Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

October 16, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ms. Marconi:

Re: Generic Hearing on Uniform Transmission Rates – Phase 2
OEB File Number: EB-2022-0325

Please find attached OEB staff's submission in the above referenced proceeding, pursuant to Procedural Order No. 4.

Yours truly,

Thomas Eminowicz

Digitally signed by Thomas Eminowicz
Date: 2024.10.16 15:36:00 -04'00'

Thomas Eminowicz

Senior Advisor, Generation & Transmission

Encl.

cc: All parties in EB-2022-0325

ONTARIO ENERGY BOARD

OEB Staff Submission

Generic Hearing on Uniform Transmission Rates
Phase 2

EB-2022-0325

October 16, 2024

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Background

The Ontario Energy Board (OEB) established a generic public hearing on its own motion under sections 19, 21 and 78 of the *Ontario Energy Board Act, 1998* to consider various issues related to Ontario's Uniform Transmission Rates (UTRs).

On May 9, 2024, the OEB issued a decision on three issues to this proceeding, with the following issues remaining:

- Charges caused by planned transmission outages
- Basis for billing renewable, non-renewable, and energy storage facilities for transmission
- Gross load billing thresholds for renewable and non-renewable generation

On April 2, 2024, Hydro One Network Inc. (HONI) filed, pursuant to Procedural Order No. 1, a Background Report on the above, Issues 4, 5, and 6 to this proceeding. This report provided HONI's perspective on these issues and potential options for the OEB, OEB staff, and participants to consider. HONI also responded to clarification questions regarding this report on May 13, 2024.

On July 5, 2024, after receiving submissions from the participants regarding the detailed issues list, the OEB set the remaining issues for this proceeding. Among other things, the OEB made the following findings:

- This phase of the generic proceeding only deals with UTRs, so the impacts of double-peak billing on distribution connected customers will not be examined
- The gross load billing versus net load billing issue is important but with broader implications than was contemplated in the second phase of the OEB's examination into UTRs

On July 10, 2024, Entegrus Powerlines Inc. (EPI) filed a letter of comment expressing concern that, as a distribution connected LDC, it would not benefit from any potential solution to double peak billing that excluded distribution connected customers. EPI echoed several submissions on the detailed issues list that transmission charges and distribution delivery charges are inextricably linked.

On August 29, 2024, the Local Distribution Company (LDC) Transmission Group, a collaboration of five approved intervenors to this proceeding, and Glencore Canada Corporation (GCC) filed evidence relating to Issue 4. Each filed interrogatory responses October 2, 2024, and October 8, 2024, respectively.

Summary of OEB Staff Submission

The remaining issues in this proceeding relate to a wide range of considerations. Issue 4 primarily addresses the application of provincial transmission service (PTS) charges and their charge determinants under circumstances relating to transmission outages, either planned or unplanned. There are three such charges: the network service charge, the transformation connection charge, and the line connection charge. Issues 5 and 6 primarily deal with questions of gross load billing and associated definitions for applying the transmission charges. The questions mostly relate to how specific terms should apply to the gross load billing thresholds. One sub-issue to Issue 5 is concerned with how the UTR schedules should be applied to energy storage facilities, which are undefined in the schedule.

OEB staff submits that the transmission charges should be applied on the basis of usage of the facilities that underly the respective asset pools. The issue of transmission charges associated with transmission outages in fact relates to a type of load transfer, and this material intra-month load transfer results in double peak billing. OEB staff submits that transmission outages do not warrant special treatment and examines the general question of how the three transmission charges are currently applied when transmission customers perform load transfers. As a result, OEB staff submits that line and transformation connection charges should continue to be charged on a delivery point basis. On this basis, double peak billing a reflection of how a transmission customer uses those facilities.

With regard to "double peak billing" and network service charges, OEB staff submits that the facilities that underly the network service charge, the facilities of the high-voltage transmission system, serve the purpose of transferring energy across this system. As such, OEB staff submits that this asset pool does not relate to the specific delivery point and that on this basis, the OEB should consider applying the network service charge on an aggregated basis.

OEB staff does not support revising the definition of the transmission charge determinants nor the creation of a deferral account to reduce the charges associated with transmission outages.

With respect to the specific terms and definitions, OEB staff submits that the status quo should be maintained in regard the application of gross load billing thresholds on a unit basis and that there is insufficient basis to revise these thresholds at this time.

With respect to energy storage facilities, OEB staff submits that the UTR schedule should acknowledge the accepted definitions of such facilities, such as the definition contained within the Distribution Service Code (DSC).[1]

OEB staff submits that, in the context of the UTR schedule, embedded energy storage

[1] DSC, section 1.2: Definitions, energy storage facilities are defined as "storage facility" and in the context of connections

facilities should be treated similarly to renewable embedded generation. This is on the basis that energy storage is similarly in the societal interest as renewable generation was when the 2 MW threshold was established. OEB staff submits that transmission connected energy storage facilities should be exempt from transmission charges when providing a service to the transmission system, such as being scheduled for operating reserve, providing voltage support, providing reactive power, or following a real-time market dispatch to withdraw load.

Finally, OEB staff notes that for many of the sub-issues, little specific evidence has been proffered through the course of this proceeding. While the initial invitation to a stakeholder conference to initiate this proceeding, dated December 20, 2022, was sent a wide range of licensed and rate-regulated entities, several sub-issues received little or no attention.

Details are provided under each of the specific issues to this proceeding below.

Issue 4: Charges caused by planned transmission outages

The Notice describes Issue 4 as follows:

> In a month when a planned transmission outage occurs, a transmission customer that transfers its load to another of its delivery points is charged more than it would be if the outage did not occur. This is because transmission charges are based on the monthly peak at each delivery point.

The situation associated with the charges that arise due to transmission outages is also termed “double peak billing.” This is because a transmission customer needs to perform a load transfer between multiple delivery points in order to maintain supply. In this way, it pays for two independent monthly peaks: that under “normal” conditions and that under the condition of the transmission outage.

There are two core considerations to this issue: the nature of the double peak event and the charges associated with the event. The sub-issues are different considerations for mitigating the double peak billing charges.

The OEB established the UTRs in RP-1999-0044 under the principle of cost causality, with consideration for fairness and concerns about free-ridership or gaming of the charges. OEB staff submits that the principle of cost causality remains as the primary consideration. The RP-1999-0044 proceeding was an application by Ontario Hydro Networks Company Inc. (OHNC), now HONI, to approve transmission cost allocation and rate design for the year 2000.

The cost causality principle states that there must be a link between the charges levied upon a customer and how that customer uses the electricity system. In the case of the infrastructure that composes the transmission system, the transmitter has built the network and the facilities of the system to meet the needs of its customers. A similar principle is the "beneficiary pays" principle. The beneficiary pays principle states that to the extent a customer benefits from a facility, it has caused part of the costs associated with that facility. The principle also has an inverse notion: that a customer should not pay for facilities they neither use nor benefit from.

The first sub-issue resurrects a question from RP-1999-0044 on the matter of applying transmission charges based on each delivery point or an aggregation of all delivery points for a customer basis of billing. OEB staff submits that applying line and transformation connection charges at the delivery point reflects the usage of these particular facilities and that this should be maintained.

OEB staff submits that applying the network service charge to customers on a delivery point basis does not reflect the demand placed on this pool of transmission facilities. OEB staff submits that the current charge determinants for the network service charge allay the core concerns about gaming when a customer has access to multiple delivery points. Additionally, since the proceeding that established the transmission charge determinants, the IESO has implemented a totalization process that is capable of aggregating multiple delivery points among several non-geographically contiguous facilities, providing options that may not have been available at the time the UTRs were established. Specifically, it appears to OEB staff that there is now an intermediary option of aggregating certain facilities if there is reason to not aggregate on a customer basis. Therefore, OEB staff submits that this question warrants consideration.

Issue 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?

The current application of the three provincial transmission service charges was established in RP-1999-0044. In its decision in that proceeding, the OEB accepted the proposed delivery point basis citing both the user-pay principle and fairness.[2] Therefore, to consider this Issue 4.1 is to reconsider the rationale from RP-1999-0044.

First, OEB staff submits that the user-pay principle remains the cornerstone of addressing this issue. The user-pay principle is founded on cost causality. Cost causality is based on the link between the charges levied upon a customer and how that customer uses the electricity system or its facilities.

In the case of the infrastructure that composes the transmission system, the transmitter has built the network and the facilities of the system to meet the needs of its customers. Network facilities are built for many purposes and for the use of all customers, and the

[2] RP-1999-0044, Decision with Reasons, para 3.4.9

nature of these customers is not static.[3] Connection facilities are built with specific requirements for specific customers.[4] To consider cost causality, each of the three transmission charges should be considered in turn, on the basis of the respective asset pools.[5] The transmission connection charges will be considered first, commencing with transformation. One aspect that OEB staff believes is important to remember is that transmission connection facilities are used and/or useful in accordance with the particular customers connected to them.

The asset pool for the transformation connection charge is composed of the transformation connection facilities owned by the transmitter that step down the voltage from above 50 kV to below 50 kV.[6] If the transmission customer fully owns all the transformation connection assets associated with the transmission delivery point, the customer will not incur transformation connection charges.

During events, such as short-term load transfers, where a transmission connected customer uses the transformation connection facilities differently, and where this results in greater usage of a particular facility or set of facilities, the increased usage should be accordingly charged to that customer. OEB staff submits that the current application of the transformation connection charge, on a delivery point basis, accurately reflects the usage of transformation connection facilities and the current practice should continue.

The asset pool relating to the line connection charge is composed of transmission facilities that are neither related to the transformation of energy between transmission and distribution levels of voltage, nor the transmission lines used for the benefit of all customers to convey energy across the high voltage transmission system.[7] These lines are specific transmission lines that facilitate conveying energy to transmission customers.

OEB staff takes the same position with regard to line connection charges as transformation connection charges: when a transmission customer performs a load transfer between its delivery points, it is in fact using and benefiting from the facilities to a different degree than before the load transfer. As a result, the increased usage, albeit short-term, should incur a commensurate charge. This nature of the line and transformation connection facilities is also reflected in the charge determinants: these connection facilities are charged on the basis of the customer's non-coincident peak.

The asset pool that underlies the network service charge is that of the transmission lines that are used for the common benefit of all customers and also the terminating

[3] RP-1999-0044, Decision with Reasons, para. 3.2.23
[4] RP-1999-0044, Decision with Reasons, para. 3.2.38
[5] The asset pools for each of the three transmission charges are defined in the Uniform Transmission Rate Schedule attached to each UTR decision
[6] Ontario Uniform Transmission Rate Schedules, as in EB-2023-0222, Part D) of the Terms and Conditions
[7] Ibid.

stations.[8] These assets are all the high voltage transmission lines, the interconnections of these lines, and all major transformation and switching stations associated with these lines.[9] In plain words, these assets are used to convey energy across the high voltage transmission system through the entire province.

OEB staff submits that the facilities of the network pool serve their function in the context of the entire transmission system. This means that the usage of these facilities is not related to the particular delivery points or their geographic location. In other words, Ontario's UTRs are structured in such a way that the network facilities would be used in the same manner to convey energy among 10 delivery points as they would for 100 delivery points. From this, OEB staff submits that, on the principle of cost causality, for a customer with multiple delivery points, the OEB should reconsider the delivery point basis for the network service charge, and consider aggregating the delivery points.

OEB staff notes that the IESO has established processes, Market Rules, and IT infrastructure to support aggregating delivery points across multiple facilities for both market operations and settlement. For certain hydroelectric generating facilities, a market participant may "group (aggregate) interdependent generators and flexibly operate them to meet a 'totalized' dispatch instruction."[10]

While compliance aggregation specifically applies to IESO dispatch instructions, OEB staff notes that the Market Rules allow Market Participants to apply to disaggregate the facilities for bidding and settlement purposes.[11] If the request is granted, the Market Participant may elect to implement a Meter Disaggregation Model. This model defines the relationship of the physical meters, summary meters, and delivery points. The Market Manual related to Metering provides examples of apparently sophisticated meter aggregation and totalization models.[12] The Market Manual is clear that these totalization models are utilized in the IESO settlement systems.

Furthermore, the IESO's states that compliance aggregation applies to related facilities, those that are on the same river system.[13] From this, OEB staff infers that these totalization models are, or could be, applied to hydroelectric facilities connected at a variety of locations on the transmission system and to transmission lines of varying voltages. While OEB staff defers to the expertise of the IESO, OEB staff is unaware of any Market Rules that preclude applying these principles, or these models, to load facilities.

As noted, the question of charging by delivery point or aggregating to the customer level was explored and decided upon in RP-1999-0044. The concern of fairness was

[8] Ontario Uniform Transmission Rate Schedules, as in EB-2023-0222, Part D) of the Terms and Conditions
[9] RP-1999-0044, Hearing Transcript February 16, 2000, transcript page 43
[10] IESO Quick Take: Compliance Aggregation – Issue 23, Revised January 30, 2008
[11] IESO Market Manual 3: Metering, Part 3.7: Totalization Table Registration, section 2.3.7: Meter Disaggregation
[12] IESO Market Manual 3: Metering, Part 3.7: Totalization Table Registration, Appendices F, G, and H
[13] IESO Quick Take: Compliance Aggregation – Issue 23, Revised January 30, 2008, p. 1

articulated throughout the hearing, exploring the charge determinants and examining concerns of free-ridership.[14] These concerns related to customers who would have the ability to reduce their coincident peak load while others, with few delivery points, would be at a disadvantage. These concerns were obviated by the OEB's acceptance of the network service charge determinants as proposed by OHNC.

When the notion of fairness was further examined in the context of delivery point billing, OHNC stated that the core intent of the charge determinants and their application is that the charges reflect the demands put upon the system by the customer's use.[15] In the decision, the OEB stated that cost causality was not unequivocal and that the particular circumstances of Ontario's network transmission system and other considerations, such as revenue requirement, efficiency and fairness, must also be weighed.[16] OEB staff submits that the RP-1999-0044 decision, with it's adoption of OHNC's proposal for the non-coincident peak charge determinant largely addresses the issue of fairness.

In conclusion, OEB staff submits that line and transformation connection charges should continue to be charged to transmission customers on a delivery point basis. The purpose of these facilities is to convey energy from the high voltage transmission network to the transmission customer. OEB staff submits that the OEB should consider aggregating delivery points for the purpose of the network service charge.

Issue 4.2: 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?

The definitions of the charge determinants for the three provincial transmission service charges were established in RP-1999-0044. The charge determinant for the network service charge is the higher of the hourly coincident peak demand during the month and 85% of the customer's non-coincident peak demand in any one hour during the peak period between 7 AM to 7 PM on weekdays that are not statutory holidays.[17] The charge determinant for line and transformation connection services is based on the customer's monthly non-coincident peak demand at each delivery point.[18] The definitions of these charge determinants have remained in place unchanged.

The primary concern of Issue 4 is the double peak billing event. The double peak event arises out of a load transfer performed by a transmission customer between multiple delivery points. To incur double peak billing charges, the load transfer must occur within the billing month. Such load transfers can therefore be deemed short-term load transfers. Therefore, the question this issue asks is whether a sub-type of short-term load transfer, due to a transmission outage, should be afforded special treatment.

[14] RP-1999-0044, Hearing Transcript, February 16, 2000
[15] RP-1999-0044, Hearing Transcript, February 17, 2000, transcript page 307
[16] RP-1999-0044, Decision with Reasons, Board Findings to Charge Determinants and Related Matters
[17] RP-1999-0044, Decision with Reasons, para. 3.4.29
[18] RP-1999-0044, Decision with Reasons, para. 3.4.34

OEB staff submits that transmission outages, either planned or unplanned, should not be afforded special treatment when considering transmission charges. When considering cost causality, the load transfer due to a transmission outage does not merit different treatment from any other load transfer. Furthermore, the LDC Transmission Group has explained that load transfers may occur for different reasons.[19] The LDC Transmission Group has also identified that other maintenance activities or operational considerations may be included with the load transfer, making instances where the precise cause or duration are difficult to distinguishable.

As mentioned previously, in RP-1999-0044, the OEB stated that in determining the charge determinants, the principle of cost causality was not unequivocal and that fairness, along with revenue requirement and efficiency, were among other considerations to be weighed. OEB staff acknowledges that some parties would be inclined to argue that the double peak billing event is unfair on the basis that the transmission customer is receiving the same level of energy while being charged, by virtue of the double peaks, for more than the energy they consume. In this case, OEB staff submits that the transmission customer realizes the benefit of the redundant delivery points and that, to the extent the transmission customer is charged for transformation and line connection charge, it should be charged according to the increased usage of those transmission facilities.

HONI has noted, from its perspective, several disadvantages to revising the charge determinants for the provincial transmission charges to prevent double peak billing events due to transmission outages.[20] In addition to the administrative effort on HONI's part to change its forecasting methodology and the IESO's part regarding settlement for new charge determinants, OEB staff notes that HONI has stated that there is no historical dataset that allows distinguishing double peak billing events.[21] This is in addition to the complexity noted above that short-term load transfers may occur for other reasons than transmission outages and that even the LDCs participating in this proceeding are unable to completely distinguish between the different types of load transfers nor are they consistently tracked.

Finally, there is the question of materiality. HONI notes that for the three rates for the transmission service charges to reflect a change with double peak billing events removed, the UTRs would need to include four decimal places for the change to materialize.[22] This is only an estimation, as HONI has stated that there is no historical dataset that could be used as a baseline for the setting future billing determinants absent of double peak billing events and that HONI is unsure if it would even be feasible to isolate such events.[23]

[19] Interrogatory Response M1-Staff-5
[20] HONI Background Report, Issue 4, section 1.4.3.2
[21] Ibid.
[22] HONI Background Report, Issue 4, section 1.4.4.3
[23] HONI Response to Clarifying Question Issue 4 VECC-2

The OEB has already determined that the dollar impact of changing the UTRs to four decimal places resulted in a monetary difference in UTRs transmission revenue pools that is less than any transmitter's revenue requirement materiality threshold.[24]

As a result of the above, OEB staff submits that the charge determinants should not be revised to exclude the impact of transmission outages on customers with multiple delivery points.

<u>Issue 4.3: Should double peak billing impact of planned and unplanned transmission outages be tracked in a deferral account?</u>

As per the preceding sections of this submission, OEB staff has already taken the position that load transfers due to transmission outages do not warrant special treatment or consideration.

Regardless, OEB staff will address the question of a deferral account. To consider a deferral account, one must first demonstrate that the eligibility criteria for establishing a new deferral account have been met.[25]

- Causation: the forecast amount to be recorded in the proposed account must be clearly outside of the base upon which rates were derived.
- Materiality: the annual forecast amounts to be recorded in the proposed account must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed or capitalized in the normal course and addressed through organizational productivity improvements.
- Prudence: the nature of the amounts and forecast quantum to be recorded in the proposed account must be based on a plan that sets out how the amounts will be reasonably incurred, although the final determination of prudence will be made at the time of disposition. For any costs incurred, in terms of the quantum, this means that the utility must provide evidence demonstrating that the option selected represented a cost-effective option (not necessarily least initial cost) for ratepayers.

Despite the LDC Transmission Group indicating some support for this solution, the eligibility criteria were not addressed.[26] Neither did HONI's Background Report. Through Interrogatory Responses, GCC also indicated this option could potentially provide the resolution it seeks.[27] OEB staff invites any participant supporting a deferral account solution to address the eligibility criteria in their reply submission if not done so in their initial submission.

As already noted in the preceding issue, the HONI Technical Report implies that double

[24] Decision on Issues 1, 2, and 3, p. 4
[25] Filing Requirements for Electricity Distribution Rate Applications, Chapter 2, section 2.9.2
[26] Exhibit M1, page 20
[27] Interrogatory Response to M3-VECC-4

peak billing events would not meet the monetary materiality threshold for transmitters. Additionally, OEB staff expects that it is unlikely that double peak billing events have a material impact on the operations of transmitters. While the LDC Transmission Group goes to great detail to describe the operational steps taken to avoid double peak billing events, the LDC Transmission Group acknowledges that the additional transmission charges are a pass-through cost subject to existing Group 1 variance account treatment.[28]

OEB staff submits that satisfying the eligibility criteria for establishing a "transmission outage double peak billing" deferral account for transmitters and regulated transmission customers would be difficult.

In addition to the eligibility criteria for establishing such an account, OEB staff submits that the OEB must also consider the logistics of reviewing balances and approving them for disposition. From the perspective of a regulated transmission customer, the primary consideration lies in the fact that entries to such a variance account would require reconciliation with RSVA accounts 1584 and 1588. There are numerous reasons for entries into each of these accounts. If a new variance account is created related to transmission charges, the costs associated only with transmission outages would need to be isolated. The LDC Transmission Group has stated they do not currently perform the level of tracking that would allow isolation for the impact solely due to transmission outages.[29]

Additionally, such a deferral account would require reconciliation between the regulated transmission customer and the transmitter to confirm that the account additions correctly balance. Then there is the complication of embedded or partially embedded LDCs, creating a further layer of interaction between deferral accounts.

Finally, the situation of unregulated transmission customers must also be considered. For a transmitter, in addition to reconciling entries with each deferral account of each of its LDCs, the deferral account additions would need to be reconciled with credits to unregulated transmission customers.

OEB staff submits that any participant proposing a deferral account should address the eligibility criteria to establish a new deferral account and also address the disposition of additions to such an account.

OEB staff does not support a deferral account solution. It is a remedy that seeks to address only the symptoms and not the root cause. OEB staff also does not support the underlying premise: that a sub-type of load transfers should be afforded special treatment. OEB staff submits that if a solution is sought, it must be predicated on sound regulatory principles.

[28] Exhibit M1, page 4
[29] Interrogatory Response to M1-Staff-5

Issue 4.4: 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?

OEB staff submits that any objective that seeks to address transmission charges that arise from load transfers should be anchored in the principles of cost causality. As stated above, OEB staff submits that transmission outages, regardless as to whether they are planned or unplanned, are leading to a load transfer, and as such sub-types of load transfers do not warrant special treatment The application of transmission charges to a transmission customer should be rooted in how that transmission customer utilizes the given facilities.

OEB staff submits that the concerns of certain transmission customers, namely LDCs, in this proceeding are rooted in concerns relating to load transfers. OEB staff submits that the OEB should consider the issue on the basis of the principles of the transmission charges and in doing so would inherently address legitimate concerns that arise in situations of transmission outages.

Issue 5: Basis for Billing Renewable, Non-renewable and Energy Storage Facilities for Transmission Charges

The Notice describes Issue 5 as follows:

> The UTR establishes a gross load billing threshold of greater than 1 MW for non-renewable generating units and greater than 2 MW for renewable generating units for the transformation and connection rate pools paid for by transmission customers. The scope of this issue is to review whether the 1 MW and 2 MW thresholds are still the appropriate thresholds. The scope also includes considering the appropriate billing threshold for energy storage facilities. The scope of this issue does not include billing for distribution or whether energy storage facilities should be considered renewable or non-renewable (or something else) for purposes of gross load billing. The scope of this issue has been revised by the OEB from how it was first described in the October 15, 2021 Notice of Hearing for Phase 1 of the generic hearing on UTR-related issues.

This issue has two parts:

- The application of gross load billing thresholds, and
- The basis for billing energy storage facilities

The consideration of energy storage facilities, in turn, is two-fold: the basis for gross load billing on account of an embedded energy storage facility; and the basis for billing a transmission connected energy storage facility.

The current basis for gross load billing was first established with RP-1999-0044 and updated in RP-2002-0120, with consideration of embedded renewable resources. At the time of both proceedings, energy storage facilities were not contemplated. Through the development of the issues list, the question of the actual thresholds for gross load billing was added as a sub-issue to issue 6. Also, the question of refurbishments, originally posed as Issue 6, was included in sub-issue 5.1.

The following is a summary of OEB staff's submission on Issue 5. The details are provided with each sub-issue that follows.

OEB staff submits that the gross load billing threshold continue to be applied on a per unit basis: OEB staff submits that the basis described in Hydro One's technical report is compelling.

OEB staff submits that refurbishments to generator units that existed on or prior to October 30, 1998 should be considered on the basis of incremental transmission system load that is obviated by the refurbishment. As such, these refurbishments should consider the incremental capacity on the basis of the facility if it is logical to do so, otherwise the capacity should be evaluated at the unit level.

Similarly, OEB staff submits that inverter based embedded generation, such as solar facilities should be evaluated on a "per unit basis" that is applied logically based on the technology.

Regarding energy storage facilities, OEB staff submits that the gross load billing threshold for renewable generation should also be applied to embedded energy storage facilities. OEB staff submits that transmission connected energy storage facilities should be exempt from transmission charges when providing a service to the IESO or following a real-time load dispatch from the IESO. OEB staff submits that transmission connected energy storage facilities should incur transmission charges associated with the load from withdrawing energy on a self-scheduled basis and station service.

<u>Issue 5.1: Should 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.</u>

This sub-issue combines two related issues. The first part to this sub-issue is to confirm whether the gross load billing threshold applies to the embedded generator's individual units or the entire facility. This stems from the UTR schedule's use of the term "generating unit" without an explicit definition. The second part, which was identified as Issue 6 in the Notice to this proceeding, then poses the question of applying the usage of the term "unit" to refurbishments.

OEB staff submits that the clarity sought in this sub-issue should focus on the intent of the gross load billing threshold: the UTR schedule need not explicitly define a "unit" or a "facility." Both these terms are standard terms, especially in that a facility may have one or more units. Additionally, a facility need not be limited to one building, where customer may have an operation with multiple buildings on the same property. Within such facilities there may be multiple, metered, “units” that are then aggregated to the facility level. This is consistent with the OEB’s Bulletin concerning the Industrial Conservation Initiative for the purpose of billing Global Adjustment charges.[30] The question lies in how to apply the gross load billing threshold.

To consider the gross load billing threshold is to consider the intended purpose of gross load billing and the basis for the threshold. The basis for the threshold was established in RP-1999-0044 as a matter of simplicity to reduce the administrative effort and cost associated with metering and settlement.[31] OEB staff notes that in RP-1999-0044, the OEB accepted OHNC’s proposal.

OEB staff submits that the OEB’s findings in RP-1999-0044 remain relevant today, and that it remains simpler, more cost-effective and less of an administrative burden to continue to apply the threshold on a generating unit basis. OEB staff submits that, absent clearly physical determination of what the unit is, the logical demarcation is the set of equipment that would logically be metered, if a meter were to be installed. Furthermore, OEB staff submits that generating equipment should have a “capacity rating” that could be used to determine the unit capacity.

The refurbishment question of Issue 5.1

To apply the threshold question to refurbishments, OEB staff looks to the purpose of gross load billing. The OEB determined gross load billing should be used for connection charges so as to address the concern of stranded asset costs.[32]

The HONI Background Report identifies an apparent inconsistency between the UTR schedule and the OEB’s response to a specific example brought forward through an Industry Relations Enquiry (IRE) regarding whether the UTR schedule applies to units or facilities.[33] The IRE describes an embedded generation facility undergoing a refurbishment where four 800 kW units are refurbished to two 2,000 kW units.[34]

HONI sought to assess the threshold to the incremental unit capacity: 1,200 kW. In this case, gross load billing would apply. Whereas the transmission customer believed the threshold should be assessed on the basis of the incremental facility capacity: 800 kW. In this case, gross load billing would not apply. In the IRE response, it was OEB staff’s opinion that in this case, the threshold should be evaluated on the basis of the facility.

OEB staff submits that the interpretation of how to assess refurbishments should be grounded in the principle that established gross load billing. OEB staff submits that this is based on the demand that leaves the system, that which might leave the asset

[30] OEB Bulletin, Administering the Industrial Conservation Initiative: Load Aggregation, Calculating the Peak Demand Factor and Determining Peak Demand Eligibility for Class A Consumers, October 18, 2018
[31] RP-1999-0044, Decision with Reasons, para. 3.2.44
[32] RP-1999-0044, Decision with Reasons, para. 3.2.38 and 3.2.39
[33] HONI Background Report, Issues 5 and 6, section 1.3.1
[34] HONI Background Report, Issues 5 and 6, Appendix A: IRE-2021-0210

stranded. Once one accepts that a refurbishment can result in a change in the number of units, then facility level evaluation is appropriate.

Issue 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)?

HONI has described the considerations related to embedded generation that does not have a clear demarcation of a "unit" in assessing gross load billing threshold.[35] HONI's example relates to embedded solar generation, but is framed as a question relating to inverter based generation. An inverter-based facility, broadly, means one that has a power interface between the AC electrical system to which it connects and the source of electricity. As a result, it may more also refer to wind and battery powered electricity sources.

Regarding this issue, OEB staff would reiterate its statements from issue 5.1: the gross load billing threshold was first established on the basis of reducing the administrative burden and cost associated with installing meters to gross-up the customer's load upon settlement. Therefore, OEB staff submits that logical demarcation point for what is considered a "unit" in a non-conventional facility would be the point at which a meter would likely be installed.

HONI has stated that its practice is to look to the inverter capacity in evaluating the "unit capacity" for the purpose of evaluating gross load billing thresholds. OEB staff submits that HONI's current practice is a reasonable and that there is no evidence in this proceeding to indicate otherwise.

Issue 5.3: How should the UTR schedule apply to energy storage facilities?

Currently the UTR schedule does not specifically acknowledge energy storage facilities. OEB staff submits that there are three considerations relating to applying the UTR schedule to energy storage facilities: defining energy storage facilities, applying that definition in the context of embedded storage facilities, and applying that definition in the context of transmission connected storage facilities.

The OEB defines an energy storage facility as a facility that uses electrical energy (i.e. charges), and then stores such energy for a period of time, and then provides electrical energy as an output, minus any losses (i.e. discharges).[36] This definition is wholly consistent with the *Electricity Act*.[37] It is also consistent with United States Federal Energy Regulatory Commission.[38] In July 2024, OEB staff kicked-off a Transmission Connections Review engagement focused on an issues list that includes taking steps to

[35] HONI Background Report, Issues 5 and 6, section 1.2.2
[36] OEB Distribution System Code, section 1.2: Definitions, as "storage facility" for the purpose of connections
[37] O. Reg 610/98, *The IESO*, under the *Electricity Act 1998*, s. 1(4)
[38] FERC Order 841, *Electricity Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*

add a definition of energy storage to the Transmission System Code. The Transmission System Code governs the connection and ongoing operational matters between transmitters and their customers, but not the amounts charged to customers, which is governed by the UTR.

OEB staff submits that the UTR schedule should recognize the existing definitions of an energy storage facility, as in the Distribution System Code and the *Electricity Act*. Referencing the Distribution System Code definition would be consistent with the definition that OEB staff expects to propose for inclusion in the Transmission System Code. In doing so, the UTR schedule can then identify how to apply transmission charges in both forms of such facilities: in the context of gross load billing, when the energy storage facility is an embedded facility, and as a transmission connected facility. The embedded energy storage facility and gross load billing will be addressed first.

With respect to embedded energy storage facilities, HONI has stated that the core question is which gross load billing threshold to apply to these facilities.[39] OEB staff concurs.

OEB staff supports HONI's current practice of assessing the gross load billing threshold for embedded energy storage on the basis that when an energy storage facility discharges its energy, it acts as an embedded generator.

The next question that follows is which gross load billing threshold to apply. The current non-renewable 1 MW threshold was established on the basis of simplicity and administrative costs.[40] The current renewable 2 MW threshold was established reflecting a societal interest in increasing the proportion of renewable generation and the technical reality that embedded renewable generation has advanced to be greater than 1 MW.[41]

OEB staff submits that, without considering whether energy storage facilities are inherently renewable or non-renewable, energy storage facilities are similarly in the societal interest as renewable embedded generation was at the time of RP-2002-0120. First, the OEB has initiatives intended to support energy storage integration.[42] This includes the OEB's Framework for Energy Innovation.[43] Second, the IESO has received several Ministerial Directives that relate to the procurement or facilitation of energy storage facilities.[44] OEB staff also notes that storage has the ability to increase the efficacy of renewable generation, such as solar and wind since it is intermittent in nature and does not necessarily produce energy when the system needs it.[45] Finally, OEB staff notes that the IESO's LT1 procurement selected 1,784 MW of capacity from energy

[39] HONI Background Report, Issues 5 and 6, section 1.2.3
[40] RP-1999-0044, Decision with Reasons, para. 3.2.44
[41] RP-2002-0120, Decision with Reasons, para. 2.5.1
[42] OEB News Release, *Enabling storage in Ontario's electricity system*, April 18, 2022
[43] OEB Framework for Energy Innovation: Setting a Path Forward for DER Integration, January 2023
[44] January 24, 2023 directive relating to financing, November 24, 2022 directive relating to specific energy storage projects, and October 7, 2022 directive relating to capacity procurements
[45] [Energy Storage (ieso.ca)](https://www.ieso.ca/Learn/Ontario-Electricity-Grid/Energy-Storage): https://www.ieso.ca/Learn/Ontario-Electricity-Grid/Energy-Storage

storage across 10 energy storage projects.[46] Therefore, OEB staff submits that it is reasonable for the UTR schedule to specify that the gross load billing threshold used for renewable embedded generation should apply to embedded energy storage.

The final consideration is that of transmission connected energy storage facilities. The unique nature of energy storage facilities is that these facilities withdraw energy from the electricity system for the purpose of delivering that energy, less applicable efficiency losses, back to the electricity system. This uniqueness is widely recognized both internally in Ontario and across neighbouring jurisdictions. OEB staff notes that many neighbouring regional transmission organizations and independent system operators exempt transmission connected energy storage facilities from transmission service charges when providing any of a variety of electricity system related services.

OEB staff submits that the UTR schedules should identify similar exemptions for transmission connected energy storage facilities that provide a service to the transmission system. This is on the basis of jurisdictional precedent, applying the analogous exemption currently afforded to generators, and the fundamental conflict transmission charges can pose with IESO load dispatches and the electricity market signals.

OEB staff notes that PJM, NYISO, and ISO-NE all exempt energy storage facilities from transmission charges when those facilities are providing services to the electricity system. In PJM, energy storage facilities do not pay transmission service charges in any of the cases when the facility receives an energy load dispatch in real-time, is assigned to regulation service, operating reserve, or reactive energy service, or is dispatched for reliability purposes.[47] Similarly, in NYISO, an energy storage facility does not pay transmission charges for energy withdrawals when it is either scheduled for operating reserve schedule, supplying regulation service schedule, supplying voltage support, or dispatched by the system operator for reliability in that same hour.[48]

ISO-NE has similar language and provisions, where the monthly "regional network service" rate is reduced to zero when the energy storage facility is providing one or more of reactive power voltage support, operating reserves, regulation and frequency response, balancing energy supply and demand, or addressing a reliability concern.[49] The ISO-NE tariff further clarifies that balancing energy supply and demand is provided when the facility is responding to ISO dispatch in the real-time market. OEB staff notes that the all the afore referenced transmission tariffs specifically note that both the load to serve station service or withdrawn on a self-scheduling basis be subject to transmission charges.

In addition to considering the exemptions provided in neighbouring jurisdictions, OEB staff submits that the exemption currently afforded to generators also merits

[46] IESO Long-Term RFP (LT1 RFP) – Final Results, June 6, 2024
[47] PJM Manual 27: Open Access Transmission Tariff Accounting, section 8.1
[48] NYISO Open Access Transmission Tariff, section 2.7.2.1.5
[49] ISO-NE Open Access Transmission Tariff, section II.21.3

consideration. RP-1999-0044 established that generators be exempt from transmission charges, since these would be borne by the load customers through the pricing of the commodity. OEB staff submits that there is a parallel to energy storage facilities: while not exact, energy storage facilities would be expected to consider transmission charges as an input to their generation offers, thus putting these costs on load customers. For an energy storage facility, the costs associated with charging the facility are the “fuel cost.” This fuel cost would include the commodity cost of the energy and also any associated charges. Therefore, if an energy storage facility incurs transmission charges to withdraw energy, this cost would logically be included when the facility offers energy back to the market at its marginal cost.

The generation offers would also consider the efficiency of the units of that facility, meaning that the charges are amplified as 1 unit of energy to charge results in less than 1 unit of energy to offer into the market. Therefore, any transmission charges incurred by an energy storage facility would be similarly borne by the load customers, albeit amplified in accordance with the efficiency of the storage facility. Treatment of transmission charges as related to storage facilities by IESO settlement should be confirmed as part of reply submissions or the implementation phase of this proceeding.

Not only would transmission charges be passed on to load consumers through the generation offers of an energy storage facility, but in fact, the network service charge is altogether prohibitive to the utilization of transmission connected energy storage facilities.[50] In addition to being prohibitively expensive, the network service charge also conflicts with IESO market signals and dispatches. This is because the network service charge is applied on a temporal basis, without consideration of real-time market or transmission system conditions.

An energy storage facility operates in the electricity market on the basis of price arbitrage. It is a fact that there may be hours when the market prices are such that it could be economic to withdraw energy to charge an energy storage facility between 7am and 7pm on non-holiday weekdays. This would be either in anticipation of a future market opportunity or after injecting energy in response to market prices at an earlier period. On the basis of market signals, the operator of an energy storage facility would seek to charge when electricity is cheap and offer this energy back when it is expensive.

By virtue of a properly functioning market, the market price would be low during periods of low system demand and high during high system demand. Therefore, an energy storage operator bidding into the market would not be expected to receive a dispatch to withdraw energy for charging, and arbitrage, during periods of high demand. This case is even more applicable under a locational marginal pricing regime where the real-time market price reflects transmission constraints.

[50] EB-2020-0290, Exhibit L H-SEC-04, footnote 1: OPG states the network service charge presents a prohibitively large costs and as a result, OPG seeks to avoid charging its energy storage facility during the hours when the network service charge applies

Additionally, it is a fact that in today's market, a dispatchable facility may receive IESO dispatches due to local transmission conditions that are not reflective in the Ontario market clearing price. When there is a conflict between the market clearing price and the IESO dispatch, dispatchable resources are compensated for this uneconomic condition through congestion management settlement credits (CMSCs). However, this is only on the basis of IESO market prices and bids or offers. There is no such mechanism to compensate an energy storage facility for the conflict between an IESO dispatch to increase load and the network service charge, despite the situation being analogous to those that are compensated by CMSCs.

Based on the above, OEB staff submits that, when responding to an IESO dispatch in real-time or providing a service such as operating reserve, reactive power, or voltage regulation, or directed by the IESO for system reliability, a transmission connected energy storage facility should be exempt from transmission charges. This is OEB staff's proposal for a definition of "transmission system services." OEB staff submits that transmission charges should apply when the energy storage facility withdraws energy from the electricity system as a self-scheduler and for system service load.

The basis for the proposed exemption is that of providing a transmission system service. OEB staff is conscious that, generally, any change in how transmission charges apply may also set the framework for distribution delivery (transmission pass-through) charges. In this aspect, OEB staff notes that this phase of the generic proceeding only deals with UTRs.

Additionally, since HONI's methodology to derive the rates for the provincial transmission service charges is based on historical load, OEB staff submits that there should not be an impact on revenue requirement recovery. The few transmission connected energy storage facilities currently in service that are subject to transmission service charges would avoid charging during network service charge hours, implies minimal impact on the load that underlies the rates.

Issue 6: Gross load billing thresholds for renewable and non-renewable generation

The Notice to this proceeding describes issue 6 as follows:

> Beyond the question of appropriate gross load billing thresholds, set out in issue 5, there has been some uncertainty around the application of those thresholds to transmission customers – for example, with respect to incremental capacity resulting from a generator refurbishment. Clarification is currently provided to customers through OEB guidance.

Through the development of the detailed issues list, this particular issue was absorbed into Issue 5.1 and Issue 6, in turn, evolved to focus on the question of the level of the gross load billing thresholds themselves and exemptions to them.

As detailed below, OEB staff submits that the status quo remains reasonable and at the time of submission, there is no evidence as part of this proceeding to suggest changes.

Issue 6.1: What should the gross load billing thresholds be for renewable and non-renewable embedded generation?

As stated above, the 1 MW gross load billing threshold for non-renewable embedded generation was established, primarily in the context of reducing the administrative and cost burden associated with installing meters and establishing the associated settlement process for grossing up the customer's load. The 2 MW threshold was established on the basis of a "societal interest" in renewable embedded generation and the advancement of renewable generation technology.

There were no submissions from participants recommending different gross load billing thresholds. However, OEB staff notes that HONI stated that more than half of the installed embedded wind generation capacity is being billed on a gross load basis, as these wind generating units tend to be larger than 2 MW.[51] OEB staff submits that it is likely that this is a reflection of the continued advancement in technology that itself led to the establishment of a higher threshold through RP-2002-0120.

OEB staff submits that the societal interest that predicated the initial 2 MW threshold for renewable embedded generation remains. Also, OEB staff submits that it should be rather intuitive to suppose that technology has continued its advance since RP-2002-0120. As a result, OEB staff submits that it is reasonable to consider increasing the threshold for embedded renewable generation units. However, OEB staff notes there were no specific submissions or evidence as part of this proceeding.

Regarding the non-renewable 1 MW threshold, OEB staff submits that, at the least, the administrative burden regarding metering and settlement processes that predicated the original establishment of this threshold likely still remains.

Issue 6.2: Should gross load billing exemptions be available in certain limited circumstances?

HONI has provided two examples of considering exemptions when applying gross load billing criteria.[52]

OEB staff submits that the OEB cannot formulate a UTR schedule that can pre-sage every potential scenario and that HONI poses legitimate questions in how to interpret the UTR schedule. OEB staff submits that the UTR schedule should identify the potential need for an exemption from time to time, if the UTR schedule appears to be in conflict with either reality or logic, and should inform transmitters that if this need arises a transmitter should request an exemption in writing to the OEB.

The first example is that of a customer seeking to connect a new load that cannot be supplied by the current line connection facilities. In this case, the customer plans to

[51] HONI Background Report, Issues 5 and 6, p. 8, lines 9-11
[52] HONI Background Report, Issues 5 and 6, section 1.3.2

install significant embedded generation to serve its load, a load that cannot be served by the existing transmission facilities. If gross load billing were to be applied, the level of the load for billing would exceed the capacity of the transmission connection facilities, and by a significant margin.

OEB staff submits that the example provided by HONI illustrates that gross load billing amounts should not exceed the capacity of the transmission connection facilities that serve the load. Similar to the principle of protecting transmitters from stranded asset risk, the beneficiary pays principle protects consumers from paying for facilities that they do not use or are not useful to them. OEB staff submits that it would be illogical for consumers to pay transmission charges for a gross load that exceeds the capacity of the transmission connection facilities that serve them.

The second example is that of a Class A customer who installed embedded generation for the purpose of peak-shaving under the Industrial Conservation Initiative (ICI). Applying gross load billing in this scenario would create an inverse cost signal to the customer from that of the ICI. The ICI and gross load billing apply to different electricity costs. The ICI program relates to Global Adjustment and the cost supplying energy whereas gross load billing applies to transmission connection facilities relating to conveying energy to the specific customer. OEB staff submits that consideration for gross load billing should relate to the underlying principle, that of stranded costs. OEB staff submits that as long as the UTR schedule has provision for gross load billing, its use and application should be based on the principle that established it.

In summary, with respect to this Issue 6.2, OEB staff submits that the UTR schedule should identify that transmitters could seek exemptions in relation to the UTR schedule when needed.

Additional Comments and Considerations

While Procedural Order No. 3 clearly states that this phase of the OEB's generic proceeding deals only with UTRs, OEB staff submits that there are two related considerations that warrant the OEB's attention. So far, OEB staff's submission has been primarily focused on transmission connected customers. However, there are also distribution connected double peak billing impacts that affect customers. Additionally, as demonstrated by GCC's evidence and participation in this proceeding, there are customers with both transmission and distribution system connections. OEB staff submits that, while this proceeding is focused on UTRs, it would be reasonable to nonetheless consider how any changes to the UTRs in this proceeding would flow downstream to implementation for distribution system charges.

The first consideration is highlighted by the letter of comment filed by Entegrus Powerlines Inc. (EPI) on July 10, 2024. EPI acknowledges that the impact of double peak billing of distribution connected customers is not in the scope of the current issues before the OEB. EPI's letter emphasizes the complication of a transmission connected

LDC that serves an embedded LDC. EPI states that, as an embedded LDC, it incurs additional distribution delivery charges when the host LDC performs a load transfer and that any measure solely focused on transmission charges due to load transfers could have inappropriate consequences for the embedded customer.

OEB staff submits that, regardless of the OEB's findings to Issue 4, the OEB should ensure there is no imbalance between the provincial transmission service charges incurred by the host and the distribution delivery charges incurred by the embedded distributor. Simply put, OEB staff submits that no transmission customer that charges distribution delivery charges should profit on the basis of an imbalance between transmission and distribution charges.

Furthermore, OEB staff reiterates that any solution to double peak billing should address the root cause of any determined problem and that the solution should be grounded on rate-making principles. It is OEB staff's view that EPI's apparent concern reinforces staff's aversion to band-aid solutions such as variance accounts. Any changes to the UTRs must be principled so that they can be effectively translated to distribution delivery charges. If the measures are too complicated, it will be all the more difficult to ensure fair treatment to embedded customers such as EPI.

Along the same vein, OEB staff submits that the matter of a customer with both transmission and distribution connections warrants additional consideration. Unlike the examples provided by the LDC Transmission Group, the load transfers performed by GCC at its Sudbury facility are rare and usually planned in advance.[53] In fact, GCC states that the metering under the load transfer is temporary and that the billing is on a "one off" basis.[54] [55] While OEB staff assumes that the evidence provided by GCC is representative, OEB staff submits that materiality must be considered.

The evidence is clear that when a load transfer to a secondary supply is performed, the base transmission connected delivery point has a reading of nil or zero. OEB staff submits that within a settlement process, this provides an indication of a change in the transmission customer's configuration. OEB staff presumes that it would be reasonable for this to be a trigger for a settlement process to consider if a secondary settlement process should be initiated to consider the transmission customer's load transfer.

While it seems feasible for the IESO and the host distribution company of the back-up supply to share meter data for the purpose of evaluating the customer's use of transmission facilities, OEB staff would defer to the IESO, and in this case HONI, whether it is practical to do so. Theoretically, it would be reasonable for the IESO to evaluate the meter data and credit the host distributor for any charges that are not incremental to those of the base configuration. The host distributor would then extend the credit to the customer in the billing of distribution services.

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[53] Interrogatory Response to M3-Staff-10
[54] Interrogatory Response to M3-Staff-9, regarding the metering configuration during a load transfer
[55] Interrogatory Response to M3-Staff-12, regarding the "one off" nature of the billing

OEB staff defers to the billing entities as to the feasibility of enhancing the settlement processes to this degree. To the extent possible, OEB staff intends to address implementation of proposals in the submissions from participants in its reply submission. OEB staff invites interested parties that propose changes from the status quo to address implementation in their reply submissions.

OEB staff also submits that after the OEB has rendered its findings on the issues, if needed, the OEB should initiate a draft rate order process to determine any revised language that needs to be incorporated into the UTR tariff and/or to determine the process to address any additional matters, including distribution impacts, as part of a future phase.

~All of which is respectfully submitted~