# 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 Transmission Rate Schedules which were effective on January 1, 2010 as part of the Board's EB-2008-0272 December 16, 2009 Decision and Order, are filed at Exhibit H2, Tab 1, Schedule 1. In proceeding EB-2010-0003, Hydro One sought review and variance of the Board's decision of December 16, 2009 in EB-2008-0272. The Board's EB-2010-0003 Decision and Order did not vary their EB-2008-0272 decision as requested by Hydro One, and the Board confirmed the 2010 rates prescribed in the Board's rate order dated January 21, 2010 as a part of EB-2008-0272 as final.

Since rates are established on a uniform basis, Hydro One Transmission's requested revenue requirement for the 2011 and 2012 Test Years is a contributor to the total revenue requirement to be collected from the provincial transmission tariffs. The revenue requirement for the other three transmitters in the province, Great Lakes Power Limited, Canadian Niagara Power Inc., and Five Nations Energy Inc., 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.

The total revenue requirement from all transmitters must be allocated to the four rate pools in order for uniform rates by pool to be established. The revenue requirement by Rate Pool for the other three transmitters is based on the proportions established by Hydro One Transmission's Cost Allocation process. Once the revenue requirement by rate pool has been established, then rates need to be established by the Board by applying the appropriate Provincial charge determinants for each pool to the associated total revenue for each pool. The Provincial charge determinants are the sum of all charge determinants for the four transmitters, by Rate Pool.

# 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 12, Schedule 3. 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 maximum non-coincident peak demand for each customer 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 coincident peak demand for each customer 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 average monthly Coincident Peak demand, which is based on the average of the 12 monthly values for the total customer delivery point demand at the time of the monthly system peak demand.
- The average monthly Non-Coincident Peak demand, which is based on the average of the 12 monthly values for the total customer delivery point peak demand independent of the monthly system peak demand.
- The average monthly demand, which is based on the average of the 12 monthly values for the total customer delivery point demand value 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 6% higher than their average monthly coincident peak demand. For end-use transmission customers the non-coincident peak is about 42% 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**
**2011 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 | 430 | 18,310 | 93.5% | 18,466 | 91.6% | 19,457 | 90.5% |
| End-Use Customers | 90 | 1,255 | 6.4% | 1,537 | 7.6% | 1,782 | 8.3% |
| Transmission-Connected Generators | 89 | 25 | 0.1% | 146 | 0.7% | 254 | 1.2% |
| **TOTAL TRANSMISSION** | 609 | 19,590 | 100.0% | 20,150 | 100.0% | 21,493 | 100.0% |

**Table 2**
**2012 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 | 430 | 18,051 | 93.4% | 18,201 | 91.7% | 19,183 | 90.7% |
| End-Use Customers | 90 | 1,235 | 6.4% | 1,501 | 7.6% | 1,738 | 8.2% |
| Transmission-Connected Generators | 89 | 47 | 0.2% | 142 | 0.7% | 228 | 1.1% |
| **TOTAL TRANSMISSION** | 609 | 19,333 | 100.0% | 19,845 | 100.0% | 21,149 | 100.0% |

# 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 three transmitters for the Network, Line Connection and Transformation Connection rate pools can be used by the Board to determine uniform transmission rates. This exhibit also includes a discussion of the charge determinants based on AMPCO's proposal for Network charges, as directed by the OEB in its decision on Proceeding EB-2008-0272.

## 2.0 SUMMARY OF CHARGE DETERMINANTS

The rate pool charge determinants are summarized in Table 1 for the 2011 and 2012 Test Years.

**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) |
|---|---|---|---|---|
| 2011 | 20,150 | 19,500 | 16,850 | 100 |
| 2012 | 19,845 | 19,286 | 16,667 | 75 |

## 3.0 NETWORK CHARGE DETERMINANT

The Network Service charge determinant, as per the methodology approved in the Board's EB-2006-0501 and EB-2008-0272 Decisions, 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.

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. Previous Board Decisions in RP-1999-0044, EB-2006-0501 and in EB-2008-0272 recognized that the existing charge determinants definition represent a trade-off between the principles of cost causality, revenue and rate stability, efficiency, and fairness while recognizing the potential for free ridership.

As noted in the currently approved Ontario Transmission Rate Schedules [refer to Exhibit H2, Tab 1, Schedule 1] , Network Charges are applied as follows:

- All customers that are connected to Hydro One's transmission system incur charges based on the Network Service Rate.
- "The demand (MW) for the purpose of Network charges will be measured as the energy consumed during the clock hour, on a Per Transmission Delivery Point basis. The billing demand supplied from the transmission system will 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."
- "The Network 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 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 the 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 IESO settlement systems."

## 4.0 AMPCO's PROPOSAL

AMPCO proposes an alternative rate design applicable to Network charges. The alternative is that a fixed monthly charge be calculated for each customer based on that customer's average coincident peak demand on the IESO's 5 highest peak days of the previous year, (the "High 5 Proposal"). The Network charge for new transmission customers would be based on their forecast of summer weekday peak demand consistent with the load shape that the customer is required to provide the IESO through its Connection Assessment and Approval (CAA) Process. The transmitter would be permitted to bill for any calculated shortfall.

In the Board Decision with Reasons in Proceeding EB-2008-0272, page 69, Hydro One Transmission was directed to further analyze the AMPCO proposal, and to propose an implementation plan in the event the Board decides to change the network charge determinant in 2011. In response to the direction from the Board and given the particular expert knowledge required to respond to the Board's direction, Hydro One Transmission retained a consultant to further analyze the High 5 Proposal. Hydro One followed a rigorous request for proposal process to retain the stakeholder facilitator and the consultant to undertake the study, in accordance with the new provincial government guidelines for government agencies imposed in the summer of 2009. As a result, the processes leading to conducting the first stakeholder session and retaining a consultant took longer than anticipated and the consultant was engaged by mid March 2010. The consultant's report is provided as Attachment 1 to this Exhibit.

The issues, costs and benefits associated with adopting the High 5 Proposal are fully documented in the attached consultant's report. Hydro One Transmission awaits the Board's Decision on whether the High 5 methodology should be adopted for the recovery of transmission Network Service costs for all transmitters in Ontario.

### 4.1 Implementation of the "High 5 Proposal"

Based on the AMPCO proposal, each customer is billed their share of the approved revenue requirement based on their historical actual consumption, as determined by the "High 5 Proposal". In addition, each new transmission customer (i.e., those customers without the required historical consumption data) will be billed based on a forecast of their summer weekday peak demand). In effect, there would be no charge determinants under this proposal, and each customer would be assigned a percentage of the annual revenue requirement which will form the basis of their uniform monthly bill in the test year.

The new Network charge determinants for Hydro One based on the High 5 Proposal are included in Table 2. As a full year of 2010 demand data is not available, actual demand data from 2009 has been used as a proxy to determine the Network charge determinants for illustrative purposes.

Table 2

Network Charge Determinants Based on AMPCO's "High 5 Proposal"

| | | **2011*** | **2012**** |
|---|---|---|---|
| Sum of Coincident Peak Demand on 5 highest peak days for all Transmission Customers (MW) | A | 106,452 | To be determined |
| All Customers' Average Coincident Peak Demand (MW) | A/5 | 21,290 | To be determined |

* 2011 values based on actual 2009 demand for illustrative purposes. In practice, 2010 data would be used.
** 2012 values will be based on actual 2011 demand

Transmission customers would be billed based on their share of the average coincident peak demand and their monthly transmission charges would be determined as 1/12th of the following:

$$\boxed{\text{Customer Charge}} = \boxed{\frac{\text{Customer Average Coincident Peak Demand}}{\text{All Customers' Average Coincident Peak Demand}}} \times \boxed{\text{Revenue Requirement}}$$

If the Board chooses to adopt the High 5 Proposal, Hydro One Transmission believes this new methodology should only be implemented starting January 1, 2012 given the following implementation considerations:

1. As noted in the consultant's report at page 24, it would be appropriate to have a complete year in which transmission customers understood the consequences of changing the Network pricing methodology so they have an opportunity to modify their behaviour with full knowledge of the consequences of not doing so.
2. The High 5 methodology is based on consumption in the prior year. The 2010 data would not be available in time to determine the 2011 Network payments effective January 1, 2011.
3. The IESO have indicated they would require at least 4 months to implement the necessary tool and business process changes, as well as any required market rules

amendments. The IESO would initiate implementation activities only after the OEB has rendered a decision on this issue, which per Procedural Order No.1 in this proceeding, is expected on or about January 7, 2011. The IESO have also indicated that, given past experience in dealing with issues of this similar nature, any number of issues could arise during implementation that may require further input from the Board or additional stakeholder consultation.

4. Time will be required to update the Uniform Transmission Rates Schedules to reflect the High 5 methodology for the Network Service Rate.
5. All the other transmitters in Ontario will need to assess the impact of this new methodology on their Network charge determinants.
6. Hydro One Networks will need to develop settlements processes necessary to verify the IESO bills and advise of any concerns within the mandated 6 day period of receiving the IESO payments.

As noted by the consultant on page 56, there is also a potential issue associated with the fact that distribution connected customers (e.g. large users) are charged for transmission service on the basis of the current methodology for developing Retail Transmission Service Rates (RTSR) applicable to distribution customers. The derivation of RTSR charges is currently aligned with the Uniform Transmission Rates methodology, and adopting the High 5 Proposal for the transmission Network Service rate alone will result in unequal treatment between large users connected to the transmission versus distribution systems. A January 1, 2012 implementation date would allow the Board time to review and consider the need to change the RTSR methodology, and how the transition to new RTSR rates for individual LDCs would be addressed.

A January 1, 2012 implementation date would allow time to address the issues noted above and would permit the establishment of a process to resolve any further issues that could arise during implementation.

## 5.0 FORECAST OF EXISTING NETWORK CHARGE DETERMINANTS

The Transmission Delivery Points that attract Network Service charges are determined using the criteria described in Section 3.0 above. The 2011 and 2012 load forecast data for these Transmission Delivery Points is then used to identify the total charge determinants that attract Network Service charges.

## 6.0 LINE CONNECTION CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The Line Connection Service charge determinant, as per the methodology approved by the Board's EB-2006-0501 and EB-2008-0272 Decisions, is the customer's non-coincident monthly peak demand.

As noted in the currently approved Ontario Transmission Rate Schedules [refer to Exhibit H2, Tab 1, Schedule 1] , Line Connection Charges are applied as follows:

- The customers that utilize Line Connection assets owned by Hydro One Transmission would incur charges based on the Line Connection Service Rate. "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 demand (MW) for the purpose of Line Connection Service charges will be measured as the energy consumed during the clock hour, on a per transmission delivery point basis. The billing demand supplied from the transmission system will

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."

- "The Billing Demand for Line Connection Service 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 2 MW or more for renewable generation[1] and 1 MW or higher for non-renewable generation. The term renewable embedded 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."

## 7.0 FORECAST OF LINE CONNECTION CHARGE DETERMINANTS

The Transmission Delivery Points that attract Line Connection charges are determined using the criteria described in Section 6.0 above. The 2011 and 2012 load forecast data for these Transmission Delivery Points is then used to identify the total charge determinants that attract Line Connection Service charges.

[1] This is an addition from what was approved in Proceeding RP-1999-0044. The change was approved in the Transmission System Code Phase 1 Policy Decision with Reasons, Proceeding RP-2002-0120 and subsequently incorporated into the current Rate Schedules issued as part of Proceeding EB-2005-0241.

## 8.0 TRANSFORMER CONNECTION CHARGE DETERMINANTS AND PAYMENT OBLIGATIONS

The Transformation Connection Service charge determinant, as per the methodology approved by the Board's EB-2006-0501 and EB-2008-0272 Decisions, is the customer's non-coincident monthly peak demand.

As noted in the currently approved Ontario Transmission Rate Schedules [refer to Exhibit H2, Tab 1, Schedule 1] , Transformation Connection Charges are applied as follows:

- "The customers that utilize transformation connection assets owned by the Hydro One Transmission would incur charges based on the Transformation Connection Service Rate. 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 demand (MW) for the purpose of Transformation Connection Service charges would be measured as the energy consumed during the clock hour, on a per Transmission Delivery Point basis. The billing demand supplied from the transmission system would 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 station associated with the Transmission Delivery Point."
- "The Billing Demand for Transformation Connection Service 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 2 MW or more[2] for renewable generation and 1 MW or higher for non-renewable generation. The term renewable embedded 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."

## 9.0 FORECAST OF TRANSFORMER CONNECTION CHARGE DETERMINANTS

The Transmission Delivery Points that attract Transformation Connection charges are determined using the criteria described in Section 8.0 above. The 2011 and 2012 load forecast data for these Transmission Delivery Points is then used to identify the total of the charge determinants that attract Transformation Connection Service charges.

## 10.0 WHOLESALE METER POINTS

The forecasted number of Wholesale Meter Points is based on i) the 2009 year end Wholesale Meter Points of 174, ii) the experience gained in the number of conversions done since 2005 and iii) knowledge of the complexity of the remaining meter points.

The forecasted remaining Wholesale Meter Points are:

| | **# of Meter Points** | | | |
|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 |
| Year End | 174 | 112 | 88 | 62 |
| Mid Year | | | 100 | 75 |

[2] This is an addition from what was approved in Proceeding RP-1999-0044. The change was approved in the Transmission System Code Phase 1 Policy Decision with Reasons, Proceeding RP-2002-0120 and subsequently incorporated into the current Rate Schedules issued as part of Proceeding EB-2005-0241.

# Assessment of AMPCO's High 5 Proposal for Establishing Network Charge Determinants

Prepared for:

July 6, 2010

Prepared by:

www.poweradvisoryllc.com

Table of Contents

## Executive Summary

In Hydro One Network Inc.'s (HONI's or Hydro One's) transmission rate proceeding, EB-2008-0272, the Association of Major Power Consumers in Ontario (AMPCO) proposed that network charge determinants be based on an alternative rate design under which a fixed monthly network charge would be calculated for each transmission customer based on that customer's demand during the hour of peak demand during the 5 highest peak days of the previous year. Hydro One, and all transmission providers in Ontario, currently base network transmission charges for each customer on their respective demand level calculated each month as the higher of:

1. The customer's demand at the time of the monthly coincident peak demand, or
2. 85% of the customer's maximum non-coincident demand between 7:00 A.M. and 7:00 P.M. on weekdays that are not holidays.

In its Decision With Reasons, the OEB directed Hydro One to come forward at its next application with:

1. further analysis of AMPCO's proposal; and
2. a suitable proposal for implementation for the OEB's consideration in the event the OEB decides to change the charge determinant.

Power Advisory LLC (Power Advisory) was engaged by HONI to provide this further analysis of AMPCO's proposal and more specifically, to perform an analysis of the costs and benefits of implementing the High 5 rate design including the potential load shifts in response to changes in prices (as represented by estimated shadow prices), transmission cost shifts, and commodity cost impacts. Hydro One also asked Power Advisory to analyze the potential impacts on long-term network investment requirements. The report draws upon the record in OEB Docket No. EB-2008-0272 and begins with a detailed review of AMPCO's proposal and the comments provided by other parties to the proceeding.

AMPCO acknowledges that its proposal will shift cost responsibility from directly connected transmission customers to local distribution companies (LDCs), and thereby to the customers of LDCs. AMPCO asserts that the High 5 methodology will incent customers to shift usage away from potential peak hours and thereby reduce energy prices (Hourly Ontario Energy Price – HOEP). On balance, AMPCO claimed that the resulting cost shifting among transmission customers would be modest ($0.9 million) relative to the potential commodity cost savings for all customers ($11.3 million).

Power Advisory's assessment of AMPCO's proposal is summarized in Section 2.3 with more detailed assessments provided in subsequent Chapters. Power Advisory concludes that the methodology used to determine cost responsibility must reflect the particular circumstances of the network. AMPCO asserts that investment in HONI's transmission network is "largely determined" by system peaks that occur during relatively few months. However, HONI's transmission system does not peak at the same time in every area and regional peaks frequently occur on days that vary from the system peak days. In addition, an increasingly important driver of transmission investment in Ontario is the need to connect new renewable generation, including wind and hydro resources. These resources tend not to experience their maximum output at the time of peak demands and the transmission network must be designed accordingly. Thus, it is not apparent that transmission investment is largely determined by system peaks as claimed by AMPCO. With respect to recovery of past investments, the transmission network was built to serve Ontario's transmission peak demands throughout the year and in each local region and thus the High 5 proposal is also inconsistent with the cost causality principle where costs are assigned to customers and rate classes in accordance with their contribution to the costs that have been incurred.

The key elements of AMPCO's benefits presentation are the estimation of shadow prices and the elasticity of demand by industry segment. However, the AMPCO shadow price analysis is subject to considerable uncertainty due to many assumptions that must be made to reflect the efforts by customers to reduce demand in order to avoid using transmission facilities during peak hours. Power Advisory has developed a range of shadow prices to reflect this uncertainty.

AMPCO applied its calculated shadow prices to econometrically derived own-price elasticity estimates for five industrial sectors to develop estimates of load shifts. Power Advisory explains that these equations are subject to criticism that could affect the price elasticity estimates, and therefore the resulting projected load shifts. Power Advisory has reviewed other studies that estimated price elasticity of demand and elasticity of substitution for industrial customers and proposed that it is more appropriate to apply a range of values of elasticities of substitution to capture the uncertainty. The center of the range is taken from empirical estimates for industries in Ontario.

Based on these values, Power Advisory estimates a range of potential load shifts that are subsequently used to calculate the two components of the benefits assessment: transmission cost shifts and commodity cost savings. These load shifts are presented in Table ES 1.

**Table ES 1: Estimated Load Shifts**

**Estimated Load Shifts**

| | | AMPCO | Power Advisory Low | Power Advisory Central | Power Advisory High |
|---|---|---|---|---|---|
| Quantity | MW | 29 | 40 | 86 | 151 |
| Annual Hours | Hours | 300 | 60 | 120 | 200 |

Power Advisory has applied its model of the Ontario electricity market to estimate the reduction of HOEPs (and resulting cost savings) during on-peak hours from the reduction in demand as well as the increase in HOEPs in the off-peak hours from the shifting of demand. Power Advisory's estimates of the net commodity cost reductions are significantly smaller than AMPCO's (from about one-tenth to less than a quarter), even though both our estimates of the shifted load and the estimated average price changes are higher than AMPCO's. This is due primarily to the fact that we assumed that the benefits of the load shift occur for fewer hours (e.g., 120 hours for Power Advisory's Central Shift Case compared to all summer peak hours – 12 hours per day for all days (including weekends and holidays) in the months of May, June, July and August – for AMPCO). The total load to which our on-peak commodity cost savings is applied is from one-twentieth (High Load Shift Case) to about one-fifth (Low Load Shift Case) of that assumed by AMPCO.

**Table ES 2**

| Case | Commodity Cost Changes for Load Shifts: 2011 — Average Price Impact: Reduction on-peak ($/MWh) | Average Price Impact: Increase off-peak ($/MWh) | Total Cost Change ($M) |
|---|---|---|---|
| High | -$ 2.45 | $ 0.84 | -$ 2.44 |
| Central | -$ 0.94 | $ 0.40 | -$ 1.71 |
| Low | -$ 0.36 | $ 0.16 | -$ 0.98 |

With respect to transmission cost shifts, there are two potential sources of cost shifting: (1) from customers shifting load from peak to off-peak hours, and (2) from applying the new methodology to the existing load profile.  AMPCO calculated only the short-term revenue impact of load shifts. In fact, the cost shifts resulting from the change in methodology are an order of magnitude greater than cost shifts from load shifting and are much larger than the estimated commodity cost savings that would accrue to all customers, leaving all customers that don't shift load and reduce their network determinants worse off after application of the High 5 proposal.

**Table ES 3: Transmission Cost Shifting from Change to High 5 Methodology and Load Shifting 2011Revenue Requirements ($ Millions)**

**A. Impact of a Change In Methodology**

| | Current Methodology | | | High 5 Methodology | | | |
|---|---|---|---|---|---|---|---|
| | Determinants (kW) | Proportionate Responsibility | Cost Responsibility | Determinants (kW) | Proportionate Responsibility | Cost Responsibility | Impact |
| LDCs | 221,592,973 | 90.9% | $763.6 | 100,018,607 | 94.0% | $789.0 | $25.3 |
| Directs | 19,138,492 | 7.9% | $66.0 | 6,142,364 | 5.8% | $48.5 | -$17.5 |
| Power Producers | 2,935,229 | 1.2% | $10.1 | 291,128 | 0.3% | $2.3 | -$7.8 |
| Total | 243,666,694 | 100.0% | $839.7 | 106,452,099 | 100.0% | $839.7 | $0.0 |

**B. Combined Impact of a Change In Methodology and Load Shifting**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| LDCs | 221,592,973 | 90.9% | $763.6 | 100,018,607 | 94.3% | $792.2 | $28.5 |
| Directs | 19,138,492 | 7.9% | $66.0 | 5,712,364 | 5.4% | $45.2 | -$20.7 |
| Power Producers | 2,935,229 | 1.2% | $10.1 | 291,128 | 0.3% | $2.3 | -$7.8 |
| Total | 243,666,694 | 100.0% | $839.7 | 106,022,099 | 100.0% | $839.7 | $0.0 |

| | | |
|---|---|---|
| Hydro One 2011 Network Revenue Requirements | | $839.7 |
| Reduction in Direct Determinants due to Load Shifting: | | |
| | Central (MW) | 86 |
| | Central (kW) | 86,000 |
| | Times 5 for 5 High Peaks | 430,000 |
| | Revised Direct Determinants | 5,712,364 |

As shown in Table ES 3 (Impact of a Change in Methodology), power producers benefit most significantly (cost responsibility decreases by $7.8 million or over 75%) as they tend to rely on station power during planned outages scheduled during off-peak months. Their reliance on Hydro One's transmission system diminishes greatly during peak periods because they will then be net generators of power. The power stations require no action to realize significant cost savings. Under this scenario, direct customers also benefit significantly (cost responsibility decreases $17.5 million or 26.5%). The LDCs fund the shortfall ($25.3 million or a 3.3% increase) and must pass these increased transmission costs on to their customers to recover their higher revenue requirements.

To estimate the transmission cost shift resulting from the combination of both load shifts and a change in methodology, Power Advisory reduced the High 5 charge determinants for direct customers based on our central estimate of load shifting or 86 MW. As shown in part B of Table ES 3, the combined impact is a reduction in direct connect customer cost responsibility of $20.7 million, a reduction of power station cost responsibility of $7.8 million, and an increase in LDC cost responsibility of $28.5 million or a 3.7% total increase in network transmission cost responsibility.

While the impact on network cost responsibility is significant, the impact on a residential customer's total electricity bill would be relatively small. For example, the average monthly bill for an Ontario residential customer using 800 kWh per month is approximately $120/month. This varies among LDCs, as do the individual components of the bill. Network charges represent about 60% of total transmission costs, and transmission charges represent approximately 7.5% of this total bill or approximately $9/month. Thus, based on the impact calculations above, an average LDC residential customer would see an increase in their total monthly bill of $0.20/month or $2.40/year.

However, presenting these data at the segment level masks changes in impacts among customers within each segment. For example, LDC customers that have a lower load factor relative to other LDCs will bear the greatest burden and thus, LDCs with large percentages of heating and cooling loads will bear the largest burden. One can anticipate that some LDCs will receive network transmission cost increases well in excess of the average 3.7%. The impact on individual customers of these LDCs depends on the rate design that is applied to recover the LDC's transmission costs.

Transmission cost shifts that result from a change in use of the transmission system as a result of customers changing their load shapes are years away based on our understanding of Hydro One's current transmission plan and the relatively small impacts from the amount of load shifting that is likely to occur.

On balance, Power Advisory concludes that the High 5 methodology is likely to have a net benefit only to the directly connected transmission customers and the power station customers.

# 1. Introduction

In Hydro One Network Inc.'s (HONI's or Hydro One's) transmission rate proceeding, EB-2008-0272, the Association of Major Power Consumers in Ontario (AMPCO) proposed that network charge determinants be based on an alternative rate design under which a fixed monthly network charge would be calculated for each transmission customer based on that customer's demand during the hour of peak demand during the 5 highest peak days of the previous year. Under this proposal the customer's Network Charge remains the same for each month of the year and any shift in demand away from the current year's peaks would reduce the charge applicable for the following year.

In its Decision With Reasons, the OEB directed Hydro One to come forward at its next application with:

1. further analysis of AMPCO's proposal; and
2. a suitable proposal for implementation for the OEB's consideration in the event the OEB decides to change the charge determinant.[1]

## 1.1 Scope of Review

Power Advisory LLC (Power Advisory) was engaged by Hydro One Networks Inc. (HONI) to provide this further analysis of AMPCO's proposal. Specifically, HONI requested that the consultant respond to the following issues identified by the OEB:

(1) Provide a comprehensive impact analysis of the likely and potential effects, costs and benefits of implementing the High 5 rate design evaluating:
- Level of load shift;
- Transmission cost shifts;
- Magnitude of impact on commodity cost;
- Impact on transmission connected customers; who pays and who benefits?;
- Localized transmission system impacts; and
- What other potential positive or negative consequences or side effects might such a rate structure result in.

(2) Further analysis of the effect of the AMPCO proposal on long term network investment requirements;

(3) Review and analyze the various criticisms which have been made about AMPCO's analysis (and its expert's analysis); and

[1] This second item was not an element of Power Advisory's scope of work and is not addressed in this report.

(4) Identify ways to monitor such a program (i.e. AMPCO's proposal) and measure its effect on commodity prices.

## 1.2 Contents of Report

This report provides Power Advisory's evaluation of AMPCO's High 5 Proposal and addresses each of these issues. Our evaluation is organized around eight chapters. The first contains this introduction. The second chapter reviews AMPCO's High 5 Proposal and reviews and analyzes the various criticisms made about AMPCO's analysis. Chapter 3 provides Power Advisory's assessment of the likely level of the load shift, by first reviewing how customer demands would change based on the High 5 Proposal. This assessment reviews and recommends appropriate price elasticity estimates (i.e., the change in demand in response to a change in price) and establishes the perceived price (i.e., the shadow price) from the High 5 Proposal to produce the resulting load shifts. Chapter 4 reviews the resulting transmission cost shift among customers and assesses the impact on transmission customers, before any other potential benefits from the AMPCO proposal are considered. Chapter 5 reviews the commodity cost impacts from these resulting load shifts. Chapter 6 reviews the localized transmission impacts and assesses the effect of the proposal on long-term network investment requirements. Chapter 7 reviews the issues with monitoring the effect on commodity prices of adopting the High 5 proposal. Conclusions are presented in Chapter 8.

## 2. Review and Analysis of AMPCO's High 5 Proposal

This section of the report presents a review and analysis of the various criticisms and comments made by parties to EB-2008-0272 regarding AMPCO's presentation, including the econometric analyses sponsored by AMPCO witness Dr. Anindya Sen.[2] In order to place these criticisms in context, it is necessary to first summarize the AMPCO proposal and claimed benefits. The remaining two subsections of this chapter are a review of the critique by other parties and the Power Advisory perspective with respect to the AMPCO proposal.

Power Advisory reviewed the filings by AMPCO and other parties in Docket No. EB-2008-0272, including final arguments, responses to interrogatories, oral hearing transcripts, and responses to undertakings agreed to during the oral hearings. The final arguments submitted by the parties, in particular, provide a thorough review of the arguments in favor of and in opposition to AMPCO's High 5 Proposal. Power Advisory met with AMPCO to review its High 5 proposal and discuss the analytical methods employed to estimate the benefits of the proposal.[3]

### 2.1 Summary of AMPCO's High 5 Proposal

HONI, and all transmission providers in Ontario, currently base network transmission charges for each customer based on their respective demand level calculated each month as the higher of:

1. The customer's demand at the time of the monthly coincident peak demand, or
2. 85% of the customer's maximum non-coincident demand between 7:00 A.M. and 7:00 P.M. on weekdays that are not holidays.

The second criterion is commonly referred to as a demand ratchet. The demand charge paid by both LDCs and direct end-use transmission customers varies each month as peak demand in the prior month varies. The demand ratchet reduces this variation. HONI's contribution to the provincially established Uniform Transmission rates (UTRs), and in particular the transmission network service rate, is established in HONI rate cases based on test-year transmission costs and a forecast of customer loads. Thus, under the current UTR approach network charges vary monthly based on customers' coincident and non-

[2] The Board's Order in EB-2008-0072 stated that Hydro One should present further analysis of AMPCO's proposal in its next application including a need to "address the various criticisms which have been made about the AMPCO's analysis (and its expert's analysis)". (p. 69).

[3] The meeting was held on April 20, 2010.

coincident peak demands occurring throughout the twelve months of the year.

In contrast, AMPCO has proposed that the monthly network charge determinants shall be constant throughout the year and be based on the customer's demand during the hour of peak demand on five highest peak days of the previous year (referred to as the "High 5 Proposal"). These peak days occur primarily during the summer months although Ontario sometimes experiences peak days during the winter season.[4] The five peak days could occur within the same month of the preceding year.

An AMPCO witness explained that its proposal is intended to foster efficient demand management:

> The other reason we're here is that through my involvement with AMPCO, we continue to hear from AMPCO and other customers about their frustration with the current rate design. Their concern is that it serves as an impediment to efficient demand management, that it's quite arbitrary, that it provides signals to reduce demand when demand response has no value, and that it fails to provide signals for demand response when demand response can be immensely valuable.[5]

AMPCO acknowledges that its proposal will shift cost responsibility from end-use transmission customers to local distribution companies (LDCs), and thereby to the customers of LDCs. AMPCO asserts that the High 5 methodology will incent customers to shift usage away from potential peak hours and thereby reduce energy prices (Hourly Ontario Energy Price – HOEP). On balance, AMPCO claimed that the resulting cost shifting among transmission customers would be modest ($0.9 million) relative to the potential commodity cost savings for all customers ($11.3 million). The load shift and energy cost savings estimates were based on econometric analyses performed by Dr. Sen, an Associate Professor of Economics at the University of Waterloo. In addition to Dr. Sen's expert report, AMPCO sponsored testimony by one of its members, Mr. MacDonald of Gerdau Ameristeel, who testified that his firm had modified its demand shape in response to similar transmission charge methodologies employed in PJM and ERCOT.[6]

AMPCO asserts that its High 5 proposal is superior to the current methodology because it:

[4] See discussion in Chapter 3 regarding when these High 5 demands have occurred.
[5] Transcript, Volume 6, page 14.
[6] AMPCO presented its witnesses as a panel. The other two AMPCO witnesses were Wayne Clark, President of SanZoe Consulting, Inc. and Adam White, President and CEO of AITIA Analytics, Inc.

1. Allocates transmission costs more fairly among customers according to how those customers use the transmission system;
2. Promotes better asset utilization and more efficient transmission by Hydro One;
3. Provides more efficient signals to customers regarding the costs their consumption imposes on the system;
4. Promotes more efficient demand management and specifically peak-shifting; and
5. Provides greater revenue certainty to Hydro One and greater cost certainty to customers, reducing risk and increasing the financial viability of the electricity sector overall.[7]

AMPCO states that demand charges should reflect the primary drivers of transmission costs, particularly investment in new infrastructure. A primary reason for limiting the peak period to five peak days was AMPCO's contention that investment in the transmission network is "largely determined" by the need to meet demand when it peaks during relatively few months and that other months' peak demands did not influence the need for new transmission capacity. AMPCO claims that the use of all months, rather than only months that experience system peaks, mutes the price signal. AMPCO suggests that, under the current methodology, customers have little incentive to peak shave once they have experienced a peak day in the month and that operations would be adversely affected if customers had to reduce demand for an entire 12-hour peak pricing period, when peaks only occur during a few hours of the day.[8]

AMPCO also took issue with the demand charge ratchet provision asserting that it also mutes the price signal for customers to reduce their demand during peak periods. In AMPCO's view, the price signal would be stronger if it more directly encouraged customers to decrease their usage during peak periods and rewarded shifting of demand from peak to off-peak periods. AMPCO elaborated on this concept in response to an interrogatory:

> The current design does provide a limited incentive to reduce peak demand, but only to the 85% level. The fact that the incentive disappears at peak periods once the 85% threshold is reached is the basic problem with the current design.[9]

[7] AMPCO Evidence in Docket EB-2008-0272, January 14, 2009, page 2.
[8] Transcript, Volume 6, page 23.
[9] AMPCO response to VECC Interrogatory #18, dated January 28, 2009.

In order to estimate the impact of its proposal, AMPCO employed a "shadow price" methodology. In economics, a shadow price is the marginal benefit of relaxing a constraint by one unit or the marginal cost of tightening the constraint by one unit. As applied by AMPCO, the shadow price is a measure of the savings customers perceive they will realize if they were to consume one less unit of demand at the time that the transmission system is experiencing a peak. AMPCO calculates the shadow price as an estimate of the average savings that would be experienced by customers from reducing demand by 1 MW.[10] AMPCO applies the following formula to calculate the shadow price:

$$Shadow\ price\ (\frac{\$}{MWh}) = \frac{Network\ charge\ (\frac{\$}{MWh})\ X\ Demand\ reduction\ (MW)}{Duration\ of\ reduction\ (Hours)}$$

Applying this formula, AMPCO calculated a shadow price of $102.80/MWh.[11,12] As shown below, this calculation depends critically on assumptions regarding the number of times and hours a customer takes action to reduce their demand in order to avoid a system peak.

The $102.80/MWh shadow price is calculated as follows:

(1) The network charge ($2.57/kW-month) x 1,000 (to convert from kW/Month to MW/Month) x 12 months = $30,840

(2) Divided by "300" calculated as:

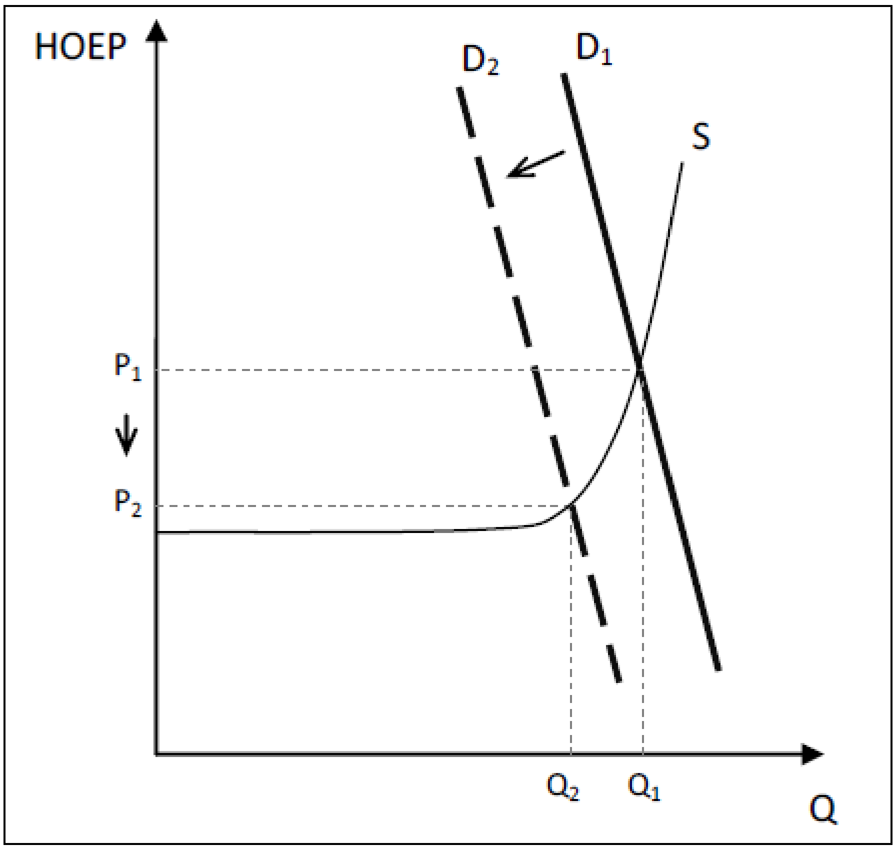
- number of peak periods (5) to be avoided
- x the assumed number of demand reductions required to avoid each High 5 peak period (5)
- x duration of the hours of customer load reductions on-peak (12)[13]

(3) = $102.80/MWh.

[10] Transcript, Volume 6, page 17.
[11] Undertaking Exhibit No. J6.3, page 2.
[12] AMPCO updated its calculations on two occasions after making its initial filing: (1) in response to VECC interrogatories, and (2) in Undertakings made during the oral hearings. The calculations cited in this section rely on the corrected Undertaking exhibits.
[13] See AMPCO response to VECC Interrogatory #17(b). AMPCO states that customers need to reduce their peak consumption for only four hours to avoid the system peak, but they realize savings over the entire 12-hour peak period. The shadow price estimates customer savings.

AMPCO estimates the impact of changes in demand (i.e., a shift in the demand curve or the price equation) on the average peak and off-peak HOEP by using elasticities derived using regression techniques. As shown below in Figure 1 based on an illustration made by Dr. Sen during the oral hearings[14], AMPCO's basis is to assume a leftward shift in the demand curve during peak hours which results in a reduction in energy prices. Conversely, a rightward shift in the demand curve as load is shifted to off-peak hours results in an increase in off-peak energy prices.

**Figure 1: Impact of Load Shift on Price**




To estimate the impact on HOEP of changes in demand, AMPCO used the following regression model:

HOEP ($/MWh) =
b0 (the intercept)
+ b1 Total Market Demand (MW)

[14] Copy of Dr. Sen diagram provided by AMPCO in Undertaking Exhibit No. J6.8, page 2.

+ b2 Imports (MW)
+ b3 Exports (MW)
+ b4 Natural Gas Price ($/MMBtu)
+ b5 Power Supply Fuel Mix (e.g., coal, nuclear, natural gas, and hydro)
+ Hourly, Monthly and Annual Dummy Variables
+ e (“residual” or unexplained variation in hourly demand)

The change in price depends critically on where the shift occurs along the supply curve. AMPCO postulates that the supply curve is steepest during periods of high demand, resulting in a more significant decline in energy prices then as compared to a more modest increase in prices that will be observed during off-peak hours.

The equations used to estimate the responsiveness of price to demand for on-peak and off-peak hours are presented in Appendix A.

Using the coefficient for Total Market Demand, AMPCO estimates that the price will increase by $15.97/MWh during peak hours for every 1000 MW of additional demand. The price is reduced by $5.71/MWh during off-peak periods for every 1000 MW of decreased demand.[15] By way of reference, the average summer peak price in 2007 (the basis for regression data) was $57.50/MWh. The average off-peak price observed during this period was $32.72/MWh.

Having estimated the effect of demand on price resulting from a shift in the demand curve, AMPCO estimates the impact of price on demand for five key industrial sectors (pulp, metal, iron, motor and petroleum products refining).[16] This represents the impact of a change in price on demand associated with a movement along the demand curve. Dr. Sen tested the hypothesis that firms, on average, shift their demand for electricity to periods of lower prices (non-peak hours) in response to high prices during hours of peak consumption (peak hours). He specified the following equation using hourly load data provided by the IESO:

Hourly Demand averaged over a 12 hour period =
b0 (the intercept)
+ b1 Hourly Ontario Energy Price (HOEP) averaged over a 12 hour period

[15] Calculated as the coefficient of the Total Market Demand variable, denoted as “odem” in the regression equation, times 1,000 on pages 2 and 3 of Undertaking Exhibit J6.2.

[16] AMPCO selected these five sectors. Power Advisory has not evaluated whether these are the only sectors that could respond to the High 5 proposal. However in Chapter 3, Power Advisory includes one additional industry, non-metallic mineral products, in its calculation of load shifts.

+ b2 Hourly Ontario Energy Price (HOEP) averaged over the previous 12 hours
+ Month Dummy Variables
+ e ("residual" or unexplained variation in hourly demand)

As shown in Appendix A, statistically significant elasticity estimates (% change in demand in response to a 1% increase in price to estimate the average hourly change in demand) were obtained for the pulp (-0.234), metal (-0.043), and iron (-0.047) industries. The price elasticity estimates for the motor and petroleum products refining industries were positive, suggesting that these industries did not respond to electricity prices and were thus dropped from the next step in AMPCO's analysis. As shown in Table 1, AMPCO applies these elasticity estimates to estimate the hourly change in demand.[17] Although the R-squareds, which measure the explanatory power of the equation, were low, Dr. Sen suggested that the signs of the coefficients and the statistical significance of the coefficient estimates as indicated by t-statistics were more important.[18]

**Table 1**

**The Effect of Transmission Rates on Demand in Real-Time**

| a | b | c | d | e | f | g | h |
|---|---|---|---|---|---|---|---|
| | **Industrial demand Summer 2007 Peak Periods** | **Average HOEP Summer 2007 Peak Periods** | **Transmission Shadow Price** | **% change in price on-peak** | **Elasticity of Demand with respect to HOEP in Real-Time** | **Change in demand in response to change in price** | **Average Hourly Change in Demand** |
| | Qnp | Pnp | T$ | (t$+P)/P | e=(dq/dp)*(P/Q) | dq/dp | MW |
| Pulp | 408.05 | | | | -0.2344403 | -1.664% | -18.93 |
| Metal | 508.78 | | | | -0.0433269 | -0.383% | -5.44 |
| Iron | 465.43 | $57.50 | $102.80 | 279% | -0.0468795 | -0.379% | -4.92 |
| Motor | 157.75 | | | | | | |
| Petrol | 219.49 | | | | | | |
| Note: statistically insignificant results are excluded | | | | | | | -29 |

The final column, Average Hourly Change in Demand, is calculated as the product of columns b, e, and g. In other words, if the peak price were to be increased by adding the transmission shadow price to the average observed HOEP ($57.50/MWh) or by 279% in each of the three industries with negative and significant price elasticity estimates,[19] then the average hourly demand for these three industries would decline in aggregate by 29

[17] AMPCO response to Undertaking J6.3, page 3.
[18] Transcript, Volume 6, page 80-81.
[19] During the hearings, an AMPCO witness explained that the auto industry does not operate during the graveyard shift and therefore has more limited ability to shift demand to off-peak hours. Transcript, Volume 6, page 40.

MW. Among these three industries, the pulp industry has the largest price-elastic response.

AMPCO performed a similar analysis to estimate the impact of changes in peak prices on off-peak demand. In this case, all five industries exhibit a positive price coefficient (i.e., as on-peak prices increase, off-peak demand is expected to increase as customers shift demand to off-peak hours). In other words, if the peak price were to be increased by adding the transmission shadow price to the average observed HOEP ($57.50/MWh) or to 279% of its original value, then the average off-peak hourly demand for all five industries would increase in aggregate by 24 MW.[20] [21] This analysis is summarized in Table 2.

**Table 2**

**The Effect of Transmission Rates on Peak Shifting**

| a | b | c | d | e | f | g | h |
|---|---|---|---|---|---|---|---|
| | Industrial demand Summer 2007 Non-Peak Periods | Average HOEP Summer 2007 Peak Periods | Transmission Shadow Price | % change in price on-peak | Elasticity of Demand: Average HOEP for past 12 hours | Change in demand in response to change in price | Average Change in Demand |
| | Qnp | Pnp | T$ | (t$+P)/P | e=(dq/dp)*(P/Q) | dq/dp | MW |
| Pulp | 479.74 | | | | 0.1033274 | 0.862% | 11.53 |
| Metal | 532.85 | | | | 0.0554928 | 0.514% | 7.64 |
| Iron | 486.77 | $57.50 | $102.80 | 279% | 0.0262302 | 0.222% | 3.01 |
| Motor | 148.77 | | | | 0.1550334 | 0.401% | 1.66 |
| Petrol | 220.20 | | | | 0.01582819 | 0.061% | 0.37 |
| Note: statistically insignificant results are excluded | | | | | | | 24 |

Finally, AMPCO estimates the energy cost impact using their calculation that the 29 MW of reduced demand during peak hours would reduce the peak period HOEP by $0.47/MWh. Multiplying this savings by total peak period demand (27,219,556 MWh) yields savings of approximately $12.7 million.[22] This is partially offset by $1.4 million of increased costs during off-peak hours as off-peak prices increase by $0.14/MWh due to the increase in demand during off-peak hours.[23]

[20] Undertaking Exhibit J6.3, page 4.

[21] AMPCO included all five industries in the off-peak adjustment because the coefficients were all of the correct sign and t-statistics for the 12-hour lagged price variables were statistically significant at the 80% level.

[22] The AMPCO analysis is concentrated on transmission demand and commodity prices. AMPCO did not analyze other potential societal costs such as the reduction in market revenues to generators. In Ontario, as a result of the Global Adjustment mechanism and the fact that a significant portion of the market is under contract, reductions in HOEP can result in increases in the Global Adjustment.

[23] Undertaking Exhibit J6.3, page 5.

This net energy cost savings from peak shifting of $11.3 million must be reduced by the savings that will be realized by customers that can peak shift ($0.9 million) as these costs will be recovered from all customers in order for HONI and other transmitters to continue to recover their transmission cost of service. Thus, AMPCO estimates that its proposal will, on balance, provide $10.4 million of savings each year.

Under the current pricing mechanism the network transmission charges that customers pay, and the revenues that HONI and other transmitters receive, vary each month as demand changes. AMPCO asserts that its High 5 proposal provides revenue stability to HONI and other transmitters because customer charges, and revenues, would remain constant throughout the year.[24]

AMPCO acknowledged during the hearing that the improved revenue certainty for the transmitters is achieved by shifting cash flow risk to the end-use transmission customers because their bills are based on last year's consumption. Thus, they will not receive any benefit in terms of reduced network transmission charges from reduced demand at the time of the five highest peak days until the following year.[25]

## 2.2 Comments Presented by Other Parties in Docket No. EB-2008-0272

The primary parties that expressed opinions on AMPCO's network charge determinant methodology and, most importantly, on the potential benefits of a change to this methodology were HONI, the Electricity Distributors Association (EDA), the Vulnerable Energy Consumers Coalition (VECC), Pollution Probe (PP), and the Canadian Manufacturers and Exporters (CME).

For the most part, these parties challenge the benefits that AMPCO claims from its High 5 proposal focusing on claimed improvements in economic efficiency (price signals and resource allocation) and fairness. The following sub-sections address these concerns as well as comments on AMPCO's econometric models, shadow price calculations, and other areas.

### 2.2.1 Comments on the Economic Efficiency of AMPCO's Proposal

Three of AMPCO's five stated goals assert that the High 5 Proposal will lead to a more efficient transmission network and greater economic efficiency overall:

2. Promotes better asset utilization and more efficient transmission by Hydro One;

[24] Absent a rate case establishing a new cost of service and cost allocation study, rates are adjusted each year based solely on changes to charge determinants.
[25] Transcript, Volume 6, pages 105 and 150.

3. Provides more efficient signals to customers regarding the costs their consumption imposes on the system; and

4. Promotes more efficient demand management and specifically peak-shifting.

The EDA opposes the High 5 proposal, although it acknowledges that the transmission system benefits from peak shaving during the time of summer system peaks and that it is conceivable that this could contribute to a lower HOEP during those hours.[26] However, EDA challenges the foundation of AMPCO's proposal, asserting that HONI's transmission system is not currently capacity constrained and that investments in new transmission are not being driven by system capacity requirements but by rather by more localized conditions including the need to connect new generation.[27] EDA cites the Board's decision in RP-1999-0044, which reads in relevant part,

> A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC network transmission system either today or in the foreseeable future.[28]

The EDA point out that approximately 90% of the load on the transmission system is by LDCs, and not by end-use transmission service customers.[29] They assert that system peak is being driven by LDC demand. EDA states further that LDCs do not always peak at the same time as the system. EDA notes that LDCs have a limited ability to shift peak and do not use coincident peak as a billing determinant for service to their customers, and thus, these customers would not see a High 5 price signal.[30] EDA states that this is contrary to concerns raised by the Decision in RP-1999-0044.[31] As a result, the 65 end-use transmission customers will have the primary opportunity to shift peak and costs will be shifted to the customers of LDCs. They state further that there was no evidence that the 65 customers are located on the network where there is transmission congestion.[32] VECC claims that half of these customers are located in Northern Ontario, where transmission investments are not driven by peak demand.[33]

[26] EDA Final Argument, pages 1-2.
[27] HONI also cited the need to replace aging equipment as a driver of transmission investment. Transcript, Volume 1, page 9.
[28] Citing RP-1999-0044 Decisions with Reasons, paras. 3.4.24 – 3.4.27
[29] EDA cites Transcript, Volume 5, page 10, lines 2-4 and Transcript, Volume 5, page 74, lines 12-23
[30] EDA Final Argument, pages 4-5.
[31] EDA Final Argument, page 9.
[32] EDA Final Argument, page 7.
[33] VECC Final Argument, page 45.

VECC also challenges the premise of AMPCO's proposal that the primary cost driver for transmission investment is system peak demand. They claim that new generation will drive transmission investments over the next five years and that much of the new generation is wind and hydro that do not peak at the same time as the system overall.[34] VECC notes as well that local area transmission investments are driven by local demands and not regional or system demands.[35] To the extent that these local peaks differ from the system peaks, load shifting that results from the AMPCO proposal could actually exacerbate local system peaks.[36]

The EDA also notes that the transmission network charges comprise approximately 6% of a customer's total bill and that energy prices provide sufficient incentive for end-use customers to shift peak. They assert that energy investment decisions that relate to shifting peak should focus on customer response to energy prices. [37] The EDA suggests that transmission prices should be established independent of energy prices and should not be set with a mind toward influencing energy prices.

AMPCO also cites efficiency concerns in opposing continuation of the 85% ratchet mechanism used to set customer demand charge determinants. AMPCO asserts that the ratchet provision serves to mute the price signal that customers receive. VECC takes a different view, arguing that the ratchet encourages customers to manage their peak over a broader period than the few hours that the system peaks.[38]

PP supports the AMPCO proposal on efficiency grounds suggesting that it will encourage customers to pursue demand response actions. According to PP, reductions in peak demand will reduce the need for new and expensive transmission investments. They also claim that reductions in peak demand will facilitate the phase-out of Ontario's coal plants.[39]

Finally, EDA supports continuation of the current HONI methodology citing the existing rate incentives for customers to either shift load from peak to off-peak hours or install more efficient equipment and customer generation.[40]

[34] VECC Final Argument, page 44.
[35] VECC Final Argument, page 44.
[36] VECC Final Argument, page 45.
[37] EDA Final Argument, page 2.
[38] VECC Final Argument, pages 46, 50.
[39] PP Final Argument, page 5.
[40] EDA Final Argument, page 6.

### 2.2.2 Comments on the Fairness of AMPCO's Proposal

AMPCO asserts that its High 5 proposal, "[a]llocates transmission costs more fairly among customers according to how those customers use the transmission system".[41] VECC notes that AMPCO's witness made reference to United States Federal Energy Regulatory Commission (FERC) guidelines, but that application of these guidelines supports use of a 12CP methodology.[42]

The fairness of AMPCO's High 5 proposal is challenged by EDA based on the likelihood that it will shift cost recovery from end-use transmission customers that can shift load to the end-use customers of LDCs that cannot as easily shift load away from transmission peaks. EDA claims that this result is unfair. EDA also asserts that the end-use transmission customers shift their demand in response to energy price peaks and if these peaks coincide with transmission peaks, then these customers will be getting a "free ride" on the transmission network related to the transmission costs that are shifted to the customers of LDCs.[43] CME asserts that the customers of LDCs will see their transmission charges increase as a result of the High 5 proposal, and thus adversely impact their members that are served by LDCs. This is acceptable to CME as long as these customers receive a net benefit when also considering energy cost savings.[44]

EDA also asserts that cost recovery is related to investments that have already been made (i.e., sunk costs) and that cost recovery should follow cost incurrence principles.

By focusing only on five peak days, HONI notes that the High 5 proposal will allocate costs based on customer usage on the hottest or coldest days and thus allocate more costs to weather-sensitive heating and cooling customers.[45]

### 2.2.3 Comments on Dr. Sen's Econometric Analyses

AMPCO's quantitative presentation consists of two primary elements: econometric analyses by Dr. Sen and the use of these estimates and shadow prices to estimate the impact of changes in transmission prices on customers' shifts in load and on HOEP. Dr. Sen performed two analyses: an estimate of the price elasticity of demand and an estimate of the impact of changes in demand on the HOEP.

---

[41] AMPCO Evidence in Docket EB-2008-0072, January 14, 2009, page 2.
[42] VECC Final Argument, page 49.
[43] EDA Final Argument, pages 7-8.
[44] CME Final Argument, Redacted, page 37.
[45] HONI Reply Argument, page 53.

With respect to the demand equations, VECC and HONI each expressed concern with the validity of Dr. Sen's price elasticity analyses.[46] They observed that the "R-squared", a measure of the ability of the explanatory variables to explain variations in demand for electricity, were low (ranging from 0.3009 to 0.4877 for the three industrial sector estimates that were relied upon to calculate load shifts).[47]

VECC noted that Dr. Sen's specification did not appropriately test the High 5 proposal because it did not look specifically at the peak hour in the five peak days, but used 12-hour averaging for on-peak demand and prices and for off-peak prices. As a result, VECC claims that the approach cannot be relied upon to estimate load shifting.[48]

VECC provided several other comments on Dr. Sen's analysis. Most critically, VECC suggests that the demand equation may not be properly specified and may be subject to bias as the price elasticity coefficient would change, a result of not including important explanatory variables.[49] HONI raises a technical econometric concern, namely that the two independent price variables, the on-peak and off-peak prices are not independent.[50] [51] VECC also questions the specification of the equation relied upon to estimate the impact of demand on HOEP. VECC notes in particular that the natural gas price coefficient exhibits an incorrect sign relative to the hypothesis that an increase in natural gas prices would decrease the demand for electricity.[52] HONI noted the relatively low R-squared for this equation and asserted in response to a rationalization proffered by AMPCO, that this was not a result of a small sample size, that 244 observations can be considered to be a large sample.[53]

Finally, VECC suggests that some level of desired load shifting may already have occurred as OPA introduced demand response programs in 2007, the same year as data used by Dr. Sen to estimate his equations. There was a discussion during the oral hearings as to whether the benefits of the High 5 proposal based on 2007 data resulted in any double counting attributable to the introduction of demand response programs during 2007.[54]

---

[46] VECC Final Argument, page 46; HONI Reply Argument, page 53.
[47] AMPCO Undertaking J6.3, page 2.
[48] VECC Final Argument, page 46.
[49] VECC Final Argument, pages 46-47.
[50] HONI Reply Argument, page 53.
[51] This condition is referred to in econometrics as multicollinearity. The consequence of multicollinearilty is that minor changes to the model or data can change the coefficients significantly, increasing the uncertainty with respect to the coefficients.
[52] VECC Final Argument, page 48.
[53] HONI Reply Argument, page 53.
[54] VECC Final Argument, page 48.

### 2.2.4 Comments on AMPCO's Shadow Price Calculations

VECC questions AMPCO's implicit assumption that the 29 MW of demand reduction will occur during all 1,476 summer hours and not only for the 300 hours used in arriving at a shadow price of $102.80/MWh. VECC claims that this 29 MW reduction, when averaged over all summer peak hours, results in a demand reduction of only 5.9 MW.[55]

VECC also challenges AMPCO's methodology by asserting that AMPCO has failed to reflect the fact that current transmission rates only apply in the peak period. According to VECC, AMPCO should have included the current peak period transmission shadow price when calculating the percentage increase in price to be experienced by customers. VECC calculates a current peak period transmission shadow price of $42.84/MWh for customers that are billed based on their coincident peak and $8-$9/MWh for customers subject to the 85% ratchet.[56]

### 2.2.5 Other Comments on AMPCO's Proposal

HONI asserts that the cost shift may have been underestimated by AMPCO, citing a 12CP analysis that it had performed in EB-2006-0501 as a point of reference. In that case the analysis indicated that end-use transmission customers would see their charges decrease by approximately 15% while LDC charges would increase by approximately 2 %. HONI suggests that the cost shifting would be even greater under a 5CP methodology. HONI also expressed its belief that the approximately $0.9 million of cost-shifting estimated by AMPCO is based solely on load shifting and does not include impacts resulting from changing the methodology.[57] A change in the charge determinants for all LDCs (and not just HONI) as a result of the High 5 proposal would likely have dramatic impacts on the cost responsibility among all customers.

Several implementation issues were also raised during the proceeding. There appears to be an understanding that a mid-year implementation date may be impractical as the implementation may take place after winter peak hours that are among the five highest peaks have occurred. There are also questions about how to establish a charge determinant for new customers that begin taking service in the middle of the year.

CME has suggested that implementation be accompanied by a monitoring and reporting mechanism to test the hypothesis that energy prices will be reduced as a result of the

[55] VECC Final Argument, page 47.
[56] VECC Final Argument, page 47.
[57] HONI Reply Argument, pages 52-53.

High 5 proposal.[58] HONI questions whether it is possible to design a reliable monitoring and reporting mechanism.[59]

Finally, there were questions raised regarding the comparability of similar approaches that AMPCO asserts are being employed within the PJM and ERCOT regions. A brief overview of this experience is presented in Appendix B.[60]

## 2.3 Critical Assessment of Arguments Made Regarding the High 5 Proposal

This section provides our perspective regarding the arguments made by the parties regarding the High 5 Proposal. In the following Chapters we evaluate the technical merits of the methods employed by AMPCO to estimate the benefits of the High 5 proposal. Our critical assessment of AMPCO's methods is provided in subsequent chapters. Power Advisory met with representatives from AMPCO, VECC and HONI to supplement its understanding of the AMPCO proposal and the concerns that have been raised.

### 2.3.1 Consistency with Cost Responsibility Principles

As discussed in Section 2.1, AMPCO claims that the High 5 methodology will allocate fixed transmission cost responsibility more efficiently and fairly. Others dispute this assertion as described above in Section 2.2.

Network transmission facilities are "common facilities", implying that all customers use the system, requiring the selection of a cost responsibility methodology that reflects joint usage and the respective demands placed on the system by customer classes. This is accomplished in the rate setting process in the cost allocation and rate design steps. The primary criterion regulatory agencies, including the OEB, use to determine an appropriate cost responsibility methodology is cost causality. This concept of cost causality assigns responsibility to customers and rate classes in accordance with their contribution to the costs that have been incurred to serve them.

Transmission costs are almost entirely fixed costs associated with the return of and on invested assets that last forty years or longer. The transmission system is designed to meet peak demands across the network and additions or modifications are based on

[58] CME Final Argument, Redacted, page 38.
[59] HONI Reply Argument, page 54.
[60] As each market has unique characteristics, Power Advisory has included Appendix B for informational purposes only.

network studies that consider growth in demand by area and the need to connect and integrate new generation resources.

The methodology used to determine cost responsibility must reflect the particular circumstances of the network.[61] AMPCO asserts that investment in HONI's transmission network is "largely determined" by system peaks that occur during relatively few months. However, HONI's transmission system does not peak at the same time in every area and regional peaks frequently occur on days that vary from the system peak days. Under these circumstances, a High 5 methodology would potentially provide an incentive to avoid a system peak, but transmission investment in the region may be driven by local circumstances. As discussed in Section 6.3, an increasingly important driver of transmission investment in Ontario is the need to connect new renewable generation, including wind and hydro resources. These resources tend not to experience their maximum output at the time of peak demands and the transmission network must be designed accordingly.

As discussed further in the Chapter 6, it is not apparent that that transmission investment is largely determined by system peaks as claimed by AMPCO. With respect to recovery of past investments, the transmission network was built to serve Ontario's transmission peak demands throughout the year and in each local region and thus the High 5 proposal is also inconsistent with the cost causality principle where costs are assigned to customers and rate classes in accordance with their contribution to the costs that have been incurred.

### 2.3.2 Shadow Prices and Elasticity Estimates

AMPCO presented analytical evidence to calculate the benefits of its High 5 proposal. The key elements of AMPCO's presentation are the estimation of shadow prices and the elasticity of demand by industry segment. Power Advisory's perspective with respect to each of these issues is discussed in more detail in Section 3.

The AMPCO shadow price analysis is subject to considerable uncertainty. The shadow price calculations, as discussed in Section 3, depend on several assumptions that reflect the efforts by customers to reduce demand in order to avoid using transmission facilities during peak hours.

[61] AMPCO cites PJM and ERCOT as examples with charge determinant methodologies that are similar to its High 5 proposal. However, the circumstances in Ontario are distinct from those in the Northeast United States and Texas.

When calculating the change in electricity prices faced by customers. AMPCO essentially assumes that the current transmission shadow price is zero, thus overstating the price change used to calculate the elasticity response. Partly as a result, the price change is over 150%, a price shock so large that it may not be appropriate to apply the econometric elasticity estimates to a price change of this magnitude.[62]

The econometric equations, as also discussed in Section 3, are also subject to criticism. Even setting aside the relatively low explanatory power of the industry-specific equations, greater effort should be devoted to addressing potential econometric model specification problems. The potential for specification errors is particularly problematic as it directly affects the elasticity estimates that are relied upon to estimate the impact on demand during the peak hours.

### 2.3.3 Impact on Energy Prices

AMPCO claims that one of the primary benefits of shifting demand from peak to off-peak hours is lower energy prices that will benefit all customers. Dr. Sen employs an econometric equation to estimate the impact of lower demand on peak energy prices. Moreover, the econometric equation used to estimate this relationship is based on a data set that does not suffer from the same shortcomings of the industry-specific elasticity equations. Nonetheless, Power Advisory believes that an econometric model does not properly analyze the impact of relatively small changes in total demand. Power Advisory's analysis indicates that the commodity cost savings from the High 5 proposal would be one-twentieth ($600,000) to one-quarter ($2.4 million) of the value estimated by AMPCO.

### 2.3.4 Transmission Cost Shifting

AMPCO's analysis focuses exclusively on transmission cost shifts that result from load shifting by direct connect customers. However, as noted by Hydro One in EB-2008-0272, there are two potential sources of cost shifting resulting from the High 5 proposal: (1) from customers shifting load from peak to off-peak hours, and (2) from simply changing the charge determinant methodology.[63] AMPCO addressed only the first impact. As discussed in Chapter 4, this is a critical shortcoming.

With respect to load shifting impacts, AMPCO estimates that load shifting customers will save approximately $900,000 per year, representing the amount of cost responsibility that

[62] The estimated price elasticities are based on a data with prices that are well below the shadow price estimates and it may not be appropriate to apply the elasticities to prices outside of this range.

[63] Hydro One Reply Argument, pages 52-53.

must be shifted to other customers in order for Hydro One to recover its revenue requirement. However, as discussed in Chapter 4, the transmission cost shift impacts from changing the methodology are quite dramatic and many times larger than the impact from load shifting, approaching $20 million of transmission network costs that would be shifted from direct customers and power stations to LDCs and their customers.

Thus, the transmission cost shifts from a change in methodology are clearly much more significant than those that result solely from load shifting. A central question is whether or not LDCs have the ability to respond to this impact by promoting load shifting by their customers. There may also be some ability for LDCs to reduce their peak demands by implementing new demand response programs or modifying existing programs. However, it often takes time to design and implement new programs or make significant changes to existing programs, and customer interest also ramps up over time.

In order to provide a direct incentive for customers of LDCs to reduce their transmission costs by load shifting, the LDCs would have to implement new rate designs to align Ontario's transmission network service rate design with the rate design for recovery of transmission costs from LDC customers. This alignment of rate designs will result in larger rate increases for customers that consume a greater percentage of their power during the five peak hours relative to other LDC customers, thus exacerbating any rate impact concerns. Until this step is undertaken, rate designs for large industrial customers that are directly connected to the transmission system would be significantly different from rate designs for industrial customers served by LDCs, raising potential competitive and fairness concerns.

### 2.3.5 The Demand Ratchet

Demand ratchets serve to provide a boundary around a customer's demand determinant when the customer is subject to wide swings in demand throughout the year. These ratchets provide a degree of stability to the costs paid by these customers, by other customers, and to the utility revenue stream as well. In this instance, the demand ratchet ensures that customers that place their peak demand on the transmission network, but not at the time of the monthly coincident peak, will continue to pay a significant portion of transmission costs. The ratchet captures the fact that the transmission system has been built over time based on the need to meet system peaks but also to meet the peaks of large customers, regardless of when those peaks occur. The ratchet is designed to reflect this and results in a fairer rate design as customers that are subject to the ratchet will contribute to recovery of costs incurred to serve them.[64] The fairness issue was recognized by the OEB in approving the ratchet in Proceeding RP-1999-0044:

> The fairness issue of recovering the sunk transmission system costs therefore becomes important. Exclusive reliance on the coincident peak method where some customers may be able to withhold demand in that period while others do not have such opportunity will result, in the Board's view, in unfairness. . . . . Under the OHNC proposal (the higher of the customer's demand coincident with the system peak and 85% of the non-coincident peak demand), concerns about free ridership and gaming are somewhat reduced.[65]

Moreover, the argument that a ratchet mutes the price signal holds true only if transmission investments are driven largely by the need to serve system peaks. As discussed above, investments in the transmission network are also driven by local peaks and by the need to connect new generation.

#### 2.3.5.1 Promoting Demand Response

AMPCO claims that the High 5 rate design methodology will promote demand response. Power Advisory finds that there is merit to this claim and that it is supported to some extent by the response experienced in ERCOT. However, in ERCOT the transmission cost responsibility methodology is but one aspect of a comprehensive approach to managing system costs in a system that is clearly summer peaking. Indeed, the primary focus of customers within ERCOT, and the present focus of customers in Ontario, is to reduce demand during periods when energy prices are highest. To the extent that the transmission peaks occur at similar times, and costs are allocated based on these transmission peak hours or days, then the High 5 methodology would reinforce and be consistent with the strong incentive already provided by electricity pricing to reduce demand at these times. This contribution would be a marginal increase in demand response. Similarly, while the current rate design provides an incentive to shift loads from peak to off-peak hours, as pointed out by the EDA, the High 5 rate design methodology may increase such actions on the margin.

There is also the related matter as to whether customers are driven almost entirely by energy prices and would receive a "free ride" in the form of lower transmission costs as a result of implementation of the High 5 methodology. To the extent that reduced demand

[64] The ratchet also reflects the benefits that accrue to customers as a result of having the transmission system being available to meet their high demand hours, regardless of when they might occur.
[65] May 26, 2000 OEB Decision, page 44.

charge determinants for certain customers do not impact transmission investments, the free-rider concern is present.

The Ontario Power Authority (OPA) is actively involved in developing Ontario's demand response capabilities through several programs. One of the most significant of these, Demand Response 3, is administered by the IESO and is aimed at reducing load during certain periods of the year.[66] It is a contract-based program with customers being compensated both for being available to reduce load and then for actual load reductions. As of May 1, 2010, the OPA reports that approximately 20 participants have contracts to provide 554 MW of capacity. This program is currently under review. The OPA also administers several other programs including Demand Response 2, a contract program designed to promote load shifting from on-peak to off-peak periods.[67] It is possible that customers would try to optimize their participation in Demand Response 2 along with efforts to avoid peaks if the High 5 proposal is adopted.

Two key questions, in Power Advisory's view, are (1) whether a desire for increased demand response should be pursued by changing the transmission network charge determinant methodology, and (2) whether the High 5 methodology is most appropriate to accomplish this end. The use of a transmission cost allocator is one instrument that may impact demand response but with other unintended consequences including cost shifting to customers that either do not currently see the price signal in their retail rates (e.g. customers of LDCs) or do not have the capability to modify their demand on relatively short notice. There may be other, more targeted approaches that accomplish greater demand response in a more efficient manner and without such unintended consequences.

The implementation of a rate design that does not allow similarly situated customers the same opportunity to respond to the price signal also raises fairness concerns, at least until such time as LDCs can adjust their own rate designs. If and when LDCs align their own rate designs with the transmission network service rate design, the impact is likely to fall heaviest among heating and cooling customers. To the extent that heating and cooling loads are driving transmission investment, then this would not necessarily be a fairness concern, but could lead to rate shock, requiring the OEB to implement the change over an extended time period.

---

[66] For more details, see http://www.ieso.ca/imoweb/consult/demandresponse.asp

[67] OPA's programs are described at http://www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=147

In summary, Power Advisory believes that the impact on demand response should be considered to be but one aspect of establishing an appropriate transmission cost responsibility methodology and should not necessarily be the determining or a primary consideration. Rate design balances a myriad of objectives and is one of the most important responsibilities of a regulator.[68]

#### 2.3.5.2 Hydro One Revenue Implications

It appears that the High 5 methodology will result in greater revenue stability to HONI, and no party claimed that this would not occur. However, there are potential adverse consequences that should be taken into account.

First, the High 5 proposal is likely to affect the cash flow of customers that shift load. These customers would incur costs to shift load, but not receive the benefits in the form of reduced transmission costs until the following year. Presumably customers would consider this when assessing whether to shift loads in response to the High 5.

Second, with respect to Hydro One's ability to recover its revenue requirement, there are issues here as well. Under the current approach, Hydro One is at risk to the extent that the actual demand differs from the forecast of demands used to design rates. This is a common approach used by regulated utilities, absent a form of true up, such as rate decoupling. The proposed High 5 methodology would provide more certainty in the recovery of the approved revenue requirement by requiring the recalculation of rates each year, using the High 5 demands from the prior year and the most recently approved transmission revenue requirements.[69] However, the greater revenue certainty does not necessarily imply that the earned return will be more stable as the likelihood that revenues and costs will change in the same direction may actually be reduced. For example, an increase in demands placed on the transmission network from extreme weather may lead to greater unplanned outages of equipment that requires maintenance, repair or replacement that exceed the budgeted amounts. Under the High 5 proposal there would be no corresponding increase in transmission network revenues to offset these increased expenses.

[68] Common rate design objectives include economic efficiency, fairness, rate continuity, and promotion of conservation and other policy objectives. With respect to the notion that different rate components should be determined independently of one another, this is not always the case. For example, the limitations on customer charge increases impact revenue requirements to be recovered from other rate components.

[69] Transcript Volume 6, page 20.

There are transition issues as well in moving from the current methodology to the High 5 methodology. For example, the methodology could not be adopted right away as you need the 5CP data from a complete year in which customers understood the consequences of a change to the High 5 methodology. Typically, significant changes in rate design are communicated to customers prior to their taking effect. In this case, customers could have already experienced one or more High 5 hours before a mid-year change in rate design, eliminating any opportunity that they might have had to change their behavior with full knowledge of the consequences of not doing so.[70] As noted in a recent National Regulatory Research Institute rate design publication, "[c]ustomers should (a) know about changes to their rates or new rate options and (b) understand how to minimize their bills under new rates." [71]

There is also a more practical concern. The determination of the High 5 hours, and network charge determinants would not be available until some time after the beginning of the year. As it is possible that a High 5 hour could occur in January or February, it is important that the new rates be established as early in the year as possible. If this can only be accomplished with a hearing process, in order for stakeholders to comment on the calculations, then this becomes problematic.[72]

[70] AMPCO acknowledges that customers would need advance notice before the new rate design was implemented. Transcript Volume 6, page 148-149.

[71] "How to Induce Customers to Consume Energy Efficiently: Rate Design Options and Methods", Adam Pollock and Evgenia Shumilkina, NRRI, January 2010.

[72] This has been an issue in ERCOT where proposed rate determinants for the upcoming year are the subject of litigation.

# 3. Review and Assessment of Potential Load Shift

A key element of our assessment of the likely effects of AMPCO's High 5 proposal is our evaluation of the reasonableness of its methodology for estimating the impact of the High 5 proposal on electricity demand in Ontario. The estimates of the magnitude of the impact depend on the savings customers expect from changes in their demand levels (the "shadow price"), and their degree of responsiveness to such expected savings (the "elasticity").

This Chapter first reviews the concept of a shadow price and its application to the analysis of the High 5 proposal. Then it considers elasticities by reviewing the available literature, critically analyzing the empirical estimates made by Dr. Sen for AMPCO, and recommending elasticities to be used in the analysis. Finally, the chapter computes the amount of load that the industrial users can be expected to shift in response to the implementation of the High 5 proposal and compare these estimates to AMPCO's.

For our analysis of the potential load shift and its impact on electricity prices, Power Advisory used the same three-step approach as AMPCO did:

- First we calculate a perceived transmission price ("shadow price") as an addition to the energy price, to which customers would react;
- Second, we apply estimated elasticities to determine an amount of load that customers would shift out of peak periods in order to avoid the High 5 hours; and
- We estimate the impact on the commodity electricity price (HOEP) of that amount of reduction in peak demand. This last step is in Chapter 5 of this Report.

However, Power Advisory's methodologies to arrive at the values to be used in each of those steps differ from AMPCO's, and therefore our values also differ. We also differ from AMPCO in not using single point estimates either for the shadow price or for the elasticities to calculate shifted load, so that we produce a range of outcomes, both of shifted load and of price impacts.

As indicated by the load data presented by AMPCO, its members are already focusing their load in off-peak hours. Data presented by AMPCO show that four of the five industries in their study have higher average demand in off-peak than in on-peak hours.[73]

[73] AMPCO, Undertaking response, Exhibit J6.3. The table on pg. 3 shows average peak demand and the table on pg. 4 shows average off-peak demand for the five industries. The only one with higher peak than off-peak demand is petroleum refining.

This suggests that AMPCO members have already moved load out of the high-priced peak periods and into low-priced off-peak periods. As a result, there may be less scope for further load shifting than if the customers had not already faced time-differentiated prices in the IESO-administered Ontario market.[74]

However, it is clear that industrial electricity customers do respond to changes in electricity price. As a recent report from EPRI stated, "[b]usinesses have demonstrated the ability to alter their daily routines to adjust electricity usage under a time-varying price schedule."[75] EPRI notes they can do this by shifting the time of production, either within the same production period or from one time period to another. But the study notes that the nature of the production process can temper the demand response, as for example if production is continuous and costly to stop while the price increase is only for one hour.[76] These considerations suggest that the number of hours each customer will reduce demand in a day will depend on its particular circumstances of process, equipment and work force.

For a study in New York, 119 large customers were asked what strategies they employ during periods of high price, conservation appeals, and NYISO emergency events. Less than half of these (44) were manufacturing customers. Only 22% of the total said that they would shift usage from one time period to another and "[s]ome industrial customers reported shutting down plants or buildings or altering their production processes."[77] If most of the customers who report shifting load were manufacturers, then about half of the manufacturing operations are able to shift load from one time period to another. This study did not specify the time periods from which shifting occurred. The more advance warning the company has of a coming high price period, the greater its response to the price change.

## 3.1 Shadow Price

Chapter 2 reviewed AMPCO's High 5 proposal and methodology for quantifying the benefits from its implementation, including its use of a "shadow price" to represent the

---

[74] In its review of the elasticity literature, EPRI commented on one study showing that its current estimates of price elasticity were below those of 25 years earlier. They suggest this could be due to California's aggressive programs of energy efficiency, conservation and load control. Electric Power Research Institute (EPRI), "Price Elasticity of Demand for Electricity: A Primer and Synthesis", Palo Alto, CA: January 2008, 1016264, pg. 26. (The EPRI Report)

[75] Ibid., pg. 5.

[76] Ibid, pg. 3.

[77] Nicole Hopper, Charles Goldman and Bernie Neenan, *Demand Response from Day-Ahead Hourly Pricing for Large Customers,* LBNL 59630, April 2006. http://eetd.lbl.gov/ea/emp/reports/59630.pdf, pg. 6.

price that customers would impute as the average value to them of reducing their demand by one kW in order to achieve a reduction in their network transmission charge determinants.

In mathematical economics, a shadow price is the value of relaxing a constraint in an optimization problem.[78] In simple terms the shadow price is the value to a firm of one more unit of a resource. This is not its market price; it is its value to the firm, which must at least equal the market price of the input if it is to be used. From this interpretation, the concept of a shadow price has been extended by economists to denote a value for an input or resource that is not directly observable. In the Ontario electricity market, for example, the locational marginal prices computed by the IESO are called shadow prices; they are not directly observable.

AMPCO's use of the term "shadow price" stretches the concept, because this is a constructed price. Its use reflects the analytical need for a price that customers can use in their decision-making regarding shifts in their electricity demand in response to the High 5 proposal's change in network transmission charge determinants. It is intended to represent the savings that a customer expects to realize by reducing its consumption by one MW for one hour. The price must be constructed because the reductions happen in terms of peak power demand, measured in MW (or kW as used in the Ontario transmission rate schedule), and the resulting network transmission charge to the customer will be calculated as a per-MW cost times the demand in MW at the peak times. The charge to the transmission customer is therefore denominated in \$/kW-year while the shadow price is denominated in \$/MWh.

However, it is difficult to measure customers' reaction to changes in prices per kW of peak demand. The existing literature and the data available to AMPCO for its empirical estimations all deal with customers' reactions to changes in energy price. Therefore, it is necessary for this analysis to convert the expected reduction in transmission cost per peak kW into a price per MWh.

### 3.1.1 Challenges to Estimating Shadow Prices for Network Transmission Charges

There is considerable uncertainty regarding estimation of shadow prices. The basic problem is twofold:

- The consumer cannot know when its reduction in demand will actually affect its network transmission costs, and

[78] See, for example, Kelvin Lancaster, *Mathematical Economics*, (MacMillan, 1968), pg. 35.

- The effect on the customer's network transmission costs will not be felt until some time well after the reduction in demand.

As a result, the shadow price calculation depends on two critical assumptions: how many days the customer will need to reduce its demand in order to have reasonable assurance of hitting the days on which the High 5 hours occur, and for how many hours it will have to reduce demand on each of those days in order to have reasonable assurance that it will have reduced demand at the time of the system peak.

Therefore, the computation of a shadow price is subject to considerable uncertainty, reflecting the uncertainty the customer faces with respect to the success of its efforts to reduce its billing determinants. Even if a customer has excellent day-ahead forecasts of the level of demand, it cannot tell which days will include the peak for that year, so it must reduce demand on those days which are likely to include one of the High 5 hours. For example, if the IESO forecasts that a hot day in mid-May will have the peak demand for that year to date, the customer cannot know whether subsequent days in July and August will have higher demand or not, and so must balance its cost of rescheduling operations in order to reduce demand against the return if the May day does prove to have one of the High 5 hours. The same uncertainty holds through several months of the year. In essence, the customer's best decision is to reduce its load while being uncertain that it had actually achieved the desired reduction in billing determinants.

Power Advisory believes that this uncertainty regarding when the High 5 will occur may cause some industrial customers to be reluctant to reduce demand in an effort to capture the High 5 hours. Customers may find that the risk of missing some of the High 5 hours makes the savings too uncertain to offset the costs associated with the number of required load reductions.

During the proceeding, AMPCO changed the number of hours it used in the computation of the shadow price. The AMPCO report[79] calculated the shadow price based on reductions for four hours per day. AMPCO used twelve hours per day as the period over which the customer would benefit and therefore the period to calculate the shadow price in its response to a VECC information request, reiterated this use in the hearing, and used it again in a transcript undertaking.[80]

[79] AMPCO "The Benefits of Improvements in Transmission Rate Design", EB-2008-0272, pg. 8.
[80] EB-2008-0272, Exhibit 1, Tab 17, Schedule 14, pg. 2 and Transcript, v. 6, pg. 73, and Transcript undertaking, Exhibit J6.3 pg. 2.

Given this uncertainty regarding the number of hours that customers would need to reduce their load to capture the High 5 hours, Power Advisory believes that the analysis of the demand response should use a range of values to calculate the shadow price, rather than the single value proposed by AMPCO.

The center of this range should be a reasonable estimate of both the number of hours and number of days on which customers would need to reduce demand to ensure that they reduce their High 5 demand.[81] The other values should then reflect a reasonable range of customer behavior.

### 3.1.2 Hours Required for Load Shift

We now discuss the number of hours that customers can be expected to shift load.

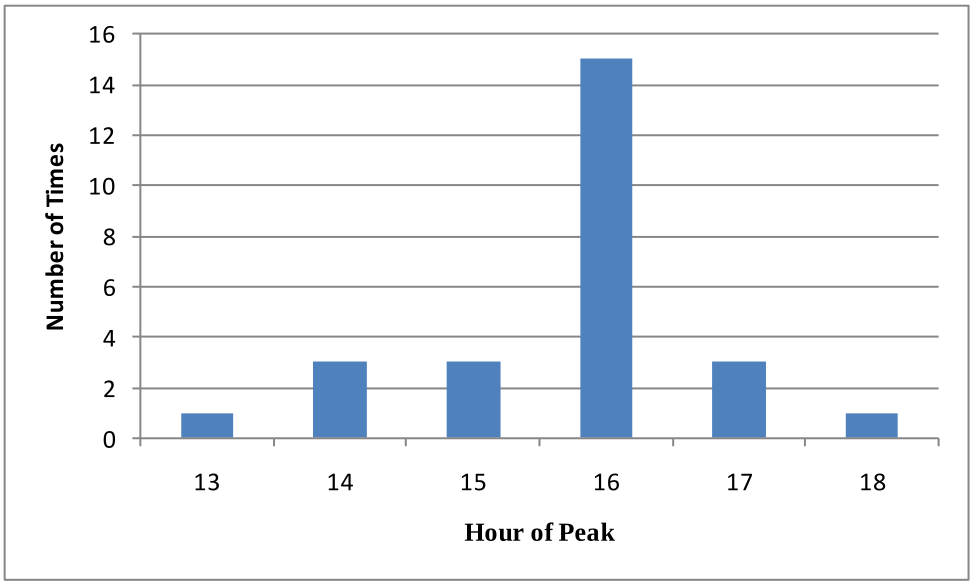
There are two primary determinants of the number of hours that customers will shift load to avoid the peak: (1) the load shape during peak days and the uncertainty regarding when the peak is likely to occur, with flatter loads around the peak hour potentially requiring a longer duration load shift so as to avoid the peak period; and (2) operating practices and processing requirements of the industrial customer (e.g., the labour intensiveness and the storage capabilities for inputs of the process that would be rescheduled). We first review the implications of Ontario's load shape during peak days to assess the implications for the number of hours that customers would have to reduce loads to avoid the peak hour and then review the operating practices and processing requirements.

As shown by Figure 2, the summer High 5 load has occurred in six different hours since 2003, but typically occurs at 4 PM. High 5 hours rarely occur at 1 and 6 PM (about 4% of the hours each) and are more common at 2, 3 or 5 PM (about 12% of the hours for each). To increase the likelihood of capturing the High 5 hour, one would expect the industrial customer to reduce its load for all six of these hours. However, by reducing load at 2 PM through 5 PM industrial customers would avoid most (all but 8% for the summer period from 2003 to 2009) of the High 5 hours. This analysis suggests that if customers were seeking to ensure that they avoided all the potential High 5 hours they would pursue a 6-hour load reduction.

[81] In fact, Power Advisory believes that the number of hours that demand would need to be curtailed is likely to vary depending on demand conditions during that day, with a longer duration reduction required for the annual peak given the greater potential for the peak hour to shift as a result of load reductions and sudden changes in weather (e.g., thunderstorms).. However, for the purposes of this analysis we are using an average value.

Another consideration regarding how long a load reduction is required to avoid the High 5 hours is the shape of the load curve during peak days. If the load curve is particularly flat during the peak period then reducing load in a few hours could cause the peak load hour to shift. The larger the load shifts produced by the High 5 and by demand management programs sponsored by the OPA and Ontario LDCs which target the peak hour the more likely such a load shift is to occur. Power Advisory reviewed the anticipated duration that would be required for a 300 MW load reduction from the High 5 and various demand management programs. This analysis suggested that a four to six hour load reduction was likely to be required during most High 5 days to avoid shifting the peak.

**Figure 2: Incidence of Hour of Summer High 5 Load**




Source: Power Advisory analysis of data from IESO

A second factor influencing the duration of load reduction will be process and staffing considerations. For example, if some firms have batch processes taking a full shift, they might be able to reduce demand by rescheduling a full 8-hour shift. While this might be difficult on relatively short notice, like a day ahead, in some cases it may be less costly for the firm to reschedule a shift than to suspend production activities in the middle of a shift (as would be required for a 4-hour reduction). An AMPCO witness (Mr. MacDonald of Gerdau Ameristeel) said that, for his firm, a four-hour period was typical, though it could be more or less.[82] An outside range of shifting would be to reschedule an entire 8-hour shift.

Power Advisory chooses three periods for time shifting: four, six and eight hours. As discussed above, six hours represents the load shifting period likely to capture the High 5 hour if the shift occurs on a day containing a High 5 hour. A company willing to take a higher risk of missing the High 5 hour in order to avoid the cost of rescheduling activities could capture over 90% of the High 5 hours by shifting load for a four-hour period. The maximum period represents rescheduling a full work shift and a high likelihood of capturing the High 5 hour.

#### 3.1.3 Days Required for Load Shift

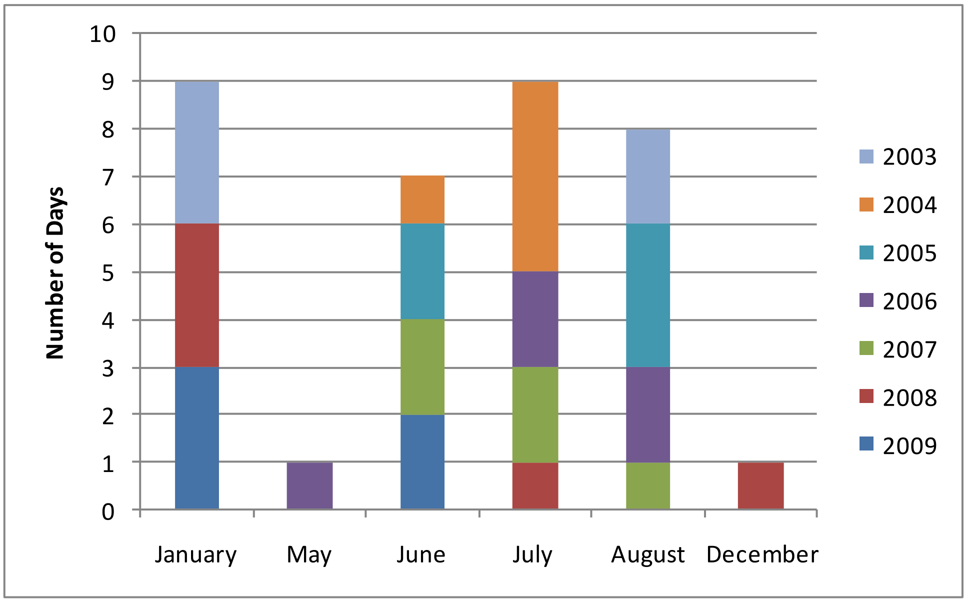
To estimate the days we consider how many days are candidates for the High 5. A review of the days when the High 5 demand has occurred provides insights regarding the potential difficulty for customers of capturing all of the High 5 hours. As indicated by Figure 3, High 5 demands have occurred in six different months from 2003 to 2009. These High 5 demands typically occur in January, June, July and August, but have also occurred in May and December. With Ontario becoming a more predominately summer peaking system, six of the nine High 5 demands for January occurred in 2003 and 2004, suggesting that in the future there is lower probability of a High 5 demand occurring in January.

With High 5 demands spread over so many months, there is a greater likelihood that customers will miss one or more of the High 5 demand hours in a year. While 2009 demand was anomalous given economic conditions, it does provide an indication of the difficulty of anticipating peak demands. Three of the High 5 peaks were in January and these peak loads were 500 MW below the winter peak forecast, suggesting that these were by not driven by extreme weather conditions. This indicates that customers would have missed these High 5 Hours given that they would not have anticipated High 5 peak demands in January that were 500 MW lower than the forecast winter peak.

Another factor contributing to the difficulty of anticipating the High 5 hours is that peak loads are predominantly weather driven. In a year with particularly mild summer weather, a High 5 load hour could be experienced in May or September.

[82] AMPCO, "The Benefits of improvements in Transmission Rate Design, pg. 8, and EB-2008-0272, Transcript v. 6 pg. 27.

**Figure 3: Number of Days by Month when High 5 Demand Occurred from 2003 to 2009**




Source: Power Advisory analysis of data from IESO

Power Advisory estimated the number of days that a customer would have to reduce load to capture all of the High 5 hours. Specifically, we estimated the mean and standard deviation for the range of loads between the annual peak and the fifth highest daily peak load and then estimated the MW difference such that there would only be a 10% probability of being exceeded.[83] We then calculated the number of days on which there were peak loads within this range. On average there were 17 days from 2003 to 2009, but in 2009 and 2006 there were only six and four days, significantly reducing the average. This analysis doesn't consider forecast uncertainty associated with estimating daily peak loads. Considering this uncertainty would increase the number of days when customers would need to reduce load to capture the High 5 hours.

To provide a second estimate of the number of days on which customers would likely be required to reduce load, Power Advisory evaluated weather data. Recognizing that summer peak loads are driven by high temperatures, we estimated the average number of days that the daily peak temperature is likely to be within about 3.5 degrees C of the average seasonal peak.[84] This is projected to produce the same difference in load (i.e.,

[83] This produced a range of 1,912 MW between the annual peak and the fifth highest High 5 hour.
[84] The 3.5 degrees C was derived by dividing 1,912 MW (estimated range between the annual peak load and fifth highest High 5 hour) and 550 MW/degree C which is an estimate of the temperature sensitivity of peak loads in Ontario.

range between the annual peak and the fifth highest High 5 peak) as produced by the High 5. We evaluated weather data for Hamilton given that it is generally reflective of weather conditions in Southern Ontario which is summer peaking. There were about nineteen days where the peak daily temperature in Hamilton was within 3.5 degrees C of the average seasonal peak. This suggests industrial customers would need to reduce load on about nineteen days to ensure that they capture the High 5 hours and this doesn't consider the potential for High 5 peak loads to occur during the winter period or the forecast uncertainty.

Figure 3 shows that the High 5 days are most likely to occur during the summer from June to August. These three months would have 65 days (13 weeks) of weekdays, of which two are holidays making 63 non-holiday weekdays. Peaks have also occurred with extreme weather in January and May. Assuming they would most likely be in the last week of May and in the second week of January potentially adds another 10 non-holiday weekdays. That gives a total of 73 candidate days. In some years, extreme weather could also occur in September or other parts of January, so some customers might choose reductions outside of those 73 days.

Clearly, the minimum number of days that a customer would have to reduce demand is 5, but a realistic minimum must be more than that. Gerdau AmeriSteel indicated that they typically shutdown their plants in New Jersey fifteen times during the summer period, but in New Jersey the period for establishing transmission charge determinants is limited to June through September.[85] With assistance from the IESO or from commercial services offering to identify peak days, customers might be able to be more accurate than AMPCO's assumption of five days of reduction for each High 5 day. A modest improvement might be to 4 days, for a total of 20, consistent with the results of our statistical analysis. This is our central estimate.

We assume a low estimate of 15 days and a high estimate of 25 days, which is consistent with AMPCO's estimate.

The upper limit to the number of hours of reduction is therefore 8 hours per day for 25 days, or 200 hours. The central estimate is 20 days for 6 hours, for a total of 120 hours.

The low estimate is 20 days for 4 hours a day. However, 20 days covers less than a third of the non-holiday weekdays in June through August, leading to a possibility that the customer would not be reducing demand in one of the High 5 hours. Recall that a 4-hour

[85] EB-2008-0272, Transcript, v. 6, pg. 27

load reduction would capture the peak 92% of the time and the estimate of the number of days during which load reductions would be required was based on a 90% probability of capturing the fifth High load hour. Forecast errors and other uncertainties should also be considered. Therefore, in calculating the shadow price for the low estimate, we have assumed that the customer counts on getting only 4/5 of the benefit and therefore has a shadow price that is 80% of the shadow price calculated by dividing the network transmission cost savings by the number of reduction hours. Table 3 calculates the resulting shadow prices which constitute the high, central and low estimates of shadow price. The table also compares Power Advisory's shadow prices with those offered by AMPCO.

**Table 3**

**Shadow Price Calculations**

| | Network Transmission Charge ($/MW-year) | Hours/ day | Days | Total Hours | % High 5 Hours Captured | Shadow Price ($/MWh) |
|---|---|---|---|---|---|---|
| **Power Advisory** | | | | | | |
| High | $30,840 | 4 | 15 | 60 | 80% | $411.20 |
| Center | $30,840 | 6 | 20 | 120 | 100% | $257.00 |
| Low | $30,840 | 8 | 25 | 200 | 100% | $154.20 |
| **AMPCO** | | | | | | |
| Report | $30,840 | 4 | 25 | 100 | 100% | $308.40 |
| IR Response | $30,840 | 12 | 25 | 300 | 100% | $102.80 |
| Testimony | $30,840 | 12 | 25 | 300 | 100% | $102.80 |

This table provides high, central and low values of shadow prices for use in the calculation of the amount of demand which can be shifted by the large industrial customers. The Power Advisory shadow prices are all above the price used by AMPCO in its final calculations, but below the price offered in its report.[86] However, all but the high price are below the shadow price first offered by AMPCO. This is due to AMPCO's switch from 4 to 12 hours per day for the period of benefit for the computation of the shadow price, while Power Advisory has used a range of days and hours per day.

## 3.2 Elasticity Estimates

This section first considers what type of elasticity (e.g., elasticity of substitution or own-price elasticity) would be appropriate to estimate the load shift from implementing

[86] EB-2008-0272, Exhibit 1, Tab 17, Schedule 14, pg. 2 and Transcript, v. 6, pg. 73, and Transcript undertaking, Exhibit J6.3 pg. 2.

AMPCO's High 5 proposal. It then critically reviews the methodology used and the elasticities estimated by AMPCO's expert Dr. Sen to determine if they provide a reasonable basis upon which to estimate the load shift. We then consider the results available from the literature, starting with Ontario-specific and industry-specific estimates and including for comparison estimates of elasticities for US industrial consumers. Finally we recommend elasticities for use in the calculation of the impact of the High 5 proposal on electricity demand in Ontario.

Dr. Sen estimated elasticities by estimating single-equation regressions using econometric techniques on Ontario-specific electricity load and price data obtained from the IESO. Dr. Sen estimated demand equations for five industries (pulp and paper, metals, iron and steel, motor vehicle manufacture and petroleum refining) from which he derived empirical estimates of price elasticity and applied those estimates to the industry demand to estimate the load shift.

### 3.2.1 What Elasticities to Use

Elasticity is a measure of the responsiveness of one economic factor to changes in another. Own-price elasticity is the relative change in demand for a good to a change in its own price, often stated as

$$\eta_p = (\text{\% change in demand}) / (\text{\% change in price}).$$

For businesses, the elasticity which measures their response to changes in the relative prices of their inputs is the elasticity of substitution, which is the relative change in demand for an input to the relative change in price of another input. It can be given by the formula[87]

$$\eta_{s12} = \{d(Q1/Q2) \div Q_1/Q_2\} \div \{d(P2/P1) \div P_2/P_1\},$$

where $Q_1$ and $Q_2$ are the quantities of the inputs 1 and 2, respectively, and $p_1$ and $p_2$ are their prices.

In the case of substitution of electricity at one time period (peak) for electricity at another time period (off-peak), the elasticity of substitution is the (% change in the ratio of peak/off-peak demand)/(% change in off-peak/peak price) and the formula becomes

$$\eta_s = \{d(Qp/Qo) \div Q_p/Q_o\} \div \{d(Po/Pp) \div P_o/P_p\}$$

where $Q_p$ is the quantity of electricity used at peak, $Q_o$ is off-peak electricity, and $P_o$ is the off-peak and $P_p$ the on-peak price.

87 EPRI Report, pg. 9.

Unlike own-price elasticity, the elasticity of substitution focuses on the relative changes in ratios, not in levels. Elasticities of substitution describe how a firm's input mix changes as its input prices change while the firm's output is held constant.

Empirical analyses of the effect of time-differentiated electricity pricing define electricity as different products when taken at different times, as it is in the formula above for elasticity of substitution. Businesses can be expected to view peak and off-peak electricity as substitutes for each other.

The elasticity of substitution between peak and off-peak electricity describes their response to the relative price change.

For the analysis of the AMPCO High 5 proposal, the appropriate elasticity is therefore the elasticity of substitution between peak and off-peak electricity.[88] It is not appropriate to use own-price elasticities, because they only measure the change in electricity that occurs with price change, not the reallocation of electricity usage to different times. Own-price elasticities allow all production conditions to change, including the firm's level of output.

Estimation of the elasticity of substitution starts with a model which places the appropriate restrictions on the equations. Once such a model is specified, econometric analysis of the firm's behavior as prices change allows an empirical estimation of the elasticity of substitution. A model that is often used for such estimations is to assume a production function with inputs that include electricity at various times as separate inputs. Then the firm is viewed as choosing an optimal level of expenditures on electricity which it allocates to the different electricity products.[89]

[88] Power Advisory also discussed this question with leading experts in elasticity and load research, including Bernie Neenan, Vice President of EPRI and principal author of EPRI's report *Price Elasticity of Demand for Electricity: A Primer and Synthesis* and Prof. Dean Mountain, Director of McMaster Institute of Energy Studies, author of the articles and report cited below and formerly load researcher for Ontario Hydro. When consulted by Power Advisory, these experts agreed that the proper elasticity for this case is the elasticity of substitution. We also consulted Prof. Carol Dahl, Professor in the Division of Economics and Business, Colorado School of Mines, who maintains extensive bibliographies and summaries on estimated energy demand elasticities from the literature and who has provided the US Department of Energy with compendia of elasticity estimates.

[89] See, for example, J. Zarnikau, "Customer Responsiveness to Real-Time Pricing of Electricity, *The Energy Journal*, 1990, v. 11 no. 4, pp. 99-116 or Dean Mountain, "A Quadratic Cobb-Douglas Extension of the Multi-Input CES Formulation", *European Economic Review*, 1989, v.33, pp 143-158.

We use caution in applying the elasticity of substitution,[90] because the AMPCO High 5 proposal is not a simple case of time-differentiated pricing such as the ones underlying the empirical estimates in the literature. Under time-differentiated pricing, customers know in advance what price they will pay. Under the AMPCO High 5 proposal, the effective price at the time of load shifting is not known until well after the fact. The customer is substituting off-peak for on-peak energy in response not to a change in their relative energy prices but to a change in the anticipated impact on the demand charge, which for analytical purposes we are treating as a change in relative electricity prices. In order to accomplish this substitution, the customer must also make other changes in its production arrangements.

In essence, customers have to incur costs in the hope of reducing costs (i.e., reducing the relevant network charge determinants and the resulting network transmission charges). Customers' willingness to reduce demand to reduce these charges will be affected by the degree to which they believe that can reduce their demand in the High 5 hours. Therefore, the elasticity of substitution estimates which don't consider this uncertainty may overstate the appropriate elasticity estimate to be used in this analysis.

### 3.2.2 Discussion of Dr. Sen's Methodology and Results

We first consider whether Dr. Sen's results present elasticity estimates that are reliable for the purpose of estimating load shifts.

Dr. Sen's study could not directly assess the reaction of customers to the High 5 proposal. Instead, it estimates the change in electricity demand averaged over 12 hours to changes in prices averaged over 12 hours. It used data from the Ontario market, which does not have the same price certainty as the real-time pricing and critical peak pricing programs forming the basis for other studies of customer reactions. The price averaging technique smoothes out much of the more extreme variations in price so it does not allow direct analysis of the impact on demand of short-lived periods of high price, which is what the High 5 proposal would produce.

Dr. Sen's approach implicitly has prices for electricity at two different times, on-peak (from 8 AM to 8 PM) and off-peak. Two definitions of off-peak are used: electricity purchased from 8 PM to 8 AM and electricity purchased during the 4 hours from 8 PM to midnight.

Because the regressions were run in double-log form, the estimated coefficients can be interpreted as elasticities. The coefficient of the current price is the own-price elasticity.

[90] In this case caution is exercised bv bracketing the elasticity estimates in our calculations.

The coefficient of the lagged price variable shows the effect of the average price lagged by one period.

Dr. Sen's approach makes the results of questionable value for the purpose of calculating the amount of load shifting. Chief among the problems is the lack of a properly formulated production function to constrain the system and the failure to consider that the response to price change is to change the ratios of the inputs. The customer is reacting to a change in the relative price of two of its inputs by rebalancing their use, shifting away from the one that became relatively more expensive and towards the one that is now relatively cheaper. At the same time, we are assuming that the customer plans to maintain its total output, which places a restriction on the way that the substitution occurs.[91] To represent this situation properly requires development of a production function in a form consistent with the assumptions.[92] Dr. Sen failed to construct any production function and therefore places no constraints on the results. As one result of this lack of constraint, Dr. Sen's results lead to AMPCO's computation of less load shifted into the off-peak period than was shifted out of the on-peak period. This would imply that the customer is reducing its output in response to the transmission price increase, which violates the assumptions of the analysis.[93]

Even if we were to accept Dr. Sen's approach as valid, several of its aspects call into question the robustness and degree of statistical bias of these elasticity estimates. Many of these points were made by other participants in EB-2008-0272, as we detailed in Section 2.2.3 of this report. These results are questionable for several reasons:

- The omission of explanatory variables can in part explain the relatively low observed $R^2$, as Dr. Sen agreed.[94] It also can lead to bias in the estimated coefficients if the included variables are positively correlated with the omitted variables and therefore pick up some of their effect.[95]
- There is multicollinearity[96] because the independent variables are correlated with each other, but Dr. Sen did not report the degree of correlation.[97] Multicollinearity

[91] An alternative assumption is that the customer has a fixed electricity budget and rebalances to keep within it. This assumption requires a different specification of the production function and model to be estimated.
[92] A form that is often used is the constant elasticity of substitution (CES) production function.
[93] This could also occur if the companies have and use their own generation facilities, but that is generally not the case in Ontario.
[94] EB-2008-0272, Transcript, v. 6, pg. 47
[95] Robert S. Pindyck and Daniel L. Rubinfeld, *Econometric Models and Econometric Forecasts*, Second Edition, 1981, p. 129.
[96] Multicollinearity occurs in an econometric estimation when two independent variables are highly correlated with each other, The consequences of multicollinearity are difficulty in identifying properly the

can make the coefficient estimates suspect in relation to each other. As Dr. Sen said at the hearing, multicollinearity makes it very hard to disentangle the effect of lagged from current prices.[98] In response to an information request from VECC, AMPCO agreed that there is multicollinearity but said that it had been dealt with appropriately by clustering.[99] However, clustering does not address the main problem of the consequent unreliability of the coefficient estimates due to the multicollinearity.[100]

- Dr. Sen's estimated coefficients are not robust under different estimation time frames and different specification of the independent variables.

In some empirical investigations, the degree of reliability of particular coefficient estimates is of lower importance than, for example, the reliability of the entire equation (or system of equations) for forecasting. In this case, however, the intent of the econometric investigation is to discover a quantitative relationship between the dependent and independent variables (i.e., the estimated coefficients) in order to calculate the effect of changes in the independent variables (the prices) on the dependent variable (the amounts of electricity used). The reliability of the specific coefficient estimates is therefore important.

Table 4 shows the estimated coefficients as reported, first in Dr. Sen's report (using 4-hour averaging of off-peak prices), second in response to a request from VECC and finally as reported in a transcript undertaking.[101] The first set of results uses a four-hour price averaging period for the off-peak price; the second set of results uses a twelve-hour averaging period for the off-peak price; the third set of results does not specify which off-peak price data are used.

AMPCO used the results of this econometric estimation to obtain quantitative estimates of elasticities to use in a further computation of the amount by which customers would reduce their on-peak demand on those days when they did reduce. Therefore, the value

relative effects of the independent variables and coefficient estimates that become very sensitive to changes in the data chosen. See, for example, J. Johnston, *Econometric Methods*, 2nd Edition, 1972, pg. 160.

[97] AMPCO response to IR from VECC, EB-2008-0272, Exhibit 1, Tab 17, Schedule 4, pg. 7

[98] EB-2008-0272, Transcript, v. 6, pg. 50

[99] AMPCO response to IR from VECC, EB-2008-0272, Exhibit 1, Tab 17, Schedule 4, pg. 7. In this response, AMPCO also said "The way to mitigate any error in standard errors of coefficient estimates is to cluster them by day, which was done." Addressing errors in the standard errors of the coefficient estimates only affects the level of statistical significance ascribed to them, not their values or their degree of bias.

[100] See Joshua D. Angrist and Jörn-Steffen Pischke, *Mostly Harmless Econometrics*, Princeton University Press, 2009, pp 308-09.

[101] EB-2008-0272, AMPCO Report, "The Benefits of Improvement in Transmission Rate Design", Ex. 1, Tab 17, Schedule 2 and Exhibit J6.3, pg. 2.

of the estimated coefficients, which are the quantitative estimates of the elasticities, matters; an elasticity estimate that varies by a factor of two means that the results will vary by a factor of two.

**Table 4**

| Elasticities as Estimated by AMPCO | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Estimated with 4-hour Averaging Off-peak prices | | | Estimated with All Off-peak Hours Averaged | | | Final Estimates | | |
| | | Industry | | | Industry | | | Industry | | |
| Year | Variable | Pulp and Paper | Metals | Iron and Steel | Pulp and Paper | Metals | Iron and Steel | Pulp and Paper | Metals | Iron and Steel |
| 2007 | $P_t$ | -0.226 | -0.045 | -0.044 | -0.163 | -0.012* | -0.023 | -0.234 | -0.043 | -0.0469 |
| | $P_{t-1}$ | 0.0969 | 0.058 | 0.025* | 0.098 | 0.037 | 0.028 | 0.103 | 0.056 | 0.026* |
| 2006 | $P_t$ | -0.259 | -0.021* | -0.037 | -0.207 | -0.001* | 0.002* | -0.263 | -0.022* | -0.0358* |
| | $P_{t-1}$ | 0.133 | 0.097 | 0.097 | 0.11 | 0.078 | 0.064 | 0.136 | 0.096 | 0.093 |

By this criterion, these estimated coefficients are generally not robust, either across years or across variable definitions. These estimates are not robust when using the different time frame for averaging prices. AMPCO uses the 2007 estimates for the current price elasticities to compute the amount of load shifted. For the three industries for which shifts were computed, the estimated 2007 current price elasticity with the 12-hour averaging of the off-peak price is from 27% to 72% of the estimate using 4-hour averaging of the off-peak price. They are also not robust between the two time periods of 2006 and 2007. The 2007 elasticity estimates given in the undertaking response and used for the calculation of shifted load are, respectively, 89%, 195% and 131% of the 2006 estimates from the same source.

Relative to some econometric results, these cross-price elasticity estimates are not highly unstable. They retain their signs throughout and do not differ by an order of magnitude. However, taking the two sets of results together, the lagged price elasticity estimates for pulp and paper range from 0.0969 to 0.133, those for metals from 0.037 to 0.097 and those for iron and steel from .025 to .097. This means that the estimated load shifted would differ by a factor of from about 1.4 to about 4. No one of these estimates is therefore a reasonable point estimate of the elasticity.

### 3.2.3 Ontario Empirical Studies

In looking for elasticity estimates to use for the computation of the potential load shifting, it is preferable to use Ontario-specific results, and particularly results which relate to

Ontario industries.

Ontario Hydro had an active program of load research, much of it led by Dean Mountain, who is now Director of the McMaster Institute of Energy Studies and a Professor at McMaster University.[102]

As in other jurisdictions, many of the pricing experiments in Ontario have been aimed at residential customers. Professor Mountain (with Ken Deal) recently compiled a report for the IESO surveying the available information on demand responsiveness in Ontario.[103]

Deal and Mountain concluded that, although the direct evidence on elasticity in Ontario is sparse, a reasonable range of elasticities of substitution for industrial customers would be from 0.035 to 0.24.[104] For industrial customers with interruptible processes and their own generation, own-price elasticity would group around a value of -0.27.[105]

Table 5 below summarizes the results of load research performed by William Cheng and Dean Mountain for Ontario Hydro in 1993.[106] This is the one study we found with estimates of elasticities of substitution for individual industries in Ontario. Because it was performed by Ontario Hydro, this research had access to individual customer data for all of the directly connected (large wholesale) industrial customers in Ontario. Confidentiality considerations make such data access difficult today. The study estimated elasticities of substitution under time of use rates for Ontario industries ranging from 0 to .38, with the majority of the estimates in the range of .05 to .11.

A recent study for the Fraser Institute[107] used a similar methodology to that of Dr. Sen for AMPCO. It obtained data from the IESO on industrial electricity consumption and hourly prices and estimated demand as a function of lagged demand, price (HOEP plus

[102] Power Advisory discussed with Professor Mountain the available literature on empirical estimates of elasticities of electricity demand in Ontario.
[103] Ken Deal and Dean Mountain, "Assessing Whether Firm Day Ahead Prices Lead to Changes in Elasticity of Demand and Greater Customer Efficiencies" April 2008 (Draft).
[104] Deal and Mountain, op. cit., pg. 23.
[105] Ibid.
[106] Cheng, William and Dean C. Mountain (1993), "Econometric Study of the 1992 Time-of-Use Impact on Direct Industrial Customers," Product Testing and Analysis Department and Economics and Forecasts Division, Ontario Hydro, mimeo, pg 13. Also cited in Deal and Mountain, op. cit, pg. 14.
[107] Gerry Angevine and Dara Hrytzak-Lieffers, "Ontario Industrial Electricity Demand Responsiveness to Price," Fraser Institute Technical Paper, Sept. 2007.

hourly uplift[108]) and a set of monthly dummies. The $R^2$ from these estimates were uniformly much higher than those obtained by Dr. Sen, which is largely explained by the addition of the lagged dependent variable. Table 6 below shows the estimated coefficients and own-price elasticities (calculated by Power Advisory) from that study.

**Table 5**

| Industrial Elasticity Estimates for Ontario: 1991 | | | |
|---|---|---|---|
| Industry | No. of Customers | Morishima Elasticity of Substitution | Allen Own-price Elasticity |
| Mining | 23 | 0.107 | -0.053 |
| Paper and Allied Products | 24 | 0.074 | -0.053 |
| Non-Metallic Mineral Products | 13 | 0.050 | -0.021 |
| Refined Petroleum and Coal | 5 | 0.000 | 0.000 |
| Chemicals and Chemical Products | 17 | 0.027 | -0.009 |
| Primary Metals | 8 | 0.120 | -0.037 |
| Transportation Equipment | 4 | 0.000 | 0.000 |
| Total | 106 | 0.083 | -0.050 |

Source: Cheng and Mountain, "Econometric Study of the 1992 Time of Use Impact on Direct Industrial Customers", Ontario Hydro, mimeo, March 1993, pg. 13.

**Table 6**

| Price Response Estimates for Ontario | | | | |
|---|---|---|---|---|
| | Own-price coefficient Period | | On-peak own price Elasticity | |
| Industry | May-Jul 2003 | Jun-Aug 2006 | May-Jul 2003 | Jun-Aug 2006 |
| Iron and steel | -0.042 | -0.038 | -0.108 | -0.111 |
| Metal Mining | -0.004 | -0.017 | -0.012 | -0.057 |
| Pulp and paper | -0.058 | -0.105 | -0.102 | -0.271 |
| Motor vehicle manufacturing | -0.002 | -0.007 | -0.015 | -0.063 |
| Petroleum products | 0.000 | 0.000 | 0.000 | 0.000 |
| Other | -0.012 | 0.004 | -0.030 | 0.012 |
| Total | -0.102 | -0.141 | -0.051 | -0.088 |

Period 1 = May 2002-July 2003
Period 2 = June 2005 -August 2006
Source: Angevine and Hryutzal-Lieffers, 2007

[108] The paper defines hourly uplift to include congestion management charges, operating reserve charges, intertie offer guarantee costs, and transmission losses, all of which are referred to as wholesale market service charges.

Because this equation was run in linear form, its estimated coefficients cannot be interpreted as elasticities. Instead, Power Advisory computed elasticities from these estimates at the apparent mid-point of the demand curve, the point usually chosen for such computations.[109] The table shows computed own-price elasticities ranging from 0 to -.27 for the identified industries.

In one respect, these two studies are consistent with Dr. Sen's: electricity use is not responsive to electricity prices in the Ontario petroleum and refining industry and the motor vehicle manufacturing industry. Both Angevine and Cheng and Mountain find zero elasticity estimates for petroleum refining, consistent with Dr. Sen's results. Cheng and Mountain also find a zero elasticity for motor vehicle manufacturing, while Angevine estimates an elasticity which is the lowest or second-lowest. These results are reasonable given the nature of the industries. The refining industry uses processes which run best as continuous processes and stopping the process just to save on electricity costs may not be economic. The motor vehicle (transportation equipment) industry also runs continuously during any scheduled shift. If it is not already running three shifts a day, it could save electricity costs by shifting some production from peak to off peak hours. But such a shift would produce other costs and probably could not readily be a reaction to an upcoming period of high electricity prices.

### 3.2.4 Elasticities of Substitution from the Literature

Before choosing elasticities to recommend for use in Ontario, Power Advisory considered the estimates available in the more general literature to ensure that our recommendations are consistent with findings elsewhere.

The most directly relevant results from the literature would come from empirical analysis of a case very similar to the AMPCO High 5 proposal. Power Advisory found no studies in the literature for a case like the AMPCO High 5 proposal. Therefore, we reviewed the most relevant studies in the literature.

A good starting point for this review is the EPRI Report [110] which surveyed a number of studies specifically aimed at the response of industrial and commercial customers to critical peak pricing (CPP), real- time pricing (RTP) or time-of- use pricing.[111]

[109] The computation is an approximation, because the available data were not sufficient to allow computation of the mean of the dependent variable.
[110] EPRI Report
[111] Richard Boisvert, Peter Cappers, Bernie Neenan, and Bryan Scott, *Industrial and Commercial Customer Response to Real Time Electricity Prices,* Neenan Associates, 2004. In this case, RTP refers to price

The elasticity of substitution which is the most applicable to the High 5 proposal is that of CPP experiments, in which customers are given low off-peak rates in return for agreeing to a certain number of hours in the year when rates will be set very high – five to ten times or more the off-peak rates – in order to induce them to reduce demand.  This is similar in concept to the High 5 proposal, in that it assigns a very high value to electricity in a limited number of hours in a year.  It differs from the High 5 proposal in that the cost consequences are considerably more certain; the critical peak price is set in advance and customers are given firm advance notice of when a CPP period will occur.  As discussed, this is a critical difference which is likely to result in higher elasticity estimates than are appropriate for the High 5 proposal.

The next most relevant studies would be those which looked at customer reaction to prices which can change hourly to levels specified in advance; these are called real time pricing (RTP) experiments.  Customers here know with certainty the value of reducing their usage during the peak times.   Power Advisory also found studies looking at customer reaction to time of use prices, in which customers are given time-differentiated prices that are fixed both in level and time of application.

Power Advisory did not find many studies with industry-specific estimates of elasticities of substitution, which is consistent with other survey findings.[112]  The literature mostly analyzes reaction to CPP and RTP at the customer class level, with some breakdowns to aggregated industries.

Table 7 summarizes the results in the EPRI Report from all the studies which reported elasticities of substitution for industrial customers.  Even this comprehensive report only found six separate such studies.[113]

**Table 7**

regimes where customers do not directly pay the real-time price in the market but they are informed in advance of periods of high prices.  The information includes the prices they will pay in the high-price period.

[112] EPRI, op. cit.

[113] The EPRI report surveyed 57 studies and reported elasticities from 19 of them; only 5 had elasticities of substation for commercial and industrial customers.  All the TOU results were for residential customers.

| Estimates of Elasticity of Substition for Commercial and Industrial Customers | | | | | |
|---|---|---|---|---|---|
| Study No | Treatment | Elasticity interval | Elasticity of Substitution | Customer Size | Data Dates |
| 1 | CPP | peak hours | 0.06 | 20<kW<200 | 2003-04 |
| 2 | DA RTP | peak hours | 0.1-0.18 | >1 MW | 1998-2001 |
| 2 | HA RTP | peak hours | 0.2-0.27 | >1 MW | 1998-2001 |
| 3 | DA RTP | aggregate hours | 0.04 | >1 MW | 1994-1999 |
| 3 | DA RTP | between days | 0.03 | >1 MW | 1994-1999 |
| 4 | DA RTP | peak hours | 0.16 | 2<MW<20 | 2000-2001 |
| 5 | DA RTP | aggregate hours | 0.09 | | 1985 |
| 5 | DA RTP | inter-day | 0.16 | | 1985 |
| 6 | TOU | | 0.11 | 200<kW<500 | 1980-1982 |

Source: EPRI, *Price Elasticity of Demand for Electricity: A Primer and Synthesis*, Jan. 2008

CPP= Critical Peak Pricing
RTP = Real Time Pricing
DA = Day ahead
HA = Hour ahead

Two of the studies in the EPRI Report found that the vast majority of the price responsiveness came from relatively few of the participants.[114] Roughly 75-80% of the response could be attributed to roughly 20-25% of the participants. This is taken to reflect the significant differences between companies, even those in the same industry. Assuming this pattern holds true in Ontario, it can be expected that relatively few of the wholesale customers will get significant benefits from the AMPCO High 5 proposal by changing their time of electricity use. This finding suggests that, within industries where there is response, most of the response is likely to come from a few firms.

More detail on some of the specific studies included in the EPRI Report is contained in Appendix C.

Finally, Power Advisory found an older study which had elasticities of substitution for a small number of industries. Its results are shown in Table 8.[115]

**Table 8**

[114] EPRI, op. cit, pg. 25, citing Nicole Hopper, Charles Goldman and Bernie Neenan, op. cit.
[115] Chinbang Chung and Dennis Aigner, “Industrial and Commercial Demand for Electricity by Time of Day: A California Case Study”, *The Energy Journal*, 1981, v. 2 #3, pp 91-110. Results provided by Carol Dahl.

| Industrial Elasticities | | |
|---|---|---|
| Industry | On-peak Own price | Substitution Peak to off-peak |
| Paper mill | -0.086 | 0.069 |
| Petroleum refining | -0.059 | 0.029 |
| Motor vehicle manufacture | -0.064 | 0.071 |

Source: Chung and Aigner, 1981

The elasticities of substitution estimated in the studies found range from as low as 0.03 to as high as 0.27, though most are in the range of about 0.06 to 0.16. This information will be helpful in choosing elasticities for our analysis.

### 3.2.5 Elasticities to Use for Calculation of Load Reductions

Table 9 and Table 10 summarize the available empirical estimates for elasticities for Ontario. First are the results from Cheng and Mountain, who estimated elasticities of substitution for industrial customers under time of use rates in Ontario. Then the table has the estimates of lagged price elasticity made by Dr. Sen as given in the transcript undertaking. These elasticities are not directly comparable to the Cheng and Mountain estimated elasticities of substitution, but they help inform the choice of elasticities to use in our calculation.

**Table 9**

| | Estimated Elasticities for Ontario Industries | | | | |
|---|---|---|---|---|---|
| **Source:** | **Pulp and Paper** | **Iron and Steel** | **Metal Mining** | **Refined Petroleum and Coal** | **Motor vehicle manufacturing** |
| Cheng and Mountain (elasticity of substitution) | 0.074 | 0.120 | 0.107 | 0 | 0 |
| Sen (lagged-price elasticity) | 0.103 | 0.056 | 0.026 | 0.155 | 0.016 |

Sources: Cheng and Mountain, op. cit, and Ex J6.3, pg. 2

These estimates fall within the range indicated above and within the range of elasticity estimates found in the literature and summarized above, though none is above 0.2 while the estimates from the literature did get that high. The adopted elasticities of substitution for individual industries can therefore readily fall within the overall range indicated above.

The Cheng and Mountain results are the best available empirical estimates of substitution elasticities in Ontario.[116] However, they relate to a period before industrial customers had strong incentives (in the form of hourly prices) to shift load off peak and before current demand response programs which can pay customers for such shifts. They may therefore overstate the current customers' reaction to changes in prices because there is less scope for shifting than at the time of their estimation. For that reason and because we have only a single study, Power Advisory has chosen to use a range of elasticity estimates centering on the Cheng and Mountain results. The range was chosen to be roughly symmetrical around the central estimate and to keep the elasticities within the range of the empirical estimates from the literature.

Taking all of this information into account, Power Advisory recommends the use of the range of elasticity of substitution estimates contained in Table 10. This table also contains elasticity estimates for one industry that was not included in the AMPCO study: non-metallic mineral products. This is an electricity-intensive industry for which we were able to get data from the IESO and for which the Cheng and Mountain study had an elasticity of substitution, so Power Advisory added the industry to the analysis.

**Table 10**

| | **Recommended Elasticities of Substitution for Ontario Industries** | | |
|---|---|---|---|
| **Industry** | **Low** | **Central** | **High** |
| Pulp and Paper | 0.050 | 0.074 | 0.100 |
| Iron and Steel | 0.080 | 0.120 | 0.160 |
| Metal Mining | 0.060 | 0.107 | 0.155 |
| Non-metallic minerals | 0.030 | 0.050 | 0.070 |
| Petroleum Refining | 0 | 0 | 0.020 |
| Motor Vehicles | 0 | 0 | 0.020 |

Given the consistency of the results from both Cheng and Mountain and Dr. Sen showing no (or no significant) elasticities for the petroleum refining and automobile industries, a small nominal elasticity is used for those industries only in the high case.

[116] These estimates are treated as the center of a range to reflect the uncertainty in any one estimate, especially estimates made some time ago.

## 3.3 Calculating Demand Reduction

The elasticity estimates in the table above can be combined with the shadow prices calculated earlier to produce low, central and high estimates of the amount of demand industrial customers will shift.

These estimates are reasonable for this use. Like all empirical estimates, they are highly dependent on the data used for their estimation. Since the elasticities fall within the range of estimates from other sources, both for Ontario and for industrial elasticity of substitution as a whole, they can be accepted as the basis for the calculation of load shifts.[117] We have used a range of elasticity values – all of them within the range found in the literature – to represent the uncertainty in many aspects of this study, including the elasticity estimates.

The base price for the calculation of the amount of power shifted is the sum of the HOEP at the time of shifting, the Global Adjustment (GA), debt retirement charge and wholesale market service charges (WMSCs). In addition, as VECC pointed out, customers pay a demand charge for transmission usage. Depending on whether they pay according to the 85% ratchet or according to the 12 CP, the implicit transmission shadow price is $8.50/MWh or $102.80/MWh.[118] Since Power Advisory does not know how many of the current transmission customers pay according to the 12 CP, we have included the 85% ratchet value in the base price.

Computation of the base price at peak times to be used in the analysis is shown in Table 11 below.[119] The Power Advisory computed shadow prices shown in Table 3 range from $154.20/MWh to $411.20/MWh. Relative to the HOEP, GA, debt retirement charge and WMSCs, these shadow prices produce increases in the electricity price the end-use customers respond to from more than double to about four times the base price. At least the median and upper shadow prices take the effective price to be well above the prices observed in the empirical data used to derive the elasticity estimates. The empirical results do not necessarily reflect the reaction of industrial customers to price increases that large.

**Table 11**

[117] The estimated own-price elasticity for pulp and paper is near the top of the range, close to the level that Deal and Mountain suggested could be achieved by industries with interruptible processes and their own generation. (See note 105 in Section 3.2.3 above.) The other elasticity estimates are within the range.
[118] EB-2008-0272, Transcript, v. 6, pg. 65 and EB-2008-0272, Exhibit 1, Tab 17, Schedule 14, pg. 2.
[119] Data for GA, DRC and WMSC are the averages from the IESO Monthly Reports for June, July and August of 2008, the period from which the customer load data was taken. HOEP is the average for four-hour afternoon peak hours over the same period.

| Base Price Calculations | | | | |
|---|---|---|---|---|
| Average Peak HOEP ($/MWh) | GA ($/MWh) | DRC + WMSC ($/MWh) | Current Transmission Shadow Price ($/MWh) | Total Base Price ($/MWh) |
| $ 80.02 | $3.47 | $13.29 | $8.50 | $105.28 |

One of the real-time pricing experiments described in the EPRI report did increase prices by an amount similar to the shadow price. In Study 2 from that table, the utility was allowed (with prior notice) to increase price by $380 per MWh. That experiment produced the highest elasticities among all the EPRI studies. It differs from the AMPCO High 5 proposal in that the customers were informed in advance of the price increase to be imposed, so their savings from rescheduling were not subject to uncertainty. This result suggests that the use of these elasticity estimates may not overstate the response.

These considerations suggest that the recommended elasticities of substitution can form a reasonable basis for calculating expected reactions by the industrial customers, but that they should not be considered to be firm predictions.

As the basis for the load to be shifted, Power Advisory obtained data from the IESO covering both 2008 and 2009. These data broke out demand by industry for each hour. The peak demand data in Table 12 below are for 2008 for the six industries in our calculation of shifted load.[120] The demands are averages for the same time period as used to obtain the average peak price.

Power Advisory chose not to use the data for 2009 because it is an anomalous year. Industrial demand and total Ontario demand fell rapidly through the year. Using those data would underestimate the amount of load shifting possible in a more normal year because it would start with an abnormally low base from which to shift.

The use of a range of estimates of both prices and elasticities provides a range of demand shifts that should be robust against alternative circumstances like changes in base prices and in levels of demand. Having a range of results also is a more explicit recognition of the degree of uncertainty inherent in empirical analyses and of the particular uncertainties pointed out in this analysis.

[120] The IESO has two additional industrial categories: “other manufacturing” and “other”. For the same period as shown in Table 12, these two categories had demand of 312.8 MW and 91.8 MW, respectively. They are not included in the analysis because we do not have appropriate elasticity estimates for these diverse categories. The six included industries account for over 80% of the average peak load.

**Table 12**

| Demand Shifts | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Industry | Peak Demand (MW) | Implicit Base Price ($/MWh) | Elasticities of Substitution Low | Center | High | High Five Shadow Prices ($/MWh) Low | Center | High | Demand Shift (MW) Low | Center | High |
| Pulp and Paper | 439.3 | $ 105.28 | 0.050 | 0.074 | 0.100 | $ 154.20 | $ 257.00 | $ 411.20 | -10 | -19 | -31 |
| Iron and Steel | 536.1 | $ 105.28 | 0.080 | 0.120 | 0.160 | $ 154.20 | $ 257.00 | $ 411.20 | -17 | -35 | -58 |
| Metal Mining | 517.2 | $ 105.28 | 0.060 | 0.107 | 0.155 | $ 154.20 | $ 257.00 | $ 411.20 | -13 | -30 | -55 |
| Non-metallic minerals | 65.5 | $ 105.28 | 0.030 | 0.050 | 0.070 | $ 154.20 | $ 257.00 | $ 411.20 | -1 | -2 | -3 |
| Petroleum Refining | 199.8 | $ 105.28 | 0 | 0 | 0.020 | $ 154.20 | $ 257.00 | $ 411.20 | 0 | 0 | -3 |
| Motor Vehicles | 137.7 | $ 105.28 | 0 | 0 | 0.020 | $ 154.20 | $ 257.00 | $ 411.20 | 0 | 0 | -2 |
| Totals | 1895.6 | | | | | | | | -40 | -86 | -151 |

Table 12 above shows the resulting demand shifts for the low, central and high cases. These amounts are small relative to total demand in Ontario. The summer peak demand in 2008 was about 24,200 MW, so the amount of load shifted in the high case is about 0.6% of the summer peak load. The fractions shifted in the other cases are correspondingly smaller.

The estimates for load shift in Table 12 are for the amount of load to be shifted in each hour that a shift is assumed. For the high case, for example, the amount of shift occurs in each of the 60 hours assumed for that case. This is different from AMPCO's estimate, which they state is for all summer peak hours, not just the 300 hours in which they assume that the load shifts actually take place. Power Advisory believes that AMPCO load shift assumptions that were used to establish the shadow price are totally inconsistent with its assumptions regarding the commodity cost impacts which assumes that load shift occurs for all summer peak hours.

All the Power Advisory load shift estimates are above the load shift estimated by AMPCO, though the Power Advisory shifts occur in fewer hours.[121] Some of the difference can be accounted for by the motor vehicles industry; in the Cheng and Mountain data, its elasticity of substitution was equal to that in the iron and steel industry. More generally, with the exception of the pulp and paper industry, the AMPCO elasticities are lower than those found in the literature. The elasticities of substitution used by Power Advisory are well within the range of those found in the literature.

[121] Power Advisory has reviewed the computational formula used by AMPCO to derive its load shift estimates and finds that it appears to misapply the elasticity formula.

## 4. Transmission Cost Shifting

A central element in AMPCO's proposal is that all customers will benefit as a result of adoption of the High 5 methodology.[122] The AMPCO calculus rests on the conclusion that any shifting of cost responsibility from load shifting industrial customers to other customers, estimated by AMPCO to be $0.9 million, will be more than offset by AMPCO's estimated savings to all customers of $11.3 million that result from a lower HOEP resulting from load shifts during peak hours, after accommodating for a higher HOEP during off-peak hours.[123] Power Advisory's assessment of these commodity cost savings is discussed in Chapter 5.

In this section, we present our analysis of transmission cost shifts. To the extent that transmission cost shifting is significant and even greater than the commodity cost savings, then it would contradict AMPCO's assertion that a change to the High 5 methodology will provide benefits to all customers. If a significant change in rate design is proposed, a major consideration taken into account by regulators is the magnitude of the impact on customers. A regulator may decide to reject a proposal on these grounds, or implement it over a number of years if it concludes that the change is otherwise beneficial.

### 4.1 Definition of Transmission Cost Shifts

AMPCO's analysis focuses exclusively on transmission cost shifts that result from load shifting by direct connect customers. It performs a relatively straightforward calculation of the transmission network costs avoided by customers that shift load by multiplying the reduction in load (kW) by the uniform transmission network rate ($/kW-year). However, as noted by Hydro One in EB-2008-0272, there are two potential sources of cost shifting: (1) from customers shifting load from peak to off-peak hours, and (2) from simply changing the charge determinant methodology.[124] AMPCO addressed only the first impact.

The second impact can be expected to be significantly greater than the load shifting impact as the High 5 represents a fairly dramatic change in the allocation of transmission cost responsibility from customers that have relatively high load factors to customers whose demands are highest when Ontario is experiencing peak loads. Further, the

[122] AMPCO Final Argument, pages 12-13.
[123] AMPCO Exhibit J6.3, page 5.
[124] Hydro One Reply Argument, pages 52-53.

transmission cost shift will be greatest for customers that rely on electricity for heating during the winter months and cooling during the summer months, particularly if they are not able to alter their consumption patterns. These customers tend to have lower load factors than other customers.

In fact, as presented below in Section 4.3, the cost shift resulting from a change in methodology is an order of magnitude greater than the load shifting impact.

## 4.2 Transmission Cost Shifts from Load Shifting

AMPCO's calculation of transmission cost shifting due to load shifts as well as Power Advisory's estimate, based on AMPCO's approach, is presented in Table 13**Error! Reference source not found.**, updated to incorporate the transmission network rate that became effective in January 2010 of $2.97/kW.[125] This cost shift is calculated by simply multiplying the reduced High 5 demand of customers that shift load by the uniform network transmission charge. There is no offsetting increase in costs during the off-peak period as Hydro One's network charge would only be assessed during the peak period. Applying AMPCO's methodology, Power Advisory has estimated the transmission cost shifts from load shifting as well, for the low, central and high estimates. This is also shown in Table 13.

**Table 13: Transmission Cost Shifting from Customer Load Shifts**

| | | | **Power Advisory** | | |
|---|---|---|---|---|---|
| | | AMPCO | Low | Central | High |
| Network Charge | $/kW/Mo | $2.97 | $2.97 | $2.97 | $2.97 |
| Convert To: | $/MW/Mo. | $2,970 | $2,970 | $2,970 | $2,970 |
| Convert To: | $/MW/Yr | $35,640 | $35,640 | $35,640 | $35,640 |
| Estimated Load Shift | MW | 29 | 40 | 86 | 151 |
| Transmission Cost Shift | | $1,033,560 | $1,425,600 | $3,065,040 | $5,381,640 |

[125] Hydro One has charge determinant data for 2009, but not for 2008. Power Advisory has estimated the load shift based on 2008 data because of the economic downturn in 2009. However, use of the 2009 data for transmission cost shifts from a change in methodology in Section 4.3 that follows are reasonable for estimating the magnitude of the load shift in a representative year. The precise cost shift will vary from year to year.

As shown in this table, application of the AMPCO methodology and assumptions with the 2010 Network Transmission charge results in an estimate that load shifting customers will save $1,033,560[126] per year, representing the amount of cost responsibility that must be shifted to other customers in order for Hydro One and other transmitters to recover their revenue requirement. Power Advisory estimated load shifts that are higher than those estimated by AMPCO and therefore, the cost shifts are greater, ranging from a low of approximately $1.4 million to a high of $5.4 million per year, with a central estimate of $3.1 million.

In section 4.3 that follows, Power Advisory has estimated the transmission cost shifting that occurs under the High 5 methodology in a more direct manner, by adjusting the charge determinants for direct connect customers.

Moreover, AMPCO did not consider potential load shifts by other direct connect customers (i.e., other than the five industry sectors included in their load shift analysis) or by LDCs. Other direct connect industrial customers may respond to the High 5 proposal. To the extent that customers in other industries, (i.e., other than the five industries identified by AMPCO or the six industries considered by Power Advisory) then these estimates would increase.

### 4.3 Transmission Cost Shifts from a Change in Methodology

A change in charge determinant methodology from the existing Ontario approach to the High 5 proposal will change cost responsibility for all network service customers as their respective contributions to the High 5 peaks will necessarily differ from their proportionate responsibilities based on the existing methodology.

In order to calculate this impact, Hydro One provided Power Advisory with the annual charge determinants that were in effect during 2009 for all of its customers based on the existing two-part rate design methodology described in Chapter 2, grouped into three market segments: direct industrials, power stations, and LDCs. Hydro One Transmission represents approximately 98.1 % of Ontario transmission loads and so the analysis based on Hydro One's data alone is fairly representative of the impacts from applying this approach to the aggregate of all Ontario transmitters. These charge determinants were converted to a percent cost responsibility by simply expressing each segment as a percentage of the total for all three segments. This is shown below in Table 14.

[126] This differs from the AMPCO estimate of $903,208 presented in Exhibit J6.3, page 4 due to rounding of the MW reduction to 29 MW and applying the current transmission network rate.

Hydro One also provided its estimates of charge determinants for each of the same three market segments under the High 5 methodology based on its analysis of 2009 load data. [127] These charge determinants were also converted to a percent cost responsibility by expressing each segment as the percentage of the total for all three segments. Finally, Power Advisory estimated the cost responsibility for each market segment under the existing and High 5 methodologies by applying these respective percentages to Hydro One's 2011 requested network revenue requirements of $839.7 million.[128] The results are shown in Table 14.

The High 5 impacts are calculated by applying 2009 charge determinants to 2011 revenue requirement. As implemented under AMPCO's proposal, the High 5 methodology would have 2011 revenue requirements assigned to customers based on 2010 charge determinants, or a one-year lag. For comparison purposes, however, it is most instructive to perform the analysis using load data from the same year.

**Table 14: Impact of Transmission Cost Shifting from Change to High 5 Methodology 2011 Revenue Requirements ($in Millions)**

| | Current Methodology | | | High 5 Methodology | | | |
|---|---|---|---|---|---|---|---|
| | Determinants (kW) | Proportionate Responsibility | Cost Responsibility | Determinants (kW) | Proportionate Responsibility | Cost Responsibility | Impact |
| LDCs | 221,592,973 | 90.9% | $763.6 | 100,018,607 | 94.0% | $789.0 | $25.3 |
| Directs | 19,138,492 | 7.9% | $66.0 | 6,142,364 | 5.8% | $48.5 | -$17.5 |
| Power Producers | 2,935,229 | 1.2% | $10.1 | 291,128 | 0.3% | $2.3 | -$7.8 |
| Total | 243,666,694 | 100.0% | $839.7 | 106,452,099 | 100.0% | $839.7 | $0.0 |

As shown in this table, the transmission cost shift impacts from changing the methodology are quite dramatic and many times larger than the impact from load shifting. Power stations benefit most significantly (cost responsibility decreases by $7.8 million or over 75%) as they tend to rely on station power during planned outages scheduled during off-peak months. They will be a net generator of power during peak periods and their reliance on Hydro One's transmission system diminishes greatly. The power stations require no action to realize significant cost savings. Focusing solely on the cost shifts from a change in methodology, direct customers also benefit to an extraordinary degree (cost responsibility decreases $17.5 million or 26.5%).

[127] Power Advisory has requested comparable data from the IESO to perform a comparable analysis based on this data. However, this data was not available at the time of filing of this Report.

[128] Hydro One Pre-filed evidence in EB-2010-0002, Exhibit G1, Tab 1, Schedule 1, page 2.

To estimate the transmission cost shift resulting from the combination of both load shifts and a change in methodology, Power Advisory reduced the High 5 charge determinants for direct customers based on our central estimate of load shifting or 86 MW. This is shown on Table 15. As shown in this table, the combined impact is a reduction in direct connect customer cost responsibility of $20.7 million, a reduction of power station cost responsibility of $7.8 million, and an increase in LDC cost responsibility of $28.5 million or a 3.7% total increase in network transmission cost responsibility.

**Table 15: Transmission Cost Shift Impacts from Change in Methodology and Load Shifting**

($ in Millions)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| LDCs | 221,592,973 | 90.9% | $763.6 | 100,018,607 | 94.3% | $792.2 | $28.5 |
| Directs | 19,138,492 | 7.9% | $66.0 | 5,712,364 | 5.4% | $45.2 | -$20.7 |
| Power Producers | 2,935,229 | 1.2% | $10.1 | 291,128 | 0.3% | $2.3 | -$7.8 |
| Total | 243,666,694 | 100.0% | $839.7 | 106,022,099 | 100.0% | $839.7 | $0.0 |

| | | |
|---|---|---|
| Hydro One 2011 Network Revenue Requirements | | $839.7 |
| Reduction in Direct Determinants due to Load Shifting: | | |
| | Central (MW) | 86 |
| | Central (kW) | 86,000 |
| | Times 5 for 5 High Peaks | 430,000 |
| | Revised Direct Determinants | 5,712,364 |

While the impact on network cost responsibility is significant, the impact on a residential customer's total electricity bill would be relatively small. For example, the average monthly bill for an Ontario residential customer using 800 kWh per month is approximately $120/month. This varies among LDCs, as do the individual components of the bill. Network charges represent about 60% of total transmission costs, and transmission charges represent approximately 7.5% of this total bill or approximately $9/month. Thus, based on the impact calculations above, an average LDC residential customer would see an increase in their total monthly bill of $0.20/month or $2.40/year.

However, presenting these data at the segment level masks changes in impacts among customers within each segment. For example, LDC customers that have a lower load factor relative to other LDCs will bear the greatest burden and thus, LDCs with large percentages of heating and cooling loads will bear the largest burden, but one can anticipate that some LDCs will receive network transmission cost increases well in excess of the average 3.7%.

## 4.4 Implications and Conclusions

The transmission cost shifts from a change in methodology are clearly much more significant than those that result solely from load shifting. A central question is whether or not LDCs have the ability to respond to this impact by promoting load shifting by their customers. There may also be some ability for LDCs to reduce their peak demands by implementing new demand response programs or modifying existing programs. However, it often takes time to design and implement new programs or make significant changes to existing programs, and customer interest also ramps up over time.

In order to provide a direct incentive for customers of LDCs to shift load, the LDCs would have to implement new rate designs to align Ontario's transmission network service rate design with the rate design for recovery of transmission costs from LDC customers. It is likely that this alignment of rate designs will result in large rate increases for customers that consume a greater percentage of their power during the five peak hours relative to other LDC customers, thus exacerbating any rate impact concerns. Until this step is undertaken, rate designs for large industrial customers that are directly connected to the transmission system would be significantly different from rate designs for industrial customers served by LDCs, raising potential competitive and fairness concerns.

Finally, the costs of owning, operating, maintaining and expanding the transmission system that may result from changes in use of the transmission system as a result of customers changing their load shapes are years away based on our understanding of Hydro One's current transmission plan and the relatively small impacts from the amount of load shifting that is likely to occur.

## 5. Commodity Price Impacts

AMPCO postulated that real-time hourly prices in the Ontario market would be affected by the switch of demand from one time period to another. This would occur because the generation resources needed to meet demand have varying levels of cost and the cheapest resources are used first so that prices in off-peak periods when load would increase are typically lower than in peak periods when load would decrease. AMPCO estimated that the price decrease when loads are shifted out of peak times would be $.01597 per MWh; the price increase when loads are shifted into the off-peak times would be $.00571 per MWh.[129] To obtain their estimate of the price change, AMPCO applied these coefficients to the estimate of shifted load (29 MW).

This chapter first describes the price-setting mechanism in the Ontario electricity market. Then it sets out AMPCO's and Power Advisory's methodologies for estimating price impacts of load shifting and compares results from the two methodologies.

Customers in the Ontario electricity market pay several charges. Some vary from hour to hour because they depend on the conditions of the market in any given hour and some are fixed based on average costs because they do not depend on hourly conditions or are based on other criteria than demand in each hour.

The hourly charges are

- Hourly Ontario energy price (HOEP), the price determined by the IESO through matching supply and demand; and
- Wholesale Market Service Charges (WMSC), which include both variable (such as congestion) and fixed (such as IESO administration) costs.

Charges which do not vary hourly are

- The Global Adjustment, which allocates on an average cost basis the benefits or costs from regulated prices paid for electricity from certain Ontario Power Generation assets and the costs for electricity supply contracted by the Ontario Power Authority and the Ontario Electricity Financial Corporation; and
- Debt retirement charge.

[129] Ex. 1, Tab 17, Schedule 14, pg. 3. These are the estimated coefficients from the equation explaining HOEP by, among other variables, the level of demand. AMPCO applied these coefficients to their estimated amounts of shifted load (29 MW shifted from on-peak hours and 24 MW shifted to off-peak hours) to arrive at their estimated price impacts of a reduction of $0.47/MWh and increase of $0.14/MWh, respectively. See AMPCO Undertaking Response, Exhibit J6.3, pg. 5.

Customers also pay a transmission charge according to the Ontario uniform transmission rate and their charge determinants.

In Chapter 3, to calculate the amount of load that would be shifted out of peak periods, the price we used (Table 11) included all of these charges plus the implicit amount of the transmission charge that would be imputed under current rules (or the current "shadow price" of transmission). In this Chapter, we calculate the impact on the hourly prices that would result from the load shifts that we estimated from on-peak hours when customers would curtail to capture the High 5 peaks into off-peak hours. The only element of price that will vary in this analysis is the hourly Ontario energy price (HOEP); all the other elements of price remain fixed.[130] Our interest is in the impact of a load shift on the hourly price.[131]

## 5.1 Setting HOEP

HOEP is set on the basis of offers from suppliers and demands from users, using the cheapest resources first. The market-clearing price is the bid price of the last unit of generation needed to meet the demand. As demand increases, the system operator is generally required to use more and more expensive supply resources.

The prices at which supply is offered into the market typically depend only on the marginal operating costs (variable operations and maintenance and fuel) of the supply resource. Once a resource is in place, it should be operating at any price that recovers its variable costs of operation, whether or not such costs are high enough to cover its total costs including fixed costs. The cheapest sources are those with zero or low operating costs, such as windpower or hydroelectric generation. The next cheapest source is nuclear generation, followed by coal-fired generation and gas-fired generation. At the most expensive end of the supply curve are reliability must-run resources and measures such as demand reduction, where customers are paid to reduce their electricity use.

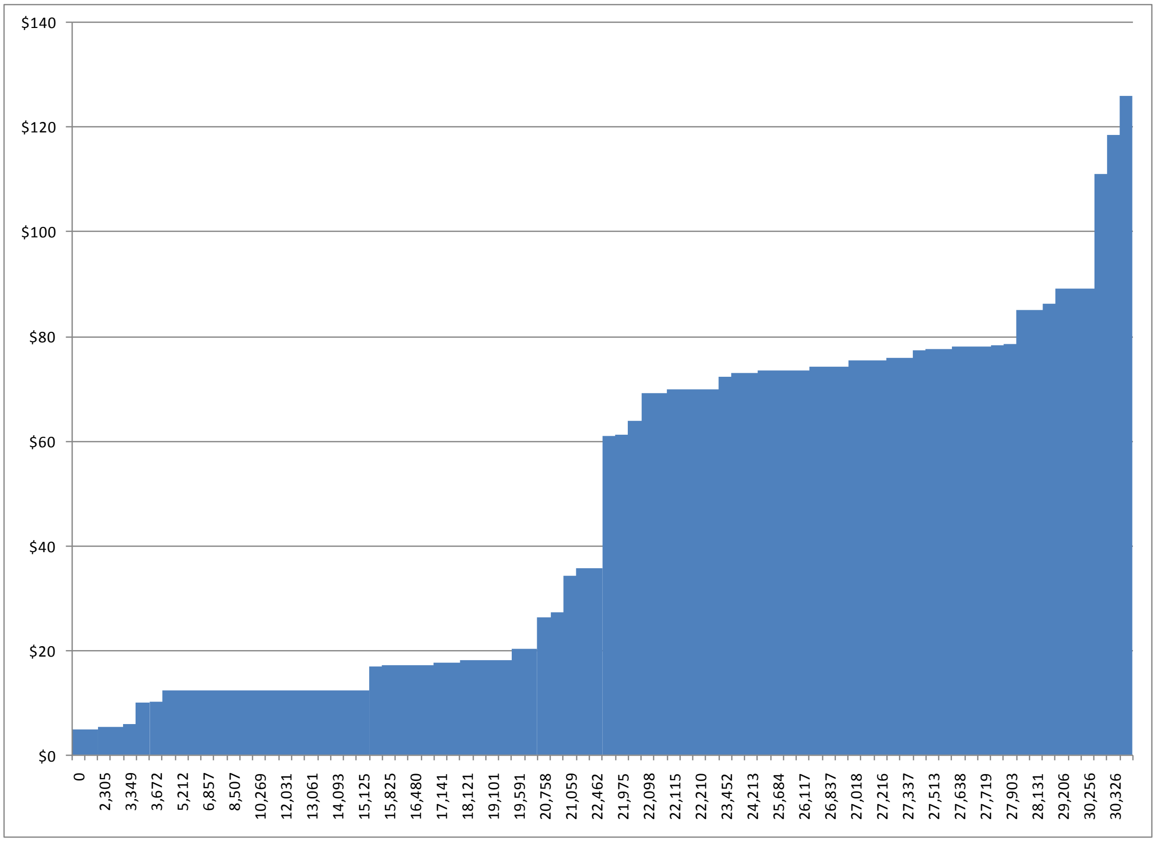
Each supply resource has amount(s) of electricity that it can supply and price(s) at which it supplies the amount(s). These price-quantity pairs can be aggregated to produce a supply curve. Figure 4 below is an illustrative supply curve for the Ontario market.

[130] Chapter 4 presented the analysis of the impact of the High 5 proposal on the transmission tariffs paid by direct customers and other customers.

[131] Note that any reduction in HOEP would, in practice in the current Ontario market, be offset at least in part by an increase in the cost to consumers of the Global Adjustment (GA). Part of the GA covers the difference between the contracted cost of some generators and their revenue from the IESO-administered market. The lower HOEP is, the lower their market revenue and therefore the more they must be paid through payments that eventually are included in the Global Adjustment. Power Advisory has not estimated this impact quantitatively, but generation assets with contracts represent about 60% of Ontario's generation.

Available capacity will vary based on scheduled and forced outages as well as the availability of variable renewable resources.

**Figure 4: Ontario Electricity Supply Curve**




This supply curve is not smooth. It has several sections that are flat or nearly so. These flat portions represent the capacity of large generation units whose marginal cost is essentially the same for their total supply. One flat portion is the nuclear fleet. There are also flat spots in the part of the supply curve representing gas-fired generation. The curve also rises in steps, reflecting the movement from one finite supply resource to another. Currently forecasted extreme weather summer peaks are about 25,500 MW. Baseload (the amount of demand present over 70% of the time) is about 15,500 MW.

## 5.2 Estimating HOEP Impacts

### 5.2.1 AMPCO's Methodology

One way to estimate HOEP impacts from load shifts is to use statistical techniques to fit an estimated equation to the observed data. The fitted equation can then be used to describe how price will react to a change in the variables that determine price, including a change in demand.  Depending on the specification of the estimating equation, the fitted curve's relation between price and demand can be more or less smooth and therefore can more or less closely match the shape of the supply curve.

The methodology Dr. Sen chose abstracts from the supply curve details and produces a smooth relationship between price and the amount supplied.  The supply curve he fitted (described in more detail in Appendix A) estimated linear relationships between on-peak price and Ontario electricity demand, exports, imports, gas price, supply mix (coal, nuclear, gas, hydro) and several dummy variables representing hours, days and months. AMPCO applied the estimated coefficients from these equations to their estimates of shifted on-peak and off-peak load to arrive at the price impacts of the shifted load.

The econometrics of these equations did not draw much attention during the OEB proceeding.  VECC noted that the sign of the gas price coefficient was negative, which is surprising since gas is a generation fuel and a higher price for it should increase HOEP. Similarly, Power Advisory observes that the gas variable has the wrong (negative) sign (though it is not significantly different from zero); that is, it indicates that the more gas generation is in use, the lower the price.  Since gas is the fossil fuel with the highest marginal cost, its presence is expected to raise HOEP, not lower it.

Another difficulty with this estimated equation is its lack of supply-side information.  In competitive electricity markets, price spikes (brief periods of very high prices due to supply shortages) typically occur in high demand periods when some supply is unavailable due either to generation or transmission failure.  Price spikes can have a significant impact on average prices.  Dr. Sen's equation cannot model price spikes.

For the purpose of the analysis of the price impact of relatively small changes in demand, the largest problem with the estimated equation is its assumption of a smooth relationship between demand and price, while in reality, as indicated by the flat portions of the supply curve, relatively small increases or decreases increases or decreases in demand would not have a significant impact on price if they occur at a point where the supply curve is flat or close to flat.

### 5.2.2 Power Advisory Methodology

A methodology which takes into account more of the operation of the electricity supply system is the construction of a model of the system.  Such models are a well-accepted methodology for understanding the consequences of changes in an electricity supply system.  For example, the models can be used iteratively to determine an equilibrium expansion path.[132] The Ontario Power Authority relied in part on a production cost model to produce its Integrated Power System Plan[133] and Navigant Consulting used such a model to forecast wholesale power prices for the Regulated Price Plan on behalf of the Ontario Energy Board.

Many system models are based on production cost. Such models contain a complete inventory of the major generation sources in the jurisdictions being modeled. The inventories describe the generation in terms of its size, fuel source and heat rate (giving a fuel cost per unit of output), its variable operating costs, and potentially other variables. Then the model simulates the operation of the dispatch function of the system operator by dispatching generation to meet changing demands in the order of their supply cost. The model will therefore dispatch low-cost generation in times of low demand, gradually adding more and more expensive generation as demand increases over the course of a day, week, or month. Such models allow exploration of the impact on market prices of changes in either supply or demand, assuming that the system is always dispatched so that the last unit of demand is met by energy from the supply sources with the lowest marginal cost and that these marginal costs are the market prices paid by and to all participants.[134]

For this analysis Power Advisory used its hourly dispatch model of the Ontario electricity supply system. Our model is similar to models employed by other consulting firms which offer wholesale market price forecasting services. We have used this model to provide electricity market price forecasts for clients.

Features of the model include:

- Single iteration dispatch, so that the model must be iterated for it to balance;
- Generators are dispatched according to their marginal cost;
- The market price produced by the model is the marginal cost of the last unit needed to meet the last MW of demand; and
- The capacity of the marginal plant is derated when its capacity is needed to meet the last MW of demand (which means that the market price will be unaffected by

[132] If the model at first shows supply shortages and consequent high prices, or on the other hand supply surpluses and low prices, the input data are adjusted by adding or subtracting generation until prices settle at a level that supports the entry of the generation needed to meet the projected demand.
[133] Ontario Power Authority, "Development of the IPSP", OEB Docket EB-2007-0707. Ex. B, Tab 3, Schedule 1, pg. 32-33.
[134] Production cost models are also capable of simulating the likely offer strategies of such resources as storage hydro, which have low marginal costs but are crucial to balancing peak demands and therefore typically use an offer strategy under which they shadow the price of gas or other expensive peaking resources.

changes in demand that are less than the amount of used or remaining capacity of the marginal unit).

Marginal costs for generators are based on their variable operation and maintenance (O&M) costs plus fuel costs. For this analysis, Power Advisory first established a baseline of results from the model. These results are forecasts of electricity prices in 2011. Then we used this baseline as the starting point against which to measure the results of the High 5 proposal. We chose 2011 as the most immediate forecast year. We note that the scheduled closure in 2014 of Ontario's coal-fired plants will affect the shape of the supply curve and could affect the savings realized in future years. After 2014, it is expected that the supply curve may become flatter through more of its range because of the removal from the supply stack of the relatively low-cost coal stations.

The analysis determined the days on which load shifts would occur by inspecting the daily loads in the model. The analysis chose the days on which the forecast hourly peak demand was the highest. The number of days on which demand was assumed to be shifted was chosen in accordance with the assumptions used for the calculation of the three (high, central, low) cases.

## 5.3 Data

For this analysis, Power Advisory obtained data from the IESO and from other publicly available sources.

The specification of generation resources in the Power Advisory model uses Power Advisory expertise, market knowledge and publicly available information on the size, fuel type, and other characteristics of generation in Ontario.

The amounts of load to be shifted come from Power Advisory's analysis in Chapter 3. These amounts of load shift used data from 2008, including prices and demands. This year was chosen because the most recent year for which data are available, 2009, was an anomalous year. Ontario electricity market demand, especially demand from the industrial sector, fell throughout the year as a result of the economic crisis. Using the actual industrial demand in 2009 as the basis for the estimation of the load shifting would therefore likely underestimate the amount of shifting that can occur.

The amounts of load to be shifted are derived from an analysis of historical data for 2008 and the analysis of the price impacts uses the Power Advisory forecast of Ontario market conditions for 2011. We used 2008 as the base year for load shifting because we have good historical data on actual demand at the industry level for that year. We focus on price impacts in 2011 given that we are interested in future year price impacts and Power Advisory has the model specified for 2011.

## 5.4 Results

The results in terms of average price impacts and the change in the commodity cost of electricity are shown in Table 16. Results are given for 2011 for the three cases described in Chapter 3. The price impacts shown are the average of the on-peak price reductions and off-peak price increases for those hours when loads are shifted. The averages are computed for the average load after the load shifts.

The total commodity cost changes were computed by multiplying the amount of load in each hour (after the load shift) by the change in commodity price (negative or positive) due to the shift. Then the average price change is simply the total commodity cost change divided by the total load in the relevant hours. For example, if in hour 16 of day 25 (a peak time) 151 MW of load is shifted off peak, reducing HOEP by $5 per MWh, and the load after the shift was 22,000 MW, then the commodity cost reduction in that hour would be $110,000. The totals are computed by aggregating these results for all hours in which load is shifted.

**Table 16: Commodity Cost Saving Estimates**

| | Commodity Cost Changes for Load Shifts: 2011 | | |
|---|---|---|---|
| Case | Average Price Impact | | Total Cost Change |
| | Reduction on-peak ($/MWh) | Increase off-peak ($/MWh) | $M |
| High | -$ 2.45 | $ 0.84 | -$ 2.44 |
| Central | -$ 0.94 | $ 0.40 | -$ 1.71 |
| Low | -$ 0.36 | $ 0.16 | -$ 0.98 |

The results show generally expected, but modest, impacts of the demand shifts. The average on-peak price is reduced in all cases, and the average off-peak price is increased in all cases. The average price reductions in the peak period are highest in the high case and lowest in the low case. The average price reductions in the off-peak periods are always lower than the average price increases in the peak periods, in accordance with the assumption that the supply curve is steeper in the on-peak than the off-peak period. The results therefore show overall savings in commodity costs for all of the cases. The highest savings are in the high case, at about $2.44 million. Savings in the central case are $1.71 million and in the low case about $980,000.

Power Advisory's estimates of the commodity cost savings from the load shift are considerably smaller than those of AMPCO, although our estimates of the price impacts are higher in the high and central cases. AMPCO says that the average reduction in HOEP during peak hours is $0.47/MWh and the average off-peak price increase is $0.14 per MWh, resulting in a net reduction in commodity cost of $11.3 million.[135] Power Advisory's estimate of the decrease in HOEP in peak hours is $2.45/MWh for the high case, $0.94 for the central case, and $0.36 for the low case, yet our estimate of the total commodity cost saving in our high case is less than one-quarter of AMPCO's.

This difference is due to our assumptions on the timing of the load shift and the cost savings. We calculated our results for the commodity cost savings occurring only in those hours when load shifting actually occurred. In our high case, for example, 151 MW of load is shifted only in 60 hours (4 hours per day for 15 days), so we assumed that prices and commodity costs were reduced only in those hours. By contrast, AMPCO applied their commodity price reduction ($0.47 per MWh) to 1,476 summer peak hours (as they calculate them).[136,137] Applying the commodity cost saving as the reduction in HOEP in each summer peak hour[138] produced a much higher total reduction in commodity cost. AMPCO's estimate of the total load for the peak hours in which the commodity cost savings occur is 27.2 TWh versus 1.3 TWh (twenty times greater) for our high load shift case and 4.1 TWh (six times greater) for our low load shift case.[139]

In some hours, the Power Advisory model showed no price impact from the load shifts. These results follow from the state of the supply/demand balance in Ontario, the shape of the Ontario supply curve, and the size of the load shifts. When the peak loads with and

[135] AMPCO undertaking response, Exhibit J6.3, pg. 5.
[136] AMPCO considers the summer months to be May, June, July and August. AMPCO considers the summer peak hours to be the 123 total days in those months times 12 peak hours per day. They do not differentiate between weekends and weekdays. See EB-2008-0272, Oral hearing transcript, v. 6, pg. 71.
[137] Therefore, it appears that AMPCO's assumption regarding the number of hours that commodity cost savings would be realized is inconsistent with their assumption regarding the required hours of load shift to capture the High 5 period.
[138] The reduction in HOEP was calculated by multiplying the shifted load (29 MW for every peak hour) by the reduction in HOEP per MW shifted (0.0159704, as estimated by Dr. Sen) to produce a reduction of $0.47 per MWh. This was applied to all load in all summer peak hours. See AMPCO Undertaking Response, Exhibit J6.3, pg. 5.
[139] Total Ontario demand in 2007 was 152.2 TWh, so AMPCO applied its estimated cost reduction to about 18% of the total load in that year.

without the load shift intersect the supply curve at a flat point (i.e., where generating unit offers don't vary significantly) there will be little price impact from the load shift. This would more typically occur in off-peak periods. However, with the significant decline in load and increases in baseload supply, this can also occur during peak periods, particularly if the marginal generating resources are combined cycle gas turbines (CCGTs) which have similar operating costs and as a result offer strategies.

The resulting excess capacity means that Ontario demand rarely reaches the right hand portion of the supply curve where the cost begins to increase rapidly. In Ontario, such resources are represented by, for example, the Lennox generating station (a gas-fired steam facility) and demand response initiatives.

These results relate to 2011. As the coal-fired plants are taken out of service, the system will come to rely more heavily on gas-fired generation, so that by 2015 it can be expected that more of the supply curve will relate to gas plants, most of them CCGTs. Combined with the expected continued slow demand growth and continued overcapacity especially in baseload generation, this will likely mean that the supply curve will become flatter at the times of system peaks. Then the commodity price effect of any shifting of load off peak can be expected to diminish.

# 6. Potential Impact of the High 5 Proposal on Transmission Deferral

As discussed in Section 2.1, one of the principal goals of AMPCO's High 5 proposal is to reduce and/or defer the need for investment in the transmission network. This chapter assesses the degree to which implementing the High 5 Proposal is likely to allow transmission investments to be deferred. We first review the conditions required for major transmission investments to be deferred, then review Hydro One Transmission's development capital budget to identify the types of projects that could be deferred and finally discuss how implementation of the High 5 Proposal might affect the need for transmission investment.

## 6.1 Conditions for Deferring Transmission Investment

There are many drivers of transmission investment. However, in the simplest terms, for the High 5 Proposal to defer transmission investment, it must result in load reductions that are greater than forecast load growth in the area that would be served by the transmission facilities.[140] This basic condition suggests the challenge associated with the ability of the High 5 proposal to defer transmission investment. In general, load growth in Ontario is driven by increasing residential and commercial requirements. Areas where there is significant industrial load growth (e.g., Woodstock) have relatively limited existing industrial load or industries with more limited potential for load shifts given operating requirements for their industrial processes. Furthermore, the areas in Ontario with significant load growth (e.g., GTA) have relatively limited concentrations of industrial load which limit the load reduction potential.

A critical factor influencing whether industrial load reductions are likely to be sufficient to defer such investments is the magnitude and type of industrial load in the area or zone where the transmission investment is required as well as the forecast of peak load growth in the area. Table 17 presents 2008 direct industrial customer annual energy consumption and average load by zone and indicates where industrial electricity consumption is concentrated and the significance of industrial consumption in each zone.[141] Figure 5 identifies these nine different zones.

---

[140] In a report prepared for the Ontario Energy Board, Power Advisory outlined a methodology for estimating the number of years that a specific transmission investment would be deferred by distributed generation (DG) by dividing the available DG capacity by the forecast load growth, with the result an estimate of the number of years that the transmission investment could be deferred. Power Advisory LLC, *Development of a Standard Methodology for the Quantification of DG Benefits*, July 31, 2008. We employ this approach to evaluate the ability of the load reductions from the implementation of the High 5 Proposal to defer transmission investments.

[141] The percent of total peak load is a comparison of the average industrial load in 2008 to the forecast energy requirements for 2010 assuming normal weather. This is a rough estimate of the significance of

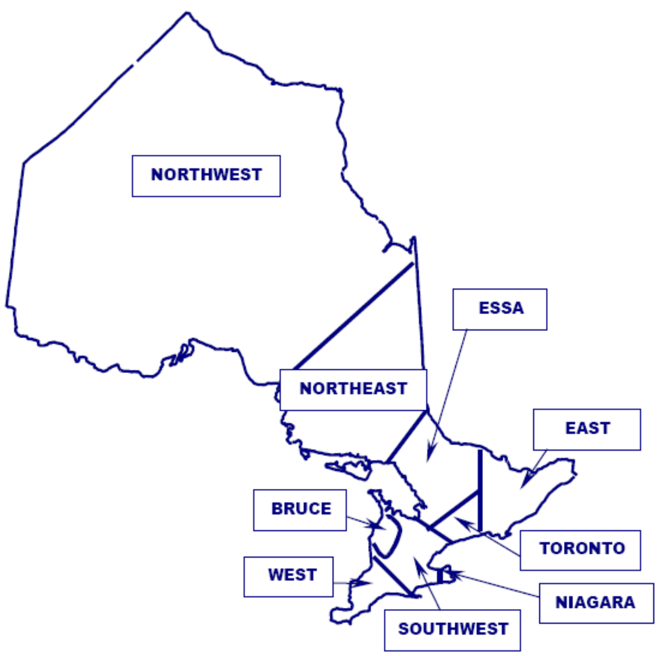
The zones with the highest proportion of industrial load and among the highest levels of industrial consumption are the Northeast and Northwest zones that each have negligible forecast load growth.[142] As such these zones aren't likely to require additional transmission investment to accommodate increased customer load which in turn could be deferred by peak load reductions achieved by the implementation of the High 5 Proposal.

**Table 17: 2008 Direct Industrial Customer Load by Zone**

| Zone | Total | East | Essa | Niagara | Northeast | Northwest | Ottawa | Southwest | Toronto | West |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 Industrial Energy (GWh) | 20,633 | 912 | 88 | 597 | 6,371 | 2,911 | 364 | 4,355 | 1,491 | 2,946 |
| % of Total | | 4.4% | 0.4% | 2.9% | 30.9% | 14.1% | 1.8% | 21.1% | 7.2% | 14.3% |
| 2008 Ave. Ind. Load (MW) | 2,349 | 104 | 10 | 68 | 725 | 331 | 41 | 496 | 170 | 335 |
| Total 2010 Forecast Energy (GWh) | 141,124 | 9,308 | 8,969 | 4,668 | 11,063 | 4,941 | 11,117 | 27,879 | 48,154 | 14,502 |
| % Indstrial Energy of Total Forecast | 14.6% | 9.8% | 1.0% | 12.8% | 57.6% | 58.9% | 3.3% | 15.6% | 3.1% | 20.3% |

Sources: 2008 Energy consumption from IESO.
2010 Forecast Energy from IESO *18-Month Outlook*, November 17, 2009, excluding Bruce Zone. Total reflects Bruce zone energy.

**Figure 5: Ontario Load Zones**




Source: IESO

industrial load in each zone. There wasn't a consistent data series so we had to use two different data series (i.e., actual industrial load data for 2008 and 2010 IESO energy forecast) from different years.

[142] In fact, the Ontario Power Authority's Integrated Power System Plan (IPSP) indicates that declines in load are forecast through 2017 for the Northwest and Northeast Zones. Integrated Power System Plan, EB-2007-0707, Exhibit D, Tab 1, Attachment 2, p. 7 of 11. Specifically, the regional peak at the time of the system summer peak in the Northwest Zone was forecast to be 927 MW in 2009 and 815 MW in 2027 and in the Northeast Zone to be 1,437 MW in 2009 and 1,388 MW in 2027.

### 6.2 Review of Hydro One's Transmission Development Budget

Power Advisory reviewed with Hydro One its transmission planning and investment process to assess whether demand reductions achieved by implementing the High 5 Proposal would likely allow Hydro One to defer network transmission investments. Hydro One Transmission's three-year capital budget and capital budgeting process are presented in its May 19, 2010 submission for 2011and 2012.[143] Its capital budget is composed of three types of projects: (1) sustaining (i.e., investments required to replace or refurbish components to ensure that the transmission system functions as originally designed); (2) development (i.e., investments required to upgrade or enhance system capabilities); and (3) operations (i.e., investments in infrastructure required to sustain central transmission operations and modifications and expansion of infrastructure to respond to new operating requirements.) This is the most complete long-term view of Hydro One Transmission's capital budget and transmission investment requirements. All of the identified development projects have in-service dates which range from 2011 to 2014. Our focus is on the development budget given that these projects can be deferred under the proper conditions.

Hydro One's transmission development capital covers funding for new or upgraded transmission facilities to:

(1) provide inter-area network transfer capability to deliver electricity from supply areas to load centers;
(2) provide adequate capacity to reliably deliver electricity to local areas;
(3) connect load customers and generating stations;
(4) maintain the performance of the Hydro One transmission system;
(5) develop and implement solutions to better utilize the existing infrastructure; and
(6) upgrade the infrastructure to connect renewable generation.[144]

The capital budgeting drivers for each of these six different types of transmission investments and additional subclasses of transmission investment are discussed below. These investment drivers offer insights regarding whether the High 5 Proposal may allow such investments to be deferred.

Table 18 reviews the projected transmission capital expenditures for development projects. Included within the table are four types of development projects which are listed separately because they are undertaken as a result of Government direction. (Identified by italics.) All are primarily targeted to integrating renewable energy

[143] EB-2010-0002, Exhibit D1, Tab 3, Schedule 3.
[144] Hydro One, op. cit., p. 1.

facilities.[145] Consistent with the presentation in Hydro One Transmission's rate filing, Smart Grid, Performance Enhancement and Risk Mitigation investments are also shown separately.

**Table 18: Transmission Capital Expenditures: Development**

| ($ Million) \ (%) | 2010 | % of Total | 2011 | % of Total | 2012 | % of Total |
|---|---|---|---|---|---|---|
| **Inter-Area Network Transfer Capability** | 424.5 | 75.0% | 303.4 | 42.0% | 116.7 | 21.8% |
| **Local Area Supply Adequacy** | 63.4 | 11.2% | 163.3 | 22.6% | 116.5 | 21.8% |
| **Load Customer Connection** | 48.1 | 8.5% | 130.6 | 18.1% | 124.2 | 23.2% |
| **Generation Customer Connection** | 10.8 | 1.9% | 44.5 | 6.2% | 23.3 | 4.4% |
| ***Enabling Facilities*** | 0.0 | 0.0% | 0.1 | 0.0% | 16.9 | 3.2% |
| ***Bulk& Regional Transmission*** | 0.0 | 0.0% | 4.5 | 0.6% | 22.6 | 4.2% |
| ***Station Upgrades & Additions for Renewables*** | 0.0 | 0.0% | 33.6 | 4.6% | 64.5 | 12.1% |
| ***Protection & Control for Distribution Connected Generation*** | 0.6 | 0.1% | 11.4 | 1.6% | 36.0 | 6.7% |
| **Smart Grid** | 1.4 | 0.2% | 7.8 | 1.1% | 6.8 | 1.3% |
| **Performance Enhancement** | 1.7 | 0.3% | 4.0 | 0.6% | 4.0 | 0.7% |
| **Risk Mitigation** | 15.8 | 2.8% | 20.0 | 2.8% | 3.2 | 0.6% |
| **Total** | 566.3 | 100.0% | 723.2 | 100.0% | 534.7 | 100.0% |

Government directed investments shown in *italics*.
Source: EB-2010-0002, Exhibit D1, Tab 3, Schedule 3, p. 10 of 37.

The planning and development budgets for network upgrades are based on increasing the inter-area transfer capability between generation and load centers within Ontario or increasing the interconnection capability with neighbouring markets. In its Investment Summary Document, Hydro One Transmission identified five development projects that would increase inter-area network transfer capability, including the $695.5 million Bruce to Milton double circuit 500 kV line.[146] These five projects represent 75% of Hydro One Transmission's 2010 Development capital budget. All of these projects are needed to accommodate new generation, with all five of the projects being pursued to incorporate new renewable generation. The Bruce to Milton Project is also being built to accommodate 1,500 MW of nuclear capacity.

New or upgraded facilities for local area supply are driven by load growth and local area reliability considerations.[147] Local area supply investments can include investments required by generation supply additions. In its 2011 and 2012 Application (EB-2010-0002), Hydro One Transmission identified six local area supply projects with budgets of greater than $3 million. Power Advisory believes that two of these projects (i.e., the Woodstock Area Transmission Reinforcement and Guelph Area Transmission Reinforcement) are the types of investments that could potentially be deferred if the High

[145] These include: Enabling Facilities, Bulk & Regional Transmission, Station Upgrades & Additions for Renewables, and Protection & Control for Distribution Connected Generation.
[146] EB-2010-0002, Exhibit D2, Tab 2, Schedule 3.
[147] Local areas are confined, small or radial portions of the system.

5 Proposal were implemented given that their need is based on a growth in overall energy requirements.

Hydro One Transmission noted that the Woodstock project has already been approved by the Ontario Energy Board and has been released for construction. As such this specific investment couldn't be deferred. Furthermore, the major driver of load growth in the Woodstock area is a new Toyota plant and our research indicates that the motor vehicle manufacturing sector has low price elasticities (See discussion in Section 3.2) and often can't justify reducing electricity costs by shifting demand during peak periods to off-peak periods.[148] With respect to the Guelph area project, about half of the investment is for end-of-life replacement of facilities which wouldn't be deferred by the High 5 proposal. Finally, the Guelph area load has a limited industrial component.

The planning and development budgets for load connections are driven primarily by customer requests. Typically, a portion of the costs of these investments is recovered from benefiting customers under Hydro One's Transmission Customer Contribution Policy which conforms to the Transmission System Code. Power Advisory identified one customer load connection transmission investment (i.e., Leamington TS to ensure reliability of supply) that could potentially be deferred by load shifts promoted by the High 5 Proposal, but here as well there are very limited industrial loads. The High 5 Proposal would provide an additional incentive to reduce load during peak periods, in addition to the avoiding capital contributions stemming from these connection costs.[149]

The planning for transmission connected generation (Generation Customer Connection in Table 18) has traditionally been based on customer requests. However, the *Green Energy Act* (*GEA*) recognizes the critical role that transmission development has in enabling renewable generation development. In September 2009 the Minister of Energy and Infrastructure requested that Hydro One initiate planning and development work of potentially 20 different transmission projects in support of the *GEA* and in anticipation of the increase in renewable energy generation associated with the OPA's FIT Program. Future commitment of any of these projects would be based on the need to incorporate renewable generation rather than for meeting new load.

[148] This is probably attributable to the relatively low proportion that electricity costs are of total costs, the difficulty of rescheduling production given constraints posed by labour agreements and the high value of the product.
[149] However, any deferral of such investments doesn't represent a broader benefit that could offset transmission cost shifting from implementation of the High 5 Proposal.

The planning and development capital for performance enhancements and risk mitigation projects is driven primarily by reliability considerations and in accordance with Market Rules, the Transmission System Code and various NERC and NPCC standards. Load reductions from the High 5 Proposal are unlikely to affect the need for such investments.

## 6.3 Summary: Assessment of Transmission Deferral Potential of the High 5 Proposal

The preceding review of the different types of Development projects undertaken by Hydro One Transmission indicates that only two of the six types of projects (i.e., local area supply and load customer connection) could potentially be deferred by the implementation of the High 5 Proposal. Furthermore, of the 47 development projects with budgets of greater than three million dollars, only two could potentially be deferred by the High 5 Proposal. The relevant investment in these two projects represents a capital budget of about $88 million out of a total transmission development capital budget of $1.8 billion through 2012. Clearly, the vast majority of Hydro One's projected network transmission investment wouldn't be deferred by load reductions from the High 5 proposal. The ability of the High 5 Proposal to defer specific transmission investments is assessed in the next section. As indicated, the actual proportion of investment likely to be deferred by the High 5 Proposal is smaller than suggested by this high level assessment.

After Power Advisory established the potential load shift from the High 5 proposal, we discussed the transmission deferral potential of the High 5 with Hydro One Transmission's system planners. Our initial analysis suggested that a "high case" load reduction could be as high as 100 to 150 MW for the transmission system as a whole. Hydro One Transmission's system planners indicated that load reductions of this magnitude would have no ability to defer any major transmission investments given that the load reductions would be spread across the Province roughly in proportion to the concentration of industrial load in different zones.[150] (See analysis presented in Table 19.)

## 6.4 Project Specific Considerations for Assessing Transmission Deferral Potential

As mentioned, for one of these specific projects or a subsequent development project to be deferred the load reduction must be greater than the annual increase in load for the area served by the transmission facility. For this to occur there must be sufficient industrial load in the area such that the resulting load shift is greater than the increase in demand. While this requires a case-by-case assessment, a rough indication regarding the likelihood of this occurring is provided in Table 19 which compares load growth

[150] Based on information provided by Hydro One on June 1, 2010.

expressed in MWs by zone at two different assumed load growth rates (2% and 1%) with the projected level of load shift based on high load shift level we forecast in Chapter 3. The 2% load growth is more reflective of load growth rates in higher growth areas where much of the potentially deferrable transmission investment is likely to occur. The 1% load growth assumption is generally representative of load growth levels experienced in Ontario before the impact of conservation programs is considered.

As indicated, the only zones where the load shift is likely to be greater than the annual load growth are the Northeast and Northwest. The Northeast and Northwest zones offer the greatest potential load shift given the concentration of industrial load in these zones. However as discussed, actual forecast load growth in the Northeast and Northwest is negative and as a result there is unlikely to be any significant transmission investments in this area that are specifically attributable to incremental load growth other than new project-driven load growth which requires transmission investment to connect them into the IESO-controlled grid. Furthermore, these zonal loads are spread over large areas and as a result the resulting load reductions may not be sufficiently concentrated in the area where the transmission facility investment is required to defer the local area investment.

**Table 19: High Level Evaluation of Potential for Transmission Investment Deferral by Zone (MW)**

| Zone | East | Essa | Niagara | Northeast | Northwest | Ottawa | Southwest | Toronto | West | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Load Growth Rate: 2% | 28 | 30 | 17 | 24 | 11 | 35 | 91 | 180 | 54 | 470 |
| Potential Load Shift: Central Estimate | 4 | 0 | 2 | 27 | 12 | 2 | 18 | 6 | 12 | 84 |
| Load Growth Rate: 1% | 14 | 15 | 9 | 12 | 6 | 18 | 45 | 90 | 27 | 235 |
| Potential Load Shift: High Estimate | 7 | 1 | 4 | 47 | 21 | 3 | 32 | 11 | 22 | 147 |

Source: IESO Data

## 6.5 Other Considerations regarding Transmission Investment Deferral

Since the areas with the highest proportion of industrial customers (Northern and Southwestern Ontario), and hence with the most significant potential load reductions from the High 5 Proposal, are also areas with significant renewable energy facility development, reductions in load can actually increase the level of transmission congestion. This is particularly true for Northern Ontario where there are significantly more resources than load and output by storage hydro facilities causes their output to be concentrated to on-peak periods when limited by available water.[151] Another major transmission constraint where there is significant concentration of industrial load is the area West of London, with industrial load concentrated in Sarnia and Windsor. However, with natural gas-fired generation development in these load centres and significant renewable resource development in the area, this area has a surplus of generation and requires additional load to reduce congestion, not load reductions. Therefore, reductions

[151] This demonstrated by reviewing the production profiles for these units during such periods.

in load in on-peak periods can exacerbate congestion, rather than alleviate it.[152] In addition, such reductions in these areas are also likely to increase losses as the load reductions increase the need to transmit power from areas of generation surpluses to areas of load concentration.

However in other zones, shifting load from peak to off peak periods could reduce congestion costs. Specifically, such a load shift could result in a flatter overall load shape in the area where the renewable energy is produced and reduce the need to curtail renewable energy projects during off-peak periods given limited transmission availability. In general, during such off-peak periods dispatchable resources wouldn't be operating and system transfer capabilities are higher given more favourable ambient conditions. This limits the occurrence of such conditions.

Another location where load reductions from the High 5 proposal would reduce congestion is in the GTA and the "Golden Horseshoe". One of the projects that is a candidate for deferral is located in this area (i.e., Guelph). However, there is relatively low proportion of industrial load in the GTA and Golden Horseshoe. Table 1 indicates that direct customer industrial load represents about 3% of load in Toronto and about 16% of load in the Southwest zone. Furthermore, the vast majority of Hydro One's network transmission investment is driven by the objective of reducing congestion to enable the interconnection of additional renewable energy resources.

### 6.6 Conclusion

The relatively limited load reductions that are projected to be provided by the High 5 proposal and the anticipated concentration of these load reductions in areas with generation surpluses will limit the potential for the High 5 proposal to defer major transmission investment. None of the forty-seven major transmission development projects identified in Hydro One Transmission's Investment Summary Document are likely to be deferred by the implementation of the High 5 Proposal. While at least one of these projects has already been released for construction and as such couldn't be deferred, the load impacts from the High 5 proposal aren't likely to be sufficient to defer such investment. Finally, Power Advisory doesn't expect that the conditions that are driving much of the transmission investment (i.e., the development of renewable energy resources in response to the mandates of the *Green Energy Act*) to change for the foreseeable future. Therefore, we don't expect that the drivers for transmission will be load growth in the areas where there may be appreciable load shifts from the implementation of the High 5 proposal.

[152] This point was also made by Hydro One's transmission planners in our March 26, 2010 and June 1, 2010 phone calls.

## 7. Monitoring the Effect of Adoption of the High 5 Methodology

In its Decision with Reasons in EB-2008-0272, the Board noted that "Hydro One has suggested it would not be possible to monitor such a program and measure its effect on commodity prices …[and the Board] believes that it should be possible to do so to some extent and directs Hydro One to include this as part of its analysis."[153] This chapter presents Power Advisory's assessment of what would be required to monitor the impacts of such a program and estimates its effect on commodity prices.

There are two principle issues that must be addressed. First, it would be necessary to validate that load shifting had occurred and that such load shifting was attributable to customer efforts to shift load in response in an effort to reduce transmission network charges. Second, and assuming that load shifts had been validated, it would be necessary to estimate what commodity prices would have been absent the load shift in order to estimate the impact of load shifting on these prices. Each step is fraught with difficulties.

The challenges associated with monitoring whether load shifting had occurred are similar those experienced in efforts to monitor the impacts of conservation and demand management programs. Specifically, one must isolate the impacts of load changes due to a change in transmission network rate design from many other potential sources of changing load, including changes in business operations and responses to market prices. However, it would be extremely challenging without input from load shifting customers to accurately distinguish between load shifts that are in response to market prices and demand response (DR) programs versus those that are in response to an effort to reduce network charge determinants. For DR programs that are triggered in response to specific system conditions the DR impacts could presumably be estimated based on the average DR triggered load reduction. Absent customer-specific data, one method for estimating impacts would be to specify an econometric equation to explain customer load levels. However, as demonstrated by the equations specified by Dr. Sen such an approach is fraught with difficulty.

Establishing the impact of load shifting on commodity prices is perhaps even more difficult. AMPCO has used an econometric equation to estimate the relationship between price and demand in an attempt to predict the impact on price. Power Advisory has applied a electricity pricing model to this task. However, monitoring is an after-the-fact exercise that requires isolation of the impact of one factor (e.g., load shifting) from all

[153] p. 70.

other impacts. Here as well several different methodologies could be employed. An approach similar to that employed by AMPCO could be used whereby price impacts are estimated based on an econometric equation. An estimate of the amount of load shifting that had occurred would be included as an independent variable. This methodology doesn't recognize that there are flat portions of Ontario's supply curve where load shifts can have little or no impact on price. Alternatively, the IESO could use resource bid data to perform an after-the-fact analysis of what market-clearing prices would have been absent the load shifting. This is likely to be far more accurate but resource intensive.

One overriding concern with monitoring the impact of the High 5 proposal is that the load shifts are not so significant, particularly relative to other factors that result in changing load, that the range of uncertainty associated with the estimates may be so large as to render the estimates of limited value. In short, the impacts of the High 5 methodology could be monitored, but such monitoring would involve a considerable degree of analytical complexity and the resulting estimated impacts would be subject to uncertainty given the difficulty of distinguishing between customer's response to other demand determinants and other factors that influence market prices.

## 8. Conclusions

The evidence submitted by AMPCO in Docket EB-2008-0272 represented a comprehensive assessment and analysis of its High 5 proposal. Nonetheless, we believe that adoption of the High 5 methodology is not adequately supported due to theoretical, methodological, and analytical concerns.

Perhaps most importantly, the appropriateness of the High 5 methodology rests on the theory that peak demands during relatively few periods of the year are driving investments in Ontario's network transmission facilities. However, at the current time and at a minimum for the next several years, that does not appear to be the case. Rather, investments in network transmission facilities have historically been made to serve peaks that occur throughout the system. On a forward-looking basis, the largest investments are anticipated to be driven by a need to connect renewable resources and address localized issues, and not to meet system peaks occurring during a few times of the year.

Power Advisory agrees with AMPCO that the network transmission rate design can influence customers to shift their demands to off peak periods, at least on the margin. Customers have already demonstrated that they are willing to shift demand to off-peak hours in response to energy prices. For those network transmission facilities that may be deferred by demand reductions, it may be more effective and efficient to design and implement such programs to do this. This would avoid the cost shifting that the High 5 promotes.

From a methodological standpoint, AMPCO's analysis of transmission cost shifting fails to take into account the cost shifting that occurs due to a change in methodology. AMPCO only considered the anticipated impacts from load shifting by those direct connect customers that would be able to respond to the High 5 proposal. AMPCO claimed that all customers will benefit from a change to the High 5 methodology as a result of commodity cost savings that are much larger than the transmission cost shifting due to load shifts. However, this is no longer the case when one considers transmission cost shifts that are attributable to a change in methodology. Rather, the High 5 proposal would benefit direct connect and power station customers with the resulting shortfall shifted to LDCs, and ultimately, customers of LDCs that do not currently have the same price incentive to shift load as the direct customers have.

A second methodological concern relates to the estimated commodity cost savings as a result of a decrease in peak demand by direct customers. Power Advisory's analysis also indicated a decrease in peak energy prices (HOEP) from High 5 induced load shifts and indicated that off-peak energy prices would increase as load is shifted to off-peak hours. AMPCO estimated these impacts using an econometric equation. Power Advisory used its Ontario electricity model to estimate these impacts based on Ontario's resource portfolio. AMPCO's analysis assumes that these commodity cost savings are realized over all summer peak hours and implies that direct industrial customers would be reducing load during these hours in an effort to avoid the High 5 hours. The number of hours that prices would be reduced in AMPCO's analysis is inconsistent with the number of hours used to estimate the shadow price upon which AMPCO's load shift estimate was based.

Finally, from an analytical perspective, Power Advisory has noted several areas of concern with respect to the estimation of both shadow prices and price elasticities. Shadow price estimates require approximations of anticipated behavioral responses by industrial customers based on limited information and are therefore necessarily uncertain. AMPCO presented its own analysis and Power Advisory agrees with many of the concerns that were raised by parties during EB-2008-0272. With respect to price elasticities, rather than attempt to introduce a new empirical analysis, Power Advisory searched the literature to identify potential points of comparison with AMPCO, concluding that the estimates derived by AMPCO, while flawed, were within the range of other studies. Power Advisory concludes that it is appropriate to consider a range of both shadow prices and price elasticities in order to estimate load shifts. When applying these ranges, Power Advisory has arrived at load shifts in excess of those estimated by AMPCO, but commodity cost savings well below those estimated by AMPCO.

Power Advisory has analyzed the benefits that AMPCO attributes to a change to the High 5 methodology for determining network transmission charges. Our conclusions are that these benefits are overstated and may not occur.

- It is unlikely that future transmission investment would be deferred.
- Significant costs would be shifted from direct customers and generators to customers of LDCs, without justification in terms of cost causation.
- The benefits to electricity consumers from reductions in commodity costs of electricity due to load shifting will be much less than the transmission costs to be shifted to them.

# Appendix A: AMPCO Econometric Equations

I. **Price Elasticity Equations (2007 Data)** – As Provided in Response to VECC Interrogatory #4 (a)

A. Pulp

Fit Summary

| | |
|---|---|
| R-square | 0.2707 |
| Root MSE | 0.1242 |
| Denominator DF | 30 |

Estimated Regression Coefficients

| Parameter | Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | 6.6189796 | 0.11512305 | 57.49 | <.0001 |
| lhoep | -0.2260794 | 0.02186786 | -10.34 | <.0001 |
| lhoepl | 0.0968973 | 0.02159990 | 4.49 | <.0001 |
| mm1 | -0.0149659 | 0.02462949 | -0.61 | 0.5480 |
| mm2 | -0.0594246 | 0.02413192 | -2.46 | 0.0198 |
| mm3 | -0.0593645 | 0.02987683 | -1.99 | 0.0561 |

B. Metal

Fit Summary

| | |
|---|---|
| R-square | 0.4775 |
| Root MSE | 0.07113 |
| Denominator DF | 30 |

Estimated Regression Coefficients

| Parameter | Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | 6.2751075 | 0.08064904 | 77.81 | <.0001 |
| lhoep | -0.0451720 | 0.01320993 | -3.42 | 0.0018 |
| lhoepl | 0.0581636 | 0.01078319 | 5.39 | <.0001 |
| mm1 | -0.0244235 | 0.01093338 | -2.23 | 0.0331 |
| mm2 | -0.1305586 | 0.01776333 | -7.35 | <.0001 |
| mm3 | -0.1441804 | 0.01739332 | -8.29 | <.0001 |

## C. Iron

| | |
|---|---|
| R-square | 0.4305 |
| Root MSE | 0.09051 |
| Denominator DF | 30 |

Estimated Regression Coefficients

| Parameter | Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | 6.1382786 | 0.10986650 | 55.87 | <.0001 |
| lhoep | -0.0439256 | 0.01730631 | -2.54 | 0.0166 |
| lhoepl | 0.0254336 | 0.01921707 | 1.32 | 0.1957 |
| mm1 | 0.1621057 | 0.02160992 | 7.50 | <.0001 |
| mm2 | 0.1668569 | 0.01975757 | 8.45 | <.0001 |
| mm3 | 0.0356795 | 0.02353001 | 1.52 | 0.1399 |

## D. Motor

Fit Summary

| | |
|---|---|
| R-square | 0.3665 |
| Root MSE | 0.2704 |
| Denominator DF | 30 |

Estimated Regression Coefficients

| Parameter | Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | 2.9753165 | 0.29413471 | 10.12 | <.0001 |
| lhoep | 0.3665096 | 0.04589222 | 7.99 | <.0001 |
| lhoepl | 0.1505515 | 0.04369858 | 3.45 | 0.0017 |
| mm1 | 0.1897371 | 0.05331766 | 3.56 | 0.0013 |
| mm2 | 0.1058539 | 0.05881057 | 1.80 | 0.0819 |
| mm3 | -0.2031320 | 0.08180325 | -2.48 | 0.0188 |

## E. Petrol

| | |
|---|---|
| R-square | 0.9364 |
| Root MSE | 0.05402 |
| Denominator DF | 30 |

Estimated Regression Coefficients

| Parameter | Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | 4.90787312 | 0.05634515 | 87.10 | <.0001 |
| lhoep | 0.01360895 | 0.00948146 | 1.44 | 0.1615 |
| lhoepl | 0.01561346 | 0.00911141 | 1.71 | 0.0969 |
| mm1 | 0.42187906 | 0.02032713 | 20.75 | <.0001 |
| mm2 | 0.48792513 | 0.01610866 | 30.29 | <.0001 |
| mm3 | 0.50506929 | 0.01230688 | 41.04 | <.0001 |

## II. **Summary of Price Elasticity Equations –** As Provided in AMPCO Response to Undertakings – Schedule J6.3

Note: these coefficients differ from those reported above and have been used to calculate the 29 MW of reduction in peak load demand from load shifting that is also reported in Schedule J6.3.

| | *Pulp* | *Metal* | *Iron* | *Motor* | **Petrol** |
|---|---|---|---|---|---|
| **A. 2007** | | | | | |
| Current HOEP | -0.234 | -0.043 | -0.0469 | 0.353 | 0.0137 |
| | (0.0215)a | (0.0127)a | (0.0167)a | (0.044)a | 0.008879) |
| Average HOEP for past 12 hours | 0.103 | 0.056 | 0.026 | 0.155 | 0.016 |
| | (0.021)a | (0.010)a | (0.0188) | (0.042)a | (0.009)b |
| Month Fixed Effects | Yes | Yes | Yes | Yes | Yes |
| Observations | 244 | 244 | 244 | 244 | 244 |
| R Square | 0.2994 | 0.4798 | 0.4308 | 0.3617 | 0.9364 |

**III. Responsiveness of HOEP to a Change in Ontario Demand (2007 Data)** – As Updated and Provided in AMPCO Responses to Undertakings J6.2

A. <u>On-Peak Hours</u>

A. Peak Hours (8 am – 6:59 pm)

The SURVEYREG Procedure

Regression Analysis for Dependent Variable price

Data Summary

| | |
|---|---|
| Number of Observations | 1476 |
| Mean of price | 57.49991 |
| Sum of price | 84869.9 |

R-square 0.5057

Estimated Regression Coefficients

| Parameter | Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | 51.2352159 | 24.6521175 | 2.08 | 0.0619 |
| odem | 0.0159704 | 0.0062200 | 2.57 | 0.0262 |
| imp | -0.0088862 | 0.0074577 | -1.19 | 0.2585 |
| exp | 0.0167312 | 0.0060332 | 2.77 | 0.0181 |
| coal | -0.0104992 | 0.0062777 | -1.67 | 0.1226 |
| gas | -0.0067930 | 0.0070470 | -0.96 | 0.3558 |
| CERIgp | -5.8898629 | 1.9594914 | -3.01 | 0.0120 |
| nuclear | -0.0166563 | 0.0066812 | -2.49 | 0.0299 |
| hydro | -0.0060805 | 0.0061855 | -0.98 | 0.3467 |
| HHI1 | -0.0098745 | 0.0030713 | -3.22 | 0.0082 |
| day | 0.1142513 | 0.0436348 | 2.62 | 0.0239 |
| m5 | 12.4180926 | 2.8900283 | 4.30 | 0.0013 |
| m6 | 5.2932215 | 1.3794597 | 3.84 | 0.0028 |
| h8 | -0.8671432 | 1.0379846 | -0.84 | 0.4213 |
| h9 | 0.8259198 | 0.5389933 | 1.53 | 0.1537 |
| h10 | 6.7190488 | 0.1263713 | 53.17 | <.0001 |
| h11 | 6.3177964 | 0.3260975 | 19.37 | <.0001 |
| h12 | 11.0888485 | 0.5108943 | 21.70 | <.0001 |
| h13 | 11.1952184 | 0.6753793 | 16.58 | <.0001 |
| h14 | 8.5257180 | 0.6708382 | 12.71 | <.0001 |
| h15 | 6.9028988 | 0.5416215 | 12.74 | <.0001 |
| h16 | 5.5757208 | 0.5085211 | 10.96 | <.0001 |
| h17 | 6.6707858 | 0.5091761 | 13.10 | <.0001 |
| h18 | 3.3228123 | 0.2849786 | 11.66 | <.0001 |

B. Off-Peak Hours

```
A. Non Peak Hours (7 pm - 12 am)
The SURVEYREG Procedure

Regression Analysis for Dependent Variable price

            Data Summary

Number of Observations          1476
Mean of price               32.71623
Sum of price                 48289.2


R-square           0.7141
```

| Parameter | Estimate | Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | -38.820361 | 11.7200303 | -3.31 | 0.0069 |
| odem | 0.005709 | 0.0028288 | 2.02 | 0.0686 |
| imp | 0.000948 | 0.0028566 | 0.33 | 0.7461 |
| exp | 0.004846 | 0.0028901 | 1.68 | 0.1217 |
| coal | -0.001439 | 0.0027999 | -0.51 | 0.6174 |
| gas | 0.006002 | 0.0040495 | 1.48 | 0.1664 |
| CERIgp | -1.336357 | 1.6876091 | -0.79 | 0.4452 |
| nuclear | -0.005835 | 0.0027181 | -2.15 | 0.0550 |
| hydro | -0.004554 | 0.0027673 | -1.65 | 0.1281 |
| HHI1 | 0.009086 | 0.0014149 | 6.42 | <.0001 |
| day | 0.140885 | 0.0297250 | 4.74 | 0.0006 |
| m5 | 2.475128 | 3.1010104 | 0.80 | 0.4417 |
| m6 | -2.171433 | 1.1397651 | -1.91 | 0.0832 |
| h1 | 0.145213 | 1.2683744 | 0.11 | 0.9109 |
| h2 | -0.652653 | 1.3123390 | -0.50 | 0.6288 |
| h3 | -0.556896 | 1.3764820 | -0.40 | 0.6935 |
| h4 | -0.160127 | 1.3632336 | -0.12 | 0.9086 |
| h5 | -0.264388 | 1.2661780 | -0.21 | 0.8384 |
| h20 | 6.816701 | 2.7156966 | 2.51 | 0.0290 |
| h21 | 10.818919 | 2.6772194 | 4.04 | 0.0019 |
| h22 | 1.905429 | 2.1172029 | 0.90 | 0.3874 |

## Appendix B: Potential Insights from ERCOT and PJM

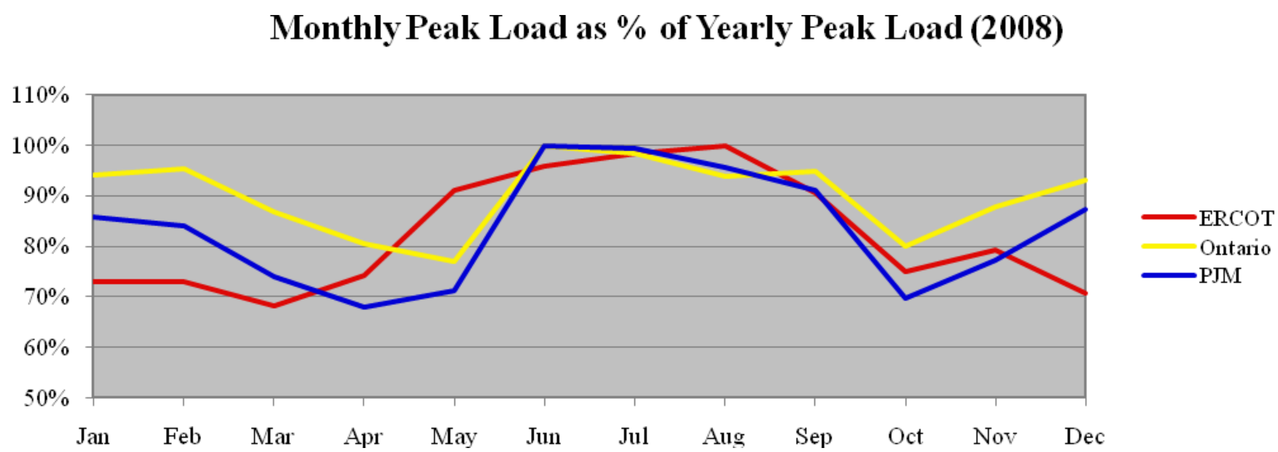
AMPCO cited PJM and ERCOT as markets that have transmission cost allocation and rate design approaches that are similar to the proposed High 5 approach. AMPCO witness MacDonald of Gerdau AmeriSteel Corporation (Gerdau AmeriSteel), in particular, described efforts by his firm to avoid transmission system peaks for two plants located in PJM and one plant located in ERCOT.[154] [155]

Mr. MacDonald noted that the cost-saving incentive to curtail production during potential peak periods needs to be sufficient to compensate for costs that may be incurred to shut down the plant, including the need to carry additional inventories and pay employees for periods when they may not be fully utilized. With an adequate forecast of when these peaks might occur, Gerdau AmeriSteel can schedule maintenance activities to be performed during the shutdown. Gerdau AmeriSteel attempts to identify potential system peaks by monitoring weather and electricity market conditions and alerting plant managers as necessary. Within PJM, where they have been engaged in this effort since 2004, he indicates that they begin shutting down an hour in advance and remain shutdown until the peak has passed for periods of three to eight hours. He indicated that they typically shut down their plants for four hours about 15 times per year.

Power Advisory has reviewed the PJM and ERCOT markets to determine if there are insights that may be relevant to the consideration of the High 5 proposal in Ontario. The PJM and ERCOT market areas apply a 5 coincident peak (CP) and 4CP methodology for establishing transmission charge determinants, respectively. The diagram at on the following page presents the 2008 monthly system peaks of Ontario, PJM, and ERCOT expressed as a percentage of the annual to illustrate the respective peak demand patterns. As shown in this diagram, the ERCOT and PJM are likely to experience peaks during the June through August period. In contrast, Ontario may experience has high peak demands (relative to the annual peak) in seven months: December through January and June through September.

[154] Transcript, Volume 6, pages 22, 24-29.

[155] The two PJM plants are served by Jersey Central Power & Light and Public Service Electric & Gas; the ERCOT plant is served by Oncor.




## 1. ERCOT

Prior to the restructuring of its electricity market, Texas relied extensively on interruptible and real time pricing tariffs to ensure reliability for a region with limited interconnections with neighboring markets. As a result, many large Texas industries, including petroleum refineries, chemical production facilities, steel mills and air separation plants, are capable of reducing or curtailing (with on-site generation) purchases from the grid.

ERCOT member utilities allocate transmission costs to load serving entities based on the contribution to the 15-minute interval peak demand during four months (June – September).[156] The peak typically occurs between 3:45 and 5:15 PM.[157] Many load serving entities pass through transmission costs to end-use customers using the same methodology[158] creating an incentive to reduce consumption during the four summer peaks. In addition, industrial customers that had previously been served by LDC tariffs are now exposed to market prices, increasing their motivation to participate in demand response programs.

ERCOT has several demand response programs, including programs that enable demand response to be dispatched and compete directly with supply. These include a "Load acting as a Resource" market and the provision of emergency interruptible load. Load

[156] ERCOT Protocol 9: Settlement and Billing, pages 18-19.
[157] Cirro Energy Services Presentation, May 9, 2006.
[158] An estimation technique is applied to non-interval metered customer classes.

serving entities also have contracts with customers that provide a source of curtailable load that is triggered by the ERCOT market clearing price of energy (MCPE).

Customers also curtail load in an effort to avoid system peaks in response to the 4CP transmission cost allocation and rate design methodology.[159] Transmission costs represent approximately 6% of the total bill and 30% of the delivery bill. These customers must be 700kW or greater and have an Interval Data Recorder (IDR) meter. According to ERCOT, the incentive to avoid a transmission peak can be as much as $20,000 per MW-year and demand charges are based on the contribution to peak during the preceding year. Customers may also avoid relatively high MCPE prices by curtailing demand. There are firms that provide a service to help customers identify potential system peaks. A June 2007 survey indicated that LSEs have contracts with 172 customers that provide 223 MW of curtailable load. This total does not include customers that rely solely on the 4CP warning services provided by third parties.[160]

**2. PJM**

PJM has multiple zones and allocates its existing transmission system costs to zones based on historical cost incurrence principles as the investments were made prior to restructuring and the formation of PJM, whose own footprint has grown.[161] Each zone has distinct Locational Marginal Prices (LMP).[162] The 5CP, calculated based on the 5 highest peak days that occur during a four-month period, June – September, is used to allocate transmission costs to load serving entities ("LSEs") within each zone, after PJM has allocated costs to each zone. [163] LSEs use a comparable methodology to allocate transmission costs to their customers. As in ERCOT, third-party service providers can help customers identify potential peak days.[164]

PJM also has several programs designed to integrate demand response into market operations. PJM certifies "Curtailment Service Providers" that work directly with end-use customers to facilitate their participation in energy, capacity, and ancillary services markets and be compensated for their demand reductions. Customer can bid reduced

[159] Paul Wattles, Supervisor, "Demand Response ERCOT" – Presentation dated September 18, 2008
[160] Paul Wattles, Webinar, date unknown, http://gulfcoastpower.org/default/f07confpdf/f07wattles.pdf
[161] See FERC Opinion 494 in Docket EL05-121 issued April 19, 2007 for further discussion as well as a discussion of the more contentious issue of determining cost responsibility for new transmission facilities.
[162] LMPs can also differ based on differences in losses at different nodes.
[163] "Calculation of a Customer Peak Load Contribution, PPL Electric Utilities Supply Meeting, August 24, 2009.
[164] See, by way of example, http://www.energysoftware.com/5cp-warnings

loads into the day-ahead energy market or real-time market.[165] They can participate directly in ancillary service markets, participating like a generator. They can also contribute in an emergency both energy and capacity, and recent efforts will establish a Price Responsive Demand program that takes advantage of advanced metering technology. Even though these customers pay average prices for energy, the demand response programs provide them with the ability to respond to wholesale market prices and thus contribute to a more efficient market. PJM estimates that more than 7,600 MW of demand and energy efficiency resources are committed as capacity resources for the 2012/2013 year.[166]

Customers may also benefit from lower transmission costs as their peak load contribution for cost allocation purposes under the Network Integration Transmission Service (NITS) is based on metered data at the time of the PJM zone's five peak hours, including losses.[167] [168] An estimation algorithm is required for end-use customers that do not have demand meters. As specified in PJM's tariff, PJM establishes a "Peak Load Share NITS Obligation" or zonal transmission peak to each LDC zone on an annual basis. For customers receiving non-zone transmission service, the allocation is based on the PJM region's peak hour from the previous year.

The LDC, in turn, assigns the Peak Load Share and NITS obligation to suppliers based on their portfolio of customers, a calculation that is done on a daily basis to accommodate customer switching among suppliers.

### 3. Conclusions

AMPCO asserted that Gerdau AmeriSteel's experience in PJM and ERCOT offered insights regarding industrial customers' ability to reduce demand during peak periods to reduce the transmission charges that they were assessed. Power Advisory believes that this experience is relevant, but that there are important differences between PJM and ERCOT and Ontario.

The ERCOT and PJM regions each base establish transmission cost responsibility on CP methodologies that focus on the months in which system peaks are likely to occur. In

[165] ISO-RTO Council Report, Harnessing the Power of Demand How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets, p 10. http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf

[166] PJM Demand Response Fact Sheet, March 31, 2010.

[167] PJM Manual #27, OATT Accounting, pages 19-20.

[168] This determination is based on the five PJM system peak hours for JCP&L, and for the five zonal peak hours for PSE&G (the two LDCs that serve Gerdau AmeriSteel's plants.

ERCOT, demand in the three summer months (June – August) is markedly higher than the adjoining months and dramatically higher than the winter months. PJM is also clearly a summer peaking region. This evidence supports the application of the 4CP and 5CP methodologies. Because PJM and ERCOT establish transmission cost responsibility on the basis of peaks during summer months, it is much easier for industrial customers to establish when they need to curtail load to avoid the peak.

The situation in Ontario is not as clear-cut, as the northern half of the province remains winter peaking. The Ontario system has also peaked during the winter months in recent years.

However, the ability to avoid transmission costs is only a portion of the overall demand response opportunity. ERCOT, in particular, has a long history of pursuing demand response programs, including interruptible tariffs. While certain customers attempt to avoid transmission peaks, the overwhelming focus of the market is to avoid peak energy prices. PJM has also been very aggressive in its efforts to increase the contribution of demand response into its market operations.

## Appendix C: Elasticity of Substitution Studies

### 1. Descriptions of Elasticity of Substitution Studies in the Literature

One large experiment was the California Statewide Pricing Pilot (SPP) study, shown as study 1 in Table 7 in the body of this report. It was carried out from July 2003 to December 2004.[169] This experiment offered two kinds of CPP, one with a fixed critical peak period with day-ahead notification and one with a variable critical peak period and same-day notification. The critical peak price was about five times the normal price, or six times the off-peak price. The pilot project also included standard time of use pricing.

This pilot project included only residential, commercial and small industrial customers. All of the participants in the pilot had central air conditioning and were offered a technology (smart thermostats) that would automatically respond to the critical peak pricing period.

The largest commercial and industrial customers in the pilot had demand between 20 and 200 kW. They showed demand reduction in critical peak periods of 13.8%, but of that 11.2% is attributed to the enabling technology and only 3.6% to the effect of the critical peak price. In this case, the peak price was about 6.5 times the off-peak price (71 cents/kWh vs. 11 cents/kWh) and about three times the 24 cent/kWh daily price. These results suggest relatively low price responsiveness of this group to peak pricing.[170]

The elasticity of substitution found in this study was 0.06.

This pilot project differs from the AMPCO High 5 proposal in two important ways. First, it was aimed at smaller customers than the AMPCO customers in Ontario. Second, the main impact was expected to come from changes in space conditioning, not from rescheduling production operations. Also, the Charles River report suggests that price responsiveness of these customers in California had fallen from that seen in similar experiments 25 years earlier because of the large number of demand management initiatives implemented since then.[171] This is also likely to be true for the High 5 proposal given Ontario is aggressively pursuing conservation and demand management potential in all customer classes and that, as the earlier discussion showed, many customers in these industries appear already to have shifted their electricity use out of the high-priced

[169] Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot", March 2005.
[170] Charles River Associates, op. cit., pg. 121
[171] Cite

peak periods.

Another study was carried out by Niagara Mohawk in 1985.[172] It is shown as study 5 in Table 7 in the body of this report. This study targeted large industrial customers only and looked at their response to peak prices for which they got notice in the afternoon of the preceding day. This study's methodology analyzed impacts for each of the 15 customers (9 customers in the treatment group and 6 in a control group) individually, comparing their response to the peak pricing with their historical baseload usage patterns. As the study noted, industrial electricity users, even some in the same SIC code, "are not homogenous. This heterogeneity can cause large sampling variances and reduced the likelihood of uncovering significant treatment effects".[173]

Overall, the study found that most of the response to the high prices came from two customers in the treatment group which had consistent and large reactions to the price changes. These were the two largest customers in the study, one in the stone, glass and clay industry and one in transportation equipment; they were the only firms in these industries in this study. The study computed elasticities of substitution for both intra-day and inter-day effects for the customers in aggregate. It found intra-day elasticity of .093 and inter-day elasticity of 0.163 for the pooled data from all of the customers.

Study 2 in **Table** 7 in the body of this report[174] reported on an experiment where large customers were offered two different RTP pricing systems, one (RTP) in which they were given day-ahead firm prices and allowed to react to them, and one (RTP-LR) in which they were paid to give the utility an option to increase their electricity price by $.38 per kWh under certain system conditions. The results were analyzed with assumptions of periods of reduction ranging from 3 to 6 hours. For those on the regular RTP, elasticities of substitution ranged from .10 to .16, with the higher elasticities associated with the shorter time periods of high prices. For those on the RTP-LR, elasticities ranged from .20 to .27.

For all of these studies, participation was voluntary. As noted, firms which can react effectively to such peak pricing are more likely to volunteer for the experiment, suggesting that these results might overstate the reactions of the population of all industrial customers.

---

[172] Joseph A. Herriges, S. Mostafa Baladi, Douglas W. Caves and Bernard E. Neenan, "The Response of Industrial Customers to Electric Rates Based Upon Dynamic Marginal Costs", *Review of Economics and Statistics*, 1993, v. 75 No. 3, pp. 446-454
[173] Ibid., pg.
[174] Richard Boisvert, Peter Cappers, Bernie Neenan, and Bryan Scott, *Industrial and Commercial Customer Response to Real Time Electricity Prices*, Neenan Associates, 2004.

# 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-2008-0272, 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 meter rebates in Proceedings EB-2008-0272, EB-2006-0501 and RP-2003-0188, and it is the same basis on which customers pay the exit fee when exiting the Wholesale Meter pool.

As of the end of 2009 there were 174 Meter Points owned by Hydro One Transmission. The total number of meter points forecast to be using regulated meter service in 2011 and 2012 is based on a review of the number and timing of meter installations that have exited to date, the type of meter installations remaining in the pool and the reseal dates for the remaining meter installations.

[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 below provides data for 2011 and 2012 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. An average rate of $8,400 per Meter Point per year for 2011 and 2012 is proposed.

**Table 1**

| Year | Annual Revenue Requirement ($ Million) | Forecast Number of Meter Points | Wholesale Meter Service Rate ($ / Meter Point / Year) |
|---|---|---|---|
| 2011 | 0.83 | 100 | 8,272 |
| 2012 | 0.64 | 75 | 8,555 |

The increase in rates from the current level of $6,900 reflects the fact that the remaining metering installations on average are more complex and thus more expensive than those that comprised the original pool of 975 wholesale meter points in 2005. This higher share of the Rate Base results in a higher allocated share of the Revenue Requirement. Further, many of these metering installations are being high-side converted which has slowed the conversion process and increased their handling costs.

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 Net Book Value of stranded wholesale revenue metering assets, remain at $5,200 per meter point as approved in the Board in RP-2003-0188, EB-2006-0501 and EB-2008-0272.

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, Wholesale Meter service charge is administered by Hydro One Transmission.

# RATES FOR EXPORT TRANSMISSION SERVICE

## 1.0 INTRODUCTION

As part of the Settlement Agreement approved by the Board under EB-2006-0501 the parties agreed that the IESO would conduct a study of alternative Export Transmission Service ("ETS") tariffs.

On October 6 2009, the OEB issued a letter stating the following:

> "The IESO's study was completed and filed with the Board on August 28, 2009. The study recommended that no changes be made to the current export tariff….The Board has decided that this matter should be considered in the Hydro One Transmission Rate Hearings for the 2011 and 2012 test years. The Board expects that the IESO will participate as necessary in that hearing to address its study. In the meantime the Board will make no change to the approved rates including the $1MWh applicable to the export service for the 2010 test year."

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

A description of the IESO study and the results of the study are included as Exhibit H1, Tab 5, Schedule 2.

## 2.0 EXPORT TRANSMISSION SERVICE RATE

The existing ETS rate of $1/MWh is in effect for the purpose of determining the Revenue Requirement and associated rates for Network Service for 2011 and 2012.

For 2011 and 2012 the ETS revenue will continue to be disbursed through a decrease to the revenue requirement for the Network Pool. The forecast for ETS revenue is $10.1 million and $10.2 million per year for 2011 and 2012, respectively. This forecast is based on the IESO's 2010-2012 Business Plan which was filed as part of their 2010 Rate Submission in Proceeding EB-2009-0377.

## 3.0 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 recommendation for ETS.

# EXPORT TRANSMISSION SERVICE TARIFF

## 1.0 INTRODUCTION

Hydro One's Export Transmission Service (ETS) revenues are determined based on the approved tariff of $1/MWh and the volume of electricity exported from or wheeled-through Ontario over its transmission system. 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 has not changed since its original inception in 1999. At the time, 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] Hydro One has since continued to monitor and report to the Board on the evolution of the ETS tariff market in Ontario and related developments in interconnected markets.

In Hydro One's Transmission Rate Application (EB-2006-0501), the Board approved a stakeholder settlement agreement which, among other things, called for the current ETS tariff of $1/MWh to be maintained for the time being; however, the IESO was identified as the entity

---

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

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 ETS tariff study and recommendation was filed with the Board on August 28, 2009, the complete ETS tariff report and supporting documentation is provided as Attachment 1 to this exhibit. The study findings and recommendation served to highlight the operational benefits of the export electricity market to Ontario and the value of pursuing ETS tariff design principles, or an ETS tariff, that will maximize the benefits of integrated regional electricity markets and trades. This goal is consistent with the current realities facing the electricity industry in Ontario and is also aligned with the Board's longstanding premise that reducing energy costs through competition can be served by the development of larger, open and integrated power markets where trade can take place with the minimum of impediment, an outcome that an appropriately designed ETS tariff can play a significant role in achieving.

## 2.0 SUMMARY OF EXPORT TRANSMISSION SERVICE TARIFF STUDY

A working group (IESO Stakeholder Engagement SE-78) comprising of various electricity sector market participants was established to support this work. The stakeholder engagement process provided a forum through which individuals or organizations with an interest in, or concern about, the ETS tariff could provide the IESO with their input.

There were three primary ETS tariff design options identified in the settlement agreement for the IESO to study. A fourth option was later added to the scope of study at the behest of stakeholders. The four ETS tariff design options that were ultimately assessed as part of the study are as follows:

**Option 1:** Status Quo – Under this option the ETS tariff would remain at $1/MWh applicable to export and wheel-through transactions.

**Option 2:** Equivalent Average Network Charge - Under this option, export and wheel through transactions would pay a rate equivalent to the average Network Transmission Service cost, but using energy as the charge determinant (i.e. $/MWh).

**Option 3:** Reciprocal Treatment of the ETS Charge - This option considers two potential forms of reciprocal treatment:

1) the mutual elimination of all ETS tariffs between jurisdictions; and
2) establishing Ontario's ETS tariff based upon the regulated average network cost of providing transmission service in each of the other jurisdictions, except New York wherein the ETS is deemed to be jointly eliminated.[2]

**Option 4:** Unilateral Elimination of the ETS tariff - This option considers two potential scenarios:

1) unilateral elimination of the tariff in all hours; and
2) unilateral elimination of the tariff only during off-peak hours.

The study approach adopted by the IESO for this work involved both quantitative and qualitative review and assessment. The quantitative review involved the examination and analysis of a number of key variables in order to determine the incremental changes in these variables against the "Status Quo". Charles River Associates International (CRA) was contracted, via a competitive tendering process, to undertake the quantitative aspect of the review and analysis using its North American Electricity and Environment Model (NEEM)[3]. The summary of results of the quantitative review is set out in Tables 3 – 5 of the ETS tariff report. The test variables are reflective of stakeholders' broad interests and concerns in regards to the ETS tariff and are as follows:

[2] The IESO and the New York Independent System Operator reached tentative agreement earlier to engage in discussions towards mutually elimination of the export transmission service tariff between Ontario and New York.
[3] NEEM is a production model which represents the U.S. electric power system and portions of the Canadian system.

a) **Total electricity export and import volumes** - a measure of the projected incremental change in export, wheel-through and import volumes.

b) **ETS tariff revenues –** a measure of the projected incremental change in export and wheel-through revenues.

c) **Hourly Ontario Energy Price (HOEP) –** a measure of the incremental change in HOEP.

d) **Market efficiency** – a measure of allocative efficiency calculated as the incremental change in the consumer and producer surplus.

e) **Cross-border emissions –** a measure of the total change in NOx, SOx and CO2 from generation sources in the region associated with incremental import and export and wheel-through volumes.

As part of our work, the IESO held a series of preliminary discussions with our neighbours to ascertain their willingness to work towards developing acceptable reciprocal agreements for the elimination of all ETS tariffs between our respective markets. With the exception of New York, our preliminary discussions concluded that elimination of the ETS tariff was not considered a priority to our neighbours at that time.

The IESO also concluded a series of qualitative reviews aimed at testing whether there would be any expected regulatory or legal impediments to the selection or implementation of the ETS tariffs under consideration, or that would create any operational challenges in the administration of the electricity markets or maintaining the reliability of the IESO-controlled grid. The summary results of the qualitative assessments are set out in Table 6 of the ETS tariff report.

## 3.0 ETS TARIFF STUDY KEY FINDINGS AND RECOMMENDATION

The results of the IESO's analysis and assessment indicated that Option 2 (i.e., a tariff based on Average Embedded Network Transmission cost) best satisfies the principles of simplicity of implementation, consistency with rates in neighbouring markets, fair and equitable, and net Ontario benefit, principally through shifting of a portion of transmission network cost recovery from the domestic consumer to the exporting parties. As discussed earlier in this submission, under Option 2 exporters would pay a tariff on export and wheel-through transactions from Ontario that would be equivalent to the Average Network Transmission Service cost. For the purpose of the study, this was estimated to be approximately $5.00/MWh, adjusted to the base-year 2007.[4]

The IESO noted that it observed that a number of factors that could materially alter the results of the ETS tariff study had changed significantly from the period when the study began, some of which may continue to evolve for sometime into the foreseeable future. These factors included load deterioration due to economic conditions and the transformation of Ontario's resource mix as a result of recent legislative changes (specifically the Green Energy and Green Economy Act) which are expected to combine to increase occurrences of surplus base-load generation conditions over the next few years. All of these changes have served to highlight the continued operational benefits of a vibrant export market. During low load periods, especially relative to Option 2, the current tariff will contribute to alleviating or even avoiding surplus base-load generation situations through the facilitation of export sales. As the deployment of renewable electricity resources become more prevalent in Ontario, supply is expected to become more variable and exports can help manage such variability through capturing the benefits of resource diversity in the region, as well as potentially contributing to short, intermediate and long-term energy balancing (e.g., by way of better sharing of reserve and regulation through the interties).

In view of this, the IESO concluded that greater value or weighting should be placed on tariff design principles, or an ETS tariff, which will maximize the benefits of integrated regional electricity markets and trades with our neighbours. Accordingly, the IESO found that implementing an ETS tariff such as Option 2, while appearing to be attractive from the

[4] 2007 was established as the base year for the study (i.e., it provided a basis on which to measure and analyse the incremental effects of each ETS tariff option on export and import volumes, export revenues, HOEP, market efficiency and cross-border emission the 2010 and 2015 test years). The Average Embedded Network Cost was determined by dividing the 2007 aggregate network revenue requirement for all Ontario transmitters (approximately $700 Million), as filed with the Ontario Energy Board, by the annual provincial energy consumption (approximately 150 TWh).

perspective of increased export revenues, would place downward pressure on export volumes in a climate of lower electricity demands and a future faced by potentially significant increases in variable renewable generation. In the IESO's view, this would not be a prudent decision considering the new reality of the electricity market in Ontario. Furthermore, the magnitude of the net Ontario benefits observed in Option 2 are relatively small (i.e., $20 Million in 2010 and $13 Million in 2015) when compared with the overall size of the electricity market in Ontario (i.e. $10 Billion in annual sales) and may well be further degraded as a result of the changing conditions. The effects of the current ETS tariff on the electricity market are well known. It appears that the incremental benefit seen with Option 2 is not sufficiently material as to warrant a change to the export tariff.

The study also assessed whether there are any genuine legal or regulatory impediments with continuation of the current ETS tariff that could lead to (i) potential conflicts with existing inter-jurisdictional trade obligations; (ii) compliance issues with respect to domestic electricity export permit and license obligations; and (iii) potential conflicts relating to foreign reciprocal transmission access, tariff design and export principles. It was concluded that continuation with the status quo is not likely to hinder Ontario market participant's ability to comply with applicable laws and regulatory practices. Additionally, the study also reviewed trade patterns influenced by the current ETS tariff, as well as examined the potential impacts, on reliability and operation of the IESO-controlled under various changing market conditions, and concluded that these are also manageable. Therefore, the IESO recommends that we maintain the ETS tariff of $1.00/MWh throughout the period of the current planned transformation of the electricity industry in Ontario or until the IESO have engaged and concluded agreements with willing neighbours regarding reciprocal elimination of the export tariffs with those jurisdictions. The IESO believes that gradual steps towards the elimination of the ETS tariff with neighbours continues to be a worthwhile goal, as this will contribute to maximizing market efficiency and trades within the region. To this end, the IESO will undertake to negotiate reciprocal agreements with willing partners for the elimination of the export transmission tariff; in particular, the New York Independent System Operator who has already shown interest in pursuing this end.

## 4.0 SUMMARY

1. The ETS tariff study findings and recommendation served to highlight the operational benefits of the export electricity market to Ontario and the value of ETS tariff design principles, or an ETS tariff, that will maximize the benefits of integrated regional electricity markets and trades.

2. Consideration of ETS tariff design principles, or an ETS tariff, that will maximize the benefits of integrated regional electricity markets and trades is a desirable goal given the new reality of the electricity industry in Ontario. This aim is also consistent with the Board's longstanding premise that reducing energy costs through competition can be served by the development of larger, open and integrated power markets where trade can take place with the minimum of impediment, an outcome that an appropriately designed ETS tariff can play a significant role in achieving.

3. The IESO recommends that we maintain the ETS tariff of $1.00/MWh throughout the period of the current planned transformation of the electricity industry in Ontario or until the IESO has engaged and concluded discussions with willing neighbouring system and market operators regarding reciprocal elimination of the export tariffs with respective jurisdiction(s).

4. The Status Quo (ETS rate of $1.00/MWh) has been assumed to be in effect for test years 2011 and 2012 for the purpose of determining Hydro One's revenue requirement and associated rates for Network Service.

5. It is understood that continuation of current ETS tariff of $1.00/MWh does not limit in any way the IESO's pursuit of reciprocal agreements to eliminate the tariff with other willing jurisdictions. Subject to approval by the Board, any reciprocal agreement(s) negotiated by the IESO in this regard would supersede the existing ETS tariff applicable to transactions with and through those jurisdiction(s) with which the IESO has negotiated a reciprocal agreement.

# Export Transmission Service (ETS) Charge

## Recommendation of an Appropriate ETS Charge for Ontario

August 2009

# Table of Contents

# 1.0 Introduction

Export Transmission Service (ETS) tariff revenues are based on the volume of electricity exported from or wheeled-through Ontario at a rate of $1/MWh. The IESO collects these revenues and remits them on a monthly basis to the transmission company whose transmission system is used to facilitate the export. Ontario's ETS tariff has not changed in the past decade since it was originally set in 1999. At the time, it was considered to be a compromise between the many competing proposals that were advanced by stakeholders in the course of that year's proceeding. Moreover, it was seen as an interim solution to a rather complex and contentious issue.

In Hydro One's Transmission Rate Application (EB-2006-0501), the parties to the settlement agreement were supportive of the IESO 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 expected that this study would be completed prior to the 2010 transmission rate re-setting process and it was understood that any change to the ETS tariff must be approved by the Ontario Energy Board (the "Board") as part of this process. As an outcome of the earlier Hydro One preceding the IESO was asked to consider a minimum of three options. A fourth option was later added to the scope of work at the request of stakeholders.

The four options that were assessed as part of the study are as follows:

**Option 1:** Status Quo – Under this option the ETS tariff would remain at $1/MWh applicable to export and wheel-through transactions.

**Option 2:** Equivalent Average Network Charge - Under this option, export and wheel through transactions would pay a rate equivalent to the average Network Transmission Service cost, but using energy as the charge determinant (i.e. $/MWh).

**Option 3:** Reciprocal Treatment of the ETS Charge - This option considers two potential forms of reciprocal treatment: 1) the mutual elimination of all ETS tariffs between jurisdictions; and 2) establishing Ontario's ETS tariff based upon the regulated average network cost of providing transmission service in each of the other jurisdictions, except New York wherein the ETS is deemed to be jointly eliminated.

**Option 4:** Unilateral Elimination of the ETS tariff - This option considers two scenarios: 1) unilateral elimination of the tariff in all hours; and 2) unilateral elimination of the tariff only during off-peak hours.

A working group (Stakeholder Engagement SE-78) comprising of various electricity sector market participants was established to support this work. The stakeholder engagement process provided a forum through which individuals or organizations with an interest in, or concern about, the ETS tariff could provide the IESO with their input. A list of the stakeholder working group participants is provided in Appendix B. A summary of stakeholder feedback received to date is provided in Appendix C. In addition, further information regarding the stakeholdering activities is available on IESO's web site at http://www.ieso.ca/imoweb/consult/consult_se78.asp

# 2.0 Study Approach

## 2.1 OVERVIEW

The study approach adopted for this work involved both a quantitative and qualitative review. The quantitative review involved the examination and analysis of a number of key variables in order to determine the incremental changes in these variables against the Status Quo. The summary of results of the quantitative review are set out in Tables 3 – 5. The test variables are reflective of stakeholders' broad interests and concerns in regards to the ETS tariff. These are as follows:

a) **Total electricity export and import volumes** - a measure of the projected incremental change in export, wheel-through and import volumes.

b) **ETS tariff revenues** – a measure of the projected incremental change in export and wheel-through revenues.

c) **Hourly Ontario Energy Price (HOEP)** – a measure of the incremental change in HOEP.

d) **Market efficiency** – a measure of allocative efficiency calculated as the incremental change in the consumer and producer surplus. [1]

e) **Cross-border emissions** – a measure of the total change in $NO_x$, $SO_x$ and $CO_2$ from generation sources in the region associated with incremental import and export and wheel-through volumes. [2]

The aim of the study was not to optimize any of the variables but rather to ascertain and measure the incremental impact on these variables attributed to each ETS tariff option. In so doing, this would allow the IESO to determine an "appropriate" ETS tariff based on findings of the independent study. Charles River Associates International (CRA) was contracted, via a competitive tendering process, to undertake the quantitative aspect of the review and analysis using its North American Electricity and Environment Model (NEEM).[3]

The results of CRA's quantitative analysis are included in the *Export Transmission Service (ETS) Tariff Scenario Analysis – Final Report and Findings* ("the ETS Report") which is included in Appendix A.

The IESO also conducted a series of qualitative reviews aimed at testing whether there would be any regulatory or legal impediments to the selection or implementation of the ETS tariffs under consideration, or that would create any operational challenges in the administration of the electricity markets or maintaining the reliability of the IESO-controlled grid. The summary results of the qualitative assessments are set out in Table 6.

---

[1] The **consumer surplus** is the amount that Ontario consumers benefit by being able to purchase electricity for a price that is less than they would otherwise be willing to pay. The **producer surplus** is the amount that producers benefit by selling at a market price higher than they would otherwise be willing to sell for in the market. The change in consumer surplus is calculated using the price change in each load block. The change in producer surplus is calculated using the changes in the total energy margin for all Ontario units (energy margin is the difference between energy revenue and variable costs). The change in total surplus is determined as the sum of the changes in consumer surplus and producer surplus and is an aspect of determining the net benefit to Ontario of each ETS tariff option considered. In the ETS tariff study, the net benefit to Ontario that is attributed to the tariff is determined by adding total surplus and export revenues.

[2] Cross-border emissions are generally of concern to stakeholders such as the Green Energy Coalition and Pollution Probe whose primary interest in this matter is to ensure that the export and wheel-through tariff, or policy change, will not exacerbate or promote increased emission discharge from generation resources in the region.

[3] NEEM is a production model which represents the U.S. electric power system and portions of the Canadian system.

The results of the quantitative and qualitative reviews provided useful insight into the impacts of each ETS tariff option under consideration and assisted the IESO in developing its recommendation of an appropriate tariff for Ontario. For an ETS tariff to be considered appropriate, it should be characteristic of, or demonstrated to exemplify, the following principles which were also adopted from Hydro One's transmission rate proceeding:

- Simplicity of implementation (i.e., the tariff should be relatively simple to implement and administer);
- Consistency with rates in neighbouring markets (i.e., the tariff should be comparable to neighbouring markets);
- Fair and equitable (i.e., the tariff should reflect the cost of the transmission network that is used to provide the service and all users should contribute to this cost accordingly) ; and
- Net Ontario Benefit (i.e., the tariff should result in Ontario being better off overall).

## 2.2 CALCULATION OF ETS TARIFF AND ALL-IN COSTS

The ETS tariff values and associated transactions costs used in the study are set out in the tariff and costs matrix that is found in *Appendix B – ETS Tariff and All-In Costs* of the ETS Report. A summary of these charges are also provided in Table 1 below.

The following assumptions and approach were adopted in determining the ETS tariff values for years 2010 and 2015 (future year values were adjusted to 2007 dollar values using time value for money):[4]

- For the year 2007, the IESO assumed an Ontario ETS Tariff of $1.00/MWh and associated uplifts of $3.48/MWh.

- The average embedded network cost associated with Option 2 was determined to be $5.00/MWh. This is based on the Ontario transmitters' network 2007 revenue requirements as filed with the Ontario Energy Board (approximately $700 Million) divided by the annual provincial energy consumption (approximately 150 TWh). All-in costs for other jurisdictions were developed from a number of sources including publicly available transmission tariff

[4] It was important to adjust future year's values into 2007 values given that the baseline and comparator year is 2007; accordingly, this provided an equal basis on which to measure and analyse incremental changes from each of the ETS tariff. All references to dollars are in Canadian currency, except where otherwise noted.

schedules and the J.R. Rudden survey report on neighbouring transmission export and wheel through service rates that was prepared earlier for Hydro One. As agreed by stakeholders, the ETS tariffs for the other jurisdictions should be based on their annual firm transmission service schedule to permit suitable comparison.

**Table 1 – Summary of Export and Wheel-through Costs**

| **Path** | | **Export & Wheel-through Costs ($/MWh)** | | |
|---|---|---|---|---|
| Source | Sink | Transmission Service Charge | Other Charges | All-In Export Costs |
| ON | NY, MISO, HQ | 1.00 (Status Quo) | 3.48 | 4.48 |
| | | 5.00 (Option 2) | 3.48 | 8.48 |
| HQ | ON | 8.08 | 4.44 | 12.52 |
| MISO | ON | 4.49 US | 0.61 US | 5.10 US |
| MISO | PJM | 0.00 US | 0.61 US | 0.61 US |
| NYISO | ON | 3.42 US | 3.18 US | 6.30 US |
| PJM | MISO | 0.00 US | 0.55 US | 0.55 US |
| PJM | NYISO | 3.35 US | 0.55 US | 3.90 US |
| NYISO | PJM | 4.71 US | 3.18 US | 7.89 US |

- The 2007 ETS tariff and all-in costs were estimated to increase by the annualized change in the Consumer Price Index (CPI) as forecasted by the Toronto Dominion (TD) Economics as of March 2009. The annual CPI change forecast for year 2015 was kept at the 2013 level, the longest horizon covered.
- Projected currency valuation (i.e., exchange rates used for converting US and Canadian dollars) was also based on TD's Bank Exchange Rate and Inflation Forecasts[5]. The exchange rate for year 2015 was kept at the year 2010 level, the longest horizon covered.

[5] The referenced forecasts can be found at: www.td.com/economics/qef/long term mar09.pdf.

- The TD's CPI Adjustments were also used to rebase, in 2003 US dollars, for the years 2010 and 2015.

The example below provides the calculation used to determine the Status Quo 2010 export tariff out of Ontario ( 2008 $ /MWh) as shown in *Appendix B – ETS Tariff and All-In Costs* (page 84) of the ETS Report. All amounts shown in Appendix B of the ETS Report are calculated in a similar manner:

<u>2010 Status Quo Export Tariff out of Ontario (in 2008 $ /MWh): **$1.02**</u>

- Ontario ETS for year 2007: **$1.00**
- Use the annualized March 2009 TD Forecast for CPI to reflect the 2010 Ontario ETS Tariff of **$1.02** (escalation factors for 2008: +2.4%; 2009: -0.8%; 2010: +0.8%)
- Use Exchange Rate of 1.136525 to convert for the 2010 Ontario ETS Tariff to **$0.90 USD** ($1.02 Cdn/1.136525)
- Rebase in 2003 USD for 2010 Ontario ETS Tariff using TD Forecast CPI Adjustment of 1.16562: **$0.77 USD** ($0.90 USD/1.165652)
- Use CPI adjustment of 1.170386 to convert to 2008 USD and Exchange Rate of 1.136525 to convert back to 2008 Cdn: **$1.02** ($0.77 USD*1.170386*1.13625)

# 3.0 Recommendation

The IESO's quantitative and qualitative analysis indicates that Option 2 (i.e. a tariff based on Average Embedded Network Transmission cost) would be the tariff option that best satisfies the four selection principles of simplicity of implementation, consistency with rates in neighbouring markets, fair and equitable, and net Ontario benefit, principally through shifting of a portion of transmission network cost recovery from the domestic consumer to the exporting parties.

Since undertaking the study the IESO has observed a number of factors that have changed significantly including: load deterioration due to economic conditions, recent legislative changes through the Green Energy and Green Economy Act, and increased occurrences of surplus base-load generation conditions. All of these changes have served to highlight the operational benefits of exports. During low load periods, surplus situations can be alleviated or even avoided through exports. As variable renewable resources become more prevalent in Ontario, the supply/demand balance will become more volatile and exports can help smooth out such volatility. As a result, a recommendation that would place downward pressure on exports is not considered appropriate or consistent with the new reality of lower demands and a future with significant increases in variable renewable generation. The magnitude of the net Ontario benefits observed in option 2 are relatively small ($20M and $13M in 2010 and 2015) when compared with the overall Ontario transactional costs (i.e. $10 B in annual sales) and may well be further degraded as a result of the changing conditions. It appears that the incremental benefit seen with option 2 is not sufficiently material as to warrant a change to the export tariff. The IESO therefore recommends that we remain with the $1/MWh until such time as conditions change or we are able to engage in meaningful discussions with our neighbours regarding the reciprocal elimination of the export tariffs; the option which we believe would be the most beneficial option for efficiency in the region and for the province of Ontario.

**Table 2 – Summary of Selection Principles Comparison**

| ETS Tariff Option | Simplicity of implementation | Consistent with rates in neighbouring markets | Fair & Equitable* | Net Ontario Benefit** |
|---|---|---|---|---|
| Option 1 - Status Quo | Simple | No | No | N/A |
| Option 2 - Equivalent Average Embedded Network Rate | Relatively Simple | Yes | Yes | Positive |
| Option 3 (1) - Reciprocal Treatment - Joint ETS tariff elimination | Complex | Yes | Yes | Negative |
| Option 3 (2) - Reciprocal Treatment - Avg. Embedded Network Cost, except New York. | Moderately complex | Yes | Partial | Negative |
| Option 4 (1) - Unilateral Tariff Elimination - In All-hours. | Simple | No | No | Negative |
| Option 4 (2) - Unilateral Tariff Elimination - Off-peak hours only. | Moderately complex | No | No | Negative |

*As a measure of user pay principles.
** As a measure of total surplus (i.e., sum of consumer and producer surplus) and export revenues.

# 4.0 General Assumptions

## 4.1 STUDY INPUTS AND DATA SOURCES

The ETS tariff study was performed using input data and information from a number of sources including public and commercial agencies. In particular, the load forecast and underpinning resource mix and developmental plan for the 2010 and 2015 test years was provided by the Ontario Power Authority (OPA). Some of the key inputs and assumptions used in the study are listed in the final report under the "*Key Assumptions for Calibration and Scenario Analysis*" section of the ETS Report (pages 7 – 16) which is included in Appendix A.

# 5.0 Quantitative Assessment

## 5.1 DESCRIPTION OF THE MODEL

As noted earlier, the ETS tariff study and economic analysis were carried out by CRA using its proprietary North American Electricity and Environment Model (NEEM). The NEEM is a regional production cost model that represents the US electric power system as 29 regions and portions of the Canadian system as 5 regions (i.e., BC, Alberta, Manitoba, Ontario and Quebec). For this particular analysis, the model constructs a generation offer curve based on the estimated production costs of Ontario generating units.[6] The model then uses this supply stack (i.e., a ranking of the generation costs) to meet forecasted demand using lowest cost generation first and the most expensive generation last. This matching of supply and demand occurs in the model (using "load blocks") while respecting the capability of the interties connecting Ontario with surrounding markets and neighbours (i.e., Quebec, New York, PJM and MISO which included Manitoba). The transaction costs associated with trades (i.e., all-in cost which includes the ETS tariff and other related export or wheel-through transaction charges) are also factored into the model in order to generate the most economical trades based on the price differentials between markets. In other words, the model permits imports and exports between regions in order to optimize the total system supply costs. Accordingly, trade decisions are assumed to incorporate the all-in costs, and critical to this analysis of the export tariffs, pertaining to inter-market transactions. The model produces key outputs for Ontario such as prices (HOEP), export and import volumes, export revenues, consumer and producer surplus and emission quantities and permits the calculation of Ontario net benefit and the assessment of impact on SBG events. It was also important, for the effectiveness of the study, that the tool be able to model Ontario's mix of forecasted generation, and cost structure in future years.

[6] Production costs for the Ontario generating units were estimated by CRA.

## 5.2 BENEFITS OF THE MODEL

The NEEM uses a large amount of input data and assumptions to represent and approximate the dynamic operation of the North American power system while respecting a number of operational factors including:

- Capability of interties and interregional power flows;
- Reserve margins requirements;
- Environmental constraints;[7]
- Generating resource operational capability and energy limits; and
- Generation unit's maintenance requirements.

For the study, 2007 was established as the baseline year. The model was calibrated and the key outputs verified against 2007 actual results. The calibrated model produced outputs that closely mirrored the 2007 baseline actual results (as can be seen on pages 20 to 23 of the ETS Report). This exercise provided confidence that the model is able to produce results that reasonably approximate real-world situations.

As with most modelling exercises, there was a need to make some trade-offs between the level of detail deemed necessary in order to gain meaningful insight into the likely impacts of each ETS tariff option on the key test variables, and the resources and time required to do so. NEEM was determined to be appropriate in this regard. Modeling the ETS tariff options was a fairly complex exercise requiring consideration of many inter-related and moving parts. For example, for this analysis it was necessary that the tool had the ability to model the dynamic trade flows between regions.

## 5.3 ASSUMPTIONS AND POTENTIAL LIMITATIONS OF THE MODEL

In carrying out the study there was a need to simplify certain features of the Ontario market or how these are features are replicated in the model in order to create a reasonable representation of the integrated power system. It is not possible to perfectly represent all aspects of the real-world or the dynamic nature of the integrated power system in the model due to, among other things, complexity and lack of information about these features. However, through simplification these were reasonably

[7] It was important to model the potential effects of Ontario emissions policy (i.e., coal retirement and limits on sulphur dioxide and nitrogen dioxide) as well as future impact of a North American Federal carbon policy. Given this, these policies are expected to influence, among other things, resource mix and trade patterns.

replicated. While simplification of certain features may contribute to disparities between the observed and actual results, a review of the calibrated baseline results would suggest that any such disparities are unlikely to be sufficiently material as to alter the results. The following section discusses the various assumptions or simplifications that were adopted and used in the model.

### Treatment of gas generators

There are a number of generators with signed contracts in place with the OPA. As a result, some may have incentives to respond to prices while others may not. Furthermore, how certain gas generators offer into the market may also be influenced by their participation in programs such as Spare Generation On-Line (SGOL) and Day Ahead Commitment Process (DACP). Since these details are generally not public knowledge or may be limited for the most part, these resources may have been modelled in more limited detail than the specific provisions of their operational arrangements. In addition, all Non-Utility Generators (NUGs) and Combined Heat and Power (CHP) resources are treated as price-taking resources (i.e., their bidding behaviour and output is not deemed to be influenced by the market prices in the model).

New gas generation resources are treated in the model as price sensitive merchant generation. Strategic bidding of gas units are simplified in the model and the peak gas units are assumed to always bid a fixed percentage over their variable cost at all times, but are restricted from bidding in such a way as to capture scarcity rents.[8] In addition, except for the calibration of the model where Lennox G.S. production was adjusted to reflect actual 2007 output, the output from Lennox G.S. was allowed to vary with prices in the market for the test years 2010 and 2015.

[8] Rents are the difference between the price and the marginal cost during scarcity conditions.

### Treatment of coal generation

Coal generation, although the full capacity is available, is modeled to respect the emissions limits (i.e., $NO_x$, $SO_x$ and $CO_2$) imposed by Ontario's environmental regulation. Furthermore, in reality the units may actually be producing less energy than is limited by the emissions caps.

### Treatment of Quebec and New York hydroelectric generation

In general, Quebec and New York hydroelectric production profiles are based on publicly available data sources. This is due to a lack of access to generation production information in those markets, as well as our limited understanding of how these resources are expected to operate strategically in these regions. For example, the month-to-month variation in Quebec hydroelectric production was estimated using NEB statistics and demand data filed with the North American Electric Reliability Corporation (NERC). A run-of-the-river portion of hydropower production was estimated based on minimum load requirements and historical operational information for Quebec and New York, respectively.

### Consideration of potential transmission limitations

Ontario was modeled as a single electricity pool and the transfer capacity on the interties were assumed to be the same for every hour of the year (i.e., the study did not account for potential transmission constraints or operational limitations within Ontario and the interties).

## 5.4 KEY STUDY FINDINGS AND CONCLUSIONS

The study and analysis provided the basis on which to identify any correlation between the ETS tariff and export and import volumes, producer and consumer surplus, export revenues, HOEP, market efficiency and emissions. The study also provided a basis on which to assess whether there is a material correlation between the ETS tariff options and SBG events. The following is a summary of some of the key findings and conclusions from the ETS tariff study:

## Impact on Export and Import Volumes

Unilateral elimination of the ETS tariff (i.e., Option 4) will contribute to marginal increases in export volumes from the Status Quo but imports are generally less affected on an absolute basis. In the case where the ETS tariff is mutually eliminated in all jurisdictions (i.e., Option 3, Scenario 1), increase in export volumes from the Status Quo are expected to be greater on average; however, import volumes are even more affected because Ontario's neighbours have a higher export tariff to begin with (i.e., all things being equal, external participants will see a greater change in the incremental price differentials between markets with joint elimination of the ETS tariff). For example, under Option 3, Scenario 1, as illustrated in Table 3, in 2010 export and import volumes will increase by as much as 38% and 174%, respectively. On the other hand, an increase in the ETS tariff from the Status Quo will tend to add downward pressure on export volumes. In this regard, as can also be seen in Table 3, Option 2 is expected to add downward pressure on export volumes by as much 35% in 2010 and 46% in 2015.

## Producer and Consumer Surplus

Options that are associated with unilateral elimination of the ETS tariff (i.e. Option 4 scenarios 1 & 2) tend to increase producer surplus (i.e., correlates with increased export volumes) and correspondingly reduce consumer surplus resulting from upward pressure on HOEP associated with more export demand. As can be seen in Table 3, under Option 4, scenarios 1 and 2, in 2010 the incremental producer surplus was $102 million and $35 million, respectively. Conversely, under the options where the ETS tariffs are increased or mutually eliminated, this tends to increase consumer surplus and decrease producer surplus. Option 2 involves a unilateral increase in the ETS tariff, consequently reducing external demand for Ontario power which will add downward pressure on HOEP. In addition, given that Ontario's ETS tariff is considerably lower than its neighbours to begin with, reciprocal tariff elimination (i.e., Option 3, Scenario 1) will tend to reduce net exports from Ontario which decreases producer surplus and increases consumer surplus. While mutual elimination of the ETS tariffs also appears to be an attractive option, this will be very difficult to achieve in the near term.

**Table 3 - Summary of Incremental ETS Tariff Impacts**

| ETS Tariff Option | Export Volume (GWh) | | Import Volume (GWh) | | Producer Surplus ($Millions) | | Consumer Surplus ($Millions) | |
|---|---|---|---|---|---|---|---|---|
| Test Year | 2010 | 2015 | 2010 | 2015 | 2010 | 2015 | 2010 | 2015 |
| Status Quo | 11,715 | 12,996 | 5,511 | 5,259 | $5,971 | $9,999 | - | - |
| Avg. Embedded Network Rate | -35% | -46% | -33% | -35% | -$214 | -$187 | $207 | $176 |
| Reciprocal Treatment - Joint ETS Tariff Elimination | 38% | 24% | 174% | 158% | -$299 | -$198 | $297 | $192 |
| Reciprocal Treatment - Avg. Embedded Network Cost | 1% | -1% | 3% | -5% | -$14 | -$53 | -$5 | $46 |
| Unilateral ETS Tariff Elimination - All-Hours | 7% | 10% | 14% | 6% | $102 | $59 | -$111 | -$56 |
| Unilateral ETS Tariff Elimination - Off-Peak Hours | 3% | 6% | 6% | 1% | $35 | $20 | -$36 | -$18 |

**All dollar values are 2008 dollars.**

## Export Tariff Revenues

ETS tariff revenues rise in the scenarios that involve tariff increases; while this tends to reduce export volume, in general, the reduced exports volumes are offset by the higher tariff revenues (i.e., Option 2 and Option 3, scenario 2);

## Impact on HOEP

A lower tariff also results in upward pressure on HOEP because external demand and exports from neighbouring markets are expected to rise. Conversely, as can be seen in Table 4, where there are increases in the tariff this tends to add downward pressure on HOEP.

**Table 4 - Summary of Incremental ETS Tariff Impacts**

| ETS Tariff Option | ETS Tariff Revenues ($Millions) | | HOEP ($/MWh) | | Market Efficiency ($Millions) | | Net Ontario Benefit ($Millions) | |
|---|---|---|---|---|---|---|---|---|
| Test Year | 2010 | 2015 | 2010 | 2015 | 2010 | 2015 | 2010 | 2015 |
| Status Quo | $12 | $13 | $52 | $79 | - | - | - | - |
| Avg. Embedded Network Rate | $27 | $23 | -2.5% | -1.4% | -$7 | -$10 | $20 | $13 |
| Reciprocal Treatment - Joint ETS Tariff Elimination | -$12 | -$13 | -3.7% | -1.6% | -$1 | -$6 | -$13 | -$19 |
| Reciprocal Treatment - Avg. Embedded Network Cost | $2 | $2 | -0.2% | -0.4% | -$19 | -$7 | -$17 | -$5 |
| Unilateral ETS Tariff Elimination - All-Hours | -$12 | -$13 | 1.3% | 0.4% | -$9 | $3 | -$21 | -$10 |
| Unilateral ETS Tariff Elimination - Off-Peak Hours | -$9 | -$10 | 0.5% | 0.2% | -$1 | $2 | -$10 | -$8 |

**All dollar values are 2008 dollars.**

## Market Efficiency

Establishing the definition of market efficiency enables the IESO to calculate the net incremental benefit to Ontario from each of the ETS tariff option. In this case, the market efficiency was determined based on the allocative efficiency, calculated as the net incremental change in the consumer and producer surplus or the “total surplus”. As discussed above, the study results show that there is a relationship between consumer and producer surplus and changes in the ETS tariff.

The overall net incremental Ontario benefit was determined based on the total surplus and ETS tariff revenues; accordingly.

## Emissions

It is expected that the potential impacts on $SO_2$ and $NO_x$ emissions will be relatively minor in all options considered, as a result of the following factors:

- Ontario's policy to close the coal fired generation plants concurrently reduces $SO_2$ and $NO_x$ emissions well below their regulated caps irrespective of the ETS tariff scenario;
- The US Clean Air Interstate Rule (CAIR) policy restricts the emissions of both pollutants in neighbouring U.S. regions; however, some scenarios show small increases in regional emissions relative to the Status Quo; and
- Under a North American cap-and-trade policy aimed at curbing $CO_2$ emissions, the ETS tariffs will have no significant effect on North American power system $CO_2$ emission levels because such a policy would control any $CO_2$ leakage that may be associated with export and import volumes resulting from a change in the ETS tariff.

**Table 5 - Summary of Incremental ETS Tariff Impacts**

| ETS Tariff Option | Cross-Border Emissions | | | | | |
|---|---|---|---|---|---|---|
| | Regional NOx (tonnes) | | Regional SOx (tonnes) | | Regional $CO_2$ (thousand tonnes) | |
| Test Year | 2010 | 2015 | 2010 | 2015 | 2010 | 2015 |
| Status Quo | 790,349 | 769,716 | 2,558,569 | 2,154,373 | 873,511 | 858,314 |
| Avg. Embedded Network Rate | -999 | -1,052 | -5,547 | -1,941 | 304 | 196 |
| Reciprocal Treatment - Joint ETS Tariff Elimination | -3,143 | 287 | -15,004 | -1,678 | 1,609 | 2,067 |
| Reciprocal Treatment - Avg. Embedded Network Cost | -327 | -449 | -905 | 606 | -516 | -342 |
| Unilateral ETS Tariff Elimination - All-Hours | -112 | -9 | -657 | 1,347 | -130 | -75 |
| Unilateral ETS Tariff Elimination - Off-Peak Hours | 103 | 68 | 22 | 244 | -6 | 34 |

# 6.0 Qualitative Assessment

## 6.1 OPERABILITY AND RELIABILITY IMPACTS

The ETS Tariff study conducted by the IESO also considered the potential reliability and operational implications of each of the ETS tariff options. This analysis involved a review of historical trade patterns under various market conditions as well as a qualitative examination of the potential impacts, on reliability and operation of the IESO-controlled grid, given incremental trade volumes (both increases and decreases) observed with each ETS tariff option. The IESO also reviewed the impact that each ETS tariff option would have on IESO settlement process and the market rules. For the purposes of the assessment, Option 1 – Status Quo, was used as a baseline against which the other options were measured. Although Option 1 is used as the baseline it does not suggest any preference to this option but is simply a means by which to compare the potential changes in trade volumes or impacts associated with each of the other options relative to today's environment.

### Assessment

Each of the ETS tariff options was studied with quantitative analysis performed by CRA. From this study each option has been shown to have pricing (HOEP), export revenue, import and export volumes, and market efficiency and emission impacts relative to the Status Quo. Because actual future outcomes will be impacted by changes in, among other things, economic activities, generation resource mix, government policy change (e.g., $CO_2$), etc. internal and external to Ontario, the IESO's reliability and operational assessment did not rely solely on the findings of the CRA study and analysis. The IESO also relied on its knowledge of historical practices and an understanding of how participants generally react to changing market and system conditions.

In the CRA findings the transactional changes relative to the Status Quo showed, depending on the option, export volume changes which range from a potential reduction of 35% to a 38% increase for the 2010 test period. Correspondingly, import volumes are projected to range from a potential 33% reduction to an increase of up to 174% of current export volume. Year 2015 revealed similar patterns with export volumes ranging from a potential 46% decrease to an increase of 24%, while import volumes range from a potential decrease of 35% to an increase of up to 158%. It is not possible to accurately predict the actual reliability or operational impacts that these changes will have on the integrated power system, given that changes to Ontario trade patterns will likely have an associated cause and effect in respect of the surrounding jurisdictions. In all ETS tariff cases however, a change in trade volumes will result in a change in loop-flows across the system and will also impact the frequency and magnitude of congestion arising from contract path scheduled flows, as well as unscheduled flows. Since market opening, the IESO has witnessed a wide range of transaction scheduling and loop-flows across the interfaces with our neighbours. For example, in 2002 during periods when Ontario was energy deficient, the IESO saw record imports exceeding 4,000 MW per hour, while more recently with the turn in the economy, due to reduced demands and large amounts of surplus base-load generation Ontario has been exporting at unprecedented volumes. In that time Ontario has also experienced a change in loop flow patterns where the predominately and sometimes extreme counter-clockwise Lake Erie circulation has reversed clockwise reaching comparable extremes.

During these dynamic periods of operation, the combination of market and operational responses and processes employed in Ontario has successfully managed reliability effects within the prescribed requirements of the prevailing standards authorities. On reviewing the CRA study, the IESO also observed that the incremental changes in trade volumes attributed to different ETS tariff options fall well within the boundaries of the extremes that have been observed to date; accordingly, they are manageable from a market and reliability perspective. The IESO's dispatch processes are designed to ensure that all transmission and adequacy requirements are maintained within reasonable limits, and the transmission system optimized and resources scheduled and dispatched to account for prevailing transmission limits, including the impact of loop-flow and demand requirements. The CRA study didn't reveal any new challenges that the IESO dispatch and reliability management processes cannot accommodate; accordingly potential operational and reliability impacts are considered manageable.

In reviewing the options under consideration only Option 2 and Option 3, scenario 2 would require market rule changes and Option 3, scenario 2 and Option 4, scenario 2 would require changes to settlement systems or processes. None of the other options considered would require market rule or settlement changes.

### 6.2 LEGAL AND REGULATORY ASSESSMENT

Qualitative research and analysis was undertaken to assess the potential legal and regulatory implications of each of the ETS tariff options (however, given that Option 3 was deemed to not be feasible mid-way through the study, legal and regulatory assessment of this option was limited)[9]. The research and analysis was carried out to determine whether there are any genuine legal or regulatory related impediments to the selection or implementation of each of the particular ETS tariff options and, among other things, focused on the following specific areas: (i) potential conflicts with existing inter-jurisdictional trade obligations; (ii) compliance issues with respect to domestic electricity export permit and license obligations; and (iii) potential conflicts relating to foreign reciprocal transmission access, tariff design and export principles.

As a result of its qualitative assessment, the IESO is comfortable that none of ETS tariff Options 1, 2 and 4, if implemented, appear likely to hinder Ontario market participant's ability to comply with applicable laws and regulatory practices.

### 6.3 SURPLUS BASELOAD GENERATION

Surplus base-load generation (i.e., SBG) is a condition that occurs when Ontario's electricity production from base-load resources such as nuclear, wind, non-utility generators (NUGS) and must-run hydroelectric units (e.g. Sir Adam Beck 1 and 2, Decew, and R.H. Saunders) is greater than market demand. Surplus base-load generation periods are typically the result of low demand and may be exacerbated by other conditions such as:

a) spring freshet when hydroelectric stations has limited ability to reduce their generation output;

---

[9] The primary basis for limiting further legal and regulatory assessment of Option 3 was twofold:

1) Given that the IESO was unable to secure interest among all the parties to pursue joint elimination of the ETS tariff, Option 3, Scenario 1 is not considered reasonable at this time; and

2) If implemented, Option 3, Scenario 2 would likely result in the Board having to materially depart from the traditional cost of service basis for approving or fixing just and reasonable rates for transmission service.

b) the inability of neighbouring jurisdictions to absorb surplus energy in the form of exports; and

c) high production from intermittent resources such as wind generation.

The issue of SBG was raised by several stakeholders who requested that the IESO consider how each of the ETS options will likely affect SBG outcomes in the future. Initially, this was considered to be outside the scope of the IESO's review; in particular, given the IESO's limited resources. With recent negative pricing in the Ontario market resulting from SBG, this heightened the need for consideration of other ETS tariff options and scenarios and potential impacts on future SBG occurrences. Given this situation, and in response to requests from various stakeholders, the IESO expanded the scope of its review to consider two additional ETS tariff options and to undertake a qualitative review of the potential impacts of each of the options on SBG events.[10]

The study and subsequent analysis shows that, given the assumptions regarding certain factors such as demand forecasts, resource mix, transfer capability and limitations and planned outages, we would not expect any SBG events in either 2010 or 2015 test years. This outcome is a function of the key assumptions that were used in the model. It is extremely difficult (if not impossible) to predict with any reasonable degree of accuracy how these factors are likely to unfold or develop in the future; accordingly, a potentially different outcome could occur if these key factors were to unfold in a materially different way from how they were modelled in the study. The following section summarises the key assessment and assumptions that were used to arrive at this conclusion.

## SBG Assessment and Assumptions

For our analysis the IESO used the SBG definition provided in the IESO Operability Report [11] and the simulated market conditions as represented in the CRA NEEM model to assess potential SBG events under each ETS option. The SBG analysis makes the following assumptions:

- Planned nuclear outages are optimally chosen by the model. As a result, these outages tend to occur in the fall/spring and are distributed evenly over the whole month;

[10] Bruce Power agreed to reimburse the IESO for some of the additional cost of studying the potential impacts of the ETS tariff on future SBG events.

[11] IESO Operability Review of OPA's Integrated Power System Plan, Issue 2 available at http://www.ieso.ca/imoweb/pubs/ircp/IESO-Operability_Review_of_IPSP.pdf

- The amount of run-of-the river (i.e., must-run) hydroelectric generation in Ontario during SBG periods varies between 3,100-4,700 MW in 2010 and 3,300-4,900 MW in 2015;
- Wind generation is considered as a price-taking non-dispatchable resource and is used ahead of nuclear generation;
- Combined Heat and Power (CHP) and Non-utility Generation (NUGs) are treated as price-taking non-dispatchable resources and they are also used ahead of nuclear generation; and
- The amount and duration of exports during SBG periods are determined within the model and are driven, in large part, by economical arbitrage opportunities between markets.

Under these assumptions the model selects the least costly set of generation assets that is required to meet a forecasted demand value in each load block. A load block is simply an interval of time that has a fixed demand value (the hours that comprise a load block in NEEM are typically not sequential). Whenever the nuclear generation is backed down across load blocks the analysis identifies potential SBG hours since it would suggest that there is too much base-load generation to meet demand in that block. It should be noted that the analysis and results are merely an indication of the "potential" for SBG to occur, because in reality the IESO generally has a number of control actions at its disposal to minimize the need for manoeuvring base-load resources such as nuclear and run-of-river hydro. Given the assumptions and data inputs which formed the basis of the analysis (e.g., demand, load shape, transfer capability), the study did not find SBG to be of a material concern in the test years 2010 and 2015 for any of the ETS options considered.

### Potential Limitations of SBG Analysis

The study simplifies a fairly complex market issue by attempting to predict future expected outcomes (i.e., SBG) based on a set of assumptions about future market conditions and events. From these assumptions, and the input data used, the model produces a set of results. A material change in any of the key inputs or assumptions can therefore have an impact on the outcome of the model. In section 5.3, we also discuss how certain features of the Ontario market were simplified or replicated in the model in order to create a reasonable representation of the integrated power system. This section provides a qualitative assessment of the potential impact on future SBG events resulting from a material change in key input data and assumptions.

### Demand Forecast

Future demand is among the most difficult factors to accurately predict. Over time, actual consumption may deviate from forecasted levels due to any number of uncontrollable factors such as weather or economic conditions. Needless to say that the demand forecast is also one of the most significant factors in determining the potential for occurrences of SBG events, their magnitude, and duration and timing of occurrence. As noted, the actual demand forecast used by the IESO in the study is based on the OPA's earlier outlook for the 2010 and 2015 tests years and is of particular importance to the study because they correspond with the OPA's current resource plan for same period. Since this earlier outlook the forecast has not been revised by the OPA to reflect any modifications to its assumptions. In 2009, we are already seeing demand levels which are significantly lower than was earlier forecasted. If this trend continues throughout the 2010 and 2015 test years, all other factors being equal, we would expect to see a higher frequency of SBG events than resulted from this analysis.

### Wind Generation Output

In the model, it is assumed that wind production is below nuclear generation in the generation supply stack and is also fixed across each load block. It is also assumed that wind production over test years will mirror that of 2007-2008 actual production profile. In the future, it is possible that wind production profile across Ontario may change and wind resource may be treated differently in the Ontario market; where currently it is treated as a base-load resource that is not responsive to changes in market prices, in particular during periods of surplus base-load resource. If the wind production profile across Ontario changes materially (e.g., increase frequencies when peak wind production coincides with low demand periods), all things being equal, this could contribute to increase occurrences of SBG events. On the other hand, if wind resource was treated as a dispatchable resource or made to be price responsive (e.g., if wind is manoeuvred down when prices are negative), this measure would likely contribute to lower frequencies of SBG occurrences. Deviations in the capacity of Ontario wind builds (versus planned) could also influence the number of SBG occurrences.

### Nuclear Outage Schedule

The NEEM model chooses the optimal time for scheduled nuclear outages; it does this in a way which allocates the outages uniformly across the month. For example, it may allocate nuclear outages for the whole month of April to correspond with high hydroelectric production from spring run-offs. In reality the facility may be out of service for only part of the month; consequently, this would have the effect of underestimating the amount of energy that may in fact be generated in the period and the potential frequency of SBG events in the analysis that might otherwise be observed in the period.

### Consideration of potential transmission limitations

In balancing demand and resources in the integrated markets, the model selects the optimal amount of net exports based on the price differences between markets. The model doesn't attempt to impose limitations on the interties to account for potential transmission outages, congestion or contingencies that could actually occur in real-time. This has the effect of showing potentially higher exports than might otherwise be reasonable if the interties were in fact restricted or de-rated in real time. For example, the study results show exports in certain circumstances in excess of 5,000 MW; in particular, during low demand periods in 2010 and 2015 (i.e., the lower demand periods usually correlates with the highest differential price periods). While we don't have any reason to believe this will not occur in the future, we are cognizant that the analysis doesn't take into consideration transmission limitations that could in fact occur during the period. Lower levels of exports than that considered by the model due to transmission limitations will have the effect of increasing the occurrences of SBG events, as well as impact the magnitude and periods of when these occur.

## 6.4 SUMMARY OF IMPLEMENTATION IMPACT TESTS

As noted earlier, the qualitative reviews were aimed at testing whether there would be any regulatory or legal impediments to the selection or implementation of the tariff, or that would create any operational challenges in the administration of the electricity markets or maintaining the reliability of the IESO-controlled grid. The summary results of the qualitative assessments are set out in the following table.

**Table 6 - Summary of Implementation Impact Tests**

| ETS Tariff Option | Implementation Impact Tests | | | |
|---|---|---|---|---|
| | Operations & Reliability | Regulatory & Legal | Surplus Base-load Generation Events | |
| | | | 2010 | 2015 |
| Status Quo | Impacts manageable. No rules or settlement changes required. | Regulatory and legal tests are satisfied. | Limited | Limited |
| Avg. Embedded Network Rate | Potential impacts manageable. Market Rules amendment required. | Regulatory and legal tests are satisfied. | Moderate | Moderate |
| Reciprocal Treatment - Joint ETS Tariff Elimination | Potential impacts manageable. No rules or settlement changes required. | Regulatory and legal tests are satisfied. | Limited | Limited |
| Reciprocal Treatment - Avg. Embedded Network Cost | Potential impacts manageable. Market Rules and settlement changes required. | Appears to be in conflict with traditional "cost of service" principles for approving or fixing just and reasonable rates. | Moderate | Moderate |
| Unilateral ETS Tariff Elimination - All-Hours | Potential impacts manageable. No rules or settlement changes required. | Regulatory and legal tests are satisfied. | Limited | Limited |
| Unilateral ETS Tariff Elimination - Off-Peak Hours | Potential impacts manageable. No rules changes required; however, minor settlement changes required. | Regulatory and legal tests are satisfied. | Limited | Limited |

Appendix A – Export Transmission Service (ETS) Tariff Scenario Analysis – Final Report and Findings, July 30, 2009.

Appendix B – List of Stakeholder Working Group Participants

Appendix C - Summary of Stakeholder Feedback

# Export Transmission Service (ETS) Tariff Scenario Analysis

## Final Report and Findings

Prepared for
Independent Electricity System Operator

July 30, 2009

INTERNATIONAL

## Key Study Objectives

- Assess and analyse the potential incremental impact of each ETS tariff option with respect to:
  - Hourly Ontario Energy Price (HOEP);
  - Export Revenues
  - Export and Import Volumes; and
  - Market Efficiency (i.e., total consumer and producer surplus)
- Aim is not to optimize these parameters; rather, to ascertain the potential incremental impact of each option on these key parameters.
- Observe and analyse potential incremental impacts on environmental emissions (i.e., $SO_2$, $NO_x$ and $CO_2$ ) in the region attributed to each ETS tariff option.

# General Conclusions

- ETS tariff options such as the *average embedded network rate* and the modeled *reciprocal treatment* tend to increase consumer surplus and decrease producer surplus
  - The average embedded network rate scenario involves a unilateral increase in the ETS tariff, consequently reducing external demand for Ontario power, and reducing the HOEP
  - Because Ontario has a lower export tariff than its neighbours, reciprocal tariff elimination reduces net exports from Ontario, decreases producer surplus, and increases consumer surplus.
- ETS tariff options such as *unilateral tariff elimination* tend to increase producer surplus and decrease consumer surplus
- Ontario's ETS revenues increase in the scenarios that involve ETS tariff increases
- Impacts on SO2 and NOx emissions are small as a result of:
  - Ontario's CO2 policy concurrently reduces those emissions well below their regulated caps irrespective of the ETS tariff scenario
  - The US Clean Air Interstate Rule (CAIR) policy restricts the emissions of both pollutants in neighbouring U.S. regions.
  - However, some scenarios show small increases in regional emissions relative to the status quo (but all scenarios are well below their caps)
- Under a North American cap-and-trade policy for CO2 emissions, the ETS tariff scenario will have no significant effect on North American power system CO2 emissions (because emissions would be set by the cap)

# Limitations of Analysis

- Contracted generator arrangements and obligations for the most part have been modeled with limited detail (i.e., with the exception of NUG/CHP resources)
- Strategic bidding behaviour within Ontario and within Ontario's neighbouring regions has been modeled in only a rudimentary fashion
  - Peaking gas units' bids are inflated to reflect strategic bidding on-peak
  - Coal units' bids are reduced to reflect bidding behaviour off-peak
- Implications of potential changes in uplift charges, and their consequential impacts on export/import transactions are not considered
- Limited understanding of hydropower output shape in Quebec and New York
- Some potential transmission constraints into, out of, and inside of Ontario are not modeled.  No internal constraints are modeled.

# Outline

**Key Assumptions for Calibration and Scenario Analysis**

**2007 Model Calibration Results**

**Scenario Definitions**

**Results by Scenario**

**Emissions Impacts by Scenario**

**General Conclusions**

**Appendices**

# Unit characteristics - coal

| Unit | Summer MW | Heat Rate (Btu/kWh) | SO2 Controls | NOx Controls |
|---|---|---|---|---|
| Atikokan GS 1 | 211 | | | |
| Lambton GS 1 | 485 | | | |
| Lambton GS 2 | 485 | | | |
| Lambton GS 3 | 475 | | FGD | SCR |
| Lambton GS 4 | 475 | | FGD | SCR |
| Nanticoke 1 | 440 | | | |
| Nanticoke 2 | 440 | | | |
| Nanticoke 3 | 460 | | | |
| Nanticoke 4 | 440 | | | |
| Nanticoke 5 | 460 | | | |
| Nanticoke 6 | 460 | | | |
| Nanticoke 7 | 480 | | | SCR |
| Nanticoke 8 | 480 | | | SCR |
| Thunder Bay GS 2 | 155 | | | |
| Thunder Bay GS 3 | 155 | | | |
| Capacity-weighted Average | 6,101 | | | |

**Sources: Ventyx Velocity Suite and IESO.**

**Note: Heat rates are considered confidential information; accordingly, these are not disclosed.**

Key Assumptions

# Unit characteristics (2007) - other

| Technology | Summer MW | Capacity-weighted Average Heat Rate (Btu/kWh) |
|---|---|---|
| Nuclear | 11,504 | 10,500 |
| Natural Gas Combined-Cycle | 3,065 | 7,691 |
| Natural Gas Combustion Turbine | 397 | 12,257 |
| Peaking Oil | 1,070 | 11,000 |
| Steam Turbine Gas/Oil | 2,120 | 9,891 |
| Hydroelectric | 7,935 | N/A |
| Wind Turbine | 396 | N/A |
| Other Renewables | 93 | N/A |

**Note: Non-coal units are aggregated in CRA's NEEM model. Combined-cycle units are grouped into two or three tiers (depending on year) and combustion turbines into two tiers. Tiers are based on heat rate, in-service year, and operational characteristics (NUGs are in their own tier).**

**Sources: Ventyx Velocity Suite and IESO.**



CRA INTERNATIONAL

# Key assumptions

| | Notes | 2007 | 2010 | 2015 |
|---|---|---|---|---|
| **Load** | Ontario electricity demand, in TWh | 152 | 159 | 165 |
| **Peak/Min Demands*** | Peak/Min hour electricity demand, in MW | 25,737 / 11,798 | 26,986 / 10,937 | 28,099 / 11,350 |
| **Hydro Output** | Annual total of hydro-generated electricity, in GWh | 33,400 | 36,734 | 39,225 |
| **$SO_2$ 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 | None | 15.6 | coal retired |
| **Nuclear POD**** | Annual planned outage days for Ontario nuclear fleet | altered to target 2007 nuclear generation | 39 | 36 |
| **Nuc. Forced Outage Rate**** | Annual forced outage rate for Ontario nuclear fleet | | 3.5% | 3.4% |

Source: IESO data

* Minimum demand is expressed for the minimum load block in the NEEM model. Therefore, *it is not the true lowest demand for the year.*

** Nuclear POD and forced outage rate reflect a capacity-weighted annualized rate calculated from IESO reliability assessment data

## Key Transfer Limits

Key Assumptions

| FROM | TO | Transfer Limit (MW) |
|---|---|---|
| **Ontario** | Quebec | 1,600 (only 350 MW in 2007) |
| **Ontario** | New York + PJM via NY<br>PJM via NY | 1,450<br>1,050 |
| **Ontario** | Michigan + PJM via Michigan | 2,150 |
| **Ontario** | Manitoba | 274 |
| **Ontario** | Minnesota | 140 |
| Quebec | **Ontario** | 1,600 (only 350 MW in 2007) |
| New York + PJM via NY | **Ontario** | 1,550 |
| Michigan + PJM via Michigan<br>PJM via Michigan | **Ontario** | 1,800*<br>1,500* |
| Manitoba | **Ontario** | 342 |
| Minnesota | **Ontario** | 90 |

*** PJM-to-Michigan + Michigan-to-Ontario is limited to 3,000 MW. For example, if 1,201 MW is transferred from PJM to Michigan, only 1,799 MW can be transferred from Michigan to Ontario.**

Key Assumptions

# Forecasted Ontario hydro output by month was provided by the IESO

## Hydro Energy On-peak and Off-peak

| Month | On/Off-Peak | MWh 2010 | MWh 2015 |
|---|---|---|---|
| Jan | Off-Peak | 1,507,276 | 1,580,781 |
| Jan | On-Peak | 1,427,344 | 1,650,064 |
| Feb | Off-Peak | 1,310,327 | 1,467,978 |
| Feb | On-Peak | 1,351,465 | 1,527,088 |
| Mar | Off-Peak | 1,304,916 | 1,592,998 |
| Mar | On-Peak | 1,645,621 | 1,710,196 |
| Apr | Off-Peak | 1,533,539 | 1,649,420 |
| Apr | On-Peak | 1,580,534 | 1,729,833 |
| May | Off-Peak | 1,959,169 | 2,027,629 |
| May | On-Peak | 1,720,857 | 1,807,942 |
| Jun | Off-Peak | 1,449,395 | 1,502,878 |
| Jun | On-Peak | 1,797,971 | 1,907,897 |
| Jul | Off-Peak | 1,442,111 | 1,456,945 |
| Jul | On-Peak | 1,615,329 | 1,763,502 |
| Aug | Off-Peak | 1,347,874 | 1,494,490 |
| Aug | On-Peak | 1,514,388 | 1,494,371 |
| Sep | Off-Peak | 1,267,121 | 1,331,106 |
| Sep | On-Peak | 1,431,909 | 1,508,148 |
| Oct | Off-Peak | 1,542,192 | 1,547,099 |
| Oct | On-Peak | 1,496,555 | 1,631,385 |
| Nov | Off-Peak | 1,432,817 | 1,574,989 |
| Nov | On-Peak | 1,776,502 | 1,802,899 |
| Dec | Off-Peak | 1,591,419 | 1,696,968 |
| Dec | On-Peak | 1,687,533 | 1,768,231 |
| TOTAL | | 36,734,162 | 39,224,839 |

**Source: IESO**

## Run-of-River Hydro Output (corresponds to off-peak output)

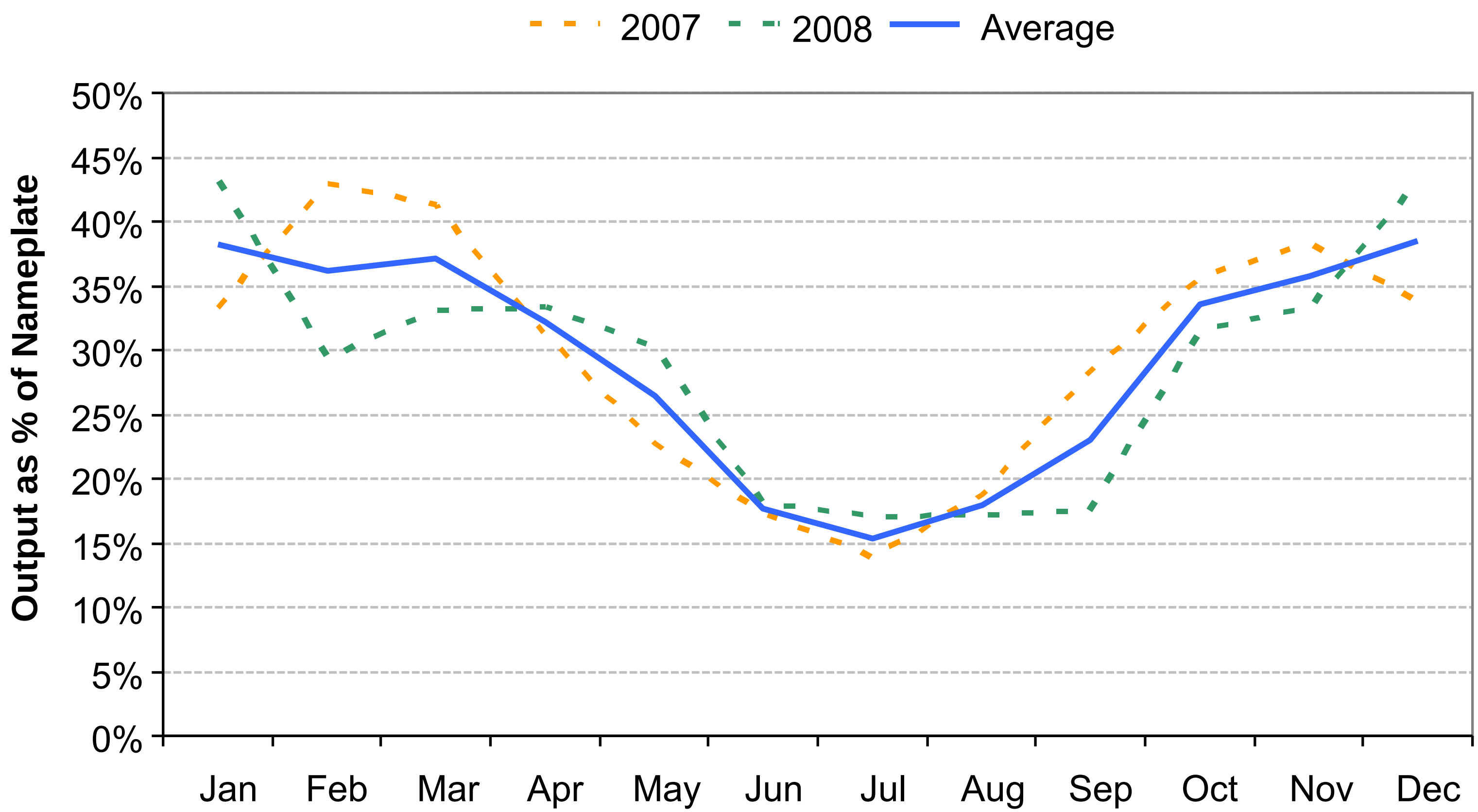
| MW | 2010 | 2015 |
|---|---|---|
| Jan | 3,621 | 3,797 |
| Feb | 3,485 | 3,904 |
| Mar | 3,135 | 3,827 |
| Apr | 3,807 | 4,094 |
| May | 4,706 | 4,871 |
| Jun | 3,598 | 3,731 |
| Jul | 3,464 | 3,500 |
| Aug | 3,238 | 3,590 |
| Sep | 3,145 | 3,304 |
| Oct | 3,705 | 3,716 |
| Nov | 3,557 | 3,910 |
| Dec | 3,823 | 4,076 |

**Note: The hydro energy output is met by a combination of run-of-river resources and hydro resources that are economically optimized by NEEM. The maximum possible (combined) hydro output is about 7900 MW and 8700 MW in 2010 and 2015, respectively.**



CRA INTERNATIONAL

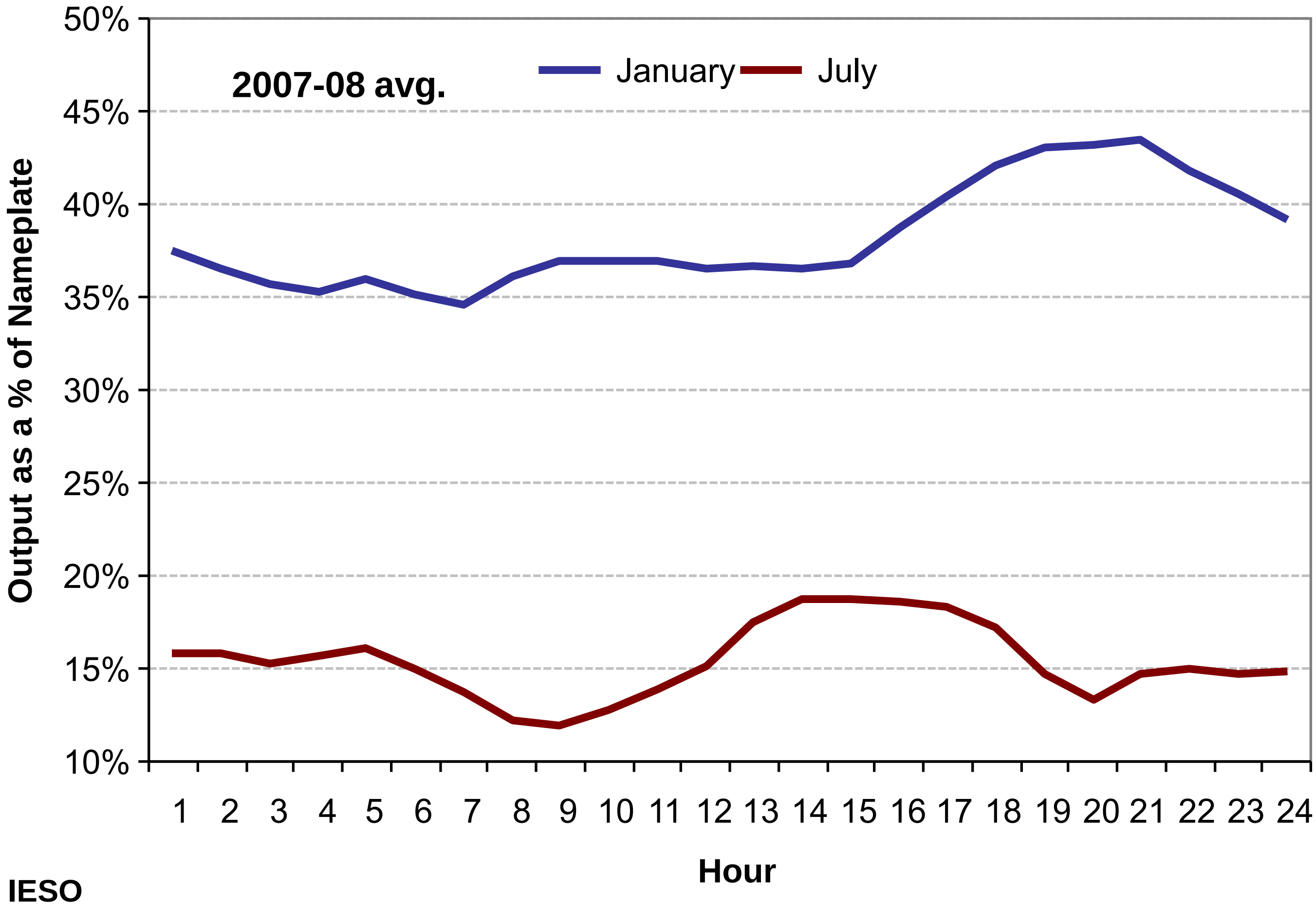
# Wind output assumptions (monthly) are based on historical data




**Source: IESO**

**Ontario wind output in NEEM reflects an average of historical wind resource performance.**

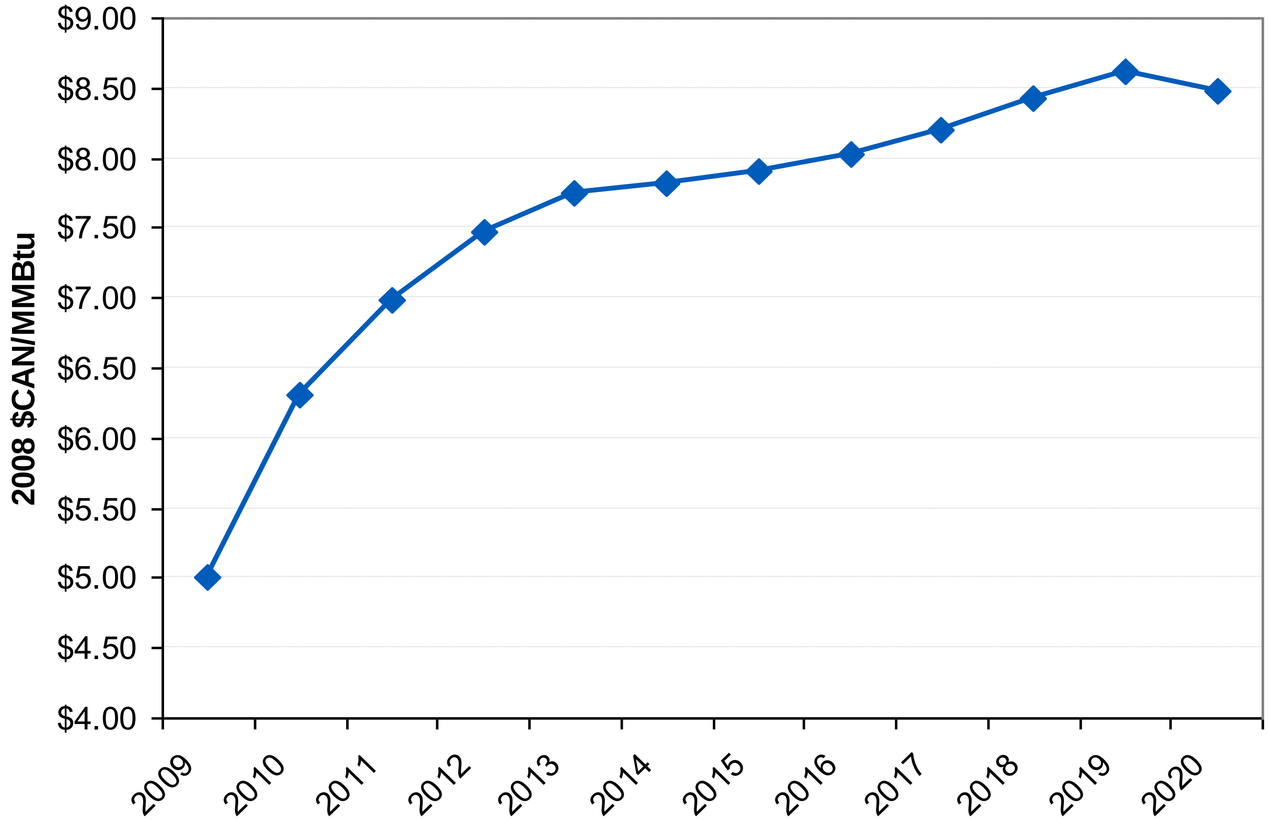
# Wind output assumptions (diurnal variation in winter and summer)




Source: IESO

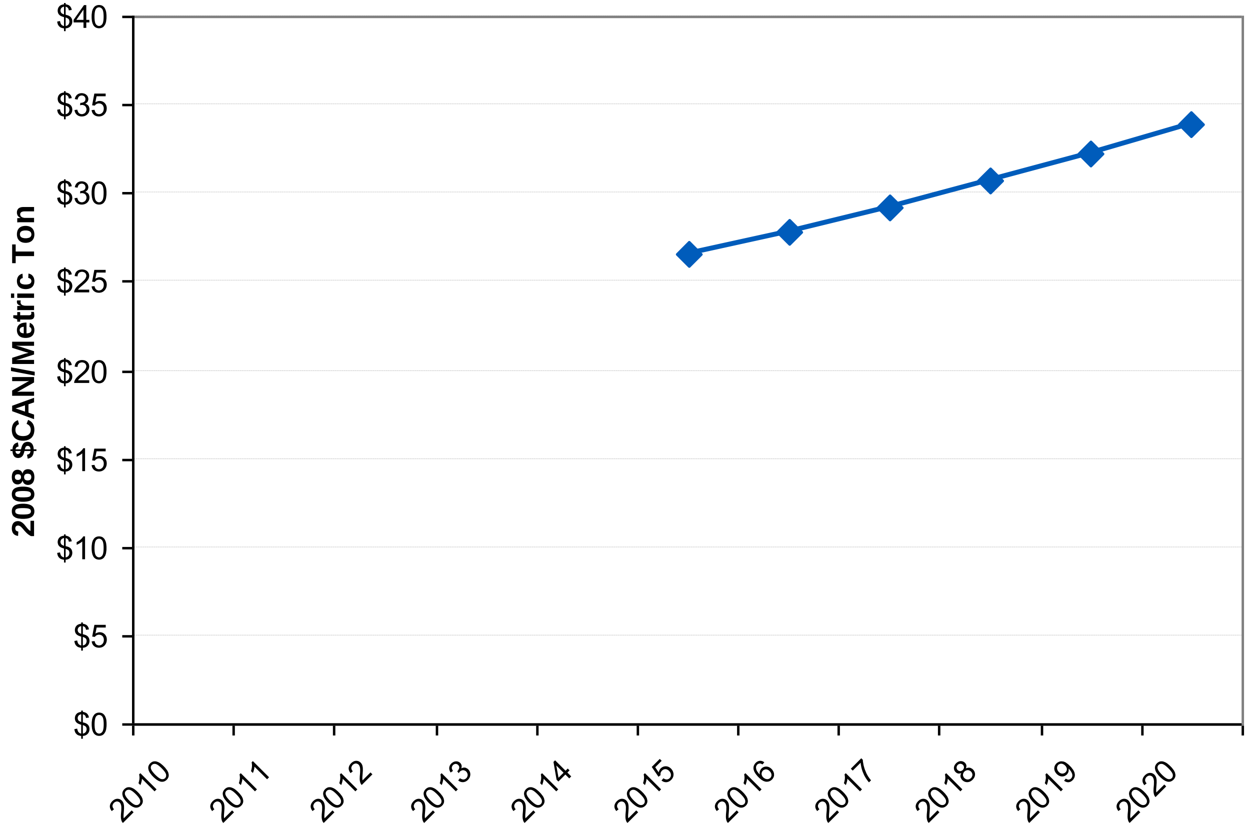
**Summer and winter output levels and shapes are different.**

## Natural gas delivered prices to Ontario power plants



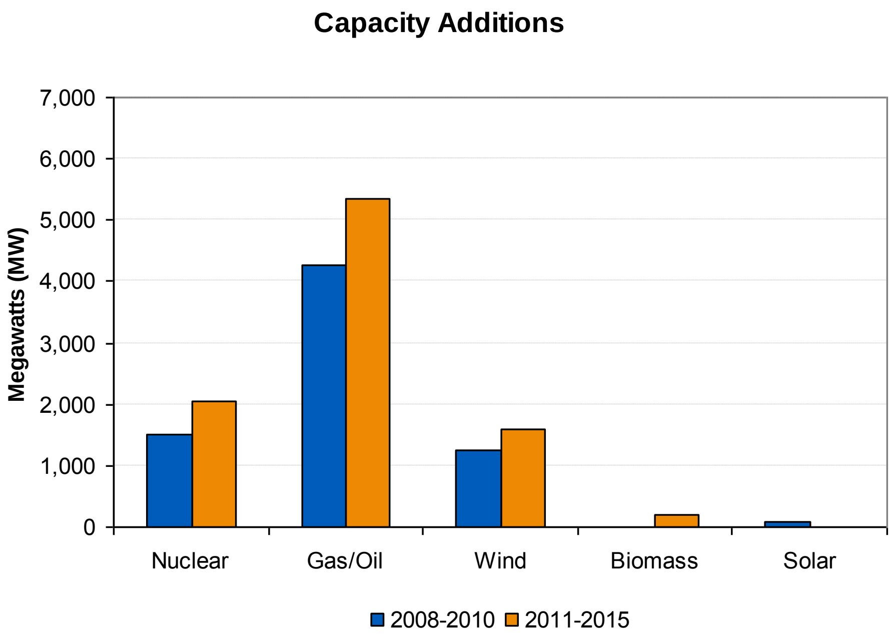

**Henry hub prices are based on a blend of NYMEX futures (April 1, 2009) and Energy Information Administration's Annual Energy Outlook (AEO) 2009 forecast. A regional basis differential adjusts the AEO forecast to Ontario delivered prices.**

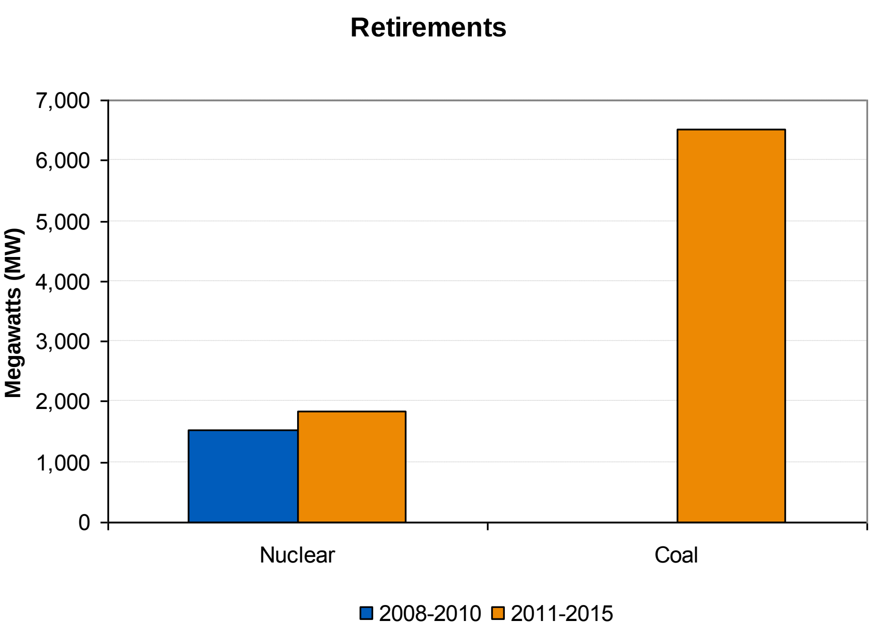
# North-American CO2 policy affects 2015 assessment




**North-American carbon policy is assumed to start in 2015 at a $CO_2$ price of $26.53/tonne (2008 CAN$), escalating at 5% real.**

# New build and retirement schedule (by 2010 and *during* 2011-2015)




Notes: (1) Although NEEM was allowed to select economic additions, it did not choose any over or above IESO's reported planned builds/retirements schedule

(2) Gas/oil retirements were determined by the model; many of these resources remained only for capacity reasons but did not generate energy

**Gas, nuclear, and wind comprise the majority of new capacity in transition to low-emissions fleet.**

Key Assumptions

# Calculation of Changes in Consumer Surplus and Producer Surplus (*focus on Ontario producers and consumers only*)

**Change in Consumer Surplus in any block* = (Price $_{\text{status quo}}$ – Price $_{\text{scenario}}$) * block demand**

**Total change in Consumer Surplus ➔ sum across the 120 blocks**

---

**Change in Producer Surplus in any block = change in energy margin for all Ontario units**

**[Energy margin = Energy Revenue less all variable costs (e.g., fuel, variable operating and maintenance costs, and allowance costs, etc.) ]**

**Total change in Producer Surplus ➔ sum across the 120 load blocks**

*** The CRA NEEM model divides the annual load curve into 120 blocks. There are 10 blocks in each month. The loads are sorted from highest to lowest (within each month) and are not necessarily sequential.**

## Status Quo Economics (facilitates understanding of changes under the various scenarios reported subsequently)

- **2010 Producer Surplus = $5,971 (Million 2008 CAN$)**
- **2015 Producer Surplus = $9,999 (Million 2008 CAN$)**

- ***Status quo consumer surplus cannot be reported because load is fixed (demand is perfectly inelastic), so consumer surplus cannot be measured***

- **2010 ETS Tariff Revenue = $12.0 (Million 2008 CAN$)**
- **2015 ETS Tariff Revenue = $13.5 (Million 2008 CAN$)**

Key Assumptions for Calibration and Scenario Analysis

**2007 Model Calibration Results**

Scenario Definitions

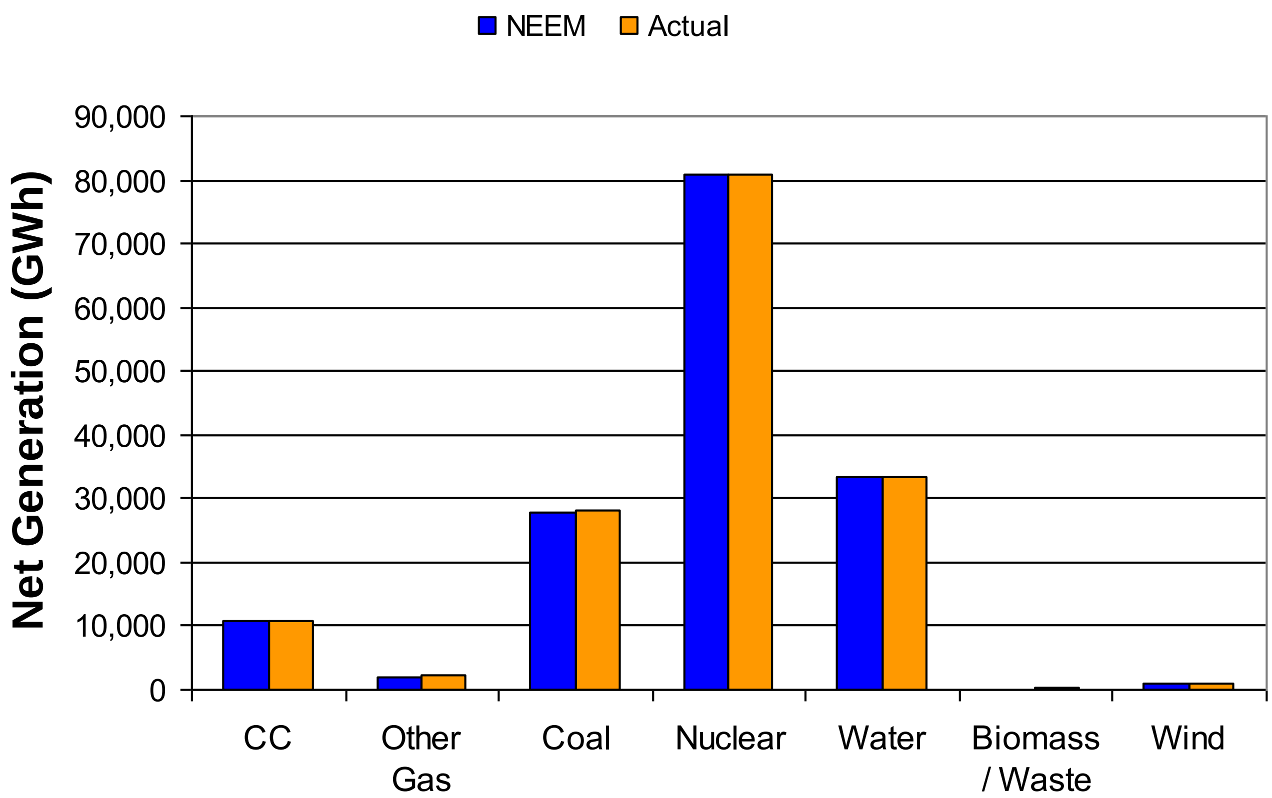
Results by Scenario

Emissions Impacts by Scenario

General Conclusions

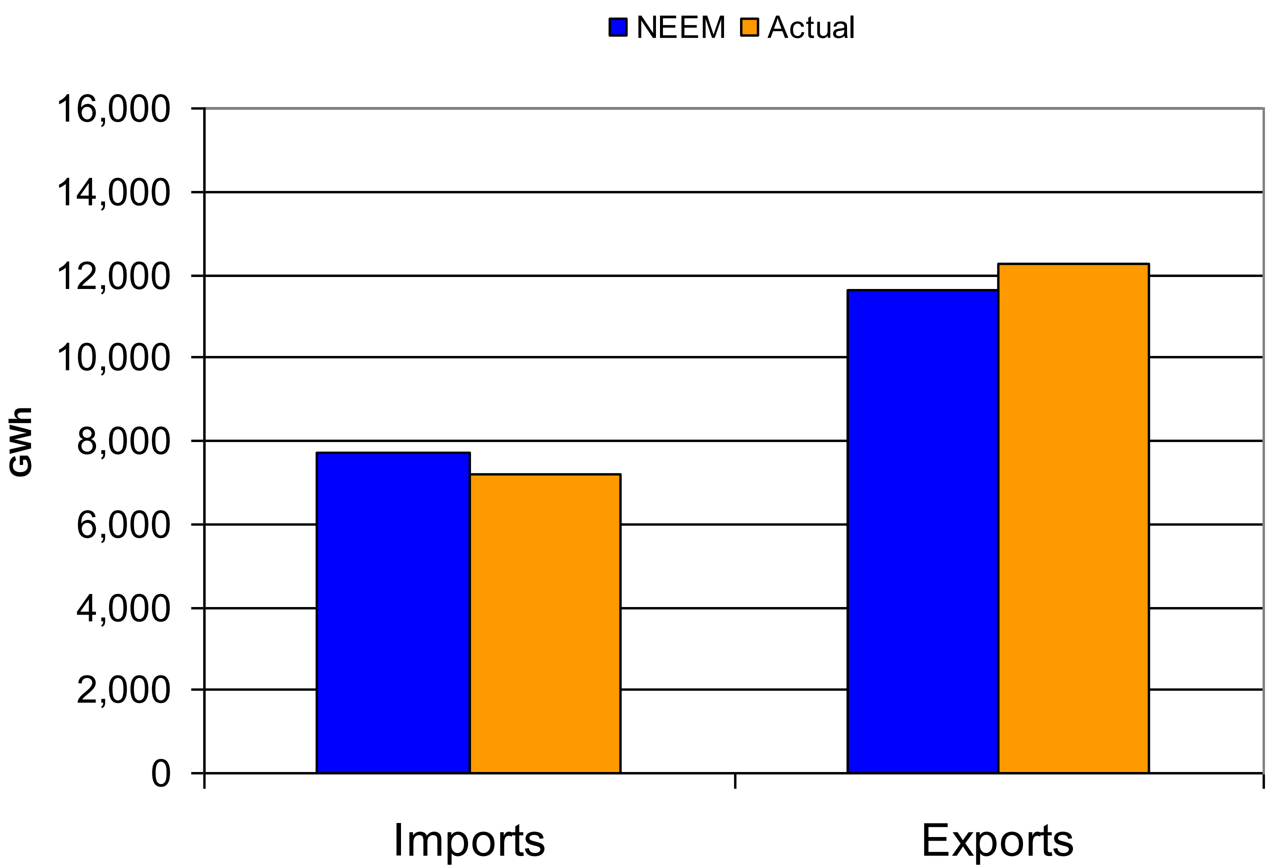
Appendices

# Generation Calibration - 2007

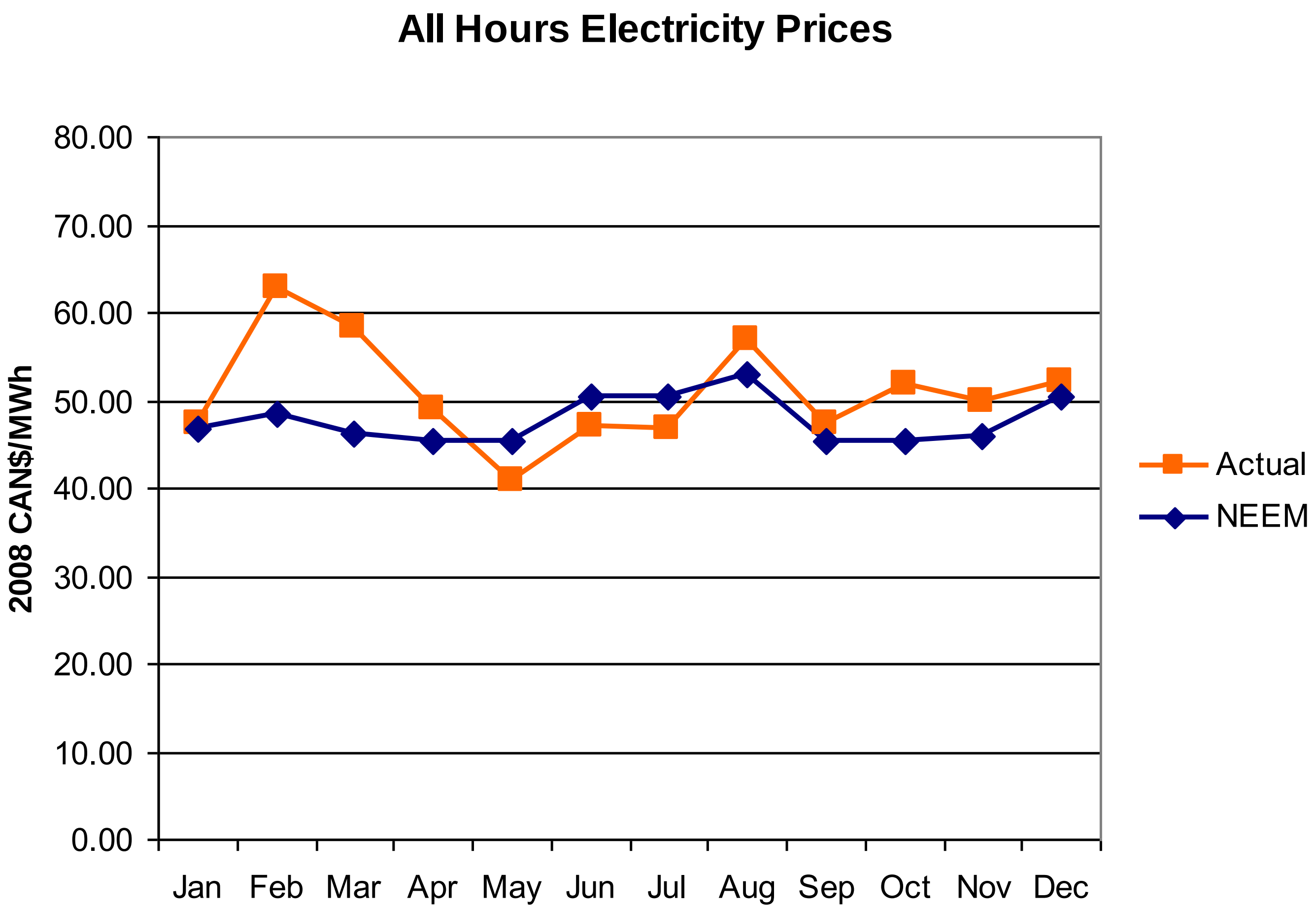



**Coal bids are calibrated to roughly match generation. NUGs (included in CC or Combine-Cycle) are assumed to operate with 74% capacity factor. Other Gas is bid down by 25-35% percent. In 2010 and 2015, the Coal/Gas adjustments are the same except Other Gas is not bid down because of expected contractual changes (i.e., Lennox RMR Agreement). In 2010 and 2015, CHP is projected to operate at 42% capacity factor.**

# Import/Export Balance Calibration - 2007



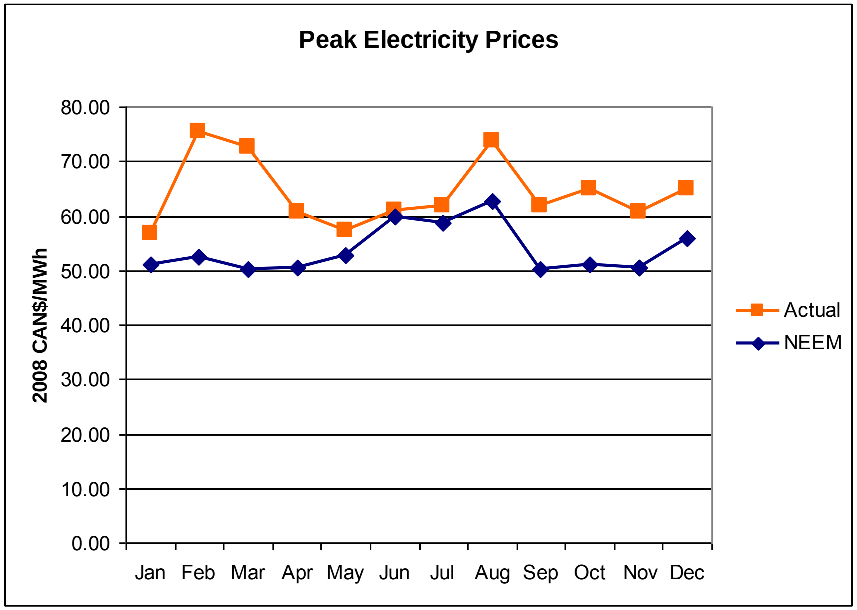
# All-Hours Prices Calibration

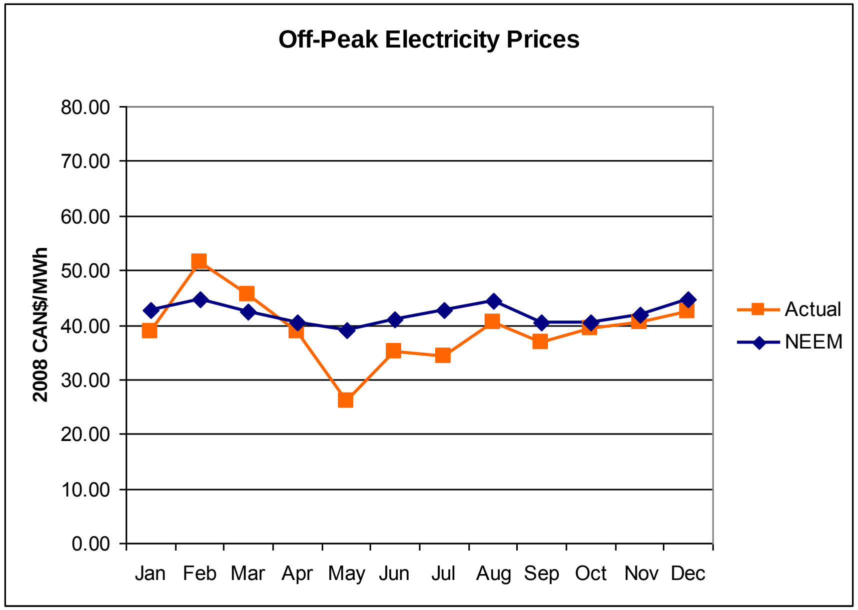



**NEEM-projected all-hours prices are quite close to actual (with the exception of February and March). In these two months (especially February), even though actual Ontario prices are high, actual exports were high and imports were low.**

2007 Calibration

# Peak and Off-peak Prices Calibration




**On-peak prices from production cost models (like CRA's NEEM Model) typically are lower than real-world on-peak prices. Production cost models anticipate load and generator outages perfectly and hence do not have periods when units that are otherwise available are not committed. In the real world, these unit commitment errors result in peakers running more than they would otherwise (increasing on-peak prices). Similarly, production cost models tend to have off-peak prices that are higher than actual prices because they do not capture the off-peak bidding behaviour of base load units. Base load units often offer capacity at prices below marginal cost to remain on-line during low load periods.**

Key Assumptions for Calibration and Scenario Analysis

2007 Model Calibration Results

**Scenario Definitions**

Results by Scenario

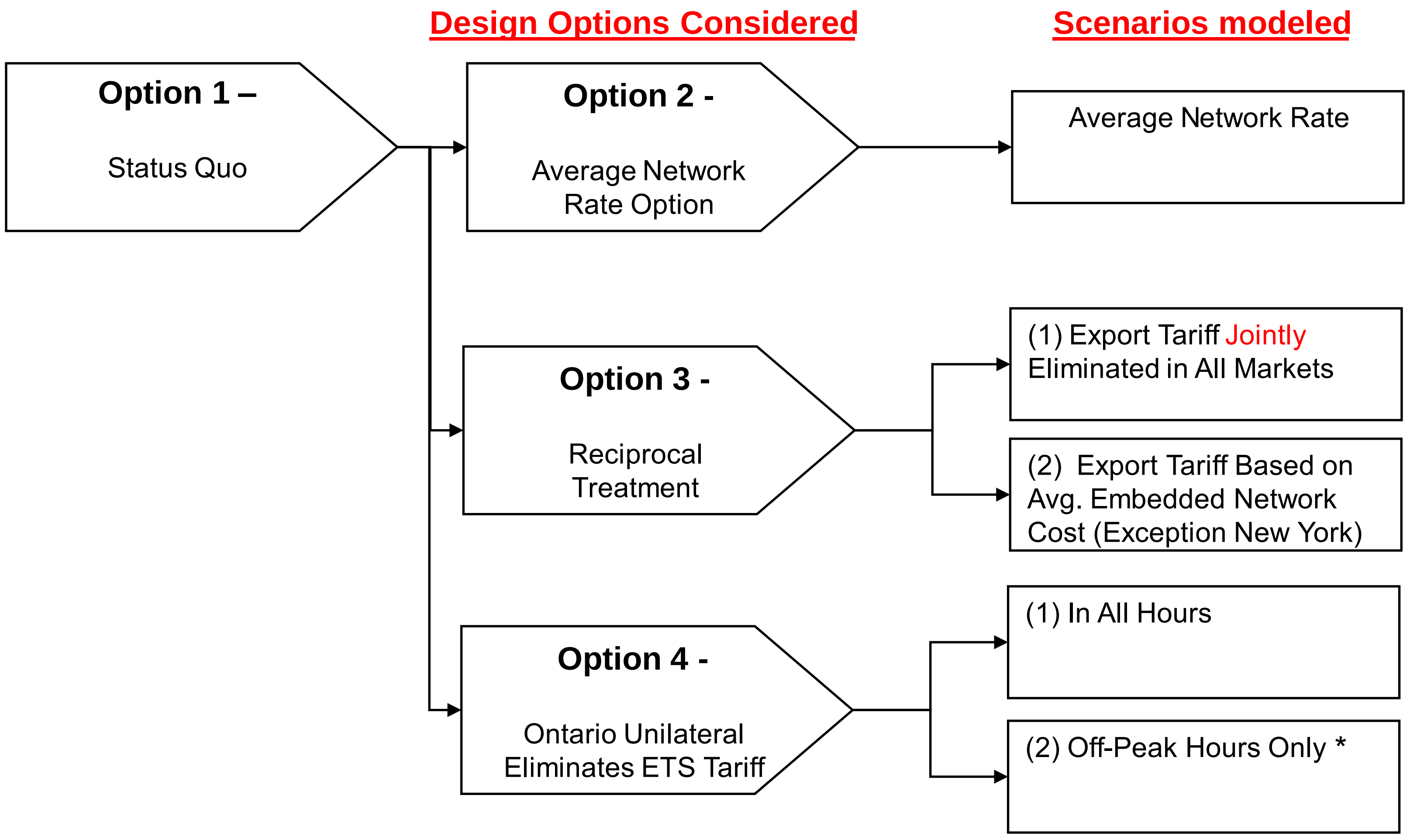
Emissions Impacts by Scenario

General Conclusions

Appendices

Scenario Definitions

# ETS Tariff Design Options and Scenarios Considered




* On-peak is 5x12 basis for this scenario.

**See Appendix B for more detail on the ETS tariff and all-in costs scenarios considered.**

Key Assumptions for Calibration and Scenario Analysis

2007 Model Calibration Results

Scenario Definitions

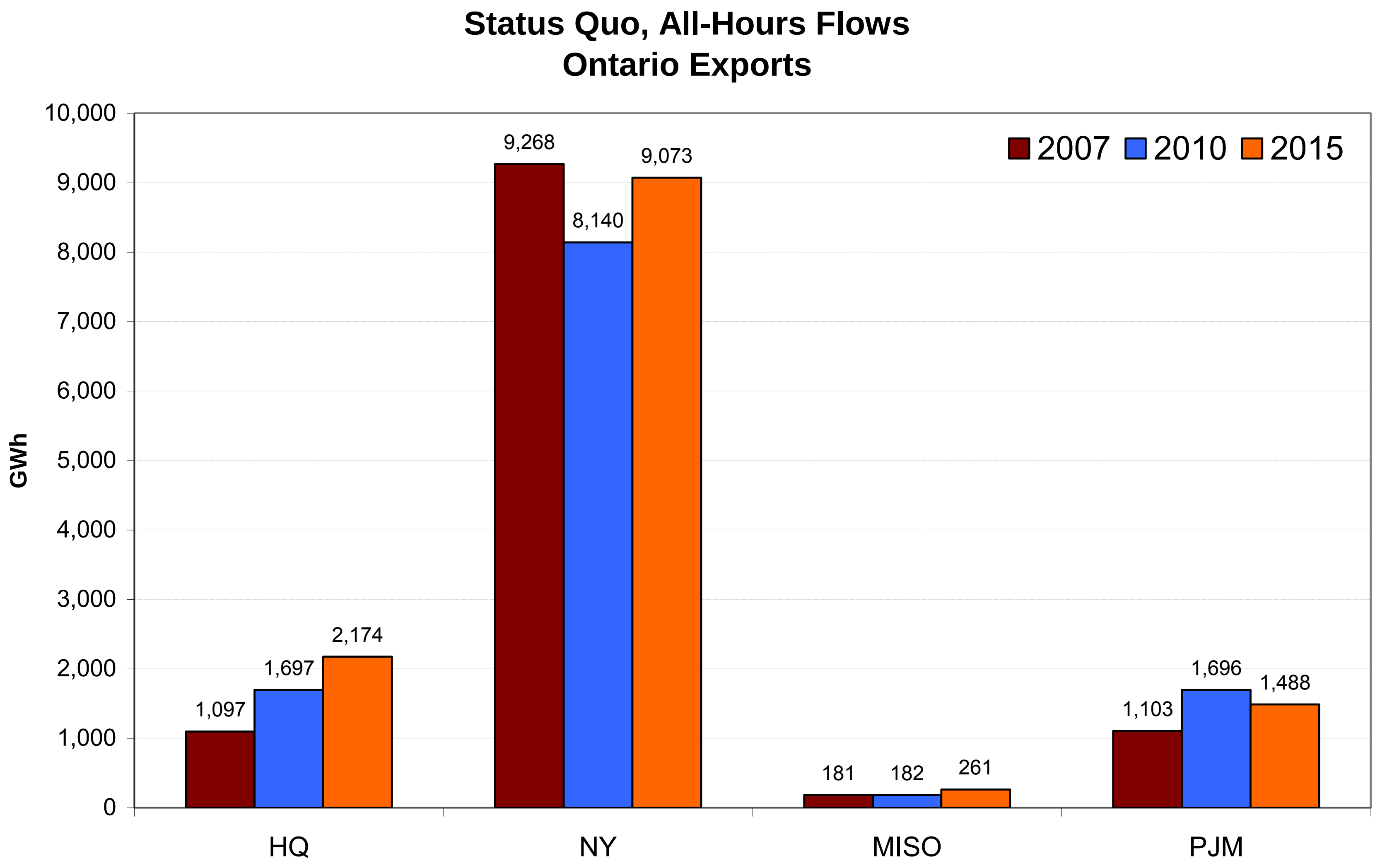
**Results by Scenario**

Emissions Impacts by Scenario

General Conclusions

Appendices

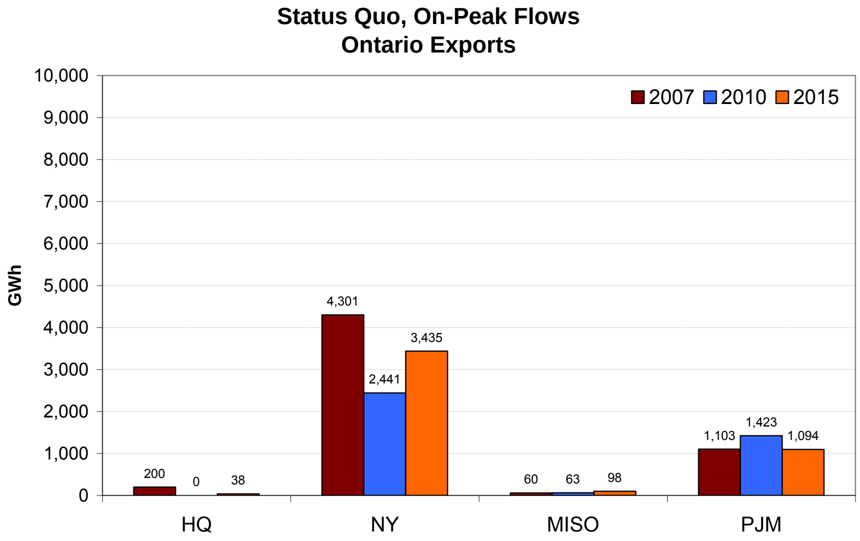
# Observation: Exports are predominantly to NYISO

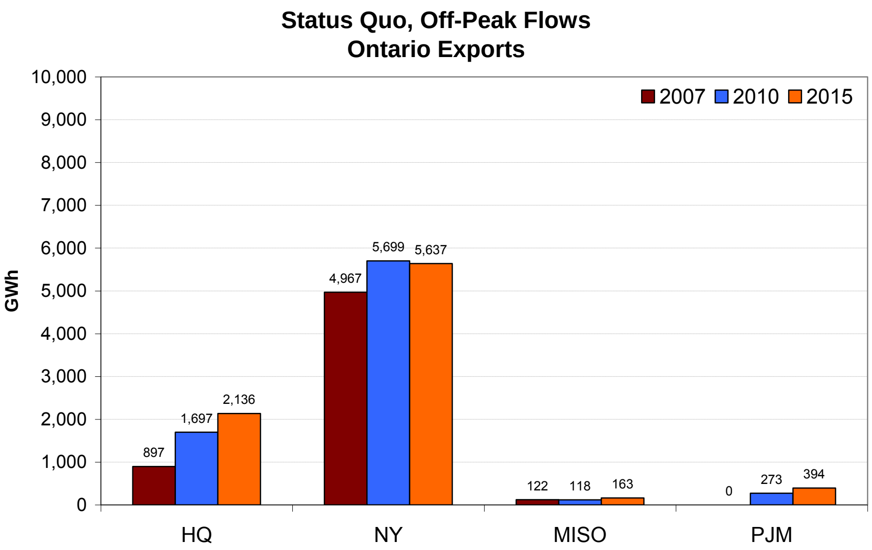





CRA INTERNATIONAL

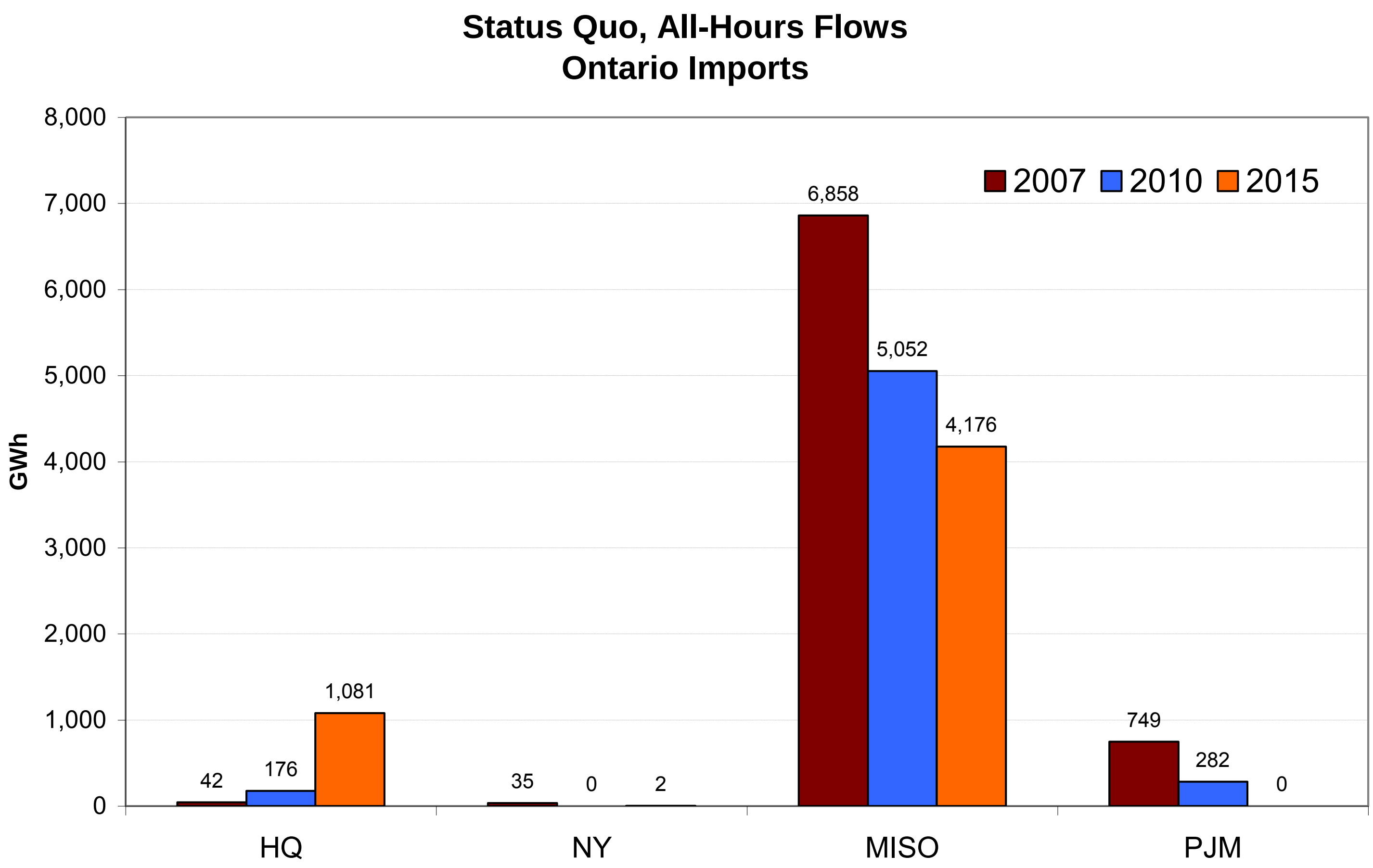
# Status Quo Exports: On-Peak and Off-Peak



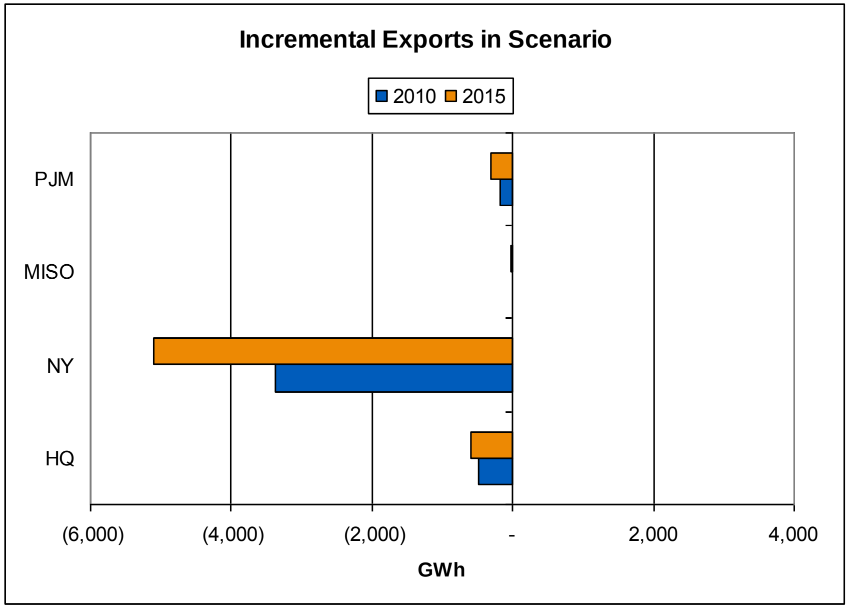



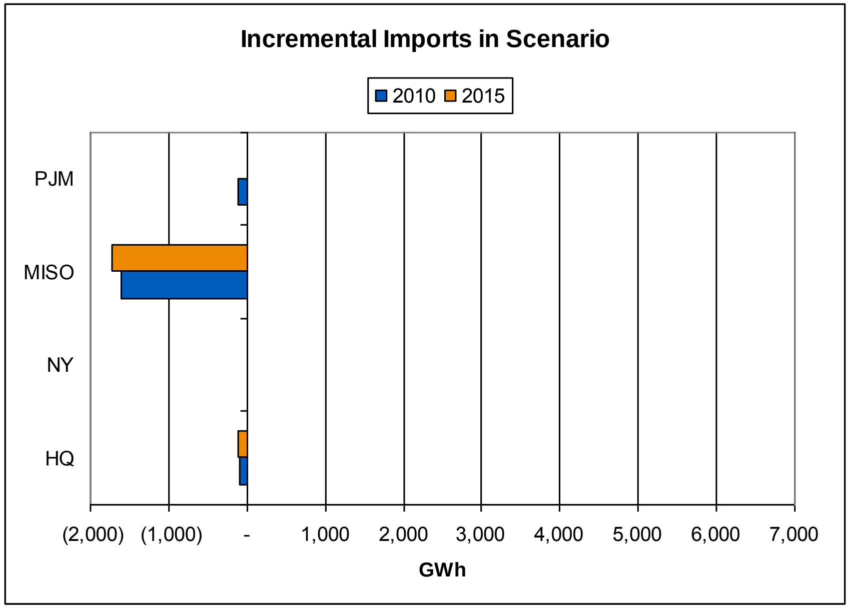

**Exports to Quebec are primarily off-peak.**

# Observation: Imports are predominantly from PJM/MISO



# Option 2 (average network rate option)

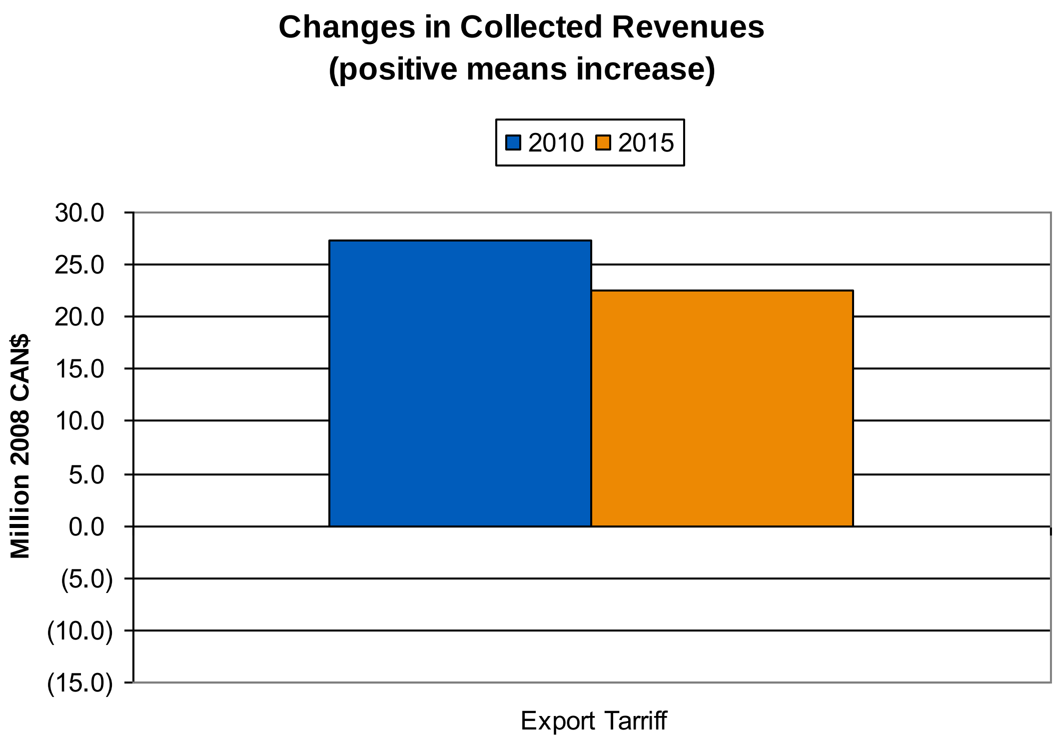



| Year | Change in Total Exports from Status Quo | Change in Total Imports from Status Quo |
|---|---|---|
| 2010 | (35%) | (33%) |
| 2015 | (46%) | (35%) |

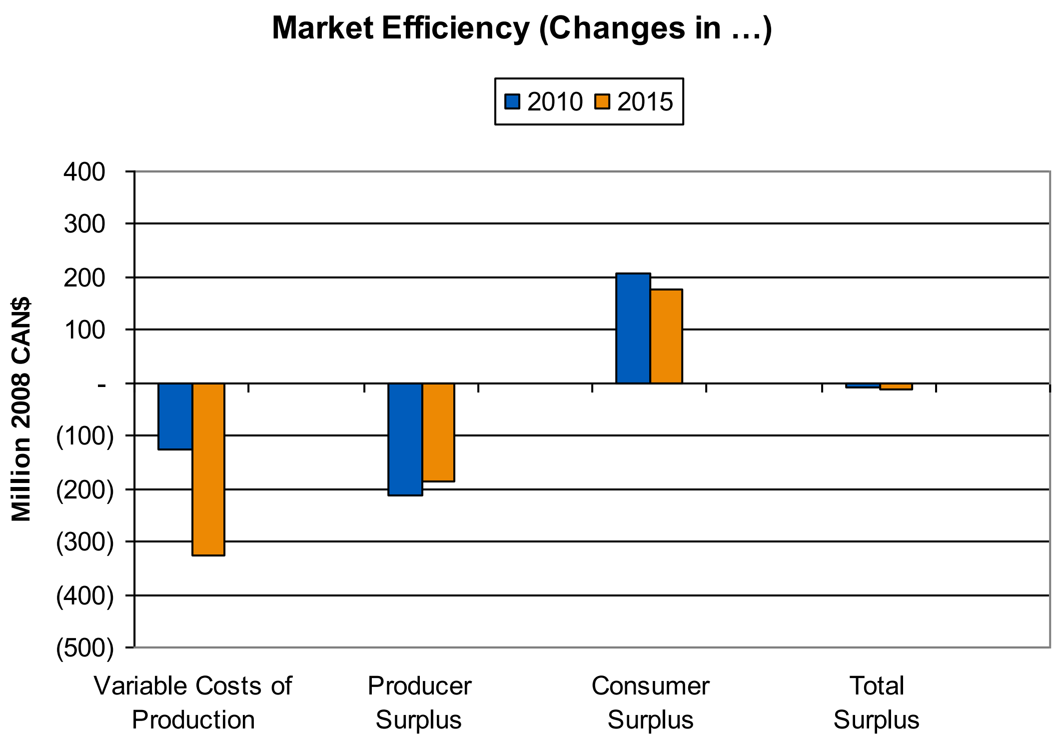
**Observation: Exports are reduced because of the increased ETS tariff. Imports are less affected on an absolute basis.**

# Option 2 (average network rate option)




**Observation: A reduction in export volume is more than offset by the higher ETS tariff; accordingly, there is an increase in ETS tariff revenues.**

# Option 2 (average network rate option)



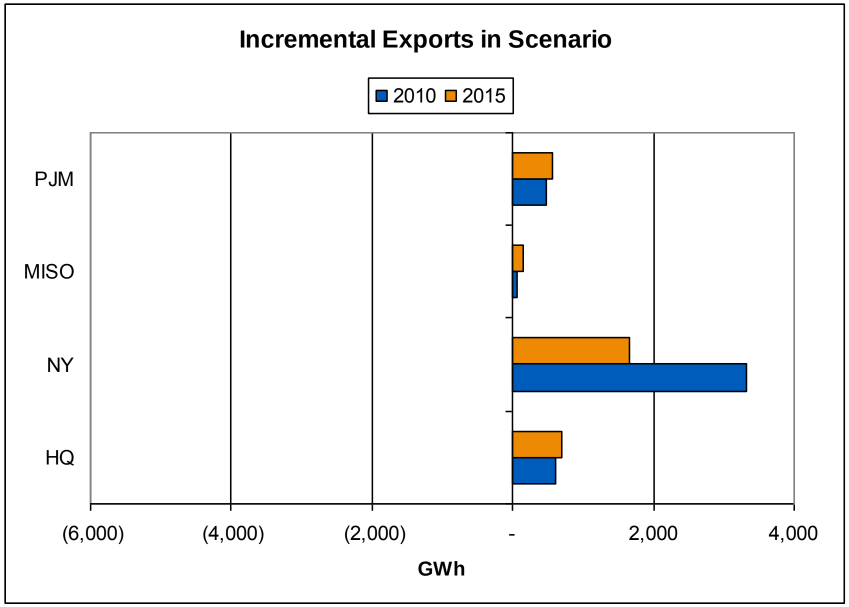

**Observation: A unilateral increase in the ETS tariff reduces producer surplus (through reduced exports) but increases consumer surplus by lowering prices (i.e., there is less upward pressure on prices due to reduction in external demand).**

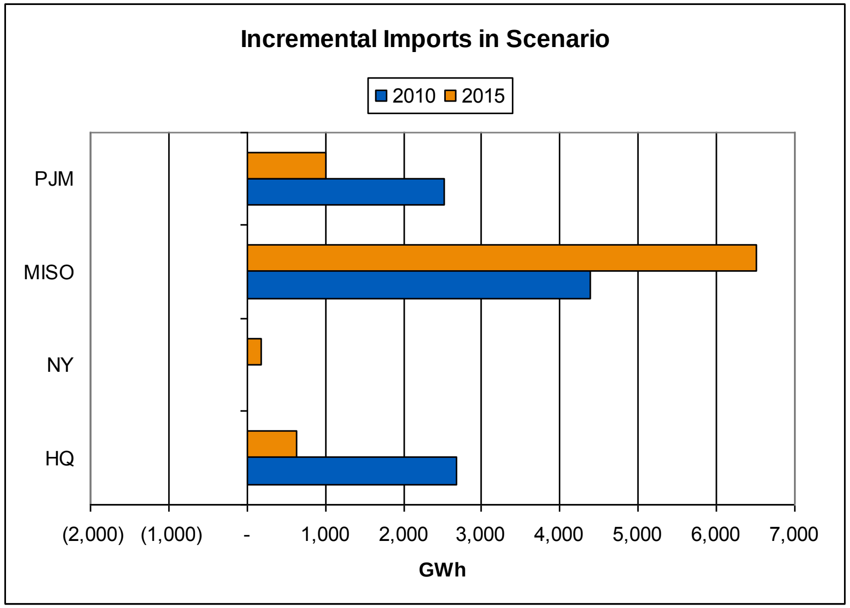
# Option 2 (average network rate option)

| | Change in Electricity Prices Relative to Status Quo | | |
|---|---|---|---|
| **Year** | **All-Hours** | **Peak** | **Off-Peak** |
| 2010 | (2.5%) | (1.9%) | (3.2%) |
| 2015 | (1.4%) | (1.2%) | (1.7%) |

**Observation: Prices are lower because the increased ETS tariff dampens external demand.**

# Option 3, Scenario 1 (reciprocal treatment, ETS tariff jointly eliminated)

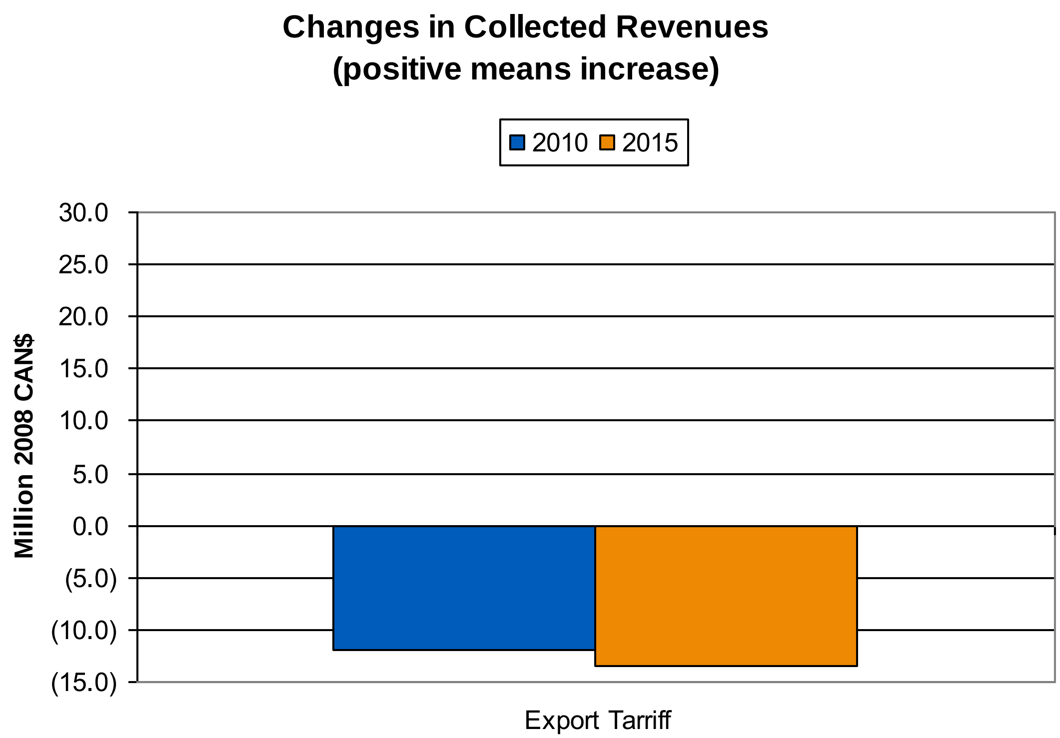



| Year | Change in Total Exports from Status Quo | Change in Total Imports from Status Quo |
|---|---|---|
| 2010 | 38% | 174% |
| 2015 | 24% | 158% |

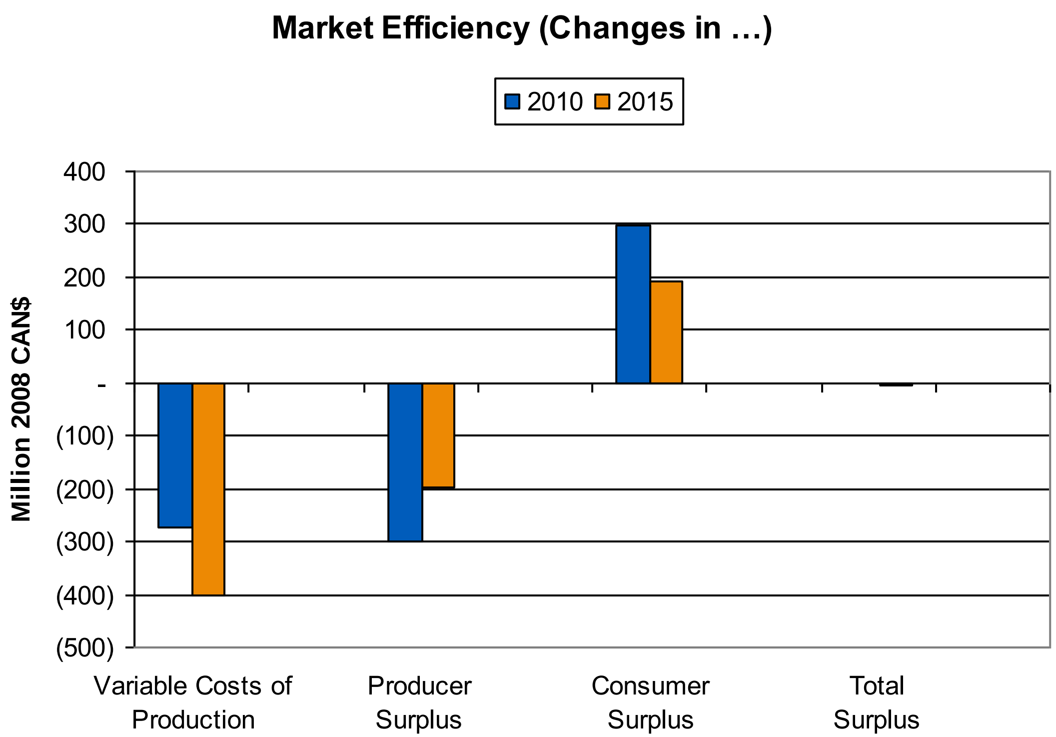
**Observation: Reducing Ontario's ETS tariff to zero has a relatively small impact on exports because the tariff is low in status quo. However, imports to Ontario are more affected because Ontario's neighbours have a higher export tariff to begin with in status quo.**

# Option 3, Scenario 1 (reciprocal treatment, ETS tariff jointly eliminated)




**Observation: ETS tariff revenue is reduced to zero when the tariff is eliminated.**

# Option 3, Scenario 1 (reciprocal treatment, ETS tariff jointly eliminated)



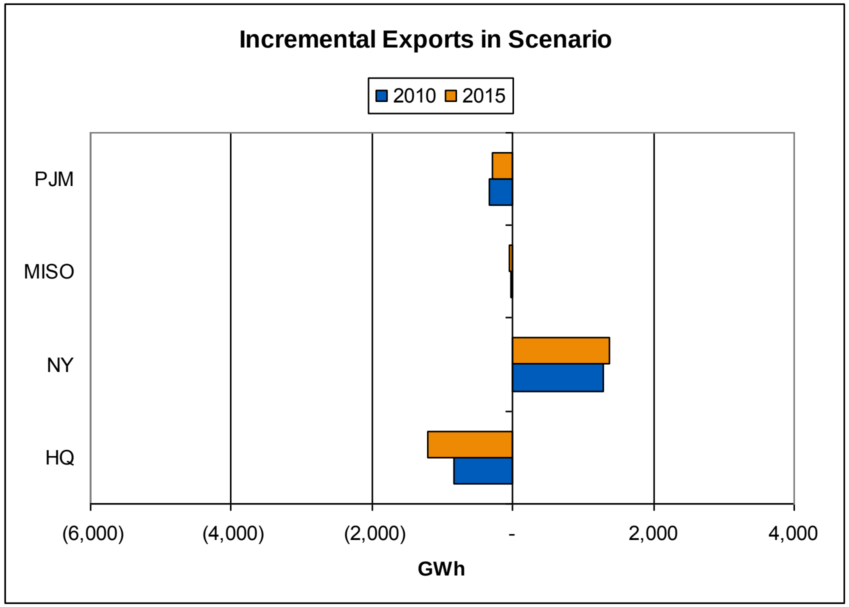

**Observation: Since Ontario's neighbours' export tariffs are higher to begin with (i.e., in status quo), Ontario's net exports (after tariff is eliminated) decrease and therefore producer surplus decreases. Consumer surplus increases as imports are subject to lower tariffs when exiting Ontario's neighbours' systems.**

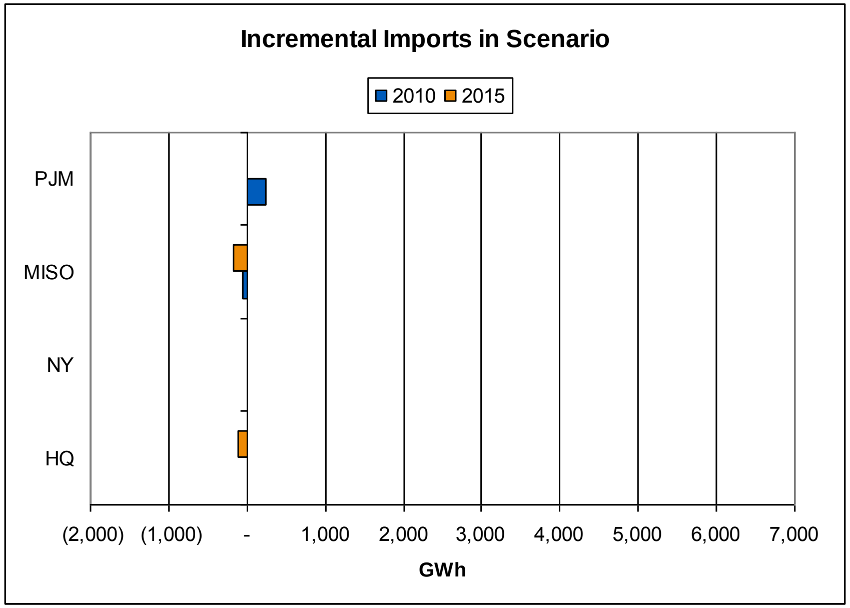
# Option 3, Scenario 1 (reciprocal treatment, ETS tariff jointly eliminated)

| | Change in Electricity Prices Relative to Status Quo | | |
|---|---|---|---|
| **Year** | **All-Hours** | **Peak** | **Off-Peak** |
| 2010 | (3.7%) | (2.7%) | (4.9%) |
| 2015 | (1.6%) | (1.0%) | (2.4%) |

**Observation: Prices are lower in Ontario in this scenario. As export tariffs are eliminated in neighbouring regions (i.e., by a larger increment than in Ontario), export costs from those regions are lowered, exerting downward pressure on prices in Ontario.**

# Option 3, Scenario 2 (reciprocal treatment, avg. embedded network cost)



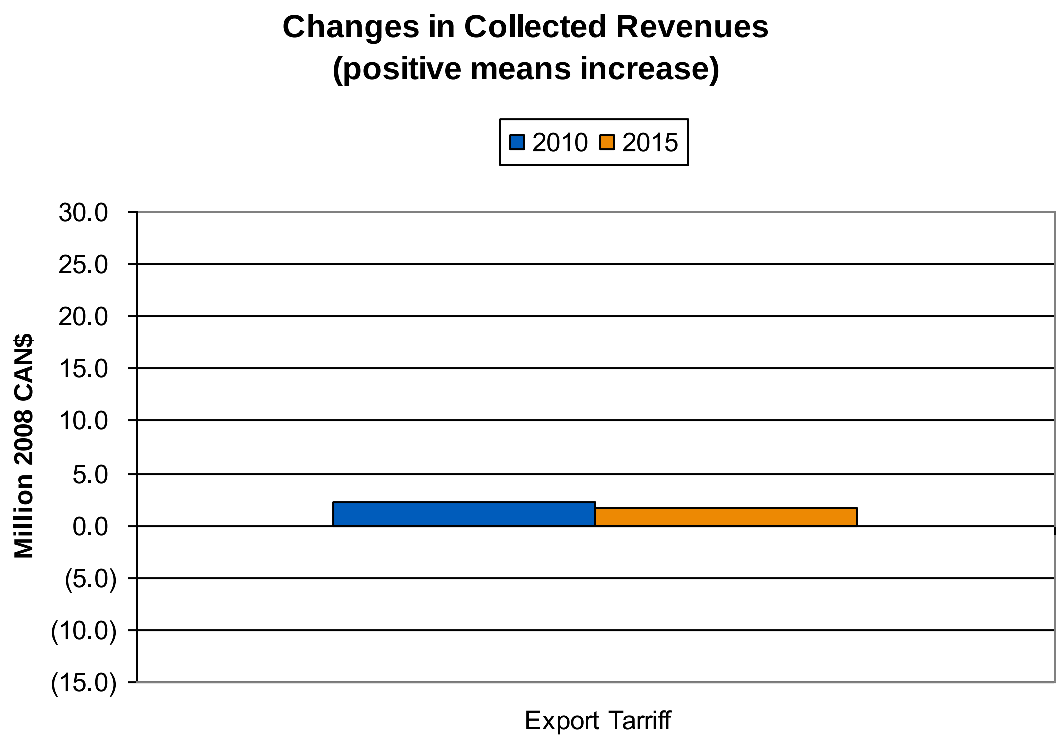




| Year | Change in Total Exports from Status Quo | Change in Total Imports from Status Quo |
|---|---|---|
| 2010 | 1% | 3% |
| 2015 | (1%) | (5%) |

**Impacts on Ontario's total imports/exports are relatively small under this scenario.**

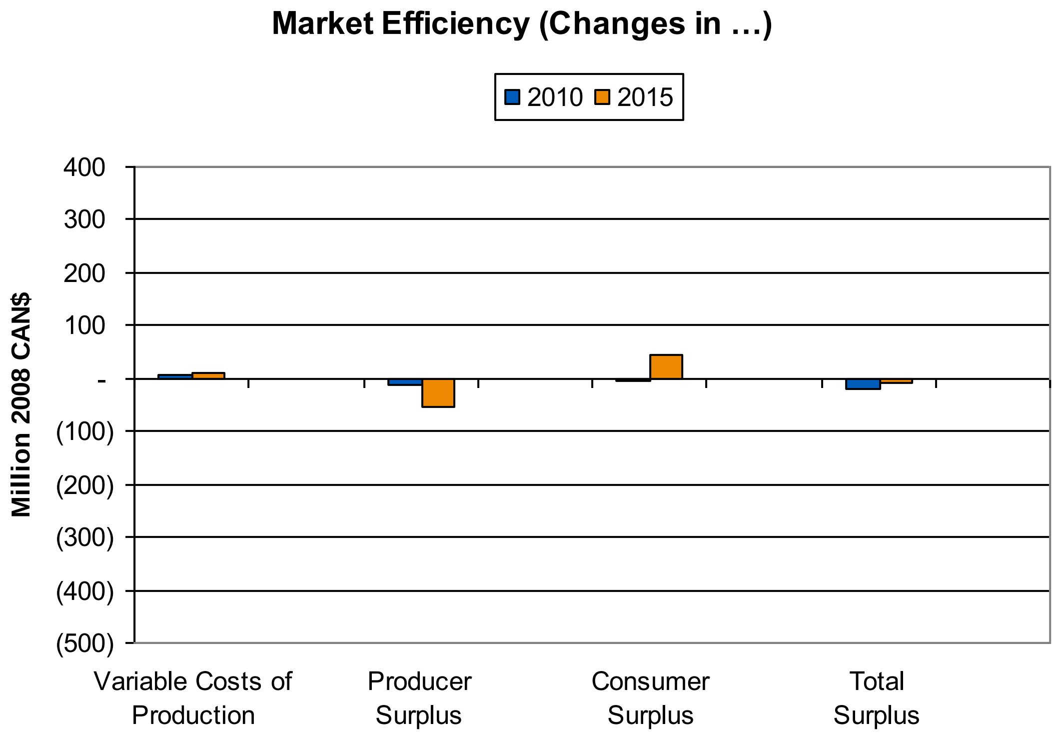
**Exports to NY are expected to increase in both test years because NY is the only neighbour to which the ETS tariff is assumed to be eliminated.**

# Option 3, Scenario 2 (reciprocal treatment, avg. embedded network cost)




**Observation: The export revenue that is lost on exports to NY (when the NY tariff is eliminated) offsets most of the revenue gained in exports to Ontario's other neighbours.**

# Option 3, Scenario 2 (reciprocal treatment, avg. embedded network cost)




**Observation: Because impacts on net exports are relatively small, the impacts on producer and consumer surplus are relatively small. In 2015 (when impacts are somewhat larger), lower prices lead to increased consumer surplus and decreased producer surplus.**

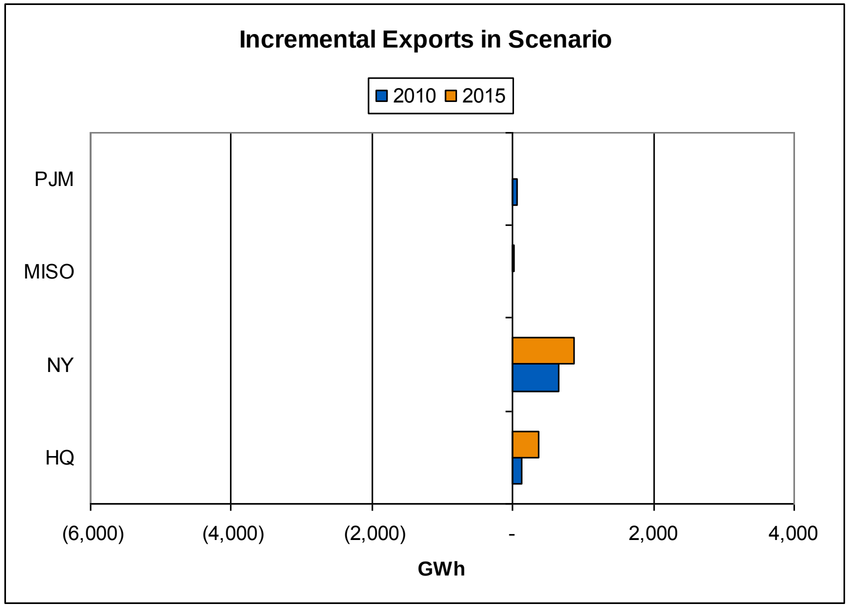
# Option 3, Scenario 2 (reciprocal treatment, avg. embedded network cost)

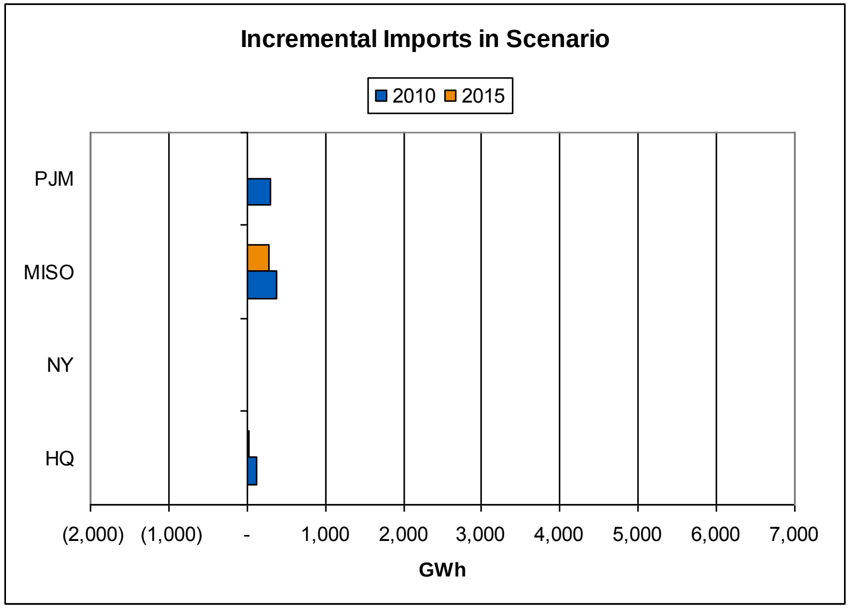
| | Change in Electricity Prices Relative to Status Quo | | |
|---|---|---|---|
| **Year** | **All-Hours** | **Peak** | **Off-Peak** |
| 2010 | (0.2%) | 1.0% | (1.5%) |
| 2015 | (0.4%) | 0.0% | (0.8%) |

**Observation: All-hours prices (duration-weighted) are reduced under the scenario in both years. Higher peak prices in 2010 reduce consumer surplus slightly as shown on the previous slide (*note: the change in the load-weighted all-hours price in 2010 is actually positive and not negative*).**

Scenario Results

# Option 4, Scenario 1 (unilateral tariff elimination in all hours)

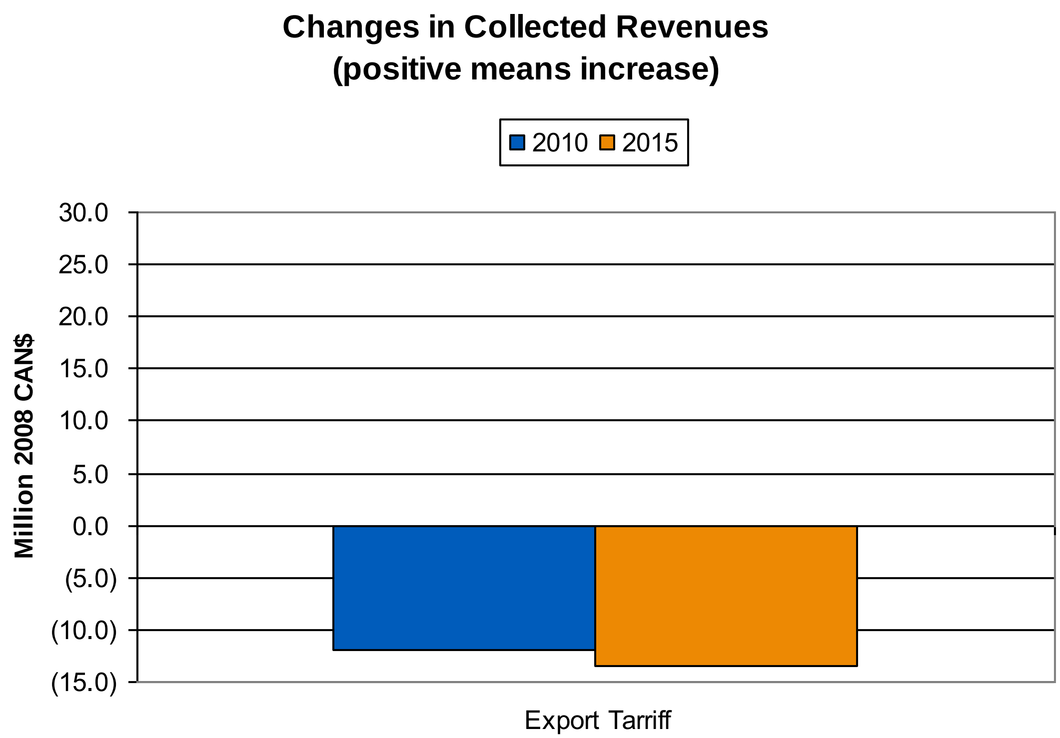



| Year | Change in Total Exports from Status Quo | Change in Total Imports from Status Quo |
|---|---|---|
| 2010 | 7% | 14% |
| 2015 | 10% | 6% |

**Observation: Since the Ontario ETS tariff is relatively small, increases in export volumes are expected to be small when the ETS tariff is unilaterally eliminated. Likewise, impacts on imports are expected to be small.**

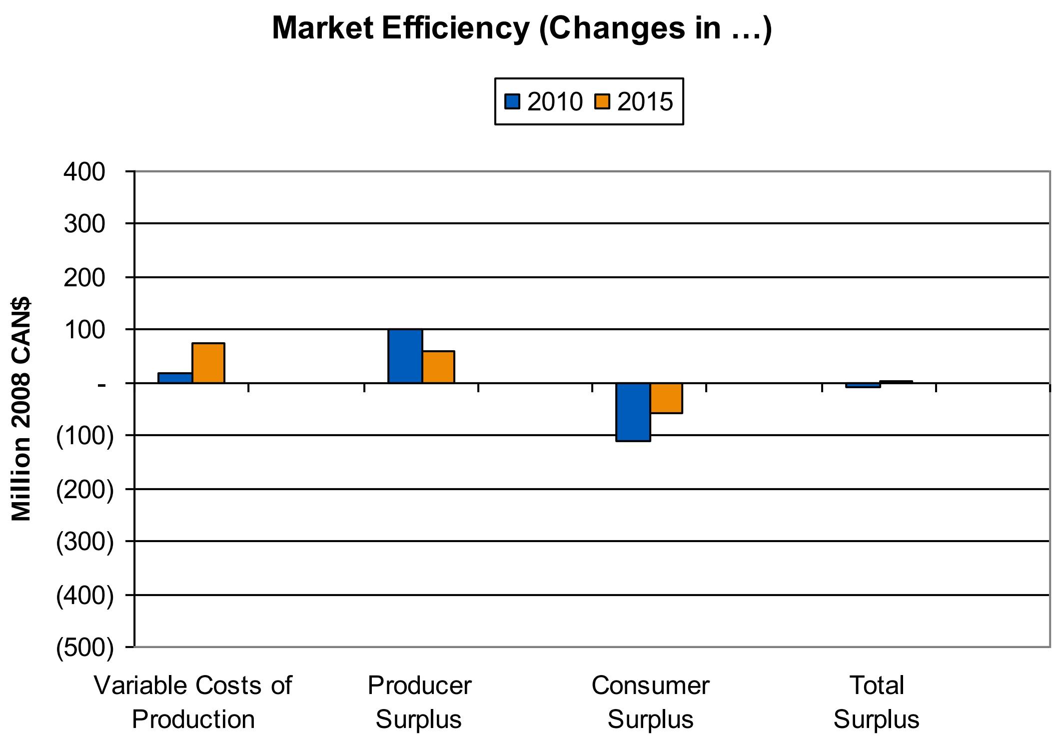
# Option 4, Scenario 1 (unilateral tariff elimination in all hours)




**Observation: The ETS tariff revenue is eliminated under this scenario. The consequential loss in ETS tariff revenue is the same as in Option 3, scenario 1.**

Scenario Results

# Option 4, Scenario 1 (unilateral tariff elimination in all hours)



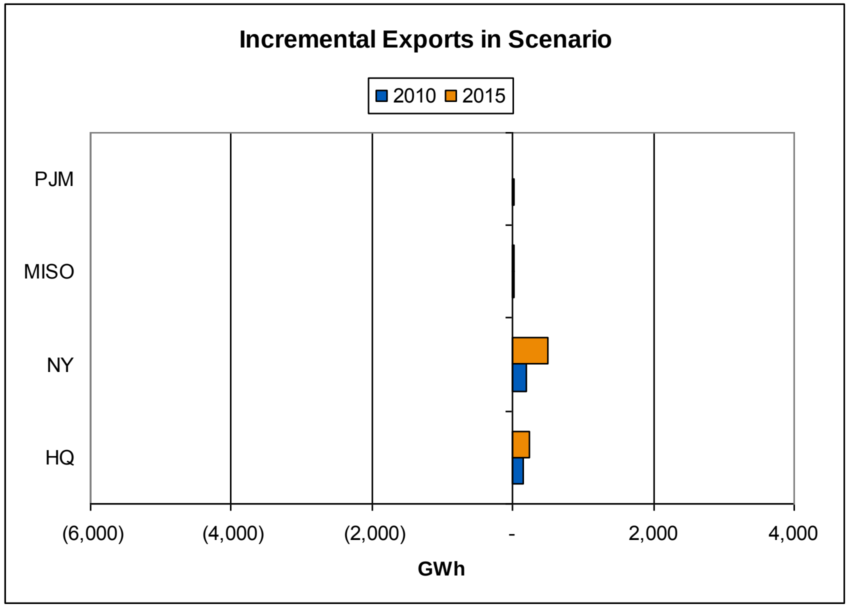

**Observation: When the ETS tariff is unilaterally eliminated there is a consequential increase in exports, as well as prices. This increases producer surplus and reduces consumer surplus.**

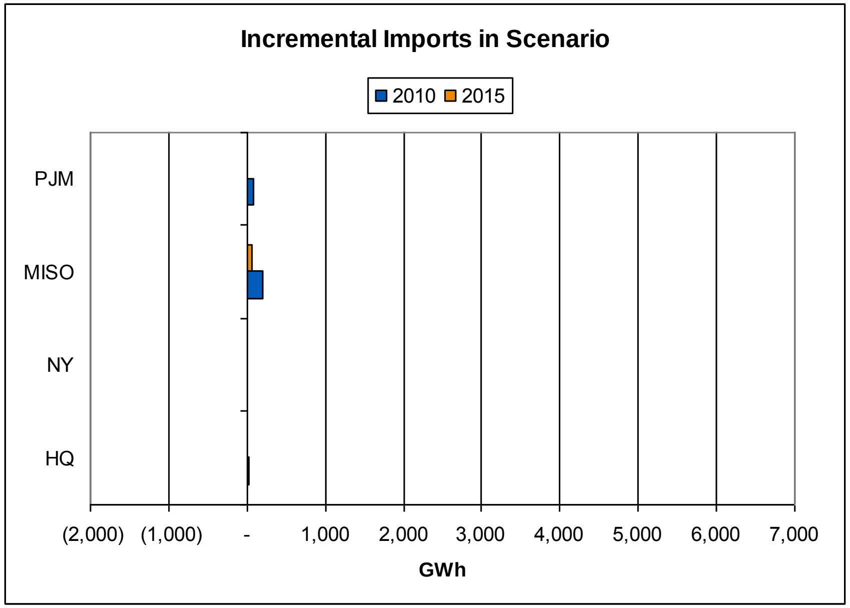
# Option 4, Scenario 1 (unilateral tariff elimination in all hours)

| | Change in Electricity Prices Relative to Status Quo | | |
|---|---|---|---|
| **Year** | **All-Hours** | **Peak** | **Off-Peak** |
| 2010 | 1.3% | 1.4% | 1.2% |
| 2015 | 0.4% | 0.5% | 0.3% |

**Observation: A unilateral reduction in the ETS tariff increases prices in Ontario because external demand and exports increase.**

# Option 4, Scenario 2 (unilateral tariff elimination, off-peak only)

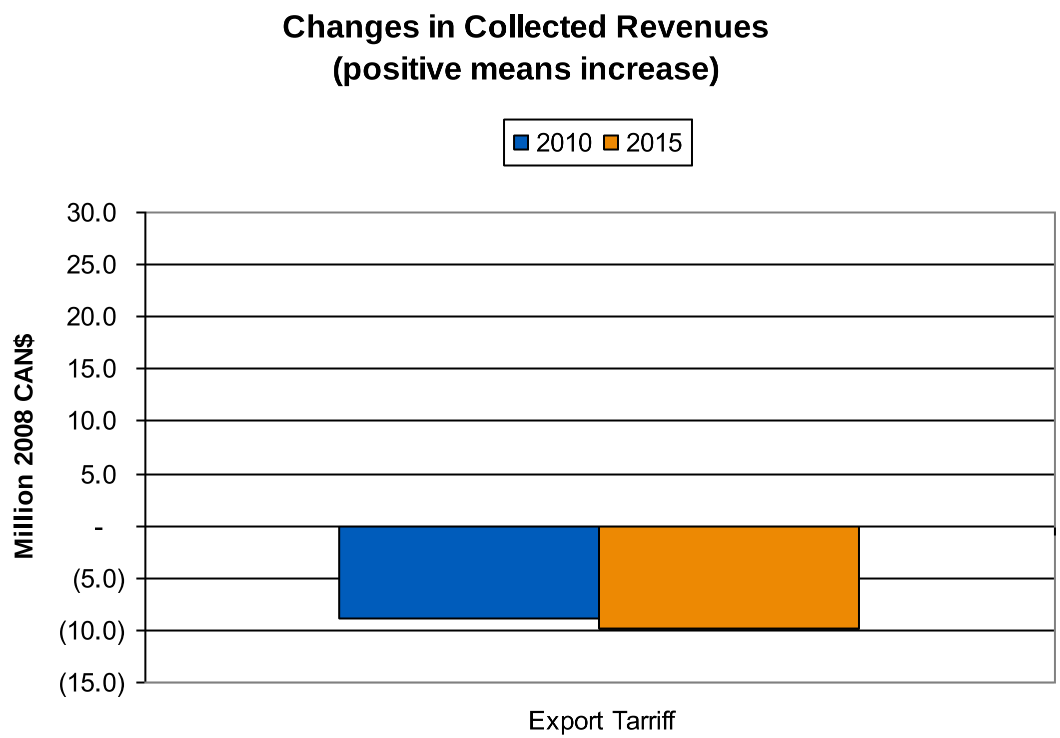



| Year | Change in Total Exports from Status Quo | Change in Total Imports from Status Quo |
|---|---|---|
| 2010 | 3% | 6% |
| 2015 | 6% | 1% |

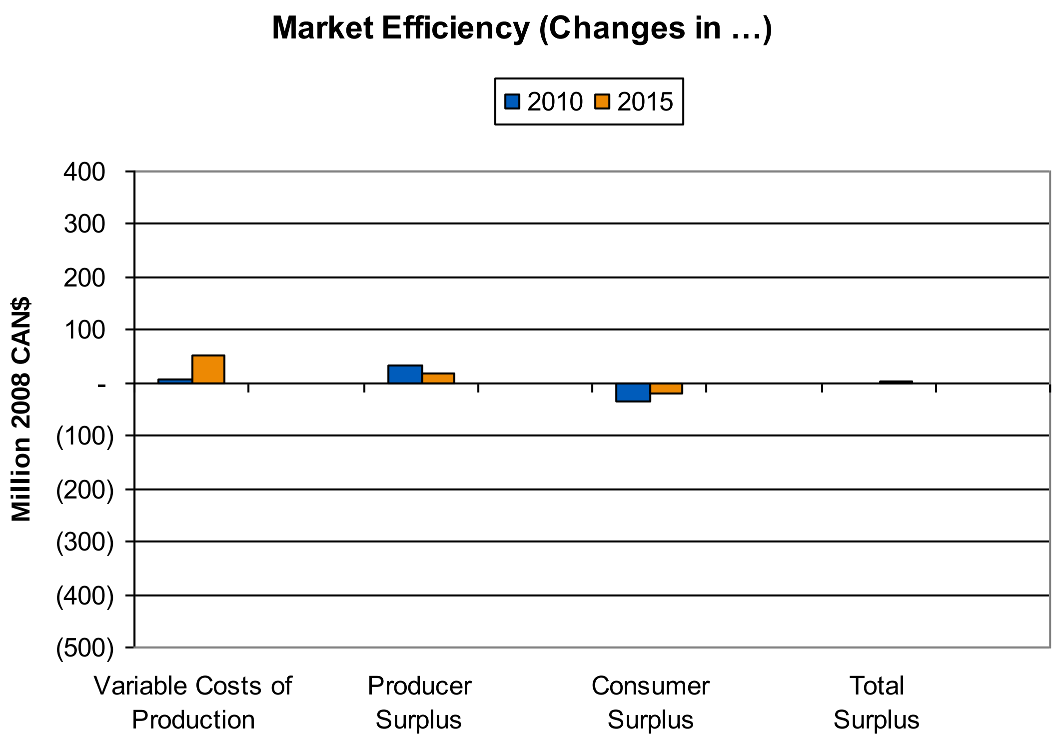
**Observation: This results in a similar outcome as Option 4, Scenario 1. Given that the Ontario ETS tariff is small, impacts on exports are expected to be modest when the tariff is eliminated in off-peak hours. Impacts on imports are also modest.**

# Option 4, Scenario 2 (unilateral tariff elimination, off-peak only)




**Observation: This scenario has a lower-magnitude (negative) impact on the ETS tariff revenue than Option 4, scenario 1 (because the tariff is retained during peak hours, creating a revenue stream).**

# Option 4, Scenario 2 (unilateral tariff elimination, off-peak only)




**Observation: When compared to Option 4, Scenario 1, the incremental increase in producer surplus and decrease in consumer surplus are smaller. This is due to the ETS tariff being retained during on-peak hours under Option 4, Scenario 2.**

# Option 4, Scenario 2 (unilateral tariff elimination, off-peak only)

| | Change in Electricity Prices Relative to Status Quo | | |
|---|---|---|---|
| **Year** | **All-Hours** | **Peak** | **Off-Peak** |
| 2010 | 0.5% | 0.1% | 0.9% |
| 2015 | 0.2% | 0.1% | 0.2% |

**Observation: A unilateral elimination of the ETS tariff increases prices because external demand increases. Under Option 4, Scenario 2, this is more pronounced during the off-peak hours when the ETS tariff is eliminated.**

Key Assumptions for Calibration and Scenario Analysis

2007 Model Calibration Results

Scenario Definitions

Results by Scenario

**Emissions Impacts by Scenario**

General Conclusions

Appendices

# Changes in Net Exports (these generally drive emissions impacts)

Change in Net Exports - 2010
GWh

| Option | Scenario | Destination | | | | |
|---|---|---|---|---|---|---|
| | | PJM | MISO | NY | HQ | Total |
| Option 2 | | (76) | 1,610 | (3,379) | (406) | (2,252) |
| Option 3 | Scenario 1 | (2,037) | (4,338) | 3,319 | (2,080) | (5,135) |
| Option 3 | Scenario 2 | (560) | 41 | 1,289 | (836) | (66) |
| Option 4 | Scenario 1 | (235) | (369) | 656 | 4 | 56 |
| Option 4 | Scenario 2 | (78) | (186) | 195 | 133 | 64 |

Change in Net Exports - 2015
GWh

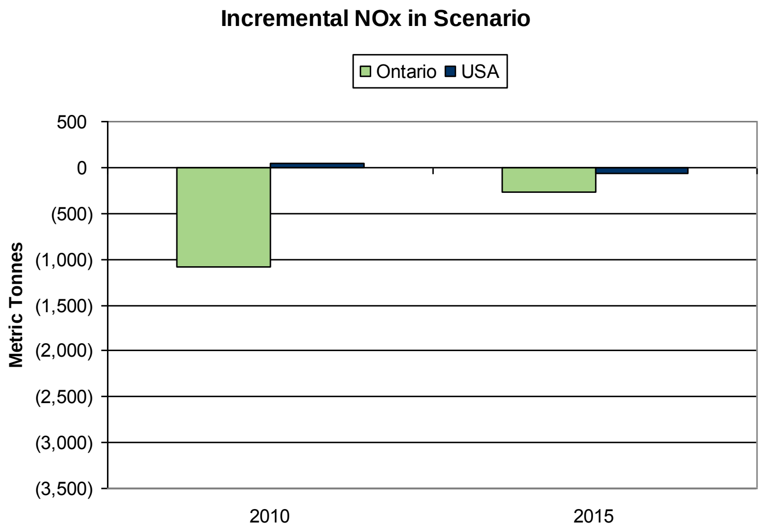
| Option | Scenario | Destination | | | | |
|---|---|---|---|---|---|---|
| | | PJM | MISO | NY | HQ | Total |
| Option 2 | | (312) | 1,700 | (5,104) | (469) | (4,185) |
| Option 3 | Scenario 1 | (445) | (6,357) | 1,487 | 73 | (5,243) |
| Option 3 | Scenario 2 | (283) | 129 | 1,364 | (1,101) | 108 |
| Option 4 | Scenario 1 | (3) | (257) | 867 | 337 | 944 |
| Option 4 | Scenario 2 | (10) | (55) | 494 | 233 | 663 |

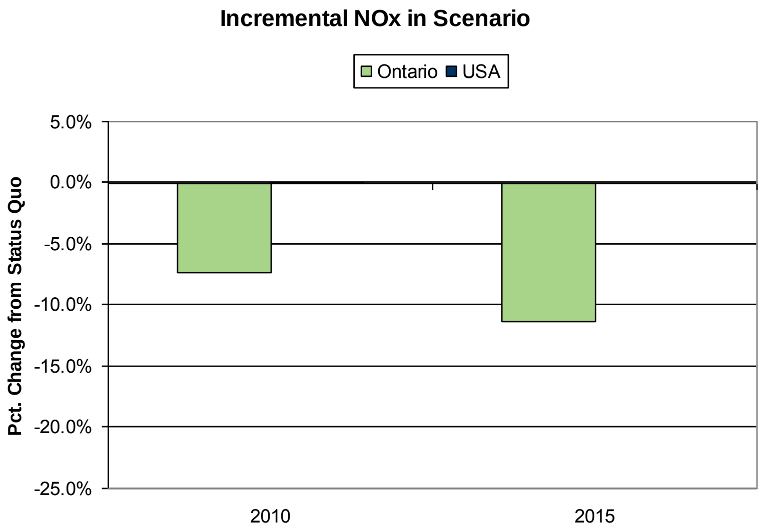
**Note: A negative value means that Ontario's net exports (exports less imports) would decrease.**

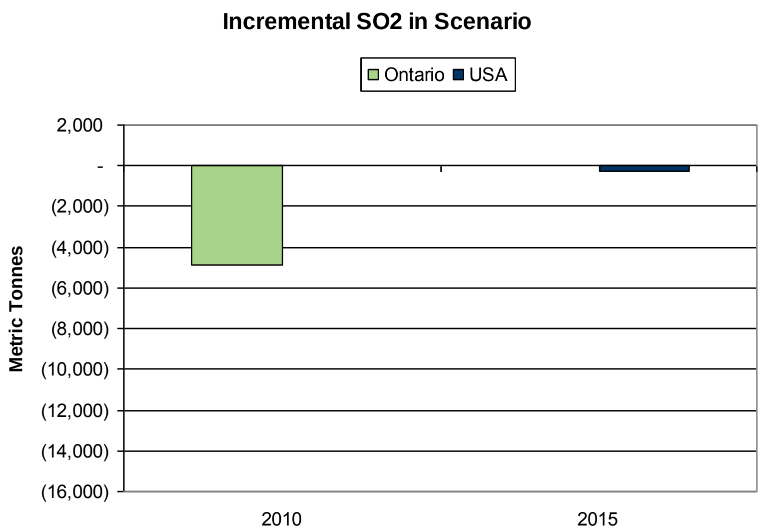


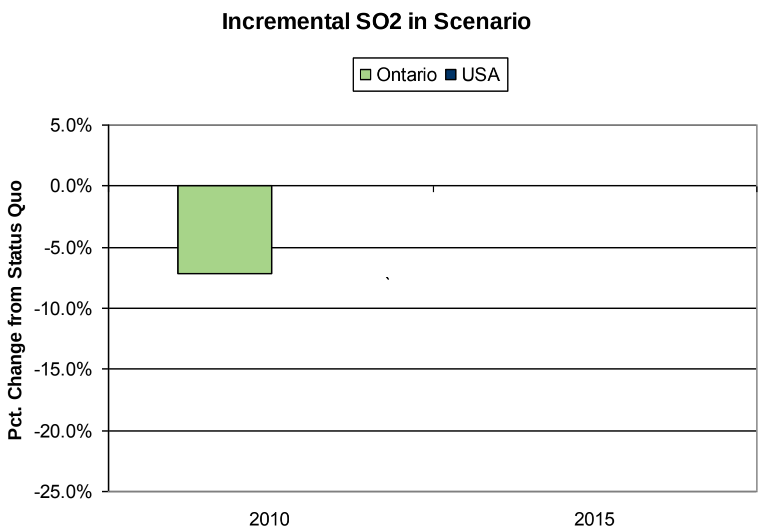
INTERNATIONAL

# Option 2 (average network rate option)



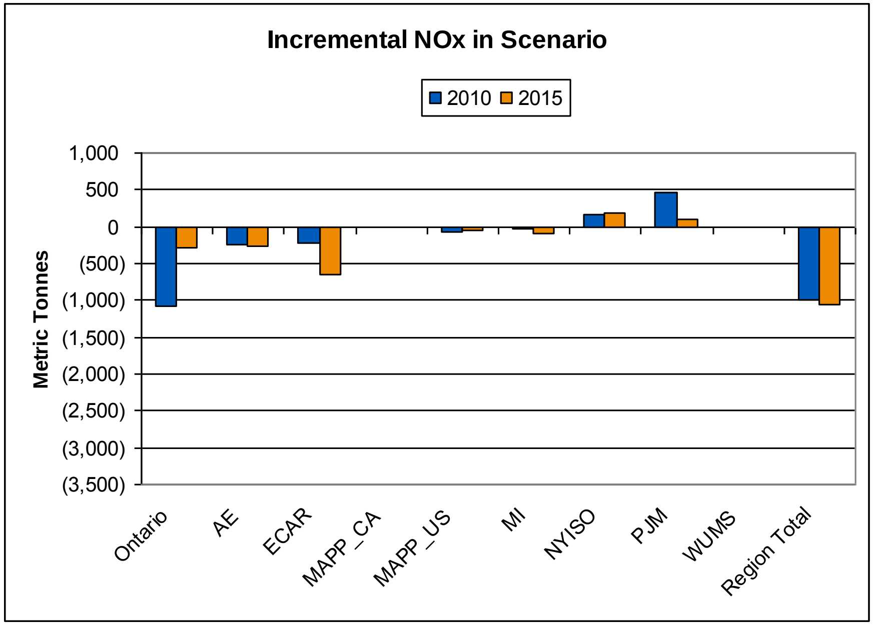



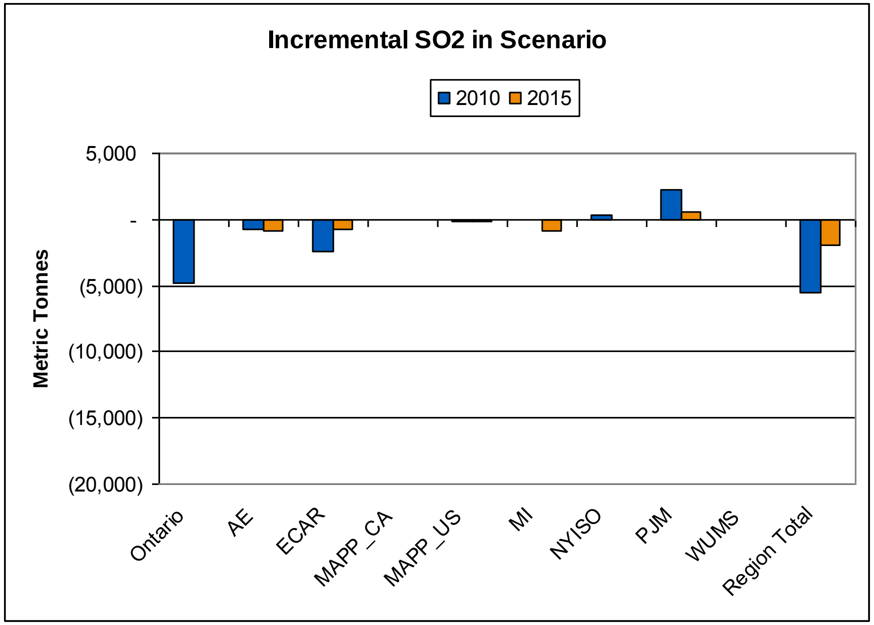



# Option 2 - $SO_2$ and $NO_x$

- Ontario $SO_2$ and $NO_x$ emissions would be well under the caps in both Status Quo and Option 2 (in 2010 and 2015) due to the consequential impacts of Ontario's $CO_2$ cap (and Ontario's policy to retire the coal-fired generation fleet by the end of 2014)
- Option 2 reduces Ontario emissions relative to Status Quo because Option 2 assumes Ontario has unilaterally increased its export tariff; accordingly, there is a decrease in net exports
- There is no change in $SO_2$ in Ontario in 2015 (versus status quo) because the coal-fired fleet is assumed to be retired by the end of 2014, and hence there are no $SO_2$ emissions
- $SO_2$ and $NO_x$ emissions are relatively unchanged (versus status quo) in the U.S. because of US CAIR policy restrictions pertaining to both pollutants

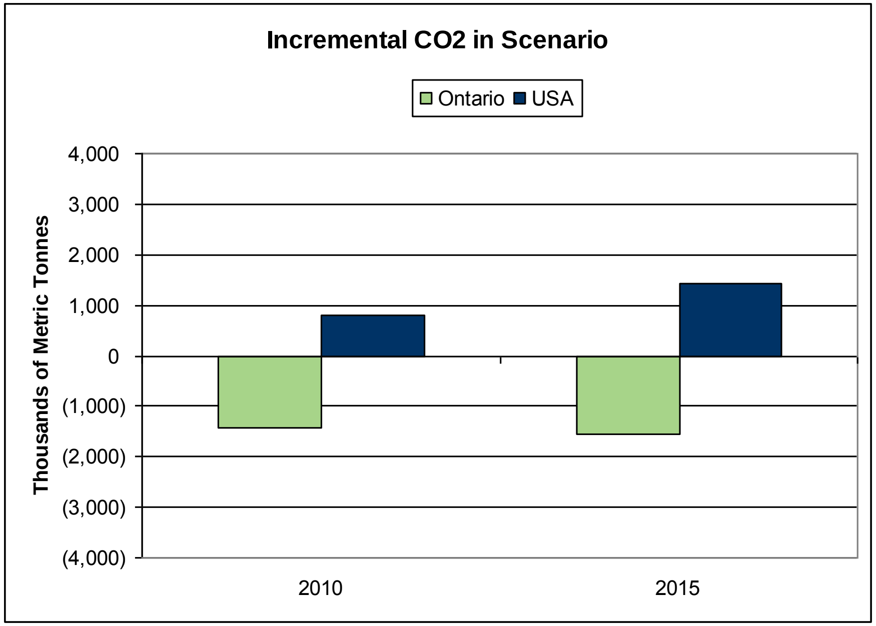
# Option 2 (average network rate option)

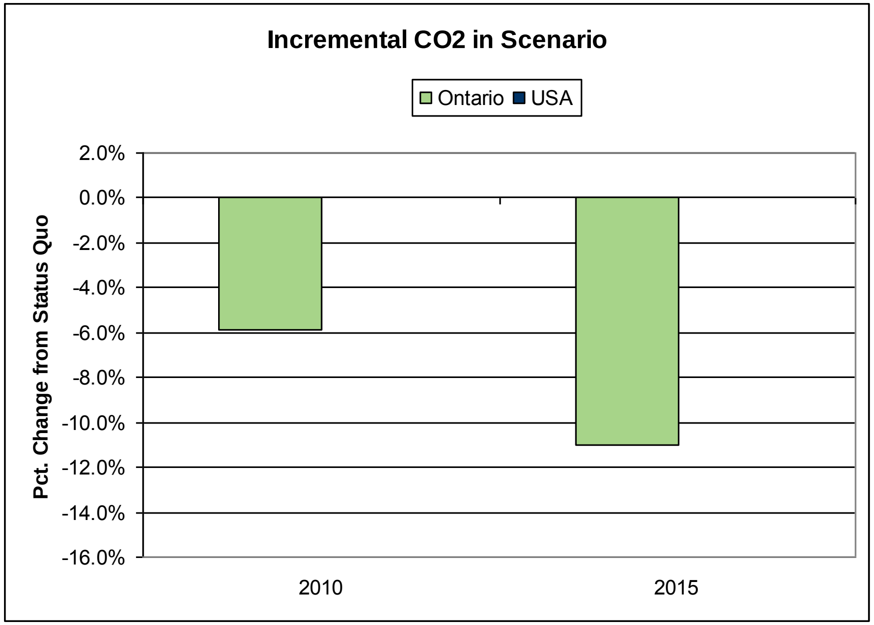



**See Appendix C for a map of NEEM's regions.**

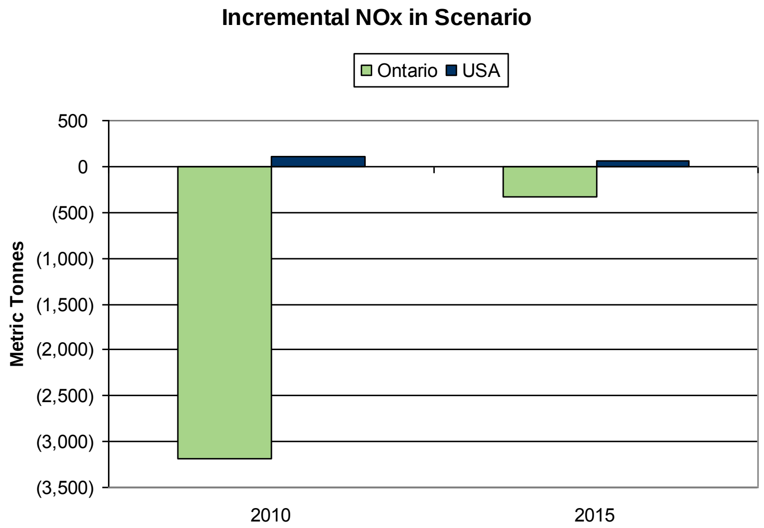
# Option 2 (average network rate option)

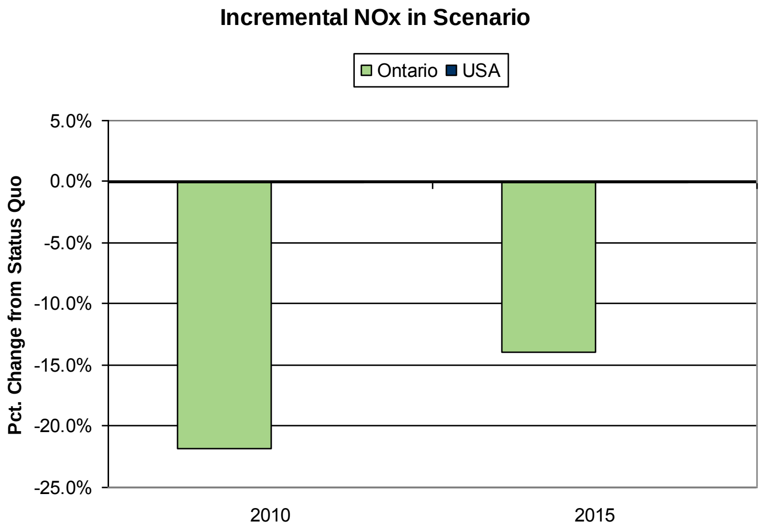


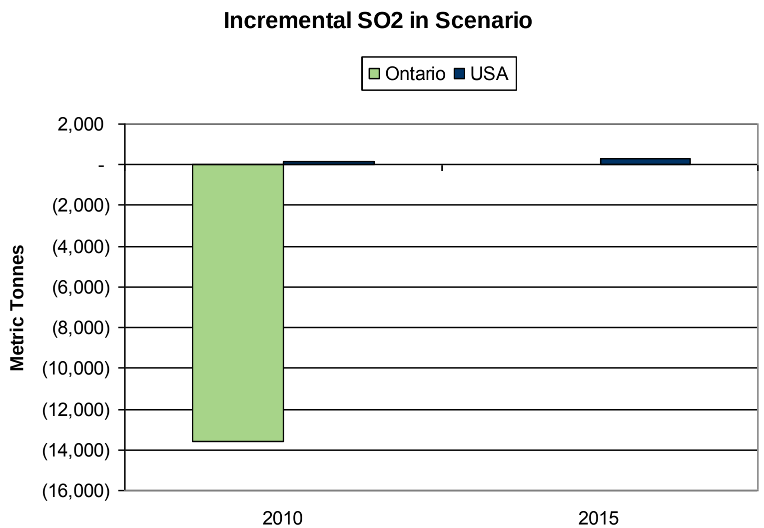



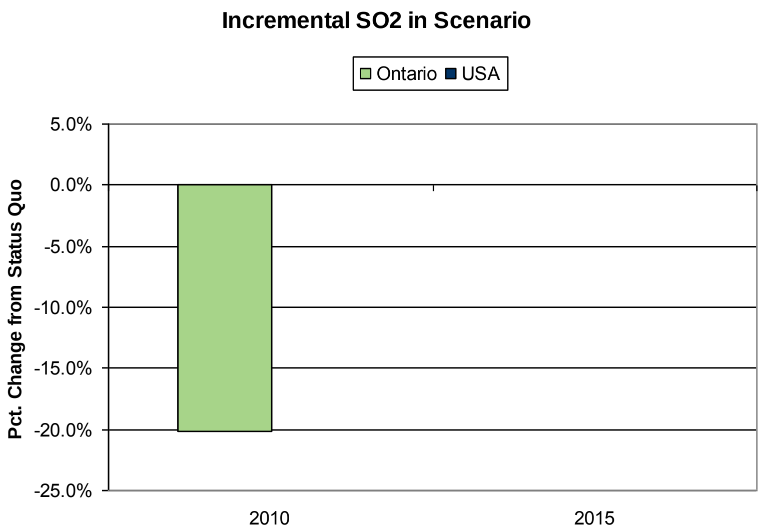

**$CO_2$ impacts are small and offsetting.**

# Option 3, Scenario 1 (reciprocal treatment, tariff eliminated)



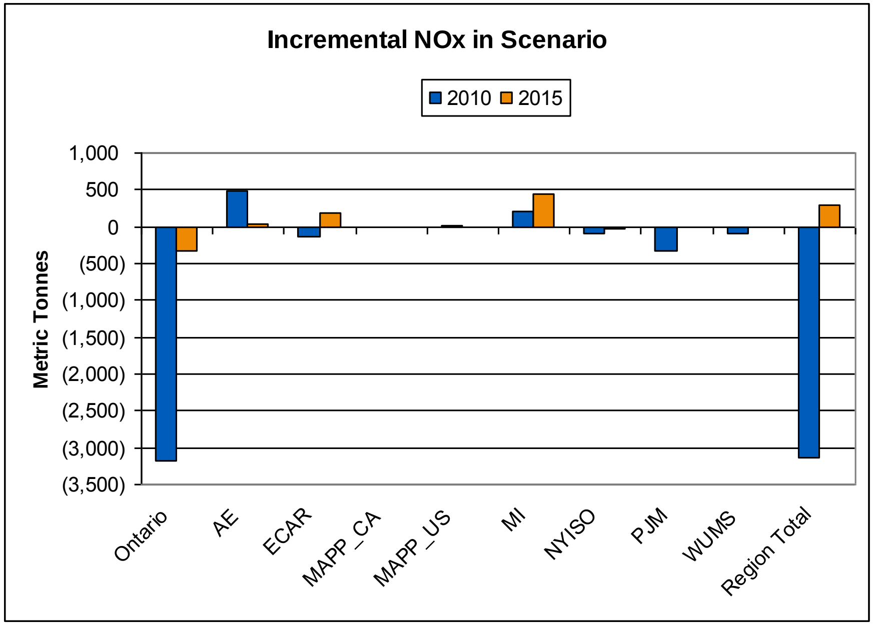



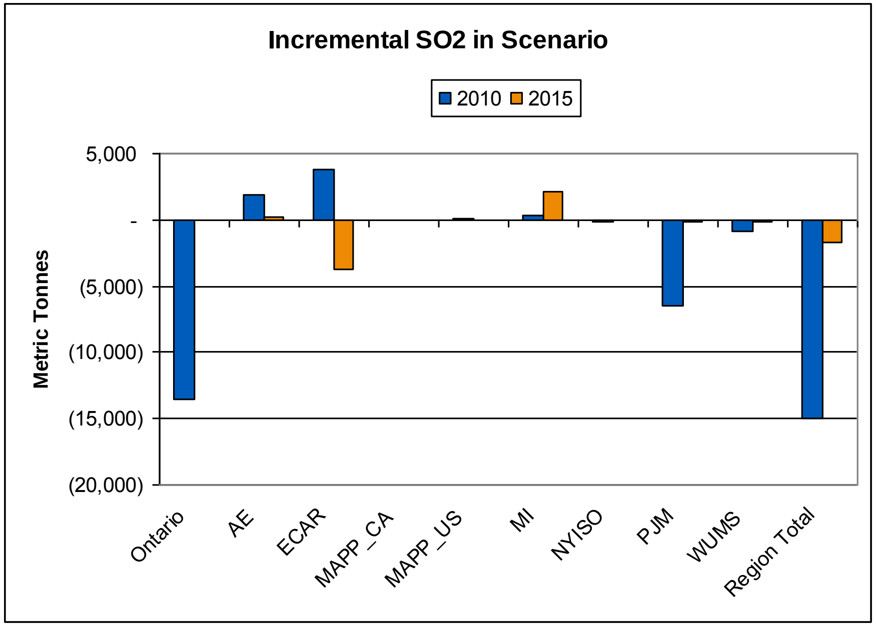



# Option 3, Scenario 1 – SO2 and NOx

- Ontario SO2 and NOx emissions would be well under the caps in both Status Quo and Option 3, Scenario 1 (in 2010 and 2015) due to the consequential impacts of Ontario's CO2 cap (and Ontario's policy to retire the coal-fired generation fleet by the end of 2014)
- Option 3, Scenario 1 reduces Ontario emissions relative to Status Quo because Ontario's net exports are decreased (because Ontario's neighbours' tariffs are cut more than Ontario's tariffs)
- There is no change in SO2 in Ontario in 2015 (versus status quo) because the coal-fired fleet is assumed to be retired by the end of 2014, and hence there are no SO2 emissions
- SO2 and NOx emissions are relatively unchanged (versus status quo) in the U.S. because of US CAIR policy restrictions pertaining to both pollutants

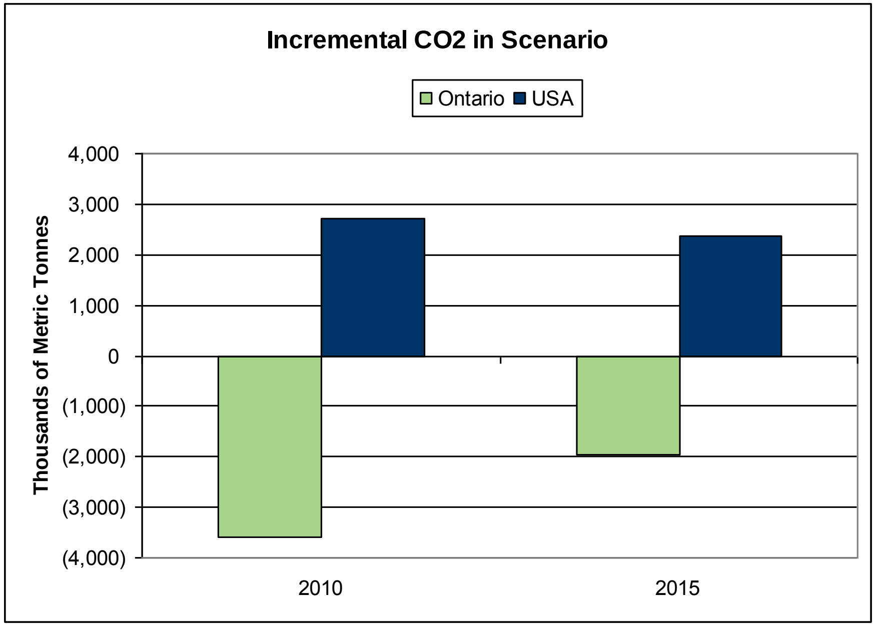
# Option 3, Scenario 1 (reciprocal treatment, tariff eliminated)

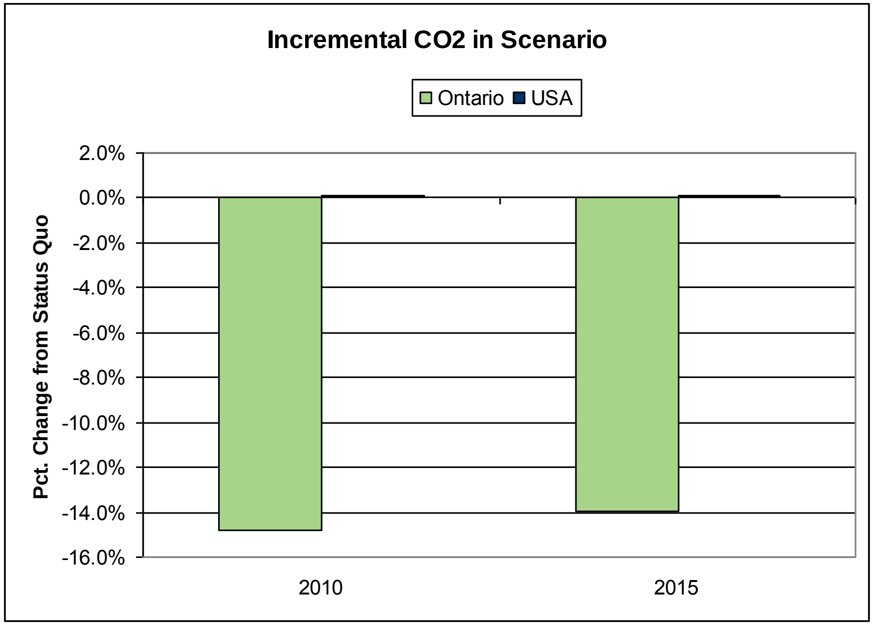



**See Appendix C for a map of NEEM's regions.**

# Option 3, Scenario 1 (reciprocal treatment, tariff eliminated)

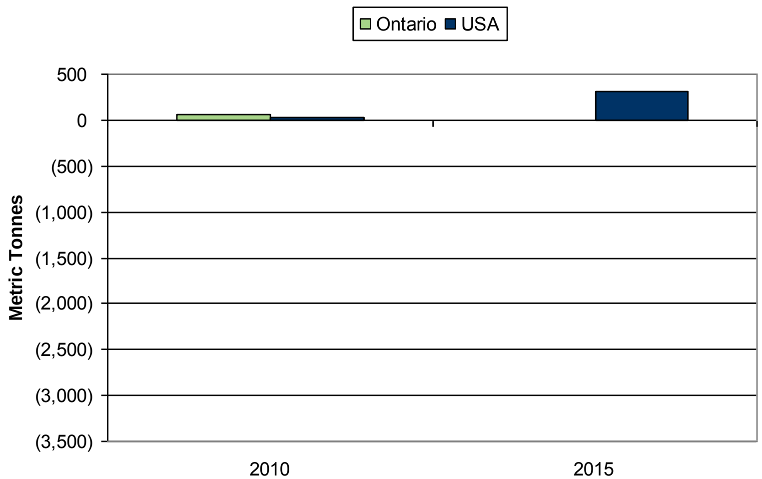


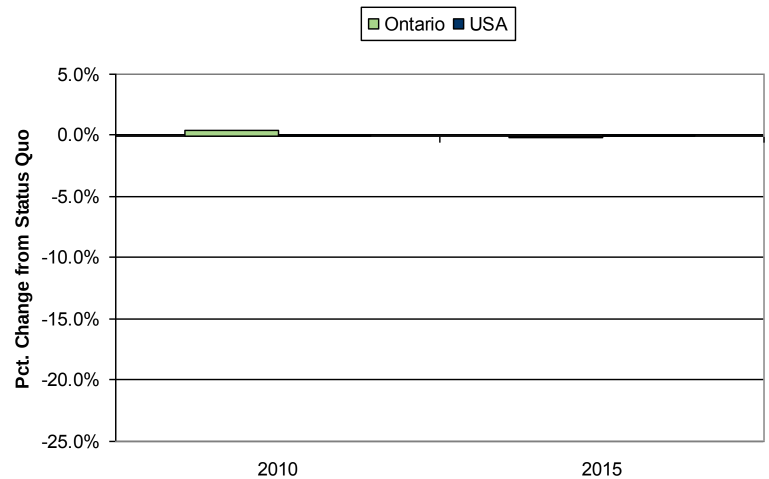

**CO2 impacts are small and nearly offsetting.**

# Option 3, Scenario 2 (reciprocal treatment, avg. embedded network cost)

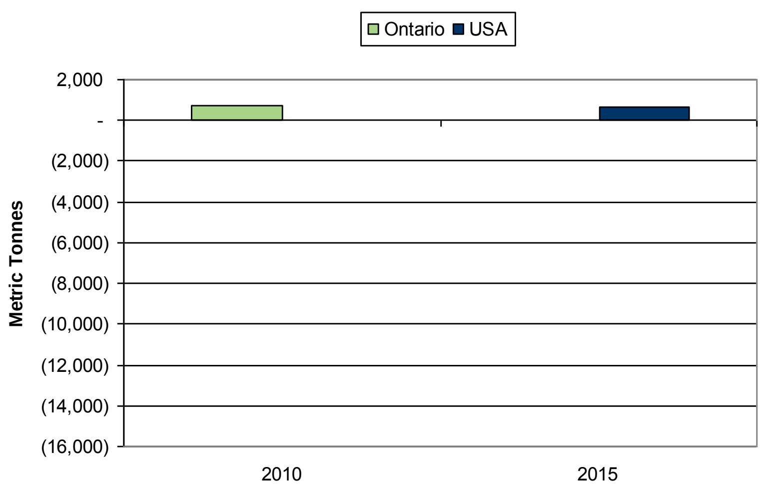
**Incremental NOx in Scenario**



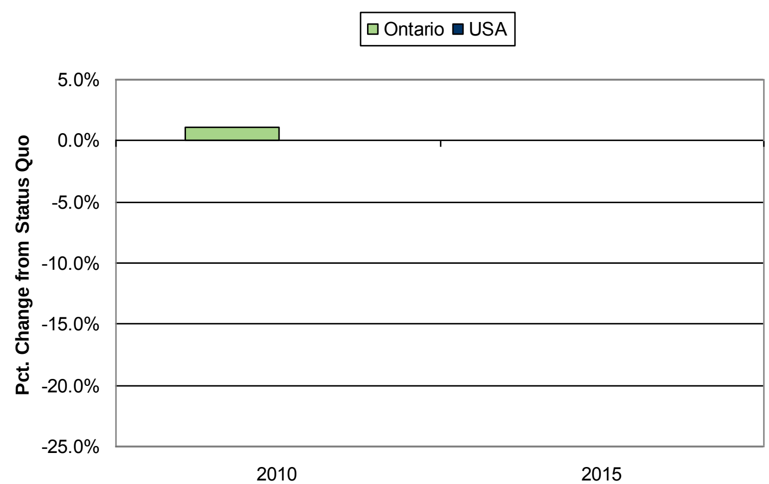

**Incremental NOx in Scenario**




**Incremental SO2 in Scenario**



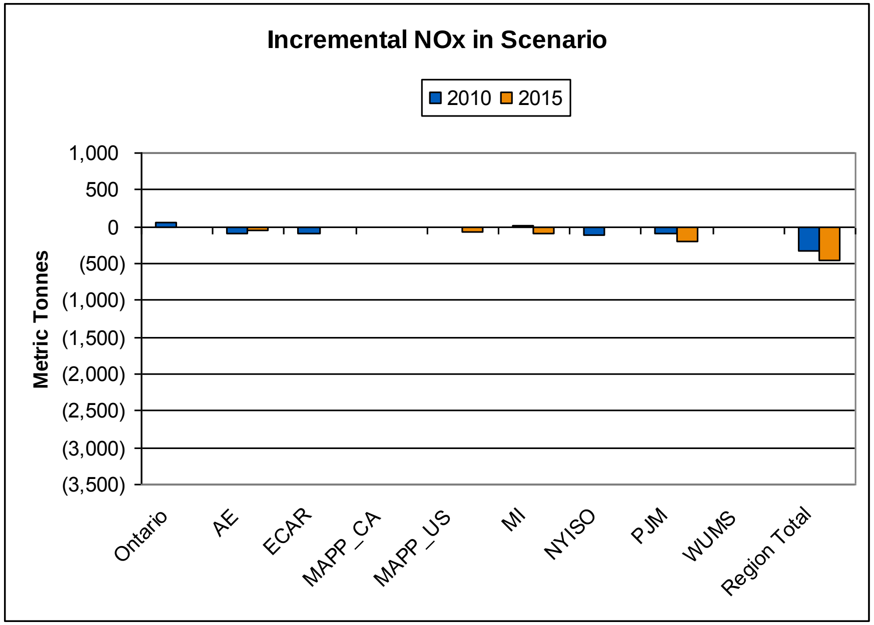

**Incremental SO2 in Scenario**

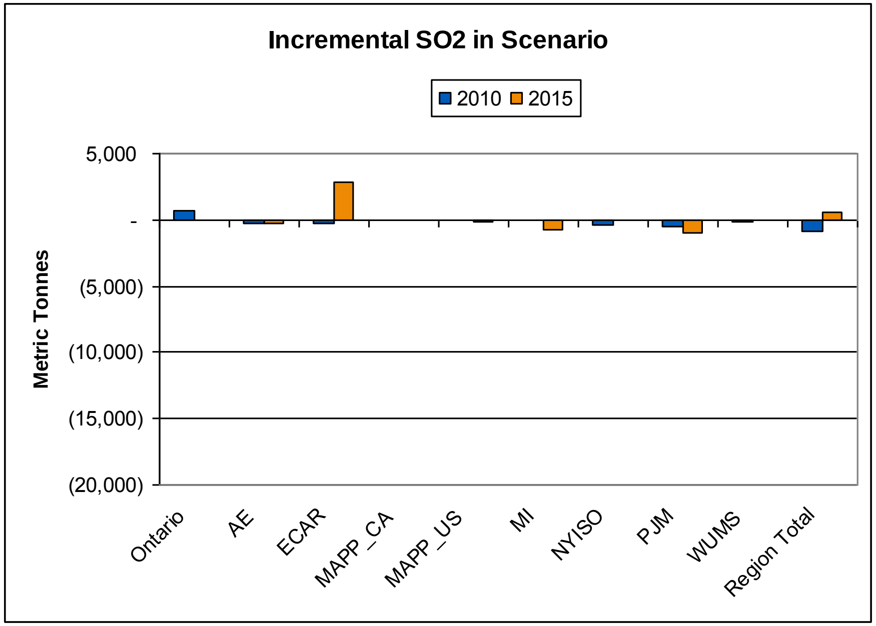


# Option 3, Scenario 2 – SO2 and NOx

- Ontario SO2 and NOx emissions would be well under the caps in both Status Quo and Option 3, Scenario 2 (in 2010 and 2015) due to the consequential impacts of Ontario's CO2 cap (and Ontario's policy to retire the coal-fired generation fleet by the end of 2014)
- Impacts on emissions are small in this scenario because the impact on net exports is small
- There is no change in SO2 in Ontario in 2015 (versus status quo) because the coal-fired fleet is assumed to be retired by the end of 2014, and hence there are no SO2 emissions
- SO2 and NOx emissions are relatively unchanged (versus status quo) in the U.S. because of US CAIR policy restrictions pertaining to both pollutants

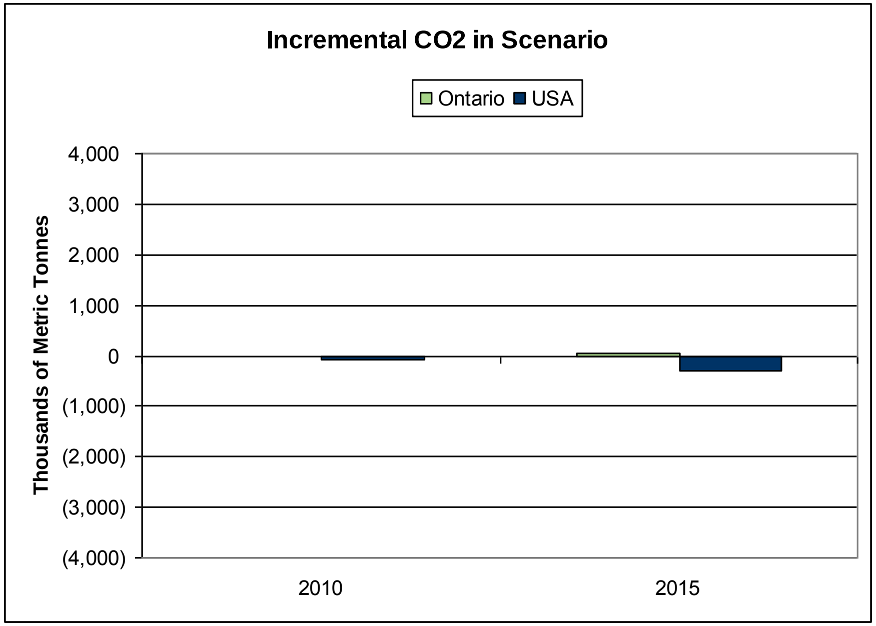
# Option 3, Scenario 2 (reciprocal treatment, avg. embedded network cost)

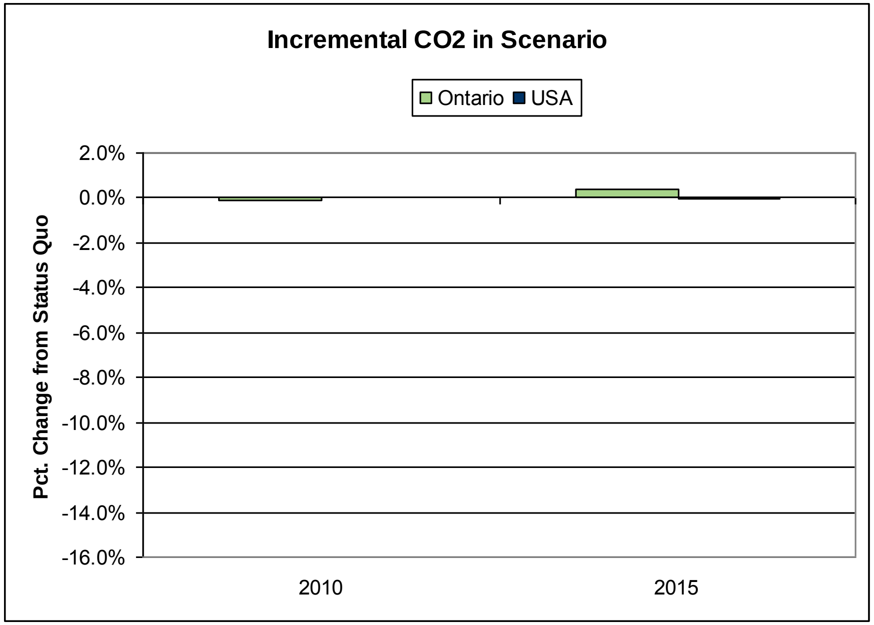



**See Appendix C for a map of NEEM's regions.**

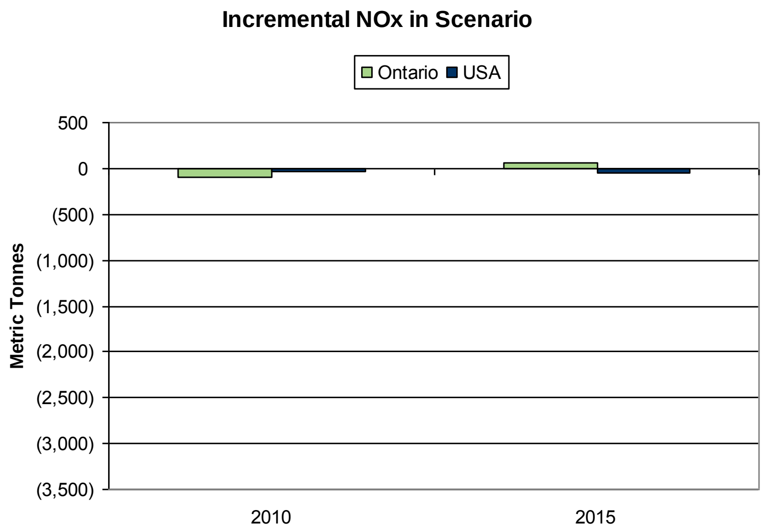
# Option 3, Scenario 2 (reciprocal treatment, avg. embedded network cost)

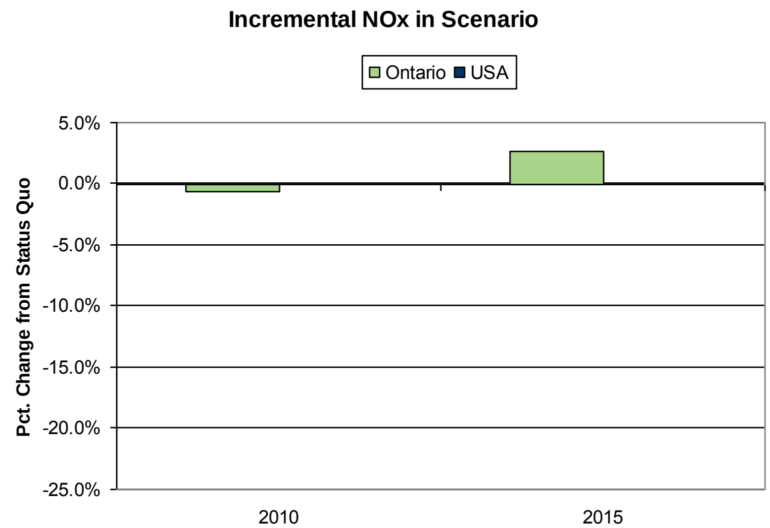


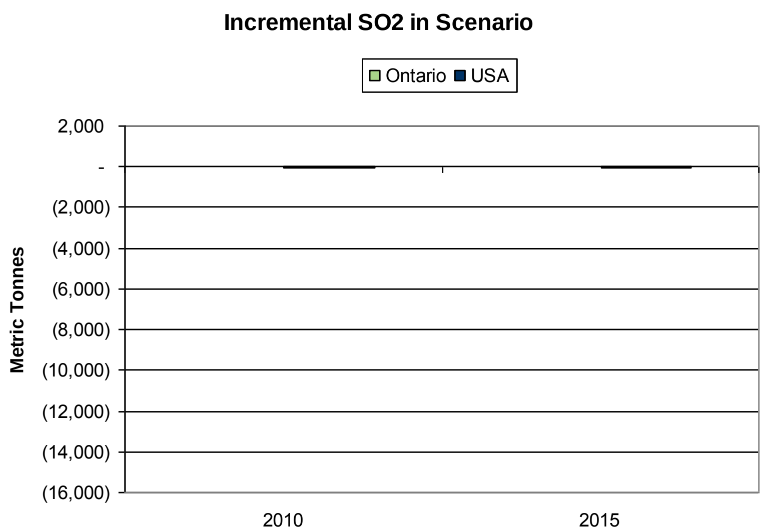



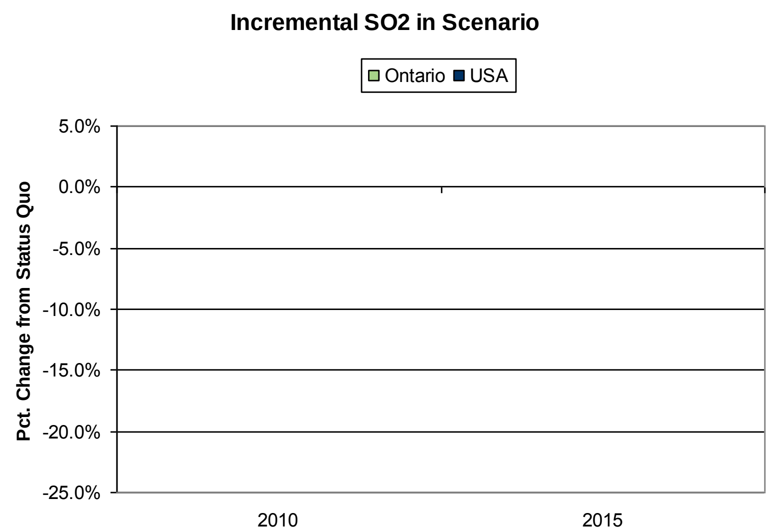

**CO2 impacts are very small.**

# Option 4, Scenario 1 (unilateral tariff elimination in all hours)



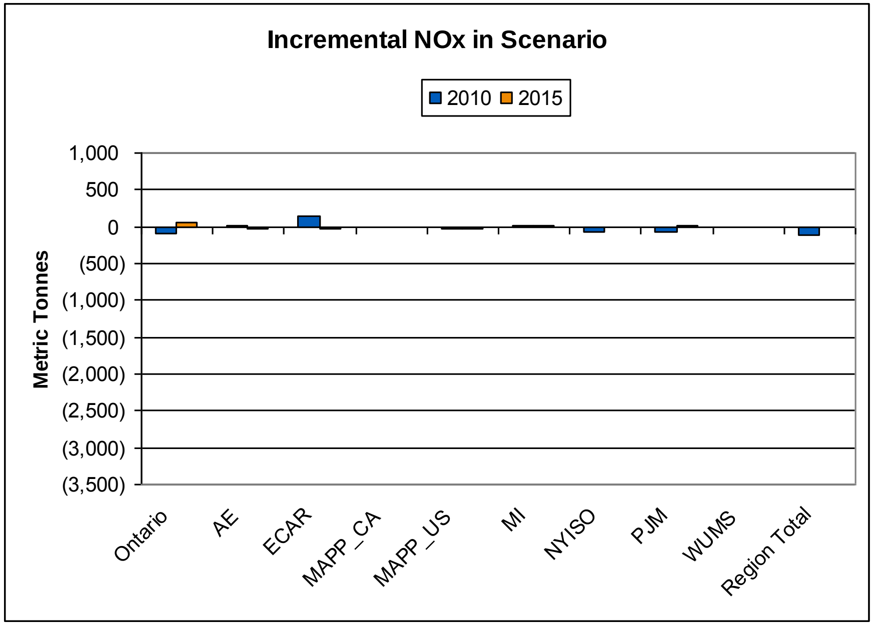



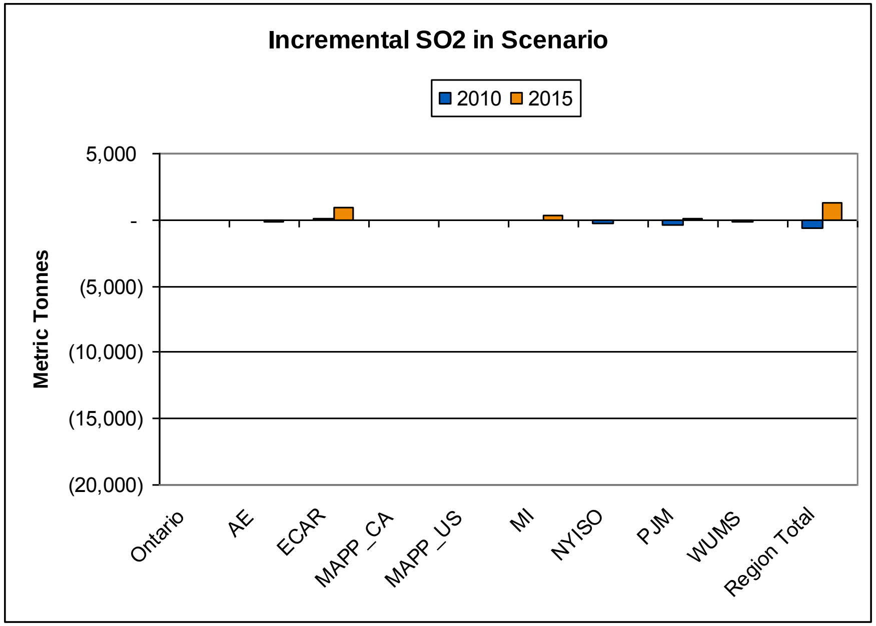



# Option 4, Scenario 1 – $SO_2$ and $NO_x$

- Ontario $SO_2$ and $NO_x$ emissions would be well under the caps in both Status Quo and Option 4, Scenario 1 (in 2010 and 2015) due to the consequential impacts of Ontario’s $CO_2$ cap (and Ontario’s policy to retire the coal-fired generation fleet by the end of 2014)
- Impacts on emissions are small in this scenario because the impact on net exports is small
- There is no change in $SO_2$ in Ontario in 2015 (versus status quo) because the coal-fired fleet is assumed to be retired by the end of 2014, and hence there are no $SO_2$ emissions
- $SO_2$ and $NO_x$ emissions are relatively unchanged (versus status quo) in the U.S. because of US CAIR policy restrictions pertaining to both pollutants

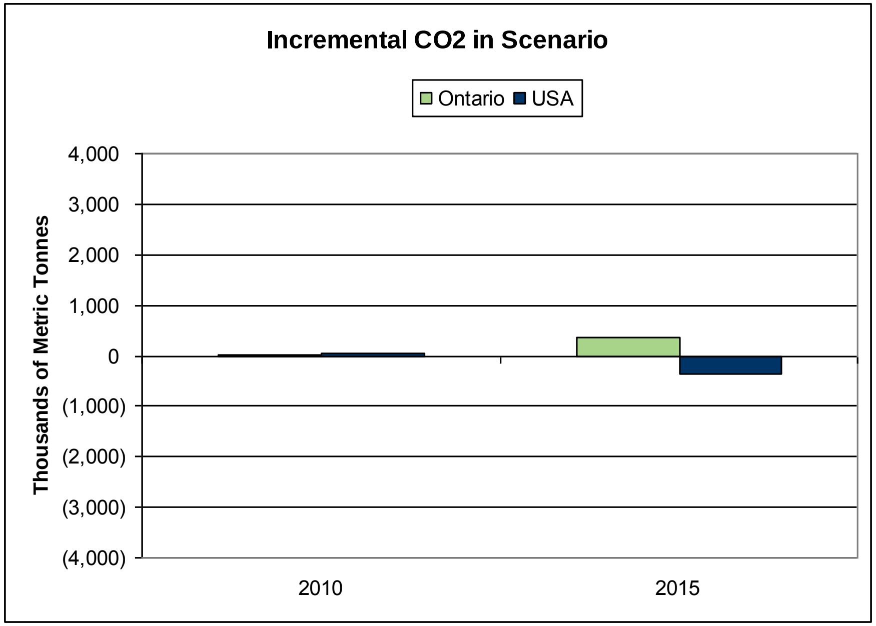
# Option 4, Scenario 1 (unilateral tariff elimination in all hours)



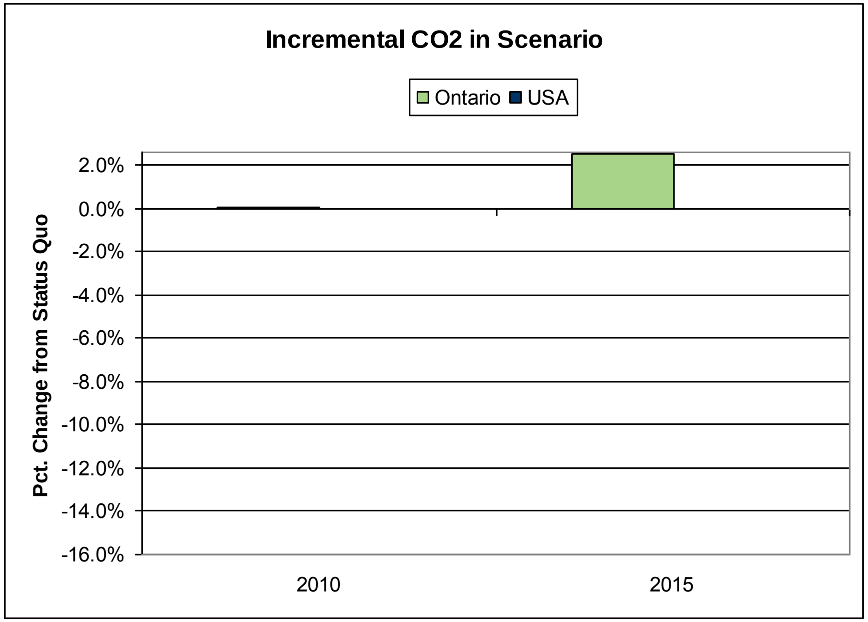




**See Appendix C for a map of NEEM's regions.**

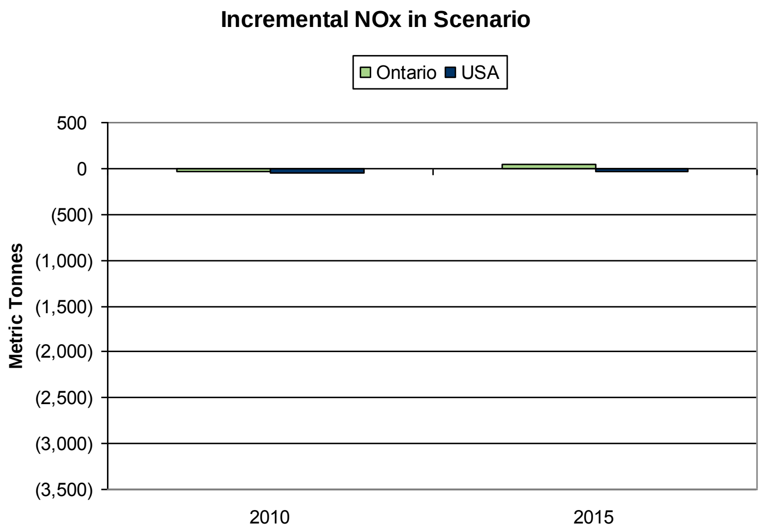
# Option 4, Scenario 1 (unilateral tariff elimination in all hours)

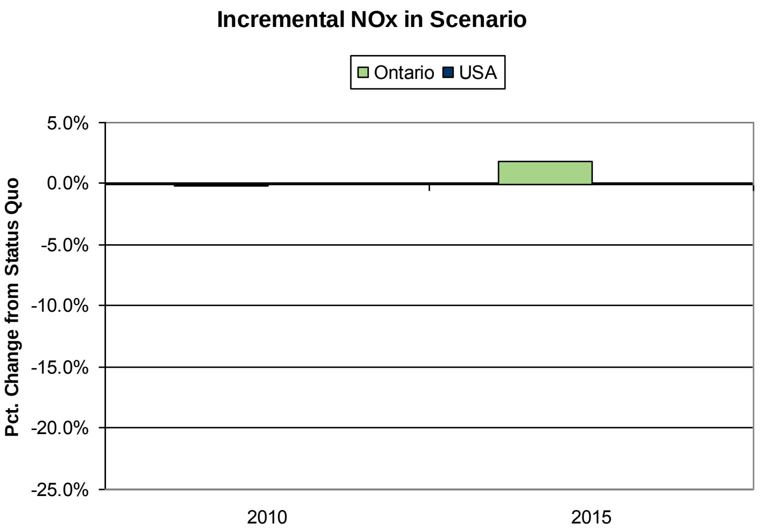


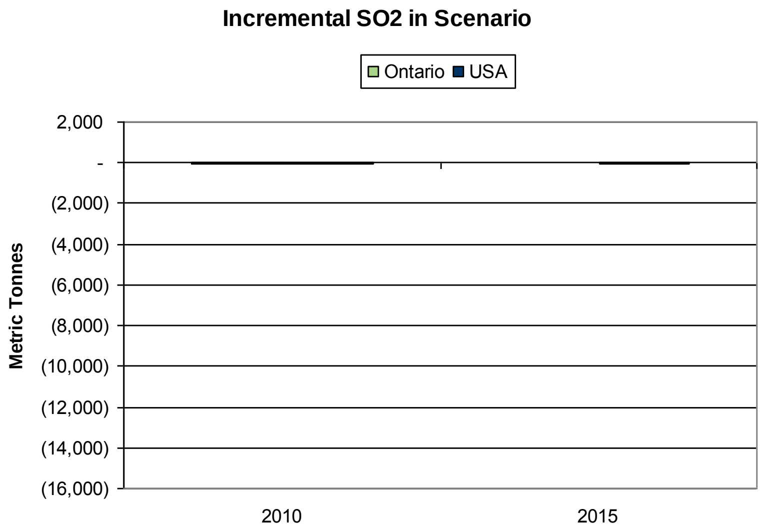

**CO2 impacts are small.**

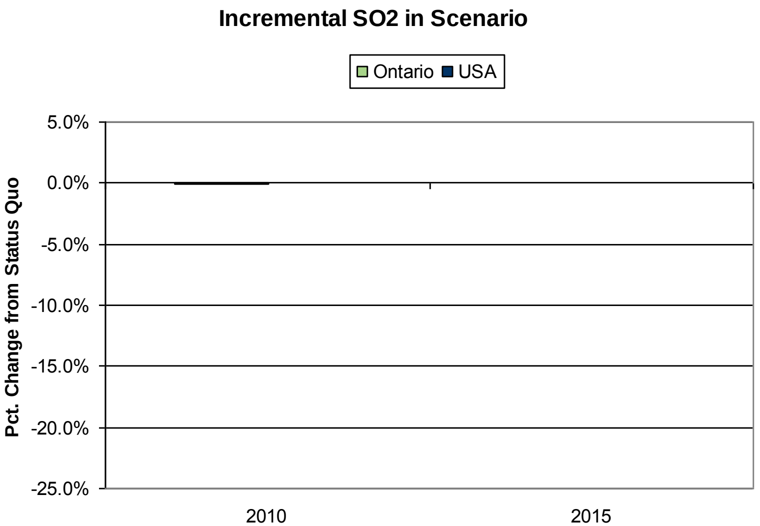


# Option 4, Scenario 2 (unilateral tariff elimination, off-peak hours only)



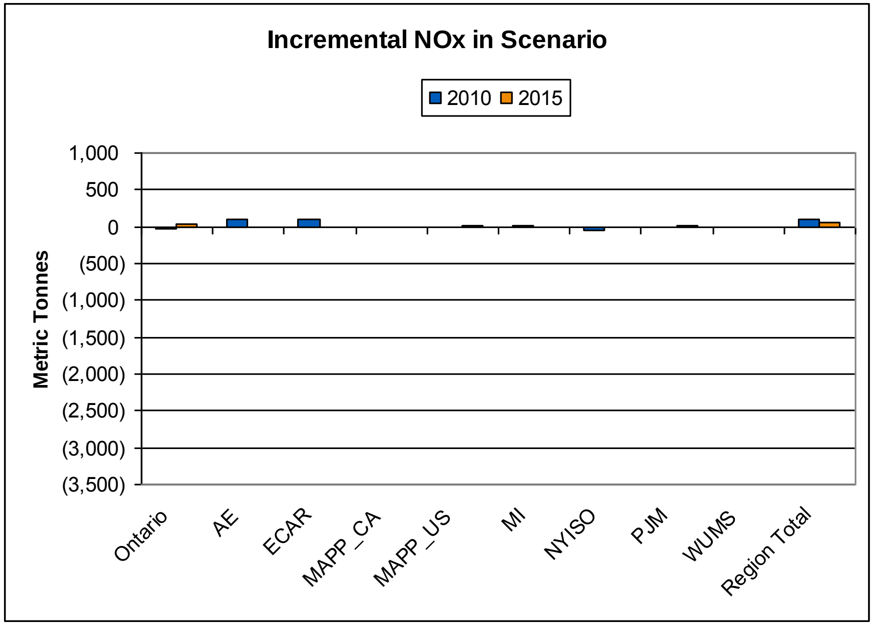



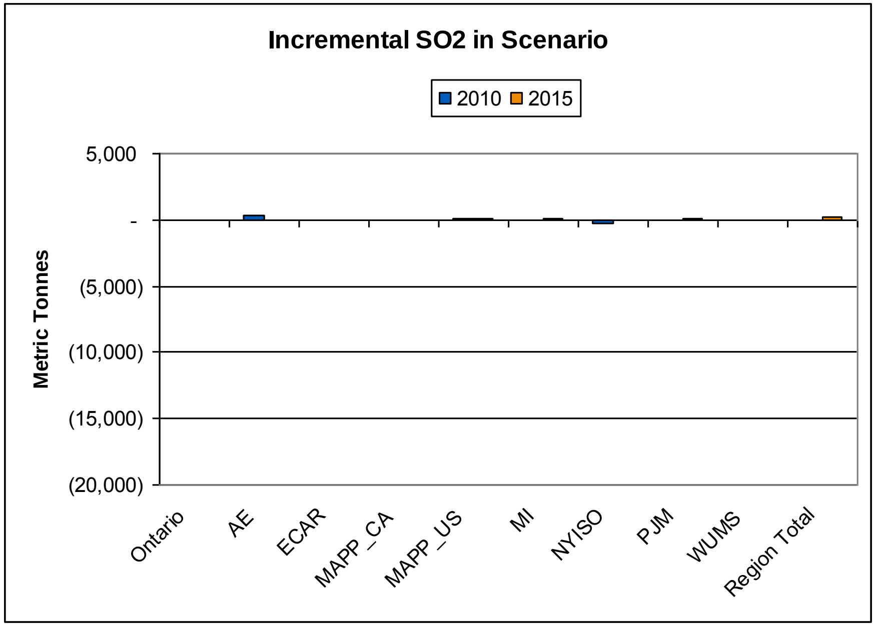



# Option 4, Scenario 2 – SO2 and NOx

- Ontario SO2 and NOx emissions would be well under the caps in both Status Quo and Option 4, Scenario 2 (in 2010 and 2015) due to the consequential impacts of Ontario's CO2 cap (and Ontario's policy to retire the coal-fired generation fleet by the end of 2014)
- Impacts on emissions are small in this scenario because the impact on net exports is small
- There is no change in SO2 in Ontario in 2015 (versus status quo) because the coal-fired fleet is assumed to be retired by the end of 2014, and hence there are no SO2 emissions
- SO2 and NOx emissions are relatively unchanged (versus status quo) in the U.S. because of US CAIR policy restrictions pertaining to both pollutants

# Option 4, Scenario 2 (unilateral tariff elimination, off-peak only)



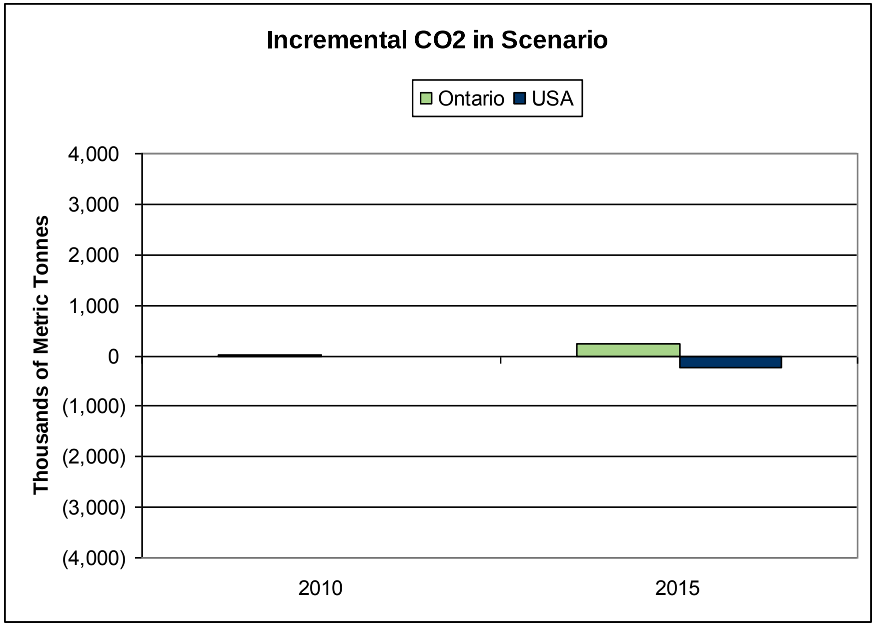



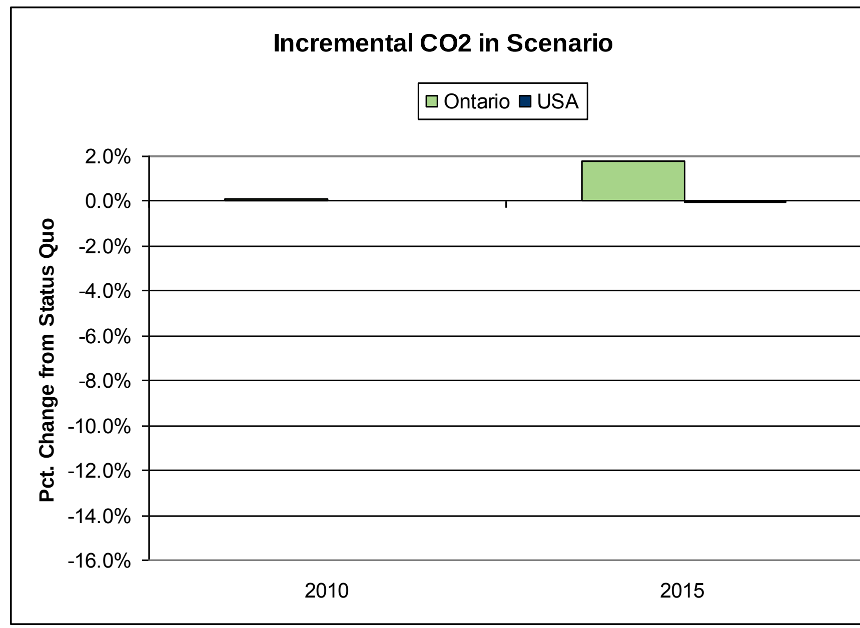

**See Appendix C for a map of NEEM's regions.**



CRA INTERNATIONAL

# Option 4, Scenario 2 (unilateral tariff elimination, off-peak only)




**CO2 impacts are small.**

Key Assumptions for Calibration and Scenario Analysis

2007 Model Calibration Results

Scenario Definitions

Results by Scenario

Emissions Impacts by Scenario

**General Conclusions**

Appendices

# Economic Impacts

- Option 2 (average embedded network rate) and Option 3 (reciprocal treatment) tend to increase consumer surplus and decrease producer surplus (the small decrease in consumer surplus in Option 3, scenario 2 in 2010 is the exception)
- Option 4, scenarios 1 and 2 increase producer surplus, but scenario 2 less so. Option 4, scenarios 1 and 2 decrease consumer surplus, but scenario 2 less so. (These are the unilateral tariff elimination options - Scenario 2 involves tariff elimination only in the off-peak hours)
- Option 2 and Option 3, scenario 2 increase ETS tariff revenue. These are the options that involve an increase in the ETS tariff. The increase in Option 3, scenario 2 is small because tariffs are both increased and decreased (depending on the recipient of the exports). All other options decrease ETS tariff revenue.

# Emissions Impacts

- Overall emissions impacts are small
- Ontario SO2 and NOx will be well below their caps regardless of the export tariff scenario due to the consequential effects of Ontario's CO2 cap (and Ontario's policy to retire the coal-fired generation fleet by the end of 2014)
- North American cap-and-trade policy for CO2 would control any CO2 leakage associated with export tariff changes
  - If all power sector CO2 emissions in North America were subject to cap-and-trade, North American CO2 emissions would not be affected by the choice of export tariff scenario
  - Since we modeled the North American policy as a CO2 price and allowed emissions to change, we see small net changes in CO2 emissions

Key Assumptions for Calibration and Scenario Analysis

2007 Model Calibration Results

Scenario Definitions

Electric Power Results by Scenario

Emissions Impacts Sector Results by Scenario

General Conclusions

**Appendices**

# Appendix A: Summary Results Tables

# Impacts on Ontario Exports

Incremental Exports - 2010
GWh

| Option | Scenario | Destination | | | | |
|---|---|---|---|---|---|---|
| | | PJM | MISO | NY | HQ | Total |
| Option 2 | | (184) | (3) | (3,380) | (493) | (4,060) |
| Option 3 | Scenario 1 | 478 | 55 | 3,320 | 601 | 4,453 |
| Option 3 | Scenario 2 | (323) | (19) | 1,290 | (839) | 109 |
| Option 4 | Scenario 1 | 56 | 2 | 657 | 132 | 847 |
| Option 4 | Scenario 2 | 13 | 8 | 195 | 152 | 368 |

Incremental Exports - 2015
GWh

| Option | Scenario | Destination | | | | |
|---|---|---|---|---|---|---|
| | | PJM | MISO | NY | HQ | Total |
| Option 2 | | (312) | (17) | (5,105) | (591) | (6,025) |
| Option 3 | Scenario 1 | 560 | 148 | 1,664 | 698 | 3,070 |
| Option 3 | Scenario 2 | (283) | (44) | 1,367 | (1,215) | (175) |
| Option 4 | Scenario 1 | (2) | 25 | 868 | 360 | 1,251 |
| Option 4 | Scenario 2 | (9) | 13 | 494 | 237 | 735 |

# Impact on Ontario Imports

Incremental Imports - 2010
GWh

| Option | Scenario | Origin PJM | MISO | NY | HQ | Total |
|---|---|---|---|---|---|---|
| Option 2 | | (107) | (1,613) | (0) | (87) | (1,808) |
| Option 3 | Scenario 1 | 2,515 | 4,392 | 0 | 2,681 | 9,588 |
| Option 3 | Scenario 2 | 237 | (60) | 0 | (3) | 174 |
| Option 4 | Scenario 1 | 291 | 370 | 0 | 128 | 791 |
| Option 4 | Scenario 2 | 91 | 194 | 0 | 19 | 304 |

Incremental Imports - 2015
GWh

| Option | Scenario | Origin PJM | MISO | NY | HQ | Total |
|---|---|---|---|---|---|---|
| Option 2 | | 0 | (1,718) | (1) | (123) | (1,840) |
| Option 3 | Scenario 1 | 1,005 | 6,505 | 177 | 625 | 8,313 |
| Option 3 | Scenario 2 | (0) | (173) | 4 | (114) | (284) |
| Option 4 | Scenario 1 | 0 | 282 | 1 | 23 | 307 |
| Option 4 | Scenario 2 | 0 | 68 | 0 | 4 | 72 |

# ETS Tariff Revenue and Market Efficiency Impacts

Change in ETS Revenue
Million 2008$CAN

| Option | Scenario | 2010 | 2015 |
|---|---|---|---|
| Option 2 | | 27.4 | 22.5 |
| Option 3 | Scenario 1 | (12.0) | (13.5) |
| Option 3 | Scenario 2 | 2.2 | 1.7 |
| Option 4 | Scenario 1 | (12.0) | (13.5) |
| Option 4 | Scenario 2 | (8.9) | (9.8) |

Market Efficiency Impacts - 2010
Million 2008$CAN

| Option | Scenario | Sum Variable Costs | Producer Surplus | Consumer Surplus | Total Surplus |
|---|---|---|---|---|---|
| Option 2 | | (126) | (214) | 207 | (7) |
| Option 3 | Scenario 1 | (272) | (299) | 297 | (1) |
| Option 3 | Scenario 2 | 9 | (14) | (5) | (19) |
| Option 4 | Scenario 1 | 16 | 102 | (111) | (9) |
| Option 4 | Scenario 2 | 6 | 35 | (36) | (1) |

Market Efficiency Impacts - 2015
Million 2008$CAN

| Option | Scenario | Sum Variable Costs | Producer Surplus | Consumer Surplus | Total Surplus |
|---|---|---|---|---|---|
| Option 2 | | (325) | (187) | 176 | (10) |
| Option 3 | Scenario 1 | (403) | (198) | 192 | (6) |
| Option 3 | Scenario 2 | 10 | (53) | 46 | (7) |
| Option 4 | Scenario 1 | 76 | 59 | (56) | 3 |
| Option 4 | Scenario 2 | 53 | 20 | (18) | 2 |

# Impacts on the HOEP

Impacts on the HOEP
% Change

| Option | Scenario | 2010 | 2015 |
|---|---|---|---|
| Option 2 | | -2.5% | -1.4% |
| Option 3 | Scenario 1 | -3.7% | -1.6% |
| Option 3 | Scenario 2 | -0.2% | -0.4% |
| Option 4 | Scenario 1 | 1.3% | 0.4% |
| Option 4 | Scenario 2 | 0.5% | 0.2% |
| | | | |

# NOx Emissions Impacts

Incremental NOx Emissions - 2010

Tonnes

| Option | Scenario | Ontario Ontario | Neighbor AE | Neighbor ECAR | Neighbor MAPP_US | Neighbor MI | Neighbor NYISO | Neighbor PJM | Neighbor WUMS | Region Total | USA Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Option 2 | | (1,077) | (242) | (227) | (65) | (18) | 173 | 456 | 3 | (999) | 48 |
| Option 3 | Scenario 1 | (3,189) | 476 | (137) | 16 | 202 | (102) | (319) | (92) | (3,143) | 101 |
| Option 3 | Scenario 2 | 55 | (95) | (82) | (4) | 17 | (111) | (98) | (8) | (327) | 24 |
| Option 4 | Scenario 1 | (93) | 12 | 143 | (28) | 6 | (73) | (68) | (11) | (112) | (37) |
| Option 4 | Scenario 2 | (32) | 93 | 99 | (13) | 16 | (53) | (7) | 0 | 103 | (43) |

Incremental NOx Emissions - 2015

Tonnes

| Option | Scenario | Ontario Ontario | Neighbor AE | Neighbor ECAR | Neighbor MAPP_US | Neighbor MI | Neighbor NYISO | Neighbor PJM | Neighbor WUMS | Region Total | USA Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Option 2 | | (276) | (272) | (643) | (49) | (101) | 195 | 102 | (8) | (1,052) | (63) |
| Option 3 | Scenario 1 | (339) | 35 | 182 | (1) | 446 | (20) | (5) | (11) | 287 | 58 |
| Option 3 | Scenario 2 | (5) | (44) | (17) | (72) | (94) | (14) | (201) | (1) | (449) | 309 |
| Option 4 | Scenario 1 | 64 | (22) | (33) | (21) | 7 | (17) | 12 | 2 | (9) | (57) |
| Option 4 | Scenario 2 | 43 | 3 | (9) | 17 | 3 | (3) | 15 | (1) | 68 | (29) |

**See Appendix C for a map of NEEM's regions.**



CRA INTERNATIONAL

# SO2 Emissions Impacts

Incremental SO2 Emissions - 2010
Tonnes

| Option | Scenario | Ontario Ontario | Neighbor AE | Neighbor ECAR | Neighbor MAPP_US | Neighbor MI | Neighbor NYISO | Neighbor PJM | Neighbor WUMS | Region Total | USA Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Option 2 | | (4,853) | (751) | (2,358) | (126) | (33) | 334 | 2,306 | (66) | (5,547) | 34 |
| Option 3 | Scenario 1 | (13,576) | 1,871 | 3,838 | 75 | 276 | (108) | (6,485) | (896) | (15,004) | 162 |
| Option 3 | Scenario 2 | 718 | (314) | (204) | (31) | (62) | (432) | (478) | (103) | (905) | (8) |
| Option 4 | Scenario 1 | 17 | (9) | 98 | (18) | (6) | (264) | (349) | (126) | (657) | (21) |
| Option 4 | Scenario 2 | (61) | 303 | 12 | 76 | (4) | (275) | (26) | (3) | 22 | (39) |

Incremental SO2 Emissions - 2015
Tonnes

| Option | Scenario | Ontario Ontario | Neighbor AE | Neighbor ECAR | Neighbor MAPP_US | Neighbor MI | Neighbor NYISO | Neighbor PJM | Neighbor WUMS | Region Total | USA Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Option 2 | | - | (881) | (695) | (100) | (875) | 12 | 625 | (30) | (1,941) | (260) |
| Option 3 | Scenario 1 | - | 195 | (3,753) | 27 | 2,077 | (25) | (115) | (86) | (1,678) | 276 |
| Option 3 | Scenario 2 | - | (208) | 2,790 | (203) | (754) | (7) | (1,009) | (3) | 606 | 661 |
| Option 4 | Scenario 1 | - | (94) | 976 | 19 | 281 | (12) | 154 | 23 | 1,347 | (54) |
| Option 4 | Scenario 2 | - | (41) | (15) | 58 | 129 | 1 | 113 | (1) | 244 | (55) |

**See Appendix C for a map of NEEM's regions.**



CRA INTERNATIONAL

## CO2 Emissions Impacts



Incremental CO2 Emissions

Thousand Tonnes

| Option | Scenario | 2010 Ontario | 2010 USA | 2015 Ontario | 2015 USA |
|---|---|---|---|---|---|
| Option 2 | | (1,420) | 795 | (1,548) | 1,423 |
| Option 3 | Scenario 1 | (3,603) | 2,721 | (1,967) | 2,358 |
| Option 3 | Scenario 2 | (27) | (66) | 51 | (293) |
| Option 4 | Scenario 1 | 19 | 46 | 358 | (367) |
| Option 4 | Scenario 2 | 23 | (0) | 249 | (230) |

Incremental CO2 Emissions

% Change

| Option | Scenario | 2010 Ontario | 2010 USA | 2015 Ontario | 2015 USA |
|---|---|---|---|---|---|
| Option 2 | | -5.8% | 0.0% | -11.0% | 0.1% |
| Option 3 | Scenario 1 | -14.8% | 0.1% | -13.9% | 0.1% |
| Option 3 | Scenario 2 | -0.1% | 0.0% | 0.4% | 0.0% |
| Option 4 | Scenario 1 | 0.1% | 0.0% | 2.5% | 0.0% |
| Option 4 | Scenario 2 | 0.1% | 0.0% | 1.8% | 0.0% |

## Status Quo

**2010**

| All-In Export Costs (2008 $CAN/MWh) | | | To: ON | To: HQ | To: PJM Via MISO | To: PJM Via NY | To: NY | To: MISO |
|---|---|---|---|---|---|---|---|---|
| From | ON | | | 17.47 | 5.31 | 13.64 | 4.60 | 4.60 |
| | HQ | | 12.87 | | | | 12.87 | |
| | PJM | Via MISO | 6.48 | | | | 4.47 | 0.63 |
| | | Via NY | 12.04 | | | | | |
| | NY | | 7.57 | 20.44 | 9.04 | | | |
| | MISO | | 5.85 | | 0.70 | | | |

**2010**

| Export Tariff out of Ontario (2008 $CAN/MWh) | |
|---|---|
| HQ | 1.02 |
| NY | 1.02 |
| MISO | 1.02 |

**2015**

| All-In Export Costs (2008 $CAN/MWh) | | | To: ON | To: HQ | To: PJM Via MISO | To: PJM Via NY | To: NY | To: MISO |
|---|---|---|---|---|---|---|---|---|
| From | ON | | | 17.55 | 5.33 | 13.67 | 4.63 | 4.63 |
| | HQ | | 12.93 | | | | 12.93 | |
| | PJM | Via MISO | 6.48 | | | | 4.47 | 0.63 |
| | | Via NY | 12.04 | | | | | |
| | NY | | 7.57 | 20.49 | 9.04 | | | |
| | MISO | | 5.85 | | 0.70 | | | |

**2015**

| Export Tariff out of Ontario (2008 $CAN/MWh) | |
|---|---|
| HQ | 1.04 |
| NY | 1.04 |
| MISO | 1.04 |

# Option 2 – Average Embedded Network Rate

**2010**

| **All-In Export Costs (2008 $CAN/MWh)** | | | To | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | ON | HQ | PJM Via MISO | PJM Via NY | NY | MISO |
| From | ON | | | 21.60 | 9.43 | 17.77 | 8.72 | 8.72 |
| | HQ | | 12.87 | | | | 12.87 | |
| | PJM | Via MISO | 6.48 | | | | 4.47 | 0.63 |
| | | Via NY | 12.04 | | | | | |
| | NY | | 7.57 | 20.44 | 9.04 | | | |
| | MISO | | 5.85 | | 0.70 | | | |

**2010**

| **Export Tariff out of Ontario (2008 $CAN/MWh)** | |
|---|---|
| HQ | 5.15 |
| NY | 5.15 |
| MISO | 5.15 |

**2015**

| **All-In Export Costs (2008 $CAN/MWh)** | | | To | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | ON | HQ | PJM Via MISO | PJM Via NY | NY | MISO |
| From | ON | | | 21.68 | 9.46 | 17.79 | 8.75 | 8.75 |
| | HQ | | 12.93 | | | | 12.93 | |
| | PJM | Via MISO | 6.48 | | | | 4.47 | 0.63 |
| | | Via NY | 12.04 | | | | | |
| | NY | | 7.57 | 20.49 | 9.04 | | | |
| | MISO | | 5.85 | | 0.70 | | | |

**2015**

| **Export Tariff out of Ontario (2008 $CAN/MWh)** | |
|---|---|
| HQ | 5.16 |
| NY | 5.16 |
| MISO | 5.16 |

# Option 3, Scenario 1 – Reciprocal Tariff Joint Elimination

| **2010** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **All-In Export Costs (2008 $CAN/MWh)** | | | To | | | | | |
| | | | ON | HQ | PJM Via MISO | PJM Via NY | NY | MISO |
| From | ON | | | 16.45 | 4.28 | 12.62 | 3.58 | 3.58 |
| | HQ | | 4.56 | | | | 12.87 | |
| | PJM | Via MISO | 1.33 | | | | 4.47 | 0.63 |
| | | Via NY | 8.11 | | | | | |
| | NY | | 3.64 | 20.44 | 9.04 | | | |
| | MISO | | 0.70 | | 0.70 | | | |

| **2010** | |
|---|---|
| **Export Tariff out of Ontario (2008 $CAN/MWh)** | |
| HQ | 0 |
| NY | 0 |
| MISO | 0 |

| **2015** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **All-In Export Costs (2008 $CAN/MWh)** | | | To | | | | | |
| | | | ON | HQ | PJM Via MISO | PJM Via NY | NY | MISO |
| From | ON | | | 16.52 | 4.30 | 12.63 | 3.59 | 3.59 |
| | HQ | | 4.59 | | | | 12.93 | |
| | PJM | Via MISO | 1.33 | | | | 4.47 | 0.63 |
| | | Via NY | 8.11 | | | | | |
| | NY | | 3.64 | 20.49 | 9.04 | | | |
| | MISO | | 0.70 | | 0.70 | | | |

| **2015** | |
|---|---|
| **Export Tariff out of Ontario (2008 $CAN/MWh)** | |
| HQ | 0 |
| NY | 0 |
| MISO | 0 |

# Option 3, Scenario 2 – Reciprocal Treatment, Avg. Embedded Network Cost**

| 2010 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **All-In Export Costs (2008 $CAN/MWh)** | | | To | | | | | |
| | | | ON | HQ | PJM | | NY | MISO |
| | | | | | Via MISO | Via NY | | |
| From | ON | | | 24.76 | 9.43 | 12.62 | 3.58 | 8.72 |
| | HQ | | 12.87 | | | | 12.87 | |
| | PJM | Via MISO | 6.48 | | | | 4.47 | 0.63 |
| | | Via NY | 8.11 | | | | | |
| | NY | | 3.64 | 20.44 | 9.04 | | | |
| | MISO | | 5.85 | | 0.70 | | | |

| 2010 | |
|---|---|
| **Export Tariff out of Ontario (2008 $CAN/MWh)** | |
| HQ | 8.31 |
| NY | 0 |
| MISO | 5.15 |

| 2015 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **All-In Export Costs (2008 $CAN/MWh)** | | | To | | | | | |
| | | | ON | HQ | PJM | | NY | MISO |
| | | | | | Via MISO | Via NY | | |
| From | ON | | | 24.85 | 9.44 | 12.63 | 3.59 | 8.74 |
| | HQ | | 12.93 | | | | 12.93 | |
| | PJM | Via MISO | 6.48 | | | | 4.47 | 0.63 |
| | | Via NY | 8.11 | | | | | |
| | NY | | 3.64 | 20.49 | 9.04 | | | |
| | MISO | | 5.85 | | 0.70 | | | |

| 2015 | |
|---|---|
| **Export Tariff out of Ontario (2008 $CAN/MWh)** | |
| HQ | 8.34 |
| NY | 0 |
| MISO | 5.15 |

**Note: Except between New York where the ETS tariff is deemed to be eliminated.

# Option 4, Scenario 1 and 2 – Unilateral Tariff Elimination (note: *Scenario 2 is status quo on-peak*)

**2010**

| All-In Export Costs (2008 $CAN/MWh) | | | To | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | ON | HQ | PJM Via MISO | PJM Via NY | NY | MISO |
| From | ON | | | 16.45 | 4.28 | 12.62 | 3.58 | 3.58 |
| | HQ | | 12.87 | | | | 12.87 | |
| | PJM | Via MISO | 6.48 | | | | 4.47 | 0.63 |
| | | Via NY | 12.04 | | | | | |
| | NY | | 7.57 | 20.44 | 9.04 | | | |
| | MISO | | 5.85 | | 0.70 | | | |

**2010**

| Export Tariff out of Ontario (2008 $CAN/MWh) | |
|---|---|
| HQ | 0 |
| NY | 0 |
| MISO | 0 |

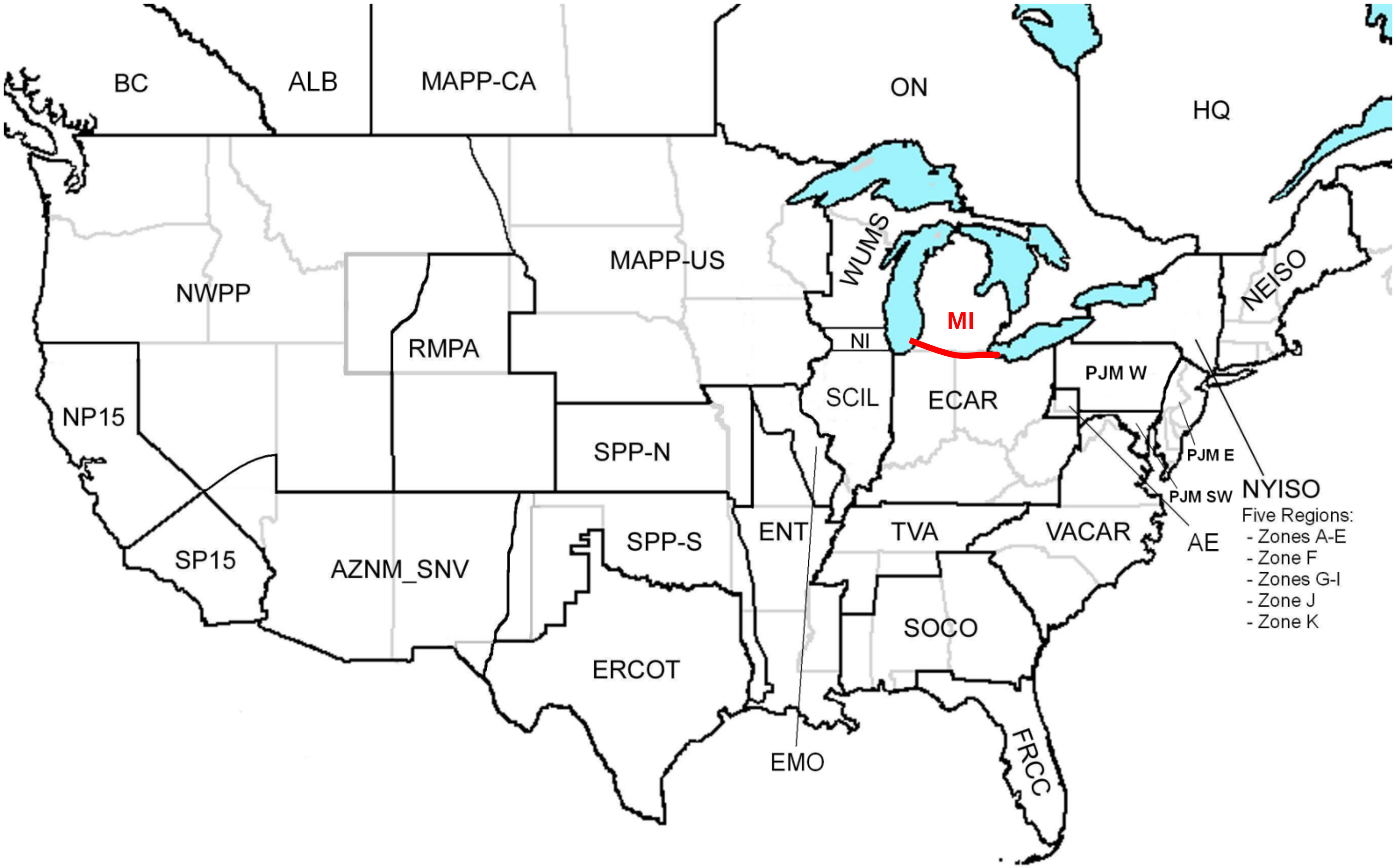
**2015**

| All-In Export Costs (2008 $CAN/MWh) | | | To | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | ON | HQ | PJM Via MISO | PJM Via NY | NY | MISO |
| From | ON | | | 16.52 | 4.30 | 12.63 | 3.59 | 3.59 |
| | HQ | | 12.93 | | | | 12.93 | |
| | PJM | Via MISO | 6.48 | | | | 4.47 | 0.63 |
| | | Via NY | 12.04 | | | | | |
| | NY | | 7.57 | 20.49 | 9.04 | | | |
| | MISO | | 5.85 | | 0.70 | | | |

**2015**

| Export Tariff out of Ontario (2008 $CAN/MWh) | |
|---|---|
| HQ | 0 |
| NY | 0 |
| MISO | 0 |

# Map of NEEM Regions




**Michigan is a separate region.**

# Export Transmission Service Tariff Study (SE-78)

## Working Group List

Power to Ontario. On Demand.

| Company Names |
|---|
| Brookfield Energy Marketing Incorporated |
| Bruce Power |
| Consumers Council of Canada |
| Hunt Management Services Limited |
| Hydro One |
| Hydro Quebec |
| NorthPoint Energy Solutions |
| Ontario Energy Board |
| Ontario Power Generation |
| Power Workers Union |
| SanZoe Consulting Incorporated |
| Shell Energy |
| TransCanada Energy |

# Export Transmission Service Tariff Study (SE-78)
## Stakeholder Feedback

**On December 11, 2008, the IESO posted the Export Transmission Service Tariff Study stakeholder engagement plan. Stakeholders were asked to send in written comments by January 12, 2009.**

Two comments were received.

The following is a summary of Stakeholders key comments on each topic followed by the IESO response which has been indented for ease of reading.

**Vulnerable Energy Consumers Counsel**

Roles and Responsibilities

Mr. Bounaguro observes that: [a]s the Plan notes, the ultimate responsibility for approving the Export Tariff lies with the OEB and the ultimate responsibility for making the associated application for approval lies with Hydro One Networks. It is VECC's understanding that the IESO's involvement in this issue arises primarily due to the need to determine whether reciprocal arrangements can be made with neighbouring jurisdictions regarding transmission pricing for power exchanges between jurisdictions. As a result, VECC considers this to be a key and central aspect of the IESO's study.

> **IESO Response**
> The IESO agrees that the ongoing discussions with neighbouring jurisdictions to pursue arrangement for reciprocal treatment of the export tariff is an important aspect of this undertaking. We believe that due to our role as both System and Market operator the IESO was deemed as appropriately positioned to engage our neighbours in these discussions.

Objectives

Mr. Bounaguro suggests that the assessment approach described in the Stakeholder Engagement Plan appears to focus almost entirely on the issue of market efficiency with no consideration regarding the fairness/equity of the resulting rates. And that this is significant shortcoming as the Board's objectives include consumer protection and Hydro One Network's pricing principles require that pricing methodologies be fair and equitable and should not favour any group or type of customers. Furthermore, fairness and equity should be particularly important consideration, if as the stakeholder plan observes, establishing arrangements for reciprocal treatment of the export tariff with neighbouring jurisdictions does not appear to be a reasonable outcome at this time.

**IESO Response**

In formulating the approach for undertaking the study and process for reviewing and recommending the appropriate ETS tariff, the IESO will rely upon parameters and evaluation principles that were discussed as part of Hydro One's transmission rate review (EB-2006-0501, Exhibit HI, Tab 5, Schedule 1, Page 7 -8). The primary focus of the IESO's effort is to consider various alternatives to the current tariff design and rate, and the likely impacts of each of these alternatives on a number of parameters that were identified as being important to stakeholders. These parameters include: export volumes, ETS revenues, HOEP and market efficiency. Based on a review of the impacts of the current and alternative tariff design on these parameters, the IESO will propose the appropriate tariff design and rate(s) which will strike a balance between simplicity of implementation, fairness and equity, the degree to which it will promote market efficiency in the region, and consistency with rates in neighbouring jurisdictions.

Mr. Bounaguro also notes that: in terms of objectives, the degree of need for consistency with rates in neighbouring jurisdictions will depend on whether reciprocity in transmission pricing arrangements is possible. What is likely more important is consistency in rate setting methodologies – recognizing that costs and therefore rates will vary by jurisdiction.

**IESO Response**

The IESO recognizes the potential for inconsistent treatment of the export tariffs between jurisdictions if the parties are unable to arrive at an arrangement to eliminate the tariff on a reciprocal basis. Accordingly, under option 3 the IESO will also be reviewing scenarios that could otherwise ensure reciprocal treatment of the tariff between Ontario and each of the interfacing markets.

Mr. Bounaguro further notes that: the Plan suggests (page 6) that Ontario could end-up with a mix of ETS rates at its different interfaces. There is a need to distinguish between reciprocity in terms of common transmission charges/methodologies versus reciprocity in terms of elimination of overlapping transmission charges. These are two very different interpretations and it is VECC's view that the IESO should be pursuing the later with neighbouring jurisdictions while maintaining a common export tariff where applicable.

**IESO Response**

The IESO agrees that these are separate interpretations. However, given the status of the discussions with our neighbours, the IESO will likely assess the potential impacts of both scenarios under option 3 of the study.

**<u>SanZoe Consulting Inc. (Representing AMPCO)</u>**

**Process**

Mr. Clark suggested that the IESO should consider seeking agreement/approval from the OEB in order to fund intervenor involvement in this initiative. Mr. Clarke believes that such action would ensure maximum involvement of intervenors.

Mr. Clark suggests that the IESO should provide specific notice to all intervenors in EB-2008-0272 (Hydro One Transmission Rate Application) of this review, with indication of whether intervenor funding will be available.

> **IESO Response**
> Any change to the ETS tariff will need to be approved by the Board as part of a rate setting process. Since this stakeholder engagement is not a hearing, the IESO believes that it is more appropriate for intervenors to request funding as part of any subsequent hearing before the Board to review and approve changes to the current transmission tariff. In addition, the IESO's stakeholdering process is quite flexible, enabling all interested stakeholders to participate in the process with limited time and resource commitments. As such the IESO will not be providing intervenor funding in support of this Stakeholder Engagement.
>
> In addition to its weekly bulletin, the IESO has sent a notification to all intervenors in Hydro One's Transmission Rate hearing.

<u>Assessment of Options</u>

Mr. Clark asked that cost allocation be added to the items to be evaluated.

> **IESO Response**
> In formulating the approach for undertaking the study and process for reviewing and recommending the appropriate ETS tariff, the IESO will rely upon parameters and evaluation principles that were discussed as part of Hydro One's transmission rate review (EB-2006-0501, Exhibit HI, Tab 5, Schedule 1, Page 7 -8). The primary focus of the IESO's effort is to consider various alternatives to the current tariff design and rate, and the likely impacts of each of these alternatives on a number of parameters that were identified as being important to stakeholders. These parameters include: export volumes, ETS revenues, HOEP and market efficiency. Based on a review of the impacts of the current and alternative tariff design on these parameters, the IESO will propose the appropriate tariff design and rate(s) which will strike a balance between simplicity of implementation, fairness and equity, the degree to which it will promote market efficiency in the region, and consistency with rates in neighbouring jurisdictions.

The result of the IESO's review of potential alternatives to the current ETS tariff, and recommendation regarding an appropriate ETS tariff design and rate(s) may assist AMPCO and others in any subsequent discussions and review of cost allocation undertaken by the Board.

Mr. Clark suggested that the review should provide comment on the options being considered in terms of the extent to which they may incent or discourage "phoney" wheeling for financial purposes only.

**IESO Response**
The study will look at the impact on import, export and wheel through transactions and we expect to be able to perform a qualitative assessment of whether the proposed options will either incent or discourage circuitous wheel through transactions as occurred in New York in 2008.

Mr. Clark asked for the reason for the insertion of cross border emissions as part of the review.

**IESO Response**
Although potential implications on cross-border emissions was not specifically identified as a proposed evaluation parameter for the ETS tariff study it has been raised as a potential concern by certain stakeholders. To address the potential concern, the IESO considered that it may be beneficial to obtain a better understanding of what impacts, if any, new or reciprocal transmission export tariffs may have on electricity trades and consequentially on air emissions in the region. If this issue is not considered important to stakeholders it can certainly be removed from the scope of the study.

**On January 22, 2009, the IESO posted the Export Transmission Service Tariff Study Approach and Methodology. Stakeholders were asked to send in written comments by February 5, 2009.**

One comment was received.

**Bruce Power Comments and Observations**

There should be some recognition by the OEB, IESO and participants that this study approach is not a substitute for a full cost of service finding for export transmission service. This study will not determine the cost of exports to the transmission system as a full cost of service hearing would. The rate ultimately determined from this model will have no connection with the cost of providing export service. The rates used in this analysis should not be construed to be the 'appropriate' or 'efficient rate'. The model as proposed will not determine the optimal rate for export transmission service. The model will use the ETS rate as an input to calculate the lowest cost of meeting demand in the region (Ontario, New York, PJM, etc). The efficiency results and trade flows that result from the model will be affected directly by the choice of the ETS tariff. The ETS rate used in the model has been chosen arbitrarily during discussion at the stakeholder session and should not be construed as an efficient rate. The model will demonstrate the market impacts of various rates and provides the IESO, OEB and stakeholders with information to determine the potential impact of different ETS rates. Following this study an open question remains as to the true cost of exports of the transmission system.

**IESO Response**

We believe that Bruce Power's concern is that the ETS design and rate(s) which will be studied are not the result of a full cost of service study; accordingly, any ensuing ETS design and rate that may be proposed in this regard should not be construed as being "appropriate" or "efficient".

As discussed at the first stakeholder session on January 22, 2009, the IESO will not attempt to duplicate the Ontario Energy Board (the "Board") transmission rate review and approval processes nor would this be appropriate. The IESO noted that three ETS design options and various rate scenarios will be reviewed as part of the study—one of which is based on current and projected cost of providing transmission service from network assets (i.e., the ETS design and rate that that will be modelled under Option 2 will be based on the average cost of providing network transmission service). In addition, transactional costs (i.e., applicable uplifts) that are associated with facilitating export and wheel-through will also be taken into consideration. Accordingly, the cost of service applicable to export and wheel-though transactions will be considered under Option 2.

The appropriateness of the three options will be determined based on the impact of each option on four key parameters: HOEP, export and import volumes, export revenues and market efficiency. Further, any change to the ETS rate will have to be reviewed and approved by the Board as part of its provincial uniform transmission rate review process.

**Bruce Power Comments and Observations**

When conducting the ETS review Bruce Power requests the IESO to investigate the impact of a peak and off-peak rate for export transmission service. This proposal is based in part on the assertion that most surrounding jurisdictions have peak and off-peak rates for export transmission service.

**IESO Response**

Due to the complexity, cost and time required to undertake a study of additional multifaceted ETS design and rate scenarios, this study will be limited to a review of the three ETS design options and rate scenarios discussed at the stakeholder meeting. We note that in the two jurisdictions (i.e., PJM and MISO) where export and wheel-through transmission service is available on a time-of-use basis, this form of service is only available on a short-term basis (i.e., weekly, daily and/or hourly basis). It was discussed and endorsed by stakeholders at the stakeholder meeting on January 22, 2009 that, for the purpose of undertaking an appropriate and comparative analysis, the IESO should adopt and used the long-term (i.e., annual) firm transmission rate for export and wheel-through service applicable to each jurisdiction.

The IESO appreciates stakeholders concern regarding the need to optimize the use of Surplus Base-load Generation (SBG) resource. We note however that there are potentially numerous ways of addressing this issue. Also, it is also worthwhile noting that this issue is currently under reviewed by IESO working group SE-57. http://www.ieso.ca/imoweb/consult/consult_se57.asp

In terms of the current ETS study, the IESO will modify the scope of the study to enable us to gain greater insight with respect to any material correlation that may exist between export transmission rates and SBG. We believe this information could also help to inform the discussion in SE-57.

**Bruce Power Comments and Observations**

With a study of this type the assumptions used in the analysis will have a direct impact on the results. For this reason it is very important to understand the inputs used for model. For this reason all the input assumptions should be released publicly wherever possible. When it is not possible to publish the exact input assumptions a qualitative statement of the inputs should be presented in its place. Promoting transparency in a study like this is the only way to ensure that all stakeholders have the opportunity to clearly understand the results and the drivers that lead to the results.

**IESO Response**

The IESO agrees that it is important for stakeholders have a thorough understanding of the inputs and assumptions which forms the basis of the study and analysis. Accordingly, the IESO will, to the extent possible, make public any non-confidential data and assumptions used in the model, as well as information that will not prejudice the competitive position of any market participant or interfere with known contractual or other negotiations involving participants.

**On June 25, 2009 and July 14, 2009, the IESO posted the preliminary results and impact assessments. Stakeholders were asked to send in written comments by July 21, 2009. Four comments were received. Also, there were a number of key issues raised at the June 25 meeting that needed to be addressed before moving forward. A complete list of those issues and the IESO response is noted in the chart below.**

| Issue No. | Issue | Raised by | Response |
|---|---|---|---|
| 1 | It was unclear whether the study had modeled the Manitoba - Ontario transmission interface at all. The key transmission links cited in the presentation listed all of Ontario's transmission interfaces that were modeled, including the Minnesota link at International Falls (90/140 MW transfer capability). However, there wasn't any mention of the much larger Manitoba-Ontario interface. If the study model inadvertently omitted the Manitoba - Ontario interface, the IESO must repeat the analysis, this time including the Manitoba-Ontario interface in order for the study results to be meaningful. | Manitoba Hydro | There are multiple transmission interfaces connecting Ontario and adjacent dispatch areas or markets, or virtual markets in the case of how PJM is considered in the study. Slide 7 of the Export Transmission Service (ETS) Charge Scenario Analysis - Overview: Draft Preliminary Report and Findings ("overview presentation") shows the links between the IESO-administered market and adjacent dispatch regions that were considered in the study. Slide 80 of the overview presentation is intended to provide a summary of the aggregate transfer capability of the interfaces between the IESO-administered market and other dispatch areas considered in the study. The reference to Ontario-Minnesota transfer limit is not to suggest that this interface is representative of a separate dispatch area in the model; rather, it is to show the Ontario-Minnesota transfer capability within the aggregate MISO dispatch area. Also, it is not intended to suggest that the Ontario-Manitoba transfer capability was not taken into account in the study. The IESO will update slide 80 to show the Ontario-Manitoba transfer limit that is included in the aggregate MISO dispatch area total. |
| 2 | The study has lumped Manitoba inside the MISO market. That is, Manitoba isn't treated as a separate market like the Hydro-Quebec system. Why was that study approach taken?<br>Although Manitoba Hydro coordinates transmission service with the Midwest ISO, the Manitoba Hydro open access transmission tariff is an | Manitoba Hydro | The study doesn't treat Manitoba as a separate dispatch area; but rather as part of the MISO footprint given that electricity trades between Ontario and Manitoba, as well as transmission reservations are facilitated through the IESO and MISO markets. For example, Manitoba Hydro's Open Access Transmission Tariff (OATT) requires that the processing of short-term firm and non-firm point-to-point transmission service request be conducted by MISO on behalf of Manitoba Hydro.<br><br>Unbundling Manitoba into a separate and distinct market would effectively result in the creation of a sub-market |

| Issue No. | Issue | Raised by | Response |
|---|---|---|---|
| | independent tariff and MH Transmission Services can have a different export tariff than MISO.<br><br>Recently, Manitoba Hydro's transmission tariff rate was removed from the MISO schedules (schedule 7 for firm point-to-point service and 8 for non-firm service). Manitoba Hydro's rates are no longer included in the MISO system average rate for drive-out transmission service. These changes were driven by a revision to the MH-MISO coordination agreement, effective Nov 1, 2008. Due to the current "carve-out" of Manitoba Hydro's transmission rates, it is not appropriate to lump the Manitoba system inside the MISO region. Manitoba's interaction with the Ontario market should be explicitly modeled, similar to the HQ system. | | within the MISO dispatch foot print. For the purposes of the ETS study, this would be a significant and costly undertaking which we do not believe would add any additional benefit to the study or change the results in a material way. In addition, while Manitoba is permitted to administer a separate OATT from that of MISO, export and wheel-through transactions that originate in Manitoba and terminate in Ontario would not be put at a disadvantage with respect to applicable transmission charges given the reciprocity and non-discriminatory requirements of the two tariffs. Likewise, transactions destined for Manitoba from Ontario will attract the same transmission charges as with other zones within the MISO footprint. Furthermore, Manitoba has not demonstrated how modeling it as part of the MISO footprint will limit or adversely impact its ability to trade with Ontario market participants, or facilitate wheel-through transactions through Ontario under any of the Export and Wheel-through Tariff (EWT )options under consideration.<br><br>While Manitoba's transmission tariff, including the EWT has been unbundled from the MISO transmission tariff schedules for point-to-point services, in our view this has little impact on the ETS Study, especially given the relatively small transfer capability (342 MW) and limitations on the Ontario and Manitoba transmission interface. The IESO has confirmed with the Ontario Power Authority that there is currently no plan for increasing the transfer capability with Manitoba. Accordingly, regardless of whether Manitoba is treated as a separate market or integrated as part of the broader MISO footprint or the applicable EWT, we do not believe that this will have a material impact on the basis for determining a reasonable EWT for Ontario. In comparison to the Quebec interface, the Ontario-Manitoba transfer capability is almost five times smaller. |
| 3 | General concerns on the CRA NEEM model, which is non-chronological and significantly aggregates the data into large averaged load | Manitoba Hydro | The study did not aim to establish the detail or quantify the potential impacts of the ETS options on potential operation and implementation issues (e.g., potential impact on uplift payments to nuclear and wind generators that may be subject to fixed price contracts or hourly SBG events). For |

| Issue No. | Issue | Raised by | Response |
|---|---|---|---|
| | blocks. Such a coarse model cannot adequately capture operational issues and hence the CRA NEEM model may underestimate the potential impact of Option 2 and Option 3 ETS rate designs. It is unclear what impact these Options may have on uplift payments to nuclear generators and fixed price contracts for wind.<br>In order for the IESO to capture operations issues (such as SBG) as it has tried to do, it will need to utilize an hourly chronological market model. | | example, with respect to surplus baseload generation (SBG), the aim was to observe the potential impact of each option on SBG events in respect of their magnitude, duration (e.g. # of hours/month) and timing. In our earlier stakeholder meeting we also identified and discussed certain potential limitations of the analysis that was to be undertaken; in particular, we explained that the study did not account for any price protection and obligations that may be afforded to contracted generators, as well as material changes in uplift costs and revenues.<br><br>While more detailed inputs such as contracted nuclear and wind generator arrangements and requirements might have provided more granular insights into potential impacts on various operational and administrative issues such as SBG and uplifts, the NEEM model was deemed to be satisfactory by those present at the initial stakeholder meeting for carrying out the objectives, and the scope of work which was outlined in the ETS Stakeholder Plan. Accordingly, we are confident that the NEEM model is appropriate to undertake the quantitative analysis (impact on HOEP, export revenues, export and wheel-through volumes and market efficiency) of this study. |
| 4 | How was Hydro Quebec's hydro fleet modelled | OPG | The total hydro electric output used in the model for Quebec is 192 TWh (Source: Hydro-Quebec annual report) and the month-to-month variation in Quebec hydropower output was inferred by the shape of Quebec demand plus net exports (Source of net exports: Canada National Energy Board; Source of demand forecast: NERC); While the analysis released in June 2009 had the Quebec hydropower resources operating flat within each month, the final July 2009 analysis has a run-of-river portion which is sized to approximately meet the minimum load in each month. The remainder of each month's hydro output is optimized. |
| 5 | On page 9 of the report (page 11 of the overview presentation) we have stated that the cap for CO2 in 2015 is 11.5 million metric tonnes. There is general concern regarding this number | Bruce Power | The Ontario coal units are retired in the CRA NEEM model by 2015, with the exception of tiny fractions of units needed to avoid modeling infeasibilities. Therefore, the modeled emissions of CO2 from Ontario's coal-fired generation are essentially zero in 2015. The amount of CO2 emissions from the Ontario coal in 2015 have no practical significance whatsoever and do not affect the analysis conclusions. |

| Issue No. | Issue | Raised by | Response |
|---|---|---|---|
| | considering there should be no emissions from coal fired plants in 2015 | | The Ontario Government's Shareholder Declaration (dated May 15, 2008) and Resolution (dated May 16, 2008) requires OPG to stage the reduction measures to meet, on a forecast basis, the interim CO2 emission targets of 19.6 million tonnes in 2009, and 15.6 million tonnes in 2010.<br><br>Proposed amendment to the current enabling regulation would require a reduction in CO2 emissions to 11.5 million tones beginning in 2011, from CO2 emissions of 34.5 million tonnes in 2003. The limit would continue on an annual basis until December 31, 2014.<br><br>The table on page 9 will be revised to show 0 tonnes of CO2 in 2015. |
| 6 | Concern from Stakeholders that the model uses a flat hydroelectric production profile for the analysis. Many think that this is an incorrect assumption as hydro units would be used for peak shaving in future years | OPG | Please refer to responses to issue no. 4 and 13 |
| 7 | On page 13 the prices shown for natural gas for Ontario seems way too high and the curve is too steep. There is a concern that this may have a significant impact since the model is cost based | APPrO | The 2010 gas prices used in the analysis are based on NYMEX futures (Henry Hub) from the beginning of April 2009. These prices are the futures that were available at the time the model was loaded in the model. The 2015 prices are based on the EIA AEO 2009 (April release) forecast.<br><br>We do not believe it is material to update the gas price forecast for the following two reasons: 1) since all regions are subject to the same underlying gas price forecast, the effect of different gas prices on the differential impact of the tariff scenarios is likely immaterial, 2) while it is possible that the 2010 gas prices currently in the model could be too low relative to next year's actual gas prices, it is also possible that the assumed 2010 gas price will be very realistic for 2011 or 2012 and therefore remains quite meaningful to establishing an appropriate ETS for Ontario (regardless of the exact time path of actual future gas prices). |

<table>
<tr><th>Issue No.</th><th>Issue</th><th>Raised by</th><th>Response</th></tr>
<tr><td>8</td><td>On page 15 there is a need to provide a justification for the new build and retirement numbers for wind and nuclear. There is concern that the nuclear numbers are too high and the wind is too low.</td><td>Bruce Power</td><td>The information was provided by the OPA and is consistent with its planned resource scenario.<br><br>Committed nuclear in year 2010 includes the Bruce units 3 and 4 at 1500 MW installed capacity. In 2010, it is anticipated that Bruce units 1 and 2 (each 770 MW) are taken out of service for refurbishment. They are subsequently assumed to return to service in years 2012 and 2013 and factored into the committed nuclear annual installed capacity for those years. Similarly, in year 2013, Pickering B unit 4 at 516 MW is taken out of service for refurbishment and assumed to return in service in year 2015 and subsequently an additional Pickering B unit 6 and Bruce unit 5 coming out of service in 2015. This is summarized in the table below:<br><br>The installed wind capacity represents nameplate capacity and is consistent with the OPA's publicly announce planned resource scenario.<br><br>
<table>
<tr><th></th><th></th><th>2010</th><th>2015</th></tr>
<tr><td>Additional Capacity</td><td></td><td>Bruce Units 3 and 4 -1500 MW</td><td>Bruce Units 1 and 2 – 1540 MW</td></tr>
<tr><td></td><td></td><td></td><td>Pickering – 516 MW</td></tr>
<tr><td></td><td>Total</td><td>1500 MW</td><td>2056 MW</td></tr>
<tr><td>Planned Refurbishment</td><td></td><td>Bruce Units 1 and 2 – 1540 MW</td><td>Pickering B – 4 & 6 Units & Bruce Unit 5 – 1829 MW</td></tr>
<tr><td></td><td>Total</td><td>1540 MW</td><td>1829 MW</td></tr>
</table></td></tr>
<tr><td>9</td><td>For the data shown on page 18 of the overview presentation it is unclear what bidding/offer</td><td>Multiple</td><td>For the 2007 calibration, NUGS were modeled as price takers, combined-cycle gas were exposed to market prices and oil/ gas units (predominantly Lennox units) had their</td></tr>
</table>

| Issue No. | Issue | Raised by | Response |
| --- | --- | --- | --- |
| | strategies were assumed and if this was used for current and future years | | bids adjusted downward by roughly 15-25%. The coal units' bids were also adjusted by lowering the effective heat rate. None of the bid adjustments affect the actual costs borne by the units. For the future years of 2010 and 2015, we used same adjustments with the exception of the following:<br>Oil/gas units (other than NUGs/CHP) - The bid adjustments were removed for future years to reflect that contractual arrangements for Lennox are expected to change.<br>NUGS/CHP units – The units are modeled as per OPA issued capacity factors. |
| 10 | On page 24 of the overview presentation, CRA had included additional information to the far right of the slide indicating the price differences used in the model. These should be explained | Multiple | Over the study period (i.e., 2007-2010 and 2007-2015) ETS "all-in costs" were estimated to increase by the annualized change in Consumer Price Index (CPI) as forecasted by the Toronto Dominion Economics as at March 2009. The annual CPI change forecast for 2015 is kept at the 2013 levels. Projected currency valuation (exchange rates used for converting US and Canadian dollars) is also based on Toronto Dominion's Bank Exchange Rate and Inflation Forecasts. The exchange rate for 2015 is kept at 2010 levels. The forecasts can be found at: www.td.com/economics/qef/long_term_mar09.pdf.<br><br>The Toronto Dominion's Consumer Price Index Adjustments was also used to rebase, in 2003 US dollars, for 2010 and 2015 ETS all-in costs and the US Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2009 chain-type price index was used to convert 2003 US dollars to 2008 US dollars. The latter can be found at: http://www.eia.doe.gov/oiaf/aeo<br>The example below shows the sources for the consumer price indices used for rebasing and exchange rates for converting to US and Canadian dollars and associated calculations:<br><br>Option 3, Scenario 1: Ontario decreases rate by $0.95 Cdn<br>• 2007 ON ETS: $1.00 Cdn<br>• Used the annualized March 2009 TD Forecast for CPI Index to reflect 2010 ON ETS: $1.02 Cdn (escalation factors for 2008:+2.4%; 2009:-0.8%; |

| Issue No. | Issue | Raised by | Response |
|---|---|---|---|
| | | | 2010:+0.8%)<br>• Used US Exchange Rate @ 1.136525 to convert to USD for 2010 ON ETS: $0.90 USD ($1.02*1.136525)<br>• Rebased in 2003 USD for 2010 ON ETS using TD Forecast CPI Adjustment of 1.165652: $0.77 USD ($0.90*1.165652)<br>• Used CPI adjustment of 1.145 to convert to 2008 USD and Exchange Rate @ 1.078 to convert back to Cdn: $0.95 ($0.77*1.145*1.078) |
| 11 | On page 27 of the report there was a request for further explanation of the numbers for HQ in 2010 and 2015 specifically concerning the peak/off peak hours. | Bruce Power | For the draft preliminary analysis, the hydroelectric shapes in the region were all flat. The level varied by month and the resources were different in the different regions (e.g., Quebec and Ontario hydro resources are modeled as separate units in their respective regions). One consequence of this simplified assumption (flat shapes) was that Quebec had excess hydroelectric power off-peak but was short on-peak. This resulted in Ontario exporting to Quebec significantly more during the on-peak hours than in the off-peak hours. This is not realistic given Quebec's storage capabilities.<br><br>For the revised final analysis, all hydroelectric resources in the region are divided into a run-of-river resource and a portion that can be optimized and thus used more intensively on-peak. Consequently, in the revised analysis, Ontario tends to export to Quebec predominantly during the off-peak hours. This is consistent with the comments received during the June 2009 stakeholder meeting. |
| 12 | On page 39 of the report (page 30 of the overview presentation)need to clarify that non-NY neighbours includes HQ, MISO and PJM | Hydro Quebec | Report has been adjusted to clarify that non-NY neighbours include HQ, MISO and PJM. |
| 13 | General concerns with the SBG analysis including:<br>- Size and shape of the demand curve<br>- Hydro electric profile | Multiple | The IESO is carrying out a review of the SBG analysis taking into account the various concerns expressed by stakeholders, including confirming the seasonal demand forecast used in the earlier runs, use of Ontario on-peak and off-peak hydro production forecasts, and refining Quebec's |

| Issue No. | Issue | Raised by | Response |
|---|---|---|---|
| | - Lack of granularity of the model<br>- Results are counterintuitive<br>- Wind inputs<br>- Imports from Quebec | | hydro production assumptions. For example, the refined approach for modeling Ontario hydro production is as follows:<br>Ontario's Hydroelectric output has been separated into a base- load (Run-of-River) component and a "storable" component The approach used in the model is to allocate total hydro electric generation between baseload and storable components. The quantity allocated to the baseload component varies by month and by seasons. The historical off peak hydro electric output has been used as a proxy for baseload. In the model, the storable component is allowed to manoeuvre in response to economic conditions such that peaking hydro resource production correlates with the highest price periods. The net result of this approach is an improved hydroelectric production profile which we believe should address the concerns of stakeholders. |

| Ontario Hydro Resources | | |
|---|---|---|
| | 2010 (MW) | 2015 (MW) |
| Run of River | 3,100-4,700 | 3,300-4,900 |
| Storable | 3,200-4800 | 3,800 - 5,400 |
| Total Ontario Hydroelectric Output (incl. Run of River and Storable) | 7,900 | 8,700 |

**Four comments that were received.**

**Brookfield Power**

**Analysis/Model concerns:**

The four options that will be assessed as part of the study are as follows:

**Option 1:** Remain the same at $1/MWh applicable to export transactions (Status Quo).
**Option 2:** Equivalent Average Network - Under this option, export and wheel through transactions would pay a rate equivalent to Transmission Network Service, but using energy as the charge determinant (i.e. $/MWh).
**Option 3:** Reciprocal Treatment of Export Transmission Service Charge. This option considers two potential mode of reciprocal treatment, including the mutual elimination of all ETS tariffs between jurisdictions.
**Option 4:** Unilateral Elimination of the ETS tariff. This option considers two scenarios under which the Ontario ETS tariff could be unilaterally eliminated: 1) unilateral elimination of the tariff in all hours; and 2) unilateral elimination of the tariff only during off-peak hours.

- The model does not properly shape generating units and is thus giving inaccurate results/forecasts.
- The model's results show the exact opposite of what the real market results have been (SBG events are forecasted during winter and summer and none during spring). This is the exact opposite of real events and could render the analysis/model irrelevant. We do agree that the explanation of some of the past SBG "can" happen in the summer months as the example given was a holiday, but we do not forecast SBG to occur most/all of the time in the summer or winter and none in the spring; the results are clearly incorrect.
- SBG study does not look into positive effects of exports (as they would clearly have a positive impact on resolving these issues).
- Why does the model show more exports to HQ on-peak rather than off-peak (we would assume more exports off-peak than on peak as on all other interties HQ exports on-peak and imports off-peak).
- We have not been given any information about internal studies into reliability and transmission issues.
- Bidding behavior is not consistent over time and excluding that may skew the results.
- Not considering transmission constraints will skew results (actual flows, constraints, limitations, outages)
- NEEM's model "flattens" prices: on-peak low and off-peak high. "flattening" of prices effected by the assumption that outages/dispatches are all perfectly anticipated/implemented/dispatched. This will decrease the benefits of imports and exports for supply/demand balancing as in real events nothing happens perfectly.
- 2009 gas price of $5, huge economic changes since initial price set for model. How will a more accurate gas price affect results?

- Were FTR auction values included in the model? (If not, FTR auction prices would inevitably increase for all models reducing export fees and would be reduced for models that increase export fees. This will reduce the surplus in options with increased fees and increase the surplus in models with decreased export fees). This value will also offset some of the reductions in tariffs collected for transmission providers. (high export fees reduce otherwise economic transactions from occurring and decrease global market efficiency)

**BEMI's Conclusions:**

BEMI agrees that if there is no chance of negotiating a reciprocal elimination of export fees then we can conclude that Option #3 – Scenario 1 can be eliminated from our list of available options.

BEMI agrees that to charge more than the cost of service for transmission could be against a FERC mandate, so reciprocal fee treatment in Option #3 – Scenario 2 can be eliminated from our list of available options.

Since emissions are well below cap for all options, we can conclude that this is not a major issue that should determine which option is optimal.

**BEMI's Recommendation:**

BEMI believes on a high level evaluation that market efficiency will be achieved through the reduction (or better) the elimination of transaction fees. As predicted, the model (even though inaccurate, we believe it will always produce a higher total surplus when transaction fees are eliminated; as basic economic theory on market efficiency predicts) shows that the surplus is greatest for Option #4 – Scenario 1 (Option #4 – Scenario 2 had the second highest surplus). Option #2 had the largest negative surplus and basic economic principals would predict that this will decrease market efficiency.

*As both Scenario's in Option #4 are the only ones that increase net exports, we believe that they will have additional benefits for the forecasted SBG events and reliability benefits; as well as, they will increase global market efficiency through dispatching the least cost generator across interconnected markets.*

Surplus Results Analysis:

- Option #2 shows a transfer of surplus from producers to consumers of: -$271 million from producers and +$256 million for consumers for 2010 and -$284 million from producers and +$246 million for consumers for 2015. This creates a transfer difference of $527 million for 2010 and $530 million for 2015; although the total market surplus is only (-$15 million) for 2010 and (-$38 million) for 2015.
- Option #4 – Scenario 1 shows a transfer of surplus from consumers to producers of: -$47 million from consumers and +$47 million for producers for 2010 and -$52 million from consumers and +$60 million for producers for 2015. This creates a transfer difference of $94 million for 2010 and

$112 million for 2015; although the total market surplus is only $0 for 2010 and +$8 million for 2015.

- Option #4 – Scenario 2 shows a transfer of surplus from consumers to producers of: -$33 million from consumers and +$30 million for producers for 2010 and -$6 million from consumers and +$6 million for producers for 2015. This creates a transfer difference of $63 million for 2010 and $12 million for 2015; although the total market surplus is only -$2 million for 2010 and +$1 million for 2015.

***as mentioned earlier: both Options #4 will have an increased surplus when FTR values are included and Option #2 will have a decreased surplus***

As you can see not only does Option #4 produce the only positive total surplus, it has the smallest transfer of surplus from one group to another. An extremely large transfer of surplus would seem unfair for whichever stakeholder who is negatively affected the most. Although Option #4 – Scenario 2 has the smallest magnitude of transfer from one group to another, we believe that Option #4 – Scenario 1 is the best overall option as it has the highest total surplus while maintaining a small transfer differential.

Regardless of future results, we believe that as markets evolve we see that market efficiency is achieved through the reduction of transaction fees and to move away from the inevitable solution would not make sense (as we see the continued effort to reduce transaction fees and increase global market efficiency). This is also a view held by OEB in RP-1999-0044 section 3.8.20; *"The Board considers that the Government's long-term objective of reducing energy costs through competition can be served by the development of larger, open power markets where trade can take place with the minimum of impediment. In this regard, the Board appreciates the recommendation by the Market Design Committee that EWT transactions should be subject to only incremental transaction-specific charges and no contribution to sunk costs should be levied"*, which supports the idea of no export tariff in able to encourage market efficiency; as well, since load has first priority to the transmission grid (exports are cut first for reliability) then sunk or fixed network costs would be born by the load even if there are no exports. Exports are a marginal transaction and only occur when economically feasible and should not incur any fixed or sunk costs.

We believe that a model that predicts more closely real market events (or this model re-run with new assumptions that allow NEEM to better predict current market conditions) would be more useful for analysis, but we believe inevitably all results will show that the reduction of transaction fees and a move toward a more efficient global marketplace will benefit the market as a whole the most in the future; as well as, the IESO should continue to strive towards an efficient market regardless of the co-operation of other adjoining control areas decisions. BEMI supports Option #4-1, but Option #4-2 is an improvement from status quo and is a small step towards the many benefits/goals listed above. Any other option would be contrary to market development/efficiency and would result in negative surplus (so other than Options #4, keeping the status quo is the only other option that does not negatively impact many participants and the market as a whole).

**AMPCO**

I am writing with comments on the IESO's recent study of options to replace the current $1/MWh export transmission service tariff.

The economic analysis that the IESO has commissioned provides useful insight into the comparative and incremental impacts of implementing options to the status quo. Of interest to AMPCO is the implicit acknowledgement of the deleterious impact of the current tariff on the welfare of consumers. The reality is that domestic consumers have, since 1999 at least, subsidized foreign consumers. While the study makes no explicit estimate of this, the conclusions of the study must be considered in this context, i.e., that an increase in consumer surplus relative to producer surplus necessarily represents an improvement from the status quo, whereas a relative increase in producer surplus would make a bad situation worse.

AMPCO supports the fundamental principle of "user pay". With respect to transmission services, AMPCO has taken the position that, as closely as possible, charge determinants for network services should be designed to reflect the marginal cost of providing those services. Since perfect marginal cost pricing of transmission service is not currently practical, AMPCO has proposed a network charge determinant (in the recent OEB hearing of Hydro One's application for transmission rates in 2009 and 2010) based on customers' demand during periods of peak demand on the network. AMPCO's proposal is based on the understanding that transmission network investment is largely driven by peak, not average demand, and is similar to rates already in place in other jurisdictions. We recognize however, as a practical matter, that a tariff design that is best for a domestic customer might be unsuitable for a foreign consumer. Exports are unlike domestic consumers in that export transactions are transitory and not necessarily or readily attributable to a specific customer or consumption pattern.

While we support the IESO's efforts to review all the potential impacts of a change in the ETS tariff, we would suggest that effects on air emissions in the USA are not of primary relevance to the determination of an optimal tariff for export service by the IESO. (Looking at emissions of a few selected contaminants hardly qualifies as an environmental impact assessment in any case; if environmental attributes were to be used as a basis for rate design, we would expect a much more comprehensive analysis.) We note also the limitations of the study with respect to modelling market responses, changes in market players, fuel costs, etc.

Option 1 (status quo) is not acceptable to AMPCO, since it proposes to continue with a tariff that has no factual foundation in cost drivers. While we understand the original rationale for this level as a "placeholder" tariff, the time has long passed since it should have been discarded.

Option 2 (average network cost, calculated on a $/MWh basis) would appear to provide the simplest solution by doing a simple update of the current tariff. It also has the appeal of eliminating the existing subsidy of exporters by Ontario customers. However, it is not clear that the value calculated by the IESO has considered properly the actual usage of the network by exports and how this usage drives the cost of export transmission service. We would appreciate the IESO providing more detail on how the value of the equivalent average network cost has been calculated.

Option 3 (reciprocal agreements) appears to be a non-starter, given the lack of interest by other jurisdictions.

Option 4, Scenario 1 (unilateral elimination of the ETS tariff) is unacceptable, since it would clearly provide preferential treatment for exports over Ontario customers.

Option 4, Scenario 2 (status quo during peak hours, elimination of the tariff during off peak hours) is unacceptable as written, since it would continue the unjustified $1/MWh tariff during peak hours. This option does, however, contain the basic elements of an ETS tariff design that we suggest should be explored further. AMPCO would support a tariff design similar to this scenario if the tariff during peak hours were calculated based on the average cost of service during peak hours. Presumably, this average network cost would be higher than that calculated by the IESO as an "all hours" average. While not perfect, such a design would more closely reflect the cost of providing export service and would be an improvement on the current design.

We support the IESO's leadership in this area and look forward to the next iteration of the analysis incorporating our suggestions.

**Ontario Power Generation**

Thank you for the opportunity to comment on the results of the Export Transmission Tariff Study undertaken by the IESO at the direction of the OEB.

During the stakeholder meeting held at the IESO on June 25, 2009 the participants expressed concerns with the model inputs used in performing the analyses. It was our belief that there was a need for the IESO to review the inputs and give consideration to revising the inputs and rerunning the model.

The IESO captured the identified concerns in the June 25, 2009 Meeting Minutes Action Items and provided an assessment of each of the concerns. It is our belief that the IESO has adequately addressed each of the concerns either through explanation or revision to the initial input. The minutes have indicated that the IESO is undertaking a rerun of the study using revised inputs. OPG looks forward to seeing the results of the most recent run of the model.

The IESO has made an assessment of the potential impact of the 4 scenarios on future SBG events. SBG continues to be a growing concern in the Ontario market and the problem is expected to increase in magnitude in the coming years. It is important that the final decision gives consideration to this important issue.
In the past OPG has cautioned the IESO that any assessment of the differences in tariffs between neighbouring markets compare total cost of export from each market. For example, Ontario's current export tariff does not include uplift, which is a separate charge to exporters. Conversely, other markets imbed some or all of these uplift charges directly in the export tariff.

It is difficult to provide any further comment until such time as the IESO publishes the results from the latest version of the study.

**Power Workers Union**

**<u>The PWU's Comments</u>**

The PWU's comments on the ETS Study's preliminary results and the responses to stakeholders' questions that the IESO posted on July 14, 2009, are made in recognition of the following:

The PWU recognizes the effort that the IESO staff and CRA have made in the face of the challenging task of attempting to determine the potential incremental impacts of each of the options under consideration on the four parameters established under the objectives of the Study as accurately as possible. The PWU recognizes that a number of variables and data that have the ability to skew the findings of the Study are hard to identify, quantify or account for due to the constant change of circumstances particularly in the recent few years and months. Factors related to the ETS require a lot of resources and time to analyze and forecast their impacts. These factors include, among others,: changes in economic activities, the anticipated Cap and Trade policy for $CO_2$ emissions, the recent decline in demand for electricity in Ontario, the negative price phenomena, the uncertainty around the new nuclear build planned by the government, and the varying interests of the jurisdictions that trade electricity with Ontario.

The PWU believes that it is important that the Study's findings are factual-based, reasonably acceptable to stakeholders from a public interest perspective and one that is durable or able to adjust and respond to the Ontario power market as it continues to evolve in Ontario given the significant implications of adopting any one of the tariff options.

Having reviewed both the preliminary results of the Study and the responses to questions that were posted subsequently, the PWU is of the view that the Study results, while informative, do not realistically provide for a decision making framework that can be relied on. The Study requires further improvement in many areas. Moreover, the preliminary results and the responses alone do not provide sufficient information to enable stakeholders to propose the appropriate tariff option or options that the IESO should recommend to the Board. For example, the PWU has not received at the time of preparing these comments the IESO's report in respect of its assessment of potential impacts on the Federal Energy Regulatory Commission ("FERC") / U.S. Department of Energy ("DOE") non-discriminatory transmission access and rate principles, which the IESO has promised to release. Similarly, with respect to questions and concerns raised on Surplus Baseload Generation ("SBG") analysis, it is not clear how the data provided to show the impact of the options on SBG relates to the OPA's projection of almost 800 hours in 2014 in the Integrated Power System Plan submission[1] . Also the IESO's latest communication with stakeholders indicates that further work is still underway:

[1] IESO Operability Assessment of the OPA's Integrated Power System Plan Issue 2.0 – April 21, 2008 Table 3 pg 15

**The IESO is carrying out a review of the SSG analysis taking into account the various concerns expressed by stakeholders, including confirming the seasonal demand forecast used in the earlier runs, use of Ontario on-peak and off-peak hydro production forecasts, and refining Quebec's hydro production assumptions.**[2]

With respect to the responses to the Action Items identified on June 25, 2009, the PWU notes that in some instances the Study will be updated to reflect stakeholders' comments, in other instances the response has been that such concerns were reviewed but deemed to be too insignificant to have any material impacts. The PWU is of the view that without the opportunity to review the results of the re-run of the model that takes into consideration stakeholders' comments, stakeholders would find it difficult to determine the materiality of the updates and their implications on the potential incremental impacts of the proposed tariff options.

**Recommendations**

The PWU intends to make its position with respect to each of the proposed options once the above noted clarification and update from the IESO and eRA are made available. For the purpose of assisting the IESO in its effort to make a reasonable recommendation to the Board, the PWU recommends that the IESO consider the following:

a. Market efficiency improves with reduction of export transaction fees; in fact, the elimination of transaction fees as a means of achieving market efficiency should be considered as the ultimate goal.

b. As can be seen from recent events and as projected by the OPA, it is likely that SBG will increase over time which will significantly increase operating pressure on nuclear generation and puts these assets at increased operating and reliability risk as well as increased cost of maintenance and operations. As recently as July 14, 2009, the 795MW Unit 8 at the Bruce B generating station was taken offline at the request of the IESO due to SBG in Ontario. Appropriate compensation should be made to generators maneuvered as a result of such SBG decisions. A tariff option that results in the largest net export will allow nuclear units to operate on a more predictable load profile and avoid unexpected maneuvering of nuclear units that are deleterious to these assets. Moreover, the recommendation should take into account the potential and the need for more exports in light of contracted generator arrangements that have been made with the OPA.

c. As pointed out by the ETS Study, due to its relatively green generation mix, Ontario has an excellent opportunity to export more capacity when carbon trading comes into place.

d. On balance, therefore, Option #4 appears to be superior to the other options in terms of positive impacts on export and market efficiency

[2] Responses to Action Items – ETS Stakeholder Session – June 25, 2009

e. According to an update by the IESO staff at the stakeholders' meeting held on June 25, 2009, the IESO's discussion with its direct neighbours on the possibility of reciprocal elimination of the tariff (Option 3) has not been successful with the exception of the New York ISO ("NYISO"). The IESO indicated that, Hydro Quebec Trans-Energie had sent a letter stating that they have no basis on which to engage in any negotiation or to participate in any reciprocal arrangements on ETS elimination. Similarly, it was indicated that the Midwest ISO ("MISO") and its committees have not indicated a willingness to participate in such discussions. In this respect, the PWU is of the view that the IESO take this unwillingness on the part of these parties to negotiate a reciprocal elimination of tariff as a key consideration when making recommendations to the Board. In fact, given this circumstance, the PWU does not see the need to keep Option #3 - Scenario 1 in the list of options.

f. While the PWU is still waiting for the IESO's report in respect of its assessment of potential impacts of the proposed options on FERC/OOE non-discriminatory transmission access and rate principles, the PWU agrees with the comments of Brookfield Renewable Power that reciprocal fee treatment proposed under Option #3 Scenario 2 could result in the possibility of charges that are in excess of the cost of service for transmission which is contrary to FERC's mandate. Therefore, subject to the IESO's expected report, the PWU suggests that Option #2 Scenario 2 should be ruled out.

g. Reciprocal fee treatment under Option #3 would also be more complex and administratively more difficult to manage and may have some disadvantages related to achieving optimal utilization of the transmission system.

h. The PWU notes that the assessment of the reliability and operational impacts of the proposed options relied not just on the findings of the ETS Study and analysis but also on the IESO's knowledge of historical practices and understanding of how participants generally react to market and system conditions. The PWU is satisfied that the assessment report is clear on the issue and that the various ETS tariffs considered will not adversely impact the IESO's ability to maintain reliability in that the potential trade volumes contemplated under the various ETS tariff scenarios do not represent a new risk or impairment to Ontario's reliability. The PWU also submits that the option that allows more export from Ontario through lower ETS tariff (at least lower off-peak tariff) would offer more reliability by allowing nuclear units to operate on a more predictable load profile and avoiding the maneuvering of units on short notice. The serious reliability risk that SBG places on Bruce Power and Ontario Power Generation should not be minimized and it is essential that the OEB is fully informed on this issue in the IESO's submission to the OEB.

i. The appropriate option should also be one that prevents gaming the system by wheel through transactions carried out solely for financial gain. This is a potential threat under options that involve varying reciprocal fee arrangements with different neighbouring jurisdictions which, if not strictly regulated, could result in circuitous wheel through transactions.

**CONCLUSION**

The PWU will be making further comment and submission when complete information and analysis is available. Based on the information so far, the PWU is inclined to recommend the following options in order of preference:

1. Option 4, Scenario 1 (Unilateral Elimination of the ETS tariff in all hours);
2. Option 4, Scenario 2 (Unilateral Elimination of the ETS tariff in off-peak hours); and
3. Option 1, Status Quo.