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BY EMAIL AND RESS

May 13, 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 Background Reports on Issues 4 and 5/6 – Responses to Clarification Questions

Further to Procedural Order No. 2 issued April 19, 2024, Hydro One is providing its responses to clarification questions on HONI's background reports on Issue 4 and 5/6, as well as responses from the Independent Electricity System Operator (IESO).

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

Sincerely,

Uri Akselrud

CLARIFYING QUESTIONS OF AMPCO - 01

Reference:
Background Report Page 3

Interrogatory:
A double peak billing event can occur in instances where a transmission customer is supplied by more than one connection point to the transmission system, each of which is referred to as a delivery point (DP).

a) Please provide the number of LDCs impacted by double peak billing for each of the years 2020 to 2023.

b) Please provide the number of industrial customers impacted by double peak billing in 2020 to 2023.

c) Please provide the number of large commercial customers impacted by double peak billing 2020 to 2023.

Response:
The responses below are based on the following scenarios which Hydro One is able to capture (i) transmission-connected customers' inquiries to Hydro One with respect to their double peak billing (which were billed by the IESO[1]) or (ii) ad-hoc load transfer settlements directly between Hydro One and the transmission-connected customers.

a) 3

b) 2

c) 0

[1] Hydro One does not have the information related to double peak billing events billed by the IESO which were not identified by the transmission-connected customers. Hydro One anticipates that this represents majority of the double peak billing events.

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CLARIFYING QUESTIONS OF AMPCO - 02

Reference:
Background Report Page 5

Interrogatory:
Please provided a detailed description of the issue of double peak billing on the distribution side.

Response:
As stated in Section 1.4.2.2 of the Background Report on Issue 4, page 9 of 20, Hydro One Distribution's Sub-Transmission rate class customers with multiple DPs have the same double peak billing impact as the transmission-connected customers since they are currently billed by each of their DPs (to be consistent with the transmission billing practices). Thus, detailed description of the issue described in Section 1.2 of the Background Report on Issue 4 for transmission-connected customers also applies to Hydro One Distribution's Sub-Transmission rate class customers with multiple DPs.

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CLARIFYING QUESTIONS OF AMPCO - 03

Reference:

Background Report Page 5

Interrogatory:

a) Please provide the number of LDCs that have both transmission and distribution DPs for each of the years 2020 to 2023.

b) Please provide the number of industrial customers that have both transmission and distribution DPs for each of the years 2020 to 2023.

c) Please provide the number of large commercial customers that have both transmission and distribution DPs for each of the years 2020 to 2023.

Response:

a) Based on the current information, 28 LDCs have both transmission and distribution DPs.

b) Based on the current information, 8 industrial customers have both transmission and distribution DPs.

c) Based on the current information, 0 large commercial customers have both transmission and distribution DPs.

Hydro One Transmission's customer supply configuration is separate from Hydro One Distribution's customer supply configuration. As such, Hydro One is unable to confirm if the customers referred to in parts a) to c), have ability to transfer load between transmission and distribution DPs.

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CLARIFYING QUESTIONS OF AMPCO - 04

Reference:

Background Report Page 6

Interrogatory:

Double peak billing events result in incremental billing costs for those customers with the ability to transfer load between their multiple transmission DPs, which are costs they would not otherwise incur absent these transmission charges.

a) Please provide the cost impacts of double billing events for transmission-connected LDCs for each of the years 2020 to 2023.

b) Please provide the cost impacts of double billing events for transmission-connected industrial customers for each of the years 2020 to 2023.

c) Please provide the cost impacts of double billing events for transmission-connected large commercial customers for each of the years 2020 to 2023.

Response:

Based on the information provided in response to Clarifying Questions Issue 4, AMPCO-1, estimated incremental billing costs for the transmission-connected customers that made double-peak billing inquiries to Hydro One, is summarized below:

a) $258,000

b) $429,000

c) $0

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CLARIFYING QUESTIONS OF AMPCO - 05

Reference:

Background Report Page 7 Section 1.4

Interrogatory:

a) With respect to the four options proposed, which option is Hydro One's preferred option and why?

b) Please rank the 4 options and provide the criteria used and relative rankings.

c) Did Hydro One consult with transmission connected customers (LDCs and C&I) on the four options?
   i. If yes, please provide details.
   ii. If no, please explain why not.

d) Did Hydro One consult with other parties prior to this consultation on the four options?
   i. If yes, please provide details.
   ii. If no, please explain why not.

Response:

a) First, to clarify, none of the four options have been "proposed". Instead, they have been identified to assist the parties and the OEB in considering the issues in this generic proceeding, in which Hydro One is a party but not the applicant.

   Notwithstanding this, because of its experience and role in the Ontario electricity system, Procedural Order 1, dated December 8, 2023, ordered Hydro One to prepare and file, without prejudice, the background report for this proceeding regarding Issues 4, 5, and 6. Furthermore, the OEB contemplated a process in which Hydro One would respond to clarifying questions about the report, not interrogatories about Hydro One's position in respect of issues identified in the report. At a later stage in the generic proceeding, after it has heard and considered the views of all participants, Hydro One expects to advocate for one or more options as being the option(s) that it prefers. At that time, Hydro One will provide the reasons for its views in that respect. For Hydro One to express a preference before the issues list and certain scoping issues identified in the report have been finalized, and before having the benefit of input from other parties, would be premature, as well as out of step with the process contemplated by the OEB for this proceeding.

b) Please see part a) above.

c) Hydro One did not reach out to any transmission-connected customers (LDCs or C&I customers) to consult on any of the four options. Hydro One notes that it was contacted by several interested parties regarding issues in this proceeding. The content of the report was not influenced by any conversations Hydro One may have had with these parties.
   i. Not applicable.
   ii. As noted in response to part a), above, Hydro One is a participant and not the applicant in this generic proceeding. Procedural Order 1 issued by the OEB did not suggest or request that Hydro One consult with parties prior to the filing of the background report.

   Hydro One's understanding is that this proceeding is intended to provide an opportunity for the OEB, as the initiator of this generic proceeding, to hear from all of the relevant stakeholders that have an interest in the outcome of this proceeding. Hydro One's report was filed to provide background information to facilitate dialogue among the parties. Hydro One anticipates that as part of the dialogue among the parties to this proceeding, interested parties will put forward comments, positions and potentially evidence. Hydro One looks forward to learning from the perspectives of parties as part of this proceeding.

d) No, Hydro One did not consult with parties prior to this consultation on the four options.
   i. Not applicable.
   ii. See response to part c) (ii) above.

CLARIFYING QUESTIONS OF GLENCORE CANADA CORPORATION - 01

<u>Reference:</u>
OPTION 1: HONI Background Report, Issue 4, Page 7, Lines 26-29
OPTION 2: HONI Background Report, Issue 3, Pages 8-9
OPTION 3: HONI Background Report, Issue 3, Pages 10-11
OPTION 4: HONI Background Report, Issue 3, Pages 12-13

<u>Interrogatory:</u>
OPTION 1

1. The report states:

> In the view of the OEB in the Original UTR Decision, the current practice was seen to follow the user-pays principle as transmission-connected customers with more than one DP were seen as receiving the benefit of increased reliability and should as a result expect to pay for this type of reliability.

   Please provide the citation to the Original UTR Decision where this view of the OEB is set out.

2. Please confirm that double peak billing event demands are currently included in forecasts used to set UTRs. [Page 10, lines 1-2]

3. The Report indicates that the same double peak billing issues arise for unplanned as for planned outages [see page 4, lines 24 *et seq.*]. Should any solution adopted in this process be applied to both types of outages?

OPTION 2

4. HONI's Option 2 for addressing double peak billing is to bill by customer instead of by DP.

a) Please confirm that, currently, transmission connected customers pay Network, Line Connection and Transformation Connection charges based on their peak monthly demand at each Delivery Point.

b) Is a transmission connected customer's peak monthly demand currently determined as;
   i. the sum of the peak demand during the month at each Delivery Point; or

ii. the highest sum during the month of the demands at all of the customer's Delivery Points?

c) Which of these two approaches best reflects the customer's demand during the month on the transmission system?

d) Does the suggested Option 2 methodology essentially reflect the aggregation approach set out at part 2.(b)(ii) above?

e) At page 8, lines 15-21, HONI states:

> Customers with multiple DPs may gain unfair advantage because of a diversity of demand across their DPs. This is because different DPs may experience peak demand at different times. In this case the aggregated demand for the customer could be less than the sum of the peak demand at each DP resulting in lower charges for the customer. This revenue deficit from the lower aggregated demand will need to be made up by higher rates, shifting costs to the customers with single DP.

i. Please confirm that this statement defines "fairness" relative to the current allocation of network charges, rather than relative to the optimal reflection of responsibility for/benefit from network costs.

f) HONI's report includes the following statement (page 8, lines 22-28):

> While all transmission-connected load customers pay the Network Charge, customers who own their Line and/or Transformation Connection assets do not pay these charges. Currently, there are some transmission connected customers with multiple DPs who own Line/Transformation assets at some of the DPs. Aggregating the demand at customer level will require additional consideration to make sure customers are not charged for the demand supplied by assets they own.

Please discuss how this issue could be addressed. (For example, elimination of the demand associated with any Delivery Point for which the customer owns the line and/or transformation facilities when allocating those cost pools.)

g) Can the IESO provide any information regarding the scope/cost of work to adopt a solution like HONI's Option 2?

h) Can HONI elaborate on its view of the nature of, and process for, the updates to the UTR schedule referred to at page 9, line 3?

i) Please explain what is meant by a “Sub-Transmission customer”.
   i. Please confirm that HONI’s concern regarding Sub-Transmission (ST) customer fairness [page 9, lines 4-21] is that HONI distribution would benefit from the “customer level” allocation inherent in Option 2, and unless ST customers are similarly treated they will overpay relative to HONI Distribution’s transmission payment obligations, and the excess would be refunded through variance treatment to all customers of that distributor (i.e. a subsidy from double peak billed customers to other customers of HONI distribution).
   ii. Please confirm that adopting the same “customer level” allocation for ST customers as for transmission connected customers would avoid this unfairness.

j) Please explain how network, line connection and transformation connection costs are allocated to large volume distribution connected customers (including the impact of the demands of distribution connected large customers on their host distributors transmission cost allocations).

k) Is the host distributor’s peak monthly demand currently determined as;
   i. the sum of the peak demand during the month at each Delivery Point; or
   ii. the highest sum of the demands at all of the host distributor’s Delivery Points?

l) Under Option 2, how would the Network, Line Connection and Transformation Connection charges be determined for a customer with one Delivery Point at a transmission system connection point and a second Delivery Point at a distribution system connection point?

OPTION 3

5.

a) Given the absence of a historical data set which excludes demands associated with double peak billing events, how would “Option 3” for addressing the double peak billing issue be implemented (i.e. how would charge determinants which exclude the impact of double peak billing events be determined)?

b) Can the IESO address the scope and cost of adopting its systems and processes in the manner suggested by HONI under its option 3 of not charging customers for double peak events?

c) HONI suggests that adjusting the charge determinants to remove the impact of double peak billing events would result in a reduction in the charge determinants and a corresponding increase in the UTR rates.

Would this result not obtain for any mechanism adopted to address the double peak billing issue? (For example, if the customer refund/transmitter variance account solution – Option 4 - were adopted, would such refunds not ultimately be included in future forecasts of demand used to determine UTR rates, in order to preclude under-recovery of transmission pooled costs?)

d) Can HONI elaborate on the nature of, and process for, the updates to the UTR schedule referred to at page 11, line 4?

OPTION 4

6.

a) HONI cites as a disadvantage of its suggested Option 4 (tracking double peak billing impact in a transmitter deferral account) unfairness to Hydro One Distribution sub-transmission customers.
   i. Please elaborate on the "unfairness".
   ii. Could deferral account treatment as proposed be extended to the sub-transmission level for affected customers to address this "unfairness"?

b) In connection with Option 4 HONI suggests it would be necessary for UTRs to be rounded to 4 decimal places.

   What are the considerations/concerns in doing so?

__**Response:**__

1. The referenced statements are Hydro One's interpretation of the following excerpt from the Original UTR Decision (Section 3.4.9):

> In the Board's view, the alternative of allowing customers to aggregate demand from delivery points for billing purposes would provide an unfair advantage to those customers with diversity of demand from geographically different delivery points at the expense of other customers. The Board is also of the view that allowance for shifting as suggested by MEA is cumbersome, inconsistent with the user-pay or fairness principle and impractical.

2. Confirmed.

3. The OEB has described the scope of the issue for this proceeding as being in relation to planned outages only. As stated in Section 1.2 of Hydro One's Background Report on Issue 4, at page 4 of 20, Hydro One believes that a clarification from the OEB as to

the treatment of unplanned outages with respect to double peak billing, in the context of the current proceeding, will help avoid future customer complaints and confusion. As such, Hydro One defers to the OEB in finalizing the issues list and scope for this proceeding as to whether a solution in this proceeding should encompass double peak billing arising from unplanned outages.

4.

a) Line and Transformation Connection charges are based on customer's peak monthly demand at each DP.

However, Network charge determinant is calculated as follows:

Higher of:

i. DP's coincident peak demand in the hour of the month when the total hourly demand of all customers is highest for the month; or
ii. 85% of the DP's peak demand during any hour 7 AM to 7 PM business days.

As with Line and Transformation Connection charges, Network charge is also billed by DP.

b) For a transmission-connected customer with multiple DPs, the total monthly charge determinants are derived as sum of the individual charge determinants at each of the customer's DPs.

c) The response is provided based on the assumption that the question is asking to compare the current practice of DP level billing and customer level billing (based on aggregated load from all customer's DPs) in terms of which of the two options best reflects the customer's demand on the transmission system.

For a customer with multiple DPs that are located in close geographic proximity, aggregate demand from each of their DPs can more appropriately reflect their demand on Network assets. However, this may not be the case for a customer with multiple DPs that are spread out across the province.[1]

Regardless of the location of customer's DPs, demand at each individual DP more appropriately reflects their impact on the system when it comes to the Connection assets (i.e. Line and Transformation).

[1] RP-1999-0044 (Original UTR Proceeding), Transcript Volume 2, pages 306-309.

d) Under Option 2, hourly load from each of the customer's DPs will be aggregated and the customer's monthly charge determinants will be derived based on this aggregated hourly load profile.

e) The words "unfair advantage" used in the referenced statement is in the context of the potential reduction in the total Network, Line Connection and Transformation Connection charges that customers with multiple DPs would pay under Option 2, as compared to customers with single DP which could see potentially higher transmission charges relative to the status quo approach.

f) Please refer to Hydro One's response to Clarifying Questions Issue 4, VECC-6, part a).

g) ***Response from IESO:***
Please refer to the IESO's response to Clarifying Questions Issues 5 & 6, VECC-25, part c).

h) In Hydro One's view, changes would be required to the UTR "Terms and Conditions" including at a minimum adding a new section detailing how aggregation across multiple DPs would be defined for the purpose of assessing transmission charges. The transmission rate schedule would also have to be updated to reflect the new definition of billing demand for Network, Line and Transformation Connection services.

i) Hydro One's Sub-Transmission rate class is defined as:[2]
   - Embedded supply to Local Distribution Companies (LDCs). "Embedded" meaning receiving supply via Hydro One Distribution assets, and where Hydro One is the host distributor to the embedded LDC. Situations where the LDC is supplied via Specific Facilities are included; or
   - Load which:
     - is three-phase; and
     - is connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive, where 44 kV and 13.8 kV are the voltage of the primary side of the local transformer; local transformer can be Hydro One owned or customer-owned; and
     - is greater than 500 kW (monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is greater than 500 kW).

   i. Confirmed.
   ii. Confirmed.

[2] Partial Decision and Rate Order, EB-2023-0030, page 38/56

j) Hydro One Distribution recovers its Network, Line Connection and Transformation Connection transmission costs from their customers through Retail Transmission Service Rates (RTSRs). These costs are allocated to each of the distribution rate classes in proportion to their coincident demand to Hydro One's Network and Connection peaks at the transmission DPs.

Hydro One's large volume distribution-connected customers are either in the Sub-Transmission (ST) rate class, as described in part i) above or in the General Service Demand-billed rate class. The impact of their demands on the allocation of transmission costs depends on their contribution to the coincident demand of their respective rate class to Hydro One's Network and Connection peaks at the transmission DPs. This methodology was most recently approved in Hydro One's 2023-2027 rate application (EB-2021-0110) and is further described in Exhibit L, Tab 2, Schedule 1 of that proceeding.

k) See response to part b) above.

l) Please refer to Hydro One's response to Clarifying Questions Issue 4, VECC-6, part b).

5.

a) As stated in Section 1.4.3.2 of the Background Report on Issue 4, page 10 of 20, Hydro One is unclear on the effort that would be required – or if it is even possible – to accurately remove the impact of double peak events from the historical charge determinant data.

b) ***Response from IESO:***
Please refer to the IESO's response to Clarifying Questions Issues 5 & 6, VECC-25, part c).

c) While the dollar impact for the transmitters might be similar under Options 3 and 4, the timing of the UTR impact will differ. Under Option 3 the forecast charge determinants will be adjusted to remove the impact of double peak billing events, resulting in increased UTRs. In other words, transmitters will be able to collect their full revenue requirement in each year. Under option 4, the refund amounts will be added to the transmitter's revenue requirement in future years, meaning that there will be a lag for the transmitters in collecting their approved revenue requirements (after the issued refunds).

d) In Hydro One’s view, changes would be required to the UTR “Terms and Conditions” including at a minimum adding a new section detailing how double peak events are defined and how the charge determinants for all the impacted DPs would be calculated under double peak events. The transmission rate schedule would also have to be updated to reflect the new definition of charge determinants for Network, Line and Transformation Connection services.

6.

a)

i. The “unfairness” in regards with the Hydro One Distribution Sub-Transmission (ST) customers is further described in Section 1.4.2.2 of the Background Report on Issue 4, page 9 of 20 under Disadvantages of Option 2.

ii. A deferral account for Hydro One Distribution could be an option to address the unfairness concerns. However, specifics of implementation will have to be agreed upon among the stakeholders.

b) Please refer to Hydro One’s response to Clarifying Questions Issue 4, VECC-2, part c)

CLARIFYING QUESTIONS OF LDC TRANSMISSION GROUP - 01

Reference:
HONI Background Report on Issue 4, Page 3, Line 22

Interrogatory:
a) Could HONI please explain whether the incremental revenue from double peak billing, realized from year to year, is incorporated into existing Uniform Transmission Rates and, if so, describe how this is done?

Response:
a) The forecast charge determinants used to set the 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 the 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.

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CLARIFYING QUESTIONS OF LDC TRANSMISSION GROUP - 02

Reference:
HONI Background Report on Issue 4, Page 8, Line 29

Interrogatory:

a) HONI has noted that Option 2 would involve significant effort for the IESO billing and settlement systems. Presumably this would also be the case for HONI should it also adopt this approach. How many meters could HONI totalize before significant changes to the billing and settlement systems are required?

b) Can we ask the IESO this same question?

Response:

a) Hydro One does not anticipate any significant impacts since transmission-connected customers are billed by the IESO.

b) ***Response from IESO:***
Please refer to the IESO's response to Clarifying Questions Issues 5 & 6, VECC-25, part c).

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CLARIFYING QUESTIONS OF LDC TRANSMISSION GROUP - 03

Reference:

HONI Background Report on Issue 4, Page 12, Line 16

Interrogatory:

a) HONI notes that under an approach where double peak billing was tracked in a deferral account, a methodology for calculating the refund amount would need to be established. Please provide details on how HONI would envision the calculation of the double peaking deferral account working, including deferral account mechanics and other considerations.

b) Please provide details on how Hydro One would foresee instances of double peaking being identified.

Response:

a) Once a methodology is established to calculate the impact of the qualified double peak billing events, taking into considerations the items identified in Section 1.4.4.3 of the Background Report on Issue 4, page 12 of 20, Hydro One would issue a refund in accordance with the methodology established. The deferral account would then capture the amounts refunded to the transmission-connected customers impacted by all qualified double peak billing events.

b) Hydro One believes that the most efficient approach would be for customers to review their bills and raise double peak billing instances to the transmitter for review and refund.

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CLARIFYING QUESTIONS OF LDC TRANSMISSION GROUP - 04

Reference:
HONI Background Report on Issue 4, Page 10, Lines 1-2 and Lines 21 – 30

Interrogatory:
a) Please explain how double peaking from planned (or unplanned) outages are currently factored into HONI's load forecast.

b) Is there any other manner in which double peaking is factored into Hydro One's current rate design?

Response:
a) Double peak events from planned (or unplanned) outages are factored into Hydro One's load forecast by virtue of the fact that such double peak events which have occurred in the past are part of the historical charge determinant data that is used as the base from which the load forecast is derived.

b) No

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CLARIFYING QUESTIONS OF LDC TRANSMISSION GROUP - 05

Reference:

HONI Background Report on Issue 4, Page 6 Lines 21 – 29 and Page 7 Lines 1-6
HONI Background Report on Issue 4, Appendix B

Interrogatory:

a) Please provide details of all circumstances in the examples in Appendix B where HONI has worked with an LDC to mitigate double peaking in the manner described in the evidence referenced above.

b) Please discuss all other mitigating actions (including permitting chargeback compensation from the LDC to Hydro One) facilitated with customers to mitigate double peaking transmission costs in the Appendix B examples.

c) Please provide any other examples since January 1, 2014 of either HONI Transmission or HONI Distribution providing LDCs with measures to mitigate double peaking (i.e. operational, maintenance timing, or chargeback compensation) to LDCs.

Response:

a) Hydro One is unsure of what is being requested in this question. If the question is asking for more details regarding the examples in Appendix B, Hydro One notes that the examples in Appendix B are written to provide information as part of the Background Report on Issue 4 and were specifically intended not to provide details that would allow customers to be identified.

b) Hydro One is unsure of what is meant by “other mitigating actions” facilitated with customers in the Appendix B examples. If the question is asking for more details regarding the examples in Appendix B, Hydro One notes that the examples in Appendix B are written to provide information as part of the Background Report on Issue 4 and were specifically intended not to provide details that would allow customers to be identified. However, please see part c) below.

c) The actions that Hydro One has taken to mitigate double peaking include the following:
   - Aligning the start and the end date of the planned transmission outage with the start and end date of the billing period as described in the Background Report on Issue 4, page 6, lines 21-26
   - Coordinating the work so that planned outages are taken when electricity demand is lowest, as described in the Background Report on Issue 4, page 7, lines 1-2

- Hydro One conducts regularly scheduled meetings to coordinate outage activity with all stakeholders involved in Ontario Bulk Electricity System operations. All these meetings are to promote developing a common goal of cooperation and efficiency while scheduling, coordinating, accessing, and approving all forward planned Hydro One transmission outages with all stakeholders.

In respect of unplanned/forced outages, Hydro One notes that its mandate is to restore power to its customers as quickly and safely as possible. Mitigation of double peak billing is not a priority in the case of unplanned/forced outages.

CLARIFYING QUESTIONS OF LDC TRANSMISSION GROUP - 06

Reference:
HONI Background Report on Issue 4, Page 4 Lines 24 - 29

Interrogatory:
a) HONI notes that clarification from the OEB as to the treatment of unplanned outages in the context of the current proceeding will help avoid future complaints and confusion. Please provide indicate whether HONI feels unplanned outages should be included in the proceeding and why?

Response:
a) Please refer to Hydro One’s response to Clarifying Questions Issue 4, GCC-1, part 3.

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CLARIFYING QUESTIONS OF LDC TRANSMISSION GROUP - 07

Reference:
HONI Background Report on Issue 4, Page 5 Lines 10 – 18

Interrogatory:

a) Please explain in more detail the anomalous/unfair outcome for customers if double peak billing issues are resolved for transmission-connected customers in the current proceeding, but not for distribution-connected customers.

Response:

a) Please refer to further details in Section 1.4.2.2 of the Background Report on Issue 4, page 9 of 20, lines 4-21.

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CLARIFYING QUESTIONS OF LDC TRANSMISSION GROUP - 08

Reference:

HONI Background Report on Issue 4, Appendix B

Interrogatory:

a) In Appendix B, multiple examples of HONI Distribution incurring double peak billing are described. Since January 1, 2014, what has been the annual frequency of occurrence of double peak billing to HONI Distribution, as well as the financial impact of such double peak billing?

b) Are double peaking billing costs passed on to the customers of HONI Distribution. If so, how?

Response:

a) Hydro One (Transmission or Distribution) does not keep track of double peak billing events, as such is not able to provide the requested information.

The examples provided in Appendix B were identified based on customer inquiries and reflect certain instances of Hydro One Distribution being impacted by double peak billing among other transmission-connected customers. Please also refer to Hydro One’s response to Clarifying Questions Issue 4, VECC-2, part a).

b) If Hydro One distribution were to experience a double peak billing event as a transmission-connected customer, the additional costs are then passed on to Hydro One distribution customers through Retail Transmission Service Rates (RTSRs).

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CLARIFYING QUESTIONS OF LPMA - 01

Reference:
Page 6, Lines 21-26

Interrogatory:

a) Is the "reliability risk" noted here related to the DP that is out of service for the month or to the DP that has the additional load transferred to it for the month?

b) Is there additional wear and tear on the DP that has had the additional load transferred to it for an extended period such as a month?

Response:

a) The reliability risk noted in the referenced section of the of the Background Report on Issue 4 is related the customer experiencing the double peak billing event when their DP is kept unnecessarily out of service for a full month to avoid double peak billing charges.

b) No, there is no additional wear and tear on the DP that has had the additional load transferred to it for a period such as a month.

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CLARIFYING QUESTIONS OF LPMA - 02

Reference:
Page 2, Lines 11-15

Interrogatory:

a) In a typical year, how many eligible double peak events/planned outages does Hydro One have?

b) What is the typical length of a planned outage, or what is a range in days for a typical planned outage?

c) Out of the number of planned outages from part (a), approximately how many of the outages were extended to be a calendar month at the request of the LDC?

Response:

a) Hydro One does not track all double peak events or all planned outages that cause a double peak event.

b) Hydro One has many different types of outages. As such, there is no typical outage.

c) As indicated in part a) above, Hydro One does not track all double peak events or all planned outages that cause a double peak event. Hydro One also does not track each time a planned outage is extended at the request of an LDC.

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CLARIFYING QUESTIONS OF LPMA - 03

Reference:
Section 1.4

Interrogatory:
Which, if any, of the four options provided does Hydro One believe is the best option?

Response:
Please refer to Hydro One's response to Clarifying Questions Issue 4, AMPCO-5, part a).

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CLARIFYING QUESTIONS OF SEC - 01

Reference:
Background Report, Page 4

Interrogatory:
SEC seeks to understand the magnitude of the double peak billing issue:

a) For each year between 2021 and 2023, and by customer type (LDC and non-LDC customers), please provide the number of customers impacted by double peak billing as a result of scheduled outages, and the frequency in that year (e.g. in 2021 3 LDC customers had 1 double billing month, 1 LDC customers had two double billing months etc). If an exact numbers cannot be determined, please provide an estimate, and specify all the assumptions made.

b) Please provide a revised version of part (a), for double billing events caused by non-schedule outages.

c) If Option 4 had been implemented beginning in 2021 for schedule outages, what would the balance be in the DVA for each year between 2021 and 2023. Please also provide a breakdown between amounts related to double peak billing by LDC and all other load customers. If an exact amount cannot be determined, please provide an estimate, and specify all the assumptions made.

d) Please provide a revised version of part (d), assuming the DVA also captured non-schedule outages.

Response:

a) Please refer to Hydro One’s response to Clarifying Questions Issue 4, VECC-2 part a).

b) Please see part a) above

c) Please see part a) above

d) Please see part a) above.

CLARIFYING QUESTIONS OF SEC - 02

Reference:

Background Report, Page 4

Interrogatory:

Hydro One raises the issue that there are similar double peak billing events for certain distribution customers. SEC seeks to understand the magnitude of double peaking billing on the distribution system:

a) How many Hydro One Distribution, by rate class, are served by more than 1 connection that would allow load to be shifted between connections.

b) Please provide an estimate of the annual total number of customers, by rate class, who are impacted by double peak billing, caused by each of scheduled and non-scheduled outages.

Response:

a) Only the Hydro One Distribution Sub-Transmission (ST) LDC customers are served by more than 1 connection that allow load to be shifted between connections.

b) 43 Hydro One Distribution Sub-Transmission (ST) LDC customers could be impacted by scheduled and non-scheduled outages.

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CLARIFYING QUESTIONS OF SEC - 03

Reference:
Background Report, Page 3, ft 3

Interrogatory:
Hydro One raises the issue of customers who are connected to both the transmission and distribution system.

a) For all non-LDC Hydro One Transmission load customers located in Hydro One Distribution's service territory, how many have a connection to both the transmission and distribution system that would allow load to be shifted between the two connections?

b) What are the potential options in dealing with this issue?

Response:
a) Please refer to Hydro One's response to Clarifying Questions Issue 4, AMPCO-3, parts b) and c).

b) Potential options to deal with the double peak billing issue for transmission-connected customers are described in Section 1.4 of the Background Report on Issue 4. Once a solution is determined as part of the current proceeding, a similar solution can also be applied in the above-mentioned scenario.

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CLARIFYING QUESTIONS OF SEC - 04

Reference:
Background Report, Page 7

Interrogatory:
Please provide Hydro One's preferred option to address the double peak billing issue and the reasoning.

Response:
Please refer to Hydro One's response to Clarifying Questions Issue 4, AMPCO-5, part a).

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CLARIFYING QUESTIONS OF VECC - 01

Reference:
HONI Background Report, Issue 4, Pages 3 and 5

Preamble:
The Report states (page 3):

> A double peak billing event can occur in instances where a transmission customer is supplied by more than one connection point to the transmission system, each of which is referred to as a delivery point (DP).

The Report states (page 5):

> The transmission-connected customers most likely to experience double peak billing events are LDCs, as approximately 70% of LDCs have multiple DPs. While approximately 25% of large commercial and industrial transmission-connected customers have multiple transmission DPs, many are not located such that load could be transferred between transmission DPs so as to result in double peak billing events

And

> Certain transmission-connected LDCs and transmission-connected Commercial and Industrial customers with only one transmission-connected DP may have another source of supply through connection to the distribution system (essentially multiple DPs).

Interrogatory:

a) Please clarify whether the 70% (for LDCs) applies to Network Service DPs, Line Connection DPs and Transformation Connection DPs. If the percentage is different for each of the three charge types, please provide the respective percentage of LDC customers for each.

b) For each of the three services does HONI have any estimate as to the percentage of the LDC DPs where load could be transferred between DPs so as to result in a double peak billing event (per page 5)? If so, please provide.

c) Please clarify whether the 25% (for large commercial and industrial transmission connected customers, i.e. C&I customers) applies to Network Service DPs, Line Connection DPs and Transformation Connection DPs. If the percentage is different for each of the three charge types, please provide the respective percentage of C&I customers for each.

d) For each of the three services does HONI have any estimate as to the percentage of the C&I customer DPs where load could be transferred between DPs so as to result in a double peak billing event (per page 5)? If so, please provide.

e) For those transmission connected LDCs and C&I customers that only have one DP overall (i.e., including both transmission and distribution connections), can service be maintained or is it interrupted in the event of a planned or forced outage at that single DP?

f) For those transmission connected LDCs and C&I customer that have multiple DPs (including distribution connections), but load cannot be fully transferred between DPs, can service be maintained or is it interrupted in the event of a planned or forced outage at one such DP?

Response:

a) The referenced 70% (for LDCs) applies to Network Service DPs, Line Connection DPs and Transformation Connection DPs.

b) Hydro One does not have an estimate for the percentage of the LDC DPs where load could be transferred between DPs since each load transfer is unique and situation specific.

c) The referenced 25% (for large commercial and industrial transmission-connected customers, i.e. C&I customers) applies to Network Service DPs, Line Connection DPs and Transformation Connection DPs.

d) Hydro One does not have visibility with respect to supply configuration within the customers' facilities. As such, Hydro One is unable to confirm the number of C&I customers where load could be transferred between transmission DPs. However, 5 C&I customers have DPs located within close proximity. As a result, it may be possible for these 5 C&I customers to transfer load between their transmission DPs so as to result in a double peak billing event. Please also refer to Hydro One's response to Clarifying Questions Issue 4, AMPCO-3 for load transfer from transmission to distribution DPs.

e) For transmission-connected LDCs and C&I customers that only have one DP overall, service cannot be maintained if it is interrupted in the event of a planned or forced outage at that single DP. Hydro One considers this stranded load. Any planned or forced outages to this single DP would interrupt the customers.

f) For transmission-connected LDCs and C&I customers that have multiple DPs, with load that cannot be fully transferred between DPs, service cannot be maintained for the load that is not transferrable to another DP. Hydro One considers this stranded load. Any planned or forced outages to this DP would interrupt the non-transferable customers, while the transferable loads would be moved to another DP to maintain supply to the customers.

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CLARIFYING QUESTIONS OF VECC - 02

Reference:

HONI Background Report, Issue 4, Pages 4, 10 and 12-13

Preamble:

The Report states (page 4):

> However, it is also worth noting that not all load transfers for transmission connected customers with multiple DPs result in double peak billing events.

The Reports states (page 10):

> There is no historical data set for transmission charge determinants excluding double peak billing events and therefore there is no historical baseline that could be used for setting future charge determinants forecasts that exclude double peak billing events. It is not clear the effort that would be required – or if it is even possible – to accurately remove the impact of double peak events from the historical charge determinant data.
>
> Adjusting the charge determinants to remove the impact of double peak billing events would result in a reduction in the charge determinants used to calculate UTR rates, which would result in a corresponding increase in the UTR rates applicable to all transmission-connected customers.

The Report states (pages 12-13):

> The costs related to double peak billing will be small when compared to total provincial transmission revenue requirement. Therefore, in order to ensure that transmitters recover the costs associated with refunding customers experiencing double peak billing events, it will be necessary for UTRs to be rounded to 4 decimal places.

Interrogatory:

a) Can HON please provide separate annual histories (e.g., 5 years) as to the number of transmission connected LDCs and the number of transmission connected C&I customers where load transfers between DP points were required due to the planned or forced transmission outage (regardless of whether or not it resulted in a double billing event)? If applicable, please provide separate histories for Network, Line Connection and Transformation Connection Service.

b) Given the statement on page 10 that “there is no historical data set for transmission charge determinants excluding double peak billing events” what is the basis for the statement on pages12-13 that “the costs related to double peak billing will be small when compared to total provincial transmission revenue requirement.”

c) Please provide any supporting analysis HON has performed to support the statement that "in order to ensure that transmitters recover the costs associated with refunding customers experiencing double peak billing events, it will be necessary for UTRs to be rounded to 4 decimal places".

Response:

a) Providing separate annual histories as to the number of transmission-connected LDCs and the number of transmission-connected C&I customers where load transfers between delivery points were required due to planned or forced transmission outages is an onerous task due to the number of yearly outages processed by Hydro One.

Number of outages completed per year are as follows:
2019: 12,356
2020: 11,217
2021: 11,310
2022: 10,358
2023: 11,226

Hydro One would need to filter through 55,000+ outages to find outages that meet the criteria of requiring load transfers between delivery points. It would take significant effort and time to analyze all outages in an effort to compile and provide the requested information.

b) The statement on pages 12-13 of 20 of the Background Report on Issue 4 that "the costs related to double peak billing will be small when compared to total provincial transmission revenue requirement." is based on the following understanding from Hydro One:

i. Current provincial transmission revenue requirement is over $2.2 billion.
ii. Double peak billing events only impact a portion of transmission-connected customers when an outage results in a load transfer between two DPs such that the customer gets billed for the peak demand on both DPs.
iii. Based on the information available to Hydro One as summarized in response to Clarifying Questions Issue 4, AMPCO-4, the dollar impact associated with double peak billing events are expected to be small when compared to total provincial transmission revenue requirement. However, Hydro One notes that the impacts summarized reflect only the known amounts for double peak billing events as further explained in Clarifying Questions Issue 4, AMPCO-4.

c) Hydro One estimates that with UTRs rounded to two decimal places, the provincial transmission revenue requirement for <u>each</u> of the three rate pools will have to increase by over $1.5 million to result in a corresponding increase in the UTRs. Please refer to part b) above and the response to Clarifying Questions Issue 4, APMCO-4 which supports the statement that annual refund amounts may be lower than this threshold.

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CLARIFYING QUESTIONS OF VECC - 03

Reference:
HONI Background Report, Issue 4, Page 5

Preamble:
The Report states:

> A double peak billing event can occur in instances where a transmission customer is supplied by more than one connection point to the transmission system, each of which is referred to as a delivery point (DP). At a time of a planned transmission outage (for example to facilitate system maintenance or system upgrades initiated by the transmitter or the transmission-connected customer), the customer's load may be transferred from an impacted DP to another one of the customer's DPs in order to avoid or minimize power interruption.

Interrogatory:

a) Please outline the circumstances/reasons that would lead to facilities being constructed such that the load can be served from either of two transmission DPs and the capacity at each DP being sized so as to be able to supply the full load being served by both DPs as opposed either i) a single transmission DP capable of carrying the full load in question or ii) two DPs each only capable of carrying the load normally served.

b) If not addressed in the response to the preceding question, please address the following issues:
   i. Is the cost to the transmitter higher or lower when the customer is served via two DPs each capable of carrying the full load normally served by both DPs as opposed to the alternatives noted? (Note: By cost, the question is referring to the costs incurred by the transmitter to construct and operate the associated facilities)
   ii. Are there reliability (or other) benefits for the transmission customer from being served via two such DPs as opposed to the other alternatives noted?
   iii. Who (transmitter or customer) determines the number and supply capability of the DPs?
   iv. Are there instances where the transmission customer has requested that HONI provide two such DPs for reliability or other reasons?

c) If the existence of two DPs being able to service the same load improves the reliability of service to the customer, is there an argument to be made that the double billing (which effectively charges the customer for the use of both DPs) can be viewed as the cost of providing the increased reliability?

i. Furthermore, could one posit there should be a “standby” charge for those months where load transfers and double billing do not occur?

Response:

a) Two-DP supply is a standard configuration for Hydro One. Transmission facilities are designed such that the load can be served from either of two transmission DPs so that there is no supply interruption for a single outage. In a dense urban environment, such as the City of Toronto, load may be supplied from more than two DPs. Furthermore, a single-DP supply is an exception and only considered at a customer request in instances when a customer does not want to pay any capital contribution and is willing to accept reduced reliability.

b)
  i. Yes, the cost of two DPs each capable of carrying the full load normally is higher. Cost is recovered through rates and/or capital contribution from the customer consistent with the Transmission System Code (TSC).
  ii. Yes, Two-DP supply customers will rarely face a supply interruption or an outage due to planned maintenance.
  iii. Consistent with the TSC, customers can decide if they want a single-DP supply. This is considered by a customer based on its operation when Transmission line lengths are exceedingly long resulting in higher costs and larger capital contribution from the customer.
  iv. As outlined in part a) and b) iii above, Hydro One’s standard design is two-DP supply, but customers have the option to reduce their cost by electing for the single-DP supply and reduced reliability.

c) Hydro One’s transmission charges reflect the costs associated with the transmission assets used to provide service to a customer. As noted in the response to part a), the reliability of a two-DP supply is a standard configuration for Hydro One.
  i. Double peak billing is associated with the transfer of load between two DPs and should not be associated with standby charges, which are typically related to reserving capacity. The transmission charges currently levied to customers with multiple DPs, in those months where load transfers do not occur, appropriately reflect the costs associated with the assets used to provide transmission service to the multiple DPs. Therefore, Hydro One does not believe that a “stand by” charge should apply in those instances.

CLARIFYING QUESTIONS OF VECC - 04

Reference:

HONI Background Report, Issue 4, Page 7
HONI Background Report, Issues 5&6, Page 12

Preamble:

The Report states (Issue 4, Page 7):

> Hydro One notes that any proposed solutions to address the double peak billing issue should meet the following two objectives:
>
> i. Avoid levying the additional transmission charges related to double peak events or ensure refunding of the additional charges incurred by the affected customers; and
>
> ii. All transmitters should be able to fully collect their OEB-approved revenue requirement".

The Report states (Issues 5&6, Page 12):

> In establishing the unit size thresholds for embedded generation and other load displacement technologies, the OEB will need to balance fairness, practicality and cost.

Interrogatory:

a) Does any proposed solution for double billing also need to consider the objectives related to fairness, practicality and cost of implementation (as HONI has suggested for unit size thresholds)? If not, why not?

Response:

a) Hydro One agrees that objectives related to fairness, practicality and cost to implement are appropriate considerations in assessing potential solutions.

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CLARIFYING QUESTIONS OF VECC - 05

Reference:
HONI Background Report, Issue 4, Page 8

Preamble:
The Report states:

> Under this approach (Option 2), transmission charges would be calculated based on each customer's aggregated demand from all of their DPs, for a given time interval. In other words, transmission charges would be calculated at the customer level, rather than the current practice of billing at each DP.

And

> While all transmission-connected load customers pay the Network Charge, customers who own their Line and/or Transformation Connection assets do not pay these charges. Currently, there are some transmission-connected customers with multiple DPs who own Line/Transformation assets at some of their DPs. Aggregating the demand at customer level will require additional consideration to make sure customers are not charged for the demand supplied by assets they own. While all transmission-connected load customers pay the Network Charge, customers who own their Line and/or Transformation Connection assets do not pay these charges. Currently, there are some transmission-connected customers with multiple DPs who own Line/Transformation assets at some of their DPs. Aggregating the demand at customer level will require additional consideration to make sure customers are not charged for the demand supplied by assets they own.

Interrogatory:
a) Please comment on the advantages and disadvantages of a hybrid version of Option 2 where: i) Network Service charges are based on aggregated demand while ii) Line Connection and Transformation Connection charges are (continued) to be based on a DP basis.

Response:
a) In Hydro One's view, the following are the advantages and disadvantages of the hybrid version of Option 2 as contemplated in the question (in addition to the disadvantages already outlined with respect to Option 2 in the Background Report on Issue 4):

Advantages:

- Would address the double peak billing charges associated with the Network charge, which represent the biggest share of transmission charges customers pay.

Disadvantages:

- Customers would still be subjected to double peak billing charges associated with Line and Transformation Connection charges.
- Would not address Hydro One's concerns regarding delays in maintenance and capital work.
- Would increase the complexity in the settlement process.

Furthermore, the aggregation approach for Network charge would have to be determined and agreed upon.

CLARIFYING QUESTIONS OF VECC - 06

Reference:
HONI Background Report, Issue 4, Page 8

Preamble:
The Reports states:

> While all transmission-connected load customers pay the Network Charge, customers who own their Line and/or Transformation Connection assets do not pay these charges. Currently, there are some transmission-connected customers with multiple DPs who own Line/Transformation assets at some of their DPs.
> <u>Aggregating the demand at customer level will require additional consideration to make sure customers are not charged for the demand supplied by assets they own." (emphasis added)</u>

Interrogatory:

a) Does HONI have any suggestions as to how the billing for transmission service under Option 2 could be adjusted to account for the circumstances described in the referenced statements?

b) Setting aside the issue of double billing, how would Option 2 work in a situation where the transmission customer had multiple delivery points and one (or more) was connected to the transmission system and subject to the UTRs while others (one or more) were served from a "host" LDC and subject to the host's RTSRs? Would transmission charges be based on the "aggregated demand" for all the transmission-connected DPs?

Response:

a) In Hydro One's view, the aggregated charge determinant for each of the Line Connection and Transformation Connection charges would have to be setup so as to exclude the meter reads associated with customer owned assets. Hydro One notes that all billing of transmission-connected customers is performed by the IESO.

b) Hydro One does not propose any changes to the existing definition or delineation between the transmission and distribution systems. Separate charges should be maintained for customers directly connected to the transmission system and customers directly connected to the distribution system. As such, aggregated demand under option 2 would only apply to customer demand directly connected to the transmission system (transmission-connected customers).

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CLARIFYING QUESTIONS OF VECC - 07

Reference:

HONI Background Report, Issue 4, Pages 9-13

Preamble:

The Report states (page 10) with respect to Option 3:

> Adjusting the charge determinants to remove the impact of double peak billing events would result in a reduction in the charge determinants used to calculate UTR rates, which would result in a corresponding increase in the UTR rates applicable to all transmission-connected customers.

The Report states (page 11) with respect to Option 4:

> The affected transmitter will track the refunded amounts in a deferral account.

Interrogatory:

a) Would the revenue shortfall under Option 3 that results in the need to increase the UTR rates be equal to the amounts that would be recorded in the deferral account under Option 4?
   i. If not, why not?
   ii. If yes, is the main difference between Option 3 and Option 4 the fact that Option 3 requires major administrative efforts and system changes by the IEO whereas, under Option 4, it is HONI that would incur the major administrative burden and system changes?

b) How does the revenue shortfall under Options 3 or 4 compare with the revenue shortfall associated with Option 2? (Note: An order of magnitude difference as opposed to dollar estimate would be sufficient).

Response:

a) Yes.
   i. Not applicable.
   ii. Hydro One agrees that a key difference between Option 3 and Option 4 is where the additional administrative and implementation burden lies under each option. There are also other notable differences between Option 3 and Option 4 as described in Sections 1.4.3 and 1.4.4 of the Background Report on Issue 4.

b) Option 3 and Option 4 address the double peak billing event without altering the current billing methodology, while Option 2 changes the underlying billing methodology from billing at the DP level to billing at the customer level. Not all customers with multiple DPs are impacted by a double peak billing event in a given year, and hence, the dollar impact associated with implementation of Option 3 or Option 4 is limited to the additional charges paid by the impacted customers. Under Option 2, customers with multiple DPs will be billed on aggregated demand basis at all of their DPs. This could result in shifting of costs from customers supplied by multiple DPs to customers supplied by a single DP. The information required for Hydro One to provide an order of magnitude difference in the dollar impact between Option 2 and Options 3 and 4 is not readily available. However, Hydro One expects that the cost shifting under Option 2 will be significantly higher than the revenue shortfall under Options 3 and 4 for the above-mentioned reason.

CLARIFYING QUESTIONS OF APPRO AND ESC - 01

Reference:

Exhibit A-4-1 Page 5

HONI Background Report, Issues 5 and 6, Page 2 of 24

> Embedded generation reduces demand on the transmission system. Given that the costs of transmission infrastructure are largely fixed, there was a need for the OEB to consider whether transmission customers who reduce their load supplied from the transmission system by installing embedded generation should continue to be charged for the sunk costs of the transmission system that was built to supply their original load (gross load billing), or they should not bear those sunk costs (net load billing).

HONI Background Report, Issues 5 and 6, Page 3 of 24

> The OEB determined that net load billing shall apply when calculating Network Service Charges because in that circumstance (among other reasons) it is fair, more practical and simpler to apply. However, with respect to Line Connection Service and Transformation connection Service charges, the OEB determined that gross load billing shall apply, but only for load customers who connect new embedded generation.

Interrogatory:

1. Please describe the supply/demand characteristics of the Ontario electric system at the time the OEB first determined that gross load billing should apply to PTS-L and PTS-T transmission charges. Please provide copies of any relevant long-term energy plan or similar document that may have been available at that time.

2. Please file the IESO's Pathways to Decarbonization report issued December 15, 2022, and, if you are of the view that any other report better evidences the anticipated impacts of the energy transition on the electricity system in Ontario please file those other report(s) together with a reason why you think it is better.

3. Please summarize the key differences between (a) and (b) as it relates to the supply/demand characteristics of the Ontario electricity system, and the implications for Ontario's transmission system.

4. Do customers with embedded generation / storage continue to pay PTS-L and PTS-T transmission charges on a gross load basis in circumstances in which their original load is replaced by other customers?

5. Do customers with embedded generation/storage pay transmission charges if, prior to connection, actual loads exceed the loads originally considered by IESO / HONI in system planning when the asset in question was built?

6. If a load customer that was not specifically considered in transmission system planning installs their own generation exceeding 1MW (or 2MW of renewable generation), do they pay the applicable transmission charges on a gross load basis?

7. If new transmission capacity is installed due to growing demand, will existing customers with embedded generation / storage continue to be billed on a gross load basis for PTS-L and PTS-N for “sunk costs”?

8. Has HONI considered the potential for reducing gross load charges when overall demand growth exceeds a certain threshold and reduces the risk of stranded assets arising from embedded generation/storage?

9. When conducting transmission system planning for the Line and Transformation Connection asset pools, are gross load volumes considered reserved for a customer that has embedded generation/storage and thus unavailable to other customers?

10. Has the billed demand at any transmission station ever exceeded its peak demand capacity in any month? If yes, please provide a table identifying the date this occurred and provide an explanation for why this happened in each instance. If the reason this happened is due, in whole or in part, to gross load billing (versus some other reason), please indicate this clearly in the table.

11. Does Hydro One’s system planning assume there will be no customers with embedded generation / storage connected to new stations? On what factual basis does Hydro One make its assumption?

12. Has HONI considered the potential of customers with embedded generation / storage reducing the demand on existing transmission assets and thus reducing the need for costly system expansions? If no, why not?

Response:

1. As part of this proceeding, Hydro One was ordered to provide a background report on issues 4, 5 and 6 to facilitate discussion. In preparing the background report, Hydro One relied on the OEB’s decision from the Initial UTR Proceeding as that is all that was available. In addition, Hydro One made a request to the OEB’s library for a number of the other documents from the Initial UTR Proceeding to be uploaded to RESS, but they did not become available in time to inform the background report to any significant

extent, and Hydro One has not performed a detailed review of those materials since. Hydro One therefore encourages APPrO and ESC, as well as other parties, to review those materials for the requested information. Hydro One is not otherwise aware of any information that would be responsive to the request.

2. Hydro One declines to file the IESO's report or any other report. This is a generic proceeding in which Hydro One is a party, not an applicant, just as APPrO and ESC are parties. Hydro One was ordered by the OEB to prepare the background report to facilitate discussion during this proceeding, not to be a conduit through which all other parties put information on the record. If APPrO and/or ESC wish to file the IESO's Pathways to Decarbonization report or any other report that in their view better evidences the anticipated impacts of the energy transition on the electricity system in Ontario, and they require such report for any relevant purpose, it is expected that they will have an opportunity to do so at a later stage of this proceeding.

3. Please see answers 1 and 2 above.

4. If a customer installs embedded generation or storage and is subject to gross load billing, the customer's gross load is considered in determining the demand that must be supplied by the system.

5. The demand of all customers is considered in planning the transmission system. The capabilities of the system are assessed to determine whether an unforecasted customer can connect and their resultant demand is accounted for in future planning activities.

6. Yes. When a customer applies to connect an embedded generator or storage facility, eligibility for gross load billing is reviewed in the connection impact assessment.

7. Hydro One does not understand the question as asked.

8. Hydro One applies gross load billing requirements described in note 3 of the Uniform Transmission Rates (UTR) Schedule. Hydro One does not have the authority to adjust gross load billing charges for a customer under the UTR rule.

9. Hydro One designs and builds its system to be able to supply the total peak connected load. If assets were installed to serve a transmission customer (and paid by the customer consistent with the TSC) and the customer later displaces their load with embedded generation/storage, these assets are still maintained to supply the customer's load in the event that their generation/storage facility becomes unavailable. Capacity can only be freed up on the system to supply additional load if

the customer opts to relinquish the capacity that has been built on the system to supply their load.

10. Billed demand at any transmission station can theoretically exceed its peak demand capacity in any month due to unanticipated load transfers. Hydro One does not track this or have means to track this today; however, the system is designed to be able to meet peak loading. However, note that a transmission station can only ever exceed its peak demand capacity if and when there is an abnormal configuration due to planned work or an unplanned contingency. Even then peak demand shall be brought below its capacity by taking operating measures such as utilizing short term emergency ratings or temporary load shedding.

11. No, Hydro One's system planning assumes there are customers with embedded generation/storage connected to new stations and this information is considered, where it is known. This information may also be provided by LDCs and the IESO as an input to planning process based on a provided forecast.

12. See answer above.

CLARIFYING QUESTIONS OF APPRO AND ESC - 02

Reference:

Transmission System Code

Interrogatory:

1. How are revenues from gross load billing accounted for in LDC customer contribution security deposit true-up calculations related to Hydro One Transmission-constructed transmission stations?

2. Considering large use (>5MW) customers that make contributions toward LDC contributions for transmission stations in accordance with the Transmission System Code, how are revenues from gross load billing accounted for in contribution security deposit true-up calculations?

3. Given that the economic evaluation period for a low risk customer like an LDC is 25 years, what sunk costs are realized by Hydro One for an LDC customer with embedded generator storage connecting 25 years after the station is built?

Response:

1. True-up calculations are in respect of capital contribution, and not security deposits. Hydro One carries out economic evaluations and true-up calculations to determine capital contribution as per section 6.5 of the Transmission System Code, which includes further specific requirement for true-up calculations for an LDC to add the amount of any embedded generation that would also be subject to gross load billing, and was installed during the true-up period, to the actual load (TSC Section 6.5.8).

2. Please see response to part 1 above.

3. If transmission supply infrastructure is built to serve the growing load needs of an LDC customer, the transmitter performs an economic evaluation to determine if a capital contribution is required based on the LDC customer’s demand and use of this infrastructure. If the LDC’s forecast demand is reduced over the economic evaluation period due to connection of embedded generation or energy storage, the use of gross load billing ensures that ratepayers are held whole in this circumstance if the revenue collected by the transmitter from the LDC customer based on their demand supplied by the transmission system is less than forecast. Gross load billing also ensures that any shortfall in demand is recovered from those customers causing the shortfall and not subsidized by the LDC customers' other ratepayers.

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CLARIFYING QUESTIONS OF APPRO AND ESC - 03

Reference:
Benefits of Embedded Generation

Interrogatory:
1. Please provide the volumes billed by Gross Load Billing in each of the last five years.

2. Is Ontario's Line and Transformation Connection capacity sufficient to meet actual demands plus average monthly gross load billed demands?

3. What is the average cost per MW of peak system demand?

4. What is the forecasted capital cost of the network investments that would be required to meet system demands equal to actual demands plus average monthly gross load billed demands?

5. What is the forecasted average annual revenue requirement of a new transmission station built in 2025 (if it varies based on capacity, then please provide responses for each)?

6. What is the present value of deferring investment in a new transmission station for (i) 1 year, (ii) 3 years?

Response:
The reference listed to this question is "Benefits of Embedded Generation". There is no reference to any clarification required on Hydro One's background report.

Hydro One believes that understanding the benefits of embedded generation is an important issue and looks forward to discussing this issue with stakeholders in future OEB proceedings. However, "Benefits of Embedded Generation" is not currently an issue proposed for resolution in this proceeding. Should the OEB determine that this issue is to be resolved in this proceeding, Hydro One will provide answers to questions that are relevant to the issue.

At this time, Hydro One has provided answers to questions 1 and 2 only.

1. Please refer to Hydro One's response to Clarifying Questions Issue 5 and 6, ED-7, part d).

2. Hydro One works in close collaboration with the IESO, LDCs, customers and stakeholders to ensure that adequate transmission capacity exists for safe, secure and reliable operation consistent with NERC, NPCC and ORTAC requirements. This plan is based on meeting actual and forecasted peak demands and Hydro One believes that Ontario's Line and Transformation Connection capacity is currently sufficient to meet actual demands. Additional investments have been identified to reinforce the Lines and Transformation capacity. As a result, average monthly gross load billed demands are also expected to be met.

3. N/a

4. N/a

5. N/a

6. N/a

CLARIFYING QUESTIONS OF APPRO AND ESC - 04

Reference:
Gross Load Billing for Energy Storage

Interrogatory:
1. If Hydro One were to adopt Option #1 (exempt energy storage from GLB), does Hydro One have an estimate of the financial impact of that change?

2. Does HONI know the total capacity of embedded energy storage capacity?

3. Does HONI have a forecast of potential embedded energy storage capacity?

Response:
1. Please refer to Hydro One's response to Clarifying Questions Issues 5 and 6, VECC-17, part a).

   Existing energy storage projects would be exempt from gross load billing under option 1. Hydro One does not have the financial impact information readily available. It would take significant time and effort for Hydro One to estimate the financial impact of such a change, and this analysis cannot reasonably be completed within the timeframe allowed for responses.

2. There are 80 embedded energy storage projects with 160 MW of installed capacity.

3. Please refer to Hydro One's response to Clarifying Questions Issues 5 and 6, VECC-17, part a).

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CLARIFYING QUESTIONS OF DRC - 01

Reference:
Issues 5 and 6, Page 5-6 of 24

Preamble:
Hydro One Networks Inc. ("HONI") references the OEB's statement from 2002 that "the output of some renewable source generation equipment has advanced from under 1 MW per unit to just under 2 MW per unit".

It goes on to allege that certain customers are engaged in avoidance activities that involve the installation of multiple generation units.

Interrogatory:

a) Please describe HONI's understanding of how renewable source generation equipment has developed since 2002 as it pertains to the OEB's quoted statement that "the output of some renewable source generation equipment has advanced from under 1 MW per unit to just under 2 MW per unit".

b) In the instances of avoidance that HONI alleges, did it perform any review as to whether the approach to installation might have reasons other than avoidance of the applicable gross billing threshold?

c) If the answer is yes, please describe those efforts and what HONI discovered.

d) What are any other reasons that HONI is aware of, aside from avoidance of the threshold, as to why commercial and industrial customers might choose to install multiple units as opposed to one larger unit with the same output potential?

Response:

a) The statement was a direct quote from the OEB. As such, the OEB would be in a better position to comment on what was meant by its statement. However, Hydro One speculates that, at the time, the OEB was trying to strike a balance in establishing gross load billing requirements for renewable generation. The OEB noted that the size of renewable generator units being installed seemed to be increasing and, therefore, the OEB felt that it was appropriate to adjust the gross load billing threshold for renewable generation accordingly.

b) Hydro One did not perform any such reviews. In the Background Report on Issues 5 and 6, Hydro One indicated that the current UTR rules provide an opportunity for customers to avoid gross load billing settlement charges based on the manner in which the thresholds are applied. Hydro One does not know if customers intentionally or unintentionally sized their generator units for the purpose of avoiding gross load billing settlement charges and/or for any other purposes.

c) Please see response to part b) above.

d) Please see response to part b) above with respect to the reference to avoidance. Hydro One is not aware of what other factors a customer may or may not consider in their generation facility design decisions. Hydro One hypothesizes that one reason for installing multiple units as opposed to a single unit might be that it could increase the reliability and availability of generation.

CLARIFYING QUESTIONS OF DRC - 02

Reference:
Issues 5 and 6, Page 7 of 24

Preamble:
HONI states that solar facilities are often designed to include multiple sets of arrays, with each array having their own inverter. It provides various facts concerning inverter capacity and states that no customers with embedded solar generation are being billed on a gross load basis.

Interrogatory:

a) Please describe the viability of approaches that would reduce the number of units in a larger facility, as well as any disadvantages to any such alternatives from the perspective of the owner of the solar facility, aside from consequences relating to the gross load billing threshold.

b) Does it remain HONI's understanding that inverter capacity for solar generation "is typically small (under 0.5 MW)"?

c) What is HONI's understanding as to the percentage of inverter capacity in Ontario that is: a) over 0.5 MW; b) over 1 MW; and c) over 2 MW? How has this changed, generally speaking, over the past ten years?

d) What is HONI's understanding as to the percentage within each of the categories listed in the previous question of inverters with bidirectional capacity?

e) What is the largest inverter capacity in Ontario that a single customer exercises that HONI is aware of? How has this changed, generally speaking, over the past ten years?

f) Does it remain the case today that "no customers with embedded solar generation are being billed on a gross load basis"?

Response:

a) Hydro One is unable to comment on the viability of different approaches to the design of solar generation facilities.

b) Yes.

c) Hydro One distribution does not serve all of Ontario and therefore cannot provide the percentage of inverter capacity in Ontario that is above or below the requested thresholds.

d) The flow of power generated by a solar array is typically in one direction and therefore bi-directional capability at the inverter is not required. Hydro One is unable to comment on whether the inverters used for solar generation facilities have bi-directional capability.

e) As noted above, Hydro One distribution does not serve all of Ontario.

f) Yes.

CLARIFYING QUESTIONS OF DRC - 03

Reference:
Issues 5 and 6, Page 8 of 24

Preamble:
HONI states that it has determined that 1,268 MW of embedded solar generation is currently exempt from gross load billing charges, while more than half of the installed embedded wind generation capacity is being billed on a gross load basis.

Interrogatory:

a) Does HONI's cited figure of 1,268 MW of embedded solar generation as currently exempt from gross load billing charges include residential in addition to industrial and commercial users?

b) Regardless of the answer, please provide the number of users (approximations if necessary) that constitute the cited figure of 1,268 MW of embedded solar generation, broken down by user category (i.e., residential, commercial and industrial, or otherwise as determined by Hydro One along these same lines).

c) Please provide the number of users (approximations if necessary) that constitute the cited comparable figure for wind generation, broken down by user category (i.e., residential, commercial and industrial, or otherwise as determined by Hydro One along these same lines).

d) What percentage of HONI's cited figure of 1,268 MW of embedded solar generation as currently exempt from gross load billing charges is represented by embedded solar generation with bi-directional capacity?

Response:

a) The majority of the projects in the 1,268 MW of embedded solar generation figure quoted represent IESO Feed-In-Tariff (FIT) or Renewable Energy Standard Offer Program (RESOP) participants.

b) 138 projects constitute the cited figure of 1,268 MW of embedded solar generation. Please refer to part a) above.

c) A comparable figure for wind generation is 22 projects with installed capacity of 250 MW. Most of the projects represent the IESO Feed-In-Tariff (FIT) or Renewable Energy Standard Offer Program (RESOP) participants.

d) The flow of power generated by a solar array is typically in one direction and therefore bi-directional capability at the inverter is not required. Hydro One is unable to comment on whether the inverters used for solar generation facilities have bi-directional capability.

CLARIFYING QUESTIONS OF DRC - 04

Reference:
Issues 5 and 6, Page 10 of 24

Preamble:
HONI states that some customers have questioned HONI's practice of applying gross load billing to energy storage

Interrogatory:
a) What are the characteristics of customers that have questioned Hydro One's practice of applying gross load billing to energy storage? Do they include any customers who are not directly engaged in energy storage activities themselves?

Response:
a) Large customers (mostly Dx connected) with larger energy storage facilities have questioned Hydro One's practices. Hydro One is not aware of customers, who are not directly engaged in energy storage activities, commenting on these practices.

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CLARIFYING QUESTIONS OF ED - 01

Reference:
HONI Background Report on Issues 5 & 6, Page 2 (GLB purposes)

Preamble:
The background report states as follows:

> Embedded generation reduces demand on the transmission system. Given that the costs of transmission infrastructure are largely fixed, there was a need for the OEB to consider whether transmission customers who reduce their load supplied from the transmission system by installing embedded generation should continue to be charged for the sunk costs of the transmission system that was built to supply their original load (gross load billing), or they should not bear those sunk costs (net load billing).

Interrogatory:

a) Please comment on the degree to which transmission customers who reduce their load will necessarily result in sunk costs in light of the increasing demand growth expected to occur in the coming decades due to electrification.

b) Please comment on the pros and cons of pausing gross load billing for any new renewable generation projects in areas that are transmission constrained or expect to be transmission constrained in the near future. Please consider and speak to the potential benefits from encouraging embedded generation that could defer or avoid transmission upgrades.

c) Please provide a list of the top 20 transmission capacity upgrade projects planned for Ontario, with a brief description of each.

d) Please comment on the pros and cons of charging all transmission costs through coincident peak charges to reduce the original drivers for gross load billing.

Response:

a) Please refer to Hydro One's response to Clarifying Questions Issues 5 and 6, VECC-9, part b).

b) Hydro One discusses this issue in Section 1.3.2 of its Background Report on Issues 5 and 6 and notes that there is merit in considering exemptions in specific circumstances, such as where there are existing supply constraints on the system. Hydro One agrees that embedded generation installed by transmission customers could be used to defer or avoid transmission upgrades. The potential for using embedded generation installed by transmission customers as a non-wires solution option is being considered more extensively as part of the regional planning process. However, where such options are pursued, the transmission customer would need to forego the capacity originally built on the transmission system to supply their load, which is now being displaced by embedded generation.

c) Hydro One is not clear on the relevancy of this question to Hydro One's Background Report or the issues in this proceeding as currently defined.

d) Hydro One has not done any analysis, which would be a significant effort, to be able to comment on this approach. In its Background Report Background Report on Issues 5 and 6, Hydro One has focused on identifying and discussing the issues related to gross load billing that require clarification or resolution.

CLARIFYING QUESTIONS OF ED – 02

Reference:
HONI Background Report on Issues 5 & 6, Page 7 (solar)

Interrogatory:

a) Please confirm that gross load billing only applies to rates that are charged on the basis of non-coincident peak demand? (Or if there is a mix, please quantify that mix.)

b) Please provide a rough estimate of the degree to which a 2 MW solar facility (including multiple units/inverters) is likely to reduce a customer's non-coincident peak demand in light of the fact that solar cannot be controlled to ensure that it is producing at the time of the customer's peak. For instance, would HONI expect a 2 MW solar facility to impact the coincident peak demand by an amount that is closer to 0.1 MW, 0.5 MW, 1 MW, or 2 MW on average over a year?

c) Please provide a table of the different generator types (e.g. gas, solar, wind, storage, etc.) and different generator use cases showing for each the likely average ratio of generator capacity to average reduction in co-incident peak demand.

d) Please confirm whether GLB is applied based on the output of the generator at the time of the customer's non-coincident peak or the capacity of the generator.

Response:

a) Confirmed.

b) A solar facility's impact on reducing a customer's non-coincident peak would depend on a number of factors, which would make any analysis difficult to perform.

c) Hydro One does not have this information and it would be a significant level of effort to provide this data.

d) Gross load billing is applied based on the output of the generator at the time of the customer's non-coincident peak. Please refer to the IESO Market Rules and Manuals for further details.

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CLARIFYING QUESTIONS OF ED - 03

Reference:
HONI Background Report on Issues 5 & 6, Page 7 (storage)

Interrogatory:

a) Does HONI believe that a significant percent of owners of storage are operating it in an effort to reduce the GLB charges they pay by reducing the customer's monthly non-coincident peak, or would do so if covered by GLB? If yes, what percent? Please comment on the cost-effectiveness of doing so (versus other uses of storage, such as peak shaving).

b) The Ontario Government is seeking to procure storage capacity. Please comment on how those efforts might be impacted by applying the 2 MW threshold to storage.

c) Please discuss a high, low, and mid-range amount of gross load billing charges for a 2 MW storage unit.

Response:

a) Hydro One does not believe that storage facility owners are operating their facilities in a way to reduce gross load billing charges. Generally, storage is deployed by load customers to reduce their monthly non-coincident peak demand (i.e. peak shaving). If this is the case, gross load billing should apply to customers with energy storage in the same manner that gross load billing applies to customers with embedded generation who use their generation to reduce their non-coincident peak demand.

b) Hydro One would like to clarify that storage is currently subject to the 1 MW threshold for gross load billing.

   The applicability of gross load billing to energy storage could be seen as a negative factor to deploying storage. However, a customer's decision to install energy storage would be predicated on a number of other factors. While a customer who installs energy storage may object to gross load billing, Hydro One is not certain if applicability of gross load billing charges would impact their decision and their business case to install an energy storage facility.

c) Energy storage has the highest impact on UTR gross load billing charges when it is deployed at full capacity to offset a customer's monthly peak demand, which is the billing determinant for their UTR connection charges. In this scenario, the additional 2 MW will result in $8,320 connection charges. Conversely, the least impact is $0, which happens when the customer's monthly peak demand occurs when the storage unit is not in use. A calculation of the high and low amounts of gross load billing are provided below. A mid-range amount of gross load billing charges cannot be provided. This is because the charges will vary within a broad range of customer-specific uses, for example IESO contracts and ICI initiative in addition to offsetting peak demand to lower charges where gross load billing does not apply.

Monthly UTR Charges for 2 MW Energy Storage	**UTR Rate ($/kW)**	**Contribution to Peak Demand Charge Determinant from 2 MW Energy Storage**		**UTR Charge**	
		High (MW)	**Low (MW)**	**High ($)**	**Low ($)**
	A	B	C	A x B	A x C
UTR - Line Connection	0.95	2,000	-	1,900	-
UTR - Transformation Connection	3.21	2,000	-	6,420	-
Total				**8,320**	**-**

CLARIFYING QUESTIONS OF ED - 04

Reference:

HONI Background Report on Issues 5 & 6, Page 11 (threshold)

Interrogatory:

a) Please comment on the pros and cons of greatly increasing the GLB threshold (e.g. to 20 MW) in transmission constrained areas of the province.

Response:

a) As discussed in Section 1.3.2 the Background Report on Issues 5 and 6, Hydro One is supportive of having discussions as to whether gross load billing exemptions should be granted in cases where transmission constraints exist. Instead of establishing a specific threshold, criteria could be established for addressing these specific cases to ensure fair treatment for all customers.

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CLARIFYING QUESTIONS OF ED - 05

Reference:
HONI Background Report on Issues 5 & 6, Page 13 (exemptions)

Interrogatory:

a) If exemptions are allowed, should HONI have the authority to grant them case-by-case or should HONI be required to develop criteria, and for the latter, should this be subject to OEB approval? Please discuss, including a discussion of other options.

b) Please provide a table for all the exemptions that HONI would put in place if exemptions were allowed, including the criteria to quality and the rational for the exemption. Please provide that on a high-level and preliminary basis, without prejudice to HONI decisions on this issue in the future.

Response:

a) Subject to OEB approval, Hydro One believes that this proceeding provides an opportunity to establish criteria that would allow for exemptions to be granted in specific cases. To ensure Hydro One has appropriate flexibility to consider other cases, as they arise in the future, that may also warrant an exemption, Hydro One should be able to seek and obtain OEB approval in a timely manner.

b) Please refer to Section 1.3.2 of the Background Report on Issues 5 and 6 for known case examples that could be used to develop the exemption criteria. Hydro One looks forward to considering the viewpoints of parties to this proceeding prior to assessing whether it believes other cases may warrant consideration for an exemption.

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CLARIFYING QUESTIONS OF ED - 06

Reference:
HONI Background Report on Issues 5 & 6

Interrogatory:

a) Please provide a breakdown of all customers subject to gross load billing by type (LDC, etc.), size range, and total gross load billing.

b) Please comment on the pros and cons of allowing LDCs to reduce gross load billing amounts owing to the extent that their demand declines from embedded generation is offset by demand increases over time (e.g. due to electrification), on the basis that they are not causing the sunk costs that originally motivated GLB.

Response:

a) 174 LDC projects (generators or customers of transmission-connected LDCs) and 9 commercial and industrial projects are currently subject to gross load billing.

b) Please refer to Hydro One’s response to Clarifying Questions Issued 5 and 6, VECC-9, part b).

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CLARIFYING QUESTIONS OF ED - 07

Reference:
HONI Background Report on Issues 5 & 6

Interrogatory:
a) Does gross load billing reduce the revenue forecasting risk faced by HONI?

b) If yes, and charges in this process result in less gross load billing, what adjustments can be made to the rate structure to ensure that HONI is made whole and does not face additional revenue forecasting risk?

c) Please provide a table for the most recent year indicating total revenue received by HONI transmission, with a breakdown by the network service rate, line connection service rate, and transformation connection service rate, and other rates.

d) Please provide a version of table (c) in a scenario where there was no gross load billing.

Response:
a) Hydro One is unclear as to the reference to revenue forecasting risk in the question. In general terms, in order for Hydro One to recover its approved revenue requirement, the approved charge determinants and the associated methodology at the time of approving UTRs should be on the same basis as the charge determinants used to bill those UTRs.

b) In order to reduce the risk of under-recovering the OEB approved revenue requirement due to any changes to UTRs that result in less gross load billing, Hydro One would need to forecast the potential increase in customer adoption of load displacement generation in response to any such changes. In order to forecast the impact of any changes to the current UTRs net load billing process, Hydro One will require details of how such changes would be implemented as well as information on how those changes would have impacted historical billing determinants.

Hydro One notes that it is currently in its second year of an approved five-year Custom IR period, which approved the annual revenue requirements and charge determinants (i.e. load forecast) until 2027. Unless otherwise approved by the OEB, Hydro One cannot adjust for changes in the approved period and will therefore under-recover its revenue requirement if changes in this process result in less gross load billing.

c) and d)

Please see table below for estimated revenue contribution of GLB billed customers connected to the Hydro One transmission system to the Hydro One transmission revenue collected by the IESO:

Service Rate	Revenue Contribution (%)
Network Service rate	0.0
Line Connection Service rate	1.6
Transformation Connection Service rate	1.4

CLARIFYING QUESTIONS OF SEC - 05

Reference:
Background Report, Page 18

Interrogatory:
As part of its options analysis, Hydro One references increased customer metering costs that would need to be incurred to implement gross-load billing. Please provide details regarding an estimate range of costs a customer would incur for the required metering infrastructure. Please confirm that those costs would be paid for by the specific customer.

Response:
- For LDCs with embedded retail generators, Gross Load Billing (GLB) settlement is performed based on the existing metering that is used to pay the embedded retail generator. There are no additional meter costs.

- For C&I load customers with load displacement generation, customers are required to install additional meters based on the IESO Market Rules and Manuals. Metering infrastructure costs are not readily available. Metering costs are paid by the customers.

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CLARIFYING QUESTIONS OF SEC - 06

Reference:
Background Report, Page 19

Interrogatory:
Please explain Hydro One's view on the appropriateness of gross-load billing in general.

Response:
Please refer to Hydro One's response to Clarifying Questions Issues 5 and 6, SEC-7.

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CLARIFYING QUESTIONS OF SEC - 07

Reference:

Background Report, Page 15

Interrogatory:

Please explain Hydro One's preferred option for addressing each of its 4 identified sub-issues.

Response:

Procedural Order 1, dated December 8, 2023, ordered Hydro One to prepare and file, without prejudice, the background report for this proceeding regarding Issues 4, 5, and 6. Furthermore, the OEB contemplated a process in which Hydro One would respond to clarifying questions about the report, not interrogatories about Hydro One's position in respect of issues identified in the report. At a later stage in the generic proceeding, after it has heard and considered the views of all participants, Hydro One expects to advocate for one or more options as being the option(s) that it prefers. At that time, Hydro One will provide the reasons for its views in that respect. For Hydro One to express a preference before the issues list and certain scoping issues identified in the report have been finalized, and before having the benefit of input from other parties, would be premature, as well as out of step with the process contemplated by the OEB for this proceeding.

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CLARIFYING QUESTIONS OF VECC - 08

Reference:

HONI Background Report, Issues 5 & 6, Page 2

Preamble:

The Report states:

> Under gross load billing, the charges for a transmission customer are calculated as they are under net load billing plus the load supplied by any embedded generation.

Interrogatory:

a) In the case of transmission connected LDCs does the gross load billing provision apply to both: i) generation embedded in the LDC's service area that delivers power directly to the LDC and ii) generation that is embedded behind the meter of a customer of the LDC?

b) What processes/procedures does the IESO and/or HONI employ to ensure that all embedded generation subject to potentially gross load billing is: i) identified and ii) metered accordingly?

Response:

a) Yes, in the case of transmission-connected LDCs, gross load billing provision applies to both: i) generation embedded in the LDC's service area that delivers power directly to the LDC and ii) generation that is embedded behind the meter of a customer of the LDC.

b) ***Response from Hydro One:***

Gross load billing eligibility is identified during the Hydro One Connection Impact Assessment (CIA) process. Gross load billing metering requirements are outlined in the IESO Market Rules and Manuals.

Response from IESO:

The transmission customer has an obligation to inform the transmitter of any embedded generation facility connected to its distribution system. The transmitter determines if the embedded generation facility is subject to gross load billing, and if so, the transmission customer and transmitter agree on the metering provision that will be utilized for gross load billing (see Chapter 6, section 4.5.1 of the Market Rules and Manuals). This information is communicated to the IESO by the transmitter via the transmitters list. The transmission customer has the obligation to commence registration of the embedded generation facility with the IESO and the transmitter signs off on the registration once completed. Settlement of transmission tariffs are done in accordance with the UTR and the registration status of the transmitters list.

CLARIFYING QUESTIONS OF VECC - 09

Reference:
HONI Background Report, Issues 5 & 6, Page 2

Preamble:
The Report (page 2) describes the OEB's rationale (per its Original UTR Decision) for adopting gross load billing as follows:

> Embedded generation reduces demand on the transmission system. Given that the costs of transmission infrastructure are largely fixed, there was a need for the OEB to consider whether transmission customers who reduce their load supplied from the transmission system by installing embedded generation should continue to be charged for the sunk costs of the transmission system that was built to supply their original load (gross load billing), or they should not bear those sunk costs (net load billing).

The Report states (page 20):

> Gross load billing should be applied practically and achieve the objectives set out in the Original UTR Decision. The OEB should consider providing certain flexibility in applying the gross load billing rules where a situation merits such treatment and, where possible and appropriate, the OEB should provide clear direction as to how these situations should be addressed.

Interrogatory:

a) In HONI's view does the cited reference from page 2 describe the objectives of gross load billing per the Original UTR Decision that it is referring to?
   i. If not, in HONI's view, what were the objectives of gross load billing that the OEB set out in the Original UTR Decision?

b) When planning either new or the need to upgrade existing Line Connection and Transformation Connection facilities due to increased load how does HONI (and/or the IESO) account for the impact of: i) existing customer embedded generation or ii) customers' plans for new embedded generation on the load that will need to be served? In responding please specifically address whether or not such plans size the associated transmission facilities under the assumption that they will/may be required to serve load that would otherwise be served by the embedded generation.

Response:

a) In the Original UTR Decision, the OEB determined that it was appropriate for Transmission customers who connect new embedded generation to be billed on a gross load basis for Line and Transformation Connection service charges because these assets were installed specifically to meet the supply needs of these customers. It is Hydro One's understanding that the OEB considered administrative simplicity and cost efficiency in establishing the gross load billing rules and thresholds but it is unclear how these factors were exactly considered and what analysis was performed.

i. See part a) above.

b) ***Response from Hydro One:***

Hydro One plans the transmission system to meet the peak demand of the customers connected to its system. While customers may displace their load through embedded generation, the system is planned to account for the scenario that this embedded generation may not be available or not be at full capacity when the peak is reached.

Response from IESO:

As it relates to IESO Bulk System Planning, load displacing embedded generation is not explicitly factored into the provincial demand forecast and thus not considered when planning bulk transmission solutions, unless it is captured on aggregate as part of the Industrial Conservation Initiative. As it relates to IESO Regional Planning, embedded generation is factored in as a load modifier to the extent the information is provided by the transmitter for its directly-connected transmission customers and by local distribution companies as part of its demand forecast for its service territory, or is contracted by the IESO.

CLARIFYING QUESTIONS OF VECC - 10

Reference:

HONI Background Report, Issues 5 & 6, Pages 3, 5 and 11-12

Preamble:

The Report states (page 3):

> Furthermore, the OEB determined that, for reasons of administrative simplicity and cost efficiency, new embedded generation under 1 MW serving existing load should be exempt from gross load billing and billed on a net load basis. The OEB considered that gross load billing requires the installation of separate metering for the embedded generation and the incorporation of this data into the IESO's billing and settlement processes, which would create costs and complexities that would likely outweigh any benefits from billing customers with smaller embedded generators on a gross load basis. The OEB also considered that such generators would be exempt from IESO dispatch and scheduling requirements.

The Report states (page 5):

> In determining whether a transmission customer who installs embedded generation behind their meter is subject to gross load billing, the UTR Schedule states that the thresholds for renewable and non-renewable generation apply to "customer demand that is supplied by an embedded generator unit.

The Report states (page 11):

> In the Original UTR Decision, the OEB acknowledged that, in principle, all embedded generation could cause stranding of transmission system assets. However, after considering the customer cost and administrative complexity associated with implementing gross load billing, the OEB determined that new embedded generation under 1 MW should be exempt from gross load billing.

The Report states (pages 11-12):

> If the OEB intends to review whether the current gross load billing thresholds for renewable and non-renewable embedded generation remain appropriate, the OEB should consider whether its assessment of the factors noted above remains valid and if other factors should now be considered in assessing the appropriateness of the current thresholds. For example, the OEB may want to review whether the incorporation of meter data from embedded generation into the IESO settlement process is administratively complex or burdensome on the market operator and the OEB may want to examine whether the cost of installing an additional gross load billing meter would deter customers from installing embedded

generation and at what point does this cost become excessive for the customer. In establishing the unit size thresholds for embedded generation and other load displacement technologies, the OEB will need to balance fairness, practicality and cost.

Interrogatory:

a) Per page 3, the 1 MW threshold appears to have been established based on considerations of administrative efficiency, cost efficiency and generation exempt from IESO dispatch and scheduling requirements. Assuming it is determined that gross load billing is appropriate (e.g., fairly recovers costs), what are HONI's views on the following:
   i. Are the "considerations" taken into account by the OEB in its original UTR decision cost still appropriate when determining the need for threshold for the application of gross load billing?
   ii. Aside from those noted on page 12, are there other "considerations" that should be taken into account at this point in time?

b) Apart from the implications as to who pays Line Connection Service and Transformation Connection Service Charges, what are the advantages and disadvantage of using individual generating unit capacity versus overall facility capacity when determining how any threshold should be applied (e.g., are administration and metering costs impacted by the number of units installed at a facility, for purposes of gross load billing are individual generating units currently required to be metered or just the overall facility and does the IESO dispatch individual generation units or just the facility overall)?

Response:

a) Please see responses to i. and ii. below.
   i. Hydro One believes that administrative efficiency and cost efficiency are factors that need to be considered in determining how gross load billing should be applied. Given that the Original UTR Decision was issued over 20 years ago and based on the experience gained from implementing gross load billing to date, it is possible that these factors may be viewed differently now. Hydro One does not believe that IESO dispatch and scheduling requirements should continue to be viewed as an important consideration because most embedded generation connected behind the meter of transmission customers is not currently dispatchable by either the IESO or the distributor.

   ii. Hydro One believes that, as a first step, the OEB should review and confirm whether the factors that were considered in the Original UTR Decision are relevant and applicable. Next, the OEB should consider whether other factors should be reviewed, including whether gross load billing supports and is aligned with other policy direction and regulatory guidance. Furthermore, Hydro One believes that gross load billing rules should not provide preferential treatment based on technology or fuel type.

b) Please refer to Sections 1.2.1 and 1.4.1 of the Background Report on Issues 5 and 6 for further commentary on the advantages and disadvantages of using a unit versus facility approach to gross load billing. If a facility-based approach for gross load billing was implemented, more embedded generation facilities would be eligible for gross load billing than they would be based on the current rules. However, the change in approach would not have any impact on current metering and administration costs.

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CLARIFYING QUESTIONS OF VECC – 11

Reference:

HONI Background Report, Issues 5 & 6, Page 4
OEB's Draft Benefit-Cost Analysis Framework for Addressing Electricity System Needs, December 2023 (EB-2023-0125), Section 2.1

Preamble:

The Report notes that in EB-2002-0120 the OEB decided to:

> …increase the qualifying limit for exemption from gross billing from 1 MW per unit to 2 MW per unit for renewable generation installations. This increase reflects a societal interest in increasing the proportion of renewable generation in the overall generation mix in the province, and the technical reality that the output of some renewable source generation equipment has advanced from under 1 MW per unit to just under 2 MW per unit.

The OEB's Draft Benefit-Cost Analysis Framework states:

> The intent of the BCA Framework is to encourage the development of solutions that are in the best interests of both an electricity distributor's customers and Ontario's energy customers more broadly and to help level the playing field between NWS and traditional poles-and-wires infrastructure solutions to meet an electricity system need. As stated in the FEI Report, <u>it is not the role of the OEB to increase or accelerate NWS adoption, or to choose one technology solution over another.</u> (emphasis added)

Interrogatory:

a) Does HONI view there to be an inconsistency between the approach adopted in EB-2022-0120 that favoured renewable generation and the approach adopted by the recent FEI Report and OEB Draft Benefit-Cost Analysis Framework that it is not the role of the OEB to favour/choose one technology solution over another? If not, why not?

Response:

a) Hydro One concurs that the current gross load billing rules, in particular the thresholds and the reliance on generator unit size for determining eligibility, favour renewable generation, in contrast to the principle articulated in the second paragraph of the preamble.

   In its Background Report for Issues 5 and 6, Hydro One has recommended that the current gross load billing thresholds and approach for assessing eligibility be reviewed with respect to all types of generation and resources deployed for load displacement purposes to ensure fair treatment and the achievement of intended outcomes.

Hydro One notes that s. 1 of the OEB Act, which sets out the OEB's statutory objectives with respect to electricity, has changed over the years. Notably, in the oldest version available on the Province of Ontario's 'e-laws' site, which was in effect from December 2003, s. 1 included as an objective "To promote energy conservation, energy efficiency, load management and the use of cleaner energy sources, including alternative and renewable energy sources, in a manner consistent with the policies of the Government of Ontario."

In contrast, the current version of s. 1 does not include any references to the use of clean energy sources or renewable energy sources. The difference between the two paragraphs from the preamble may have been driven, at least in part, by the differences in the OEB's statutory objectives in 2002 as compared to the present, with each being an expression of the OEB's statutory objectives then in effect. This may be something that the OEB wishes to take into consideration as it reviews its approach to gross load billing that was established over 20 years ago.

Finally, Hydro One notes that over 20 years have passed between the referenced statements, and it is for the OEB to determine if there has been any change in circumstances which would merit a change in approach.

CLARIFYING QUESTIONS OF VECC – 12

Reference:
HONI Background Report, Issues 5 & 6, Pages 3 and 7

Preamble:
The Report states (page 3):

> However, with respect to Line Connection Service and Transformation connection Service charges, the OEB determined that gross load billing shall apply, but only for load customers who connect new embedded generation.

And

> Furthermore, the OEB determined that, for reasons of administrative simplicity and cost efficiency, new embedded generation under 1 MW serving existing load should be exempt from gross load billing and billed on a net load basis.

Interrogatory:

a) For each of Line Connection Service and Transformation Connection Service, what was the annual average monthly adjustment (e.g., based on the last 3-5 years) to the billing determinants (province –wide) due to: i) the application of the 1 MW threshold for non-renewable generation and ii) the application of the 2 MW threshold for renewable generation? In each case, what does this adjustment represent as a percentage of the actual billing determinants used for each Service?

b) For each of Line Connection Service and Transformation Connection Service, what is the number of generating units (province-wide) whose capacity results in gross load billing due to: i) the application of the 1 MW threshold for non-renewable generation and ii) the application of the 2 MW threshold for renewable generation?

c) Can HONI provide an estimate of the impact (i.e., increase in billing determinants for Line Connection and Transformation Connection) if the threshold for renewable generation was reduced to 1 MW?

d) Can HONI provide an estimate as to the number of additional embedded generating units (based on HONI's current practice with respect to defining a renewable generating unit per page 7) if the threshold for renewable generation was reduced to 1 MW?

Response:

a) Hydro One does not have the required information with respect to province-wide UTR adjustments. With respect to customers supplied directly by Hydro One Transmission, as there are no billing or service requirement to track the requested differences, the information is also not available.

b) Gross load billing currently applies to 183 projects. Hydro One does not have the information as to the number of generating units for each of these 183 projects.

c) If the threshold for renewable generation was reduced from 2MW to 1 MW, then gross load billing would apply to additional 4 projects with installed capacity of 6.2 MW. Hydro One does not have the requested information as it would take significant effort and time to perform the required calculation.

d) Please refer to parts b) and c) above.

CLARIFYING QUESTIONS OF VECC – 13

Reference:
HONI Background Report, Issues 5 & 6, Pages 6, 7 and 8

Preamble:
The Report states (page 6):

> In view of the above, there appears to be an acceptance and understanding from a regulatory standpoint that, in the context of generation facilities, a 'unit' is a component of a generation facility and refers to each individual set of equipment or devices that is capable of functioning independently to generate electricity.

The Report states (page 7):

> In general, a solar generation facility will consist of a set of photovoltaic cell arrays that are connected through an inverter to produce electrical power. Often, a solar facility will be designed to include multiples sets of arrays, with each array having their own inverter. In such an arrangement, each array/inverter set could be viewed as independent from an operational standpoint and would represent a single generator unit. Hydro One's practice has been to use the capacity of the inverter for each array/inverter set within an embedded solar generation facility to define an individual generator unit. In its transmission revenue requirement proceeding for years 2020-2022 (EB-2019-0082), Hydro One indicated that, when providing data to the IESO for billing Line Connection and Transformation Connection Service charges, an inverter capacity greater than or equal to 1 MW was being used as a cut-off for applying gross load billing to embedded solar generation. When questioned about the application of this threshold, Hydro One responded that, in its experience, inverter capacity for solar generation is typically small (under 0.5 MW) and, as result, the threshold limit is irrelevant.

The Report states (page 8):

> The fact that embedded solar generation is currently exempt from gross load billing (based on Hydro One's practice of using the inverter capacity of each array/inverter set within an embedded solar generation facility to define an individual generator unit) highlights an important need to review the threshold applicable to solar generation and whether the approach of using the inverter size to define the size of a generator unit is appropriate and achieves the intended objectives contemplated in the Original UTR Decision and the RP-2002-0120 Decision. By applying the 2 MW threshold on a per-unit basis, Hydro One has determined that 1,268 MW of embedded solar generation is currently exempt from gross load billing charges.

Interrogatory:

a) How else could “an individual generator unit” be defined for solar generation that could be considered to be consistent with the definition of a generating unit per page 6?

   i. Would any of these definitions result in some (or all) of the currently connected solar generation being subject to gross generation using: i) a 1 MW threshold or ii) the current 2 MW threshold?

b) If the threshold was applied on a “facility basis”, how much of the 1,268 MW of embedded solar generation would be subject to gross load billing using: i) a 1 MW threshold or ii) the current 2 MW threshold?

Response:

a) For a solar generation facility, it makes sense to use the inverter to define an individual generator unit as it establishes the set of generation equipment and devices that is capable of operating independently to generate electricity. There is no other way to define a unit within a solar generation facility unless you consider the whole facility as a unit. However, this would ignore the fact that the facility could be broken down into smaller components that can function individually and independently.

   i. As mentioned above, there is no way to further break down a unit within a solar generation facility. If the whole facility was considered a single unit, more solar generation installations would be subject to gross load billing.

b) All of the 1,268 MW of embedded solar generation would be subject to gross load billing using the current 2 MW threshold. It will take significant effort and time to calculate the impact based on 1MW threshold.

CLARIFYING QUESTIONS OF VECC – 14

Reference:

HONI Background Report, Issues 5 & 6, Page 8

Preamble:

The Report states:

> In contrast, more than half of the installed embedded wind generation capacity is being billed on a gross load basis. This is due to the fact that wind generating units tend to be larger than 2 MW.

Interrogatory:

a) Does the reference to "wind generating units" refer to each individual wind turbine? If not, how does HONI define a "wind generating unit"?

Response:

a) Yes, with respect to wind generation installation, each individual wind turbine would be considered a unit.

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CLARIFYING QUESTIONS OF VECC – 15

Reference:
HONI Background Report, Issues 5 & 6, Pages 4 and 9

Preamble:
The Report states (page 4):

> For the purpose of defining renewable generation, the OEB adopted the definition of Renewable Generating Facility being used by the Ontario government at the time, which refers to a facility that generates electricity from sources such as wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water.

The Report states (page 9):

> In its transmission revenue requirement proceeding for years 2020-2022 (EB-2019-0082), Hydro One described its treatment of energy storage and the applicability of the 1 MW threshold for gross load billing. Hydro One explained its approach for treating energy storage like generation and that applying this threshold is appropriate given that the energy provided by storage is not created from a renewable process.

Interrogatory:
a) Has the Government of Ontario adopted a more recent definition of Renewable Generation than that used in EB-2002-0120?
   i. If yes, please provide the most recent definition.

Response:
a) Hydro One has not performed an exhaustive search of all possible definitions adopted by the Government of Ontario since the referenced proceeding.

   Based on a keyword search of consolidated current statutes and regulations on the Province of Ontario's 'e-laws' site, Hydro One did not identify the term "Renewable Generation" as being used in any current statute or regulation. Hydro One does note that the Electricity Act defines "renewable energy generation facility" to mean a generation facility that generates electricity from a renewable energy source, and further defines "renewable energy source" to mean an energy source that is renewed by natural processes and includes wind, water, biomass, biogas, biofuel, solar energy, geothermal energy, tidal forces and such other energy sources as may be prescribed by the regulations, but only if the energy source satisfies such criteria as may be prescribed by the regulations for that energy source. These terms are incorporated by reference into the OEB Act. Lastly, the term "renewable generation" is defined in the

Transmission System Code and refers to “a generation facility that generates electricity using a renewable energy source as defined in the Electricity Act.”

i. Please see part a) above

CLARIFYING QUESTIONS OF VECC – 16

Reference:

HONI Background Report, Issues 5 & 6, Page 8

Preamble:

The Report states (page 8):

> The UTR Schedule does not clarify whether an embedded generator unit includes an embedded energy storage unit. Furthermore, the UTR Schedule does not specify whether or not, in the circumstances where an embedded energy storage unit reduces a transmission customer's non-coincident peak in the same manner that an embedded generation unit would, energy storage should be treated as generation for the purpose of assessing gross load billing eligibility.

Interrogatory:

a) Is the installation of customer storage, particularly large capacity customer storage, a recently new phenomenon?

b) When planning either new or the need to upgrade existing Line Connection and Transformation Connection facilities due to increased load does HONI (and/or the IESO) take into account the impact of: i) existing customer storage facilities or ii) customers' plans for new storage facilities on the peak load that will need to be served? In responding please specifically address whether or not such plans size the associated transmission facilities under the assumption that they will/may be required to serve peak load that could otherwise be served by the storage facilities.

Response:

a) Hydro One Distribution received the first application for >10kW customer storage in 2020.

b) ***Response from Hydro One:***

Please refer to Hydro One's response to Clarifying Questions Issues 5 and 6, VECC-9, part b).

Response from IESO:

Please see response to I-05-06-VECC-09 b).

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CLARIFYING QUESTIONS OF VECC – 17

Reference:

HONI Background Report, Issues 5 & 6, Pages 8-9

Preamble:

The Report states (page 8):

> In the absence of further guidance on these aspects, Hydro One has adopted the practice of applying gross load billing to embedded energy storage because energy storage is typically deployed by customers to reduce their non-coincident peak demand. Since storage does not rely on a renewable process for injecting power, Hydro One has applied the non-renewable generation unit threshold (1 MW) for assessing gross load billing eligibility. Where appropriate, Hydro One has relied on its practice of using the inverter to delineate units within a storage facility, consistent with its approach for treating inverter based generation.

Interrogatory:

a) To-date, how much existing and planned storage capacity (i.e., MWs) has been identified as being subject to gross load billing?

b) How would the application of the 1 MW threshold on a facility basis (as opposed to on an inverter basis) impact the MWs subject to gross load billing?

c) How would the application of a 2 MW threshold (on an inverter basis) impact the MWs subject to gross load billing?

d) How would the application of a 2 MW threshold on a facility basis (as opposed to on an inverter basis) impact the MWs subject to gross load billing?

Response:

a) To-date, approximately 72 MW (25 projects) of existing and 32 MW (15 projects) of planned storage capacity has been identified as being subject to gross load billing.

b) Approximately additional 68 MW (28 projects) of existing and 134 MW (40 projects) of planned storage capacity would be subject to gross load billing based on 1 MW threshold on a facility basis criteria (as opposed to on an inverter basis).

c) Approximately 45.3 MW (23 projects) of the existing and the planned storage capacity would be exempt from gross load billing from the information provided in part a) above.

d) Approximately 67.3 MW (26 projects) of the existing and the planned storage capacity would be exempt from gross load billing from the information provided in part b) above.

CLARIFYING QUESTIONS OF VECC – 18

Reference:
HONI Background Report, Issues 5 & 6, Pages 12-13 and Appendix A

Preamble:
The Report states:

> In one case, the customer of an LDC, which is connected to Hydro One's transmission system, disagreed with Hydro One's methodology for calculating the incremental capacity that should be subject to gross load billing following a refurbishment. The transmission- connected LDC and their customer argued that the incremental capacity should be calculated at the facility level and not at the unit level, which in this case would have resulted in a lower incremental capacity value. (emphasis added)

The Report states (Appendix A):

> Load Customer has an existing (pre-1998) facility consisting of four 800 kW generating units and is replacing the four units with two new 2,000 kW units.

And

> Per the current UTR tariff, GLB shall be applied to the incremental capacity associated with any unit refurbished after 1998 and the incremental capacity is 1 MW or greater for non-renewable generation Based on the current UTR, Hydro One proposes to apply GLB on a generation unit basis and not at a facility level since the incremental capacity of each unit is 1,200 kW, which is greater than 1 MW, GLB would apply to each of the new units.
>
> The total incremental capacity subject to GLB would therefore be 2,400 kW.

Interrogatory:
a) Given that the load customer was replacing the existing units with units of a completely difference size why was the project considered to be a "refurbishment" which is addressed in the current UTR tariff as opposed to the "replacement" of a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 which is a circumstance that is not addressed in the current UTR tariff?

Response:
a) A refurbishment is considered a major modification/upgrade to the units of a facility and could include a replacement of the units. There is nothing preventing a customer from changing the size of their generating units as part of a refurbishment.

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CLARIFYING QUESTIONS OF VECC – 19

Reference:

HONI Background Report, Issues 5 & 6, Pages 13-14

Preamble:

In the Report (pages 13-14) HONI cites a couple of examples of where it views it may be appropriate for the transmitter to exempt a customer from gross load billing.

The Report states (page 14):

> Another example where discretion may be warranted is when a customer installs embedded generation for the sole purpose of "peak shaving" and mitigating their Class A Global Adjustment charges under the Industrial Conservation Initiative. In this scenario, the embedded generation is run only at select times to reduce the customer's non-coincident peak demand during anticipated Ontario peak demand hours over a base period. <u>Where embedded generation is being deployed in this manner, this results in only a marginal impact to the customer's monthly non-coincident peak demand.</u> Therefore, in this circumstance, it may be appropriate to exempt such embedded generation from gross load billing. (emphasis added)

Interrogatory:

a) With respect to the example referenced from page 14, what is the basis for the conclusion that "where embedded generation is being deployed in this manner, this results in only a marginal impact to the customer's monthly non-coincident peak demand"? Would this apply for all customers using embedded generation for peak shaving to mitigate their Class A Global Adjustment charges?

Response:

a) In the specific scenario, it is contemplated that where embedded generation is being used exclusively for peak shaving to mitigate Class A Global Adjustment charges, the generation may only be operated on a limited or sporadic basis when there is a chance that a system peak could be reached. Effectively, the generation may only be run for a small number of hours every year. In such cases, while the customer would achieve the intended objective of mitigating its Class A Global Adjustment charges, its demand-based charges would be largely unaffected and, therefore, an exemption could be warranted. However, if a generator was being operated continuously and regularly for peak shaving purposes, the customer's monthly demand charges would be impacted by the generator's operation and the generator should be subject to gross load billing. By allowing for an exemption in the case where the generator is not run continuously and the customer's monthly demand is not materially affected, rules would need to be established to ensure that the generator is only being operated to reduce Class A

Global Adjustment charges through peak shaving and that its operation would not impact its monthly demand.

CLARIFYING QUESTIONS OF VECC – 20

Reference:

HONI Background Report, Issues 5 & 6, Pages 6 and 15-17

Preamble:

The Report (pages 15-17) sets out two options for addressing the application of gross load billing to “embedded generator units”.

The Report describes Option #2 as follows:

> Revise the rules in the UTR Schedule to clarify that the thresholds for gross load billing apply to the aggregate installed capacity of all embedded generator units installed by the customer at that connection point to the system.

The Report (page 6) states:

> Hydro One is aware of several instances in which a customer has installed multiple generator units and the aggregate rated capacity of these units (i.e. the installed capacity of the embedded generation facility) exceeds the applicable gross load billing threshold. However, since none of the individual generator units exceeds the threshold on its own, the load supplied by these units has been, and continues to be, exempt from gross load billing charges.

Interrogatory:

a) With respect to Option 2, would the adoption of a facility as opposed to unit definition for determining the threshold for gross load billing require a re-consideration of the threshold limits (Issue #4)?

b) As noted on page 6, there are instances where customers have sized the generating units at their facility so as to be exempt from gross load billing. If Option 2 was adopted would there be any ability on the part of customers (particularly those with solar wind or wind generators) to re-configure what might be otherwise be viewed as one “facility” which would exceed the threshold into two (or more) “facilities”, request/obtain a separate delivery point for each and thereby be exempt from gross load billing?
   i. If yes, would such an approach be easier for customers to implement with certain types of generation and, if so, which types?

Response:

a) Hydro One believes that it would be appropriate to consider Issue 4 (Threshold Limits for Gross Load Billing) if Option 2 was adopted.

b) It is possible that a customer could re-configure their generation facility into two or more facilities. However, the belief is that this would be unfeasible in most cases and the costs of doing so may outweigh the gross load billing costs.

   i. Hydro One believes that this approach would not be feasible to implement in most cases. Typically, if a customer has implemented embedded generation, the generation is situated and installed in the same location. Hydro One cannot comment if this would be easier to implement for a certain type of generation as opposed to another type of generation.

CLARIFYING QUESTIONS OF VECC – 21

Reference:

HONI Background Report, Issues 5 & 6, Page 17

Preamble:

For Issue #2, Option 1 is “Clarify applicability of the gross load billing thresholds to embedded generation that employs inverters, such as embedded solar generation.”

The Report states as one of the “pros” of such clarification:

> The gross load billing rules would not enable customers who deploy inverter-based embedded generation to be exempt from gross load billing more easily than customers who deploy other types of embedded generation.

Interrogatory:

a) The Report does not indicate what the clarification would be. Please describe the nature of the clarification proposed/anticipated by HONI such that it “would not enable customers who deploy inverter-based embedded generation to be exempt from gross load billing more easily than customers who deploy other types of embedded generation”.

Response:

a) As stated in the Background Report on Issues 5 and 6, Hydro One believes that a clarification or modification of the rules and thresholds applicable to inverter-based generation would be appropriate.

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CLARIFYING QUESTIONS OF VECC – 22

Reference:

HONI Background Report, Issues 5 & 6, Page 17

Interrogatory:

a) For Issue 2 (Application of Gross Load Billing to Embedded Solar Generation), please provide an assessment as to the pros and cons of maintaining the status quo.

Response:

a) The pro of maintaining the status quo is that Hydro One would not need to change its processes with respect to gross load billing or the treatment of generation that has been exempted.

The con of maintaining the status quo is that the current framework enables larger facilities to be exempt from gross load billing, due to the reliance on unit size for assessing eligibility. Solar may have more of an advantage over other types of embedded generation due to the design of embedded solar generation facilities.

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CLARIFYING QUESTIONS OF VECC – 23

Reference:

HONI Background Report, Issues 5 & 6, Pages 18-19

Preamble:

The Report states that the pros associated with Option #1 include: i) Customers installing energy storage would not have to pay for additional metering costs to implement gross load billing and ii) Would simplify administration of IESO settlement processes.

Interrogatory:

a) Is the cost of metering to implement gross load billing higher for energy storage than other types of embedded generation and, if so, why?

b) Is it more difficult for the IESO to administer the settlement process for an energy storage facility than for other types of embedded generation (where both exceed the 1 MW threshold) and, if so, why?

Response:

a) Hydro One does not believe that the cost of metering to implement gross load billing is higher for energy storage than other types of embedded generation.

b) ***Response from IESO:***

From the IESO's perspective, the effort and cost to administer the settlement process for an energy storage facility as compared to any embedded generation facility is the same. The metering registration and settlement processes support both resource types (generation and energy storage).

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CLARIFYING QUESTIONS OF VECC – 24

Reference:
HONI Background Report, Issues 5 & 6, Pages 18-20

Preamble:
For Issue 3, the Report cites one of the pros of Option #2 is that "Gross load billing rules would be technologically agnostic and would treat energy storage customers the same as other embedded generation."

For Issue 3, the Report also cites one of the cons of Option #2 as "Customers with energy storage would continue to be billed on a gross load basis which could discourage future deployment of energy storage by customers."

Interrogatory:
a) With respect to Issue 3, would the assessment of Option #2 necessitate a consideration of whether a 1 MW or 2 MW threshold would be appropriate for energy storage?
   i. If yes, would such a consideration involve some of what would be assessed under Option #1 for Issue 4 (i.e., consideration of whether a higher threshold is appropriate for certain technologies)?

b) In considering the specific pro and specific con cited in the Preamble for Option 2, in HONI's view, which should be given more weight and why?

Response:
a) While it is not necessary, it would seem appropriate to consider the size threshold applicable to energy storage if it determined that storage should be treated like embedded generation from a gross load billing perspective.
   i. Correct. In Hydro One's view, there needs to be a review of the existing factors (as well any new factors) that should be considered in establishing appropriate thresholds for all applicable technologies that should be assessed for gross load billing.

b) In accordance with the OEB's direction in Procedural Order 1, dated December 8, 2023, Hydro One's Background Report on Issues 5 and 6 seeks to identify the potential pros and cons associated with possible options for addressing issues related to gross load billing. While Hydro One is not prepared to take a position at this time, Hydro One believes that the pros and cons cited under Option 2 for Issue 3 are equally important and should be considered if changes are proposed.

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CLARIFYING QUESTIONS OF VECC – 25

Reference:

HONI Background Report, Issues 5 & 6, Pages 19-20

Preamble:

The cons cited for Option #1 under Issue #4 include: i) “updates to transmitter billing systems may be required to reflect changes” and ii) “updates to IESO billing and settlement processes may be required to reflect changes”

Interrogatory:

a) As the IESO does the billing for Transmission Service Charges (UTRs), what “transmitter billings systems” are being referred to in the reference?

b) Is it fair to say that for all of the issues considered in the Report related to either double billing of DPs or gross load billing the options that involve a change from the status quo would necessitate updates to transmitter billing systems?
   i. If not, which non-status quo options related to double billing would not require changes to transmitter billings systems?
   ii. If not, which non-status quo options related to gross load billing would not require changes to transmitter billings systems?

c) Is it fair to say that for all of the issues considered in in the Report related to either double billing of DPs or gross load billing that the options that involve a change from the status quo would necessitate updates to IESO billing and settlement processes with the possible exception of Option 4 related to double billing of DPs? If not, why not?

Response:

a) “Transmitter billings systems” in this reference is the transmitter list described in the IESO “Market Manual 3: Metering Part 3.8: Creating and Maintaining Delivery Point Relationships, Appendix B: Sample of Transmitters List.”

b) Hydro One believes that updates would be required to either billing systems or processes for any of the options adopted that deviates from status quo.
   i. N/A
   ii. N/A

c) ***Response from IESO:***

The level and nature of changes to the IESO's billing and settlement processes associated with each option varies. In particular, Options 2 or 3 would necessitate material changes to the IESO's processes and systems and require multiple years to implement. The IESO would need to account for these projects in its business planning processes, given their size and the resources that would be necessary to develop them. Additionally, projects would need to be scheduled and balanced against other competing priorities, such as those being undertaken in support of the Market Renewal Program. The IESO business planning process includes gaining Minster of Energy approval for its plan, and subsequently, seeking OEB approval of the associated budget.

The IESO has provided additional details below on the updates to the IESO's billing and settlement processes that it anticipates would be needed to accommodate each option related to either double peak billing or gross load billing.

Double Peak Billing	
Option 1 – Maintain Status Quo	No changes would be required to the IESO processes or current billing practices to maintain the status quo.
Option 2 – Bill by Customer, instead of by DP	The IESO's current processes and systems are tightly integrated and aligned with the current UTR requirements. The processes involved are market registration, meter registration and settlement/billing, specific for transmission tariffs. Calculating transmission charges at the customer level, rather than the current practice of billing at each delivery point, would introduce significant changes to several, but not necessarily all, of the following IESO processes, systems and reporting requirements, depending on the approach: • Market Registration processes • Meter Registration processes • Settlement processes • Online IESO system • Customer Data Management System (CDMS) – repository of all registration data • Commercial Reconciliation System • Transmission Tariff Demand Calculator • Downstream reporting and re-registrations under new requirements

	The Market Rules would need to be aligned with the changes to any new UTR requirements. Depending on the approach, Market Rules in several Chapters would need revision. This would initiate the Market Rule amendment process requiring full stakeholder engagement. The above changes require further analysis and project development to determine the full impact and timelines to implement. It is anticipated to be a multi-year project. These changes would apply to the same processes and systems that support the Market Renewal Program and therefore would introduce further complexity. Given that the Market Renewal Program is already in flight, implementing the above changes to IESO processes and systems would be very challenging and need to be tightly coordinated.
Option 3 – Revise the Definition of the Transmission Charge Determinants	Revising the definition of transmission charge determinants would require updates to the IESO's settlement processes and controls to permit transmitter override of the established billing determinants used for settlement. Redefining charge determinants to exclude the impact of planned transmission charges would require significant time and effort, given the variability of power switching conditions that can give rise to a double peak charge. Due to this variability and the lack of a historical data set, it may not be feasible to establish a comprehensive set of business rules that would identify and determine the impact of such events under all situations. Further, implementing a complex set business rules into the IESO's settlement systems would require significant effort. As a result, this approach could take multiple years to implement. Alternatively, a manual assessment jointly undertaken by the transmission customer and transmitter based on principles established by the Board (as opposed to specific business rules) could be implemented. Once the impact of double peak charge is determined via manual assessment, a provision in the transmission settlement process can be established which would provide for an adjustment to the impacted transmission customer. The basic structure of the adjustment process would be as follows: • IESO bills the transmission customer based on the status quo • The transmission customer and transmitter assess any double peak charge and determine if adjustment warranted (based on the established principles) • The transmission customer and transmitter agree to double peak adjustment and submit information to the IESO for processing

<table>
<tr><td></td><td>Adjustment processed by the IESO via recalculated settlement statement (full transparency)
The Market Rules in several chapters would need revision to accommodate either approach to Option 3. This would initiate the Market Rule amendment process requiring full stakeholder engagement.
The manual assessment would necessitate changes to certain IESO processes, systems and reporting requirements, including:
On-Line Settlement Form
Commercial Reconciliation System/Transmission Tariff Design Calculator
Downstream Reporting
Projects of similar scope would typically take 9 months to complete. </td></tr>
<tr><td>Option 4 – Track Double Peak Billing Impact in a Deferral Account</td><td>No changes would be required to the IESO processes or current billing practices.</td></tr>
<tr><td colspan="2">Threshold Limits for Gross Load Billing</td></tr>
<tr><td>Option 1 – Review factors that were used to establish the existing threshold limits</td><td>Adjusting the threshold limits for gross load billing would result in an increase of the volume or number of facilities that will need to be registered with the IESO for gross load billing. This increase in registration volume can be accommodated by IESO and would not require any changes to IESO billing systems.</td></tr>
</table>

CLARIFYING QUESTIONS OF VECC – 26

Reference:

HONI Background Report, Issues 5 & 6, Pages 19-20

Interrogatory:

a) With respect to Issue 4 (Threshold Limits for Gross Load Billing), please provide assessment as to the pros and cons of maintaining the status quo.

Response:

a) The pro of maintaining the status quo is that Hydro One would not need to change its processes with respect to gross load billing or the treatment of generation that has been exempted.

The con of maintaining the status quo is that the current framework enables certain facilities to be exempt based on the unit size. Given the issues currently facing the sector, a more current and comprehensive review of the factors that were considered in the original UTR Decision should be undertaken to determine if they remain valid and should continue to apply.

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CLARIFYING QUESTIONS OF VECC – 27

Reference:

HONI Background Report, Issues 5 & 6, Page 20

Interrogatory:

a) With respect to Section 1.5.1 (Calculating Incremental Capacity for Gross Load Billing Eligibility), is the resolution of this issue linked to the outcome of Issue 1?
   i. If not, why not?
   ii. If yes, wouldn't it be reasonable to consider the issue raised in Section 1.5.1 as part of Issue 1 (Section 1.4.1)?

Response:

a) Yes, these issues are related.
   i. N/A, please refer to part a) above.
   ii. Hydro One agrees that it would not be appropriate to make a determination on these specific issues in isolation.

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CLARIFYING QUESTIONS OF VECC – 28

Reference:
HONI Background Report, Issues 5 & 6, Pages 2 and 20

Preamble:
The Report states (page 2):

> Under gross load billing, the charges for a transmission customer are calculated as they are under net load billing plus the load supplied by any embedded generation.

The Report states (page 20):

> There may be instances where a customer reduces their demand by installing embedded generation but the monthly transmission charges paid by the customer to the transmitter for the cost of supplying them is not affected.

The Report states (page 20):

> Gross load billing should be applied practically and achieve the objectives set out in the Original UTR Decision. The OEB should consider providing certain flexibility in applying the gross load billing rules where a situation merits such treatment and, where possible and appropriate, the OEB should provide clear direction as to how these situations should be addressed.

Interrogatory:

a) Please explain the relevance of the first cited reference from page 20 as to whether or not a customer should be “exempt” from gross load billing.

b) In HONI’s view how could/should the OEB provide the suggested flexibility (i.e., what options should the OEB consider)?

Response:

a) Gross load billing is intended to ensure that the sunk costs of assets built to serve a particular customer are recovered (as appropriate) from that customer (and not other customers) in the event that they reduce their non-coincident demand by installing embedded generation. The specific example cited is relevant to the gross load billing discussion because if a customer’s embedded generation is operated on a limited basis such that their non-coincident monthly demand charges are not materially changed, there would not be a need to bill the customer on a gross load basis.

b) Please refer to Hydro One’s response to Clarifying Questions issues 5 and 6, ED-5.

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