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Ontario Energy Board
2300 Yonge Street
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September 6, 2022
Our File: EB20210243

Attn: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: EB-2021-0243 – UTR Generic Proceeding – SEC Submissions

We are counsel to the School Energy Coalition ("SEC"). Pursuant to Procedural Order No.3, please find SEC's submissions in the above-noted proceeding.

Separately, SEC is filing a appendix to these submissions which we seek to file on a confidential basis (the "Confidential Appendix") pursuant to the OEB's *Practice Direction on Confidential Filings.* The Confidential Appendix is SEC's submissions on the Power Advisory excel model that was filed in response to Undertaking JT2.2, and which APPrO has requested by granted confidentiality treatment in its entirety. We are also filing, and request confidential treatment, a version of the Power Advisory excel model with certain SEC calculations detailed in the Confidential Appendix.

We request that APPrO review the Confidential Appendix and provide the undersigned with its views on what aspects can be filed on the public record. Once we have APPrO's views, we propose to file a redacted version that can be placed on the public record.

Yours very truly,
Shepherd Rubenstein P.C.

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Mark Rubenstein

cc: Brian McKay, SEC (by email)
Intervenors (by email)

EB-2021-0243

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF a Generic Hearing on Uniform Transmission Rates Related Issues and the Export Transmission Service Rate.

SUBMISSIONS OF THE

SCHOOL ENERGY COALITION

Overview

1. Hydro One Networks Inc. ("Hydro One"), as part of its 2023-2027 joint rate application (EB-2021-0110), filed evidence regarding an appropriate Export Transmission Service ("ETS") rate. Subsequent to the filing of the application, the Ontario Energy Board ("OEB" or "Board"), on its own motion, initiated a proceeding to consider various issues related to Ontario's Uniform Transmission Rates ("UTRs"). The first phase of the proceeding is focused on the setting of an ETS rate. As part of Procedural Order No.1, the OEB required Hydro One to consult with the Independent Electricity System Operator ("IESO") to clarify their recommendation for the ETS rate, and file on the record in this generic proceeding the related evidence it had filed as part of its 2023-2027 rates application.

2. These are the submissions of the School Energy Coalition ("SEC") on this first phase of the proceeding, the appropriate ETS rate.

3. The OEB has considered the issue of an appropriate ETS rate on several occasions over the years, but has never reached a decision on a specific methodology or approach that should be adopted. In its decision in RP-1999-0044, the first proceeding to consider the issue, the OEB noted that it "has proven to be a contentious and complex issue".[1] Two decades later, it has become even more complex.

[1] *Decision with Reasons* (RP-1999-0044), May 26 2000, p.66

4. As discussed in detail in these submissions, there is not a single methodology that ensures a just and reasonable ETS rate. The issue of the appropriate ETS rate engages not just traditional rate-setting and cost allocation principles, but also the impact exporters have on the broader energy market, which in turn has an effect on the amount domestic customers pay for electricity. In addition, trying to determine a forward-looking approach at this time is made more difficult as the Ontario electricity market is entering a period of significant change, and recent history, which is the basis of much of the evidence in this proceeding, may not be a good indicator of the future.

5. The OEB should continue to charge an ETS rate, even though exporters may also be required to pay Intertie Congestion Pricing ("ICP"). They are two different mechanisms intended to recovery different costs. With respect to the appropriate ETS rate, a balanced approach is required, and SEC proposes a rate that is at the midpoint of the current $1.85/MWh rate and the fully allocated cost-based methodology (80% scenario) proposed in the evidence filed by Elenchus Research Associates ("Elenchus").

6. SEC has had the opportunity to discuss the issues raised in this proceeding with many of the parties, their witnesses, and experts. While we may disagree in some cases with their perspectives, evidence, and conclusions, we have benefited greatly from those discussions in working through this complex issue.

Background

7. Unlike domestic load customers, exporters who purchase energy in Ontario and use the transmission system to transport electricity out of the IESO-controlled area (i.e. Ontario) do not pay directly or in-directly UTRs for their use of the transmission system. Exporters are charged a different rate, for a separately named service, the ETS.[2]

8. There is a lengthy history that is detailed in the evidence of the OEB grappling with the issue of an appropriate ETS rate. For market opening, the OEB, "emphasiz[ing] the interim

[2] Hydro One ETS Rate Submission, p.2

nature of the decision", set the rate at \$1.00/MWh. [3] The rate remained the same until 2011, when the OEB increased it to \$2.00/MWh, noting the previous rate was made in the "absence of any particular analytical underpinning", yet simultaneously warning that future panels should not "regard this new rate as having any particular precedential value."[4]

9. In Hydro One's subsequent transmission rates application, the issue was considered once again and evidence was filed that considered various options, but the OEB rejected all of them, including the elimination of the ETS rate. In its decision, no change was made to the \$2.00/MWh rate, but the OEB did order "Hydro One to perform a cost allocation study to establish a cost basis for the ETS rate."[5]

10. Hydro One responded to the OEB's direction and retained Elenchus to conduct a cost allocation study which was filed as part of the company's 2015-2016 transmission rates application ("2014 Elenchus Study"). The 2014 Elenchus Study recommended a methodology that allocated certain costs to a new export class, but did not allocate any shared network assets. The methodology resulted in a recommended rate of \$1.70/MWh. Parties to the application reached a settlement agreement, which was approved by the OEB, that set the ETS rate at \$1.85/MWh. The settlement agreement explicitly noted that acceptance of the level "shall not be construed as acceptance of the methodology, assumptions, or scenarios used in the Elenchus Study", and that "the parties observe that the cost allocation methodology proposed by the Elenchus Study remains untested and the parties do not necessarily agree with its methodology." [6]

11. In Hydro One's 2020-22 transmission rates application, the issue was again explored, and the OEB decided to maintain the current ETS rate of \$1.85/MWh. In doing so, the OEB noted that further work was required before it was prepared to amend that rate, and specifically, that the "use of shared network facilities by exporters needs to be considered in setting the ETS

[3] RP-1999-0044, p.68
[4] *Decision with Reasons,* (EB-2010-0002), December 23, 2010 p.75
[5] *Decision and Order* (EB-2012-0031), June 6, 2013, p.9
[6] EB-2014-0140, Section II, Settlement Agreement, p.25

rates."[7] In addition, the OEB requested that Hydro One update the jurisdictional review that it had previously filed back in 2012.

12. In this proceeding, Hydro One filed as part of its evidence, a new cost allocation study prepared by Elenchus (the "2021 Elenchus Study")[8], an updated Charles Rivers Associates ("CRA") jurisdictional review[9], and evidence prepared on the implications of a change in the ETS rate by the IESO.[10]

Issue 1: 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?

13. SEC submits that it is appropriate to continue to have both an ETS rate and ICP. Fundamentally, the ETS rate and ICP are two very different types of charges that are meant to reflect different sets of costs that exporters should be required to pay. Regardless of the original intent of the ICP at the time of market opening, it is not the same today. The Ontario electricity market has substantially evolved over-time, and both mechanisms are required to ensure domestic ratepayers are properly compensated for the exporters' use of, not just the transmission system, but also the value of the commodity purchased itself.

Intertie Congestion Pricing

14. While ICP is a separate category of costs that exporters pay, it is more accurate to consider it as a function of their energy market bid when there are capacity constraints at an intertie, that limit the volume that can be physically exported. Exporters do not make one bid into the energy market for the cost of the commodity, and then make a separate bid into an ICP market. They make a single bid which reflects what an exporter is willing to pay to export energy through a specific intertie.[11] ICP that is paid during a given hour for each quantity of electricity exported is the difference between the market clearing specific Intertie Zonal Price (essentially, a

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[7] *Decision and Order* (EB-2019-0082), April 23, 2020, p.179-180

[8] Hydro One ETS Rate Submission, Attachment 1

[9] Hydro One ETS Rate Submission, Attachment 2

[10] Hydro One ETS Rate Submission, Attachment 3

[11] Presentation Day Transcript, p.89-91; Power Advisory Report, *Expert Report For The Market Impacts of Changes To The ETS Rate,* May 2022 (["Power Advisory Report"], p.27-28

type of Locational Marginal Price) and market clearing Ontario-wide price (i.e. the Hourly Ontario Electricity Price, or HOEP). This reflects the additional value above HOEP that exporters are willing to pay for electricity because of capacity limits on that specific intertie. It is thus more appropriate to consider ICP as part of the price for energy that exporters pay, and not for their use of the transmission system.

15. This view is also shared by the Brattle Group, who were retained by the IESO in 2019 to review the allocation methodology for disposition of balances in the account where ICP revenue is credited, the Transmission Rights Clearing Account ("TRCA"). In its report, the Brattle Group noted, in responding to arguments that exporters may make, that congestion costs "are not costs that are associated with the physical transmission system, but instead are costs of the energy that is sent through the system."[12]

16. In the lead up to market opening, an ICP mechanism may have been conceived of as a way to offset intertie infrastructure costs[13], but it no longer does that, if it ever did. ICP now is a mechanism to efficiently price energy that is meant for export when there are physical limitations at the intertie (i.e. it is congested). Hydro One does not consider ICP revenue when looking at intertie expansion, nor has it ever been part of its revenue requirement application. ICP does not even attempt to reflect the cost of use of the interties. In most hours, exporters do not even pay ICP.[14] The IESO itself noted that each of the ICP and ETS (as well as uplift) charges "have different objectives".[15] Additionally, ICP revenues that are disbursed through the TRCA, and are credited to domestic customers, are reflected on customers' bills through Account 1588 (Wholesale Market Service Charges), which is allocated differently than transmission costs (UTRs or RTSRs).[16]

[12] Undertaking JT 1.6, Attachment 1, p.19
[13] Interrogatory Response OEB Staff 34b; Undertaking JT1.1
[14] Hydro One Submission on ETS Rate, Attachment 1, p.19-23; Technical Conference Transcript, July 29, 2022, p.117
[15] Interrogatory Response Pollution Probe-10(b)
[16] Undertaking JT1.3

ICP Mechanism Is Unique to Ontario, But Other Jurisdictions Extract The Same Value Through LMP

17. Ontario has a unique electricity market structure where the real-time electricity market, is less about determining appropriate costs, and more about operational dispatch decisions. Most commodity costs are determined by contract or rate-regulation, and the difference between what a resource receives in the market and the contract or regulated amount, is recovered through the Global Adjustment.[17] Exporters do not pay any of the Global Adjustment, even though it reflects most of the cost domestic customers pay for the electricity commodity.[18]

18. While the ICP is unique to Ontario, other jurisdictions extract the same value (i.e. type of costs) from exporters through their energy market. Mr. DesLauriers, on behalf of CRA, found that most neighboring jurisdictions have a Locational Marginal Pricing ("LMP") system, and so the value of the ICP (i.e. congestion) is simply reflected in the LMP.[19]:

> 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.[20]

19. In Ontario, there is a form of LMP at each intertie, Intertie Zonal Pricing, but because of the province-wide price (i.e. HOEP) the value of congestion is captured separately through ICP. ICP for any given export transaction is simply the difference between, the specific Intertie Zonal Price and HOEP.[21]

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[17] Technical Conference Transcript July 28, 2022, p.162; Power Advisory Report, p.22

[18] See Average HOEP vs. Global Adjustment (https://www.ieso.ca/en/Power-Data/Price-Overview/Global-Adjustment)

[19] Interrogatory Response SEC-2

[20] Technical Conference Transcript July 28, 2022, p.69-70

[21] It is slightly more complex than this. As noted in the Power Advisory Report: "Intertie congestion is determined in the hour before real-time, known as PD-1. The congestion export bids are then set at $2,000/MWh in real-time (to ensure they flow) and the congestion price determined in PD-1 is added to HOEP". (Power Advisory Report, p. 27, ft. 17)

20. Telling, in none of the other jurisdictions which have LMP do they consider it to be an offset to transmission costs or intertie costs. Almost all of those neighbouring jurisdictions still charge exporters a 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.

21. The CRA report found that in most other jurisdictions it surveyed in the US, exporters pay cost-based rates that are based on a transmitters annual revenue requirement, based on certain FERC requirements.[22] Similarly, Elenchus found in its survey of other jurisdictions that exports are analogous to "Point-to-Point" transmission service, where the charges are calculated based on the Network Service charge, which is analogous to Ontario's domestic transmission tariff (i.e. the network services component of the UTRs).[23]

22. In most cases there is no distinction between the rates domestic and export customers are charged for use of the transmission system. Most are well above the current $1.85/MWh ETS rate.[24] Where there is a difference between classes of customers, it is usually based on a reciprocal arrangement between jurisdictions (for example between NYISO and IESO-NE, or PJM and MISO).[25]

ETS Rate Meant to Recover Costs of Use of Entire Transmission System

23. In contrast to ICP, the ETS rate is meant to reflect the cost of the use of the transmission system. This should include not just the costs of the intertie, but also the entire system which exporters use, since electricity exporters use other aspects of the transmission system before they get to the border intertie.

24. The use of ICP as an offset mechanism to intertie costs would violate the "no free rider principle", that those who benefit from use of these assets should pay their fair share. ICP is only

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[22]Hydro One ETS Rate Submission, Attachment 2, p.4, Interrogatory Response OEB Staff -20; Presentation Day Transcript, p.56
[23] Hydro One ETS Rate Submission, Attachment 1, p.24
[24] Hydro One ETS Rate Submission, Attachment 2, p.16
[25] Hydro One ETS Rate Submission, Attachment 2, p.8-9

paid if there is congestion at a given intertie.[26] Between 2017 and 2021, only 48% of scheduled exports were subjected to congestion. This means more than half of export volumes were not subject to any ICP.[27]

25. The matter is complicated by the presence of the Transmission Rights ("TRs") market. Exporters, as well as other entities, often bid to purchase TRs that act as a hedge against congestion and the need to pay ICP. A holder of TR, on a specific intertie path and for a specific volume, will have their ICP payments effectively refunded back to them.[28] Since TR auction revenues are credited into the TRCA when collected after an auction, and amounts paid out are debited during the life of the TRs, which generally begin over a year later[29], is difficult at any given time to assess how much net revenue related to intertie congestion is collected at any given time. The IESO estimates that approximately 40% of export transactions are backed by TRs.[30]

<u>Issue 2: If an ETS rate were to continue to exist alongside ICP, what approach should be used to set the ETS rate?</u>

Rate-Setting Principles

26. The setting of a just and reasonable ETS rate is principally a cost allocation exercise among different classes of customers. The OEB is tasked with allocating costs of the Ontario transmission system between domestic load customers and exporters. That system is primarily, although not exclusively, owned and operated by Hydro One. Domestic customers pay for transmission service by way of the UTRs, generally flowed through to them through Retail Transmission Service Rates, while exporters pay the ETS rate.

27. Like any other cost allocation exercise that the OEB regularly undertakes, costs should be allocated to respective classes of customers that appropriately reflect, not just who causes those costs, but also who benefits from them. FERC describes this principle as it relates to

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[26] Interrogatory Response OEB-Staff-6a
[27] Interrogatory Response OEB-Staff-1, Attachment, 1 Table 21
[28] Hydro One Submission on the ETS Rate, Attachment 3, p.11
[29] See TR Market Schedule (https://www.ieso.ca/en/Sector-Participants/Calendars/Market-Calendars/2022-Transmission-Rights-Auction-Schedule). By way of example, a 1-year TR from October 1, 2022 to September 30, 2023, the TR auction took place in August 2022, with payment due August 31, 2022.
[30] Presentation Day, Transcript, p.98

transmission cost allocation as the principle that "t[h]e cost of transmission facilities must be allocated to those….that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits."[31] The OEB has applied this principle in different contexts, including most recently, adopting this "beneficiary pays" guiding principle to the allocation of the costs for certain new infrastructure under the Transmission System Code.[32]

28. Cost allocation should be fair, objective, avoid cross-subsidization, while promoting efficiency, stability, predictability, and remain practical and understandable.[33] These are standard ratemaking principles that guide most, if not all, OEB rate decisions and are consistent with its statutory objectives for electricity to "…protect [customers] interests with respect to prices…", and "promote the economic efficiency and cost effectiveness in the generation, transmission…of electricity.."[34] The OEB has previously identified three main principles for rate-design: full cost recovery, fairness and efficiency. These are equally applicable to the setting of the ETS rate.[35] These three main principles "encompass all of the Bonbright attributes of a sound rate structure".[36]

29. As a general policy, the OEB cost allocation approach is that of the use of fully allocated costing.[37] Most recently, it confirmed this approach in the context of its review of the approach to setting Energy Retailer Service Charges, finding that "fully allocated costing methodology is appropriate as it reflects cost causality and value to customers, and would minimize cross-subsidization."[38]

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[31] FERC Order 1000 (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities), p.622

[32] See Proposed Amendments to the Transmission System Code and the Distribution System Code to Facilitate Regional Planning (EB-2016-0003), September 21, 2017, p.3

[33] See James C. Bonbright, *Principles of Public Utilities Rates*, 2nd Ed, Chapters 16 and 19

[34] *Ontario Energy Board Act*, *1998*, section 1(1)1,2

[35] OEB Staff Discussion Paper; *Rate Design for Recovery of Electricity Distribution Costs (EB-2007-0031),* March 31, 2008, p.15,; See also Interrogatory Response VECC-1.2

[36] *Ibid*

[37] Technical Conference Transcript, July 29, 2022, p.121

[38] *Report of the Ontario Energy Board: Energy Retailer Services Charges* (EB-2015-0304), November 29, 2018, p.14

30. In the context of setting the ETS rate, a fully allocated costing approach requires that not just a portion of intertie infrastructure costs be allocated to exporters, but also shared network assets, even though the transmission system is designed for domestic customers. This ensures that it is not just those who cause a cost pay their fair share, but those who benefit from a cost (i.e. the transmission assets) do so as well. Elenchus calls this the "no free riders" principle[39], but may be more aptly be an application of the long-standing benefits follow costs (or costs follow benefits) principle.

31. Exporters benefit from network assets.[40] They purchase electricity to export which traverse potentially hundreds of kilometres of transmission lines from the generator to the intertie. They should be allocated a portion of those costs.

Elenchus Approach

32. The 2021 Elenchus Report filed in this proceeding is an update to the 2014 Elenchus Study, which was its first attempt to address past OEB concerns that the ETS rate needed to be cost-based.[41] The 2021 Elenchus Report directly addressed the OEB's concern in EB-2019-0082 that there was insufficient information on the record to determine what allocation of common network costs should be allocated to exporters.[42] The OEB directed "that a cost allocation methodology that includes the allocation of shared network costs to exporters should be provided", and that it should "include different scenarios to take into consideration the fact that exporters do not receive the same priority access as domestic service until they are scheduled."[43]

33. The 2021 Elenchus Report includes multiple scenarios which allocates to exporters a portion (based on its share of demand) either 100%, 80%, or 50% of the costs of shared network assets. What Elenchus does is take the total shared network costs allocated to exporters, and then multiplies that amount by 100%, 80% or 50%. Based on Hydro One's proposed 2023 revenue

[39] Hydro One Submission on ETS Rate, Attachment 1, p.28-29
[40] Technical Conference Transcript, July 29, 2022, p.118
[41] *Decision and Order* (EB-2012-0031), June 6, 2013, p.10
[42] *Decision and Order* (EB-2019-0082), April 23, 2020, p.179
[43] *Decision and Order* (EB-2019-0082), April 23, 2020, p.179-180

requirement, this would reflect an increase in the ETS rate on an adjusted basis up to $6.54/MWh, if the allocation to exporters was on the basis of 100% of shared network assets.[44]

34. The reason for consideration of a methodology, that only includes a portion of the demand allocator that would otherwise be allocated to exporters, is that there is a differing treatment of exports as compared to domestic loads by the IESO. Domestic loads have priority access to the transmission system, while export loads can be curtailed. [45] Yet, as Elenchus points out, export volumes are rarely curtailed. Over the top 5 peak hours over the last 5 years, only in 11 of those 25 hours were *some* exports curtailed, and when they did, it only amounted to 10% of those scheduled.[46] Elenchus' understanding of the limited extent exports are curtailed is one of the reasons that it now supports allocation of a portion of shared network assets to exporters, whereas it did not recommend such an approach in 2014.[47]

35. Each of the 50% and 80% scenarios in the 2021 Elenchus Report reflects a 'discount' of the amount that would otherwise be allocated to exporters based on their coincident peak to reflect the differing level of service. While Elenchus refers to this as its curtailment model,[48] it is a fully allocated costing methodology that simply reflects an adjustment reflecting the differing services attributes.

36. SEC does agree that some discount to the allocation of the share of network assets to exporters is reasonable, on the basis that the services they receive are not identical to domestic customers. Since the actual difference in service is not that significant, discounting the amount allocated by 20% (i.e. using the 80% scenario) is the most appropriate approach that recognized

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[44] Elenchus cost allocation methodology is based on Hydro One's 2023 revenue requirement as proposed in the EB-2021-0110 proceeding. It then adjusts the proposed ETS rate to account for the revenue requirement of all other transmitters in Ontario. It does this by adjusting the rates by 7.77%, which is the sum of Hydro One's 2023 revenue requirement and that network revenue of all other transmitters as approved in EB-2020-0251 and dividing it by Hydro One's 2023 revenue requirement (See Hydro One Submission on ETS Rate, Attachment 1, p.35, ft 11) While likely not a material difference, this approach understates the appropriate adjustment since it uses the approved 2022 network revenue requirement of all other transmitters, not their forecast 2023 network revenue requirements similar to Hydro One's 2023 revenue requirement.

[45] Hydro One Submission on ETS Rate, Attachment 1, p.19-23

[46] Hydro One Submission on ETS Rate, Attachment 1, p.23; Technical Conference Transcript, July 29, 2022, p.117

[47] Technical Conference Transcript, July 29, 2022, p.117

[48] Hydro One Submission on ETS Rate, Attachment 1, p.29

the true extent of the difference in domestic and export transmission service. Based on Hydro One's proposed 2023 revenue requirement, this would reflect an ETS rate of $5.42/MWh.[49]

IESO

37. The IESO takes a different view regarding what the OEB should consider in setting the ETS rate, one that is not based on fully allocated costing. As the Ontario system operator, they approach the issue from the broader energy market implications of a change in the ETS rate. The IESO's evidence discusses how exports provide operational and economic benefits, and the implications and risks of a higher ETS rate.[50] The IESO's view is that a higher ETS rate would decrease ICP revenues, which overwhelmingly flow to domestic ratepayers, as well cause an overall reduction in exports which will have an adverse operational impact and increase costs through additional resource curtailments.[51]

38. As the system operator, the IESO has a natural bias towards the operational implications of a change in the ETS rate. Its view is that a materially higher ETS rate creates a risk to operational flexibility that exporters provide.[52] This is an understandable perspective from the IESO.

39. What is surprising is that, if the IESO felt so strongly about the risks generated by a significantly higher ETS rate, it should have undertaken a detailed analysis to demonstrate with some certainty that the risk may materialize and impact its ability to manage the electricity system. Unfortunately, the IESO did not undertake any quantitative analysis to show the expected financial or operational impact of a change in the ETS rate.[53] With respect to the operational concerns, we are left with little but conjecture about the possible need for nuclear shutdowns or maneuvers.[54] These have occurred in the past on multiple occasions, but when asked directly about this by the OEB panel at the Presentation Day, Mr. Chapman, on behalf of

[49] Hydro One Submission on ETS Rate, Attachment 1, p45
[50] Hydro One Submission on ETS Rate, Attachment 3
[51] Hydro One Submission on ETS Rate, Attachment 3, p.8
[52] Hydro One Submission on ETS Rate, Attachment 3, p.13; Technical Conference Transcript, July 28, 2022, p.133
[53] Interrogatory Response SEC-3
[54] Presentation Day Transcript, July 29, 2022, p.88

the IESO, could not necessarily say it had anything to do with the ETS rate or exports more generally.[55]

40. This has put all parties, including the OEB, in a very difficult position. A higher ETS may very well increase the operational risk to the IESO, but without any quantification, it is impossible to determine how much weight to give to this consideration. What we do know is that when the OEB previously doubled the ETS rate from $1/MWh to $2/MWh, the IESO did not claim that this caused any material operational issues or financial impacts.

Power Advisory Approach

41. Since the IESO did not undertake any quantitative modelling, Power Advisory, who were retained on behalf of the Association of Power Producers of Ontario ("APPrO"), who represent exporters[56], filed evidence attempting to quantify these broader market implications, as they impact domestic customers, of a change in the ETS rate. [57]

42. Power Advisory's evidence attempts to show that if the ETS rate had been set at the highest end of the 2021 Elenchus Report range ($6.54/MWh), between 2018 and 2021, while there would have been an increase in overall ETS revenue ($245M), domestic customers would have been $42.6M worse-off. [58] This was as a result of lower export volumes caused by the increase in the ETS rate, which would have also resulted in reduced ICP and market revenues, as well as, increased wind curtailment and hydroelectric spill.[59] In contrast, if the ETS rate had been eliminated over that same period, domestic ratepayers would not have benefited from the $140.5M in ETS revenue that would have been collected, but exports would have increased, and that would have had the effect of providing a net benefit to customers of $37.7M through increased ICP revenue and reduced wind curtailment and hydroelectric spill.[60]

[55] Presentation Day Transcript, July 29, 2022, p.100
[56] APPrO Intervention Request, September 24, 2021, p.2
[57] Power Advisory Report, p.4
[58] Power Advisory Report, p.42-43
[59] Power Advisory Report, p.42-43
[60] Power Advisory Report, p.45-46

43. Power Advisory's approach is based on using changes in HOEP as a proxy for changes to the ETS rate. [61] Using publicly available data from 2018 to 2021, Power Advisory estimated the impact of a change in the ETS rate by showing the differences in export volumes and ICP revenue, when HOEP was increased, by increments of $4.69/MWh (the difference between the current ETS rate of $1.85/MWh and $6.54/MWh).[62] It did this by comparing the export volumes and ICP revenue between various $4.69/MWh intervals. Using those changes in export volume, it then calculated, based on a number of assumptions, the increase in hydroelectric spill, wind curtailment, as well as reduced market revenues.[63] A similar approach was used to estimate the impact of reducing the ETS rate from the current $1.85/MWh to $0/MWh.

44. At a high-level, SEC does not dispute the contention that all else being equal, an increase in the ETS rate will reduce overall export volumes. The ETS rate is a cost to exporters, and so as with all but the most inelastic of costs, the higher it is, the less demand there will be. Reduced exports will have financial impacts besides reduced ETS revenue. But those broad impacts in the energy market as it impacts domestic customers, are not as simple as the Power Advisory's net benefits analysis shows.

45. While SEC commends Power Advisory for attempting to quantify some of the impacts of a change in the ETS rate that were discussed primarily at a qualitative level in the IESO evidence, there are some significant issues with its methodology. SEC understands that Power Advisory was faced with significant data limitations due to the unfortunate lack of market data made available by the IESO.[64] Even with the data it had available, there are problems with its methodology, which leads to a significantly overstated financial impact of a change in the ETS rate. Some of these detailed methodological concerns are discussed in the confidential appendix to these submissions. But what they do show, when corrected, is that the overall harms to

[61] Power Advisory Report; Presentation Day Transcript, p.129

[62] Power Advisory Report, p.48; APPrO IRRs, Attachment A

[63] Power Advisory Report, p.48; APPrO IRRs, Attachment A

[64] According to Power Advisory, these data limitations include, price quantity pairs (Presentation Day Transcript, p.135), wind and hydroelectric curtailment data (see Interrogatory Responses PA-VECC-23.2; PA-VECC-27.2) and intertie PD-1 pricing (Technical Conference Transcript, July 29 2022, p.84)

customers from a significant increase in the ETS rate and the benefits of reducing the ETS rate to zero, are both significantly reduced.

46. Fundamentally, Power Advisory's analysis is premised on the direct relationship between HOEP and export volumes, so that it can estimate how changes in the former, as a proxy for changes to the ETS rate, impacts the latter. The problem is the data the Power Advisory uses shows that the relationship cannot so easily be explained. In its report, Power Advisory provides a chart that plots HOEP against export volumes, with a downward sloping trend-line meant to indicate that there is a clear relationship between price and exports.[65] When asked for statistical analysis of that trend, Power Advisory revealed that the R^2 value was only 0.077.[66] Such a small statistical fit is a clear indication that changes in the price of HOEP cannot be used to accurately estimate the level of changes in export volumes. Additionally, no sensitivity analysis was done on any of its analysis. [67]

47. The decisions that drive export behavior are complicated. The most important is the price spread between Ontario and neighbouring jurisdictions where exporters plan to sell the purchased power.[68] Exporters are primarily engaged in price arbitrage.[69] While the ETS rate is a part of that spread, the biggest impact is the difference in the market price. The market price in a neighbouring jurisdiction is a function of the individual supply and demand conditions prevalent in that market, and a lot of that will depend on their specific supply mix. This will have nothing to do with Ontario. Even then, price arbitrage is not always the reason for exporters' trades. In certain circumstances, exports flow into a jurisdiction with a lower market price.[70]

48. Another problem is that as Power Advisory points out, 2 of its 4 years that it looked at (2020 and 2021) took place during the heart of the COVID-19 pandemic, when there was an "unprecedented shutdown of large parts of the Ontario and global economies".[71] This had a

[65] Power Advisory Report, p.37
[66] Undertaking JT2.1
[67] Interrogatory Response PA-Staff-3d
[68] Interrogatory Response PA-Staff-16c; Interrogatory Response PA-Energy Probe-3f
[69] Power Advisory Report, p.32
[70] Power Advisory Report, p.46
[71] Technical Conference Transcript, July 29,2022, p.23

significant impact on electricity demand and caused "material instances of SBG in Ontario and surplus generating capacity in neighbouring jurisdictions."[72]

49. Power Advisory chose to leave those years in to show the benefits of exports, but that was not the purpose of its analysis. Its report was meant to attempt to quantify the impacts of a change in the ETS rate. Using historic data, which includes a once-in-a-generation pandemic, tells us little about the conditions that should be expected in the future.[73] How much 2020 and 2021 skewed the results, if at all, is unclear. SEC asked for a breakdown of the financial impact in its analysis by year, but Power Advisory refused on the basis of the time to complete and volume of interrogatories it had received.[74]

The Future May Look Very Different Than Even the Recent Past

50. Even if one accepts the results of the Power Advisory analysis, all it can tell us is what would have happened if the ETS rate increased between 2018 and 2021. The future should look substantially different than the past for a number of reasons.

51. First, the IESO's own forecast from its 2021 Annual Planning Outlook ("APO") indicates that Surplus Baseload Generation ("SBG") is expected to fall significantly.[75] This is likely to reduce periods where exports are in need for operational purposes, but also SBG periods are where HOEP is very low and a change in the ETS rate would likely have a much greater impact. It is during SBG hours where exports provide the most benefits to domestic customers.[76]

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[72] Power Advisory Report, p.46

[73] Power Advisory Report, p.46

[74] Interrogatory Response PA-SEC-11

[75] IESO, *Annual Planning Outlook* (December 2021), p.49, Figure 23. See also OEB Staff 1, Attachment 1, Table 24. The IESO has provided historic SBG numbers (OEB Staff 1, Attachment, Table 23) but those numbers are not comparable since they are after exports, where as the future numbers do not include a forecast of exports. SEC requested that the IESO provide an apples-to-apples comparison by removing exports from the historic numbers. In its response to Undertaking JT 1.8, the IESO did not provide the response commenting that it was not a realistic scenario. The intent of the Undertaking was not to provide a scenario without exports, but simply to allow the historic and forecast SBG to be compared on the same basis.

[76] IESO, *Annual Planning Outlook* (December 2021), p.49, Figure 23

52. Second, after the release of the APO, the IESO revealed that the need for additional capacity was more urgent than previously thought[77] and, based on Ministerial direction, a number of procurement activities were fast-tracked.[78] This will undoubtedly change the forecast of SBG that was included in the APO. This will again affect the impact that a change in the ETS rates has on export volumes and ICP revenue.

53. Third, the IESO is embarking on the largest change to its electricity market since market opening through its Market Renewal Program ("MRP").[79] Although the launch of MRP is delayed from the original fall 2023 date[80], the impact of adding a single schedule market, and a Day Ahead Market, on the need and operation of exports is not known, but as both IESO and Power Advisory note, there may be some.[81]

54. Fourth, as discussed earlier, the biggest driver of export activity is the price spread, which is highly influenced by the specific market conditions in neighbouring jurisdictions. Mr. Yauch, on behalf of Power Advisory, commented that not only is Ontario facing a capacity shortfall, but so are NYSIO, MISO, and PJM, who are "going through vast changes in their supply mix".[82] The impact of these changes may result in large changes to the price spread, which may either increase or decrease export volumes and effect the sensitivity to changes in the ETS rate.

55. Finally, one of the major components of the Power Advisory analysis is the financial impact of hydroelectric spill that would occur from changes in export volumes. Unlike with wind curtailment costs, which are a function of IESO contracts, the OEB has a significant role to play regarding the mechanism which currently allows OPG, in certain circumstances, to receive the full value of hydroelectric production, if the IESO determines it is not needed. These costs are captured in OPG's OEB approved Surplus Baseload Generation Variance Account. In addition, the OEB has approved a Hydroelectric Incentive Mechanism ("HIM") that provides an incentive

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[77] IESO, *2022 Annual Acquisition Report* (April 2022)
[78] See Letter from the Ministry of Energy to the IESO (April 4, 2022)
[79] See https://www.ieso.ca/en/Market-Renewal/Background/Overview-of-Market-Renewal
[80] Undertaking JP1.3
[81] See Interrogatory Response SEC-8; Interrogatory Response PA-Staff-7; Technical Conference Transcript, July 29, 2022, p.37, 92
[82] Presentation Day Transcript, p.129

to the company to reduce hydroelectric spill. As a result of the timing of OPG's next Custom IR application, which is expected to review the now frozen hydroelectric payment amounts, as well the terms of the approved settlement in EB-2021-0290, the OEB will almost certainly have an opportunity to review both the SBG Variance Account and the HIM, beginning in the next few years.[83] The OEB may very well make changes that would have a material impact on the need for exports to reduce hydroelectric spill.

Balancing of the Differing Approaches

56. While a fully allocated cost-based approach is the appropriate starting point, SEC does accept that because of the unique nature of the Ontario electricity market, domestic customers may be worse off if there is a significant increase in the ETS rate. The Elenchus approach, which is based on fully allocated costing methodology, and the Power Advisory approach, which is based on pure economic efficiency, directly conflict. SEC submits the OEB needs to consider both in determining a just and reasonable ETS rate that balances all of the various rate-setting principles.

57. This balancing of different approaches was recognized by both Elenchus and Power Advisory themselves. Mr. Blair (Elenchus) stated that "w[e] looked at one stream of it, which is allocated costs…[b]ut we understand there are other policy objectives and other considerations for the Board to look at."[84] Similarly, Mr. Yauch (Power Advisory) commented that "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."[85]

58. The difficulty is there does not appear to be a "magic number" between the current ETS rate of $1.85/MWh and the most appropriate fully allocated cost-based methodology (80% scenario, $5.42/MWh), based on the 2021 Elenchus Report. With that said, SEC proposes that the OEB set the ETS rate at the half-way point between the two amounts. This would reflect an

[83] As part of the EB-2021-0110 Settlement Proposal, OPG is expected file an application with the OEB in advance of the implementation of MRP, which may include any changes to the HIM. (EB-2020-0290, Settlement Proposal, July 16, 2020, p.19). OPG is also expected to file another Custom IR application for rates beginning in 2027, in which the hydroelectric rate freeze ends (see section 13 of O.Reg 53/05).

[84] Technical Conference Transcript, July 29, 2022, p.114. See also Interrogatory Response PA-VECC-22

[85] Technical Conference Transcript, July 29, 2022, p.4

ETS rate of \$3.64/MWh, based on Hydro One's 2023 proposed revenue requirement. The amount is still significantly below the \$6.54/MWh ETS rate that Power Advisory modelled in its evidence and reflects a balance of approaches that still incorporates fully allocated costing as a key component.

59. Since the change will impact export behavior, and those exporters are active in the TR market to hedge against congestion rents, it may be preferable to postpone the effective date of any material change in the ETS rate until after the expiry of any current TRs have lapsed.[86] SEC requests that the IESO comment in its reply submissions directly on this issue. This would allow exporters and others to adjust their participation in the TR market.

60. While SEC supports a rate-setting approach that balances the various considerations that are detailed in the evidence, what would not be appropriate is a rate that is not grounded at all in allocating an appropriate set of costs to exports.

61. The OEB has already said in two previous decisions that it is seeking a cost based ETS rate. In EB-2012-0031, in ordering Hydro One to undertake a cost allocation study, it did so as to "establish a cost basis for the ETS rate".[87] In EB-2019-0082, when the OEB ordered a further cost allocation study to be undertaken, it did so because it found that not enough costs were being allocated to exporters. The OEB "determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates", but found in the context of the specific record in that proceeding, that there was "insufficient information to conclude what the appropriate allocation of common network costs should be for exporters."[88] It would not be appropriate to ignore the OEB's previous findings on the issue and deviate from the stated need for a ETS rate that is grounded in allocation of appropriate costs to exporters..

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[86] See TR Auction Schedule https://www.ieso.ca/en/Sector-Participants/Calendars/Market-Calendars/2022-Transmission-Rights-Auction-Schedule

[87] *Decision and Order* (EB-2012-0031), June 6, 2013, p.9

[88] *Decision and Order* (EB-2019-0082), April 23, 2020, p.180

Annual Adjustment to the ETS Rate is Required

62. After the OEB determines the appropriate ETS rate, it should also approve an annual adjustment mechanism that applies, until the next proceeding, where a more in-depth review will take place. Continuing to maintain the same ETS rate between rate applications, as has been the case in the past, inherently leads to a cross-subsidization between domestic and export customers.[89] Domestic customers are facing annual increases in UTRs as the revenue requirements of Hydro One and other transmitters are increasing faster than any increase in system load, but as currently the case, the ETS rate does not increase on a similar basis.

63. SEC believes there are two viable options to adjusting the ETS rate annually that would be simple to implement. The first would be adjusting the ETS rate using the same annual transmission Revenue Cap Index adjustment (Inflation Factor – Stretch Factor + Capital Factor), that is approved for Hydro One.[90] Hydro One notes that may cause regulatory complexity.[91] SEC cannot understand how this would be the case. Hydro One is required to file an annual rate adjustment application for its revenue requirement, and there is no reason it could not apply the same methodology to the ETS rate. This requires very limited extra effort on behalf of Hydro One.

64. The second option would be to adjust the ETS rate annually based on the percentage annual increase in the Network Service Rate component of the UTRs. The benefit of this approach is it accounts not just for the change in the costs of Hydro One, but also all transmitters. With significant new transmission lines expected to be built in the coming years[92], this may be the preferable option.

How Often the ETS Rate Should Be Set (Issue 2.4).

65. SEC believes that the current practice of considering the ETS rate on the same rate schedule as Hydro One transmission rates continues to make sense. If the OEB approved a 5-

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[89] Technical Conference Transcript, July 29, 2022, p.125
[90] Undertaking JT 1.2
[91] Technical Conference Transcript, July 28, 2022, p.35
[92] See for example the recent Order-in-Council and Directive to the OEB regarding Hydro One's development and construction of 4 new transmission lines.

year Custom IR framework for Hydro One through 2027, then the ETS rate should be examined in detail again in conjunction, although potentially in a separate proceeding or process, for 2028 rates. The benefit of waiting 5 years is it will give the exporters time to adapt to any changes and allow parties to better understand the implications of many of the upcoming changes to the broader Ontario electricity market.

66. The OEB should also consider reviewing the appropriate ETS rate if there is material change in intertie capacity. For example, until this past August when the project was put on hold, if not outright cancelled,[93] the Ministry of Energy had directed the IESO to enter into negotiations with ITC Holdings for its Lake Erie Connector transmission line project[94], which would have added a 1,000MW of bi-directional intertie capacity between Ontario and PJM.[95] This project, if constructed, would have had a significant impact on export flows, and intertie related costs, which have implications the OEB would need to consider in setting the ETS rate. If the project is revived, or another project to expand intertie capacity is constructed, the OEB would need to reconsider the ETS rate in advance of any scheduled review.

Settlement-Based Approach Should be Allowed (Issue 2.2)

67. Considering SEC's position is that the OEB needs to balance two fundamentally different approaches to rate-setting to determine an appropriate ETS rate, this is the type of rate that is most amenable to being set though a settlement process in the future.

Future Analysis Required

68. SEC believes that additional analysis is required to ensure that when the OEB next considers the appropriate ETS rate, it can more accurately assess the impact of changes to export volumes, congestion rents, and market revenues. Power Advisory attempted to quantify the impact, but they faced significant data limitations, which required the use of a methodology that SEC believes if far from robust to draw too many specific conclusions. SEC requests, that APPrO, in its reply submissions provide the OEB with its perspective on what specific type of data is required for a more robust analysis and what directions should be given to the IESO for

[93] Undertaking JT 2.10
[94] Minister of Energy Directive to the IESO, March 31, 2022, p.3
[95] Minister of Energy Directive to the IESO, March 31, 2022, p.; Interrogatory Response, SEC-13

any future study. Another potential approach is that the OEB create a working group of interested parties to meet over the next couple years to determine what, if any, study can reasonably be undertaken, and what data the IESO would need to provide. The group could also provide input into the methodological design, in order to best forecast the impact of changes in the ETS rate.

Summary

69. SEC believes that the OEB should continue to set an ETS rate even though exporters may also be required to pay ICP. These amounts represent different costs and the ICP should not be mistaken for the collection of the cost of exporters use of the entire transmission system.

70. With respect to the appropriate ETS rate, the OEB should set the rate at the midpoint between the current $1.85/MWh rate and the Elenchus fully allocated cost-based methodology (80% scenario). This would appropriately balance the various rate-setting principles, ensuring exporters pay a share for their use of the transmission system, while recognizing the broad impacts a change may have to domestic customers on other parts of their bill, due to the unique nature of the Ontario electricity market. The ETS rate should also mechanistically increase each year on a similar basis to UTR rates paid by domestic customers.

Respectfully, submitted on behalf of the School Energy Coalition this September 6, 2022.

Mark Rubenstein 2022.09.06 13:42:26-04'00'

Mark Rubenstein
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Appendix – SEC Submissions on the Power Advisory Model

[Confidential]