PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DÉFENSE DE L'INTÉRÊT PUBLIC

September 6, 2022 **VIA E-MAIL**

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Toronto, ON

Dear Ms. Marconi:

Re: Generic UTR Issues Proceeding
Export Transmission Service Rate (EB-2021-0243)
Submission of the Vulnerable Energy Consumers Coalition (VECC)

Please find attached VECC's Submission in the above referenced proceeding, pursuant to Procedural Order No. 3. VECC is requesting that the Attachment to the Submission be held confidential by the OEB pursuant to section 5 of the OEB's Practice Direction on Confidential Filings.

The Attachment contains specific references to the Power Advisory Model which APPrO has requested be held confidential by the OEB and, as such, may contain information considered confidential by APPrO. Therefore, the Attachment is being filed confidentially pursuant to Rule 10 of the OEB's Rules of Practice and Procedure and, in keeping with the requirements of the Practice Direction, is being filed only with the Registrar, APPrO and parties who have signed the OEB's Declaration and Undertaking.

Yours truly,

W Harper

William Harper
Consultant for VECC/PIAC

Email copy:
All parties to EB-2021-0243

PUBLIC INTEREST ADVOCACY CENTRE
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Generic Hearing on Uniform Transmission Rates Related Issues and the Export Transmission Service Rate

(EB-2021-0243)

Submission of the

Vulnerable Energy Consumers Coalition

September 6, 2022

Vulnerable Energy Consumers Coalition
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1. INTRODUCTION

On August 5, 2021 Hydro One Networks Inc. ("Hydro One" or "HONI") filed an application with the Ontario Energy Board (OEB) under section 78 of the Ontario Energy Board Act, 1998, seeking approval for changes to the rates that it charges for electricity transmission and distribution, beginning January 1, 2023 and for each following year through to December 31, 2027. As part of the Application, Hydro One filed evidence[1] regarding the Export Transmission Service (ETS) rate, including: i) a cost allocation study prepared by Elenchus Research Associates, ii) a jurisdictional review prepared by Charles River Associates (CRA) and iii) commentary by the IESO regarding the market implications of the ETS rate.

On October 15, 2021 the Ontario Energy Board issued a Notice that it intended to hold a public hearing on its own motion under sections 19, 21 and 78 of the OEB Act to consider various issues related to Ontario's Uniform Transmission Rates (UTR). The Notice indicated that the first phase of the hearing would focus on reviewing and setting the Export Transmission Service rate. Other UTR-related issues will be considered in a subsequent phase or phases of the hearing. The OEB also adopted all of the evidence filed in EB-2021-0110 that is relevant to the issues to be determined for the generic hearing as part of the record for the ETS proceeding.

Subsequently the OEB issued Procedural Orders[2] setting out the process by which it would review the ETS rate and related issues. This process included: i) establishing an Issues List, ii) providing for information requests regarding the evidence filed by Hydro One and the IESO, iii) providing for evidence to be filed by OEB Staff and/or intervenors, iv) providing for information requests regarding evidence (if any) filed by OEB Staff or intervenors, v) providing for a Technical Conference where parties could seek further clarification on any of the information request responses, vi) providing for a Presentation Day where those parties that had filed evidence would present an overview of their evidence to the OEB Panel and respond to any questions of clarification by the OEB Panel, vii) providing for untranscribed discussions amongst

[1] EB-2021-0110, Exhibit H-Tab 9-Schedule 1
[2] Procedural Order No. 1 (November 30,2022) and Procedural Order No. 2 (April 1, 2022)

participating parties to synthesize the evidence, share perspectives and discuss options, viii) the filing of written submissions and ix) the filing of reply submissions.

Set out below are VECC's submissions regarding the ETS rate.

2. VECC's SUBMISSIONS

2.1 Purpose of the ETS Rate

Ontario currently has interties with five neighbouring jurisdictions: Manitoba, Quebec, Michigan, New York and Minnesota. The ETS rate is a rate charged to parties exporting from the province to one of these jurisdictions. It is collected by the IESO and remitted to Hydro One Networks (the owner of the interties). Hydro One Networks includes these revenues in the determination of its Transmission Revenue Requirement as a "revenue offset". As result, revenue from the ETS rate serves to reduce the transmission-related costs that need to be recovered from Ontario ratepayers. The ETS rate is currently $1.85/MWh and annual revenues are in the order of $35 M[3].

The ETS Rate was first approved by the OEB in May 2000 as result of an application filed by Ontario Hydro Networks Company Inc. (subsequently renamed Hydro One Networks Inc.) for an order or orders approving a cost allocation and rate design proposal for the transmission of electricity. With respect to the ETS rate, in its Decision the OEB stated[4]:

> "Export of power from Ontario generators (exports) or the pass-through of power from generators located outside Ontario to customers in other jurisdictions (wheel-through), collectively referred to as Export and Wheel-through Transactions (EWT), in addition to paying to the IMO the specific transaction costs, also utilize the assets and facilities of the Ontario transmission system. The issue is how to assess transmission costs to these transactions."

In the current proceeding both HONI and the IESO were asked for their views as to the purpose of the ETS rate. In its response HONI stated[5]:

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[3] 2017-2021 average per Exhibit I, Tab 1, Schedule1, Attachment 1, Table 7

[4] RP-1999-0044, Decision with Reason, Paragraph 359

[5] Exhibit I, Tab 1, Schedule 1 (Staff 1 a))

““In Hydro One’s view, the purpose of the ETS rate is to recover the cost of export customers’ use of the transmission system from which they benefit. This is consistent with section 3.8.2 of the OEB’s decision in RP-1999-0044 where the OEB states that exporters: “in addition to paying to the IMO the specific transaction costs, also utilize the assets and facilities of the Ontario transmission system. The issue is how to assess transmission costs to these transactions.”

HONI expanded on this during the Technical Conference as follows[6]:

““And from Hydro One's view, really the purpose to the ETS is to recover the cost of export transmission's use of the transmission system from which they benefit. The ETS rate essentially limits cross-subsidization between Ontario transmission customers and exporters. And when we say transmission system, in this context we're referring specifically to the towers, poles, wires, et cetera that Hydro One builds and maintains and which comprise Hydro One's revenue requirement.”

When asked as to the purpose of the ETS rate, the IESO stated[7]:

“The IESO’s understanding is that the ETS was established as a compromise between the competing objectives discussed in the Board’s decision in RP-1999-0044 – in particular, the recovery of a portion of the total transmission system costs from exporters while allowing for the development of larger, open power markets where trade can take place with the minimum of impediments.”

During the Technical Conference the IESO was asked to distinguish between the purpose of the rate and the considerations that should go into the determination of the rate. The IESO responded[8] that, with respect to the purpose of the rate, parties should look to the original RP-1999-0044 Decision.

In VECC’s view it is important to distinguish between the purpose/objective of the ETS rate and the principles/considerations that should go into the establishment of the ETS rate. VECC agrees with the statement in the OEB’s original RP-1999-0044 Decision

[6] Presentation Day, page 17
[7] IESO response to Staff 1 b)
[8] Technical Conference (TC), Day 1 Transcript, pages 131-132

and the views of HONI that the purpose of the rate is to assess exporters an appropriate share of the total transmission system costs.

2.2 Principles (or Considerations) in Setting the Appropriate ETS Rate

At the conclusion of the Presentation Day, the Presiding Member of the OEB Panel stated[9]:

> "It would be also helpful if you were to highlight in your submissions what principles you think we should be weighing when we're setting the ETS rate. And as we're weighing them, what weight should we be giving to those principles? Are those generally accepted regulatory principles, and some of which we heard about today? Are there principles related to what we heard about the FERC order that applies in the States? Should we be looking at just the lowest overall cost to the Ontario market? Should it be who is paid for the transmission assets and that are being used for the exports?"

In VECC's view the starting point for establishing the principles (or considerations) to be used in setting the ETS rate should be the OEB's statutory objectives. In this regard Section 1(1) of the *OEB Act* states:

> "1 (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
>
> > 1. To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service.
> >
> > 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
> >
> > 3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

[9] Presentation Day, pages 143-144

4. To facilitate innovation in the electricity sector."

Of these four objectives VECC considers the first two as the most relevant for the OEB in its determinations regarding the ETS Rate.

In VECC view, another primary consideration that the OEB should take into account is what is referred to as "generally accepted rate making principles". As noted by HONI[10] these principles are derived from a book authored by James C. Bonbright – "Principles of Public Utility Rates" – and are summarized as "full cost recovery, fairness and efficiency".

In VECC's view the general rate making principles of cost recovery, fairness and efficiency are aligned with the OEB's statutory objectives in that:

- The principle of cost recovery is consistent with the Board's objective of facilitating the maintenance of a financially viable electricity industry,
- The principle of fairness is consistent with the Board's objective of protecting consumers' interests with respect to prices, where protecting consumers interests with respect to price includes not only the matter of overall price levels but also the equitable or fair recovery of costs from different groups of consumers, and
- The principle of efficiency is consistent with the Board's objective of promoting economic efficiency and cost effectiveness in the generation, transmission, distribution and sale of electricity.

Principles (Considerations) Raised During the Proceeding

In VECC's view, the evidence to date indicates broad support for the need to consider the principles of fairness and efficiency, where efficiency encompasses efficient operation of the system from an operational/reliability perspective as well as an economic/cost effectiveness perspective.

In response to information requests[11] Hydro One stated:

[10] Exhibit I, Tab 5, Schedule 1 (VECC 1.2)
[11] Exhibit I, Tab 5, Schedule 1 (VECC 1.2)

> "In Hydro One's view, the principles of full cost recovery, fairness and efficiency are among the principles that the OEB should consider in determining the ETS rate for Ontario, but they may not be the only principles that should be considered. In considering these principles, it is Hydro One's view that the OEB should also consider that the context of setting the ETS rate differs from the context of setting distribution or transmission rates directly for a utility."

When asked for further clarification regarding the reference to efficiency, Hydro One stated[12]:

> "I think when you think of efficiency, a few things come to mind. Certainly, the notion below, a more efficient use of the system. I think efficiency, you know, other things that come to mind as well are the, you know, simplicity of administration, understandability, those things as well I think come to mind as well when I think of that category."

When asked for further clarification as to how the "context" for setting ETS rates differs, Hydro One stated[13]:

> "I think what we talk about really is that last sentence, which talks about weighting the relative benefits of the, you know, those broader system benefits which have been discussed by the IESO, with kind of direct cost causality and cost recovery.
>
> And I think it is more that broader policy context of overall objectives. That's why we talk about the context being a little bit different here."

The IESO has indicated that its perspective with respect to the ETS rate is based on its role as system operator and its mandate to operate the system and market so as to balance electricity supply and demand at lowest cost[14]. Given this context, the IESO's initial submission concluded with the following statement[15]:

[12] TC, Day 1, page 10
[13] TC, Day 1, page 11
[14] Exhibit I, Tab 5, Schedule 2 (VECC 2.3) and Presentation Day, pages 83 & 95
[15] Exhibit H, Tab 9, Schedule1, Attachment 3, page 16 of 17

> "In summary, when setting the ETS, consideration should be given to maximizing the operational and economic benefits provided by exports by minimizing transaction costs. Any increase in the ETS rate will reduce the value of interties, leading to less system flexibility to reliability manage the grid and higher costs for Ontario consumers."

Similarly, during the Technical Conference, Mr. Chapman observed that:

> "What we wanted to highlight is that, in making those decisions, consideration should be given to the operational impacts of the actual ETS rate itself and to be mindful that, you know, ETS -- that the amount that the ETS has set out has implications for inter-tie trade and correspondingly impacts on our ability to operate the grid reliably and cost-effectively."[16]

During Presentation Day[17] the IESO expanded on the implications changes to the ETS rate could have on the reliable operation of the system as well as system costs. However, at the same time, Mr. Chapman acknowledged that there are a number of considerations that need to be taken into account to set an ETS rate[18] and that the IESO still agreed[19] with its EB-2012-0031 submission which stated:

> "The IESO appreciates that in establishing an ETS tariff for Ontario, the Board must have regard to general ratemaking principles and its statutory objects — protecting the interests of consumers, promoting economic efficiency and cost effectiveness, and facilitating a financially viable electricity industry — and that the Board's consideration of these factors invariably entails a balancing of interests."

Power Advisory's evidence focused on the impact changes to the ETS rate could have on overall system costs/benefits derived from exports[20]. However, in response to

[16] TC Day 1, page 133
[17] Presentation Day, pages 86-88
[18] TC, Day 1, page 133
[19] TC, Day 1, page 132
[20] Power Advisory Report, page 3

information requests[21] as to whether it had a recommendation as to the appropriate level for the ETS rates Power Advisory stated:

> "No, but we do want to highlight that a rate of $0/MWh would have increased system-wide benefits. That said, a regulator can determine a rate based on a number of principles – i.e. fairness and transparency, among others. While one rate may produce the highest benefit, it may not be preferred by a regulator for other reasons."

During the Technical Conference Mr. Yauch expanded[22] on the response as follows:

> "I think you also recognize that there are a number of other considerations of putting fairness and transparency that need to be balanced eventually by the regulator in making any decision on the ETS rate?
>
> MR. YAUCH: That's right. Rate-setting, as you know, is a very complex endeavour, and regulators can include a number of variables when they go to set rates, and so we say straight-up economic efficiency may not have to be the only consideration the OEB would consider, but -- so it opens it up to a variety of other rates and the options."

Similarly, Mr. Blair, an author of the cost allocation study filed by HONI, agreed[23] that the Commissioners on the Panel should consider system benefits, although separately from the results of the cost allocation study.

VECC agrees that the setting of ETS rates involves considerations regarding fairness and efficiency (both operational and in terms of overall system benefits/cost effectiveness). In addition, consideration should be given to what Bonbright[24] has termed "practical" attributes" required by ratepayers such as simplicity, understandability (e.g., transparency) and predictability.

The following two sections look more closely at the specific issues raised to date with respect to fairness and efficiency/cost effectiveness as they relate to the ETS rate.

[21] PA-VECC 5.2
[22] TC, Day 2, page 4
[23] TC, Day 2, pages 101-102
[24] James C. Bonbright, *Principles of Public Utility Rates*, 1961, page 291

2.2.1 Fairness Considerations

During the Technical Conference HONI stated[25]:

> "I think, you know, fairness can be assessed quite broadly. I think one item that comes to mind certainly would be in terms of fairness in terms of the recovering an appropriate level of costs from all parties who benefit."

HONI then went on to agree that a cost allocation study was "one of the inputs that would inform fairness"[26].

VECC agrees and, indeed, submits that cost allocation studies are the primary tool used by regulators and, more specifically, the OEB to determine if the rates charged to different customer classes are fair. To this end, the OEB has established[27] a cost allocation methodology for use by Ontario electricity distributors and policies[28] regarding how the results should be used in setting distribution rates. Similarly, HONI relies on an established cost allocation methodology when determining the transmission rates for Network, Line Connection and Transformation Connection services[29].

In its past Decisions the OEB has also expressed the view that the ETS rate should be supported by a cost allocation study. In its EB-2012-0031 Decision the OEB stated[30]:

> "The Board will require Hydro One to perform a cost allocation study to establish a cost basis for the ETS rate."

In response to the directive, Hydro One engaged Elenchus Research Associates to prepare a cost allocation study (the "2014 Study") which was filed by Hydro One in the EB-2014-0140 proceeding dealing with 2015 and 2016 transmission rates. This cost allocation study followed the traditional steps of functionalizing, classifying and allocating HONI's transmission revenue requirement between Domestic and Export customers. Costs were functionalized as between those Dedicated to Exports, those Dedicated to Domestic and those Shared by both. All of the costs were classified as

[25] TC, Day 1, page 9
[26] TC, Day 1, page 9
[27] RP-2005-0317, Board Directions on Cost Allocation Methodology For Electricity Distributors
[28] EB-2007-0667, Application of Cost Allocation for Electricity Distributors and EB-2010-0219, Review of Electricity Distribution Cost Allocation Policy
[29] EB-2021-0110, Exhibit H, Tab 1, Schedule 2
[30] Page 9

demand related. Cost functionalized as Export and Domestic were directly allocated to the respective customer classes. In the case of Shared costs, the allocation was as follows[31]:

- Rate Base was allocated between the two classes based on a 12CP allocator[32],
- OM&A was allocated between the two classes based on the allocation of the total Rate Base as between the two classes, and
- Asset-related costs (e.g., depreciation, return of debt, return on equity, income taxes, income & capital taxes, etc.) were all allocated to the Domestic customers.

The ETS rate for 2015 and 2016 was eventually established via a Settlement Agreement and continued unchanged in subsequent Board Decisions.

However, in a recent Decision (EB-2019-0082) the OEB "determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates"[33] and directed Hydro One to provide an ETS cost allocation methodology that includes the allocation of shared network costs to exporters in its next transmission rebasing application. In response to the OEB's directions from EB-2019-0082, Hydro One filed as part of its pre-filed evidence in EB-2021-0110, an ETS cost allocation study prepared by Elenchus which was subsequently included as part of the record for this proceeding.

In VECC's submission consideration of the cost allocation study provided by Elenchus (in terms of both the appropriateness of the methodology and the results) is a key input in determining the appropriate level of the ETS rate from a "fairness" principle perspective.

During the current proceeding the question has arisen as to whether the fact exporters pay congestion rents for access to interties when they are congested should be factored in when applying the principle of "fairness" to the determination of ETS rates. This is evidenced by the counsel for APPrO's questions of Elenchus during the Technical

[31] Exhibit H, Tab 9, Schedule1, Attachment 1, page 7
[32] Based on one year's hourly data
[33] Page 180

Conference regarding: i) the inclusion of congestion rents in the cost allocation study[34] and ii) whether, by paying congestion rents and ETS rates, exporters aren't paying twice for the use of the transmission system[35]. A related matter is Issue #1 from the approved Issues List: *Is it appropriate to continue to rely on an Export Transmission Service (ETS) rate and on Intertie Congestion Pricing (ICP) to charge for export service?*

These issues as well as issues related specifically to the Elenchus Cost Allocation Study are discussed in the following sections.

2.2.1.1 Elenchus Cost Allocation Study

The Cost Allocation Study (the "2021 Study") prepared by Elenchus for the current proceeding is in many ways similar to the 2014 Study in that:

- It uses the same overall approach wherein the transmission revenue requirement is functionalized, classified and then allocated to the Export and Domestic customer classes and
- Cost are functionalized as between Export, Domestic and Shared on the same basis.

Changes from the 2014 Study included[36]:

- Whereas costs (capital and OM&A) related to interties were directly allocated to Exports in the 2014 Study, the 2021 Study allocated the costs associated with interties as between Exports and Imports (i.e., Domestic) based on the 12CP allocator.
- Allocating to Exports a share of the asset-related costs associated with Shared Network facilities. For this the Elenchus study examined three options which are discussed in more detail below.
- Allocating the Shared Network OM&A costs based on the allocation of Shared Network Assets as oppose to total Network Assets.

[34] TC, Day 2, pages 103-106
[35] TC, Day 2, page 109
[36] Exhibit I, Tab 5, Schedule 26

- The allocation of External Revenues to both Export and Domestic commensurate with the allocation of Shared Network Assets between the two.
- The inclusion of the test year's refund/recovery of Transmission deferral and variance account balances[37] in the 2021 Study and their allocation to Exports and Domestic based on the allocation of the total revenue requirement as between the two classes.
- The basis for the billing determinant (i.e. MWh) was changed from a three year historical average to a single year (2020).

To-date the controversial aspects of Elenchus 2021 Study have been: i) the allocation of a portion of the Shared Network Asset-related cost to Exports, ii) the need (if any) and how to recognize the difference in service received by Export vs. Domestic customers in the allocation of Shared Network Asset-related costs and iii) whether the cost allocation study should also include revenues generated by intertie congestion pricing and the transmission rights auctions. The first two issues deal with alternative approaches for allocating HONI's Transmission Revenue Requirement and are discussed below. The third issue represents a different conceptual approach to Transmission cost allocation and is discussed in the following section.

Inclusion of Exports in the Allocation of Shared Network Asset-Related Costs

The exclusion of Exports from the allocation of Shared Network Asset–Related costs in the 2014 Study was based on input at the time from HONI that planning of the Network transmission system does not take into consideration the capacity needed to supply export customers and is only based on the capacity needs of domestic customers. It was also based on the view that exports are considered to be an interruptible service[38].

In contrast, the inclusion of Exports in the 2021 Study's allocation of Shared Network Asset-related costs followed from the OEB's direction in EB-2019-0082[39] that: "the OEB has determined that the use of shared network facilities by exporters needs to be

[37] Excluding those in the Excess Export Service Revenue Variance Account.
[38] TC, Day 2, page 115 and EB-2014-0140, Exhibit H1-Tab 5, Schedule1, Attachment 1, page 12
[39] Page 180

considered in setting the ETS rates". However, Mr. Blair confirmed[40] that Elenchus' thinking had evolved since the 2014 Study and that, even in the absence of the OEB's direction, they now considered it appropriate to allocate a portion of the Shared Network Asset-related cost to Exports. Mr. Blair explained the reasons for this as follows:

> "MR. BLAIR: No. We would agree that a portion of shared network asset related costs should be allocated to the export class and the two -- the export class is defined is curtailable rather than interruptible, and looking for some information of exactly what the difference is. It is the curtailed and not curtailed in most hours, and even when they're curtailed, it is about -- in peak hours when they're curtailed it is only about 10 percent.
>
> There are a couple of quotes in the report we got from the IESO to get a sense of the proportion of curtailments and they're largely not interrupted and do have fairly good access and increasing access to the shared system.
>
> MR. VELLONE: Okay. On the second reason why you originally decided not to allocate on the planning -- it is not planned for them, the fixed costs aren't planned for them.
>
> MR. BLAIR: It is not planned by them, but we also look at who is using the system, so the value derived from the system. And this is a concept that is used in other jurisdictions as well. Like in the Quebec report, no free service is a principle of cost allocation in Quebec and the FERC transmission cost allocation guidelines, the first one is that the benefit should be -- the costs should be roughly commensurate with benefits."

In VECC's view the debate turns on interpretation of fairness and cost causation in the context of a cost allocation study as raised in VECC's information requests and confirmed by Elenchus[41], which noted:

> "there are two approaches to allocating the asset-related costs. One where the allocation is based on considerations as to why and for whom the assets were

[40] TC, Day 2, pages 116-117
[41] Exhibit I, Tab 5, Schedule 23 (VECC 23.3 and 23.4)

designed and constructed and the second being based on considerations of how the assets are used and who benefits from their use."

The approach used in the 2014 Study uses a strict interpretation of "cost causation" based on why and for whom the assets were designed and constructed. A similar interpretation is employed by Power Advisory in their criticism of Elenchus' 2021 Study[42]. The approach used by Elenchus in the 2021 Study takes a broader interpretation of "cost causation" and included considerations as to who benefits from the use of the assets. In support of this broader view Elenchus' pre-filed evidence references[43]:

- FERC Oder 1000's first cost allocation principle that "costs should be allocated in a way that is roughly commensurate with benefits" and
- The Régie de l'énergie in Quebec's long-standing "no free service" guiding principle for cost allocation and rate design.

In response to the information requests Elenchus further notes[44]:

> "An allocation of costs considering only why and for whom assets were designed may adhere strictly to the principle of cost causality in the short run, but transmission assets are long- term assets that may be used by different customers over time. A transmission asset that has excess capacity may allow another transmission investment to be avoided.
> Absent any other consideration it is Elenchus' view that, based strictly on cost causality, the methodology that allocates Shared Network Assets and costs to exporters is the preferable approach, as it reflects how the transmission system is currently used by exporters."

Despite its Evidence, VECC notes that Power Advisory is not opposed to the "user pay" principle with the caveats that "the user pay principle must include a) distinct services between customers (interruptible versus firm, for example), b) all revenues collected from a particular customer class (congestion rents and TR revenues) and c) the system-

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[42] Power Advisory Evidence, page 16
[43] 2021 Study, page 25
[44] Exhibit I, Tab 5, Schedule 23 (VECC 23.4)

wide benefit that a particular customer class provides to the system (moving fixed cost, surplus supply to a different market for a higher price)"[45]. Furthermore, during the Technical Conference[46] Power Advisory noted that items (b) and (c) did not need to be incorporated into the cost allocation study but did need to be considered in conjunction with the results of the cost allocation model.

> "MR. HARPER: Okay. That's fine. Can we go to your response to Energy Probe 3C. I guess, and maybe this goes to the same topic, because here you were asked whether you were opposed to a user pay principle, which to some extent is a benefit paid principle, because users benefit from the system, and you say, no, but then you list a number of specific caveats that you think should be taken into account if you actually apply that principle.
>
> I guess what I see is the clear distinction, specifically when I come to points B and C in your response, between incorporating those elements specifically in the cost allocation model itself, as opposed to considering them in conjunction with the results of a cost allocation model.
>
> And I guess within the context of your caveat there, were you proposing that they should be specifically incorporated into the cost allocation model? Or at the end of the day they should be considered -- it is important to have them considered in conjunction with the results of the cost allocation model?
>
> MR. LUSNEY: Our view, it is considered. I mean, these are aspects that need to be weighed as part of any decision-making process.
>
> And there are core principles that you can go down to that might help you divide and come to conclusions. But at the end of the day, I mean this is a complex cost allocation requirement and build-out and you are trying to at least make sense of it from a principles point of view, but it is not hard rules."

In addition, VECC notes that in evidence[47] previously prepared for a proceeding before the Alberta Utilities Commission Mr. Lusney made specific reference to FERC's

[45] Power Advisory Responses to Energy Probe 3 c)
[46] TC, Day 2, pages 6-7
[47] Power Advisory Response to VECC 10.3, Attachment

adoption of the "user pay" principle[48] and the FERC's view that it avoids the potential for "free riders"[49].

Finally, VECC notes that the "user pay" principle is reflected in HONI's current transmission cost allocation methodology used in assigning costs to rate pools. In that methodology, the functionalization of assets is based on how they are currently used[50]:

> ""A key activity in determining the rates revenue requirement for each rate pool is the process of grouping similar physical assets owned by Hydro One into functional categories. The assignment of functional categories is based on the normal system operating condition of assets in-service as of the end of 2020, with due consideration given to the OEB Decision in Proceeding EB-2011-0043 in regards to the expanded definition of Network assets, the electrical system and customer connectivity, and the load forecast data for the 2023 test year"

Similarly, Mr. Blair has confirmed that the "user pay" principle is reflected the Board's approach to cost allocation for electricity distributors[51].

VECC also notes that concerns regarding "free riders" are not new to the Ontario Energy Board and were a consideration in the Board's initial RP-1999-0044 Decision regarding transmission rates as evidenced by the following references:

- "When comparing AMPCO's one-hour coincident peak option with the average 50- hour coincident peak option, while the advantages appear to be similar, the result of the one-hour coincident peak option is a higher potential for free ridership and gaming as customers may likely attempt to escape the coincident peak hour."[52]
- "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".[53]

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[48] Power Advisory Response to VECC 10.3, Attachment, page 13
[49] Power Advisory Response to VECC 10.3, Attachment, pages 15-16
[50] EB-2021-0110, Exhibit H, Tab 1, Schedule 2, page 2
[51] TC, Day 2, page 122
[52] RP-1999-0044, Paragraph 240
[53] RP-1999-0044, Paragraph 241

Overall, VECC agrees with Elenchus that that the cost allocation methodology should be based on the principle of allocating costs to those who benefit from the use of the assets.

Treatment of Export vs. Domestic Customers in the Allocation of Shared Network Asset-related Costs

As noted previously, the Elenchus 2021 Study[54] included three options for allocating Shared Network Asset-related Cost to Export and Domestic customers:

- Fully allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets using the 12CP allocator.
- Apply an adjusted Shared Net Fixed Assets allocator with the Export 12CP discounted by 50%, as a proxy for a hybrid model, half-way between no allocation and full allocation of Shared Network Asset-related costs to exports.
- Apply an adjusted Shared Net Fixed Assets allocator with the Export 12CP allocator discounted based on the service curtailment that affected exports in the last few years. Assuming that exports were curtailed 20% of the hours in the last few years, adjust export volumes to 80%.

In the information request responses[55] Elenchus indicated that it recommended the first option on the basis that:

> "This option reflects how exporters use the transmission system, which accounts for curtailments in peak hours, and allocates Shared Network Assets and costs to exporters. This option also is similar to how exporters are charged in jurisdictions surveyed by Elenchus, where the export charges are based on domestic revenue requirement."

Specifically with respect to the practice in other jurisdictions, the Elenchus pre-filed evidence stated:

> "The majority of jurisdictions surveyed by Elenchus, including all Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs)

[54] Page 30
[55] Exhibit I, Tab 1, Schedule 18 (Staff 18 b) & c))

in the United States and most ISOs and transmitters in Canada set Open Access Transmission Tariffs (OATTs) in accordance with FERC Orders No. 888, 889, 890, and 2000. All Canadian provinces operate within the OATT framework except Ontario and Alberta.

These jurisdictions have postage stamp "Network Service charges" that are analogous to Ontario's domestic transmission tariff. Exports are analogous to "Point-to-Point" transmission service, which are applied to the transmission of energy along specific paths, from a point of receipt to a point of delivery. Unlike Ontario's Domestic and Export rates, which are set based on an allocation basis, Point-to-Point charges are calculated3 based on the Network Service charge."

Charles River Associates (CRA) came to a similar conclusion[56] based on its jurisdictional survey:

"All the jurisdictions surveyed by CRA in the US set ETS rates in accordance with FERC Orders 888, 889, 890 and 2000. The methodology allocates each transmission owner's annual transmission revenue requirement by their peak load contribution on specific timeframe."

VECC also notes that the results of CRA's survey[57] indicate that US jurisdictions generally charge the same rates for both firm and non-firm export service even though firm implies a higher priority service and therefore when curtailments for reliability reasons are needed, transactions scheduled under non-firm service would be curtailed prior to firm service[58].

The only notable exceptions identified by Elenchus and CRA were the AESO (in Alberta) and the reciprocal agreements between: i) ISO-NE and NYISO and ii) MISO and PJM[59]. VECC notes that APPrO Counsel's request for a version of the Elenchus Cost Allocation Study where the export volumes are adjusted to 20% (Undertaking JT2.3) appears to be premised on the assumption that the AESO's methodology bases

[56] Exhibit I, Tab 1, Schedule 19 (Staff 19 g))
[57] CRA Pre-Filed Evidence, Table 1
[58] Exhibit I, Tab 1, Schedule 24 (Staff 24 a))
[59] CRA Pre-Filed Evidence, pages 8-9 and Attachment C

it export tariffs on 20% of network costs. However, the approach used by the AESO classifies transmission costs on the basis of both capacity and energy where 20% of the capacity costs and 100% of the energy costs are used to derive the XOS/XOM rates[60]. The net result is that these XOS/XOM rates reflect roughly 25% of the transmission costs underpinning domestic customers' transmission as opposed to 20%.

In VECC's view Export customers and Domestic customers are not "equal" in terms of the transmission service they are provided and Elenchus' Option 1 is not appropriate. While the Export loads used in Elenchus' cost allocation methodology reflect any curtailments that have been made, the fact that such curtailments can and will occur means the two services are not equivalent. Having said this, the adjustment to recognize this will be a matter of judgement as there is no established methodology either in Ontario or elsewhere for doing so. While the AESO applies a discount of roughly 75%, no explanation has been provided as to how this value was derived and/or why it is appropriate. In VECC's view, Option 2 is a preferable approach. It reflects the extent to which exports are subject to curtailment in Ontario. It also represents a balance between the 25% factor used by the AESO and the 100% factor (i.e., no adjustment) used by the majority of transmission companies.

Other Issues Regarding the Elenchus Methodology

VECC notes that Elenchus applies the 80% adjustment factor to 12CP value for purposes of allocating not only Shared Network Asset-related costs but also the Shared Generation Line Connection Asset-related costs and Shared Generation Transformation Connection Asset-related costs[61]. In the case of Generation Line Connection and Generation Transformation Connection assets the facilities are designed to meet the requirements of the generators and, as such, there should be no distinction made between Export and Domestic when allocating these costs. In VECC's submission the 100% of 12CP allocator should be used for Exports when allocating these costs regardless of the adjustment made to the 12CP allocation factor for purposes of allocating Shared Network Asset-related costs.

[60] See Tab B-11 in the document referenced in Footnote 42 of CRA's pre-filed Evidence.
[61] This can be seen in Exhibit I, Tab 24, Attachment 3, Tab E4-TB Allocation Details

VECC has estimated[62] that applying the 80% adjustment factor just to the Shared Network Asset-related costs and using 100% for the Generation Connection Asset-related costs (both Line and Transformation) would result in an adjusted ETS Rate of $5.48/MWh (as compared to $5.42/MWh based on Elenchus' Option 2).

2.2.1.2 ICP and ETS Cost Allocation/Rate Design

As noted above, issues have arisen during the proceeding as to: i) whether congestion rents should be included in the cost allocation study[63] and ii) whether, by paying congestion rents and ETS rates, exporters aren't paying twice for the use of the transmission system[64].

Purpose of the ICP

In VECC's view, to address these issues it is important to understand the purpose of the inter-tie congestion pricing which results in exporters paying congestion rents and the subsequent disbursement of the transmission rights clearing account balances.

In its initial submission the IESO stated[65]:

> ""[e]xporters contribute to the cost of the transmission system through two mechanisms. The first mechanism is through the ETS rate, a fixed volumetric charge, which is the focus of this rate application. The second mechanism is through the ICP mechanism, a dynamic charge set based on its market value to traders, administered through the IESO-administered market. <u>ICP revenues are collected entirely from intertie importers and exporters for the purpose of offsetting transmission service charges</u>." (emphasis added)

In VECC's view, the emphasized part of the preceding reference deals with the disbursement of the congestion rents received and not the purpose of the ICP mechanism itself.

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[62] Using the Cost Allocation Model in Exhibit I, Tab 5, Schedule 24, Attachment 4 and changing the allocators for Rate Base – Generation Line Connection and Rate Base-Generation Transformation Connection in Tab E4 to 12CP.
[63] TC, Day 2, pages 103-106
[64] TC, Day 2, page 109
[65] Attachment 3, page 5

Subsequently, in response to information requests the IESO responded[66]:

> "Both mechanisms are intended to offset intertie infrastructure costs to Ontario customers. However, they differ in their application. The purpose of the ICP mechanism is to competitively, fairly, and transparently allocate access to an intertie when there is more demand than capability, resulting in efficient use as part of the operation of the wholesale electricity market. By allocating transmission capacity to traders on a willingness to pay basis, it ensures that any surplus funds collected from traders are returned to Ontario consumers to reduce transmission service charges."

In VECC's submission, this response focuses more specifically on the purpose of the ICP mechanism.

This issue arose again during the Technical Conference and resulted in the IESO providing the following response[67]:

> "MR. HARPER: No, I'm sorry, and I am just trying to go back to the original question, because the discussion with Mr. Rubenstein talked more about how -- seemed to talk more about how the money was disbursed than what the purpose of the mechanism was in the first place, and that was my understanding of what the question actually was.
>
> MR. DUFFY: Okay. Fair enough.
>
> MR. CHAPMAN: I think, let me start again. So some of it is a bit lost in the mists of time, back to the days of the markets committee. But as a system operator and a market operator, our mandate is cost-effective reliability. And so we're constantly wanting to make sure that we are maximizing the utility or the value of the electricity infrastructure that we operate, including the inter-ties.
>
> And the ICP mechanism that ensures that at any moment in time we are maximizing the value of inter-tie transactions, because it ensures -- you know, as I have mentioned a few times, the market is changing on an hourly -- five-minute

[66] Staff 34 b)

[67] TC, Day 1, page 124

> basis. It is changing constantly, you know, according to demand and supply in Ontario and our neighbours.
>
> So by having the dynamic mechanism like ICP that is adjusting in tune with how the market is changing ensures that any moment in time we are maximizing the value of that asset. "

It also led to the IESO undertaking[68] to provide "its view with references to appropriate historical documentation as to the purpose of the ICP mechanism."[69] In that Undertaking the IESO described both the purpose of the ICP mechanism as well as changes over time in how the resulting congestion revenues were disbursed. In terms of the purpose, the following reference was provided regarding the origins of the ICP mechanism:

> "Sections 3.3, 4.5 and 4.6 of the Final Report of the Market Design Committee (MDC) dated January 29, 1999 outlined a framework and rationale that would become the basis of the ICP, the TR market and exporter's responsibility for uplift charges. The Final Report is filed as Attachment 1 to this undertaking. The Committee noted at page 4-11 that "this congestion pricing approach will encourage the efficient use of the interties and will provide useful price signals to market participants regarding the relative merits of alternative investments in generation on either side of the constrained interties or transmission upgrades to expand the intertie capabilities."

In considering the foregoing reference VECC again considers that it is important to distinguish between the purpose behind the ICP mechanism and the allocation of any resulting revenues. In terms of purpose, VECC submits the objective is not to assess a portion the transmission system costs to exporters but rather (as stated in the above references to the Market Design Committee's Final Report and confirmed by the IESO in this proceeding[70]) to: "competitively, fairly, and transparently allocate access to an

[68] JT1.11
[69] TC, Day 1, page 129
[70] Staff 34 b), TC Day 1, page124 and JT1.11

intertie when there is more demand than capability, resulting in efficient use as part of the operation of the wholesale electricity market."

Indeed, VECC submits that congestion rents should be viewed as a "cost of energy". Throughout this proceeding numerous references have been made to the uniqueness of the Ontario electricity market and, in particular, its approach to congestion pricing as illustrated by the following comments by CRA[71]:

> "MR. VELLONE: Okay. Thank you for that.
>
> I am going to come back to the comment that you didn't find congestion payments in your jurisdictional review that are similar to how they're set here in Ontario. That is really -- if I understood that part of your evidence properly, the way Ontario does its calculation and process for congestion rents is unique based on your -- the review of the jurisdictions that you looked at?
>
> MR. DesLAURIERS: My understanding is that it is unique. I have not seen in the course of the work that we conducted for the export rate analysis -- we have not seen a similar mechanism for congestion rent recovery. That is a mechanism that I understand is in place in Ontario which is an option-based approach."

However, the Ontario market is also unique in other regards and one is the overall construct of its energy market as noted, again, by CRA[72]:

> "The question that was posed in that response was, which one of those is directly comparable to Ontario, and the reason we responded in that way was to respond to that particular question, that Ontario is unique, that it has an auction-based energy market, but another mechanism to make generators whole."

The "other mechanism" that Mr. DesLauriers is referring to is the Global Adjustment. The uniqueness of the Ontario market is this regard was also noted by Power Advisory in its report[73]:

> "The hybrid design is a unique feature of Ontario's electricity grid and

[71] TC, Day 1, page 54. See also Exhibit I, Tab 5, Schedule 35, VECC 35.3 and Exhibit I, Tab 8, Schedule 2, SEC 2 a)
[72] TC, Day 1, page 82
[73] Page 22

differentiates it materially from neighbouring jurisdictions with competitive wholesale markets. It is commonly referred to as a "hybrid" market, as it combines a competitive wholesale market with out-of-market payments made as a result of contracting and rate-regulation. The hybrid design results in Ontario's electricity grid largely being one of fixed costs."

Power Advisory also observes[74] that:

> "The combination of wholesale market revenues and out-of-market payments through the Global Adjustment (GA) is a key feature of the hybrid market design. As noted, the hybrid design largely "locks in" the overall cost of supply in Ontario and reduces – or eliminates altogether – the price signal in determining investment or retirement of generating capacity in Ontario."

This market structure leads to Ontario market prices (i.e., HOEP) being lower than what would exist in a "true market" where bids by generators would have to be structured (over time) to cover their full costs. In VECC's view, this is one of the reasons why market prices are lower in Ontario than in neighbouring jurisdictions. However, exporters do not contribute to the Global adjustment which is paid fully paid for by domestic load customers[75]. As a result, exporters can arbitrage and benefit from the differences between Ontario's market prices and those of neighbouring jurisdictions arising from Ontario's hybrid market structure. In VECC's view this is one of the reasons why congestion exists on Ontario interties as frequently and to extent it does such that the ICP mechanism needs to be employed resulting in congestion rents. In this context congestion rents are really an "energy cost". This view is supported by the Brattle Group Report[76] ("Analysis of the TRCA Surplus Allocation Methodology") undertaken for the IESO in 2019:

> "these are not costs that are associated with the physical transmission system, but instead are costs of the energy that is sent through the system."

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[74] Page 22
[75] www.ieo.ca/en/Power-Data/Price-Overview/Global-Adjustment
[76] JT1.06, Attachment 1, page 19

While other jurisdictions do not use an ICP approach to manage congestion, the CRA study found that most neighbouring jurisdictions have a Locational Marginal Pricing ("LMP") system, and the value of congestion is reflected in the LMP.[77]:

> "I think we all agree that congestion -- the costs of congestion are reflected in the transaction in the U.S. jurisdictions. They are just reflected in a different part of the transaction, which is the LMP, which is the locational marginal price, as opposed to an ICP in Ontario, which is an option-based bid for that capacity at that particular inter-tie at that point in time.
>
> So congestion costs do play a role. In the U.S., for instance, they provide a signal for where additional economic benefit could be achieved by relieving congestion points on the system".[78]

However, none of the other jurisdictions which have LMP consider it to be an offset to transmission costs or intertie costs. Almost all of those neighbouring jurisdictions still charge exporters a separate (cost-based) rate for use of the transmission system that is in addition to any congestion costs that are captured through LMP. The cost for congestion is part of the price they pay for the commodity of electricity through the clearing energy market price.

Are Exporters Paying Twice?

Based on the foregoing submissions regarding the purpose of the ICP mechanism, VECC submits that ICP payments are not payments for the use of the transmission system. As a result, by making ICP payments, exporters are not paying twice for the use of the transmission system.

Furthermore, with respect to Issue #1 on the Approved Issues List[79] ("Is it appropriate to continue to rely on an Export Transmission Service (ETS) rate and on Intertie Congestion Pricing (ICP) to charge for export service?), in VECC's submission the

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[77] Interrogatory Response SEC-2
[78] TC, Day 2, pages 69-70
[79] Decision on Issues List, January 28, 2022

answer is yes. The ETS rate and the ICP serve fundamentally different purposes as discussed in the preceding sections.

Finally, both the IESO and Power Advisory[80] have emphasized the need for "transparency" in the operation of the Ontario market. Indeed, when asked about "combining" charges, the IESO responded[81]:

> "The IESO does not believe it is feasible or necessarily desirable to consolidate the three charges (ETS, ICP and Uplift) into one charge because they are established under different regimes, are set at different timeframes and serve different objectives. …
>
> The IESO also notes that consolidating charges would result in less transparency on costs compared to today, leaving exporters with less information on how to manage those costs."

Inclusion of Congestion Rents in the ETS Cost Allocation/Rate Design

During the proceeding Elenchus explained that while congestion rents and other system benefits are considerations that the OEB should take into account in setting the ETS rate they should not be included in the cost allocation as they are not part of Hydro One Networks' Transmission Revenue Requirement[82]:

> "Yes, they should consider those other factors, those other policy decisions for setting the ETS rate. But in terms of the cost-allocation methodology, I don't think it is appropriate to include these other factors that aren't exactly related to the Hydro One transmission revenue requirement or other transmitter revenue requirements within the cost-allocation model.
>
> So the consideration of those is sort of outside of the realm of cost allocation."

When asked how the congestion rents would be treated if congestion revenues were paid directly to Hydro One Network's transmission system, the response was[83]:

[80] Power Advisory Report, pages 30 & 35 and PA-VECC 5.2
[81] Exhibit I, Tab 3, Schedule 10, Pollution Probe 10 c)
[82] TC, Day 2, page 102
[83] TC, Day 2, page 103

> "If they were another revenue for Hydro One transmission, then for the purpose of setting allocated costs that consider other allocated revenues as well, to have a total full cost allocation model, it would be included as another line item.
>
> We would probably consider it separately from other external revenues and consider it on its own basis as a line item."

This led to the filing of Undertakings JT2.4 and JT2.5 where Elenchus was asked to model the impacts on the cost allocation study if i) congestion rent or ii) the transmission rights clearing account balance was directly remitted to HONI.

In VECC's submission the incorporation of congestion rents or transmission rights clearing account balances into the cost allocation is not a straight-forward exercise. This is clearly demonstrated by the fact Elenchus' initial interpretation of the undertaking requested by APPrO's counsel need to be revised[84]. It is also illustrated by following exchange during the Technical Conference[85]:

> "And would you agree there is a number of other considerations or issues that would have to be taken into account if that was -- if that change in paradigm was to take place in terms much how the ICP revenues were treated.
> I think of a couple of things like, you know. The transmission rates are based on a forecast revenue requirement. Correct?
> MR. BLAIR: Correct.
> MR. HARPER: So one would have to come up with forecast values for ICP revenues, if I am not mistaken.
> MR. BLAIR: That's correct.
> MR. HARPER: And also I think the Board often weighs in on the -- when it is looking at external revenues, it often weighs in on what is the appropriate level of those values and sometimes the costing behind those values. That might be issues that might come before the Board as well if these revenues were included in the transmission revenue requirement. Would that be a fair comment?
> MR. BLAIR: That would be fair, yes.

[84] See the amended versions to JT2.4 and JT2.5 filed on August 11, 2021
[85] TC, Day 2, pages 131-132

MR. HARPER: Also actually you got into a debate with this with Mr. Rubenstein that I think one method has been suggested to you as to how to treat these within a cost allocation model. But would you agree that if a formal proposal was to come forward from yourselves and/or Hydro One as to a question of how those costs should be functionalised, classified, and allocated would be ripe issues for discussion and perhaps disagreement in a future proceeding?

MR. BLAIR: Yes, absolutely.

More importantly though, it is VECC's submission that it would be fundamentally wrong to include congestion rent in the cost allocation study for a number of reasons. First, as discussed above, the purpose of the ICP mechanism is not to assess a portion of the transmission system costs to exporters but rather to "competitively, fairly, and transparently allocate access to an intertie when there is more demand than capability, resulting in efficient use as part of the operation of the wholesale electricity market."[86] As a result, it is inappropriate to view congestion revenues as a transmission revenue requirement offset. Rather the ICP, like the Global Adjustment, is a fundamental part of Ontario's hybrid electricity market.

Second, not only are congestion rents currently not remitted to Hydro One Networks, but the IESO has just recently gone through an extensive review[87] of how surpluses in the transmission rights clearing account should be dispersed resulting in the current methodology. Furthermore, in evaluating the various options available the Brattle Group considered the responsibilities exporters and domestic load each have with respect to paying for transmission system costs.[88]

Third, and finally, VECC notes that there is no precedent for doing so. While other jurisdictions do not base their ETS rates on a cost allocation, their ETS rates are cost-

[86] Exhibit I, Tab 5, Schedule 34, VECC 34 b)
[87] See JT1.11, page 3
[88] See JT1.06, Attachment 1, pages 19-21

based[89] and the derivation of their export rates does not include any consideration of revenues from market based mechanisms such as Ontario's ICP[90].

2.2.2 Efficiency/System Benefit Considerations

2.2.2.1 IESO

In its submission and presentation to the OEB Panel, the IESO addresses the market implications of the ETS rate from both an economic and operational perspective[91].

Economic Benefits

From an economic perspective, the IESO notes that exports generate more than just ETS revenue. They also generate uplift revenues and congestion rents as well as allowing the Ontario electricity system to avoid system costs that would otherwise be incurred as a result of having to curtail wind resources, spill water at hydroelectric stations and/or maneuver of nuclear units during periods of low domestic demand[92]. This last benefit, in terms of avoided system costs, arises primarily due to: i) the fact that Ontario has a high share of baseload and other facilities in its supply mix that have low variable costs and ii) the construct of the Ontario's hybrid market where (as noted previously) contracted supply resources receive top up payments beyond market revenue to recover fixed costs and certain variable costs[93]. The result is that generators are compensated for their foregone energy when their generation is curtailed with Ontario consumers paying for such compensation through the Global Adjustment[94]. Overall, the IESO estimates that exports of energy from Ontario have contributed between $330-520 million of value annually to Ontario between 2017 and 2020, with ETS revenues making up $35-$38 million annually[95].

As a result the IESO submission states that "it is important to consider the implications of increasing the ETS rate for exports on the other economic benefits that exports

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89 TC, Day 2, pages 135-137
90 Exhibit I, Tab 1, Schedule 3, Staff 3 a) – c) & e); & Schedule 29, Staff 29 a) and Exhibit I, Tab 5, Schedule 5, VECC 5.1 (iv)
91 IESO Submission, page 6 and Presentation Day, page 83
92 IESO Submission, pages 9-10
93 PA-Staff 6 b)
94 IESO Submission, page 13
95 IESO Submission, page 8

provide for Ontario consumers"[96]. In this regard, the IESO states that "any increase in ETS from its current rate will likely reduce the value to ratepayers of exports using the interties, which in turn will result in higher system costs that would need to be recovered from domestic consumers"[97]. However, subsequent discussion in the Submission indicates that the impact of a higher ETS rate would depend on the market conditions at the time[98]:

- When there is a wide difference, or 'spread', between the price to buy electricity in Ontario and sell electricity in neighbouring jurisdictions[99], an increase to the ETS will result in an offsetting decrease in ICP but no impact to export flows. The IESO has indicated[100] that the trade-off in the level of the ETS versus the ICP will be almost 1:1. This would suggest that under such circumstances there would be virtually no change in overall system benefits.
- When there is less price difference to buy electricity in Ontario and sell electricity in neighbouring jurisdictions, the tighter price spread means there will be less demand to export, and therefore the ICP will be less to start with. As a result, there will be less or no ICP to offset an increase to the ETS such that with an increase in the ETS some exports will become uneconomic. This will reduce export volumes which will reduce the system revenue from uplift fees and further reduce the revenue from ICP, (over and above the one to one revenue trade-off between the ETS and ICP). It also means that, in circumstances where there is surplus baseload generation which needs to be managed, there will be increased system costs. Finally, the impact on ETS revenues themselves will depend on the reduction in export volumes relative to the increase in the ETS rate.

[96] IESO Submission, page 9
[97] IESO Submission, page 12
[98] IESO Submission, pages 12-13
[99] As confirmed during the Technical Conference (TC, Day 1, page 140) it is during periods when there is wide spread in prices between jurisdiction that one would expect interties to be congested and the ICP mechanism to apply.
[100] TC, Day 1, page 140 and Presentation Day, page 92

Of the two situations, the IESO Submission notes that it is under the tight price spread situation that an increase in the ETS rate is likely to have a negative economic impact[101].

VECC accepts that exports generate additional economic benefits for domestic consumers over and above the revenues generated by the ETS rate. VECC also acknowledges that the potential impacts on these benefits of a change (up or down) in the ETS rate should be taken into consideration when the Board makes its determination regarding future ETS rates. However, the critical question then becomes what is the impact on these other revenues and system costs of a change in the ETS rate.

In its Submission the IESO states[102]:

> "At this time, the IESO has not undertaken a quantitative analysis to estimate the impact of a higher ETS rate on exports; however, even a relatively small increase in the ETS rate beyond the historical range of $1-2/MWh could have a material impact on heavily traded interties where price margins are already small. The 2012 CRA analysis demonstrates that in one case increasing the ETS rate from $0 to $5.80/MWh would cause a 50% reduction in export volumes (expressed as a percentage of status quo volumes).

VECC has a number of concerns regarding this statement. The first has to with the suggestion that a "small increase" in the ETS rate could have a material impact on Ontario's heavily traded interties. Data provided in response to the information requests[103] indicate that Michigan and New York are the most heavily traded interties. In the case of New York, average annual export volumes over the period 2017-2021 were 7.02 TWh while average annual export volumes when the ICP was greater than $1.81/MWh were 2.32 TWh[104]. This would suggest that a close to doubling of the current ETS rate could impact a material portion of trade volumes on this intertie. But

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[101] IESO Submission, pages 12-13

[102] Page 13

[103] Exhibit I, Tab 1, Schedule 1, Attachment 1, Table 1

[104] These values are calculated based on Tables 1 from Exhibit I, Tab 1, Schedule1, Attachment 1 and Table 14 from JT1.7

there is no evidence what the impact of a smaller increase would be. In the case of Michigan, the average annual exports over the period 2017-2021 were 8.78 TWh while the average annual export volumes when the ICP was greater than $1.81/MWh were 6.34 TWh (over 70% of the total)[105]. As a result, in this case a close to doubling of the ETS would only impact less than 30% of the export volumes and presumably a smaller increase would have a lesser effect.

VECC's second concern is with respect to the IESO reference to the 2012 CRA analysis. In that analysis the CRA analyzed the impact of increases in the ETS on three different years: 2013, 2015 and 2017. The impact of increasing the ETS rate from $0 to $5.80/MWh on export volumes varied widely across the three years. Based on the IESO's information request responses[106] the 50% was calculated using the result of the 2013 analysis and expressing the impact of on export volumes of increasing the ETS rate from $0/MWh to $5.80/MWh as a percentage of Status Quo volumes. In VECC's view the use of the Status Quo volumes in the denominator is incorrect and the percentage calculation should have been based either on:

i) The impact on export volumes of increasing the rate from $0/MWh to $5.80/MWh as compared to the export volumes assuming a $0/MWh ETS rate which would have yielded a result of 43% or

ii) The impact on export volumes of changing the rate from the status quo to $5.80/MWh as compared to export volumes assuming the status quo ETS rate which would have yielded an impact of 26%[107].

However, of more concern to VECC is the fact that the impact on export volumes varied widely across the three years analyzed. Indeed, while the reduction in export volumes as between the Unilateral Elimination case ($0/MWh) and the Equivalent Average Network Charge case ($5.80/MWh) was 43% for 2013, the reduction in 2017 was only

105 These values are calculated from the same source
106 Exhibit I, Tab 5, Schedule 8, VECC 8.1
107 Based on the 2012 CRA study results for 2013 as referenced in Exhibit I, Tab 5, Schedule 8

16% and for 2015 was less than 0.5%[108]. In its information requests VECC sought an explanation for the variation in the results and the IESO responded as follows[109]:

> "The IESO has not attempted to quantify the impact of specific ETS rates on exports beyond what has been studied in the 2012 CRA Report. Due to its fixed nature, a higher ETS will result in more occasions when market conditions are such that the ETS will make exports uneconomic and prevent an otherwise economic export from transacting. While market and system conditions impact the frequency of such occasions, the inverse nature of the relationship between a fixed ETS and the level of exports will remain true regardless of the assumptions made about market and system conditions in the 2023-2027 period."

This issue was further explored during the Technical Conference where the IESO was asked which of the "years" analyzed in the 2012 CRA Study most closely reflected the supply conditions expected over the next 10 years. In its undertaking response[110] the IESO stated:

> "As discussed in the IESO's Annual Planning Outlook (APO) the future supply mix is uncertain, with recognition that there is a potential for considerable change in the 2020s and into the 2030s. However, based on recent history and the nature of Ontario's supply mix, CRA's 2013 and 2015 model years are more representative of near-term supply conditions."

VECC notes that the years 2013 and 2015 were the years where the 2012 CRA analysis produced the highest and lowest impacts on export volumes due to a change in the ETS rate. As result the response does not provide any further insight into what the impact of a change in the ETS rate could have on export volumes and, hence, overall system costs going forward.

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[108] Again, calculated using the 2012 CRA Study results referenced in Exhibit I, Tab 5, Schedule 8 based on the impact of on export volumes of increasing the ETS rate from $0/MWh to $5.80/MWh as a percentage of the volumes assuming a $0/MWh ETS rate.

[109] Exhibit I, Tab 5, Schedule 8, VECC 8.2

[110] Exhibit JT 1.9

In information requests[111] the IESO was asked about the outlook for future exports. In responses the IESO explained that it does not forecast future market conditions and intertie congestion. However, in its responses the IESO referred to the surplus baseload generation forecast in its 2021 Annual Planning Outlook (2021 APO). The forecast is provided in Exhibit I, Tab 1, Schedule 1 – Attachment 1, Table 24. The average over the 2023-2027 period is slightly less than 2 TWh annually as compared to roughly 2.4 TWh[112] over the last four years (2018-2021). However, the two numbers are not comparable as the historic values represent surpluses after exports and would be higher if there had been no exports[113]. In contrast the forecast surplus is before exports[114] suggesting the surplus baseload generation will be lower in the next five years. Further complicating the comparison is the fact that the 2021 APO does not account for new capacity acquisitions[115]. The forecast amount of surplus generation could increase, depending upon the types of resources acquired. In this regard, VECC notes that the IESO's most recent acquisition activity[116] less than 10% of the capacity acquired would be considered "baseload generation".

Overall, the evidence from the IESO demonstrates that the impact of changing the ETS rate on the overall system benefits generated by exports will vary depending upon system and market conditions and can vary widely. VECC has acknowledged that the impact of the ETS rate on overall system benefits and cost to domestic load is a relevant consideration in determining the level of the ETS rate. However, in VECC's submission the evidence from the IESO provides little insight into what impact changes to the ETS rate could have going forward other than suggesting that they could be large under certain market/system conditions if the ETS rate were to change materially. However, at the same time it is appears that surplus generation will be less in the coming year five years than in the past[117]. Furthermore, even with an ETS rate of zero,

[111] Exhibit I, Tab 2, Schedule 3 (Energy Probe 3 d)) and Exhibit I, Tab 5, Schedule 9 (VECC 9.1 & 9.2)
[112] Exhibit I, Tab 1, Schedule 1, Attachment 1, Table 23.
[113] Exhibit JT1.8. See also footnotes to Table 23
[114] Exhibit I, Tab 5, Schedule 21 (VECC 21.1)
[115] TC, Day 1, page 143
[116] Exhibit JT 1.12, see link to Mid-Term RFP
[117] Exhibit I, Tab 8, Schedule 3 (Energy Probe 3 c) iii))

system/market conditions could emerge that would lead to operational/reliability issues with respect to the management of baseload generation[118].

Operational Benefits

Apart from the economic benefits, the IESO also views exports as providing operational benefits. In its Submission the IESO states that intertie trading provides benefits in terms of system flexibility, ancillary services, regional reliability, emergency events and geographical distribution. The nature of these benefits was further described in Exhibit I, Tab 5, Schedule 12 (VECC 12.1).

Based on the response to VECC 12.1, VECC's view is that some of the benefits attributed to the intertie trading in the submission are linked more to the existence of the interties than the level of export volumes. However, based on the following comments[119] provided by Mr. Chapman, VECC does acknowledge that there are operational/reliability benefits from being able to use exports to manage surplus baseload generation:

> "If we didn't have exports, as I mentioned, we have a high share of baseload resources in the province. A lot of those resources need time in order to manoeuvre and to reduce their output. They can't switch on and off or even ramp up and down as flexibly as some other resources, and that makes it difficult to manage.
>
> So if we didn't have the exports and the exports respond very dynamically to changes in market conditions, the IESO would have to take what we would call control actions as part of our operational planning time frame to, for example, increase spill at hydro-electric units. And if we ask the large hydro generators to increase their spill, again it is not something they can turn on and turn off.
>
> The spill may take a few days to organize, it may take a few days to come back to normal operations, and it is particularly acute with the nuclear units. If we ask them to curtail, it is not a straightforward exercise and in a worst case, if we ask

[118] For example, the IESO has acknowledged (Presentation Day, pages 100-101) that the difficulties experienced in 2017-2018 weren't directly related to the level of the ETS rate.

[119] Presentation Day, pages 86-87

them to shut down as we have done in 2017, 2018, it can take three days for a nuclear unit to return to service.

In the meantime, as the grid operator, that means we have to change our operational plans, and it means we don't have the same supply stack to meet our day-to-day operational needs as we would if we hadn't had to curtail these resources.

What does that mean? First of all, it means an awful lot of work to rearrange our operational plans which is an additional stress on the control room. And it means if we run into unexpected events in the real time, our supply stack is skinnier than it would have been, which means there is less resources to call upon before we have to take out of market control actions such as, you know, reducing voltage, curtailing exports, other undesirable out of market conditions that are both costly and operationally problematic."

During his presentation[120], Mr. Chapman made specific reference to the fact that over the 2017-2018 period "there were times when we were in those years doing up to 1,000 nuclear curtailments and there were two to three complete nuclear shutdowns". However, when asked as to whether any of the curtailments were due to uneconomic exports versus other operational reasons, Mr. Chapman responded[121]:

"MR. CHAPMAN: A good question. I think it is hard -- it would be hard to isolate -- it would be hard to isolate, you know, a nuclear shutdown or curtailment specifically to the ETS.

I guess it's a combination of factors and maybe I did a poor job explaining.

As these transaction costs increase, we increase the risk, the chances we will have to take one of these control actions. It is hard to pinpoint exactly what triggered it, but a combination of the ETS, market conditions, the supply-demand imbalance, combined with other issues on the grid could lead to -- it would be

[120] Presentation Day, pages 87-88
[121] Presentation Day, page 100

one contributor to leading to one of those control measures.

The more -- the higher the ETS, I guess, the higher weighting it would play in that. But it would be hard to isolate it specifically."

Mr. Chapman then went on to explain that given the uncertainty regarding the materiality of an ETS rate of $1.85/MWh versus zero was one of the reasons why the IESO has not strongly advocate for an ETS going to zero because of operations[122]. He also stated:

"We have been able to manage the grid in its historical range. What we have seen is across the interties, margins during hours or particular in size can be very small. Our concern is more if the ETS was to increase, because it could then become the deciding factor between taking a nuclear unit off-line or not.

MR. SARDANA: Yes.

MR. CHAPMAN: To date, there's been issues, in particular years where we have had surplus, 2016-2019, it wasn't helping because it was an extra contributor. At the current levels, it is manageable. To be honest, from an operational perspective, the risk would be reduced if the went to zero. But it's not as if it isn't manageable at the current levels."

In further follow-up Mr. Chapman as to what level of increase in the ETS (over current levels) would lead to issues regarding market operations and the response was[123]:

"MR. CHAPMAN: Yeah. No, I understand the question. It increases -- an increase in the ETS would increase the probability that we would have to take some of these types of control actions.

You know, it is hard to pinpoint precisely the impact it would have on trade volumes, like, you know, down to the specific number, but it increases the probability that in the absence of exports we would have to take undesirable

[122] Presentation Day, page 101
[123] Presentation Day, page 109

control actions.

The only point I would say is that, again, it is not really a linear relationship. It is not like if you increased it by 20 percent there will be a 20 percent chance you might have to take a control action.

There are certain times when it comes like a step function, right? You hit a point where you now have to take a nuclear unit offline because of system conditions at the time, and it could be that that price point is $1.87.

...

Other times it might not be, you know, it might not be -- it might be a much higher number, but it really increases the probability that we will need to take one of these types of active, you know, actions.

MS. ANDERSON: So it is a question of probabilities, basically?

MR. CHAPMAN: Yes. I think, yes."

In VECC's view there are two conclusions to be drawn from the IESO Submission and subsequent comments. The first is that there is no demonstrated need to reduce the ETS rate due to operational or reliability considerations. This point was confirmed during the IESO's Presentation Day[124] appearance:

"And while the ETS has traditionally been or historically been relatively low, one to two dollars since market opening, from the IESO's perspective we haven't seen a material impact on our ability to operate the grid as a result of the ETS."

This conclusion is also supported by Power Advisory's evidence that "there does not appear to be any market failure" that the regulatory process needs to address[125].

The second is that are that while increases in the ETS rate could impact operational risks the impacts will (again) be based on system conditions such that there is no magic number at which the ETS rate creates an unacceptable level of risk. Rather the

[124] Page 84

[125] TC, Day 2, pages 2-3

conclusion to be drawn is that the higher the ETS rate the more likely it is that system conditions will arising that could affect the operations/reliability of Ontario's electricity system. However, the degree of the change in risk as the ETS rate changes is unknown.

2.2.2.2 Power Advisory

In its evidence Power Advisory presents analysis as to the impacts a higher or lower ETS rate during the 2018-2021 timeframe on the system costs for Ontario's domestic customers. The higher ETS rate was based on an increase to $6.54/MWh, reflective of the results of the Elenchus cost allocation study under Option 1 (Allocation on Basis of 100% of Shared Net Fixed Assets) while the lower rate ETS rate was assumed to be zero. The system benefits included the analysis reflected the impacts of changes in: i) ETS revenue, ii) congestion rents (i.e., revenues from ICP), iii) curtailment costs related to hydro and wind generation and iv) overall market revenue in the case of the higher ETS rate[126].

Overall, the Evidence concludes[127] that:

> "The financial impact to Ontario ratepayers from increasing the ETS rate to $6.54/MWh would have been a net increase in costs of $42.6 million over the 2018 – 2021 timeframe. The increase is a result of lower congestion rents, increased curtailment at wind and hydro generators and lower market revenues from selling Ontario power in neighbouring jurisdictions. The net benefit to Ontario ratepayers of lowering the ETS rate to $0/MWh in that time frame would have been a reduction in costs of $33.7 million. The benefit results due to a decrease in curtailment and increased congestion rents."

When asked as to whether Power Advisory had a recommendation regarding the appropriate level for the ETS rate Power Advisory responded[128]:

> "No, but we do want to highlight that a rate of $0/MWh would have increased system-wide benefits. That said, a regulator can determine a rate based on a

[126] Power Advisory Report, pages 6-10
[127] Power Advisory Report, page 10
[128] PA-VECC 5.2

number of principles – i.e. fairness and transparency, among others. While one rate may produce the highest benefit, it may not be preferred by a regulator for other reasons."

In its evidence[129] and during the Technical Conference[130] Power Advisory noted there were a number of limitations with respect to the available public data compared to what is required to provide a highly accurate estimate of price elasticity and system-wide benefits for exports. Specific areas of concern were:

- the lack of published offer and bid data, the availability of which would allow greater clarify on the impact of changes in the ETS rates and
- the lack of data regarding curtailment and surplus energy.

In its analysis Power Advisory used the fact average hourly exports and average ICP payments per hour both decreased as the value for HOEP increased[131] to estimate the impact of a change in ETS rates on export volumes and congestion rents. Then Power Advisory used the change in HOEP as a proxy for the change in ETS rates to estimate the impact of a change in the ETS rate on both export volumes and on the ICP[132]. In the case of the $4.69 increase in the ETS rate (i.e., $1.85 to $6.54) this was done by looking at the export volumes over a range of HOEP prices (-$0.10.MWh to $100/MWh) in intervals of $4.69 and then comparing the export volumes in a given interval with those in the next highest interval to estimate the impact of an increase in the ETS rate to $6.54/MWh. A similar approach was used to estimate the impact on congestion rents.[133]

VECC recognizes the data limitations faced by Power Advisory and the need to estimate the impact of a change in ETS rates on export volumes, congestion rents and curtailment costs using alternative approaches. However, VECC has a number of concerns regarding the methodology adopted and the resulting analysis undertaken by Power Advisory. Some of VECC's concerns can be explained with reference to

[129] Power Advisory Report, page 35
[130] TC, Day 2, pages 20-21
[131] Power Advisory Report, pages 35-38
[132] TC, Day2, page 13
[133] PA-VECC 19 – Attached Methodology and TC, Day 2, pages 14-17

evidence provided on the public record. However, some of VECC's concerns can only be explained and/or explained more fully by reference to the Power Advisory Model provided on a confidential basis in response to JT2.2. Set out below is an explanation of VECC's concerns based on the public record of this proceeding. In an attachment, filed on a confidential basis, VECC provides more details on some of the concerns outlined below as well as describing some additional concerns regarding Power Advisory's analysis.

VECC's Concerns – General Approach

Power Advisory's analysis is based on the assumption that the impact of an increase/decrease in ETS rates on export volumes and congestion rents can be estimated by looking at the export volumes and congestion rents when the value of HOEP was higher/lower by an amount equivalent to the assumed change in the ETS rate. The flaw in this approach is that it assumes that the value for HOEP is the only (or if not the only the major) determinant of export volumes and congestion rents in a given hour.

In response to an Energy Probe information request[134], the IESO stated that:

> "Electricity trading over the interties in Ontario is a competitive marketplace driven by profit-seeking traders transacting based on the expected electricity price differences between jurisdictions. Therefore, the future amount of exports can be influenced by fundamental drivers such as supply mix characteristics, weather, demand patterns as well as transaction costs such as the ETS and uplift charges."

In the Technical Conference the IESO confirmed[135] that the reference to supply mix characteristics included those in both Ontario and the neighbouring jurisdictions and that these circumstances change hourly as can the available capacity on the interties. The IESO also confirmed that these same comments would apply to historical variations in hourly export volumes and congestion revenues. Power Advisory has also

[134] Exhibit I, Tab 2, Schedule 3 (Energy Probe 3 F)
[135] TC, Day 1, pages 135-136

confirmed[136] that export volumes are influenced by more than just the value of HOEP. As a result, VECC has serious reservations about Power Advisory assumption that the change in export volumes that would occur in a given hour if the HOEP or ETS were changed by $4.69 in that particular hour, can be estimated by looking at export volumes in a different hour when the HOEP is $4.69 higher, but when system conditions are likely to be totally different. When this question was put to Power Advisory the response was[137]:

> "our objective and why we were retained was to provide help to the panel in making the decision, and provide an analysis on what an impact of a higher ETS or lower ETS.
> As we state throughout our evidence, you know, this is a very complex, convoluted, real time impacted, month ahead impacted.
> So what we've attempted to do, and we believe we have achieved in our analysis, is providing a clear and transparent and simplistic at times analysis to provide guidance to the panel, so that they can come to their own appropriate decision when looking at our evidence and other information that's been filed by all other participants in this proceeding.
> So we recognize there is a lot more complexity, but back to the part of the issue, without more firm data points to allow us to dig deeper, there is a risk that the analysis becomes less, much less helpful.
> So we wanted to be grounded in a foundation that is fruitful for the panel to consider."

Unfortunately, this response does not allay or even really address VECC's concerns. Instead, it confirms VECC's view that the analysis is overly simplistic in its approach. Furthermore, information subsequently provided in Undertaking JT2.1[138] that the R^2 value for the trend line Power Advisory established between HOEP and export volumes is 0.077 (indicating that HOEP explains less than 10% of the hourly variation in export volumes) simply re-affirms VECC concerns.

[136] TC, Day 2, pages 21-22
[137] TC, Day 2, pages 23-24
[138] A correction to JT2.1 was filed on August 22, 2022

VECC Concerns – Methodology

During the Technical Conference Mr. Yauch explained that for purposes determining the change in export volumes Power Advisory's analysis compared the total export volumes in each HOEP interval versus the total export volumes in the next adjacent interval with higher HOEP prices and used the difference as the basis for the change in export volumes as a result of a change in prices[139]. VECC's concern is that each of the HOEP intervals will likely capture a different number of hours (i.e., the number of hours when HOEP is between $-0.10 and $4.69/MWh will differ from the number of hours HOEP is between $4.69 and $9.38/MWh). However, Power Advisory's entire approach is based on the premise that the exports in any hour will vary based on the value of HOEP and that changes in HOEP can be used as a proxy for changes in the ETS rate as illustrated by the following statement in the Power Advisory Report:

> "Focusing on exports when prices are between $0/MWh and $50/MWh – which would incorporate the marginal cost of a majority of Ontario's supply mix – a $5/MWh increase in the Ontario price results in 160 MW reduction in <u>hourly</u> export volumes. More importantly, looking at exports when the Ontario price moves from $0/MWh to $5/MWh – likely when Ontario is experiencing severe SBG and curtailment – <u>hourly</u> exports decrease, on average, by nearly 280 MW. Total exports between 2018 and 2021 when HOEP was $0/MWh were more than 13 TWh, falling to 7 TWh when HOEP increased to $5/MWh." (emphasis added)

Not accounting for the differences in the number of hours in each interval will skew the results. To illustrate this point, assume the first interval covers 100 hours and total exports in the interval are 1,000 MWh or 10 MW per hour. Then assume the next highest interval covers only 50 hours with total exports of 250 MWh or 5 MW per hour. Simply comparing the total volume of exports would suggest that an increase in the HOEP equivalent to the difference in HOEP prices covered by the two intervals results in a decrease in export volume of 750 MWh. However, the change in the average hourly exports is only 5 MW and if this 5 MW change was assumed to occur in each of the hours in the initial interval the change in export volumes would be 500 MWh (i.e., 5

[139] TC, Day 2, pages 16.

MW x 100 hours). In VECC's view this is the way the calculation should be performed. The specific implications with respect to the Power Advisory analysis are discussed in the confidential attachment to these submissions.

VECC Concerns – Specific Model Calculations

VECC also has additional concerns with respect to specific calculations in the Model. Unfortunately these can only be described by referencing the Model itself and, therefore, are set out in the confidential attachment to these submissions.

Conclusions

Similar to VECC's conclusion's regarding the IESO evidence, it is VECC's view that the Power Advisory evidence provides little insight into what the impact of a change in the ETS rate on overall system benefits would be. The reasons for this are two-fold. First, as discussed above, in VECC's view both the general approach that the Power Advisory analysis is based on as well as the analysis itself is flawed such that the results do not represent what would have occurred over the 2018-2021 period if the ETS rate had been higher or lower. Second, as Power Advisory has acknowledged, the future is uncertain[140] and the future of Ontario's electricity market may be very different than the last ten years[141]. In VECC's view, an appropriate analysis of historical periods can assist in understanding how changes in ETS rates could affect overall system benefits. However, one of the clear conclusions from the evidence of Power Advisory[142] (and the IESO) is that the impacts on system benefits will vary with system conditions.

Having said this, VECC notes that the only area where higher ETS rates could potentially have a favourable impact is with regards to ETS revenues. On the other hand, higher ETS rates are likely to negatively impact congestion rents, uplift revenues and the cost of managing "baseload generation. While the extent of these impacts for a given change in the ETS rates is not well understood, for purposes of the current proceeding VECC considers a reasonable to adopt as a "working assumption" that higher ETS rates are most likely to have a negative impact on overall system benefits.

[140] PA-SEC 1 and PA-Staff 23 c)
[141] Power Advisory Report, page 47
[142] Power Advisory Report, page 47, PA-SEC 12, PA-VECC 2.2 and PA-VECC 13.4

2.3 Weighting of Relevant Principles (Considerations) and Resulting ETS Rate

As noted previously, at the conclusion of the Presentation Day the Presiding Member requested[143] that parties not only highlight in their submissions the principles/considerations that should be weighed in setting the ETS rate but also the weight should be given to them. The following discussion also addresses the following items on the approved Issues List:

> *Issue #2. If an ETS rate were to continue to exist alongside ICP, what approach should be used to set the ETS rate?*
>
> > *2.1. If a cost-based approach is used to set the ETS rate, what methodology should be used?*
> >
> > *2.2. Should a settlement-based approach be permitted?*
> >
> > *2.3. What other methods for setting the ETS rate should be considered?*
> >
> > *2.4. How often should the ETS rate be set?*
>
> *Issue #3. Are there other key issues the OEB should consider related to the ETS rate?*

2.3.1 Weighting of the Relevant Principles

In its strictest interpretation "weighting" implies a process whereby values for the ETS rate would be established based on each "principle", weights would be developed for each of the principles based on their relative importance and then the ETS rate would be derived as a matter of simple arithmetic. However, in the case of the ETS rate this approach is neither appropriate nor practical.

While a value for the ETS rate can be established using a cost allocation study as a measure of fairness, similar comparable "rates" cannot be established with respect to the efficiency and transparency principles. In the case of operational efficiency, the higher the ETS rate the more likely it is that system conditions will arise that could affect the operations/reliability of Ontario's electricity system. However, the degree of the change in risk as the ETS rate changes is unknown. In the case of economic efficiency

[143] Presentation Day, pages 143-144

(i.e., overall system benefits), reliable information does not exist as to the impact on overall system benefits of changes in the ETS rate. Furthermore, such impacts will be largely dependent on future system conditions which are difficult to forecast[144]. Finally, matters of transparency are not readily quantifiable but rather need to be assessed on a qualitative basis. As result, VECC submits that the determination of the appropriate ETS rate is more a matter of balancing (qualitatively) as opposed to weighting (qualitatively) considerations of fairness, efficiency and practical attributes.

In balancing these principles, VECC submits that, based on the points raise in Section 2.2 above, the Board should consider the following:

- With respect to Operational Efficiency:
  - While there is a potential risk to reliability in increasing the ETS rate the extent to which risk would increase with a given level of increase in the ETS rate is unknown. At the same time there is a degree of risk associated with any level of the ETS rate and risk is inherent in the operation of the electricity system. What is important is managing that risk such that the level of risk is acceptable.
  - The IESO has acknowledged that it has been able to reliably operate the system when the ETS rate is in the $1 - $2 range and is not strongly advocating the rate be reduced to zero.
  - Current indications are that surplus baseload generation levels over the next five years are likely to be lower than those experienced in the last five years.
  - Overall, this would suggest that, from an operational efficiency perspective, there is no need to reduce the ETS rate. It also indicates that ETS rates could be increased in the future without increasing operational risk over what the system has been historically exposed to. At the same time, any increases to the ETS rate should be done gradually such that the potential changes in reliability can be monitored and understood.
- With respect to Economic Efficiency (System Benefits):

[144] TC, Day 1, page 90

- Changes in the ETS rate will impact not only ETS rate revenues but also impact congestion rent revenues, uplift revenues and out-of-market costs related to the management of baseload generation.
- The impact on export volumes and, hence ETS and uplift revenues, depends on market/system conditions, primarily the market price spreads between Ontario and neighbouring jurisdictions and any resulting congestion on the interties. Market/system conditions will also determine the extent to which changes in the ETS rates (and resulting export volume changes) will impact congestion revenues and the out-of-market costs related to the management of baseload generation. However the lower levels of surplus baseload generation expected in the future will help mitigate the impact of higher ETS rates on out-of-market costs.
- Based on the "working assumption" that higher ETS rates will most likely have a negative impact on system benefits, any increases in ETS rates should be moderate and introduced on a gradual basis.

- With respect to Fairness:
  - Subject to a refinement regarding the treatment of Generation Line Connection and Generation Transformation Connection Asset-related costs, the Elenchus' 2021 Study using Option 2 (12CP Export allocator reduced by 20%) appropriately assesses transmission-related costs to exporters based on the principle of "cost causality". The resulting adjusted ETS Rate using Hydro One Networks' proposed 2023 revenue requirement (per its 2023-2027 Customer Incentive Rate Application) is $5.48/MWh.
  - To date the OEB has placed a strong reliance on cost allocation studies when setting rates. As discussed earlier, this is evident in the Board's approach to setting both transmission and distribution rates. However, the principle that rates should be "cost-based" is also underpins the Board's approaches in other areas such as Retail Service Charges[145] and Affiliate Charges[146]. Also,

[145] Report of the Ontario Energy Board: Energy Retailer Services Charges (EB-2015-0304), November 29, 2018, page 14

[146] Affiliate Relationship Code for Electricity Distributors and Transmitters, Revised March 15, 2010, Sections 2.3.3.6 and 2.3.4.2

the ETS rates in Ontario's neighbouring jurisdictions are generally set on a "cost basis". This would suggest that significant weight should be given to the cost allocation results when determining the ETS rate for Ontario.

- With respect to Practical Attributes:
  - Given that changes to the ETS rate will have an impact on exporters and how they participate in Ontario's energy market, the rate needs to be readily understandable in terms of how it will be applied and how it relates to other market charges.
  - In addition, changes in rates should be predictable going forward and made in a manner that allows exporters to anticipate and adjust their business practices accordingly. However, VECC notes that the average cost for exporting a MWh in 2021 was over $37/MWh[147]. Based on the OEB's 10% total bill criterion[148], the ETS rate would have to increase by more than $3.70/MWh (i.e., to over $4.55/MWh) before the increase is considered to be excessive.

2.3.2 Recommendations

2.3.2.1 ETS Rate

VECC submits that a reasonable balance between these principles and their associated considerations can be achieved by:

- Increasing the ETS rate to $3.00/MWh somewhere between 6-12 months after the Board issues its Decision (resulting in an ETS rate adjustment sometime mid to late 2023).
- Increasing ETS Rate on January 1 of each year during Hydro One Networks' CIR period (2024 to 2027) by the same RCI percentage that is used to adjust Hydro One's transmission revenue requirement and

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[147] Includes ETS costs of $1.85/MWh, average Uplift and Fees of $3.84/MWh (per Exhibit I, Tab 1, Schedule 1, Table 19), an average ICP value of $6.67 (per Exhibit I, Tab 1, Schedule 1, Table 10 ($114.7 M in congestion rent) & Table 1 (17.2 TWh in Exports) and average HOEP for exports of $25.25 (calculated from data in Power Advisory Interrogatory Responses – Attachment B).

[148] Ontario Energy Board Filing Requirements for Electricity Distributor Rate Applications, 2022 Edition for 2023 Rate Applications, Chapter 2 – Cost of Service, page 55

- Undertaking a review of the ETS rate at the time of the next rebasing of Hydro One Networks' transmission revenue requirement (currently 2028 based on Hydro One Networks' proposed five year term in its current CIR Plan application).

The $3.00/MWh is less than one-third of the way between the current $1.85/MWh and the $5.48/MWh resulting from VECC's recommended adjustments to the Elenchus cost allocation methodology and only slightly more than 50% of the $5.48/MWh. Also, the $1.15/MWh increase is only slightly more than the $1.00/MWh increase approved by the OEB in EB-2010-0002. Finally, it results in an increase in the average cost of exporting a MWh of roughly 3%, well below the Board's 10% criterion for bill impact mitigation. In VECC' view this provides ample deference to both the impact an increase in the ETS rate will have on exporters and may have on system operations and efficiency.

Delaying the initial ETS adjustment for six to twelve months will give exporters time to adjust. VECC requests that, in it reply submissions, the IESO comment on what would be an appropriate delay period given the status of Transmission Rights currently held by exporters and other parties.

Adjusting the ETS rate annually by the RCI percentage reflects Hydro One Networks' own suggestion[149] as to how the ETS rate could be adjusted annually. Hydro One Networks has noted that such an adjustment would increase regulatory complexity and would not be expected to result in a material impact on UTRs for domestic customers. VECC notes that the ETS rate can readily be adjusted on an annual basis. The regulatory complexity arises in incorporating the resulting increase in ETS revenues into the annual Transmission Revenue Requirement adjustment. VECC does not see this as being an issue as Hydro One Networks will be applying annually for adjustments to its Transmission Revenue Requirement during the CIR period. However, if this is a concern to the OEB, such complexity can readily avoided by allowing the impact of the increase in the ETS rate to be captured by the Export Service Revenue Variance Account. Adjusting the ETS rate annually allows the ETS rate to keep pace with Hydro One Networks' transmission revenue requirement and avoids any need for a "catch-up" in future proceedings. At the same time, the annual percentage changes in the rate are

[149] Exhibit JT 1.2

expected to be in the 3% - 6% range[150] such that there will not be undue shocks to either exporters or overall market operations.

Revisiting the ETS rate at the time of Hydro One Networks next "rebasing" means that:

- There will be a detailed transmission cost forecast available as input for purposes of updating the cost allocation study,
- Sufficient time will have elapsed to gain experience with the higher ETS rate and its implications,
- The Market Renewal Program that is currently underway will likely have been completed and been in place for a period of time[151], and
- The timing will align with the 2027 date where the IESO currently plans to have the resources being targeted by its long-term RFPs in place[152] such that there will be a better understanding of the outlook for future system conditions.

2.3.2.2 Future Studies

While it is impossible to forecast future market conditions, in VECC' view additional analyses are required as to understand: i) how higher/lower ETS rates would have impacted historic export volumes, congestion rents, and market revenues/costs, and ii) how the future outlook for surplus baseload generation differs from that experienced historically. This information will assist the Board in better understanding how future decisions regarding the level of the ETS rate may affect system operations and efficiency.

Power Advisory acknowledged that they faced significant data limitations. As result, as a first step processes (e.g. working group or some other mechanism, etc.) should be established to determine what data is required, how best to assemble it (recognizing possible issues regarding confidentiality) and what specific methodology should be employed. The OEB can be a catalyst/driver in this regard.

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[150] EB-2021-0110, Exhibit A, Tab 4, Schedule 2, page 5

[151] Exhibit JP1.3 states that the current schedule for the Program is being updated and will be available towards the end of Q3 2022.

[152] Exhibit JT 1.12. See IESO Resource Adequacy Update-August 23, 2022 (pages 2-3) found under the first link referenced

3. <u>COSTS</u>

VECC respectfully submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ATTACHMENT

FILED AS CONFIDENTIAL