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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2009 – April 2010

August 2010

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Ontario

August 30, 2010

The Honourable Howard I. Wetston, Q.C.
Chair & Chief Executive Officer
Ontario Energy Board
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Mr. Wetston:

Re: Market Surveillance Panel Report

On behalf of my colleagues on the Market Surveillance Panel, Don McFetridge and Tom Rusnov, I am pleased to provide you with the Panel's 16th semi-annual Monitoring Report of Ontario's wholesale electricity market, the IESO-administered markets.

This report, covering the period November, 2009 to April, 2010, is submitted pursuant to Article 7.1.1 of Ontario Energy Board By-law #3.

As you know, Don McFetridge's term on the Panel came to an end on July 31st. Don was appointed to the Panel at its inception in 2002. I would like to recognize and thank him for his enormous contributions to the Panel's work and to each of its reports over the past eight years.

Best Regards,

Neil Campbell
Chair, Market Surveillance Panel

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Executive Summary

Overall Assessment

Ontario's IESO-administered wholesale electricity market has operated reasonably well according to the parameters set for it over the winter period, November 2009 to April 2010, although there were occasions where actions by market participants or the IESO led to inefficient outcomes.

The Market Surveillance Panel (MSP) did not find an abuse of market power to have occurred in this period. However, a market participant has requested the MSP initiate an investigation of possible abuse of market power by a market participant. The investigation is ongoing and the Panel will report on the outcome of this investigation when it is completed.

The MSP has not initiated any formal gaming investigations in this period. However, the Panel has observed behaviours associated with extraction of congestion management settlement credit (CMSC) payments that profit some participants at the expense of the market as a whole. It has not yet determined whether to commence a formal investigation in respect of these activities but has made general recommendations relating to the availability of CMSC payments for dispatchable loads in certain situations.

Demand and Supply Conditions

Total Ontario Demand was 138.28 TWh this period, down 7.89 TWh (5.4 percent) compared to the previous period.

There were several notable changes to Ontario's supply of electricity between May 2009 and April 2010. A combined heat and power (CHP) facility and a wind generating facility became commercially operational and another combined-cycle gas-fired facility began commissioning. These changes added 1,117 MW of installed capacity to the Ontario system.

Net exports decreased more than 2 TWh (18.5 percent) to 9.1 TWh during the 2009/10 reporting period. This decrease in net exports was primarily due to a drop in exports (10.8 percent decline) rather than growth in imports (3 percent increase).

Exports (excluding linked wheel transactions) declined this period by 1.9 TWh (10.8 percent) to 15.5 TWh with the majority of exports flowing through Michigan and New York. Ontario went from being an annual net exporter of electricity to Quebec at 350 GWh in 2008/2009 to being an annual net importer of 1,877 GWh in 2009/2010, a year-to-year difference of 2,527 GWh. Approximately 1,500 GWh of imports flowed over the new Outauouais tie with Quebec.

There were zero hours of import congestion on either the Michigan or NYISO interties during the 2009/2010 reporting period, down from 15 and 63 hours respectively during the previous reporting period. Congestion at all other interties significantly increased as the volume of imports increased for all three interties. Hours of import congestion at the Manitoba interface increased from 504 to 1219 hours, while the import volume over that intertie increased by 14.9 percent. The Minnesota intertie experienced the most hours of import congestion at 2,523, up from 418 the previous period, while the total volume of imports over the Minnesota intertie increased by 19.8 percent. The volume of imports over the Quebec intertie increased by 632.5 percent and was accompanied by an increase of 255 hours that experienced import congestion.

In comparison to 2008/2009, the number of hours that experienced export congestion dropped for all intertie groups except Manitoba, which saw a slight increase. Michigan, Minnesota, and NYISO all experienced drops in total volume of exports, and corresponding drops in the number of export congested hours. Quebec experienced an 88.4 percent increase in the volume of exports to a total of 1,538 GWh, yet also saw a decrease in export congested hours from 1,375 to 394 hours (71 percent drop). This can be explained by the opening of new Outauouais intertie transmission facilities.

Market Prices, Uplifts and the Global Adjustment

The average Hourly Ontario Energy Price (HOEP) was $28.30/MWh in this period, a reduction from $44.61/MWh (36.6 percent) from the past period. Seven of the eight lowest monthly average HOEP's since market opening in May 2002 occurred during the latest annual period. One reason for the steep decline in HOEP was due to reduced demand for electricity this year. Lower fuel prices also contributed to a lower HOEP this year. Both natural gas and Central Appalachian (CAPP) coal prices were significantly lower this year (by approximately 45 percent each).

Although HOEP was down significantly relative to the previous period, the effective HOEP, which includes the Global Adjustment, OPG Rebate and hourly uplift, actually increased by 12 percent from $59.76/MWh in 2008/2009 to $67.12/MWh in 2009/2010. The combined Global Adjustment and OPG rebate portion of the charge exceeded the HOEP portion for the period. This primarily reflects regulated and contractual price guarantees for various sources of generation. The structure of generator cost guarantee (GCG) program payments also continues to be a contributor to reduced HOEP and increased Global Adjustment as described in a later section.

Market Outcomes

In pre-dispatch, exports set the pre-dispatch price 4 percent more often this period (up from 20 to 24 percent this year), while imports remained constant at 26 percent and generation decreased from 54 percent to 50 percent.

Coal units continue to be the most frequent price setter in real-time even after experiencing a 15 percent share decline (from 60 percent to 45 percent) compared to the previous period. Shares for hydro units and oil/gas units increased approximately equally to make up for the coal reduction.

On average, there were net improvements in both the average and absolute average differences between one-hour ahead and pre-dispatch prices over the last annual period. This result is a consequence of many factors including:

- The change by the IESO to the use of average demand forecast for non ramp-up hours in pre-dispatch in mid December 2009
- Average error of self-scheduling facilities has decreased over recent months after some high differences were observed in many months between mid 2008 and late 2009
- Offset by increasing aggregate wind forecast error associated with increasing wind capacity
- While the failure rate of export transactions (MW failed relative to MW scheduled) increased from 4.12 percent last year to 5.99 percent this year, the import failure rate fell from 7.27 percent last year to 4.44 percent.

Average nodal prices in all 10 internal Ontario zones declined by approximately 50 percent in comparison to the previous annual period, consistent with reduced demand and fuel prices. Of particular note, the annual average zonal price in the Northwest dropped significantly from -$190.37/MWh in 2008/2009 to -$404.08/MWh in 2009/2010. Reduced demand in the zone, abundant supply of very low-priced water, as well as abundant energy available from imports and congestion of export interfaces continues to lead to energy surpluses in the area and downward pressure on zonal prices.

Operating Reserve (OR) prices dropped by approximately 90 percent over the reporting period as the amount of offered reserve increased with new fossil units coming on-line, ending with 2-year lows of $0.41/MWh for all types of OR. Since October 2009, there also appears to be a convergence of the 10S/10N prices (which are typically similar) and the 30R price (which historically has been lower).

Wholesale electricity consumption continued its downward trend since 2003. This included a post-market-opening monthly low of 1,688 GWh of wholesale consumption in June 2009. Current period wholesale consumption levels are roughly 2/3 of the consumption levels observed in 2003.

In spite of reduced demand and increasing supply on the system, the average monthly pre-dispatch (one-hour ahead) supply cushion fell from 17.7 percent in 2008/2009 to 16.6 percent in 2009/2010. This was primarily associated with a drop in supply cushion in off-peak periods. However, the total number of hours with a pre-dispatch supply cushion less than 10 percent dropped from 2,156 hours to 1,988 hours.

The average monthly real-time supply cushion dropped from 20.7 percent to 18.8 percent. In addition, the number of hours that experienced a supply cushion of 10 percent or less increased from 1,087 hours to 1,368, meaning that 15.6 percent of all hours experienced a supply cushion of 10 percent or less during the 2009/2010 reporting period.

After a noticeable increase in the forced outage rate for coal units between December 2008 and April 2009, the forced outage rate has declined and remained below 20 percent from July 2009 onwards. In fact, the coal forced outage rate fell below 10 percent in four months over the recent annual period, a threshold that had never been observed since market opening. On the other hand, the nuclear forced outage rate appeared slightly higher this period compared to previous annual periods. In May 2009, the nuclear forced outage rate climbed above 30 percent for only the second month since market opening, the other month being April 2005. Aside from May 2009, the nuclear forced outage rate fluctuated between 12 and 24 percent for the remainder of the current period. The oil/gas forced outage rate was the lowest of the three fuel types in most months in the current period but it did reach a historical high of 17.3 percent in October 2009, surpassing the previous record high of 16.8 percent set in June 2003.

Changes in Ontario HOEP were generally consistent with trends in other jurisdictional prices. Only New England, and to an extent PJM, diverged considerably from the group of Northeast interconnected markets. These two jurisdictions were almost always the most expensive regions and saw prices soar above the other jurisdictional prices from November to March. Although the average annual HOEP was materially lower than all other jurisdictions, there were three occasions when the monthly HOEP was higher than the average price in a neighbouring jurisdiction. Such instances occurred in August (MISO), February (NYISO), and April (MISO).

Anomalous Events

There was one hour during the November 2009 through April 2010 review period where the HOEP was greater than $200/MWh. Prices were reflective of tight supply/demand conditions at the time.

There were 460 hours in which the HOEP was less than $20/MWh, including 26 hours where the HOEP was negative. This represented a significant decline from the previous November - April period. Abundant baseload supply relative to total demand (1,470 MW surplus on average during low price hours) was the most important factor leading to the low priced hour outcomes over the latest winter period, followed by demand deviation (237 MW), and finally failed net exports (180 MW).

On April 2, 2010, HE 7, the HOEP fell to -$128.15/MWh, easily surpassing the previous record low HOEP of -$52.08/MWh set on June 7, 2009, HE 6. Factors contributing to the low HOEP included real-time demand that was lighter than projected in pre-dispatch, a large volume of export failures, and greater than anticipated generation from wind facilities. However, the main factor which contributed to a new record low HOEP resulted from a change in the offer strategy at a nuclear facility.

On November 23, 2009, daily CMSC totalled $1.17 million at the Michigan interface. Approximately 80 percent of the CMSC paid was to a single market participant whose export transactions at high bid prices that were destined for PJM were cut over most hours of the day to address potential real-time shortage issues in the OR market. This resulted when the IESO pre-emptively curtailed exports after control action operating reserve (CAOR) had been scheduled as a component of operating reserve (OR) in real-time. Following discussion with the MAU, the IESO’s procedures were clarified to prevent a recurrence of this action.

Matters to Report in the Ontario Electricity Marketplace

OPG Non-Prescribed Assets

The price cap on OPG's non-prescribed asset generation expired on May 1, 2009 and these generating units became directly exposed to the market price. The Panel's observations to date suggest that OPG's peaking hydroelectric generating units are responding to negative market price signals by spilling water more frequently, which is a directionally efficient market outcome (provided that spilling is feasible and not costly).

Hydroelectric Offer Strategies

The Panel's Monitoring of Offers and Bids Document indicates that the possibility of market power being exercised by energy limited resources through economic withholding or pricing up will be assessed by considering offers in relation to the generator's opportunity cost.

Between May 2009 and April 2010, hydroelectric resources set the MCP at a price above $500/MWh in 22 intervals. Although these offers may have been based on a "do not want to run unless necessary" signalling strategy, rather than an actual opportunity cost analysis, the Panel does not view the negative implications to the market from potential pricing up to be material at this point due to the limited number of intervals where the MCP was set by these resources.

Anomalous CMSC Paid to two Dispatchable Loads

Beginning in February 2010 two dispatchable load facilities began to receive extremely high CMSC payments. Collectively these two facilities have a maximum dispatchable capability of 190 MW, representing approximately 20 percent of Ontario's dispatchable load capability.

Over the five month period from February 2010 to June 2010 these two facilities received over $18 million in net CMSC payments. The $18 million paid to these two dispatchable loads is in sharp contrast to the approximately $590,000 of net CMSC payments made to all other dispatchable loads in Ontario over the same period. Put differently, these two facilities that represent 20 percent of Ontario's dispatchable load capacity received approximately 97 percent of CMSC payments made to all Ontario dispatchable loads for the period February to June 2010. On an annualized basis, this would be expected to translate into approximately $43 million in consumer uplift charges, or an uplift charge of approximately $0.28/MWh based on annual market demand of 155 TWh. The CMSC payments made to the two dispatchable loads again highlight aspects of the two schedule system which do not contribute to market efficiency. Three recommendations are made to address the specific concerns identified in these situations and the Panel believes their magnitude warrants immediate action on the part of the IESO.

Two Dispatch Sequence Structure in Ontario

In its last report the Panel urged the industry to reconsider the two schedule system of the Ontario Market. Investigations over the current period reinforce the Panel's view that the frequency and magnitude of two-schedule issues arising and the difficulty of effectively addressing these inefficiencies strongly suggest that it is time to take a more fundamental look at the Ontario market design.

Update on Changes to the IESO's Generation Cost Guarantee Program

In previous Monitoring Reports the Panel has discussed the IESO's GCG program, also referred to as the spare generation online (SGOL) and day-ahead commitment (DACP) programs. On December 9th, 2009 the IESO introduced a rule amendment that was intended to restrict eligibility under the program and to better align GCG participation with economics. The Panel's assessment of the first 4½ months of operation indicates that this rule change does not appear to have eliminated the distortive market effects of the GCG program. Specifically, the continued use of after-the-fact cost submissions -

which represent approximately 61.8 percent of participating generators' total costs - appear to have led to inefficient dispatch, a depressed market clearing price, high uplift charges and an inflated global adjustment. A recommendation has been made to address this continuing market distortion.

Transmission Rights Market

Transmission Rights (TR) can be used by intertie traders to hedge the risks associated with congestion at an external market interface and can potentially improve market efficiency. They may also be purchased by parties that are not hedging physical translations.

The IESO maintains a TR Clearing Account associated with the TR Market. The IESO Board of Directors is authorized to disburse funds from the TR Clearing Account at such times it determines appropriate. This account includes the TR auction revenue, congestion rent collected, and payouts to TR holders (as well other related items such as interest earned, etc.).

The IESO Board has since 2004 set a threshold of $20 million for the TR Clearing Account in order to offset possible congestion rent shortfalls. When the TR Clearing Account exceeds the threshold, the IESO is instructed to increase the amount of TRs for sale until the accumulated amount drops close to the threshold, or the TR amount for sale at any interface reaches its expected maximum transfer capability, whichever comes first. In simple terms, in operating the TR market, the IESO has not been attempting to balance congestion rent collected with the TR payout obligation.

The Panel has observed some fundamental design problems in the current TR market operation. In particular, the market is designed as "closed", such that most revenues (i.e. congestion rent and much of the TR auction revenue) are purposely distributed to TR holders. This has led to very high rates of return to TR holders and left only a portion of

TR auction revenue that can be distributed to customers or transmission owners, or that could be used to build more transmission lines to relieve congestion.

On average, payouts to TR holders have been much higher than Auction Clearing Prices. Simply put, TRs sell at a significant discount to the historic average payout on them. While there is room for debate about the risk premium a TR investor might require, it is hard to imagine that it would approach the premium implicit in the returns that have been realized (the average, annual return to TR holders has been about 100 percent).

The Panel suggests the IESO 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. Pending such a review, the IESO should revise its operating practices to adhere to the original planned design of balancing the TR payout with the congestion rent.

Recommendations

The Panel has made six recommendations in the areas of Price Fidelity, Dispatch, and Hourly Uplift Payments.

Price Fidelity

The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market.

Recommendation 3-5 (Chapter 3, section 2.3)

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 (Chapter 3, section 2.3)

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

Dispatch

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market.

Recommendation 3-4 (Chapter 3, Section 2.2)

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.

Recommendation 3-2 (Chapter 3, Section 2.1)

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.

Hourly Uplift Payments

The Panel examines hourly uplift payments both in respect of their contribution to the effective HOEP and also their impact on the efficient operation of the market.

Recommendation 3-1 (Chapter 3, section 2.1)

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

Recommendation 3-2 (Chapter 3, section 2.1)

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.

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Chapter 1: Market Outcomes May 2009 to April 2010

1. Highlights of Market Indicators

This Chapter provides an overview of the results of the IESO-administered markets over the period May 1, 2009 to April 30, 2010.

1.1 Pricing

The average Hourly Ontario Energy Price (HOEP) was $28.30/MWh this period, representing a reduction in HOEP of 36.6 percent over the previous period's average of $44.61/MWh. Seven of the eight lowest monthly average HOEP's since market opening in May 2002 occurred during the latest annual period. These months occurred primarily in 2009 and ranged in price from $18.99/MWh to $28.22/MWh.

Although HOEP was down significantly since the previous period, the effective HOEP, which includes the Global Adjustment, OPG Rebate and hourly uplift, actually increased from $59.76/MWh in 2008/2009 to $67.12/MWh in 2009/2010, an increase of 12.3 percent. The combined Global Adjustment and OPG Rebate portion of the per MW charge actually exceeded the HOEP portion of the per MW charge for the period.

1.2 Demand

Total Ontario Demand was 138.28 TWh this period, down 7.89 TWh (5.4 percent) compared to the previous period. All months saw a decline this period over last, except February which saw a tiny increase. June and July experienced the largest proportional drops of 10.6 and 13.9 percent respectively.

Exports (excluding linked wheel transactions[1]) declined this period by 1.9 TWh (10.8 percent) to 15.5 TWh with the majority of exports flowing through Michigan and New York.

1.3 Supply

There were several notable changes to Ontario's supply of electricity between May 2009 and April 2010. A combined heat and power (CHP) facility and a wind generating facility became commercially operational and another combined-cycle gas-fired facility began commissioning. These changes added 1,117 MW of installed capacity to the Ontario system. In addition, the status of another CHP facility changed from self-scheduler to dispatchable.

1.4 Imports and Exports

Net exports decreased more than 2 TWh (18.5 percent) to 9.1 TWh during the 2009/2010 reporting period. Declines in on-peak exports accounted for 82 percent of the absolute drop in exports, with off-peak reductions making up the remainder. This decrease in net exports was primarily due to a drop in exports (10.8 percent decline) rather than growth in imports (3 percent increase).

2. Pricing

2.1 Ontario Energy Price

Table 1-1 presents the monthly average HOEP for May to April 2008/2009 and 2009/2010. The average HOEP for the May 2009 to April 2010 period was \$28.30/MWh, down from \$44.61/MWh (37 percent) compared to one year earlier. Both

[1] A linked wheel transaction occurs when an intertie trader simultaneously imports electricity into Ontario and exports the same quantity out of Ontario.

on and off-peak average HOEP fell this year, although the percentage change decline was higher during the on-peak hours (40 percent reduction in on-peak HOEP compared to a 32 percent reduction in off-peak HOEP).

With the exception of April 2010, the average HOEP was lower in all months with the most significant year-over-year changes occurring in the summer months of June, July, and September 2009. In April 2010, the HOEP was 68 percent higher than the previous April average. The percentage increase was primarily indicative of a transmission constraint that had limited export volumes at the New York (and indirectly the Michigan interface) for much of April 2009.

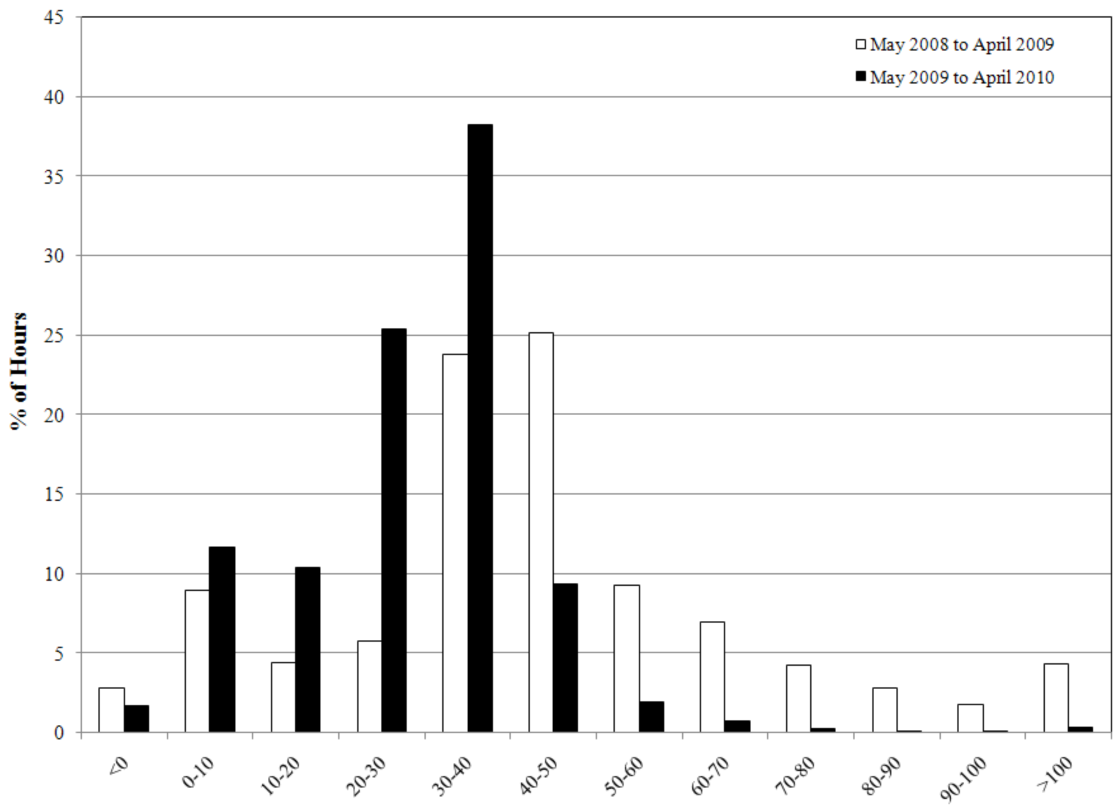
One reason for the steep decline in HOEP was due to reduced demand for electricity this year relative to one year ago as shown in Table 1-23 below. Factors affecting supply, such as lower fuel prices, also contributed to a lower HOEP this year. Both natural gas and Central Appalachian (CAPP) coal prices were approximately 45 percent lower this year relative to the previous annual period.

Table 1-1: Average HOEP, On-peak and Off-peak, May–April 2008/2009 & 2009/2010 ($/MWh)

	Average HOEP			Average On-Peak HOEP			Average Off-Peak HOEP		
	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change
May	34.56	27.77	(19.6)	47.12	35.35	(25.0)	24.21	22.04	(9.0)
June	57.44	22.84	(60.2)	76.57	30.58	(60.1)	42.13	15.43	(63.4)
July	56.58	18.99	(66.4)	82.78	24.19	(70.8)	35.00	14.31	(59.1)
August	46.57	26.07	(44.0)	60.63	34.92	(42.4)	35.96	19.40	(46.1)
September	49.09	20.76	(57.7)	58.58	27.62	(52.9)	40.78	14.75	(63.8)
October	45.27	29.22	(35.5)	55.87	34.92	(37.5)	35.75	24.53	(31.4)
November	51.78	26.54	(48.7)	59.98	32.66	(45.5)	45.22	21.18	(53.2)
December	46.34	35.05	(24.4)	57.67	39.62	(31.3)	37.02	31.28	(15.5)
January	53.22	37.40	(29.7)	62.32	40.93	(34.3)	45.73	34.73	(24.1)
February	47.24	35.90	(24.0)	57.78	39.95	(30.9)	38.53	32.56	(15.5)
March	28.88	28.22	(2.3)	36.65	30.89	(15.7)	21.90	25.62	17.0
April	18.40	30.83	67.6	28.62	37.57	31.3	10.22	25.43	148.8
Average	44.61	28.30	(36.6)	57.05	34.10	(40.2)	34.37	23.44	(31.8)

Figure 1-1 presents the frequency distributions of HOEP over the last two years. During the May 2008 to April 2009 period, the HOEP most frequently fell into the $40-50/MWh price range (25 percent of all hours). In the latest annual period, the HOEP was most frequently in the $30-40/MWh price category (approximately 38 percent of all hours) while the frequency of HOEP in the $40-50/MWh dropped (less than 10 percent of all hours). There was also a large increase in the number of observations in the $20-30/MWh range. Declining fossil fuel prices this year contributed to this change. Finally, there were fewer negative HOEP's, this year, falling from 247 hours last year to 147 hours this year.

Figure 1-1: Frequency Distribution of HOEP,
May–April 2008/2009 & 2009/2010
(% of total hours in $10/MWh price ranges)



2.1.1 *Load-weighted HOEP*

Table 1-2 reports the load-weighted HOEP by load type for the 2008/2009 and 2009/2010 periods. Load-weighted HOEP provides a more accurate representation of the actual price paid by loads since it is weighted by hourly demand. Similar to the unweighted HOEP, there were significant declines in the load-weighted HOEP for all load types in 2009/2010. Relative to the same period one year ago, load-weighted HOEP for the all loads category declined by $17.95/MWh or 37.7 percent.

As expected, the average load-weighted HOEP was lowest for the dispatchable load category at $27.95/MWh ($1.77/MWh or 6.0 percent less than load weighted HOEP for all loads overall). To the extent possible, these resources attempt to avoid higher price periods by reducing load during higher-price periods and/or shifting consumption to lower-price periods. Other wholesale loads also make some attempt to do so and paid an average load-weighted HOEP of $28.35/MWh ($1.37/MWh or 4.6 percent less than for all loads overall). Finally, LDC load, which represents the least price responsive component of load but most significant in magnitude, paid an average load-weighted HOEP of $29.90/MWh ($0.18/MWh or 0.6 percent more than for all loads overall).

Table 1-2: Load-Weighted Average HOEP by Load Category May–April 2008/2009 & 2009/2010 ($/MWh)

Year	Unweighted HOEP	Load-weighted HOEP[2]			
		LDC	Dispatchable Load	Other Wholesale Loads	All Loads
2008/2009	44.61	48.06	43.03	45.26	47.67
2009/2010	28.30	29.90	27.95	28.35	29.72
Difference	(16.31)	(18.16)	(15.08)	(16.92)	(17.95)
% Change	(36.6)	(37.8)	(35.0)	(37.4)	(37.7)

[2] Unadjusted – like the unweighted HOEP, the load-weighted HOEP does not include the impact of the Global Adjustment or the OPG Rebate.

2.1.2 *Impact of the Global Adjustment, OPG Rebate, and Hourly Uplift on the Effective HOEP*

Figure 1-2 plots the monthly average HOEP and effective HOEP between April 2005 and April 2010 as well as payments made through the Global Adjustment (GA) and the OPG Rebate.[3] Hourly uplift payments are also included in the effective HOEP as they represent another payment from consumers to generators, intertie traders and to dispatchable loads.[4][5] The GA tends to moderate the effective HOEP by lowering (increasing) the net payments to generators when the average HOEP is high (low) during a month. From January 2006 to April 2009, the effective HOEP (including hourly uplift) generally remained between $50/MWh and $60/MWh with only six occurrences where the effective HOEP climbed above $60/MWh. The effective HOEP has consistently remained above $60/MWh since May 2009 and exceeded $70/MWh in October 2009.

The Global Adjustment has been increasing since the beginning of 2009 for three reasons. First, for most price-guaranteed generation procured into the system by the Ontario Power Authority, the gap between the HOEP and the guaranteed contract price becomes a component of the Global Adjustment. The substantial decline in average HOEP beginning March 2009 triggered substantial increases in Global Adjustment payments. Second, more contracted energy has come online and in certain situations contract prices have increased. Third, the structure of the IESO's GCG program has contributed to lower HOEP, which in turn has increased the Global Adjustment. Over the last 12 months, Global Adjustment on average has been larger than the average HOEP with the exception of three months (December 2009 to February 2010, which are the only three months where the average HOEP was higher than $35/MWh since February 2009).

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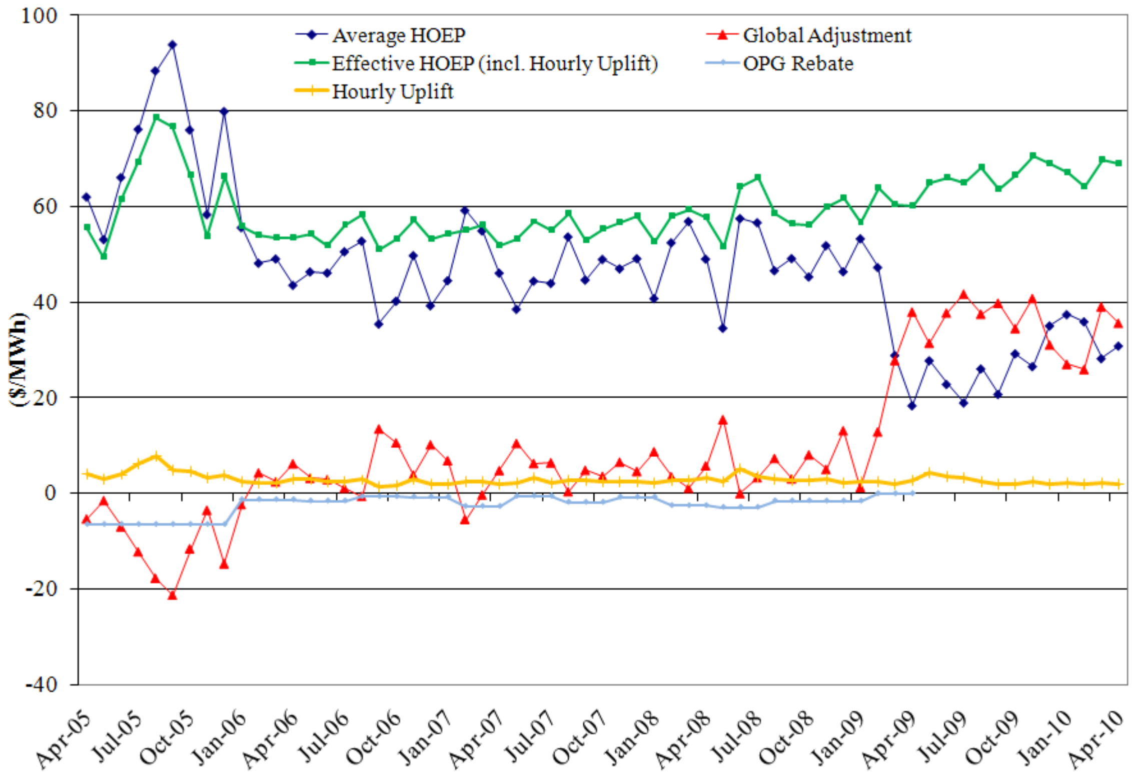
[3] The OPG Rebate provided regulated compensation arrangements to OPG's non-prescribed assets. It was discontinued in April 2009.
[4] In previous Panel Reports, the Effective HOEP did not incorporate the hourly uplift component. Hourly uplifts are discussed in Section 2.2 below.
[5] Dispatchable loads pay hourly uplift based on consumption, but unlike other loads can also earn hourly uplift payments, including CMSC and operating reserve payments.

Global Adjustment reached a peak of $41.72/MWh in July 2009 with an average HOEP of $18.99/MWh in the month.

Figure 1-2: Monthly Average Effective HOEP Adjusted for OPG Rebate, Global Adjustment, and Hourly Uplift
April 2005 – April 2010
($/MWh)



*Note – OPG Rebate was discontinued after April 2009

Table 1-3 reports the average HOEP relative to the load-weighted HOEP with and without the Global Adjustment, OPG Rebate, and hourly uplift over the last two May to April periods. The combination of the OPG Rebate and Global Adjustment component increased this year by $25.71/MWh (276 percent). The hourly uplift component fell by 14 percent, from $2.78/MWh last year to $2.39/MWh this year. Although the load-weighted HOEP fell by $17.95/MWh this period, the offsetting effect of the increase to the Global Adjustment component led to a net increase in the effective load-weighted HOEP of $7.36/MWh, or 12 percent.

Table 1-3: Impact of Adjustments and Uplifts on HOEP, May–April 2008/2009 & 2009/2010 ($/MWh)

Year	Average HOEP	Load-Weighted HOEP	Global Adjustment and OPG Rebate[6]	Hourly Uplift	Effective Load-Weighted HOEP
2008/2009	44.61	47.67	9.31	2.78	59.76
2009/2010	28.30	29.72	35.01	2.39	67.12
Difference ($)	(16.31)	(17.95)	25.71	(0.39)	7.36
% Change	(36.6)	(37.7)	276.2	(13.9)	12.3

2.2 Hourly Uplift and Components

Table 1-4 reports the monthly total hourly uplift charges for the last two reporting periods. Total hourly uplift charges dropped from $405.5 million in 2008/2009 to $329.6 million in 2009/2010, a reduction of 19 percent. Payments for losses dropped considerably, Operating Reserve (OR) payments and CMSC payments fell only slightly, and Intertie Offer Guarantee (IOG) payments remained relatively stable.

Table 1-4: Monthly Total Hourly Uplift Charge by Component and Month, May–April 2008/2009 & 2009/2010 ($ millions and %)

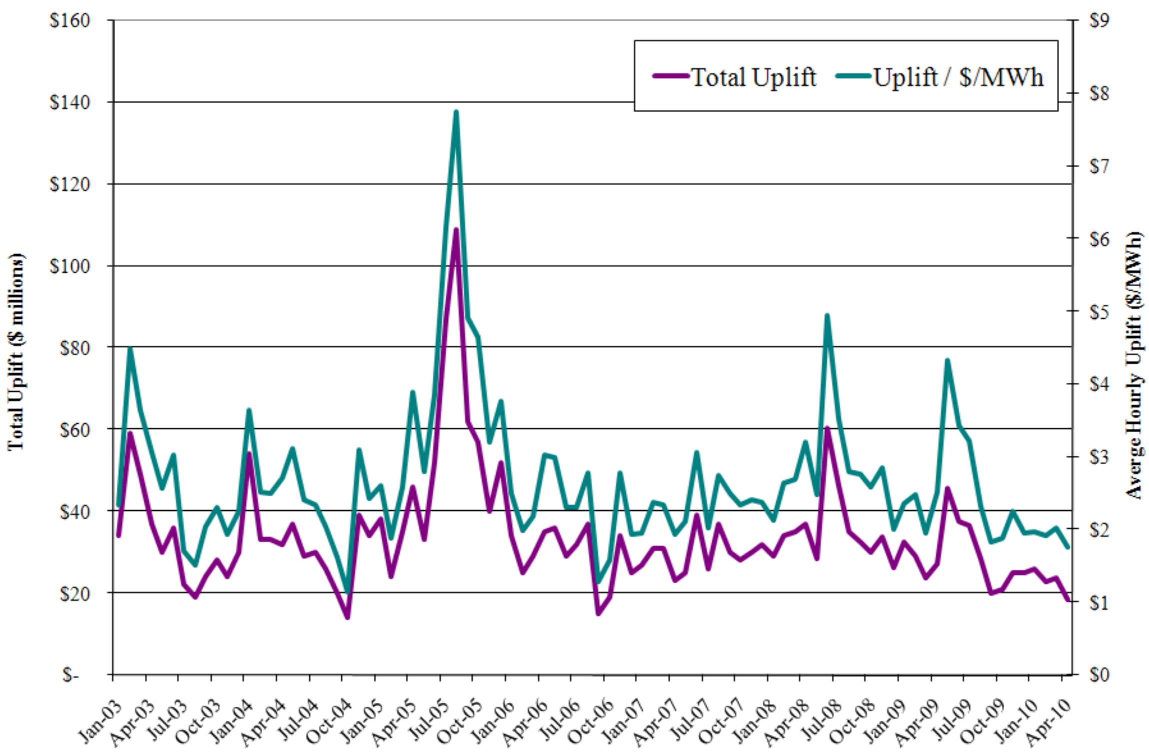
	Total Hourly Uplift		IOG		CMSC		Losses		Operating Reserve	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	28.4	45.6	1.6	1.0	11.3	25.0	10.4	8.8	5.1	10.8
June	60.4	37.4	3.5	1.5	34.7	21.4	17.5	7.6	4.7	7.0
July	46.3	36.5	2.0	5.7	18.8	18.0	19.5	5.7	6.1	7.1
August	35.1	28.5	1.0	1.4	16.3	12.2	15.1	8.4	2.7	6.5
September	32.5	20.0	1.7	2.4	16.1	11.0	13.9	3.7	0.9	3.0
October	30.1	21.0	1.5	2.0	14.5	10.3	9.9	7.5	4.2	1.2
November	33.8	25.0	2.3	0.5	15.5	14.7	11.9	6.7	4.1	3.1
December	26.2	24.9	1.4	1.1	6.3	10.4	16.0	10.3	2.5	3.1
January	32.5	26.0	1.3	0.9	9.8	11.6	15.2	10.1	6.2	3.4
February	29.1	22.7	1.0	0.5	7.9	10.6	13.3	9.2	6.8	2.4
March	23.9	23.7	0.8	0.9	10.4	12.5	8.4	7.5	4.2	2.8
April	27.1	18.4	0.3	0.7	13.1	10.5	6.0	6.9	7.6	0.3
Total	405.5	329.6	18.4	18.6	174.8	168.2	157.1	92.4	55.2	50.5
% of Total	100.0	100.0	4.5	5.6	43.1	51.0	38.7	28.0	13.6	15.3

[6] A positive value represents a payment from consumers to generators.

- IOG Payments – Annual IOG Payments stayed relatively constant over the last two annual reporting periods, only increasing $0.2 million. The 2009/2010 monthly high occurred in July 2009 and saw payments of $5.7 million, a $2.2 million (62.9 percent) increase over the 2008/2009 high of $3.5 million reached in June 2008. IOG payments tend to be larger in months when pre-dispatch to real-time price differences are highest. As shown later in Table 1-10, the average difference between the one-hour ahead pre-dispatch and real-time price in July 2009 was almost 9 percent, which is higher than any other month in the current and previous annual periods.
- Losses – Total payments for losses declined dramatically by $64.7 million (41 percent) this period over last. This decrease occurred consistently across all months with the exception of April 2010, where payment increased by $0.9 million (15 percent) relative to April 2009. The decline in payments is consistent with the reduction in HOEP that occurred in almost every month (as seen in Table 1-1) because payments to generators for losses are directly related to the price of energy as well as the quantity of losses incurred.
- CMSC Payments – CMSC payments decreased $6.6 million (4 percent) but showed much less volatility month to month than during the previous period. The maximum monthly payment of $25.0 million occurred in May 2009 and the minimum monthly payment of $10.3 million occurred in October 2009. As a percentage of total uplift payments, CMSC increased from 43.1 percent to 51.0 percent, driven by the large declines in losses.
- Operating Reserve Payments – Annual OR payments fell $4.7 million (9 percent) from $55.2 million in 2008/2009 to $50.5 million in 2009/2010. All months from May to September 2009 saw increases in total OR payments when compared to payments made the same month of the previous year. Conversely, all subsequent months (with the exception of December 2009) saw drops in total OR payments made over the same month in the previous year. This is consistent with the decline in OR prices observed after October 2009 relative to the same months one year earlier, as reported in Tables 1-21 and 1-22 below.

Figure 1-3 plots hourly uplift charges in millions of dollars and in $/MWh between January 2003 and April 2010. From May 2009 to April 2010 both total uplift and uplift $/MWh have deviated from their relative long-term stability. After an early summer 2009 spike, total uplift and uplift $/MWh declined steadily to $18.4 million total uplift and $1.76/MWh of uplift in April 2010, representing the lowest values observed since the fall of 2006.

Figure 1-3: Total Hourly Market Uplift and Average Hourly Market Uplift, January 2003–April 2010 ($ millions and $/MWh)



2.3 Price Setters

Over the latest twelve-month period, there has been a noticeable difference in real-time price-setting shares across fuel type categories. Specifically, coal-fired units set the price significantly less often than one year ago, which was offset by increases in shares for hydro and gas units. Pre-dispatch price setting was relatively stable, with a small increase in the share set by exports offsetting a decline in the share set by generation.

2.3.1 *Real-time Price Setters*

Table 1-5 presents the monthly average share of real-time MCP set by resource type for the 2008/2009 and 2009/2010 periods.[7] The table shows that the average share by resource type shifted significantly from coal to hydro and gas units. However, coal units continue to be the most frequent price setter in real-time during the 2009/2010 period even after experiencing a 15 percent share decline (from 60 percent to 45 percent) compared to the previous period. Shares for hydro units and gas units both increased in the current period by 7 percent and 8 percent to 31 percent and 23 percent, respectively. Nuclear units set the real-time MCP 1 percent of all intervals this year which is unchanged relative to the previous May to April period. The shift in the average share from coal units to hydro and gas units is consistent with an annual decline in coal production along with the growing capacity of gas-fired units over the last two years.[8]

Table 1-5: Average Share of Real-time MCP set by Resource Type, May–April 2008/2009 & 2009/2010 (% of Intervals)

	2008/2009	2009/2010	Difference
Coal	60	45	(15)
Hydro	24	31	7
Gas	15	23	8
Nuclear	1	1	0
Total	100	100	0

Tables 1-6 to 1-8 report the monthly share of real-time MCP set by resource type for the last two twelve-month periods for all intervals, on-peak, and off-peak intervals respectively. Table 1-6 indicates that coal's share of setting the real-time MCP was

[7] Dispatchable loads are also able to set the real-time MCP but are removed from Tables 1-4 to 1-7 since they do so infrequently. For example, between May 2009 and April 2010, dispatchable loads set the real-time MCP in 0.05 percent of all intervals.
[8] Coal production totalled 9.4 TWh between May 2009 and April 2010, a decline of 9.8 TWh (51 percent) compared to the same period one year earlier.

considerably lower between May and November of the current period but returned to more historic levels for the remainder of the current reporting period. However, the increase in the share during the winter months did not offset the decline during the other months in the beginning of the 2009/2010 period and thus the average share for coal decreased by 15 percent.

Hydro units set the MCP much more frequently this year, especially between June and November 2009. Gas units set the MCP more often in most months during the 2009/2010 period with the exception of July and January (2 percent and 11 percent lower). Nuclear units average share was relatively unchanged year-over-year and mainly during off-peak hours only.

Table 1-6: Monthly Share of Real-Time MCP set by Resource Type, May–April 2008/2009 & 2009/2010 (% of Intervals)

	Coal		Gas		Hydro		Nuclear	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	67	47	3	22	31	30	0	1
June	60	35	16	16	24	45	0	3
July	56	26	18	16	26	57	0	1
August	64	35	9	27	26	37	0	1
September	59	32	13	27	28	39	0	2
October	67	39	9	27	24	34	0	1
November	59	38	24	30	17	31	0	1
December	60	61	19	23	20	16	1	0
January	61	70	26	15	13	14	0	0
February	69	66	19	23	12	11	0	0
March	63	52	8	20	26	28	3	0
April	35	37	13	32	41	32	11	0
Average	60	45	15	23	24	31	1	1

During the on-peak intervals, Table 1-7 shows that coal's share declined from 57 percent to 46 percent overall, with the largest monthly decrease occurring in May (36 percent) and August 2009 (26 percent). Coal's share fell during both on-peak and off-peak hours, but the effect was greater during the off-peak hours (19 percent decline off-peak compared to 11 percent on-peak) as shown in Table 1-8. As previously noted, the monthly average shares for both hydro units and gas units increased in 2009/2010. The increase for hydro units appears to have only occurred during off-peak hours only while in the case of gas units, the share increased during both on-peak and off-peak hours.

Table 1-7: Monthly Share of Real-Time MCP set by Resource Type, On-Peak, May–April 2008/2009 & 2009/2010 (% of Intervals)

	Coal		Gas		Hydro		Nuclear	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	82	46	5	39	13	16	0	0
June	54	48	28	26	19	25	0	1
July	51	38	34	27	15	35	0	0
August	68	42	17	44	15	13	0	0
September	55	44	22	40	23	15	0	0
October	67	45	17	43	16	12	0	0
November	47	47	41	41	12	12	0	0
December	44	47	37	43	19	10	0	0
January	44	56	46	30	10	14	0	0
February	56	49	33	42	11	9	0	0
March	67	49	14	33	19	18	0	0
April	44	36	23	49	32	14	1	0
Average	57	46	26	38	17	16	0	0

Table 1-8: Monthly Share of Real-Time MCP set by Resource Type, Off-Peak, May–April 2008/2009 & 2009/2010 (% of Intervals)

	Coal		Gas		Hydro		Nuclear	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	54	47	1	10	45	41	0	1
June	65	23	7	7	28	64	0	5
July	61	15	4	7	35	77	0	1
August	61	30	4	14	35	55	0	1
September	63	22	5	15	32	60	0	4
October	67	34	2	13	32	51	0	1
November	69	29	10	20	21	49	0	2
December	73	71	5	8	21	21	1	0
January	75	81	10	4	15	15	0	0
February	79	80	7	7	14	13	0	0
March	59	54	3	7	32	38	6	0
April	28	37	5	18	48	45	19	1
Average	63	44	5	11	30	44	2	1

2.3.2 *Pre-dispatch Price Setters*

Table 1-9 presents the percentage of hours that the one-hour ahead pre-dispatch price was set by resource type on a monthly basis for the 2008/2009 and 2009/2010 periods.[9] Overall, there was no change for imports setting the pre-dispatch price this period, although there were some minor monthly fluctuations. Exports set the pre-dispatch price 4 percent more often this period (up from 20 to 24 percent this year), which offset the 4 percent decline by generators (down from 54 to 50 percent this year).

Table 1-9: Monthly Share of Final Pre-dispatch Price set by Resource Type, May–April 2008/2009 & 2009/2010 (% of Hours)

	Imports		Exports		Generation	
	2008/ 2009	**2009/ 2010**	**2008/ 2009**	**2009/ 2010**	**2008/ 2009**	**2009/ 2010**
May	27	27	19	25	54	47
June	29	27	16	32	55	41
July	29	33	18	24	53	43
August	21	29	18	21	61	51
September	34	30	20	25	46	45
October	32	24	21	31	47	45
November	36	12	21	32	43	56
December	24	18	25	28	52	54
January	24	25	23	19	53	56
February	27	36	20	10	53	54
March	14	33	17	20	69	48
April	11	22	22	18	67	61
Average	26	26	20	24	54	50

2.4 One-Hour Ahead Pre-dispatch Prices and HOEP

Production and consumption decisions are improved when market participants can rely on accurate pre-dispatch price projections. Therefore, the differences between one-hour ahead pre-dispatch price and HOEP is an important statistic to monitor. A sound pre-dispatch price signal can translate into real-time dispatch efficiencies.

[9] The table excludes the very small (on the order of 0.1 percent) contribution from Dispatchable Loads.

2.4.1 *One-hour Ahead Pre-dispatch Price*

Table 1-10 presents the differences between the one-hour ahead pre-dispatch price and the HOEP for May to April 2008/2009 and 2009/2010. On average, there were improvements in both the average and absolute average differences over the last two periods. The average difference decreased from $4.01/MWh to $3.23/MWh (19.5 percent) while the absolute average difference decreased from $10.44/MWh to $6.41/MWh (38.6 percent).[10] In fact, the absolute average difference fell in all months this year compared to the same months one year earlier.

Similar patterns are not observed when the differences are presented as a percentage of HOEP. As mentioned in the previous section, the average HOEP has fallen dramatically over the current period and thus, the average difference between pre-dispatch and real-time prices expressed as a percentage of average HOEP appears higher. The overall average difference as a percentage of HOEP increased from 9.7 percent to 13.4 percent in the recent period with the largest monthly increases occurring in July and September 2009 (37.8 percent and 18.4 percent higher). Not surprisingly, the average HOEP was lowest during these two months as shown in Table 1-1 above.

[10] The positive arithmetic averages indicate that pre-dispatch prices are generally higher than real-time prices, with the averages in each month relative to the corresponding month last period.

Table 1-10: Measures of Differences between One-Hour Ahead Pre-Dispatch Prices and HOEP, May–April 2008/2009 & 2009/2010 ($/MWh)

	Average Difference		Absolute Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of Average HOEP[11]	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	4.86	3.57	9.33	7.49	63.30	44.58	(45.40)	(121.33)	13.02	11.46	14.1	12.9
June	8.60	5.73	14.97	8.74	115.21	41.01	(217.42)	(54.84)	22.60	11.19	15.0	25.1
July	5.21	8.92	11.66	10.79	61.08	82.47	(155.88)	(46.66)	17.67	11.84	9.2	47.0
August	1.23	1.80	10.54	8.01	36.54	86.94	(330.15)	(326.31)	22.67	22.54	2.6	6.9
September	1.88	4.60	11.33	6.11	334.24	36.80	(337.64)	(37.34)	27.03	8.08	3.8	22.2
October	2.88	3.59	9.12	7.88	38.77	48.79	(234.55)	(247.31)	18.14	16.82	6.4	12.3
November	4.81	3.30	8.99	6.31	42.90	38.21	(67.71)	(141.34)	11.81	12.01	9.3	12.4
December	3.08	2.71	9.92	4.66	83.79	81.04	(177.65)	(41.62)	18.12	7.76	6.6	7.7
January	7.42	0.26	12.44	4.63	1,925.02	35.85	(379.76)	(455.14)	73.97	18.18	13.9	0.7
February	0.18	0.93	11.29	2.83	60.23	42.73	(1,846.87)	(59.24)	81.92	5.20	0.4	2.6
March	4.35	2.48	7.87	4.05	66.62	31.87	(125.82)	(30.98)	13.35	5.59	15.1	8.8
April	3.66	0.87	7.82	5.39	57.88	160.9	(80.80)	(139.98)	11.89	12.69	19.9	2.8
Average	4.01	3.23	10.44	6.41	240.47	60.93	(333.30)	(141.84)	27.68	11.95	9.7	13.4

2.4.2 *Reasons for Differences*

To date, the Panel has identified four main factors that lead to discrepancies between pre-dispatch and real-time prices:[12]

- Pre-dispatch to real-time demand forecast deviations;
- Performance of self-schedulers and intermittent (primarily wind) generators;

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[11] In previous MSP Reports, the average difference as a percentage of HOEP statistics found in the last column of Tables 1-9 and 1-10 was calculated hourly and then averaged over the month. However, given the high frequency of HOEP around $0/MWh (and sometimes a HOEP equal to $0/MWh leading to an undefined result), the statistic was being driven up (or down) by some very large outliers. To minimize this outlier effect, the calculation has been revised as the average price difference as a percentage of the average HOEP in each month (denominator being the monthly average HOEP reported in Table 1-1). Results from the 2007/2008 winter period have also been adjusted.

[12] Pre-dispatch and real-time scheduling also differ in the magnitude of control action operating reserve (CAOR) incorporated, although this tends primarily to affect operating reserve price differences, with an indirect and smaller influence on energy prices. Up to September 2008 there were 400 MW of CAOR available in pre-dispatch and 800 MW in real-time. Subsequently, the 400 MW in pre-dispatch was dropped. See the Panel's January 2009 Monitoring Report, pp. 191-193.

- Failure of scheduled imports and exports; and
- Frequency that imports (or exports) set the pre-dispatch price.

Table 1-11 presents the average and absolute average differences for each of the first three factors listed above for the past twelve-month period.[13] Monthly averages and absolute averages provide some indication as to which of the factors are most important in leading to discrepancies between pre-dispatch and real-time prices. However, any one of these factors can lead to significant price discrepancies in a given hour.

Table 1-11: Average and Absolute Average Hourly Differences by Discrepancy Factor, May 2009–April 2010 (MW)

Discrepancy Factor	Average Difference (MW)	Absolute Average Difference (MW)	Average Difference as % of Ontario Demand*	Absolute Average Difference as % of Ontario Demand*
PD to Real-time Average Demand Forecast Deviation	186	254	1.2	1.6
PD to Real-time Demand Forecast Error	14	161	0.1	1.0
Self-Scheduling and Intermittent Deviation	31	80	0.2	0.5
Net Export Failures	84	119	0.5	0.8

*Average hourly Ontario Demand (denominator) for the twelve month period was 15,703 MW

Overall, the largest absolute average differences result from demand forecast discrepancies. The pre-dispatch to real-time average demand difference was 186 MW (1.2 percent of Ontario Demand), on average, over the latest 12 month period and the absolute average difference was 254 MW (1.6 percent of Ontario Demand). In the case of pre-dispatch to real-time demand forecast error, the average difference was 14 MW (0.1 percent of Ontario Demand) while the absolute average difference was 161 MW (1 percent of Ontario Demand). Average and absolute average net export failures were

[13] The summary table does not report the frequency that imports (or exports) set the pre-dispatch price since the metric to measure the frequency (percentage of hours) does not necessarily translate into an hourly quantity (MW) statistic like the three other factors that lead to discrepancies between pre-dispatch and real-time prices.

second highest in magnitude at 84 MW (0.5 percent of Ontario Demand) and 119 MW (0.8 percent of Ontario Demand), respectively, followed by self-scheduling and intermittent deviation.

2.4.2.1 Demand Discrepancies

In a move to help reduce Surplus Baseload Generation (SBG) events and improve dispatch efficiencies, the IESO switched to using average demand forecast for non ramp-up hours in pre-dispatch in mid December 2009.[14] The previous practice generated a forecast that targeted peak interval demand in an hour, meaning many intervals during the hour had actual demand levels well below the forecast peak. This placed downward pressure on real-time prices relative to the pre-dispatch projections. With the exception of some morning and evening ramping hours, the new method (average demand forecasting) targets the average demand during that hour and uses the forecast to schedule resources in pre-dispatch.[15] This change is consistent with historical issues raised by the Panel about the use of peak demand forecasts dating back to its inaugural report in 2002.[16]

Although the time horizon subsequent to the pre-dispatch demand forecast change is limited, there is evidence that demand discrepancy and demand forecast errors have been reduced. This section reports on two aspects of demand forecast discrepancy that can contribute to differences in pre-dispatch and real-time prices. The first compares average differences between the pre-dispatch forecast and average real-time demand and represents demand forecast deviation. The second compares the pre-dispatch forecast with the targeted real-time demand value and represents IESO demand forecast error.

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[14] The announcement, dated November 19, 2009, is available on the IESO website at: http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=4973

[15] As of December 15, 2009, average demands are used to forecast real-time demand in all hours, with the exception of HE 6-9 between February and October and HE 6-9 and HE 17-18 between November and January where peak demands are used.

[16] The use of a peak demand forecast in pre-dispatch was first identified as an issue in the Panel's October 2002 Monitoring Report, pp. 87-94. The MSP identified the use of peak demand as a problem for two reasons; it leads to inaccurate price signals and can contribute to dispatch inefficiencies.

Pre-dispatch to Real-time Average Demand Forecast Deviation

The difference between the pre-dispatch demand forecast and real-time average demand can lead to discrepancies between pre-dispatch and real-time prices. As mentioned above, there was a change in the forecast used to schedule resources in pre-dispatch in mid December 2009. Specifically the IESO now uses the average demand forecast in pre-dispatch for all hours, with the exception of traditional morning ramp-up and evening ramp-down hours. The move from peak demand forecast to average demand forecast in pre-dispatch would be expected to reduce demand forecast deviations.

Table 1-12 presents the three-hour ahead and one-hour ahead pre-dispatch to real-time average demand forecast deviation by month between May 2008 and April 2010.[17] Improvements in average monthly demand deviation are apparent in both the three-hour ahead and one-hour ahead metrics. The three-hour ahead measure fell 0.16 percent, from 2.04 percent last year to 1.88 percent this year while the one-hour ahead measure fell by 0.18 percent, from 1.84 percent last year to 1.66 percent in the latest May to April period.

[17] Pre-dispatch forecast to real-time average demand discrepancy is calculated as the absolute value of pre-dispatch minus real-time average demand divided by real-time average demand

Table 1-12: Pre-dispatch to Real-time Average Demand Forecast Deviation, May–April 2008/2009 & 2009/2010 (% of Real-time Average Demand)

	Three-Hour Ahead		One-Hour Ahead	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	1.78	2.03	1.65	1.85
June	2.33	2.09	2.08	1.93
July	2.27	2.33	1.96	2.04
August	1.97	2.38	1.85	2.09
September	1.74	2.06	1.68	1.89
October	1.88	1.83	1.77	1.68
November	1.96	2.15	1.85	2.04
December	2.22	1.98	1.98	1.69
January	2.20	1.50	1.94	1.22
February	1.92	1.28	1.74	1.06
March	2.11	1.44	1.81	1.15
April	2.07	1.51	1.81	1.24
Average	2.04	1.88	1.84	1.66

There was a noticeable decline in both the three-hour ahead and one-hour ahead demand deviation measures after December 2009. The decline coincides with the implementation of average demand forecasting in pre-dispatch and consequently the calculation of the pre-dispatch price projection. Prior to December 2009, the one-hour ahead average demand forecast deviation never fell below 1.65 percent in any given month over the last two years, with the exception of May 2008. However, between January and April 2010, the one-hour ahead average demand forecast deviation never exceeded 1.24 percent (April 2010) and reached a low of 1.06 percent in February 2010. Three-hour ahead monthly demand forecast deviations exhibited a similar pattern of improvement.

Pre-dispatch to Real-time Demand Forecast Error

As mentioned above, the IESO implemented a change in December 2009 to using average demand forecasts (for most hours of the day) to generate pre-dispatch schedules and prices. In previous reports, the Panel reported on the performance of the IESO's pre-dispatch forecast relative to the real-time demand outcome it was intended to target. Prior to December 2009, this was referred to as the peak-to-peak demand forecast error since a forecast of peak demand was used in pre-dispatch scheduling. This metric was adjusted as of December 16, 2009 to compare the IESO's forecast with real-time average demand for all applicable hours when average demand is used in pre-dispatch. This measurement provides some insight into how closely the IESO's pre-dispatch demand forecasts come to meeting the expected demand target in real-time. Large differences can lead to discrepancies in pre-dispatch and real-time prices.

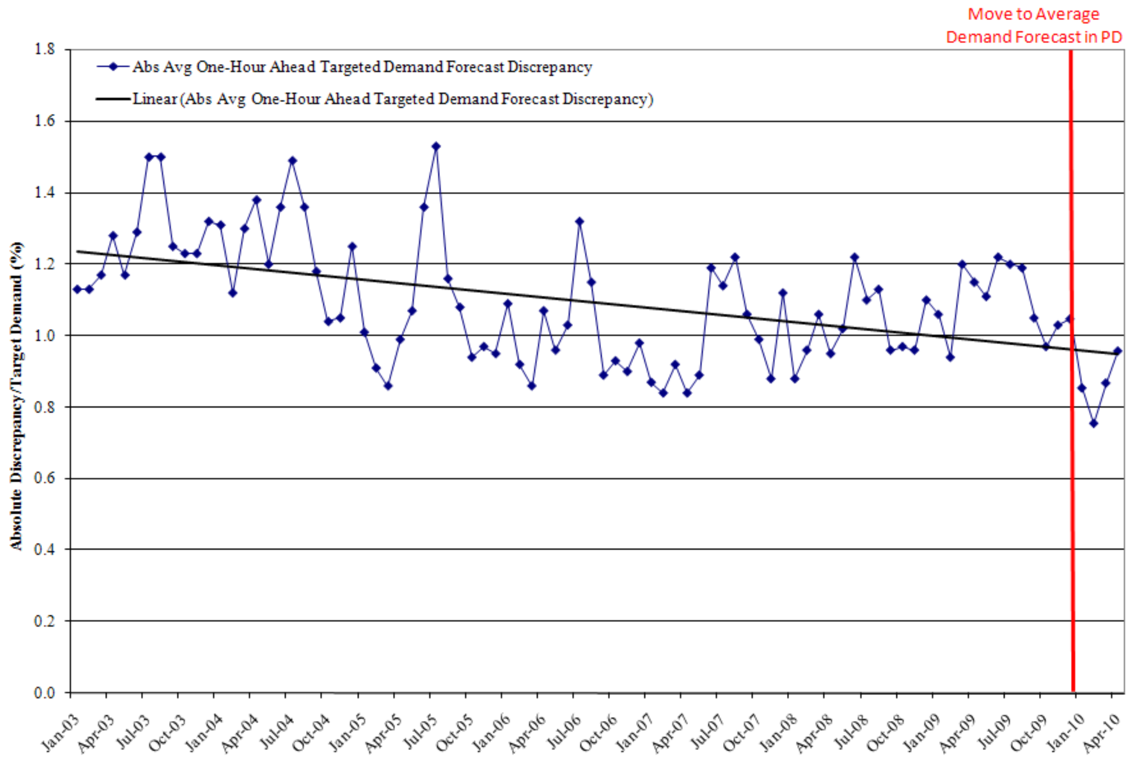
Table 1-13 reports the one-hour and three-hour ahead mean absolute demand forecast errors on a monthly basis for the 2008/2009 and 2009/2010 reporting periods. This switch to average demand in pre-dispatch has coincided with forecast accuracy improvements for both one-hour and three-hour ahead demand forecasts since its implementation in December 2009. Pre-dispatch to real-time demand forecast errors in all 2010 months were below the yearly average, setting a two year low for the one-hour and three-hour ahead measurements in February 2010. Prior to December 2009, most months in the current reporting period had forecast errors higher than those observed in the same months one year earlier. On an annual basis, demand forecast errors dropped 0.05 percent for both the one-hour and three-hour ahead measurements, with most of the improvement realized in the final four months of the period.

Table 1-13: Pre-dispatch to Real-time Demand Forecast Error, May–April 2008/2009 & 2009/2010 (% of Real-time Demand)

	Mean absolute forecast difference: pre-dispatch minus real-time demand divided by real-time demand			
	Three-Hour Ahead		One-Hour Ahead	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	1.26	1.32	1.02	1.11
June	1.55	1.42	1.22	1.22
July	1.51	1.54	1.10	1.20
August	1.36	1.53	1.13	1.19
September	1.14	1.25	0.96	1.05
October	1.11	1.17	0.97	0.97
November	1.13	1.26	0.96	1.03
December	1.40	1.35	1.10	1.05
January	1.32	1.11	1.06	0.85
February	1.17	0.96	0.94	0.75
March	1.51	1.14	1.20	0.87
April	1.41	1.19	1.15	0.96
Average	1.32	1.27	1.07	1.02

Figure 1-4 reports average monthly one-hour ahead absolute targeted demand forecast discrepancy between January 2003 and April 2010. The linear trend line suggests an overall improvement in the accuracy of demand forecasts since 2003. During the current annual reporting period, historic monthly lows were observed after December 2009, the lowest occurring in February 2010 at 0.75 percent. Although the number of observations is limited, demand forecast error has shown an improvement in every month in 2010 relative to the same month one-year earlier and relative to historic levels since 2003. The most recent results following the IESO's adoption of average demand forecast for non ramp up hours in pre-dispatch suggest the IESO should realize continuing improvement, which in turn will help the accuracy of pre-dispatch price projections.

Figure 1-4: Absolute Average One-Hour Ahead Targeted Demand Forecast Discrepancy, January 2003–April 2010 (% of Peak Demand)



Figures 1-5 and 1-6 plot the one-hour ahead absolute average forecast error by hour of the day for two separate time segments within the 2009/2010 reporting period. Figure 1-5 focuses on demand forecast error by hour of the day between May 1, 2009 and December 14, 2009, the time period when peak demand forecasts were used in pre-dispatch. Figure 1-6 reports on average demand forecast error by hour of the day for the remaining days in the latest reporting period (December 15, 2009 to April 30, 2010). The average absolute forecast error (represented by the red horizontal lines) dropped from 1.11 percent during the May to mid December 2009 period down to 0.87 percent in the second period. Although the magnitude of the demand forecast errors were different between the two time periods, hourly patterns were similar. Demand forecasts were the most inaccurate in HE 6 of both time periods with an average absolute forecast error of 1.66 percent during the first period and 1.29 percent in the second period. Furthermore, forecast errors appear lowest during midday hours for both time segments, specifically in HE 14 and HE 15.

Figure 1-5: Absolute Average One-Hour Ahead Demand Forecast Error by Hour Prior to Move to Average Demand in PD, May 1, 2009 – December 14, 2009 (% of Real-time Average Hourly Demand)

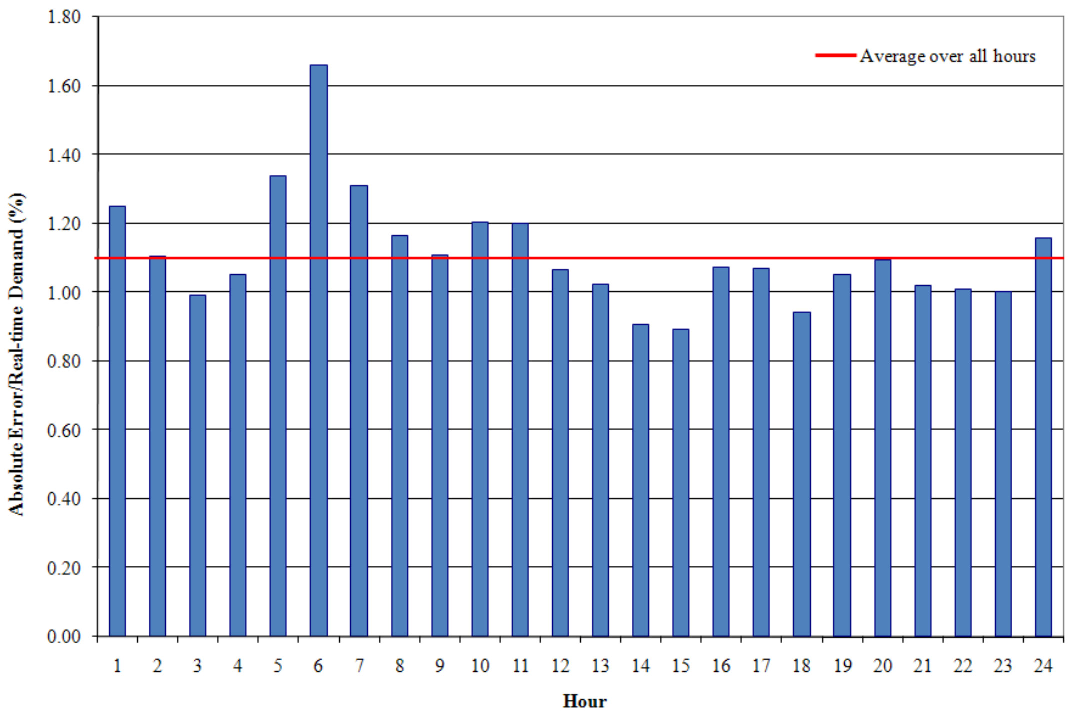
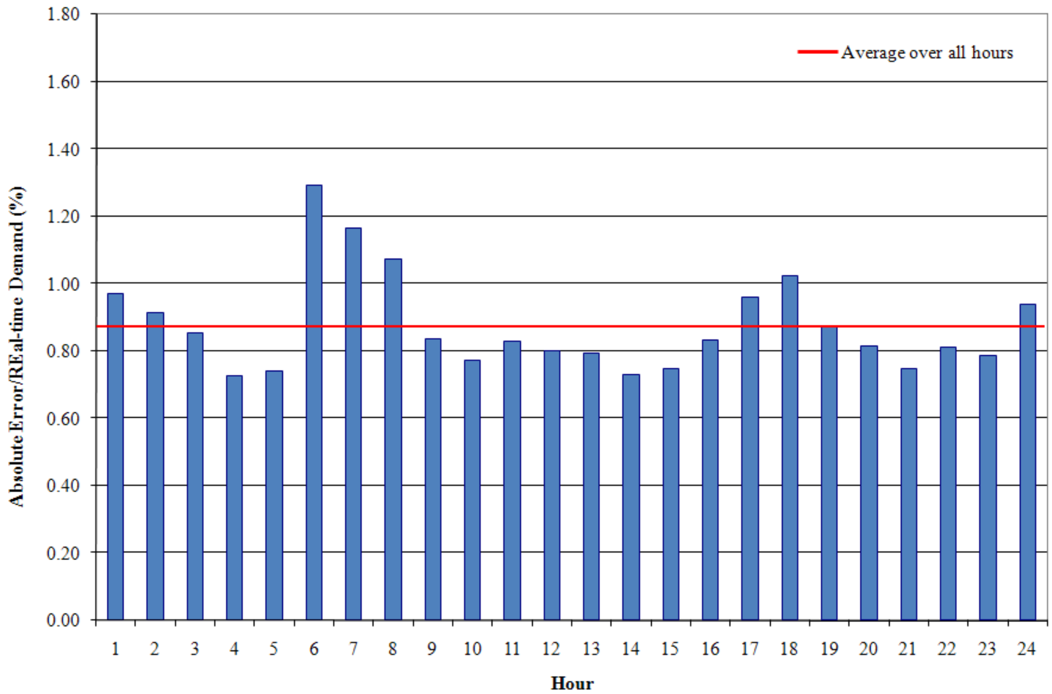


Figure 1-6: Absolute Average One-Hour Ahead Demand Forecast Error by Hour After Move to Average Demand in PD, December 15, 2009 – April 30, 2010 (% of Real-time Average Hourly Demand)



While the absolute average indicates the magnitude of the demand forecast errors, the arithmetic average shows the bias of the error, which can be positive or negative. Figures 1-7 and 1-8 present arithmetic average one-hour ahead demand forecast error by hour of the day over the May 1 to December 14, 2009 and December 15, 2009 to April 30, 2010 time periods. The average one-hour ahead forecast error was positive for both time periods at 0.08 percent and 0.14 percent, indicating that on average pre-dispatch forecasts were slightly higher than actual demand. Similar to absolute average demand forecast errors reported above, the largest arithmetic errors occurred in HE 6 for both time periods (0.98 percent in the time period prior to the change to average forecasts in pre-dispatch and 1.05 percent for the subsequent time period).

Figure 1-7: Arithmetic Average One-Hour Ahead Demand Forecast Error by Hour Prior to Move to Average Demand in PD, May 1, 2009 - December 14, 2009 (% of Real-time Average Hourly Demand)

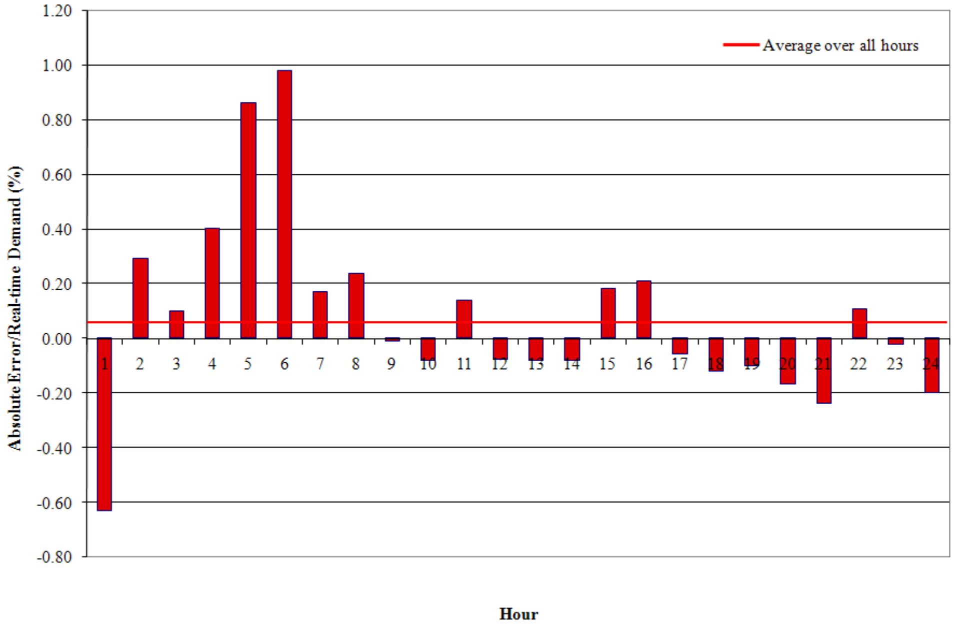
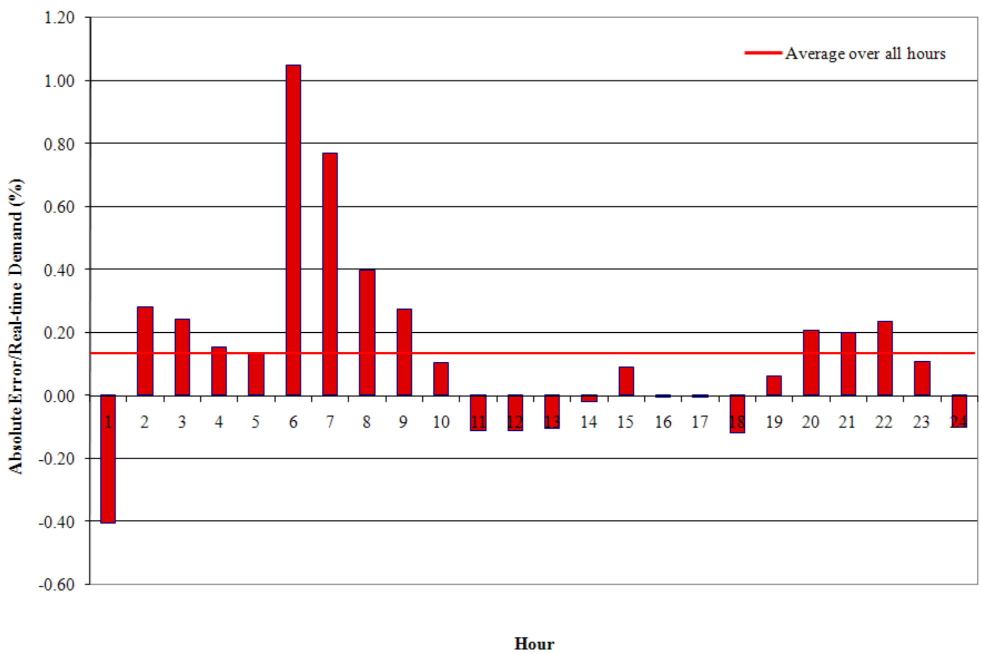


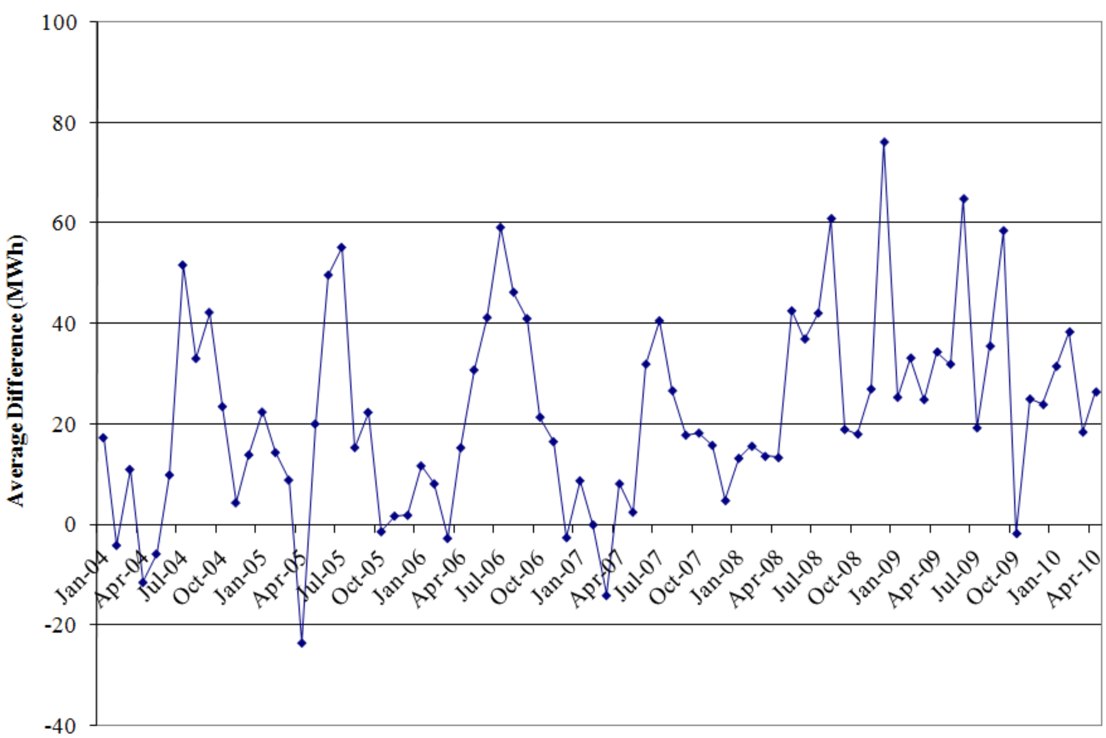
Figure 1-8: Arithmetic Average One-Hour Ahead Demand Forecast Error by Hour After Move to Average Demand in PD, December 15, 2009 – April 30, 2010 (% of Real-time Average Hourly Demand)



2.4.2.2 Performance of Self-Scheduling and Intermittent Generation

Figure 1-9 plots the monthly average difference between the amount of energy self-scheduling and intermittent generators forecasted and the amount of energy they actually delivered in real-time. Average error decreased in recent months after some high differences were observed in many months between mid 2008 and late 2009. During the current 2009/2010 12-month period, the overall average error fell to 31 MW while the monthly average difference only exceeded 40 MW in two months, June and September (65 MW and 58 MW respectively). In October 2009, the average difference was negative 2 MW indicating that on average, the amount of energy delivered in a given hour was greater than the submitted forecast. The last time a negative average difference occurred was in March of 2007. Historically, the largest peaks in self-scheduling and intermittent generation error have occurred during the summer months.

Figure 1-9: Average Difference between Self-Scheduling and Intermittent Generator Forecasted and Delivered Energy January 2004 – April 2010 (MWh)



Wind Generation

Since first entering the market in early 2006, the amount of wind generating resources coming on-line has steadily increased. As of April 2010, there was a combined name-plate capacity of 1,089 MW of wind generation in Ontario.[18] Figure 1-10 presents the average and absolute average difference between wind generators' forecasted and delivered energy. Average hourly wind output is also plotted and represented by the green dashed line.[19]

Figure 1-10 shows that both the average and absolute average wind forecast error has been increasing since 2006 and the magnitude of the error has climbed as wind output has increased, although the average difference fell to less than 10 MW in March and April 2010. The overall average of the absolute forecast error grew by 20 MW in the recent annual period to 69 MW, up from 49 MW in 2008/2009. Absolute average wind error exceeded 70 MW six of the twelve months in the current period but only occurred once in the 2008/2009 period. This is mainly driven by increases in wind capacity over the last five years.

[18] See the OPA's Wind-power webpage for details on wind projects that are currently operational and those under development at: http://64.34.71.254/Page.asp?PageID=924&SiteNodeID=234

[19] In previous MSP Reports, nameplate capacity was plotted to show that amount of wind available in a given month. However, using average hourly wind output provides a better measure of actual wind generation performance in a given month as outages and other factors constraining wind generation at specific facilities are reflected in actual output levels but not in the nameplate capacity value. Average hourly wind output is also used to deflate average and absolute average wind error in Figure 1-8.

Figure 1-10: Average and Absolute Average Difference between Wind Generator Forecasted and Delivered Energy and Average Hourly Wind Output, March 2006–April 2010 (MW)

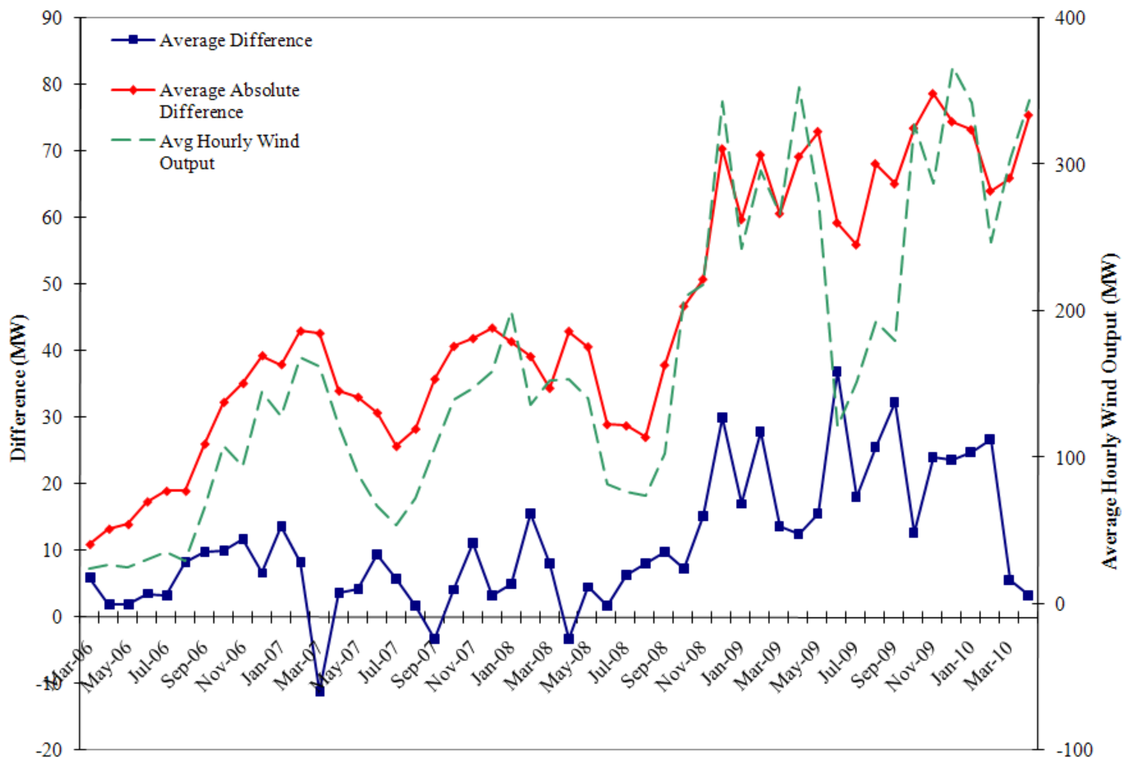
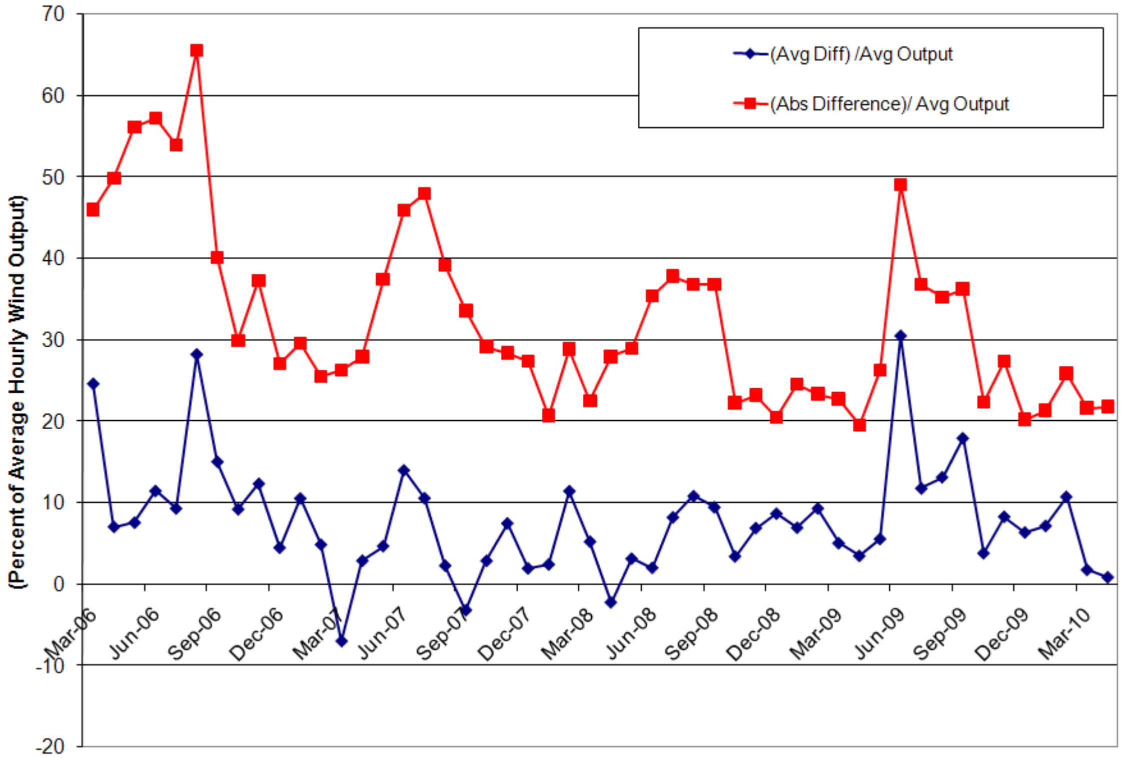


Figure 1-10 above provides some evidence that absolute average difference, and to a lesser extent average difference, has increased since early 2006. However when these error measurements are normalized by average hourly wind output, little trend is apparent. Figure 1-11 plots the average and absolute average difference between wind generators' forecasted energy and actual energy produced, as normalized using hourly average wind output since March 2006. With the exception of a few months during the recent summer (June to September 2009), normalized absolute average difference as a percentage of hourly wind output typically fluctuated between 20 to 30 percent and the average difference generally remained below 10 percent of the hourly average wind output in the given month. However, for the months June to September 2009, the normalized absolute average difference and the average difference climbed well above its historical average.

Figure 1-11: Normalized Average and Absolute Average Difference between Wind Generators' Forecasted and Delivered Energy, March 2006 - April 2010 (% of Wind Output)



In August 2009, the IESO announced that it will launch a centralized wind forecasting service on behalf of wind generators.[20] This decision is consistent with the Panel's recommendation in its January 2009 Monitoring Report that the IESO consider the option of centralized forecasting to help reduce errors associated with wind resources in the pre-dispatch schedules.[21] The IESO is currently in the process of gathering stakeholder feedback and developing a process plan, which will include a timeline for implementation.[22]

[20] IESO News Release dated August 18, 2009 is available at: http://www.ieso.ca/imoweb/media/md_newsitem.asp?newsID=4842

[21] See Recommendation 4-1 in Chapter 4 of the Panel's January 2009 Monitoring Report, p. 256.

[22] For the latest update on the centralized wind forecasting initiative, see the IESO's presentation to SE-57 on March 10, 2010 titled, "*Centralized Wind Forecasting*" and available at: http://www.ieso.ca/imoweb/pubs/consult/se57/se57-20100310-Centralized-Wind-Forecasting.pdf

2.4.2.3 Real-Time Failed Intertie Transactions

Failed import and export transactions are another factor that can contribute to differences between pre-dispatch prices and HOEP. In real-time, import failures represent a loss of supply while export failures represent a decline in demand, both of which result in discrepancies between pre-dispatch to real-time prices.

Export Failures

Table 1-14 provides summary statistics on the frequency and magnitude of failed export transactions over the latest two annual periods. The number of hours when exports failed declined by 294 hours over the current annual period, from 4,951 hours to 4,657 hours. However, this still represented 53 percent of all hours in the review period. Although the frequency of export failures fell, the magnitude of hourly export failures were up by 58 MW, on average, and were higher in nine of the twelve months. As a result, the failure rate (MW failed relative to MW scheduled) increased from 4.12 percent last year to 5.99 percent this year.

Table 1-14: Frequency, Average Magnitude, and Rate of Failed Exports from Ontario, May–April 2008/2009 & 2009/2010

	Number of Hours when Failed Exports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	645	341	875	1,342	190	165	7.33	4.91
June	554	392	1,003	1,144	172	236	5.66	5.30
July	502	527	1,858	1,739	138	330	3.81	8.50
August	394	429	709	1,844	138	212	3.27	5.53
September	356	385	679	989	151	172	4.14	5.21
October	370	314	725	1,050	140	134	3.44	3.98
November	314	174	552	779	131	118	2.93	2.01
December	386	431	1,645	1,430	176	187	4.62	5.45
January	434	434	965	1,280	133	209	3.07	5.77
February	340	393	675	935	134	245	3.28	7.67
March	337	457	1,815	892	168	227	3.79	7.95
April	319	380	900	980	108	233	4.13	9.64
Total/Average	4,951	4,657	1,033	1,200	148	206	4.12	5.99

* The incidents with less than 1 MW and linked wheel failures are excluded.
** Based on those hours in which a failure occurs.
*** Total failed export MWh divided by total scheduled export MWh (excluding the export leg of linked wheels) in the unconstrained schedule in a month.

Causes of Export Failures

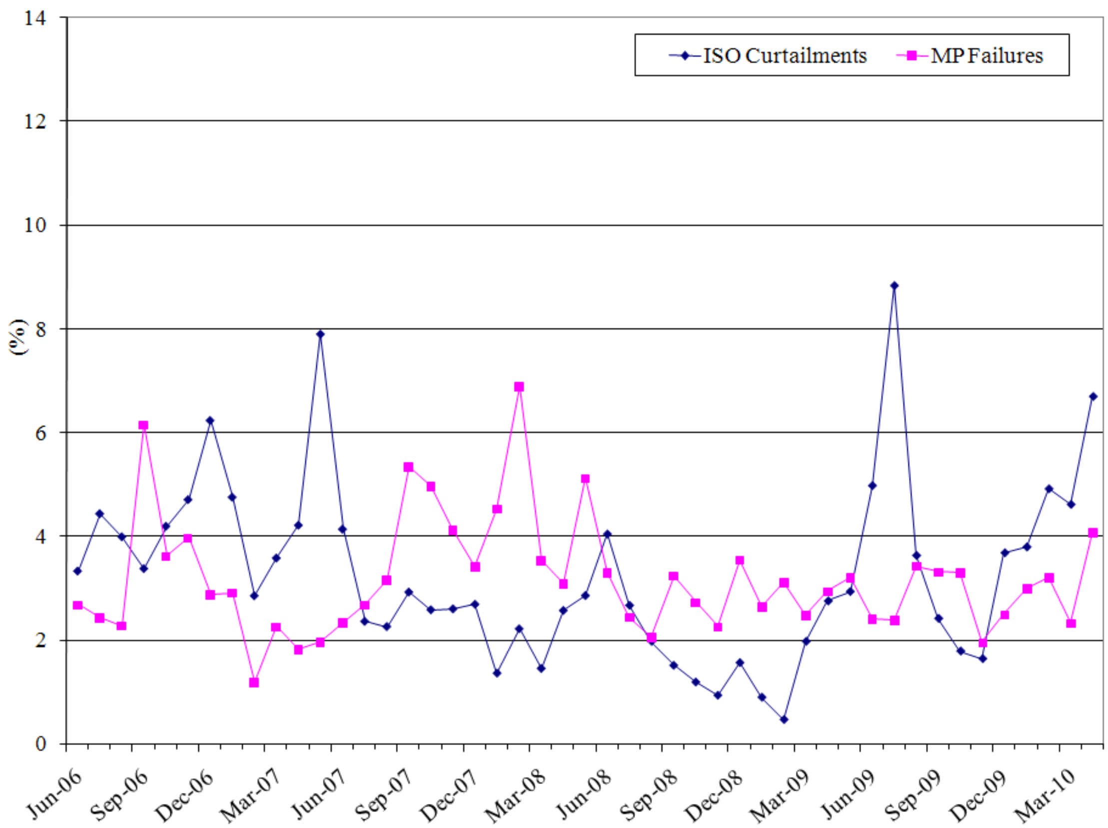
Figure 1-12 plots the export failure rates beginning in June 2006, the date of introduction of the real-time intertie failure charge. Export failures (and import failures below) are separated by those under the market participants' control (labelled MP failures) and those under the control of a system operator (labelled ISO curtailments).[23] The failure rate is determined as a percentage of failed to total exports (or imports) in MWh per month (linked-wheel failures are not included).

The export failure rate, as illustrated in Figure 1-12, has been relatively stable since June 2006. MP failures have fluctuated between 2 and 4 percent over the last two years.

[23] The IESO Compliance database that separates failures into ISO curtailments and market participant failures does so for constrained schedule failures only. Therefore, failure rates vary slightly from the statistics reported in Tables 1-13 and 1-14, which report unconstrained schedule failures in aggregate.

However, large spikes in ISO curtailment failures occurred in July 2009, reaching a 5-year high of 8.85 percent, and in April 2010 were at 6.71 percent. The high percentage in July 2009 was driven by a series of exports cuts throughout the month using the TLRe code at the MISI interface due to a mixture of surplus generation conditions in PJM and PJM ramp issues. During the first half of April 2010, the New York ISO had a TLR procedure in place limiting the amount of flow on the Niagara-Packard flowgate, which resulted in a series of export curtailments at the MISI interface (coded TLRe) to respect the limits.

Figure 1-12: Monthly Export Failures as a Percentage of Total Exports by Cause, June 2006 – April 2010 (%)



Export Failures by Intertie Group

Table 1-15 reports average monthly export failures by intertie group and by cause for the period May 2009 to April 2010. Export failures at the Michigan intertie accounted for approximately 56 percent of all export failures during the reporting period. Of those failures, 74.4 percent were ISO curtailments. Despite this, it was the Minnesota intertie which had the highest ISO induced failure rate at 13 percent of its total scheduled exports. The NYISO intertie was responsible for roughly 67 percent of total MP export failures and had the highest MP failure rate at 8.1 percent. Historically, MP failures have been the highest at the New York intertie.[24]

Table 1-15: Average Monthly Export Failures by Intertie Group and Cause, May 2009–April 2010 (GWh and % Failures)

	Average Monthly Exports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
New York	308.9	2.6	4.7	24.9	67.5	0.8	8.1
Michigan	764.7	41.5	74.4	10.4	28.2	5.4	1.4
Manitoba	22.6	2.3	4.1	0.6	1.6	10.2	2.7
Minnesota	51.7	6.7	12.0	0.3	0.8	13.0	0.6
Quebec	126.6	2.7	4.8	0.8	2.2	2.1	0.6
Total	1274.5	55.8	100.0	36.9	100.0	4.4	2.9

<u>Import Failures</u>

Table 1-16 provides monthly summary statistics on the frequency and magnitude of failed import transactions during the last two May to April periods. Similar to export failures over the recent annual period, the total number of hours when failed imports occurred decreased from 3,032 hours in 2008/2009 to 2,924 hours (33 percent of total hours in the period) in 2009/2010, a drop of 108 hours (4 percent). There was also a decline in the magnitude of import failures. The average hourly failure dropped 66 MW (42 percent), while the largest instance of failure in an hour decreased from 1,085 MW in 2008/2009 to 1,024 MW in 2009/2010, a drop of 61 MW (5.6 percent). As a result, the import failure rate fell from 7.27 percent last year to 4.44 percent this year.

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[24] Participants selling into New York must place offers to sell the energy in real-time which allows for the possibility that transactions are not economic and not scheduled in New York even when scheduled in Ontario. The potential for mismatched economic scheduling with NYISO is unique among the jurisdictions directly connected to Ontario. This distinction also applies for imports to Ontario.

Table 1-16: Frequency, Average Magnitude, and Rate of Failed Imports to Ontario, May–April 2008/2009 & 2009/2010

	Number of Hours when Failed Imports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	289	235	1,085	381	182	67	9.87	3.47
June	285	269	807	783	176	101	7.35	7.07
July	271	320	818	619	163	104	7.07	5.02
August	254	261	880	1,024	145	97	7.36	3.74
September	348	330	989	965	218	97	10.46	4.41
October	338	265	1,029	855	187	96	8.89	3.84
November	282	244	730	580	152	79	5.13	6.88
December	220	253	812	625	143	107	7.17	7.28
January	287	218	600	410	143	99	5.99	3.10
February	145	119	800	388	158	63	5.26	1.19
March	163	132	575	453	98	59	5.70	1.32
April	150	278	425	506	108	107	7.00	5.97
Total/Average	3,032	2,924	796	632	156	90	7.27	4.44

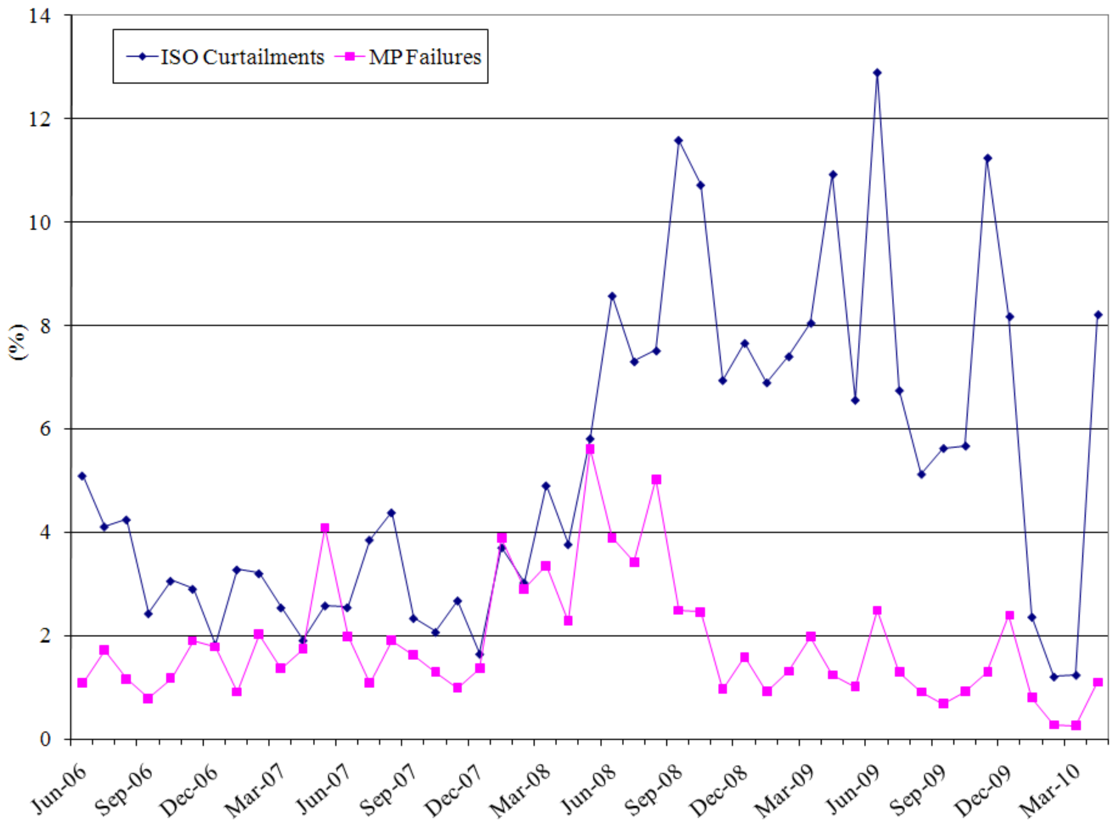
* The incidents with less than 1 MW and linked wheel failures are excluded.
** Based on those hours in which a failure occurs.
*** Total failed import MWh divided by total scheduled import MWh (excluding the import leg of linked wheels) in the unconstrained schedule in a month.

Causes of Import Failures

Figure 1-13 plots the import failure rates by cause since June 2006. Import failures due to ISO curtailments account for the majority of import failures since mid-2008.[25] This trend continued during the past reporting period including a 5-year high failure rate occurring in July 2009 as ISO controlled failures surpassed 12 percent of total imports. The observed increase in ISO curtailed imports is attributable to increased curtailments at the MISI interface in mid 2008 and the MNSI interface beginning May 2009. The majority of curtailments were coded MrNh from January through March 2010, which means transmission and ramp limitations on the MISI interface. The import failure percentage induced by ISO curtailment dropped to around 2 percent, reaching a 5-year low of 1.22 percent in February 2010.

MP import failures fluctuated around 1 to 2 percent and reached a 5-year low of 0.26 percent in March 2010. Import failure rates (both ISO and MP controlled) were considerably lower in February and March 2010 compared to the rest of the reporting period.

Figure 1-13: Monthly Import Failures as a Percentage of Total Imports by Cause June 2006 – April 2010 (%)



Import Failures by Intertie Group

Table 1-17 reports average monthly import failures by intertie and cause for the period starting May 2009 and ending April 2010. Quebec imports accounted for nearly 62 percent of all imports. They had an ISO controlled failure rate of only 1.7 percent and an MP failure rate of 0.3 percent. In addition to the highest ISO controlled export failure rate, the Minnesota intertie also had the highest ISO controlled import failure rate at 36.9

percent. Minnesota import failures began to increase in May 2009, in large part due to ramp limitations in the MISO jurisdiction. However, the Minnesota intertie averaged the lowest monthly imports of all interties by a large margin at 9.2 GWh. The Michigan import failure rate was also materially high at 13.4 percent and accounted for approximately 54 percent of all ISO controlled import failures. NYISO and Minnesota had the highest MP controlled failure rates at 4.6 percent and 4.3 percent respectively.

Table 1-17: Average Monthly Import Failures by Intertie Group and Cause, May 2009–April 2010 (GWh and % Failures)

	Average Monthly Imports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
New York	43.3	1.6	6.1	2	42.6	3.7	4.6
Michigan	105.1	14.1	54.0	1.2	25.5	13.4	1.1
Manitoba	25.2	2	7.7	0.3	6.4	7.9	1.2
Minnesota	9.2	3.4	13.0	0.4	8.5	36.9	4.3
Quebec	296.5	4.9	18.8	0.8	17.0	1.7	0.3
Total	479.4	26.1	100.0	4.7	100.0	5.4	1.0

2.4.2.4 Imports or Exports Setting Pre-dispatch Price

A fourth factor identified by the Panel that leads to discrepancies between pre-dispatch and real-time prices is the frequency of imports and exports setting the pre-dispatch MCP. An increased frequency of imports or exports setting the pre-dispatch price will lead to an increased divergence between pre-dispatch and real-time prices.[26]

Table 1-18 shows the frequency of hours that imports and exports set the pre-dispatch price for May to April 2008/2009 and 2009/2010. For the current reporting period, imports or exports set the pre-dispatch price in roughly half of all hours. The number of hours increased from 3,994 hours in 2008/2009 to 4,376 hours in 2009/2010, a 4 percent

[26] For a detailed explanation of why this occurs, see pp. 30-33 of the Panel's July 2007 MSP Monitoring Report.

increase. The largest monthly increase occurred in March, which jumped from 232 hours in March 2008 to 389 hours in March 2009, an increase of 157 hours (67.7 percent).

Table 1-18: Frequency of Imports or Exports Setting the Pre-Dispatch Price, May–April 2008/2009 & 2009/2010 (Number of Hours and % of Hours)

	2008/2009		2009/2010		Difference	
	Hours	%	Hours	%	Hours	% Change
May	340	46	392	53	52	7
June	322	45	423	59	101	14
July	350	47	427	57	77	10
August	289	39	366	49	77	10
September	389	54	395	55	6	1
October	394	53	413	56	19	3
November	411	57	314	44	(96)	(13)
December	361	49	341	46	(20)	(3)
January	352	47	326	44	(25)	(3)
February	319	47	308	46	(12)	(2)
March	232	31	389	52	157	21
April	238	33	283	40	45	6
Total	3,994	46	4,376	50	382	4

2.5 Internal Zonal Prices and CMSC Payments

Table 1-19 presents average nodal prices for the 10 internal Ontario zones for each six month period for the last three six-month periods.[27] Figure 1-14 shows the same average nodal prices graphically for each zone for the recent winter period. The average nodal price for a zone, also referred to here as the internal zonal price, is calculated as the average of the nodal prices for generators in the zone.[28]

Table 1-19 shows that average internal zonal prices were lower in the current annual period relative to the previous annual period. Current annual values are approximately 45 to 48 percent below the previous annual period for all zones with the exception of the Northeast and Northwest zones, which is consistent with the observed drop in the

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[27] See the IESO's "Ontario Transmission System" publication for a detailed description of the IESO's ten zone division of Ontario at http://www.ieso.ca/imoweb/pubs/marketreports/OntTxSystem_2005jun.pdf
[28] All nodal and zonal prices have been modified to +$2,000 (or -$2,000) when the raw interval value was higher (or lower).

Richview nodal price. The average Richview nodal price was $29.88/MWh over the latest annual period, which is $24.26/MWh, or 44.8 percent, lower than the previous period. These price movements in the southern zones are largely related to generally lower demand and increased supply in southern Ontario.

Table 1-19: Internal Zonal Prices, May 2008–April 2010 ($/MWh and %)

Zone	May 08 – Apr 09	May 09 – Apr 10	% Change from May 08 – Apr 09 to May 09 – Apr 10
Bruce	51.95	28.44	(45.3)
East	51.29	27.77	(45.9)
Essa	52.35	28.66	(45.3)
Northeast	30.11	12.47	(58.6)
Niagara	52.00	26.76	(48.5)
Northwest	(190.37)	(404.08)	(112.3)
Ottawa	55.07	30.05	(45.4)
Southwest	52.10	28.84	(44.6)
Toronto	54.41	29.66	(45.5)
Western	53.64	29.62	(44.8)
Richview Nodal Price	54.14	29.88	(44.8)

As observed for previous periods, congestion in the Northwest is the primary reason for the large negative shadow prices in the area. The average zonal price in the Northwest dropped to -$404.08/MWh, which is more than two times lower than the -$190.37/MWh average price in the 2008/2009 summer months. Reduced demand in the zone and abundant supply of very low-priced water, including energy available from imports, continues to lead to energy surpluses in the area and places downward pressure on prices.

Similar to the Northwest zone, the Northeast also has a large amount of hydroelectric supply, but experienced less surplus and congestion than observed in the Northwest. The average zonal price in the Northeast fell from $30.11/MWh last year to $12.47/MWh in the recent annual period, a decline of 58.6 percent.

Figure 1-14: Average Internal Zonal Prices
May 2009 – April 2010
($ millions)

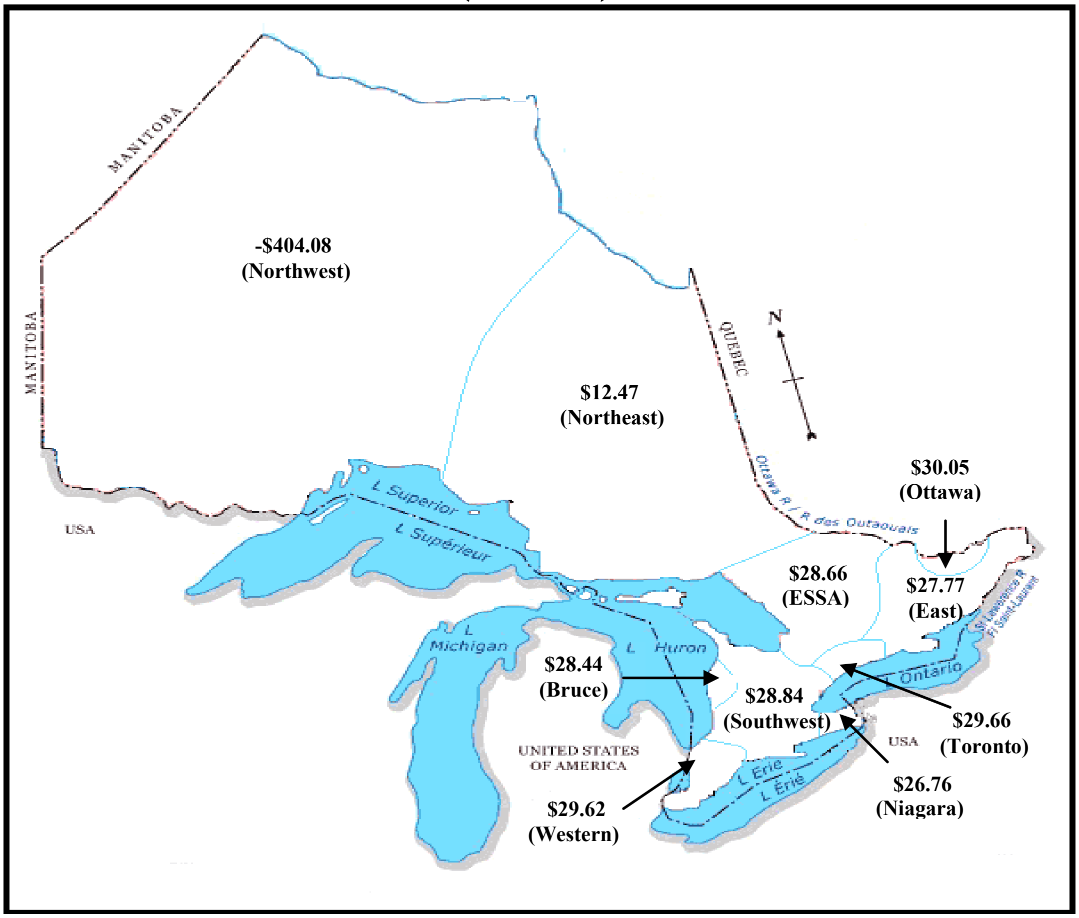


Figure 1-15 provides a summary of congestion payments (CMSC) across the same 10 zones for the last annual reporting period. For each zone, there is a total for CMSC paid for constraining off generation or imports or constraining on exports from the zone. In this analysis, imports or exports refer to the individual zone, not the province. The data has been aggregated in this manner since constraining on exports is an alternative to constraining off supply when supply is bottled (oversupply in zone), and so this amount is an indicator of the bottling of supply in the zone. A second total shows the CMSC for constrained on generation or imports, or constrained off exports. This is a measure of the need for additional or out-of merit supply in a zone (undersupply in zone).[29] However, not all CMSC is induced by transmission limits (including losses) or security. For example, the 3-times ramp rate or slow ramping of generation units can induce CMSC, so the total CMSC is not entirely a measure of congestion or losses.

Of the $62.4 million of CMSC for constrained-off supply or constrained-on exports, $36.2 million (or 58 percent) occurred in the Northwest zone, primarily as the result of the East-West flow limits which bottle the low-cost supply in the area. The other major contributors to the total were the Northeast zone at $11.1 million (or 18 percent) and the Niagara zone at $7.5 million (or 12 percent).

CMSC for constrained on supply and constrained off exports totalling $66.1 million was mainly concentrated in Southern Ontario. Significant payments were also made in the Western zone at $19.4 million (or 29 percent), the Toronto zone at $15.7 million (or 24 percent), and the Niagara zone at $8.1 million (or 12 percent).

[29] CMSC paid to dispatchable load is omitted here since the largest portion of those payments are self-induced, as opposed to being related to congestion, losses or other system requirements. For further discussion, see Chapter 3, Section 3.1 of this report.

Figure 1-15: Total CMSC Payments by Internal Zone,
May 2009 – April 2010
($ millions)

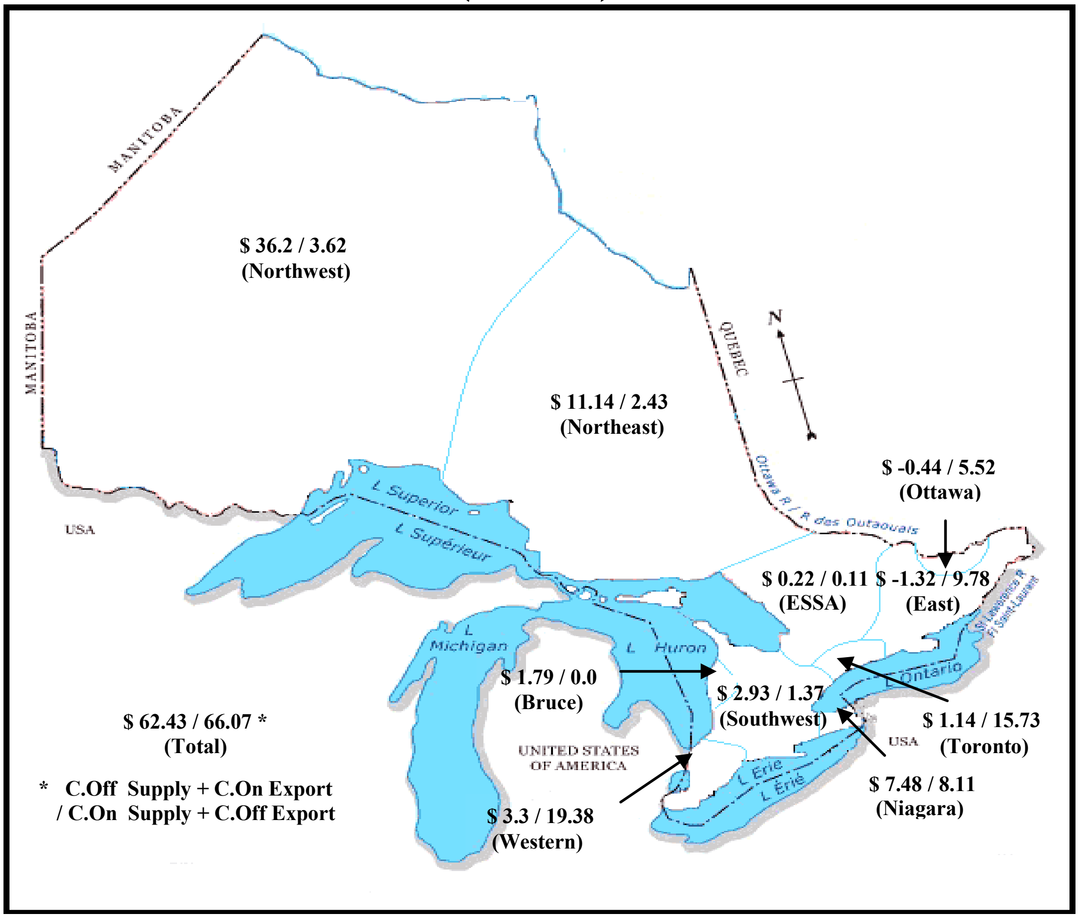


Table 1-20 provides similar data on a comparative basis relative to the previous annual reporting period. Overall, there were significant changes in the amount and proportion of payments made by zone.

Table 1-20: Total CMSC Payments by Internal Zone, May–April 2008/2009 & 2009/2010 ($ millions)

Zone	Constrained off Supply plus Constrained on Exports			Constrained on Supply plus Constrained off Exports		
	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change
Bruce	3.5	1.8	(49)	-0.1	0.0	(100)
East	1.4	-1.3	(193)	9.5	9.8	3
Essa	0.2	0.2	0	0.3	0.1	(67)
Northeast	21.2	7.5	(65)	6.3	8.1	29
Niagara	4.1	11.1	171	11.4	2.4	(79)
Northwest	64.2	36.2	(44)	1.6	3.6	125
Ottawa	0.0	-0.4	N/A	0.0	5.5	N/A
Southwest	4.2	2.9	(31)	0.7	1.4	100
Toronto	0.5	1.1	120	6.2	15.7	153
Western	4.6	3.3	(28)	16.1	19.4	20
Total	103.8	62.4	(40)	51.9	66.1	27

Total yearly constrained off supply plus constrained on exports fell by $41.4 million, or 40 percent from the previous period's total. The largest contributors to the decrease in payments were the Northeast and Northwest regions which saw drops of $13.7 million and $28 million respectively (65 percent and 44 percent). The East region went from contributing a debt of $1.4 million in 2008/2009 to a credit of $1.3 million in 2009/2010. Only the Niagara and Toronto regions saw increases in payments from the previous period, Niagara being the largest increase at $7 million, or 171 percent.

Total constrained on supply plus constrained off exports increased $14.2 million (27 percent) from 2008/2009 to 2009/2010. The largest absolute increase in payments occurred in the Toronto region jumping $9.5 million (153 percent) from the previous period. Ottawa went from receiving the least payments in 2008/2009, to receiving the fourth largest sum of payments ($5.5 million) in 2009/2010. Most other regions saw modest increases in payments, while three regions saw slight declines, the largest being Niagara dropping $9 million. Total payments for all regions and both types of payments dropped $27.2 million, or 17.5 percent.

2.6 Operating Reserve Prices

Table 1-21 presents average monthly operating reserve prices during on-peak hours over the last two reporting periods. On-peak prices for all three types of OR have decreased by at least 20 percent when comparing 2008/2009 to 2009/2010 annual periods. All three categories saw increases in OR prices in almost every month from May 2009 to September 2009, followed by sharp declines in prices from October 2009 onward (except December). OR prices dropped from the start of the reporting period (May 2009) to the end (April 2010) by approximately 90 percent; ending with 2-year lows of $0.41/MWh for all types of OR. Since October 2009, there also appears to be a convergence of the 10S/10N prices (which are typically similar) and the 30R price (which is typically lower).

Table 1-21: Operating Reserve Prices, On-Peak, May–April 2008/2009 & 2009/2010 ($/MWh)

	10S			10N			30R		
	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change
May	10.18	18.67	83.4	10.15	18.61	83.3	7.40	11.77	59.1
June	10.13	15.89	56.9	10.10	15.81	56.5	9.46	9.17	(3.1)
July	12.62	14.41	14.2	12.50	14.28	14.2	12.13	9.26	(23.7)
August	6.03	10.93	81.3	6.02	10.91	81.2	5.69	9.05	59.1
September	1.67	4.98	198.2	1.63	4.98	205.5	1.57	4.49	186.0
October	7.29	1.84	(74.8)	7.04	1.84	(73.9)	5.52	1.84	(66.7)
November	7.40	5.59	(24.5)	7.37	5.55	(24.7)	6.90	4.92	(28.7)
December	4.85	5.06	4.3	4.84	5.06	4.5	4.67	5.01	7.3
January	12.23	4.66	(61.9)	12.23	4.66	(61.9)	11.35	4.58	(59.6)
February	19.47	4.75	(75.6)	19.47	4.75	(75.6)	17.65	4.68	(73.5)
March	8.37	4.03	(51.9)	8.32	4.03	(51.6)	6.82	3.81	(44.1)
April	15.54	0.41	(97.4)	15.14	0.41	(97.3)	7.91	0.41	(94.8)
Average	9.65	7.60	(21.2)	9.57	7.57	(20.8)	8.09	5.75	(28.9)

Table 1-22 presents average monthly operating reserve prices during off-peak hours over the last two reporting periods. Off-peak prices have not been as volatile as on-peak prices over the last two years. Although on-peak prices have seen considerable decreases from one reporting period to the next, off-peak prices for all three categories have actually increased on average by at least 7 percent. All categories saw considerable price jumps in May, August, September, and December 2009, when compared to those same months in 2008. These high increases were somewhat offset by sharp decreases in OR prices from February to April 2010. The net effect is a 7.3 percent increase in the 10S category, a 35 percent increase in the 10N category, and a 25 percent increase in the 30R category when comparing 2008/2009 to 2009/2010. Average prices for all categories ended the current reporting period at 2-year lows ($0.28/MWh for 10S, $0.27/MWh for 10N, and $0.27/MWh for 30R) and showed almost complete price convergence among the three categories.

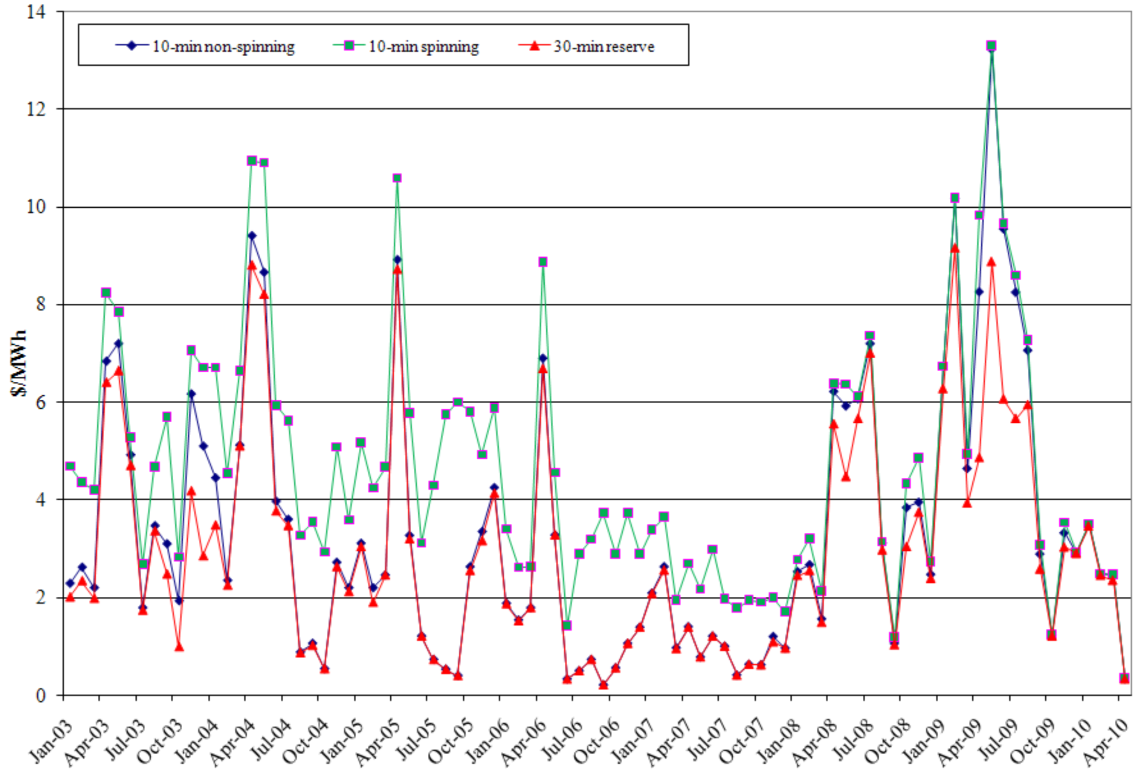
Table 1-22: Operating Reserve Prices, Off-Peak, May–April 2008/2009 & 2009/2010 ($/MWh)

	10S			10N			30R		
	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change
May	3.21	9.24	187.9	2.43	9.17	277.4	2.05	6.69	226.3
June	2.90	3.71	27.9	2.84	3.56	25.4	2.63	3.10	17.9
July	3.03	3.36	10.9	2.83	2.84	0.4	2.78	2.43	(12.6)
August	0.95	4.48	371.6	0.92	4.16	352.2	0.92	3.59	290.2
September	0.77	1.40	81.8	0.56	1.06	89.3	0.56	0.91	62.5
October	1.68	0.73	(56.5)	0.97	0.72	(25.8)	0.81	0.69	(14.8)
November	2.83	1.72	(39.2)	1.22	1.37	12.3	1.22	1.37	12.3
December	0.99	1.16	17.2	0.51	1.16	127.5	0.51	1.16	127.5
January	2.21	2.62	18.6	2.21	2.62	18.6	2.09	2.62	25.4
February	2.50	0.60	(76.0)	2.49	0.60	(75.9)	2.14	0.60	(72.0)
March	1.85	0.92	(50.3)	1.34	0.92	(31.3)	1.33	0.92	(30.8)
April	5.25	0.28	(94.7)	2.76	0.27	(90.2)	2.42	0.27	(88.8)
Average	2.35	2.52	7.3	1.76	2.37	35.0	1.62	2.03	25.1

Demand for operating reserve, which is reflected in the level of the OR requirement established by the IESO, was slightly higher this year relative to last year. The average OR requirement for the 2008/2009 annual period was 1,432 MW while in 2009/2010, the requirement was slightly higher at 1,496 MW, an increase of 4.5 percent.

Figure 1-16 shows monthly average operating reserve prices since 2003. From 2003 to early 2008, OR prices had been on the decline but subsequently increased from early 2008 to late 2009 as a result of a decline in OR resources available and increased demand.[30] Since October 2009, OR prices have dropped and returned to pre-2008 levels, settling at their lowest prices in several years (as per Tables 1-21 and 1-22) as the amount of offered OR increased with new fossil units coming on-line.

Figure 1-16: Monthly Operating Reserve Prices by Category, January 2003–April 2010 ($/MWh)



[30] The factors leading to the increase in OR price observed in 2008 and 2009 were specified in the Panel's July 2009 Monitoring Report, pp.45-46.

3. Demand

3.1 Aggregate Consumption

Table 1-23 compares Ontario monthly energy demand and net exports for the 2008/2009 and 2009/2010 reporting periods.

Table 1-23: Monthly Domestic Energy Demand and Exports (Market Schedule), May–April 2008/2009 & 2009/2010 (TWh)

	Ontario Demand*			Exports (Excluding Linked Wheels)			Total Market Demand (Excluding Linked Wheels)		
	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change
May	11.41	10.52	(7.8)	1.55	1.09	(29.7)	12.96	11.61	(10.4)
June	12.20	10.91	(10.6)	1.59	1.66	4.4	13.79	12.57	(8.8)
July	13.15	11.32	(13.9)	1.75	1.88	7.4	14.90	13.20	(11.4)
August	12.57	12.26	(2.5)	1.61	1.55	(3.7)	14.18	13.81	(2.6)
September	11.82	10.97	(7.2)	1.25	1.21	(3.2)	13.07	12.18	(6.8)
October	11.67	11.22	(3.9)	1.46	1.02	(30.1)	13.13	12.24	(6.8)
November	11.85	11.16	(5.8)	1.36	1.00	(26.5)	13.21	12.16	(7.9)
December	13.09	12.69	(3.1)	1.40	1.40	0.0	14.49	14.09	(2.8)
January	13.75	13.17	(4.2)	1.82	1.48	(18.7)	15.57	14.65	(5.9)
February	11.71	11.78	0.6	1.34	1.16	(13.4)	13.05	12.94	(0.8)
March	12.18	11.74	(3.6)	1.44	1.20	(16.7)	13.62	12.94	(5.0)
April	10.77	10.54	(2.1)	0.8	0.84	5.0	11.57	11.38	(1.6)
Total	146.17	138.28	(5.4)	17.37	15.49	(10.8)	163.54	153.77	(6.0)
Average	12.18	11.52	(5.4)	1.45	1.29	(10.9)	13.63	12.81	(6.0)

* Non-dispatchable loads plus dispatchable loads

Annual Ontario Demand fell by 7.89 TWh, or 5.4 percent, from 146.2 TWh in 2008/2009 to 138.3 TWh in 2009/2010 largely due to worsened economic conditions, which led to reduced consumption in the manufacturing sector. Ontario Demand declined in every month, except February where it saw a slight increase. The summer months of May, June, and July saw the largest reductions in demand from the same month the previous year, with drops of 7.8 percent or greater.

Total annual exports (excluding linked wheel transactions) declined from 17.4 TWh in 2008/2009 to 15.5 TWh in 2009/2010, a decline of 1.9 TWh, or 10.8 percent. Percentage declines of over 10 percent from 2008/2009 to 2009/2010 occurred in 6 of the 12 months, with the largest drop of 30.1 percent occurring in October.

The sum of Ontario Demand and export volumes makes up the 'total market demand'. Total Market Demand declined by 9.77 TWh, or 6.0 percent and was lower in every month this year compared to the prior year. The largest monthly percentage difference occurred in July at 11.4 percent and the smallest difference occurred in April at 0.8 percent.

3.2 Wholesale and LDC Consumption

Figure 1-17 plots the separate monthly energy consumption of wholesale loads and Local Distribution Companies (LDC's) between January 2003 and April 2010.

There are clear seasonal fluctuations in LDC demand. Typically, LDC consumption is highest during the December/January and July/August months. Over the latest reporting period, LDC demand peaked in January 2010 at 10,743 GWh, the lowest peak month of any May to April reporting period since the market opened in May 2002. LDC consumption hit a post-market-opening low of 8,263 GWh in April 2010. These numbers typify a period that saw a considerable softening of demand in the Ontario market.

Wholesale electricity consumption continued its downward trend since 2003; including setting a post-market-opening monthly low of 1,688 GWh of wholesale consumption in June 2009. Current period wholesale consumption levels are roughly 2/3 of the consumption levels observed in 2003.

Figure 1-17: Monthly Total Energy Consumption, LDC and Wholesale Loads, January 2003–April 2010 (GWh)

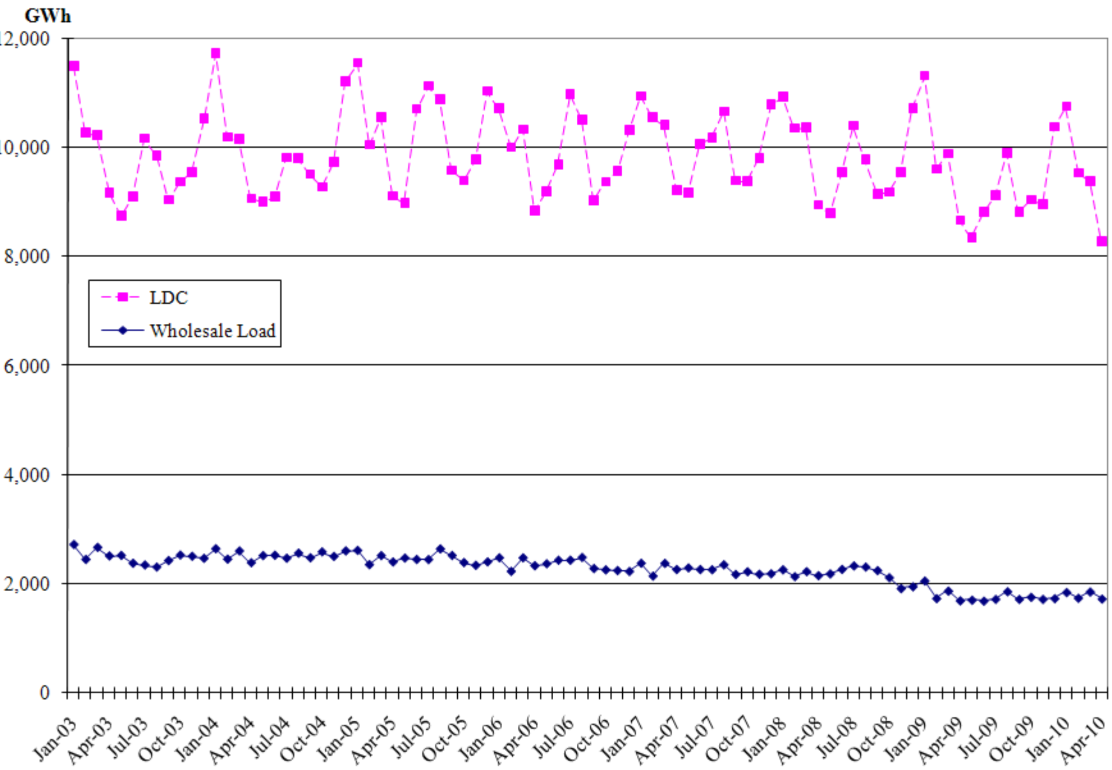
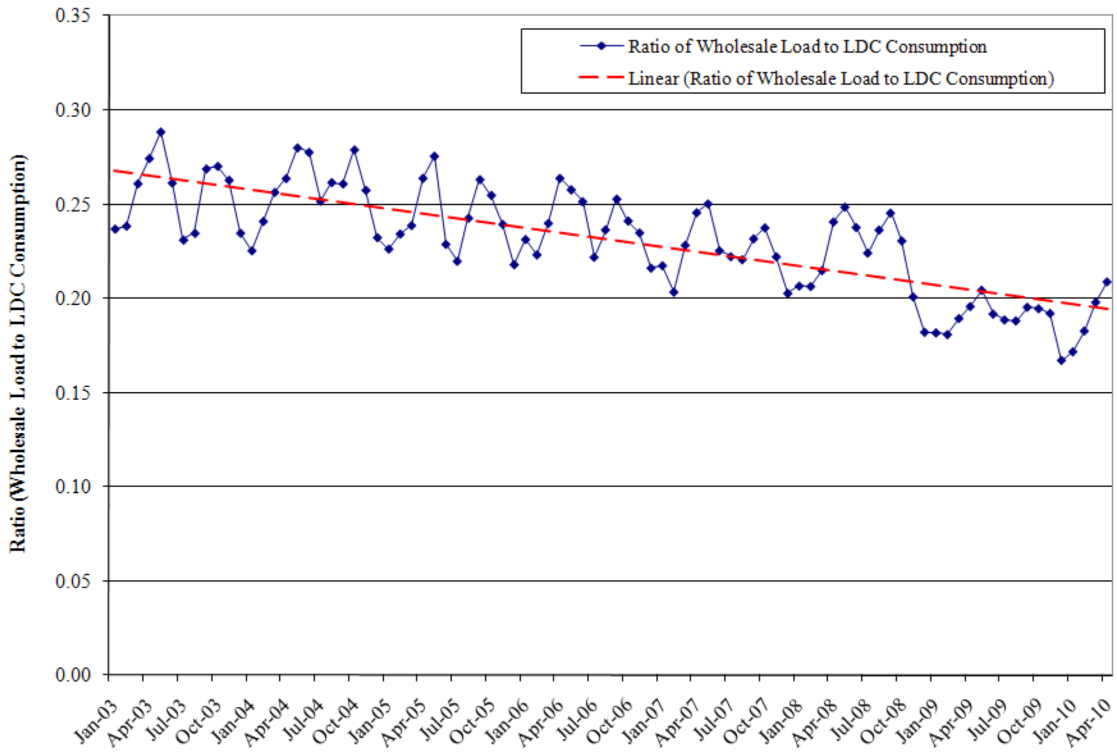


Figure 1-18 presents the ratio of wholesale load to LDC consumption since January 2003. The continued decrease in the ratio is consistent with the more rapid decline of wholesale consumption compared to LDC consumption presented in Figure 1-17. The ratio reached an all-time low of roughly 0.17:1 in December 2009; this corresponds with the seasonal LDC demand spike experienced in December/January of every year as shown in 1-17 above.

Figure 1-18: Ratio of Wholesale Load to LDC Consumption, January 2003–April 2010 (Wholesale Load to LDC Consumption)



4. Supply

4.1 New Generating Facilities

Between May 2009 and April 2010 a wind generation facility came online, a combined heat and power (CHP) facility[31] became fully dispatchable and another combined-cycle gas-fired facility began commissioning:

- The Thorold Cogeneration Project, a 287 MW CHP generating facility located in Thorold, Ontario became dispatchable at the beginning of April 2010 after performing commissioning tests since mid-January 2010. The Thorold facility represents the largest CHP project procured by the OPA to date.[32]

[31] Combined heat and power plants are designed to produce both electricity and heat from a common fuel source.
[32] For a listing of all CHP facilities in operation, see the OPA's CHP webpage at: http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=174

- The Halton Hills Generating Station, a 631.5 MW combined-cycle facility located in Halton Hills Ontario began commissioning at the end of April 2010. The facility is expected to become dispatchable sometime in Q3 2010.
- The Wolfe Island Wind Project, a 198 MW wind facility located off the coast of Kingston, Ontario became operational in June 2009.

The total capacity of these units (including the capacity of the commissioning unit) represents an additional 1,117 MW, or approximately 3.1 percent of total installed capacity in Ontario.[33] In addition, the East Windsor Cogeneration Center, an 84 MW CHP generating facility changed from a self-scheduling facility to a dispatchable facility in mid-November 2009. The East Windsor facility had been commissioning since early June 2009.

4.2 The Supply Cushion

Tables 1-24 and 1-25 present monthly summary statistics on the pre-dispatch and real-time supply cushion for the last two annual reporting periods.[34] The final pre-dispatch supply cushion measure includes all sources of supply (including imports) while the real-time domestic supply cushion focuses only on supply from internal generation.[35]

[33] As of May 5, 2010, existing installed generating capacity is reported to be 35,781 MW on p. 7 of the IESO's 18-month Outlook (from June 2010 to November 2011). The document is available on the IESO's website at: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2010may.pdf

[34] The supply cushion measure used by the Panel differs from the IESO's supply cushion: see the Panel's January 2009 Monitoring Report, pp. 205-206.

[35] In pre-dispatch, all dispatchable resources (including imports and exports) are able to set the projected price, while in real-time imports and exports are fixed and cannot set price.

4.2.1 *Pre-dispatch (One-hour ahead)*

Table 1-24 indicates that the average monthly pre-dispatch supply cushion fell from 17.7 percent in 2008/2009 to 16.6 percent in 2009/2010 with the largest monthly declines observed between June and September. As shown in Tables A-6 and A-7 of the Statistical Appendix, the decline in the average pre-dispatch supply cushion was mainly attributable to declines observed in off-peak hours. The on-peak average increased from 12.9 percent last year to 13.2 percent this year while the off-peak average fell from 21.7 percent last year to 19.5 percent this year.

Although the average monthly pre-dispatch supply cushion fell this year, other indicators of supply cushion performance showed an improvement. The number of hours with a negative supply cushion was reduced from one in 2008/2009 to zero in 2009/2010. In addition, the total number of hours with a supply cushion less than 10 percent dropped from 2,156 hours to 1,988 hours, a reduction of 1.9 percent.

Table 1-24: Final Pre-Dispatch Total Supply Cushion, May–April 2008/2009 & 2009/2010 (% and Number of Hours under Certain Levels)

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2008/ 2009	2009/ 2010	2008/ 2009	%	2009/ 2010	%	2008/ 2009	%	2009/ 2010	%
May	15.7	16.9	1	0.1	0	0.0	255	34.3	144	19.4
June	19.2	15.5	0	0.0	0	0.0	167	23.2	169	23.5
July	19.6	14.6	0	0.0	0	0.0	153	20.6	218	29.3
August	21.6	16.4	0	0.0	0	0.0	120	16.1	194	26.1
September	22.9	15.3	0	0.0	0	0.0	62	8.6	166	23.1
October	19.7	18.4	0	0.0	0	0.0	150	20.2	117	15.7
November	18.6	19.5	0	0.0	0	0.0	127	17.6	54	7.5
December	17.2	16.7	0	0.0	0	0.0	170	22.8	158	21.2
January	14.4	16.9	0	0.0	0	0.0	262	35.2	208	28.0
February	13.5	14.9	0	0.0	0	0.0	261	38.8	227	33.8
March	13.8	13.9	0	0.0	0	0.0	279	37.5	274	36.8
April	16.7	20.7	0	0.0	0	0.0	150	20.8	59	8.2
Total	17.7	16.6	1	0.0	0	0.0	2,156	24.6	1,988	22.7

4.2.2 *Real-time*

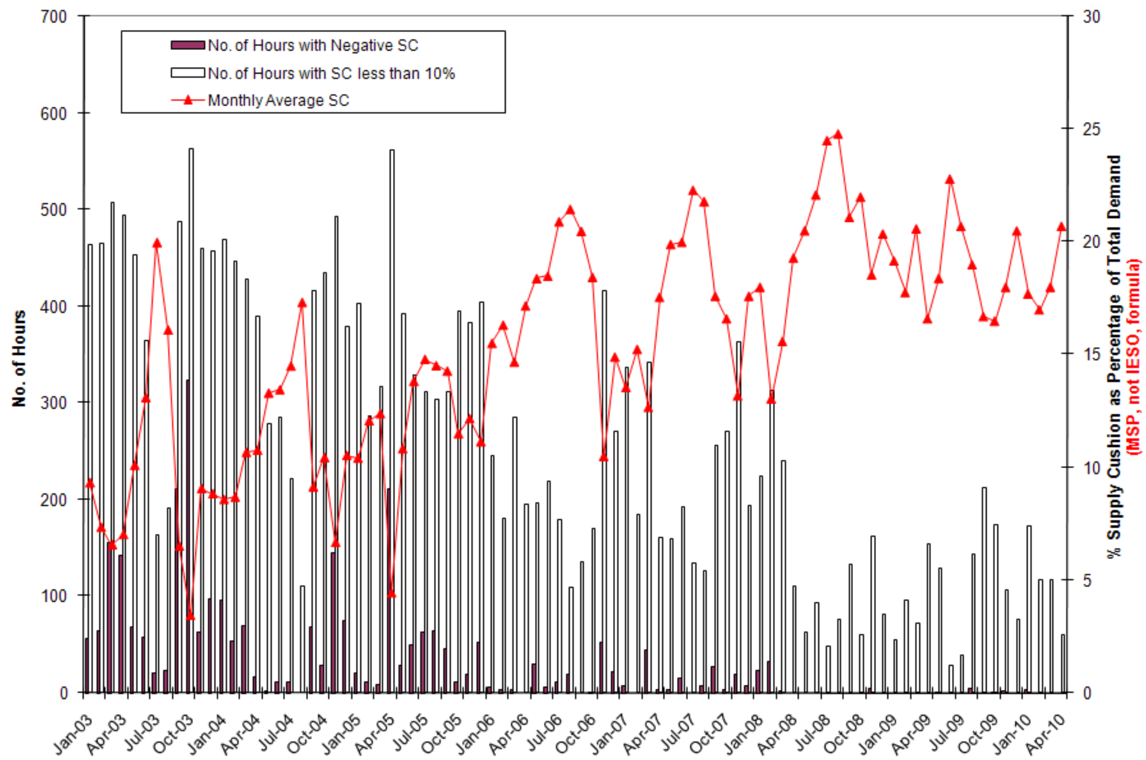
Table 1-25 indicates that the real-time supply cushion worsened from 2008/2009 to 2009/2010. The average monthly supply cushion dropped from 20.7 percent to 18.8 percent. The number of hours where there was a negative supply cushion spiked in 2009/2010 with 12 instances, compared to only 5 in 2008/2009. (In 2009/2010 there were 5 such instances in August alone.) The number of hours that experienced a supply cushion of 10 percent or less increased from 1,087 hours to 1,368. This 25 percent increase meant that 15.6 percent of all hours experienced a supply cushion of 10 percent or less during the 2009/2010 reporting period.

Table 1-25: Real-time Domestic Supply Cushion, May–April 2008/2009 & 2009/2010 (% and Number of Hours under Certain Levels)

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2008/ 2009	2009/ 2010	2008/ 2009	%	2009/ 2010	%	2008/ 2009	%	2009/ 2010	%
May	20.5	18.4	0	0.0	1	0.1	62	8.3	128	17.2
June	22.1	22.8	0	0.0	0	0.0	93	12.9	28	3.9
July	24.5	20.7	0	0.0	0	0.0	47	6.3	38	5.1
August	24.8	19.0	0	0.0	5	0.7	76	10.2	143	19.2
September	21.1	16.7	0	0.0	0	0.0	132	18.3	212	29.4
October	22.0	16.5	0	0.0	1	0.1	60	8.1	173	23.3
November	18.5	18.0	5	0.7	2	0.3	162	22.5	106	14.7
December	20.4	20.5	0	0.0	0	0.0	81	10.9	76	10.2
January	19.2	17.7	0	0.0	3	0.4	54	7.3	172	23.1
February	17.8	17.0	0	0.0	0	0.0	95	14.1	117	17.4
March	20.6	18.0	0	0.0	0	0.0	71	9.5	116	15.6
April	16.6	20.7	0	0.0	0	0.0	154	21.4	60	8.3
Total	20.7	18.8	5	0.1	12	0.1	1,087	12.4	1,369	15.6

Figure 1-19 plots real-time domestic supply cushion summary statistics between January 2003 and April 2010. The long-term trend appears to show that the real-time supply cushion has consistently been improving since 2003, although falling slightly from the peak levels observed in the summer of 2008. Both the number of hours with a supply cushion less than 10 percent and the number of hours with a negative supply cushion have decreased substantially since January 2003, although rebounding slightly during the current reporting period.

Figure 1-19: Monthly Real-time Domestic Supply Cushion Statistics, January 2003–April 2010 (% and Number of Hours under Certain Levels)



4.3 Baseload Supply

Table 1-26 presents average hourly market schedules by baseload generation category and Ontario Demand over the last two May to April periods. Overall, average hourly baseload supply declined by 2.3 percent, from 12.9 GW last year to 12.6 GW this year. Total baseload supply was up during the 2009 summer months between June and August compared to 2008 but fell (or stayed constant) for all remaining months in 2009 and 2010. However, average hourly Ontario Demand fell by 5.4 percent from 16.7 GW last year to 15.8 GW this year, considerably more than the drop in average baseload supply. Therefore, average hourly baseload supply expressed as a percentage of average hourly Ontario Demand increased from 77.2 percent last year to 79.7 percent this year.

Table 1-26: Average Hourly Market Schedules by Baseload Generation Type and Ontario Demand, May–April 2008/2009 & 2009/2010 (GWh)

	Nuclear		Baseload Hydro		Self-Scheduling Supply		Total Baseload Supply		Ontario Demand		Total Baseload Supply as a % of Ontario Demand	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	8.2	6.7	2.2	2.4	1.0	1.1	11.4	10.2	15.8	14.1	72.2	72.3
June	9.1	9.5	2.0	2.3	0.8	1.2	11.9	13.0	16.4	15.2	72.6	85.5
July	10.0	10.0	2.1	2.3	0.7	0.9	12.8	13.2	18.3	15.2	69.9	86.8
August	10.1	10.0	2.0	2.3	0.7	0.9	12.8	13.2	16.9	16.5	75.7	80.0
September	9.8	9.4	2.0	2.3	0.8	0.9	12.6	12.6	15.9	15.2	79.2	82.9
October	9.7	8.6	1.9	2.2	1.1	1.2	12.7	12.0	16.2	15.1	78.4	79.5
November	9.4	9.1	2.0	2.1	1.1	1.2	12.5	12.4	15.9	15.5	78.6	80.0
December	10.6	10.2	2.1	2.1	1.4	1.3	14.1	13.6	18.2	17.1	77.5	79.5
January	10.6	9.9	2.0	2.1	1.2	1.3	13.8	13.3	18.5	17.7	74.6	75.1
February	10.2	10.0	2.1	2.1	1.3	1.2	13.6	13.3	15.7	17.5	86.6	76.0
March	10.3	9.5	2.2	2.2	1.5	1.4	14.0	13.1	18.1	15.8	77.3	82.9
April	8.6	8.5	2.1	2.1	1.5	1.2	12.2	11.8	14.5	14.6	84.1	80.8
Average	9.7	9.3	2.1	2.2	1.1	1.2	12.9	12.6	16.7	15.8	77.2	79.7

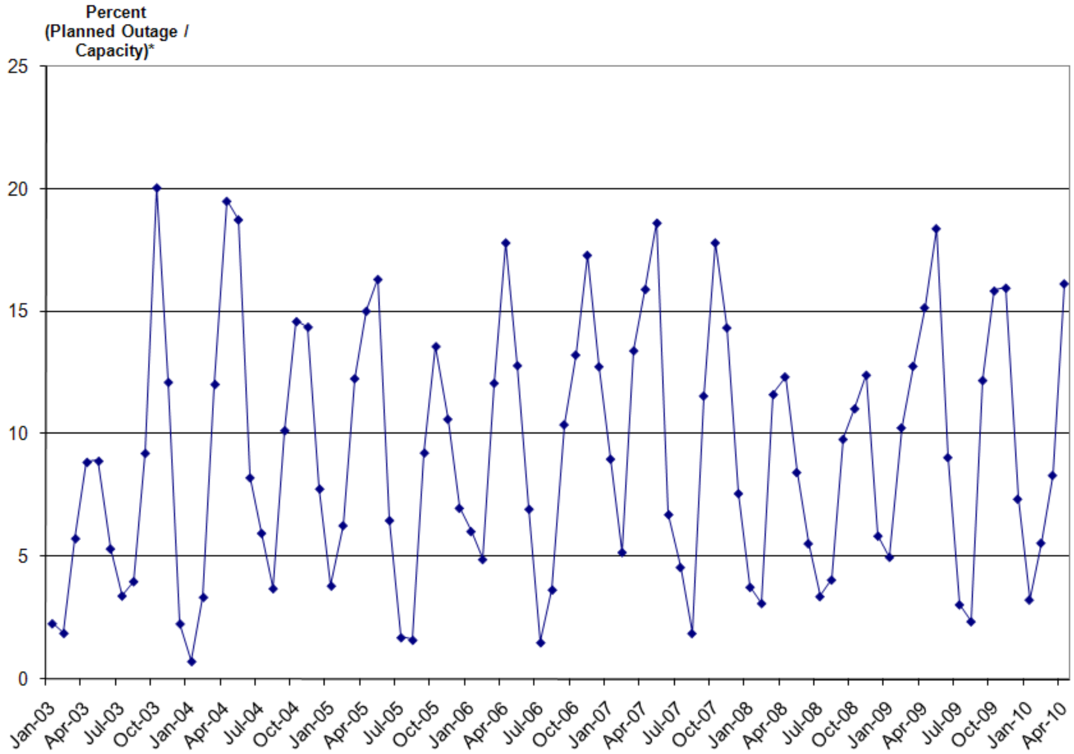
4.4 Outages

Generator outage patterns are important to monitor as they place upward pressure on market prices as supply is removed from the market. The following sections report on planned and forced outage rates by fuel type since January 2003.

4.4.1 *Planned Outages*

Planned outages are typically taken during the low demand periods in the spring and fall months. Figure 1-20 plots monthly planned outages as a percentage of capacity since 2003. Planned outage rates over the latest May to April period showed seasonal fluctuations similar to those observed in previous years.

Figure 1-20: Planned Outages Relative to Capacity, January 2003–April 2010 (% of Capacity)

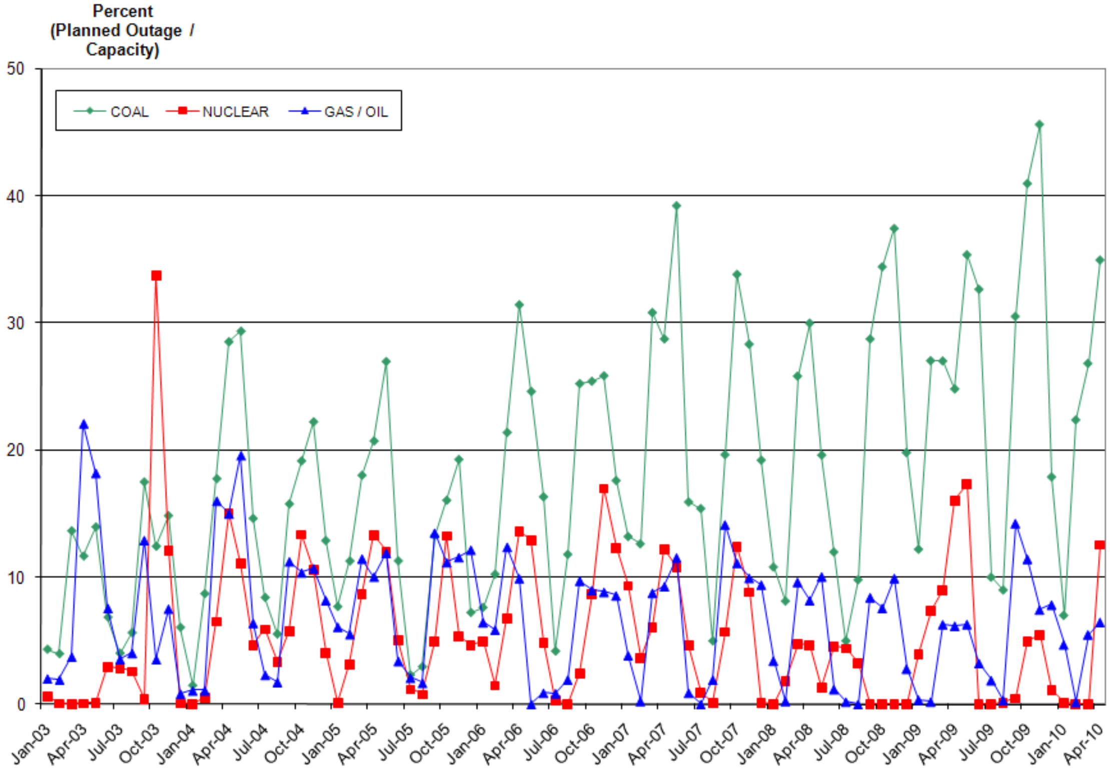


*Includes Nuclear, Coal, and Gas units.

Figure 1-21 presents planned outage rates as a percentage of total capacity for coal, nuclear, and oil/gas generators since 2003. Planned outages for each fuel type show seasonal patterns similar to the aggregate planned outage rate presented above.[36] Similar to previous spring and fall (low demand) months, coal planned outage rates were above 30 percent of capacity in May-June 2009, October-November 2009, and April 2010.

[36] For the purposes of our outage statistics, OPG's CO_2 outages are classified as planned outages rather than forced outages as done by the IESO (See the Panel's July 2009 Monitoring report pp. 58-59 for details on why this adjustment was made). Furthermore, the capacity that was removed from the market by designating units as NOBA is not reflected in either the planned or forced outage statistics. This adjustment is only relevant for most 2009 summer months. OPG's 2010 CO_2 emissions strategy eliminated the use of the CO2 outage designation.

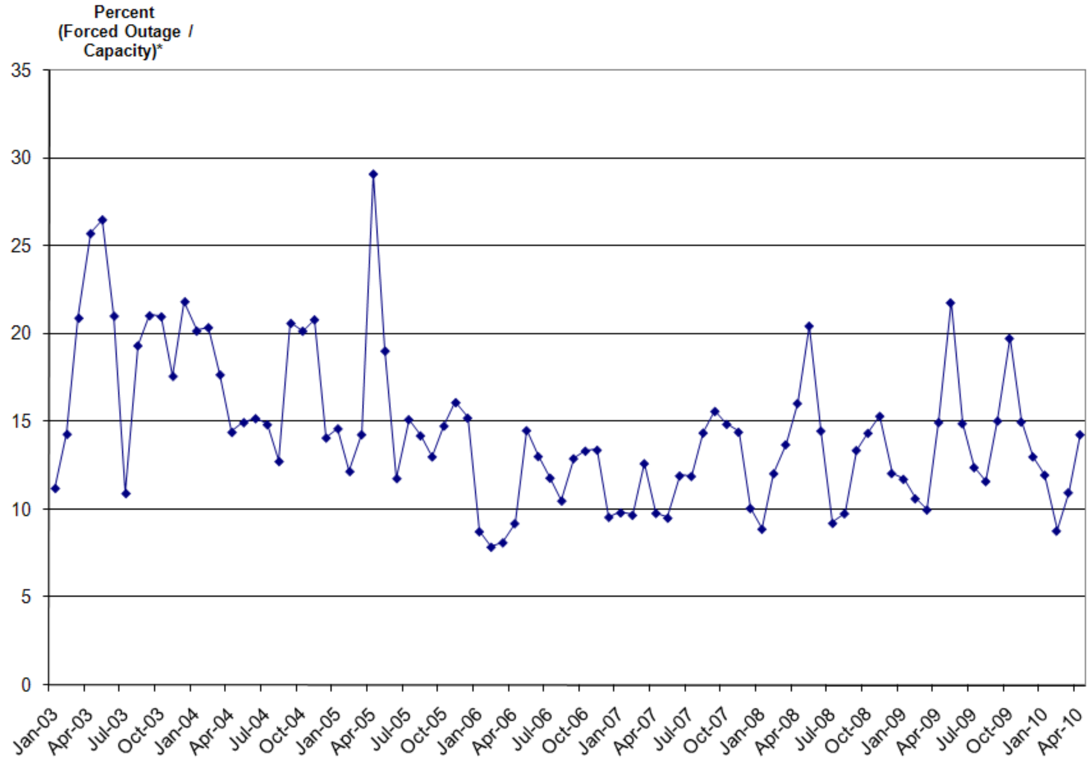
Figure 1-21: Planned Outages Relative to Capacity by Fuel Type
January 2003–April 2010
(% of Capacity)



4.4.2 *Forced Outages*

Given that forced outages occur unexpectedly, they do not exhibit the same level of seasonality as planned outage rates. Figure 1-22 plots aggregated forced outages as a percentage of capacity since January 2003. Over the most recent annual period, the aggregate rate fluctuated between 10 and 15 percent with three exceptions; May 2009 at 21.8 percent, October 2009 at 19.8 percent, and February 2010 at 8.8 percent. Although the monthly observations above 15 percent are high relative to the recent annual period, they remain well below the high forced outage rates experienced prior to 2005.

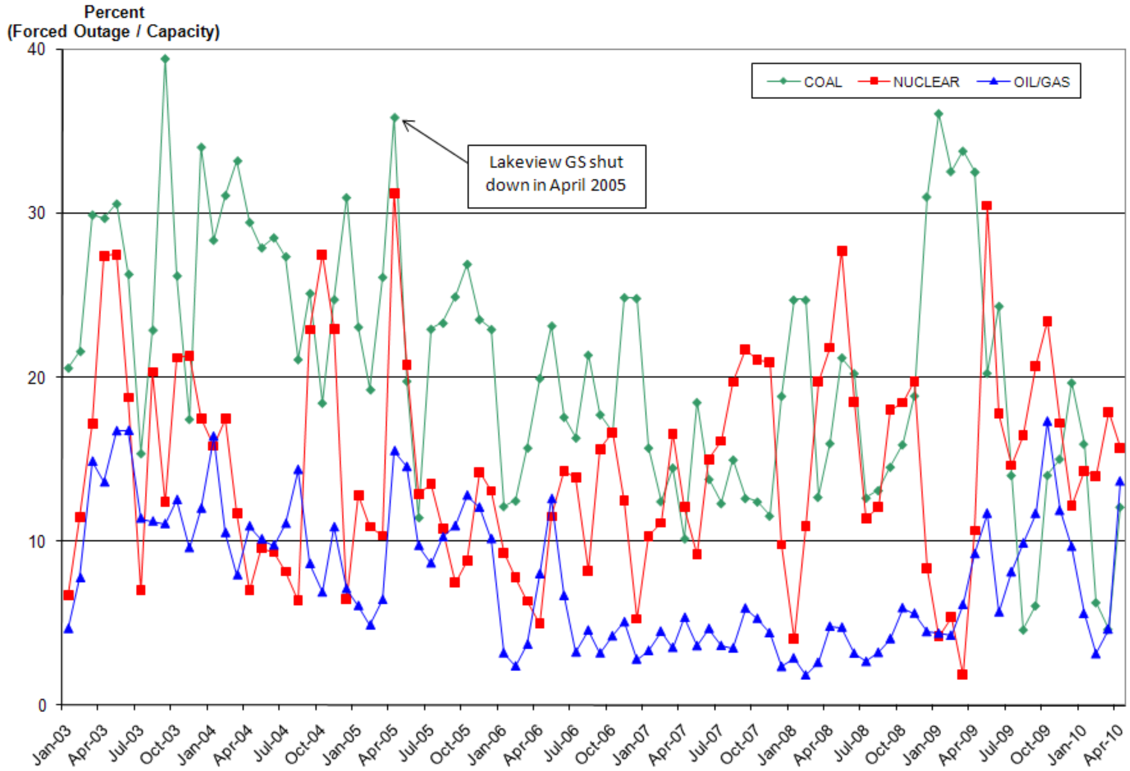
Figure 1-22: Forced Outages Relative to Capacity,*
January 2003–April 2010
(% of Capacity)



* Includes Nuclear, Coal, and Oil/Gas units.

Figure 1-23 separates forced outage rates by fuel type since 2003. After a noticeable increase in the forced outage rate for coal units between December 2008 and April 2009, the forced outage rate has declined and remained below 20 percent in July 2009 onwards. In fact, the coal forced outage rate fell below 10 percent in four months over the recent annual period, a threshold that had never been observed since market opening. On the other hand, the nuclear forced outage rate appeared slightly higher this period compared to previous annual periods. In May 2009, the nuclear forced outage rate climbed above 30 percent for only the second month since market opening, the other month being April 2005. Aside from May 2009, the nuclear forced outage rate fluctuated between 12 and 24 percent for the remainder of the current period. The gas forced outage rate was the lowest of the three fuel types in most months in the current period but it did reach a historical high of 17.3 percent in October 2009 surpassing the previous record high of 16.8 percent set in June 2003.

Figure 1-23: Forced Outages Relative to Total Capacity by Fuel Type, January 2003–April 2010 (% of Capacity)



4.5 Changes in Fuel Prices

Tables 1-27 and 1-28 present average monthly coal and natural gas spot prices over the last two reporting periods. Based on a comparison of annual averages, both coal and natural gas prices saw significant drops from 2008/2009 levels.

4.5.1 *Coal Prices*

Average monthly Central Appalachian (CAPP) and Powder River Basin (PRB) Coal spot prices are presented in Table 1-27 for the last two reporting periods. [37] In percentage terms, both types of coal plummeted in price relative to the prices experienced during the previous reporting period, although they did not decline equally. CAPP coal prices

[37] Coal prices have been converted from US$ to CDN$ on a daily basis using the Bank of Canada's noon exchange rate.

decreased from a monthly average of $3.90/MMBtu in 2008/2009 to $2.20/MMBtu in 2009/2010, a drop of 43.5 percent. PRB coal prices decreased 24 percent, from $0.72/MMBtu last period to $0.55/MMBtu this period. Although, on average, both prices had decreased when comparing reporting period averages, from the beginning of the current period (May 2009) to the end of the current period (April 2010), CAPP and PRB prices increased by 10 percent and 29 percent respectively.

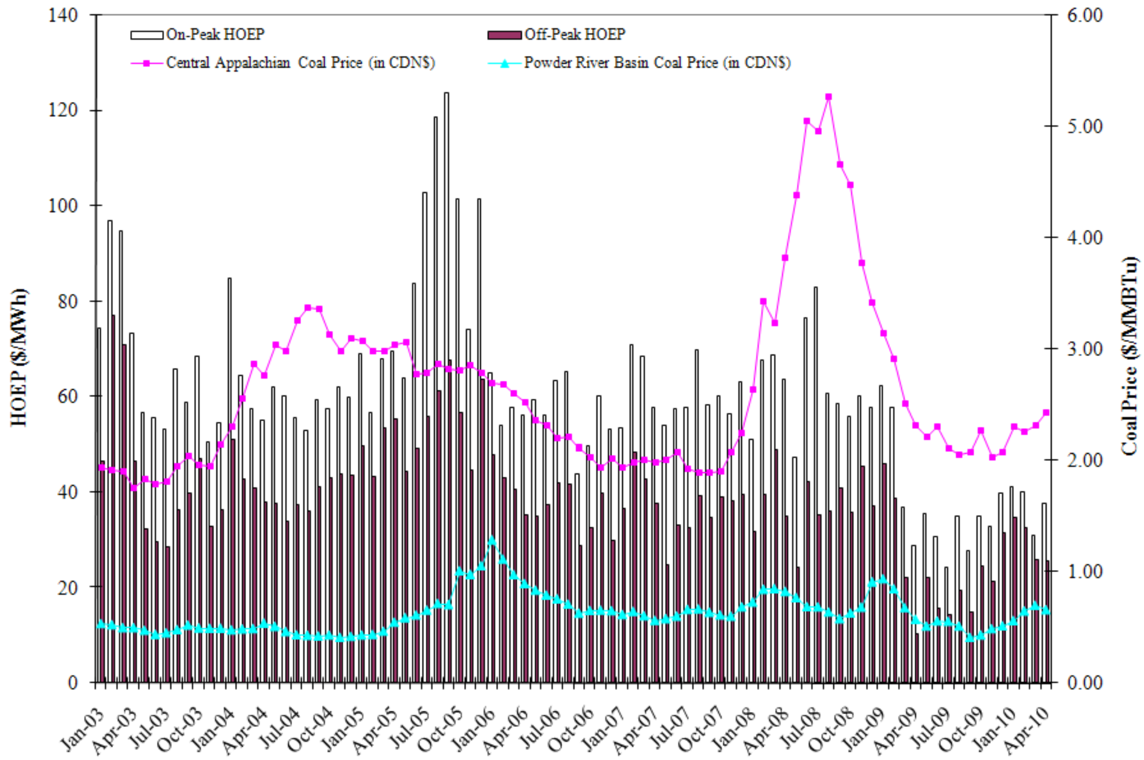
Table 1-27: Average Monthly NYMEX Coal Futures Settlement Prices by Type, May–April 2008/2009 & 2009/2010 ($CDN/MMBtu)

	NYMEX Central Appalachian Coal (CAPP) Price			NYMEX Western Rail Powder River Basin Coal (PRB) Price		
	2008/ 2009	**2009/ 2010**	**% Change**	**2008/ 2009**	**2009/ 2010**	**% Change**
May	4.38	2.22	(49.4)	0.77	0.51	(33.8)
June	5.04	2.30	(54.4)	0.69	0.56	(18.8)
July	4.96	2.11	(57.5)	0.68	0.55	(19.1)
August	5.26	2.06	(60.9)	0.64	0.51	(20.3)
September	4.65	2.07	(55.5)	0.58	0.41	(29.3)
October	4.47	2.27	(49.1)	0.63	0.43	(31.7)
November	3.77	2.02	(46.3)	0.68	0.49	(27.9)
December	3.42	2.08	(39.2)	0.91	0.52	(42.9)
January	3.15	2.31	(26.6)	0.94	0.56	(40.4)
February	2.91	2.26	(22.3)	0.85	0.65	(23.5)
March	2.51	2.32	(7.6)	0.68	0.70	2.9
April	2.31	2.44	5.3	0.57	0.66	15.8
Average	3.90	2.20	(43.5)	0.72	0.55	(24.0)

Source: EIA Coal News and Market Reports

Figure 1-24 plots the monthly average CAPP and PRB coal prices, along with the on-peak and off-peak HOEP. Historically the Panel has not found a close correlation between the CAPP and PRB prices and HOEP. However, in recent periods the on-peak and off-peak HOEP seems to reflect a combination of the two fuel prices to a degree. For example; in mid-to-late 2008 when CAPP prices spiked and PRB prices declined slightly, there was a modest increase in HOEP. From early 2009 onward, both CAPP and PRB prices dropped considerably as did the average HOEP.

Figure 1-24: Central Appalachian and Powder River Basin Coal Prices and HOEP, January 2003–April 2010 ($/MWh and $/MMBtu)



4.5.2 *Natural Gas Prices*

Natural gas prices, measured by the Henry Hub Spot and Dawn Daily Gas prices,[38] are presented in Table 1-28 for the last two reporting periods. Based on annual averages, both prices decreased significantly from the 2008/2009 reporting period to the current 2009/2010 period. The Henry Hub price declined by $3.66/MMBtu (45.5 percent) while the Dawn Daily price fell by $3.7/MMBtu (43.8 percent) year-over-year. The largest year-over-year price change occurred in June for both Henry Hub and Dawn Daily, which saw a prices drop of over 60 percent from the previous June. All months of the 2009/2010 reporting period had equal or lower monthly average prices when compared to the same months of the 2008/2009 reporting period.

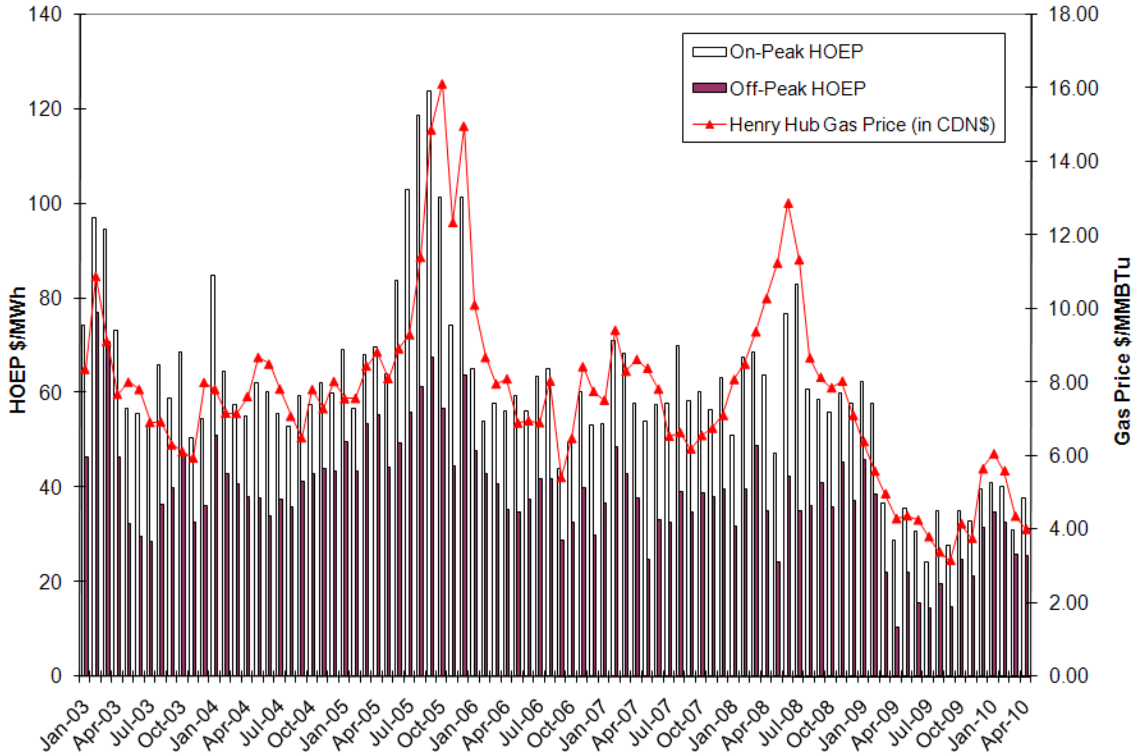
[38] The Henry Hub is a point on the natural gas pipeline located in Erath, Louisiana while the Union Dawn Hub is located near Sarnia, Ontario. Henry Hub prices are converted from US$ to CDN$ on a daily basis using the Bank of Canada's noon exchange rate.

Table 1-28: Average Monthly Natural Gas Prices
May–April 2008/2009 & 2009/2010
($CDN/MMBtu)

	Henry Hub Spot Price			Dawn Daily Gas Price		
	2008/ 2009	**2009/ 2010**	**% Change**	**2008/ 2009**	**2009/ 2010**	**% Change**
May	11.25	4.37	(61.2)	11.67	4.81	(58.8)
June	12.88	4.26	(66.9)	13.05	4.47	(65.7)
July	11.34	3.81	(66.4)	11.64	4.05	(65.2)
August	8.67	3.39	(60.9)	8.88	3.53	(60.2)
September	8.14	3.16	(61.2)	8.05	3.42	(57.5)
October	7.86	4.16	(47.1)	8.15	4.76	(41.6)
November	8.04	3.77	(53.1)	8.43	4.47	(47.0)
December	7.11	5.65	(20.5)	7.80	6.10	(21.8)
January	6.39	6.07	(5.0)	7.26	6.23	(14.2)
February	5.60	5.60	0.0	6.15	5.88	(4.4)
March	4.98	4.37	(12.2)	5.40	4.71	(12.8)
April	4.30	4.01	(6.7)	4.78	4.45	(6.9)
Average	8.05	4.39	(45.5)	8.44	4.74	(43.8)

Figure 1-25 plots the monthly average Henry Hub spot price along with the on-peak and off-peak HOEP prices. As the Panel has observed in the past, movements in gas prices appear to roughly coincide with movements in the HOEP.

Figure 1-25: Henry Hub Natural Gas Spot Price and HOEP, January 2003–April 2010 ($/MWh and $/MMBtu)



5. Imports and Exports

5.1 Overview

Table 1-29 presents monthly net exports (imports) from (to) Ontario during on-peak and off-peak hours. Ontario remained a net exporter during all months for both off-peak and on-peak, although the magnitude of net exports declined. Off-peak net exports dropped 377 GWh (5.9 percent) while on-peak net exports dropped 1,685 GWh (35.1 percent). This means that overall net exports dropped 2,062 GWh (18.5 percent) from 2008/2009 to 2009/2010. When comparing the current period to the previous period, on-peak net exports dropped in almost all months (except two), while off-peak saw growth in net exports during the summer and a decline in early 2010.

Table 1-29: Net Exports (Imports) from (to) Ontario, Off-peak and On-peak, May–April 2008/2009 & 2009/2010 (GWh)

	Off-Peak			On-Peak			Total		
	2008/2009	2009/2010	% Change	2008/2009	2009/2010	% Change	2008/2009	2009/2010	% Change
May	601	474	(21.1)	470	179	(62.0)	1,070	652	(39.0)
June	507	734	44.8	448	563	25.7	955	1,297	35.8
July	668	838	25.4	494	408	(17.4)	1,163	1,246	7.2
August	655	686	4.7	490	210	(57.1)	1,145	896	(21.7)
September	344	384	11.7	251	132	(47.1)	594	516	(13.1)
October	415	274	(33.9)	396	105	(73.6)	811	379	(53.2)
November	363	478	31.7	200	261	30.5	562	738	31.3
December	553	657	18.9	441	395	(10.4)	993	1,052	5.9
January	634	502	(20.8)	546	301	(44.8)	1,180	803	(31.9)
February	585	286	(51.1)	348	252	(27.6)	932	538	(42.3)
March	657	415	(36.8)	516	205	(60.2)	1,173	621	(47.1)
April	387	262	(32.2)	195	98	(50.0)	582	360	(38.2)
Total	6,368	5,991	(5.9)	4,793	3,108	(35.1)	11,161	9,100	(18.5)

When the market opened in 2002, Ontario was a net importer of energy. Over the years it has become a net exporter as favourable supply conditions in the province made it less dependent on imports to meet internal energy needs. As can be seen in Figure 1-26, the trend toward increasing net exports has slowed, although Ontario continues to be a considerable net exporter.

Figure 1-26: Net Exports (Imports) from Ontario, On-peak and Off-peak, January 2003–April 2010 (GWh)

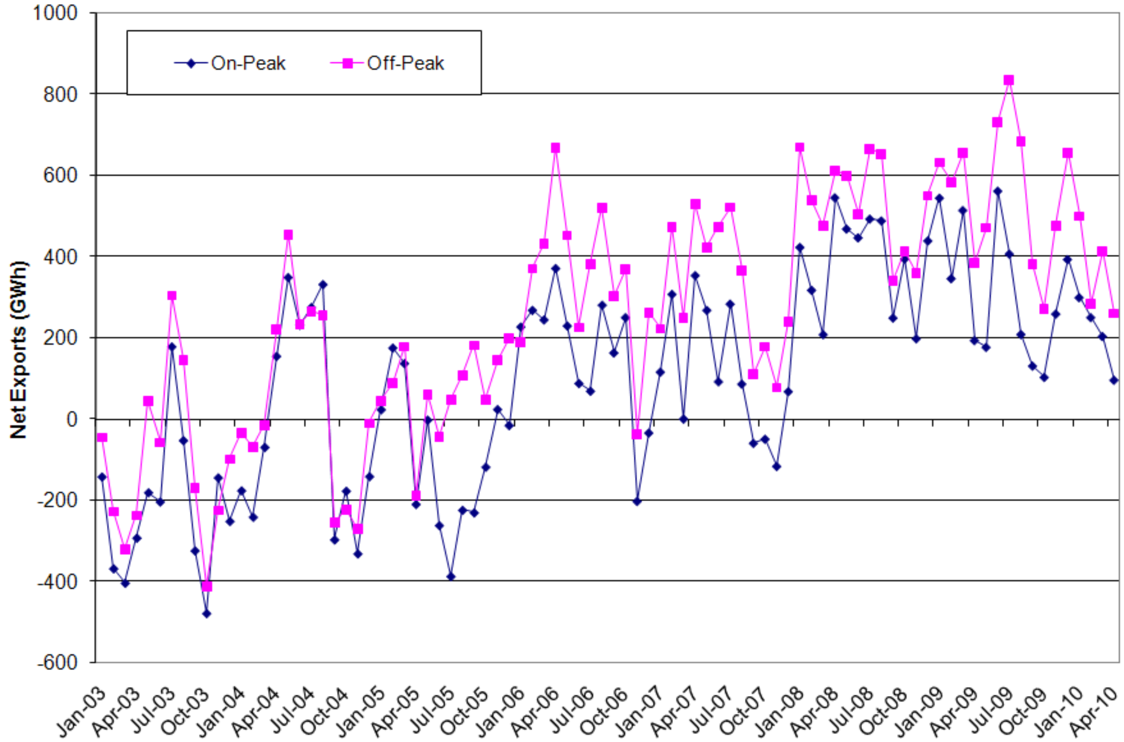


Table 1-30 presents total net exports by neighbouring intertie group for the 2008/2009 and 2009/2010 reporting periods. While earlier Table 1-28 reports total provincial net exports ignoring linked wheel volumes (because each linked wheel includes a simultaneous injection and withdrawal of energy to and from Ontario, thus netting to zero), linked wheel volumes are included in the net exports by intertie group calculations because the import and export legs are scheduled at different intertie groups (i.e. they do not net to zero at a given intertie).

Table 1-30: Net Exports (Imports) from (to) Ontario by Neighbouring Intertie Group May–April 2008/2009 & 2009/2010 (GWh)

	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	(92)	(130)	1,298	649	3	(36)	(232)	286	93	(118)	1,070	652
June	(144)	(133)	925	1,206	(30)	(38)	164	351	39	(88)	955	1,297
July	(151)	(161)	850	1,186	(25)	(15)	522	449	(33)	(213)	1,163	1,246
August	(166)	(170)	739	891	(21)	(39)	620	454	(28)	(239)	1,145	896
September	(136)	(125)	143	737	(29)	(17)	567	368	50	(446)	594	516
October	(160)	(164)	212	612	(35)	(32)	705	326	89	(364)	811	379
November	(160)	(141)	47	517	(38)	(16)	647	193	67	185	562	738
December	6	(97)	345	392	18	(27)	562	217	63	567	993	1,052
January	(45)	(110)	300	838	(24)	(33)	902	397	47	(288)	1,180	803
February	(96)	(69)	533	905	(22)	(15)	537	104	(19)	(388)	932	538
March	(69)	(121)	1,011	931	(16)	(22)	260	144	(14)	(311)	1,173	621
April	(70)	(117)	505	367	12	(26)	140	311	(4)	(174)	582	360
Total	(1,282)	(1,537)	6,906	9,231	(207)	(316)	5,394	3,599	350	(1,877)	11,161	9,100

With the exception of Quebec, if Ontario was an annual net importer or exporter to a specific region during the 2008/2009 reporting period, it remained one throughout the 2009/2010 period. Ontario went from being an annual net exporter of electricity to Quebec at 350 GWh in 2008/2009 to being an annual net importer of 1,877 GWh in 2009/2010, a year-to-year difference of 2,527 GWh. Ontario was a net importer from Manitoba in every month and the annual net imports from Manitoba increased by 255 GWh (20 percent). Ontario's largest export partner continued to be Michigan where annual net exports increased by 2,325 GWh (33.7 percent). Unlike 2008/2009 where Ontario was sometimes a monthly net importer and sometimes a monthly net exporter to Minnesota, Ontario was a net importer of Minnesota electricity in every month of the 2009/2010 period. This resulted in annual net imports from Minnesota increasing by 109 GWh (52.7 percent).

Imports and exports are separately reported in Table 1-31 and 1-32, showing totals for each intertie over the last two annual periods. The tables also show the flows at each intertie excluding linked wheels at that intertie.

5.2 Imports

As reported in Table 1-31, total imports fell to 6,786 GWh, a decrease of 2,248 GWh or 25 percent compared to last year. Excluding linked-wheel transactions, imports were up by 3 percent in latest 12 month period.

The most significant increase in import volumes occurred at the Quebec interties. Total imports increased by over 633 percent from 466 GWh last year to 3,415 GWh this year while the year over year percentage increase was even higher (1,179 percent) for import volumes excluding linked wheels. The volume increase was attributable to the introduction of the new Quebec DC intertie at Outaouais that was brought partially into service in July 2009 and fully into service in November 2009, as well as increased imports at Beauharnois. Total imports at Outaouais represented an additional 1,462 GWh of Quebec imports compared to the last May to April period while year-over-year imports at Beauharnois were up by 1,185 GWh (386 percent).

Table 1-31: Imports to Ontario by Intertie, May–April 2008/2009 & 2009/2010 (GWh)

	Total			Total Excluding Linked Wheels		
	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change
Manitoba	1,359	1,562	14.9	1,359	1,562	14.9
Michigan	3,622	881	(75.7)	3,616	880	(75.7)
Minnesota	347	416	19.8	347	416	19.9
New York	3,241	512	(84.2)	630	381	(39.5)
Quebec	466	3,415	632.5	246	3,146	1,178.9
Total	9,034	6,786	(24.9)	6,198	6,385	3.0

5.3 Exports

The decrease in total exports, as shown in Table 1-32 was 4,311 GWh or 21 percent. Excluding linked wheels, the decline was 10.8 percent. With the exception of the Quebec intertie group, total exports were down in May 2009 to April 2010 relative to one year earlier, although exports excluding linked wheels were higher at the Michigan intertie. Due to the introduction of the new DC tie at Quebec, total exports were up by 88 percent.

Total exports at the Outaouais intertie were 1,427 GWh representing 93 percent of total Quebec export volumes.

Table 1-32: Exports from Ontario by Intertie, May–April 2008/2009 & 2009/2010 (GWh)

	Total			Total Excluding Linked Wheels		
	2008/ 2009	2009/ 2010	% Change	2008/ 2009	2009/ 2010	% Change
Manitoba	76	25	(67.2)	76	25	(67.1)
Michigan	10,528	10,112	(4.0)	7,698	9,717	26.2
Minnesota	140	100	(28.7)	140	100	(28.6)
New York	8,635	4,111	(52.4)	8,629	4,106	(52.4)
Quebec	816	1,538	88.4	816	1,538	88.5
Total	20,196	15,885	(21.3)	17,359	15,486	(10.8)

5.4 *Congestion at Interties*

Congestion refers to economic trade at an intertie being limited by the capacity of that intertie to support the flow of energy. In general, intertie congestion levels tend to increase at Ontario's interties as the volume of inter-jurisdictional transactions increase or intertie capability decreases.

5.4.1 *Import Congestion*

Table 1-33 reports the number of occurrences of import congestion by month and intertie group over the last two reporting periods. There were zero hours of import congestion on either the Michigan or NYISO interties during the 2009/2010 reporting period, down from 15 and 63 hours respectively during the previous reporting period. This is attributable in large part to decreases in import volumes to Ontario from both Michigan and NYISO, greatly reducing line congestion (see Table 1-31). Congestion at all other interties significantly increased as the volume of imports increased for all three interties. Hours of import congestion at the Manitoba interface increased by 715 hours (142 percent) from 504 to 1219 hours, while the import volume over that intertie increased by 14.9 percent. The Minnesota intertie experienced the most hours of import congestion at 2,523, up from 418 the previous period. This is an increase of 2,105 hours (504 percent), while the total volume of imports over the Minnesota intertie increased by 19.8 percent. The volume of imports over the Quebec intertie increased by 632.5 percent and was accompanied by an increase the number of hours that experienced import congestion by 255 hours (1,342 percent).

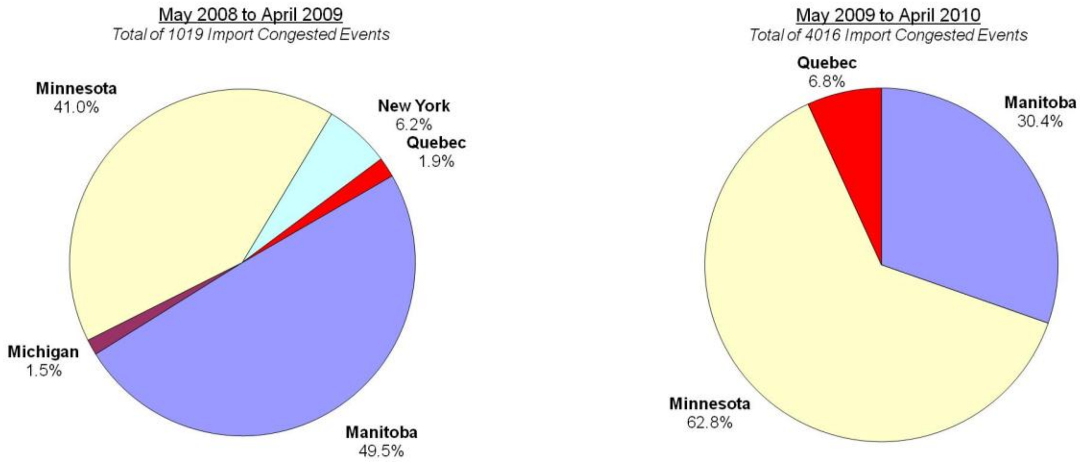
Table 1-33: Import Congestion in the Market Schedule by Intertie, May–April 2008/2009 & 2009/2010 (Number of Hours)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	0	101	1	0	6	84	51	0	0	10
June	19	100	3	0	48	146	10	0	0	4
July	6	61	0	0	22	90	1	0	9	69
August	100	147	0	0	15	259	0	0	6	21
September	10	85	9	0	78	203	1	0	2	107
October	53	54	1	0	57	248	0	0	0	10
November	80	104	1	0	54	203	0	0	1	0
December	14	111	0	0	21	113	0	0	0	0
January	33	241	0	0	10	245	0	0	0	15
February	121	36	0	0	58	237	0	0	0	22
March	61	57	0	0	26	383	0	0	0	7
April	7	122	0	0	23	312	0	0	1	9
Total	504	1219	15	0	418	2,523	63	0	19	274

Figure 1-27 compares the number of hours of import congestion by intertie group as a percentage of total import congestion events for the 2008/2009 and 2009/2010 reporting periods.[39] Minnesota is now the cause of almost two thirds of import congestion while Manitoba and Quebec make up the remaining third. The number of import congested hours skyrocketed from 1,019 in 2008/2009 to 4,016 in 2009/2010, an increase of 2,997 instances (294 percent).

[39] It is possible to have more than one intertie import (export) congested during the same hour. For the purposes of the pie charts above (and in the export congestion section), these are treated as individual import (export) congestion events.

Figure 1-27: Percentage of Import Congestion Events in the Market Schedule by Intertie, November–April 2008/2009 & 2009/2010 (%)



5.4.2 *Export Congestion*

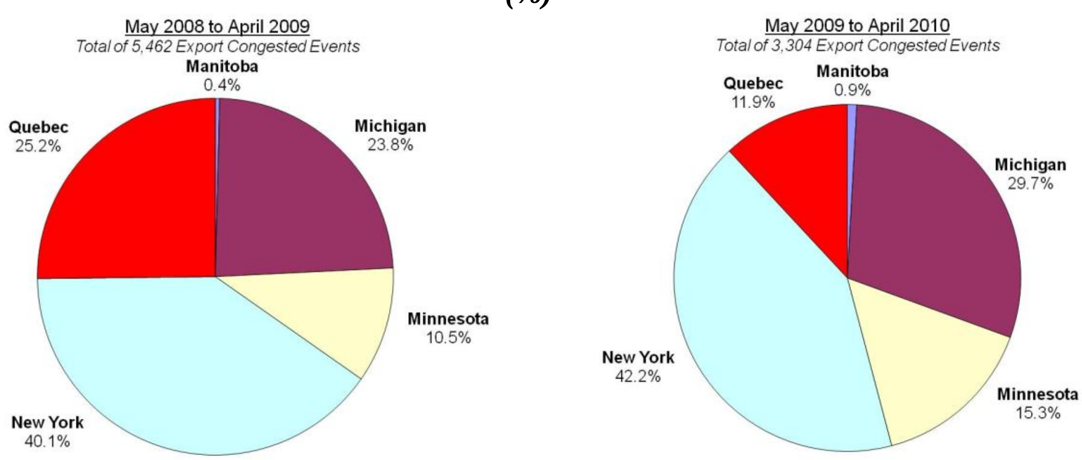
Table 1-34 provides the frequency of export congestion by month and intertie group for the 2008/2009 and 2009/2010 reporting periods. In comparison to 2008/2009, the number of hours that experienced export congestion in 2009/2010 dropped for all intertie groups, except Manitoba which saw a slight increase. Michigan, Minnesota, and NYISO all experienced drops in total volume of exports, and corresponding drops in the number of export congested hours. Although export volume on the Manitoba intertie dropped by 67.2 percent, the number of hours experiencing export congestion increased by 8 hours (38 percent). Instances of export congestion on this intertie are so infrequent (29 instances) that some anomalous occurrences could lead to this counter-intuitive result. Quebec experienced an increase in the volume of exports of 88.4 percent to a total of 1,538GWh, yet also saw a decrease in export congested hours from 1,375 to 394 hours (71 percent drop). This drop, despite an increase in export volume, can be explained by the opening of new intertie transmission facilities during the 2009/2010 reporting period, thus allowing for more power to flow between the two jurisdictions at a given time.

Table 1-34: Export Congestion in the Market Schedule by Intertie, May–April 2008/2009 & 2009/2010 (Number of Hours)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	0	0	243	47	47	9	162	125	300	75
June	0	0	153	215	9	3	233	340	203	95
July	0	0	129	225	13	21	348	330	101	18
August	0	0	131	81	25	4	391	185	75	14
September	0	0	30	52	7	150	297	132	181	3
October	0	0	13	26	14	56	235	69	153	0
November	0	9	40	155	18	127	103	35	37	77
December	12	7	54	47	102	46	82	15	31	102
January	0	10	6	53	9	26	258	106	71	8
February	0	1	1	44	12	45	50	3	27	1
March	3	1	205	36	80	12	27	1	46	1
April	6	1	297	0	238	7	4	53	150	0
Total	21	29	1302	981	574	506	2190	1394	1375	394

Figure 1-28 compares the percentage of export congestion events by intertie group for the last two reporting periods. NYISO remained the largest contributor to instances of export congestion, Quebec showed congestion share decline, while Michigan and Minnesota had modest increases in share. The number of export congested instances dropped from 5,462 in 2008/2009 to 3,304 in 2009/2010, a drop of 2,158 instances (39.5 percent).

Figure 1-28: Percentage of Export Congestion Events in the Market Schedule by Intertie, November–April 2008/2009 & 2009/2010 (%)



5.4.3 *Congestion Rent*

Congestion rent occurs as the result of different prices faced by importers and Ontario load, or exporters and Ontario generation. These price differences are induced by congestion at the interties, with importers and exporters receiving or paying the intertie price, and Ontario generators and loads receiving or paying the uniform Ontario price (either the interval MCP or HOEP). When there is export congestion and exporters are competing for the limited intertie capability, the intertie price rises above the Ontario price, and congestion rent is collected from the exporters. When there is import congestion, the intertie price falls below the Ontario price, and congestion rent is the result of the lower price paid to importers, relative to the uniform price.

Tables 1-35 and 1-36 report the congestion rent for the five intertie groups comparing the 2008/2009 and 2009/2010 reporting periods. Congestion rent is calculated as the MW of net import or net export that actually flow (i.e. the constrained schedule) multiplied by the price difference between the congested intertie zone in Ontario and the uniform price. This represents a cost to traders, either in the form of a congestion price premium paid for exports or the reduction in the payment for imports. However, traders that have transactions in the opposite direction to the congested flow may actually benefit from these differentials. For example, an import on an export congested intertie would receive a higher payment than HOEP because of the higher intertie price. Similarly, an export on an import congested intertie would pay a lower price than the HOEP. Such counter-flows in the constrained schedule can induce negative components in the congestion rent as occasionally observed below.

Table 1-35 indicates that total congestion rent for import events dropped $608,000 (or 46 percent), from 2008/2009 levels. The New York intertie was almost solely responsible for the overall drop, with virtually no congestion rent in 2009/2010, down from over $1.3 million in 2008/2009. This drop can be easily explained by the zero hours of import congestion on the New York intertie as shown in Table 1-33. Michigan was the only other intertie to experience a drop in congestion rent to almost zero due to no hours of import congestion. All other interties saw congestion rent increase, the largest of which occurred on the Quebec intertie where the congestion rent increase was $351,000 (702 percent). The Minnesota intertie remained the only jurisdiction with negative import congestion rent, although the total amount nearly halved.

Table 1-35: Import Congestion Rent by Intertie, May–April 2008/2009 & 2009/2010 ($ thousands)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON		Total	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	0	5	(1)	0	(9)	(8)	931	0	0	0	922	(4)
June	46	75	6	0	(75)	58	386	0	0	0	363	133
July	6	53	0	0	(38)	13	2	0	16	58	(14)	124
August	163	51	0	0	(17)	(22)	0	0	30	42	176	72
September	7	28	21	0	(130)	14	0	0	2	178	(100)	220
October	21	66	1	0	(10)	(134)	0	0	0	16	12	(52)
November	1	53	1	0	(20)	(16)	0	0	2	0	(16)	37
December	2	(3)	0	0	3	3	0	0	0	0	5	0
January	17	38	0	0	8	22	0	0	0	27	25	86
February	(11)	7	0	0	8	(37)	0	0	0	44	(3)	15
March	(25)	13	0	0	(21)	(59)	0	0	0	13	(46)	(33)
April	6	91	0	0	(4)	5	0	0	0	23	2	119
Total	233	478	28	0	(305)	(161)	1,319	0	50	401	1,326	718

As can be seen from Table 1-36, total export congestion rent was also considerately lower this period at just over $26 million, representing a reduction of almost $40 million or 60 percent. All interties saw at least some reduction in export congestion rent, the smallest being a 10 percent decline and the largest a 69 percent decline. This coincides with a reduction in the number of hours experiencing export congestion at all interties, except Manitoba (see Table 1-34).

Table 1-36: Export Congestion Rent by Intertie, May–April 2008/2009 & 2009/2010 ($ thousands)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC		Total	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	0	0	8,700	549	86	1	741	1,521	492	38	10,019	2,109
June	0	0	6,351	3,300	6	1	3,997	2,861	328	436	10,682	6,597
July	0	0	4,389	3,465	11	17	5,946	1,987	122	2	10,468	5,470
August	0	0	2,757	1,047	19	2	6,098	1,105	102	30	8,976	2,184
September	0	0	200	424	4	50	4,087	637	205	2	4,496	1,113
October	0	0	52	177	5	13	2,507	279	346	0	2,910	469
November	0	51	467	2,267	10	89	952	225	51	110	1,480	2,741
December	68	6	718	248	424	42	2,600	130	39	894	3,849	1,319
January	0	5	27	1,183	20	26	4,098	950	43	25	4,188	2,189
February	0	0	5	914	6	21	427	22	16	7	454	964
March	1	0	3,238	536	95	4	219	0	48	1	3,601	541
April	1	0	4,164	0	174	1	23	381	119	0	4,481	382
Total	69	62	31,068	14,109	860	266	31,695	10,097	1,911	1,544	65,604	26,079

There are several factors which can influence congestion rent since it is based on both the magnitude of actual imports or exports at the intertie and the Intertie Congestion Price (ICP). ICP is the difference between the uniform Ontario price (HOEP) and the intertie zonal price. It depends on the price of the marginal import or export at the intertie, relative to the marginal resource within Ontario in the unconstrained scheduling process. The magnitude of the actual import or export flow is dependent on:

i) the maximum capability of the intertie,
ii) temporary reductions in the intertie capability,
iii) loop flows, which use up part of, or add to, the intertie capability,
iv) import or export failures, and
v) constrained-on or constrained-off imports or exports.

Congestion rent can be viewed as the risk that an importer may be paid less than the Ontario uniform price or an exporter may pay more than the uniform price. To hedge the risk, the IESO makes available Transmission Rights (TR) which compensates the TR holder for differences between the intertie and uniform prices. In previous reports the

Panel has observed that TR payouts generally exceed congestion rent received by the IESO and we examine this issue in more detail in Chapter 3 of this report.[40]

Tables 1-37 and 1-38 show TR payouts by intertie for each month of the 2008/2009 and 2009/2010 reporting periods, separately for import congestion events and export congestion events. TR payouts for imports totalled $5.6 million, which is up more than $1.2 million (29 percent) over the previous period. While payouts on the Michigan and New York interties declined to zero, the remaining three interties saw increases in TR payouts. The largest absolute increase of over $1.2 million occurred on the Manitoba intertie where hours of import congestion more than doubled (Table 1-33). August was the month with the highest import TR payouts ($861,000) as both Minnesota and Manitoba had abnormally high instances of import congested hours.

Table 1-37: Monthly Import Transmission Rights Payments by Intertie, May–April 2008/2009 & 2009/2010 ($ thousands)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON		Total	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	0	451	2	0	8	77	860	0	0	1	870	528
June	182	363	15	0	102	107	393	0	0	0	692	471
July	39	277	0	0	36	104	4	0	59	26	138	408
August	517	562	0	0	26	265	0	0	37	34	580	861
September	100	236	44	0	184	84	0	0	3	218	331	537
October	209	161	1	0	61	173	0	0	0	23	271	358
November	526	378	1	0	93	160	0	0	3	0	623	538
December	47	214	0	0	30	82	0	0	0	0	77	296
January	71	470	0	0	19	147	0	0	0	44	90	661
February	293	38	0	0	65	99	0	0	0	44	358	181
March	252	75	0	0	27	206	0	0	0	10	279	292
April	26	273	0	0	16	172	0	0	0	33	27	478
Total	2,262	3,498	63	0	667	1,677	1,257	0	102	434	4,336	5,609

As presented in Table 1-38, total TR payouts for exports were $32.8 million, which is 65 percent lower than the prior period. As with export congestion rent, export TR payouts dropped at all interties due primarily to the reduction in total hours of export congestion across all interties with the exception of export congestion at Manitoba (Table 1-34). The

[40] See the Panel's January 2009 Monitoring Report, p. 75.

largest percentage drop by jurisdiction was New York at 76 percent, while the smallest was Manitoba at 22 percent.

Table 1-38: Monthly Export Transmission Rights Payments by Intertie, May–April 2008/2009 & 2009/2010 ($ thousands)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC		Total	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	0	0	6,342	537	87	12	4,958	1,995	684	71	12,071	2,615
June	0	0	6,474	3,332	6	3	9,994	4,702	512	507	16,986	8,545
July	0	0	4,582	3,830	13	17	13,011	3,249	184	3	17,790	7,099
August	0	0	3,367	1,228	20	2	9,551	920	126	40	13,064	2,190
September	0	0	481	509	8	647	6,010	665	246	3	6,745	1,823
October	0	0	59	187	93	41	3,146	300	406	0	3,704	528
November	0	49	740	3,941	70	225	1,005	136	70	82	1,884	4,433
December	81	7	2,665	590	944	224	5,523	151	40	583	9,254	1,556
January	0	14	49	1,036	45	31	3,541	1,140	47	20	3,683	2,241
February	0	1	4	725	36	174	465	16	18	8	523	925
March	8	0	5,327	476	206	25	256	0	129	1	5,925	503
April	2	0	993	0	533	10	5	349	317	0	1,849	359
Total	91	71	31,083	16,391	2,061	1,412	57,465	13,623	2,779	1,318	93,478	32,815

Tables 1-39 and 1-40 provide the sum of monthly Intertie Congestion Prices (ICPs) by intertie for imports and exports respectively.[41] The ICP represents the difference in the intertie price and the uniform price, which is the congestion rent (and the basis for TR payouts). The sum of the ICPs represents the amount that the IESO has received over the month (or year) from intertie traders who are faced with costs during hours of congestion. The cumulative ICPs for imports were generally higher for the recent annual period compared to the year before, particularly at the Minnesota intertie, where the cumulative ICP increased by 160 percent from $8,191/MW-year to $21,328/MW-year. This is consistent with the observed increase in hours of congestion at the Minnesota intertie as shown in Table 1-32 above. Cumulative ICPs for exports fell at most interfaces this year compared to last year with the most significant declines occurring at the Michigan (63 percent decline), New York (69 percent decline), and Quebec (74 percent decline) interties.

[41] Monthly observations denoted as 'n/a' represent months where there was no congestion on the intertie.

Table 1-39: Monthly Cumulative Import Congested Prices by Intertie, May–April 2008/2009 & 2009/2010 **($/MW-Month and $/MW-year)**

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	n/a	2,002.5	1.4	n/a	88.6	1,149.2	801.7	n/a	n/a	16.9
June	760.3	1,780.6	13.1	n/a	1,202.4	1,603.2	366.0	n/a	n/a	2.1
July	162.7	1,238.8	n/a	n/a	425.0	1,153.6	3.9	n/a	195.4	43.8
August	2,297.1	2,753.2	n/a	n/a	311.6	2,949.3	n/a	n/a	58.6	74.0
September	442.4	1,154.5	30.2	n/a	2,161.3	1,401.3	0.4	n/a	5.0	481.4
October	869.8	790.1	0.9	n/a	717.4	2,662.4	n/a	n/a	n/a	63.9
November	1,970.2	1,696.2	1.1	n/a	1,088.7	2,465.4	n/a	n/a	5.0	n/a
December	178.6	954.0	n/a	n/a	354.5	909.6	n/a	n/a	n/a	n/a
January	377.9	1,842.4	n/a	n/a	225.1	1,635.3	n/a	n/a	n/a	92.5
February	1,567.4	218.8	n/a	n/a	969.5	1,101.1	n/a	n/a	n/a	69.9
March	1,346.6	434.8	n/a	n/a	405.1	2,372.1	n/a	n/a	n/a	13.7
April	116.1	1,461.8	n/a	n/a	241.5	1,925.1	n/a	n/a	n/a	52.3
Total	10,089.0	16,327.6	46.7	0.0	8,190.6	21,327.5	1,172.1	0.0	264.0	910.5

Table 1-40: Monthly Cumulative Export Congested Prices by Intertie, May–April 2008/2009 & 2009/2010 **($/MW-Month and $/MW-year)**

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC	
	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010	2008/ 2009	2009/ 2010
May	n/a	n/a	4,841.4	402.9	621.5	87.8	3,784.8	2,102.3	7,667.5	831.3
June	n/a	n/a	4,942.0	2,353.1	44.6	21.0	7,628.9	5,538.7	6,021.9	5,969.3
July	n/a	n/a	3,398.9	2,637.9	94.9	121.8	12,705.8	3,900.1	2,167.6	44.2
August	n/a	n/a	2,497.8	673.9	143.4	11.3	9,327.4	1,365.3	1,485.9	64.0
September	n/a	n/a	435.0	334.8	57.7	4,619.9	5,439.0	862.1	2,894.6	4.1
October	n/a	n/a	53.4	132.1	664.7	818.4	2,846.7	367.2	4,777.6	n/a
November	n/a	2,040.8	757.8	3,481.0	497.5	4,505.3	981.3	250.1	702.9	421.8
December	311.5	40.4	2,879.3	340.9	6,746.0	1,601.2	5,393.6	179.4	440.4	793.1
January	n/a	53.2	35.4	670.0	322.0	224.7	3,231.2	1,236.8	474.4	26.6
February	n/a	9.0	3.0	418.0	341.0	1,245.0	397.4	18.8	183.7	10.8
March	50.0	1.0	4,652.2	274.6	1,945.9	180.4	223.2	0.2	1,293.8	0.9
April	10.6	1.2	7,042.4	n/a	5,030.2	69.8	16.3	502.5	3,725.0	n/a
Total	372.1	2,145.5	31,538.6	11,719.2	16,509.3	13,506.6	51,975.4	16,323.4	31,835.3	8,166.2

Chapter 3 presents a more detailed examination of the performance of Ontario's TR market since market opening. Congestion patterns, ownership characteristics, and funding issues are presented in Section 3.3. A detailed comparison of auction prices relative to TR payouts at each individual intertie (and direction) and a discussion on informational inefficiencies in the TR market are provided in the Appendix to Chapter 3.

5.5 Wholesale Electricity Prices in Neighbouring Markets

5.5.1 Price Comparisons

Table 1-41 provides average wholesale market prices for Ontario and neighbouring jurisdictions over the last two reporting periods.[42] For several years, energy prices in Ontario have generally been the lowest of the five jurisdictions. This trend continued in the 2009/2010 reporting period. Ontario had the lowest average overall price by $2.14/MWh, the lowest on-peak price by $1.57/MWh, and the lowest off-peak prices by $1.86/MWh. All prices, both on and off-peak, in all jurisdictions dropped significantly in 2009/2010 compared to 2008/2009 average price levels. All prices saw an annual average price decrease of 26 percent or greater, with most experiencing a fall between 35 and 45 percent. Overall, the average annual price for all five jurisdictions dropped 38.7 percent to $34.70/MWh. The New England-Internal Hub price declined the most, although they had by far the highest prices to begin with and their prices still remain the highest of the five jurisdictions.

Table 1-41: Average HOEP Relative to Neighbouring Market Prices, May–April 2008/2009 & 2009/2010 ($CDN/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)

[42] To make these figures more comparable, all dollar values have been converted to Canadian dollars using the daily noon exchange rate published by the Bank of Canada. However, caution should be used when comparing market prices across jurisdictions due to their differing market designs and payment structures. For example in Ontario, the Global Adjustment and various uplift charges represent actual charges not reflected in the average HOEP. Other jurisdictions, such as ISO New England-, New York ISO and PJM, have various capacity market designs that require consumers to pay capacity charges.

Figures 1-29 to 1-31 compare monthly average prices for Ontario's neighbouring jurisdictions for the current reporting period, for all hours, on-peak hours, and off-peak hours respectively. The Richview shadow price is also shown since it is generally regarded as a more accurate indicator of the marginal cost of incremental output, particularly in southern Ontario. Most noticeable in these figures is the slight upward trend in prices since May 2009 and the relative convergence of prices by the end of the current period. Since prices in the current reporting period were well below previous period averages, it is not surprising that prices rebounded somewhat in the latter part of the period.

Ontario HOEP experienced no major diversions from other jurisdictional prices. Only New England, and to an extent PJM, diverged considerably from the group. These two jurisdictions were almost always the most expensive regions and saw prices soar above the other jurisdictional prices from November to March. Although the average annual HOEP was materially lower than all other jurisdictions, there were three occasions when the monthly HOEP was higher than the average price in a neighbouring jurisdiction (excluding Richview). Such instances occurred once in each of August (MISO), February (NYISO), and April (MISO).

Figure 1-29: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, All Hours, May 2009–April 2010 ($CDN/MWh)

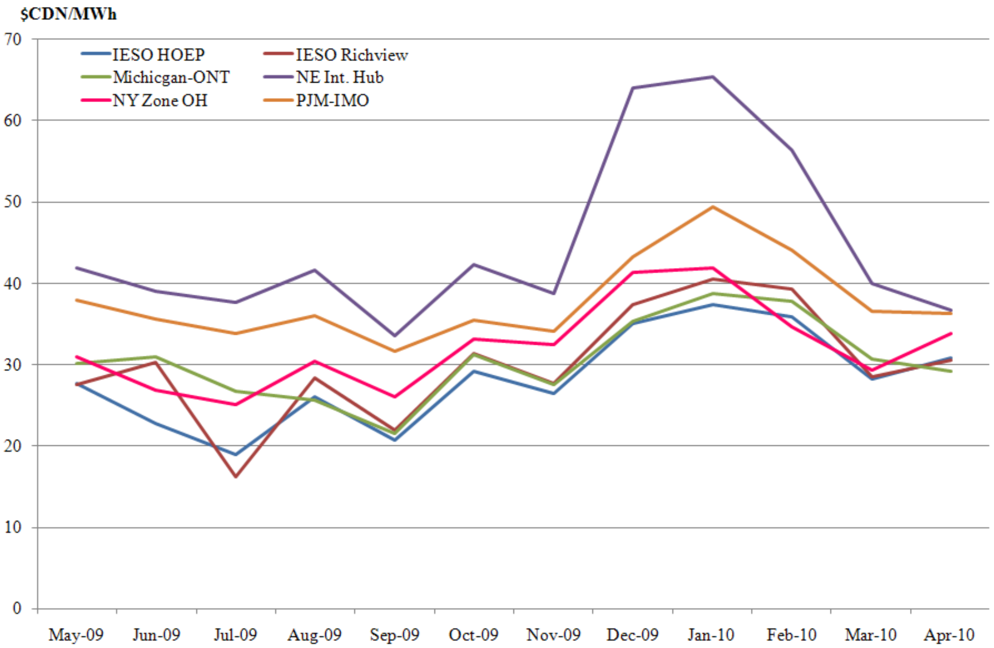


Figure 1-30: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, On-Peak, May 2009–April 2010 ($CDN/MWh)

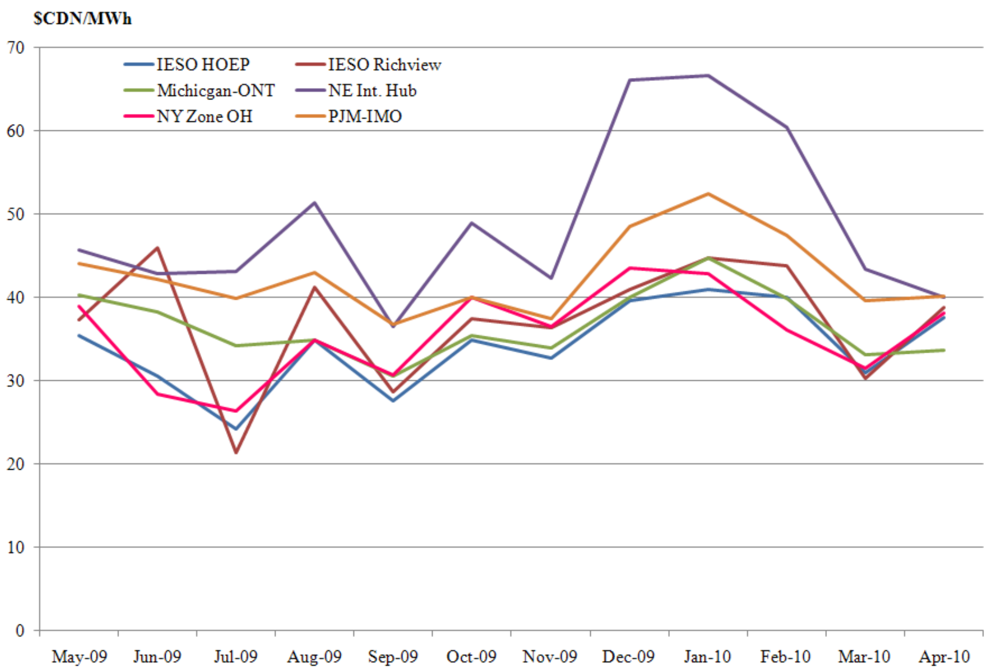
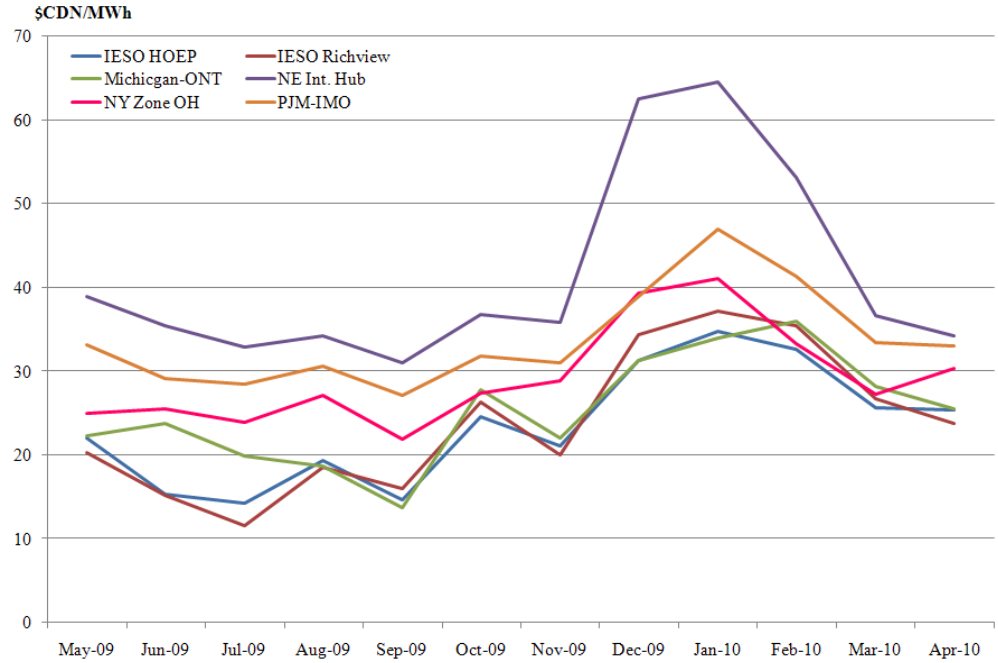


Figure 1-31: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, Off-Peak, May 2009–April 2010 ($CDN/MWh)



Chapter 2: Analysis of Market Outcomes

1. Introduction

The Market Assessment Unit (MAU), under the direction of the Market Surveillance Panel (MSP), monitors the market for anomalous events and behaviour. Anomalous behaviours are actions by market participants or the IESO that may lead to market outcomes that fall outside of predicted patterns or norms.

The MAU monitors and reports to the Panel both high and low-priced hours as well as other events that appear anomalous given the circumstances. The Panel believes that an explanation of these events provides transparency with respect to why certain outcomes occurred in the market, leading to learning by all market participants. As a result of this monitoring, the MSP may recommend changes to Market Rules or the tools and procedures that the IESO employs.

On a daily basis, the MAU reviews the previous day's operation and market outcomes, not only to discern anomalous events but also to review:

- changes in offer and bid strategies – both price and volume;
- the impact of forced and extended planned outages;
- import/export arbitrage opportunities as well as the behaviour of traders;
- the appropriateness of uplift payments;
- the application of IESO procedures; and
- the relationship between market outcomes in Ontario and neighbouring markets.

The daily review process is an important part of market monitoring. This daily review often leads to identification of anomalous events that may be discussed with the relevant market participants and/or the IESO. The daily reviews may also lead to more detailed examinations or formal investigations related to abuse of market power, gaming or efficiency issues.

The Panel defines high-priced hours as all hours in which the HOEP is greater than $200/MWh and low-priced hours as all hours in which the HOEP is less than $20/MWh,[43] including negative-priced hours.

There was one hour during the latest six-month review period, November 2009 through April 2010, where the HOEP was greater than $200/MWh. Section 2.1 of this Chapter summarizes the event and factors contributing to the relatively high HOEP.

Between November 2009 and April 2010, there were 460 hours in which the HOEP was less than $20/MWh including 26 hours where the HOEP was negative. Section 2.2 of this Chapter reviews the factors typically driving prices to low levels in these hours.

In the January 2009 Monitoring Report, the Panel refined the indicators of anomalous uplift as payments in excess of $500,000/hour for Congestion Management Settlement Credits (CMSC) or Intertie Offer Guarantees (IOG) and $100,000/hour for OR payments. Daily payments of $1,000,000 for CMSC or IOG in the intertie zones are also considered anomalous.[44] During the study period, there was one hour with OR payments greater than $100,000 and one hour with daily CMSC greater than $1,000,000 at a single intertie. The anomalous uplift hour associated with the high OR payment occurred on the same hour as the high price hour and is reviewed as part of Section 2.1. The anomalous uplift event associated with the high daily CMSC is reviewed in Section 3 of this Chapter.

2. Anomalous HOEP

2.1 Analysis of High Price Hours

The MAU reviews all hours where the HOEP exceeds $200/MWh. The objective of this review is to understand the underlying causes that led to these high prices and to

[43] Depending on fuel prices, $200/MWh is roughly an upper bound for the cost of a fossil generation unit while $20/MWh is an approximate lower bound for the cost of a fossil unit.
[44] See the Panel's January 2009 Monitoring Report, pp. 178-184.

determine whether further analysis of the design or operation of the market or of market participant conduct is warranted.

Table 2-1 depicts the total number of hours per month where HOEP exceeded $200/MWh during the winter period since 2006/2007. There was one hour between November 2009 and April 2010 where HOEP exceeded $200/MWh. This was lower than the 8 high HOEP hours observed for the same six month period one year earlier and identical to the number of high HOEP hours that occurred during the 2006/2007 and 2007/2008 periods.

Table 2-1: Number of Hours with a High HOEP November to April 2006/07 – 2009/10, (Number of Hours)

	Number of Hours with HOEP >$200/MWh			
	2006/2007	2007/2008	2008/2009	2009/2010
November	0	0	0	0
December	0	0	2	0
January	0	0	3	1
February	0	1	2	0
March	0	0	1	0
April	1	1	0	0
Total	1	1	8	1

In previous reports, we have noted that a HOEP greater than $200/MWh typically occurs during hours when at least one of the following occurs:

- real-time demand is much higher than the pre-dispatch forecast of demand;
- one or more imports fail real-time delivery; and/or
- one or more generating units that appear to be available in pre-dispatch become unavailable in real-time as a result of a forced outage or derating.

In addition, a significant increase in net exports in the unconstrained sequence from one hour to the next can place additional upward pressure on the market clearing price (MCP) in the first few intervals, thereby increasing HOEP for that hour. Spikes in the MCP in the first few intervals of an hour in which net exports increase became more pronounced after the assumed ramp rate in the unconstrained sequence was reduced from 12 to three in September 2007. The change in the assumed ramp rate removed some of the fictitious energy supply that the unconstrained sequence had perceived to be 'available' to meet increased export demand at the beginning of the hour. This led to higher MCPs in the first intervals of hours in which net exports were increasing.[45]

Each of the factors discussed above has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion. Spikes in HOEP above $200/MWh are most likely to occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10 percent.[46]

2.1.1 *January 2, 2010 HE 18*

On January 2, 2010 HE 18, the HOEP was $505.94/MWh. Factors that contributed to the price spike included an outage at a fossil-fired generation facility, demand under-forecast, and significant amounts of unoffered capacity.

Table 2-2 lists the real-time and pre-dispatch information for HE 18 on January 2, 2010. The MCP reached $1,998.00/MWh during intervals 5 and 6 of HE 18 after gradually increasing from $137.00/MWh in interval 1. The MCP remained above $175.00/MWh for all subsequent intervals in the hour. Real-time demand came in 413 MW heavier, on average, than forecast in pre-dispatch while there were no net export failures in HE 18.

[45] For more details, see the Panel's July 2008 Monitoring Report, pp. 134-140.
[46] The Panel's March 2003 Monitoring Report, pp. 11-16 noted that a supply cushion lower than 10 percent was more likely to be associated with a price spike. The Panel began reporting a revised supply cushion calculation in its July 2007 Monitoring Report, pp. 79-81. It remains the case, however, that when the supply cushion is below 10 percent, a price spike becomes increasingly likely.

Table 2-2: One-hour Ahead PD and RT MCP, Ontario Demand and Net Exports, January 2, 2010, HE 18 ($/MWh and MW)

Delivery Hour	Int	PD MCP	RT MCP	Diff	PD Ontario Demand	RT Ontario Demand	Ontario Demand Diff	PD Net Exports	RT Net Exports	RT Diff
18	**1**	50.80	137.00	86.20	19,651	19,525	(126)	1,087	1,087	0
18	**2**	50.80	175.81	125.01	19,651	19,777	126	1,087	1,087	0
18	**3**	50.80	205.01	154.21	19,651	19,926	275	1,087	1,087	0
18	**4**	50.80	225.34	174.54	19,651	20,001	349	1,087	1,087	0
18	**5**	50.80	1,998.00	1,947.20	19,651	20,180	529	1,087	1,087	0
18	**6**	50.80	1,998.00	1,947.20	19,651	20,177	526	1,087	1,087	0
18	**7**	50.80	240.14	189.34	19,651	20,182	531	1,087	1,087	0
18	**8**	50.80	240.13	189.33	19,651	20,219	567	1,087	1,087	0
18	**9**	50.80	225.35	174.55	19,651	20,234	582	1,087	1,087	0
18	**10**	50.80	225.34	174.54	19,651	20,222	570	1,087	1,087	0
18	**11**	50.80	225.34	174.54	19,651	20,216	565	1,087	1,087	0
18	**12**	50.80	175.81	125.01	19,651	20,109	458	1,087	1,087	0
Average		**50.80**	**505.94**	**455.14**	**19,651**	**20,064**	**413**	**1,087**	**1,087**	**0**

Demand Forecast Error

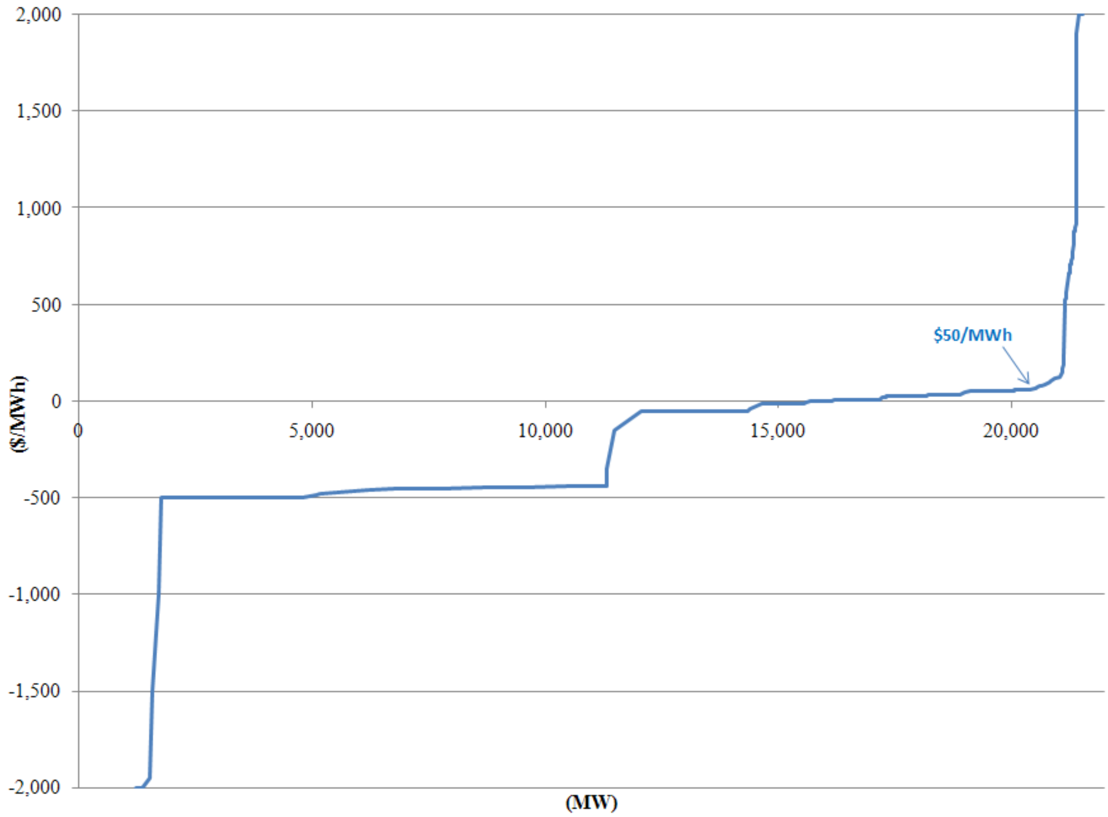
Pre-dispatch forecasts of Ontario Demand in HE 18 beginning in the first pre-dispatch run day-ahead ranged between 19,290 MW and 19,651 MW (one-hour ahead). In real-time, Ontario demand was 20,064 MW as shown in Table 2-2 above, which was over 400 MW (2.1 percent) higher than the forecast of demand one-hour earlier. The under-forecast of demand was mainly due to cooler than anticipated temperatures which placed additional pressure on the real-time HOEP.

Tight Supply Conditions in Real-Time

January 2, 2010 fell on a weekend. Going into January 2, 2010, only one nuclear unit and two fossil units were on forced outage representing approximately 1,500 MW of unavailable capacity. As is often the case on weekend days, numerous fossil-fired units initially submitted energy offers day-ahead but eventually removed their offers in advance of real-time as they were not being scheduled in pre-dispatch.

As shown above, the MCP jumped from $225.34/MWh interval 4 to $1,998.00/MWh in interval 5. Figure 2-1 illustrates the real-time offers available from generators for HE 18 on January 2, 2010. Above $200/MWh, there was less than 400 MW of available energy offers, some of which were accompanied with operating reserve offers and eventually selected to fulfill the IESO's operating reserve requirement.

Figure 2-1 – Real-time Energy Offer Curve
January 2, 2010, HE 18
($/MWh)



Fossil Unit Deratings

As is often the case when the HOEP increases above $200/MWh, generation unit outages were a factor in the price spike on January 2, 2010 HE 18. Three units at a fossil-fired generating facility were forced derated by almost 500 MW at the end of HE 17. These deratings occurred shortly after startup. The outage lasted for approximately 90 minutes. The units were scheduled for a combined 550 MW in HE 18 in pre-dispatch, but due to the forced derating were only able to produce 60 MW in real-time.

Supply Cushion

The real-time supply cushion was slightly less than 2 percent in HE 18 confirming there was little excess supply to meet demand in the hour. The one-hour ahead pre-dispatch supply cushion was also small at 2.3 percent.

Energy and OR MCPs

Table 2-3 below presents energy and operating reserve MCP's by interval for HE 18. As mentioned above, energy prices were very high during these hours due to a combination of demand forecast error, tight supply conditions, and fossil unit deratings. Energy MCP increased to $1,998.00/MWh in intervals 5 and 6 due to a combination of increasing demand in the hour and ramping limitations of a fossil unit. As shown in Table 2-2 above, RT Ontario Demand was steadily increasing throughout the first half of HE 18 from 19,525 MW in interval 1 to 20,180 MW in interval 5 and 20,177 MW in interval 6. This increase in Ontario Demand placed additional upward pressure on prices. Secondly, a 440 MW fossil unit was ramping up in HE 18 and based on ramp characteristics, was unable to reach maximum output in the unconstrained schedule until the beginning of HE 19.

Table 2-3 – Energy and Operating Reserve MCPs
January 2, 2010 HE 18
($/MWh)

Delivery Hour	Interval	Energy MCP	Marginal Resource (Energy)	10N MCP	10S MCP	30R MCP
18	**1**	137.00	Hydro	75.00	75.00	75.00
18	**2**	175.81	Hydro	100.00	100.00	100.00
18	**3**	205.01	Hydro	100.00	100.00	100.00
18	**4**	225.34	Hydro	100.00	100.00	99.91
18	**5**	1,998.00	Dispatchable Load	1,998.00	1,998.00	1,998.00
18	**6**	1,998.00	Dispatchable Load	1,998.00	1,998.00	1,998.00
18	**7**	240.14	Hydro	100.00	100.00	99.91
18	**8**	240.13	Hydro	100.00	100.00	99.91
18	**9**	225.35	Hydro	100.00	100.00	99.91
18	**10**	225.34	Hydro	100.00	100.00	100.00
18	**11**	225.34	Hydro	100.00	100.00	100.00
18	**12**	175.81	Hydro	100.00	100.00	100.00
Average		**505.94**		**414.25**	**414.25**	**414.22**

At the beginning of HE 18, the Multi-Interval Optimizer (MIO) indicated a 30-minute operating reserve shortfall in the middle of the hour suggesting tight OR supply conditions. The IESO cut 50 MW of exports in interval 6 and an additional 479 MW of exports beginning interval 7 to address a large negative Area Control Error (ACE) of -400 MW. The TLRi source code was applied to these export curtailments and therefore had no impact on the unconstrained schedule and HOEP. The average hourly OR price exceeded $400.00/MWh for all OR categories and OR MCP reached a maximum of $1,998/MWh during intervals 5 and 6, which was identical to the energy MCP. This is indicative of OR shortage conditions in the middle two intervals of HE 18. As noted in a previous Panel report, the OR MCP is set equal to the Energy MCP when available resources (including available CAOR) are not sufficient to meet the OR Requirement.[47,48] Due to the high OR MCP's in the hour, total OR payments in HE 18 exceeded $100,000, which constitutes an anomalous CMSC event. In summary, prices were reflective of tight supply/demand conditions at the time.

2.2 *Analysis of Low Price hours*

Table 2-4 below presents the number of hours when the HOEP was less than $20/MWh (low HOEP) or negative by month over the last four November to April periods. The total number of hours with a low HOEP declined over the latest winter period by 229 hours (33 percent) relative to the same months in 2008/2009. The largest monthly decline occurred in April 2010 where the number of low price hours fell by 250 hours (71 percent). Although there was a significant drop in low price hours this winter, the total is noticeably higher than those observed in the 2006/2007 and 2007/2008 periods.

[47] In times of a reserve shortfall, the operating reserve price is the greater of the highest priced reserve offer or the energy price for the interval. (http://www.ieso.ca/imoweb/pubs/training/ORGuide.pdf, p. 7)
[48] The IESO is permitted to run short of 30-minute operating reserves if it is anticipated to last less than 4 hours. For more details, Market Manual 7: System Operations, Section 7.4 available at http://www.ieso.ca/imoweb/pubs/systemOps/so_GridOpPolicies.pdf

The number of hours when the HOEP was negative has also decreased this winter relative to last winter, as shown in Table 2-3 below. There were 26 negative price hours this winter, which is down from 219 hours (88 percent) last winter. Many of the negative price hours last year were attributable to transmission line outages at the New York interface, which led to a significant reduction in the export capability at both the Michigan and New York interties.[49] No such outages were scheduled in 2010 so fewer instances of a negative HOEP were observed over the recent period.

Table 2-4: Number of Hours with Low and Negative HOEPs November to April 2006/2007 – 2009/2010 (Number of Hours and %)

	Hours when HOEP<$20/MWh				Hours when HOEP<$0/MWh			
	2006/2007	2007/2008	2008/2009	2009/2010	2006/2007	2007/2008	2008/2009	2009/2010
November	25	10	31	181	0	0	0	16
December	103	78	62	50	3	0	5	0
January	18	59	25	11	0	0	0	1
February	0	30	25	2	0	4	0	0
March	0	0	192	112	0	0	58	0
April	43	84	354	104	0	1	156	9
Total	189	261	689	460	3	5	219	26

As outlined in previous Panel reports, the primary factors leading to a low (or negative) HOEP are identified as[50]:

- Low market demand
- Abundant low price supply (i.e. nuclear, baseload hydro, self-scheduling and intermittent generation, fossil generation up to minimum loading point, and other hydro generation offering energy at prices less than $20/MWh).

Additional factors include:

- Demand deviation: the forecast demand that is used in PD is typically different from, and often greater than, the average RT demand that determines the HOEP.

[49] For more information on the transmission outages at the New York intertie in March and April 2009, see the Panel's July 2009 Monitoring Report, p. 137.
[50] These factors were first identified in the Panel's June 2004 Monitoring Report, pp. 84-85.

- Failed export transactions: These can place downward pressure on the HOEP as these failures represent a reduction in demand in RT relative to PD.

2.2.1 *Low Price Hours*

Table 2-5 shows real-time output by generation type and unscheduled generation that offered at prices less than $20/MWh (called 'low price supply') for all low price hours this period. Generation categories are segmented into nuclear, baseload hydro, self-scheduling and intermittent (wind) resources, and other hydroelectric resources (both run-of-the river and peaking). Run-of-the-river and peaking hydro units may want to operate when market prices are low, especially when an abundant supply of water is available and spilling is the only alternative. Average hourly import volumes, excluding linked wheels, during low price hours are also included in the low price supply table.

Table 2-5: Low Price Supply During Low Price Hours November 2009 – April 2010 (MW)

Month	Low Price Supply						
	Scheduled Nuclear	Scheduled Baseload Hydro*	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Other Unscheduled Generation (offered <$20)	Imports (excl. linked wheels)	Total
November	9,215	1,702	1,169	1,903	2,712	312	17,013
December	10,308	1,741	1,492	1,889	1,712	467	17,609
January	10,405	1,908	1,495	1,877	1,692	570	17,947
February	10,449	2,031	1,095	1,402	1668	497	17,142
March	9,576	2,000	1,404	1,610	1101	471	16,162
April	9,409	1,619	1,318	1,049	1252	395	15,042
Average	9,894	1,834	1,329	1,622	1,688	452	16,819

*includes generation at the Beck, Saunders, and DeCew generation stations.

Summary statistics portraying the demand conditions during the low price hours are presented in Table 2-6, specifically monthly average Ontario Demand, Net Exports, and Total Market Demand over the low price hours this summer. The final column in Table

2-5 also reports the difference between low price supply and market demand over all low price hours.

Table 2-6: Demand and Excess Low Price Supply During Low Price Hours November 2009 – April 2010 (MW)

Month	Number of Low-Priced Hours	Demand			Excess Low Price Supply (Supply - Demand)
		Ontario Demand	Net Exports	Market Demand	
November	181	13,551	1,179	14,730	2,283
December	50	14,992	1,117	16,109	1,500
January	11	15,119	1,095	16,214	1,733
February	2	15,351	528	15,879	1,263
March	112	14,197	1,112	15,309	853
April	104	12,637	1,217	13,854	1,188
Average	460	14,308	1,041	15,349	1,470

On average, low price supply (including scheduled imports) was 1,470 MW higher than total market demand during the low price hours between November 2009 and April 2010, with a maximum monthly difference of 2,283 MW in November 2009. On average, excess low price supply was lowest in March 2010 by 853 MW.

Table 2-7 provides some additional monthly summary information on the low price hours between November 2009 and April 2010 including failed net exports, the difference between pre-dispatch demand and real-time average demand (referred to as 'Demand Discrepancy'), and average pre-dispatch and real-time prices. As discussed earlier in Chapter 1, demand discrepancy can result from demand forecast errors or simply result from differences in peak and average demand within an hour. Abundant baseload supply relative to total demand (1,470 MW surplus on average) was the most important factor leading to the low HOEP outcomes over the latest winter period, followed by demand deviation (237 MW), and finally failed net exports (180 MW).

Table 2-7: Average Monthly Summary Data for Low Price Hours November 2009 to April 2010 ($/MWh and MW)

	Excess Supply	Failed Net Exports (MW)	RT Average Demand (MW)	PD Demand Forecast (MW)	PD to RT Demand Deviation (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Difference (RT - PD) ($/MWh)
November	2,283	20	13,551	13,927	376	9.23	20.53	(11.29)
December	1,500	219	14,993	15,299	306	12.23	25.43	(13.20)
January	1,733	211	15,119	15,454	334	11.09	25.86	(14.76)
February	1,263	307	15,351	15,511	160	15.54	26.27	(10.74)
March	853	206	14,197	14,292	95	14.19	24.16	(9.97)
April	1,188	119	12,637	12,790	152	8.27	22.27	(13.99)
Total/ Average	1,470	180	14,308	14,545	237	11.76	24.08	(12.33)

2.2.2 April 2, 2010, HE 7

On April 2, 2010, HE 7, the HOEP fell to -$128.15/MWh, easily surpassing the previous record low HOEP of -$52.08/MWh set on June 7, 2009, HE 6.[51] Factors contributing to the low HOEP included real-time demand was lighter than projected in pre-dispatch, a large volume of export failures, and greater than anticipated generation from wind facilities. However, the main factor which led to a new record low HOEP resulted from a change in the offer strategy at a nuclear facility prior to the April 2010 long weekend.

Prices and Demand

Table 2-8 presents pre-dispatch and real-time summary statistics for HE 6 to HE 8 on April 2, 2010. Pre-dispatch prices between HE 6 and HE 8 were positive and greater than or equal to $30.00/MWh. However in real-time, prices dropped dramatically relative to the one-hour ahead projection, especially during HE 7 where the HOEP fell to -$128.15/MWh in real-time, which is -$160.15/MWh lower than the pre-dispatch price of $32.75/MWh.

[51] For a review of the previous record low HOEP of -$52.08/MWh, see the Panel's January 2010 Monitoring Report, pp. 42-45.

April 2, 2010 was a holiday (Good Friday) and relative to average demand during other low price hours this period (as shown in Table 2-7 above), Ontario Demand was low at 12,064 MW in HE 7. The pre-dispatch projection of Ontario Demand was 12,726 MW, which was 662 MW higher than in real-time representing a demand over forecast of 5.5 percent. This over forecasting of demand placed downward pressure on real-time prices relative to pre-dispatch projected prices.

Table 2-8: One-hour Ahead PD and RT MCP, Demand, and Net Exports April 2, 2010, HE 6 to HE 8 ($/MWh and MW)

Delivery Hour	PD MCP ($/MWh)	RT MCP ($/MWh)	Diff MCP (RT-PD) ($/MWh)	PD Ontario Demand (MW)	Average Ontario Demand (MW)	Diff Ontario Demand (RT-PD) (MW)	PD Net Exports (MW)	RT Net Exports (MW)	Net Export Failure (MW)
6	32.00	-0.84	-32.84	11,947	11,762	-185	1838	1,638	-200
7	32.75	-128.15	-160.90	12,726	12,064	-662	1699	1,300	-399
8	30.00	12.43	-17.57	13,341	12,701	-640	1477	1,461	-16

Pre-dispatch and Real-time Conditions

Due to transmission overload concerns on the Ontario-Frontier interface (a component of the New York interface) and concerns that export curtailments could lead to numerous nuclear reductions, a 1,300 MW limit was implemented for total exports on the NYSI and MISI interfaces going into April 2, 2010. In HE 7, 399 MW of net export curtailments occurred in real-time (682 MW of exports and 283 MW of imports) placing additional downward pressure on real-time prices.[52]

Another factor placing additional downward pressure on HOEP in HE 7 was excess generation from wind facilities relative to their pre-dispatch forecasts. In HE 7, combined wind output in real-time was scheduled for 478 MW in pre-dispatch but produced 674 MW in real-time, a surplus of almost 200 MW (41 percent). The majority

[52] As a result of the export curtailments, MIO dispatched down Bruce units by 600 MW. The 283 MW of import curtailments in HE 7 were made after the export curtailments to alleviate the need to dispatch down Bruce nuclear units by the magnitude indicated by MIO.

of the surplus was generated by two specific wind facilities. The control room contacted these two wind facilities in HE 7 and requested a schedule change for subsequent hours and both complied with the request.

Assessment

Table 2-9 shows that nuclear units set the real-time MCP in all intervals of HE 7 on April 2, 2010. The MCP fluctuated within a tight price range between -$128.10/MWh and -$128.30/MWh. In previous reviews of low price hours, the MCP rarely fell below -$11/MWh to - $50/MWh because there was a large quantity of offered MW in this price range from a nuclear generating facility. Going into the April 2010 long weekend, a nuclear facility changed their offer prices downward for their large lamination of offered MW. This was done to reduce the frequency of dispatch down instructions as SBG conditions were expected throughout the Easter weekend and is an important reason why the price reached a historically low level.

Table 2-9: Real-time MCP and Fuel Type of Price Setting Resource April 2, 2010, HE 7 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Fuel Type
7	1	-128.30	Nuclear
7	2	-128.20	Nuclear
7	3	-128.20	Nuclear
7	4	-128.20	Nuclear
7	5	-128.10	Nuclear
7	6	-128.10	Nuclear
7	7	-128.10	Nuclear
7	8	-128.10	Nuclear
7	9	-128.10	Nuclear
7	10	-128.10	Nuclear
7	11	-128.10	Nuclear
7	12	-128.20	Nuclear
Average		**-128.15**	

In its July 2009 Monitoring Report, the Panel observed that the new payment structure applied to OPG's prescribed assets provides an incentive for OPG to make more efficient production and pump storage decisions related to their prescribed hydro assets.[53] It was acknowledged that the payment mechanism will not always lead to the most efficient production decisions and spill may not occur when it appears efficient due to environmental or safety regulations. On April 2, 2010, OPG's prescribed assets were scheduled for a combined 2,264 MW in pre-dispatch. In real-time, only 1,429 MW were scheduled, representing a reduction of 835 MW relative to pre-dispatch. Thus, the extremely low HOEP of -$128.15/MWh appears to have provided some incentive for OPG to avoid production at their prescribed asset facilities, but it did not completely eliminate production for reasons beyond the incentives implicit in the new prescribed asset payment mechanism.

In summary, the record low HOEP of -$128.15/MWh in HE 7 on April 2, 2010 was set due to and a change in offer prices at a nuclear generating facility. Had these nuclear units offered these MW at prices similar to historical levels, the MCP would not have reached such low record levels but would have been set at prices similar to previous negative price hours. Other factors that placed downward pressure on HOEP in HE 7 included a significant difference between the pre-dispatch demand forecast and real-time demand, export failures, and excess production from wind resources relative to submitted forecasts.

3. Anomalous Uplifts

During the study period November 2009 to April 2010, there was one hour with OR payments greater than $100,000 and one day with CMSC greater than $1,000,000 at a single intertie. The anomalous uplift event associated with the high operating reserve payments is discussed alongside the April 2, 2010 high price hour in Section 2.1 above.

[53] For a detailed assessment of the new prescribed asset payment regime, see the July 2009 MSP Monitoring Report, pp.209-218.

There were no other hours when the other anomalous uplift criteria were met (hourly CMSC payments or IOG payments greater than $500,000).

3.1 Daily CMSC Payments Greater than $1,000,000 at the MISI Intertie on November 23, 2009

On November 23, 2009, daily CMSC totalled $1.17 million at the Michigan interface. Approximately 80 percent of the CMSC paid was to a single market participant whose export transactions at high bid prices that were destined for PJM were cut over most hours of the day to address potential real-time shortage issues in the OR market. Table 2-10 below presents the amount of CMSC paid to participants related to transactions at this interface. The table shows that the largest payments were made during a series of on-peak hours, specifically HE 9, 10, 11, 13, 18, and 19. A

Table 2-10: CMSC Payments for Transactions on the MISI Interface by Hour, November 23, 2009 ($ thousands)

Delivery Hour	CMSC Amounts		
	Total	Pre-Emptively Curtailed Exports to PJM to Address OR Shortage	Other
1	-3.1	0.0	-3.1
2	-1.2	0.0	-1.2
3	3.2	0.0	3.2
4	0.2	0.0	0.2
5	2.7	0.0	2.7
6	2.3	0.0	2.3
7	4.2	4.5	-0.3
8	11.0	16.5	-5.5
9	171.0	162.8	8.2
10	231.5	159.1	72.4
11	229.7	154.8	74.9
12	5.7	0.0	5.7
13	161.1	161.1	0
14	1.8	0.0	1.8
16	0.6	0.0	0.6
17	2.2	0.0	2.2
18	170.0	159.5	10.5
19	176.5	171.7	4.8
20	1.6	1.6	0
21	0.0	0.0	0
22	1.1	0.0	1.1
23	1.6	0.0	1.6
Total	**1,173.8**	**991.6**	**182.2**

In early November 2009, the 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. As a result, significant constrained-off payments were made to exporters, including the event summarized above where the constrained-off payments were as high as $1,999/MWh.

Following further discussion with the IESO, the MAU was notified that the applicable internal procedure had been updated to provide greater clarity so that the control room would no longer preemptively cut exports when CAOR formed a component of OR that was scheduled in real-time. While the Panel considers this specific issue to be closed, the broader topic of the pricing of CAOR and the differential treatment of CAOR between pre-dispatch and real-time are continuing concerns to be studied by the IESO, although the stakeholder engagement plan (SE-72) associated with studying this issue was put on hold in early 2009.[54]

[54] For more details, see the IESO's Control Action Operating Reserve Study (SE-72) webpage at: http://www.ieso.ca/imoweb/consult/consult_se72.asp

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Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. Introduction

This Chapter summarises changes in the market related to matters discussed in the Panel's last report that impact the efficient operation of the IESO-administered markets. It also identifies and discusses new developments arising in the marketplace.

Section 2 identifies material changes that have occurred in the market since our last report related to matters discussed in that or prior reports. This section includes two issues:

- Ontario Power Generation's Non-Prescribed Assets.
- Hydroelectric Offer Strategy – Summary of High Price Offers.

In Section 3 the Panel comments on new issues arising:

- Anomalous CMSC Paid to two Dispatchable Loads.
- Update on Changes to the IESO's Generation Cost Guarantee Program.
- Transmission Rights Market.

2. Changes to the marketplace since the Panel's last report

2.1 Ontario Power Generation's Non-Prescribed Assets

Since market opening in May 2002, OPG has been subject to a variety of measures designed to constrain or reduce its potential to exercise market power. In 2009, OPG generated approximately two-thirds of total Ontario energy production. From market opening until April 2005, OPG was obliged to pay rebates to consumers under the Market Power Mitigation Agreement (MPMA).[55] Beginning April 1, 2005, the MPMA was

[55] For a detailed description of MPMA, see the Panel's October 2002 Monitoring Report, pp 300-332.

replaced with new regulations which separated OPG's generation assets into three categories: prescribed assets, non-prescribed assets, and Lennox.

- The prescribed assets are composed of OPG's nuclear units, which are currently paid a fixed price of $58.20/MWh and the Beck, Saunders and Decew Falls hydroelectric units (often referred to as baseload hydro), which are currently paid a fixed price of $38.84/MWh on their average hourly production during the month adjusted by the MCP for either production in excess of average hourly production for the month (payment) or for production that is less than the average hourly production for the month (charge).[56]
- The non-prescribed assets (NPA) include all of OPG's coal-fired generators and all of its non-baseload hydroelectric units. From May 1, 2006 to April 30, 2009 these assets were subject to a price cap on 85 percent of their hourly output with the balance receiving the MCP.
- The Lennox gas-fired station had a Reliability-Must-Run (RMR) contract with the IESO from October 1, 2005 to September 30, 2009, but the contract was not renewed upon expiry.[57]

The price cap on OPG's non-prescribed asset generation expired on May 1, 2009 and these generating units became directly exposed to the market price. This section focuses on the implications of the expiration of the price cap mechanism and the transition to market pricing for OPG's non-prescribed (peaking) hydroelectric generation assets. Implications for coal generation are discussed elsewhere in this report.

The Panel believes that the exposure of OPG's peaking hydroelectric generation to the market price is potentially efficiency enhancing although this could be undermined by OPA generation contracts and IESO reliability programs. This is discussed in detail later in this section.

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[56] For a description of the new regulations, see the Panel's July 2009 Monitoring Report, pp 209-211. This payment/charge structure creates an incentive for OPG to operate during higher-priced, on-peak hours.

[57] Subsequent to the expiration of the OPG/IESO RMR contract for Lennox, the Minister of Energy and Infrastructure has directed the OPA to negotiate a contract covering Lennox for the purposes of system adequacy. The directive is available on the OPA's website at: http://www.powerauthority.on.ca/Storage/113/16041_January_6_2010_-_Lennox_Generating_Station.pdf

2.1.1 *OPG's Non-prescribed Hydroelectric Generation Capacity and Output*

The total generation capacity of OPG's non-prescribed hydroelectric assets is approximately 4.15 GW. These assets account for roughly 11 percent of total installed generation capacity in Ontario. Table 3-1 presents the capacity and output from OPG's non-prescribed hydroelectric generating assets during the periods May to April 2008/2009 and 2009/2010. Output at OPG's non-prescribed hydroelectric generation declined by 8.8 percent in the most recent 12-month period compared to a year earlier.

Table 3-1: OPG Non-prescribed Hydroelectric Capacity and Generation May – April, 2008/2009 & 2009/2010 (GW and %)

	Capacity (GW)	Total Output in May 08 – Apr 09 (GW)	Total Output in May 09 –Apr 10 (GW)	Output Change (%)
Total	4.15	16,600	15,141	(8.8)

2.1.2 *Implications of the Elimination of the Price Cap on OPG's Non-prescribed Hydroelectric Generation*

Under the price cap mechanism in place during the period from May 2006 to April 2009, OPG was obligated to make quarterly payments to Ontario consumers based on the following formula (subject to other minor adjustments):[58]

$$Rebate = \sum_{t=1}^{No.of\ Hours} (HOEP_t - Price^{cap}) * MW_t * 0.85$$

Where

No. of Hours -- the total number of hours in the quarter

$HOEP_t$ -- the Hourly Ontario Energy Price

$Price^{cap}$ -- the price cap ($48/MWh for May 2008 to April 2009)

[58] The formula is detailed under the IESO's licence ED-2008-0088, pp 16-18.

MW_t -- the hourly output at non-prescribed generation assets

If the average HOEP (weighted with OPG's output from the non-prescribed assets) was smaller than the price cap, the calculation would yield a negative number. In these instances, OPG was not required to make a quarterly payment and the negative value could be carried forward and offset against positive amounts in the following quarter or quarters. This carry-over approach essentially guarantees OPG the price cap for 85 percent of its output while the remaining 15 percent is exposed to the HOEP. During the three years that the price cap was in place the calculation never yielded a negative value except in the final quarter (February to April 2009), when the amount was -$58 million. Because the rebate mechanism expired, however, this negative amount was not carried forward to offset any payments OPG might have had to make in subsequent quarters. Had the price cap been renewed, OPG would not have had to make any payments since the average price of $28.30/MWh (not weighted) during the period May 2009 to April 2010 was well below the $48/MWh price cap.

As the formula indicates, the previous payment mechanism allowed OPG to retain 15 percent of revenue associated with its non-prescribed asset production that exceeded the $48/MWh price cap. This payment structure provided OPG with an incentive to shift output from off-peak hours to higher-priced on-peak hours while providing little incentive to spill water if the average HOEP were expected to be less than $48/MWh. The willingness to spill water during negative-priced hours is limited if the revenue paid to the 85 percent of output that is "guaranteed" the price cap is greater than the loss incurred by the 15 percent of output that is exposed to the negative price.

If OPG were to have spilled water during hours with negative prices the overall result may have been to enhance market efficiency. That's because during periods of negative pricing the crowded-out marginal resource was often nuclear generation. Nuclear units can incur large additional costs (e.g. cost of removing reactive rods) to manoeuvre or shutdown whereas there are limited costs associated with spilling water at a hydroelectric unit.[59]

The new payment mechanism compensates OPG's non-prescribed hydroelectric resources at the market clearing price. To the extent possible, OPG would presumably wish to avoid generating during negative price hours so that it would not have to pay the negative MCP to the market. Accordingly, OPG would be expected to be cautious about offering non-prescribed hydroelectric generation at negative prices during low price periods. Table 3-2 below lists the occurrences of negative priced hours by hour of the day for the periods May to April 2008/2009 (rebate mechanism applied) and 2009/2010 (rebate mechanism expired). In addition, the table provides information on the quantum of energy (in GWh) offered during these negative priced hours and expresses these negative offers as a percentage of total energy offered from OPG's non-prescribed hydroelectric units. The number of hours with a negative HOEP declined by 100 hours (40 percent) from 247 hours last year to 147 hours during the most recent annual reporting period. During the two periods, the average amount of energy offered during instances of negative priced hours was nearly the same (a slight decline from 3.04 GWh in 2008/2009 to 2.99 GWh in 2009/2010). However, the average quantity offered at a negative price during instances of negative priced hours dropped 18 percent, from 1.50 GWh in 2008/2009 to 1.22 GWh in 2009/2010. This is also reflected in the 8.3 percent decline in the percentage of negative price offers relative to total offers during the negative price hours, a decline from 49.3 percent in 2008/2009 to 41.0 percent in 2009/2010.

[59] There are some limited costs associated with spilling water, including maintenance of sluice gates, spillway inspections and regulatory requirements (for example sturgeon rescue). More significantly, safety concerns such as spillway inspections may limit OPG's ability to spill water even when prices are negative.

Table 3-2: OPG Non-prescribed Hydroelectric Units
Numbers of Hours with a HOEP< $0/MWh and Offers < $0/MWh during Negative Price Hours Only
May - April, 2008/2009 & 2009/2010

Hour	May 2008 to April 2009				May 2009 to April 2010			
	Number of Hours with a HOEP <$0/MWh	Negatively Priced Offer (GWh)	Total offer (GWh)	% of GWh Offered < $0/MWh	Number of Hours with a HOEP <$0/MWh	Negatively Priced Offer (GWh)	Total offer (GWh)	% of GWh Offered < $0/MWh
Total	247	370.3	751.1	49.3	147	179.8	438.9	41.0
Average per Neg. P. Hours	1	1.50	3.04	49.3	1	1.22	2.99	41.0

While not conclusive, the decline in the proportion of energy offered at negative prices as a percentage of total energy offered during negative priced is consistent with the incentives associated with the expiration of the rebate mechanism. The Panel believes that a change in offer strategy to respond to the market price signal is generally market efficiency improving, given other market constraints as will be discussed below.

With the expiration of the rebate mechanism, OPG also has a greater financial incentive to spill water during periods of low (or negative) prices, since a failure to do so would reduce profits. Currently, spill volumes are reported by OPG on a daily basis so it is not possible to isolate the amount of spill that occurred during the negative price hours only. Although spill can occur for many reasons including lower market demand, higher baseload supply, or physical operational constraints (such as environmental or regulatory requirements), aggregate spill patterns can provide some insight into potential changes in OPG operating behaviours related to their non-prescribed hydroelectric facilities. Table 3-3 below presents the monthly spill (expressed as energy loss in GWh) between May 2008 and April 2010 at OPG's non-prescribed hydroelectric assets. The amount of spill at these facilities increased by 566 percent compared to one year earlier. Spill levels were particularly high in July and August 2009 relative to the same months a year earlier while spill was slightly lower between January and March 2010 compared to 2009.

Table 3-3: OPG Non-prescribed Hydroelectric Generation Spill Volumes[60]
May - April, 2008/2009 & 2009/2010
(Energy loss in GWh)

Month	2008/2009	2009/2010	Difference	% Change
May	0.72	3.18	2.46	339.8
June	1.26	17.38	16.13	1,282.9
July	4.56	69.91	65.36	1,434.9
August	13.43	82.90	69.47	517.4
September	5.84	28.59	22.75	389.5
October	7.92	38.26	30.34	383.0
November	0.51	29.00	28.49	5,586.3
December	1.05	28.05	27.00	2,561.4
January	0.20	0.17	(0.03)	(14.9)
February	5.26	0.80	(4.45)	(84.7)
March	3.61	2.03	(1.59)	(44.0)
April	0.87	0.92	0.05	5.6
Total	45.23	301.19	255.97	566.0

Water availability is an important factor that can influence the way OPG offers energy into the market and the quantity of spill. A measure of water availably has been constructed in Table 3-4 below and is measured as the sum of production and spill at OPG's NPA hydro-electric facilities. Water supply in Ontario's river systems has been less favourable this year relative to last year due to low precipitation levels during the recent winter and spring seasons. The table shows that total availability declined by 7.2 percent when compared to the previous May to April period. Large monthly declines in water availability occurred between January and April 2010 relative to the same months in 2009 with the largest decline in availability occurring in April (515 GW or 34.6 percent). Although water availability was lower this year, the amount of spill is over six times higher this year compared to last year as shown in Table 3-3 above suggesting factors other than availability led to increased spill activity this year.

[60] Data supplied by OPG.

Table 3-4: Total of NPA Hydroelectric Production and Spill – Measure of Availability May - April, 2008/2009 & 2009/2010 (GWh)

Month	2008/ 2009	2009/ 2010	Difference	% Change
May	1,997	1,945	(52)	(2.6)
June	1,568	1,426	(142)	(9.0)
July	1,671	1,277	(394)	(23.6)
August	1,409	1,309	(101)	(7.1)
September	975	930	(45)	(4.6)
October	997	1,092	95	9.6
November	1,115	1,389	274	24.6
December	1,248	1,417	169	13.5
January	1,492	1,307	(185)	(12.4)
February	1,342	1,158	(184)	(13.7)
March	1,345	1,220	(125)	(9.3)
April	1,487	972	(515)	(34.6)
Total	16,645	15,442	(1,203)	(7.2)

2.1.3 *The Impact of OPA Contracts and IESO Programs*

As illustrated above, the Panel observes that the expiration of the rebate mechanism in general has created market-driven incentives and is therefore potentially efficiency-improving. However, the increased frequency of water spill does reinforce some of the Panel's longstanding concerns about the overall efficiency of the current market design.

A high volume of water available contributes to lower generation costs to Ontario consumers because of the relatively low incremental cost of these water resources. The market should encourage water resources to be dispatched ahead of fossil generators or imports from neighbouring U.S. jurisdictions where marginal resources are typically fossil generators. Spilling water in order to keep fossil generators online or to import from the U.S. has the effect of dampening broader market efficiency.

As the Panel concluded in its July 2009 report[61], many fossil generators holding non-utility generation (NUG) contracts generated power during SBG conditions and negative priced hours. These generators have much higher incremental and start-up costs than peaking hydroelectric resources, but are induced to generate because they receive a fixed price for generation. The Panel has recommended that when these NUG contracts are up for renewal the relevant agency or agencies should design the contracts in a way to motivate these generators to respond to market prices.

The IESO's current generation cost guarantee (GCG) program also has the effect of reducing market efficiency[62] and may have led to inefficient water spill, as these units are not dispatched based solely on economic efficiency.[63] Moreover, once these generators are dispatched they are constrained-on for the duration of their minimum generation block run time (MGBRT) and at their minimum loading point (MLP). For an individual generator this may translate to over 100 MWh being constrained on for upward of 10 hours. This may lead to less costly water resources being spilled, should hydroelectric resources become marginal or near marginal at any time during the GCG Participant's MGBRT.

In addition, in previous reports the Panel observed that a significant portion of IOG payments were made during the off-peak period when there appears to be little to no reliability concerns. The Panel recommended that the IESO review the program to determine whether it provides a commensurate improvement in reliability.[64] The IOG payment encourages imports over OPG non-prescribed hydroelectric resources, which do not have a similar real-time price guarantee. As a result, in many cases the market was importing from neighbouring markets, while OPG was spilling water. The IESO has

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[61] The Panel's July, 2009 Monitoring, Report, pp 221-235.
[62] The Panel's July 2007 Monitoring Report, pp 114-127.
[63] GCG program participants will be dispatched when, based on pre-dispatch prices, they are economic for 50 percent of their minimum generation block run time (MGBRT) at their minimum loading point (MLP). In addition, these generators recover large costs associated with bringing their units online or taking their units offline. At present these additional costs are not incorporated within offer prices nor are they considered as part of the dispatch decision.
[64] The Panel's July 2008 Monitoring Report, pp 140-152.

moved to using forecast average demand in pre-dispatch during non-ramp hours beginning in December 2009,[65] which is expected to reduce inefficient imports. As recommended in the July 2008, the Panel believes the IESO should review the real-time IOG program and determine if it is providing commensurate improvements in reliability.[66]

2.2 Hydroelectric Offer Strategy – Summary of High Price Offers

In the January 2010 Monitoring Report, the Panel indicated that peaking hydroelectric resources were often setting the MCP during the high price hours in the 2009 summer months at prices above \$200/MWh, including many intervals with MCPs above \$500/MWh.[67] The Panel also indicated that the implications of the offer strategies currently used by peaking hydroelectric generators would be examined further in this report.

The Panel's Monitoring of Offers and Bids Document indicates that, offers for energy limited generation (such as peaking hydroelectric resources), the possibility of market power being exercised through economic withholding or pricing up will be assessed by considering offers in relation to the generator's opportunity cost.[68]

Many factors influence the offer behaviour of hydroelectric resources including water availability, storage capability, environmental and regulatory restrictions, the co-ordinated operation of units on a river system, and joint optimization of energy and operating reserves. The Panel's review for the current reporting period indicated that many peaking hydroelectric offers appeared to be based on opportunity cost

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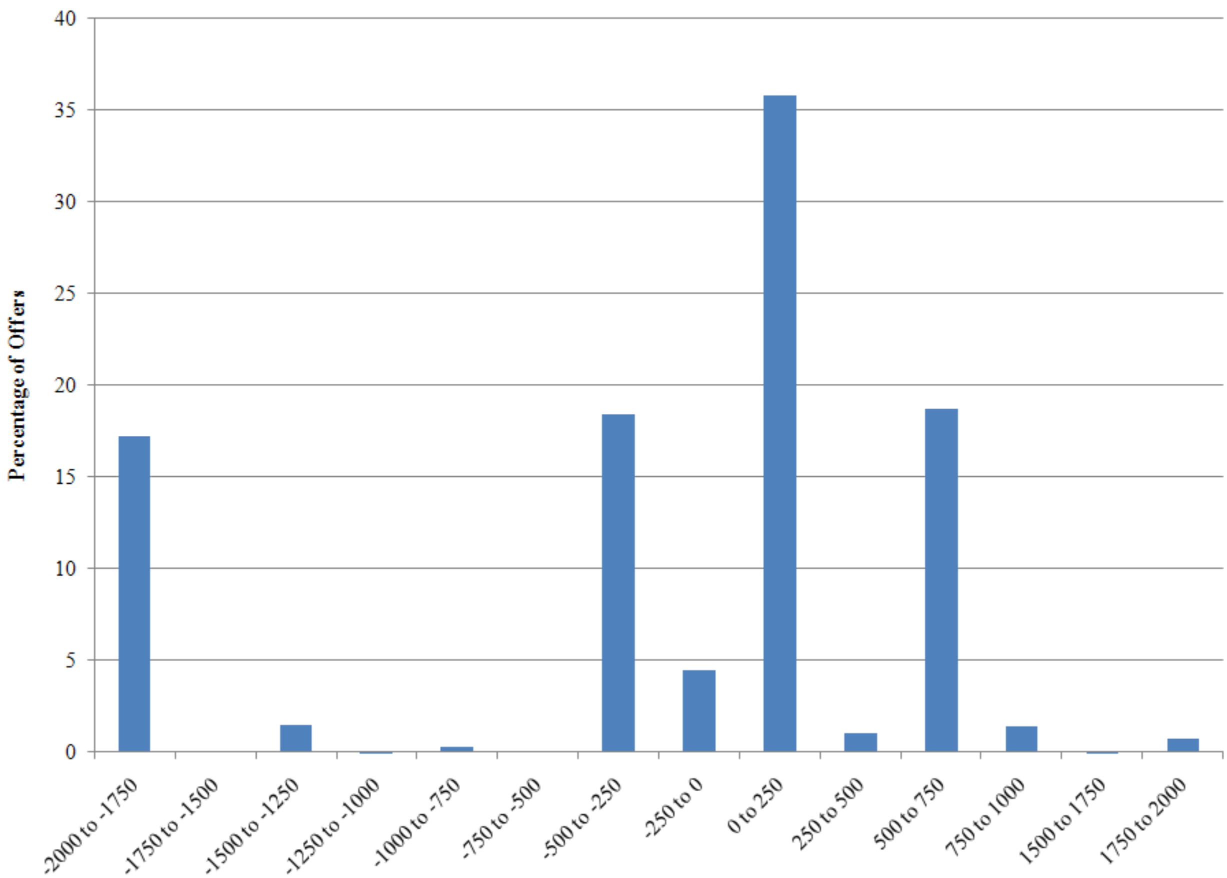
[65] see: http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=4973
[66] According to the IESO, Recommendation 3-1 from the July 2008 MSP Report is still in progress and being assessed internally, although it is considered low priority.
[67] See the Panel's January 2010 MSP Report, pp. 34-35.
[68] See the Panel's October 2009 Monitoring Document: Monitoring of Offers & Bids in the IESO-Administered Electricity Markets, p. 36 available at http://www.oeb.gov.on.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance/Monitoring+Offers+and+Bids

considerations. However, a significant percentage of offers at $500/MWh and above (and occasionally less) were used by participants to signal an unwillingness to be scheduled for energy except as a last resort.

Figure 3-1 presents the frequency distribution of peaking hydroelectric offers between May 2009 and April 2010 in $250/MWh increments. Approximately 21 percent of all submitted real-time offers fell in price categories above $500/MWh.

Figure 3-1: Frequency Distribution of Peaking Hydroelectric Offers May 2009 - April 2010 (% of Total Offers in $250/MWh price ranges)



Between May 2009 and April 2010, hydroelectric resources set the MCP at a price above $500/MWh in 22 intervals (equivalent to less than 2 hours), with only 2 intervals over the latest six-month period. Although these offers appear to have been based on a "do not want to run unless necessary" signalling strategy rather than an actual opportunity cost analysis, the Panel does not view the negative implications to the market from pricing up to be material at this point due to the limited number of intervals where the MCP was set by these resources.[69] The Panel has asked the MAU to continue to monitor instances of signal-based offers made by peaking hydroelectric resources set the real-time MCP in accordance with the Panel's Monitoring of Offers and Bids Document.

3. New Matters

3.1 Anomalous CMSC Paid to two Dispatchable Loads

Beginning in February 2010 two dispatchable load facilities began to receive extremely high CMSC payments. One of the facilities operates exclusively as a dispatchable load (Facility D). The second facility has both a registered load and a registered generator (Facility C) but typically operates as a net load, meaning the facility's consumption typically exceeds the facility's on-site generation. Collectively these two dispatchable load facilities have a maximum dispatchable capability of approximately 190 MW or approximately 20 percent of Ontario's dispatchable load capabilities.

Over the five month period from February 2010 to June 2010 these two facilities received over $18 million in net CMSC payments.[70] The $18 million paid to these two dispatchable loads is in sharp contrast to the approximately $590,000 of net CMSC payments made to all other dispatchable loads in Ontario over the same period. Put differently, two facilities that represent only 20 percent of Ontario's dispatchable load capability received approximately 97 percent of CMSC payments made to all Ontario dispatchable loads for the period February to June 2010.

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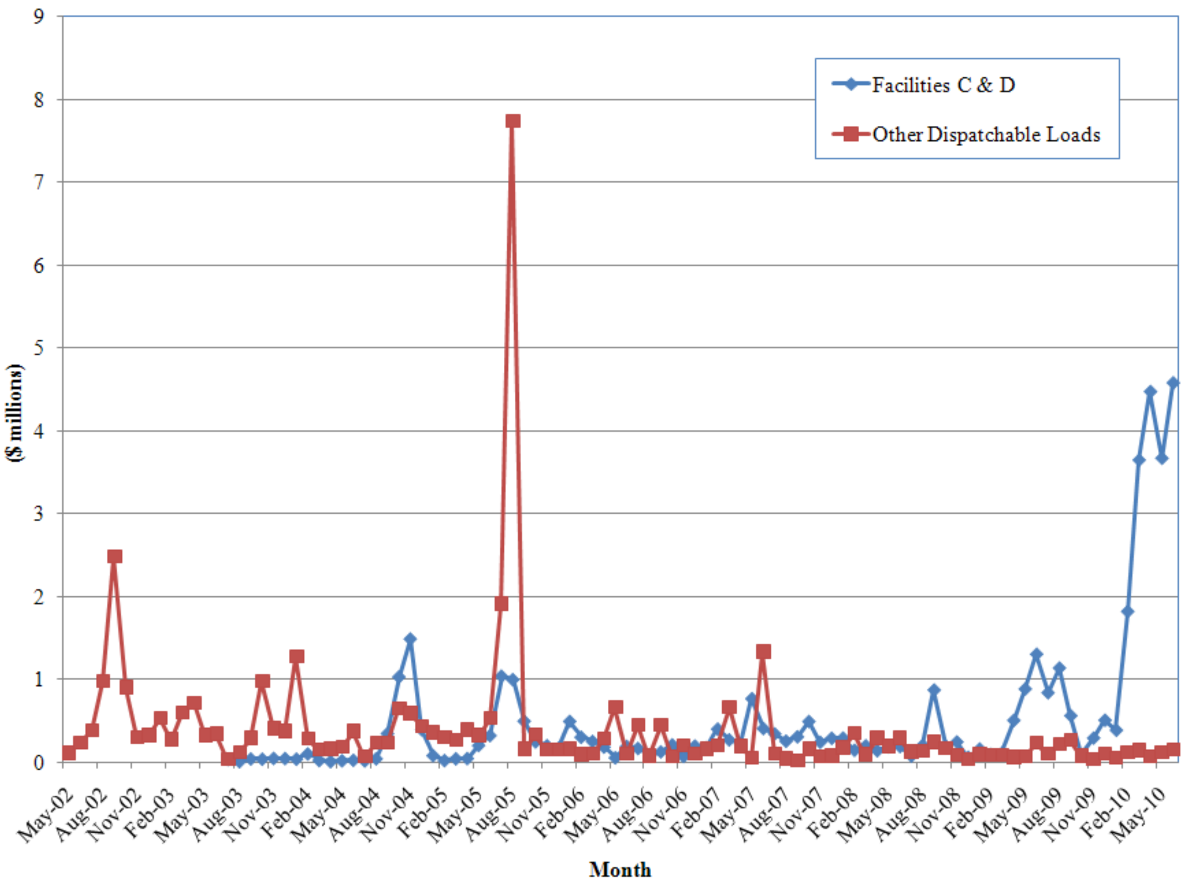
[69] As noted in the Monitoring of Offers and Bids Document, p. 30, a specific quantitative materiality threshold has not been adopted by the Panel. However, the Panel notes that two of the most significant factors in materiality assessments are the magnitude of the increases above competitive levels and the frequency and duration of such outcomes.

[70] Gross CMSC payments were approximately $32 million, but IESO settlement tools automatically clawback CMSC payments under certain constrained off consumption deviation situations.

Figure 3-2 below compares the monthly net CMSC payments made to the two facilities against monthly net CMSC payments made to all other dispatchable loads in Ontario for the period May 2002 to June 2010. Historically CMSC payments to the two facilities were well below $1 million per month but beginning in February increased dramatically and during the period March to June 2010 averaged approximately $4 million per month. Historically, CMSC paid to all other dispatchable loads has been negligible.[71]

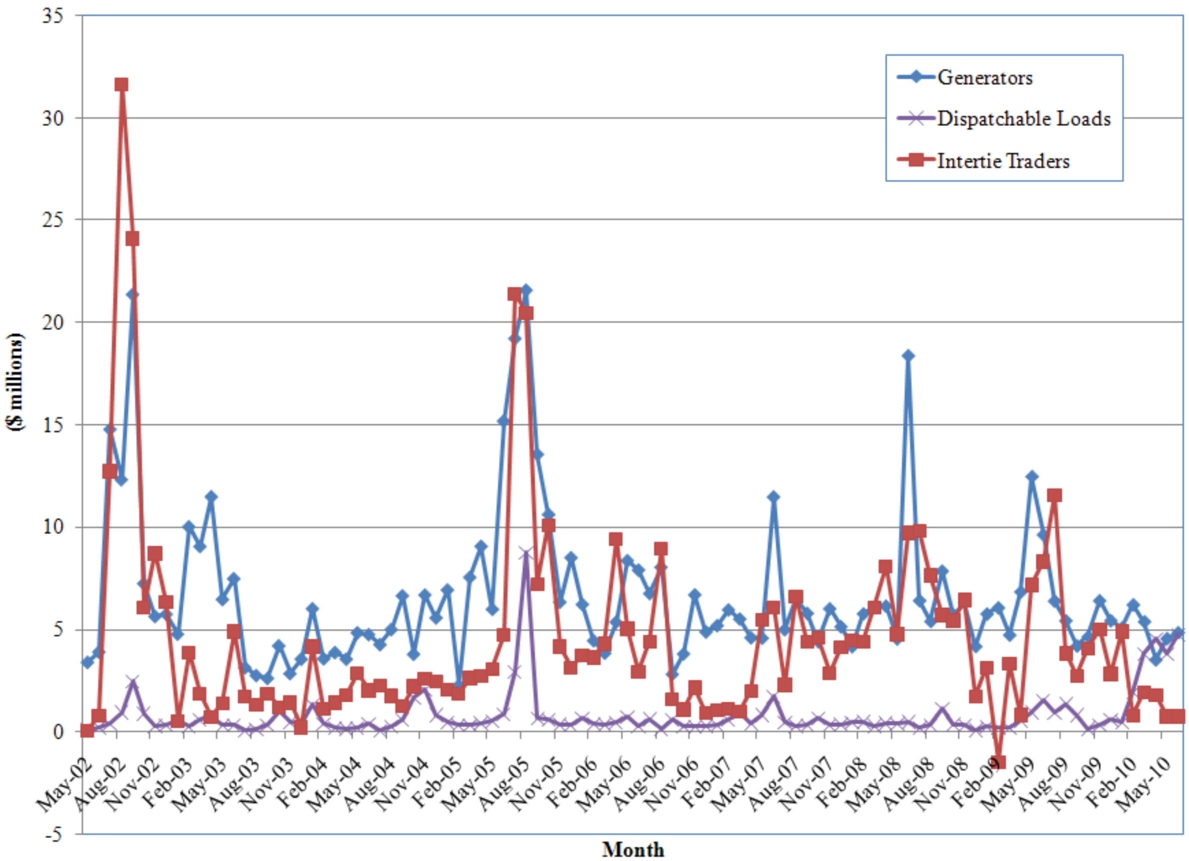
Figure 3-2: CMSC Payments to Dispatchable Loads
May 2002 - June 2010
($ millions)



[71] One notable exception was August 2005 when the Ontario market experienced extremely high demand, which caused dispatchable loads to be constrained down over the course of several days. Even though payments to dispatchable loads were high in August 2005, they remained significantly lower than CMSC payments made to either generators or intertie traders.

The sharp increase in CMSC payments to the two facilities is also in contrast to the net CMSC payments received by generators and intertie traders. For the period February to June 2010, these two facilities capable of providing 190 MW of dispatchable capacity have received approximately 75 percent as much CMSC as was received by all of Ontario's approximately 35,000 MW of dispatchable generation (see Figure 3-3 below).

Figure 3-3: CMSC Payments to All Market Participants May 2002 - June 2010 ($ millions)



The MAU notified the Panel of these extremely high CMSC payments and identified possible causes of the payments. Since then, the MAU has contacted the owners of the relevant facilities to gather information regarding bidding behaviour and operational characteristics. At the time of publication of this report the Panel continues to monitor and assess the behaviour of the two dispatchable load facilities. This section discusses the main factors that have contributed to the high CMSC payments to the two dispatchable load facilities and potential remedies for the identified problems.

The Panel has observed four primary factors that have contributed to the increase in CMSC 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

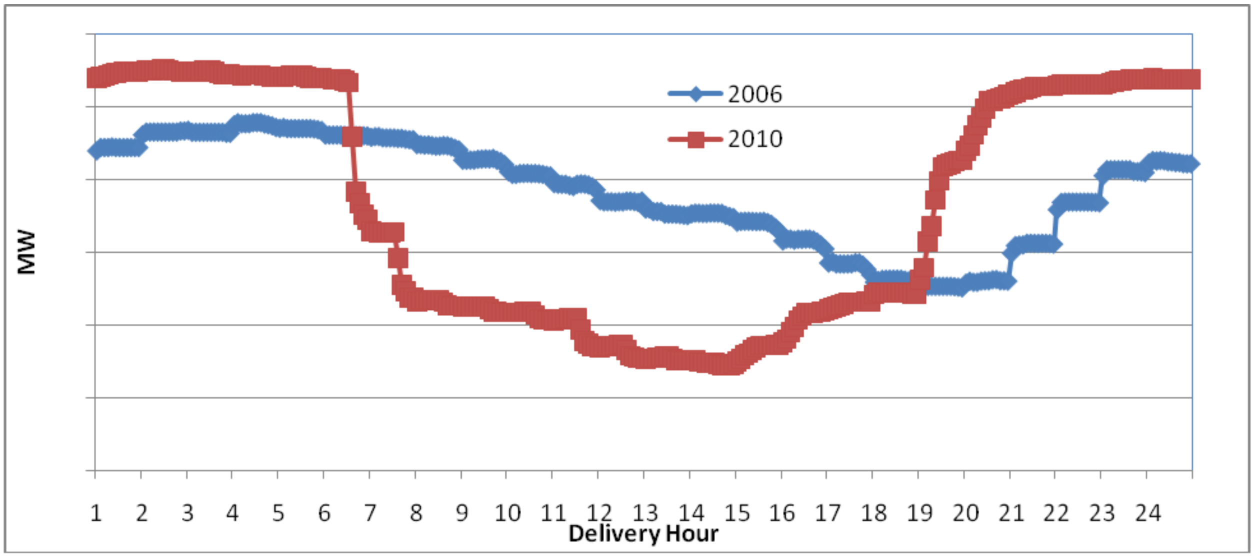
3.1.1 *CMSC Resulting From Frequent Ramp with a Reduced Ramp Rate and an Increased Bid Price*

Facility D had historically followed a relatively stable consumption pattern. It tended to gradually ramp down beginning in the early morning hours before slowly ramping back up in HE 21. The consumption profile of Facility D changed beginning in February 2010. Facility D began to sharply ramp down in HE 6 and then sharply ramped back up in HE 19.[72] Figure 3-4 below depicts the average interval consumption over the period February to May 2006 (which is representative of historic operations) and the same months in 2010.[73] The sharp ramps in HE 6 and HE 19 generate an opportunity for CMSC payments because each creates a large divergence between the constrained and unconstrained sequences (the unconstrained sequence uses three times ramp rate while the constrained sequence uses the actual ramp rate, and the constrained sequence ramps at the end of the prior hour whereas the unconstrained sequence ramps at the start of the new hour when it ramps down, both of which automatically lead to schedule differences).

[72] The market participant advised the MAU that it has an OPA DR2 contract, which compensates the market participant for shifting consumption from peak hours to off peak hours. For further information about the OPA's DR2 program, see:
http://www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=147

[73] The facility was not registered as a dispatchable load from 2007 to 2009.

Figure 3-4: Average Hourly Consumption at One Dispatchable Load Facility February - May, 2006 and 2010 (MW)

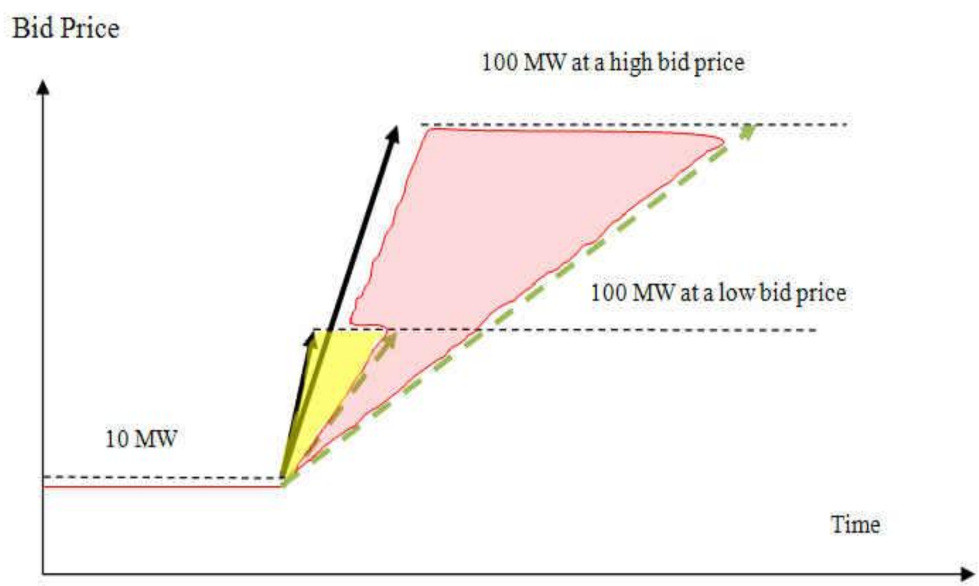


While sharp ramps create an opportunity for CMSC payments, the magnitude of the payments is based on the market participant's bidding behaviour as well the ramping capabilities at its facilities. The higher the bid price and the slower the ramp rates, the higher the CMSC payments.[74] In February 2010, Facility D adopted an extremely high bid price strategy. The market participant explained the significant increase to the bid price as necessary to signal its desire to avoid being dispatched down while still being scheduled as a dispatchable load in order to provide operating reserve to the market. Following discussions with the MAU the market participant has since adopted a somewhat lower bid price, which the market participant has indicated is more reflective of the opportunity cost of lost consumption. In addition, the facility's ramp rates are slower than they have been historically. The market participant explained to the MAU that the slower ramp rates are a consequence of changed operating characteristics at the facility, specifically a reduction in the number of machines operating at any given time.

[74] A slow ramp rate at a facility prolongs the divergence between the constrained and unconstrained sequences, thereby increasing the number of intervals during which CMSC is paid.

The changes in operating characteristics and the adoption of the higher bid price have led to the extremely high CMSC payments. Figure 3-5 below provides a hypothetical illustration of how a high CMSC payment could be induced by changing the ramp rate and the bid price. The facility indicates that it wants to ramp up from 10 MW to 100 MW. The solid black lines represent the ramp in the unconstrained sequence: the shorter line indicates a shorter time to ramp in the past while the longer line a longer time to ramp now. The dotted green lines represent the ramp in the constrained sequence: the shorter line indicates a fast ramp in the past while the longer line a slow ramp now. In the past, the load could ramp up fast in both sequences and thus the induced CMSC payment was relatively small (the yellow area), while currently the load ramps slowly, coupled with a high bid price, leading to a larger CMSC payment (the pink area plus most of the yellow area).

Figure 3-5: Hypothetical Illustration of How CMSC Could Be Increased With a Lower Ramp Rate and a Higher Bid Price



Over the period February to June 2010, Facility D received approximately $7.6 million in net CMSC payments associated with this daily ramping activity. In other words, Ontario consumers paid $7.6 million or approximately $0.13/MWh to cover the CMSC payments made to this dispatchable load to follow its voluntary, daily ramping activity. Even at the lower bid price that was implemented subsequent to conversations with the MAU, CMSC payments to this dispatchable load continue to average approximately $32,000 per day or $11.7 million per year. In the Panel's view, payments of this nature do not contribute to market efficiency or system reliability and are an unintended consequence of Ontario's two-schedule market structure.

One argument that the CMSC for ramping is needed is that the dispatchable load may be constrained-off at times when the locational price is higher than its bid price. In such circumstances, the dispatchable load would be paid the constrained-off payment just like generators. However, during the ramp period, the dispatchable load's chance of being constrained-off is largely limited by the fact that it is already ramping.

- When the dispatchable load is ramping down, the IESO tool will ramp it down based on its submitted ramp rate. As a result, the dispatchbale load faces no further risk of being constrained-off. The CMSC payment to keep the dispatchable load whole is unnecessary.

- When the dispatchable load is ramping up, the dispatchable load may be instructed to ramp down while ramping up. In this case, the dispatchable load does face the risk of not consuming the amount that it wants (although it is efficient to the market). The lost consumption in this case is only the difference between its intended amount based on its ramp rate and the instructed amount based on the system condition. However, the CMSC payment is calculated based on the difference between the unconstrained amount (which is typically its full capability within a few intervals after it starts to ramp) and the instructed amount, which is usually much greater than the difference between its intended amount based on its ramp rate and the instructed amount. In other words, the CMSC payment for ramping up to cover the risk of being constrained off is substantially overstated relative to what is required to compensate the load for a change dictated by system conditions.

3.1.2 *Consumption Deviation Leading to Constrained-off CMSC*

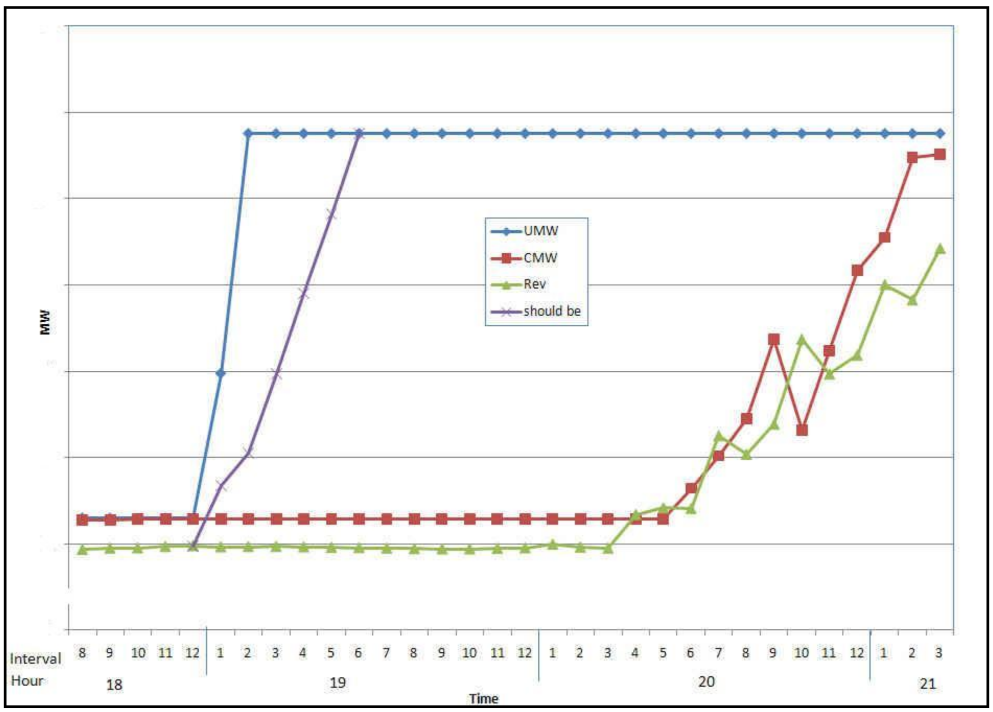
Consumption deviation refers to the situations where a dispatchable load has consumed a different quantity of energy than the IESO has instructed. Figure 3-6 below provides an example illustrating how constrained off CMSC is induced by consumption deviation at Facility D. In Figure 3-6, the dispatchable load facility indicates a desire to increase consumption by increasing the MW's bid from a daytime low level in HE 18 to an evening high level in HE 19, with an extremely high bid price associated with all MWs. Accordingly, the facility receives an unconstrained schedule which ramps to the higher level during interval 1 and interval 2 of the HE 19 (the blue or "UMW" line). The constrained sequence, however, takes six intervals to ramp from the initial actual consumption to the planned new level (the purple or "should be" line) if the facility follows the dispatch instruction. The variance between the numbers of ramping intervals required by the unconstrained and the constrained sequences reflects the prevailing fiction of three times ramp rate (i.e. the unconstrained schedule pretends that facilities can ramp at a rate 3 times faster than they actually can). If the facility were to have simply followed the dispatch instructions represented by the purple or "should be" line, the discrepancy with the unconstrained schedule would have given rise to the type of CMSC described in the Section 3.1.1 above.

In HE 18, the facility is consuming less (the green or "Rev" line) than its dispatch schedule. This deviation is permissible within the compliance deadband of 15 MW of dispatch deviation for dispatchable loads.[75] In HE 19 the facility should begin to be dispatched to the planned higher level in accordance with its bids, but the IESO dispatch tool notes that the facility has failed to ramp toward its HE 19 dispatch schedule. Recognizing the failure of the facility to ramp toward its existing dispatch schedule, the dispatch tool continues to dispatch the facility at the HE 18 level for one and a half hours (the red or "CMW" line). After an hour and a half the facility began to ramp toward its dispatch schedule. The tool observes the movement, removes the original constrained

[75] For a facility with greater than 30 MW capability, the compliance deadband is 15 MW or 2 percent of the capability, whichever is greater. For a facility less than 30 MW, the compliance deadband is 10 MW. For details, see: http://www.ieso.ca/imoweb/pubs/interpretBulletins/ib_IMO_MKRI_0001.pdf

schedule amount, and begins to dispatch the facility toward the planned level. In contrast, during the entire one and a half hours when the facility's consumption remained flat, the unconstrained sequence scheduled the facility at the higher planned level. As a result, the facility was constrained off by the difference between the original and planned consumption levels for one and half hours, generating approximately $300,000 in CMSC payments. Of this amount, $240,000 was clawed back under the IESO's automated settlement tool.). The MAU will seek recovery of the remaining $60,000 of constrained-off CMSC under the authority granted by Chapter 9, s. 3.5.1A of the market rules, which allow for recovery of constrained-off CMSC resulting from a participant's consumption deviations.[76]

Figure 3-6: Constrained-off CMSC Induced by Consumption Deviation (MW of consumption by interval)



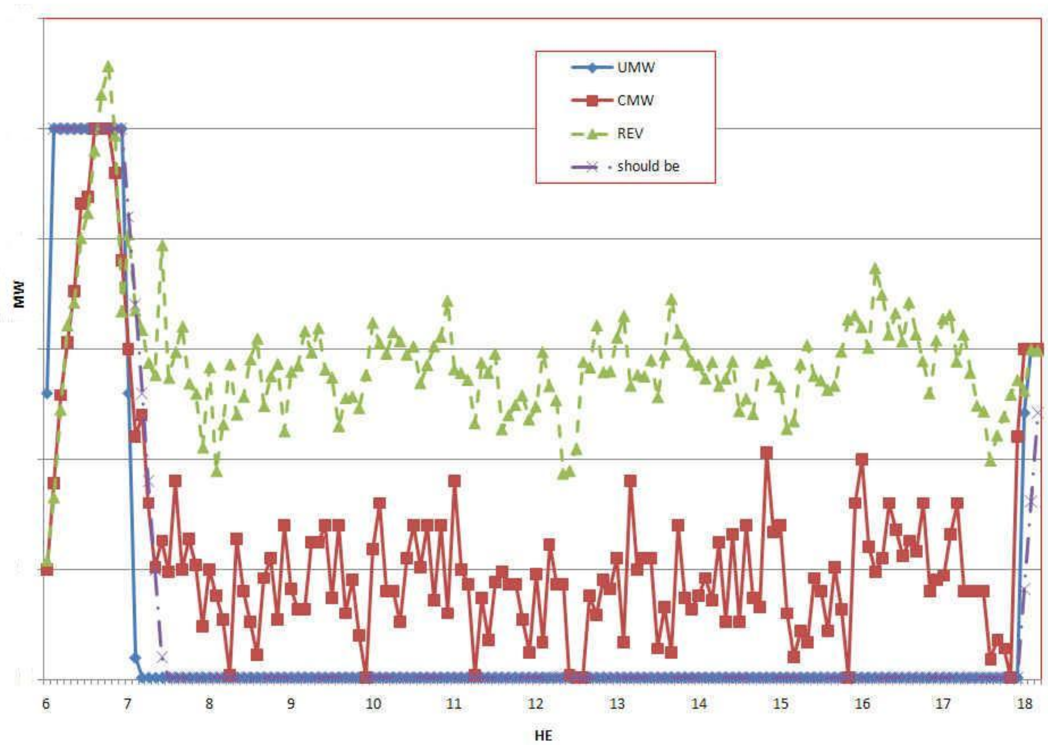
[76] The market rule only allows recovery for constrained off consumption deviation, not constrained on consumption deviation.

3.1.3 *Consumption Deviation Leading to Constrained-on CMSC*

Figure 3-7 below depicts a situation at Facility C where the load is ramping down. In HE 7, the facility signals a desire to reduce consumption from its night time level to 0.1 MW. It does so by changing it bid structure such that the dispatchable capability, which had all been bid at a very high price in HE 6 are bid in two laminations beginning in HE 7. The first lamination of 0.1 MW is bid at $2,000/MWh [77] and the remaining larger lamination is bid at a large negative price. Accordingly, the IESO dispatch tool dispatched down this facility beginning interval 1 and the unconstrained scheduled reached 0.1 MW in interval 3 (the blue line). In contrast, based on its actual ramp rate, the facility was only technically capable of reaching a consumption level of 0.1 MW by interval 7 (the purple line). Rather than reducing consumption to 0.l MW by interval 7, the facility continued to consume (the green line). The IESO dispatch tool identified that the facility was not ramping toward its dispatch schedule, and then calculated a new dispatch schedule, based on its actual consumption and its ramp rate (the red line). The result was that the facility was constrained-on, leading to a quantity difference in the two schedules (i.e. the constrained schedule level vs. an unconstrained schedule of 0.1 MW). The consumption deviation was within the allowed compliance deadband. This deviation led to a constrained-on payment of about $110,000, none of which could be clawed back under the current provision in the market rules.[78]

[77] A $2,000/MWh bid indicates to the IESO that that component of consumption should be treated as non-dispatchable.
[78] There are two provisions in the market rules that could result in CMSC being clawed back from dispatchable loads: the Local Market Power (LMP) provision and the constrained-off CMSC clawback. The former deals only with high CMSC payments resulting from transmission congestion or security issues and is not applicable in this instance. The latter allows for CMSC recovery caused by constrained-off consumption deviation, but the rule does not extend to CMSC caused by constrained on consumption deviation.

Figure 3-7: Constrained-on CMSC Induced by Consumption Deviation (MW of consumption by interval)



Following a discussion with the MAU, the facility has largely addressed failures to fully respond to dispatch instructions that had led to constrained on CMSC payments associated with consumption deviation. The facility has also proposed to repay constrained-on CMSC payments arising from consumption deviation, which represent approximately 10 percent of net CMSC paid to the two facilities over the period February to June 2010.

These three factors described above led to a significant amount of CMSC paid to dispatchable loads since February 2010. In the absence of fundamental changes in the two schedule system, the Panel encourages the IESO to immediately eliminate CMSC paid to dispatchable loads that have voluntarily chosen to change their consumptions levels or are deviating from scheduled consumption levels. The removal of payments associated with the frequent ramping portion of the CMSC paid to dispatchable loads (as described in Section 3.1.1) is analogous to what the Panel previously recommended to eliminate the CMSC paid to generators when they have voluntarily chosen to shut down.[79] Constrained-on and constrained-off payments associated with consumption deviation are also considered unwarranted as they do not contribute to the efficiency or reliability of the market.

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.***

3.1.4 *Combination of a Dispatchable Load with a Dispatchable Generator*

Beginning in late January 2010, the owner of Facility C chose to combine a dispatchable load facility with a dispatchable generation facility located at the same site for IESO settlement purposes. As a result of this combination, the market participant offers/bids net output/consumption to the market, as opposed to separately offering its generation facility and bidding its dispatchable load facility. If planned generation exceeds planned consumption (i.e. a net generator) the market participant offers as a generator. Conversely, if planned consumption exceeds planned generation (i.e. a net load) the market participant bids as a dispatchable load. The combination of the load with the generator reduced the market participant's net energy withdrawal. In turn, this reduced the market participant's transmission/connection and Global Adjustment charge as well as other charges calculated based on the net consumption such as the debt retirement charge and IESO and OPA fees.

Table 3-5 below lists the total payments and CMSC settled by the IESO at the combined facility from February to June 2010. In the five month period, the combined load and generator received about $3.5 million greater than its total payments to the market for the net energy consumed. Thus, on average, Facility C was paid $62.48/MWh for each net

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[79] See the Panel's January 2009 Monitoring Report, pp. 213-221.

MWh withdrawn from the market. This compares sharply to the $86.56 /MWh that Ontario consumers paid to consume energy over the same period. In addition, Facility C avoided approximately $4.3 million in Global Adjustment charges by combining its generation with its load.

Table 3-5: Payment and Revenue at Facility C February - June 2010 ($ thousands and $/MWh)

Month	Net Payment ($1,000)	Average Cost ($/MWh)	Estimated Avoided Global Adjustment ($1,000)	Average Costs by all Ontario Load ($/MWh
Feb-10	(49)	(6.99)	786	87.92
Mar-10	(524)	(59.14)	1,233	87.05
Apr-10	(976)	(80.04)	1,077	88.15
May-10	(36)	(2.01)	558	88.29
Jun-10	(1,922)	(185.36)	648	82.99
Total	(3,508)	(62.48)	4,301	86.56**

* including delivery and connection charges, IESO fees, OPA fees, etc.
** average for January to June 2010

Technically, any load could build an on-site generator to reduce its net energy withdrawal from the market, thereby reducing its Global Adjustment and consumption-based charges. Since the Global Adjustment has become a significant component of the overall cost of electricity, this could create an incentive to build and operate on-site generation in an inefficient manner. An independent generator is likely to operate if and only if the expected HOEP is greater than the avoidable average incremental cost; whereas an on-site generator is likely to operate whenever the expected HOEP plus the expected avoided Global Adjustment is greater than the avoidable average incremental costs.

The issue becomes more complex where a load with on-site generation capability is a dispatchable load. As described above, dispatchable loads are eligible for CMSC payments. When the net load bids to consume at a large negative price (as is the case here), and when the shadow price is below the negative bid price, the net load can be constrained on. A net load can deal with this either though increasing consumption or through reducing its generation. In either case, the result is a large constrained-on payment.

When a dispatchable load reduces net consumption through reducing generation, this generation is effectively treated differently from independent generation. For example, assume the net load bids 1 MW at -$1,999/MWh to consume and the shadow price reaches -$2,000/MWh. The net load is constrained-on and the facility reduces its generation by 1 MW. From a settlements' perspective, this reduction in output by the on-site generator appears as an increase in consumption of 1 MW by the net load. As a result, the combined facility is paid $1,999 ((HOEP-$1,999) – HOEP) for not generating the 1 MW of energy. Had the facilities been registered separately and had the generator reduced its consumption, it would have been paid the HOEP, which is almost always far lower than $1,999/MWh. [80]

The root of the payment inconsistency lies in the two-dispatch sequence regime. In the last report, the Panel 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.[81] The Panel understands that a rule amendment is under discussion at the IESO Technical Panel.[82] Assuming the new rule is implemented along the lines currently being proposed, these CMSC payments to net load/generation facilities will be significantly reduced. In order to limit the excessive magnitude of constrained-on payments to these net load/generation facilities, the Panel recommends that this rule amendment be expedited.[83]

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[80] This could also occur under the DR3 program. A load with on-site generation capability can increase its production (thus reducing the net withdrawal from the market) and effectively receive $200/MWh for the increased generation, while an independent generator only receives the market price, which is typically much lower than $200/MWh.

[81] See the Panel's January 2010 Monitoring Report, Recommendation 3-4, pp.104-105.

[82] Market Rule Amendment: *MR-00370 - Limit CMSC Payments for Exporters and Dispatchable Loads with Negative Bids.* For details, see www.ieso.ca/imoweb/amendments/tp_meetings.asp

[83] If implemented, Recommendation 3-1 would effectively eliminate constrained-on payments to dispatchable load due to consumption deviation (see Section 3.1.3). If not implemented, the use of a replacement bid would at least reduce the magnitude of these 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.***

3.1.5 Conclusions

Typically, dispatchable loads have a high opportunity cost for lost consumption and thus bid a high price into the market in order to avoid being dispatched down at times when the price is low. Given that both the HOEP and the locational shadow price are generally much lower than their bid price, dispatchable loads are rarely dispatched off/on.

During ramping, the IESO's two dispatch sequence regime can automatically generate a difference between the constrained and unconstrained sequence as illustrated in Figure 3-5. The two dispatch sequence can reward loads (or generators) with slow ramp rates through CMSC payments.[84] These CMSC payments are contrary to the principle that an efficient market should incent loads or generators that can offer greater flexibility. As shown in Figure 3-5, under the current two sequence design, an inflexible dispatchable load with slow ramp rates receives greater CMSC revenue than a more flexible dispatchable load with faster ramp rates. Such CMSC payments may incentivize: (i) investments in slower ramping facilities, (ii) reductions to ramping capability at existing facilities, (iii) claims of slower than actual ramping capabilities.

Over a period of five months from February to June 2010, two dispatchable loads received $18 million in net CMSC payments. Annualized, this would translate to

[84] Generators with a slow ramp rate are also rewarded through the CMSC payment. As the Panel pointed out in its January 2009 Monitoring Report at pp. 213- 217, a generator will often offer a high price to indicate to the market that it is going to shutdown. However, the two dispatch sequence will often provide the generator with a CMSC payment up to its offer price. As a result, the slower the ramp rate, the greater the CMSC payment. The Panel therefore recommended eliminating CMSC payments when generators are shutting down.

approximately $43 million in consumer uplift charges, or an uplift charge to loads of approximately $0.28/MWh based on annual market demand of 155 TWh. The CMSC payments made to the two dispatchable loads discussed in this section highlight many of the identified issues in the Panel's past series of monitoring reports. They are direct consequences of the two schedule system and, in the Panel's view, do not contribute to market efficiency or system reliability. The Panel will further comment on the unintended consequences associated with the two dispatch sequence in Chapter 4.

3.1.6 *Compliance Deadband for Dispatchable Loads*

The IESO's compliance deadband for dispatchable loads is currently set at the greater of 15 MW or 2 percent of the load's maximum consumption level for dispatchable loads with a normal capacity of greater than 30 MW and 10 MW for dispatchable loads with a normal capacity of less than 30 MW. Since most dispatchable loads have a consumption level of less than 750 MW but greater than 30 MW, their compliance deadband is set at 15 MW. This deadband can allow large deviations in percentage terms (e.g. 15 percent for a 100 MW load or 50 percent for a 30 MW load). As demonstrated above, the wide compliance deadband contributes to the ability of loads to receive significant CMSC payments, particularly where a load has a slow ramp rate. For many loads, the difference between their actual consumption and dispatch instructions will consistently be less than 15 MW.[85] The 15 MW compliance deadband may lead to two unintended consequences.

First, market participants may inadvertently fail to ramp because the IESO's dispatch instruction (i.e. constrained schedule) does not change, even though the market participant indicated a desire to ramp through its bid (or offer). The Panel has observed that at times market participants have called the IESO asking why their dispatch schedules have not changed. These market participants had not realized that the problem stemmed from their own consumption (or generation) deviation, which had been permitted due to the 15 MW compliance deadband. Had a narrower compliance

[85] For example, a load with a ramp rate of 1 MW/minute will ramp up only 5 MW per dispatch interval (5 minutes). Given that the IESO DSO schedules dispatchable loads based on their actual consumption level, the load will be scheduled 5 MW more than its actual consumption. It will not violate the market rules even though the load does not move at all.

deadband been in place, the facility's failure to follow dispatch instructions more closely would have led it to be non-compliant. The risk of non-compliance encourages market participants to better align their actual consumption (or generation) with their dispatch instructions.

Second, a large compliance deadband also provides market participants with opportunities to manipulate dispatch schedules to generate CMSC payments. A market participant can manipulate its consumption (or generation) level while remaining in full compliance with the market rules. The result can be large, unjustified CMSC payments. In many instances this CMSC cannot be recovered under the market rules. Accordingly, the Panel encourages the IESO to revisit its definition of compliance deadband for dispatchable loads, perhaps by linking the deadband more closely to a facility's size and ramping capability.

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.***

3.2 Update on Changes to the IESO's Generation Cost Guarantee Program

3.2.1 Introduction

In the previous Monitoring Report the Panel discussed a market rule amendment affecting the IESO's cost guarantee (GCG) program, also referred to as the spare generation online (SGOL) program.[86] As background, the IESO introduced the GCG program in 2003 as a reliability initiative to encourage non-quick start generators (typically coal and gas) to provide spare online capacity such that their units could quickly respond to IESO dispatch instructions in the event of a system disturbance. A

[86] See the Panel's January 2010 Report, at pp. 106 – 113.

day-ahead version of the program was introduced as part of the Day-ahead Commitment Process in 2006. Under these GCG programs, coal and gas generators[87] that provided online generation capacity were guaranteed to be constrained-on to their minimum loading point (MLP) for the duration of their minimum run time (MRT). Several days later, these eligible GCG generators could provide cost submissions to the IESO and would be entitled to a full reimbursement of their costs. Given supply concerns at the time the GCG program was implemented, eligibility criteria was set very low. To achieve GCG eligibility and the corresponding guarantee, a generator needed only to be economically scheduled for a single MW in a single hour of its MRT. The reimbursement in turn was comprehensive, covering all submitted fuel and O&M costs for ramping the unit to its MLP as well as for all MWs generated over the duration of the MRT (up to the generator's MLP).[88]

With the guarantee in place, generators were fully insulated against downside variability to the MCP. For example, a market participant that wished to have its generation facility dispatched could submit a negative priced offer. Following the generation event the market participant would submit an after-the-fact cost submission to the IESO and would be fully reimbursed for the cost of operating the unit. At no point was the generator exposed to an operating loss because the GCG program ensured that at a minimum all of the generator's costs would be fully reimbursed. The generator did, however, have upside profit potential. If generation revenue exceeded the GCG cost submission the generator would keep the operating revenue.[89] Because generators could offer at sub-marginal costs without any exposure to losses, the GCG program effectively created an opportunity for interested generators to operate in a manner similar to self-schedulers or non-utility generators. In a previous report the Panel raised concerns about the structure

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[87] The steam units of combined cycle generators are also eligible for the GCG program.
[88] Pre-December 9th there was in fact a discrepancy between the real-time and day-ahead GCG programs. Day-ahead participants were guaranteed fuel and O&M costs, whereas real-time GCG participants could not claim O&M costs.
[89] If revenues exceeded the GCG cost submission the generator would not receive a GCG payment from the IESO. Conversely if the GCG cost submission exceeded revenues, the generator would be "topped up" the difference between revenues from the market and the GCG cost submission. Consequently eligible GCG generators had no exposure to downside variability in MCP, but unlimited (up to the maximum market clearing price) upside exposure.

of the GCG program. The Panel's primary concern was that the guarantee program meant that the true cost of running the generator was not transparent at the time of dispatch and accordingly led to inefficient dispatch. At the time, the Panel recommended that the IESO consider basing the GCG payment on the offer submitted by the generator or to implement another solution that would allow actual generation costs to be taken into account at the time of scheduling decisions.[90]

On December 9th, 2009 the IESO introduced a GCG rule amendment[91] that was intended to restrict eligibility under the program and to better align IESO dispatch decisions with GCG generator costs. Under the amended rule generators need to be economically scheduled at their MLP for at least half of their minimum generation block run-time (MGBRT) in order to qualify for the guarantee. Significantly, the rule amendment divided the guarantee into two component parts. One component is calculated based on the generator's MBGRT offer price. Specifically this MGBRT component is calculated as the generator's MGBRT duration, multiplied by the generator's offer price, multiplied by the generator's MLP. As a result this MGBRT component is fully transparent and accounted for at the time of dispatch. Contrary to the Panel's earlier recommendation that the full amounts of the GCG cost reimbursements be accounted for in scheduling decisions, the IESO chose to continue to permit generators to make some after-the-fact cost submissions to recover fuel as well as operating and maintenance (O&M) costs associated with start-up and with ramping generation units to MLP. This second start-up component is neither transparent nor accounted for at the time of dispatch.

The Panel's analysis of outcomes since the December 9th, 2009 market rule change indicates that it has not eliminated the distortive market effects of the GCG program. Specifically the continued use of after-the-fact cost submissions appear to have led to

[90] See the Panel's August 2007 Monitoring Report, at pp. 121-123. Also, see the Panel's January 2009 Monitoring Report, at p. ix.
[91] Market Rule #356 - Interim Changes to Real-Time and Day-Ahead Generation Cost Guarantee Programs Also, see the IESO Real-Time and Day-Ahead Generation Cost Guarantees (SE-80) stakeholdering web page at: http://www.ieso.ca/imoweb/consult/consult_se80.asp

inefficient dispatch, a depressed market clearing price, and an inflated global adjustment. The Panel's findings are discussed in greater detail below.

3.2.2 *Assessment*

For the period December 9th, 2009 to April 30th, 2010 there were 1,387 GCG eligible runs or an average of 9.70 GCG eligible runs per day.[92] In total, 40 different generation facilities, representing coal, gas and steam (from combined cycle facilities) made GCG submissions. The breakdown of daily GCG runs and payouts by fuel source for the periods May 1, 2009 to December 8, 2009 and December 9, 2009 to April 30, 2010 are set out in Table 3-6 below.

Table 3-6: Total and Average GCG Payments Received by Fuel Type May 1, 2009 - Dec 8, 2009 and December 9, 2009 - April 30, 2010 ($ thousands)

	May 1, 2009 – December 8, 2009				December 9, 2009 – April 30, 2010			
	Number of GCG Starts	**Amount of GCG Payments Received**	**Average GCG Payment Received per Start**	**% of Total GCG Payout by Fuel Source**	**Number of GCG Starts**	**Amount of GCG Payments Received**	**Average GCG Payment Received per Start**	**% of total GCG Payout by Fuel Source**
Coal	588	5,302	9.018	9	243	12,005	49.403	31
Gas	1,592	56,932	35.761	91	967	26,139	27.031	68
Steam	114	3	0.030	0	177	446	2.519	1
Total	**2,294**	**62,237**	**27.131**	**100**	**1,387**	**38,590**	**27.822**	**100**

Table 3-6 indicates that the average GCG payment per eligible GCG run increased modestly following the December 9th rule change. The most significant change before and after the rule change is the significant increase in GCG payments made to coal generators.[93]

Table 3-7 below shows the total generator GCG submissions by component part (start-up and MGBRT) for the period December 9, 2009 to April 30, 2010 (post rule-change).

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[92] Calculated as 1,387 runs divided by 143 days. This compares to an average of 10.33 runs per day from the period May 1, 2009 to December 8, 2009 calculated as 2,294 GCG runs divided by 222 days.

Table 3-7: Total GCG Submissions by Fuel Type and Component Part December 9, 2009 – April 30, 2010 ($ millions)

	Start-Up Cost Submissions		MGBRT Costs	Total
	Total Fuel Cost Submitted	Total O&M Cost Submitted	Total MGBRT Cost Covered	Total Costs Covered under GCG
Coal	3.31	9.86	1.91	15.08
Gas	11.98	19.90	23.57	55.45
Steam	0.22	0.39	2.76	3.37
Total	**15.51**	**30.15**	**28.24**	**73.9**

The total cost submissions associated with the GCG program for the period December 9, 2009 to April 30, 2010 was approximately $73.9 million. After-the-fact submissions to recover start-up fuel and O&M costs accounted for $45.7 million, or 61.8 percent of total submission, whereas the guarantee component associated with the MGBRT runs accounted for only $28.2 million, or 38.2 percent of total GCG submissions.[94] In other words only 38.2 percent of costs recoverable under the GCG program were reflected in generators' offer prices and therefore considered when the IESO made its dispatch decision.

Table 3-8 below compares by resource type the percentage of intervals that the MCP was set by a generator on the GCG program for the periods May 1, 2009 to December 8, 2009 and December 9, 2009 to April 30, 2010. During both periods GCG generators frequently set the MCP. In all 1,387 GCG runs made following the December 9th rule amendment, generators made after-the-fact submissions for start up costs.[95] Since in each instance that a GCG generator set the market clearing price the full cost of generation was not accounted for, each of these instances necessarily depressed the market clearing price and inflated the global adjustment. In fact, any time a GCG generator was scheduled but would not have been scheduled but for the existence of the GCG program,

[94] The portion of the guarantee associated with the MGBRT run is calculated as: offer price * MLP MWs * MGBRT hrs.
[95] Prior to the December 9th rule amendment, the entire GCG payment was associated with an after-the-fact cost submission.

the market price would have been depressed and the global adjustment would have been inflated.[96]

Table 3-8: Percentage of Intervals where a GCG Generator Set the MCP, by Resource Type, May 1, 2009 to December 8, 2009 and December 9, 2009 to April 30, 2010 (% of Intervals)

	May 1, 2009 - December 8, 2009	December 9, 2009 - April 30, 2010	May 1, 2009 – April 30, 2010
Coal	8.71	3.32	6.60
Gas	7.10	11.27	8.74
Steam	0.13	2.29	0.98
Total	**15.94**	**16.89**	**16.31**

As noted above, GCG cost submissions associated with start up costs accounted for 61.8 percent of total cost submissions made under the GCG program. The Panel also observed a wide discrepancy among generators as to the percentage of GCG costs that were recovered through start up costs as opposed to recovered through MGBRT offers. For example, the percentage of total GCG costs attributed to start-up costs ranged from 5 percent to 70 percent among the 17 generation units that were scheduled for at least 30 GCG runs during the period December 9, 2009 to April 30, 2010. Expressed differently, anywhere between 30 percent and 95 percent of these 17 GCG generators' total costs were reflected in their MGBRT offer prices and therefore accounted for as part of the IESO's dispatch decision.

While it is beyond the scope of the present analysis, the Panel did notice a huge discrepancy in start-up cost submissions among generators that on their face appeared to be quite similar in nature (i.e. similar vintage, MLP, and MGBRT). The ability to submit after-the-fact costs raises the possibility of gaming opportunities, especially if the program is not regularly audited. The Panel encourages the IESO to exercise the

[96] Unless the contracted price to all generators with an OPA contract was below the MCP

authority granted to it under the market rules to audit the cost submissions that generators have made under the GCG program.

As Table 3-6 above indicates, the vast majority (69.7 percent) of GCG eligible runs were made by gas generators during the period December 9, 2009 to April 30, 2010. Eight gas units, operated by three different market participants accounted for 669 or 48 percent of all GCG eligible runs during this period.[97] These gas units have MLP's ranging from 80 MW to 126 MW and MGBRT's ranging from 6 to 8 hours. All of the units have been built recently, coming online within the last two years. Table 3-9 below details each generators' average start-up cost submission for the period December 9, 2009 to April 30, 2010.

Table 3-9: Average Start-Up Cost Submissions of Selected Generating Facilities Under the GCG Program December 9, 2009 – April 30, 2010 ($)

	Average Fuel Cost Submission	Average O&M Cost Submission	Average Total Start-up Cost Submission
Generator A	21,600	9,171	30,770
Generator B	5,604	9,125	14,728
Generator C	16,629	44,443	61,072

More significantly, Table 3-10 below demonstrates that the generator with the lowest average MGBRT offer price was by far the most expensive to operate once start-up costs were accounted for.[98] From an IESO dispatch perspective, however, the most expensive generator (Generator C) would always be dispatched ahead of the cheaper Generators A and B. That is because in making the dispatch decision only considers the generator's MGBRT offer price.

[97] Each market participant had at least 150 GCG eligible runs by gas units.
[98] Average "all-in" cost per MWh is calculated as total GCG cost submissions (start-up and MGBRT components) divided by MW's injected during start-up and over the duration of the MGBRT (up to the units MLP).

Table 3-10: Average 'All-In' Cost of Selected Generating Facilities Under the GCG Program
December 9, 2009 – April 30, 2010
($/MWh and Rank)

	Average MGBRT Offer Price		Average Cost Submission	Average 'All-In' Cost per MWh Assuming Units Generated at MLP	Average After-the-Fact 'All-In' Cost per MWh based on Actual MW Injected[99]	
	$/MWh	Rank	$/MWh	$/MWh	$/MWh	Rank
Generator A	36.92	2	23.43	60.35	58.35	1
Generator B	44.56	3	22.30	66.86	62.54	2
Generator C	36.32	1	81.77	118.09	96.58	3

Assuming the generators' submitted start-up costs are reflective of their true costs, any instance where Generator C or Generator B was dispatched ahead of Generator A would have resulted in an inefficient dispatch decision; yet this is precisely what would have happened.

Table 3-11 below provides an estimate of the efficiency loss related to the scheduling of Generator C per month though the GCG program for the period December 9, 2009 to April 30, 2010. Total efficiency loss associated with Generator C's GCG runs was $16.3 million and 94.8 percent of starts were inefficient. An inefficient start is a start that would not have occurred but for the existence of the GCG program.

[99] This calculation conservatively assumes that the generators knew in advance of running the exact number of MWh's in excess of their MLP that they would produce and that these MW's were offered at the same price as MW's up to MLP. For example if the unit had an MLP of 100 MW and offered those MW's at $30/MWh but actual production was 110 MW, the calculation assumes that all 110 MW's were offered at $30/MWh.

Table 3-11: Total Efficiency Loss by Generator C Resulting from Scheduling of Generator C in the GCG Program December 9, 2009 – April 30, 2010 (% and $ millions)

	Percentage of Inefficient Starts (%)	Total Efficiency Loss ($ millions)
December 2009	70.6	1.2
January 2010	96.6	3.2
February 2010	96.4	3.9
March 2010	97.7	4.5
April 2010	100.0	3.5
Total	94.8	16.3

Efficiency loss was calculated on an interval by interval basis and aggregated for each GCG run. We use locational price at the location where Generator C operates to represent the cost of the next marginal resource if generator C was not operating. Each run was defined as all megawatts injected between the start of the first GCG interval to the last megawatt injected, including megawatts injected during ramp-up and ramp-down. The formula for calculating efficiency loss per run was as follows:

A negative value represents an efficiency gain while a positive value represents an efficiency loss. In conducting the efficiency analysis the Panel made the following three assumptions: (i) the generator's submitted start-up costs (including fuel cost and O&M costs) represented the generator's true start-up costs[100]; (ii) the generator's MGBRT offer price is a marginal price offer and that the generator continued to use the MGBRT offer price even after the MGBRT had ended, including during ramp down[101]; and (iii) the

[100] If the submitted cost is overstated, the efficiency loss may also be overstated. However, if the submitted costs are overstated it would suggest generators are not compiling with the GCG program rules.
[101] This assumption would understate the efficiency loss if a generator raised its offer price following the MGBRT run. For the period December 9, 2009 to April 30, 2010, Generator C would consistently increase its offer price following its MGBRT run, typically raising the price by a magnitude of 5 times or more to signal a desire to shut down the unit.

locational price remained constant, i.e. it was not affected by the generation status of the generator.[102]

In addition to the efficiency analysis relating to Generator C, the Panel conducted a simulation to determine the overall impact that all GCG runs had on the MCP. To do so, the Panel replaced the final pre-dispatch[103] MGBRT offer price of each generator that participated in the GCG program with that generator's average after-the-fact 'all-in' cost per MWh based on actual MW injected. For example, for the purposes of the simulation, Generator C's actual $36.32/MWh offer price was replaced with an offer price of $96.58/MWh (see Table 3-10 above). The results of the simulation are detailed in Table 3-12 below.

Table 3-12: Simulation of Impact of GCG-Eligible Generators' Below-Cost Bids on HOEP,
December 9, 2009 – April 30, 2010
($/MWh)

	Simulated Actual HOEP (A)	Simulated HOEP with Revised GCG Offers (B)	Difference (B-A)	% Change
Dec-09[104]	37.38	70.48	33.08	88.6
Jan-10	37.64	81.93	44.34	117.7
Feb-10	37.03	76.60	39.77	106.9
Mar-10	30.81	49.24	18.55	59.8
Apr-10	31.73	54.01	22.26	70.2
Average/Total	**34.75**	**66.07**	**31.39**	**90.1**

The simulation indicates that, accounting for GCG generators' all-in costs at the time of dispatch would have increased HOEP by over 85 percent for the period January to April 2010. Interestingly, the simulated market clearing price is very similar to Ontario's

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[102] The assumption of constant locational price may overstate the efficiency loss.
[103] A pre-dispatch simulation allows for intertie transactions to be rescheduled, whereas a real-time simulation does not, because intertie transactions are set in the final pre-dispatch run. A pre-dispatch simulation, however, cannot take into account dynamic responses that would occur at least two-hours out (due to offer/bid window restrictions) by market participants, which may have occurred as they see altered pre-dispatch price signals approaching real-time.
[104] From December 9, 2009 to December 31, 2009 reflecting date that new GCG market rule came into effect.

effective price of $66.97/MWh for the period May 1, 2009 to April 30, 2010 and which includes the Global Adjustment and OPG Rebate. The Panel notes that there are limitations associated with running a simulation of this magnitude and complexity. A key limitation is an inability to fully account for dynamic responses by market participants. However, the results are directionally consistent with the expected effect of a generator having left out a portion of their costs from their submitted offers.

Table 3-13 below compares the simulation results for net exports for the period December 9, 2009 to April 30, 2010. The results indicate that a higher MCP would have led to a significant decline in net exports in all months of the study period.[105] This suggests that the GCG program, which contributed to an artificially low HOEP in Ontario, also contributed to a significant number of inefficient intertie transactions.

Table 3-13: Simulation of Impact of GCG-Eligible Generators' Below-Cost Bids on Net Exports
December 9, 2009 – April 30, 2010
(in TWh)

	Simulated Actual Net Export (TWh)	Simulated Net Export with Revised GCG Offers (TWh)	Net Export Change (TWh)	Percentage Change (%)
December 2009	0.85	0.52	(0.33)	(38.9)
January 2010	0.88	0.38	(0.50)	(56.5)
February 2010	0.64	0.20	(0.43)	(68.2)
March 2010	0.72	0.35	(0.37)	(51.4)
April 2010	0.42	0.18	(0.25)	(58.6)
Total	3.52	1.63	(1.88)	(53.6)

The 1.9 TWh of net export change reflects a combination of:

[105] These results are likely understated. The simulator cannot account for dynamic response by intertie traders and assumed no change in bidding behaviour in response to price changes. Ontario often sees export bids at extremely high prices, which indicates that the exporter wishes to be price taker. It is understandable that an exporter would be a price taker in Ontario, where MCP's are consistently lower than in other jurisdictions. However, if Ontario's MCP were to rise above the price in other jurisdictions, one would expect a dynamic response by intertie traders. Traders would no longer be willing to act as price takers in Ontario. In theory, if Ontario were to become the new high price jurisdiction, one would expect Ontario to become a net importer.

1. A 0.37 TWh increase in incremental imports (12.6 percent) that would have been scheduled ahead of domestic generation if offer prices reflected full costs.
2. A 1.52 TWh decrease in incremental exports (23.6 percent) that would have been scheduled ahead of domestic generation if offer prices reflected full costs.

3.2.3 *Conclusions*

The Panel concludes that GCG program, which permits after the fact costs submissions, led to inefficient dispatch, a depressed market clearing price, and an inflated global adjustment.

The Panel's *Monitoring Document: Monitoring of Offers and Bids in the IESO-Administered Electricity Markets* (MOB document)[106] indicates an expectation that fossil-fired generation would be priced at the higher of marginal cost or average incremental cost. Average incremental cost is defined in the MOB document as "the cost per MW of starting a generating unit and running it at a specified rate for a specified number of hours".[107] The Panel recommends that the IESO remove all cost guarantees based on after-the-fact cost submissions. To the extent that the IESO believes a reliability program such as the GCG program continues to be warranted, the Panel recommends that the IESO base the GCG payment on the offer submitted by the generator or that the IESO implement another solution that would allow actual generation costs to be taken into account at the time of scheduling decisions. This would incentivize generators seeking GCG eligibility to offer at a price which reflects their average incremental cost, leading to more efficient dispatch, an increase to the fidelity of the market clearing price and a decline in non-transparent costs such as the global adjustment.

[106] See: http://www.oeb.gov.on.ca/OEB/_Documents/MSP/MSP_Monitoring_Offers_Bids_Document_20091026.pdf
[107] *Ibid*, at page 32.

At present the IESO is working toward the implementation of an enhanced day-ahead commitment process (EDAC) and has an expected implementation date of late 2011. Under EDAC, generation units will be scheduled using a three-part optimization process with 24 hour optimization. Once EDAC is implemented, it should eliminate dispatch inefficiencies scheduled on a day-ahead basis. Given the change in demand/supply conditions relative to when the GCG programs were implemented, it may be desirable for the IESO to reassessment the benefit of a real-time GCG program. In addition, the IESO may wish to consider more generally whether a generation cost guarantee program is necessary.

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.***

3.3 Transmission Rights Market

The Ontario market is currently divided into 15 zones (including the Quebec Outaouais interface that came into service in July 2009), 14 of which are referred to as 'external zones' and one of which is referred to as the Ontario zone. External zones represent the major transmission lines that link Ontario with external markets or jurisdictions. They act as proxies for the external market or jurisdiction to which they are linked and reflect the limited transmission capability that links Ontario with that external market or jurisdiction. Conversely, the Ontario zone covers all domestic generation and loads, and calculates the HOEP based on imports and exports scheduled in the unconstrained sequence.

Congestion

The IESO runs two dispatch sequences: the constrained and the unconstrained. The constrained sequence takes into account most physical constraints in the electricity network (including some characteristics of external networks), while the unconstrained sequence ignores most of these constraints. Both sequences model the bi-directional Scheduling Limit (import and export limits), which is typically the intertie specific transfer capability (subject to adjustments for outages, projected loop-flow induced by external control areas, reliability margin, etc). On the basis of Scheduling Limits, the constrained sequence further accounts for the impact of internal transmission and generation conditions on the interface. This is referred to as an Operating Scheduling Limit (OSL). In other words, the unconstrained sequence uses the Scheduling Limit, while the constrained sequence uses both the Scheduling Limit and OSL, whichever is binding first.

The IESO also runs two pre-dispatch sequences (constrained and unconstrained) and two real-time sequences (constrained and unconstrained). Intertie transactions are determined by the final one hour ahead pre-dispatch sequences and carried over to real-time. As a result, intertie congestion typically related to congestion in the final pre-dispatch.[108]

Congestion can arise in either sequence. An interface is congested in the constrained sequence when the physical power flow at the interface reaches its OSL and/or Scheduling Limit. In the unconstrained sequence, congestion occurs when the net schedules reach the Scheduling Limit.

- When an interface is congested in the constrained sequence, the associated congestion price is not applied for settlement purposes; rather, it is used to determine the schedules. If the offer/bid prices of these scheduled transactions are different from the market price, the traders may receive or be charged a CMSC payment (see examples in Table 3-12 below).

[108] Congestion can also result in real-time but not in pre-dispatch. If this is the case, the IESO may have to curtail intertie transactions to avoid overload the transmission lines in real time.

- When an interface is congested in the unconstrained sequence, the price at the external zone differs from the price in the Ontario zone. There are two implications to traders: a price implication and a CMSC implication. Under these circumstances, an importer or exporter faces the risks that the power it has contracted to buy or sell may not flow; or, if it does flow, the final price (the market price plus the CMSC payment) may be unfavourable. Unless otherwise stated, congestion in the following analysis refers to congestion in the unconstrained sequence.

The following examples in Table 3-14 illustrate how the two sequences work and how a trader faces different financial consequences. Assume the intertie is export congested, either in the constrained sequence or the unconstrained sequence. There are two exporters: Exporter 1 bids 200 MW at $100/MWh, and Exporter 2 100 MW at $45/MWh. When there is congestion in the constrained sequence only, Exporter 1 has the same schedules in both sequences and pay the external zonal MCP of $40/MWh while Exporter 2 is constrained off but receives $5/MWh of CMSC payment. When the intertie is congested in the unconstrained sequence only, Exporter 1 has the same schedules in both sequences and pays $80/MWh while Exporter 2 is constrained on but pays $45/MWh (its bid price) after adjusting for the CMSC payment. These examples highlight the complexity of the two sequence design and the different financial consequences for different offer/bid strategies when congestion occurs**.**

Table 3-14: Illustrated Examples of Export Congestion

	Congestion in the Constrained Sequence Only	Congestion in the Unconstrained Sequence Only
Bid	Exporter 1: 200 MW @ $100/MWh Exporter 2: 100 MW @ $45/MWh	
Price/Shadow Price	(1) Shadow price: $80/MWh (external) vs. $50/MWh (internal) (2) MCP: $40/MWh for both	(1) MCP: $80/MWh (external) vs. $50/MWh (internal) (2) Shadow price: $40/MWh for both
Exporter 1	(1) 200 MW scheduled in both sequences (2) Pays $40/MWh	(1) 200 MW scheduled in both sequences (2) Pays $80/MWh
Exporter 2	(1) 0 MW in the constrained sequence but 100MW in the unconstrained sequence (2) Receives $5/MWh for being constrained off	(1) 100 MW in the constrained sequence but 0MW in the unconstrained sequence (2) Pays $80/MWh (3) Receives $35/MWh for being constrained on

The two dispatch sequence system also imposes additional risks to traders, compared to domestic generators or load. For example, if there are transmission constraints within Ontario as well as congestion at the intertie itself (e.g. there is import congestion as the HOEP is greater than the intertie zonal MCP), an import may be accepted in the unconstrained sequence but not in the constrained sequence (in other words, it is constrained-off). The resulting constrained-off payment to the importer is the difference between the zonal MCP and the importer's offer price. This differs from the constrained off payment that would be made to a domestic generator (the difference between the HOEP and the offer price at the generator or $0/MWh, whichever is greater). Because the zonal MCP is lower than HOEP, constraining off an importer results in a lower constrained off CMSC payment to the importer than constraining off a domestic generator.

Various Ontario interfaces have become increasingly export congested in the unconstrained sequence since market opening. In contrast, the Manitoba and Minnesota interfaces have been increasingly import congested in recent years. The percentage of hours with congestion is shown in Table 3-15. The increase in export congestion is a result of improved supply and demand conditions in Ontario relative to external markets in recent years. The increase in import congestion in the Northwest appears to be mainly a result of increased participation at the interties, with traders having an interest in obtaining constrained-off payments for their proposed imports.[109]

Table 3-15: Percentage of Hours with Transmission Congestion (in the Unconstrained Sequence)
May-April, 2003-2010
(%)

		2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009	2009/2010
Export	**Manitoba**	0	0	0	1	0	0	0
	Michigan	0	0	0	0	6	15	11
	Minnesota	0	0	0	1	10	7	6
	New York	2	3	10	8	16	25	16
	PQAT	n/a	n/a	n/a	n/a	n/a	n/a	2
	PQDA	0	0	0	0	0	0	0
	PQHZ	2	3	6	1	10	16	3
Import	**Manitoba**	1	1	1	1	1	6	14
	Michigan	12	12	17	1	4	0	0
	Minnesota	0	16	23	8	7	5	29
	New York	1	0	1	0	0	1	0
	PQAT	n/a	n/a	n/a	n/a	n/a	n/a	2
	PQBE	0	0	0	1	1	0	0
	PQDA	0	0	0	0	0	0	0
	PQDZ	1	0	0	0	0	0	0
	PQPC	0	0	0	1	0	0	0
	PQXY	0	0	0	0	0	0	0

The increasing incidence of transmission congestion at a few major interfaces has two potential effects. First, payments to TR holders may increase, and anticipation of increased payments may increase the TR auction price for current rounds of TR auctions (assuming informational efficiency).[110] Second, congestion rents should increase.

[109] Because of large surplus supply in Northwest, generators and importers are typically constrained-off, and are paid constrained-off payments for not producing or importing. For detailed discussion on the Northwest issues, refer to the Panel's January 2010 Monitoring Report, pp. 89-104.
[110] For a discussion of the extent to which TR auctions reflect accurate expectations of TR payouts, see the Section titled *Auction Price and Payout*.

Transmission Rights

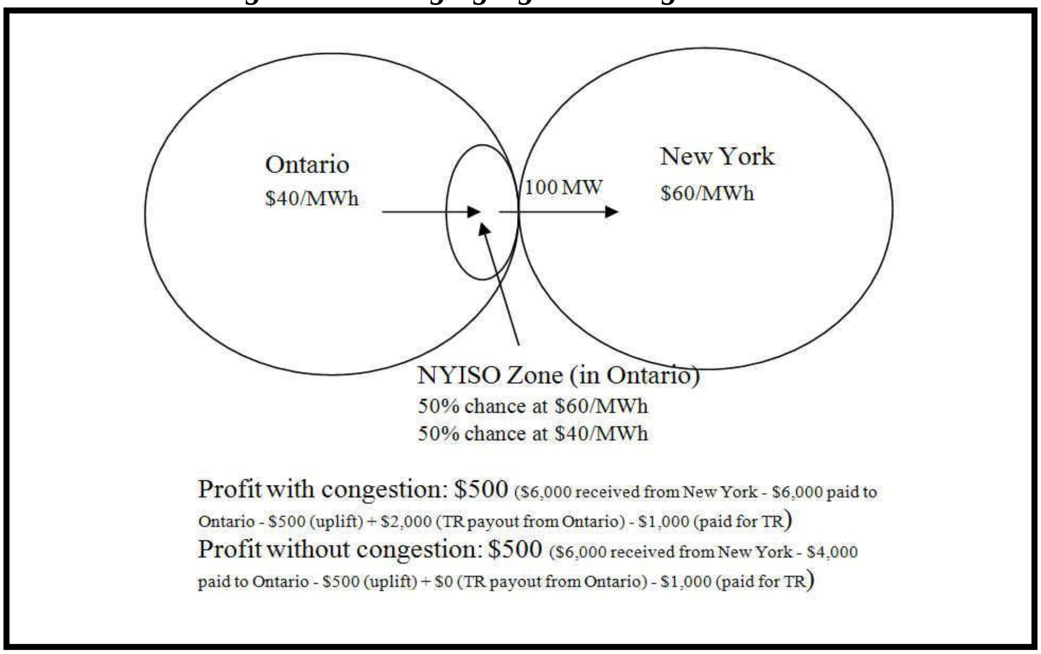
Transmission Rights (TR) can be used by intertie traders to hedge the risks associated with congestion at the interface and can potentially improve market efficiency. They may also be purchased by parties that are not hedging physical transactions. When an intertie is congested in the direction that the TR holder owns TRs, the TR holder is entitled to a payment ("payout") equal to the price difference between the external zonal price and the HOEP. For instance, a TR holder who has 100 MW of TRs for exports on the NYISO interface during the year 2010 would be entitled to a payout of 100 times the positive Intertie Congestion Price (ICP) (which in this case is the price at the NYISO zone minus the price in the Ontario zone) for each hour of the whole year.[111] In this example, the TR holder would be hedged against the risk of export congestion on the NYISO intertie.

The example below in Figure 3-8 depicts how a trader could hedge the congestion risk by holding TRs. Assume a trader has observed two possibilities: no congestion at all with a possibility of 50 percent and an export congestion ICP of $20/MWh with a possibility of 50 percent. Then the expected ICP is $10/MWh. Based on the expected congestion cost, the trader has determined that a contract with Ontario generators to purchase 100 MW of energy at $40/MWh and with New York consumers to sell the same amount of energy at $60/MWh would allow him $5/MWh of profit (assuming $5/MWh of transaction costs). If there is no congestion, the trader receives a profit of $15/MWh. However, when the intertie is congested, the trader will lose $5/MWh. To hedge against the uncertainty, the trader decides to purchase TRs. By holding TRs, the trader would receive $15/MWh of TR payout from the congestion and his total profit returns back to $15/MWh, which is exactly the same as when there is no congestion. Thus the trader's financial risk resulting from congestion is fully hedged (at the expense of the auction price paid for holding

[111] The actual TR payout is based on real-time price differences between the zones, which equals the ICP except when one of the prices is capped at plus or minus $2,000/MWh (the Maximum Market Clearing Price). (When the ICP is negative, only the TR holders with TRs for imports rather than exports are entitled to the TR payout for congestion.)

those TRs[112]). For example, assume the purchase price for a TR is $10/MWh. The trader's net return is $5/MWh (i.e. $60-$40-$5-$10) when there is no congestion. Similarly, the trader's net return is $5/MWh (i.e. $60-$60-$5+$20-$10) when there is congestion. The trader's net return is exactly the same under both scenarios and the uncertainty associated with congestion is fully hedged.

Figure 3-8: Hedging Against Congestion Risk



In reality, most physical traders do not have TRs or have TRs at different paths than their physical transactions. This is not a surprise given that traders typically arbitrage the real time price differentials between Ontario (external zones) and external markets and do business in the markets or products that they are familiar with. The basic point is that when an interface is congested, the TR holders collect the payout regardless of whether or not they are actually trading, and thus the trading decision depends purely on the price difference between the Ontario external zones and external markets. In this sense, all TR holders are financial participants. However, a trader with contractual commitments over a

112 How much a trader is willing to pay for TRs depends on his risk aversion. For example, a risk averse trader may be willing to pay up to $15/MWh for the TR (so that it breaks even) while another risk taking trader may be willing to pay only up to $8/MWh for the TRs.

path may want to lock in the expected ICP over the duration of the contract, or may not contract until he/she has locked in the expected ICP. That trader would be willing to pay up to or even more than the expected value of the ICP for the requisite FTR, depending on its tolerance of risks. This locks in the ICP over the duration of the contract at the cost of the auction price for owning the TRs, and the trader is fully hedged against congestion at the path.

Table 3-16 below shows the total transactions with and without corresponding TRs and the total TRs owned by physical traders and financial participants who never have had any physical power transactions. On average, about 64 percent of intertie trades have no associated TRs, with a high of 70 percent in May 2008 to April 2009 and a low of 56 percent in May 2005 to April 2006. Financial participants (who never have had physical transactions) have purchased on average 23 percent of total TRs sold. The data indicates that most of the TRs sold are not used for purposes of hedging the financial risks resulting from physical transactions. Theoretically, even if TR's were not used for hedging purposes financial participants could play an important role by improving the price discovery process, thereby enhancing information brought to the market and improving market efficiency. As is indicated in the Appendix at the end of this Chapter, it does not appear this theoretical benefit has materialized in Ontario's TR market.

Table 3-16: Transmission Rights Owned by Physical Traders and Financial Participants May – April, 2003/2004 - 2009/2010[113] (in TWh equivalents)

Annual Period	Physical Traders				Financial Participants	
	Transaction without Corresponding TRs (TWh)	Transaction With Corresponding TRs (TWh)	Percentage of Transaction without Corresponding TRs (%)	Total TRs Owned (TWh)	TRs Owned (TWh)	Own %
May 03-Apr 04	11	6	66	43	11	21
May 04-Apr 05	12	8	59	44	14	24
May 05-Apr 06	12	9	56	57	6	9
May 06-Apr 07	10	6	62	60	8	12
May 07-Apr 08	17	9	66	46	25	35
May 08-Apr 09	20	8	70	35	20	36
May 09-Apr 10	14	6	69	47	15	24
Total	**96**	**53**	**64**	**334**	**98**	**23**

The IESO offers both short and long-term TRs for sale. Short-term TRs are rights for the following month, while long term TRs have a duration of 12 months. Both guarantee the TR holder a revenue stream for each hour in which there is congestion during the period when the TRs are valid.

TR Clearing Account

In compliance with the Market Rules,114 the IESO maintains a TR Clearing Account. This account includes the TR auction revenue, congestion rent collected, and payouts to TR holders (as well other related items such as interest earned etc.). Auction revenue is the revenue from selling TRs (both short-term and long-term). Congestion rent is the

[113] The data for the first year of the market (May 2002 to April 2003) is not included because not all TRs were sold at beginning of the market as a result of a lack of historical relevance to both the IESO and market participants.
[114] Market Rules, Chapter 8, Section 4.18.1.

amount that the IESO collected as a result of congestion at interfaces.[115] The TR payout is the amount that the IESO paid to the TR holders for congestion,[116] (i.e. the TR awarded times the ICP). Table 3-17 below provides details on these three components over the past eight May to April periods. Congestion rent shortfall is defined as the difference between congestion rent collected and the payouts to TR holders[117], which will be further discussed in later sections. As a whole, the IESO had accumulated an account balance of $49 million[118] by the end of April 2010 (after deducting a refund of $57 million to consumers and exporters in 2007). The IESO Board of Directors is authorized to disburse funds from the TR Clearing Account at such times it determines appropriate.[119]

Table 3-17: Transmission Rights Clearing Account Summary
May – April, 2002/2003 - 2009/2010
($ millions)

Annual 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)
May 02-Apr 03	82.21	81.37	(0.84)	11.62	70.58	10.78
May 03-Apr 04	38.13	34.85	(3.28)	16.70	21.43	13.42
May 04-Apr 05	29.02	22.10	(6.92)	27.51	1.51	20.59
May 05-Apr 06	90.63	65.01	(25.62)	40.66	49.96	15.04
May 06-Apr 07	25.78	16.18	(9.60)	39.51	(13.73)	29.91
May 07-Apr 08	69.34	41.62	(27.72)	25.64	43.69	(2.08)
May 08-Apr 09	97.92	68.32	(29.60)	28.38	69.54	(1.22)
May 09-Apr 10	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 consumers and exporters in 2007, the account balance is $49 million

There are two major observations:

- The total TR Payouts (Column A) has exceeded the total Congestion Rent (Column B) in all periods, leading to a Congestion Rent shortfall of $113.12

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115 Congestion Rent is the real-time net schedules in the constrained sequence times the ICP. Thus if the real-time net schedules is different from the TR awarded, the congestion rent collected by the IESO would be different from the payment to TR holders.
116 The revenue from selling long-term TRs is evenly allocated to 12 months for which the TRs are valid.
117 Congestion rent shortfall is similarly defined in other markets, such as NYISO, MISO and CAISO.
118 Other account activities (e.g. interest adjustment, penalty, etc.) are not considered. For more details, see: http://www.ieso.ca/imoweb/marketdata/marketSummary.asp
119 Market Rules, Chapter 9, Section 4.19.

million since market opening. The large shortfall indicates that the volume of TRs sold may be greater than the actual net schedules and/or there may be significant transaction failures on at least some interfaces**,** as will be examined in more detail below. The large shortfall is being more than offset by other sources, in the current case, by the TR auction revenue, which has amounted to 23.6 percent of total TR payouts since market opening.

- TR Payout (Column A) has exceeded Auction Revenue (Column C which is what TR holders have paid) in most periods by about 110 percent on average. The excess payment represents a high rate of return for TR holders (as discussed more fully in the Section *Auction Price and Payout*), possibly indicating either a high risk of owning TRs, or potential flaws in the TR auction design/process (e.g. overselling TRs in order to stabilize the TR account which increases the volatility of TR amount for sale and/or decreases the TR auction price), or uncertainty at some interfaces where essentially only one player has dominated the transactions**.**

The following sections assess in more detail the issue of congestion rent shortfall issue and the high rate of return.

Congestion Rent Shortfall

As illustrated above, there are three main cash flows in the TR market: congestion rent, payouts to TR holders and revenue from TR auctions. Conceptually:

- Congestion rent is the money generated by congestion and collected by the market operator who manages the congestion. For example, when the NYISO interface is export congested, exporters pay the IESO a higher zonal price at the NYISO zone, while the IESO pays a lower price to internal generators for producing the energy. The difference (i.e. the ICP times the net export schedules) is the congestion rent.
- Payout to TR holders is the amount paid to TR holders by the IESO who also collects the congestion rent. The payouts to TR holders tend to be roughly equal to the congestion rent collected if the quantity of TRs sold is close to the net schedule on a path in real-time.

- Revenue from TR auctions is effectively the price for scarce transmission capacity, which in a market with commercial transmitters would accrue to the transmission owners. The auction revenue can be used for constructing new transmission lines, or offsetting the transmission service charge to end users, which eventually benefits the market. In return for the auction revenue, the transmission owners keep their capacity available. If they do not, they may be charged for overselling capacity.[120]

As noted above, the Panel defines the congestion rent shortfall (or surplus) as the difference between the collected congestion rent and TR payout to TR holders. In a world without a TR market, there would be no sale of a fungible TR rights. Rather, traders wishing to use scarce transmission would compete with one another to purchase firm transmission service from the transmission owners. The payments made to the transmission owner for this firm transmission service is conceptually equivalent to congestion rent in a TR market.[121] In addition, absent a TR market there would be no payouts or auction revenues. Accordingly, when a TR market is introduced, payouts to TR holders should not exceed congestion rents since congestion rents reflect the conceptual value of the TR right. That's because transmission owners would have sold the TR rights to TR holders at a price that reflects the expected value of congestion. In Ontario this principle should still apply even though the owner of all intertie transmission capacity (Hydro One) does not directly participate in the TR market.

In fact, according to the Market Rules, [122] the amount of TR's for sale should be established in such a way that the congestion rent collected by the IESO should be

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[120] For example, see:
http://www.nyiso.com/public/webdocs/documents/tariffs/market_services/services_tariff.pdf.
[121] In Ontario all scheduled transactions are treated as having firm transmission service. As such, bids and offers implicitly include the expected cost of congestion.
[122] Market Rules, Chapter 8, section 4.6.1 states that "*the IESO shall conduct a simultaneous feasibility test during each TR auction to ensure that the congestion rent collected by the IESO...shall, under most circumstances, be sufficient to cover any payment obligations owing by the IESO to TR holders ... in respect of all transmission rights outstanding and all transmission rights to be offered during the TR auction*". Recognizing the potential congestion rent shortfall in some periods, Section 4.7.1 further states that "(t)he *IESO Board* shall establish a confidence level reflecting the degree to which the congestion rents

sufficient to cover the payouts to TR holders under most circumstances. In other words, the TR market is designed in a way similar to what the Panel has anticipated, and thus Column B in Table 3-17 should be approximately equal to or greater than Column A. However, the results listed in the table indicate that, on that aggregate basis, this has not occurred in any year since market opening.

In its response to the Ontario Energy Board's questions related to the Panel's reports, the IESO stated that:[123]

> *The TR market is a "closed" design which is entirely funded by TR rights auction proceeds and "congestion rents", and it is designed so that these proceeds and rents are sufficient to fund TR payouts. Specifically, the market is designed so that over time the offset of TR auction proceeds/congestion rents and TR payouts maintains a rolling balance of approximately $20 million. Over time, non-TR market participants (and rate payers) are therefore not exposed to TR market costs. Similarly, the reference at p. 96 of the MSP report to "paying less rebate to Ontario consumers" is not a potential consequence of the current TR market designs. As noted, the market is designed to maintain a rolling balance of $20 million and to not rebate any surplus to Ontario consumers.* (pp. 5)

The Panel disagrees with this interpretation. As stated above, auction revenue conceptually belongs to transmission owners and thus the TR market should not be considered as a 'closed' market. Using the auction revenue to offset the congestion rent shortfall reduces the payment to transmission owners (likely the ratepayers in the Ontario case if the auction revenue is used to reduce transmission charges to them) and over-compensates the TR holders, with little apparent benefit to the market.

collected by the *IESO* in a given period described in section 4.18.1.1 will be sufficient to cover the *IESO's* payment obligations to *TR holders* under section 4.4.1 for that period".

[123] Questions for IESO at Technical Conference Relating to MSP Monitoring Report on the IESO-Administered Electricity Markets for the Period from May 2009 – October 2009 (and previous MSP reports), EB-2009-0377, filed February 22, 2010.

- First, over-compensating TR holders does not help reduce congestion. Over-compensating TR holders neither brings in more transmission capacity, nor distributes electricity more efficiently, which would also reduce transmission congestion.
- Second, over-compensating TR holders does not necessarily lead to more intertie transactions or greater intertie competition. As illustrated above, physical intertie transactions are typically divorced from TR ownership, unless traders condition their transactions on TR ownership. Table 3-16 shows that the majority of physical transactions have no associated TR, implying that TR ownership has limited relationship with physical transactions. Moreover, a better way to promote intertie competition is to improve the price fidelity and solve seam issues at the interties.
- Third, over-compensating TR holders does not necessarily result in a greater participation in the TR market. As will be showed in Section *Auction Price and Payout* later in Chapter 3, there is a persistent lack of competition in the TR market and a persistent large amount of unsold TRs. All these signs indicate that the TR market is not working efficiently and the design warrants some serious rethinking by the IESO.

A few important factors may have contributed to the significant excess of TR payouts over congestion rent collected.

- Transaction Failure: the congestion rent is determined by multiplying the intertie congestion price set in pre-dispatch by the net transaction volume which is scheduled in real-time. When a transaction that has contributed to congestion in pre-dispatch subsequently fails in real-time, the total congestion rent collected (based on the pre-dispatch ICP) is smaller than what had been expected in PD because of the lower real-time volume. For example, assume the NYISO interface is export congested with an ICP of $20/MWh and a pre-dispatch net export flow of 1,000 MW. If all transactions successfully flow in real-time, then $20,000 of congestion rent will be collected. If a 50 MW export has failed after the pre-dispatch run, however, then lost congestion rent is $1,000 ($20/MWh times 50

MW) because the congestion rent is collected based on the real-time net schedule of 950 MW.

- Overselling of TRs: this could occur as a result of unexpected outages or deratings, and/or intentional overselling of TRs. The IESO's current practice is to stabilize the TR account, which could leads to potential over-selling of TRs. Since 2004, the IESO Board has set a threshold of $20 million for the TR Clearing Account in order to offset possible congestion rent shortfalls. When the TR Clearing Account has accumulated above the threshold, the IESO is instructed to increase the TR amount for sale until the accumulated amount drops close to the threshold, or the TR amount for sale at any interface reaches its expected maximum transfer capability, whichever comes first.[124] In simple terms, in operating the TR market, the IESO has been advised not to balance congestion rent collected with the TR payment obligation. This purposely led to overselling of TRs.

- The Two Schedule Market Design: as mentioned before, the IESO's two dispatch sequence design adds further complexity to the market. The unconstrained sequence, which determines the ICP, uses a scheduling limit that typically reflects the capability specific to the interface. However, the constrained sequence applies the lower of the OSL/Scheduling Limit which can reflect constraints elsewhere the entire system. In other words, the two dispatch sequence design leads to a net schedule for collecting congestion rent being different from the net scheduling limit that is used to calculate the ICP.

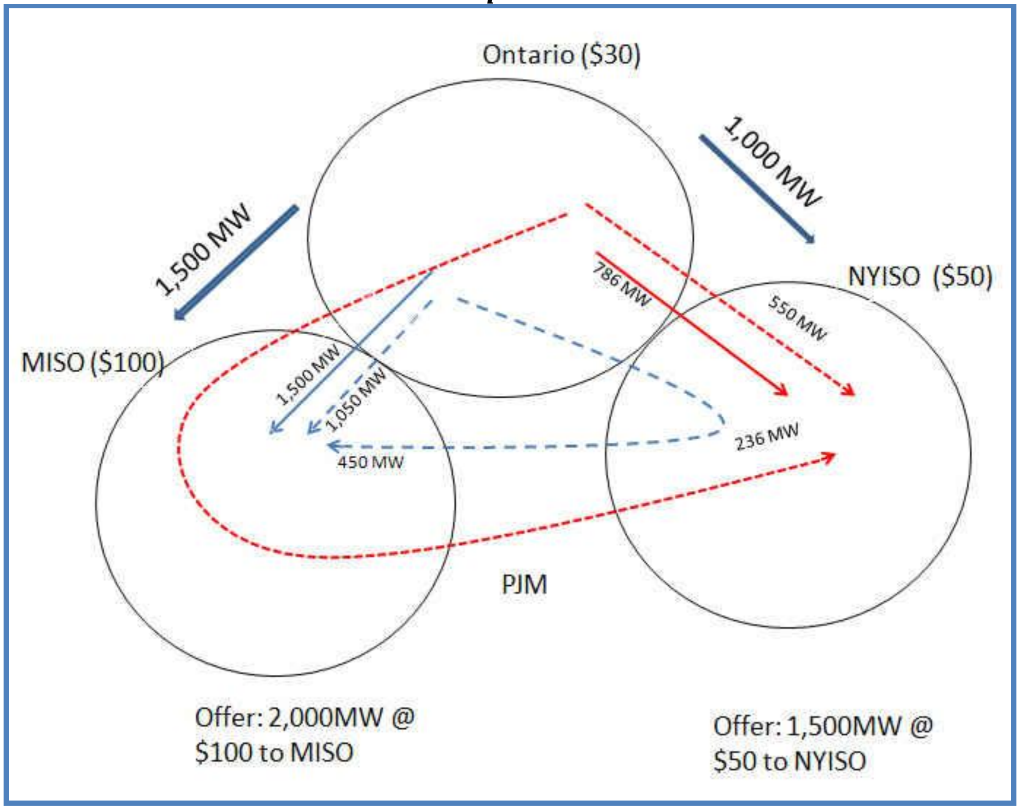
Figure 3-9 below illustrates one example, showing how the IESO's two dispatch sequences can lead to congestion rent shortfall. Assume both the unconstrained export Scheduling Limits and TRs sold are 1,500 MW at the MISO interface and 1,000 MW at the NYISO interface. There are 2,000 MW of exports bid at the MISO interface at

[124] For details, see: http://www.ieso.ca/imoweb/pubs/training/TRworkbook.pdf and http://www.ieso.ca/imoweb/pubs/consult/se17/se17-20070201-TR-Info.pdf . It is worth noting that the estimated maximum transfer capability could be much higher than real-time actual transfer capability because of forced outages/deratings, parallel flow, and other factors that affect the real-time operation.

$100/MWh, and 1,500 MW at the NYISO interface at $50/MWh. In the unconstrained sequence, both interfaces are export congested with a zonal price of $100/MWh at the MISO interface and $50/MWh at the NYISO interface. Assume the Ontario HOEP is $30/MWh. As a result, the TR holders will collect payouts of $105,000 (1,500 MW * ($100-$30)) at the MISO interface and $20,000 (1,000 MW * ($50-$30)) at the NYISO interface. However, because of parallel flows of these export transactions (assume 30 percent of exports to MISO actually flow through NYISO, and 30 percent of exports to NYISO actually flow through MISO), there are 1,500 MW scheduled at the MISO interface but only 786 MW scheduled at the NYISO interface in the constrained sequence.[125] Consequently, the congestion rent collected is $105,000 at the MISO interface (matching the TR payout), but only $15,720 at the NYISO interface, (leading to a congestion rent deficiency relative to the TR payout of $4,280 at the NYISO interface).

[125] For a detailed discussion of parallel flow, see the Panel's July 2009 Monitoring Report, pp. 164-180. The 786 MW is calculated in order not to overload the NYISO interface based on the portion of exports to MISO is through the NYISO interface.

Figure 3-9: Scheduling Differences between the Unconstrained and Constrained Sequence



To isolate the effects identified above, the Panel has decomposed the congestion rent shortfall into three components: shortfalls due to the overselling of TRs compared to the unconstrained Scheduling Limit; shortfalls due to the difference between the net unconstrained schedules and the net constrained schedules, (when there is congestion in the unconstrained sequence, the net unconstrained schedules are equal to the unconstrained Scheduling Limit); and shortfalls due to transaction failures. Mathematically, the decomposition can be expressed as follows:

$$\begin{aligned}
Congestion\ Rent\ Shortfall &= TR\ Payment - Congestion\ Rent \\
&= TR * ICP - RT^{CMW} * ICP \\
&= (PD^{CMW} - RT^{CMW}) * ICP \\
&\quad + (TR - PD^{UMW}) * ICP \\
&\quad + (PD^{UMW} - PD^{CMW}) * ICP
\end{aligned}$$

Where *TR* --- the TR amount sold

PD^{UMW} --- Pre-dispatch Net Schedules in the unconstrained sequence

PD^{CMW} --- Pre-dispatch Net Schedules in the constrained sequence

RT^{CMW} --- Real-Time Net Schedules at the same direction as the congestion

- The first component ($(PD^{CMW} - RT^{CMW}) * ICP$) measures how much of the congestion rent shortfall was induced by transaction failures. Ideally, this component should be further decomposed into failures due to IESO's action, external ISO's actions, and market participants' actions. However, because of continual adjustments to IESO coding practices, it is difficult to consistently identify the failure reason. This is especially true when the IESO changed its code in July 2007 at the NYISO interface to better reflect the true causes of the failures.[126]

- The second component ($(TR - PD^{UMW}) * ICP$) measures how much of the congestion rent shortfall was due to the IESO overselling the TRs in comparison to the unconstrained Scheduling Limits. If the unconstrained scheduling limits are the proper limits (because the ICPs are calculated based on these limits), then this component measures the effect of overselling TRs.
- The third component ($(PD^{UMW} - PD^{CMW}) * ICP$) measures how much of the congestion rent shortfall was induced by the difference between the two dispatch sequences.

Table 3-18 reports the total congestion rent shortfall and its decomposition. There are a few observations:

[126] Before July 2007, the IESO assumed almost all transaction failure other than the IESO's curtailment as failure due to NYISO reliability. After having identified that some of the failures occurred because transactions were not scheduled in NYISO simply due to being uneconomic, the IESO changed the coding practice to better reflect the failure causes.

- Transaction failures were the cause of most shortfalls in only one May to April annual period (2003/2004).
- The overselling of TRs was the major cause of congestion rent shortfall in four out of seven annual periods (2004/2005, 2006/2007, 2007/2008 and 2008/2009).
- The difference between the unconstrained and constrained sequence contributed to most of the shortfall in two out of seven annual periods (2005/2006 and 2009/2010).

Table 3-18: Congestion Rent Shortfall by Reasons
May – April, 2003/2004 - 2009/2010
($ millions*)

Annual Period	Due to Transaction Failure	Due to Overselling of TRs	Due to Two Sequences	Total Shortfall
May 03-Apr 04	1.91	(0.99)	1.70	2.62
May 04-Apr 05	1.38	3.67	1.94	6.99
May 05-Apr 06	9.63	3.39	13.36	26.38
May 06-Apr 07	1.96	5.23	2.57	9.76
May 07-Apr 08	3.60	19.46	4.89	27.95
May 08-Apr 09	4.29	14.34	12.11	30.74
May 09-Apr 10	1.22	(1.86)	13.45	12.81
Total	**23.99**	**43.24**	**50.02**	**117.25**

*The numbers are slightly different from Table 3-17 above because of missing numbers in the schedule tables due to IESO tool failures. For example, the pre-dispatch constrained sequence may fail, leading to no pre-dispatch record in the database.

The analysis above suggests that congestion rent shortfall can be significantly reduced if the IESO reduces the number of TRs for sale and better matches the unconstrained Scheduling Limits with the constrained OSL/Scheduling Limits.[127] Intertie failure was also a significant cause for congestion rent shortfall.

[127] Matching the two can also reduce the CMSC payment to intertie traders because match the two limits would reduce the difference between the schedules in the constrained and unconstrained sequences.

Shortfalls Arising from Transaction Failures

Table 3-19 below lists the transaction-failure-induced congestion rent shortfall by failure reason from the period of May 2007 to April 2010.[128] Market participants who own TRs have been responsible for the transaction failures that contributed 21 percent to 36 percent of the annual congestion rent shortfall, with an average of 29 percent over the past three years. In other words, market participants holding TRs have contributed congestion and received TR payments but have made no contributions to the congestion rent due to transaction failures they were responsible for. This represented $2.6 million of the shortfall over the past three years.

Table 3-19: Contribution of Congestion Rent Shortfall by, Failure Reasons May – April, 2007/2008 - 2009/2010 ($ thousands and %)

Annual Period	Participants without TRs	Participants with TRs			Total	Participant-Controlled as % of Total Failure
		Participant controlled	IESO	External ISO		
May 07-Apr 08	2,117	747	241	495	3,600	21
May 08-Apr 09	1,972	1,536	486	294	4,288	36
May 09-Apr 10	350	346	93	427	866	28
Total	**4,439**	**2,629**	**820**	**1,216**	**9,104**	**29**

It is possible that a TR holder may strategically offer or bid to congest an intertie and then subsequently fail its transaction in order to receive TR payout. Table 3-20 below lists the failed transactions under market participants' control by TR holder type. A transaction under a participants' control is failed if the trader owns a TR on that interface in the same direction as the trade. The amount of TRs owned by the trader could be different from the amount of MWs scheduled or failed (e.g. a trader may own 100 MW of TRs while trading 500 MW but failing only 200 MW). Upon review, there is no evidence

[128] Before July 2007, almost all failed transactions at the NYISO interface that were induced by participants' actions were coded as NYISO reliability. The estimate of congestion shortfall due to actions under market participants' control for the period May to June 2007 is incomplete.

that TR holders have strategically congested an interface only to subsequently fail the transaction.

Table 3-20: Transaction Failures under Participants' Control by Type of TR Holder May – April, 2007/2008 - 2009/2010 (TWh and %)

Transaction Type	Annual Period	Traders with TR			Traders without TR		
		Failed Transactions	Scheduled in PD	Failure Rate (%)	Failed Transactions	Scheduled in PD	Failure Rate (%)
Import	May 07 - Apr 08	41	4,839	0.8	146	5,397	2.7
	May 08 - Apr 09	49	4,896	1.0	160	4,430	3.6
	May 09 - Apr 10	14	2,419	0.6	46	3,757	1.23
	Total	**104**	**12,154**	**0.9**	**352**	**13,583**	**2.6**
Export	May 07 - Apr 08	199	8,660	2.3	343	8,753	3.9
	May 08 - Apr 09	217	11,100	2.0	308	9,533	3.2
	May 09 - Apr 10	186	7,785	2.4	207	7,936	2.6
	Total	**603**	**27,545**	**2.2**	**857**	**26,222**	**3.3**

The Panel also reviewed the failure rate at the individual level and found no evidence indicating that any participant has employed such a strategy. However, given that $2.6 million out of the $9 million of congestion rent shortfall induced by transaction failure were due to market participants' own actions, the Panel has asked the MAU to continue monitoring the issue.

Congestion Rent Shortfall by Interface

Table 3-21 below reports the congestion rent shortfall by interface (all Quebec interfaces are grouped together). As indicated by the data, the largest contributor to the congestion rent shortfall is the NYISO interface, followed by the Minnesota interface. These two interfaces accounted for about 74 percent of total congestion rent shortfall. Note the Minnesota interface is a small interface with a normal import/export capacity of less than 150 MW, in contrast to about 2,000 MW each at the MISO and NYISO interface, 270 MW at the Manitoba interface, and more than 1,000 MW at Quebec interfaces (excluding the new 1,250 MW PQAT interface that came into service in July 2009). Given its small size, the average contribution to the congestion rent shortfall at the Minnesota interface was far greater than any other interface.

Table 3-21: Congestion Rent Shortfall by Interface, May – April, 2002/2003 - 2009/2010 ($ millions and %)

Annual Period	New York	Michigan	Minnesota	Manitoba	Quebec	Total
May 03-Apr 04	6.64	(4.06)	(0.05)	(0.07)	0.16	2.62
May 04-Apr 05	(0.45)	2.58	3.50	0.11	1.25	6.99
May 05-Apr 06	15.87	3.16	5.67	0.32	1.37	26.39
May 06-Apr 07	4.70	0.98	0.84	0.42	2.81	9.75
May 07-Apr 08	10.67	8.64	4.23	1.46	2.95	27.95
May 08-Apr 09	25.64	(0.11)	2.16	2.14	0.91	30.74
May 09-Apr 10	3.49	2.18	3.94	3.35	(0.15)	12.81
Total	**66.56**	**13.37**	**20.29**	**7.73**	**9.27**	**117.25**
% of Total	**57**	**11**	**17**	**7**	**8**	**100**

Table 3-22 below decomposes the causes of congestion rent shortfall at the NYISO and Minnesota interface into three categories: transaction failures, the overselling of TRs and differences between, the two dispatch sequences.

- At the NYISO interface, overselling TRs were the largest contributor to the congestion rent shortfall (47 percent of the total). However in May 08 to April 09, this factor contributed to \$17.59 million,[129] accounting for about 60 percent of total shortfall due to overselling of TRs. Otherwise, the three factors had roughly comparable contributions to the congestion rent shortfall.
- At the Minnesota interface, overselling TRs was the largest contributor (61 percent of the total shortfall), followed by the difference between the unconstrained and constrained sequences (39 percent). Transaction failures did not contribute to the congestion rent shortfalls.

[129] There was significant export congestion in June and July 2008. There were also two hours in December 2008 with an ICP of above \$1,900/MWh, leading to about \$2.9 million of congestion shortfall due to overselling or TR (sold TR 1,024 MW vs. Scheduling Limit of 400 MW due to forced outages at the Michigan interface).

Table 3-22: Congestion Rent Shortfall by Reasons at the NYISO and Minnesota Interfaces
May – April, 2003/2004 - 2009/2010
($ millions)

Annual Period	New York				Minnesota			
	Due to Overselling of TR	Due to Two Sequences	Due to Transaction Failure	Total Shortfall	Due to Overselling of TR	Due to Two Sequences	Due to Transaction Failure	Total Shortfall
May 03-Apr 04	4.35	1.19	1.10	6.64	(0.06)	0.01	0.00	(0.05)
May 04-Apr 05	(1.30)	0.35	0.50	(0.45)	3.14	0.29	0.07	3.50
May 05-Apr 06	2.12	7.67	6.08	15.87	3.26	2.42	(0.01)	5.67
May 06-Apr 07	1.56	1.61	1.53	4.70	0.42	0.42	0.00	0.84
May 07-Apr 08	6.85	1.35	2.47	10.67	3.38	0.82	0.03	4.23
May 08-Apr 09	17.59	4.64	3.41	25.64	0.81	1.34	0.01	2.16
May 09-Apr 10	(0.20)	3.33	0.36	3.49	1.41	2.65	(0.12)	3.94
Total	**30.97**	**20.14**	**15.45**	**66.56**	**12.36**	**7.95**	**(0.02)**	**20.29**

Table 3-23 shows the decomposition of the causes of congestion rent shortfall at the NYISO interface by transaction direction. It can be seen that there were more problems with the export direction (83 percent of total shortfall). This is not surprising given that the NYISO interface was typically export congested in both sequences, and the export failure rate was the highest (see Chapter 1), and the schedules were highly impacted by the Lake Erie Circulation.

Table 3-23: Import and Export Congestion Rent Shortfall by Reason at the NYISO Interface
May – April, 2003/2004 - 2009/2010
($ millions)

Annual Period	Imports				Exports			
	Due to Transaction Failure	Due to Overselling of TR	Due to Two Sequences	Total Shortfall	Due to Transaction Failure	Due to Overselling of TR	Due to Two Sequences	Total Shortfall
May 03-Apr 04	0.03	5.32	0.17	5.52	1.07	(0.97)	1.02	1.12
May 04-Apr 05	0.01	0.02	0.00	0.03	0.49	(1.32)	0.35	(0.48)
May 05-Apr 06	0.99	3.05	1.07	5.11	5.09	(0.93)	6.60	10.76
May 06-Apr 07	0.00	0.21	0.08	0.29	1.53	1.35	1.53	4.41
May 07-Apr 08	0.08	0.46	0.04	0.58	2.39	6.39	1.31	10.09
May 08-Apr 09	0.06	(0.13)	0.01	(0.06)	3.35	17.72	4.63	25.70
May 09-Apr 10	0.00	0.00	0.00	0.00	0.36	(0.20)	3.33	3.49
Total	**1.17**	**8.93**	**1.37**	**11.47**	**14.28**	**22.04**	**18.77**	**55.09**

Table 3-24 presents the import and export path decompositions for the Minnesota interface. The bulk of the shortfall (63 percent of the total) arose in the import direction. The Minnesota interface was often import congested in the unconstrained sequence but often had no corresponding imports in the constrained sequence, as the Panel noted in its January 2010 Monitoring Report.[130]

Table 3-24: Import and Export Congestion Rent Shortfall by Reason at the Minnesota Interface May – April, 2003/2004 - 2009/2010 ($ millions)

	Imports				Exports			
Annual Period	**Due to Transaction Failure**	**Due to Overselling of TR**	**Due to Two Sequences**	**Total Shortfall**	**Due to Transaction Failure**	**Due to Overselling of TR**	**Due to Two Sequences**	**Total Shortfall**
May 03-Apr 04	0.00	0.06	0.01	0.07	0.00	(0.12)	0.00	(0.12)
May 04-Apr 05	0.06	1.12	0.29	1.47	0.00	2.03	0.00	2.03
May 05-Apr 06	(0.01)	3.23	2.42	5.64	0.00	0.03	0.00	0.03
May 06-Apr 07	0.00	0.33	0.42	0.75	0.00	0.09	0.00	0.09
May 07-Apr 08	(0.01)	0.65	0.80	1.44	0.04	2.74	0.02	2.80
May 08-Apr 09	(0.14)	0.22	0.90	0.98	0.16	0.59	0.44	1.19
May 09-Apr 10	(0.14)	0.29	2.63	2.78	0.01	1.11	0.02	1.14
Total	**(0.24)**	**5.90**	**7.47**	**13.13**	**0.21**	**6.47**	**0.48**	**7.16**

The Panel has observed some fundamental design problems in the current TR market operation. In particular, the market is designed as "closed" and all revenues (including TR auction revenue and congestion rent) are purposely distributed to TR holders. This has led to an over-compensation to TR holders and TR auction revenue that could have been used more efficiently (e.g. building more transmission lines to relieve congestion). In the near term, the IESO should revise its current design that has led to a significant congestion rent shortfall and balance the TR payout with the congestion rent.

[130] See the Panel's January 2010 Monitoring Report, pp. 89-105.

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.***

Auction Price and Payout

The above analysis has assessed the design of the transmission market. The other important aspect of this market is the financial implications to the TR holders, i.e. how much TR holders have paid and how much they have received for owning the TRs. The appendix to this chapter provides details on how profitable the TR market is and how different it is at individual interties.

In summary, the Panel has achieved several purposes through the study:

- to show the distribution of profits or returns received by investors in TRs and also how these returns vary by type of TR, by path and over time;
- to show how the characteristics of paths differ in terms of the number of auctions held, the number of bidders per auction, growth or variation in the number of bidders and the incidence of congestion;
- to investigate the possibility of a systematic relationship between the returns received by investors in TRs and the characteristics of the path to which the TRs apply;
- to quantify the payoff foregone on TRs not purchased and find the circumstances under which this occurs; and
- to measure the extent to which two-round auction design of long-term auctions reduces the discrepancy between the auction clearing price and the payout on the TR concerned (this is called the price discovery effect).

The Panel finds that, while some paths are better than others, the TR market as a whole is not informationally efficient. In other words, the auction clearing price (ACP) of a TR provides relatively little information about the future payout on it. This may be because bidders cannot readily predict incidents of congestion or predict the ICP when there is congestion, or both. There is some limited indication that bids may respond to past incidents of high payouts but, as is the case with flipping coins, the past has not been a reliable guide to the future.

On average, payouts to TR holders have been much higher than ACPs, but on some paths and during some time periods there is a preponderance of payouts less than ACPs. Profits on TRs are due principally to occasionally very high payouts. Payouts vary widely from period to period while ACPs vary within a much narrower band.

While the findings reported above are consistent with an inability on the part of bidders to predict incidents of very high payouts, an inability to predict specific incidents of high payouts is not a sufficient explanation for high returns experienced on most paths over fairly long periods. In the simplest terms, TRs sell at a significant discount to the historic average payout on them and while there is room for debate about the risk premium an uncovered TR investor might require, it is hard to imagine that it would approach the premium implicit in the long term return that have been realized on most paths and in aggregate (about 100 percent) since market opening. It may be the case that bidders' expectations regarding the long-run average payout over time are simply less than the historic experience but there are other possible explanations.

The number of bidders on most paths is small and, with a few exceptions (most notably the export path to Michigan), has not increased appreciably over time. The number of bidders on most paths has also been fairly steady from period to period. There is at present little to indicate the presence of potential bidders poised to bid in auctions on paths on which returns to TR holders have been high.

While imperfectly competitive bidding cannot be ruled out as a reason for the high long term returns to TR holders on many paths, there is no simple relationship between the long term return on a path and its characteristics. Long term returns vary markedly across paths and are lowest on some of the paths with the fewest bidders. Further analysis will be required to better understand the nature of the linkage between path long term returns and path characteristics.

A major implication of the findings in this report is distributive. If the auction revenue collected by the IESO was equal on average to the amount it pays out to TR holders, this would leave the entire congestion rent collected by the IESO available to rebate to transmission owners or transmission users (loads and exporters) according to the market rules. However, the amount the IESO pays out to TR holders is well in excess of the auction revenue it receives from them, so a significant part of its payout to TR holders comes out of congestion rents. Thus, the result of the TR auctions is that a significant fraction of congestion rents collected by the IESO has effectively been shared with TR holder, many of whom are not participants in the physical market. In principle, the participation of purely financial investors in the TR market should increase competition, liquidity and information flows thereby resulting in a more informationally efficient market. At present, there is little to indicate that this has occurred to any meaningful degree. The IESO may wish to address the question of whether it sees the TR market as a sharing device for congestion rents that would otherwise be rebated to transmission owners or users and if so, who it wishes to share these rents with and to what end.

The informational inefficiency of the TR market may also have implications for the efficiency of the physical market. If market participants are unable to predict intertie congestion prices, they may enter into some intertie transactions that turn out to be inefficient *ex post*. But the TR market is merely reflecting this rather than causing it. If market participants were to use ACPs in TR auctions as a signal of future intertie congestion prices and the ACP is distorted, say, by lack of competitive bidding, then the informational inefficiency of the TR market could have adverse efficiency consequences for the physical market.

Summary

Some fundamental TR market design issues were identified by the Panel is this section. The Panel identified the issues with the ‘closed’ nature of the TR market where all revenues (including TR auction revenue and congestion rent) are purposely distributed to TR holders. Futhermore, the TR market was identified as not being informationally efficient and the average payouts to TR holder were much higher than the auction clearing prices since market opening in 2002. Based on these observations, the Panel suggests the IESO conduct a full study to assess whether the TR market has performed its primary function of helping physical traders hedge their financial risks and to identify barriers that have prevented it from properly functioning.

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.***

Chapter 3 Appendix: Analysis of Transmission Rights Auction Price and Payout

1.1 Introduction

This appendix analyzes the transmission right auction revenue (to TR holders, it is the cost paid for owning TRs) and payout (to TR holders, it's the revenue for owning the TRs) and has the following objectives:

- to show the distribution of profits or returns received by investors in TRs and also how these returns vary by type of TR, by path and over time;
- to show how the characteristics of paths differ in terms of the number of auctions held, the number of bidders per auction, growth or variation in the number of bidders and the incidence of congestion;
- to investigate the possibility of a systematic relationship between the returns received by investors in TRs and the characteristics of the path to which the TRs apply;
- to quantify the potential profit on TRs not purchased and find the circumstances under which this occurs; and
- to measure the extent to which two-round auction design of long-term auctions reduces the discrepancy between the auction clearing price and the payout on the TR concerned. [131]

The balance of this section is organized as follows. Section 1.1 outlines the dataset that the Panel has used and how to interpret the auction series in the report. The relative importance of short-term and long-term auctions and export and import paths is examined in Section 1.2 Section 1.3 reports on differences in the average number of bidders per auction across paths and over time. Section 1.4 reports the numbers of participants at each intertie. Section 1.5 explains our measures of the profitability of TRs to those who have invested in them. We define two measures of profitability, *Return* and *Cumulative*

[131] Economists call this the price discovery effect

Return, and report values of them for each path and for various time periods. Section 1.6 reports on the proportion of TRs offered at auction for which there were no bids and on the ultimate payout, if any, on these TRs. Section 1.7 examines the question of whether the two round auction format in long-term TR auctions results in second round auction clearing prices that predict payouts more accurately.

Section 2 of this appendix focuses on groups of paths. In Section 2.1, the variation over time in the payout to holders of TRs and in the auction revenue received by the IESO on all paths taken together is analyzed. Section 2.2 provides an analysis of the time pattern of the payout to TR holders and the auction revenue received by the IESO on import paths and export paths respectively.

Section 3 provides an analysis of the TR markets for each individual path. This analysis includes a description of the behaviour of the auction market clearing price (ACP), the payout per TR and the return on TRs over time on each path. It also includes an examination of the relationship between the ACP in each auction and the payout on the TRs involved in order to shed some light on the role of TR market in providing information about future intertie congestion and intertie congestion prices (ICPs).

Section 4 contains some general conclusions arising from the analysis in the preceding three sections.

1.2 Data used in this report

The data used in this report runs from market opening to March 2010. This covers auctions from May, 2002 until February, 2010.[132] The last monthly auction for which we can calculate a return or profit to an investor in a short-term TR is the February 2010

[132] We have omitted 12 observations on short-term TRs from 2002-2003 from our graphical analysis of the ACP, Payout and Return variables. These were cases in which there was no monthly auction in the month prior to the month in which the TR paid out. The omitted observations are confined to the first year of the market. These observations are not excluded from our calculation of the Cumulative Return since market opening.

auction. The last quarterly auction for which we can calculate a profit or return to an investor in a long-term TR is the February 2009 auction. A long-term TR purchased in February 2009 would be valid from April 1, 2009 until March 31, 2010 that is, it would have a payout period beginning April 1, 2009 and would be designated Q2 2009 under the naming convention we have adopted.

1.3 Relative importance of auction types and paths

There are two types of Financial Transmission Rights (TRs): short-term (monthly) and long-term (annual). Auction revenues received by the IESO and payouts to TR holders are reported in Appendix Table 3-1 below. Long-term TRs account for nearly 75 percent of both the TR auction revenues received by the IESO and the payouts to TR holders. Viewed in terms of either auction revenue received by the IESO or the amount paid out to TR holders, the long-term TRs are more important than short-term TRs. Appendix Table 3-1 also shows that export paths are slightly more important than import paths in terms of the percentage of auction revenues and payouts for which they account. Export paths have accounted for 55 percent of the payouts and 53 percent of the IESO auction revenues since market opening.

Appendix Table 3-1
Auction Revenues and Payouts by Auction Type and Path
May 2002 – March 2010 133
($ millions)

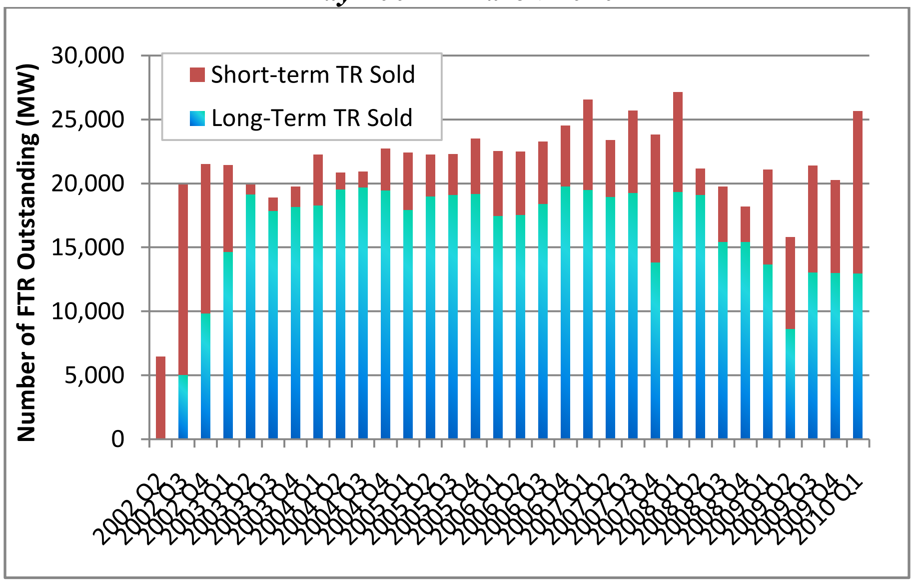
Type of TR	Auction Revenue				Payout			
	Import Paths	Export Paths	Total	Percentage of Total (%)	Import Paths	Export Paths	Total	Percentage of Total (%)
Short-Term	21	35	56	26.5	78	48	126	26.9
Long-Term	79	76	155	73.5	131	211	342	73.1
Total	100	111	211	100.0	209	259	468	100.0

The number of short-term (ST) and long-term (LT) TRs sold each quarter since market opening is shown in Appendix Figure 3-1. Each TR represents a MW. The figure shows,

[133] These totals include long-term auctions running from market opening in May, 2002 to February, 2009 and short-term auctions running from market opening to February, 2010. These are the auctions in our data set for which we have completed payout periods.

for example, that TRs totalling 27,163 MW were sold during Q1 2008. This is comprised of 3,107 short-term plus 6,449 long-term TRs in January, 2,884 short-term plus 6,449 long-term TRs in February and 1,825 short-term plus 6,449 long-term TRs in March. The chart shows that although there is considerable variation over time, long-term TRs to account for a greater portion of TRs sold than do short-term TRs.

Appendix Figure 3-1: Transmission Rights Sold
May 2002 – March 2010



1.4 Number of bidders per auction

The average number of bidders per auction on each path is reported in Appendix Tables 3-2 through 3-5 below.[134] The number of bidders in an auction is one of the factors that determine how competitive the bidding is. Another factor is the number of potential bidders.

As is shown in Appendix Tables 3-2 and 3-3, the average number of bidders per auction since market opening is between 2 and 2.5, depending on the path, on the Manitoba and Minnesota interties, close to four on the Michigan intertie and between three and four on the New York intertie. The average number of bidders on the Quebec interties ranges

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[134] This is the average number of bidders in auctions with completed payout periods as of March 31, 2010.

from less than two to over five.[135] The export path from Ontario to Quebec at PQAT has averaged over five bidders for short-term TRs but this is based on only seven recent auctions.

The largest number of bidders in any auction to date is thirteen. This occurred on the Ontario to Michigan export path in the May, 2009 monthly auction.

Appendix Table 3-2
Average Number of Bidders per Auction, Import Paths
May 2002 – March 2010

Auction Type	Intertie									
	Manitoba	Michigan	Minnesota	New York	Quebec					
					PQAT	PQBE	PQDA	PQDZ	PQPC	PQXY
Short -Term	2.0	3.9	2.2	3.3	3.6	2.8	2.2	2.0	2.4	1.8
Long -Term	2.0	4.0	2.2	3.2	n/a*	2.6	2.1	1.9	2.4	1.8

* No complete LT TR data available.

Appendix Table 3-3
Average Number of Bidders per Auction, Export Paths
May 2002 – March 2010

Auction Type	Intertie						
	Manitoba	Michigan	Minnesota	New York	Quebec		
					PQAT	PQDA	PQHZ
Short -Term	2.5	3.8	2.5	4.3	5.3	2.7	2.3
Long -Term	2.3	3.4	2.3	3.5	n/a*	2.2	2.3

* No complete LT TR data available.

The number of bidders per auction has increased on some paths since market opening. The number of bidders has increased slightly on all export paths (except PQDA), especially in the case of short-term TRs on exports to Michigan. This can be seen in Tables Appendix 3-4 and 3-5 which show the average number of bidders per auction for auctions held in 2008 and 2009. This is consistent with the increased incidence of export congestion in recent years.

[135] Because of the nature of these interfaces, of the seven interties between Ontario and Quebec, six are able to handle imports (because there are only generators on the Quebec side) and three are able to handle exports (because there are either load or transfer capability on the Quebec side).

Appendix Table 3-4
Average Number of Bidders per Auction, Import paths

2008-2009 Auction Type	Intertie									
	Manitoba	Michigan	Minnesota	New York	Quebec					
					PQAT	PQBE	PQDA	PQDZ	PQPC	PQXY
Short -Term	2.0	4.5	2.1	3.3	4.5	3.1	2.6	1.8	2.8	na*
Long -Term	2.1	6.2	2.3	3.6	n/a*	2.8	2.3	2.1	2.6	2.0

* No complete LT TR data available.

Appendix Table 3-5
Average Number of Bidders per Auction, Export Paths
2008-2009

Auction Type	Intertie						
	Manitoba	Michigan	Minnesota	New York	Quebec		
					PQAT	PQDA	PQHZ
Short -Term	2.8	5.6	3.1	4.9	5.5	2.6	2.5
Long -Term	2.3	4.4	2.5	4.4	n/a*	2.1	2.7

* No complete LT TR data available.

The average number of bidders per path on short-term TRs on all import paths and all export paths taken together is shown in Appendix Figure 3-2. The number of bidders on export TRs shows an upward trend since 2004 with some spikes in 2007 and 2009. This result is due largely to some spikes in participation in auctions for the export paths to Michigan and New York. This feature is illustrated in Appendix Figure 3-3.

The average number of bidders per path long-term TRs on all import paths and all export paths taken together is shown in Appendix Figure 3-4. There is no apparent trend in the case of long-term auctions although there have been several incidents of spikes to three bidders since 2007.

While there is variation in the average number of bidders per auction on export and import paths taken as a whole, the number of bidders on most paths has remained relatively steady over time. The export path to Michigan appears to be an exception. The export path to New York may also be an exception.[136]

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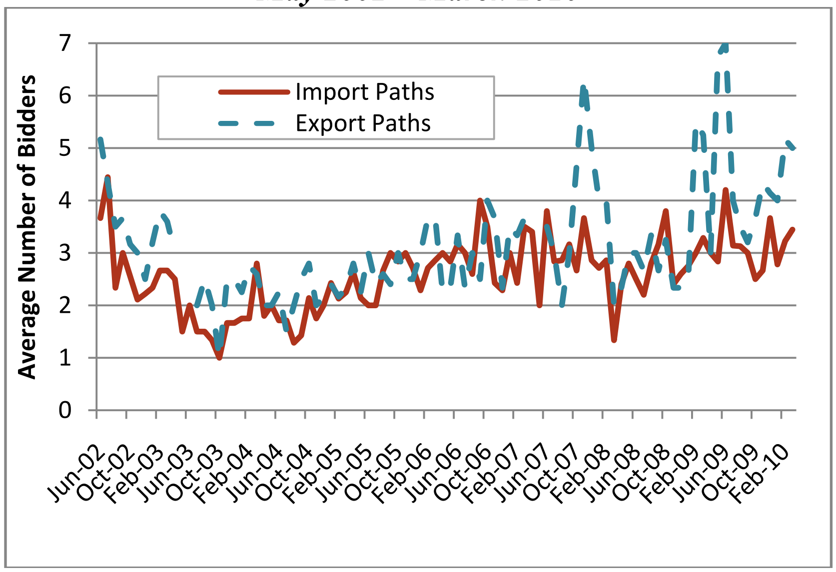
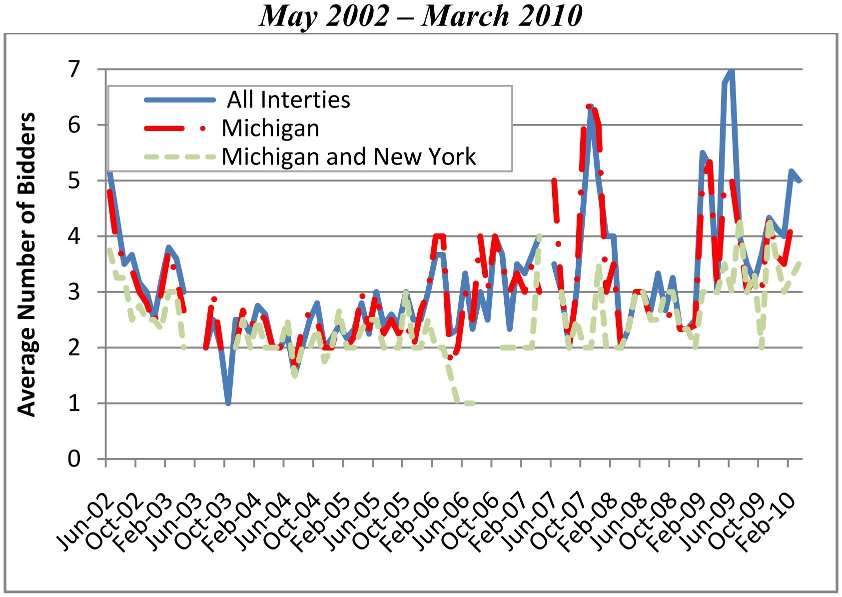
[136] Whether the apparent increase in participation on these paths reflects a systematic response to anticipated congestion or profit opportunities remains to be determined.

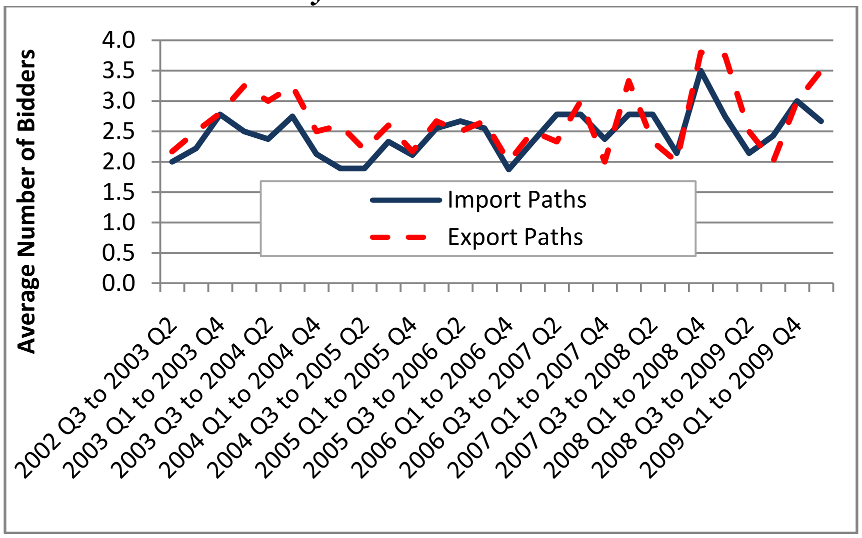
Appendix Figure 3-2: Average Number of Bidders, Short-Term Auctions May 2002 – March 2010



Appendix Figure 3-3: Average Number of Bidders, Export Paths Short-Term Auctions, May 2002 – March 2010



Appendix Figure 3-4: Average Number of Bidders, Long-Term Auctions May 2002 – March 2010



1.5 Profitability of TR Purchase

1.5.1 Definitions

The profit or return to the holder of a MW of TR is measured in this report as the ratio of the amount paid out by the IESO on it (referred to in this report as the payout) to the price paid for it (i.e. the auction price). This measure is referred to as Return throughout the balance of this appendix. Thus, a MW of TR that is purchased at auction for $100/MW and yields a subsequent payout of $130/MW is defined to have yielded a Return of 1.30 or a revenue of $1.30 for every dollar invested.[137]

The Return received by the holder of a short-term TR is the payout on the TR (usually the sum of the hourly intertie congestion prices (ICP) on the path concerned during the month concerned) divided by the amount paid for the TR in the preceding month's auction. The price paid for a MW of TR in the preceding month's auction is the auction

[137] In other words, the profit is $0.30/MW for every dollar invested. For those more interested in rates of return, the decimal fraction rate of return is simply (Return - 1) and the percentage return is (Return – 1) x 100 i.e. 30 percent in this example.

clearing price (ACP) in that auction. The ACP for all TRs sold in an auction is equal to the bid of the marginal successful bidder in the auction.

The Return received by the holder of a long-term TR is the payout on that TR during the year it is in effect divided by the amount paid for it in the preceding quarterly auction (the ACP). The payout on a long-term TR is the sum of the hourly intertie congestion prices (ICP) or congestion rents on the path concerned during the year it is effective.

The C*umulative Return* received by the holder of short-term TRs during a given time period is the sum of the monthly payouts received on short-term TRs during that time period divided by the sum of the amounts paid for these TRs. For example, the Cumulative Return on short-term TRs during the year 2009 would be the sum of the payouts on short-term TRs during 2009 divided by the sum of the ACPs in the relevant monthly auctions (in this case, auctions held between December 2008 and November 2009).

The Cumulative Return on long-term TRs during a given time period is the sum of the payouts received on long-term TRs outstanding during the period concerned divided by the sum of the amounts paid for these TRs at auction.

The Cumulative Return is a weighted average Return where the weights are auction revenue shares. The cumulative return over two periods (months, quarters) can be expressed as follows:

$$CR = (P_1Q_1 + P_2Q_2)/(A_1Q_1 + A_2Q_2) = \left(\frac{A_1Q_1}{A_1Q_1 + A_2Q_2}\right)\left(\frac{P_1}{A_1}\right) + \left(\frac{A_2Q_2}{A_1Q_1 + A_2Q_2}\right)\left(\frac{P_2}{A_2}\right)$$

where CR = cumulative return over periods (months, quarters) 1 and 2

P_i = payout per TR on TRs valid for period *i*

A_i = ACP of TRs valid for period *i*

Q_i = quantity of TRs sold for period *i*

In contrast to the Cumulative Return, the simple average or unweighted mean Return gives equal weight to individual monthly or quarterly Returns. Using the notation defined above, the two period unweighted mean or simple Average Return (AR) can be written as follows:

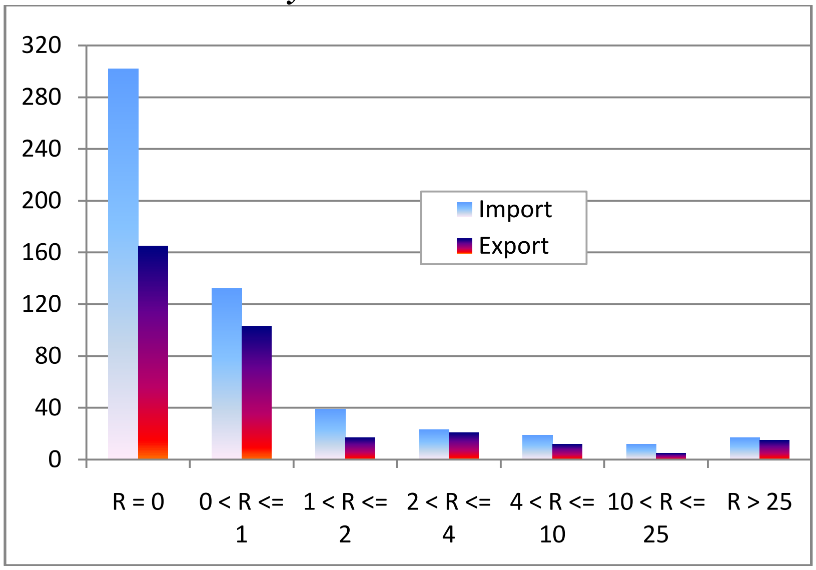
$$AR = \frac{1}{2}\left(\frac{P_1}{A_1}\right) + \frac{1}{2}\left(\frac{P_2}{A_2}\right)$$

1.5.2 Findings

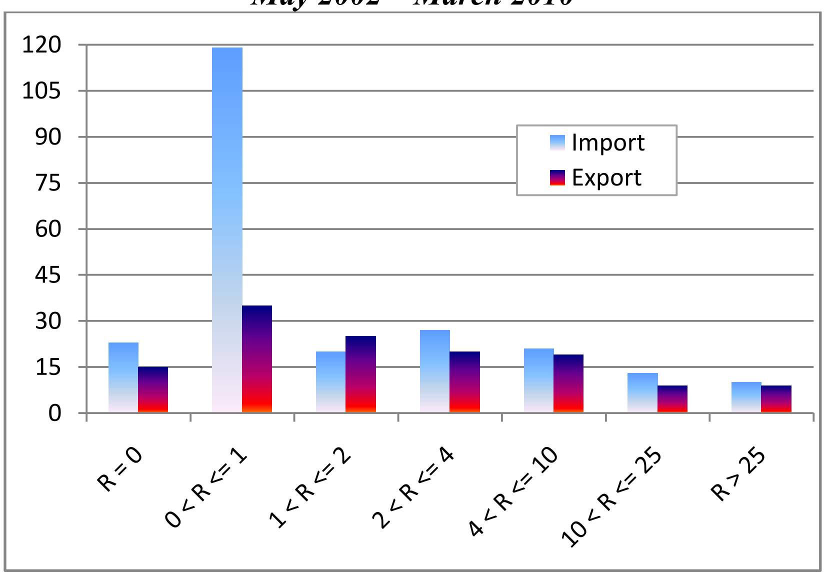
The distribution of Returns on TRs is skewed to the right. It is characterized by a preponderance of low or zero Returns with some infrequent high and very high Returns. This is illustrated in Appendix Figure 3-5 and 3-6. Appendix Figure 3-5 shows the distribution of Returns on short-term export and import TRs. Most of these Returns are either below one or zero but there are some above 25 (i.e. a revenue of $25 for every dollar invested). Appendix Figure 3-6 shows the distribution of Returns on long-term export and import TRs. There are fewer zero Returns but many below one. There are also incidents of Returns above 25.

While they are relatively few in number, the very high Returns pull the simple (unweighted) mean upwards so that it is well above the median Return on most paths. This is especially true of Returns on short-term TRs.

Appendix Figure 3-5: Distribution of Return, Short-Term Auctions
May 2002 – March 2010



Appendix Figure 3-6: Distribution of Returns, Long-Term Auctions
May 2002 – March 2010



The simple mean and median Returns on short and long-term TRs for individual paths are shown in Tables Appendix 3-6, 3-7 and 3-8. There are Returns on short-term TRs as high as 5,500 but this particular case is due to TRs that were sold at $0.01/MW each paying off $55/MW. These high Returns result in a very high simple average Return although very little money may be involved. An extreme example is the export path to Michigan. The simple average Return on short-term TRs for the period May 2002 to

March 2010 is 73.55 (i.e. a $1 investment yields a $73.55 of revenue) but the median Return is zero and, in fact, 80 percent of the monthly Returns on this path have been zero. The distribution of Returns on long-term TRs is less highly skewed than the short-term Returns. There are fewer zero returns because incidents of congestion are more likely during a year than during a single month. There also fewer extreme Returns on long-term TRs because high Return months with small payouts carry little weight in the full twelve month payout period. Nevertheless, the simple average Return in the study period on long-term TRs for exports to Minnesota, for example, is 11.40 (i.e. a revenue of $11.40 for every dollar invested), the median Return is 4.38 and 31 percent of the Returns on this path were below one.

Appendix Table 3-6
Simple Average and Median Returns by Path and TR Type
May 2002 – March 2010

Type	Intertie											
	Manitoba			Michigan			Minnesota			New York		
	Mean	Median	Percentage of Return <1 (%)	Mean	Median	Percentage of Return <1 (%)	Mean	Median	Percentage of Return <1 (%)	Mean	Median	Percentage of Return <1 (%)
ST Import	0.98	0.47	69	2.06	0.26	71	2.83	0.68	56	3.94	0.00	86
ST Export	0.12	0.00	96	85.01	0.00	77	11.92	0.13	76	2.10	0.50	65
LT Import	2.77	2.08	29	4.63	1.59	42	4.26	1.57	38	4.64	0.95	50
LT Export	2.92	0.92	53	4.76	2.53	32	10.69	3.74	29	3.54	2.30	32

Appendix Table 3-7
Simple Average and Median Returns, Imports from Quebec
May 2002 – March 2010

Type	Intertie											
	PQBE			PQDA			PQDZ			PQPC		
	Mean	Median	Percentage of Return <1 (%)	Mean	Median	Percentage of Return <1 (%)	Mean	Median	Percentage of Return <1 (%)	Mean	Median	Percentage of Return <1 (%)
Short-Term	12.92	0.14	72	4.72	0.00	96	1.32	0.00	87	12.93	0.00	94
Long-Term	7.32	2.34	43	0.15	0.03	96	1.23	0.27	82	13.00	0.08	75

Appendix Table 3-8
Simple Average and Median Returns, Exports to Quebec
May 2002 – March 2010

Type	Intertie					
	PQDA			PQHZ		
	Mean	Median	Percentage of Return <1 (%)	Mean	Median	Percentage of Return <1 (%)
Short-Term	8.95	0.00	92	33.40	0.13	74
Long-Term	0.29	0.01	80	15.69	2.27	14

The Cumulative Return is much less sensitive to extreme observations than the simple average Return. This is because the Cumulative Return is a weighted average where the weights are given by auction revenue shares.[138] The Cumulative Returns on short-term and long-term TRs on each path in the study period and for various sub-periods are reported on Appendix Table 3-9 to 3-14 below. It is apparent that the Return to TR holders varies widely between short-term and long-term TRs and among paths and time periods. TR holders at every auction would have done very well on most paths: The Cumulative Returns on short-term and long-term TRs on export and import paths at the Michigan, Minnesota and New York interties, for example, range from 1.04 to 5.02 (see Appendix Table 3-9 and 3-10). On the other hand, TR holders confining themselves to specific paths or time periods could have done very poorly. For example, short-term TR holders with payout periods in 2008 – 2009 would have lost money on all but two import paths (see Appendix Table 3-11).

Appendix Table 3-9
Cumulative Return, Import Paths
May 2002 – March 2010

Auction & Path	Intertie									
	Manitoba	Michigan	Minnesota	New York	Quebec					
					PQAT*	PQBE	PQDA	PQDZ	PQPC	PQXY
Short -Term	0.70	1.76	2.17	4.90	1.03	6.35	0.13	7.13	6.56	0.23
Long -Term	1.83	1.47	1.88	1.73	n/a	3.83	0.15	1.82	4.91	0.55

* No complete LT TR data available.

[138] To take a simple example, suppose 10 TRs were sold in month 1 for 10¢ each and each paid \$5/MW resulting in a monthly Return of 50. Suppose 10 TRs sold in month 2 for \$10/MW each and each paid \$20/MW resulting in a Return of 2. The simple average Return for the two months would be 26. The Cumulative Return would be 2.48. The cumulative return is [(50+200)/(1+100)] = 2.48.

Appendix Table 3-10
Cumulative Return, Export Paths
May 2002 – March 2010

Auction & Path	Intertie						
	Manitoba	Michigan	Minnesota	New York	Quebec		
					PQAT*	PQDA	PQHZ
Short -Term	0.19	1.04	2.07	1.23	1.70	0.38	1.14
Long -Term	0.36	5.02	4.77	2.25	n/a	0.23	1.89

* No complete LT TR data available.

Appendix Table 3-11
Cumulative Return on Short-Term TRs, Import Paths
2008-2009

Intertie									
Manitoba	Michigan	Minnesota	New York	Quebec					
				PQAT	PQBE	PQDA	PQDZ	PQPC	PQXY
0.67	0.08	1.24	0.09	1.97*	11.55	0.00	0.04	1.09	n/a**

* There were four auctions on this path with payout periods in 2008 – 2009.
** There were no auctions on this path with payout periods in 2008 – 2009.

Appendix Table 3-12
Cumulative Return on Short-Term TRs, Export Paths
2008-2009

Intertie						
Manitoba	Michigan	Minnesota	New York	Quebec		
				PQAT	PQDA	PQHZ
0.39	1.08	0.89	1.12	2.59*	0.50	1.00

* There were four auctions on this path with payout periods in 2008 - 2009.

Appendix Table 3-13
Cumulative Return on Long-Term TRs, Import Paths
Auctions held between Q1 2007 and Q1 2009

Intertie								
Manitoba	Michigan	Minnesota	New York	Quebec				
				PQBE	PQDA	PQDZ	PQPC	PQXY
3.36	0.76	1.96	1.25	4.40	0.01	0.09	0.45	0.01

Appendix Table 3-14
Cumulative Return on Long-Term TRs, Export Paths
Auctions held between Q1 2007 and Q1 2009

Intertie					
Manitoba	Michigan	Minnesota	New York	Quebec	
				PQDA	PQHZ
0.09	6.41	5.64	2.78	0.49	2.20

1.6 TRs Not Taken at Auction

In some cases, the quantity of TR bidders demand at auction is less than the quantity offered for sale. In this case, the ACP is equal to the lowest bid price, which is the marginal bid. One reason this occurs may be that there has been no recent congestion on the path concerned and market participants may see little prospect of a payout during the month or year concerned. Another reason is that the number of TRs offered for sale on some paths in a monthly auction is much greater than has been offered in the preceding auctions.

Given that TRs have been purchased for as little as $0.01/MW per month, it would generally have been profitable in retrospect to enter a "low ball" bid at each TR auction and purchase any TRs that would otherwise have gone unsold. The (decimal) fraction of TRs not taken and the payout they would have yielded is shown in Tables Appendix 3-15 and 3-16 below. The payout "left on the table" (i.e. the sum of unsold TRs times ICP) in the study period amounts to $9,138,000/MW. The New York import path and the Michigan export path each account for more than one quarter of this total.

Appendix Table 3-15
Proportion and Value of TRs Not Taken, Import Paths
May 2002 to March 2010

Auction & Path	Intertie									
	Manitoba	Michigan	Minnesota	New York	Quebec					
					PQAT	PQBE	PQDA	PQDZ	PQPC	PQXY
ST Proportion Not Taken	0.000	0.079	0.000	0.294	0.095	0.045	0.017	0.007	0.000	0.000
ST Value Not Taken, $1,000	0	4	0	2,454	0	1,434	0	0	0	0
LT Proportion Not Taken	0.000	0.014	0.000	0.014	n/a*	0.064	0.000	0.000	0.002	0.053
LT Value Not Taken, $1,000	0	1,097	0	471	n/a*	18	0	0	0	5

* No complete LT TR data available.

Appendix Table 3-16
Proportion and Value of TRs Not Taken at Auction, Export Paths
May 2002 – March 2010

Auction & Path	Intertie						
	Manitoba	Michigan	Minnesota	New York	Quebec		
					PQAT	PQDA	PQHZ
ST Proportion Not Taken	0.000	0.088	0.000	0.025	0.007	0.000	0.000
ST Value Not Taken, $1,000	0	2,488	0	274	20	0	0
LT Proportion Not Taken	0.000	0.034	0.023	0.003	n/a*	0.000	0.025
LT Value Not Taken, $1,000	0	123	109	441	n/a*	0	204

* No complete LT TR data available.

1.7 Effect of the Two Round Auction Design on the Informational Efficiency of Long-Term TR Auctions

The IESO runs the long-term TR auction quarterly, with approximately 25 percent of the annual total long-term TR offered at each auction. Each auction is done in two rounds to allow price discovery, with 25 percent of total available for that auction offered for sale in the first round accounting and the remaining 75 percent in the second round.

The price discovery opportunity arising from the second round, the long-term auction can be regarded as beneficial (improving informational efficiency) if the ACP in the second round auction is closer to the ultimate payout to the rights holder than the ACP in the first round auction. Put another way, if the absolute difference between the payout and the second round ACP is less than the absolute difference between the payout and the first round ACP, this supports the inference that second round bidders learned something from the results of the first round auction.[139]

[139] Given that the second auction is usually held three days after the first auction, it's likely that the major information from the first round is the ACP. There are possibly other information flows in the three days, such as transmission and generation outage planning, and forced outages at major transmission lines and generation, both internal and external.

We define the Discovery variable for a long-term TR with a payout period beginning in quarter t as:

$$Discovery\ (t) = (|Payout_{t} - ACP_{1t}\ | - |\ Payout_{t} - ACP_{2t}\ |) / ACP_{1t}$$

where:

$Payout_{t}$ = payout on an long-term TR with a payout period beginning in quarter t

ACP_{1t} = first round auction market clearing price for an long-term TR with a payout period beginning in quarter t

ACP_{2t} = second round auction market clearing price for a long-term TR with a payout period beginning in quarter t.

$|Payout_{t} - ACP_{1t}\ |$ represents the absolute difference.

The Discovery variable is greater than zero if the second ACP is closer to the payout on the TR concerned than the first round ACP. The discovery variable is less than zero if the gap between the ACP and the payout is greater in the second round than the first round.

The values of the Discovery variable reported in the Tables Appendix 3-17, 3-18 and 3-19 below show that, since market opening, the absolute difference between the ACP and the payout has been greater in the second round in some cases, notably on both Manitoba paths and the PQDA and New York import paths, and lower in some cases, most notably on the export paths to Michigan and Minnesota. Averaging across paths, the second round ACP has been closer to the payout than the first round ACP and this effect is more pronounced with the export paths. For long-term auctions held between Q1 2007 and Q1 2009, the second round ACP is, on average, closer still to the payout and this effect is more pronounced with export paths.

In sum, the results of the first round auction do not inform bidding behaviour in the second round auction in all cases. However, they do so on average. The extent to which the results of first round bidding behaviour inform second round bidding is greater in the case of export paths and has improved over time.

Appendix Table 3-17
Price Discovery: Percentage Reduction in Second Round vs. First Round Discrepancy between Payout and ACP, Long-Term Auctions, Import Paths
May 2002 – March 2010

Time Frame & Path	Intertie								
	Manitoba	Michigan	Minnesota	New York	Quebec				
					PQBE	PQDA	PQDZ	PQPC	PQXY
Since market opening	-13	4	-3	-4	7	-1	24	25	1
Auctions held between Q1 2007 and Q1 2009	-5	57	9	-13	-27	-6	7	30	-6

Appendix Table 3-18
Price Discovery: Percentage Reduction in Second Round vs. First Round Discrepancy between Payout and ACP, Long-Term Auctions, Export Paths
May 2002 – March 2010

Time Frame & Path	Intertie					
	Manitoba	Michigan	Minnesota	New York	Quebec	
					PQDA	PQHZ
Since market opening	-5	13	31	4	-4	11
Auctions held between Q1 2007 and Q1 2009	-3	19	51	7	-12	21

Appendix Table 3-19
Price Discovery: Average Percentage Reduction in Second Round vs. First Round Discrepancy between Payout and ACP in Long-Term Auctions
May 2002 – March 2010

Time Period	Import Paths	Export Paths
Since Market Opening	4	8
Auctions held between Q1 2007 and Q1 2009	5	14

2. Analysis of Aggregate Auction Revenues and Payout

2.1 Time Pattern of Auction Revenue and Payout on All Paths

The aggregate auction revenue received by the IESO and the aggregate payout to holders of long-term TRs are plotted against time in Appendix Figure 3-7. Aggregation across paths washes out random fluctuations in individual paths so that underlying cycles or trends are easier to discern.

To interpret Appendix Figure 3-7, note that vertical axis is in dollars and the horizontal axis represents time, measured in quarters. The blue line is the revenue received by the IESO from the auction of long-term TRs with a payout period beginning in a given quarter. The red line is the payout to holders of TRs with a payout period beginning in a given quarter.

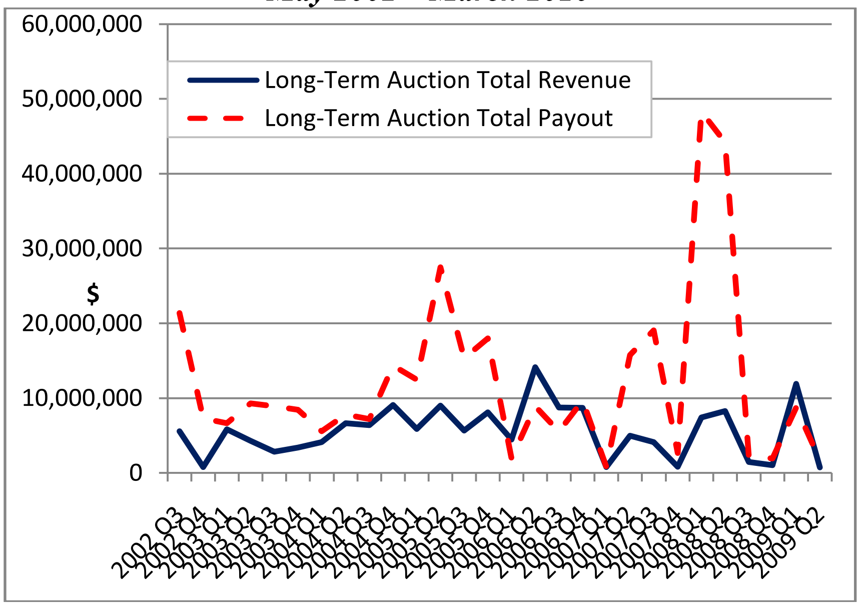
Examining Appendix Figure 3-7, we find that, for the most part, the payout to TR holders exceeds the auction revenue received by the IESO, sometimes by a very large amount. The difference between the two series is the profit to TR holders. The auction revenue tracks the payout but does so very imperfectly. Sometimes it misses turning points in the payout entirely. Other times, it increases with the payout but by a smaller amount. In essence, while the payout varies widely, the auction revenue varies within a much narrower range.

The auction revenue received by the IESO and the payout to holders of short-term TRs are much more volatile than is the case with long-term TRs. This is shown in Appendix Figure 3-8.[140] There are many spikes in monthly payouts that have a muted effect on annual payouts. Moreover, the payouts on long-term TRs auctioned each quarter overlap so the payout series is effectively a moving average. Looking past this volatility, there is

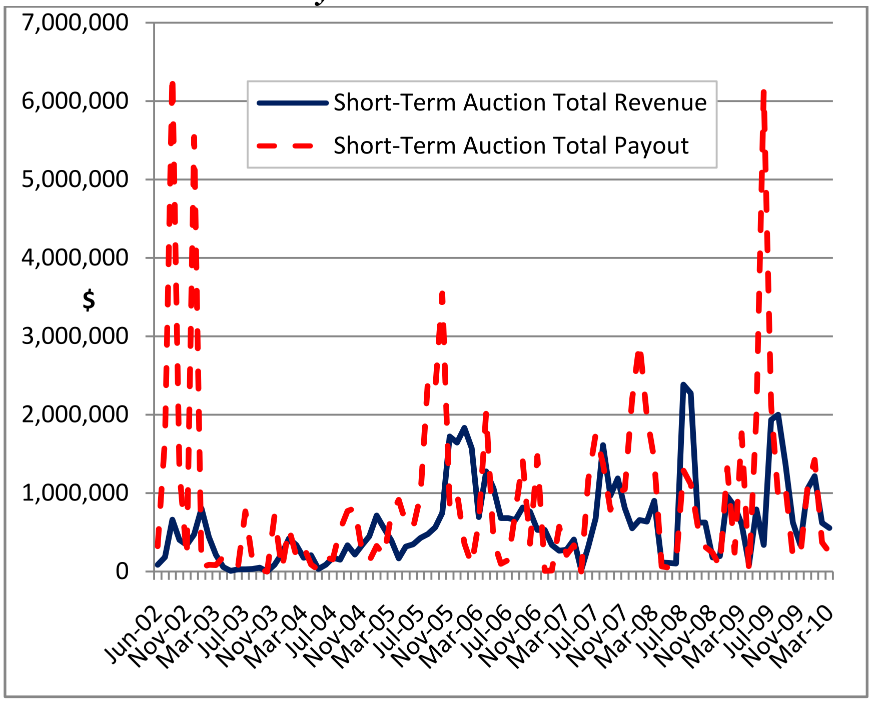
[140] September 2002 is omitted from Appendix Figure 3-8 as it is a significant outlier and would otherwise distort the Figure. Total revenues and payouts for the month were $42.3 million and $0.6 million, respectively.

essentially the same message – auction revenues do not anticipate subsequent spikes in payouts very well.

Appendix Figure 3-7: Auction Revenue and Payout,
Long-Term, All Paths
May 2002 – March 2010



Appendix Figure 3-8: Auction Revenue Received and Payout, Short-Term TRs, All Paths May 2002 – March 2010



The relationship between the aggregate revenue received by the IESO for long-term TRs in each quarterly auction and the aggregate payout to holders of these TRs is shown in Appendix Figure 3-9. The IESO auction revenue is on the vertical axis and the payout to TR holders is on the horizontal axis. The scatter of points in the figure represents the IESO auction revenue and the payout to TR holders associated with each quarterly auction. The scatter of observations in this figure is well-behaved compared with the scatters for individual paths. There are no zero observations and only a few clustered close together.

There are three lines in Appendix Figure 3-9. The first is the Auction Revenue = Payout line. Although it may not appear so due to the scaling of the axes of the figure, the slope of the Auction Revenue = Payout line is one by definition. If the IESO's revenue at each auction equalled the subsequent payout on the TRs concerned, all the data points in Appendix Figure 3-9 would lie along this line. In this case, bidders would just break-even (Return = 1). This line represents the situation of a perfectly informationally efficient market in which bidders anticipate the payout on a TR and pay their break-even price for it.[141]

The second (dashed) line is the Auction Revenue = Average Payout line. This line is horizontal because Average Payout is a constant. If the revenues the IESO received from each auction were equal to the average payout since market opening, all the data points in over the long-term Appendix Figure 3-9 would lie along this line. Bidders would also just break-even in this case. This line represents a more realistic but still idealized situation in which bidders cannot predict the payout on individual TRs but do know what the average payout over time will be and they bid that amount in every auction. When there is no payout, they lose money and by definition they make enough money when the payouts occur to break-even over time.

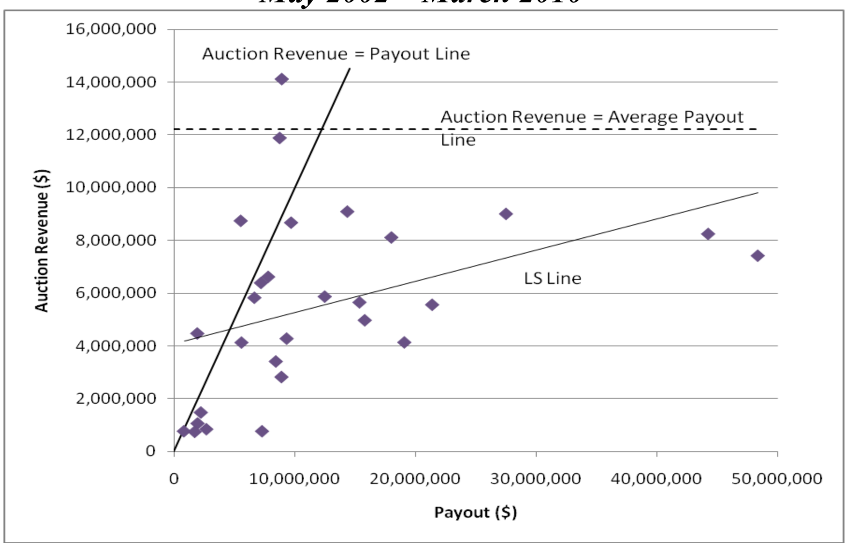
The third line is the LS (least squares) line fitted through the scatter of IESO auction revenue and payout observations. This line provides a rough estimate of the average relationship between the revenues received by the IESO in individual long-term TR auctions and the payouts on these TRs. If the LS line slopes upwards, this means that there is some tendency for bidders to pay more for TRs that turn out to yield higher payouts.

In Appendix Figure 3-9 we see that the scatter of observations around the Auction Revenue = Payout line shows that occasionally the auction revenue received by the IESO is higher than the payout to TR holders but most of the time it is lower. The LS line reflects this. It lies below the Auction Revenue = Payout line except at very low payouts. It has a positive intercept and a positive slope that is less than one. The positive intercept is a reflection of the positive prices paid for TRs when it turns out that there is little congestion. The positive slope implies that that bidders pay somewhat higher prices for TRs that turn out to have higher payouts but not on a dollar for dollar basis. As a

[141] Depending on the risk aversion, some traders may be willing to pay a higher price than the expected payout, while others willing to pay a lower price. On average, the auction price in a well-behaved TR market should be approximately equal to the payout.

consequence, their Return on high payout TRs is very high and this more than offsets low Returns on TRs with low payouts. This is also implied by the scatter of observations around the Auction Revenue = Average Payout line. All but one observation are below it, implying that with one exception, the revenue received by the IESO from each auction is less than the average payout to TR holders since market opening.

Appendix Figure 3-9: Auction Revenue and Payout, Long-Term, All Paths May 2002 – March 2010



2.2 Time Patterns of IESO Auction Revenue and Payout to TR Holders on Import and Export Paths

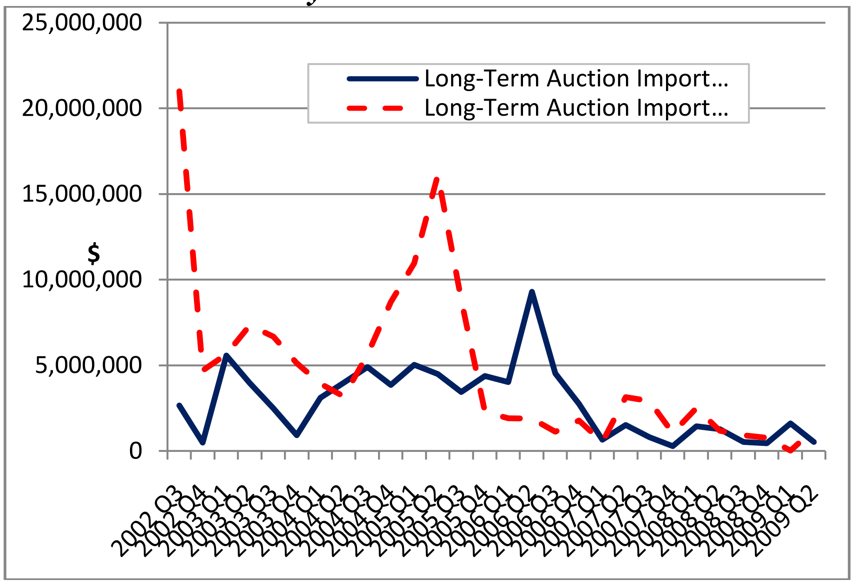
The auction revenues received by the IESO and payouts to holders of long-term TRs sold on all import paths and all export paths respectively show clear patterns over time and these illustrate another characteristic of the TR market. High payouts on import path TRs reflect import congestion during the early years of the market. High payouts on export path TRs reflect export congestion in recent years. It is also apparent that for the very high payout TRs, payouts vastly exceed the prices paid thus resulting in very high Returns to TR holders as well.

One implication of this is that inferences as to whether Returns to TR holders on a particular path are high or not differ according to the time period examined. This can lead to false inferences about whether there has been learning among potential bidders or whether bidding has become more or less competitive. The declining trend of Returns to TR holders on import paths does not necessarily imply more competitive bidding while the increasing trend of Returns to TR holders on export paths does not necessarily imply less competitive bidding.

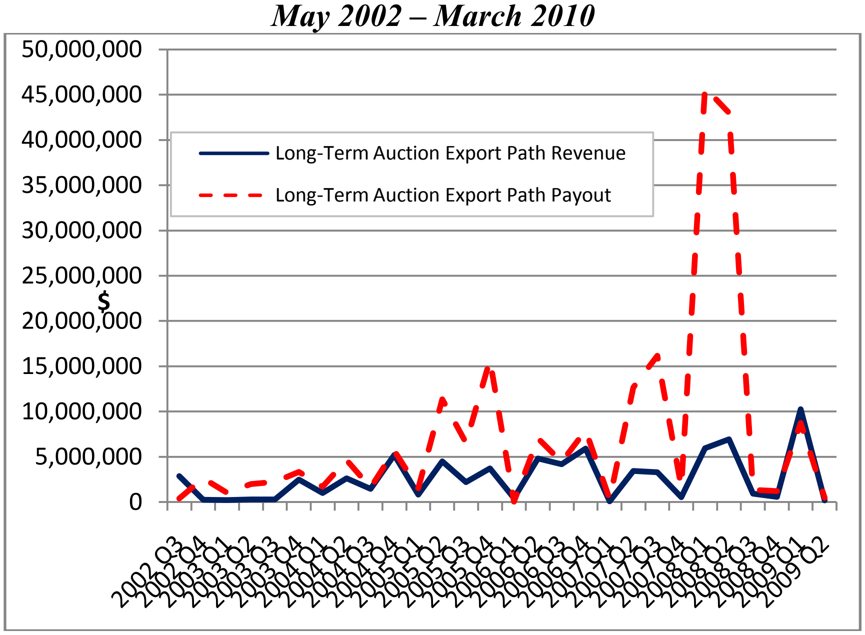
The auction revenue received by the IESO and the payout on long-term TRs on all import paths are shown in Appendix Figure 3-10. The pattern is one of very high payouts, well in excess of the prices paid for these TRs, in 2002 and 2005 with much smaller payouts thereafter. The highest annual payout (nearly $21 million on TRs that sold for under $2.7 million) occurred for the Q3 2002 TR (July 2002 – June 2003 payout period). The second highest annual payout (over $16 million on TRs that sold for $4.5 million) was for the Q2 2005 TR (April 2005 – March 2006 payout period).

The auction revenue received by the IESO and the payout on long-term TRs on all export paths are shown in Appendix Figure 3-11. The pattern is one of very low payouts in the early years of the market with much higher payouts in recent years. The highest annual payout ($45.8 million for TRs that sold for under $6 million) was for the Q1 2008 TR (payout period January – December 2008). The second highest payout ($43 million for TRs that sold for under $7 million) was for the Q2 2008 TR.

Appendix Figure 3-10: Auction Revenue and Payout Long-Term TRs, All Import Paths May 2002 – March 2010



Appendix Figure 3-11: Auction Revenue and Payout Long-Term TRs, All Export Paths May 2002 – March 2010



The relationship between the quarterly auction revenue received by the IESO for long-term TRs on all import paths the subsequent payout on them is shown in Appendix Figure 3-12. The relationship between the quarterly auction revenue received by the

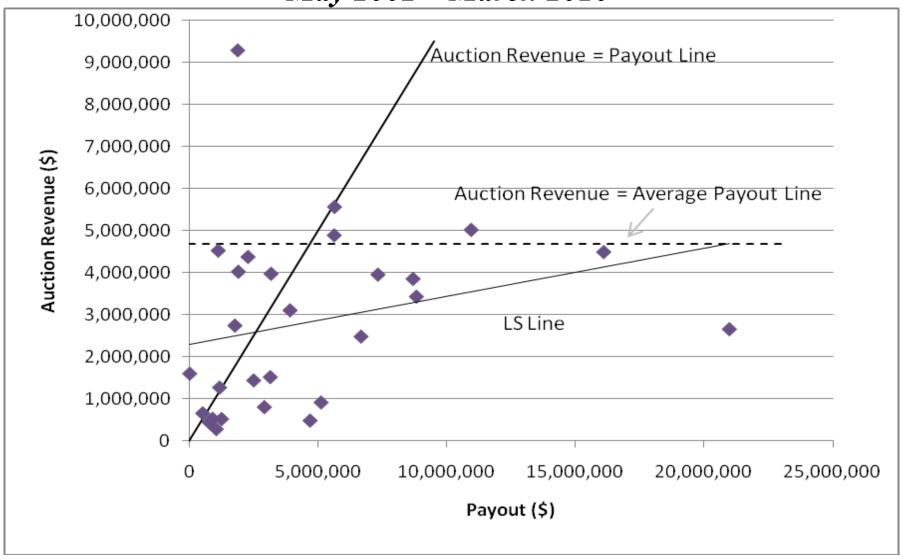
IESO for long-term TRs on all export paths and the subsequent payout on them is shown in Appendix Figure 3-13.

As was explained above in connection with the analysis of the relationship between IESO auction revenues and payouts to TR holders on all import and export paths taken together, IESO auction revenue is on the vertical axis and the payout to TR holders is on the horizontal axis. The scatter of points in these figures therefore represents auction revenue-payout combinations for long-term export or import path TRs auctioned in each quarter since market opening. The LS (least squares) line fitted through the scatter of auction revenue - payout observations provides a rough estimate of the extent to which auction revenues received by the IESO on export paths and import paths vary with the subsequent payouts to TR holders.

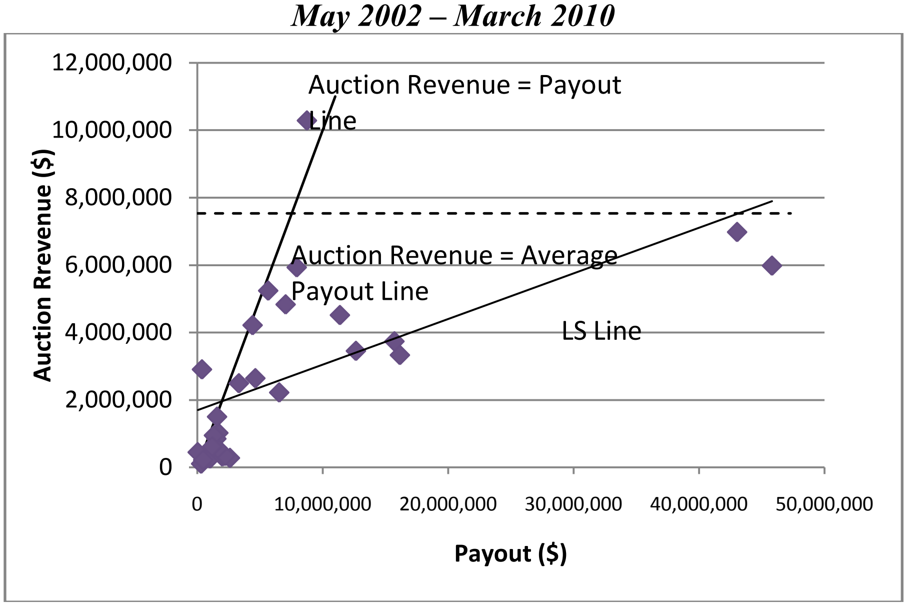
There are some observations above the Auction Revenue = Payout line in Appendix Figure 3-12 but most are below it and some are very far below it. Similarly, there are some observations above the Auction Revenue = Average Payout line but most are below it. The LS line, fit through the center of the scatter, reflects this. It lies below the Auction Revenue = Payout line except at relatively low payouts. It has a positive intercept and a positive slope that is less than one. The positive intercept is a reflection of the positive prices paid for TRs that turn out to have low payouts. The positive slope implies that that bidders pay somewhat higher prices for TRs that turn out to have higher payouts but not on a dollar for dollar basis. As a consequence, their Return on high payout TRs is very high and this more than offsets low Returns on TRs with low payouts. The position of the LS line below the Auction Revenue = Average Payout line implies the same thing.

Appendix Figure 3-13 (for export paths) can be interpreted in the same way as Appendix Figure 3-12 with the results implying a higher Cumulative Return to TR holders. There is only one observation above the Auction Revenue = Average Payout line. There are only three observations above the Auction Revenue = Payout line implying a Return greater than one in all but three payout periods. As the LS line indicates, TRs yielding higher payouts tend on average to fetch higher ACPs but this is not sufficient to keep the Return on high payout TRs from being much higher.

Appendix Figure 3-12: Auction Revenue and Payout Long-Term TRs, Import Paths May 2002 – March 2010



Appendix Figure 3-13: Auction Revenue and Payout Long-Term TRs, Export Paths May 2002 – March 2010



3. Analysis of Individual Path

3.1 Introduction

The analysis of the TR markets for individual export and import paths makes use of three sets of figures. The first set plots the ACP and payout, on short-term and long-term TRs respectively, against time. This provides an indication of the dollar magnitude of payouts and ACPs and of the difference between them.

The second set of figures plots the Return (Payout/ACP) on short-term and long-term TRs respectively against time. It is useful to look at the first two sets of figures together because there are many instances in which the Return is very high but the dollar payout involved is quite small. [142]

The third set of figures summarizes the relationship between the prices paid for short-term and long-term TRs respectively and the subsequent payouts on them since market opening. The ACP is on the vertical axis and the payout per TR is on the horizontal axis of these figures. The scatter of points in the figures represents the ACP and payout resulting from each TR auction since market opening.

The position of the LS line relative to the ACP = Payout line and the ACP = Average Payout line tells us something about both the informational efficiency and profitability (to holders of TRs) of the TR market concerned. If the LS line coincides with the ACP = Payout line, the market (for the TR type and path concerned) is informationally efficient. That is, the ACP is an unbiased estimator of the future payout on the TR concerned. In this case, TR markets provide information about future congestion and Intertie Congestion Prices (ICPs). If the LS line coincides with the ACP = Average Payout line, bidders break even over time but the ACP provides no information about the future payout on the TR concerned and therefore no information about congestion during the payout period of the TR concerned. If the LS line has a zero slope and lies below the

[142] Twelve short-term auctions in 2002-3 are omitted from these figures.

ACP = Average Payout line, bidders have made profits on average and the ACP provides no information about congestion during the payout period of the TR involved.

As stated above, the LS line provides a rough estimate of the relationship between the ACP and the payout in the auctions held to date. This estimate can be very rough indeed. If the scatter of observations around the LS line is highly dispersed, estimates of its slope and intercept can be very imprecise. This is also the case if there are extreme observations or if there are many observations massed on a single point (for example, at the zero payout point). In such situations, even though the estimated slope of the LS line may be positive, the slope is statistically indifferent from zero. Thus, in the cases examined below, a positively sloped LS line may imply that that the TR market is providing some indication of future ICPs but it is also possible that it is providing none.

3.2 Manitoba

3.2.1 Imports from Manitoba

There is one path for imports from Manitoba. There have been 86 short-term and 24 long-term auctions on this path in the study period. There has been an average of two bidders in both the short-term and long-term auctions.

The auction clearing price (ACP) and payout per TR on short-term TRs on the import path from Manitoba are plotted against time in Appendix Figure 3-14. Note that in contrast to the aggregate results presented in Appendix Figures 3-8, 3-10 and 3-11 above, the figures for the individual paths show the price and the payout on a single TR (1 MW) on the vertical axis.

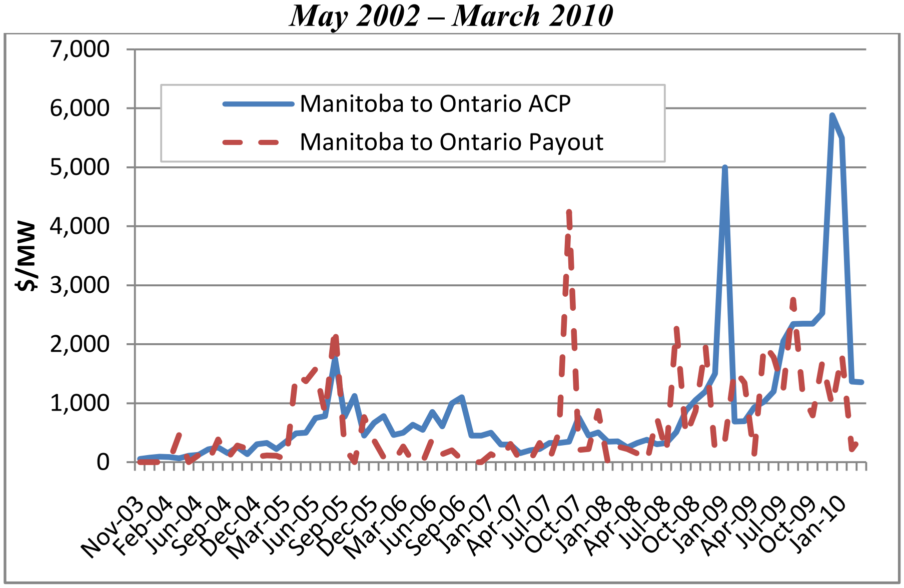
The Return on short-term TRs is plotted against time in Appendix Figure 3-15. The Cumulative Return on short-term TRs was 0.70 (i.e. a revenue of $0.70 per dollar invested in TRs). The Cumulative Return on short-term TRs was 0.67 (or a revenue of $0.67 to TR holders for every dollar they invested) in 2008-09 and 0.58 in 2009.

Notwithstanding these negative Returns, all TRs offered in monthly auctions for this path have been taken.

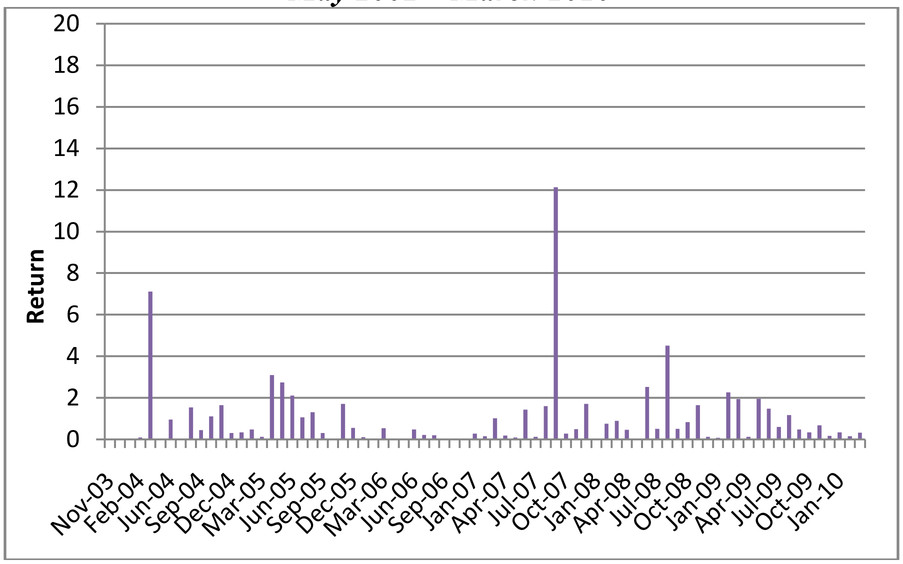
The ACP and payout per TR on long-term TRs on the import path from Manitoba are plotted against time in Appendix Figure 3-16. The Return on long-term TRs is plotted against time in Appendix Figure 3-17.

The Cumulative Return on long-term TRs is 1.83. The Cumulative Return on long-term TRs auctioned between Q1 2007 and Q1 2009 was 3.36 (or $3.36 revenue to TR holders for every dollar they invested). As can be seen in Appendix Figure 3-17, the high Cumulative Return is the result of three episodes of high Returns: 2003, 2005 and 2007-09.

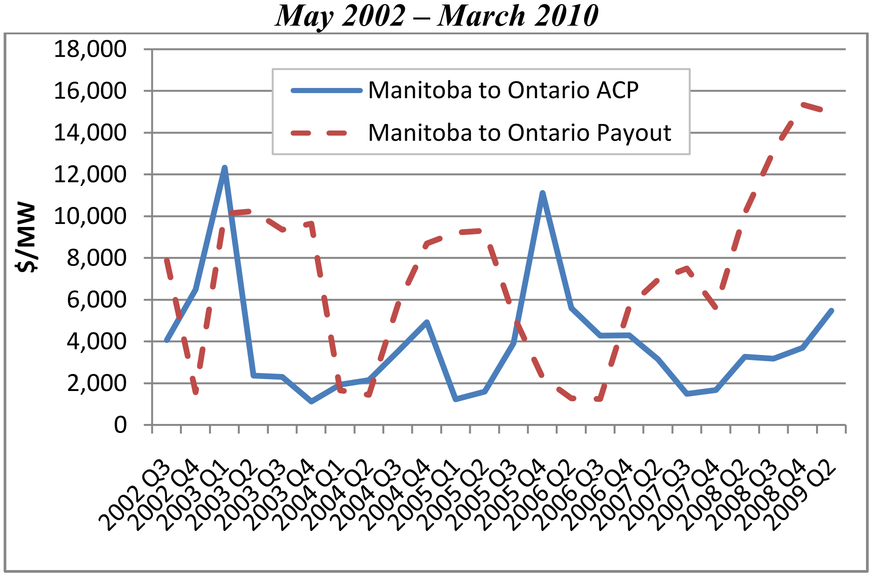
Appendix Figure 3-14: ACP and Payout for Short-Term TRs
Manitoba to Ontario
May 2002 – March 2010



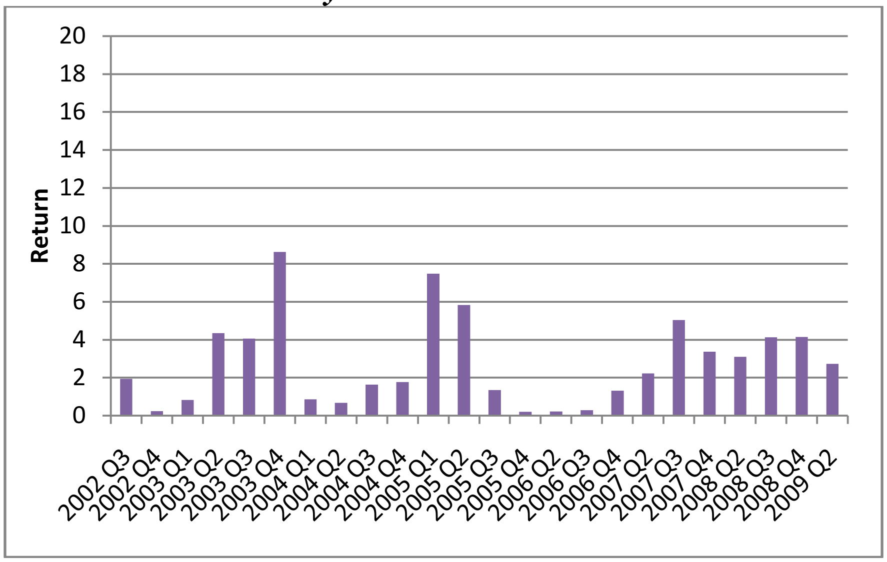
Appendix Figure 3-15: Return on Short-Term TRs
Manitoba to Ontario
May 2002 – March 2010



Appendix Figure 3-16: ACP and Payout, Long-Term TRs
Manitoba to Ontario
May 2002 – March 2010



Appendix Figure 3-17: Return on Long-Term TRs Manitoba to Ontario May 2002 – March 2010



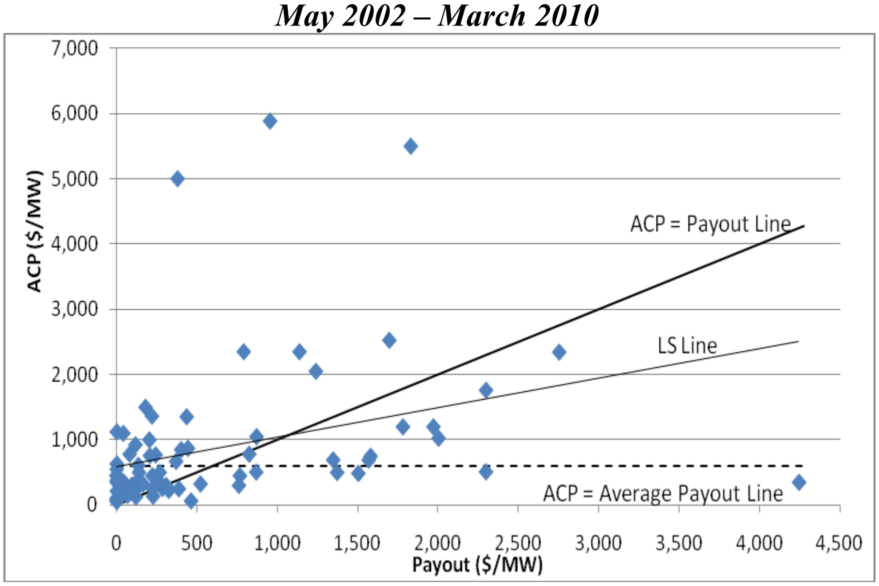
The relationship between the prices paid for short-term TRs and the subsequent payout on them is shown in Appendix Figure 3-18. The relationship between the prices paid for long-term TRs and the subsequent payout on them is shown in Appendix Figure 3-19. The ACP is on the vertical axis and the payout per TR is on the horizontal axis of these figures. The scatter of points in the figures represents the ACP and payout resulting from each TR auction.

In the case of short-term TRs on this path (Appendix Figure 3-18), the LS line lies above the ACP = Average Payout line implying that, on average, the ACP has tended to exceed the average payout. The LS line has a positive slope that is less than one. This implies that the ACPs are somewhat higher for TRs that turn out to have higher payouts but not on a dollar for dollar basis. The slope of the LS line is pulled down by two extreme observations with relatively high payouts and relatively low ACPs implying very high Returns to TR holders. The market for short-term TRs on this path differs from most other paths (although it is similar to some of the Quebec paths) in that, on balance, bidders have ended up with a Cumulative Return that is less than one, i.e. TR holders have lost money in the TR market. .

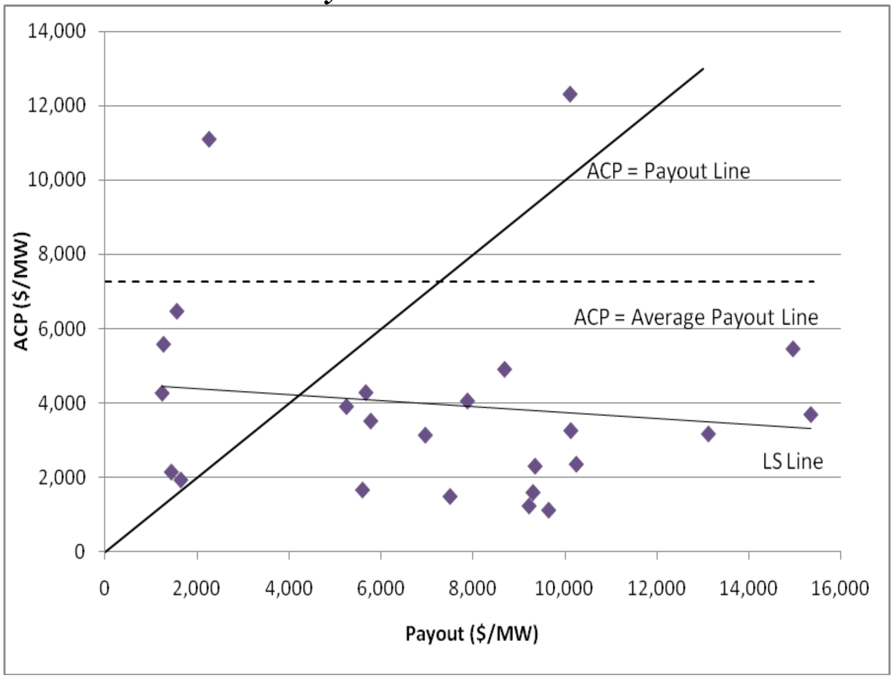
The estimates of the slope and intercept of the LS line are very sensitive to extreme observations such as the TR that sold for $350/MW and paid $4,246.19/MW in September, 2007. Given the broad scatter of the ACP-Payoff observations around the LS line, the extreme observations and the number of observations massed at the zero payout point, neither the slope nor the intercept of the LS line can be said to have been estimated with any degree of accuracy.

The relationship between the ACPs and the payouts for long-term TRs is another matter entirely. The LS line in Appendix Figure 3-19 has a slightly negative slope indicating that, if anything, bidders end up paying slightly less for TRs with higher payouts. Given the imprecision of the slope estimate, the LS line can be treated as being horizontal implying that the ACP provides no information about differences in payouts from auction to auction. The position of the LS line as well as most of the scatter of observations below the ACP = Average Payout line reflects the Cumulative Return of 1.83.

Appendix Figure 3-18: ACP and Payout on Short-Term TRs
Manitoba to Ontario
May 2002 – March 2010



Appendix Figure 3-19: ACP and Payout on Long-Term TRs
Manitoba to Ontario
May 2002 – March 2010



3.2.2 Exports to Manitoba

There have been 58 short-term and 19 long-term auctions on exports to Manitoba path in the study period. The number of bidders since market opening has averaged 2.5 in the short-term auction and 2.3 in the long-term auction. The average number of bidders in the short-term auctions increased to three in 2009.

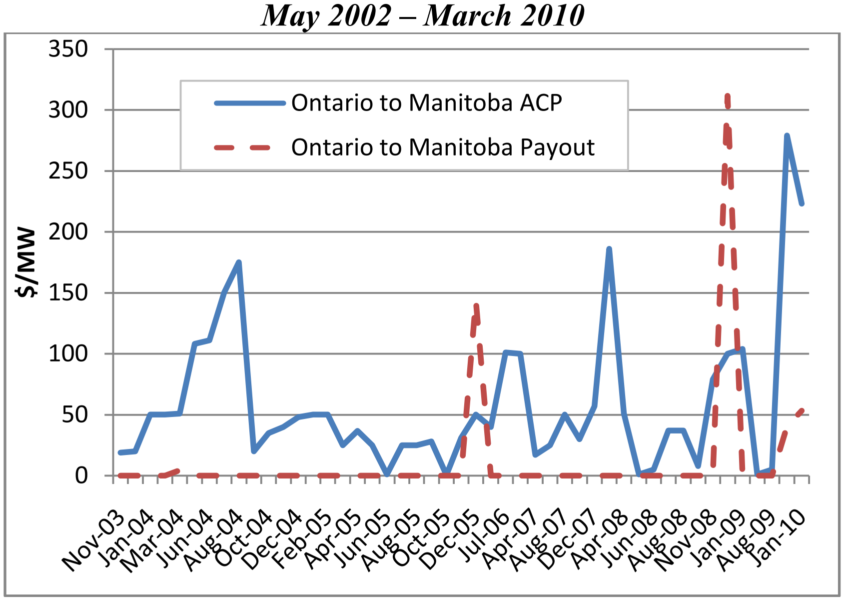
The time pattern of the ACP and payout on short-term TRs on this path is shown in Appendix Figure 3-20. The Return on short-term TRs is shown in Appendix Figure 3-21.

The Cumulative Return on short-term TRs since market opening is 0.19 (or $0.19 received by TR holders for every dollar they invested). The Cumulative Return on short-term TRs was 0.39 in 2008-09 and 0.10 in 2009. There have been only two instances (December 2005 and December 2008) in which the payout materially exceeded the ACP. Despite the negative average Returns, all of the short-term TRs offered on this path since market opening have been taken.

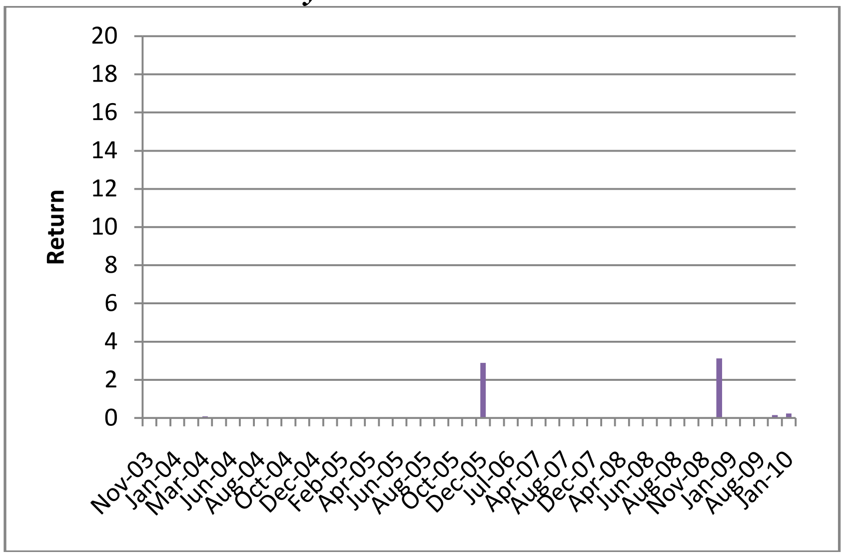
The time pattern of the ACP and payout on long-term TRs on this path is shown in Appendix Figure 3-22. The Return on long-term TRs is shown in Appendix Figure 3-23.

The Cumulative Return on long-term TRs since market opening is 0.36. The Cumulative Return on long-term TRs auctioned between Q1 2007 and Q1 2009 was 0.09. There have been only two quarters in which the payout materially exceeded the ACP (payout periods beginning Q2 2006 and Q3 2006 respectively). Despite the negative average Returns, all long-term TRs offered on this path have been taken.

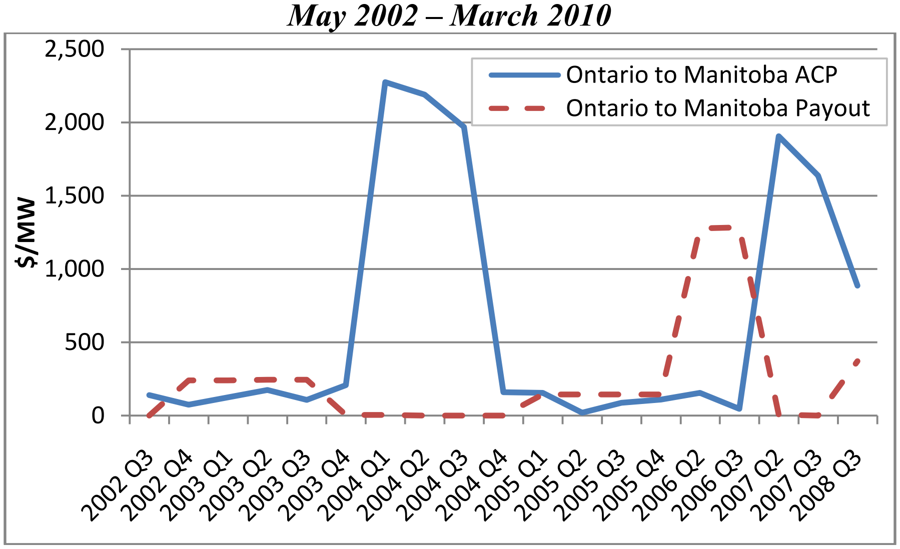
Appendix Figure 3-20: ACP and Payout on Short-Term TRs
Ontario to Manitoba
May 2002 – March 2010



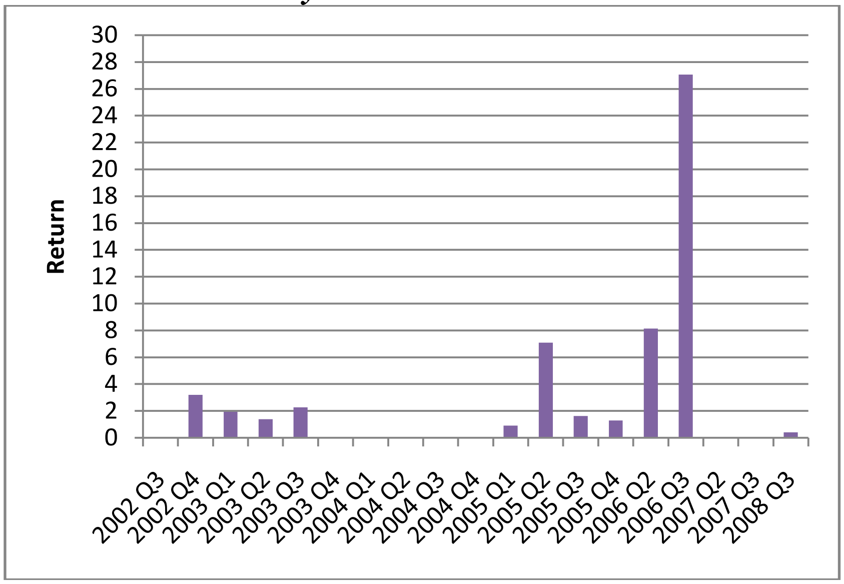
Appendix Figure 3-21: Return on Short-term TRs
Ontario to Manitoba
May 2002 – March 2010



Appendix Figure 3-22: ACP and Payout on Long-Term TRs
Ontario to Manitoba
May 2002 – March 2010



Appendix Figure 3-23: Return on Long-Term TRs
Ontario to Manitoba
May 2002 – March 2010

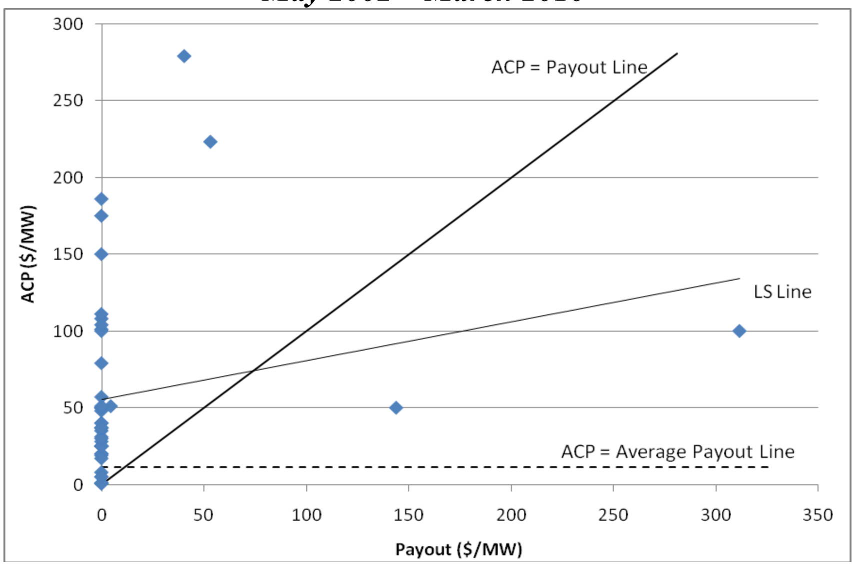


The relationship between the prices paid for short-term TRs and the subsequent payout on them is shown in Appendix Figure 3-24. The relationship between the prices paid for long-term TRs and the subsequent payout on them is shown in Appendix Figure 3-25.

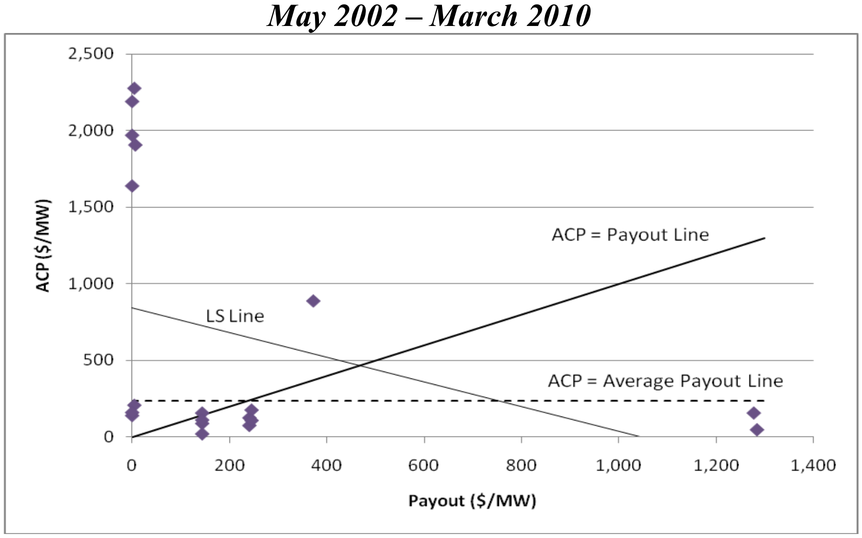
In the case of the short-term TRs (Appendix Figure 3-24), most of the observations lie above both the ACP = Payout line and the ACP = Average Payout line and the LS line does so as well. This is consistent with the Cumulative Return on short-term TRs being less than one. The LS line has a positive intercept and a positive slope that is less than one, indicating that bidders pay more for TRs with higher payouts but not dollar for dollar. This slope estimate is the result of only a few observations, however, as most data points are massed on the vertical axis (positive ACP, zero payout).

In the case of the long-term TRs (Appendix Figure 3-25), the LS line has a positive intercept and a negative slope. This is a result of some high ACPs for TRs on which there was no payout (in 2004 and 2007, see Appendix Figure 3-21) and two TRs (Q2 2006 and Q3 2006) that yielded high Returns but sold for relatively low ACPs. This combination of high ACPs with no payout and high Returns but modest payouts also resulted in Cumulative Return since market opening that is less than one.

Appendix Figure 3-24: ACP and Payout on Short-Term TRs Ontario to Manitoba May 2002 – March 2010



Appendix Figure 3-25: ACP and Payout on Long-Term TRs Ontario to Manitoba May 2002 – March 2010



3.3 Michigan

3.3.1 Imports from Michigan

There is one import path from Michigan to Ontario. There have been 80 short-term and 24 long-term auctions on this path in the study period. The number of bidders since market opening has averaged close to 4 in both the short-term and long-term auctions. The number of bidders in auctions for short-term TRs with payout periods in 2009 increased to an average of 4.8. The number of bidders in long-term auctions averaged 6.2 in auctions held between Q1 2007 and Q1 2009.

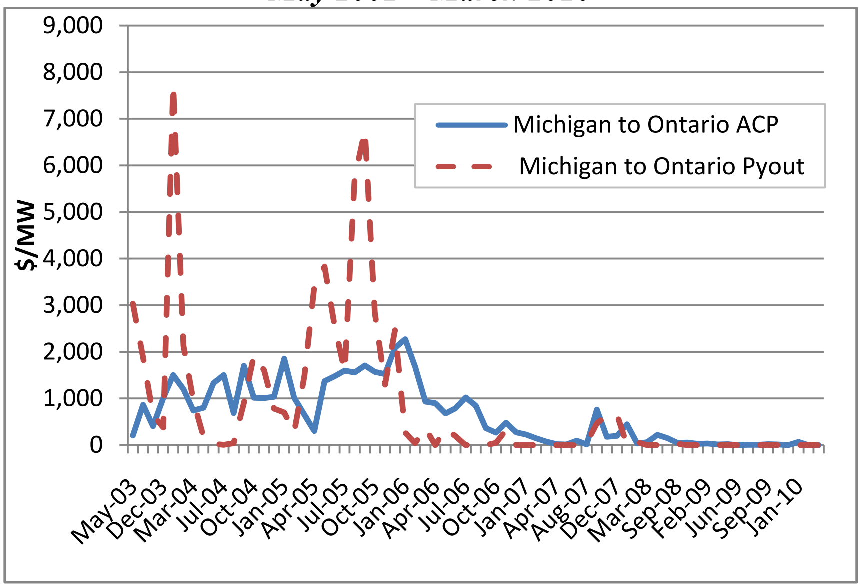
The time pattern of the ACP and payout on short-term TRs on this path is shown in Appendix Figure 3-26. The Return on short-term TRs is shown in Appendix Figure 3-27.

The Cumulative Return on short-term TRs since market opening is 1.76, but this is driven by some extremely high Returns in 2002, 2003 and 2005. As is shown on Appendix Figure 3-27, short-term TR holders on this path have earned much lower Returns since the end of 2005. The Cumulative Return on short-term TRs was 0.08 (or $0.08 received by TR holders for every dollar they have invested) in 2008-09 and zero in 2009. A consequence of these negative Returns was that about 20% of the short-term TRs offered in 2008-09 were not taken.

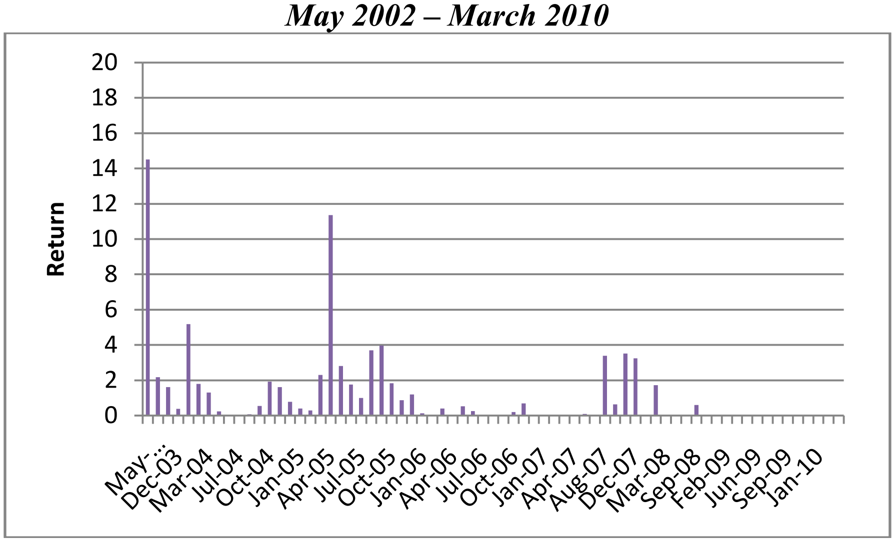
The time pattern of the ACP and payout on long-term TRs on this path is shown in Appendix Figure 3-28. The Return on long-term TRs is shown in Appendix Figure 3-29.

The Cumulative Return on long-term TRs is 1.47. This is driven in part by exceedingly high Returns in 2002 (over $20 per dollar invested) as well as generally high Returns between 2002 and 2005. Since then, Returns have been lower, frequently less than one. This is shown on Appendix Figure 3-29. The Cumulative Return on long-term TRs auctioned between Q1 2007 and Q1 2009 was 0.76.).

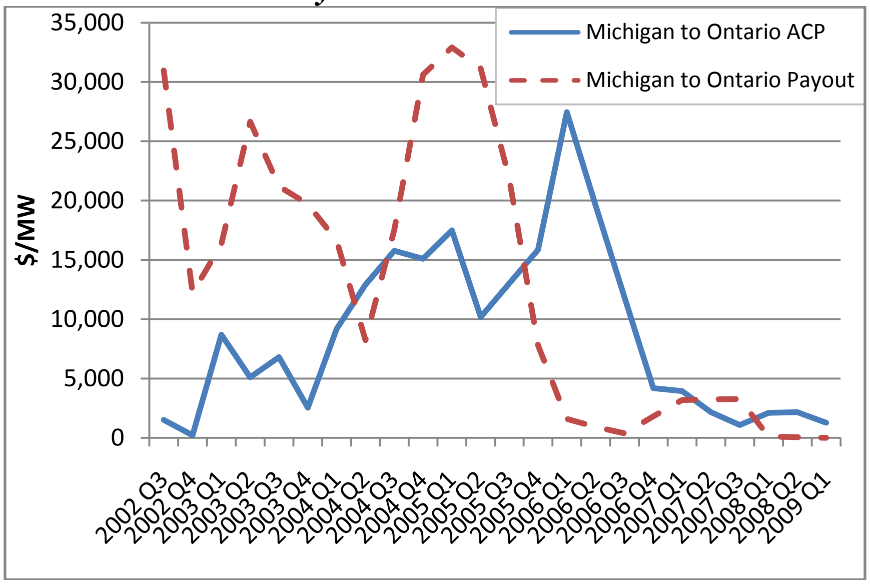
Appendix Figure 3-26: ACP and Payout on Short-Term TRs
Michigan to Ontario
May 2002 – March 2010



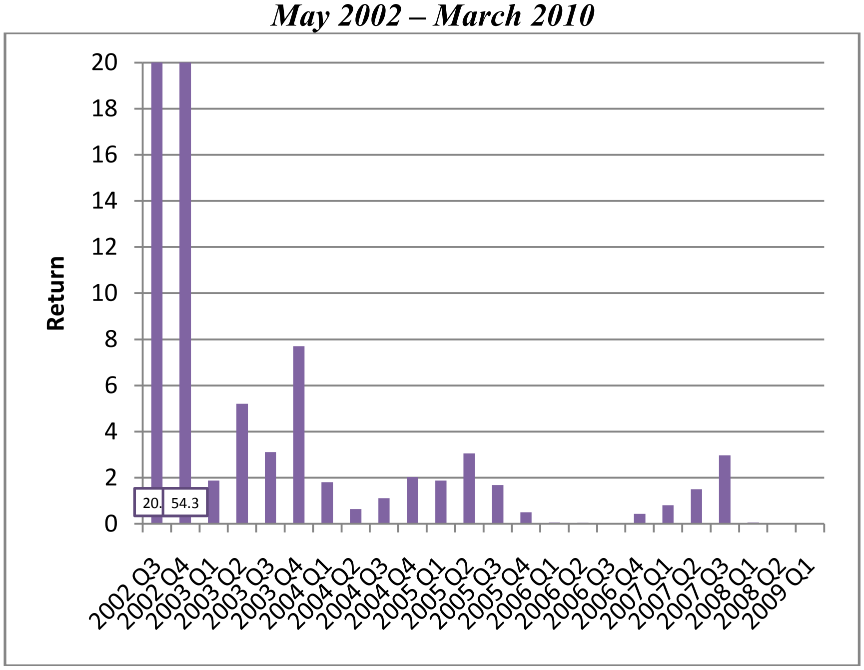
Appendix Figure 3-27: Return on Short-Term TRs
Michigan to Ontario
May 2002 – March 2010



Appendix Figure 3-28: ACP and Payout on Long-Term TRs
Michigan to Ontario
May 2002 – March 2010



Appendix Figure 3-29: Return on Long-Term TRs
Michigan to Ontario
May 2002 – March 2010



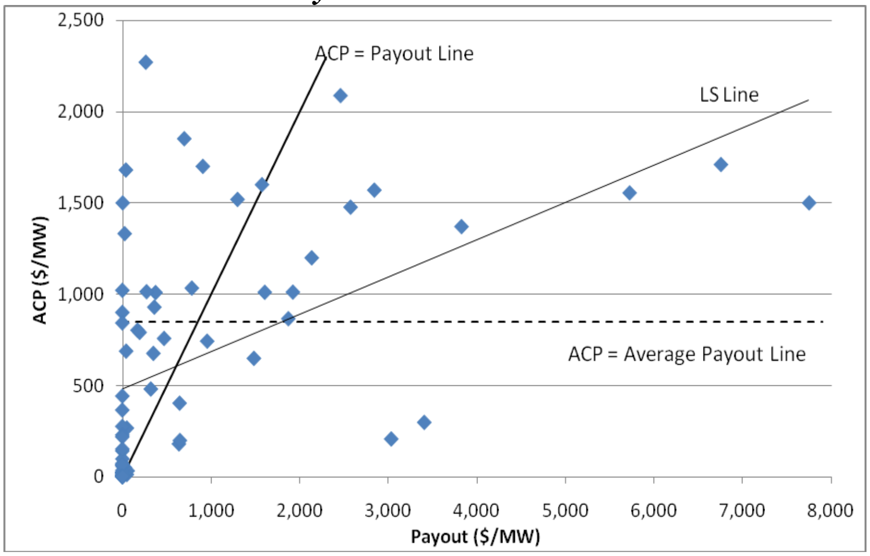
The relationship between the prices paid for short-term TRs and the subsequent payout on them is shown in Appendix Figure 3-30. The relationship between the prices paid for long-term TRs and the subsequent payout on them is shown in Appendix Figure 3-31.

In the case of short-term TRs, the LS line has a positive intercept and a positive slope that is less than one. The positive intercept reflects the instances in which TRs have sold for positive ACPs but have yielded zero payouts. The positive slope implies that bidders tend on average to pay more for TRs that turn out to have higher payouts although not on a dollar for dollar basis. Examination of the scatter of ACP-payout observations in Appendix Figure 3-30 reveals that there are many observations above the ACP = Payout line, that is, there are many instances in which bidders ended up paying more for TRs than the payout they received on them. Nevertheless, for the most part the least squares (LS) line through the scatter lies below the ACP = Payout line. This reflects the influence of a few instances of extremely high payout on the right hand side of the figure.

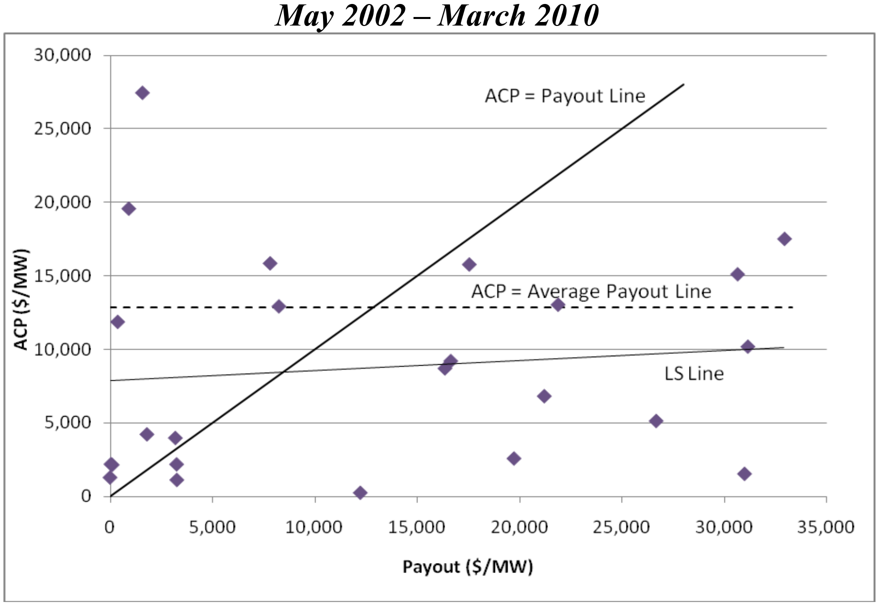
The estimate of the slope of the LS line in Appendix Figure 3-30 is sensitive to extreme observations such as the TR that sold for $1,500/MW and paid $7,749/MW in January, 2004. Given the broad scatter of the ACP-Payoff observations around the LS line, the considerable number of observations massed on the vertical axis (zero payout) and the extreme observations, the slope of the LS line cannot be said to have been estimated with any degree of accuracy.

In the case of long-term TRs, the LS line has a positive intercept and a slight positive slope. Given the broad scatter of the data points, this indicates little, if any, relationship between ACPs for TRs and the subsequent payouts on them. The LS line lies uniformly below the ACP = Average payout line. This tells us that while there are instances in which the ACP exceeded the average payout since market opening, on average it did not. This is consistent with the Cumulative Return of 1.47 on this path.

Appendix Figure 3-30: ACP and Payout on Short-Term TRs
Michigan to Ontario
May 2002 – March 2010



Appendix Figure 3-31: ACP and Payout on Long-Term TRs
Michigan to Ontario
May 2002 – March 2010



3.3.2 Exports to Michigan

There have been 82 short-term and 22 long-term auctions on this export path in the study period. The number of bidders since market opening has averaged 3.8 in the short-term and 3.5 in the long-term auctions. The number of bidders in the short-term auctions has increased in recent years, averaging 6.5 in auctions with 2009 payout periods.

The time pattern of the ACP and payout on short-term TRs on this path is shown in Appendix Figure 3-32. The Return on short-term TRs is shown in Appendix Figure 3-33.

The Cumulative Return on short-term TRs is 1.04 (or $1.04 payout per dollar purchase) but the Return has been much higher recently. The Cumulative Return on short-term TRs was 1.08 in 2008-9 and 1.57 in 2009. This is largely a consequence of a payout of $4,293/MW in March, 2009 on TRs that sold for $295/MW. Appendix Figure 3-33 shows that there have been a number of instances of very high Returns on this path. The reason is that while the Returns were high, in many instances the ACPs and payouts involved were not very large (see Appendix Figure 3-32) so the high Return carries relatively little weight in the Cumulative Return. For example, the March 2004 TR paid out $58.33/MW but sold for $0.01/MW yielding a Return of 5,833.

Almost 9% of short-term TRs offered on this path have not been taken. In 2009, 25% of the short-term TRs offered were not taken. These TRs would have paid out almost $2.2 million.

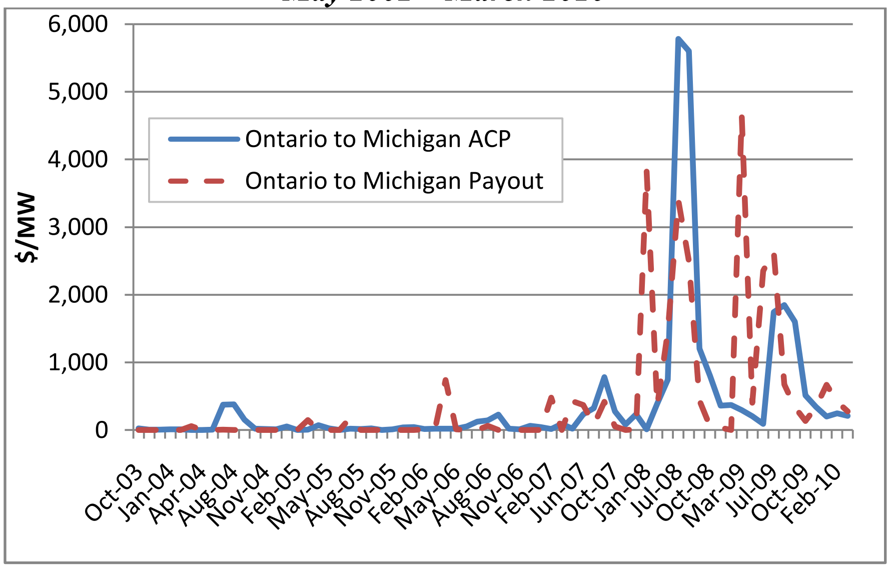
The time pattern of the ACP and payout on long-term TRs on this path is shown in Appendix Figure 3-34. The Return on short-term TRs is shown in Appendix Figure 3-35.

The Cumulative Return on long-term TRs since market opening is 5.02). The Cumulative Return on long-term TRs auctioned between Q1 2007 and Q1 2009 was 6.59. Consistent with these high Returns, all TRs offered in these nine auctions have been taken.

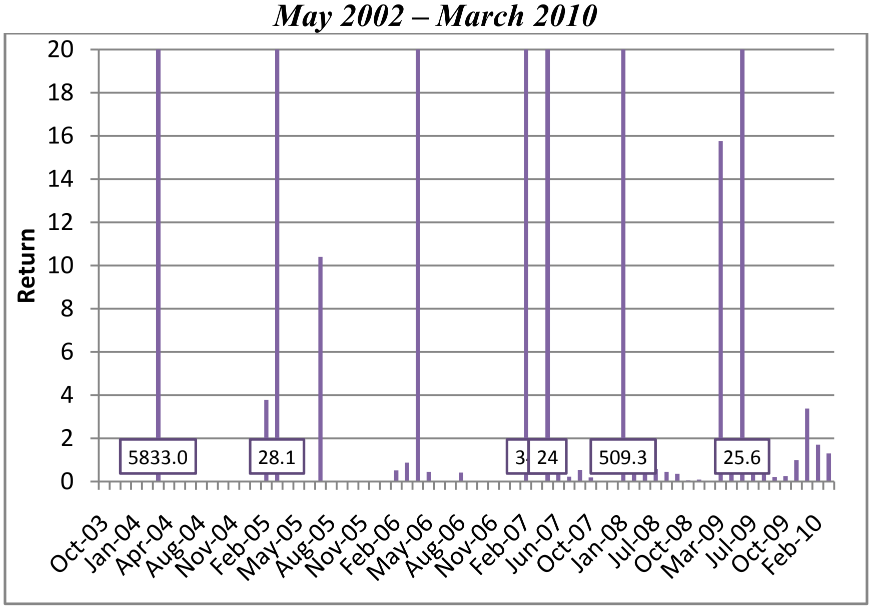
As Appendix Figures 3-34 and 3-35 show, the high Cumulative Return on long-term TRs on this path is a consequence of high payouts in 2007 – 2009 which resulted in high

Returns and also of much lower payouts in 2004 which, nevertheless, resulted in high Returns as well.

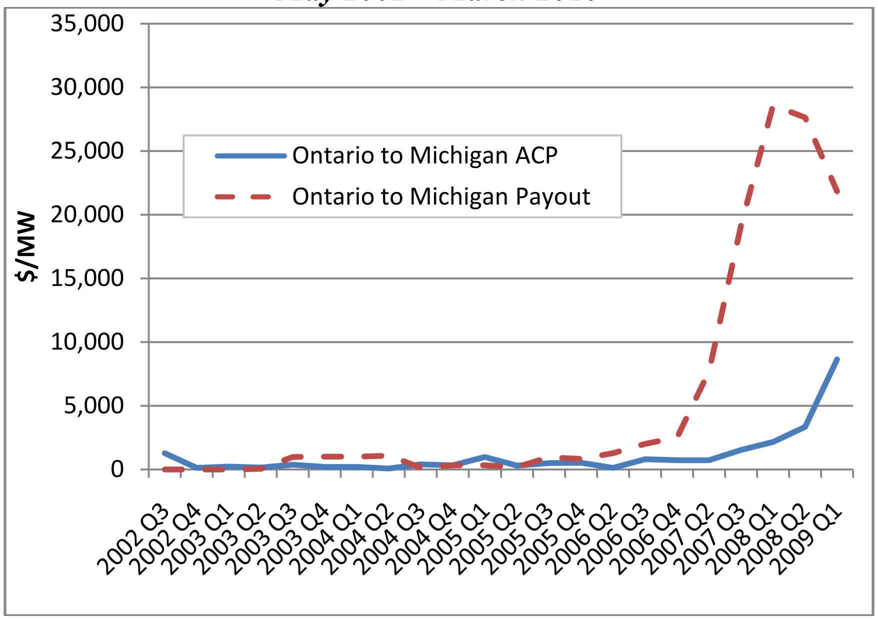
Appendix Figure 3-32: ACP and Payout on Short-Term TRs
Ontario to Michigan
May 2002 – March 2010



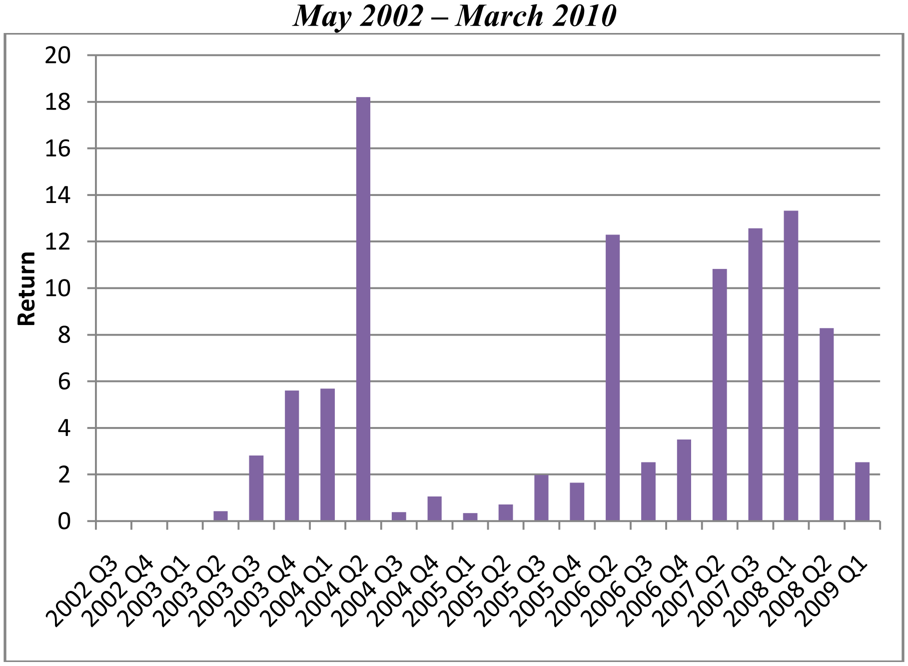
Appendix Figure 3-33: Return on Short-Term TRs
Ontario to Michigan
May 2002 – March 2010



Appendix Figure 3-34: ACP and Payout on Long-Term TRs
Ontario to Michigan
May 2002 – March 2010



Appendix Figure 3-35: Return on Long-Term TRs
Ontario to Michigan
May 2002 – March 2010



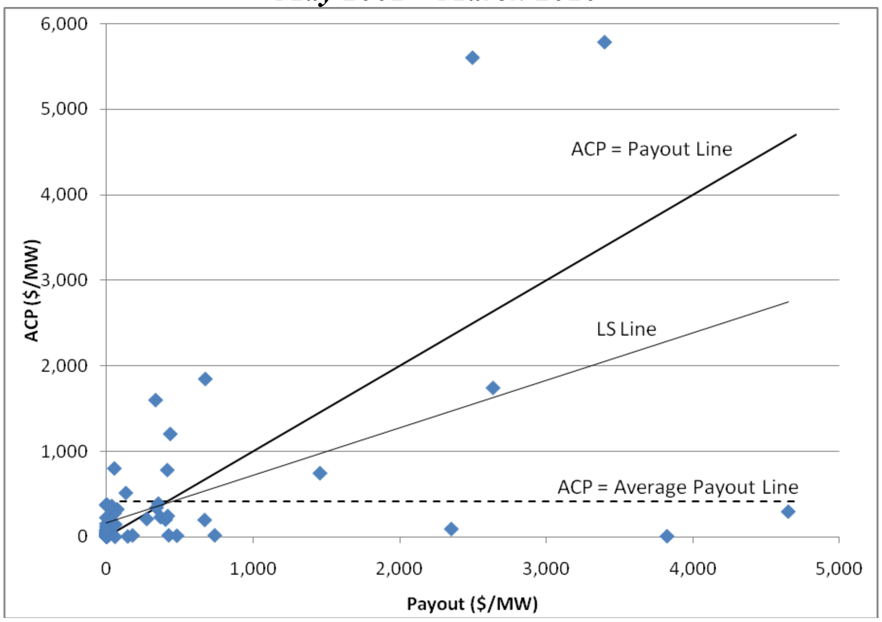
The relationship between the prices paid for short-term TRs and the subsequent payout on them is shown in Appendix Figure 3-36. The relationship between the prices paid for long-term TRs and the subsequent payout on them is shown in Appendix Figure 3-37.

The LS line in Appendix Figure 3-36 has a positive slope that is less than one. The positive slope implies that bidders tend on average to pay more for short-term TRs that turn out to have higher payouts although not on a dollar for dollar basis. While the usual caveat about the accuracy of the estimates of the slope and intercept of the LS line applies, the LS line is “closer” to the ACP = Payout line than is the case on most other paths. This is consistent with the Cumulative Return since market opening being 1.04.

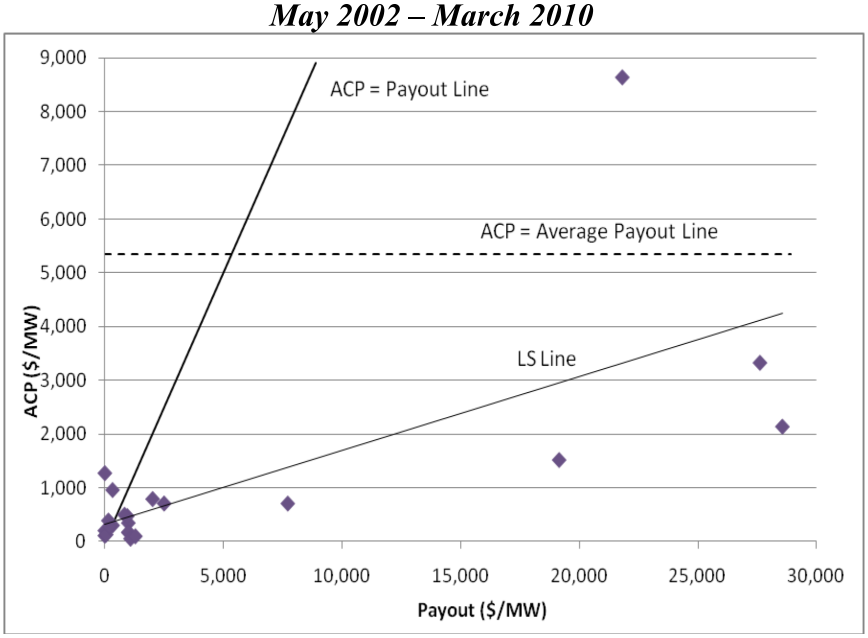
The LS line in Appendix Figure 3-37 has a positive slope that is less than one implying that bidders tend on average to pay more for long-term TRs that turn out to have a higher payout but not on a dollar for dollar basis.[143] Although there may be some rough tendency for auction prices to anticipate higher payouts, the ACP was frequently less, often much less than the TR involved ultimately paid out. Moreover, the scatter is almost entirely below, generally well below the ACP = Average Payout line. This means that the ACP was generally well below that average payout on this path since market opening. This is consistent with the Cumulative Return since market opening of 5.02.

[143] Given the broad scatter of the data points and the number of observations massed near the origin of the figure, the caveat explained in Section 3.1 regarding the precision of the estimated slope of the LS line applies.

Appendix Figure 3-36: ACP and Payout on Short-Term TRs Ontario to Michigan May 2002 – March 2010



Appendix Figure 3-37: ACP and Payout on Long-Term TRs Ontario to Michigan May 2002 – March 2010



3.4 Minnesota

3.4.1 Imports from Minnesota

There have been 31 short-term and 21 long-term auctions on this import path in the study period. The number of bidders since market opening has averaged just over 2 in both the short-term and long-term auctions. This has not changed in recent years.

The time pattern of the ACP and payout on short-term TRs on this path is shown in Appendix Figure 3-38. The Return on short-term TRs is shown in Appendix Figure 3-39.

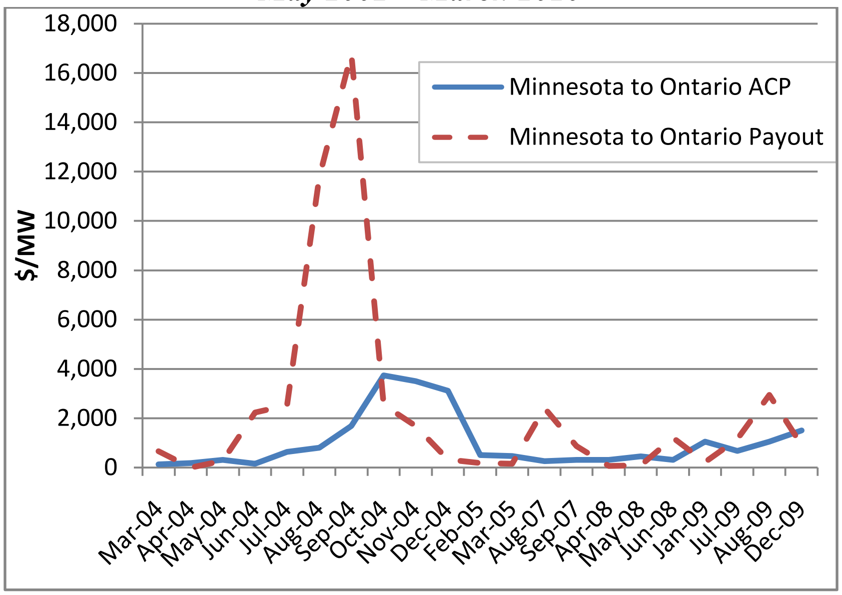
The Cumulative Return on short-term TRs is 2.17 (or $2.17 received for every dollar invested) but this is driven in part by very high payouts and Returns in June and September 2004 (there was a payout of $16,779/MW on a TR that sold for $1,678/MW) and in August 2007. As is shown in Appendix Figure 3-38, more recent years have been characterized by lower payouts and somewhat lower Returns. The Cumulative Return on short-term TRs was 1.24 in 2008-09 and 1.23 in 2009. All of the short-term TRs offered since market opening have been taken.

The time pattern of the ACP and payout on long-term TRs on this path is shown in Appendix Figure 3-40. The Return on long-term TRs is shown in Appendix Figure 3-41.

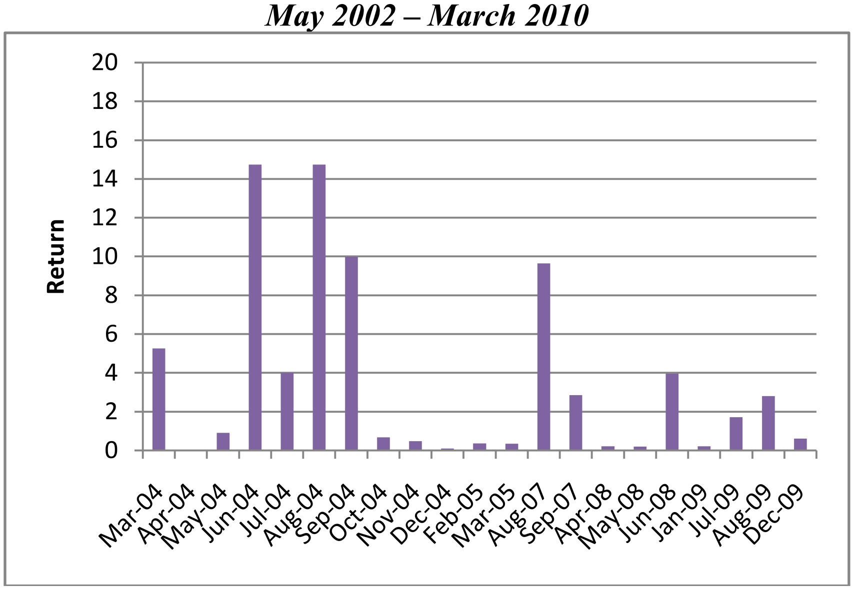
The Cumulative Return on long-term TRs since market opening is 1.88. High payouts and Returns in 2004 and 2005 have been offset in part by lower Returns, occasionally less than one, since then. This is shown on Appendix Figures 3-40 and 3-41. The Cumulative Return on long-term TRs auctioned between Q1 2007 and Q1 2009 was 1.69 received.). All long-term TRs offered since market opening have been taken.

Appendix Figures 3-38 and 3-40 show a possible lagged response of auction prices to past payouts. For example, increases in the ACP of long-term TRs valid beginning Q4 2005 could be viewed as a delayed response to increases in payouts that began with TRs for Q2 2004.

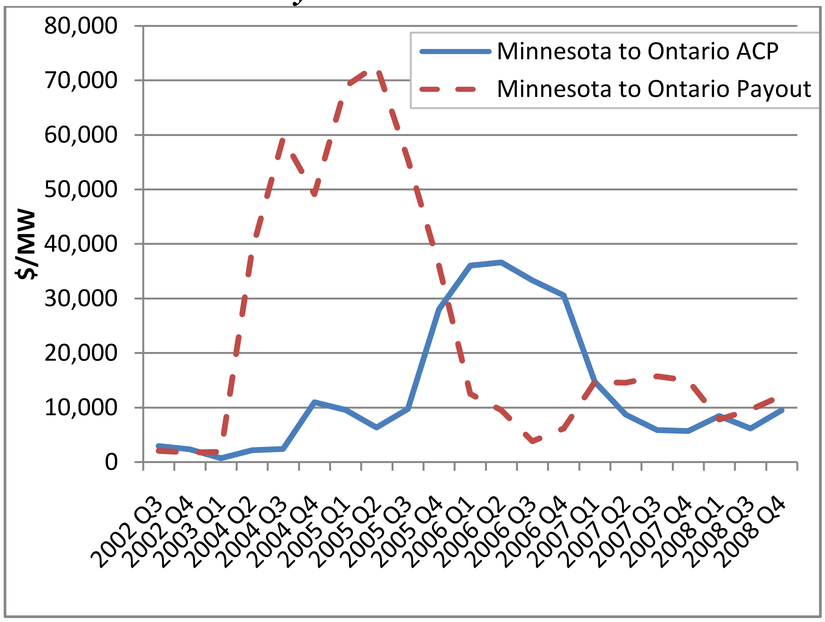
Appendix Figure 3-38: ACP and Payout on Short-Term TRs Minnesota to Ontario May 2002 – March 2010



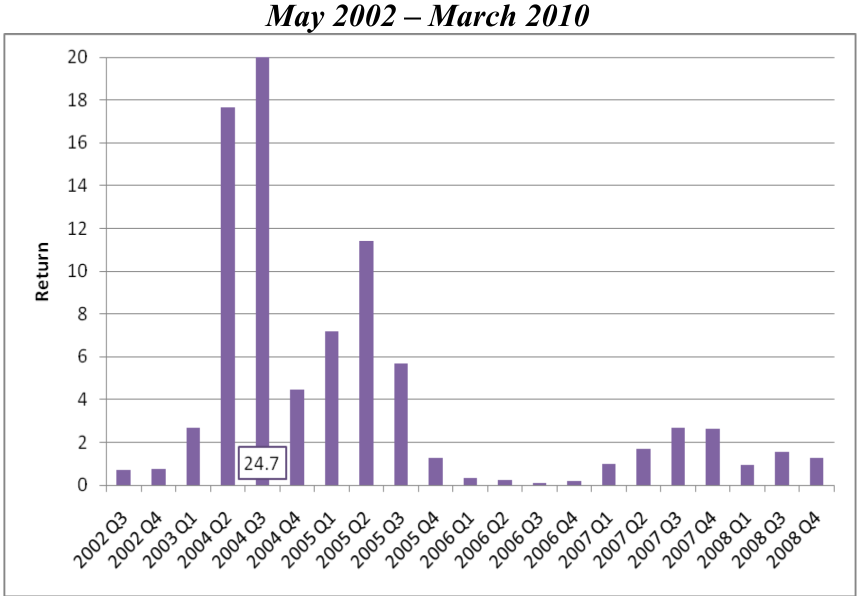
Appendix Figure 3-39: Return on Short-Term TRs Minnesota to Ontario May 2002 – March 2010



Appendix Figure 3-40: ACP and Payout on Long-Term TRs
Minnesota to Ontario
May 2002 – March 2010



Appendix Figure 3-41: Return on Long-Term TRs
Minnesota to Ontario
May 2002 – March 2010



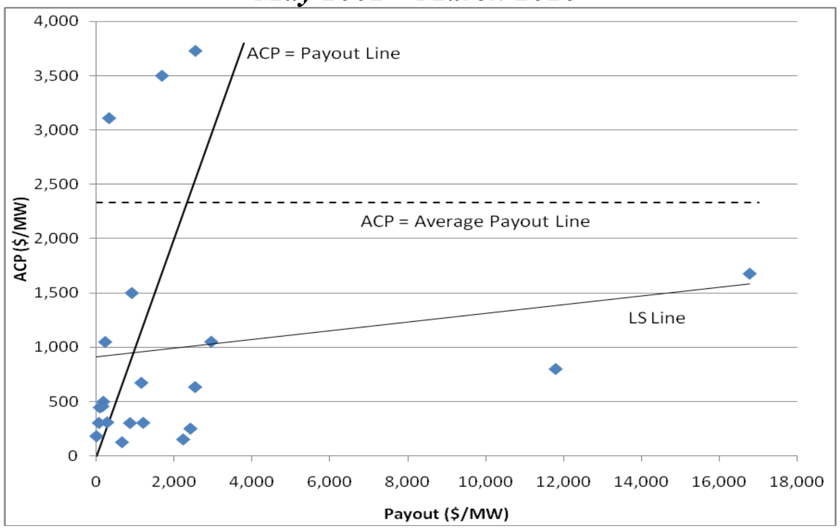
The relationship between the prices paid for TRs and the subsequent payout on them is shown in Appendix Figure 3-42 and 3-43.

In the case of short-term TRs (Appendix Figure 3-42), the LS line has a positive intercept and a slight positive slope. This implies that that bidders are willing to pay slightly higher prices for TRs that turn out to have higher payouts (a $25/MW increase in the payout would result in a $1/MW increase in the ACP) and that they also end up overpaying (after the fact) for TRs that turn out to have a low return.

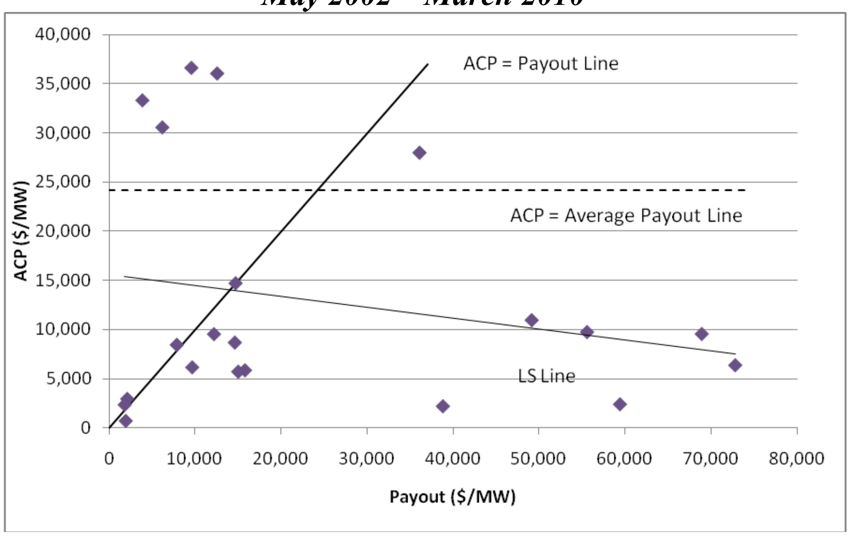
The estimates of the slope and intercept of the LS line are sensitive to extreme observations such as the TR that sold for $1,678/MW and paid $16,779/MW in September 2004 and the TR that sold for $800/MW and paid $11,795/MW in August 2004. Given the number of observations massed near the origin, the number of extreme observations and the wide scatter of observations around the LS line, the usual caveat regarding the precision of the estimates of the slope and the intercept of the LS line applies.

In the case of long-term TRs (Appendix Figure 3-43), the LS line has a positive intercept and a slight negative slope. This is the result of a string of high ACPs with relatively low payouts in 2006 and a series of relatively low ACPs with high payouts in 2004-05. Given the imprecision with the slope of the LS line is estimated, however, it can be treated as being horizontal. That is, the ACP conveys no information about the future payout on the long-term TRs on this path. The position of the LS line below the ACP = Average Payout line is consistent with the Cumulative Return of 1.88 since market opening.

Appendix Figure 3-42: ACP and Payout on Short-Term TRs Minnesota to Ontario May 2002 – March 2010



Appendix Figure 3-43: ACP and Payout on Long-Term TRs Minnesota to Ontario May 2002 – March 2010



3.4.2 Exports to Minnesota

There have been 40 short-term and 21 long-term auctions on this export path in the study period. The number of bidders since market opening has averaged 2.5 in the short-term auctions and 2.3 in the long-term auctions. The average number of bidders in auctions for short-term TRs with payment periods in 2009 was 3.3.

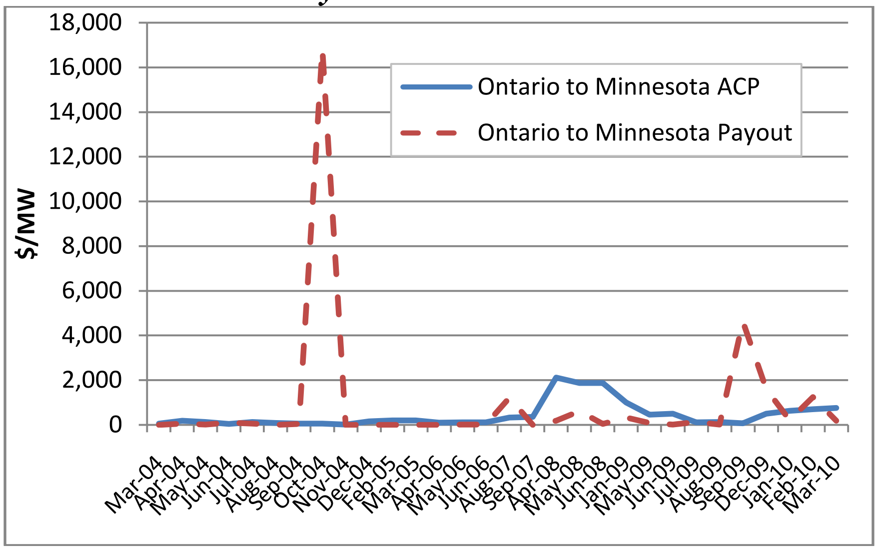
The time pattern of the ACP and payout on short-term TRs on this path is shown in Appendix Figure 3-44. The Return on short-term TRs is shown in Appendix Figure 3-45.

The Cumulative Return on short-term TRs since market opening is 2.07 (or a revenue of $2.07 for every dollar invested). As is evident from Appendix Figures 3-44 and 3-45, this Cumulative Return is driven by two high payout, high Return events. These are: (1) the TR for October 2004 sold for $52/MW and paid $16, 840/MW and; (2) the TR for September 2009 sold for $72/MW and paid $4,620/MW. As is also apparent on Appendix Figures 3-44 and 3-45, short-term TR holders on this path received Returns much lower than this average between 2005 and 2008 with Returns spiking again in 2009. The Cumulative Return on short-term TRs was 0.89 in 2008-09 and 2.47 in 2009. All of the short-term TRs offered since market opening have been taken.

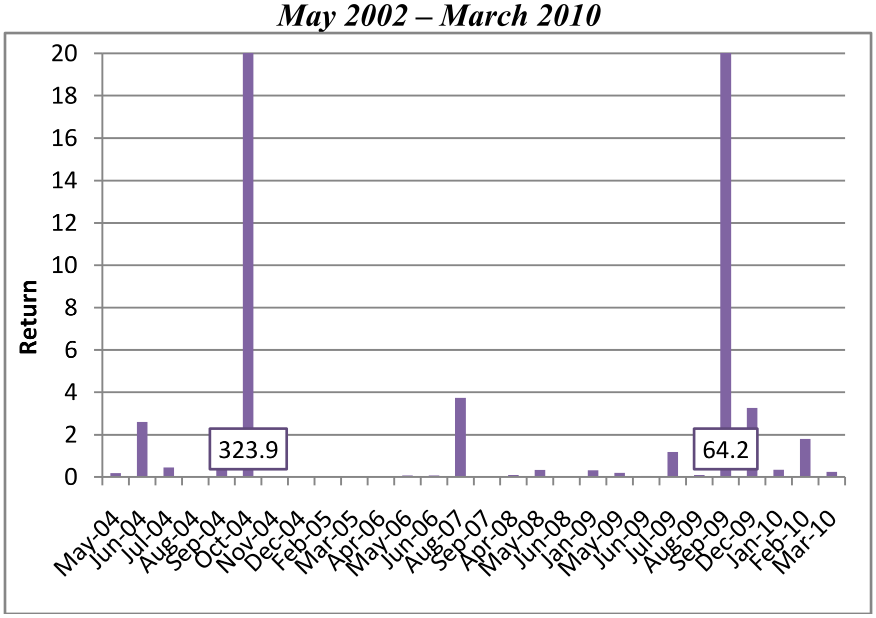
The time pattern of the ACP and payout on long-term TRs on this path is shown in Appendix Figure 3-46. The Return on long-term TRs is shown in Appendix Figure 3-47.

The Cumulative Return on long-term TRs since market opening is 4.77 (i.e. a $4.77 revenue for every dollar invested). The Cumulative Return on long-term TRs auctioned between Q1 2007 and Q1 2009 was 5.64. As is illustrated in Appendix Figures 3-46 and 3-47, events contributing to these high Cumulative Returns include: (1) TRs with a payout period beginning in Q2 2004 sold for $368/MW and yielded a payout of $17,126/MW; (2) TRs for Q3 2004 sold for $1,244/MW and yielded a payout of $17,024/MW; (3) TRs for Q2 2007 sold for $1,048/MW and yielded a payout of $31,647/MW and; (4) TRs for Q1 2008 sold for $3,908/MW and yielded a payout of $35,221/MW. Almost all long-term TRs offered since market opening have been taken.

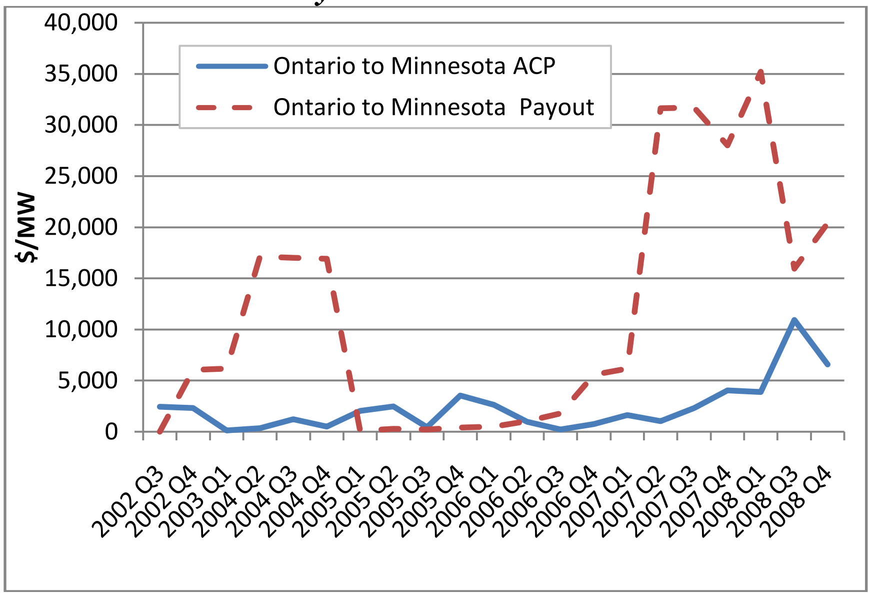
Appendix Figure 3-44: ACP and Payout on Short-Term TRs
Ontario to Minnesota
May 2002 – March 2010



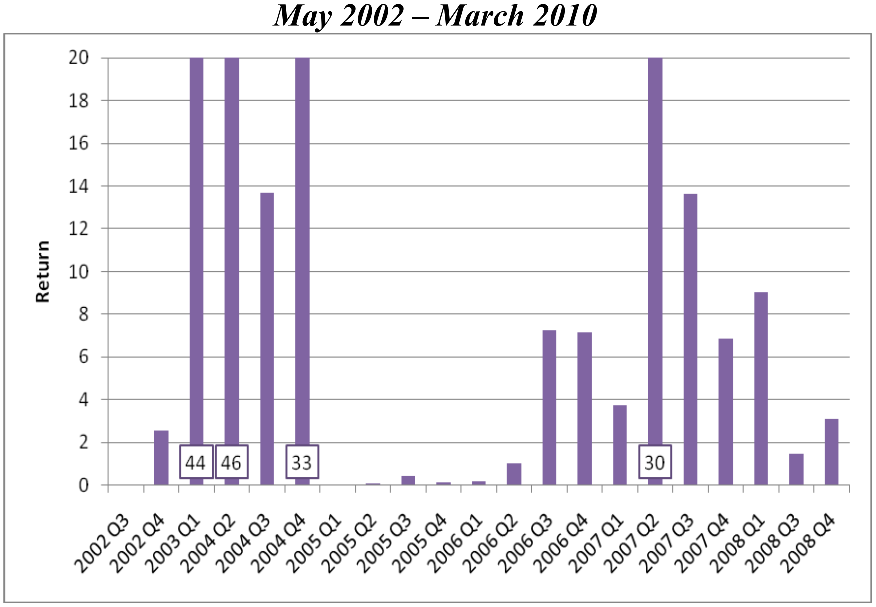
Appendix Figure 3-45: Return on Short-Term TRs
Ontario to Minnesota
May 2002 – March 2010



Appendix Figure 3-46: ACP and Payout on Long-Term TRs
Ontario to Minnesota
May 2002 – March 2010



Appendix Figure 3-47: Return on Long-Term TRs
Ontario to Minnesota
May 2002 – March 2010

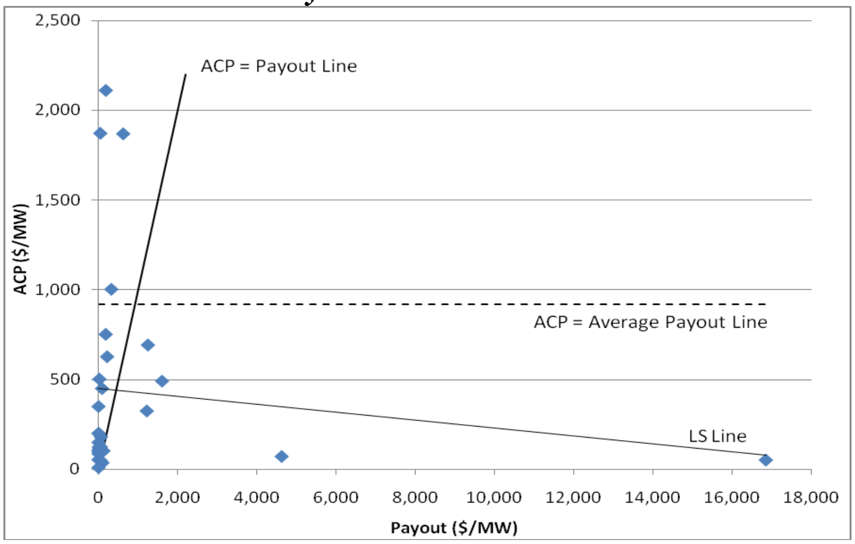


The relationship between the prices paid for short-term TRs and the subsequent payout on them is shown in Appendix Figure 3-48. The relationship between the prices paid for long-term TRs and the subsequent payout on them is shown in Appendix Figure 3-49.

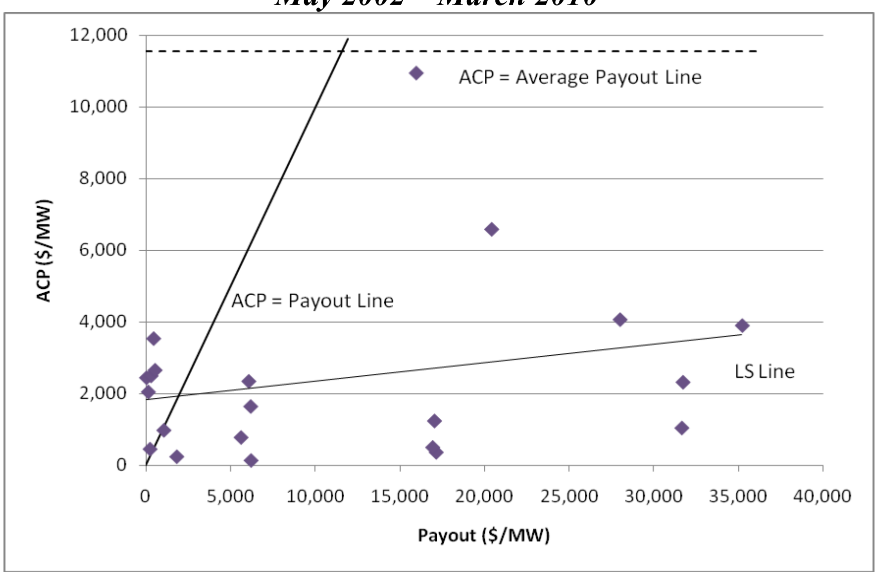
As is evident from Appendix Figure 3-48, the LS line for short-term TRs for this path has a negative slope implying that bidders have paid lower prices for TRs yielding higher payouts. The downward slope of the LS line in this case is the result of the two extreme observations referred to above (October, 2004 and September 2009). While excluding these observations would likely result in an LS line with a positive slope, the characteristics of the scatter of the remaining points, in particular, the number of observations massed at zero payout, are such that any slope estimate would be subject to a large amount of error. In essence, the ACP in short-term auctions on this path provides little or no information about future payouts on the TRs concerned.

Appendix Figure 3-49 shows the LS line for long-term TRs. It has a positive intercept and a positive slope that is much less than the slope of the ACP = Payout line (i.e., much less than one). This implies a slight tendency for the ACPs of TRs yielding higher payouts to be higher (perhaps $1 increase in the ACP for a $16 increase in the payout, with the usual caveat regarding statistical reliability). Looking at the scatter itself reveals that ACPs tended to vary within a relatively narrow range between $200/MW and $4,000/MW for payouts that ranged from zero to $35,000/MW and averaged nearly $12,000/MW. Reasonable inferences to draw from this evidence are, first, that the ACP in the long-term auctions on this path contains little information about the ultimate payout on the TRs involved and second, that the bids of the marginal bidders in these auctions have tended to be a relatively small fraction of the average payout since market opening. This is, of course, just another way of stating that the Cumulative Return on long-term TRs on this path has been very high.

Appendix Figure 3-48: ACP & Payout on Short-Term TRs
Ontario to Minnesota
May 2002 – March 2010



Appendix Figure 3-49: ACP and Payout on Long-Term TRs
Ontario to Minnesota
May 2002 – March 2010



3.5 New York

3.5.1 Imports from New York

There are multiple interties between New York and Ontario but they are treated as one path. There have been 80 short-term and 24 long-term auctions on this import path since market opening. The number of bidders since market opening has averaged 3.3 in both the short-term auctions and long-term auctions.

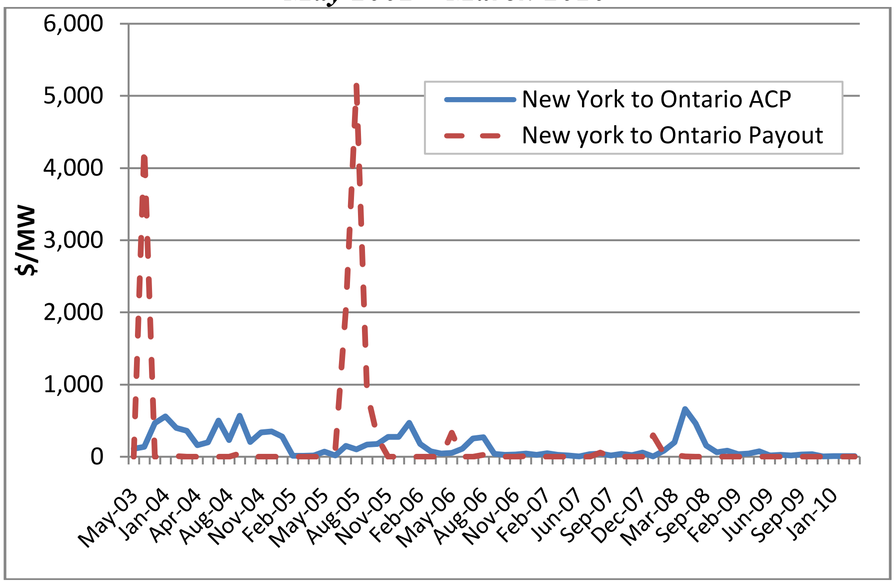
The respective time patterns of the ACP and payout on short-term TRs on this path are shown in Appendix Figure 3-50. The Return on short-term TRs is shown in Appendix Figure 3-51.

The Cumulative Return on short-term TRs since market opening is 4.90 (i.e. a $4.90 revenue for every dollar spent) but this is driven by exceptionally large payouts in September and December 2002. As Appendix Figures 3-50 and 3-51 show, there were also high Returns resulting from large payouts in December 2003 and September 2005 and these would also have contributed to the high Cumulative Return. Holders of short-term TRs on this path have not earned much is the way of Returns since September 2005. The large spike in Return in January 2008 (see Appendix Figure 3-50) was the result of a payout of $298/MW on TRs that sold for $3/MW. The Cumulative Return on short-term TRs was 0.19 in 2008-09 and zero in 2009. A consequence of these loss-making Returns was that 30% of the short-term TRs offered in 2008-09 were not taken.

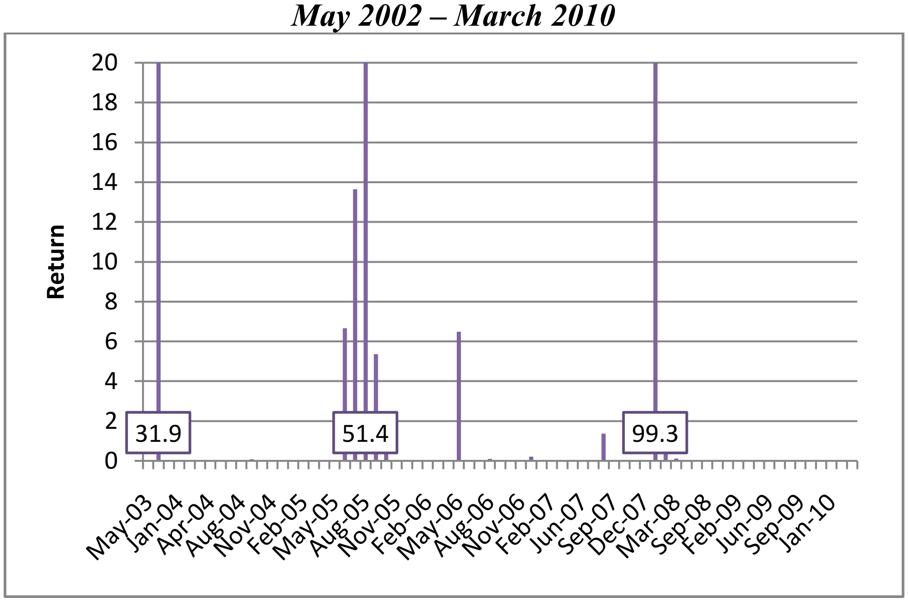
The respective time patterns of the ACP and payout on long-term TRs on this path are shown in Appendix Figure 3-52. The Return on long-term TRs is shown in Appendix Figure 3-53.

The Cumulative Return on long-term TRs since market opening was 1.73. This is again driven by high payouts and Returns in 2002-03 and in the first three quarters of 2005. Since that time, payouts and, with some exceptions, Returns have been much lower (see Appendix Figures 3-52 and 3-53). The Cumulative Return on long-term TRs purchased in the nine auctions between Q1 2007 and Q1 2009 was 1.25. All TRs offered on this path since market opening have been taken.

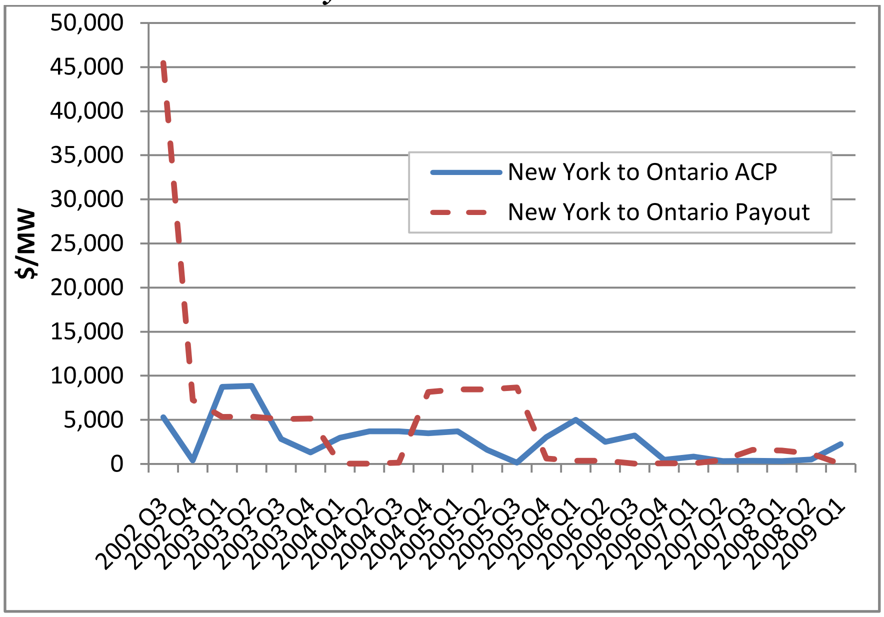
Appendix Figure 3-50: ACP and Payout on Short-Term TRs
New York to Ontario
May 2002 – March 2010



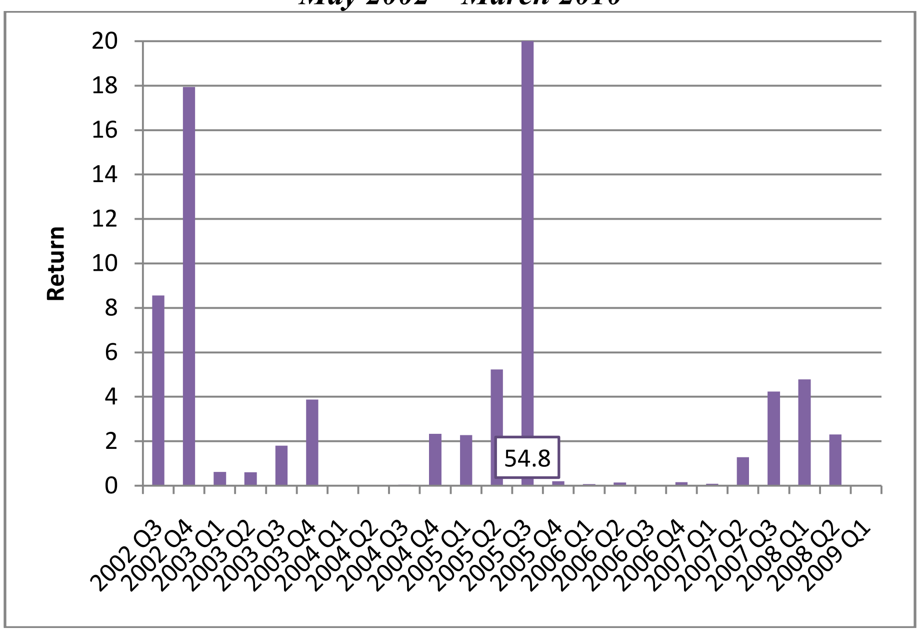
Appendix Figure 3-51: Return on Short-Term TRs
New York to Ontario
May 2002 – March 2010



Appendix Figure 3-52: ACP and Payout on Long-Term TRs
New York to Ontario
May 2002 – March 2010



Appendix Figure 3-53: Return on Long-Term TRs
New York to Ontario
May 2002 – March 2010

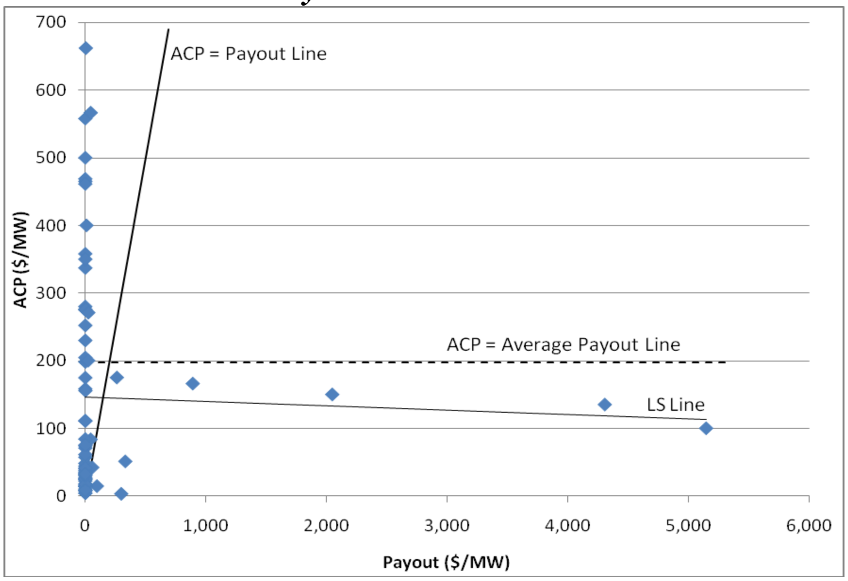


The relationship between the prices paid for short-term and long-term TRs and their payouts is shown in Appendix Figures 3-54 and 3-55 respectively.

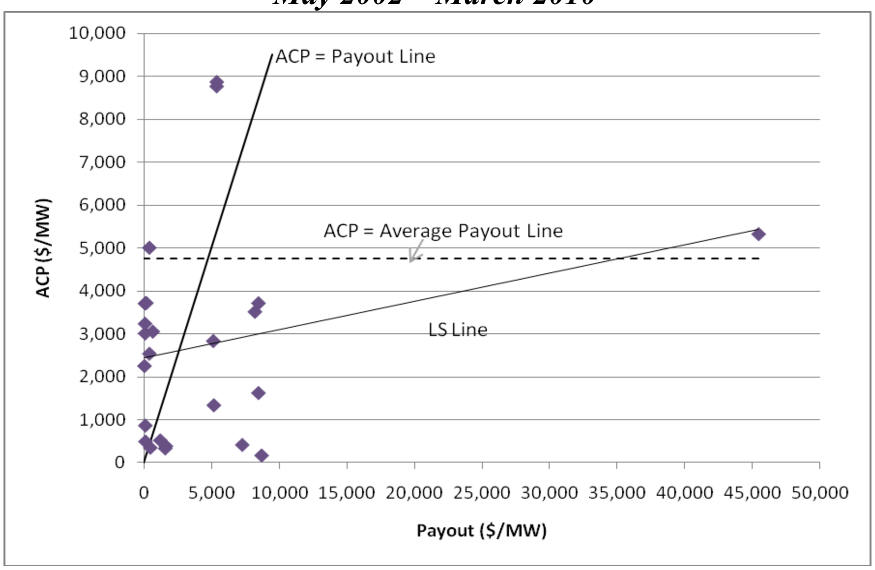
The LS line in Appendix Figure 3-54 has a slight negative slope implying that bidders on this path tended to pay less for TRs with higher future payouts. This is the result of a few extreme observations including: (1) the TR for August 2005 which sold for $100/MW and paid $5,144/MW; (2) the TR for November 2003 which sold for $135/MW and paid $4,304/MW; and (3) the July 2005 TR which sold for $150/MW and paid $2,046/MW. Given the scatter of ACP and Payout observations, the number of observations massed on the vertical (zero payout) axis and the extreme observations, there is essentially nothing to indicate that the ACP of short-term TRs for this path provides any indication of their future payout.

The relationship between prices paid for long-term TRs and their payout is shown in Appendix Figure 3-55. The LS line has a positive intercept and a positive slope implying ACPs are higher for TRs with higher future payouts. But for one extreme observation (TR with a payout of $45,448/MW beginning in Q3 2002, sold for $5,317/MW), the slope of the LS line would likely be greater.

Appendix Figure 3-54: ACP & Payout on Short-Term TRs
New York to Ontario
May 2002 – March 2010



Appendix Figure 3-55: ACP and Payout on Long-Term TRs
New York to Ontario
May 2002 – March 2010



3.5.2 Exports to New York

There are multiple interties between Ontario and New York but they are treated as one path. There have been 80 short-term and 22 long-term auctions on this export path in the study period. The number of bidders has averaged 4.3 in the short-term auctions and 3.5

in the long-term auctions but this has increased in recent years. The average number of bidders in short-term auctions was 5.7 in 2009. The average number of bidders in long-term auctions held between Q1 2007 and Q1 2009 was 4.4.

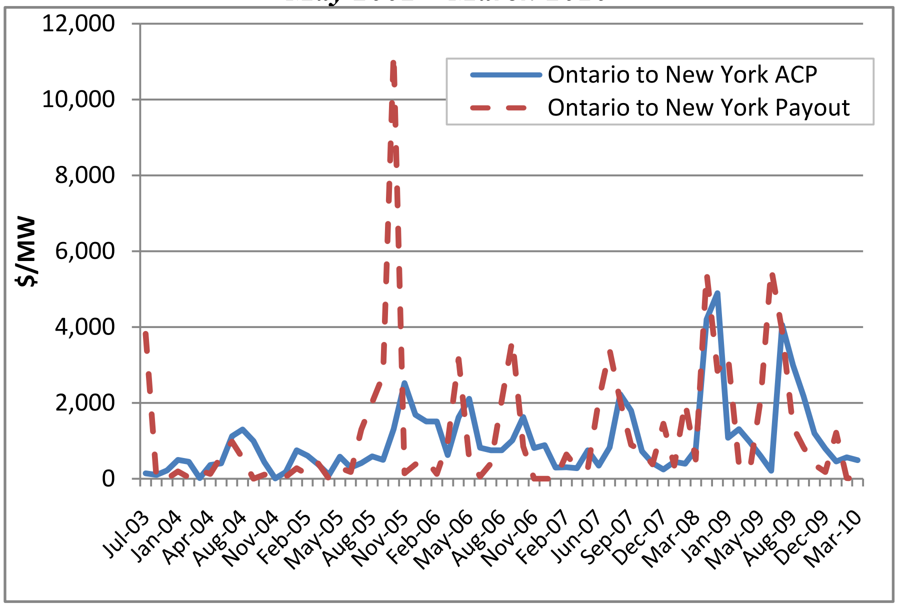
The respective time patterns of the ACP and payout on short-term TRs on this path are shown in Appendix Figure 3-56. The Return on short-term TRs is shown in Appendix Figure 3-57.

The Cumulative Return on short-term TRs since market opening is 1.23 ($1.23 payout per dollar spent). The Cumulative Return on short-term TRs was 1.12 in 2008-09 and 1.18 in 2009. Extreme values pulling up this average include (1) the TR for July 2003 that paid $3,817/MW but sold for $144/MW; (2) the TR for October 2005 that paid $11,212/MW but sold for $1,309/MW; (3) the TR for June 2009 that paid $5,529/MW but sold for only $215/MW. While 2.5% of the short-term TRs offered since market opening have not been taken, all have been taken in recent years.

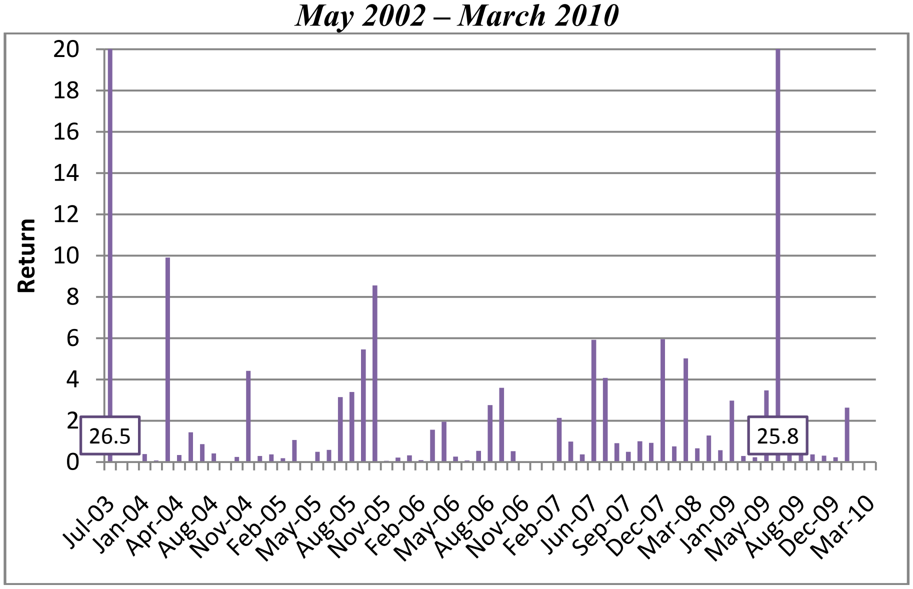
The respective time patterns of the ACP and payout on long-term TRs on this path are shown in Appendix Figure 3-58. The Return on long-term TRs is shown in Appendix Figure 3-59.

The Cumulative Return on long-term TRs since market opening is 2.25 ($2.25 payout per dollar invested). The Cumulative Return on long-term TRs purchased in the nine auctions between Q1 2007 and Q1 2009 was 2.78. As Appendix Figures 3-58 and 3-59 show, a very high Return in Q4 2002 and high payouts and Returns in both the first three quarters of 2005 and the first two quarters of 2008 have contributed significantly to the high Cumulative Returns observed.

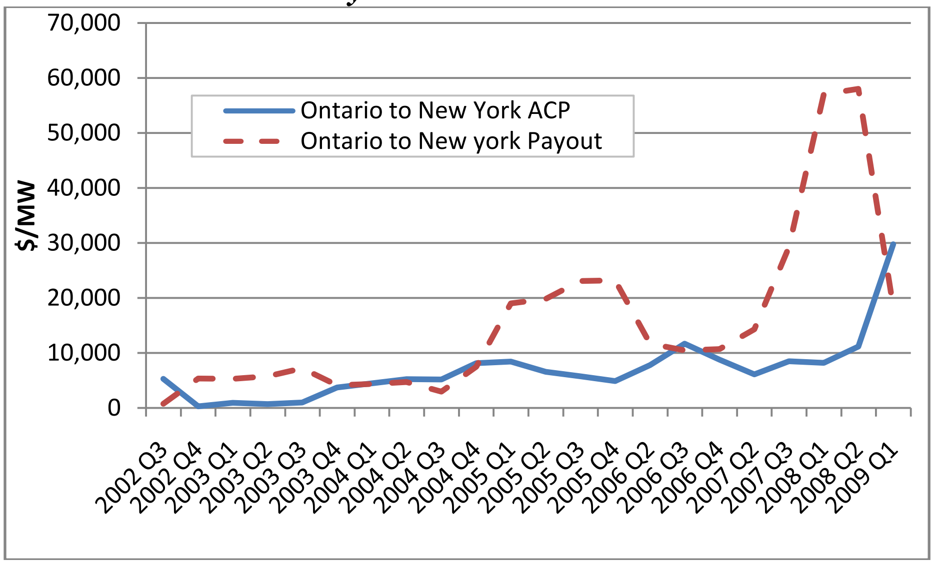
Appendix Figure 3-56: ACP and Payout on Short-Term TRs
Ontario to New York
May 2002 – March 2010



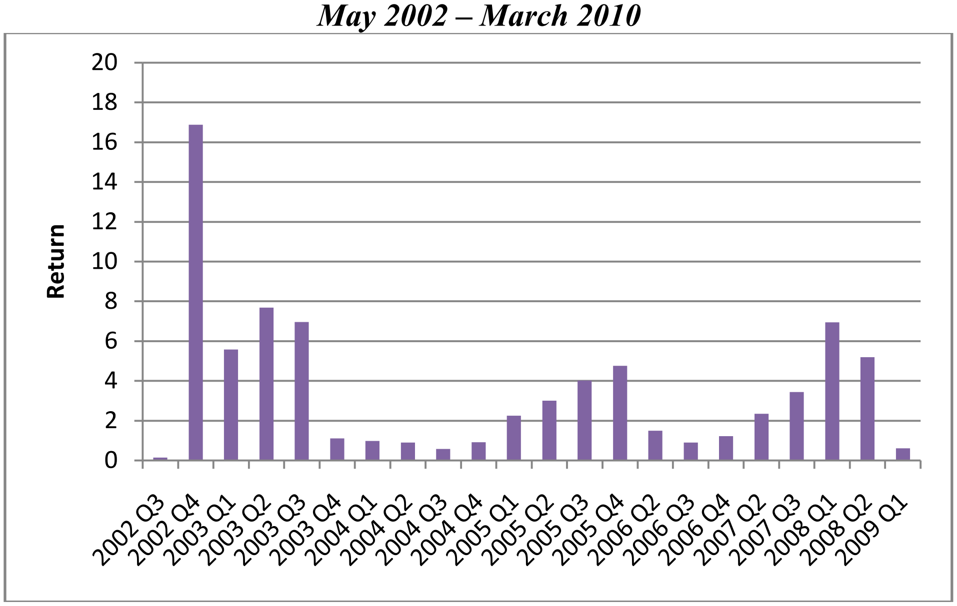
Appendix Figure 3-57: Return on Short-Term TRs
Ontario to New York
May 2002 – March 2010



Appendix Figure 3-58: ACP and Payout on Long-Term TRs Ontario to New York May 2002 – March 2010



Appendix Figure 3-59: Return on Long-Term TRs Ontario to New York May 2002 – March 2010

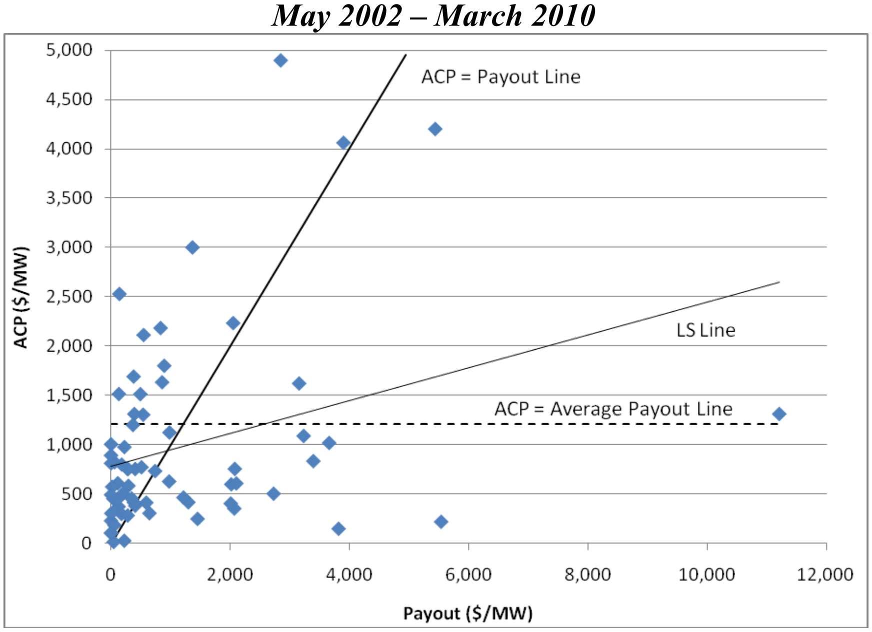


The relationship between the prices paid for short-term TRs and the payout on them is shown in Appendix Figure 3-60. The relationship between the prices paid for long-term TRs and the payout on them is shown in Appendix Figure 3-61.

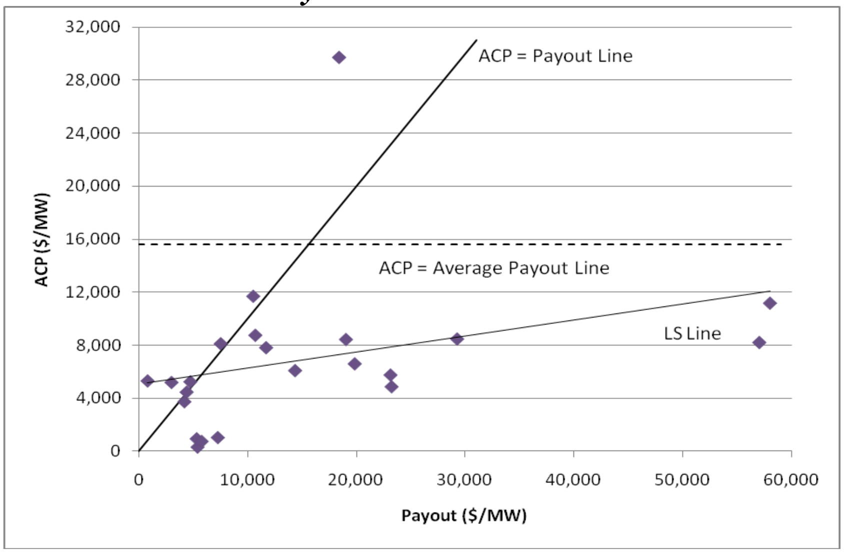
In the case of short-term TRs, the LS line has a positive intercept indicating that bidders have paid positive amounts for TRs when there turns out to be no congestion, and a positive slope implying that bidders on this path tended to pay more for TRs with higher future payouts. Absent the observation for October 2005 (referred to above), the slope of the LS line would have been steeper. Examination of the scatter of observations in Appendix Figure 3-60 reveals that a large number of observations are massed in the area in the lower left hand corner of the figure in which both the ACP and the payout are less than $1,000/MW. This is one reason why the Cumulative Return on this path is closer to one than on most other paths.

Appendix Figure 3-61 shows the information for long-term TRs. The LS line has a positive intercept and a positive slope that is less than one. As a very rough estimate, the slope implies that, on average, bidders paid $0.16 for a dollar of additional payout since market opening. Absent the extreme values for Q1 2008 and Q2 2008 (payouts of $57,000/MW and $58,000/MW for TRs that sold at $8,000/MW and $11,000/MW respectively), the intercept of the LS line would likely be smaller and the slope steeper (closer to one).

Appendix Figure 3-60: ACP and Payout on Short-Term TRs
Ontario to New York
May 2002 – March 2010



Appendix Figure 3-61: ACP and Payout on Long-Term TRs
Ontario to New York
May 2002 – March 2010



3.6 Quebec

There are six import interties and three export interties connecting Ontario's electricity market with Quebec. Each is treated as a separate path for TR's because of most of these interface are radial, i.e. they can either import or export, but not both at the same time. Analysis will be conducted on four of the import paths and two of the export paths. For the other three paths there have been too few auctions to reach any meaningful conclusions.

3.6.1 Imports from Quebec at PQBE

There have been 83 short-term and 28 long-term auctions on this import path located in Cornwell (east Ontario). The number of bidders since market opening has averaged 2.8 in short-term auctions, but has increased to an average of 3.3 in 2009. The number of bidders has averaged 2.6 in long-term auctions and has been relatively stable in recent years, averaging 2.8 for those auctions held between Q1 2007 and Q1 2009.

The respective time patterns of the ACP and payout on short-term TRs on this path are shown in Appendix Figure 3-62. The Return on short-term TRs is shown in Appendix Figure 3-63.

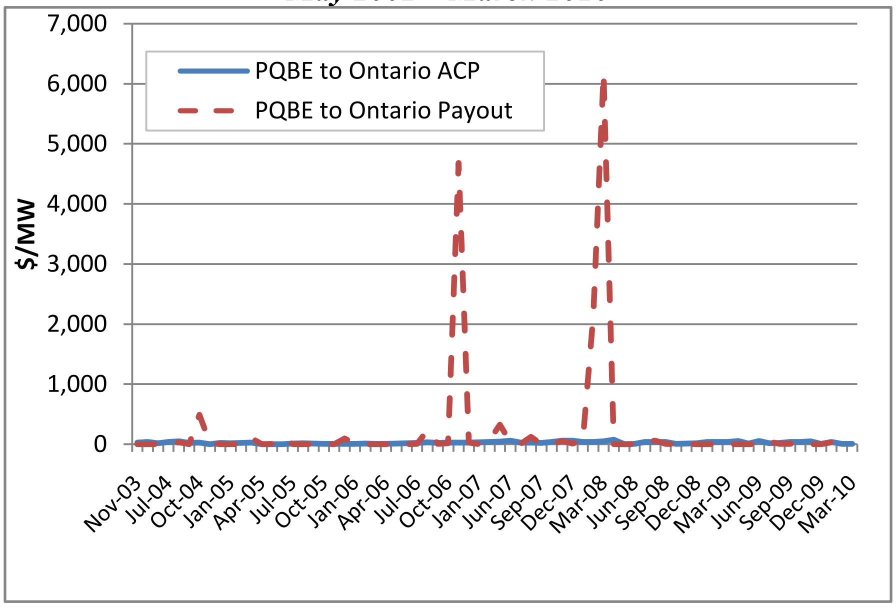
The Cumulative Return on short-term TRs since market opening is 6.35 ($6.35 paid out per dollar spent at auction). The Cumulative Return on short-term TRs was 11.55 and 0.23 for the periods 2008-09 and 2009, respectively. Extreme values pulling up these Cumulative Returns include (1) the TR for November 2006, which paid $4,680/MW but sold for $26/MW; (2) the TR for February 2008, which paid $2,148/MW but sold for $40/MW; and (3) the TR for March 2008, which paid $6,180/MW but sold for $50/MW. The latter two extreme values are largely responsible for the high Cumulative Return over the period 2008-09. These extreme values are evident in Appendix Figures 3-62 and 3-63 below. While 4.5% of short-term TRs offered since market opening have not been taken, all of the approximately $1.44 million of value not taken occurred in February and March, 2008.[144]

The respective time patterns of the ACP and payout on long-term TRs on this path are shown in Appendix Figure 3-64. The Return on short-term TRs is shown in Appendix Figure 3-65.

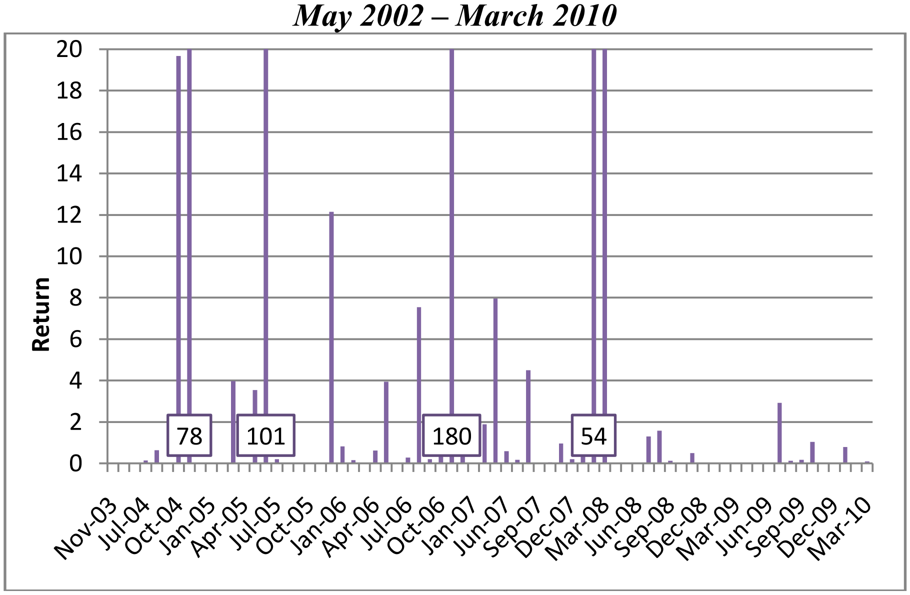
The Cumulative Return on long-term TRs since market opening is 3.83 ($3.83 paid out per dollar spent at auction). The Cumulative Return on long-term TRs purchased at auctions held between Q1 2007 and Q1 2009 was 4.40. As illustrated in Appendix Figures 3-64 and 3-65, high payouts relative to corresponding auction prices over the quarters Q1 2006 to Q4 2006 and Q2 2007 to Q1 2008 contribute significantly to the high Cumulative Returns observed.

[144] For greater clarity, there were short-term TRs not taken in October 2002 and February 2010 but the payout in each of these months was $0.

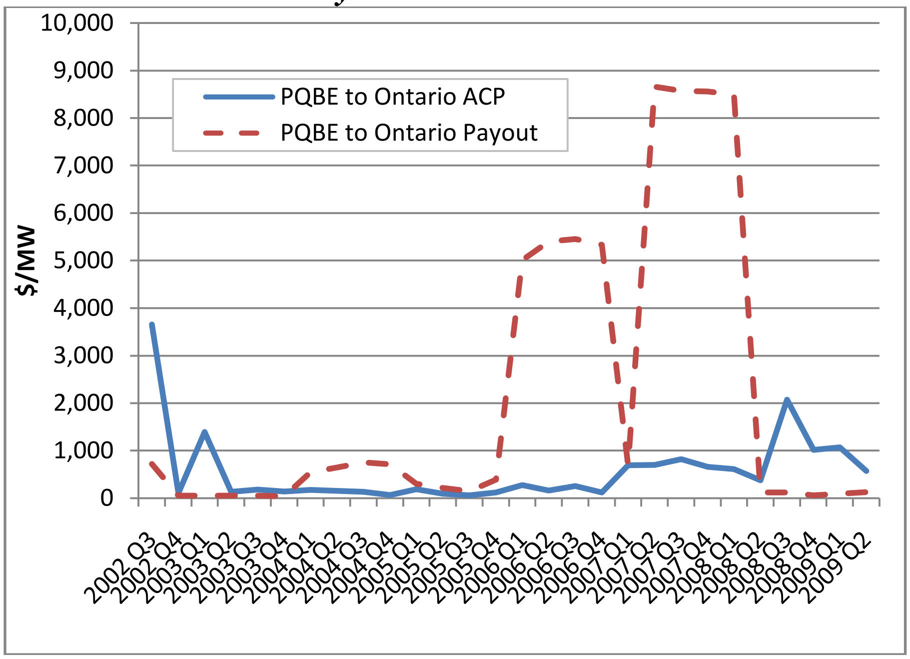
Appendix Figure 3-62: ACP and Payout on Short-Term TRs
PQBE to Ontario
May 2002 – March 2010



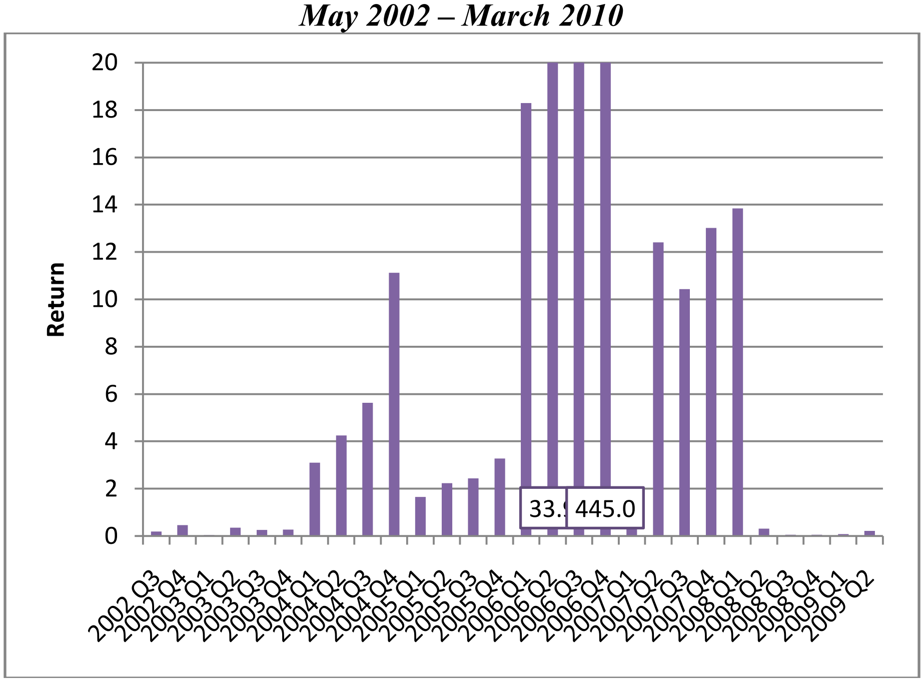
Appendix Figure 3-63: Return on Short-Term TRs
PQBE to Ontario
May 2002 – March 2010



Appendix Figure 3-64: ACP and Payout on Long-Term TRs
PQBE to Ontario
May 2002 – March 2010



Appendix Figure 3-65: Return on Long-Term TRs
PQBE to Ontario
May 2002 – March 2010

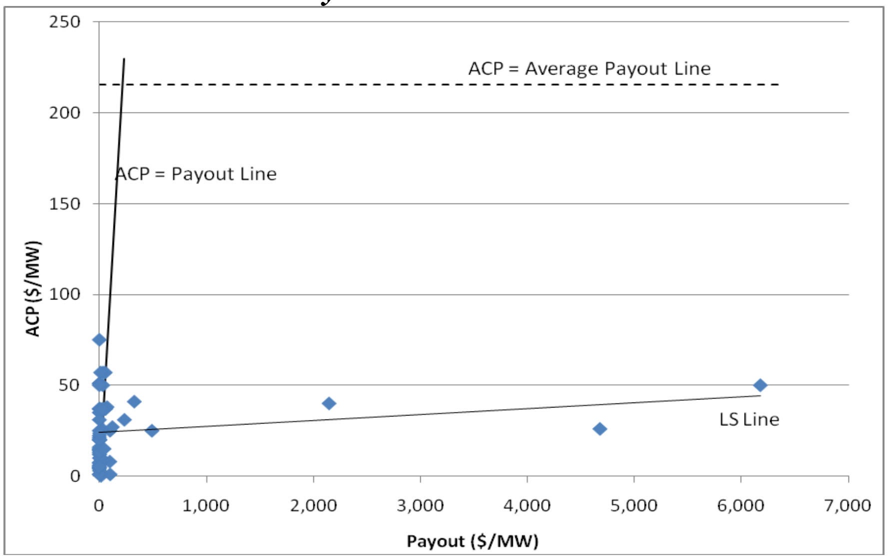


The relationship between prices paid at auction for TRs and the subsequent payout on them is illustrated in Appendix Figures 3-66 and 3-67.

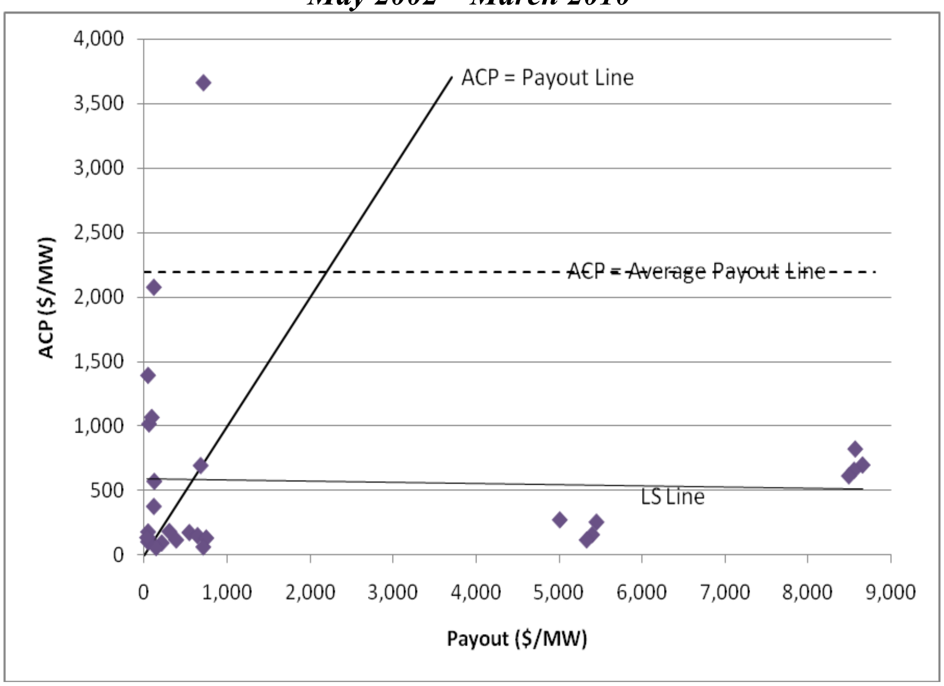
With respect to short-term TRs (Appendix Figure 3-66), the LS line has a positive intercept and slight positive slope. This relationship implies that bidders pay more for TRs that ultimately produce higher payouts, but that they also end up over-paying for TRs that turn out to have zero or low payouts and under-paying for TRs that turn out to have high payouts. The particular location of the LS line is sensitive to the extreme observations of November 2006, and February and March, 2008. Indeed, since the scatter in this case is essentially observations massed near the origin and along the vertical axis as well as the extreme observations mentioned above, the LS line is not particularly meaningful.

With respect to long-term TRs (Appendix Figure 3-67), the LS line has a positive intercept and a slight negative slope. This is the result of the eight relatively high Returns discussed above, together with several observations with high ACPs and low payouts yielding very low Returns. Given the imprecision with which the LS slope is estimated, the LS line can be treated as being horizontal implying that the ACP provides no information regarding the ultimate payout on the TR concerned. The LS line is well below the ACP = Average Payout line which is consistent with the Cumulative Return of 3.83 since market opening.

Appendix Figure 3-66: ACP and Payout on Short-Term TRs PQBE to Ontario May 2002 – March 2010



Appendix Figure 3-67: ACP and Payout on Long-Term TRs PQBE to Ontario May 2002 – March 2010



3.6.2 Imports from Quebec at PQDA

There have been 82 short-term and 28 long-term auctions on this import path (located near Ottawa) since market opening. The number of bidders in short-term auctions has averaged 2.2 since market opening, but this has increased to 2.6 in 2009. The number of bidders since market opening has averaged 2.1 in long-term auctions and has been relatively stable in recent years, being 2.3 for those auctions held between Q1 2007 and Q1 2009.

The respective time patterns of the ACP and payout on short-term TRs on this path are shown in Appendix Figure 3-68. The Return on short-term TRs is shown in Appendix Figure 3-69.

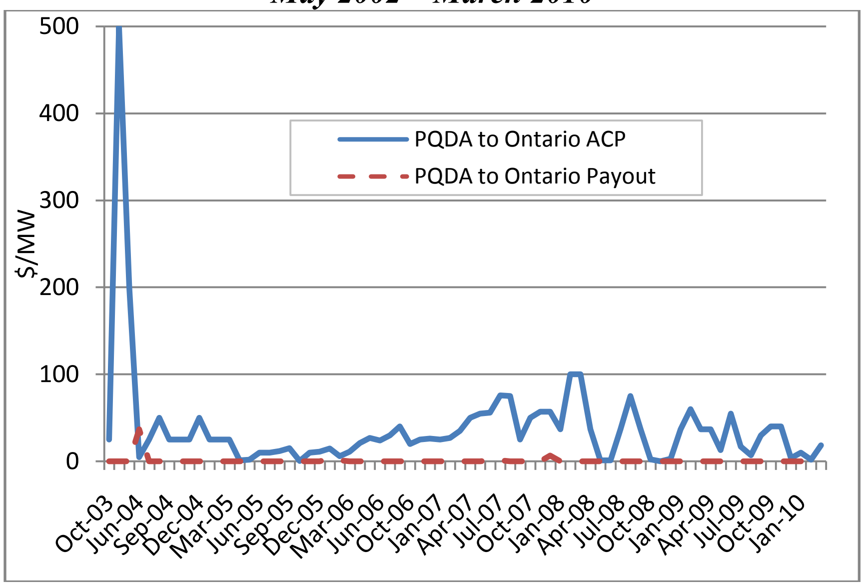
The Cumulative Return on short-term TRs since market opening was 0.13. The Cumulative Return over the period 2008-9 was zero, a period during which all 24 monthly payouts were zero. The low Cumulative Return is the result of bidders repeatedly paying a positive price for TRs that have usually had a zero payout. There has been only one short-term TR since May 2003 in which Return has exceeded one. This was the June 2004 TR, which paid $37/MW but sold for $5/MW and is clearly evident in Appendix Figure 3-69. With the exception of March 2008, in which 87% of TRs were not taken and the eventual payout was zero, all TRs offered on this path have been sold.

The respective time patterns of the ACP and payout on long-term TRs on this path are shown in Appendix Figure 3-70. The Return on long-term TRs is shown in Appendix Figure 3-71.

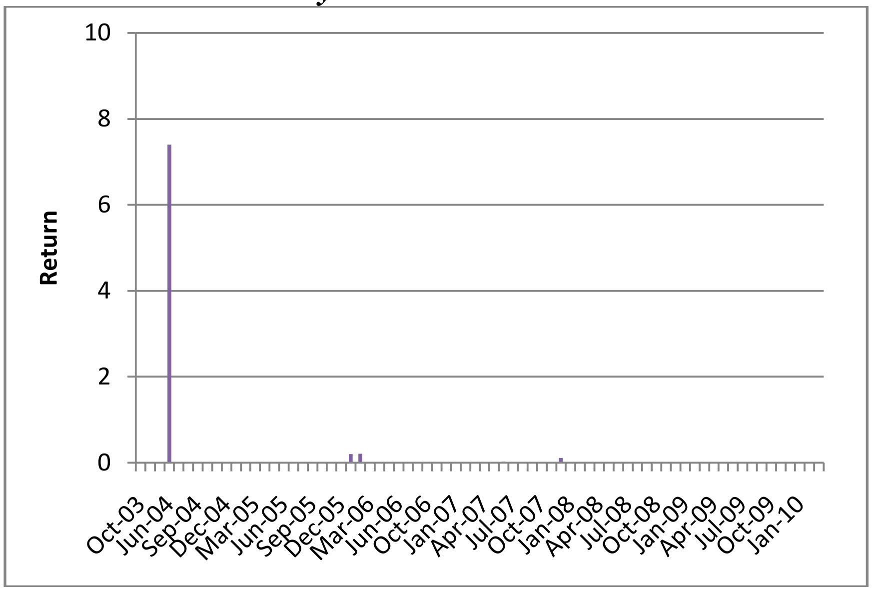
The Cumulative Return on long-term TRs since market opening was 0.15. The Cumulative Return on long-term auctions held between Q1 2007 and Q1 2009 was 0.01. The only positive payouts during this period were in June, July, and December, 2007. The only long-term auction on this path to result in a return in excess of one was held in August 2002 for the period Q4 2002 to Q3 2003. In this case, which is readily apparent in Appendix Figure 3-71, the auction price was $104/MW with a subsequent payout of $211/MW. All TRs offered on this path since market opening have been taken.

The data in Appendix Figures 3-68 and 3-70 suggest a persistent excess of ACPs over payouts on this path.

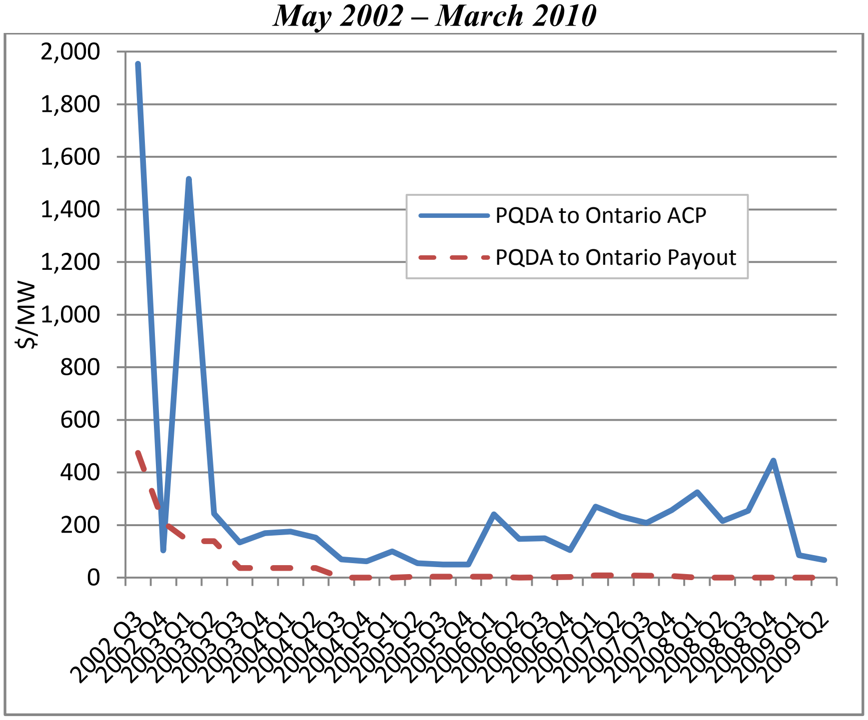
Appendix Figure 3-68: ACP and Payout on Short-Term TRs PQDA to Ontario May 2002 – March 2010



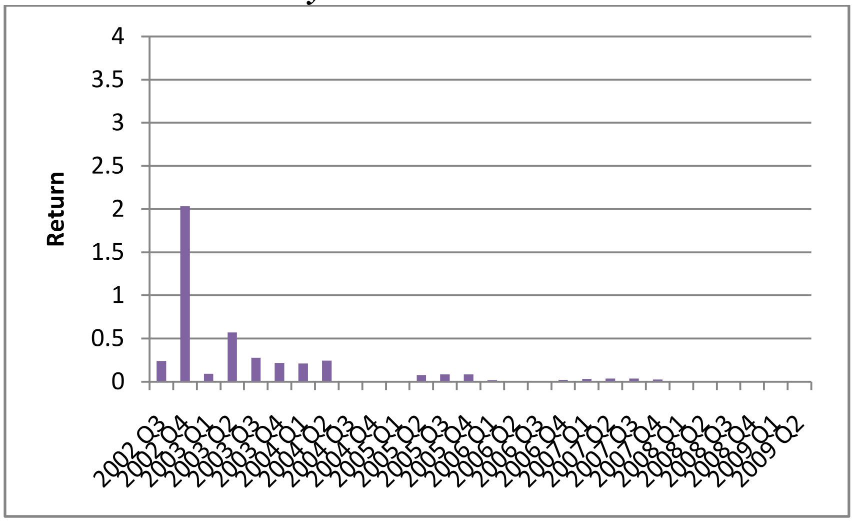
Appendix Figure 3-69: Return on Short-Term TRs
PQDA to Ontario
May 2002 – March 2010



Appendix Figure 3-70: ACP and Payout on Long-Term TRs
PQDA to Ontario
May 2002 – March 2010



Appendix Figure 3-71: Return on Long-Term TRs
PQDA to Ontario
May 2002 – March 2010

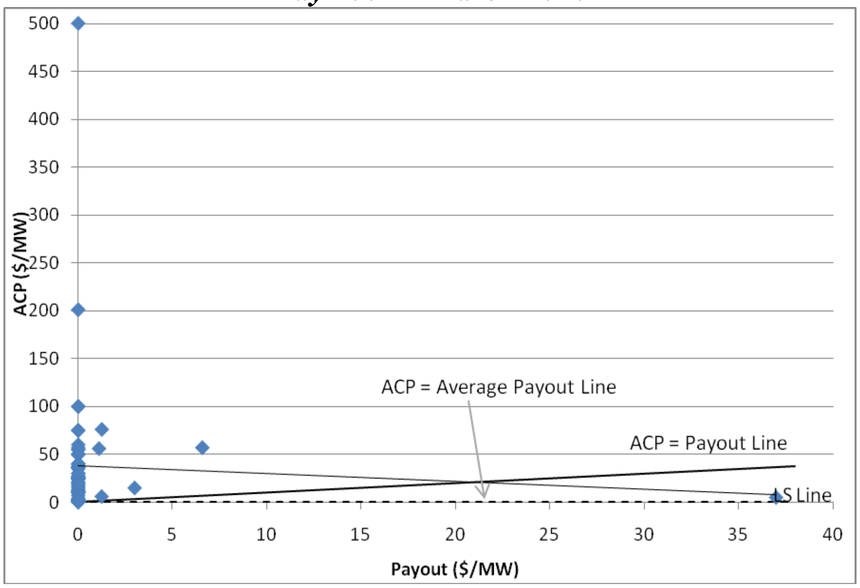


The relationship between prices paid at auction for TRs and the subsequent payouts on them is illustrated in Appendix Figures 3-72 and 3-73.

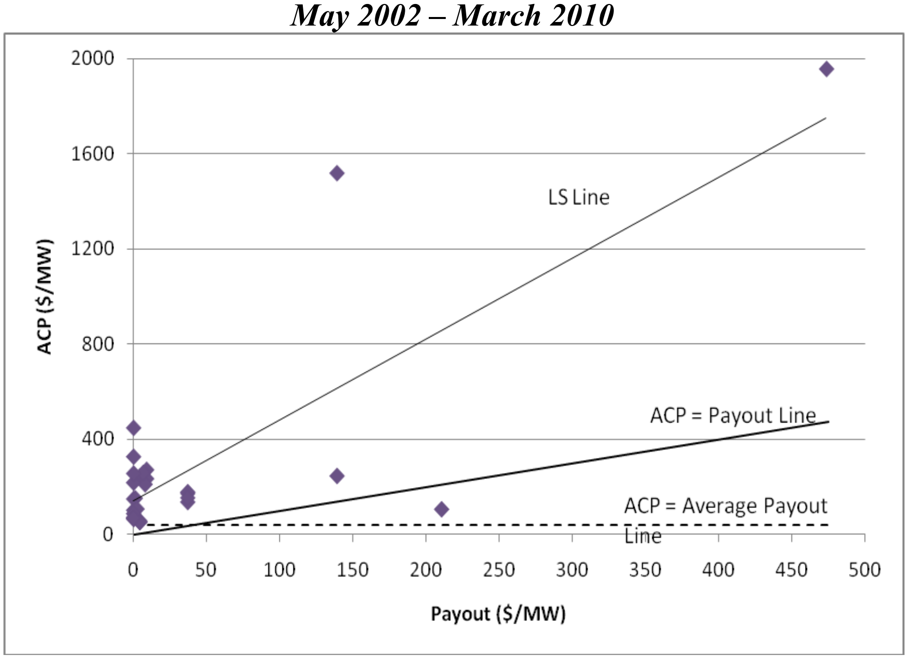
With respect to short-term TRs (Appendix Figure 3-72), the LS line has a positive intercept and a negative slope. This is the result of the June 2004 TRs (which were sold for $5/MW and paid out $37/MW for a Return of 7.4) and a series of subsequent auctions with ACPs as high as $100/MW for TRs that paid out zero. Excluding outliers, the LS line can be treated as being horizontal. Both the LS line and the scatter lie above the ACP = Average Payout line implying that bidders have consistently paid more for short-term TRs on this path than the average payout since market opening The result has been a Cumulative Return less than one.

With respect to long-term TRs (Appendix Figure 3-73), the LS line has a positive intercept and a positive slope that is much steeper than the ACP = Payout line (i.e. much greater than one). This is the result of several outlying observations. Subject to the usual caveat regarding statistical significance, this relationship indicates that bidders end up paying more for TRs that ultimately produce higher payouts. The LS line lying strictly above the Payout = ACP line also indicates that bidders have generally paid more for TRs than their average payout since market opening. This is consistent with the Cumulative Return of 0.15.

Appendix Figure 3-72: ACP and Payout on Short-Term TRs PQDA to Ontario May 2002 – March 2010



Appendix Figure 3-73: ACP and Payout on Long-Term TRs PQDA to Ontario May 2002 – March 2010



3.6.3 Imports from Quebec at PQDZ

There have been 50 short-term and 28 long-term auctions on this import path located in the Northeast area in the study period. The number of bidders in short-term auctions has averaged 2, which has declined to 1.8 in 2009. Of the 7 short-term TR auctions with exactly one bidder, only one resulted in a Return greater than 1. For long-term auctions, the average number of bidders since market opening is 1.9, increasing to 2.1 for the nine auctions held over the period Q1 2007 to Q1 2009.

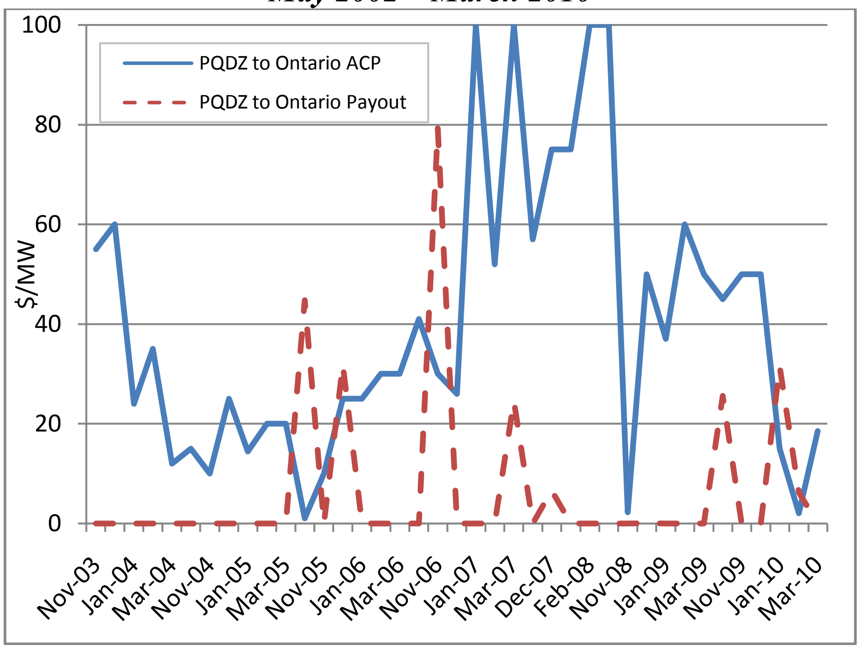
The respective time patterns of the ACP and payout on short-term TRs on this path are shown in Appendix Figure 3-74. The Return on short-term TRs is shown in Appendix Figure 3-75.

The Cumulative Return on short-term TRs since market opening was 7.13. The Cumulative Returns over the periods 2008-09 and 2009 were 0.04 and 0.09, respectively. The relatively high Cumulative Return since market opening is the result of two extreme values: (1) the TR for June 2002, which paid $515/MW but sold for $74/MW; and (2) the TR for July 2002 paid $18,899/MW but sold for $200/MW. These data points are among the twelve that we have omitted from all our figures (and the estimation of the LS line) as they outliers and distorted the graph as well as the LS line. With the exception of the March 2008 TRs, half of which were not taken and yielded a payout of zero, all short-term TRs on this path have been taken.

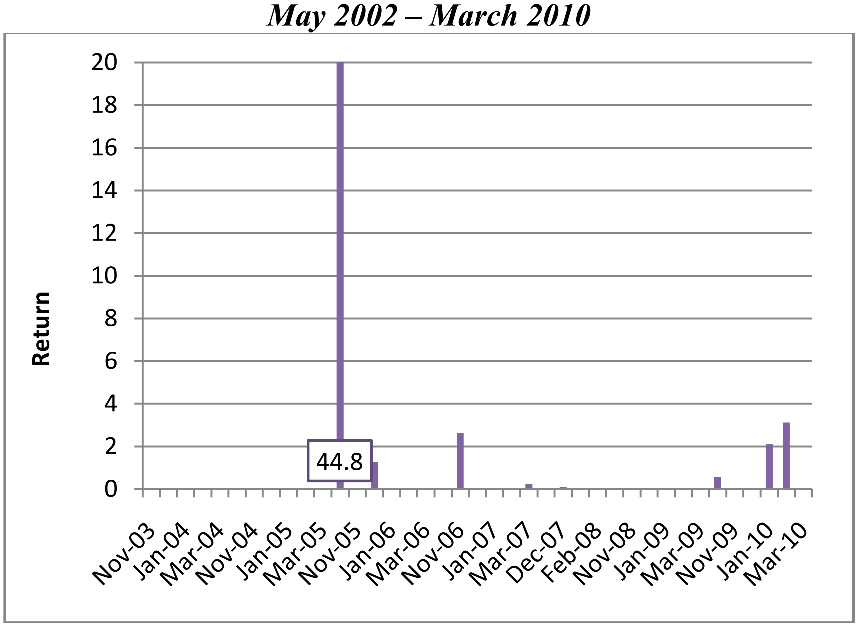
The respective time patterns of the ACP and payout on long-term TRs on this path are shown in Appendix Figure 3-76. The Return on long-term TRs is shown in Appendix Figure 3-77.

The Cumulative Return on long-term TRs since market opening was 1.82. The Cumulative Return on long-term auctions held between Q1 2007 and Q1 2009 was 0.09. The significantly lower Cumulative Return over more recent auctions reflects two facts: (1) over the period Q1 2007 to Q1 2009, none of the long-term TRs ultimately had a Return in excess of one; and (2) nearer to market opening there were several extreme observations, including the TR auctioned in May 2002 for the period Q3 2002 to Q2 2003, which sold for $1,840/MW and paid out $18,951/MW. All long-term TRs offered on this path since market opening have been taken.

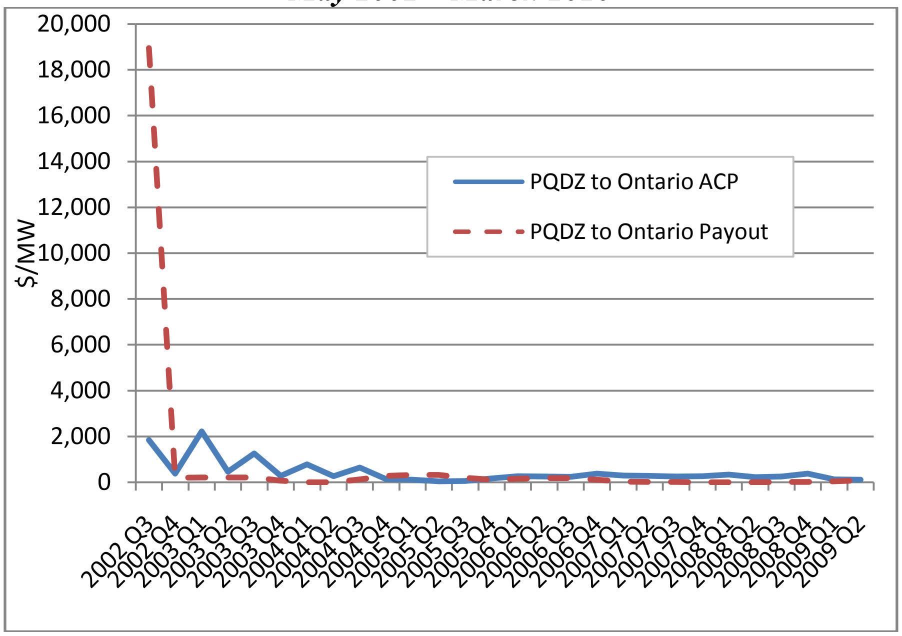
Appendix Figure 3-74: ACP and Payout on Short-Term TRs
PQDZ to Ontario
May 2002 – March 2010



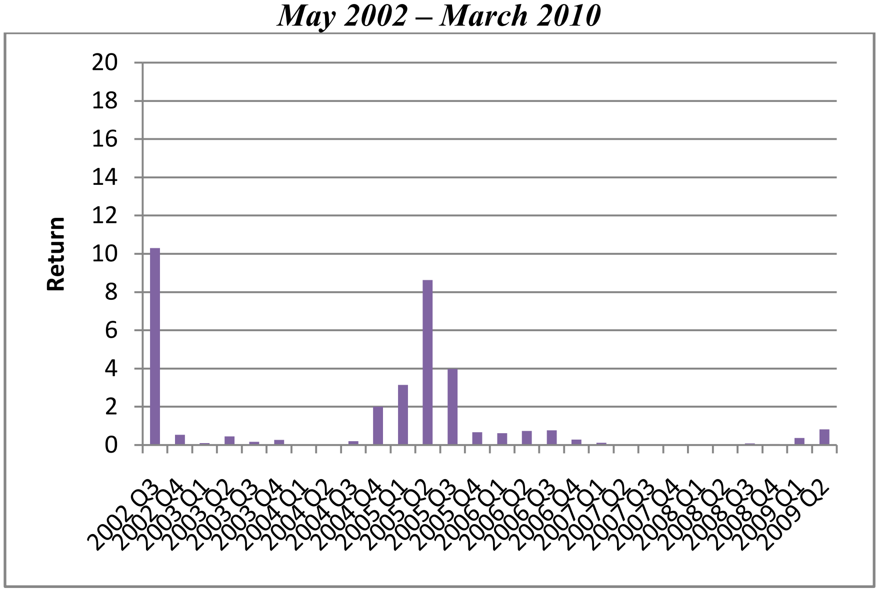
Appendix Figure 3-75: Return on Short-Term TRs
PQDZ to Ontario
May 2002 – March 2010



***Appendix Figure 3-76: ACP and Payout on Long-Term TRs
PQDZ to Ontario
May 2002 – March 2010***



***Appendix Figure 3-77: Return on Long-Term TRs
PQDZ to Ontario
May 2002 – March 2010***

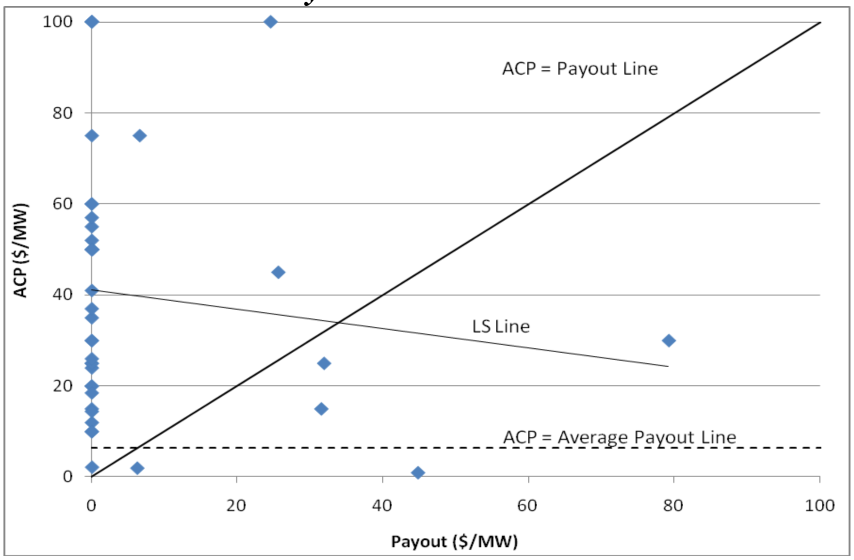


The relationship between prices paid at auction for TRs and the subsequent payouts on them is illustrated in Appendix Figures 3-78 and 3-79.

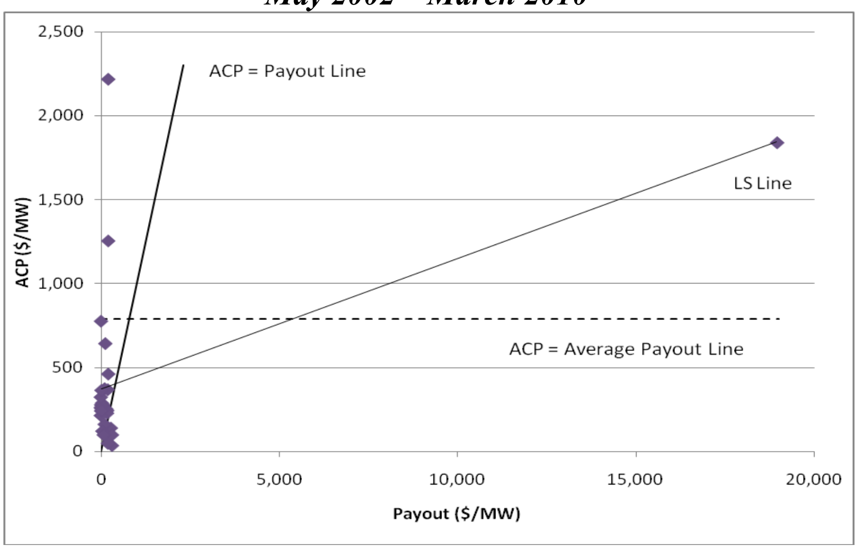
With respect to short-term TRs (Appendix Figure 3-78), the LS line has a positive intercept and a negative slope. This is the result of a large number of TRs with positive ACPs but payouts of zero as well as various outliers, including the TR for April 2005, which paid $45/MW but sold for $1/MW. The slope estimate is, therefore, associated with a significant degree of imprecision and, given this, the LS line can be treated as being horizontal. While the LS line lies well above the ACP = Average Payout line, implying that the ACP has been more than the average payout since market opening, this is a result of the omission of some very high Return observations in 2002 from the figure. These observations are included in the calculation of the Cumulative Return since market opening of 7.13, implying that bidders have paid much less for TRs than the average payout since market opening.

With respect to long-term TRs (Appendix Figure 3-79), the LS line has a positive intercept and slight positive slope. This positive slope is due to one extreme observation (the TR auctioned in May 2002, as discussed above). The balance of the scatter implies a horizontal LS line lying below the ACP = Average Payout line which is consistent with a Cumulative Return of 1.82 since market opening.

Appendix Figure 3-78: ACP and Payout on Short-Term TRs
PQDZ to Ontario
May 2002 – March 2010



Appendix Figure 3-79: ACP and Payout on Long-Term TRs
PQDZ to Ontario
May 2002 – March 2010



3.6.4 Imports from Quebec at PQPC

There have been 69 short-term and 28 long-term auctions on this import path located near Ottawa since market opening. The number of bidders in short-term auctions has averaged 2.4 since market opening, but has increased in recent years to 2.8 for 2008-09 and 3.0 for 2009. There have been six short-term auctions with only one bidder, all of which resulted in a Return less than one. For long-term auctions, the average number of bidders since market opening is 2.4, which has been stable in recent years.

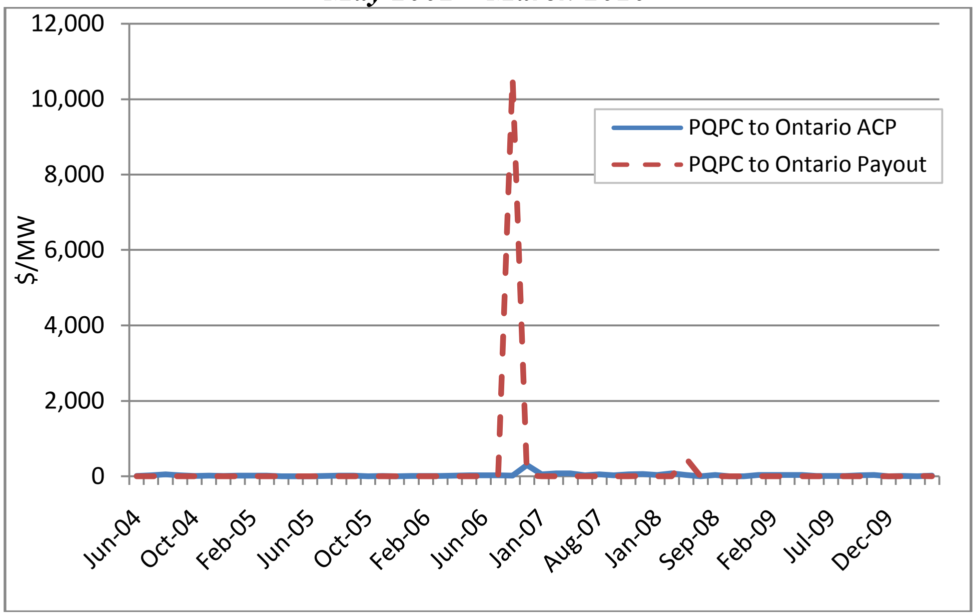
The respective time patterns of the ACP and payout on short-term TRs on this path are shown in Appendix Figure 3-80. The Return on short-term TRs is shown in Appendix Figure 3-81.

The Cumulative Return on short-term TRs since market opening is 6.56. The Cumulative Returns over the periods 2008-09 and 2009 were 1.09 and 0, respectively (there were no payouts in 2009). As illustrated in Appendix Figure 3-80, the Cumulative Return for the period 2008-09 is largely a result of the April 2008 TR, which paid $474/MW but sold for $37/MW. The much higher Cumulative Return since market opening is, as illustrated in Appendix Figure 3-80, largely a result of the November 2006 TR, which paid $10,587/MW but sold for $706/MW. All short-term TRs offered on this path since market opening have been taken.

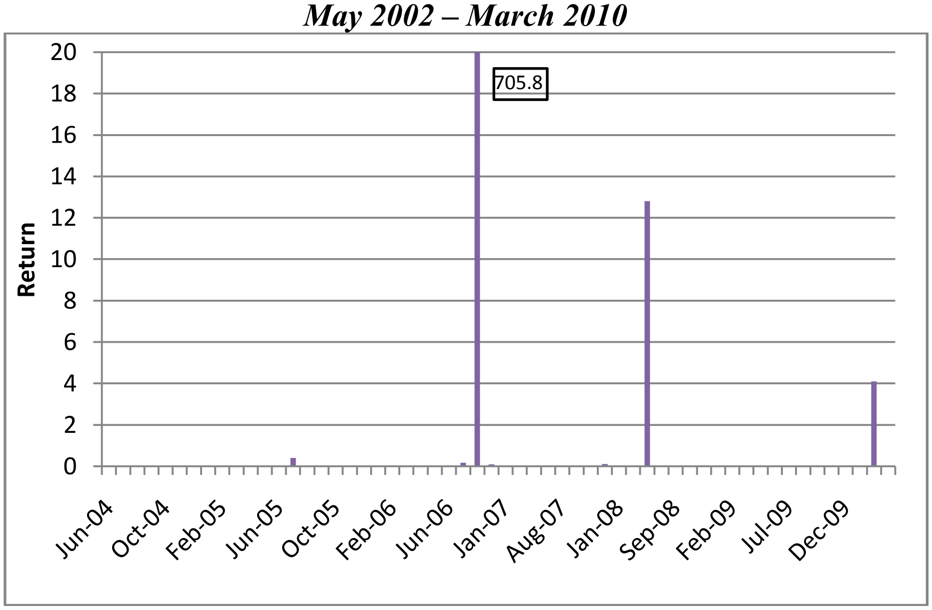
The respective time patterns of the ACP and payout on long-term TRs on this path are shown in Appendix Figure 3-82. The Return on long-term TRs is shown in Appendix Figure 3-83.

The Cumulative Return on long-term TRs since market opening is 4.91. The Cumulative Return on long-term auctions held between Q1 2007 and Q1 2009 was 0.45. The significantly lower recent Cumulative Return reflects the impact of the relatively large payout in November 2006 as discussed above, which resulted in the four long-term TRs covering that month being characterised by extremely high payouts and Returns (This situation is readily apparent in Appendix Figures 3-82 and 3-83). With the exception of the May 2003 auction of TRs for the period Q3 2003 to Q2 2004, in which three TRs with an eventual value of approximately $13 were not taken, all long-term TRs offered on this path since market opening have been taken.

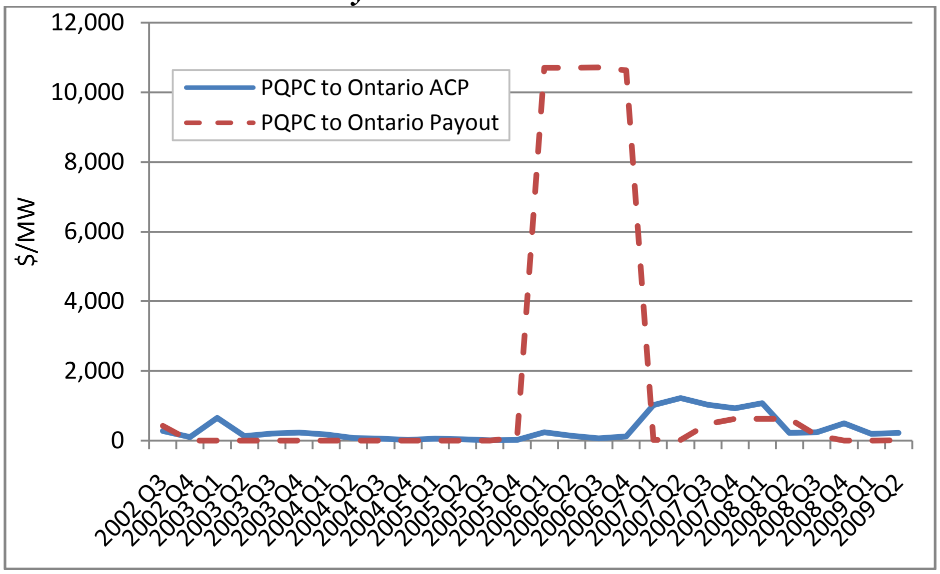
***Appendix Figure 3-80: ACP and Payout on Short-Term TRs
PQPC to Ontario
May 2002 – March 2010***



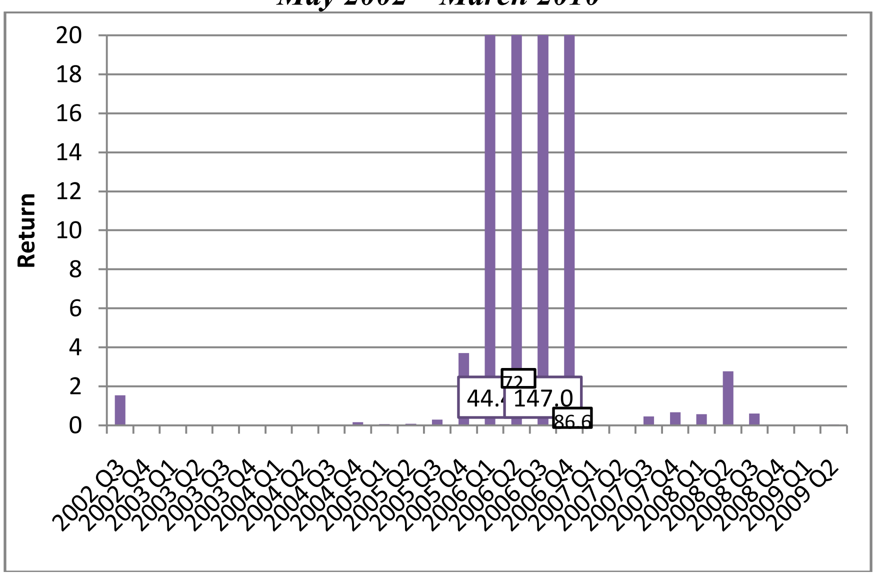
***Appendix Figure 3-81: Return on Short-Term TRs
PQPC to Ontario
May 2002 – March 2010***



Appendix Figure 3-82: ACP and Payout on Long-Term TRs PQPC to Ontario May 2002 – March 2010



Appendix Figure 3-83: Return on Long-Term TRs PQPC to Ontario May 2002 – March 2010

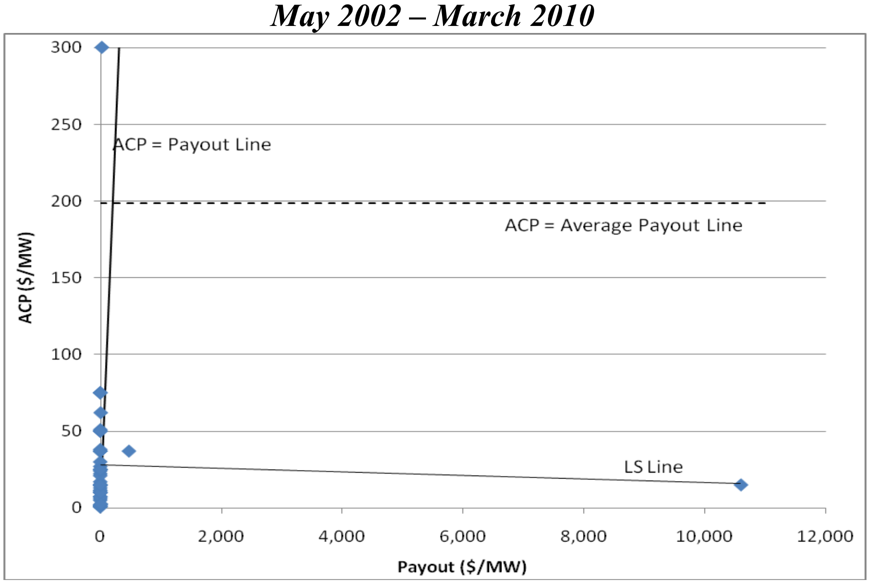


The relationship between prices paid at auction for TRs and the subsequent payouts on them is illustrated in Appendix Figures 3-84 and 3-85.

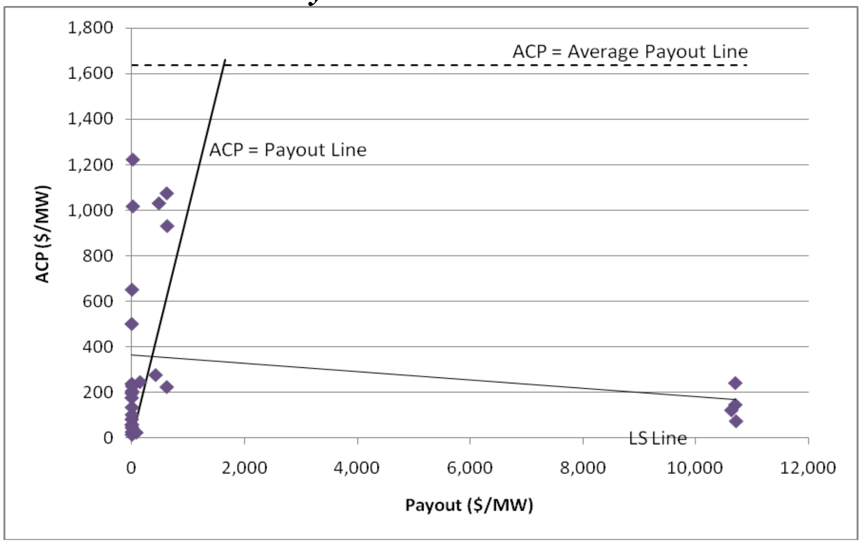
With respect to short-term TRs (Appendix Figure 3-84), the LS line has a positive intercept and essentially no slope, implying that the ACP of a TR conveys no information regarding its future payout. While the location of the LS line below the ACP = Average Payout line implies that ACPs have been less than the average payout since market opening and is consistent with the Cumulative Return of 6.56, this is the result of a few outlying observations. Most of the scatter lies above the ACP = Payout line implying that in most of the auctions bidders ended up paying more for TRs than these TRs ultimately paid out.

With respect to long-term TRs (Appendix Figure 3-85), the LS line is strongly influenced by the presence of the four outliers resulting from the high November 2006 payout. Treating the LS line as horizontal, and given its position far below the ACP = Average Payout line, it appears that bidders typically paid less for TRs than the average payout on them. This is consistent with the Cumulative Return of 4.91 since market opening. Examination of the scatter in Appendix Figure 3-85 reveals the impact of the outliers on both the average payout since market opening and the Cumulative Return. Most of the scatter lies above the ACP = Payout line implying that in most auctions bidders actually ended up paying more for the TR concerned than it paid out.

Appendix Figure 3-84: ACP and Payout on Short-Term TRs
PQPC to Ontario
May 2002 – March 2010



Appendix Figure 3-85: ACP and Payout on Long-Term TRs
PQPC to Ontario
May 2002 – March 2010



3.6.5 Exports to Quebec at PQDA

There have been 43 short-term and 20 long-term auctions on this export path located near Ottawa since market opening. The number of bidders in short- and long-term auctions has averaged 2.7 and 2.2 since market opening, respectively. Both values have been stable in recent years.

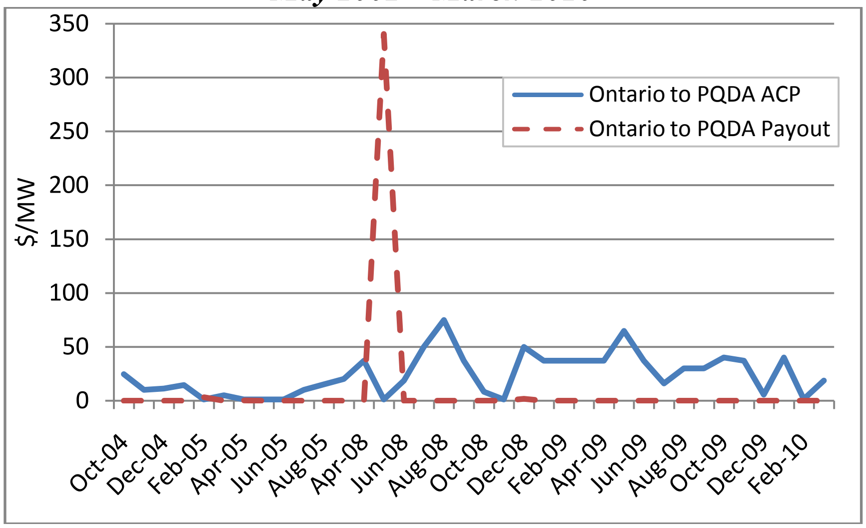
The respective time patterns of the ACP and payout on short-term TRs on this path are shown in Appendix Figure 3-86. The Return on short-term TRs is shown in Appendix Figure 3-87.

The Cumulative Return on short-term TRs since market opening was 0.38. The Cumulative Returns over the periods 2008-09 and 2009 were 0.50 and zero, respectively. As illustrated in Appendix Figures 3-86 and 3-87, these results were driven by the May 2008 TR which was a significant outlier. As most other payouts were zero, the Cumulative Return was zero in 2009 and low over other time periods. All short-term TRs offered on this path since market opening were taken.

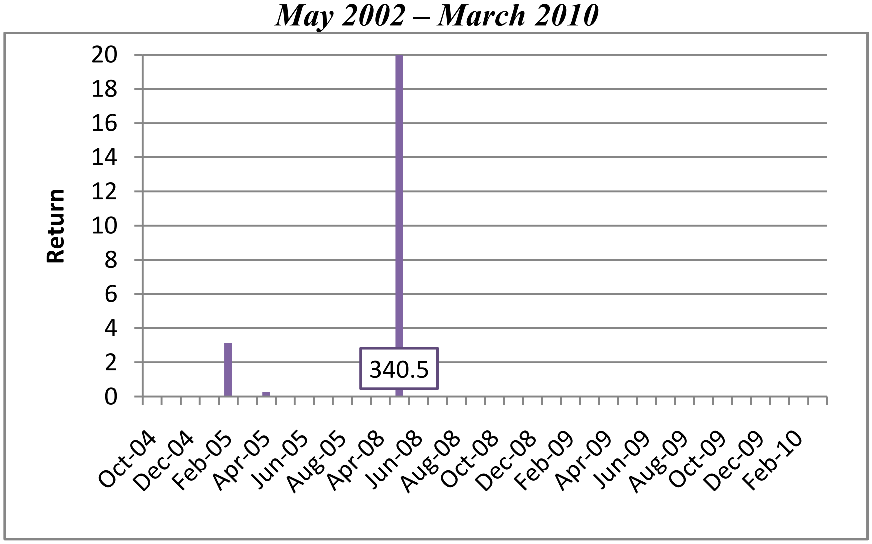
The respective time patterns of the ACP and payout on long-term TRs on this path are shown in Appendix Figure 3-88. The Return on short-term TRs is shown in Appendix Figure 3-89.

The Cumulative Return on long-term TRs since market opening is 0.23, and was 0.49 over the auctions held between Q1 2007 and Q1 2009. The large payout in May 2008, as illustrated in Appendix Figures 3-88 and 3-89, impacts these values as well. All long-term TRs offered on this path have been taken.

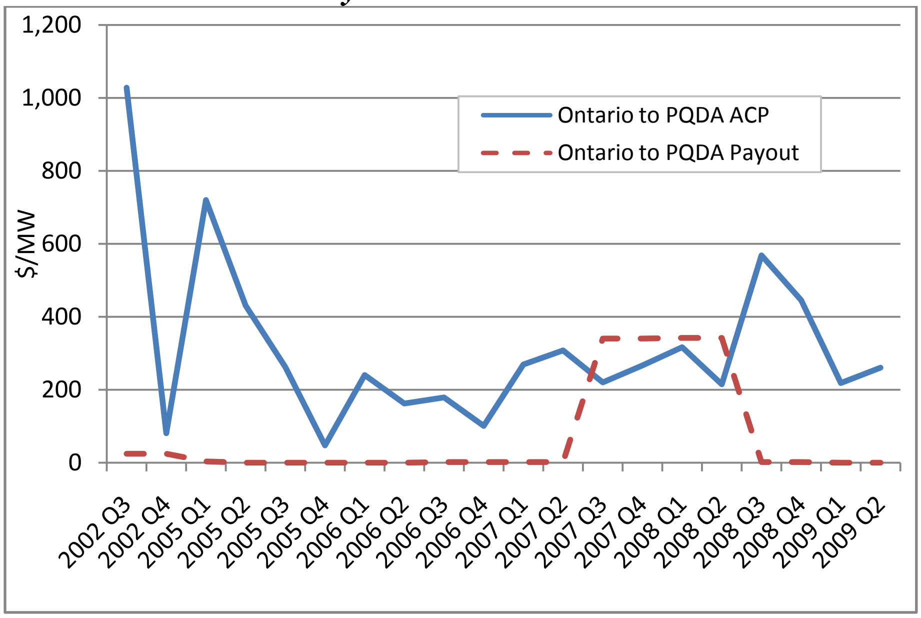
Appendix Figure 3-86: ACP and Payout on Short-Term TRs
Ontario to PQDA
May 2002 – March 2010



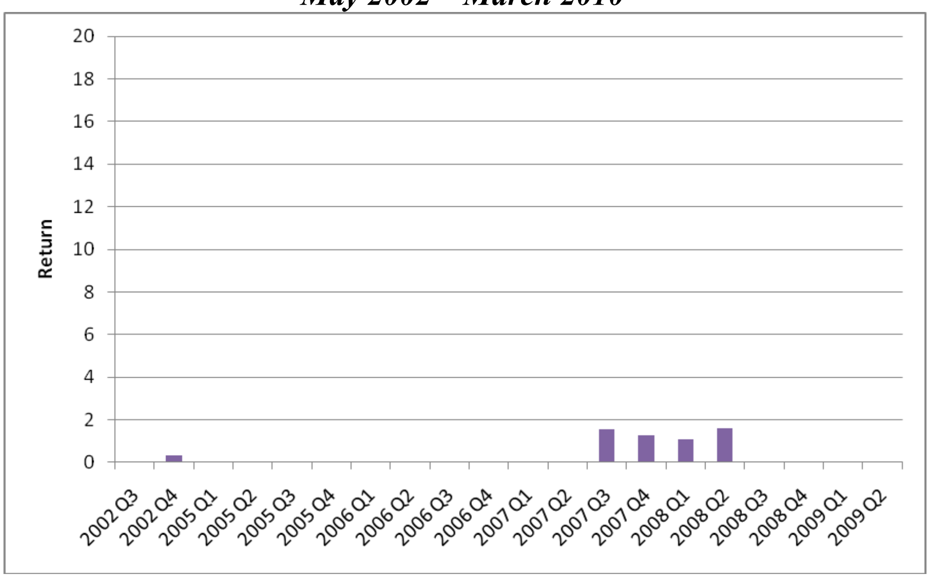
Appendix Figure 3-87: Return on Short-Term TRs
Ontario to PQDA
May 2002 – March 2010



Appendix Figure 3-88: ACP and Payout on Long-Term TRs
Ontario to PQDA
May 2002 – March 2010



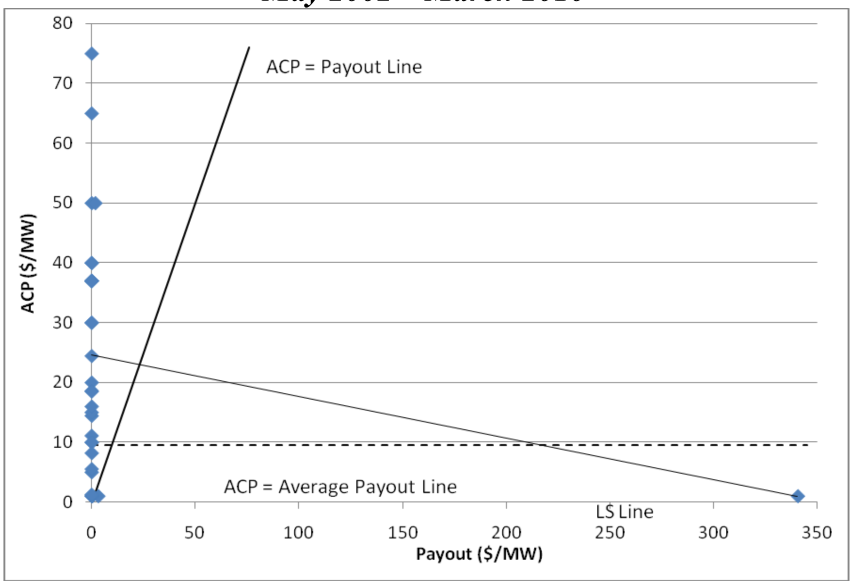
Appendix Figure 3-89: Return on Long-Term TRs
Ontario to PQDA
May 2002 – March 2010



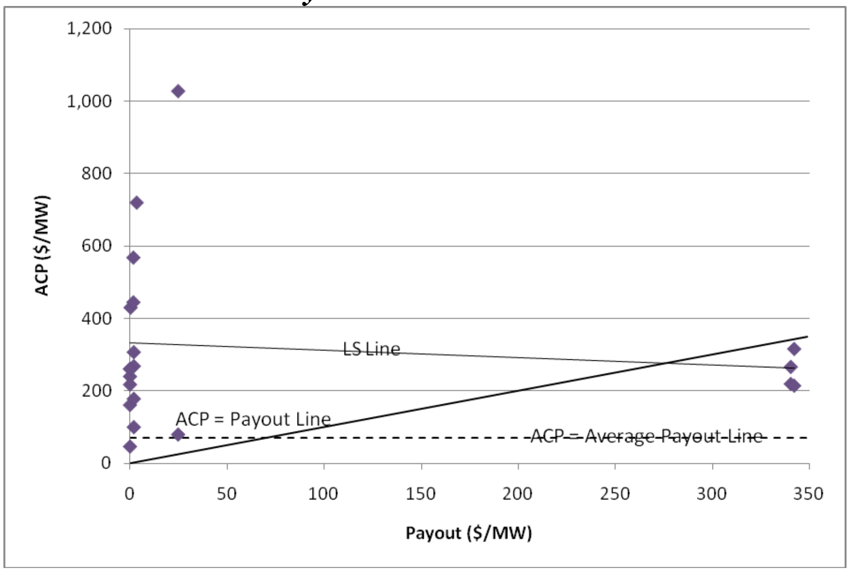
The relationship between prices paid at auction for TRs and the subsequent payouts on them is illustrated in Appendix Figures 3-90 and 3-91.

The LS lines in Appendix Figures 3-90 and 3-91 have similar characteristics. In both cases, the line has a positive intercept and a slight negative slope. The slope is likely to be strongly influenced by the May 2008 outlier. Treated as horizontal, the LS line lies above the ACP = Average Payout line, indicating that bidders have tended to pay in excess of the expected payout. This is consistent with most observations also being above the Payout = ACP line and with the low Cumulative Returns. A possible explanation of the apparent persistence of this outcome may be that the ACP on this path is set by bidders who require TRs as a hedge and who are therefore willing to accept Returns less than one on a continuing basis.

Appendix Figure 3-90: ACP and Payout on Short-Term TRs
Ontario to PQDA
May 2002 – March 2010



Appendix Figure 3-91: ACP and Payout on Long-Term TRs Ontario to PQDA May 2002 – March 2010



3.6.6 Exports to Quebec at PQHZ

There have been 53 short-term and 28 long-term auctions on this export path located in the Northeast area since market opening. The number of bidders in short-term auctions has averaged 2.3 since market opening, but has increased in recent years to 2.5 and 2.8 for the periods 2008-09 and 2009, respectively. For long-term auctions, the average number of bidders since market opening has been 2.3, increasing to 2.7 for the nine auctions held over the period Q1 2007 to Q1 2009.

The respective time patterns of the ACP and payout on short-term TRs on this path are shown in Appendix Figure 3-92. The Return on short-term TRs is shown in Appendix Figure 3-93.

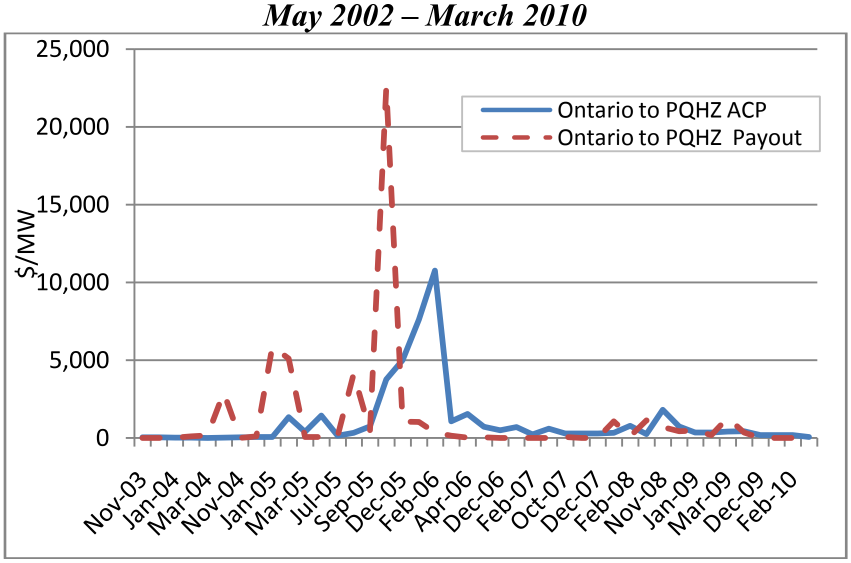
The Cumulative Return on short-term TRs since market opening is 1.14. The Cumulative Returns over the periods 2008-09 and 2009 were 1.00 and 1.29, respectively. As illustrated in Appendix Figures 3-92 and 3-93, there were a number of outliers between Q1 2005 and Q1 2006, inclusive. However, unlike most other paths, in this case the outlying ACPs and payouts are roughly balanced in various sub-periods. Hence the

Cumulative Return in each of these periods is near one. All short-term TRs offered on this path since market opening have been taken.

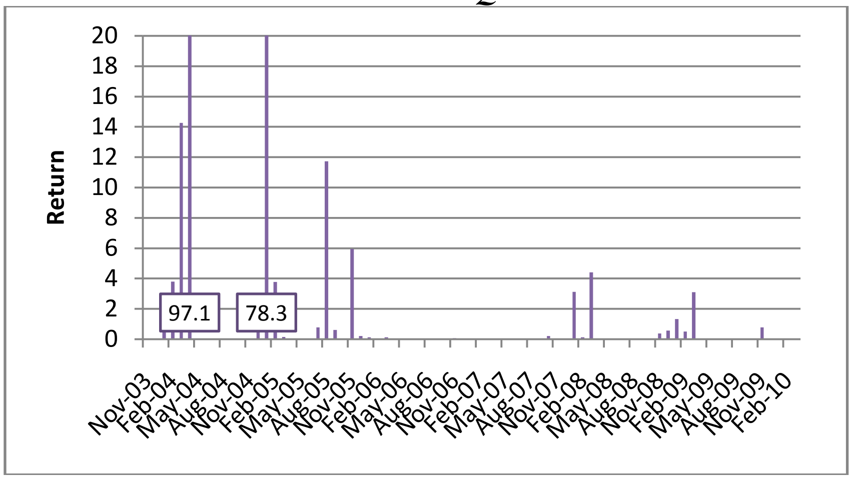
The respective time patterns of the ACP and payout on long-term TRs on this path are shown in Appendix Figure 3-94. The Return on long-term TRs is shown in Appendix Figure 3-95.

The Cumulative Return on long-term TRs since market opening is 1.89, and was 2.20 over the auctions held between Q1 2007 and Q1 2009. As illustrated in Appendix Figures 3-94 and 3-95, there have been no recent, significant outliers on this path. Approximately 2.5 % of TRs offered at auction since market opening have not been taken. They had a total value of about $204,000/MW.

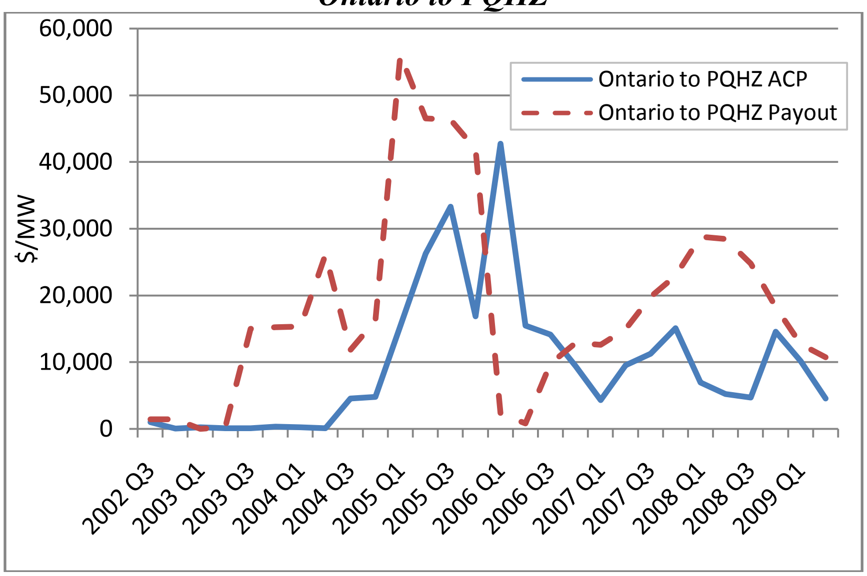
Appendix Figure 3-92: ACP and Payout on Short-Term TRs
Ontario to PQHZ
May 2002 – March 2010



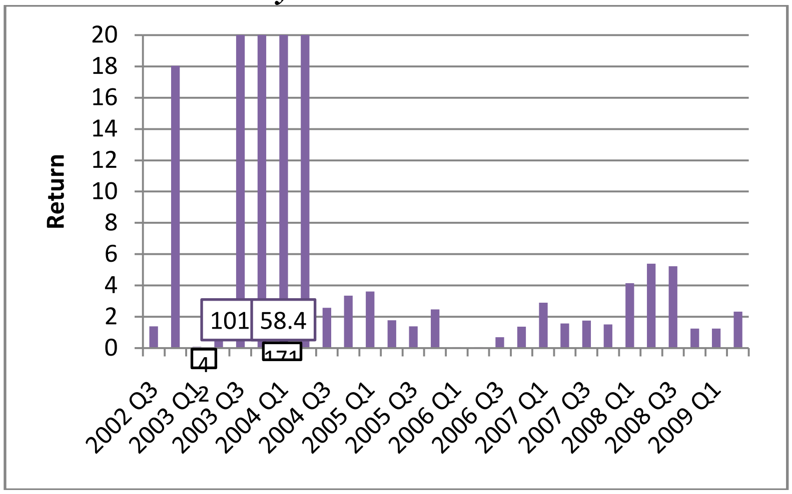
Appendix Figure 3-93: Return on Short-Term TRs
Ontario to PQHZ



Appendix Figure 3-94: ACP and Payout on Long-Term TRs
Ontario to PQHZ



Appendix Figure 3-95: Return on Long-Term TRs
Ontario to PQHZ
May 2002 – March 2010

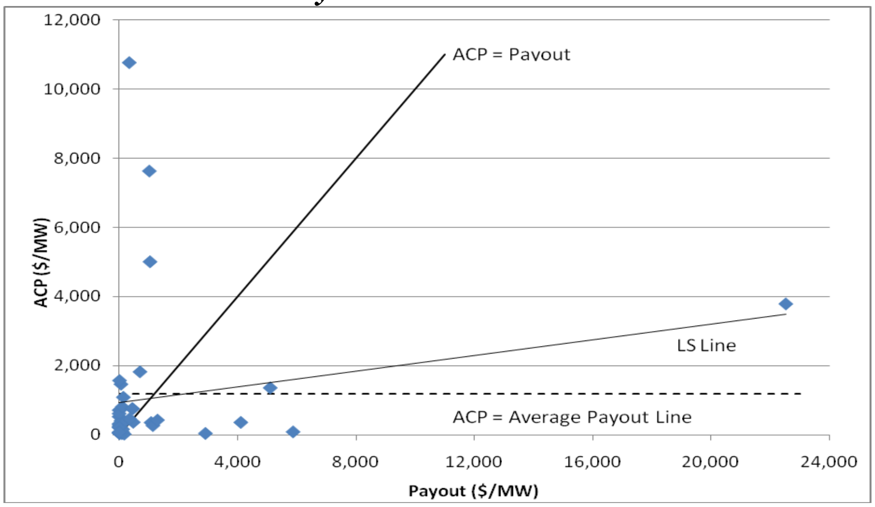


The relationship between prices paid at auction for TRs and the subsequent payouts on them is illustrated in Appendix Figures 3-96 and 3-97.

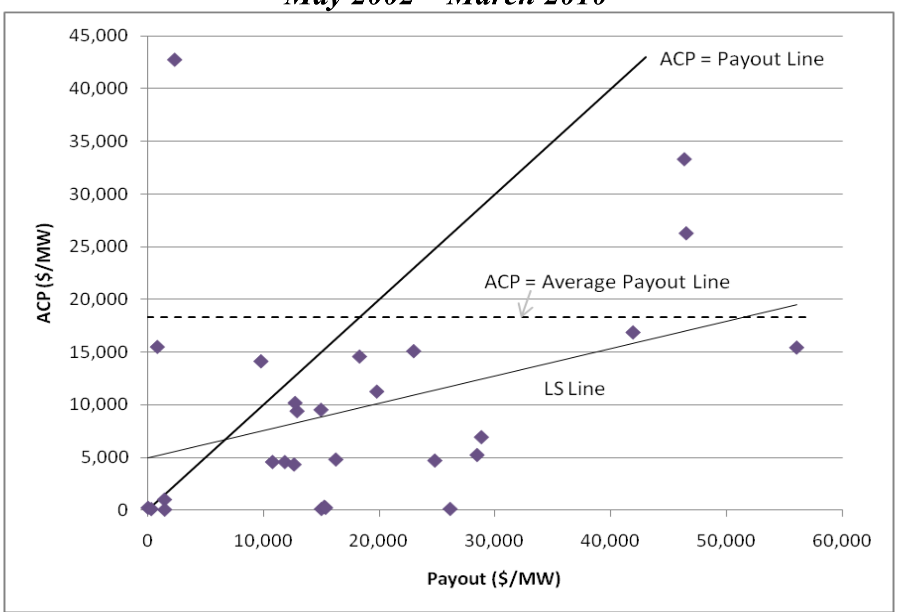
With respect to short-term TRs (Appendix Figure 3-96), the LS line has a positive intercept and slope. The slope is likely to have been strongly influenced by the November 2005 TR, which paid out $22,524/MW but sold for $3,780/MW. Without the influence of this observation the LS line would be roughly horizontal and also roughly coincident with the ACP = Average Payout line. This suggests that the ACP of a TR does not imply much about the future payout on it but that it is roughly equal to the average payout since market opening.

With respect to long-term TRs (Appendix Figure 3-97), the LS line has a positive intercept and slope. Unlike the short-term TR data, the scatter plot suggests that the positive relationship between the ACP and the subsequent payout on long-term TRs is not due to a few extreme observations. That is, the LS line may be statistically more reliable in this case. The slope of the LS line is roughly one-half, suggesting that the ACP increases by 50¢ for every dollar increase in the payout. The LS line and most of the scatter lie below the ACP = Average Payout line which is consistent with the observed Cumulative Return of 1.89 since market opening.

Appendix Figure 3-96: ACP and Payout on Short-Term TRs Ontario to PQHZ May 2002 – March 2010



Appendix Figure 3-97: ACP and Payout on Long-Term TRs Ontario to PQHZ May 2002 – March 2010



4. Conclusions

The findings reported above imply that, while some paths are better than others, the TR market as a whole is not informationally efficient. The ACP of a TR provides relatively little information about the future payout on it. This may be because bidders cannot readily predict incidents of congestion or predict the ICP when there is congestion, or both. There is some limited indication that bids may respond to past incidents of high payouts but, as is the case with flipping coins, the past has not been a reliable guide to the future.

On average, payouts to TR holders have been much higher than ACPs (Cumulative Return greater than one), but on some paths and during some time periods there is a preponderance of Return values less than one. Profits on TRs are due principally to very high Return values on occasional high payout TRs. Payouts vary widely from period to period while ACPs vary within a much narrower band.

While the findings reported above are consistent with an inability on the part of bidders to predict incidents of very high payouts, an inability to predict specific incidents of high payouts is not a sufficient explanation for high Cumulative Returns experienced on most paths over fairly long periods. In the simplest terms, TRs sell at a significant discount to the historic average payout on them and while there is room for debate about the risk premium an uncovered TR investor might require, it is hard to imagine that it would approach the premium implicit in the Cumulative Returns that have been realized on most paths and in aggregate (about 100 %) since market opening. It may be the case that bidders' expectations regarding the long-run average payout over time are simply less than the historic experience but there are other possible explanations.

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The number of bidders on most paths is small and, with a few exceptions (most notably the export path to Michigan), has not increased appreciably over time. The number of bidders on most paths has also fairly steady from period to period. There is at present little to indicate the presence of potential bidders poised to bid in auctions on paths on which Returns to TR holders have been high.

While imperfectly competitive bidding cannot be ruled out as a reason for the high Cumulative Returns to TR holders on many paths, there is no simple relationship between the Cumulative Return on a path and its characteristics. Cumulative Returns vary markedly across paths and are lowest on some of the paths with the fewest bidders. Further analysis will be required to better understand the nature of the linkage between path Cumulative Returns and path characteristics.

A major implication of the findings in this report is distributive. If the auction revenue collected by the IESO was equal on average to the amount it pays out to TR holders, this would leave the entire congestion rent collected by IESO available to rebate to transmission owners or, transmission users (loads and exporters) according to the market rules.[145] But the amount the IESO pays out to TR holders is well in excess of the auction revenue it receives from them, so a significant part of its payout to TR holders comes out of congestion rents. Thus, the result of the TR auctions is that a significant fraction of congestion rents collected by the IESO has effectively been shared with TR holder, many of whom are not participants in the physical market.[146] In principle, the participation of purely financial investors in the TR market should increase competition, liquidity and information flows thereby resulting in a more informationally efficient market. At present, there is little to indicate that this has occurred to any meaningful degree. The IESO may wish to address the question of whether it sees the TR market as a sharing device for congestion rents that would otherwise be rebated to transmission owners or users and if so, who it wishes to share these rents with and to what end.

The informational inefficiency of the TR market may also have implications for the efficiency of the physical market. If market participants are unable to predict intertie congestion prices, they may enter into some intertie transactions that turn out to be inefficient *ex post*. But the TR market is merely reflecting this rather than causing it. If market participants were to use ACPs in TR auctions as a signal of future intertie congestion prices and the ACP is distorted, say, by lack of competitive bidding, then the informational inefficiency of the TR market could have adverse efficiency consequences for the physical market.

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[145] For further discussion, see section 3.3 of Chapter 3 of this report.
[146] See Table 3-14**.**

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Chapter 4: The State of the IESO-Administered Markets

4. General Assessment

This is our 16th semi-annual Monitoring Report of the IESO-administered markets. It covers the winter period, November 2009 to April 2010. As in our previous reports, we conclude that the market has operated reasonably well according to the parameters set for it, although there were occasions where actions by market participants or the IESO led to inefficient outcomes. We again observed some areas of concern that affect market efficiency and have made recommendations for improvement. These recommendations are summarized at the end of this Chapter.

5. Unintended Consequences Caused by the Two Schedule Market Structure in Ontario

In its last report, the Panel discussed how Ontario's two schedule market structure system compensates dispatchable resources for costs or implied losses to operating profit imposed on them by transmission congestion, ramp limitations, and IESO manual actions. The Panel also reiterated that, on many occasions, significant inefficient outcomes have arisen as a result of the two schedule system. The Panel indicated that exploring a structural change to the existing two schedule system should be a high priority.[147]

In the past the Panel has recommended a number of measures to limit CMSC payments where they did not contribute to market efficiency. In Chapter 3, Section 3.1 of this report, the Panel made three further recommendations to limit CMSC payments to dispatchable loads that in the Panel's opinion do not improve market efficiency.

[147] See the Panel's January 2010 Monitoring Report, p. 123. The Panel recognizes that complete elimination of the inefficiencies associated with the two schedule market design requires the adoption of some form of locational marginal pricing. However, it is possible that the supply-side of the market could be compensated by local prices while loads could pay a common purchase price.

There are several limitations associated with this proposed approach. First, individually and collectively the recommendations do not address the root problem that is giving rise to the CMSC payments, namely the two schedule system itself. Until such time as the industry eliminates the two-schedule system altogether, limiting CMSC payments in various ways will be piecemeal solutions. Accordingly, the Panel reiterates here its suggestion from the previous report that the industry makes it a high priority to pursue a structural change to the existing two schedule system. Second, a consequence of a piecemeal approach to limiting CMSC is that the market rules become increasingly complex and opaque, which in turn may hinder market efficiency or give rise to unintended consequences, such as gaming opportunities. Third, practically speaking, managing multiple rule changes may prove to be logistically and practically difficult for the IESO to implement and for market participants to understand. A more effective and potentially simpler solution would be to completely eliminate CMSC payments to dispatchable loads. While on its face this may appear to result in unduly harsh treatment of dispatchable loads, the Panel believes in practice this may not be the case, for the reasons outlined below.

As discussed in the Chapter 3, Section 3.1, two dispatchable load facilities have received approximately $18 million in net CMSC in the period February to June 2010. The Panel identified four causes of these payments:

1. CMSC resulting from frequent ramps
2. Consumption deviation leading to constrained-off CMSC[148]
3. Consumption deviation leading to constrained-on CMSC
4. CMSC as a result of the combination of dispatchable load with a dispatchable generator

[148] Chapter 9, s. 3.5.1A of the market rules allows for recovery of constrained-off CMSC resulting from a participant's consumption deviations. In practice, the IESO's automated recovery tool is unable to recover 100 percent of constrained-off payments due to practical difficulties in identifying the precise amount of consumption deviation.

The first issue identifies significant payments made to a dispatchable load due to daily ramping activities. The payments are a result of the two-schedule system and exacerbated by a high bid price and slow ramp rate. The second and third issues identify CMSC payments made to dispatchable loads that have failed to consume the amounts of energy that the IESO has instructed them to consume by virtue of their constrained schedule. In Chapter 3 the Panel recommended that the IESO should eliminate CMSC paid to dispatchable loads that have voluntarily chosen to change their consumption levels or received payments through consumption deviation. If implemented, this rule change would eliminate the CMSC payments made under the first three factors identified above.

In the previous report the Panel recommended that for the purposes of calculating CMSC payments, the IESO should revise its constrained-on payment calculation using a replacement bid (such as $0/MWh) when dispatchable loads bid at a negative price.[149] If implemented, this rule change would substantially mitigate CMSC payments associated with the fourth factor. The Panel recommends in Chapter 3 that this rule amendment be expedited to reduce these CMSC payments. If the rules changes proposed in Chapter 3 had been in place almost all of the $18 million in CMSC paid to the two dispatchable loads would either (i) not have been paid, or (ii) would have been recoverable by the IESO. The Panel supports the IESO plan to take action through the urgent rule amendment process to significantly reduce the types of CMSC payments discussed in Chapter 3 on the basis that they do not contribute to the efficiency of the market.

Finally, the Panel also notes that the market impact of such payments is ultimately borne by other loads that must bear the uplift costs associated with the CMSC payments that have been made to the two dispatchable load facilities.

While the Panel has not explicitly recommended that all CMSC payments be eliminated for generators or dispatchable loads in this report, the Panel suggested in 2003 that all

[149] See the Panel's January 2010 Monitoring Report, p.104

constrained-off CMSC be eliminated.[150] In addition, the Panel has previously recommended that constrained-on CMSC be limited to generators under certain circumstances. In its last report, the Panel raised concerns about gaming opportunities where generators used extremely high offer prices to obtain significant CMSC payments.[151] In the most extreme cases, the Panel has observed instances where generators have used $2,000 "signal" offers to advise the IESO they want to come offline. As a result of the discrepancies between the constrained and unconstrained schedules, these generators are paid constrained-on CMSC at a value of $2,000/MWh. These payments in turn must be recovered from all Ontario loads through uplift charges. As demonstrated in Table 4-1 below, constrained-on CMSC payments (or uplift charges to consumers) paid to generators for shutting down their units averaged approximately $1 million per month for the period May 2009 to April 2010.

Table 4-1: Monthly Constrained on CMSC Payments Resulting from Generator Shutdowns
May 2009 – April 2010
($ thousands)

	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
Total	**12,652**

[150] See the Panel's July 3, 2003 report titled, "Constrained-off Payments and Other Issues in the Management of Congestion", p. 13 available at:
http://www.oeb.gov.on.ca/documents/msp/panel_cmscconsultation_070303.pdf
[151] See the Panel's January 2010 Monitoring Report, at pp. 112-113.

In Chapter 3 of this report, the Panel again noted how CMSC payments arising from quantities differences between the constrained versus unconstrained schedules and that the magnitude depends on a facility's bid/offer price and its ramp rate. Moreover, high CMSC payments associated with ramping limitations could have the perverse effect of rewarding slower ramping and more inflexible generators and dispatchable loads. Notably, of the $12.7 million paid to generators from May 2009 to April 2010, over $5 million (or 40 percent) was paid to a single market participant whose combined cycle generation facilities have extremely slow ramp rates. Over the corresponding period the market participant concerned consistently offered its generation capacity into the market at price of less than $50/MWh. During ramp down it typically used a 'signal' offer price that was several times higher and generated sizeable CMSC payments often for as long as two hours to come offline.

In its January 2009 Report, the Panel recommended that the IESO take "action to limit CMSC payments where the CMSC payments are induced by the generator strategically raising its offer price to signal the ramping down of its generation."[152] In response the IESO began to stakeholder a market rule amendment, which as currently proposed, would eliminate constrained-on CMSC payments made to generators that are shutting down.[153]

As Table 4-1 above indicates, CMSC payments to generators shutting down are contributing approximately $12 million per year in uplift paid by consumers, which based on an annual market demand of 155 TWh translates into a consumer uplift charge of $0.0775/MWh. These payments are being made to facilities for shut downs that would occur in any event and are not contributing to market efficiency. The Panel therefore reiterates this recommendation and urges the IESO to expedite its efforts to implement a market rule amendment limiting CMSC paid to generators that are shutting down.

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[152] See the Panel's January 2009 Monitoring Report, pp. 216-217.
[153] IESO Stakeholder Engagement 84, *Congestion Management Settlement Credit (CMSC) Payments for Generation Facilities*. For more information see the IESO's SE-84 web page at: http://www.ieso.ca/imoweb/consult/consult_se84.asp

More generally, the Panel urges the IESO and the stakeholders to begin to explore alternatives to the current two schedule regime that would reduce complexity, promote efficiencies, and decrease the gaming opportunities.

6. Implementation of Panel Recommendations from Previous Report

The Panel's January 2010 report contained five recommendations, two of which were directed at the IESO.

6.1 Recommendations to IESO

The IESO formally reports on the status of actions it has taken in response to the Panel's recommendations. Following each of the Panel's Monitoring Reports the IESO posts this information on its web site and discusses the recommendations and its actions with the Stakeholder Advisory Committee (SAC).

In this section we review the status of the recommendations from our last Monitoring Report, released in January 2010. The IESO responses to these are summarized in Table 4-2 below.

Table 4-2: Summary of IESO Responses to Recommendations in the Panel's January 2010 Monitoring Report

Recommendation Number & Status	Subject	Summary of Action
3-4 **Open IESO to Monitor**	Congestion Management Settlement Credit	"The IESO agrees with this recommendation and intends to pursue a market rule amendment to limit constrained on CMSC payments to exporters and dispatchable loads based on a $0 replacement bid price. Although this proposal is consistent with the existing limit on constrained off CMSC payments to generators and importers, the IESO will need to consider whether a $0 replacement bid price creates any unintended consequences that could undermine market efficiency or reliability."
3-5 **Open IESO to Monitor**	Plant Operating Characteristics	"The IESO is already in conversation with the OPA on this topic. The IESO plans to initiate a review, with the OPA's assistance, to investigate further generating plants' capabilities and establish requirements which ground the facilities' associated technical characteristics. Progress on this initiative is dependent on the outcome of business planning resourcing discussions. Following the completion of this project, a compliance and review mechanism may be developed as recommended by MSP in (ii)."

6.2 Other Recommendations

The January 2010 Monitoring Report made three recommendations directed at participants or agencies other than the IESO, one recommendation to OPA and another to the Hydro One and IESO together, and a third to Hydro One.

1. (i) The Panel recommends that the Ontario Power Authority (OPA) should target all Demand Response Phase 3 (DR3) activations, except those required for 'testing' purposes, based on efficiency considerations. This would involve improved identification of periods when system need is greatest and the value of foregone consumption is less than the incremental cost of providing the energy.
   (ii) The Panel recommends that OPA explore the feasibility of introducing a bidding process to allow demand response resources to bid the value at which they are prepared to reduce consumption and work with the IESO to align such a

process with the Enhanced Day-Ahead Commitment (EDAC) process in order to avoid over-commitment of generation and/or imports.

The Panel has been advised that OPA is putting together an exploratory discussion paper that will assess the OPA's DR3 program which is expected to be published in 2011. As part of this process, the OPA will consider the Panel's recommendation relating to the DR 3 program.

2. The Panel recommends that IESO and Hydro One work with their counterparts in Michigan and New York to bring the Phase Angle Regulators (PARs) into service as soon as possible. The Panel encourages the IESO and Hydro One to pursue available channels, including intra-regional discussions, to address any potential future delays resulting from issues raised by the owner of the Michigan PAR in order that Ontario and its neighbouring markets obtain the benefits available from operation of this equipment.

   The matter is currently before FERC, with FERC seeking further information from a number of interested parties, including both the IESO and Hydro One on a voluntary basis.[154] The Panel understands that IESO and Hydro One plan to respond and to advocate for prompt activation of the PARs.

3. The Panel recommends that Hydro One work with its transmission counterpart in New York (National Grid) to return the BP76 transmission line at the New York/Ontario interface at Niagara into service in order to mitigate Surplus Baseload Generation (SBG) situations and realize gains from efficient trading opportunities for participants in the Ontario and New York markets.

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[154] New York Independent System Operator Inc., Docket No. ER08-1281-004 "Order on Compliance Filing" (July 15, 2010); 132 FERC ¶61,031 (2010) available at: http://elibrary.ferc.gov/idmws/file_list.asp?document_id=13832432

The BP76 transmission line will be returning to service in by-pass mode by November 2010.[155]

7. Implementation of Panel Recommendations from Other Reports

During the current reporting period a change to the status of two previous recommendations are considered noteworthy as outlined in Table 4-3.

[155] IESO 18-month Outlook Update from September 2010 to February 2012, p.16 available at: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2010aug.pdf

Table 4-3: Update on Outstanding Recommendations from Previous Panel Reports

Recommendation Number & Status	Subject	Recommendation	Change
MSP Report #14, 3-1 (Chapter 3, section 2.2) **Closed**	Coal-Fired Generation	(i) Ontario Power Generation (OPG) should discontinue the use of Not Offered but Available (NOBA) designations and CO_2 outages in excess of regular planned outages for the remainder of 2009 since they do not appear to be necessary to meet its 2009 CO_2 emission target, and (ii) To the extent that OPG forecasts a need to reduce coal-fired generation in order to comply with its CO_2 emissions limit, the Panel recommends OPG should employ a strategy that utilizes an emissions adder alone as the most efficient way to offer an energy-limited resource into the market at the times when it has the most economic value.	OPG has issued a Revised CO_2 Strategy for 2010, including the removal of NOBA units.[156] MAU will continue to monitor outcomes.
MSP Report #12, 3-3 (Chapter 3, section 3.1) **Closed**	Published Information Frequency Change	The MSP recommends that the IESO publish generating unit output using a one-hour lag rather than the current two-hour lag.	IESO to implement the change to address the recommendation in September 2010.

8. Summary of Recommendations

The IESO's Stakeholder Advisory Committee has encouraged the Panel to provide information about the relative priorities of the recommendations in its reports.[157] In doing so, the Panel notes that it has in the past and will continue to provide efficiency, frequency or other measures of quantitative impact where this is feasible, but that some issues are not readily quantifiable. In addition, the Panel has always recognized that

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[156] See OPG's Strategy to Meet the 2010 CO_2 Emission Target (November 27, 2009) available at: http://www.opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202010%20CO2%20Emission%20Target.pdf and the discussion in Panel's January 2010 Monitoring Report, pp. 67-68.
[157] See Agenda Item 4 in the minutes of the February 6, 2008 meeting of the Stakeholder Advisory Committee available at: http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20080206-Minutes.pdf

recommendations may have implications which extend beyond its focus on market power, gaming and efficiency and that the mandate and resources of the Panel do not extend to stakeholdering of potential changes or detailed assessments of implementation issues. Accordingly, many of the Panel's recommendations are framed as encouraging responsible institutions such as the IESO to consider whether, when and how a particular recommendation should be implemented, including process issues such as whether stakeholdering is useful and the use of detailed cost-benefit analysis or other forms of evaluation.

As in the previous report, the Panel considered that it would be useful to group the recommendations thematically by category: price fidelity, dispatch, transparency and hourly uplift payments. Some recommendations could have impacts in more than one category (e.g. a scheduling change could affect prices as well as uplift) and we have included the recommendation in the category of its primary effect. Within each category of price fidelity, dispatch and hourly uplift payments[158], the recommendations are prioritized in the order that they appear.

8.1 Price Fidelity

The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market.

[158] The Panel does not have any recommendations in this report relating to transparency.

<u>Recommendation 3-6 (Chapter 3, section 3.3)</u>

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.

<u>Recommendation 3-5 (Chapter 3, section 3.3)</u>

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.

8.2 Dispatch

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market.

<u>Recommendation 3-4 (Chapter 3, Section 3.2)</u>

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.

<u>Recommendation 3-3 (Chapter 3, Section 3.1)</u>

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.

8.3 Hourly Uplift Payments

The Panel examines hourly uplift payments[159] both in respect of their contribution to the effective HOEP and also their impact on the efficient operation of the market.

<u>Recommendation 3-1 (Chapter 3, Section 3.1)</u>

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

<u>Recommendation 3-2 (Chapter 3, Section 3.1)</u>

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.

[159] Hourly uplift is the term used to describe wholesale market related uplifts as opposed to other forms of uplift payments.

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

Ontario

Market Surveillance Panel

Statistical Appendix

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2009 – April 2010

PUBLIC

August 2010

List of Tables

Table A-1: Outages, May 2008 - April 2010 (TWh)*

	Total Outage		Planned Outage**		Forced Outage	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	5.43	7.70	1.69	3.85	3.74	3.85
Jun	4.15	4.89	1.21	2.01	2.94	2.88
Jul	2.99	3.70	0.90	0.94	2.09	2.76
Aug	3.24	3.57	1.00	0.96	2.24	2.61
Sep	5.09	6.01	2.32	3.14	2.77	2.87
Oct	5.38	7.52	2.68	3.84	2.70	3.68
Nov	5.50	6.26	2.63	3.59	2.87	2.67
Dec	3.74	4.35	1.23	1.73	2.51	2.62
Jan	3.56	3.39	1.03	0.93	2.53	2.46
Feb	3.87	2.99	1.94	1.34	1.93	1.65
Mar	4.74	4.16	2.78	1.97	1.96	2.19
Apr	5.99	5.96	3.09	3.45	2.90	2.51
May – Oct	26.28	33.39	9.80	14.74	16.48	18.65
Nov - Apr	27.40	27.11	12.70	13.01	14.70	14.10
May - Apr	53.68	60.50	22.50	27.75	31.18	32.75

* There are two sets of data that reflect outages information. Past reports have relied on information from the IESO's outage database. This table reflects the outage information that is actually input to the DSO to determine price. The MAU has reconciled the difference between the two sets of data by applying outage types from the IESO's outage database to the DSO outage information.
** CO_2 Outages are recorded as forced outages by the IESO but are classified as planned outages for purposes of our statistics.

Table A-2: Ontario Consumption by Type of Usage, May 2008 – April 2010 (TWh)

	LDC's*		Wholesale Loads		Generators		Metered Energy Consumption**		Transmission Losses		Total Energy Consumption***	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	8.79	8.34	2.18	1.71	0.07	0.09	11.04	10.14	0.37	0.36	11.41	10.50
Jun	9.53	8.80	2.27	1.69	0.09	0.07	11.89	10.56	0.30	0.32	12.19	10.88
Jul	10.39	9.11	2.33	1.73	0.09	0.10	12.81	10.97	0.35	0.35	13.16	11.32
Aug	9.77	9.89	2.31	1.85	0.08	0.09	12.16	11.89	0.39	0.34	12.55	12.23
Sep	9.14	8.81	2.24	1.71	0.09	0.08	11.47	10.65	0.32	0.28	11.79	10.93
Oct	9.17	9.03	2.12	1.76	0.09	0.08	11.37	10.92	0.26	0.26	11.63	11.18
Nov	9.54	8.96	1.92	1.72	0.08	0.08	11.54	10.81	0.29	0.30	11.83	11.11
Dec	10.70	10.37	1.95	1.73	0.08	0.09	12.73	12.28	0.36	0.39	13.09	12.67
Jan	11.31	10.75	2.06	1.84	0.08	0.11	13.45	12.79	0.28	0.36	13.73	13.15
Feb	9.60	9.53	1.74	1.73	0.07	0.08	11.40	11.41	0.30	0.34	11.70	11.75
Mar	9.88	9.38	1.87	1.85	0.06	0.07	11.81	11.35	0.36	0.34	12.17	11.69
Apr	8.65	8.26	1.69	1.73	0.08	0.12	10.43	10.11	0.32	0.36	10.75	10.47
May –Oct	56.79	53.98	13.46	10.45	0.51	0.50	70.72	65.14	2.01	1.91	72.73	67.04
Nov - Apr	59.68	56.37	11.23	10.43	0.45	0.52	71.36	67.74	1.91	2.09	73.27	70.84
May -Apr	116.47	110.35	24.69	20.88	0.96	1.02	142.08	132.88	3.92	4.00	146.00	137.88

* LDC's is net of any local generation within the LDC
** Metered Energy Consumption = LDC's + Wholesale Loads + Generators
*** Total Energy Consumption = Metered Energy Consumption – Transmission Losses

Table A-3: Total Hourly Uplift Charge by Component, May 2008 – April 2010 ($ Millions)

	Total Hourly Uplift*		RT IOG**		DA IOG*		CMSC***		Operating Reserve		Losses	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	28.44	45.58	1.56	0.80	0.05	0.15	11.33	24.99	5.06	10.81	10.44	8.84
Jun	60.39	37.39	3.38	1.36	3.48	0.10	34.69	21.40	4.70	6.98	17.51	7.55
Jul	46.34	36.54	1.89	5.61	1.95	0.11	18.79	18.01	6.08	7.07	19.52	5.74
Aug	35.13	28.51	1.01	1.30	1.04	0.12	16.31	12.19	2.66	6.52	15.13	8.38
Sep	32.54	20.02	1.52	2.19	1.74	0.16	16.05	11.01	0.89	2.98	13.87	3.68
Oct	30.11	21.03	1.44	1.81	1.46	0.22	14.54	10.32	4.21	1.18	9.90	7.51
Nov	33.80	24.98	1.94	0.49	2.31	0.05	15.46	14.70	4.11	3.05	11.93	6.70
Dec	26.23	24.85	1.19	1.06	1.42	0.05	6.33	10.40	2.54	3.07	15.95	10.27
Jan	32.47	25.98	1.21	0.85	1.25	0.02	9.79	11.64	6.23	3.39	15.20	10.09
Feb	29.08	22.65	0.97	0.53	1.03	0.01	7.94	10.56	6.82	2.38	13.29	9.18
Mar	23.85	23.65	0.79	0.93	0.82	0.01	10.44	12.46	4.24	2.75	8.35	7.49
Apr	27.11	18.41	0.31	0.61	0.32	0.05	13.12	10.49	7.64	0.31	6.02	6.94
May- Oct	232.95	189.07	10.80	13.07	9.72	0.86	111.71	97.92	23.60	35.54	86.37	41.70
Nov - Apr	172.54	140.52	6.41	4.47	7.15	0.19	63.08	70.25	31.58	14.95	70.74	50.67
May -Apr	405.49	329.59	17.21	17.54	16.87	1.05	174.79	168.17	55.18	50.49	157.11	92.37

* Total Hourly Uplift = RT IOG + DA IOG + CMSC + Operating Reserve + Losses
** The IOG numbers are not adjusted for IOG offsets, which was implemented in July 2002. IOG offsets are reported in Table A-16. All IOG Reversals have been applied to RT IOG.
*** Numbers are adjusted for Self-Induced CMSC Revisions for Dispatchable Loads, but not for Local Market Power adjustments.

Table A-4: CMSC Payments, Energy and Operating Reserve, May 2008 – April 2010 ($ Millions)

	Constrained Off		Constrained On		Total CMSC for Energy*		Operating Reserves		Total CMSC Payments**	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	5.57	9.31	3.42	10.84	9.87	20.46	2.06	3.94	11.93	24.40
Jun	23.06	13.33	9.47	6.75	34.43	20.69	1.7	2.86	36.13	23.55
Jul	12.52	15.20	5.37	4.93	19.48	20.54	1.43	2.24	20.92	2.28
Aug	11.14	0.91	3.92	3.04	16.49	12.70	0.69	1.03	17.18	13.73
Sep	11.86	7.60	4.69	2.85	17.56	10.69	0.63	1.72	18.19	12.41
Oct	9.13	9.20	3.89	2.61	13.81	12.11	1.26	0.07	15.07	12.85
Nov	11.54	8.97	5.12	0.37	17.33	13.27	1.50	2.49	18.83	15.75
Dec	3.98	7.86	1.83	3.73	6.42	11.92	0.82	1.12	7.24	13.04
Jan	5.66	7.67	2.23	2.96	9.31	11.07	1.30	0.70	10.61	11.76
Feb	5.10	6.70	1.96	3.44	7.70	13.30	1.13	0.76	8.83	14.06
Mar	3.84	6.70	4.37	3.05	9.53	14.10	1.29	1.14	10.82	15.24
Apr	5.45	4.30	5.72	2.60	11.59	10.48	2.01	0.35	13.60	10.83
May- Oct	73.28	55.55	30.76	31.01	111.64	97.19	7.77	11.86	119.42	89.21
Nov - Apr	35.57	42.21	21.23	16.15	61.88	74.14	8.05	6.55	69.93	80.69
May -Apr	108.85	97.75	51.99	47.16	173.52	171.34	15.82	18.41	189.35	169.90

* The sum for energy being constrained on and off does not equal the total CMSC for energy in some months. This is due to the process for assigning the constrained on and off label to individual intervals not yet being complete. Note that these numbers are the net of positive and negative CMSC amounts.
** The totals for CMSC payments do not equal the totals for CMSC payments in Table A-11: Total Hourly Uplift Charge as the values in the uplift table include adjustments to CMSC payments in subsequent months. Neither table includes Local Market Power adjustments.

Table A-5: Share of Constrained On Payments for Energy by Type of Supplier, May 2008 – April 2010 (%)

	Domestic Generators		Imports	
	2008 / 2009	2009 / 2010	2008 / 2009	2009 / 2010
May	58	97	42	3
Jun	64	89	36	11
Jul	56	64	44	36
Aug	87	91	13	9
Sep	76	76	24	24
Oct	77	84	23	16
Nov	72	101	28	(1)
Dec	87	89	13	11
Jan	84	83	16	17
Feb	71	91	29	9
Mar	85	80	15	20
Apr	96	96	4	4
May- Oct	70	84	30	17
Nov - Apr	83	90	18	10
May -Apr	76	87	24	13

Table A-6: Supply Cushion Statistics, On-Peak,
May 2008 – April 2010
(% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	9.6	15.1	1	0	193	66	14.4	14.2	0	0	58	75
Jun	11.4	13.8	0	0	129	95	14.6	18.5	0	0	69	27
Jul	12.5	12.7	0	0	118	120	16.4	15.4	0	0	38	34
Aug	13.5	12.7	0	0	94	111	16.0	12.0	0	5	59	124
Sep	14.4	12.7	0	0	59	110	12.8	11.6	0	0	108	155
Oct	12.9	15.3	0	0	129	62	15.2	11.9	0	1	53	131
Nov	12.4	16.3	0	0	97	43	12.1	14.1	5	0	135	81
Dec	11.5	12.2	0	0	137	121	14.4	14.2	0	0	73	66
Jan	15.2	11.2	0	0	85	141	20.2	11.5	0	0	16	124
Feb	14.3	10.4	0	0	102	156	18.0	12.4	0	0	35	66
Mar	11.3	10.3	0	0	152	198	17.4	13.0	0	0	52	92
Apr	15.8	16.0	0	0	94	49	16.7	15.2	0	0	83	49
May- Oct	12.4	13.7	1	0	722	564	14.9	13.9	0	6	385	546
Nov - Apr	13.4	12.7	0	0	667	708	16.5	13.4	5	0	394	478
May -Apr	12.9	13.2	1	0	1,389	1,272	15.7	13.7	5	6	779	1,024

* This category includes hours with a negative supply cushion

Table A-7: Supply Cushion Statistics, Off-Peak,
May 2008 – April 2010
(% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	20.7	18.3	0	0	62	78	25.5	21.7	0	1	4	53
Jun	25.5	17.2	0	0	38	74	28.1	27.0	0	0	24	1
Jul	25.5	16.2	0	0	35	98	31.1	25.6	0	0	9	4
Aug	27.7	19.2	0	0	26	83	31.5	24.3	0	0	17	19
Sep	30.3	17.5	0	0	3	56	28.4	21.2	0	0	24	57
Oct	25.9	20.9	0	0	21	55	28.1	20.2	0	0	7	42
Nov	23.5	22.3	0	0	30	11	23.7	21.4	0	2	27	25
Dec	21.9	20.3	0	0	33	37	25.2	25.7	0	0	8	10
Jan	13.7	21.1	0	0	177	67	18.3	22.4	0	3	38	48
Feb	12.8	18.6	0	0	159	71	17.5	20.7	0	0	60	51
Mar	15.8	17.5	0	0	127	76	23.2	22.9	0	0	19	24
Apr	17.6	24.4	0	0	56	10	16.5	25.0	0	0	71	11
May- Oct	25.9	18.2	0	0	185	444	28.8	23.3	0	1	85	176
Nov - Apr	17.6	20.7	0	0	582	272	20.7	23.0	0	5	223	169
May -Apr	21.7	19.5	0	0	767	716	24.8	23.2	0	6	308	345

* This category includes hours with a negative supply cushion

Table A-8: Resources Selected in the Real-time Market Schedule, May 2008 – April 2010 (TWh)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear		Domestic Generation*	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	1.58	0.47	2.65	1.12	1.40	0.85	0.69	0.97	4.04	4.08	6.09	4.96	12.22	10.87
Jun	1.57	0.37	2.52	1.67	2.19	0.45	0.83	1.23	3.50	3.46	6.52	6.87	13.03	12.02
Jul	1.27	0.63	2.43	1.88	2.31	0.34	0.80	1.09	3.63	3.43	7.47	7.47	14.21	12.34
Aug	0.55	0.71	1.69	1.6	2.10	0.76	0.72	1.33	3.22	3.39	7.54	7.47	13.58	12.95
Sep	0.66	0.76	1.26	1.27	1.80	0.33	0.77	1.3	2.60	2.83	7.05	6.79	12.23	11.25
Oct	0.65	0.65	1.46	1.03	1.47	0.59	0.82	1.35	2.62	2.91	7.18	6.37	12.09	11.23
Nov	0.79	0.26	1.36	1	1.59	0.49	1.04	1.29	2.76	3.21	6.75	6.55	12.14	11.54
Dec	0.41	0.35	1.41	1.41	1.62	1.41	1.17	1.1	3.03	3.19	7.90	7.6	13.71	13.29
Jan	0.64	0.74	1.82	1.55	2.16	2.1	1.28	0.93	3.30	3.14	7.89	7.36	14.64	13.53
Feb	0.41	0.7	1.35	1.23	1.34	1.5	1.12	0.85	3.03	2.87	6.83	6.74	12.33	11.96
Mar	0.65	0.67	1.42	1.29	0.96	0.62	1.18	1.03	3.27	3.21	7.63	7.06	13.04	11.92
Apr	0.79	0.47	1.35	0.84	0.56	0.63	1.06	1.08	3.19	2.64	6.19	6.12	10.99	10.46
May – Oct	6.28	3.59	12.01	8.57	11.27	3.32	4.63	7.27	19.61	20.1	41.85	39.93	77.36	70.66
Nov - Apr	3.69	3.19	8.71	7.32	8.23	6.75	6.85	6.28	18.58	18.26	43.19	41.43	76.85	72.7
May - Apr	9.97	6.78	20.72	15.89	19.50	10.07	11.48	13.55	38.19	38.36	85.04	81.36	154.21	143.4

* Domestic generation is the sum of Coal, Oil/Gas, Hydroelectric, and Nuclear.

Table A-9: Demand Forecast Error; Pre-Dispatch versus Average and Peak Hourly Demand, May 2008 – April 2010 (MW and %)

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	269	278	247	252	193	186	156	157	1.8	2.0	1.7	1.9	1.3	1.3	1.0	1.1
Jun	390	313	343	286	269	219	210	187	2.3	2.1	2.1	1.9	1.6	1.4	1.2	1.2
Jul	396	346	336	299	274	235	198	183	2.3	2.3	2.0	2.0	1.5	1.5	1.1	1.2
Aug	333	381	307	333	240	256	197	200	2.0	2.4	1.9	2.1	1.4	1.5	1.1	1.2
Sep	280	308	267	281	188	194	159	161	1.7	2.1	1.7	1.9	1.1	1.3	1.0	1.1
Oct	290	270	272	247	175	177	153	147	1.9	1.8	1.8	1.7	1.1	1.2	1.0	1.0
Nov	318	325	298	307	186	194	159	159	2.0	2.2	1.9	2.0	1.1	1.3	1.0	1.0
Dec	388	329	346	282	248	252	193	207	2.2	2.0	2.0	1.7	1.4	1.5	1.1	1.2
Jan	403	264	355	213	244	247	197	214	2.2	1.5	1.9	1.2	1.3	1.4	1.1	1.2
Feb	333	220	300	182	205	227	165	214	1.9	1.3	1.7	1.1	1.2	1.3	0.9	1.2
Mar	341	224	292	179	248	252	198	221	2.1	1.4	1.8	1.2	1.5	1.6	1.2	1.4
Apr	305	217	266	178	213	257	175	223	2.1	1.5	1.8	1.2	1.4	1.8	1.2	1.5
May – Oct	326	316	295	283	223	211	179	173	2.0	2.1	1.9	1.9	1.3	1.4	1.1	1.1
Nov – Apr	348	263	310	224	224	238	181	206	2.1	1.7	1.9	1.4	1.3	1.5	1.1	1.3
May - Apr	337	290	302	253	224	225	180	189	2.0	1.9	1.9	1.7	1.3	1.4	1.1	1.2

*Table A-10: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges, May 2008 – April 2010 (%)**

	> 500 MW		200 to 500 MW		100 to 200 MW		0 to 100 MW		0 to -100 MW		-100 to -200 MW		-200 to -500 MW		<-500 MW		>0 MW		< 0 MW	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	1	1	13	12	15	15	18	21	22	20	15	15	16	17	1	1	47	49	54	53
Jun	5	4	21	13	14	14	16	18	14	18	12	14	16	18	2	1	56	49	44	51
Jul	4	3	18	18	12	16	17	17	16	17	15	15	16	14	3	1	51	54	50	47
Aug	3	3	15	18	13	14	18	20	16	15	13	9	20	18	3	3	49	55	52	45
Sep	0	1	13	17	11	14	19	21	23	19	16	14	16	11	1	2	43	53	56	46
Oct	1	1	15	13	17	13	21	18	19	24	16	17	11	15	1	1	54	45	47	57
Nov	2	2	17	16	16	18	23	21	19	18	12	14	10	10	1	1	58	57	42	43
Dec	4	2	20	15	17	10	20	17	15	17	11	14	11	21	2	5	61	44	39	57
Jan	3	1	26	7	17	8	20	15	13	17	10	18	10	27	1	7	66	31	34	69
Feb	2	0	17	6	18	8	19	15	20	17	12	16	11	28	1	8	56	29	44	69
Mar	1	0	19	7	13	8	16	12	17	17	12	18	18	30	3	8	49	27	50	73
Apr	1	0	16	6	14	6	18	11	18	19	14	19	16	31	2	8	49	23	50	77
May – Oct	2	2	16	15	14	14	18	19	18	19	15	14	16	16	2	2	50	51	51	50
Nov – Apr	2	1	19	10	16	10	19	15	17	18	12	17	13	25	2	6	57	35	43	65
May - Apr	2	2	18	12	15	12	19	17	18	18	13	15	14	20	2	4	53	43	47	57

* Data includes both dispatchable and non-dispatchable load.

Table A-11: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities,
May 2008 – April 2010
(MW and %)*

	Pre-Dispatch (MW)		Pre-Dispatch (MW)						Fail Rate** (%)	
					Minimum		Average			
	2008 / 2009	2009 / 2010	2008 / 2009	2009 / 2010	2008 / 2009	2009 / 2010	2008 / 2009	2009 / 2010	2008 / 2009	2009 / 2010
May	782,035	870,407	466.4	333.3	(187.6)	(297.8)	42.6	32.0	4.4	3.1
Jun	572,393	885,315	257.9	916.1	(138.3)	(423.0)	37.0	64.8	5.0	6.0
Jul	574,125	719,422	259.5	217.2	(524.7)	(227.2)	42.1	19.4	5.3	2.1
Aug	599,291	722,427	666.2	328.4	(178.7)	(306.5)	60.9	35.6	7.5	3.7
Sep	625,327	710,740	874.8	291.0	(1014.6)	(252.9)	19.0	58.5	2.0	6.5
Oct	861,952	927,991	1055.6	312.1	(334.1)	(392.0)	18.1	(1.7)	0.8	(0.1)
Nov	840,871	878,206	232.9	307.1	(207.1)	(331.4)	27.1	25.1	2.4	2.5
Dec	1,075,374	1,013,138	635.3	386.3	(179.2)	(308.7)	76.1	24.0	5.2	1.9
Jan	935,618	996,683	590.1	291.0	(279.3)	(313.2)	25.4	31.6	1.9	2.4
Feb	925,681	848,610	616.4	358.6	(261.7)	(324.3)	33.2	38.4	2.4	3.2
Mar	1,130,834	1,020,117	535.4	348.0	(266.5)	(309.0)	25.0	18.5	1.3	1.4
Apr	1,089,791	888,135	893.0	523.9	(529.8)	(388.7)	34.4	26.5	2.2	2.1
May – Oct	669,187	806,050	596.7	399.7	(396.3)	(316.6)	36.6	34.8	4.2	3.6
Nov – Apr	999,695	940,815	583.9	369.2	(287.3)	(329.2)	36.9	27.3	2.6	2.3
May - Apr	834,441	873,433	590.3	384.4	(341.8)	(322.9)	36.7	31.0	3.4	2.9

* Self-scheduled generators comprise list as well as those dispatchable units temporarily classified as self-scheduling during testing phases following an outage for major maintenance.
** Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-12: Discrepancy between Wind Generators' Offered and Delivered Quantities, May 2008 – April 2010

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	107,523	217,700	173.9	280.6	(178.0)	(301.9)	4.5	15.6	2.6	11.2
Jun	59,868	113,192	144.1	194.7	(162.9)	(279.5)	1.7	36.9	0.4	30.1
Jul	61,196	126,285	154.8	200.5	(125.6)	(212.7)	6.3	18.0	(317.9)	16.0
Aug	60,478	162,390	122.0	269.9	(209.2)	(285.7)	8.0	25.5	14.3	21.2
Sep	81,062	151,860	182.1	307.3	(182.0)	(264.5)	9.8	32.3	8.6	25.9
Oct	160,840	252,763	191.9	309.8	(234.7)	(356.7)	7.3	12.7	4.3	8.3
Nov	167,804	223,722	190.5	277.1	(191.8)	(291.6)	15.2	24.0	7.0	13.4
Dec	277,106	290,193	312.3	352.2	(226.9)	(297.5)	30.0	23.6	11.7	10.4
Jan	192,994	273,083	242.0	284.2	(252.3)	(302.1)	17.0	24.8	12.1	13.6
Feb	217,694	183,677	283.6	258.7	(251.3)	(238.3)	27.8	26.7	14.6	16.6
Mar	207,877	229,711	262.5	250.7	(357.3)	(307.1)	13.6	5.6	7.9	6.9
Apr	262,595	249,059	285.0	317.8	(317.8)	(388.8)	12.5	3.2	4.1	4.3
May – Oct	88,495	170,698	161.5	260.5	(182.1)	(283.5)	6.3	23.5	(48.0)	18.8
Nov – Apr	221,012	241,574	262.7	290.1	(266.2)	(304.2)	19.4	18.0	9.6	10.9
May - Apr	154,753	206,136	212.1	275.3	(224.2)	(293.9)	12.8	20.7	(19.2)	14.8

* Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-13: Failed Imports into Ontario, On-Peak, May 2008 – April 2010 (Incidents and Average Magnitude)

	Number of Hours with Failure*		**Maximum Hourly Failure (MW)**		**Average Hourly Failure (MW)**		**Failure Rate (%)****	
	2008/2009	**2009/2010**	**2008/2009**	**2009/2010**	**2008/2009**	**2009/2010**	**2008/2009**	**2009/2010**
May	156	74	680	220	182	5	3.6	1.6
Jun	185	132	1,369	455	225	94	5.5	5.2
Jul	165	160	979	582	172	90	4.1	3.7
Aug	120	122	880	1,079	144	11	5.9	3.2
Sep	141	170	702	642	175	66	8.0	2.8
Oct	147	107	1,029	224	181	58	8.2	2.0
Nov	104	89	730	270	145	69	3.9	4.8
Dec	114	100	531	689	138	102	7.0	5.8
Jan	125	100	575	410	127	10	5.7	2.4
Feb	60	89	800	300	152	65	4.7	1.4
Mar	44	113	375	453	64	67	2.2	1.6
Apr	31	113	225	429	75	72	2.1	2.9
May-Oct	914	765	940	534	180	54	5.9	3.1
Nov-Apr	478	604	539	425	117	64	4.3	3.1
May-Apr	1392	1369	740	479	148	59	5.1	3.1

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-14: Failed Imports into Ontario, Off-Peak, May 2008 – April 2010 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	208	164	1,085	381	235	82	5.7	5.3
Jun	217	138	1,225	783	242	109	5.8	9.7
Jul	174	164	818	619	192	118	5.2	6.9
Aug	151	151	600	750	141	94	7.2	4.6
Sep	209	173	989	965	247	14	12.0	6.2
Oct	193	160	950	855	193	122	9.6	5.4
Nov	181	155	725	580	154	85	6.2	8.6
Dec	109	162	812	625	147	118	7.4	9.3
Jan	171	131	600	300	152	100	6.4	3.9
Feb	91	72	605	388	155	98	5.8	2.5
Mar	141	76	575	371	120	64	10.3	2.3
Apr	119	171	425	506	116	132	11.2	10.4
May-Oct	1,152	950	945	726	208	90	7.6	6.3
Nov-Apr	812	767	624	462	141	100	7.9	6.1
May-Apr	1,964	1,717	784	594	175	95	7.7	6.2

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-15: Failed Exports from Ontario, On-Peak, May 2008 – April 2010 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	306	144	915	1,342	211	118	4.9	4.1
Jun	261	179	1,100	1,120	246	260	5.3	5.6
Jul	242	254	1,263	1,739	184	389	3.7	11.3
Aug	170	182	558	1,968	139	260	3.0	7.1
Sep	167	168	610	908	148	127	4.4	4.0
Oct	178	125	725	485	150	1	3.7	3.1
Nov	130	67	552	350	155	104	3.4	1.8
Dec	183	190	1,645	1,430	189	23	5.1	7.3
Jan	204	192	965	1,280	158	247	3.8	6.2
Feb	160	184	675	939	145	264	4.2	6.8
Mar	159	244	1,102	1,019	159	289	3.8	9.6
Apr	106	202	578	980	94	228	3.2	11.0
May-Oct	1,324	1,052	862	1,260	180	193	4.2	5.8
Nov-Apr	942	1,079	920	1,000	150	192	3.9	7.1
May-Apr	2,266	2,131	891	1,130	164	193	4.0	6.5

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-16: Failed Exports from Ontario, Off-Peak, May 2008 – April 2010 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	365	198	1,100	1,160	237	204	5.8	5.4
Jun	344	216	1,450	1,144	227	215	5.4	5.0
Jul	322	274	1,858	1,563	141	276	3.4	6.5
Aug	234	254	709	1,117	140	18	3.4	4.5
Sep	192	225	729	989	154	218	4.0	6.2
Oct	199	190	492	1,050	131	153	3.3	4.5
Nov	185	107	497	779	114	127	2.6	2.2
Dec	203	241	1,271	1,176	165	16	4.2	4.4
Jan	231	243	639	1,005	115	186	2.6	5.2
Feb	184	212	484	933	124	250	2.7	8.6
Mar	201	215	1,815	830	174	176	4.2	5.7
Apr	213	180	900	830	114	239	4.7	8.6
May-Oct	1,656	1,357	1,056	1,170	172	181	4.2	5.3
Nov-Apr	1,217	1,198	934	926	134	166	3.5	5.8
May-Apr	2,873	2,555	995	1,048	153	173	3.9	5.5

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-17: Sources of Total Operating Reserve Requirements, On-Peak Periods, May 2008 – April 2010

	Average Hourly Reserve (MW)		% of Total Requirements														Export	
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import					
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010			2008/2009	2009/2010
May	1,374	1,453	16.1	7.4	22.6	24.0	39.2	39.5	9.3	18.2	9.4	10.8	0.0	0.0			3.4	0.0
Jun	1,316	1,478	18.7	6.4	37.5	37.5	18.0	34.8	13.6	9.8	8.2	11.6	0.0	0.0			3.9	0.0
Jul	1,315	1,511	18.3	7.1	44.1	43.5	13.9	34.0	14.6	7.1	5.8	7.2	0.0	1.1			3.3	0.0
Aug	1,317	1,516	20.4	12.6	51.6	47.4	10.3	30.7	10.8	5.8	3.0	3.5	0.0	0.0			4.0	0.0
Sep	1,324	1,555	19.2	12.2	58.5	49.4	9.1	24.9	7.4	9.3	1.6	3.7	0.0	0.4			4.2	0.0
Oct	1,491	1,412	9.2	13.0	61.0	60.1	15.3	15.2	6.4	10.4	4.3	1.3	0.1	0.0			3.7	0.0
Nov	1,546	1,487	4.8	11.8	64.7	41.9	13.5	26.9	9.4	11.2	4.2	6.4	0.2	1.8			3.3	0.0
Dec	1,516	1,514	5.4	12.3	73.4	56.0	8.1	18.3	8.3	8.8	1.8	1.4	0.0	3.2			2.9	0.0
Jan	1,522	1,514	6.2	12.6	56.3	57.7	21.2	19.7	12.0	8.5	4.2	1.4	0.0	0.1			0.0	0.0
Feb	1,472	1,519	4.3	15.2	56.0	55.3	26.2	19.9	8.1	8.2	5.4	1.3	0.0	0.1			0.0	0.0
Mar	1,456	1,547	7.9	14.8	53.4	56.8	27.2	19.2	7.2	7.4	4.3	1.1	0.0	0.7			0.0	0.0
Apr	1,588	1,396	5.3	15.0	42.7	72.7	29.1	3.6	14.8	7.0	8.2	0.9	0.0	0.8			0.0	0.0
May-Oct	1,356	1,488	17.0	9.8	45.9	43.6	17.6	29.9	10.3	10.1	5.4	6.3	0.0	0.2			3.8	0.0
Nov-Apr	1,517	1,496	5.7	13.6	57.7	56.7	20.9	17.9	10.0	8.5	4.7	2.1	0.0	1.1			1.0	0.0
May-Apr	1,436	1,492	11.3	11.7	51.8	50.2	19.2	23.9	10.2	9.3	5.0	4.2	0.0	0.7			2.4	0.0

Table A-18: Sources of Total Operating Reserve Requirements, Off-Peak Periods, May 2008 – April 2010

	Average Hourly Reserve (MW)		% of Total Requirements														Export	
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import					
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010			2008/2009	2009/2010
May	1,333	1,453	22.3	10.8	42.7	45.3	19.4	27.6	9.7	10.9	1.7	5.4	0.1	0.0			4.1	0.0
Jun	1,358	1,498	20.9	9.7	54.9	71.4	5.4	7.8	12.1	8.2	2.4	2.8	0.0	0.0			4.3	0.0
Jul	1,315	1,504	19.5	10.2	57.2	71.8	7.6	7.3	10.3	7.1	1.7	2.0	0.0	1.6			3.7	0.0
Aug	1,321	1,510	21.3	12.9	61.9	68.8	2.2	10.7	9.6	6.0	0.5	1.6	0.0	0.0			4.5	0.0
Sep	1,329	1,578	20.7	12.1	65.3	71.1	0.4	6.2	8.4	7.1	0.8	1.3	0.0	2.2			4.4	0.0
Oct	1,477	1,398	13.1	12.7	72.5	74.1	4.2	3.7	6.2	9.0	0.4	0.6	0.0	0.0			3.7	0.0
Nov	1,523	1,483	7.0	11.8	79.0	64.2	3.3	10.1	6.4	9.6	0.5	3.9	0.0	0.4			3.7	0.0
Dec	1,507	1,522	5.5	10.6	81.2	72.7	2.5	5.3	7.2	10.0	0.2	0.6	0.0	0.8			3.3	0.0
Jan	1,517	1,514	8.8	11.6	79.4	75.2	4.6	3.3	6.3	9.2	0.9	0.5	0.0	0.3			0.0	0.0
Feb	1,466	1,520	7.0	13.0	79.4	72.7	7.3	4.4	5.2	9.1	1.0	0.3	0.0	0.6			0.0	0.0
Mar	1,454	1,585	10.3	14.4	78.6	69.1	4.5	6.8	6.2	8.8	0.5	0.4	0.0	0.5			0.0	0.0
Apr	1,530	1,434	9.2	14.6	70.4	77.6	9.8	1.1	8.9	6.5	1.7	0.2	0.0	0.0			0.0	0.0
May-Oct	1,356	1,490	19.6	11.4	59.1	67.1	6.5	10.5	9.4	8.0	1.2	2.3	0.0	0.6			4.1	0.0
Nov-Apr	1,500	1,510	7.9	12.7	78.0	71.9	5.3	5.1	6.7	8.9	0.8	1.0	0.0	0.4			1.2	0.0
May-Apr	1,428	1,500	13.8	12.0	68.6	69.5	5.9	7.8	8.0	8.5	1.0	1.6	0.0	0.5			2.6	0.0

Table A-19: Monthly Payments for Reliability Programs, May 2008 – April 2010 ($ millions)

	DA IOG*		RT IOG*		OR		DA GCG		SGOL		Total	
	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010	2008/2009	2009/2010
May	0.05	0.15	1.42	0.80	5.07	11.02	1.07	3.07	0.13	0.69	7.74	15.73
Jun	0.10	0.10	3.06	1.29	4.79	7.40	3.31	2.85	0.03	1.03	11.29	12.67
Jul	0.06	0.11	1.62	5.19	6.09	7.37	3.52	7.26	0.15	1.60	11.44	21.53
Aug	0.03	0.12	0.90	1.30	2.66	6.71	2.82	8.12	0.01	1.25	6.42	17.50
Sep	0.22	0.16	1.44	2.18	0.89	3.04	2.32	9.37	0.03	0.94	4.90	15.69
Oct	0.02	0.22	1.30	1.79	4.21	1.20	1.73	6.79	0.12	1.14	7.38	11.14
Nov	0.37	0.05	1.82	0.50	4.17	3.05	3.86	9.07	0.03	0.52	10.25	13.19
Dec	0.23	0.05	1.10	1.03	2.56	3.09	5.68	9.62	0.18	2.09	9.75	15.88
Jan	0.04	0.02	1.15	0.78	6.23	3.39	5.47	2.48	0.59	4.49	13.48	11.16
Feb	0.06	0.01	0.92	0.50	6.82	2.39	5.16	1.26	0.64	5.40	13.60	9.56
Mar	0.03	0.01	0.76	0.90	4.28	2.75	7.58	2.11	0.87	8.93	13.52	14.70
Apr	0.01	0.05	0.30	0.59	7.58	0.31	1.80	1.47	0.44	8.16	10.13	10.58
May – Oct	0.48	0.85	9.74	12.54	23.71	36.74	14.77	37.45	0.47	6.65	49.17	94.23
Nov – Apr	0.74	0.19	6.05	4.31	31.64	14.99	29.55	26.01	2.75	29.58	70.73	75.08
May - Apr	1.22	1.04	15.79	16.85	55.35	51.73	44.32	63.46	3.22	36.23	119.9	169.31

* In certain situations, payments for the same import are made via the DA IOG and RT IOG programs but subsequently one of the payments is recovered through the IOG reversal. Since June 2006, approximately $3.15 million has been received through the IOG reversal. The data reported in this table does not account for the IOG reversal.

Table A-20: Summary Statistics for Hours when HOEP < $0/MWh, May 2009 – April 2010

Month	Number of Hours*	PD Demand (MW)**	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	% Change in Price	Minimum HOEP
May	24	12,019	11,628	(3.3)	250	10.96	(4.67)	(142.6)	(23.46)
June	41	11,845	11,571	(2.3)	306	2.72	(9.56)	(452.0)	(52.08)
July	14	11,736	11,427	(2.6)	392	5.37	(5.24)	(197.4)	(14.42)
August	11	12,212	11,908	(2.5)	388	8.41	(4.88)	(158.0)	(11.35)
September	25	12,387	11,996	(3.2)	161	14.87	(6.77)	(145.5)	(15.78)
October	5	12,132	11,924	(1.7)	380	24.09	(9.04)	(137.5)	(15.19)
November	16	12,916	12,432	(3.7)	2	12.38	(6.34)	(151.2)	(15.3)
December	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
January	1	15,260	14,737	(3.4)	393	25.05	(7.28)	(129.1)	(7.28)
February	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
March	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
April	9	12,078	11,688	(3.2)	155	20.31	(34.05)	(267.7)	(128.15)
Total	146	12,149	11,800	(2.9)	247	9.86	(8.63)	(187.5)	(128.15)

* Monthly figures reflect the average of hourly PD and RT Demand, Net Failed Exports, and PD and HOEP prices over all hours when HOEP was negative.