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BY EMAIL AND RESS

October 16, 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 – Hydro One Submission on Issues 4, 5, and 6

In accordance with Procedural Order #4 issued by the OEB on July 29, 2024, Hydro One is providing its submissions on Issues 4, 5 and 6.

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

Sincerely,

Uri Akselrud

Uri Akselrud

HYDRO ONE SUBMISSION ON ISSUES 4, 5, AND 6

INTRODUCTION

Hydro One is providing its Submissions on the approved issues list[1] for issues 4, 5 and 6 in response to Procedural Order #4 dated July 29, 2024.

As previously stated in its response to AMPCO interrogatory #5, part a) and SEC interrogatory #7, Hydro One would like to hear from all parties to this proceeding before making its final recommendation on a preferred approach for dealing with the issues in this proceeding. While there has been some input from parties in the form of direct evidence and interrogatory responses, final submissions from all parties are only due on October 16, 2024. Accordingly, once the final submissions from all parties are reviewed and considered, Hydro One may alter its current preferences as part of its Reply Submission to be filed on October 30, 2024.

4.0 ISSUE 4 - CHARGES CAUSED BY PLANNED TRANSMISSION OUTAGES

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

With respect to Issue 4.1, which is defined as whether all transmission charges (Network, Line Connection, Transformation Connection) should continue to be on a per delivery point basis (customer charges would continue to be calculated separately for each delivery point) or whether they should instead be on an aggregate per customer basis (customer charges would be calculated on the customer's aggregate demand for all delivery points), Hydro One submits the following.

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[1] Complete issues list was identified in Procedural Order #3 dated July 5, 2024.

The determination that transmission charges shall be based on the monthly peak at each delivery point originates from the OEB's Decision with Reasons in RP-1999-0044, dated May 26, 2000 (the "Original UTR Decision"). As such, the calculation of all transmission charges on a per delivery point basis would be a continuation of the status quo methodology approved in the Original UTR Decision. Hydro One notes that any additional transmission charges incurred due to load transfers between delivery points as a result of either planned or unplanned transmission outages reflect the benefit that transmission customers receive from having the ability to transfer their load between delivery points. As such, Hydro One believes that the status quo methodology is a just and reasonable way to charge for transmission services.

As the transmission system was built with the capacity to permit load transfers between delivery points to occur, it could be argued that it is therefore reasonable and consistent with the user pay principle, that transmission charges for customers that experience load transfers between multiple delivery points include the cost of having those assets in place. However, the issue is that the status quo methodology does not address the double peak billing concerns raised by transmission customers in this proceeding and does not address the challenges currently experienced by Hydro One in trying to schedule planned outages as a result of transmission customers' response to the way transmission charges are applied under the status quo methodology.

As outlined in its Background Report on Issues 4, 5 and 6 (the "Background Report"),[2] Hydro One recognizes that calculating transmission charges on an aggregate basis by customer would address the concerns with respect to double peak billing for both planned and unplanned outages. Aggregation of delivery points by customer was discussed as Option 2 in the Background Report as a possible way to address the concerns with respect to double peak billing. However, the Background Report also outlined numerous disadvantages with respect to calculating transmission charges on an aggregate basis per customer. One key disadvantage is that it may provide an unfair advantage to customers with multiple delivery points because of a diversity in demand across their delivery points, ultimately shifting costs to customers with a single delivery point. As such, Hydro One does not support the aggregation approach on a per customer basis.

[2] EB-2022-0325 – Phase 2 of the Generic Hearing on Uniform Transmission Rates – Related Issues – HONI Background Reports on Issues 4 and 5/6, April 2, 2024.

As part of their evidence, the LDC Transmission Group proposed an aggregation approach of select delivery points referred to as totalization of select delivery points.[3] Although Hydro One does not support this approach due to the concerns discussed below, Hydro One believes that it is preferred over aggregation by customer as it eliminates the aggregation of delivery points across non-contiguous service areas and it only allows for aggregation of delivery points for those situations where electricity can in fact be shared across them. Aggregation of select delivery points, instead of by customer, also aligns more closely with the Original UTR Decision which specifically considered and rejected the aggregation of transmission charges by customer. However, Hydro One has a number of concerns with the totalization approach proposed by the LDC Transmission Group.

The first concern relates to the complications and effort associated with the development and ongoing administration of an OEB application process for approving requests from transmission customers for the aggregation of their select delivery points. A second concern is with the timing for implementing the OEB decision on an application for aggregating delivery points given that the decision will impact the charge determinant forecast approved for the transmitter's cost of service period in effect at the time of aggregation, as well as impacting the UTR rates which are calculated based on the previously approved charge determinant forecast.

Hydro One also notes that numerous concerns were raised by the IESO in their response to VECC interrogatory #25, part c) regarding the aggregating of delivery points, including:

- The significant changes that would be required to a large number of IESO processes, systems and reporting requirements including registration and settlement processes.

- The complications associated with coordinating any UTR changes with the ongoing changes to the Market Rules (e.g. Market Renewal program).

- The further analysis and project work required to determine the full impact and timelines to implement any changes, including the fact that this could be a multi-year project.

In summary, given the concerns discussed above, Hydro One recommends that transmission charges remain on a per delivery point basis as currently structured. In order to address the concerns related to double peak billing, Hydro One favours the use of a deferral account approach as further discussed under Issue 4.4.

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[3] The LDC Transmission Group consists of the following local distribution companies: Niagara-on-the-Lake Hydro Inc, Canadian Niagara Power Inc., Enwin Utilities Ltd, Entegrus Powerlines Inc. and Halton Hills Hydro Inc. Their evidence in this proceeding was filed on August 29, 2024.

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

With respect to Issue 4.2, which is defined as whether measures to address the impact of double peak billing should apply to both planned and unplanned outages, or whether there should be separate measures, Hydro One submits the following.

Hydro One believes that measures to address the impact of double peak billing should only apply to planned outages and that separate measures for unplanned outages are not required.

It could be argued that additional transmission charges, if any, that may be incurred as a result of load transfers between delivery points due to unplanned outages appropriately reflect the benefit that transmission customers receive from having the ability to transfer their load between delivery points. A transmitter would have built the transmission system with the capacity to permit those load transfers between delivery points to occur, and transmission charges should include the cost of having those assets in place.

A similar argument could be made for double peak billing charges resulting from planned outages. That is, transmission assets put in place to permit the transfer of load during a planned outage also provide a benefit that customers should pay for. The issue is that when it comes to planned outages, transmission customers are incented under the status quo methodology to take actions to mitigate the amount of those charges. In particular, Hydro One has identified that customer actions in these situations have resulted in delays and complications related to scheduling of planned outages, which subsequently cause delays to required maintenance or capital work and increase the cost of doing the work. Additionally, both Hydro One and the LDC Transmission Group noted that mitigating actions taken when a planned outage is scheduled, such as doing the work outside of normal business hours and scheduling outages to start and end at midnight on the first and last day of the month that an outage is taken, increase transmission system reliability risks, increase the costs associated with doing planned outage work, and potentially increase safety risks for both the transmitter and customer.

These same concerns do not apply for unplanned outages. When an unplanned outage occurs, the focus is on restoring power to customers quickly, safely and efficiently, and not on transmission charges.[4] Additionally, as stated in the Background Report, unplanned

[4] As per Hydro One's response LDC-TG interrogatory #5, part c)

outages are outside the control of transmitters and customers and do not always result in double peak billing. Furthermore, including unplanned outages as part of any measure to mitigate the double peak billing issue raises a number of concerns. The first concern is that while Hydro One has some understanding of the number of double peak billing occurrences due to planned outages and how to manually calculate the associated impacts on transmission charges, the frequency and impact of double peak billing related to unplanned outages has not been assessed by Hydro One or explored in any detail as part of this proceeding. The second concern is that given the dynamic and potentially complex and wide-ranging impact of unplanned outages on the transmission system (e.g due to extreme weather situations), and the lack of experience in manually assessing those impacts, it is not clear if double peak impacts could be calculated for all unplanned outage situations, or if the data necessary to calculate the impacts would even be available.

In summary, as further discussed under Issue 4.4, Hydro One favours the use of a deferral account approach for addressing the concerns with double peak billing for planned outages. However, if the OEB chooses to include unplanned outages in the calculation of double peak billing impacts, then Hydro One does not support the use of a deferral account approach as it is not clear that this approach could feasibly be implemented if unplanned outages are included.

4.3 SHOULD THE DEFINITION OF THE TRANSMISSION CHARGE DETERMINANTS, USED TO ESTABLISH UTRS AND BILL TRANSMISSION CHARGES, BE REVISED TO EXCLUDE THE IMPACT OF PLANNED TRANSMISSION OUTAGES ON CUSTOMERS WITH MULTIPLE DELIVERY POINTS?

With respect to Issue 4.3, which is defined as whether the definition of transmission charge determinants used to establish UTRs and bill transmission charges should be revised to exclude the impact of planned transmission outages for customers with multiple delivery points, Hydro One submits the following.

Revising the definition of transmission charge determinants was discussed as Option 3 in the Background Report as a possible way to address the concerns with respect to double peak billing. Hydro One does not support this revision for the reasons discussed below. Hydro One further notes that the LDC Transmission Group also indicated that they do not support this approach.

In the Background Report, Hydro One identified a number of disadvantages with respect to redefining the transmission charge determinants. One key disadvantage is the lack of historical data set for transmission charge determinants excluding double peak billing events related to planned outages, which would be necessary to establish an appropriate forecast of the charge determinants used to set the UTRs. Another disadvantage is that excluding planned outages from the charge determinants 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 customers. One final key disadvantage is the time and effort associated with the IESO implementing this option.

With respect to the IESO implementation, in its response to VECC interrogatory #25, part c) the IESO elaborated on its concerns with Option 3. Specifically, the IESO stated that redefining the charge determinants to exclude the impact of planned transmission outages would require significant time and effort given the variability of power switching conditions that can give rise to a double peak charge. Furthermore, the IESO indicated that due to this variability and lack of historical data it may not be feasible to establish a comprehensive set of business rules that would identify and determine the impact of such double peak billing events under all circumstances. The IESO also highlighted the complexity of implementing any changes to the calculation of charge determinants into their settlement systems and the fact that this could take multiple years to implement.

The IESO’s response also indicated that as an alternative implementation approach this could be done based on a manual assessment jointly undertaken by the transmission customer and transmitter based on OEB-established principles for calculating the impact of double peak charges. The manually calculated impact of double peak charges could then be processed by the IESO via a recalculated settlement statement. Hydro One does not support the alternative implementation approach suggested by the IESO as it would still necessitate a number of changes to IESO processes, systems and reporting requirements. More importantly, this alternative would result in an under-collection of a transmitter’s OEB-approved revenue requirement given that refunds would be provided to transmission customers without a mechanism for the transmitter to recover the cost of those refunds either by adjusting its revenue requirement or revising the charge determinants and UTR rates necessary to keep transmitters whole. Hydro One notes that the deferral account approach discussed under Issue 4.4, has similar elements to the manual assessment approach suggested by the IESO, but also addresses the concern with respect to under-collection of the OEB-approved revenue requirement for transmitters.

In summary, given the concerns discussed above, Hydro One does not support revising the definition of transmission charge determinants to exclude the impact of planned transmission outages for customers with multiple delivery points.

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

With respect to Issue 4.4, which is defined as whether the impact of double-peak billing for planned and unplanned transmission outages should be tracked in a deferral account, Hydro One submits the following.

Hydro One favours the use of a deferral account approach to address the concerns with double peak billing for planned transmission outages. For the reasons discussed under Issue 4.2, Hydro One does not support the inclusion of the impact of unplanned transmission outages in the deferral account.

Tracking the impact of planned transmission outages in a deferral account was identified as Option 4 in the Background Report as a possible way to address the concerns with respect to double peak billing. Hydro One identified a number of advantages to this solution, including:

- No changes are required to the IESO's existing processes and systems.

- No changes are required to the transmitter's existing load forecasting process. This also means that the IESO does not need to track demand data without double peak events, as transmitters will continue to use metered data (unadjusted) as the basis for producing a charge determinant forecast.

- There is no risk of under or over recovery of a transmitter's approved revenue requirement related to costs associated with double peak billing since the exact amounts provided as refunds to transmission customers are recovered through the disposition of the deferral account at a future date.

- As the transmitter issues refunds directly to the affected transmission customers, there are no administrative or settlement requirements imposed on unaffected transmitters or the IESO.

- Provides clear visibility to the magnitude and impact of double peak billing events as part of the regulatory process for disposition of the associated deferral account.

Based on the additional information gathered during this proceeding, it is further noted that this approach could be implemented more quickly than any of the options that require making changes to the current billing approach. Additionally, since this option does not impact the charge determinant forecast, it can be implemented at any time after an OEB decision in this proceeding without affecting any existing approvals for the current cost of service period and without the need to coordinate with the timing of any future cost of service applications.

Hydro One further submits that if the OEB decision in this proceeding is to adopt a deferral account approach with respect to planned transmission outages, Hydro One notes that the following next steps would be required:

- The impacted transmitters will need to develop new business processes to accept and administer requests (to be initiated by transmission customers) for refunds due to a double peak billing event resulting from a planned outage.

- The impacted transmitters will need to work in partnership with interested transmission customers to establish a methodology for calculating the refund amount (e.g. estimation of meter readings by installing temporary measuring devices or using historical readings where metering is not installed, or meter data is not available).

- The impacted transmitters will need to establish a process for tracking the refund amounts in a deferral account. The refund methodology and deferral account tracking details will need to be submitted to OEB staff for review/comment/approval.

While it is likely that the need for a deferral account will mostly apply to Hydro One, such an account could also apply to other transmitters if double peak billing is an issue for their transmission customers.

Although Hydro One favours the use of a deferral account approach to address the concerns with respect to double peak billing, there are some reservations with this approach. Specifically, Hydro One is concerned that it is taking on accountabilities in the settlement of transmission charges that are typically the responsibility of the IESO under the current rules for operating Ontario’s electricity market. The work associated with this additional accountability is compounded by the fact that the volume of requests from transmission customers for refunds associated with double peak billing due to planned transmission outages may increase substantially from what was observed historically. This will have staffing implications for transmitters and could result in a situation where the administrative effort and cost associated with the deferral account approach becomes significant. Hydro One submits that to address these concerns with the use of a deferral account approach, the impacted transmitters should be permitted to include all costs associated with administering the process related to double peak billing transmission charges as part of the deferral account.

In summary, given the advantages discussed above, Hydro One favours the use of a deferral account approach to address double peak billing concerns for planned transmission outages.

4.5 OTHER CONSIDERATIONS FOR ISSUE 4

It is Hydro One's expectation that whatever approach the OEB chooses to adopt for dealing with the double peak billing issue, it will eliminate the challenges that have occurred in the past with respect to coordinating planned transmission outages, while ensuring that the solution permits transmitters to collect their OEB-approved revenue requirements. As previously stated, the two common approaches currently used to mitigate or eliminate double peak billing charges have been to schedule work outside normal business hours when electricity demand is lowest (e.g. on evenings or weekends) or to align the start and end of planned transmission outages with the start and end of a transmission billing period (for the full calendar month). As discussed by both Hydro One and the LDC Transmission Group, the current approaches for dealing with this issue increase transmission system reliability risks, increase the costs associated with doing planned outage work, and potentially increase safety risks. It is also Hydro One's experience that transmission customers' desire to reduce or eliminate double peak billing often results in delays to planned outages, which could postpone the necessary maintenance or capital work and increases the cost of doing the work.

Furthermore, the OEB made it clear in Procedural Order #3 dated July 5, 2024 that this proceeding is focused on transmission issues (namely the impact of double peak billing for load transfers that occur between transmission delivery points) and that double peak billing issues for distribution-connected customers will not be examined as part of the current proceeding. While Hydro One has focused its submission on transmission issues, Hydro One notes that similar double peak billing concerns exist in distribution and need to be addressed (specifically the impact of double peak billing for load transfers that occur between a transmission delivery point to a distribution delivery point and load transfers that occur between distribution delivery points). As explained in the Background Report, double peak billing events can impact both transmission-connected and distribution-connected customers, and as such, the distribution aspects will need to be addressed after the transmission aspects of double peak billing are addressed in the current proceeding. As further discussed in the Background Report, there is an anomalous/unfair outcome for customers if double-peak billing issues are resolved for transmission-connected customers but not for distribution-connected customers. Also, the specific situation for customers that have load transfers from transmission to distribution, as evident from the Glencore Canada Corporation (GCC) evidence, will need to be addressed.[5]

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

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

As stated in the Background Report, Hydro One is aware of several instances in which the current practice of assessing gross load billing based on the installed capacity of each individual unit of a generation facility (rather than the aggregate installed capacity of all units that comprised the generation facility) has enabled customers to be exempt from gross load billing charges in ways that may not have been contemplated when the rules were established. As such, Hydro One notes that the ability for customers to leverage the current rules in this manner has called into question whether the current rules are appropriate and leading to outcomes that are fair and consistent with the objectives of the Original UTR Decision. Furthermore, Hydro One believes that the current rules for billing embedded generation in the UTR Schedule may result in unintended outcomes and could be argued as unfair or unreasonable in terms of how different types of renewable generation are considered with respect to gross load billing.

One way to address these concerns could be by revising the rules to clarify that gross load billing applies to the aggregate installed capacity of all embedded generator units installed by the customer at their connection point to the system. From a practical perspective, changing to this approach for gross load billing is more closely aligned to the cost impact to other transmission ratepayers which are directly impacted by embedded generation as this is more appropriately measured by the size of the generation facility installed and not by the size of the individual units of the facility.

In addressing the central issue of whether gross load billing should be applied on a per unit basis or on a per facility basis, it is important for the OEB to also consider how existing generation facilities should be treated. Hydro One does not believe that existing generation facilities should be permanently exempted from gross load billing solely based on when this generation was installed. Permanently grandfathering existing generation on

[5] EB-2022-0325, Exhibit M3, Filed August 29, 2024 and GCC Responses to Interrogatories, Filed October 2, 2024.

this basis would continue to maintain a practice where new and older embedded generation facilities are treated differently. Hydro One believes that if an existing generation facility undergoes a refurbishment (regardless of whether the refurbishment increases the total size of the facility), this should trigger the need for the embedded generation facility to comply with the current gross load billing rules. This would represent a more appropriate and fair way for treating new and existing generation from a gross load billing perspective. Furthermore, Hydro One does not believe that gross load billing should apply only to the incremental installed capacity of facility-based approach for assessing gross load billing. In Hydro One's view, the refurbishment of an existing facility should require the entire facility to comply with the current gross load billing rules, which is similar and consistent with how compliance is enforced in the IESO Market Rules for generation facilities that have been grandfathered.

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

Hydro One believes that in principle, the gross load billing rules in the UTR Schedule should not provide customers who deploy inverter-based embedded generation (such as solar generation) a technological advantage that would exempt them from gross load billing more easily than customers who deploy other types of embedded generation with larger generating units (for example wind generation).

As explained in the Background Report, 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. Since the inverter capacity for solar generation is typically small, the threshold limit for renewable generation becomes irrelevant in determining whether gross load billing should apply. As a result, no customers with embedded solar generation are currently being billed on a gross load basis even though in many cases the size of these solar generation facilities exceeds the renewable generation threshold limit. As mentioned in the Background Report, this has created a disparity between the amount of embedded solar generation that is exempt from gross load billing compared to other types of renewable generation.

The advantage currently enjoyed by customers who install inverter-based embedded generation could be addressed by changing the gross load billing rules in the UTR Schedule to apply to the size of the customer's embedded generation facility instead of on a per unit basis as discussed under Issue 5.1. Whether the OEB proceeds with this change or not, the OEB should also decide whether the current 2MW threshold limit for renewable generation remains appropriate for assessing gross load billing eligibility for embedded solar generation. Given that the threshold limits have not been reviewed for some time, the OEB should determine whether the outcomes from the application of these limits align with and support current policy objectives related to the connection of embedded generation facilities by customers. Thresholds for renewable and non-renewable generation are further discussed under Issue 6.1.

Furthermore, should the OEB proceed with changes or clarifications to the gross load billing rules applicable to inverter-based embedded generation facilities, the OEB must consider how the rules would apply to existing embedded solar generation facilities, which are currently exempt from gross load billing based on the existing methodology for gross load billing. In Hydro One's view, new embedded solar generation should not be treated differently from existing embedded solar generation and any change to the gross load billing rules should not permanently exempt existing embedded solar generation from compliance with these rules. Similarly to applicability of any changes discussed under Issue 5.1 for existing embedded generation, Hydro One notes that the OEB should clarify that the refurbishment or replacement of an inverter-based embedded generation unit would trigger the need to comply with the current rules for inverter-based embedded generation.

Finally, as stated in the Background Report, solar generation facilities are almost exclusively connected to the distribution system or behind the meter of distribution-connected customers. Therefore, the issue of determining appropriate rules for gross load billing embedded solar generation applies only to transmission-connected distributors and, by corollary, their customers who install embedded solar generation. With respect to embedded solar generation, if gross load billing is only being triggered by customers with embedded solar generation who are connected to the distribution system, the OEB needs to issue guidance or clarity that these customers, who are triggering these costs, are responsible for paying for these costs and not other distribution customers. For this reason, Hydro One believes that the OEB will need to issue guidance to the distribution sector so that the principles of cost causality are maintained.

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

Hydro One believes that the OEB should clarify whether gross loss billing applies to energy storage (including clarification of the applicable threshold) so that there is no ambiguity in terms of how energy storage should be treated from a gross load billing perspective. As indicated in the Background Report, Hydro One's current practice is to apply gross load billing to energy storage and assess eligibility based on the unit threshold established for non-renewable generation (1MW).

In Hydro One's view, it should not matter whether a customer installs a load displacement facility that can store energy consumed from the grid or generate their own energy if the facility is operated by the customer in such a manner that reduces their non-coincident peak demand and results in costs being shifted to other ratepayers. As a result, Hydro One notes that if the gross load billing rules are established such that they would favour one technology over another, this will ultimately lead to behaviour and actions taken by customers to avoid gross load billing.

As such, Hydro One believes that the gross load billing rules should be principle-based. The gross load billing rules that apply to energy storage, including the thresholds that are established, should consider and take into account the way in which the facility will be operated, the resultant impact on the customer's non-coincident peak demand and the costs associated with implementing gross load billing (in addition to any other factors deemed appropriate by the OEB). In terms of establishing the appropriate threshold limit for energy storage, the OEB should review the factors that were considered in establishing the current thresholds for renewable and non-renewable generation. The OEB needs to determine whether these factors remain appropriate or if other factors should be reflected in the derivation of the thresholds for energy storage. If the OEB determines that a different threshold should apply for energy storage, the OEB needs to consider how this new threshold should be applied to new and existing energy storage facilities and any potential billing/settlement implications. Further discussion with respect to thresholds is captured under Issue 6.1.

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

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

At this time, Hydro One is not in a position to comment on what the gross load billing thresholds should be for renewable and non-renewable generation. Hydro One notes that for the OEB to determine whether the current thresholds remain appropriate or should be updated, Hydro One recommends that the OEB review the factors that were used to establish the current thresholds and confirm whether the analysis remains valid or if other factors or objectives should be considered in the analysis. Any change to the current thresholds would also depend on whether the OEB changes its approach to assess gross load billing on a facility basis as discussed under Issue 5.1.[6] As mentioned in the Background Report, the OEB should review whether the incorporation of meter data from

[6] For instance, if it is determined that gross load billing should be assessed on a facility basis rather than on a per unit basis, maintaining the current thresholds will result in more embedded generation being subject to gross load billing. As such, the OEB will need to decide if that is appropriate or not.

embedded generation into the IESO settlement process is administratively complex or burdensome for the market operator. The OEB should also examine whether the cost of installing an additional gross load billing meter would deter customers from installing embedded generation and how this cost should be considered in determining the appropriate threshold. Finally, any determination on these factors must consider how a change to the thresholds would be applied to existing embedded generation. In making these determinations, the OEB will need to balance fairness, practicality and cost in determining appropriate thresholds and how they should be applied in the context of other changes to the gross load billing rules that may be proposed.

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

Hydro One believes that gross load billing should be applied practically and achieve the objectives set out in the Original UTR Decision. However, in certain limited circumstances, the OEB should provide the transmitters with certain flexibility and discretion in its application of the gross load billing rules where it is appropriate to do so including a clear direction as to how they should be addressed.

For instance, if the monthly line and connection transmission charges paid by a customer are not affected by the installation of their embedded generation, the transmitter may deem that the customer should not be gross load billed. In making this decision, the onus would be on the transmitter to ensure that the customer does not alter the operation of their generation in a way that would make them eligible for gross load billing. In the Background Report, Hydro One has identified several examples of cases that have arisen where it believes that a gross load billing exception is justified and should be granted.

7.0 OTHER CONSIDERATIONS FOR ISSUES 5 AND 6

As stated in the Background Report, Hydro One strongly believes that the OEB needs to maintain consistency in terms of how gross load billing principles and practices are implemented at the transmission and distribution levels. This is necessary to ensure that transmission costs are recovered fairly from those customers connected to the distribution system who are driving these costs.

If the OEB proposes to change any of the existing practices with respect to gross load billing rules in the UTR Schedule as covered under Issues 5 and 6, the OEB should consider and clarify how these changes would impact gross load billing of distribution customers. Currently, Hydro One distribution applies the same approach for gross load billing that has been established in the UTR Schedule for determining demand-billed Retail Transmission Service Rates (RTSRs) and Sub-Transmission (ST) rates. If changes are made to the gross load billing rules or practices in the UTR Schedule, similar changes need to be reflected in the gross load billing rules or practices for distribution customers. Otherwise, this could result in transmission charges not being recovered appropriately from those distribution customers causing those charges. Hydro One believes that any permitted exemptions from gross load billing should apply in the distribution context as well. Additionally, since embedded solar generation currently is exclusively connected to the distribution system or behind the meter of distribution customers, any changes made to the treatment of embedded solar generation should be rolled down to the distribution level and applied consistently as outlined under Issue 5.2. Similarly, as more energy storage projects connect to the distribution system, there is need for alignment in how energy storage should be treated.

Hydro One therefore requests that clear direction be provided as part of the current proceeding with respect to distribution.

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