Ontario Energy Board
Commission de l'énergie de l'Ontario

The IESO Administered Markets November 2009 – April 2010

Market Surveillance Panel's 16th Monitoring Report

Presentation to the Stakeholder Advisory Committee
by Neil Campbell, MSP Chair, October 26, 2010

Agenda

- Recent Panel Activities
- Summary of Key Findings / Highlights
- Recommendations
  - CMSC Payments to Dispatchable Loads
  - Generator Cost Guarantee Program
  - Transmission Rights Market
- Issues Addressed by the IESO
- Hydroelectric Offer Strategies

Recent Panel Activities

- Personnel changes on the Panel
  - Prof. Don McFetridge completed 8 years of distinguished service
  - Prof. Roger Ware joined the Panel in August 2010
  - Recruitment under way to replace Tom Rusnov when his term expires in January 2011
- Two ongoing investigations

Winter 2009/2010 – Key Findings

- Market worked reasonably well according to its design
- Hourly prices generally reflected underlying supply and demand forces or were explainable by Ontario’s two-schedule model and the uplift and Global Adjustment regimes
- There were occasions where actions by market participants or the IESO led to inefficient market outcomes

Highlights - Compared to Previous Annual Period - Prices

	May 2008 – Apr 2009	May 2009 – Apr 2010	% Change
HOEP - average (excl. uplift and Global Adjustment) ($/MWh)	44.61	28.30	-37%
Richview Shadow Price - average ($/MWh)	54.14	29.88	-45%
Gas Price - Henry Hub ($/MMBtu)	8.05	4.39	-46%
Coal Price - Central Appalachian ($/MMBtu)	3.90	2.20	-44%
Coal Price - Powder River ($/MMBtu)	0.72	0.55	-24%
Average of Surrounding Markets (NY, PJM, MISO, NE) (C$/MWh)	59.63	36.30	-39%

- Ontario remains the lowest hourly energy price market in northeastern North America

Highlights - Compared to Previous Annual Period – Change to Effective Prices (Uplifts and Adjustments)

	May 2008 – Apr 2009	May 2009 – Apr 2010	% Change
HOEP - average ($/MWh)	44.61	28.30	-37%
Load-weighted HOEP ($/MWh)	47.67	29.72	-38%
Global Adjustment + OPG Rebate* ($/MWh)	9.31	35.01	+276%
Total Hourly Uplift ($/MWh)	2.78	2.39	-14%
Effective Load-weighted HOEP + Hourly Uplift ($/MWh)	59.76	67.12	+12%

**** OPG Rebate discontinued as of May 2009***

- Global Adjustment is growing due to increased OPA payments for contracted supply and demand response and other conservation programs
- Hourly Uplift decrease resulted from large decline in payments for Losses and smaller declines in OR and CMSC payments (IOG payments remained relatively stable)

Highlights - Compared to Previous Winter Period – Anomalous Events

	Nov 2008 – Apr 2009	**Nov 2009 – Apr 2010**	**% Change**
High Price Hours (>$200/MWh)	8	1	-88%
Low Price Hours (<$20/MWh)	689	460	-33%
Negative Price Hours	219	26	-88%
Anomalous Uplift	5	2	-60%

- Significant declines in both high and low price hours as well as anomalous uplift hours over the current annual period

Highlights - High Price Hours

- Only 1 hour with HOEP > $200/MWh this winter
  - HOEP of $505.94/MWh occurred on January 2, 2010, HE 18
- Factors previously identified by Panel continue to explain price spikes
  - Real-time demand 2.1% higher than pre-dispatch forecast
  - Generating units representing 2.3% of supply available in pre-dispatch failed to deliver in real-time
- Interval MCPs set by peaking hydro and dispatchable loads

Highlights - Low and Negative Price Hours

- Low price hours less frequent this winter
- Factors previously identified by Panel continue to explain low and negative prices
- Record lowest HOEP of -$128.15/MWh occurred on April 2, 2010, HE 7
  - Change in offer strategy at nuclear facility was a major contributor to record low HOEP
  - Demand low (slightly more than 12,000 MW)
  - Real-time demand 5.5% lower than pre-dispatch forecast
  - 399 MW of failed net exports represented over 3% of demand
  - Abundant low price supply (over 12,500 MW of generation with negative offers)

Recommendations - Overview

- Panel has made 6 recommendations in this report:
  - Two relate to dispatch
  - Two relate to reducing uplifts
  - Two relate to price fidelity
- All recommendations are addressed to the IESO

Recommendations on Uplifts
Dispatchable Load CMSC Payments

- Two dispatchable loads representing 30% of total dispatchable load capability receiving large CMSC payments between February and June 2010

	Total CMSC Paid		**% of CMSC paid to Dispatchable Resources**	
	Feb - Jun 2009	Feb – Jun 2010	Feb - Jun 2009	Feb - Jun 2010
Two Dispatchable Loads (280 MW)	$3 million	$18 million	7	42
All Other Dispatchable Loads (570 MW)	$0.5 million	$0.6 million	1	1
All Dispatchable Generation (approx. 35,000 MW)	$40 million	$24 million	92	56
All Dispatchable Load and Generation	$43.5 million	$42.4 million	100	100

Recommendations on Uplifts
Dispatchable Load CMSC Payments

- The Panel has observed four primary factors that have contributed to these payments:
  - Frequent ramp with a reduced ramp rate and increased bid price
  - Consumption deviation leading to constrained-off CMSC
  - Consumption deviation leading to constrained-on CMSC
  - Combination of a dispatchable load with a dispatchable generator (settled on the basis of net load)
- IESO issued an urgent interim rule suspending CMSC for all dispatchable loads

*MR-00373-R00: Congestion Management – Suspend CMSC for Constrained Off Dispatchable Loads, effective August 28, 2010

Recommendations on Uplifts
Limit CMSC payments

Recommendation 3-1

The IESO should immediately eliminate self-induced CMSC paid to dispatchable loads resulting from either a voluntary change in consumption or a consumption deviation

Recommendations on Dispatch
Compliance Deadband

- A large compliance deadband provides market participants with opportunities to generate CMSC payments
  - For units with rated output of at least 30 MW, the deadband is the greater of 15 MW or ±2% of a facility’s dispatch instruction
  - Depending on the consumption/output capability of a facility, 15 MW can represent as much as 50% of a facility’s dispatch instruction
  - In many instances, CMSC arising from consumption deviations that are within the deadband cannot be recovered under existing market rules

Recommendations on Dispatch
Compliance Deadband (cont'd)

Recommendation 3-3

The IESO should explore the feasibility of tightening its compliance deadband definition for dispatchable loads by linking the deadband more closely to the facility's dispatchable capability and/or ramp rate

Recommendation on Uplifts

Combination of a Dispatchable Load with a Dispatchable Generator

- In January 2010 the owner of a dispatchable load facility chose to combine it with a dispatchable generation facility located at the same site for IESO settlement purposes
  - Offers/bids net output/consumption to the market, as opposed to separately offering its generation facility and bidding its load
  - Transmission/connection and Global Adjustment charges avoided
- CMSC received by facility between February and June 2010 was more than double the payments made to consume energy
  - Facility effectively compensated $62.48/MWh for each net MW withdrawn (in addition to avoiding transmission / connection and Global Adjustment charges)

Recommendation on Uplifts

Combination of a Dispatchable Load with a Dispatchable Generator (cont'd)

- Payments are arising from frequent ramping and deviations from scheduled consumption levels
- Bidding at large negative amounts for its net load increases the magnitude of the CMSC payments
- Panel's January 2010 report recommended that for CMSC calculation purposes the IESO should use a replacement bid (such as $0/MWh) to mitigate large CMSC payments made to dispatchable loads in relation to negative bids
  - A rule amendment is under discussion at the IESO Technical Panel which should reduce these CMSC payments to net load/generators
  - Earliest expected date of enactment is December 2010

Recommendations on Uplifts

Constrained-on CMSC Payments

Recommendation 3-2

The IESO should expedite the implementation of the Panel's previous recommendation that, for the purposes of calculating Congestion Management Settlement Credit (CMSC) payments, the IESO should revise its constrained on payment calculation using a replacement bid (such as $0/MWh) when a dispatchable load bids at a negative price.

Recommendations on Dispatch
Generation Cost Guarantees (GCG)

- The Panel previously recommended that the IESO base GCG payments on the offer submitted by the generator or implement another solution that would require actual generation costs to be taken into account at the time of scheduling decisions
- Market rule amendment # 356 was implemented December 9, 2009
  - Generators required to be economically scheduled at their minimum loading point (MLP) for at least half of their minimum generation block run-time (MGBRT) in order to qualify for the guarantee
  - GCG during run-time capped by offer price
  - Generators submit after-the-fact start-up costs (fuel and O&M)

Recommendations on Dispatch

Generation Cost Guarantees (cont'd)

- The market rule change has not eliminated the distortive market effects of the GCG program
  - 62% of GCG generators' costs not reflected in MGBRT offer prices, and therefore not accounted for as part of the IESO's dispatch decision
  - Dispatch decision which only considers the generator's MGBRT offer price will result in dispatch inefficiencies (e.g. Generator C has highest all-in cost but will be scheduled first because of lowest average MGBRT offer price)

	Average MGBRT Offer Price		Average Start-Up Cost Submission per Run	Average All-in Cost (assuming generation at MLP)	
	$/MWh	Rank	$/MWh	$/MWh	Rank
Generator A	36.92	2	23.43	60.35	**1**
Generator B	44.56	3	22.30	66.86	2
Generator C	36.32	**1**	81.77	118.09	3

Recommendations on Dispatch

Generation Cost Guarantees (cont'd)

- Panel conducted simulation to assess the market impact if GCG program had required generators to submit offers reflecting "all-in" cost per MWh (start-up as well as running costs) for the 4.5 month period December 9, 2009 to April 30, 2010

	Current GCG Program (Simulated)	Simulated with "All-in" Costs	Difference	
			Amount	%
HOEP ($/MWh)	35.81	66.93	+31.12	+87%
Exports (TWh)	5.28	4.05	-1.23	-23%
Imports (TWh)	2.61	2.94	0.33	+13%

Recommendations on Dispatch
Generation Cost Guarantees (cont'd)

Recommendation 3-4

To the extent that the IESO believes a reliability program such as the generation cost guarantee program continues to be warranted, the IESO should base the guarantee payment on the offer submitted by the generator or should implement another solution that would require actual generation costs to be taken into account at the time of scheduling decisions

Recommendations on Price Fidelity
Transmission Rights Payments

- Traders scheduling transactions with other jurisdictions face financial risk if there is intertie congestion
- Transmission Rights (TR) market was established to allow intertie traders to hedge the risks associated with congestion and can potentially improve market efficiency
- Panel has looked in detail at outcomes since market opening
- 23% of TRs are held by financial participants
- Most physical traders do not have TRs or have TRs at different paths than their physical transactions
  - 64% of participant trades were not accompanied by a TR

Recommendations on Price Fidelity

Transmission Rights Payments (continued)

- TR Clearing Account has 3 main components:

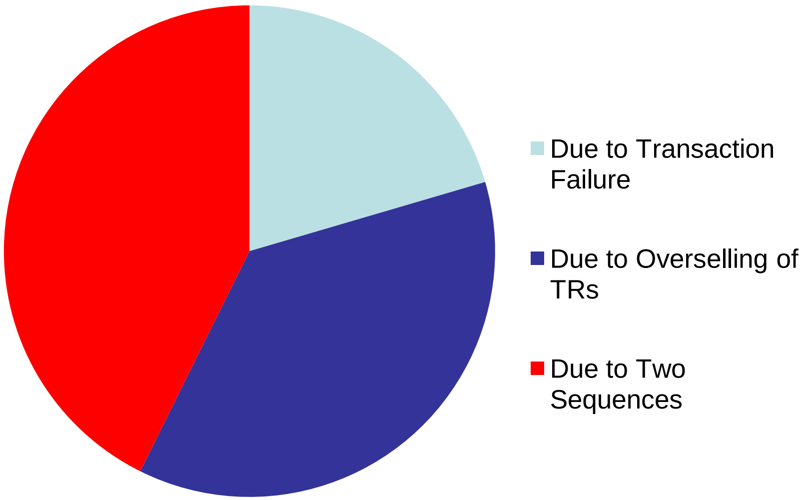
  Congestion Rent Collected + TR Auction Revenue - Payouts to TR Holders = Account Balance

TR Clearing Account Components, 2002-2010 ($ millions)						
May to April Period	**TR Payouts (A)**	**Congestion Rent (B)**	**Congestion Rent Shortfall (B-A)**	**Auction Revenue (C)**	**Profit of Holding TRs (A-C)**	**Surplus (Deficit) (B+C-A)**
2002/2003	82.21	81.37	(0.84)	11.62	70.58	10.78
2003/2004	38.13	34.85	(3.28)	16.70	21.43	13.42
2004/2005	29.02	22.10	(6.92)	27.51	1.51	20.59
2005/2006	90.63	65.01	(25.62)	40.66	49.96	15.04
2006/2007	25.78	16.18	(9.60)	39.51	(13.73)	29.91
2007/2008	69.34	41.62	(27.72)	25.64	43.69	(2.08)
2008/2009	97.92	68.32	(29.60)	28.38	69.54	(1.22)
2009/2010	38.40	27.17	(9.54)	30.43	7.97	19.20
Total*	469.72	356.60	(113.12)	220.46	250.95	**105.65***

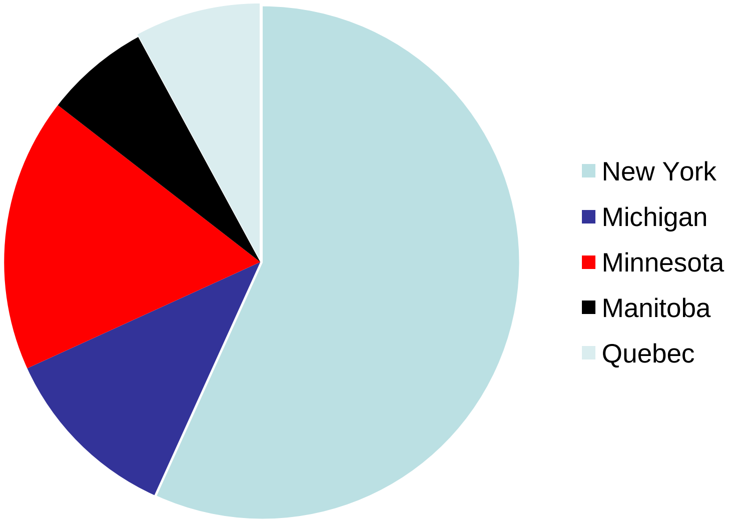
* After reimbursement of $57 million to Ontario load and exporters in 2007, the account balance is $49 million as of April 2010

High Returns to TR Holders

- Congestion Rent cumulative shortfall of $113 million has three sources:
  - 37% attributable to overselling of TR’s relative to the scheduling limit in the unconstrained schedule (of this, 57% relates to the New York interface)
  - 20% due to transaction failures
  - 43% due to the presence of the two-sequence system



Shortfall by Reason



Shortfall by Interface

High Returns to TR Holders

- TR market does not appear to be informationally efficient
  - The Auction Clearing Price (ACP) of a TR provides relatively little information about future congestion levels and payouts
  - e.g. long-term export TRs for Jan-Dec 2008 that were sold for $6M were paid $45.8M
- Payouts to TR holders have been much higher than ACPs
  - Mean return for short-term and long-term TR's greater than 100% since market opening

	Short-Term	**Long-Term**
Import TRs	271%	66%
Export TRs	37%	178%
All TRs	125%	121%

Recommendations on Price Fidelity
Transmission Rights Payments (cont'd)

- Panel believes the IESO should reassess fundamental TR market design including:
  - Is the TR market effectively performing its primary function of helping intertie traders hedge their risks?
  - Are the large returns to TR holders providing value to the market?
  - Are there lessons to be learned from significant TR market design differences in foreign jurisdictions (e.g. exposure to downside as well as upside risks, secondary markets for issued TRs, etc.)
  - Why has the market proven to be informationally inefficient?
  - Should TR clearing account surpluses be distributed to domestic loads, exporters, TR holders or transmission owners, or be earmarked for investments to relieve congestion?

Recommendations on Price Fidelity
Transmission Rights Payments (continued)

Recommendation 3-5

The IESO should limit the number of transmission rights auctioned to a level where the congestion rent collected is approximately sufficient to cover the payouts to transmission right holders

Recommendation 3-6

The IESO should reassess the design of the Ontario TR market to determine whether it can play a more effective role in supporting efficient trade with neighbouring jurisdictions

Unintended Consequences of Two-schedule Market Structure

- January 2010 MSP Report - The Panel suggested that exploring a structural change to the existing two-schedule system should be a high priority
- Many Panel recommendations related to transaction failure coding practices and uplift payments arise from two-schedule system design
- Numerous Panel recommendations since 2003 have been aimed at limiting CMSC payments
  - Source of unnecessary uplift charges and potential inefficiencies
  - Root causes relate to the two-schedule system

Monthly Constrained on CMSC Payments Resulting from Generator Shutdowns *($ thousands)*

- Generators use signal-based offers to indicate their intention to shut-down
- Discrepancy between two sequences results in constrained-on payments during ramp-down
- January 2009 MSP Report – Panel recommended these self-induced CMSC payments be limited
- Over $16 million in CMSC due to generator shutdowns has been paid since May 2009.
- These payments will be limited by Market Rule Amendment 252

	Settlement Amount
May-09	1,126
Jun-09	1,494
Jul-09	1,168
Aug-09	1,204
Sep-09	1,111
Oct-09	829
Nov-09	943
Dec-09	700
Jan-10	771
Feb-10	1,234
Mar-10	1,061
Apr-10	1,011
May 10	1,088
Jun-10	898
Jul-10	987
Aug-10	1,104
Total	**16,729**

Issues Addressed by the IESO

- In November 2009, MAU began to observe a practice whereby the IESO would occasionally preemptively curtail exports when control action operating reserve (CAOR) had been scheduled as a component of operating reserve (OR) in real-time
- This led to significant constrained-off payments to exporters
  - e.g. $1.17 million in CMSC paid at the Michigan interface on November 23, 2009 which exceeded the monitoring threshold for an anomalous uplift event
- After discussion with the IESO, the MAU was notified that internal procedures were clarified to stop this practice

Hydroelectric Offer Strategies

Summary of High Price Offers

- In previous MSP Report, Panel observed that peaking hydroelectric resources were setting the MCP during many high price hours in the 2009 summer months, including some intervals with MCPs above $500/MWh
- Panel applies analytical framework for energy limited generation from *Monitoring of Offers and Bids Document*
  - Possibility of market power being exercised (pricing-up or economic withholding) assessed by considering offers in relation to the generator's opportunity cost

Hydroelectric Offer Strategies

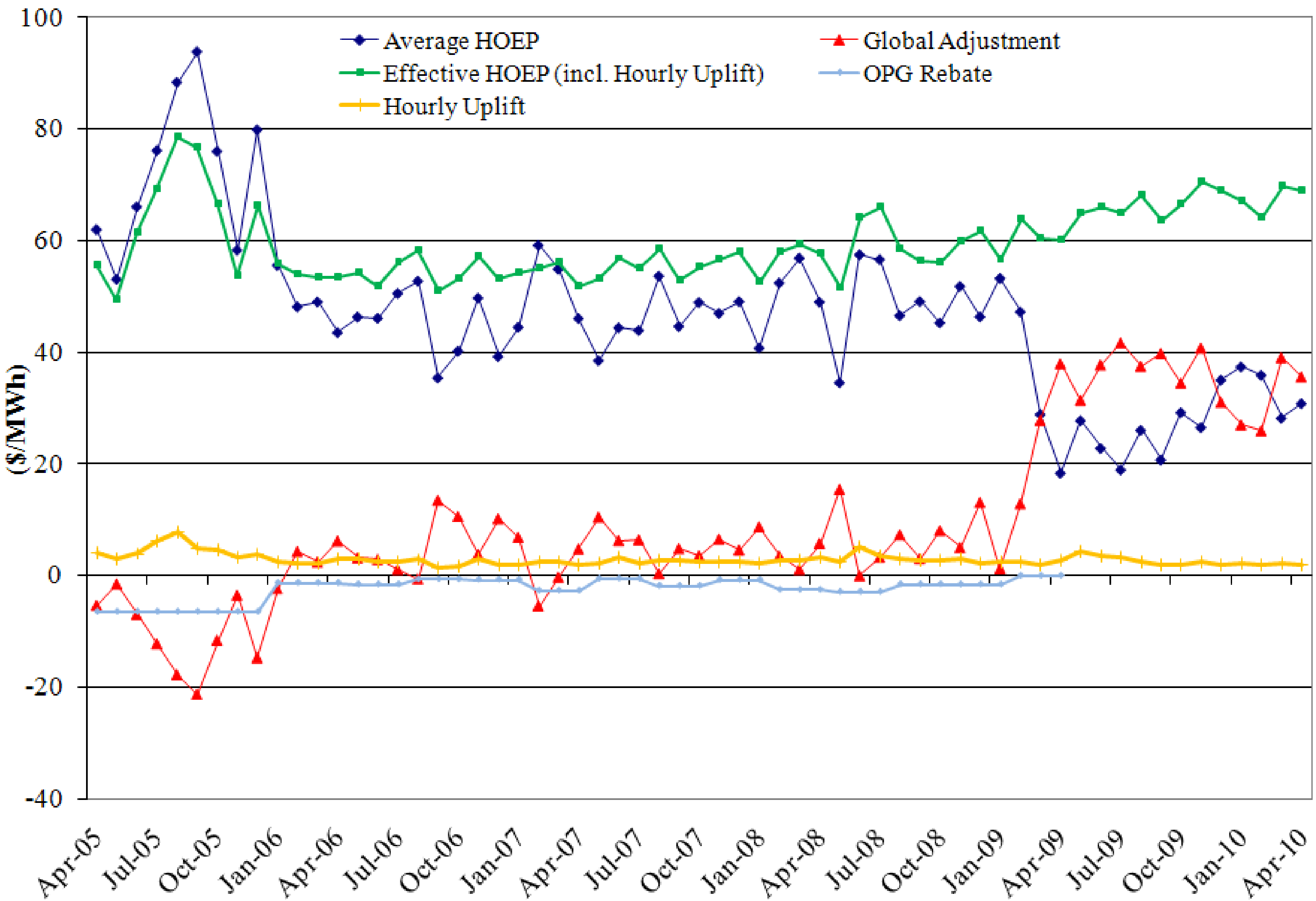
Summary of High Price Offers (cont’d)

- Many hydroelectric offers appear to be based on opportunity cost
  - MAU was advised that some offers in $500/MWh vicinity were used by participants to signal an unwillingness to be scheduled for energy except as a last resort
- Hydroelectric resources set the MCP above $500/MWh in only 22 intervals (0.04% of total intervals) between May 2009 and April 2010
  - Negative implications to the market appear limited based on low price-setting frequency
  - Panel has asked the MAU to continue to monitor instances of signal-based offers setting the real-time MCP in accordance with *MOB Document*

Background Slides

Monthly HOEP versus Effective HOEP

April 2005 – April 2010 ($/MWh)

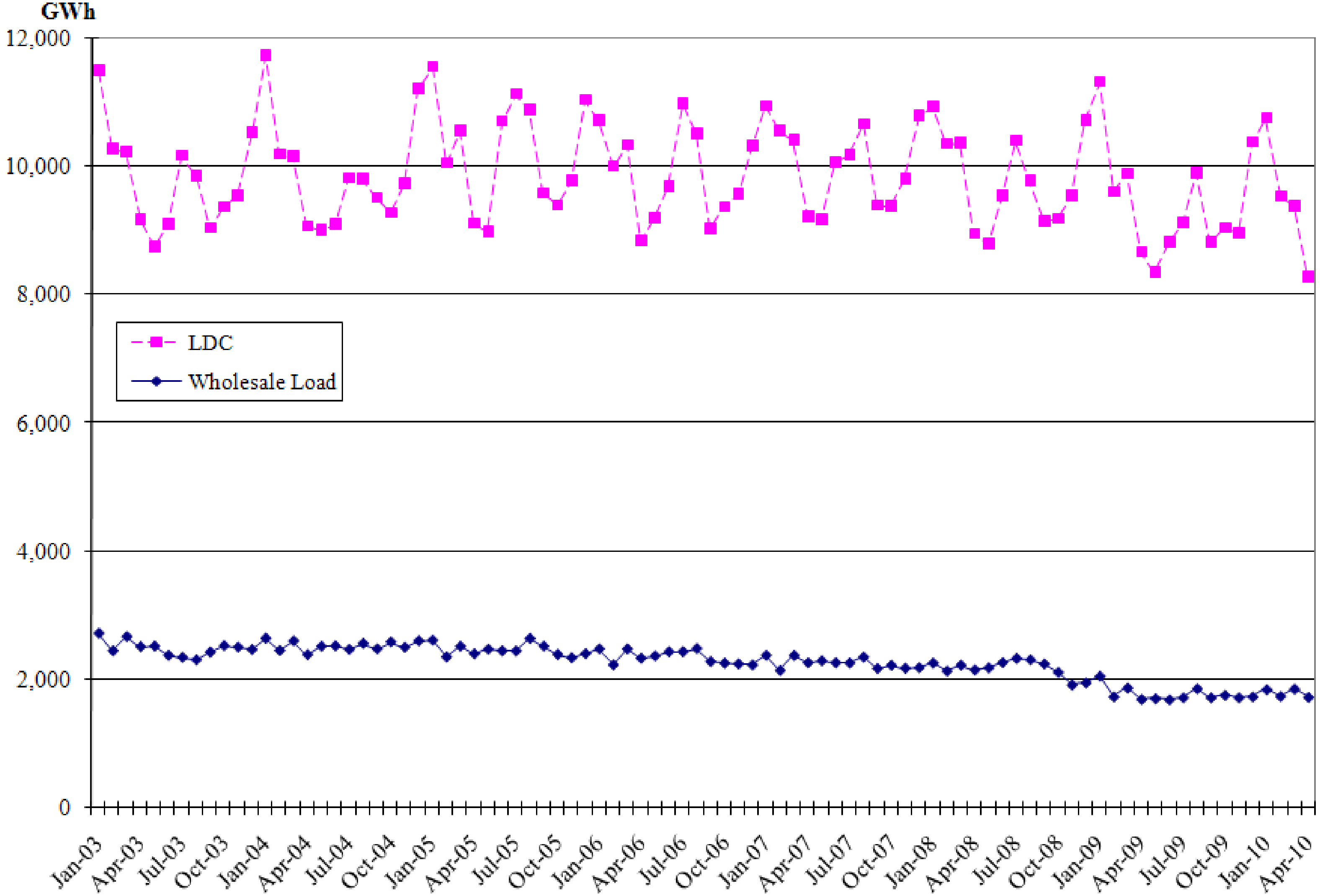


Demand Indicators

- Ontario energy demand fell by 5.4% (7.89 TWh) in May-April 2009/2010 compared to 2008/2009
  - Combination of wholesale load and LDC
- Total market demand (Ontario demand plus net exports) declined by 6.3% (9.91 TWh)
  - Ontario was a net exporter in all months

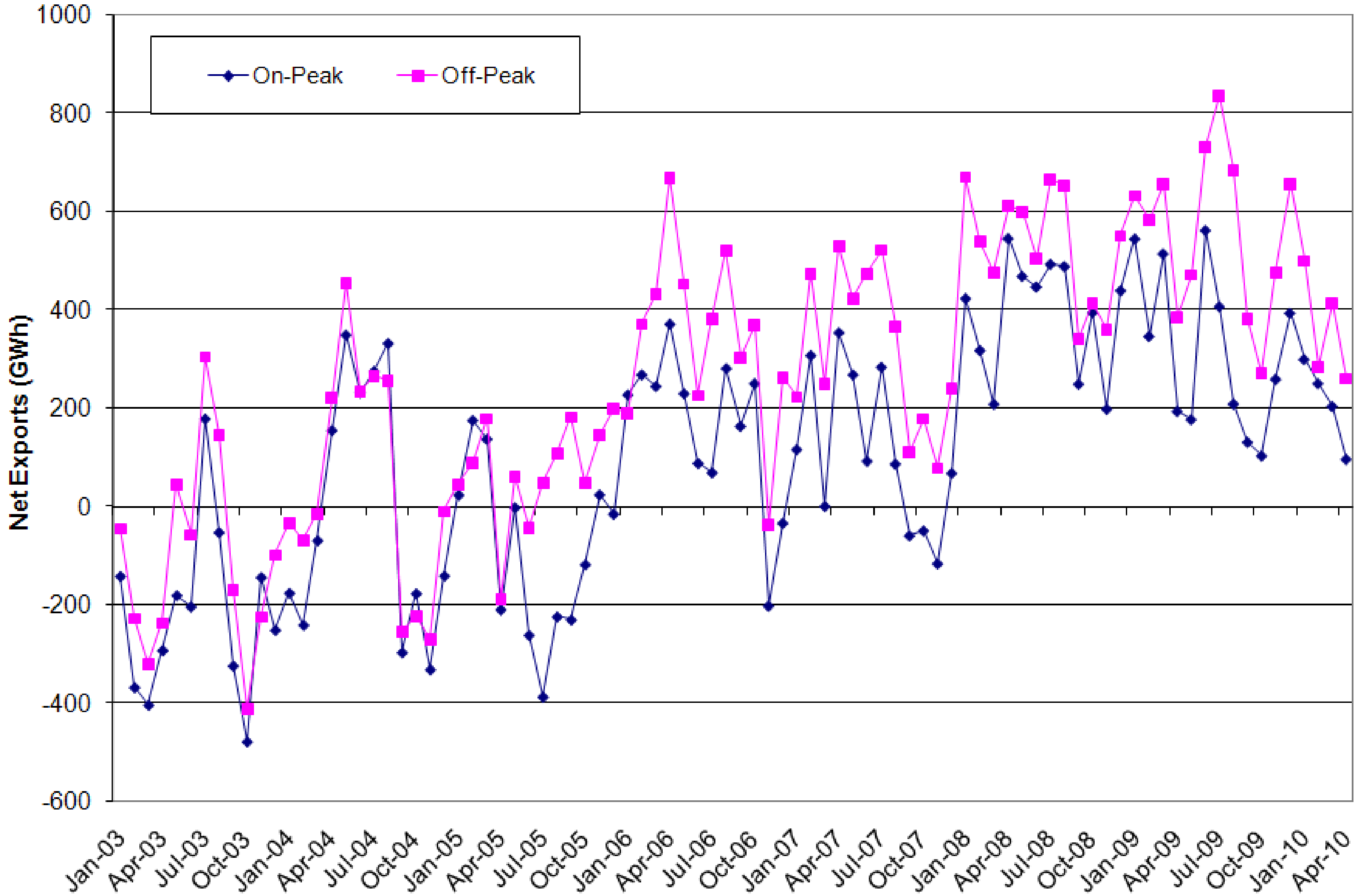
LDC and Wholesale Load Declining

January 2003 – April 2010 (GWh)



Continuing Net Exporter

January 2003 – April 2010 (GWh)

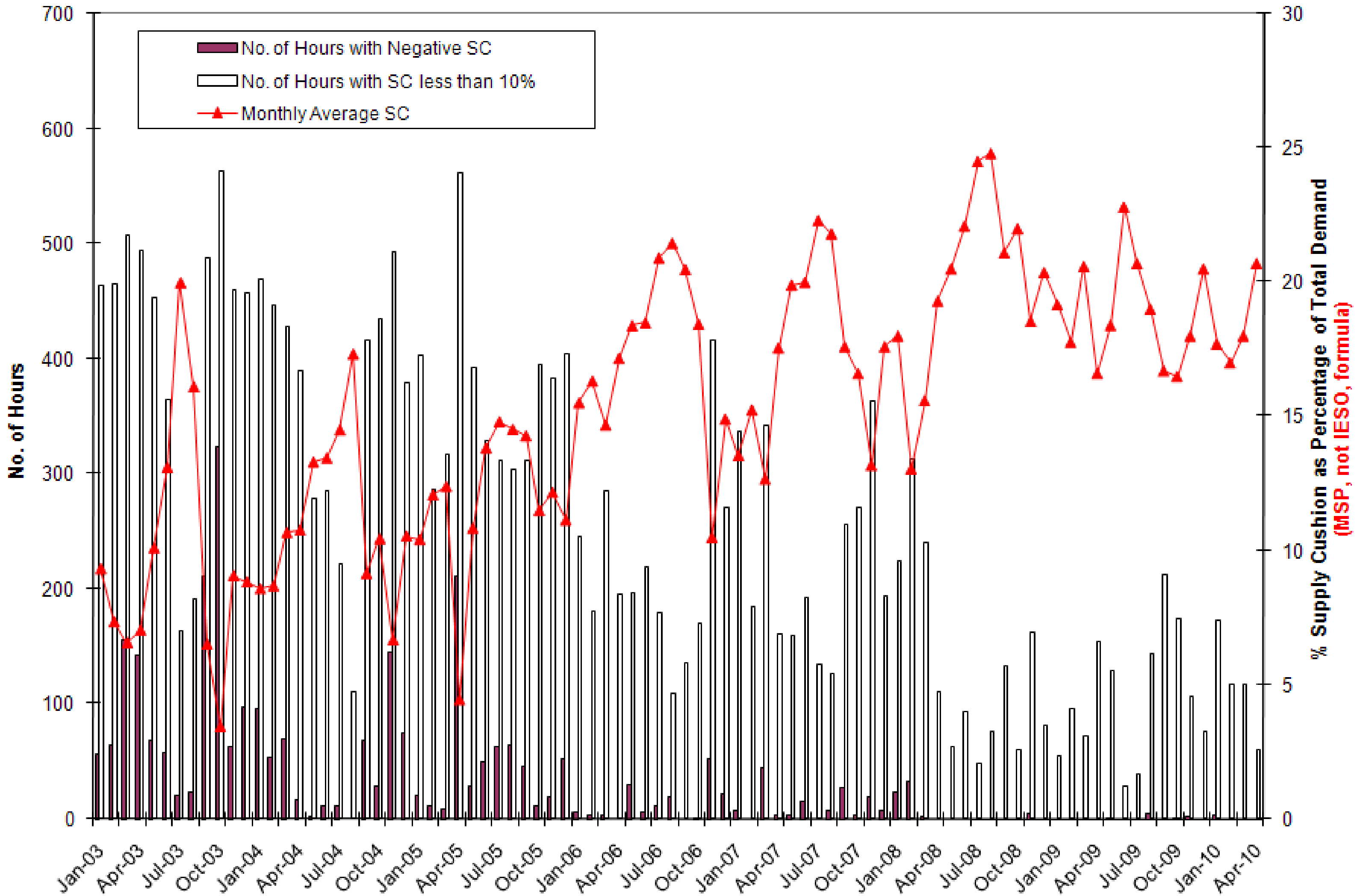


Supply Indicators

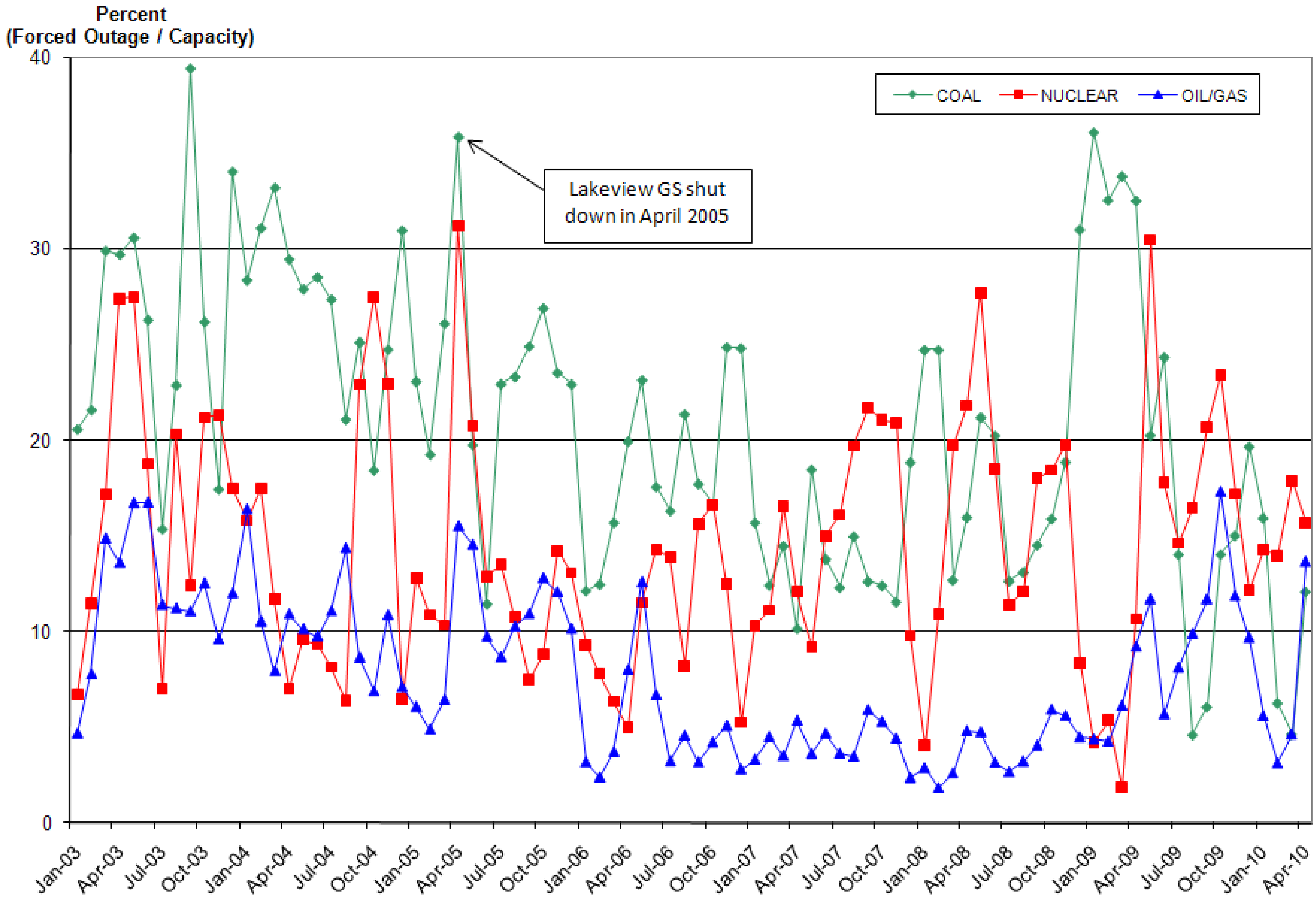
- Average real-time domestic supply cushion declined slightly this year relative to last year
  - 20.7% in 2008/2009 compared to 18.8% this year
- Coal forced outage rate was lower in 2009/2010 relative to the previous annual period
  - Below 10% in four months, a threshold not observed since market opening
- Average absolute wind forecast error remains closely related to growth in hourly wind output
  - 69 MW in 2009-2010, up from 49 MW last year

Improved Real-time Supply Cushion Conditions

January 2003 – April 2010 (Hours and %)

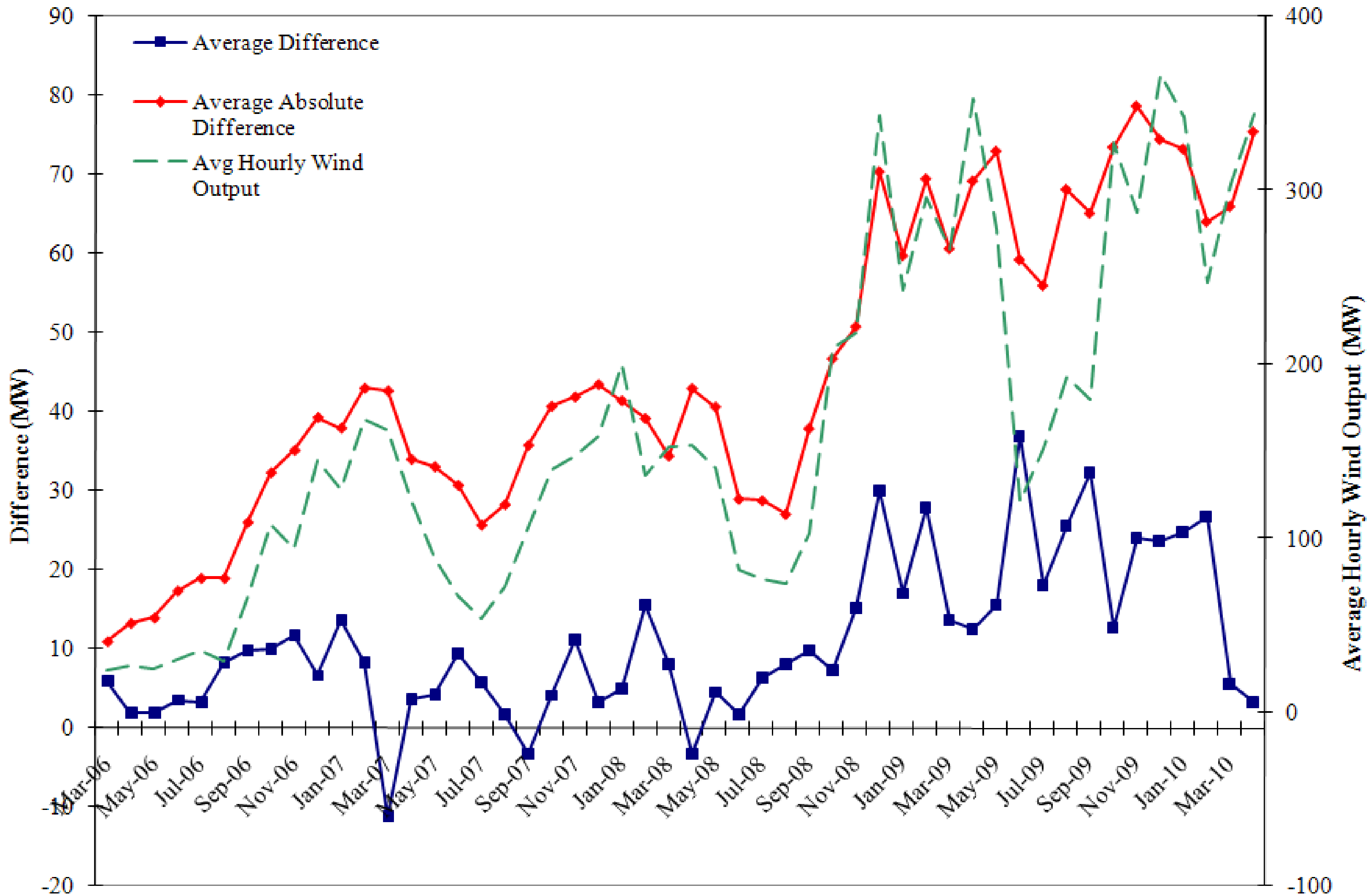


Forced Outages Relative to Total Capacity by Fuel Type
January 2003 – April 2010 (%)



Average and Absolute Average Difference between Wind Generator Forecasted and Delivered Energy and Average Hourly Wind Output

March 2006 – April 2010 (MW)

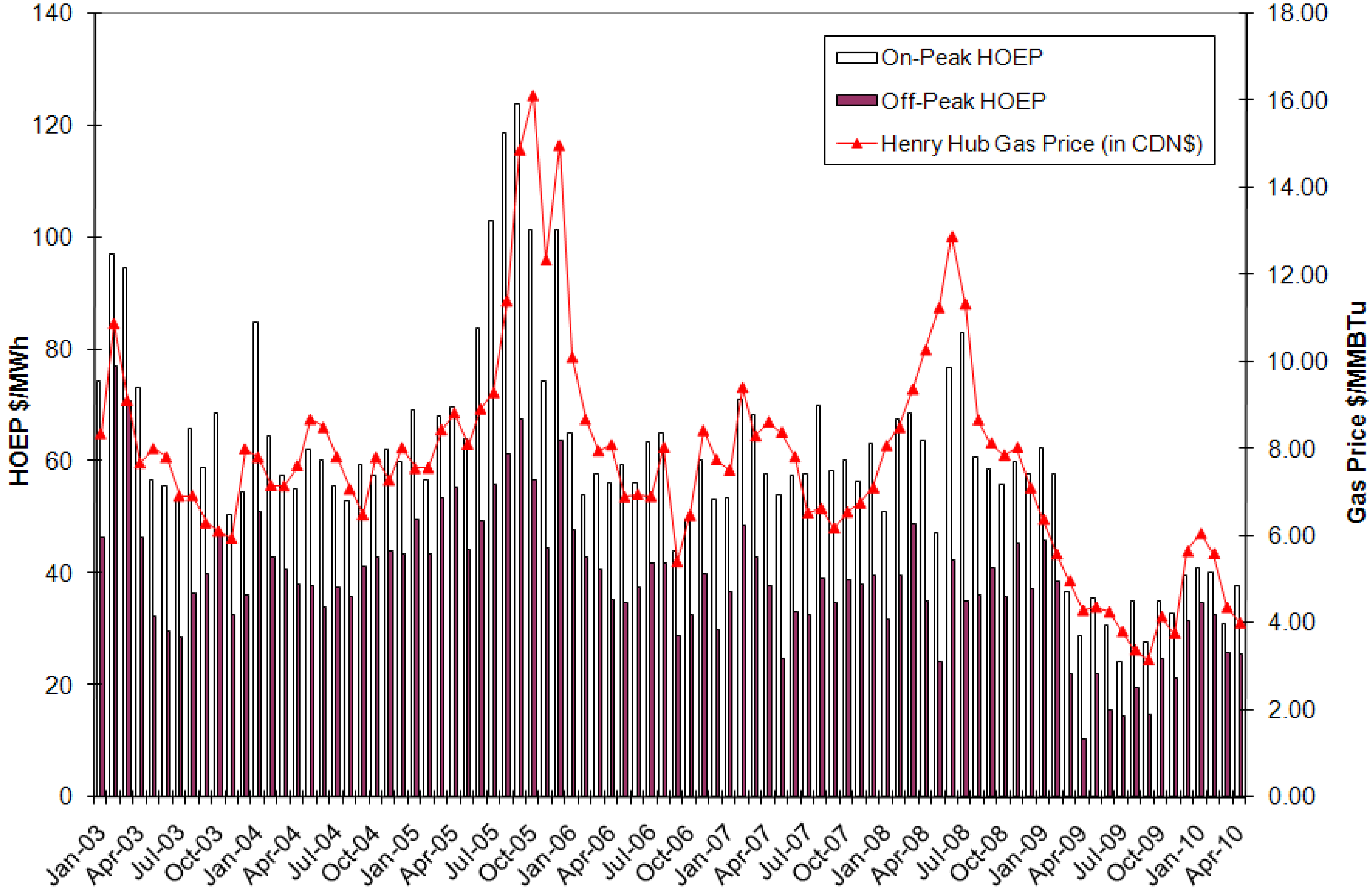


Supply Indicators (cont'd) – Underlying Fuel Prices

- Both average coal and natural gas prices declined in May 2009 – April 2010 relative to the same period one year earlier
  - Central Appalachian coal prices (used by Lambton) fell by 44%
  - Powder River Basin coal prices (used by Nanticoke) fell by 24%
  - Natural gas prices at Henry Hub declined by 46%

Monthly Natural Gas Prices vs. HOEP

January 2003 – April 2010 ($/MWh and $/MMBtu)

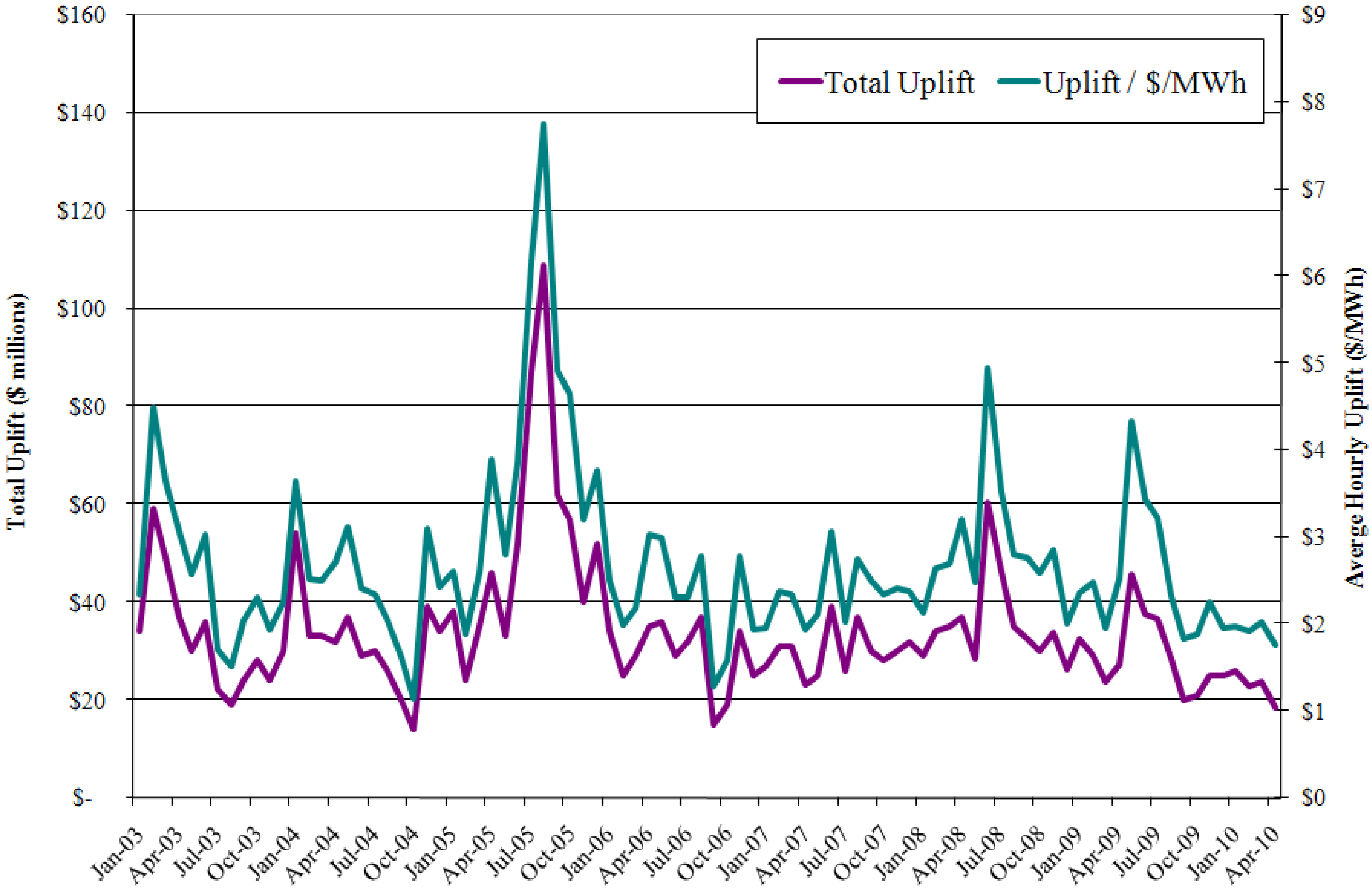


Hourly Market Uplifts

- Hourly uplift declined 19%, from $405.5 million in 2008/2009 to $329.6 million in 2009/2010
  - Mostly the result of a $64.7 million (41%) decline in Losses (primarily due to the HOEP decrease)
  - Operating reserve payments also fell by 9%, from $55.2 million in 2008/2009 to $50.5 million in 2009/2010
- Northwest shadow prices averaged -$404/MWh due to abundant hydroelectric energy and low Northwest demand
  - Generators receive payment equivalent to HOEP when constrained-off
  - Intertie transactions also frequently constrained

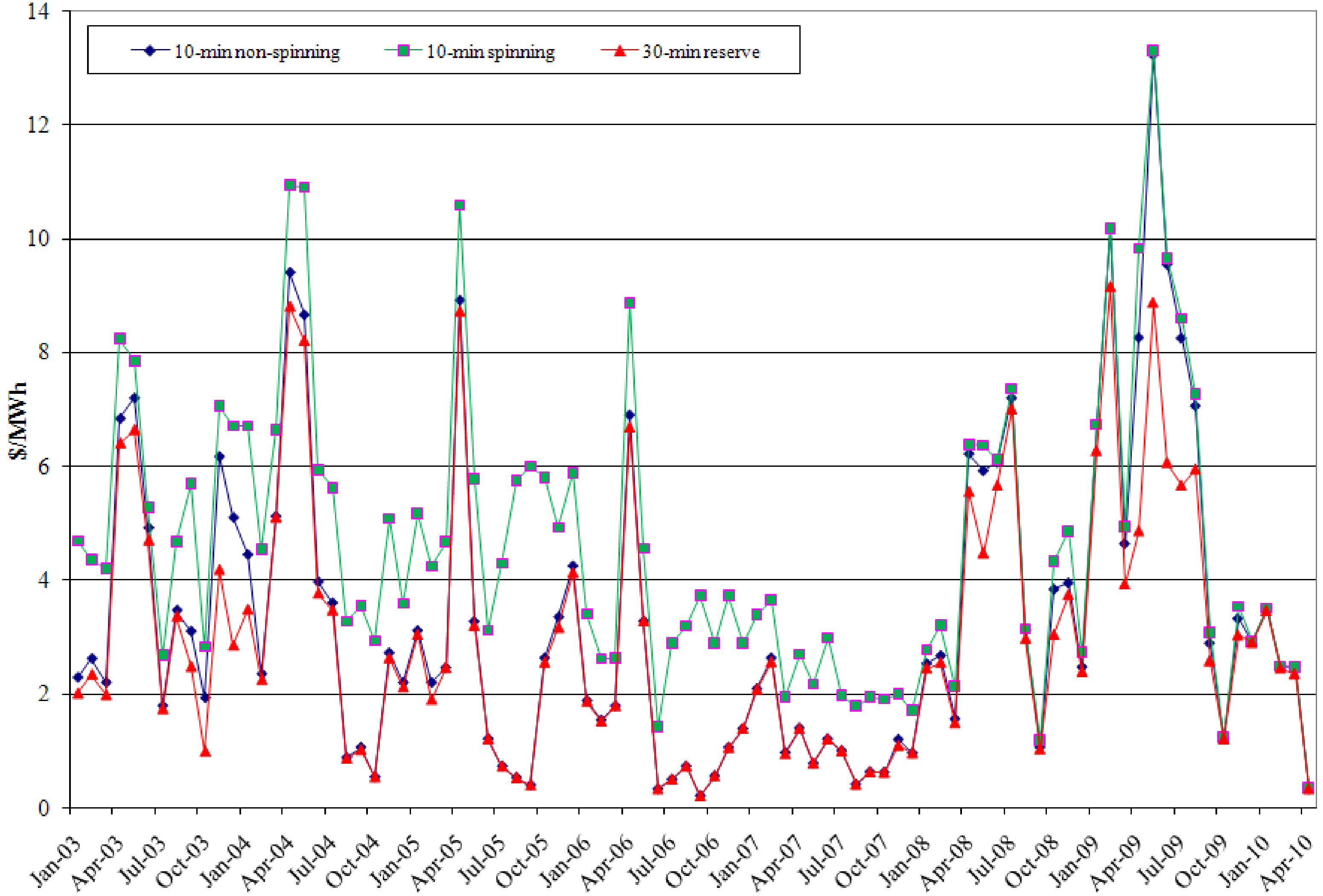
Hourly Market Uplifts

January 2003 – April 2010 ($ million and $/MWh)



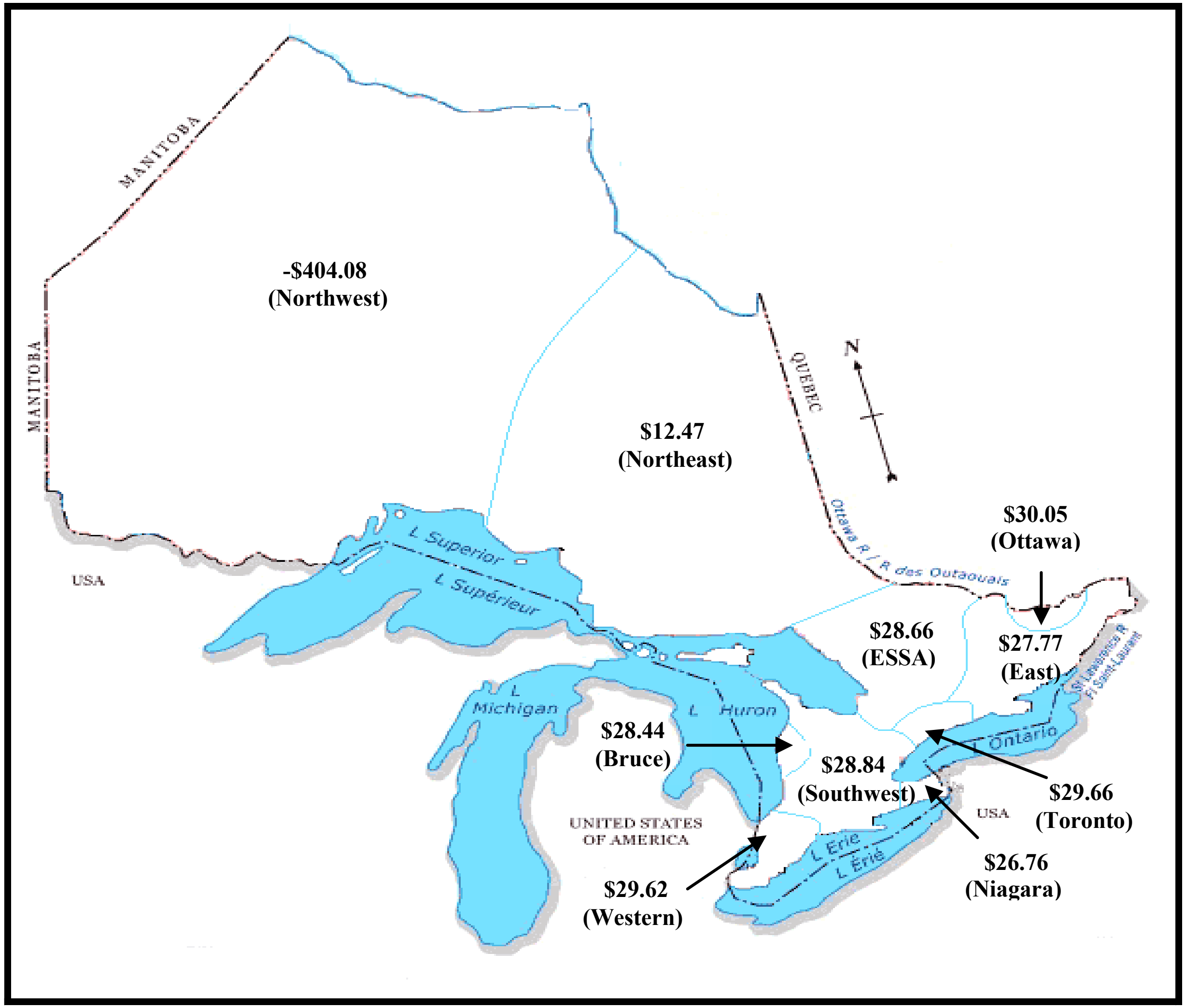
Monthly Operating Reserve Prices by Class

January 2003 – April 2010 ($/MWh)



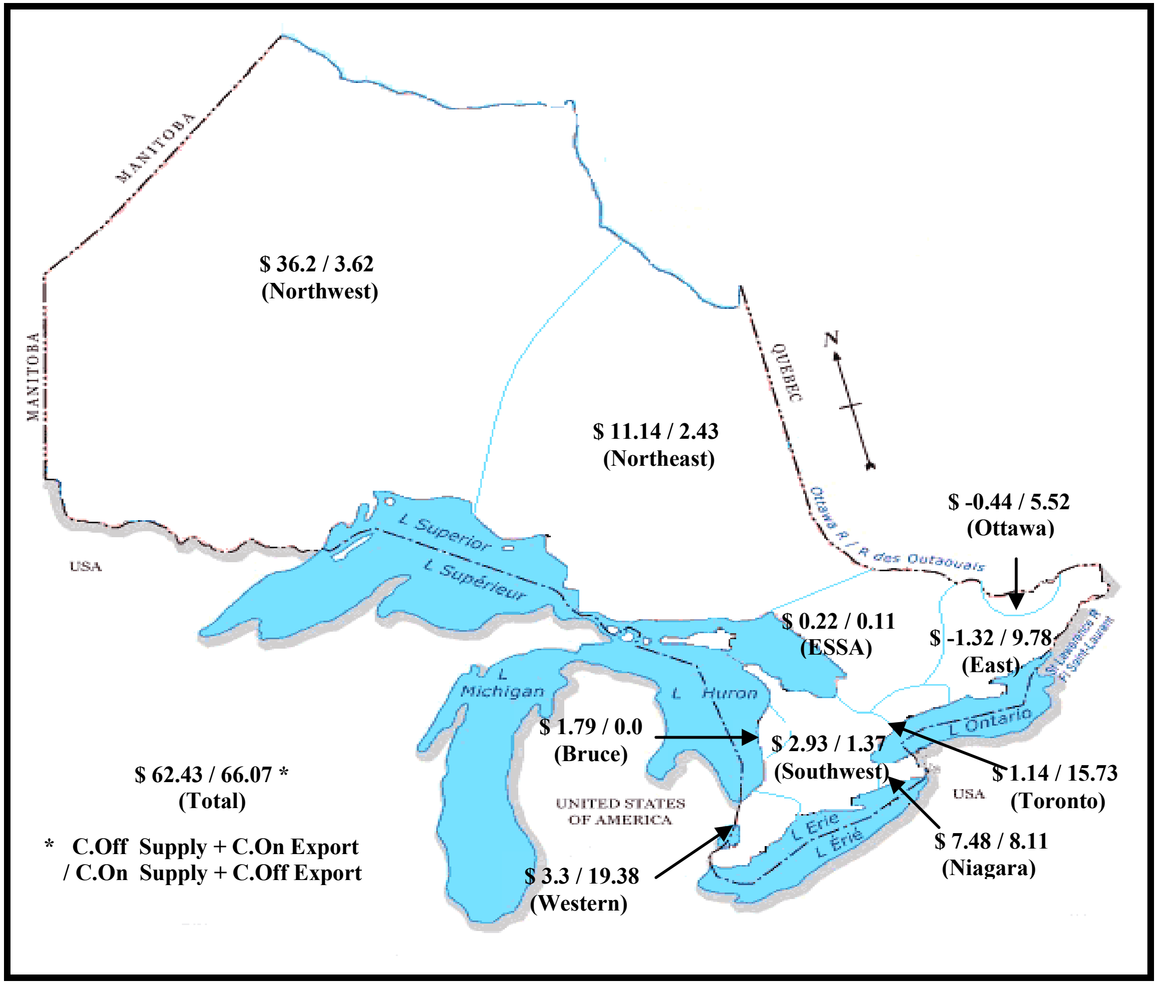
Average Shadow Prices by Zone

May 2009 – April 2010 ($/MWh)



Total CMSC Payments by Zone

May 2009 – April 2010 ($/MWh)



Trade Flow Indicators

- Total export and import volumes declined this winter compared to last winter
  - Total exports fell 21% (declined 11% excluding linked-wheels)
  - Total imports fell 25% (increased 3% excluding linked-wheels)
- HOEP the lowest six-month hourly energy price compared to surrounding markets: NY, PJM, MISO and New England
  - $2.14/MWh (7.6%) lower than the average MISO-ONT price
  - These comparisons exclude uplift, capacity payments, Global Adjustment, etc.

Total Import and Export Volumes

May – April 2008/2009 and 2009/2010 (GWh)

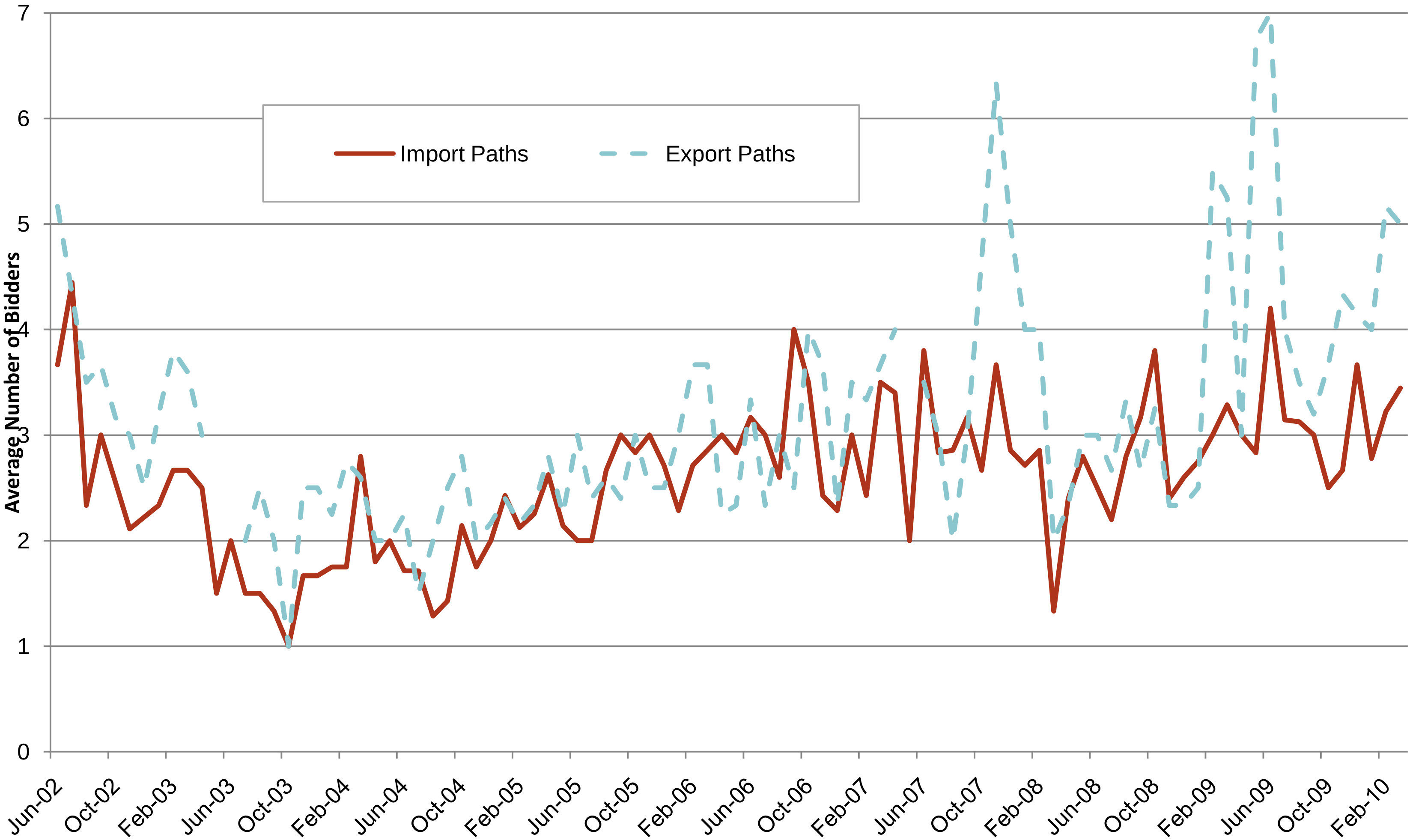
	Total			Total Excluding Linked Wheels		
	2008/2009	**2009/2010**	**% Change**	**2008/2009**	**2009/2010**	**% Change**
Imports	9,034	6,786	(24.9)	6,198	6,385	3.0
Exports	20,196	15,885	(21.3)	17,359	15,486	(10.8)
Net Exports	11,162	9,099	(18.5)	11,161	9,101	(18.5)

Average HOEP Relative to Neighbouring Market Prices

May–April 2008/2009 & 2009/2010 (C$/MWh)

	All Hours			On-peak Hours			Off-peak Hours		
	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change
Ontario - HOEP	44.61	28.30	(36.6)	57.05	34.10	(40.2)	34.37	23.44	(31.8)
MISO – ONT	45.35	30.44	(32.9)	58.78	36.59	(37.8)	34.32	25.30	(26.3)
NYISO – Zone OH	55.27	32.14	(41.8)	62.70	35.67	(43.1)	49.21	29.23	(40.6)
PJM – IMO	60.91	37.84	(37.9)	73.50	42.66	(42.0)	50.67	33.79	(33.3)
New England – Internal Hub	77.00	44.79	(41.8)	85.89	48.93	(43.0)	69.62	41.33	(40.6)
Average	56.63	34.70	(38.7)	67.58	39.59	(41.4)	47.64	30.62	(35.7)

Number of Bidders in TR Auctions



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