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October 16, 2024 **VIA E-MAIL**

Nancy Marconi
Registrar
Ontario Energy Board
Toronto, ON

Dear Ms. Marconi:

Re: Generic Hearing on Uniform Transmission Rates - Phase 2 (EB-2022-0325)
VECC's Submissions – Issues 4, 5 and 6

Please find attached VECC's submission on the above referenced matter, pursuant to Procedural Order No 4. Please contact me if any clarification is required (bharper.consultant@bell.net)

Yours truly,

William Harper
Consultant for VECC/PIAC

cc. J. Lawford, PIAC

GENERIC HEARING ON UNIFORM TRANSMISSION RATES (EB-2022-0325)
VECC'S SUBMISSIONS – PHASE 2: ISSUES 4, 5 AND 6

1. INTRODUCTION

On October 27, 2023 the Ontario Energy Board (OEB) issued a Notice of Hearing (Notice) wherein it initiated a public hearing on its own motion[1] to consider various issues related to Ontario's Uniform Transmission Rates (UTRs). The Notice identified the following six issues for the proceeding:

1. The timing of UTR decisions,
2. Number of decimal places for UTRs,
3. Prorating transmission charges for new connections to account for when the connection took place in the month,
4. Charges caused by planned transmission outages,
5. Basis for billing renewable, non-renewable, and energy storage facilities for transmission, and
6. Gross load billing thresholds for renewable and non-renewable generation

In Procedural Order No. 1 the OEB indicated that the Hearing would consist of two phases. For the first phase OEB staff provided background information and recommendations on how to address Issues 1, 2, and 3. Intervenors were then invited to consider these recommendations and provide submissions. On May 9, 2024, the OEB issued its decision on Issues 1, 2, and 3.

With respect to Issues 4, 5 and 6, in Procedural Order No. 1 the OEB ordered Hydro One Networks Inc. (Hydro One) to file a background report to support consideration of these three issues. HON's Background Report (the "Background Report" or "Report") was filed on April 2, 2024. Procedural Order No. 1 also made provision for a Technical Conference to provide intervenors with an opportunity to review and clarify the Background Report prepared by HONI on Issues 4, 5, and 6. However, given the significant number of advance questions HONI received, the OEB decided to cancel the planned Technical Conference and directed HONI to provide responses in writing and for OEB Staff to develop a draft detailed issues list[2].

On April 29, 2024, OEB staff filed a Draft Detailed Issues List on Issues 4, 5, and 6. Following submissions from various intervenors the OEB issued an approved Issues List on July 5, 2024 with respect to Issues 4, 5 and 6[3]. The OEB's earlier Procedural Orders also included provisions for parties to indicate their intention to file evidence. A number did so and the OEB's Procedural Order No. 4 granted the requests of the LDC Transmission Group, ENWIN Utilities Inc. (ENWIN), and Glencore Canada Corporation (GCC) to file evidence.

Procedural Order No. 4 also included provisions for: i) parties to file written interrogatories with respect to any evidence filed by any intervenor and the subsequent

[1] Under sections 19, 21, and 78 of the Ontario Energy Board Act, 1998
[2] Procedural Order No. 2
[3] Procedural Order No. 4

timing of the subsequent responses; ii) the filing of submissions and iii) the filing of rely submissions.

Set out below are VECC's submissions regarding Issues 4, 5, and 6.

2. VECC's SUBMISSIONS

2.1. GUIDING PRINCIPLES

In addressing the outstanding issues in this proceeding VECC submits that the OEB should be guided by Board's statutory objectives for electricity which are set out in Section 1(1) of the Ontario Energy Board Act:

1. To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate innovation in the electricity sector.

More specifically, in the case of electricity rates for transmission and distribution the OEB Act (Section 78(3)) requires that the rates ordered by the Board be "just and reasonable". In VECC's view "just and reasonable" rates are ones that align with Bonbright's attributes of a sound rate structure as set out in Attachment A.

VECC notes that Bonbright's attributes/principles have underpinned previous OEB initiatives with respect to rate design including:

- EB-2007-0031 – Rate Design for Recovery of Electricity Distribution Costs: The Staff Discussion Paper[4] issued as part of this process noted that the Board's ultimate responsibility is to set rates that are just and reasonable and to do so consistent with the Board's guiding objectives as set out in section 1(1) of the *Ontario Energy Board Act, 1998.* The Staff Discussion Paper went on to note that the Bonbright's eight regulatory principles for establishing rate structures were considered appropriate as guiding principles for the initiative.
- EB-2012-0410 – Rate Design for Electricity Distributors: The Draft Report of the Board issued as part of process noted[5] that the principles used for the proposed rate design "encompass all of the Bonbright attributes of a sound rate structure":
- EB-2023-0071 – Electric Vehicle Integration Initiative: Electric Delivery Rates for EV Charging: The Report prepared for the OEB by Power Advisory[6] evaluated the various options using Bonbright's principles.

Also, while Bonbright's principles were not specifically referenced in the RP-1999-0044 Decision that established the current cost allocation and rate design for transmission rates, cost causality, efficiency along with administrative practicality were key

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[4] Rate Design for Recovery of Electricity Distribution Costs, March 2008, page 9
[5] EB-2012-0410, Draft Report of the Board Rate Design for Electricity Distributors, March 2014, page 5
[6] Electricity Delivery Rates for Electric Vehicle Charging, April 13, 2023, page 22

considerations in the Board's Decision[7]. VECC notes that all three of these are included in Bonbright's attributes of a sound rate structure.

2.2. ISSUE #4: CHARGES CAUSED BY PLANNED TRANSMISSION OUTAGES

The original Notice of Hearing provided the following overview regarding this issue:

> "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."

In its Background Report[8], Hydro One Networks Inc. (HONI) referred to these occurrences as "double peak billing events" and provided the following more detailed explanation of the issue:

> "A double peak billing event can occur in instances where a transmission customer is supplied by more than one connection point to the transmission system, each of which is referred to as a delivery point (DP). At a time of a planned transmission outage (for example to facilitate system maintenance or system upgrades initiated by the transmitter or the transmission-connected customer), the customer's load may be transferred from an impacted DP to another one of the customer's DPs in order to avoid or minimize power interruption. When this occurs, the customer may be charged for the same load on both DPs in a given month as a result of transmission charges being based on the monthly peak at each DP. For example, if during a billing cycle the load is transferred from DP(A) to DP(B), this would result in a higher monthly peak at DP(B) due to the combined load at DP(B) after the transfer. As such, the customer would be charged for the load based on the monthly peak at DP(A) prior to or after the transfer period, plus the monthly peak at DP(B) which represents the combined load during the transfer period at DP(B)."

In its Background Report[9], HONI also made the following points regarding the scope of the issue:

- Double peak billing impacts transmission-connected customers irrespective of whether the load transfer event is initiated by the transmitter or the transmission connected customer. The Background Report assumed that the solution would be applicable to both instances.
- As described in the Notice, Issue 4 includes only planned outages and as a result, planned outages are the focus of its background report. However, double peak billing events can and do occur in circumstances of both planned and unplanned transmission outages. While unplanned outages are beyond the control of transmitters and customers and do not always result in double peak billing events, Hydro One noted that clarification from the OEB as to the treatment of unplanned outages in the context of the current proceeding would help avoid future customer complaints and confusion.

[7] See RP-1999-0044, pages 18-20, 27, 31-38, and 45-48
[8] Issue 4, page 3 of 20
[9] Issue 4, pages 4-5

- Double peak billing events can impact both transmission-connected and distribution-connected customers (i.e. there is a parallel concern on the distribution side) and are particularly impactive for LDCs that have both transmission and distribution DPs. HONI expressed the view that the distribution issues would also need to be addressed either in parallel to or after the transmission issues were addressed as part of the current proceeding.

In its Decision regarding the Issues List[10], the OEB determined that addressing double-peak billing customer mitigation measures for both transmission-connected customers and distribution-connected customers was beyond the scope of this phase of the current proceeding. As a result, the impacts of double-peak billing on distribution-connected customers would not be examined. However, the Decision regarding the Issues List did determine that the issue of measures to address the impact of double-peak billing related to both planned and unplanned transmission outages would be addressed as part of the current proceeding (see Issue 4.2).

2.2.1. Issue 4.1

The approved Issues List sets out Issue 4.1 as follows:

> "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?"

VECC submits that all transmission charges should continue to be calculated on a per delivery point basis and not calculated on the customer's aggregate demand for all delivery points for a given time interval. Such an approach would address the issue of double billing due to load transfers triggered by planned/unplanned outages. However, as HONI notes[11] under this approach while all customers with multiple DPs would be billed based on their aggregate demand not all customers with multiple DPs are impacted by double peak billing events each month or even in a given year. HONI was unable to provide an estimate as to the cost shifting (primarily between transmission customers with multiple vs. a single DP) would occur using the aggregate demand approach. However, HONI does indicate that it would be significantly higher than the costs associated with double peak billing events.

Indeed, VECC notes that HONI estimates[12] only 3 LDCs and 2 industrial customers were impacted annually by double peak billing over the 2020-2023 period. Furthermore the annual costs associated with double billing over the same period totalled less than $700,000[13]. VECC notes that this represents less than 0.03% of HONI's total approved revenue requirement for 2023 and less than 0.1% of the total approved 2023 revenue

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[10] Procedural Order No. 3

[11] Responses to Clarifying Questions, VECC -7 b)

[12] Responses to Clarifying Questions, AMPCO-1 a) & b). HONI acknowledges that these estimates only reflect known double peak billing events. See also VECC-2 b)

[13] Responses to Clarifying Questions, AMPCO-4 a) & b). HONI acknowledges that these estimates only reflect known double peak billing events. See also VECC-2 b)

requirement associate with HONI's Line and Transformation Connection Pools[14]. In VECC's view the number of customers and the costs associated with double billing are in no way material enough to warrant such a significant change in the approach to calculating transmission charges and the resulting cost shifting between transmission customers. This is particularly the case when, as discussed below, the change would be inconsistent with the principle that rates should reflect cost causality.

In the case of Network Charges[15], the billing determinant for each Delivery Point (DP) is calculated as the higher of:
i. the DP's coincident peak demand in the hour of the month when the total hourly demand of all customers is highest for the month; or
ii. 85% of the DP's peak demand during any hour 7 AM to 7 PM business days.

VECC notes that if the Network billing determinants for all of a customer's DPs are based on the DPs' coincident peak demands in the hour of the month when the total hourly demand of all customers is highest for the month then double peak billing will not occur with the current UTR Schedule. However, billing such transmission customers based on their aggregate demand for all delivery points could change (i.e., increase[16]) the value of the Network billing determinant.

On the other hand, if the Network billing determinant at one or more of a customer's DPs is based on 85% of the DP's peak demand during any hour 7 AM to 7 PM business days, then calculating the billing determinant based on the customer's aggregate demand (across all DPs) could potentially result in a double peak billing event.

VECC notes that in the original RP-1999-0044 Decision[17] the use of 85% of the DP's peak demand during any hour 7 AM to 7 PM business days as one of the billing determinants was meant to represent a compromise between coincident and non-coincident peak demand billing and to address concerns regarding free ridership and gaming. However, in VECC's view it also addresses the fact that there are regional variations as to timing of the peak on the Network portion of the Transmission system. Given the presence of Hydro One Networks-Distribution in more than one region of the province and the recent consolidations resulting in LDCs with non-contiguous service areas, VECC submits that it is important, from a cost causality perspective, to continue to determine Network charges on a per Delivery Point basis and give some weight to the each Delivery Point's non-coincident peak.

In the case of Line Connection and Transformation Connection the charges are based on the customer's peak monthly demand at each DP[18]. As a result, it is with respect to these charges that double peak billing is more likely to occur. However, as noted in the original RP-1999-0044 Decision, these facilities are built specifically to serve a single or relatively small group of customers and the associated capacity is designed to meet the

[14] EB-2021-0110, Decision and Order, Attachment 1, Schedule 2.4.1
[15] Responses to Clarifying Questions, GGC-1.4 a)
[16] This would occur if the transmission customer's maximum aggregate demand in a month did not occur at the same time as aggregated peak demand for all transmission customers.
[17] RP-1999-0044, Decision with Reasons, Paragraphs 3.4.15 and 3.4.28
[18] Responses to Clarifying Questions, GGC-1.4 a)

local demand[19]. This means that from a cost-causality perspective it is more appropriate to calculate the charges for these facilities per delivery point. Put another way, since the facilities in question are designed to meet the non-coincident demand at each delivery point, aggregating customer's demand across the delivery points would reduce the value of transmission customer's monthly billing determinant and provide the customer with an unwarranted diversity benefit. Such diversity benefits can be readily seen from the LDC Transmission Group's interrogatory responses[20] which demonstrate that for each of NOTL, Enwin, HHI and Milton Hydro the sum of the average monthly peaks for each of their transmission delivery points is higher than the average monthly aggregate peak value.

The LDC Transmission Group has proposed[21] that transmission charges would be calculated on the customer's aggregate demand for all delivery points in those circumstances that would exclude:

- Non-contiguous service areas.
- LDCs with both Transmission-connected and Distribution-connected delivery points.
- Service areas beyond a certain number of delivery points (to be determined).

VECC submits that the OEB should not adopt the LDC Transmission Group's proposal. Many of the concerns raised by VECC regarding the calculation of transmission charges based on a customer's aggregate demand for all delivery points also apply to limited applications proposed by the LDC Transmission Group. This is particularly the case for Line Connection and Transformation Connection charges which is where the impact of double peak billing is more profound. Furthermore, it will result in different charge determinants being applied to transmission customers for the same service which can/will be viewed as unfair and discriminatory.

2.2.2. Issue 4.2

The approved Issues List sets out Issue 4.2 as follows:

> "Should the measures to address the impact of double-peak billing be applied to both planned and unplanned transmission outages or should there be separate measures? What should be the objectives of those measures?"

While the transmission customer may be able to work with the transmitter so as to reduce the impact double peak billing due to planned outages, this is not the case in the event of an unplanned outage. As a result, VECC submits that the impact of double peak billing due to unplanned outages warrants the same (if not more) consideration than the impact of planned outages. Furthermore, VECC expects that the distinction between a planned and unplanned outage may not be as clear as one might think. For example, a planned outage to undertake a pre-specified amount of work could take longer than anticipated if unknown deficiencies are uncovered and the outage needs to be extended beyond the "planned" period.

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[19] RP-1999-0044, Decision with Reasons, Paragraphs 3.4.31 and 3.4.33

[20] Exhibit N1, VECC 5.1, 6.3, 8.3 and 10.4

[21] Exhibit M1, pdf pages 18-19. Note: In Exhibit N, HONI-1 the LDC Transmission Group acknowledges that its listed conditions may not be complete

VECC does not see why the same measures should (and could) not be used to address the impact of double peak billing for both planned and unplanned outages. However, VECC will be interested in reviewing the submissions by HONI and participating transmission customers who have more familiarity and experience with planned vs. unplanned transmission outages.

In VECC's view the objective of such measures should be to ensure that transmission customers only pay their fair share of the overall cost of providing transmission service, where "fairness" takes into account considerations regarding cost causality and administrative practically.

2.2.3. Issue 4.3

The approved Issues List sets out Issue 4.3 as:

> "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 approach suggested under Issue 4.3 is essentially Option 3 from HONI's Background Report[22]. Both HONI's assessment[23] and the IESO's assessment[24] of this option identify that significant changes would be required to the IESO's billing and settlement systems and processes. The IESO further notes that these changes would require significant time (perhaps years) and effort. The IESO also questions the feasibility of establishing a comprehensive set of business rules that would identify and determine the impact of such events under all situations.

VECC does not support this approach given it requires significant time (and likely resources) to implement and it is uncertain as to whether a "workable" solution can be developed.

As an alternative to developing a comprehensive set of business practices such that the impact of double peak billing can be removed as part of the IESO's billing and settlement processes, the IESO suggests an alternative approach whereby[25]:

i. IESO bills the transmission customer based on the status quo,
ii. The transmission customer and transmitter assess any double peak charge and determine if adjustment warranted (based on the established principles),
iii. The transmission customer and transmitter agree to double peak adjustment and submit information to the IESO for processing, and
iv. The adjustment is processed by the IESO via recalculated settlement statement (full transparency).

VECC submits that the IESO's suggested alternative is equivalent to HONI's Option 4 except under Option 4 the double peak adjustment is tracked in a deferral account as opposed to being refunded through the IESO's settlement processes. HONI's Option 4 is simpler to implement (i.e., does not involve the IESO or require changes to the IESO's settlement processes). Furthermore, HONI's Option 4 is more transparent as

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22 Issue 4, pages 9-11
23 Background Report, Issue 4, page 10
24 Responses to Clarifying Questions, Issue 4, VECC-25 c)
25 Responses to Clarifying Questions, Issue 4, VECC-25 c)

the amounts in question will be subject to review by the OEB when the deferral account balances are cleared. Finally, Option 3 will not address all potential double peak billing issues for transmission service. As indicated in the LDC Transmission Group's interrogatory responses[26] not all billings for transmission services are done through the IESO (e.g. Milton Hydro is billed directly by Oakville Hydro for the use of the Glenorchy MTS owned by Oakville Hydro).

2.2.4. Issue 4.4

The approved Issues List sets out Issue 4.4 as follows:

> "Should the double-peak billing impact of planned and unplanned transmission outages be tracked in a deferral account?"

In VECC's view this is the preferred option out of the four presented by HONI in the Background Report[27] based on the advantages identified in HONI's Background Report. However, as HONI has noted[28]:

- New business processes and coordination between various internal and external teams will be required to keep track of every eligible double peak event.
- Methodology (including the possible use of temporary metering) will need to be established to determine the amount of load "transferred" during each event.
- UTRs will need to be calculated to 4 decimal places.

In addition to the above VECC submits that:

- Determinations will need to be made as to how to address those circumstances where there is be more than transmission asset owner involved (e.g. Oakville Hydro and HONI as is the case of Milton Hydro) giving rise to more than one transmitter with a deferral account (e.g., to which transmitter's deferral account is the impact of a particular double peak billing event recorded).
- Criteria will need to be established that will allow the transmitter (along with the affected transmission customers) to demonstrate the prudence in the management of each event. For example, in the case of planned outages this could involve providing an explanation as to the reason for the outage and confirmation/demonstration that HONI and the affected transmission customer have worked together to minimize the impact of the double peak billing event.
- Activities should be initiated to address the parallel issues regarding load transfers and double peak billing events that exist for distribution connected customers as described in the Background Report[29], by the LDC Transmission Group[30] and by Glencore Canada Corporation (GCC)[31].

In order to address the issues with respect to distribution-connected customers the LDC Transmission Group[32] has suggested that a working group be established. VECC submits that such an approach (i.e., the establishment of a working group) would also

[26] Exhibit N1, VECC-10.1
[27] Issue 4, pages 7-12
[28] Background Report, Issue 4, pages 12-13
[29] Issue 4, page 5
[30] Exhibit M1, pdf pages 4-5
[31] GCC Evidence, pages 4-5
[32] Exhibit M1, pdf page 20

be useful in addressing and resolving the outstanding issues noted above regarding the implementation of deferral accounts to address the double peak billing issue associated with transmission DPs.

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

The original Notice of Hearing provided the following overview for this issue:

> "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."

VECC notes that OEB, in approving the Issues List, rejected[33] submissions from some parties that proceeding should consider: i) whether gross load billing remains the appropriate approach for billing renewable, non-renewable, and energy storage facilities for transmission charges and ii) the benefits of embedded generation. The OEB determined that these were important issues but with broader implications than were contemplated in the second phase of the OEB's examination into UTRs. The OEB found that these proposed issues are more appropriately examined in Phase 3 of the UTR proceeding following the go-live date of the Market Renewal Program (MRP).

2.3.1. Issue 5.1

The approved Issues List sets out Issue 5.1 as follows[34]:

> "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."

The HONI Background Report explained[35] that:

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

The Background Report also explained that the UTR Schedule does not define "unit" or "embedded generator unit", nor are these terms defined in the Transmission System Code (TSC), the Electricity Act or the Ontario Energy Board Act. However, the Background Report noted that statements in the Transmission System Code clearly distinguish between generation facilities on the one hand and generating units on the

[33] Procedural Order No. 3
[34] Procedural Order No. 3
[35] Issues 5 and 6, page 5

other and that it is understood that generation facilities include individual units of generation capacity. The Report notes that similar inferences can be drawn from the OEB's Decision with Reasons in RP-2002-0120 which seemed to acknowledge that a customer's embedded generation could include more than one generator unit and that the size of each individual generator unit shall be used to determine whether gross load billing is applied. As a result, HONI's practice has been, and continues to be, to assess gross load billing eligibility by applying the thresholds in the UTR Schedule on a 'per-unit' basis as opposed to a 'facility' basis[36].

The Report then goes on to note that[37]:

> "For commercial and industrial customers seeking to reduce their demand under the Industrial Conservation Initiative, the way in which the gross load billing rules have been established has effectively provided customers with an opportunity to size the units of their embedded generation facility to avoid gross load billing settlement charges. Hydro One is aware of several instances in which a customer has installed multiple generator units and the aggregate rated capacity of these units (i.e. the installed capacity of the embedded generation facility) exceeds the applicable gross load billing threshold. However, since none of the individual generator units exceeds the threshold on its own, the load supplied by these units has been, and continues to be, exempt from gross load billing charges."

At the same time, HONI acknowledges[38] that it has not formally investigated why customers have chosen the unit sizes actually installed and therefore "does not know if customers intentionally or unintentionally sized their generator units for the purpose of avoiding gross load billing settlement charges and/or for any other purposes."

The Report also notes[39] that the application of gross load billing on a "per unit basis" has created issues with respect to the requirement in the UTR Schedule that "the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998." As an example, HONI cited[40] a case where a customer of an LDC refurbished an existing 3,200 kW facility consisting of four 800 kW units such that the new facility consisted of two 2,000 kW units. HONI's application of the threshold methodology on a per unit basis resulted in 2,400 kW of incremental capacity which exceeded the 1 MW threshold and led to the total capacity being subject to gross load billing. In contrast, if considered at the facility level the incremental capacity would only be 800 kW and not subject to gross load billing.

It is VECC's view that the application of the thresholds for gross load billing should be defined at the facility level, both for new embedded generation as well as for refurbishments to generating unit/facilities that existed on or prior to October 30, 1998.

[36] Report, Issues 5 and 6, pages 5-6
[37] Issues 5 and 6, page 6
[38] HONI's Clarifying Question Responses, Issue 5&6, DRC-01 b) & d)
[39] Report, Issues 5 and 6, pages 12-13 and Appendix A
[40] Report, Appendix A

VECC notes that the OEB's original RP-1999-0044 Decision established a 1 MW threshold for gross billing based primarily on considerations of administrative costs and simplicity. In this regard the Decision specifically stated[41]:

> "The only remaining issue, in the Board's view, is that of administrative costs and simplicity. Gross load billing for smaller loads would require the installation of metering and the incorporation of these loads in the IMO's billing and settlement process, thus creating costs and complexities for both the generator and the system as a whole which would likely outweigh any benefits from billing for such facilities."

However, as part of its rationale the Board also noted that, based on information provided, generators of less than 1 MW are also exempt from IMO dispatch and scheduling requirements."

The OEB's subsequent decision to apply a 2 MW gross billing threshold for renewable generation was intended to reflect a societal interest in increasing the proportion of renewable generation in the overall generation mix in the province, and the technical reality that the output of some renewable source generation equipment had advanced from under 1 MW per unit to just under 2 MW per unit[42].

In its responses to the Clarifying Questions HONI has indicated[43] that:

i. It does not believe that IESO dispatch and scheduling requirements should continue to be viewed as an important consideration because most embedded generation connected behind the meter of transmission customers is not currently dispatchable by either the IESO or the distributor.
ii. If a facility-based approach for gross load billing was implemented, the change in approach would not have any impact on current metering and administration costs.

In its responses to the Clarifying Questions[44] HONI has also observed that the OEB's decision to apply a different (and higher) gross load billing threshold for renewable generation was consistent with its statutory objectives at the time as section 1 of the OEB Act included as an objective "To promote energy conservation, energy efficiency, load management and the use of cleaner energy sources, including alternative and renewable energy sources, in a manner consistent with the policies of the Government of Ontario." However, since then the OEB's statutory objectives have been revised and the current version of section 1 of the OEB Act does not include any references to the use of clean energy sources or renewable energy sources. Furthermore, both the OEB's recent FEI Report and also its Draft Benefit-Cost Analysis Framework have adopted the view that it is not the role of the OEB to favour/choose one technology solution over another[45].

[41] Paragraph 3.2.44
[42] Report, Issues 5 and 6, page 4
[43] Responses to Clarifying Question, VECC-10 a) & b)
[44] VECC-11
[45] OEB's Draft Benefit-Cost Analysis Framework for Addressing Electricity System 5 Needs, December 2023 (EB-2023-0125), Section 2.1

As result, the considerations that influenced the OEB's original decision to implement an eligibility threshold for gross load billing are not germane to the question of whether the gross billing threshold is applied on a per unit or per facility basis. However, in VECC's view there are other relevant considerations related to cost responsibility and economic efficiency that need to be taken into account when determining whether the eligibility threshold is applied on a per unit or a per facility basis.

HONI has confirmed[46] that it plans the transmission system to meet the peak demand of the customers connected to its system. Furthermore, HONI has indicated that while customers may displace their load through embedded generation, the system is planned to account for the scenario that this embedded generation may not be available or not be at full capacity when the peak is reached. For both connection impact assessment purposes and longer term planning purposes, it is the potential load at the point where the customer connects to the transmission system that determines the level of transmission service that needs to be provided and the resulting costs. Therefore what is relevant from the transmitter's perspective is the potential impact of the embedded generation facility on the customer's overall load requirements. Thus from cost responsibility perspective VECC submits that gross load billing thresholds should be defined (and applied) on a facility basis.

Furthermore, application of any gross load billing thresholds on a facility basis will also promote economic efficiency. As HONI has indicated, application of gross load billing thresholds on a per unit basis can influence a transmission customer's choice as to generating unit size. In VECC's view the gross load billing rules should not influence a customer's decisions as to the generation technology, fuel type or choice between number vs. size of units unless the customer's decisions will directly impact the level and resulting cost of providing transmission service. Decisions on these matters should be left to the customer based on the customer's assessment as to costs and benefits associated with such choices. In VECC's view such an approach will promote economically efficient outcomes for both the customer and the transmitter.

VECC acknowledges that if the OEB changes the basis for the application of the gross billing threshold from a "per unit" to a "per facility" basis then:

i. There may be a need to address the appropriate threshold level(s). See Issue 6.1
ii. Consideration should be given to grandfathering the definition of the gross load billing threshold for the existing renewable generation facilities/units. In this regard, "existing renewable generation facilities" could be defined as those that are either in operation or had formally applied for a connection impact assessment on or before the Notice of Hearing date.

2.3.2. Issue 5.2

The approved Issues List sets out Issue 5.2 as follows[47]:

> "Is additional clarity needed on the applicability of gross load billing thresholds to embedded generation that employs inverters (such as embedded solar generation)?"

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[46] Responses to Clarifying Questions, VECC-9 b) and APPrO 1.4

[47] Procedural Order No. 3

With respect to solar generation, the Report explains[48] that:

> "In general, a solar generation facility will consist of a set of photovoltaic cell arrays that are connected through an inverter to produce electrical power. Often, a solar facility will be designed to include multiples sets of arrays, with each array having their own inverter. In such an arrangement, each array/inverter set could be viewed as independent from an operational standpoint and would represent a single generator unit."

The Report then goes on to explain that inverter capacity for solar generation is typically small (under 0.5 MW) and, as result, no customers with embedded solar generation are currently being billed on a gross load basis.

In response to the clarifying questions[49] HONI indicated that for solar, apart from using the inverter to define an individual generator unit, there was no other way to define a unit within a solar generation facility unless one considered the whole facility as a unit. As a result, if the OEB decides to continue to apply the gross load billing thresholds on a per unit (as opposed to per facility) basis, HONI's practice of using the capacity of the inverter for each array/inverter set within an embedded solar generation facility to define an individual generator unit would appear to be the only practical approach and should be confirmed by the OEB.

However, as noted in response to Issue 5.1, VECC is recommending that the gross load billing threshold(s) be applied on a per facility basis and this would apply to all embedded generation including solar. In its clarifying questions VECC asked how much of the 1,268 MW of embedded solar generation would be subject to gross load billing using: i) a 1 MW threshold or ii) the current 2 MW threshold if the threshold was applied on a "facility basis". The response stated[50]:

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

VECC does not see how the first and second sentences can both be correct. Presumably if all of the 1,268 MW of embedded solar generation would be subject to gross load billing using the current 2 MW threshold applied on a facility basis then all would also be subject to gross load billing if the threshold was lowered to 1 MW. Either the first sentence should state none would be subject to gross load billing if the current 2 MW threshold was used or, alternatively, the MW values in the two sentences are reversed and the first sentence is meant to indicate that all of the 1,268 MW would be subject to gross load billing if the threshold is set at 1 MW. HONI may wish to clarify this response as part of its October 30th reply.

2.3.3. Issue 5.3

The approved Issues List sets out Issue 5.3 as follows[51]:

> "How should the UTR schedule apply to energy storage facilities?"

The Report explains[52] that the UTR Schedule does not:

[48] Issues 5 and 6, page 7
[49] VECC-13 a)
[50] Responses to Clarifying Question, VECC 13 b)
[51] Procedural Order No. 3

i. Clarify whether an embedded generator unit includes an embedded energy storage unit.
ii. Specify whether or not, in the circumstances where an embedded energy storage unit reduces a transmission customer's non-coincident peak in the same manner that an embedded generation unit would, energy storage should be treated as generation for the purpose of assessing gross load billing eligibility.

The Report then goes on to indicate that, in the absence of further guidance on these aspects, Hydro One has adopted the practice of applying gross load billing to embedded energy storage based on the rationale that energy storage is typically deployed by customers to reduce their non-coincident peak demand. Furthermore, since storage does not rely on a renewable process for injecting power, Hydro One has applied the non-renewable generation unit threshold (1 MW) for assessing gross load billing eligibility. Also, where appropriate, Hydro One has relied on its practice of using the inverter to delineate units within an energy storage facility, consistent with its approach for treating inverter based generation[53].

In VECC's view there are three issues to be addressed with respect to the UTR Schedule's application to storage facilities:
i. Should storage facilities be subject to gross load billing?
ii. If subject to gross load billing, should the application of gross load billing threshold be on a per unit (i.e., inverter) basis or a per facility basis?
iii. If subject to gross load billing, what is the applicable threshold?

Should Storage Facilities Be Subject to Gross Load Billing

In VECC's view the answer to this question is closely related to:
i. How the anticipated impact of storage facilities are treated for purposes of the transmitter's connection impact assessments, cost responsibility at the time of connection and long term planning.
ii. Whether there are any material differences in the cost of administering gross load billing for storage facilities as opposed to embedded generation.

With respect to the first point, HONI's response to VECC 16 b) indicates that the treatment of storage facilities is the same as that for embedded generation (i.e., the system is planned to account for the scenario that this embedded generation may not be available or not be at full capacity when the peak is reached[54]).

With respect to the second point, the responses to VECC 23 indicate that: i) the customer's cost for metering in order to implement gross load billing is the same storage facilities as for other types of embedded generation and ii) from the IESO's perspective, the effort and cost to administer the settlement process for an energy storage facility as compared to any embedded generation facility is the same.

Based on these responses, VECC submits that storage facilities should be subject to gross load billing.

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[52] Issues 5 and 6, page 8
[53] Issus 5 and 6, pages 8-9
[54] Reponses to Clarifying Questions, VECC-9 b)

Gross Load Billing Threshold Application (per Unit or per Facility)

Consistent with VECC's submissions regarding Issue 5.1, VECC submits that the application of any gross load billing threshold to energy storage should be on a per facility basis.

HONI has indicated[55] that, to-date, approximately 72 MW (25 projects) of existing and 32 MW (15 projects) of planned storage capacity have been identified as being subject to gross load billing. Changing the application of the threshold to a per facility basis (as opposed to an inverter basis) would lead to approximately an additional 68 MW (28 projects) of existing and 134 MW (40 projects) of planned storage capacity being subject to gross load billing assuming the same 1 MW threshold.

Again, VECC acknowledges that if the OEB changes the basis for the application of the gross billing threshold from a "per unit" to a "per facility" basis then consideration should be given to grandfathering the definition of the gross load billing threshold for the existing storage facilities/units. In this regard, "existing storage facilities" could be defined as those that are in operation or had formally applied for a connection impact assessment on or before the Notice of Hearing date.

Applicable Gross Load Billing Threshold for Storage Facilities

This issue is addressed below as part of Issue 6.1.

2.4. ISSUE #6: GROSS LOAD BILLING THRESHOLDS FOR RENEWABLE AND NON-RENEWABLE GENERATION

2.4.1. Issue 6.1

The approved Issues List sets out Issue 6.1 as follows[56]:

> "What should the gross load billing thresholds be for renewable and non-renewable embedded generation?

VECC notes that HONI's Background Report[57] does not put forward any options (i.e., in terms of suggested thresholds) regarding this issue but rather identifies the need to review the factors that were used to determine the current thresholds remain valid and also to determine if there are other factors that need to be considered in assessing/establishing the appropriate gross load billing thresholds. This view is reiterated in HONI's responses to the clarifying questions[58]. VECC agrees.

As discussed under Issue 5.1 (above) the factors considered by the OEB in establishing the current thresholds were customer costs (e.g., metering), administrative costs (e.g., the IESO's billing and settlement processes) along with government policy as reflected in the OEB's statutory objectives at the time.

In VECC's view, the procedural steps established for the current proceeding have not provided sufficient opportunity for the relevant factors to be identified let alone any

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55 Responses to Clarifying Questions, VECC 17 a) & b)
56 Procedural Order No. 3
57 Issues 5 and 6, pages 11-12 and 19.
58 Responses to Clarifying Questions, VECC-24 a) and VECC-26 a)

assessment made as to how they may impact the appropriate level for the gross load billing impact threshold(s).

Despite this, set out below are VECC's preliminary observations regarding the factors the OEB needs to consider in establishing the thresholds for gross load billing:

- Administrative Costs: Adjustments to the threshold limits for gross load billing would result in an increase/decrease in the volume (i.e., number of facilities) that would need to be registered with the IESO for gross load billing, which would have impact on the time required by the IESO to input such changes. However, the IESO indicates that any increase in registration volume can be accommodated by IESO and would not require any changes to IESO billing systems[59]. As a result, while this may be factor for consideration, in VECC's view it does not appear to be one that warrants significant consideration.
- Metering Costs: HONI notes[60] that for LDCs with embedded retail generators, gross load billing settlement is performed based on the existing metering that is used to pay the embedded retail generator. As a result, there are no additional meter costs. In contrast, for C&I load customers with load displacement generation, customers are required to install additional meters based on the IESO Market Rules and Manuals. Such metering costs are paid for by the customers. However, HONI has indicated that metering infrastructure costs are not readily available. While the impact of such costs may impact the economics of project, VECC would anticipate that the incremental cost would be small relative to the overall project cost unless the project itself was extremely small.
- Planning Materiality: It is not clear whether or not HONI applies any materiality thresholds when accounting for embedded generation in it its long-term planning for future transmission requirements. In VECC's view generation is treated by the IESO and HONI for these purposes is a relevant factor in determining the threshold(s) for gross load billing and warrants further investigation.
- Cost Shifting: HONI has indicated[61] that gross load billing currently accounts for 1.6% of the Line Connection Service revenues and 1.4% of the Transformation Connection Service revenues. In VECC's view another relevant factor to be considered is the impact that any change in the gross load billing threshold (in conjunction with VECC's recommendation that the threshold be applied on a per facility as opposed to per unit basis) will have on the overall revenue collected through gross load billing. It will provide an indication as to the overall impact the change(s) will have on both: i) the transmission costs to be recovered from those customers subject to gross load billing and ii) the transmission costs to be recovered from the balance of the system's transmission customers.

VECC does not see any need or justification for gross load billing thresholds to be different as between renewable and non-renewable generation. As noted in VECC's submissions regarding Issue 5.1, section 1 of the OEB Act no longer includes as one of the OEB's statutory objectives: "To promote energy conservation, energy efficiency, load management and the use of cleaner energy sources, including alternative and

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[59] Responses to Clarifying Questions, VECC-25 b)
[60] Responses to Clarifying Questions, SEC-5
[61] Responses to Clarifying Questions, ED-7 c) & d)

renewable energy sources, in a manner consistent with the policies of the Government of Ontario." Furthermore, as wind, solar and energy storage are known and proven technologies, VECC submits that establishing higher gross billing thresholds for them cannot be view as furthering the OEB statutory objective to "facilitate innovation in the electricity sector". Indeed, favouring such technologies could be viewed as being inconsistent with the OEB's statutory objective to ''promote economic efficiency and cost effectiveness in the generation".

2.4.2. Issue 6.2

The approved Issue List set out Issue 6.2 as follows:

> "Should gross load billing exemptions be available in certain limited circumstances?

HONI's Background Report has identified two circumstances where it may be appropriate for a transmitter to exempt a customer from gross load billing. The first is when a customer applies to connect a new load or increase their existing load but the transmission system is constrained and cannot accommodate their requested connection or full load. The Report indicates that, if the customer installs embedded generation to meet their supply needs, it may be appropriate to exempt their embedded generation from gross load billing in full or to the extent the embedded generation is required to meet their supply needs[62].

VECC agrees that an exemption from gross load billing could be warranted in such circumstances. However, the customer would also need to commit to having the necessary combination of operating procedures and equipment in place to ensure that its load did not exceed the transmission system's capability in the event its embedded generation was not available.

The second circumstance identified in the Report[63] is when a customer installs embedded generation for the sole purpose of "peak shaving" and mitigating their Class A Global Adjustment charges under the Industrial Conservation Initiative. In this scenario, the embedded generation is run only at select times to reduce the customer's non-coincident peak demand during anticipated Ontario peak demand hours over a base period. The Report notes that where embedded generation is being deployed in this manner, it results in only a marginal impact to the customer's monthly non-coincident peak demand and it may therefore be appropriate to exempt such embedded generation from gross load billing.

VECC does not support providing an exemption to gross load billing under such circumstances. First, VECC questions whether it possible to determine those circumstances where a customer installs embedded generation for the sole purpose of "peak shaving" and mitigating their Class A Global Adjustment charges under the Industrial Conservation Initiative. Furthermore, even if it was, there is no guarantee that the customer will continue to use the embedded generation for such purposes on a going forward basis. Second, if the operation of the embedded generation only has a

[62] Report, Issues 5 and 6, pages 13-14.
[63] Issues 5 and 6, page 14

marginal impact on the customer's monthly non-coincident peak demand then there are little to no savings to be gained by the customer from such an exemption.

In its clarifying questions Environmental Defense[64] raised a third possible circumstance where an exemption may be warranted. The scenario put forward was one where there were existing/emerging limits on the transmission system's capability to meet serve load and an existing customer undertook to relieve the constraints by installing embedded generation and, thereby, reducing their load. In its response HONI agreed that an exemption could be warranted in such circumstances. However, HONI then went on to note that the transmission customer would need to forego the capacity originally built on the transmission system to supply their load and which is now being displaced by embedded generation.

VECC agrees with HONI's response. However, it is VECC's view that the transmission customer would also need to commit to having the necessary combination of operating procedures and equipment in place to ensure that its load did not exceed pre-specified levels in the event its embedded generation was not available

2.5. CONCLUSION

As suggested by VECC's preceding comments, while the outcome of the current proceeding can provide a policy framework for addressing issues related to double peak billing and the application of gross load billing thresholds, additional work is still required to work through the necessary details. VECC looks forward to working with the OEB and other interested parties on these matters.

[64] Responses to Clarifying Questions, ED-07 b)

BONBRIGHT'S ATTRIBUTES OF A SOUND RATE STRUCTURE[65]

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality or safety.

2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use:

a. in the control of the total amounts of service supplied by the company.

b. in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no inter-customer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

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[65] The Principles of Public Utility Rates, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports Inc., pages 383-4.