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**BY EMAIL AND RESS**

October 30, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

**EB-2022-0325 – Phase 2 of the Generic Hearing on Uniform Transmission Rates – Related Issues – HONI Reply Submission on Issues 4, 5, and 6**

Further to Procedural Order No. 4 issued July 29, 2024, please find enclosed Hydro One's reply submission regarding Issues 4, 5, and 6.

An electronic copy of this reply submission has been submitted using the Board's Regulatory Electronic Submission System.

Sincerely,

Uri Akselrud

# HYDRO ONE REPLY SUBMISSION ON ISSUES 4, 5, AND 6

## INTRODUCTION

After having the opportunity to review the submissions from APPrO and ESC, ED, GCC, SEC, DRC, LPMA, VECC, LDC Transmission Group, and OEB staff,[1] Hydro One is providing its reply submission on the approved issues list[2] for Issues 4, 5 and 6 in response to Procedural Order 4 dated July 29, 2024.

## 4.0 ISSUE 4 - CHARGES CAUSED BY PLANNED TRANSMISSION OUTAGES

### 4.1 SHOULD ALL TRANSMISSION CHARGES (NETWORK, LINE CONNECTION, TRANSFORMATION CONNECTION) CONTINUE TO BE ON A PER DELIVERY POINT BASIS, WHEREBY THE CUSTOMER'S CHARGES WOULD BE CALCULATED SEPARATELY FOR EACH DELIVERY POINT, OR SHOULD THEY INSTEAD BE CALCULATED ON AN AGGREGATE PER CUSTOMER BASIS, WHEREBY THE TRANSMISSION CHARGES WOULD BE CALCULATED ON THE CUSTOMER'S AGGREGATE DEMAND FOR ALL DELIVERY POINTS FOR A GIVEN TIME INTERVAL?

Hydro One agrees with OEB staff's submission that to consider this issue is to reconsider the rationale from the OEB Decision in RP-1999-0044 (the "Original UTR Decision") and therefore there would need to be a strong rationale to move away from the Original UTR Decision.[3] After reviewing the submissions for Issue 4, Hydro One understands that most parties believe that there is no strong rationale for moving away from charging all transmission charges on a per delivery point basis.

Hydro One's October 16th submission noted that any additional transmission charges incurred due to load transfers between delivery points, as a result of either planned or unplanned outages, reflect the benefit that transmission customers receive from having the ability to transfer their load across delivery points.[4] OEB staff's submission makes a similar argument regarding the benefit provided to customers that have the ability to transfer load under outage situations, stating that "when a transmission customer performs a load transfer between its delivery points, it is in fact using and benefiting from the

[1] Hydro One notes that the OEB staff submission reflected different labeling of Issue 4.2, 4.3 and 4.4.
[2] Complete issues list was identified in Procedural Order #3 dated July 5, 2024.
[3] OEB staff Submission, page 4.
[4] Hydro One Submission, page 2.

facilities to a different degree than before the load transfer. As a result, the increased usage, albeit short term, should incur a commensurate charge."[5]

VECC's submission uses established rate making principles and the rationale provided in the Original UTR Decision to support the view that the demand used to calculate Line Connection, Transformation Connection and Network charges should continue to be on a per delivery point basis, and not aggregated.[6]

While OEB staff submits that Line and Transformation Connection charges should continue to be charged on a per delivery point basis, their submission also notes that the OEB should consider aggregating delivery points for the purpose of the Network charge. OEB staff further states that Network assets are used to convey energy across the high voltage transmission system through the entire province and that the usage of these facilities is not related to particular delivery points or geographic locations. Based on these statements OEB staff writes that the OEB should consider aggregating the delivery points for purpose of the Network charge.[7] Hydro One disagrees with OEB staff's position with respect to the Network charge. While it is true that the high voltage transmission network does connect load and generation customers across the entire province, there are some limitations on the flow of electricity between certain parts of the transmission network and there are regional variations as to when the network peaks in certain parts of the province, which could make it inappropriate to aggregate certain delivery points. An even more important consideration as to why aggregating the Network charge is not required, is driven by the fact that the Network charge billing determinant for each delivery point is calculated as the <u>higher of</u> two conditions:

1. The delivery point's coincident peak demand in the hour of the month when total hourly demand of all customers is highest for the month; or

2. 85% of the delivery point's peak demand during any hour between 7AM to 7PM business days.

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[5] OEB staff Submission, page 5.
[6] VECC Submission, pages 5-7.
[7] OEB staff Submission, pages 5-6.

Hydro One agrees with VECC's submission that under the current Network charge methodology, double peak billing will not occur under condition 1)[8] since at the time when hourly demand is highest for all customers (i.e. system peak) an individual customer's demand will either be at the delivery point from which it is normally supplied, or it will be at the delivery point to which load is transferred if there was an outage, but not at both at the time of the system peak. With respect to condition 2), the possibility of double peak billing does exist; however, the use of 85% of the delivery point's non-coincident peak demand was put in place by the OEB in the Original UTR Decision as a compromise between various parties' positions on coincident vs. non-coincident peak billing and to address specific concerns regarding free ridership and gaming. As noted in VECC's submission, "it is important, from a cost causality perspective, to continue to determine Network charges on a per delivery point basis and give some weight to each delivery point's non-coincident peak".[9]

OEB staff's submission also supports the appropriateness of condition 2) of the Network charge billing determinant given their statement that "the RP-1999-0044 decision, with its adoption of OHNC's proposal for the non-coincident peak charge determinant [i.e. condition 2)] largely addresses the issue of fairness".[10] Given OEB staff's support for condition 2) and the understanding that double peak billing cannot occur under condition 1), it is not clear why OEB staff suggests aggregating delivery points for the purpose of the Network charge.

Hydro One notes that SEC's submission also does not support aggregation of delivery points by customer. In particular, SEC does not support aggregation for Line and Transformation Connection charges because there is no sound cost-causality rationale for doing so and because of concerns with cross-subsidization between customers with multiple delivery points and those with only one. SEC also does not support aggregation for Network charges because there has been no analysis of the impact of such a change, and they are concerned that the impact could be significant for certain customers.[11]

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[8] VECC Submission, page 6.
[9] VECC Submission, page 6.
[10] OEB staff Submission, page 8.
[11] SEC Submission, page 1.

Hydro One notes that the OEB staff submission also includes inferences on the IESO's ability to aggregate transmission delivery points based on existing Market Rules and Market Manual, and OEB staff points to the aggregation of certain hydroelectric facilities connected at a variety of locations on the transmission system as an example.[12] While aggregation may be technically possible, when asked specifically about the aggregation of transmission delivery points, the IESO had material concerns with doing so, as detailed in the IESO's response to VECC interrogatory #25, part c).

While OEB staff make a number of points that Hydro One supports with respect to maintaining transmission charges on a per delivery point basis, it is not clear from their submission how OEB staff proposes that the OEB address the very real issues driven by double peak billing charges with respect to the negative impacts on transmitters and transmission customers associated with scheduling and completing work that require planned outages. OEB staff's submission to maintain the status quo for Line and Transformation Connection charges, while not supporting a change to the charge determinant definition (as discussed under Issue 4.3) and also not supporting a deferral account approach (as discussed under Issue 4.4) means that the issues associated with double peak billing that gave rise to this proceeding will not be addressed in full.

Hydro One, VECC, SEC and LPMA advocate for maintaining the status quo of transmission charges by delivery point but recognize that a solution needs to be found for the issues raised by double peak billing and therefore advocate for a deferral account approach, as discussed further under Issue 4.4.

With respect to the aggregation of select delivery points as proposed by the LDC Transmission Group, Hydro One stands by the concerns previously highlighted in its October 16th submission.[13] Hydro One also notes an additional concern that was raised by VECC in its submission, which is that the LDC Transmission Group's proposal would result in different charge determinants being applied to transmission customers for the same service – which may be viewed as unfair and discriminatory.[14] Furthermore, the LDC Transmission Group's submission states that Hydro One and the IESO currently totalize meters and therefore implementing totalization of select delivery points should be technically simple to implement.[15] As the entity that would be responsible for implementing the change with respect to totalization of select delivery points, the IESO's response to VECC interrogatory #25, part c) indicates that this would not be the case.

[12] OEB staff Submission, page 6.
[13] Hydro One Submission, page 3.
[14] VECC Submission, page 7.
[15] LDC Transmission Group Submission, page 2.

Lastly, given the principle-based arguments against the aggregation of delivery points that were raised by most parties to this proceeding as discussed above, Hydro One submits that it is not necessary or appropriate to initiate a working group to delve into the details of aggregating of delivery points by customer as suggested by LPMA.[16]

## 4.2 SHOULD THE MEASURES TO ADDRESS THE IMPACT OF DOUBLE-PEAK BILLING BE APPLIED TO BOTH PLANNED AND UNPLANNED TRANSMISSION OUTAGES OR SHOULD THERE BE SEPARATE MEASURES? WHAT SHOULD BE THE OBJECTIVES OF THOSE MEASURES?

While the submissions from various parties agree that both planned and unplanned outages can lead to double peak billing situations, both Hydro One and OEB staff's submissions express a similar view that transmission charges associated with load transfers between delivery points due to any type of outage are appropriate and reflect the benefit customers receive from how they use the transmission facilities. This was previously discussed above under Issue 4.1. As a result, Hydro One disagrees with SEC's view that there is an "unfairness" caused by both planned and unplanned outages on customers with more than one delivery point when they transfer load.[17]

As outlined in its October 16th submission, Hydro One notes that unplanned outages do not result in the same unintended consequences associated with the actions transmission customers take to avoid transmission charges when they are faced with planned outages. Those unintended consequences include:[18]

- Delays and complications related to a transmitter trying to schedule planned outages, which can delay required maintenance or capital work and increase the cost of doing the work; and

- Scheduling work outside of normal business hours or scheduling outages to start and end at midnight on the first and last day of the month, which can increase transmission system reliability risks, increase the costs associated with doing planned outage work and potentially increase safety risks - for both the transmitter and transmission customers.

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[16] LPMA Submission, page 4.
[17] SEC Submission, page 2.
[18] Hydro One Submission, pages 4-5.

The concerns noted above do not apply to unplanned outages. When an unplanned outage occurs, the focus is on restoring power to customers quickly, safely and efficiently, and not on transmission charges.[19]

Furthermore, VECC's submission indicates that while they did not see why the same measures could not be used to address both planned and unplanned outages, they were interested to see the submissions from Hydro One and others who have more familiarity and experience with planned vs. unplanned outages.[20] As outlined in its October 16th submission, Hydro One reiterates that including unplanned outages as part of any measure to mitigate double peak billing issues raises a number of concerns:[21]

- While Hydro One has some understanding of the number of double peak billing occurrences due to planned outages and how to manually calculate the associated impacts on transmission charges, the frequency and impact of double peak billing related to unplanned outages has not been assessed by Hydro One or explored in any detail as part of this proceeding.

- Given the dynamic and potentially complex and wide-ranging impact of unplanned outages on the transmission system (e.g. due to extreme weather situations), and the lack of experience in assessing those impacts, it is not clear that double peak impacts could be calculated for all unplanned outage situations, or if the data necessary to perform the calculations would even be available.

Hydro One believes the OEB has sufficient input on this matter to decide whether any measures to address double peak billing issues should apply to both planned and unplanned outages. As such, Hydro One does not support LPMA's suggestion that a working group is required to look at similarities and differences between planned and unplanned outages.[22]

VECC's submission also raises the issue that there may be a lack of clarity in distinction between planned and unplanned outages. VECC provides as an example the extension of a planned outage beyond the original planned period to address additional work that was not originally contemplated.[23] Hydro One believes that the exact nature of what would be considered a planned outage for the purpose of getting a double peak billing refund should be one of the items to be determined as part of the working group looking at the deferral account details, as discussed further under Issue 4.4.

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[19] LDC Transmission Group interrogatory #5, part c).
[20] VECC Submission, page 6.
[21] Hydro One Submission, page 5.
[22] LPMA Submission, page 4.
[23] VECC Submission, page 7.

Should the definition of the transmission charge determinants, used to establish UTRs and bill transmission charges, be revised to exclude the impact of planned transmission outages on customers with multiple delivery points?

Hydro One shares OEB staff's view that transmission outages, either planned or unplanned, should not be afforded special treatment when considering transmission charges, and therefore transmission charge determinants should not be revised to exclude the impact of transmission outages on customers with multiple delivery points.[24]

Both OEB staff's and VECC's submissions include many of the same concerns with respect to revising the definition for transmission charge determinants that Hydro One raised in its October 16th submission, including the various concerns identified by the IESO. Specifically, in response to VECC interrogatory #25, part c) the IESO stated that redefining the charge determinants to exclude the impact of planned transmission outages would require significant time and effort given the variability of power switching conditions that can give rise to a double peak charge. Furthermore, the IESO indicated that due to this variability and lack of historical data it may not be feasible to establish a comprehensive set of business rules that would identify and determine the impact of such double peak billing events under all circumstances. The IESO also identified the complexity of implementing any changes and the fact that this could take multiple years to implement. Furthermore, consistent with Hydro One's submission, VECC's submission also recognizes that the "alternate" approach suggested by IESO in the response to VECC interrogatory #25, part c) is essentially Hydro One's Option 4 (deferral account approach). VECC further notes that the deferral account approach is "simpler to implement" and "more transparent".[25]

### 4.3 SHOULD THE DOUBLE-PEAK BILLING IMPACT OF PLANNED AND UNPLANNED TRANSMISSION OUTAGES BE TRACKED IN A DEFERRAL ACCOUNT?

The submissions from Hydro One, VECC, SEC, LPMA and GCC all indicate a preference for a deferral account approach for dealing with double peak billing issues. SEC's submission noted that this option is "the most transparent for transmitters, double-peak billed customers, all other customers, and the OEB".[26]

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[24] OEB staff Submission, page 8.
[25] VECC Submission, page 8.
[26] Hydro One Submission, pages 7-9; VECC Submission, pages 9-10; LPMA Submission, page 5; GCC Submission, page 3.

While some of the submissions suggest that transmission charges associated with planned and unplanned outages should be included in the deferral account, Hydro One believes it is not appropriate to include unplanned outages for the reasons previously discussed under Issue 4.2. Consistent with its October 16th submission, Hydro One notes that if the OEB decides to include unplanned outages, Hydro One does not support the use of a deferral account approach as it is not clear that this approach could feasibly be implemented if unplanned outages are included.[27]

Of all the parties to this proceeding that responded to Issue 4, OEB staff is the only party that does not support the use of deferral account approach and specifically requested that any participant supporting this approach address the eligibility criteria (Causation, Materiality, Prudence) for establishing a deferral account as part of their Reply.[28] Hydro One does so below, but notes that in light of the goal of finding a solution to the double-peak billing issue for the benefit of impacted transmitters, LDCs and customers and given the overall context of this proceeding, Hydro One does not believe the OEB should be restricted by the eligibility criteria normally applied when a utility seeks to establish a deferral account.

**Causation:**
The amounts to be recorded in the deferral account result directly from additional transmission charges associated with the transfer of load between delivery points due to planned outages. These additional charges would be refunded to the impacted transmission customers and are to be captured in the deferral account by the impacted transmitter for a future recovery. Transmission customers' actions in response to these additional charges are currently driving unintended consequences that have a detrimental impact for both the transmitters and transmission customers on the efficient and safe operation of the system. The amounts captured in the deferral account will be clearly outside the base upon which transmission revenues and associated rates are derived.

[27] Hydro One Submission, page 7.
[28] OEB staff Submission, page 10.

**Materiality:**

Hydro One believes that the amounts to be captured in the deferral account are expected to be material based on historical experience with transmission-connected customers that made double-peak billing inquiries[29] and the expectation that establishing a deferral account for recovery of double peak billing events will significantly increase the number of such inquiries and requests for a refund. Furthermore, LPMA's submission includes an extensive discussion on the materiality of the charges caused by planned transmission outages and conclude that while the individual peak billing incremental revenue to Hydro One is small, in aggregate it could amount to material amounts.[30]

Additionally, LPMA's submission further notes that even small incremental costs due to double peak billing can have significant and material impacts on distribution customers. This is evident from the examples provided in the evidence submitted by the LDC Transmission Group.[31] The LDC Transmission Group's submission also included a number of points supporting the fact that double peak billing is a significant problem, and they note that in addition to the costs borne by its distribution customers, there are also "costs and operational inefficiencies from steps taken to try to avoid double peak transmission billing" and that the "large number of LDCs devoting time and effort to fix this issue … is an indication of its significance".[32]

**Prudence:**

The quantum of costs associated with a double peak billing event can be precisely calculated by the transmitter using the approved UTRs once a methodology is established to identify the load that is shifted between delivery points due to a planned outage. As discussed further below, a working group would need to be established to work out the details of the deferral account, subject to review and approval by the OEB, for accepting and administering double peak billing refund requests to be initiated by the transmission customers related to planned outages.

OEB staff's submission also raises several concerns regarding the logistics of reviewing balances and approving them for disposition.[33] Hydro One submits that most of these concerns relate to how deferral and variance accounts are treated in the distribution business. For example, OEB staff refers to RSVA accounts 1584 and 1586[34] which are distribution accounts that do not apply for transmitters. In transmission, once the prudency

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[29] AMPCO interrogatory #4.
[30] LPMA Submission, page 3.
[31] Exhibit M1, Joint Submission of the LDC Transmission Group, Appendix "The LDC Transmission Group Experiences".
[32] LDC Transmission Group Submission, page 1.
[33] OEB staff Submission, page 10.
[34] In OEB staff submission, this RSVA account is incorrectly referred to as Account 1588. Hydro One assumes this is a typographical error in the OEB staff submissions.

of an account is approved, the amount is simply included as part of the transmitter's revenue requirement to be recovered through rates and not through a rate rider as is the case in distribution. It would be Hydro One's expectation that any refunds issued to LDCs would be captured as part of their RSVAs (1584 and 1586) to offset the transmission charges from the IESO and that reconciliation would occur as a matter of course when those RSVA are cleared. Since RSVAs do not apply to transmission-connected customers that are not LDCs, Hydro One's expectation is that reconciliation would not apply to them. As for transmitters, Hydro One expects that details will be maintained on who received refunds and how the refund amounts were calculated, and this would be examined as part of the prudence review process at the time of the disposition. In any case, any such concerns OEB staff might have could be addressed as part of the working group, as discussed below.

Hydro One supports the suggestion from many other parties that it would be appropriate for the OEB to establish a working group to work out the details of the deferral account approach. The working group could be tasked with addressing the items raised by parties in this proceeding regarding the deferral account approach, including:

- Developing the new business process for transmitters to accept and administer requests from transmission customers for refunds due to double peak billing event resulting from a planned outage.

- Developing the methodology for calculating the refund amount (e.g. process for estimating meter readings by installing temporary measuring devices or using historical readings where metering is not installed, or meter data is not available).

- Addressing how the refund amounts are to be tracked in the deferral account.

- Developing the process for clearing the deferral account.

- Defining planned outages for the purpose of getting a refund (e.g. VECC's example of how to treat an extension to a planned outage beyond the original planned period to address additional work that was not originally contemplated).[35]

- Developing a process for situations when more than one transmission asset owner is involved (e.g. Milton/Oakville issue raised in VECC's submission).[36]

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[35] VECC Submission, page 7.
[36] VECC Submission, page 9.

- Outlining what information, if any, needs to be tracked in support of the deferral account to demonstrate prudence in the management of outage events.

- Considering how the deferral account could be used to reimburse a transmission customer (e.g. Hydro One Distribution) for transmission charges associated with a load transfer *through the distribution system* to supply a transmission customer connected at another transmission delivery point (e.g. GCC situation).[37]

- Other considerations that the OEB finds appropriate.

As noted in its October 16th submission, Hydro One is concerned that a deferral account approach means that transmitters are effectively taking on accountabilities in the settlement of transmission charges that are typically the responsibility of the IESO. This additional work is compounded by the fact that the volume of requests Hydro One anticipates receiving for refunds associated with double peak billing due to planned outages may increase substantially from what was observed historically.[38] There is also potentially increased administrative effort associated with satisfying the requirements from the working group on how to address the items noted above. All of this will have staffing implications for transmitters and could result in a situation where the administrative effort and cost associated with a deferral account approach could become significant. As such, Hydro One submits that in order to address its concerns with the use of a deferral account approach, impacted transmitters should be permitted to include any costs associated with administering the process related to double peak billing transmission charges as part of the deferral account.

## 4.4 OTHER CONSIDERATIONS FOR ISSUE 4

Hydro One notes that all parties to this proceeding who provided submissions on Issue 4 support the OEB looking at the issue of double peak billing events for distribution, and how any changes made to address this issue for transmission-connected customers could be applied to distribution-connected customers. Consistent with its submission from October 16th Hydro One notes that similar double peak billing concerns exist in distribution and need to be addressed (specifically the impact of double peak billing for load transfers that occur between a transmission delivery point to a distribution delivery point and load transfers that occur between distribution delivery points).[39] Furthermore, as stated in the October 16th submission, Hydro One expects that the solution adopted by the OEB will eliminate the challenges that have occurred in the past with respect to coordinating

[37] GCC Submission, paragraph 14.
[38] Hydro One Submission, pages 8-9.
[39] Hydro One Submission, pages 9-10.

planned transmission outages, while ensuring that the solution permits transmitters to collect their OEB-approved revenue requirements.[40]

Additionally, in its submission, the LDC Transmission Group states that “double peak transmission billing results in incremental revenue for a transmitter that experiences an outage. This has awful optics and is evidence of poor rate setting”.[41] Hydro One is compelled to clarify that there is no incremental revenue and to challenge the claim of poor rate setting.

As explained by Hydro One in its response to LDC Transmission Group interrogatory #1:

> The forecast charge determinants used to set UTRs assume that a certain amount of double peak billing events will occur over the forecast period consistent with the amount of double peak events that are part of the historical charge determinant data used as the basis for setting the forecast. Given that the forecast charge determinants used to calculate UTR rates are slightly higher to account for double peak events, the resulting rates are slightly lower than they would otherwise have been. When these slightly lower rates over the forecast period are applied to actual charge determinants over the forecast period which include the impact of double peak events, Hydro One recovers its approved revenue requirement. As a result, double peak billing events do not result in incremental revenue relative to Hydro One’s approved revenue requirement.

With respect to the claim of poor rate setting, as the discussion under Issue 4.1 demonstrates a strong case can be made that the current methodology of applying charges by delivery point (which results in double peak billing charges) is appropriate and consistent with cost causality principles.

[40] Hydro One Submission, page 9.
[41] LDC Transmission Group Submission, page 2.

## 5.0 ISSUE 5 - BASIS FOR BILLING RENEWABLE, NON-RENEWABLE AND ENERGY STORAGE FACILITIES FOR TRANSMISSION CHARGES

### 5.1 SHOULD THE APPLICATION OF GROSS LOAD BILLING THRESHOLDS TO EMBEDDED GENERATOR UNITS BE DEFINED BY GENERATING UNIT OR GENERATING FACILITY OR BY SOME OTHER APPROACH? THIS INCLUDES REFURBISHMENTS APPROVED AFTER OCTOBER 30, 1998, TO A GENERATOR UNIT THAT EXISTED ON OR PRIOR TO OCTOBER 30, 1998.

At the outset, Hydro One would like to stress that clarifications regarding the application of the gross load billing rules are needed now from the OEB to ensure there is a consistent understanding of the rules by customers and transmitters. These clarifications should be provided as part of the current phase of the proceeding. Hydro One disagrees with suggestions that decisions in the current phase cannot be made without a further review of whether gross load billing should continue to be applied.[42]

Without clarity on the issues identified to be determined in Phase 2, there will continue to be customer dissatisfaction and complaints.

The above being said, Hydro One does not disagree that a broader, more comprehensive assessment of gross load billing, which the OEB intends to undertake in Phase 3 of this proceeding, would be important and beneficial. This type of holistic exploration of the need for gross load billing will require an in-depth examination into system planning practices and will take significant time to complete.

With respect to Issue 5.1 specifically, consistent with its submission from October 16th, Hydro One believes that it would be more equitable to apply gross load billing on a facility basis as opposed to on a unit basis. In Hydro One's view, the current approach to gross load billing has enabled customers in several instances to be exempt from gross load billing charges in ways that may not have been contemplated when the rules were established.[43]

[42] See, for example, page 1 of the Environmental Defense submissions.
[43] Hydro One Submission, page 10.

In respect of the following specific points made by parties:

- At page 12 of the OEB staff submission, OEB staff states “the gross load billing threshold continue to be applied on a per unit basis: OEB staff submits that the basis described in Hydro One’s technical report is compelling.”[44]

  Hydro One is unclear as to what the above statement refers to given that Hydro One has recommended that the gross load billing threshold be applied on a facility basis. The statement quoted above could imply that Hydro One’s Background Report supports a unit-based approach for assessing gross load billing, which is a misinterpretation of Hydro One’s position.

- At page 13 of the OEB staff submission, it is stated that the original reason for charging on a per unit basis was “a matter of simplicity to reduce the administrative effort and cost associated with metering and settlement” and that the same reasons still apply today. However, OEB staff’s submission does not explain why it is simpler, cost-effective and less of an administrative burden to continue to apply the threshold on a unit basis.

  The only way in which maintaining the current approach to gross load billing may be simpler and cost-effective is because it would reduce the number of new installed embedded generation units that would be subject to gross load billing. However, it raises questions as to whether this approach is equitable, fair and appropriate from a principled perspective. The main concern with the current approach is that it provides customers with the ability to be exempt from gross load billing in ways that may not have been contemplated and clearly favours certain generation technologies over others. Furthermore, Hydro One would like to clarify that the implementation of a facility-based approach for assessing gross load billing eligibility would not introduce additional complexities from a settlement and administration standpoint.

- With respect to refurbishments, Hydro One maintains the view that OEB staff’s recommended approach for assessing and addressing generator unit refurbishments[45] would be inconsistent with the current gross load billing rules established in the UTR Schedule. Whether a scenario involves a new embedded generation connection or a refurbishment of an existing connection should not result in a different application of the gross load billing rules. Hydro One acknowledges that refurbishment scenarios could result in a change to the number

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[44] OEB staff Submission, page 12.
[45] OEB staff Submission, pages 13-14.

of units, which introduces additional complications when assessing gross load billing eligibility and determining the incremental installed capacity. For this reason, Hydro One believes that it would be fundamentally appropriate to assess gross load billing based on the total facility size when a refurbishment is undertaken.

- With respect to VECC's submission on page 12 which quotes Hydro One's response to interrogatory VECC 10,[46] Hydro One would like to clarify that the interrogatory response was provided with respect to existing customers already subject to gross load billing (who would not be subject to additional metering and administrative costs as a result of changing the approach from unit to facility.)

## 5.2 IS ADDITIONAL CLARITY NEEDED ON THE APPLICABILITY OF GROSS LOAD BILLING THRESHOLDS TO EMBEDDED GENERATION THAT EMPLOYS INVERTERS (SUCH AS EMBEDDED SOLAR GENERATION)?

As stated in its October 16, 2024 submission, Hydro One believes that in principle, the gross load billing rules in the UTR Schedule should not provide customers who deploy inverter-based embedded generation (such as solar generation) a technological advantage that would exempt them from gross load billing more easily than customers who deploy other types of embedded generation with larger generating units (for example wind generation).[47] In the OEB staff submission, it is proposed that the "logical demarcation point for what is considered a "unit" in a non-conventional facility would be the point at which a meter would likely be installed."[48] Hydro One is not clear how this definition for a unit would be applied in practice and why the definition of a unit would be tied to the "likely" point at which a meter would be installed. Furthermore, it is not clear to Hydro One what is meant by "non-conventional". Additionally, Hydro One does not believe that inverter-based generation or storage facilities should be viewed as non-conventional. Moreover, the suggested method of establishing the "logical demarcation point" is not consistent with any currently published regulatory or technical approaches for defining a "unit" and could result in further potential ambiguity and inconsistent treatment in terms of how gross load billing should be applied.

It is important to Hydro One that the OEB provide clarity in this phase of the proceeding as to whether Hydro One should to continue to use the capacity of the inverter for each array/inverter set within an embedded solar generation facility to define an individual generator unit, or whether another practice would be more technically suitable. If other criteria for defining a "unit" is recommended, the criteria should be clear and unambiguous.

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[46] VECC Submission, page 12.
[47] Hydro One Submission, page 11.
[48] OEB staff Submission, page 14.

*Clarification point regarding Hydro One's response to VECC interrogatory #13, part b):*

In response to VECC's submission that Hydro One clarify its answer to VECC interrogatory #13, part b),[49] Hydro One provides the following clarification: The 1,268 MW figure stated in the Background Report represents the total aggregate installed capacity of all solar generation facilities greater than 2 MW currently exempt from gross load billing charges. As part of its response, Hydro One did not analyze the details for the total aggregate installed capacity represented by all solar generation facilities greater than 1 MW. If a 1 MW capacity threshold was used, the total aggregate installed capacity of all solar generation facilities that would be subject to gross load billing would be higher the 1,268 MW figure.

### 5.3 HOW SHOULD THE UTR SCHEDULE APPLY TO ENERGY STORAGE FACILITIES?

On this issue, Hydro One does not have any further submissions to make other than what Hydro One set out in its October 16, 2024 submission.[50] However, Hydro One reiterates that it is important for the OEB to clarify whether gross loss billing applies to energy storage (including clarification of the applicable threshold) to eliminate any ambiguity in terms of how energy storage should be treated from a gross load billing perspective.

*Clarification point with respect to OEB staff submission page 17:*

The OEB staff submission states that "RP-1999-0044 established that generators be exempt from transmission charges, since these would be borne by the load customers through the pricing of the commodity. OEB Staff submits that there is a parallel to energy storage facilities."[51]

Hydro One notes that generators do in fact pay Network charges and are therefore not exempt from transmission charges.

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[49] VECC Submission, page 14.
[50] Hydro One Submission, pages 12-13.
[51] OEB staff Submission, page 17.

## 6.0 ISSUE 6 – GROSS LOAD BILLING THRESHOLDS FOR RENEWABLE AND NON-RENEWABLE GENERATION

### 6.1 WHAT SHOULD THE GROSS LOAD BILLING THRESHOLDS BE FOR RENEWABLE AND NONRENEWABLE EMBEDDED GENERATION?

On this issue, Hydro One does not have any further submissions other than what Hydro One set out in its October 16, 2024 submission.[52]

### 6.2 SHOULD GROSS LOAD BILLING EXEMPTIONS BE AVAILABLE IN CERTAIN LIMITED CIRCUMSTANCES?

On this issue, Hydro One notes that OEB staff suggested that the UTR schedule should allow for a transmitter to seek an exemption from time to time from the application of gross load billing, where necessary and appropriate.[53] Hydro One agrees with OEB staff that a license amendment could be sought to facilitate an exemption request if required. However, Hydro One does believe that, in the specific case where the transmission system cannot adequately supply a customer's demand and the customer installs embedded generation or storage to address this shortfall, a transmitter should not be required to seek OEB-approval for such an exemption. It is Hydro One's view that this scenario could become more prevalent due to the increased demand for electricity that is being projected over the next decade. To avoid unnecessary connection delays in such cases, a transmitter should be permitted within the UTR to limit the customer demand eligible for gross load billing to only the capacity that can be supplied by the transmission system.

## 7.0 OTHER CONSIDERATIONS FOR ISSUES 5 AND 6

As stated in Hydro One's October 16th submission, Hydro One strongly believes that the OEB needs to maintain consistency in terms of how gross load billing principles and practices are implemented at the transmission and distribution levels. This is necessary to ensure that transmission costs are recovered fairly from those customers connected to the distribution system who are driving these costs. If the OEB proposes to change any of the existing practices with respect to gross load billing rules in the UTR Schedule as covered under Issues 5 and 6, the OEB should consider and clarify how these changes would impact gross load billing of distribution customers. Hydro One therefore reiterates the need for a clear direction as part of the current proceeding with respect to distribution.[54]

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[52] Hydro One Submission, pages 13-14.
[53] OEB staff Submission, page 20.
[54] Hydro One Submission, pages 14-15.

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