# OVERVIEW OF UNIFORM TRANSMISSION RATES

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002 as per the Board's Decision in Proceeding RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Ontario Uniform Transmission Rates (UTR) Schedules, which were effective on January 1, 2012 as part of the Board's Order under EB-2011-0268 issued December 20, 2011, are filed at Exhibit H2, Tab 1, Schedule 1.

Since rates are established on a uniform basis, Hydro One Transmission's requested revenue requirement for the 2013 and 2014 Test Years is a contributor to the total revenue requirement to be collected from the provincial UTRs. The revenue requirement for all the other transmitters in the province approved to participate in the UTRs must be added to that of Hydro One Transmission in order to calculate the total transmission revenue requirement for the province for the test years.[1]

The total revenue requirement from all transmitters must be allocated to the Network, Line Connection and Transformation Connection rate pools in order to establish uniform rates by pool. The revenue requirement by rate pool for the other transmitters is currently based on the proportions established by Hydro One Transmission's Cost Allocation process. Once the revenue requirement by rate pool has been established, rates are determined by applying the Provincial charge determinants for each pool to the total revenue for each pool. The Provincial charge determinants are the sum of all charge determinants, by rate pool, approved by the Board for each of the transmitters participating in the UTR.

[1] The other three transmitters currently included in the UTRs are Great Lakes Power Transmission Inc., Canadian Niagara Power Inc., and Five Nations Energy Inc.

A forecast of the 2013 and 2014 Uniform Transmission Rates is provided at Exhibit H2, Tab 1, Schedule 2 based on the values proposed for Hydro One Transmission in this application and maintaining the currently approved values for other transmitters.

# TRANSMISSION CUSTOMERS LOAD FORECAST

## 1.0 INTRODUCTION

This schedule summarizes the forecast customer demand by customer delivery point based on the load forecast methodology described in Exhibit A, Tab 15, Schedule 2. The forecast provides the information necessary for cost allocation, and to determine the charge determinants for the Network, Line Connection and Transformation Connection rate pools.

## 2.0 LOAD FORECAST FOR TRANSMISSION CUSTOMERS

### 2.1. Load Forecast Data for Cost Allocation

The load forecast data required to calculate the cost allocation of Dual Function Line Assets described in Exhibit G1, Tab 2, Schedule 1, Section 4.1.1 is the monthly coincident peak demand, adjusted for applicable losses, for each customer's transmission delivery point downstream of a Dual Function Line. The resulting allocation factors are listed in Exhibit G2, Tab 2, Schedule 1.

The sum of the forecasted monthly maximum non-coincident peak demand, adjusted for applicable losses for each customer's transmission delivery point downstream of Generation Connection Assets is required to calculate the allocation factors for Generation Connection Assets, as described in Exhibit G1, Tab 2, Schedule 1, Section 4.1.2. The resulting allocation factors are listed in Exhibit G2, Tab 3, Schedules 1 and 2.

### 2.2. Load Forecast Data for Charge Determinants

The load forecast data required to calculate the charge determinants for the rate pools is as follows:

- The monthly Coincident Peak demand values, adjusted for applicable losses, for each customer’s transmission delivery point at the time of the monthly system peak demand.
- The monthly Non-Coincident Peak demand values, adjusted for applicable losses, for each customer’s transmission delivery point, independent of the monthly system peak demand.
- The monthly demand values, adjusted for applicable losses, for each customer’s transmission delivery point that is the higher of a) the monthly Coincident Peak demand or b) 85 % of the monthly Non-Coincident Peak demand between 7 AM and 7 PM on working weekdays for each customer delivery point.

The load forecast data shown in Table 1 and Table 2 at the end of this Schedule is for all transmission customer delivery points, irrespective of the transmission service charges they attract. The charge determinants for the Line Connection and Transformation Connection pools will be a subset of the non-coincident peak demand totals shown in Tables 1 and 2. The determination of which customer delivery points are included for the purpose of calculating the charge determinants for the Network, Line Connection and Transformation Connection pools is discussed in Exhibit H1, Tab 3, Schedule 1.

As Tables 1 and 2 illustrate, LDCs represent roughly 90% of the demand. The average monthly non-coincident peak demand for LDCs is forecast to be only about 7% higher than their average monthly coincident peak demand. For end-use transmission customers the non-coincident peak is about 47% higher than their coincident peak. This illustrates that LDC demand is largely what drives the overall system peak demand, and it also reflects the increased ability of end-use transmission customers to shift load away from the system peak, or have maximum demands at different times than LDCs.

**Table 1**
**2013 Forecast Demand by Customer Category**
(The forecast demand in this table is for all customers, irrespective of whether they pay Connection Service charges)

| Category | # of Customer Delivery Points | Sum of Average Monthly Coincident Peak (CP) Demand | | Sum of Average of [Higher of Monthly CP or 85 % of NCP from 7AM to 7PM] | | Sum of Average Monthly Non-Coincident Peak (NCP) Demand | |
|---|---|---|---|---|---|---|---|
| | | MW | % of Total | MW | % of Total | MW | % of Total |
| LDCs | 437 | 18,009 | 93.0% | 18,220 | 91.0% | 19,268 | 89.7% |
| End-Use Customers | 89 | 1,314 | 6.8% | 1,626 | 8.1% | 1,939 | 9.0% |
| Transmission-Connected Generators | 89 | 33 | 0.2% | 177 | 0.9% | 279 | 1.3% |
| **TOTAL TRANSMISSION** | 615 | 19,355 | 100.00% | 20,023 | 100.00% | 21,487 | 100.00% |

**Table 2**
**2014 Forecast Demand by Customer Category**
(The forecast demand in this table is for all customers, irrespective of whether they pay Connection Service charges)

| Category | # of Customer Delivery Points | Sum of Average Monthly Coincident Peak (CP) Demand | | Sum of Average of [Higher of Monthly CP or 85 % of NCP from 7AM to 7PM] | | Sum of Average Monthly Non-Coincident Peak (NCP) Demand | |
|---|---|---|---|---|---|---|---|
| | | MW | % of Total | MW | % of Total | MW | % of Total |
| LDCs | 437 | 17,713 | 93.7% | 17,925 | 91.7% | 19,004 | 90.5% |
| End-Use Customers | 89 | 1,161 | 6.1% | 1,463 | 7.5% | 1,743 | 8.3% |
| Transmission-Connected Generators | 89 | 30 | 0.2% | 164 | 0.8% | 259 | 1.2% |
| **TOTAL TRANSMISSION** | 615 | 18,905 | 100.00% | 19,553 | 100.00% | 21,006 | 100.00% |

# CHARGE DETERMINANTS

## 1.0 INTRODUCTION

This exhibit provides the derivation of Hydro One Transmission's charge determinants for the approved rate pools, which when combined with the charge determinants of the other transmitters for the Network, Line Connection and Transformation Connection rate pools can be used by the Board to determine Uniform Transmission Rates (UTRs).

## 2.0 SUMMARY OF CHARGE DETERMINANTS

The rate pool charge determinants are summarized in Table 1 for the 2013 and 2014 Test Years. All charge determinants have been calculated per the methodology approved in the Board's EB-2010-0002 Decision.

**Table 1**
**Summary of Rate Pool Charge Determinants**

| Charge Determinant [average monthly] | Network (MW) | Line Connection (MW) | Transformation Connection (MW) | Wholesale Meter (Meter Points at Mid-Year) |
|---|---|---|---|---|
| 2013 | 20,022.8 | 19,406.2 | 16,759.0 | 118 |
| 2014 | 19,552.9 | 18,990.1 | 16,399.6 | 87 |

## 3.0 NETWORK CHARGE DETERMINANT

The Network Service charge determinant is the higher of a customer's demand coincident with the monthly system peak or 85% of the customer's non-coincident monthly peak demand between 7 AM to 7 PM as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1.

The Network charge determinant provides customers with time-of-use signals that encourage use of the transmission system outside the 7 AM to 7 PM period, for which no transmission Network charges apply. It also encourages customers to avoid the monthly system peak, with the potential for lowering their Network charges by up to 15% of their non-coincident peak demand between the hours of 7 AM to 7 PM multiplied by the Network rate.

All customers that are connected to Hydro One's transmission system incur Network Service charges on a per Transmission Delivery Point basis. The 2013 and 2014 load forecast data for each customer's Transmission Delivery Points, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Network Service charges.

## 4.0 LINE CONNECTION CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The Line Connection Service charge determinant is the customer's non-coincident monthly peak demand as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1.

All customers that utilize Line Connection assets owned by Hydro One Transmission incur Line Connection Service charges on a per Transmission Delivery Point basis. The customer demand supplied from a Transmission Delivery Point will not incur Line Connection Service charges if a customer fully owns, or has fully contributed toward the costs of, all Line Connection assets that connect the transmission delivery point to a Network station. Similarly, customers will not incur Line Connection Service charges for demand at a Transmission Delivery Point located at a Network station.

The Billing Demand for Line Connection Service is the customer's loss-adjusted demand supplied from the transmission system plus the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2 MW or more for renewable generation[1] and 1 MW or higher for non-renewable generation.

The 2013 and 2014 load forecast data for each customer's Transmission Delivery Points, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Line Connection Service charges.

## 5.0 TRANSFORMER CONNECTION CHARGE DETERMINANTS AND PAYMENT OBLIGATION

The Transformation Connection Service charge determinant is the customer's non-coincident monthly peak demand as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1.

All customers that utilize transformation connection assets owned by the Hydro One Transmission incur charges on a Transmission Delivery Point basis. The customer demand supplied from a Transmission Delivery Point will not incur Transformation Connection Service charges if a customer fully owns, or has fully contributed toward the costs of, all transformation connection assets associated with that Transmission Delivery Point.

The Billing Demand for Transformation Connection Service is the customer's loss-adjusted demand supplied from the transmission system plus the demand that is supplied

[1] This change was approved in the Transmission System Code Phase 1 Policy Decision with Reasons, Proceeding RP-2002-0120 and subsequently incorporated into the Rate Schedules issued as part of Proceeding EB-2005-0241.

by embedded generation for which the required government approvals were obtained after October 30, 1998 and which have installed capacity of 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation.

The 2013 and 2014 load forecast data for each customer's Transmission Delivery Point, adjusted for losses as appropriate, is then used to calculate the total charge determinants that attract Transformation Connection Service charges.

## 6.0 WHOLESALE METER POINTS

The forecasted number of Wholesale Meter Points is based on the 2011 year end Wholesale Meter Points and the meters anticipated to exit the wholesale meter pool based on the experience gained in the number of conversions done since 2005, as well as knowledge of the conversion requirements for the remaining meter points.

The forecasted remaining Wholesale Meter Points are:

**Table 2**

| | **# of Meter Points** | | | |
|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 |
| Year End | 140 | 136 | 99 | 75 |
| Mid Year | | | 118 | 87 |

# RATES FOR WHOLESALE METER SERVICE

## 1.0 INTRODUCTION

This Exhibit summarizes the derivation of rates applicable to the provision of Wholesale Meter Service. The Wholesale Meter Service rates are designed to recover the Wholesale Meter Pool revenue requirement identified in Exhibit G1, Tab 5, Schedule 1.

## 2.0 CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

Per the existing Rate Schedules approved by the Board in EB-2011-0268, the revenue requirement for the wholesale revenue meter function is collected from the meter service customers that are served by the Hydro One Transmission-owned wholesale revenue meters that form the Wholesale Meter Pool.

The revenue requirement for the Wholesale Meter Pool will continue to be collected using a uniform Wholesale Meter Service rate determined on a "per meter point" basis[1]. This is consistent with the approach used to set rates in Proceeding EB-2010-0002, and it is the same basis on which customers pay the exit fee when exiting the Wholesale Meter pool.

Table 1 below provides data for 2013 and 2014 on the forecast number of meter points, the revenue requirement to be recovered and the applicable rate (in $ / meter point / year) for Wholesale Meter service.

[1] A unique meter point is deemed to exist with respect to each instrument transformer associated with a metering installation that is used for the purpose of billing and settlement by the IESO.

**Table 1**

| Year | Annual Revenue Requirement ($ Million) | Forecast Number of Meter Points | Wholesale Meter Service Rate ($ / Meter Point / Year) |
|---|---|---|---|
| 2013 | 0.94 | 118 | 7,958 |
| 2014 | 0.69 | 87 | 7,941 |

There is no proposed change from the current level of $7,900.

Regulated Wholesale Meter Service charges shall not apply to any metering installation(s), and associated meter points, that have exited from the Wholesale Meter pool. It is proposed that the Exit Fee for meter installations, which is based on the average Net Book Value of stranded wholesale revenue metering assets, remain at $5,200 per meter point as approved by the Board in EB-2010-0002.

The Rate Schedule for Wholesale Meter Service, including the Exit Fee, is provided in Exhibit H2, Tab 2, Schedule 1.  As currently approved by the Board, the Wholesale Meter service charge is administered by Hydro One Transmission.

# RATES FOR EXPORT TRANSMISSION SERVICE

## 1.0 INTRODUCTION

The Export Transmission Service (ETS) rate was increased to $2/MWh, effective January 1, 2011, as directed by the OEB in the EB-2010-0002 Decision with Reasons. The previous rate of $1/MWh had been in effect since market opening.

Hydro One Transmission is not seeking changes to the ETS Rates as part of this submission.

## 2.0 BACKGROUND

The IESO collects ETS revenues and remits them on a monthly basis to Hydro One, whose transmission system is used to facilitate export and wheel-through transactions at the point of interconnection with the neighbouring markets. The ETS tariff was initially set at a rate of $1/MWh and remained at this level until December 31, 2010. When initially set, the tariff was considered by the Ontario Energy Board ("Board") to be a reasonable compromise between the many competing interests and proposals that were advanced by stakeholders in the course of Hydro One's transmission rate proceeding. Moreover, the tariff was considered by the Board to be an interim solution to a rather complex and contentious set of issues. Among other things, the contention emerged from what stakeholders believed should be the basis of, or purpose of, the tariff design and what ought to be an appropriate charge level to help defray the costs to domestic customers for the use of network transmission facilities to facilitate export and wheel-through transactions. As well, there were concerns about potential impacts of the tariff on international trade agreements and reciprocity obligations, the development of open and efficient regional markets, as well as the potential environmental consequences from higher exports that may be influenced by the tariff.[1]

In Hydro One's Transmission Rate Application EB-2006-0501, the Board approved a stakeholder settlement agreement which called for the ETS tariff of $1/MWh to be maintained for the time being; however, the IESO was identified as the entity responsible for undertaking a study of an appropriate ETS tariff and, through negotiation with neighbouring jurisdictions, to pursue acceptable reciprocal arrangements with the intention to jointly eliminate all ETS tariffs. It was understood that any proposed change to the tariff must be reviewed and approved by the Board as part of Hydro One's transmission rate review and approval process.

The IESO's initial ETS tariff study and recommendation was filed with the Board on August 28, 2009 and reviewed under proceeding EB-2010-0002.

In the EB-2010-0002 Decisions with Reasons the Board concluded that an additional study was required.

> "The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's view, the most appropriate party to undertake the study is the IESO."

The IESO is undertaking a new ETS study with an expected completion date in May of 2012. When the study has been finalized, a copy will be included as part of this

[1] Decision with Reasons, Ontario Hydro Networks Company Inc. Transmission Rate Application, RP-1999-0044, Export and Wheel-through Transactions.

application. Additional information on the study can be obtained from the IESO's web site: http://www.ieso.ca/imoweb/consult/consult_se94.asp.

The OEB also directed Hydro One to increase the ETS rate to $2/MWh in the EB-2010-0002 Decision with Reasons.

> "Accordingly, the Board will direct that a change be made to the ETS rate for 2011 and 2012, increasing the rate to two dollars per MWh. In making this change the Board seeks to recognize the directional preference of the CRA study, and the absence of any particular analytical underpinning for the current rate. Subsequent panels assessing the level of this rate should not, however regard this new rate as having any particular precedential value. It is the Board's view that the new rate has more analytical support than the status quo, but that in order to arrive at a genuinely robust and valid rate, more study is required."

## 3.0 EXPORT TRANSMISSION SERVICE REVENUE

Hydro One's Export Transmission Service (ETS) revenues are determined based on the approved tariff of $2/MWh and the 3 year average volume of electricity exported from or wheeled-through Ontario over its transmission system.

For 2013 and 2014 the ETS revenue will continue to be disbursed through a decrease to the revenue requirement for the Network Pool, as per the cost allocation process approved by the Board in EB-2010-0002. The forecast for ETS revenue is $31.0 million and $30.1 million per year for 2013 and 2014, respectively.

## 4.0 NEXT STEPS

If directed by the Board, Hydro One Transmission will file with the OEB any required changes to the existing ETS rate resulting from the review of the IESO's new ETS study and will update the forecast for ETS revenue consistent with the revised ETS rate.

# IESO EXPORT TRANSMISSION SERVICE STUDY

In its December 23, 2010, Hydro One Networks Inc., Decision with Reasons (EB-2010-0002), the Ontario Energy Board ("Board") considered changes to the Export Transmission Service ("ETS") tariff. The tariff of $1 MWh was established at the time of market opening as a placeholder and was "not the product of an objective, principled or pragmatic study." The Board stated that there was "little virtue in replacing one placeholder with another in the absence of evidence supporting the new value." The Board concluded that "the most pressing requirement is that a genuinely comprehensive study be undertaken to indentify a range of proposed rates and the pros and cons associated with each proposed rate". The Board stated that the Independent Electricity System Operator ("IESO") was the most appropriate party to administer the study and directed the IESO to procure the study and "circulate the terms of reference to ensure that the scope is sufficiently broad and well-defined."

In accordance with the Board's directive, in May 2011, the IESO formally commenced Stakeholder Engagement 94 ("SE 94"). The IESO invited wholesale market participants and stakeholder groups, in particular, transmission customers, generators and wholesale consumers directly involved in performing export, import and wheel-through transactions, to participate in the stakeholdering process.

On May 30, 2011, the inaugural meeting was held at which time the IESO addressed stakeholder engagement principles and the proposed scope of the ETS study. Approximately twenty different stakeholder groups attended and participated in the discussion. (A complete list of parties that participated in the stakeholdering is attached as Appendix A.)

Following the May 30, 2011 meeting, attendees and other interested parties were invited to submit written comments on the proposed tariff designs and rate scenarios. Many stakeholders submitted feedback which was posted on the IESO website. As per the IESO's stakeholder engagement protocol, the IESO posted written responses to all submissions.

With the assistance of the stakeholders, the IESO developed a Request for Proposal ("RFP") process to select a consultant to undertake the ETS study. The RFP was issued publicly through the MERX Canadian Public Tenders service; the RFP was posted in October 2011; and Charles River Associates (CRA) was selected in December 2011.

Over the course of the study, the IESO held numerous meetings and teleconferences to update interested parties on the status of the study and to provide them with the opportunity to provide input, including on the study approach and methodology. Throughout the process, the IESO documented how stakeholders' input and comments were taken into account and posted stakeholders' submissions and the IESO's responses.

On May 24, 2012, a draft of the ETS Study was presented to stakeholders by CRA. A question and answer session followed and a further opportunity was provided to stakeholders to provide feedback.

On June 22, 2012, the IESO posted its responses to stakeholders' questions along with an ETS Study Addendum.

On June 28, 2012, the IESO delivered to Hydro One Networks Inc., for filing with the Board, the final ETS Study and Addendum and is included as Appendix B to this exhibit.

The details of the SE-94 are posted on the IESO's website at: http://www.ieso.ca/imoweb/consult/consult_se94.asp

# Appendix A

Parties that participated in the Stakeholdering, by constituency represented or company name:

1. APPrO
2. Manitoba Hydro
3. Customized Energy Solutions
4. Brookfield Renewable Power
5. Hydro One Networks
6. TransCanda
7. Consumers Council of Canada
8. AMPCO
9. Econalysis Consulting Services
10. Torys LLP
11. Elenchus on behalf of PWU
12. Bruce Power
13. Energy Probe Research Foundation
14. Northpoint Energy
15. Ontario Power Generation
16. Ontario Energy Board
17. Hydro Quebec Energy Marketing
18. Rob Carey & Associates (for Goreway)
19. RBC Capital Markets
20. Shell Energy
21. Constellation Energy
22. Canadian Manufacturers and Exporters
23. Navigant Economics
24. Vitol

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

www.ieso.ca

**BY EMAIL AND COURIER**

June 28, 2012

Mr. Allan Cowan
Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, ON M5G 2P5

Dear Mr. Cowan:

**Re: <u>Export Transmission Service Tariff Study - EB-2012-0031 – Hydro One Networks Inc. Transmission Rate Hearing</u>**

Please find enclosed the Export Transmission Service ("ETS") Tariff Study, prepared by Charles River Associates, for filing with the Ontario Energy Board ("the Board") as evidence of Hydro One Networks Inc., in its 2013 – 2014 Revenue Requirement and Rate Filing.

**Background**

In its December 23, 2010, Hydro One Networks Inc., Decision with Reasons, the Board addressed the original ETS rate stating that it was established as a placeholder and that it was "not the product of an objective, principled or pragmatic study." The Board went on to say that there was "little virtue in replacing one placeholder with another in the absence of evidence supporting the new value." In considering the issues around the ETS and noting that there had been little analytical study done to date, the Board concluded that "the most pressing requirement is that a genuinely comprehensive study be undertaken to indentify a range of proposed rates and the pros and cons associated with each proposed rate". The Board's view was that the IESO was the most appropriate party to undertake the study.

**IESO Stakeholdering**

In its Decision with Reasons, the Board stated that "the IESO should, in procuring the study, circulate the terms of reference to ensure that the scope is sufficiently broad and well-defined." To that end, the IESO initiated a Stakeholder Engagement in May 2011, which included meeting with stakeholders and interested parties to solicit their input on the work scope and plan. The IESO also kept stakeholders updated on ongoing study progress. Throughout the process, the IESO documented how stakeholders' input and comments were taken into account.

Yours truly,

***Original signed by***

Paula Lukan
Senior Regulatory Analyst
Independent Electricity System Operator

c. Henry Andre, Hydro One Networks Inc.
Lynne Anderson, Ontario Energy Board
Harold Thiessen, Ontario Energy Board

# Export Transmission Service (ETS) Tariff Study

Prepared for:

Independent Electricity System Operator

Charles River Associates

May 16, 2012

# *Table of Contents*

# Executive Summary

In response to a request from the Ontario Energy Board ("OEB") following Hydro One's 2010 transmission rate case, the IESO engaged Charles River Associates (CRA) to undertake a review of Export Transmission Service ("ETS") tariff options for Ontario. As part of this review, CRA has reviewed tariff rates and structures in neighbouring markets; assessed the proposed rate options on the basis of conformance with generally accepted rate-making principles (consistency with neighbouring markets, simplicity, fairness and efficiency), and; quantified the impact of each of the options on Ontario consumers, producers, and the Ontario market as a whole. This study also reports impacts of each option on exports and imports, market and total bill prices, export tariff revenue, production costs, carbon emissions, and the frequency and duration of Surplus Baseload Generation ("SBG") periods.

Five options (including the Status Quo) were modeled for 2013, 2015 and 2017, using CRA's North American Energy and Environment Model ("NEEM"). We also conducted a calibration for 2011. NEEM, a linear programming model, simulates economic dispatch for most North American markets and provides the detail needed to make a realistic assessment of the impacts of policy changes within a rapidly changing market that is responding to a variety of external influences. In particular, the model predicts and incorporates the impacts of the changing generation supply mix in Ontario and neighbouring markets and the implementation of existing and anticipated policy changes. NEEM reflects transfer limits between Ontario its neighbours as well as broader trade flows within North America. Ontario is modeled as three regions to reflect the consequences of internal congestion.

Four alternative ETS tariff rates and rate structures, in addition to the current $2.00/MWh rate, were examined:

- The unilateral elimination of the export tariff in Ontario (i.e. a $0/MWh rate);
- An increase in the ETS tariff to the current Equivalent Average Network Charge ("EANC") of $5.80;
- A tiered rate of $5.80/MWh during on-peak hours and $0/MWh during off-peak hours, and;
- A tiered rate of $3.50/MWh on-peak and a $1.00/MWh rate off-peak.

The choice of these rate options broadly reflects the range of views of stakeholders with respect to the appropriate sharing of transmission costs, most of which are fixed, combined with potential ETS tariff changes that could enhance the operation of the Ontario market.[1]

The Ontario electricity market is in the midst of a period of dramatic change:

- Coal-fired generation, which in most North American markets serves as the baseload workhorse, is being phased out in Ontario by 2015;

1 The ETS rate options modeled are the options discussed in the IESO's meeting with stakeholders on September 19, 2011. See *Export Transmission Service (ETS) Tariff Study, SE-94, Meeting Notes (September 19, 2011)*, available online at http://www.ieso.ca/imoweb/pubs/consult/se94/se94-20110919-meeting_notes.pdf.

- The Province's Long Term Energy Plan calls for 10,700 MW of non-hydro renewable generation capacity by 2017, and the FIT Review has accelerated that target date to 2015;
- Industrial demand for power has been battered by the recession and the high dollar;
- The Province's transmission system is being rapidly expanded to cope with an energy mix that is facing major changes in technology and location of production;
- Ontario plans to join the Western Climate Initiative ("WCI") cap-and-trade carbon reduction program, although the timing is uncertain;
- Like other markets that have undertaken to incorporate large amounts of renewable energy, Ontario sees increasing challenges in balancing supply and demand, and;
- There are frequent periods of Surplus Baseload Generation, where the Province's production of wind, baseload hydro, and nuclear energy exceeds its demand for power.

It is broadly recognized that coping with these challenges will require a multi-faceted strategy. Measures that facilitate more efficient trade with neighbouring markets are part of the arsenal countries like Denmark and Germany employ to deal with the challenges of efficiently integrating large amounts of clean power. It is in this context that the OEB review of potential changes to export tariffs will take place. The purpose of this study is to help inform that review.

A projection of trends already underway shows the broad evolution of the Ontario power market to 2017. Compared to 2011, 2013 will see an increase of 2000 MW of wind and solar power already contracted for, the addition of 1500 MW of additional nuclear power as the Bruce A refurbishment and the Bruce to Milton transmission project are completed and an additional 735 MW of natural gas-fired capacity (simple-cycle and combined-cycle capacity and excluding the drop in NUG capacity), bringing total additions to Ontario's gas-fired generation fleet since 2006 to nearly 8000 MW. At the same time, demand in Ontario remains flat.

These trends will continue through 2015, with a further addition of 4000 MW of intermittent power and potentially two additional natural gas-fired plants. On the other hand, between 2015 and 2020, a large proportion of the nuclear fleet must be refurbished or retired.

Making optimal use of Ontario's more than 6000 megawatts of interties with neighbouring markets can help the system operator manage the supply-demand balance through this period. Trade between markets within an integrated regional power system has a range of benefits:

- It allows consumers to take advantage of lower-priced or cleaner power in other markets;
- It allows producers to sell power that is surplus to local needs and competitively priced with neighbouring jurisdictions;
- It allows markets with different seasonal peaks to jointly serve these peaks efficiently, without overbuilding for non-peak periods;
- It provides the opportunity to use power from other markets to meet local contingencies. In times of stress, it allows system operators to divert exports from markets not under duress;

- It provides a range of paths to use to avoid system failures.[2]

In order to assess the impacts of each rate option, the study calculates the impacts on consumer welfare, producer welfare and intertie congestion revenue. In aggregate, these three elements provide a measure of total welfare impact in Ontario.

Changes in consumer surplus measure the flows of value arising from the policy in question that can be reasonably expected to increase or decrease the costs borne by Ontario consumers. Most of these costs are reflected in consumers' total electricity bills. The study has not attempted to quantify secondary effects *via* the tax system or other redistributive policies. Impacts on the consumer surplus of Class A customers, primarily industrial customers with load exceeding 5 MW, and Class B customers (all other customers) were also calculated for each option.

The change in producer surplus measures the impact of the policy option on the net income of Ontario producers, taking account of changes in producer revenue *via* both market returns and Global Adjustment payments, as well as changes in producer costs.

Intertie congestion revenue accrues to Ontario whenever an Ontario intertie is export congested.[3] When this is the case, exporters pay a higher price to the IESO to take power relative to the price that the IESO pays Ontario generators to supply power. Intertie congestion revenue is calculated as the price difference between the intertie zone and Ontario (accounting for the ETS tariff, uplift, and friction costs) multiplied by the export quantity flowing over the constrained intertie.

The study also estimates the net impact on total North American production costs associated with each option. This is a broader regional measure of the welfare impacts of these potential policy changes.

**Quantitative Results**

The quantitative results of the analysis conducted for this study suggest a number of conclusions:

- Lower export tariffs lead to higher levels of exports, resulting in higher market prices in Ontario;
- Conversely, higher export tariffs lead to lower levels of exports and lower market prices;
- Changes in Ontario market prices resulting from changes in the ETS tariff rate are largely offset by changes in Global Adjustment payments so that the net impact on consumers' bills and producers' net income is generally small;
- Most of the differences in export levels between each scenario and the Status Quo in both on-peak and off-peak periods reflect increases or decreases in natural gas-fired

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2 By way of example, much of the motivation for the recently completed back-to-back DC intertie between Quebec and Ontario was the result of Quebec's desire to improve the reliability of its system in the wake of the 1998 ice storm. At the same time, this intertie provides economic benefits to Ontario in the form of lower prices and an outlet for excess Ontario baseload generation. Regulators in both provinces recognized these benefits and agreed to the recovery of construction costs in their respective rate bases.

3 The IESO collects congestion rents at interties on behalf of Ontario whenever congestion occurs. The IESO also sells, through an auction, financial transmission rights which provide rights holders with payments equal to congestion rents.

generation. Ontario generally exports all baseload generation that is not consumed domestically, and exports natural gas-fired generation when it is competitive in export markets, which is generally during on-peak periods only. Since both baseload generation and Ontario load generally are the same in each scenario as in the Status Quo, changes in exports are typically the result of changes in natural gas-fired generation in on-peak periods. The amount of gas-fired generation required to balance Ontario system needs and local requirements is not usually affected by ETS tariff levels and is therefore the same in both the Status Quo and scenario cases;

- The net impact on Ontario welfare is sensitive to the supply mix and policy constraints in Ontario and neighbouring markets;
- Where Ontario has excess supply capacity and costs that are competitive with neighbouring markets as in 2013, impacts of changes in the ETS tariff tend to be large;
- Where Ontario faces tight supply, impacts of changes in the ETS tariff are smaller;
- The marginal cost of Ontario baseload production (nuclear, non-dispatchable hydro, wind, solar) is well below the marginal cost of coal-fired baseload generation in US markets. As result and subject to transmission availability and grid conditions in the receiving market, there is usually a market for Ontario baseload generation in excess of output required to meet Ontario's domestic needs;
- However, intertie capacity and a series of operational considerations place a practical limit on the capacity of intertie transactions to alleviate SBG conditions;
- None of the tariff changes studied has a material impact on the volume of baseload exports during SBG periods;
- In terms of relative impacts, Class A customers, who pay a larger proportion of their power bills *via* market prices, are adversely affected by higher exports and the resulting increase in Ontario prices. Class B customers tend to benefit from higher market prices because the Global Adjustment part of their bill, which is relatively large, declines more than their market costs rise. This is particularly true when Ontario demand is less than contracted supply, since this is when export revenues offset payments to contracted supply;
- Conversely, Class A customers benefit disproportionately from measures that reduce exports and lower Ontario prices;
- The introduction, under the WCI, of carbon pricing for Ontario generators and border adjustments for non-WCI exporters to Ontario would sharply reduce trade in fossil-based power in both directions, and;
- Two Tier cases lead to a shift in exports between on-peak and off-peak periods and maintain ETS revenue levels, but have little net impact on either consumer or total welfare.

**Qualitative Assessment**

- Tariff levels and structures vary among Ontario's neighbours. None of the options under consideration would create additional inefficiencies due to being inconsistent with other markets;
- Unilateral elimination of Ontario's ETS tariffs would be inconsistent with approaches in neighbouring markets, but would not impede trade;
- All of the options under consideration would be reasonably simple to administer, although Two Tier options would require changes to market systems;
- Charging exporters rates consistent with those charged other users of the system would be consistent with the notion of horizontal fairness. However, to the extent the transmission service exporters enjoy is less favourable than the service provided to other users, this would be inconsistent with vertical fairness (i.e. treating customers who impose different costs and receive different benefits in a way that reflects these differences);
- Tariff increases within the range considered in our study tend to improve consumer surplus by collecting more revenue to reduce all customers' transmission rates;
- The efficiency results for the scenarios considered, as measured by their impact on total Ontario welfare, vary substantially, particularly in 2013 when Ontario has a significant surplus available for export. In 2013, the range of changes in total Ontario surplus across scenarios is $40.4 million (the increase in total surplus in the unilateral elimination scenario is $17.6 million, and the reduction in the EANC scenario is $22.8 million), while for 2015 and 2017 the range of total surplus changes across scenarios is about $6 million or less, and;
- Reductions in ETS tariffs contribute to improved regional efficiency.

The remainder of this Report is structured as follows:

Section 1 provides an Introduction

Section 2 describes the NEEM model that was used for our analysis and provides a summary of model assumptions

Section 3 describes the results of the calibration of the NEEM model against 2011 actuals

Section 4 reports the transmission costs for Ontario imports and exports from and to other markets

Section 5 describes the results of our modeling of ETS scenarios for 2013, 2015, and 2017, including market outcomes and effects on surplus

Section 6 provides an evaluation of each of the scenario against the following four criteria: consistence, simplicity, fairness, and efficiency

Appendices A – K provide additional detail about modeling assumptions, and Appendix L provides a detailed summary of surplus changes for each of the modeled scenarios.

# 1. Introduction

Charles River Associates ("CRA") was engaged by the Ontario Independent System Operator ("IESO") to perform an analysis of four different Export Transmission Service ("ETS") tariff scenarios for the years 2013, 2015, and 2017. Using the Status Quo, where the ETS tariff remains at $2.00/MWh, as the benchmark, we estimated the effects of each assumed ETS structure on a number of market outcomes. We also used these forecasted effects on market outcomes to calculate the change, for each ETS tariff scenario, in the net economic benefits to groups in Ontario. The four alternative ETS scenarios were also evaluated based on four criteria: (1) consistency with rates in neighbouring markets; (2) administrative simplicity; (3) fairness; and; (4) efficiency.

For this analysis, CRA simulated the Ontario electricity market using its North American Electricity and Environment Model ("NEEM").[4] Prior to conducting the analysis, CRA conducted a calibration for the year 2011. The calibration was performed in order to ensure that the NEEM model reasonably replicates reality.

As part of our analysis, we completed a Tariff Designs and Rates Report. This report serves to provide background on the approaches to ETS determination used in nearby markets. CRA examined export tariffs in the New York ISO, PJM ISO, Midwest ISO, New England ISO, and Quebec.

### Overview

The Ontario electricity market is in the midst of a basic structural change with the closure of coal-fired generation and rapid expansion of intermittent wind and solar generation. This transformation creates challenges for the Ontario power system in terms of ensuring reliable supply and ongoing supply-demand balance. Other changes anticipated over the next five years, such as nuclear refurbishment and the potential introduction of a carbon cap-and-trade system, may also have major consequences for the sector.

In that context, a reexamination of the role of imports and exports and the factors that constrain them is warranted. Like neighbouring markets, Ontario levies an ETS tariff on electricity exports. This tariff reflects exporters' contribution to the costs of building and maintaining Ontario's high voltage transmission system. That tariff is currently set at $2.00/MWh.

The alternative ETS tariff options considered in our analysis are as follows:

- Unilateral elimination of the ETS. That is, the ETS tariff rate is $0/MWh;
- A rate equal to the Equivalent Average Network Charge ("EANC") of $5.80/MWh;
- A tiered rate of $5.80 during on-peak hours and a $0/MWh off-peak (referred to below as "Two Tier Option A"), and;

4 CRA's NEEM model is discussed in more detail in the Appendix to this report. NEEM is a load-duration curve-based dispatch and planning model of the electric sector in the continental US and large parts of Canada. The reader may wish to review the portion of the Appendix that addresses the NEEM model in order to understand the load-duration curve structure that is referred to in this report.

- A tiered rate of $3.50/MWh on-peak and $1.00/MWh off peak ("Two Tier Option B").

With the phased elimination of coal-fired generation and the expansion of intermittent renewable generation, there are increasing periods where the volume of baseload generation in Ontario exceeds provincial load.[2] These periods where baseload generation exceeds Ontario load are known as periods of Surplus Baseload Generation ("SBG").[5] The impact of the recent recession and of the increased value of the Canadian dollar on industrial demand in Ontario has further aggravated this situation. The challenges of maintaining supply-demand balance in the face of increasing penetration of intermittent supply are also evident in other jurisdictions that have embarked upon a policy of expanding renewable energy, including Denmark and Germany. Exports and imports can potentially play a role in helping smooth the supply-demand balance during SBG events.

We have examined the impact of changes in the ETS rate and structure on a number of outcomes, including:

- Exports and imports;
- Ontario power prices: both the Hourly Ontario Electricity Price (HOEP) and the total energy cost per kWh paid by Ontario consumers;
- Frequency and duration of SBG events;
- Export tariff revenue;
- Production costs, and;
- Ontario carbon emissions.

In addition, we have analyzed the impact of each rate structure separately on consumer surplus, producer surplus, and intertie congestion revenue. Change in consumer surplus is calculated as the sum of changes in the following components: global adjustment payments to power producers by Ontario consumers; market payments for electricity consumption by Ontario consumers; ETS tariff revenue, and; uplift revenue paid by all exporters. We have assumed that ETS payments and uplift paid on export transactions are used to reduce the rates Ontario customers pay to finance fixed transmission costs. Changes in Ontario producer surplus are calculated as the changes in the difference between revenues earned by Ontario generators, including export revenues, and production costs incurred by these generators.

The revenue earned by Ontario generators has two components: market returns and offsetting payments from the Ontario Power Authority, the IESO, or the Ontario Electrical Finance Corporation to most generators to provide them with contracted prices or net revenue. We have referred to these latter payments as "GA revenue" since they are collected from customers through the Global Adjustment. The change in intertie congestion revenue is calculated as the price in export markets less costs of acquiring and selling energy into export markets. Intertie congestion revenue is in effect the congestion rent at export interties. Change in total Ontario surplus, which is a measure of the net economic benefits to Ontario resulting from a move from the Status Quo to each of the ETS tariff scenarios, is calculated as the sum of changes in consumer surplus, producer surplus, and intertie congestion revenue. More detail about the calculation of surplus is provided below.

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5 Unlike most other markets in North America, coal-fired generation has not been used as baseload generation in recent years. It has been treated as a constrained resource and has been dispatched sparingly primarily to ensure reliable operation of the grid.

## 2. Summary of Analysis Assumptions

The IESO held a stakeholder conference call on January 19, 2012. This section reviews the analysis assumptions presented during that call and also provides additional details where such details were not yet available for the conference call with stakeholders. In some cases, the approach used has varied from the approach presented at the January meeting, but without loss of analytical rigour.

For the purposes of this analysis, CRA has used its North American Electricity and Environment Model. NEEM is a linear programming model that simulates economic dispatch, capacity additions, retirements, emissions, reactions to environmental rules, and other market features. The long-term decisions (e.g., builds, retirements, retrofits) are generally applicable to the US in this analysis and were used to define the generation fleet in the future. The annual simulations are based on detailed load duration curves and generator characteristics.

The key model input assumptions are presented below. Additional details about NEEM and the modeling are provided in Appendix A. CRA chose to use NEEM, which models transmission using transportation algorithms instead of using the full electrical detail of power flow in a model such as General Electric's Multi-Area Production Simulation ("GE MAPS"). The ETS tariff study requires tracking of transactions along contract paths, which is how power markets charge for transmission service across regional borders but not how power actually flows. CRA uses GE MAPS for many studies and puts transmission charges on the lines between areas. The GE MAPS model's objective function sums up *as-flowed* charges. As an example, we have created two virtual contract paths from Ontario to PJM, one *via* New York and one *via* Michigan with different charges. NEEM (like an exporter) can choose either path up to the transfer capability on each portion of the path and pay the charge for the path. If we used GE MAPS, a transaction from Ontario to PJM would flow over both paths according to their impedances and would incur a blended *as-flowed* charge.

For the purposes of this analysis, Ontario was divided into three sub-regions: Northeast, Northwest, and the rest of Ontario (the "South"). This disaggregation was undertaken to capture any interaction between ETS rate changes and internal congestion in Ontario. A map of these sub-regions is provided in Appendix B.

In the South sub-region where most of the generation capacity is, there is a diversified capacity mix of nuclear, coal, gas, hydro, wind, and solar. The coal retires by 2015 and combined-cycle generators ("CCGT") capacity expands by 2000 MW by 2017. Wind capacity expands by 4000 MW by 2017.

In the Northeast region, there is predominantly hydro capacity and NUGs. The total capacity is about 12% of the South region's capacity in 2013. There is a modest amount of capacity expansion (mainly renewables) over the analysis period by 2017.

In the Northwest region, there are some renewables (hydro, wind, biomass, and solar) and a small amount of coal generation that will be retired by 2015, being nearly replaced by CCGT. The total capacity is less than half of that in the Northeast region, so about 6% of the South region's capacity in 2013.

## Generating Unit Characteristics

The IESO provided CRA with information about the generating units in Ontario in 2011 and projections for the non-dispatchable units for 2013, 2015, and 2017. This information is based on the assumptions used by the Ontario Power Authority ("OPA") and those contained in Ontario's Long Term Energy Plan ("LTEP"). IESO provided technology-specific capacities by Ontario sub-region. CRA gathered Ontario heat rate information and coal unit pollution control information from the Ventyx Energy Velocity database. For non-utility generators ("NUGs") and combined heat and power ("CHP") facilities, the IESO provided average heat rate information to CRA.

## Generating Units' Operation and Dispatch

The model assumes that all resources, with the exception of dispatchable hydro, bid their marginal production costs. That is, the model assumes that there is no strategic bidding.

### Nuclear

Nuclear generation was modeled as baseload in the Ontario South sub-region. CRA modeled the nuclear outages as a uniform derate of 13%, including planned and forced outages. The choice of a uniform derate was made because models such as NEEM optimize the planned outages unrealistically well (the alternative would have been to use a forced outage rate of a few percent and a planned outage rate of about 10%). It should be noted that the selected uniform derate of 13% somewhat overstates availability; this is intentional because surplus baseload generation will bring nuclear generator availability to approximately the levels seen in recent history.

### Hydropower

Within each of the three Ontario sub-regions, hydropower was broken into three tranches as follows:

*Non-Dispatchable Run-of-River:* this hydro tranche runs at the same level of output in each load block of a given month and cannot be curtailed during an SBG event. This tranche represents about 70% of the total Ontario hydro energy output;

*Dispatchable Run-of-River:* this hydro tranche is similar to the non-dispatchable run-of-river tranche except that it can be curtailed during an SBG event. This represents only about 3% of Ontario's total hydro energy, and;

*Optimizable:* this hydro tranche is fully optimizable and represents the remainder of the total hydro energy in Ontario. This tranche is assumed to bid its opportunity cost and will play an increasingly pivotal role in the determination of Ontario energy prices.

The division among the hydro energy tranches was based on historical offer data and dispatch schedules provided to CRA by the IESO. Graphical information pertaining to the hydro modeling is provided in Appendix C. Hydro output for Quebec was modeled based on information provided by the IESO from a 2007 Hydro Quebec energy accounting document. CRA assumed that the Quebec hydro output was fully optimizable within a month.

### Gas-Fired Generation

Gas-fired generation in Ontario includes CCGT, simple-cycle gas turbines ("SCGT"), and the Lennox steam/oil gas unit. Within each of the Ontario sub-regions, the combined- cycle and simple-cycle generators were aggregated separately. These units are dispatched economically in the NEEM model.

### Non-Utility Generators

NUGs were modeled using the same output shape as occurred in the year 2011. The NUGs are non-dispatchable. Within each of the three Ontario sub-regions, the NUGs were aggregated. The capacity factors of the NUGs were about 31% in each of the sub-regions. Fuel costs for the NUGs were based on an approximate heat rate for this class of units. For the purposes of this analysis, NUGs are assumed to continue to operate as non-dispatchable units.

### Combined Heat and Power

Combined Heat and Power generating units were modeled as being optimally dispatched. Within each of the three Ontario sub-regions, the CHP units were aggregated. Their contribution to total generation is negligible.

### Coal-Fired Generators

Coal-fired generating units, represented individually, were modeled as being optimally dispatched subject to transmission constraints. Their contribution to total generation is negligible. All Ontario coal-fired units are assumed to be retired by 2015.

### Wind and Solar

Wind and solar generators were modeled based on future output profile data provided by the OPA. CRA mapped the renewables profiles into the NEEM load blocks. The wind capacity factors range between 25-37%, depending on the region and the forecast year. Wind output tends to be high in low-load load blocks where SBG events tend to occur. See Appendix D for a chart of the Ontario wind shape.

Depending on the Ontario sub-region and the year, the solar capacity factors are about 12-14%. The solar output in the low-load load blocks where SBG events tend to occur is low. In other words, solar is not a major factor with respect to SBG.

## Demand for Electricity

For Ontario, the IESO provided CRA an hourly demand forecast for 2013, 2015, and 2017. The forecast was provided for each of the three Ontario sub-regions. CRA converted the hourly data to the load-duration curves used in the NEEM model. Hourly actuals were also provided by IESO for the 2011 calibration year (discussed in more depth below). For the purposes of this analysis, Ontario load is assumed to be inelastic.

For Quebec, CRA used the *État d'avancement du Plan* for 2011. The shape of the Quebec load was based on information obtained from the Ventyx Energy Velocity database.

For the US, CRA used the Regional Transmission Organizations' ("RTO") forecasts and the US Federal Energy Regulatory Commission ("FERC") Form 714 forecasts. CRA shapes the load based on the 2006 load shape – the hours are mapped into load blocks for all regions in the Eastern

Interconnection based on Midwestern PJM. For example, the highest load hours in Midwestern PJM from July 2006 are put into the highest July block. The same hours in the Ontario South sub-region are also put into the top block, irrespective of whether they are the highest load hours in the Ontario South sub-region or not. This process ensures that the load shapes reflect actual relationships among various regions' load-duration curves. The 2006 shapes are carried forward into the future years for the ETS tariff rate analysis, after adjusting for projected changes in total energy demand.

## Capacity Expansion, Unit Retirements, and Pollution Control Retrofits

Prior to running the 2013, 2015, and 2017 NEEM simulations, CRA forecasted the generation fleet into the future. For Ontario, new investment, retirements, and long-term unit outages were projected in accordance with the LTEP and information from the OPA.

For Quebec, the generation system was assumed constant over the analysis period, with the exception of small increases in the hydro system peak output. These peak output increases were based on Hydro Quebec's 2009 – 2013 *Strategic Plan*.

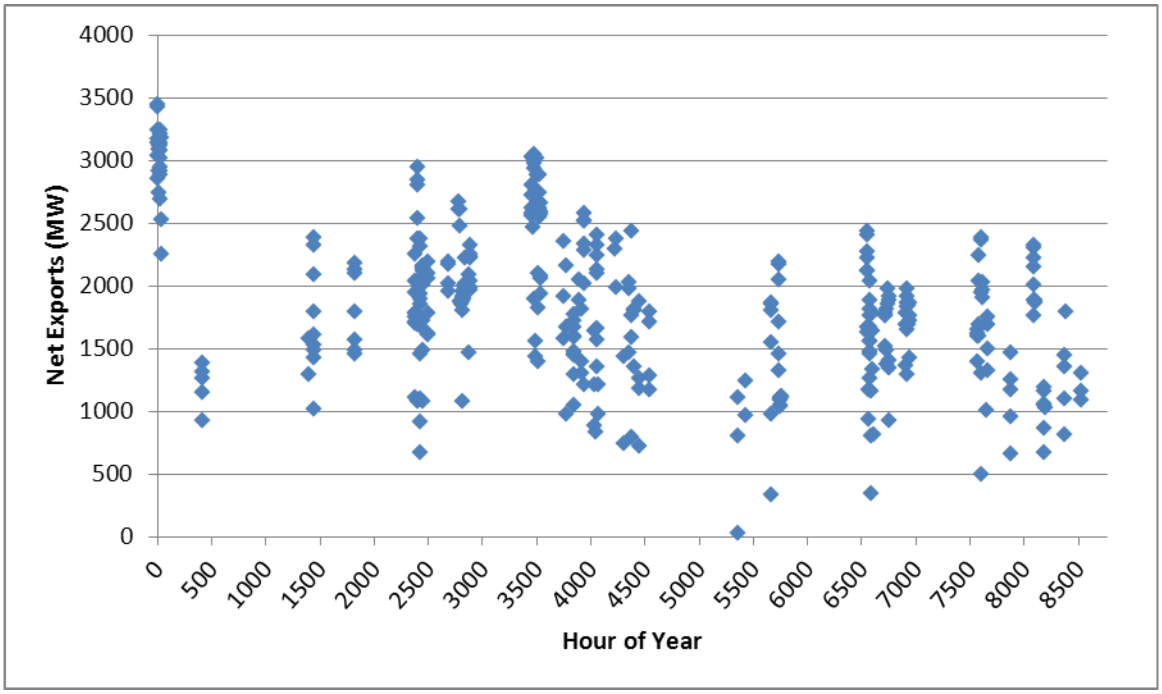
For the US, the generation system was modeled using NEEM, taking into account demand growth, peak demand growth, fuel prices, and environmental policy. This is significant because environmental policy in the US is expected to drive major levels of coal retirements between the present time and 2017.

## Transfer limits

CRA and the IESO (in concert with OPA) identified the total transfer capacity at the interfaces between Ontario and its neighbouring regions. The model will not allow these transfer limits on the interregional power flows to be exceeded. These transfer limits are tabulated in Appendix E.

Total simultaneous export capability from Ontario in 2011 was 6044 MW. In 2011, the average net export during hours when SBG maneuvers occurred but there was no SBG unit shutdown was 1,858 MW. Net exports ranged from 28 MW to 3,446 MW during these events, and were above 3,000 MW for only 22 hours. The Ontario net exports during these SBG hours are shown in Figure 1. Note that the maximum net exports in 2011 occurred on January 31 hour ending 20, when the HOEP was about $71.

**Figure 1: Ontario Net Exports During 2011 SBG Maneuvers**



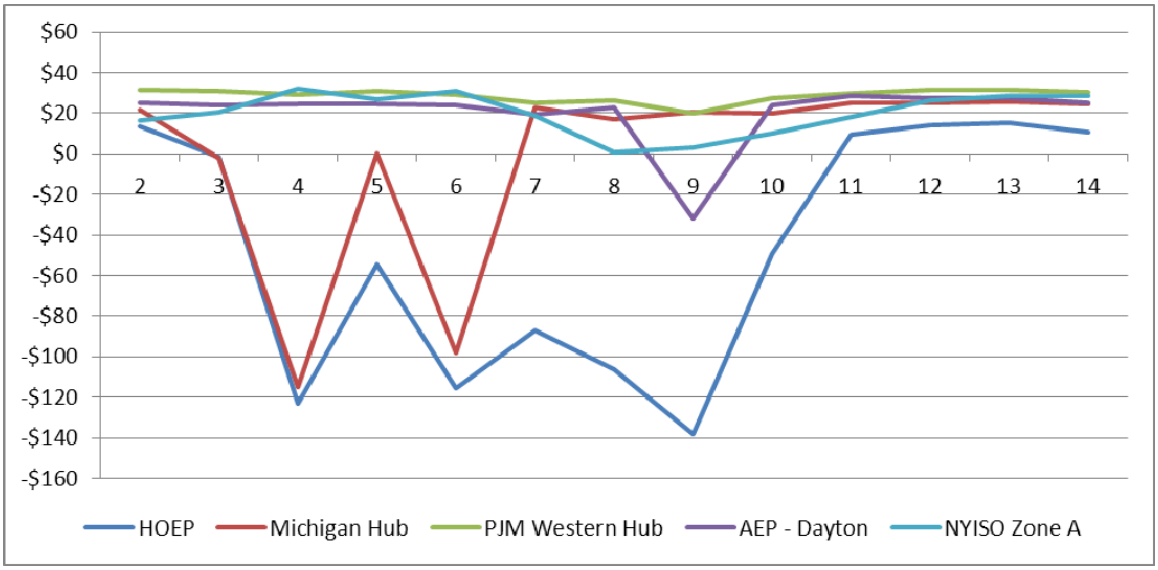

Periods of nuclear maneuvering without shutdown are the best indicator of maximum export capability during SBG events. Once capacity is taken offline to deal with SBG, the exports will, if anything, decrease since there is less baseload generation in Ontario available for export.

Based on this analysis, we set the maximum export capability at 3,000 MW during the lowest load hours of every month (10-30 hours) when SBG is likely to occur, consistent with our observations about 2011 exports.

There are a number of reasons why exports may be limited during SBG events. First, there may be transmission outages limiting exports. Second there may be transmission issues in Ontario that prevent more exports. Third, neighboring systems might be experiencing similar baseload generation problems. On January 1 when Ontario experienced SBG during hours ending 2 through 14, MISO had a maximum generation emergency. However, PJM did not report a baseload generation problem, and New York prices were fairly high[6] (please see Figure 2). Thus, it appears that limitations did not occur on all neighboring systems during these hours. In fact, during the majority of SBG hours neither MISO nor PJM reported a baseload generation problem. Thus, while neighboring regions do experience the equivalent of SBG, in 2011 limitations on exports do not appear to have been the result of these types of conditions in most SBG hours.

6 As a matter of practice, the New York ISO does not report baseload generation problems.

**Figure 2: Market Prices for January 1, 2011**
**Hours Ending 2 through 14**




## Natural Gas Prices

Natural gas prices (at Henry Hub) in the NEEM model were based on the US Energy Information Administration's ("EIA") Annual Energy Outlook 2012 ("AEO 2012") early release. For 2013 only, the forecast is based on NYMEX futures. Basis differentials from Henry Hub to each NEEM region are based on regression analysis. The Ontario natural gas price forecasts are presented in Appendix F.

## Policy Assumptions

### Carbon Policy

CRA modeled a carbon price in the Western Climate Initiative ("WCI") Partner regions (Ontario, British Columbia, Manitoba, Quebec, and California) based on the WCI's results from July 2010. Although there have been some developments in the Partner regions since 2010 (e.g., US states dropping out), the intent of the program remains the same and the allowance price forecasted by the WCI remains an indicative assumption. In California and Quebec, the policy is set for implementation and enforcement in 2013. For our analysis, it was assumed that Ontario would join the WCI by 2015. The WCI carbon price assumption is provided in Appendix G.
As a result of these assumptions, in 2013 Quebec will apply border adjustment charges to its imports from Ontario and other exporters to reflect the average carbon intensity each exporter to Quebec. In 2015 and 2017, both provinces are assumed to be part of the WCI so inter-regional charges between Ontario and Quebec do not apply. However, Quebec and Ontario both charge their neighbours for the carbon intensity of their exports during the years in which Quebec and Ontario are participating in the WCI. In most markets that have introduced carbon pricing, any resulting revenue is either returned to consumers through offsetting tax changes or used to finance carbon reduction measures.

### Ontario Emissions Policies

Ontario's $SO_2$, NOx, and $CO_2$ emissions caps were modeled. These caps are presented in Appendix H. These caps did not become binding constraints in any of the scenarios considered in our study.

### US Environmental Policies

CRA modeled the following forthcoming US environmental policies:

- US EPA's Mercury and Air Toxics Standards ("MATS"), to control toxic emissions from US coal plants, will force major US coal retrofits and retirements by 2015. The MATS policy targets mercury, acid gas, and particulate emissions. The MATS policy was modeled and it affects the 2015 and 2017 simulations. In addition to forcing coal retirements, MATS will change the variable operating costs of the remaining coal units (e.g., heat rate penalties, retrofit variable costs, etc.) – these impacts were simulated;
- For this analysis, it was assumed that the major retirements would occur by the start of 2015. Further, it was assumed that the majority of the pollution control retrofits would be put on by the start of 2015. However, units that required wet Flue Gas Desulfurization ("wet FGD") to become MATS-compliant were assumed to complete their retrofits in 2016 (in time for the 2017 simulation but not the 2015 simulation). The reasoning behind this assumption is that MATS provides flexibility for the retrofit timeline to extend into 2016 and CRA expects this extension to be granted most commonly for units that require wet FGD to become MACT ("Maximum Achievable Control Technology") -compliant due to the relatively long construction period for wet FGD. It is noted that this approach differs somewhat from the approach outlined on the January 19, 2012 stakeholder call. CRA made this modification because it believes that the chosen approach is more likely to be realized;
- EPA's Cross State Air Pollution Rule ("CSAPR") was modeled for the eastern US starting in 2013, tightening for phase II in 2014;
- Compliance for the water intake rule (316b) was assumed by 2020. Due to the perfect foresight nature of the NEEM model, the retirement decisions under MATS take into account the additional, potential capital expenditures required for 316b compliance in the 2020 timeframe and affect the level of retirements for MATS in 2015 and 2017;
- CRA assumed that the Regional Greenhouse Gas Initiative ("RGGI") will continue to have a $CO_2$ price trading at the auction floor price of less than $2.00 per ton, and;
- The US state and regional Renewable Portfolio Standards ("RPS") were modeled.

## Macroeconomic Assumptions

Historical and projected inflation in Canada, historical and projected inflation in the US, and historical and projected exchange rates were obtained from the Ontario Ministry of Finance's Consensus Forecast. Inflation is expected to remain near 2% and the C$ exchange rate to remain near parity with the US$ over the period to 2017. Macroeconomic assumptions are reported in Appendix I.

## Modeling of Surplus Baseload Generation

Surplus Baseload Generation occurs when electricity production from baseload facilities (such as nuclear, hydro and wind) is greater than Ontario demand. Exports provide one opportunity to help restore supply-demand balance. In the previous sections of this report, some references have been made to SBG. Here we provide some more details on the SBG modeling. The order of curtailments during SBG was modeled in the following manner:

- Optimizable hydro will move economically during potential SBG events;
- Dispatchable run-of-river hydro curtails first;
- Nuclear generation maneuvers or shuts down next;
- Wind curtails next, and;
- Non-dispatchable run-of-river hydro, NUGs, and solar are at the bottom of the stack and are not dispatched during SBG events.

CRA also modeled all ETS tariff scenarios under an alternative assumption about dispatch, where wind is curtailed before nuclear. The scenarios were modeled under this alternative assumption because of feedback from stakeholders, who noted the current uncertainty about the dispatch merit order for baseload generation in the future (discussions relating to dispatch of wind and solar resources are on-going in SE-91, *Renewable Integration*). When wind is curtailed before nuclear generation in our model, there are scenarios where all the wind generation would be curtailed, so that some nuclear would have to curtail also. The reverse was not true (when nuclear curtails first, wind never curtails due to global SBG[7]). This is because the nuclear output is larger than the wind output. The logic for nuclear maneuvers and curtailments are based on historical actions taken by nuclear operators.[8]

SBG results are tabulated in Table 1 for the case where nuclear maneuvers or shuts down before wind.

7 In our analysis, wind in the Northwest sub-region of Ontario does curtail at times due to local transmission constraints / local SBG.

8 Changes in surplus resulting from ETS rate changes are not materially different when wind curtails first compared to the nuclear curtailment case. In this study, we report surplus changes for each scenario relative to the status quo for cases where nuclear curtails before wind only.

**Table 1: SBG Results if Nuclear Maneuvers or Shuts Down before Wind
Status Quo Scenario**

| | 2013 | 2015 | 2017 |
|---|---|---|---|
| Nuclear Manoeuvres | 76 | 93 | 10 |
| Average Number of Units Manoeuvred | 2.78 | 3.08 | 2.00 |
| MWh Nuclear Manoeuvres | 253,200 | 343,200 | 24,000 |
| Nuclear Shutdowns | 20 | 27 | 0 |
| Average Number of Units Shutdown | 1.45 | 2.07 | 0.00 |
| MWh Nuclear Shutdown | 1,670,400 | 3,225,600 | 0 |
| Total MWh Nuclear Curtailment | 1,923,600 | 3,568,800 | 24,000 |
| Renewable SBG Event | 0 | 0 | 0 |
| Average MW of Wind Manoeuvre | 0 | 0 | 0 |
| Total MWh Wind Curtailment | 0 | 0 | 0 |
| **Total MWh Curtailed** | **1,923,600** | **3,568,800** | **24,000** |

The above table shows that there are nuclear maneuvers and shutdowns in the Status Quo. The results above were generated through an offline (i.e., outside of the NEEM model) analysis that reflects minimum maneuver (4 hours) and shutdown periods (72 hours). These results also reflect the lumpy nature of the nuclear maneuvering and shutdowns (e.g., 300 MW).

The number of nuclear maneuvers reported represents the number of events. Since events are 4 hours long, there can be more than one event in a single day. The depth of the maneuvers is reflected by the reported average number of units per event. The MWh of maneuver captures the combination of hours and depth.

Shutdowns are reported similarly in the table. Each shutdown is a minimum 72 hours. Therefore, if our modeling shows that shutdown would have occurred twice within 72 hours, it is counted as only one event. We have again reported the average depth and MWh of shutdown.

While not shown, CRA also performed an offline comparison of these modeled results to a bottom-up hourly SBG forecast.[9] In general, the above-tabulated results overstate the hourly-constructed forecast because the non-dispatchable run-of-river hydro output, in reality, includes some dynamism on an hourly basis that our NEEM model analysis does not capture.

9 CRA conducted a spreadsheet analysis to forecast SBG, based on the hourly generation and load forecasts provided by the IESO, in order to have a benchmark to compare with the NEEM model results. The analysis found the baseload generation in excess of domestic load for each hour and then placed a 3000 MW export restriction in the deep off-peak blocks (as done in NEEM). CRA assumed this deep off-peak baseload generation in excess of domestic and limited export demand to be Surplus Baseload Generation events that cause generation to be curtailed off.

# 3. 2011 NEEM Model Calibration

Prior to running the NEEM simulations for 2013, 2015, and 2017, CRA calibrated the model to ensure reasonable replication of actual 2011 results. It is important from a modeling standpoint to know that actual results compare reasonably well with modeled results. The calibration involved comparison of the following items:

- Ontario generation by technology type
- HOEP
  - Average HOEP by month
  - Within-month HOEP across load blocks
- Exports from Ontario to each neighbour
  - Total exports
  - Off-peak exports
  - On-peak exports
- Imports to Ontario from each neighbour
  - Total imports
  - Off-peak imports
  - On-peak imports
- SBG
  - Months of occurrence for both maneuver and shutdown

The calibration involved refinements to model inputs such as neighbouring regions' hydro operation, transfer limits among regions in the US, and frictions between regions. The final, calibrated model results aligned reasonably against 2011 actuals with respect to the bulleted items listed above. The following high-level calibration metrics are reported:

- Modeled annual, total generation is low by 2.4%, with the primary difference being coal generation;
- Modeled imports are 15.5% in excess of actuals;
- Modeled exports are 24.7% less than actuals, but the relative imports and exports with the neighbouring jurisdictions are close to actual proportions. Exports are scaled correctly;
- The modeled monthly HOEP tends to be 4% higher than actuals. The modeled monthly average HOEP ranges from 7% below the actual to 16% above, and;
- The calibration run detected SBG in 8 months of 2011, while SBG occurred in all 12 months in actuality. The calibration run found nuclear shutdowns in May and June, while in actuality they occurred in May, June, but also August.

In our judgment, the calibration was reasonably close to actuals. In particular, generation by type, wholesale prices, and the relative pattern of exports closely aligned with actuals. This gave us comfort in the starting point for the ETS study.

# 4. Transmission Costs at Interties and Modeled ETS Scenarios

The following table provides the transmission costs for the Status Quo. The same costs were used for the 2011 calibration.

**Table 2: Transmission Costs for 2011 Calibration Modeling and Status Quo Scenario (C$2011/MWh)**

| From | To | On-Peak/Off-Peak/All | Export Charge | Uplift/ Administrative Costs | All-In Costs for 2011 |
|---|---|---|---|---|---|
| Ontario | New York | On-Peak | $2.00 | $3.33 | $5.33 |
| | New York | Off-Peak | $2.00 | $3.33 | $5.33 |
| | Quebec | On-Peak | $2.00 | $3.33 | $5.33 |
| | Quebec | Off-Peak | $2.00 | $3.33 | $5.33 |
| | MISO | On-Peak | $2.00 | $3.33 | $5.33 |
| | MISO | Off-Peak | $2.00 | $3.33 | $5.33 |
| New York | Ontario | All | $4.05 | $1.98 | $6.03 |
| | PJM | All | $5.48 | $1.98 | $7.45 |
| | Quebec | All | $2.91 | $1.98 | $4.89 |
| | NEISO | All | $0.00 | $1.98 | $1.98 |
| MISO | Ontario | On-Peak | $6.99 | $1.42 | $8.41 |
| | Ontario | Off-Peak | $3.32 | $0.78 | $4.10 |
| | PJM | On-Peak | $0.00 | $1.42 | $1.42 |
| | PJM | Off-Peak | $0.00 | $0.78 | $0.78 |
| PJM | MISO | All | $0.00 | $2.47 | $2.47 |
| | New York | On-Peak | $4.44 | $2.47 | $6.91 |
| | New York | Off-Peak | $2.11 | $2.47 | $4.58 |
| NEISO | New York | All | $0.00 | $0.37 | $0.37 |
| | Quebec | All | $7.13 | $0.37 | $7.50 |
| Quebec | Ontario | All | $8.24 | $0.29 | $8.53 |
| | New York | All | $8.24 | $0.29 | $8.53 |
| | NEISO | All | $8.24 | $0.29 | $8.53 |

The other ETS scenarios differ from the above table according to the following (all dollar units in C$2011):

*Unilateral Elimination Scenario* – The export tariff out of Ontario was cut to $0 per MWh.

*Equivalent Average Network Charge Scenario* – The export tariff out of Ontario was raised to $5.80 per MWh, the current equivalent average network rate.

*Two Tier Option A* – The export tariff out of Ontario was raised to $5.80 per MWh on-peak and cut to $0 per MWh off-peak. The on-peak vs. off-peak definition is 5x12 for the purpose of constructing this scenario.

*Two Tier Option B* - The export tariff out of Ontario was raised to $3.50 per MWh on-peak and cut to $1.00 per MWh off-peak. The on-peak vs. off-peak definition is 5x12 for the purpose of constructing this scenario.

All charges were held constant in real terms for the 2013, 2015, and 2017 simulations.

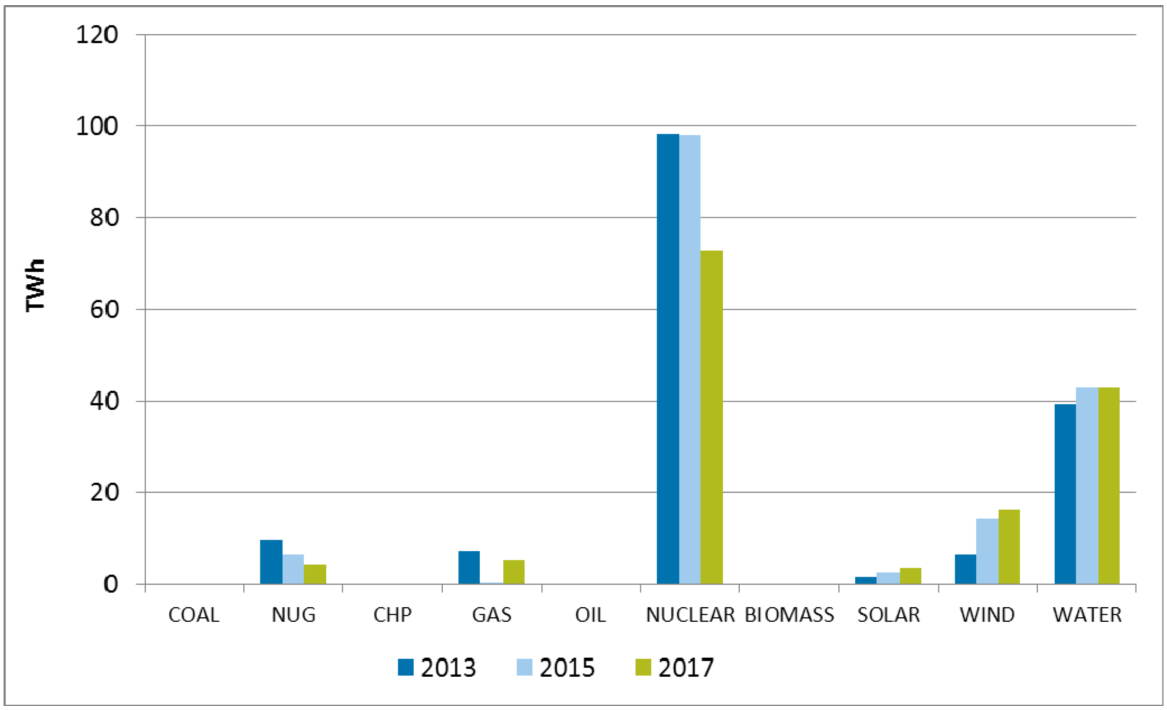
# 5. Model Results

In this section of our report, we discuss the results of our modeling of ETS tariff rate scenarios. We begin by providing an overview of the results from our Status Quo modeling, which provides forecasts of outcomes under the assumption that the ETS tariff rate remains at $2.00/MWh. We then explain how we calculated changes in surplus to Ontario market participants. The main part of this section is our discussion of the effects of changes in the ETS tariff rate on market outcomes and surplus.

## Model Results for the Status Quo

In this section we discuss various outcomes of our Status Quo model for 2013, 2015, and 2017. Figure 3 provides the Ontario generation by technology type for each model year.

**Figure 3: Projected Ontario Generation by Technology Type, Status Quo Scenario**




Nuclear generation falls in 2017 because nuclear units will be offline for refurbishment. Non-NUG gas generation falls in 2015 because there is more solar, wind, and hydro running underneath the gas. With Ontario's assumed entry into the WCI by 2015, gas-fired generators will be required to acquire carbon offsets and to build carbon costs into their prices. This reduces the competitiveness of Ontario gas-fired generation, both in Ontario and in export markets. The gas-fired generation recovers in 2017 as more generation is needed in the Ontario market to compensate for the offline nuclear generation.

Another notable feature of the Status Quo scenario's generation is the increase in wind generation over time.

Figures 4 and 5 provide the on-peak and off-peak exports from Ontario, respectively.

**Figure 4: On-peak exports from Ontario**

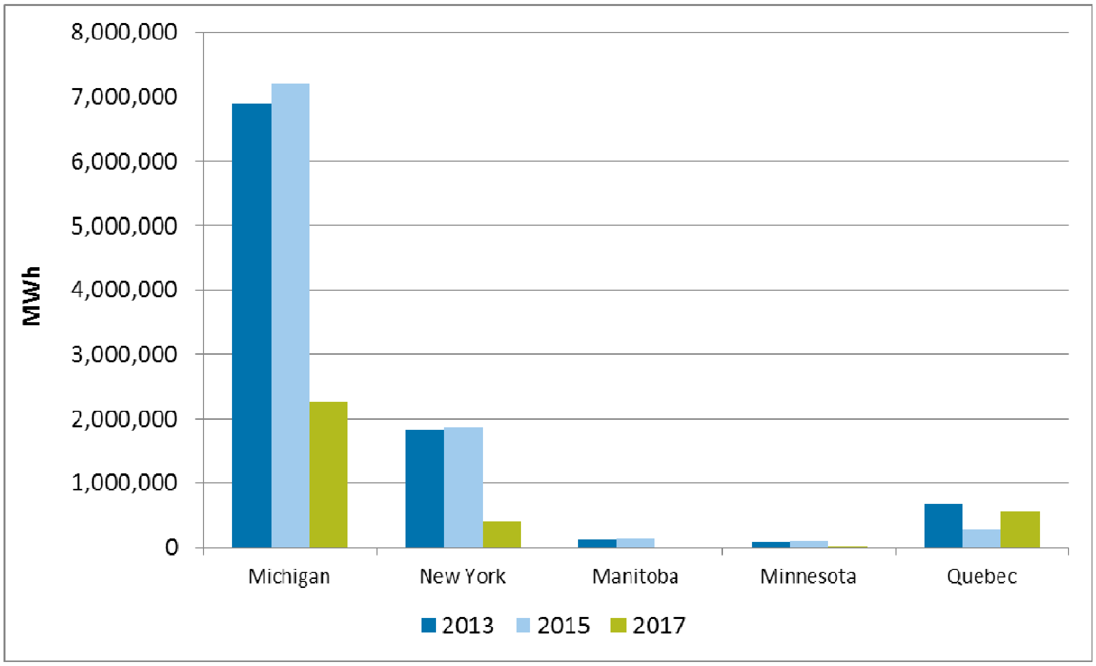
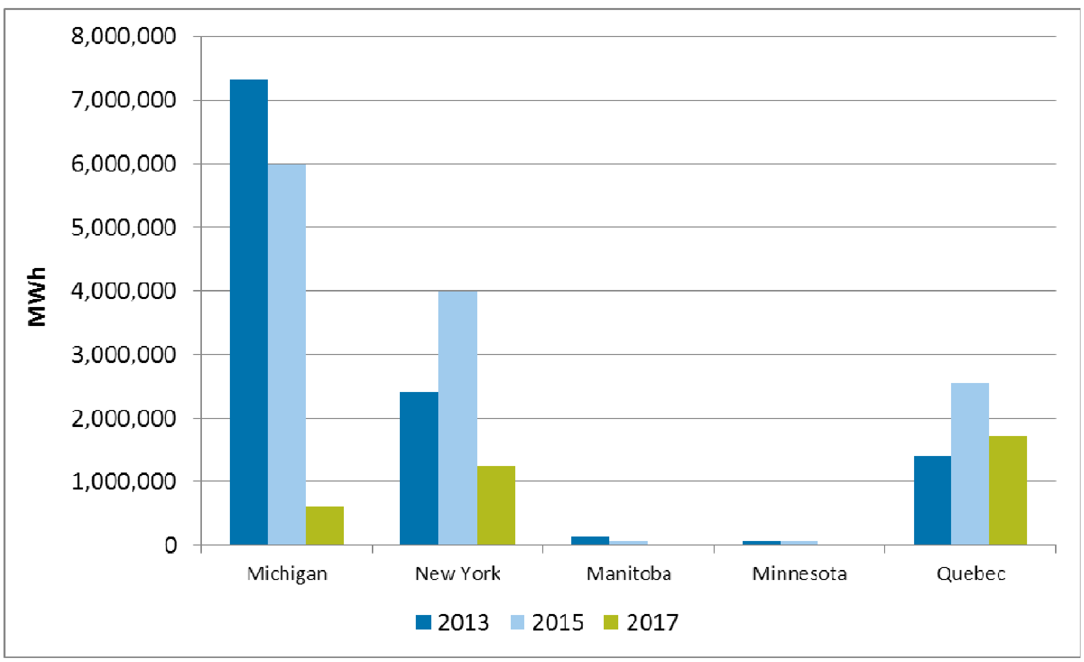


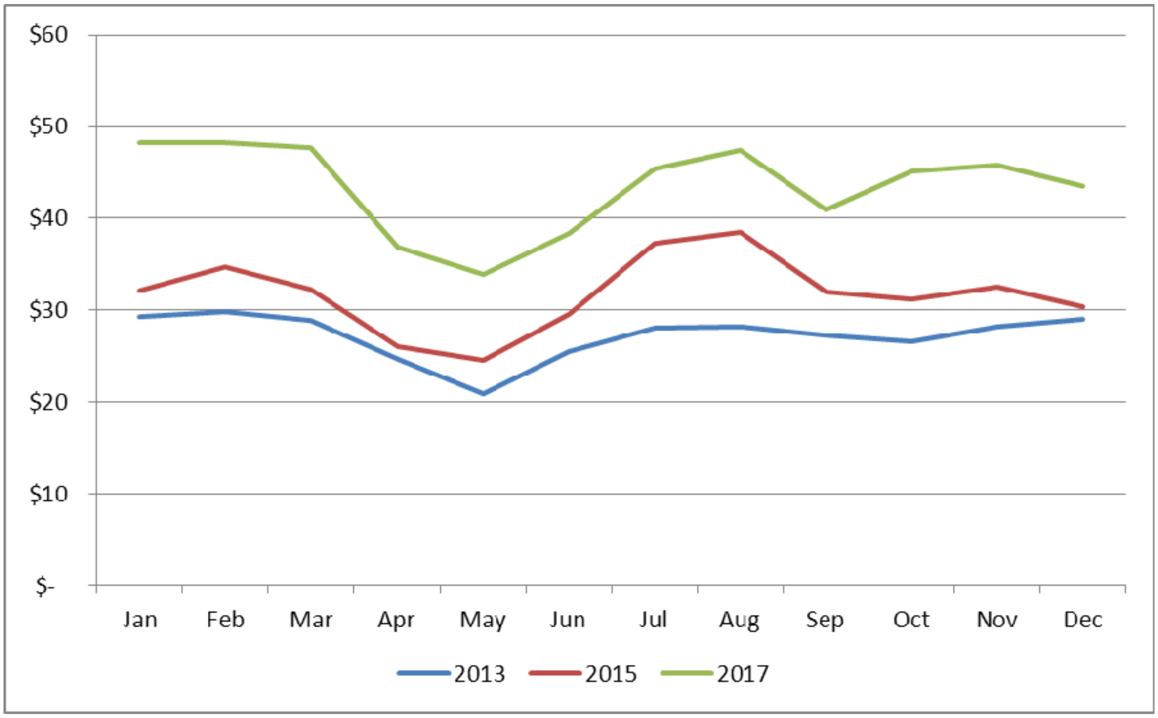

**Figure 5: Off-peak exports from Ontario**




PJM (*via* Michigan) and New York are the primary importers of Ontario power. These imports occur during both on-peak and off-peak hours. Quebec imports power from Ontario primarily during the off-peak hours. While not shown, Ontario primarily imports power from Quebec during the on-peak hours. Ontario's exports fall in 2017 when nuclear units are offline.

The monthly hourly HOEPs forecasted by the model for each model year are provided in Figure 6.

**Figure 6: Monthly Average HOEP (C$/MWh)**




In 2013, prices are relatively flat as Ontario gas-fired generation is on the margin most of the time, other than during the spring, when mild temperatures and ample water lead to more periods where baseload generation is the effective price setter. In 2015, with carbon pricing making Ontario gas-fired generation less competitive in export markets than they were in 2013, Ontario prices are increasingly set by returns available in the export market. These export market prices tend to follow price patterns in the US Midwest and Northeast, which are stronger summer peaking than Ontario (thus the greatest increases between 2013 and 2015 prices occurs during July and August). In 2017, nuclear production is reduced and Ontario becomes a net importer. Imports and Ontario gas-fired generation, inclusive of carbon costs, are increasingly on the margin in that year, leading to a further increase in HOEP prices in Ontario.

## Scenario Model Results

In this section we discuss the results of our scenario modeling on outcomes of interest. Our explanation and interpretation of these results, and our discussion of surplus implications, are discussed in a later section. We provide results below only for our model runs assuming nuclear curtailment. Appendix J provides our results assuming that wind is curtailed.

### Exports

The model results show that the elimination of the ETS tariff results in increased exports. Increasing the ETS tariff to the Equivalent Average Network Charge reduces exports. The Two Tier scenarios involve opposing impacts during the peak and off-peak hours; therefore, the magnitude of the annual impacts in these scenarios are lower than for the elimination and equivalent average network charge scenarios.

Table 3 provides the changes in total exports from Ontario for each ETS tariff scenario versus the Status Quo scenario, based on the assumption that nuclear generation is dispatched off before wind in SBG situations.

**Table 3: Change in Exports (Scenario – Status Quo) (MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| **Unilateral Elimination** ***Nuclear Curtailment*** | **Total** | 5,643,898 | 793,426 | 636,356 |
| | ***On Peak*** | *1,784,118* | *427,230* | *558,127* |
| | ***Off Peak*** | *3,859,780* | *366,196* | *78,229* |
| **Equivalent Average Network Charge** ***Nuclear Curtailment*** | **Total** | -4,985,661 | -285,016 | -1,210,946 |
| | ***On Peak*** | *-2,234,026* | *-140,802* | *-681,256* |
| | ***Off Peak*** | *-2,751,635* | *-144,214* | *-529,690* |
| **Two-Tiered Scenario A** ***Nuclear Curtailment*** | **Total** | -338,225 | -192,397 | -528,493 |
| | ***On Peak*** | *-3,444,346* | *-2,068,797* | *-1,154,821* |
| | ***Off Peak*** | *3,106,121* | *1,876,400* | *626,328* |
| **Two-Tiered Scenario B** ***Nuclear Curtailment*** | **Total** | 1,282,775 | -110,243 | -285,183 |
| | ***On Peak*** | *-955,365* | *-674,397* | *-712,468* |
| | ***Off Peak*** | *2,238,140* | *564,154* | *427,285* |

### Total Ontario Generation

Table 4 provides the changes in total Ontario power generation for each ETS tariff scenario relative to the Status Quo. These changes in Ontario generation follow a similar pattern to the impacts on exports (they differ because imports wheeled through Ontario change).

**Table 4: Change in Generation (Scenario – Status Quo)
(MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| Unilateral Elimination *Nuclear Curtailment* | Total | 5,643,912 | 133,312 | 456,759 |
| | *On Peak* | *1,806,415* | *120,661* | *428,729* |
| | *Off Peak* | *3,837,497* | *12,651* | *28,031* |
| Equivalent Average Network Charge *Nuclear Curtailment* | Total | -4,985,678 | -12,755 | -636,458 |
| | *On Peak* | *-2,329,026* | *-5,266* | *-373,874* |
| | *Off Peak* | *-2,656,653* | *-7,489* | *-262,584* |
| Two-Tiered Scenario A *Nuclear Curtailment* | Total | -338,214 | -12,703 | -258,595 |
| | *On Peak* | *-3,363,754* | *-1,796,865* | *-935,744* |
| | *Off Peak* | *3,025,540* | *1,784,161* | *677,149* |
| Two-Tiered Scenario B *Nuclear Curtailment* | Total | 1,282,773 | -3,264 | -160,768 |
| | *On Peak* | *-923,487* | *-512,732* | *-607,914* |
| | *Off Peak* | *2,206,261* | *509,468* | *447,145* |

### Prices

Table 5 provides the impact on the annual average HOEP (average based on generation-weighting) of the ETS tariff scenarios relative to the Status Quo.

**Table 5: Change in HOEP (Scenario – Status Quo)
(C$2011/MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| Unilateral Elimination *Nuclear Curtailment* | Total | $0.72 | $1.62 | $0.62 |
| | *On Peak* | *$0.37* | *$1.49* | *$0.51* |
| | *Off Peak* | *$0.96* | *$1.70* | *$0.68* |
| Equivalent Average Network Charge *Nuclear Curtailment* | Total | -$2.20 | -$3.45 | -$1.17 |
| | *On Peak* | *-$1.51* | *-$3.18* | *-$0.82* |
| | *Off Peak* | *-$2.64* | *-$3.62* | *-$1.40* |
| Two-Tiered Scenario A *Nuclear Curtailment* | Total | $0.43 | $0.25 | -$0.14 |
| | *On Peak* | *$0.02* | *-$0.52* | *-$0.59* |
| | *Off Peak* | *$0.75* | *$0.81* | *$0.19* |
| Two-Tiered Scenario B *Nuclear Curtailment* | Total | $0.28 | $0.22 | $0.06 |
| | *On Peak* | *$0.04* | *-$0.21* | *-$0.20* |
| | *Off Peak* | *$0.46* | *$0.52* | *$0.24* |

In the ETS tariff elimination scenario, the HOEP rises in response to greater market demand. In the EANC scenario, the HOEP decreases as market demand is reduced. In both the unilateral elimination and EANC scenarios, HOEP moves in the same direction in both on-peak and off-peak periods.

In both of the Two Tier cases, the ETS tariff rate is higher during on-peak periods and lower during off-peak periods when compared with the Status Quo. As a result total demand, including export demand, and prices are higher during off-peak periods. Conversely, total and demand and (relative) prices are lower during on-peak periods. There are exceptions in the on-peak during 2013, where the effect is close to zero.

### Production Costs

The impacts of each ETS scenario (versus Status Quo) on the raw variable production costs are provided in Table 6. The ETS elimination scenario leads to increased production costs for Ontario generators due to the need to serve increased export demand. The opposite is true for the EANC scenario. These results are intuitive. The Two Tier scenario results depend on the relative impacts during the on-peak and off-peak periods, but follow the trend of changes in total generation shown in Table 4.

**Table 6: Change in Production Costs (Scenario – Status Quo) (C$2011 Millions)**

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** ***Nuclear Curtailment*** | $168.48 | $6.02 | $21.89 |
| **Equivalent Average Network Charge** ***Nuclear Curtailment*** | -$141.36 | -$0.57 | -$30.58 |
| **Two-Tiered Scenario A** ***Nuclear Curtailment*** | -$7.79 | -$0.58 | -$12.25 |
| **Two-Tiered Scenario B** ***Nuclear Curtailment*** | $37.84 | -$0.15 | -$7.64 |

### Surplus Baseload Generation

With respect to SBG, the model results indicate that SBG is invariant to all the ETS tariff scenarios. This is true for both curtailment cases: nuclear first and wind first. In order to assess further this SBG invariance in our core analysis, we conducted some side sensitivity analyses with a modification to the 3000 MW joint constraint applied to the bottom two load blocks in each month, when SBG is most likely to occur. Our sensitivity analysis removed the 3000 MW joint constraint so that only the 6044 MW technical export constraint was enforced. We examined the year 2015 (when SBG would be most likely, based on the higher volume of wind and nuclear capacity assumed to be online) for the ETS tariff elimination and EANC scenarios. The conclusion from these sensitivity analyses was the same as for our core analyses – SBG did not vary across the ETS tariff scenarios. While the level of SBG was reduced with the greater export capacity, the ETS tariff itself did not affect the occurrence of SBG in our analysis. It appears that the differentials in baseload variable costs between Ontario sources and US baseload generation, which is mainly coal based, are so large that none of the proposed tariff changes would alter export decisions during SBG events.

## Explanation of Surplus Calculations

Outputs from the NEEM model for the modeled scenarios and data provided by the IESO were used as inputs in the calculation of changes in surplus to Ontario market participants. For each scenario, we calculated the change, relative to the Status Quo, in consumer surplus, producer surplus, and intertie congestion revenue. The sum of surplus changes to each set of Ontario market participants is equal to the change in total Ontario surplus. While we have calculated surplus for each group within the economy, it should be recognized that the allocation of that surplus is based on assumptions that are somewhat subjective, particularly in a system with a high degree of government ownership. By way of example, we have treated net income earned by OPG on its non-prescribed hydro operations as producer surplus, but that revenue flows to OPG's bottom line, which in turn affects Ontario's fiscal balance to the benefit of Ontario taxpayers/consumers. Changes in total surplus to Ontario market participants can be used as a measure of the effects on economic efficiency of adopting each of the ETS rate structures considered in our analysis. We did not measure the effects on surplus on a regional basis, nor did we measure the effects on surplus accruing to anyone outside of Ontario. However, we have measured the impact of ETS tariff changes in Ontario on total North American production costs. This is a measure of the overall regional efficiency effects associated with the various scenarios and is discussed in more detail below.

### Consumer Surplus

Consumer surplus changes when there are changes in the prices paid by Ontario consumers for energy.[10] One part of consumer surplus can therefore be calculated as the change in the price (between the scenario and the Status Quo) multiplied by (the fixed) demand. A second component of consumer surplus is the ETS tariff revenue collected; export tariff revenues offset transmitters' revenue requirements and therefore reduce transmission rates paid by Ontario consumers by an offsetting amount. Increases in ETS revenue collected therefore result in an increase in consumer surplus. Similarly, increases in uplift charges collected on exports are a benefit to Ontario consumers.

We calculate the change in each component of consumer surplus as follows:

<u>Changes in consumer surplus resulting from price changes</u>. We calculate the price paid by Ontario consumers as the sum of the Global Adjustment and expenditures for Ontario load. The Global Adjustment was built up from contract prices for each type of generation in the model, using data and certain assumptions about unit output provided by the IESO. Expenditures on energy by Ontario consumers were calculated using data on the HOEP generated by the model and Ontario load, projected by the OPA.

<u>ETS Tariff Revenue</u>. ETS tariff revenue is calculated as the ETS rate multiplied by the quantity of exports.

<u>Uplift Revenue</u>. Uplift revenue in a given scenario is calculated as the uplift rate (assumed to be a uniform $3.33/MWh, which is consistent with historical averages) multiplied by the quantity of exports.

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10 Ontario demand is highly inelastic, and in our model we assumed that Ontario demand is perfectly inelastic; that is, in our model, Ontario demand does not respond at all to changes in price. We recognize that in reality, Class A customers and some Class B customers can and do respond to price changes to a certain degree.

### Producer Surplus

Producer Surplus accruing to Ontario generators is calculated as the change in revenue received by generators less production costs. Revenues are calculated as the Global Adjustment payments received by generators plus market revenues received by generators, including those for exports. Changes in these two components of producer income largely offset one another. The other component of producer surplus is production costs, which are an output of the NEEM model. Appendix K explains the generator contract structure in Ontario.

### Intertie Congestion Revenue

Whenever an intertie connected to Ontario is export congested, the price at that intertie zone is higher than the Ontario price. Exporters end up paying the IESO a higher price to take away power than what the IESO pays Ontario generators to supply the power. This price difference between the intertie zone and Ontario times the export quantity flowing over the constrained intertie is the congestion rent accrued to the IESO.

In our analysis this Intertie Congestion Revenue is calculated as the volume of exports to each markets times the price in each export market, less costs of acquiring and selling energy, which consist of the cost of acquiring power in Ontario, the ETS tariff, the uplift charge, and a friction cost. Prices in export markets and the Ontario prices are generated by the NEEM model (the friction is an input to NEEM). Within the domestic market, Ontario has uniform hourly prices (HOEP) set by the unconstrained balancing of supply and demand.

## Interpretation of Model Results

The following contains our discussion of the effects of each ETS tariff scenario on consumer surplus for Ontario load, producer surplus for Ontario generators, the intertie congestion revenue accruing to Ontario, and total Ontario surplus (calculated as the sum of consumer surplus, producer surplus, and intertie congestion revenue). Prior to the interpretation of each scenario, we provide a table (Tables 7 through 10) summarizing our surplus calculations. In the top section of each table, we report the change in consumer surplus for Class A and Class B load combined. The bottom section of each table reports the change in consumer surplus for Class A and Class B loads separately.

Consumer surplus is broken out into the following components:

- The change in surplus accounted for by the change in the Global Adjustment (Δ Global Adjustment);
- The change in surplus accounted for by the change in payments for Ontario load evaluated at the HOEP (Δ Market Payments);
- The total change in payments by Ontario load, calculated as the sum of changes in the Global Adjustment and market payments (Δ GA + Market);
- The change in ETS tariff revenue (Δ ETS Revenue), and;
- The change in uplift payments (Δ Uplift).

Producer surplus is broken out by the change in revenues from the Global Adjustment (Δ Global Adjustment); the change in market revenues (Δ Market Revenues); the change in total revenues (Δ Total Revenues), which is calculated as the sum of changes in Global Adjustment and market revenues, and; the change in production costs.

The change in the Intertie Congestion Revenue (Δ Intertie Congestion Revenue) measures the net revenue accruing to Ontario as a result of exports to higher-priced markets. The Intertie Congestion Revenue is reported separately, and is allocated to neither producers nor consumers. It is, however, assumed to accrue to Ontario, and is therefore included in the calculation of the change in total surplus in Ontario

Note that the summary tables below report *increases* in surplus in the ETS scenario relative to the Status Quo, which may be positive (when surplus is higher in the ETS scenario than in the Status Quo) or negative (when surplus is lower in the ETS scenario than in the Status Quo). For example, when payments by Ontario load (for either the Global Adjustment or for market payments) are *higher* in the ETS scenario relative to the Status Quo, the corresponding change in consumer surplus is represented by *negative* value (i.e. a reduction in consumer surplus) in our tables, and *vice versa*. Similarly, a reduction in production costs is represented by a positive value (i.e. an increase in producer surplus), and an increase in revenue accruing to producers is also represented as a positive surplus change.

### Impacts of ETS rate changes on Class A and Class B customers

The Global Adjustment system works to provide payments to generators who have fixed prices or contracted returns. In general, when HOEP rises, power producers derive a larger proportion of their income from the market and smaller proportion from Global Adjustment payments. When HOEP falls, the opposite is generally true.

With the introduction of the new approach to allocating Global Adjustment between Class A and Class B, the two classes of customers are affected very differently by policy changes that result in changes in the HOEP. Class A customers pay only the HOEP for their power during the vast majority of hours. Their Global Adjustment payments are based on their individual consumption of grid-supplied power during the five highest load hours of the previous year. In contrast, Class B customers pay the remaining Global Adjustment, based on their share of total power consumption over the course of each month. In 2010, prior to the introduction of the reallocation regulation, Class A customers accounted for about 16% of power consumed in the Province, but consumed only 11% of the power during the five peak hours. Data for 2011 is not yet available. As a result of this approach, Class A customers pay a larger proportion, relative to Class B customers, of their bills through market payments based on HOEP and a smaller proportion through Global Adjustment.

Lower export barriers, in the form of lower ETS rates, generally result in greater export demand and this leads to a higher market clearing price in Ontario. In these cases, the average cost of power, inclusive of Global Adjustment charges, tends to rise for Class A customers. For Class B customers, who pay a relatively larger share of their bills through the Global Adjustment, power costs, inclusive of Global Adjustment, tend to fall as their share of the Global Adjustment declines by more than the HOEP rises.

Conversely when HOEP is reduced, Class A customers, on average, see lower total power bills as the rise in Global Adjustment they pay is less than the reduction in market prices. Class B customers see the opposite effect.

In addition, Class A customers have, on average, flatter load curves and as a result account for a higher proportion of off-peak consumption relative to on-peak consumption. Thus, any policy change that raises off-peak prices relative to on-peak prices tends to cost Class A customers, on average, and to benefit Class B customers, once Global Adjustment offsets are accounted for.

The bottom sections of Tables 7 through 10 show the impacts of each ETS tariff scenario on the consumer surplus for each class of customer. These calculations are based on the assumption that the share of power consumption by Class A customers remains at 10% through the study period. Since the Global Adjustment allocation scheme is designed to provide strong incentives to large customers to reduce their peak power use, this share may change over the study period. A one percent decrease (or increase) in the share of Class A power consumption during the five peak hours would result in a further shift in total costs between the two classes equal to about 10% of Class A's total Global Adjustment payments. When calculating consumer surplus by customer class, we assume that Class A customers account for 13% of on-peak consumption and 17% of off-peak consumption, reflecting the flatter load curves of Class A customers. These shares are based on an extrapolation of the load patterns for customers directly connected to the transmission system, who constitute the majority of Class A customers. Since comparable data for Class A customers embedded in distribution systems is not available, we assumed their consumption patterns are similar to those of directly connected customers.

**Table 7: Summary of Surplus Changes for Unilateral Elimination Scenarios (C$2011/MWh)**

| Surplus Component | 2013 | 2015 | 2017 |
|---|---|---|---|
| **(Class A & Class B)** | | | |
| Δ Global Adjustment | $97.8 | $244.1 | $77.3 |
| Δ Market Payments | -$90.7 | -$234.9 | -$84.6 |
| *Δ GA + Market* | *$7.1* | *$9.2* | *-$7.3* |
| Δ ETS Revenue | -$42.0 | -$44.5 | -$13.7 |
| Δ Uplift | $18.8 | $2.6 | $2.1 |
| **Δ Consumer Surplus** | **-$16.1** | **-$32.6** | **-$18.9** |
| | | | |
| Δ Global Adjustment | -$97.8 | -$244.1 | -$77.3 |
| Δ Market Revenues | $275.9 | $272.3 | $109.7 |
| *Δ Total Revenue* | *$178.1* | *$28.2* | *$32.4* |
| Δ Production Costs | -$168.5 | -$6.0 | -$21.9 |
| **Δ Producer Surplus** | **$9.6** | **$22.2** | **$10.5** |
| | | | |
| **Δ Intertie Congestion Revenue** | **$24.0** | **$10.1** | **$3.9** |
| | | | |
| ***Δ Total Surplus*** | ***$17.6*** | ***-$0.3*** | ***-$4.5*** |
| | | | |
| **Change in Consumer Surplus for Class A and Class B Load** | | | |
| **Class A Load** | | | |
| Δ Global Adjustment | $9.8 | $24.4 | $7.7 |
| Δ Market Payments | -$14.6 | -$36.5 | -$13.2 |
| *Δ GA + Market* | *-$4.9* | *-$12.1* | *-$5.5* |
| Δ ETS Revenue | -$6.3 | -$6.7 | -$2.1 |
| Δ Uplift | $2.8 | $0.4 | $0.3 |
| **Δ Consumer Surplus (Class A)** | **-$8.3** | **-$18.4** | **-$7.2** |
| | | | |
| **Class B Load** | | | |
| Δ Global Adjustment | $88.0 | $219.7 | $69.6 |
| Δ Market Payments | -$76.0 | -$198.4 | -$71.4 |
| *Δ GA + Market* | *$12.0* | *$21.3* | *-$1.8* |
| Δ ETS Revenue | -$35.7 | -$37.8 | -$11.6 |
| Δ Uplift | $16.0 | $2.2 | $1.8 |
| **Δ Consumer Surplus (Class B)** | **-$7.7** | **-$14.2** | **-$11.6** |

### *Unilateral Tariff Elimination*

The NEEM model results associated with reducing Ontario's ETS rate from $2.00/MWh to $0/MWh show impacts on the variables of interest changing substantially over the three years modeled as the generation structure of the Ontario power system evolves, with wind and solar generation increasing substantially from 2013 to 2017, and refurbishment of nuclear units resulting in a significant reduction in nuclear generation by 2017. Ontario's entry into the Western Climate Initiative cap-and-trade process also has significant impacts on prices and trade patterns.

**Exports.** The elimination of Ontario's ETS tariff in 2013 substantially improves the competitive position of Ontario's generators in export markets. In particular, the model shows that this cost reduction leads to a 5.6 million MWh increase in power exports, with nearly 70% of this increase occurring in sales to the PJM market, primarily through Michigan. Imports are little changed. There is a corresponding increase in CCGT output from Ontario's gas-fired fleet.

After consultation with the IESO, CRA has assumed that Ontario will enter the WCI regime by 2015. As a result, fossil generators will need to acquire carbon allowances and reflect those costs in its bids, as it does now with fuel costs. The resulting cost increase will raise the costs of gas-fired generation in Ontario relative to other non-WCI markets. With the current nuclear fleet in full service and increased renewable generation, the overall volume of gas-fired generation is expected to decline in 2015 in both the base case and the ETS elimination case. As a result the increase in exports associated with ETS removal in 2015, at 0.8 million MWh, is considerably smaller than the 5.6 million MWh figure found in the modeling for 2013. Moreover, over 80% of the increase in exports with tariff elimination is met by increased imports, mostly from Quebec, which does not face the carbon price penalty on its hydro production.

In 2017, two nuclear units are out of service and being refurbished. While renewable production is assumed to meet the LTEP target, substantial gas-fired production is required to meet Ontario's intermediate and peak load. In that case and with carbon prices inhibiting exports to non-WCI markets, the impact of an ETS tariff elimination remains limited, resulting in only a 0.6 million MWh expansion of exports.

**HOEP.** The elimination of the ETS tariff in 2013 substantially improves the competitiveness of Ontario gas-fired CCGT generation in US markets. The resulting increase in demand for Ontario production leads to gas-fired generation being on the margin more often. As a result, average Ontario market prices rise by $0.72/MWh.

In 2015, the tariff elimination makes exports more attractive in US export markets, but carbon pricing limits the increase in Ontario gas-fired generation to meet that growing export demand. Most of the increase in exports is matched by an increase in imports. Given the limited amount of gas-fired production, Ontario prices are to a large extent set by prices available in export prices, which rise by $1.62/MWh to reflect the lower ETS.

In 2017, ETS tariff elimination results in an increase in the average HOEP of $0.62/MWh.

In each year, the impact of the rise in the HOEP is largely offset by opposite changes in Global Adjustment payments. A fuller description of how the interaction between market prices and global adjustment payments affects total customer bill in each case is provided in the Consumer Surplus section below.

**Export Tariff Revenue.** The elimination of the ETS tariff reduces ETS revenue from $42 million in the Status Quo case to zero in 2013 and by a similar amount in 2015. In 2017, export volumes are substantially lower in both the Status Quo case and the ETS elimination case. As a result the impact of tariff removal is smaller, at $13.7 million.

**Uplift Revenue.** The 5.6 million MWh increase in exports in 2013 generates an $18.8 million increase in exporters' contribution to transmission cost. For 2015, the smaller impact on export volumes produces an increase of $2.6 million and in 2017 the contribution is $2.1 million.

**Carbon Pricing and Emissions.** In the 2013 ETS elimination case, there is a substantial increase in gas-fired generation, resulting in an increase in $CO_2$ emissions from Ontario's fossil fleet rising from 6.0 million megatonnes to 8.0 million megatonnes.

By 2015, Ontario is assumed to join the WCI and implement a regulatory regime similar to the one to be introduced in Quebec in 2013. As a result, Ontario fossil generators will acquire carbon allowances and build those prices into their bids. In addition, building on the Quebec model, imports from non-WCI markets will face border adjustments reflecting the average carbon content in those markets.

In 2015, increased exports are met primarily by increased imports from Quebec and Manitoba. As a result, there is little impact on Ontario carbon emissions. This pattern continues in 2017.

**Consumer Surplus.** Consumer surplus in 2013, calculated as the sum of total market and global adjustment payments by Ontario consumers plus the change in transmission revenue and the change in uplift payments, is reduced by $16.1 million. This reflects the impact of ETS revenue reductions more than offsetting increased uplift contributions and a small decrease in total power costs.

The impact on consumer surplus in 2015 is a net reduction of $32.6 million, due to the loss of $44.5 million in ETS tariff revenue with the elimination of the tariff. In 2017, the net reduction in consumer surplus is $18.9 million.

Both Class A and Class B customers see a net reduction in consumer surplus under this scenario. Class A customers, who pay Global Adjustment based on their peak consumption, are more affected by changes in HOEP since it is a proportionally larger part of their bill. In 2013, the rise in market prices more than offsets the impact of Global Adjustment for this class of customers. The net $4.9 million increase in Class A power costs in 2013, combined with higher transmission rates to compensate for the loss of ETS revenue and partially offset by a small increase in uplift revenue, results in an $8.3 million reduction in consumer surplus for Class A. For Class B customers, the reduction in Global Adjustment more than offsets higher market prices, leading to a reduction in total payments for energy by this class of customers. However, once higher domestic transmission rates, resulting from the absence of an ETS tariff revenue offset, partially offset by increased Uplift revenue, are taken account of, Class B customers still face a $7.7 million reduction in consumer surplus. Both classes of customers also see net reductions in consumer welfare in 2015 and 2017 when ETS tariffs are removed, primarily due to the loss of exporters' contribution to fixed transmission costs *via* the ETS tariff.

**Producer Surplus.** With increased exports and higher HOEP in 2013, market revenue gains for generators more than offsets reduced Global Adjustment payments and higher costs, primarily for natural gas and O&M costs at gas-fired facilities. The net producer surplus gain is $9.6 million. In 2015 and 2017, the net increase in producer surplus is $22.2 million and $10.5 million, respectively.

**Intertie Congestion Revenue.** The elimination of the ETS tariff and increased exports generate a market value difference between Ontario and export markets, after taking account of costs associated with exports, of $24 million. In 2015 and 2017, the corresponding figures are $10.1 million and $3.9 million. This Intertie Congestion Revenue is the difference between the price the IESO sells power for on congested transmission lines and the price it pays Ontario producers.

**Net Ontario Benefit.** In 2013, the net Ontario benefit, defined as the sum of consumer surplus, producer surplus and gains from trade is positive, at $17.6 million. In 2015 and 2017, the loss in ETS revenue more than offsets other gains, resulting in negative impacts of $0.3 million and $4.5 million, respectively.

## Table 8: Summary of Surplus Changes for EANC Scenarios (C$2011/MWh)

| Surplus Component | 2013 | 2015 | 2017 |
|---|---|---|---|
| **(Class A & Class B)** | | | |
| Δ Global Adjustment | -$313.6 | -$521.0 | -$147.5 |
| Δ Market Payments | $303.5 | $499.2 | $156.1 |
| *Δ GA + Market* | *-$10.1* | *-$21.8* | *$8.6* |
| Δ ETS Revenue | $50.8 | $82.8 | $18.9 |
| Δ Uplift | -$16.6 | -$0.9 | -$4.0 |
| **Δ Consumer Surplus** | **$24.1** | **$60.1** | **$23.5** |
| | | | |
| Δ Global Adjustment | $313.6 | $521.0 | $147.5 |
| Δ Market Revenues | -$484.2 | -$569.5 | -$196.7 |
| *Δ Total Revenue* | *-$170.6* | *-$48.5* | *-$49.2* |
| Δ Production Costs | $141.4 | $0.6 | $30.6 |
| **Δ Producer Surplus** | **-$29.2** | **-$47.9** | **-$18.6** |
| | | | |
| **Δ Intertie Congestion Revenue** | **-$17.7** | **-$7.9** | **-$5.8** |
| | | | |
| ***Δ Total Surplus*** | ***-$22.8*** | ***$4.2*** | ***-$1.0*** |
| | | | |
| **Change in Consumer Surplus for Class A and Class B Load** | | | |
| **Class A Load** | | | |
| Δ Global Adjustment | -$31.4 | -$52.1 | -$14.8 |
| Δ Market Payments | $48.2 | $77.5 | $24.7 |
| *Δ GA + Market* | *$16.8* | *$25.4* | *$10.0* |
| Δ ETS Revenue | $7.6 | $12.4 | $2.8 |
| Δ Uplift | -$2.5 | -$0.1 | -$0.6 |
| **Δ Consumer Surplus (Class A)** | **$21.9** | **$37.7** | **$12.2** |
| | | | |
| **Class B Load** | | | |
| Δ Global Adjustment | -$282.2 | -$468.9 | -$132.8 |
| Δ Market Payments | $255.4 | $421.8 | $131.4 |
| *Δ GA + Market* | *-$26.9* | *-$47.2* | *-$1.4* |
| Δ ETS Revenue | $43.2 | $70.4 | $16.1 |
| Δ Uplift | -$14.1 | -$0.8 | -$3.4 |
| **Δ Consumer Surplus (Class B)** | **$2.2** | **$22.4** | **$11.3** |

### *Equivalent Average Network Charge (EANC)*

Raising the ETS to the average network charge in Ontario ($5.80/MWh) would generate more revenue to offset domestic consumers' transmission costs but would also discourage exports. Impacts on variables of interest are reviewed below:

**Exports.** Increasing the ETS rate to the EANC will make Ontario power exports less competitive and in 2013 is estimated to cause a reduction in exports of nearly 5 million MWh. This is reflected primarily in a decline in CCGT production of about two-thirds from Status Quo output.

In 2015, the impact on exports is small since, with carbon costs incorporated into the price of gas-fired generation, exports of gas-fired power are very small in the Status Quo. The impact on exports is roughly matched by a reduction in imports. This primarily reflects a negative impact of the increased export tariff on wheeling from Quebec through Ontario into the US mid-west. The negative impact of the ETS tariff increase on Ontario prices also makes Ontario a less attractive market for exports from Quebec.

In 2017, with reduced nuclear production in the Status Quo, Ontario expects to see sharply reduced exports and more imports, making the province a net importer. The impact of raising the ETS is to further reduce exports, as well as imports. The impact of the ETS increase on imports likely reflects lower wheeling through Ontario from Quebec.

**HOEP.** The higher export tariff has a substantial negative impact on HOEP in 2013 and 2015, but has less impact in 2017. In the 2013 case, the $3.80/MWh increase in the ETS tariff makes Ontario CCGT exports much less competitive. This added cost effectively reduces the return Ontario producers can earn in export markets, and that export price effectively sets prices in Ontario much of the time. As a result, average HOEP declines by $2.20. There is a larger reduction in HOEP of $3.45/MWh in 2015. In 2017, exports are small, as is the impact on HOEP, which falls by $1.17/MWh

**Export Tariff Revenue.** Raising the ETS rate to $5.80 would increase total revenue collected from exporters in 2013, despite a sizeable drop in exports. The net increase is calculated to be $50.8 million --- more than doubling current ETS tariff revenue. In 2015, the export tariff revenue increase resulting from the higher rate is $82.8 million, even with the higher export tariff since the higher tariff has little impact on Ontario export volumes, which in 2015 are primarily baseload generation. In 2017, we see reduced nuclear production and higher prices reflected in both the Status Quo and the tariff increase case. These factors reduce exports sharply and in doing so reduce the revenue yield from higher tariff rates.

**Uplift Revenue.** In each year, uplift revenue is reduced with the tariff increase in line with reduced exports.

**Carbon Pricing and Emissions.** In 2013, this increase in export tariffs reduces production and export of gas-fired power. As a result electricity sector emissions are reduced from 6.6 megatonnes to 4.7 megatonnes. As there is no pricing of carbon assumed in 2013, there is no financial impact to that emission reduction. In 2015, there is very limited gas-fired generation in either case and so emissions are largely unaffected. Emissions rise in 2017 as gas-fired generation ramps up to serve Ontario load while two nuclear units are unavailable, but the tariff increase has little impact on the level of gas-fired generation since gas-fired exports are minimal in either case.

**Consumer Surplus.** Raising the ETS rate in 2013 results in lower consumer prices, but this effect is more than offset by higher Global Adjustment payments. This occurs because the payment by export customers for baseload production is effectively reduced, as the higher ETS tariff lowers market prices paid by Ontario exporters. ETS revenue rises by $50.8 million while uplift payments are reduced due to lower exports. The sum of these changes is a net increase in consumer welfare of $24.1 million.

In 2015, the net gain in consumer surplus, taking account of the ETS revenue growth associated with high export volumes in both the base case and the EANC case and slightly lower uplift revenue, is $60.1 million. In 2017, the comparable figure is a smaller net gain for consumers of $23.5 million, reflecting export volumes that are much lower than earlier years in both the Status Quo and EANC cases, resulting in a lower level of ETS revenue.

Class A consumers, on average, gain as the lower market prices they pay more than offsets the increase in Global Adjustment. Class B customers, on average, face a higher total cost for energy as Global Adjustment payments more than offset reductions in market prices. Both classes benefit on net because of increased ETS and Uplift revenues, which are assumed to lower their transmission service bills.

**Producer Surplus.** In 2013, an increase in the ETS tariff rate to the EANC would reduce producers' revenue, from both the market and the Global Adjustment by $170.6 million and reduce their costs (primarily fuel) by $141.4 million, for a net producer welfare loss of $29.2 million. In 2015, producer market revenue is lower due to lower Ontario prices. Most of this revenue reduction is offset by higher Global Adjustment payments. The net effect is a reduction in producer surplus of $47.9 million. In 2017, the ETS rate change reduces producer surplus by $18.6 million.

**Intertie Congestion Revenue.** The EANC tariff rate has the effect of reducing the volume of exports by making Ontario production less competitive in export markets. The ETS rate increase also reduces the price exporters can charge in export markets. While the average price exporters pay for Ontario power is also reduced, there is not a full offset. As a result, Intertie Congestion Revenue is reduced by $17.7 million in 2013. The comparable figures in 2015 and 2017 are reductions of $7.9 million and $5.8 million, respectively.

**Net Ontario Benefit.** In 2013, the net Ontario benefit, defined as the sum of changes in consumer surplus, producer surplus and exporter surplus is a reduction of $22.8 million, as the reductions in producer surplus and intertie congestion revenue more than offset the net welfare gain by consumers. For 2015 and 2017, the net benefit to Ontario is close to neutral as consumer surplus gains are roughly offset by reductions in producer surplus and intertie congestion revenue.

**Table 9: Summary of Surplus Changes for Two Tier Option A (C$2011/MWh)**

| Surplus Component | 2013 | 2015 | 2017 |
|---|---|---|---|
| **(Class A & Class B)** | | | |
| Δ Global Adjustment | $64.0 | $38.8 | -$15.2 |
| Δ Market Payments | -$58.8 | -$31.3 | $20.5 |
| *Δ GA + Market* | *$5.2* | *$7.4* | *$5.3* |
| Δ ETS Revenue | -$3.5 | $2.8 | -$0.5 |
| Δ Uplift | -$1.1 | -$0.6 | -$1.8 |
| **Δ Consumer Surplus** | **$0.6** | **$9.6** | **$3.0** |
| | | | |
| Δ Global Adjustment | -$64.0 | -$38.8 | $15.2 |
| Δ Market Revenues | $61.1 | $40.2 | -$31.0 |
| *Δ Total Revenue* | *-$2.9* | *$1.5* | *-$15.9* |
| Δ Production Costs | $7.8 | $0.6 | $12.2 |
| **Δ Producer Surplus** | **$4.9** | **$2.1** | **-$3.6** |
| | | | |
| **Δ Intertie Congestion Revenue** | **-$1.4** | **-$5.8** | **-$3.8** |
| | | | |
| ***Δ Total Surplus*** | ***$4.1*** | ***$5.9*** | ***-$4.4*** |
| | | | |
| **Change in Consumer Surplus for Class A and Class B Load** | | | |
| **Class A Load** | | | |
| Δ Global Adjustment | $6.4 | $3.9 | -$1.5 |
| Δ Market Payments | -$9.9 | -$6.7 | $2.1 |
| *Δ GA + Market* | *-$3.5* | *-$2.8* | *$0.6* |
| Δ ETS Revenue | -$0.5 | $0.4 | -$0.1 |
| Δ Uplift | -$0.2 | -$0.1 | -$0.3 |
| **Δ Consumer Surplus (Class A)** | **-$4.2** | **-$2.5** | **$0.2** |
| | | | |
| **Class B Load** | | | |
| Δ Global Adjustment | $57.6 | $34.9 | -$13.6 |
| Δ Market Payments | -$48.9 | -$24.7 | $18.4 |
| *Δ GA + Market* | *$8.7* | *$10.2* | *$4.7* |
| Δ ETS Revenue | -$2.9 | $2.4 | -$0.5 |
| Δ Uplift | -$1.0 | -$0.5 | -$1.5 |
| **Δ Consumer Surplus (Class B)** | **$4.8** | **$12.1** | **$2.8** |

## Table 10: Summary of Surplus Changes for Two Tier Option B (C$2011/MWh)

| Surplus Component | 2013 | 2015 | 2017 |
|---|---|---|---|
| **(Class A & Class B)** | | | |
| Δ Global Adjustment | $39.9 | $34.4 | $7.5 |
| Δ Market Payments | -$37.0 | -$30.3 | -$6.8 |
| *Δ GA + Market* | *$2.9* | *$4.1* | *$0.7* |
| Δ ETS Revenue | $3.1 | $0.6 | -$0.4 |
| Δ Uplift | $4.3 | -$0.4 | -$0.9 |
| **Δ Consumer Surplus** | **$10.3** | **$4.3** | **-$0.6** |
| | | | |
| Δ Global Adjustment | -$39.9 | -$34.4 | -$7.5 |
| Δ Market Revenues | $80.7 | $36.3 | -$0.1 |
| *Δ Total Revenue* | *$40.8* | *$1.8* | *-$7.6* |
| Δ Production Costs | -$37.8 | $0.2 | $7.6 |
| **Δ Producer Surplus** | **$2.9** | **$2.0** | **$0.1** |
| | | | |
| **Δ Intertie Congestion Revenue** | **-$1.5** | **-$2.9** | **-$1.9** |
| | | | |
| ***Δ Total Surplus*** | ***$11.7*** | ***$3.4*** | ***-$2.5*** |
| | | | |
| **Change in Consumer Surplus for Class A and Class B Load** | | | |
| **Class A Load** | | | |
| Δ Global Adjustment | $4.0 | $3.4 | $0.8 |
| Δ Market Payments | -$6.2 | -$5.7 | -$1.6 |
| *Δ GA + Market* | *-$2.2* | *-$2.3* | *-$0.8* |
| Δ ETS Revenue | $0.5 | $0.1 | -$0.1 |
| Δ Uplift | $0.6 | -$0.1 | -$0.1 |
| **Δ Consumer Surplus (Class A)** | **-$1.1** | **-$2.2** | **-$1.0** |
| | | | |
| **Class B Load** | | | |
| Δ Global Adjustment | $35.9 | $31.0 | $6.8 |
| Δ Market Payments | -$30.8 | -$24.6 | -$5.2 |
| *Δ GA + Market* | *$5.1* | *$6.4* | *$1.6* |
| Δ ETS Revenue | $2.6 | $0.5 | -$0.3 |
| Δ Uplift | $3.6 | -$0.3 | -$0.8 |
| **Δ Consumer Surplus (Class B)** | **$11.3** | **$6.5** | **$0.4** |

### *Two Tier Options A and B*

To the extent that the goal of the review is to allow greater exports of surplus baseload power, while preserving transmitters' contribution to the maintenance and operation of the transmission system, some stakeholders have proposed two-tiered rates. The implications of a rate based on a $5.80/MWh rate during on-peak periods, in line with the charge applied to other users of the system and a zero rate in off-peak periods are addressed below (Tier Two Option A). Two Tier Option B assumes rates of $3.50/MWh on-peak and $1.00/MWh off-peak. This analysis assumes 12 hours on-peak and 12 hours off-peak for each weekday. Weekends are off-peak.

**Exports.** The Two Tier structures produce relatively little change in total export levels in most years, but with a major shift between on-peak and off-peak periods (see Table 3 above). The exception is the Two Tier Option B scenario, where the $1/MWh reduction in the off-peak rate has a substantially larger positive impact on exports than the negative impact of the $1.50/MWh increase in the on-peak periods in 2013. In 2015 and 2017, imports from Quebec are also reduced, reflecting reduced incentive to wheel power through Ontario into US markets during peak periods.

**HOEP.** On average, these options have a small positive impact on Ontario market prices, with impacts ranging from a reduction of $0.14/MWh for Two Tier Option A in 2017, to an increase of $0.43/MWh for Two Tier Option A in 2013.

**Export Tariff Revenue.** With the exception of 2013, the Two Tier options generate little change in ETS revenue. In the Two Tier Option B scenario, higher charges on on-peak transactions are offset by the elimination of off-peak tariffs. The $1/MWh tariff decrease is sufficient to generate a larger increase in off-peak exports and associated ETS revenue. In the Two Tier Option A scenario, there is a $3.5 million loss in ETS revenue.

**Uplift Revenue.** In the 2013 simulation of Two Tier Option B, uplift revenue rises by $4.3 million as off-peak export gains more than offset on-peak reductions. In all the other cases, there is little impact on the volume of exports in any year, and therefore there is little change in uplift revenue.

**Carbon Pricing and Emissions.** There is little impact on emissions in any of these cases.

**Consumer Surplus.** With the exceptions of the Two Tier Option B scenario in 2013 and the Two Tier Option A scenario in 2015, there is little impact on consumer surplus in these cases. In the Two Tier Option B scenario in 2013, the substantial increase in off-peak exports results in an increase of approximately $7 million in ETS revenue and uplifts, to the benefit of Ontario consumers. In the Two Tier Option A scenario in 2015, the net improvement in consumer surplus is about $10 million.

Since Class A customers have, on average, flatter load profiles, they represent a larger share of off-peak load than of on-peak load. Lowering off-peak ETS tariff rates and increasing on-peak rates in these two cases results in higher off-peak demand (inclusive of exports) and prices and lower (relative) on-peak total demand and prices. As a result, the average price paid by Class A customers rises and the average price, including the Global Adjustment, paid by Class B customers is reduced. Once changes in ETS and uplift revenue are accounted for, Class B customers, on average, see a net improvement in consumer surplus in each scenario and each year. Class A customers, on average, see a net reduction in consumer surplus in both scenarios and most years.

**Producer Surplus.** In each case and each year (with one exception), there is an increase in producer surplus, ranging from $0.1 million to $4.9 million. The larger number reflects higher market payments to OPG non-prescribed hydro production as a result of somewhat higher market prices. For this producer there is no Global Adjustment offset. The one exception is the Two Tier Option A scenario in 2017 where producer surplus falls by $3.6 million.

**Intertie Congestion Revenue.** In the Two Tier Option A scenario, intertie congestion revenues decline by an average of about $4 million per year, reflecting a smaller difference between prices in Ontario and export markets and smaller on-peak and total export volumes. The reduction in intertie congestion revenues in the Two Tier Option B scenario averages $2 million.

**Net Ontario Benefit.** In 2013 the Two Tier Option B scenario produces a net Ontario benefit of $11.7 million, on the strength of higher ETS and Uplift revenue associated with an increase in off-peak exports. The net benefit in the other cases and years is small, ranging from a loss of $4.4 million to a gain of $5.9 million.

## Regional Welfare: North American Production Costs

Within an interconnected region, prices will tend to equalize as lower-cost production from one region displaces higher-cost production in another. Trade thus has the effect of lowering total production costs across the region. This reduction in total regional production costs is a measure of regional welfare effects. Barriers to trade, such as export tariffs, tend impede this trade, leading to higher total costs and reducing total regional welfare.

The CRA NEEM model estimated production costs in all North American jurisdictions. The elimination of Ontario's $2.00/MWh ETS tariff would result in lower total production costs, producing a regional welfare gain of US$37 million in 2013, US$3 million in 2015 and US$7 million in 2017 (see Table 11). The gain is smaller in the latter years, primarily because the inclusion of carbon costs in Ontario's gas-fired generation and of carbon border adjustments on imports from more carbon intensive markets sharply reduce trade in gas-fired power in 2015 and beyond. With nuclear capacity reduced between 2015 and 2020, there is less baseload generation available for export in the scenarios and in the Status Quo. From the perspective of Ontario consumers, however, these changes lead to a net loss in consumer welfare as the loss of ETS tariff revenue, and the resulting increase in Ontario consumers' transmission charges, more than offsets Ontario's share of the gains from expanded trade.

Conversely, in the case where Ontario export tariff rates are raised to $5.80/MWh in the EANC scenario, trade is reduced and total regional production costs are increased by US$56 million, US$3 million and US$15 million, in 2013, 2015, and 2017 respectively. However, ETS revenue more than offsets Ontario consumers' share of this net loss.

The elimination of the ETS tariff during off-peak periods in the Two Tier Option A scenario results in a substantial improvement in regional efficiency in 2013 and smaller improvements in 2015 and 2017. Two Tier Option B shows mixed impacts on regional production costs as lower costs in off-peak periods are offset by higher costs in on-peak periods.

**Table 11: Change in North American Production Costs (Scenario – Status Quo) (US$2011 Millions)**

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** ***Nuclear Curtailment*** | -$37 | -$3 | -$7 |
| **Equivalent Average Network Charge** ***Nuclear Curtailment*** | $56 | $3 | $15 |
| **Two-Tiered Scenario A** ***Nuclear Curtailment*** | $26 | $7 | $8 |
| **Two-Tiered Scenario B** ***Nuclear Curtailment*** | -$2 | $1 | $4 |

# 6. Discussion of Assessment Criteria

In this section we provide an assessment of the ETS tariff scenarios based on four principles: consistency with neighbouring markets, simplicity, fairness and efficiency. We begin with an overview of the criteria, and then provide an assessment of the extent to which each scenario satisfies the listed criteria.

### Consistency

Inconsistencies in design can create additional costs or impose barriers to the smooth operation of interconnected markets. None of the ETS rate options under consideration in this review are likely to create substantial costs or inefficiencies due to being inconsistent with rates in neighbouring markets. ETS rate structures and levels, as described in more detail in the SE-94 document *Review of Rates in Neighbouring Markets*, vary among those neighbouring markets. The NYISO having volume-based rates similar to Ontario's while most other nearby markets having fixed yearly, monthly and daily rates. Some markets differentiate between firm and non-firm service and between peak and off-peak rates, while others do not. Therefore, no rate structure for Ontario could be entirely consistent with structures in other markets. The Status Quo rate in Ontario is lower than ETS rates in most nearby markets, while the average network service charge rate is closer to that average. Ontario, like New York, imposes volumetric charges, but unlike New York, Ontario applies a single province-wide rate. New York, in contrast, has a complex set of rates that reflects costs for service from various sources and to different external loads. A unilateral removal of export charges would be inconsistent with experience elsewhere, but would not create incremental barriers or costs.

### Simplicity

None of the options under consideration are prohibitively complex. Moving to a tiered rate structure would require changes to settlement systems and processes. MISO and PJM have short-term volumetric rates that vary by time of day but are based on a 5x16 on-peak period rather than the weekday 12-hour peak period proposed for Ontario.

### Fairness

Fairness can be viewed in two dimensions: horizontal (ensuring that like consumers pay like charges) and vertical (ensuring that consumers who impose different costs and derive different benefits are treated in a way that reflects those costs and benefits). In assessing the various ETS rate options included in this study, there are alternative views as to how these rates should be structured to reflect generally accepted rate-making principles, particularly when considering the use of the transmission infrastructure which costs generally do not vary with usage. At one end of that range is the view that there should be equal sharing of cost recovery between all users of the transmission infrastructure, irrespective of how often that infrastructure is used by the various transmission customers.

At the other end of that range, the opposing view is that frequency of usage and quality of service are important considerations because those who use the transmission system constantly, i.e. domestic consumers, gain the greatest benefit from that transmission infrastructure. In that view, interconnections with neighbouring markets were put in place primarily to reduce the risks and costs of ensuring reliable supply for domestic needs. Moreover, export transactions are more prone to failure than domestic transactions. The Market Surveillance Panel reports that about 7% of on-peak export transactions fail. The corresponding figure for off-peak transactions is about 5%. More than half of these failures are the result of operator actions to maintain the reliability of the system. Consequently, in this infrequent users of the transmission infrastructure should not have to share in the recovery of infrastructure costs but rather pay only for the marginal cost of usage, which generally entails cost of congestion and marginal losses. Any revenue from infrequent users, such as exporters, would be an additional benefit to the domestic users. This range of views is fairly represented by the variety of ETS tariff structures that were identified in the ETS rate report[11].

Another consideration that should be taken into account when assessing rate options is to recognize the fact that transmission costs account for a relatively small proportion of the customer's total electric bill, about 10% of a typical consumers electric bill. About 50% of the domestic consumer's electricity bill is accounted for by energy costs, and ETS structure or rate changes can affect other elements of the total bill, including HOEP, SBG costs, Wholesale Market Charges and Global Adjustment. Charging exporters for transmission may create other effects that ultimately have a negative impact on the consumer's total bill. For example, forcing exporters to pay for transmission may deter them from exporting and this could create additional costs in Ontario that may increase the overall price of electricity, thus negatively impacting domestic consumers. The table below thus reports the net impact on consumer surplus for each case considered.

**Table 12: Summary of Change in Consumer Surplus by Scenario (C$2011 Millions)**

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** | -$16.1 | -$32.6 | -$18.9 |
| **Equivalent Average Network Charge** | $24.1 | $60.1 | $23.5 |
| **Two-Tiered Scenario A** | $0.6 | $9.6 | $3.0 |
| **Two-Tiered Scenario B** | $10.3 | $4.3 | -$0.6 |

### Efficiency

The impact of alternate rate structures on the Ontario electricity sector can be measured by the resulting Net Ontario Benefit, as measured by the sum of consumer benefit, producer benefit and gains from trade. As noted above, this calculation takes account of impacts on market prices, global adjustment costs, volumes and composition of exports and imports, carbon costs and credits, changes in system costs and export revenue.

11 CRA "Export Transmission Service Tariff Study – Review of Rates in Neighbouring Markets".

**Table 13: Summary of Change in Total Ontario Surplus by Scenario (C$2011 Millions)**

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** | $17.6 | -$0.3 | -$4.5 |
| **Equivalent Average Network Charge** | -$22.8 | $4.2 | -$1.0 |
| **Two-Tiered Scenario A** | $4.1 | $5.9 | -$4.4 |
| **Two-Tiered Scenario B** | $11.7 | $3.4 | -$2.5 |

More detail of the assessment of each option against the chosen rate making principles is provided below.

## Status Quo-- $2/MWh

| Principle | Evaluation |
|---|---|
| Consistency | • Ontario ETS is consistent with the fact that all jurisdictions provide an hourly rate for ETS transactions.<br>• Consistent with transmission ETS rates in NYISO, Hydro Quebec and ISONE in that there is no rate distinction between peak and off-peak periods.<br>• Inconsistent with approach in PJM and MISO where a rate distinction is made between peak and off-peak periods.<br>• Substantially lower than ETS rates in these neighbouring markets.<br>• The methodology used to derive the Ontario ETS rate is inconsistent with the methodology used in neighbouring jurisdictions as the rate is set arbitrarily by the OEB and is not derived directly from transmission owners' transmission revenue requirement over a specified time period.<br>• The fact that other jurisdictions employ hourly ETS rates suggests that there is commonality in rate structure and use between neighbouring jurisdictions and hence does not create inefficiencies due to inconsistencies in structures. |
| Simplicity | • A flat hourly rate is familiar to market participants.<br>• Very simple to administer since no change required to existing Market Rules in Ontario.<br>• Rate structure simple to understand by market participants. |
| Fairness | • Exporters pay a lower rate for use of the system than other users.<br>• Cost of transmission service is shared in different proportion by domestic and export transmission users in Ontario --- consistent with the view that exporters impose different costs on the system and receive different benefits, but inconsistent with the view that all customers should share equally.<br>• Domestic consumers who pay the most of the cost of transmission infrastructure in Ontario benefit from exporters' usage of transmission system.<br>• Exporters' share of the cost of using the existing transmission infrastructure in Ontario set arbitrarily. |
| Efficiency | • Somewhat lower barriers to export transactions out of Ontario by the fact that the rate is substantially lower than corresponding rates in neighbouring jurisdictions (except those relating to transaction between NYISO and ISONE, and PJM and MISO which ETS rates are set to zero).<br>• Exporters have no opportunity to switch to lower rate time periods as these don't exist. |

## Unilateral Elimination-- $0/MWh

| Principle | Evaluation |
|---|---|
| Consistency | • Consistent with ETS rates between NYISO and ISONE and between MISO and PJM (Note that these are bilateral deals, not unilateral actions).<br>• Consistent with the trend toward elimination of rate pancaking between trading jurisdictions in the US.<br>• Inconsistent with ETS rates charged in neighbouring markets immediately adjacent to Ontario, e.g. NYISO, Hydro Quebec and MISO.<br>• Substantially lower than ETS rates in neighbouring markets immediately adjacent to Ontario |
| Simplicity | • Very simple to administer.<br>• Administrative burden would not be reduced by the absence of ETS charges since ETS transactions would continue to be charged for Ancillary Services (uplift) other related Market Participant costs.<br>• Simple to understand by market participants. |
| Fairness | • Cost of transmission service not shared by all users of transmission infrastructure in Ontario --- inconsistent with the view that all users should share the cost of the system.<br>• Burden of cost of transmission service in Ontario placed entirely on domestic consumers in Ontario, i.e. domestic consumers gain no benefit from non-domestic users of transmission system; thus inconsistent with transmission charge approach in other jurisdictions (except those trading between NYISO and ISONE and PJM and MISO).<br>• Ontario consumer welfare, in terms of total charges for generation and transmission increase in each year examined. The net cost to consumers versus the Status Quo rate in 2013, 2015 and 2017 is $13.5 million, $28.8 million and $31.5 million, respectively. |
| Efficiency | • Reduces barrier to export transactions.<br>• May provide some benefit for external parties to wheel through Ontario instead of through other jurisdiction because the ETS rate is zero that could impact operations in Ontario by increasing flows on transmission infrastructure.<br>• Total Ontario welfare is roughly unchanged over the three years examined, versus the Status Quo.<br>• Total North American production costs are reduced by US$37 million in 2013, US$3 million in 2015 and US$7 million in 2017. |

## Equivalent Average Network Service Rate - $5.80/MWh

| Principle | Evaluation |
|---|---|
| Consistency | • Consistent with ETS rates in neighbouring markets, e.g. NYISO, Hydro Quebec and ISONE in that the flat rate is invariant between peak and off-peak periods.<br>• Inconsistent with PJM and MISO where there is rate distinction between peak and off-peak periods.<br>• ETS rate approx. in the mid-range of hourly rates for peak period in these neighbouring markets.<br>• Methodology for deriving ETS rate consistent with the methodology used to derive hourly rates in other jurisdictions as rate is directly linked to transmission owners' transmission revenue requirement.<br>• The fact that other jurisdictions employ hourly ETS rates suggests that there is commonality in rate structure and use between neighbouring jurisdictions and hence does not create inefficiencies due to inconsistencies in structures. |
| Simplicity | • Not an issue for implementing this rate since existing Market Rules in Ontario contains the methodology for charging hourly rates to exporters.<br>• Rate structure relatively simple to understand by market participants and comparable in form to other jurisdictions |
| Fairness | • Cost of transmission service shared equally between domestic consumers and export customers ---consistent with the view that all customers should share equally, but inconsistent with the view that rates should reflect differential cost impacts and benefits.<br>• Transmission customers in Ontario treated in the same manner as those in neighbouring jurisdictions (excepting those involved in transactions between NYISO and ISONE and PJM and MISO) in that they pay for ETS charges and domestic transmission charges.<br>• Cost to exporters may not reflect lower level of service they receive. (i.e. vertical equity test not fully met.)<br>• Reduces costs for Ontario consumers by an annual average of about $50 million per year, primarily as higher ETS revenues from exports leads to lower transmission rates for other customers. |
| Efficiency | • May increase barrier to export transactions out and through Ontario because of the relative increase in the ETS rate; more than double the Status Quo rate.<br>• Exporters have no opportunity to switch exports to lower rate time periods as these don't exist<br>• Increases overall welfare in Ontario, with the gain varying widely between years.<br>• Reduces regional efficiency by increasing total North American production costs by an average of about US$25 million per year |

## Two Tier Tariff Option A - $5.80/MWh on-peak and $0/MWh off-peak

| Principle | Evaluation |
|---|---|
| Consistency | • Somewhat consistent with ETS rates in PJM and MISO where a rate distinction is made between peak and off-peak periods; however these jurisdictions have non-zero off-peak rates.<br>• Inconsistent with ETS rates in NYISO, Hydro Quebec and ISONE where no rate distinction exists between peak and off-peak periods.<br>• On-peak ETS rate approx. in the mid-range of hourly rates for peak period in all neighbouring markets.<br>• Methodology for setting the rate is consistent with the methodology used to derive rates in other jurisdictions in that the ETS rate is directly linked to transmission owners transmission revenue requirement<br>• The calculation of rates applicable to off-peak time-periods is not consistent with the approach to calculate period specific hourly rates used in neighbouring jurisdictions (excepting NYISO).[12]<br>• The on-peak portion of the rate is consistent with the method of determination with that of the NYISO hourly rate<br>• The fact that other jurisdictions employ hourly ETS rate suggests that there is commonality in rate structure and use between some jurisdictions and hence does not create inefficiencies due to inconsistent structures. |
| Simplicity | • Time differentiated rate structure similar to that in other jurisdictions and so familiar to market participants.<br>• Market rules in Ontario would require amendments to implement the differentiation of rates by time-period both from a data collection and settlement perspective.<br>• Splitting of rates by time-period increases complexity for market participants. |
| Fairness | • Exporters and domestic customers share somewhat in the cost of the transmission service in Ontario and therefore Ontario's electricity consumers gain lower transmission rates from exporters paying this rate.<br>• Time differentiation of ETS rates, particularly with zero charges during off-peak period, will decrease the benefit to domestic customers compared to those scenarios where the higher rate invariant with time periods is applicable<br>• Sharing in the cost of transmission services is less equitable than in scenarios where a flat rate is applicable<br>• Reflects lower impact of exporters in terms of losses and congestion in off-peak period<br>• Small net benefit to consumers v. Status Quo, averaging $3 million per year. |
| Efficiency | • May increase barrier to on-peak export transactions out and through Ontario because of the relative increase in the ETS rate; more than double the Status Quo rate during peak period<br>• Exporters have opportunity to switch to off-peak period when ETS rate is zero resulting in lower peak system use and higher off-peak use. This could delay or reduce transmission investment needs.<br>• Designed to help address SBG, while maintaining ETS revenue<br>• Discourages use of dispatchable hydro to address regional peak demand<br>• Large net benefit to Ontario in 2013 as price of off-peak exports rises<br>• Average reduction in North American costs of $13 million |

12 This refers to the methodology used in other jurisdictions to set rates for different time periods, i.e. hourly (peak, off-peak), daily (peak, off-peak), monthly etc., which is discussed on page 15 of CRA report "Export Transmission Service Tariff Study – Review of Rates in Neighbouring Markets."

## Two Tier Tariff Option B - $3.50/MWh on-peak, and $1/MWh off-peak

| Principle | Evaluation |
|---|---|
| Consistency | • Consistent with ETS rates in PJM and MISO where a rate distinction exists between peak and off-peak periods.<br>• Inconsistent with ETS rates in NYISO, Hydro Quebec and ISONE where no rate distinction exists between peak and off-peak periods.<br>• On-peak ETS rate is at the lower range of hourly rates for peak period in neighbouring markets.<br>• Methodology for setting the rate is inconsistent with the methodology used to derive rates in other jurisdictions in that the ETS rate is not directly linked to transmission owners' transmission revenue requirement but rather appears to be discounted from the flat rate.<br>• The calculation of rates applicable to time-periods is not consistent with the approach to calculate period specific hourly rates used in neighbouring jurisdictions[13]<br>• The on-peak portion of the rate is consistent with the method of determination with that of the NYISO hourly rate<br>• The fact that other jurisdictions employ hourly ETS rates suggests that there is commonality in rate structure and use between some jurisdictions and hence there is inefficiency introduced by this rate due to inconsistent structures.= |
| Simplicity | • Time differentiated rate structure is similar to that in other jurisdictions and so is familiar to market participants.<br>• Market rules in Ontario would require amendments to implement the differentiation of rates by time-period both from a data collection and settlement perspective.<br>• Splitting of rates by time-period increases complexity for market participants. |
| Fairness | • Exporters and domestic customers share somewhat in the cost of the transmission service in Ontario and domestic customers therefore benefit from exporters paying this rate.<br>• The proposed time differentiation of ETS rates, will decrease the ETS contribution to domestic customers compared to those scenarios where a flat rate invariant with time periods is applicable (To be quantified later)<br>• Consistent with lower congestion and losses contribution during off-peak period<br>• Lower rate than other customers directionally consistent with lower service levels for exporters (e.g. operator-ordered export failures)<br>• Net benefit of $16 million to Ontario consumers in 2013. Little change subsequently. |
| Efficiency | • May increase barrier to entry for export transactions out and through Ontario because of the relative increase in the ETS rate on-peak; more than double the Status Quo rate.<br>• Exporters have opportunity to switch to off-peak period when ETS rate is lower. Could contribute to delayed or reduced transmission investment.<br>• Substantial increase in net benefit for Ontario in 2013.<br>• Little impact on total regional production costs in any year. |

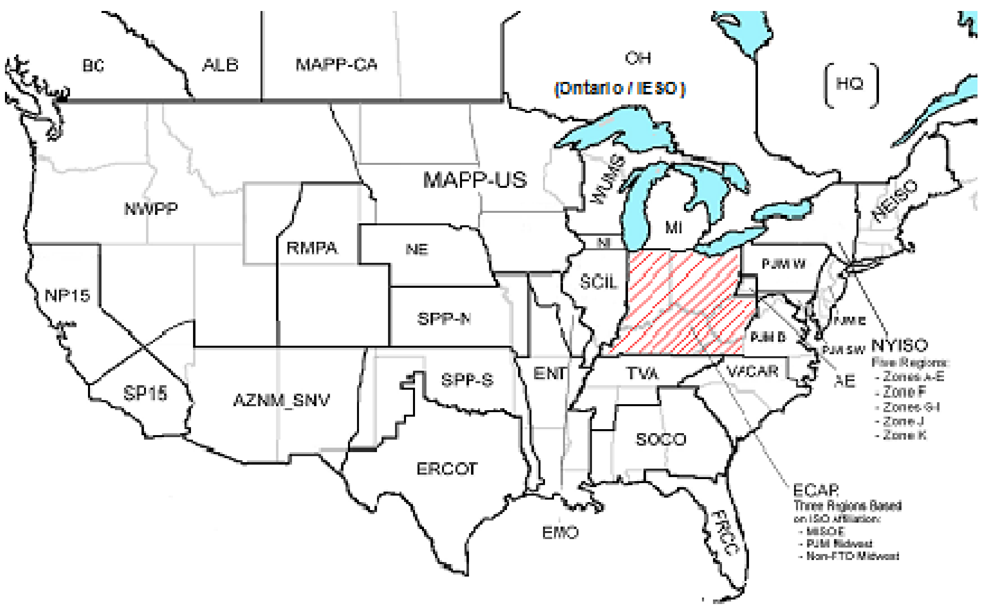
13 *ibid*

# Appendix

# Appendix A – Description of North American Electricity and Environment Model (NEEM)

CRA's NEEM model is a linear programming model that simulates economic dispatch for North America. NEEM minimizes the present value of incremental costs to the electric sector while meeting electricity demand and complying with relevant environmental limits. NEEM is a perfect foresight model. NEEM was designed specifically to be able to simultaneously model least-cost compliance with all state, regional and national, seasonal and annual emissions caps for $SO_2$, $NO_X$, and $CO_2$. NEEM models EPA's Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standard (MATS), and Cooling Water regulations. As part of the cost minimization solution, NEEM produces forecasts of short-term and long-term decisions such as coal choices, investments in pollution control equipment, and new capacity additions and retirements in a manner that minimizes the total costs to the electrical sector.

NEEM represents the North American power system as 39 individual demand regions (34 US regions, and five Canadian regions), as depicted in the map below and interconnected by limited transmission capabilities. Coal units are represented in detail as these are most affected by environmental regulation. Typically, all coal except small coal units (< 200 MW) are modeled at a unit level. All non-coal generating units in the United States are also represented in the model, with some level of unit aggregation. Units are dispatched to load-duration curves within each region so that all loads are met at least cost.




For the purposes of the ETS Tariff analysis, NEEM was used both for a long-term simulation (new capacity additions, retirements, and pollution control retrofits) and also for annual simulations for 2011 (calibration), 2013, 2015, and 2017. The annual simulations are the focus of the ETS study. For the annual simulations, more detailed load-duration curves were employed. The annual simulations use 120 load blocks instead of the (standard) 20 load blocks used in the long-term simulation.

Load-duration curves are not chronologically ordered. They are ordered from highest to lowest loads for a single region (Midwestern PJM in this case for the Eastern Interconnection) and the other regions have the same hours' loads mapped into the same blocks. The block duration is measured in hours. For the long-term simulation, there are 10 blocks in the summer (May – September), 5 blocks in the winter (December, January, February), and 5 blocks in the shoulder (October, November, March, April). For the annual simulations, there are 10 blocks per month. For the annual simulations, there is a high degree of time resolution at the top and bottom of each month's load-duration curve, as shown in the April and May examples below.

### Example Time-Resolution in April and May Load-Duration Curves

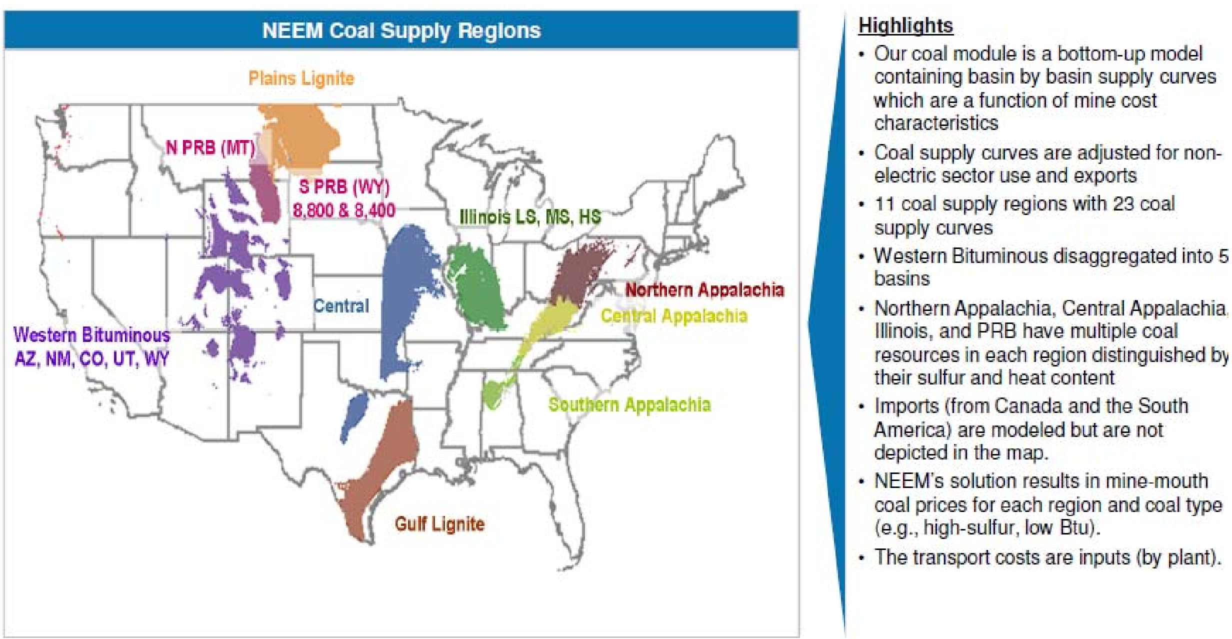
| Duration (hours) | April | May |
|---|---|---|
| **Block_1** | 8 | 4 |
| **Block_2** | 13 | 4 |
| **Block_3** | 155 | 52 |
| **Block_4** | 156 | 148 |
| **Block_5** | 93 | 148 |
| **Block_6** | 93 | 149 |
| **Block_7** | 93 | 149 |
| **Block_8** | 93 | 60 |
| **Block_9** | 8 | 18 |
| **Block_10** | 8 | 12 |

Key inputs to NEEM include operating characteristics of the generators, gas and oil prices, electricity demand, environmental policies, transfer limits among regions, and wheeling charges. Key outputs from NEEM include wholesale electricity prices by region, emission allowance prices, coal prices, unit retirements, resource additions, unit retrofits, and power flows among regions.

Constraints in NEEM ensure:

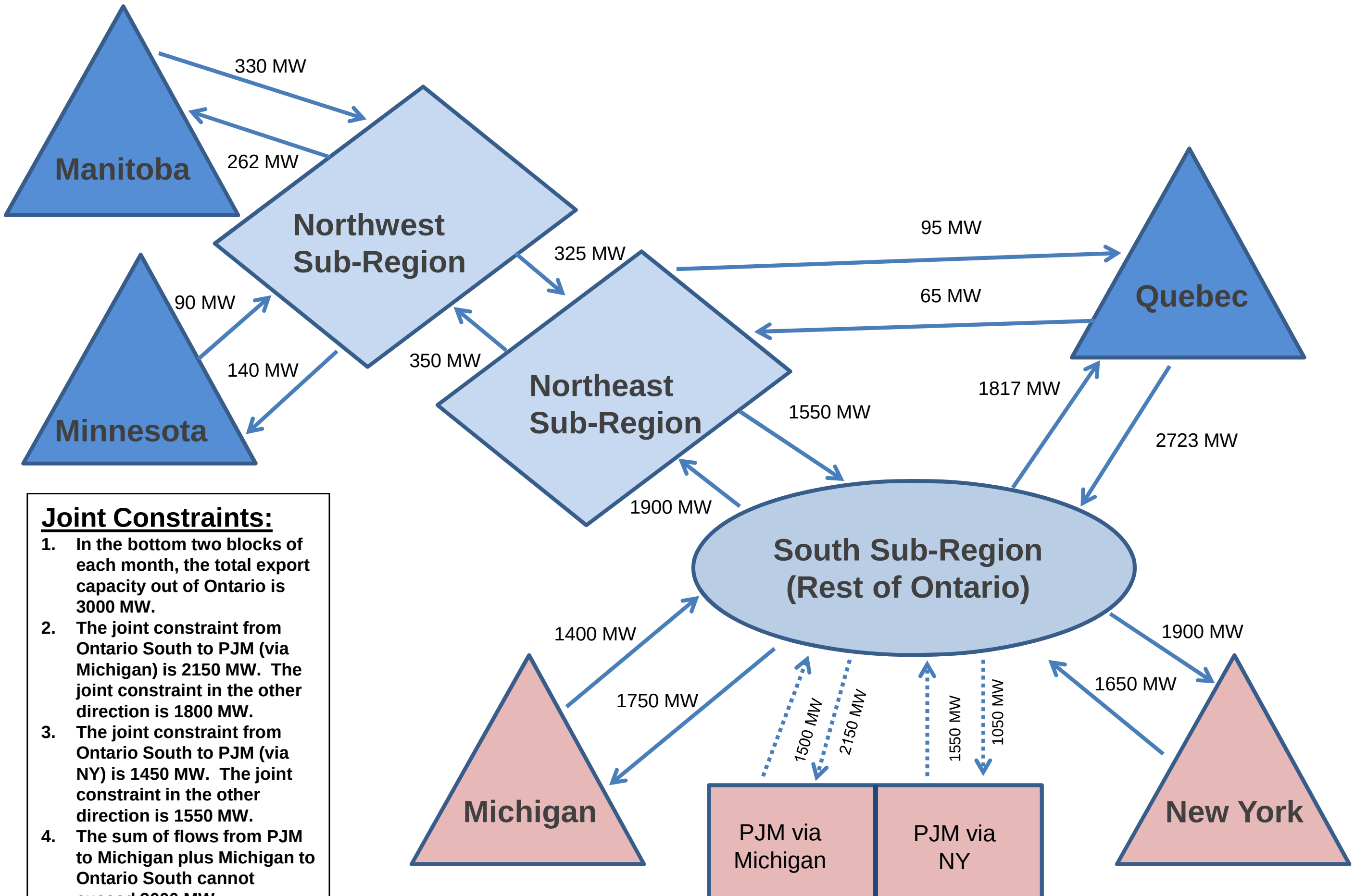
- Electricity demand is met;
- Reserve margin requirements are met;
- Environmental constraints are satisfied (e.g., $SO_2$ caps);
- Unit operational limits and energy limits cannot be exceeded (e.g., maximum hydro output by season);
- Limits on interregional power flows cannot be exceeded (i.e., transfer limits);
    - True for intra-Ontario flows also, if internal constraints are modeled;
- Unit maintenance requirements are met (i.e., PODs and forced outages), and;
- Renewable Portfolio Standards (RPS) standards are met.

NEEM's coal supply module is depicted in the figure below.



# Appendix B – Map of Ontario Sub-Regions

## Ontario Regions and Interfaces (summer, 2013+)

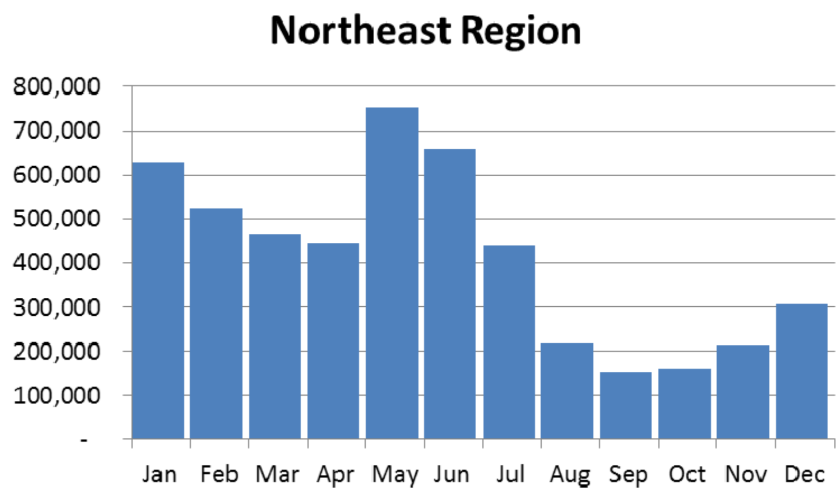


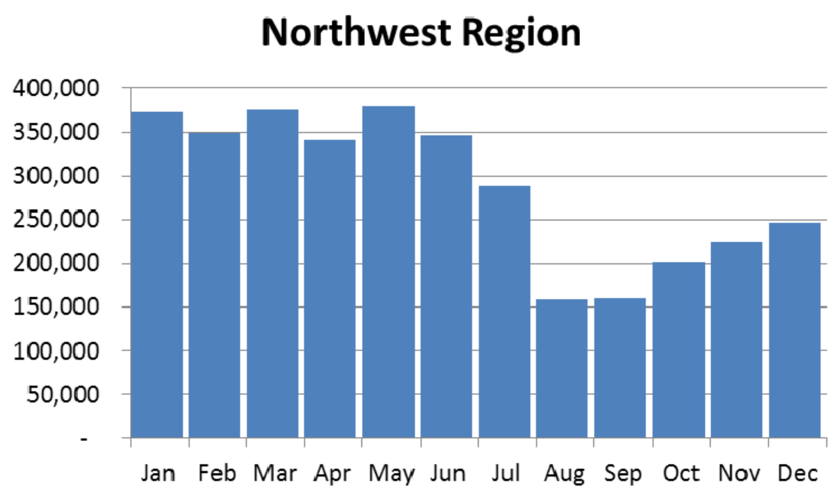

**Joint Constraints:**

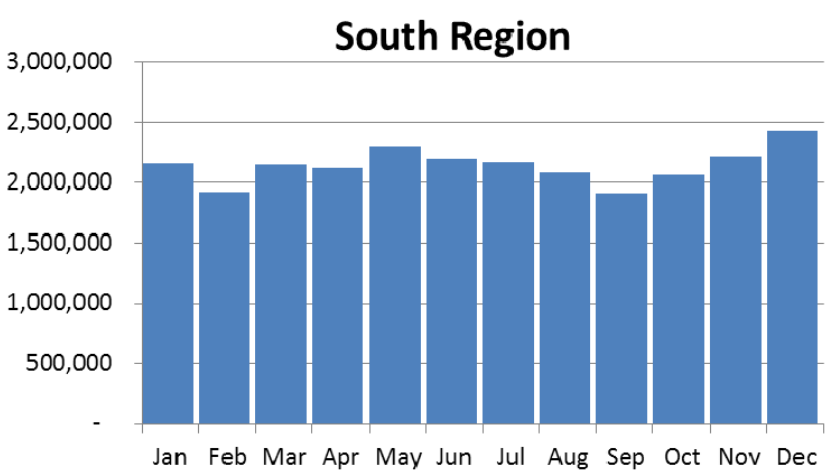
1. In the bottom two blocks of each month, the total export capacity out of Ontario is 3000 MW.
2. The joint constraint from Ontario South to PJM (via Michigan) is 2150 MW. The joint constraint in the other direction is 1800 MW.
3. The joint constraint from Ontario South to PJM (via NY) is 1450 MW. The joint constraint in the other direction is 1550 MW.
4. The sum of flows from PJM to Michigan plus Michigan to Ontario South cannot exceed 3000 MW.

# Appendix C – Additional Detail on Hydro Modeling

## Monthly Hydro Output by Ontario Sub-Region (MWh)



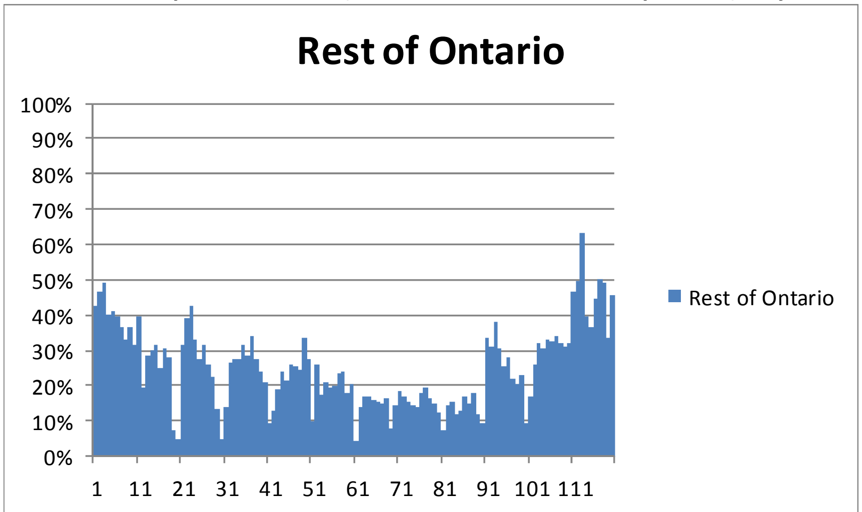
## Ontario Sub-Region Hydro Installed Capacity (MW) and Generation (GWh)

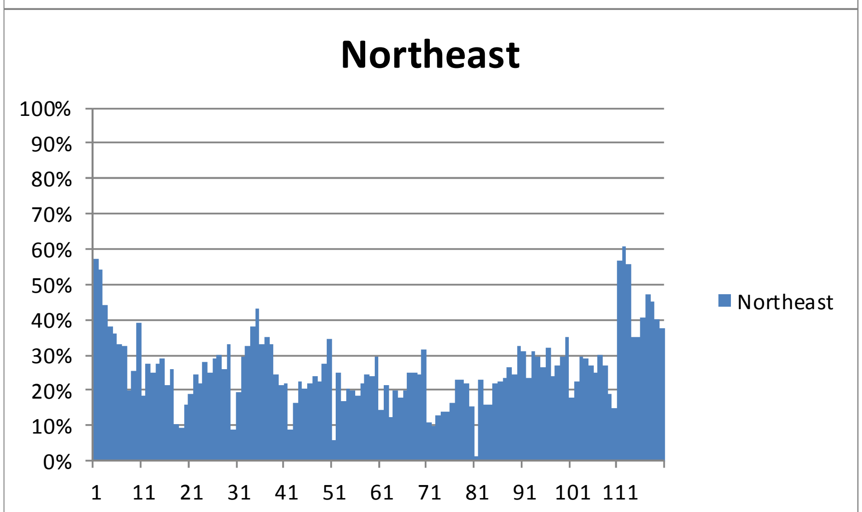
| | 2011 | | 2013 | | 2015 | | 2017 | |
|---|---|---|---|---|---|---|---|---|
| Sub-region | Installed Capacity (MW) | Total Generation (GWh) | Installed Capacity (MW) | Total Generation (GWh) | Installed Capacity (MW) | Total Generation (GWh) | Installed Capacity (MW) | Total Generation (GWh) |
| Northwest | 768 | 3,443 | 768 | 4,272 | 799 | 4,403 | 799 | 4,431 |
| Northeast | 2,620 | 4,962 | 2,620 | 9,256 | 3,138 | 10,533 | 3,138 | 10,484 |
| Rest of Ontario | 4,924 | 25,749 | 4,924 | 25,987 | 4,935 | 27,949 | 4,936 | 28,016 |
| **TOTAL** | **8,312** | **34,154** | **8,312** | **39,514** | **8,872** | **42,886** | **8,874** | **42,932** |

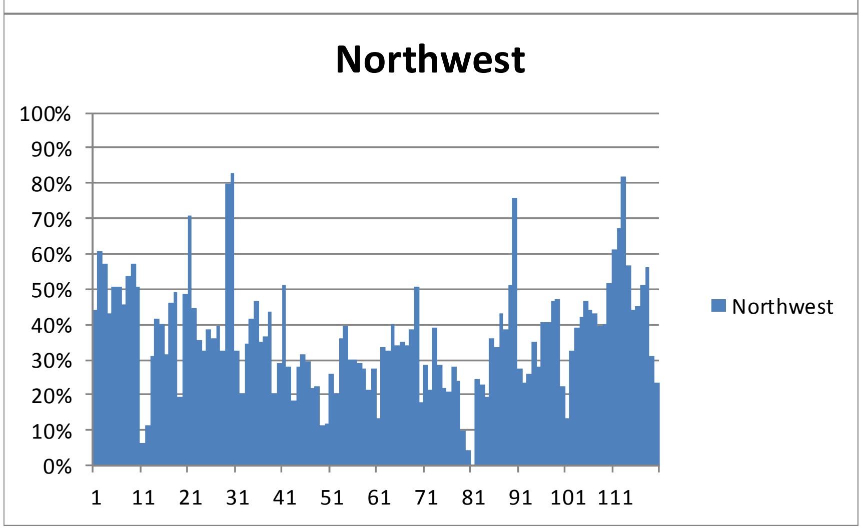
*Totals may not equal the sum of individual regions due to internal rounding.*

# Appendix D – Additional Detail on Wind Modeling

## Wind Output Level (fraction of nameplate) by Load Block (2015)



## Wind Capacity Factors

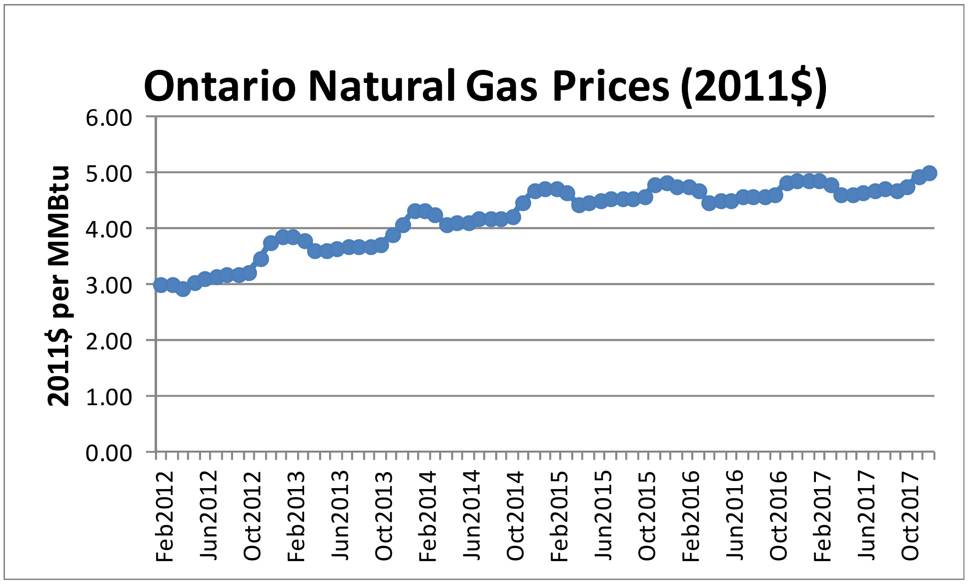
| Average Fixed Output Capacity Factor: | | | |
|---|---|---|---|
| | **2013** | **2015** | **2017** |
| **South** | 28% | 27% | 26% |
| **Northeast** | 25% | 27% | 27% |
| **Northwest** | 37% | 37% | 37% |

# Appendix E – Transfer Limits

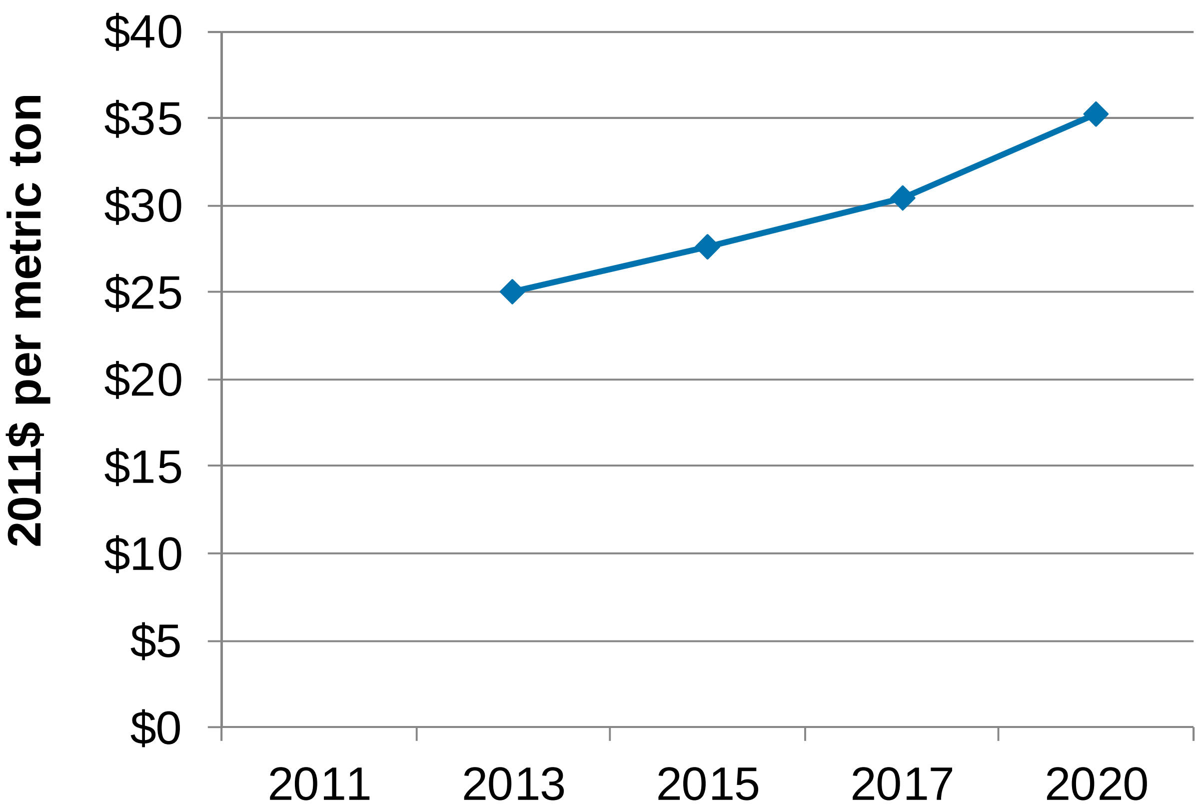
| From | To | Season | Current Capacity (MW) | 2013+ Capacity (MW) |
|---|---|---|---|---|
| Ontario_Northwest | Ontario_Northeast | ALL | 325 | 325 |
| Ontario_Northeast | Ontario_Northwest | ALL | 350 | 350 |
| Ontario_Northeast | Rest of Ontario | ALL | 1400 | 1550 |
| Rest of Ontario | Ontario_Northeast | ALL | 1900 | 1900 |
| Ontario_Northwest | Manitoba | Summer | 262 | 262 |
| Ontario_Northwest | Manitoba | Winter | 274 | 274 |
| Ontario_Northwest | Manitoba | Shoulder | 274 | 274 |
| Ontario_Northwest | Minnesota | ALL | 140 | 140 |
| Manitoba | Ontario_Northwest | Summer | 330 | 330 |
| Manitoba | Ontario_Northwest | Winter | 342 | 342 |
| Manitoba | Ontario_Northwest | Shoulder | 342 | 342 |
| Minnesota | Ontario_Northwest | ALL | 90 | 90 |
| Ontario_Northeast | Quebec | Summer | 95 | 95 |
| Ontario_Northeast | Quebec | Winter | 110 | 110 |
| Ontario_Northeast | Quebec | Shoulder | 110 | 110 |
| Quebec | Ontario_Northeast | Summer | 65 | 65 |
| Quebec | Ontario_Northeast | Winter | 85 | 85 |
| Quebec | Ontario_Northeast | Shoulder | 85 | 85 |
| Rest of Ontario | Quebec | Summer | 1817 | 1817 |
| Rest of Ontario | Quebec | Winter | 1887 | 1887 |
| Rest of Ontario | Quebec | Shoulder | 1887 | 1887 |
| Quebec | Rest of Ontario | Summer | 2723 | 2723 |
| Quebec | Rest of Ontario | Winter | 2798 | 2798 |
| Quebec | Rest of Ontario | Shoulder | 2798 | 2798 |
| Rest of Ontario | New York | ALL | 1650 | 1900 |
| New York | Rest of Ontario | ALL | 1200 | 1650 |
| Rest of Ontario | Michigan | Summer | 1840 | 1750 |
| Rest of Ontario | Michigan | Winter | 1980 | 1800 |
| Rest of Ontario | Michigan | Shoulder | 1980 | 1800 |
| Michigan | Rest of Ontario | Summer | 1580 | 1400 |
| Michigan | Rest of Ontario | Winter | 1860 | 1400 |
| Michigan | Rest of Ontario | Shoulder | 1860 | 1400 |

Note: A joint export constraint of 3000 MW was enforced in 2013, 2015, and 2017 in the bottom two blocks of each month.

# Appendix F – Ontario Natural Gas Prices



## Appendix G – WCI Carbon Dioxide Price Assumption



# Appendix H – Ontario Emissions Caps

| | Notes | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| **$SO_2$ Cap** | Ontario cap on $SO_2$ emissions, in kilotonnes | 127 | 127 | 127 |
| **$NO_x$ Cap** | Ontario cap on $NO_x$ emissions, in kilotonnes | 41.3 | 41.3 | 41.3 |
| **$CO_2$ Cap** | Ontario cap on $CO_2$ emissions from **coal –fired power plants**, in million metric tons | 11.5 | Coal retired | Coal retired |

# Appendix I - Macroeconomic Assumptions

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| **Ontario CPI** | 1.9 | 1.9 | 2.0 | 1.9 | 1.9 | 1.9 |
| **Canada CPI** | 2.1 | 2.1 | 2.1 | 2.0 | 2.0 | 2.0 |
| **US CPI** | 2.1 | 2.3 | 2.4 | 2.4 | 2.4 | 2.5 |
| **US$/C$** | .98 | 1.00 | 1.03 | 1.02 | 1.01 | .98 |
| **C$/US$** | 1.02 | 1.00 | .97 | .98 | .99 | 1.02 |

Source: Ontario Ministry of Finance Survey of Forecasts (January, 2012) and Blue Chip Economic Indicators (December 2011)

# Appendix J – Status Quo Results if Wind is Curtailed before Nuclear

**Table J-1: SBG Results if Wind Curtails before Nuclear, Status Quo Scenario**

| | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Nuclear Manoeuvres** | 36 | 31 | 0 |
| **Average Number of Units Manoeuvred** | 2.69 | 3.03 | 0.00 |
| **MWh Nuclear Manoeuvres** | 116,400 | 112,800 | 0 |
| **Nuclear Shutdowns** | 12 | 12 | 0 |
| **Average Number of Units Shutdown** | 1.17 | 1.00 | 0.00 |
| **MWh Nuclear Shutdown** | 806,400 | 691,200 | 0 |
| **Total MWh Nuclear Curtailment** | 922,800 | 804,000 | 0 |
| **Renewable SBG Event** | 54 | 57 | 8 |
| **Average MW of Wind Manoeuvre** | 206 | 431 | 92 |
| **Total MWh Wind Curtailment** | 142,250 | 304,268 | 9,373 |
| **Total MWh Curtailed** | **1,065,050** | **1,108,268** | **9,373** |

**Table J-2: Change in Generation (Scenario – Status Quo) (MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| **Unilateral Elimination** ***Wind Curtailment*** | **Total** | 5,643,905 | 133,304 | 456,788 |
| | ***On Peak*** | *1,802,343* | *120,597* | *430,901* |
| | ***Off Peak*** | *3,841,563* | *12,707* | *25,887* |
| **Equivalent Average Network Charge** ***Wind Curtailment*** | **Total** | -4,985,607 | -12,729 | -636,436 |
| | ***On Peak*** | *-2,334,708* | *-5,118* | *-374,574* |
| | ***Off Peak*** | *-2,650,899* | *-7,611* | *-261,863* |
| **Two-Tiered Scenario A** ***Wind Curtailment*** | **Total** | -338,224 | -12,709 | -258,607 |
| | ***On Peak*** | *-3,362,460* | *-1,796,513* | *-934,932* |
| | ***Off Peak*** | *3,024,237* | *1,783,804* | *676,325* |
| **Two-Tiered Scenario B** ***Wind Curtailment*** | **Total** | 1,282,744 | -3,278 | -160,756 |
| | ***On Peak*** | *-920,201* | *-512,192* | *-608,953* |
| | ***Off Peak*** | *2,202,945* | *508,915* | *448,197* |

**Table J-3: Change in Exports (Scenario – Status Quo) (MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| **Unilateral Elimination** ***Wind Curtailment*** | **Total** | 5,643,899 | 793,471 | 636,386 |
| | ***On Peak*** | *1,783,394* | *427,338* | *560,527* |
| | ***Off Peak*** | *3,860,505* | *366,133* | *75,859* |
| **Equivalent Average Network Charge** ***Wind Curtailment*** | **Total** | -4,985,612 | -284,916 | -1,210,921 |
| | ***On Peak*** | *-2,235,440* | *-140,490* | *-682,283* |
| | ***Off Peak*** | *-2,750,172* | *-144,426* | *-528,638* |
| **Two-Tiered Scenario A** ***Wind Curtailment*** | **Total** | -338,222 | -192,338 | -528,476 |
| | ***On Peak*** | *-3,443,577* | *-2,068,690* | *-1,156,167* |
| | ***Off Peak*** | *3,105,355* | *1,876,352* | *627,691* |
| **Two-Tiered Scenario B** ***Wind Curtailment*** | **Total** | 1,282,732 | -110,239 | -285,143 |
| | ***On Peak*** | *-954,506* | *-674,116* | *-713,814* |
| | ***Off Peak*** | *2,237,238* | *563,877* | *428,672* |

**Table J-4: Change in HOEP (Scenario – Status Quo)**
**(C$2011/MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| **Unilateral Elimination** ***Wind Curtailment*** | **Total** | $0.72 | $1.63 | $0.62 |
| | ***On Peak*** | $0.37 | $1.49 | $0.51 |
| | ***Off Peak*** | $0.96 | $1.71 | $0.68 |
| **Equivalent Average Network Charge** ***Wind Curtailment*** | **Total** | -$2.20 | -$3.45 | -$1.17 |
| | ***On Peak*** | -$1.51 | -$3.18 | -$0.82 |
| | ***Off Peak*** | -$2.64 | -$3.62 | -$1.40 |
| **Two-Tiered Scenario A** ***Wind Curtailment*** | **Total** | $0.43 | $0.25 | -$0.14 |
| | ***On Peak*** | $0.02 | -$0.52 | -$0.59 |
| | ***Off Peak*** | $0.75 | $0.81 | $0.19 |
| **Two-Tiered Scenario B** ***Wind Curtailment*** | **Total** | $0.28 | $0.22 | $0.05 |
| | ***On Peak*** | $0.04 | -$0.21 | -$0.21 |
| | ***Off Peak*** | $0.46 | $0.52 | $0.24 |

**Table J-5: Change in Production Cost (Scenario – Status Quo)**
**(C$2011 Millions)**

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** ***Wind Curtailment*** | $168.48 | $6.02 | $21.90 |
| **Equivalent Average Network Charge** ***Wind Curtailment*** | -$141.36 | -$0.58 | -$30.58 |
| **Two-Tiered Scenario A** ***Wind Curtailment*** | -$7.79 | -$0.58 | -$12.25 |
| **Two-Tiered Scenario B** ***Wind Curtailment*** | $37.84 | -$0.15 | -$7.63 |

**Table J-6: Change in Adjusted Production Cost (Scenario – Status Quo) (C$2011 Millions)**

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** ***Wind Curtailment*** | -$21.87 | -$23.40 | -$4.40 |
| **Equivalent Average Network Charge** ***Wind Curtailment*** | $35.91 | $33.88 | $8.96 |
| **Two-Tiered Scenario A** ***Wind Curtailment*** | $1.77 | -$1.68 | $2.97 |
| **Two-Tiered Scenario B** ***Wind Curtailment*** | -$5.81 | -$1.28 | $1.61 |

# Appendix K – Contract Structure in Ontario

Over 90% of the electricity output in Ontario is provided at regulated prices, under fixed-price contracts or contracts that provide gas-fired generators cost recovery and a return on their investment. The Ontario Energy Board's Regulated Price Plan Price Report* provides a summary of the contract provisions and their impact on Global Adjustment payments. For the purposes of this study, Charles River associates used aggregated contract information provided by the Ontario Power Authority and the IESO to calculate the impact of changes in market prices and quantities on Global Adjustment payments to generators in Ontario. For the purposes of this report, payments for other purposes, such as conservation, have been ignored. In most cases, changes in market prices for contracted and regulated output lead to corresponding and opposite changes in contract payments. The main exception to this pattern is OPG's non-prescribed hydro generation which receives market prices. This provides an incentive for OPG to bid these dispatchable hydro resources in such a way that they maximize revenues. This market based generation accounts for approximately 9% of Ontario generation on average.

Charles River Associates has assumed that contracted and regulated generation is bid into the Ontario market at its marginal cost. OPG's non-prescribed hydro generation is assumed to bid its opportunity cost, effectively selling its available at the highest available prices within each month, subject to physical limitations.

The analysis incorporates existing contract prices and terms for:

- OPG regulated assets
- NUG contracts with the OEFC
- FIT and other renewable generation (RES, RESOP)
- Bruce Power contract prices and floor prices
- Cost-recovery payments to OPG coal-fired units
- Payments under the Hydroelectric Energy Supply Agreements, which covers new hydro
- Payments under the Hydro Contract Initiative (HCI), covering existing hydro.

Where price terms for new generation (e.g. FIT 2.0) are available, they have been assumed to apply to new generation. Where future prices are not available, Charles River Associates has assumed that terms for new generation will mirror recent patterns and that prices for other new generation will rise in line with inflation.

Existing NUG contracts are assumed to continue to operate as they currently do, without economic dispatch.

* Available at www.ontarioenergyboard.ca/OEB/EB2004-0205/RPP_Price_Report_May 2012_20120419.pdf

# Appendix L – Detailed Summary of Surplus Changes

## Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Unilateral Elimination Nuclear Dispatch** |
| **Year** | **2013** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $97.8 |
| | Δ Market* | | -$90.7 |
| | **Δ GA + Market** | | **$7.1** |
| **ETS Tariff Revenue** | Δ ETS | $0 - $2 | |
| | Δ Exports (TWh) | 5.6 | |
| | **Δ ETS Revenue** | | **-$42.0** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | 5.6 | |
| | **Δ Uplift** | | **$18.8** |
| **Δ CONSUMER SURPLUS** | | | **-$16.1** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$97.8 |
| | Δ Market** | $275.9 |
| | **Δ Revenue** | **$178.1** |
| **Production Costs** | **Δ Costs** | **-$168.5** |
| **Δ PRODUCER SURPLUS** | | **$9.6** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **$24.0** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$17.6** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $9.8 | $88.0 |
| Δ Market* | -$14.6 | -$76.0 |
| **Δ GA + Market** | **-$4.9** | **$12.0** |
| **Δ ETS Revenue** | -$6.3 | -$35.7 |
| **Δ Uplift** | $2.8 | $16.0 |
| **Δ CONSUMER SURPLUS** | **-$8.3** | **-$7.7** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

## Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Unilateral Elimination Nuclear Dispatch** |
| **Year** | **2015** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $244.1 |
| | Δ Market* | | -$234.9 |
| | **Δ GA + Market** | | **$9.2** |
| **ETS Tariff Revenue** | Δ ETS | $0 - $2 | |
| | Δ Exports (TWh) | 0.8 | |
| | **Δ ETS Revenue** | | **-$44.5** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | 0.8 | |
| | **Δ Uplift** | | **$2.6** |
| **Δ CONSUMER SURPLUS** | | | **-$32.6** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$244.1 |
| | Δ Market** | $272.3 |
| | **Δ Revenue** | **$28.2** |
| **Production Costs** | **Δ Costs** | **-$6.0** |
| **Δ PRODUCER SURPLUS** | | **$22.2** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **$10.1** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **-$0.3** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $24.4 | $219.7 |
| Δ Market* | -$36.5 | -$198.4 |
| **Δ GA + Market** | **-$12.1** | **$21.3** |
| **Δ ETS Revenue** | -$6.7 | -$37.8 |
| **Δ Uplift** | $0.4 | $2.2 |
| **Δ CONSUMER SURPLUS** | **-$18.4** | **-$14.2** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Unilateral Elimination Nuclear Dispatch** |
| **Year** | **2017** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $77.3 |
| | Δ Market* | | -$84.6 |
| | **Δ GA + Market** | | **-$7.3** |
| **ETS Tariff Revenue** | Δ ETS | $0 - $2 | |
| | Δ Exports (TWh) | 0.6 | |
| | **Δ ETS Revenue** | | **-$13.7** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | 0.6 | |
| | **Δ Uplift** | | **$2.1** |
| **Δ CONSUMER SURPLUS** | | | **-$18.9** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$77.3 |
| | Δ Market** | $109.7 |
| | **Δ Revenue** | **$32.4** |
| **Production Costs** | **Δ Costs** | **-$21.9** |
| **Δ PRODUCER SURPLUS** | | **$10.5** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **$3.9** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **-$4.5** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $7.7 | $69.6 |
| Δ Market* | -$13.2 | -$71.4 |
| **Δ GA + Market** | **-$5.5** | **-$1.8** |
| **Δ ETS Revenue** | -$2.1 | -$11.6 |
| **Δ Uplift** | $0.3 | $1.8 |
| **Δ CONSUMER SURPLUS** | **-$7.2** | **-$11.6** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

## Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Equivalent Average Network Charge Nuclear Dispatch** |
| **Year** | **2013** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | -$313.6 |
| | Δ Market* | | $303.5 |
| | **Δ GA + Market** | | **-$10.1** |
| **ETS Tariff Revenue** | Δ ETS | $5.80 - $2 | |
| | Δ Exports (TWh) | -5.0 | |
| | **Δ ETS Revenue** | | **$50.8** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -5.0 | |
| | **Δ Uplift** | | **-$16.6** |
| **Δ CONSUMER SURPLUS** | | | **$24.1** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | $313.6 |
| | Δ Market** | -$484.2 |
| | **Δ Revenue** | **-$170.6** |
| **Production Costs** | **Δ Costs** | **$141.4** |
| **Δ PRODUCER SURPLUS** | | **-$29.2** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$17.7** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **-$22.8** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | -$31.4 | -$282.2 |
| Δ Market* | $48.2 | $255.4 |
| **Δ GA + Market** | **$16.8** | **-$26.9** |
| **Δ ETS Revenue** | $7.6 | $43.2 |
| **Δ Uplift** | -$2.5 | -$14.1 |
| **Δ CONSUMER SURPLUS** | **$21.9** | **$2.2** |

Class A share of GA = 10%.
Class A share of consumption = 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue = 15%

# Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Equivalent Average Network Charge Nuclear Dispatch** |
| **Year** | **2015** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | -$521.0 |
| | Δ Market* | | $499.2 |
| | **Δ GA + Market** | | **-$21.8** |
| **ETS Tariff Revenue** | Δ ETS | $5.80 - $2 | |
| | Δ Exports (TWh) | -0.3 | |
| | **Δ ETS Revenue** | | **$82.8** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.3 | |
| | **Δ Uplift** | | **-$0.9** |
| **Δ CONSUMER SURPLUS** | | | **$60.1** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | $521.0 |
| | Δ Market** | -$569.5 |
| | **Δ Revenue** | **-$48.5** |
| **Production Costs** | **Δ Costs** | **$0.6** |
| **Δ PRODUCER SURPLUS** | | **-$47.9** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$7.9** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$4.2** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | -$52.1 | -$468.9 |
| Δ Market* | $77.5 | $421.8 |
| **Δ GA + Market** | **$25.4** | **-$47.2** |
| **Δ ETS Revenue** | $12.4 | $70.4 |
| **Δ Uplift** | -$0.1 | -$0.8 |
| **Δ CONSUMER SURPLUS** | **$37.7** | **$22.4** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

## Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Equivalent Average Network Charge Nuclear Dispatch** |
| **Year** | **2017** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | -$147.5 |
| | Δ Market* | | $156.1 |
| | **Δ GA + Market** | | **$8.6** |
| **ETS Tariff Revenue** | Δ ETS | $5.80 - $2 | |
| | Δ Exports (TWh) | -1.2 | |
| | **Δ ETS Revenue** | | **$18.9** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -1.2 | |
| | **Δ Uplift** | | **-$4.0** |
| **Δ CONSUMER SURPLUS** | | | **$23.5** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | $147.5 |
| | Δ Market** | -$196.7 |
| | **Δ Revenue** | **-$49.2** |
| **Production Costs** | **Δ Costs** | **$30.6** |
| **Δ PRODUCER SURPLUS** | | **-$18.6** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$5.8** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **-$1.0** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | -$14.8 | -$132.8 |
| Δ Market* | $24.7 | $131.4 |
| **Δ GA + Market** | **$10.0** | **-$1.4** |
| **Δ ETS Revenue** | $2.8 | $16.1 |
| **Δ Uplift** | -$0.6 | -$3.4 |
| **Δ CONSUMER SURPLUS** | **$12.2** | **$11.3** |

Class A share of GA = 10%.
Class A share of consumption = 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue = 15%

# Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option A** |
| | **Nuclear Dispatch** |
| **Year** | **2013** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $64.0 |
| | Δ Market* | | -$58.8 |
| | **Δ GA + Market** | | **$5.2** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | -0.3 | |
| | **Δ ETS Revenue** | | **-$3.5** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.3 | |
| | **Δ Uplift** | | **-$1.1** |
| **Δ CONSUMER SURPLUS** | | | **$0.6** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$64.0 |
| | Δ Market** | $61.1 |
| | **Δ Revenue** | **-$2.9** |
| **Production Costs** | **Δ Costs** | **$7.8** |
| **Δ PRODUCER SURPLUS** | | **$4.9** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$1.4** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$4.1** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $6.4 | $57.6 |
| Δ Market* | -$9.9 | -$48.9 |
| **Δ GA + Market** | **-$3.5** | **$8.7** |
| **Δ ETS Revenue** | -$0.5 | -$2.9 |
| **Δ Uplift** | -$0.2 | -$1.0 |
| **Δ CONSUMER SURPLUS** | **-$4.2** | **$4.8** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option A<br>Nuclear Dispatch** |
| **Year** | **2015** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $38.8 |
| | Δ Market* | | -$31.3 |
| | **Δ GA + Market** | | **$7.4** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | -0.2 | |
| | **Δ ETS Revenue** | | **$2.8** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.2 | |
| | **Δ Uplift** | | **-$0.6** |
| **Δ CONSUMER SURPLUS** | | | **$9.6** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$38.8 |
| | Δ Market** | $40.2 |
| | **Δ Revenue** | **$1.5** |
| **Production Costs** | **Δ Costs** | **$0.6** |
| **Δ PRODUCER SURPLUS** | | **$2.1** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$5.8** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$5.9** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $3.9 | $34.9 |
| Δ Market* | -$6.7 | -$24.7 |
| **Δ GA + Market** | **-$2.8** | **$10.2** |
| **Δ ETS Revenue** | $0.4 | $2.4 |
| **Δ Uplift** | -$0.1 | -$0.5 |
| **Δ CONSUMER SURPLUS** | **-$2.5** | **$12.1** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

## Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option A** |
| | **Nuclear Dispatch** |
| **Year** | **2017** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | -$15.2 |
| | Δ Market* | | $20.5 |
| | **Δ GA + Market** | | **$5.3** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | -0.5 | |
| | **Δ ETS Revenue** | | **-$0.5** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.5 | |
| | **Δ Uplift** | | **-$1.8** |
| **Δ CONSUMER SURPLUS** | | | **$3.0** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | $15.2 |
| | Δ Market** | -$31.0 |
| | **Δ Revenue** | **-$15.9** |
| **Production Costs** | **Δ Costs** | **$12.2** |
| **Δ PRODUCER SURPLUS** | | **-$3.6** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$3.8** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **-$4.4** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | -$1.5 | -$13.6 |
| Δ Market* | $2.1 | $18.4 |
| **Δ GA + Market** | **$0.6** | **$4.7** |
| **Δ ETS Revenue** | -$0.1 | -$0.5 |
| **Δ Uplift** | -$0.3 | -$1.5 |
| **Δ CONSUMER SURPLUS** | **$0.2** | **$2.8** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option B Nuclear Dispatch** |
| **Year** | **2013** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $39.9 |
| | Δ Market* | | -$37.0 |
| | **Δ GA + Market** | | **$2.9** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | 1.3 | |
| | **Δ ETS Revenue** | | **$3.1** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | 1.3 | |
| | **Δ Uplift** | | **$4.3** |
| **Δ CONSUMER SURPLUS** | | | **$10.3** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$39.9 |
| | Δ Market** | $80.7 |
| | **Δ Revenue** | **$40.8** |
| **Production Costs** | **Δ Costs** | **-$37.8** |
| **Δ PRODUCER SURPLUS** | | **$2.9** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$1.5** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$11.7** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $4.0 | $35.9 |
| Δ Market* | -$6.2 | -$30.8 |
| **Δ GA + Market** | **-$2.2** | **$5.1** |
| **Δ ETS Revenue** | $0.5 | $2.6 |
| **Δ Uplift** | $0.6 | $3.6 |
| **Δ CONSUMER SURPLUS** | **-$1.1** | **$11.3** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option B** |
| | **Nuclear Dispatch** |
| **Year** | **2015** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $34.4 |
| | Δ Market* | | -$30.3 |
| | **Δ GA + Market** | | **$4.1** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | -0.1 | |
| | **Δ ETS Revenue** | | **$0.6** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.1 | |
| | **Δ Uplift** | | **-$0.4** |
| **Δ CONSUMER SURPLUS** | | | **$4.3** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$34.4 |
| | Δ Market** | $36.3 |
| | **Δ Revenue** | **$1.8** |
| **Production Costs** | **Δ Costs** | **$0.2** |
| **Δ PRODUCER SURPLUS** | | **$2.0** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$2.9** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$3.4** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $3.4 | $31.0 |
| Δ Market* | -$5.7 | -$24.6 |
| **Δ GA + Market** | **-$2.3** | **$6.4** |
| **Δ ETS Revenue** | $0.1 | $0.5 |
| **Δ Uplift** | -$0.1 | -$0.3 |
| **Δ CONSUMER SURPLUS** | **-$2.2** | **$6.5** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

## Changes in Surplus

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option B Nuclear Dispatch** |
| **Year** | **2017** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $7.5 |
| | Δ Market* | | -$6.8 |
| | **Δ GA + Market** | | **$0.7** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | -0.3 | |
| | **Δ ETS Revenue** | | **-$0.4** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.3 | |
| | **Δ Uplift** | | **-$0.9** |
| **Δ CONSUMER SURPLUS** | | | **-$0.6** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$7.5 |
| | Δ Market** | -$0.1 |
| | **Δ Revenue** | **-$7.6** |
| **Production Costs** | **Δ Costs** | **$7.6** |
| **Δ PRODUCER SURPLUS** | | **$0.1** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$1.9** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **-$2.5** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $0.8 | $6.8 |
| Δ Market* | -$1.6 | -$5.2 |
| **Δ GA + Market** | **-$0.8** | **$1.6** |
| **Δ ETS Revenue** | -$0.1 | -$0.3 |
| **Δ Uplift** | -$0.1 | -$0.8 |
| **Δ CONSUMER SURPLUS** | **-$1.0** | **$0.4** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# ETS Tariff Study: Model Results and Surplus Changes Assuming Ontario Does Not Join the Western Climate Initiative Until After 2017

Addendum to

*Export Transmission Service (ETS) Tariff Study,* Report Prepared for the IESO

Charles River Associates

May 16, 2012

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*(Numbering of tables and figures corresponds to numbering in May 16, 2012 Report)*

**Figure 6: Monthly Average HOEP (C$/MWh)**

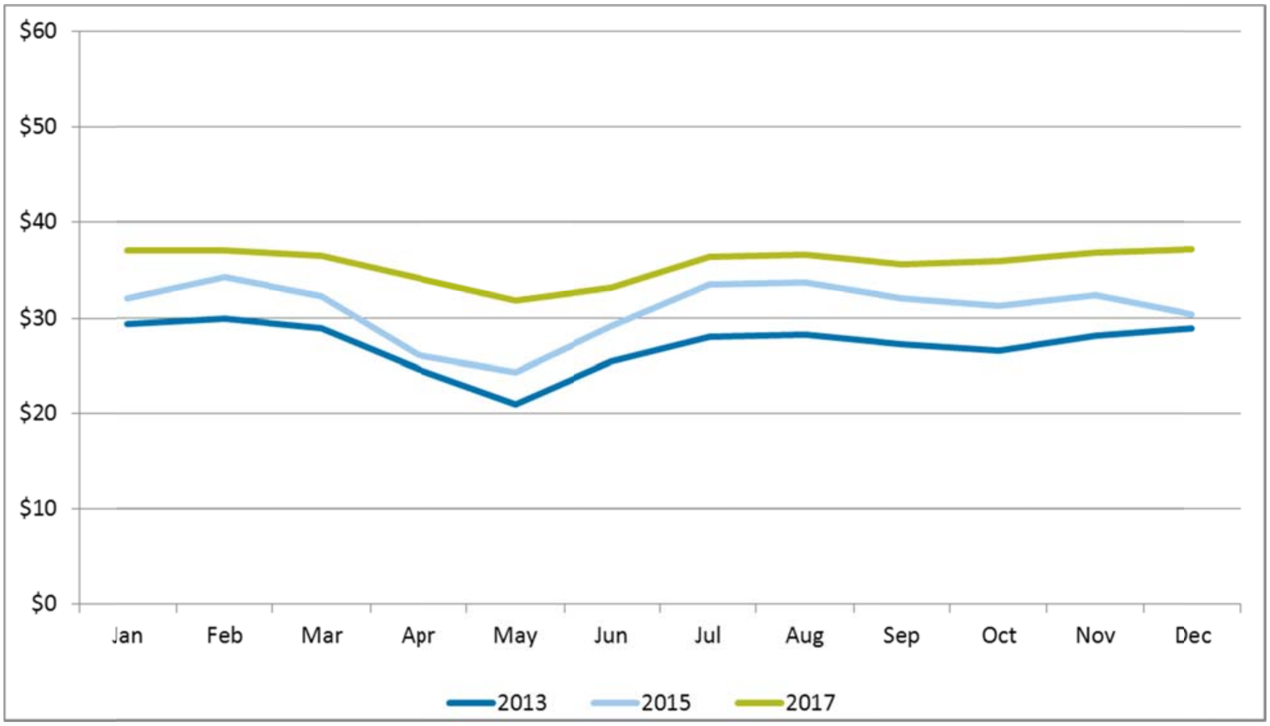


**Table 3: Change in Exports (Scenario – Status Quo) (MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| Unilateral Elimination *Nuclear Curtailment* | **Total** | 5,643,898 | 1,632,342 | 3,804,720 |
| | ***On Peak*** | *1,784,118* | *621,264* | *1,320,408* |
| | ***Off Peak*** | *3,859,780* | *1,011,078* | *2,484,313* |
| Equivalent Average Network Charge *Nuclear Curtailment* | **Total** | -4,985,661 | -697,079 | -3,623,036 |
| | ***On Peak*** | *-2,234,026* | *-386,876* | *-1,920,742* |
| | ***Off Peak*** | *-2,751,635* | *-310,203* | *-1,702,294* |
| Two-Tiered Scenario A *Nuclear Curtailment* | **Total** | -338,225 | -536,031 | -236,005 |
| | ***On Peak*** | *-3,444,346* | *-2,312,814* | *-1,871,350* |
| | ***Off Peak*** | *3,106,121* | *1,776,783* | *1,635,345* |
| Two-Tiered Scenario B *Nuclear Curtailment* | **Total** | 1,282,775 | -144,474 | 1,367,682 |
| | ***On Peak*** | *-955,365* | *-739,968* | *70,960* |
| | ***Off Peak*** | *2,238,140* | *595,494* | *1,296,723* |

**Table 4: Change in Generation (Scenario – Status Quo)**
**(MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| **Unilateral Elimination** *Nuclear Curtailment* | **Total** | 5,643,912 | 1,578,122 | 3,685,262 |
| | ***On Peak*** | *1,806,415* | *682,778* | *1,352,677* |
| | ***Off Peak*** | *3,837,497* | *895,345* | *2,332,585* |
| **Equivalent Average Network Charge** *Nuclear Curtailment* | **Total** | -4,985,678 | -626,453 | -3,623,434 |
| | ***On Peak*** | *-2,329,026* | *-387,768* | *-2,042,326* |
| | ***Off Peak*** | *-2,656,653* | *-238,685* | *-1,581,108* |
| **Two-Tiered Scenario A** *Nuclear Curtailment* | **Total** | -338,214 | -499,079 | -319,052 |
| | ***On Peak*** | *-3,363,754* | *-2,145,067* | *-1,978,456* |
| | ***Off Peak*** | *3,025,540* | *1,645,988* | *1,659,403* |
| **Two-Tiered Scenario B** *Nuclear Curtailment* | **Total** | 1,282,773 | -144,781 | 1,348,189 |
| | ***On Peak*** | *-923,487* | *-643,339* | *76,855* |
| | ***Off Peak*** | *2,206,261* | *498,558* | *1,271,334* |

**Table 5: Change in HOEP (Scenario – Status Quo)**
**(C$2011/MWh)**

| Scenario | | 2013 | 2015 | 2017 |
|---|---|---|---|---|
| **Unilateral Elimination** *Nuclear Curtailment* | **Total** | $0.72 | $1.21 | $0.39 |
| | ***On Peak*** | *$0.37* | *$0.84* | *$0.10* |
| | ***Off Peak*** | *$0.96* | *$1.45* | *$0.60* |
| **Equivalent Average Network Charge** *Nuclear Curtailment* | **Total** | -$2.20 | -$3.24 | -$0.81 |
| | ***On Peak*** | *-$1.51* | *-$2.76* | *-$0.25* |
| | ***Off Peak*** | *-$2.64* | *-$3.54* | *-$1.20* |
| **Two-Tiered Scenario A** *Nuclear Curtailment* | **Total** | $0.43 | $0.41 | $0.30 |
| | ***On Peak*** | *$0.02* | *-$0.18* | *-$0.01* |
| | ***Off Peak*** | *$0.75* | *$0.85* | *$0.54* |
| **Two-Tiered Scenario B** *Nuclear Curtailment* | **Total** | $0.28 | $0.31 | $0.19 |
| | ***On Peak*** | *$0.04* | *-$0.03* | *$0.04* |
| | ***Off Peak*** | *$0.46* | *$0.55* | *$0.30* |

## Table 6: Change in Production Costs (Scenario – Status Quo) (C$2011 Millions)

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** ***Nuclear Curtailment*** | $168.48 | $55.35 | $134.53 |
| **Equivalent Average Network Charge** ***Nuclear Curtailment*** | -$141.36 | -$21.78 | -$131.39 |
| **Two-Tiered Scenario A** ***Nuclear Curtailment*** | -$7.79 | -$17.35 | -$12.51 |
| **Two-Tiered Scenario B** ***Nuclear Curtailment*** | $37.84 | -$5.00 | $48.96 |

## Table 11: Change in North American Production Costs (Scenario – Status Quo) (US$2011 Millions)

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** ***Nuclear Curtailment*** | -$36.61 | -$9.85 | -$22.11 |
| **Equivalent Average Network Charge** ***Nuclear Curtailment*** | $54.76 | $9.03 | $38.89 |
| **Two-Tiered Scenario A** ***Nuclear Curtailment*** | $25.20 | $11.62 | $15.39 |
| **Two-Tiered Scenario B** ***Nuclear Curtailment*** | -$1.60 | $2.07 | -$5.82 |

**Table 12: Summary of Change in Consumer Surplus by Scenario (C$2011 Millions)**

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** ***Nuclear Curtailment*** | -$16.1 | -$31.2 | -$18.5 |
| **Equivalent Average Network Charge** ***Nuclear Curtailment*** | $24.1 | $57.1 | $24.9 |
| **Two-Tiered Scenario A** ***Nuclear Curtailment*** | $0.6 | $7.5 | $14.7 |
| **Two-Tiered Scenario B** ***Nuclear Curtailment*** | $10.3 | $4.4 | $13.4 |

**Table 13: Summary of Change in Total Ontario Surplus by Scenario (C$2011 Millions)**

| Scenario | 2013 | 2015 | 2017 |
|---|---|---|---|
| **Unilateral Elimination** ***Nuclear Curtailment*** | $17.6 | $4.0 | $6.1 |
| **Equivalent Average Network Charge** ***Nuclear Curtailment*** | -$22.8 | -$0.6 | -$10.5 |
| **Two-Tiered Scenario A** ***Nuclear Curtailment*** | $4.1 | $2.0 | $7.3 |
| **Two-Tiered Scenario B** ***Nuclear Curtailment*** | $11.7 | $2.9 | $11.2 |

## Changes in Surplus (No WCI)

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Unilateral Elimination Nuclear Dispatch** |
| **Year** | **2015** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $179.7 |
| | Δ Market* | | -$170.2 |
| | **Δ GA + Market** | | **$9.6** |
| **ETS Tariff Revenue** | Δ ETS | $0 - $2 | |
| | Δ Exports (TWh) | 1.6 | |
| | **Δ ETS Revenue** | | **-$46.2** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | 1.6 | |
| | **Δ Uplift** | | **$5.4** |
| **Δ CONSUMER SURPLUS** | | | **-$31.2** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$179.7 |
| | Δ Market** | $251.7 |
| | **Δ Revenue** | **$71.9** |
| **Production Costs** | **Δ Costs** | **-$55.3** |
| **Δ PRODUCER SURPLUS** | | **$16.6** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **$18.6** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$4.0** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $18.0 | $161.7 |
| Δ Market* | -$27.0 | -$143.1 |
| **Δ GA + Market** | **-$9.1** | **$18.6** |
| **Δ ETS Revenue** | -$6.9 | -$39.3 |
| **Δ Uplift** | $0.8 | $4.6 |
| **Δ CONSUMER SURPLUS** | **-$15.2** | **-$16.0** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# Changes in Surplus (No WCI)

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Unilateral Elimination Nuclear Dispatch** |
| **Year** | **2017** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $53.2 |
| | Δ Market* | | -$55.7 |
| | **Δ GA + Market** | | **-$2.5** |
| **ETS Tariff Revenue** | Δ ETS | $0 - $2 | |
| | Δ Exports (TWh) | 3.8 | |
| | **Δ ETS Revenue** | | **-$28.6** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | 3.8 | |
| | **Δ Uplift** | | **$12.7** |
| **Δ CONSUMER SURPLUS** | | | **-$18.5** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$53.2 |
| | Δ Market** | $195.7 |
| | **Δ Revenue** | **$142.6** |
| **Production Costs** | **Δ Costs** | **-$134.5** |
| **Δ PRODUCER SURPLUS** | | **$8.0** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **$16.5** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$6.1** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $5.3 | $47.9 |
| Δ Market* | -$9.3 | -$46.4 |
| **Δ GA + Market** | **-$4.0** | **$1.4** |
| **Δ ETS Revenue** | -$4.3 | -$24.3 |
| **Δ Uplift** | $1.9 | $10.8 |
| **Δ CONSUMER SURPLUS** | **-$6.3** | **-$12.1** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

## Changes in Surplus (No WCI)

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Equivalent Average Network Charge Nuclear Dispatch** |
| **Year** | **2015** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | -$489.4 |
| | Δ Market* | | $465.1 |
| | **Δ GA + Market** | | **-$24.3** |
| **ETS Tariff Revenue** | Δ ETS | $5.80 - $2 | |
| | Δ Exports (TWh) | -0.7 | |
| | **Δ ETS Revenue** | | **$83.8** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.7 | |
| | **Δ Uplift** | | **-$2.3** |
| **Δ CONSUMER SURPLUS** | | | **$57.1** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | $489.4 |
| | Δ Market** | -$556.0 |
| | **Δ Revenue** | **-$66.6** |
| **Production Costs** | **Δ Costs** | **$21.8** |
| **Δ PRODUCER SURPLUS** | | **-$44.8** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$13.0** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **-$0.6** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | -$48.9 | -$440.5 |
| Δ Market* | $72.7 | $392.5 |
| **Δ GA + Market** | **$23.7** | **-$48.0** |
| **Δ ETS Revenue** | $12.6 | $71.2 |
| **Δ Uplift** | -$0.3 | -$2.0 |
| **Δ CONSUMER SURPLUS** | **$35.9** | **$21.2** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# Changes in Surplus (No WCI)

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Equivalent Average Network Charge Nuclear Dispatch** |
| **Year** | **2017** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | -$110.5 |
| | Δ Market* | | $114.1 |
| | **Δ GA + Market** | | **$3.6** |
| **ETS Tariff Revenue** | Δ ETS | $5.80 - $2 | |
| | Δ Exports (TWh) | -3.6 | |
| | **Δ ETS Revenue** | | **$33.3** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -3.6 | |
| | **Δ Uplift** | | **-$12.1** |
| **Δ CONSUMER SURPLUS** | | | **$24.9** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | $110.5 |
| | Δ Market** | -$255.5 |
| | **Δ Revenue** | **-$145.0** |
| **Production Costs** | **Δ Costs** | **$131.4** |
| **Δ PRODUCER SURPLUS** | | **-$13.6** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$21.8** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **-$10.5** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | -$11.1 | -$99.5 |
| Δ Market* | $18.8 | $95.3 |
| **Δ GA + Market** | **$7.7** | **-$4.1** |
| **Δ ETS Revenue** | $5.0 | $28.3 |
| **Δ Uplift** | -$1.8 | -$10.3 |
| **Δ CONSUMER SURPLUS** | **$10.9** | **$13.9** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# Changes in Surplus (No WCI)

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option A**<br>**Nuclear Dispatch** |
| **Year** | **2015** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $65.5 |
| | Δ Market* | | -$60.0 |
| | **Δ GA + Market** | | **$5.4** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | -0.5 | |
| | **Δ ETS Revenue** | | **$3.9** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.5 | |
| | **Δ Uplift** | | **-$1.8** |
| **Δ CONSUMER SURPLUS** | | | **$7.5** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$65.5 |
| | Δ Market** | $53.4 |
| | **Δ Revenue** | **-$12.1** |
| **Production Costs** | **Δ Costs** | **$17.3** |
| **Δ PRODUCER SURPLUS** | | **$5.3** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$10.8** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$2.0** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $6.5 | $58.9 |
| Δ Market* | -$10.6 | -$49.5 |
| **Δ GA + Market** | **-$4.0** | **$9.5** |
| **Δ ETS Revenue** | $0.6 | $3.3 |
| **Δ Uplift** | -$0.3 | -$1.5 |
| **Δ CONSUMER SURPLUS** | **-$3.7** | **$11.3** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

## Changes in Surplus (No WCI)

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option A** |
| | **Nuclear Dispatch** |
| **Year** | **2017** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $43.7 |
| | Δ Market* | | -$44.2 |
| | **Δ GA + Market** | | **-$0.5** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | -0.2 | |
| | **Δ ETS Revenue** | | **$15.9** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.2 | |
| | **Δ Uplift** | | **-$0.8** |
| **Δ CONSUMER SURPLUS** | | | **$14.7** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$43.7 |
| | Δ Market** | $36.3 |
| | **Δ Revenue** | **-$7.4** |
| **Production Costs** | **Δ Costs** | **$12.5** |
| **Δ PRODUCER SURPLUS** | | **$5.1** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$12.5** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$7.3** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $4.4 | $39.3 |
| Δ Market* | -$7.6 | -$36.6 |
| **Δ GA + Market** | **-$3.2** | **$2.7** |
| **Δ ETS Revenue** | $2.4 | $13.5 |
| **Δ Uplift** | -$0.1 | -$0.7 |
| **Δ CONSUMER SURPLUS** | **-$0.9** | **$15.6** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

## Changes in Surplus (No WCI)

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option B Nuclear Dispatch** |
| **Year** | **2015** |

### Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $48.9 |
| | Δ Market* | | -$45.3 |
| | **Δ GA + Market** | | **$3.6** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | -0.1 | |
| | **Δ ETS Revenue** | | **$1.3** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | -0.1 | |
| | **Δ Uplift** | | **-$0.5** |
| **Δ CONSUMER SURPLUS** | | | **$4.4** |

* Ontario Load

### Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$48.9 |
| | Δ Market** | $47.8 |
| | **Δ Revenue** | **-$1.1** |
| **Production Costs** | **Δ Costs** | **$5.0** |
| **Δ PRODUCER SURPLUS** | | **$3.9** |

** Including Exports

### Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$5.4** |

### Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$2.9** |

### Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $4.9 | $44.0 |
| Δ Market* | -$7.8 | -$37.5 |
| **Δ GA + Market** | **-$2.9** | **$6.5** |
| **Δ ETS Revenue** | $0.2 | $1.1 |
| **Δ Uplift** | -$0.1 | -$0.4 |
| **Δ CONSUMER SURPLUS** | **-$2.8** | **$7.2** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# Changes in Surplus (No WCI)

**($ Millions)**

*Note: Changes Reported As Increases in Scenario Relative to Status Quo*

| | |
|---|---|
| **Scenario** | **Two-Tier Scenario - Option B Nuclear Dispatch** |
| **Year** | **2017** |

## Consumer Surplus

| | | | Increase in Surplus |
|---|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | | $26.3 |
| | Δ Market* | | -$27.7 |
| | **Δ GA + Market** | | **-$1.4** |
| **ETS Tariff Revenue** | Δ ETS | | |
| | Δ Exports (TWh) | 1.4 | |
| | **Δ ETS Revenue** | | **$10.3** |
| **Uplift** | Rate | $3.33 | |
| | Δ Exports (TWh) | 1.4 | |
| | **Δ Uplift** | | **$4.6** |
| **Δ CONSUMER SURPLUS** | | | **$13.4** |

* Ontario Load

## Producer Surplus

| | | |
|---|---|---|
| **GA and Payments for Ontario Load** | Δ GA | -$26.3 |
| | Δ Market** | $79.1 |
| | **Δ Revenue** | **$52.9** |
| **Production Costs** | **Δ Costs** | **-$49.0** |
| **Δ PRODUCER SURPLUS** | | **$3.9** |

** Including Exports

## Intertie Congestion Revenue

| | |
|---|---|
| **Δ Intertie Congestion Revenue** | **-$6.1** |

## Total Surplus

| | |
|---|---|
| **CHANGE IN TOTAL SURPLUS** | **$11.2** |

## Class A and Class B Load+

| | Class A | Class B |
|---|---|---|
| Δ GA | $2.6 | $23.6 |
| Δ Market* | -$4.6 | -$23.1 |
| **Δ GA + Market** | **-$2.0** | **$0.6** |
| **Δ ETS Revenue** | $1.5 | $8.7 |
| **Δ Uplift** | $0.7 | $3.9 |
| **Δ CONSUMER SURPLUS** | **$0.2** | **$13.2** |

Class A share of GA = 10%.
Class A share of consumption
= 13% on-peak, 17% off-peak
Class A share of ETS Tariff Revenue and Uplift Revenue
= 15%

# ETS Scenarios Assuming No Carbon Pricing in Ontario

**Background**

Charles River Associates has carried out an analysis of the impact of changes in Export Transmission Services ("ETS") tariff rates and rate structures for 2013, 2015 and 2017.[1] For this analysis, it was assumed that Ontario would participate in the Western Climate Initiative ("WCI")[2] and institute carbon pricing for fossil-based generation and implement import price adjustments to reflect the average carbon content of imports into Ontario from non-WCI markets. WCI forecasts for carbon prices were used and were built into costs and bids by gas-fired generators in Ontario.

After the presentation of the results of our May 16 report stakeholders asked that alternate model runs be undertaken to determine the impacts of ETS rate and structure changes under the assumption that Ontario does not institute carbon pricing before 2018.

The IESO agreed that undertaking these additional runs would provide valuable input and provide a basis for assessing ETS policy changes under either plausible assumptions and asked CRA to undertake these additional model runs for each of the four ETS scenarios:

- Unilateral elimination of the ETS tariff (the ETS tariff is $0/MWh);
- Increasing the ETS tariff from $2/MWh to the Equivalent Average Network Charge (EANC) of $5.80/MWh;
- A tiered rate of $5.80/MWh during on-peak hours and $0/MWh during off-peak hours, and;
- A tiered rate of $3.50/MWh on-peak and a $1.00/MWh rate off-peak.

**Results of Model Runs**

Removal of carbon prices from gas-fired generation prices in 2015 and 2017 resulted in lower market prices in Ontario, compared to the WCI case, particularly during the peak summer hours when natural-gas fired generation tends to be on the margin in Ontario and most neighbouring markets.

Removal of carbon costs from Ontario gas-fired generation costs and the removal of carbon border adjustments on imports from non-WCI markets also removed impediments to trade in both directions. This, in turn, tended to make Ontario production and exports more sensitive to changes in ETS rates and structures.

<u>1. Unilateral ETS Tariff Elimination</u>

In 2013, prior to the implementation of carbon pricing, the unilateral removal of the ETS tariff resulted in expanded exports and an overall welfare gain of $17.6 million. With carbon pricing, the impact of ETS tariff removal on exports was small in both 2015 and 2017 and correspondingly, the net surplus change for Ontario was also small (-$0.3 million and -$4.5

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1 *Export Transmission Service (ETS) Tariff Study*, Charles River Associates, May 16, 2012.

2 This assumption was made after discussions with the IESO and was discussed with stakeholders at a meeting on January 19, 2012.

million, respectively) as the loss in ETS revenue from tariff removal more than offset the gains associated with small increases in trade.

Without carbon pricing, export increases associated with ETS tariff removal were larger and the change in total Ontario surplus remained positive throughout the period, at $4.0 million and $6.1 million in 2015 and 2017, respectively.

2. Equivalent Average Network Charge (EANC)

In 2013 prior to carbon pricing, raising export tariffs by $3.80/MWh had the effect of discouraging exports by approximately 5 TWh. This led to lower market prices in Ontario and resulted in a shift of more of the burden of supporting contracted generation to Ontario consumers who pay the Global Adjustment. With lower producer surplus and less intertie Congestion Revenue, the net impact on Ontario welfare in 2013 was a reduction of $22.8 million. In 2015 and 2017, with carbon pricing in place, Ontario exports consisted largely of baseload generation. The EANC tariff had the effect of discouraging Quebec from wheeling power through Ontario into US markets.

Without carbon pricing, Ontario gas-fired exports in 2015 and 2017 would be higher and the imposition of the EANC tariff increase would have a larger negative impact on these exports. As a result, the trade loss increases relative to the ETS revenue gain for consumers and the net effect on overall provincial welfare becomes somewhat more negative, although not dramatically so.

3. Two-Tier Cases

In the two-tier cases, the principle impact of creating differentiated rates for production on- and off-peak is to create an incentive to move some optimizable hydro production from on-peak periods to off-peak periods. In Case A, the $5.80/MWh differential causes about 2% of water-based generation to make this shift. In Case B, the smaller $2.50/MWh induces a shift of about 1%. Carbon pricing has little impact on this pattern. In both Case A and Case B, the increase in off-peak gas-fired generation is also larger than under the WCI assumption.

# CURRENT ONTARIO TRANSMISSION RATE SCHEDULES

The current Uniform Transmission Rate (UTR) schedules are included in Attachment 1 and the revenue requirement and charge determinants for all transmitters used to establish the current Uniform Transmission Rates and Revenue Disbursement Allocators are included in Attachment 2.

The Transmission Rate Schedules were originally approved under the Decision and Order for RP-1999-0044/RP-2001-0034/35/36 dated April 30, 2002, and subsequently re-issued under the Decision and Order for Proceedings RP-1999-0044/RP-2001-0034/35/36/EB-2005-0241 (Dec 8, 2005), EB-2007-0759 (Oct 17, 2007), EB-2008-0113 (Aug 28, 2008), EB-2008-0272 (Jul 3, 2009), EB-2010-0002 (Jan 18, 2011) and EB-2011-0268 (Dec 20, 2011).

# ONTARIO TRANSMISSION RATE SCHEDULES

## EB-2011-0268

**The rate schedules contained herein shall be effective January 1, 2012.**

Issued: December 20, 2011
Ontario Energy Board

# TERMS AND CONDITIONS

**(A) APPLICABILITY** The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario. **(B) TRANSMISSION SYSTEM CODE** The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

**(C) TRANSMISSION DELIVERY POINT** The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV. **(D) TRANSMISSION SERVICE POOLS** The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS.

# TRANSMISSION RATE SCHEDULES

The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns, or has fully contributed toward the costs of, all transformation connection assets associated with that transmission delivery point. The PTS customers that utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS-L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns, or has fully contributed toward the costs of, all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station. **(E) MARKET RULES** The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate associated Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein. **(F) METERING REQUIREMENTS** In accordance with the Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid. (**G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including

# TRANSMISSION RATE SCHEDULES

Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets. **(H) EMBEDDED CONNECTION POINT** In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO-administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

***APPLICABILITY:***

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

| | Monthly Rate ($ per kW) |
|---|---|
| **Network Service Rate (PTS-N):**<br>$ Per kW of Network Billing Demand[1,2] | **3.57** |
| **Line Connection Service Rate (PTS-L):**<br>$ Per kW of Line Connection Billing Demand[1,3] | **0.80** |
| **Transformation Connection Service Rate (PTS-T):**<br>$ Per kW of Transformation Connection Billing Demand[1,3,4] | **1.86** |

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a “Per Transmission Delivery Point” basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.
2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter
(i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.
3 The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.
4 The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

***TERMS AND CONDITIONS OF SERVICE:***

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

| RATE SCHEDULE: ETS | EXPORT TRANSMISSION SERVICE |
|---|---|

***APPLICABILITY:***

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

| | **Hourly Rate** |
|---|---|
| **Export Transmission Service Rate (ETS):** | $2.00 / MWh |

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

***TERMS AND CONDITIONS OF SERVICE:***

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

**Hydro One Networks Inc.**

Implementation of Decision with Reasons on EB-2010-0002 and EB-2011-0268

Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2012 to December 31, 2012)

| Transmitter | Revenue Requirement ($) *(Note 3, Note 4)* | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | **Total** |
| FNEI | $3,831,576 | $836,127 | $1,659,387 | $6,327,089 |
| CNPI | $2,793,216 | $609,536 | $1,209,692 | $4,612,443 |
| GLPT | $21,345,462 | $4,658,009 | $9,244,336 | $35,247,808 |
| H1N *(Note 1)* | $838,477,537 | $182,972,674 | $363,129,562 | $1,384,579,773 |
| All Transmitters | $866,447,790 | $189,076,346 | $375,242,977 | $1,430,767,113 |

| Transmitter | Total Annual Charge Determinants (MW) *(Note 3, Note 4)* | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | |
| FNEI | 187.120 | 213.460 | 76.190 | |
| CNPI | 583.420 | 668.600 | 668.600 | |
| GLPT | 3,954.620 | 2,937.438 | 985.415 | |
| H1N *(Note 2)* | 238,134.047 | 231,433.958 | 200,008.248 | |
| All Transmitters | 242,859.207 | 235,253.456 | 201,738.453 | |

| Transmitter | Uniform Rates and Revenue Allocators *(Note 4)* | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | |
| Uniform Transmission Rates ($/kW-Month) | **3.57** | **0.80** | **1.86** | |
| | | | | |
| **FNEI** Allocation Factor | **0.00442** | **0.00442** | **0.00442** | |
| **CNPI** Allocation Factor | **0.00322** | **0.00322** | **0.00322** | |
| **GLPT** Allocation Factor | **0.02464** | **0.02464** | **0.02464** | |
| **H1N** Alocation Factor | **0.96772** | **0.96772** | **0.96772** | |
| Total of Allocation Factors | 1.00000 | 1.00000 | 1.00000 | |

*Note 1: Hydro One Networks (H1N) 2012 UTR Revenue Requirement per Exhibit 2.0*

*Note 2: Hydro One Networks (H1N) Charge Determinant per Exhibit 3.0*

*Note 3: Data for Other Transmitters per Exhibit 4.1*

*Note 4: Calculated data in shaded cells.*

# PROPOSED UNIFORM TRANSMISSION RATES

The 2013 and 2014 Uniform Transmission Rate (UTR) rates based on assuming the Hydro One Transmission revenue requirement and charge determinants proposed in this application, and assuming the revenue requirement and charge determinant values approved for the other transmitters in the Board's most recent Rate Order (EB-2011-0268), are provided in this exhibit.

## 2013 Draft Uniform Transmission Rates effective January 1, 2013

| Transmitter | Revenue Requirement ($) | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | **Total** |
| FNEI (Note 3) | $3,891,753 | $779,930 | $1,655,406 | $6,327,089 |
| CNPI (Note 4) | $2,837,085 | $568,568 | $1,206,790 | $4,612,443 |
| GLPT (Note 5) | $21,680,705 | $4,344,939 | $9,222,163 | $35,247,808 |
| H1N (Note 1) | $859,629,756 | $172,274,795 | $365,654,430 | $1,397,558,980 |
| All Transmitters | $888,039,298 | $177,968,232 | $377,738,790 | $1,443,746,320 |

| Transmitter | Total Annual Charge Determinants (MW) | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | |
| FNEI (Note 3) | 187.1 | 213.5 | 76.2 | |
| CNPI (Note 4) | 583.4 | 668.6 | 668.6 | |
| GLPT (Note 5) | 4,019.8 | 2,939.4 | 1,057.6 | |
| H1N (Note 2) | 240,274.0 | 232,874.3 | 201,107.9 | |
| All Transmitters | 245,064.3 | 236,695.8 | 202,910.3 | |

| Transmitter | Uniform Rates and Revenue Allocators | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | |
| Uniform Transmission Rates ($/kW-Month) | **3.62** | **0.75** | **1.86** | |
| | | | | |
| **FNEI Allocation Factor** | **0.00438** | **0.00438** | **0.00438** | |
| **CNPI Allocation Factor** | **0.00319** | **0.00319** | **0.00319** | |
| **GLPT Allocation Factor** | **0.02441** | **0.02441** | **0.02441** | |
| **H1N Alocation Factor** | **0.96802** | **0.96802** | **0.96802** | |
| Total of Allocation Factors | 1.00000 | 1.00000 | 1.00000 | |

*Note 1: Proposed Hydro One Networks (H1N) 2013 Revenue Requirement*
*Note 2: Proposed Hydro One Networks (H1N) 2013 Charge Determinants*
*Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.*
*Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.*
*Note 5: GLPT Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2010-0291 dated on December 19, 2011.*
*Note 6: Calculated data in shaded cells.*

## 2014 Draft Uniform Transmission Rates effective January 1, 2014

| Transmitter | Revenue Requirement ($) | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | **Total** |
| FNEI (Note 3) | $3,876,363 | $783,960 | $1,666,767 | $6,327,089 |
| CNPI (Note 4) | $2,825,866 | $571,506 | $1,215,072 | $4,612,443 |
| GLPT (Note 5) | $21,594,970 | $4,367,388 | $9,285,450 | $35,247,808 |
| H1N (Note 1) | $913,870,536 | $184,822,095 | $392,947,964 | $1,491,640,594 |
| All Transmitters | $942,167,734 | $190,544,948 | $405,115,252 | $1,537,827,934 |

| Transmitter | Total Annual Charge Determinants (MW) | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | |
| FNEI (Note 3) | 187.1 | 213.5 | 76.2 | |
| CNPI (Note 4) | 583.4 | 668.6 | 668.6 | |
| GLPT (Note 5) | 4,019.8 | 2,939.4 | 1,057.6 | |
| H1N (Note 2) | 234,635.3 | 227,880.9 | 196,795.3 | |
| All Transmitters | 239,425.6 | 231,702.4 | 198,597.7 | |

| Transmitter | Uniform Rates and Revenue Allocators | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | |
| Uniform Transmission Rates ($/kW-Month) | **3.94** | **0.82** | **2.04** | |
| | | | | |
| **FNEI Allocation Factor** | **0.00411** | **0.00411** | **0.00411** | |
| **CNPI Allocation Factor** | **0.00300** | **0.00300** | **0.00300** | |
| **GLPT Allocation Factor** | **0.02292** | **0.02292** | **0.02292** | |
| **H1N Alocation Factor** | **0.96997** | **0.96997** | **0.96997** | |
| Total of Allocation Factors | 1.00000 | 1.00000 | 1.00000 | |

*Note 1: Proposed Hydro One Networks (H1N) 2014 Revenue Requirement*
*Note 2: Proposed Hydro One Networks (H1N) 2014 Charge Determinants*
*Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.*
*Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.*
*Note 5: GLPT Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2010-0291 dated on December 19, 2011.*
*Note 6: Calculated data in shaded cells.*

# HYDRO ONE NETWORKS INC.
# TRANSMISSION RATE ORDER
# EB-2011-0268

# WHOLESALE METER SERVICE
# And
# EXIT FEE SCHEDULE

Rate Schedule: HON-MET
Issued: December 20, 2011
Ontario Energy Board

| RATE SCHEDULE: HON-MET | HYDRO ONE NETWORKS - WHOLESALE METER SERVICE |
|---|---|

***APPLICABILITY:***

This rate schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks (“Networks”) and to *metered market participants* that are customers of a Local Distribution Company (“LDC”) that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

**(a) Wholesale Meter Service**

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual rate of $ 7,900 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

The Wholesale Meter Service rate covered by this schedule shall remain in place until such time as the rate is revised by Order of the Ontario Energy Board.

**(b) Fee for Exit from Transitional Arrangement**

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.

# HYDRO ONE NETWORKS INC.
# TRANSMISSION RATE ORDER
# EB-2012-0031

# PROPOSED

# WHOLESALE METER SERVICE
# And
# EXIT FEE SCHEDULE

Rate Schedule: HON-MET
Issued: Date To Come
Ontario Energy Board

| RATE SCHEDULE: HON-MET | HYDRO ONE NETWORKS - WHOLESALE METER SERVICE |
|---|---|

***APPLICABILITY:***

This rate schedule is applicable to the *metered market participants*[*] that are transmission customers of Hydro One Networks ("Networks") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

**(a) Wholesale Meter Service**

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual rate of $7,900 for each *meter point* that is under a transitional arrangement for a *metering installation* whereby regulated meter services are provided by Networks.

The Wholesale Meter Service rate covered by this schedule shall remain in place until such time as the rate is revised by Order of the Ontario Energy Board.

**(b) Fee for Exit from Transitional Arrangement**

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.