ETS Rate Generic Proceeding

EB-2021-0243

Technical Conference
APPrO Compendium

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence to own and operate a transmission system consisting of the facilities described in Schedule 1 of this Licence, including all associated transmission equipment.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the Licensee are set out in Schedule 2 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; and

b) the Transmission System Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Requirement to Enter into an Operating Agreement

6.1 The Licensee shall enter into an agreement ("Operating Agreement") with the IESO providing for the direction by the IESO of the operation of the Licensee's transmission system. Following a request made by the IESO, the Licensee and the IESO shall enter into an Operating Agreement

2.1.1.1 [Intentionally left blank]

2.1.1.2 [Intentionally left blank]

2.1.1.3 [Intentionally left blank]

2.1.1.4 [Intentionally left blank]

2.2 Billing and Payment for Service

Billing Procedure

2.2.1 The *IESO* shall include a line item on each *invoice* issued in respect of an *energy market billing period* pursuant to Chapter 9 to each *transmission customer* that is required to pay for a *transmission service* with respect to which the *IESO* is required to collect charges in accordance with this Chapter, which shall cover the charges for *transmission services* during that *energy market billing period*. The charges for *transmission service* in such *invoice* shall be paid by the *transmission customer* on the *market participant payment date* associated with the *invoice* at the same time and in the same manner as required for the payment of *invoices* under Chapter 9.

Reimbursement of Transmitters

2.2.2 The *IESO* shall include a line item on each *invoice* issued in respect of an *energy market billing period* pursuant to Chapter 9 to each *transmitter* that is entitled to payment for a *transmission service* with respect to which the *IESO* is required to collect charges in accordance with this Chapter. Such line item shall, subject to section 2.2.2A, reflect and amount equal to that portion of the charges for *transmission services*, as invoiced to *transmission customers* pursuant to section 2.2.1, relating to that *transmitter's transmission system*. On each *IESO payment date* in respect of each applicable *energy market billing period*, the *IESO* shall remit any amount owing pursuant to such *invoice* to each applicable *transmitter* by *electronic funds transfer* in the manner provided in Chapter 9 and in accordance with the applicable rate order issued by the *OEB* to the *transmitter*.

2.2.2A Notwithstanding any other provision of these *market rules*, the *IESO* shall not be required to make payment to a *transmitter* in respect of charges for *transmission services* relating to that *transmitter's transmission system* that have been *invoiced* to a *transmission customer* that is not a *market participant* until such time as the *IESO* has received payment from such *transmission customer* for such charges.

4.17.2 The amount payable by the *IESO* to a successful *TR offeror* in respect of *transmission rights* sold in a given round of a *TR auction* shall be the aggregate of the *TR market clearing price* of each *transmission right* sold by that successful *TR seller* in that round.

4.18 TR Clearing Account

4.18.1 The *IESO* shall establish and maintain a *TR clearing account* and shall:

4.18.1.1 credit to the *TR clearing account*, in respect of each *settlement hour*, the net congestion rents calculated in accordance with section 3.6.2 of Chapter 9;

4.18.1.1A credit to the *TR clearing account* the amounts referred to in sections 4.20.1A and 4.20.1B;

4.18.1.2 subject to section 4.19.5, credit to the *TR clearing account* the net revenues received from the sale of *transmission rights* in a *TR auction* in accordance with section 4.19.4;

4.18.1.3 debit from the *TR clearing account* any amounts required to be paid to *TR holders* pursuant to section 4.4.1;

4.18.1.4 debit from the *TR clearing account* any amounts required to be paid to successful *TR offerors* pursuant to section 4.19.6;

4.18.1.5 debit from the *TR clearing account* any amounts authorized to be debited and used to offset *transmission services charges* in accordance with section 4.18.2; and

4.18.1.6 credit to the *TR clearing account* any *transmission rights settlement* credits adjusted under section 6.6.10A.2 of Chapter 3.

4.18.2 Subject to section 4.18.3, the *IESO Board* may, at such times as it determines appropriate, authorize the debit of funds from the *TR clearing account* in accordance with section 3.6.3 of Chapter 9 for the purpose of using those funds to offset *transmission services charges*.

4.18.3 The *IESO Board* shall establish a reserve threshold for the *TR clearing account*.

3. Regulatory Research by Region

CRA researched regulatory rationale for the ETS rates reviewed. CRA's steps included a systematic search and review of relevant documentation for the various ISOs/RTOs and the FERC in the United States, and appropriate commissions and market operators in Canada. Our research covered applicable regulatory orders and related documentation.

3.1. ISO-New England (ISO-NE)

In New England, the outbound point-to-point rates – or Through or Out Service (TOUT)[8] – setting process was adopted as part of the tariff reform in response to FERC's restructuring directive in Order No. 888. Specifically, the process used at the time by the New England Power Pool (NEPOOL) was considered compliant by the FERC and adopted during the inception of the ISO.[9]

Notably, there is no difference between firm and non-firm transmission service as to rates; however, the ISO could curtail any external transactions to maintain system reliability. Per the ISO-NE procedure, *"All curtailments are determined in a nondiscriminatory manner and an appropriate reason is indicated."*[10] ISO-NE and NYISO have entered into a reciprocal agreement, in the form of a memorandum of understanding (MOU), that has adopted an exception to the rule such that the TOUT rate is reduced to zero for any Through or Out Service transaction that goes through or out of the New England Control Area and has the New England/New York Control Area boundary as its Point of Delivery.[11] The ISO-NE tariff states rates on an annual $/kW-Yr basis, however service can be provided on hourly and monthly terms.[12]

3.2. New York ISO (NYISO)

In a similar way that ISO-NE applies, NYISO's method derives from the pre-ISO era rates used by the NY Power Pool (NYPP). These power pool rates were later adopted during the formation of the NYISO on December 1, 1999.[13] NYISO provides Point to Point service with the Firm Point to Point rate including specific Transmission Owner charges needed to recover the embedded cost of transmission. As per the NYISO OATT Schedule H, the wholesale transmission service charge (TSC) recovers each Transmission Owner's embedded costs, as well as the transmission component of their control area costs, and is determined separately for each load zone. The TSC is adjusted to account for revenues from grandfathered

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8 In accordance with Section II.25.3 of the ISO-NE OATT, a Transmission Customer pays to the ISO the RNS Rate for Through or Out Service reserved for it in accordance with Section II.24 of the ISO-NE OATT. The Transmission Customer shall also be obligated to pay any applicable ancillary service charges.

9 *New England Power Pool*, 83 FERC P. 61,045 at 61,237 (1998)

10 ISO New England Operating Procedure No. 9 Scheduling and Dispatch of External Transactions, [illegible]

11 ISO-NE Transmission, Markets & Services Tariff, Section II25.3. [illegible]

12 ISO-NE's rate per hour for Through or Out Service is the annual TOUT *Rate* divided by 8760. Similarly, the month rate is the annual divided by 12.

13 FERC Docket OA97-470 - FERC order establishing of New York Independent System Operator.

agreements, financial transmission rights, and congestion payments. The net of all these quantities for each Transmission Owner is divided by the total annual billing quantities (MWh) to give a $/MWh rate. The purpose of this rate design, developed by the Transmission Owners during the formation of the NYISO, was to allocate charges and revenues for exports and wheel-through transactions in a way that reflected the use of multiple Transmission Owners' facilities by a single transaction, as well as the divergence of revenue requirements for each Transmission Owner.

Per the NYISO formation Order: *"Export transactions and through transactions pay a charge based on the cost of the transmission provider that owns the intertie which serves as the point of delivery to the adjacent control area."*[14,15] Section 3.1.6 of the NYISO OATT provides details related to the curtailment of Firm Point to Point service *"In the event that a curtailment of the NYS Transmission System…Curtailments will be made on a non-discriminatory basis to the Transactions that effectively relieve the Constraint."*[16] Non-Firm Point to Point Transmission Service is not available in the markets administered by the NYISO.[17] Per the MOU described above, there are no Transmission Service Charges for transactions with Point of Delivery to the New England border.

3.3. Pennsylvania-New Jersey-Maryland Interconnection (PJM)

Under the guidance of FERC Order No. 888, PJM adopted a transmission service structure that includes firm and non-firm point-to-point transmission service to each zone in PJM and to the border of the PJM Region under Part II of the PJM Tariff ("Border Rate"). The ETS rate reflects the composite or average cost of service in the PJM Region under the principle that all of the facilities are available to provide such service.

The Border Rate does not apply to any point-to-point transmission service or network service to serve load in the Midcontinent Independent System Operator, Inc. (MISO). This reciprocal arrangement falls under the Joint Agreement between MISO and PJM and is incorporated in Schedules 7 and 8 that provide the Border Rate.[18]

The Border Rate level has not changed significantly since 2012. In 2019, PJM's proposed Tariff revisions were accepted by the FERC and included changes in the Border Rate calculation methodology going from the 12-month coincident peak sum to the sum of all zonal peak loads for the purposes of cost allocation and billing units for the rates; changes also included addition of a methodology for updating rates on an annual basis beginning after 2020 to more accurately reflect the cost of transmission and other services. This update also includes an annual update for zonal transmission system costs. The regulatory rationale

14 FERC Docket No. ER97-1523 Page 15

15 Note that "cost" refers to a total transmission cost burden assessed based on the zone in which the load is located (or, in the case of exports, the zone of exit), rather than a subset of costs for export and through or out service.

16 NYISO OATT, Section 3.1.6

17 NYISO OATT, Section 3.2 of

18 In Docket ER19-2105, the PJM TOs noted that under an agreement approved by the FERC, there is no charge under schedules 7 and 8 for points of delivery within the MISO region. The JOA is located here: https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf

This principle is not unique to the OEB. For example, the Régie de l'énergie in Quebec has a long-standing "no free service"[7] guiding principle for cost allocation and rate design. FERC Order No. 1000 states as its first cost allocation principle that "costs should be allocated in a way that is roughly commensurate with benefits".[8]

6.2 Cost Allocation Methodology for Assets Dedicated to Interconnect

Assets dedicated to interconnect serve both exports and imports. The May 2014 methodology recommended allocating all assets and costs for functions dedicated to interconnect to the Export class because importers do not pay for the use of the transmission system.

Since importers also use interconnection assets not all asset-related costs and OM&A related to interconnection should be directly allocated only to the Export class. Energy is imported to serve domestic load therefore a portion of interconnection assets, asset-related costs, and OM&A should be allocated to the Domestic class. Elenchus recommends that the intertie 12CP be used to allocate Dedicated to Interconnect assets and costs to the Export and Domestic classes. The intertie 12CP is derived in Table 8.

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[7] *"l'absence de service gratuity"* - For example, see Régie Decisions D-429 and D-97-47. Elenchus discussed this principle in its *Report on Énergir's Cost Allocation and Pricing of Gas Supply, Transportation and Load Balancing Services and Supply of Interruptible Service* (R-3867-2013A-0219)

[8] FERC Order No. 1000 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* addresses cost allocation with respect to new transmission facilities

Table 8

Intertie Coincident peak 2018 to 2020

	2018			2019			2020		
	Export	Import	Total	Export	Import	Total	Export	Import	Total
1CP	4,343	2,519	6,862	3,556	1,589	5,145	3,485	2,159	5,644
12CP	35,099	21,110	56,209	35,779	18,806	54,585	39,117	15,430	54,547

	2018 to 2020 Average		
	Export	Import	Total
1CP	3,795	2,089	5,884
12CP	36,665	18,449	55,114

The intertie 1 CP and 12 CP percentage allocators using 2018 to 2020 data are shown in the table below.

Table 9

Intertie Coincident peak %

	2020 Data			Average 2018 – 2020 Data		
Coincident Peak	Export	Import	Total	Export	Import	Total
1CP	61.75	38.25	100.00	64.49	35.51	100.00
12CP	71.71	28.29	100.00	66.53	33.47	100.00

Elenchus proposes to allocate assets and expenses that are categorized as Dedicated to Interconnect by the Intertie 12CP between Domestic and Export class.

6.3 Cost Allocation Methodology for Shared Network Assets

Since exporters are able to use the transmission system unless they are curtailed by the IESO, even at the times of the Ontario transmission system peak, Shared Network Asset-related costs can be allocated to export customers based on the cost causality principle. Elenchus' suggested allocator is based on data from peak periods, including peak periods in which export customers are curtailed. When they are curtailed, export peak volumes

elenchus
34 King Street East, Suite 600
Toronto, Ontario, M5C 2X8
elenchus.ca

Export Transmission Service Rate

Cost Allocation Methodology

Report Prepared by
Michael Roger
Elenchus Research Associates Inc.

On Behalf of HONI

May 7, 2014

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.

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.

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

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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.