EB-2021-0243/EB-2022-0235
Exhibit N1

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.

Response to Interrogatories

HONI-1:

Reference:
LDC Transmission Group Evidence, Page 2 (Executive Summary)

Preamble:
The evidence refers to the fact that "there are a number of other LDCs who have double peak billing issues but who are not party of this evidence".

Interrogatory:

a) Can the LDC Transmission Group provide an estimate of how many other LDCs have experienced double peak billing issues?

b) Can the LDC Transmission Group provide a sense of how many of these other LDCs are (i) transmission connected only, (ii) transmission and distribution connected, or (iii) distribution connected only?

Response

The LDC Transmission Group has not tried to survey the full LDC community on this issue so does not know the full number. The LDC Transmission Group is aware of at least 10 other LDCs that have identified double peak billing as an issue. The LDC Transmission Group has strong relations with these LDCs and has had conversations with them on this matter. The LDC Transmission Group has not tried to reach out to all LDCs; only those with these close relationships. These are a mix of all three connection types identified (transmission only, transmission and distribution and distribution only). For some of these LDCs the double peak billing is a significant issue while for others it is an issue they can manage by somewhat mitigating the costs but it would still be better if there was a proper solution.

HONI-2:

Reference:
LDC Transmission Group Evidence, Page 2 (Executive Summary)

Preamble:
The first solution proposed by the LDC Transmission Group is to allow totalizing of delivery points.

Interrogatory:

a) Has the LDC Transmission Group had any discussion with IESO regarding the effort and costs associated with updating their billing and settlement systems to adopt this solution?

Response:

The LDC Transmission Group has not had any discussion with IESO regarding the effort and costs associated with updating their billing and settlement systems to adopt this solution. The LDC Transmission Group notes that the IESO did provide a related response to the VECC-25 clarifying question from the HONI background report but that this response was for totalizing all meters for all LDCs and not the more limited totalizing proposed by the LDC Transmission Group. The LDC Transmission Group also notes that some delivery points have multiple meters and the IESO currently totalizes these.

HONI-3:

Reference:
LDC Transmission Group Evidence, Pages 7-17

Preamble:
The evidence provides the experiences of the LDC Transmission Group members related to Issue #4.

Interrogatory:

a) To assist the OEB in better understanding the scope of the issue, can the LDC Transmission Group please indicate how many of the double peak billing examples provided by the LDC Transmission Group members on pages 7 to 17 relate to each of the following situations:
   i. Between only transmission connected delivery point
   ii. Between transmission and distribution connected delivery points
   iii. Between only distribution connected delivery points

Response

The examples provided in the submission were a mix of actual illustrations and generic situations. These are also examples and not all the double peak billing events. Not all the examples were clear on whether the connection points involved were transmission or distribution connected as the focus was on the double peak billing impact. Including the generic situations the best estimate as to the nature of the connections is as follows:

i.	Between only transmission connected delivery points	7
ii.	Between transmission and distribution connected delivery points	3
iii.	Between only distribution connected delivery points	4

HONI-4:

Reference:
LDC Transmission Group Evidence, Page 19

Preamble:
The LDC Transmission Group suggests that LDCs be allowed to apply to the OEB for totalizing select delivery points as a solution to the double peak billing issue. They list a number of parameters that could be used to determine whether totalizing of delivery points should apply.

Interrogatory:

a) Is this a complete list of the parameters the LDC Transmission Group thinks could apply?

b) If these parameters are not developed in advance of any applications to the OEB for totalizing select delivery points, what does the LDC Transmission Group expect the OEB to use in making consistent decisions across applications?

c) Does the LDC Transmission Group believe that this solution could also be applied to other transmission-connected customers, not only LDCs?

d) Please list the disadvantages of the proposed solution of totalizing of select delivery points.

Response:

a) The concept of the parameters arose out of discussions with a stakeholder on this topic. The LDC Transmission Group does not consider their use a requirement but believes their use might facilitate progressing on this issue. The LDC Transmission Group does not have an opinion as to whether the list is complete but would not want to add any items to the list that might prevent valid totalizing opportunities.

b) The OEB decision making process allows for participants to present their views in a manner that promotes consistent decision-making. The OEB also strives for that consistency.

c) The LDC Transmission Group does not have extensive expertise with non-LDC transmission connections but, at first glance, does not see why the solution could not apply if a customer has multiple delivery points that allow for load transfers between these points.

d) One disadvantage is that this solution would still require an application to the OEB to get totalizing approved. It would be nice if a more expeditious solution could be found. A second disadvantage is that it does not address situations that involve both transmission and distribution connected delivery points so a second solution would still need to be found for these.

HONI-5:

Reference:
LDC Transmission Group Evidence, Pages 18-20

Preamble:
The evidence provides recommended solutions to address double peak billing concerns including totalizing of delivery.

Interrogatory:

a) What is the LDC Transmission Group's view on the timing for implementing an OEB decision on any applications to totalize delivery points given that load forecast/charge determinants for transmitters are approved at the time of their respective cost of service applications for the duration of the application period (typically five years)? As a result, any changes to the billing approach during the cost of service application period (once load forecast/charge determinants are approved) would not align with how the load forecast/charge determinants were approved and would result in an inconsistency between how UTRs are set and how customers are charged, leading to an under-recovery of the transmitter's approved revenue requirement.

Response:

The LDC Transmission Group understands the issue HONI is raising but believes the concept of materiality should apply. The Transmission Group notes that in many years there are no double peak billing events at some LDCs so the charge determinants are only in aggregate and not per LDC. The LDC Transmission Group is not adverse to either the use of a variance account or to updating the forecast charge determinants should the impact of the totalizing be material.

M1-Staff-1
Ref 1: Hydro One Response to Clarifying Question AMPCO-1
Ref 2: Hydro One Response to Clarifying Question AMPCO-3
Ref 3: Hydro One Response to Clarifying Question AMPCO-4
Ref 4: Hydro One Response to Clarifying Question LDC-TG-8

Preamble:

Several of Hydro One's responses to Clarifying Questions relate to LDCs. OEB staff would like the LDC Transmission Group's view on some of the responses.

Question(s):

a) Of the LDCs represented by Exhibit M1, how many have been impacted by double peak billing in each of years 2020 to 2023? Please list the affected LDCs.
b) Of the LDCs represented by Exhibit M1, how many have both transmission and distribution delivery points to supply their load? Please list the LDCs.
c) For each of the years 2020 to 2023, please provide an estimate of the cost impact to the LDCs represented by the LDC Transmission Group. Please explain how these costs are derived, with a representative calculation.
d) Please confirm the number of customer enquiries made by LDCs represented by the LDC Transmission Group to Hydro One regarding double peak billing in each of the years 2020 to 2023.

Responses:

a) At least seven LDCs have been impacted by double peak billing in the years 2020 to 2023: NOTL Hydro, Halton Hills, Milton, Enwin, WNP, Hearst and Renfrew. Entegrus was impacted in 2017-2018.

b) Five of the LDCs in the LDC Transmission Group have both transmission connected and distribution connected delivery points. These are Halton Hills, Milton, Kingston, Entegrus and Hearst.

c) The primary cost impact is to customers, not LDCs, as transmission costs are a pass-through. However, LDCs also incur costs in trying to mitigate these double peak billing costs. As detailed in the evidence, these mitigation efforts can also result in sub-optimal delivery of electricity to customers. The costs to the LDCs are not measured but are operational in nature as involve overtime, truck rolls and significant planning. Some of the costs to customers are provided in the examples and gross to over $1 million. As not all LDCs track these costs and as the mitigation efforts are extensive, the total cost to customers is unknown.

d) LDCs do not track their interactions with Hydro One in the manner requested by the question. For some LDCs, there are ongoing discussions and meetings with Hydro One of which this would be one of many topics. For others, the position of Hydro One had been clearly set forth prior to 2020 so making further enquiries would add no value. Several LDCs reported that they had been told by Hydro One prior to 2020 that this was a regulatory matter so that the LDCs would need to take it up with the OEB. No further discussions were then had with Hydro One on this matter by these LDCs.

M1-Staff-2
Ref 1: Exhibit M1, pdf page 2 of 20
Ref 2: Hydro One Response to Clarifying Question LDC-TG-1

Preamble:

With reference 1, the LDC Transmission Group states that double peak billing results in incremental revenue to transmitters. At reference 2, Hydro One states that double peak billing events are inherently included in the historical dataset that sets the UTRs and that there is no incremental revenue due to these events.

Question(s):

a) Please explain the basis of the statement that transmitters see incremental revenue from double peak billing events. Please resolve the apparent discrepancy between references 1 and 2.
b) Please explain the process by which retail transmission rates are determined for the represented LDCs. More particularly, and without limitation, please explain any distinctions among the represented LDCs. Please explain how double peak billing events are considered when the represented LDCs apply to set retail transmission rates. Are double peak billing events part of this historical data that support setting retail transmission rates? If they are not considered, why not?

Response:

a) When the LDC Transmission Group refers to incremental revenue from double peak billing they use their customers' perspective. The transmission revenue, or transmission cost to the customer, is incremental to what it would have been if the combined peaks had matched the actual aggregate customer demand. Hydro One is referring to double peak billing from their perspective as the receiver of transmission revenue. Hydro One builds an estimate of this double peak billing revenue into their model in calculating UTR rates.

b) Retail transmission rates are set for all LDCs as per the OEB filing guidelines. A link is provided. https://www.oeb.ca/oeb/_Documents/Regulatory/G-2008-0001_Guideline_EDRTSR_Rev4_20120628.pdf . Double peak billing events are not known in advance so are not captured in retail transmission rates prior to their occurrence. In a year in which a double peak billing event occurs the LDC will have a debit balance in their variance account that will need to be recovered as part of the rate setting process for variances. Going forward, a double peak billing event would be part of the historical data used to set retail transmission rates.

M1-Staff-3
Ref 1: Exhibit M1

Preamble:

Several examples provide estimated impacts from double peak billing in terms of $ per customer. The LDC Transmission Group has stated that LDCs are not financially affected as these additional costs are passed through to the final customers, presumably through a deferral account. OEB staff presumes that the impact of the resultant rate rider may be material to the LDC customers. OEB staff requests that the LDC Transmission Group provide additional information for the evidentiary record with respect to the impact to their customers.

Question(s):

a) Please provide a representative calculation for the $ per customer impact.

b) Please confirm whether all LDC customer classes bear the impacts of double peak billing or if only some customer classes bear the impacts. If only some, please generally explain the nature of the difference. Please explain whether the impact is the same for all those customer classes that are affected. If different, please explain.

c) Please complete the following table, for each of the years 2020 to 2023, including an explanation of any assumptions, calculations, or any other information the LDC Transmission Group deems relevant. Please confirm whether the dollar impact is per month, per year, or some other time frame. Please provide the % impact relative to the total bill for that time period:

Annual Impact of Double Peak Billing for a Typical Residential Customer

	NOTL		ENWIN		HHHI		Milton Hydro	
	$	%	$	%	$	%	$	%
2020								
2021								
2022								
2023								

	KHC		WNP		Hearst Power		RHI	
	$	%	$	%	$	%	$	%
2020								
2021								
2022								
2023								

d) Please complete the following table, for each of the years 2020 to 2023, including an explanation of any assumptions and calculations, or any other information the LDC Transmission Group deems relevant. Please confirm whether the dollar impact is per month, per year, or some other time frame. Please provide the % impact relative to the total bill for that time period.

Annual Impact of Double Peak Billing for a Typical General Service Customer

	NOTL		ENWIN		HHHI		Milton Hydro	
	$	%	$	%	$	%	$	%
2020								
2021								
2022								
2023								

	KHC		WNP		Hearst Power		RHI	
	$	%	$	%	$	%	$	%
2020								
2021								
2022								
2023								

Responses:

a) The calculation of the $ per customer impact would be:
(Actual Monthly Transmission cost – Estimated monthly transmission cost without double peak billing event) / # customers.

b) All customer classes bear the impact of double peak billing. The impact by class will vary and will vary between LDCs following the OEB methodology for allocating the variance account balance.

c) Table below with sample calculations. The calculation is for the impact in the month in which the double peak billing incident occurs. The table is incomplete as these are only for events that have been measured and reported. Some LDCs have not tracked and measured all the events. In other cases, LDCs have been able to mitigate the double peak billing event, with associated increases in operating costs, and the avoided customer cost is unknown.

Impact of Double Peak Billing Event(s) for a Typical Residential Customer

	NOTL		ENWIN		HHHI		Milton Hydro	
	$	%	$	%	$	%	$	%
2020	-	-					-	-
2021	$3.89	0.28%					-	-
2022	-	-					-	-
2023	-	-					-	-
2024	$9.37	0.57%	$0.06	0.004%			$5.35	0.35%

	KHC		WNP		Hearst Power		RHI	
	$	%	$	%	$	%	$	%
2020			$2.27		-	-	$0.55	0.5%
2021			$3.73		$5.80	0.39%	-	-
2022			$4.71		-	-	$0.26	0.2%

	KHC		WNP		Hearst Power		RHI	
	$	%	$	%	$	%	$	%
2023			$13.16		-	-	-	-

Notes: NOTL Hydro has had two events so far in 2024
Milton was advised of the need of an outage in 2023 but took mitigation measures that reduced the cost. The cost without these measures is provided.
Enwin has not bee able to calculate these costs for 2020-2022 in the interrogatory response timeline.
Halton Hills and Kingston were unable to provide the requested information in the proceeding timelines.

d) Table below. See c) for further details on the calculations, notes and the incompleteness of the table.

Impact of Double Peak Billing Event(s) for a Typical General Service Customer

	NOTL		ENWIN		HHHI		Milton Hydro	
	$	%	$	%	$	%	$	%
2020	-	-					-	-
2021	$11.45	0.33%					-	-
2022	-	-					-	-
2023	-	-					-	-
2024	$31.45	0.77%	$0.17	0.005%			$16.41	0.46%

	KHC		WNP		Hearst Power		RHI	
	$	%	$	%	$	%	$	%
2020					-	-	$1.46	0.5%
2021					$15.46	0.45%	-	-
2022					-	-	$0.82	0.3%
2023					-	-	-	-

M1-Staff-4
Ref 1: Exhibit M1

Preamble:

OEB staff would like additional clarification regarding the LDC Transmission Group's evidence on connection points and delivery points. OEB staff would also like additional information from the LDC Transmission Group on meters and meter data in the context of transmission service charges as they relate to LDCs.

Question(s):

a) For those represented by the LDC Transmission Group, please confirm who owns and maintains the meters used for billing transmission charges for load served by a Transmitter. Please confirm the same for charges for load served when the alternate source is another, separate LDC, such as Hydro One Distribution.

b) Please confirm that LDCs have access to all data from these meters. If not, please explain.

c) Please confirm, in general for an LDC, that a transformer station can have more than one connection point. If not, please explain.

d) Please explain whether and how a connection point can have multiple delivery points.

e) Please explain whether and how a delivery point can have multiple meters.

f) When an LDC is charged more than one transmission service charge, is the same data used for all the applicable charges or are there distinct datasets for each charge? For example, at a delivery point that attracts all three of Network, Transformation Connection, and Line Connection charges, would there be individual meters for each charge or would one meter be used for all three, assuming there is only one meter for that single delivery point?

g) Halton TS is cited in more than one example. Please confirm that, according to Exhibit M1, Halton TS serves multiple customers. Please explain whether any delivery points are shared between customers / LDCs. For example, is it possible for two customers to use the same delivery point? Similarly, please explain whether any meters are shared between customers / LDCs.

h) Is it possible for Halton Hills Hydro Inc. to be served by Halton TS while it is not possible for Milton Hydro to be served by Halton TS? Please briefly explain. Are there recent instances where a transmission outage caused one LDC to be served from Halton TS while the other was not? Please explain. Similarly, please explain if this is possible under scenarios unrelated to transmission outages.

i) Please complete the following table to identify which transmission charges apply to the given LDC with respect the examples provided in Exhibit M1.

Transmission Charges that Apply before the Transmission Outage Short-Term Load Transfer

	Network Service	Transformation Connection	Line Connection
NOTL			
ENWIN			
HHHI			
Milton Hydro			
KHC			
WNP			
Hearst Power			
RHI			

j) Please complete the following table to identify which transmission charges apply to the given LDC with respect the examples provided in Exhibit M1

Transmission Charges that Apply after the Transmission Outage Short-Term Load Transfer

	Network Service	Transformation Connection	Line Connection
NOTL			
ENWIN			
HHHI			
Milton Hydro			
KHC			
WNP			
Hearst Power			
RHI			

k) If there are any instances where the types of charges that are incurred changes as a result of the short-term load transfer, please explain why.

l) Please confirm that in the examples of Exhibit M1, the load supplied to the LDCs is supplied from a Transmitter both before and after the short-term load transfer. Please also confirm that the IESO is the entity that issues the bills to the LDCs both before and after the short-term load transfer. If not, please explain.

Responses

a) The ownership of the wholesale meters varies though-out the industry. In some cases, the meters will be owned by the LDC and either the IESO or the other supplier has access to the data. In other cases, both the LDC and the other supplier will own a meter. Finally, in other cases, the other supplier (usually Hydro One) owns the meter. It appears that the LDC has access to the data in most, but not all, cases. It is believed, but is not confirmed, that the IESO itself does not own meters at the wholesale delivery points.

b) Please see the response above.

c) A transmission station can have more than one connection point if it is supplied by more than one transmission line. These will commonly be DESN stations.

d) A transmission station will have more than one feeder line emanating from it that supply distribution customers. In some cases, these feeder lines will be owned by more than one LDC. In these situations, this station will be a delivery point for each LDC.

e) A transmission station can have more than one transformer. If the station only supplied one LDC then the meters may be at the transformer rather than at the feeder line. These meters are totalized to create one delivery point. Alternatively, an LDC may own several feeder lines coming from one station and each feeder line may have a meter. These meters are totalized to create one delivery point.

f) The same meter or meters are used to determine the Network, Transmission Connection and Line Connection charges. The specific data used will vary as the calculation of each of these charges can be different but it will all be from the same meter dataset.

g) The Halton TS supplies Milton Hydro and Halton Hills Hydro. There are no delivery points on the distribution feeders that supply both Milton Hydro and Halton Hills Hydro which are shared by another LDC/ customer at the same time. There are no meters shared between the Milton Hydro and another LDC/ customer either.

h) A transmission outage would likely affect both Milton Hydro and Halton Hills Hydro. In such instances, it is likely both LDC's would have to transfer load to other delivery points as occurred in early 2024 when Halton TS was isolated by Hydro One as documented by both Milton Hydro and Halton Hills Hydro in Exhibit M1 pages 11-13. It is possible that feeders allocated to either Milton Hydro or HHHI could be isolated at Halton TS thus requiring those feeders load to be transferred to another delivery point (ie: another transformer station) while the other LDC continues to receive service from Halton TS. In this case, Milton Hydro would perform switching operations on its distribution system to move the affected feeders load to an alternate feeder. Additionally, in this case, should HHHI feeder be isolated, HHHI would also perform switching operations, moving load to another feeder or station. Neither Milton Hydro, nor HHHI is not aware of recent transmission outages that affected one LDC and not the other.

i) Transmission Charges that Apply before the Transmission Outage Short-Term Load Transfer

	Network Service	Transformation Connection	Line Connection
NOTL	X		X
ENWIN	X	X	X
HHHI	X	X	X
Milton Hydro	X	X	X

KHC	X	X	X
WNP	X	X	X
Hearst Power	X	X	X
RHI	x	x	x

j)

Transmission Charges that Apply after the Transmission Outage Short-Term Load Transfer

	Network Service	Transformation Connection	Line Connection
NOTL	X		X
ENWIN	X	x	X
HHHI	X	X	X
Milton Hydro	X	X	X
KHC	X	X	X
WNP	X	X	X
Hearst Power	X	X	X
RHI	x	X	x

k) The types of transmission charges do not change as a result of short-term load transfers; only the amount of the charge. If the load transfer is between a distribution-connected and a transmission-connected delivery point then the party billing the transmission charge may change but not the type of charge itself. When transferring loads from the IESO to a host distributor, additional Low Voltage Charges from the host distributors may apply, however, the quantum of incremental costs would be significantly less than the cost of Transmission Charges, on a per kW basis.

l) Some of the examples in Exhibit M1 relate to distribution connections. In these cases, the load is supplied by another distributor. This is usually, but not always, Hydro One. If a distributor supplied the load then it is the distributor that bills the LDC, not the IESO.

M1-Staff-5
Ref 1: Exhibit M1

Preamble:
OEB staff would like to better understand load transfers in the context of LDC operations.

Question(s):

a) Please provide the LDC Transmission Group's definition of a load transfer in relation to transmission service. How is this type of load transfer different from load transfers for other reasons?

b) Are there any situations, unrelated to transmission outages, where an LDC that is normally served by multiple delivery points could have no load served from one of those delivery points? Please explain the different situations and their general expected frequency if they exist.

c) Please explain the different situations to perform load transfers that could change transmission service charges relative to what an LDC would consider "normal" operating conditions.

d) Please complete the following table. For the purpose of this table, OEB staff would like to distinguish between a load transfer and switching operations. For example, in Renfrew Hydro's September 2020 event of RHI's supply being fed through Cobden TS, instead of the normal Stewartville supply, this event would be one load transfer.

Load Transfers (LTs) among the LDCs represented by the LDC Transmission Group

	Due to Transmission Outages				All Load Transfers			
	# of LTs	Duration			# of LTs	Duration		
		Max	Min	Average		Max	Min	Average
2020								
2021								
2022								
2023								

Responses:

a) A load transfer in the context of this issue is a transfer of load between delivery points. For operational reasons there may be load transfers between feeder lines that have no impact on the delivery point loads. There were formerly cases where one LDC supplied the customers of another LDC with load at the distribution level. These load transfers have since been eliminated.

b) An LDC may request that a delivery point be taken out of service due to repairs or maintenance on the feeder lines. Alternatively, if an LDC owns the transmission station they may need to take the station out of service for repairs or maintenance on it. Neither of these situations is a transmission outage. It is difficult to estimate a frequency of these occurrences. It can be definitively stated that the frequency of these situations is not as high as it should be, as part of good utility practice, due to the cost of double peak billing.

Another situation where an LDC may be required to transfer load between delivery points relates to major storms where parts of the distribution may have to be isolated to safely make repairs and restore power. This is irregular as often responding to a storm requires sectionalizing a portion of the affected distribution system, not the entire system load supplied by a delivery point to effect repairs and restore power.

c) "Normal" operating conditions in the context of this question would be a month with no load transfers. Situations that could lead to load transfers that would then result in double peak billing include planned and unplanned transmission outages, planned and unplanned station work and planned and unplanned work on the distribution system.

d) The LDC Transmission Group is unable to complete the table. Not all load transfers are tracked. In the case of a transmission outage, the LDC may decide to keep the load transfer in place for other reasons such as to perform other maintenance or avoid further double peak billing costs by transferring the load back. This makes the duration due solely to the outage untracked.

M1-Staff-6
Ref 1: Milton Hydro Example from Exhibit M1, pdf page 11 of 20

Preamble:
The Milton Hydro example states:

> "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."

Question(s):

a) Please explain what is meant by "all stations" in the reference. Does the referenced excerpt mean that Milton Hydro is fed by 17 feeders between all the stations that supply Milton Hydro or that there are a total of 17 feeders at Halton TS? How many Milton Hydro feeders were offloaded from Halton TS to the other three Transformer Stations?

b) With respect to Halton TS and Milton Hydro, how many delivery points does Milton Hydro have at Halton TS? If this number differs from the number of feeders, please explain.

c) Please confirm how many connection points Milton Hydro has at Halton TS.

Responses:

a) Milton Hydro is supplied from Hydro One owned transformer stations at Halton TS (9 – 27.6kV feeders), Tremaine TS (4 – 27.6kV feeders) and Palermo TS (2 – 27.6kV feeders). Additionally, Glenorchy MTS owned by Oakville Hydro provides Milton hydro with an additional 2 – 27.6kV feeders temporarily until 2032. The result is a total of 17 – 27.6kV feeders supplying Milton Hydro at present. The referenced scenario required Milton Hydro to perform numerous switching procedures to offload the 9 feeders supplied from Halton TS to adjacent feeders supplied from Palermo TS, Tremaine TS, and Glenorchy TS.

b) Milton Hydro is supplied from 9 – 27.6kV feeders at Halton TS, each having its own wholesale meter.

c) Milton Hydro has 9 connection points at Halton TS.

REQUESTOR NAME:	**VULNERABLE ENERGY CONSUMERS COALITION (VECC)**
INFORMATION REQUEST ROUND NO:	**#1**
TO:	**LDC TRANSMISSION GROUP**
DATE:	**SEPTEMBER 12, 2024**
PROJECT NO:	**EB-2022-0325**
APPLICATION NAME:	**GENERIC HEARING ON UTRs – PHASE 2**

1.0 Reference: Exhibit M1, pdf page 2

Preamble: The Evidence states:

"Not every LDC has issues with double peak billing, some have delivery point configurations that preclude the potential for double peak billing"

1.1 What types of delivery point configurations preclude the potential for double peak billing?

1.2 Do these types of delivery point configurations (i.e., ones that preclude double peak billing) provide the same level of service reliability as those that do include the potential for double billing?

Response:

One type of delivery point configuration that precludes the potential for double peak billing is a single source of supply; a station with multiple feeders. It is likely that this does not supply the same level of service reliability as the entire station or the transmission line serving the station can be out of service. Also, if one feeder is down then the other feeders may not have sufficient capacity or may have voltage issues.

Another type of delivery point configuration that precludes the potential for double peak billing is a DESN transmission station. It would have a higher level of service reliability.

A third type of delivery point configuration that diminishes rather than precludes the potential for double peak billing is multiple (more than two) sources of supply. This would likely have a higher level of reliability due to the multiple options available.

There may be other configurations that preclude the potential for double peak billing.

2.0 Reference: Exhibit M1, pdf pages 2-3

Preamble: The Evidence states:
"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." (emphasis added)

2.1 In the last sentence of the referenced quote should the sentence read "with a single distributor" as opposed to "with a single transmitter"?

Response:

No. It should read with "a single transmitter". Some LDCs have embedded connections to other LDCs (example: Milton Hydro). Totalizing these meters with meters at Hydro One connections would not work in these situations.

3.0 Reference: Exhibit M1, pdf pages 2 and 4

Preamble: The Evidence states:
"The LDC Transmission Group is providing two solutions to this issue. The first is to allow the totalizing of delivery points. 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." (pdf page 2)
And
"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." (pdf page 4)

3.1 If the OEB were to adopt the first solution would the degree to which the monthly peaks at the two (or more) delivery points are coincident be a relevant consideration in determining whether totalization was appropriate for a particular situation?

Response:

The LDC Transmission Group believes that the degree to which the monthly peaks are coincident should not be a relevant consideration. The loads served by different delivery points vary over time as customers change and as feeder lines change. Customers fed from one delivery point at one point in time may be fed by another at a different time.

4.0 Reference: Exhibit M1, pdf page 6

Preamble: The Evidence states:
"In other situations, this cost minimizing action is not possible such as if there is not the capacity for the load (to) be carried by the alternative delivery points for the full month."

4.1 For electricity distribution utilities where this situation exists, does this mean that a single unplanned forced transmission outage occurring at certain times of the month/year could result in some/all of the distributors' customers being without power?

4.1.1 If yes, please indicate whether such a result is consistent with current system planning reliability criteria.

Response:

The answer is yes. In fact, there are customers for whom any transmission outage results in a customer outages as there are no alternative sources of supply. Whether this is "consistent with current system planning reliability criteria" is a question for Hydro One. The LDC Transmission Group does not have sufficient knowledge of the costs and benefits of this issue to answer that part of the question. The LDC Transmission Group does know that some LDCs have invested in transmission stations to address this concern.

There are also situations where there is a secondary source of supply but its use has other ramifications such as requiring certain generation to go off-line due to a lack of telemetry.

5.0 Reference: Exhibit M1, pdf page 7

Preamble: The Evidence states:
"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."

5.1 Based on the most recent 12 months, what is NOTL Hydro's: i) current maximum system peak demand, ii) average monthly peak demand at each of its two transformer stations (excluding any hours were double billing is considered to have occurred) and iii) average monthly peak demand (assuming the loads at the two transformer stations were totalized)?

5.2 What is the capacity of each of Hydro One's 115 kV transmission lines (i.e., Q11S and Q12S) and was each purposely sized at the time they were constructed such they could serve the entire NOTL Hydro load?

5.3 Has NOTL Hydro requested and does Hydro One maintain sufficient available capacity on each of the Q11S and Q12S transmission lines such that the line is able to serve the entire NOTL Hydro load in the event of an unplanned forced outage of one of NOTL's transformers?

5.4 Please confirm that if all three transformers were located at the same site (i.e., the same transformer station), then the monthly meter readings at all three transformers would be totalized for purposes of transmission billing and there would be no double billing issue.

5.4.1 If not confirmed, please explain why.

5.4.2 If yes, why weren't NOTL three transformers all installed on the same site?

Response:

5.1 The current maximum system peak demand is 55.2 MW. The includes load supplied from generation within NOTL. The average monthly peak demand at the two stations over the past twelve months as used for transmission billing is 44.3 MW. This excludes the month of June and July when there were double peak billing issues as described in the evidence. The average monthly peak demand at the two stations over the same time period, assuming the loads were totalized, is 43.4 MW.

5.2 NOTL Hydro is unable to answer the question as to the capacity of the Hydro One lines. That is a question for Hydro One. NOTL Hydro does know that these transmission lines serve multiple delivery points beyond NOTL Hydro's so were not sized based on just the NOTL Hydro load.

5.3 NOTL Hydro has not specifically made this request but has put its full load on either line on multiple occasions without incident. It is NOTL Hydro's understanding that the system planning managed by the IESO facilitates this redundancy.

5.4 As mentioned, NOTL Hydro's two transformers at the NOTL Station are totalized so it is NOTL Hydro's understanding that if there were three transformers at this station then they would also be totalized. The NOTL Station is solely fed by the Q11S. It was built in the 1980s. Connecting the Q12S would involve building a 5 km transmission line. The York Station is currently connected to the Q12S but could also be connected to the Q11S. It was built in 2005. Having all three transformers at the same station would both require a considerable cost and the benefit of having supply from two transmission lines, and the resulting redundancy, would be lost.

6.0 Reference: Exhibit M1, pdf page 8

Preamble: The Evidence states:
"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."

6.1 Please confirm (or otherwise explain) that ENWIN incurs: i) Line Connection transmission charges for all nine delivery points and ii) Transformation Connection transmission charges for the 6 delivery points where the transformer stations are owned by Hydro One.

Response:
ENWIN incurs Line Connection transmission charges at all nine (9) of its delivery points and it incurs Transmission Connection charges at all six (6) delivery points where transformer stations are owned by Hydro One.

6.2 What is the transformation capability (i.e. number of transformers and size of each) at each of the nine transformer stations? (Note: For purposes of the response, if considered confidential, there is no need to disclose which station is customer-owned, i.e. they can simply be numbered 1 through 9)

Response:
The transformation capability at each of ENWIN's nine (9) delivery points is as follows:

Transformer	**Transformation Capability**
Delivery Point 1	2 X 50/67/83
Delivery Point 2	2 X 50/66/83
Delivery Point 3	2 X 50/66.6/83.3
Delivery Point 4	2 X 20/26.6/33.3
Delivery Point 5	2 X 50/66.6/83.3
Delivery Point 6	2 X 50/66.6/83.3
Delivery Point 7	2 X 30/40/50
Delivery Point 8	2 X 50/66.6/83.3
Delivery Point 9	2 X 75/100/125

6.3 Based on the most recent 12 months, what is ENWIN's: i) current maximum system peak demand, ii) average monthly peak demand at each of the nine transformer stations (excluding any hours were double billing is considered to have occurred) and iii) average monthly peak demand (assuming the loads at all nine transformer stations were totalized)? (Note: For purposes of the response, if considered confidential, there is no need to disclose which station is customer- owned, i.e. they can simply be numbered 1 through 9)

Response:

i) Based on the most recent 12 months (September 1, 2023 – August 31, 2024), ENWIN's max system peak demand (totalizing demand across all nine transformer stations) was 420.3 MW. This value is non-loss adjusted.

ii) Based on the most recent 12 months (September 1, 2023 – August 31, 2024), the average monthly peak demand at each of the 9 transformer stations (excluding any hours where double billing is considered to have occurred) was as follows:

Transformer	Avg Monthly Peak (Excluding Double Peak Billing Hours)
Delivery Point 1	42,627 KW
Delivery Point 2	39,601 KW
Delivery Point 3	69,188 KW
Delivery Point 4	14,872 KW
Delivery Point 5	56,021 KW
Delivery Point 6	46,050 KW
Delivery Point 7	19,079 KW
Delivery Point 8	24,065 KW
Delivery Point 9	36,621 KW

All values in the table are non-loss adjusted.

Delivery Point 2 was shutdown for 2 months during this time period, which is reflected in its average value.

iii) Based on the most recent 12 months (September 1, 2023 – August 31, 2024), the average monthly peak demand (assuming the loads at all nine transformer stations were totalized) was 330.8 MW. This value is non-loss adjusted.

7.0 Reference: Exhibit M1, pdf page 9

Preamble: The Evidence states:
"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."

7.1 Please confirm (or otherwise explain) that ENWIN's ability to 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.) exists because: i) the capacity of the Hydro One's Line Connection facilities allows such load to be transferred between delivery points (i.e., overall capacity of all the Line Connection facilities significantly exceeds ENWIN's current/forecast system peak load) and ii) the capacity of the Hydro One-owned, ENWIN-owned and customer-owned transformer stations allows such load to be transferred between delivery points (i.e., the overall capacity of all these transformer stations significantly exceeds ENWIN's current/forecast system peak load).

Response:

Hydro One-owned transformer stations provide feeder starting points. ENWIN is responsible for constructing its feeder network. It can transfer load between various delivery points because of how it constructed and operates its feeder network and because ENWIN maintains enough capacity to operate its system with one transformer station out of service. This allows ENWIN to provide safe, reliable, and high-quality service to its customers.

7.2 At the time of their construction were the Hydro One-owned and ENWIN- owned transformer stations (and their associated Hydro One-owned line connections) purposefully sized so as to enable load to transferred between delivery points when necessary in order to facilitate Hydro One/ENWIN work on owned facilities and to ensure continued service during an unplanned outage (e.g. loss of supply, weather event, etc.)?

Response:

Hydro One-owned and ENWIN-owned transformer stations were sized with several considerations in mind, including unplanned power requirements, and in accordance with standard transformer sizes.

8.0 Reference: Exhibit M1, pdf page 10

Preamble: The Evidence states:

"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."

8.1 Please confirm (or otherwise explain) that HHHI incurs: i) Line Connection transmission charges for all four delivery points and ii) Transformation Connection transmission charges for the 3 delivery points where the transformer stations are owned by Hydro One.

Response:

(i) Confirmed
(ii) Confirmed

8.2 What is the transformation capability (i.e. number of transformers and size of each) at each of the four transformer stations?

Response:

HHHI defers to HONI to supply the transformation capacity for the Fergus, Pleasant and Halton TS. The MTS owned by HHHI has 2 feeders with a nameplate capacity of 83 MVA each.

8.3 Based on the most recent 12 months, what is HHHI's: i) current maximum system peak demand, ii) average monthly peak demand at each of the four transformer stations (excluding any hours were double billing is considered to have occurred) and iii) average monthly peak demand (assuming the loads at all four transformer stations were totalized)?

Response:

i) the maximum system peak demand in 2023 was 107,809 kWs

ii) The average monthly peak demand at each TS in 2023 was:

- Fergus 10,918 kW
- Pleasant 50,053 kW

- Halton10,741 kW
- MTS 15,664 kW

iii) The average monthly peak demand (assuming the loads at all four transformer stations were totalized) would be 86,660kWs.

9.0 Reference: Exhibit M1, pdf pages 10-11

9.1 Has HHHI ever incurred double-billing charges due to the need to transfer load between transformer stations as a result of: i) an unplanned forced outage at one of the four transformer stations or ii) due to planned or unplanned outages on the HHHI feeders supplied by the transformer stations?

Response

i) Yes

ii) Yes

9.2 Please confirm (or otherwise explain) that HHHI's ability to transfer load between delivery points to facilitate Hydro One work, its own work, or to ensure continued service during an unplanned outage (e.g. loss of supply, weather event, etc.) exists because: i) the capacity of the Hydro One's Line Connection facilities allows such load to be transferred between delivery points (i.e., overall capacity of all the Line Connection facilities significantly exceeds HHHI's current/forecast system peak load) and ii) the capacity of the Hydro One-owned and HHHI-owned transformer stations allows such load to be transferred between delivery points (i.e., the overall capacity of all these transformer stations significantly exceeds HHHI's current/forecast system peak load).

Response:

i) Not confirmed. HHHI's ability to transfer load is due to HHHI load management of feeders, feeder tie design and system redundancy designs.

ii) Confirmed with explanation. HHHI has the ability to transfer load between transformer stations for planned outages and contingency events. HHHI built the MTS with the expectation of significant load from the Vision Georgetown development. At the moment, the Vision Georgetown load is unrealized, thus allowing for current capacity availability on the 230kV system. It was only due to this current availability that HHHI was able to "absorb" the load from the M21, M29 and M30 feeders in February 2024.

Additionally, it was a result of HHHI's good utility practice in managing feeder loads with feeder ties between stations that provided the opportunity to transfer the loads from the Halton TS when requested.

9.3 At the time of their construction were the Hydro One-owned and HHHI- owned transformer stations (and their associated Hydro One-owned line connections) purposefully sized so as to enable load to transferred between delivery points when necessary in order to facilitate Hydro One/EHHHI work on owned facilities and to ensure continued service during an unplanned outage (e.g. loss of supply, weather event, etc.)?

Response:

In relation to the HHHI owned MTS, the MTS was purposefully sized to enable load to be transferred when necessary. HHHI defers to HONI to respond in relation to their own transformer stations and the ability to transfer transmission needs between stations.

10.0 Reference: Exhibit M-1, pdf page 11

Preamble: The Evidence states:
"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."

10.1 How is Milton Hydro currently charged for the use of the Glenorchy MTS owned by Oakville Hydro (i.e. what is the rate charged, how is it determined, is it part of the UTRs or part of Oakville Hydro's approved distribution rates and does Milton Hydro pay Oakville Hydro directly, as opposed to paying the IESO)?

Response:
Oakville Hydro charges Milton Hydro Transmission Rates as approved by the OEB on its Tariff of Rates and Charges. Refer to EB-2023-0044 page 10 of 13 of the Tariff of Rates and Charges for the rates that Oakville Hydro's charges its customers who are part of the Embedded Distributor Service Classification. Partially embedded distributors such as Milton Hydro pay their host distributors' charges directly. Oakville Hydro and Hydro One Networks Inc. are the two host distributors that Milton Hydro's service territory is currently embedded in.

10.1.1 Can this lead to double peak billing?

Response:
Being an embedded distributor in of itself, does not lead to double peak billing. Double peak billing occurs when load is transferred between either wholesale delivery points billed by the IESO or Host Distributors stations for a short period of time, incremental kW peak demands can occur, and when there are short term load transfers, there can be double peak billing, and distributors could pay extra transmission charges that their customers would be responsible to pay for.

10.2 Please confirm (or otherwise explain) that Milton Hydro incurs both: i) Line Connection transmission and ii) Transformation Connection transmission charges for each of the 3 delivery points where the transformer stations are owned by Hydro One.

Response:
Milton Hydro is fed by four Hydro One Networks Inc. owned stations. It is billed directly by Hydro One Networks Inc. (HONI) at two different Transformer Stations, at

Palermo TS and Fergus TS based on HONI's approved tariffs or rates and charges for Line Connection transmission, Transformation Connection transmission charges, Transmission Network transmission charges, and also Low Voltage Charges. Milton Hydro is billed by the IESO at the other two HONI owned TS', Tremaine TS and Halton TS and confirms that it is charged for Line Connection transmission, Transformation Connection transmission charges, and Transmission Network transmission charges by the IESO.

10.3 What is the transformation capability (i.e. number of transformers and size of each) at each of the four transformer stations?

Response:
- Tremaine TS, HONI, Two (2) transformers, each 125 MVA (27.6 kV Feeders)
- Palermo TS, HONI, Two (2) transformers, each 83.3 MVA (27.6 kV Feeders)
- Halton TS, HONI, Two (2) transformers, each 125 MVA (27.6 kV Feeders)
- Glenorchy MTS, Oakville Hydro, Two (2) transformers, each 125 MVA (27.6 kV Feeders)

10.4 Based on the most recent 12 months, with respect to deliveries to Milton Hydro from the four transformer stations, what was: i) the maximum coincident peak demand, ii) the average monthly peak demand at each of the four transformer stations (excluding any hours were double billing is considered to have occurred) and iii) average monthly peak demand (assuming the loads at all four transformer stations were totalized)?

Response:
Data from the most recent 12 months includes data from the date ranges September 1st, 2023 through August 31st, 2024. All values are given in hourly kW, or kWh.

i) the maximum coincident peak demand:

Halton TS	Tremaine TS	Palermo TS	Glenorchy MTS	**Total**
95323	42542	24551	25247	**187663**

ii) the average monthly peak demand at each of the four transformer stations (excluding any hours where double billing is considered to have occurred)

Halton TS	Tremaine TS	Palermo TS	Glenorchy MTS
89634	32412	21318	21436

iii) average monthly peak demand (assuming the loads at all four transformer stations were totalized)

Average Monthly Peak Demand: **155837**.

11.0 Reference: Exhibit M1, pdf pages 11-13

Preamble: On the referenced pages the Evidence outlines a situation where the need for Hydro One to perform work on its equipment led to double peak billing.

11.1 Has Milton Hydro ever incurred double-billing charges due to the need to transfer load between transformer stations as a result of: i) an unplanned forced outage at one of the four transformer stations or ii) due to planned or unplanned outages on the HHHI feeders supplied by the transformer stations?

Response:

Please see Exhibit M1 to EB-2022-0325, pages 11 – 13 which describes incremental cost scenarios related to Hydro One's request to transfer load off the Halton TS delivery point to effect repair on its station equipment.

11.2 Please confirm (or otherwise explain) that Milton Hydro's ability to transfer load between delivery points to facilitate Hydro One work, its own work, or to ensure continued service during an unplanned outage (e.g. loss of supply, weather event, etc.) exists because: i) the capacity of the Hydro One's Line Connection facilities allows such load to be transferred between delivery points (i.e., overall capacity of all the Line Connection facilities significantly exceeds Milton Hydro's current/forecast coincident peak load on these facilities) and ii) the capacity of the Hydro One-owned and Oakville-owned transformer stations allows such load to be transferred between delivery points (i.e., the overall capacity of all these transformer stations significantly exceeds Milton Hydro's current/forecast coincident peak load for these facilities).

Response:

i) the capacity of the Hydro One transmission line connection facilities exceeds Milton Hydro's peak system load and is not a constraint at this time.

ii) The capacity currently available to Milton Hydro from Hydro One and Oakville Hydro owned delivery points at Halton TS, Palermo TS, Tremaine TS, and Glenorchy MTS provides for an ability to transfer load between delivery points to a degree (ie: single/ partial feeder transfers are possible, entire station transfers require significant coordination. In October 2023, Hydro One made a request of Milton Hydro to offload its 9-27.6kV feeders at Halton TS to allow Hydro One to effect repairs. Halton TS supplies the majority of Milton Hydro's load and is the largest of our delivery points. To accommodate this request, the load at Halton TS was moved to Palermo TS, Tremaine TS, Glenorchy MTS and Halton Hills MTS. Currently, Milton Hydro's assigned capacity from Hydro One owned transformer stations is 200MW, and from Oakville Hydro owned transformer stations in 40MW. The contracted capacity from Oakville Hydro's expires in 2032 and requires Milton Hydro to reallocate load connected to Glenorchy MTS to adjacent feeders prior to contract expiry. In 2023, the summer coincident peak was 162.1MW. Currently, Milton Hydro's system load as compared to the available capacity permits planned transferring of delivery points between one or more alternate delivery points. Identified in Milton Hydro's recent load forecast supplied to Hydro One as part of the GTA West IRP, Milton Hydro anticipates the coincident peak will exceed total available capacity of its three (3) Hydro One delivery points by 2025 and will limit potential to transfer one delivery point to another in totality.

11.3 At the time of their construction were the Hydro One-owned and Oakville Hydro-owned transformer stations (and their associated Hydro One- owned line connections) purposefully sized so as to enable load to transferred between delivery points when necessary in order to facilitate Hydro One/Milton work on owned facilities and to ensure continued service during an unplanned outage (e.g. loss of supply, weather event, etc.)?

Response:
A Dual Spot Elements Network (DESN) Transformer Station design allows for load transfers between the transformers and buss within the station. Transfer of load between different transformer station must be carefully reviewed to ensure the receiving transformer station and feeder have sufficient capacity to accommodate load and mitigate potential power quality issues. However, it should be noted that Milton Hydro is not the only distributor supplied from Halton TS, Palermo TS, and Tremaine TS. Available capacity to transfer load between delivery points must be coordinated with Hydro One and the other distributors supplied from these delivery points.

12.0 Reference: Exhibit M1, pdf page 14
EB-2022-0044, Exhibit 2, page 111 of 505

Preamble: The Evidence states:

"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."

12.1 What is the transformation capability (i.e. number of transformers and size of each) at each of the Hydro One Frontenac station (115kV) and Hydro One Gardiner DESN1 station (230kV)?

12.2 Please confirm (or explain otherwise) that KHC owns the M2, M4 and M5 Dedicated 44kV feeders and is billed is billed the UTRs for deliveries from Hydro One's Frontenac Station.

12.3 Please confirm (or explain otherwise) that Frontenac Feeder M3 and the Gardiner DESN1 M7, M9, M12 Dedicated Feeders are owned by Hydro One and KHC is billed using Hydro One's ST rates (including RTSRs) for the use of these facilities.

12.4 Based on the most recent 12 months, with respect to deliveries to KHC from these two stations, what was: i) the maximum coincident peak demand, ii) the average monthly peak demand for each of the three billing points (i.e., the totalized loads for a) Frontenac M2, M4, M5 Dedicated Feeders, b) Gardiner DESN1 M7, M9, M12 Dedicated Feeders and c) Frontenac M3 Shared Feeder - excluding any hours were double billing is considered to have occurred) and iii) average monthly peak demand (assuming the loads at all delivery points were totalized)?

12.5 At the time of their construction were the Hydro One-owned Frontenac station (115kV) and Gardiner DESN1 station purposefully sized so as to enable load to transferred between delivery points when necessary in order to facilitate Hydro One/KHC work on owned facilities and to ensure continued service during an unplanned outage (e.g. loss of supply, weather event, etc.)?

Response:

Kinsgston Hydro was unable to provide a response to these questions. Kingston is not an intervenor but has provided their information and example to facilitate the discussion.

13.0 Reference: Exhibit M1, pdf page 15

Preamble: The Evidence states:
"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."

13.1 What is the supply capability of each of the HONI 44 kV lines serving the Town of Mount Forest?

Response:
The supply capacity of the HONI 44 kV lines serving the Town of Mount Forest was determined by HONI and the loading of the source TS. The maximum supply WNP has received from the two stations has been as follows:

Hanover TS : 10,544 kV
Palmerston TS : 13,194 kV

13.2 Out of the 17 instances, how many were due to: i) unplanned outages on Hydro One-owned facilities, ii) unplanned outages on WNP owned facilities, iii) planned outages for work on Hydro One-owned facilities and iv) planned outages for work on WNP facilities?

Response:
The numbers of outages based on the four categories stated in the question were:

i) 9
ii) 0
iii) 4
iv) 4

13.3 What was the rationale for construction of the second 44 kV line to supply the Town of Mount Forest (one of WNP's service territories) and was the line purposefully sized so that it would be capable of supply the Town's entire load?

Response:
The rationale for a second 44 kV line to supply was as follows:

1) Load capacity for economic development and growth

i) Intensive energy consumers were increasing their current energy demand requirements at the time of construction.
ii) Energy users were planning to increase their future energy demands
iii) Municipality wanted to attract growth and development in the area

2) Reliability
i) Critical load customers can be switched in the event of an outage.
ii) Customers – can regain power for long duration outages.

3) It was advantageous to HONI to implement the second line feed to Mount Forest, because it also made it possible for them to feed their customers through WNP's system from multiple supply sources. To accommodate this , the new line can more than supply the needs of the entire town.

14.0 Reference: Exhibit M1, pdf page 16

Preamble: The Evidence states:
"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."

14.1 Please confirm (or explain otherwise) that for the month of April 2021 Hearst Power paid: i) the IESO Network, Transformation Connection and Line Connection UTRs based on 10.65 MW and ii) HONI RTSRS (for Network and Connection) based on 8.4 MWs.

Response: Hearst Power confirms this is accurate.

14.2 At the time of their construction were the M1, M2 and M3 feeders purposefully sized so as to enable load to transferred between feeders when necessary in order to facilitate Hydro One/Hearst Power work on owned feeders and to ensure continued service during an unplanned outage (e.g. loss of supply, weather event, etc.)?

Response: Hearst Power is unaware of the feeder builds planning as they are all connected to the Hydro One Hearst TS and Hearst Power does not have any documentation on this subject. It is our understanding that the Hearst TS was originally built in the 1960's. Hydro One is more likely to be able to answer this question.

15.0 Reference: Exhibit M1, pdf page 17

Preamble: The Evidence states:
"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."

15.1 Does Hydro One purposefully ensure that sufficient (spare) capacity is always available at the Cobden TS in order to service RHI if there is an outage at Stewartville?

Response:

RHI is unable to determine if Hydro One purposely ensures sufficient feeder capacity from Cobden TS as it is their system. It could be presumed that sufficient capacity is available as RHI is feed at 44 kV and RHI's peak load has been consistently under 16 MVA over the last 5 years as well as Cobden service area is smaller than RHI's with less energy intensive industry, however RHI does not have knowledge of whether Cobden TS supplies other service areas.