ETS TARIFF

EB-2012-0031

Hearing Compendium

Navigant (Opening Statement Outline)
APPrO (Cross-Examination Materials)

February 2013

INDEX

Tab 1

Opening Statement of Cliff Hamal

- Relationship of CRA modeling to my conclusion
- Benefits will largely pass to consumers
  - Producer surplus
  - Incremental IC revenues equate to IC rents
  - Incremental IC rents are expected to flow to consumers
- Relative importance of CRA scenarios
- Shortcomings in the CRA modeling and implications
  - Critical market prices are not realistic
  - Surplus baseload generation changes are missed
  - Trading behavior assumptions are simplistic

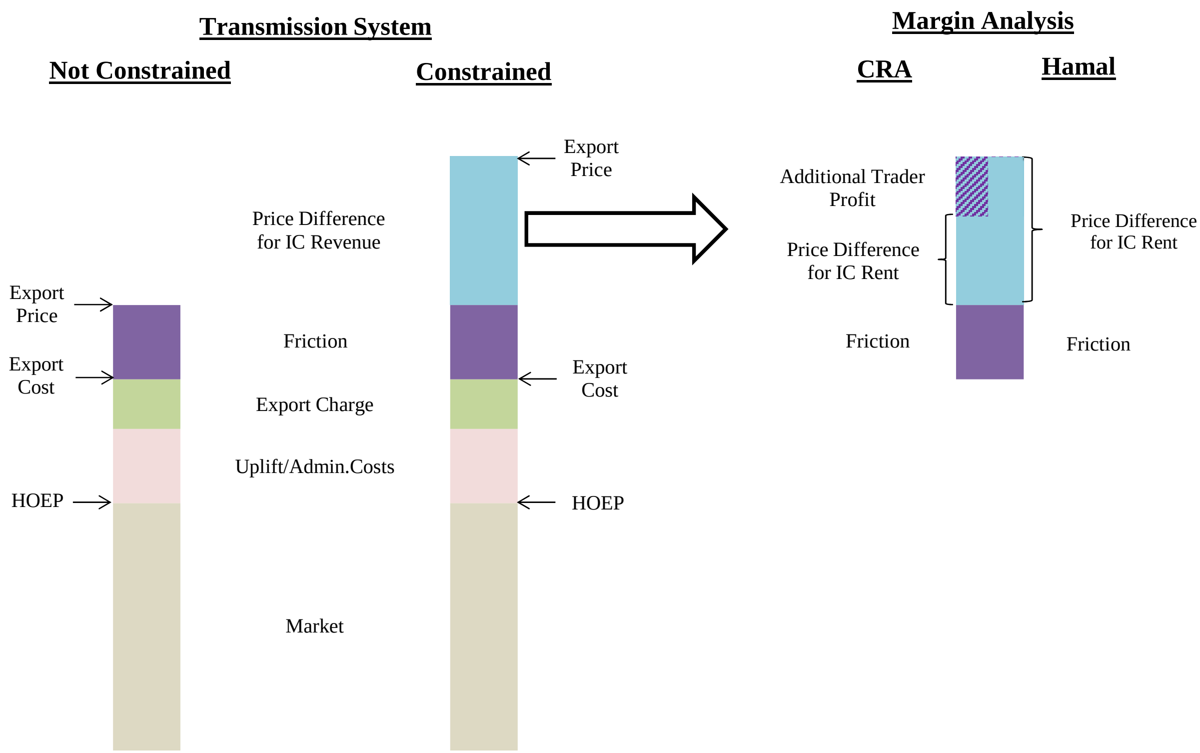
Tab 2

Summary of Surplus Changes
($2011/MWh)

Surplus Component	2013 No Tariff	2013 EANC	2015 No Tariff	2015 EANC	2017 No Tariff	2017 EANC
CRA Analysis						
Consumer Surplus	-$16.1	$24.1	-$32.6	$60.1	-$18.9	$23.5
Intertie Congestion Revenue	$24.0	-$17.7	$10.1	-$7.9	$3.9	-$5.8
Producer Surplus	$9.6	-$29.2	$22.2	-$47.9	$10.5	-$18.6
Subtotals						
CS + ICR	$7.9	$6.4	-$22.5	$52.2	-$15.0	$17.7
CS + ICR + PS	$17.5	-$22.8	-$0.3	$4.3	-$4.5	-$0.9

Joint Witness Statement
3. Joint Explanation of IC Revenue Calculated in the CRA Model

CRA Analysis



Summary of Surplus Changes - Assuming No Ontario WCI Participation ($2011/MWh)

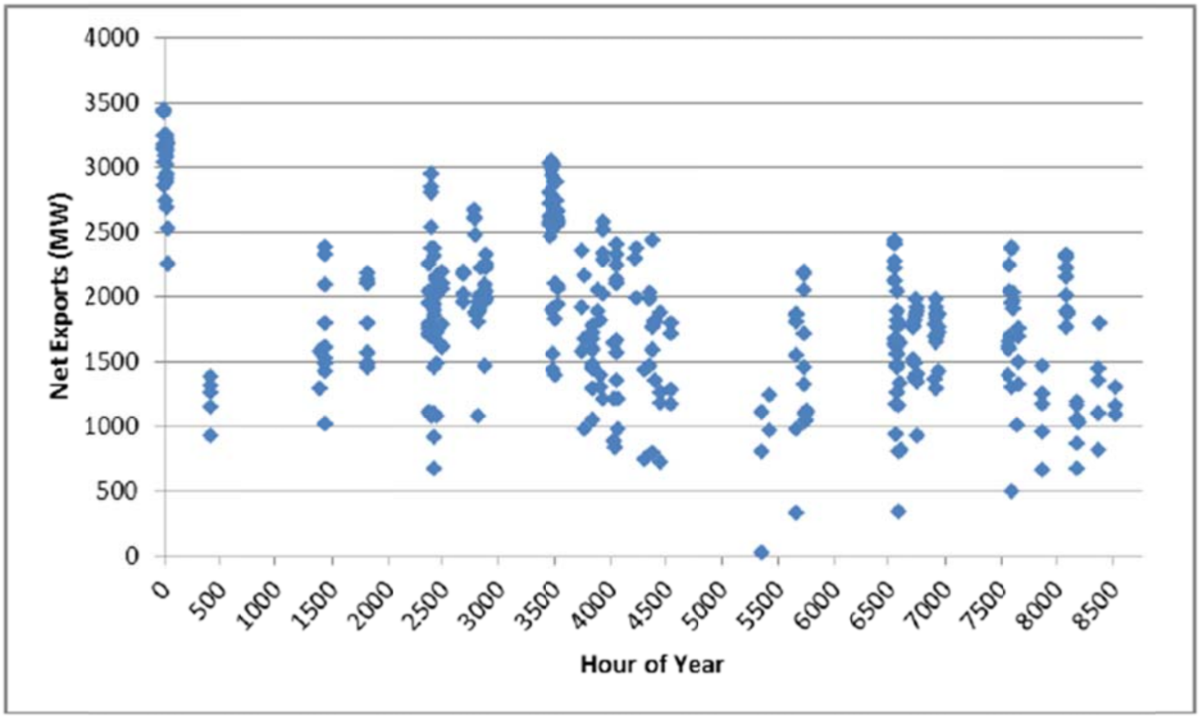
	2013		2015		2017	
Surplus Component	**No Tariff**	**EANC**	**No Tariff**	**EANC**	**No Tariff**	**EANC**
CRA Analysis						
Consumer Surplus	-$16.1	$24.1	-$31.2	$57.1	-$18.5	$24.9
Intertie Congestion Revenue	$24.0	-$17.7	$18.6	-$13.0	$16.5	-$21.8
Producer Surplus	$9.6	-$29.2	$16.6	-$44.8	$8.0	-$13.6
Subtotals						
CS + ICR	$7.9	$6.4	-$12.6	$44.1	-$2.0	$3.1
CS + ICR + PS	$17.5	-$22.8	$4.0	-$0.7	$6.0	-$10.5

Actual Real-Time Prices
July 2011 through June 2012
Based on Tranches Consistent with CRA Report

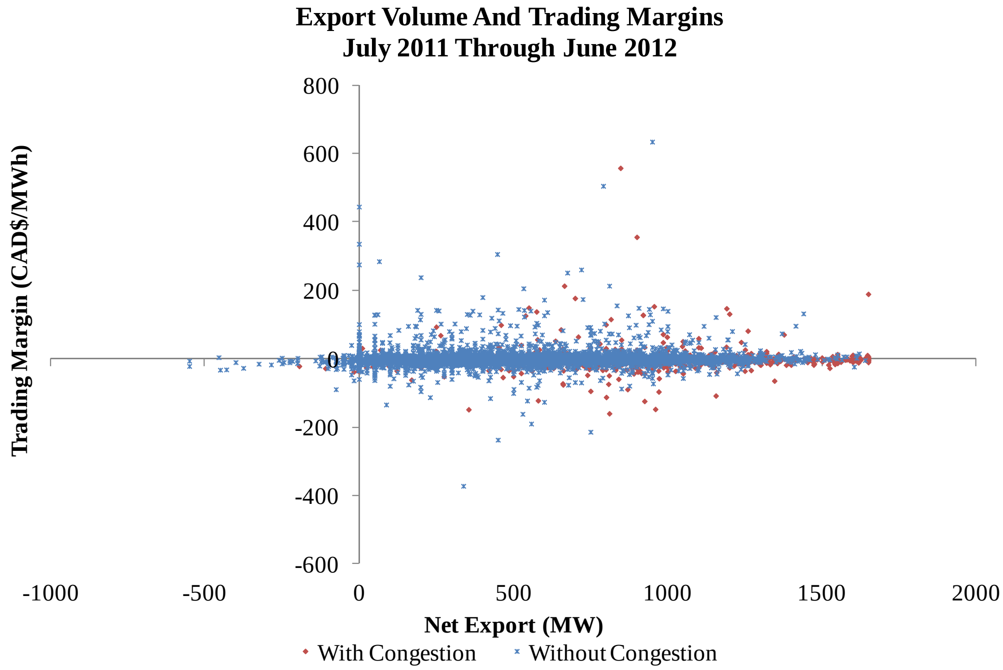
	Count of Months with Prices:			
Market	**<$30/MWh**	**<$20/MWh**	**<$10/MWh**	**<$0/MWh**
Ontario				
HOEP	12	11	7	4
PJM				
PJM - Western Hub	12	11	9	6
MISO				
MISO - Ontario Interface	12	11	3	2
New York				
NYISO - Ontario Interface	12	10	2	1
ISONE				
ISONE - Internal Hub	11	5	0	0

Hamal Evidence
Figure 6

Figure 1: Ontario Net Exports During 2011 SBG Maneuvers

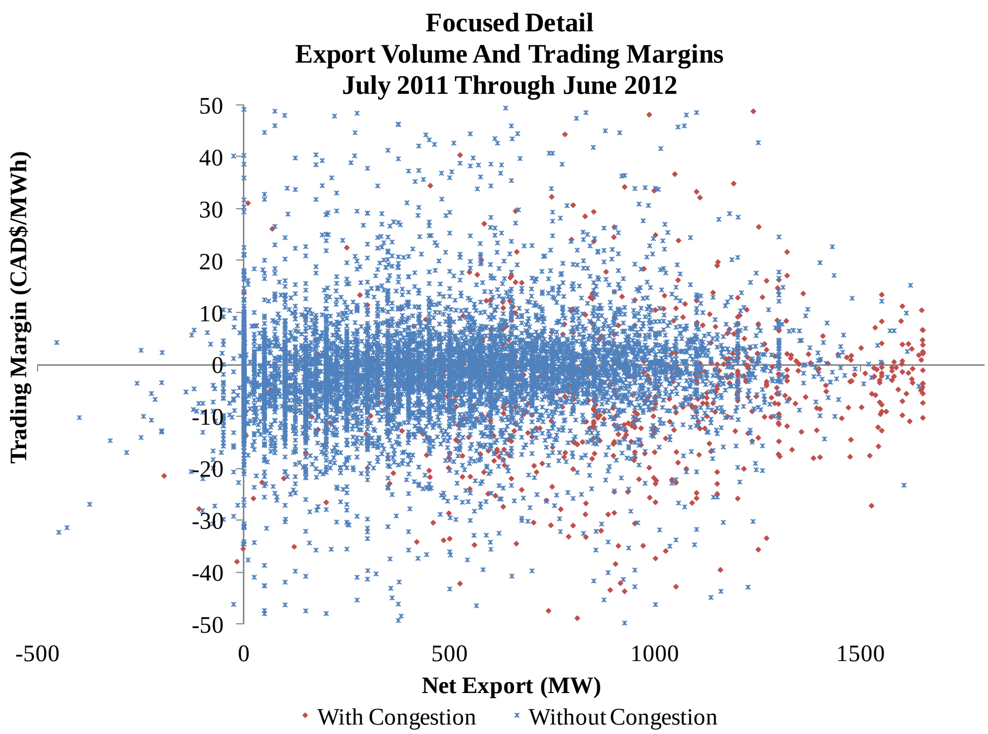


Hamal Evidence
Figure 4a

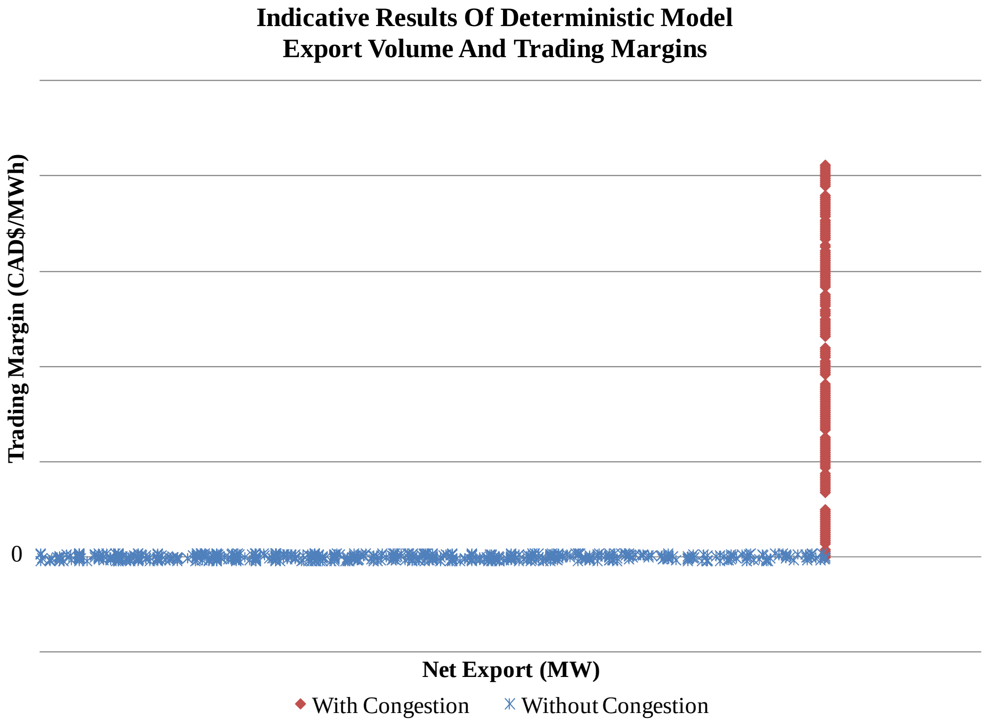


Note: Trading margin is the real-time price difference between NYISO and IESO markets less outbound fees. Outbound fees include hourly, daily, and monthly uplift charges, IESO fees, and Hydro One fees.

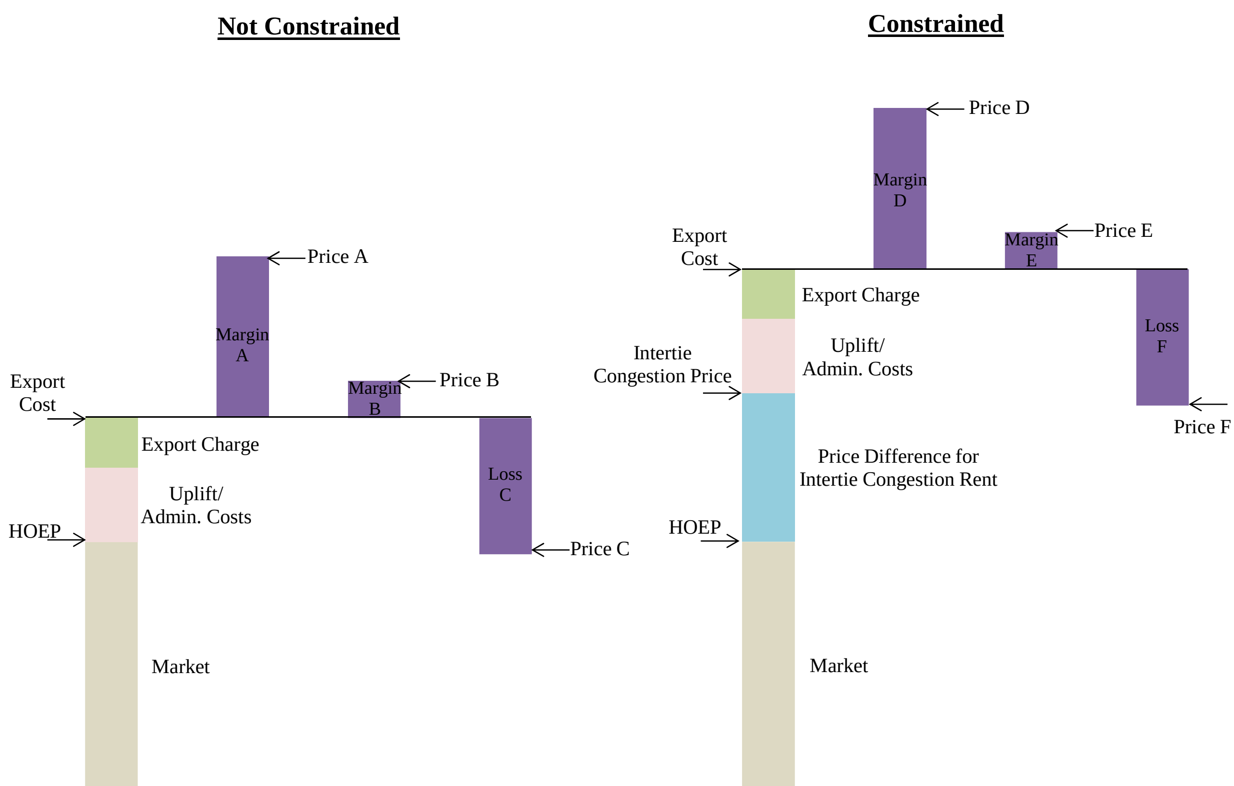
Hamal Evidence
Figure 4b



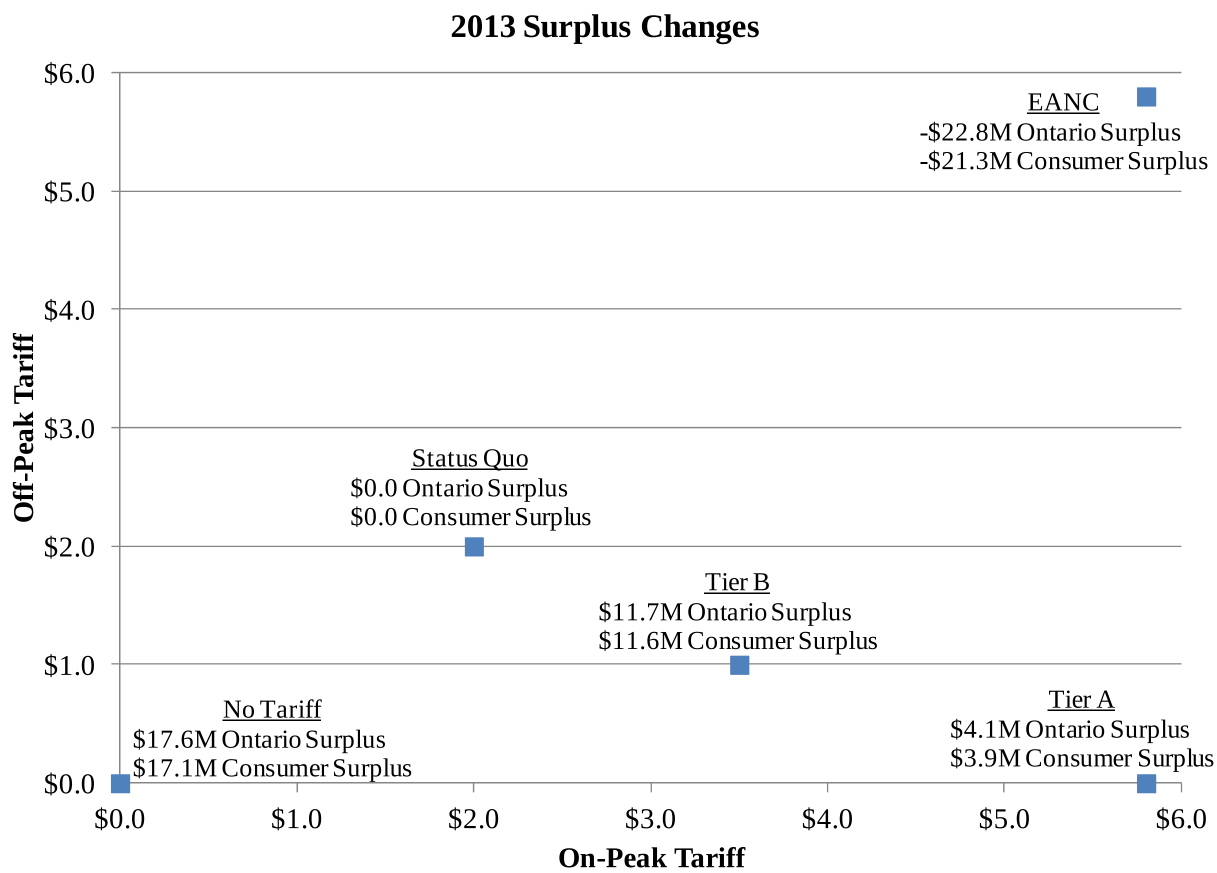
Hamal Evidence
Figure 5



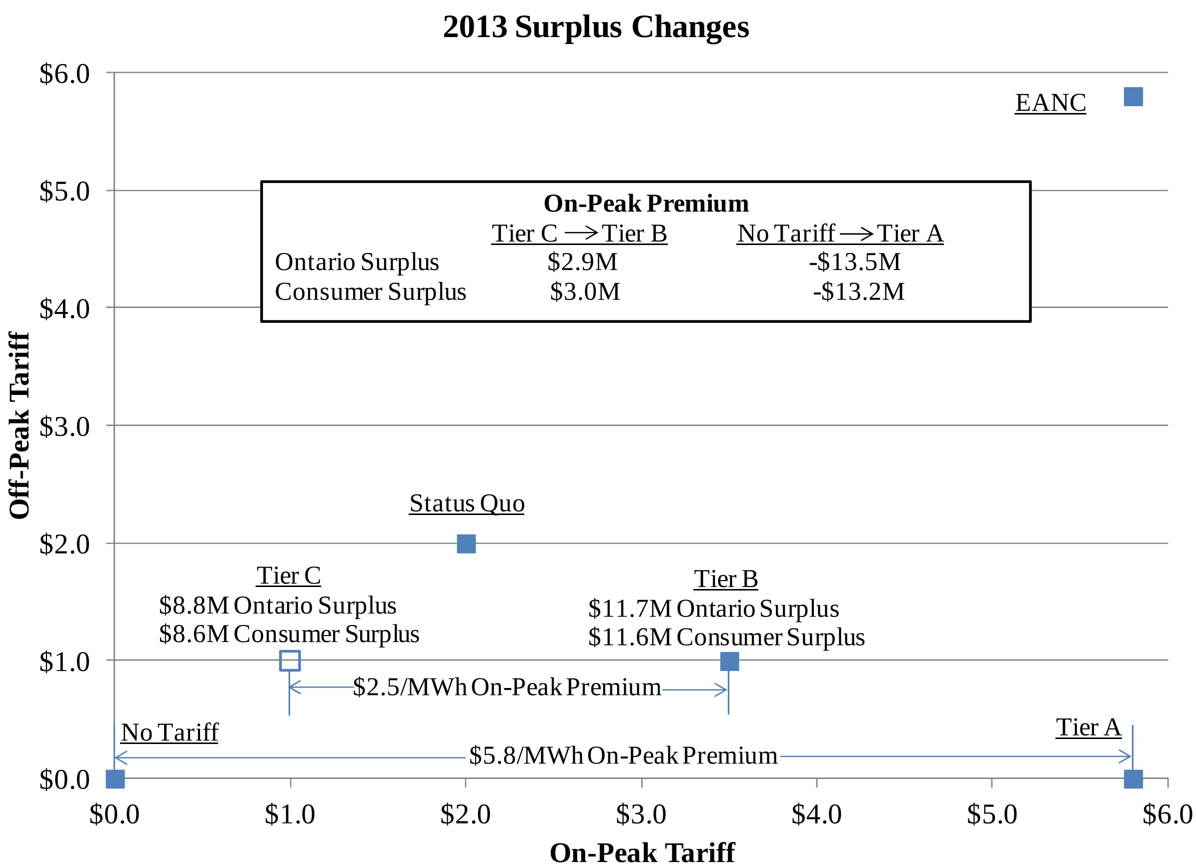
Actual Market



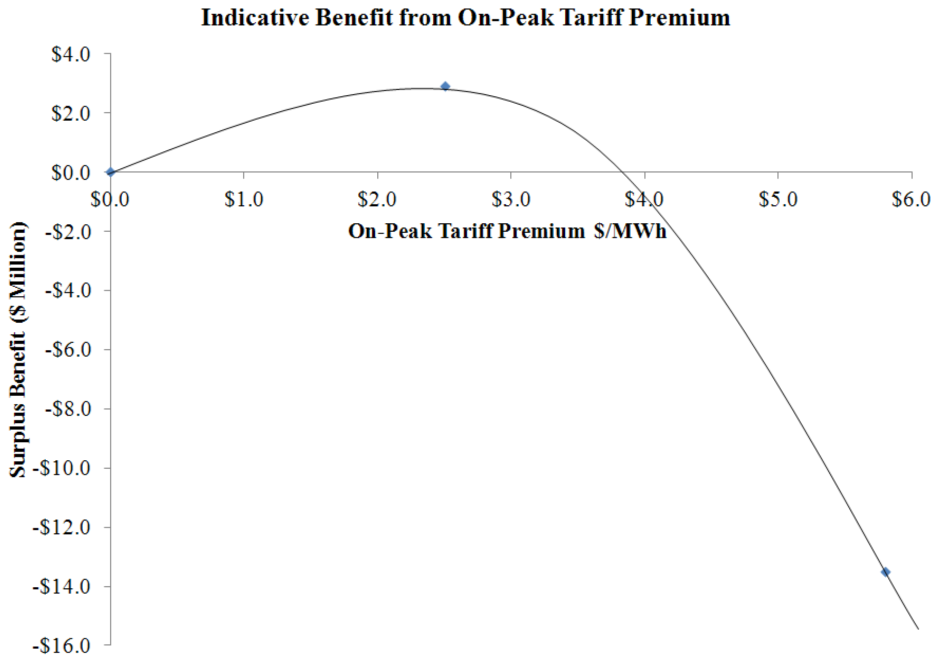
Hamal Evidence
Figure 7



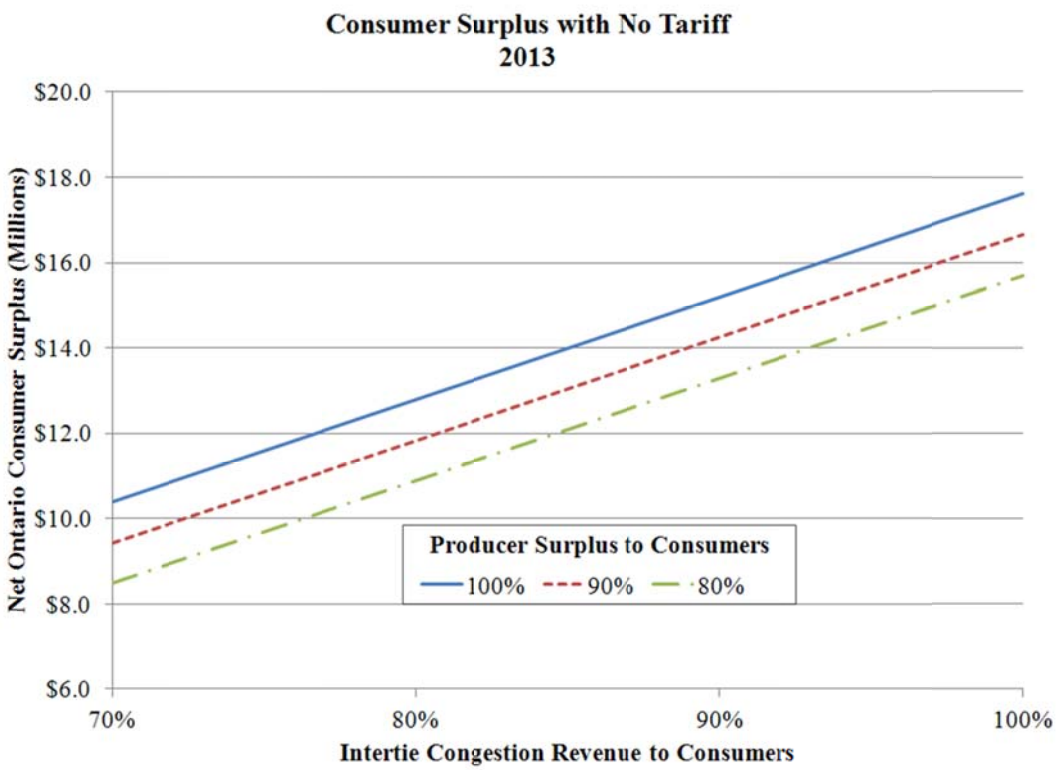
Hamal Evidence
Figure 8



Hamal Evidence
Figure 9



Hamal Evidence
Figure 1



Hamal Evidence
Figure 2

Summary of Surplus Changes
($2011/MWh)

	2013		2015		2017	
Surplus Component	**No Tariff**	**EANC**	**No Tariff**	**EANC**	**No Tariff**	**EANC**
CRA Analysis						
Consumer Surplus	-$16.1	$24.1	-$32.6	$60.1	-$18.9	$23.5
Intertie Congestion Revenue	$24.0	-$17.7	$10.1	-$7.9	$3.9	-$5.8
Producer Surplus	$9.6	-$29.2	$22.2	-$47.9	$10.5	-$18.6
Total						
Ontario Surplus	$17.6	-$22.8	-$0.3	$4.2	-$4.5	-$1.0
Consumer Surplus	$17.1	-$21.3	-$1.4	$6.6	-$5.0	-$0.1

Hamal Evidence
Figure 3

Summary of Surplus Changes Assuming No WCI Participation
($2011/MWh)

	2013		2015		2017	
Surplus Component	**No Tariff**	**EANC**	**No Tariff**	**EANC**	**No Tariff**	**EANC**
Ontario Surplus	$17.6	-$22.8	$4.0	-$0.6	$6.1	-$10.5
Consumer Surplus	$17.1	-$21.3	$3.2	$1.6	$5.7	-$9.8

Tab 3

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto ON M4P 1E4
Telephone: (416) 481-1967
Facsimile: (416) 440-7656
Toll Free : 1-888-632-6273

Rosemarie T. Leclair
Chair & CEO

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4
Téléphone: (416) 481-1967
Télécopieur: (416) 440-7656
Numéro sans frais : 1-888-632-6273

Rosemarie T. Leclair
Présidente et Directrice Générale

Ontario

January 14, 2013

BY E-MAIL AND WEB POSTING

Mr. Paul Murphy
President and Chief Executive Officer
Independent Electricity System Operator
655 Bay Street, Suite 410
Toronto, ON M5G 2K4

Dear Mr. Murphy:

RE: Market Surveillance Panel Monitoring Report

The Market Surveillance Panel ("MSP") has delivered to me its *Monitoring Report on the IESO-Administered Electricity Markets* for the period from November 2011 – April 2012 (the "MSP Report"). I attach a copy of the MSP Report for your reference.

The MSP Report sets out five recommendations, all of which pertain to the transmission rights ("TR") market and are directed to the Independent Electricity System Operator (the "IESO"). The five recommendations, which the MSP believes will enhance market efficiency and help to reduce uplift and other payments, are as follows (listed in the order in which they appear in the MSP Report):

Recommendation related to efficiency

- The IESO should reassess the design of the Ontario TR market to determine whether it is achieving its intended purpose.

Recommendations related to uplift and other payments

- The IESO should limit the number of TRs auctioned to a level where the congestion rent collected is approximately sufficient to cover the payouts to TR holders.
- (A) The IESO Board of Directors should authorize the disbursement of the portion of the TR 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 TR Clearing Account balances in excess of the Reserve Threshold after each year end.

- The IESO policy of selling only long-term TRs on single-circuit interfaces should be replaced by a policy of reserving a significant portion of the available TRs for sale at short-term TR auctions.
- 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 TR market.

I would appreciate if you would advise me in writing within 30 days of: a) the steps that the IESO plans to take in response to the above recommendations and the timelines for completion of those steps; and b) whether, in the IESO's view, any actions or market rule amendments, in addition to those reflected in the MSP's recommendations, should be taken or initiated.

I would also appreciate if you would include in your response an update on the status of actions taken by the IESO further to the recommendations set out in the MSP's previous monitoring report, relative to the IESO's responses that are set out in Table 4-1 of the MSP Report.

Please do not hesitate to contact me should you have any questions or wish to discuss the above.

Yours truly,

Rosemarie Leclair
Chair, Ontario Energy Board

cc Bill Rupert, Acting Chair, Market Surveillance Panel

ieso
Power to Ontario.
On Demand.

Independent Electricity
System Operator
655 Bay Street
Suite 410, PO Box 1
Toronto, Ontario M5G 2K4
t 416 506 2800

www.ieso.ca

February 12, 2013

Ms. Rosemarie T. Leclair
Chair & CEO
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Leclair:

Re: Market Surveillance Panel Monitoring Report

Your letter of January 14, 2013, requests that I advise you of: a) the steps that the IESO plans to take in response to the recommendations made in the Market Surveillance Panel (MSP) *Monitoring Report on the IESO-Administered Electricity Markets* for the period from November 2011 – April 2012, and the estimated timelines for completion of those steps; and b) whether, in the IESO's view, any actions or market rule amendments, in addition to those reflected in the underlying the MSP's recommendations, should be taken or initiated. In addition, your letter requests an update on the status of actions taken by the IESO in response to the recommendations set out in the previous MSP monitoring report.

The IESO has been requested to address five recommendations in the January 2013 Report. Four of the recommendations, numbered by the MSP as 3-1, 3-2, 3-3, 3-4, pertain to the transmission rights market. Recommendation 3-5 is related to the interaction of the transmission rights market and day-ahead intertie offer guarantee. A comprehensive listing of the status of recommendations from the current and previous report is appended. The status of active recommendations from all prior MSP reports is also regularly published on our website, and can be found on the IESO's market monitoring page at: http://www.ieso.ca/imoweb/marketMonitoring/monitoring.asp. Closed recommendations will appear in the status report until the next update.

The most recent MSP recommendations, and recommendations from the previous report, are discussed below.

Transmission Rights

Recommendation 3-1, MSP Monitoring Report for November 2011 – April 2012
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, MSP Monitoring Report for November 2011 – April 2012
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 review will get underway immediately as the first stage of the comprehensive review (refer to recommendation 3-1). The findings at 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 this summer.

Recommendation 3-3, MSP Monitoring Report for November 2011 – April 2012
(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 later this week, being its first regular meeting since the MSP Report was issued. Following that meeting I will advise you of any decisions taken in this regard. Consideration of annual disbursements, as noted in Recommendation 3-3(B) will be part of the comprehensive review.

Recommendation 3-4, MSP Monitoring Report for November 2011 – April 2012
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 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 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, MSP Monitoring Report for November 2011 – April 2012*
> *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.

Previous Report Recommendations

> *Recommendation 3-4, MSP Monitoring Report for May 2011 – October 2011*
> *The Panel recommends that the IESO improve its internal controls and external processes to ensure that all information about outages and other relevant contingencies is taken into account when establishing the level of Transmission Rights to be auctioned.*

As stated in response to the previous report, the IESO agrees with this recommendation and has implemented new processes with the neighbouring jurisdictions to improve communication of outage plans, allowing this information to be considered in the sales of transmission rights. This recommendation has been completed and closed by the IESO.

> *Recommendation 3-5, MSP Monitoring Report for May 2011 – October 2011*
> *The IESO should ensure that, when a trader which owns Transmission Rights has failed its intertie transactions (at the same interface in the same direction), either the Transmission Right payout should not be paid or the Congestion Rent should be charged for the quantity of the failed transactions.*

The IESO agrees with this recommendation. As stated previously, the IESO has market rules in place to allow for the recovery of transmission rights payouts when the trader fails its intertie transactions, and intends to adjust settlement amounts paid or payable to traders in situations where the trader has failed to schedule the transaction with the appropriate scheduling entity other than for bona fide and legitimate reasons. This recommendation has been completed and closed by the IESO.

Electricity Market Forum

> *Recommendation 4-1, MSP Report for May 2011 – October 2011*
> *The Panel recommends that the IESO proceed with development work on those recommendations of the Electricity Market Forum that are directed at improving market efficiency, including the consideration of options to replace the two-schedule structure of the current market design.*

The IESO agrees with this recommendation. The IESO has initiated work based on the Electricity Market Forum's recommendations aimed at improving market efficiency, including reviews of HOEP, Global Adjustment (GA), the two-schedule system and intertie trading. Requests for Proposals (RFP's) related to the HOEP and GA recommendations were awarded in September 2012. Stakeholder engagement initiatives for reach review are underway (SE-105 (HOEP) and SE-106 (GA)). Reports for both reviews are expected to be published in April 2013. Further work may need to be initiated based on the recommendations from each report. Work on the two-schedule structure will be influenced by the results of the HOEP effort and it is anticipated that an RFP for this work will be issued by the end of Q1 2013. The current expectation is that the final report on the two-schedule structure will be completed by Q2 2014. The IESO has also begun work on the recommendations related to improving trading processes.

Regional Reserve Sharing

> *Recommendation 3-1, MSP Monitoring Report for May 2011 – October 2011*
> *The Panel recommends that the IESO continue to pursue the introduction by the Northeast Power Coordinating Council of a revised Regional Reserve Sharing Program and the negotiation of any necessary implementing agreements with neighbouring ISOs as expeditiously as possible.*

The IESO agrees with this recommendation and is continuing to advocate, within the relevant NPCC processes, for the reintroduction of regional reserve sharing.

Generation Cost Guarantees

> *Recommendation 3-2, MSP Monitoring Report for May 2011 – October 2011*
> *The Panel recommends that the IESO implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping-down generators.*

The IESO has initiated internal work in preparation for a review of the real-time and day-ahead guarantee programs. Ramping down CMSC will be considered in the context of this broader review to ensure that generators are compensated for only legitimate costs incurred during ramp down. Stakeholder engagement is currently anticipated to commence in Q2 2013, with findings and recommendations targeted for Q4 2013. The market rules process will flow from those findings and recommendations.

Please do not hesitate to contact me should you have any additional questions on these matters.

Yours truly,

Paul Murphy
President & CEO

c: Bill Rupert, Acting Chair, Market Surveillance Panel

Attach.

IESO Response Matrix
MSP Recommendations
May 2011- April 2012

MSP Report for the period from November 2011 to April 2012 (released January 2013)
Recommendation 3-1 *The IESO should reassess the design of the Ontario transmission rights market to determine whether it is achieving its intended purpose.* IESO Response 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.* IESO Response The IESO agrees that this recommendation warrants further review. This review will get underway immediately as the first stage of the comprehensive review (refer to recommendation 3-1). The findings at 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 this summer.
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.* IESO Response 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. 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.*

IESO Response

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 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 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.

IESO Response

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.

MSP Report for the period from May 2011 to October 2011 (released April 2012)
Recommendation 3-1 *The Panel recommends that the IESO continue to pursue the introduction by the Northeast Power Coordinating Council of a revised Regional Reserve Sharing Program and the negotiation of any necessary implementing agreements with neighbouring ISOs as expeditiously as possible.* IESO Response The IESO agrees with this recommendation and is pursuing this within the requirements of NPCC's Regional Reliability Reference Directory #6. Directory #6 contains NPCC's set of requirements regarding participation in Reserve Sharing Groups (RSG). These requirements outline who can participate in an RSG, the obligations of the RSG once formed (for example each RSG will have an RSG Agreement), and the Reserve Sharing Implementation requirements within the RSG Agreement.
Recommendation 3-2 *The Panel recommends that the IESO implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping-down generators.* IESO Response The IESO has initiated internal work in preparation for a review of the real-time and day-ahead guarantee programs. Ramping down CMSC will be considered in the context of this broader review to ensure that generators are compensated for only legitimate costs incurred during ramp down. Stakeholder engagement is currently anticipated to commence in Q2 2013, with findings and recommendations targeted for Q4 2013. The market rules process will flow from those findings and recommendations.
Recommendation 3-4 *The Panel recommends that the IESO improve its internal controls and external processes to ensure that all information about outages and other relevant contingencies is taken into account when establishing the level of Transmission Rights to be auctioned.* IESO Response: Closed The IESO agrees with this recommendation. Since the event referenced in the MSP Report, the IESO has and will continue to implement new processes with the neighbouring jurisdictions to improve communication of outage plans, allowing this information to be considered in the sales of Transmission Rights.
Recommendation 3-5 *The IESO should ensure that, when a trader which owns Transmission Rights has failed its intertie transactions (at the same interface in the same direction), either the Transmission Right payout should not be paid or the Congestion Rent should be charged for the quantity of the failed transactions.* IESO Response: Closed The IESO agrees with this recommendation. The IESO currently has market rules in place to allow for the recovery of transmission rights payouts when the trader fails its intertie

transactions, and intends to adjust settlement amounts paid or payable to traders in situations where the trader has failed to schedule the transaction with the appropriate scheduling entity other than for bona fide and legitimate reasons. Refer to the Market Rules Chapter 3, section 6.6.10A and Chapter 7, sections 7.5.8A and 7.5.8B.

Recommendation 4-1
The Panel recommends that the IESO proceed with development work on those recommendations of the Electricity Market Forum that are directed at improving market efficiency, including the consideration of options to replace the two-schedule structure of the current market design.

IESO Response
The IESO agrees with this recommendation. The IESO has initiated work based on the Electricity Market Forum's recommendations aimed at improving market efficiency, including reviews of HOEP, Global Adjustment (GA), the two-schedule system and intertie trading. Requests for Proposals (RFP's) related to the HOEP and GA recommendations were awarded in September 2012. Stakeholder engagement initiatives for each review are underway (SE-105 (HOEP) and SE-106 (GA)). Reports for both reviews are expected to be published in April 2013. Further work may need to be initiated based on the recommendations from each report. Work on the two-schedule structure will be influenced by the results of the HOEP effort and it is anticipated that an RFP for this work will be issued by the end of Q1 2013. The current expectation is that the final report on the two-schedule structure will be completed by Q2 2014. The IESO has also begun work on the recommendations related to improving trading processes.

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

Ontario

Market Surveillance Panel

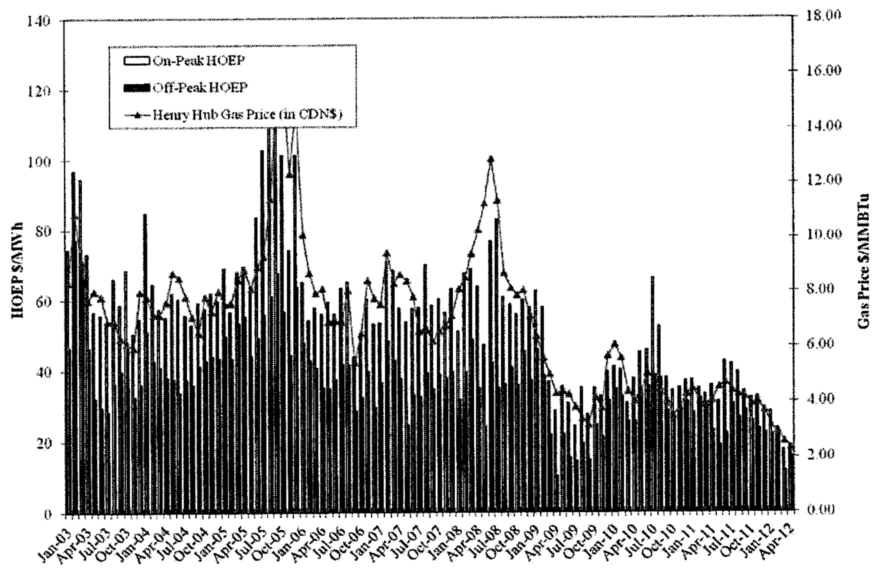
Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2011 – April 2012

January 2013

Table of Contents

Figure 1-25: Henry Hub Natural Gas Spot Price and HOEP
January 2003 – April 2012
($/MWh and $CDN/MMBtu)



5. Imports and Exports

This section reports on intertie activity, using data that is based on the unconstrained schedules as these directly affect market prices.[42]

5.1 Overview

Table 1-27 presents monthly net exports from Ontario during on-peak and off-peak hours.

Ontario remained a net exporter for both off-peak and on-peak hours during all months in the 2011/12 Annual Period. Off-peak net exports increased by 792 GWh (15.5%) while on-peak net exports decreased by 1,036 GWh (25.1%). As a result, overall net exports

[42] Although the schedules in the constrained schedule 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).

declined by 244 GWh (2.6%) from the 2010/11 Annual Period to the 2011/12 Annual Period. Relative to the 2010/11 Annual Period, on-peak net exports decreased from June 2011 to January 2012, while off-peak exports were more volatile after persistent gains during the first four months of the 2011/12 Annual Period.

Table 1-27: Net Exports (Imports), On-peak and Off-peak May – April 2010/2011 & May – April 2011/2012 (GWh)

Month	On-Peak			Off-Peak			Total		
	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change
May	3	390	13271.4	34	915	2554.5	37	1303	3391.5
June	299	153	(48.8)	356	536	50.5	655	689	5.2
July	226	173	(23.4)	330	401	21.5	556	574	3.3
August	257	113	(56.1)	286	415	45.2	543	528	(2.8)
September	507	121	(76.1)	415	346	(16.7	922	466	(49.4)
October	384	267	(30.4)	540	481	(10.9)	924	748	(19.0)
November	424	233	(45.1)	365	368	1.0	788	601	(23.8)
December	816	155	(81.0)	859	326	(62.1)	1,675	481	(71.3)
January	475	324	(31.8)	671	463	(31.0)	1,146	787	(31.3)
February	290	308	6.3	332	433	30.3	622	741	19.1
March	281	410	46.1	379	588	55.0	660	999	51.2
April	176	452	157.5	546	634	16.2	722	1086	50.6
Total	4,136	3,100	(25.1)	5,114	5,906	15.5	9,250	9,006	(2.6)

Figure 1-26 reports the long-term trend in net exports since 2003. A positive number indicates net export, while a negative number net import. In earlier years, Ontario was a net importer of electricity. Over the years it has become a net exporter as supply and demand conditions in the province have improved.

Figure 1-26: Net Exports (Imports), On-peak and Off-peak
January 2003 – April 2012
(GWh)

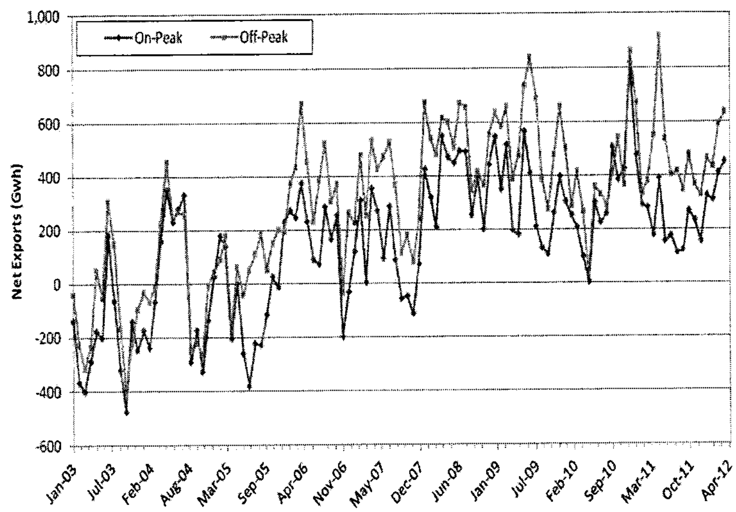


Table 1-28 presents net exports by neighbouring interface group for the 2010/11 and 2011/12 Annual Periods. It is worth noting that the sum of net exports in Table 1-28 is not equal to the numbers in Table 1-27 because of the impact of linked wheeling transactions. Linked wheeling transactions net out to zero for Ontario as a whole. These transactions, however, do have an impact on the net exports at a specific interface because the import and export legs are scheduled at different interfaces (i.e., they do not net to zero at a given interface).

Table 1-28: Net Exports (Imports) by Interface Group May – April 2010/2011 & May –April 2011/2012 (GWh)

Month	Manitoba 2010/ 2011	Manitoba 2011/ 2012	Michigan 2010/ 2011	Michigan 2011/ 2012	Minnesota 2010/ 2011	Minnesota 2011/ 2012	New York 2010/ 2011	New York 2011/ 2012	Québec 2010/ 2011	Québec 2011/ 2012
May	(94)	(113)	176	569	(38)	(26)	98	590	(104)	287
June	(126)	(154)	661	407	(43)	(9)	111	299	51	146
July	(156)	(156)	222	606	(40)	(20)	276	398	254	(254)
August	(172)	(112)	6	393	(35)	(20)	275	315	468	(47)
September	(156)	(115)	(158)	207	(36)	(33)	486	244	787	163
October	(145)	(123)	(47)	366	(30)	(21)	283	301	863	225
November	(146)	(120)	45	430	(32)	(26)	78	164	844	154
December	(152)	(112)	640	455	(39)	(10)	458	155	767	(7)
January	(108)	(127)	703	484	(28)	(17)	364	431	215	14
February	(120)	(108)	419	528	(18)	(18)	256	378	85	(39)
March	(139)	(83)	510	541	(22)	(9)	255	667	57	(117)
April	(118)	(78)	310	726	(16)	(2)	363	738	183	(298)
Total	(1,632)	(1,401)	3,487	5,712	(377)	(212)	3,303	4,680	4,470	227

Although Ontario remained a large net exporter as a whole over the 2011/12 Annual Period, the situation varied significantly among interfaces:

- Ontario electricity exports at the Québec interface fell sharply in the 2011/12 Annual Period: they decreased by 4,243 GWh from 4,470 GWh, representing 94.9% of the exports in the 2010/11 Annual Period. Ontario was a net importer on the Québec interface in half of the months in the 2011/12 Annual Period.
- Net exports at the Michigan interface rose from 3,487 GWh to 5,712 GWh, and this 63.8% increase made it the largest net exporting interface during the 2011/12 Annual Period.
- New York remained a large export market during the 2011/12 Annual Period, and saw an increase of 1,377 GWh (41.7%) in the 2011/12 Annual Period relative to the 2010/11 Annual Period.
- Ontario remained a net importer from Manitoba and Minnesota in every month of the 2011/12 Annual Period. However, many of the imports in the unconstrained schedule were constrained off because of surplus supply in the Northwest zone of the province. Only a small fraction of the amount of net

imports at the Manitoba interface in the constrained schedule flowed into Ontario, while Ontario actually had net exports to Minnesota in the constrained schedule in 4 months during the 2011/12 Annual Period.

Imports and exports during the 2010/11 and 2011/12 Annual Periods are separately reported in Tables 1-29 and 1-30, showing for each interface both the total imports or exports and the total imports or exports net of the components of linked wheeling transactions . (Linked wheeling transactions increased from 121 GWh in the 2010/11 Annual Period to 454 GWh in the 2011/12 Annual Period, which represents 7.1% of total imports and 2.4% of total exports in the 2011/12 Annual Period.)

5.2 Imports

As reported in Table 1-29, total imports fell to 4,683 GWh in the 2011/12 Annual Period, a decrease of 1,558 GWh or 25.0% compared to the 2010/11 Annual Period. Excluding linked wheeling transactions, imports were down by 1,891 GWh, or 30.9%.

The only increase in import volumes occurred at the Québec interface, where total imports increased from 1,270 GWh in the 2010/11 Annual Period to 2,561 GWh in the 2011/12 Annual Period (an increase of 101.7%). In contrast, imports from Michigan decreased from 2,598 GWh in the 2010/11 Annual Period to 330 GWh in the 2011/12 Annual Period (a decrease of 87.3%).

Table 1-29: Imports by Interface Group May – April 2010/2011 & May - April 2011/2012 (GWh)

Interface Group	Total Imports			Total Excluding Linked Wheeling Transactions		
	2010/2011	2011/2012	%Change	2010/2011	2011/2012	% Change
Manitoba	1,663	1,412	(15.1)	1,663	1,412	(15.1)
Michigan	2,598	330	(87.3)	2,593	329	(87.3)
Minnesota	417	265	(36.5)	417	265	(36.5)
New York	293	115	(60.8)	270	81	(72.0)
Québec	1,270	2,561	101.7	1,177	2,142	82.0
Total	6,241	4,683	(25.0)	6,120	4,229	(30.9)

5.3 Exports

As shown in Table 1-30, total exports decreased by 1,802 GWh or 11.6% in the 2011/12 Annual Period relative to the 2010/11 Annual Period. Excluding linked wheeling transactions, the decline was 2,136 GWh or 13.9%. The New York interface saw an increase in total exports of 1,200 GWh (33.4%) and an increase of 1,175 GWh (32.8%) without linked wheeling transactions. In contrast, the Québec interface saw a decrease in total exports of 2,952 GWh (51.4%) and a decrease of 3,371 GWh (58.6%) when linked wheeling transactions are excluded.

Table 1-30: Exports by Interface Group May – April 2010/2011 & May – April 2011/2012 (GWh)

Interface Group	Total			Total Excluding Linked Wheeling Transactions		
	2010/2011	2011/2012	% Change	2010/2011	2011/2012	% Change
Manitoba	30	11	(63.3)	30	11	(63.3)
Michigan	6,084	6,041	(0.7)	5,973	6,040	1.1
Minnesota	41	53	29.3	41	53	29.3
New York	3,595	4,795	33.4	3,586	4,761	32.8
Québec	5,740	2,788	(51.4)	5,740	2,369	(58.7)
Total	15,490	13,688	(11.6)	15,370	13,234	(13.9)

5.4 *Congestion at Interties*

In general, intertie congestion levels tend to increase as the volume of inter-jurisdictional transactions increase or intertie capability decreases. Due to the two-schedule design of the Ontario market, there are two types of intertie congestion: congestion in the constrained schedule and congestion in the unconstrained schedule. [43] The congestion level can be measured by the intertie congestion price (unconstrained) or nodal price (constrained) difference at the two ends of an intertie. Congestion may occur in the constrained schedule without occurring in the unconstrained schedule, and vice versa. Except as otherwise noted, this section discusses congestion in the unconstrained schedule only.

5.4.1 Import Congestion

Table 1-31 reports the number of occurrences of import congestion by month and interface group over the 2010/11 and 2011/12 Annual Periods. Total hours of import congestion declined from 8,239 to 4573 (a 44% decrease). This represents an import congestion rate of 10.4% during the 2011/12 Annual Period (down from 18.8% in the 2010/11 Annual Period). Congestion at the Minnesota interface saw a pronounced decline: from 4,264 hours to 2,042 hours, or a 52.1% decrease.[44] The Manitoba interface also saw a decline in congestion of 1,319 hours, which represents a 34.5% decrease. Of the remaining three import regions, the New York interface saw a decline in congestion from 27 hours to 0; the Québec interface saw an 11 hour increase in congestion to 31 hours, up from 20 hours in the 2010/11 Annual Period; and the Michigan interface saw a decrease in congestion from 110 hours to a single hour.

[43] Congestion in the constrained schedule reflects that the power flow has reached the maximum capability allowed for the interface. Congestion in the unconstrained schedule reflects that the economic transactions have reached the thermal limit at the interface. The former has little impact on price, but traders may be compensated through CMSC payments for constrained-off exports or imports (or uneconomic exports/imports that are constrained on to relieve congestion). In contrast, the latter generates a price difference between the external zone and the Ontario zone, which is manifested in the Intertie Congestion Price (ICP).

[44] Although the numbers of hours with import congestion at the Minnesota interface has decreased in the 2011/12 Annual Period, the seriousness of congestion (measured by the average Intertie Congestion Price during the congestion hours) has actually increased. For more details, see Chapter 3.

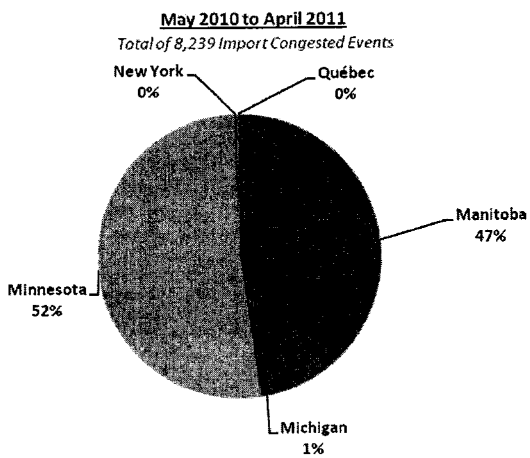
Table 1-31: Import Congestion by Interface Group May – April 2010/2011 & May – April 2011/2012 (number of hours in the unconstrained schedule)

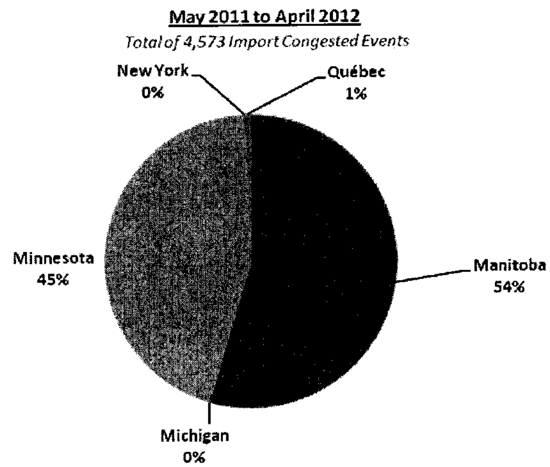
Month	Manitoba		Michigan		Minnesota		New York		Québec	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	321	230	10	0	404	273	26	0	7	1
June	334	314	0	1	429	90	0	0	1	7
July	244	264	3	0	449	150	1	0	6	8
August	471	167	26	0	463	113	0	0	0	6
September	284	215	69	0	292	216	0	0	0	2
October	403	198	1	0	342	230	0	0	1	0
November	337	172	0	0	419	181	0	0	0	0
December	235	129	0	0	307	66	0	0	0	0
January	187	297	0	0	157	291	0	0	1	0
February	410	232	0	0	307	72	0	0	2	0
March	381	141	0	0	406	205	0	0	0	0
April	211	140	0	0	293	155	0	0	2	7
Total	3,818	2,499	110	1	4,264	2,042	27	0	20	31

Figure 1-27 compares the share of import congestion events[45] by interface group for the 2010/11 and 2011/12 Annual Periods. Of the 43,920 total hours (8,784 hours × 5 interface groups) during the 2011/12 Annual Period, there were 4,573 import congested events, which is a 44.5% decrease from the level in the 2010/11 Annual Period. The interfaces in the Northwest (Manitoba and Minnesota) have accounted for the vast majority of congestion hours in both the 2010/11 and 2011/12 Annual Periods. The share accounted for by the Manitoba interface increased by 7% in the 2011/12 Annual Period, with a corresponding reduction at the Minnesota interface.

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

Figure 1-27: Share of Import Congestion by Interface Group
May – April 2010/2011 & May – April 2011/2012
(% of congested events in the unconstrained schedule)





5.4.2 Export Congestion

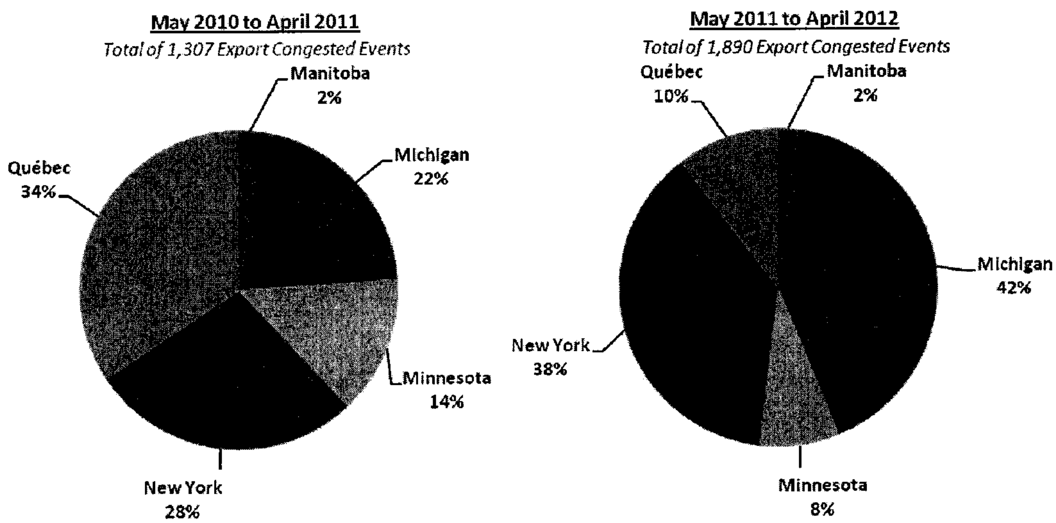
Table 1-32 reports the number of occurrences of export congestion by month and interface group for the 2010/11 and 2011/12 Annual Periods. The total number of export congestion events increased from 1,721 to 1,890 hours (9.8%). This represents a congestion rate of 4.3% of total hours during the 2011/12 Annual Period (up from 3.9% in the 2010/11 Annual Period). The greatest year-to-year increase was seen at the Michigan interface, with export congestion increasing by 508 hours or 179.5%. The New York interface also saw an increase in export congestion hours (97.2%), while congestion at the Québec interface decreased (56.1%).

Table 1-32: Export Congestion by Interface Group May – April 2010/2011 & May – April 2011/2012 (number of hours in the unconstrained schedule)

Month	Manitoba		Michigan		Minnesota		New York		Québec	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	0	0	15	77	2	14	0	170	7	63
June	1	0	98	55	9	3	5	80	18	13
July	0	0	41	138	3	23	8	51	13	8
August	0	2	19	26	11	22	14	12	22	2
September	0	2	17	9	0	26	101	30	84	11
October	0	2	1	6	3	1	60	90	81	79
November	2	1	0	12	40	5	0	0	90	20
December	11	3	0	86	9	8	0	0	52	0
January	6	2	60	28	13	3	26	11	56	0
February	3	1	19	105	44	6	9	8	1	0
March	1	11	13	99	23	14	1	122	0	1
April	6	13	0	150	27	28	137	138	25	0
Total	30	37	283	791	184	153	361	712	449	197

Figure 1-28 compares the share of export congestion events by interface group for the 2010/11 and 2011/12 Annual Periods. The Michigan interface overtook the Québec interface as the most congested interface. The New York interface also increased its share of total congestion hours, while the Québec and the Minnesota interfaces saw their shares decline significantly.

Figure 1-28: Share of Export Congestion Events by Interface Group May – April 2010/2011 & May – April 2011/2012 (% of congested events in the unconstrained schedule)



5.4.3 Congestion Rent

Congestion rent is the result of different prices in the unconstrained schedule at either end of an intertie. These price differences are induced by congestion at the interface (i.e., net schedules of economic transactions have reached the maximum thermal limit at the interface). In such situations, the importers or exporters are receiving or paying the intertie price, while Ontario generators and loads are receiving or paying the uniform Ontario price (either the interval MCP or the HOEP).

When there is export congestion, the intertie price rises above the uniform Ontario price. Congestion rent results from the IESO collecting a higher price from exporters while paying the (lower) uniform price to generators. When there is import congestion, the intertie price falls below the uniform Ontario price, and congestion rent results from the IESO paying a lower price to importers relative to the (higher) uniform price.[46]

---

[46] The congestion rent is the price difference between the external zone and the Ontario zone (the Intertie Congestion Price or ICP) times the net schedules (net imports or net exports) on that intertie. For example, if an intertie has export congestion with an ICP of $10/MWh and net exports are 100 MW, then the congestion rent is $1,000 for the hour. The congestion arises in respect of those exports or imports which

Congestion rent effectively represents a reduction in profit to traders, either in the form of a congestion price premium paid for exports or a reduction in the payment made for imports, compared to the uniform Ontario price.[47]

Tables 1-33 and 1-34 present the congestion rent by interface group during the 2010/11 and 2011/12 Annual Periods.

Table 1-33 indicates that total congestion rent for import events in the 2011/12 Annual Period decreased by approximately $807,000 (or 15.6%) from 2010/11 Annual Period levels. The Manitoba interface saw the largest decrease at approximately $1.9 million (37.1%). In the 2011/12 Annual Period, the Michigan interface had no import congestion rent, compared with $635,000 in the 2010/11 Annual Period. Similarly, the New York interface had no import congestion rent, compared with $264,000 in the 2010/11 Annual Period. The Minnesota interface had the greatest increase, from -$788,000 in the 2010/11 Annual Period to $864,000 in the 2011/12 Annual Period.

are scheduled in the constrained schedule and that flow in real-time. When a transaction is not scheduled in the constrained schedule but is scheduled in the unconstrained schedule, the transaction may attract CMSC and/or Intertie Offer Guarantee (or IOG) payments. Congestion rent can be negative if power flows in the direction opposite to that of the unconstrained congestion. For example, the Minnesota interface is import congested due to cheaper import offers, but power actually flows out of Ontario due to exports being constrained on.

[47] However, traders that have transactions in the direction opposite to that of the congested flow may actually benefit from these differentials. For example, an import on an export-congested intertie would receive a higher payment than the HOEP because of the higher intertie price. Similarly, an export on an import-congested intertie would pay a lower price than the HOEP. Such counter-flows in the constrained schedule can induce the negative components in the congestion rent that are occasionally observed below.

Table 1-33: Import Congestion Rent by Interface Group May – April 2010/2011 & May – April 2011/2012 ($ thousands)*

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	(8)	119	51	0	(64)	(110)	264	0	0	0	243	8
June	317	341	0	0	(54)	(74)	0	0	3	10	266	276
July	628	396	7	0	(85)	(175)	1	0	57	222	609	443
August	1,114	138	79	0	(208)	8	0	0	0	83	985	230
September	522	252	499	0	(23)	89	0	0	0	5	998	345
October	637	142	0	0	(22)	150	0	0	0	0	615	292
November	550	105	0	0	(52)	37	0	0	0	0	498	142
December	236	74	0	0	0	4	0	0	0	0	236	77
January	169	104	0	0	13	282	0	0	1	0	182	386
February	204	503	0	0	56	18	0	0	1	0	261	520
March	303	930	0	0	(208)	524	0	0	0	0	95	1,454
April	340	54	0	0	(142)	112	0	0	1	40	198	206
Total	5,012	3,155	635	0	(788)	864	264	0	63	360	5,186	4,379

*Negative amounts represent net flows in the direction opposite to the congestion as indicated in the unconstrained schedule

As can be seen from Table 1-34, total export congestion rent was high in the 2011/12 Annual Period at over $28.3 million, an increase of approximately $12.1 million or 74.7%. There were minor decreases in export congestion rent at the Manitoba and Minnesota interfaces. The Québec interface saw $2.4 million (39.3%) less export congestion rent than in the 2010/11 Annual Period. In contrast, the New York interface saw $5.4 million (145.1%) more export congestion rent than in the 2010/11 Annual Period, and the Michigan interface experienced a $9.1 million (144.3%) increase.

Table 1-34: Export Congestion Rent by Interface Group May – April 2010/2011 & May – April 2011/2012 ($ thousands)*

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	0	0	220	3,580	0	5	0	2,622	5	948	225	7,154
June	0	0	1,598	1,389	8	0	28	810	105	76	1,739	2,273
July	0	0	1,383	5,987	0	16	79	2,409	116	31	1,578	8,443
August	0	0	646	805	5	15	104	95	342	9	1,097	923
September	0	(4)	197	81	0	20	1,138	173	1,124	171	2,459	441
October	0	0	(3)	86	0	0	658	622	838	2,374	1,494	3,082
November	0	0	0	195	7	0	0	0	858	79	865	274
December	2	0	0	531	10	11	0	0	318	0	330	542
January	(4)	0	1,546	267	8	(1)	471	141	2,071	0	4,093	407
February	0	0	571	573	28	0	144	35	1	0	744	610
March	0	5	179	816	3	(13)	19	1,158	0	2	201	1,967
April	45	1	0	1,174	8	4	1,072	1,036	298	0	1,423	2,217
Total	43	2	6,338	15,486	78	58	3,713	9,099	6,076	3,690	16,248	28,334

*Negative amounts represent net flows in the direction opposite to the congestion as indicated in the unconstrained schedule

There are several factors which can influence congestion rent since it is based on both the magnitude of the actual net schedule in the constrained schedule at the intertie and the Intertie Congestion Price or ICP. The ICP in turn depends on the offer price of the marginal import or export at the intertie, relative to the offer price of the marginal resource within Ontario in the unconstrained schedule. The magnitude of the actual net schedule in the constrained schedule is dependent on:

- the maximum thermal capability of the intertie;
- temporary reductions in the intertie capability;
- inadvertent flows, which use up part of the intertie capability in the direction of the inadvertent flow but increase the capability in the opposite direction;
- import or export failures; and

- the impact of parallel flow effects resulting from congestion on other transmission lines.[48]

5.4.4 Transmission Rights

As noted above, congestion rent is the dollar amount difference that results from an importer being paid less than the Ontario uniform price or an exporter being charged more than the uniform price. Events where congestion rent is "collected" occur when in the unconstrained schedule the demand for transmission exceeds available transmission, leading to a divergence between the intertie zonal price and the market clearing price, and the transactions are scheduled in the constrained schedule.

Congestion on an intertie represents a financial risk to traders. Transmission rights (TRs) provide a financial hedge against that risk by compensating the TR holder for differences between the intertie and Ontario prices. In its August 2010 Monitoring Report, the Panel observed that TR payments by the IESO (the non-negative ICP times the TRs that have been sold) generally exceed the congestion rent received by the IESO, leading to a congestion rent shortfall which then was offset by TR auction revenues.[49] Tables 1-35 and 1-36 show TR payous by interface group for each month in the 2010/11 and 2011/12 Annual Periods for imports and exports, respectively.

As shown in Table 1-35, TR payouts for imports totalled $15.6 million in the 2011/12 Annual Period, which is a decrease of more than $5.8 million (27%) relative to the 2010/11 Annual Period. There were almost no TR payouts associated with the Michigan or New York interfaces, reflecting the lack of import congestion at these interfaces. The Manitoba interface had a relatively large decrease in TR payouts from $15.6 million in the 2010/11 Annual Period to $9.4 million in the 2011/12 Annual Period (a 40.1%

---

[48] For example, due to congestion at the Queenston Flow West (QFW) interface within Ontario, scheduled exports or imports at the New York intertie may be reduced even though there is still transfer room at the New York intertie.
[49] See the Panel's August 2010 Monitoring Report (at pp. 140-167), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.

decrease). TR payouts associated with the Minnesota interface increased by $2.0 million, or 54.3%, in the 2011/12 Annual Period. The issue of import congestion at the Minnesota interface is discussed in greater detail in Chapter 3.

Table 1-35: Monthly Import Transmission Rights Payments by Interface Group May – April 2010/2011 & May –April 2011/2012 ($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Québec		Total	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	572	985	357	0	282	228	835	0	180	1	2,226	1,214
June	774	1,693	0	4	317	153	0	0	5	11	1,096	1,860
July	1,628	1,203	5	0	373	155	1	0	115	232	2,122	1,590
August	3,123	322	74	0	421	45	0	0	0	213	3,619	581
September	1,186	682	424	0	175	261	0	0	0	5	1,785	948
October	1,874	377	0	0	249	897	0	0	3	0	2,126	1,275
November	983	254	0	0	420	78	0	0	0	0	1,403	332
December	580	120	0	0	206	21	0	0	0	0	786	141
January	328	343	0	0	81	1,300	0	0	2	0	410	1,643
February	2,038	709	0	0	532	42	0	0	1	0	2,571	751
March	1,885	1,774	0	0	427	1,938	0	0	0	0	2,312	3,713
April	657	897	0	0	226	606	0	0	1	21	884	1,523
Total	15,628	9,359	860	4	3,709	5,724	836	0	307	483	21,340	15,571

As shown in Table 1-36, total TR payouts for exports were $38.8 million in the 2011/12 Annual Period, which is 118.7% higher than in the 2010/11 Annual Period. The greatest increase in monthly export TR payouts was at the Michigan interface, which saw a $14.3 million (191.2%) increase. The New York and Québec interfaces also had higher TR payouts in the 2011/12 Annual Period, with increases of $6.7 million (201.8%) and $0.7 million (13.5%),[50] respectively, relative to the 2010/11 Annual Period. Over 27% of all export TR payouts in the 2011/12 Annual Period occurred in July 2011.

[50] The large TR payouts at the Québec interface in October 2011 were mainly due to an overselling of TRs at the PQAT intertie. For more details, see the Panel's April 2012 Monitoring Report (at pp. 72-86), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf.

Table 1-36: Monthly Export Transmission Rights Payments by Interface Group May – April 2010/2011 & May – April 2011/2012 ($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Québec		Total	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	0	0	159	4,844	0	309	0	1,489	3	1,182	162	7,824
June	5	0	1,776	2,504	97	32	41	1,258	131	72	2,050	3,867
July	0	0	1,588	7,264	1	32	50	3,375	179	44	1,819	10,714
August	0	2	723	866	43	25	77	114	298	8	1,142	1,015
September	0	12	246	86	0	25	1,003	119	974	237	2,224	480
October	0	56	16	102	16	5	756	761	826	4,676	1,614	5,600
November	1	0	0	213	83	21	0	0	810	88	894	321
December	19	1	0	1,013	51	12	0	0	287	0	356	1,026
January	7	0	1,843	456	51	6	342	275	1,779	0	4,023	738
February	1	0	863	1,097	200	11	96	43	0	0	1,161	1,151
March	2	5	257	1,559	139	91	15	1,103	0	1	414	2,759
April	326	2	0	1,748	323	27	950	1,512	272	0	1,871	3,289
Total	361	78	7,471	21,752	1,004	596	3,330	10,049	5,559	6,308	17,730	38,784

5.5 *Wholesale Electricity Prices in Neighbouring Markets*

Table 1-37 provides average wholesale market prices for Ontario and its neighbouring jurisdictions over the 2010/11 and 2011/12 Annual Periods.[51] All jurisdictions experienced significant price declines in the 2011/12 Annual Period relative to the 2010/11 Annual Period. For several years, energy prices in Ontario were generally the lowest of the five jurisdictions until the 2010/11 Annual Period. In that Annual Period, the Ontario price was slightly higher than the Michigan price in both on-peak and off-peak hours. In the 2011/12 Annual Period, Ontario returned to having the lowest average price relative to neighbouring markets. As between neighbouring jurisdictions, the average Ontario HOEP saw the largest percentage decrease, the sole exception being the decrease in on-peak and overall average (all hours) prices experienced in New England (Internal Hub).

[51] These price comparisons can provide a useful overall indicator of the export and import market opportunities available to traders. However, caution should be used when comparing market prices across jurisdictions for other purposes due to the differing market designs and payment structures. For example, in Ontario the GA and various uplift charges represent actual charges to domestic loads that are not reflected in the average HOEP or the price paid by exporters. As another example, other jurisdictions such as ISO New England, NYISO and PJM have capacity markets where customers pay capacity charges.

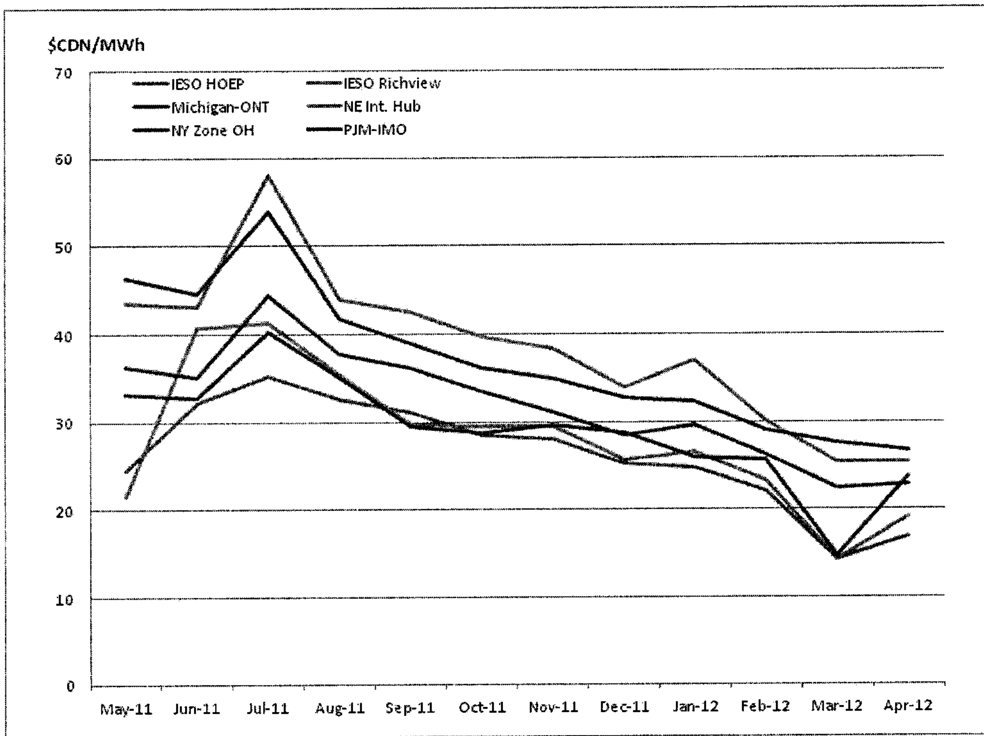
*Table 1-37: Average HOEP Relative to Neighbouring Market Prices May – April 2010/2011 & May – April 2011/2012 ($CDN/MWh)**

Markets	All Hours			On-peak Hours			Off-peak Hours		
	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change
Ontario - HOEP	35.64	26.29	(26.2)	41.19	30.78	(25.3)	31.01	22.44	(27.6)
MISO – ONT	34.13	29.03	(14.9)	40.87	34.92	(14.6)	28.52	23.76	(16.7)
NYISO – Zone OH	39.78	32.04	(19.5)	44.73	36.10	(19.3)	35.64	28.26	(20.7)
PJM – IMO	43.94	37.15	(15.5)	51.22	43.68	(14.7)	37.87	31.18	(17.7)
New England – Internal Hub	52.36	38.47	(26.5)	59.88	42.78	(28.6)	46.11	34.41	(25.4)
Average	41.17	32.60	(20.8)	47.58	37.65	(20.9)	35.83	27.97	(21.9)

*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

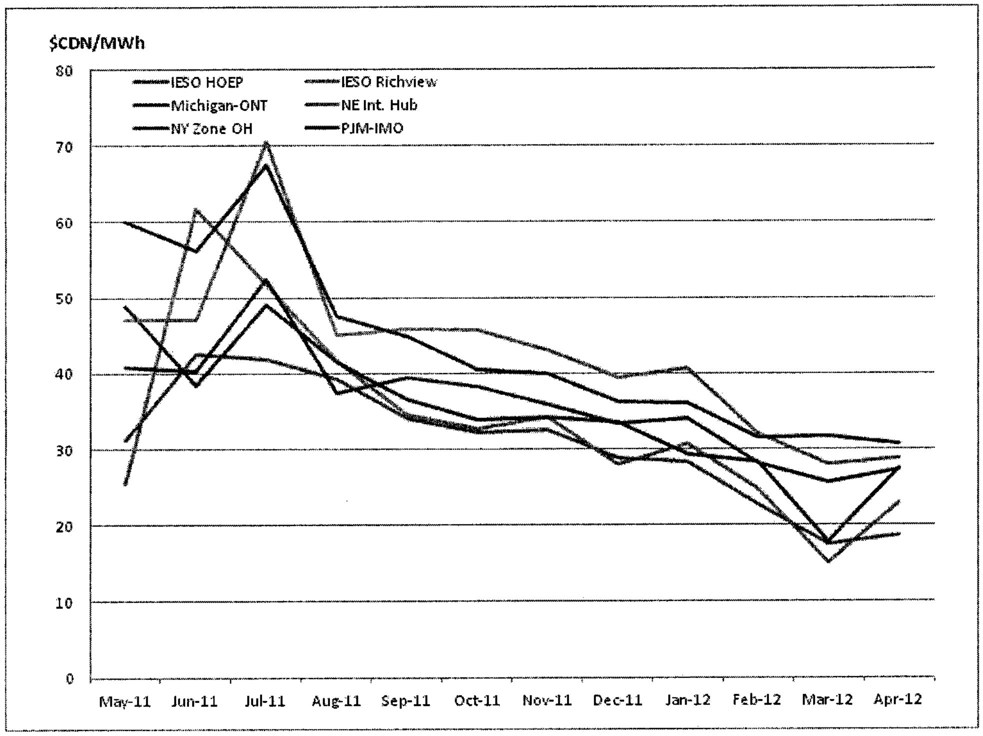
Figures 1-29 to 1-31 compare monthly average prices for Ontario and its neighbouring jurisdictions for the 2011/12 Annual Period, for all hours, for on-peak hours and for off-peak hours, respectively. The Richview nodal price is also shown since it is regarded as a useful indicator of the marginal cost of incremental output in the major load area. The Ontario HOEP followed the same general trends as prices in neighbouring jurisdictions. The New England and PJM electricity prices are regularly and distinctly greater than those of their neighbours (as they have been historically). The Ontario HOEP is the generally the lowest price, but it is occasionally greater than the Michigan electricity price.

Figure 1-29: Average Monthly HOEP and Richview Nodal Price Relative to Neighbouring Market Prices, All Hours May 2011 – April 2012 ($CDN/MWh)*



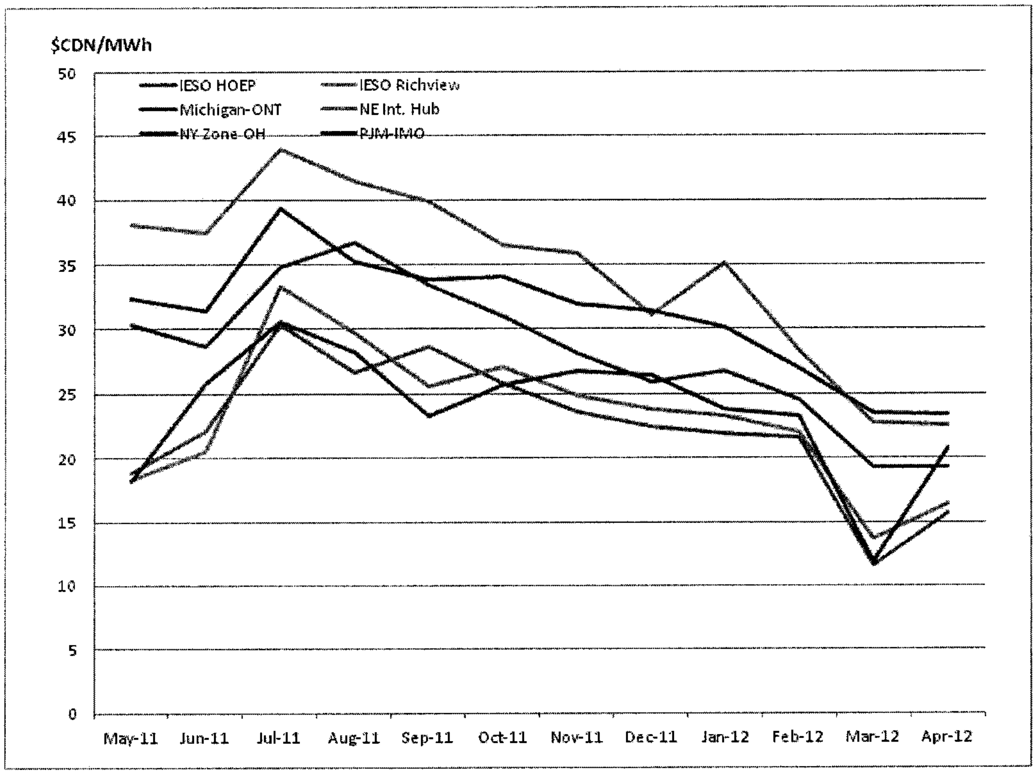
*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

Figure 1-30: Average Monthly HOEP and Richview Nodal Price Relative to Neighbouring Market Prices, On-Peak May 2011 – April 2012 ($CDN/MWh)



*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

Figure 1-31: Average Monthly HOEP and Richview Nodal Price Relative to Neighbouring Market Prices, Off-Peak
May 2011 – April 2012
($CDN/MWh)



*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

6. *Operating Reserve*

6.1 *Operating Reserve Requirements*

The operating reserve (OR) requirement is determined by the IESO in accordance with reliability standards established by authorities such as NERC and the Northeast Power Coordinating Council. OR requirements (in MW) are based on the largest single unexpected event (contingency) plus half of the second largest contingency. However, during shortage conditions or when OR is activated, the OR requirement can be reduced. The average OR requirement for the 2010/11 Annual Period was 1,520MW, while in the 2011/12 Annual Period the requirement was slightly lower at 1,516 MW.

4.2 Issues Arising in the Transmission Rights Market

In 2010, the Panel conducted an in-depth review of the operation of the transmission rights ("TR") market, and made a number of recommendations in that regard. While the IESO accepted those recommendations,[105] it did not address them given other urgent priorities. Since then, the Panel has identified specific concerns relating to the sale of TRs by the IESO in respect of a Québec interface in its April 2012 report,[106] and in this report discusses issues associated with TRs at the Minnesota interface (see section 4.3 below) as well as issues associated with the interplay between TRs and day-ahead intertie offer guarantee payments (see section 4.4 below).

The Panel believes that the concerns identified in its 2010 analysis remain valid. Given that the TR market involves approximately $20 million to $30 million per year (as measured by auction revenues) and that there is now a large accumulated surplus in the TR Clearing Account, the Panel provides an update and extension of its 2010 analysis and recommendations below before addressing the additional specific experience observed in respect of TRs at the Minnesota interface.

4.2.1 Intertie Congestion

The Ontario market is currently divided into 15 zones, 14 of which are referred to as "external zones" and one of which is referred to as the Ontario zone. External zones represent the major transmission lines that link Ontario with external markets or jurisdictions. They act as proxies for the external market or jurisdiction to which they are linked and reflect the limited transmission capability that links Ontario with that external market or jurisdiction.

The IESO runs two dispatch schedules. The constrained schedule takes into account most physical constraints in the electricity network (including some characteristics of external

[105] See the Panel's August 2010 Monitoring Report (at pp. 140-267), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.
[106] See the Panel's April 2012 Monitoring Report (at pp. 72-85), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf

networks), while the unconstrained schedule ignores most of these constraints. Both schedules take into account the bi-directional Scheduling Limit (import and export limits), which is typically the intertie-specific transfer capability (subject to adjustments for outages, projected loop flow induced by external control areas, reliability margin, etc). On the basis of Scheduling Limits, the constrained schedule further accounts for the impact of internal transmission and generation conditions on the interface. This is referred to as an Operating Security Limit (OSL). In other words, the unconstrained schedule uses the Scheduling Limit, while the constrained schedule uses either the Scheduling Limit or the OSL, whichever is lower.[107]

Congestion can be reflected in either schedule. An interface is congested in the constrained schedule when the physical power flow at the interface reaches its OSL and/or Scheduling Limit. In the unconstrained schedule, congestion occurs when the net schedules reach the Scheduling Limit.[108]

The relevant price for settling transactions at a given intertie is equal to the real-time unconstrained Ontario zonal price (Ontario MCP) plus the Intertie Congestion Price (ICP). The ICP is set in the one hour ahead pre-dispatch unconstrained schedule, and is equal to the price difference between the external zonal price and the Ontario zonal price. The ICP as determined in the final pre-dispatch schedule is locked in and carried over to real-time.

When an interface is congested in the unconstrained schedule, the price in the relevant external zone differs from the price in the Ontario zone (i.e., the Ontario MCP):

- When an intertie is import congested, there are offers that are economic in the external zone and that are in excess of the Scheduling Limit. With the unconstrained schedule only able to select net imports up to the Scheduling Limit, the lowest priced imports are scheduled, with the next additional megawatt over the Scheduling Limit setting the

[107] The OSL and the Scheduling Limit will be the same where internal transmission and generation conditions do not affect transfer capability on the intertie.

[108] When an interface is congested in the constrained schedule, the associated congestion price is not applied for settlement purposes; rather, it is used to determine the schedules. Unless otherwise stated, all further references to 'congestion' in this chapter refer to congestion in the unconstrained schedule.

external zonal price. The result of import congestion is an external zonal price that is equal to or less than the Ontario zonal price. For example, import offers in pre-dispatch may give rise to an external zonal price of $10/MWh whereas the Ontario zonal price is $30/MWh. This $20/MWh price difference sets the ICP, which is carried over to real-time. Provided that there is no change in the Ontario zonal price from pre-dispatch to real-time, Ontario loads are charged $30/MWh for the imported power while the importer is paid $10/MWh for delivering power. The $20/MWh discrepancy is referred to as congestion rent and is allocated to the TR Clearing Account that is administered by the IESO (as described more fully below).

- When an intertie is export congested, there are economic export bids in pre-dispatch in excess of the Scheduling Limit. With the unconstrained schedule only able to select net exports up to the Scheduling Limit, the highest priced bids are scheduled. The result of export congestion is an external zonal price that is equal to or higher than the Ontario zonal price. For example, in pre-dispatch, export bids may give rise to an external zonal price of $50/MWh whereas the Ontario zonal price is $30/MWh. The ICP is set at $20/MWh and carried over to real-time. Provided that there is no change in the Ontario zonal price from pre-dispatch to real-time, the exporter is charged $50/MWh while internal generators are paid $30/MWh. As with the import example, the incremental $20/MWh collected by the IESO as congestion rent is allocated to the TR Clearing Account.

4.2.2 Transmission Rights

TRs are financial instruments established and auctioned by the IESO. They can be used by intertie traders to hedge the risks associated with congestion at an interface. TRs may also be held for speculative purposes (i.e., held by participants not hedging physical transactions).

When an intertie is not congested the Ontario zonal price and the external zonal price are the same. When an intertie is congested in the direction for which the TR holder owns TRs, the TR holder is entitled to a payment (payout) equal to the absolute price difference between the external zonal price and the MCP. By hedging a physical transaction with a TR, an importer ensures that it will receive the equivalent of the MCP to deliver power, while an exporter ensures that it will pay the equivalent of the MCP to purchase power. Using the import example from above, an importer is paid \$10/MWh to deliver power into Ontario while Ontario loads are charged \$30/MWh. The \$20/MWh in congestion rent is allocated to the TR Clearing Account. If the importer held TRs, it would receive a \$20/MWh payout for each TR that it held. If the importer held a TR for every MW it imported, its transaction would be entirely hedged. On a net basis the importer would receive \$30/MWh, composed of a \$10/MWh energy payment and a \$20/MWh TR payout.

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

4.2.3 Transmission Rights Clearing Account

As required by the Market Rules,[109] the IESO maintains a TR Clearing Account. There are three main cash flows into or out of the TR Clearing Account: congestion rent collected, revenue from TR auctions, and payouts to TR holders:

- As noted above, congestion rent is the cash flow generated by the difference between the relevant prices in the Ontario zone and in the applicable external zone. For any given hour, the difference between the two prices (i.e., the ICP) times the real-time net import/export schedules in the *constrained* schedule is the congestion rent collected by the IESO.
- TR auction revenue is the money received by the IESO for the sale of short-term and long-term TRs.

[109] See section 4.18.1 of Chapter 8 of the Market Rules, available at http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter8.pdf.

- TR payouts are equal to the amount paid by the IESO to TR holders for congestion in the pre-dispatch *unconstrained* schedules and are calculated as the absolute value of the ICP times the quantity of outstanding TRs. The TR payouts for a given intertie will be roughly equal to the congestion rent collected on that intertie provided that the quantity of TRs sold is close to the OSL and no transactions fail or are constrained off in real-time.

4.2.4 Design of the Transmission Rights Market

In Ontario, TRs are essentially options contracts. The most a TR holder can lose is the price it paid to acquire the TRs. This would occur if the intertie for which the TR was held was never congested during the period that the TR was valid. The holder will receive a payout when there is congestion in the direction of the TR, but is not required to pay the IESO when there is congestion in the other direction. TR payouts are always made in full, and are not limited to the amount of congestion rent collected by the IESO.

The Panel's 2010 study of the TR market resulted in the following findings:[110]

- Financial participants that have never had a physical import or export transaction in the Ontario market purchased 23% of TRs. Additionally, for 64% of intertie transactions there were no associated TRs. This data indicated that most TRs purchased were not used for hedging purposes.
- There was substantial "overselling"[111] of TRs by the IESO (see the further discussion in section 4.2.5 below).
- The overselling was leading to congestion rent shortfalls that were effectively being funded by auction revenues, leading to lower-than-contemplated offsets to the transmission service charges payable by loads.
- TR holders were able, on average, to achieve very substantial returns on their investments in short-term or long-term TRs.

[110] See the Panel's August 2010 Monitoring Report (at pp. 140-267), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.
[111] As discussed below, the Panel defines "overselling" as occurring where the real-time intertie transfer capability is less than the level of TRs outstanding, usually as a result of planned or forced outages.

- It was not clear that the Ontario TR market design was as effective as it could be in contributing to efficient import and export transactions.

As a result, the Panel recommended that:

> *The IESO should reassess the design of the Ontario Transmission Rights market to determine whether it can play a more effective role in supporting efficient trade with neighbouring jurisdictions.*[112]

The IESO responded[113] that it agreed that a reassessment would be useful but that efforts to address this recommendation needed to be put on hold to enable the IESO to address other priorities, including various issues relating to the implementation of the *Green Energy and Green Economy Act, 2009* (GEA).[114]

As noted above, the Panel believes that the conclusions set out in its August 2010 report remain valid.[115] The Panel also notes that many transmission rights markets in the United States include active secondary markets. The Ontario Market Rules contemplate the existence of a secondary / resale market for TRs, but none has been implemented. The Panel believes that a fundamental review of the TR market could usefully include consideration of whether an IESO-administered secondary market would help to facilitate efficient inter-jurisdictional trade.

Implementation of the GEA is substantially advanced and should no longer be an impediment to addressing TR market design issues. Given the size of the TR market (approximately $20 million to $30 million per year based on auction revenues), and the concerns identified by the Panel in recent reports as well as in this one, the Panel believes that the IESO should, as a matter of some priority, conduct a reassessment of the design of Ontario's TR market design to

---

[112] See Recommendation 3-6 in the Panel's August 2010 Monitoring Report (at p. 167), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.
[113] See "*IESO Responses to the Market Surveillance Panel (MSP) Report (Period: November 2009 to April 2010)*" available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20120621.pdf.
[114] *Green Energy and Green Economy Act, 2009* available at http://www.e-laws.gov.on.ca/html/source/statutes/english/2009/elaws_src_s09012_e.htm
[115] Section 4.2.5 below contains an updated analysis relating to congestion rent shortfalls and TR auction revenues.

determine whether it is achieving its intended purpose. The Panel also notes that the IESO's Chief Executive Officer recently announced that the IESO will be undertaking work to attempt to move to the more frequent dispatch of intertie transactions[116] (which is already occurring among various northeastern US system operators). Since TRs are currently structured on an hourly basis, consistent with the hourly dispatch of imports and exports, a review of the TR market design would be particularly timely in parallel with the potential changes to intertie transaction dispatch frequency.

Recommendation 3-1:

> ***The IESO should reassess the design of the Ontario transmission rights market to determine whether it is achieving its intended purpose.***

4.2.5 Congestion Rent Shortfall

In addition to recommending a fundamental reassessment of the TR market, the Panel's August 2010 Report addressed the continuing issue of the imbalance between TR payouts and congestion rent collected.

The Panel defines congestion rent shortfall (or surplus) as the difference between the congestion rent collected and the payouts to TR holders.[117] In its August 2010 assessment of the TR market, the Panel identified three causes of congestion rent shortfall:

(i) The **two-schedule design**, including differences between the intertie limit in the unconstrained schedule versus the constrained schedule. Additionally, congestion in the

---

[116] Remarks by Mr. Paul Murphy to the APPrO Conference, November 6, 2012. The Panel recommended that the IESO examine the feasibility of more frequent (e.g., 15 minute) dispatch for imports and exports in its November 2011 Monitoring Report (Recommendation 2-2, at pp. 99-100), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf. The Electricity Market Forum subsequently recommended that the IESO maximize potential benefits to Ontario from greater alignment with regional markets through intertie transactions. See "Report of the Electricity Market Forum" (December 2011) (Recommendation 12, at p. 18), available at http://www.ieso.ca/imoweb/pubs/consult/Market_Forum_Report.pdf .
[117] Congestion rent shortfall is similarly defined in other markets, such as New York Independent System Operator, Midwest Independent System Operator and California Independent System Operator.

pre-dispatch unconstrained schedule (and, hence, TR payouts), but constrained-off transactions in the real-time constrained schedule (resulting in reduced congestion rent collected) also leads to congestion rent shortfall. The Panel estimated this accounted for $50 million (43%) of the $117 million total shortfall as of April 2010;

(ii) **Overselling of transmission rights** relative to the real-time intertie transfer capability, which contributed to $43 million (37%) of the total shortfall; and

(iii) **Transaction failures,** which accounted for $24 million (20%) of the total. [118]

In its August 2010 Report, the Panel concluded that "payouts to TR holders should not exceed congestion rents since congestion rents reflect the conceptual value of the TR right."[119] The Panel also noted that it believed the Market Rules support this approach.[120] If this approach were to be implemented, the revenues received by the IESO when TRs are auctioned would be available to offset transmission service charges to Ontario loads, as provided for in section 4.18.2 of Chapter 8 of the Market Rules.

The Ontario TR market has, however, been operated in a much different manner, and there have been significant congestion rent shortfalls that have had to be covered by TR auction revenues. As the Panel acknowledged in its August 2010 Report, the IESO's position has been that it is appropriate to use auction revenues to cover TR payouts where there are congestion rent shortfalls. This position was clearly set out in the following IESO response in 2010 to questions from OEB staff on past Panel reports: "[T]he TR market is a 'closed' design which is entirely funded by TR auction rights proceeds and 'congestion' rents, and it is designed so that those proceeds and rents are sufficient to fund TR payouts… [t]he market is designed to maintain a

---

[118] For details, see the Panel's August 2010 Monitoring Report (at pp. 140–267), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.
[119] For details, see the Panel's August 2010 Monitoring Report (at p. 151), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf
[120] section 4.6.1 of Chapter 8 of the Market Rules states as follows: "The *IESO* shall conduct a simultaneous feasibility test during each *TR auction* to ensure that the congestion rent collected by the *IESO*...shall, under most circumstances, be sufficient to cover any payment obligations owing by the *IESO* to *TR holders* ... in respect of all *transmission rights* outstanding and all *transmission rights* to be offered during the *TR auction*". Recognizing the potential for congestion rent shortfall in some periods, section 4.7.1 goes on to state that "(t)he *IESO Board* shall establish a confidence level reflecting the degree to which the congestion rents collected by the *IESO* in a given period described in section 4.18.1.1 will be sufficient to cover the *IESO's* payment obligations to *TR holders* under section 4.4.1 for that period".

rolling balance of $20 million and to not rebate any surplus to Ontario consumers."[121] This interpretation of the Ontario market design has, in the Panel's view, led to the overselling of TRs, resulting in additional congestion rent shortfalls that have had to be covered by TR auction revenues.

In its August 2010 Report, the Panel stated that it disagreed with the IESO's interpretation of the market design for various reasons.[122]

In the Panel's view, TR auction revenues ought to be paid to loads as a reduction in transmission charges. If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for scarce transmission capacity, suggesting that the rents might be paid to transmission owners. But as the transmission companies are rate regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario loads) would benefit from congestion rents.

Once TRs are introduced, congestion rents are effectively diverted to TR holders in the form of TR payouts. In return, TR holders pay for TRs (in the periodic auctions), the prices of which presumably reflect their assessment of the amount of future congestion rent at an intertie. If loads are not entitled to receive TR auction revenues then, in the Panel's view, loads would be worse off with a TR market than without one. The Panel believes that such a result is neither appropriate nor intended by the designers of the Ontario market.

[121] Questions for IESO at Technical Conference Relating to MSP Monitoring Report on the IESO-Administered Electricity Markets for the Period from May 2009 – October 2009 (and previous MSP reports), EB-2009-0377, filed February 22, 2010. This position was informed by a July 2003 decision of the Board of Directors of the Independent Electricity Market Operator and by related Market Rule amendments that came into effect on January 6, 2004. See IMO Market Rule Amendment Proposal MR-00242-R00, available at: http://www.ieso.ca/imoweb/pubs/mr/mr_00242-R00-R04_BA.pdf.

[122] For details, see the Panel's August 2010 Monitoring Report (at pp. 151-152), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf

Since April 2010, the accumulated congestion rent shortfall has continued to grow. Table 3-2 below shows TR payouts, congestion rent collected, congestion rent shortfall, and TR auction revenue since market opening. From market opening until April 2012, TR payouts totalled \$564.7 million, compared with congestion rent collected of \$414.6 million, resulting in a total congestion rent shortfall of \$150.1 million since May 2002.

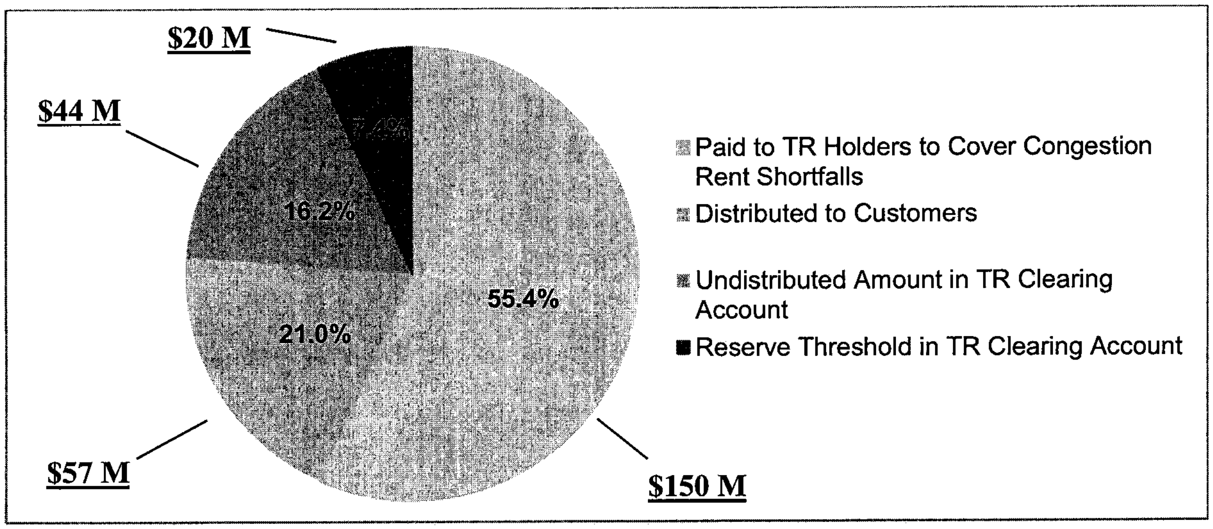
Table 3-2: Transmission Rights Payouts, Congestion Rent, Congestion Rent Shortfall and Transmission Rights Auction Revenues May 2002 to April 2012 (\$ millions)

Annual Period	TR Payouts	Congestion Rent Collected	Congestion Rent Shortfall	TR Auction Revenue
May 02-Apr 03	82.2	81.4	0.8	11.6
May 03-Apr 04	38.1	34.9	3.3	16.7
May 04-Apr 05	29.0	22.1	6.9	27.5
May 05-Apr 06	90.6	65.0	25.6	40.7
May 06-Apr 07	25.8	16.2	9.6	39.5
May 07-Apr 08	69.3	41.6	27.7	25.6
May 08-Apr 09	97.9	68.3	29.6	28.4
May 09-Apr 10	38.4	27.2	11.2	30.4
May 10-Apr 11	38.9	26.2	12.7	19.8
May 11-Apr 12	54.4	31.8	22.6	31.0
Total	**564.7**	**414.6**	**150.1**	**271.2**

Since market opening, the TR payouts were 136% of the congestion rent collected. Because the TR Clearing Account is used to fund the congestion rent shortfall, 55% of the total auction revenues collected have flowed back to TR holders.

Figure 3-2 displays cumulative auction revenue from market opening until April 2012 and how that revenue has been distributed.

Figure 3-2: Distribution of TR Auction Revenues
May 2002 to April 2012



Between market opening and April 2012, 55.4% of all TR auction revenue collected has been paid to cover congestion rent shortfalls, and hence $150 million of accumulated auction revenue has not been available to offset transmission service charges payable by Ontario loads. The Panel does recognize, however, that the current design has very likely increased TR auction revenues than would have been the case had the IESO sold TRs at a level designed to balance TR payouts with congestion rent collected.[123]

Of the remaining amount, $57 million (21%) was distributed to wholesale customers in 2007 and 2008, while $64 million (23.6%) remained in the TR Clearing Account. As of October 2012, the amount in the TR Clearing Account was $69 million.

The Panel acknowledges that it is not possible to ensure that congestion rents will always equal TR payouts. The Panel identified TR "overselling" as situations where the real-time intertie transfer capability in an hour is less than the amount of TRs outstanding, usually due to planned outages unknown to the IESO at the time of the relevant TR auction, or to forced outages. The

[123] All else being equal, the more TR's sold, the greater the TR auction revenues. It is also possible that the greater the number of TRs outstanding the higher probability of congestion, thereby increasing the value associated with holding a TR.

Panel recognizes that there will be many cases in which an overselling of TRs becomes apparent only after the TR auction has occurred. Similarly, constrained-on or constrained-off transactions and differences between the limits in the unconstrained and constrained schedules will be difficult to determine within the lead times applicable to TR auctions, and specific transaction failures are not ascertainable until real-time. Nevertheless, the Panel expects that it may be possible to use historical data to estimate average ratios that could be used to mitigate the impact of these chronic sources of congestion rent shortfall.[124] As discussed in section 4.3. below, changes to the IESO's policies related to the auction quantities for short-term and long-term TRs could also help to reduce the overselling risk by increasing the prospect of outages being known and taken into account in determining the number of TRs to be auctioned at any given time.

Given the significant continuing congestion rent shortfalls observed in 2011 and 2012, the Panel believes that this issue should be promptly addressed by the IESO. The Panel therefore reiterates the recommendation that it originally made in its August 2010 Report: [125]

<u>Recommendation 3-2:</u>

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

---

[124] Recognizing that the TR market is settled on an hourly basis, whereas TRs cover a period of one month or one year, the Market Rules contemplate that the TR Clearing Account may temporarily fall out of balance. For example, an interface de-rating that was either unexpected or went beyond normal contingency planning would result in the effective transfer capability of the line being less than the quantity of outstanding TRs. Accordingly, if the intertie were to become congested, TR payouts would exceed congestion rent collected. To manage these potential imbalances, section 4.18.3 of Chapter 8 of the Market Rules requires that the IESO Board of Directors establish a Reserve Threshold for the TR Clearing Account. The Reserve Threshold was $10 million until 2007, when it was increased to the current level of $20 million.

[125] See Recommendation 3-5 in the Panel's August 2010 Monitoring Report (at p. 164), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf. At the time, the IESO noted that it also agreed with this recommendation, but again that efforts to address this recommendation needed to be put on hold. See "*IESO Responses to the Market Surveillance Panel (MSP) Report (Period: November 2009 to April 2010)*" available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20120621.pdf.

4.2.6 Disposition of Auction Revenues Credited to the TR Clearing Account

Prior to market opening, the Minister of Energy commissioned the Market Design Committee (MDC) to advise on the structure of the proposed Ontario electricity market. The MDC's final report established the fundamental framework for the eventual design of the Ontario market, and included the following recommendation regarding the TR market:

> *We recommend that the congestion rentals collected from the intertie pricing approach be used by the IMO to support a system of "financial" rights or hedges that would be allocated, through IMO auctions, to market participants as a means to hedge the price uncertainties associated with congestion-related price differences on IMO-controlled interties. <u>Net auction revenues should be used to offset revenue requirements for Basic Use [transmission] Service.</u> The amounts by which the settlement surplus from intertie transactions exceed or are less than the payment obligations of the allocated rights for any settlement period should be managed through an uplift account.*[126] (emphasis added)

In the Panel's view, the MDC's implicit expectation that the use of congestion rents to support a system of financial rights or hedges would involve congestion rents being collected in amounts that should approximately equal TR payouts has been reflected in the Market Rules.[127]

Similarly, the Market Rules also incorporate the MDC's recommendation that net auction revenues should be used to offset transmission charges. Specifically, the Market Rules authorize

---

[126] See Chapter 4 of the Market Design Committee's Final Report, particularly p. 13, available at http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/FinalReport/Vol1/chapter4-TransmissionDistribution.pdf. Along the same lines, the Transmission and Distribution Technical Panel (a working group established under the auspices of the MDC to assist in the development of the market design), made the following recommendation to the MDC: "Proceeds for the auction would be fed back to the internal customers by using them to contribute to the fixed costs of the embedded transmission system." See Appendix 4 of the Market Design Committee's Final Report, particularly p. 38, available at http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/FinalReport/Vol3/Appendix%204%20-%20TD%20Tech%20Panel%20Report.pdf

[127] See section 4.6.1 of Chapter 8 of the Market Rules, referred to above. If TR payouts were to exceed congestion rent collected then, on an aggregate basis, the financial rights would compensate a TR holder beyond what was necessary to fully hedge an intertie transaction.

the IESO Board of Directors to debit the TR Clearing Account for the purposes of offsetting "transmission services charges",[128] which are defined by the Market Rules as "all charges administered by the IESO to recover the costs of transmission services".[129] One such payment occurred in 2007 when the IESO Board of Directors approved a $57 million disbursement of TR Clearing Account funds to wholesale customers (12 payments totaling $4.75 million each, beginning in April 2007).[130]

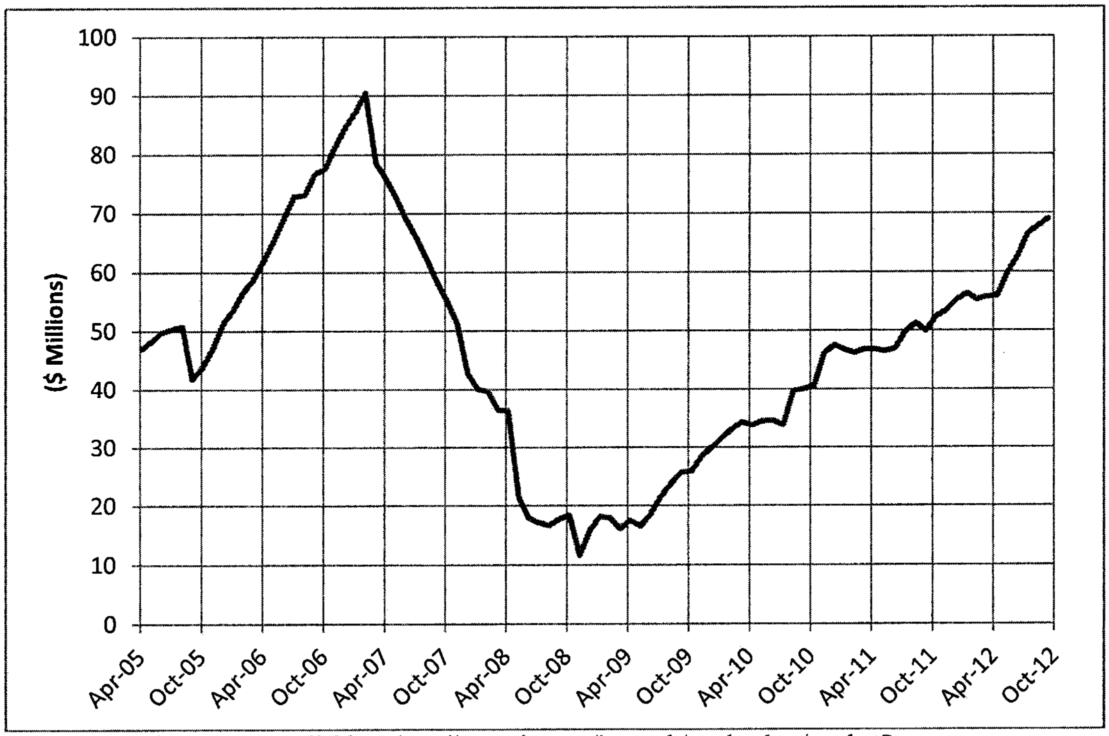
Figure 3-3 displays the TR Clearing Account balance from April 2005 to October 2012. The account balance has grown steadily since the $57 million payment authorized by the IESO Board of Directors in 2007. As of October 31, 2012, the balance in the TR Clearing Account was $69.3 million, substantially above the $20 million Reserve Threshold established by the IESO Board of Directors and almost at the level at which it was when the last disbursement was made by the IESO.

[128] See section 4.18.1.5 of Chapter 8 of the Market Rules, available at http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter8.pdf. The other authorized bases for debiting the TR Clearing Account are for TR payouts (section 4.18.1.3) and TR resale market transactions (section 4.18.1.4 – not implemented).

[129] See Chapter 11 of the Market Rules, available at http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter11.pdf

[130] See IESO "Participant News" dated May 10, 2007, available at http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=3453 .

Figure 3-3: TR Clearing Account Balance
April 2005 to October 2012



Source: IESO monthly reports available at http://www.ieso.ca/imoweb/marketdata/marketSummary.asp

Recommendation 3-2 above calls for the IESO to take steps to restore the balance between TR payouts and congestion rents collected. If implemented, that recommendation will result in a larger TR Clearing Account balance that can be periodically used to offset transmission charges. In the meantime, the Panel is not aware of any reason why an amount in excess of the $20 million Reserve Threshold set by the IESO Board should be retained. The Panel therefore makes the following recommendation:

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.

4.3 Transmission Rights Issues at the Minnesota Interface

In this section the Panel discusses the congestion rent shortfall observed in respect of imports on the Minnesota intertie as a result of a series of outages experienced during the Winter 2012 Period (the period from November 2011 to April 2012). Further to that analysis, the Panel makes a recommendation aimed at mitigating overselling and congestion rent shortfalls that could be applied to the IESO's TR auction policies prior to any changes that may arise as a result of any broader reassessment of the design of Ontario's TR market by the IESO.

4.3.1 Congestion

The Minnesota interface represents roughly 2% of Ontario's total intertie transfer capability.[131] In its August 2010 report, the Panel found that: [132]

(i) The Minnesota interface accounted for 17% ($20 million) of the total congestion rent shortfall from May 2003 to April 2010, of which 61% ($12 million) was due to the overselling of TRs and the remainder was due to the two-schedule market design.

(ii) Congestion rent shortfall in the import direction accounted for 63% ($13 million) of the total Minnesota shortfall, of which 46% ($6 million) was due to the overselling of TRs and 54% ($7 million) was due to the two-schedule market design.

[131] The normal Minnesota intertie transfer capability is 140 MW in the export direction, and 90 MW in the import direction.
[132] See the Panel's August 2010 Monitoring Report (at pp. 161-163), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.

Since 2010, the Minnesota interface has frequently been import-congested in the unconstrained schedule, even though exports are often flowing the other way. Table 3-3 lists the total number of import congestion hours at the Minnesota interface from May 2010 to April 2012, as well as the average ICP during congested hours. In October 2011, and again in January, March and April 2012 (the "four months of interest"), the interface was import-congested during 30% of the operating hours, often with a highly negative ICP. During the four months of interest, the weighted average hourly ICP during import congested hours was -$78.39/MWh compared with a weighted average hourly ICP of -$10.32/MWh during all other months over this two-year period.[133]

[133] The weighted average hourly ICP during all months in the two-year period was -$24.41/MWh, and reflects the distortive effects of the ICPs in the four months of interest.

Table 3-3: Import Congestion and Average Intertie Congestion Price at the Minnesota Interface May 2010 to April 2012 (number of hours and $/MWh)

Month	No. of Hours with Import Congestion	Average ICP in Congestion Hours ($/MWh)
May-10	404	-7.76
Jun-10	429	-8.21
Jul-10	448	-12.81
Aug-10	461	-14.02
Sep-10	292	-9.22
Oct-10	342	-8.13
Nov-10	419	-11.14
Dec-10	307	-5.70
Jan-11	157	-5.70
Feb-11	303	-19.50
Mar-11	405	-11.71
Apr-11	292	-8.60
May-11	273	-9.29
Jun-11	90	-18.89
Jul-11	150	-11.47
Aug-11	113	-4.42
Sep-11	216	-13.44
Oct-11	230	-43.17
Nov-11	181	-4.77
Dec-11	66	-3.59
Jan-12	291	-68.32
Feb-12	72	-8.94
Mar-12	205	-145.08
Apr-12	155	-60.15
Total	**6,301**	**-24.41**

An intertie may experience import congestion for a variety of reasons, including but not limited to: a large difference between the Ontario MCP and external market prices; forced outages or de-ratings at the interface; or the offer strategy of intertie traders. Upon further review of the congestion events identified in Table 3-3 above, the Panel determined that multiple de-ratings on the intertie caused the quantity of outstanding TRs to significantly exceed the real-time Scheduling Limit for extended periods of time.

4.3.2 Congestion Rent Shortfall

The import congestion hours identified in Table 3-3 caused significant congestion rent shortfall at the Minnesota interface. As shown in Table 3-4, the total payouts to import TR holders at the Minnesota interface from May 2010 to April 2012 were over \$9.4 million, while the net congestion rent collected by the IESO was only \$73,000 — a shortfall of over \$9.3 million. Of that shortfall, \$3.7 million (39%) was accrued during the four months of interest.

Table 3-4: TR Payouts and Congestion Rent Collected for Imports at the Minnesota Interface May 2010 to April 2012 ($ thousands)

Month	TR Payouts ($000)	Congestion Rent* ($000)	Congestion Rent Shortfall ($000)
May-10	282	-64	346
Jun-10	317	-54	371
Jul-10	373	-86	459
Aug-10	421	-208	629
Sep-10	175	-23	198
Oct-10	249	-22	271
Nov-10	420	-52	472
Dec-10	206	0	206
Jan-11	81	13	68
Feb-11	532	56	476
Mar-11	427	-208	635
Apr-11	226	-142	368
May-11	228	-110	338
Jun-11	153	-74	227
Jul-11	155	-175	330
Aug-11	45	8	37
Sep-11	261	89	172
Oct-11	897	150	747
Nov-11	78	36	42
Dec-11	21	4	17
Jan-12	1,300	281	1,019
Feb-12	42	18	24
Mar-12	1,938	524	1,414
Apr-12	606	112	494
Total	**9,434**	**73**	**9,361**

* Congestion rent collected will be negative when there is import congestion in the pre-dispatch unconstrained schedule (where the congestion price is determined), but there are net exports flowing in the real-time constrained schedule. This is typically a result of low shadow prices resulting in constrained-off imports, constrained-on exports or both.

4.3.3 Reductions of the Import Scheduling Limit

During the four months of interest, the transmission line that links the Minnesota border with a major transformer station in the northwest region of Ontario (the K24F transmission line) was out of service on the following dates:

- October 13 to October 20, 2011;
- October 24 to November 4, 2011;
- January 9 to January 29, 2012; and
- March 19 to April 23, 2012.

The loss of the K24F line caused the IESO to reduce the Scheduling Limit for imports at the Minnesota interface to 65 MW, from a normal transfer capability of 90 MW.[134] In addition to the outage of the K24F line, a generator in the area was also out of service for numerous planned and forced outages on the following trade dates:

- Planned for October 14 to October 24, 2011, and extended as a forced outage to November 9, 2011;
- December 23, 2011 to January 30, 2012; and
- February 27 to April 23, 2012.

With the generator out of service, the local system's ability to withstand a large and sudden drop in power supply brought about by a loss of imports from Minnesota was reduced. In order to mitigate this risk, the IESO limited the import transfer capability at the Minnesota interface to 15 MW during the period in which both the K24F line and the generator were on planned outages.[135]

[134] While K24F is not the transmission line that traverses the Minnesota/Ontario border, the IESO's dispatch scheduling optimizer (DSO) must prepare for a potential contingency wherein an additional transmission line is forced out of service, causing imports to overload a nearby transmission line.
[135] The IESO has advised the Panel that if the generator in question is out of service but all other elements are in-service there is no impact on the transfer capability at the Minnesota interface.

4.3.4 Transmission Rights sold in Quantities Exceeding the Real-time Scheduling Limit

The IESO has various policies that govern the quantity of short-term and long-term TRs made available for sale in respect of a given intertie. The IESO establishes the quantity of TRs to be auctioned based in large part on the forecasted Scheduling Limit of the intertie for the trade dates covered by the TRs. The IESO uses the maximum achievable transfer capability as a starting point and adjusts downward based on anticipated conditions, such as equipment outages and security requirements. More specifically, when determining the quantity of TRs for sale the IESO considers individual outages longer than one month for long-term auctions, and individual outages exceeding one week for short-term auctions.[136] The composition of long-term versus short-term TRs is largely dependent on whether or not the intertie is a single-circuit or multi-circuit transmission line. For single-circuit interties, such as the Minnesota intertie, the IESO normally sells long-term TRs up to the Scheduling Limit forecasted for the intertie for the coming year (leaving no TRs for sale at short-term auctions).

Table 3-5 displays the quantity of outstanding TRs at the Minnesota interface by month, from May 2010 to April 2012. In accordance with the single-circuit TR policy noted above, all TRs sold in that two-year period were long-term TRs. As evidenced by the IESO's decision to sell TRs totaling the maximum transfer capability of the intertie (90 MW) for all months from October 2010 to December 2011, the IESO did not foresee any individual de-ratings longer than one month on the Minnesota intertie at the time the quarterly auctions were held. Table 3-5 also displays the average real-time Scheduling Limit by month. As a result of frequent de-ratings on the Minnesota intertie, the real-time Scheduling Limit was often much less than the number of outstanding TRs. This resulted in TRs being oversold relative to the average real-time Scheduling Limit in all but two months during the two-year period at issue. The average discrepancy was 28%.

[136] Outages of shorter lengths may be considered on a case-by-case basis, but are not always reflected in the amount of TRs for sale. For more details, see IESO Market Manual 7, Part 11: Transmission Reliability Margin Implementation (at p. 8), available at http://www.ieso.ca/imoweb/pubs/tr/TRMID_IESO_PRO_0729.pdf

Table 3-5: Average Real Time Scheduling Limit and Transmission Rights Outstanding for Imports at the Minnesota Interface May 2010 to April 2012 (MW)

Month	Average Real-Time Scheduling Limit (MW)	TRs Outstanding (MW)	Difference	
			MW	%
May-10	75	90	15	16
Jun-10	79	90	11	12
Jul-10	68	65	-3	-4
Aug-10	62	65	3	5
Sep-10	76	65	-11	-17
Oct-10	64	90	26	29
Nov-10	62	90	28	31
Dec-10	81	90	9	10
Jan-11	77	90	13	14
Feb-11	35	90	55	61
Mar-11	39	90	51	57
Apr-11	40	90	50	55
May-11	57	90	33	36
Jun-11	18	90	72	80
Jul-11	67	90	23	25
Aug-11	78	90	12	13
Sep-11	75	90	15	17
Oct-11	53	90	37	41
Nov-11	77	90	13	15
Dec-11	81	90	9	10
Jan-12	38	65	27	42
Feb-12	49	65	16	24
Mar-12	36	65	29	45
Apr-12	21	65	44	68
Weighted Average	**59**	**83**	**24**	**28**

4.3.5 Proportion of TRs Sold in Short-Term Auctions

Outages and de-ratings can be broken down into known and unknown events, based on whether or not the IESO was aware of them at the time of the relevant auction. In the Panel's view, TR policies that maximize opportunities for the IESO to account for outages and de-ratings in determining the quantity of TRs to be sold would assist in mitigating the risk of congestion rent shortfalls.

Outages and de-ratings unknown by the IESO at the time of the relevant TR auction will often lead to considerable divergences between the quantity of outstanding TRs and the real-time Scheduling Limit. The likelihood of unknown outages or de-ratings occurring increases the further into the future the IESO sells TRs. At a long term auction, TRs are sold for trade dates up to 13.5 months into the future,[137] leaving a considerable period of time for additional planned or extended unplanned outages to arise. By selling TRs closer to the relevant trade dates, the IESO will have more accurate and complete information at its disposal on which to estimate the eventual real-time Scheduling Limit, helping to mitigate congestion rent shortfall.

One way in which the IESO could minimize its long-term TR commitments is by altering the composition of long-term versus short-term TRs for sale. Table 3-6 below displays the quantity of long-term import TRs sold for the Minnesota interface at each quarterly auction, and the quantity of outstanding TRs for quarterly trade periods in 2011 and 2012.

[137] Long-term TRs are auctioned every three months, and cover trade dates for the period of one year commencing in the month that is one and a half months from the date of the auction.

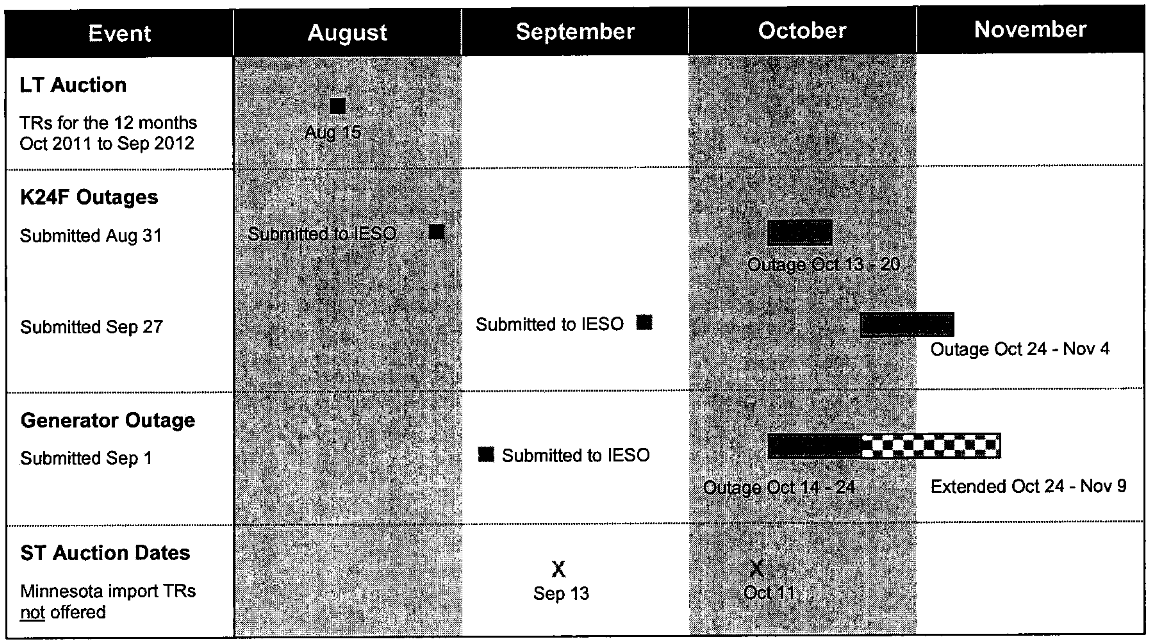
Table 3-6: Long-Term Import TRs Outstanding at the Minnesota Interface January 2011 to December 2012 (MW)

Month in Which Long-Term TR Auction was Held	Trade Dates Covered by TRs						
	2011				2012		
	January - March	April - June	July - September	October - December	January - March	April - June	July - September
May 2010	10	10					
August 2010	55	55	55				
November 2010	25	25	25	25			
February 2011		0	0	0	0		
May 2011			10	10	10	10	
August 2011				55	55	55	55
November 2011					0	0	0
February 2012						0	0
May 2012							0
Total Outstanding	**90**	**90**	**90**	**90**	**65**	**65**	**55**

Between January 2011 and September 2012, all outstanding TRs for the Minnesota intertie were sold at long-term auctions. The Panel considers this practice unnecessarily risky, and notes that it has contributed to a significant amount of congestion rent shortfall. To illustrate the benefit of not selling all TRs at long-term auctions, the following analysis will focus on the October 2011 to December 2011 trade dates (specifically October and November) and the August 2011 long-term auction.

As noted in section 4.3.3, there were two outages to the K24F transmission line and one outage to a local generator that affected the Scheduling Limit at the Minnesota interface during October 2011 and November 2011. These outages led to a Scheduling Limit of 15 MW (down from a maximum transfer capability of 90 MW) for the majority of the time that the outages were in effect. The first K24F outage period lasted 8 days, from October 13 to 20, 2011, and according to the IESO was first submitted to it on August 31, 2011. The second K24F outage period lasted 12 days, from October 24 to November 4, 2011, and was first submitted to the IESO on September 27, 2011. The planned part of the generator outage lasted 11 days, from October 14 to 24, 2011, and was first submitted to the IESO on September 1, 2011. On October 24, 2011 the generator was forced out-of-service, extending the outage until November 9, 2011. Figure 3-4 provides a visual representation of the relevant auction dates, outage notifications, and outages.

Figure 3-4: Auction Dates, Outage Notifications Dates, and Outages Respecting the Minnesota Intertie
August to November, 2011



None of the outages were known to the IESO at the time of the August 2011 long-term auction. The IESO offered 55 MW of TRs for sale at the August 2011 long-term auction, all of which were bought bringing the outstanding TR position for the October 2011 to December 2011 trade dates to the maximum transfer capability of 90 MW. When the Minnesota intertie was later de-rated, large congestion rent shortfalls accrued (see Table 3-4).

Reserving a portion of TRs for single-circuit interfaces to be sold at short-term auctions would reduce the IESO's exposure (and by extension the exposure of loads) to events that could cause significant congestion rent shortfalls. If the IESO always reserved a portion of TRs for sale at short-term auctions, it could adjust the number of TRs sold to account for planned (or in some cases lengthy unplanned) outages of which it becomes aware closer to the TR auction date. To illustrate, when all available TRs are sold on a long-term basis, the IESO must select an auction quantity based on planned outages that are known 1.5 to 13.5 months in advance. However, when a portion of the maximum potential TRs are reserved for auction on a short-term basis, the IESO can adjust the auction quantities based on outages that are known as little as 0.5 to 1.5 months in advance.

Additionally, outages of shorter duration are more likely to be accounted for in determining the quantity of TRs for sale at short-term auctions than is the case with long-term auctions. As discussed earlier, when determining the quantity of TRs to sell the IESO, as a matter of policy, only considers outages of one month or longer for long-term auctions, and outages of one week or longer for short-term auctions. As a result, a known planned outage of 29 days or less may not be accounted for in determining the number of long-term TRs for sale, whereas that same outage would be taken into account in determining the quantity of TRs for sale at a short-term auction (provided the outage is longer than 6 days).

Taking the example above, the October 13-20, 2011 K24F outage was submitted on August 31, 2011 and could have been taken into account for the short-term auction held on September 13, 2011 (for TRs valid in October 2011). Similarly, the October 24 to November 4, 2011 K24F outage was submitted on September 27, 2011 and could have been considered in setting the quantities for the short-term auction held on October 11, 2011 (for TRs valid in November 2011). The generator outage was submitted on September 1, 2011 and could also have been considered in setting the quantities for the September 13, 2011 short-term auction. In each of these cases, the IESO could have reduced the total quantity of TRs for sale,[138] thereby reducing the likelihood and magnitude of congestion rent shortfall.

Selling a combination of short and long-term TRs not only benefits the IESO, it also benefits the market participants who purchase TRs. The time period covered by a TR is a fundamental characteristic of the product. A short-term TR and a long-term TR cover different periods, which may be of greater or lesser interest (value) to particular physical traders or financial purchasers at various times depending on their business strategies.[139] Potential purchasers are

---

[138] For example suppose the IESO offered only 10 MW of TRs for sale at the August 15, 2011 long-term auction, and withheld the remaining 45 MW for possible sale at the relevant short-term auctions (i.e. a 'reserve' of 50% of the normal Minnesota Import Scheduling Limit — meaning a total of 45 MW offered at long-term auctions, and 45 MW possibly offered at short-term auctions). When the IESO was informed of the October 2011 outages that would eventually result in an average intertie transfer capability of 53 MW for the month (see Table 3-5), the IESO could have restricted the quantity of short-term TRs sold in the September 13, 2011 auction to 8 MW, bringing the outstanding TR commitment to 53 MW for the month of October 2011.

[139] For example, market participants looking to hedge financial transactions have a much better sense of expected congestion and therefore their potential interest in purchasing a TR, at a short-term auction of two weeks before the

likely to be better off if there are at least some short-term TRs available for auction (on each interface in each direction) every month, in addition to the quarterly auctions of long-term TRs. In the worst case, where there is absolutely no demand (i.e., no purchaser places any value on short-term TRs and no bids are received) the TRs will remain unsold. In all other cases, purchasers will benefit by obtaining the financial protection against uncertainty provided by a TR at a price equal to (or less than) the value they place on that product at the time the auction occurs.

In determining a target mix for short-term and long-term TRs (either generally or on an intertie-by-intertie basis), the IESO may find it useful to look at historic planned and forced outage information. This would allow the IESO to estimate the number of TRs that should be reserved for short-term auctions, thus allowing the IESO to account for outages that are planned but notified with relatively short lead times and to provide for the contingency attributable to forced outages. In addition, the relative prices in historic auctions may provide the IESO with indications of the relative demand for long-term versus short-term TRs from purchasers, and this could inform the "demand side" assessment of a target reserve margin.

In summary, reserving some portion of TRs for sale at short-term auctions potentially offers significant benefits for TR holders and the IESO, while also reducing loads' exposure to the risks of congestion rent shortfalls (including the loss of offsets against transmission service charges they might otherwise have the benefit of). Accordingly, the Panel recommends the following:

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.***

beginning of a trading month relative to the time lags involved with purchasing long-term TRs. Market participants looking to make short-term investments or adjust their hedge position from month-to-month would also benefit from the sale of TRs at a short-term auction.

As this recommendation pertains to IESO operating policies, the Panel believes that it can be addressed promptly and need not await the broader reassessment of the TR market recommended earlier.

4.3.6 Spreading Out the Sale of Long-term TRs

Until recently, it had been the policy of the IESO to sell all available TRs at the earliest relevant long-term auction.

The experience on the Minnesota interface illustrates how this approach can restrict the IESO's flexibility, limit the opportunities for TR purchasers, and increase the risk of congestion rent shortfalls. The August 2011 auctioning of the maximum available TR quantity of 55 MW locked this quantity in until September 2012 and precluded downward adjustment of the outstanding TRs at the November and February quarterly auctions. None of the outages affecting the real-time Scheduling Limit were known to the IESO at the time they sold 55 MW of TRs at the August 2011 long-term auction. When the outages occurred, the real-time average intertie transfer capability dropped, and was exceeded by the number of MWs of TRs outstanding at the time. This contributed to considerable congestion rent shortfall. In addition, with respect to the April 2011 to June 2011 trade dates displayed in Table 3-6, the IESO sold TRs in May, August and November, 2010 which resulted in the outstanding TRs equaling the intertie's maximum transfer capability (90 MW). Accordingly, when the February 2011 long-term auction was held, the IESO was not able to offer any additional TRs. This meant that there were no TRs for sale in respect of the trade dates from April 2011 to March 2012, although there may have been demand for such a product.

The Panel understands that the IESO has recently adopted a proportional selling approach under which the TRs offered for sale at a given long-term auction will be approximately 25% of the forecasted intertie transfer capability.[140] The Panel supports this change in policy.

---

[140] See IESO Market Manual 7, Part 11: Transmission Reliability Margin Implementation (at p. 7), available at http://www.ieso.ca/imoweb/pubs/tr/TRMID_IESO_PRO_0729.pdf

Congestion rent shortfalls have been persistent since market opening. All of the above recommendations related to transmission rights in this report are directed at restoring balance by bringing the TR Clearing Account back to the level where congestion rent collected is approximately equal to TR payouts, as originally contemplated.

Congestion rent surpluses are conceptually possible, but they can only arise when the quantity of outstanding TRs is less than the intertie transfer capability, generally leading to congestion rent collected in excess of TR payouts when congestion occurs. The Panel does not believe that the recommendations set out in this report will result in the systematic underselling of TRs relative to the real-time intertie transfer capability, or in systematic congestion rent surpluses.

4.4 Issues at the Manitoba Interface

4.4.1 Introduction

As noted in Chapter 2, while no Intertie Offer Guarantee (IOG) payments exceeded the Panel's threshold for anomalous events, the Panel did identify an hour during the Winter 2012 Period with a large IOG payment.

The highest hourly IOG payment of the Winter 2012 Period occurred on March 5, 2012 in HE 23. During that hour one market participant ('Participant A') received $325,407 in IOG payments, of which $307,925 was paid in respect of imports at the Manitoba interface, with the remaining $17,482 paid in respect of imports at the Minnesota interface.

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.[141]

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 day-ahead commitment process (DACP)[142] and the real-time price clears below its 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.[143]

All IOG payments associated with the March 5, 2012 event were day-ahead payments. Day-ahead, the import transactions were scheduled at positive prices, but in real-time the interface price dropped precipitously, triggering a large IOG payment. As discussed in greater detail below, two factors contributed to the highly negative real-time prices at the relevant interfaces, and thus to the high IOG payments: (i) an offer price reduction on the imports scheduled day-ahead, and (ii) additional imports offered at highly negative prices following the completion of the DACP.

The following sections examine the market conditions and participant behavior that resulted in the highly negative real-time price at the Manitoba interface, in respect of which the largest of the IOG payments occurred.

---

[141] 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.

[142] This is the Enhanced DACP referred to in earlier sections of this Chapter. For ease of reference, this section refers more simply to DACP.

[143] In past reports, the Panel has questioned the appropriateness of off-peak real-time IOG payments, given that reliability concerns during off-peak hours are extremely infrequent. 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

4.4.2 Reduction in Offer Price for Imports Scheduled Day-ahead

Day-ahead, Participant A offered to import 150 MW at $34/MWh and an additional 55 MW at $44/MWh, all across the Manitoba interface. Of the imports offered, 152 MW were committed by the DACP (150 MW at $34/MWh and 2 MW at $44/MWh). Imports committed day-ahead are guaranteed to receive, at a minimum, the offer price at which they were committed—in this case, $34/MWh for 150 MW and $44/MWh for 2 MW. Following the completion of the DACP, Participant A reduced its offer price on all 152 MW of its committed imports to -$2,000/MWh. This action ensured that Participant A's committed import megawatts would be scheduled in the final pre-dispatch run, and that Participant A would receive its guaranteed day-ahead offer price while avoiding a potential failure charge.[144]

4.4.3 Incremental Imports Offered at a Highly Negative Price

With 152 MW of committed imports offered at -$2,000/MWh, but guaranteed to receive the respective day-ahead offer prices once energy and IOG payments are netted, Participant A entered a new import offer of 53 MW at approximately $25/MWh. This incremental offer was entered into the market at the same time that Participant A reduced the offer price on its day-ahead import transactions. The incremental import offered at $25/MWh was uneconomic during all pre-dispatch schedules.

With negative-priced imports offered totaling 152 MW, an additional 53 MW offered at $25/MWh but not scheduled, and an intertie Scheduling Limit of 205 MW, the interface was never congested during any of the pre-dispatch runs in advance of the two-hour ahead run. With no congestion the pre-dispatch interface price was the same as the Ontario MCP, which was consistently between $21/MWh and $24/MWh. In response to these price signals, another

[144] An import may not be scheduled due to system situations even though it is offered at -$2,000/MWh. However, the importer will be exempted from the failure charge if the importer has passed the Offer Price Test. An importer will pass the Test if it has offered its day-ahead schedule at -$2,000/MWh in real-time. For details, see the IESO's Charge Type and Equations, available at: http://www.ieso.ca/imoweb/pubs/settlements/IMO_Charge_Types_and_Equations.pdf.

participant offered to import 50 MW at $18.02/MWh two hours before the delivery hour. There were no other imports offered or exports bid at the interface during the hour in question.

In the meantime, following the final actionable price signal (the three-hour ahead pre-dispatch price) but before the deadline to submit final offers and bids, Participant A increased its offered quantity from 53 MW to 55 MW on the incremental portion of its import offer, and reduced the offer price on all incremental megawatts to -$1,999.99/MWh. The quantity increase made Participant A's final import position 207 MW, all offered at highly negative prices and displacing the other participant's 50 MWs offered at $18.02/MWh. With a final Ontario pre-dispatch price of $22.03/MWh, Participant A was alone in offering economic imports. These were in excess of the 205 MW intertie transfer capability, causing import congestion, a large drop in the intertie zonal price to -$1,999.99/MWh and a large IOG payment to all imports scheduled day-ahead.

Table 3-7 displays Participant A's import offer structure in the lead up to real-time.

***Table 3-7: Participant A's Import Offer Structure over Time
March 5, 2012, HE 23
(MW & $/MWh)***

Time	Offer #1		Offer #2		Offer #3		Total MW
	MW	$/MWh	MW	$/MWh	MW	$/MWh	MW
March 4 before DACP run	150	$34	55	$44	0	N/A	205
Scheduled in DACP	*150*	*$34*	*2*	*$44*	*0*	*N/A*	*152*
March 4 following DACP	150	-$2,000	2	-$2,000	53	$25	205
March 5 following PD-3 publication but before deadline for HE 23 offers	150	-$2,000	2	-$2,000	55	-$1,999.99	207
Scheduled in final pre-dispatch run	*150*	*-$2,000*	*2*	*-$2,000*	*53*	*-$1,999.99*	*205*

4.4.4 Interplay between TR Payouts and IOG Payments

With a final pre-dispatch Ontario MCP of $22.03/MWh and a Manitoba intertie zonal price of -$1,999.99/MWh, the ICP was set at -$2,022.02/MWh. The import congestion caused by the last-minute offer change by Participant A resulted in large payouts to all import TR holders. For the month of March 2012, Participant A owned 190 MW of import TRs, while six other market participants owned a combined 15 MW. Import TR owners are paid the absolute value of the ICP for each megawatt of TRs they hold when the intertie is import-congested in the final pre-dispatch run; in this case $2,022.02 per MW of TRs owned.

Table 3-8 lists all estimated payments associated with the Manitoba interface made during the hour in question. All payments considered, importers at the Manitoba interface realized combined profits of nearly $310,000 for the hour, of which approximately $279,515 was made by Participant A. On a profit-per-MWh delivered basis, Participant A made approximately $1,363/MWh for that hour.

Table 3-8: Estimated* Gross Profits Associated with the Manitoba Interface
March 5, 2012, HE 23
(MW, $/MWh & $)

Payment Type	Participant A			All Other Participants		
	Total MW subject to Payment (MW)	Relevant Price ($/MWh)	Total Payment Amount ($)	Total MW subject to Payment (MW)	Relevant Price ($/MWh)	Total Payment Amount ($)
Energy Market	205	-1,999.99	(409,998)	0	N/A	0
Cost of Power in External Market	205	18.82**	(3,858)	0	N/A	0
Day-ahead Intertie Offer Guarantee	150 2	2,033.99 2,043.99	305,099 4,088	0	N/A	0
Transmission Rights Payout	190	2,022.02	384,184	15	2,022.02	30,330
Estimated Gross Profit***	**$279,515**			**$30,330**		
Estimated Gross Profit per MWh Delivered	**$1,363/MWh**			**N/A**		

* Payment amounts are estimated. Final settlement amounts vary minimally due to nuances in the various settlement equations.

** Based on a Midwest Independent Transmission System Operator - Manitoba nodal price of $13.82/MWh, plus assumed transaction costs of $5.00/MWh.
*** The cost of purchasing TRs is not included in the gross profit calculation, as the purchasing cost is sunk and not linked to an individual transaction. Allocating the sunk cost incurred by Participant A of purchasing TRs for the month of March 2012 across all hours in March results in an hourly cost of $859.95 per 190 MW of TRs purchased.

Had Participant A not increased the import offer quantity on the incremental portion of its import transaction (from 53 MW to 55 MW) or not reduced its import offer price (from $25/MWh to -$1,999.99/MWh), there would have been no congestion at the interface (based on the final pre-dispatch MCP of $22.03/MWh, the final schedule would have been 152 MW of imports at -$2,000/MWh from Participant A and 50 MW of imports at $18.02/MWh from the other participant). No TR payments would have been made, and IOG payments would have been limited to the difference between Participant A's day-ahead committed offer prices ($34/MWh and $44/MWh) and the real-time intertie price had there been no congestion ($22.03/MWh).

Participant A's offer structure was profitable because of the overlapping protection provided by the IOG payment and the TR payout. As noted earlier in this Chapter, TRs are intended to provide a financial hedge against congestion-related price differences at an intertie. A TR payment ensures that an importer is paid the Ontario MCP for all megawatts that flow up to the megawatt quantity of TRs owned. This is achieved by compensating the participant for any discrepancy between the Ontario MCP and the intertie zonal price resulting from congestion at the intertie. Accordingly, import megawatts covered by TRs are fully protected from the lower price that arises when the intertie is congested.

Day-ahead IOG payments also compensate importers for a drop in the intertie zonal price caused by congestion. When a participant has an import committed day-ahead, those megawatts are guaranteed to receive at least their day-ahead offer price, and are thus protected from a drop in the real-time intertie zonal price. Changes in the intertie zonal price from day-ahead to real-time can occur for two reasons: namely; a drop in the Ontario MCP, and/or congestion at the intertie. Intertie zonal price changes due to a drop in the Ontario MCP occur when the global supply and demand conditions change, and tend to result in modest discrepancies between the real-time Ontario MCP and day-ahead pre-dispatch prices. Changes in the intertie zonal price caused by intertie congestion can occur when offers or bids are added, removed, or altered following the

DACP, or from a reduction in the intertie Scheduling Limit. These changes can result in heavy congestion and large discrepancies between day-ahead and real-time intertie zonal prices.

With both IOG payments and TR payouts compensating importers for low prices induced by intertie congestion, a participant will be more than kept whole when the sum of its day-ahead committed megawatts and its megawatts of TRs owned is greater than the amount of megawatts they flow in real-time.[145] Taking the March 5, 2012 HE 23 events to illustrate, Participant A had 152 MW committed day-ahead, and owned 190 MW of TRs, totaling 342 MW of protection against a congestion-induced price drop. With an intertie limit and final schedule of 205 MW, Participant A effectively had protection on 137 MW of imports above what was necessary. When the market settled, Participant A had to pay the -$1,999.99 intertie zonal price on the 205 MWs of energy that flowed, but was compensated for this price drop based on its 342 MW of protection. Participant A realized a gross profit of $279,515.

Generally, if the sum of a participant's day-ahead committed megawatts and megawatts of TRs owned is greater than the intertie transfer capability, offering highly negative-priced imports in excess of the import Scheduling Limit presents no financial risk to the participant. Using the circumstances at issue to illustrate, all megawatts scheduled under the DACP (152 MW) were guaranteed the moderately positive price they were scheduled at, insulating Participant A from loss due to a reduction in the real-time price. While not directly protected under a program or guarantee, all megawatts offered by Participant A at -$1,999.99/MWh (55 MW) following the DACP were also protected against the significant downside risk suggested by the participant's offer price via the TRs held by Participant A. When congestion occurred, the highly negative energy price paid to imported power (205 MW) was more than offset by the IOG payment (covering 152 MW) and TR payouts (covering 190 MW) received. Had an offsetting export

[145] There is no double protection for imports covered by a real-time IOG and TRs. Real-time IOG payments compensate imports for a drop in the real-time zonal price relative to the one-hour-ahead pre-dispatch zonal price. Because the congestion price is calculated based on the one-hour-ahead pre-dispatch price and locked in at that level for real-time, all changes in the intertie zonal price from pre-dispatch to real-time must be a result of a change in the Ontario MCP. Accordingly, the real-time IOG only compensates for a drop in the Ontario MCP, while TRs only compensate for a price drop induced by intertie congestion. In such circumstances, there is no double protection.

been scheduled and there had been no congestion, then Participant A's import would have received the Ontario MCP.

The Panel notes that Participant A has also routinely offered imports in excess of the intertie transfer capability at the Minnesota interface, causing import congestion in a large number of hours. Much like the Manitoba situation described above, on a net basis Participant A profited from the congestion due to its position in the TR market.

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.***

Chapter 4: The State of the IESO-Administered Markets

1. General Assessment

This is the Panel's 20th semi-annual monitoring report on the IESO-administered markets. It covers the winter period November 2011 to April 2012, and also reports on market outcomes for the period May 2011 to April 2012. As in previous reports, the Panel has concluded that the energy market has operated reasonably well having regard to its hybrid design, although there were occasions where the market design, actions by market participants, or actions taken by the IESO led to inefficient or potentially inefficient outcomes.

During the winter period, the Panel completed two investigations in which it concluded that neither of the market participants engaged in gaming in respect of infeasible import transactions. The Panel currently has six investigations in progress. These investigations relate to possible gaming issues involving Congestion Management Settlement Credit and other payments. As each of these investigations is completed, the Panel will submit its investigation report to the Chair of the OEB and the report will be published on the OEB's website.[146]

2. Future Development of the Market

The Panel understands that the IESO has work programs under way to assist address various issues identified in the 2011 report of the Electricity Market Forum,[147] and has retained external advisors to assist it in that regard. The Panel believes that this work is important to the future development of the Ontario wholesale electricity markets.

[146] 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 the OEB/OEB_bylaw_3.pdf.

[147] George Vegh, "Reconnecting Supply and Demand: How Improving Electricity Pricing Can Help Integrate A Changing Supply Mix, Increase Efficiency and Empower Customers (Report of the Chair of the Electricity Market Forum)" (December 2011), available at: http://www.ieso.ca/imoweb/pubs/consult/Market_Forum_Report.pdf.

3. *Implementation of Panel Recommendations from Previous Reports*

The IESO formally reports on the status of actions it has taken in response to the Panel's recommendations. Following the release of each of the Panel's monitoring reports, the IESO posts the recommendations and its responses to those recommendations on its public web site.[148] The IESO also discusses the recommendations and its responses with its Stakeholder Advisory Committee (SAC) and with the IESO Board of Directors.

The Panel's April 2012 Report contained five recommendations, four of which were directed to the IESO and one of which was directed to the OPA and the Government of Ontario.

3.1 Recommendations to the IESO from the Prior Report

The relevant IESO responses to the four recommendations in the Panel's April 2012 Report are reproduced in Table 4-1.[149]

Table 4-1: IESO Responses to Recommendations in the Panel's November 2011 Monitoring Report

Recommendation	IESO Response
Recommendation 3-1 *The Panel recommends that the IESO continue to pursue the introduction by the Northeast Power Coordinating Council of a revised Regional Reserve Sharing Program and the negotiation of any necessary implementing agreements with neighbouring ISOs as expeditiously as possible.*	"The IESO agrees with this recommendation and is pursuing this within the requirements of NPCC's Regional Reliability Reference Directory #6. Directory #6 contains NPCC's set of requirements regarding participation in Reserve Sharing Groups (RSG). These requirements outline who can participate in an RSG, the obligations of the RSG once formed (for example each RSG will have an RSG Agreement), and the Reserve Sharing Implementation requirements within the RSG Agreement."
Recommendation 3-2 *The Panel recommends that the IESO implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping-down generators.*	"The MSP monitoring document which provides guidance to generators regarding offer prices used to signal an intention to come offline has resulted in a substantial reduction in CMSC payments to ramping down generators. The IESO's judgement is that the remaining CMSC amount of $3-4M of the original $12M may well be consistent with the cost of efficiency losses that generators incur when ramping down and that removing ramping down CMSC from generator revenues would require an alternate mechanism to allow for generators to recover legitimate losses.

[148] The IESO's responses to recommendations set out in Panel reports dating back several years are available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20120621.pdf.
[149] *Ibid.*

Recommendation	IESO Response
	The IESO will conduct a review of the real-time and day-ahead guarantee programs commencing this fall and plans to have recommendations related to issues requiring consideration by Q1 2013. Ramping down CMSC will be considered in the context of this broader review to ensure that generators are compensated for only legitimate costs incurred during ramp down."
Recommendation 3-4 *The Panel recommends that the IESO improve its internal controls and external processes to ensure that all information about outages and other relevant contingencies is taken into account when establishing the level of Transmission Rights to be auctioned.*	"The IESO agrees with this recommendation. Since the event referenced in the MSP Report, the IESO has and will continue to implement new processes with the neighbouring jurisdictions to improve communication of outage plans, allowing this information to be considered in the sales of Transmission Rights."
Recommendation 3-5 *The IESO should ensure that, when a trader which owns Transmission Rights has failed its intertie transactions (at the same interface in the same direction), either the Transmission Right payout should not be paid or the Congestion Rent should be charged for the quantity of the failed transactions.*	"The IESO agrees with this recommendation. The IESO currently has market rules in place to allow for the recovery of Transmission Rights payouts when the trader fails its intertie transactions, and intends to adjust settlement amounts paid or payable to traders in situations where the trader has failed to schedule the transaction with the appropriate scheduling entity other than for bona fide and legitimate reasons. Refer to the Market Rules Chapter 3, section 6.6.10A and Chapter 7, sections 7.5.8A and 7.5.8B."
Recommendation 4-1 *The Panel recommends that the IESO proceed with development work on those recommendations of the Electricity Market Forum that are directed at improving market efficiency, including the consideration of options to replace the two-schedule structure of the current market design.*	"The IESO agrees with this recommendation. The IESO is initiating work based on the Electricity Market Forum's recommendations aimed at improving market efficiency, including reviews of HOEP, Global Adjustment (GA), the two-schedule system and intertie trading. Requests for Proposals (RFP's) related to the HOEP and GA recommendations have been posted. Work on the two-schedule structure will be influenced by the results of the HOEP effort and we anticipate initiating this work by the end of the year. The IESO has begun work on the recommendations related to improved trading processes."

3.2 Other Recommendations from the Prior Report

The Panel made the following recommendation directed toward the OPA and the Government of Ontario in its April 2012 Report:

Recommendation 3-3:

The Panel recommends that the Government of Ontario and the OPA work together to ensure that Class A customers are not compensated by both the Global Adjustment allocation methodology and an OPA

Demand Response contract for the same MW of load shedding or shifting.

Through a consultant, the OPA analysed the interplay between the OPA's Demand Response 3 program and the Global Adjustment allocation methodology as part of the OPA's regular evaluation of its demand response programs. The OPA has provided relevant excerpts from the consultant's report to the Panel for its review.[150] The Panel plans to meet with the OPA to discuss the issues noted in the consultant's report.

4. Summary of Recommendations

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 (e.g., a scheduling change could affect prices as well as uplift). In such cases the recommendation is included in the category of its primary effect.[151] Within each category, the recommendations in this report have been prioritized based on the Panel's view of their relative importance.

All of the recommendations contained in this report pertain to the TR market. Four of those recommendations speak to issues associated with the design and operation of that market, and are directed at restoring balance by bringing the TR Clearing Account back to the level where congestion rent collected is approximately equal to TR payouts. The fifth recommendation relates to the interplay between the TR market and the day-ahead Intertie Offer Guarantee program.

4.1 Efficiency

Efficient dispatch is one of the IESO's primary objectives in operating the wholesale market.

[150] The OPA's response and the excerpt from the consultant's report are available at http://www.ontarioenergyboard.ca/OEB/Industry/About%20the%20OEB/Electricity%20Market%20Surveillance/Market%20Surveillance%20Panel%20Reports.
[151] The Panel does not have any recommendations in this report relating to transparency or price fidelity, but many of the efficiency and uplift recommendations would also have positive implications in these areas.

Recommendation 3-1:

The IESO should reassess the design of the Ontario transmission rights market to determine whether it is achieving its intended purpose.

4.1 Uplift and Other Payments

The Panel examines uplift and other payments[152] both as they contribute to the effective price paid by customers and as they impact the efficient operation of the market.

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.

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.

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.

[152] Uplift charges are collected from customers in the wholesale market to pay for Operating Reserve; for Congestion Management Settlement Credit, Intertie Offer Guarantee and cost guarantee program payments; and other costs such as energy losses on the IESO-controlled grid. See section 2.3.1 of chapter 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.