EB-2019-0082

ONTARIO ENERGY BOARD

IN THE MATTER OF *the Ontario Energy Board Act*, *1998*, S.O.1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an order or orders made pursuant to section 78 of the *Ontario Energy Board Act*, *1998* approving rates for the transmission of electricity.

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COMPENDIUM OF THE SCHOOL ENERGY COALITION
(Panel 4 – Rates & Custom IR)

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Export Transmission Service Rate

Cost Allocation Methodology

Report Prepared by
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On Behalf of HONI

May 7, 2014

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EXECUTIVE SUMMARY

This report presents Elenchus' recommendation on the cost allocation methodology that should be used to determine a cost-based Export Transmission Service rate in Ontario.

The recommended methodology should be based on:

- Using prior year actual hourly data for domestic and export customers,
- 12 CP should be the allocator used in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared OM&A expenses,
- Only dedicated assets used to serve export customers and the related costs should be allocated to the export customer class,
- OM&A expenses related to the use of shared assets should be allocated to export customers using composite assets as allocator,
- No external revenues should be allocated to the export customer class,
- The ETS rate should be based on HONI's OEB approved Network revenue requirement, as used in determining the Uniform Transmission Rates, marked-up to include other transmitters' approved revenue requirement as reflected in the Uniform Transmission Rates.

The proposed cost allocation methodology determines the ETS rate based on cost causality principles. Given the range of values calculated using 2013, 2015, 2016 data in the proposed methodology and the related scenario sensitivity results, a value between $1.7/MWh and $1.8/MWh for the ETS rate can be considered to be cost-based.

Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of $1.7 MWh be implemented for 2015 and that the ETS rate be maintained for at least 2 years to provide stability in determining the rate.

1 INTRODUCTION

Hydro One Networks Inc. ("HONI") retained Michael Roger of Elenchus Research Associates Inc. in order to develop a cost-based methodology to establish the Export Transmission Service ("ETS") rate.

In its Decision with Reasons dated June 6, 2013 on 2013 Export Transmission Service rates, (EB-2012-0031, Decision and Order, page 10), the Ontario Energy Board ("OEB") directed HONI to include a proposal of the appropriate cost-based ETS rate, with supporting rationale, to the OEB at its next transmission rates application.

More specifically the OEB stated on page 9 of its Decision with Reasons in Proceeding EB-2012-0031 that:

> *"The Board will require Hydro One to perform a cost allocation study to establish a cost basis for the ETS rate. Some parties have suggested that such a study would be prohibitively costly. However, the Board accepts the Elenchus testimony that a study could be properly scaled to address the magnitude of the issue and could be completed for a reasonable cost. The Board expects that this study will be completed in time for Hydro One's next cost of service transmission rate application. While Hydro One has the responsibility for completing this study, the Board expects that the IESO will assist Hydro One as required to fully address the ETS rate issue."*

This report presents the results of the cost-based methodology developed by Elenchus to establish the ETS rate.

This report is divided into 5 main sections. Section 2 provides a background on the evolution of the ETS rate from market opening in 2002 until now, section 3 presents the principles of cost allocation methodology, section 4 describes the proposed cost allocation methodology to determine the ETS rate, section 5 presents the results of applying the recommended methodology using 2013 proposed data and 2015 and 2016 proposed data and section 6 presents conclusions and recommendations to the OEB on the proposed cost allocation methodology and the ETS rate. Appendix A contains the CV for Michael Roger.

Michael Roger has been an expert dealing with cost allocation, rate design and rate regulation issues for over 35 years. Michael worked for over 32 years at Ontario Hydro, Ontario Power Generation and Hydro One and spent most of his career dealing with Cost Allocation and Rate Design issues for wholesale and retail electricity customers in Ontario. He has also testified on numerous occasions at OEB proceedings on behalf of utilities and other stakeholders and also has provided expert advice to the OEB in various task forces dealing with cost allocation and rate design issues. Michael's vast experience with Cost Allocation issues was applied in developing the cost-based cost allocation methodology to develop the ETS rate and forms the basis for Elenchus recommended methodology to the OEB.

2 BACKGROUND

In Proceeding RP-1999-0044 the OEB reviewed the issue of establishing an ETS rate to be implemented at market opening.

In its Decision with Reasons dated May 26, 2000, the OEB summarized the various arguments presented by stakeholders in this proceeding on what the ETS rate should be. The OEB decided that as an interim measure, the ETS rate should be fixed at $1/MWh. This was seen as a reasonable compromise between the competing interests and proposals presented by stakeholders in the proceeding on what was described as a complex and contentious issue. 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 the network transmission facilities to facilitate export and wheel-through transactions.

The OEB directed that HONI monitor and report at its next main rate submission how the export market was functioning and the developments in interconnected jurisdictions and whether the ETS rate should be reviewed.

HONI retained R. J. Rudden to do a "Jurisdictional Survey of Export and Wheel-through Service Rates". The survey was filed with the OEB on June 26, 2006 and was reviewed in proceeding EB-2006-0501.

As part of EB-2006-0501, the OEB approved a stakeholder settlement agreement which maintained the ETS rate of $1/MWh. In the agreement, the Independent Electricity System Operator ("IESO") was identified as the entity responsible for undertaking a study on the appropriate ETS rate. The settlement agreement stated that:

> *"...the IESO should now be identified as entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study."*[1]

The IESO retained Charles River Associates ("CRA") to do a quantitative analysis of the future effect of several export rate scenarios, with respect to exports and wheel-through volumes, ETS tariff revenue, and the Hourly Ontario Energy Price. The IESO's ETS study and recommendation was filed with the OEB on August 28, 2009 and was reviewed in proceeding EB-2010-0002. The IESO study reviewed four alternatives for setting the ETS rate:

1. Status Quo;
2. Equivalent average network charge;
3. Reciprocal treatment, and
4. Elimination.

[1] EB-2006-0501, Exhibit M, Tab I, Schedule 1, page 17, April 3, 2007

The IESO recommended the status quo alternative to the OEB.

In the Decision with Reasons in proceeding EB-2010-0002, page 75, the OEB concluded that an additional study was required. The OEB stated that:

> *"The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's view, the most appropriate party to undertake this study is the IESO. In procuring the study, the IESO should circulate the terms of reference to the Applicant and the intervenors of record in this case with a view to ensuring that the resulting study will provide detailed analysis on the issues.*
>
> *This review of the terms of reference is not intended to be a strategic negotiation, but rather a technical exercise to ensure that the scope of the project is sufficiently broad and well-defined to ensure a useful and appropriate outcome. Work on this study should begin soon, to ensure completion well in advance of the time for the filing of the next transmission rates application by Hydro One."*

The OEB in the same proceeding increased the ETS rate to $2/MWh, providing the following rationale:

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

In response to the OEB directive, the IESO engaged CRA to conduct a further review of the ETS rate. CRA reviewed the tariff and structures in neighbouring markets and assessed five proposed rate options against generally accepted rate making principles (consistency, simplicity, fairness and efficiency). The rate options considered were:

1. Status Quo
2. Elimination

3. Equivalent average network charge
4. Tiered rates (two alternatives)

The CRA study was filed and reviewed in proceeding EB-2012-0031.

In the IESO's submission to the OEB, the IESO indicated that none of the ETS tariff options materially impact reliability, but elimination of the tariff would best promote efficient operation of the wholesale electricity market.

As stated in the introduction in this report, the OEB directed HONI in proceeding EB-2012-0031 to develop a cost-based methodology to determine the ETS rate.

3 PRINCIPLES OF COST ALLOCATION

In order to determine cost-based rates, a cost allocation study is performed by a utility to fairly allocate shared assets and expenses to the customer groups served by the utility.

The cost allocation study is based on actual historical or forward looking test year data and reflects the operating circumstances of the utility at a particular point in time, either the last year for which actual historical information is available, or for the future test year for which rates are being established.

Traditionally three steps are followed in a cost allocation study: Functionalization, Categorization or Classification, and Allocation.

Assets and expenses that are identified with a particular customer class and that are not shared with other customer classes are "Directly" allocated to that particular customer class.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, high voltage transmission, customer service, meter reading, etc. Hence, as a first step in a cost allocation study, the function(s) served by the assets or expenses of the utility are identified so that costs can be attributed appropriately to the identified functions.

Categorization or Classification is the process by which the functionalized assets and expenses are classified as energy, demand and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of volume, system demand, or number of customers.

Allocation, which is the final step, is the process of attributing the energy, demand, and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to energy, demand, or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class.

It is in this Allocation step that customers are grouped based on common characteristics, or utility asset utilization reflecting cost causality.

4 PROPOSED COST ALLOCATION METHODOLOGY

Elenchus proposes a cost allocation methodology to determine the ETS rate that is based on cost causality, is simple and follows the traditional three steps of a cost allocation methodology.

Elenchus looked at how transmission assets are being used to sell electricity, either to domestic customers of to neighbouring jurisdictions by exporters.

In Ontario generators do not pay for the use of the transmission system when they inject power into the grid in order to supply domestic electricity needs. Elenchus applied this same principle when evaluating the interconnected assets with neighbouring jurisdictions used by exporters. The interconnected assets are used to both export and import power and since generators in Ontario do not pay for the use of the transmission assets and the ETS rate is not applied to power imported into Ontario, Elenchus assumed that importers would also continue to not be charged for the use of the transmission system.

The proposed methodology considered the sale of electricity to domestic customers and neighbouring jurisdictions, not how the electricity was sourced and made available to satisfy sales.

HONI's 2013 transmission assets and revenue requirements were used in developing the recommended approach.

The proposed cost allocation methodology to determine the ETS rate reflects the interruptible nature of exports. The basis for treating exports as interruptible loads is found in the OEB's Decision with Reason in proceeding EB-2012-0031 that on page 5 states that:

> *"First, whether curtailments originate from generation issues or transmission issues, the Board agrees that export service does not receive the same priority access as domestic service. The Board accepts that the market rules treat exporters more as an interruptible load. This difference in treatment related to generation capacity has consequences for the overall service, even if export transmissions rights are technically as firm as domestic transmission rights. As a result, the Board finds that it may be appropriate for the export service to be* viewed as a separate class."

This has implications for how costs are allocated, as discussed in Section 4.3.

4.1 FUNCTIONALIZATION

In consultation with HONI, Elenchus determined that the assets and expenses associated with export activities can be found in the following HONI's transmission functions:

- Network (500 kV, 230 kV, and 115 kV lines)
- Dual Function lines (Network portion)
- Generation Line Connection
- Generation Transformation Connection
- Common (telecommunication equipment, control centre)
- Other (facilities not allocated to other functions under normal operating conditions)

These functions include dedicated and shared assets, and related expenses used by domestic and export customers.

The remaining functions used by Hydro One Transmission in determining its revenue requirement (e.g. transformation, line connection, line connection portion of dual function lines) are considered to be used only by domestic customers.

External revenues were also considered in the development of the cost allocation methodology. These revenues result mainly from secondary land use in right of ways and from providing maintenance services to other entities. These revenues are the result of using HONI's assets which have been designed to serve domestic customers only, therefore, no external revenues are proposed to be allocated to export customers.

4.2 CLASSIFICATION

Generally in costs allocation, transmission assets and expenses are classified as demand related. Transmission assets are designed to meet the maximum demand imposed by users of the system. Based on the functions evaluated, it was determined that the assets and expenses considered in the development of the ETS rate methodology are all demand related. There are no energy related or customer related assets and expenses.

4.3 ALLOCATION

In the cost allocation methodology developed to determine the ETS rate two customer groups are considered: domestic and export.

Assets dedicated to domestic customers are assets that only serve to connect Hydro One customer's load to the network.

Assets dedicated to interconnect (export) are assets that only serve to connect to another transmission utility.

Shared assets are those that serve both domestic and export customers, including assets associated with generation connection.

As export is considered to be interruptible service, no asset related costs associated with shared assets are proposed to be allocated to the export customer class.

This is considered appropriate because, as confirmed by Hydro One staff, HONI's planning of the Network transmission system does not take into consideration the capacity needed to supply export customers, transmission planning is only based on the capacity needs of domestic customers.

The assets dedicated to serve export customers have been directly allocated to the export customer class as well as the related expenses.

The OM&A expenses related to the use of shared assets have been allocated between domestic and export customers using the allocators described below.

4.3.1 Coincident Peak Allocator

In cost allocation, the allocation of demand related assets that are closest to the customer are allocated based on the non-coincident demand of the customer. The required assets are sized reflecting the maximum customer electricity demand.

Further away from the customer and closer to the generation system, it is the aggregate electricity demand of all customers, and not the sum of the individual customer demands, that determines the size of the facilities required to satisfy customers' electricity needs. In cost allocation, when apportioning assets and expenses further away from the customer (e.g. generation, transmission) and closer to the generation of electricity, it is the coincident demand that is used as an allocator, reflecting the criteria used to size the required assets.

Using 2010, 2011 and 2012 actual hourly load data for domestic and export customers from the IESO, coincident peak ("CP") allocators were developed.

Coincident peak is the hourly demand of domestic and export customers at the hour of maximum demand in the Ontario electricity system.

1 CP is the demand for each customer class at the hour of maximum system demand in a year. 12 CP is the average of the demand for each customer class at the hour of each month's maximum system demand.

1 CP or 12 CP are used by utilities in cost allocation studies to apportion generation and transmission costs amongst customer groups.

The following table includes the values developed for coincident peak.

Table 1

Coincident peak 2010 to 2012

	2010			2011			2012			Average		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	2,687	25,048	27,735	2,549	25,450	27,999	2,179	24,636	26,815	2,472	25,045	27,516
12CP	30,897	255,485	286,382	31,343	250,819	282,161	28,164	251,842	280,006	30,134	252,715	282,850

The 1 CP and 12 CP percentage allocators using 2010 to 2012 data are show in the table below

Table 2

Coincident peak %

	2012 Data			Average 2010 – 2012 Data		
Coincident Peak	Total	Domestic	Export	Total	Domestic	Export
1 cp	100.00	91.87	8.13	100.00	91.02	8.98
12 cp	100.00	89.94	10.06	100.00	89.35	10.65

The 1 CP and 12 CP values for the period 2011 to 2013 using actual hourly data are shown in the table below.

Table 3

Coincident peak 2011 to 2013

	2,011			2,012			2,013			Average		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	2,549	25,450	27,999	2,179	24,636	26,815	1,952	24,927	26,879	2,227	25,004	27,231
12CP	31,343	250,819	282,161	28,164	251,842	280,006	30,240	255,417	285,657	29,916	252,692	282,608

The 1 CP and 12 CP percentage allocators using 2011 to 2013 data are show in the table below

Table 4

Coincident peak %

	2013 Data			Average 2011 – 2013 Data		
Coincident Peak	Total	Domestic	Export	Total	Domestic	Export
1 cp	100.00	92.74	7.26	100.00	91.82	8.18
12 cp	100.00	89.41	10.59	100.00	89.41	10.59

Elenchus recommends that 12 CP should be used to allocate shared assets between domestic and export customers using the last year for which information is available.

When system loads are relatively flat and do not show a pronounced yearly peak, 12 CP is usually used by utilities to allocate demand related assets and expenses. In instances where there is a significant yearly peak compared to other peaks in the year, that is a very peaky load profile with low load factor, then 1 CP would be used to allocate demand related assets and expenses.

In Proceeding RP-1999-0044, the OEB reviewed allocators that could be used to recover Network assets and expenses and recommended against the use of non-

coincident peak and settled on the use of coincident peak. With respect to using 1 CP, in paragraph 3.4.27 of the OEB Decision it states that:

> *"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 [Hydro One] network transmission system either today or in the foreseeable future."*

12 CP is used by HONI in apportioning assets and expenses when allocating Dual Function Line assets, (Proceeding EB-2012-0031, Exhibit G1, Tab 2, Schedule 1, pages 110-111).

4.3.2 Composite Allocators

The asset functions identified in section 4.1 were apportioned between domestic and export customers using the 12 CP allocator based on 2012 actual hourly data in order to develop composite allocators used to allocate shared OM&A expenses to domestic and export customer classes.

The OM&A expenses related to the identified shared functions were allocated in the cost allocation methodology to domestic and export customers using Net Shared Assets as composite allocators. Table 5 includes the percentage allocation of the composite allocators to the two customer classes based on 12 CP.

Table 5

Composite Allocators using 2012 actual hourly data

	Total	Domestic	Export
Net Shared Assets	**100.00%**	**92.89%**	**7.11%**
Dedicated to Domestic	**100.00%**	**100.00%**	**0.00%**
Dedicated to Interconnect	**100.00%**	**0.00%**	**100.00%**

Using 2013 actual domestic and export hourly data, the composite allocators are included in the following tables based on 12 CP and the 2015 and 2016 financial data.

Table 6

Composite Allocators using 2013 actual hourly data for 2015

	Total	Domestic	Export
Net Shared Assets	**100.00%**	**92.74%**	**7.26%**
Dedicated to Domestic	**100.00%**	**100.00%**	**0.00%**
Dedicated to Interconnect	**100.00%**	**0.00%**	**100.00%**

Table 7

Composite Allocators using 2013 actual hourly data for 2016

	Total	Domestic	Export
Net Shared Assets	**100.00%**	**92.79%**	**7.21%**
Dedicated to Domestic	**100.00%**	**100.00%**	**0.00%**
Dedicated to Interconnect	**100.00%**	**0.00%**	**100.00%**

5 ETS RATE RESULTS

The results of applying the proposed cost allocation methodology to develop a cost-based ETS rate are shown below.

The proposed cost allocation methodology was developed using 2012 actual hourly load data and 2013 proposed HONI financial data as submitted in proceeding EB-2012-0031.

The model was run again with 2013 actual hourly load data and the proposed 2015 and 2016 financial data being submitted by HONI at its rate submission.

5.1 USING 2012 LOAD DATA AND 2013 HONI PROPOSED FINANCIAL DATA

5.1.1 BASE CASE ETS RATE

The base case result for developing the ETS rate using the proposed cost allocation methodology is based on the following assumptions:

- Shared Assets are apportioned using 2012 actual hourly data between domestic and export customers using the 12 Coincident Peak method in order to develop the composite allocators to be used to allocate shared expenses
- Only dedicated assets used to serve export customers and related expenses are being allocated to export customers
- No asset related costs associated with shared assets are allocated to export customers
- Shared OM&A expenses are allocated between domestic and export customers based on composite allocator of Net Shared Assets
- No External revenue credit is allocated to export customers
- HONI's proposed 2013 data, (Assets and Expenses), as submitted in proceeding EB-2012-0031 were used to develop the ETS rate based on the proposed cost allocation model.

Using HONI's export sales forecast for 2013, the resulting ETS rate is $1.77/MWh.

5.1.2 ETS RATE INCLUDING OTHER TRANSMITTERS' REVENUE REQUIREMENT

The hourly data used from the IESO reflect all transmission electricity sales in Ontario, not just Hydro One's, while the financial assets and expense data used in developing the cost allocation methodology reflects only Hydro One's data. Marking-up the calculated ETS rate to reflect other transmitters approved Network revenue requirement would result in consistency between the sales data and the financial data, both of which would reflect all transmitters in Ontario.

As seen in the 2014 Uniform Transmission Rates, HONI's Network function revenue requirement is $882.9 million. The revenue requirement for all Ontario transmitters is $912.8 million, or 3.4% higher than HONI's revenue requirement.

Increasing the ETS rate of $1.77/MWh by 3.4%, results in an ETS rate of $1.83/MWh. This higher ETS rate would take into account the revenue requirement of all transmitters in Ontario.

5.1.3 SCENARIOS

The following scenarios were run in order to determine the results sensitivity of the proposed cost allocation methodology to various assumptions.

Table 8 Scenarios (2012 load data)

Scenario	Description	ETS rate ($/MWh)[2]
1	Same as Base case, but using 12 CP average of 3 years (2010 to 2012)	1.82
2	Same as Base case, but using 1 CP (2012)	1.59
3	Same as Base case, but using 1 CP average of 3 years (2010 to 2012)	1.67
4	Same as Base case, but allocation $0.16M External Revenue credit to Export customers	1.76
5	Allocating only shared OM&A costs to Export customers, no dedicated export assets allocated to Export[3]	1.22
6	Allocating to Export customers same Network function assets and expenses as Domestic customers, $1.43M External Revenue credit, using 12 CP (2012)[4]	4.73

5.2 Using 2013 Load Data and 2015 and 2016 HONI Proposed Financial Data

5.2.1 Base Case ETS rate

The same assumptions described in section 5.1.2 are used in developing the ETS rate:

- Shared Assets are apportioned using 2013 actual hourly data between domestic and export customers using the 12 Coincident Peak method in order to develop

[2] Using HONI 2013 export sales forecast
[3] Assuming exporters do not pay for dedicated assets and related expenses
[4] Assuming export is treated as firm load, similar to domestic load

the composite allocators to be used to allocate shared expenses to domestic and export customer classes

- Only dedicated assets used to serve export customers and related expenses are being allocated to export customers
- No asset related costs associated with shared assets are allocated to export customers
- Shared OM&A expenses are allocated between domestic and export customers based on composite allocator of Net Shared Assets
- No External revenue credit is allocated to export customers
- HONI's proposed 2015 and 2016 data, (Assets and Expenses), as submitted in this proceeding are used to develop the ETS rate based on the proposed cost allocation model.

Using HONI's 2015 and 2016 export sales forecast, the resulting ETS rate is $1.63/MWh for 2015 and $1.62/MWh for 2016.

5.2.2 ETS Rate Including Other Transmitters' Revenue Requirement

In HONI's proposed 2015 and 2016 Uniform Transmission Rates, HONI's Network function revenue requirements are $933.6 million and $972.0 million respectively. The revenue requirements for all Ontario transmitters are $963.0 million, and $1,001.3 million for 2015 and 2016, or 3.2% and 3.0% higher than HONI's proposed revenue requirements.

Increasing the 2015 ETS rate of $1.63/MWh by 3.2%, and the 2016 ETS rate of $1.62/MWh by 3.0% results in ETS rate of $1.68/MWh for 2015 and $1.67/MWh for 2016. This higher ETS rates would take into account the revenue requirements of all transmitters in Ontario.

5.2.3 Scenarios

The following scenarios were run in order to determine the results sensitivity of the proposed cost allocation methodology to various assumptions.

Table 9 Scenarios (2013 load data)

Scenario	Description	ETS rate 2015 ($/MWh)[5]	ETS rate 2016 ($/MWh)[6]
1	Same as Base case, but using 12 CP average of 3 years (2011 to 2013)	1.63	1.62
2	Same as Base case, but using 1 CP (2013)	1.34	1.33
3	Same as Base case, but using 1 CP average of 3 years (2011 to 2013)	1.42	1.41
4	Same as Base case, but allocation $0.12M External Revenue credit to Export customers	1.62	1.61
5	Allocating only shared OM&A costs to Export customers, no dedicated assets allocated to Export [7]	1.15	1.13
6	Allocating to Export customers same Network function assets and expenses as Domestic customers, $1.3M External Revenue credit, using 12 CP (2013)[8]	4.84	4.88

6 CONCLUSIONS AND RECOMMENDED METHODOLOGY

The results of the proposed cost allocation methodology to develop a cost-based ETS rate and the sensitivity scenarios run using 2010 to 2012 load data show a Base Case result of $1.77/MWh and a range for the ETS rate between $1.22/MWh to $1.82/MWh

[5] Using HONI 2015 export sales forecast
[6] Using HONI 2016 export sales forecast
[7] Assuming exporters do not pay for dedicated assets and related expenses
[8] Assuming export is treated as firm load, similar to domestic load

for scenarios 1 to 5. The financial data is based on HONI's 2013 proposed data and excludes other transmitter's revenue requirement.

Using hourly load data for the period 2011 to 2013 and financial data for HONI as proposed for 2015 and 2016, the Base Case result for the ETS rate for 2015 is $1.63/MWh and for 2016 is $1.62/MWh. The range for the ETS rate is between $1.13/MWh to $1.63/MWh for scenarios1 to 5. The financial data excludes other transmitter's revenue requirement.

It is Elenchus' recommendation that the cost allocation methodology to be used to develop the ETS rate should be based on:

- Using the last year of actual hourly data for domestic and export customers. Forecast domestic and export hourly data is not available either from HONI or IESO,
- 12 CP should be the allocator used in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared expenses.
- Only dedicated assets used to serve export customers and related expenses should be allocated to the export customer class,
- No asset related costs associated with shared assets should be allocated to export customers
- Expenses related to the use of shared assets should be allocated to export customers using composite assets as allocator,
- No External revenues should be allocated to the export customer class, and
- The ETS rate should be based on HONI's OEB approved Network revenue requirement, as used in determining the Uniform Transmission rate, marked up to include other transmitters' approved revenue requirement as reflected in the Uniform Transmission Rates.

The proposed cost allocation methodology provides a supporting basis for determining the ETS rate based on cost causality principles. Given the range of values calculated using 2013, 2015, 2016 data and the related scenario sensitivity results, a value

between $1.7/MWh and $1.8/MWh for the ETS rate can be considered to be cost-based.

Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of $1.7 MWh be implemented for 2015 and that the ETS rate be maintained for at least 2 years to provide stability in determining the rate.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #10

Interrogatory

In the Executive Summary, it is stated that only dedicated assets should be used to allocate costs to the Export Customer Class.

a) Is it Elenchus' view that the export customer class use of the transmission system drives no costs whatsoever when using non-dedicated transmission assets, such as control room costs, energy losses, transformer ageing, etc.?
b) Are there other customer classes that Elenchus believes should be allocated only costs based on their use of dedicated assets, either in distribution or transmission cost allocation?
c) Did Elenchus review methodologies used for establishing ETS rates in other jurisdictions to determine if it was following commonly applied cost allocation principles for this customer class?

Response

a) Elenchus is of the view that the assets that are shared or are used exclusively by domestic customers should not be allocated to interconnections. That is, the associated depreciation, return, etc. costs in Rate Base associated with these assets should not be allocated to export customers.

   The depreciation, return, etc. in Rate Base associated with assets dedicated to interconnections are included in the Elenchus' proposed methodology.

   In the Elenchus' proposed methodology, interconnections are allocated the expenses (OM&A costs included in the revenue requirement) associated with all shared assets in addition to the OM&A expenses associated with the assets dedicated to interconnections.

b) Elenchus did not review how assets are allocated to other customer classes either in distribution or transmission cost allocation. Elenchus is aware that the OEB's Cost Allocation Methodology used by distributors in Ontario includes Sheet 9 "Direct Allocation", that allows distributors to directly allocate assets and/or expenses to customer classes if there are circumstances that meet the criteria of assets and/or expenses being associated with only one customer class and not shared with other customer classes.

c) No.

VECC INTERROGATORY #55

Reference:

I2-04-01 p. 3-4

Interrogatory:

a) Please provide a schedule setting out the calculation of the export volumes for 2020, 2021 and 2022 as used in the initial Application.

b) Please provide a schedule setting out the calculation of the export volumes for 2020, 2021 and 2022 as used in the Updated Application.

Response:

a) The export volumes for 2020 to 2022 were calculated based on a three year rolling average of the prior year's amounts. The table below provides the export volumes for 2020 to 2022 period as used in the initial Application:

2015 Actual	2016 Actual	2017 Actual	2018 (2015 - 2017 Avg)	2019 (2016 - 2018 Avg)	2020 (2017- 2019 Avg)	2021 (2018- 2020 Avg)	2022 (2019- 2021 Avg)
23,138,052	22,157,981	19,346,599	21,547,544	21,017,374	20,637,172	21,067,364	20,907,304

b) The same calculation as in part (a) was used for the Updated Application; however the data for 2018 was updated to reflect actual volumes. The table below provides the export volumes for 2020 to 2022 period as used in the Updated Application:

2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 (2016 - 2018 Avg)	2020 (2017- 2019 Avg)	2021 (2018- 2020 Avg)	2022 (2019- 2021 Avg)
23,138,052	22,157,981	19,346,599	18,771,464	20,092,015	19,403,359	19,422,279	19,639,218

Witness: Clement Li, Henry Andre

APPRO INTERROGATORY #3

Reference:

I2-04-01 p.3 Table 1

Interrogatory:

Preamble:

In Hydro One's updated cost allocation study shown in Table 1, the Total Hydro One Revenue Requirement allocated to Export for 2020 is $22.1 million.

a) Using the proposed ETS rate of $1.85/MWh, please calculate the estimated revenues collected by Hydro One from exporters paying the ETS rate in 2020 and the resulting cost to revenue ratio.

b) Using the assumed ETS rate of $1.05/MWh, please calculate the estimated revenues collected by Hydro One from exporters paying the ETS rate in 2020 and the resulting cost to revenue ratio.

c) Using the assumed ETS rate of $1.25/MWh, please calculate the estimated revenues collected by Hydro One from exporters paying the ETS rate in 2020 and the resulting cost to revenue ratio.

d) Using the assumed ETS rate of $1.45/MWh, please calculate the estimated revenues collected by Hydro One from exporters paying the ETS rate in 2020 and the resulting cost to revenue ratio.

e) Please explain the forecasted level of exports in 2020 used to arrive at the results in the responses to part a) to d).

Response:

a) to d) Hydro One's Revenue Requirement allocated to Export for 2020 is $22.1 million, but per Elenchus' recommended methodology, the Ontario cost associated with exports is estimated to be $23.5 million, as shown in Exhibit I, Tab 3, Schedule APPrO-1 part (b).

Witness: Clement Li

For the purpose of determining the revenue to cost ratio, the estimated revenues are calculated by multiplying the ETS export volume of 18,800,000 MWh by the ETS Rate. The table below shows the estimated 2020 export revenue resulting from the assumed ETS rate in parts (a) to (d) and the resulting revenue to cost ratios.

Response	ETS Rate ($/MWh)	Volume (MWh)	Estimated Revenues	Ontario ETS Revenue Requirement (Cost)*	Revenue to Cost Ratio
	A	B	C = A X B	D	E = C/D
Part a	1.85	18,800,000	$34,780,000	$23,532,133	1.48
Part b	1.05	18,800,000	$19,740,000	$23,532,133	0.84
Part c	1.25	18,800,000	$23,500,000	$23,532,133	1.00
Part d	1.45	18,800,000	$27,260,000	$23,532,133	1.16

** Note: 2020 Ontario ETS Revenue Requirement provided in Exhibit I, Tab 3, Schedule APPrO-1 part (c)*

e) The forecast level of exports in 2020, used to derive the results to parts (a) to (d) above, is based on the actual 2018 export volume.

The Inflation Factor in Table 3 will be updated annually, as described in section 1.1 of this Exhibit. Hydro One proposes that the Productivity Factor will remain unchanged throughout the Custom IR term and that the 2021 and 2022 Capital Factors approved in this application would remain unchanged in subsequent annual update applications. Table 4 below summarizes the Total Revenue Requirement that would result from the OEB's approval of Hydro One's Custom IR, were the Application to be approved as filed.

Table 4: Revenue Requirement by Year

Year	Formula	Revenue Requirement
2020	Cost of Service	$1,673.8 million
2021	2020 Revenue Requirement x 1.0549	$1,765.8 million
2022	2021 Revenue Requirement x 1.0499	$1,853.8 million

** Calculations assume that Inflation Factor remains at 1.4% through term.*

2. ADDITIONAL CUSTOM IR FEATURES

Hydro One is proposing the following additional features in this Application to align its interests with those of customers and provide an additional element of protection for customers.

2.1 EARNINGS SHARING MECHANISM (ESM)

Hydro One proposes to share with customers 50% of any earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of Hydro One's next rebasing. The calculation of the actual ROE for a test year will use the OEB approved mid-year

rate base for that period to avoid double counting with amounts in the proposed capital in-service variance account, described below.

2.2 CAPITAL IN-SERVICE VARIANCE ACCOUNT (CISVA)

A CISVA is a mechanism to track the difference between the revenue requirement associated with the actual in-service capital additions during a rate year and the revenue requirement associated with the OEB-approved in-service capital additions for that year. If in-service additions in a test year are less than the OEB-approved level, the balance of the account would be negative and refunded to customers in a future rate-setting period. If actual in-service capital additions are equal or greater than the OEB-approved level in the test year, no entry would be recorded in the account.

Hydro One is proposing a CISVA with the following key features:

1. The account will track the impact on revenue requirement of any in-service additions that are on a cumulative basis 98% or lower of the OEB-approved amount for each year of the Custom IR term;
2. For cumulative in-service additions that are 98% or lower of the OEB-approved level, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account; and
3. At the end of the three-year term of the Custom IR Plan, in 2022, the sum of the variances in each year will be disposed of for the benefit of customers with the following conditions;
    - Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and

- Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry will be made in the variance account and no amount will be recoverable from ratepayers

Hydro One believes that a dead band is appropriate for the capital in-service variance account in order to ensure alignment between the behaviours that are incented by the account and the outcomes that rate payers value. The in-service variance account should incent Hydro One to cost-effectively deliver on its plans in a timely fashion while providing rate payers with protection from over-paying in the instance that Hydro One does not substantially deliver on its proposed in-service targets.

Absent the 2% dead band, Hydro One is incented to fully spend 100% of its planned capital amounts and focus on identifying any additional productivity initiatives on OM&A programs where part of the savings can be kept by the utility. Additionally, Hydro One is incented to do whatever it can (e.g. pay for additional overtime) to ensure planned projects are in-serviced by December 31st of each year rather than minimizing the execution cost. Though customers are not materially impacted if a project is in-serviced on December 31st as opposed to January 3rd, Hydro One would be financially impacted.

By including the 2% dead band, Hydro One is incented to find ways to lower the cost of capital projects, as well as OM&A, while still affording the sharing of benefits of significant cost savings with customers. The proposed 2% dead band was chosen because it has minimal impact on customers, while incenting behaviour that better aligns with the outcomes that rate payers value and is consistent with the OEB's outcomes-based approach under the Renewed Regulatory Framework.

Table 1 - Productivity Savings Forecast Summary ($Millions)

$mm	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	259
Progressive Operations (Defined Capital)	6	12	12	10	10	49
Corporate	12	11	9	7	6	45
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	45
Information Technology	6	9	10	10	10	44
Corporate	7	6	5	4	3	25
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Progressive Operations (Undefined Capital)	11	27	49	68	81	237
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive Productivity						
Progressive Operations (Defined Capital)	6	12	12	10	10	49
Progressive Operations (Undefined Capital)	11	27	49	68	81	237
Progressive Productivity Placeholder	17	39	61	78	91	286

As noted in the table above, Hydro One has identified savings opportunities totalling approximately $704M over the 2020-2024 TSP period. This reflects Tier 1 Productivity savings only. There are $353M in capital productivity savings, $114M in OM&A productivity savings and $237M in undefined capital savings. This latter category of savings falls within "Progressive Productivity". Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB's decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned

CCC INTERROGATORY #14

Reference:

A-03-01 p.10

Interrogatory:

With respect to an earnings sharing mechanism did HON consider alternative approaches? If so, why were those rejected? Would HON be adverse to an approach that shared earnings above the allowed return with its customers without a deadband? If so, please explain why this approach is not acceptable to HON given its objective to improving customer satisfaction. In any of its customer engagement activities has HON provided its customers with information regarding its allowed and achieved ROEs? If not, why not?

Response:

Page 27 of the OEB's *Handbook for Utility Rate Applications* states that "utilities that achieve productivity improvements above what is expected are allowed to keep certain savings above the approved ROE." Hydro One notes that this approach is consistent with the 100 basis-point dead band for the earnings sharing mechanism that was approved by the OEB in the proceeding for Toronto Hydro's Custom IR application (EB-2014-0116), and Hydro One Networks Distribution 2018-2022 Custom IR application (EB-2017-0049). As such, Hydro One would not be in support of an earnings sharing mechanism without a dead band.

The customer engagement did not provide customers with information related to our allowed and achieved ROEs. In recognition of the time and effort of our customers to participate in the engagement process, there is a desire to keep the engagement focused on areas that are of greatest importance to them.

Witness: Stephen Vetsis, Samir Chhelavda, Spencer Gill

ENERGY PROBE INTERROGATORY #24

Reference:

G-01-01 p.2

Interrogatory:

a) Please provide the Historic ROE for Hydro One Networks and the ROE for the Transmission Business.

b) Please provide a Table and a chart that shows for the Transmission Business, the Revenue Requirement and allowed and actual ROE for each of the 5 historic years.

c) Please discuss the reasons for any material over-earning

Response:

a) The ROE for Hydro One Transmission is included in the table below.

The Hydro One consolidated ROE is calculated on a GAAP basis, includes many non-regulatory items and therefore cannot be compared to the Transmission ROE.

b) The approved revenue requirement, and allowed and achieved ROE for Hydro One Transmission for the 5 historical years 2014-2018 are shown in the table below.

$millions	2018	2017	2016	2015	2014
Approved Revenue Requirement*	1,510.7	1,437.8	1,480.7	1,477.3	1,446.4
Allowed Return	9.00%	8.78%	9.19%	9.30%	9.36%
Achieved Return	11.08%	9.03%	10.02%	10.93%	13.12%

**Rates Revenue Requirement*

c) For 2018, return was higher due to a number of factors including lower income taxes due to the recognition of the deferred tax asset, lower depreciation and interest costs due to lower fixed assets and removal costs, and these reductions were partially offset by higher OM&A.

For 2017 and 2016, the achieved ROE was not materially (less than 100 basis points) different than the approved level.

Witness: Samir Chhelavda

For 2014 to 2015, favourable weather resulted in higher peak demand and greater than expected revenues. Additionally, cumulative in-service additions were less than planned resulting in lower depreciation expense and lower rate base. This also affects the amount of equity and therefore, mathematically, the level of ROE.