**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Ontario Energy Board Act*, 1998
S.O. 1998, c. 15, Schedule B, as amended;

**AND IN THE MATTER OF** a Generic Hearing on Uniform
Transmission Rates Related Issues

**JOINT SUBMISSION OF:**

Niagara-on-the-Lake Hydro Inc.
Canadian Niagara Power Inc.
Enwin Utilities Ltd.
Entegrus Powerlines Inc.
Halton Hills Hydro Inc.

**Submitters**

This is a joint submission of Niagara-on-the-Lake Hydro Inc., Canadian Niagara Power Inc., Enwin Utilities Ltd., Entegrus Powerlines Inc. and Halton Hills Hydro Inc. (collectively "the LDC Transmission Group"). This submission is also supported by a number of other LDCs who are not intervenors but who have the same issue and who have provided additional evidence. These LDCs include:

Milton Hydro Distribution Inc.
Kingston Hydro Corporation
Wellington North Power Inc.
Hearst Power Distribution Company Ltd.
Renfrew Hydro Inc.

## Executive Summary

This submission is solely focused on Issue 4.

The LDC Transmission Group comprises of 5 LDCs whose customers are charged incremental transmission costs due to double peak billing. It is also supported by 5 other LDCs whose customers have the same issue. Not every LDC has issues with double peak billing, some have delivery point configurations that preclude the potential for double peak billing, but it is known that there are a number of other LDCs who have double peak billing issues but who are not a party of this evidence.

Double peak billing occurs when the monthly bill an LDC receives for transmission services is higher than it would be have been if the transmission services were all from one delivery point or if the delivery points had been totalized for the purposes of transmission billing. Significant double peak billing charges occur when there has been a planned or unplanned outage and the load is shifted between delivery points during the month. The LDC Transmission Group believes it to be unfair for its customers to incur these additional charges, which can be very significant, while others do not. The idea that transmitters get paid more when they have an outage is also bad optics. The LDC Transmission Group notes that, as these charges flow through to the final customers, the LDCs themselves are not financially affected; only their customers. Double peak billing can occur whether an LDC is connected directly to the transmission grid or connected at the distribution level.

Numerous examples of double peak billing at a variety of LDCs under a variety of scenarios have been provided along with the impacts of the double peak billing on their customers.

The LDC Transmission Group is providing two solutions to this issue. The first is to allow the totalizing of delivery points. This would eliminate the double billing issue in situations where this can be implemented. Recognizing the concerns with this proposal that Hydro One raised in their background report, the LDC Transmission Group is proposing that LDCs would need to apply to the OEB for delivery points to be totalized on a go forward basis. This would allow the OEB staff, Hydro One or other intervenors to raise objections if they did not believe totalizing would be appropriate for the particular situation.

Totalizing of delivery points can be implemented in situations where the delivery points are all transmission-connected or all distribution-connected with the same transmitter. The LDC Transmission

Group recognizes that the OEB limited this hearing to transmission-connected customers but believes this solution is easily implemented for both situations and encourages the OEB to consider implementing it for distribution-connected customers with a single transmitter as well as part of the hearings findings.

The second proposed solution, for situations where totalizing would not work, such as for LDCs that are both transmission and distribution connected, is for a working group to be established to see if they can develop a working approach to the deferral account that Hydro One proposed as option #4 in their background report. This working group recommendation will allow this hearing to stick more closely to the OEB approved scope of transmission-connected customers only while also ensuring that the momentum from this generic hearing is not lost and a subset of customers is not burdened with double peak billing for an indeterminant future period.

## Issue Description

This submission is solely focused on Issue 4. The Ontario Energy Board (OEB) has succinctly described the issue as:

**Charges caused by planned transmission outages.**

*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 LDC Transmission Group agrees with this description though would add that this issue also exists for unplanned transmission outages as these can also cause a load transfer in order to return power to customers as quickly as possible. A planned transmission outage may also be instigated by either the transmitter or the customer depending on a range of factors.

Double peak billing also occurs naturally with multiple delivery points as the peak at each delivery point will not be coincidental due to natural variations in demand across customers. Generally, the incremental cost from this variation is not significant though it is real.

In its Procedural Order No. 3, dated July 5, 2024, the OEB limited this hearing to only transmission-connected customers. The LDC Transmission Group recognize this though, as Entegrus pointed out in their following letter of July 10, 2024, *"transmission-connected double-peak billing and distribution-connected double-peak billing are fundamentally intertwined"*. Hydro One also recognized this in their Background Report as they deliberately included examples with distribution-connected customers and argued that "*It is Hydro One's view that, for the following two reasons, the distribution issues will also need to be addressed either in parallel to or after the transmission issues are addressed as part of the current proceeding: First, from a consistency perspective a decision in respect of transmission-connected customers can be applied on the distribution side, provided that customers who may be impacted by the decision are involved in the proceeding. Second, as explained in detail in Sections 1.4.2.2, 1.4.3.2, and 1.4.4.2 below, there is an anomalous/unfair outcome for customers if double-peak billing issues are resolved for transmission[18]-connected customers but not for distribution-connected customers."*

The LDC Transmission Group also support providing a decision for distribution-connected customers either as part of this hearing if feasible and workable or as soon as possible thereafter. Some members of the LDC Transmission Group are either solely distribution-connected or both transmission-connected and distribution-connected. This evidence will include proposals to address both transmission-connected customers and distribution-connected customers. This evidence will also include examples of both recognizing that while distribution-connected customers may not be part of the decision from this hearing there will remain significant double-peak billing issues that will need to be addressed.

The incremental charges are an issue for the customers of a local distribution company (LDC) rather than for the LDC itself. Differences in transmission revenues and costs are booked to a variance account. If the transmission outage results in higher transmission costs, then this will result in higher rates than would have been the case by means of a rate rider to clear the variance account. For the LDC, this becomes a cash flow timing issue which could be significant. For the distribution customers of that LDC, this is a higher electricity bill. The LDC Transmission Group wish to protect their customers from these incremental charges so have intervened in this hearing.

There are a variety of situations in which this incremental billing can occur. The LDC can have more than one transmission station that can serve the same distributions customers connected to the IESO managed transmission grid or the LDC can have more than one station connected to Hydro One sub-transmission lines that can serve the same distribution customers. It is also possible that the incremental charges can be created by transfers between feeder lines coming out of one station if the feeder lines are separately metered. The LDC can own the stations, Hydro One can own the stations or the ownership of the stations can be shared. The stations can also be dedicated or can serve multiple LDCs.

In some situations, LDCs can take actions to reduce the financial impact of planned transmission outages on LDC customers but these have their own side effects. For instance, when a transmission outage is planned, the LDC could plan to transfer the load to another delivery point or several other delivery points for the entire month. This significantly reduces the incremental charge as the monthly peak at the in-use delivery point will be roughly equivalent to the combined likely monthly peaks of the two delivery points under normal circumstances. The side effects of this action can include the following:

- With all the load on the one delivery point, the impact of an unplanned transmission outage becomes much more significant than it would otherwise be. The risk of this occurrence is now also for the full month rather than just the time of the planned transmission outage.
- Future regular outages may be prolonged due to the extra switching involved.
- The feeder set-up from the one delivery point will not be as effective as from the two delivery points. This can result in voltage issues for customers which would otherwise not be the case.

- In order for this strategy to be effective, the switching from two delivery points to one and back again must occur just before midnight on the last day of the month before the planned transmission outage and just after midnight in the month following the planned transmission outage. This may require overtime work of the LDC staff with its associated costs and could potentially have increased safety risks.

In other situations, this cost minimizing action is not possible such as if there is not the capacity for the load be carried by the alternative delivery points for the full month.

Several of the intervening and supporting LDCs have had experiences in the past with Hydro One reimbursing them or not charging them for the incremental cost of the planned outage. However, this has not been offered by Hydro One for a number of years.

One of the ironies of this issue is that the beneficiary of almost all the incremental charges is Hydro One through their share of the Uniform Transmission Rates. While we are in no way implying that Hydro One is doing anything other than maintaining its transmission line using best practices, the optics are not optimal. Explaining to customers that they will be charged more because there was a transmission outage is also a challenge.

It should be noted this issue has no impact on the revenue requirements of transmitters. Rather, it is on how the resulting UTR rates are determined. Based on the interrogatories on the Hydro One submission of April 2, 2024, it is understood that the incremental revenue from double-peak billing has been built into the determination of UTR rates.

Finally, it is understood by the LDCs that the adjusting actions being taken by the LDCs to reduce the incremental transmission charges has an operational impact on Hydro One. Not having to plan for prolonged delivery point outages or for increased coordination with the local LDC on the timing of maintenance activities would simplify operations for Hydro One.

## The LDC Transmission Group Experiences

The following are the experiences of the LDC Transmission Group with this issue and their impact on their distribution customers.

### Niagara-on-the-Lake Hydro Inc. (NOTL Hydro)

NOTL Hydro is supplied by the Hydro One 115 kV Q11S and Q12S transmission lines through two transformer stations. York Station (NOTL MTS 1) is connected to Q12S and NOTL Station (NOTL MTS 2) is connected to Q11S.

Each station has the capacity to serve the entire NOTL Hydro load and each is 100% owned by NOTL Hydro. York Station has one 83 MVA transformer while NOTL Station has one 50 MVA transformer and one 41.7 MVA transformer. Each transformer is separately metered. For the purposes of transmission billing the two meters at NOTL Station are totalized.

As the OEB issues list has described, each delivery point (station) is charged based on its monthly peak. For most months, the sum of the two monthly peaks is close to the total distribution peak and the incremental cost is not significant. If a planned outage is required by either Hydro One or NOTL Hydro, the affected station will be taken offline for the entire month. NOTL Hydro tries to coordinate with Hydro One so that both utilities are using the station outage for their required maintenance work. While this avoids most of the incremental transmission charges it does create other issues including some voltage issues for some customers and overtime for NOTL Hydro staff at the start and end of the month. One important note, NOTL Hydro tries to manage the maintenance so that each evening the station with the outage could be brought back online if needed.

Three examples of double-billing are provided:

In October 2021, Hydro One had a planned outage on the Q11S so the entire NOTL Hydro load was moved to the York station (which is fed by Q12S) for that month to reduce the incremental transmission charges. On October 9, 2021, the Q12S transmission line lost power. The entire Town of Niagara-on-the-Lake was out of power. NOTL Hydro had to make the decision of waiting to see if the outage was short-lived or of bringing the power back up using the NOTL Station. As it was clear the outage was more than temporary and as the duration of the outage was unknown, the decision was made to bring the power back up using NOTL Station. As a result, at some point during the month, each station was carrying the full

NOTL Hydro load. NOTL Hydro estimate's the incremental transmission charge for this month to be around $90k or over $9 per customer.

In May 2024, Hydro One notified NOTL Hydro that a hot spot had been identified on the radial portion of the Q11 transmission line feeding the NOTL Station. Arrangements were made to take the NOTL Station out of service for the full month of June to allow for the necessary service work and to avoid the double peak billing. The full load was transferred to the York Station. On June 13, 2024, a fault occurred on one of the feeder lines egressing the York Station. To make the necessary repairs and to ensure NOTL Hydro had full capacity before the summer heat, the full load was transferred to the NOTL Station (Hydro One had completed their work by this time). As a result, both stations ended up carrying the full load at some point during the month. NOTL Hydro estimates the double transmission billing to be $229k or $23 per customer.

On July 17, 2024, Hydro One took the Q11S offline due to gas alarms at one of their transformers. The Q11S feeds the NOTL Hydro NOTL Station. NOTL Hydro transferred the affected load to its York Station. The Hydro One outage lasted around 2 1/2 hours. Once service was restored, NOTL Hydro transferred the affected load back to its NOTL Station. NOTL Hydro estimates the double transmission billing to be $147k or $15 per customer. Explaining to our customers that they will be charged more because Hydro One had an outage remains a challenge.

**ENWIN Utilities Ltd. (ENWIN)**

ENWIN is currently supplied by Hydro One Networks Inc. ("Hydro One") transmission lines through nine (9) delivery points or transformer stations. ENWIN's service territory also has three (3) additional transformer stations which are dedicated for use by wholesale market participants. Of these transformer stations, six (6) are owned by Hydro One, five (5) are owned by ENWIN, and one (1) is owned by a customer.

ENWIN is the registered transmission customer at each of these delivery points and thus attracts monthly transmission charges billed by the Independent Electricity System Operator ("IESO"). The billing method for line and transformation connection transmission charges ("transformation charges") is based on a "per delivery point basis" and is defined as the non-coincident peak demand in any hour of the month at that delivery point. This billing method can reasonably reflect cost causality in some instances when the sum of the monthly peaks at each delivery point is close to the aggregate peak for ENWIN's service territory.

However, that is often not the case when ENWIN is asked or required to make temporary changes to its system to accommodate various system needs.

For example, ENWIN is asked by the transmitter to transfer load from one delivery point to another to facilitate its work or accommodate a request from the IESO to reconfigure the transmission system. While this work may be unrelated to the ENWIN distribution system, ENWIN strives to accommodate these requests, utilizing the flexibility that has been built into its distribution system and its multiple delivery points to efficiently manage outages on the collective system and cooperate with its transmitter. With respect to requests originating from the IESO, ENWIN is generally required to cooperate.

Being cognizant of the available capacity of the delivery points serving its territory, ENWIN may also transfer load between delivery points to facilitate its own work, or to ensure continued service during an unplanned outage (e.g. loss of supply, weather event, etc.), where other delivery points have available capacity. ENWIN will return the load back to the original delivery point as soon as possible to reduce the strain on its distribution system and continue to provide safe, reliable, and high-quality service for its customers. This flexible and collaborative approach to operating the integrated electricity system and managing outages has been a hallmark of industry for decades and is something ENWIN continues to support.

However, these prudent operational decisions can have an impact on the transmission charges ENWIN incurs. Where ENWIN temporarily transfers load between two delivery points within the same month, the non-coincident peak demands used for billing will increase such that ENWIN will pay higher transmission charges in total, even though these peaks occurred at different times, and the overall system peak for the service territory is unchanged. In other words, temporary load transfers can cause "double peak billing" even though the overall demand and strain placed on the transmission system is unchanged. This would not occur if, for example, transmission charges were billed on the monthly coincident peak for the service territory as a whole, or some other form of coincident peak billing which removes the impact of intra-month load transfers between delivery points from influencing the level of charges assessed.

ENWIN expects double peak billing to become more prevalent in the future as its systems are progressing to a point where automated switching may occur to accommodate various system needs. This increasing system flexibility offers tremendous benefits to customers, allowing service to be maintained in the event of system upset, as well as enabling the connection of new and varied resources that present different strains on the system.

ENWIN strives for operational excellence, managing its system in a manner which provides safe, reliable, and high-quality services while doing its part to facilitate the energy transition. Therefore, it is ENWIN's position that the Ontario Energy Board should reconsider the approach to transmission charge billing to ensure that it properly reflects cost causality and to ensure that the billing method is consistent with, and does not deter, otherwise prudent operation of an increasingly dynamic system.

**Halton Hills Hydro Inc. (HHHI)**

HHHI is supplied by Hydro One at 230 kV T38B/T39B, H29/H30, and D6V/D7V transmission lines through four transformer stations. Fergus Station is connected D6V/D7V and supplies HHHI via a metering point on the M4 feeder (44 kV) shared with Hydro One, Alectra and Milton Hydro Distribution Inc. Halton TS is connected to the T38B and T39B and supplies HHHI via the M21, M29, and M30 feeders (27.6kV). The M21 Feeder is shared with Hydro One Dx, while the M29 and M30 feeders are dedicated to HHHI via a Tx agreement. Pleasant TS is connected H29/H30 and supplies HHHI via three dedicated express feeders, the M23, M25, and M28 (44 kV). Additionally, the HHHI owned Halton Hills MTS is connected to the T38B and T39B via the Halton Hills Generating Station Facility (HHGS CGS). The HH MTS facility is metered on each transformer at the 230 kV level.

Each feeder/transformer is separately metered. For the purposes of HONI transmission billing, the three meters/ feeders at the Pleasant Station are totalized.

Two examples of double peak billing are provided.

In October 2022, Hydro One Networks Inc. indicated that they would be shutting down the Pleasant TS to install safety fencing and as such, requested that HHHI transfer load off the 3 HHHI feeders at Pleasant onto other feeders. The 3 feeders at Pleasant account for approximately half the load that HHHI utilizes for the distribution system. HHHI determined that only half the Pleasant load could be moved over to other feeders and that an outage would still result for approximately a quarter of all customers. HHHI negotiated with HONI to perform the work on a Saturday morning for a duration not exceeding 5 hours. However, even if the partial switch was conducted at that time, HHHI estimated a double peak billing of approximately $100,000 or approximately $4 per customer through RSVA account dispositions, including some of whom would still have been without power. To ensure the most equitable result, HHHI took the full outage for the duration to ensure that customers were not forced to pay additional costs through double peak billing.

On October 27, 2023, Hydro One identified a deficient piece of equipment in the Halton TS, which required a 48-hour total outage for replacement. HHHI has 3 feeders out of Halton TS. Moving load off the Halton TS onto other feeders for a 48 hour timeframe would result in double peak billing on the other feeders. Based on a mitigation strategy, to minimize costs while also achieving system reliability, HHHI decided to offload the Halton TS at around midnight February 1st, 2024 and to keep as much of Halton TS offline as possible for the entire month of February while maintaining system reliability. Load was moved just after midnight to HHHI's MTS #1 (the only feeders able to handle the load) and was moved back around midnight on February 29th, 2024. This eliminated the double peak billing on the Halton TS feeders, however, additional OM&A costs were incurred to have crews available for switching around midnight on the dates identified. It was a result of HHHI's MTS#1 having available capacity that avoided the double peak billing.

**Milton Hydro Distribution Inc. (Milton Hydro)**

Milton Hydro serves approximately 44,000 customers in the Town of Milton, Ontario. The Milton Hydro distribution system is supplied by a mix of direct connections to the IESO/Hydro One Networks Inc. (HONI) transmission system, and embedded connections to HONI and Oakville Hydro Electricity Distribution Inc. distribution systems.

Milton Hydro's 27.6kV distribution system is supplied from four Hydro One owned Transformer Stations (TS), (Halton TS, Tremaine TS, Palermo TS & Fergus TS) and one owned by Oakville Hydro (Glenorchy MTS). Transferring load between TSs causes double peak billing.

On October 27, 2023, Hydro One identified a deficient piece of equipment in the Halton TS, which required a 48-hour total outage for replacement. Halton TS is the largest load serving TS in Milton Hydro's territory. A 48-hour outage at Halton TS required that all nine (9) feeders from Halton TS out of a total of seventeen (17) feeders between all stations was required to be offloaded to Tremaine TS, Palermo TS and Glenorchy TS.

Milton Hydro analyzed the scenarios for double-peak billing to determine what the best course of action would be for Milton Hydro and its customers.

Table 1 below provides the incremental transmission costs that Milton Hydro and its customers would have been exposed to if Milton Hydro agreed to Hydro One's original request to perform the maintenance work on a weekday. Total incremental cost of $642K would have been expected due to double-peak billing for the 48-hour Halton TS outage on a weekday, $196K related to Transmission-Connection facilities and $446K related to Distribution-Connection facilities.

**Table 1: Scenario 1- Total Incremental Transmission Cost Estimate for 48-hour Weekday Outage**

| Transmission Source | Incremental Transmission Connection Costs: | Incremental Transmission Network Costs: | Total Incremental Transmission Costs |
|---|---|---|---|
| Transmission-Connected | $80,843.35 | $115,681.10 | $196,524.45 |
| Distribution-Connected | $187,212.67 | $258,458.07 | $445,670.74 |
| Total | $268,056.02 | $374,139.17 | $642,195.19 |

Table 2 below provides the incremental transmission costs that Milton Hydro and its customers would have been exposed to if Milton Hydro had implemented the 48-hour outage over only a weekend in February. Total incremental cost of $213K would have been expected due to double-peak billing for the 48-hour Halton TS outage on a weekend, $64K related to Transmission-Connection facilities and $149K related to Distribution-Connection facilities.

**Table 2: Scenario 2 – Total Incremental Transmission Cost Estimate for 48-hour Weekend Outage**

| Transmission Source | Incremental Transmission Connection Costs: | Incremental Transmission Network Costs: | Total Incremental Transmission Costs |
|---|---|---|---|
| Transmission-Connected | $64,457.00 | $0.00 | $64,457.00 |
| Distribution-Connected | $148,650.83 | $0.00 | $148,650.83 |
| Total | $213,107.83 | $0.00 | $213,107.83 |

Milton Hydro also looked at a third option, Scenario 3, based on a mitigation strategy, to minimize costs while also achieving system reliability. This option was to offload the Halton TS at around midnight at the end of the month of January and to keep as much of Halton TS offline as plausible for the entire month of February while maintaining system reliability. Total incremental cost of $76K would have been expected due to double-peak billing based on Milton Hydro's mitigation strategy, ($180K) related to Transmission-Connection facilities and $256K related to Distribution-Connection facilities.

Milton Hydro decided to implement Scenario 3, the mitigation strategy to minimize costs for customers while still maintaining system reliability. Due to system constraints, three (3) of nine (9) feeders at Halton

TS could not be transferred other than during the 48-hour full Halton TS outage which was taken during low-loading periods over the weekend of February 3rd and 4th. The other six (6) Halton TS feeders were offline for the full month of February. Table 3 provides the resulting incremental transmission costs that Milton Hydro incurred due to the deployment of this strategy.

**Table 3: Scenario 3 - Total Actual Incremental Costs Incurred Based on Mitigation Strategy**

| Transmission Source | Incremental Transmission Connection Costs: | Incremental Transmission Network Costs: | Total Incremental Transmission Costs |
|---|---|---|---|
| Transmission-Connected | -$25,392.59 | -$154,272.02 | -$179,664.61 |
| Distribution-Connected | $113,821.20 | $142,410.43 | $256,231.63 |
| Total | $88,428.60 | -$11,861.59 | $76,567.01 |

**Implementing the mitigation strategy resulted in an estimated savings of approximately $565K vs Hydro One's original 48-hour weekday outage, and system reliability was maintained, $189K related to Transmission-Connection facilities and $376K related to Distribution-Connection facilities.**

The above mitigation strategy was successful as a result of its implementation; however, there were additional costs borne by Milton Hydro and operational risks that Milton Hydro was exposed to as a result of implementing this strategy:

- Operating with more customers on fewer feeders for the month of February increased the reliability risk in case of an unplanned outage, with potentially higher number of impacted customers with longer outage restoration time, negatively impacting MHDI's reliability metrics. This risk was mitigated by ensuring that Halton Feeders were available for load transfer for a faster outage restoration (other than during the required 48-hour outage)
- Significant planning and engineering time was required to plan out switching and optimize load re-distributions of an entire station (9 of 17 total system feeders).
- Around $21k in labour and overtime costs for power line technicians and system operators who had to perform switching in a short window at around midnight on February 1st, the weekend of February 3/4, and March 1st.
- Some customers experienced voltage issues due to the switching (within CSA limits). This was because they were further away from the previous supply point. This issue was mitigated by switching them back to the original feeder.

**Kingston Hydro Corporation (KHC)**

KHC has a contiguous distribution area that is supplied from Hydro One Frontenac station (115kV) and Hydro One Gardiner DESN1 station (230kV) via seven 44kV sub-transmission feeders.

Each 44kV sub-transmission feeder is metered separately and used for the following settlements:

- Frontenac M2, M4, M5 Dedicated Feeders - the three feeder meters are totalized and monthly demand charges are billed at the applicable HONI Transmission rates.
- Gardiner DESN1 M7, M9, M12 Dedicated Feeders – the three feeder meters are totalized and monthly demand charges are billed at the applicable HONI Transmission and HONI Distribution rates
- Frontenac M3 Shared Feeder – monthly demand charges from this feeder meter are billed at the applicable HONI Transmission and HONI Distribution rates
- The seven meters above are totalized for IESO monthly wholesale energy purchase settlements

The KHC distribution system configuration and operation is as follows:

- Tie switches exist between the dedicated 44kV feeders of Frontenac and Gardiner DESN1 that allow KHC to routinely transfer load between the two stations. KHC frequently transfers 5-12MW between the two stations. In some instances, KHC has transferred load from an entire station (ranging from 25-50MW depending on the time of year).
- Sometimes the load transfers are for the benefit of Hydro One operations and sometimes the load transfers are for the benefit of Kingston Hydro operations.
- Load transfers can result in double billing because Frontenac and Gardiner DESN1 have separate settlement points. For example, the incremental monthly cost for an 8MW load transfer at peak times could be as much as $80K.

**Wellington North Power Inc. (WNP)**

WNP is an embedded distributor within Hydro One's service territory and is connected to the grid through Hydro One's Transmission Station feeders as per table below:

| Feeder | Feeder # | Dx Supply Point | WNP Community Serviced | Notes |
|---|---|---|---|---|
| Fergus TS 73M1 | Fergus M1 | Fergus T.S. (NA73) | Arthur | |
| Hanover TS 36M5 | Hanover M5 | Hanover T.S. (NA36) | Mount Forest | *Normal open point between the Hanover M5 and the Palmerston M2 is located within the distributor's territory* |
| Palmerston TS 28M2 | Palmerston M2 | Palmerston T.S. (NW28) | Mount Forest | *Normal open point between the Palmerston M2 and the Hanover M5 is located within the distributors territory* |
| Holstein DS F3 | Holstein F3 | Holstein D.S. (GE632) | Holstein | |

In December 2016, WNP energized a new second 44 kV line to supply the Town of Mount Forest – one of WNP's service territories. This new 44 kV line runs from Hydro One Networks Inc.'s Palmerston Transmission Station and HONI named this Distribution Supply Point 'LIS6BENT-LBS'. New Primary Meter Equipment was installed at the demarcation point between HONI and WNP and consequently, this is a new delivery point that HONI can charge WNP. (Prior to this new second 44 kV line, Mount Forest was solely fed by the HONI's 44 kV line from HONI's Hanover Transmission Station.) Consequently, since December 2106, the Town of Mount Forest is fed by two HONI 44 kV lines – one from HONI's Hanover Transmission Station and the second from HONI's Palmerston Station.

The Town of Mount Forest's monthly peak demand is typically between 9,000 kW to 11,000 kW. With two 44 kV lines supplying Mount Forest, the combined kW demand of both lines therefore should be between 9,000 kW and 11,000 kW per month. Since the energization of a second 44 kV line, there have been 17 instances where HONI has invoiced WNP a "double-peak demand charge", that is the aggregated peak demand of the two PME metered supply points.

WNP acknowledges that having two supply feeds to the Town of Mount Forest are beneficial both to the LDC and HONI (e.g. switching during a power outage or maintenance work when load can be transferred to avoid / minimize power outages to WNP and/or HONI customers.

One instance of "double-peak demand billing" occurred on February 17, 2023, the 44 kV supply from Hydro One's Palmerston Transmission station (feeder Palmerston M2) was interrupted resulting in a Loss of Supply to embedded distributor Wellington North Power Inc. (WNP). During the Loss of Supply, a large section of Mount Forest was without power. Power was restored by both HONI and WNP line-switching to enable the whole Town of Mount to be fed from HONI's Hanover TS (feeder Hanover M5). The outage duration was 156 minutes affecting 42% of WNP's customers. Later in the month, HONI and WNP performed line-switching to return the system back to normal configuration. The Low-Voltage components of HONI's invoice for February 2023 totaled $41,084 which is approx. $11,000 more than the monthly average LV Invoiced amount for 2023 (excluding double-peak demand charge months of July 2023 and September 2023) or approx. $3 per customer.

In its 2021 Cost of Service application (EB-2020-0061), WNP included "double-peak demand charge" information Exhibit 8 and Interrogatory Response 8-Staff-78 noting that *"HONI (and its' customers) are billed for the double-peak by the IESO under the UTR schedule. As a suggestion to the OEB, one approach to resolving this matter could be for the IESO to adjust the UTR billing requirements such that the double peak charge is not billed to HONI, in which case HONI would not have to pass the double peak charge on to embedded LDCs."*

**Hearst Power Distribution Co. Ltd. (Hearst Power)**

Hearst Power purchases electricity and pays charges to both the IESO and Hydro One for the electricity in Hearst Power's network via three feeders: M1, M2, and M3. One feeder, M2, is billed by the IESO and owned by Hearst Power, while the other two, M1 and M3, are billed and owned by Hydro One. All feeders are connected to the Hydro One Hearst Transformer Station, "Hearst TS," which is the only station in this area.

Both the IESO and Hydro One, bills its Network, Connection, and Transformation charges to Hearst Power based on the highest kW demand at any point in time during the month, according to the feeder readings. To illustrate, the typical electricity demand for the month of April is 5 MW on the Hearst Power IESO feeder (M2) and 8.5 MW on the Hydro One feeders combined (M1 and M3), equivalent to a total demand of 13.5 MW.

In April 2021, Hydro One made repairs at the Hearst TS and transferred the load from the M3 feeder onto the M2 feeder for a few days, temporarily increasing the demand on the M2 feeder to 10.65 MW, while bringing the demand on the M3 feeder to 0 kW during this time. Since the M2 feeder had a higher demand during the repairs, it was billed for 10.65 MW (approximately $50,000 more than usual) but the demand charges for the M1 and M3 feeders remained the same as usual at 8.4 MW, resulting in a total demand charged of 19 MW for April, instead of 13.5 MW which was the combined max demand at any point in time during that month.

Hearst Power customers had to absorb/pay for what is known as "double peak billing," and the extra $50,000 cost is equivalent to $18 per customer. Since these charges are pass through charges, this does not impact the corporation of Hearst Power, but it directly impacts Hearst Power customers' electricity pricing.

**Renfrew Hydro Inc. (RHI)**

RHI is fully embedded in Hydro One territory. RHI is fed normally through Stewartville but can also be fed from Cobden TS. Two recent examples are provided due to Hydro One outages at Stewartville in which they switched the RHI feed to Cobden TS.

September 2018, Additional charge of $76,962, without this amount our costs would have ben $507,409 for the year, so the additional cost increase was 15% or around $18 per customer.

September 2020, Additional charge of $30,114, without this amount our costs would have been $603,985 for the year, so the additional cost increase was 5% extra or $7 per customer.

## Recommended Solutions

The LDC Transmission Group reviewed a number of potential solutions to this issue including those provided by Hydro One in their Background report. These include:

- Maintain the status quo (Hydro One Option 1);
- Bill by customer, instead of by delivery point (Hydro One Option 2);
- Totalize meters on an ongoing basis where this makes sense;
- Revise the definition of transmission charge determinants (Hydro One Option 3);
- Track double peak billing impact in a deferral account (Hydro One Option 4).

Each of these will be assessed with the LDC Transmission Group thoughts provided.

**Maintain the status quo (Hydro One Option 1)**
As per the Issue Description above, the experiences provided and their intervention in this hearing, the LDC Transmission Group do not support this Option.

**Bill by customer, instead of by delivery point (Hydro One Option 2)**
As the description by Hydro One of the disadvantages of this option make clear, this is not an ideal solution. While it addresses the double peak billing issue, it creates other issues such as how to apply the discount for customer owned line or transformation assets, the totalizing of transmission peaks across non-contiguous service areas and the calculation of charges for sub-transmission customers. The LDC Transmission Group do not support this option.

**Totalize meters on an ongoing basis where this makes sense**
There is a variation of Hydro One Option 2 that the LDC Transmission Group believes does make sense. In many, but not all, of the LDCs significantly impacted by double peak billing this solution makes sense. Instead of it being a blanket solution across all LDCs, the LDC Transmission Group propose that LDCs be allowed to apply to the OEB to be billed with select delivery points totalized. For some LDCs all the delivery points could be totalized while for others only select delivery points could be totalized. This would allow this option to be applied based on the merits of the situation.

If desired and as part of this solution, parameters could be developed for when it can and should not apply. For instance,

- Non-contiguous service areas should not be totalized.
- Transmission-connected and distribution-connected delivery points should not be totalized.
- Service areas beyond a certain number of delivery points (to be determined) should not be totalized. This would prevent large service areas where many of the delivery points cannot be shared from looking to be treated as one delivery point. However, it could be that certain select delivery points within these service territories could be totalized if merited.

It is not an absolute requirement for these parameters to be developed in advance. It is an option. The nature of the OEB application process will define these parameters over time.

Totalizing selectively is a potential solution for a number of reasons including:

- It is a permanent solution so not requiring adjustments to the monthly settlement process like the meter readings adjustments proposal and not subject to potential disputes like the Hydro One or IESO reimbursement solution.
- Both the IESO and Hydro One already totalize meters so the solution can be functionally implemented.
- LDCs would have to apply to the OEB to have the solution implemented for their specific issues so this allows the OEB to control its roll-out and would allow Hydro One to have input on its roll-out.
- This solution addresses the double billing issue for transmission connected customers which is the focus of this hearing. However, it should be noted that this solution would also address the double billing issue for customers that are solely distribution connected customers with Hydro One as the sole transmitter they are connected to. Some of the examples in this evidence meet this criterion.
- Though it is the dominant transmitter, Hydro One is not the only solution for the purposes of UTRs. Having Hydro One provide reimbursements implies some leakage as the incremental revenue is shared. This solution avoids that issue.
- The OEB application process will also result in this solution being phased in by LDC. This will reduce and stretch out its impact on the setting of UTR rates.

This solution is the preferred solution for customers that are only transmission-connected. It is also the preferred solution for customers that are only distribution-connected with one transmitter. The LDC Transmission Group recognizes that the OEB limited this hearing to transmission-connected customers but believes this solution is easily implemented for both situations and encourages the OEB to consider implementing it for distribution-connected customers with a single transmitter as well.

This solution would address many of the current significant double peak billing situations but will not address them all.

**Revise the definition of transmission charge determinants (Hydro One Option 3)**

As the description by Hydro One of the disadvantages of this option make clear, this is not an ideal solution. From the perspective of the LDC Transmission Group, the biggest challenge with this issue is one of timing. Calculating the impact of double peak billing is not straight forward. Actual peaks are being compared with hypothetical peaks as if the planned or unplanned outage had not occurred. Given monthly timing constraints for transmission billing and potential disagreements on the calculations, the LDC Transmission Group do not support this option.

**Track double peak billing impact in a deferral account (Hydro One Option 4)**

The LDC Transmission Group also support this option though only for situations where the totalizing of meters will not work. Those LDCs that are not able to utilize the option of totalizing their meters can use this option. An example where this solution could be implemented would include where a customer has both transmission connected and distribution connected delivery points with switching between these points. Another example would be if a customer has distribution connected delivery points with more than one supplier such as Hydro One for one delivery point and another LDC for the other. As Hydro One has indicated, for this solution processes will need to be established and a methodology for calculating the double peak billing impact will need to be determined.

The LDC Transmission Group recognizes the challenges with implementing this solution as described by Hydro One in their background report. It also recognizes that this is outside the scope of this proceeding as defined by the OEB in Procedural Order #3 as will always involve distribution-connected customers. Due to this, the LDC Transmission Group recommends that a working group be established comprised of Hydro One, some interested LDCs (including some members of the LDC Transmission Group), OEB staff and any other participants the OEB consider to be appropriate. The working group would be tasked to seeing if they can develop a working approach for the deferral account.

This working group recommendation will allow this hearing to stick more closely to the OEB approved scope of transmission-connected customers only while also ensuring that the momentum from this generic hearing is not lost and a subset of customers is not burdened with double peak billing for an indeterminant future period.