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
May 2012 – October 2012

June 2013

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Executive Summary

This semi-annual monitoring report covers the period May1, 2012 to October 31, 2012 (the "Summer 2012 Period"). As is the Market Surveillance Panel's practice for reports covering a May to October period (the "Summer Period"), this report focuses on the results of the Panel's review of high-price and low-price hours and of other market outcomes that are potentially anomalous (Chapter 2). It also discusses notable changes and developments that affect the efficient operation of the IESO-administered markets (Chapter 3), as well as the implementation of recommendations made in the Panel's last monitoring report (Chapter 4).

1. Overall Assessment

Consistent with the Panel's streamlined approach to Summer Period monitoring reports referred to in Chapter 1, the Panel is deferring its assessment of the state of the IESO-administered markets to its next monitoring report (covering the winter period November 2012 to April 2013).

The Panel did not find an abuse of market power to have occurred in the Summer 2012 Period. The Panel currently has six investigations underway, all of which relate to possible gaming issues.

2. Demand and Supply Conditions

Ontario demand totalled 71.1 TWh in the Summer 2012 Period, up by 0.9 TWh (1.3%) from the preceding Summer Period. In the Summer 2012 Period, demand was greater in the months of May through August, and lighter during September, compared to the same months in 2011. Relative to 2011, the largest percentage increase in demand occurred in June at 4.6%.

Two refurbished Bruce Power nuclear units returned to service in the Summer 2012 Period and added approximately 1,552 MW to the province's supply. In addition, the

York Energy Centre, with a capacity of 464 MW, became fully dispatchable in May 2012, providing valuable flexibility to the system.

Ontario Power Generation's coal-fired Atikokan generating station (211 MW capacity) was closed in early September, and is being converted to use biomass (wood pellets) as its main fuel source.

3. Market Prices and the Global Adjustment

The average load-weighted Hourly Ontario Energy Price (HOEP) was $25.90/MWh during the Summer 2012 Period, a decrease of $6.54/MWh from the prior Summer Period. The lowest monthly average load-weighted HOEP of the Summer 2012 Period was $20.11/MWh (in May 2012), and the highest was $33.64/MWh (in July 2012). The average load-weighted HOEP was lower in every month in the Summer 2012 Period relative to the corresponding months in the previous Summer Period.

The Panel reports what it calls the "effective price" for Ontario consumers, which is comprised of the HOEP, Global Adjustment (GA) charges and uplift. For the Summer 2012 Period, the effective price was $46.00/MWh for Class A consumers that are directly connected to the IESO-controlled grid, and $74.04/MWh for all other consumers (Class B consumers and Class A consumers that are connected at the distribution level).[1] The principal reason for the difference in the effective prices is the amount of GA that was charged to each Class of consumer. In the Summer 2012 Period, the average GA cost was $20.60/MWh for Class A consumers that are directly connected to the IESO-controlled grid and was $46.08/MWh for all other consumers.

Operating reserve prices fell by between 70% and 83% (depending on the category) in the Summer 2012 Period compared to prices in the preceding Summer Period.

[1] The "Class A" and "Class B" distinction stems from the classification of consumers into different classes for purposes of the allocation of the GA, with Class A consumers being those whose average peak demand exceeds 5 MW and Class B consumers being all other consumers. This is discussed in greater detail in section 4 of Chapter 3, as is the reason why Class A consumers that are connected at the distribution level are grouped with Class B consumers for purposes of the much of the discussion in this report.

Transmission right auction prices for imports into the Northwest (Manitoba and Minnesota) continued to be very high relative to auction prices for other interties; however, those prices were lower, and in some cases significantly lower, than auction prices in the Summer 2011 Period.

4. *Market Outcomes*

There was only one hour in the Summer 2012 Period in which the HOEP exceeded $200/MWh. This is the lowest number of high-price hours in any Summer Period since market opening. The single high-price event was primarily the result of high demand due to extreme temperatures, coupled with forced outages at several large dispatchable generators.

In the Summer 2012 Period, there was a total of 1,377 low-price hours, comprised of 1,285 hours in which the HOEP was between $0/MWh and $20/MWh (compared to 718 hours in the previous Summer Period), and 92 hours in which the HOEP was negative (compared to 96 hours in the previous Summer Period). Surplus baseload generation and other factors previously identified by the Panel largely continue to explain the low-price hours. A sharp increase in the amount of fossil fuel-fired generation being offered at less than $20/MWh, particularly gas-fired generation, was an important contributor to much of the low-price hours experienced in the Summer 2012 Period. There were eight consecutive hours of negative prices from late on October 29 through the early morning of October 30, largely reflecting the effects of Hurricane Sandy.

There were three instances in which the Panel's anomalous uplift screening criteria were met. On two days in the Summer 2012 Period, Congestion Management Settlement Credit (CMSC) payments exceeded $1,000,000. The Panel's analysis of the CMSC payments made on one of those days has led it to make a recommendation to the Independent Electricity System Operator (IESO) to consider expanding its local market power framework to cover circumstances that arise as part of the day-ahead commitment process. The third instance was the one day on which Intertie Offer Guarantee payments exceeded $1,000,000.

5. Matters to Report in the Ontario Electricity Marketplace

Phase Angle Regulators

Phase angle regulators (PARs) are special transformers that can control power flow over a transmission line. Without such control, actual power flows differ from the flows that have been scheduled, which can have both reliability and economic implications. Lake Erie Circulation (LEC) has historically been a significant issue for the IESO and neighbouring U.S. system operators, leading to congestion and CMSC payments.

In July 2012, two new PARs became fully operational at the Ontario-Michigan border. Together with the three already operational PARs, these devices now allow the IESO to better control power flows at the border. The Panel analyzed the first five months of operation of the five PARs and found that: LEC is down significantly from historic levels; there have been fewer curtailments of imports or exports by the IESO and neighbouring system operators; and CMSC payments made to intertie traders at the Michigan and New York interfaces have dropped significantly.

Ramp-Down CMSC Payments to Generators

The Panel has on several occasions expressed its view that CMSC payments to generators that raise their offer prices in order to shut down are unwarranted. After the IESO suspended work on proposed rule changes to address this issue, the Panel issued a Monitoring Document in August 2011 that sets out the evaluative criteria that the Panel uses in monitoring for gaming in relation to prices offered by generators in order to take their units offline. Since issuance of the Monitoring Document, ramp-down CMSC payments to generators have declined from an average of roughly $1,000,000 dollars per month to an average of about $370,000 per month. The Panel considers this to be a very positive development. However, ramp-down CMSC payments remain sizable, and are largely attributable to generators that continue to offer at prices above the levels set out in the Monitoring Document.

The Panel will continue to monitor generators' ramp-down offer prices and may, in appropriate circumstances, initiate gaming investigations. However, the Panel's view remains that gaming investigations are not the solution to the ramp-down CMSC issue and that a permanent, rule-based solution is required. The Panel therefore repeats an earlier recommendation to the IESO to eliminate such CMSC payments.

Efficiency Implications of the Global Adjustment Allocation

Beginning in January 2011, the method of allocating the GA changed. Consumers with average peak demand exceeding 5 MW (known as Class A consumers) are now allocated GA for a year based on their share of total Ontario demand in the five hours with the highest demand in the preceding year. Other consumers (known as Class B consumers) continue to pay GA on a volumetric (per MWh) basis. In this report, the Panel examines the efficiency implications of the revised GA allocation methodology, based in part on an econometric study commissioned by the Panel which the Panel understands to be the first of its kind.

The Panel acknowledges that its analysis does not lend itself to definitive conclusions in a number of areas, and that further work needs to be done in this area in order to achieve a more comprehensive understanding of the efficiency implications of the revised GA allocation. The Panel encourages the development of additional analyses, potentially using other variables and data sources to the extent that they might serve to enhance the overall accuracy of the results. Based on its work to date, however, the Panel has not seen evidence of an increase in efficiency due to the revised GA allocation. The Panel hopes that publication of its analysis will serve to inform and stimulate further discussion on the issue, and will make a useful contribution to the consultation recently initiated by the IESO to review the GA.

6. Recommendations

In this report, the Panel makes two recommendations relating primarily to uplift and other payments.

a) A large portion of the roughly $1 million of CMSC payments that were incurred on June 8, 2012 was paid to a generator that was scheduled under the IESO's day-ahead commitment process. The generator submitted uneconomic offers but was constrained on to resolve a security violation on the transmission system. In other circumstances, the IESO would have been able to review (and potentially adjust or recalculate) these CMSC payments under the local market power framework set out in the market rules. However, the local market power framework does not currently cover units scheduled in the day-ahead commitment process.

Recommendation 2-1

The IESO should consider expanding the current local market power framework to cover analogous circumstances that arise as part of the day-ahead commitment process.

b) The Panel continues to believe that self-induced CMSC payments to generators during ramp down should be eliminated. The Panel therefore repeats the recommendation that appeared in its April 2012 monitoring report.

Recommendation 3-1

The IESO should implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping down generators.

Chapter 1: Market Outcomes

This chapter provides a brief summary of the results for the IESO-administered markets over the period May 1, 2012 to October 31, 2012, with comparisons to the same period one year earlier. [2] For ease of reference, the May to October period is referred to as the "Summer Period".

1.1 *Pricing*

This section sets out a summary of pricing in the IESO-administered markets, covering: the Hourly Ontario Energy Price (HOEP); effective prices (HOEP plus the Global Adjustment (GA) and uplift[3]); operating reserve prices; and transmission rights auction prices. For the purposes of the first two categories of prices, the information is presented by consumer class, generally aligned with the consumer classification that applies to the allocation of the GA. For GA allocation purposes, consumers are divided into two groups: Class A, being consumers whose average peak demand exceeds 5 MW (these consumers can be directly connected to the IESO-controlled grid or connected at the distribution level); and Class B, being all other consumers.[4] Because information regarding consumption by Class A consumers that are connected at the distribution level is not readily available from distributors, information pertaining to Class A consumers below relates only to Class A consumers that are directly connected to the IESO-controlled grid (referred to as "Direct Class A"), who account for approximately 67% of all Class A consumption. Class A consumers that are connected at the distribution level (referred to as "Embedded Class A") are grouped with Class B consumers.

[2] Beginning in 2009, the Panel adopted a streamlined format for its summer period semi-annual reports. A more detailed analysis of market outcomes will be provided in the report for the winter period ending April 2013.
[3] In this report, uplift refers to hourly uplift, which includes hourly payments for operating reserve, Congestion Management Settlement Credit payments and Intertie Offer Guarantee payments.
[4] See Ontario Regulation 398/10 (Adjustments under section 25.33 of the Act) made under the *Electricity Act, 1998*, available at http://www.e-laws.gov.on.ca/html/source/regs/english/2010/elaws_src_regs_r10398_e.htm. Further detail regarding the allocation of the GA between Class A and Class B consumers is set out in Chapter 3.

1.2 *HOEP and Effective Prices*

The average load-weighted HOEP[5] was $25.90/MWh during the Summer 2012 Period, representing a decrease of $6.54/MWh from the prior Summer Period. The lowest monthly average load-weighted HOEP of the Summer 2012 Period was $20.11/MWh (in May 2012), and the highest monthly average load-weighted HOEP was $33.64/MWh (in July 2012). As shown in Table 1-1, all months during the Summer 2012 Period featured lower average load-weighted HOEPs than their Summer 2011 Period counterparts. The monthly average load-weighted HOEP varied slightly more during the Summer 2012 Period relative to that in 2011, with the highest-price month (July) having an average HOEP that was $13.53/MWh (67%) greater than the lowest-price month (May). In the Summer 2011 Period, the highest-price month (July) had an average HOEP that was $11.18/MWh (43%) greater than the lowest-price month (May).

Table 1-1: Average Load-Weighted Hourly Ontario Energy Price by Consumer Class May – October, 2011 & 2012 ($/MWh)

Month	2012			2011		
	All Consumers	Direct Class A	Class B plus Embedded Class A	All Consumers	Direct Class A	Class B plus Embedded Class A
May	20.11	19.04	20.25	25.88	24.20	26.09
June	21.92	19.38	22.21	34.54	31.59	34.86
July	33.64	30.30	34.00	37.06	34.81	37.29
August	29.32	27.53	29.52	34.49	32.27	34.73
September	26.11	24.68	26.29	31.88	31.09	31.97
October	22.45	21.27	22.60	29.37	28.28	29.51
Average	25.90	23.72	26.16	32.44	30.35	32.68

As shown in Table 1-2, the effective price for electricity in the Summer 2012 Period was $46.00/MWh for Direct Class A consumers and $74.04/MWh for Class B/ Embedded Class A consumers.

[5] A "load-weighted" measure of HOEP is a more accurate reflection of the electricity prices paid by consumers in that it reflects the fact that some consumers that are exposed to the HOEP may alter their consumption in response to price changes. The Panel's previous Summer Period report (the April 2012 Monitoring Report) did not present HOEP or uplift on a load-weighted basis, and the pricing information set out in section 1.2 is therefore not directly comparable with the pricing information set out in that report.

Relative to the Summer 2011 Period, the effective price in the Summer 2012 Period was lower for Direct Class A consumers (by $8.43/MWh) but higher for Class B/Embedded Class A consumers (by $0.46/MWh). Both classes saw reduced HOEP and uplift in the Summer 2012 Period. However, Direct Class A consumers paid less GA in the Summer 2012 Period (by $1.42/MWh) [6] while Class B/ Embedded Class A consumers paid more (by $7.33/MWh). Direct Class A consumers, who consumed about 10.7% of the province's total electricity output, paid 5.4% of the total GA charges in the Summer 2012 Period, while Class B/Embedded Class A consumers, who consumed about 89.3% of the electricity output in the province, paid 94.6% of the total GA charges.

Table 1-2: Effective Electricity Price by Consumer Class
May – October, 2011 & 2012
($/MWh)

Consumer Class	Weighted HOEP	Average GA	Weighted Uplift	Effective Price
Direct Class A - 2012	23.72	20.60	1.68	46.00
Direct Class A - 2011	30.35	22.02	2.06	54.43
Class B plus Embedded Class A - 2012	26.16	46.08	1.80	74.04
Class B plus Embedded Class A - 2011	32.68	38.75	2.15	73.58

1.3 *Operating Reserve Prices*

Table 1-3 presents average monthly operating reserve (OR) prices over the 2011 and 2012 Summer Periods. In the Summer 2012 Period, the average amounts paid for 10-minute spinning

[6] The GA charges for an individual Class A consumer may vary greatly from the average since, as discussed in greater detail in Chapter 3, the GA payable by a Class A consumer in a year is determined based on the energy consumed by that consumer in the five peak hours of the preceding year.

OR, 10-minute non-spinning OR and 30-minute OR were $1.27/MW per hour, $1.24/MW per hour and $0.54/MW per hour, respectively. On average, there has been a significant decrease in price for all categories of OR compared to the Summer 2011 Period. OR prices were lower in May through August of the Summer 2012 Period than in the same months of the Summer 2011 Period. The most significant OR price increase relative to the Summer 2011 Period occurred in October 2012, with OR price increases ranging from 374% to 582% depending on the category of OR.

Table 1-3: Average Monthly Operating Reserve Prices by Category May – October, 2011 & 2012 ($/MW per hour)

Month	10-Minute Spinning			10-Minute Non-Spinning			30-Minute		
	2012	2011	% Change	2012	2011	% Change	2012	2011	% Change
May	0.74	13.54	-95%	0.73	13.41	-95%	0.22	9.09	-98%
June	0.78	6.03	-87%	0.71	5.93	-88%	0.33	4.87	-93%
July	1.14	1.68	-32%	1.05	1.63	-36%	0.29	1.54	-81%
August	1.04	2.49	-58%	1.04	2.37	-56%	0.34	2.36	-86%
September	1.25	0.74	69%	1.22	0.68	79%	0.25	0.66	-62%
October	2.67	0.52	413%	2.66	0.39	582%	1.80	0.38	374%
Average	1.27	4.18	-70%	1.24	4.08	-70%	0.54	3.16	-83%

As with energy, OR can be constrained on or off, leading to Congestion Management Settlement Credit (CMSC) payments. Total constrained-off CMSC payments for OR were $1,093,000 in the Summer 2012 Period, of which approximately half (47.4%) was paid to market participants in the Northeast zone (about 7% to dispatchable loads and about 93% to generators). Just over a quarter of the constrained-off CMSC payments for OR was paid to market participants in the Northwest zone.

Constrained-on CMSC payments for OR totalled about $1,187,000 in the Summer 2012 Period. Market participants in the Northeast zone received the largest share of those payments (25.3%), followed by those in the Northwest zone (22.5%).

1.4 *Transmission Right Auction Prices*

The IESO offers two types of transmission rights (TR) for sale: long-term TRs, which are valid for 12 months and are auctioned quarterly; and short-term TRs, which are valid for a period of one month and are auctioned monthly.

TRs guarantee the TR holder a payout for each hour in which there is congestion during the period when the TR is valid. Auction prices for transmission rights therefore reflect TR holders' expectations of congestion at a given interface over the relevant period, and are influenced by factors such as planned outages for the interface in question, expected price differences between Ontario and the relevant external market, and speculation as to the actions of intertie traders. TR prices will vary depending on the time period covered, the interface and/or the direction (import or export) in question, and can in some cases be very volatile.

Table 1-4 presents average long-term TR auction prices by interface and direction in the 2011 and 2012 Summer Periods. The numbers presented in the table are weighted average prices for two rounds at each auction. Since many small, import-only interfaces exist between Ontario and Québec, only the prices at the Outaouais interface are reported in this table and in Table 1-5.[7] No auctions for long-term TRs were held for the New York or Michigan interfaces during the Summer 2012 Period.

[7] These small interfaces are rarely congested and, as such, their TR auction prices are typically very low.

Table 1-4: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction May – October, 2011 & 2012 ($/MW)

Direction	Auction Date	Period TRs are Valid	Manitoba		Minnesota		Outaouais	
			2012	2011	2012	2011	2012	2011
Import	May	July – June	31,731	49,549	N/A	34,816	136	N/A
	August	October – September	18,291	59,337	34,591	38,105	269	977
Export	May	July – June	N/A	N/A	6,956	N/A	1,301	N/A
	August	October – September	1,164	2,293	6,938	6,334	499	499

Short-term TRs are valid for the month after which they are auctioned. Table 1-5 displays monthly auction prices for short-term TRs by interface and by direction. During the Summer 2012 Period, import TR prices were generally the highest at the Manitoba interface. However, these prices plummeted in October 2012, coincident with the coming into effect of amendments to the market rules that eliminated constrained-off CMSC payments for import transactions in the Northwest.[8] The rule amendment likely caused the reduction in import TR auction prices at the Manitoba interface for both the October short-term TRs and for the long-term TRs that were auctioned in August 2012 (and valid for the period October 2012 through September 2013). With the opportunity to earn constrained-off CMSC eliminated, the expected outcome would be fewer import offers and fewer low-priced offers. Both factors would contribute to a lower frequency of congestion and lower intertie congestion prices, which in turn would make the ownership of TRs for the relevant interties less profitable.

[8] Under amendments to Chapters 9 and 11 of the market rules that came into effect on October 1, 2012, an import transaction in a "designated chronically congested area" that is constrained off in the last pre-dispatch run prior to the dispatch hour is not eligible for constrained-off CMSC payments. A "designated chronically congested area" is an area within Ontario, including connected intertie zones, that has been designated as such by the IESO by reason of oversupply due to transmission constraints. Currently, only one area – the Northwest (which includes the Manitoba and Minnesota interties) – has been so designated. For details, see Market Rule Amendment Proposal MR-00395-R00, available at http://www.theimo.com/imoweb/pubs/mr2012/MR-00395-R00_Amendment_Proposal_v5_Board_Approved.pdf.

Table 1-5: Short-Term (One Month) Transmission Right Auction Prices by Interface and Direction May – October, 2011 & 2012 ($/MW)

Direction	Auction Date	Manitoba		Michigan		Minnesota		New York		Outaouais	
		2012	2011	2012	2011	2012	2011	2012	2011	2012	2011
Import	May	2,292	7,641	4	N/A	N/A	N/A	12	N/A	18	52
	June	2,794	9,389	6	25	N/A	N/A	7	29	22	14
	July	2,284	9,702	7	30	N/A	N/A	15	49	45	20
	August	2,748	4,500	14	31	N/A	N/A	8	30	58	10
	September	4,834	5,436	22	N/A	N/A	N/A	N/A	N/A	60	79
	October	652	3,378	30	82	2,189	N/A	N/A	101	60	60
Export	May	50	N/A	930	N/A	N/A	N/A	975	N/A	107	100
	August	250	N/A	1,504	382	0	N/A	1,188	636	52	501
	July	250	N/A	1,719	1,250	759	N/A	1,272	841	55	501
	August	90	N/A	1,691	1,438	789	N/A	1,488	871	60	239
	September	75	N/A	1,034	N/A	N/A	N/A	N/A	N/A	60	101
	October	N/A	54	243	258	N/A	N/A	N/A	601	149	532

1.5 *Demand*

Ontario electricity demand totalled 71.1 TWh in the Summer 2012 Period, up by 0.9 TWh (1.3%) from the Summer 2011 Period. Demand was greater May through August, and lighter during September, compared to the same months in 2011. October demand in the Summer 2012 Period was slightly above that observed in October 2011. As between the two Summer Periods, the largest percentage decrease in demand occurred in September at 1.4%, while the largest percentage increase occurred in June at 4.6%.

1.6 *Supply*

During the Summer 2012 Period, the return to service of two refurbished Bruce Power nuclear units added approximately 1,552 MW to the province's supply resources. Unit 1 produced energy for the first time in 15 years on September 19, followed closely by Unit 2 on October 16. In addition, the York Energy Centre, with a capacity of 464 MW, became fully dispatchable in May 2012, providing valuable flexibility to the system.

The closure of Ontario Power Generation's coal-fired Atikokan generating station in early September 2012 reduced Ontario's electricity capacity by 211 MW. The plant is being converted to biomass (using wood pellets as its main fuel source), and is expected to have a capacity of 200 MW when it returns to service (projected for 2014).

1.7 *Imports and Exports*

This section reports on intertie activity, using data that is based on the unconstrained schedules as these directly affect market prices.[9]

As shown in Table 1-6, net electricity exports totalled 3.88 TWh in the Summer 2012 Period, down 0.42 TWh (9.8%) from the Summer 2011 Period.

Exports (excluding linked wheeling through transactions) increased by 0.18 TWh (2.7%) to 6.90 TWh in the Summer 2012 Period relative to the Summer 2011 Period. The largest monthly decline in exports occurred in May, when exports were 0.43 TWh (27.2%) lower than in May 2011. The largest monthly increase in exports occurred in July, when exports were 0.22 TWh (21.6%) higher than in July 2011. In the Summer 2012 Period, approximately 46% of exports flowed through the New York intertie, followed by the Michigan and Québec interties at 44% and 9%, respectively. In the Summer 2011 Period, Michigan led the way at 38%, while New York and Québec registered at 33% and 28%, respectively.

Imports (excluding linked wheeling through transactions) increased by 0.60 TWh (24.8%) from 2.42 TWh in the Summer 2011 Period to 3.02 TWh in the Summer 2012 Period. Off-peak[10] hours accounted for 29% of total import flows in the Summer 2012 Period, down from 34% during the Summer 2011 Period. The Québec interties accounted for 65% of total import volumes over the Summer 2012 Period, with Manitoba being the other significant import source at 20%. New York, Michigan and Minnesota contributed 7%, 6%, and 3%, respectively.

[9] Although the constrained schedules are also important for various monitoring and assessment purposes, they are not related to intertie congestion prices or to the Ontario uniform price (either in pre-dispatch or in real-time).
[10] For this purpose, "off-peak" refers to hours ending 24 through 7, reflecting the IESO's practice.

Table 1-6: Total Imports, Exports & Net Exports[*]
May – October, 2011 & 2012
(TWh)

Month	2012			2011		
	Exports	Imports	Net Exports	Exports	Imports	Net Exports
May	1.15	0.33	0.82	1.58	0.28	1.30
July	1.24	0.44	0.80	1.02	0.33	0.69
June	1.29	0.76	0.53	1.20	0.63	0.57
August	1.19	0.68	0.51	1.04	0.51	0.53
September	0.85	0.43	0.42	0.84	0.38	0.46
October	1.18	0.38	0.80	1.04	0.29	0.75
Total	6.90	3.02	3.88	6.72	2.42	4.30

[*] Linked wheeling through transactions are excluded.

Chapter 2: Analysis of Market Outcomes

1. Introduction

The Market Surveillance Panel is responsible for monitoring activities related to the IESO-administered markets and the conduct of market participants with a view to identifying, among others, anomalous market conduct and activities of the IESO that may have an impact on market efficiencies or effective competition. The Panel also monitors and reports on market outcomes that fall outside of predicted patterns or norms, which contributes to transparency and enhances market participant understanding of the market.

Day-to-day monitoring of the market is undertaken by the IESO's Market Assessment Unit (MAU) under the direction of the Panel. In addition to identifying high- and low-price hours (as defined below), the MAU also reviews:

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

Where anomalous events are identified through this daily monitoring, the matter may be discussed with the relevant market participant(s) or the IESO, or may be the subject of more detailed examination. Where appropriate, the Panel makes recommendations for changes to the market rules or to IESO processes, procedures or tools. Where warranted, the Panel may also initiate an investigation into a matter.

The Panel defines high-price hours as all hours in which the Hourly Ontario Energy Price (HOEP) is greater than $200/MWh, and defines low-price hours as all hours in which the HOEP is less than $20/MWh or is negative.[11]

As discussed further in section 2.1, there was one hour during the period May 1, 2012 through October 31, 2012 (the "Summer 2012 Period") when the HOEP was greater than $200/MWh.

As discussed further in section 2.2, in the Summer 2012 Period there were 1,377 hours in which HOEP was less than $20/MWh, including 92 hours where the HOEP was negative.

In section 2.3, the Panel reports on hours with anomalously high uplift payments; namely, Congestion Management Settlement Credit (CMSC) payments in excess of $500,000/hour or of $1,000,000/day, Intertie Offer Guarantee (IOG) payments in excess of $500,000/hour or of $1,000,000/day, and operating reserve (OR) payments in excess of $100,000/hour.[12] Additionally, the Panel reports on the hour or day in which the largest payments in each of these uplift categories were incurred, even if those payments do not exceed the threshold set by the Panel. It was the past practice of the Panel to report on instances where CMSC payments on the interties exceeded $1,000,000 for a given day. While the Panel still considers such events to be anomalous, it has expanded the daily CMSC threshold to include all CMSC payments made in the province, not simply those on the interties. The threshold value remains at $1,000,000 per day.

The sections below discuss the factors contributing to high-price and low-price hours and to hours with anomalous uplift payments in the Summer 2012 Period, and include comparative data from preceding years as relevant. References in this chapter to a "Summer Period" are to the period running from May to October, inclusive.

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[11] Historically, $200/MWh has been a rough upper bound, and $20/MWh a rough lower bound, for the marginal cost of a fossil fuel-fired generation unit.
[12] For a discussion of the thresholds established for each category of uplift payment, see the Panel's January 2009 Monitoring Report (at pp. 178-184), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf

2. High-and Low-price Hours

2.1 *Analysis of High-Price Hour*

Table 2-1 depicts the number of hours per month in which the HOEP exceeded $200/MWh in the Summer 2012 Period and the preceding four Summer Periods. In no other Summer Period since market opening has the number of high-price hours been as low as was the case in the Summer 2012 Period (only 1 such hour).

Table 2-1: Number of Hours with a HOEP > $200/MWh
May to October, 2008 – May to October, 2012
(Number of Hours)

Month	**Number of Hours with HOEP > $200/MWh**				
	2008	**2009**	**2010**	**2011**	**2012**
May	0	0	0	2	0
June	4	0	1	3	0
July	3	0	4	0	1
August	2	4	0	1	0
September	5	0	1	0	0
October	3	2	1	0	0
Total	**17**	**6**	**7**	**6**	**1**

In previous reports, the Panel has noted that the HOEP is greater than $200/MWh typically in 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 in real-time;
- one or more generating units that appear to be available in pre-dispatch are unavailable in real-time as a result of a forced outage, de-rating, participant error or, in the case of intermittent generation, forecasting discrepancy; and/or
- there is a large increase in net exports in the unconstrained schedule from one hour to the next.

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 the 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%.[13]

The section below examines the circumstances surrounding the single high-price hour experienced during the Summer 2012 Period, in hour ending (HE) 17 on July 4, 2012.

2.1.1 July 4 2012 HE 17

The HOEP was $209.16/MWh in HE 17 on Wednesday, July 4, 2012. Unlike many high-price hours, there was no one interval that experienced a large price spike relative to the preceding interval. Instead, over the course of two hours the interval-by-interval market clearing price (MCP) increased consistently, culminating with an MCP of $243.46/MWh in interval 6 of HE 17. The high-price event was primarily the result of high demand due to extreme temperatures, coupled with forced outages at several large dispatchable generators.

Prices, Demand and Supply

Over the course of HE 16 and 17, Ontario demand climbed to a high of 23,913 MW in interval 9 of HE 17 before declining for the balance of the hour. The largest interval-over-interval demand increase occurred from interval 10 to interval 11 of HE 16, when demand increased by 115 MW and contributed to an increase in the MCP from $145.04/MWh to $176.31/MWh.

The HE 17 hourly average Ontario demand of 23,828 MW was the tenth highest demand of the Summer 2012 Period. A daily high temperature of 34 degrees Celsius (42 degrees Celsius with the Humidex) was the primary driver behind the high demand levels. Severe thunderstorms in the London area with the potential for tornado activity further strained the grid throughout the day.

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[13] In its March 2003 Monitoring Report (available at http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_240303.pdf), the Panel noted that a supply cushion lower than 10% is more likely to be associated with a price spike (see pp. 11-16). The Panel began reporting a revised supply cushion calculation in its August 2007 Monitoring Report (at pp. 79-81), available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf . It remains the case that as the supply cushion falls below 10%, a price spike becomes increasingly likely.

In interval 1 of HE 17 Ontario demand declined briefly and, when coupled with the change in net exports, resulted in a decline in total demand (Ontario demand plus net exports) of 100 MW from interval 12 of HE 16 to interval 1 of HE 17. This decrease in demand provided some temporary price relief, with the MCP dropping from $178.68/MWh in interval 12 of HE 16 to $147.46/MWh in interval 1 of HE 17.

Table 2-2 lists real-time MCPs, Ontario demand and net exports for HE 16 and HE 17 on July 4, 2012.

Table 2-2: Real-time MCP, Ontario Demand and Net Exports
July 4, 2012 HE 16 & HE 17
(MW & $/MWh)

Delivery Hour (HE)	Interval	Real-Time MCP ($/MWh)	Real-Time Ontario Demand (MW)	Real-Time Net Exports (MW)	Real-Time Ontario Demand plus Net Exports (MW)	Change in Ontario Demand plus Net Exports from Previous Interval (MW)	Average Change in Net Exports from Previous Hour (MW)
16	**1**	52.39	23,434	244	23,678	204	199
16	**2**	55.04	23,519	244	23,763	85	199
16	**3**	65.04	23,543	244	23,787	24	199
16	**4**	65.04	23,609	244	23,853	66	199
16	**5**	84.70	23,645	244	23,889	36	199
16	**6**	85.04	23,670	244	23,914	25	199
16	**7**	84.70	23,658	244	23,902	-12	199
16	**8**	116.26	23,689	244	23,933	31	199
16	**9**	124.99	23,699	244	23,943	10	199
16	**10**	145.04	23,732	244	23,976	33	199
16	**11**	176.31	23,847	244	24,091	115	199
16	**12**	178.68	23,871	244	24,115	24	199
Average		**102.77**	**23,660**	**244**	**23,904**	**53**	**199**
17	**1**	147.46	23,778	237	24,015	-100	-7
17	**2**	214.82	23,775	237	24,012	-3	-7
17	**3**	214.82	23,797	237	24,034	22	-7
17	**4**	214.82	23,813	237	24,050	16	-7
17	**5**	241.55	23,865	237	24,102	52	-7
17	**6**	243.46	23,858	237	24,095	-7	-7
17	**7**	214.60	23,829	237	24,066	-29	-7
17	**8**	199.64	23,873	237	24,110	44	-7
17	**9**	214.82	23,913	237	24,150	40	-7
17	**10**	214.82	23,906	237	24,143	-7	-7
17	**11**	214.82	23,880	237	24,117	-26	-7
17	**12**	174.23	23,646	237	23,883	-234	-7
Average		**209.16**	**23,828**	**237**	**24,065**	**-19**	**-7**

Pre-dispatch Conditions

Table 2-3 displays pre-dispatch prices, Ontario demand and net exports for the five pre-dispatch hours leading up to HE 17 on July 4, 2012. With demand trending heavier than forecasted in the delivery hours leading up to HE 17, the IESO increased forecasted Ontario demand prior to the three hour ahead pre-dispatch run for HE 17. From five hours ahead to one hour ahead the pre-dispatch Ontario demand increased by 212 MW (0.9%), from 23,535 MW to 23,747 MW. The increase in pre-dispatch Ontario demand contributed to a 475 MW (77.6%) decrease in net exports, from 612 MW five hours ahead to 137 MW one hour ahead.

As is the case in many hours, the scheduled quantity of both imports and exports increased significantly from three hours ahead to two hours ahead. Traders frequently alter their trading positions following the publication of the three hour ahead pre-dispatch data, but before the two hour ahead pre-dispatch run, as this is their final opportunity to do so. The changing of offers and bids has direct effects on the quantity of imports and exports scheduled, as well as an indirect effect via resultant changes in the pre-dispatch price. As it relates to HE 17 on July 4, 2012, the pre-dispatch price increased from $55.14/MWh four hours ahead to $62.00/MWh three hours ahead. Following this price signal, several intertie traders decreased the offer price on their previously uneconomic imports, and offered additional imports. Scheduled imports increased by 500 MW from three hours ahead to two hours ahead, 198 MW of which were imports newly offered into the market following the publication of the three hour ahead pre-dispatch price. The incremental offers and offer price changes, coupled with the decrease in forecasted Ontario demand, led to a decrease in the pre-dispatch price and an associated increase in the quantity of exports scheduled from three hours ahead to two hours ahead.

***Table 2-3: Pre-dispatch Demand, MCP and Net Exports
Hours leading up to July 4, 2012 HE 17
(MW & $/MWh)***

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Ontario Demand plus Net Exports (MW)
5	55.04	23,535	1,375	1,987	612	24,147
4	55.14	23,581	1,375	1,888	513	24,094
3	62.00	23,737	1,375	1,758	383	24,120
2	50.01	23,713	1,875	2,076	201	23,914
1	51.01	23,747	1,875	2,012	137	23,884

Real-Time Conditions

Table 2-4 displays pre-dispatch versus real-time demand and supply conditions for each interval in HE 16 and HE 17 on July 4, 2012. Despite the IESO's upward revision to forecasted Ontario demand, real-time average demand was 87 MW (0.4%) higher than forecasted in HE 16, and 81 MW (0.3%) higher than forecasted in HE 17. While the demand forecast discrepancies were relatively small,[14] they nonetheless had an impact when coupled with other pre-dispatch to real-time discrepancies. Self-scheduling and intermittent resources generated less than forecasted, under-delivering by an average of 36 MW (3%) in HE 16, and by an average of 159 MW (12%) in HE 17. In HE 16, the New York intertie had a 50 MW export and a 5 MW import fail between pre-dispatch and real-time due to market participants failing to acquire transmission and/or match schedules between jurisdictions. These failures resulted in an increase in net supply of 45 MW, which helped converge the real-time supply-demand conditions with the forecasted conditions. In HE 17, a 100 MW import failed when a market participant once again failed to properly navigate markets, resulting in a loss of real-time supply. All told, HE 16 and HE 17 averaged 78 MW and 340 MW, respectively, of additional demand and unrealized supply relative to pre-dispatch forecasts, contributing to higher than forecasted real-time prices.

[14] These demand forecast discrepancies were well below the IESO's performance measure (internal metric) for one hour-ahead demand forecast discrepancy, which is 1.75% relative to eventual real-time demand levels.

Table 2-4: Pre-dispatch and Real-time Demand and Supply Conditions July 4, 2012 HE 16 & 17 (MW)

HE	Interval	Ontario Demand			Self-Scheduling and Intermittent			Net Exports			Total PD vs. RT Discrepancy
		PD	RT	PD - RT	PD	RT	RT - PD	PD	RT	Failed	
16	**1**	23,573	23,434	139	1,222	1,240	18	289	244	45	202
16	**2**	23,573	23,519	54	1,222	1,227	5	289	244	45	104
16	**3**	23,573	23,543	30	1,222	1,217	-5	289	244	45	70
16	**4**	23,573	23,609	-36	1,222	1,205	-17	289	244	45	-8
16	**5**	23,573	23,645	-72	1,222	1,185	-37	289	244	45	-64
16	**6**	23,573	23,670	-97	1,222	1,169	-53	289	244	45	-105
16	**7**	23,573	23,658	-85	1,222	1,158	-64	289	244	45	-104
16	**8**	23,573	23,689	-116	1,222	1,168	-54	289	244	45	-125
16	**9**	23,573	23,699	-126	1,222	1,162	-60	289	244	45	-141
16	**10**	23,573	23,732	-159	1,222	1,161	-61	289	244	45	-175
16	**11**	23,573	23,847	-274	1,222	1,169	-53	289	244	45	-282
16	**12**	23,573	23,871	-298	1,222	1,174	-48	289	244	45	-301
Average		**23,573**	**23,660**	**-87**	**1,222**	**1,186**	**-36**	**289**	**244**	**45**	**-78**
17	**1**	23,747	23,778	-31	1,350	1,197	-153	137	237	-100	-284
17	**2**	23,747	23,775	-28	1,350	1,201	-149	137	237	-100	-277
17	**3**	23,747	23,797	-50	1,350	1,211	-139	137	237	-100	-289
17	**4**	23,747	23,813	-66	1,350	1,218	-132	137	237	-100	-298
17	**5**	23,747	23,865	-118	1,350	1,204	-146	137	237	-100	-364
17	**6**	23,747	23,858	-111	1,350	1,175	-175	137	237	-100	-386
17	**7**	23,747	23,829	-82	1,350	1,197	-153	137	237	-100	-335
17	**8**	23,747	23,873	-126	1,350	1,219	-131	137	237	-100	-357
17	**9**	23,747	23,913	-166	1,350	1,228	-122	137	237	-100	-388
17	**10**	23,747	23,906	-159	1,350	1,188	-162	137	237	-100	-421
17	**11**	23,747	23,880	-133	1,350	1,146	-204	137	237	-100	-437
17	**12**	23,747	23,646	101	1,350	1,105	-245	137	237	-100	-244
Average		**23,747**	**23,828**	**-81**	**1,350**	**1,191**	**-159**	**137**	**237**	**-100**	**-340**

Table 2-5 displays real-time MCPs, the fuel type of the marginal resource and any notable events for each interval in HE 16 and HE 17 on July 4, 2012. All MCPs were set by either a gas-fired generator or a hydroelectric generator.

Table 2-5: Real-time MCP and Marginal Resources
July 4, 2012 HE 16 & HE 17
($/MWh & Fuel Type)

Delivery Hour (HE)	Interval	Real-time MCP ($/MWh)	Marginal Resource (Fuel Type)	Notable Events
Prior to HE 16		-	-	• Coal-fired unit 1 forced de-rated to 200 MW due to equipment concerns. No generation loss, 280 MW capacity loss.
16	**1**	52.39	Gas	
16	**2**	55.04	Water	
16	**3**	65.04	Water	
16	**4**	65.04	Water	• Coal-fired unit 2 forced out of service due to equipment concerns. 430 MW generation loss, 520 MW capacity loss.
16	**5**	84.70	Water	
16	**6**	85.04	Water	
16	**7**	84.70	Water	
16	**8**	116.26	Water	• Coal-fired unit 3 forced de-rated to 300 MW due to equipment concerns. 85 MW generation loss, 180 MW capacity loss.
16	**9**	124.99	Water	• Coal-fired unit 3 further forced de-rated to 150 MW due to equipment concerns. 150 MW generation loss, 150 MW capacity loss.
16	**10**	145.04	Water	
16	**11**	176.31	Gas	
16	**12**	178.68	Gas	
Average		**102.77**	**-**	
17	**1**	147.46	Gas	
17	**2**	214.82	Water	• Hydroelectric unit forced de-rated to 71 MW. 68 MW generation loss, 68 MW capacity loss. • Gas-fired unit forced de-rated to 380 MW due to equipment concerns. 20 MW generation loss, 145 MW capacity loss.
17	**3**	214.82	Water	
17	**4**	214.82	Water	
17	**5**	241.55	Gas	
17	**6**	243.46	Gas	
17	**7**	214.60	Water	
17	**8**	199.64	Gas	
17	**9**	214.82	Water	
17	**10**	214.82	Water	
17	**11**	214.82	Water	
17	**12**	174.23	Gas	
Average		**209.16**	**-**	

A major contributor to the high-price event was the accumulation of outages and de-ratings at large dispatchable generation facilities. In HE 6 on July 4, 2012, a coal-fired generation unit experienced equipment issues and was forced de-rated to 200 MW for the remainder of the day.

When the unit was forced de-rated, 280 MW of inexpensive generation was removed from the supply stack for the remainder of the day.

In addition, early in HE 16 another coal-fired unit was generating 430 MW when it was forced out of service due to equipment concerns. From that point on, the unit was gradually ramped down until it was brought offline in the unconstrained schedule in interval 11 of HE 16. The gradual loss of this capacity coincided with a steady increase in the real-time MCP as more expensive facilities were ramped up to compensate for the loss of the unit.

Equipment concerns also forced the removal of another dispatchable generator from the supply stack, as a third coal-fired unit was de-rated to 300 MW in interval 8 of HE 16, and then further de-rated to 150 MW in interval 9. In total, the de-rating of the unit resulted in 235 MW of lost generation and 330 MW of lost capacity.

In interval 2 of HE 17, a hydroelectric facility was forced de-rated a total of 68 MW, while a gas-fired unit was also de-rated 20 MW. While Ontario demand decreased 3 MW from interval 1 to 2, this 88 MW decrease in supply led to a 45% increase in the MCP, from $147.46/MWh to $214.82/MWh (see Table 2-2).

2.1.2 Overall Assessment

The single high-price event during the Summer 2012 Period was primarily the result of high demand due to extreme temperatures, coupled with forced outages at several large dispatchable generators.

As seen in Table 2-1, high-price hours were far less frequent in the Summer 2012 Period relative to previous Summer Periods. Prior to the Summer 2012 Period, the fewest high-price hours during a Summer Period was four, in 2007. The fact that there was only one high-price hour in the Summer 2012 Period is in part due to the addition of new supply in the province. The York Energy Centre, with a capacity of 464 MW, became fully dispatchable in May 2012. When scheduled, the quick ramping facility can displace more expensive supply resources and provide valuable flexibility to the system, contributing to lower prices.

2.2 *Analysis of Low-Price Hours*

Table 2-6 presents the number of hours when the HOEP was less than $20/MWh (including when it was negative), by month, in the Summer 2012 Period and in the preceding four Summer Periods. The total number of low-price hours increased by 659 hours (92%) to 1,377 in the Summer 2012 Period relative to the previous Summer Period.

Table 2-6: Number of Hours with Low and Negative HOEPs
May – October, 2008 to 2012
(Number of Hours)

Month	Hours when HOEP < $20/MWh (including HOEP < $0/MWh)					Hours when HOEP < $0/MWh				
	2008	**2009**	**2010**	**2011**	**2012**	**2008**	**2009**	**2010**	**2011**	**2012**
May	193	210	22	267	370	6	24	0	31	19
June	87	295	8	122	376	0	42	0	23	24
July	144	393	20	48	103	16	14	0	4	8
August	126	236	19	87	143	4	11	0	17	9
September	90	297	143	66	155	0	25	9	6	5
October	84	188	149	128	230	2	5	10	15	27
Total	**724**	**1,619**	**361**	**718**[15]	**1,377**	**28**	**121**	**19**	**96**	**92**

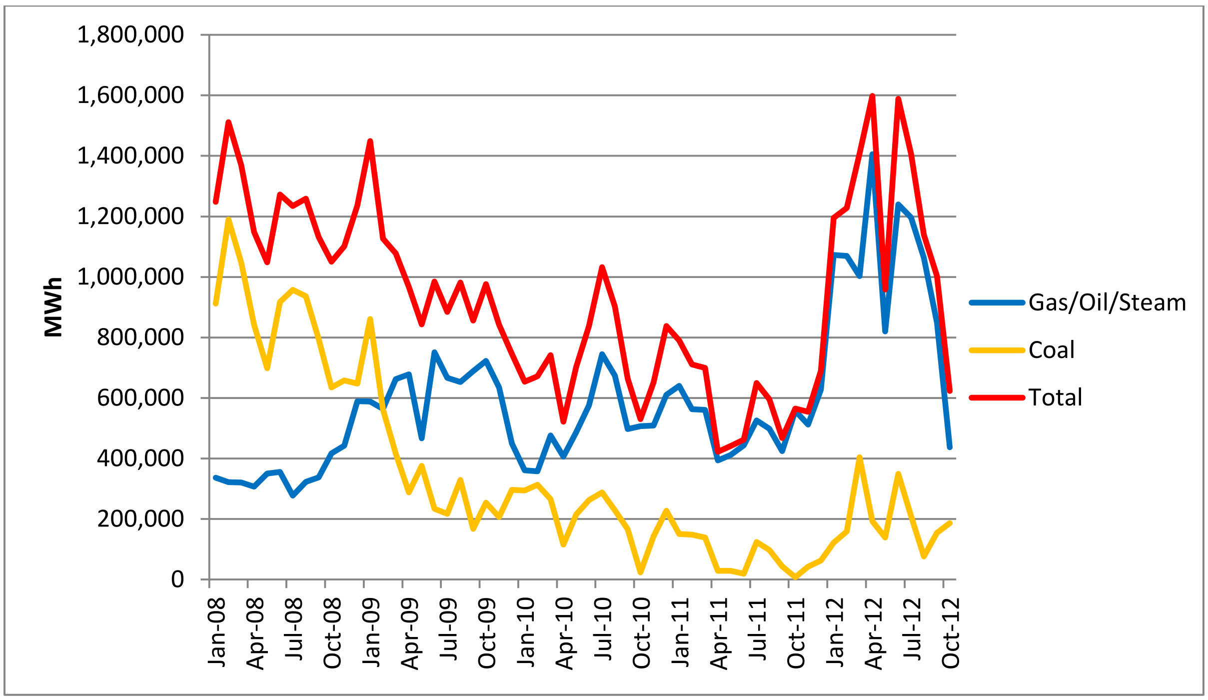
As outlined in previous Panel reports, the primary factors leading to low-price hours are:[16]

- low market demand;
- abundant low-priced supply, defined as supply that is offered at a price of less than $20/MWh (typically offered by nuclear, baseload hydro, self-scheduling and intermittent generation, and fossil fuel-fired generation up to minimum loading point);
- pre-dispatch to real-time demand deviation (the forecast demand that is used in pre-dispatch is typically different from, and often greater than, the average real-time demand that determines the HOEP); and
- failed export transactions (these can place downward pressure on the HOEP by reducing demand in real-time relative to pre-dispatch).

[15] As a result of a discrepancy in measurement, the low-price hours reported here (718) differ from those reported in the Panel's April 2012 Monitoring Report covering the Summer 2011 Period (711).
[16] These factors were first identified in the Panel's June 2004 Monitoring Report (at pp. 84-85), available at http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_140604.pdf

Much of the increase in the number of low-price hours experienced in the Summer 2012 Period can be attributed to a sharp increase in the amount of fossil fuel-fired generation being offered at less than $20/MWh, particularly gas-fired generation. More gas-fired generation offered at low prices leads to low-price hours even at higher levels of demand. [17] Figure 2-1 displays total generation offered at less than $20/MWh by fossil fuel-fired generators by month from January 2008 to October 2012.[18]

Figure 2-1: Fossil Fuel-Fired Generation Offered at < $20/MWh
January 2008 to October 2012
(MWh)



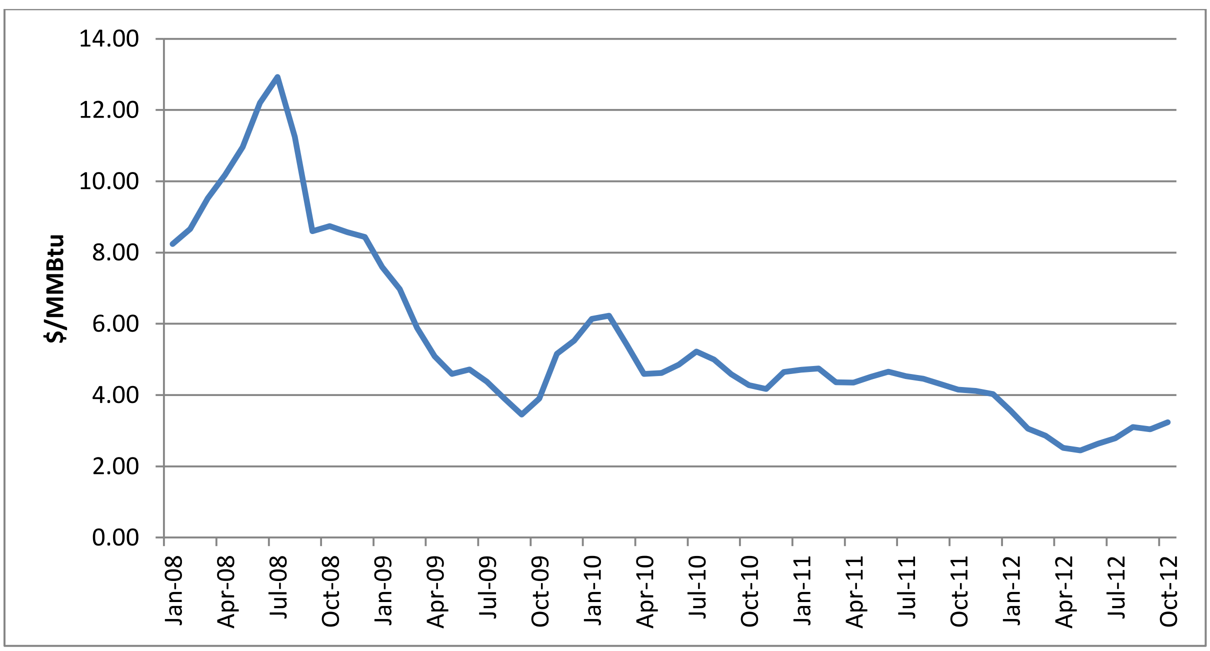
Total low-priced supply from fossil fuel-fired units declined considerably from January 2008 to April 2011. This trend was largely driven by decreases in low-priced supply from coal-fired generators as some units were decommissioned and others offered reduced capacity. The reduced quantity of fossil fuel-fired generation offered at less than $20/MWh persisted through

[17] An increase in the quantity of fossil fuel-fired generation offered at less than $20/MWh leading to increased low-price hours was first identified by the Panel in its January 2013 Monitoring Report, available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf.
[18] Figure 2-1 updates Figure 2-2 of the Panel's January 2013 Monitoring Report, and includes a previously omitted coal-fired generator.

the Summer 2011 Period, contributing to the modest total of 718 low-price hours during that period as shown in Table 2-6. Low-priced supply from fossil fuel-fired units then spiked in late 2011, as the amount of gas-fired generation (and associated steam-fired generation) offered at less than $20/MWh increased considerably. The increase was in part due to increases in the installed capacity of gas generation and decreases in the price of gas. In October 2012, there was a sharp decline in the quantity of gas-fired (and associated steam-powered) generation offered at less than $20/MWh. While an increase in the price of natural gas played a role in that decline, the temporary unavailability of generators on outage for scheduled maintenance was also a major contributor.

Figure 2-2 displays the Dawn average monthly spot price for natural gas in dollars per MMBtu from January 2008 to October 2012.

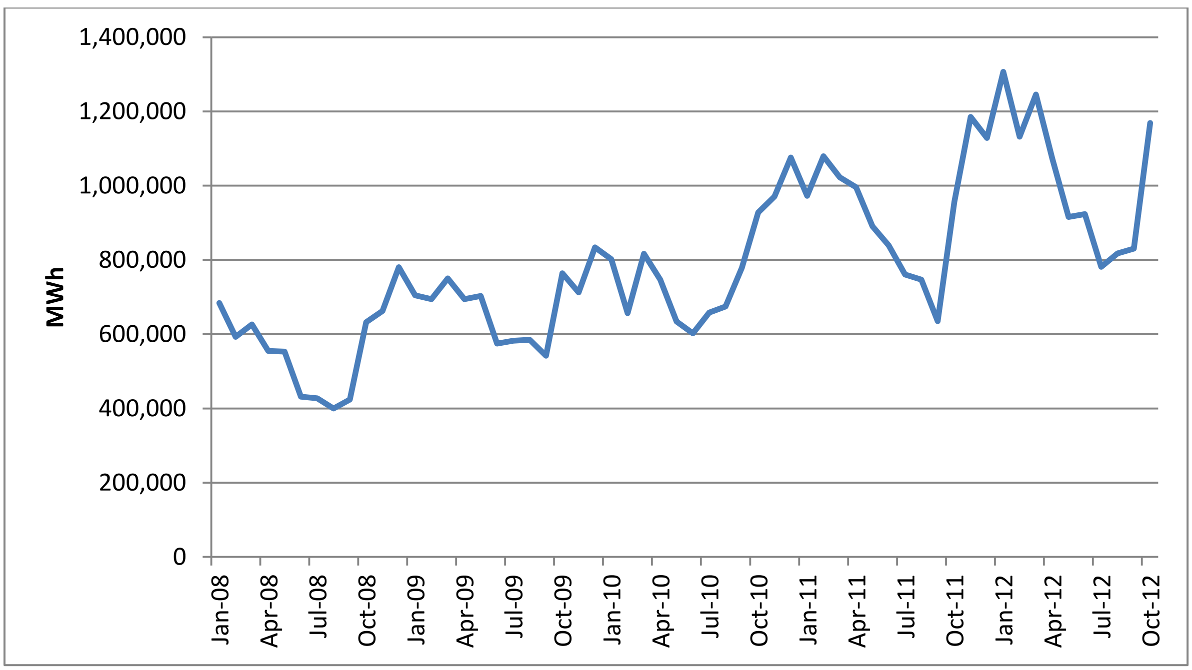
Figure 2-2: Dawn Average Monthly Spot Price for Natural Gas
January 2008 to October 2012
($/MMBtu)



After the average monthly spot price peaked at $12.93/MMBtu in July 2008, increases in supply side factors, including the availability of shale gas, drove down the average Dawn spot price to a low of $2.45/MMBtu in May 2012. While gas prices have risen since that time, average prices remained considerably lower in the Summer 2012 Period relative to the previous Summer Period.

The amount of real-time self-scheduling and intermittent generation also had a considerable effect on the frequency of low-price hours. Due to the non-dispatchable nature of these generators, all real-time megawatts that they produce are treated as though offered at the minimum market clearing price of -$2,000/MWh to ensure that they are dispatched. Any increase in the amount of self-scheduling and intermittent generation therefore increases the amount of negative-priced supply in the real-time energy market, thus leading to low-price hours even at higher levels of demand. Figure 2-3 displays total real-time generation from self-scheduling and intermittent resources by month from January 2008 to October 2012.

Figure 2-3: Self-Scheduling and Intermittent Generation
January 2008 to October 2012
(MWh)



Monthly output from self-scheduling and intermittent generation resources has roughly doubled since January 2008. The increase in output is primarily the result of significant additions to the installed capacity of wind generation across the province. Total monthly output from self-scheduling and intermittent resources has exhibited a strong seasonal pattern – there is considerably less production in the summer months than in the remainder of the year. Lower levels of output in the summer reflect the decrease in production from wind generators due to lower wind levels relative to the winter months. Run-of-the-river hydroelectric facilities also produce less in the summer, as water levels are lower at that time relative to water levels that prevail during shoulder seasons. The difference in output from self-scheduling and intermittent generation resources between the winter output peaks and the summer troughs has become more pronounced as more wind generation capacity has been added to the system.

As shown in Table 2-6, the number of hours when the HOEP was negative decreased slightly in the Summer 2012 Period relative to the previous Summer Period. There were 92 negative-price hours in the Summer 2012 Period, down 4 hours (4%) from 96 hours in the Summer 2011 Period.

Table 2-7 shows real-time scheduled supply by resource or transaction type, including average hourly scheduled imports (but excluding linked wheeling transactions), as well as unscheduled generation that offered at prices less than $20/MWh for all low-price hours in the Summer 2012 Period. For comparative purposes, Table 2-8 shows the same information for all low-price hours in the Summer 2011 Period. In these tables and in Table 2-12 further below, generation resources are shown by resource type as follows: nuclear, baseload hydroelectric,[19] other hydroelectric,[20] self-scheduling and intermittent, and gas-/coal-fired (including steam units at combined cycle plants).

[19] For the purposes of the current analysis, baseload hydro resources include the generators at the Beck, Saunders, and DeCew Falls stations owned by Ontario Power Generation. Payment amounts for the output from these facilities are set by the Ontario Energy Board.

[20] Market participants that operate non-baseload hydroelectric units may wish to operate even when market prices are low when the supply of water is abundant, as spilling may be the only alternative.

Table 2-7: Low-Priced Supply During Low-Price Hours May to October 2012 (MW)

Month	Low-Priced Supply							Total
	Scheduled Nuclear	Scheduled Baseload Hydro	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Scheduled Gas/Coal (including steam)	Imports (excluding linked wheels)	Unscheduled Generation Offering < $20/MWh	
May	9,278	2,171	1,235	1,468	807	331	1,077	16,367
June	9,729	2,048	1,320	1,330	1,432	406	1,815	18,081
July	10,845	1,822	1,059	703	1,101	421	815	16,766
August	10,268	1,747	1,124	637	1,001	351	849	15,976
September	9,428	1,766	1,279	581	787	202	942	14,985
October	10,110	1,674	1,680	860	504	204	1,002	16,034
Average	**9,777**	**1,939**	**1,313**	**1,085**	**967**	**325**	**1,208**	**16,613**

Table 2-8: Low-Priced Supply During Low-Price Hours May to October 2011 (MW)[21]

Month	Low-Priced Supply							Total
	Scheduled Nuclear	Scheduled Baseload Hydro	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Scheduled Gas/Coal (including steam)	Imports (excluding linked wheels)	Unscheduled Generation Offering < $20/MWh	
May	9,416	2,161	1,217	1,965	524	267	984	16,535
June	9,150	2,224	1,163	1,382	620	253	1,202	15,993
July	9,930	2,058	1,058	990	761	451	748	15,997
August	10,876	1,987	1,108	407	673	240	874	16,164
September	10,395	1,750	948	303	572	391	856	15,216
October	9,790	1,681	1,447	379	721	230	853	15,100
Average	**9,739**	**2,021**	**1,200**	**1,176**	**614**	**278**	**957**	**15,984**

Average low-priced gas- and coal-fired generation scheduled during low-price hours increased by 57% in the Summer 2012 Period relative to the previous Summer Period, from 614 MW to 967 MW. Unscheduled generation offered at less than $20/MWh (typically gas- and coal-fired units offering at the high end of the less than $20/MWh spectrum) also increased by 251 MW (26%) to 1,208 MW in the Summer 2012 Period relative to the preceding Summer Period,

[21] The figures in this table are updated relative to Panel's April 2012 Monitoring Report covering the Summer 2011 Period, with increased granularity for scheduled gas- and coal-fired units.

reflecting increased quantities of low-priced supply offered from gas- and coal-fired generators in the Summer 2012 Period as shown in Figure 2-1. Exemplifying this trend, June 2012 experienced the largest amount of unscheduled generation offered at less than $20/MWh during low-price hours in the Summer 2012 Period (see Table 2-7), despite those hours experiencing the highest average demand (see Table 2-9). The high levels of unscheduled low-priced generation were attributable to increased levels of gas- and coal-fired generation offered at less than $20/MWh. As shown in Figure 2-1, total low-priced supply from gas/oil/steam-fired and coal-fired generators reached a Summer 2012 Period high in June 2012. That month also represented the second highest monthly total of such low-priced supply since January 2008.

Tables 2-7 and 2-8 show that production from self-scheduling and intermittent resources during low-price hours also increased in the Summer 2012 Period relative to the preceding Summer Period, from 1,200 MW to 1,313 MW (9%). All told, average low-priced supply during low-price hours increased by 629 MW (4%) from 15,984 MW in the Summer 2011 Period to 16,613 MW in the Summer 2012 Period.

As noted above, the number of low-price hours increased considerably from 718 in the Summer 2011 Period to 1,377 in the Summer 2012 Period, with supply-side factors (particularly wind and gas-fired generation) playing a significant role in that increase.

Summary statistics related to demand conditions during low-price hours in the Summer 2012 Period are presented in Table 2-9. The table includes monthly average Ontario demand, exports (excluding linked wheeling transactions) and market demand (Ontario demand plus exports) during the low-price hours. Excess low-priced supply is presented in the final column of Table 2-9, and is calculated as the difference between low-priced supply (see Table 2-7) and market demand over all low-price hours.

***Table 2-9: Average Monthly Demand and Excess Low-Priced Supply during Low-Price Hours
May to October 2012
(MW)***

Month	Number of Low-Price Hours	Demand			Excess Low-Priced Supply
		Ontario Demand	Exports (excluding linked wheels)	Market Demand	
May	370	13,737	1,553	15,290	1,077
June	376	14,697	1,569	16,266	1,815
July	103	14,182	1,769	15,951	815
August	143	13,746	1,381	15,127	849
September	155	12,816	1,226	14,042	943
October	230	13,312	1,721	15,033	1,001
Average		**13,859**	**1,547**	**15,406**	**1,208**

On average, low-priced supply exceeded market demand by 1,208 MW (7.8%) during the low-price hours in the Summer 2012 Period. Despite June having the highest average monthly market demand during low-price hours, excess low-priced supply reached a Summer 2012 Period high of 1,815 MW during that month. Excess low-priced supply in the Summer 2012 Period was lowest in July, at 815 MW.

Table 2-10 provides additional average summary information by month for all low-price hours in the Summer 2012 Period, including failed net exports, the difference between pre-dispatch demand and real-time average demand (referred to as 'demand discrepancy'), and pre-dispatch and real-time prices. Demand discrepancy can result from demand forecast discrepancies or simply from differences between peak and average demand within an hour. The HOEP during low-price hours was an average of $4.80/MWh (30%) lower than pre-dispatch prices in the Summer 2012 Period.

Table 2-10: Average Monthly Summary Data for Low-Price Hours May to October 2012 (MW & $/MWh)

Month	Excess Low-Priced Supply (MW)	Failed Net Exports (MW)	RT Average Demand (MW)	PD Demand Forecast (MW)	PD to RT Demand Deviation (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Price Difference (HOEP - PD) ($/MWh)
May	1,077	58	13,737	13,778	41	11.97	15.46	-3.49
June	1,815	55	14,697	14,794	97	11.70	16.43	-4.73
July	815	21	14,182	14,376	194	10.84	16.64	-5.80
August	849	25	13,746	13,798	52	12.56	16.56	-4.00
September	943	-17	12,816	12,869	53	12.37	15.35	-2.98
October	1,001	7	13,312	13,373	61	6.31	14.60	-8.29
Average	**1,208**	**34**	**13,859**	**13,932**	**73**	**10.97**	**15.77**	**-4.80**

The section below outlines the market conditions that led to eight consecutive negative-price hours, including the Summer 2012 Period's lowest-price hour, in the late hours of October 29, 2012 and the early hours of October 30, 2012.

2.2.1 October 29 & 30, 2012

On Monday, October 29, 2012, the HOEP dropped to -$2.70/MWh in HE 23, the first of eight consecutive negative-price hours. One hour later, in HE 24, the HOEP reached a Summer 2012 Period low of -$128.13/MWh.[22] The HOEP remained negative for six more hours before returning to a positive price in HE 7 on October 30, 2012. The eight consecutive negative-price hours was the longest string of consecutive hours with a negative HOEP of the Summer 2012 Period.[23]

The prolonged string of negative-priced hours coincided with the height of Hurricane Sandy in the northeastern United States. Market demand for Ontario power sagged as exports destined for New York and New England were curtailed in step with storm-related load decreases in those

[22] The lowest HOEP in the history of the Ontario market was -$138.79/MWh on April 30, 2011 in HE 24: see the Panel's November 2011 Monitoring Report (at pp. 105-107), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf

[23] The longest string of consecutive negative-price hours is 22, stretching from HE 13 on March 28, 2009 to HE 10 on March 29, 2009.

regions. Domestic load was also tempered by Hurricane Sandy, leading to pre-dispatch demand forecasts in excess of eventual real-time conditions.

Prices, Demand and Supply

Table 2-11 displays the HOEP, real-time Ontario demand and net exports for HE 22 on October 29 to HE 7 on October 30, 2012.

Table 2-11: HOEP, Ontario Demand and Net Exports
October 29, 2012 HE 22 to October 30, 2012 HE 7
(MWh & $/MWh)

Delivery Date	Delivery Hour (HE)	HOEP ($/MWh)	Real-Time Ontario Demand (MWh)	Real-Time Net Exports (MWh)	Real-Time Ontario Demand plus Net Exports (MWh)	Change in Ontario Demand plus Net Exports from Previous Hour (MWh)
Oct. 29	**22**	2.51	16,077	980	17,057	-939
	23	-2.70	14,697	1,587	16,284	-773
	24	-128.13	13,694	1,551	15,245	-1,039
Oct. 30	**1**	-108.92	13,096	1,904	15,000	-245
	2	-128.03	12,823	2,068	14,891	-109
	3	-116.51	12,670	2,301	14,971	80
	4	-116.51	12,733	2,432	15,165	194
	5	-85.93	13,219	2,138	15,357	192
	6	-11.67	14,609	1,569	16,178	821
	7	29.40	16,252	1.348	16,253	75

The hours being examined comprise the overnight period, when Ontario demand declines and reaches its overnight trough before increasing back up in the morning. In this particular instance, the HOEP became negative as the market transitioned into the overnight demand trough, compounded by the effects of the storm. Ontario demand fell consistently until it bottomed out in HE 3 on October 30 at 12,670 MWh, after which it started to pick back up for the typical morning increase in demand. As Ontario demand decreased and negative prices persisted, net exports increased in step with the surplus supply conditions. After peaking at 2,432 MWh in HE 4, net exports declined as Ontario demand increased and prices climbed.

Table 2-12 shows real-time scheduled supply by resource or transaction type, including average hourly scheduled imports (but excluding linked wheeling transactions), as well as unscheduled generation that offered at prices less than $20/MWh, for the eight consecutive negative-price hours spanning October 29 and 30, 2012. Total low-priced supply averaged 16,758 MWh during that eight-hour period, with scheduled nuclear generation (10,745 MWh or 64%) and scheduled self-scheduling and intermittent resources (2,026 MWh or 12%) accounting for the majority of the low-priced supply. Imports were not a factor in seven of the eight consecutive negative-price hours as they were either uneconomic or, in one case, preemptively curtailed due to surplus baseload generation (SBG) conditions in the province.[24] Average low-priced supply of 16,758 MWh in those eight hours was only 145 MWh (0.9%) greater than the 16,613 MWh average experienced during all low-price hours in the Summer 2012 Period as shown in Table 2-7.

Table 2-12: Low-Priced Supply During Negative-Price Hours October 29, 2012 HE 23 to October 30, 2012 HE 6 (MWh)

Delivery Date	Delivery Hour (HE)	Low-Priced Supply							Total
		Scheduled Nuclear	Scheduled Baseload Hydro	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Scheduled Gas (including steam)	Imports (excluding linked wheels)	Unscheduled Generation Offering < $20/MWh	
Oct. 29	**23**	10,937	1,556	2,062	1,242	488	45	1,040	17,370
	24	10,420	1,356	2,069	911	488	0	1,714	16,958
Oct. 30	**1**	10,713	1,357	1,991	417	523	0	1,379	16,380
	2	10,671	1,353	1,946	399	523	0	1,445	16,337
	3	10,756	1,350	1,962	380	523	0	1,575	16,546
	4	10,823	1,350	2,025	444	523	0	1,402	16,567
	5	10,755	1,360	2,062	657	523	0	1,360	16,717
	6	10,884	1,535	2,094	1,111	554	0	1,013	17,191
Average		**10,745**	**1,402**	**2,026**	**695**	**518**	**6**	**1,366**	**16,758**

Table 2-13 shows Ontario demand, exports (excluding linked wheeling transactions) and market demand (Ontario demand plus exports) during the eight consecutive negative-price hours on October 29 and 30, 2012. Excess low-priced supply is presented in the final column of Table 2-13, and is calculated as the difference between low-priced supply (see Table 2-12) and market demand during the eight negative-price hours. On average, there was 1,366 MWh of excess low-priced supply, with a maximum excess of 1,713 MWh in HE 24 on October 29, the lowest priced hour of the Summer 2012 Period.

[24] A 9 MW import from Québec was pre-emptively curtailed for SBG in HE 6 on October 30, 2012.

Table 2-13: Demand and Excess Low-Priced Supply during Negative-Price Hours October 29, 2012 HE 23 to October 30, 2012 HE 6 (MWh)

Delivery Date	Delivery Hour (HE)	Demand			Excess Low-Priced Supply
		Ontario Demand	Exports (excluding linked wheels)	Market Demand	
Oct. 29	23	14,697	1,632	16,329	1,041
	24	13,694	1,551	15,245	1,713
Oct. 30	1	13,096	1,904	15,000	1,380
	2	12,823	2,068	14,891	1,446
	3	12,670	2,301	14,971	1,575
	4	12,733	2,432	15,165	1,402
	5	13,219	2,138	15,357	1,360
	6	14,609	1,569	16,178	1,013
Average		**13,443**	**1,949**	**15,392**	**1,366**

Low demand and considerable baseload generation meant that the IESO was operating under SBG conditions. Having forecasted these conditions in advance of real-time, the IESO control room re-priced all wind offers from -$1/MWh to -$2,000/MWh to create more accurate pre-dispatch schedules and prices.[25] With SBG conditions persisting, the IESO ramped down three nuclear units a total of 850 MW, and curtailed all imports from Manitoba and Minnesota in all eight negative-price hours.

Table 2-14 displays pre-dispatch market clearing prices as well as pre-dispatch Ontario demand and net exports for the eight consecutive negative-price hours on October 29 and 30, 2012.

[25] Offers for wind generators are priced at -$1/MWh in pre-dispatch but re-priced to -$2,000/MWh in real-time to prevent the generators from being economically dispatched down. Re-pricing wind at -$2,000/MWh in pre-dispatch creates better fidelity between pre-dispatch and real-time conditions. For more information regarding the process and implications of re-pricing wind generation, see the Panel's April 2012 Monitoring Report, available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf

***Table 2-14: Pre-dispatch MCP, Demand and Net Exports
October 29, 2012 HE 23 to October 30, 2012 HE 6
(MW & $/MWh)***

Delivery Date	Delivery Hour (HE)	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
Oct. 29	**23**	14.00	14,993	143	1,782	1,639
	24	-5.00	13,929	128	1,886	1,758
Oct. 30	**1**	5.00	13,156	246	2,288	2,042
	2	1.00	12,877	122	2,533	2,411
	3	1.00	12,731	104	2,646	2,542
	4	5.00	12,793	222	2,706	2,484
	5	10.00	13,426	167	2,433	2,266
	6	27.36	15,724	176	1,614	1,438
Average		**7.30**	**13,704**	**164**	**2,236**	**2,073**

Final pre-dispatch prices were positive for all but one of the eight consecutive negative-price hours, thus failing to provide a reliable prediction of real-time market conditions. Discrepancies between pre-dispatch supply and demand conditions and actual real-time conditions may lead to real-time price issues as a result of the timing of import and export scheduling. Both imports and exports are scheduled in the final pre-dispatch run, and are locked in for real-time (barring any control actions taken by the IESO). Intertie transactions are therefore scheduled based on pre-dispatch supply and demand conditions, which rely on forecasts of Ontario demand and of supply from self-scheduling and intermittent generators. In hours where these forecasts differ greatly from the eventual real-time conditions, the level of scheduled imports or exports may be suboptimal relative to the level that would have been optimal under the eventual real-time conditions. In the case of the negative-price hours in question, the uncertainty associated with forecasting during extreme weather conditions led to discrepancies between forecasted and actual conditions. For hours when the HOEP was well below $0/MWh (HE 24 on October 29, 2012 to HE 5 on October 30, 2012), there was an average of 169 MW of unscheduled exports bid at prices below the pre-dispatch MCP but above the HOEP (excluding bids on export congested interties and exports to jurisdictions already curtailing Ontario exports for security reasons during the same hour).[26] Had pre-dispatch prices more accurately reflected eventual real-time

[26] With respect to hours with only moderately negative prices, there was 225 MW of unscheduled exports bid at prices below the pre-dispatch MCP but above the HOEP for HE 23 on October 29, 2012, and 2,405 MW for HE 6

conditions, these unscheduled exports might have been scheduled and hence helped to alleviate excess supply conditions.

Table 2-15 displays the supply and demand forecast discrepancy that contributed to the price differential between final pre-dispatch and real-time for the eight consecutive negative-price hours on October 29 and 30, 2012.

Table 2-15: Pre-dispatch and Real-time Demand and Supply Conditions October 29, 2012 HE 23 to October 30, 2012 HE 6 (MWh)

Delivery Date	Delivery Hour (HE)	Ontario Demand			Self-Scheduling and Intermittent Generation			Net Exports			Total PD vs. RT Discrepancy
		PD	RT	PD - RT	PD	RT	RT - PD	PD	RT	Failed	
Oct. 29	23	14,993	14,697	296	2,200	2,062	-138	1,639	1,587	52	210
	24	13,929	13,694	235	1,957	2,069	112	1,758	1,551	207	554
Oct. 30	1	13,156	13,096	60	1,922	1,991	69	2,042	1,904	138	267
	2	12,877	12,823	54	2,011	1,946	-65	2,411	2,068	343	332
	3	12,731	12,670	61	2,033	1,962	-71	2,542	2,301	241	231
	4	12,793	12,733	60	1,954	2,025	71	2,484	2,432	52	183
	5	13,426	13,219	207	2,041	2,062	21	2,266	2,138	128	356
	6	15,724*	15,287*	437	2,111	2,094	-17	1,438	1,569	-131*	967
Average		**13,704**	**13,443**	**176**	**2,029**	**2,026**	**-3**	**2,073**	**1,944**	**129**	**387**

Note: Unlike all other hours where forecasted hourly demand is calculated as the average of the forecasted demand during the 12 intervals of the hour, in HE 6 through 9 and HE 16 through 19 the IESO's forecasted hourly demand is based on the highest forecasted demand of the 12 intervals. Accordingly, when examining demand discrepancy in these hours, we compare the pre-dispatch forecasted demand to the real-time peak demand for that hour, as opposed to the average demand.
* Negative failed net exports indicate failed imports in excess of failed exports.

On average, real-time demand ran 176 MWh (1.3%) lighter than forecasted, putting downward pressure on real-time prices. Real-time market demand was also affected by an average of 129 MWh of net exports that failed to materialize in real-time, as exports to destinations affected by Hurricane Sandy were curtailed. Despite the variable wind conditions associated with Hurricane Sandy and the potential for wind cut-outs,[27] pre-dispatch forecasts of output for self-scheduling

on October 30, 2012. Both figures exclude bids on export congested interties and exports to jurisdictions already curtailing Ontario exports for security reasons during the same hour.

[27] During high-speed wind conditions, wind turbines may need to be brought offline to avoid damage associated with rapid rotation of the blades. Forecasting wind output in periods when turbines may need to be shut down is challenging. Similarly, once turbines are offline due to high wind speeds, it is difficult to predict when they will come back online.

and intermittent resources were accurate, averaging -3 MWh discrepancy (with an absolute average discrepancy of 70 MWh, or 3.5%). The largest under-forecasting of output from self-scheduling and intermittent resources occurred in HE 24 on October 29, when real-time generation outperformed forecasted levels by 112 MWh (5.7%). All told, there was an average of 387 MWh of extra supply and unrealized demand during the eight consecutive negative-price hours.

In summary, low domestic and external demand caused by Hurricane Sandy precipitated the eight consecutive negative-price hours experienced on October 29 and 30, 2012. Discrepancies between pre-dispatch and real-time demand and supply had an adverse effect on pre-dispatch price fidelity. A more accurate pre-dispatch price might have helped partially relieve excess supply conditions, as a negative pre-dispatch price could have induced greater scheduled net exports during the negative-price hours. However, the Panel recognizes that more accurate forecasts would have been difficult to achieve given the storm conditions affecting Ontario and surrounding jurisdictions.

3. Anomalous Uplift

3.1 Congestion Management Settlement Credit Payments

As noted earlier in this chapter, the Panel considers hours in which CMSC payments exceed $500,000 to be anomalous. There were no such hours in the Summer 2012 Period.

As also noted above, the Panel considers CMSC payments in excess of $1,000,000 on a given day to be anomalous. There were two such days in the Summer 2012 Period.

3.1.1 June 20, 2012

The highest CMSC payments per day in the Summer 2012 Period were incurred on June 20, 2012, in respect of which a total of $1,326,408 was paid to numerous market participants across the province. On that day, temperatures reached a high of 34 degrees Celsius, with heavy storms and a tornado warning in the Northwest (NW) zone. With high temperatures, Ontario demand reached a daily peak of 23,901 MW, the third highest daily peak of the Summer 2012 Period. Of the total CMSC payments for the day, $512,764 (39%) was paid to resources in the NW and for intertie transactions in the same region.

The transmission system in the NW was constrained for all hours of the day as heavy storms and threats of a tornado required careful management of power flows in the area. With such volatile grid conditions, the Dispatch Scheduling Optimizer (DSO) was unable to correctly dispatch units to respect all transmission limits in the NW. Accordingly, the IESO control room was required to take out-of-market control actions and manually dispatch generators located in the NW. While generators were receiving manually dispatched constrained schedules based on power flow needs, the generators' unconstrained schedules were still being generated by the DSO based on the economic merits of their offer prices (regardless of grid constraints). This led to regular divergences between the generators' constrained and unconstrained schedules, resulting in considerable constrained-on and constrained-off CMSC payments.

A total of $473,265 in CMSC payments were made in respect of intertie transactions across the province, of which $338,453 (72%) was paid in respect of exports. The majority of the CMSC payments made to exporters were a result of the IESO manually curtailing export transactions to manage power flows on the strained transmission system.

A large generator was paid approximately $188,000 in constrained-off CMSC when a local transformer station was partially de-rated, requiring the IESO to manually reduce generation at the facility.

Generally, CMSC payments per constrained-off megawatt were relatively high on June 20, 2012 on account of the tight supply conditions and the resultant high energy prices.

3.1.2 June 8, 2012

On Friday June 8, 2012, $1,018,328 in CMSC payments were incurred and paid to various market participants across the province. Of this total, $27,200 was paid in respect of intertie transactions, $75,302 to dispatchable loads and $99,540 to dispatchable generators. The balance of $816,286 (or 80% of the total) was paid to a generator in respect of a single gas-fired unit in circumstances that are described below.

When all units are in service, the generation facility in question operates as a combined-cycle facility with multiple gas-fired turbines and one steam turbine. On June 8, 2012, the steam turbine was out of service as part of an extended forced outage, meaning that the multiple in-service gas-fired units were offering as simple-cycle facilities. Day-ahead, the generator was offering the 110 MW minimum loading portion of each unit's capacity at $480/MWh or more for all hours on June 8, 2012. The start-up and speed no-load cost components of the three-part offers for each unit were $0 for the entirety of the day.

Just as the DSO must respect grid limitations when dispatching units in real-time, the day-ahead commitment process (DACP) must respect those same limitations when committing units day-ahead. When the DACP was committing units for June 8, 2012, a security violation was detected on a transformer station located near the generation facility. In order to resolve the violation, the DACP determined that committing one of the facility's gas-fired units to its minimum loading point of 110 MW from HE 1 to HE 16 was the most efficient solution.

In order to ensure that the generator's day-ahead commitment for the unit was respected in real-time, a constraint was input into the DSO ensuring that the unit's real-time constrained schedule would be a minimum of 110 MW from HE 1 until HE 16. When real-time arrived, the energy offers associated with the gas-fired unit remained unchanged from day-ahead at $480/MWh. The real-time energy market MCPs between HE 1 and HE 16 never cleared above $30/MWh, meaning that all of the unit's megawatts were uneconomic. With the unit's unconstrained schedule at 0 MW but its constrained schedule fixed at a minimum of 110 MW, the market participant was receiving considerable constrained-on CMSC payments in every hour.

Circumstances frequently arise on the IESO-controlled grid in which a transmission constraint or security limit necessitates the constrained dispatch of a resource. The local nature of a given transmission constraint, coupled with a lack of resources competing to provide the requisite physical service, may give rise to local market power conditions. Under these conditions, market participants may receive excessive CMSC payments. The market rules provide the IESO with a framework to mitigate excessive CMSC payments resulting from instances of local market power by empowering the IESO to adjust (or "recalculate") CMSC payments.[28] The recalculation of CMSC payments is intended to return the market participant to the level of profit it would have earned had its resource not been constrained on or off, but had instead been dispatched in accordance with the unconstrained schedule.

Under the local market power framework, the IESO must first determine whether local market power existed at the relevant time.[29] The screening process that the IESO uses for that purpose comprises three tests as follows:

- Can the constrained dispatch of the facility or intertie transaction in question be causally linked to a transmission constraint or security limit?
- Are there insufficient resources competing to provide the physical service that is necessitated by the transmission constraint or security limit?
- Is the market participant's investigated offer or bid price inconsistent with its historical pricing behaviour for the resource in question?

If all three of the above questions are answered in the affirmative, then the IESO considers that there may have been local market power for the intervals in question.[30] The next step is for the IESO to determine whether the investigated offer or bid price is consistent with certain costs or benefits (depending on the nature of the facility, some combination of (i) marginal costs, (ii) opportunity costs or replacement energy costs and (iii) the value or benefits of consumption). At this stage, the market participant is entitled to make representations to explain its bid or offer price. If the IESO determines that the investigated price is not consistent with appropriate costs or benefits, the IESO may choose to reduce the CMSC payments made to the market participant.

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[28] The local market power rules are primarily contained in Appendix 7.6 of Chapter 7 of the Market Rules, and in "Market Manual Part 2.12: Treatment of Local Market Power", available at http://www.ieso.ca/imoweb/manuals/marketdocs.asp

[29] The screening process described below does not need to be applied in cases where there are persistent and significant constrained-off events for a registered facility in what is referred to as a "designated constrained off watch zone".

[30] A determination that there may have been local market power applies only to the event under consideration at the time. The local market power screening process must be applied anew for any subsequent events involving the market participant.

The recalculation is done by replacing the investigated offer or bid price with the IESO's measure of the participant's marginal cost or benefit.[31]

The conditions surrounding the large CMSC payment made on June 8, 2012 in respect of the gas-fired unit referred to above appear to the Panel as seemingly justifying further review on the grounds of local market power. Had the local market power framework been applicable, and the IESO determined that the $480/MWh offer submitted by the market participant was inconsistent with the marginal operating cost of the generation unit, the CMSC payments could have been recalculated using the IESO's measure of the unit's marginal cost. However, in its current form the local market power framework does not extend to cover units committed day-ahead under the DACP.

The current local market power framework is geared towards vetting incremental energy offers and bids. In the Panel's view, given the evolution of the market a robust local market framework should integrate the DACP, consider start-up and speed-no-load cost submissions and capture not only excessive CMSC payments but also excessive Production Cost Guarantee (PCG) payments. While CMSC payments were involved in the case described above, they could just as easily have been PCG payments. Had the market participant reduced its real-time offers below the offer price submitted day-ahead, and had those offers been economic in real-time, a portion or all of the payments would have been PCG payments. Alternatively, a generator who receives a cost guarantee based on inflated start-up or speed-no-load costs would receive PCG payments, and not CMSC payments. The Panel has observed instances of day-ahead local market power resulting in large PCG payments; however these payments are not recoverable under the current framework.

While the Panel recognizes there may be complexities involved, the Panel believes the IESO should consider the merits of integrating the day-ahead commitment process into the local market power framework.

[31] Replacing the investigated offer/bid price is done solely for the purpose of recalculating CMSC payments; the market is not resettled based on the new offer/bid price.

Recommendation 2-1

> ***The IESO should consider expanding the current local market power framework to cover analogous circumstances that arise as part of the day-ahead commitment process.***

3.2 Operating Reserve Payments

As noted earlier in this chapter, the Panel considers hours in which total OR payments exceed $100,000 to be anomalous. There were no such hours in the Summer 2012 Period.

High OR payments are associated with instances of high OR prices. Due to the joint optimization of the energy and OR markets, energy and OR prices typically move in the same direction as supply and demand conditions change. Instances of high OR prices and payments are typically associated with tight supply conditions in both the energy and OR markets.

The hour with the highest OR payments in the Summer 2012 Period was HE 19 on September 20, 2012, when OR payments totaled $66,203. During that hour, the prices for 10-minute spinning reserve, 10-minute non-spinning reserve and 30-minute reserve were $64.63/MWh, $64.63/MWh and $61.16/MWh, respectively. The HOEP during the hour was $177.31/MWh, indicating tight supply conditions. On average, real-time demand in HE 19 was 390 MW greater than forecasted, with wind generators delivering an average of 380 MW less than forecasted. The result was tight real-time supply conditions relative to pre-dispatch, high prices in the energy market and, by virtue of the joint optimization of the markets, high prices in the OR markets.

3.3 Intertie Offer Guarantee Payments

As noted earlier in this chapter, IOG payments in excess of $500,000 for a given hour or in excess of $1,000,000 for a given day are considered anomalous by the Panel. There was one such day in the Summer 2012 Period.

An IOG payment is intended to protect an import scheduled day-ahead or in the final pre-dispatch run from a drop in the real-time price relative to the price at which the import was scheduled. When the real-time price drops below the scheduled import offer price, an IOG payment is made equaling the difference between the real-time price and the offer price on each megawatt.[32]

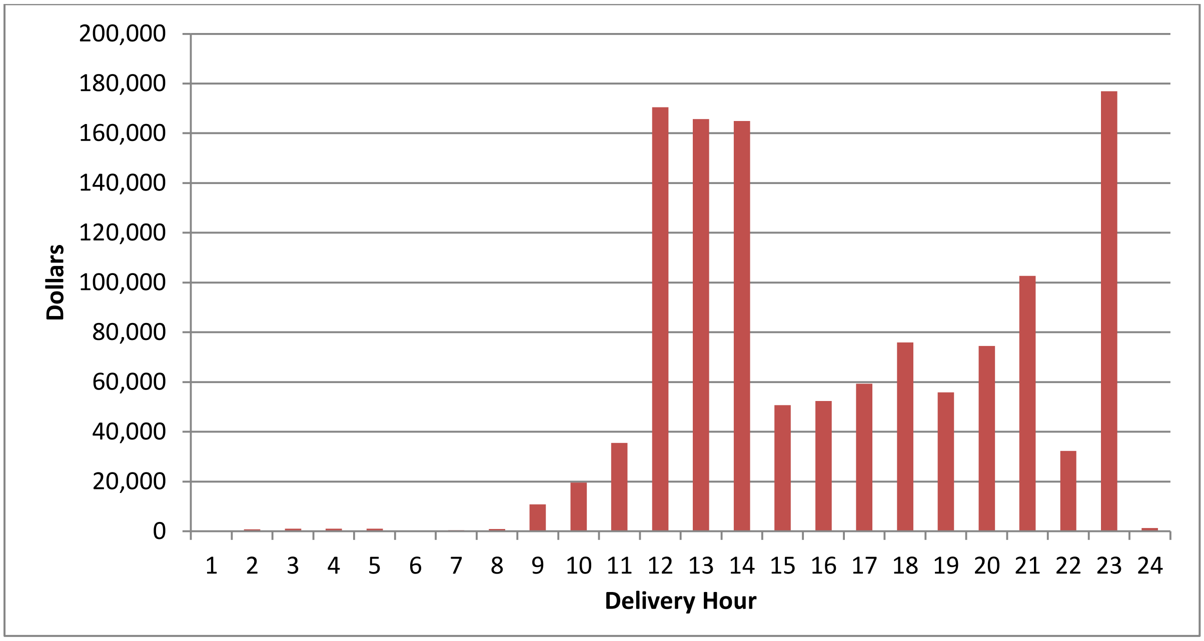
There are two types of IOG payments: day-ahead IOG payments and real-time IOG payments. A day-ahead IOG payment is made when a market participant's import transaction is committed under the DACP and the real-time price clears below the participant's day-ahead offer price. A real-time IOG payment is made when an import is scheduled in the final pre-dispatch run and the real-time price subsequently drops below the participant's offer price. Both types of IOG payments are intended to increase system reliability by providing compensation certainty to importers, thereby incenting them to import power into the province.[33]

On September 12, 2012, IOG payments totaling $1,254,485 were incurred in respect of various market participant import transactions, representing 9% of the total IOG payments made during the Summer 2012 Period. Figure 2-4 displays the IOG payments for each hour of that day.

[32] When an intertie is uncongested, the real-time price is equal to the Ontario MCP. When an intertie is congested, the real-time price is equal to the external zonal price at the interface.

[33] The Panel has previously questioned the appropriateness of off-peak real-time IOG payments, given that concerns over inadequate supply resources during off-peak hours are extremely rare. The Panel ultimately recommended that the IESO review the IOG program to determine whether or not it results in reliability improvements commensurate with its cost. For details, see the Panel's July 2008 Monitoring Report (at pp. 140-152), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200807.pdf.

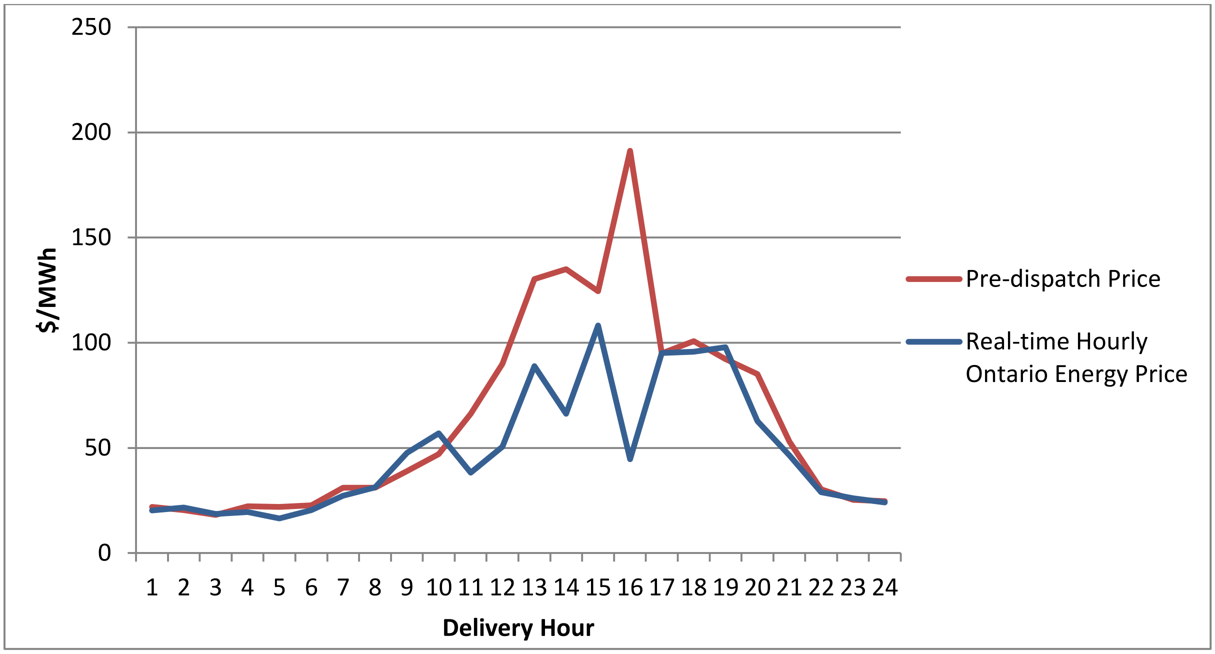
Figure 2-4: Intertie Offer Guarantee Payments by Hour
September 12, 2012
($)



The majority of the IOG payments were incurred during peak hours, with HE 23 accounting for the largest hourly IOG payment of day at $176,969. HE 12 through HE 14 also experienced large payments relative to the remaining hours of the day.

The final pre-dispatch run forecasted tight supply conditions in many of the hours of the day, leading to pre-dispatch prices as high as $191.30/MWh. Although real-time supply conditions were tight, with the HOEP reaching a high of $108.24/MWh, real-time prices were generally lower than forecasted in the final pre-dispatch run. Figure 2-5 displays final pre-dispatch and real-time prices on September 12, 2012.

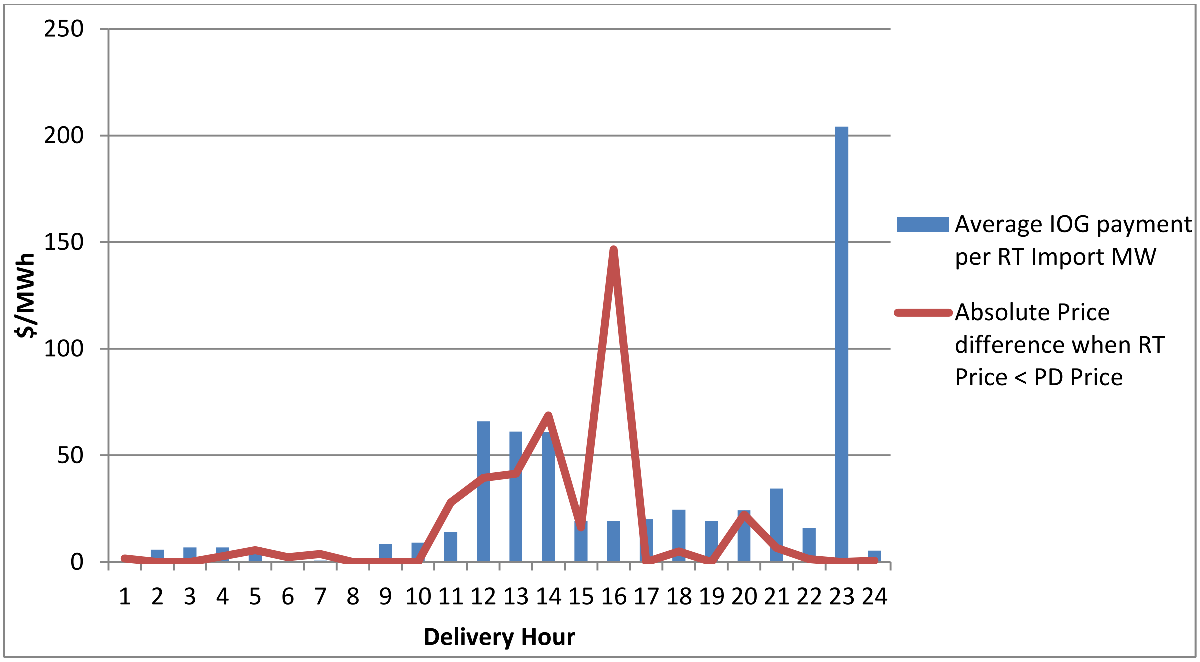
Figure 2-5: Pre-dispatch and Real-time Energy Prices
September 12, 2012
($/MWh)



Real-time prices that are lower than pre-dispatch prices often lead to real-time IOG payments. As discussed earlier, intertie transactions are scheduled based on the final pre-dispatch supply/demand conditions and carried over to real-time, but are settled based on real-time prices. If the real-time price drops below the offer price at which an import is scheduled in pre-dispatch, a real-time IOG payment will be made to top up the market participant to its scheduled offer price. In 16 of the 24 delivery hours on September 12, 2012, the real-time price was lower than the pre-dispatch price.

Figure 2-6 displays average IOG payments per megawatt by hour on September 12, 2012 as well as the absolute difference between the pre-dispatch and real-time price in hours when the real-time price was lower (hours in which the real-time price was higher than the pre-dispatch price are displayed as a $0 difference).

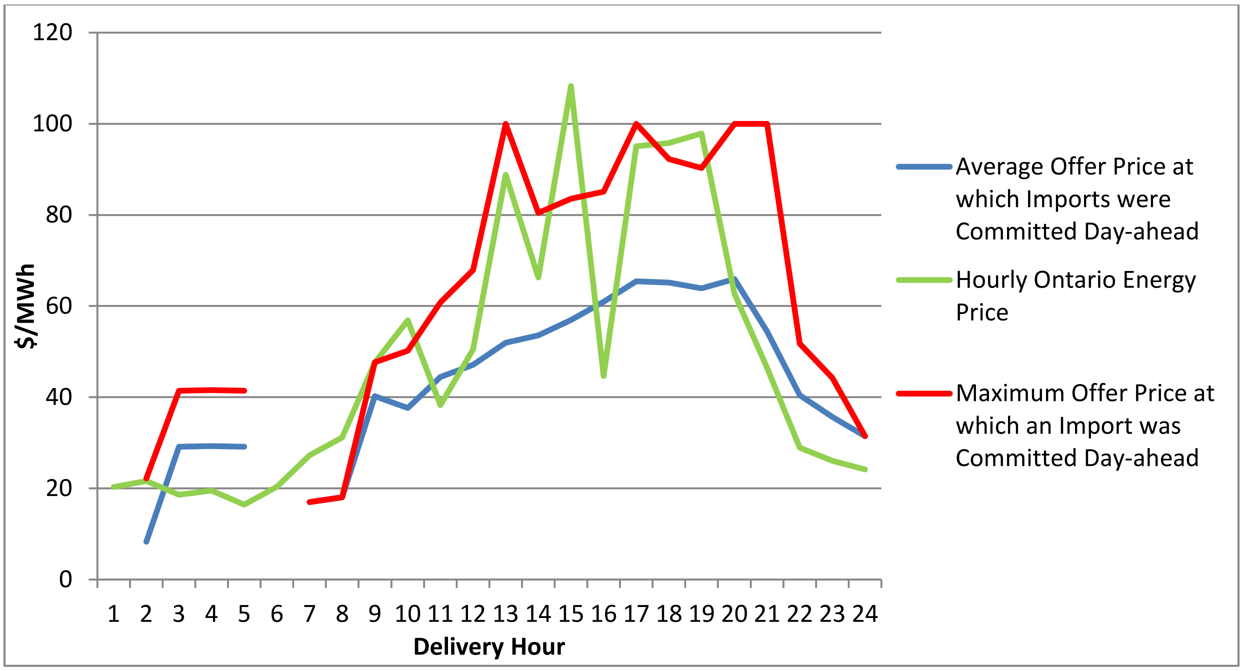
Figure 2-6: Hourly IOG Payments and the Absolute Difference between Pre-dispatch and Real-time Prices when the Real-time Price is Lower
September 12, 2012
($/MWh)



As one would expect, in the hours in which the real-time price was lower than the pre-dispatch price, there was a positive correlation between the absolute difference in prices and the average IOG payment per megawatt. Hours in which the average IOG payment exceeded the absolute price difference, such as HE 23, indicate that some or all of the IOG payments during that hour were associated with day-ahead commitments and not pre-dispatch scheduling.

Of the 39,999 MWhs of imports scheduled in real-time, 23,086 MW (58%) were committed day-ahead. The average offer price at which imports were committed day-ahead was $54.26/MWh, while the average HOEP was $48.06/MWh. Figure 2-7 displays the HOEP and the average and maximum offer price at which imports were committed day-ahead for each hour of September 12, 2012.

Figure 2-7: HOEP and the Average and Maximum Offer Price at which Imports were Committed Day-ahead
September 12, 2012
($/MWh)



NOTE: There were no day-ahead committed imports in HE 6.

In the majority of hours, the average offer price at which imports were committed day-ahead was lower than the HOEP, indicating that, absent import congestion, most import megawatts committed day-ahead received no IOG payment. The spread between the maximum offer price at which an import was committed day-ahead and the HOEP represents the largest IOG payment per megawatt an import could receive, again absent import congestion. This spread reached a daily maximum of $53.62/MWh in HE 21. While spreads between the maximum offer price at which imports were committed day-ahead and the HOEP account for a portion of the high per megawatt IOG payments seen in Figure 2-6, the spreads are not large enough to account for average IOG payments per megawatt of over $53.62, such as those experienced in HE 12, 13, 14 and 23.

Having already accounted for IOG payments associated with a drop in the HOEP relative to the offer price at which imports were scheduled (be it day-ahead or in the final pre-dispatch), large IOG payments in some hours must be associated with intertie congestion. Table 2-17 displays the HOEP, intertie congestion price (ICP) and zonal price for the two interties that experienced significant congestion on September 12, 2012, all of which was import congestion.[34]

Table 2-16: HOEP, ICPs and Intertie Zonal Prices
September 12, 2012
($/MWh)

Delivery Hour (HE)	HOEP	Manitoba		Minnesota	
		ICP	Zonal Price	ICP	Zonal Price
1	20.28	-13.04	7.24	0.00	20.28
2	21.64	-13.04	8.60	0.00	21.64
3	18.59	-13.04	5.55	-21.09	-2.50
4	19.50	-11.20	8.30	-19.25	0.25
5	16.40	-11.27	5.13	0.00	16.40
6	20.34	-19.08	1.26	0.00	20.34
7	27.24	-11.93	15.31	0.00	27.24
8	31.15	-18.99	12.16	0.00	31.15
9	47.59	-19.08	28.51	0.00	47.59
10	56.88	-19.08	37.80	-6.11	50.77
11	38.29	-18.66	19.63	-1.45	36.84
12	50.51	-2,022.80	-1,972.29	-9.83	40.68
13	88.81	-2,023.25	-1,934.44	-4.19	84.62
14	66.28	-2,024.59	-1,958.31	-6.25	60.03
15	108.24	-22.80	85.44	-7.08	101.16
16	44.68	-27.74	16.94	-9.12	35.56
17	95.06	0.00	95.06	-5.23	89.83
18	95.79	0.00	95.79	0.00	95.79
19	97.89	0.00	97.89	-14.01	83.88
20	62.70	0.00	62.70	-23.02	39.68
21	46.38	-597.90	-551.52	-30.23	16.15
22	28.95	-580.67	-551.72	0.00	28.95
23	26.06	-2,040.98	-2,000.00*	0.00	26.06
24	24.13	-19.09	5.04	0.00	24.13

* Zonal prices have a price floor of-$2,000/MWh

Economic net import transactions in excess of the intertie transfer capability leads to import congestion and a negative ICP, resulting in an intertie zonal price below the HOEP. Because import transactions are paid the intertie zonal price to deliver power, as the zonal price goes down the quantum of the IOG payment required to top up the market participant to its scheduled offer price goes up.

[34] The Québec interface PQAT was the only other intertie to experience congestion on September 12, 2012. In HE 10, import congestion led to an ICP of -$2.35/MWh.

Import congestion at the Manitoba intertie had intertie zonal prices approaching -$2,000/MWh in HE 12, 13, 14 and 23, and just above -$550/MWh in HE 21 and 22. During those hours, $576,183 in IOG payments were paid to a single market participant (Participant A) transacting over the Manitoba intertie. During all heavily congested hours, Participant A offered imports in excess of the intertie Scheduling Limit, all at deeply negative prices. As a result, the Manitoba interface was import congested at a highly negative zonal price, resulting in participants paying to import power into the zone. Despite paying to import power, Participant A's offer behavior was nonetheless profitable on a net basis because of its position in the transmission rights market.[35]

In total, $607,395 in IOG payments were made to importers in the Northwest (including the $576,183 paid to Participant A), representing 48% of the total daily IOG payments made in respect of all Ontario imports on September 12, 2012. Importers in the Northwest received 48% of the IOG payments despite accounting for only 9% of the real-time unconstrained imports scheduled (excluding linked wheels).

[35] The Panel has previously noted other instances of Participant A's import offer behaviour, and discussed the overlap in protection that is provided by IOG payments and payouts under transmission rights. See Section 4.4 of the Panel's January 2013 Monitoring Report, available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. Introduction

This Chapter summarizes notable changes and developments that affect the efficient operation of the IESO-administered markets, making recommendations where relevant to promote market objectives. Section 2 identifies developments since issuance of the Panel's last monitoring report, while section 3 provides an update on Panel investigations. In section 4, the Panel sets out its analysis of the efficiency implications of the allocation of the Global Adjustment.

2. Developments in the Market

This section provides an update on the operation of phase angle regulators (PARs) at the Michigan interface, as well as a review of Congestion Management Settlement Credit (CMSC) payments made to generators during ramp down.

2.1 *Operation of the Phase Angle Regulators at the Michigan Interface*

2.1.1 Introduction

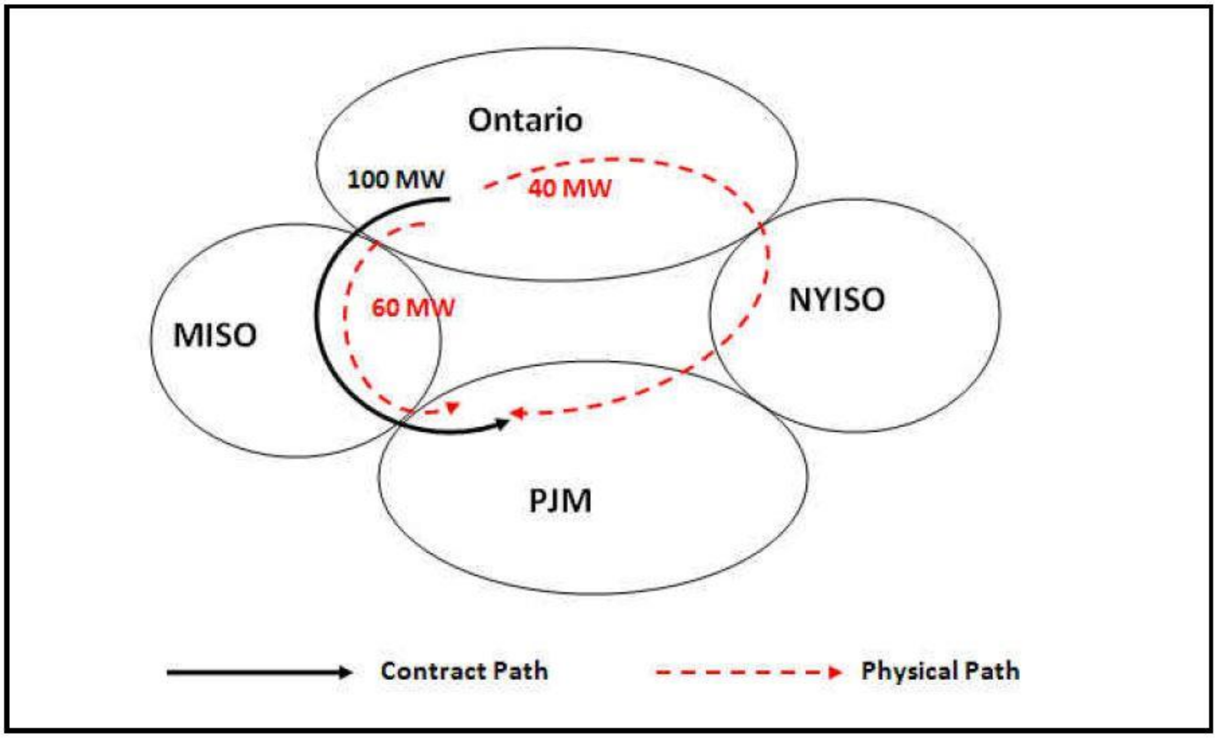
A PAR is a special transformer that is used to control the power flowing over a transmission line. There are currently five PARs on four transmission lines at the Ontario-Michigan interface (three owned by Ontario's Hydro One and two by Michigan's International Transmission Company (ITC)), with an estimated capability of controlling up to 600 MW of Lake Erie Circulation (LEC). To effectively control LEC – often referred to as "loop flow" – PAR control is required on all in-service circuits. With any one of the PARs out of service or by-passed, the remaining PARs have limited capability to control LEC.

LEC is a loop flow issue that significantly affects both Ontario and its neighbouring jurisdictions.[36] As its name implies, LEC refers to the phenomenon by which unscheduled power flows around the Lake Erie region. The IESO measures LEC as the difference between scheduled and actual power flows at the Michigan-Ontario interface. At the interface, LEC can either be "clockwise" or "counter-clockwise".[37] Figure 3-1 illustrates the concept of inadvertent flow in the case of an export from Ontario to the PJM Interconnection (PJM) service area. In the example, a trader is scheduled to export 100 MW of power from Ontario into the PJM service area by way of Michigan transmission lines. However, because power flows along the path of least resistance, only 60 MW follows the scheduled path. The remaining 40 MW, rather than flowing through Michigan (part of the Midwest Independent Transmission System Operator (MISO) service area), crosses through the New York Independent System Operator (NYISO) service area to reach the PJM service area. This represents 40 MW of clockwise inadvertent or loop flow.

[36] For a detailed explanation of the causes and implications of loop flow, see the Panel's July 2009 Monitoring Report (at pp. 166-181), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200907.pdf

[37] Prior to the PARs being brought into service, exports scheduled from Ontario through Michigan and into the PJM service area would flow roughly 57% through Michigan and 43% through New York. These numbers were estimated by the Panel based on the relationship between exports to the PJM service area and LEC. For more details, see the Panel's July 2009 Monitoring Report (at pp. 166-181), available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200907.pdf. The 43% of unscheduled energy flowing through New York is referred to as "clockwise LEC". Clockwise LEC can cause congestion at the West-Central interface in New York. As such, it can lead to curtailment actions by the New York Independent System Operator. Similarly, exports scheduled to New York or the PJM service area by way of New York transmission lines would partially flow through Michigan, causing counter-clockwise LEC and possible curtailments by the Midwest Independent Transmission System Operator.

Figure 3-1: Illustrative Scheduled Flow and Actual Flow for Exports to PJM



Inadvertent flow has both reliability and economic implications. From a reliability perspective, inadvertent flow may cause a system operator to take actions to offset or reduce the flow, such as curtailing a transaction or re-dispatching internal generation to accommodate the flow. In the case of Ontario, these actions may give rise to CMSC payments, which are ultimately recovered from all consumers in the province.

As noted above, five PARs are currently installed on four transmission lines at the Ontario-Michigan interface; three are owned by Ontario's Hydro One and two by Michigan's ITC.[38] While all of these PARs have been functional since 2009, a lengthy regulatory proceeding

[38] Apart from the five PARs at the Michigan border, there are two PARs at the Manitoba interface, one at the Minnesota interface and two at the St. Lawrence station at the New York border. There is no need for PARs on a direct current (DC) line, as the power flow is fully controlled when power is converted from alternate current to direct current.

delayed the coming into service of the two ITC-owned PARs until April 2012.[39] However, a series of outages on the Michigan interface as well as the testing of the ITC-owned PARs prevented them from becoming fully operational until July 18, 2012.[40]

2.1.2 Observations

The following significant changes have been observed since the two ITC-owned PARs came into full operation on July 18, 2012:

- LEC has been reduced below historical levels;
- fewer power flow curtailment procedures[41] have been issued by NYISO, MISO and the IESO; and
- CMSC payments made to intertie traders at the Michigan and New York interfaces have dropped significantly.

These results are consistent with those that the Panel expected to see from the full operation of all five of the PARs.

Figure 3-2 depicts LEC for the period July 18 to October 31 in each year from 2008 to 2012. Since all five PARs became fully operational, the IESO and MISO have established a 200 MW threshold for LEC, meaning that LEC should not, for the most part, exceed 200 MW in either a clockwise or counter-clockwise direction. Where LEC is maintained within 200 MW, IESO transactions on both the New York and Michigan interfaces are deemed to be flowing on their scheduled paths and are therefore not subject to curtailment. Since July 18, 2012, LEC flows have generally not exceeded the 200 MW threshold.

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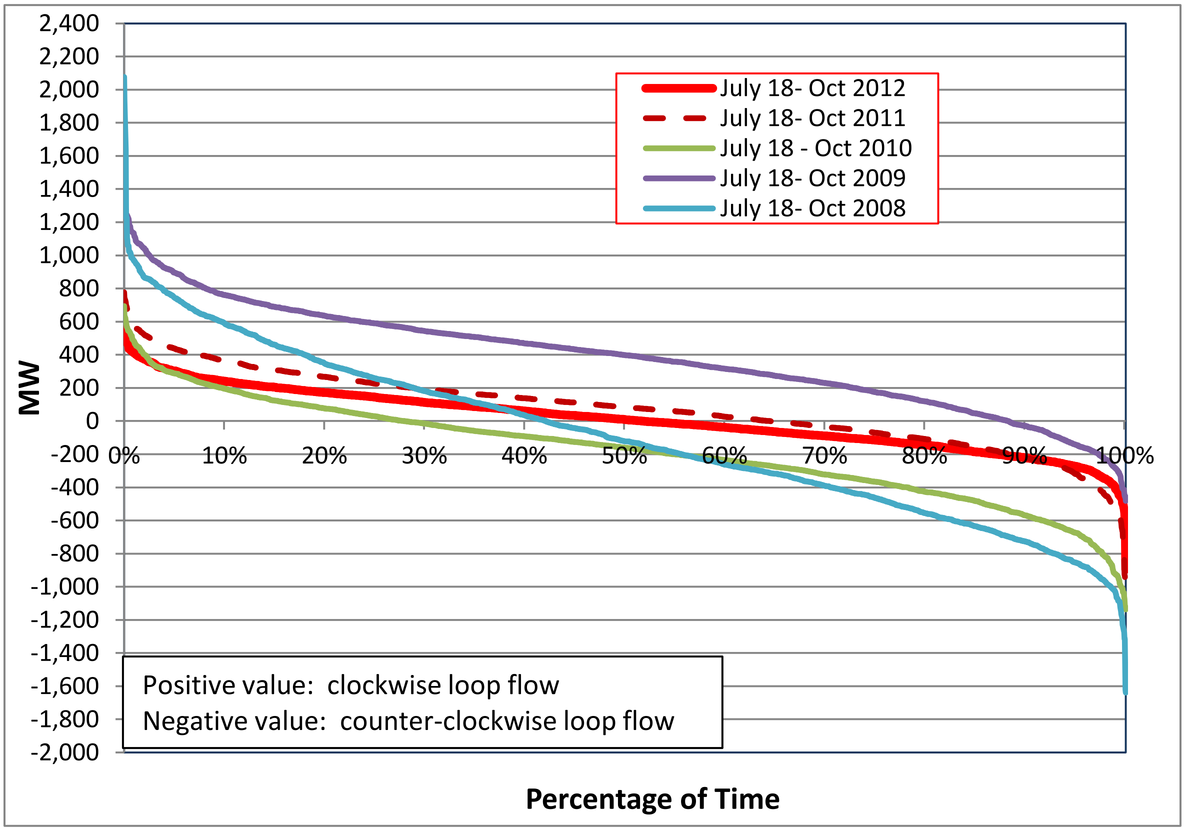
[39] For more detail, see the Panel's March 2011 Monitoring Report (at pp. 66-67), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20110310.pdf

[40] In accordance with a procedure established between the IESO, MISO, ITC and Hydro One, the IESO controls the operation of all five of the PARs. Whenever LEC exceeds the threshold set out in the procedure (currently 200 MW clockwise or counter-clockwise), the IESO will initiate a call with MISO, ITC, and Hydro One and instruct ITC and Hydro One to adjust the taps at the PARs with a view to controlling LEC.

[41] The specific types of curtailments referred to in this section are Transmission Loading Relief (TLR) curtailments. There are six categories of TLRs (from Level 0 to Level 6), depending on congestion levels. For details, see http://www.nerc.com/fileUploads/File/4b_TLR_Levels_reference_document.pdf. For corresponding actions under each TLR category, see: http://www.nerc.com/page.php?cid=5%7C67%7C205 .

Figure 3-2: Lake Erie Circulation, July 18 – October 31, 2008 to 2012 (MW)



Intertie transactions can be curtailed for a variety of reasons. To identify the impact of LEC on curtailment actions, the Panel evaluated each curtailment against several criteria, including the transaction type (import or export), the relevant intertie (Michigan or New York), the direction of flow (clockwise or counter-clockwise), and the curtailment reasons recorded by the IESO. For the period July 18, 2012 onwards, only transactions that were curtailed when LEC exceeded 200 MW were reviewed. For the period prior to July 18, 2012, all curtailments were reviewed.

Table 3-1 displays the proportion of time in each month from January 2011 to December 2012 in which curtailments thought to be caused by LEC occurred. It also lists the total amount of energy curtailed in each month that is thought be a result of LEC. The coming into full operation of the two ITC-owned PARs in July 2012 coincided with a significant decline in both the number of hours in which LEC-based curtailments occurred and the quantity of energy so curtailed. Interestingly, both metrics had already declined significantly in June 2012, one month prior to the ITC-owned PARs becoming fully operational. One possible reason for the reduction is that exports to PJM were down significantly in June, reducing clockwise LEC and, in turn, congestion at the New York interface. A second possible reason is that the PARs were partially in service while being tested in June.

Table 3-1: Number of Curtailment Hours and MWh Curtailed at the Michigan and New York Interfaces Estimated to be Due to Lake Erie Circulation January 2011 to December 2012

	Total Hours	Curtailment Hours	MWh Curtailed	Curtailment Hours as % of Total Hours	Average MWh Curtailed per Curtailment Hour
January 2011	744	399	319,890	53.63%	802
February 2011	672	85	51,826	12.65%	610
March 2011	744	163	81,265	21.91%	499
April 2011	720	65	19,344	9.03%	298
May 2011	744	121	77,672	16.26%	642
June 2011	720	173	48,141	24.03%	278
July 2011	744	112	40,719	15.05%	364
August 2011	744	60	27,495	8.06%	458
September 2011	720	49	11,140	6.81%	227
October 2011	744	27	5,999	3.63%	222
November 2011	720	9	834	1.25%	93
December 2011	744	73	50,445	9.81%	691
January 2012	744	53	11,159	7.12%	211
February 2012	696	110	79,461	15.80%	722
March 2012	744	115	63,105	15.46%	549
April 2012	720	111	65,304	15.42%	588
May 2012	744	110	45,688	14.78%	415
June 2012	720	23	4,109	3.19%	179
July 1-17, 2012	408	6	1,827	1.47%	305
Monthly average January 2011 – July 17, 2012	**-**	**98**	**52,996**	**13.47%**	**539**
July 18-31, 2012	336	1	177	0.30%	177
August 2012	744	2	211	0.27%	106
September 2012	720	5	246	0.69%	49
October 2012	744	2	1,015	0.27%	508
November 2012	720	15	1,604	2.08%	107
December 2012	744	1	345	0.13%	345
Monthly average July 18, 2012- February 28, 2013	**-**	**5**	**635**	**0.62%**	**140**

With all five PARs fully operational, scheduling limits and schedules at the two interfaces are less likely to be affected by LEC. In turn, the relevant unconstrained and constrained schedules are less likely to diverge. A reduction in differences between these schedules will, all else being equal, result in lower CMSC payments. Table 3-2 depicts monthly constrained-on and constrained-off CMSC payments made to traders at the Michigan and New York interfaces for the period from January 2011 to December 2012. CMSC payments for the 5 ½ months after the PARS were all fully operational averaged $73,000 per month. This is significantly lower than the prevailing average of $440,000 per month over the immediately preceding 18 months. If current savings are extrapolated over the period of a year, approximately $4.4 million in savings could be realized by Ontario loads in the form of reduced uplift charges.[42]

[42] Not all of the reduction in CMSC payments is necessarily directly attributable to the PARs, as changes in internal congestion, among other factors, may also have contributed. However, the Panel believes that the PARs have had a significant impact on CMSC payments.

Table 3-2: Monthly Constrained-on and Constrained-off CMSC paid for Transactions at the Michigan and New York Interfaces January 2011 to December 2012 ($ thousands)*

Month	Constrained-on CMSC	Constrained-off CMSC	Total CMSC
Jan-11	20.15	724.40	744.55
Feb-11	25.50	219.49	244.99
Mar-11	26.46	256.09	282.54
Apr-11	-26.54	198.72	172.19
May-11	52.71	410.67	463.37
Jun-11	318.84	980.40	1,299.24
Jul-11	141.73	851.51	993.24
Aug-11	28.47	199.15	227.62
Sep-11	73.52	310.61	384.13
Oct-11	11.24	696.26	707.49
Nov-11	59.70	256.98	316.68
Dec-11	-5.15	102.00	96.85
Jan-12	-80.43	288.85	208.42
Feb-12	-46.31	5.07	-41.24
Mar-12	-26.54	561.70	535.16
Apr-12	14.95	208.00	222.95
May-12	118.69	545.03	663.72
Jun-12	98.70	574.20	672.89
July 1 to July 17 2012	44.87	123.07	167.94
Monthly average January 2011 – July 17, 2012	**44.77**	**395.38**	**440.15**
July 18 to July 31 2012	32.00	54.50	84.50
Aug-12	-11.26	-79.18	-90.44
Sep-12	85.14	148.13	233.27
Oct-12	0.99	-7.50	-6.51
Nov-12	3.53	228.44	231.97
Dec-12	-1.55	-0.73	-2.28
Monthly average July 18, 2012- February 28, 2013	**15.37**	**57.83**	**73.20**
Total (all months)	**1,005.15**	**7,954.94**	**8,960.09**

*CMSC can be negative (i.e. a charge), if the constraint resulted in the trader avoiding a loss as implied by its market schedule. To illustrate, assume an exporter bids $50/MWh to export 1 MW but is constrained off. In pre-dispatch, the exporter has a constrained schedule of 0 MW and an unconstrained schedule of 1 MW. If in real-time the market clears at $60/MWh, the exporter would have been charged $60 to purchase the 1 MW of power if it had flowed in real time, $10 more than it had bid. The market will consider the exporter to have avoided a $10 loss ($50-$60) as a result of being constrained off. To make the exporter "whole" to its unconstrained schedule, the exporter will be charged $10 in the form of a negative CMSC payment (i.e. a CMSC charge).

2.2 *Ramp-Down CMSC Payments*

CMSC payments arose from the decision to adopt a uniform-price market in Ontario. The committee charged with designing Ontario's electricity market proposed such payments to compensate dispatchable facilities for reductions in their operating profits that resulted from their being required to respond to system operator instructions to alter their output or consumption in order to relieve transmission constraints:

> A uniform "market" price (the price is actually administratively determined) implies a set of corresponding market quantities that each participant would sell or buy at that uniform market price. <u>However, transmission constraints may prevent participants from injecting or withdrawing those corresponding market quantities</u>. In order to relieve the actual constraints and remain within system security limits during dispatch, the IMO [now IESO] may have to direct generators (and dispatchable loads) to produce (consume) more or less energy than they are willing to produce (consume) at the uniform price, given the prices each participant has indicated in its bid or offer. To induce generators and loads to change their outputs or takes to the required levels, <u>a uniform pricing approach thus requires the IMO to compensate participants for any differences between the uniform price and their bids/offers whenever they are "constrained on" or "constrained off" in order to relieve transmission constraints</u>.[43] (emphasis added)

CMSC payments were not intended to provide a revenue stream for market participants that take a voluntary action, such as ramping down for reasons other than responding to IESO instructions. For several years, the Panel has been monitoring CMSC payments made to generators during ramp downs.[44] The Panel has consistently concluded that CMSC payments associated with self-

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[43] Market Design Committee, Final Report, January 29, 1999, Volume 1, ch. 3, p. 8, available at: http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/Q4Report.asp

[44] See, in chronological order, the Panel's January 2009 Monitoring Report, pp. 216-217, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf; the Panel's January 2010 Monitoring Report, p. 113, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_201001.pdf; the Panel's August 2010 Monitoring Report, p. 270-273, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf; the Panel's February 2011 Monitoring Report, p. 93, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20110310.pdf; the Panel's November 2011 Monitoring Report, p. 123, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf; and the Panel's April 2012

induced (i.e., voluntary) ramp downs are not warranted and has recommended that the IESO eliminate these payments.

Although the IESO initiated a stakeholder consultation that included consideration of a possible market rule amendment to recover or limit CMSC payments to generators during ramp down, the relevant portion of that consultation was suspended in July 2010.[45]

In August 2011, the Panel issued a Monitoring Document entitled "Generator Offer Prices used to Signal an Intention to Come Offline" (the "Monitoring Document") that sets out evaluative criteria to be used by the Panel for monitoring potential gaming in relation to prices offered by generators in order to take their units offline.[46] The Monitoring Document notes:

> The Panel recognizes that real-time prices may vary from pre-dispatch prices and that a generator that is seeking to come offline may want a high degree of assurance that this outcome will occur at the planned time. Based on an analysis of historical pricing patterns, the Panel believes that offer price levels that are not more than 30% above a generator's 3-hour ahead pre-dispatch shadow price would normally provide a high degree of assurance that the unit will be dispatched below its [minimum loading point] and be able to come offline in real-time. However, if prices are low, it is possible that the 3-hour ahead pre dispatch shadow price may be below the generator's cost. In some instances, even an offer price that is 30% above the 3-hour ahead pre-dispatch shadow price could be below the generator's marginal cost. Accordingly, where there are *bona fide* business reasons for a generator to come offline, the Panel normally would not consider a gaming investigation to be warranted where the generator's offer price does not exceed the greater of (i) 130% of the generator's 3-hour ahead pre-dispatch constrained schedule (shadow) price, or (ii) the generator's marginal (or other incremental or opportunity) cost.[47]

Monitoring Report, p. 52, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf.

[45] IESO, "Congestion Management Settlement Credit (CMSC) Payments for Generation Facilities (SE-84)", available at: http://www.ieso.ca/imoweb/consult/consult_se84.asp.

[46] Market Surveillance Panel, "Monitoring Document on Generator Offer Prices Used to Signal an Intention to Come Offline" (19 August 2011), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MonitoringDocument_GeneratorOfferPrices_20110819.pdf.

[47] *Ibid*, pp. 7-8.

The Monitoring Document also notes that prices above the levels set out in the above excerpt will not automatically lead to a gaming investigation, nor will prices below those levels necessarily preclude one.

Ramp-down CMSC payments have fallen significantly since the Panel issued the Monitoring Document on August 19, 2011. Table 3-3 shows the value of these payments in each of the 14 months before and after the Monitoring Document was released.

Table 3-3: Ramp-Down CMSC Payments by Month
July 2010 to October 2012
($ thousands)

July 2010 to August 2011		August 2011 to October 2012	
Month	**Amount**	**Month**	**Amount**
Jul-10	888	**Sep-11**	435
Aug-10	1,058	**Oct-11**	289
Sep-10	1,093	**Nov-11**	870
Oct-10	881	**Dec-11**	276
Nov-10	1,096	**Jan-12**	403
Dec-10	938	**Feb-12**	369
Jan-11	1,260	**Mar-12**	377
Feb-11	1,053	**Apr-12**	293
Mar-11	1,044	**May-12**	174
Apr-11	638	**Jun-12**	368
May-11	1,146	**Jul-12**	498
Jun-11	1,306	**Aug-12**	420
Jul-11	1,236	**Sep-12**	239
Aug-11	904	**Oct-12**	173
Total	**14,540**	**Total**	**5,184**

The amount of ramp-down CMSC payments paid in any given month depends on how many times (and which) generators ramp down in that month, the ramp down offer prices submitted by those generators and the prevailing market prices during the hours that the generators are coming offline. Thus, the difference in the totals shown in Table 3-3 is only a rough indication of how the Monitoring Document has affected the amount of ramp-down CMSC payments.

Table 3-4 provides a better indication of the reduction in CMSC payments resulting from the issuance of the Monitoring Document. For the five generators that received the highest amounts of ramp-down CMSC payments before issuance of the Monitoring Document, the table shows "before" and "after" shutdown offer prices and CMSC payments per shutdown. Had the five generators retained the shutdown offer prices they typically used before the issuance of the Monitoring Document, the CMSC payments would have been $8.9 million higher in the post-Monitoring Document period from August 20, 2011 to October 31, 2012 than they actually were.

Table 3-4: CMSC Savings After Issuance of the Panel's Monitoring Document by Generator
June 2011 to October 2012
($/MWh & $ thousands)

Generator	June 1, 2011 to August 19, 2011		August 20, 2011 to October 31, 2012			CMSC Savings per Shutdown ($)	CMSC Reduction (%)	Total Estimated CMSC Savings ($)
	Typical Shutdown Offer Price ($/MWh)	CMSC per Unit per Shutdown ($)	Typical Shutdown Offer Price ($/MWh)	No of UnitShutdowns	CMSC per Unit per Shutdown ($)			
Participant 1	149	5,000	99	967	1,900	3,100	62%	2,681
Participant 2	240	3,900	35	1,173	400	3,500	90%	5,236
Participant 3	200	1,300	55	450	500	800	62%	388
Participant 4	150	4,100	40	201	700	3,400	83%	695
Participant 5	60	900	65	912	1,100	-200	-22%	-87
Total								8,913

Although the Panel is pleased that ramp-down CMSC payments have fallen significantly, as shown in Table 3-3 the amount of such CMSC payments remains sizable. Table 3-5 shows the proportion of ramp-down CMSC payments since August 2011 attributable to shutdown offer prices exceeding the 130% threshold set out in the Monitoring Document. For the 14 months from September 1, 2011 through October 31, 2012, 76% of all ramp-down CMSC payments were attributable to generators submitting offer prices that were higher than 130% of the three-hour ahead pre-dispatch shadow price.

Table 3-5: Ramp-Down CMSC Payments Attributable to Offer Prices Exceeding 130% of the Three-Hour Ahead Pre-Dispatch Shadow Price September 2011 to October 2012 ($ thousands)

	Total Ramp-Down CMSC Payments	Ramp-Down CMSC Payments Attributable to Offers > 130%	Proportion of Ramp-Down CMSC Payments Attributable to Offers > 130%
Sep-11	435	356	82%
Oct-11	289	215	74%
Nov-11	870	686	79%
Dec-11	276	175	64%
Jan-12	403	331	82%
Feb-12	369	322	87%
Mar-12	377	266	71%
Apr-12	293	206	70%
May-12	174	108	62%
Jun-12	368	267	73%
Jul-12	498	380	76%
Aug-12	420	306	73%
Sep-12	239	180	75%
Oct-12	173	134	77%
Total	**5,184**	**3,932**	**76%**

In its April 2012 monitoring report, the Panel recommended that the IESO eliminate self-induced CMSC payments to ramping-down generators.[48] In its response to this recommendation, the IESO noted the significant reduction in ramp-down CMSC payments since issuance of the Monitoring Document. It also stated that the remaining CMSC payments may well be consistent with efficiency losses that generators incur when ramping down, and that removing ramping down CMSC payments from generator revenues would require an alternate mechanism to allow for generators to recover legitimate costs.[49]

As noted above, CMSC payments are intended to compensate a market participant when the IESO instructs it to supply electricity in an amount that is less profitable for the participant relative to the quantity in the participant's market schedule. In the Panel's view, the CMSC

[48] See the Panel's April 2012 Monitoring Report (at p. 53), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf.
[49] For the entire response, see http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20120621.pdf

mechanism was therefore not intended to deal with costs incurred by a generator during a voluntary shut down. Under a voluntary ramp-down scenario, the IESO is not instructing the facility to generate in order to support local reliability; rather, the generator receives a constrained schedule as a result of ramping limitations at its own facility. Furthermore, it appears to the Panel that, if CMSC payments were equal to the amount of a generator's shut down costs, this would be by coincidence and not design. If it is in fact appropriate for generators to be compensated for higher costs incurred during ramp down, in the Panel's view this is better addressed by a market rule aimed directly at the issue rather than by use of the CMSC mechanism.

The Panel therefore remains of the view that self-induced ramp down CMSC payments are not appropriate, and the IESO should implement rules to eliminate them. Thus, the Panel repeats its earlier recommendation:

> ***The IESO should implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping down generators.***

Until such time as the market rules are amended to eliminate self-induced CMSC payments for ramp down, the Panel will continue to monitor generators' ramp-down offer prices and may, in appropriate circumstances, initiate gaming investigations.[50] The Panel's view remains, however, that gaming investigations are not the solution to the ramp-down CMSC issue.

3. Panel Investigations

The Panel currently has six investigations in progress. These investigations relate to possible gaming issues involving CMSC and other payments. As each of these investigations is

[50] As noted below, the Panel already has several investigations under way related to possible gaming issues involving CMSC and other payments.

completed, the Panel will submit its investigation report to the Chair of the Ontario Energy Board (OEB) and the report will be published on the OEB's website.[51]

[51] The submission and posting of Panel investigation reports is addressed in Article 7 of the OEB's By-law #3 (Market Surveillance Panel), available at http://www.ontarioenergyboard.ca/OEB/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf

4. Allocation of the Global Adjustment

4.1 *Introduction*

The output of most generation facilities in Ontario is subject to a contract (with the Ontario Power Authority (OPA) or the Ontario Electricity Financial Corporation (OEFC))[52] or to payment amounts set by the Ontario Energy Board (OEB).[53] The Global Adjustment (GA) is a charge collected from Ontario consumers that principally recovers the difference between the contract or regulated amounts payable to generators and the revenues that they earn in the IESO-administered energy market. In addition, the GA recovers the costs of OPA and certain other conservation and demand management programs.

Allocation of Global Adjustment

The Global Adjustment (GA) was originally allocated in the same manner to all consumers on a per MWh basis. In other words, a monthly per MWh GA rate was applied uniformly to all consumers in the province. Beginning in January 2011, this allocation changed: while Class B consumers continue to be charged the GA based on their monthly consumption, this is no longer the case for Class A consumers. Rather, the GA payable by a Class A consumer is based on the percentage that the consumer's peak demand contributes to overall system demand during the five peak hours in the 12-month "base period" (these "High-5 hours" must occur on five different days). For example, if a Class A consumer's demand represented 0.5% of peak demand during the five peak hours of the base period, that consumer will be charged 0.5% of the total monthly GA throughout the subsequent 12-month billing period (also referred to as the adjustment period").

From its introduction in 2005 to the end of 2010, the GA was recovered uniformly from all Ontario consumers on a volumetric (dollar per MWh) basis. This method for allocating the GA was changed in January 2011.[54] Consumers are now divided into two classes – Class A (consumers with high average peak demand) and Class B (all other consumers). The GA payable by a Class A consumer is determined based

[52] These contracts include the OPA's clean energy and renewable energy supply contracts, the so-called "early mover" contracts, OEFC's contracts with the legacy non-utility generators (or NUGs) and contracts under the OPA's Feed-in Tariff (FIT and microFIT) program. These contracts are identified in Ontario Regulation 427/04 (Payments to the Financial Corporation re Section 78.2 of the Act) and Ontario Regulation 578/05 (Prescribed Contracts re Sections 78.3 and 78.4 of the Act), both made under the *Ontario Energy Board Act, 1998.*
[53] The OEB sets payment amounts for the nuclear facilities operated by Ontario Power Generation and for Ontario Power Generation's baseload hydroelectric facilities.
[54] The components of the Global Adjustment and the allocation methodology are set out in Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998.*

on its peak demand factor, which is the ratio of the consumer's electricity consumption during the highest peak hours in a year relative to total consumption in each of those hours. The remainder of the GA continues to be charged to Class B consumers on a volumetric basis.[55]

The rationale for the change in the GA allocation methodology was expressed by the Ministry of Energy through a posting on the Environmental Registry as follows:

> The proposed changes to the global adjustment mechanism would provide large consumers with a strong incentive to reduce consumption at critical times, consistent with the government's commitment to creating a culture of conservation. By reducing peak demand, the proposal is expected to avoid costly investments in new peaking generation resources and imports of electricity from jurisdictions reliant on coal-fired generation.
>
> Currently, a global adjustment rate is published monthly by the Independent Electricity System Operator (IESO). This is calculated as the sum of total global adjustment costs divided by the total volume of electricity consumed. This flat rate credit or charge is passed on to electricity consumers on a volumetric basis, regardless of when electricity was actually consumed. In recent years this has led to inefficient price signals to consumers in the market since electricity consumed during off–peak periods is charged the same global adjustment rate as electricity consumed during on–peak periods. Concerns have also been raised that large volume consumers, who are not the primary drivers of costs to meet peak demand, are paying more than their fair share of costs.[56]

In previous reports, the Panel discussed the change in the GA allocation and noted that assessing the efficiency implications of the revised allocation was a complex issue, and one that the Panel would return to in a future report.[57]

In the sections that follow, the Panel discusses the results of its further examination of the market efficiency implications of the revised GA allocation. Section 4.2 describes the incentive for Class A consumers to reduce peak demand and provides some data on consumption by Class A consumers both before and after the GA allocation was revised. Section 4.3 sets out the details

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[55] As discussed in section 4.4 below, for most residential and small business consumers the GA is built in to their commodity price. They do not see the GA as a separate line item on their bills.

[56] See the "Proposal to Make a Regulation under the Electricity Act to Amend O. Reg. 429/04", posted to the Environmental Registry on August 27, 2010 (EBR Registry Number 011-0973), available at http://www.ebr.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTEwNzI0&statusId=MTY2MTgw&language=en

[57] See the Panel's November 2011 Monitoring Report (pp. 125) and April 2012 Monitoring Report (pp. 53), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf, and http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf, respectively.

of, and highlights the conclusions drawn from, an econometric study commissioned by the Panel to assist in understanding the extent to which the revised GA allocation methodology might be driving changes in consumption by Class A consumers. Section 4.4 describes the impact of the revised GA allocation on Class B consumers, and section 4.5 contains the Panel's observations regarding the efficiency implications of the GA allocation.

As far as the Panel has been able to ascertain from publicly-available materials, the econometric study described in section 4.3 is the first undertaking using statistical methods aimed at quantifying the impact of the revised GA allocation on the consumption of Class A consumers. The Panel acknowledges that its analysis does not lend itself to definitive conclusions in a number of areas, and that further analysis may lead to a more comprehensive understanding of the efficiency implications of the revised GA allocation. The Panel hopes that publication of its analysis will serve to inform and stimulate further discussion on the issue. The Panel encourages the development of additional analyses, potentially using other explanatory variables and data sources to the extent that they might serve to enhance the overall accuracy of the results in terms of explaining changes in the consumption of Class A consumers. The Panel is aware that the IESO has, in response to a recommendation made in the December 2011 Electricity Market Forum report, initiated a consultation to review the GA with a view to examining "potential options that would meet the goal of greater customer responsiveness to costs currently in" the GA.[58] It is also the Panel's hope that its analysis can make a useful contribution to that initiative.

[58] Details of the IESO's consultation are available at http://www.ieso.ca/imoweb/consult/consult_se106.asp

4.2 *"High-5" Allocation of Global Adjustment for Class A Consumers*

Since January 2011, the GA charged to a Class A consumer in any year has been determined entirely by that consumer's share of energy demand during the five hours with the highest total demand in a 12-month base period (the "High-5 hours"). Each base period runs from May 1 in one year to April 30 in the following year. For example, a Class A consumer's share of GA charges for the 12-month billing period from July 2013 to June 2014 was set by that consumer's share of total Ontario demand in the High-5 hours in the base period from May 2012 to April 2013. The highest demand hours in that base period are shown in Table 3-6.

Class A Consumers

Class A consumers are consumers with average peak demand over 5 MW. Class A consumers can be either directly-connected to the IESO-controlled grid ("Direct Class A") or connected at the distribution level ("Embedded Class A"). Hourly consumption data for Embedded Class A consumers is not included in the IESO's database and is not readily available from distributors. Thus, the Panel's analysis in the sections that follow is based only on data for Direct Class A consumers, which account for approximately 67% of all Class A consumption. Given the lack of data for Embedded Class A consumers, the Panel has reached no conclusions about how the GA allocation has affected consumption by those consumers. (Consumers with average peak demand greater than 5 MW can opt to be classified as Class B consumers. The Panel understands there are currently approximately 10 such consumers directly-connected to the IESO-controlled grid.)

Class A consumers can substantially reduce their overall future electricity bills by reducing consumption during the High-5 hours. The estimated GA cost savings for a Class A consumer of reducing its demand by one MW during just one of the High-5 hours (or, alternatively, the estimated incremental GA cost of consuming one MW in that hour) equals:

(Estimated GA for the billing period)

÷

(Estimated total demand in all High-5 hours in the base period)

The total GA for the 12-month period from May 1, 2013 to April 30, 2014 has been estimated at $8.8 billion.[59] Total load aggregated over all of the High-5 hours in the May 2012 to April 2013 base period was 119,419 MW (the total of the load amounts in Table 3-6). The future GA cost to a Class A consumer of having consumed just one MW in a single High-5 hour in that base period is therefore estimated to be $73,690/MWh ($8.8 billion/119,419 MW). That amount is 350 to 1,800 times higher than the HOEP in the High-5 hours in that base period (see Table 3-6). The future annual GA cost of having consumed one MW in all of the High-5 hours in the May 2012 to April 2013 base period is five times the estimated $73,690/MWh, or $368,000.[60]

Table 3-6: Load and HOEP in Five Highest Demand Hours in the Base Period May 1, 2012 to April 30, 2013 (MW & $/MWh)

Date	Delivery Hour (HE)	Total Load* (MW)	HOEP ($/MWh)
July 17, 2012	16	24,465.2	$144.32
July 4, 2012	17	23,799.6	$209.16
June 20, 2012	16	23,869.9	$44.68
July 23, 2012	14	23,813.2	$40.08
July 6, 2012	16	23,471.1	$94.72

* Net Ontario demand plus embedded generation. Peak load data is from the IESO's "Global Adjustment for Class A Customers" web page at http://www.ieso.ca/imoweb/b100/ga_changes.asp

Peak demand hours generally occur on summer afternoons, but the exact timing of the High-5 hours in any base period cannot be predicted with certainty. Class A consumers, if they are able to be flexible in their consumption, will likely target several possible peak hours in the summer months and plan ahead to avoid or limit consumption at those times. Thus, the estimated future GA cost of consuming in each of the High-5 hours must be apportioned among hours that are

[59] The estimate was prepared by Navigant Consulting for the purpose of forecasting the GA for inclusion in the commodity price payable by consumers on the OEB's Regulate Price Plan. The 12-month period used for that purpose varies from the billing period for Class A consumers (which is from July 1, 2013 to June 30, 2014). However, it is the most recent available forecast of the GA that closely corresponds to the Class A billing period. See the OEB's April 5, 2013 *Regulated Price Plan Report, May 1, 2013 to April 30, 2014* (at page 19), available at http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Price_Report_May2013_20130405.pdf

[60] A Class A consumer would have to pay HOEP and uplift in each of the High-5 hours. Those costs would be trivial relative to the future GA cost of consuming one MW in those hours. For example, as shown in Table 3-6, the HOEP in the High-5 hours in the May 2012 to April 2013 base period ranged from $40.08 to $209.16 per MWh.

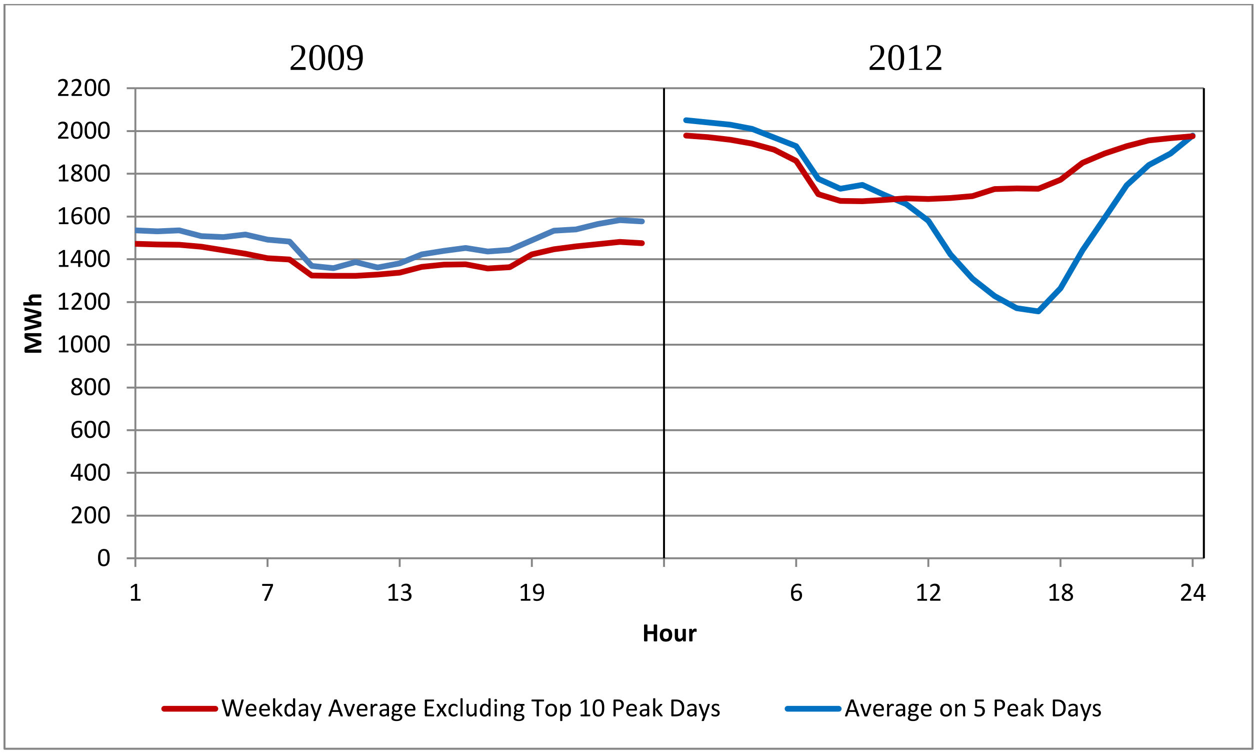
likely to be the five peak hours. For example, if a Class A consumer were to target four hours on each of ten summer days as possible peak demand hours, and if the consumer were to assume that each of those hours had an equal probability of being a High-5 hour, then the corresponding expected cost of consuming one MW in any one of those 40 hours would be the estimated annual GA cost ($368,000) divided among the 40 hours, or $9,200/ MWh (if each of the 40 hours is assigned equal probability of containing one of the High-5 hours).

The Panel's review of peak hour consumption data for Direct Class A consumers for 2011 and 2012 shows a decline in consumption in some peak hours in 2011 and 2012 compared to peak hours in earlier years. Figure 3-3 plots two averages of hourly consumption by Direct Class A consumers in 2009 and 2012: the first is the average on the High-5 days (or what would have been the High-5 days) in each year; the second is the average on summer (June to August) weekdays not including the ten highest demand days.[61] The Panel decided to use 2009 rather than 2010 as the comparative period for purposes of assessing peak hour demand changes, as the Panel believes that Direct Class A consumers may well already have started to change their consumption behaviour during peak times in 2010.[62]

[61] Direct Class A consumers reduced their consumption on ten days in the summer of 2012, even though only five of those days included the High-5 hours. To make a meaningful comparison between consumption on average weekdays, the Panel has excluded these ten days from the average in Figure 3-3.

[62] There was publicly-available information about the possible change in the GA allocation on the IESO's website in March of 2010, and large industrial consumers would have been aware that their GA costs in 2011 could be based on their share of demand during peak hours in 2010.

Figure 3-3: Average Direct Class A Consumption on High-5 Days and on Weekdays in June, July, and August excluding Top 10 Peak Days 2009 and 2012 (MWh)



As shown in Figure 3-3, there is little difference in the average consumption on the five peak (High 5) days relative to the summer weekday average in 2009. In 2012, however, it is clear that consumption by Direct Class A consumers has changed at peak times. Figure 3-3 also indicates that average summer weekday consumption in 2009 was much lower than it was in 2012. This difference may be due in part to the impact of a depressed economic climate in 2009. For example, one of the largest Class A loads had reduced consumption significantly in 2009 as the result of shutting down operations over the entire summer.

Figure 3-4 plots the consumption of Direct Class A consumers during each of the five peak (High-5) days in 2012 (the days noted in Table 3-6), as well as the average weekday consumption of those consumers over the summer months of June, July and August 2012, again omitting the top ten highest demand days.

Figure 3-4: Direct Class A Consumption on High-5 Days and Average on Weekdays in June, July, and August excluding Top 10 Peak Days 2012 (MWh)

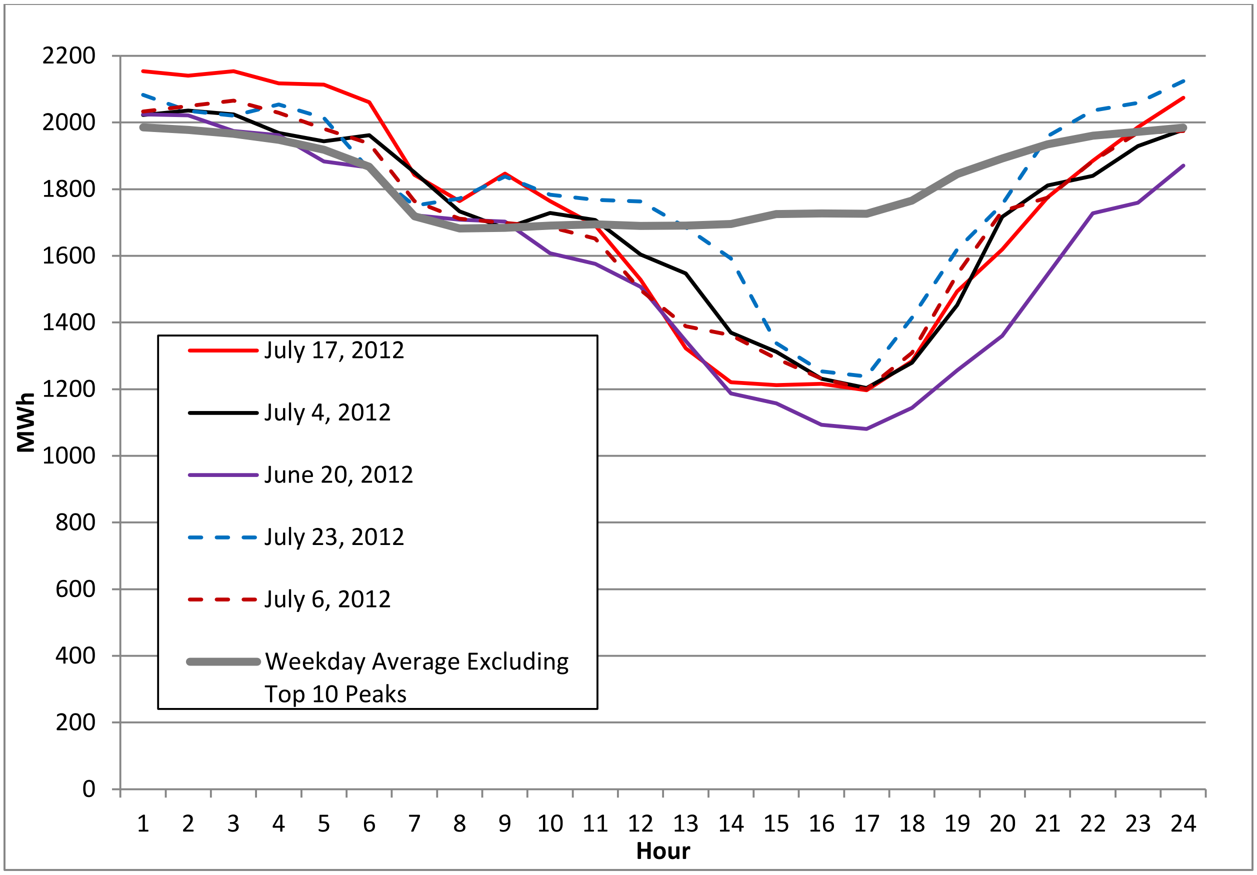


Figure 3-4 shows a large reduction in consumption during peak hours by Direct Class A consumers on each of the High-5 days relative to the summer weekday average. The biggest reduction in consumption compared to average weekday consumption occurred on June 20, 2012 and amounted to almost 650MW in hour ending 17; the average reduction in hour ending 17 on all of the High-5 days as compared to the summer average was approximately 570 MW. It also appears that Direct Class A consumers shifted some consumption away from the afternoon (when the chance of demand reaching a peak is highest), as demand in the morning on all of the High-5 days is above the summer weekday average. From this Figure, it therefore appears that the change in the GA allocation elicited a response from Direct Class A consumers. Table 3-7 presents the data that is plotted in Figure 3-4.

Table 3-7: Average Direct Class A Consumption on High-5 Days and on Weekdays in June, July and August excluding Top 10 Peak Days 2012 (MWh)

Delivery Hour (HE)	Average on High-5 Days	Summer Average Omitting Top 10 Peak Days	Difference
1	2,051	1,985	66
2	2,040	1,978	62
3	2,030	1,966	64
4	2,011	1,948	63
5	1,969	1,918	51
6	1,930	1,867	63
7	1,776	1,719	58
8	1,730	1,682	48
9	1,747	1,685	63
10	1,702	1,690	12
11	1,659	1,695	-36
12	1,580	1,690	-110
13	1,424	1,691	-268
14	1,309	1,696	-387
15	1,228	1,725	-497
16	1,171	1,727	-556
17	1,155	1,726	-571
18	1,264	1,765	-501
19	1,442	1,845	-403
20	1,594	1,893	-299
21	1,747	1,935	-188
22	1,840	1,961	-120
23	1,895	1,972	-77
24	1,978	1,985	-6
Average in hours HE 7- HE 19			**-242**
Average in hours HE 14-HE 18			**-502**

Raw consumption data for Direct Class A consumers can provide some insight into the effect of the revised GA allocation, and the data presented above appears to indicate that the revised GA allocation has had an impact on Direct Class A consumption. However, there are many other factors, beyond just the revised GA allocation, that might cause the hourly demand of Direct Class A consumers to change. In an effort to get a better measure of just how the revised GA allocation has affected the consumption behaviour of Direct Class A consumers, the Panel commissioned the econometric study that is described in the next section.

4.3 *Estimating the Effects of the Global Adjustment on Class A Consumption*

The Panel retained Prof. Anindya Sen of the University of Waterloo to perform an econometric study on the changes in consumption by Direct Class A consumers after the revised GA allocation methodology took effect. This study took into account the pattern of consumption of Direct Class A consumers prior to the revision of the GA allocation in order to quantify the magnitude of the change in consumption behaviour. Dr. Sen's study is attached as an Appendix to this report.

The main objective of the study was to quantify the magnitude of the change in consumption by Direct Class A consumers during the High-5 hours. For this reason, the study uses data from the three months in the summer (June, July and August) when the High-5 hours are likely to occur. A second objective was to attempt to assess whether the change in GA allocation had any impact on consumption during hours outside of the High-5 hours. The study uses statistical techniques to identify changes in consumption by Direct Class A consumers during the High-5 hours and at other times. The independent variables used in the study include hourly price data (HOEP and GA for the period prior to the revision to the GA allocation, and HOEP only thereafter), and controls for differences between daily, monthly and annual consumption patterns.

The Panel chose not to use 2010 as the comparative period for purposes of quantifying changes in peak demand behaviour. As noted above, some Direct Class A consumers may have anticipated the change in GA allocation and adjusted their peak consumption behaviour accordingly in 2010, even though the revised allocation was not implemented until January 1, 2011. However, data from 2010 is relevant in assessing the change in consumption patterns during hours outside of the High-5 hours; although Direct Class A consumers may have expected that future costs under the revised GA allocation would be based on consumption behaviour during the five peak hours in 2010, these consumers continued to pay GA costs in 2010 on a dollar per MWh basis. Therefore, their consumption behaviour in 2010 during times outside of the High-5 hours should not have been affected by the future impact of any revisions to the allocation of the GA. For this reason, data from 2009 and 2010 was used to assess changes in consumption during non-High-5 hours.[63]

4.3.1 Changes during Highest Demand Hours

As noted above, the main objective of Prof. Sen's study was to quantify the change in consumption by Direct Class A consumers during system peaks. To assess this change, Prof. Sen measured the changes in demand across time during the highest demand hours in the year. The data was divided amongst the highest demand hours during the months of June, July and August in three tranches as follows: the top 1% (22 hours each year), 1%-5% (a further 88 hours each year), and 5%-10% (another 110 hours each year). These tranches represent the 1% of hours over the summer when demand was highest; the next 4% of summer hours when demand was highest (that is, the 5% of hours with highest demand, but excluding the highest 1% of hours), and the next 5%-10% of summer hours when demand was highest. Consumption by Direct Class A consumers in the top 1% of all hours is expected to be lower under the revised GA allocation (because this 1% of all hours contains the five peaks) than it was during the top 1% of hours in the years prior to its introduction. The study attempts to account for other factors that influence demand in order to isolate the impact of the change in GA allocation on consumption by Direct Class A consumers during peak hours.

As shown in Table 3-8, the difference in consumption by Direct Class A consumers in the highest (top 1%) demand hours in 2011 and 2012 relative to 2009 amounted to 379 MW after controlling for other variables. This amount represents the reduction in Direct Class A consumer peak demand in the top 1% (22 hours) of the highest summer demand hours that is attributable to the revised GA allocation.

[63] The data used in the study is limited to the three months of June, July and August, as the primary focus of the study was to quantify changes in consumption during the High-5 hours. The use of annual data may be more appropriate for assessing changes in consumption in the non-High-5 hours.

Table 3-8: Prof. Sen's Estimates of the Change in Direct Class A Consumption in the Highest Demand Hours: Summer 2011and 2012 relative to Summer 2009 (MW)

(Full results are in Table 6 of Prof. Sen's Report)

	Top 1% of Hours	Top 1% - 5% of Hours	Top 5% - 10% of Hours
Change in Consumption during highest demand hours *Summer 2011 and 2012 relative to Summer 2009*	**-379 MW**	**-122 MW**	**Not statistically different from zero**

As also shown in Table 3-8, Prof. Sen found that in the percentile of high demand hours from 1%-5%, the average reduction in consumption by Direct Class A consumers in 2011 and 2012 amounted to 122 MW relative to 2009. However, in the remaining 5%-10% of high demand hours their consumption was reduced by a statistically insignificant amount. This can be interpreted to mean that there was no appreciable reduction in demand in the top 5%-10% of high demand hours in 2011 and 2012 compared to 2009 that is attributable to the revised GA allocation. Such a result is consistent with Direct Class A consumers having predicted the High-5 hours with reasonable success.

4.3.2 Changes in Other Hours

A second objective of Prof. Sen's study was to quantify changes in consumption outside of the High-5 hours. Although Prof. Sen's study does shed some light on the question of how off-peak consumption patterns changed in response to the change in GA allocation, for the reason noted below the results from this part of the study are not as conclusive as the results on peak demand described above.

Off-peak consumption would be affected by the revised GA allocation for two reasons. The first is the shifting of consumption away from potential High-5 hours, in order to reduce future GA charges. The second is that (marginal) prices for Class A consumers are lower at off-peak times; because GA costs are not affected by a Class A consumer's consumption outside of the High-5 hours, the marginal price they pay for each MWh (outside of the High-5 hours) is lower relative to what it would have been under the previous allocation of the GA. A lower price in non-High-5 hours should therefore lead to an increase in consumption during those hours.

To assess the change in consumption outside of the High-5 hours, Prof. Sen divided consumption by Direct Class A consumers into consumption during peak and off-peak periods on High-5 and non-High-5 days in the summer months. The peak period used comprised the 12 hours from 7 am to 6:59 pm, and the off-peak period used comprised the other 12 hours of the day.[64] Where a given hour fell on a High-5 day, it was assigned to the High-5 day category; otherwise it was assigned to the non-High-5 day category. Thus, each hour was assigned to one of four categories: High-5 day peak, High-5 day off-peak, non-High-5 day peak, and non-High-5 day off-peak. Prof. Sen then measured how consumption had changed over time within the three categories of interest: peak and off-peak on non-Hig-5 days and off-peak on High-5 days.

The econometric model used the difference in consumption patterns across the years, but within each category of hours, to identify changes in response to the revision of the GA allocation. The result for a given category of hours therefore corresponds to the difference in average consumption before and after the revision in the GA allocation for that category.

Table 3-9 contains Prof. Sen's estimates of changes in consumption by Direct Class A consumers within each category of hours since the revised GA allocation was introduced. These findings suggest that off-peak hour consumption in the summer was higher in 2011 and 2012 relative to 2009 and 2010 on both High-5 and non-High-5 days. Consumption by Direct Class A consumers in 2011 and 2012 during off-peak hours in the summer was estimated to be 54 MW higher on non-High-5 days and 59 MW higher on High-5 days relative to 2009 and 2010. The results also indicate that consumption by Direct Class A consumers during summer peak hours on non-High-5 days was higher by 14 MW in 2011 and 2012 relative to 2009 and 2010.

[64] The peak period used by Prof. Sen for the purposes of his study is narrower than the peak period concept as used by the IESO (hours ending 8 through 23, inclusive). The IESO's definition includes hours in the evening when demand is typically low.

Table 3-9: Prof. Sen's Estimates of the Difference in Average Direct Class A Consumption during Peak and Non-peak Hours on High-5 Days and non-High-5 Days Summer 2011 and 2012 relative to Summer 2009 and 2010 (MW)

(Full results are in Table 8 of Prof. Sen's Report)

	Off-peak Hours Non-High-5 days	Off-peak Hours High-5 days	Peak Hours Non-High-5 days
Change in Consumption *Summer 2011 and 2012 relative to Summer 2009 and 2010*	**54 MW**	**59 MW**	**14 MW**

Prof. Sen analyzed whether the differences in peak and off-peak consumption remained consistent when 2011 and 2012 data was compared separately with each of 2009 and 2010. Off-peak consumption in the summer of 2011 and 2012 was higher relative to 2009 but lower relative to 2010. As a result, we cannot say with confidence that off-peak consumption has increased following the revision to the GA allocation. As such, the results from this part Prof. Sen's study are not as conclusive as the results for changes consumption during the highest demand days.

4.4 *Class B Consumers*

Class B consumers, who account for over 80% of electricity consumption in the province, consist of the following types of consumers:

- Low-volume (residential and small business) consumers served by distributors. The majority of these consumers are on the OEB's Regulated Price Plan (RPP), which includes GA costs.[65]

[65] RPP prices are set based on a 12-month forecast of market prices (HOEP) and GA charges, and are adjusted every six months as required. RPP prices, even time-of-use RPP prices, do not vary each hour with the cost of production. Because RPP prices include forecast GA amounts, however, they are much higher than HOEP in most, if not all, hours.

- Industrial and commercial consumers with average peak demand of less than 5 MW, who are often served by distributors. These consumers are charged GA on a volumetric basis, that is, for each MWh they consume.

- Consumers with average peak demand over 5 MW who have opted to be billed as Class B consumers rather than as Class A consumers. These consumers are also charged GA for each MWh they consume.[66]

Table 3-10 shows the shares of energy consumption and GA costs for 2011 and 2012 by consumer Class. Under the revised GA allocation, Class A consumers (whether Direct or Embedded) pay around 10% of the total GA costs although they consume about 16% of the province's electricity supply. The Panel estimates that Class A consumers paid approximately $302 million less in GA in 2011 and $422 million less in 2012 than they would have paid under the former volumetric allocation.[67]

Table 3-10: Share of Energy Consumption and GA Costs by Class
2011 & 2012
(%)

Year	Class	Consumption	GA Paid
2011	A	16.11%	10.42%
	B	83.89%	89.58%
2012	A	16.49%	10.04%
	B	83.51%	89.96%

[66] As noted above, there are approximately ten consumers in this category that are directly connected to the IESO-controlled grid.
[67] The reduction in GA costs charged to Class A consumers in 2011 and 2012 is only partly due to the peak demand reductions of those consumers during the High-5 hours. Most large industrial consumers historically have had relatively flat demand profiles over the course of a day. That is, compared to residential or small commercial and industrial consumers, large consumers have always had a smaller share of peak load than of energy consumption during a year. Thus, the revised GA allocation would have shifted some GA costs from Class A consumers to Class B consumers even without any change in peak hour demand by Class A consumers. This effect cannot be quantified with precision because overall consumption may have been affected by the revision to the GA allocation. Nevertheless, based on actual consumption data the Panel estimates that approximately $290 million in GA costs was shifted from Class A consumers to Class B consumers in 2012 (the corresponding amount for 2011 is $210 million) before accounting for any reduction in consumption during the High-5 hours by Class A consumers. The remaining $120 million of GA shifted in 2012 ($90 million in 2011) was due to demand reductions by Class A consumers in the High-5 hours.

Given the increase in their per MWh GA charges, one would expect Class B consumers to have reduced their consumption of electricity. The Panel is not able to estimate the extent of any such reduction because it does not have hourly consumption data for consumers served by distributors, and because prices for Class B consumers are not all the same. RPP consumers, who number over 4.8 million, do not face prices that vary hourly; most (about 4 million) are subject to time-of-use (TOU) prices that include GA costs and that change only every six months.[68] In contrast, Class B commercial and industrial consumers are charged HOEP (which varies hourly) plus a volumetric per MWh GA charge that is set every month.

4.5 *Impact on Efficiency*

The Panel launched its analysis of the revised GA allocation with the intention of assessing whether it has increased or decreased efficiency in the energy market.

4.5.1 Short-term Efficiency

The results of Prof. Sen's study with regard to changes in off-peak consumption suggest that the elasticity of demand for Class A consumers is low. Other than in the High-5 hours, the marginal price for Class A consumers is the HOEP, which is less than half of the hourly price these consumers faced before the change in GA allocation. Average hourly prices for Class A consumers in non-High-5 hours have fallen by over 50%, but their consumption in those hours has increased by less than 3%, if at all. This indicates that Direct Class A consumers have not significantly increased electricity consumption in off-peak hours in response to lower prices.

The revised GA allocation provides a very large incentive for Class A consumers to reduce consumption in the highest demand hours. As noted in section 4.2, a Class A consumer could save over $368,000 in GA costs in the billing period from July 2013 to June 2014 by reducing consumption by one MW in each of the High-5 hours in the May 2012 to April 2013 base period. As also noted earlier, for a Class A consumer that targets four hours on each of ten days during

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[68] The revised GA allocation increased the cost to Class B consumers by approximately $3.50/MWh, calculated as the GA shifted from Class A to Class B consumers divided by total Class B consumption. The average Ontario household consumes approximately 800 kWh per month or 9.6 MWh per year. Since the increase in GA costs will be reflected in the calculation of RPP rate adjustments, as a rough estimate the revised GA allocation contributed to a $33.60 increase per year in the average Ontarian household's electricity bill ($3.50/MWh * 9.6 MWh per year).

the summer as potential High-5 hours, for a total of 40 target hours each year, the expected future GA cost of consuming one MW in each of those hours will be 1/40th the annual total of $368,000, or $9,200/MWh (if each of the 40 hours is assigned equal probability of containing one of the High-5 hours). The average HOEP during the High-5 hours in 2012 was close to $100/MWh (see Table 3-6), so that including the expected future GA cost means that the cost of consuming during those hours has increased by approximately 9,300%.

With such a large increase in price, one might expect that most, if not all, Class A consumers would shut down their operations during the High-5 hours (or during hours with a high probability of being High-5 hours). That has not been the case.[69] Prof. Sen estimates average demand reductions of less than 400 MW in the top 1% of high demand hours. Even if the reductions in some of those hours amount to as much as 600 MW, the reduced demand would only be roughly 33% lower than the average level of Class A consumption during the summer. While this demand response may seem large, given the relative change in prices at these times the response is in fact quite small. This supports our conclusion that the price elasticity of demand of Class A consumers, as a group, is modest.

[69] There could be several reasons for the relatively small demand reduction response in peak hours by Class A consumers to the very large financial incentive. The production processes of some consumers might limit the amount of demand reduction that can occur on short notice, regardless of the size of the incentive. Other Class A consumers might face sizable start-up costs if they substantially shut down operations. The relatively small response could also be tied to the fact that consumers that are directly connected to the IESO-controlled grid have been exposed to variable prices since the market opened in 2002, and since that time have therefore had an incentive to reduce consumption at times when prices are high. Class A consumers have also been offered incentives to reduce demand through various demand response and conservation programs, which may have exhausted their ability to further change their consumption behaviour.

Allocative Efficiency and Deadweight Loss

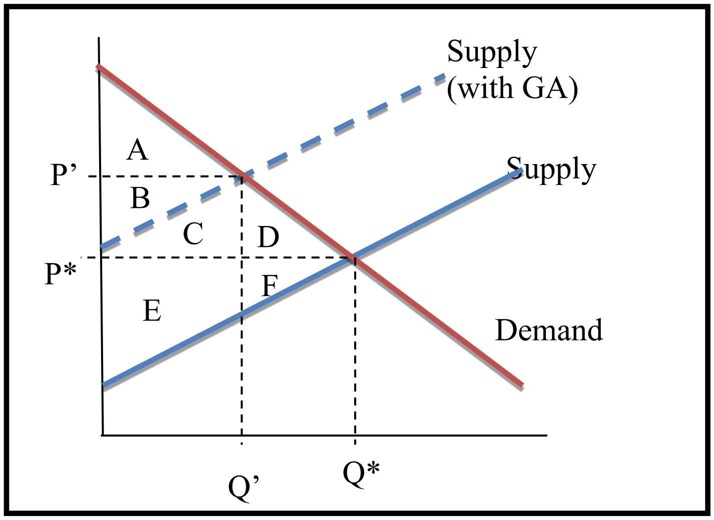
An efficient market is one that maximizes the benefits that consumers and producers receive from participating in that market. In general, these benefits are maximized when prices are high enough to cover the short-run marginal cost of production, but no higher. When the price just covers the marginal cost of production, the level of consumption is considered to be efficient because consumers buy up to the point where the gains from trade are fully exhausted; the last buyer places a value on the good that is just equal to the marginal cost of production. All the buyers up to the last buyer receive value from consuming because they pay a price below their willingness to pay. The value that these consumers receive is referred to as "consumer surplus", and similarly the value producers receive is called "producer surplus". In general, prices equal to marginal costs maximize consumer and producer surplus.

When prices are set above marginal costs, consumers will buy less of the good, and both consumers and producers will receive less surplus. This reduces the total surplus in the market, which is referred to as a deadweight loss. The deadweight loss is created because although some consumers would be prepared to buy the product at a price that would cover the marginal cost of producing it, the price set above marginal costs means they do not consume. The difference between the total surplus when the price is equal to marginal cost and the total surplus when the price is above marginal cost is the deadweight loss.

The concept of deadweight loss is illustrated in Figure 3-5. In this simple illustration, the supply curve reflects the marginal cost of production. The efficient price is P* and the corresponding level of demand is Q* (assuming, for now, that no GA is charged to any consumer). The area bounded by the demand curve, the supply curve and the y-axis is the total surplus in the market. The consumer surplus equals the area A + B + C + D. The producer surplus equals the area E+F.

Adding the volumetric GA charge to Figure 3-5 means that, at every level of demand, consumers face a price of HOEP (based on the supply curve) plus GA (a constant, per MWh amount). This change can be displayed in the figure as an upward shift of the supply curve. The supply curve including GA intersects the demand curve at a level of consumption equal to Q', with a corresponding marginal cost of P’ (which includes GA) for their consumption. Total surplus in the market is lower and there is a deadweight loss represented by the area D + F.

Figure 3-5: Deadweight Loss in a Market



The question the Panel has sought to answer through its analysis is whether the deadweight loss under the former volumetric GA allocation is larger or smaller than the deadweight loss under the revised GA allocation. If the deadweight loss is smaller after the introduction of the revised GA allocation, that would lead to an improvement in efficiency. If the deadweight loss is larger, the revised GA allocation would have reduced overall efficiency in the market.

The revised GA allocation has likely had an adverse impact on consumer surplus for Class B consumers. As noted earlier, these consumers now pay a higher per MWh price for electricity than they would have under the former GA allocation methodology, which has likely reduced their consumption. Such a reduction in consumption will lead to an increase in deadweight loss relative to the deadweight loss under the former GA allocation methodology. The Panel has not attempted to measure any change in deadweight loss associated with changes in consumption by

Class B consumers.[70] For the purposes of what follows, the Panel has also set aside changes in producer surplus.[71] Although any net increase in consumption in non-High-5 hours would increase the producer surplus, in the Panel's view this change in surplus is unlikely to be substantial because the supply curve in these hours is relatively flat (elastic), so that changes in demand do not lead to significant changes in prices. Additionally, lower consumption in the high demand hours would tend to reduce the producer surplus.

For Class A consumers, the impact on deadweight loss is twofold. First, marginal prices for Class A consumers are set equal to HOEP, which will ensure that these consumers consume up to the efficient level during all hours other than potential High-5 hours. This will reduce the deadweight loss relative to what it would have been under the former volumetric GA allocation. Second, the GA payable by Class A consumers is based on their consumption during the High-5 hours. In an hour which is likely to be a High-5 hour, there are likely to be Class A consumers who would otherwise pay the marginal cost of production but who choose not to consume in order to reduce their future GA charges. This reduction in consumption increases the deadweight loss.

The relative size of each of these impacts on deadweight loss determines the net impact of the revised GA allocation on deadweight loss for Class A consumers. Given the relatively small changes in consumption among Class A consumers in response to substantial changes in prices, the Panel attempted to determine whether those changes in consumption reduced the overall deadweight loss for at least that group of consumers, setting aside the impact of the change in GA allocation on Class B consumers and on producers. The Panel therefore examined whether the reduction in deadweight loss from higher consumption during non-High-5 hours outweighs the increase in deadweight loss due to lower consumption in the High-5 hours.

In order to quantify the changes in deadweight loss for Class A consumers, we need to measure the changes in consumption during the High-5 and non-High-5 hours in the year. As discussed

[70] As noted in section 4.4, the Panel does not have access to data relating to changes in consumption by Class B consumers.
[71] Changes in consumption could affect producer surplus. As noted above, however, other than during high demand hours the supply curve is relatively elastic—changes in consumption do not affect prices significantly. For this reason changes in producer surplus accruing to generators are ignored.

in section 4.3 and shown in Tables 3-8 and 3-9, Prof. Sen's study provided the following estimates of the changes in consumption by Direct Class A consumers following the introduction of the revised GA allocation:

- Increase in demand of 54 MW during off-peak hours on non-High-5 days (and 59 MW during off-peak hours on High-5 days) when consumption during the summer months in 2011 and 2012 is compared against consumption in the summer months in 2009 and 2010;
- Increase in demand of 14 MW during peak hours on non-High-5 days, when consumption in the summer months in 2011 and 2012 is compared against consumption in the summer months in 2009 and 2010;
- Decrease in consumption of 379 MW in the 22 hours that are the top 1% of highest demand hours in the summer (as well as a drop of 122 MW in the top 1%-5% of highest demand hours in the summer), when consumption in 2011 and 2012 is compared against consumption in 2009 only.

The results from Prof. Sen's study can be used to calculate a rough estimate of how much the deadweight loss associated with Direct Class A consumers has been reduced during non-High-5 hours due to higher consumption in those hours. Although Prof. Sen's findings are based on results from the summer months only, the Panel has used these results as an approximation for the changes in consumption during non-High-5 hours throughout the rest of the year.

Calculating the change in deadweight loss also requires an assumption about the shape of the demand curve. The Panel has assumed that the demand curve is linear (the most common assumption in applied welfare economics calculations). Using the quantity of increased demand and the difference in prices (that is, prices with and without GA costs), the Panel has estimated that the reduction in deadweight loss due to the change in consumption in non-High-5 hours ranges from $5.6 million in 2011 to just over $6.8 million in 2012.[72]

[72] The calculation of this number is as follows: the change in non-High-5 consumption (54 MW in off-peak hours on non-High-5 days; 59 MW in off-peak hours on High-5 days; 14 MW in peak hours on non-High five days)

As noted above, the reduction in deadweight loss in the non-High-5 hours should be compared to the increase in deadweight loss from lower consumption during the hours that are likely to be the High-5 hours (that is, all of the hours in which Class A consumers respond to the incentive to reduce consumption). Given the uncertainty around the total cost of consuming for a Class A consumer during the highest demand hours (before the High-5 hours are known), the Panel has not attempted to directly calculate the increase in deadweight loss in the High-5 hours.

The Panel has instead approximated the price at which the reduction in deadweight loss in non-High-5 hours is just equal to the increase in deadweight loss in the top 1% of the highest demand hours. If the price to which Class A consumers respond is, in reality, higher than this number, it is likely that the gain from lower non-High-5 deadweight loss is negated by a larger deadweight loss in the highest demand hours.[73] The calculation of the price that equalizes the net change in deadweight loss leads to a number in the range of $1,340/MWh to $1,620/MWh (again under the assumption that the demand curve is linear). In order for the revised GA allocation to have reduced the total level of deadweight loss in the market, Class A consumers must face a price of consuming during the highest demand hours that is below $1,620/MWh. If the price of consuming during the High-5 hours is above this level, the additional deadweight loss created in the High-5 hours would offset the reduced deadweight loss in other hours.

The Panel believes that the actual price faced by Class A consumers in high demand hours is much higher than the price derived above of between $1,340/MWh and $1,620/MWh. As noted in section 4.2, the cost of consuming one MWh in a single High-5 hour bears an implicit price of $73,690/MWh in 2012. If apportioned among 40 potential High-5 hours, that implicit price amounts to $9,200/MWh. That per MWh price is sufficiently higher than the $1,340/MWh to

multiplied by the change in prices (the per MWh additional GA cost that Direct Class A consumers would have paid, which is approximately $38 and $46 in 2011 and 2012 (see Table 1-2 in Chapter 1)). One half of this number represents the area below a linear demand curve, which we take to be the reduction in deadweight loss resulting from the increase in consumption at the lower price. This reduction in deadweight loss occurs in approximately 4,380 off-peak hours and 4,358 peak hours each year. The total annual reduction in deadweight loss is therefore the hourly amount times the number of hours in which it occurs. This is equal to just under $5.6 million, given a price difference of $38, while it is approximately $6.8 million based on a price difference of $46.

[73] This price does not represent a price that, if charged to consumers, would leave their surplus unchanged (the reduction in consumption in the High-5 hours would be different, as it depends on the price). Rather, it represents the price at which the gain in surplus in the non-High-5 hours is exactly equal to the loss in surplus from the reduction in consumption in the high demand hours.

$1,620/MWh "break-even" price that an increase in efficiency seems unlikely. In fact, it is more likely that any reduction in deadweight loss from higher consumption outside of the highest demand hours is outweighed by a bigger deadweight loss from reduced consumption in the highest demand hours.[74] This has the net effect of reducing efficiency in the electricity market.

Regardless of the overall impact on efficiency, the low price elasticity of demand of Class A consumers may be relevant to any future re-examination of the GA allocation. Efficiency may be enhanced when the price charged to various consumer groups varies according to each group's price elasticity of demand.[75] The more elastic a particular group's demand for a product, the lower the price charged to that group.

A broader perspective is that the revised GA allocation creates a strong incentive for Class A consumers to shift demand away from potential High-5 hours to all other hours of the year, in order to reduce their GA costs for the following year. This strategy appears to have no short term efficiency justification (recall that Class A consumers were paying a price above marginal cost even in peak hours under the former GA allocation system) and will likely reduce efficiency both because of the lost consumption in potential High-5 hours and because Class B consumers will pay higher GA costs to the extent that the GA costs of Class A consumers are lower. Set against that is the enhancement to pricing efficiency for Class A consumers in all time periods created by the introduction of two-part pricing, which allows the marginal price per MWh to be reduced to the HOEP, or marginal cost. The rough calculations carried out by the Panel in the preceding paragraphs indicate that the latter positive effect is unlikely to outweigh the former negative effect on short-term efficiency.

4.5.2 Long-term Efficiency

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[74] Class A consumers may be supportive of the revised GA allocation because, as discussed above, a large portion of the GA costs that they were responsible for are now paid by Class B consumers. Producers will be unaffected by the change in GA allocation to the extent that supply is relatively elastic (that is, small changes in quantity do not lead to significant changes in prices).

[75] Jeffrey R. Church and Roger Ware, *Industrial Organization: A Strategic Approach*. New York: McGraw-Hill, 2000, p. 788.

It may be argued that the short-term impact on efficiency will be outweighed by long-term benefits. The Panel has not undertaken any analysis to assess the long-term impact of the revised GA allocation because it is not clear how the incentive for Class A consumers to reduce peak demand will evolve over the long term. Currently, the HOEP is low largely because the province has excess supply. Because generators do not earn enough revenue from the HOEP to cover their contracted or regulated payments, the GA is correspondingly high. In an environment of abundant supply, where the HOEP is low and the GA is high, Class A consumers have a large incentive to reduce demand as a means of avoiding higher GA costs.

In an environment of supply scarcity, however, the HOEP will rise and the GA will be correspondingly lower. This would give Class A consumers less of an incentive to reduce peak demand (because the GA costs they can avoid by reducing peak demand will be smaller) even though supply scarcity makes a reduction in peak demand more valuable. It is therefore not clear how the revised GA allocation will affect peak consumption behaviour in the future; as the value of peak reduction grows, the incentive under the revised GA allocation for Class A consumers to reduce peak demand falls. For this reason, it is unclear whether the peak reduction we currently observe will persist over the longer term. In the Panel's view, this makes it difficult to assess any long term benefits that may be associated with the revised GA allocation.

The Panel does note, however, that the revised GA allocation is inherently most effective at reducing peak demand (that is, it offers the largest incentive) when demand reductions are least valuable (that is, under excess supply conditions). It is least effective at reducing peak demand (because the incentive is smaller) when demand reduction is most valuable (because of scarcity of supply).

Chapter 4: Panel Recommendations

This Chapter sets out responses to recommendations made by the Panel in its last monitoring report, and the Panel's comments on some of those responses. It also reiterates the recommendations made in earlier chapters of this report.

Consistent with the Panel's streamlined approach to Summer Period (May to October) monitoring reports referred to in Chapter 1, the Panel is deferring its assessment of the state of the IESO-administered markets to its next monitoring report (covering the winter period November 2012 to April 2013).

1. Response to Panel Recommendations in the January 2013 Report

Following the release of each of the Panel's semi-annual monitoring reports, the IESO posts on its public web site its responses to any Panel recommendations that have been directed to it.[76]

The Panel's January 2013 report contained five recommendations, all of which related to the transmission rights (TR) market and were directed to the IESO.[77] The IESO's responses to those recommendations are set out in Table 4-1 below.

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[76] The IESO's responses to those of the Panel's recommendations that have been directed to the IESO since issuance of the Panel's June 2006 Monitoring Report are available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20130214.pdf. Following the issuance of each Monitoring Report, the IESO updates its response document to reflect the new recommendations received as well as to reflect the status of previous Panel recommendations.

[77] See the Panel's January 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

Table 4-1: IESO Responses to Recommendations in the Panel's January 2013 Monitoring Report

Recommendation	IESO Response
Recommendation 3-1 *The IESO should reassess the design of the Ontario transmission rights market to determine whether it is achieving its intended purpose.*	"The IESO agrees that this recommendation warrants further review and will perform a comprehensive review of the transmission rights market to determine whether the transmission rights market is achieving its intended purpose, and to determine what improvements can be made. This overall review is a longer term commitment expected to commence in Q2 2013."
Recommendation 3-2 *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.*	"The IESO agrees that this recommendation warrants further review. This recommendation will be addressed in the early stages of the transmission rights market comprehensive review (refer to recommendation 3-1). The findings of this first stage and any resultant changes to the stabilization design will go through our normal stakeholder process with the intent to return to the IESO Board of Directors with a recommendation by the summer of 2013."
Recommendation 3-3 *(A) The IESO Board of Directors should authorize the disbursement of the portion of the Transmission Rights Clearing Account balance that currently exceeds the Reserve Threshold to reduce the transmission charges payable by loads.* *(B) In the future, the IESO Board of Directors should authorize disbursements of Transmission Rights Clearing Account balances in excess of the Reserve Threshold after each year end.*	"The IESO Board of Directors will consider the matter of disbursement of a portion of the Transmission Rights Clearing Account balance at its meeting in February 2013. Consideration of annual disbursements, as noted in recommendation 3-3 (B) will be part of the comprehensive review of the transmission rights market (refer to recommendation 3-1)."
Recommendation 3-4 *The IESO policy of selling only long-term transmission rights on single-circuit interfaces should be replaced by a policy of reserving a significant portion of the available transmission rights for sale at short-term transmission right auctions.*	"The IESO does not have a policy of selling only long-term transmission rights on single-circuit interfaces. The IESO's procedure is to sell a combination of long-term and short-term transmission rights on every interface. This procedure is implemented by offering only a portion of the long-term transmission rights available in each long-term auction. Any additional rights available in a specific month (due to higher monthly transmission ratings), along with any unsold long-term transmission rights, are then offered as short-term transmission rights. The total long-term plus short-term rights offered at an interface are capped by the available transfer capability of the interface in each month. "There may have been some instances of offering only long-term transmission rights on single-circuit interfaces. This can happen for a variety of reasons, such as short term outages or lower monthly ratings which can result in no incremental rights being available over and above the long-term transmission rights sold cumulatively in the previous auctions for that period. "Following each auction the IESO publishes a post auction sales and price report to summarize auction activity. These reports are available on the public reports site of the IESO website at: http://reports.ieso.ca/public/. "The IESO agrees there is merit in considering a more conservative approach to determining available long-term and short-term

Recommendation	IESO Response
	transmission rights for single-circuit interfaces. The IESO will investigate the merits of this option under the broader review of the transmission rights market as noted in our response to recommendation 3-1."
Recommendation 3-5 *As part of the IESO's planned review of the Enhanced Day-Ahead Commitment Process, the Panel recommends that the IESO examine the interplay between the day-ahead intertie offer guarantee program and the transmission rights market.*	"The IESO agrees with this recommendation. The IESO will review the interplay between the day-ahead intertie offer guarantee program and the transmission rights market and determine whether there is an immediate solution that does not affect reliability or market efficiency. If no immediate solution is found, the issue will be addressed as part of the review of the real-time and day-ahead guarantee programs. The IESO has commenced internal work on the review of the guarantee programs and expects to begin the stakeholder process as early as Q2, 2013."

2. Panel Commentary on IESO Responses

The Panel is pleased that the IESO has launched stakeholder engagement 110, *Transmission Rights Market Review* (SE-110), to review the current design of the TR market.[78] As set out in the SE-110 Stakeholder Engagement Plan, the review will be conducted in two phases. In Phase one, the IESO will look at the confidence level of the TR market and its associated stabilization design. This goes to the question of the degree to which congestion rents collected by the IESO exceed the IESO's payment obligations to TR holders. Phase one is therefore expected to focus on the issue identified in the Panel's recommendation 3-2, and the associated or underlying concern that auction revenues be disbursed to consumers rather that to TR holders. In Phase two, the IESO will conduct a comprehensive review of the basic design of the TR market to determine whether it is providing the intended benefits and to make recommendations about potential efficiencies or improvements. This comprehensive review is directly responsive to the Panel's recommendation 3-1, and is expected to include consideration of the Panel's recommendations 3-2, 3-3(B) and 3-4.

In its response to the Panel's recommendation 3-4, the IESO has stated that it does not have a policy of selling only long-term TRs on single-circuit interfaces. The Panel notes, however, that this has nonetheless generally been the IESO's practice. Between January 2008 and December

[78] Further information on SE-110 is available on the IESO's website at http://www.ieso.ca/imoweb/consult/consult_se110.asp

2012, roughly 90% of all TRs outstanding on single-circuit lines were long-term TRs. During the same period, in roughly 60% of the months the only TRs outstanding on single-circuit lines were similarly long-term TRs.

With respect to the Panel's recommendation 3-3(A), the Panel notes that the IESO Board of Directors has authorized a $42 million disbursement from the TR Clearing Account to transmission customers (Ontario consumers and exporters).[79] The funds are being paid in 12 equal monthly payments, commencing in April 2013. Even with the disbursement approved by the IESO Board of Directors, significant funds remain in the TR Clearing Account above the current approved Reserve Threshold of $20 million.[80] According to the IESO, this additional margin will avoid the potential for disruption of the stabilization program and provide flexibility when considering potential changes stemming from the SE-110 initiative.[81]

3. Recommendations in this Report

The Panel groups its recommendations into four categories: price fidelity, efficiency, transparency and hourly uplift payments. Some recommendations may have impacts in more than one category (for example, a scheduling change could affect prices as well as uplift) and, where this is the case, the recommendation is included in the category of its primary effect.

The two recommendations made in this report relate primarily to uplift and other payments, which the Panel examines both as they contribute to the effective price paid by consumers and as they affect the efficient operation of the market.

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[79] Further information on the disbursement is available on the IESO's website at http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=6368

[80] The balance in the TR Clearing Account at the end of March, 2013 was approximately $78 million.

[81] See the February 21, 2013 letter from Paul Murphy, then President and CEO of the IESO, to Rosemarie Leclair, Chair and CEO of the Ontario Energy Board, available on the Board's website at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/IESO_Reply_to_OEB_Letter_20130221.pdf

Recommendation 2-1

> ***The IESO should consider expanding the current local market power framework to cover analogous circumstances that arise as part of the day-ahead commitment process.***

Recommendation 3-1

> ***The IESO should implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping down generators.***

APPENDIX

ESTIMATING THE EFFECTS OF GLOBAL ADUSTMENT ON ELECTRICITY CONSUMPTION BY CLASS A CUSTOMERS: EVIDENCE FROM A NATURAL EXPERIMENT

A Report Submitted to the Market Surveillance Panel of Ontario

By

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1. Objective

The Global Adjustment (GA) is an electricity charge that is levied on consumers in Ontario over and above the commodity cost of wholesale prices. The revenue from this charge is reimbursed to generators if the wholesale price they obtain from the market is less than the per MW price they are guaranteed through contracts. The objective of these contracts is to ensure a steady supply of electricity as well as the possible expansion of generation capacity. Further, the

[1] This Report does not represent the opinion of the Department of Economics at the University of Waterloo or the University of Waterloo. The author takes responsibility for all opinions and errors contained in this Report.

need for guaranteeing wholesale prices to generators arises because of the fact that market prices reflect short run marginal costs, and therefore, full cost recovery in an industry like electricity generation which exhibits significant economies of scale, is often not possible.

Prior to 2011, the GA was recovered uniformly from all Ontario customers on the basis of individual consumption. Basically, the total GA owed to generators was divided by the total number of MW's consumed in the month, resulting in a dollar per MW GA charge. However, Ontario Regulation 429/04 enacted by the Government of Ontario - and effective from January 2011 - implemented changes in which the Global Adjustment is allocated to customers. Basically, customers are distinguished by their volume of consumption, with Class A customers typically being large industrials (who have 5 MW average peak demand during a certain base or assessment period for billing purposes), and Class B customers constituting small business and residential consumers who obtain their needs from Local Distribution Companies (LDCs).

The new regulation yields significant incentives to industrials to shift consumption from peak to off peak periods, during the five coincident peak hours in the assessment period used to calculate the total electricity bill for each Class A customer. The five coincident peak hours each year is simply the five hours in which total demand for electricity by all consumers – Class A and B – is the highest. This is because they are correspondingly charged a lower share of the GA, if their share of consumption during these five peak periods is low- irrespective of their electricity usage during remaining hours. The new billing structure is clearly explained in the November 2011 Monitoring Report by the Market Surveillance Panel, which states – "….., if Class A customers are responsible for 10% of system demand (MW) during the five peak hours in the Base Period, that group will be allocated 10% of the GA for the Billing Period. This is true even if Class A customers as a group consume more or less than 10% of the total energy (MW) used in Ontario during all the remaining hours in the Billing Period." Further, once the GA has been allocated to each group, "…each Class A customer pays its share of the aggregate Class A GA amount based on its consumption during the five coincident peak hours in the Base Period."[2]

This significant change in the policy range resulted in rather dramatic incentives to large industrials to shift consumption away from the five coincident peak (Hi-5) hours. From a policy perspective, an evaluation of the magnitude of such shifts in electricity consumption by large industrials becomes quite important. Several policy questions arise, which this study aims to address. Specifically;

1. Controlling for other factors, did Class A customers significantly reduce their consumption during the five peak hours of the summer of 2011 and 2012, relative to earlier years? What is the empirical magnitude of this relationship?

2. Did the policy result in spillover effects with a reduction of demand by Class A customers during non-Hi 5 days?

3. If patterns in consumption by industrials did change from 2011 onwards with the introduction of the new Global Adjustment – did that impact the HOEP in a significant manner, with ramifications for all consumers (Class A and B)?

4. What is the price elasticity of demand before and after the policy?

[2] Available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf. The Base Period refers to the period in which electricity consumption by each Class A customer is monitored and the corresponding electricity bill is accordingly calculated.

5. What are the elasticities of substitution between peak and nonpeak hours? Specifically, if Class A customers did shift their consumption from Hi-5 peak hours – did they increase their consumption during other hours?

6. What are the overall elasticities of demand and elasticities of substitution across industrial sectors?

Given that Hi-5 peaks occur almost always in June, July, and August, I was asked to restrict my analyses to these months for 2009, 2010, 2011, and 2012. In terms of key findings, OLS estimates suggest that the GA amendments were associated with a significant reduction in electricity usage by industrials. Specifically, treating 2009 as the control period and 2011 and 2012 as the treatment periods, post-policy electricity usage by industrials were roughly 200 MW lower during Hi-5 days in June, July, and August of 2011-12, relative to Hi-5 days in 2009. The new policy also had spillover effects as electricity usage by industrials during the top 1% hours was approximately 379 MW lower in 2011-12, relative to similar hours in 2009. While post-policy electricity usage during off peak hours also increased significantly, this shift in consumption did not impact the Hourly Ontario Energy Electricity Price (HOEP).

I find no evidence that the GA amendments had any impact on the relationship between the HOEP and electricity consumption by industrials. Further, pre-policy and post-policy price elasticities based on the HOEP are comparable, ranging from -0.02 to -0.05. Consistent with previous studies, I find evidence that industrials shift consumption between peak and off periods, in order to reap the benefits of a lower HOEP. Finally, chemicals, mining, and pulp and paper are the industries that significantly reduced post-policy electricity usage during Hi-5 days.

The remainder of the paper is organized as follows. Section 2 discusses the theoretical model and the relevant empirical specification. Section 3 presents some broad data trends. The main empirical estimates are contained in section 4. Section 5 concludes with a summary of the main results.

2. Theoretical framework and empirical models

The Stone-Geary Approach

The empirical framework is based on the Stone-Geary utility function which takes the form

$$U = \Pi\ (K_i - \gamma)^{\beta_i} \qquad (1)$$

Where U is the utility of an individual, K_i is her consumption of a good i, where i $=1,2,\dots.n$, and $\gamma > 0$, $\beta_i > 0$ are parameters. If $\gamma_i > 0$, then the Stone-Geary function reduces to a Cobb Douglas utility function. γ is often interpreted as a minimum consumption parameter for good i.

Maximizing the Stone-Geary utility function subject to a standard budget constraint gives rise to the Linear Expenditure System (LES) and demand functions for each good. Specifically, K_i equals

$$K_i = \gamma_i + \beta_i / P_i(y - \Sigma\ \gamma_j P_j) \qquad (2)$$

Where y is the individual's income (or expenditure) and i is not equal to j. For the purpose of econometric estimation, we parametrize a two good version of (2) as

$$K_i = \gamma + \eta_i P_i/P + \eta_{ij} P_j/P + \partial_i (y/P) \tag{3}$$

Where P is a price index, and η_i, η_{ij}, and ∂_i are coefficients. In estimation, it is necessary to account for homogeneity of degree of one in income ($\Sigma\eta_i$=1) and symmetry of the matrix of compensated price elasticities ($\eta_{ij} = \eta_{ji}$). The specific econometric estimating equation can be written as

$$K_{hdmy} = \beta_0 + \beta_1 P_{hdmy} + \beta_2 GA_{my} + Z_{hdmy} + D + M + \varepsilon_{ihd} \tag{4}$$

K_{hdmy} is the hour specific consumption by an industrial sector or Class A customer, where h is the specific hour, d the day, m the month, and y the year. P_{hdmy} is the price, which is the Hourly Ontario Energy Price (HOEP). GA_{my} is the Global Adjustment, which is the month specific amount (in dollars) for all hours in 2009 and 2010, and zero for all hours in 2011 and 2012. This is intended to reflect the change in the marginal price experienced by Class A customers after 2010. Z_{hdmy} represents other covariates that could plausibly affect hourly or daily consumption by industrials. In this case, Z_{hdmy} includes controls for daily average temperature and relative humidity in Toronto. I downloaded city specific information on hourly average temperature and relative humidity levels from the National Climate Data and Information Archive maintained by Environment Canada and available from www.climate.weatheroffice.gc.ca. D and M are vectors containing day of week and month specific dummy variables. The use of month dummies precludes the use of other covariates such as unemployment rates or consumer price indices that vary only by month. The effects of such variables are absorbed by the month dummies. ε_{hdmy} is the error term, which is assumed to be independently and identically distributed.

The above specification does not take into account the significant post 2010 change in incentives to Class A customers, with respect to reducing consumption during peak hours. Given the absence of other policies that could have similarly impacted consumption by Class A customers over the same time period, it is possible to treat all hours in 2009 and 2010 as the pre-policy or 'control' sample, and all hours in 2011 and 2012 as the post-policy or 'treatment' sample. Therefore, I employ a standard difference-in-difference specification. The estimable equation thus becomes;

$$K_{hdmy} = \beta_0 + \beta_1 P_{hdmy} + \beta_2 GA_{my} + \beta_3 Peak_{hdmy} + \beta_4(Peak_{hdmy} * Post\ 2010_y) + \beta_5 Post\ 2010_y + Z_{hdmy} + D + M + \varepsilon_{hdmy} \quad (5)$$

$Peak_{hdmy}$ is a dummy variable that takes a value of 1 if the hour is a system peak hour and 0 otherwise. $Post\ 2010_y$ is a dummy variable that takes a value of 1 if the data-point is in 2011 or 2012, and is 0 otherwise. β_3 represents the effect of a peak hour on consumption during 2009 and 2010, while β_4 captures the incremental effect for 2011 and 2012, relative to pre-policy years. Therefore, $\beta_3 + \beta_4$ is the total effect of a peak system hour on consumption, on average, relative to other hours, during 2011 and 2012. Similar to the monthly dummy variables, the use of the post 2010 annual dummy variable precludes the use of other covariates that vary only by year. The variation in consumption between pre and post policy years (which may be affected by differences in the level of economic activity in each year) is absorbed by the post 2010 dummy variable.

In a sense, evaluating the effects of peak system hours on usage is an attempt to estimate the price effects of electricity consumption. Therefore, a relevant question is whether the coefficients of β_3 and β_4 could be correlated with the error term, resulting in measurement error. This is because the econometric equation basically consists of regressing quantity consumed on a price variable. However, the occurrence of a peak system is random and a function of weather. Therefore, I do not expect any measurement error in coefficient estimates.

In terms of estimation, I rely on Ordinary Least Squares (OLS) with White and Newey-West corrections for unknown heteroskedasticity and second order autocorrelation. While previous studies have acknowledged the importance of clustering standard errors with respect to difference-in-difference specifications, I obtained similar results whether I clustered the standard errors by hour or through the use of Generalized Least Squares (GLS) that correct standard errors for unknown heteroskedasticity and first order autocorrelation.

A caveat should be noted. While the use of aggregate industry level data should certainly shed some insight, what would be more desirable is actual firm level data that would enable the researcher to estimate the effects of changes to the Global Adjustment and the HOEP on actual electricity consumption by firms. Further, the use of firm specific data permits an analysis of price elasticities by firm size.

3. Data Trends

Table 1 contains mean hourly consumption and prices (with standard deviations in parentheses) by month (June, July, and August) and for the pre-policy (2009, 2010) and post-policy (2011, 2012) years. Consistent with previous studies, I count 7 am to 6:59 pm as peak hours and 7 pm to 6:59 am as off peak hours. Broadly speaking there doesn't seem to be significant differences in peak- off peak consumption between the two time periods.

However, these broad trends mask significant changes in consumption during Hi-5 hours, before and after the policy changes. Table 2 offers similar summary statistics (for June, July, and August) between peak and off peak hours, and across Hi-5 and non-Hi-5 days. In contrast to the pre-policy period, peak hour consumption during Hi-5 days is much lower relative to off-peak hour consumption on the same day, during the post-policy period. For example, in 2009, average hourly consumption during peak (off peak) hours was 1728.7 MW (1831.2 MW), with comparable statistics in 2010. On the other hand, there was a bigger peak-off peak differential in 2011 (2012), as average hourly peak and off-peak consumption was 1556.3 MW (1548.8 MW) and 1801.3 MW (1909.1 MW), respectively.

In comparison, peak and off-peak hour consumption differentials are not that strong during non-Hi-5 day between pre-policy and post-policy years. In 2009 average hourly consumption during peak and off-peak hours was 1621.5 MW and 1682.8 MW, respectively. The corresponding figures for 2010 were 1725.3 MW and 1819.1 MW. In 2011, average hourly consumption during peak and off-peak hours was 1650.0 MW and 1773.2 MW, respectively. In 2012, similar figures were 1768.6 MW and 1888 MW, respectively.

The next question is whether consumption by Class A customers was lower during certain high peak hours - that were not Hi-5. In other words, was there a spillover effect as industrials 'hunted' Hi-5 hours, and as a result, reduced consumption significantly during hours which were high system peaks, but not Hi-5? Table 3 contains summary statistics for consumption and price for each year (during June, July, and August). I define peak hours according to the top 1%, top 1%-5%, top 5%, top 5%-10%, and top 10% of Ontario demand hours for each year.

Table 3 clearly suggests that the legislation may have incented Class A customers to reduce consumption in many peak hours, in an effort to catch the Hi-5. First, there does not seem to be strong differences between peak and off-peak consumption during the pre-policy years (2009, 2010). However, the summary statistics for 2011 and 2012 are quite different from similar figures for 2009 and 2012. Specifically, mean consumption during top 1% and top 5% hours is significantly lower relative to other hours during the post-policy period (2011-2012). Unsurprisingly, the differences between top 10% and other hours are not that pronounced. Further, there are strong differences between top 1% and top 1%-5% hours, which demonstrates that the sample statistics for top 5% hours are being pulled by the top 1% hours.

Finally, in order to obtain a better idea of the correlation between Hi-5 days and top 1% Ontario demand hours, I constructed table 4 which gives the proportion of top 1% Ontario demand hours for June, July, and August, that also occurred during a Hi 5 day, for each year of the sample. As the sample proportions clearly demonstrate, there exists a very close correspondence between the top 1% Ontario system demand hours and Hi-5 days.

4. Empirical estimates

Baseline estimates

Table 5 contains baseline estimates of equation (5) based on Ordinary Least Square with standard errors Newey West-White corrected for unknown heteroskedasticity and second order autocorrelation. The results are reported separately by industry and by specific definition of a system peak hour. Therefore, Hi-5, Top 1%, Top 1%-5%, Top 5%, Top 7%, Top 5%-10%, and

Top 10% are dummy variables that take a value of 1 (and are 0 otherwise), if the hour is within a Hi-5 day, or is either a Top 1%, Top 1%-5%, Top 5%, Top 7%, Top 5%-10%, or Top 10% Ontario demand hour. I employ data for total electricity consumption by industrials, as well as specific electricity usage by industrial gas and equipment, chemicals, mining, manufacturing, steel, and pulp and paper, which were given to me on special request by the Independent Electricity System Operator (IESO).[3] Elasticities for the HOEP are computed at mean values and are reported in square brackets beneath the standard error of coefficient estimates. The table focuses on the marginal effects of consumption during a peak hour for pre-policy and post-policy hours and suppresses other coefficient estimates.

The first notable result is that coefficient estimates of the HOEP with respect to consumption by all industrials are negative across columns and statistically significant when system peaks are defined by a Hi-5 day, Top 5%-10%, or Top 10% hour. The implied elasticities are small – but this is to be expected with hourly data, as responses in consumption between successive hours are, on average, relatively limited.

The second key finding is that coefficient estimates of peak hour consumption during 2009 and 2010 (β_3) are positive, but with the exception of peak usage being defined in terms of a Hi-5 day, statistically insignificant. On the other hand, coefficient estimates of peak system consumption (β_4), independent of the precise definition, are statistically significant (at varying levels) across all columns. The coefficient estimate of a Hi-5 day implies that, on average, consumption during a Hi-5 day post-policy, is approximately 173 MW lower for each hour relative to similar hours during pre-policy years. The cumulative effect ($\beta_3 + \beta_4$) implies a

[3] Although I also had access to electricity consumption by the automobile industry, I do not report empirical estimates for that industry as coefficient estimates are in most cases, statistically insignificant.

reduction of roughly 112 MW during hours within a Hi-5 day relative to non-Hi-5 days, in post-policy years.

The corresponding impacts for the Top 1% hours are larger, as the specific coefficient estimates suggest that consumption by industrials during such peak hours in post-policy years is roughly 289 MW lower than corresponding peak hours in pre-policy hours. The cumulative effect is approximately a 265 MW reduction in comparison to other non-Top 1% hours. While remaining statistically significant, coefficient estimates of consumption during system peaks for 2011 and 2012, decline in magnitude across columns. For example, the coefficient estimates (β_4) for Top 5% and 10% hours are -132.81 MW and -56.51 MW, respectively. The cumulative effects ($\beta_3 + \beta_4$) for Top 5% and 10% are comparable at -122 MW and 53 MW, respectively.

These findings have some important implications. First, they demonstrate that the policy did successfully incent industrials to reduce their consumption during system peak hours. Second, industrials, on average, were successful in identifying system peaks – or ‘catching the peak’. This observation is based on the remarkable increase in the magnitude of coefficient estimates with the narrowing of system peak definitions.

In summary, coefficient estimates of consumption during peak hours (whether Hi-5, Top 1%, 5%) in 2011 and 2012, are negative and statistically significant, offering some strong evidence that industrials did respond to the new policy by reducing consumption during system peak hours by non-trivial amounts. As should be the case, coefficient estimates of consumption during peak hours (in 2011 and 2012) increase as the definition of a system peak hour becomes narrower. While the coefficient estimate for consumption during top 10% of hours is -56.51, the corresponding estimates for top 7%, 5%, and 1% of all hours are larger in magnitude at -89.07 MW, -132.8 MW, and -288.46 MW, respectively.

Estimates by industry

There is considerable industry heterogeneity in estimates across industries. The first finding is that coefficient estimates of the HOEP are negative and statistically significant for industrial gas and equipment, mining, and pulp and paper, with implied elasticities ranging from -0.017 to -0.026.

Coefficient estimates of consumption during peak system hours for 2009 and 2010 are positive and statistically significant across all columns for steel and other industries. Estimates for industrial and gas equipment are for also statistically significant, but negative. Corresponding estimates for other industries display no strong trends or consistent pattern in terms of magnitude or statistical significance.

In contrast, it is clear which industries significantly reduced peak system electricity usage, post-policy. Consumption by chemicals, mining, steel, pulp and paper are roughly 15 MW, 30 MW, 83 MW, and 43 MW lower each hour during Hi-5 days in 2011 and 2012, relative to any reductions conducted by these industries during Hi-5 days in 2009 and 2010. The cumulative impacts imply that post-policy electricity usage by chemicals, mining, steel, pulp and paper are roughly 10 MW, 30 MW, 83 MW, and 43 MW lower in Hi-5 days in comparison to non-Hi-5 days.

Corresponding reductions during the Top 1% of all system hours are of a larger magnitude, with electricity usage by chemicals, mining, steel, and pulp and paper being approximately 31 MW, 52 MW, 156 MW, and 60 MW lower each hour during these days in 2011 and 2012, relative to any reductions conducted by these industries during similar hours in 2009 and 2010. In terms of electricity consumption relative to non-Top 1% hours, usage by chemicals, mining, steel, pulp and paper are about 25 MW, 42 MW, 148 MW, and 53 MW lower for each Top 1% hour.

In summary, the empirical results do not reveal any significant reduction in consumption during peak hours by industrial gas and equipment. There is some modest shifting by chemicals during Hi-5 days and Top 1% of system peak hours. The mining industry displays a greater proclivity towards shifting as the coefficient estimates of consumption (during 2011 and 2012) with respect to the top 7%, 5%, and 1% of all hours are -8.66, -18.39, and -52.35, respectively, with statistical significance ranging from the 10% to 1% levels.

Electricity consumption by manufacturing is not significantly lower during peak system hours. On the other hand, the steel industry does reduce consumption significantly during the same hours. For example, controlling for other factors, electricity consumption by steel in 2011 and 2012 is roughly 83 MW and 155.9 MW lower (on an hourly basis) during Hi-5 and Top 1% hours. Electricity usage by pulp and paper is also lower during peak hours, with coefficient estimates of -43.45 MW and -60 MW with respect to Hi-5 days and the top 1% of all hours. As is the case with steel, coefficient estimates of consumption for different system peaks for 2011 and 2012, are negative and statistically significant (at the 1% level) across all columns. However, similar to trends in overall consumption, coefficient estimates of the impacts of system peaks with respect to 2011 and 2012 become smaller as the definition of a system peak becomes broader.

Sensitivity Analysis

It is possible that industrials gained knowledge in 2010, of legislative amendments to the Global Adjustment that would amend its allocation from 2011 onwards. If this is true, then it is better to define 2009 as the 'pure control regime' and drop 2010 from the analysis. Table 6 contains difference-in-difference estimates of consumption during peak system periods defined as Hi-5 days, Top 1% of all hours, Top 1%-5%, Top 5%, Top 7%, Top 5%-10%, and Top 10% of all hours.

The marginal effects of consumption by all industrials during peak system hours in 2011 and 2012 (panel A) are negative and statistically significant at the 1% level across all columns. These coefficient estimates are larger in magnitude relative to corresponding estimates in Table 5. The regression estimates imply that relative to 2010, post-policy electricity usage by industrials were 194.96 MW, 378.72 MW, 122.81 MW, 188.32 MW, 138.25 MW, and 98.190 MW lower during Hi-5, Top 1%, 1%-5%, 5%, 7%, and 10% of all hours.

However, the cumulative impacts ($\beta_3 + \beta_4$) for 2011 and 2012 are comparable to findings contained in the previous table, as coefficient estimates of marginal effects for 2009 and 2010 are also larger in magnitude. Specifically, the regression results reveal that total consumption by industrials for 2011 and 2012 ($\beta_3 + \beta_4$) are approximately 110 MW, 258 MW, 67 MW, 123 MW, 84 MW, and 51 MW lower during Hi-5, Top 1%, 1%-5%, 5%, 7%, and 10% hours relative to other hours. Recall that the corresponding estimates from Table 5 (in the same order) are 112 MW, 265 MW, 66 MW, 122 MW, 85 MW, and 53 MW, respectively. The striking result in both tables is that the coefficient estimates of marginal and cumulative effects for the Top 1% hours is larger than the estimate of Hi-5 hours, implying that industrials did significantly shift consumption during non-Hi-5 hours in an effort to find the proper peaks.

In terms of other key results, coefficient estimates of the HOEP are negative and statistically significant across all columns with comparable elasticities, relative to Table 5. With respect to other industries, recall that estimates in Table 5 indicate an absence of a statistically significant correlation between electricity usage and peak system hours for industrial gas and equipment. However, the cumulative reduction by this group during Hi-5 days and Top 1% hours is now statistically significant, and ranges from 9 MW to 11 MW. On the other hand, estimates for chemicals, steel, mining, and pulp and paper do not change that much, as they still demonstrate evidence of reductions in consumption during peak hours.

Decomposing the reduction in consumption during system peaks

The above results establish that industrials did respond to the new Hi-5 Global Adjustment by significantly reducing consumption during system peaks. A relevant question is whether industrials simply reduced overall demand or if they shifted their consumption to other hours. In order to further explore these issues, I constructed the following empirical specification;

$$K_{\mathrm{hmdy}} = \beta_0 + \beta_1 P_{\mathrm{hdmy}} + \beta_2\, Hi5day\text{-}PeakH_{\mathrm{hdmy}} + \beta_3 Hi5day\text{-}OffPeakH_{\mathrm{hdmy}} + \beta_4\, NHi5day\text{-}Offpeak_{\mathrm{hdmy}} + Z_{\mathrm{h}} + D + M + \varepsilon_{\mathrm{hdmy}} \qquad (6)$$

The above model evaluates differences in consumption during peak and off peak hours during a Hi 5 day and during off-peak hours on other days, relative to peak hour consumption during non Hi 5 days. $Hi5day\text{-}PeakH_{\mathrm{hdmy}}$ is a dummy variable that takes a value of 1 for peak hours during a Hi-5 day and is 0 otherwise. $Hi5day\text{-}OffPeakH_{\mathrm{hdmy}}$ is a dummy variable that takes a value of 1 for off peak hours during Hi 5 days and is 0 otherwise. $NHi5day\text{-}OffPeakH_{\mathrm{hdmy}}$ is a dummy variable that takes a value of 1 for off peak hours during non Hi 5 days and is 0 otherwise. Therefore, β_2 represents the difference in consumption during peak hours within Hi-5 days relative to peak hours during non-Hi 5 days, while β_2 and β_3 yields the marginal effect on consumption during off-peak hours within Hi-5 days and non-Hi 5 days, respectively, relative to peak hours during non-Hi-5 days.

While the intended objective of the new Global Adjustment is to incent reductions in consumption during peak system hours, it is important to acknowledge that such behavior might have adverse welfare consequences. Specifically, if as a result of the policy, electricity consumption by industrials correspondingly rose during non-Hi 5 days or off-peak hours within Hi-5 days, then there is a possibility that the increased demand may have also resulted in a higher HOEP for these hours, relative to pre-policy outcomes. In order to test this possibility, I employ a similar empirical specification to equation (6), in order to evaluate the relationship between the HOEP and consumption during peak and off peak hours.

$$HOEP_{\mathrm{hdmy}} = \beta_0 + \beta_1\, Hi5day\text{-}PeakH_{\mathrm{hdmy}} + \beta_2 Hi5day\text{-}OffPeakH_{\mathrm{hdmy}} + \beta_3\, NHi5day\text{-}Offpeak_{\mathrm{hdmy}} + Z_{\mathrm{h}} + D + M + \varepsilon_{\mathrm{hdmy}} \qquad (7)$$

In the above equation, β_1 represents the difference in the HOEP during peak hours within Hi-5 days relative to peak hours during non-Hi 5 days, while β_2 and β_3 yields the marginal effect on the HOEP during off-peak hours within Hi-5 days and non-Hi 5 days relative to peak hours within non-Hi-5 days.

Panel A in table 7 contains estimates of equation (6) while panel B contains results with respect to equation (7). Column (1) contains results for all years, column (2) contains estimates with respect to 2011 and 2012, column (3) for 2012, column (4) for July and August 2012, column (5) for 2009 and 2010, and column (6) for 2009. The results in panel A, column 1, imply that consumption during peak hours within Hi 5 days is roughly 49 MW lower than peak hours in non-Hi-5 days. In contrast, electricity usage during off peak hours for Hi-5 days and non-Hi-5 days is about 161 MW and 110 MW higher than peak hours in non-Hi-5 days. The marginal effects for peak hour consumption during Hi 5 days become much larger in magnitude once we use data for 2011 and 2012 (column 2), 2012 (column 3), and July and August 2012 (column 4).

Specifically, the results indicate that, on average, peak hour consumption during High-5 days is approximately 136 MW, 172 MW, and 212 MW lower than peak hours in non-Hi-5 days, for 2011 and 2012, 2012, and for July and August for 2012. All these coefficient estimates are statistically significant at the 1% level. However, the results in columns 2, 3, and 4, also indicate that these reductions may have been offset by an increase in electricity usage during off peak hours. Specifically, the estimates suggest that, on average, consumption during off peak hours in Hi-5 days are 147 MW, 160 MW, and 127 MW higher than peak hours in non-Hi-5 days, for 2011 and 2012, 2012, and July and August 2012. The corresponding magnitude of effects for off peak hours during off-peak hours within non-Hi-5 days are also positive and range from 100 MW to 121 MW. Finally, coefficient estimates for peak hour consumption during Hi-5 days and off peak hour consumption for non-high 5 days with respect to 2009 and 2010 are positive (columns 5 and 6). In tandem, these estimates suggest that industrials may have shifted much of their reduction in consumption during peak hours within Hi-5 days to off-peak hours within the same day.

These results suggest that the possibility that Class B consumers may have been significantly impacted by these shifts in consumption by industrials if such changes in consumption patterns significantly increased demand during off-peak hours, resulting in a higher HOEP. However, estimates in table 5 offer evidence against this notion. Specifically, while coefficient estimates of peak hour consumption during Hi-5 days are positive and statistically significant for most columns, corresponding estimates for off-peak hour consumption during Hi-5 and non-Hi-5 days are negative and statistically significant, implying that the HOEP is, on average, lower during these specific hours relative to peak hour consumption during non-Hi-5 days. Therefore, I find no evidence that potential load shifting by industrials did result in a higher HOEP during off –peak hours – for Hi-5 and non-Hi-5 days.

Table 8 explores the changes in post –policy consumption for different hours, by exploiting time-series variation. The table contains results of estimates based on electricity consumption by industrials during Hi 5 day peak hours (columns 1, 4, 7), non-Hi 5 day peak hours (columns 2, 5, 8), and non – Hi 5 days off peak hours (columns 3, 6, 9). Each column in the table contains estimates of changes in post-policy consumption for specific hours. The difference between columns stems from whether we use 2009, or 2009 and 2010, or 2010 as benchmark periods.

Columns 1, 2, and 3 suggest modest increases in post policy electricity usage during hours other than peak hour Hi 5 days. Empirical estimates suggest that controlling for all else, post-policy electricity usage during Hi 5 off peak, non Hi 5 peak, and non Hi 5 off peak hours increased by roughly 59 MW, 14 MW, and 54 MW, respectively. However, corresponding estimates in columns 4, 5, and 6, which are based on 2009 as the benchmark year, are much larger in magnitude. Specifically, they imply that relative to 2009, post-policy electricity usage during Hi 5 off peak, non Hi 5 peak, and non Hi 5 off peak hours increased by roughly 239 MW, 77 MW, and 126 MW, respectively. These results should be compared against the roughly 172 MW decrease in electricity usage in Hi 5 days during post-policy years, which our econometric results (from table 6) imply. In contrast, estimates in columns 7, 8, and 9 suggest that consumption during Hi 5 off peak, non Hi 5 peak, and non Hi 5 off peak hours in 2011 and 2012 were lower relative to 2010.

Price Elasticities of Demand

It is important to acknowledge that the estimates of price elasticities of demand reported above, are in most cases, small in magnitude. However, this is unsurprising as these results are based on hourly data, and changes in consumption across adjacent hours is likely to be quite limited. What is perhaps more relevant, is the change in peak/off peak consumption patterns in response to corresponding changes in peak/off-peak prices. In order to test this hypothesis, I estimated a similar specification to (5), but after converting the hourly data into peak and off peak averages. This is in fact, the empirical strategy employed by previous studies (For example, Sen et al. (2011).[4]

Specifically, all hours between 7 am and 6:59 pm are treated as peak, and all hours from 7 pm to 6:59 am the next day, are treated as off-peak. Therefore, each day has two mean consumption and price observations. In other words, electricity consumption is assumed to be a function of average prices during the specific time period as well lagged prices. Hence, when the data refers to electricity consumption during *peak* hours (7 am to 6:59 pm), the lagged price is average *off peak* prices from 12 am to 6:59 am of the same day, but earlier in the morning. On the other hand, when electricity consumption is during *off peak* hours (7 pm to 6:59 am the next day), the lagged price is average *peak* price between 7 am to 6:59 pm of the same day, reflecting the effects of electricity substitution *across* days. In addition to these price covariates, I also employ controls for average temperature and humidity levels, day specific dummies, and the

[4] Wai Choi & Anindya Sen & Adam White, 2011. "Response of industrial customers to hourly pricing in Ontario's deregulated electricity market," *Journal of Regulatory Economics*, Springer, vol. 40(3), pages 303-323, December.

month specific dummies. In order to study changes in elasticities of demand over time, I run separate regressions for each year. These regression results are reported in Table 9.

The first notable result is, that with the exception of 2009, coefficient estimates of the current HOEP with respect to total consumption by industrials are negative and statistically significant at either the 1% or 10% levels, and suggest that industrials do drop consumption contemporaneously, in response to higher prices. The implied elasticities for 2010 and 2011 are -0.056 and -0.047, respectively. In comparison, the corresponding elasticity for 2012 is lower, at -0.023. The second key finding is that coefficient estimates of the lagged HOEP – which captures the impacts of load shifting and are elasticities of substitution – are positive and statistically significant across all columns, at either the 5% or 1% levels. The implied elasticities are quite similar across years, ranging from 0.2 to 0.04.

There is considerable industry heterogeneity in estimates across industries. While empirical estimates of the HOEP on consumption by industrial gas and equipment are negative for all years, they are also statistically insignificant. Coefficient estimates of the lagged HOEP are also insignificant across all columns. The coefficient estimate for the HOEP with respect to chemicals is statistically significant (at the 5% level) for 2009, but positive. On the other hand, empirical estimates of the HOEP are negative and statistically significant (at the 1% level) for 2011 and 2012, with implied elasticities of roughly -0.03 and -0.02. The lagged HOEP is positive and statistically significant for 2009 but negative and significant for 2011. Therefore, we obtain some evidence on contemporaneous reduction in consumption in response to increases in price.

Coefficient estimates of the HOEP are negative for all years with respect to consumption by mining. The estimates for 2010 and 2011 are statistically significant at the 1% level with implied elasticities of roughly -0.11. Corresponding coefficient elasticities of the lagged HOEP do not display consistent patterns across years. However, the coefficient estimate for 2012 is positive and statistically significant at the 1% level with an implied elasticity of 0.035. Estimates with respect to manufacturing are a bit different from the above industries. First, coefficient estimates of the HOEP are statistically significant for most years, and positive. On the other hand, coefficient estimates of the lagged HOEP are in most cases, statistically insignificant. Other covariates are also statistically insignificant. But the adjusted R square is also reasonably high for most years.

The results for steel parallel the findings for the industrial gas and equipment industry as coefficient estimates for the HOEP are negative for most years, but statistically imprecise. The HOEP covariates with respect to electricity consumption by pulp and paper are statistically significant at the 1% or 5% levels. The implied price elasticities for the current HOEP range from -0.13 to -0.21, while the elasticities associated with the lagged HOEP are from 0.16 to 0.29. Implied elasticities for both these covariates diminish over time. In summary, the important point is that I obtain much more sizable implied elasticities with respect to the HOEP, once the data are converted into peak and off peak averages, within the same day. In other words, some industrials do respond to within day peak – off peak price differentials by adjusting electricity usage. Specifically, it is not possible to dismiss the fact that some industrials do decrease (increase) peak (off peak) hour consumption not only because the peak (off peak) hour price is higher – but also because the off peak (peak) hour price is correspondingly lower (higher).

5. Conclusion

This study evaluates the effects of 'Hi-5' changes with respect to Global Adjustment allocations to Class A customers that came into force in 2011, as well as changes in price elasticities (with respect to the HOEP) over time. The results offer some strong evidence that the policy incented industrials to significantly reduce electricity consumption during Hi 5 days. Specifically, taking 2009 and 2011-12 as the control and treatment periods, I find that consumption during Hi-5 days after the Global Adjustment amendments was roughly 200 MW lower relative to Hi 5 days in 2009. Further, the policy had significant spillover effects, as electricity usage during the top 1% hours experienced a roughly 378 MW reduction in consumption by industrials, after the enactment of the new Global Adjustment, in comparison to the top 1% system peak hours in 2009. However, the magnitude of reductions in electricity consumption after the Global Adjustment amendments diminish once the definition of system peaks expands to the top 5% and 10% of all hours. The key industries which exhibit significant reductions in electricity usage during system peaks include mining, steel, and pulp and paper.

Did industrials reduce their overall consumption, or did they simply increase their consumption during certain off-peak hours? These are questions that can be answered only with individual firm level data. However, employing aggregate data allows an analysis of off-peak consumption after the enactment of Global Adjustment amendments. The empirical estimates demonstrate that off peak electricity consumption increased significantly after the policy amendments. On average, consumption during off peak hours in Hi-5 (non Hi-5) days are roughly 160 (121) MW higher than peak hours during non Hi 5 days, for 2012. The increase in consumption during off-peak hours raises the possibility that the HOEP also rose during these hours. However, I do not find any evidence of such a correlation.

The next question of policy importance relates to whether industrials also moderate consumption in response to a higher HOEP. Estimates based on hourly data yield price elasticities that are sometimes statistically significant, but small in magnitude. However, this is unsurprising, as substitution in consumption across adjacent hours is likely to be limited. Most empirical studies have estimated price elasticities by averaging consumption and electricity prices by peak and off peak hours, and then evaluating the effects of peak/off peak price differentials on corresponding differences in consumption. Employing a comparable model, I obtain evidence that, on average, industrials not only respond to contemporary changes in the HOEP, but also to differentials across time periods. Empirical estimates from OLS models reveal that a 10% rise in the HOEP is significantly associated with roughly a 0.2%-0.5% drop in consumption. Elasticities of substitution are also statistically significant and suggest that a 10% increase in the HOEP during peak (off peak) periods is significantly associated with a 0.2%-0.4% increase in off peak (peak) consumption. However, clearly the magnitude of peak load shifting exclusively in response to the HOEP is limited in comparison to the amount that has occurred as a result of the amendments to the Global Adjustment.

Table 1. Average Electricity Consumption by Industrials

	2009, 2010			2011,2012	
Aggregate					
	Peak Consumption	**Peak price**		**Peak Consumption**	**Peak price**
June	1663.2 (185.57)	36.74(18.691)	June	1633.3 (128.68)	32.316 (25.686)
July	1640.1 (238.49)	41.48(34.885)	July	1667.1 (131.36)	38.280 (21.403)
August	1710.5 (214.43)	40.665(28.408)	August	1736.3 (143.00)	34.650 (23.400)
	Off Peak Consumption	**Off peak price**		**Off Peak Consumption**	**Off peak price**
June	1743.9 (134.29)	25.500 (16.340)	June	1751.7 (151.71)	18.595 (26.709)
July	1723.7 (213.03)	27.179 (18.229)	July	1819.2 (127.41)	27.505 (15.806)
August	1787.9 (132.23)	28.834 (17.023)	August	1845.6 (111.26)	24.795(21.883)

Notes: Data are hourly for the months of June, July, and August and in MW. Standard deviations in parentheses

Table 2. Average Electricity Consumption by Industrials by year

	Pre-Policy					**Post Policy**			
2009	**Hi-5**		**Other days**		**2011**	**Hi-5**		**Other days**	
	Consumption	Price	Consumption	Price		Consumption	Price	Consumption	Price
Peak Hours	1728.7 (73.920)	76.958 (86.653)	1621.5 (227.59)	25.507 (18.130)		1556.3 (153.96)	56.483 (31.785)	1650.0 (134.50)	36.795 (20.013)
Off peak hours	1831.2 (47.634)	29.341 (3.0810)	1682.8 (222.02)	16.680 (12.782)		1801.3 (83.129)	37.399 (14.242)	1773.2 (99.898)	27.966 (20.963)
2010					**2012**				
	Hi-5		**Other days**			**Hi-5**		**Other days**	
	Consumption	Price	Consumption	Price		Consumption	Price	Consumption	Price
Peak Hours	1730.2 (339.37)	78.970 (39.250)	1725.3 (212.68)	53.324 (30.422)		1548.8 (202.32)	77.873 (53.811)	1768.0 (107.30)	33.103 (19.687)
Off peak hours	1883.0 (67.29)	46.762 (19.775)	1819.9 (84.123)	38.383 (14.341)		1909.1 (108.24)	32.453 (19.276)	1888.6 (112.85)	23.277 (16.960)

Notes: Data are hourly and for the months of June, July, and August. Consumption are in MW and prices in $/MW. Standard deviations in parentheses. The statistics are computed by year, by Hi-5 and other days, and peak hours. Peak hours are defined as being from 7 am to 7 pm, with off peak hours being the remainder.

Table 3. Average Electricity Consumption by Industrials by year and system peaks

	2009		2010		2011		2012	
	Consumption	**Price**	**Consumption**	**Price**	**Consumption**	**Price**	**Consumption**	**Price**
Top 1% hours	1775.2 (307.99)	77.239 (75.815)	1669.7 (304.27)	85.116 (23.053)	1432.8 (159.33)	85.594 (35.580)	1416.0 (144.57)	97.128 (43.887)
Obs	24		24		24		24	
Other	1641.6 (204.75)	22.037 (17.309)	1774.6 (165.33)	44.813 (23.557)	1668.9 (136.90)	32.775 (24.542)	1812.8 (124.19)	25.624 (19.687)
Obs	2184		2184		2184		2184	
Top 1%-5%	1696.2 (186.61)	49.235 (39.00)	1730.3 (223.98)	86.854 (34.791)	1585.6 (106.01)	59.177 (39.146)	1696.2 (186.61)	49.235 (39.000)
Obs	87		87		87		87	
Top 5%	1713.3 (219.38)	55.290 (50.251)	1717.2 (243.33)	86.478 (32.526)	1552.5 (134.48)	64.889 (39.775)	1607.9 (201.86)	71.388 (38.183)
Obs	111		111		111		111	
Other	1639.3 (205.20)	20.908 (14.753)	1776.5 (162.25)	43.069 (21.258)	1672.4 (136.96)	31.680 (23.115)	1819.2 (117.02)	24.020 (17.127)
Obs	2097		2097		2097		2097	
Top 5%-10%	1660.4 (107.09)	37.052 (8.787)	1732.1 (73.277)	79.368 (53.874)	1647.8 (88.190)	48.639 (22.265)	1792.1 (102.63)	47.381 (23.017)
Obs	112		112				112	
Top 10%	1686.7 (174.02)	46.130 (37.058)	1724.7 (179.10)	82.907 (44.588)	1600.4 (123.01)	56.728 (33.137)	1700.4 (184.33)	59.330 (33.645)
Obs	223		223		223		223	
Other	1638.1 (209.32)	19.997 (14.494)	1779.0 (165.51)	41.021 (15.377)	1673.8 (139.09)	30.723 (22.795)	1820.7 (117.62)	22.702 (15.739)
Obs	1985		1985		1985		1985	

<u>Notes</u>: Data are hourly and for the months of June, July, and August. Consumption are in MW and prices in $/MW. Standard deviations in parentheses. The statistics are computed by yea and by system peaks. Peak hours are defined as being from 7 am to 7 pm, with off peak hours being the remainder.

Table 4. Correspondence between Top 1% and High 5 Days

Year	Percentage of Top 1% Ontario Demand Hours that fall in Hi 5 Days
2009	83%
2010	92%
2011	100%
2012	83%

Table 5: Difference in Difference estimates of the effects of system consumption peaks on electricity use by industrials - hourly data for 2009, 2010, 2011, 2012

	Hi 5 Days	Top 1% of all hours	Top 1%-5% of all hours	Top 5% of all hours	Top 7% of all hours	Top 5%-10% of all hours	Top 10% of all hours
A. Total							
HOEP	-0.24086 (0.1166)** [-0.0045]	-0.1452 (0.115) [-0.0027]	-0.2365 (0.1258)* [-0.0044]	-0.1409 (0.1211) [-0.0026]	-0.1606 (0.123) [-0.0030]	-0.2742 (0.1229)** [-0.0051]	-0.1986 (0.1247)* [-0.004]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 & 2010 relative to other hours during the same years	60.379 (13.72)***	23.091 (45.61)	15.505 (17.98)	10.533 (17.56)	3.3552 (13.77)	-0.717 (8.69)	3.486 (11.18)
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009, 2010	-172.98 (28.91)***	-288.46 (52.01)***	-82.103 (23.44)***	-132.81 (24.00)***	-89.072 (19.25)***	-23.69 (12.81)*	-56.512 (15.31)***
Sample Mean of total consumption (High 5 days)	1722.9 (0.0462)						
Adjusted R Square	0.2000	0.2026	0.1938	0.2011	0.1976	0.1916	0.1946
B. Industrial Gas and Equipment							
HOEP	-0.0511 (0.012)*** [-0.023]	-0.0507 (0.101)*** [-0.023]	-0.049 (0.012)*** [-0.023]	-0.039 (0.012)*** [-0.018]	-0.0369 (0.012)*** [-0.0169]	-0.057 (0.0124)*** [-0.026]	-0.0389 (0.012)*** [-0.0176]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 & 2010 relative to other hours during the same years	-10.653 (1.094)***	-11.510 (2.459)***	-7.392 (1.223)***	-9.5014 (1.22)***	-8.92 (1.08)***	-3.283 (0.93)***	-7.724 (0.95)***

Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009, 2010	-0.069 (1.308)	1.7719 (2.579)	-0.037 (1.886)	0.169 (1.664)	0.95 (1.42)	2.7 (1.3)**	1.537 (1.217)
Sample Mean of total consumption by Industrial & Gas Equipment	69.762						
Adjusted R Square	0.4895	0.4783	0.4807	0.4859	0.4865	0.4752	0.4852
C. Chemicals							
HOEP	0.0262 (0.0254) [0.0021]	0.0341 (0.0258) [0.0027]	0.033 (0.0263) [0.0026]	0.0423 (0.027) [0.0033]	0.046 (0.027)* [0.0037]	0.0289 (0.025) [0.0023]	0.047 (0.027)* [0.0037]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 & 2010 relative to other hours during the same years	5.241 (3.54)	5.7731 (13.03)	-8.641 (4.88)*	-6.449 (4.936)*	-10.055 (3.77)**	-13.524 (2.142)***	-11.808 (2.909)***
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009, 2010	-15.438 (4.705)***	-30.746 (13.63)**	3.683 (5.197)	-4.3097 (5.37)	2.7761 (4.142)	19.377 (2.482)***	8.146 (3.192)***
Sample Mean of total consumption by Chemicals	405.18						
Adjusted R Square	0.4864	0.4869	0.4861	0.4867	0.4870	0.4877	0.4877
D. Mining							
HOEP	-0.2587 (0.0438)*** [-0.021]	-0.245 (0.0438)*** [-0.0203]	-0.252 (0.044)*** [-0.0209]	-0.2371 (0.0439)*** [-0.0196]	-0.23898 (0.0446)*** [-0.0198]	-0.2578 (0.0447)*** [-0.0214]	-0.236 (0.0449)*** [-0.0195]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 & 2010 relative to other hours during the same years	10.628 (4.102)**	9.9581 (9.554)	-4.3377 (4.993)	-2.4883 (4.860)	-4.8931 (3.939)	-14.329 (3.200)***	-10.295 (3.402)**
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009, 2010	-29.645 (7.696)***	-52.355 (12.99)***	-7.6668 (7.227)	-18.386 (6.815)**	-8.6571 (5.697)	21.476 (5.099)***	1.9064 (4.772)
Sample Mean of total consumption by Mining	385.11						
Adjusted R Square	0.5773	0.5776	0.5762	0.5774	0.5767	0.5769	0.5768
E. Manufacturing							

HOEP	0.0193 (0.0034)*** [0.0162]	0.0179 (0.0034)*** [0.0151]	0.0181 (0.0034)*** [0.0153]	0.0165 (0.0035)*** [0.0139]	0.0156 (0.0035)*** [0.0132]	0.0186 (0.0034) [0.0157]	0.01489 (0.0035)*** [0.0126]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 & 2010 relative to other hours during the same years	0.533 (0.3435)	2.447 (0.975)**	0.70283 (0.4272)*	1.2653 (0.420)***	1.3970 (0.356)***	0.7044 (0.3260)**	1.3102 (0.309)***
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009, 2010	-0.5712 (0.6095)	-1.0595 (1.084)	0.428 (0.5596)	0.12645 (0.5217)*	0.0631 (0.437)	0.663 (0.459)	0.434 (0.381)
Sample mean of consumption by manufacturing	37.807						
Adjusted R Square	0.3247	0.3259	0.3255	0.3268	0.3280	0.3263	0.3298
F. Steel							
HOEP	0.0858 (0.0515) [0.0066]	0.14638 (0.0499)** [0.0113]	0.0723 (0.0556) [0.0056]	0.1177 (0.053)** [0.0091]	0.09777 (0.0543)* [0.0076]	0.0617 (0.0540) [0.0048]	0.0688 (0.055)* [0.0053]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 & 2010 relative to other hours during the same years	33.525 (6.627)***	7.4539 (17.99)	21.629 (7.687)**	16.159 (7.718)**	16.000 (6.335)**	20.223 (5.162)***	21.068 (5.41)***
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009, 2010	-83.362 (16.41)***	-155.86 (22.72)***	-39.643 (11.27)***	-67.661 (12.11)***	-48.883 (9.748)***	-6.505 (7.540)	-38.65 (7.872)***
Sample Mean of consumption by Steel	412.86						
Adjusted R Square	0.2617	0.2682	0.2540	0.2612	0.2579	0.2538	0.2568
Pulp and Paper							
HOEP	-0.2256 (0.0424)*** [-0.0262]	-0.2103 (0.0425)*** [-0.0244]	-0.213 (0.0439)*** [-0.0247]	-0.18568 (0.042)*** [-0.0216]	-0.18282 (0.0425)*** [-0.0212]	-0.229 (0.0443)*** [-0.0266]	-0.1817 (0.0425)*** [-0.0211]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 & 2010 relative to other hours during the same years	12.817 (4.352)***	6.9317 (12.14)	2.2543 (6.071)	0.9614 (5.624)	-1.1868 (4.814)	-1.4962 (4.301)	-3.1064 (4.080)

Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009, 2010	-43.447 (6.949)***	-60.025 (13.20)***	-38.324 (7.406)***	-44.838 (6.794)***	-36.943 (5.859)**	-13.334 (5.553)**	-30.752 (4.938)***
Sample Mean of Consumption of Pulp and Paper	274.65			239.81			
Adjusted R Square	0.5850	0.5846	0.5858	0.5882	0.5882	0.5832	0.5885
Other industries							
HOEP	0.1633 (0.0244)*** [0.0379]	0.1628 (0.0242)*** [0.0378]	0.1545 (0.0240)*** [0.0359]	0.14432 (0.0242)*** [0.0335]	0.1382 (0.0244)*** [0.0321]	0.1607 (0.0242)*** [0.0373]	0.1269 (0.0241)*** [0.0295]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 & 2010 relative to other hours during the same years	8.288 (2.606)***	2.038 (5.59)	11.290 (3.226)***	10.586 (3.083)***	11.013 (2.747)***	10.988 (2.543)***	14.041 (2.366)***
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009, 2010	-0.449 (4.465)	9.805 (6.020)*	-0.542 (4.443)	2.092 (3.956)	1.622 (3.408)	-0.658 (3.531)	0.8690 (2.931)
Sample Mean of consumption by Others				1592.3			
Adjusted R Square	0.2691	0.2677	0.2702	0.2709	0.2722	0.2709	0.2769

Notes: The results in the above table are based on OLS estimates with standard errors Newey West corrected for unknown heteroskedasticity and second order autocorrelation. ***, **, * denote statistical significance at the 1%, 5%, and 10% levels. Standard errors are in parentheses. Hourly temperature and relative humidity, day of week, month, and hour specific dummies were included in all regressions. The data are hourly for June, July, and August and consists of 8,832 observations.

Table 6: Difference in Difference estimates of the effects of Hi 5 consumption peaks based on hourly data – 2009, 2011, 2012

	Hi 5 Days	Top 1% of all hours	Top 1%-5% of all hours	Top 5% of all hours	Top 7% of all hours	Top 5%-10% of all hours	Top 10% of all hours
A. Total							
HOEP	-0.4363 (0.1496)*** [-0.0070]	-0.334 (0.1484)** [-0.0054]	-0.430 (0.162)** [-0.0069]	-0.3186 (0.1540)** [-0.0051]	-0.3476 (0.1558)** [-0.0056]	-0.483 (0.161)*** [-0.0078]	-0.3951 (0.1584)*** [-0.0064]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 relative to other hours during the same years	83.759 (15.60)***	120.34 (67.71)*	55.980 (21.87)**	65.741 (22.51)***	54.018 (17.93)***	20.289 (11.09)*	46.859 (14.76)***

Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009	-194.96 (29.33)***	-378.72 (72.22)***	-122.81 (26.78)***	-188.32 (28.12)***	-138.25 (22.76)***	2.839 (14.80)	-98.190 (18.29)***
Sample Mean of total consumption							
Adjusted R Square	0.2474	0.2503	0.2390	0.2496	0.2448	0.2352	0.2409
B. Industrial Gas and Equipment							
HOEP	-0.07024 (0.016)*** [-0.0300]	-0.7075 (0.0164)*** [-0.030]	-0.0697 (0.016)*** [-0.0298]	-0.0598 (0.0162)*** [-0.0255]	-0.0603 (0.016)*** [-0.026]	-0.0778 (0.016)*** [-0.033]	-0.0635 (0.0161)*** [-0.0271]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 relative to other hours during the same years	-5.638 (1.063)***	-2.282 (2.408)	-5.0312 1.433	-5.393 (1.334)***	-5.281 (1.277)***	-0.76081 1.354	-3.971 (1.183)***
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009	-5.267 (1.296)***	-7.716 (2.576)***	-3.003 (2.036)	-4.405 (1.769)**	-3.031 (1.598)*	-0.407 (1.644)	-2.497 (1.417)*
Adjusted R Square	0.3295	0.3208	0.3258	0.3309	0.3306	0.3177	0.3278
C. Chemicals							
HOEP	0.0192 (0.0306) [0.0013]	0.03219 (0.0313) [0.0022]	0.0223 0.031 [0.0015]	0.0379 (0.0325) [0.0026]	0.0350 (0.0324) [0.0024]	0.0127 (0.0305) [0.0020]	0.02898 (0.0323) [0.0020]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 relative to other hours during the same years	9.063 (4.179)**	7.822 (21.39)	-3.13 (7.418)	-1.764 (7.609)	-4.108 (5.694)	-6.8040 3.383	-5.196 (4.346)
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009	-21.554 (5.252)***	-36.732 (21.85)*	-4.3750 (7.740)	-12.311 (8.097)	-5.7811 (6.163)	10.443 (3.598)	-0.71443 (4.708)
Adjusted R Square	0.5221	0.5225	0.5204	0.5221	0.5214	0.5203	0.5207
Mining							
HOEP	-0.36000 (0.0587)*** [-0.0250]	-0.34417 (0.0599)*** [-0.0239]	-0.35613 (0.0597) [-0.0247]	-0.32974 (0.0589)*** [-0.0229]	-0.3385 (0.06)*** [-0.1279]	-0.37555 (0.060) [-0.0261]	-0.3454 (0.0604)*** [-0.0240]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10%	7.514 (5.157)	8.6704 (15.23)	-7.3708 (6.506)	-5.796 (6.478)	-7.617 (5.171)	-15.911 (4.902)***	-12.910 (4.672)***

hours on consumption in 2009 relative to other hours during the same years							
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009	-30.903 (8.532)***	-52.017 (18.09)***	-7.34 (8.465)	-18.445 (8.263)**	-8.071 (6.797)	23.033 (6.340)***	3.024 (5.822)
Adjusted R Square	0.6085	0.6088	0.6076	0.6092	0.6081	0.6076	0.6079
Manufacturing							
HOEP	0.024897 (0.0044)*** [0.0175]	0.0235 (0.0045)*** [0.0165]	0.0235 (0.004)*** [0.015]	0.0220 (0.0045)*** [0.0155]	0.0215 (0.005)*** [0.0151]	0.0241 (0.004)*** [0.017]	0.0210 (0.0044)*** [0.0148]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 relative to other hours during the same years	-0.4401 (0.3804)	1.1351 (1.392)	0.603 (0.553)	0.8673 (0.5373)	1.1350 (0.4655)**	-0.1105 (0.4716)	0.6146 (0.425)
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009	0.2696 (0.6247)	0.0891 (1.484)	0.556 (0.672)	0.4956 (0.6344)	0.2882 (0.5445)	1.453 (0.583)**	1.065 (0.489)**
Adjusted R Square	0.2283	0.2287	0.2295	0.2303	0.2315	0.2304	0.2333
Steel							
HOEP	-0.0016 (0.0657) [-0.0001]	0.0664 (0.0633) [0.0045]	-0.01008 (0.0703) [-0.0007]	0.0391 (0.0677) [0.0026]	0.0232 (0.0678) [0.0016]	-0.0166 (0.0691) [-0.0011]	-0.00083 (0.0686) [-0.0001]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 relative to other hours during the same years	44.714 (7.874)***	54.194 (23.83)**	37.402 10.10	40.052 (10.11)****	35.709 (8.470)***	26.732 (6.847)***	38.129 (7.211)***
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009	-88.389 (16.34)***	-194.19 (27.47)***	-51.992 (13.07)***	-87.461 (13.66)***	-65.371 (11.15)***	-12.940 (8.788)	-53.446 (9.080)***
Adjusted R Square	0.3141	0.3215	0.3051	0.3141	0.3105	0.3042	0.3095
Pulp and Paper							
HOEP	-0.17448 (0.0499)*** [-0.0180]	-0.16530 (0.0494)*** [-0.0170]	-0.16255 (0.052) [-0.0167]	-0.13276 (0.0498)*** [-0.0137]	-0.13221 (0.05)*** [-0.0136]	-0.184 (0.052)*** [-0.019]	-0.1330 (0.0499)*** [-0.0137]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10%	11.786 (4.976)**	38.253 (12.16)***	18.567 (6.879)**	21.378 (6.304)***	19.687 (5.776)***	8.314 (6.283)	14.056 (5.538)***

hours on consumption in 2009 relative to other hours during the same years							
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009	-43.601 (7.251)***	-89.905 (13.21)***	-53.988 (8.069)	-64.824 (7.360)***	-56.164 (6.667)***	-20.229 (7.231)**	-45.676 (6.143)***
Adjusted R Square	0.5948	0.5952	0.5966	0.6001	0.6000	0.5927	0.5997
Other industries							
HOEP	0.12593 (0.0287)*** [0.0250]	0.12403 (0.0288)*** [0.0246]	0.1226 (0.028)*** [0.0243]	0.10461 (0.029)*** [0.0208]	0.1037 (0.029)*** [0.0206]	0.1340 (0.028)*** [0.0266]	0.0976 (0.0284)*** [0.0194]
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2009 relative to other hours during the same years	16.759 (3.045)***	12.548 (8.645)	14.940 (4.829)***	16.397 (4.519)***	14.493 (4.103)***	8.829 (3.922)**	16.136 (3.468)***
Effect of Hi-5, Top 1%, Top 5%, Top 7%, or Top 10% hours on consumption in 2011, 2012 relative to similar hours in 2009	-5.514 (4.634)	1.7533 (8.964)**	-2.66 (5.763)	-1.3709 (5.222)	-0.1217 (4.645)	0.1487 (4.655)***	0.0536 (3.928)
Adjusted R Square	0.2940	0.2892	0.2920	0.2942	0.2950	0.2910	0.2995

Notes: The results in the above table are based on OLS estimates with standard errors Newey West corrected for unknown heteroskedasticity and second order autocorrelation. ***, **, * denote statistical significance at the 1%, 5%, and 10% levels. Standard errors are in parentheses. Hourly temperature and relative humidity, day of week, month, and hour specific dummies were included in all regressions. The data are hourly for June, July, and August and consists of 8,832 observations.

Table 7. Estimates of the effects of Hi 5 peak and off peak hours and non-Hi 5 day off peak hours on consumption based on hourly data

	2009, 2010, 2011, and 2012 (1)	**2011 and 2012** (2)	**2012** (3)	**July and August 2012** (4)	**2009 and 2010** (5)	**2009** (6)
A. Consumption						
Peak Hours Consumption during High 5 Day	-49.049 (22.53)**	-136.62 (26.96)***	-172.35 (46.94)***	-212.71 (61.96)***	20.153 (31.78)	123.57 (41.30)***
Off Peak Hours Consumption During High 5 Day	161.26 (13.24)***	147.19 (18.43)***	159.85 (28.10)***	127.14 (39.56)***	153.65 (17.06)***	152.30 (15.94)***
Off peak Hours Consumption During	110.13 (5.474)***	122.26 (6.540)***	121.34 (6.301)***	114.41 (7.991)***	96.226 (8.369)***	60.082 (12.80)***

Non-High 5 Days						
Obs	8,812	4,416	2,208	1,488	4,416	2,208
Adjusted R Square	0.1314	0.2213	0.3384	0.3392	0.1034	0.1355
B. Price						
Peak Hours Consumption during High 5 Day	11.479 (4.024)***	10.992 (4.374)**	21.694 (7.967)**	23.732 (14.52)	10.951 (6.746)	20.155 (11.33)**
Off Peak Hours Consumption During High 5 Day	-8.619 (1.602)***	-5.349 (1.969)***	-4.9252 (3.378)	-4.1086 (7.250)	-11.203 (2.431)***	-8.322 (1.905)***
Off peak Hours Consumption During Non-High 5 Days	-3.555 (0.5538)***	-2.6395 (0.756)***	-2.489 (0.928)**	-0.2012 (1.059)***	-2.4306 (0.7161)***	-4.9335 (0.8142)***
Obs	8,812	4,416	2,208	1,448	4,416	2,208
Adjusted R Square	0.2665	0.2459	0.3392	0.3224	0.3366	0.3138

Notes: The results in the above table are based on OLS estimates with standard errors Newey West corrected for unknown heteroskedasticity and second order autocorrelation. ***, **, * denote statistical significance at the 1%, 5%, and 10% levels. Standard errors are in parentheses. Hourly temperature and relative humidity, day of week, month, and hour specific dummies were included in all regressions. The data are hourly for June, July, and August. Estimates with respect to electricity consumption (top panel) also include controls for the HOEP and month Global Adjustment.

Table 8. Estimates of differences in post policy (2011, 2012) consumption with respect to Hi 5 off peak hours and non Hi-5 day peak and off peak hours - based on hourly data

	Hi 5 day off peak hours – 2009, 2010, 2011, and 2012	**Non-Hi 5 day peak hours – 2009, 2010, 2011, and 2012**	**Non-Hi 5 day off peak hours- 2009, 2010, 2011, and 2012**	**Hi 5 day off peak hours – 2009, 2011, and 2012**	**Non-Hi 5 day peak hours – 2009, 2011, and 2012**	**Non-Hi 5 day off peak hours- 2009, 2011, and 2012**	**Hi 5 day off peak hours – 2010, 2011, and 2012**	**Non-Hi 5 day peak hours – 2010, 2011, and 2012**	**Non-Hi 5 day off peak hours- 2010, 2011, and 2012**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Post Policy Consumption relative to 2009, 2010	59.080 (25.75)**	14.317 (7.119)**	54.113 (7.859)***						

Post Policy Consumption relative to 2009				238.99 (47.54)***	77.075 (8.828)***	126.43 (10.58)***			
Post Policy Consumption relative to 2010							-41.72 (18.91)**	-55.642 (8.692)***	-26.435 (7.775)***
Obs	187	4,563	3,861	143	3,419	2,893	143	3,419	2,893
Adjusted R Square	0.1223	0.0455	0.0097	0.4010	0.1236	0.2140	0.2774	0.0651	0.0646

Notes: The results in the above table are based on OLS estimates with standard errors Newey West corrected for unknown heteroskedasticity and second order autocorrelation. ***, **, * denote statistical significance at the 1%, 5%, and 10% levels. Standard errors are in parentheses. Hourly temperature and relative humidity, the HOEP, day of week (columns 2, 3, 5, 6, 8, and 9), and month specific dummies were included in all regressions. The data are hourly for June, July, and August.

Table 9: OLS estimates of the effects of current and lagged HOEP on electricity consumption (by industrial sector).

	2009	**2010**	**2011**	**2012**
Total				
Current HOEP	1.336 (1.151)	-2.239 (0.82)*** [-0.056]	-2.376 (0.713)*** [-0.047]	-1.636 (0.988)* [-0.023]
Lagged HOEP	2.561 (0.613)*** [0.0344]	1.374 (0.493)*** [0.0344]	1.0348 (0.515)** [0.0204]	2.684 (0.452)*** [0.0380]
Adjusted R Square	0.0827	0.2711	0.2376	0.3425
Industrial Gas and Equipment				
Current HOEP	-0.206 (0.0701) [-0.0846]	-0.058 (0.066) [-0.0301]	-0.0182 (0.0805) [-0.009]	-0.0425 (0.0732) [-0.0146]
Lagged HOEP	-0.093 (0.0518)* [-0.0380]	-0.056 (0.058) [-0.0260]	0.0408 (0.0913) [0.0210]	0.0272 (0.053) [0.0093]
Adjusted R Square	0.3474	0.2202	0.0900	0.1556
Chemicals				

Current HOEP	0.679 (0.288)**	-0.0732 (0.185) [-0.0075]	-0.35051 (0.0975)*** [-0.0305]	-0.283 (0.077)*** [-0.0198]
Lagged HOEP	0.428 (0.135)***	-0.222 (0.132) [-0.023]	-0.0645 (0.0794) [-0.0056]	-0.131 (0.047)** [-0.0091]
Adjusted R Square	0.0727	0.5640	0.1126	0.1771
Mining				
Current HOEP	-0.0779 (0.2588) [-0.005]	-0.904 (0.349)*** [-0.114]	-1.285 (0.352)*** [-0.106]	-0.316 (0.197) [-0.017]
Lagged HOEP	0.02611 (0.2055) [0.0018]	-0.578 (0.269)** [-0.073]	-0.154 (0.295) [-0.0127]	0.643 (0.143)*** [0.035]
Adjusted R Square	0.0462	0.1209	0.1652	0.1182
Manufacturing				
Current HOEP	0.0811 (0.0300)** [0.0497]	0.0308 (0.018) [0.0400]	0.0385 (0.016)** [0.0315]	0.0634 (0.0153)*** [0.0402]
Lagged HOEP	-0.00446 (0.0147) [-0.0027]	-0.0462 (0.0185)*** [-0.0600]	0.0096 (0.016) [0.0079]	-0.0055 (0.0155) [-0.0034]
Adjusted R Square	0.1101	0.3464	0.3658	0.3265
Steel				
Current HOEP	0.203 (0.572)	-0.0556 (0.346) [-0.006]	-0.044 (0.237) [-0.0034]	-0.3016 (0.5472) [-0.0173]
Lagged HOEP	-0.0898 (0.3977)	0.821 0.2581 [0.0839]	0.2610 (0.202) [0.0202]	0.863 (0.197) [0.0492]**
Adjusted R Square	0.0826	0.2561	0.3544	0.4492
Pulp and Paper				
Current HOEP	-0.1848 (0.597) [-0.0126]	-1.455 (0.405)** [-0.216]	-1.061 (0.3691)*** [-0.1495]	-1.235 (0.3275)*** [-0.1294]
Lagged HOEP	2.977 (0.457)*** [0.2025]	1.9361 (0.318)*** [0.2878]	1.1684 (0.2587)*** [0.164]	1.523 (0.309)*** [0.1584]

Adjusted R Square	0.2692	0.5109	0.3055	0.4724

Notes: The results in the above table are based on OLS estimates with standard errors Newey West corrected for unknown heteroskedasticity and second order autocorrelation. ***, **, * denote statistical significance at the 1%, 5%, and 10% levels. Standard errors are in parentheses and associated elasticities are in square brackets. Daily mean temperature and relative humidity covariates and day of week dummies and month were included in all regressions. Peak hours are from 7:00am to 6:59pm of each day. Off peak hours are from 7 pm to 6:59 am the next day. Therefore, each day has two observations. The data are daily for June, July, and August.