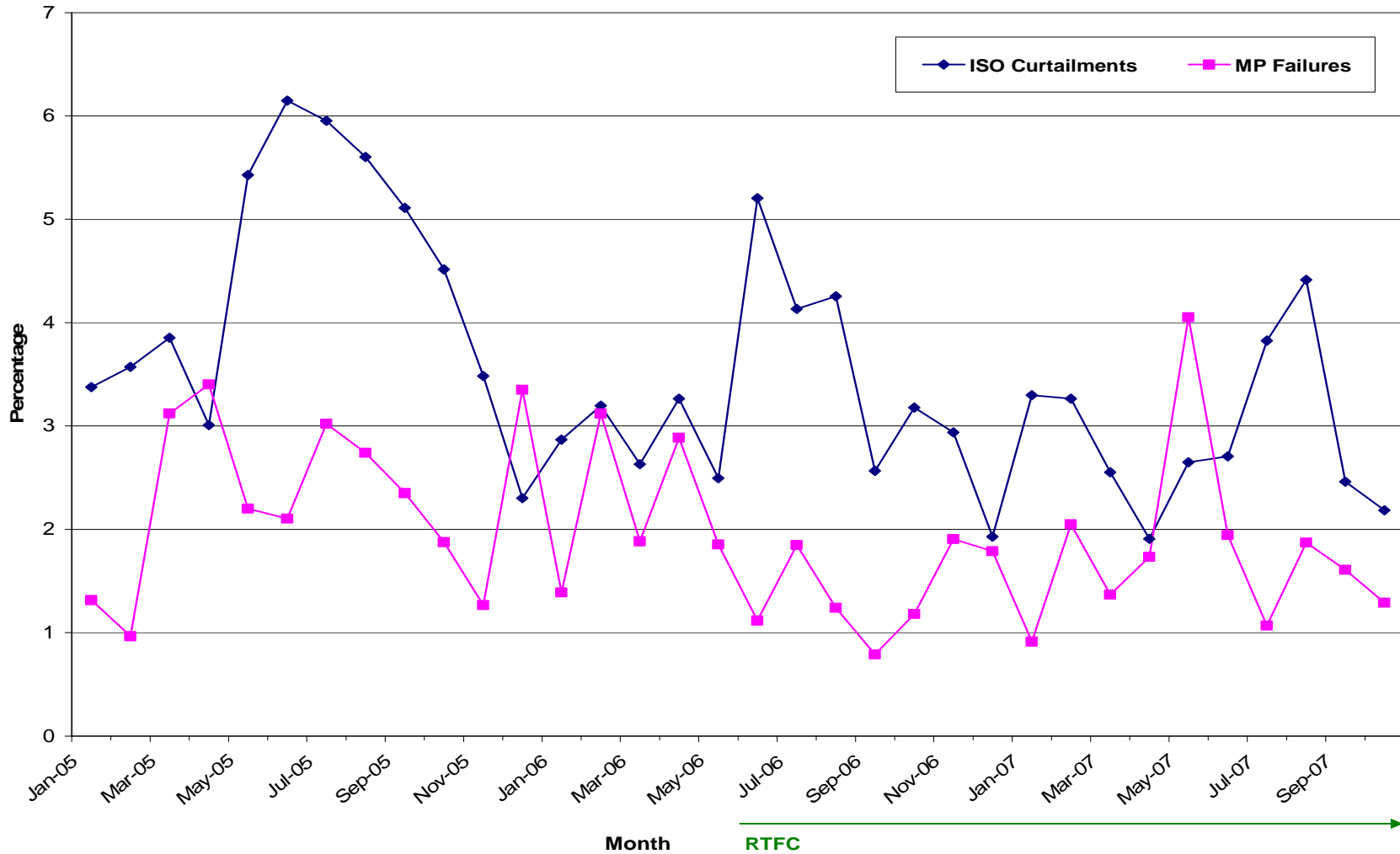
Monthly Export Failures as a % of Total Exports

(January 2005 - October 2007)



Monthly Import Failures as a % of Total Imports

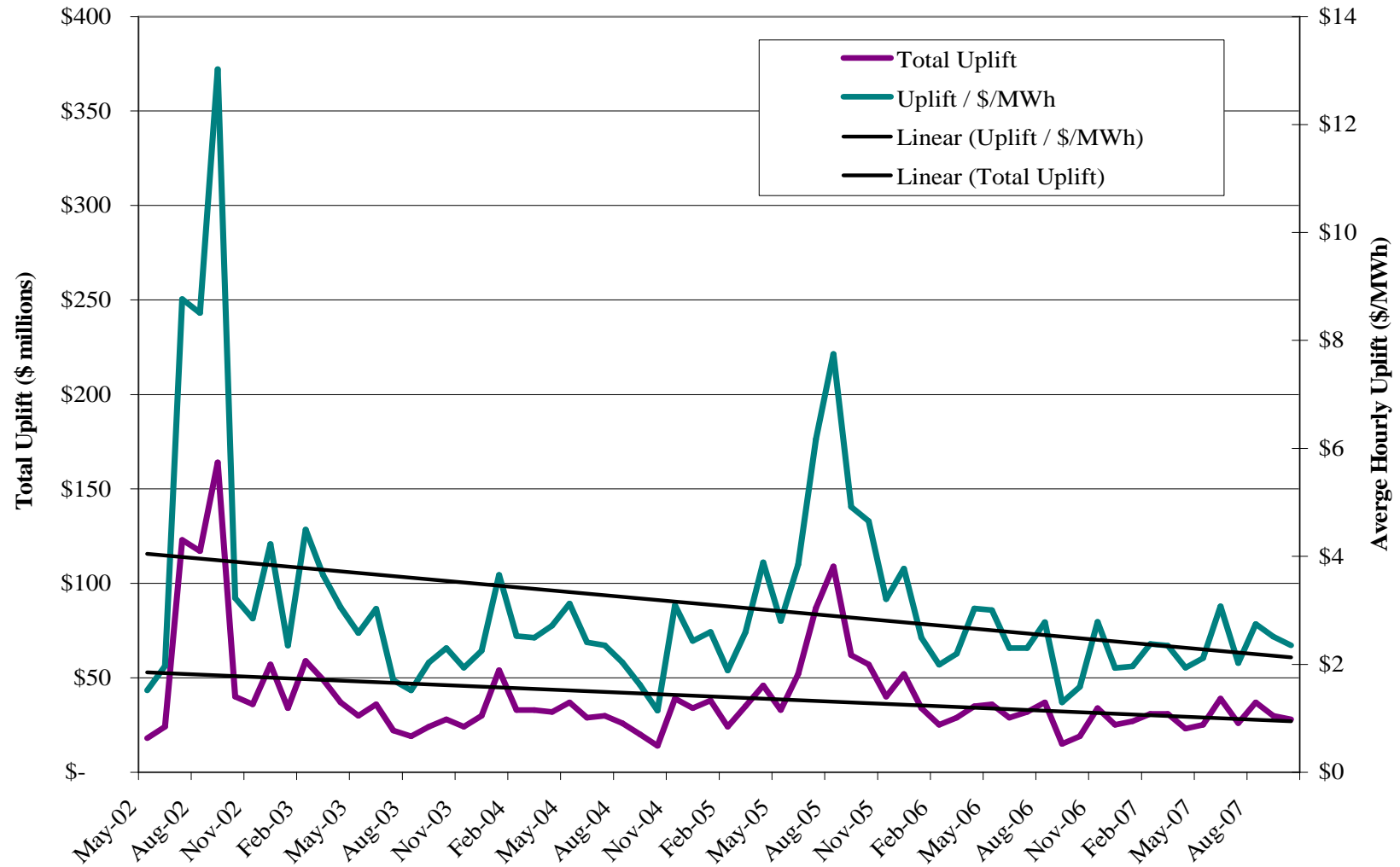
(January 2005 - October 2007)



- Lower incidents of imports setting the pre-dispatch price, the less of a tendency for real-time prices to fall.
- Imports set the pre-dispatch price 46 hours less frequently than in the 2006 summer months (one percent decline).

- The components of uplift include:
 - IOG payments (Day-ahead and Real-time)
 - CMSC payments
 - Operating Reserve payments, and
 - Losses
- Total Uplift reported in \$ while Hourly Uplift is in \$/MWh
- Total Uplift charges lower than same period last year
 - \$167 million in 2006 and \$183 million in 2007
- Increase primarily due to a \$10 million increase in CMSC payments and a \$5 million increase in DA-IOG payments.

Uplift Charges since Market Opening

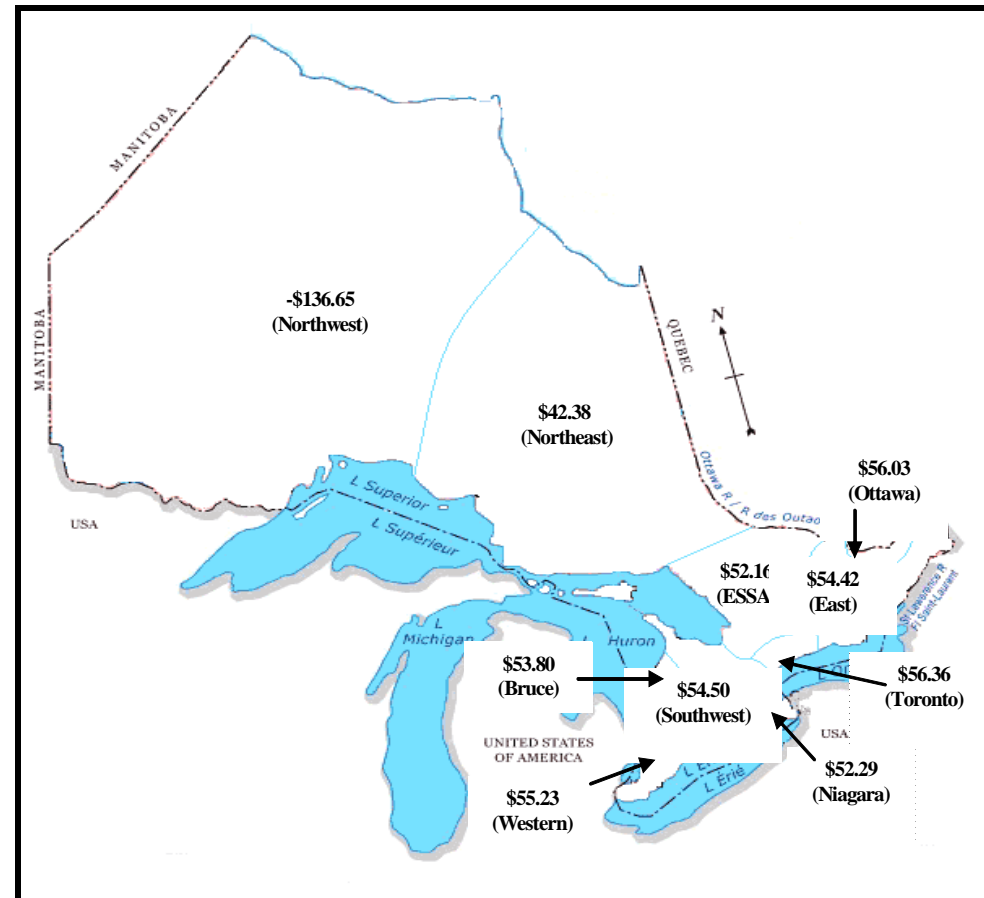


Average Zonal Prices

(May – October 2007)

(\$/MWh)

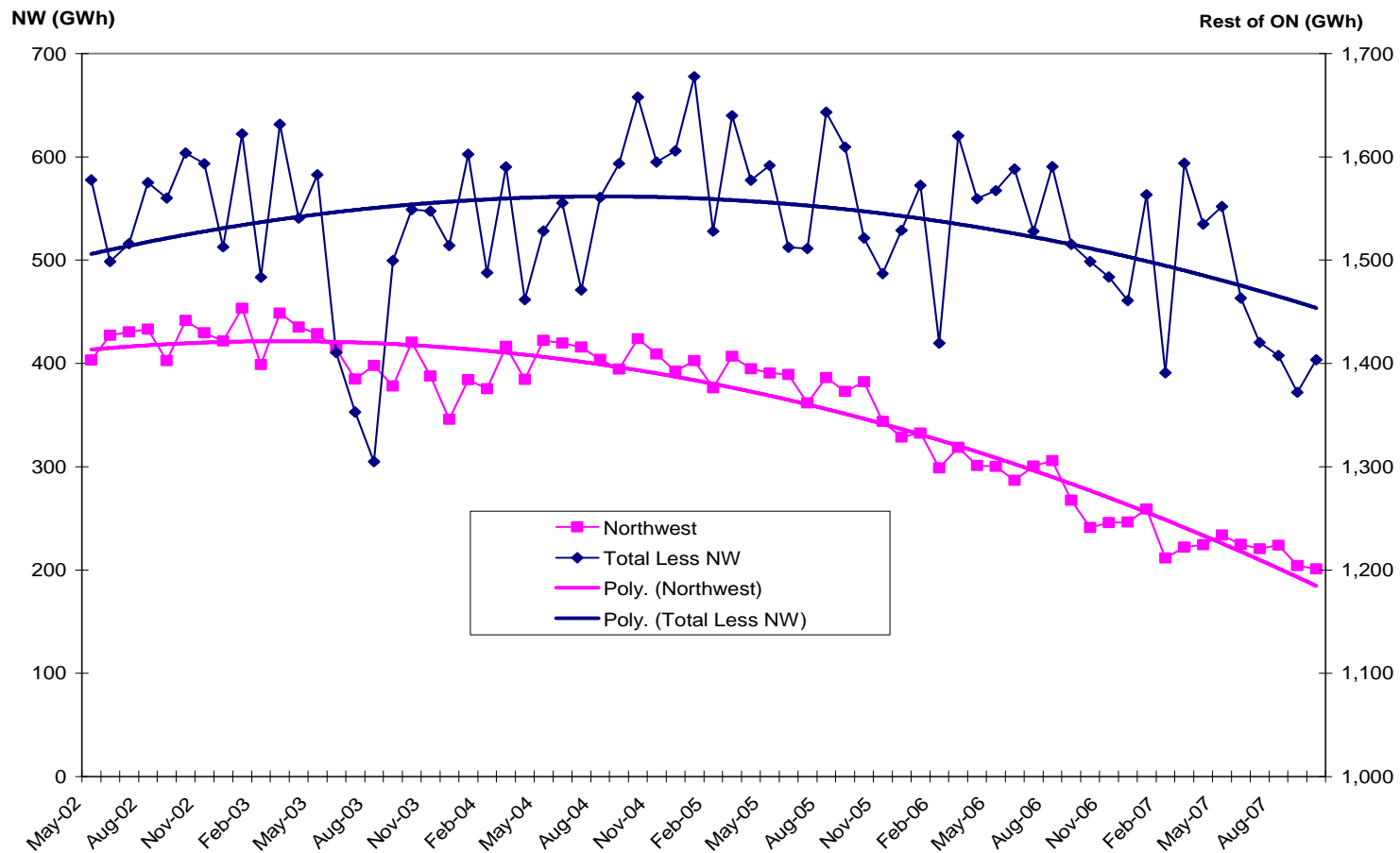
- Shadow prices in the Northwest averaged minus \$136/MWh
 - Abundant Hydroelectric Energy
 - Low Northwest Demand
- CMSC paid in the Northwest for constrained-off supply increased by over \$10 million to \$22.9 million



- Ontario demand virtually fell by less than 1 percent this summer compared to 2006
 - Ontario Demand declined 7.5 percent in July (5 percent decline in Market Demand) due to cooler weather

	Ontario Demand*			Total Market Demand		
	2006	2007	% Change	2006	2007	% Change
May	11.99	11.83	(1.3)	13.19	12.91	(2.1)
June	12.59	12.69	0.8	13.50	13.74	1.8
July	13.89	12.85	(7.5)	14.92	14.15	(5.2)
August	13.32	13.47	1.1	14.53	14.60	0.5
September	11.58	11.95	3.2	12.41	12.88	3.8
October	11.99	11.92	(0.6)	12.97	12.85	(0.9)
Total	75.36	74.71	(0.9)	81.52	81.13	(0.5)
Average	12.57	12.45	(0.9)	13.59	13.52	(0.5)

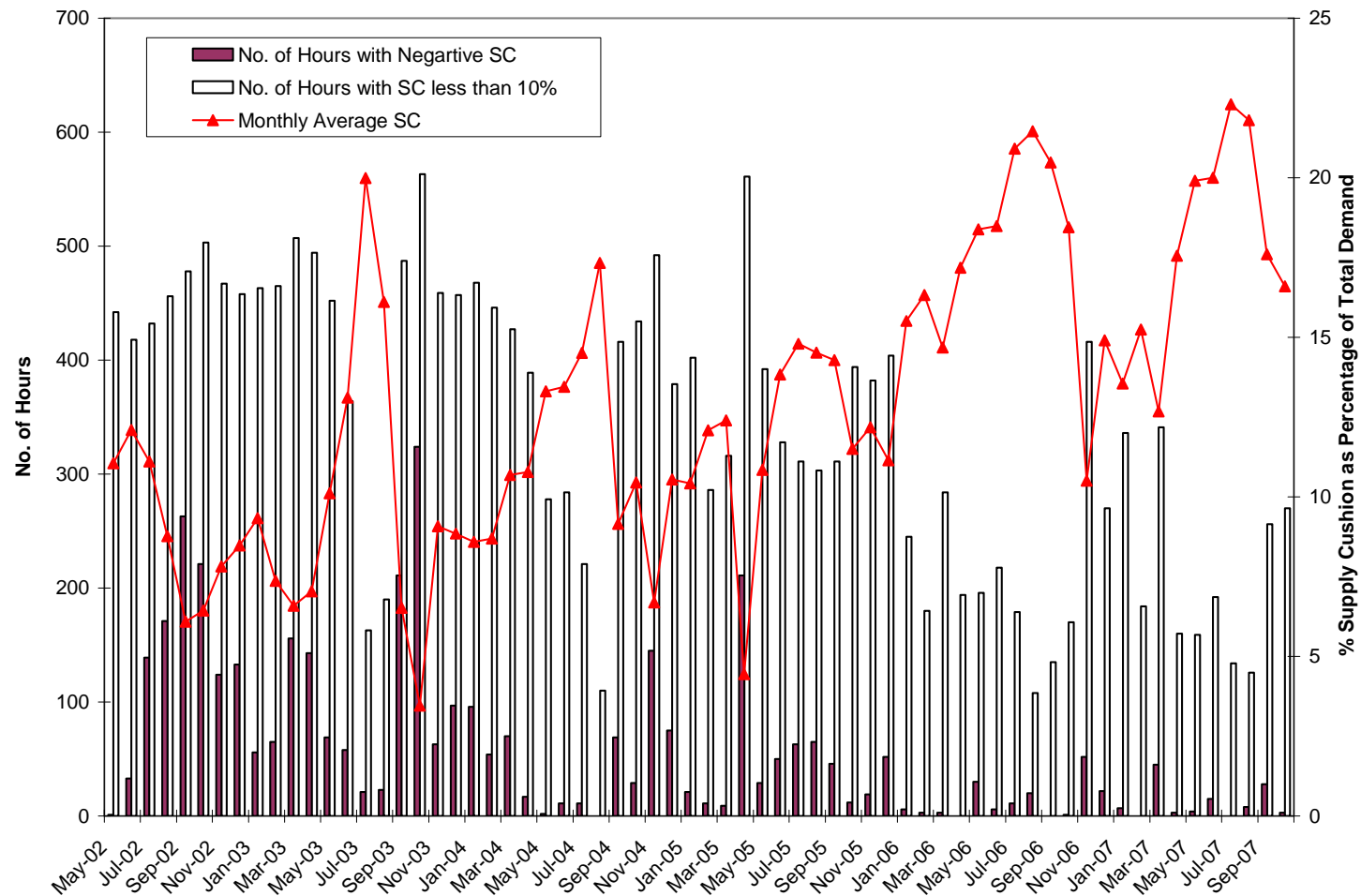
- Wholesale load has fallen by approximately 30 percent since January 2005, mainly due to declining Northwest wholesale load



- Supply cushion represents the amount of excess supply available for dispatch in a given hour
- Average pre-dispatch domestic supply cushion increased 2.3 percent
 - increased in all months except October
 - decline in negative hours and hours less than 10%
- Average real-time domestic supply cushion remained unchanged at 19.7 percent
 - 22.3 percent in July 2007 (record high)

Average Real-time Domestic Supply Cushion

May 2002 – October 2007

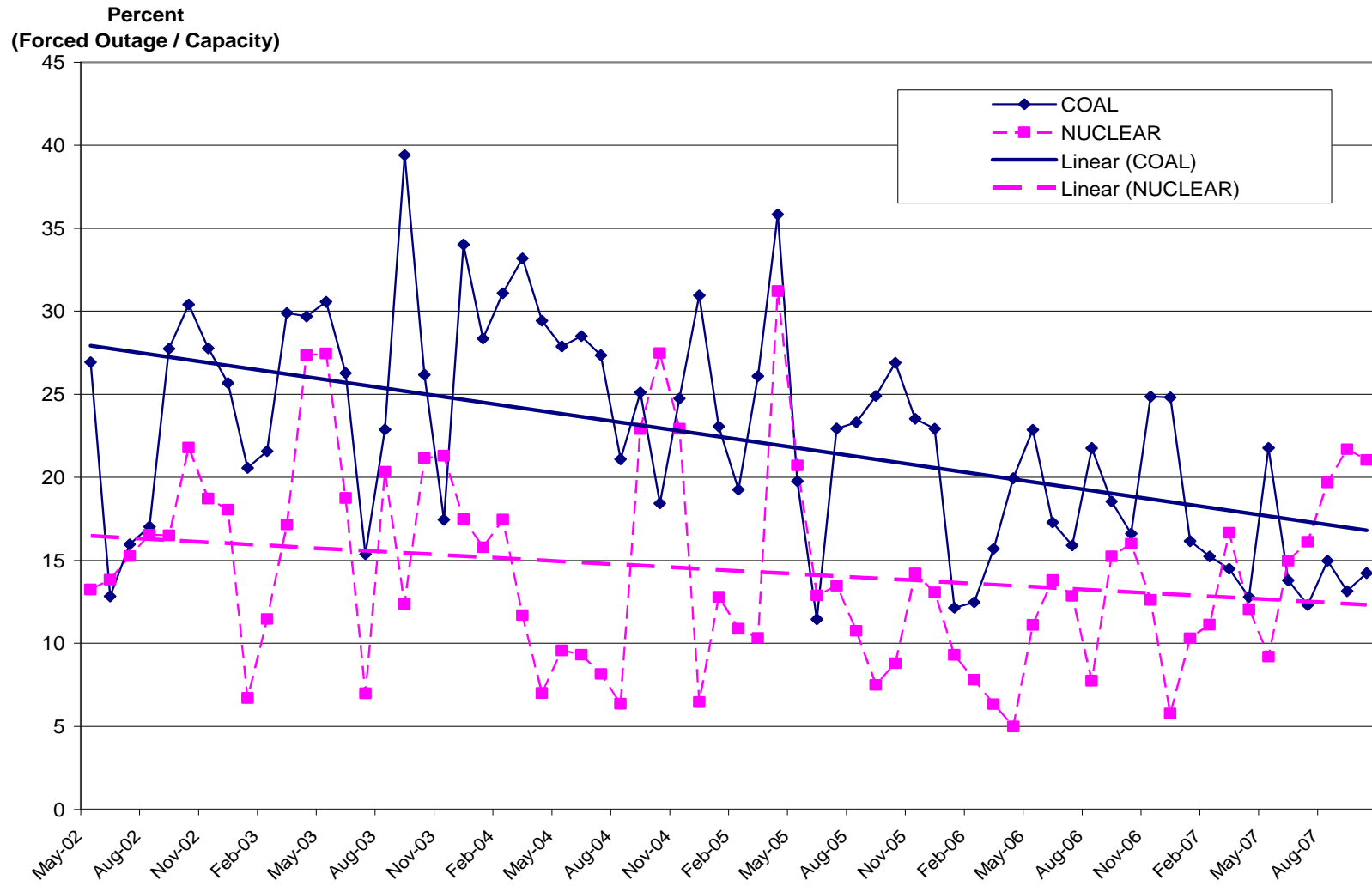




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Forced Outages Relative to Total Capacity

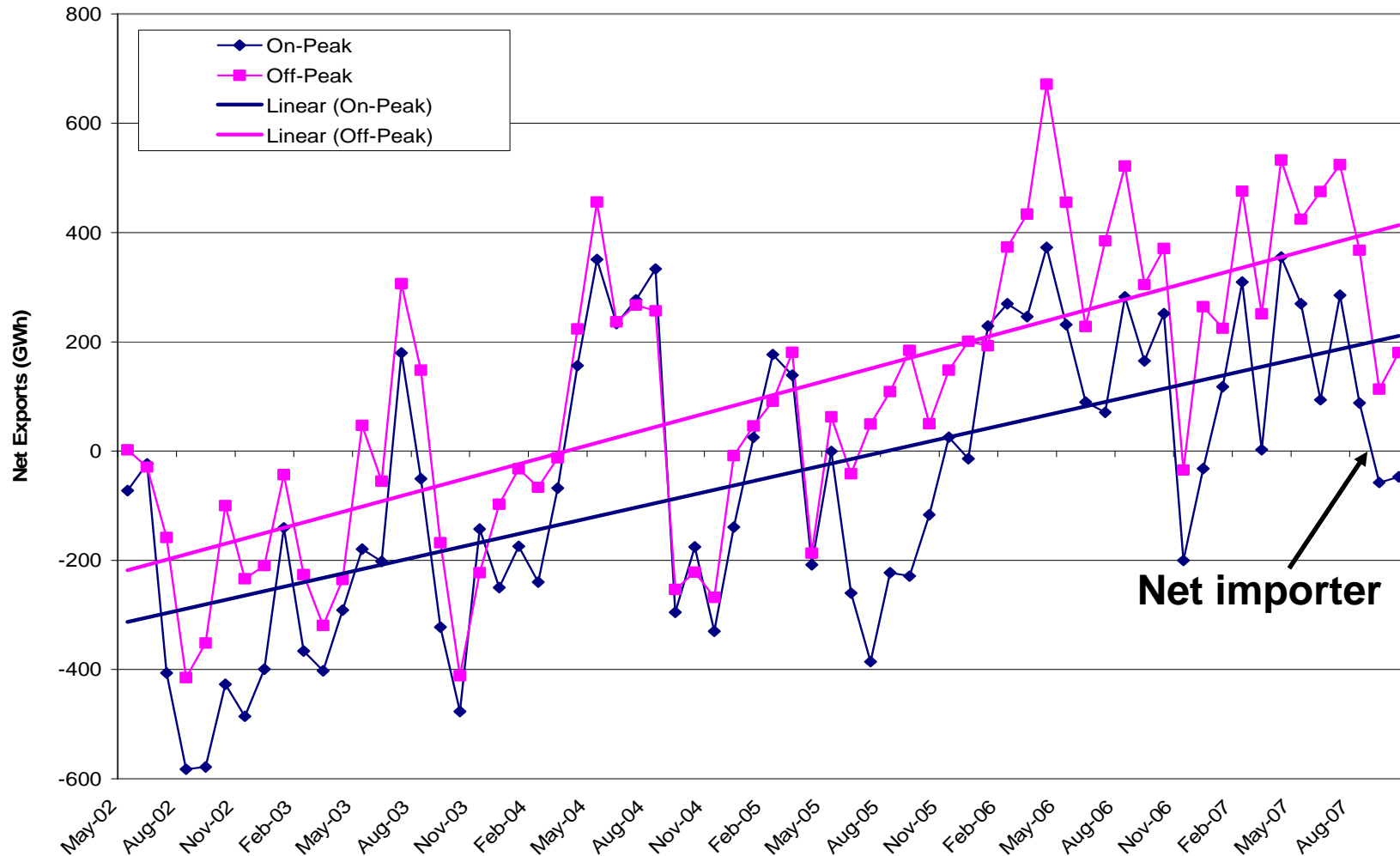
May 2002 – October 2007 (%)



- Observed declines in fuel prices influenced by strengthening of Canadian dollar relative to U.S. dollar

	Coal Price (NYMEX OTC Central Appalachian)			Natural Gas Price (Henry Hub Spot)		
	2006	2007	% increase	2006	2007	% increase
May	2.36	2.00	(15.3)	6.92	8.39	21.2
June	2.32	2.07	(10.8)	6.94	7.82	12.7
July	2.18	1.93	(11.5)	6.91	6.54	(5.4)
August	2.22	1.90	(14.4)	8.03	6.64	(17.3)
September	2.12	1.88	(11.3)	5.62	5.61	(0.2)
October	2.02	1.89	(6.4)	6.66	6.56	(1.5)
Average	2.20	1.95	(11.7)	6.85	6.93	1.2

- Exports increased by 240 GWh (4 percent)
- Imports increased by 880 GWh (31 percent)
- Ontario was a net exporter for all months during the summer months of 2007
 - Net exports totaled 2.7 TWh, down 19 percent from the summer of 2006
 - Net importer during the on-peak hours in September and October 2007



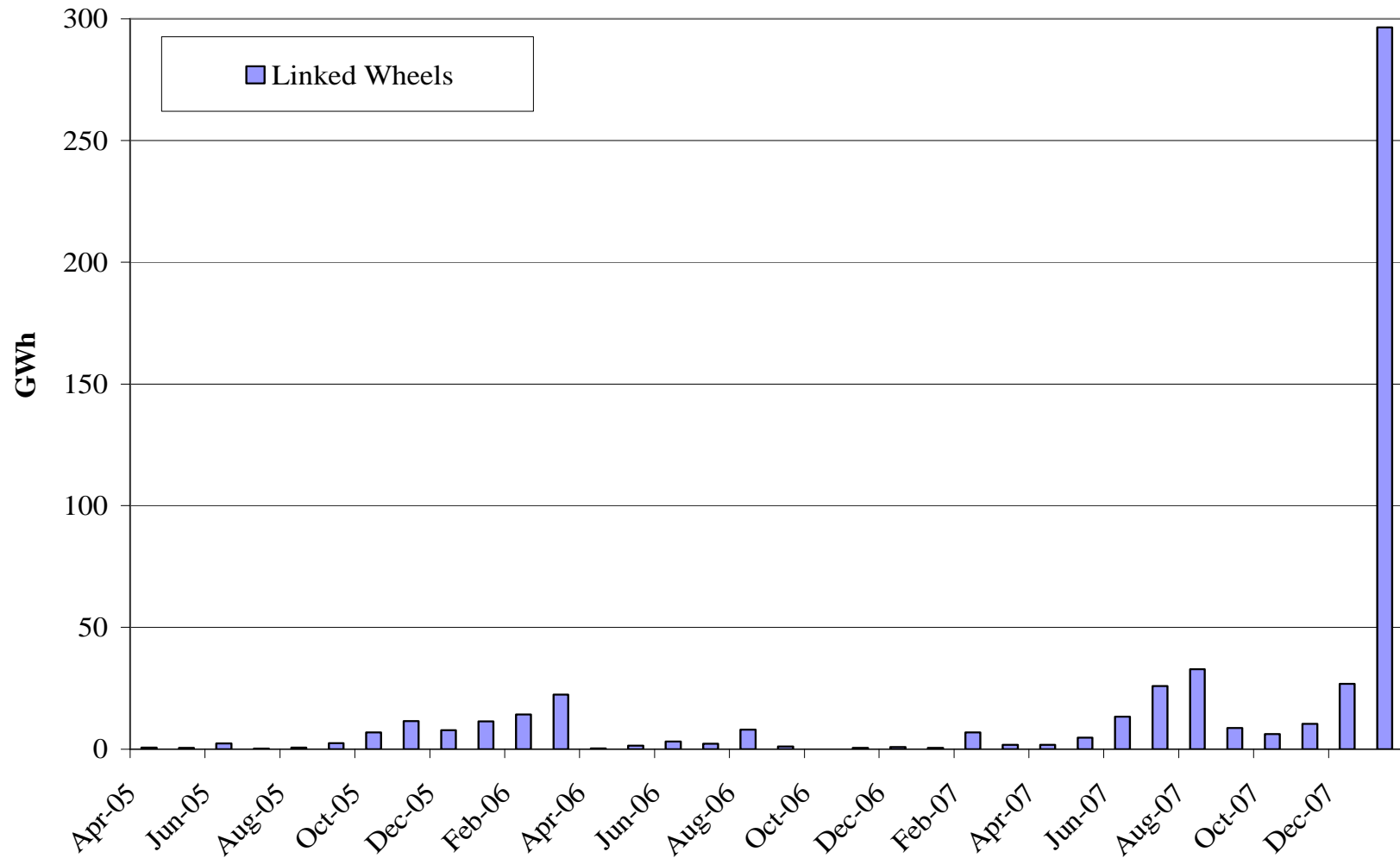
Wholesale Electricity Prices in Neighbouring Markets

- On average, market prices in Ontario are the lowest of neighbouring markets during the 2007 summer months

	Off-Peak	On-peak	Total
Ontario (HOEP)	33.82	59.51	45.66
MISO	36.27	68.64	50.95
New England	57.26	75.90	65.72
New York	40.86	67.81	53.12
PJM	51.13	84.61	66.02
Average	43.87	71.29	56.29

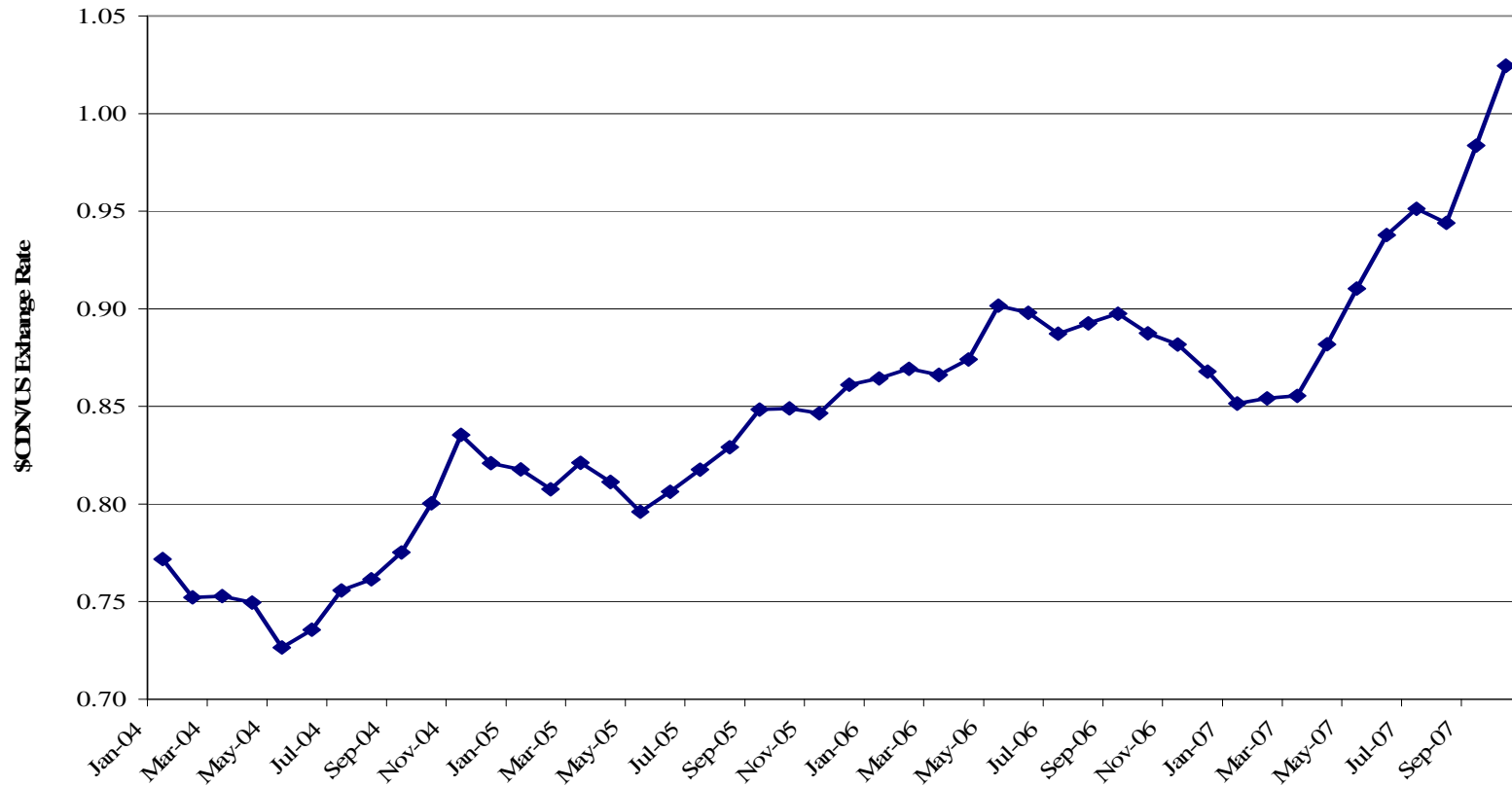
Linked Wheel-through Transactions (GWh)

(April 2006 – January 2007)



Exchange Rates and Trade Flows

- Substantial appreciation in the Canadian dollar relative to the US dollar
 - Exchange rate increased by 13 percent since May 2007 and 20 percent since January 2007



- Two effects to consider:
 1. Direct impact on traders transacting between two jurisdictions with different currencies
 - Creates arbitrage opportunities
 2. Indirect impact of fuel prices in Ontario relative to the US energy markets
 - Appreciating CDN dollar lowers fuel prices relative to US generators
- Therefore, exchange rate has two offsetting effects:
 1. Increases the US cost of purchasing Ontario energy
 2. reduces the Ontario market prices relative to the US markets because the fuel costs are lower, theoretically by the same amount, all else held constant.

Chapter 2: Analysis of Market Outcomes

Andy He
MAU, IESO



- In this chapter, we discuss:
 - High priced hours ($> \$200/\text{MWh}$): 4 hours
 - Low prices hours ($< \$20/\text{MWh}$): 331 hours
 - Uplift greater than HOEP: 3 hours
 - Other anomalous events such IESO's control actions, participants' behaviours, market design flaws, etc.
 - Event of June 12, 2007

- *June 8 HE12: \$205 (vs. \$73 in PD)*
 - PD condition
 - 3.4% of supply cushion, Indicating a very steep offer curve above \$73
 - 320MW net exports
 - RT condition
 - 126MW imports from Michigan failed
 - A coal-fired unit was derated by 85MW
 - Peak demand was 533MW heavier than the PD forecast
 - RT supply cushion dropped to -0.9%
 - Assessment
 - Demand underforecast and failed imports were the main causes
 - No inappropriate behaviour by participants

Chapter 2: High-priced Hours (con't)

- *June 12 HE15: \$436 (vs. \$105 in PD)*
 - PD condition
 - 3.1% of supply cushion, Indicating a very steep offer curve above \$105
 - 332MW net imports
 - RT condition
 - 146MW imports from Quebec failed
 - A gas-fired unit was derated by 507MW from interval 6 on
 - Peak demand was 869MW heavier than the PD forecast
 - RT supply cushion dropped to -2.4%
 - Assessment
 - Demand was persistent underforecast on the day
 - The derating of the fossil unit was the last straw

Chapter 2: High-priced Hours (con't)

- *July 17 HE10: \$271 (vs. \$60 in PD)*
 - PD condition
 - 6.6% of supply cushion
 - 2,109MW net exports
 - RT condition
 - Three fossil-fired units were derated by 360MW
 - One fossil-fired unit failed to start up due to incorrect offers
 - Peak demand was 440MW heavier than PD forecast
 - RT supply cushion dropped to -0.5%
 - Assessment
 - The deratings at the three fossil units were legitimate
 - Demand underforecast and the deratings were the causes.

Chapter 2: High-priced Hours (con't)

- *October 24 HE18: \$297 (vs. \$60 in PD)*
 - PD condition
 - 5.5% of supply cushion
 - 23MW net imports
 - RT condition
 - Peak demand only 60MW heavier than PD forecast
 - 100MW from Michigan failed
 - RT supply cushion dropped to -2.2%
 - Assessment
 - Primarily driven by an error in the offers of a generator
 - wrong bid status
 - 523MW was scheduled in PD but 0 available in RT
 - Compliance is assessing the causes
 - Had the offers been removed correctly, the RT would have been \$82 as a result of a 377MW increase in net import

- IESO used all available manual actions
 - Export curtailment
 - Emergency energy
 - Dispatchable load curtailment
 - OR activation
 - 5% voltage reduction
- Primary cause: the temperature was significantly underforecast day ahead and revisions were too little and too late (up to 1,600MW underforecast day ahead and 600MW one hour ahead)
- Other factors
 - A forced outage on D501P (loss of 800MW hydro)
 - Lowered import capability on B31L due to Quebec reliability
 - High LEC leading to QFW congested

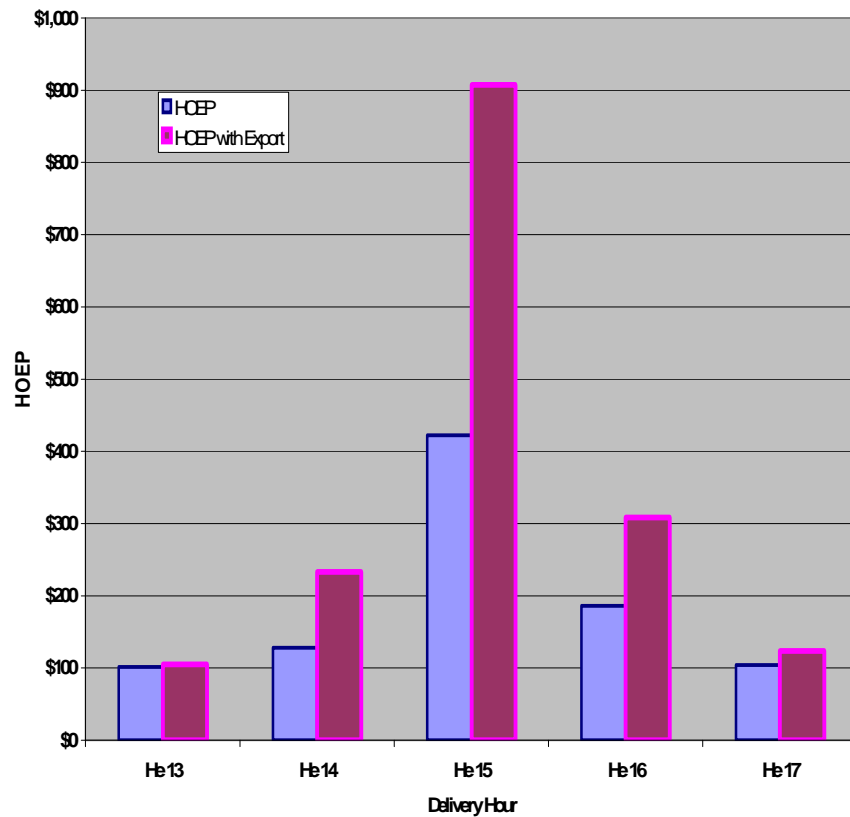
- The Panel comments
 - The reduction in the OR requirement as a result of OR activation distorted the price signal (re-enforcing *Recommendation 2-1* in the July 2007 report)

– Recommendation 2-1

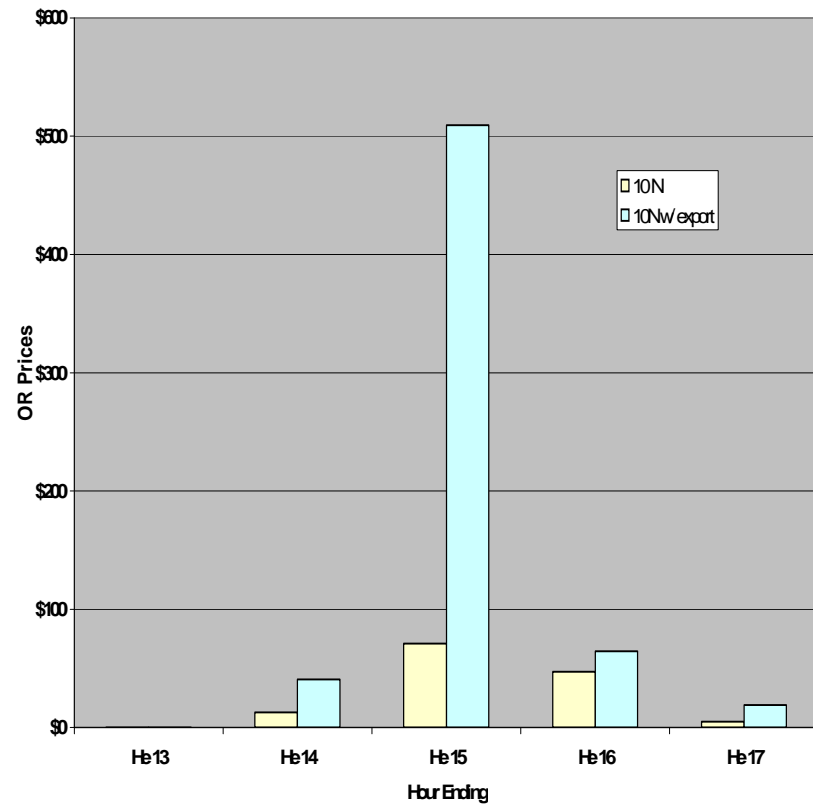
- *Export curtailment due to 'adequacy' has an effect of suppressing the market price during times of serious scarcity since the curtailed amount is removed from the market schedule, thus distorting the market price signal. The Panel recommends that the IESO not remove the curtailed amount due to 'adequacy' from the market schedule.*
- It should be noted that in cases where exports need to be curtailed due to internal transmission issues (TLRi), these MW's are left in the market schedule and presently **do** impact the HOEP.

Chapter 2: Event of June 12, 07 (con't)

June 12th Simulated HOEP with Export Remaining in the USchedule



June 12th 10N Reserve



Chapter 2: Event of June 12, 07 (con't)

	Export Failure for Adequacy (MWh), 2006- 2007
24-Jun-06	200
31-Jul-06	564
20-Nov-06	461
19-Dec-06	150
12-Jun-07	1,053
21-Jun-07	150
29-Jun-07	514
29-Aug-07	400
06-Sep-07	2
08-Oct-07	710
04-Nov-07	250
02-Dec-07	276
31-Jan-08	450
01-Feb-08	787
Total	5,967

- Three hours
 - May 12, 2007 HE3 (\$6.36 vs. HOEP \$5.72)
 - Sep. 16, 2007 HE3 (\$1.08 vs. HOEP \$0.39)
 - Sep. 18, 2007 HE1 (\$2.12 vs. HOEP -\$0.40)
- All events were due to a very low HOEP

- 331 hours with a HOEP < \$20
- One negative HOEP -\$0.40 (September 18, 2007 HE1)
 - Peak demand was 248MW overforecast
 - 731MW failed exports (further suppressed the HOEP in HE2 due to a binding NISL)
 - 140MW more generation from self-scheduling and intermittent generators (118MW from a wind generator, leading to *Recommendation 1-1* in Chapter 1)

Chapter 3 + 4: Matters to Report in the Ontario Electricity Marketplace

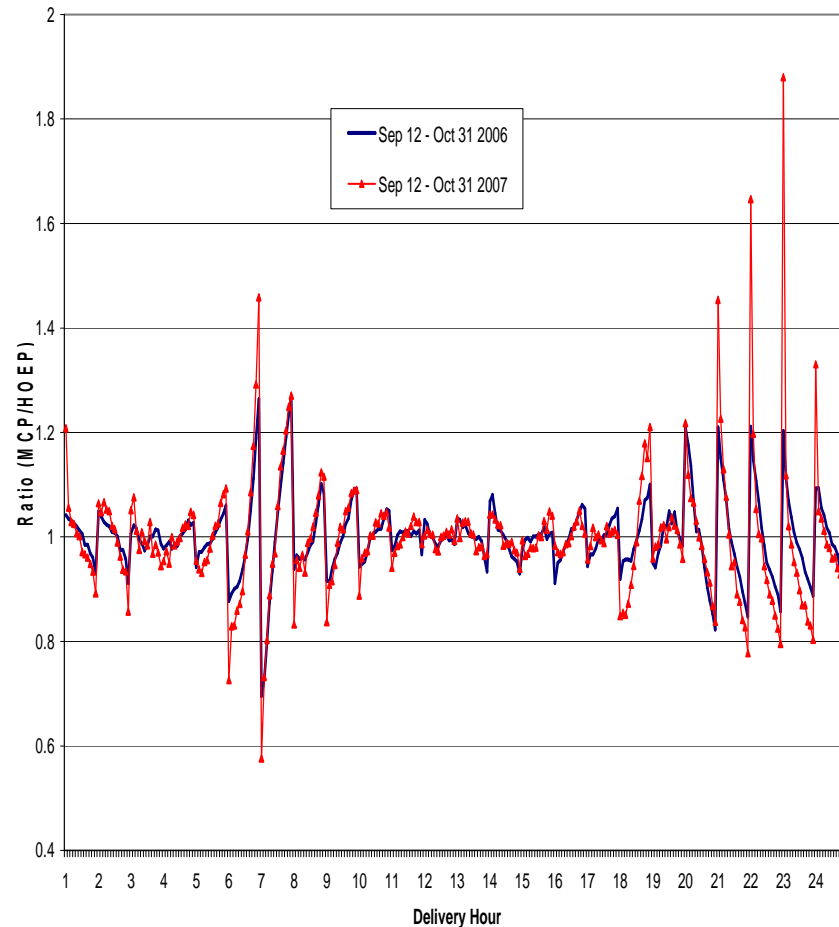
Richard Penn
MAU, IESO



- In this chapter, we discuss:
 - 3X Ramp rate Observations
 - convergence of the Richview (nodal) price with the HOEP
 - the Lambton phase shifter (PARs) issue that was identified in our December 2005 report.

- Limited observations with only 49 days of data
- MSP has asked MAU to come back and report when more data available
- Price effects seem most apparent in interval 12 and first few intervals of next hour when ramp is most constrained

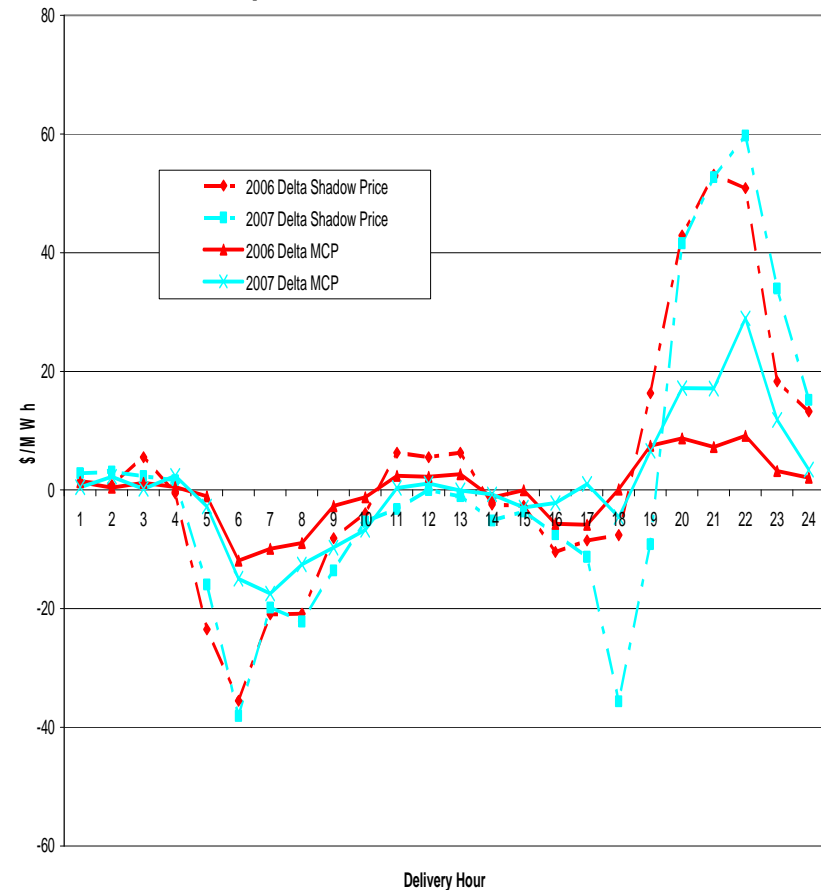
Figure 3-1: Average Interval MCP Relative to Average HOEP by Hour, September 12 to October 31, 2006 and 2007



Chapter 3: 3X Ramp (con't)

- Analysis Comparing MCP to Shadow Price between intervals 12 and 1.
- Delta MCP is more reflective of prices seen in the Constrained Schedule.
- Prices become more intuitive and are more of a reflection of cost.

*Average Changes in Prices
between Intervals 12 and 1,
Unconstrained and Constrained (Richview) Sequences
September 12 - October 31, 2006/2007*



Chapter 3: Convergence of the Average Richview Price and the Average HOEP

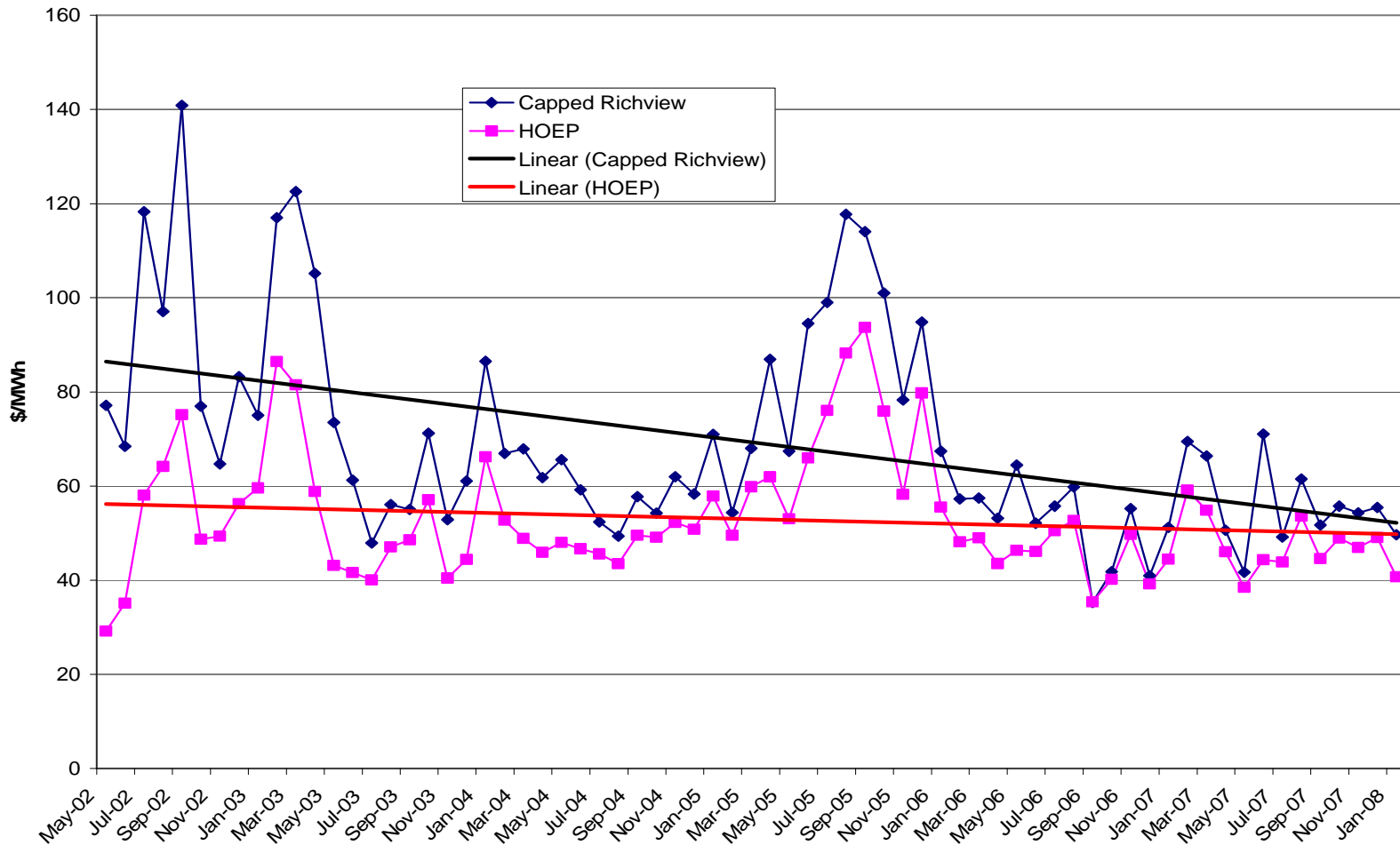
A convergence between the HOEP and the Richview price could be taken to imply that there has been a reduction in the inefficiencies associated with the uniform pricing regime.

Panel undertook to understand what was causing that convergence.

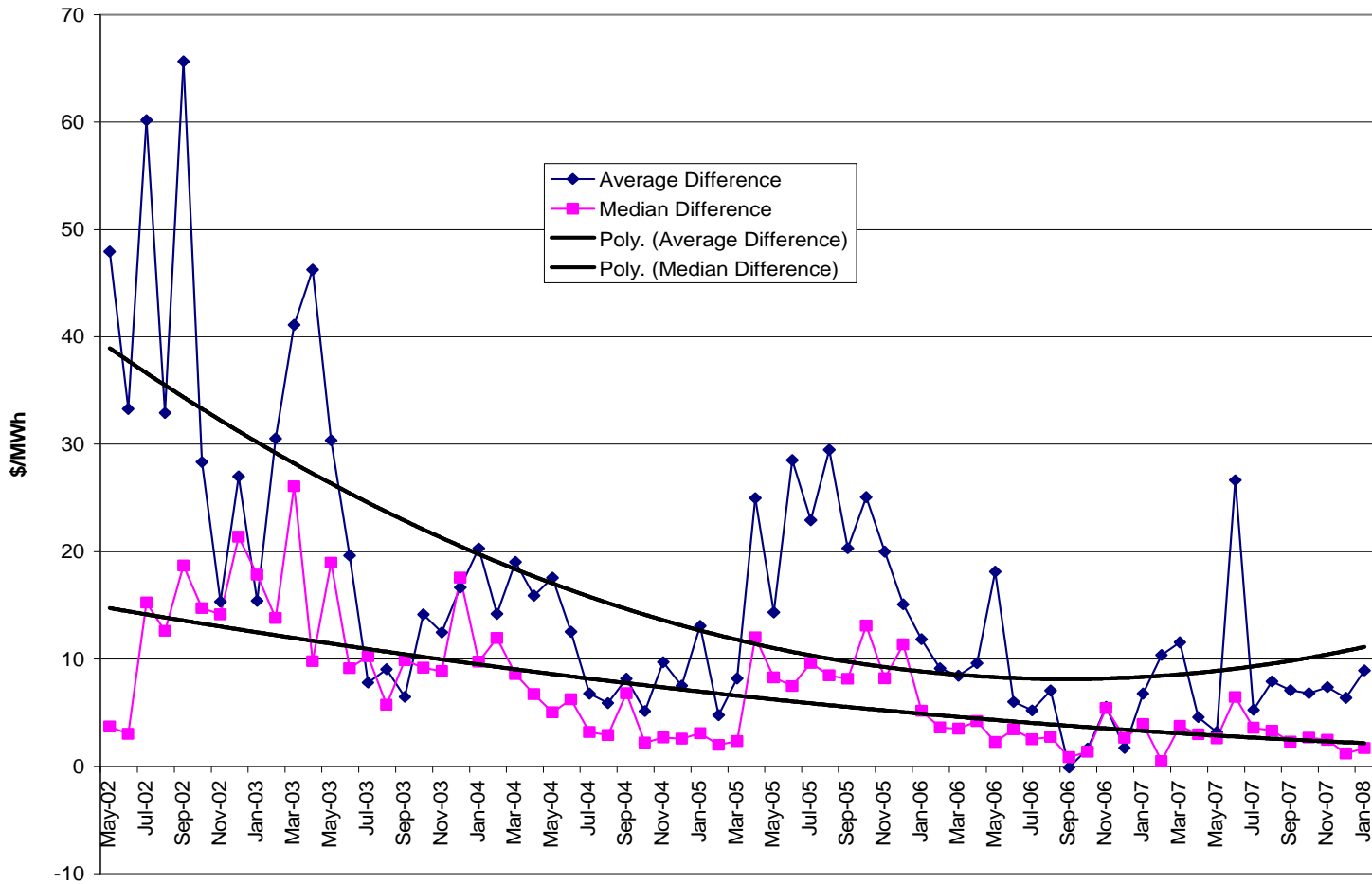
- HOEP approaching Richview implies a gain in efficiency as the efficient price is transparent

- Richview approaching HOEP, may imply biases in the Richview price and convergence may not imply efficiency.

Chapter 3: Convergence of the Average Richview Price and the Average HOEP



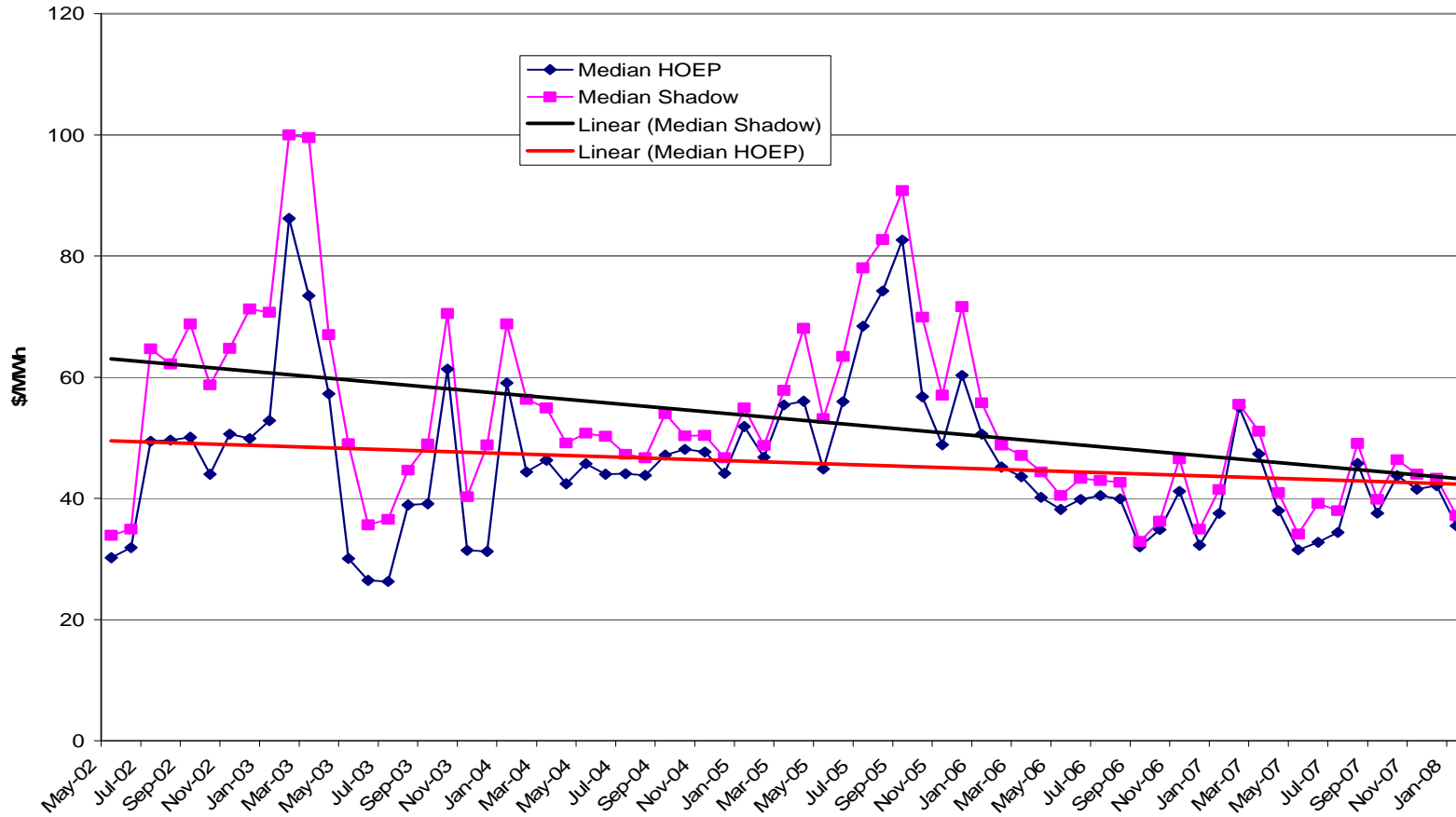
Chapter 3: Comparison of Convergence difference of the Median and Average





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Chapter 3: Convergence of the Median Richview Price and Median HOEP



Chapter 3: Convergence of the Average Richview Price and the Average HOEP

Factors considered included:

- Transmission congestion from the northwest;
- Demand forecast error;
- Manually constrained on generation;
- Constrained off (net) exports; and
- Changes in the real-time supply cushion

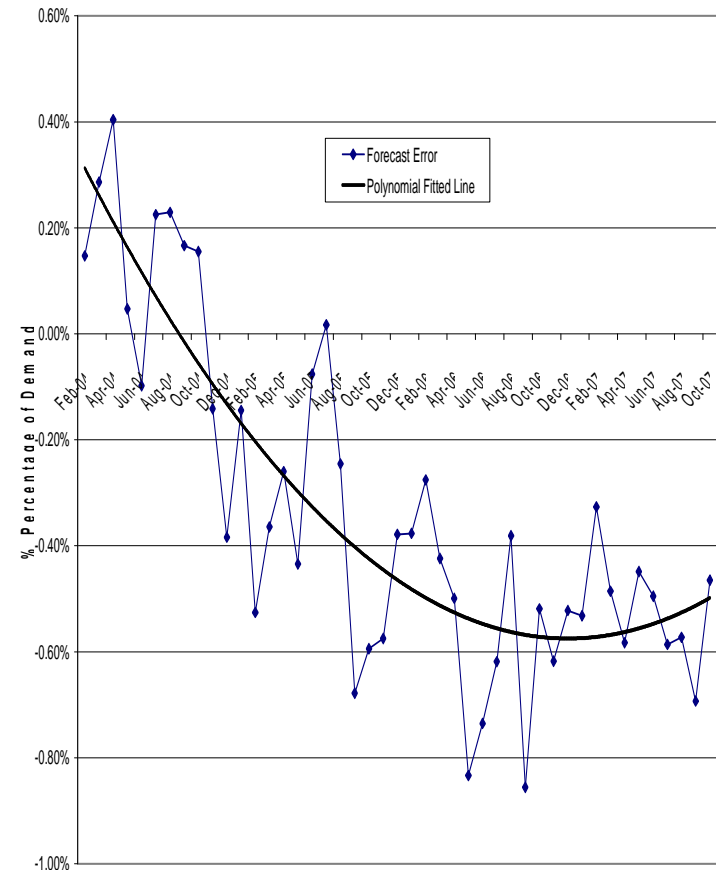
Chapter 3: Convergence – Demand Forecast Error

- Constrained Demand has been persistently under forecasted since early 2005
- Consumption deviation of dispatchable load can be a source of forecast error

Recommendation 3-1:
Consistent with prior recommendations directed at improving the IESO load predictor, whose algorithm imputes changes in non-dispatchable load that can induce consumption inefficiency and forecast errors, the Panel recommends that the IESO review its load predictor methodology to determine if it is a source of persistent under-forecasting of demand

Demand Forecast Error,

February 2004–October 2007

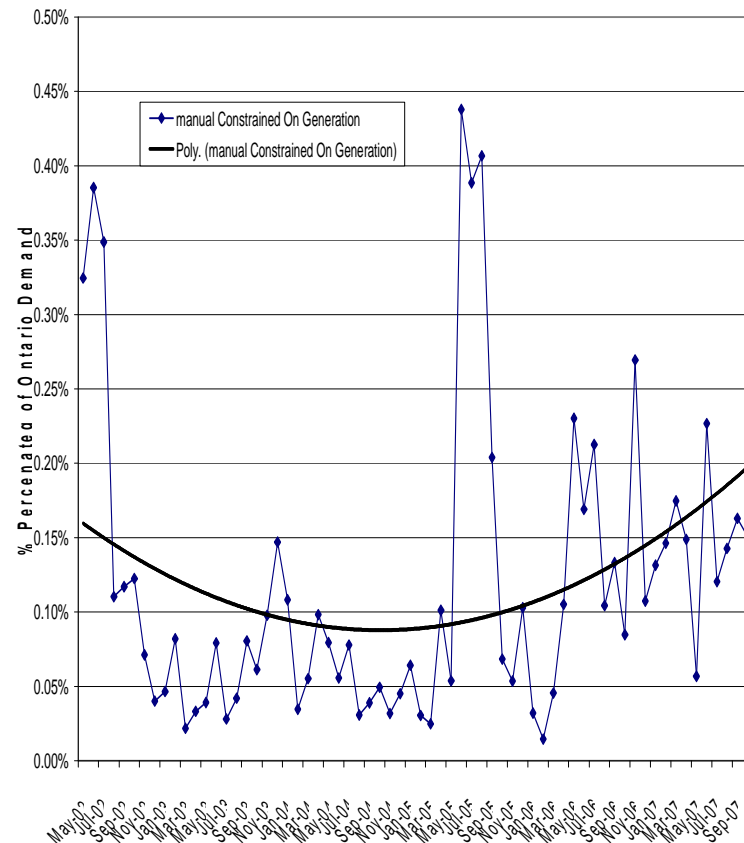


Chapter 3: Convergence – Manually Constraining on Generation

- Manually Constrained On generation is increasing
- Tendency to suppress the Richview price as a result
- May be due to the Physical Characteristics of the Generation
- MSP has in the past recommended 24 hour optimisation to reduce necessity for manual constraints

**Manually Constrained on Energy
Relative to the Ontario Demand,**

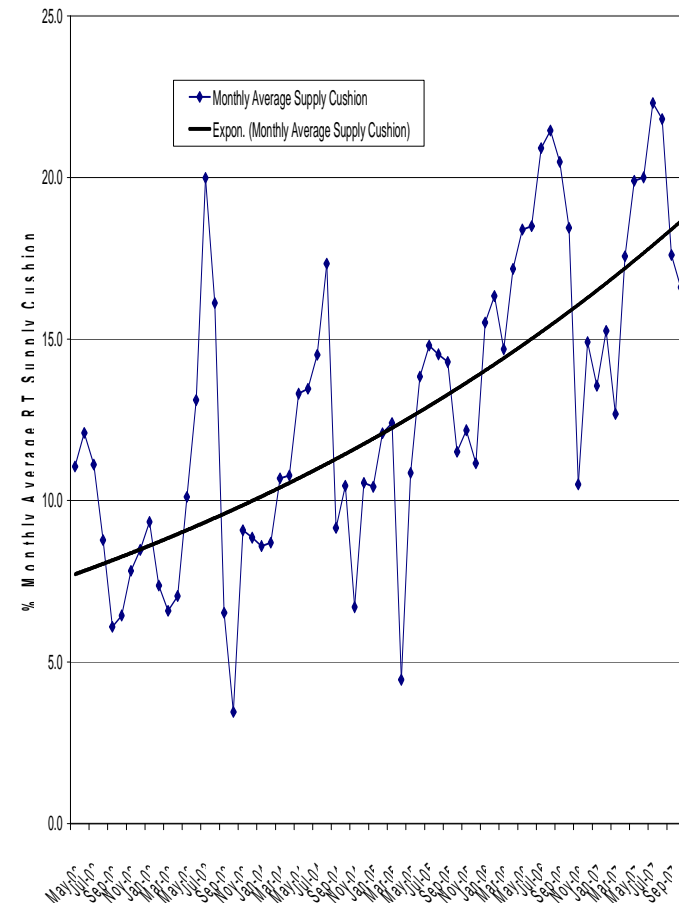
May 2002–October 2007



Chapter 3: Convergence – Increase in Domestic Supply Cushion

- Domestic Supply Cushion is increasing
- When there is a disturbance, to smooth price spikes in both sequences
- Tendency is proportionally greater smoothing in the Constrained sequence due to Transmission Constraints
- Would reduce the Gap between the sequences

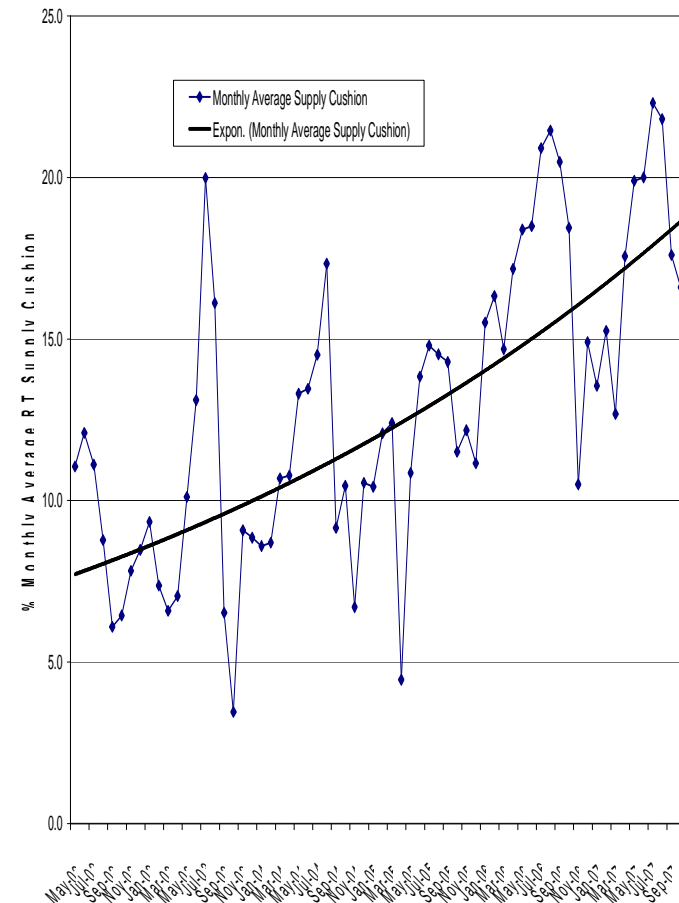
Average Monthly Real-Time Domestic Supply Cushion, May 2002-October 2007



Chapter 3: Convergence – Increase in Domestic Supply Cushion

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Average Monthly Real-Time Domestic Supply Cushion, May 2002-October 2007



Chapter 3: Inefficient Demand Response Event

- Illustration of an Inefficient Demand Response event

Panel Reminder

Incentive programmes that induce customers to curtail consumption at times when the value they derive from the service is greater than the incremental cost of providing do not conserve resources in the true sense of the word.”^[1]

^[1] See our December 2006 report at page 140.

*Prices, Implied Value, and Efficiency Loss
November 7, 2007*

	3 hr ahead price \$/MWh	HOEP \$/MWh	Marginal Cost in North \$/MWh	Contract Price \$/MWh	Implied Value to Consumer \$/MWh	Efficiency Loss to Market \$ thousand	Constrained off to Otter Rapid \$ thousand
18	87.56	54.71	3	80	160	8	3
19	99.29	96.11	3	80	160	8	5
20	83.99	62.96	3	80	160	8	3
21	87.56	48.83	3	80	160	8	2
22	87.56	41.97	3	80	160	8	2
23	83.41	35.66	3	80	160	8	2
Total						48	17

Recommendation 3-2 (Chapter 3 Section 2.5)

- *The IESO should expedite completion of the necessary agreements with Hydro One, the Midwest ISO and ITC Transmission for operation of the phase angle regulators on the Michigan intertie. The IESO (and Hydro One) should also complete necessary staff training as soon as possible. Any improvement on the spring 2008 implementation target would have positive efficiency (as well as reliability) effects on the Ontario (and Midwest ISO) system and any slippage would have the opposite effects.*
- *Hydro One should work towards developing ratings that will safeguard the phase angle regulators and provide operationally useful limited time ratings as soon as possible.*

Recommendation 3-6 (Chapter 3 Section 4.3)

- *It is important for the efficiency of the Ontario electricity market that Hydro One attempt to complete the Queenston flow west transmission expansion as soon as practicable. The ability to fully utilize 'bottled' generation in the Niagara region and maximize economically viable imports with New York (and Michigan) will enhance the efficiency (and reliability) of the Ontario market.*

- A large portion of dispatch issues occur in the first few intervals of the hour. These abrupt changes are causing efficiency problems.

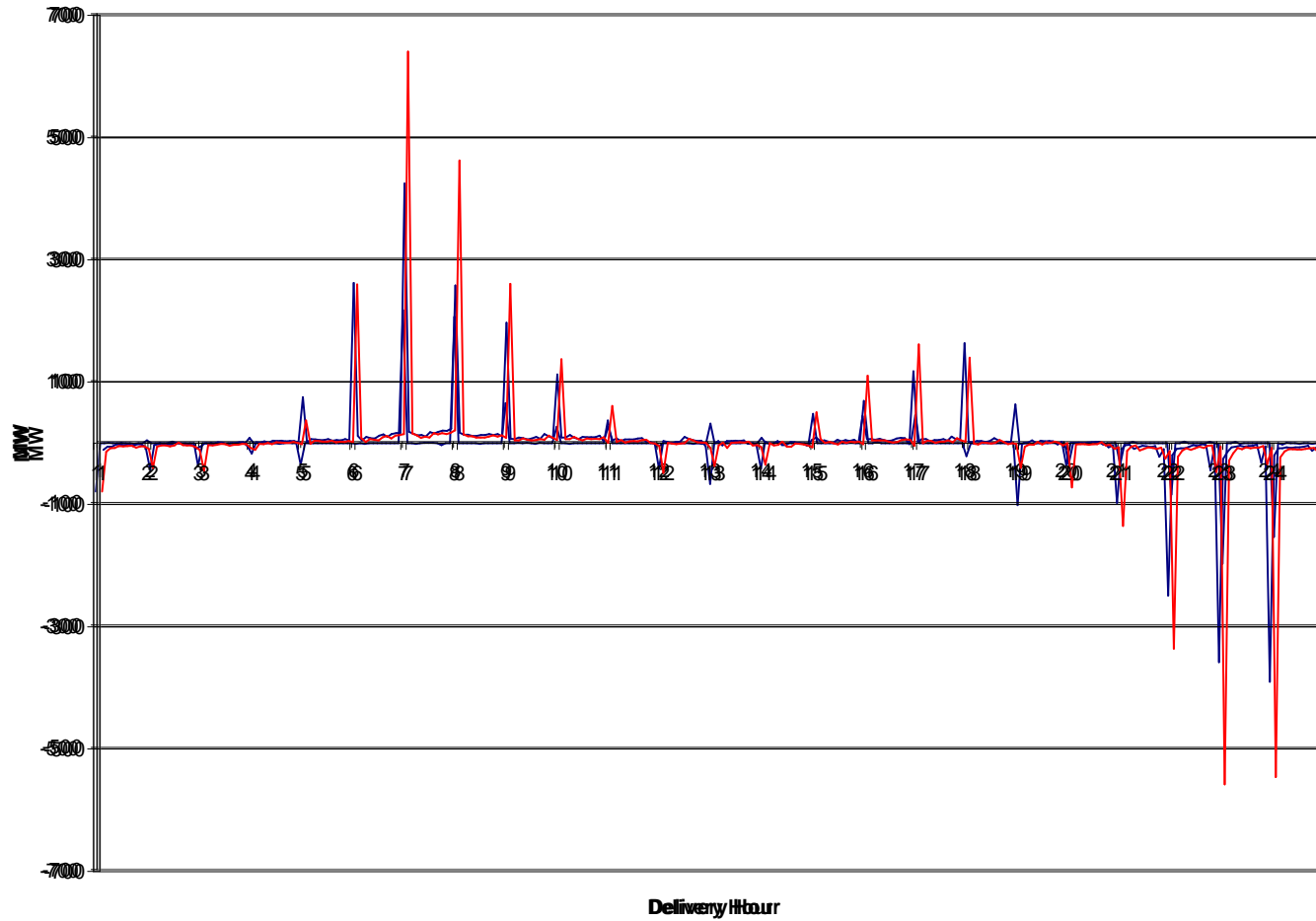
Efficiency opportunities include:

- Better co-ordination with other markets
- Less ramping of fossil generation
- Better ability to co-ordinate hydroelectric and fossil dispatch



Total hydro change hydro plus imports

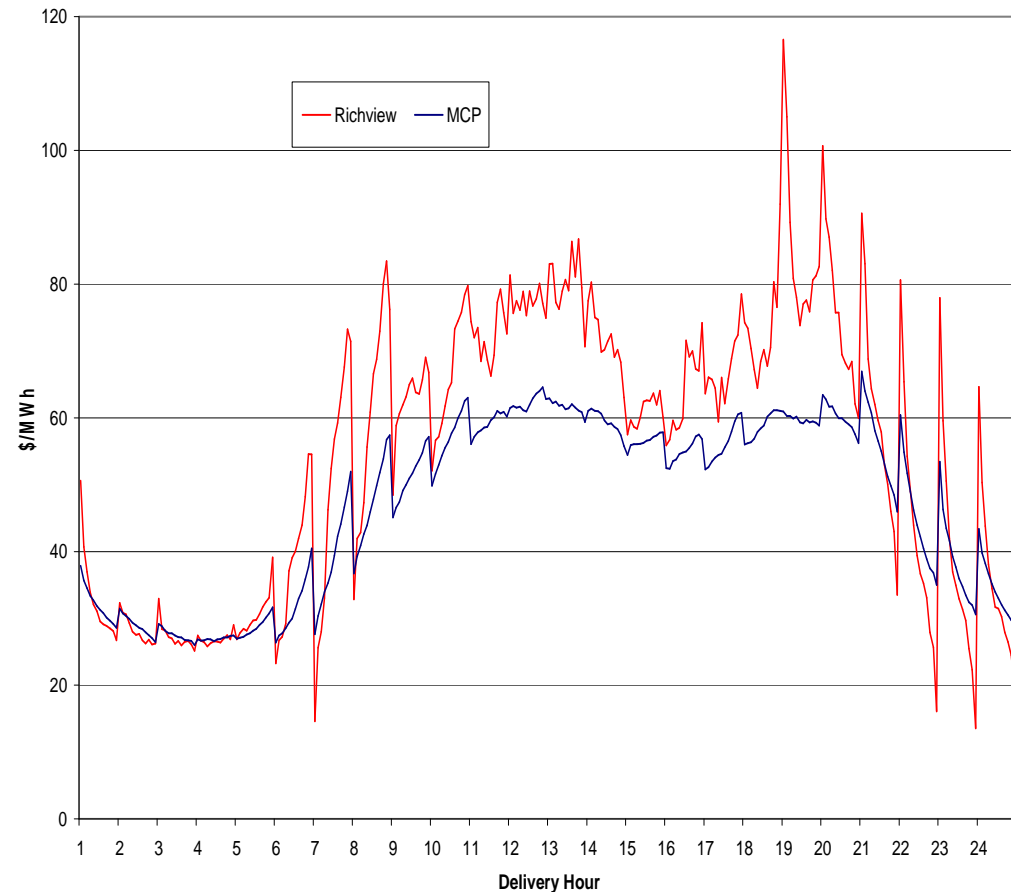
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Average MCP and Richview shadow price by interval, November 2006 - October 2007

- Abrupt changes in net import and Hydroelectric output can be observed causing sudden interval to interval price changes in both the Richview and Uniform Prices

Recommendation 3-3
(Chapter 3 Section 3.1)
The MSP recommends the IESO begin investigation of a 15 minute dispatch algorithm to enhance the efficiency of the market.



Chapter 3 - Recommendations directed at the IESO to reduce uplifts

Recommendation 3-4 (Chapter 3 Section 4.1)

- *The IESO should initiate a rule change to allow the recovery of self-induced congestion management settlement credit (CMSC) payments which are made to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons.*

Recommendation 3-5 (Chapter 3 Section 4.2)

- *The IESO should initiate a rule change to make Intertie Offer Guarantee (IOG) payments subject to offsets where affiliated market participants are simultaneously importing and exporting.*

Chapter 3 Policy issue – efficiency of public agency contracts

- The spot market continues to have a central role to play in ensuring that consumption, investment and dispatch decisions in the hybrid market are efficient.
- MSP has reviewed the various public agency (OPA and IESO) contract structures to provide guidance on creating contracts that work well within the hybrid market structure and enhance efficiency.
- Strike price contracts (CES style) appear to operate efficiently whereas many of the other contracts contain incentives or triggers which can induce inefficient behaviour.

Chapter 3 Policy issue – efficiency of public agency contracts

- Changes in output from OPA standard offer generators appear simply as changes in demand to the IESO and become part of the demand forecast error.
- Significant demand forecast error may lead the IESO to have to constrain on generation or in some areas, to reduce transmission capability to handle forecast uncertainty.
- Better information from these generators should reduce potential inefficiencies.

Recommendation 3-7 (Chapter 3 Section 4.4.3)

To the extent possible in its stakeholder consultation on embedded generation, the IESO should consider opportunities to reduce inefficiency through the development of the capability for accurate forecasting of embedded generation production, which may require the provision of real-time production and related information (e.g. outages).

- The MSP has noted that several of the contract structures may place externalities on loads.
 - Standard offer contracts involve generation “behind a meter” (LDC or a load’s revenue meter) and as a result allow for the avoidance of some uplift costs.
 - With uplifts rising as new contracted generation comes to market, uplift avoidance will lead to larger uplifts being shared across a smaller pool of load.



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Chapter 3 - Recommendations to OPA regarding contracts

Recommendation 3-8 (Chapter 3 Section 4.4.6)

- *The Panel recommends that the Ontario Power Authority structure future contracts to maintain the energy market price as the driver for production decisions (for example, using a strike price structure similar to the payment provisions in the existing clean energy supply contracts).*

Chapter 4 - Recommendations to IESO and OPA to improve transparency

Recommendation 4-1 (Chapter 4 Section 2)

- *The Ontario Power Authority should create more transparency regarding the ongoing monthly payments and energy delivered for each of its various procurement programs in order to promote a better understanding of the costs and effectiveness of these programs and to help market participants gain a better understanding of the component costs of the Global Adjustment.*
- *Similarly, the IESO should consider providing aggregate monthly payments associated with Ontario Power Generation's regulated baseload assets, as it currently does for the OPG Rebate.*