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BY COURIER

April 23, 2015

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON
M4P 1E4

Dear Ms. Walli:

EB-2013-0421 – Hydro One Networks Inc. Section 92 – Supply to Essex County Transmission Reinforcement Project – Hydro One Networks Phase 2 Responses to Interrogatory Questions

Please find attached an electronic copy of the responses provided by Hydro One Networks to interrogatory questions. Two hard copies will be couriered to the Board shortly.
Below is the Tab numbers for each intervenor:

Tab	Intervenor
1	Ontario Energy Board
2	E3 Coalition
3	London Property Management Association (LPMA)
4	Power Workers Union (PWU)
5	Electricity Distributors Association (EDA)
6	School Energy Board
7	Consumer Council of Canada (CCC)
8	EnWin Utilities
9	Canadian Manufacturers and Exporters (CME)
10	Association of Major Power Consumers in Ontario (AMPCO)
11	Energy Probe (EP)
12	Coalition of Large Distributors (CLD)

For clarification purposes, on January 1, 2015 the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO"), creating a new organization that carries the name IESO. The new IESO combines the previous mandates of both former organizations and has been referred to as the IESO throughout Hydro One's interrogatory responses.

Finally, many of the enclosed interrogatory responses refer to sections of the Transmission System Code ("TSC"). As such, for ease of reference purposes and to assist the Board and registered intervenors, Hydro One is providing an excerpt of the various referred sections of the TSC as Appendix A to these interrogatory responses.

An electronic copy of these interrogatory responses have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

Attach.

c/EB-2013-0421 Phase 2 Intervenors (electronic only)

***Ontario Energy Board (Board Staff) INTERROGATORY* #1**

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 5 (OPA Cost Responsibility Evidence)
Exhibit B, Tab 1, Schedule 5, page 35 (OPA Evidence on Need and Alternatives)

The OPA has provided two reports in support of Hydro One's application. One discuses "Need and Alternatives" and the other discusses "Cost Responsibility". The latter discusses the OEB's proposed TSC amendment (i.e., new sections 6.3.8A, 6.3.8B and 6.3.8C), as the proposed cost allocation is premised on those proposed amendments, and notes the intent of the amendment is that the transmitter shall not require customer(s) to make a capital contribution in relation to an investment in transmitter-owned connection facilities where it is determined that investment in connection facilities is more cost effective than an investment in transmitter's network facilities (or network facilities in combination with the transmitter-owned connection facilities). The other OPA report discusses the two transmission alternatives that were assessed to meet the need in the Windsor-Essex area. The higher cost alternative relative to the SECTR project is described in application as "reinforcing the existing 115 kV system".

OEB staff believes that the two potential scenarios set out in the proposed TSC amendment are correctly described by the OPA. As noted, under the proposed amendment, it must involve connection investments that avoid the need to make a less cost effective investment in a transmitter's network facilities for a deviation from the existing cost responsibility rules to be triggered (i.e., some connection asset costs recovered from all ratepayers). It is unclear to staff from the evidence what higher cost investment involving a network facility is being avoided by the SECTR project. Please clarify.

Response

A $22.5 million network investment for the upgrading of J3E-J4E, the installation of 50 MVar of reactive support, and an upgrade of the autotransformers at Keith TS, is avoided by the proposed SECTR facilities.

Ontario Energy Board (Board Staff) INTERROGATORY #2

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 5 (OPA Cost Responsibility Evidence)

The OPA refers to the OEB's Notice issued on August 26, 2013 (the "August 2013 Notice") discussing the proposed TSC amendments. That Notice stated

"… the issue identified by Hydro One is most likely manifested in one scenario … namely, where the construction of and/or modification to … transmitter-owned connection facilities is a more cost effective means of meeting the needs of … load customers than the construction or modification of the transmitter's network facilities. Under such a scenario, it is expected that the construction or modification of network facilities can only be avoided by the construction of and/or modification to transmitter owned connection facilities that exceed the capacity needs of the triggering load customer(s). In such a case, it is appropriate that the load customer(s) whose needs trigger the project should only bear the cost to the extent that they benefit from the construction of and/or modification to the transmitter-owned connection facilities. Any incremental costs should be … recovered from the network pool, as the costs associated with the avoided construction of or modification to … the network facilities would have been recovered from the network pool."

(a) OEB staff understands from the application that the SECTR project does not "exceed the capacity needs of the triggering load customer(s)". Is that understanding correct? If not, please identify the extent that the SECTR project exceeds the needs of the triggering load customer(s).

(b) The OEB also discussed the Hydro One concern regarding a potential unfair allocation of costs under certain circumstances that led to the proposed TSC amendments in the August 2013 Notice. As described in that OEB Notice, to address that concern, Hydro One recommended that the OEB accept the notion that connecting customers should not be held responsible for the costs of facilities that are primarily required to address system needs. OEB staff understands from the application that the SECTR project is primarily required to address load customer needs. Is that understanding correct? If not, please explain.

Response

(a) OEB staff's understanding is correct. The SECTR project does not "exceed the capacity needs of the triggering load customer(s)".

(b) OEB staff’s understanding is correct. The SECTR project is required primarily to address the needs of load customer.

***Ontario Energy Board (Board Staff) INTERROGATORY* #3**

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 6-7 (OPA Evidence on Cost Responsibility)

Table 1 discusses the needs and beneficiaries and identifies the need to minimize the impact of supply interruptions to customers in the Windsor-Essex Area (specifically, within the J3E-J4E Subsystem) as a “broader system” benefit. OEB staff’s understanding of a “system” benefit is a benefit that accrues to all ratepayers in Ontario. Please explain why those supply interruptions are characterized as a “system” benefit and not a “customer” benefit.

Response

The minimization of supply interruption is described as a system benefit because the SECTR Project will deliver this benefit broadly across the region; it is not a benefit that will accrue only to a local area or small group of customers.

Ontario Energy Board (Board Staff) INTERROGATORY #4

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 5, page 8-11 (OPA Evidence on Need and Alternatives)

Figure 2 shows historical electricity demand in the Windsor-Essex Area has decreased since 2006 by almost 25% (from 1060 MW to 800 MW). That reduction in historical demand occurred while a major customer (Heinz) was in operation. As explained on page 11, the closure of that "large food processing facility" was recently announced. On page 10, the application also notes the significant growth in forecast demand in east Essex is due to the planned expansion of greenhouse customers based on customer connection requests to Hydro One distribution. Please set out in a table the forecast demand of each greenhouse customer that has requested a connection and the peak demand of the Heinz facility in 2013.

Response

Below is the table of new large load customer connections in the Kingsville and Leamington areas, as well as their forecast peak summer demand, taken from connection applications received between March 2011 and October 2014 (with the majority received in 2013 and 2014). The Heinz facility is a customer of Essex Powerlines, and thus demand for their facility was included in the historical and forecast loading submitted by Essex Powerlines utilized in the SECTR filing for cost allocation purposes.

	Summer Peak Demand (kW)
Customer 1	900
Customer 2	960
Customer 3	750
Customer 4	276
Customer 5	350
Customer 6	1100
Customer 7	172
Customer 8	50
Customer 9	400
Customer 10	250
Customer 11	500

Customer 12	300
Customer 13	500
Customer 14	400
Customer 15	400
Customer 16	250
Customer 17	870
Customer 18	250
Customer 19	450
Customer 20	1300
Customer 21	2400
Customer 22	250
Customer 23	760
Customer 24	450
Customer 25	300
Customer 26	700
Customer 27	200
Customer 28	664
Customer 29	2000
Customer 30	400
Customer 31	900
Customer 32	150
Customer 33	450
Customer 34	450

1

Ontario Energy Board (Board Staff) INTERROGATORY #5

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 8-9 (OPA Cost Responsibility Evidence)

OEB staff finds the discussion related to the OPA's "Recommended Cost Allocation Treatment" confusing. It discusses the costs if the limitations on the operation of Brighton Beach GS and supply capacity needs of the load customers in the Windsor-Essex area were to be individually addressed. It notes that three transmission upgrades would be required in relation to Brighton GS at a total cost of approximately $22.5 million. At the same time, the OPA notes that the SECTR project would still be implemented at a total cost of approximately $77.4 million to address the load customer supply capacity needs in the Windsor-Essex. As a result, the OPA notes the total cost of individually addressing system and customer needs in the Windsor-Essex area is approximately $99.9 million.

(a) The application notes the SECTR project would address the Brighton Beach GS limitations. If that is the case, why would Hydro One subsequently request approval of the three additional transmission upgrades noted above with a later expected need date of 2019 (i.e., after the SECTR project is in place)?
(b) Is there a lower cost transmission solution that would meet the load customer needs in the Windsor-Essex area that could be implemented but would not also address the Brighton Beach GS limitations?
(c) Please identify where the need for transmission upgrades associated with Brighton Beach GS has been demonstrated.

Response

(a) The following is an attempt to clarify the IESO's proposed cost allocation.

The IESO only identified two near-term reliability "needs" to be addressed: (i) supply capacity in Kingsville-Leamington subsystem (i.e., a customer need); and (ii) restoration capability in the broader regional J3E–J4E subsystem (i.e., system need).

The IESO determined that an appropriate way to apportion costs between load customers and transmission ratepayers — in accordance with the beneficiary pays principle underlying the Board's proposed amendment of the TSC — was to allocate to load customers a portion of the overall $77.4 million SECTR Project cost. The IESO allocated this cost based on the following analysis:

i. The lowest-cost option for addressing the supply capacity needs of customers in the Kingsville-Leamington subsystem is the SECTR Project at a cost of approximately $77.4 million.

ii. The SECTR Project also addresses the restoration need in the broader J3E-J4E region.

iii. The lowest-cost option to only address the restoration need in the broader J3E-J4E region is to carry out a package of three upgrades to improve the J3E-J4E transmission supply at a cost of approximately $22.5 million.

iv. An integrated solution (i.e., the SECTR Project) which addresses both needs is therefore the most cost effective solution since it reduces the cost ($77.4 million cost of integrated solution vs. $99.9 million cost of separate solutions) that load customers and transmission ratepayers would pay if their needs were addressed separately, for example if the restoration need were addressed in advance of the supply capacity need.

v. The cost of the SECTR Project to be allocated to load costumers may be appropriately calculated as 77.5% of the total SECTR Project costs of $77.4 million (i.e., $60 million), since this is the proportionate cost of the transmitter-owned connection facility upgrades required to meet load customer needs.

There is a potential future need for additional supply capacity to meet resource adequacy requirements in Ontario. A number of alternatives may be available to address this need at the provincial level including, in part, the SECTR Project which will unlock approximately 180 MW of constrained capacity at Brighton Beach. It is uncertain at this time when this need may emerge and what the preferred option would be for addressing this need when it arises.

The SECTR Project will reduce delivery limitations for Brighton Beach, or other generation connected at Keith TS, as would the package of three upgrades to improve the J3E-J4E transmission supply which was used as a proxy for allocating the cost to transmission ratepayers. The value of reducing delivery limitations for generation in the region was not quantified and was not considered in proposing a cost allocation because this is not a need that drove the IESO's recommendation to proceed with the SECTR Project.

(b) Please refer to the response for part (a).

(c) Please refer to the response for part (a).

Ontario Energy Board (Board Staff) INTERROGATORY #6

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 8 (OPA Cost Responsibility Evidence)
Exhibit B, Tab 1, Schedule 5, page 30 (OPA Evidence on Need and Alternatives)

In the OPA "Need and Alternatives" evidence, the OPA notes their provincial forecast shows Ontario will experience a capacity shortfall beginning around 2019 and the 180 MW constrained capacity at Brighton Beach GS could advance the need for system capacity resources. The OPA also notes that the capital cost of supplying 180 MW of peaking capacity is approximately $160 million based on the cost of a simple cycle gas-fired generator. As such, the OPA further notes that removing limitations on Brighton Beach GS would reduce the longer-term need for additional peaking resources elsewhere in the province and would reduce costs for all ratepayers. In the OPA "Cost Responsibility" evidence, it notes that if the broader system restoration needs and limitations on the operation of Brighton Beach GS were to be individually addressed, approximately $22.5 million in transmission upgrades would be required.

(a) In the absence of the SECTR project, why would the OPA consider a new $160 million simple cycle gas-fired generation facility to be a viable option, when the evidence notes a $22.5 million investment in transmission upgrades – a cost that is over seven-fold lower – would address the limitations at the existing Brighton Beach generation facility?

(b) Within the context of the above question, please explain the statement "would reduce costs for all ratepayers."

Response

(a) Mitigating congestion in the Windsor-Essex area was described in the evidence (Exhibit B, Tab 1, Schedule 5) as an added benefit of the SECTR Project and to provide further context for the IESO's recommendation. The evidence does not intend to suggest in any way that the IESO recommends a new $160 million simple cycle gas turbine to address future potential capacity needs.

(b) Reducing the peak deliverability limitation would make more generation in the Windsor-Essex area available to the provincial system. This could result in avoided investment in additional peak capacity to meet resource adequacy requirements for the province, which would reduce costs for all ratepayers.

Ontario Energy Board (Board Staff) INTERROGATORY #7

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 9 (OPA Cost Responsibility Evidence)

The OPA notes that in accordance with the beneficiary pays principle, approximately 77.5% of the SECTR costs should be paid for by local load customers and approximately 22.5% of the connection asset costs should be paid for by all transmission ratepayers under its proposed allocation. The basis for that is the hypothetical scenario whereby the load customer needs and Brighton Beach GS limitations are addressed separately through separate sets of transmission upgrades.

(a) Is OEB staff's understanding correct that the sole rationale for allocating 22.5% of the SECTR project cost to all ratepayers is it would have the ancillary benefit of addressing the Brighton Beach GS forecast limitations?

(b) If OEB staff's understanding is correct and the OEB were to approve the proposed cost allocation set out in the application but it is ultimately found that the forecast additional supply from Brighton GS is not needed in 2019 (i.e., no ratepayer benefit), should the cost allocation then be revised based on the beneficiary pays principle. If not, please explain why?

(c) Given Brighton Beach GS would also benefit, please explain why the application does not propose allocating any coats to Brighton Beach GS, in accordance with the beneficiary pays principle.

Response

(a) This understanding is not correct; please see the responses to Board Staff Interrogatories 1 and 5 (Exhibit I-P2, Tab 1, Schedules 1 and 5). The rationale for allocating 22.5% of the cost of the SECTR Project to all ratepayers is that it would address the restoration need identified in the J3E-J4E subsystem. This is an immediate need.

(b) The understanding from part (a) is not correct. The rationale for allocating 22.5% of the SECTR Project cost to all ratepayers is unrelated to addressing the peak deliverability limitation for generation connected at Keith TS and does not depend on the timing of a capacity shortfall for the province.

(c) Please see Exhibit I-P2, Tab 1, Schedule 5.

Ontario Energy Board (Board Staff) INTERROGATORY #8

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 4, page 5 (Evidence on Need)

Hydro One notes under "Need Classification", that *"the SECTR Project is considered non-discretionary, as it will: (1) enable ORTAC requirements to be met; (2) accommodate new load; and, (3) mitigate circuit overloading where the load level has exceeded capacity.*

(a) Are any of those reasons for it being non-discretionary not related to meeting the needs of load customers in the Windsor Essex area? If any are not related to load customer needs, please identify.

(b) Given the proposed allocation of connection asset costs, please explain why addressing the limitations associated with Brighton Beach GS is not included in the list above.

Response

(a) The work required to enable ORTAC requirements to be met was identified by the IESO as providing a system benefit. The accommodation of new load and mitigation of overloading are related to meeting the needs of load customers.

(b) The SECTR Project is not being undertaken for the purpose of addressing limitations associated with Brighton Beach generation. Consequently, it is not included in the "Needs Classification" list. However, once in place, the SECTR Project facilities will provide opportunity to mitigate those limitations, as a side benefit.

Ontario Energy Board (Board Staff) INTERROGATORY #9

Interrogatory

Reference: Exhibit A, Tab 3, Schedule 1, page 5 (Evidence on Methodology and on Cost Allocation)

As part of the relief sought in this application, Hydro One requests that "*the Board endorse the methodology for allocation of upstream costs at the distribution level as set out in this Application*".

(a) OEB staff observes that Hydro One is asking the OEB to "endorse" the proposed methodology. Please clarify what is meant by "endorse the methodology" in this context.

(b) By seeking endorsement of the above referenced methodology, is it Hydro One's intention to apply the proposed methodology for other projects?

(c) In Hydro One's view is its proposed methodology in keeping with the provisions of the current TSC and DSC. Please provide the relevant sections of the codes as they pertain to the proposed methodology. Please also comment on the amendments, if any, that may be required to the codes.

(d) Did Hydro One seek and receive input from the affected LDCs or affected large customers (such as greenhouses) when developing the proposed methodology?

(e) If the affected LDCs were consulted, please provide (i) a description of the consultation process specifically in respect of the above referenced methodology, (ii) a summary of LDC views/concerns as submitted to Hydro One and (iii) the steps Hydro One took to address these concerns.

(f) If affected LDCs and large customers were not consulted in the development of the cost allocation proposal, then please explain why they were not consulted.

Response

(a) Hydro One requests that the OEB approve a cost allocation methodology, so that there can be certainty for distributors and their customers regarding cost responsibility thus allowing needed investment to proceed in a timely fashion.

(b) Hydro One intends to apply the approved methodology to other projects.

(c) It is Hydro One's view that the proposed methodology is not in conflict with either the TSC or the DSC, as both Codes are silent on the allocation of upstream transmission costs at the distribution level. Hydro One expects the methodology approved by the OEB may require amendments to the DSC (and possibly the TSC) in order to prescribe the appropriate treatment of upstream costs. Additionally there may be an opportunity to align the customer connection horizons in the DSC with the refund period in section 6.3.17 of the TSC.

(d) Hydro One did not seek or receive input from the affected LDCs or affected large customers when developing the proposed methodology. However, LDCs and large customers were informed that Hydro One would be allocating cost to them before the Application was submitted.

(e) Not applicable.

(f) Given the precedent setting potential and policy implications of this Decision, Hydro One believes it was appropriate for the OEB to have convened a generic hearing for Phase 2 and to allow more parties to have input into that process. Hydro One's key priority at the time was to develop a proposal on the methodology to allow the investment to move forward.

Ontario Energy Board (Board Staff) INTERROGATORY #10

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 5 (OPA Evidence on Need and Alternatives)

At the reference on page 18, a schematic diagram shows 3 generating units of the Brighton Beach Generating Station are connected to Keith TS, with two of these g enerating units are connected to the 230 kV buses and the third generating unit is connected to the 115 kV bus.

At the reference on page 20, Table 1 shows the contract capacity and the summer effective capacity for all three generating units of Brighton Beach Power Station to be 514 MW, and 526 MW respectively.

(a) Please provide a breakdown of the total Brighton Beach contract capacity of 514 MW and effective capacity of 526 MW, between the corresponding two voltage levels i.e., 230 KV and 115 kV, by completing the table below:

Technology	Generating Station Name	Contract Expiry	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generation Facility	Brighton Beach Power Station	December 31, 2014	Keith TS at 230 kV Level		
			Keith TS at 115 kV Level		

Response

Technology	Generating Station Name	Contract Expiry	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generation Facility	Brighton Beach Power Station	December 31, 2014	Keith TS at 230 kV Level	370	360
			Keith TS at 115 kV Level	171	166

Ontario Energy Board (Board Staff) INTERROGATORY **#11**

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 3, pages 2-4. (Evidence on Hydro One Proposed Cost Responsibility)

In the reference at page 3, lines 6 – 19, Hydro One indicated that:

- with the establishment of Leamington TS sufficient load will be transferred from Kingsville TS to the proposed Leamington TS. This will reduce the need for the current four transformers at Kingsville TS to two transformers.
- three of the transformers at Kingsville TS are at end-of-life with planned replacement in 2015, only one of these three transformers will need to be replaced at a cost of $ 6 million;
- the estimated cost to replace one transformer and reconfigure the station to a two transformer station is $12M. This represents a $6M reduction in cost due to the SECTR Project.
- given that 77.5% of the cost of SECTR is assigned to the customer, this same percentage of the savings due to SECTR is to be credited to the customer at the transformation pool - for economic evaluation purposes.

In the reference, at page 4 Hydro One summarized the results of the cost responsibility in table form.

(a) Please indicate how the treatment of the "6M transformer reduction" is consistent with the overall cost allocation methodology that is being put forward.

Response

(a) Since the $6 million savings at Kingsville TS is contingent on the SECTR Project, it is appropriate that this savings also be apportioned between the Project's beneficiaries. Hydro One notes that the 77.5%/22.5% customer/system benefit split was developed without consideration of Kingsville TS costs. However, this effect is mitigated by the exclusion of the Kingsville TS costs in the allocation of the SECTR Project costs. Although Hydro One is of the view that this approach is reasonable where the 'secondary' project (Kingsville TS transformer replacement) costs are small relative to the 'primary' project (SECTR Project facilities and avoided system benefit investment) costs, Hydro One nevertheless acknowledges that a proportionate benefit split based on *all* related project costs would be an arguably purer approach, especially if an approved methodology is to become policy for use in all such similar investments.

E3 Coalition INTERROGATORY #1

Interrogatory

Reference: Transmittal letter dated February 12, 2015 regarding Hydro One Updates to Prefiled Evidence.

Hydro One's February 12, 2015 updates transmittal letter refers to "*updated economic assumptions*" having been taken into account in the updated evidence.

Did the "*updated economic assumptions*" influence Hydro One's proposed allocation of the costs of the SECTR project? If so please explain how and quantify the allocation impacts of the updated assumptions.

Response

The "updated economic assumptions" did not influence Hydro One's proposed allocation of the costs of the SECTR Project.

In addition to 2015 approved Transmisson rates, the Project Economics in Exhibit B, Tab 4, Schedule 3, were revised to reflect "updated economic assumptions" including an in-service date of March 2018 and other economic evaluation model parameters and assumptions (please refer to Exhibit B, Tab 4, Schedule 3, Table 6).

E3 Coalition INTERROGATORY #2

Interrogatory

Reference: Exhibit A, Tab 1, Schedule 1, page 3, lines 7-11.

The prefiled evidence references *"the OEB's 'beneficiary pays' principle"* in support of Hydro One's proposed allocation at the distribution level of transmission investment costs associated with the SECTR project.

The OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012 addresses a *"beneficiary pays principle"* at page 43, in reference to facilitation of the implementation of regional infrastructure planning, as follows:

> *The Board believes that a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate in that regard.*

Please provide any further references related to the Board's articulation of the *"beneficiary pays principle"* which support Hydro One's proposed allocation of the costs of the SECTR project.

Response

The Board has discussed the 'beneficiary pays' principle in the following proceedings:

- EB-2011-0043 – Notice of Proposal to Amend a Code, Supplementary Proposed Amendment to the Transmission System Code, August 26, 2013, pages 10–12.

- EB-2006-0189 – Hydro One Networks Inc. Transmission Connection Procedures Hearing - Decision and Order, September 6, 2007, pages 20–23.

These references inform, but do not explicitly support, Hydro One's proposed allocation of costs. For ease of reference, the specific excerpt of each document noted is provided as Attachment 1 and 2 of this interrogatory response.

the subject of ongoing studies being undertaken by the Independent Electricity System Operator ("IESO") in relation to transmission rates proceedings. In relation to item (iii), the Board notes that there would already be no refund, where an asset becomes stranded, as there would not be a connected customer to which a refund could be provided. The Board does not believe that item (iv) needs to be addressed through code amendments at this time.

No stakeholder objected to the elimination of section 6.3.6 from the TSC (the "otherwise planned" provision). However, Hydro One did suggest the need for an alternative provision, which is discussed in section C below.

4. Anticipated Costs and Benefits

The anticipated costs and benefits of the May Proposed Amendments were set out in the May Notice, and interested parties should refer to that Notice for further information in that regard. The Board believes that the revisions made to the May Proposed Amendments as described above will provide greater clarity for all concerned, and will not result in material incremental costs to distributors, transmitters or ratepayers.

5. Coming Into Force

As contemplated in the May Notice, the Final Amendments to the TSC and the DSC set out in Attachments A and B, respectively, come into force today, being the date on which they are posted on the Board's website after having been made by the Board.

C. Supplementary Proposed Amendment to the TSC

1. Proposal to Add a New Section to the TSC

As noted above, although there was support for the elimination of section 6.3.6 from the TSC, Hydro One suggested that it is important to preserve the concept of fairness in assigning cost responsibility where a new or modified connection facility is intended to provide benefits to the overall transmission system as well as to a particular connecting customer. Hydro One expressed concern about the fairness of the Board's approach to cost responsibility, as set out in the May Proposed Amendments, and recommended that the Board accept the notion that connecting customers should not be held responsible for the costs of facilities that are primarily required to address system needs. Hydro One suggested that this could be addressed by amending section 6.3.8 of the TSC by including the following: "A transmitter shall not require a customer to make a capital contribution in relation to a new or modified connection facility for any costs associated with meeting the general reliability and integrity needs of the transmission system." In Hydro One's view, the elimination of section 6.3.6 of the TSC without an alternative mitigating provision of this nature may lead to imprudent investments from a regional perspective, as distributors may be motivated to pursue "cheaper" local options (e.g., a sub-optimal distribution alternative) in order to avoid subsidizing transmission investments that address common needs.

Hydro One suggested two possible approaches to cost responsibility in such cases, both of which it stated could be accommodated by its proposed amendment to section 6.3.8. In one case, cost responsibility for the entire investment would be assigned to the network pool (i.e., all ratepayers) based on an independent assessment by, and input from, the OPA and/or the IESO. Alternatively, cost responsibility could be determined based on the proportional benefit between the connecting customer and the overall system, although Hydro One noted that this may be difficult to accomplish with precision in practice.

The Board sees merit in addressing the issue raised by Hydro One. The Board is of the view that the first approach proposed by Hydro One, where all of the costs would be borne by the network pool, would not be appropriate. As noted above, Hydro One's rationale for its proposed amendment is that the triggering customer(s) would unfairly bear the costs associated with any system benefits. Under Hydro One's first approach, however, unfairness would also exist; that is, it would rest with ratepayers who would bear all of the costs even though the triggering customer(s) would receive a benefit. The Board therefore believes that apportionment of the costs would be more appropriate. An approach based on apportionment is more consistent with the RRFE Board Report, where the Board identified a shift in emphasis to the "beneficiary pays" principle.[3] It is also consistent with Hydro One's suggestion that it is important to preserve the concept of fairness in assigning cost responsibility.

The Board believes that the issue identified by Hydro One is most likely manifested in one scenario in particular; namely, where the construction of and/or modification to one or more transmitter-owned connection facilities is a more cost effective means of meeting the needs of one or more load customers than the construction or modification of the transmitter's network facilities. Under such a scenario, it is expected that the construction or modification of network facilities can only be avoided by the construction of and/or modification to transmitter-owned connection facilities that exceed the capacity needs of the triggering load customer(s). In such a case, it is appropriate that the load

[3] The RRFE Board Report stated "The Board concludes that a reconsideration of the TSC cost responsibility rules is desirable to facilitate the implementation of regional infrastructure planning and the execution of regional infrastructure plans. The Board believes that a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate in that regard."

customer(s) whose needs trigger the project should only bear the cost to the extent that they benefit from the construction of and/or modification to the transmitter-owned connection facilities. Any incremental costs should be attributed to the transmitter and recovered from the network pool, as the costs associated with the avoided construction of or modification to the transmitter's network facilities would have been recovered from the network pool.

The Board is therefore proposing to amend the TSC to add new sections 6.3.8A, 6.3.8B and 6.3.8C to address this particular circumstance, which the Board expects will only arise on an exceptional basis. Where it does arise, as independently confirmed based on an assessment by the IESO, it is proposed that the transmitter be required to apportion the cost of the transmitter-owned connection facilities based on the non-coincident incremental peak load requirements of the triggering load customer(s), and to apply to the Board for approval of that apportionment. The Board believes that apportionment based on non-coincident incremental peak load should achieve an adequate level of precision in terms of the respective benefits. The load customer(s) whose needs trigger the project should neither be better off nor worse off by reason of a decision to implement a solution that results in investments that exceed the triggering customer(s) capacity needs but is more cost effective than an investment in network facilities. The Board also notes that this proposed approach is akin to the approach set out in section 6.3.5 of the TSC, under which a transmitter may in exceptional circumstances apply to the Board for permission to obtain a capital contribution from a customer in relation to the construction of or modifications to network facilities.

The Board recognizes that the more cost effective solution confirmed by the IESO may involve the modification of a transmitter-owned connection facility that serves one or more customer(s) other than the triggering load customer(s). This may occur where the transmitter modifies or constructs connection facilities to shift load from the triggering customer's connection facility to another connection facility with excess capacity. The non-triggering customer(s), who have no need for additional capacity, should not bear the cost of that modification or construction, and the Board is therefore proposing to include a new section 6.3.8C in the TSC to that effect.

The text of the proposed new sections 6.3.8A, 6.3.8B and 6.3.8C of the TSC is set out in Attachment E to this Notice. The Board remains of the view that section 6.3.6 should be eliminated from the TSC irrespective of the outcome of the consultation on the proposed new sections. The Board has therefore not considered it necessary to defer the elimination of section 6.3.6 (or any other of the Final Amendments relating to cost responsibility or other matters) pending the outcome of that consultation.

3.5.2 Board Findings

First, it is important to emphasize that this combined proceeding has as its exclusive focus the review and approval of the respective connection procedures filed by the Hydro One and GLPL pursuant to section 6.1.5 of the Code.

It is not a process to review or revise the Code per se, which can only be undertaken pursuant section 70.1 of the Act after appropriate notice to interested parties. The Board's task in this case is to consider the extent to which the connection procedures filed are consistent with the Code as it stands. A number of the submissions filed in response to Procedural Order No. 3 with respect to this issue seem to have been directed to rewriting the Code (in other words, to identify how the Code should address the issue), not interpreting it according to its current language.

Section 6.3.6 of the Code provides as follows:

> *A transmitter shall develop and maintain plans to meet load growth and maintain the reliability and integrity of its transmission system. The transmitter shall not require a customer to make a capital contribution for a connection facility that was otherwise planned by the Transmitter, except for advancement costs.*

The purpose of this section is two-fold. First, it requires the transmitter to develop "plans" that address load growth and the reliability and integrity of the system. Second, it provides a qualified exception to the general rule that a connection customer has an obligation to make a capital contribution for the creation of or enhancement of connection facilities that are intended to provide particular benefit to that customer.

The remainder of section 6.3 of the Code provides direction to the transmitter with respect to obtaining capital contributions from customers who benefit from system enhancement. For example, section 6.3.2 provides:

> *Where a transmitter has to modify a transmitter-owned facility to meet a load customer's needs, the transmitter shall require the load customer to make a capital contribution to cover the cost of the modification.*

This language is highly prescriptive and non-discretionary.

That section goes on to limit the capital contribution required to an amount derived from the economic evaluation technique provided for in section 6.5 of the Code.

Like provisions, with like effects, govern the case where a generator requires system enhancements.

The Code also addresses situations where more than one customer will benefit from the enhancement, and where a customer seeks to benefit from an enhancement within five years of its completion (see sections 6.3.9, 6.3.17, 6.2.24 and 6.2.25 of the Code). In all these situations capital contributions are required.

These provisions demonstrate that the fact that a number of customers benefit from an enhancement does not, by itself, eliminate the need for customer contributions.

It is clear that, taken as a whole, section 6.3 of the Code (including the sections referenced above) provides that in almost all cases where the transmitter is enhancing its equipment to accommodate the needs of a line connection, a capital contribution will be required from the customer or customers who benefit from the enhancement.

The qualified exception appearing in section 6.3.6 of the Code allows a customer to avoid a contribution where an enhancement has been "otherwise planned" by the transmitter to address system needs identified by the transmitter. The kind of plan that can operate to unseat the typical requirement for a capital contribution will be discussed more fully below, but it is in the Board’s view that it cannot be a "plan" that is created primarily at the request of a connecting customer. To permit such a "plan" to displace the general requirement for capital contributions would be to completely ignore the thrust of section 6.3 as a whole, and to perversely make what is clearly expressed as an exception to the rule.

Section 6.3.6 of the Code is an expression of the concept that an individual customer ought not to bear any unique responsibility for projects within established plans for things such as additions or improvements to the system for reliability and integrity improvements which have been already identified and planned for by the transmitter, except for any additional costs associated with the advancement of the improvements at the request of that customer.

This structure is an expression of another key concept which underpins the Code. That principle is that the system should grow and be reinforced and enhanced in a planned and cost effective manner. This means that the transmitter needs to develop, in concert with other responsible agencies, an orderly and "right-sized" approach to system growth and reinforcement.

Where an individual customer has a pressing local requirement, which does not form part of a planned reinforcement, or which requires an advancement of a planned enhancement, the Code provides for a method to impose, in a manner that is fair to all of the competing interests, an appropriate capital contribution. In this way the "user-pay" and cost causality principle can be implemented in a manner that permits expansion of the system, but discourages overbuild. Those responsible for unplanned reinforcements must bear some responsibility for the costs associated with such projects. This addresses concerns raised by AMPCO that transmitters may take advantage of the absence of a capital contribution requirement to expand their respective asset bases excessively.

Distinguishing Between Plans – Customer Driven versus System Needs

The Board agrees with the submissions by Hydro One and the CLD that there can be ambiguity with respect to whether an enhancement of the system is one which is designed primarily to address system integrity and reliability issues as identified by the transmitter, on the one hand, and those which are primarily of benefit to one or a small group of customers who have a pressing local need, on the other. In the one case, the Code would not require capital contributions, in the other it would.

That ambiguity is most easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process and not merely because a customer has requested it. To be clear, where planning involves joint studies between Hydro One and one or more distributor(s) to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required.

In the Board's view this means that, to qualify for the exception to the general rule, a project must be encompassed in a plan that has been developed by the transmitter substantially independent of customer request. This does not preclude an appropriate level of discourse between the Transmitter and affected customers in order to ensure the accuracy of the plan.

Each of the other transmitters that made submissions in relation to this issue recognized that an integral part of their undertaking involves the establishment by the transmitter of plans that address load growth identified by the transmitter in its ongoing planning process, together with system reliability and safety requirements. Integrating load growth projections, reliability and safety needs is at the heart of the transmitter's planning process. It is the product of that activity that can give rise to the exception contained in section 6.3.6 of the Code.

Whether the plan meets the criteria giving rise to the exception in any given case is a matter of evidence to be considered by the Board on a case-by-case basis.

The key feature of a plan giving rise to the exception is the extent to which it addresses system reliability and integrity concerns which arise from the utility's assessment of projected load growth and not the requirements of a specific customer or customers within a local area.

The plan should demonstrate that the projects embedded in it are designed to have a long term positive effect on system reliability and integrity.

The plan should contain significant detail respecting the needs being addressed, the equipment associated with the various elements of the projects, and the implementation timetable.

Perhaps most importantly, the plan should incorporate the input from other responsible agencies such as the IESO and the OPA and should be reflected in the planning documents produced by Hydro One and these agencies.

Filing Requirements for Project Justification

The Board reminds transmitters that they are obliged to present evidence of their approach to capital contribution in every case, whether it intends to seek a contribution from a customer or not. The extent to which the criteria outlined above are met in a given case is to be determined by the Board Panel considering it. A consideration is necessary whether the transmitter is requiring a connecting customer to make a

***E3 Coalition INTERROGATORY* #3**

Interrogatory

Reference: Exhibit A, Tab 3, Schedule 1, page 4, lines 10-11.

The evidence requests a written hearing on the basis, *inter alia*, that *"[t]here will be a minor customer total bill impact (approximately 0.01%) as a result of the new line facilities."*

(a) Please confirm that this bill impact statement is made in respect of transmission cost impacts of the SECTR project only.

(b) Please advise whether Hydro One has performed any analysis of customer bill impacts at the distribution level for any of the distributors to whom SECTR project costs are proposed to be allocated.

(c) If any such analysis has been performed, please provide bill impacts for the customers of these distributors once the distribution level costs proposed by Hydro One are included. Please detail assumptions used, and calculations in support of, any such anticipated bill impacts.

Response

(a) Confirmed.

(b) Please see Exhibit I-P2, Tab 7, Schedule 3 and Exhibit I-P2, Tab 9, Schedule 6.

(c) Not applicable.

E3 Coalition INTERROGATORY #4

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, page 2, lines 19-22;
Exhibit B, Tab 5, page 20;
Exhibit I-P1, Tab 1, Schedule 8

The evidence notes six customer-owned generating plants in the Windsor-Essex region, and provides information about the nature, capacity and contract expiry dates of these generation facilities.

(a) Please provide the in-service dates of each of these generators.

(b) Please detail, for each of these generating stations, the extent to which its connection had an impact on the available connection capacity, reliability and generation constraining transmission congestion in the region.

(c) The OPA's evidence notes that two of these generation facilities are assumed not to be available over the planning period because expiry of their current power purchase contracts with the IESO is imminent. The evidence further indicates that re-contracting of some of this generation would help meet the restoration requirement in the J3E-J4E subsystem, which the SECTR project also addresses.

(i) Please indicate whether re-contracting of this generation would reduce the scope and/or cost of the SECTR project, and if so how and by how much.

(ii) Could the IESO please indicate its expectations regarding timing for such re-contracting if it is being/to be pursued (by either the IESO or the generator).

Response

(a) The response to parts (a) and (b) are shown in the table below. Please note, for part (b) the following applies:

"available connection capacity" is supply capacity at the existing Kingsville TS, and
"reliability" is interpreted as restoration capability

Transmission Connected Generation Facilities in the Windsor-Essex Area

Station Name	In-Service Date	Impact on Available Connection Capacity	Impact on Reliability	Impact on Generation Constraining Transmission Congestion
Brighton Beach Power Station	July 1, 2004	No Impact	*230 kV connected generation:* Provides restoration capability up to the capacity of the Keith 230/115 kV transformer *115 kV connected generation:* Provides restoration capability up to the capacity of the J3E/J4E cable	Impacted by congestion – assumed to be dispatchable
West Windsor Power	Approximately May 31, 1996*	No Impact	Provides restoration capability up to the capacity of the J3E/J4E cable	Impacted by congestion
TransAlta Windsor	Approximately December 1, 1996*	No Impact	Provides restoration capability	Not impacted by congestion
East Windsor Cogeneration Centre	Nov. 6, 2009	No Impact	Provides restoration capability	Not impacted by congestion
Gosfield Wind Project	Sept. 16, 2010	No Impact	Provides restoration capability	Not impacted by congestion
Point Aux Roches Wind Farm	Dec. 7, 2011	No Impact	Provides restoration capability	Not impacted by congestion

*West Windsor Power and TransAlta Windsor contracts are held by the Ontario Electricity Financial Corporation. These in-service dates are estimated based on the contract expiry dates, assuming the contracts were for a 20-year term.

(b) Please see answer to (a).

c) (i) Re-contracting of generation with upcoming contract expiry dates (West Windsor Power and TransAlta Windsor) would not reduce the scope and/or cost of the SECTR Project. As shown in the above table, re-contracting these generation facilities could address the restoration need for the J3E-J4E sub-system, however these facilities do not impact the supply capacity at Kingsville TS. Therefore, re-contracting of these facilities would not reduce the scope of the SECTR Project.

(ii) A resolution on the contracting status for these facilities is anticipated later this year.

***E3 Coalition INTERROGATORY* #5**

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 5, page 40, lines 17-18;
Exhibit I-P1, Tab 1, Schedule 8, page 2

The evidence indicates that the SECTR project will reduce the peak deliverability limitation for the Brighton Beach GS. The evidence further indicates that the value to the province of 180 MW of simple cycle gas fired generation is $162 million.

Has the value of this benefit to the province and/or Brighton Beach GS been considered in the proposed allocation of the SECTR project costs? If so, how? If not, why not?

Response

Please see Exhibit I-P2, Tab 1, Schedule 5.

***E3 Coalition INTERROGATORY* #6**

Interrogatory

Reference: Exhibit I-P1, Tab 1, Schedule 2, Attachment A, pages 4 and 5 of Attachment.

The evidence, an excerpt from the 2007 IPSP addressing the Windsor-Essex Area transmission constraints, mentions four power generators and the 400 MW Michigan/Ontario transmission intertie in discussing transmission congestion related to generation in west Windsor.

(a) Please discuss the extent to which the SECTR project eliminates or mitigates this congestion, and to the benefit of what parties.

(b) Has the value of elimination of this congestion been quantified? If yes, please provide. If not, why not?

(c) Has the value of elimination of this congestion been considered in the proposed allocation of the SECTR costs? If it has, how? If it has not, why not?

Response

(a) Please see response to Exhibit I-P2, Tab 1, Schedule 5. The IESO did not evaluate these matters because relieving congestion was not a need that drove the IESO's recommendation of the SECTR Project.

(b) See the response to part (a).

(c) See the response to part (a).

E3 Coalition INTERROGATORY #7

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 3, page 4.

The evidence includes a table indicating the proposed cost responsibility (as between the transmission pool and customers) for the elements of work to be done on the project.

(a) Please restate the table on the basis that the pool is allocated responsibility for SECTR project costs equal to the total of the costs avoided by the pool as a result of the project (and the balance of the SECTR project costs are allocated to customers).

(b) Please comment on the appropriateness of allocating to the transmission pool an amount equal to all costs avoided by the transmission pool as a result of the SECTR project, and allocating the balance of the SECTR project costs to customers.

Response

(a) See response to (b) below.

(b) Hydro One believes that the proportional benefit approach to cost responsibility proposed in Exhibit B, Tab 4, Schedule 3, results in the fairest allocation to all customers. Three possible cost responsibility approaches are set out in the tables below. Each table shows the cost responsibility outcome for one of the following three approaches:

A. Customer pays costs in excess of pool's avoided costs
B. Proportional benefit (proposed)
C. Pool pays costs in excess of customer's avoided costs

It is Hydro One's view that Approach A would unfairly burden ratepayers with costs associated with benefits to the triggering customers, whereas Approach C would unfairly burden the triggering customers with costs associated with system benefits.

Hydro One notes that the table associated with Approach A represents the restatement requested in part (a) of this interrogatory of the table in Exhibit B, Tab 4, Schedule 3, page 4.

Hydro One also notes that Approach C represents the cost responsibility outcome under the Transmission System Code as it stands today. Furthermore, Hydro One believes that the Supplementary Proposed Amendment to the Transmission System Code, dated August 26, 2013, would not alter this outcome.

Approach A - Customer pays costs in excess of pool's avoided costs

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3	32.1	13.2[1]	28.1
Station Facilities	32.1	16.8	15.3[2]	4.6
Total	**77.4**	**48.9**	**28.5**	**32.7**

[1] $13.2 million = $22.5 million pool avoided cost x line-to-total cost ratio = 22.5 x (45.3 / 77.4)
[2] $15.3 million = $22.5 million pool avoided cost x station-to-total cost ratio plus $6 million Kingsville cost reduction
= 22.5 x (32.1 / 77.4) + 6

Approach B - Proportional benefit (Proposed Approach)

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3[1]	35.1	10.2	31.2
Station Facilities	32.1	20.2[2]	11.9	8.2
Total	**77.4**	**55.3**	**22.1**	**39.4**

[1] Line costs of $45.3 million include $43.0 million of up front capital costs plus $2.3 million removal costs
[2] $20.2 million = ($32.1 million station facilities costs less $6 million Kingsville cost reduction) x 77.5%

Approach C - Pool pays costs in excess of customer's avoided costs

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3	45.3	0	41.8
Station Facilities	32.1	32.1	0	20.6
Total	**77.4**	**77.4**	**0**	**62.4**

E3 Coalition INTERROGATORY #8

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 3, pages 7 and 9, Tables 1 and 2; Exhibit I-P1, Tab 1/Schedule 3.

(a) Please file a copy of the most recent Windsor-Essex Regional Planning Status Letter (or other such communication), and please file a copy of the Windsor-Essex Regional Plan when it is available (according to the second reference noted above, by April 28, 2015).

(b) Please indicate the time horizon of the current plan, which includes the SECTR project.

(c) Please detail Hydro One's current expectations for when incremental facilities in addition to the SECTR project may be required in order to reliably serve loads in the Windsor-Essex region, and Hydro One's current expectation of what such facilities might be and what further capital contributions might be required from the affected distributors.

Response

(a) Please see Attachments 1 and 2 for status letters with respect to Regional Planning from Hydro One Transmission to Hydro One Distribution (dated November 14, 2013) and to ENWIN Utilities Inc. (dated March 21, 2014). A copy of the Windsor-Essex Integrated Regional Resource Plan (IRRP) will be provided shortly after the report is released on April 28, 2015.

(b) The Windsor-Essex IRRP uses a planning horizon to 2033.

(c) In the context of Regional Planning, facilities additional to the SECTR Project to meet customer load requirements in the Windsor – Essex Region are not expected within the next fifteen years.

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November 14, 2013

Mr. Paul Brown
Director, Distribution Asset Management
Hydro One Distribution
Toronto

Via email: Paul.Brown@HydroOne.com

Dear Mr. Brown**:**

Subject: Regional Planning Status – Hydro One Distribution

This letter is in response to your request for a Planning Status letter. Please note that the province has been divided into 21 Regions for the purpose of regional planning. These 21 Regions are assigned to one of the 3 Groups to prioritize and manage the regional planning process. A map showing details with respect to the 21 Regions and the list of LDCs in each Region are attached in Appendix A and B respectively. Hydro One Networks is a lead transmitter in the 19 Regions and Hydro One Distribution (HOD) belongs to each of these 19 Regions with the following grouping:

Group 1 Regions	**Group 2 Regions**	**Group 3 Regions**
Burlington to Nanticoke	London area	Chatham/Lambton/Sarnia
Greater Ottawa	Peterborough to Kingston	Greater Bruce/Huron
GTA North	South Georgian Bay/Muskoka	Niagara
GTA West	Sudbury/Algoma	North/East of Sudbury
KWCG		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		
GTA East **		

** GTA East has been reassigned to Group 1 from Group 2

This letter confirms that a regional planning process for regions within Group 1 with the exception of GTA East is currently underway for the entire region or sub-region. The planning status for each of the regions in Group 1 is discussed below. This letter also confirms that the regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the regions listed in Group 2 and Group 3.

Group 1 Regions

Burlington to Nanticoke

As part of the Integrated Region Resource Planning (IRRP), the OPA is leading a small sub-regional planning process in this region for the Brant area to address near-term supply capacity issue. Hydro One Distribution (HOD) is an active participant in this sub-regional planning process. The preliminary findings are that installation of cap banks at a MTS may provide a solution for several years. The addition of cap banks will eliminate constraints on line rating because of voltage limitation and provide capacity for HOD and other LDC(s) in the region.

The regional planning process for the rest of the Burlington to Nanticoke has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed. I am expecting, as per the new process, that the regional planning for the Burlington to Nanticoke Region will be initiated before the end of 2013. Hydro One Networks will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

Greater Ottawa

The OPA is leading a sub-regional planning process in this region for the Ottawa Area and has an Integrated Regional Resource Plan (IRRP) under development.

In advance of initiating the Regional Planning Process, Hydro One Networks is planning construction of Orleans TS which is expected to be in-service in early 2015. HOD is required to coordinate and include distribution feeder construction and related investments in their business plan to match the TS in-service.

Hydro One Networks expects that Regional Planning for the remainder of the for the Outer Ottawa Area (Chat Falls/Hawksbury area) will commence in the first quarter of 2014.

GTA North

Regional planning for the GTA North – York sub-region is already underway with the exception of the Western sub-region supplied from the Kleinberg tap (circuits V43 and V44). The planning study for the York sub-region underway is led by the OPA and includes representatives from Hydro One distribution, the Independent Electricity System Operator (IESO) and the directly affected LDCs. The study working group is assessing the reliability needs of the sub-region to develop an integrated plan to assess the appropriate mix of investments (e.g. CDM, DG and wires) to address the electricity needs of the area.

The IRRP process has so far identified the following transmission reinforcements to address the near and medium-term reliability needs of the York Sub-region region:

- Installation of two in-line breakers and associated motorized disconnect switches on circuit B82V/B83V at or close to the Holland TS property.

- Design and implementation of a Load Rejection (L/R) scheme for the stations connected to B82V/B83V system, or have available operational measures adequate for providing similar relief, as permitted by ORTAC.

- Improve reliability of supply from the 230kV “Parkway Belt” circuits (V71P/V75P).

The wires solutions for GTA North - York sub-region will now be further developed by the planning group led by Hydro One Networks. The study will confirm the options, scope, preliminary costs and schedule of the above facilities to optimize their specifications and configuration as part of the Regional Infrastructure Plan. Current outcomes of this planning study and investments in transmission supply facilities are expected to be pool funded.

It is expected that an IRRP for the Region will be complete in fourth quarter of 2014.

GTA West

The Northwest Greater Toronto Area (NWGTA) is a sub-region within the GTA West Region. This sub-region is currently in the early phases of the IRRP led by the OPA.

Hydro One Networks expects that Regional Planning for the remainder of the GTA West - Southern sub-region will commence, begininning with a Needs Assessment /Screening in the fourth quarter of 2013.

It is expected that an IRRP for the Region will be complete in 2015.

KWCG

A regional planning process for the KWCG Region is already underway. The “KWCG planning group”, is led by the OPA and includes representatives from HOD, Hydro One Networks, the IESO and the LDCs in the KWCG area. OPA in collaboration with LDCs is assessing the reliability needs within this region to develop an integrated plan for the appropriate mix of investments (e.g. CDM, DG and wires) to address the electricity needs. It is expected that a KWCG IRRP will be complete by the end of 4^{th} quarter 2014.

In brief, the draft KWCG IRRP indicates that the demand for electricity in the region is expected to grow substantially over the next 20 years, driven by population growth and strong economic activity. Three of the KWCG subsystems, namely the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems, already exceed their supply capacity. In addition, the Kitchener, Cambridge, and Waterloo-Guelph subsystems do not comply with prescribed service interruption criteria. In combination with conservation and distributed generation resources, the KWCG IRRP study results identified the following two transmission reinforcements to address near and medium-term reliability needs of the KWCG area:

• Guelph Area Transmission Refurbishment (GATR) - installing two new 230/115 kV autotransformers, four 115 kV breakers, and rebuilding approximately 5 km of existing 115 kV transmission line between Campbell TS and CGE junction in Guelph to a double-circuit 230 kV transmission line and two 230kV circuit breakers located at Guelph North Junction.

- Preston TS - Install a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support.

The GATR project is currently under development and the options for Preston TS are now being further developed by the KWCG planning group led by Hydro One Transmission as part of the Regional Infrastructure Plan for the KWCG area. Both of these projects are expected to be pool funded and customer capital contributions are not expected.

It is expected that an IRRP for KWCG Region will be complete in 2014.

Metro Toronto

Regional planning for the Central-Downtown Toronto sub-region of Metro Toronto Region is currently underway and is in the options development phase of the OPA's IRRP process. This sub-region under consideration does not impact HOD.

Hydro One Networks expects that regional planning for the Northern sub-region (outer areas) of the Metro Toronto Region will commence in the fourth quarter of 2013.

Northwest Ontario

The report of the OEB's Planning Process Working Group has noted "that not all regions of Ontario are the same and that the Regional Planning processes will need to be flexible to accommodate those differences." The Northwest Region was identified to be "different from the other regions due to, among other reasons, the uncertainties related to changing resources and industrial loads, which may require consideration of a broader range of scenarios, expanded list of participants and means of grouping studies".

The Northwest is a large region with diverse needs. In order to understand and meet specific local needs, the OPA, together with Hydro One Networks and local communities, is undertaking planning processes in six sub-areas, which together will represent an overall Northwest regional plan. Individual area plans are focused on those unique areas, but the solutions are interrelated. At this time, Hydro One Networks is in an early stage of discussions with the OPA with regard to the process to follow in carrying regional planning in the Northwest taking into account the unique nature of the Northwest Region and the planning work that has already begun and in progress by the OPA in the region.

Below is a summary and description of the six areas and their planning statuses:

1. **East-West Tie**
   - Need for transmission development was identified as a priority project in the 2010 LTEP and a report was submitted to the OEB
   - The OEB has designated Upper Canada Transmission Inc. to undertake the development

2. **City of Thunder Bay**
   - Regional Planning process for the City of Thunder Bay will be initiated in Q1 2014.

3. **West of Thunder Bay**
   - Need is being assessed and options are being developed

4. **Existing North of Dryden System**
   - Generation and transmission options assessed
   - Stakeholder engagement underway

5. **Remote Communities North of Red Lake and Pickle Lake**
   - Draft Remote Community Connection Plan released August 2012 to the Northwest Ontario First Nations Transmission Planning Committee
   - Recommends connection of up to 21 communities
   - Community engagement almost complete
   - Report expected to be finalized in late 2013

6. **Ring of Fire Area Mines and Remote Communities**
   - Generation and transmission options assessed
   - Stakeholder engagement underway

In addition, HOD and other industrial customer (s) are assessing their additional capacity requirements to supply incremental load north of Dryden. The specific investment will depend after additional capacity requirements by HOD and other customers are finalized.

The regional planning process for this region has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed. I am expecting, as per the new process, that the regional planning for the Northwest Region will be initiated in the first quarter of 2014. Hydro One Networks will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

<u>Windsor – Essex</u>

The OPA and Hydro One Networks have been monitoring developments in the Windsor – Essex region since 2011. This region currently has an Integrated Regional Resource Plan (IRRP) under development. The regional planning study is being updated in consideration of an updated demand forecast for the Kingsville/ Leamington area.

Currently, the draft study is assessing a new TS in Leamington to address near and medium-term needs of the area. To facilitate this project, Hydro One Networks is preparing a Section 92 application to build a 13km of a new 230kV double circuit line from this new TS and new taps on 230kV circuits between Chatam TS and Sandwich Junction. This option may require HOD to plan, coordinate and identify investments in their distribution plan.

GTA East

The regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the GTA East Region. Hydro One Networks will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process for this Region.

However, in GTA East, LDCs and Hydro One Networks have been assessing and reviewing options that may include expansions at an existing TS or the addition of a new TS to address near-term needs for transformation capacity. The projects stemming out of these studies may require capital contribution from HOD.

Group 2 and 3 Regions

In advance of the initiating the Regional Planning process, Hydro One Networks is discussing with HOD to address near-term connection capacity needs in Group 2 and Group 3 Regions.

- Sudbury/Algoma – Study/assessments is underway for a new station at Hanmer TS, which may require a capital contribution from HOD.
- Niagara – HOD is assessing its need for an additional feeder from Allanburg TS.

The new planning process provides flexibility, during the transition period, and will ensure that both distribution and transmission planning continue to address any urgent or near-term needs. For a region or sub-regions that involve HOD but for which regional planning activities have not yet commenced Hydro One Networks will formally notify you, and other stakeholders, in advance, of launching the regional planning process.

Hydro One Networks looks forward to working with HOD in executing the new regional planning process. If you have any further questions, please feel free to contact me.

Sincerely,

Ajay Garg, |Manager - Regional Planning Coordination and Transmission Load Connections|
Hydro One Networks Inc.

Cc:
Bing Young, Director – Transmission System Development
Farooq Qureshy, Manager – Transmission Planning (Central and East)
Ibrahim El-Nahas, Manager – Transmission Planning (North and South West)
Brad Colden, Manager – Customer Business Relations

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March 21, 2014

Mr. James F. Brown, P.Eng.
Director, Infrastructure
EnWin Utilities Inc.
787 Ouellette Avenue,
Windsor, Ontario
N9A 5T7

Via email: jbrown@enwin.com

Dear Mr. Brown:

Subject: Regional Planning Status Letter

This letter is in response to your request for a Planning Status Letter. Please note that the province has been divided into 21 regions for the purpose of regional planning. These 21 regions are assigned to one of three groups to prioritize and manage the regional planning process. A map with details about the 21 regions and a list of Local Distribution Companies (LDCs) in each region are attached in Appendix A and B respectively. Hydro One Networks Inc. (HONI) is the lead transmitter for 19 of the 21 regions.

Your LDC belongs to the Windsor-Essex region, which is in Group 1.

Group 1: Windsor-Essex Region

The OPA and HONI have been monitoring developments in the Windsor – Essex region since 2011. Currently, this region has an Integrated Regional Resource Plan (IRRP) under development led by the OPA. The regional planning study is being updated in consideration of an updated demand forecast for the Kingsville/ Leamington area.

Currently, the study has identified a new TS in Leamington to address near and medium-term needs of the area. To facilitate this project, HONI submitted a Section 92 application to the Ontario Energy Board in January 2014 for construction of 13 km of new 230 kV double circuit line to supply the proposed Leamington TS from new taps (Leamington Junction) on the 230kV circuits located between Chatham Switching Station and Keith TS.

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The new planning process provides flexibility during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs. Hydro One will formally notify your organization and other stakeholders prior to launching any further regional planning activities for this Region. Hydro One looks forward to working with EnWin Utilities Ltd. in executing the new regional planning process.

Please feel free to contact me if you have any questions.

Sincerely,

Ajay Garg, |Manager - Regional Planning Coordination and Transmission Load Connections|
Hydro One Networks Inc.
Cc: Bing Young – Director, Transmission System Development [HONI]
Brad Colden – Manager, Customer Business Relations [HONI]

E3 Coalition INTERROGATORY #9

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 3, pages 7 and 9, Table 5;
Exhibit I-P1, Tab 1, Schedule 6, page 2

(a) Please confirm that the 2014 figures provided in the table found at the second referenced exhibit are actuals. If they are not, please provide actual figures.

(b) How were the load forecasts used in the DCF analysis determined?

(c) Please file the individual distributors' incremental load forecasts relied upon by Hydro One. (Please note that the E3 Coalition members – E.L.K., Entegrus and Essex – take no objection to the public filing of any load forecasts or other information regarding current or expected load that they have provided to Hydro One.)

(d) Please provide the most current estimates, with supporting calculations, of the capital contributions that are forecast to be required from each of the affected distributors (including Hydro One Distribution).

(e) Please describe the basis for, and if possible quantify, any uncertainties associated with the estimated required capital contributions.

Response

(a) The values shown in Exhibit I-P1, Tab 1, Schedule 6 are forecast numbers. The actual values for 2014 are:

Windsor-Essex Region: 802 MW
Kingsville Leamington Area: 121 MW

(b) The process used to produce the load forecast was the same as the one Hydro One Distribution would normally utilize for facility planning purposes, as outlined below:
- the historical loading of the facility (in this case, Kingsville TS) is first identified
- any specific step increases in new growth planned for the region are added to determine the load forecast for the immediately subsequent years (in this case, the forecast was provided by Essex Energy Corporation[1] in June, 2012, and included a 5-

[1] Essex Energy Corporation was established in 2000 and supports municipalities, utilities and industries in Essex County with their energy needs.

year forecast of greenhouse and other large development in the Kingsville and Leamington areas)

- from 2018 forward, Hydro One's growth rates will be used.

(c) The table below summarizes the load forecasts provided by the E3 Coalition members in March, 2014, and subsequent analysis performed by Hydro One to confirm the historical loading. Forecasts for Entegrus Powerlines, and E.L.K Energy were not changed. For Essex Powerlines, the 2013 actual peak load was approximately 3.6MW higher than what was submitted by Essex Powerlines. Hydro One adjusted the historical load to actual measured values, and applied Essex Powerlines submitted growth rates, to determine the Essex Powerlines load forecast for cost allocation purposes.

Peak MW	Entegrus	E.L.K	EPL
2013 peaks submitted by LDC	2.6	31.6	32.0
2013 peaks based on historical data	2.6	31.6	35.6
LDC growth rate (average)	0.75%	0%	-0.1%

(d) Capital Contribution Allocation Estimate Summary

Table 1 summarizes the current estimate of the capital contributions required from each of the affected distributors.

Table 1

Capital Contribution Allocation to Distributors *in $ millions, excluding HST*	Line Pool	Transformation Pool	Total
Hydro One Distribution	26.3	6.0	32.3
Essex Powerlines	2.2	0.5	2.7
E.L.K.	1.8	0.2	2.0
Entegrus	0.3	0.1	0.4
Total	**30.7**	**6.8**	**37.4**[2]

[2] Of the $39.4M capital contribution to Hydro One Transmission, the allocation process results in an unallocated contribution amount of $2.0M between the embedded distributors. For details, please see Appendix 1.

Table 2 summarizes the current estimate of capital contributions required from new ST customers in Hydro One Distribution's service territory.

Table 2

Capital Contribution Allocation to New ST Customers[3] *in $ millions, excluding HST*	Line Pool	Transformation Pool	Total
Hydro One Distribution Ratepayers	13.8	4.5	18.3
New ST Customers	12.1	0.6	12.7
Total	**26.0**	**5.1**	**31.1**[4]

Please see Attachment 1 to this interrogatory response for supporting calculations.

(e) Hydro One notes that the capital contribution estimates referenced in E3 Coalition's intervention request (November 26, 2014) were based on load forecast provided to Hydro One on June 15, 2012. Based on the forecasts, the following capital contributions were communicated to the affected distributors:

$/million	Capital Contribution based on 2013 forecast	Capital Contribution based on 2014 forecast
Essex Powerlines	4.5	2.7
ELK Hydro	14.0	2.0
Entegrus	1.0	0.4
Hydro One Distribution	21.0	32.3
Total	**$40.5**	**$37.4**

The table above illustrates that the capital contributions required from benefitting parties are subject to large swings depending on each parties load forecast and their projection of new large customers. Changes to the load forecast and any latter true-up lead to uncertainties in any of the calculated capital contributions provided in this Application.

A further example of uncertainty is a scenario where the forecast of new ST customers in Hydro One Distribution's service territory to connect to the facilities does not materialize.

[3] Hydro One Distribution has determined that only ST load customers would be required to make capital contributions. This approach would apply to ST customers requesting a connection to Hydro One's distribution system (e.g. "new") and those existing ST customers requiring additional capacity.

[4] Of the $32.3M capital contribution allocated to Hydro One Distribution, the allocation process results in an unallocated contribution amount of $1.2M between New ST Customers and Hydro One Distribution Ratepayers. For details, please see Appendix 1.

The following chart illustrates the estimated $8.9 million in additional capital contributions required if no new ST customers connect and contribute to the project economics.

Capital Contribution Allocation to Distributors *in $ millions, excluding HST*	Line Pool	Transformation Pool	Total
Hydro One Distribution	25.5	11.2	36.7
Essex Powerlines	4.1	1.6	5.7
ELK Hydro	3.6	1.2	4.8
Entegrus	0.6	0.3	0.9
Total	**33.8**	**14.3**	**48.1**

If a greater than forecast number of new ST customers connect then these numbers will change again.

In addition to changes in the load forecast, customer additions and estimated project costs represent uncertainties to the initial economic evaluation and the resulting capital contributions. All of these estimates will be reconciled to actuals at the appropriate time.

Hydro One is asking the Board to approve a methodology of allocating costs at the distribution level. The basis for this request is the volatility of the capital contributions that will be required from the affected distributors depending on the load forecast used. The OEB endorsement and approval of a methodology should provide assurance to the distributors that they can recover their capital contributions from their customers.

Whether the SECTR Project ultimately proceeds will depend upon the acceptance by each party (distributors and/or large customers) of the cost responsibility associated with their portion of the project. Hydro One anticipates this will occur after OEB approval and upon execution of the required agreements.

ATTACHMENT 1

Capital Contribution Allocation Supporting Calculations

Line Capital Contribution Allocation

Attachment 1 Table 1 provides an overall summary of the proposed approach to allocate the upstream cost of the line investment by Hydro One Transmission of $45.3 million—$10.2 million of which is assessed to be for system benefit—to meet the capacity needs of four distributors (one of which is Hydro One Distribution and the other three are embedded customers of Hydro One Distribution), totaling 84 megawatts of non-coincident incremental peak load. The total capital contribution payable at the transmission level, as determined through an economic evaluation performed by Hydro One Transmission, is $31.2 million. See Exhibit B, Tab 4, Schedule 3, for detailed information on the transmission level project economics.

At the distribution level, economic evaluations were performed by Hydro One Distribution to allocate the total $31.2 million capital contribution among the four distributors (including Hydro One Distribution itself).

i. For purposes of economic evaluation, Hydro One Distribution attributed a portion of the project cost to each distributor in proportion to that distributor's contracted capacity. See Attachment 1 Table 2, for detailed calculations.
ii. Individual economic evaluations were then performed for each distributor taking into consideration the expected transmission revenues that will be generated according to the distributor's load forecast. Each of these economic evaluations produced an individual capital contribution allocation for each distributor. The supporting economic evaluations for each distributor are summarized in Attachment 1 Tables 3 through 6. The economic evaluations result in capital contribution allocations of 84%, 7%, 6% and 1% for Hydro One Distribution, Essex Powerline, ELK Hydro, and Entegrus, respectively. Each individual distributor's pays a capital contribution equal to its capital contribution allocation. Attachment 1 Table 7 summarizes the individual distributor capital contributions.

Hydro One envisions that each distributor will then perform a second level of economic evaluations to determine the capital contribution it will require from its new large customers, as well as an additional economic evaluation for its ratepayers generally. In the case of Hydro One Distribution, the economic evaluations result in a $12.1 million capital contribution from Hydro One Distribution's new large customers. Although currently forecast as a group, capital contribution allocations will be calculated separately for each new large customer. Attachment 1 Table 11 provides Hydro One Distribution's allocation calculations with the supporting economic evaluations for its new large customers and for its ratepayers generally summarized in Attachment 1 Tables 9 through 10.

Transformation Capital Contribution Allocation

Attachment 1 Table 12 provides an overall summary of the proposed approach to allocate the upstream cost of the transformation investment by Hydro One Transmission of $32.1 million—$11.9 million of which is assessed to be for system benefit—to meet the capacity needs of four distributors (one of which is Hydro One Distribution and the other three are embedded customers of Hydro One Distribution), totaling 84 megawatts of non-coincident incremental peak load. The total capital contribution payable at the transmission level, as determined through an economic evaluation performed by Hydro One Transmission, is $8.2 million. See Exhibit B, Tab 4, Schedule 3, for detailed information on the transmission level project economics.

At the distribution level, economic evaluations were performed by Hydro One Distribution to allocate the total $8.2 million capital contribution among the four distributors (including Hydro One Distribution itself).

i. For purposes of economic evaluation, Hydro One Distribution attributed a portion of the project cost to each distributor in proportion to that distributor's contracted capacity. See Attachment 1 Table 13, for detailed calculations.
ii. Individual economic evaluations were then performed for each distributor taking into consideration the expected transmission revenues that will be generated according to the distributor's load forecast. Each of these economic evaluations produced an individual capital contribution allocation for each distributor. The supporting economic evaluations for each distributor are summarized in Attachment 1 Tables 14 through 17. The economic evaluations result in capital contribution allocations of 73%, 6%, 3% and 1% for Hydro One Distribution, Essex Powerline, ELK Hydro, and Entegrus, respectively. Each individual distributor's pays a capital contribution equal to its capital contribution allocation. Attachment 1 Table 18 summarizes the individual distributor capital contributions.

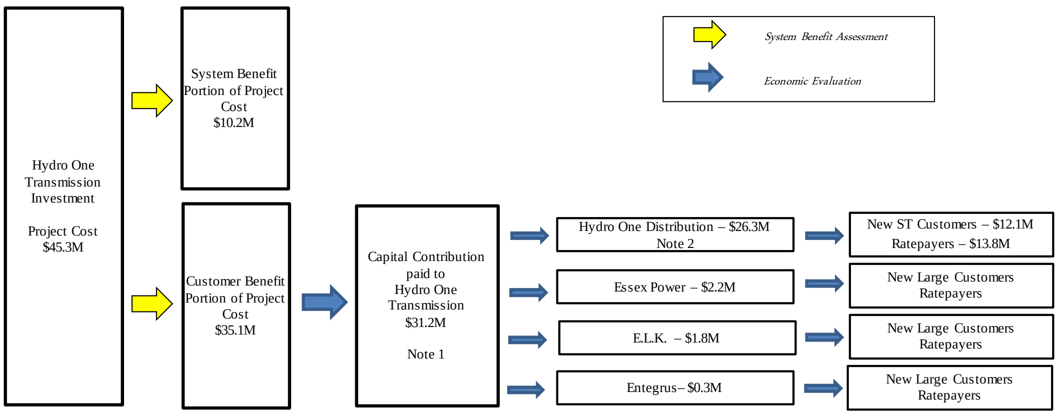
Hydro One envisions that each distributor will then perform a second level of economic evaluations to determine the capital contribution it will require from its new large customers, as well as an additional economic evaluation for its ratepayers generally. In the case of Hydro One Distribution, the economic evaluations result in a $0.6 million capital contribution from Hydro One Distribution's new large customers. Although currently forecast as a group, capital contribution allocations will be calculated separately for each new large customer. Attachment 1 Table 22 provides Hydro One Distribution's allocation calculations with the supporting economic evaluations for its new large customers and for its ratepayers generally summarized in Attachment 1 Tables 19 through 21.

Allocated Capital Contribution Variance

The individual economic evaluations result in 2% of the capital contribution to Hydro One Transmission not being allocated between the embedded distributors for Line Pool and 17% for Transformation Pool. Furthermore, 1% of the allocated capital contribution to Hydro One Distribution is not allocated between New ST Customers and Ratepayers for Line Pool, and 15% for Transformation Pool. This variance is a result of the differing monthly load profile assumptions used in the economic evaluations for Hydro One Distribution at the transmission level versus the monthly load profile used for the economic evaluations for each of the embedded distributors. Similarly monthly profile assumptions may also differ between the parties at the distribution level. For details on the individual embedded distributor and customer load forecast, please see Attachment 1 Table 23 to 28

Although the amount of the variance is expected to be small, Hydro One nevertheless believes it is important to establish a clear treatment for the variance, to avoid uncertainty regarding these costs. Hydro One suggests that one possible treatment may be for the impact of the variance to be applied to the distribution pool of the upstream distributor allocating the capital contribution. Hydro One notes that this approach would be more efficient administratively than the current proposed methodology since it would eliminate the need for separate economic evaluations for ratepayers.

Table 1: Line Pool Allocation of Capital Contribution Summary



Distributor	Contracted Capacity (MW)	Attributed Project Cost (Input to Economic Evaluation) ($M)	Capital Contribution Allocation based on Economic Evaluation	Capital Contribution ($M)		
Hydro One Distribution	71.8	30.0	84.3%	26.3	New ST Customers	12.1
					Ratepayers	13.8
Essex Power	5.9	2.5	6.9%	2.2	New ST Customers	
					Ratepayers	
E.L.K.	5.3	2.2	5.9%	1.8	New ST Customers	
					Ratepayers	
Entegrus	0.9	0.4	1.1%	0.3	New ST Customers	
					Ratepayers	
TOTAL	83.9	35.1	98.2%	30.7		

Note 1: Of the $31.2M capital contribution to Hydro One Transmission, the allocation process results in an unallocated contribution amount of $0.6M .
Note 2: Of the $26.3M capital contribution allocation to Hydro One Distribution, the allocation process results in an unallocated contribution amount of $0.4M .

Table 2: Allocation of Line Project Costs to Distributors

Distributor Capacity	Contracted Capacity (MW)	% of Contracted Capacity
Hydro One Distribution	71.8	85.6%
Essex Power	5.9	7.1%
E.L.K.	5.3	6.3%
Entegrus	0.9	1.0%
TOTAL	**83.9**	**100.0%**

Project Costs	
Capital Expenditures	$ 33.3
Removal Costs	$ 1.8
Total Costs	**$ 35.1**

Allocation of Project Costs by Distributor Capacity	Hydro One Distribution	Essex Powerlines	E.L.K.	Entegrus	Total Costs
% of Contracted Capacity	85.6%	7.1%	6.3%	1.0%	100.0%
Capital Expenditures	$ 28.5	$ 2.4	$ 2.1	$ 0.3	$ 33.3
Removal Costs	$ 1.5	$ 0.1	$ 0.1	$ 0.0	$ 1.8
Total	**$ 30.0**	**$ 2.5**	**$ 2.2**	**$ 0.4**	**$ 35.1**

Table 3: Line Pool Economic Contribution from Hydro One Distribution Page 1

Date:	14-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Hydro One Distribution

		Month / Year	In-Service Date Mar-31 2018	<------- Mar-31 2019	Mar-31 2020	Mar-31 2021	Project year ended - annualized from In-Service Date Mar-31 2022	Mar-31 2023	--------> Mar-31 2024	Mar-31 2025	Mar-31 2026	Mar-31 2027	Mar-31 2028	Mar-31 2029	Mar-31 2030
			0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast															
Load Forecast (MW)				33.7	34.8	35.9	37.0	38.1	39.2	40.3	41.4	42.5	43.6	44.7	45.9
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				33.7	34.8	35.9	37.0	38.1	39.2	40.3	41.4	42.5	43.6	44.7	45.9
Tariff Applied ($/kW/Month)				0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M				0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Removal Costs - $M			(1.5)												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			(1.5)	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Income Taxes			0.4	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Operating Cash Flow (after taxes) - $M			(1.1)	0.4	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	(A)	4.9	(1.1)	0.4	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(28.5)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(28.5)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(28.5)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.1**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	(B)	(28.4)	**(28.4)**												
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)	(23.5)	(29.5)	(29.2)	(28.7)	(28.2)	(27.8)	(27.4)	(27.0)	(26.7)	(26.4)	(26.1)	(25.9)	(25.7)	(25.4)

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - % 5.83%

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		6.0		6.0	
PV OM&A Costs		(1.7)		(1.7)	
PV Municipal Tax		(1.6)		(1.6)	
PV Income Taxes		(0.7)		(0.7)	(0.0)
PV CCA Tax Shield		3.0		0.2	(2.8)
PV Capital - Upfront	(28.5)		(28.5)		
Add: PV Capital Contribution Allocation	**0.0**	(28.5)	**26.3**	(2.2)	26.3
PV Capital - On-going		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		(23.5)		(0.0)	23.5
Profitability Index*		**0.2**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 3: Line Pool Economic Contribution from Hydro One Distribution Page 2

Date:	14-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Hydro One Distribution

<------- Project year ended - annualized from In-Service Date -------->

	Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
	Year	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		47.0	48.1	49.2	50.4	51.5	52.6	53.6	54.8	56.0	57.2	58.3	59.5	60.8
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		47.0	48.1	49.2	50.4	51.5	52.6	53.6	54.8	56.0	57.2	58.3	59.5	60.8
Tariff Applied ($/kW/Month)		0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M		0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Removal Costs - $M														
On-going OM&A Costs - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Income Taxes		0.1	0.1	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(25.2)**	**(25.0)**	**(24.9)**	**(24.7)**	**(24.5)**	**(24.4)**	**(24.2)**	**(24.1)**	**(24.0)**	**(23.9)**	**(23.7)**	**(23.6)**	**(23.5)**

Table 4: Line Pool Economic Contribution from Essex Powerlines Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Essex Powerlines

			In-Service Date	<-------		Project year ended - annualized from In-Service Date			-------->						
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				4.0	3.9	3.9	3.9	3.9	3.8	3.8	3.8	3.8	3.7	3.7	3.7
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				4.0	3.9	3.9	3.9	3.9	3.8	3.8	3.8	3.8	3.7	3.7	3.7
Tariff Applied ($/kW/Month)				0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M			(0.1)												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Cash Flow (after taxes) - $M			(0.1)	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	(A)	**0.4**	**(0.1)**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(2.4)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(2.4)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(2.4)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(2.3)**	**(2.3)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(1.9)**	**(2.4)**	**(2.4)**	**(2.3)**	**(2.3)**	**(2.3)**	**(2.2)**	**(2.2)**	**(2.2)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.1)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		0.5		0.5	
PV OM&A Costs		(0.1)		(0.1)	
PV Municipal Tax		(0.1)		(0.1)	
PV Income Taxes		(0.1)		(0.1)	0.0
PV CCA Tax Shield		0.2		0.0	(0.2)
PV Capital - Upfront	(2.4)		(2.4)		
Add: PV Capital Contribution Allocation	**0.0**	(2.4)	**2.2**	(0.2)	2.2
PV Capital - On-going		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		**(1.9)**		**(0.0)**	**1.9**
Profitability Index*		**0.2**		**1.0**	

Notes:

*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 4: Line Pool Economic Contribution from Essex Powerlines Page *2*

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Essex Powerlines

<------- Project year ended - annualized from In-Service Date -------->

	Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
	Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.5	3.5	3.5
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.5	3.5	3.5
Tariff Applied ($/kW/Month)		0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M														
On-going OM&A Costs - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**	**(1.9)**	**(1.9)**	**(1.9)**	**(1.9)**

Table 5: Line Pool Economic Contribution from E.L.K. Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	E.L.K.

			In-Service Date	<-------		Project year ended - annualized from In-Service Date			------->					
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast														
Load Forecast (MW)				4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Tariff Applied ($/kW/Month)				0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M			(0.1)												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Cash Flow (after taxes) - $M			(0.1)	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.4**	**(0.1)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC			(2.1)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(2.1)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(2.1)**												
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(2.1)**	**(2.1)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(1.7)**	**(2.2)**	**(2.1)**	**(2.1)**	**(2.0)**	**(2.0)**	**(2.0)**	**(1.9)**	**(1.9)**	**(1.9)**	**(1.9)**	**(1.8)**	**(1.8)**	**(1.8)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont		**After Cont**	**Impact**
		$M		$M	$M
PV Incremental Revenue		0.5		0.5	
PV OM&A Costs		(0.1)		(0.1)	
PV Municipal Tax		(0.1)		(0.1)	
PV Income Taxes		(0.1)		(0.1)	(0.0)
PV CCA Tax Shield		0.2		0.0	(0.2)
PV Capital - Upfront	(2.1)		(2.1)		
Add: PV Capital Contribution Allocation	**0.0**	(2.1)	**1.8**	(0.2)	1.8
PV Capital - On-going		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		**(1.7)**		**0.0**	**1.7**
Profitability Index*		**0.2**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 5: Line Pool Economic Contribution from E.L.K. Page 2

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	E.L.K.

<------- Project year ended - annualized from In-Service Date -------->

		Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
Month / Year		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
		13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast														
Load Forecast (MW)		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Tariff Applied ($/kW/Month)		0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M														
On-going OM&A Costs - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes		0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(1.8)**	**(1.8)**	**(1.8)**	**(1.7)**	**(1.7)**	**(1.7)**	**(1.7)**	**(1.7)**	**(1.7)**	**(1.7)**	**(1.7)**	**(1.7)**	**(1.7)**

Table 6: Line Pool Economic Contribution from Entegrus Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Entegrus

			In-Service Date	<-------		Project year ended - annualized from In-Service Date		-------->							
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Tariff Applied ($/kW/Month)				0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M			(0.0)												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Cash Flow (after taxes) - $M			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.0**	**(0.0)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(0.3)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(0.3)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(0.3)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(0.3)**	**(0.3)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(0.3)**	**(0.4)**	**(0.4)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		0.1		0.1	
PV OM&A Costs		(0.0)		(0.0)	
PV Municipal Tax		(0.0)		(0.0)	
PV Income Taxes		(0.0)		(0.0)	(0.0)
PV CCA Tax Shield		0.0		0.0	(0.0)
PV Capital - Upfront	(0.3)		(0.3)		
Add: PV Capital Contribution Allocation	**0.0**	(0.3)	**0.3**	(0.0)	0.3
PV Capital - On-going		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		**(0.3)**		**0.0**	**0.3**
Profitability Index*		**0.1**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 6: Line Pool Economic Contribution from Entegrus Page 2

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Entegrus

		<-------			Project year ended - annualized from In-Service Date			-------->						
	Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
	Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
		13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast														
Load Forecast (MW)		0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Tariff Applied ($/kW/Month)		0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M														
On-going OM&A Costs - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**

Table 7: Allocation of Line Contribution to Distributors ($M)

Hydro One Distribution Capital Contribution to Hydro One Transmission	**$**	**31.2**

Distributor	Capital Contribution Allocation		Allocation Percentage
Hydro One Distribution	$	26.3 [1]	84.3%
Essex Powerlines	$	2.2 [2]	6.9%
E.L.K.	$	1.8 [3]	5.9%
Entegrus	$	0.3 [4]	1.1%
Total	**$**	**30.7**	**98.2%**

1. Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 3
2. Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 4
3. Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 5
4. Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 6

Table 8: Line Pool Cost Allocation to New ST Customers ($M)

Customer Capacity	**Contracted Capacity (MW)**	**% of Contracted Capacity**
Hydro One Distribution Ratepayers	36.1	50.2%
New ST Customers	35.8	49.8%
TOTAL	**71.8**	**100.0%**

Allocation of Project Costs to Hydro One Distribution		
Capital Expenditures	$	28.5
Removal Costs	$	1.5
Total Costs	**$**	**30.0**

Allocation of Hydro One Distribution Project Costs by Customer Capacity	**Hydro One Distribution Ratepayers**		**New ST Customers**		**Total**	
% of Contracted Capacity		50.2%		49.8%		100.0%
Capital Expenditures	$	14.3	$	14.2	$	28.5
Removal Costs	$	0.8	$	0.7	$	1.5
Total	**$**	**15.1**	**$**	**15.0**	**$**	**30.0**

Table 9: Line Pool Economic Contribution from New ST Customers Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	New ST Customers

			In-Service Date	<-------	Project year ended - annualized from In-Service Date			-------->							
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
			0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast															
Load Forecast (MW)				27.1	27.4	27.8	28.1	28.5	28.8	29.2	29.5	29.9	30.2	30.6	30.9
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				27.1	27.4	27.8	28.1	28.5	28.8	29.2	29.5	29.9	30.2	30.6	30.9
Tariff Applied ($/kW/Month)				0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Removal Costs - $M			(0.7)												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			(0.7)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Income Taxes			0.2	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Operating Cash Flow (after taxes) - $M			(0.6)	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	(A)	3.3	(0.6)	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(14.2)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(14.2)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(14.2)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	(B)	(14.2)	(14.2)												
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)	(10.9)	(14.7)	(14.5)	(14.1)	(13.8)	(13.6)	(13.3)	(13.1)	(12.9)	(12.7)	(12.5)	(12.3)	(12.2)	(12.0)

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		4.2		4.2	
PV OM&A Costs		(0.9)		(0.9)	
PV Municipal Tax		(0.8)		(0.8)	
PV Income Taxes		(0.7)		(0.7)	0.0
PV CCA Tax Shield		1.5		0.2	(1.3)
PV Capital - Upfront	(14.2)		(14.2)		
Add: PV Capital Contribution Allocation	**0.0**	(14.2)	**12.1**	(2.1)	12.1
PV Capital - On-going		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		(10.9)		(0.0)	10.9
Profitability Index*		**0.2**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 9: Line Pool Economic Contribution from New ST Customers Page 2

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	New ST Customers

<------- Project year ended - annualized from In-Service Date -------->

Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast													
Load Forecast (MW)	31.3	31.6	32.0	32.3	32.7	33.0	33.4	33.7	34.1	34.4	34.8	35.1	35.5
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	31.3	31.6	32.0	32.3	32.7	33.0	33.4	33.7	34.1	34.4	34.8	35.1	35.5
Tariff Applied ($/kW/Month)	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Removal Costs - $M													
On-going OM&A Costs - $M	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Income Taxes	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
PV Operating Cash Flow (after taxes) - $M (A)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Capital Expenditures - $M													
Upfront - capital cost before overheads & AFUDC													
- Overheads													
- AFUDC													
Total upfront capital expenditures													
On-going capital expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures													
Total capital expenditures - $M													
Capital Expenditures - $M													
PV CCA Residual Tax Shield - $M													
PV Working Capital - $M													
PV Capital (after taxes) - $M (B)													
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	(11.9)	(11.8)	(11.7)	(11.6)	(11.5)	(11.4)	(11.3)	(11.2)	(11.1)	(11.1)	(11.0)	(10.9)	(10.9)

Table 10: Line Pool Economic Contribution from Hydro One Distribution Ratepayers Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Hydro One Distribution Ratepayers

			In-Service Date	<-------		Project year ended - annualized from In-Service Date		-------->						
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast														
Load Forecast (MW)				9.8	10.5	11.3	12.0	12.8	13.5	14.3	15.0	15.8	16.6	17.3	18.1
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				9.8	10.5	11.3	12.0	12.8	13.5	14.3	15.0	15.8	16.6	17.3	18.1
Tariff Applied ($/kW/Month)				0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Removal Costs - $M			(0.8)												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			(0.8)	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Income Taxes			0.2	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Operating Cash Flow (after taxes) - $M			(0.6)	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**1.9**	**(0.6)**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC			(14.3)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(14.3)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(14.3)**												
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(14.3)**	**(14.3)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(12.4)**	**(14.8)**	**(14.7)**	**(14.5)**	**(14.3)**	**(14.1)**	**(14.0)**	**(13.8)**	**(13.7)**	**(13.6)**	**(13.5)**	**(13.4)**	**(13.3)**	**(13.2)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		**After Cont** $M	**Impact** $M
PV Incremental Revenue		2.3		2.3	
PV OM&A Costs		(0.9)		(0.9)	
PV Municipal Tax		(0.8)		(0.8)	
PV Income Taxes		(0.2)		(0.2)	0.0
PV CCA Tax Shield		1.5		0.1	(1.5)
PV Capital - Upfront	(14.3)		(14.3)		
Add: PV Capital Contribution Allocation	**0.0**	(14.3)	**13.8**	(0.5)	13.8
PV Capital - On-going		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		**(12.4)**		**0.0**	**12.4**
Profitability Index*		**0.1**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 10: Line Pool Economic Contribution from Hydro One Distribution Ratepayers Page 2

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Hydro One Distribution Ratepayers

<------- Project year ended - annualized from In-Service Date -------->

		Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
	Month / Year	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		18.9	19.6	20.4	21.2	22.0	22.8	23.5	24.3	25.1	25.9	26.8	27.6	28.5
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		18.9	19.6	20.4	21.2	22.0	22.8	23.5	24.3	25.1	25.9	26.8	27.6	28.5
Tariff Applied ($/kW/Month)		0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Incremental Revenue - $M		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Removal Costs - $M														
On-going OM&A Costs - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Income Taxes		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(13.1)**	**(13.0)**	**(12.9)**	**(12.9)**	**(12.8)**	**(12.7)**	**(12.7)**	**(12.6)**	**(12.6)**	**(12.5)**	**(12.5)**	**(12.4)**	**(12.4)**

Table 11: Allocation of Line Contribution to New ST Customers ($M)

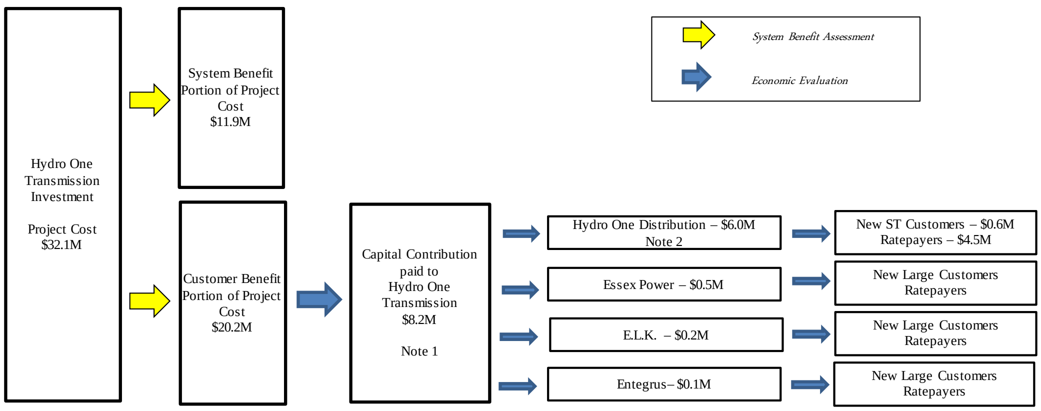
Hydro One Distribution Lines Capital Contribution Allocation	**$**	**26.3**

Customer	Capital Contribution Allocation		Allocation Percentage
Hydro One Distribution Ratepayers	$	13.8 [1]	52.5%
New ST Customers	$	12.1 [2]	46.1%
Total	**$**	**26.0**	**98.6%**

[1] Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 10

[2] Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 9

Table 12: Transformation Pool Allocation of Capital Contribution Summary



Distributor	Contracted Capacity (MW)	Attributed Project Cost (Input to Economic Evaluation) ($M)	Capital Contribution Allocation Percentage based on Economic Evaluation	Capital Contribution ($M)		
Hydro One Distribution	71.8	17.3	73.4%	6.0	New ST Customers	0.6
					Ratepayers	4.5
Essex Power	5.9	1.4	5.6%	0.5	New ST Customers	
					Ratepayers	
E.L.K.	5.3	1.3	2.9%	0.2	New ST Customers	
					Ratepayers	
Entegrus	0.9	0.2	1.3%	0.1	New ST Customers	
					Ratepayers	
TOTAL	83.9	20.2	83.2%	6.8		

Note 1: Of the $8.2M capital contribution to Hydro One Transmission, the allocation process results in an unallocated contribution amount of $1.4M .
Note 2: Of the $6.0M capital contribution allocation to Hydro One Distribution, the allocation process results in an unallocated contribution amount of $0.9M .

Table 13: Allocation of Transformation Project Costs to Distributors

Distributor Capacity	Contracted Capacity (MW)	% of Contracted Capacity
Hydro One Distribution	71.8	85.6%
Essex Power	5.9	7.1%
E.L.K.	5.3	6.3%
Entegrus	0.9	1.0%
TOTAL	**83.9**	**100.0%**

Project Costs		
Capital Expenditures	$	20.2
Removal Costs	$	-
Total Costs	**$**	**20.2**

Allocation of Project Costs by Distributor Capacity	Hydro One Distribution	Essex Powerlines	E.L.K.	Entegrus	Total Costs
% of Contracted Capacity	85.6%	7.1%	6.3%	1.0%	100.0%
Capital Expenditures	$ 17.3	$ 1.4	$ 1.3	$ 0.2	$ 20.2
Removal Costs	$ -	$ -	$ -	$ -	$ -
Total	**$ 17.3**	**$ 1.4**	**$ 1.3**	**$ 0.2**	**$ 20.2**

Table 14: Transformation Pool Economic Contribution from Hydro One Distribution Page 1

Date:	14-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Hydro One Distribution

<------- Project year ended - annualized from In-Service Date -------->

		Cumulative PV @ 5.83%	In-Service Date Mar-31 2018 (0)	Mar-31 2019 (1)	Mar-31 2020 (2)	Mar-31 2021 (3)	Mar-31 2022 (4)	Mar-31 2023 (5)	Mar-31 2024 (6)	Mar-31 2025 (7)	Mar-31 2026 (8)	Mar-31 2027 (9)	Mar-31 2028 (10)	Mar-31 2029 (11)	Mar-31 2030 (12)
Revenue & Expense Forecast															
Load Forecast (MW)				33.7	34.8	35.9	37.0	38.1	39.2	40.3	41.4	42.5	43.6	44.7	45.9
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				33.7	34.8	35.9	37.0	38.1	39.2	40.3	41.4	42.5	43.6	44.7	45.9
Tariff Applied ($/kW/Month)				2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M				0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			0.0	0.7	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Income Taxes			0.0	(0.0)	0.1	0.1	0.1	0.0	0.0	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M			0.0	0.7	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
PV Operating Cash Flow (after taxes) - $M	**(A)**	12.1	**0.0**	**0.7**	**0.8**	**0.8**	**0.7**	**0.7**	**0.6**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(17.3)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(17.3)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(17.3)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.1**												
PV Working Capital - $M			**0.0**												
PV Capital (after taxes) - $M	**(B)**	(17.2)	**(17.2)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	(5.1)	**(17.2)**	**(16.5)**	**(15.7)**	**(14.9)**	**(14.2)**	**(13.5)**	**(12.9)**	**(12.2)**	**(11.7)**	**(11.1)**	**(10.6)**	**(10.1)**	**(9.6)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		**After Cont** $M	**Impact** $M
PV Incremental Revenue		14.1		14.1	
PV OM&A Costs		0.0		0.0	
PV Municipal Tax		(1.0)		(1.0)	
PV Income Taxes		(3.5)		(3.5)	(0.0)
PV CCA Tax Shield		2.6		1.7	(0.9)
PV Capital - Upfront	(17.3)		(17.3)		
Add: PV Capital Contribution Allocation	**0.0**	(17.3)	**6.0**	(11.3)	6.0
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		**(5.1)**		**0.0**	**5.1**
Profitability Index*		**0.7**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 14: Transformation Pool Economic Contribution from Hydro One Distribution Page 2

Date:	14-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Hydro One Distribution

<------- Project year ended - annualized from In-Service Date -------->

Month Year	Mar-31 2031 13	Mar-31 2032 14	Mar-31 2033 15	Mar-31 2034 16	Mar-31 2035 17	Mar-31 2036 18	Mar-31 2037 19	Mar-31 2038 20	Mar-31 2039 21	Mar-31 2040 22	Mar-31 2041 23	Mar-31 2042 24	Mar-31 2043 25
Revenue & Expense Forecast													
Load Forecast (MW)	47.0	48.1	49.2	50.4	51.5	52.6	53.6	54.8	56.0	57.2	58.3	59.5	60.8
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	47.0	48.1	49.2	50.4	51.5	52.6	53.6	54.8	56.0	57.2	58.3	59.5	60.8
Tariff Applied ($/kW/Month)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.5
Removal Costs - $M													
On-going OM&A Costs - $M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4
Income Taxes	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Operating Cash Flow (after taxes) - $M	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1
PV Operating Cash Flow (after taxes) - $M (A)	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Capital Expenditures - $M													
Upfront - capital cost before overheads & AFUDC													
- Overheads													
- AFUDC													
Total upfront capital expenditures													
On-going capital expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures													
Total capital expenditures - $M													
Capital Expenditures - $M													
PV CCA Residual Tax Shield - $M													
PV Working Capital - $M													
PV Capital (after taxes) - $M (B)													
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	(9.2)	(8.8)	(8.4)	(8.0)	(7.6)	(7.2)	(6.9)	(6.6)	(6.2)	(5.9)	(5.7)	(5.4)	(5.1)

Table 15: Transformation Pool Economic Contribution from Essex Powerlines Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Essex Powelines

		In-Service Date	<-------	Project year ended - annualized from In-Service Date	-------->									
	Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
	Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			4.0	3.9	3.9	3.9	3.9	3.8	3.8	3.8	3.8	3.7	3.7	3.7
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			4.0	3.9	3.9	3.9	3.9	3.8	3.8	3.8	3.8	3.7	3.7	3.7
Tariff Applied ($/kW/Month)			2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Removal Costs - $M		0.0												
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M			(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Income Taxes		0.0	(0.0)	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M (A)	**1.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC		(1.4)												
- Overheads		0.0												
- AFUDC		0.0												
Total upfront capital expenditures		**(1.4)**												
On-going capital expenditures			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures		0.0												
Total capital expenditures - $M		**(1.4)**												
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M		**0.0**												
PV Working Capital - $M		**0.0**												
PV Capital (after taxes) - $M (B)	**(1.4)**	**(1.4)**												
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	**(0.4)**	**(1.4)**	**(1.3)**	**(1.3)**	**(1.2)**	**(1.1)**	**(1.0)**	**(1.0)**	**(0.9)**	**(0.9)**	**(0.8)**	**(0.8)**	**(0.7)**	**(0.7)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		1.2		1.2	
PV OM&A Costs		0.0		0.0	
PV Municipal Tax		(0.1)		(0.1)	
PV Income Taxes		(0.3)		(0.3)	(0.0)
PV CCA Tax Shield		0.2		0.1	(0.1)
PV Capital - Upfront	(1.4)		(1.4)		
Add: PV Capital Contribution Allocation	**0.0**	(1.4)	**0.5**	(1.0)	0.5
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		**(0.4)**		**(0.0)**	**0.4**
Profitability Index*		**0.7**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 15: Transformation Pool Economic Contribution from Essex Powerlines Page *2*

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Essex Powelines

<------- Project year ended - annualized from In-Service Date -------->

	Month Year	Mar-31 **2031**	Mar-31 **2032**	Mar-31 **2033**	Mar-31 **2034**	Mar-31 **2035**	Mar-31 **2036**	Mar-31 **2037**	Mar-31 **2038**	Mar-31 **2039**	Mar-31 **2040**	Mar-31 **2041**	Mar-31 **2042**	Mar-31 **2043**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.5	3.5	3.5
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.5	3.5	3.5
Tariff Applied ($/kW/Month)		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Removal Costs - $M														
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Income Taxes		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(0.7)**	**(0.6)**	**(0.6)**	**(0.6)**	**(0.5)**	**(0.5)**	**(0.5)**	**(0.5)**	**(0.5)**	**(0.4)**	**(0.4)**	**(0.4)**	**(0.4)**

Table 16: Transformation Pool Economic Contribution from E.L.K. Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	E.L.K.

			In-Service Date	<-------		Project year ended - annualized from In-Service Date		-------->							
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
			0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast															
Load Forecast (MW)				4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Tariff Applied ($/kW/Month)				2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Income Taxes			0.0	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M			0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	(A)	1.1	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(1.3)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(1.3)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(1.3)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**0.0**												
PV Capital (after taxes) - $M	(B)	(1.3)	**(1.3)**												
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)	(0.2)	**(1.3)**	**(1.2)**	**(1.1)**	**(1.0)**	**(1.0)**	**(0.9)**	**(0.8)**	**(0.8)**	**(0.7)**	**(0.7)**	**(0.6)**	**(0.6)**	**(0.5)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - % 5.83%

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		1.3		1.3	
PV OM&A Costs		0.0		0.0	
PV Municipal Tax		(0.1)		(0.1)	
PV Income Taxes		(0.3)		(0.3)	0.0
PV CCA Tax Shield		0.2		0.2	(0.0)
PV Capital - Upfront	(1.3)		(1.3)		
Add: PV Capital Contribution Allocation	**0.0**	(1.3)	**0.2**	(1.0)	0.2
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		(0.2)		0.0	0.2
Profitability Index*		**0.8**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 16: Transformation Pool Economic Contribution from E.L.K. Page 2

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	E.L.K.

<------- Project year ended - annualized from In-Service Date -------->

		Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
Month / Year		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
		13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast														
Load Forecast (MW)		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Tariff Applied ($/kW/Month)		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Removal Costs - $M														
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Income Taxes		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV Operating Cash Flow (after taxes) - $M	**(A)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	(0.5)	(0.5)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)

Table 17: Transformation Pool Economic Contribution from Entegrus Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Entegrus

			In-Service Date	<-------		Project year ended - annualized from In-Service Date		-------->							
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Tariff Applied ($/kW/Month)				2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(0.2)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(0.2)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(0.2)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**0.0**												
PV Capital (after taxes) - $M	**(B)**	**(0.2)**	**(0.2)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(0.1)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		0.1		0.1	
PV OM&A Costs		0.0		0.0	
PV Municipal Tax		(0.0)		(0.0)	
PV Income Taxes		(0.0)		(0.0)	
PV CCA Tax Shield		0.0		0.0	(0.0)
PV Capital - Upfront	(0.2)		(0.2)		
Add: PV Capital Contribution Allocation	**0.0**	(0.2)	**0.1**	(0.1)	0.1
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		**(0.1)**		**(0.0)**	**0.1**
Profitability Index*		**0.6**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 17: Transformation Pool Economic Contribution from Entegrus Page 2

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Entegrus

		<-------		Project year ended - annualized from In-Service Date			-------->							
	Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
	Year	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Tariff Applied ($/kW/Month)		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M														
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**

Table 18: Allocation of Transformation Contribution to Distributors ($M)

Hydro One Distribution Capital Contribution to Hydro One Transmission	**$**	**8.2**

Distributor	Capital Contribution Allocation		Allocation Percentage
Hydro One Distribution	$	6.0 [1]	73.4%
Essex Powerlines	$	0.5 [2]	5.6%
E.L.K.	$	0.2 [3]	2.9%
Entegrus	$	0.1 [4]	1.3%
Total	**$**	**6.8**	**83.2%**

1. Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 14
2. Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 15
3. Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 16
4. Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 17

Table 19: Transformation Pool Cost Allocation to New ST Customers ($M)

Customer Capacity	Contracted Capacity (MW)	% of Contracted Capacity
Hydro One Distribution Ratepayers	36.1	50.2%
New ST Customers	35.8	49.8%
TOTAL	**71.8**	**100.0%**

Allocation of Project Costs to Hydro One Distribution		
Capital Expenditures	$	17.3
Removal Costs	$	-
Total Costs	**$**	**17.3**

Allocation of Hydro One Distribution Project Costs by Customer Capacity	Hydro One Distribution Ratepayers		New ST Customers		Total	
% of Contracted Capacity		50.2%		49.8%		100.0%
Capital Expenditures	$	8.7	$	8.6	$	17.3
Removal Costs	$	-	$	-	$	-
Total	**$**	**8.7**	**$**	**8.6**	**$**	**17.3**

Table 20: Transformation Pool Economic Contribution from New ST Customers Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	New ST Customers

			In-Service Date	<-------		Project year ended - annualized from In-Service Date			------->					
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast														
Load Forecast (MW)				27.1	27.4	27.8	28.1	28.5	28.8	29.2	29.5	29.9	30.2	30.6	30.9
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				27.1	27.4	27.8	28.1	28.5	28.8	29.2	29.5	29.9	30.2	30.6	30.9
Tariff Applied ($/kW/Month)				2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M				0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			0.0	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Income Taxes			0.0	(0.1)	0.0	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M			0.0	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**8.0**	**0.0**	**0.5**	**0.6**	**0.5**	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC			(8.6)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(8.6)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(8.6)**												
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**0.0**												
PV Capital (after taxes) - $M	**(B)**	**(8.6)**	**(8.6)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(0.5)**	**(8.6)**	**(8.0)**	**(7.5)**	**(6.9)**	**(6.4)**	**(6.0)**	**(5.5)**	**(5.1)**	**(4.7)**	**(4.3)**	**(4.0)**	**(3.7)**	**(3.4)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		9.7		9.7	
PV OM&A Costs		0.0		0.0	
PV Municipal Tax		(0.5)		(0.5)	
PV Income Taxes		(2.4)		(2.4)	
PV CCA Tax Shield		1.3		1.2	(0.1)
PV Capital - Upfront	(8.6)		(8.6)		
Add: PV Capital Contribution Allocation	**0.0**	(8.6)	**0.6**	(8.0)	0.6
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		(0.5)		(0.0)	0.5
Profitability Index*		**0.9**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 20: Transformation Pool Economic Contribution from New ST Customers Page 2

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	New ST Customers

		<-------			Project year ended - annualized from In-Service Date		-------->							
	Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
	Year	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		31.3	31.6	32.0	32.3	32.7	33.0	33.4	33.7	34.1	34.4	34.8	35.1	35.5
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		31.3	31.6	32.0	32.3	32.7	33.0	33.4	33.7	34.1	34.4	34.8	35.1	35.5
Tariff Applied ($/kW/Month)		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Removal Costs - $M														
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Income Taxes		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Operating Cash Flow (after taxes) - $M		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
PV Operating Cash Flow (after taxes) - $M (A)		**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M (B)														
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)		**(3.1)**	**(2.8)**	**(2.5)**	**(2.3)**	**(2.0)**	**(1.8)**	**(1.6)**	**(1.4)**	**(1.2)**	**(1.0)**	**(0.9)**	**(0.7)**	**(0.5)**

Table 21: Transformation Pool Economic Contribution from Hydro One Distribution Ratepayers Page 1

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Hydro One Distribution Ratepayer

			In-Service Date	<-------			Project year ended - annualized from In-Service Date			-------->					
		Month	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31	Mar-31
		Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				9.8	10.5	11.3	12.0	12.8	13.5	14.3	15.0	15.8	16.6	17.3	18.1
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				9.8	10.5	11.3	12.0	12.8	13.5	14.3	15.0	15.8	16.6	17.3	18.1
Tariff Applied ($/kW/Month)				2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M				0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			0.0	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Income Taxes			0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M			0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
		Cumulative PV @ 5.83%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**4.8**	**0.0**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(8.7)												
- Overheads			0.0												
- AFUDC			0.0												
Total upfront capital expenditures			**(8.7)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(8.7)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**0.0**												
PV Capital (after taxes) - $M	**(B)**	**(8.7)**	**(8.7)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(3.8)**	**(8.7)**	**(8.4)**	**(8.1)**	**(7.8)**	**(7.6)**	**(7.3)**	**(7.1)**	**(6.8)**	**(6.6)**	**(6.4)**	**(6.2)**	**(6.0)**	**(5.8)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.83%**

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		5.4		5.4	
PV OM&A Costs		0.0		0.0	
PV Municipal Tax		(0.5)		(0.5)	
PV Income Taxes		(1.3)		(1.3)	0.0
PV CCA Tax Shield		1.3		0.6	(0.7)
PV Capital - Upfront	(8.7)		(8.7)		
Add: PV Capital Contribution Allocation	**0.0**	(8.7)	**4.5**	(4.2)	4.5
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		**(3.8)**		**0.0**	**3.8**
Profitability Index*		**0.6**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Table 21: Transformation Pool Economic Contribution from Hydro One Distribution Ratepayers Page 2

Date:	13-Apr-15
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Capital Contribution Allocation
Customer:	Hydro One Distribution Ratepayer

<------- Project year ended - annualized from In-Service Date -------->

	Month / Year	Mar-31 **2031**	Mar-31 **2032**	Mar-31 **2033**	Mar-31 **2034**	Mar-31 **2035**	Mar-31 **2036**	Mar-31 **2037**	Mar-31 **2038**	Mar-31 **2039**	Mar-31 **2040**	Mar-31 **2041**	Mar-31 **2042**	Mar-31 **2043**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		18.9	19.6	20.4	21.2	22.0	22.8	23.5	24.3	25.1	25.9	26.8	27.6	28.5
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		18.9	19.6	20.4	21.2	22.0	22.8	23.5	24.3	25.1	25.9	26.8	27.6	28.5
Tariff Applied ($/kW/Month)		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Incremental Revenue - $M		0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Removal Costs - $M														
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Income Taxes		(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(5.6)**	**(5.4)**	**(5.3)**	**(5.1)**	**(4.9)**	**(4.8)**	**(4.6)**	**(4.5)**	**(4.3)**	**(4.2)**	**(4.1)**	**(3.9)**	**(3.8)**

Table 22: Allocation of Transformation Contribution to New ST Customers ($M)

Hydro One Distribution Transformation Capital Contribution Allocation	**$**	**6.0**

Customer		Capital Contribution Allocation	Allocation Percentage
Hydro One Distribution Ratepayers	$	4.5 [1]	74.5%
New ST Customers	$	0.6 [2]	10.7%
Total	**$**	**5.1**	**85.2%**

[1] Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 21

[2] Exhibit I, Phase 2, Tab 2, Schedule 9 Attachment 1 Table 20

Table 23: Derivation of Load used for Hydro One Distribution

Annual Non-Coincident Peak Load Forecast for SECTR Project

Relevant Hydro One Distribution Loads		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Load Forecast	MW	101.0	102.3	103.6	104.9	106.2	107.4	108.7	110.0	111.3	112.6	113.9	115.2	116.5
Current Capacity	MW	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2
Load in excess of capacity, calendar-year basis	MW	38.8	40.1	41.4	42.7	44.0	45.2	46.5	47.8	49.1	50.4	51.7	53.0	54.3
PLI-adjustment		*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*
PLI-adjusted load in excess of capacity	MW	33.4	34.5	35.6	36.7	37.8	38.9	40.0	41.1	42.2	43.3	44.4	45.6	46.7
Adjusted for in-service month:														
Project Year*			***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***
			March 31, 2018 to March 30, 2019	March 31, 2019 to March 30, 2020	March 31, 2020 to March 30, 2021	March 31, 2021 to March 30, 2022	March 31, 2022 to March 30, 2023	March 31, 2023 to March 30, 2024	March 31, 2024 to March 30, 2025	March 31, 2025 to March 30, 2026	March 31, 2026 to March 30, 2027	March 31, 2027 to March 30, 2028	March 31, 2028 to March 30, 2029	March 31, 2029 to March 30, 2030
Load in excess of capacity, project-year basis	**MW**		**33.7**	**34.8**	**35.9**	**37.0**	**38.1**	**39.2**	**40.3**	**41.4**	**42.5**	**43.6**	**44.7**	**45.9**

Annual Non-Coincident Peak Load Forecast for SECTR Project

Relevant Hydro One Distribution Loads		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Load Forecast	MW	117.7	119.1	120.4	121.8	123.1	124.2	125.6	126.9	128.3	129.7	131.1	132.5	134.0
Current Capacity	MW	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2
Load in excess of capacity, calendar-year basis	MW	55.5	56.9	58.2	59.6	60.9	62.0	63.4	64.7	66.1	67.5	68.9	70.3	71.8
PLI-adjustment		*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*	*86%*
PLI-adjusted load in excess of capacity	MW	47.8	48.9	50.1	51.2	52.4	53.3	54.5	55.7	56.9	58.0	59.2	60.5	61.8
Adjusted for in-service month:														
Project Year*		***13***	***14***	***15***	***16***	***17***	***18***	***19***	***20***	***21***	***22***	***23***	***24***	***25***
		March 31, 2030 to March 30, 2031	March 31, 2031 to March 30, 2032	March 31, 2032 to March 30, 2033	March 31, 2033 to March 30, 2034	March 31, 2034 to March 30, 2035	March 31, 2035 to March 30, 2036	March 31, 2036 to March 30, 2037	March 31, 2037 to March 30, 2038	March 31, 2038 to March 30, 2039	March 31, 2039 to March 30, 2040	March 31, 2040 to March 30, 2041	March 31, 2041 to March 30, 2042	March 31, 2042 to March 30, 2043
Load in excess of capacity, project-year basis	**MW**	**47.0**	**48.1**	**49.2**	**50.4**	**51.5**	**52.6**	**53.6**	**54.8**	**56.0**	**57.2**	**58.3**	**59.5**	**60.8**

Table 24: Derivation of Load used for Essex Power Lines

		Annual Non-Coincident Peak Load Forecast for SECTR Project												
Relevant Essex Powerlines Loads		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Load Forecast	MW	35.3	35.3	35.3	35.2	35.2	35.1	35.1	35.1	35.0	35.0	35.0	35.0	34.9
Current Capacity	MW	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4
Load in excess of capacity, calendar-year basis	MW	5.9	5.9	5.8	5.8	5.8	5.7	5.7	5.7	5.6	5.6	5.6	5.5	5.5
PLI-adjustment		*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*
PLI-adjusted load in excess of capacity	MW	4.0	3.9	3.9	3.9	3.9	3.8	3.8	3.8	3.8	3.8	3.7	3.7	3.7

Adjusted for in-service month:													
Project Year*		***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***
		March 31, 2018 to March 30, 2019	March 31, 2019 to March 30, 2020	March 31, 2020 to March 30, 2021	March 31, 2021 to March 30, 2022	March 31, 2022 to March 30, 2023	March 31, 2023 to March 30, 2024	March 31, 2024 to March 30, 2025	March 31, 2025 to March 30, 2026	March 31, 2026 to March 30, 2027	March 31, 2027 to March 30, 2028	March 31, 2028 to March 30, 2029	March 31, 2029 to March 30, 2030
Load in excess of capacity, project-year basis	**MW**	**4.0**	**3.9**	**3.9**	**3.9**	**3.9**	**3.8**	**3.8**	**3.8**	**3.8**	**3.7**	**3.7**	**3.7**

Note:

		Annual Non-Coincident Peak Load Forecast for SECTR Project												
Relevant Essex Powerlines Loads		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Load Forecast	MW	34.9	34.9	34.8	34.8	34.8	34.8	34.8	34.7	34.7	34.7	34.7	34.7	34.6
Current Capacity	MW	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4
Load in excess of capacity, calendar-year basis	MW	5.5	5.5	5.4	5.4	5.4	5.4	5.3	5.3	5.3	5.3	5.3	5.2	5.2
PLI-adjustment		*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*	*67%*
PLI-adjusted load in excess of capacity	MW	3.7	3.7	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.5	3.5	3.5

Adjusted for in-service month:														
Project Year*		***13***	***14***	***15***	***16***	***17***	***18***	***19***	***20***	***21***	***22***	***23***	***24***	***25***
		March 31, 2030 to March 30, 2031	March 31, 2031 to March 30, 2032	March 31, 2032 to March 30, 2033	March 31, 2033 to March 30, 2034	March 31, 2034 to March 30, 2035	March 31, 2035 to March 30, 2036	March 31, 2036 to March 30, 2037	March 31, 2037 to March 30, 2038	March 31, 2038 to March 30, 2039	March 31, 2039 to March 30, 2040	March 31, 2040 to March 30, 2041	March 31, 2041 to March 30, 2042	March 31, 2042 to March 30, 2043
Load in excess of capacity, project-year basis	**MW**	**3.7**	**3.7**	**3.7**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.5**	**3.5**	**3.5**	**3.5**

Note:
* Project-year load = 3/12 of current year load + 9/12 of previous calendar-year load, based on March 31, 2018 in-service date

Table 25: Derivation of Load used for E.L.K.

		Annual Non-Coincident Peak Load Forecast for SECTR Project												
Relevant E.L.K. Powerlines Loads		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Load Forecast	MW	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Current Capacity	MW	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2
Load in excess of capacity, calendar-year basis	MW	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
PLI-adjustment		*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
PLI-adjusted load in excess of capacity	MW	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0

Adjusted for in-service month:														
Project Year*			***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***
			March 31, 2018 to March 30, 2019	March 31, 2019 to March 30, 2020	March 31, 2020 to March 30, 2021	March 31, 2021 to March 30, 2022	March 31, 2022 to March 30, 2023	March 31, 2023 to March 30, 2024	March 31, 2024 to March 30, 2025	March 31, 2025 to March 30, 2026	March 31, 2026 to March 30, 2027	March 31, 2027 to March 30, 2028	March 31, 2028 to March 30, 2029	March 31, 2029 to March 30, 2030
Load in excess of capacity, project-year basis	**MW**		**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**

		Annual Non-Coincident Peak Load Forecast for SECTR Project												
Relevant E.L.K. Powerlines Loads		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Load Forecast	MW	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Current Capacity	MW	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2
Load in excess of capacity, calendar-year basis	MW	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
PLI-adjustment		*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
PLI-adjusted load in excess of capacity	MW	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0

Adjusted for in-service month:													
Project Year*		***13***	***14***	***15***	***16***	***17***	***18***	***19***	***20***	***21***	***22***	***23***	***24***	***25***
		March 31, 2030 to March 30, 2031	March 31, 2031 to March 30, 2032	March 31, 2032 to March 30, 2033	March 31, 2033 to March 30, 2034	March 31, 2034 to March 30, 2035	March 31, 2035 to March 30, 2036	March 31, 2036 to March 30, 2037	March 31, 2037 to March 30, 2038	March 31, 2038 to March 30, 2039	March 31, 2039 to March 30, 2040	March 31, 2040 to March 30, 2041	March 31, 2041 to March 30, 2042	March 31, 2042 to March 30, 2043
Load in excess of capacity, project-year basis	**MW**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**

Note:
* Project-year load = 3/12 of current year load + 9/12 of previous calendar-year load, based on March 31, 2018 in-service date

Table 26: Derivation of Load used for Entegrus

Annual Non-Coincident Peak Load Forecast for SECTR Project

Relevant Entegrus Powerlines Loads		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Load Forecast	MW	2.6	2.7	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.8
Current Capacity	MW	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Load in excess of capacity, calendar-year basis	MW	0.4	0.5	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6
PLI-adjustment		*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
PLI-adjusted load in excess of capacity	MW	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4

Adjusted for in-service month:

Project Year*		***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***
		March 31, 2018 to March 30, 2019	March 31, 2019 to March 30, 2020	March 31, 2020 to March 30, 2021	March 31, 2021 to March 30, 2022	March 31, 2022 to March 30, 2023	March 31, 2023 to March 30, 2024	March 31, 2024 to March 30, 2025	March 31, 2025 to March 30, 2026	March 31, 2026 to March 30, 2027	March 31, 2027 to March 30, 2028	March 31, 2028 to March 30, 2029	March 31, 2029 to March 30, 2030
Load in excess of capacity, project-year basis	**MW**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**

Annual Non-Coincident Peak Load Forecast for SECTR Project

Relevant Entegrus Powerlines Loads		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Load Forecast	MW	2.8	2.8	2.8	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.1
Current Capacity	MW	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Load in excess of capacity, calendar-year basis	MW	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9
PLI-adjustment		*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
PLI-adjusted load in excess of capacity	MW	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7

Adjusted for in-service month:

Project Year*		***13***	***14***	***15***	***16***	***17***	***18***	***19***	***20***	***21***	***22***	***23***	***24***	***25***
		March 31, 2030 to March 30, 2031	March 31, 2031 to March 30, 2032	March 31, 2032 to March 30, 2033	March 31, 2033 to March 30, 2034	March 31, 2034 to March 30, 2035	March 31, 2035 to March 30, 2036	March 31, 2036 to March 30, 2037	March 31, 2037 to March 30, 2038	March 31, 2038 to March 30, 2039	March 31, 2039 to March 30, 2040	March 31, 2040 to March 30, 2041	March 31, 2041 to March 30, 2042	March 31, 2042 to March 30, 2043
Load in excess of capacity, project-year basis	**MW**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**

Note:
* Project-year load = 3/12 of current year load + 9/12 of previous calendar-year load, based on March 31, 2018 in-service date

Table 27: Derivation of Load used for New ST Customers

		Annual Non-Coincident Peak Load Forecast for SECTR Project												
Relevant New ST Loads		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Load Forecast	MW	27.0	27.4	27.7	28.1	28.4	28.8	29.1	29.5	29.8	30.2	30.5	30.9	31.2
Current Capacity	MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load in excess of capacity, calendar-year basis	MW	27.0	27.4	27.7	28.1	28.4	28.8	29.1	29.5	29.8	30.2	30.5	30.9	31.2
PLI-adjustment		*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
PLI-adjusted load in excess of capacity	MW	27.0	27.4	27.7	28.1	28.4	28.8	29.1	29.5	29.8	30.2	30.5	30.9	31.2
Adjusted for in-service month:														
Project Year*			***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***
			March 31, 2018 to March 30, 2019	March 31, 2019 to March 30, 2020	March 31, 2020 to March 30, 2021	March 31, 2021 to March 30, 2022	March 31, 2022 to March 30, 2023	March 31, 2023 to March 30, 2024	March 31, 2024 to March 30, 2025	March 31, 2025 to March 30, 2026	March 31, 2026 to March 30, 2027	March 31, 2027 to March 30, 2028	March 31, 2028 to March 30, 2029	March 31, 2029 to March 30, 2030
Load in excess of capacity, project-year basis	**MW**		**27.1**	**27.4**	**27.8**	**28.1**	**28.5**	**28.8**	**29.2**	**29.5**	**29.9**	**30.2**	**30.6**	**30.9**

		Annual Non-Coincident Peak Load Forecast for SECTR Project												
Relevant New ST Loads		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Load Forecast	MW	31.6	31.9	32.3	32.6	33.0	33.3	33.7	34.0	34.4	34.7	35.1	35.4	35.8
Current Capacity	MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load in excess of capacity, calendar-year basis	MW	31.6	31.9	32.3	32.6	33.0	33.3	33.7	34.0	34.4	34.7	35.1	35.4	35.8
PLI-adjustment		*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
PLI-adjusted load in excess of capacity	MW	31.6	31.9	32.3	32.6	33.0	33.3	33.7	34.0	34.4	34.7	35.1	35.4	35.8
Adjusted for in-service month:														
Project Year*		***13***	***14***	***15***	***16***	***17***	***18***	***19***	***20***	***21***	***22***	***23***	***24***	***25***
		March 31, 2030 to March 30, 2031	March 31, 2031 to March 30, 2032	March 31, 2032 to March 30, 2033	March 31, 2033 to March 30, 2034	March 31, 2034 to March 30, 2035	March 31, 2035 to March 30, 2036	March 31, 2036 to March 30, 2037	March 31, 2037 to March 30, 2038	March 31, 2038 to March 30, 2039	March 31, 2039 to March 30, 2040	March 31, 2040 to March 30, 2041	March 31, 2041 to March 30, 2042	March 31, 2042 to March 30, 2043
Load in excess of capacity, project-year basis	**MW**	**31.3**	**31.6**	**32.0**	**32.3**	**32.7**	**33.0**	**33.4**	**33.7**	**34.1**	**34.4**	**34.8**	**35.1**	**35.5**

Note:
* Project-year load = 3/12 of current year load + 9/12 of previous calendar-year load, based on March 31, 2018 in-service date

Table 28: Derivation of Load used for Hydro One Distribution Ratepayers

		Annual Non-Coincident Peak Load Forecast for SECTR Project												
Relevant Hydro One Ratepayers Loads		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Load Forecast	MW	74.0	74.9	75.9	76.8	77.7	78.7	79.6	80.5	81.5	82.4	83.4	84.3	85.3
Current Capacity	MW	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2
Load in excess of capacity, calendar-year basis	MW	11.8	12.7	13.7	14.6	15.6	16.5	17.4	18.3	19.3	20.2	21.2	22.1	23.1
PLI-adjustment		*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*
PLI-adjusted load in excess of capacity	MW	9.6	10.3	11.1	11.9	12.6	13.3	14.1	14.9	15.6	16.4	17.2	17.9	18.7
Adjusted for in-service month:														
Project Year*			***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***
			March 31, 2018 to March 30, 2019	March 31, 2019 to March 30, 2020	March 31, 2020 to March 30, 2021	March 31, 2021 to March 30, 2022	March 31, 2022 to March 30, 2023	March 31, 2023 to March 30, 2024	March 31, 2024 to March 30, 2025	March 31, 2025 to March 30, 2026	March 31, 2026 to March 30, 2027	March 31, 2027 to March 30, 2028	March 31, 2028 to March 30, 2029	March 31, 2029 to March 30, 2030
Load in excess of capacity, project-year basis	**MW**		**9.8**	**10.5**	**11.3**	**12.0**	**12.8**	**13.5**	**14.3**	**15.0**	**15.8**	**16.6**	**17.3**	**18.1**

		Annual Non-Coincident Peak Load Forecast for SECTR Project												
Relevant Hydro One Ratepayers Loads		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Load Forecast	MW	86.2	87.2	88.2	89.2	90.2	90.9	91.9	92.9	94.0	95.0	96.0	97.1	98.3
Current Capacity	MW	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2
Load in excess of capacity, calendar-year basis	MW	24.0	25.0	26.0	27.0	28.0	28.7	29.7	30.7	31.8	32.8	33.8	34.9	36.1
PLI-adjustment		*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*	*81%*
PLI-adjusted load in excess of capacity	MW	19.4	20.2	21.0	21.8	22.7	23.2	24.1	24.9	25.7	26.6	27.4	28.3	29.2
Adjusted for in-service month:														
Project Year*		***13***	***14***	***15***	***16***	***17***	***18***	***19***	***20***	***21***	***22***	***23***	***24***	***25***
		March 31, 2030 to March 30, 2031	March 31, 2031 to March 30, 2032	March 31, 2032 to March 30, 2033	March 31, 2033 to March 30, 2034	March 31, 2034 to March 30, 2035	March 31, 2035 to March 30, 2036	March 31, 2036 to March 30, 2037	March 31, 2037 to March 30, 2038	March 31, 2038 to March 30, 2039	March 31, 2039 to March 30, 2040	March 31, 2040 to March 30, 2041	March 31, 2041 to March 30, 2042	March 31, 2042 to March 30, 2043
Load in excess of capacity, project-year basis	**MW**	**18.9**	**19.6**	**20.4**	**21.2**	**22.0**	**22.8**	**23.5**	**24.3**	**25.1**	**25.9**	**26.8**	**27.6**	**28.5**

Table 29: DCF Assumptions

Hydro One Networks -- Transmission Connection Economic Evaluation Model
2015 Parameters and Assumptions

Transmission rates are based on current OEB-approved uniform provincial transmission rates.

Monthly Rate ($ per kW)	
Transformation	**2.00**
Line	**0.86**

Grants in lieu of Municipal tax (% of up-front capital expenditure, a proxy for property value):		**0.42%**	Based on Transmission system average
Income taxes:			
Basic Federal Tax Rate - % of taxable income:	2015	**15.00%**	Current rate
Ontario corporation income tax - % of taxable income:	2015	**11.50%**	Current rate
Capital Cost Allowance Rate: Class 47 costs	2015	**8%**	Current rate
After-tax Discount rate:		**5.83%**	Based on OEB-approved ROE of 9.3% on common equity and 2.16% on short-term debt, 4.98% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5%

Other Assumptions:

Estimated Incremental OM&A: Project specific ($ k):

Overhead Line	**$1.5**	per new km of line each year

E3 Coalition INTERROGATORY #10

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 4, lines 11-17.

The evidence provides *"the OPA's view that the most appropriate way to apportion the costs of the SECTR project between load customers and transmission ratepayers is to apportion the total cost by reference to the costs that load customers and transmission ratepayers would otherwise have to pay if they were to individually address customer and system needs."* The evidence goes on to propose an allocation between the transmission pool and customers in proportion to the costs that would be incurred to address these interests separately.

(a) Please discuss the approach to allocation of SECTR project costs that would result from application of the OEB's current applicable cost responsibility rules, including quantification, with supporting calculations, of resulting cost allocations between the transmission pool and customers, and among each of the affected distributors.

(b) Please indicate alternative cost allocation approaches considered beyond the approach now proposed and the basis for rejection of any such alternatives.

Response

Section 6.3.1 of the Transmission System Code ("TSC") states:

> "6.3.1 Where a load customer elects to be served by transmitter-owned connection facilities, a transmitter shall require a capital contribution from the load customer to cover the cost of a connection facility required to meet the load customer's needs. A capital contribution may only be required to the extent that the cost of the connection facility is not recoverable in connection rate revenues. To that end, the transmitter shall include in the economic evaluation the relevant annual connection rate revenues over the applicable economic evaluation period that are derived from that part of the customer's new load that exceeds the total normal supply capacity of any connection facility already serving the customer and that will be served by the new connection facility. The transmitter shall calculate any capital contribution to be made by the load customer using the economic evaluation methodology set out in section 6.5."

(a) In accordance with section 6.3.1 of the TSC, the transmission customer (Hydro One Distribution) would be responsible for the entire $77.4 million cost of the SECTR Project facilities, subject to an appropriate economic evaluation. This is because the SECTR Project facilities represent the minimum design required to meet the transmission customer's needs. Neither the TSC nor the DSC fully addresses the allocation of upstream transmission costs among distribution customers.

(b) Please see Exhibit I-P2, Tab 6, Schedule 1.

E3 Coalition INTERROGATORY #11

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 9, lines 12 to 14.

(a) Did IESO base the costs of the project only on incremental load requirements, or was renewal of capacity to service existing load also a consideration?

(b) Are the SECTR project costs based only on building new facilities, or do the project costs include the costs of replacing or refurbishing existing facilities?

Response

(a) The Project was planned to meet new load requirements and also address overloading at Kingsville TS.

(b) The SECTR Project costs are based on the construction of a new station (Leamington TS), a new short segment of transmission line extending from the new station, and the replacement and refurbishment of existing idle transmission line facilities for the remainder of the 13 km transmission line.

E3 Coalition INTERROGATORY #12

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, page 2, lines 12-14.

The evidence describes how Hydro One proposes to allocate SECTR project costs among affected distributors, in a manner said to be consistent with section 6.3.15 of the TSC.

Section 6.3.15 of the TSC provides as follows:

> *"Where more than one load customer triggers the need for a new or modified transmitter-owned connection facility, a transmitter shall attribute the cost to those load customers:*
>
> *(a) in accordance with such methodology as may be agreed between the transmitter and all such load customers; or*
>
> *(b) failing such agreement, in proportion to their respective non-coincident incremental peak load requirements, as reasonably projected by the load forecasts provided by each such load customer or by such modified load forecast as may be agreed by such load customer and the transmitter and, in the case of line connection facilities, taking into account the relative length of line used by each load customer."*

(a) Did Hydro One pursue alternative (a) described in TSC section 6.3.15 before deciding on an allocation in proportion to non-coincident peak load?

(b) If yes, please provide any material provided to the affected distributors in the course of the required consultations.

(c) If not, please explain why not.

Response

(a) Hydro One did not consider any other methodologies for attributing the cost to distributors other than that provided in the Application.

(b) Not applicable.

(c) It is Hydro One's view that non-coincident incremental peak load is an appropriate basis for attributing costs to load customers and further believes that a consistent application of this approach helps avoid discriminatory customer treatment. Hydro One notes that this is consistent with the OEB's Notice of Proposal to Amend a Code – Supplementary Proposed Amendment to the Transmission System Code, dated August 26, 2013, in the EB-2011-0043 proceeding, which states that “the Board believes that apportionment based on non-coincident incremental peak load should achieve an adequate level of precision in terms of the respective benefits.” The Notice further states that “it is proposed that the transmitter be required to apportion the cost of the transmitter-owned connection facilities based on the non-coincident incremental peak load requirements of the triggering load customer(s),”

E3 Coalition INTERROGATORY #13

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, page 3, lines 3-11.

The evidence lists four distributors that Hydro One considers will benefit from the SECTR project.

(a) Please name the other distributors (transmission connected or embedded) in the Windsor Essex region.

(b) Are there any benefits to these other distributors arising from the SECTR project?

Response

(a) The only other distributor in the Windsor – Essex Region is ENWIN Powerlines Ltd.

(b) The SECTR Project will minimize the impact of supply interruptions to most customers in the Windsor – Essex region. This system benefit is reflected in the 22.5%[1] allocation of Project costs to the pool.

[1] Exhbit B, Tab 4, Schedule 4, page 9

E3 Coalition INTERROGATORY #14

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, page 3, lines 13-17.

The evidence discusses the process for capital contribution by the affected distributors.

(a) Please provide a copy of the Capital Cost Recovery Agreement form that the listed distributors will be required to execute.

(b) Please provide the amount of the security deposit that will be required from each affected distributor, and the currently expected timing for the payment of that deposit.

(c) Please:

(i) Indicate the currently expected timing for the payment of the balance of each affected distributor's contribution.

(ii) Indicate the currently expected in-service timing for the SECTR facilities.

(iii) Indicate whether any of the distributor's payment obligations will be contingent upon, or related to the timing of, the connection by the distributors of new customers and related payments by such new customers to the distributors.

(iv) To the extent of a timing difference between the time that the capital contribution is required by the affected distributors and the time that the affected distributors are able to obtain capital contributions in respect of the incremental loads on their respective distribution systems, indicate Hydro One's expectations for how the affected distributors will finance the capital contribution being sought.

Response

(a) Hydro One believes it is premature to provide a draft CCRA template at this time. Should the Board approve a cost allocation methodology, Hydro One's CCRA template would reflect that methodology. The capital contributions would be required before the SECTR Project is put in-service, with payments made in accordance with a payment schedule set out in the CCRA, which both parties will have agreed upon.

(b) Please see the response to part (a) above.

(c)

(i) Please see the response to (a) above.

(ii) Per the construction schedule filed in Exhibit B, Tab 5, Schedule 2 (updated May 23, 2014), the in-service date is anticipated to be March, 2018.

(iii) Yes, as additional capacity is allocated to unforecasted customers, the amount of the obligation from each distributor will be re-calculated.

(iv) Hydro One is sensitive to the distributors' concerns respecting cash flows and financing, but is not in a position to recommend how they manage these issues.

E3 Coalition INTERROGATORY #15

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, pages 5, lines 20-28.

The evidence notes Hydro One's assumption that the demand triggering the need for the SECTR facilities is caused by incremental load, as opposed to self-generation by greenhouse growers in the region.

(a) Please explain the implications of this assumption for the proposed allocation of the SECTR project costs.

(b) Are any of the facilities required as a result of generator customer load requirement, or are the facilities required only because of the need of load customers?

(c) How would the proposed allocation of SECTR project costs change if it were assumed that self-generation also contributes to the demand for the project?

Response

Section 6.3.16 of the Transmission System Code ("TSC") states:

> "For a new or modified transmitter-owned connection facility that will serve a mix of load customers and generator customers, a transmitter shall attribute the cost of the new connection facility or modification to the customers that cause the net incremental coincident peak flow on the connection facility that triggered the need for the new or modified connection facility. If and to the extent that the net incremental coincident peak flow is triggered by one or more load customers, the transmitter shall attribute the cost to each of those triggering load customers in the manner set out in section 6.3.15. If and to the extent that the net incremental coincident peak flow was triggered by one or more generator customers, the transmitter shall attribute the cost to each of those triggering generator customers in the manner set out in section 6.3.14."

(a) Consistent with section 6.3.16 of the TSC, since the net incremental coincident peak load triggering the need for the SECTR Project facilities is caused by load customers, Hydro One has attributed the costs of the SECTR Project facilities to them.

If the net incremental coincident peak flow triggering the need for the SECTR Project facilities was caused by generator customers, then the cost of the SECTR Project facilities would be attributed to only those triggering generator customers.

(b) The SECTR Project facilities are required to meet the load requirements of all customers in the area, regardless of whether individual customers have only load requirements or both load and generation requirements. For cost allocation purposes, a "generator customer" with load requirements is treated the same as a load customer in respect of its load requirements. Once in place, the SECTR Project facilities will facilitate the connection of distributed generation in the Kingsville-Leamington area.

(c) The proposed cost allocation would not change.

E3 Coalition INTERROGATORY #16

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, page 7, Table 1 and page 9, lines 1-14.

The evidence indicates under "Customer Benefits" that there will be benefit from enabling the connection of additional distributed generation in the Kingsville/Leamington area.

How were the benefits to future distributed generation customers taken into consideration in determining the proposed capital contributions by the affected distributors?

Response

Benefits to future distributed generation customers were not taken into consideration in determining the proposed capital contributions by the affected distributors. See also Exhibit I-P2, Tab 2, Schedule 15.

E3 Coalition INTERROGATORY #17

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, page 6, lines 14-16.

In answering the following questions, please note that the E3 Coalition members – E.L.K., Entegrus and Essex – take no objection to release of information provided by them to Hydro One or the IESO (then OPA), save for the request included below that the identities of specific end-use customers be protected by the use of coding (numbers or letters) in place of customer names.

Please provide a list, for each of the affected distributor's service territories, of the customer loads (new load or incremental to existing load) anticipated and triggering the requirement for the SECTR project. To maintain confidentiality, please label each customer by code (i.e. number or letter) rather than providing the customer name. For each such customer please:

(a) Provide as specific a description as possible of location of the load, mindful of customer confidentiality concerns.

(b) Provide the amount of the load.

(c) Provide the assumed in-service date of the load.

Response

(a) Hydro One does not have a specific list of new or incremental customer loads anticipated in each of the affected distributors' service territories. Hydro One utilized the following table, provided to them by the Essex Energy Corporation ("EEC") on June 15, 2012. Hydro One understands that the EEC developed a 5-year forecast of new large load connections in the Kingsville and Leamington area. This information was directly applied to the 2012 actual loading to determine the forecast for years 2013-2017 inclusive. Greenhouse lighting load was also provided by the EEC, but has been excluded from the below table and the load forecast in the SECTR Project as it is off-peak.

Cumulative Peak kW	Year 1	Year 2	Year 3	Year 4	Year 5
Kingsville	739.77	2,219.3	3,910.2	5,178.38	6,446.55
Leamington	380.45	1,542.94	2,811.12	3,656.57	4,502.02
Greenhouse - Non-Lighting	2,207.20	8317	10,684.15	13,019.31	15,354.47

(b) See above response to part a) above.

(c) See above response to part a) above.

E3 Coalition INTERROGATORY #18

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, page 6, lines 14-19.

The evidence contemplates that the affected distributors, including Hydro One Distribution, will perform economic evaluations to allocate required SECTR project capital contributions among new large customers and existing ratepayers. E3 Coalition understands that the evidence, when referring to "new large customers", is intended to refer to new large customer loads, which would include specifically identified new and incremental load requirements of existing large customers. On this basis:

(a) Given that the allocation to the distribution level of SECTR project costs is on account of the provision by the SECTR project of capacity for new distribution level customer loads, please explain the basis upon which SECTR project costs would be allocated by distributors to existing distribution customers.

(b) Does Hydro One anticipate that the affected distributors will include in their respective rate bases contributions to the SECTR project costs not recovered from large customers with new load requirements?

(i) If yes, what is the authority for inclusion in distribution rate base of SECTR project costs (in particular considering that the costs are in respect of assets not owned by the distributors)?

(ii) If no, please explain Hydro One's expectations for how the affected distributors will account in their respective costs of service for the required SECTR project capital contributions.

Response

(a) The capital contribution payable by the distributors that is not recovered from large customers would be recovered from that distributor's ratepayers.

(b) Yes, Hydro One does expect that the affected distributors will include the capital contribution, net of costs recovered from large customers, they have made to the project to be included in their respective rate bases.

Article 410 of the **Accounting Procedures Handbook**, Accounting for Contributions in Aid of Construction, provides this guidance:

"<u>Contributions paid by a distributor</u>
In some cases distributors will incur expenditures for amounts paid to other distributors or transmitters for capital projects (i.e. for transmission upgrades or expansion projects).

Distributors who incur such costs, should record the amounts in USoA Account 1609, Intangible Assets – Capital Contributions Paid. Accumulated amortization of intangible assets is recorded in Account 2120, Accumulated Amortization of Electric Utility Plant – Intangibles, and amortization expenses in Account 5715, Amortization of Intangibles and Other Electric Plant. <u>These amounts will typically be included in rate base at the next cost of service rate application</u>."

E3 Coalition INTERROGATORY #19

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, page 6, lines 21-22.

The evidence indicates that Hydro One will also allocate the associated project facility costs, such as distribution feeders, to the SECTR project's "beneficiaries".

(a) Please explain the nature of, and quantify, any additional costs that are to be allocated to the affected distributors and that are not already included in the $39.4 million of costs detailed in the prefiled evidence.

(b) Please provide a breakdown of the allocation of any such additional costs as among the affected distributors, including in respect of each affected distributor a description of the facilities resulting in such costs.

Response

(a) In order to move some of the Kingsville TS feeder loads to the new Leamington TS, a number of station and feeder level investments are required in addition to the $77.4M in capital costs identified in the SECTR Project evidence. These costs include:

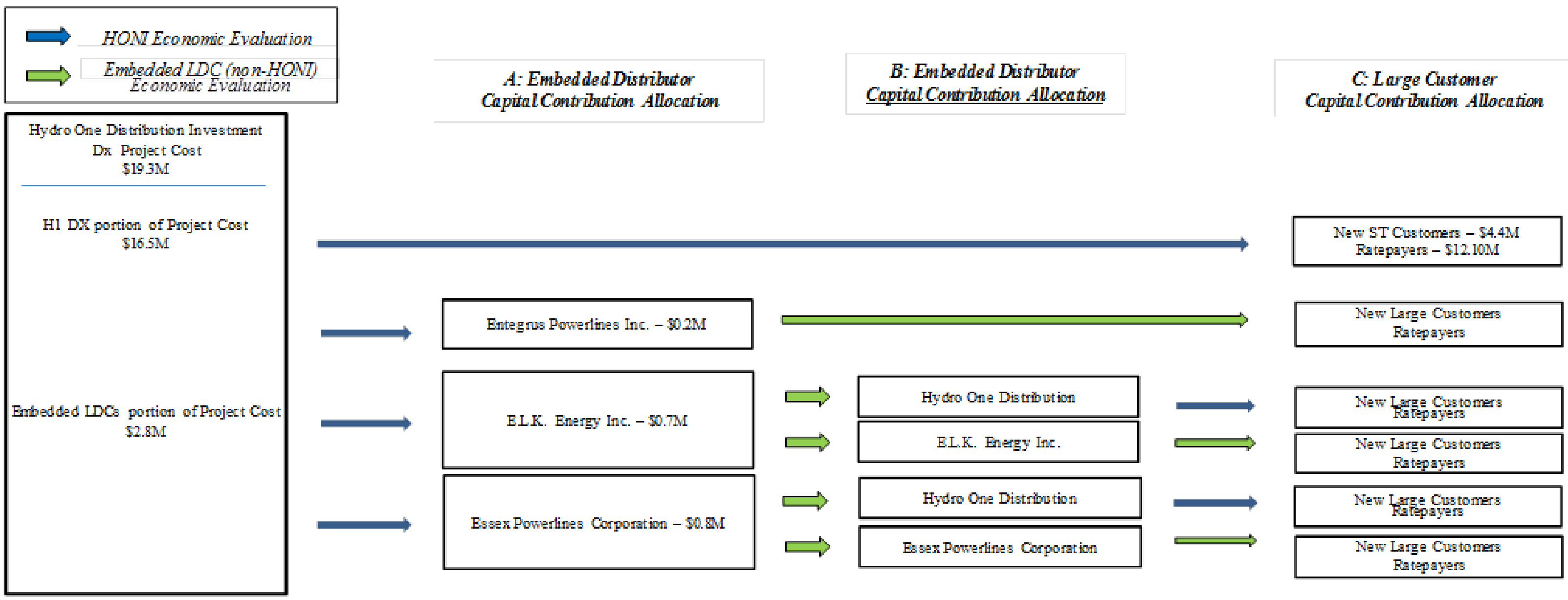
- Installation of two additional feeder breakers at Leamington TS
- Installation of eight underground feeder egresses at Leamington TS
- Removal of six Kingsville TS feeder egresses
- Construction of 8 new feeder conductors to join up with 6 existing Kingsville TS feeder, and two new feeders to account for future load growth
- Relocation and reconfiguration of 27.6kV Regulating Stations
- Leamington TS protection upgrades for in-service Kingsville DG which will be transferred to Leamington TS
- Other miscellaneous costs, including protection reconfigurations and installation of new switches to establish "open-points" between some of the Kingsville and Leamington TS feeders, etc.

The total cost of these additional items is estimated to be $19.3M, which is also proposed to be allocated to the benefitting distributors and large customers.

Hydro One in Phase 2 of this Application is seeking approval for the cost allocation methodology for this investment. There may be additional costs that are not known at this time. However, any additional costs related to the SECTR Project would be treated in a manner consistent with the proposed cost allocation methodology, if approved.

(b) The allocation of the $19.3 distribution costs between Hydro One Distribution, other embedded distributors and New ST Customers is expected to result in the following capital contributions:

Table 1: Allocation of Capital Contribution Summary



Distributor	**Distribution Related Capital Contribution**
Essex Powerlines	$0.8M
E.L.K.	$0.7M
Entegrus	$0.2M

Furthermore, Hydro One Distribution is forecasting that new ST Customers will be paying capital contributions of approximately $4.4M related to Hydro One Distribution's allocation of distribution project costs.

London Property Management Association (LPMA) INTERROGATORY #1

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4

Table 1 shows the broader system benefits having two sets of beneficiaries: all Ontario ratepayers and most transmission ratepayers in the Windsor-Essex area. At pages 8 and 9, the recommended cost allocation treatment is discussed.

a) With respect to the $22.5 million in costs associated with the broader system restoration needs and limitations on the operation of Brighton Beach that would be incurred if they were to be individually addressed, what proportion would be assigned to each of the limitations on the operation of Brighton Beach and the system restoration needs?

b) Based on the Board's beneficiary pays principle, why is there not a third cost category being proposed, in addition to the load customers and transmission ratepayers such that the transmission ratepayer portion is further divided into transmission ratepayers (all Ontario ratepayers) and regional transmission ratepayers (all Windsor-Essex ratepayers)?

Response

(a) This allocation was not calculated. Please see Exhibit I-P2, Tab 1, Schedule 5.

(b) Transmission rates in Ontario are calculated based on inputs from all transmitters and apply uniformly to all transmission connected customers across Ontario. The existing transmission rates methodology was established by the OEB under proceeding RP-1999-0044 and has been in place since 2002. In 2008 the OEB engaged London Economics International LLC to conduct a review of Ontario's Uniform Transmission Rates[1] which did not result in the OEB proposing to implement regional rates. The setting of Uniform Transmission Rates and the methodology to establish them is set by the OEB. Hydro One is not proposing changes to this methodology.

[1] A Review of Uniform Transmission Rates in Ontario *FINAL REPORT March 2008, London Economics Internation LLC*

London Property Management Association (LPMA) INTERROGATORY #2

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, page 3

a) Has Hydro One provided an estimate of the capital contribution that will be required from each of the benefitting customers shown on page 3? If not, why not?

b) Is Hydro One aware of whether or not the benefitting distributors (including Hydro One Distribution) have provided any estimated capital contributions required from the new large customers?

c) Do the "new large customers" include only new customers, or does it also include expansions at existing customers? If the former, please explain why increased demand at existing customers would not be subject to a capital contribution.

Response

(a) Yes, please see the response to Exhibit I-P2, Tab 2, Schedule 9 d) and e), which provides the most current estimates of capital contributions to be required from each of the affected distributors and the uncertainties associated with them.

(b) Hydro One is not aware of any estimated capital contributions that have been provided by the benefiting distributors to new large customers.

(c) Yes, the approach applicable to large customers also includes expansions at facilities of existing sub-transmission (“ST”) *load* customers, defined according to Hydro One’s most recent Distribution Rate Order (EB-2013-0141), i.e., an ST customer whose load:

i. is three-phase; and
ii. is directly connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive; the meaning of “directly” includes Hydro One not owning the local transformation; and
iii. is greater than 500 kW (monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is greater than 500 kW).

Power Workers Union (PWU) INTERROGATORY #1

Interrogatory

Reference (a): Exhibit B-4-5, Page 8 of 8. Flow of Cost Diagram (Illustrative Only) and Cost Responsibility Table (Illustrative Only).
Reference (b): Exhibit B-4-3, Project Economics. 2.0 Cost Responsibility.
Reference (c): Exhibit B-4-5, Page 7 of 8. Lines 2-6.

> **Economic evaluations, which take into consideration projected revenues associated with customers' load forecasts, are performed to determine the total capital contribution payable at the transmission level, and the allocation at the distribution level of that total capital contribution among the three distributors and their respective distribution customers.**

Reference (d): Exhibit B-4-5, Page 7 of 8. Lines 19-22.

> **Although not shown in the diagram and table below, capital contribution allocations are calculated separately for each new large customer. Capital contribution allocations for ratepayers are absorbed into the respective distributors' revenue requirements and recovered through rates.**

a) With respect to the Flow of Cost Diagram (Illustrative Only) indicated in Ref (a), please explain how the Capital Contribution paid to Hydro One Transmission (i.e. $80 million as per the illustrative example) is determined. Is Hydro One proposing to use the same methodology to calculate the Capital Contribution paid to Hydro One Transmission as described in Ref (b)?

b) In relation to Ref (a) and in the context of the illustration Hydro One provided, please clarify how Hydro One Transmission would recover the $95 million (i.e. $175 million - $80 million) portion of the project cost that is not covered by Capital Contribution to Hydro One Transmission?

c) The Cost Responsibility Table provided on page 4 of Ref (b) shows that, of the $55.3 million cost that is the responsibility of customers, $39.4 million will be covered through capital contribution. Based on Ref (b), the PWU's understanding is that Hydro One Transmission will recover the difference through the additional revenue that will arise from applying existing pool rates to the incremental load associated with the project over the 25-year time horizon. Please confirm if this is correct?

d) As per the Flow of Costs Diagram (Illustrative Only) in Ref (a), the $100 million Customer Benefit Portion of the Project Cost exceeds the $80 million Capital Contribution paid to Hydro One Transmission. Does Hydro One Transmission expect to recover the difference in the manner indicated in Question (c) above?

e) Please confirm if Hydro One Distribution, as the sole transmission-connected customer, will pay the Customer Benefit Portion of the Project Cost that is not covered by Capital Contribution. If confirmed, does Hydro One Distribution expect to recover the cost based on the rates applicable to its customers including the embedded distributors?

f) With respect to Ref (c), please provide a more detailed description of how the capital contribution allocation percentages for each distributor are determined. Specifically, explain how economic valuations, and variables such as non-coincident incremental peak load, projected revenues and load forecast are factored into the calculation of the capital contribution allocation percentages for each distributor.

Response

(a) The capital contribution paid to Hydro One Transmission, for both the Illustrative Example and the SECTR Project, is calculated using the economic evaluation methodology set out in Appendix 5 of the TSC, which for ease of reference purposes, is being provided as Attachment 1 of this interrogatory response.

(b) The $95 million portion would be recovered through transmission rates.

(c) The calculation of the capital contribution is based on incremental revenues over a 25-year economic horizon, as per the methodology set out in Appendix 5 of the TSC. The portion of the cost that is not recovered through capital contribution will be recovered through transmission rates.

(d) Yes, the difference is the revenues collected from existing ratepayers on a DCF basis.

(e) Hydro One Distribution will be required to pay $80M to Hydro One Transmission. This represents the DCF results that take into account revenues received from customers, to pay Transmission the $100M amount illustrated.

(f) Variables including projected revenues—which are based on forecasted non-coincident incremental load—are used to calculate a proxy capital contribution figure for each of the distributors, based on the economic evaluation methodology set out in Appendix 5 of the TSC. The capital contribution payable to the transmitter is prorated among the distributors based on the proxy figures. Please see Exhibit I-P2, Tab 2, Schedule 9 for further information.

APPENDIX 5

METHODOLOGY AND ASSUMPTIONS FOR ECONOMIC EVALUATIONS

APPENDIX 5

METHODOLOGY AND ASSUMPTIONS FOR ECONOMIC EVALUATIONS

A transmitter shall use the methodology set out in this Appendix to conduct any economic evaluation under this Code. This methodology consists of a discounted cash flow (DCF) calculation for the connection of load customer's new or modified facilities using the methodology set out below. As required by section 6.5.2, separate economic evaluations must be conducted for transformation connection facilities and line connection facilities.

Net Present Value ("NPV")	=	Present Value ("PV") of Operating Cash Flow + PV of Capital Cost Allowance ("CCA") Tax Shield - PV of Capital, calculated over the economic evaluation period.
1. PV of Operating Cash Flow	=	PV of Net Operating Cash (before taxes) - PV of Taxes
a) PV of Net Operating Cash	=	PV of (Annual Connection Revenue - Annual Connection Operating Maintenance & Administration ("OM&A") Costs).
Annual Connection Revenue	=	The relevant annual connection rates revenue derived from that part of the customer's new load that exceeds the total normal operating capacity of any connection facility already serving that customer and which will be served by a new connection facility or modification
Annual Connection OM&A Costs	=	The relevant annual administrative costs associated with supply of the customer plus the relevant annual operating and maintenance costs associated with new or modified connection facilities of the transmitter.
b)PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
Annual Municipal Taxes	=	(Municipal Tax Rate)* (Assessed Value of Relevant Property)
Annual Capital Taxes	=	(Capital Tax Rate) * (Relevant Closing Undepreciated Capital Cost Balance)
Relevant Closing Undepreciated Capital Cost Balance	=	That portion of the transmitter's Closing Undepreciated Capital Cost Balance attributed to the new or enhanced connection assets associated with the specific connection.
Annual Income Taxes	=	(Income Tax Rate) * (Net Annual Operating Cash - Annual Municipal Taxes - Annual Capital Taxes)

Net Annual Operating Cash	=	(Annual Connection Revenue - Annual Connection OM&A)

2. PV of CCA Tax Shield = [(Income Tax Rate) * (CCA Rate) * (Total Annual Capital Expenditure)] / [CCA Rate + Discount Rate]

CCA Rate	=	Capital Cost Allowance Rate
Total Annual Capital Expenditure	=	Sum of the total relevant Annual Capital Expenditures of the transmitter.

3. PV of Capital = PV of Annual Capital Expenditures

Annual Capital Expenditures	=	The relevant annual capital expenditures of the transmitter based on fully allocated costing principles including capital for new connection facilities and/or modified connection facilities to accommodate the proposed new or upgraded customer connection and any transfer price paid to a customer for any facilities built under an alternative bid option and transferred to the transmitter.

Notes:

The Capital Tax Rate is a combination of the Federal Large Corporation Tax Rate and the Provincial Capital Tax Rate.

The Income Tax Rate is a combination of the Federal Income Tax Rate and the Provincial Income Tax Rate.

Land is not eligible for CCA.

The PV of CCA Tax Shield can also be calculated annually and present valued in the PV of Taxes calculation.

An adjustment is needed to account for the ½ year CCA rule.

For purposes of the calculations above, a transmitter shall ensure that the most up-to-date current and enacted future federal and provincial tax rates are being used.

Assumptions

1. The economic evaluation period shall be determined as follows based on the risk classification of the proposed new or modified connection as determined by the transmitter in accordance with Appendix 4:

Risk Classification	**Economic Evaluation Period**
High Risk	5 years
Medium-High Risk	10 years
Medium-Low Risk	15 years
Low Risk	25 years

2. The discount rate to be used in the DCF calculation shall be based on the transmitter's current deemed debt-to-equity ratio, debt and preference share costs and Board-approved rate of return on equity. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted. The same approach to discounting will be used for revenues and OM&A expenditures.

3. Capital costs shall be based on the minimum standard design required to supply the forecasted customer load except where the new or modified facility was previously planned by the transmitter, in which case the capital costs shall be limited to the cost of advancement as required by section 6.5.2.

Power Workers Union (PWU) INTERROGATORY #2

Interrogatory

Reference (a): Exhibit B-4-5, Page 8 of 8. Flow of Cost Diagram (Illustrative Only) and Cost Responsibility Table (Illustrative Only).

Reference (b): Co-operating Interventions and Cost Eligibility Request - Entegrus/Essex Powerlines/E.L.K. November 26, 2014. Page 3.

> **Under the proposed methodology for allocating the Project costs, 77.5% of the costs ($40.4 million), would be allocated to distributors.• Detailed information on the financial impacts of the proposed methodology for allocating the Project costs has not to date been provided. Based on the material filed and preliminary discussions between the E3 Coalition members and Hydro One, it appears that the rate base increases resulting from Hydro One's proposed methodology for direct allocation of the Project costs on the respective E3 Coalition members, calculated on the most recently approved rate bases, could be, in order of magnitude, as follows:**

E.L.K	**110% -115%**
Entegrus Powerlines	**1%-1.5%**
Essex Powerllnes	**10%-15%**

a) In relation to Ref (a), does Hydro One's cost allocation approach include a methodology to allocate Hydro One Distribution's or embedded LDCs capital contribution between new large customers and ratepayers? If it does, how are those allocation percentages determined? If it doesn't, what are the applicable principles or rules in the TSC or DSC?

b) Please comment on the rate base increase estimates indicated in Ref (b).

Response

(a) The same economic evaluation methodology that will be used to allocate among distributors the capital contribution payable to the transmitter is used to allocate among new large customers and ratepayers the capital contribution payable to distributors.

(b) Please see Exhibit I-P2, Tab 2, Schedule 9d) and e) for the current forecast of capital contributions required from all four distributors and Exhibit I-P2, Tab 2, Schedule 18 b) for accounting treatment

Electricity Distributors Association (EDA) INTERROGATORY #1

Interrogatory

Reference: S. 6.5.2 of the Transmission System Code provides as follows:

> *(b) provide that the economic evaluation period will be 5 years for a high risk connection, 10 years for a medium-high risk connection, 15 years for a medium-low risk connection, and 25 years for a low risk connection;*

(a) Please indicate whether, in the methodology proposed by Hydro One for sharing the customer component of costs among LDCs, and subsequently among added large loads and "ratepayers", whether Hydro One has considered the risk level associated with the various loads.

(b) If Hydro One has considered the risks, are all the loads considered to be at the same level of risk, and if so, what is that level?

(c) If all loads are not considered to have the same level of risk, please provide the detailed risk assessment, along with the percentage of the total incremental load considered to be in each category of risk.

(d) If the various loads comprising the total incremental non-coincident peaks are viewed by Hydro One, or by the individual LDCs allocating costs, as having different levels of risk, how does Hydro One propose that these differences will be reflected in the allocation methodology?

Response

(a) Section 6.5.2 of the TSC applies only to Hydro One Distribution in this case, as the sole transmission-connected customer. The cost allocation methodology proposed by Hydro One does not attempt to apply any such risk classifications to the distribution-connected customers. However, to mitigate risk during the construction phase of a project, Hydro One proposes to collect a security deposit from customers based on the methodology set out in section 2.3 of Hydro One's OEB-approved Connection Procedures.

(b) Please refer to response in (a).

(c) Please refer to response in (a).

(d) Please refer to response in (a).

Electricity Distributors Association (EDA) INTERROGATORY #2

Interrogatory

Reference: S. 6.5.2 of the Transmission System Code provides as follows: (k) require that the customer provide its load shape in such form and detail as the transmitter may reasonably require;

(a) Please provide a copy of Hydro One's data request to the E3 LDCs specifying the form and detail required.

(b) If Hydro One has not requested load forecast and load shape data from the E3 LDCs, please explain why not, and whether it intends to do so in the future.

Response

(a) Please see Attachment 1 to this Interrogatory Response.

(b) Hydro One used the load forecasts attained from the benefitting distributors for the purposes of cost allocation. Hydro One also utilized historical Peak Load Index[1] (PLI), to determine load shape for the purposes of the allocating costs to the benefitting distributors and large customers. Use of historical PLI is Hydro One's current practice for calculating customer capital contributions. However, for the purposes of calculating capital contributions for the SECTR Project, Hydro One is willing to review submissions of PLIs from the E3 Coalition LDCs, if they differ from historical PLIs.

[1] Peak Load Index converts an annual peak into 12 monthly peaks.

From: GUO Helen
Sent: Monday, March 17, 2014 11:40 AM
To: Mark Alzner; nmacaulay@elkenergy.com; Dan Charron (Dan.Charron@entegrus.com); Mark Danelon
Cc: LEE Charlie
Subject: RE: Leamington/Kingsville Transmission Upgrade Discussion

Hello Everyone,

We are going to re-submit the Kingsville TS load forecast for the SECTR filing. Although this forecast is not going to be used for the final capital contribution calculation, we would like to make it as accurate as possible. Could you please send me a 28 year (up to 2041) annual peak forecast for your Kingsville TS load by **Wednesday March 19th**? We will need the following information in your forecast. Please let me know if you have any questions.

1) Gross forecast before any CDM and DG impact, and
2) Net forecast after CDM deductions
3) Net forecast after DG deductions
4) Both gross and net forecast should include embeded and LTLT customers
5) Both forecasts should include municipal and regional development plans

Thanks a lot and sorry for the short time notice!

Helen Guo
Distribution Investment Planning
Asset Management
Hydro One Inc
☎ (416) 345 6757 | (647) 308 4881
✉ Helen.Guo@hydroone.com

From: GUO Helen
Sent: Friday, January 10, 2014 2:36 PM
To: 'Kris Taylor'; Mark Alzner; nmacaulay@elkenergy.com; Dan Charron (Dan.Charron@entegrus.com); Justine Taylor (jtaylor@ontariogreenhouse.com)
Cc: GARZOUZI Lyla
Subject: RE: Leamington/Kingsville Transmission Upgrade Discussion

Good afternoon,

Could you please send me your historical load (past 5 years monthly peak) and a 25 year annual peak forecast for Kingsville TS before our meeting on Jan 15th? I will put them together for our Friday meeting.

Justine, if you have any additional information regarding the greenhouse loads, please feel free to send them to me.

Dan and Norm, our Account Executive Doug Fraser asked for the letter of support from you before. Are we expected to receive them prior to the Section 92 filing (Jan 22nd)?

Regards,

Helen Guo
Distribution Investment Planning
Asset Management
Hydro One Inc
☎ (416) 345 6757 | (647) 308 4881
✉ Helen.Guo@hydroone.com

-----Original Appointment-----
From: Kris Taylor [mailto:ktaylor@essexpower.ca]
Sent: Friday, January 10, 2014 11:57 AM
To: Kris Taylor; Mark Alzner; Raymond Tracey; Steve Ray; Tracy Garner; 'charlene.deboer@powerauthority.on.ca' (charlene.deboer@powerauthority.on.ca); Bob Chow (Bob.Chow@powerauthority.on.ca); nmacaulay@elkenergy.com; Mark Danelon (mdanelon@elkenergy.com); Dan Charron (Dan.Charron@entegrus.com); GUO Helen; GARZOUZI Lyla; Justine Taylor (jtaylor@ontariogreenhouse.com); nsantos@kingsville.ca; DDiGiovanni@Kingsville.ca; bmarck@leamington.ca; John Paterson
Subject: Leamington/Kingsville Transmission Upgrade Discussion
When: Friday, January 17, 2014 10:00 AM-1:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: 2199 Blackacre Drive, Suite #2

Meeting with key stakeholders to discuss load profiles, cost allocations and next steps for the Leamington/Kingsville transmission upgrade. Agenda to follow.

Thank you for all of your feedback and cooperation thus far.

Electricity Distributors Association (EDA) INTERROGATORY #3

Interrogatory

Reference: S. 6.5.3 of the Transmission System Code provides for true-ups of required capital contributions, based on re-assessment at specified points in time.

(a) Is Hydro One intending to follow the Code with respect to this provision? If not, why not?

(b) If Hydro One has assessed the incremental loads as being low risk, does it intend to use only the incremental load in computing any true-up at the fifteen year point?

(c) Does Hydro One have any proposal as to the treatment that might be applied to true-ups in distribution rates?

Response

(a) Hydro One Distribution proposes to perform true-ups on capital contributions collected from distributors based on the approach set out in section 6.5.3 of the TSC.

(b) Whether a true-up will be performed at the end of the fifteenth year will be based on a comparsion of the actual and initially-forecasted incremental load in the tenth year.

(c) A true-up payment for a capital investment would be treated as a capital contribution and accordingly would be included in a distributor's rate base for recovery. For further information, please see Exhibit I-P2, Tab 2, Schedule 18b).

Electricity Distributors Association (EDA) INTERROGATORY #4

Interrogatory

Reference: Notice of Proposal to Amend a Code, Supplementary Proposed Amendment to the Transmission System Code, Board File No. EB-2011-0043, dated August 26, 2013, Attachment E (Attached).

This Notice contains specific wording for proposed Sections 6.3.8A, B, and C to the Code, with respect to the allocation of costs.

Reference: OPA Comments dated September 9, 2013 (Attached).

(a) Please clarify whether the Board's proposed modification to the Code has been reflected in the OPA's and Hydro One's proposals for allocation of the project costs as between the transmission network and load customers. If the answer is no, please explain why not.

(b) Please recompute the allocation of costs between transmission network and load customers based on Hydro One's and/or OPA's best understanding of the Board's proposed Code modification. Please recompute the allocation between customer contributions and the line connection pool that would result.

(c) If the answer to (b) above does not result in an allocation to load customers of $34.2 million (i.e. the cost of upgrades to connection facilities under the $97.7 million option), please explain why not.

(d) Please provide any precedent in regulation or other support for the method being proposed by OPA.

(e) Did the OPA, as part of its comments dated September 9, 2013, express any concern about the methodology or potential results for purposes of cost responsibility that might flow from the Board's proposed TSC sections 6.3.8A, B, and C (other than a concern as to its role in the process)?

(f) To the knowledge of the OPA or Hydro One, was any consultation process held as to the method by which the OPA proposes to allocate costs between the network pool and connecting distributors? If so, please provide the dates of such consultations, the names of the parties consulted, and their written comments if any.

Response

a) Yes, the beneficiary pays principle underlying the Board's proposed modification to the Code has been reflected in the IESO's proposal for allocation of the project costs.

b) Please refer to the response to part (a) and see also Exhibit I-P2, Tab 2, Schedule 7.

c) The IESO proposed an allocation which it understood to be consistent with the beneficiary pays principle underlying the OEB's proposed amendments to cost allocation under the TSC. The IESO acknowledges that there may be alternative allocations which would also be consistent.

d) To the IESO's knowledge this is the first time the proportional benefits approach has been applied, therefore the IESO is not aware of any regulatory precedent for the method being proposed.

e) As part of its comments on September 9, 2013, the OPA did not express any concern about the methodology or potential results for purposes of cost responsibility that might flow from the Board's proposed TSC sections 6.3.8A, B, and C (other than a concern as to its role in the process).

f) No consultation process was carried out as to the method by which the IESO, proposed to allocate costs between load customers and transmission ratepayers, however the allocation is consistent with the proposed TSC code amendments in which a consultation process took place in 2013.

Electricity Distributors Association (EDA) INTERROGATORY #5

Interrogatory

(a) Please provide the forecast used for Hydro One Distribution in computing the contribution to incremental non-coincident peak load for purposes of allocation.

(b) Please provide a detailed description of the methodology by which Hydro One has broken down, or proposes to break down, its total distribution incremental load between new large customers and "ratepayers".

(c) If actual computations in (b) above have been made by Hydro One, please provide them. Otherwise, please illustrate the methodology with a quantitative example.

Response

(a) Hydro One Distribution used the following forecast for the SECTR Project, which does not include embedded distributor load. The total load forecast, including all embedded distributors and Hydro One Distribution, may be found in Exhibit B, Tab 4, Schedule 3, Pages 15-16, Table 5.

Peak MW	H1 Distribution Large Customers	H1 Distribution "ratepayers"	H1 Distribution Total
2018	27.00	74.03	101.03
2019	27.35	74.93	102.28
2020	27.70	75.93	103.63
2021	28.05	76.83	104.89
2022	28.40	77.75	106.15
2023	28.75	78.67	107.42
2024	29.10	79.60	108.70
2025	29.45	80.54	109.99
2026	29.80	81.47	111.27
2027	30.15	82.42	112.57
2028	30.50	83.37	113.88
2029	30.85	84.34	115.19
2030	31.20	85.31	116.52
2031	31.55	86.19	117.75
2032	31.90	87.17	119.08

Peak MW	H1 Distribution Large Customers	H1 Distribution "ratepayers"	H1 Distribution Total
2033	32.25	88.17	120.42
2034	32.60	89.17	121.77
2035	32.95	90.18	123.13
2036	33.30	90.90	124.20
2037	33.65	91.91	125.56
2038	34.00	92.93	126.93
2039	34.35	93.95	128.31
2040	34.70	94.99	129.69
2041	35.05	96.04	131.09
2042	35.40	97.09	132.50
2043	35.75	98.28	134.03

(b) Please see the response to Exhibit I-P2, Tab 2, Schedule 9, part (d), Attachment 1, Tables 27 and 28. For added clarity regarding the type of 'large customers' required to make capital contributions according to this proposal, please see the response to Exhibit I-P2, Tab 3, Schedule 2.

(c) See the response to Exhibit I-P2, Tab 2, Schedule 9, part (d).

Electricity Distributors Association (EDA) INTERROGATORY #6

Interrogatory

Please specify how growth in generation embedded in distribution systems and CDM have been accounted for, or are proposed to be accounted for, in computing incremental non-coincident peak load for purposes of allocation.

Response

The proposed cost allocation between load customers and transmission ratepayers provided by the IESO, was not based on peak load, and is therefore independent of growth in distributed generation and conservation. Rather, the proposed cost allocation apportioned the total cost by reference to the costs that load customers and transmission ratepayers would otherwise have to pay if they were to individually address customer and system needs, rather than addressing them through the proposed integrated solution.

Electricity Distributors Association (EDA) INTERROGATORY #7

Interrogatory

Please provide an Excel spreadsheet with formulas that computes, for the following theoretical example:

- Each LDC's allocated cost responsibility for a project and percentage share of the total customer component
- The breakdown of each LDC's total cost responsibility between "new large loads" and "ratepayers".

Assumptions:

i. Capital cost to be recovered is $50 million, net of amounts allocated to the transmission network.

ii. 4 LDCs are under consideration for an allocation of costs. For simplicity, each LDC is assumed to have a non-coincident peak load in the base year of 1,000 MW, and each new large load will add 5 MW to the non-coincident peak in the LDC where it is connected.

iii. For simplicity, assume the distribution rates in all 4 LDCs are the same. Hydro One should make a reasonable assumption for this.

iv. Hydro One should make reasonable assumptions as to the annual costs.

v. Forecasts for the 4 LDCs are as follows:

	LDC #1	LDC #2	LDC #3	LDC #4
Peak growth, excluding new large loads, CDM and DG				
Years 1-10	4%	2%	1%	0%
Years 11-25	1%	1%	0%	-1%
Effect of CDM	-1%	-1%	-1%	-1%
New Large Loads	4 per year, years 1-5	None	1 per year, years 1-5	None
Loss of existing large loads				2 in Year 1, 2 in Year 2
New self-supply generation	10 MW in Year 1	3 MW in each of years 1, 2 and 3	3 MW in Year 3	None

If any additional assumptions are necessary to complete the computation, please make an assumption and document it as part of the response, explaining why such assumption is necessary.

Response

Based on the load forecast provided in the theorical example, within 5 years there would be insufficient incremental load capacity provided by transmission facilities (120MW) similar to that proposed in this application. Furthermore, any analysis produced would be subject to large swings depending upon which rate pool the costs were allocated to.

Hydro One recognizes that the EDA was proposing a hypothetical scenario to create a numerical example to further the Application participants' understanding of Hydro One's proposed cost methodology and potential contributions from participants. Therefore, please refer to Exhibit I-P2, Tab 2, Schedule 9 which provides the detailed results of the methodology using the estimated project costs and current load forecast of the embedded distributors and large customers.

Electricity Distributors Association (EDA) INTERROGATORY #8

Interrogatory

The application refers to expenditures that are like for like replacements of assets that have reached the end of their useful life. Please:

a) Provide the total cost of such assets.

b) Confirm that the cost of such assets is excluded from the total project cost in allocating between the transmission network and customer connections (i.e. no portion is part of the allocation to customer connections).

c) If such costs have not been excluded from allocation, please explain why not.

Response

(a) The cost of replacing three transformers that are end-of-life at Kingsville TS is $18 million, while the cost of replacing only one of these transformers and reconfiguring Kingsville TS to a two-transformer station is $12 million. This work is not part of the SECTR Project.

(b) The total SECTR Project cost of $77.4 million is made up of line costs ($45.3 million) and station costs ($32.1 million). This $77.4 million total Project cost is allocated between the transmission network and customer connections and does not include the transformer replacement cost at Kingsville TS.

(c) Please refer to the response for part (b).

School Energy Coalition (SEC) INTERROGATORY #1

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, p.8-9

Did the OPA (now IESO) consider any other methods for apportioning costs between load customers and transmission customers? If so, please provide details and reasons for why they were ultimately not recommended.

Response

No, the IESO proposed an allocation which it understood to be consistent with the beneficiary pays principle underlying the OEB's proposed amendments to cost allocation under the TSC. The IESO acknowledges that there may be alternative allocations which would also be consistent.

School Energy Coalition (SEC) INTERROGATORY #2

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, p.8-9

Based on current wording of the Transmission System Code, please provides the apportioning of costs and supporting calculations.

Response

Please see Exhibit I-P2, Tab 2, Schedule 7.

School Energy Coalition (SEC) INTERROGATORY #3

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4, p.8-9

Please explain how the OPA (now IESO) estimate the $22.5M cost for transmission updates.

Response

The OPA obtained the $22.5M cost for transmission upgrades from Hydro One. Hydro One has provided a further breakdown of these costs as follows:

a) Upgrading of J3E-/4E: $15.5M

b) Installing 50 MVAr of reactive support: $5M

c) Incremental cost of replacing end-of-life autotransformers at Keith TS with 250 MVA units rather than with like-for-like 125 MVA units: $2M

The costing is not based on detailed engineering but on past experience with such projects.

School Energy Coalition (SEC) INTERROGATORY #4

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, p.2

Did Hydro One and the affected distributors ever discuss alternative approaches to the allocation between themselves? If so, please provide details.

Response

Please see the response to Exhibit I-P2, Tab 1, Schedule 9 d).

School Energy Coalition (SEC) INTERROGATORY #5

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, p.3

Do the capital contributions from new large customers include only new customers, or does it also include increased demand or physical expansions of existing large customers?

Response

Please see the response to Exhibit I-P2, Tab 3, Schedule 2.

School Energy Coalition (SEC) INTERROGATORY #6

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, p.6-8

Did Hydro One consider any other method for apportioning costs between distributors? If so, please provide details and reasons for why there were ultimately rejected.

Response

Hydro One did not consider any other method for apportioning costs between distributors. Please see Exhibit I-P2, Tab 1, Schedule 9d).

School Energy Coalition (SEC) INTERROGATORY #7

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, p.3

Does Hydro One believe that there may be other potential distributors who may benefit at some future date from the proposed project? If so, how does Hydro One proposed to allocate costs to them?

Response

Given the existing distributor service territories, it is very unlikely that any other distributors will benefit from the Project at some future date. However, should this situation change, Hydro One proposes to follow the refund methodology described in section 2.3 (Unforecasted Capacity Assignments) in Exhibit B, Tab 4, Schedule 5, Page 5.

School Energy Coalition (SEC) INTERROGATORY #8

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5, p.6-8

Is Hydro One proposing the Board approve the method of cost allocation between distributors existing ratepayers and any of its new large customers, in this application?

Response

Please refer to Exhibit I-P2, Tab 1, Schedule 9.

Consumers Council of Canada (CCC) INTERROGATORY #1

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4 OPA COST RESPONSIBILITY EVIDENCE

On page 4 it states;

> *"In the RRFE report, the Board concludes that a reconsideration of cost responsibility rules prescribed by the Transmission System Code ("TSC") is desirable to facilitate the effective implementation of regional planning initiatives. Specifically, in the RRFE report, the Board endorses "… a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle." RRFE report, page 43. The OPA (IESO) agrees with the Board's proposed shift to a beneficiary pays approach, which the OPA (IESO) believes will encourage more cost effective electricity system planning decisions.*
>
> *On August 26, 2013 the Board issued its Notice of Amendments to Codes which, among other things, proposed the elimination of Section 6.3.6 (the "otherwise planned" provision) in the TSC and its replacement with new Sections 6.3.8A, 6.3.8B and 6.3.8C.2. These proposed amendments reflect the shift to a beneficiary pays approach to regional planning."*

The evidence above explains that the Board endorsed the "beneficiary" pay principle in its RRFE report; that the OPA (IESO) agreed with this shift and that the Board then issued proposed Transmission System Code (TSC) amendments. It is also the understanding of the Council that these code amendments have not been finalized.

Please detail where and when there has been a full public review and discussion of the "beneficiary" pay principle as well as a discussion and approval of the proposed TSC amendments described above.

If a review has not been undertaken please explain how OPA (IESO), the OEB and the public can be sure this is the best approach?

If the proposed TSC amendments described above have not been adopted how does the OPA (IESO) and Hydro One know what the Board specifically intended in applying the "beneficiary" pay principle?

Response

Hydro One is seeking clarity in this proceeding on the cost responsibility rules relating to system benefits and the beneficiary pays principle. It is Hydro One's understanding that the review, discussion and approval of the proposed TSC amendments is occurring now in Phase 2 of this proceeding.

Consumers Council of Canada (CCC) INTERROGATORY #2

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4 OPA COST RESPONSIBILITY EVIDENCE

Table 1 on page 7 describes the Windsor-Essex Area Reliability Needs/Additional Constraints and Benefitting Parties. Local Generation Developers are listed as a beneficiary but are not allocated any of the project costs. Why?

Response

See Exhibit I-P2, Tab 2, Schedule 15 (a).

Consumers Council of Canada (CCC) INTERROGATORY #3

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4 OPA COST RESPONSIBILITY EVIDENCE

What are the estimated cost contributions for each of the local distribution companies (LDC's) that are part of this project?

What are the estimated rate impacts and customer bill impacts for each affected LDC?

Response

For the estimated cost contribution for each LDC, see the response to Exhibit I-P2, Tab 2, Schedule 9, part (d), Table 1.

Hydro One has not calculated the rate impacts on customer bills for any of the affected LDCs. Customer bill impacts are contingent upon the capital contribution which will be required to be paid from each of the affected LDCs at the time the CCRA is signed and will be trued up in accordance with the TSC. This amount will vary based upon each LDC's load forecast and will also be impacted by the number of new large customers. As shown in response to Exhibit I-P2, Tab 2, Schedule 9e), the capital contribution may vary by a large amount making any estimated rate impact meaningless.

Consumers Council of Canada (CCC) INTERROGATORY #4

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4 OPA COST RESPONSIBILITY EVIDENCE

On page 9 it states;

> *"The proposed integrated SECTR project will address both load customer and system needs/constraints at a reduced cost of approximately $77.4 million (i.e., $22.5 million less than the combined individual solutions). That is because the SECTR project, — by providing for an alternate source of supply in the Windsor-Essex area — avoids the need for, and associated cost of, upgrading the J3E/J4E circuits, installing reactive support, and increasing the size of the Keith autotransformers."*

Doesn't the OPA (IESO) always look for the most cost effective solution considering synergies and cost savings between the transmission and distribution infrastructure?

If so, why would the individual solutions even have been reviewed and costs estimated?

Response

The planning process carried out by the IESO, first identifies one or more electricity supply needs for an area and then identifies the most cost effective alternative to meet those need(s). This is one of the benefits of regional planning. As a means of analyzing cost allocation for the SECTR Project, the evidence considered a hypothetical alternative in which the restoration need for the J3E-J4E subsystem and the supply capacity need for the Kingsville-Leamington subsystem are addressed independently resulting in a total cost of approximately $99.9 million. The proposed SECTR alternative is able to address both needs at a lower cost and was therefore recommended.

Consumers Council of Canada (CCC) INTERROGATORY #5

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 4 OPA COST RESPONSIBILITY EVIDENCE

What other approaches were considered to allocate the proportion of cost between the load customers and transmission ratepayers? Why were those other approaches rejected? If other approaches were not considered, why not?

Response

No other approaches were considered. Hydro One and the IESO acknowledge that there may be other approaches, but no such alternative approaches were readily apparent.

Consumers Council of Canada (CCC) INTERROGATORY #6

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5 PROPOSED COST ALLOCATION METHODOLOGY AT THE DISTRIBUTION LEVEL FOR UPSTREAM TRANSMISSION INVESTMENTS

It states on page 5:

> *"As noted in the OPA's assessment of need for this area in Exhibit B, Tab 1, Schedule 5, the greenhouse growers in the region have indicated strong interest in developing distributed generation through investments in combined heat and power generation. The SECTR Project is therefore expected to serve a mix of load and generation customers. It is Hydro One's assumption that the net incremental coincident peak flow triggering the need for the new facilities is caused by incremental load, as opposed to generation"*

If Hydro One is now moving away from a "trigger" approach why is it not including the benefit of enabling the connection of additional distributed generation for local generation developers as one of the beneficiaries and therefore one of the contributors?

Response

See Exhibit I-P2, Tab 2, Schedule 15(a).

Consumers Council of Canada (CCC) INTERROGATORY #7

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5 PROPOSED COST ALLOCATION METHODOLOGY AT THE DISTRIBUTION LEVEL FOR UPSTREAM TRANSMISSION INVESTMENTS

How does Hydro One's economic evaluation to allocate the capital contribution among all benefiting distributors differ from the OPA's (IESO) cost responsibility approach?

Response

Hydro One's economic evaluation is a discounted cash flow calculation based on the methodology set out in Appendix 5 of the TSC, whereas the IESO's cost responsibility approach is a cost allocation based on proportional benefits. The IESO's cost responsibility approach is used to determine the portion of the project cost for which a capital contribution is required from Hydro One Distribution (the "Customer Cost"). Hydro One Distribution, in turn, performs economic evaluations based on each distributor's share of the Customer Cost to determine the amount payable by each benefiting distributor.

Consumers Council of Canada (CCC) INTERROGATORY #8

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5 PROPOSED COST ALLOCATION METHODOLOGY AT THE DISTRIBUTION LEVEL FOR UPSTREAM TRANSMISSION INVESTMENTS

On page 6 it states:

"Hydro One will also allocate the associated project facility costs, such as distribution feeders, to the Project's beneficiaries."

Are these costs above the total project cost of $77.4M?

What are the costs of the associated project facilities?

Response

Please see Exhibit I-P2, Tab 2, Schedule 19.

Consumers Council of Canada (CCC) INTERROGATORY #9

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5 PROPOSED COST ALLOCATION METHODOLOGY AT THE DISTRIBUTION LEVEL FOR UPSTREAM TRANSMISSION INVESTMENTS

On page 6 Hydro One provides an illustrative example of their proposed approach to cost allocation. Using this methodology determine the actual cost allocations for each of the LDCs (Hydro One plus the embedded utilities) for this project.

Response

See Exhibit I-P2, Tab 2, Schedule 9, part d, specifically Attachment 1, Table 1: Line Pool Allocation of Capital Contribution Summary as well as Attachment 1, Table 12: Transformation Pool Allocation of Capital Contribution Summary.

Consumers Council of Canada (CCC) INTERROGATORY #10

Interrogatory

Reference: Exhibit B, Tab 4, Schedule 5 PROPOSED COST ALLOCATION METHODOLOGY AT THE DISTRIBUTION LEVEL FOR UPSTREAM TRANSMISSION INVESTMENTS

What are the rate impacts for each of the LDCs (Hydro One plus the embedded utilities) after applying Hydro One's proposed methodology to determine the actual cost allocations for each of the LDCs (Hydro One plus the embedded utilities) for this project? Ref: Exhibit B4, Schedule 3, page 6

Response

Please see Exhibit I-P2, Tab 7, Schedule 3.

EnWin INTERROGATORY #1

Preamble:

EnWin is interested in understanding the allocation of the costs of the project and the classification of the project components. Hydro One stated, "Sustainment projects are those for maintaining the performance of the transmission network at its current standard or replacing end of life facilities on a like for like basis."

"In conjunction with transferring the majority of the load from the existing Kingsville Station to the new Leamington TS, …."

Interrogatory:

Reference: Exhibit B, Tab 1, Schedule 4, page 4, section 4.1, lines 15 to 17
Reference: Exhibit B, Tab 1, Schedule 5, page 4, lines 20 to 25

a) What is Hydro One's definition of like for like replacement?

b) To be a like for like replacement, does the replacement have to be at the same location as the original piece of infrastructure?

c) Assume a transformer at end of life is to be replaced by a new transformer that is larger than original transformer but serves the same load. Would Hydro One consider such replacement like for like? What portion of the such a replacement would be considered sustainment?

d) Does sustainment include bringing the performance of assets up to current transmission reliability standards?

e) What change to the economic analysis, and the contributions of the distributors, would result if the percentage of capacity of the Leamington TS that is to serve the load being shifted from Kingsville TS to Leamington TS was considered sustainment spending?

f) What change to the economic analysis, and the contributions of the distributors, would result if the end of life transformers at Kingsville TS were replaced like for like and at Leamington TS only the transformer capacity needed to satisfy near term (e.g. 5 year) load growth projections was constructed?

g) Would Hydro One support a phased construction of Leamington TS such that only (i) the transformers needed to replace like for like at Kingsville TS and (ii) the transformers needed to serve near term (e.g. 5 year) growth projects were constructed in order to reduce the bill impact to existing ratepayers?

Response:

a) "Like for like replacement" is defined as the replacement of existing equipment with new equipment using current design and equipment standards and technologies to effectively provide the same functionality.

b) The replacement equipment does not have to be at the same location as the equipment being replaced.

c) Such replacement would be considered "like for like" provided the smallest Hydro One transformer standard unit rating is used to deliver at least the equivalent capacity rating of the replaced transformer. The entire replacement would be pool-funded as a sustainment cost.

d) Yes, sustainment work can include bringing the performance of assets up to current transmission reliability standards (e.g., replacement of air-blast circuit breakers with SF6 breakers).

e) There would be no change since the cost impact of the proposed load transfer to Leamington TS is already taken into account by means of the $6 million savings to the SECTR Project resulting from the avoided sustainment costs at Kingsville.

f) The contributions from distributors would increase because the $22.5 million of system upgrades would still need to be carried out. Consequently, distributors would bear the full cost of the reduced Leamington TS since there would be no avoided system benefit cost to be shared between the transmitter and distributors.

g) To follow this approach would imply that the integrated approach adopted for the SECTR Project would have to be abandoned and the system upgrades would have to be undertaken in addition to the "5-year capacity Leamington project" proposed in this interrogatory. Furthermore, this initial Leamington project would then need to be followed every five years with other (upgrade) projects to replace the transformers with increasingly larger size units. Ultimately, the total cost to the distributor under this approach would be much greater than the cost of the currently proposed SECTR Project. Such phased construction would result in higher cost and increased bill impact to existing customers both in the near-term and in the long-term. For these reasons, Hydro One would not support this approach.

EnWin INTERROGATORY #2

Preamble:

EnWin wishes to understand (i) the potential impact on distributors for cash flow obligations and rate base and (ii) Hydro One's position regarding the impact on rate base for Hydro One and impacted distributors of these types of projects. Hydro One indicated planning for the SECTR Project was underway since 2007 and that it purchased the lands for the Leamington TS in 2009. The project is scheduled to be in-service in 2018.

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 4, page 9.
Reference: Exhibit I-P1, Tab 1, Schedule 1.

a) Is the land for the Leamington TS in Hydro One's transmission rate base? If so, when was it included in rate base? If not, when is it scheduled to be included in rate base?

b) Is Hydro One seeking a contribution payment from the distributors? When would the contribution from the distributors be required by Hydro One?

c) When would distributors, including Hydro One, be permitted to collect the capital contribution from load customers?

d) Is it Hydro One's position that any contribution by a distributor would be included in the distributor's rate base? If so, what would be the accounting treatment by the distributor?

e) Would a "true-up" calculation be done for each distributor or for the aggregate demand/load provided? When would such calculation be done?

Response:

(a) No, the pre-purchased land for Leamington TS is held in "Assets Under Construction" and is not included in Hydro One's rate base. The land will be placed in rate base once the SECTR Project is in-service.

(b) Yes, the Leamington TS land will form part of the SECTR Project which means a capital contribution will be sought from the distributors and large customers. The capital contributions would be required before the SECTR Project is put in-service, with payments made in accordance with a payment schedule set out in the CCRA, which both parties will have agreed upon.

(c) See part b) above.

(d) Yes, Hydro One would expect distributors to include the capital contribution, net of an contribution from new large customers, in their rate base. Please see Exhibit I-P2, Tab 2, Schedule 18b).

(e) Please see Exhibit I-P2, Tab 5, Schedule 3.

EnWin INTERROGATORY #3

Preamble:

EnWin seeks to understand the economic analysis and the principles underlying the analysis.

> *"In accordance with the beneficiary pays principle, the OPA proposes that the SECTR project costs should be allocated in proportion to what load customers and transmission ratepayers would respectively have had to contribute towards the combined cost of individual solutions…This in the OPA's view, is a fair method of allocating the total project costs based on the beneficiary pays principle, as both load customers and transmission ratepayers realize cost savings."*

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 4, page 9, lines 18 to 20.

(a) Does Hydro One agree with the OPA, now the IESO, position stated above in the quotation? Please explain why or why not.

(b) Do load customers contribute to transmission revenues?

(c) Confirm that Brighton Beach GS will have fewer constraints on generation with the completion of the SECTR Project.

(d) Will Brighton Beach contribute any capital to the unlocking of capacity provided by the SECTR Project?

(e) Will any other generator benefit from the SECTR Project?

(f) Under the "beneficiary pays principle" are generators that have capacity unlocked by a transmission project considered to have benefitted from the project in the economic analysis? If so, to whom are the costs associated with those benefits allocated?

Response:

(a) Hydro One agrees with the IESO that proration is a fair method of allocating the total Project costs. This proportional benefit approach ensures that all costs and savings are appropriately shared among all parties.

(b) Yes.

(c) Please see Exhibit I-P2, Tab 1, Schedule 5.

(d) No.

(e) Please see Exhibit I-P2, Tab 1, Schedule 5.

(f) No. See Exhibit I-P2, Tab 1, Schedule 5.

EnWin INTERROGATORY # 4

Preamble:

Hydro One has described the SECTR Project as non-discretionary and has indicated the commencement of the SECTR project is contingent upon the Board endorsing the methodology as described in Exhibit B, Tab 4, Schedule 5.

Interrogatory:

Reference: Exhibit A, Tab 1, Schedule 1, page 3, paragraph 8.
Reference: Exhibit B, Tab 6, Schedule 2, Attachments.

a) If the Board does not approve substantially the same allocation as is proposed by Hydro One, will Hydro One complete the SECTR project?

b) Under what statutory authority is Hydro One seeking approval of the cost allocation methodology?

c) Did Hydro One make the authors of the letters of endorsement aware of the proposed cost allocation prior to such letters being written? If so, please provide the information that was made available.

d) Has Hydro One received any customer feedback, from those who provided letters of endorsement or otherwise, on the SECTR project cost allocation? If so, please provide it.

e) If there has not been any consultation with customers in respect of the costs of the SECTR project, does Hydro One nevertheless take the position that customers support the project's value proposition? If so, please explain Hydro One's rationale for that position.

Response:

(a) Hydro One has proposed a cost allocation based on a "beneficiary pays" principle to allocate upstream transmission costs at the distribution level. Hydro One believes that this methodology ensures fairness in the allocation of these costs and avoids cross-subsidization at the distribution level among beneficiaries. Hydro One will follow the direction of the Board on its allocation of costs and the project will be completed under that direction.

(b) Hydro One Transmission has applied for approval of the Leave to Construct and associated economics impacts of the Project under s. 92 of the OEB Act.

The OEB filing requirements for Leave to Construct applications, Section 4.3.2.6, request Applicants to provide any "critical risk that may impact the business case supporting the project"[1]. Consequently, Hydro One requests that the Board, under s. 92 of the *OEB Act, 1998*, approve a cost allocation methodology that results in a fair allocation of costs amongst beneficiaries.

In addition, the SECTR Project also impacts non-rate regulated parties in the Windsor-Essex Region. The Filing Requirement, section 4.3.2.9 state that:

> *"Where there are costs which need to be apportioned between rate-regulated and non-rate-regulated parties, the applicant must provide details of an agreement on the apportioning of these costs to the rate-regulated party and applicants must provide details to the Board which includes the costs to be borne by the rate-regulated transmitter"*[2].

For the above reasons, Hydro One believes that approval of a cost allocation methodology for this project falls within the Board's jurisdiction under s. 92 of the *OEB Act, 1998*.

(c) No, the authors were not fully aware of what the proposed cost allocation methodology would be prior to writing letters of endorsement. Hydro One had not fully developed its proposal on cost allocation of upstream costs until just before the Application was filed. However, the benefitting customers were aware, prior to Hydro One filing that application that Hydro One was intending to propose a methodology that would result in capital contribution requirements from each of the affected distributors and large customers.

(d) Hydro One is aware that the beneficiaries have concerns over the potential capital contribution required, its impact on their financing and on their customers. Hydro One received a letter from E.L.K. Energy, Essex Powerlines and Entegrus Powerlines on September 10, 2014 (see Attachment 1), seeking further information and understanding of the cost allocation process Hydro One responded by e-mail (see Attachment 2) and by arranging a conference call with the parties on October 21, 2014 to try to answer their questions.

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[1] Filing Requirement for Electricity Transmission Applications, Chapter 4, Applications under Section 92 of the Ontario Energy Board Act, issued July 31, 2014, page 10.
[2] IBID, page 9

(e) Hydro One’s objective by proposing the cost allocation methodology is to attain regulatory certainty for distributors and their customers regarding cost responsibility.

ATTACHMENT 1
LETTER DATED SEPTEMBER 10, 2014 FROM E.L.K. ENERGY INC., ESSEX POWERLINES INC. AND ENTEGRUS POWERLINES INC.

ATTACHMENT 2
HYDRO ONE'S RESPONSE TO SEPTEMBER 10, 2014 LETTER FROM E.L.K. ENERGY INC., ESSEX POWERLINES INC. AND ENTEGRUS POWERLINES INC.

From: LEE Charlie
Sent: Wednesday, September 24, 2014 1:39 PM
To: Andrya Eagen; Mark Danelon; Richard Dimmel; David Ferguson
Cc: GUO Helen; HAMLYN Alexander; FUERTH John; RICHARDSON Joanne; JODOIN Joel; FRASER Doug; GAYDUKEVYCH Natalia; EL NAHAS Ibrahim
Subject: RE: SECTR Cost Allocation

Hello all again,

First, I would like to apologize for not providing the response to your letter earlier. We discussed your request for information with HONI Tx Planning as well as with our Regulartory Affairs. Our regulatory affairs advise that given the subject application is before the OEB for hearing it would be beneficial to all, if the issue and related questions are addressed on the public record in the public forum. While I am sure you intend to do that, as intervenors, to the application I can provide the following response to the four items raised in the letter;

i. ***Confirmation of the total dollar amount of costs to be allocated amongst the LDCs and Hydro One Distribution;***

The information sent by Helen Guo on Sept 4 is an estimate only and is preliminary based on the load forecast provided by each LDC. The cost allocation may differ depending on the final load forecast that each LDC will confirm at the time of contract following the OEB decision.

ii. ***Information supporting the allocation of total costs between transmission and distribution;***

The cost allocation between transmission and distribution was determined by OPA and Tx planning based on the preliminary cost estimate of the Tx work (230kV line and new TS). The current SECTR application proposes 77.5% of costs would be paid for by local load customers and the remaining cost is further discounted due to the load forecast. (OPA's evidence, page 4 "… the most appropriate way to apportion the costs of the SECTR project between load customers and transmission ratepayers based on the Board's beneficiary pays principle, is to apportion the total cost by reference to the costs that load customers and transmission ratepayers would otherwise have to pay if they were to individually address customer and system needs..)

iii. Copies of the load forecasts used to derive the allocation of transmission and distribution costs, including those used for each LDC, Hydro One Distribution and Hydro One Transmission;

The total Tx-Dx contribution (all LDC combined) was determined taking into consideration the HONI Dx load forecast (inclusive of LDCs). This information was provided in the SECTR application.

iv. Documentation justifying any adjustments to the LDC load forecasts (as well as any adjustments to the Hydro One Distribution and Hydro One Transmission load forecasts), that have been applied in deriving the allocation of distribution costs

No adjustment was made to the LDC forecasts. However, where LDC provided more than one load forecasts only one was used for analysis. The cost allocation is preliminary and the final allocation will vary depending the final load forecast.

In closing, unfortunately due to scheduling conflict we are unable to convene for a meeting before Sept 26. I will try to arrange a conference call in the next 2 weeks so that the cost allocation methodology as proposed in the SECTR may be explained by our decision support team member.

Sincerely,

Charlie Lee, P. Eng.
Sr. NM Engineer – Distribution Investment Planning
Tel: 416-345-5345
Cell: 416-458-8287
Location: TCT-15N
E-Mail: Charlie.Lee@hydroone.com
Address: 483 Bay Street, 15th floor, Toronto, Ontario, M5G 2P5

ATTACHMENT 2
HYDRO ONE'S RESPONSE TO SEPTEMBER 10, 2014 LETTER FROM E.L.K. ENERGY INC., ESSEX POWERLINES INC. AND ENTEGRUS POWERLINES INC.

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Cc: GUO Helen; HAMLYN Alexander; FUERTH John; RICHARDSON Joanne; JODOIN Joel; FRASER Doug; GAYDUKEVYCH Natalia; EL NAHAS Ibrahim
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The information sent by Helen Guo on Sept 4 is an estimate only and is preliminary based on the load forecast provided by each LDC. The cost allocation may differ depending on the final load forecast that each LDC will confirm at the time of contract following the OEB decision.

ii. ***Information supporting the allocation of total costs between transmission and distribution;***

The cost allocation between transmission and distribution was determined by OPA and Tx planning based on the preliminary cost estimate of the Tx work (230kV line and new TS). The current SECTR application proposes 77.5% of costs would be paid for by local load customers and the remaining cost is further discounted due to the load forecast. (OPA's evidence, page 4 "… the most appropriate way to apportion the costs of the SECTR project between load customers and transmission ratepayers based on the Board's beneficiary pays principle, is to apportion the total cost by reference to the costs that load customers and transmission ratepayers would otherwise have to pay if they were to individually address customer and system needs..)

iii. Copies of the load forecasts used to derive the allocation of transmission and distribution costs, including those used for each LDC, Hydro One Distribution and Hydro One Transmission;

The total Tx-Dx contribution (all LDC combined) was determined taking into consideration the HONI Dx load forecast (inclusive of LDCs). This information was provided in the SECTR application.

iv. Documentation justifying any adjustments to the LDC load forecasts (as well as any adjustments to the Hydro One Distribution and Hydro One Transmission load forecasts), that have been applied in deriving the allocation of distribution costs

No adjustment was made to the LDC forecasts. However, where LDC provided more than one load forecasts only one was used for analysis. The cost allocation is preliminary and the final allocation will vary depending the final load forecast.

In closing, unfortunately due to scheduling conflict we are unable to convene for a meeting before Sept 26. I will try to arrange a conference call in the next 2 weeks so that the cost allocation methodology as proposed in the SECTR may be explained by our decision support team member.

Sincerely,

Charlie Lee, P. Eng.
Sr. NM Engineer – Distribution Investment Planning
Tel: 416-345-5345
Cell: 416-458-8287
Location: TCT-15N
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EnWin INTERROGATORY #5

Preamble:

Hydro One has identified that this project will address certain deficiencies pursuant to ORTAC.

Interrogatory:

Reference: Exhibit B, Tab 1, Schedule 4, page 5.
Reference: Exhibit B, Tab 1, Schedule 5, section 5.

a) On what basis (e.g. contractual, statutory) is Hydro One subject to ORTAC?

b) Does ORTAC apply to Hydro One's service standards as a transmitter, distributor, or both?

c) Is the ORTAC standard any different in Windsor-Essex that elsewhere in Ontario? If so, how?

d) Are any other distributors in Windsor-Essex subject to ORTAC and, if so, in what ways and pursuant to what authority?

e) Please file any stakeholder submissions received by Hydro One in developing the SECTR project, the Integrated Regional Resource Planning process, or other customer consultations that cited the ORTAC deficiency.

f) If the load growth in the Leamington area had not materialized as set out in the application, did Hydro One have plans to remedy the ORTAC deficiency anyway? If so, please file those plans.

Response:

(a) The IESO is responsible for directing the operation and maintaining the reliability of the IESO-controlled grid. This responsibility is assigned to the IESO in the "Electricity Act, 1998" and in the "Market Rules", Chapter 5 Section 3.2. ORTAC was developed by the IESO to provide guidance for carrying out technical studies to assess the adequacy of the IESO-controlled grid (transmission systems operated at voltages above 50 kV) to meet general requirements on the grid and to ensure that system reliability is within standards. Hydro One is obligated to follow the requirements of ORTAC because facilities connected to the IESO-controlled grid are assessed by the IESO based on ORTAC.

(b) ORTAC applies to Hydro One's service as a transmitter and distributor whose facilities are connected to the IESO-controlled grid.

(c) ORTAC applies equally throughout the province of Ontario.

(d) All facilities that are connected to the IESO-controlled grid are subject to ORTAC, whereas facilities not connected to the IESO-controlled grid are not subject to ORTAC. Therefore, any distributor with facilities connected to the IESO-controlled grid would be subject to ORTAC. See response to (a).

(e) No stakeholder submissions were received during the Integrated Regional Resource Planning process that cited the ORTAC deficiency.

(f) The following plans have been considered to remedy ORTAC deficiencies in the Windsor – Essex Region:

- Upgrade of 115 kV circuits J3E and J4E
- Replacement of Keith 110 MVA 230-115 kV autotransformers with 250 MVA units

The two plans above are referenced on page 37 of:
http://www.ieso.ca/Documents/marketReports/10YearOutlook_2004mar.pdf,

EnWin INTERROGATORY #6

Interrogatory:

Refernce: Exhibit B, Tab 4, Schedule 5, pages 6-8.

a) Please file a "Summary of Cost Allocation Approach", similar in format to that found on page 6 of the above noted reference, but that sets out the way or ways that cost allocation would have worked were SECTR being implemented under the "trigger" regime rather than the "beneficiary pays" regime.

b) In the proposed cost allocation approach at page 6 of the above noted reference, is there any provision for truing-up the allocation among distributors over time based on actual growth?

c) Please fill out the illustrative "Flow of Costs" and "Cost Responsibility Table" at page 8 of the above noted reference based on the application's proposal.

d) What is Hydro One's basis for determining that existing customers are "beneficiaries" of the SECTR project?

Response:

(a) Hydro One assumes that the "trigger" regime means that the customer who requests ("triggers") a new or modified transmission connection facility has full cost responsibility for that facility, regardless of whether the facility provides benefits to any other entities, including the overall transmission system. The revised "Summary of Cost Allocation Approach" below is based on this assumption.

Summary of Cost Allocation Approach (for "trigger" regime)

1. The transmitter invests in new transmission connection facilities in the amount of the project cost.
2. The full project cost is attributed to the transmission customer that requested the facilities.
3. At the transmission level, the transmission customer pays a capital contribution to the transmitter, in accordance with an economic evaluation performed on the full project cost.
4. At the distribution level, the transmission customer performs economic evaluations to determine the capital contribution payable by each distributor that requested the facility.

5. Each such distributor, in turn, performs economic evaluations to determine the capital contribution payable by each of its own new large customers that requested the facility.

(b) Yes, Hydro One proposes to perform the periodic true-ups based on actual load (see Exhibit B, Tab 4, Schedule 5). Furthermore, Hydro One also proposes to perform annual refund calculations to address any unforecasted loads that connect over the previous year (see Exhibit B, Tab 4, Schedule 5).

(c) Please see Exhibit I-P2, Tab 2, Schedule 9d) for the current forecast of capital contributions required from all four distributors.

(d) Existing customers who need additional capacity to address load growth and/or overloading are considered beneficiaries because they benefit from that additional capacity.

Canadian Manufacturers & Exporters (CME) Interrogatory #1

Interrogatory:

Reference: Exhibit A, Tab 1, Schedule 1, page 3
Reference: Exhibit B, Tab 4, Schedule 5
Reference: Exhibit B, Tab 4, Schedule 4
Reference: Procedural Order No. 3, Issues 1 and 2

The evidence refers to the Ontario Energy Board's ("OEB" or the "Board") "Beneficiary Pays" principle to support Hydro One's proposal to attribute a portion of the costs of the transmission system expansion in this proceeding to "system benefits", for recovery from all transmission ratepayers, and the remainder to "customer benefits", to be recovered from connecting customers.

We seek to obtain a better understanding of Hydro One's perception of the "Beneficiary Pays" principle and its implications for manufacturers and other electricity consumers.

Our understanding is that, in its regulation of the incremental expansion costs incurred by natural gas transmitters, the Board applies a rolled-in tolling methodology so that incremental transmission costs are rolled-in with existing transmission costs before they are allocated between transmission and distribution customers for recovery in transmission and distribution rates.

In this connection, please provide the following additional information:

a) Would the application of the rolled-in tolling methodology change the outcome of the allocation of the incremental costs of the transmission expansion in this case which Hydro One is asking the Board to approve?

b) If so, then please provide a schedule which will show the cost allocation outcomes at the transmission and distribution levels of allocating the incremental costs associated with the project in this proceeding under the auspices of rolled-in transmission tolling methodology.

c) In Hydro One's view, what is the transmission tolling concept upon which the current cost responsibility provisions of the Transmission System Code ("TSC") is based? Are the transmission cost responsibility provisions of the TSC based on an "incremental" tolling concept or a "rolled-in" tolling concept?

d) Does adherence to an "incremental" transmission cost responsibility concept either facilitate or impede the objective of achieving more electricity distributor consolidation in Ontario? Please explain the rationale for your response to this question.

e) Does Hydro One regard the Board's adoption of the "Beneficiary Pays" principle to be a move away from an incremental cost responsibility model and a move towards a rolled-in cost responsibility model?

f) In Hydro One's view, does the rolled-in cost responsibility model fall inside or outside the ambit of the Board's "Beneficiary Pays" principle? Please provide the rationale for your response to this question.

g) Please advise whether any other regulated electricity transmitters or distributors in Canada apply the "Beneficiary Pays" principle. If so, then please provide copies of any regulatory decisions or tribunal policies which provide further details on how the principle is to be applied.

Response:

(a) It is not clear to Hydro One how the "rolled-in" tolling methodology would be applied to this Project. Without a better understanding of what, under the rolled in methodology, would be included in "existing transmission costs" or more detailed information on how costs are allocated between transmission and distribution rates, it is not possible to determine the outcome of applying such methodology . However, Hydro One does note that if all the Project costs were recovered through rates (i.e., no contributions from large customers) then rates would be expected to be higher in comparison to Hydro One's proposed cost allocation methodology.

(b) See response to (a).

(c) The cost responsibility provisions in the TSC relating to new or modified transmission connection facilities are based on incremental costs.

(d) It is unclear to Hydro One whether an incremental transmission cost responsibility concept facilitates or impedes the objective of achieving more electricity distributor consolidation in Ontario.

(e) Hydro One does not regard the beneficiary pays principle to be a move away from an incremental cost responsibility model and a move towards a rolled-in cost responsibility model.

(f) The beneficiary pays principle addresses ‘who pays’, while the incremental (and Hydro One suspects also the rolled-in) cost responsibility models address ‘what costs’. In Hydro One’s view, these are two independent concepts.

(g) Hydro One does not know whether any regulated electricity transmitters or distributors in Canada (outside of Ontario) apply the beneficiary pays principle.

Canadian Manufacturers & Exporters (CME) Interogatory #2

Interrogatory:

Reference: Exhibit A, Tab 1, Schedule 1, page 3
Reference: Exhibit B, Tab 4, Schedule 5
Reference: Exhibit B, Tab 4, Schedule 4
Reference: Procedural Order No. 3, Issues 1 and 2

In determining the proportion of the transmission costs associated with the project to be attributed to "system benefits", Hydro One has adopted the Ontario Power Authority's ("OPA") assessment that 22.5% of these costs should be allocated to transmission ratepayers; and the remaining 77.5% should be allocated to particular customer beneficiaries.

The OPA's derivation of these percentages is premised on the notion that cost estimates for hypothetical stand-alone projects to deal with system needs and customer-specific needs, separately, constitute the appropriate information source for determining the portions of costs to be allocated between system benefits and customer beneficiaries.

In connection with this evidence, please provide the following information:

a) Please list all options either the OPA or Hydro One considered for determining the proportions of the incremental costs of this project to be attributed to system benefits and to customer beneficiaries respectively.

b) Did either the OPA or Hydro One consider determining these percentages from information related to actual or forecast events rather than hypothetical scenarios? If so, what sources of such information were considered?

c) What would be the allocation to system benefits if the total annual incremental demands of those customers to be served by the new facilities were expressed as a percentage of total annual demands of all customers who receive a benefit from the new facilities?

d) What would be the allocation to system benefits if the total peak demands of those customers to be served by the new facilities were expressed as a percentage of total peak demands of all customers who receive a benefit from the new facilities?

Response:

a) Please refer to Exhibit I-P2, Tab 6, Schedule 1.

b) The IESO and Hydro One only considered the cost allocation alternative described in the Recommended Cost Allocation Treatment evidence filed as Exhibit B, Tab 4, Schedule 5.

c) This interrogatory has been interpreted as requesting the annual energy consumption by the customers served by the new facility as a percentage of the annual energy consumption of all customers who receive a benefit from the new facilities.

Energy consumption data for 2014 has been utilized. Because the new Leamington TS was not in-service in 2014, the annual energy consumption by customers served by Leamington TS was estimated based on the proportion of 2014 peak demand at Kingsville TS which is currently expected to be transferred to Leamington TS.

It is estimated that customers at Leamington TS would consume approximately 11% of the energy consumed by all of the customers in the J3E-J4E subsystem on an annual basis and 89% of the energy would be consumed by the remaining customers in the J3E-J4E subsystem.

The benefits to customers at Leamington TS are greater than those for other customers in the J3E-J4E subsystem. Therefore this approach is not the basis for an appropriate cost allocation.

d) This interrogatory has been interpreted as requesting the annual peak demand by the customers served by the new facility as a percentage of the annual peak demand of all customers who receive a benefit from the new facilities.

Data for 2014 has been utilized. Because the new Leamington TS was not in-service in 2014, the peak demand by customers served by Leamington TS was estimated based on the proportion of peak demand at Kingsville TS which is currently expected to be transferred to Leamington TS.

It is estimated that Leamington TS peak demand coincident to the J3E-J4E subsystem peak demand would be approximately 11% of the subsystem peak and 89% of the peak demand would result from the remaining customers in the J3E-J4E subsystem.

The benefits to customers at Leamington TS are greater than those for other customers in the J3E-J4E subsystem. Therefore this approach is not the basis for an appropriate cost allocation.

Canadian Manufacturers & Exporters(CME) Interrogatory #3

Interrogatory:

Reference: Exhibit B4, Schedule 3, page 6

The evidence indicates that, with 22% of the project costs allocated to system benefits, the impact of Hydro One's increased transmission rates on a typical residential electricity consumer is 0.01%. In connection with this evidence, please provide the following:

a) The impact on electricity consumers if 50% of the project costs are attributed to system benefits;

b) The impact on electricity consumers if 100% of the incremental costs associated with the project are allocated to system benefits.

Response:

a) The impact on the transmission component of a typical residential electricity consumer's bill if 50% of the Project costs are attributed to system benefits would be 0.01%.

b) The impact on the transmission component of a typical residential electricity consumer's bill if 100% of the Project costs are attributed to system benefits would be 0.02%.

Canadian Manufacturers & Exporters (CME) Interrogatory #4

Interrogatory:

Reference: Exhibit A, Tab 3, Schedule 1, page 2

Hydro One asks the Board to approve its proposed cost allocation method at the distribution level and states that such an approval is required in order for it to proceed with the project. In connection with this evidence, please provide the following further information:

a) How many manufacturers are located in the Windsor-Essex and Kingsville-Leamington areas whose rates will be affected by Hydro One's proposed treatment of the incremental costs associated with this transmission system expansion project?

b) Please explain how the Board can approve the proposed cost allocation approach "at the distribution level" without knowing the estimated impacts of the proposal on the electricity consumers served by the affected distributors.

Response:

(a) Any impact to Hydro One's Transmission rates will impact all manufacturers and customers in the province. If they are served by Hydro One Distribution, distribution rates will also be impacted by any cost allocation decisions from this hearing.

(b) It is Hydro One's view that the proposed cost allocation methodology should be approved by the OEB, not on the basis of its impact on one particular project, but on the basis that the methodology will become part of the cost responsibility rules in the TSC, to be applied to this and all such future projects. Hydro One believes that only in this way will there be sufficient regulatory certainty regarding cost responsibility, and that, in turn,will avoid delays to needed electricity infrastructure investments .

Canadian Manufacturers & Exporters (CME) Interrogatory #5

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 3

Please provide Schedules which will show the extent to which the capital contribution amount Hydro One Distribution must pay to Hydro One Transmission will be reduced in a scenario where 50% of the transmission system expansion costs are allocated to system benefits and 50% to customers beneficiaries.

Response:

Under this scenario, the capital contribution amount is estimated to be $22.1 million for Hydro One Distribution.

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3	22.6	22.6	18.3
Station Facilities	32.1	16.0	16.0	3.8
Total	**77.4**	**38.7**	**38.7**	**22.1**

Canadian Manufacturers & Exporters (CME) Interrogatory #6

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 5, page 3

The evidence indicates that the specific distributors who will benefit from the transmission system expansion project are:

- Hydro One Distribution
- Essex Powerlines Corporation
- E.LK. Energy Inc.
- Entegrus Powerlines Inc.

Each of these distributors will be required to make a capital contribution as will new large customers of each of those distributors.

There is no evidence of the estimated impacts of the costs associated with the transmission expansion project on electricity consumers served by each of these distributors.

In connection with this evidence, please provide the following information:

a) What is the amount of the capital contribution to be made by Hydro One Distribution which must be absorbed by Hydro One Distribution customers?

b) What amount of that capital contribution will be recovered from new large customers?

c) What is the impact of Hydro One's proposals on its distribution customers other than the new large customers who will be required to make a capital contribution?

d) What is the impact on each of the new large customers to be served by Hydro One Distribution who will be required to make a capital contribution?

e) For each of Essex Powerlines Corporation, E.L.K. Energy Inc., and Entegrus Powerlines Inc., please provide the same electricity consumer impact information requested of Hydro One in sub-paragraphs (a) to (d) above. If Hydro One does not yet have that information, then please obtain it from each of those distributors so that the

Board can consider the distribution cost responsibility impacts on their customers when evaluating Hydro One's distribution cost responsibility proposals.

Response:

a) Of the $39.4 million capital contribution to be made by Hydro One Distribution, $18.3 million is forecast to be absorbed by Hydro One Distribution customers. For further detail, please see the response to Exhibit I-P2, Tab 2, Schedule 9, part (d).

b) A $12.7 million capital contribution is forecast to be recovered from new large customers. For further detail, please see the response to Exhibit I-P2, Tab 2, Schedule 9, part (d).

c) Please see Exhibit I-P2, Tab 11, Schedule 10 b).

d) The required information to calculate the impact on each of the new large customers to be served by Hydro One Distribution who will be required to make a capital contribution is not available at this time. The capital contribution will depend upon the expected timing of the connection, forecast load of the individual customers as well as the individual connection requirements of each customer.

e) Hydro One has sent information on the capital contribution resulting from the proposed cost allocation required to Essex Powerlines Corporation, E.L.K. Energy Inc., and Entegrus Powerlines Inc. It is Hydro One's understanding from the E3 Coalition that once responses to the interrogatories from Phase 2 of this hearing are filed, E3 Coalition anticipates filing evidence which will address the impact of the SECTR Project on each of the distributor's customers. Therefore, at this time, Hydro One is unable to provide the requested information.

Canadian Manufacturers & Exporters (CME) Interrogatory #7

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 5, page 5

How is the distributor cost responsibility of Embedded Generators being treated under Hydro One's proposal? In your response, please advise how Hydro One currently derives, or plans to derive, its rates and charges to Embedded Generators for stand-by distribution service. This information will be of relevance to a determination of whether the benefits of the project to this type of customer have been appropriately considered.

Response:

Allocation of upstream transmission costs to embedded generators is addressed in Exhibit I-P2, Tab 2, Schedule 15.

Embedded generators directly connected to the distribution system, or what Hydro One refers to as the Distributed Generation rate class, do not pay stand-by distribution charges but they do pay all distribution charges for any load that they consume (e.g. if they take their generation out of service for maintenance).

The OEB has initiated a proceeding to look at the stand-by charges policy for load customers that have generators embedded within their load consuming facility which offsets their load consumption (as opposed to selling their generation into the electricity market). This type of embedded generation is typically referred to as Load Displacement Generation. The OEB's policy review of Load Displacment Generation was initiated in January 2013 under proceeding EB-2014-0004 and it is currently on hold.

Hydro One Sub-transmission (ST) rate class customers that have embedded Load Displacement Generation pay for distribution service on a gross load basis, and therefore effectively pay distribution service charges for 100% of any load supplied from their embedded Load Displacement Generation.

Association of Major Power Consumers in Ontario(AMPCO) Interrogatory # 1

Interrogatory:

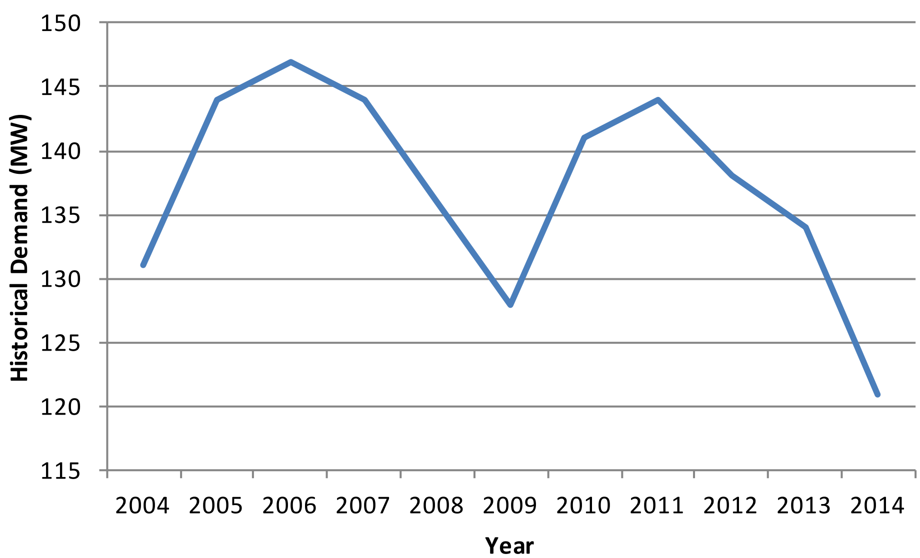
Reference: Sect B/ Tab 1/Sch5, fig 3 (p10), fig 11 (p25).

Please update these two graphs with actual demand for 2014.

Response:

The need for the SECTR Project and alternatives to meeting the need were the subject of Phase 1 of this proceeding.

The updated version of Figure 3 from the reference is shown below.



The historical demand values in Figure 4 are the same as those in Figure 3.

Association of Major Power Consumers in Ontario (AMPCO) Interrogatory #2

Interrogatory:

Reference: Sect B/Tab 1/ Sch 5, page 25, line 5&6

The reference states that the increased load requirement, net of DG and CDM is for 25MW in 2014, rising to 46MW in 2033. The proposed transmission solution to meet this need is a double circuit, 230kV line, which capacity is several times the projected incremental load. Also, the transformer station specification is for two 75/100/125MVA transformers, also with capacity well in excess of forecast requirements.

Has Hydro One or the OPA considered the option of building only a single circuit 230kV line, with a lower-rated transformer station?

Response:

The alternative of a single circuit 230 kV line with a lower-rated transformer station was not considered. The recommended solution consists of a standard dual supply for the new Leamington TS.

Energy Probe INTERROGATORY #1

Preamble:

Reference: Hydro One Tx EB-2014-0141 Decision and
Exhibit B, Tab 4, Schedule 3, Page 17, Table 6

Interrogatory:

Please provide the reference and extract for the OEB-approved 2014 and 2015 Cost of Capital.

Please provide the reference(s) for the OEB-approved Average Tx OM&A of $1.5 per km of line.

Please compare the costs provided above to those used in the DCF analyses including ROE of 9.3% on common equity, 2.16% on short-term debt, 4.98% forecast cost of long-term debt, 40/60 equity/debt split, and income tax rate (PILs) of 26.5%.

Response:

(a) For the 2014 OEB-approved Cost of Capital parameters, please refer to Exhibit 1.4 of the Rate Order approved by the OEB on January 9, 2014 for Hydro One's Transmission Rate Application for 2013 and 2014 (EB-2012-0031).

For the 2015 OEB-approved Cost of Capital parameters, please refer to Exhibit 1.4 of the Draft Rate Order filed by Hydro One on December 9, 2014 and approved by the OEB on January 8, 2015 for Hydro One's Transmission Rate Application for 2015 and 2016 (EB-2014-0140).

For ease of reference purposes, these specific exhibits have been filed as Attachment 1 and 2 of this interrogatory response.

(b) The OEB does not approve the specific amount of incremental OM&A used in the financial evaluation. Instead, the OEB approved Hydro One's methodology in determining the amount by using the system average estimates as stated in Section 2.5 Economic Evaluation Procedure of the Transmission Connection Procedures approved by the OEB (EB-2006-0189).

For ease of reference purposes, an excerpt of Section 2.5 Economic Evaluation Procedure of those Transmission Connection Procedures has been filed as Attachment 3 to this interrogatory response.

(c) Hydro One did use these amounts in the financial evaluation filed as part of the evidence update on February 12, 2015. The ROE and deemed short-term debt rate used in the analysis were issued by the OEB on November 20th, 2014 for 2015 applications. Please see Attachment 4 to this interrogatory response for the Board letter. The long-term debt rate was determined in accordance with the OEB's Cost of Capital methodology in EB-2009-0084.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2012-0031

Capital Structure and Return on Capital

($ millions)	**Supporting Reference**	**Hydro One Proposed 2014**	**OEB Decision Impact 2014**	**OEB Approved 2014**	**Cost of Capital Update 2014**	**Revised OEB Approved 2014**
Return on Rate Base					Note 2	Note 2
Rate Base	Exhibit 1.2	$ 10,050.9	$ (117.3)	$ 9,933.8	$ -	$ 9,933.8
Capital Structure:						
Third-Party long-term debt		58.6%	(1.9%)	56.7%	-2.8%	53.9%
Deemed long-term debt		-2.6%	1.9%	-0.7%	2.8%	2.1%
Short-term debt		4.0%	0.0%	4.0%	0.0%	4.0%
Common equity		40.0%	0.0%	40.0%	0.0%	40.0%
Capital Structure:						
Third-Party long-term debt	Exhibit 1.4.1	5,890.8	(258.4)	5,632.4	(275.0)	5,357.4
Deemed long-term debt		(262.2)	192.8	(69.5)	275.0	205.5
Short-term debt		402.0	(4.7)	397.4	-	397.4
Common equity		4,020.4	(46.9)	3,973.5	-	3,973.5
		10,050.9	**$ (117.3)**	**9,933.8**	**-**	**9,933.8**
Allowed Return:						
Third-Party long-term debt	Exhibit 1.4.1	4.83%	(0.00%)	4.83%	0.11%	4.94%
Deemed long-term debt	Exhibit 1.4.1	4.83%	(0.00%)	4.83%	0.11%	4.94%
Short-term debt	Note 1	2.98%	0.00%	2.98%	-0.87%	2.11%
Common equity	Note 1	9.44%	(0.16%)	9.28%	0.08%	9.36%
Return on Capital:						
Third-Party long-term debt		284.4	(12.6)	271.9	(7.4)	264.4
Deemed long-term debt		(12.7)	9.3	(3.4)	13.5	10.1
Short-term debt		12.0	(0.1)	11.8	(3.5)	8.4
AFUDC return on Niagara Reinforcement Project	see below	4.8	(0.0)	4.8	0.1	4.9
Total return on debt		**$ 288.5**	**$ (3.4)**	**$ 285.1**	**$ 2.7**	**$ 287.9**
Common equity		**$ 379.5**	**$ (10.8)**	**$ 368.7**	**$ 3.1**	**$ 371.8**
AFUDC return on Niagara Reinforcement Project						
CWIP		99.1		99.1	-	99.1
Deemed long-term debt		4.83%		4.83%	0.11%	4.94%
		4.8		4.8	0.1	4.9

Note 1: The approved rates follow the OEB's November 15, 2012 guidance on cost of capital parameters to reflect the September 2012 Consensus Forecast.
Note 2: The 2014 Cost of Capital is updated to reflect OEB approved parameters issued on November 25, 2013, updated forecast of 2014 third-party long-term debt rate and 2013 actual debt issues.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2014)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/13 ($Millions)	Total Amount Outstanding: at 12/31/14 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	0.0	148.1	4.8	
20	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
21	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
22	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
23	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
24	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
25	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
26	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.49	3.26%	154.0	154.0	154.0	5.0	
27	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.99	3.08%	165.0	165.0	165.0	5.1	
28	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.52	4.02%	68.8	68.8	68.8	2.8	
29	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.52	3.81%	52.5	52.5	52.5	2.0	
30	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.21	3.83%	141.0	141.0	141.0	5.4	
31	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	Note 1
32	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	412.5	412.5	11.8	Note 1
33	15-Mar-14	4.928%	15-Mar-44	289.8	1.4	288.4	99.50	4.96%	0.0	289.8	223.0	11.1	Note 2
34	15-Jun-14	4.091%	15-Jun-24	289.8	1.4	288.4	99.50	4.15%	0.0	289.8	156.1	6.5	Note 2
35	15-Sep-14	3.101%	15-Sep-19	289.8	1.4	288.4	99.50	3.21%	0.0	289.8	89.2	2.9	Note 2
37		**Subtotal**							4916.1	5610.6	5357.4	259.5	
38		Treasury OM&A costs										1.7	
39		Other financing-related fees										3.3	
40		**Total**							4916.1	5610.6	5357.4	264.4	4.94%

Note 1: Updated to reflect actual 2013 debt issuance
Note 2: Updated to reflect the forecast coupon rates for 2014 as per the October 2013 long-term Consensus Forecast

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2014-0140

Capital Structure and Return on Capital

($ millions)	**Supporting Reference**	**Hydro One Proposed 2015**	**Hydro One Proposed 2016**	**Settlement Impact 2015**	**Settlement Impact 2016**	**Cost of Capital Update 2015**	**Cost of Capital Update 2016**	**OEB Approved 2015**	**OEB Approved 2016**
Return on Rate Base									Note 2
Rate Base	Exhibit 1.2	$ 10,176.5	$ 10,558.0	$ (1.2)	$ (1.1)	$ -	$ -	$ 10,175.2	$ 10,557.0
Capital Structure:									
Third-Party long-term debt		50.7%	51.0%	(0.0%)	(0.0%)	0.2%	0.2%	50.9%	51.2%
Deemed long-term debt		5.3%	5.0%	(0.0%)	(0.0%)	(0.2%)	(0.2%)	5.1%	4.8%
Short-term debt		4.0%	4.0%	(0.0%)	(0.0%)	0.0%	0.0%	4.0%	4.0%
Common equity		40.0%	40.0%	(0.0%)	(0.0%)	0.0%	0.0%	40.0%	40.0%
Capital Structure:									
Third-Party long-term debt	Exhibit 1.4.1 and 1.4.2	5,157.9	5,385.9	(0.6)	(0.5)	23.1	23.0	5,180.3	5,408.4
Deemed long-term debt		541.0	526.5	(0.1)	(0.1)	(23.0)	(23.0)	517.9	503.4
Short-term debt		407.1	422.3	(0.0)	(0.0)	(0.0)	0.0	407.0	422.3
Common equity		4,070.6	4,223.2	(0.5)	(0.4)	(0.0)	0.0	4,070.1	4,222.8
		10,176.5	**10,558.0**	**$ (1.2)**	**$ (1.1)**	**$ (0.0)**	**$ (0.0)**	**10,175.3**	**10,556.9**
Allowed Return:									
Third-Party long-term debt	Exhibit 1.4.1 & 1.4.2	5.02%	5.08%	(0.05%)	(0.08%)	0.01%	(0.03%)	4.98%	4.97%
Deemed long-term debt	Exhibit 1.4.1 & 1.4.2	5.02%	5.08%	(0.05%)	(0.08%)	0.01%	(0.03%)	4.98%	4.97%
Short-term debt	Note 1	3.19%	4.45%	(0.92%)	(0.45%)	(0.11%)	0.03%	2.16%	4.03%
Common equity	Note 1	9.71%	9.96%	(0.25%)	(0.05%)	(0.16%)	(0.23%)	9.30%	9.68%
Return on Capital:									
Third-Party long-term debt		258.9	273.7	(2.6)	(4.5)	1.6	(0.3)	257.9	269.0
Deemed long-term debt		27.2	26.8	(0.3)	(0.4)	(1.1)	(1.3)	25.8	25.0
Short-term debt		13.0	18.8	(3.8)	(1.9)	(0.5)	0.1	8.8	17.0
AFUDC return on Niagara Reinforcement Project	see below	5.0	5.0	(0.0)	(0.1)	0.0	(0.0)	4.9	4.9
Total return on debt		**$ 304.0**	**$ 324.3**	**$ (6.6)**	**$ (6.9)**	**$ 0.0**	**$ (1.5)**	**$ 297.4**	**$ 316.0**
Common equity		**$ 395.3**	**$ 420.6**	**$ (10.2)**	**$ (2.2)**	**$ (6.5)**	**$ (9.7)**	**$ 378.5**	**$ 408.8**
AFUDC return on Niagara Reinforcement Project									
CWIP		99.1	99.1	-	-	-	-	99.1	99.1
Deemed long-term debt		5.02%	5.08%	(0.05%)	(0.08%)	0.01%	(0.03%)	4.98%	4.97%
		5.0	5.0	(0.0)	(0.1)	0.0	(0.0)	4.9	4.9

Note 1: The approved rates follow the OEB's November 20, 2014 guidance on cost of capital parameters to reflect the September 2014 Consensus Forecast.

Note 2: The 2016 cost of capital parameters & impacts are based on the October 2014 long-term Consensus Forecast and are for illustrative purposes only. Hydro One will submit a 2016 draft rate order to the OEB reflecting the cost of capital parameters issued by the Board once the September 2015 Consensus Forecast becomes available. At that point the up-to-date cost of capital parameters will be applied to determine the 2016 amounts.

Note 3: As per EB-2008-0272 Decision with Reasons on May 28, 2009, page 54, the deemed long-term rate has been updated to reflect Hydro One's embedded long-term debt rate.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2015)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/14 ($Millions)	Total Amount Outstanding: at 12/31/15 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
20	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
21	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	0.0	103.8	3.1	
22	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
23	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
24	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
25	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
26	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
27	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
28	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
29	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
30	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
31	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	412.5	412.5	11.8	
32	29-Jan-14	4.290%	29-Jan-64	30.0	0.2	29.8	99.44	4.32%	30.0	30.0	30.0	1.3	Note 1
33	3-Jun-14	4.170%	3-Jun-44	198.0	1.2	196.8	99.40	4.21%	198.0	198.0	198.0	8.3	Note 1
34	15-Mar-15	4.771%	15-Mar-45	159.3	0.8	158.6	99.50	4.80%	0.0	159.3	122.6	5.9	Note 2
35	15-Jun-15	3.905%	15-Jun-25	159.3	0.8	158.6	99.50	3.97%	0.0	159.3	85.8	3.4	Note 2
36	15-Sep-15	3.046%	15-Sep-20	159.3	0.8	158.6	99.50	3.15%	0.0	159.3	49.0	1.5	Note 2
37		**Subtotal**							4969.1	5297.1	5180.3	253.4	
38		Treasury OM&A costs										1.6	
39		Other financing-related fees										2.9	
40		**Total**							4969.1	5297.1	5180.3	257.9	4.98%

Note 1: Updated to reflect actual 2014 debt issuance
Note 2: Updated to reflect the forecast coupon rates for 2015 as per the September 2014 Consensus Forecast

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2016)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/15 ($Millions)	Total Amount Outstanding: at 12/31/16 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	0.0	48.5	2.3	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	0.0	13.8	0.7	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
20	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
21	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
22	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
23	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
24	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
25	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
26	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
27	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
28	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
29	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
30	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	412.5	412.5	11.8	
31	29-Jan-14	4.290%	29-Jan-64	30.0	0.2	29.8	99.44	4.32%	30.0	30.0	30.0	1.3	Note 1
32	3-Jun-14	4.170%	3-Jun-44	198.0	1.2	196.8	99.40	4.21%	198.0	198.0	198.0	8.3	Note 1
33	15-Mar-15	4.771%	15-Mar-45	159.3	0.8	158.6	99.50	4.80%	159.3	159.3	159.3	7.7	Note 2
34	15-Jun-15	3.905%	15-Jun-25	159.3	0.8	158.6	99.50	3.97%	159.3	159.3	159.3	6.3	Note 2
35	15-Sep-15	3.046%	15-Sep-20	159.3	0.8	158.6	99.50	3.15%	159.3	159.3	159.3	5.0	Note 2
36	15-Mar-16	5.521%	15-Mar-46	197.5	1.0	196.5	99.50	5.56%	0.0	197.5	151.9	8.4	Note 3
37	15-Jun-16	4.655%	15-Jun-26	197.5	1.0	196.5	99.50	4.72%	0.0	197.5	106.3	5.0	Note 3
38	15-Sep-16	3.796%	15-Sep-21	197.5	1.0	196.5	99.50	3.91%	0.0	197.5	60.8	2.4	Note 3
39		**Subtotal**							5297.1	5619.5	5408.4	264.5	
40		Treasury OM&A costs										1.6	
41		Other financing-related fees										3.0	
42		**Total**							5297.1	5619.5	5408.4	269.0	4.97%

Note 1: Updated to reflect actual 2014 debt issuance
Note 2: Updated to reflect the forecast coupon rates for 2015 as per the September 2014 Consensus Forecast
Note 3: Updated to reflect the forecast coupon rates for 2016 as per the October 2014 long-term Consensus Forecast

Section 2.5

ECONOMIC EVALUATION PROCEDURE

INTRODUCTION

Hydro One's Economic Evaluation Procedure was developed to meet the requirements of section 6.5.2 of the Transmission System Code (the Code). This procedure involves performing a financial evaluation of the relevant costs and revenues for new or modified load connections. The financial evaluation is carried out according to the methodology and inputs prescribed in the Code. To perform the evaluation, Hydro One uses a discounted cash flow model. The model and its assumptions are described below.

HYDRO ONE'S DISCOUNTED CASH FLOW MODEL

Overview

Hydro One uses its discounted cash flow (DCF) model to assess project economic feasibility and determine any contribution-in-aid-of-construction required for new or modified transmission load connections. The model assesses financial impacts of new connection projects on the basis of the relevant revenues and costs. The following revenue and cost elements are included:

- the up-front capital costs for new or modified connection facilities
- on an exception basis, capital costs for new or modified network facilities required to serve the connection as per section 6.3.5 of the Code
- fully allocated overheads on capital and interest during construction (AFUDC) for work performed by Hydro One
- advancement costs only, where Hydro One has planned a new or modified connection facility and moves the planned date forward to accommodate a customer as per section 6.5.2(d) of the Code
- for connection facilities built by a 3rd party and transferred to Hydro One, the transfer price including applicable Hydro One costs and charges
- an estimate of working capital requirements associated with the new or modified connection

Over the economic evaluation period:

- relevant transmission line and/or transformation connection and/or network (on an exception basis per section 6.3.5 of the Code) tariff revenue generated by the new or modified connection
- estimated OM&A costs to operate, maintain and administer the new connection, including property and capital taxes and excluding interest, which is accounted for in the discount rate
- applicable income taxes and income tax shields

A capital contribution will be required from the customer to make up any shortfall between the present value of the costs of the connection facility and the present value of revenues, as indicated by the DCF analysis.

The methodology and assumptions of the DCF model are consistent with the Transmission System Code and specifically the requirements outlined in section 6.5.2 and Appendix 4 –

Customer Financial Risk Classification, and Appendix 5 – Methodology and Assumptions for Economic Evaluations.

Key Assumptions Used in the Model

Economic Evaluation Periods

The economic evaluation periods that are defined in section 6.5.2 (b) and Appendix 4 of the Code are as follows:

- 5 years for high-risk connections
- 10 years for medium-high-risk connections
- 15 years for medium-low-risk connections
- 25 years for low-risk connections

More information about the methodology used to determine the appropriate economic evaluation period is provided below.

Actual or Estimated Capital Costs

The economic evaluation may be calculated initially using estimated costs, provided that subsequently the evaluation is re-calculated based on actual costs. Ordinarily this recalculation will occur within 180 days after the in-service date.

Connection Revenue

Revenue for transmission related connection projects is based on project load information and OEB-approved Line Connection and Transformation Connection tariffs. Revenue is derived from that part of the load customer's new load that exceeds the normal supply capacity of any connection facility already serving that customer, and which will be served by a new or modified connection facility. Any customer's assigned capacity transferred from an existing connection facility already serving the customer will not be credited to the customer's new connection facility revenues. Line connection and transformation connection facilities are subject to separate economic evaluations. Historic revenues and sunk costs are excluded.

Operating, Maintenance and Administrative Costs

OM&A costs are system average estimates for transformation connection and/or line connection facilities as determined and updated by Hydro One.

Incremental Working Cash Requirements

Forecast incremental working cash requirements are estimated based on Hydro One's transmission lead-lag study results applied to project OM&A costs, consistent with an OEB approved working cash methodology.

Allowance for Funds Using During Construction (AFUDC)

Project capital costs include interest during construction (AFUDC) up to the in-service date. The AFUDC rate is the standard interest capitalization rate used for all Hydro One capital projects.

Income Taxes and Net Large Corporation Tax (LCT)

Income taxes, including large corporation tax and applicable surtaxes, and Ontario capital tax, are based on current or future enacted tax rates. Property taxes are based on a transmission system average rate.

After-tax Discount Rate Used for NPV Calculations

The project discount rate is based on Hydro One's prospective capital mix, debt and preference share cost rates, income taxes, and the most recent OEB approved rate of return on common equity.

Timing of Expenditures

Project cash flows are present-valued to the in-service date (time zero). Up-front capital expenditures are treated as occurring at the beginning of the period for discounting purposes. Future capital expenditures, annual connection rate revenues and annual operating and maintenance costs are treated as occurring at the mid-point of the year in which they occur.

Customer Risk Classification

The information below is consistent with Appendix 4 of the Code and is applicable to load connections.

New or Modified Connections that are not Project Financed

For a new or modified connection that is not being financed by the load customer on a "project financing" basis, Hydro One will use a bond rating provided by the customer from a known bond rating agency to determine the risk classification.

Where no bond ratings are available for the customer, Hydro One will use the appropriate Altman Z model (for public industrial companies, private industrial companies, or non-industrial companies), as the case may be, if the necessary information to complete the analysis is available. Hydro One will normally require the customer to provide a copy of its most recent 3 years of audited financial statements in order to do the Altman Z analysis. Where audited financial statements are not available, Hydro One may, at its discretion, use un-audited financial statements or other similar information. If the results of the Altman Z model appear anomalous, Hydro One will use the Kaplan-Urwitz model as a secondary methodology. See below for details on the Altman Z model and the Kaplan-Urwitz model. Also see Appendix 1 at the end of this Procedure for further information.

Where Hydro One considers that the risk classification that results from the application of the above methods produces an anomalous result, Hydro One may, with the customer's consent, assign a different risk classification to the new or proposed connection. Where the customer does not consent, Hydro One may apply to the OEB for approval to determine the customer's risk classification using an alternate methodology.

Where a load customer has not provided Hydro One with some or all of the information necessary to determine the customer's Altman-Z or Kaplan-Urwitz score, Hydro One may use estimates based on comparable information provided by similar customers. Where no such comparable information is available or where Hydro One considers that the customer's circumstances are such as to render comparisons with similar customers inappropriate, Hydro One may classify the risk associated with the proposed new or modified connection as high risk.

Where the new connection is for a project having a finite life (e.g., a new mine with 10 years of proven reserves), the economic evaluation period will be based on the life of the project or the risk rating of the customer, whichever is less.

New or Modified Connections that are Project Financed

For a new or modified connection that is being financed by the load customer on a "project financing" basis, the customer's risk classification will be determined by the type and amount of security provided. Ordinarily a parental guarantee from an entity with an acceptable credit rating will be required. With an acceptable parental guarantee, the risk classification of the project will be based on the risk of the parent, subject to the exception noted above for finite-life projects.

Where acceptable security is not provided, the project will be assigned a high-risk classification.

Risk Horizon Table

Bond ratings or Altman Z scores or Kaplan-Urwitz scores will determine the customer's risk classification according to the tables below.

Risk Horizon Table
Bond Rating and Altman Z Score

Bond Rating*	Altman Z – Score**			Risk Profile	Risk Horizon
	Public Industrial	Private Industrial	Private Non-Industrial		
CCC and below	<1.81	<1.23	<1.10	High Risk	5 Years
B – BB	1.81 – 2.67	1.23 – 2.59	1.10 – 2.32	Medium High Risk	10 Years
Industrial BBB – AAA Non-industrial BBB	2.68 – 2.99	2.60 – 2.90	2.33 – 2.60	Medium Low Risk	15 Years
Non-industrial A - AAA	>2.99	>2.90	>2.60	Low Risk	25 Years

* Based on DBRS rating scale. Investment grade credits qualify for risk ratings of 15 years and above. Non-investment grade credits qualify for risk ratings of less than 15 years. Equivalent ratings from other rating agencies would apply if deemed suitable by Hydro One.

** Public non-industrial companies or other entities that do not fall within the compass of one of the 3 Altman Z models will be assessed using an appropriate methodology, at Hydro One's discretion

Altman Z Public Industrial Model

The Altman Z Score is calculated as:

$$Z = 1.2 * X_1 + 1.4 * X_2 + 3.3 * X_3 + 0.6 * X_4 + 1.0 * X_5$$

Where,

X_1=net working capital/total assets
X_2=retained earning/total assets
X_3=earning before interest and taxes (EBIT)/total assets
X_4=market value of equity/ total liabilities
X_5=sales/total assets

Altman Z Private Industrial Model

The Altman Z Score is calculated as:

$$Z' = 0.717 * X_1 + 0.847 * X_2 + 3.107 * X_3 + 0.420 * X_4 + 0.998 * X_5$$

Where,

X_1=net working capital/total assets
X_2=retained earning/total assets
X_3=earning before interest and taxes (EBIT)/total assets
X_4=book value of shareholders' equity/total liabilities
X_5=sales/total assets

Altman Z Private Non-Industrial Model

The Altman Z Score is calculated as:

$$Z'' = 6.56 * X_1 + 3.26 * X_2 + 6.72 * X_3 + 1.05 * X_4$$

Where,

X_1=net working capital/total assets
X_2=retained earning/total assets
X_3=earning before interest and taxes (EBIT)/total assets
X_4=book value of shareholders' equity/total liabilities

Risk Horizon Table
Bond Rating and Kaplan-Urwitz Score

Bond Rating*	Kaplan-Urwitz Score	Risk Profile	Risk Horizon
CCC and below	<0**	High Risk	5 Years
B – BB	<0**	Medium High Risk	10 Years
Industrial BBB – AAA Non-industrial BBB	> 1.57 1.57 – 3.28	Medium Low Risk	15 Years
Non-industrial A – AAA	> 3.28	Low Risk	25 Years

***** Based on DBRS rating scale. Investment grade credits qualify for risk ratings of 15 years and above. Non-investment grade credits qualify for risk ratings of less than 15 years. Equivalent ratings from other rating agencies would apply if deemed suitable by Hydro One.
** Kaplan-Urwitz bond rating-equivalency scores are not provided for non-investment grade entities (below BBB). Kaplan-Urwitz scores less than zero accordingly will be classified as either high-risk or medium-high risk based on a combination of Kaplan-Urwitz scores, Altman Z scores and other factors such as traditional credit analysis.

Kaplan-Urwitz Model

The Kaplan-Urwitz score is calculated as:

$$KU = 4.41 + 0.0012 * X_1 – 2.56 * X_2 - 2.72 * X_3 + 6.40 * X_4 - 0.53 * X_5 + 0.006 * X6$$

Where,

X_1=total assets ($000)
X_2=subordinated debt (dummy variable, 1 or 0)
X_3=long-term debt/total assets
X_4=net income/total assets
X_5=co-efficient of variation in net income over 5 years*
X_6=interest coverage (EBIT/interest expense)

* Less than 5 years' of financial statement information will be used when the information is not available.

True-Up Procedure for Load Customers

For new or modified load connection facilities, Hydro One will carry out a true-up calculation, based on actual customer load, at the following true-up points as per sections 6.5.3 to 6.5.11 of the Code:

(a) for high risk connections, at the end of each year of operation, for five years;
(b) for medium-high risk and medium-low risk connections, at the end of each of the third, fifth and tenth year of operation; and
(c) for low risk connections, at the end of each of the fifth and tenth year of operation, and at the end of the fifteenth year of operation if actual load is 20% higher or lower than the initial load forecast at the end of the tenth year of operation.

For the true-up calculation, Hydro One shall use the same methodology used to carry out the initial economic evaluation, and the same inputs except for load, which will be based on the actual load up to the true-up point and an updated load forecast for the remainder of the economic evaluation period used.

Before carrying out a true-up calculation for a load customer who did not make an initial capital contribution, Hydro One shall adjust the initial load forecast used in the initial economic evaluation to the point where the present value of connection rate revenues equals the present value of costs as per section 6.5.5 of the Code.

Where a true-up calculation shows that a load customer's actual load and updated load forecast is lower than the load in the initial load forecast, and does not generate the initial forecast connection rate revenues, Hydro One shall require the load customer to make a payment to make up the shortfall, adjusted appropriately to reflect the time value of money and net of any previous true-up payments made.

Where analysis shows that the customer has transferred assigned capacity from an existing Hydro One owned connection facility already serving the customer to the new connection facility, which is the subject of the economic evaluation, the customer's actual load for true-up purposes will be reduced in proportion to the amount transferred. The updated load forecast will also be reduced to eliminate any transferred load. If there is a shortfall, Hydro One will then require the customer to remit a payment to make up the shortfall, adjusted appropriately to reflect the time value of money and net of any previous true-up payments made.

Where a true-up calculation shows that a load customer's actual load and updated load forecast is higher than the load in the initial load forecast, and generates more than the initial forecast connection rate revenues, Hydro One will post the excess revenue as a credit to the customer in a notional account, net of any previous true-up credits. Hydro One will apply the net credit against any shortfall in subsequent true-up calculations. Hydro One will rebate to the load customer any credit balance that remains when the last true-up calculation is carried out, adjusted appropriately to reflect the time value of money and applicable income and other tax impacts. The rebate shall not exceed any capital contribution, adjusted to reflect the time value of money, previously paid by the load customer.

When carrying out a true-up calculation for a distributor, Hydro One:

(a) shall add to the actual load the amount of any embedded generation (determined in accordance with section 11.1 of the Code) that was installed during the true-up period; and
(b) shall not reduce the updated load forecast as a result of any embedded generation (determined in accordance with section 11.1 of the Code) that was installed during the true-up period.

When carrying out a true-up calculation for a load customer other than a distributor, Hydro One:

(c) shall add to the actual load the amount of any embedded generation (determined in accordance with section 11.1 of the Code) of 1 MW or less per unit, or any embedded renewable generation of 2 MW or less per unit, that was installed during the true-up period; and

(d) shall not reduce the updated load forecast as a result of any embedded generation (determined in accordance with section 11.1 of the Code) of 1 MW or less per unit, or any embedded renewable generation of 2 MW or less per unit, that was installed during the true-up period.

When carrying out a true-up calculation for any load customer, Hydro One:

(e) shall add to the actual load the amount of any reduction in the customer's load that the customer has demonstrated to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit or annual or quarterly reports from an OEB approved CDM program) has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the true-up period; and
(f) shall not reduce the updated load forecast as a result of any reduction in the customer's load that the customer has demonstrated to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit or annual or quarterly reports from an OEB approved CDM program) has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the true-up period.

Where a load customer voluntarily and permanently disconnects its facilities from a transmitter's facilities prior to the last true-up point, Hydro One shall, at the time of disconnection, carry out a final true-up calculation in accordance with the rules set out above. Where the true-up calculation shows that the load customer's load to the date of disconnection has not generated the initial forecast connection rate revenues, the transmitter shall require the load customer to make a payment to make up the shortfall, adjusted appropriately to reflect the time value of money and net of any previous true-up payments. Where a true-up calculation shows that the load customer's load to the date of disconnection has generated more than the initial forecast connection rate revenues, Hydro One shall rebate to the load customer any excess, adjusted appropriately to reflect the time value of money and applicable income and other tax impacts.

Transfer Price

Where Hydro One pays a transfer price for a connection facility constructed by a load customer, Hydro One will reflect the transfer price plus applicable charges and costs in the capital contribution that is to be paid by the customer. The amount to be reflected in the capital contribution is determined as follows:

Capital cost* = Transfer price + Hydro One project-specific costs +

(a) make-ready costs on transferred assets including inspection, testing, commissioning and any other costs of incorporation +
(b) capital costs of any Hydro One Uncontestable Work +
(c) full direct and indirect capitalized overheads on capital costs in (a)+(b).

** The above is a general definition only. Capital and operating costs for individual projects will be based on the estimated costs of those projects. Some of the cost elements listed above could be capital or operating costs, and not all cost elements may be applicable for each project.*

APPENDIX I

Further information regarding the Altman Z and Kaplan-Urwitz models, per Hydro One's response to OEB Staff Interrogatory #20 in EB-2006-0189

Ontario Energy Board (Board Staff) INTERROGATORY #20

Interrogatory

Ref.(a) H1N-CCP/ Section 2.5 Economic Evaluation/ Load Connection Applicant Without Bond Rating/ pp.33 – 35
Ref.(b) SC/Appendix 4
Ref.(c) TSC/Appendix 4/ "Report" to the Board dated March 30, 2000 referenced in Appendix 4, authored by PHB Hagler Bailly and entitled "Risk Assessment Methodology Options". The report is available from the Board's website at www.oeb.gov.on.ca.

Preamble

- The directions to the transmitter are spelled out in In Ref. (b)- Appendix 4 of the TSC, as well as in Ref.(c), covering various aspects including use of two financial Models (the Altman Z-score Model and the Kaplan-Urwitz Model) for evaluating financial risks of companies, where no bond ratings are available. The use of the two models requires certain information be available to the transmitter.

- In Ref. (b) the Board indicated that a revision to the transmitter's economic evaluation procedure to update a Model shall not constitute a material amendment to the transmitter's connection procedures for the purposes of section 6.1.5 and therefore does not require the approval of the Board.

- However, this is the first opportunity for the Board to review and compare the details of the two models (Altman Z-score and the Kaplan-Urwitz Model) outlined in Ref. (a) with the corresponding Models in the original Report [Ref.(c)]. Therefore responses to various clarifications and questions listed below are needed.

Questions/Clarification

In Ref. (a), page 34, Hydro One added two new Altman Z –score Models in addition to the Model listed in the "Report" [Ref.(c)]; the first new Model is for "Public Industrial Companies" and the second new Model is for "Private Non-Industrial Companies".

Re: Altman Z-score Model

(i) Please provide the name of the entity that publishes the Altman Z-score Models, its address and a contact person's telephone and e-mail address;

(ii) when were the two new Models developed? and how often the three Models are updated [the original listed in Ref.(C) and the two new ones in Ref. (a)]?

(iii) The two bullets below compare the two tables in the two indicated references:
  - In page 4 of Ref.(c), the table depicts three levels of "Projected Credit Risk", and the corresponding Altman Z-score which corresponds to the "Private Industrial" Model as follows:

If Altman Z-Score is:	Projected Credit Risk is
< 1.2	High
1.2-1.9	Meduim
>2.9	Low

- In page 33 of Ref. (a), The corresponding Table for the Altman Z-score covering three types of industrial companies as follows:

Bond Rating*	Altman Z – Score**			Risk Profile	Risk Horizon
	Public Industrial	Private Industrial	Private Non-Industrial		
CCC and below	<1.81	<1.23	<1.10	High Risk	5 Years
B – BB	1.81 – 2.67	1.23 – 2.59	1.10 – 2.32	Medium High Risk	10 Years
Industrial BBB – AAA Non-industrial BBB	2.68 – 2.99	2.60 – 2.90	2.33 – 2.60	Medium Low Risk	15 Years
Non-industrial A – AAA	>2.99	>2.90	>2.60	Low Risk	25 Years

With regard to the two above tables:

(a) Please provide full explanation and justification on how the score range of (1.2 – 2.9) of the Altman Z-score corresponding to "Medium Risk" of Ref. (c), was apportioned in Ref.(a) between "Medium High Risk" with Z-score range =1.23 – 2.59, and "Medium Low Risk" with Z-score range= 2.6 – 2.9.

Note: that the mid point on linear basis between the two ranges, would lead to a range in the Z-score of 1.23 – 2.1 for "Medium High Risk" and 2.2 – 2.59, for "Medium Low Risk"

(b) Please provide details and justification for selection of the ranges depicted for the Altman Z-score vis a vis the four risk categories (High, Medium High, Medium Low, and Low) for the two new Models corresponding to the Models for Public Industrial Companies and for the Private Non-industrial companies.

<u>Re: Kaplan-Urwitz Model</u>

(iv) The Model proposed for the Kaplan-Urwitz model in page 35 of Ref.(a), is identical to the Kaplan-Urwitz Model shown in page 6 of Ref.(c) except for the use of an additional term (- 2.56 * X_2) where X_2 is a "dummy" or "categorization" variable which is assigned a value X_2 = 1 if the debt is subordinated, and a value of X_2 = 0 if the debt is not subordinated.

(a) Please indicate whether this term (– 2.56 * X_2) is the original term in the Model which according to Ref. (c)/ page 6/ foot note 3, was published in April, 1979;

(b) Please indicate whether this Model is revised by the authors, or by any other entity in the financial industry? if so, please indicate by who and when was the last time it was revised;

(c) Please provide explanation and justification for the range chosen for the Kaplan-Urwitz score for the "Industrial" class where it appears that regardless of how high a company can score, it cannot exceed "Meduim Low Risk".

<u>Response</u>

(i,ii) Hydro One is not aware of an official entity that publishes the Altman Z models. The financial literature contains numerous references to versions of the Altman Z model. The 3 versions that were included in the company's filed procedures were obtained from a 1995 CPA Journal extract found on the web, "Z scores – a guide to failure prediction" by Gregory J. Eidleman. The CPA Journal is a refereed publication published by the New York State CPA Society. This article appeared to be the most concise source of information regarding the 3 Altman Z models.

Hydro One also reviewed other sources including an article by Prof. Edward Altman, the Z-model's developer ("Predicting the Financial Distress of Companies: Revisiting the Z-score and Zeta models", July 2000) also found on the web. This article provided background on the development of the 3 models and their strengths and weaknesses. As the article discusses, the first Altman Z model was developed in the late 1960's based on a sample of public manufacturing company data (the "public industrial" model included in Hydro One's filing). That model was later adapted by Altman (the article does not indicate when) for private manufacturing companies (the "private industrial" model included in Hydro One's filing). This is the model that was included in the PHB Hagler Bailly report (reference (C) of Staff's interrogatory). The final adaptation by Altman was to extend the model for use with respect to non-manufacturing companies (the "private non-industrial" model included in Hydro One's filing). This latter model is also cited occasionally in the literature as the "generalized" model and appears to be considered by some as applicable across industry-types.

Hydro One is not aware how often (if at all) the various versions of the Altman Z model are updated. Hydro One included all of the models in its connection procedure in order to provide as wide a basis as possible for assessing new connections and allow for a matching of the appropriate model with a given set of circumstances.

(iii)

(a) The PHB Hagler-Bailly report (ref. C) provided a breakdown of Altman Z-scores into 3 categories (High, Medium, Low). In order to provide a 4-category breakdown consistent with the risk-classifications established by the Board (High, Medium-high, Medium-low, Low), transmitters were required to split PHB's "medium" category into 2 sub-categories. As noted above, the version of the Altman Z model provided in the PHB report was the private manufacturing model (using Prof. Altman's terminology), and this is the version referenced in Staff's Interrogatory above. Intermediate cut-off points between the high and low values that allowed for splitting the "medium" risk category into 2 sub-categories were not available in the literature for this model, nor for the private non-industrial model. Intermediate cut-offs were, however, provided by Prof. Altman in the article referenced above for the public industrial model. The splitting of the medium category for the private industrial and private non-industrial models in Hydro One's filing was accordingly based on scaling their intermediate cut-off points using the corresponding scale from the public industrial model. The formula for the private industrial model intermediate cut-off point is as follows:

$2.59 = 2.90 \times 2.67 / 2.99$

The formula for the private non-industrial intermediate cut-off point is:

$2.32 = 2.6 \times 2.67 / 2.99$

(b) The high and low values for the two "new" Altman-Z models (Public Industrial and Private Non-industrial) included in Hydro One's connection procedure were taken from the CPA Journal article referenced above. See part (a) above for an explanation of the derivation of their intermediate cut-off points.

(iv)

(a) Hydro One is not aware whether the subordinated-debt term referenced in footnote 3 of the PHB report was included in the original Kaplan-Urwitz model; the footnote in the PHB report indicates that it was included in the "formal" model. Hydro One included the subordinated-debt term in the model filed in its connection procedure in order to provide a version of the model able to accommodate situations in which subordinated debt was present.

(b) Hydro One is not aware whether the Kaplan-Urwitz model is or has been revised by the authors or by any other entity. A web search did not provide any information in this regard.

(c) The industrial category in the Kaplan-Urwitz model is treated in a manner consistent with the methodology used for industrials in the Altman Z model and bond ratings (i.e., industrial customers are eligible for a maximum 15-year risk horizon under all approaches). This is due to the inherent riskiness of industrial companies. The 15-year maximum reflects 2 key concerns:

- Intense competition in industrial markets due to the impact of globalization, currency swings and commodity price fluctuations, among other factors. These factors expose industrial companies in particular to quickening rates of change and hence higher risk.

- The lack of liquidity in a transmission investment compared with a financial instrument such as a bond. Bond ratings are based partly on the liquidity of the instrument being rated. Accordingly, a bond rating is not a perfect tool to use in measuring the long-term risks to the transmission pool arising from an illiquid new connection. This suggests that some element of judgment is in order when using bond ratings for risk assessment purposes with respect to transmission investments.

Recognizing these concerns (increasing rates of change affecting industrial companies in particular, and the imprecise nature of bond ratings as a risk assessment tool), a 15-year maximum risk horizon for industrial companies is considered prudent in managing the risks to the transmission pool.

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BY E-MAIL AND WEB POSTING

November 20, 2014

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2015 Cost of Service and Custom Incentive Rate-setting Applications

Re: Cost of Capital Parameter Updates for 2015 Applications

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2015 applications. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report"), issued December 11, 2009.

Cost of Capital Parameters for 2015 Rates

For rates with effective dates in 2015, the Board has updated the Cost of Capital parameters based on: (i) the September 2014 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low or A:- (A-stable) commercial customers, for the Short-Term debt rate; and (ii) data three months prior to January 1, 2015 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LP, for all Cost of Capital parameters.

The Board has determined that the updated Cost of Capital parameters for 2015 rate applications for rates effective in 2015 are:

Cost of Capital Parameter	**Value for 2015 Applications for rate changes in 2015**
ROE	9.30%
Deemed LT Debt rate	4.77%
Deemed ST Debt rate	2.16%

Detailed calculations of the Cost of Capital parameters are attached.

The Board considers the Cost of Capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

As documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) issued November 21, 2013, the Board now updates Cost of Capital parameters for setting rates only once per year. For this reason, the Cost of Capital parameters above will be applicable for all cost of service and custom IR applications (as applicable) with rates effective in the 2015 calendar year.

The Board monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in individual rate hearings in support of different Cost of Capital parameters due to the specific circumstances, but must provide strong rationale and supporting evidence for deviating from the Board's policy.

All queries on the Cost of Capital parameters should be directed to the Board's Industry Relations hotline, at 416 440-7604 or industryrelations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For rate changes effective in 2015)

Cost of Capital Parameter Calculations

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2014

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
	Day	10-yr	30-yr	30-yr		
1	1-Sep-14					
2	2-Sep-14	2.09	2.64	4.04	0.55	1.40
3	3-Sep-14	2.09	2.63	4.03	0.54	1.40
4	4-Sep-14	2.12	2.66	4.06	0.54	1.40
5	5-Sep-14	2.11	2.67	4.06	0.56	1.39
6	6-Sep-14					
7	7-Sep-14					
8	8-Sep-14	2.14	2.68	4.07	0.54	1.39
9	9-Sep-14	2.17	2.70	4.09	0.53	1.39
10	10-Sep-14	2.20	2.72	4.11	0.52	1.39
11	11-Sep-14	2.20	2.72	4.11	0.52	1.39
12	12-Sep-14	2.24	2.76	4.15	0.52	1.39
13	13-Sep-14					
14	14-Sep-14					
15	15-Sep-14	2.23	2.76	4.15	0.53	1.39
16	16-Sep-14	2.24	2.77	4.16	0.53	1.39
17	17-Sep-14	2.26	2.79	4.18	0.53	1.39
18	18-Sep-14	2.28	2.79	4.18	0.51	1.39
19	19-Sep-14	2.25	2.76	4.14	0.51	1.38
20	20-Sep-14					
21	21-Sep-14					
22	22-Sep-14	2.22	2.74	4.11	0.52	1.37
23	23-Sep-14	2.17	2.72	4.09	0.55	1.37
24	24-Sep-14	2.20	2.73	4.10	0.53	1.37
25	25-Sep-14	2.15	2.68	4.05	0.53	1.37
26	26-Sep-14	2.16	2.68	4.06	0.52	1.38
27	27-Sep-14					
28	28-Sep-14					
29	29-Sep-14	2.13	2.65	4.04	0.52	1.39
30	30-Sep-14	2.15	2.67	4.06	0.52	1.39
31						
		2.18	2.71	4.10	**0.530**	**1.386**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts* Publication Date: September-08-14

	3-month	12-month		Average	
September 2014	2.500	3.200	❸	**2.850**	%

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	2.850	%
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.530	%
Long Canada Bond Forecast (LCBF)	❹	**3.380**	%

Step 4: Return on Equity (ROE) forecast

Initial ROE				9.75	%
Change in Long Canada Bond Yield Forecast from September 2009					
LCBF (September 2014) (from Step 3	④	3.380	%		
Base LCBF		4.250	%		
Difference		-0.870	%		
0.5 X Difference				-0.435	%
Change in A-rated Utility Bond Yield Spread from September 2009					
A-rated Utility Bond Yield Spread (September 2014) (from Step 1)	②	1.386	%		
Base A-rated Utility Bond Yield Spread		1.415	%		
Difference		-0.029	%		
0.5 X Difference				-0.015	%
Return on Equity based on September 2014 data				**9.30**	%

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2014 (from Step 3)	④	3.380	%
A-rated Utility Bond Yield Spread September 2014 (from Step 1)	②	1.386	%
Deemed Long-term Debt Rate based on September 2014 data		**4.77**	%

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations
(For rate changes effective in 2015)

Cost of Capital Parameter Calculations
Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in September, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	Average Spread over 90-day Bankers Acceptance		Date of input
Bank 1	100.0	bps	Sept., 2014
Bank 2	100.0	bps	Sept., 2014
Bank 3	82.5	bps	Sept., 2014
Bank 4	80.0	bps	Sept., 2014
Bank 5	100.0	bps	Sept., 2014
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	5	
High estimate	100.0	bps
Low estimate	80.0	bps

C. Average annual Spread	94.167	bps	❶

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.942	%	①
Average Bankers' Acceptance Rate	1.214	%	②
Deemed Short Term Debt Rate	**2.16**	%	

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2014

Month: September 2014

	Day	**Bankers' Acceptance Rate (%) 3-month**	
1	1-Sep-14	Bank holiday	%
2	2-Sep-14	1.21	%
3	3-Sep-14	1.21	%
4	4-Sep-14	1.21	%
5	5-Sep-14	1.21	%
6	6-Sep-14		
7	7-Sep-14		
8	8-Sep-14	1.21	%
9	9-Sep-14	1.21	%
10	10-Sep-14	1.22	%
11	11-Sep-14	1.22	%
12	12-Sep-14	1.22	%
13	13-Sep-14		
14	14-Sep-14		
15	15-Sep-14	1.22	%
16	16-Sep-14	1.22	%
17	17-Sep-14	1.22	%
18	18-Sep-14	1.22	%
19	19-Sep-14	1.21	%
20	20-Sep-14		
21	21-Sep-14		
22	22-Sep-14	1.21	%
23	23-Sep-14	1.21	%
24	24-Sep-14	1.21	%
25	25-Sep-14	1.21	%
26	26-Sep-14	1.21	%
27	27-Sep-14		
28	28-Sep-14		
29	29-Sep-14	1.22	%
30	30-Sep-14	1.22	%
31			
		1.214	%
		❷	

Source Bank of Canada / Statistics Canada
Series V39071

Reference on Calculation Method:
• Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

Energy Probe INTERROGATORY #2

Preamble:

Reference: Exhibit B, Tab 4, Schedule 3, Tables 1 & 2, DCF Analyses Line and Transformation Pools

Interrogatory:

a) Please provide a live Excel Spreadsheet with the Line and Transformation Pool baseline DCF analyses

b) Please list in detail all input assumptions and sources.

c) Please provide commentary regarding variability of these assumptions.

Response:

(a) The requested live Excel Spreadsheet has been filed with the OEB and has been electronically provided to all registered intervenors in this phase of the Application.

(b) Model assumptions are embedded with the model provided in response to (a) above.

(c) Changes to input assumptions including forecast load and estimated project costs represent uncertainties to the initial economic evaluation and the resulting capital contribution. These estimates will be reconciled to actuals at the appropriate time.

Energy Probe INTERROGATORY #3

Preamble:

Reference: Exhibit B, Tab 4, Schedule 3, Table 3, Revenue Requirement and Rate Impacts for Line Pool

Interrogatory:

Please provide a live Excel Spreadsheet for the Revenue Requirement Analyses for the Line Pool.

Please provide references/sources for Table 3 inputs:

- Average Rate Base,
- Incremental OM&A Costs,
- Depreciation.

Please provide sources/basis for following Table 3 Base Year Inputs:

- Line Pool Revenue Requirement including sufficiency/(deficiency) 207 Line GW242,
- Line Pool Rate ($/kw/month) 0.86.

Response:

(a) The requested live Excel Spreadsheet has been filed with the OEB and has been electronically provided to all registered intervenors in this phase of the Application.

(a) Please see the references as follows:

- The Average Rate Base number shown in Table 3 is the incremental rate base after the project goes in-service each year.
- The incremental OM&A Costs are the system average estimates calculated by following Section 2.5 Economic Evaluation Procedure of the Transmission Connection Procedures approved by the OEB (EB-2006-0189) which is provided at Attachment 3 to Exhibit I-P2, Tab 11, Schedule 1.
- The depreciation rate used in the model is based upon the forecast average service life of 50 years.

(b) The following references were approved as part of the Ontario Uniform Transmission Rate Order in EB-2014-0357:

- The Line Pool Revenue Requirement of $207 million is the Revenue Requirement of all Transmitters
- The GW242 is the Total Annual Charge Determinants (MW) of All Transmitters
- Line Pool Rate of 0.86($/kw/month) was approved by the OEB on January 8, 2015

The OEB Decision in the above-mentioned proceeding is provided as Attachment 1 to this interrogatory response.

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

Ontario

EB-2014-0357

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

AND IN THE MATTER OF a motion by the Ontario Energy Board to approve an order setting Uniform Transmission Rates for the transmission of electricity for 2015.

BEFORE: Ken Quesnelle
Vice Chair and Presiding Member

RATE ORDER
2015 UNIFORM ELECTRICITY TRANSMISSION RATES
January 08, 2015

The Ontario Energy Board ("the Board") established the EB-2014-0357 proceeding on its own motion to issue the 2015 Uniform Transmission Rates (UTR) as these rates are generated with the inputs of five Ontario transmitters.

Hydro One's EB-2014-0140 Draft Rate Order (DRO), submitted on December 9, 2014, included the consolidated information from the five transmitters and also contained an amended revenue allocation formula in the UTR to reflect the fact that the B2M LP assets are entirely in the network pool. Board staff and intervenors were provided an opportunity to comment on the DRO and the allocation factors. The IESO confirmed its ability to implement the revised allocation formula. The London Property Management Association and Board staff agreed with the DRO as filed.

The Board finds that Hydro One's DRO document appropriately reflects the Board's Decisions for all of the other Ontario Transmitters in the 2015 DRO with the exception of Great Lakes Power Transmission (GLPT) as the Board's decision on the 2015 GLPT rate application had not yet been issued. In the attached Rate Order, the Board has updated the GLPT information to account for the December 18, 2014 decision in the EB-2014-0238 proceeding.

This Order incorporates the Board Findings in the most recent approved revenue requirements and pool load forecasts for each of the other Ontario transmitters: Five Nations Energy Inc., Canadian Niagara Power Inc., Great Lakes Power Transmission Inc., Hydro One Networks Inc. and B2M Limited Partnership as shown below:

- Five Nations Energy Inc. (EB-2009-0387) issued December 9, 2010;
- Canadian Niagara Power Inc. (EB-2001-0034) issued December 11, 2001 and declared interim on December 18, 2014 under EB-2014-0204.
- Great Lakes Power Transmission Inc. (EB-2014-0238) 2015 Revenue Requirement issued December 18, 2014;
- Hydro One Networks Inc. (EB-2014-0140) 2015 Revenue Requirement issued on January 8, 2015; and
- B2M Limited Partnership (EB-2014-0330), as submitted on December 4, 2015 and now approved as interim by the Board on December 11, 2014.

The Board finds it appropriate to issue a final Rate Order approving the 2015 Uniform Transmission Rates.

THE BOARD ORDERS THAT:

1. The final revenue requirements by rate pool and the uniform electricity transmission rates and revenue allocators for rates effective January 1, 2015 as shown in Appendix A are approved.

2. The 2015 Ontario Uniform Transmission Rate Schedules, attached as Appendix B, are approved.

ISSUED at Toronto, January 8, 2015

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Appendix A to

Rate Order

Uniform Transmission Rates and Revenue Disbursement Allocators

Board File No: EB-2014-0357

Dated: January 8, 2015

Ontario Uniform Transmission Rates

Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2015 to December 31, 2015)

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,761,177	$857,719	$1,708,192	$6,327,089
CNPI (interim)	$2,741,895	$625,277	$1,245,271	$4,612,443
GLPT	$23,958,268	$5,463,574	$10,880,989	$40,302,831
H1N	$878,027,045	$200,230,084	$398,768,505	$1,477,025,634
B2M LP (interim)	$40,550,724	$0	$0	$40,550,724
All Transmitters	$949,039,110	$207,176,655	$412,602,957	$1,568,818,721

Transmitter	Total Annual Charge Determinants (MW)			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	187.120	213.460	76.190	
CNPI	583.420	668.600	668.600	
GLPT	3,489.236	2,725.624	626.252	
H1N	246,888.000	238,332.000	204,816.000	
B2M LP	0.000	0.000	0.000	
All Transmitters	251,147.776	241,939.684	206,187.042	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.78**	**0.86**	**2.00**	
FNEI Allocation Factor	**0.00396**	**0.00414**	**0.00414**	
CNPI Allocation Factor	**0.00289**	**0.00302**	**0.00302**	
GLPT Allocation Factor	**0.02524**	**0.02637**	**0.02637**	
H1N Allocation Factor	**0.92518**	**0.96647**	**0.96647**	
B2MLP Allocation Factor	**0.04273**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.0000	1.0000	1.0000	

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001. Set as Interim on December 18, 2014 under EB-2014-0204.

Note 3: GLPT Rates Revenue Requirement and Charge Determinants per Board Decision on Settlement Agreement for EB-2014-0238 Decision and Order dated December 18, 2014.

Note 4: H1N Rates Revenue Requirement per Oral Board Decision on Settlement Agreement for EB-2014-0140 dated December 2, 2014. Rate Order approved January 8, 2015.

Note 5: B2M LP Interim 2015 Revenue Requirement per Exhibit A - Revised in EB-2014-0330 dated December 4, 2014. OEB Interim approval on December 11, 2014.

Note 6: Calculated data in shaded cells.

Appendix B to

Rate Order

2015 Ontario Uniform Transmission Rate Schedules

Board File No: EB-2014-0140

Dated: January 8, 2015

2015 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2014-0357

The rate schedules contained herein shall be effective January 1, 2015

Issued: January 8, 2015
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS.

The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers that utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS-L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with the Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(**G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including

Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO-administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand[1,2]	**3.78**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.86**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**2.00**

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: ETS	EXPORT TRANSMISSION SERVICE

APPLICABILITY:
The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:
The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Energy Probe INTERROGATORY #4

Preamble:

Reference: Exhibit B, Tab 4, Schedule 3, Table 4, Revenue Requirement and Rate Impacts for Transformation Pool

Interrogatory:

Please provide a live Excel Spreadsheet for the Revenue Requirement Analyses for the Transformation Pool.

Please provide references/sources for Table 4 inputs:

- Average Rate Base,
- Incremental OM&A Costs,
- Depreciation.

Please provide sources/basis for following Table 4 Base Year Inputs:

- Line Pool Revenue Requirement, including suff/(defic) 413,
- Line GW 206,
- Line Pool Rate ($/kw/month) $2.00.

Response:

(a) The requested live Excel Spreadsheet has been filed with the OEB and has been electronically provided to all registered intervenors in this phase of the Application.

(a) Please see the references as follows:

- The Average Rate Base numbers shown in Table 4 reflect the incremental rate base after the project goes in-service each year.
- The incremental OM&A Costs are Nil.
- The depreciation rate used in the model is based upon the forecast average service life of 50 years.

(b) The following references were approved as part of the Ontario Uniform Transmission Rate Order in EB-2014-0357:

- The Transformation Connection Pool revenue requirement of $413 million is for all Transmitters
- The GW206 is the total annual charge determinants (MW) for all transmitters for the Transformation Connection Pool
- Transformation Pool Rate of $2.00/kw/month was approved by the OEB on January 8, 2015

The Ontario Uniform Transmission Rate Order is provided as Attachment 1 to Exhibit I-P2, Tab 2, Schedule 4.

[i]*Energy Probe INTERROGATORY #5*

Preamble:

Reference: Exhibit B, Tab 4, Schedule 3

Interrogatory:

a) Please provide a breakdown of the historic and forecast loads, including the total and individual HO Dx and LDCs.

b) Relate this to the Load Forecast used in the DCF analyses.

- 38.3 Mw in first service year,
- Historic growth rate compared to future/forecast growth rate.

Provide any required notes re differences.

c) Please provide a sensitivity analysis showing the DCF Analyses for a 10%NCP load Increase and 10% NCP load decrease in the first 5 years, 10 years and 10 years plus. Please provide the corresponding Allocations and contributions to the Transmission System Pool and to Load Customers

Response:

(a)

Table 1
Historical loads: Non-Coincidental Peaks for each year from year 2009 to 2013

LDC	Year (MW)				
	2009	*2010*	*2011*	*2012*	*2013*
HONI Dx	66.6	71.6	68.6	68.5	69.2
EPL	29.0	35.7	33	30.9	35.6*
ELK	30.9	33.6	34.3	32.6	31.6
Entegrus	2.4	2.9	2.9	2.9	2.6
Total	128.9	143.8	138.8	134.9	139

*For Essex Powerlines (EPL), the 2013 actual peak load was approximately 3.6MW higher than what was submitted by EPL. Hydro One adjusted the EPL load to actual measured values (see Exhibit I-P2, Tab 2, Schedule 9).

Table 2
Forecast Loads:

Year	LDC load (MW)				Total
	HONI Dx	EPL	ELK	Enterus	
2018	101.0	35.3	31.5	2.6	170.5
2019	102.3	35.3	31.5	2.7	171.7
2020	103.6	35.3	31.5	2.6	172.9
2021	104.9	35.2	31.5	2.6	174.2
2022	106.2	35.2	31.5	2.6	175.4
2023	107.4	35.1	31.5	2.6	176.7
2024	108.7	35.1	31.5	2.7	177.9
2025	110.0	35.1	31.5	2.7	179.2
2026	111.3	35.0	31.5	2.7	180.5
2027	112.6	35.0	31.5	2.7	181.8
2028	113.9	35.0	31.5	2.7	183.1
2029	115.2	35.0	31.5	2.8	184.4
2030	116.5	34.9	31.5	2.8	185.7
2031	117.7	34.9	31.5	2.8	186.9
2032	119.1	34.9	31.5	2.8	188.2
2033	120.4	34.8	31.5	2.8	189.6
2034	121.8	34.8	31.5	2.9	190.9
2035	123.1	34.8	31.5	2.9	192.3
2036	124.2	34.8	31.5	2.9	193.4
2037	125.6	34.8	31.5	2.9	194.7
2038	126.9	34.7	31.5	3.0	196.1
2039	128.3	34.7	31.5	3.0	197.5
2040	129.7	34.7	31.5	3.0	198.9
2041	131.1	34.7	31.5	3.0	200.3
2042	132.5	34.7	31.5	3.0	201.7
2043	134.0	34.6	31.5	3.1	203.2

(b) Hydro Notes that the load forecast number referenced in the question should be 38.2 MW vs. 38.3 MW as stated.

The 38.2 MW in the first year is the PLI adusted load that would be over the existing capacity of 120 MW. This value is derived from (170.5-120) * PLI = 38.2 MW for the first year.

The historical peak loads are actual metered values. The actual peak measurements are affected by weather, temperature, DG operation, and CDM effect.

Forecast loads are weather normalized with annual growth as provided by LDCs. Also, included are the new large loads addressed in the Essex Energy report and DG/CDM effect.

(c) The results of sensitivity analysis of various scenarios are:

Scenario A: 10% Increase to Non-coincidental peak in first five years

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3[1]	35.1	10.2	30.7
Station Facilities	32.1	20.2[2]	11.9	7.1
Total	**77.4**	**55.3**	**22.1**	**37.8**

Scenario B: 10% Decrease to Non-coincidental peak in first five years

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3[1]	35.1	10.2	31.7
Station Facilities	32.1	20.2[2]	11.9	9.3
Total	**77.4**	**55.3**	**22.1**	**41.0**

Scenario C: 10% Increase to Non-coincidental peak in first ten years

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3[1]	35.1	10.2	30.4
Station Facilities	32.1	20.2[2]	11.9	6.1
Total	**77.4**	**55.3**	**22.1**	**36.5**

Scenario D: 10% Decrease to Non-coincidental peak in first ten years

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3[1]	35.1	10.2	32.0
Station Facilities	32.1	20.2[2]	11.9	10.2
Total	**77.4**	**55.3**	**22.1**	**42.2**

1

Scenario E: 10% Increase to Non-coincidental Peak for 25 years

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3[1]	35.1	10.2	29.7
Station Facilities	32.1	20.2[2]	11.9	4.4
Total	**77.4**	**55.3**	**22.1**	**34.1**

2

Scenario F: 10% Decrease to Non-coincidental Peak for 25 years

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3[1]	35.1	10.2	32.8
Station Facilities	32.1	20.2[2]	11.9	12.0
Total	**77.4**	**55.3**	**22.1**	**44.8**

3

[1] Line costs of $45.3 million include $43.0 million of up front capital costs plus $2.3 million removal costs
[2] $20.2 million = ($32.1 million station facilities costs less $6 million Kingsville cost reduction) x 77.5%

Energy Probe INTERROGATORY #6

Preamble:

Reference: Exhibit B, Tab 4, Schedule 5 -Flow of Costs Diagram

Interrogatory:

a) Please provide a version with the individual and aggregate allocations of the Contribution(s) per TSC Section 6.5.3–6.5.11 per approach in chart above HO Dx and embedded LDCs:

- Essex Powerlines Corporation
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.

b) Please provide a version of chart showing embedded LDCs secondary <u>downstream</u> allocation to LDC's Customer Classes, including specifically New Large Customers (Greenhouse Growers) as shown in Chart.

c) Please provide a tabulation of the approximate Rate Impacts for existing customer classes of HO Dx and embedded LDCs

Response:

(a) Please see the response to Exhibit I-P2, Tab 2, Schedule 9, part (d), specifically Attachment 1, Table 1: Line Pool Allocation of Capital Contribution Summary as well as Attachment 1, Table 12: Transformation Pool Allocation of Capital Contribution Summary

(b) Same as (a) above.

Energy Probe INTERROGATORY #7

Interrogatory:

If the Large New Customers reduce load (CDM) and/or meet Load Growth with combined heat and power generation, then what will the cost consequences to these customers:

- HO Dx Customer
- LDC customers
- Transmission Pool Customers

Please delineate your responses to: if this happens prior to the 2018/19 in-service date; in the first 5 years; in the first 10 years; and beyond 10 years.

Response:

Load reductions as contemplated in sections 6.5.8 to 6.5.10 of the TSC would not be counted against customers of distributors or customers of Hydro One Distribution in the true-up calculation. Such reductions must relate to generation that was installed, or activities that occurred, during the true-up periods set out in section 6.5.3 (c)—this covers the first 10 years after in-service but not necessarily beyond 10 years. Reductions which result in a decrease in capital contributions to the transmitter will increase the cost to the transmission pool.

Energy Probe INTERROGATORY #8

Preamble:

Reference: Exhibit B, Tab 4, Schedule 5, Page 2 of 8

> *"In turn, each distributor will need to further apportion its share of the capital contribution within its own service area. Each distributor will perform an economic evaluation for each of its customers in the General Service, Sub-Transmission or equivalent rate class that requests a new or expanded connection ("new large customer"). The distributor will also perform an additional economic evaluation for its ratepayers generally. The results of these economic evaluations, performed based on the methodology set out in Appendix 5 of the TSC, will determine the proportion of the capital contribution that each new large customer and ratepayers of that distributor will be required to pay."*

Interrogatory:

Please provide a detailed breakdown of the capital contribution from the different rate classes of each of the different distributors.

Response:

Hydro One Distribution's capital contribution to Transmission, net of any customer-specific contributions, will contribute to Hydro One Distribution's return on rate base, which gets allocated to the various rate classes based on the relative share of net fixed assets within each rate class per OEB-approved rate setting methodologies. This will be determined at the time of the next cost of service.

Energy Probe INTERROGATORY #9

Preamble:

Reference: Exhibit B, Tab 1, Schedule 4, Page 1 of 6

Section 6.3.8 of the TSC says that the transmitter can't ask customers for a capital contribution for capacity that is not "attributable to that customer."

In Exhibit B, Tab 1, Schedule 4, Page 1 of 6 the Applicant states that the "growth in demand in this [Kingsville-Leamington] subsystem is largely attributable to projected growth in the greenhouse sector (as indicated by customer connection requests and the current outlook for expansion of existing greenhouse operations) and anticipated growth from new operations."

Interrogatory:

Please provide a detailed breakdown of the future demand growth from the greenhouse sector compared to residential and other rate classes.

Response:

The table below provides a breakdown of forecast growth for the large load customers, as well as resential and general service customers. For 2015-2017, growth in the large customer sector, including greenhouses, is based on a report by Essex Energy Corporation, prepared June 15, 2012. During this time period, the growth in the Kingsville-Leamington area greenhouse peak load is forecast to be 7 MW, and about 7.2 MW for other large customers. The table below outlines forecast growth beyond 2017.

	Large Load Customers (MW)	Residential/General Service (MW)
2018	0.35	0.86
2019	0.35	0.89
2020	0.35	1.00
2021	0.35	0.91
2022	0.35	0.91
2023	0.35	0.92
2024	0.35	0.93
2025	0.35	0.94
2026	0.35	0.93

	Large Load Customers (MW)	Residential/General Service (MW)
2027	0.35	0.95
2028	0.35	0.96
2029	0.35	0.97
2030	0.35	0.97
2031	0.35	0.88
2032	0.35	0.98
2033	0.35	0.99
2034	0.35	1.00
2035	0.35	1.01
2036	0.35	0.73
2037	0.35	1.01
2038	0.35	1.02
2039	0.35	1.03
2040	0.35	1.04
2041	0.35	1.05
2042	0.35	1.06
2043	0.35	1.19

Energy Probe INTERROGATORY #10

Preamble:

Reference: Exhibit B, Tab 1, Schedule 4, Page 1 of 6

The Board has ruled on the beneficiary pay principal, but it seems that the main beneficiaries of this project are distributed generators and the greenhouse sector.

Interrogatory:

a) Please provide a detailed list of the expected future distributed generation greenhouse projects in the Kingsville-Leamington area.

b) Please provide an estimate on the rate impacts to these rate classes as a result of the project.

Response:

(a) The IESO's practice is to consider only existing and contracted distributed generation for regional planning purposes. The IESO's Combined Heat and Power Standard Offer Program (CHPSOP) procurement process is currently in progress and applications are being evaluated. At this time there are no contracted CHP distributed generation projects associated with greenhouse projects in the Kingsville-Leamington area.

(b) The rate impacts for all rate classes, including the distributed generation and rate classes applicable to the greenhouse sector, is expected to be roughy equivalent to the increase in revenue requirement of Hydro One, which in 2020 would be 0.3%.

Energy Probe INTERROGATORY #11

Preamble:

Reference: Exhibit A, Tab 1, Schedule 5, Page 10, Figure 3

Exhibit A, Tab 1, Schedule 5, Page 10, Figure 3 shows historical demand in the Kingsville-Leamington area has been declining in recent years.

Interrogatory:

Please provide evidence or the assumptions behind any evidence on why demand is expected to increase over the planning period.

Response:

The load in the Kingsville-Leamington area has decreased between 2011 and 2013. There are a number of factors which may have caused this:

i. Weather influences demand, in particular during the summer peak load;

ii. CDM has reduced the electricity demand in the Kingsville-Leamington area;

iii. DG – Approximately 10MW of DG has been connected to Kingsville TS in 2011, 2012 and 2013, which would reduce the demand in the Kingsville-Leamington area;

iv. As stated in Exhibit B, Tab 1, Schedule 5, Pages 8 and 9, the decrease of electricity consumption due to economic challenges in the region.

Growth in the Kingsville-Leamington area load is expected to increase mainly due to new greenhouse and other large load connections, as forecast by the Essex Energy Corporation per the table below, with 2013 being year 1.

Cumulative Peak MW	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Kingsville Large Load Connections	0.74	2.22	3.91	5.18	6.45
Leamington Large Load Connections	0.38	1.54	2.81	3.66	4.50
Greenhouse - Non-Lighting	2.21	8.32	10.68	13.02	15.35

Energy Probe INTERROGATORY #12

Preamble:

Reference: Exhibit B, Tab 4, Schedule 5, Page 5 of 8

Interrogatory:

Please detail any planned new distributed generation facilities for the region over the planning period and what impact they will have on the project.

Response:

Based on the forecast methodology that was used for the SECTR Project evidence, the effective capacity of existing and committed distributed generation for the region was netted-out of the gross forecast on a station-by-station basis to produce the planning forecast, which was the basis for identifying needs. Please also refer to Exhibit I-P2, Tab 11, Schedule 10.

Energy Probe INTERROGATORY #13

Preamble:

Reference: Exhibit B, Tab 4, Schedule 5, Page 5 of 8 &
Exhibit B, Tab 1, Schedule 5, Page 13

In Exhibit B, Tab 4, Schedule 5, Page 5 of 8, the Applicant states that "greenhouse growers in the region have indicated strong interest in developing distributed generation through investments in combined heat and power generation."

And the OPA states in Exhibit B, Tab 1, Schedule 5, Page 13: "In addition to the distributed renewable generation described above, Great Northern Tri-Gen is an 11 MW gas-fired combined heat and power ("CHP") generation station located at Kingsville TS. In addition to producing electricity and heat, Great Northern Tri-Gen also produces carbon dioxide for use in greenhouse operations. The recent growth in the Kingsville Leamington greenhouse industry has led to local interest in this type of CHP application."

Interrogatory:

a) Please provide any evidence supporting the "local interest" in this type of distributed generation.

b) Please provide any forecasts for the amount of new distributed generation expected over the planning period.

c) Can you explain what would happen if load growth is met with distributed generation over the first five years of the planning period? Ten years? And beyond 10 years?

Response:

(a) In 2011, the OPA launched the Combined Heat and Power Standard Offer Program ("CHPSOP") and received 34 applications representing 215 MW for greenhouse CHP projects, the majority of which were located in the Kingsville-Leamington area. These applications were terminated when the CHPSOP was cancelled in 2013. A re-focused program, CHPSOP 2.0, targeting agricultural industry (e.g. greenhouses) and district energy projects was launched in 2014. Interest in CHP greenhouse projects in the Kingsville-Leamington area has remained high. The IESO received 25 applications representing 219 MW for greenhouse CHP projects in the first application window – these applications are currently being evaluated for contract awards up to 75 MW.

(b) Please see Exhibit I-P2, Tab 11, Schedule 10.

(c) The existing Kingsville TS is very close to reaching the distribution short circuit limit for the station. It is not feasible to connect additional distributed generation to meet demand growth on the existing system.

Coalition of Large Distributors (CLD) INTERROGATORY #1

Preamble:

The OPA assessment report states:

> *"It is the OPA's view that the most appropriate way to apportion costs between load customers and transmission ratepayers in accordance with the Board's beneficiary pays principle is to apportion the cost of the SECTR project by reference to the costs that load customers and ratepayers would have to pay were customer and system needs to be individually addressed, rather than addressed through the proposed integrated SECTR project.*
>
> *In accordance with the beneficiary pays principle, the OPA proposes that the SECTR project costs should be allocated in proportion to what load customers and transmission ratepayers would respectively have had to contribute towards the combined cost of individual solutions."*

Interrogatory:

Reference: Page 9 of Exhibit B, Tab 4, Schedule 4

a) Who is the ultimate arbiter that decides what portion is system benefit and what portion is customer benefit – the IESO or HONI? Does HONI envision the Regional Planning forum undertaking reviews of cost allocation for integrated projects? If not what forum will be used to discuss and agree?

b) Please provide a list of Hydro One's Transmission Investment Project over the last ten years. Please indicate which distributors would be considered the benefiting distributors under the new Cost Allocation Methodology for each projects.

c) Please identify any projects that would not have been completed under the new approach.

d) Please provide a list of Hydro One's planned Transmission Investment Projects over the next ten years. Please indicate which distributors would be considered the benefiting distributors under the new Cost Allocation Methodology for each project.

e) Please provide the Cost Allocation for the East West Tie Line and the Bruce to Milton Line. Please also provide the Cost Allocation for the East West Tie Line and the Bruce to Milton Line under the New Cost Allocation Methodology.

f) Confirm the new Cost Allocation Methodology will be implemented prospectively. For example, only on new projects started after the OEB's approval of the proposed methodology.

g) Would the new Cost Allocation Methodology be used when projects are being re-evaluated or only on new projects?

h) If the individual load forecast at the distribution level (Step 4) does not equal the non-coincident incremental peak load for the customer benefit portion at the transmission level (Step 3), how will Hydro One allocate the difference?

i) Will there be an open review process of the load forecast when there are multiple benefiting distributors?

j) Please provide Hydro One's assumption regarding non-coincident incremental peak load of the "new" large customers.

If not what forum?

Response:

(a) For purposes of the proposed proportional benefits methodology, Hydro One believes that the IESO is best positioned to assess the amount of system benefit associated with a particular investment. Hydro One envisions that whatever cost allocation methodology is ultimately approved by the OEB will provide clearer direction on how costs and benefits are to be apportioned between the system and the customer. Hydro One does not envision another forum for discussion on the subject.

(b) Hydro One has had a number of projects which provided both transmission and distribution system benefits, and where distributors would have paid capital contributions to Hydro One Transmission. A recent example of this is Hydro One's Mid-Town Toronto Project (EB-2009-0425). Other examples of projects where capital contributions were required include Midhust TS (PowerStream), Holland TS (PowerStream/Newmarket Hydro and Hydro One Distribution), Pleasant TS (Hydro One Brampton), Guelph Cedar TS (Guelph Hydro) and Woodstock TS (Woodstock Hydro).

(c) Hydro One would expect that all of these projects would still have been completed under the new approach.

(d) The projects that would be impacted by the proposed cost allocation methodology, sharing of costs between the distribution and the transmission system, would be primarily customer driven. As such, Hydro One does not currently have a list of these projects but anticipates that distributors will come forward to Hydro One once they have sufficient incremental load. However, Hydro One notes that regional planning studies are ongoing and some of the plans that would be developed as a result of these studies may be comparable to the SECTR Project in that a connection facility provides system benefits which would eliminate the need to implement pool funded transmission project(s) for which the proposed Cost Allocation Methodology would apply.

(e) Hydro One's Bruce-to-Milton Line was entirely pool-funded and would not have been impacted by the proposed cost allocation methodology. The new East-West Tie Line, for which Hydro One is not the proponent, has not yet filed a s.92 application with to the OEB, therefore Hydro One is unaware of its proposed cost allocation methodology.

(f) Hydro One defers to the OEB on whether the proposed porportional benefits methodology should apply only to new projects started after the OEB's approval of the methodology. However, should a project to which the methodology applies arise prior to such approval, Hydro One would apply the proposed methodology subject to OEB approval.

(g) Hydro One's practice with respect to capital contribution true-ups is to use the methodology that was in used for the initial economic evaluation at at the time the CCRA was signed.

(h) Hydro One would ensure that the load forecasts were consistent.

(i) The rights of distributors to disclose, or to not disclose, their confidential information will be respected.

(j) Hydro One assumes that there will likely be a significant amount of non-coincident incremental peak load from new large customers.

Coalition of Large Distributors (CLD) INTERROGATORY #2

Preamble:

According to the proposal HONI states:

> *"Where the distributors true-ups shows that the distributor's actual load and updated load forecast is lower than the load in the initial load forecast, the distributor will be required to make a payment to make up the shortfall adjusted appropriately to reflect the time value of money."*

Interrogatory:

Reference: Page 4 of 8 of Exhibit B, Tab 4, Schedule 5

What process does HONI propose to use to agree on the time value of money. Why would HONI not use the market value associated with the shortfall?

Response:

With respect to the time value of money, Hydro One takes guidance from the relevant provisions of the TSC and related documents. Section 12(b) in the Standard Terms and Conditions of Hydro One's Load Customer Connection and Cost Recovery Agreement (CCRA) template, which is filed with the OEB, sets out that the time value of money is determined using Hydro One's after-tax cost of capital, as used in the original economic evaluation performed in accordance with the TSC. Hydro One's after-tax cost of capital is the economic evaluation discount rate set out in the TSC—in section 6.5.2 (e) and Appendix 5: Methodology and Assumptions for Economic Evaluations.

Coalition of Large Distributors (CLD) INTERROGATORY #3

Preamble:

The following table is provided at Exhibit B, Tab 4, Schedule 3, Page 4 of 17.

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-4-2)	Cost Responsibility		Capital Contribution
		Customers	Pool	
Transmission Line Facilities	45.3[1]	35.1	10.2	31.2
Station Facilities	32.1	20.2[2]	11.9	8.2
Total	**77.4**	**55.3**	**22.1**	**39.4**

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 3, Page 4 of 17

a) Please provide a more detailed "Cost Responsibility" table which provides the differences between the proposed "beneficiary pays" Cost Allocation methodology and the existing "trigger pays" Cost Allocation methodology.

b) Please provide the "Cost Responsibility" table further broken down to the affected LDCs, between the proposed "beneficiary pays" and the existing "trigger pays".

c) Please provide what portion of the LDC capital contribution will be paid by new load customers versus existing customers.

d) Please identify the benefits to existing customers and provide cost benefit analysis for the same.

e) Please identify the benefits to existing transmission customers throughout the province that will be allocated a portion of the costs associated with this project. What is the impact to existing transmission customers if this project was not approved?

Response:

(a) For details regarding the proposed cost allocation methodology, see the response to Exhibit I-P2, Tab 2, Schedule 9, part (d). For a comparison to the existing "trigger pays" cost allocation methodology, see the response to Exhibit I-P2, Tab 2, Schedule 7.

(b) Please see part (a) above.

(c) Hydro One's proposed approach bases the allocation of cost on the incremental load which may be needed by existing customers as well as new customers. Therefore, a new or existing customer would contract with its distributor for its needed load increment and provide a corresponding capital contribution.

(d) Existing customers will benefit by having their load needs met at a cost which reflects their proportionate allocation of the incremental load.

(e) See Exhibit B, Tab 4, Schedule 4, pages 6 and 7.

Coalition of Large Distributors (CLD) INTERROGATORY #4

Preamble:

Lines 8 – 10 of Exhibit B, Tab 4, Schedule 4 states:

> *"The construction of the new transformer station and associated transmission line in the Windsor-Essex area will require capital contributions from benefiting customers, consistent with the Ontario Energy Board's "beneficiary pays" principle."*

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 4, OPA Cost Responsibility Evidence

Please identify:

a) Any ways in which the proposed cost allocation methodology is not consistent with the "beneficiary pays" principle; and

b) Any ways in which the proposed cost allocation methodology is in non-compliance with OEB codes and regulations.

Response:

(a) It is Hydro One's view that the cost allocation methodology is consistent with the beneficiary pays principle.

(b) Under Hydro One's proposed cost allocation methodology, project costs are apportioned based on proportional benefits, which, in Hydro One's view, preserves fairness in assigning cost responsibility where a new or modified connection facility benefits both a particular connecting customer and the overall transmission system. The TSC does not currently allow this.

Coalition of Large Distributors (CLD) INTERROGATORY #5

Preamble:

Lines 14 – 16 of Exhibit B, Tab 4, Schedule 5, page 6 states:

> *"At the distribution level, Hydro One Distribution performs economic evaluations to allocate the capital contribution among all benefiting distributors (including Hydro One Distribution Itself."*

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 5, page 6

Please describe any ways in which assessing the benefits for Hydro One Distribution differ from assessing the benefits of any remaining distributors.

Response:

There are no ways in which assessing the benefits for Hydro One Distribution differ from assessing the benefits of any remaining distributors.

Coalition of Large Distributors (CLD) INTERROGATORY #6

Preamble:

Lines 19 – 24 of Exhibit B, Tab 4, Schedule 5, page 3 states:

> *"The new large customers of each of the four distributors listed above will also be required to make a capital contribution towards the transmission investment through their respective distributors. These customers will also be required to provide a 25-year load forecast and a security deposit, and to execute a Capital Cost Recovery Agreement with their respective distributors prior to the commencement of construction of the new transmission connection facilities."*

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 5, page 3

Please identify, if possible, the "new" large customers and their respective locations per affected LDC.

Response:

Hydro One has not yet identified new large customers who will be required to make a capital contribution towards the SECTR Project. However, Hydro One's forecast did include new large customer connections based on a report prepared by Essex Energy Corporation on June 15, 2012. Hydro One does not have information on large customer connections within the service territories of E.L.K Energy, Essex Powerlines nor Entegrus.

Coalition of Large Distributors (CLD) INTERROGATORY #7

Preamble:

The construction of the new transformer station and associated transmission line will require capital contributions from benefiting customers, consistent with the Ontario Energy Board's principles of cost causation, otherwise known as beneficiary or user pays principle. The sole connected customer is Hydro One Distribution and it will be required to provide a capital contribution to Hydro One Transmission as determined by an economic evaluation. Such capital contributions will be subject to true-ups at the end of each of the fifth and tenth years of operation, and at the end of the fifteenth year of operation if actual load is twenty percent higher or lower than the initial load forecast at the end of the tenth year of operation.

Exhibit B, Tab 4, Schedule 5, Page 4, lines 6- states:

> *"These true-ups will apply the same methodology as was used to carry out the initial economic evaluation (discussed in section 2.0 above), and the same inputs except for load, which will be based on the actual load up to the true-up point and on an updated load forecast for the remainder of the economic evaluation period"*

Section 6.3.1 of the TSC states that:

> *"a capital contribution may only be required to the extent that the cost of the connection facility is not recoverable in connection rate revenues."*

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 5, Pages 1-8
Transmission System Code, Section 6.3.1

Since revenue rates and the values of other inputs such as tax rates, discount rates, etc. are likely to change during the period of the scheduled true-ups, will –Hydro One Transmission update these values to ensure that the load customers and distributors are allocated the actual revenues and costs associated with the expansion in accordance with the OEB's "user pays" principle? If not, why would Hydro One Transmission not want to ensure that customers are allocated all costs and revenues associated with the project?

Response:

To ensure a fair allocation of the upstream transmission cost, Hydro One Distribution takes guidance from the relevant provisions of the TSC, including section 6.5.4 which requires that true-up calculations make no adjustments to the input values (e.g. tariff rates, tax, OM&A, etc.) that were used in the initial economic evaluation, other than for load. Therefore, load will be the only input that will be adjusted and all other inputs will remain unchanged.

Coalition of Large Distributors (CLD) INTERROGATORY #8

Preamble:

Exhibit B, Tab 4, Schedule 4, Page 9 states:

> *"That is because the SECTR project, — by providing for an alternate source of supply in the Windsor-Essex the area — avoids the need for and associated cost of, upgrading the J3E/J4E circuits, installing reactive support, and increasing the size of the Keith autotransformers."*

Interrogatory:

Reference: Exhibit B, Tab 4, Schedule 4, Page 9

Please explain the cost benefit difference between proceeding with the alternative proposed project versus maintaining the existing transmission line. How does this proposal align with the OEB's policies on investment deferral?

Response:

The need for the SECTR Project and alternatives to meeting the need were the subject of Phase 1 of this proceeding. The IESO's evidence on Need and Alternatives (Exhibit B, Tab 1, Schedule 5) identifies the SECTR Project as the lowest cost alternative for addressing the needs which were identified.

Coalition of Large Distributors (CLD) INTERROGATORY #9

Preamble:

In point 6 of the "General Principles" the LDC is only able to apply credits for DG connected during the true-up period. This would exclude any DG that was connected after the CCRA was signed and before the true-up period (starts when the project is put into service). The customer's updated load forecast may include the impact of DG installed during the True-Up period and the incremental impact of CDM that occurred during the True-Up period.

Interrogatory:

Reference: CCRA Guiding Principles:
http://www.csc-scc.gc.ca/politiques-et-lois/005006-1003-eng.shtml

Please confirm that HONI does not object to modifying the agreement to include the following highlighted information:

The customer's updated load forecast may include the impact of DG installed **after the CCRA contract was signed** and was in service during the True-Up period and the incremental impact of CDM that occurred during the True-Up period.

Response:

See Exhibit I-P2, Tab 11, Schedule 7.

Referenced Sections of the Transmission System Code

6.3.1 Where a load customer elects to be served by transmitter-owned connection facilities, a transmitter shall require a capital contribution from the load customer to cover the cost of a connection facility required to meet the load customer's needs. A capital contribution may only be required to the extent that the cost of the connection facility is not recoverable in connection rate revenues. To that end, the transmitter shall include in the economic evaluation the relevant annual connection rate revenues over the applicable economic evaluation period that are derived from that part of the customer's new load that exceeds the total normal supply capacity of any connection facility already serving the customer and that will be served by the new connection facility. The transmitter shall calculate any capital contribution to be made by the load customer using the economic evaluation methodology set out in section 6.5.

6.3.16 For a new or modified transmitter-owned connection facility that will serve a mix of load customers and generator customers, a transmitter shall attribute the cost of the new connection facility or modification to the customers that cause the net incremental coincident peak flow on the connection facility that triggered the need for the new or modified connection facility. If and to the extent that the net incremental coincident peak flow is triggered by one or more load customers, the transmitter shall attribute the cost to each of those triggering load customers in the manner set out in section 6.3.15. If and to the extent that the net incremental coincident peak flow was triggered by one or more generator customers, the transmitter shall attribute the cost to each of those triggering generator customers in the manner set out in section 6.3.14.

6.3.17 Where a customer has made a capital contribution for the construction or modification of a transmitter-owned connection facility other than an enabler facility, and where that capital contribution includes the cost of capacity on the connection facility in excess of the customer's needs, the transmitter shall provide a refund, calculated in accordance with section 6.3.17A, to the customer as follows:

(a) where the customer made the capital contribution before August 26, 2013, the refund shall be provided if that excess capacity is assigned to another customer within five years of the date on which the connection facility or modification to the connection facility comes into service; or

(b) where the customer makes the capital contribution on or after August 26, 2013, the refund shall be provided if that excess capacity is assigned to another customer within fifteen years after the date on which the connection facility or modification to the connection facility comes into service.

(c) Where such a refund is required, the transmitter shall require a financial contribution from the subsequent customer to cover the amount of that refund.

6.5.2 A transmitter shall establish in its connection procedures referred to in section 6.1.4 and implement an economic evaluation procedure that sets out how the transmitter will carry out an economic evaluation of a proposed new or modified connection of a load customer to determine what capital contribution is to be made by the load customer. The economic evaluation procedure shall:

(a) include the methodology that will be used by the transmitter in determining the financial risk associated with a proposed connection of a load customer, which methodology shall meet the requirements of and be consistent with Appendix 4;

(b) provide that the economic evaluation period will be 5 years for a high risk connection, 10 years for a medium-high risk connection, 15 years for a medium-low risk connection, and 25 years for a low risk connection;

(c) be based on the discounted cash flow calculation set out in Appendix 5 using the forecast connection rate revenues from the connection facilities and the fully allocated capital cost, operating and maintenance cost and administrative cost of the minimum design required to meet the customer’s needs. The costs shall include the transmitter's cost of transmitter-owned equipment for monitoring and testing installed on connection facilities on either side of the connection point, and the cost of carrying out verification testing on that equipment;

(d) establish that the cost used in the economic evaluation is limited to the advancement costs where the transmitter had planned a new or modified connection facility and moves the planned date forward to accommodate a customer;

(e) use a discount rate that is based on the transmitter's current deemed debt-to-equity ratio, debt and preference share costs and Board-approved rate of return on equity;

(f) require that discounting reflect the true timing of expenditures so that up-front capital expenditures are treated as occurring at the beginning of the first year of operation, and future capital expenditures, annual connection rate revenues and average operation and maintenance costs will be treated as occurring at the mid-point of the year in which they occur;

(g) take into account all relevant tax amounts, adjusted by any applicable capital cost allowance;

(h) exclude network facility costs and network rate revenues;

(i) exclude historic revenues and sunk costs;

(j) establish that the relevant connection rate revenues shall be the revenue derived from that part of the load customer's new load that exceeds the total normal supply capacity of any connection facility already serving that customer and which will be served by a new or modified connection facility;

(k) require that the customer provide its load shape in such form and detail as the transmitter may reasonably require; and

(l) provide for separate economic evaluations for transformation connection facilities and line connection facilities.

(m) The economic evaluation procedure may permit an initial calculation of a customer’s capital contribution based on estimated costs, provided that where this occurs the transmitter must subsequently recalculate the customer’s capital contribution in accordance with paragraph (c) based on actual costs as soon as these are known, and obtain from or credit the customer for any difference between the two calculations. Such recalculated capital contribution shall thereafter be used as the customer’s capital contribution for all purposes under this Code.

6.5.3 For new or modified connection facilities, a transmitter shall carry out a true-up calculation, based on actual customer load, at the following true-up points:

(a) for high risk connections, at the end of each year of operation, for five years;

(b) for medium-high risk and medium-low risk connections, at the end of each of the third, fifth and tenth year of operation; and

(c) for low risk connections, at the end of each of the fifth and tenth year of operation, and at the end of the fifteenth year of operation if actual load is 20 percent higher or lower than the initial load forecast at the end of the tenth year of operation.

6.5.4 Subject to sections 6.5.8, 6.5.9 and 6.5.10, for the true-up calculation, a transmitter shall use the same methodology used to carry out the initial economic evaluation, and the same inputs except for load, which will be based on the actual load up to the true-up point and an updated load forecast for the remainder of the economic evaluation period used.

6.5.8 When carrying out a true-up calculation for a distributor, a transmitter:

(a) shall add to the actual load the amount of any embedded generation (determined in accordance with section 11.1) that was installed during the true-up period; and

(b) shall not reduce the updated load forecast as a result of any embedded generation (determined in accordance with section 11.1) that was installed during the true-up period.

6.5.9 When carrying out a true-up calculation for a load customer other than a distributor, a transmitter:

(a) shall add to the actual load the amount of any embedded generation (determined in accordance with section 11.1) of 1 MW or less per unit, or any embedded renewable generation of 2 MW or less per unit, that was installed during the true-up period; and

(b) shall not reduce the updated load forecast as a result of any embedded generation (determined in accordance with section 11.1) of 1MW or less per unit, or any embedded renewable generation of 2 MW or less per unit, that was installed during the true-up period.

6.5.10 When carrying out a true-up calculation for any load customer, a transmitter:

(a) shall add to the actual load the amount of any reduction in the customer's load that the customer has demonstrated to the reasonable satisfaction of the transmitter (such as by means of an energy study or audit) has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the true-up period; and

(b) shall not reduce the updated load forecast as a result of any reduction in the customer's load that the customer has demonstrated to the reasonable satisfaction of the transmitter (such as by means of an energy study or audit) has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the true-up period.