EB-2017-0336

ONTARIO ENERGY BOARD

IN THE MATTER OF a cost of service application made by Hydro One Networks Inc. on May 31, 2016 under section 78 of the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2017 and January 1, 2018;

AND IN THE MATTER OF the Decision and Order dated September 28, 2017 in this proceeding;

AND IN THE MATTER OF the Decision and Order dated November 9, 2017 in this proceeding; and

AND IN THE MATTER OF Rules 40 and 42 of the Ontario Energy Board's *Rules of Practice and Procedure.*

MOTION RECORD OF THE MOVING PARTY, HYDRO ONE NETWORKS INC. (motion for review and variance)

Date: January 15, 2018

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MOTION RECORD

on behalf of

HYDRO ONE NETWORKS INC.

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Tab	Document
16.	Extract of Exhibit J11.16, Attachment 2, pp. 16, 36.
17.	Hydro One Networks Inc., Argument-In-Chief re: EB-2016-0160, p. 76.

TAB 1

ONTARIO ENERGY BOARD

IN THE MATTER OF a cost of service application made by Hydro One Networks Inc. with the Ontario Energy Board on May 31, 2016 under section 78 of the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2017 and January 1, 2018;

AND IN THE MATTER OF the Decision and Order dated September 28, 2017 in this proceeding; and

AND IN THE MATTER OF sections 40 and 42 of the Ontario Energy Board's *Rules of Practice and Procedure.*

NOTICE OF MOTION

Hydro One Networks Inc. ("**Hydro One**") will make a motion to the Ontario Energy Board (the "**Board**") at its offices at 2300 Yonge Street, Toronto on a date and time to be fixed by the Board.

PROPOSED METHOD OF HEARING: The motion is proposed to be heard orally.

THE MOTION IS FOR:

1. An order that the Board review and vary the Board's decision and order of September 28, 2017 in EB-2016-0160 (the "**Decision**") in respect of the following determinations:

    a) that a portion of tax savings resulting from the Government of Ontario's decision to sell its ownership interest in Hydro One Limited by way of an Initial Public Offering on October 28, 2015 and subsequent sale of shares ("**IPO**") should be applied to reduce Hydro One's revenue requirement for 2017 and 2018 (Section 15 of the Decision) (the "**Tax Savings Determination**");

b) that Allowance for Funds used During Construction ("**AFUDC**") in respect of the Niagara Reinforcement Project ("**NRP**") should not be included in rates for 2018 (Section 13 of the Decision, the "**NRP Determination**"); and

c) that the costs attributable to the Ombudsman Office should not be included in rates (paragraphs 7.2.2 and pp. 47 of the Decision) (the "**Ombudsman's Office Determination**").

<u>The Threshold Test is Met</u>

2. The determinations addressed in paragraph 1 of this Notice of Motion contain errors of fact and law that meet the threshold for a review of the Decision as specified in Rule 42 of the Board's *Rules of Practice and Procedure* and Board decisions applying same.[1] Namely, that these determinations contain:

a) significant questions as to the correctness of the Decision;

b) one or more of (i) findings that were contrary to the evidence before the panel; (ii) failure to address a material issue by the panel; (iii) inconsistent findings by the panel; or (iv) something of a nature similar to (i), (ii) or (iii); and

enough substance to the issues raised such that a review could result in the Board varying its decision, that is, the errors made by the panel are material and relevant to the outcome of the Decision such that if the errors were corrected, the reviewing panel would change the outcome of the Decision.

[1] See, in particular, EB-2006-0322/0338/0340 p. 15.

THE GROUNDS FOR THE MOTION ARE:

<u>Tax Savings Determination</u>

3. Four principal errors were made in the Tax Savings Determination, namely:

a) erroneously finding that the tax paid by Hydro One to exit the payment in lieu of taxes regime (the "**PILs Departure Tax**") under the *Electricity Act* (Ontario) ("**Electricity Act**") was "variable";

b) misinterpreting and misapplying RP-2004-0188 to the facts of this case;

c) failing to apply the stand-alone utility principle and the fair return standard; and

d) making errors with respect to the applicable tax concepts.

4. Each of the errors set out above is described in detail below; the cumulative consequence of which was the adoption of a flawed benefits follows costs methodology.

I. The Decision Erred by Finding that the PILs Departure Tax was "Variable"

5. The Decision characterizes the PILs Departure Tax as a cost that was "variable at the discretion of the Province".[2] The Board then speculated upon the tax elimination options that the Province could have used to avoid the cost of the PILs Departure Tax and, in the application of the benefits follow costs principle, adopted a PILs Departure Tax value materially less than the $2,271M of PILs Departure Tax that was actually paid by Hydro One.[3] In short, the Decision errs in treating the PILs Departure Tax as, in effect, not a real or true cost.

[2] Decision, p. 98.

[3] Ibid at p. 99-100.

6. The Board's finding that the PILs Departure Tax is a variable cost (not a real or true cost) is incorrect. There is no factual basis for this finding because:

a) The PILs Departure Tax was a real cost, paid by Hydro One via wire transfer and recorded in the consolidated financial statements of Hydro One;[4]

b) Hydro One ceased to be a corporation exempt from tax under the *Income Tax Act* (Canada) ("**ITA**")[5] on the IPO which caused it to be liable for PILs Departure Tax under the Electricity Act on the excess of the fair market value ("**FMV**") of its assets over their tax basis;

c) The Minister of Energy for the Province established the $2,271M PILs Departure Tax liability of Hydro One under s. 16.1 of O. Reg. 207/99; and

d) No options were available to Hydro One to avoid paying the PILs Departure Tax liability.

7. According to the Decision, the Province could have eliminated the PILs Departure Tax by making a regulation under s. 114(1)(m) of the Electricity Act exempting Hydro One from the obligation to pay the PILS Departure Tax, or by granting a remission order in respect of the PILs Departure Tax to Hydro One under s. 95.1 of the Electricity Act.[6]

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4 See Exhibit J11.16.

5 References to the ITA should be read as including the *Taxation Act, 2007* (Ontario). Ontario corporate taxes are imposed under the *Taxation Act, 2007* (Ontario), which incorporates by reference the provisions of the ITA.

6 Page 98 of the Decision states that the "PILs Regulation empowers the Province, as the taxing authority, to exempt an obligated utility, in whole or in part" citing section 16.1 of O. Reg. 207/99. In fact, O. Reg. 207/99, s. 16.1 does not grant the Minister such a power. It provides:

> With the consent of the Minister, the corporation pays to the Financial Corporation an amount that, in the Minister's opinion, reasonably approximates the additional amounts, if any, that would be payable by the corporation under sections 89 and 90 of the Act[.] (emphasis added)

O. Reg. 207/99, s. 16.1 grants the Minister a limited authority to set the amount of the PILs Departure Tax payable to the OEFC to an amount that "reasonably approximates" the amount calculated under ss. 89 and 90 of the Electricity Act—it does not grant the Minister authority to exempt an obligated utility in whole, and limits any exempted amount such that the obligated utility remains liable to pay a reasonable approximation of the amount otherwise due. It is assumed that the Decision meant to refer to the Governor in Council's power to grant a regulatory exemption under ss. 114(1)(m) and or a remission order under s. 95.1 of the Electricity Act as referred to above.

8. However, the Province did not, in fact, either make such a regulation or issue such a remission order. Further, there was no evidence before the Board regarding the circumstances in which the Province would consider it an appropriate policy decision to take either such action. There was also no evidence before the Board regarding the reasons for the Province's policy decision to not exercise its discretion to promulgate a regulation or issue an order in council to waive or reduce the PILs Departure Tax.

9. The Decision further errs in finding that the PILs Departure Tax paid by Hydro One and funded by the Province was "effectively a payment from itself to itself" to preserve the "Exempt Utility FMV".[7] The payment of the PILs Departure Tax was not a payment by the Province to itself. The evidence on the record, ignored in the Decision, was that the PILS Departure Tax was paid by Hydro One to the Ontario Electricity Financial Corporation ("**OEFC**").[8] The payment was financed by an equity infusion from Hydro One's shareholder, the Province.[9]

10. Under the Electricity Act, the PILs Departure Tax, once paid to the OEFC, did not form part of the Province's consolidated revenue fund and the OEFC was obliged to use the amount for the purpose of carrying out its statutory objectives,[10] which include servicing and retiring debt obligations.[11] The Board had no evidence about the policy decisions made by the Province that resulted in a determination that Hydro One should pay the PILs Departure Tax to OEFC so that OEFC could fulfill its statutory obligations.[12]

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7 Decision, p. 98.

8 See Exhibit J11.16, Attachment 2, in which there is a description of the five wire transfers made to the OEFC by Hydro One's Manager, Treasury Operations on November 4, 2015.

9 Exhibit J11.16, Attachment 2, Page 36. N.B. Hydro One is a wholly-owned subsidiary of Hydro One Inc. which in turn, is wholly owned by Hydro One Limited, the publicly-traded corporation. Unless otherwise indicated, references to shareholders of Hydro One are to the ultimate shareholders of Hydro One, the Province and the public.

10 Electricity Act, s. 62.

11 *Ibid* at s. 55.

12 In fact, Exhibit K2.4 contains testimony by the Deputy Minister of Energy before the Standing Committee on Energy indicating that the PILs Departure Tax of "$2.6 billion goes towards paying down the stranded debt, so that transaction is targeted towards stranded debt".

II. The Misinterpretation of RP-2004-0188

11. The Board misinterpreted and misapplied RP-2004-0188 to the facts of this case.

12. RP-2004-0188 is a Board report providing guidance on the generic regulatory rate treatment of a number of issues, including the allocation of tax benefits arising from a costless bump in assets to FMV. The bump was costless because it resulted from a directive from the Minister of Finance and the utility paid no cost in relation to an underlying transaction.

13. RP-2004-0188 allocated the benefit of future tax savings of costless bumps to ratepayers. It did not address FMV bumps that were not costless. The FMV bump allocation conclusions in RP-2004-0188 expressly apply where a "shareholder has not incurred any cost".[13] RP-2004-0188 states that the "benefits follow costs" principle is only discounted because a shareholder has paid no cost "related to" the FMV bump.[14]

14. That is clearly not the case in this proceeding. Hydro One became liable for and paid PILs Departure Tax on the recapture and gains arising from the deemed disposition of all of its assets at FMV on the IPO as a consequence of it ceasing to be a corporation exempt from tax under the ITA.

15. RP-2004-0188 did not address the allocation of tax benefits arising from a bump in assets to FMV as a consequence of a shareholder selling an ownership interest in the parent company of a rate regulated utility thereby causing the utility to incur tax and other transaction costs. The Decision errs in finding that RP-2004-0188 applied given the evidence in this case that the PILs Departure Tax was a real cost, among other real costs caused by a shareholder decision to sell its ownership interest, all of which costs were funded by shareholders and not borne by ratepayers.

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[13] RP-2004-0188, p. 56.

[14] *Ibid*.

III. The Stand-alone Utility Principle and the Fair Return Standard

16. Pursuant to the "stand-alone utility" principle, the costs that are recoverable in rates are costs that are incurred for the provision of rate regulated services. This principle was correctly stated in the Decision[15]; however it was misapplied to the facts on the record of this proceeding. The costs incurred by Hydro One resulting from the shareholder's decision to sell its ownership interests were not caused by or related to the provision of regulated transmission services. That is why none of the IPO transaction costs, such as underwriters' fees, legal fees, accounting fees and the PILS Departure Tax, were included in Hydro One's applied-for rates revenue requirement.

17. Pursuant to the "stand-alone utility" principle, the Board is required to treat a government-owned utility in the same way as it would a privately-owned utility.[16] Past Board decisions confirm that the fair return standard does not compensate utilities for any additional risks attributable to Government ownership.[17]

18. By the Decision's finding that Hydro One's shareholder (i.e. the Province) had discretion to waive the PILs Departure Tax, Hydro One became exposed to a risk unrelated to rate regulated service, but which resulted in a reduction in Hydro One's applied-for recovery of taxes on income from rate regulated service. This is inconsistent with the fair return standard. By exposing Hydro One to a risk which is specifically excluded in its risk-based rate of return, the Decision has effectively prevented Hydro One from realizing the opportunity to earn a fair return and confiscated and transferred the value of this entitlement to customers.

19. Based on the reasoning in the Decision, it is clear that if the funding of the PILs Departure Tax had been provided by any shareholder other than the Province, the cost of the

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15 Decision, p. 10.

16 See, for example, EB-2007-0905 Decision and Order dated November 3, 2008, p. 136 and 142, see also *Reference respecting Ontario Hydro*, H.R. 16, Report of the Board, Volume I dated September 15, 1987, Ch. 11.

17 See EB-2007-0905 Decision and Order dated November 3, 2008, s. 8.3.2.

PILs Departure Tax would have been recognized as a real cost and not discounted as a "variable" cost. Employing distinctions based on the identity of the shareholder for purposes of utility rate-making is inconsistent with the stand-alone utility principle and the fair return standard.

IV. Errors in Applicable Tax Concepts

20. The Decision improperly characterized the events of the IPO as giving rise to "deemed" and "actual" sale events under the ITA which, in turn, created "actual and deemed increases" in the adjusted cost basis of Hydro One's assets:

> As a consequence of the Province's initial November 2015 IPO sale of about a 15% interest in Networks' assets and the "deemed" sale and reacquisition of the remaining 85% interest that the Province then held, the eligible asset values used for the purposes of calculating Networks' future income taxes increased from their pre-sale tax values to their FMV at the time of sale. <u>These actual and deemed increases in the tax values</u> of these assets then became available to provide Networks with substantial savings in cash taxes payable in years beyond November 2015. […]
>
> The issue to be decided in this case is how the principles expressed in the May 2005 Report are to be applied in a situation where the Province has only sold part of its ownership interest in Hydro One Limited and its subsidiaries including Networks. <u>The sale transaction in this case is partly actual and partly "deemed". Moreover, this combined actual and deemed sale transaction has triggered "recapture"</u>.[18]

21. The ITA does not distinguish between an "actual" and a "deemed" sale. The mechanism giving rise to the increase in the cost of assets under s. 149(10)(b) of the ITA is a single deemed disposition and reacquisition of all of a corporation's assets at FMV at the time that the corporation ceases to be tax exempt under the ITA. This single deemed disposition of assets at FMV caused Hydro One to be liable for the PILs Departure Tax on recapture and gains.

[18] Decision at pp. 82 and 86 (emphasis added).

22. The Decision confuses and conflates tax savings and costs to obtain tax basis. The Decision states, *inter alia*, in respect of RP-2004-0188:[19]

> In a "deemed" sale of utility assets at FMV, where the FMV Bump in the assets is not actually attributable to a purchase at FMV, the "benefits follow costs" principle does not apply to the FMV Bump related future tax savings and they are be allocated to ratepayers. (emphasis added) […]

It further states that:

> [I]n determining, for regulatory purposes, the appropriate Benefits follow Costs allocation factor in this case, it is appropriate to treat the departure tax amount of $2,271 million as an actual contribution towards the FMV Bump value of $9,794M million embedded in the total FMV of Hydro One Limited shares. […]
>
> In this scenario, [where 29% of the shares of Hydro One have been acquired by the public] the total amounts that have actually been paid towards the $9,794M million FMV Bump of Networks' asset values used for calculating the Deferred Tax Asset is 29% of $9,794M million[.][20] (emphasis added)

RP-2004-0188 does not contain any requirement that there be an asset or share payment at FMV for a FMV bump, in order to fully allocate the future tax savings from the FMV bump to shareholders. Notwithstanding what the Decisions states, no one would pay 29% of $9,794M to obtain 29% of the $9,794M FMV Bump, or, for that matter, $9,794M to obtain 100% of the $9,794M FMV Bump. The value of future tax savings from the FMV Bump, on a non-present valued basis, is $2,595M.[21] The most that would be paid for the future tax savings is $2,595M. Nonetheless, the Decision assumes that Hydro One share purchase payments have embedded in them payments of $3.77 for every $1.00 of tax savings ($9,794M/$2,595M).

19 See p. 88 of the Decision.

20 Decision, pp. 99-100. The FMV Bump represents an addition to a notional account (undepreciated capital cost) and does not have a "value" to Hydro One separate and apart from the tax savings it generates.

21 The value of $9,794M in additional tax basis (giving rise to increased capital cost allowance deductions) will depend on Hydro One's income tax rate but, at Hydro One's present 26.5% rate of tax, $9,794M of additional tax basis will yield approximately $2,595M in future tax savings: see Exhibit J11.3.

23. Using the capital invested by the Province, Hydro One, in fact, paid $2,271M of PILs Departure Tax and transaction costs of approximately $39M[22] for the $9,794M FMV Bump, which generated $2,595M in additional tax savings at current federal and Ontario corporate income tax rates (26.5%). It is axiomatic that of the purchase price paid for the shares of Hydro One[23], the amount indirectly paid for the future tax savings attributable to the FMV Bump would approximate the tax savings attributable thereto and not some multiple thereof.

24. Absent a decision by the Province to sell an ownership interest in Hydro One, there would have been no PILs Departure Tax, no FMV Bump and no future tax savings. Accordingly, a proper application of the benefits follows costs principle and the "stand-alone utility" principle should allocate 100% of the future tax savings from the FMV Bump of $2,595M to the shareholders.

NRP Determination

25. The NRP is a $100M transmission line in southwestern Ontario. Hydro One was granted leave to construct the NRP in 2005.[24] Hydro One incurred debt to finance the construction. In approving the recovery of the financing costs in transmission rates, the Board stated that it "accepts the expenditures associated with the project as prudent, and requires no further analysis from Hydro One to justify expenditures incurred to date."[25]

26. In the same decision, the Board noted that, "as a result of a land claim by aboriginal peoples and the occupation of a portion of the lands necessary for the completion of the last two kilometers of the project, the project has been frustrated, pending a multi-lateral resolution

[22] See pages 1 and 4 of Exhibit I-09-002, Attachment 2 (Hydro One Limited Supplemented Prep Prospectus dated October 29, 2015), in which the expenses of the offering are estimated to be $12,500,000 plus an underwriters' fee of $26,600,800 (without accounting for fees related to the over-allotment option). These costs reflect expenses incurred in the IPO of Hydro One Limited and are not particularized in respect of Hydro One.

[23] As a subsidiary of Hydro One Limited.

[24] EB-2004-0476.

[25] EB-2006-0501 at p. 47 (emphasis added).

of the underlying land claim issues."[26] The Board went on to find that "special regulatory treatment is appropriate for the NRP because a recognizable risk has materialized out of the land claim dispute in Caledonia, the resolution of which is beyond the control of Hydro One."[27]

27. The regulatory treatment afforded by the Board was to allow the recovery of yearly interest charge on the debt used to finance the construction (the "**AFUDC**"), but not include the NRP in rate base until it was brought into service. The Board stated that this approach was a "compromise."[28]

28. The Board thus permitted the recovery of AFUDC in rates effective January 1, 2007 "with no explicit time limit as it remains uncertain when the Caledonia dispute will be resolved. If Hydro One requires additional relief prior to the project being completed and in-service, it is free to bring an application seeking such further relief."[29]

29. Hydro One thus understood the decision to permit continued recovery on the basis approved for 2007 rates and has not sought any different relief in this application.

30. However, in Section 13 of the Decision, the Board found that Hydro One should be permitted to recover the AFUDC for 2017, but not for 2018. This finding was unreasonable, because there was no evidence before the Board that would allow it to conclude that the situation which the Board determined "was outside of Hydro One's control", and which "required a multi-lateral resolution" had changed for 2018.

31. Specifically, there was no evidence that Hydro One's negotiation efforts were insufficient, and that Hydro One is in a position to find "alternate solutions" or that any such

[26] EB-2006-0501 at p. 62 (emphasis added).

[27] EB-2006-0501 at p. 63.

[28] EB-2006-0501 at p. 64.

[29] EB-2006-0501 at p. 64.

alternate solutions exist. Neither the Board nor any parties cited any evidence respecting Hydro One's negotiation efforts or possible "alternate solutions".

32. The only evidence on the record of the proceeding in regards to the status of the NRP is found at page 162 of transcript volume 11, where Board Staff asked one of Hydro One's finance panel witnesses who did not have responsibility for matters involving work execution or strategy, about the NRP. Specifically, Board Staff first asked Hydro One's witness as to the status of the dispute relating to the NRP. Not surprisingly, the witness answered the question by stating "I have no updates, I am not aware".[30] In answer to Board Staff's further question as to the witness's expectations regarding when the line will enter service, Hydro One's regulatory accounting witness replied "I am not aware of anything".[31]

33. These answers provided the totality of the evidence on the record of this proceeding in regards to the status of the NRP.[32] There were no follow up questions asked and no undertakings requested on the NRP. In other words, there is no evidence on the record on the proceeding in regards to the NRP from witnesses who testified on First Nations matters or planning and therefore would reasonably be in a position to provide evidence on the status of the NRP.

34. The Board therefore erred in finding that Hydro One has not made sufficient effort to resolve the issues associated with the NRP. There was no evidentiary basis for that finding.

35. New facts and new circumstances that could not have been considered at the time of the EB-2016-0160 hearing are now in the public domain. On October 13, 2017, Six Nations Band Council and Six Nations of the Grand River Development Corporation announced that a

30 Transcript volume 11, p. 162.

31 Transcript volume 11, p. 162.

32 The following questions asked by Board Staff to Hydro One's expert in regulatory accounting are to confirm that the AFUDC is a "straight debt cost" and does not include any return on equity or depreciation related to the NRP. See transcript volume 11, pp. 163-164.

tentative agreement was reached with the Ontario Ministry of Energy and Hydro One.[33] This important achievement is intended to allow completion of the NRP. Reaching a tentative settlement of this sort conclusively demonstrates the conclusions reached in the Decision are incorrect.

Ombudsman's Office Determination

36. The Decision states at page 47 that "The budgeted annual compensation cost of the new Chair [of the Hydro One Board of Directors] is about $1.7 million and $1.8 million in 2017 and 2018, respectively, with about 53% of those amounts being allocable to transmission."[34] The Board's statement is incorrect and is based on a misreading of the evidence. The evidence[35] specifies that $1.4 million of the cost of the Office of the Chair relates to the cost of the Ombudsman's Office, a legally required position in respect of which the Board made no finding of imprudence.

37. On October 11, 2017, the Board amended the last full paragraph found on page 48 of the Decision to include a new sentence that reads "of those amounts, $1.4 million is attributable to the Ombudsman's Office." The October 11, 2017 revision does not fully correct the issue at hand in two respects. First, page 47 of the Decision still incorrectly states "[T]he budgeted annual compensation cost of the new Chair is about $1.7 million and $1.8 million in 2017 and 2018…". This cost relates to the Office of the Chair and not the compensation cost of the new Chair. Retaining the subsequent comparison of these amounts to "[T]he 2014 cost of the Chair that was replaced was about $300,000" maintains a mistaken belief that the compensation cost of the Chair has materially changed. The reputational impact of these misstatements are material to Hydro One and its Chair. Hydro One therefore requests that

[33] See Attachment "A" to this Motion.
[34] Decision, p. 47
[35] See undertaking J12.5.

the record be properly corrected to state the compensation costs of both Ombudsman's Office and the Chair for 2017 and 2018.

38. Second, as the $1.4 million of the Office of the Chair cost is in fact related to the Ombudsman's Office and legally required, Hydro One submits that this cost should be recovered in rates. For transmission, this amount is 53% of $1.4 million, that is, approximately $750,000. Hydro One therefeore requests that the Decision be varied to include this amount in Hydro One's revenue requirement for each of 2017 and 2018.

Rules and Other Grounds

39. Rules 8, 40 and 42 of the Board's *Rules of Practice and Procedure*.

40. Such further grounds and material as counsel may advise and the Board may permit.

THE FOLLOWING DOCUMENTARY EVIDENCE will be used at the hearing of the motion:

1. The Board's Decision with Reasons dated September 28, 2017;

2. Materials from the record of this proceeding;

3. Hydro One's submissions on this Motion, which will be delivered in accordance with the Board's procedural order(s) in regards to this Motion; and

4. Such further and other documentary evidence as counsel may advise and the Board may permit.

Date: October 18, 2017

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AND TO: Intervenors of Record

Attachment "A"

Please see attached

Aboriginal BUSINESS

Daily National News

Six Nations negotiates tentative deal, Niagara Reinforcement Line may go ahead

October 13, 2017 190 views

Towers have sat idle since 2006 Six Nations land Reclamation

By Lynda Powless

Editor

SIX NATIONS OF THE GRAND RIVER- The Six Nations Band Council and the Six Nations of the Grand River Development Corporation(SNGRDC) have negotiated a tentative agreement with the Ontario Ministry of Energy and Hydro One that would see the controversial Niagara Reinforcement Line (NRL), stopped during the 2006 Reclamation of lands at he former Douglas Creek Estates, proceed.

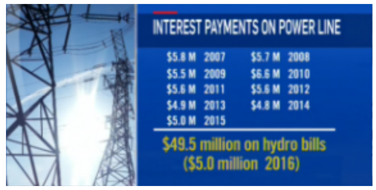
After four years of negotiations the SNGRDC announced Friday (Oct 13, 2017) it will begin a 60 day community consultation at Six Nations next week on what it sees as a long-term value for the community.

The $116 million transmission line was almost completed 11 years ago. The 76 kilometre line was and slated to bring power into Ontario from Niagara Falls New York to the area. The project came to an abrupt stop when Six Nations people stopped a subdivision being built on Six Nations unceded lands just outside Caledonia. The NRL's final connection point is at the Highway Six bypass at Caledonia. Hydro One has been unable to complete the last five kilometres of the power line since the Caledonia land claim dispute blocked the line. The power line was designed to bring 800 megawatts of electricity into southern Ontario, the same amount of power the province would get from just one of its nuclear reactors.

A portion of the towers had been used to block roads during the Reclamation (Turtle Island News photo)

The land ownership dispute led to the 2006 Reclamation of Six Nations lands, road barricades that went on for the entire summer as Ontario, Ottawa and both the Haudenosaunee Confederacy Chiefs Council representatives and Six Nations Elected Band Council representatives engaged in negotiations. Those negotiations lasted until 2010 when Six Nations Band Council first, then Ontario pulled out. Ontario said at the time it didn't need the electricity immediately because the recession had slowed manufacturing.

The disruption meant Hydro One sought and received permission from the province in 2007 to bill Ontario taxpayers for its interest payment on the $116 million capital cost of the stalled power line. As of 2015 that had amounted to nearly $50 million in interest on the power line that still is not transmitting any electricity.



The NRL route

Six Nations Elected Council (SNEC) and SNGRDC began "engaging in high level exploratory talks with the Province to arrive at a solution that would be beneficial for all parties, however nothing substantial was achieved at that time," in 2013. The talks continued in August 2016 when SNGRDC proposed a three-phase bundled solution to ENERGY and Hydro One. The three phases, the SNGRD says "will Energize, Acquire and Optimize Six Nations' energy portfolio."

They include:

- *Energize:*Hydro One is committed to offering a contract opportunity to SNGRDC's joint venture with the Aecon Group –A6N Utilities (A6N), to complete the remaining NRL transmission work.
- *Acquire:*Equity Ownership in the Line – SNGRDC will purchase 25% ownership in the line for approx. $13 million which will be financed using an Aboriginal Loan Guarantee from the province of Ontario.
- *Optimize:* In addition, ENERGY will grant a Renewable Energy capacity set-aside to Six Nations of the Grand River, to be used by SNGRDC on behalf of Six Nations, for up to 300 megawatts of new projects within the region, if further renewable generation is needed in the future.

Six Nations Elected Chief Ava Hill , in a press release said "This project will create local employment opportunities while generating long-term economic benefits for our community," said Chief Ava Hill, Six Nations Elected Council.

"Hydro One is committed to working with Six Nations to move this project forward under the principles of open communication and cooperation," said Derek Chum, Vice President, Indigenous Relations at Hydro One said in a statement. "This project will not only strengthen the working relationship between Hydro One and Six Nations, but will also provide long-term economic benefits for the community."

"Our government supports Indigenous participation in the energy sector and remains committed to ensure these opportunities continue, including partnerships on major transmission line projects such as the Niagara Reinforcement Project" said Glenn Thibeault, Minister of Energy said in a statement.

"The 300 mega-watt set aside will allow our community to take a lead role in the construction and management of new renewable energy projects in this region," said Matt Jamieson, President/CEO of SNGRDC said in a statement released Friday. "SNGRDC is always looking to find new and inventive ways to invest in renewable energy to bring economic benefits to the people of Six Nations. SNGRDC believes investing in renewable energy means investing in the future and our generations yet to come."

Community members are encouraged to attend an engagement session to learn more.. For more information visit www.snfuture.com

The Six Nations of the Grand River Development Corporation (SNGRDC) was created by the Six Nations Band council and now manages Six Nations' revenue generating projects and any economic interests, including overseeing 14 renewable energy projects the community is engaged in.

The Six Nations community's green energy portfolio is capable of producing nearly 900 MW of renewable energy through its direct or indirect involvement in seven wind, six solar and one hydroelectric project(s).   The development corporation, located on the Six Nations Reserve, employs over 140 people through various Nation Enterprises or in the administration of Economic Interests projects.

The Haudenosaunee Confederacy Chief Council has not commented on the project or negotiations.

For more information please visit www.sndevcorp.ca

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FOR IMMEDIATE RELEASE

Six Nations of the Grand River Development Corporation
2498 Chiefswood Road. P.O.Box 569
Ohsweken, ON N0A1M0

Six Nations Future Begins Community Engagement for Niagara Reinforcement Line Project

SIX NATIONS OF THE GRAND RIVER, ON – October 18, 2017 – Six Nations of the Grand River Development Corporation (SNGRDC) in conjunction with the Ontario Ministry of the Energy (ENERGY), and Hydro One, have brought forth a solution to see the Niagara Reinforcement Line (NRL) completed in exchange for long-term value for the Six Nations Community. A 60-day engagement period began on October 16th with a kick off event being held tomorrow, October 19th from 6-8PM, at the new Gathering Place by the Grand Event Centre. Community members wishing to comment on the project, are able to do so in person or in writing at any one of ten engagement sessions, or they can fill out an online comment card at www.snfuture.ca by December 15th.

The NRL, whose final connection point is located along the Highway 6 bypass in Caledonia, has sat incomplete and idle for over 10 years. In 2013, Six Nations Elected Council (SNEC) and SNGRDC began engaging in high level exploratory talks with the Province to arrive at a solution that would be beneficial for all parties, however nothing substantial was achieved at that time. These talks progressed in August 2016 when SNGRDC proposed a three-phase bundled solution to ENERGY and Hydro One. The three phases will Energize, Acquire and Optimize Six Nations' energy portfolio.

1) *Energize:* Hydro One is committed to offering a contract opportunity to SNGRDC's joint venture with the Aecon Group –A6N Utilities (A6N), to complete the remaining NRL transmission work.
2) *Acquire:* Equity Ownership in the Line - SNGRDC will purchase 25% ownership in the line for approx. $13 million which will be financed using an Aboriginal Loan Guarantee from the province of Ontario.
3) *Optimize:* In addition, ENERGY will grant a Renewable Energy capacity set-aside to Six Nations of the Grand River, to be used by SNGRDC on behalf of Six Nations, for up to 300 megawatts of new projects within the region, if further renewable generation is needed in the future.

Community members are encouraged to attend an engagement session to learn more. Informational mailers and comment cards have been sent out to every household on Six Nations with a list of engagement dates. For more information visit www.snfuture.com

Quotes

"This project will create local employment opportunities while generating long-term economic benefits for our community," said Chief Ava Hill, Six Nations Elected Council.

"Hydro One is committed to working with Six Nations to move this project forward under the principles of open communication and cooperation," said Derek Chum, Vice President, Indigenous Relations at Hydro One. "This project will not only strengthen the working relationship between Hydro One and Six Nations, but will also provide long-term economic benefits for the community."

“Our government supports Indigenous participation in the energy sector and remains committed to ensure these opportunities continue, including partnerships on major transmission line projects such as the Niagara Reinforcement Project” said Glenn Thibeault, Minister of Energy

“The 300 mega-watt set aside will allow our community to take a lead role in the construction and management of new renewable energy projects in this region,” said Matt Jamieson, President/CEO of SNGRDC. “SNGRDC is always looking to find new and inventive ways to invest in renewable energy to bring economic benefits to the people of Six Nations. SNGRDC believes investing in renewable energy means investing in the future and our generations yet to come.”

About Six Nations Future

Six Nations Futures is a community engagement tool utilized by Six Nations Consultation and Accommodation Process Team and SNGRDC to seek community insights on development projects happening in and around the Six Nations territory. The website and community engagement process has been designed to educate the Six Nations community about the financial, economic, and environmental impact associated with development projects, and provides a community wide mechanism to gather feedback that will help guide current and future projects. Community members can visit the website to get more information about past and current projects, and to review community engagement reports.

For more information please visit www.snfutures.com

About Six Nations of the Grand River Development Corporation:

Six Nations of the Grand River Development Corporation (SNGRDC) manages the Six Nations’ economic interests in 14 renewable energy projects and numerous economic development opportunities, in and around the Six Nations territory. SNGRDC’s current green energy portfolio is capable of producing nearly 900 MW of renewable energy through its direct or indirect involvement in seven wind, six solar and one hydroelectric project(s). SNGRDC is located on the Six Nations Reserve and directly employs over 140 people through Nation Enterprise or the administration of Economic Interests projects.

For more information please visit www.sndevcorp.ca

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TAB 2

Ontario

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

DECISION AND ORDER

EB-2016-0160

HYDRO ONE NETWORKS INC.

2017 and 2018 Transmission Revenue Requirements and Charge Determinants

BEFORE: Ken Quesnelle
Presiding Member

Emad Elsayed
Member

Peter C. P. Thompson, Q.C.
Member

November 9, 2017

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1. INTRODUCTION AND SUMMARY

This Decision and Order determines issues related to the draft revenue requirement/charge determinant order and draft uniform transmission rates (UTR) order and supporting materials (collectively the DRO) filed with the Ontario Energy Board (OEB) by Hydro One Networks Inc. (Hydro One) on October 10, 2017. These DRO materials were filed pursuant to the OEB's September 28, 2017 EB-2016-0160 Decision and Order pertaining to Hydro One's 2017 and 2018 transmission revenue requirements and charge determinants (Decision).

The OEB received submissions pertaining to the consistency of the DRO with the Decision from OEB staff, several intervenors and Hydro One. The issues raised by these submissions included matters pertaining to the following topics:

(i) The appropriate figure to use for the 2017 revenue requirement of Canadian Niagara Power Inc. (CNPI)

(ii) The changes in forecast capital spending and in-service additions over the 2017 - 2018 period and whether there was a sufficient explanation for them

(iii) The regulatory income tax amounts that should be reflected in the DRO

(iv) The calculation of the foregone transmission revenue amount.

The OEB's findings regarding these matters are provided in sections that follow entitled:

- CNPI Revenue Requirement and Deferral Account Request
- 2017 - 2018 Capital Spending and In-Service Additions forecasts
- Regulatory income taxes recoverable from ratepayers
- Foregone transmission revenue deferral account.

Matters not in dispute are approved in this Decision and Order in sections entitled;

- 2017 and 2018 Charge Determinants
- 2017 Other Charges
- Accounting Orders.

2. THE PROCESS

The Decision, released on September 28, 2017, required Hydro One to file:

(a) Drafts of a revenue requirement/charge determinant order and a UTR order along with supporting schedules

(b) A revision to Exhibit J11.3 separating the amounts in the “FMV in excess of Tax Basis” column between their “recapture” and “gain” components, along with a reconciliation of the “recapture” amounts to certain information contained in financial statements filed in evidence in the proceeding

(c) Calculations of the grossed up regulatory taxes recoverable from transmission ratepayers in 2017 and 2018 derived by multiplying taxes, calculated for each of those years under an assumed 100% allocation to shareholders of future tax savings benefits, by the 71% recapture ratio for transmission.

Hydro One complied with the Decision’s filing requirements on October 10, 2017. The documents filed included a covering letter, a five-page document entitled “Implementation of the Decision, October 10, 2017” and “Supporting Materials” labelled DRO Exhibits 1 to 10 inclusive.

Hydro One is one of five licensed electricity transmitters in Ontario that recover their revenues through Ontario's UTR. The OEB approves the revenue requirements and charge determinants for the individual transmitters and uses them to calculate the UTR. The Decision determined that the 2017 UTR will be effective January 1, 2017 but implemented October 1, 2017.

The total amount to be recovered by Hydro One Transmission in 2017 is derived from the OEB's EB-2016-0160 Decision. The findings in this Decision and Order will lead to the finalization of the transmission revenue requirement amounts, charge determinants and related matters for Hydro One in 2017 and 2018. For 2017, these amounts will be approved on a final basis. The 2018 revenue requirement will be adjusted in a 2018 cost of capital update when the OEB’s cost of capital parameters are issued, and will be finalized in a separate process leading to the issuance of the 2018 UTR.

The final 2017 amounts to be approved as a result of this Decision and Order will be used in the determination of the 2017 UTR along with the related amounts approved for the other four Ontario transmitters. The 2017 UTR rate order will be completed under OEB file number EB-2017-0280.

Hydro One’s draft order seeks approval for a total 2017 rates revenue requirement of $1,445.3 million, along with the charge determinants and the percentages for allocating these revenues to the three transmission rate pools. Hydro One also included in its DRO materials the 2018 revenue requirement, but this amount will be adjusted in the near future when the OEB issues its 2018 Cost of Capital parameters. These costs will be included in the 2018 UTR to be issued in late December 2017 or early January 2018.

OEB staff and six intervenors filed their comments on the DRO materials on October 16, 2017. In addition, one other Ontario transmitter, CNPI, filed comments on the draft Revenue Requirement and Charge Determinant Order. Hydro One replied to those comments on October 18, 2017. Accompanying this reply submission were supporting materials labelled as DRO Reply Submission Attachments 1 to 5 inclusive.

3. CNPI REVENUE REQUIREMENT AND DEFERRAL ACCOUNT REQUEST

In the DRO materials, Hydro One used a 2017 transmission revenue requirement for CNPI of $4,457,953. In its October 13, 2017 submissions, CNPI indicated that its 2017 transmission revenue requirement for use in the UTR calculation should be $4,647,201, as the previous total included the disposition of deferral accounts in 2016 which are not applicable outside of the 2016 rate year. Hydro One made changes to the DRO materials to reflect this amount.

In its submission, CNPI also asked the OEB to create for it a 2017 Lost Revenue Deferral Account in the UTR proceeding EB-2017-0280 identical to the one that the Decision establishes for Hydro One.

Findings

The OEB accepts a 2017 revenue requirement amount for CNPI of $4,647,201 for use in the UTR calculation. However, the OEB finds that the requested 2017 Lost Revenue Deferral Accounting Order should not be addressed in this Hydro One proceeding. CNPI’s application for that accounting order should be made in a separate OEB process.

4. 2017-2018 CAPITAL SPENDING AND IN-SERVICE ADDITIONS FORECASTS

a) 2017-2018 Capital Forecast

In the DRO materials, Hydro One provided reduced capital spending forecasts in each of the sustaining, development, operations and common corporate cost categories of expenditure to achieve the $126.1 million reduction in 2017 and the $122.2 million reduction in 2018 directed in the Decision.

In their DRO submissions, OEB staff and several intervenors questioned the lack of detailed project information related to the reductions in forecast expenditures and whether these reductions were consistent with the OEB Decision. These parties criticized Hydro One for the concentrated capital spending reductions in the development category when the Decision focused on the magnitude and pacing of the sustaining capital program. They suggested that the OEB require Hydro One to elaborate on its rationale for allocating reductions among the four categories of expenditure and how this allocation is consistent with the Decision.

With its DRO reply submission, Hydro One provided a new table of adjusted forecast capital spending that corrected clerical errors in the initially filed materials. This material reflects the forecast changes in in sustaining, development, operating and common corporate cost capital spending at the sub-category level.

Hydro One explained that its capital reductions were based on the current status of its capital projects and programs, execution risks and overall capital planning and redirection processes as of the September 28, 2017 date of the Decision, being just before the fourth quarter of 2017 and almost half way through the 2017 and 2018 rate term.

Hydro One advised that reductions in sustaining capital forecasts reflected slowed pacing of tower coatings and stations and line investments. Development capital forecast reductions reflected changes in customer demand and project forecasts. Hydro One advised that there may be further changes in demand-driven capital expenditures before the 2017-2018 rate term ends and that it will manage within the OEB-approved capital envelope accordingly.

Findings

The OEB finds that the information provided by Hydro One, both in the DRO and the DRO reply submission, is insufficient to enable the OEB to determine whether the proposed changes in capital spending forecast are consistent with the Decision.

The Decision regarding reductions in proposed capital spending for 2017 and 2018 focused entirely on the lack of full justification for the sustaining capital category; mostly the transmission stations sub-category and the tower coating program in the transmission lines sub-category.

While the OEB-imposed reduction in total capital spending for both years combined represented 11.3% of the proposed spending, the DRO reply submission (Table 1) shows that the proposed reduction in sustaining capital is only 4.9%. Furthermore, the breakdown of that reduction by sub-category (Attachment 2 of the DRO reply submission) shows that the forecast for transmission station capital has actually been increased by approximately 4.3% for both years combined. The tower coating program is not specifically listed in the breakdown of the transmission lines component in Attachment 2 of the DRO reply submission.

On the other hand, the proposed reduction in the development category, which was not a subject of specific OEB concerns in its Decision, is much higher (38.2% for both years combined). According to Hydro One, these reductions were mostly driven by timing and customer demand.

The OEB finds that the explanations provided by Hydro One in its DRO reply submission did not provide a complete rationalization of the proposed allocation of the reductions among the capital spending categories. The OEB recognizes that, given the date of its Decision, there is limited flexibility for Hydro One to adjust 2017 projects that are already underway or are at an advanced stage of planning. The OEB believes that there is more flexibility for projects which are planned to start in 2018 or for ongoing programs such as tower coating.

The OEB directs Hydro One to seek further opportunities to address the concerns raised in the OEB Decision regarding sustaining capital and to report on the specific actions taken and their impact as part of the status report which was required by the OEB in section 4.4 of its Decision. This part of the report should describe how the actions taken and associated results are consistent with the wording and intent of the Decision. This information would enable future OEB panels to determine whether any of the proposed additions to rate base should be denied.

The OEB emphasizes that Hydro One is exposed to the risk of disallowance of proposed rate base additions in future test periods for actual capital expenditure amounts that are materially and unjustifiably incompatible with the capital expenditure concerns expressed in the Decision.

b) 2017-2018 In-Service Additions (ISA) Forecast

In the DRO materials, Hydro One calculated that the $126.1 million capital budget reduction in 2017 would result in a reduction of $63.7 million of ISA in that year. The 2018 budget reduction of $122.2 million was forecast to produce $31.3 million of ISA reduction in that year.

Several parties questioned the disparity between the annual budget reductions and the materially lower annual ISA reductions. Certain intervenors asked the OEB to impose higher ISA reductions for 2017 and 2018 by applying an overall capital expenditure to ISA ratio (CAPEX to ISA ratio) derived from the evidence filed in support of the application for 2017 and 2018. Applying this ratio would increase the ISA reductions for 2017 and 2018 from the $63.7 million and $31.3 million amounts contained in the DRO materials to $109.2 million for 2017 and $131.7 million in 2018.

Hydro One criticized this proposed approach as overly simplistic and incorrect especially in relation to capital spending for work already in execution. Hydro One suggested that it would be imprudent for it to halt projects that are planned to be placed in service in 2017. It submitted that the overall CAPEX/ISA ratio approach does not align with the reality of operating a business with multi-year construction projects and that there is no evidentiary basis to support this proposal. Hydro One also noted that, to the extent that actual ISA are lower than forecast, the asymmetrical in-service variance account protects ratepayers against the risk of over-collecting related costs.

Findings

For the same reasons described in the previous section, the OEB does not have sufficient information to judge the adequacy of the proposed ISA reductions. The status report requested by the OEB in section 4.4 of its Decision already requires Hydro One to report on actual ISA compared to plan. In addition, the OEB directs Hydro One to specifically describe in that report how the actions taken by Hydro One to meet the intent of the Decision regarding capital reductions affected ISA. This information would enable future OEB panels to determine whether any of the proposed additions to rate base should be denied.

5. REGULATORY INCOME TAXES RECOVERABLE FROM RATEPAYERS

The DRO materials included, as DRO Exhibit 2.1 Attachment 1, a revision to Exhibit J 11.3 to separate the “FMV in excess of Tax Basis” between its “recapture” and “gain” components. Hydro One’s DRO reply submission Attachment 4 confirms that the recapture ratio for Hydro One Networks is 50% instead of the 77% ratio estimated in the Decision. This attachment also confirms that the recapture ratios for transmission and distribution are 52.5% (rounded to 53%) and 47.4% (rounded to 47%) instead of the 71% and 84% estimates in the Decision.

The adjusted recapture ratio for transmission of 52.5% is lower than the percentage allocation to shareholders of 62% under the allocation factor methodology established in the Decision for applying the benefits follow costs principle in the partial share sale scenario where 51% of the shares initially held by the Province of Ontario (Province) have actually been sold at fair market value (FMV).

DRO Exhibit 2.2 contains Hydro One’s calculations of the grossed up regulatory taxes in 2017 and 2018 derived by multiplying taxes calculated for each of those years under an assumed 100% allocation to shareholders of the future tax savings benefit by the Decision’s estimated recapture ratio of 71%.

The DRO materials do not contain a calculation of the regulatory taxes amounts derived by applying a multiple of 62% to taxes calculated under an assumed 100% allocation to shareholders of the future tax savings. No calculation of this nature was provided in the DRO materials even though the methodology established by the Decision for applying the benefits follow costs allocation principle produces a transmission allocation factor in favour of shareholders of 62%, which is higher than their recapture ratio allocation factor of 52.5%.

SEC, supported by other intervenors, provided DRO submissions on the regulatory taxes adjustment issue. SEC submitted that, as a result of the additional tax-related information provided by Hydro One pertaining to the calculation of the recapture ratios, the recapture ratio for transmission needed to be adjusted and reduced to 52.5%.

SEC submitted that the Decision required the benefit follows costs “Actual FMV Sales and Payments” allocation factor to be applied to derive regulatory taxes recoverable from transmission ratepayers when that allocation factor exceeded the recapture ratio allocation factor in favour of shareholders.

SEC submitted that the "Actual FMV Sales and Payments Ratio" applied to an allocation of the future tax savings benefits attributable to the goodwill component of the FMV Bump.

SEC proposed an increase to 63.5% of the Decision's Actual FMV Sales and Payments Ratio for transmission of 62%. SEC's rationale for this proposal was the Province's yet to be completed commitment to transfer to First Nations a 2.5% share interest in Hydro One Limited. Applying its proposed ratio of 63.5%, SEC calculated the regulatory taxes recoverable from transmission ratepayers to be $52.2 million for 2017 and $56.4 million for 2018.

SEC also asked the OEB to establish a deferral or tracking account to be used to verify that transmission ratepayers receive, over time, their 36.5% share of the transmission related deferred tax asset having a value of $1,476 million.

Apart from filing DRO reply submission Attachment 4, confirming the adjusted recapture ratios, Hydro One did not make any specific submissions in response to SEC's tax adjustment submissions. Hydro one did refer to the process in which it was then engaged to prepare and file a Motion to Review and Vary the Decision, part of which concerned the correctness of the income tax section and its formulation of the allocation methodologies. That motion was filed with the OEB on October 18, 2017.

Findings

5.1 Regulatory Income Taxes

For the reasons that follow, the OEB finds that the regulatory income taxes amounts to be approved for recovery in transmission rates are $51.0 million for 2017 and $55.0 million for 2018.

An overview of certain facts in the record and findings in the Decision is necessary to provide the context for these regulatory tax recovery findings. These facts and findings are as follows:

a) The regulatory income taxes that Hydro One sought to recover from transmission ratepayers of $89.1 million for 2017 and $89.6 million for 2018 were notional sums that exceeded actual income taxes payable in those years which would be zero but for Ontario minimum tax amounts[1].

b) Hydro One's calculation of these amounts presumed an allocation to shareholders of 100% of the future tax savings benefit of almost $2,600 million.

[1] EB-2016-0160 Decision and Order, September 28, 2017 (Decision) at pages 55-56.

c) The event giving rise to the $2,600 million tax shield was the Province's sale, in November of 2015, of more than10% of its shares in Hydro One Limited pursuant to an initial public offering (IPO) outlined in a prospectus dated October 29, 2015 (Prospectus).[2]

d) In the Prospectus, Hydro One Limited acknowledged and warned that there was a risk that the OEB might not accept the 100% allocation to utility shareholders of the future tax savings benefit. The Prospectus stated that the OEB might apportion the benefit between utility shareholders and ratepayers or allocate the entire benefit to ratepayers. An acknowledgement and warning to the same effect was included in Hydro One Limited's 2015 Annual Report.[3]

e) About 15% of the Provinces shares in Hydro One Limited were sold in early November 2015. These shares were sold at FMV. Under the provisions of the federal Income Tax Act (ITA), upon the sale by the Province of more than 10% of its shares, Hydro One Limited was 'deemed" to have sold and reacquired all of its assets at FMV. In this case, the share sale that triggered the "deeming" provisions of the ITA was a sale at FMV.

f) As of November 2015, about 15 % of the shares in Hydro One Limited had actually been sold at FMV. The remainder were held under the auspices of the "deemed" sale and reacquisition at FMV under the ITA.

g) The Decision identified the issue to be determined as one related to the allocation of a future tax savings benefit between utility shareholders and ratepayers.[4]

h) The Decision found that an issue of allocation between utility shareholders and ratepayers is a function that falls within the OEB's ratemaking authority.[5]

i) The Decision found that the "stand alone" principle did not apply to prescribe a 100% allocation of the benefit to shareholders.[6]

j) Issues pertaining to the allocation of future tax savings benefits that arose as a result of a "deemed" acquisition of utility assets at FMV had been considered by the OEB in a prior proceeding that concluded with the issuance of an OEB

[2] Decision at page 83.
[3] Decision at page 106 and footnote 165.
[4] Decision at page 86.
[5] Decision at page 87.
[6] Decision at page 87.

Report in May, 2005[7] and an accompanying rate handbook. The allocation of tax benefits issue had then arisen because, in conjunction with the introduction of the provincial Payment in Lieu of Taxes (PILS) regime, all tax-exempt distribution utilities were deemed to acquire their assets at FMV as of October 1, 2001. As in this case, that deemed acquisition of assets at FMV gave rise to an FMV Bump in the value of fixed assets and goodwill and consequential future tax savings that the utilities were asking the OEB to allocate entirely to utility shareholders.[8]

k) The OEB's May 2005 Report in the RP-2004-0188 (RP-2004-0188 Report) proceeding and its accompanying handbook allocated 100% of the tax benefits associated with the FMV Bump arising from a deemed transaction to ratepayers.

l) The RP-2004-0188 Report considered issues related to the benefits follow costs allocation factor and the recapture consequences of a subsequent sale of utility assets at FMV.

m) In its argument in this proceeding, Hydro One relied upon recapture and the benefits follow costs allocation principle to support its proposal that 100% of the future tax savings benefit be allocated to utility shareholders.[9] Hydro One argued that the provisions of the RP-2004-0188 Report did not apply to support any allocation of the tax savings in this case to ratepayers.

n) The Decision rejected these arguments. The Decision found that, in circumstances where only a portion of the Province's shares had been actually sold at FMV and the remainder were held under the auspices of a legislatively "deemed" sale and re-acquisition, the RP-2004-0188 Report informed the allocation between shareholders and ratepayers of future tax savings attributable to recapture as well as the allocation of those savings between them under the benefits follow costs allocation principle.[10]

o) Having been informed by the principles expressed in the RP-2004-0188 Report the Decision found that:[11]

    (i) The future tax savings related to the portion of the FMV Bump that is attributable to recapture are to be allocated to shareholders.

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[7] Decision at page 88.
[8] RP-2004-0188 "2006 Electricity Rate Handbook", Report of the Board, (11 May 2005, at pages 55-57, and 2006 Electricity Rate Handbook, May 11 2005 (Rate Handbook).
[9] Decision at page 90.
[10] Decision at page 89.
[11] Decision at pages 89-90

(ii) The benefits follow costs principles apply to future tax savings related to the portion of the FMV Bump that has actually been sold at FMV; but not to the portion of the FMV Bump that is held under the auspices of the "deemed" sale and reacquisition pursuant to the provisions of the ITA.

(iii) The recapture allocation factor applies if it provides an allocation to shareholders that exceeds the allocation to them under the benefits follow costs allocation factor.

(iv) Conversely, the benefits follow costs allocation factor applies if it provides an allocation to shareholders that exceeds their recapture allocation factor.

p) The Decision then established separate methodologies for determining the recapture and benefits follow costs allocation factors in favour of shareholders. The Decision states that these methodologies were determined in a manner that maintained consistency with the principles expressed in the RP-2004-0188 Report and the OEB's findings in this case based thereon to achieve a reasonable balance between the interests of utility shareholders and ratepayers.[12]

q) Since the additional tax related information that the Decision required Hydro One to provide reveals that the transmission recapture ratio in favour of shareholders[13] is less than their benefits follow costs allocation factor, the recapture ratio allocation factor for transmission is now of no significance to the final determination of the regulatory taxes recoverable from transmission ratepayers in this proceeding.

r) In establishing a methodology for determining the benefits follow costs allocation factor in favour of shareholders, the Decision first found that it would be unreasonable to allocate 100% of the tax savings benefits to shareholders when, currently, less than 100% of the Province's shares have actually been sold at FMV. [14]

s) The Decision considered the manner in which the departure tax liability to the Province was discharged by a payment sourced from share subscription amounts provided by the Province in a series of non–arms' length transactions. These transactions did not assign the deferred tax asset to shareholders. These

[12] Decision at page 90.
[13] Decision at pages 90-95
[14] Decision at pages 95-103.

transactions did not operate to deprive ratepayers of the share of the deferred tax asset that remained attributable to the “deemed” sale and reacquisition at FMV, The Decision also considered other attributes of that liability that made it variable at the Province’s discretion. The Decision rejected Hydro One’s position that, in and of itself, the payment of the departure tax amount of $2,271 million supported an allocation to shareholders of 100% of the tax savings related to the FMV Bump of $9,794 million.[15]

t) However, the Decision accepted that the elimination of the departure tax liability added value to the FMV Bump compared to the amount of that bump that would have been realized had the liability not been eliminated or discharged in some fashion.[16] The Actual FMV Sales and Payments methodology that the Decision establishes for determining the benefits follow costs allocation factor in favour of shareholders treats the departure tax amount of $2,271 million as an actual payment towards the FMV Bump. This feature of the methodology benefits shareholders in the 51% Share Sold scenario by increasing the allocation ratio in their favour from 51% to 62%.[17]

u) The Decision finds that, currently, the Province has sold about 51% of its shares at FMV, and that the allocation to shareholders of future tax savings related to the FMV Bump of $9,794 million is about 62%.

v) Multiplying the “Grossed up regulatory taxes” shown in DRO Exhibit 2.2 of $82.2 million for 2017 and $88.8 million for 2018 by the benefits follow costs allocation factor in favour of shareholders of 62% produces grossed up regulatory taxes recoverable from transmission ratepayers of $51 million for 2017 and $55 million for 2018.

The foregoing facts and findings provide the context for the OEB’s consideration of the tax adjustment submissions made by SEC.

5.2 Adjustment of the Recapture Ratio

The OEB agrees with SEC and finds that the additional tax related information that the Decision required Hydro One to provide reveals that the OEB’s estimate of the recapture ratio at 71% is too high and needs to be reduced to 52.5% as shown in DRO Exhibit 2.1 Attachment 1 and confirmed by DRO reply submission Attachment 4.

[15] Decision at pages 97-101.
[16] Decision at page 101.
[17] Decision at pages 101-104 and Table 15-3.

Since the recapture ratio for transmission is lower than the benefits follows costs allocation factor in favour of shareholders of 62%, the information in Decision Tables 15-1 and 15-2, adjusted for the information contained in the DRO materials is of academic interest only. That said, in order to complete the record by reflecting the DRO information in these tables, Schedule A, as attached to this Decision and Order, contains final Tables 15-1 and 15-2 that incorporate the DRO information.

5.3 Allocation Factor to be Applied to Determine 2017 and 2018 Regulatory Taxes

The OEB agrees with SEC and finds that the Decision requires the benefits follow costs "Actual FMV Sales and Payments Ratio" allocation factor to determine the amounts of regulatory taxes recoverable from transmission ratepayers in 2017 and 2018. This allocation factor is more favourable to shareholders than their recapture allocation factor.

5.4 Actual FMV Sales and Payments Allocation Factor Applies to all FMV Bump Elements

The Decision applies this allocation factor to the entire amount of the transmission FMV Bump. As shown in Exhibit J11.3 and in DRO Exhibit 2.1 Attachment 1, the components of the FMV Bump consist of Fixed Assets, Goodwill, and Construction in Progress.

The OEB agrees with SEC's submission that the "Actual FMV Sales and Payments Ratio" allocation factor applies to the goodwill component of the FMV Bump. The OEB confirms that the Decision applies this methodology, that apportions future tax savings between shareholders and ratepayers on the basis of actual FMV sales and payments, to all elements of the FMV Bump, including goodwill. Hydro One made no DRO reply submissions on this point. Hydro One's acknowledgement and warning in the Prospectus and the 2015 Annual Report that the OEB could either apportion or allocate the entire tax benefit to ratepayers supports a finding that tax savings related to all elements of the FMV Bump were potentially allocable to ratepayers.

This finding on this issue is also supported by the fact that the tax shield relating to goodwill, like the tax shield relating to fixed assets has both "recapture' and 'gain' components. DRO Exhibit 2.1 Attachment 1 shows the recapture component of goodwill for Hydro One Networks Inc. to be $151 million. The remaining goodwill amount of $3,633 million is "gain".

This finding is also supported by the provisions of the RP-2004-0188 Report and the provisions of the Rate Handbook that accompanied the release of that report. The RP-2004-0188 Report[18] at pages 54 and 55, makes it clear that a "deemed" transaction at

[18] See footnote 8.

FMV gives rise to Eligible Capital Expenditure (ECE) value adjustments that produce future tax savings and that, in an entirely "deemed" transaction scenario, these tax savings in the ECE component of the FMV Bump are to be allocated to ratepayers along with other FMV Bump components. Goodwill is a major element of ECE.

The provisions of the Rate Handbook that accompanied the release of the RP-2004-0188 Report confirm the allocation to ratepayers of ECE value adjustments attributable to a "deemed" transaction. Section 7.2.5 of that Rate Handbook entitled "Regulatory tax treatment of Eligible Capital Expenditures (ECE)" has two subsections that deal with ECE related tax benefits.

Subsection i) deals with the "adjustment" in fair market value of ECE items that stems from the October 1, 2001 "deemed" transaction that the OEB considered in the RP-2004-0188 Report. This subsection requires the value of such adjustments, to be allocated to the utility's ratepayers for the purposes of determining regulatory taxes recoverable from them. The phrase "value adjustments" applies to the FMV Bump that occurs as a result of a "deemed" transaction and tax benefits stemming from these adjustments are to be allocated to ratepayers.

In contrast, sub-section ii) deals with the situation where the amount of ECE includes "purchased" goodwill. When the goodwill is actually purchased, then tax benefits associated with that purchased goodwill are to be allocated to shareholders.

The Decision's Actual FMV Sales and Payments allocation factor achieves the same outcome. The tax savings related to the components of the FMV Bump that remain attributable to the portion of the Province's shares that are held as a result of the "deemed" sale and acquisition under the ITA are allocable to ratepayers. When some or all of that portion of the shares are sold at FMV, then the tax savings related to the additional shares sold shift to the shareholders.

The portion of a corporate tax benefit for a pure utility that relates to a value adjustment to goodwill that has not yet actually been purchased is, for regulatory purposes, allocated to ratepayers. According to the RP-2004-0188 Report at page 56, the situation can be considered as analogous to a change in the tax rules. The tax benefit is allocated to shareholders when the goodwill is actually purchased.

The OEB finds that the Decision's Actual FMV Sales and Payments Ratio allocation factor applies to goodwill and the other components of the FMV Bump which is an outcome that is compatible with OEB policy expressed in the RP-2004-0188 Report and its accompanying Rate Handbook.

5.5 SEC's Proposed Adjustment to the Actual FMV Sales and Payment Ratio

The OEB rejects, at this time, SEC's proposal to increase the Decision's benefits follow costs allocation ratio in favour of shareholders to 63.5% to reflect the Province's commitment to sell to First Nations a 2.5% interest in Hydro One Limited. The OEB's allocation methodology is intended to have the allocation to shareholders of future tax savings track actual share sales by the Province.

Since the sale to First Nations has not yet taken place, it would be premature to increase the Decision determined allocation factor of 62%.

The OEB would be prepared to consider pass through treatment to increases in regulatory taxes recoverable from ratepayers as a result of further sales by the Province of the shares it holds under the auspices of the deemed sale and reacquisition transaction provided for in the ITA. Hydro One is at liberty to apply for such pass through relief should further share sales by the Province take place.

5.6 Deferral or Tracking Account

At this time, the OEB sees no need for the tracking account that SEC has proposed. The OEB expects Hydro One to keep records of the amounts that it recovers from ratepayers on account of the shareholders' portion of the deferred tax asset and the amounts that ratepayers receive on account of their share of that asset.

If necessary, the appropriateness of tracking accounts related to each of these components of the deferred tax asset can be examined in Hydro One's current distribution rates case and/or in in its next transmission revenue requirement application.

Conclusion

For all of these reasons, the OEB finds that, for 2017, the regulatory income taxes to be included in the final orders related to Hydro One's 2017 and 2018 revenue requirements are to be $51.0 million and $55.0 million respectively and not the amounts of $58.4 million for 2017 and $63.0 million for 2018 presented in the DRO materials.

6. 2017 FORGONE REVENUE

In its DRO reply submission, Hydro One advised that, to be consistent with the approach followed in prior proceedings, it used forecast rather than actual 2017 charge determinants to determine 2017 foregone revenue. Hydro One also stated that the impact of using actual charge determinants would be small and well within the variance in revenues introduced as a result of rounding the UTR. Hydro One also provided an updated calculation of lost revenue.

Findings

The OEB accepts the use of forecast rather than actual 2017 charge determinants to derive 2017 foregone revenue. The calculation of the credit to ratepayers will need to be updated to reflect the OEB's finalization in this Decision and Order of the amount of regulatory income taxes to be recovered in Hydro One's 2017 revenue requirement.

7. 2017 AND 2018 CHARGE DETERMINANTS

The 2017 and 2018 transmission charge determinants for Hydro One were not at issue in the DRO process.

Findings

Hydro One's approved charge determinants to be incorporated into the calculation of the UTR for 2017 and 2018 are shown in Table 3.

Table 3
Charge Determinants (MW)

	Network	Line Connection	Transformation Connection
2017	244,866	236,891	202,461
2018	244,924	236,948	202,510

8. 2017 OTHER CHARGES

Hydro One also submitted the detailed calculations of two additional charges unique to its transmission operations: The Wholesale Meter Service and Exit Fee Schedule and the Low Voltage Switchgear Credit.

There were no comments from parties on the Other Charges as submitted by Hydro One.

Findings

The OEB approves Hydro One's 2017 Wholesale Meter Service and Exit Fee Schedule and the 2017 Low Voltage Switchgear Credit as submitted. These schedules are attached in Appendix A.

9. ACCOUNTING ORDERS

In its draft revenue requirement and charge determinant order, Hydro One included two draft accounting orders:

1) 2017 and 2018 In-Service Capital Additions Variance Account

Hydro One provided a draft accounting order to record the impact on 2017 and 2018 Transmission Revenue Requirement due to an actual amount for 2016 in-service additions that is less than $911.7 million; along with the difference between the 2017 and 2018 in-service additions embedded in 2017 and 2018 rate base and actual in-service additions in each of those years.

There were no comments from parties on the draft accounting order for the In-Service Capital Additions Variance Account.

2) 2017 Foregone Transmission Revenue Deferral Account

Hydro One provided a draft accounting order to record the difference between revenue earned by Hydro One Networks Transmission under the interim 2017 rates set at the 2016 UTR level and the revenues that would have been received under the approved 2017 UTR.

The OEB addressed some concerns raised with the calculation of foregone revenue at Section 6 of this Decision and Order. However, there were no comments from parties on the draft accounting order itself.

Findings

The OEB approves the Accounting Order for the 2017 and 2018 In-Service Capital Additions Variance Account and the Accounting Order for the 2017 Foregone Transmission Revenue Deferral Account. Both approved Accounting Orders are attached in Appendix A.

10. ORDER

Hydro One is required to promptly revise the draft revenue requirement/charge determinant and UTR order to reflect the further reductions in regulatory income taxes recoverable in 2017 and 2018. These updated materials should include an updated Implementation of Decision section, an updated supporting material section that should include any elaboration of items in the supporting material that was provided by Hydro One with its reply submissions.

As a result of this additional step in the finalization of Hydro One's transmission revenue requirement, the OEB will amend its finding in the September 28, 2017 Decision and Order and change the implementation date of the 2017 UTR to November 1, 2017, not October 1, 2017.

When the above filings have been received, the OEB will issue a final Hydro One transmission revenue requirement and charge determinant order and a 2017 UTR order with rates effective January 1, 2017 and implemented on November 1, 2017.

THE BOARD ORDERS THAT:

1. Hydro One shall file an updated draft revenue requirement/charge determinant order and the draft UTR rate order and supporting schedules (including a revised amount for foregone revenue), reflecting this Decision and Order, no later than November 16, 2017.

Cost Awards

2. Cost eligible intervenors in this proceeding shall submit their cost claims no later than 7 days from the date of issuance of this Decision and Order.

3. Hydro One Networks Inc. shall file with the OEB and forward to all parties any objections to the claimed costs within 14 days from the date of issuance of this Decision and Order.

4. Cost eligible intervenors shall file with the OEB and forward to Hydro One Networks Inc. any responses to any objections for cost claims within 21 days from the date of issuance of this Decision and Order.

5. Hydro One Networks Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

DATED at Toronto November 9, 2017

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Schedule A

Hydro One Networks Inc.

Transmission

EB-2016-0160

Decision and Order

2017 and 2018 Revenue Requirements and Charge Determinants

Tables 15-1 and 15-2

(revised)

November 9, 2017

Table 15-1 (revised)
Summary of Deferred Tax by Segment
(with Gain and Recapture Components)

			FMV in Excess of Tax Basis			Tax	
	FMV	Tax Basis	Recapture	Gain	Total	Rate	Total
Transmission							
Fixed Assets	$ 9,965	$ 6,482	$ 2,843	$ 640	$ 3,483	26.5%	$ 923
Goodwill*	$ 2,692	$ 51	$ 78	$ 1,890	$ 1,968	26.5%	$ 522
Construction in Progress	$ 116	-	-	$ 116	$ 116	26.5%	$ 31
Deferred Tax Asset	$ 12,773	$ 6,533	$ 2,921	$ 2,646	$ 5,567		$ 1,476
Distribution							
Fixed Assets	$ 7,121	$ 4,845	$ 1,904	$ 373	$ 2,277	26.5%	$ 603
Goodwill*	$ 2,455	$ 26	$ 72	$ 1,743	$ 1,815	26.5%	$ 481
Construction in Progress	$ 80	-	-	$ 80	$ 80	26.5%	$ 21
Deferred Tax Asset	$ 9,656	$ 4,871	$ 1,976	$ 2,196	$ 4,172		$ 1,105
Norfolk							
Fixed Assets	$ 55	$ -	-	$ 55	$ 55	26.5%	$ 15
Goodwill*	$ -	$ -	$ -		$ -	26.5%	$ -
Construction in Progress	$ -	-	$ -		$ -	26.5%	$ -
Deferred Tax Asset	$ 55	$ -	$ -	$ 55	$ 55		$ 15
Hydro One Networks Inc.							
Fixed Assets	$ 17,142	$ 11,327	$ 4,747	1,068	$ 5,815	26.5%	$ 1,541
Goodwill*	$ 5,147	$ 77	$ 151	$ 3,633	$ 3,783	26.5%	$ 1,003
Construction in Progress	$ 196	-		$ 196	$ 196	26.5%	$ 52
Deferred Tax Asset	$ 22,485	$ 11,404	$ 4,897	$ 4,897	$ 9,794		$ 2,596

Source: DRO Exhibit 2.1, Attachment 1

* only 75% of goodwill is included in cumulative eligible capital pool. So FMV in excess of Tax Basis is calculated as 75% of the FMV less the Tax Basis.

Table 15-2 (revised)
Recapture Ratios

	(1)	(2)	(3)	(4)
	FMV Bump	Gain	Recapture (1) - (2)	Recapture Ratio (3)/(1)
Transmission	$ 5,567	$ 2,646	$ 2,921	52.5%
Distribution	$ 4,172	$ 2,196	$ 1,976	47.4%
Norfolk	$ 55	-	$ -	100%
Hydro One Networks Inc.	$ 9,794	$ 4,897	$ 4,897	50%

Source: DRO Exhibit 2.1; Table 15-2 (revised)
Hydro One DRO Reply Submission, Attachment 4

Appendix A

Hydro One Networks Inc.

Transmission

EB-2016-0160

Decision and Order

2017 and 2018 Revenue Requirements and Charge Determinants

Exhibit 1.0
2017 Wholesale Meter and Exit Fee Schedule [DRO Exhibit 6.0]

Exhibit 2.0
2017 Low Voltage Switchgear Credit Schedule [DRO Exhibit 7.0]

Exhibit 3.0
2017 Foregone Revenue Accounting Order [DRO Exhibit 10.2]

Exhibit 4.0
2017 and 2018 In-Service Capital Additions Variance Accounting Order
[DRO Exhibit 10.1]

November 9, 2017

EB-2016-0160

Decision and Order

2017 and 2018 Revenue Requirements and Charge Determinants

Exhibit 1.0

2017 Wholesale Meter and Exit Fee Schedule [DRO Exhibit 6.0]

November 9, 2017

HYDRO ONE NETWORKS INC.
WHOLESALE METER SERVICE
AND EXIT FEE SCHEDULE

HYDRO ONE NETWORKS - WHOLESALE METER SERVICE

APPLICABILITY:

This fee schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks ("Networks") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

a) Fee for Wholesale Meter Service

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual fee of $7,900 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

This Wholesale Meter Service annual fee shall remain in place until all the remaining meter points exit the transitional arrangement.

b) Fee for Exit from Transitional Arrangement

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.

EB-2016-0160

Decision and Order

2017 and 2018 Revenue Requirements and Charge Determinants

Exhibit 2.0

2017 Low Voltage Switchgear Credit [DRO Exhibit 7.0]

November 9, 2017

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2016-0160

Low Voltage Switchgear (LVSG) Credit
Effective January 1, 2017

Charge Determinant (MW) *(Note 1)*	**Transformation Pool Revenue Requirement Before LVSG Credit ($M)** *(Note 2)*	**Rate Before LVSG Credit ($/kw/month)**	**Total Annual 2017 NCP Demand for Toronto Hydro and Hydro Ottawa (MW)** *(Note 3)*	**LVS Proportion (%)** *(Note 4)*	**Final Annual LVSG Credit ($M)** *(Note 5)*
(A)	(B)	(C) = (B)/(A)	(D)	(E)	(F) = (C)x(D)x(E)
202,461	407.1	2.0	35,132	19.0%	13.4

Note 1: Per Exhibit 5.0

Note 2: Equals Total Revenue Requirement for Transformation Connection Pool less Non-Rate Revenues allocated to Transformation Connection Pool, as per information in Exhibit 3.0

Note 3: Per EB-2016-0160, Exhibit G1, Tab 3, Schedule 1, Table 6; Sum of Toronto Hydro and Hydro Ottawa total annual 2017 NCP Demand, 27,141 MW and 7,991 MW, respectively.

Note 4: Per EB-2016-0160, Exhibit G1, Tab 3, Schedule 1, page 7

Note 5: Per EB-2016-0160, Exhibit G1, Tab 3, Schedule 1, Table 6; Sum of Toronto Hydro and Hydro Ottawa total annual 2017 LVSG credit, $10,369,906 and $3,053,191, respectively.

EB-2016-0160

Decision and Order

2017 and 2018 Revenue Requirements and Charge Determinants

Exhibit 3.0

2017 Foregone Revenue Accounting Order [DRO Exhibit 10.2]

November 9, 2017

ACCOUNTING ENTRIES

FOREGONE TRANSMISSION REVENUE DEFERRAL ACCOUNT

This account records the differences between revenue earned by Hydro One Networks Transmission under the interim 2017 rates set at the 2016 Uniform Transmission Rates (UTR) level, and the revenues that would have been received under the approved 2017 UTR based on the Board approved 2017 load forecast ("Foregone Revenue"). The account will capture the Foregone Revenue from January 1, 2017 to the date when the approved 2017 UTR are reflected in the revenue earned by Hydro One Networks. The accounting entries to be recorded are as follows:

USofA#	Account Description
Dr/Cr: 1508	Other Regulatory Assets – Sub account "Foregone Transmission Revenue Deferral Account"
Cr/Dr: 4110	Transmission Services Revenue

To record the Foregone Revenue.

USofA#	Account Description
Dr/Cr: 1508	Other Regulatory Assets – Sub account "Foregone Transmission Revenue Deferral Account"
Cr/Dr: 6035	Other Interest Expense

To record interest improvement on the principal balance of the "Foregone Transmission Revenue Deferral Account".

EB-2016-0160

Decision and Order

2017 and 2018 Revenue Requirements and Charge Determinants

Exhibit 4.0

2017 and 2018 In-Service Capital Additions Variance Accounting Order
[DRO Exhibit 10.1]

November 9, 2017

ACCOUNTING ENTRIES
IN-SERVICE CAPITAL ADDITIONS VARIANCE ACCOUNT

To record the impact on 2017 and 2018 Transmission Revenue Requirement due to an actual amount for 2016 in-service additions that is less than $911.7 million; along with the difference between the 2017 and 2018 in-service additions embedded in 2017 and 2018 rate base and actual in-service additions in each of those years. This account will be calculated annually and interest applied consistent with the Board-approved rate. The accounting entries to be recorded are as follows:

USofA#	**Account Description**
Dr/Cr: 4110	Transmission Services Revenue
Cr/Dr: 2405	Other Regulatory Liabilities – Sub account "In-service Capital Additions Variance Account"

To record the differences between revenue requirement associated with the actual in-service capital additions during a rate year and the revenue requirement associated with the Board-approved in-service capital additions for that year.

USofA#	**Account Description**
Dr/Cr: 6035	Other Interest Expense
Cr/Dr: 2405	Other Regulatory Liabilities – Sub account "In-service Capital Additions Variance Account"

To record interest improvement on the principal balance of the "In-service Capital Additions Variance Account".

TAB 3

Ontario

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

DECISION AND ORDER

EB-2016-0160

HYDRO ONE NETWORKS INC.

Application for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018

BEFORE: Ken Quesnelle
Vice Chair and Presiding Member

Emad Elsayed
Member

Peter C. P. Thompson, Q.C.
Member

September 28, 2017

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1.0 INTRODUCTION AND SUMMARY

This Decision responds to the application by Hydro One Networks Inc. (Hydro One or Networks) for Ontario Energy Board (OEB) approval of its transmission rates revenue requirements for 2017 and 2018.

Networks is the wholly owned subsidiary of Hydro One Inc. In turn, Hydro One Inc. is the wholly owned subsidiary of the new and recently created parent company, Hydro One Limited. Neither Hydro One Limited nor Hydro One Inc. are regulated by the OEB. Networks is the OEB regulated utility. This is because Networks is a monopoly electricity transmission and distribution services provider.

The transmission system of Networks currently accounts for about 98% of Ontario's electricity transmission capacity. This system is made up of a network of about 30,000 circuit kilometers of high voltage transmission lines, steel towers, 306 transmission stations and other related electricity transmission equipment.

Hydro One's distribution system, currently consisting of about 123,000 circuit kilometers of distribution lines, is Ontario's largest electricity distributor. It serves about 1.3 million customers, or about 25% of the total number of customers in the Province of Ontario (Province). Those served by Hydro One's distribution system include smaller distribution utilities and customers primarily located in rural and remote areas.

The transmission rates revenue requirement amounts that Hydro One asks the OEB to approve are $1,487.4 million for 2017 and $1,558.4 million for 2018. These proposed revenue requirements reflect a year-over-year increase of 0.5% for 2017 over 2016 approved levels and 4.8% for 2018 over 2017.

The transmission rates revenue requirements that are approved in this Decision reflect the OEB's determination of the amount of revenue required by Hydro One to cover the reasonably incurred costs of owning, operating and maintaining the transmission system at a level of service that meets the electricity transmission needs of its customers. Hydro One applies for, and the OEB determines just and reasonable rates for, the electricity distribution services that Hydro One provides in a separate OEB proceeding.

In this Decision the OEB has applied its outcomes based approach to rate regulation. A priority consideration under this performance based approach is whether the costs that a utility proposes to recover in rates will produce outcomes of value to its customers.

The OEB was faced with a significant challenge in determining that question in this proceeding. This was because, embedded in the applied-for rates revenue requirements, are significant cost increases associated with the transformation of the utility's unregulated parent company from one wholly owned by the Province to a company whose shares are publicly traded. Slightly more than 50% of the publicly traded shares of Hydro One Limited are currently widely held by members of the public. The remaining minority shareholding interest is currently held by the Province.

One of the objectives of this transformation was to maximize the value of the Province's shares in the parent company which were sold to the public in an initial public offering (IPO) in early November 2015 and in subsequent public share offerings in 2016 and 2017.[1] Another was to execute on a strategy of delivering increased value to shareholders by growing the earnings of existing subsidiaries, acquiring new regulated and unregulated businesses in Ontario and elsewhere that were accretive, and by maintaining a dividend payout ratio targeted at 70% to 80% of net income.[2]

Prior to the completion of the IPO, the new parent company, Hydro One Limited, made significant changes to the leadership of the Hydro One group of companies. Existing directors and senior executives were replaced with new appointees and hires who were experienced in the management of publicly traded companies and in achieving earnings growth through acquisitions. These measures were accompanied by the adoption of incentive packages for executives, directors and other management personnel that were weighted towards delivering value to shareholders. These measures significantly increased the compensation costs that Hydro One seeks to recover from transmission ratepayers.

The electricity transmission functions performed by Networks have remained essentially as they were before the transformation of the unregulated holding company to a publicly traded entity in which the Province now holds a minority interest. Networks' shares are not publicly traded. Networks' customers do not need leaders experienced in the operation of publicly traded companies or in executing on a strategy of accretive acquisitions. They need outcomes that electricity transmission customers value.

None of the future cash tax savings[3] that Networks realizes as a result of the IPO of almost $2,600 million are allocated to ratepayers under Hydro One's revenue requirements proposals.

This Decision carefully considers these matters in:

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[1] See Chapter 7 of this Decision and Order (D&O) at pages 46 and 47, sub-section 7.2.2 entitled "Decision to Sell"
[2] Exhibit I-09-002 Attachment 1, Hydro One Limited Prospectus, October 29, 2015, page 104.
[3] Throughout this D&O, the phrase "cash tax savings" refers to the difference between taxes actually payable when accounting depreciation rates are used to calculate taxable income, and the lower amounts of taxes actually payable when payable Capital Cost Allowances (CCA) at rates higher than accounting depreciation rates are used to calculate taxable income.

a) Reducing a portion of the increases in planned 2017 and 2018 capital expenditures that emerged as a result of the transformation

b) Reducing compensation to eliminate transformation related amounts that are of little, if any, value to transmission services customers

c) Reducing the regulatory income taxes that Networks recovers from its transmission services customers in 2017 and 2018 to reflect the OEB's determination that the future cash tax savings arising from the IPO are to be allocated to shareholders and ratepayers on the basis of an OEB established allocation factor. This factor allocates to shareholders the future tax savings derived from increases in Capital Cost Allowance (CCA) amounts attributable to recapture, and allocates the remaining tax savings to ratepayers

d) Emphasizing the importance of including performance metrics in Hydro One's Scorecard that provide objective year-over-year unit cost measures of productivity, safety, reliability and quality of service improvements.

This Decision calls for Hydro One to adhere to the OEB's recent report on the accounting for Pension and Other Post-Employment Benefits (OPEBs) costs.[4]

Apart from the foregoing, this Decision accepts, in large measure, the other components of the proposed 2017 and 2018 transmission rates revenue requirements. These largely accepted revenue requirement elements include:

- Rate Base (other than that related to capital expenditure reductions) and Cost of Capital
- Operations, Maintenance and Administration (OM&A) Expenses other than Compensation
- Depreciation
- Load and Revenue Forecasts
- Cost Allocation
- Deferral and Variance Accounts
- First Nations Permits
- Continuing applicability of US GAAP
- Export Transmission Service Rate
- Effective Date of Rates.

[4] EB-2015-0040, Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs Report, initial report dated May 18, 2017 and final report dated September 14, 2017.

The principles that have guided the OEB in making these determinations along with the analyses of the issues and the reasons for these determinations are set forth in the chapters that follow.

The revenue requirements and charge determinants approved in this proceeding form the key input to the approval of the 2017 Ontario Uniform Transmission rates (UTR) currently set as interim as of January 1, 2017.

2.0 THE PROCESS AND ORGANIZATION OF THE DECISION

Hydro One applied to the OEB on May 31, 2016 for approval of transmission revenue requirements for 2017 and 2018.

Following the publication of a Notice of the Application, the OEB granted intervenor status to 15 parties:

Anwaatin Inc. (Anwaatin)
Association of Major Power Consumers of Ontario (AMPCO)
Building Owners and Managers Association, Greater Toronto (BOMA)
Canadian Manufacturers and Exporters (CME)
Consumers Council of Canada (CCC)
Energy Probe Research Foundation (EP)
Environmental Defense (ED)
HQ Energy Marketing Inc. (HQEM)
Independent Electricity System Operator (IESO)
London Property Management Association (LPMA)
Ontario Power Generation Inc. (OPG)
Power Workers' Union (PWU)
Society of Energy Professionals (SEP)
School Energy Coalition (SEC)
Vulnerable Energy Consumers' Coalition (VECC)

Subsequent OEB Procedural Orders resulted in:

a) Extensive discovery of Hydro One's pre-filed evidence by way of responses to written interrogatories submitted by intervenors and OEB staff and two days of oral examination of Hydro One's witnesses at a technical conference held on September 22 and 23, 2016

b) Rulings on requests made by Hydro One that certain documents be treated as confidential

c) The establishment of an OEB approved Issues List

d) Guidance from the OEB on the preparation and scope of expert evidence that certain intervenors proposed to file

e) Rulings on intervenor requests that Hydro One provide complete responses to certain interrogatories.

The oral hearing of the application commenced on November 28, 2016 and continued for a total of 13 hearing days and concluded on December 16, 2016. Hydro One presented a total of 24 individuals in 9 witness panels to testify in support of the application. Many undertakings were given by Hydro One during the course of the examination of these witnesses. Written undertaking responses were filed by Hydro One during the course of and after the conclusion of the oral hearing.

Two intervenors filed evidence and presented witnesses to support their positions.

Hydro One delivered its written Argument-in-Chief on January 12, 2017. OEB staff delivered their written submission on January 25, 2017. Eleven intervenors filed written arguments between February 1 and 6, 2017. Hydro One filed its extensive written Reply Argument on February 16, 2017.

OEB staff structured their submission under major topic headings that followed an introductory section. In its Reply Argument Hydro One substantially followed the argument structure established by OEB staff with some additional headings for topics raised by intervenors in their arguments that were not addressed in the OEB staff submission.

This Decision is organized to substantially follow the structure established in the OEB staff submission and the Hydro One Reply Argument in combination with certain topics contained in the OEB approved Issues List. Following the introductory chapters, this Decision addresses matters in chapters entitled:

- Transmission System Plan and Capital Expenditures
- Productivity Improvements and Performance Scorecard
- Rate Base and Cost of Capital
- Operations, Maintenance and Administration (including Compensation) Expenditures
- Depreciation
- Load and Revenue Forecast
- Cost Allocation
- Deferral and Variance Accounts
- First Nations Permits
- Niagara Reinforcement Project
- Accounting Issues
- Taxes Including the Allocation of Future Tax Savings
- Export Transmission Service Rate
- Effective Date of Rates.

The Decision concludes with the terms of the OEB's Order pertaining to the relief requested by Hydro One, and also sets the stage for the issuance of the 2017 UTRs for all transmitters in Ontario.

A complete summary of the proceeding including a listing of hearing participants and witnesses is found in Appendix 1.

3.0 GUIDING PRINCIPLES

The following principles guide the OEB's assessment of the appropriateness of the 2017 and 2018 revenue requirement amounts proposed by Hydro One.

These principles paraphrase those articulated by the OEB in various policy reports and in decisions in other proceedings. These principles are being provided at the outset to describe the lens that the OEB has used to consider and determine the issues that this case raises.

3.1 BALANCING THE INTERESTS OF RATEPAYERS AND SHAREHOLDERS

When exercising its rate-making jurisdiction, the OEB has an obligation to strike an appropriate balance between the interests of utility ratepayers and shareholders. The OEB achieves this balance by allowing utilities to recover their costs of providing services that produce outcomes considered by the OEB to be of value to consumers.

3.2 PRINCIPLES RELATED TO OEB REASONABLENESS DETERMINATIONS

3.2.1 Outcomes Approach Applies

The OEB's outcomes approach to rate regulation has been applied in this proceeding.[5] This approach calls for the achievement of four performance outcomes to the benefit of existing and future electricity customers and the public interest:

(i) Customer Focus: services are provided in a manner that responds to customer preferences

(ii) Operational Effectiveness: continuous improvements in productivity and cost performance are achieved, and utilities deliver on system reliability and quality objectives

(iii) Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed by Ministerial directives to the OEB)

[5] The principles embedded in the outcomes approach to rate regulation were initially expressed in the OEB's October 2012 RRFE Report, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012. These principles are now refined and described in the OEB Handbook for Utility Rate Applications, issued October 13, 2016, as the Renewed Regulatory Framework (RRF) that applies to all OEB regulated utilities.

(iv) Financial Performance: financial viability is maintained and savings from operational effectiveness are sustainable.

The OEB expects utilities to both acknowledge and recognize the need for:

(i) Robust business planning over the five year planning horizon from which the test period plans have been derived

(ii) An emphasis on value for customers

(iii) The setting of utility performance targets having regard to the continuous improvement objective

(iv) An array of benchmarks, including unit cost benchmarks, that can reasonably be relied upon to compare a utility's year-over-year performance to that of its reasonably comparable peers as well as to its own year-over-year performance in the historic and bridge years and its expected performance in each of the years in the prospective test period.

Recovery from ratepayers is limited to the OEB's determination of amounts that satisfy the operational effectiveness and other performance objectives of the Renewed Regulatory Framework (RRF). Utility plans to spend do not, in and of themselves, give rise to a presumption of prudence. Rather the onus is on the utility to demonstrate to the satisfaction of the OEB that the money will be spent wisely to achieve outcomes that customers value. In the absence of evidence that the utility has obtained outcomes that are considered valuable to customers, the OEB more closely scrutinizes the reasonableness of cost inputs such as compensation.

3.2.2 Considering Prior Period Forecasts is Not Retroactive Ratemaking

The consideration of a utility's forecasts and actual spending in the bridge, historic and prior years for the purpose of assessing the reasonableness of the forecasts upon which rates revenue requirements for future years are based is not retroactive ratemaking.[6] The prior period information (e.g. operations, maintenance and administration (OM&A) and capital spending) is appropriately and justifiably considered when assessing the extent to which the prospective period forecasts are credible and reliable.

[6] Hydro One's retroactive ratemaking submissions in paragraphs 232 to 239 (pp. 68-69) of its Reply Argument lack merit.

3.2.3 Utility Responsibility for Prior Period Planning/Execution Deficiencies

OEB regulated utilities have a continuous responsibility to provide safe and reliable utility service. This continuing obligation exists regardless of the year-over-year amounts that the OEB approves for recovery in rates.

If an unsafe or unreliable situation materializes, then every utility is expected to act promptly and reasonably to remediate the situation. Shareholders of utilities that either delay or adopt a casual approach over an extended period of time to the remediation of known deficiencies have some cost responsibility for these deficiencies. They may be found responsible, in whole or in part, for the increased costs of having to perform remediation work, in a future time period, when that work should have commenced in prior years.[7]

3.3 STAND ALONE OR PURE UTILITY PRINCIPLE

This principle limits the amounts recoverable in utility rates to costs related to the provision of regulated utility services. For ratemaking purposes, costs related to unregulated or non-utility business activities are excluded from the ambit of the “stand-alone” or “pure” utility activities.

The business activities of a “stand-alone” or “pure” utility are limited to the provision of regulated services. For regulatory purposes, a “pure” utility is distinguishable from a holding company parent that already controls and is actively acquiring several other subsidiary enterprises.

A “transformation” vision of a holding company parent is only of relevance in a rate-setting proceeding for its stand-alone utility subsidiary to the extent that it produces outcomes of value to the customers of the utility. Experience in the management and operation of publicly owned companies is not a pre-requisite for the leaders of a pure utility whose shares are not publicly traded.

3.4 CONSIDERATION OF ACTUAL AND HYPOTHETICAL COSTS IN RATEMAKING

The OEB’s ratemaking powers are very broad. They include the power to adopt any method or technique that it considers to be appropriate. The use of actual and notional

[7] This principle has relevance to the matters related to insulator replacement planning upon which Hydro One and other parties have made submissions.

costs or a combination thereof, is an example of the manner in which the OEB's ratemaking power can be exercised.[8]

3.5 Benefits Follow Costs

If a cost, not included in the utility's revenue requirement, causes or produces a benefit, then, for ratemaking purposes, that benefit is allocated to utility shareholders and not to its ratepayers. This principle of allocation is considered in the determination of issues related to the allocation of tax benefits between utility ratepayers and shareholders.

Charitable donations are an example of costs not recoverable from ratepayers that produce a tax benefit. A portion of the donation can be used as a tax credit when calculating taxes payable. The utility's actual income tax is lower because of the tax credit produced by the charitable donation. However, ratepayers do not receive the benefit of this lower tax amount because they did not pay the costs that caused it. The tax benefit is allocated to the shareholders who are responsible for the donation costs.

The taxes collected from ratepayers will be a notional sum that is higher than the actual amount paid by the utility. The notional sum will be calculated on the basis of a taxable income amount that excludes the charitable donation expense and its related tax credit.

When applying the benefits follow costs principle of allocation in the circumstances of a particular case, care should be taken to identify the particular costs that produce the tax benefit.[9]

3.6 Allocation of Tax Savings

In its 2006 Distribution Rate Handbook Report dated May 11, 2005 (May 2005 Report)[10], the OEB considered the allocation of CCA derived tax benefits as between ratepayers and shareholders in the context of an October 1, 2001 directive from the Minister of Finance deeming Ontario electricity utilities to have acquired their assets at their fair market value (FMV) on that date. No actual sale of interests in utility assets had taken place at that time. However, under the applicable tax legislation, the

[8] This principle has relevance to the OEB's determination of the mechanism to be used by Hydro One to determine the regulatory taxes recoverable from transmission ratepayers.
[9] This principle has relevance to the determination of the allocation factors applicable to the allocation of future tax savings between shareholders and ratepayers.
[10] RP-2004-0188, 2006 Electricity Distribution Rate Handbook, Report of the Board, May 11, 2005

"deemed" sale prompted a resetting of the CCA values for the utility assets at their deemed FMV at October 1, 2001.

The May 2005 Report proceeds from a premise that, for regulatory and rate-setting purposes, it is the actual payment of the FMV for assets that produces the CCA derived tax benefits. The May 2005 Report concludes that ratepayers are to receive the increased CCA based tax savings benefits associated with the "deemed" transaction at FMV, until new share or asset purchasers have actually paid FMV for the utility's assets.[11]

The May 2005 Report also identifies matters to consider when a sale of interests in utility assets at their then FMV subsequently takes place. The allocation, between ratepayers and shareholders, of "recaptured" CCA amounts is one of the items that this report addresses. The OEB agreed with the submissions made by Hydro One and others in that proceeding that future tax benefits associated with the reuse of "recaptured" CCA related asset values should be allocated to utility ratepayers.

Maintaining consistency with the principles expressed in the May 2005 Report is an objective that guides the OEB's Decision in this case.

3.7 Earnings Sharing Mechanisms (ESMs)

In accordance with the 2016 Handbook for Utility Rate Applications (2016 Rate Handbook)[12], the OEB considers ESMs as a ratepayer protection mechanism on a case by case basis in proceedings where utilities seek approval of multi-year incentive ratemaking regimes.

The OEB seldom considers imposing an ESM as a component of an approval of Cost of Service rates for a test period of two years duration. Rates set under the auspices of a cost of service ratemaking regime of short duration are less likely to produce returns that exceed the OEB approved equity return than rates set through a longer term incentive rate making mechanism.

[11] The OEB's detailed analysis of this Report and the findings based thereon are provided in Chapter 15, Allocation of Future Tax Savings.
[12] Handbook for Utility Rate Applications, October 13, 2016

4.0 TRANSMISSION SYSTEM PLAN AND CAPITAL EXPENDITURES

4.1 PLANNING

Hydro One's evidence on its Transmission System Plan (TSP) indicates that the plan reflects Hydro One's commitment to meet customers' needs, manage health, safety and environmental risks, contain costs, fulfill its compliance obligations and be a responsible steward of its assets, and it demonstrates alignment with the principles set out in the OEB's 2016 Rate Handbook.

Hydro One develops its investment plan, or capital envelope, using its Investment Planning Process.[13] During the planning process, Hydro One assesses needs, develops alternatives to meet those needs, and chooses an alternative as the preferred way to meet each need. Hydro One noted that it optimizes its investments and incorporates feedback from internal stakeholders and customers.

The application describes that Hydro One determines its system needs from several sources including the needs and preferences of customers and the regional planning processes.[14]

Asset needs are determined by:

- Hydro One's asset management approach, which is informed by Hydro One's system Reliability Risk Model
- The Asset Risk Assessment methodology that Hydro One uses in determining which assets are investment candidates
- Hydro One's analyses of the assets that require investment based on asset condition and performance.

Once needs are determined, Hydro One's engineers develop alternatives to meet those needs. Hydro One then analyzes the alternatives and proposes candidate investments.[15] All of the need, alternatives and alternative selection information is entered into the Asset Investment Planning tool where it undergoes various managerial reviews.

Hydro One aggregates the pool of candidate investments into a consolidated investment portfolio which undergoes a risk optimization. Then feedback from internal

[13] Exhibit B1-2-7, p. 1, Figure 1
[14] Exhibit B1-2-1, p. 2, lines 3-13
[15] Exhibit B1-2-7, p. 14, lines 7-12, and Exhibit K4.4

stakeholders and customers is considered to further optimize the investment portfolio. Once approved by Hydro One's Board of Directors, it becomes Hydro One's investment plan. Table 4-2, which is presented in Section 4.3 below, shows how these reviews changed the size of the capital envelope for the test years.

OEB staff's submission was that there was some evidence that Hydro One's actual planning was inadequate (as opposed to the planning evidence). The increase in proposed capital spending from that originally forecast for the test years in the previous application, and the historic variance between proposed and actual capital spending, particularly in the sustaining capital area, may indicate some fault in the planning process at the company. In addition, staff pointed out that some of the problems noted in the Planning Investment internal audit report had not been addressed prior to this application being filed.[16]

Hydro One presented several reasons for the proposed increase in capital spending, particularly sustainment spending. In the course of the oral hearing, parties and the OEB panel learned that only one of these reasons had a major influence on proposed capital spending: new information about asset condition. Staff submitted that the oral evidence was persuasive as to the need for much of the lines work, but submitted that the asset condition evidence should have been highlighted in the TSP and other written evidence as the main, if not the sole, reason for the proposed lines projects.

Hydro One's evidence and argument indicated that the proposed intensive work in the test years to replace Canadian Ohio Brass and Canadian Porcelain insulators is due in part to deferral of the work to defer cost impacts to ratepayers. Staff submitted that the present crisis with these insulators is not the result of an identification of the work needed and a deliberate choice to defer work to reduce cost impacts. Rather, the evidence suggests that Hydro One did not adequately monitor the insulators and plan its strategy for dealing with a large number of affected assets. In addition, it is not clear whether Hydro One sought compensation from the insulator manufacturers for the defects when those companies were still in existence.

Staff submitted that proper pacing of capital investments does not mean ignoring or minimizing an identified need, but spreading needed investments over a period of time that optimizes the balance between addressing the system need and avoiding sudden cost or rate impacts. Staff questioned whether ratepayers should bear the entire cost of the intensive insulator replacement program. The potential fault with the insulators was

[16] OEB staff submission, p. 10

identified in the 1980s, and failures occurred from 2004 to 2016, but no specific replacement plan was produced until a public safety and reliability crisis arose.

Staff submitted that the evidence in this application did not present a clear, coherent and comprehensive picture of the planning process or the reasons behind project selection. Hydro One's TSP was described as the culmination of several investment planning process streams, but it was unclear how those process streams led to the proposals in this application.

Staff noted that Hydro One creates Investment Summary Documents (ISDs) to support the proposals in its revenue requirement applications. However, the comparison between the ISDs and the business cases developed for internal use for the same projects reveals significant inconsistencies and gaps. The ISDs are nearly all identical, list several needs, and include similar alternatives. The internal business cases filed by Hydro One do not mention some of the needs described in the corresponding ISDs, do not include alternatives described in the ISDs, and include significant safety concerns that are not described in the ISDs. Although asset condition is the main driver behind the selection of projects, the asset analytics scores, which give a quantitative measure of asset condition, are not included in the ISDs.

Many parties expressed similar concerns regarding Hydro One’s planning process. The lack of transparency was a common concern as were commentary on the Auditor General’s findings and the findings of an internal audit concerning severe data deficiencies and issues with the planning tools. Concerns were raised that the plans to address these deficiencies were not done in time to affect this application. The optimization process was also noted as being heavily criticized by an Internal Audit report and that the plans to address the Internal Audit occurred after the investment plan was developed for inclusion in this application.

Some parties also suggested that there should be third party review of Hydro One’s TSP.

In general, intervenors supported OEB staff’s arguments on Hydro One’s planning practices or voiced similar criticisms which eventually culminated in recommendations for significant reductions in capital expenditures in the test years. For instance, staff recommended capital spending reductions of $136.5 million in each test year[17] (supported by VECC)[18], SEC recommended capital reductions of $156.3 million in 2017

[17] OEB staff submission, p. 17
[18] VECC submission, p. 22

and $199.2 million in 2018[19], AMPCO urged reductions of $119.4 million in 2017 and $240.3 million in 2018[20] and CCC endorsed reductions of $176 million in 2017 and $222 million in 2018[21].

In its 2015 annual report, the Auditor General of Ontario criticized Hydro One's process around transmission line preventative maintenance.[22] In defending the process, the witnesses stated that Hydro One always had a well-defined asset management strategy, but it was not formally documented. The Hydro One witness indicated that the action required was to consolidate and streamline the various documents into a single strategy document.[23] Staff submitted that a similar issue may exist with the preparation of Hydro One's planning evidence for its revenue requirement applications: a reasonable process for identifying system needs and selecting projects exists, but that process is not adequately described in the TSP and supporting documentation.

OEB staff submitted that the robustness of Hydro One's planning and the execution of its capital plan would be demonstrated by a report to be included in revenue requirement applications outlining the status of major projects or programmes that appeared in the previous application. Staff recognized that circumstances change and Hydro One may have to adjust its plans to meet unexpected difficulties or opportunities. If a project or programme was not completed, or if money was redirected to a different project, the report should provide the reasons for the change. A report on the status of the projects on which the revenue requirement envelope was based would assist the OEB, stakeholders and customers to understand how and why the approved capital expenditures were used.

Findings

The OEB acknowledges Hydro One’s continuing efforts to make improvements to its planning process. However, the OEB finds that significant potential remains for improvement. The gaps in the planning process are demonstrated by a number of factors, including:

- As articulated in OEB’s 2016 Rate Handbook, a utility’s business plan for its regulated activities is fundamental to the evaluation of the proposals in its rate application. However, at the time of its current rate application (May 31, 2016), Hydro One did not have an approved strategic plan, nor did it have a finalized or

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[19] SEC submission, p. 10
[20] AMPCO submission, p. 26
[21] CCC submission, p. 13
[22] 2015 Annual Report, Auditor General of Ontario, Section 3.06, p. 258
[23] TR Vol. 6, p. 157

approved business plan. Hydro One's business plan was not approved by its Board of Directors until December 2, 2016, half way through OEB's oral hearing. This is a reversal of the expected planning process where a business plan leads to a TSP including a prioritized, optimized capital investment program. Hydro One followed the appropriate planning process when it submitted its last transmission rate application in 2014.

- In spite of the developments that occurred in Hydro One's planning process between its rate application in May 2016 and its Board of Directors' approval of the new business plan and capital investment plan in December 2016, the resulting proposed capital investment program remained identical. This raises a question about the value added by the review process during this period.
- Hydro One's evidence suggests significant gaps in its asset condition assessment process, demonstrated most notably by the current urgent issue with insulators.
- While Hydro One claims that its investment planning process facilitates the proper prioritization and optimization of its proposed capital investments, it is clear that there are deficiencies in this process demonstrated by:
    - The significant increase in proposed capital spending in the current application from what was originally forecast for the test years in the previous application; an increase of approximately $500 million or 30% over the two-year period.
    - The significant increase in proposed capital spending in the seven-month period from what was reviewed by Hydro One's executives in early November 2015 and the forecasts included in the current application at the end of May 2016; an increase of approximately $300 million over the two-year period or 16%.
    - Hydro One explained repeatedly in its Reply Argument that its proposed asset investments are essentially based on the condition of the assets. This does not explain why the proposed investments for the test years increased by $500 million in less than two years and by $300 million in seven months. Asset conditions are not expected to change this dramatically in such a relatively short period.
    - Historic variance between proposed and actual capital spending, particularly in sustaining capital, as well as the consistent over-forecasting of in-service capital additions for nine consecutive years from 2007 to 2015 by an average of 14.6%.[24]

[24] LPMA submission, p. 6

The OEB finds that Hydro One should continue to make improvements to its planning process addressing the issues that have been identified in this proceeding as well as those identified in Hydro One's internal audit, and to report on the progress made in this area in its next transmission rate application. Some of the elements that require more focus include a consistent, comprehensive asset condition assessment process which directly links to the TSP and the capital investment plan; an appropriate pacing of capital expenditures that achieves a proper balance of need and rate impact; and Hydro One's ability to execute the proposed capital program in a timely fashion.

The OEB requires Hydro One to complete an independent third-party assessment of its TSP and to file this assessment with its next transmission rate application. This assessment should include Hydro One's asset condition assessment and capital investment planning processes. While this type of assessment is not a standard requirement in similar rate cases, the OEB finds on a case-by-case basis that such an assessment could be beneficial in providing confidence to both the OEB and the applicant going forward. This assessment was suggested by the OEB in Hydro One's last transmission rate application. Hydro One's reason for not doing so, as articulated in the current proceeding, is that it had to forego this assessment in favour of conducting a customer engagement process prior to developing its capital investment plan.[25]

In the OEB's view, this demonstrates inadequate planning on the part of Hydro One given that a third-party review would have best been completed long before the investment plans were finalized and would have given more confidence to Hydro One's customers in the customer engagement process.

4.2 CUSTOMER ENGAGEMENT AND RELIABILITY RISK MODEL

Hydro One's evidence on customer engagement was summarized in its Argument-in-Chief[26], where Hydro One maintained that its TSP was consistent with the RRF and 2016 Rate Handbook requirements, and was informed by a customer engagement process appropriately structured to identify customer needs and preferences.

Hydro One indicated that its goal was to engage with customers consistently and proactively to better understand customers and enhance its ability to provide services that meet their needs and improve customers' overall satisfaction with the service they receive.

[25] Exhibit I/Tab1/Schedule 8
[26] Hydro One Argument-in-Chief, p. 23

One critical element of achieving this goal is the development of an investment plan that is outcome-focused and designed to meet customers' needs and preferences.[27]

Hydro One maintained that it has engaged in an intense and focused level of customer engagement in preparing this application,[28] and provided a detailed listing of all the sources it uses to determine customer needs; including routine communications, customer forums, working groups, advisory boards and conferences, and ongoing customer survey research.

For this particular application, Hydro One undertook a further customer engagement initiative, with the purpose of identifying the needs and preferences of customers related to the formulation of a five-year transmission system plan. This initiative was structured to identify customer needs and preferences and allow for the consideration of those customer needs and preferences in preparing the TSP as submitted in this application.

Hydro One engaged Ipsos Reid, a global market research company, to assist in the design, execution, facilitation, and documentation of the customer engagement initiative. Ipsos Reid also undertook analysis of the feedback received during the consultations.

Hydro One indicated that it found the feedback from these sessions to be critical in understanding customer preferences and being better able to identify customer needs. Customers indicated that the consultations were valuable to them in understanding Hydro One's operations and investment process.

Hydro One also indicated that it expects to continue to engage customers in the future, not only to receive input to consider in the development of future investment plans, but also to receive feedback and communicate key information about the system and investments that have or are likely to impact transmission system reliability risk and actual system performance.

In general, based on the customer engagement process, Hydro One submitted that it believes that any deterioration in current service levels is unacceptable to customers and that the maintenance of current reliability levels is a customer priority.

[27] Exhibit A/Tab 3/Schedule 1, p. 5
[28] Exhibit B1/Tab 2/Schedule 2

Timing of the Engagement

Many intervenors and OEB staff submitted that the customer engagement event took place too close to the filing date of the application to allow any real change to be made if it was warranted by the results of the engagement exercise. Indeed, very little change was made to the TSP as a result of customer engagement.

Some parties also pointed out that poor participation was likely due in part to short timeframe for engagement and questioned whether the results were representative given the poor participation levels.

Selection of the Participants

The entities invited to participate in Hydro One's focused customer engagement process were directly connected transmission customers and registered intervenors from the last two rate applications. Given the requirements in Chapter 2 of the OEB's Filing Requirements for Electricity Transmission Applications, staff submitted that this approach was reasonable. However, OEB staff recommended that Hydro One, in its ongoing efforts at customer engagement, remind local distribution company (LDC) participants that they are the source for the transmitter's knowledge of small end-use customers' views and preferences. Hydro One could have asked the LDC participants to specifically present the results of their own customer engagement exercises to inform the transmitter of the concerns of these customers.

In light of the Anwaatin evidence, staff also encouraged Hydro One to obtain information about the needs of these customers through the participation of Hydro One Distribution, Hydro One Remotes, other distributors that serve First Nations, and the Anwaatin First Nations and other First Nations organizations, in Hydro One transmission's ongoing customer engagement exercise.

Both Anwaatin and the Society submitted that Hydro One should more specifically engage First Nations and Métis groups prior to its next application. In addition, a number of parties stated that Hydro One should have engaged more with end-use customers.

Consideration of Costs

Staff submitted that the main conclusion drawn by Hydro One from the engagement sessions was that reliability was important to customers, and that they were willing to accept increased capital spending to ensure no diminution of reliability. This conclusion supported a slight increase in the proposed capital expenditures, and Hydro One argues that the resulting revenue requirement increases are "consistent with the expressed customer preferences and tolerances regarding reliability risk".[29]

Staff pointed out that it appears that the material presented to customers assumed that customers would tolerate some cost increases above historic levels. The lowest cost scenario presented to customers proposed a spending increase 1.6% higher than historic spending increases, and Hydro One indicated this spending level would result in a 10% increase in "reliability risk". Customers who enquired about a "zero" scenario that presumed a cost increase consistent with historic cost increases were told that “reliability risk” would increase by 20% under such a scenario. A true "zero" scenario which involved no cost increase was not entertained by Hydro One, as the company believed the consequent deterioration of reliability was not acceptable. Staff submitted that the customer engagement exercise emphasised potential threats to reliability at the expense of a discussion probing customers’ views on and tolerance of cost increases.

Many parties criticized the scenarios presented to customers as limited and designed to push customers to Hydro One’s preferred outcome and providing insufficient detail for customers to understand what was being presented. A number of intervenors also submitted that Hydro One had omitted pertinent information such as the fact that the reliability of Hydro One’s transmission system has been improving. They highlighted that Hydro One focused on the dramatic increases in equipment outage hours instead of the dramatic improvement in customer interruption hours between 2011 and 2015.

Reliability Risk Model

OEB staff's main criticism of Hydro One's customer engagement process is that the choices presented to customers were based on a model for "reliability risk" that was not predictive of real-world reliability, was not used by Hydro One in planning its investments, and exaggerated the benefit of capital investments.

Hydro One's Reliability Risk Model (RRM) was developed for two purposes: to provide a method for demonstrating the value of sustaining investments to customers, and to provide a directional indicator to assess the effect on reliability of an investment portfolio. Staff saw the value in quantifying the benefits of capital spending in a way that will resonate with customers. However, staff submitted that the RRM does not achieve this goal.

Most parties stated that the reliability risk model had several flaws beyond those conceded by Hydro One. Some parties supported the approach but stated that the model requires additional work to provide meaningful results.

[29] Hydro One Argument-in-Chief, p. 33

A number of parties also pointed out that the conclusions drawn by Ipsos Reid did not appear to be supported by the data presented in its report, in particular the customer preference for an outcome between Scenarios 2 and 3.

Most parties concluded that there was not sufficient information from the engagement and the reliability risk model to clearly establish customer needs and preferences as a justification for Hydro One's capital expenditures.

Findings

Although Hydro One made a good effort to engage its customers prior to filing its application, the customer engagement process was started only two months before the application was filed. In fact, the final Ipsos Reid report was submitted about one month before the application was filed. Little change was made to Hydro One's TSP as a result of these customer consultations. Given the complexity of the TSP, the OEB does not agree with Hydro One's assertion in its reply submission that such a very short elapsed time did not detract from the quality of the TSP evidence.

In addition, given the practical limitations of the RRM described below, it is not obvious that the customers were able to relate the various levels of capital investment to actual system reliability since that relationship does not exist. All they would have been able to learn from this exercise is that the higher the level of capital investment, the lower the system reliability risk (not actual reliability).

The OEB agrees with some of the submissions that some of the information presented to the participants may have been misleading (e.g. not making a distinction between planned and unplanned outages[30], not clearly communicating the historical improvements in actual system reliability[31], and using the "without investment" scenario as a base case.[32])

The selection of the participants was a topic of discussion throughout this proceeding, particularly the lack of input from First Nations as well as direct or indirect input from customers of LDC representatives. Regarding First Nations' input, Hydro One indicated that since a number of First Nations did participate in the current proceeding (the Anwaatin First Nations), First Nations would be invited to participate in future customer engagement processes. Regarding LDC end-use customers, who represent 92% of Hydro One's revenue, a number of suggestions were made to get their feedback in a practical fashion since direct involvement of all those customers in Hydro One's

[30] AMPCO submission, p. 33 and BOMA submission, p. 14
[31] AMPCO submission, p.34
[32] AMPCO submission, p. 28

engagement process is obviously impractical and does not fall within Hydro One's direct accountability. Suggestions included Hydro One seeking input from LDC participants about the relevant outcome of their own customer engagement exercises.

The RRM is a new tool that Hydro One started using in early 2016. Although the model is not used to develop Hydro One's investment program, it is used to demonstrate, on a relative or directional basis, the change in system reliability risk as a result of a certain incremental level of investment. The model uses hazard curves which are based on asset demographics, not condition, and focuses on three investment categories; lines, transformers and breakers. As described above, the model results were a key focus in Hydro One's communication with its customers to demonstrate the benefits of its proposed investments.

There was considerable discussion during the oral hearing about the use of the model results. Hydro One explained that the model cannot be "back-tested" or calibrated using historical system reliability data, even if this data is weather-normalized. As a result, according to Hydro One, the model results cannot be expressed in terms of impact on actual system reliability.

In its Reply Argument, Hydro One stated that "The fact that this tool is not used to specifically pick and choose investments, but only provides a way to communicate relative outcomes does not mean that the tool does not have a valid purpose."[33]
The OEB agrees with this statement in that the model provides an estimate of the percentage reduction in reliability risk which corresponds to a certain incremental amount of capital investment. What the model does not tell us is whether this percentage reduction in reliability risk is worth the incremental capital investment. As a hypothetical example, would spending an incremental $100 million to achieve a 1% reduction in reliability risk be a good business proposition, particularly given that this 1% reduction in reliability risk cannot be translated into any measurable result such as system reliability? According to Hydro One, establishing a relationship between reliability risk and actual reliability performance is not possible because actual reliability performance is also influenced by other external factors such as weather conditions.[34]

In summary, without some form of correlation between the model results and actual system reliability, it would be impossible to determine whether a certain reduction in reliability risk is worth a certain level of capital investment. The model may be used to

[33] Hydro One Reply Argument, p. 49
[34] TR Vol. 5, p. 128

directionally compare investment scenarios, but it cannot be used to predict the benefit of any given scenario in terms of reliability.

The OEB finds that Hydro One's customer engagement process was adequate in general. However, some improvements can be made in the following areas:

- The process should be started sufficiently in advance of filing the application to allow for timely input to be incorporated in a meaningful way and to improve the level of customer attendance.
- Hydro One should have discussions with LDCs to determine practical ways to seek some input from their end users to inform Hydro One's application.
- Hydro One should seek timely and meaningful input from First Nations representatives.
- The information presented to the customers should be unambiguous and easy to understand.

Regarding the RRM, the OEB finds that the model needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. As expected, the Ipsos Reid report indicated that customers expect to see an improvement in actual reliability performance, not necessarily only a reduced reliability risk for the proposed level of investment.

Based on the above-noted shortcomings of both the customer engagement process and the RRM, the OEB does not place significant weight on the evidence associated with these elements and, therefore, will not rely on the outcome as reported by Hydro One as compelling evidence of customer support for the proposed level of capital expenditures.

4.3 CAPITAL EXPENDITURES

Hydro One's TSP describes the processes developed and employed by Hydro One to create its capital investment plans for its transmission business. The plan results in proposed capital expenditures of $1,076.1 million and $1,122.2 million in 2017 and 2018, respectively.[35]

Tables 4-1 and 4-2 below show the overall increases in the capital budget as proposed by Hydro One for the test years. A number of intervenors and OEB staff recommended

[35] Exhibit B1-3-1, p. 1, Table 1

reductions in the capital budgets. The suggested reductions ranged from $273 million to $398 million over the two test years.

Hydro One’s proposed capital expenditures have increased significantly over historical expenditures and are forecast to continue increasing, as shown in Table 4-1.

Development capital expenditure increases in the test years are due to major inter-area network projects, such as the Supply to Essex County Transmission Reinforcement and the capacity increase at Lisgar TS.[36]

Operations capital expenditures have increased significantly due primarily to the need for a new back-up control centre and also the replacement of end-of-life grid control assets.[37]

Common Corporate Capital expenditures have increased over historical expenditures due to information technology development projects, increased facility needs for sustainment, development and operations programs, and the purchase of a new helicopter.[38]

Table 4-1
Transmission Capital Expenditures, 2012 – 2021
$ million

Investment Category	4 year Historical Actual Expenditures				Bridge Year	Test Year 1	Test Year 2	Forecast Expenditures		
	2012	2013	2014	2015	2016	2017	2018	2019	2021	2022
Sustaining	$ 389.3	$ 480.0	$ 621.3	$ 694.3	$ 724.3	$ 776.8	$ 842.1	$ 825.7	$ 915.2	$ 1,118.1
Development	$ 329.4	$ 171.7	$ 131.6	$ 166.0	$ 166.0	$ 196.4	$ 170.2	$ 244.0	$ 254.0	$ 258.3
Operations	$ 15.2	$ 17.7	$ 28.4	$ 15.6	$ 30.1	$ 25.4	$ 30.8	$ 58.8	$ 21.1	$ 24.7
Common Corporate Costs	$ 42.1	$ 49.1	$ 63.4	$ 67.1	$ 83.5	$ 77.6	$ 79.1	$ 79.1	$ 78.2	$ 73.8
Total	$ 776.0	$ 718.5	$ 844.7	$ 943.0	$1,003.9	$1,076.2	$1,122.2	$1,207.6	$1,268.5	$ 1,474.9

Source: Exhibit B1/Tab3/Schedule 1/p.1

[36] Exhibit B1-3-1, pp. 4-5
[37] Exhibit B1-3-1, p. 5
[38] Exhibit B1-3-1, p. 5

The Sustaining category of investments is both the largest contributor to the capital budget and the category that shows the largest increase over historical (2012 – 2016) spending levels.

Table 4-2
Transmission Capital Expenditures, 2017 – 2018
$ million

Investment Category	Candidate Investments		Optimization		Internal Stakeholder Engagement		Executive Approval	
Timeline	February 25 - March 3, 2017		March 11-14, 2017		March 17 - April 14, 2017		April 19, 2017	
	2017	2018	2017	2018	2017	2018	2017	2018
Sustaining	$ 934	$ 1,003	$ 748	$ 847	$ 777	$ 842	$ 777	$ 842
Development	$ 187	$ 186	$ 177	$ 164	$ 196	$ 170	$ 196	$ 170
Operations	$ 28	$ 37	$ 25	$ 31	$ 25	$ 31	$ 25	$ 31
Common Corporate Costs	$ 73	$ 80	$ 73	$ 84	$ 74	$ 74	$ 74	$ 74
Other	$ 4	$ 5	$ 4	$ 5	$ 4	$ 5	$ 4	$ 5
Total	$ 1,226	$ 1,311	$ 1,027	$ 1,131	$ 1,076	$ 1,122	$ 1,076	$ 1,122

Source: Exhibit J2.7, Table 1

Sustaining Capital Spending

Hydro One's evidence indicated that the Sustaining capital expenditures included in the application are required for Hydro One to meet its business objectives, including mitigating reliability risk and maintaining reliability in a safe manner to its customers. Other factors are decisions made to ensure compliance with regulatory, environmental and reliability standards and employee safety concerns. In addition, where feasible, asset life is extended through maintenance programs to avoid larger capital replacement costs.

Hydro One manages its Sustaining capital program by dividing the expenditures into two major categories:

- Stations, about 75% of the Sustaining capital budget, which represents the work required to refurbish or replace existing assets located within transmission stations, including existing protection, control, and telecommunication assets.

- Lines, about 25% of the budget, which is work required to refurbish or replace existing assets associated with overhead and underground transmission lines.

As shown in Table 4-3, the overall Sustaining capital requirements for the test year 2017 have increased by 7% over projected spending in the bridge year 2016. The Sustaining capital requirements for 2018 are approximately 8% higher than the 2017 requirements.

Table 4-3
Sustaining Capital ($ Millions)
2012 – 2018

Description	Historic Years 2012	2013	2014	2015	Bridge Year 2016	Test Years 2017	2018
Stations	$ 322.5	$ 355.3	$ 481.3	$ 565.8	$ 552.2	$ 537.5	$ 496.2
Lines	$ 66.8	$ 124.8	$ 140.0	$ 128.4	$ 172.2	$ 239.3	$ 345.9
Total	$ 389.3	$ 480.0	$ 621.3	$ 694.3	$ 724.3	$ 776.8	$ 842.1

Source: Exhibit D1/Tab4/Schedule 1, December 2, 2016 Update

Stations

The overall stations sustaining capital expenditures for the test year 2017 are approximately 2.7% less than the projected spending in 2016. The spending requirements for 2018 are also approximately 7.7% less than 2017 requirements. Over 80% of the stations investment is proposed to be for integrated stations.[39]

[39] Exhibit B1/Tab 3/Schedule 2, Table 2

Lines

Hydro One indicated that its lines sustaining capital funding covers expenditures required to replace or refurbish overhead and underground transmission lines or specific components that have reached the end of their service life or are in a deteriorated condition. The bulk (over 90%) of lines capital spending is spent on Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects. Overhead lines investment shows increases of 41% in 2016, 81% in 2017 and a further 5.7% in 2018, reaching a level of $180 million.[40] Steel structure coating and insulator replacements account for the bulk of these increases.

Findings

The OEB agrees with most submissions that Hydro One's proposed capital budget for 2017 and 2018 has not been fully justified.[41] A significant reason for this finding is the lack of a comprehensive planning process as described in the Planning section.

More specifically, the OEB's concerns about the proposed capital budget are summarized below.

- Sustaining capital represents the largest component of Hydro One's proposed investment program (72% in 2017 and 75% in 2018). Sustaining capital consists of two main components; lines and stations. The OEB finds that most of the proposed lines investments related to insulators and conductors are necessary based on the supporting evidence. However, the OEB is concerned about the inadequacy of Hydro One's historic assessments of the condition of its insulators and its delay in correcting previously known insulator defects. The OEB finds that the proposed significant acceleration of the tower coating program and associated cost increase have not been fully justified in terms of risk management or economic benefit. Hydro One provided more detailed justification for the magnitude and pacing of its tower coating program in its reply argument. However, the OEB believes that considering this program within the context of Hydro One's overall capital investment program, there is room for further optimization and prioritization. The OEB does not dispute the need for a proactive tower coating program as confirmed in the EPRI report.[42]

[40] Exhibit B1/Tab 3/Schedule 2, Table 16

[41] Hydro One's submission at page five of its Argument-in-Chief, noting the lack of intervenor evidence that contradicts the conclusions made by Hydro One and in paragraph nine of the Reply Argument about the absence of evidence challenging Hydro One's evidence, is a position that lacks merit. The OEB is fully empowered to determine issues of reasonableness without those who question an applicant's proposal being required to present witnesses to support their positions.

[42] Exhibit I/Tab 9/Schedule 6

However, the OEB believes that the pace of the program, which was not addressed in the EPRI report, may require further review relative to other sustaining investment priorities.

- The OEB also finds that the proposed stations investments, which represent the majority of the proposed Sustaining capital spending in both 2017 and 2018, have not been fully supported. The OEB agrees with some of the submissions that some of the stations work can be deferred without much impact on reliability or concern over coordination with nuclear outages. An independent third-party review of Hydro One's planning process, as suggested in the Planning section, may help Hydro One identify areas where its asset condition and work prioritization processes can be improved.
- As described in the Customer Engagement and Reliability Risk Model section above, the OEB does not have complete confidence in the process that Hydro One followed and, therefore, will not rely on the outcome reported by Hydro One as compelling evidence of customer support for the proposed level of capital expenditures.
- As described in the Planning section, the OEB has concerns about Hydro One's ability to complete the proposed capital investment program based on its historical performance, both in terms of capital spending and in-service additions.
- As mentioned in the Benchmarking section below, the results of the study commissioned by Hydro One don't seem to support Hydro One's proposal for a significant increasing trend in Sustaining capital in future years relative to actual historic expenditures.

The OEB approves a capital envelope of $950 million for 2017 and $1,000 million in 2018. This is a reduction of $126.1 million in 2017 and $122.2 million in 2018. The approved envelope is consistent with Hydro One's actual capital expenditure for 2015 ($943 million) and its forecast for 2016 ($1,004 million) and is significantly higher than the actual capital expenditure for the three previous years ($776.0 million in 2012, $718.5 million in 2013, and $844.7 million in 2014).

On the one hand, these approved envelopes recognize the fact that additional expenditures are required in the test period relative to the 2012 to 2014 period to deal with issues that have not been properly addressed in a timely manner (e.g. insulators). On the other hand, as described earlier, the proposed increase in 2017 and 2018 relative to 2015 and 2016 has not been justified and has therefore been reduced.

The reason for approving a capital envelope, as opposed to a specific set of projects, is that Hydro One has the judgement, expertise and tools to determine what can be accommodated within that envelope considering both work priority and execution capability. The OEB believes that, through appropriate risk management and prioritization, Hydro One should be able to achieve its objectives of responsible asset management within the approved capital envelope.

The OEB requires Hydro One to incorporate these reductions, in terms of overall impact on in-service additions, in the revenue requirement/charge determinant approval process for this proceeding.

4.4 Reporting on Status of Projects

OEB staff and several intervenors submitted that Hydro One should be required, in its revenue requirement applications going forward, to report on the status of major projects or programs that appeared in the previous application. If a project or program was not completed, or if money was redirected to a different project, the report should provide the reasons for the change. In its Reply Argument, Hydro One appears to suggest that comparison to capital spending in prior periods may not be relevant.

Findings

The OEB believes that the execution of a capital program according to plan is a clear indication of not only the ability to plan, but also of having the appropriate resources to execute the work as planned. Hydro One needs to demonstrate that its planning process is robust and, equally or more importantly, that it is capable of successfully executing the plan. The Navigant benchmarking report identified several opportunities for improvement in Hydro One's project management practices and capital investment program execution.

The OEB requires Hydro One, as part of its next transmission rate application, to provide a report detailing its overall performance in the execution of the capital program relative to plan. More specifically, the report should show the performance at the program level in terms of overall expenditures and in-service additions compared to the approved plan. In addition, for major projects or programs with total budgeted cost greater than $3 million which are planned to be completed during the test years, the report should show the status of each project and an explanation of any variances regarding scope, cost or schedule.

The OEB realizes that such a report is not explicitly required as part of OEB's Filing Requirements for Electricity Transmission Applications. The OEB also realizes that investment priorities are not static. For example, as mentioned in Section 5.0, circumstances could arise which render some of the planned projects uneconomical. However, the OEB needs to be assured that Hydro One's planning process is robust and that Hydro One ensures that it has the capability to successfully execute what has been planned. Given the process gaps that have been identified in this proceeding, as well as the significant variances between planned and actual capital expenditures and between planned and actual in-service additions over a number of years, the OEB needs to have confidence in Hydro One's processes. Such a report would be a step towards that objective.

4.5 LINE LOSSES

Environmental Defence (ED) filed evidence regarding the loss minimization practices of utilities in other jurisdictions.[43] This evidence advocates for measuring and reporting losses, benchmarking transmission losses, considering transmission losses in operational and investment decisions, and encouraging reduction of losses through explicit incentives. ED proposed that Hydro One develop a transmission loss reduction plan to identify all cost effective projects that could economically reduce losses on Hydro One's transmission system.

In the oral hearing, Hydro One's direct examination addressed these points. Hydro One stated that many of the practices advocated by ED, which are part of transmission ownership and operation in other jurisdictions, are part of the role of the Independent Electricity System Operator (IESO), in Ontario. Accordingly, Hydro One submitted that the IESO is better placed to measure and report on losses, benchmark transmission losses and encourage loss reduction through explicit incentives as part of its regional planning efforts.

Findings

There was considerable discussion during this proceeding about how Hydro One deals with transmission line losses. There was no disagreement among the parties about the fact that the cost of transmission line losses is very large. The debate was about how much of this cost can be avoided or reduced. It was also clear that the responsibility for managing line losses lies with the IESO in some areas (e.g. regional planning) and with Hydro One in some cases (e.g. asset refurbishment or replacement). ED submitted

[43] Exhibit K 12.4

evidence regarding the loss minimization practices of utilities in other jurisdictions. Some of these practices may not be applicable to Hydro One as the IESO is responsible for the operation of the Ontario transmission grid as a whole.

In its Reply Argument, Hydro One stated that when new investments are proposed and where selection of new equipment is evaluated for procurement purposes, losses are taken into account where it is appropriate to do so. However, during the oral hearing, Hydro One's witnesses were not able to point to any internal documents that describe its approach to evaluating line losses as part of its investment planning process. Hydro One's witnesses also could not recall any reference to transmission line losses in business cases associated with relevant capital investments. Hydro One also acknowledged that many of its planning decisions (e.g. choice of conductor and station configurations) are made without any input from the IESO.[44]

Hydro One's main argument is that the benefit of taking measures to reduce line losses would not justify the associated cost. The example provided by Hydro One during the hearing was disputed because it used the total project cost as opposed to the incremental cost of loss reduction measures to compare to annual savings resulting from line loss reduction.

In summary, Hydro One has not provided any evidence of specific initiatives that it has undertaken or is planning to undertake to reduce line losses.

The OEB finds that, given the magnitude of line losses, Hydro One should work jointly with the IESO to explore cost effective opportunities for line loss reduction. Hydro One should also explore, as part of its investment decision process, opportunities for economically reducing line losses. The OEB requires Hydro One to report on these initiatives as part of its next rate application.

4.6 BENCHMARKING

In the Hydro One Networks Inc. Transmission Rate Application Settlement Agreement for the 2015 and 2016 rate years,[45] Hydro One agreed to complete an independent Transmission Cost Benchmarking study to be filed with Hydro One's next transmission rates application. Hydro One commissioned Navigant Consulting and First Quartile Consulting to perform the study which was submitted with the application.[46]

[44] Hydro One Reply Argument, p. 52
[45] EB-2014-0140
[46] Exhibit B2/Tab 2/Schedule 1/Attachment 1

The objective of benchmarking is to assess the performance of a utility relative to other utilities, and thereby assess the reasonableness of the spending proposals in the application. Benchmarking is a fundamental part of the OEB's approach to regulation under the RRF. There were eight main best practice recommendations[47] in the Transmission Total Cost Benchmarking Study as show in Hydro One's evidence:

- Reassess and adjust performance indicators across all levels of the organization
- Continue building on use of external resources for engineering, to create a pipeline of construction-ready projects
- Manage the contingency budgets at the portfolio/corporate level
- Target a corrective maintenance spend that is ~25% of total corrective and preventative spending
- Work to reduce administrative costs
- Allocate project management resources to improve effectiveness
- Formalize a rolling two year capital budget and project portfolio and reporting framework, including projected earned value analysis
- Refresh formal driver training program.

Findings

As noted above, the settlement proposal approved by the OEB in Hydro One's last transmission rate application required Hydro One to complete an independent Transmission Cost Benchmarking Study to be filed with its next rate application. Hydro One commissioned Navigant and First Quartile Consulting to perform the study. In addition to total cost (capital and OM&A), the study benchmarked other parameters (reliability, project management, safety, staffing) against a group of peer utilities.

Regarding Hydro One's direct total capital cost for transmission lines and substations, the study shows that it was below median from 2011 to 2014. However, a subsequent undertaking, which compared the Sustaining capital component, which represents the major part of Hydro One's proposed capital expenditures, to the peer group, showed that Hydro One's expenditures for both transmission lines and substations started to increase in 2013 and became higher than the peer group median in 2014 while the peer group's expenditures showed a downward trend from 2013 to 2014.

This was likely due to the fact that Hydro One's expenditure on Sustaining capital increased by about 43% in 2014 compared to the average of its expenditures in 2012 and 2013. In 2015, the actual Sustaining capital expenditure increased by a further 12%

[47] Exhibit B2/Tab 2/Schedule 1/Attachment 1, p. 26

compared to 2014. The total increase in actual Sustaining capital expenditure from 2012 to 2016 was 86%. In this application, Hydro One proposes to increase it by another 15% by 2018 compared to 2016. This represents a total increase of 116% from 2012 to 2018 and 187% from 2012 for the longer term planning horizon to 2022. This proposed trend does not seem to support Hydro One's statement in its Reply Argument that, "over a span of years, the total sustaining capital investment will be near the median of the comparison panel."[48]

The OEB does not see the study results as providing support for Hydro One's proposal for a significant upward trend in Sustaining capital expenditures for the test years compared to historical expenditures.

Hydro One's direct Operations and Maintenance (O&M) cost for transmission lines and substations was below median for 2011 to 2014 and showing the same downward trend as the peer group for that period. However, when looking at the two sets of assets separately, the O&M cost for substations was consistently higher than the median while the cost for transmission lines was consistently lower than the median. This could be attributed to differences in asset condition and demographics.

Including outcome parameters such as reliability in the benchmarking study was helpful. Two sets of reliability data were gathered, one from the Canadian Electricity Association (CEA) and the other from the Transmission Availability Data System (TADS), which showed two different sets of reliability results. TADS metrics showed that Hydro One's outage frequency for lower voltage lines (< 200 kV) was among the highest (i.e. poorest) in the peer group. The CEA study shows that, for multi-circuit supplied delivery points, Hydro One performed well (top quartile) compared to the Canadian companies when it comes to frequency and duration of actual interruptions. Using different peer groups and different parts of Hydro One's transmission system made the interpretation of the benchmarking results difficult. To make benchmarking results more meaningful, future studies should use a consistent peer group composition, perhaps a larger peer group, and similar transmission system configuration.

The OEB directs Hydro One to report on its implementation of the recommendations from the benchmarking study in future proceedings. In addition, Hydro One should consider the shortcomings identified in this proceeding in undertaking future benchmarking studies. Benchmarking studies, whether external (compared to other

[48] Hydro One Reply Argument, p. 59

entities) or internal (year-over-year) should focus on comparing outcomes that are consistent with the RRF and which demonstrate continuous improvement.

5.0 PRODUCTIVITY IMPROVEMENTS AND PERFORMANCE SCORECARD

Hydro One's application included its proposed performance scorecard that is designed to track its performance in areas directly tied to its own business objectives, and are aligned with the objectives of the RRF.

Hydro One indicated that the metrics contained in the scorecard will provide the OEB and stakeholders visibility into how the company performs in a variety of areas, including cost control. The proposed scorecard included 22 specific metrics grouped across the four main RRF principles: Customer Focus, Operational Effectiveness, Policy Response and Financial Performance.[49]

In addition, Hydro One also indicated that as part of its scorecard development process, it also evaluated the use of Key Performance Indicators (KPIs) in measuring its performance. This followed a recommendation in the Benchmarking study to develop more robust KPIs to facilitate performance management.

Hydro One indicated that it would continue to develop a performance management system in which KPIs are aligned with the OEB scorecard and its business objectives to drive cost reductions and productivity improvement. It maintained that it is in the process of considering a variety of incremental metrics, and supporting systems that will increase the measurability of outcomes and identify the required changes to processes and activities to enhance productivity, reliability, customer service, customer satisfaction and other deliverables.

In its selection of KPIs, Hydro One identified two tiered sets of lower-level drivers of the top level metrics that were included in the proposed transmission scorecard.[50] Tier 2 metrics were identified as primary drivers of scorecard metrics and outcomes. Tier 3 metrics are measured at an additional level of granularity and focus on secondary drivers of the top level metrics. Hydro One maintained that the identification of these drivers of scorecard performance will allow it to recognize trends and identify and investigate underlying reasons for changes in the scorecard metrics.

As part of its scorecard evidence, Hydro One included a summary of its efforts to improve the efficiency of its organization and the productivity of its work programs. It maintained that it has begun to see the results of these efforts in its work programs and

[49] Exhibit B2/Tab 1/Schedule 1/Table 1
[50] Exhibit B2/Tab 1/Schedule 1/Table 2

budgets. For example, it highlighted that it has been able to maintain transmission OM&A at steady levels over recent years, despite factors putting upward pressure on OM&A costs.[51]

Findings

The OEB first implemented the use of scorecards as a component of its RRF when it developed a generic scorecard to be used by all regulated distributors. The use of a generic scorecard facilitates performance monitoring and benchmarking. For transmitters, the OEB more recently established its expectations regarding scorecards in its filing guidelines for transmission applications to the OEB.

The filing guidelines contain the expectation that transmitters will propose scorecards that reflect their individual business realities and that can be used to measure and monitor performance and, where appropriate, enable comparisons among transmitters.

Hydro One is seeking “approval” of its proposed scorecard. The OEB does not consider it necessary that Hydro One have an approved scorecard at this time. The OEB notes that Hydro One has indicated that it will continue to develop a performance management system and finds that Hydro One should include the OEB’s determinations that follow to further evolve its scorecard in concert with the further development of its performance management system. The OEB expects Hydro One to propose an evolved scorecard in its next transmission rate application.

Hydro One has provided its analysis of how its proposed transmission business scorecard and key performance indicators align its business interests with those of its customers. In that respect Hydro One has met the expectations of the filing requirements. Hydro One’s proposal is detailed, well-articulated and transparent. The following determinations are to inform Hydro One’s continued scorecard development.

In the area of customer satisfaction, the OEB has provided its findings on Hydro One’s customer engagement initiatives. Hydro One should develop performance indicators that better reflect the satisfaction level of the ultimate end use customer. The OEB does not consider the satisfaction level of directly connected local distributors to be indicative of their customers’ level of satisfaction. Local distributors do not necessarily represent the interests of their customers on transmission issues nor do they suffer the same negative consequences if transmission service levels are poor.

Hydro One, as a corporate entity, has 1.3 million distribution customers. Hydro One should improve its internal institutional processes to better inform the transmission

[51] Exhibit B2/Tab 1/Schedule 1/p. 11

performance management system of its distribution customers' satisfaction level for the purpose of gauging what, if any, elements of transmission operation are the cause of any dissatisfaction.

With respect to operational effectiveness, the OEB finds Hydro One's proposed Cost Control measures to be appropriate as the ratios proposed will provide meaningful measures of relative quantitative benchmarks that can be monitored over time. However, the measures proposed for asset management could potentially run counter to the cost control performance indicators. The asset management measures are directly linked to Hydro One's budget and "OEB-approved plan". It is important to note that the OEB does not approve capital plans, but rather a capital envelope which provides an input to the revenue requirement which in turn determines the approved rates. The capital plans that underpin the submitted revenue requirement in an application are intended to illustrate the need for the submitted revenue requirement on a prospective basis. In other words, the plan is provided to facilitate consideration of the reasonableness of the requested revenues.

In this Decision, the OEB has directed Hydro One to provide a report on the execution of its capital plan. The purpose of the report is to demonstrate that its planning process is robust and that it is capable of executing the plan. This report is to include rationale for any departure from the plan. Such rationale may include awareness that the plan is no longer considered economical. This awareness would be based on previously unknown situations, solutions or more generally, a change in the main drivers for the original plan. In other words, it becomes apparent that the execution of particular elements of the plan is no longer in the interest of the customer. The proposed scorecard does not encompass the potential for this eventuality and to the extent that this performance indicator drives employee compensation it has the potential to suppress the desired ongoing evaluation of the prospective plan. As the OEB has determined in this Decision, plan execution is important but it should not be driven by a performance indicator solely based on ensuring the level of spending originally considered reasonable is spent.

Asset management is at the core of Hydro One's business function. The OEB expects Hydro One to consider implementing broader Asset Management measures that are directly related to positive outcomes for its customers. For instance, performance measures related to improvements in Hydro One's asset diagnostics that enhance the accuracy of asset replacement schedules could result in direct benefits to customers.

With respect to Policy Response, the OEB does not consider Hydro One's proposed inclusion of North American Electricity Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) Standards to be aligned with the intent of this element of the OEB's Scorecard objectives. NERC and NPCC standards are established to ensure events that impact reliability are avoided and/or planned for on a contingency basis so as to avoid the degradation in reliability to the extent it is reasonable to do so. These standards are a mandatory requirement of Hydro One's transmission business that is subject to regulatory enforcement. From a customer's perspective the measure of reliability that results, in part, from compliance with these standards is already included in the context of Hydro One's proposed system reliability measures under the operational effectiveness element of the proposed scorecard.

Hydro One should consider expanding its policy response measures to include its initiatives related to the government's stated policy objectives on the development of a Smart Grid. The scorecard element of policy response should not be limited to purely quantitative measures. A qualitative assessment of Hydro One's response performance related to the policy objectives embedded in the government's smart grid initiatives is one example of the type of measure the OEB anticipates under this element of the scorecard.

The OEB recognizes Hydro One's efforts to improve its efficiency and productivity that have resulted in the leveling of OM&A costs over recent years. The OEB directs Hydro One to establish firm short and long term targets for productivity improvements and associated reduction in revenue requirements as a means to drive continuous improvement and improve its internal and external benchmarking standings. Hydro One should put more emphasis on including performance metrics in the scorecard that provide objective year-over-year unit cost measures of productivity, safety, reliability and quality of service improvements.

The OEB directs Hydro One to continue to develop its performance management system and scorecard to reflect the OEB's observations and determinations. Ultimately, the elements of the scorecard that directly relate to the customer experience should be customer facing and tied directly to the customer experience. Hydro One should consider the merits of implementing measures that reflect outcomes of Hydro One's overall business such as gross fixed assets/unit of load serving capacity to more fully illustrate its overall cost of service provision. The OEB directs Hydro One to provide its analysis of the merits of this and similar measures with its next scorecard submission.

6.0 RATE BASE AND COST OF CAPITAL

6.1 RATE BASE

Hydro One transmission's forecast rate base for the 2017 test year is $10,554.4 million and for the 2018 test year is $11,225.5 million. Table 6-1 provides a summary of the calculation. This includes a Working Capital Allowance of $26.6 million in 2017 and $27.8 million in 2018, which was determined in a lead-lag study conducted by Navigant Consulting Inc.

Table 6-1
Rate Base ($ million)
2017 and 2018

Description	2017 $ million	2018 $ million
Gross Plant	$ 16,641.1	$ 17,616.4
Less Accumulated Depreciation	-6,113.4	-6,418.7
Net Plant in Service	$ 10,527.8	$ 11,197.7
Working Capital	$ 26.6	$ 27.8
Total Rate Base	**$ 10,554.4**	**$ 11,225.5**

Source: Exhibit D1/Tab4/Schedule 1, December 2, 2016 Update

In its submission on rate base, SEC contended that Hydro One's request to add a rate base variance of $116.2 million for the period ending December 31, 2016 should be permanently disallowed. SEC argued that this request was the outcome of Hydro One's significant capital over-spending in 2016 above the capital budget envelope (of almost $1,500 million) that was accepted in the settlement agreement in the 2015/2016 transmission rate application. SEC submits that, in the absence of a dramatic event requiring additional capital spending, the expenditure of funds at variance with the agreed upon budget envelopes was imprudent.[52]

[52] SEC submission, pp. 46-47

Findings

The OEB finds that capital spending that is more or less than the envelope amounts that are accepted in the terms of an approved settlement proposal is not, in and of itself, imprudent. While the OEB has concerns with the extent to which Hydro One's actual spending and in-service additions deviate from budgeted amounts, the OEB is not persuaded that the 2016 variances were so great as to constitute evidence of imprudence. Such a finding is unlikely when the cumulative spending in the period ending on December 31, 2016 was reasonably compatible with the cumulative capital amounts for in-service additions that had been approved for the period 2014 to 2016 inclusive as presented in Hydro One's Reply Argument.[53]

The OEB requires Hydro One, during the revenue requirement/charge determinant approval phase of this proceeding, to provide information with supporting documentation to describe how it will adjust its proposed in-service additions to accommodate the reductions in capital expenditures imposed by the OEB in this Decision and Order.

The OEB finds that the proposed cash working capital component as well as the materials and supply inventory component are acceptable. The OEB also finds that the lead-lag study undertaken by Hydro One is acceptable. However, the OEB requires Hydro One to provide a detailed explanation in future applications of any material change in the lead-lag study results from previous similar studies.

6.2 COST OF CAPITAL

Hydro One transmission's deemed capital structure for rate making purposes is 60% debt and 40% common equity. The 60% debt component is comprised of 4% deemed short term debt and 56% long term debt.

Hydro One uses the OEB's cost of capital parameters for its deemed short-term debt rate and return on equity, consistent with the OEB's report on cost of capital released on October 27, 2016. Hydro One's updated application reflects a return on equity of 8.78% for each of the 2017 and 2018 test years. Hydro One indicated that it would update the return on equity and the cost of short-term debt in accordance with the OEB's formulaic approach for the purpose of establishing the final revenue requirement for 2018.

[53] Hydro One Reply Argument, p. 88

Hydro One also updated its own actual forecast weighted average long-term debt rate. The long term debt rate is calculated to be 4.67% for 2017 and 4.52% for 2018. The long term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2016, 2017 and 2018. Hydro One proposed to update the actual forecast weighted average long-term debt rate for the purpose of establishing the final revenue requirement for the 2018 test year at the time it updates revenue requirement for the 2018 cost of capital parameters. Table 6-2 provides the summary of Hydro One's cost of capital.

Table 6-2
Cost of Capital ($ million)
2017 and 2018

	2017				2018			
Amount of Deemed	$ million	%	Cost Rate %	Return $ million	$ million	%	Cost Rate %	Return $ million
Long Term Debt	$ 5,910.4	56.0%	4.67%	$ 275.8	$ 6,286.3	56.0%	4.52%	$ 284.1
Short Term Debt	$ 422.2	4.0%	1.76%	$ 7.4	$ 449.0	4.0%	1.76%	$ 7.9
Common Equity	$ 4,221.7	40.0%	8.78%	$ 370.7	$ 4,490.2	40.0%	8.78%	$ 394.2
Total	$10,554.4	100%	6.20%	$ 653.9	$11,225.5	100%	6.11%	$ 686.2

Source: Exhibit D1/Tab4/Schedule 1, December 2, 2016 Update

No party questioned Hydro One's proposed approach to determining its cost of capital.

Findings

The OEB finds that Hydro One's proposals for capital structure in 2017 and 2018 and for the timing and methodology for determining the return on equity and short term debt in each of those years are appropriate.

7.0 OPERATIONS, MAINTENANCE AND ADMINISTRATION (INCLUDING COMPENSATION) EXPENDITURES

7.1 INTRODUCTION

Hydro One summarized its OM&A expenses for several historic years, the bridge year and the two test years. These amounts, listed by main categories, are shown in the table below.

Table 7-1
Operations, Maintenance and Administration Expenditures by Major Category
2012 – 2018, $ million

	Actual				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
Sustainment	$ 204.7	$ 221.0	$ 228.6	$ 233.6	$ 227.5	$ 241.2	$ 238.5
year to year percentage change	-	8.0%	3.4%	2.2%	-2.6%	6.0%	-1.1%
Development	$ 8.4	$ 8.6	$ 7.5	$ 6.1	$ 5.3	$ 4.8	$ 5.0
year to year percentage change	-	2.4%	-12.8%	-18.7%	-13.1%	-9.4%	4.2%
Operations	$ 54.8	$ 56.7	$ 56.6	$ 59.0	$ 60.0	$ 61.3	$ 62.1
year to year percentage change	-	3.5%	-0.2%	4.2%	1.7%	2.2%	1.3%
Customer Care	$ 4.4	$ 5.3	$ 5.4	$ 5.1	$ 4.1	$ 4.0	$ 3.9
year to year percentage change	-	20.5%	1.9%	-5.6%	-19.6%	-2.4%	-2.5%
Common Corporate Costs & Other	$ 80.7	$ 75.8	$ 37.2	$ 73.9	$ 72.3	$ 49.9	$ 47.5
year to year percentage change	-	-6.1%	-50.9%	98.7%	-2.2%	-31.0%	-4.8%
Taxes other than Income Taxes	$ 62.1	$ 21.2	$ 64.1	$ 63.9	$ 62.9	$ 63.6	$ 64.3
year to year percentage change	-	-65.9%	202.4%	-0.3%	-1.6%	1.1%	1.1%
Pension & B2M LP Adjustments						-12.2	-12.0
Total OM&A	$ 415.1	$ 388.6	$ 399.4	$ 441.6	$ 432.1	$ 412.7	$ 409.3
year to year percentage change	-	-6.4%	2.8%	10.6%	-2.2%	-4.5%	-0.8%

Source: Exhibit A/Tab3/Sch1/p. 18, December 2, 2016 Update

Hydro One forecast slight decreases in overall OM&A expenses for 2016, 2017 and 2018. The table shows that one of the major contributors to the decrease in overall costs is the Common Corporate Costs and Other category, which benefits from a significant increase in capitalized OM&A.[54] In addition, the 2017 and 2018 adjustments are primarily driven by a reduction in pension costs.

OEB staff and intervenors questioned the reasonableness of various components of the total transmission related OM&A expenses that Hydro One seeks to recover in rates. These concerns included items related to compensation and items related to OM&A other than compensation.

Compensation costs represent a significant component of Hydro One's transmission related OM&A budgets for 2017 and 2018. The total compensation amounts in transmission related OM&A in 2017 and 2018 substantially exceed the total amounts for compensation in 2013 to 2016 as shown in Undertaking Response J10.2. Undertaking Response J10.2 indicates that about $184.5 million or about 44.7% of the proposed OM&A expenses for 2017 is compensation. For 2016 the compensation amount is about $173.6 million or 42.4% of the total OM&A amount of $409.3 million.

The 2017 and 2018 amounts include the significant increases in compensation for executives and other managerial personnel compared to previous years that Hydro One seeks to recover in transmission rates. Because of this the OEB, in this decision, first addresses the reasonableness of the compensation amounts that Hydro One proposes to recover in rates, and then considers the remainder of the proposed OM&A expenses, having regard to its compensation findings.

7.2 COMPENSATION

7.2.1 OEB's Role

The OEB's responsibility in considering utility requests for recovery of compensation costs is to ensure that the costs of the employee compensation packages that OEB regulated utilities seek to recover in rates are reasonable. In deciding what is reasonable the OEB considers present and future ratepayers and the financial health of the utilities. The degree of OEB scrutiny in particular cases will be influenced by the extent to which the material supporting an application does or does not contain objective evidence to demonstrate that the utility has and will continue to achieve outcomes considered by the OEB to be of value to customers. Customers are not well served if a utility cannot afford to attract employees with the necessary skills to maintain safe and reliable utility service.

[54] The "Capitalization of Overhead Costs" issue is discussed in Chapter 14 of this D&O in sub-section 14.2.

In this proceeding, the OEB regulated utility is Hydro One Networks Inc. Neither its owner, Hydro One Inc., nor its ultimate parent, Hydro One Limited, is regulated by the OEB. All three companies are free to structure their compensation packages with their employees as they see fit. The OEB's role is to limit compensation cost recovery in regulated rates to amounts that it finds to be reasonable.

When assessing the reasonableness of compensation costs recoverable in rates set under an outcomes approach to regulation, a priority consideration is whether the proposed costs will produce outcomes of value to customers. Amounts that other similarly situated entities pay for employee compensation to those who possess the requisite skills also influence the OEB's assessment of reasonableness.

Those managing businesses providing essential electricity services under the auspices of an OEB regulated monopoly do not encounter the challenges to market share faced by service providers operating in competitive markets. Their priority is to continuously maintain and enhance the quality of the monopoly service that they provide. The reasonable return recoverable in OEB regulated rates, being the OEB determined costs of debt and equity capital deployed to provide the essential utility services, is a result of continuous improvement in the provision of essential utility services. The services come first and the profit follows.

Utility earnings in excess of the OEB determined allowed rate of return are of value to consumers only to the extent that they are the outcome of sustainable efficiencies or savings in utility operations. Compensation packages with benefits that are heavily weighted towards achieving earnings growth and increases in shareholder value are of limited value to the consumers of utility services.

The challenge for the OEB in this case is to determine whether compensation amounts that Networks seeks to recover in its 2017 and 2018 transmission revenue requirements appropriately focus on outcomes of value to consumers. A pure electricity utility, whose shares are not publicly traded, does not need resources with expertise in the management and operations of a publicly owned holding company. The challenge for the OEB in this case is to determine the extent to which the substantially increased compensation costs being incurred by the holding company as a consequence of the partial privatization of Hydro One Limited can reasonably be allocated to Networks, being one of its pure utility subsidiaries. Circumstances related to the transformation of the parent holding company need to be considered to determine this issue.

7.2.2 Transformation of Hydro One

Recovery of Transformation-Related Compensation Increases in Rates

The “transformation” repeatedly emphasized in this case is the transformation of Hydro One Limited, the new holding company parent of Networks, to a publicly traded company with slightly more than 50% of its shares being widely held. Costs associated with a transformation of a holding company parent should only be recoverable from an OEB regulated utility subsidiary to the extent that they produce outcomes of demonstrable value to utility customers.

Decision to Sell

Prior to the autumn of 2015, the corporate parent of Networks was Hydro One Inc., then wholly owned by the Province. In the spring of 2015 the Province decided to sell to the public, in stages, portions of its 100% ownership in Networks and its affiliates. Matters pertaining to these share sale transactions formed the basis for a number of recommendations contained in the April 6, 2015 report of the Premier’s Advisory Council on Government Assets (Council). This report is entitled “Striking the Right Balance: Improving Performance and Unlocking Value in the Electricity Sector in Ontario.”[55]

Key issues addressed by the Council in its recommendations included the question of how to unlock maximum value from the Province’s interest in the Hydro One companies. The Council recommended that a staged sale of a partial interest in the integrated electricity transmission and distribution assets was the best way to achieve a maximum value outcome. It was recommended that as little as possible to be sold in the first round (about 15%) under the auspices of an IPO to let the market establish value and to see the potentially improved performance of the business.

The Council envisaged that taking Hydro One public provided an opportunity to create a new growing company that could, through acquisitions, consolidate electricity utility assets in Ontario in addition to pursuing other business expansion opportunities.

Other recommendations of the Council included those related to a new corporate governance framework vested in an independent Board of Directors composed of high quality business leaders.

The foregoing features of the transformation of Hydro One at the holding company level are only of relevance to rate-setting for the stand-alone transmission electricity utility to

[55] See Hydro One Limited Prospectus, October 29, 2015, at page 23 referring to the Council’s recommendations.

the extent that they produce outcomes that are considered to be of value to utility customers.

The Province decided to sell a partial interest in Hydro One in accordance with the Council's recommendations.

Leadership Changes

A new Chair of the Hydro One Board of Directors was appointed in early April, 2015. The new Chair then retained Hugessen Consulting (Hugessen) to advise on the appropriate compensation for a new Chief Executive Officer (CEO) and Chief Financial Officer (CFO) at Hydro One. Hugessen's representative met with the Chair to gain an understanding of the "new Hydro One". The vision for the new Hydro One included the expectation of being a consolidator in the industry and a "yield play" with some growth.[56]

Hugessen prepared a report which was provided to the Board of Directors. The report discussed some CEO and CFO compensation alternatives. A new CFO was hired in early July 2015 on the basis of a compensation package with incentives having a total budgeted value of about $1.5 million. The budgeted compensation consists of $500,000 of base salary, $300,000 of short term incentive pay and $700,000 of long term incentive payments. The 2014 total compensation paid to the former CFO, including benefits, was about $520,000.[57]

A new slate of Directors was appointed on August 31, 2015. Of the 14 Directors excluding the CEO, 12 were new members and 2 were members of the previous Board of Directors.[58] The budgeted annual costs for the Directors in 2017 and 2018 are about $3.4 million in each year,[59] with about 41% being allocable to transmission.[60] The actual 2014 cost for the Directors that were replaced were about $1.6 million.

The budgeted annual compensation cost of the new Chair is about $1.7 million and $1.8 million in 2017 and 2018, respectively, with about 53% of those amounts being allocable to transmission. The 2014 cost of the Chair that was replaced was about $300,000.

A new CEO was appointed in early September, 2015 on the basis of a compensation package, including incentives, having a value of about $4.0 million, consisting of base salary of $850,000, short term incentive pay of $765,000 and long term incentive

[56] Exhibit I/Tab 6/Schedule 57/Hugessen Report, p. 3
[57] Exhibit I/Tab 11/Schedule 23, p. 2
[58] TR Vol. 12, p. 71
[59] Exhibit I/Tab 13/Schedule 18, p. 1
[60] Undertaking J12.5

payments of $2,385,000. The 2014 compensation package of the individual that the new CEO replaced was about $745,000 including benefits.[61]

Public Offering of Shares

A series of IPO pre-closing transactions established Hydro One Limited, incorporated in late August 2015, as the owner of all of the shares of Hydro One Inc. and, as a result, the ultimate owner of Networks and its subsidiaries. The Province then owned 100% of the shares of Hydro One Limited. The IPO of about 15% of the Province’s shares in Hydro One Limited was completed in early November, 2015.

Another tranche of the Province’s shares in Hydro One Limited were sold by way of a public offering in the spring of 2016. This transaction reduced the Province’s share ownership position to about 70%. In the spring of 2017 a further tranche of shares was sold in a public offering reducing the Province’s ownership position in Hydro One Limited to slightly below 50%.

Short Term and Long Term Incentives

With the assistance of Willis, Towers Watson (WTW), a new compensation philosophy for the management group of employees was adopted for implementation in 2016. Significant short term “at risk” incentives were added to the compensation packages of this group of employees. Similarly significant longer term “at risk” incentives were provided for a particular subset of management executives. These short term incentives account for $16.0 million and $16.2 million in total compensation costs for 2017 and 2018, respectively.[62] The amounts allocated to transmission are about $7.8 million and $7.6 million for those years.[63] The long term incentive amounts included in total compensation costs are $5.3 million for 2017 and $8.2 million for 2018.[64] The amounts allocated to transmission are about $2.8 million and $4.3 million in each of those years.[65] A portion of each of these amounts is in transmission OM&A with the remainder in the capitalized portion of total compensation costs.[66]

Employee Share Ownership Plan (ESOP)

Management group employees can contribute up to 6% of their base pay to acquire shares in Hydro One Limited with the employer to provide a 50% match on contributions to a maximum of 3% of base salary. This item adds about $1.9 million to the total

[61] Exhibit I/Tab 11/Schedule 23, p. 2
[62] Exhibit I/Tab 6/Schedule 59, p. 2
[63] Exhibit J10.2, p. 2
[64] Exhibit I/Tab 6/Schedule 59, p. 2
[65] Exhibit J10.2
[66] Hydro One Reply Argument, p. 80

budgeted costs of compensation in each of the years 2017 and 2018 with about $0.9 million for 2017 and $1.0 million for 2018 being allocable to transmission.[67]

Lump Sum Payments

Negotiated wage increases for Union employees include negotiated annual lump sum adjustments. The new collective agreements with the PWU and the Society became effective on April 1, 2015 and April 1, 2016 respectively.[68] For PWU members, the total costs (transmission and distribution) to the employer of these measures were about $2.9 million in 2015 and about $6.1 million in 2016.The amounts allocable to transmission in 2015 and 2016 were about $1,345 million and $2.811 million respectively. For Society members these amounts are a total of about $1.4 million in 2016 and about $2.7 million in 2017 with about $0.659 million and about $1.312 million being allocable to transmission in 2016 and 2017.[69] These 2016 amounts should be included in the total costs for Hydro One employees that are used in the 2016 benchmarking studies.

Share Grants

Employees represented by the PWU or the Society are eligible to receive shares of Hydro One Limited commencing in 2017 for PWU members and in 2018 for Society members. For PWU members, these measures account for about $6.7 million of total compensation in each of the years 2017 and 2018, of which about $2.7 million is allocable to transmission each year. For Society members the amount in total 2018 compensation costs is about $2.4 million with a little less than $1.0 million allocable to transmission. Therefore, the total amounts allocable to transmission are about $2.7 million in 2017 and about $3.7 million in 2018.[70] These amounts should be included in the total costs for Hydro One employees that are used in future benchmarking studies based on 2017 or 2018 costs.

Employer Pension Contributions

The pension contributions paid by Hydro One on behalf of some of its employees continue to hover above the 50/50 ratio. The value of the employer contributions above that ratio is estimated to be about $3 million[71], part of which is allocable to transmission.

[67] Exhibit J10.2, p. 2 and EB-2017-0049, Exhibit C1/Tab 2/Schedule 1, p. 48 Appendix B.
[68] Exhibit C1/Tab 4/Schedule 1, p. 15
[69] Exhibit J10.2
[70] See Footnote 60
[71] Exhibit I/Tab 11/Schedule 31

Benchmarking Studies

Compensation cost benchmarking studies were conducted in 2016 by WTW and Mercer. The WTW study relates to a subset of management employees while the Mercer study, which includes some management positions, is dominated by positions held by members of the PWU. Each of these studies found the compensation amounts to be above the market median to some degree.

The Mercer study estimated the compensation amounts to be about 14% above the market median. This puts the total compensation for the Hydro One employees about $71 million above the market median with about $12.5 million of that amount allocable to transmission OM&A. Another portion of the $71 million would be allocable to transmission related compensation costs that are capitalized.[72]

The WTW study relating to 203 of the 596 management positions for 2016 estimated the compensation amount attributable to those positions to be about $6.3 million above the market median.[73] Part of this amount is allocable to transmission.

Electricity Transmission and Distribution Functions Remain Unchanged

Despite all of the corporate restructuring that has taken place as a result of the shareholder-induced transformation, the actual delivery of essential electricity transmission and distribution services by Networks has remained as it was before the decision to sell was made.

Networks is now, and always has been, Ontario’s largest electricity transmission and distribution company. For some 15 years or more Networks has conducted its monopoly electricity transmission and distribution business segments as a pure, stand-alone commercial enterprise.

For many years Networks has been a reporting issuer of debt securities in Canada and an active participant in the public debt markets. It has enjoyed one of the strongest credit profiles of any public company regulated utility in Canada.

Networks remains distinguishable from its new holding company parent, Hydro One Limited. Networks shares are not publicly traded. Experience in the management and operation of publicly owned companies is not a pre-requisite for the leaders of Networks. Rather the priority skill set that the leaders of Networks should possess is experience in the management and operation of electricity transmission and distribution

[72] Exhibit K9.8
[73] TCJ1.6

systems providing essential electricity services under the auspices of OEB regulated rates.

Enhancing the customer focus of its provision of utility services is not a new business objective for Networks. Since October of 2012 Networks has been subject to the customer focus requirements of the OEB's RRF. The prior leaders of Networks were engaged in enhancing the customer focus of its operations before the transformation of Hydro One was initiated. Those leaders were able to achieve earnings levels year over year that equalled or exceeded the OEB allowed rates of return[74] without compensation at the increased levels that Networks now seeks to recover in rates.

7.2.3 Total Compensation Costs

Networks uses an integrated workforce to operate its transmission and distribution business segments together. The existence of this integrated work force allows Networks to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations.

As in prior cases, Networks presents these costs for the entire integrated workforce in year over year actual and forecast year end payroll tables (Transmission Payroll Tables).[75] However, these payroll tables do not present the complete total compensation picture for Networks as a whole, because they do not include pension costs, other post-employment benefit (OPEB) costs, lump sums or employee share grant amounts.

SEC and OEB staff sought to have the entire company payroll tables broadened to include each of these excluded items of compensation costs. In addition, they asked for these broadened tables for the entire workforce to show the portion of the total for each line item that is allocated to the transmission business segment.

Networks best efforts undertaking response to these requests is contained in Exhibit J10.2. This exhibit does not present the Payroll Tables with additional columns containing the previously excluded compensation cost items. Rather it is a derivative of the broadened total company payroll tables (not provided) and is confined to the transmission business allocation amounts contained in those tables. The company wide payroll amounts including the headcount information and the missing amounts for

[74] Prospectus dated October 29, 2015, Exhibit I/Tab 9/ Attachment page 3 referring to returns on a consolidated basis and Exhibit I/Tab2/Schedule 30 showing returns for the transmission business segment.
[75] Exhibit C1/Tab 4/Schedule 1/Attachment 1

pension, OPEBs, lump sums and share grant costs are needed to enable year over year trends to be examined on a unit basis.

A total Networks wide presentation of this nature is important to provide the company-wide compensation costs base line that produces the allocations of those amounts to Networks' transmission and distribution services business segments. The OEB needs to be satisfied that the allocations of Networks-wide total compensation costs to transmission and distribution services respectively stem from the same baseline.

In Reply Argument Hydro One agreed to file a table similar to that contained in Undertaking J10.2 in its next transmission and distribution rates applications.[76] The OEB is aware that Networks has filed, in its EB-2017-0049 application for approval of 2018 – 2022 distribution rates, a table[77] (Distribution Payroll Tables) showing the allocation of all compensation costs to the distribution business segment for the years 2014 to 2022. This table is substantially the distribution equivalent of Undertaking J10.2 in this transmission revenue requirements proceeding.

Assuming that the sum of the allocations to distribution and transmission represent the total company wide compensation amounts for Networks, then, from these two tables one can extrapolate total company wide compensation costs for the years 2014 to 2018.

For 2017 and 2018 the total compensation costs are about $1,146 million and $1,163 million respectively. These amounts exceed the total payroll costs for 2017 and 2018 of about $798 million and $801 million respectively shown in the Transmission Payroll Tables at pages 5 and 6 by about $347.6 million and $362.9 million for those two years. This evidence indicates that the compensation costs not included in the payroll tables are significant and represent about 30% of the total compensation costs.

In the findings section of this chapter the OEB directs the filing by Networks, in the distribution rates application currently before the OEB, of the broadened payroll tables and the allocations to transmission and distribution that stem therefrom. This is to ensure that the total compensation baseline information and the transmission and distribution allocations that are derived therefrom, is in evidence for consideration by the OEB in that distribution proceeding.

The OEB observes from Undertaking J10.2 that total compensation costs allocated to transmission are about $539.3 million in 2017 and $525.6 million in 2018. These are very substantial amounts that warrant careful scrutiny. Moreover, about $354.8 million

[76] Hydro One Reply Argument, pp. 83-84
[77] EB-2017-0049, Exhibit C1/Tab 2/Schedule 1/Appendix B

of these costs are capitalized in 2017 and about $352.0 million in 2018.[78] These rate base amounts will lead to the recovery in rates of depreciation, return and related income taxes – yet another reason for a careful examination of the total amounts.

7.2.4 Submissions

Hydro One submitted that all of its human resources costs are reasonable. It contended that the rigorous process of transformation in which it is engaged will produce benefits for ratepayers. It pointed to its increasing sensitivity to customer needs and argues that its newly adopted compensation philosophy is compatible with the competitive market for the skilled resources that it needs to meet its electricity service obligations. Hydro One highlighted productivity improvements that new management has introduced and asserted that these benefits are more than sufficient to cover the transformation related increases in compensation costs.

OEB staff, supported by certain intervenors, pointed to the missing year-end headcount information in Undertaking J10.2 and asked the OEB to issue a directive requiring Hydro One to remedy the information deficiencies.

OEB staff and several intervenors referred to the significant increases, particularly in compensation for corporate management and other management positions, that have accompanied the holding company corporate restructuring and subsequent public offerings and sale of slightly more than 50% of the company’s shares to members of the public.

They also referred to Hydro One’s obligation to establish that these costs will produce outcomes that customers value and questioned whether Hydro One has discharged that burden. They pointed to the significant magnitude of the incentive payment amounts and their terms which they assert are heavily weighted to prompt the delivery of value to shareholders through increases in earnings per share and dividends. Some of these parties suggested either excluding the incentive payments from recovery in rates or capping the recovery of such sums at a small fraction of base pay.

These parties urged the OEB to hold compensation amounts at the levels currently recoverable in rates. They requested the OEB to make, for ratemaking purposes, a global reduction of up to $22.6 million in each of the total OM&A expenses envelopes for 2017 and 2018 which are $412.7 million and $409.3 million respectively to reflect the unreasonably high compensation amounts in those sums. In requesting this reduction

[78] Matters related to the Capitalization of Overheads are discussed in Chapter 14, Accounting Issues, in sub-section 14.2.

amount they relied on prior OEB decisions requiring Hydro One to make steady progress in reducing the compensation amounts recoverable in rates towards the market median.

These parties referred to the results of the Mercer and WTW benchmarking studies that show Hydro One's compensation amount to be higher than that median. The Mercer study shows that Hydro One's compensation is further above the median than it was in 2013. The group of employees studied by Mercer consisted substantially of labour personnel represented by unions, while the WTW study was of a particular subset of management positions.

One intervenor noted that the Mercer estimate of $12.5 million as the extent to which the total compensation allocable to transmission OM&A is higher than the median is likely low. The amounts for Hydro One's total compensation for 2016 in the Mercer study are understated because they do not include the lump sum amounts for 2016 paid as part of the compensation for PWU members.[79]

In its reply to OEB staff and intervenors, Hydro One submitted that an envelope reduction in an amount of $22.6 million per year would be punitive. It asserted that there was overlap between the Mercer and WTW studies and that combining the higher than median estimates in those reports involves double counting. It also noted that some transmission OM&A was capitalized and that any OM&A expense reduction should not include any capitalized amounts. To include such amounts in the OM&A expense reduction would be triple counting according to Hydro One.

Hydro One criticized those supporting an OM&A envelope reduction for disregarding the successes that it had obtained in its recently concluded negotiations with staff represented by unions and the productivity savings already achieved. It contended that it had acted prudently in assessing the appropriateness of the compensation arrangements that had been put in place. It contended that terms of the incentive plans were not imbalanced towards delivering value to shareholders. It relied on prior OEB decisions in two gas utility cases where incentive plan costs were approved for recovery in rates. Hydro One's position was that, taken as a whole, the compensation amounts would produce outcomes that customers value and that all of the requested amount should be recoverable in transmission rates.[80]

[79] SEC submission, p. 55
[80] Hydro One Reply Argument, p. 70

Findings

Incomplete Total Payroll Table Information

The OEB agrees with OEB staff that the elaboration of the total compensation table provided by Hydro One in Undertaking J10.2 remains incomplete. The OEB directs Hydro One to remedy this information deficiency in its current application to the OEB for approval of distribution rates for the period commencing January 1, 2018.

The total compensation cost baseline for Hydro One transmission and distribution combined, derived from the year-end payroll tables and the other information that is captured in Exhibit J10.2 and in the Distribution Payroll Tables, is the base for the allocation of such costs to the transmission and distribution utility services segments. The OEB expects Hydro One to file this complete total compensation information in the distribution rates proceeding as soon as possible. The OEB expects that the information to be filed will include the following:

a) Tables comparable to the year-end payroll tables in the Transmission Payroll Tables for each the years 2014 to 2018 containing total compensation information that reconciles with the combined totals of the amounts for each of the years 2014-2018 allocated to transmission shown in Undertaking J10.2 and the amounts shown for distribution in the Distribution Payroll Tables

b) Within these total compensation tables, for each of the line item amounts and for each year, the total number of employees in a manner that reconciles with the total number of employees information presented in Transmission Payroll Tables

c) Beside the “Total Number of Employees” information described in item (ii), the total company full time equivalent (FTE) information for each of the years 2014-2018 in a format similar to that shown in EB-2017-0049 Exhibit C1/Tab 2/Schedule 1, Table1

d) In the total compensation tables, the allocation of total compensation between capital and OM&A for each of the years 2014-2018 in a manner comparable to that shown for transmission only in Undertaking J10.2

e) As part of the total compensation table, the Pension and OPEB amounts for distribution for each of the years 2014-2018 in a table similar to the table to that effect contained in Undertaking J10.2

f) A revision of the format used in Undertaking J10.2 to reflect the format of the total compensation tables described in items a) to e)

g) An exhibit that shows how the allocation factors used to allocate the total compensation amounts between transmission and distribution are derived.

The OEB directs the above information to be presented in the distribution rates proceeding on a basis that is consistent with the combined year-end payroll information for the transmission and distribution business segments.

OM&A Envelope Reduction Related to Compensation

The transformation on which Hydro One relies in this case was a transformation of Hydro One Limited, which is now established as the ultimate new holding company parent for Networks and its affiliates. The OEB finds that the primary purpose of the corporate restructuring, at the holding company level, was to maximize the value of the holding company shares to be sold by the Province in the initial and subsequent public share offerings.

The OEB finds that, under the outcomes approach to utility rate regulation, compensation and other costs incurred in connection with the transformation of a holding company parent are recoverable from ratepayers of an OEB regulated utility subsidiary only to the extent that they produce outcomes of demonstrable value to utility customers.

The OEB shares the concerns of OEB staff and those intervenors who question whether Hydro One has adequately demonstrated that the significant increases in compensation costs associated with the parent company's transformation will produce outcomes that utility customers value. Hydro One has failed to demonstrate that the increases in the transformation-related compensation costs that it proposes to recover in rates will produce continuous measurable improvements in efficiency or productivity and in the safety, reliability and quality of electricity transmission services being provided by Networks.

The transformation measures are clearly delivering value to shareholders of Hydro One Limited. The OEB notes that the letter from the Chair of Hydro One's Board of Directors to Hydro One Limited shareholders contained in the 2016 Annual Report reports on the generation of 19.7% return to shareholders over the period of November 5, 2015 to December 31, 2016. Current rates are producing favourable outcomes for shareholders. The provisions of the compensation incentive plans linked to delivering increased shareholder value had a positive impact in the period ending December 31, 2016.

The OEB shares the concerns of those parties who expressed the view that costs of incentive plans that are primarily designed to deliver value to the shareholder should not be recoverable from utility ratepayers.

The OEB notes that total Corporate Management costs in 2014 of about $5.5 million are increasing to $22.3 million and $22.1 million in 2017 and 2018, respectively.[81] Corporate Management Costs relate to the Board of Directors, the CEO, the Treasurer, the CFO and the general Counsel and Corporate Secretariat. These individuals are responsible for providing overall strategic direction to Hydro One Limited.[82]

These Corporate Management cost increases are primarily compensation amounts[83] related to the transformation of the holding company Hydro One Limited to a company whose shares are publicly traded and in which the Province now has a minority interest. Yet only about $6.3 million of the $16.8 million increase in 2017 costs over 2014 costs remain at the holding company level and are not allocated to transmission or distribution. A similar situation prevails for 2018. The OEB is concerned that the difference between two amounts of approximately $10.5 million per year of Corporate Management Costs, incremental to those incurred before the transformation of the parent holding company, are being allocated for recovery from transmission and distribution ratepayers when the delivery of essential delivery services by Networks remains essentially as it was before that transformation.

The OEB finds that the significant increases in compensation levels for senior executives and for members of the Board of Directors that Hydro One Limited has introduced have not been justified for recovery in OEB regulated rates for transmission services.

The OEB is also concerned that Hydro One’s progress towards bringing its total compensation levels down to the market median has now reversed. The Mercer Report indicates that a reduction in compensation amounts of about $12.5 million is required to bring compensation levels to that median. Moreover the OEB agrees that Hydro One’s total compensation amounts are likely understated because not all items of Hydro One compensation were included therein. The OEB accepts that there is likely some overlap between the estimates made by Mercer and WTW, as Hydro One suggests, but probably not a great deal of overlap because of the different categories of employees that were considered in each report.

The OEB appreciates that a portion of total compensation costs are in capital budget amounts included in transmission capital projects. The OEB’s reduction in the envelope amounts for the capital budgets for 2017 and 2018 will have some compensation reduction impact. That said, Hydro One has considerable flexibility to adjust and manage any compensation reduction impacts of the capital budget envelope reductions.

[81] Exhibit I/Tab 4/Schedule 12, p. 2
[82] Exhibit C1/Tab 3/Schedule 3, p. 6
[83] Exhibit C1/Tab 3/Schedule 3, p. 4

After considering all of the evidence related to the amounts for compensation that Hydro One seeks to recover from transmission services ratepayers, the OEB finds that compensation amounts in the total OM&A envelopes for 2017 and 2018 of $412.7 million and $409.3 million are unreasonably high by an amount of approximately $15.0 million in each year.

These compensation envelope reduction amounts reflect the OEB's finding that Hydro One has failed to establish that the significantly increased levels of compensation for executives, directors and other managerial personnel should be recoverable from ratepayers. In the March 18, 2004 Union Gas Decision with Reasons[84] upon which Hydro One relies, the OEB stated:

> "The Board is in agreement with Union's use of incentive payments as a legitimate element of a total compensation package offered to attract and retain qualified managers and staff in a competitive market for human resources. The question which the Board must consider is the extent to which ratepayers benefit from, and should bear the cost of such payments."

The OEB has considered that question in this proceeding and, for the reasons already outlined, the OEB has found that incentive compensation weighted to deliver value to shareholders produces outcomes that are of little, if any, value to transmission services customers.

In making its findings to this effect the OEB has recognized that one regulatory response to incentives that are geared to deliver value to shareholders is to cap ratepayer exposure to such costs at 10% of base salary.[85] In this case the magnitude of these types of incentives is in amounts that are in several cases 100% or more of the base salary amounts. The incentives for the CEO operate to increase compensation by between four and five times the base salary amount which, in and of itself, is more than the total compensation amount for the CEO's predecessor, including benefits.

Moreover, for ratemaking purposes, compensation cost recovery should continue to trend towards the market median. Similarly, pension contributions by the employer on behalf of the employees should continue to trend towards the 50:50 ratio.

Accordingly, for ratemaking purposes the OM&A envelopes will be reduced by $15.0 million in each year to $397.7 million for 2017 and to $394.3 million for 2018 to reflect the unreasonable levels of compensation sought to be recovered from ratepayers. The holding company should have greater responsibility for the compensation amounts that

[84] RP-2003-0063/EB-2003-0097
[85] Alberta Utilities Commission, 2011-2012 General Rate Application Phase I (Decision 2011-0450), December 5, 2011, para. 751

relate to its transformation and its commitments to increase shareholder value which are of little if any value to consumers of electricity transmission services. The Black and Veatch allocation methodology should not be applied to allocate to the operating companies of Networks transformation related costs at the holding company level that have little if any value to Networks' utility services customers.

7.3 OM&A (EXCLUDING COMPENSATION)

Apart from proposed compensation reductions, OEB staff and most intervenors suggested reductions in Hydro One's proposed OM&A budgets based on two main reasons:

- Proposed increased capital spending should result in reduced OM&A needs.
- Historical OM&A under-spending compared to approved levels.

7.3.1 Expected Decline in OM&A Costs as Capital Spending Increases

In its submission, OEB staff pointed out that Hydro One's Sustainment OM&A costs rise steadily over the 2012 to 2017 time- frame except in the bridge year, where a 2.6% decrease is shown. Staff notes that sustainment capital spending increases significantly in the test years.[86] As new assets replace older deteriorated assets at or near end of life, staff submitted that it is a reasonable expectation that Sustainment OM&A spending would be reduced to reflect that new assets require less operations and maintenance spending than older assets.

Staff argued that this factor seems not to have been reflected in the Sustainment OM&A budgets for the test years. Although the evidence as filed did not allow for staff to specifically quantify how much Sustainment OM&A spending should fall as a result of this capital investment, staff submitted that a reduction in the OM&A cost is warranted for the test years. Staff submitted that a 5% reduction in Sustainment OM&A ($12 million) is an appropriate reduction for each of the test years for this factor. Most intervenors supported this position with some (SEC) focusing more specifically on reductions in reactive and corrective maintenance.[87]

Hydro One argued that there was no justification provided for how this amount was arrived at and submitted that an arbitrary reduction will result in less work being

[86] Exhibit B1/Tab 3/Schedule 1
[87] SEC submission, pp. 60-61

completed with negative consequences. Maintenance cost efficiencies from historical sustainment investment are outweighed by other legitimate sustaining maintenance requirements.[88]

7.3.2 Consistent OM&A Spending Below Approved Levels

OEB staff's submission focused on Hydro One's response to a CCC interrogatory where actual OM&A spending performance is compared to the approved OM&A level each year from 2012 to the 2016 bridge year.[89] The response showed that in every year but 2015, Hydro One has spent less than the amount approved for recovery in rates. For 2012 the over-recovery is $12.1 million, for 2013, $11.6 million (adjusted by the unforeseen tax refund), for 2014, $50.3 million; for 2015 there is an over-spend of $10.4 million and in 2016 an under-spend of $4.7 million. This is an under-spend total of $68.3 million over 5 years, an amount that ratepayers have funded through rates but was not actually needed by Hydro One. The average under-spending is $13.6 million per year.

Staff also noted that in its response to BOMA Interrogatory 30, Hydro One provided its historical rate of return on equity from 2012 to 2015 showing that earnings exceeded the deemed amount embedded in its revenue requirement by 2.99%, 4.29%, 3.76% and 1.63% respectively. In addition, for the partially completed 2016 bridge year, the current estimate is 2.5%.[90] While other factors are also in play, staff suggested that a significant portion of the excessive ROE is the under-spending of OM&A over that period. As a result, staff submitted that this consistent historical under-spending by Hydro One should result in an additional adjustment to OM&A totals for each of the two test years in the range of $15 million.

Intervenors generally supported the submissions of staff on this issue, with several suggesting even greater reductions.

In its reply submission, Hydro One submitted that staff's submission amounted to unlawful retroactive ratemaking and argued that an attempt to recoup funds from past periods by adjusting future periods effectively amounts to retroactive ratemaking. Hydro One added that the approach suggested by staff has no legal basis and should be rejected by the OEB. Hydro One also pointed out that in 2014, insurance proceeds amounting to approximately $10 million were included as a credit to actuals but that this was not included in staff's calculation. If this was properly included, the average under-spend would be approximately $11.6 million.

[88] Hydro One Reply Argument, pp. 67-68
[89] Exhibit I/Tab 13/Schedule 25
[90] TR Vol. 1, p. 85

7.3.3 Proposed Reductions (Excluding Compensation)

OEB staff summarized its total proposed reductions in its submission, acknowledging that overall OM&A costs are dropping slightly over the bridge and test years. However, staff also pointed out that increasing capitalization of OM&A costs (as shown in the "other" category) can lead to a masking of actual operational increases.

Summarized areas related to OM&A excluding compensation included:

- A reduction of 5% or $12 million in each test year would be appropriate for Sustainment OM&A, to reflect the impact of higher capital spending and resulting OM&A savings
- Consistent past OM&A under-spending by Hydro One which should result in a further reduction to OM&A totals for each of the two test years in the range of $15 million

Findings

The OEB has imposed a total reduction in the proposed capital budget for both test years of approximately $248 million which would likely put some pressure on Hydro One's OM&A programs. Therefore, the OEB finds that a further reduction in the non-compensation component of transmission-related OM&A would not be appropriate at this time. It is important that Hydro One continues to maintain the appropriate level of operational and maintenance effort to keep its assets in a condition that serves its customers in the long term.

On the historical under-spending trend issue, and as a matter of principle, the OEB does not agree with Hydro One's assertion that consideration of historical OM&A spending patterns to inform prospective decision making would amount to retroactive ratemaking[91]. The reasons for, and analysis of, historical variances do assist the OEB in assessing the appropriateness of proposed future expenditure levels. Hydro One's statement that adjustments of future spending proposals based on historical performance would be an "attempt to recoup funds from past periods by adjusting future periods" is a mischaracterization.[92]

[91] The OEB can consider the appropriateness of an intervenor or OEB staff spending envelope proposal lower than the amount that an applicant asks the OEB to approve without that lower amount having been presented to the utility witnesses during their cross-examination. The OEB does not accept Hydro One's submissions in paragraph 152 (p.51) of the reply submission to the opposite effect.
[92] Hydro One Reply Argument, p. 69

The OEB is concerned about Hydro One's historical pattern of OM&A under-expenditure since 2012. If Hydro One follows a rigorous process of identifying its OM&A work requirements in the planning stage, it is OEB's expectation that this work will be executed unless unavoidable circumstances arise. If the under-expenditure is primarily due to more efficient execution of the planned work than anticipated, the OEB would certainly consider that in a positive light. On the other hand, if the under-expenditure is due to insufficient resources to execute the necessary work, this would be an indication of improper planning and will likely result in an unjustifiable compounded increase in OM&A needs in future years.

In future applications, the OEB directs Hydro One to provide a high level description of the main contributors to any material variance between approved and actual total OM&A expenditures in previous applications and the impact of those variances on its longer-term ability to operate and maintain its assets. This information would enable the OEB to determine if there are fundamental issues affecting Hydro One's ability to complete the planned work program and the potential impact of these issues on future proposed work programs.

Despite its concerns about historic transmission OM&A under-spending, the OEB finds that total OM&A envelopes (including compensation) of $397.7 million for 2017 and $394.3 million for 2018 are appropriate for determining Hydro One's transmission rates revenue requirements for those years. The OEB finds that these envelope amounts will cover reasonably incurred costs of operating and maintaining the transmission system at a level that meets the needs of Hydro One's transmission services customers.

8.0 DEPRECIATION

Hydro One proposed to recover $424.0 million in depreciation and amortization expense in 2017 and $460.6 million in 2018. As in past cases, the depreciation and amortization expense for Hydro One's submission for 2017 and 2018 transmission revenue requirements was supported by an updated study conducted by Foster Associates Inc.[93]

Only the LPMA made submissions on Hydro One's depreciation forecast, arguing that this forecast is systematically biased in favour of the shareholder, at the expense of ratepayers. As in the case of OM&A, the depreciation and amortization expense on an actual basis has been less than the OEB approved amounts for each year in the 2012 through 2016 period.

The over-forecasting amounts to $25.4 million on average over this period or 6.8%. In the response to LPMA technical conference question # 3[94], Hydro One stated that the variances noted in depreciation and amortization expense relative to the OEB approved figures are mainly due to lower in-service additions over this period, with some additional impacts related to asset removal costs and environmental expenditures.

LPMA submitted that these are the only sources of the variance, given that Hydro One has indicated that it uses the same depreciation methodology for accounting, regulatory and planning purposes and that it uses the half year rule for calculating depreciation in the year that an asset is placed into service.[95] In other words, regardless of when an asset is placed into service in any given year, the amount of depreciation recorded is the same.

Asset removal costs and environmental expenditures represent less than 10% of the total depreciation and amortization expense in the 2012 through 2016 period.[96]

LPMA submitted that the depreciation variance is, therefore, primarily the result of lower in-service additions than approved by the OEB. This has resulted in ratepayers paying more than $25 million per year for an expense that did not materialize. Similar to the OM&A bias, the depreciation variance has been consistently in favour of the shareholders at the expense of the ratepayers.

Based on the consistent over estimation of the depreciation and amortization of expense by Hydro One in the 2012 to 2016 period, LPMA submitted that the OEB

[93] Exhibit C1/Tab 7/Schedule 1, Attachment 1
[94] Exhibit TCJ1.10
[95] Exhibit I/Tab 4/Schedule 17
[96] Exhibit C1/Tab 7/Schedule 1/Tables 1 and 2

should reduce the applied for depreciation and amortization expense of $435.7 million in 2017 and $470.7 million in 2018 by 6.8% in each year. This percentage is the average level of over-forecasting in the 2012 to 2016 period shown in the above table. This would result in a reduction in the 2017 and 2018 test year expense of $29.6 million and $32.0 million, respectively.

In its reply submission, Hydro One argued that LPMA's recommendation is essentially retroactive rate making and should be rejected by the OEB.[97] It ignores the facts with respect to the actual in-service balances being tracked in the in-service variance account which shows a positive cumulative balance over the three year period. This demonstrates that Hydro One has corrected the under achievement of OEB approved levels. Hydro One's response to SEC Interrogatory 64 shows that the 3-year cumulative value is a positive $167.4 million.

Findings

In its findings related to Hydro One's TSP and capital expenditures, the OEB has noted its concern about Hydro One's ability to complete its proposed capital program in a manner that is compatible with its capital expenditure and in-service additions budgets. As a result of these concerns, the OEB has directed Hydro One to provide a report detailing its performance at the program level in terms of overall expenditures and in-service additions compared to the approved plan.

The OEB's expectation is that, going forward, the requirement to provide performance reporting of this nature will tend to prompt a better alignment between annual budgeted and actual capital expenditures and in-service additions. The OEB finds that the combination of these new reporting requirements and the continuance of the "In-Service Capital Additions Variance Account" is a sufficient response to the concern raised by LPMA in its submissions related to Hydro One's historic over-collection from ratepayers of depreciation expenses. The matter can be revisited in Hydro One's next transmission rates application if these measures fail to prompt the desired outcome.

For these reasons, the OEB finds, except for any changes to depreciation expenses that stem from the reduced capital expenditures approved for 2017 and 2018, there will be no further adjustments to the depreciation amounts proposed by Hydro One.

[97] Hydro One Reply Argument, pp. 87-88

9.0 LOAD AND REVENUE FORECASTS

9.1 LOAD FORECAST

In its evidence, Hydro One presented its transmission system load forecast and the related methodologies used to determine its load forecast. The key forecast that underlies the transmission rates is the hourly demand load forecast by customer delivery point, which is used to define the forecast charge determinant for the three transmission rate pools: Network, Line Connection, and Transformation Connection.

Hydro One indicated that the load forecast in support of the application was prepared in March 2016, using economic and forecast information that was available in March 2016. The forecast is shown in Table 9-1. Hydro One worked with the IESO, using their latest Conservation and Demand Management (CDM) assumptions and including the resulting impacts of CDM and embedded generation in the forecast amounts.

Table 9-1
Load Forecast

Hydro One 2017 and 2018 Load Forecast
12 Month Average Peak (MW)

Year	Ontario Demand	Transmission Rate Pools (Charge Determinants)		
		Network Connection	Line Connection	Transformation Connection
2017	20,373	20,405	19,741	16,872
2018	20,378	20,410	19,746	16,876

Source: Exhibit A/Tab 3/Schedule 1 and December 2, 2016 update, Table 4

Hydro One specified that it used econometric models, end-use models, customer forecast surveys and hourly load shape analyses to produce the forecast and that the overall methodology used was the same as for previous transmission rate applications. The forecast was weather normalized using weather conditions based on the average of the last 31 years.

Findings

The OEB has considered the concerns expressed by some intervenors about Hydro One's load forecasts for 2017 and 2018.These concerns pertained to:

a) The treatment of Demand Response (DR)
b) The historic CDM values used for modelling purposes
c) The historic and forecast energy prices
d) Weather normalization.

The OEB has also considered the issue raised by CME in its argument related to the definition of the system peak determinant for the Network Service Charge (NSC).[98]

Treatment of DR

The OEB finds that Hydro One's approach to removing the impact of DR Programs from the load forecasts for 2017 and 2018 is appropriate. The approach is one that is compatible with the OEB's directive in its EB-2006-0501 Decision with Reasons, August 16, 2007 calling for the removal of the impact of DR programs from weather normal load forecasts because such programs are most effective in weather abnormal circumstances. The Hydro One approach is also compatible with the fact that the IESO now provides LDC verified results that no longer include DR.

In these circumstances the OEB is not convinced that there is a need to direct Hydro One to revisit its treatment of DR programs in its next transmission rates proceeding.

Historic CDM Values Used for Modelling Purposes

The OEB finds that the historic CDM values that Hydro One used to derive its 2017 and 2018 load forecasts are appropriate.

The OEB agrees with VECC that the best information available at the time the load forecasts are prepared and filed should be used.[99] The OEB accepts that Hydro One used the IESO estimates that were available when the load forecasts were prepared and filed in this proceeding. The OEB is satisfied that it was reasonable for Hydro One to rely on these IESO estimates. The OEB is not convinced that the load forecasts for 2017 and 2018 need to be changed to reflect changes that the IESO made to its numbers subsequent to Hydro One's completion and filing of the 2017 and 2018 load forecasts in this proceeding.

[98] CME submission, p. 25
[99] VECC submission, p. 44

Historic and Forecast Energy Prices

The OEB finds that the historic and forecast energy prices used by Hydro One in the derivation of its 2017 and 2018 load forecasts are appropriate.

The OEB notes Hydro One's agreement with the principle expressed by VECC that actual and forecast values derived on a consistent basis from the most up to date information available should be used for load forecasting purposes. The OEB urges Hydro One to continue to adhere to that principle and to examine whether alternative data sets available from other organizations such as the National Energy Board or from those responsible for preparing the next Long Term Energy Plan can be used in the preparation of future load forecasts.

Weather Normalization

The OEB finds that Hydro One's use of 31 years of weather data to define normal weather conditions to be appropriate for the purpose of deriving its 2017 and 2018 load forecasts.

The OEB notes the evidence in SEC Interrogatory response 64 that shows that the Network, Line Connection and Transmission Connection load forecasts have not been consistently under-estimated in prior years as some intervenors contend. The OEB is not persuaded that the Network load forecast should be increased by 0.74 % as proposed by LPMA.[100]

Similarly, the OEB is not convinced that the 20 year weather trend produces more appropriate load forecasts for 2017 and 2018 as submitted by AMPCO.[101]

The OEB expects Hydro One to continue to evaluate the appropriateness of the use of 31 year weather trend in years beyond 2018 and, as time passes, to propose a different weather trend if the 31 year trend ceases to produce a reasonable correlation with actual loads.

Similarly, in future proceedings, intervenors and OEB staff can continue to seek data from Hydro One that enables them to evaluate whether the use of the 31 year trend data continues to be appropriate, or whether the actual data then available supports the adoption of a weather normalization period shorter than 31 years.

The OEB finds that these measures are sufficient to ensure that the duration of the weather normalization trend used to develop load forecasts for the years 2019 and beyond is appropriate. The OEB sees no need to direct Hydro One to provide its load

[100] LPMA submission, p. 16
[101] AMPCO submission, p. 47

forecasts in future proceedings on the basis of both a 31 year and 20 year trend as AMPCO proposes.

Definition of System Peak Determinant for the Network Service Charge (NSC)

The OEB notes Hydro One's willingness to provide a report in its next transmission rates case that will address how the NSC determinant might be modified to respond to the concerns raised by CME in its argument.[102] The OEB appreciates that any modifications of the type suggested by CME will necessarily involve cost responsibility shifts from one class of customers to other classes. Without in any way prejudging the issue, the OEB finds that it would be assisted by the report that Hydro One has offered to provide and directs that this report be provided in Hydro One's next transmission rates case.

9.2 REVENUE FORECAST

Hydro One updated its cost of capital and overall revenue requirement for the test years on December 2, 2016. The update included a rates revenue requirement of $1,487.4 million for 2017 and $1,558.4 million for 2018.

The requested rates revenue requirements reflect a year-over-year increase of 0.5% for 2017 versus 2016 OEB-approved levels and 4.8% for 2018 versus 2017.

The estimated total bill increases arising from this application are:

a) 0.1% in 2017 and 0.2% in 2018 for a general service energy customer (2000 kWh/month)

b) 0.1% in 2017 and 0.2% in 2018 for medium density residential (750 kWh/month)

c) 0.2% in 2017 and 0.4% in 2018 for transmission connected-customers (assuming transmission represents 8.3% of the average total bill).[103]

Hydro One earns certain other revenues through the provision of services to third parties. These revenues are forecast to be $28.2 million in 2017 and $28.5 million in 2018. These revenues account for approximately 1.8% and 1.7% of Hydro One transmission revenues for 2017 and 2018 respectively and offset Hydro One's revenue

[102] CME submission, pp. 25-27 and Hydro One Reply Argument, p.106
[103] Hydro One Argument-in-Chief, p. 6

requirement, thereby reducing the required revenue to be collected from transmission ratepayers.

The major categories of other revenues include secondary land use, station maintenance, engineering and construction and other (telecom services, special planning studies, customer shortfall payments and leasing of idle transmission lines).

Findings

The OEB considered the submissions made by those parties who addressed the matters related to: total bill impacts; and other revenue (excluding Export Transmission Service (ETS) revenue). ETS revenue is addressed below in the section entitled Export Transmission Service Rates.

Total Bill Impacts

The OEB agrees with those who argue that insignificant total bill impacts do not, in and of themselves, establish that the applied for revenue requirements and rates for 2017 and 2018 are just and reasonable. The OEB recognizes that the total bill impacts of transmission rate increases will tend to be relatively low because transmission rates are such a small component of the total bill.

Other Revenue (excluding ETS Revenue)

The OEB finds Hydro One’s estimates of the components of Other Revenue (excluding ETS Revenue) for 2017 and 2018 to be appropriate. The OEB notes that, under the assumption that variance account protection will continue for External Secondary Land Use Revenues and for External Station Maintenance, Engineering & Construction and Other External Revenues, no parties had any objections to the level of these estimates.

10.0 COST ALLOCATION

In Hydro One's previous transmission rate application[104], the OEB approved Hydro One's methodology to allocate the transmission rates revenue requirement into four rate pools: Network, Line Connection, Transformation Connection and Wholesale Meter. In this application, Hydro One proposed to simplify the allocation process by eliminating the Wholesale Meter rate pool and allocating the rates revenue requirement into the Transformation Connection rate pool. Other than this change, the cost allocation methodology has not changed from what was approved by the OEB in the previous case.

The allocations to each rate pool are shown in Table 10-1 below:

Table 10-1
Rates Revenue Requirement by Rate Pool
2017 and 2018

Revenue Requirement (Year)	Network	Line Connection	Transformation Connection	Total
2017	$ 843.0	$ 211.7	$ 432.4	$ 1,487.1
2018	$ 883.0	$ 222.5	$ 452.7	$ 1,558.1

Source: Exhibit A/Tab3/Schedule 1, December 2, 2016 Update

Findings

The OEB notes that no party objected to Hydro One's cost allocation proposals and that VECC and LPMA supported, as reasonable, the simplification to the cost allocation process contained in Hydro One's proposal.

In these circumstances the OEB finds the transmission cost allocation proposed by Hydro One to be appropriate.

[104] EB-2014-0140

11.0 DEFERRAL AND VARIANCE ACCOUNTS

In this application, Hydro One applied for approval of 14 deferral and variance accounts, requesting disposition of nine of these accounts in the test years for a reduction to the rates revenue requirement of $47.8 million in each of the two test years. Hydro One was not seeking continuance of the LDC CDM and DR Variance Account. No new deferral or variance accounts were requested.

The accounts for which disposition was requested are shown in Table 11-1 below. These amounts are the actual audited Regulatory Account values as at December 31, 2015, plus forecast interest accrued in 2016, on the principal balances as at December 31, 2015 less any amounts approved for disposition in 2016 in EB-2014-0140. Disposition was requested to begin on January 1, 2017.

Table 11-1
Regulatory Account Balances for Disposition
$ Millions

Description	Forecast Balance as at Dec. 31, 2016	
Excess Export Service Revenue	-$	18.5
External Secondary Land Use Revenue	-$	26.7
External Station Maintenance and E&CS Revenue	$	0.7
Tax Rate Changes	$	0.1
Rights Payments	-$	3.0
Pension Cost Differential	$	6.0
Long-Term Transmission Future Corridor Acquistion and Development	$	0.6
CDM Variance	-$	54.0
External Revenue - Partnership Transmssion Projects	-$	0.9
Total Regulatory Accounts	-$	95.6

Source: Evidence Update, December 2, 2016

LPMA objects to the discontinuance of the LDC CDM and DR Variance Account if the OEB does not approve its proposed adjustment to the load forecast.

OEB staff proposed a new variance account to track the difference between the accrual method and the cash method of accounting for other post-employment benefit costs (OPEB costs or OPEBs) in 2017 and 2018. The purpose of this proposal is to allow a future OEB panel on Hydro One's next cost-based rate case to apply the outcome of the OEB's generic consultation on the regulatory treatment of Pension and OPEBs costs. The OEB has since released its Pensions and OPEBs Report on September 14, 2017 which favoured the use of accrual accounting as the basis for recovering these costs.[105]

EP proposed that a new deferral account be established to allow the recording of incentive compensation amounts when the outcomes on which these incentive amounts are based have actually been achieved.[106]

VECC submitted that a minor adjustment is required to the balance recorded in the LDC CDM and DR Variance Account and also sought an OEB directive to Hydro One to use, as the starting point for the interest calculation for this account, the year in which the impacts occur rather than the following year when the impacts are posted.[107]

The In-Service Capital Additions Variance Account is one of the four accounts that Hydro One is not proposing to clear at this time. LPMA sought to assure that wording of the continued account is substantively the same as the existing account so that it captures the revenue requirement impacts in 2017 and 2018 of any negative in-service additions variance from the $911.7 million in service additions forecast for 2016 that is embedded in the forecast amounts for 2017 and 2018 rate base.[108]

LPMA contended that without wording to this effect, any negative variance amount resulting from actual 2016 in-service additions in an amount less than $911.7 million will automatically lead to over-earnings in 2017 and 2018. LPMA disagreed with Hydro One's submission that LPMA's proposal amounts to a double counting of 2016 in-service additions, for in-service variance account purposes.

Findings

Balances in Accounts to be Cleared

The OEB accepts that the balances in the existing deferral accounts to be cleared are as proposed by Hydro One.

The OEB will not adjust the balance in the LDC CDM and DR Variance Account as proposed by VECC. The balance in that account is about $54 million. The first adjustment that VECC proposes in its submissions is a "minor" correction that Hydro One says will have a negligible effect on the $54 million balance in the account. VECC

[105] Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs, EB-2015-0040, September 14, 2017
[106] EP submission, p. 33
[107] VECC submission, pp. 49-50
[108] LPMA submission, p. 18

has not provided any information to establish the amount of the adjustment that it is proposing. In these circumstances, the OEB will not require Hydro One to make such a negligible adjustment.

The second item of relief that VECC seeks is to have the OEB direct Hydro One to include in the account, interest calculated from a date that precedes the earliest date that information is available to determine the amounts to be recorded.

The OEB will not require interest to be paid on amounts from a date earlier than the date on which the principal amount to be recorded in the account can first be determined. Ratepayers would not be in a position to make a demand for any amount owing before the information needed to quantify that amount was available. Before that information is available no quantifiable account payable exists.

Interest normally runs from the date that a quantifiable demand can be made. The OEB finds VECC's proposed interest calculation commencement date to be incompatible with this normal commercial practice.[109]

The OEB finds the amount recorded in this account by Hydro One to be appropriate.

Closure or Continuance of the LDC CDM and DR Variance Account for 2017 and 2018

The OEB finds that this account should not be closed at this time as proposed by Hydro One. The account was forecasted to generate a significant credit for ratepayers to the end of 2016 and these variances should continue to be recorded by Hydro One for the next two years. The OEB realizes that the IESO will no longer be providing actual peak savings information in those years. However, this fact should not automatically lead to the closure of the variance account. The OEB directs Hydro One to use its best efforts to obtain from other sources the peak savings information that it needs to determine the variances to be recorded in this account.

Continuance of Other Existing Accounts

The OEB approves the continuance in 2017 and 2018 of the other existing deferral accounts that Hydro One seeks to have continued subject to a requirement that the wording for the 2017 and 2018 In-Service Capital Additions Variance Account will be varied to address the legitimate concerns raised by LPMA.

[109] The OEB notes that the accounting order for this deferral account calls for interest on the deferral account to be recorded on the opening monthly balance in the account. This language effectively recognizes that no interest is to be recorded before the information is available to quantify the amount payable.

The OEB finds that the wording proposed by Hydro One for this variance account needs to be modified so that there is recorded in the account the revenue requirement impacts in 2017 and 2018 of the difference between forecast 2016 in-service additions embedded in 2017 and 2018 rate base and actual 2016 in-service additions that are less than $911.7 million. The OEB finds that wording to this effect is required to achieve the spirit and intent of this variance account which is to prevent Hydro One from realizing overearnings in future test years from forecast bridge and test year in-service additions embedded in test year rates when those forecast additions are not achieved.

The OEB finds that there is no double counting as Hydro One contends. The $911.7 million forecast for 2016 in-service additions has relevance in this proceeding for two separate and distinct purposes.

The first purpose for which the amount has relevance is to determine whether there is anything to be recorded in the in-service additions variance account for the period ending December 31, 2016. The 2016 in-service addition amount embedded in the 2016 revenue requirement determined in 2014 in the EB-2014-0140 proceeding was $673.3 million. The 2016 forecast in-service additions amount of $911.7 million, being a positive variance currently estimated to be $238.4 million, will be brought into the account for the purpose of determining whether there is any cumulative negative amount as of December 31, 2016 that will lead to an amount as of December 31, 2016 to be cleared to ratepayers.

The other separate and distinct purpose for which the $911.7 million amount for 2016 also needs to be brought into account is to establish the 2016 bridge year in-service additions amount that is embedded in 2017 and 2018 test year revenue requirements and around which the cumulative in-service additions variance account for the period 2017 and 2018 will operate.

Hydro One is directed to modify the language of the proposed in-service variance account for 2017 and 2018 to include the impact in 2017 and 2018 of negative variances between the 2016 forecast in-service additions of $911.7 million and the actual 2016 amounts. The OEB is of the view that the language proposed by LPMA needs to be revised to achieve this outcome. The language to be used to describe the account should be to the following effect:

“To record the impact on 2017 and 2018 Transmission Revenue Requirement due to an actual amount for 2016 in-service additions that is less than $911.7 million; along with the difference between the 2017 and 2018 in-service additions embedded in 2017 and 2018 rate base and actual in-service additions in each of those years.”

The OEB notes that in this case, Hydro One is proposing that no annual entries will be made to this transmission revenue requirement variance account. This proposal contrasts with the language of the currently approved account for the period ending December 31, 2016 which calls for the revenue requirement credit amounts, if any, to be made and updated annually. The OEB sees no reason to depart from the requirement that any revenue requirement credits stemming from the operation of this account be conducted annually for each of the years ending December 31, 2017 and 2018.

New Deferral Accounts

- Pension and OPEBs Variance Account

In the Accounting Issues chapter of this decision the OEB has described and applied the principles, practices and policy determinations adopted in the OEB's September 14, 2017 Pension and OPEBs Report to approve Hydro One's continuing use of the cash method to recover its pension costs and the accrual method to recover its OPEBs costs, in 2017 and 2018.

The OEB directs Hydro One to establish a variance account that will operate prospectively from January 1, 2018 and is compliant with the provisions of the Pension and OPEBs Report to track the differences between the accrual costs for OPEBs included in rates and the cash payments that would be payable under the auspices of the cash method of accounting for such costs.

- Incentive Payments Deferral Account

The OEB will not establish a new deferral account to allow the recording of incentive compensation amounts for clearance later when it is known whether the outcomes on which the incentive payments depend have actually occurred, as proposed by EP. The issue of the extent to which incentive compensation should be recoverable in transmission rates has been fully addressed in the compensation section of Chapter 7.0 of this Decision and Order.

- Foregone Transmission Revenue Deferral Account

In the Implementation chapter of this Decision and Order, the OEB has established a Transmission Revenue Deferral Account to facilitate the recovery of transmission revenue between the effective date and the implementation date that the OEB has established for the Revenue Requirement and Charge Determinant Order arising from this proceeding.

12.0 FIRST NATIONS PERMITS

As part of the OM&A cost evidence, Hydro One included information on costs incurred through agreements or permits granted by the Department of Indian and Northern Affairs, Canada (INAC). Hydro One has approval for its transmission and distribution facilities (lines, transformer and distribution stations), to cross and/or occupy First Nation Reserves. Some of these permits and agreements require Hydro One to pay annual rental fees, the payment of which are administered by INAC.

The transfer orders by which Hydro One acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer title to some assets located on lands held for First Nations under the *Indian Act* (Canada).

The transmission portion comprises approximately about 82 kilometers of transmission lines, primarily held by the Ontario Electricity Financial Corporation (OEFC). Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of them to Hydro One. Hydro One is seeking to obtain the consents necessary to complete the transfer of title to these assets. First Nations rights payments for the 2017 and 2018 test years are budgeted to be $1.5 million per year.

In cross examination, Hydro One indicated that there is currently a process underway for negotiating new agreements with the First Nations. Until a new agreement is negotiated, Hydro One continues to pay First Nations for the assets on their reserves based on previous agreements that have expired.[110]

Findings

The OEB finds that Hydro One should continue to work diligently with affected First Nations to resolve outstanding permit issues in a timely manner with the objective of providing appropriate compensation while respecting First Nations rights.

[110] TR Vol. 8, pp. 174-176

13.0 NIAGARA REINFORCEMENT PROJECT

In the EB-2006-0501 transmission rates case, the OEB provided Hydro One with relief from the carrying charges that they would incur on the funds (debt) used to finance the Niagara Reinforcement Project (NRP). The NRP was not put into service as a result of a continuing land claim dispute in Caledonia, Ontario. At that time, the OEB did not put a limit on the period of time that Hydro One could recover the Allowance for Funds used During Construction (AFUDC) on the NRP.

As part of its revenue requirement evidence in this case,[111] Hydro One has applied for recovery for an amount characterized as "AFUDC recovery on Niagara Reinforcement Project". The amounts being sought for recovery are $4.6 million in each of the 2017 and 2018 test years.

Hydro One has been recovering these costs in rates for ten years, since January 1, 2007.

OEB staff submitted that Hydro One has not made any real progress in resolving the NRP issue over the past 10 years and stated that the time has come for the OEB to disallow this cost. Staff cited the principle that regulated utilities are required to face some risk in their business operations, and that they are compensated for risk through their return on equity. OEB staff concluded that there should be no further compensation unless the transmission line goes into service. Alternatively, if the OEB should decide that some compensation should continue, staff submitted that this should be done through a short-term interest rate.[112]

LPMA, CCC and CME supported the submissions of staff.[113] The Society noted that as this dispute is between the First Nations in the region and the Province, there is limited if any ability for Hydro One to resolve this dispute, allowing it to complete and put its transmission line into service. Therefore, Hydro One should continue to recover the carrying costs.[114]

In its Reply Argument, Hydro One indicated that discussions continue to resolve the issues associated with placing the asset in service, but there is no timeframe for resolution. Given that the OEB did not, in its EB-2006-0501 decision, approve a specific timeframe in which AFUDC recovery would be permitted, and given that the

[111] Exhibit E2/Tab 1/Schedule 1
[112] Staff submission, p. 33
[113] LPMA submission, p. 8, CCC submission, p. 25 and CME submission, p. 12
[114] Society submission, p. 5

circumstances have not changed, and remain largely outside of Hydro One's control, Hydro One submitted that it should continue to receive recovery of its AFUDC costs in a manner consistent with EB-2006-0501.[115]

Findings

The OEB is not convinced that Hydro One has made sufficient effort over the last ten years to resolve issues associated with this project and to place the asset in service. While some aspects of the land claim dispute may be beyond Hydro One's control, the OEB believes that Hydro One can take a more active role in supporting the resolution of these issues.

The fact that the OEB's decision in the EB-2006-0501 rate case did not put a time limit on the recovery of carrying charges for this unfinished project does not mean that the relief provided by the OEB in that case was endless. As stated in that decision, the OEB's role is "to make decisions that are in the public interest and to determine an appropriate balance between the interests of the regulated utility and consumers." In the current proceeding, the OEB finds that it is not appropriate for the ratepayers to continue to be burdened with the carrying charges for capital expenditures that have not resulted in a used or useful asset.

The OEB will only allow for the AFUDC recovery requested for 2017 ($4.6 million) but not for 2018. It is the OEB's expectation that Hydro One will work diligently to assess and implement alternate means of resolving this issue in the longer term.

[115] Hydro One Reply Argument, p. 89

14.0 ACCOUNTING ISSUES

14.1 ACCOUNTING FOR PENSION AND OPEB COSTS

After the delivery of final arguments in this proceeding, the OEB released its Pension and OPEBs Report. This report establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications.[116]

The report recognizes that a method other than accrual accounting can be used if accrual accounting does not result in just and reasonable rates. One of the principles and practices that the report adopts is that the OEB will generally keep its treatment of pension and OPEB costs consistent over time for any given utility.[117]

The report requires utilities proposing to recover their pension and OPEB costs using a method other than the accrual method to support such proposals with evidence related to the principles and practices that the report adopts.

In conjunction with the use of the accrual accounting method, the Pension and OPEBs Report calls for a tracking account to be established to record the difference between costs calculated under the accrual method and being recovered in rates and the amounts that would be payable under the auspices of the cash accounting method over the same time period. Carrying charges at rates determined by the OEB, from time to time, will be applied to the differences recorded in the tracking accounts. These carrying charges will periodically be cleared to ratepayers.

With prior approvals from the OEB, Hydro One has, for many years, been using the cash accounting method to determine the amount of its pension costs to be recovered in rates. Hydro One has used the accrual accounting method to determine the amount of its OPEB costs to be paid by ratepayers. Hydro One proposes to continue to follow that same approach for the purpose of determining its pension and OPEB costs in its transmission revenue requirements for 2017 and 2018.

Findings

In accordance with the principles, practices and policy determinations adopted in the Pension and OPEBs Report, the OEB finds as follows:

a) Hydro One will continue to use the cash accounting methodology to recover its transmission related pension costs for 2017 and 2018.

[116] Pension and OPEB Report, p. 2
[117] Pension and OPEB Report, p. 4

b) If Hydro One proposes to continue using the cash method as the basis for recovering its pension costs beyond December 31, 2018, then, in its next transmission revenue requirement proceeding, Hydro One will provide evidence that addresses the principles, practices, and policy determinations in accordance with the provisions of the Pension and OPEBs Report.

c) Hydro One will continue to use the accrual accounting method to recover its transmission-related OPEB costs in 2017 and 2018.

d) Effective January 1, 2018, Hydro One will establish a tracking account for its transmission-related OPEB costs that is compliant with the provisions of the Pension and OPEBs Report.

14.2 CAPITALIZATION OF OVERHEAD COSTS

Using a recommendation contained in the 2016 Auditor General's Report as the point of departure, counsel for OEB staff questioned Hydro One's witnesses on the possibility of adopting Modified International Financial Reporting Standards (MIFRS) as the accounting standard for the capitalization of overheads, rather than continuing to apply United States Generally Accepted Accounting Principles (USGAAP) in the preparation of unconsolidated financial statements for Hydro One Limited.[118] In argument, OEB staff asked the OEB to mandate the adoption of the MIFRS standard for capitalization of overhead purposes.

The OEB previously approved the use of USGAAP for regulatory purposes in the OEB regulated transmission business in a decision in EB-2011-0268 issued on November 23, 2011.[119] In rendering that decision, the OEB considered the fact that the MIFRS accounting standards allow a capitalization of overheads in an amount materially lower than that permitted under USGAAP. In subsequent decisions the OEB authorized Hydro One's use of USGAAP for regulatory purposes in connection with its distribution business and its regulated electricity services for Hydro One Remote Communities.

Hydro One relies on these prior decisions to support its position that the accounting change proposed by OEB staff be rejected.

Hydro One Limited is positioning itself to be a large energy holding company with operating utility and other subsidiaries in Canada, the United States and perhaps

[118] TR Vol. 11, pp. 156 -162
[119] EB-2011-0268 Decision with Reasons, November 23, 2011

elsewhere. Its wholly owned subsidiaries such as Networks conduct their financing and other business activities in markets in the United States and elsewhere.

The OEB has previously approved the use of USGAAP for regulatory purposes by Enbridge Gas Distribution Inc. and Union Gas Ltd. These large utilities are wholly owned subsidiaries of large energy holding companies that carry on business, including financing activities, throughout North America and elsewhere.

Findings

The OEB finds that it has not been demonstrated in this proceeding that material changes in circumstances have occurred since the OEB rendered its prior decisions for Hydro One approving its use of USGAAP for regulatory purposes. That said, the OEB shares the concerns of those who question the continued appropriateness of the large capitalization amounts that USGAAP allows compared to the amounts allowed under MIFRS regulatory accounting purposes.

Hydro One's use of USGAAP for regulatory purposes in connection with its 2017 and 2018 rates revenue requirements, including the capitalization of overheads, will not be varied at this time. Separate and apart from this proceeding, the OEB will consider whether it should initiate a policy review of the appropriateness of the continued use by the utilities it regulates of USGAAP for the purpose of determining the capitalization of overhead amounts.

15.0 TAXES INCLUDING THE ALLOCATION OF FUTURE TAX SAVINGS

15.1 OVERVIEW

Upon the Province's sale of more than 10% of its shares in Hydro One Limited, that company and its subsidiaries, including Networks, became subject to federal income tax legislation. Concurrently, those companies ceased to be taxable under the provincial Payment in Lieu of Taxes (PILs) regime, except for their exposure to a departure tax liability under that legislation.

Immediately prior to the initial share sale, the Province created[120] a transaction to fund the payment by Networks and the other Hydro One Limited subsidiaries of their departure tax liabilities even though other means were available to the Province to eliminate that liability. The elimination of the departure tax prevented this liability from impairing the market value of the shares that the Province subsequently sold to members of the public.

Under the terms of the now applicable federal tax legislation, Hydro One Limited was, at the time of the completion of the IPO, deemed to have sold and reacquired all of its assets at fair market value (FMV).[121] At the time of the conclusion of the argument phase of these proceedings in February of 2017, a 29% interest in those assets had actually been sold at FMV and paid for by new share purchasers. With the Province's further sale of shares in the spring of this year, about 51% of the shares of Hydro One Limited have actually been sold to new share purchasers at FMV.

As a consequence of the Province's initial November 2015 IPO sale of about a 15% interest in Networks' assets and the "deemed" sale and reacquisition of the remaining 85% interest that the Province then held, the eligible asset values used for the purposes of calculating Networks' future income taxes increased from their pre-sale tax values to their FMV at the time of sale. These actual and deemed increases in the tax values of these assets then became available to provide Networks with substantial savings in cash taxes payable in years beyond November 2015.

Capital Cost Allowances (CCA) under federal tax legislation are a source of significant tax benefits. CCA are effectively accelerated depreciation rates specified under the auspices of income tax legislation. These rates apply to a taxpayer's capital costs of

[120] TR Vol. 11, p. 44, lines 27-28
[121] This was the same kind of "deemed "acquisition at FMV transaction by distribution utilities from themselves that was the subject matter of the OEB's RP-2004-0188 Report.

different classes of capital assets. The CCA percentage rates are materially higher than the accounting rates of depreciation that apply to those assets.

CCA is used by a taxpayer to calculate taxable income and the consequential cash taxes payable. CCA "depreciation" percentages and amounts are higher than accounting depreciation rates and amounts. As noted, these higher rates and amounts produce cash taxes payable that are materially lower than tax amounts derived from accounting rates of depreciation to produce accounting net income. However, as time passes, the spread between CCA based taxable income and cash taxes and accounting net income and taxes narrows. The point in time in the future when CCA based taxable income and cash taxes become greater than accounting net income and taxes, is referred to as "crossover".[122]

The original cost of an asset less the cumulative year-over-year CCA amounts that have been deducted for the purpose of calculating income taxes constitutes the "tax cost" of the asset.

Upon an actual or "deemed" sale of CCA eligible assets at a FMV that is higher than the pre-sale tax cost for those assets, the difference in value between the sale price and the tax cost (FMV Bump) is available to the asset owner to provide CCA related tax savings in the future.

Actual and/or "deemed" sale values falling between the pre-sale tax cost and original cost constitute "recaptured" CCA eligible capital costs. These amounts, previously used to provide tax savings in prior years, can be reused by the asset owner to produce CCA related tax savings in future years.

Actual and/or "deemed" sale values in excess of original cost are also available to the asset owner to produce CCA related tax savings in future years. However, these values

[122] The following example illustrates the points discussed in the preceding 3 paragraphs. Assume that the CCA rate for a particular asset with an economic life of 50 years is 5%. The accounting depreciation rate for an asset with a 50 year life expectancy will be 2%. Assume straight line depreciation. Assume a capital cost for the asset of $200 and that the asset will generate a constant $10 per year of net income before depreciation or CCA.

- Using CCA of 5% the deduction from income is $10 leading to no income and no taxes payable for years 1 to 20 when the asset will be fully depreciated under CCA. For years 21 to 50 the annual income will be $10 which produces annual taxes payable of $2.50 per year for 30 years. Over the 50 year life of the asset the total taxes payable will be $75.

- Using accounting income and the 2% depreciation rate, the income in each of the years 1 to 50 will be $6. Tax at 25%, being an amount of $1.50, for years 1 to 50 is a total of $75 over the economic life of the asset.

- Over the total life of the asset, the taxes paid under CCA and accounting depreciation will be the same. However, tax savings under CCA versus accounting depreciation in years 1 to 20 are $1.50 per year for a total of $30. Crossover occurs at the end of year 20. In years 21 to 50, taxes under CCA are at $2.50 per year and exceed taxes under accounting depreciation by $1 per year for a total of $30. The savings realized in years 1 to 20 are paid back in years 21 to 50.

are not "recaptured" values; they are new capital cost values attributable to the "gain" over original cost. In the fixing of rates for regulated utilities, the amount of income taxes recoverable in rates is materially influenced by an allocation of CCA produced tax savings between utility ratepayers and shareholders.

In the RP-2004-0188 proceeding more particularly described below, the OEB agreed that future tax savings attributable to recapture should be allocated to shareholders.[123] The OEB also determined that future tax savings attributable to increases in tax value that are "costless"[124] to the utility owner are to be allocated to ratepayers.

The sections that follow elaborate upon the OEB's consideration of the foregoing factors to determine the extent to which Networks' future tax savings stemming from the FMV Bump are to be allocated between its shareholders and ratepayers.

15.2 ACTUAL VERSUS HYPOTHETICAL INCOME TAXES

For years Networks' transmission rates have been based on the recovery from ratepayers of estimates of the actual income taxes that Hydro One expected to pay in the rate-setting test periods. OEB precedent decisions reflecting its preference for adhering to the inclusion of actual tax estimates in rates include its RP-2004-0188 Report[125] and decisions made many years ago adopting flow through tax accounting for gas distributors including a requirement that Union Gas Limited transition from the normalized method that it was then using to calculate income taxes recoverable in rates to the flow through or cash method of tax accounting.

In this proceeding Hydro One asks the OEB to approve rates that will recover "regulatory" income tax amounts of $81.9 million and $89.6 million in 2017 and 2018 respectively.[126] Hydro One's application also seeks approval of property taxes for 2017 and 2018 of $63.4 million and $64.3 million respectively. No one questioned the reasonableness of these forecasts of property taxes.

The "regulatory" income taxes amounts that Hydro One proposes to recover in rates are hypothetical or notional sums. These notional amounts reflect Hydro One's proposal to allocate to shareholders 100% of the future tax savings available to Networks as a

[123] May 2005 Report
[124] "Costless" is the word used by Hydro One on page 71 of its Argument-in-Chief.
[125] See RP-2004-0188 Report at page 46 where the OEB states: "The tax rates and tax rules used….should reflect to the extent possible the actual rates and rules that will be applicable…" and "Rates must be just and reasonable, and any substantial variation between taxes determined for regulatory purposes and actual taxes paid…must be justifiable."
[126] December 2, 2016 update and TR Vol. 11, pp. 46-51 and p. 81 where the evidence indicates that these are the grossed up amounts tax amounts.

result of the “deemed” FMV Bump in the value of its CCA eligible assets that occurred with the partial sale of about 15% of the shares of Hydro One Limited at the time of the IPO. This “deemed” transaction occurred as a result of the Province’s IPO at the beginning of November 2015 of about 81,100,000 of its 595,000,000 common shares of Hydro One Limited.[127]

The actual amounts for federal income taxes that Networks will pay in 2017 and 2018 will be zero; and would be zero for Ontario tax, but for its minimum tax provisions.[128] The minimum Ontario income tax amounts that Networks expects to pay in 2017 and 2018 are $12.2 million and $13.1 million respectively.[129]

Hydro One is effectively seeking the OEB’s approval for its plan to recover from the transmission and distribution ratepayers of Network, in future years, notional or hypothetical income taxes in a total amount of about $2,595 million more than the amount of taxes actually payable in those years. About $1,475 million of this notional total amount relates to transmission service. The remaining $1,120 million relates to distribution service.[130]

The significant difference between taxes collected in rates and the actual amounts payable to the tax authorities after the IPO is reflected in the 2016 numbers for Networks. The utility collected $120.9 million in 2016 transmission and distribution rates. It actually paid $19.7 million to the tax authorities.[131] The difference of $101.2 million is available to Hydro One Limited to support its delivery of value to shareholders in excess of the OEB’s allowed ROE.

At issue is the appropriateness of the proposal to allocate to shareholders 100% of the future tax savings that became available as a result of the FMV Bump.[132]

15.3 NETWORKS’ FUTURE TAX SAVINGS ARE SUBJECT TO OEB ALLOCATION

The issue in this case is one of “allocation” of the FMV Bump related benefits between shareholders and ratepayers, just as it was in the RP-2004-0188 proceeding. Hydro One’s use of the words ”exclusion’’ and “unregulated” to describe matters related to its proposal does not alter the nature of this issue as one of allocation. The request is for

[127] Oct 31, 2015 Prospectus, Exhibit I/Tab 9/Schedule 2
[128] See Financial Accountability Office (FAO) Assessment of the Financial Impact of the Partial Sale of Hydro One at page 27 referenced in Exhibits J11.2 and J11.19
[129] Exhibit J2.10
[130] Exhibit J11.3
[131] Exhibit J11.19.
[132] In this Decision the phrase FMV Bump refers to the value of the CCA eligible assets shown in the “FMV in excess of Tax Basis” column of Exhibit J11.3. For Networks as a whole that amount is $9,794 million.

OEB approval of a 100% allocation to shareholders rather than a lesser percentage. The principles established in the RP-2004-0188 Report are to be considered and applied to determine this issue.

The business activities of Networks are, and will continue to be, limited to the provision of OEB regulated electricity and distribution services. Networks, currently and prospectively, stands alone as a pure utility. The “stand-alone “principle does not operate to change the nature of the issue to something other than an issue of “allocation”.

The determination of factors to be used in allocating costs or benefits between utility ratepayers and shareholders is a function that falls within the OEB’s ratemaking authority.

The operation of the utility as a going concern produces the cash flows that give rise to the FMV Bump in the tax values of Networks’ utility assets. These future tax savings are subject to OEB allocation as between shareholders and ratepayers. Any tax liability that is a derivative of these asset value increases is also a matter that the OEB can consider when determining this allocation issue. The extent to which such a tax liability influences this allocation is a matter for the OEB to determine. These items do not lie outside the ambit of OEB jurisdiction.

All matters relating to the allocation of the future tax savings, as between shareholders and ratepayers, fall within the scope of the OEB’s rate-making jurisdiction in this case just as they did in the RP-2004-0188 proceeding.

The issue to be decided in this case is how the principles expressed in the May 2005 Report are to be applied in a situation where the Province has only sold part of its ownership interest in Hydro One Limited and its subsidiaries including Networks. The sale transaction in this case is partly actual and partly “deemed”. Moreover, this combined actual and deemed sale transaction has triggered “recapture”.

15.4 OEB’S RP-2004-0188 REPORT

The FMV Bump discussed in the RP-2004-0188 proceeding occurred as a result of an October 1, 2001 directive from the Minister of Finance. That FMV Bump was not the result of any actual sale of an interest in utility shares or assets at FMV. It was the result of a transaction that the Minister had deemed to have taken place.[133]

[133] At page 67 of its Argument-in-Chief Hydro One characterizes this transaction as a “deemed” acquisition of assets at fair market value at October 1, 2001.

The OEB concluded that, where no costs relating to an actual sale at FMV had been incurred, the CCA tax benefits associated with the FMV Bump should be allocated, in their entirety, to utility ratepayers.

In this "costless" step-up in the tax value of Networks' assets scenario, the OEB found that the "benefits follow costs" principle does not apply. In the course of reaching that conclusion the OEB accepted that costless tax reductions will tend to lead to lower prices.[134] This finding lends support to an allocation to ratepayers of the CCA tax savings benefits associated with a "costless" FMV Bump. Put another way, tax benefits related to increases in the prevailing tax values of utility assets to FMV that are "costless" are allocated to ratepayers because, in competitive markets, such costless benefits tend to reduce prices.

The parties in the RP-2004-0188 proceeding raised and the OEB considered the effect of a subsequent sale of an interest in utility assets at FMV on the allocation to ratepayers of the tax benefits associated with the "costless" FMV Bump. The OEB agreed that future tax savings that are the result of "recaptured" asset values should revert to utility shareholders when an event of recapture occurs. The May 2005 Report's finding on this point was in response to a submission made by Hydro One, an active participant in that case. The May 2005 Report states;

> "Ms. McShane testified that the savings would be subject to recapture and Hydro One submitted that if the ratepayer benefits from the FMV Bump, it should also be liable for recapture. The Board agrees that if the ratepayers benefit from this tax saving, then any subsequent recapture should be considered for recovery from ratepayers as well.[135] However, the Board has no evidence as to how frequently or to what extent this recapture will take place."

The May 2005 Report specifically notes the right of a utility to apply to the OEB for relief if an event of recapture occurs.

The Report also encourages utilities to apply to the OEB when a tax liability arises from a sale of assets or when a change in tax status occurs so that issues related to the matter can be determined in a timely manner.[136]

The principles that are expressed in the May 2005 Report include:

[134] May 2005 Report, p. 55
[135] This proposition reflects the "no double dipping" concept on which Hydro One relies at page 74 of its Argument-in-Chief.
[136] RP-2004-0188 Report, pp. 56-57

a) In a "deemed" sale of utility assets at FMV, where the FMV Bump in the assets is not actually attributable to a purchase at FMV, the "benefits follow costs" principle does not apply to the FMV Bump related future tax savings and they are be allocated to ratepayers.

b) If a transaction triggers a recapture of asset values to which CCA has been applied in prior years to provide tax savings to ratepayers, then the future tax savings attributable to those recaptured values are to be allocated to utility shareholders.

The OEB disagrees with those who argue that the May 2005 Report does not apply to the circumstances of this case. The OEB finds that the principles expressed in that Report inform the allocation of FMV Bump related future tax savings attributable to recapture. They also inform the allocation of FMV Bump related future tax savings in a scenario where only a portion of the FMV Bump is attributable to actual sales and purchases at FMV; with the remainder of the FMV Bump being attributable to a "deemed" sale and reacquisition transaction at FMV.

The OEB relies on the principles expressed in the May 2005 Report to find in this case that:

a) The proportion of the FMV Bump in this proceeding that is attributable to recapture is to be allocated to shareholders.

b) The benefits follows costs principle of allocation applies to the proportion of the FMV Bump that is attributable to actual FMV sales and purchases at FMV; but not to the proportion of the FMV Bump that remains attributable to the "deemed" sale and reacquisition at FMV.

c) If the proportion of the FMV Bump attributable to actual sales and purchases at FMV is less than the proportion attributable to recapture, then the allocation to shareholders of FMV Bump related future tax savings is limited to the proportion attributable to recapture.

In the sections that follow, the OEB applies these principles to the facts of this case to determine the future tax savings allocation issue in a manner that maintains consistency with the principles expressed in the May 2005 Report and the OEB's findings in this case based thereon, to achieve a reasonable balance between the interests of utility ratepayers and shareholders.[137]

[137] See Guiding Principles, Chapter 2, items 1 and 6

15.5 FUTURE TAX SAVINGS ATTRIBUTABLE TO RECAPTURE

Hydro One relies on the existence of "recapture" to support its proposal to allocate 100% of the FMV Bump related future tax savings to shareholders.[138] However, Hydro One does not quantify the extent to which the total FMV Bump is attributable to recapture.

Step 1 in applying the principles expressed in the May 2005 Report and the OEB's findings in this case based thereon to the circumstances of this case, is to determine the proportion of the FMV Bump that is attributable to recapture. SEC is the only party that made submissions on this point.

SEC suggested that the FMV Bump related future tax savings, being the deferred tax asset amount, attributable to recapture was 64.6%. This ratio was derived from a consideration of the effect of the deferred tax asset (calculated by Hydro One at almost $2,600 million) on the deferred income tax liabilities and assets between December 31, 2014 and December 31, 2015 as shown in Note 7 of the audited statements for Hydro One Limited for those years.[139] According to SEC the $2,600 million deferred tax asset had the effect of reducing the deferred tax liabilities of $1,713 million at December 31, 2014 to a negligible amount by December 31, 2015; and increasing deferred income tax assets from a negligible amount at December 31, 2014 to $937 million as of December 31, 2015.

SEC divides the $1,713 million of deferred tax liabilities at December 31, 2014 by the amount of $2,650 million, being the total of the $1,713 million of liabilities at December 31, 2014 and the deferred asset balance of $937 million at December 31, 2015, to derive its 64.6% ratio attributable to recapture. [140]Hydro One did not make any reply submissions on this calculation.

The OEB notes that the deferred income tax liability for Networks at October 31, 2015 is a more appropriate starting point for determining the deferred tax liability component of a calculation of this nature. At page 17 of the unconsolidated financial statements for Networks at October 31, 2015 the deferred tax liabilities attributable to "capital cost allowance in excess of depreciation and amortization" are shown at $1,794 million.[141] The total deferred tax liabilities for Networks at October 31, 2015 are shown at $1,950 million.

Unconsolidated financials for Hydro One Networks for the first reporting period in which a deferred income tax asset attributable to "depreciation and amortization in excess of

[138] Hydro One Argument-in-Chief, pp.68, 71 and 74
[139] See SEC submission, pp. 76-78 and p. 69 of the Hydro One Limited Annual Report 2015, Exhibit 8/Tab 8/Sch 1
[140] SEC submission, pp. 76-78 at paragraphs 5.5.1 to 5.5.8
[141] See Exhibit J11.16, Attachment 2.

capital cost allowance" are not in the record. However, Exhibit J11.3 contains a calculation of the deferred tax asset for Networks as a whole of $2,595 million. The financial statement deferred tax liability attributable to "capital cost allowances in excess of depreciation and amortization" at October 31, 2015 of $1,794 million is about 69% of the total deferred tax asset amount of $2,595 million. The larger amount of $1,950 million for deferred tax liabilities at that date is about 75% of the deferred tax asset amount of $2,595 million.

The financial statement amount for deferred tax liabilities at October 31, 2015 of $1,794 million includes the portion of the deferred tax asset of $2,595 that is attributable to CCA amounts subject to recapture. It is unclear whether the larger sum of $1,950 also includes CCA amounts subject to recapture. If the $1,794 million amount is derived from all CCA available for recapture as of October 31, 2015, then the portion of the FMV Bump of $9,794 million shown in Exhibit J11.3 that is attributable to recapture, is about $6,770 million.[142]

There is other information found in Exhibits J11.3 (Deferred Tax Asset) and J11.13 (Departure Tax Calculation) that assists in estimating the portion of the FMV Bump that is attributable to recapture for Networks as a whole and separately for its segregated transmission and distribution business segments. The OEB has used this information to separate the proportions of the FMV Bump shown in J11.3 that are attributable to "recapture" and to "gain" values.

Exhibit J11.3 Attachment 1 shows the "FMV in excess of Tax Basis" that gives rise to the future tax savings as an amount of $9,794 million for networks as a whole and amounts of $5,567 million and $4,171 million for transmission and distribution respectively. Attachment 1 does not separate the "FMV in excess of Tax Basis" between its "Recapture" and "Gain" components.

Exhibit J11.13 is an October 31, 2015 calculation of the Departure Tax amount paid by Networks. This exhibit shows the gain component of the FMV in excess of Tax Basis for Networks, as a whole, and for its separate transmission and distribution business activities. For Networks as a whole the gain is $2,264 million of which $1,606 million and $658 million relate to transmission and distribution respectively.

While the Deferred Tax Asset and Departure Tax calculations are different,[143] common to each of them are "recapture" and "gain" components of FMV in excess of tax costs.

For the purpose of calculating the proportion of the future tax savings for transmission that are attributable to recapture (Recapture Ratio for transmission) the OEB has used

[142] $1,794 million divided by tax rate of 26.5% = $6,670 million.
[143] TR Vol. 11, pp. 26 and 73-77 and Exhibits J11.3 and J11.13.

the “Gain” amounts in Exhibit J11.13 for Networks as a whole and for transmission and distribution that are included in the amounts shown in the “FMV in excess of Tax Basis” in Exhibit J11.3. Based on the evidence provided by Hydro One witnesses the OEB has concluded that the gain amount in Exhibit J11.13 and the gain amount in Exhibit J11.3 are the same.[144] As described below, this conclusion produces an amount of $7,530 as the proportion of the FMV Bump of $9,794 million that is attributable to recapture. This amount may be too high if the $1,794 million deferred tax liability amount recorded in the financial statements for Networks at October 31, 2015 is derived from all of the CCA available for recapture as of that date. The proportion of the FMV Bump for Networks as a whole attributable to recapture may be limited to the $6,770 million amount described above.

In these circumstances, the materials that Hydro One provides in the Draft Rate Order (DRO) Process, must separate the amounts in the “FMV in excess of Tax Basis” shown in Exhibit J11.3 between its “Recapture” and “Gain” components and reconcile the separated “recapture” amount with the deferred tax liability and deferred tax asset amounts recorded in the financial statements for Networks already filed in evidence in this proceeding for the periods immediately before and after completion of the IPO. This must include, in particular, a reconciliation to the deferred tax liability amount of $1,794 million described above. Upon receipt of this information the OEB will determine whether any of its Recapture Ratio calculations need to be reduced.

With a “Gain” amount for Networks as a whole at $2,264 million, as stated in Exhibit J11.13, the amount attributable to recapture is $7,530 million in order to produce the “FMV in excess of Tax Basis” for Networks as a whole of $9,794 million shown in Attachment 1 of Exhibit J11.3.[145]

Expressing the amount attributable to recapture of $7,530 million as a percentage of the total of $9,794 million produces a Recapture Ratio for Networks as a whole of about 77%. Using the segregated information for transmission, the OEB calculates the Recapture Ratio for that business segment at about 71%. The OEB calculates the Recapture Ratio for distribution at about 84%. The OEB will consider the information that Hydro One is to include with its DRO materials to determine whether that information prompts a need for revisions to its Recapture Ratio calculations.

The OEB notes that the Recapture Ratio for Networks as a whole of about 77%, calculated from the information in Exhibits J11.3 and J11.13, exceeds the Recapture

[144] See footnote 137 below.
[145] See TR Vol. 2, pp.169 to 171 where Hydro One’s accounting witness discussed the recapture and gain components in the increases of tax values and TR Vol. 11 at p. 76 indicating that the only two components in these increases in tax values are recapture and gain.

Ratio for Networks as a whole of about 69% that stems from the financial statement information that the OEB described above related to the level of deferred income tax liabilities and deferred income tax assets before and after the completion of the IPO. As noted above, this is one of the items that Hydro One is to address and reconcile in the materials it provides during the course of rate order finalization process.

The table below separates the "FMV in excess of Tax Basis", shown in Attachment 1 of Exhibit J11.3 between its "Gain" and "Recapture" components using the "Gain" information presented in Exhibit J11.13. This table reflects the information that the OEB has used in calculating its Recapture Ratios for the transmission and distribution segments of Networks' business activities.[146]

[146] If Hydro One's separation of the recapture and gain components of the $9,794 million FMV Bump in Exhibit J 11.3 leads to an amount of about $6,770 million to recapture based on the financial statement amount of $1,794 million, then the "gain component will be about $3,024 million rather than the $2,264 million shown in the table. The calculations in this table and in the Recapture Ratios Table 15-2 will need to be adjusted accordingly.

Table 15-1
Summary of Deferred Tax Asset by Segment
(with Gain and Recapture Components)

	FMV	Tax Basis	FMV in Excess of Tax Basis Recapture	Gain	Total	Tax Rate	Total
Transmission							
Fixed Assets	$ 9,965	$ 6,482			$ 3,483	26.5%	$ 923
Goodwill*	$ 2,692	$ 51			$ 1,968	26.5%	$ 522
Construction in Progress	$ 116	-			$ 116	26.5%	$ 31
Deferred Tax Asset	$ 12,773	$ 6,533	$ 3,961	$ 1,606	$ 5,567		$ 1,476
Distribution							
Fixed Assets	$ 7,121	$ 4,845			$ 2,277	26.5%	$ 603
Goodwill*	$ 2,455	$ 26			$ 1,815	26.5%	$ 481
Construction in Progress	$ 80	-			$ 80	26.5%	$ 21
Deferred Tax Asset	$ 9,656	$ 4,871	$ 3,513	$ 658	$ 4,172		$ 1,105
Norfolk							
Fixed Assets	$ 55	$ -			$ 55	26.5%	$ 15
Goodwill*	$ -	$ -			$ -	26.5%	$ -
Construction in Progress	$ -	-			$ -	26.5%	$ -
Deferred Tax Asset	$ 55	$ -	$ 55		$ 55		$ 15
Hydro One Networks Inc.							
Fixed Assets	$ 17,142	$ 11,327			$ 5,815	26.5%	$ 603
Goodwill*	$ 5,147	$ 77			$ 1,815	26.5%	$ 481
Construction in Progress	$ 196	-			$ 80	26.5%	$ 21
Deferred Tax Asset	$ 22,485	$ 11,404	$ 7,530	$ 2,264	$ 9,794		$ 2,596

Source: Exhibit J11.3 and Exhibit J11.13 (for the gain amounts).
* only 75% of goodwill is included in cumulative eligible capital pool. So FMV in excess of Tax Basis is calculated as 75% of the FMV less the Tax Basis.

The information presented in Table 15-1 leads to Recapture Ratios for transmission of 71%; for distribution of 84%; and 77% for Networks as a whole, all as previously described and as shown in Table 15-2 below.

Table 15-2

Recapture Ratios

	(1) FMV Bump	(2) Gain	(3) Recapture (1) - (2)	(4) Recapture Ratio (3)/(1)
Transmission	$ 5,567	$ 1,606	$ 3,961	71%
Distribution	$ 4,172	$ 658	$ 3,514	84%
Norfolk	$ 55	-	$ 55	100%
Hydro One Networks Inc.	$ 9,794	$ 2,264	$ 7,530	77%

Source:	FMV Bump & Recapture, Exhibit J10.3 and Table 15-1
	Gain, Exhibit J11.13 and Table 15-1
	Norfolk FMV Bump assumed to be entirely attributable to recapture.

The OEB finds that the methodology for calculating Recapture Ratios for Networks as a whole and for its transmission and distribution business segments described above and illustrated in Tables 15-1 and 15-2 is appropriate. The OEB directs that this methodology and its resulting Recapture Ratios be applied to determine the proportions of the FMV Bump related future tax savings to be allocated between shareholders and ratepayers.[147]

15.6 FUTURE TAX SAVINGS ALLOCABLE UNDER THE BENEFITS FOLLOW COSTS PRINCIPLE

Introduction

Conceptually an allocation to shareholders of the FMV Bump related future tax savings based on the benefits follow costs principle differs from an allocation to shareholders based on the recapture of CCA values on eligible assets previously used to benefit ratepayers.

[147] The OEB calculates that if the portion of the FMV Bump of $9,794 million attributable to recapture is $6,770 million 69% thereof rather than $7,530 million or 77% thereof, then the Recapture Ratios for transmission, distribution, and Networks as a whole reduce from 71%, 84% and 77% respectively to 65%, 76% and 69%.

The concept upon which a Benefits follow Costs allocation is based, is that those seeking the benefit of such an allocation have incurred the costs of producing that benefit. As previously noted, the OEB, in this case, relies on the principles expressed in the May 2005 Report to find that, for regulatory purposes, benefits attributable to a “deemed” transaction for which no costs have been incurred by shareholders or anyone else are to be allocated to ratepayers. In this context the OEB reiterates the acceptance contained in the May 2005 Report of the proposition that, in unregulated markets, the existence of such costless benefits will tend to reduce prices.[148]

Hydro One emphasized the existence, amount and payment of the Departure Tax to distinguish the circumstances of this case from the “costless” FMV Bump that preceded the OEB’s RP-2004-0188 Report. Hydro One’s submissions are supported by OEB staff, and two intervenors.[149] As already noted Hydro One also relied on recapture to support the allocation relief that it seeks. However, neither Hydro One’s submissions nor the submissions of others specifically address and compare the conceptual differences between these two separate and distinct approaches to the future tax savings allocation issue.

BOMA argued that, for ratemaking purposes, the OEB should effectively ascribe a zero value to the Departure Tax amount of $2,271 million[150] and apply the principles expressed in the May 2005 Report to allocate 100% of the future tax savings to ratepayers.[151] BOMA did not consider “recapture” in its submissions.

Without recommending any particular approach, SEC presented four approaches that the OEB could adopt, including the approach proposed by Hydro One and a Recapture type of approach adopted by the OEB in the preceding section of this Decision and Order.[152] CME urged the OEB to apply the logic of May 2005 Report. VECC expressed a preference for an outcome that would have ratepayers benefit from the CCA related tax shield; and, as an alternative, invites the OEB to consider adopting an Earnings Sharing Mechanism to protect the interest of ratepayers.[153]

The analysis in the preceding section demonstrates that an application of allocation factors related to recapture leads to an allocation of a substantial portion, but not all, of the future tax savings to shareholders.

[148] See section 15.1.4 of this Decision and Order.
[149] Hydro One Reply Argument, para. 302, referring to the supporting submissions of OEB staff, LPMA, and the PWU.
[150] As shown in Exhibit J11.13 this amount includes $2,264 million of departure tax for transmission and distribution and a total of $7 million for Norfolk Power Distribution Inc. and rounding.
[151] BOMA submission, pp. 2-6
[152] SEC submission, pp. 64-79
[153] CME submission, pp. 23-25 and VECC submission, pp. 36-37.

In this section the OEB considers and determines whether an application of the Benefits follow Costs principle to the facts in this case leads to an allocation to shareholders of FMV Bump related future tax savings that exceeds the allocation that results from applying the allocation factors related to recapture.

The starting point for this analysis is the finding that the costs that the allocation of FMV Bump related future tax savings follow are the proportion of the FMV Bump value embedded in the FMV of Hydro One Limited shares that is attributable to actual sales and purchases of shares from the Province at FMV and actual payments made by or on behalf of new shareholders towards that total FMV. Put another way, the Benefits follow Costs principle does not apply to the proportion of the FMV Bump that remains attributable to the “deemed” sale and reacquisition transaction at FMV.

The OEB finds that an allocation to shareholders of Hydro One Limited of 100% of the FMV Bump related future tax savings would be unreasonable when, for example, only 50% of the FMV Bump embedded in the value of those shares has actually been sold at FMV and paid for by or on behalf of new shareholders who have purchased their shares from the Province.

An allocation of the FMV Bump related future tax savings for the benefit of shareholders of Hydro One Limited that include the Province should be limited to the proportion of the FMV Bump that is attributable to actual FMV sales and payments. The allocation should exclude the proportion of the FMV Bump that remains attributable to the “deemed” sale and reacquisition at FMV component triggered by the IPO transaction. The OEB finds that it would be unreasonable to include this proportion of the FMV Bump in the calculation of an appropriate Benefits follow Costs allocation factor in this case.

Before applying these principles to establish a Benefits follow Costs allocation factor that is appropriate where the sales of interests in utility assets are a combination of actual sales to new shareholders at FMV and a deemed sale and reacquisition at FMV by the existing owner of the assets, the OEB needs to consider and determine the appropriate regulatory treatment for the departure tax payment amount upon which Hydro One so heavily relies for use in the calculation of that allocation factor. To make that determination, the OEB has considered the attributes of the departure tax described below.

Attributes of the Departure Tax

(a) Contingent Liability for Government Owned Electricity Utilities

Once the Province sold more than 10% of its 100% ownership interest in Hydro One Limited, the holding company and its subsidiaries ceased to be subject to the Ontario

PILs regime provided for in the Electricity Act and its regulations (PILs Regulation). Hydro One Limited and its subsidiaries lost their exempt status and became liable for federal income taxes under the Income Tax Act (Canada) (ITA) and provincial income tax under the Taxation Act 2007 (Ontario) (OTA).

The PILs Regulation imposes a departure tax obligation on utilities when they leave the PILs Regime. Unless the Province acts to prescribe a lesser sum, the amount of the departure tax is equal to the amount of tax that is imposed under the ITA upon an entity that sells or is deemed to have sold its assets at fair market value.

The rationale for the Province's introduction of a departure tax under the auspices of Ontario legislation included establishing a level playing field with unregulated companies.[154] Another reason for the departure tax and an additional Transfer tax[155] on Municipal Electricity Utilities (MEUs) was to ensure that the corporations, to whom the Province had effectively gifted electricity utilities, returned to the Province a reasonable amount of its investments therein. Accordingly, the attributes of the departure tax include an implicit investment payback feature that protects the interests of the Province in the investments that it had made in all of the utility companies that were effectively gifted to corporations upon the dismantling of Ontario Hydro.[156]

(b) Once Crystalized, the Tax Liability Impedes the Sale of Utilities

A sale of the assets of a utility that remains more than 90% government owned (Exempt Utility) to another Exempt Utility operating at arms-length will attract a FMV price that excludes any departure tax exposure. There is no departure tax liability when the vendor and purchaser are Exempt Utilities.

If the selling utility faces an incremental obligation to a taxing authority before a sale transaction can be completed, then the buyer will either requisition that obligation to be discharged before the transaction closes, or deduct the amount of the obligation from the purchase price and discharge the obligation using the amount deducted.

If a utility wishes to realize the Exempt Utility FMV of its assets in a sale to Non Exempt purchasers, then it will need to take action to eliminate its departure tax burden. However, in combination with the departure tax, be it at zero or at $2.271 billion, the most that the Province could reasonably expect to realize from its sale of shares in Hydro One Limited to members of the public is the Exempt Utility FMV for the portion of

[154] The Direction for Change document that McShane cites in footnote 18 on page 16 of her evidence that is in the Hydro One Book of Authorities, January 12, 2017.
[155] See Ontario Regulation124/99 and amendments thereto (Transfer Tax on Municipal Electricity Utility).
[156] The April 16, 2015 Report of the Premier's Advisory Council on Government Assets entitled "Striking the Right Balance" refers to these features at pages 18-20.

Networks' utility assets offered for sale. Put another way, an elimination of the departure tax exposure operates to preserve the Exempt Utility FMV.

The Departure and Transfer Tax charges on the Exempt Utility FMV of these electricity utility businesses are regarded as impediments to the sale of interests in such businesses.[157] Utilities seek to recover the value of their assets excluding these departure tax/transfer tax charges. However, non-exempt purchasers are generally unwilling to pay anything more than FMV after the liability for these charges is either eliminated before closing or deducted from the purchase price.

Accordingly, as a pragmatic matter, to facilitate the privatization of its wholly owned utilities, the Province had to either reduce or eliminate this departure tax burden on the Exempt Utility FMV of the assets. This is the reality that faced the Province and Hydro One in connection with the IPO. In response to that reality, the Province and Hydro One arranged to eliminate the departure tax obligation before completing a sale of shares to the public.

(c) Departure Tax is Variable

The PILs Regulation empowers the Province, as the taxing authority, to exempt an obligated utility, in whole or in part, from having to remit the full amount of the departure tax.[158] Accordingly, the departure tax is effectively variable at the discretion of the Province. If the Province chooses to exercise its exemption power under the PILs Regulation, then the amount of the tax can be reduced to as low as zero if the Province wishes.

The Province did not exercise its exemption power in favour of Hydro One Limited or any of its subsidiaries in connection with its sale of shares in Hydro One Limited pursuant to the IPO. However, the Province did recently exercise its exemption power in favour of MEUs. By O. Reg. 112/16, enacted on April 22, 2015, the Province deemed the taxable capital gain component of the departure tax to be zero for utility sale transactions occurring between January 1, 2016 and December 31, 2018.[159] In this context, from a departure tax perspective, the Province is treating the sale of MEU's more favourably than it has treated the sale of shares in Hydro One Limited.

[157] See section 3.6 of this Decision and Order and the April 16, 2015 Report of the Premier's Advisory Council on Government Assets entitled "Striking the Right Balance" at pages 18-20 where the concerns about departure and transfer taxes as barriers to consolidation are noted. Share sale transactions face these same barriers.
[158] See section 16.1 of Ontario Regulation 207/99 as amended cited by Hydro One in its Argument-in-Chief at pages 70 and 71 and in Footnote 233 thereof.
[159] See Ontario Regulation 112/16 and Footnote 233 of Hydro One's Argument-in-Chief.

(d) Options for Eliminating Departure Tax

According to Hydro One's witness, the Province "created" the cascading share acquisition process as the means for eliminating the departure Tax obligation.[160] This was not a transaction between parties operating at arms-length. The Province had other options available to it including an exercise of its power under the PILs Regulation to reduce or eliminate the amount payable. The Province could have forgiven the obligation in exchange for an issuance by Hydro One Limited of the additional shares needed to support the IPO. Incurring a "cost" of $2,271 million was not essential in order to eliminate Networks' departure tax liability.

(e) Regulatory Treatment of the Departure Tax

It is open to the OEB to consider and rely upon the variability of the departure tax at the Province's option and the tax elimination options that could have been used without involving a "cost" of $2,271 million. In these circumstances, the OEB finds that, for regulatory purposes, it could adopt a departure tax value that is materially less than $2,271 million for use in conjunction with an application of the Benefits follow Costs principle.

The OEB disagrees with the submissions made by Hydro One and others about the determinative effect that the departure tax payment has on the allocation issue under the auspices of the costs follow benefits principle. The OEB finds that neither the amount of nor the payment of the provincial departure tax is, in and of itself, determinative of the allocation of future tax savings available under federal tax legislation under the auspices of that principle.

The question that the OEB needs to decide in establishing the appropriate Benefits follow Costs allocation factor in this case is whether the departure tax amount should be brought into account as an actual payment towards the total FMV value of the shares of Hydro One Limited in which the FMV Bump is embedded. From the perspective of the Province, as the then owner of all of the shares of the Hydro One group of companies, the departure tax payment that the Province funded was effectively a payment from itself to itself, as the ultimate owner of Networks' utility assets to preserve the Exempt Utility FMV of those assets.

While the funding provided by the Province was used to subscribe for the shares of Hydro One Limited that the Province has now partially sold in three successive public share offerings,[161] the subscription payment made by the Province to Hydro One

[160] See Footnote 112.
[161] As the Province sells portions of it Hydro One Limited shares, it recovers from the share purchasers the proportion of the departure tax attributable to those shares.

Limited for those shares was not a purchase of such shares at their FMV. That said, the subscription payment made by the Province did give the Hydro One shares a greater FMV than they would have had if the Province had not made that payment. In these circumstances the OEB finds that, in determining, for regulatory purposes, the appropriate Benefits follow Costs allocation factor in this case, it is appropriate to treat the departure tax amount of $2,271 million as an actual contribution towards the FMV Bump value of $9,794 million embedded in the total FMV of Hydro One Limited shares.

The analysis below of the proportion the FMV Bump that is attributable to actual sales and payments at FMV includes, for regulatory purposes, the treatment of the departure payment as an actual payment made on behalf of all shareholders towards the total FMV Bump. The proportion of the FMV Bump that that the analysis excludes from the derivation of the allocation factor is the proportion of the FMV Bump that remains attributable to the “deemed” sale and reacquisition that was triggered by the IPO.

Actual FMV Sales and Payments Ratios

As explained below, the OEB finds that the Benefits follow Costs principle does not currently lead to an allocation of future tax savings to shareholders that exceeds the allocation of such tax savings under the auspices of the recapture allocation factor. The OEB’s analysis is based on the information related to the FMV Bump contained in Exhibit J 11.3 and the information related to departure tax amounts contained in Exhibit J 11.13. The analysis described below is presented in Table 15-3.

The departure tax of $2,271 million, constitutes a 23% contribution towards the total FMV Bump amount of $9,794 million for Networks as a whole as shown in Exhibit J11.3.[162] Moreover, as of the close of argument in this case, 29% of the departure tax amount of $2,271 million, or about $665.2 million, was attributable to the shares sold under the IPO and the subsequent public share offering in the spring of 2016. The remaining 71% or $1,612 million of the departure tax amount was effectively a contribution towards the FMV Bump related to the Province’s remaining 71% ownership interest in the utility assets.

In this scenario, the total amounts that have actually been paid towards the $9,794 million FMV Bump of Networks’ asset values used for calculating the Deferred Tax Asset is 29% of $9,794 million or about $2,840 million, plus the $1,612 million payment of departure tax attributable to the Province’s unsold 71% interest described in the preceding paragraph. These amounts total about $4,452 million or about 45% of the total FMV Bump of $9,794 million. Conversely, the proportion of the FMV Bump that

[162] Exhibit J11.13

then remained attributable to the “deemed” sale and reacquisition at FMV was about 55%.

If, for regulatory purposes, the OEB was to adopt a departure tax value of zero, then, in the 29% share sale scenario, the proportion of the FMV Bump benefits allocable to shareholders under the Benefits follow Costs allocation factor would be 29%. Including the departure tax amount in the allocation factor calculation increases the proportion allocable to shareholders to 45%. Including the departure tax amounts in the allocation factor calculations benefits shareholders by increasing their Benefits follow Costs allocation in partial share sale scenarios, but not to the point of producing a 100% allocation in their favour as Hydro One contends.

The departure tax amount of $1,612 million associated with the 71% of Hydro One Limited’s shares not then sold to the public by the Province was but a portion (about 16.4%) of the total CCA eligible utility asset values in the FMV Bump of about $9,794 million that give rise to the future tax savings. This departure tax proportion of about 16.4% and the 29% interest in Hydro One Limited then sold to the public, being a total of about 45%, did not, in percentage terms, exceed the Recapture Ratio of 77% for Networks as a whole.

Put another way the 77% proportion of the FMV Bump related future tax savings that is attributable to recapture, materially exceeds the 45% proportion of the FMV Bump related future tax savings that is attributable to actual share sales and payments made at FMV. The latter is the proportion that stems from an application of the Benefits follow Costs principle using departure tax in an amount of $2,271 million as a payment made on behalf of shareholders towards the total FMV Bump of $9,974 million.

The foregoing analysis can be completed for transmission and distribution separately using the segregated FMV Bump values for each of those business segments presented in Exhibit J11.3 and the segregated departure tax amounts for transmission and distribution presented in Exhibit J11.13. The table below presents the OEB’s calculations of the Actual FMV Sales and Payments Ratios in the 29%, 51% and 60% share sale scenarios. The 51% scenario has been included because, as of the spring of 2017, the Province had sold about 51% of its shares through three public share offerings.

Table 15-3

Actual FMV Sales and Payments Ratios

29% Shares Sold				
Transmission				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	29%	x	$ 5,567	$ 1,611
- departure tax on remainder	71%	x	$ 1,280	$ 909
Actual FMV Sales and Payments				**$ 2,520**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$2520/$5567	=		45%
Distribution				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	29%	x	$ 4,171	$ 1,210
- departure tax on remainder	71%	x	$ 984	$ 699
Actual FMV Sales and Payments				**$ 1,909**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$1909/$4171	=		46%
Hydro One Networks				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	29%	x	$ 9,794	$ 2,840
- departure tax on remainder	71%	x	$ 2,271	$ 1,612
Actual FMV Sales and Payments				**$ 4,452**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$4452/$9794	=		45%

51% Shares Sold				
Transmission				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	51%	x	$ 5,567	$ 2,839
- departure tax on remainder	49%	x	$ 1,280	$ 627
Actual FMV Sales and Payments				**$ 3,466**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$3466/$5567	=		62%
Distribution				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	51%	x	$ 4,171	$ 2,127
- departure tax on remainder	49%	x	$ 984	$ 482
Actual FMV Sales and Payments				**$ 2,609**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$2609/$4171	=		62%
Hydro One Networks				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	51%	x	$ 9,794	$ 4,995
- departure tax on remainder	49%	x	$ 2,271	$ 1,113
Actual FMV Sales and Payments				**$ 6,108**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$6108/$9794	=		62%

60% Shares Sold				
Transmission				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	60%	x	$ 5,567	$ 3,340
- departure tax on remainder	40%	x	$ 1,280	$ 512
Actual FMV Sales and Payments				**$ 3,852**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$3852/$5567	=		69%
Distribution				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	60%	x	$ 4,171	$ 2,501
- departure tax on remainder	40%	x	$ 984	$ 394
Actual FMV Sales and Payments				**$ 2,895**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$2895/$4171	=		69%
Hydro One Networks				
Actual Payment Proportions toward FMV Bump				
- by new shareholders	60%	x	$ 9,794	$ 5,876
- departure tax on remainder	40%	x	$ 2,271	$ 908
Actual FMV Sales and Payments				**$ 6,784**
Ratio: Actual FMV Sales & Payments/FMV Bump				
	$6784/$9794	=		69%

Source: Exhibit J11.3 for FMV Bump and J11.13 for Departure Tax amounts.

The OEB finds that the methodology for calculating the proportions of the FMV Bump related future tax savings that are attributable to actual FMV sales and payments and to the “deemed” sale and reacquisition at FMV described above and illustrated in Table 15-2 is appropriate. The OEB applies this methodology to determine the proportion of the FMV Bump related tax savings that is allocable to shareholders under the Benefits follow Costs allocation factor.

With purchasers having actually paid for a 29% interest in each of those business segments as of February 2017, the FMV Bump for transmission at $5,567 million and for distribution at $4,171 million, and departure tax amounts for transmission of $1,280 million and $984 million for distribution, the Benefits follow Costs principle leads to an allocation of the FMV Bump values to shareholders of about 45% in transmission and about 46% in distribution. This is well below the recapture ratios of 71% in transmission and 84% in distribution.

As of February 2017, the Benefits follow Costs principle had no application to the allocation of future tax savings because, including departure tax as an actual contribution on behalf of new asset purchasers towards the FMV Bump values, the amounts actually paid by new purchasers towards the total FMV Bump amount of $9,974 million were, for Networks as a whole, about 45% of that total amount. This ratio falls well below the recapture ratio for Networks as a whole that the OEB has estimated at 77% using the information in Exhibits J11.3 and J11.13.

The Benefits follow Costs principle will continue to be inapplicable to the allocation of future tax savings until the Actual FMV Sales and Payments Ratios[163] for transmission and distribution exceed the corresponding Recapture Ratios for those business segments. The analysis presented in Table 15-3 of the Actual FMV Sales and Payments Ratios in scenarios where 29%, 51% and 60% of the Province's shares in Hydro One Limited have actually been sold to new purchasers at FMV reveals that the Benefits follows Costs principle does not currently assist shareholders in this case.

The Benefits follow Costs principle continues to have no application, at this time, for the same reasons that it was found to have no application in the RP-2004-0188 proceeding. The percentage interests that the Province continues to hold in the transmission and distribution assets of Networks in excess of the recapture ratios in each business segment remain attributable to the "deemed" sale and reacquisition transaction triggered by the IPO, and remain as costless now as they were when the May 2005 Report was issued.

Allocation of Future Tax Savings When More Shares Are Sold

When the Province has eventually sold to the public a 60% interest in the assets of Networks, the proportion of the FMV Bump actually paid for by purchasers of interests in Networks as a whole will be 60% of $9,794 million or an amount of about $5,876 million. Added to this will be an amount of about 40% of $2,271 million or about $908 million for a total of about $6,784 million in the scenario where departure tax costs of $2,271 million are treated as a contribution towards the FMV Bump. The resulting Actual FMV Sales and Payments Ratio for Networks as a whole of about 69% continues to fall below the Recapture ratio for Networks as a whole of about 77%.

Separate calculations of the Actual FMV Sales and Payments Ratios for the distribution and transmission utility segments, as shown in Table15-3, yield a percentage for transmission of about 69% compared to the recapture ratio of 71%, and for distribution a percentage of 69% compared to its recapture ratio of 84%. The Actual FMV Sales and Payments Ratios in the scenario that currently prevails, with the Province continuing to hold about a 49% interest in the shares of Hydro One Limited, will be lower than the 69% Actual FMV Sales and Payments Ratio that prevails in the Province's 40% ownership scenario.

[163] Determined by including departure tax amounts as described above and as shown in Table 15-3.

The Benefits follow Costs principle will begin to supplement the allocation to shareholders of FMV Bump related future tax savings attributable to recapture if and when the Actual FMV Sales and Payments Ratios exceed the corresponding Recapture Ratios.

15.7 NO HARM TEST

In certain interrogatory and undertaking responses, Hydro One relies upon the "no harm" principle as further support for its position that the OEB should not do anything other than allocate 100% of the future tax savings to shareholders.[164]

The focus of the no harm test is utility customers. The OEB's January 19, 2016 Handbook for Electricity Distributor and Transmitter Consolidations states, at page 7, that to demonstrate "no harm" it must be shown that there is a reasonable expectation "'that the costs to serve customers will be no higher than they otherwise would have been". Conversely, it follows that harm exists when costs to serve customers will be higher than they otherwise would have been.

If the status quo continued, then the taxes recoverable from Networks' transmission customers would be confined to actual taxes payable by Networks to the tax authorities. Imposing notional or hypothetical taxes on ratepayers, substantially in excess of actual taxes payable, harms ratepayers unless the notional taxes being imposed are compatible with established ratemaking principles.

In this case, it is the application of the principles expressed in the May 2005 Report along with the OEB's determination in this case of principles stemming from that Report that operate to satisfy the "no harm" test. The "recapture" principle operates to ensure that ratepayers do not benefit from unfair "double dipping". Conversely, the same principle protects ratepayers from the harm of having to pay notional taxes with respect to an ownership interest in Networks held by the Province that continues to remain as "costless" as it was under the terms of the May 2005 Report.

The "no harm" principle is satisfied in this case by the OEB's considered application of the Recapture and Benefits Follow Costs principles in determining the issues pertaining to the allocation between shareholders and ratepayers of the FMV Bump related future tax savings.

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[164] See for example Exhibit I/Tab 1/Schedule 134, p. 3 and Footnote 1 therein where Hydro One relies upon the OEB's Handbook for Electricity Distributor and Transmitter Consolidation dated January 19, 2016 and Exhibit J2.9 where the concept of harm to shareholders is relied upon by Hydro One. See also TR Vol. 11, p. 151 pertaining to the topic of harm.

The “no harm” test does not apply to protect either Hydro One or its shareholders from known risks associated the OEB’s determination of the issue related to the allocation of FMV Bump related future tax savings, particularly when advance notice of these risks was provided and repeated in a timely manner.[165] The documents footnoted below recognize that falling within the range of FMV Bump related future tax savings allocation outcomes was an allocation to shareholders of less than 100% of those tax savings stemming from the completion of the IPO transaction.

15.8 EARNINGS SHARING

VECC invites the OEB to consider adopting an earnings sharing mechanism to protect ratepayers from paying rates that could provide an excessive equity return to Hydro One.[166] The OEB will not impose an earnings sharing mechanism in this Cost of Service proceeding where the test period is only of two years duration.

Findings

In summary, the OEB finds that the evidence establishes that:

a) The November 2015 IPO triggered the FMV Bump of $9,794 million that gives rise to the future cash tax savings of about $1,475 million and $1,105 million respectively for Networks’ transmission and distribution business segments.

b) The portion of this FMV Bump related to Networks’ transmission business segment is $5,567 million. For the distribution segment, the amount is $4,172 million; and the remaining $55,000 is attributable to Norfolk Distribution Inc.

c) About $7,530 million of the total FMV Bump of $9,794 million represents the recapture of CCA on eligible assets previously deducted by Networks and used in prior periods to provide tax savings to ratepayers for a Recapture Ratio of about 77%.

d) Of the transmission related FMV Bump of $5,567 million, about $3,961 million results from recaptured CCA previously used in prior periods to provide tax savings for ratepayers for a transmission-related Recapture Ratio of about 71%.

[165] See Report of Premier’s Advisory Council on Government Assets at page 2, Prospectus, October 29, 2015 at Exhibit I/Tab 9/Schedule 2, p. 162; October 2015 FAO Assessment of the Financial Impact of the Partial Sale of Hydro One, p. 28 and Annual Report of Hydro One Limited 2015, p. 33.
[166] VECC submission, p. 37

e) For distribution, about $3,961 million of its FMV Bump amount of $4,172 million consists of recaptured CCA previously used in prior periods to provide tax savings for ratepayers for a distribution-related Recapture Ratio of about 84%.

f) The variable departure tax payment amount funded by the Province could have been reduced or eliminated at the Province's option. Its elimination, prior to the IPO, removed an impediment to the market value of the shares of Hydro One Limited of which the Province was then the sole owner.

g) In calculating, for regulatory purposes, the proportion of the FMV Bump related future tax savings that is attributable to actual share sales at FMV and not the portion attributable to the deemed sale and reacquisition at FMV by the existing owner, it is appropriate to treat the departure tax payment as if it was an actual payment at FMV on behalf of all shareholders as described in this decision and order and presented in Table 15-3.

h) The Actual FMV Sales and Payments Ratios presented in Table 15-3 determine whether, in the partial share sale scenarios that have occurred, an application of the Benefits Follow Costs principle produces an allocation of FMV Bump related future tax savings to shareholders that is more favourable to them than the allocation that stems from Recapture as shown in Table 15-2.

i) With about 51% of the Province's shares currently sold, the Actual FMV Sales and Payments Ratios for transmission, distribution and Networks as a whole are about 62% in each case. These ratios are less than the Recapture Ratios for transmission, distribution, and Networks as a whole of 71%, 84%, and 77% respectively.[167] The Benefits Follow Costs allocation factor is less favourable to shareholders than the Recapture allocation factor.

j) Until such time as the Actual FMV Sales and Payments Ratios for transmission and distribution exceed the corresponding Recapture Ratios, the allocation to shareholders of the future cash tax savings that stem from the FMV Bumps in transmission and distribution are to be limited to the amount of those savings attributable to Recapture.

The OEB applies the preceding analysis and finds that:

a) The future tax savings attributable to recapture are to be allocated to Networks' shareholders for the purpose of deriving the grossed up regulatory taxes to be included in its 2017 and 2018 transmission revenue requirement.

[167] Even when 60% of the province's shares have been sold the Actual Payments at FMV Ratios remain lower than the Recapture Ratios for transmission and distribution. See Table 15-3.

b) The benefits follow costs principle does not yet apply to support an allocation to shareholders of the future tax savings benefits in excess of the allocation attributable to recapture.

c) The recovery from transmission customers of the notional or hypothetical income tax amounts for 2017 and 2018 proposed by Hydro One are to be reduced to reflect an allocation to shareholders of future tax savings that is limited to the savings attributable to recapture.

During the draft revenue requirement/charge determinant approval process, in order to determine whether its calculations of Recapture Ratios require any reduction, the OEB will consider the information to be provided by Hydro One regarding the separation of the FMV Bump in Exhibit J11.3 between its recapture and gain components and the reconciliation of that information to the deferred tax liability and deferred tax asset amounts for Networks recorded in the financial statements on record in this proceeding covering the periods immediately prior to and following the IPO.[168]

The mechanics for calculating the reductions in 2017 and 2018 income taxes recoverable in OEB approved transmission revenue requirements for each year will be determined by the OEB during the rate order finalization process. The OEB favours the adoption of a stable and transparent approach and directs Hydro One to reduce the taxes calculated under an assumed 100% allocation of tax savings benefits to shareholders to the level of the recapture ratio for transmission that the OEB calculates at 71%. This would reduce grossed up taxes proposed by Hydro One of $81.9 million in 2017 and $89.6 million to about $58.1 million and about $63.6 million in each of those years, respectively.[169]

According to the approach established in this Decision to determining the level of taxes recoverable from transmission ratepayers, the proportion of regulatory taxes calculated under an assumed 100% allocation of tax savings to shareholders would be limited to 71% per year until the cumulative amount allocated to transmission ratepayers totals 29% of $1,475 or about $428 million.

Subject to the determinations by future OEB panels, the duration of the 29% annual allocation of tax savings to ratepayers will depend on the level of income earned from the transmission business; but could be for as many as 15 or more years. The approach to recovering the tax savings attributable to recapture will then cease and the recovery of any further hypothetical taxes from ratepayers will be reviewed.

[168] As previously noted the Recapture Ratios that the OEB has calculated may need to be reduced.
[169] If the Recapture Ratio for Transmission needs to be reduced to 65% for the reasons previously described, then the grossed up taxes recoverable in rates would be about $53.2 million for 2017 and about $58.2 million in 2018.

The 71% percentage level of recovery from ratepayers of regulatory taxes calculated under an assumed 100% allocation of tax savings to shareholders will need to be reviewed before all of the transmission-related deferred tax asset attributable to recapture of $1,047 million has been recovered from ratepayers in the event that the Province sells enough of its shares in Hydro One to cause the Actual FMV Sales and Payments Ratio to exceed the Recapture Ratio for transmission.

This Decision on the Allocation of Future Tax Savings issue is based on the OEB's principled approach to resolving that issue in a manner that is consistent with the principles expressed in the May 2005 Report, the principles adopted by the OEB in this Decision having regard to that Report and fairness to Networks' transmission and distribution ratepayers. The revenue requirement implications of the Decision on this allocation issue include:

a) Less transmission utility revenue than the amounts assumed at the time of the IPO for hypothetical income taxes in 2017 and 2018; with the annual amounts of the hypothetical taxes for transmission declining to an OEB estimated percentage of 71% of the amounts requested by Networks; and

b) Less distribution utility revenue for hypothetical income taxes than the amounts assumed at the time of the IPO; with the annual amounts of the hypothetical taxes for distribution declining to an OEB estimated percentage of about 84% of the amounts anticipated by Networks.

Having made an allocation of less than 100% of the future tax savings benefits to shareholders, the OEB finds that it would be inappropriate to add an ESM in this case as suggested by VECC. Moreover, as stated in the Guiding Principles Chapter, the OEB generally regards ESM measures to be inappropriate for a determination of cost of service rates for a short duration of 2 years.

The OEB notes that Hydro One has proposed an ESM in its five-year Custom IR application for distribution rates and that it anticipates that its future transmission revenue requirement application will be filed under the OEB's Custom IR regulatory framework. The consideration of requests for the adoption of an ESM for transmission is best left for Hydro One's next transmission revenue requirement application.

16.0 EXPORT TRANSMISSION SERVICE RATE

Hydro One transmission proposes to maintain the currently settled value of $1.85/MWh for Export Transmission Service (ETS) through the 2017 and 2018 period.

The IESO collects ETS revenues and remits them on a monthly basis to Hydro One, whose transmission system is used to facilitate export transactions at the point of interconnection with the neighbouring markets.

As a part of Hydro One's 2015/2016 Transmission Rate Application[170] , Hydro One engaged Elenchus Research Associates (Elenchus) to perform a cost allocation study of network assets utilized by export transmission customers to determine the ETS rate based on cost causality principles. The cost allocation study completed by Elenchus recommended an ETS rate of $1.70/MWh for 2015 and 2016 as being reflective of the cost of providing export service.

As part of the EB-2014-0140 settlement agreement, all parties agreed to an ETS rate of $1.85/MWh for 2015 and 2016. This was then approved by the OEB.

Hydro One's ETS revenues, used for establishing the rates revenue requirement proposed in this application, are determined based on the currently approved tariff of $1.85/MWh and the three year historical average volume of electricity exported from, or wheeled through, Ontario over its transmission system.

For 2017 and 2018, the ETS revenue will continue to be disbursed through a decrease to the revenue requirement for the Network rate pool, as per the approved cost allocation process. The forecast for ETS revenue is $39.2 million and $40.1 million per year for 2017 and 2018, respectively.

LPMA proposes that the ETS rate be increased to reflect the percentage increases in the other rates that the OEB is asked to approve in this proceeding. According to LPMA, the costs giving rise to these rate increases are primarily caused by inflation, OM&A cost increases and sustainability capital expenditures. LPMA submits that these factors should lead to an increase to the ETS rate.[171]

[170] EB-2014-0140
[171] LPMA submission, p. 19

Findings

There are complexities in deriving the allocation of costs that should be used to derive the ETS rate. Such a cost allocation study was presented in Hydro One’s 2015/2016 transmission rates proceeding. That study produced a recommended ETS rate of $1.70/MWh. The results of that study were not tested at an OEB hearing because the parties to that proceeding settled on an ETS rate for 2015 and 2016 of $1.85/MWh.

The OEB notes that the addition of an inflationary increase of the type proposed by LPMA to the $1.70/MWh supported by the last cost allocation study would not produce a rate in excess of $1.85/MWh.

The OEB finds that the continuance of the ETS rate of $1.85/MWh is appropriate for 2017 and 2018. The OEB is not inclined to change this rate until such time as another cost allocation study demonstrates the rate to no longer be appropriate.

17.0 EFFECTIVE DATE OF RATES

Hydro One applied for its 2017 transmission revenue requirement and rates on May 31, 2016, seeking an effective date of January 1, 2017. A number of intervenors made submissions on the date rates should be made effective by the OEB when it renders its decision.

SEC, CCC and LPMA disagree with an effective date of January 1, 2017. Instead, they submit that the date should be the first of the month following the new rate order approval. The rationale for these submissions was that Hydro One should have filed its application earlier than it did and should bear the consequences for not doing so. LPMA added that ratepayers do not want to pay for past consumption based on rates that were not in place at the time consumption took place.

Hydro One disagreed with these submissions, noting that its last transmission application which involved an oral hearing was for the 2011 and 2012 test years.[172] In that proceeding, Hydro One filed its application on May 19, 2010 and the OEB rendered its decision on December 23, 2010, with the rate order approved on January 18, 2011, in time for rates to be effective on January 1, 2011. Hydro One filed this current application on May 31, 2016, essentially within the same timeframe of the last full hearing.

Hydro One also submitted that it had conducted itself appropriately in the preparation and filing of the application that addressed new filing requirements, such as the RRF, a TSP and the conduct of additional customer engagement activities.

Hydro One also submitted that the discovery processes leading up to the 12 full day hearing were extensive, yet Hydro One did not miss any filing deadlines regarding these processes. Hydro One also noted that in its past two rates revenue requirements applications, settlement processes were used. The OEB's decision not to pursue this option in this proceeding was stated at the conclusion of the Presentation Day held on September 8, 2016. The two-day Technical Conference held in late September gave rise to additional and numerous undertaking responses, all of which were prepared and filed on tight timelines. The original dates for the oral hearing were deferred. Timing of cross-examination at the hearing itself in most cases exceeded original estimates. A great deal of time was taken during the oral hearing to address issues that had received little or no canvassing during the discovery process such as the IPO related costs, the departure tax and the line losses issue.

[172] EB-2010-0002

Therefore, according to Hydro One, the intervenors' belief that Hydro One should have known or ought to have anticipated the complexities and timing constraints by filing its application sooner than it did, is not reasonable.

Findings

On November 24, 2016 the OEB granted Hydro One's request that the existing UTRs for 2016 be declared interim as of January 1, 2017 and that a foregone revenue deferral account be established to capture revenue foregone between January 1, 2017 and the date when the 2017 UTRs are updated.[173] Therefore, in principle, establishing an effective date which is earlier than OEB's final decision and rate order in this case would not constitute "retroactive ratemaking".

The question, as articulated by several intervenors, is whether Hydro One submitted its application in sufficient time to allow for an effective date of January 1, 2017. This in turn raises the question as to what is the reasonable duration between the application date and the proposed effective date that an applicant should anticipate to ensure approval by the OEB prior to the proposed effective date.

Both the intervenors and Hydro One cited examples of previous proceedings and practices to support their respective positions. These examples are briefly discussed below.

- The last Hydro One transmission application which involved an oral hearing (EB-2010-0002) was cited by Hydro One in its reply argument. In that case, the application date was May 19, 2010 and the proposed effective date was January 1, 2011, allowing approximately 7 months.

- The last Hydro One distribution application involving an oral hearing (EB-2013-0416) was cited by SEC in its final submission. The application was filed on December 19, 2013 with a proposed effective date of January 1, 2015, allowing approximately 12 months. However, in OEB's view, this case is not comparable to the current proceeding as it was Hydro One's first 5-year Custom Incentive Rate application which was expected to be much more complicated than the current proceeding.

- Grimsby Power's last application[174] was cited by LPMA in its final submission. This application was filed on December 23, 2015 with a proposed effective date of May 1, 2016. This proposed effective date was later revised to July 14, 2016 in

[173] TR Vol.1, p. 4
[174] EB-2015-0072

the applicant's reply submission following the OEB's declaration of the current rates as interim. This represents a duration of approximately 7 months. The OEB decided in that case to approve an effective date of September 1, 2016 (i.e. about 8 months from the application date) based on its finding that the application should have been filed earlier.

- According to LPMA[175], OEB staff in the Grimsby Power case submitted that 266 days is the "established metric" to issue a decision and rate order after an application is filed and an oral hearing is held. The 266 days, according to OEB staff in the Grimsby Power case, consisted of 235 days to issue a decision according to estimates on the OEB website for distribution rates applications with an oral hearing, plus 31 days to develop, review and approve a draft rate order. The OEB notes that the 235 days is a guideline intended to give applicants an indication of timelines for "typical application types". The actual time taken could obviously vary depending on the complexity of the case.
- SEC also quoted correspondence from the OEB regarding distributors' filing for January, 2017 rates which required their applications to be filed by April 29, 2016; a duration of about 8 months.[176]

The above examples seem to suggest that a duration of approximately 7 to 8 months between the application date and the proposed effective date is reasonable for cases similar to the current Hydro One application. In the current case, the application was filed on May 31, 2016 with a proposed effective date of January 1, 2017; a duration of 7 months. The OEB finds this to be within the range of reasonable durations of similar cases.

The OEB finds that the effective date of rates in this proceeding is January 1, 2017.

[175] LPMA submission, pp.3-4
[176] SEC submission, p. 81

18.0 IMPLEMENTATION

Hydro One is directed to submit a draft revenue requirement/charge determinant order which is consistent with all findings in this Decision. In addition, Hydro One is also directed to file a draft UTR rate order which will be used to determine the 2017 uniform transmission rates in conjunction with the OEB's approval of the revenue requirement and the load forecasts of the other transmitters in Ontario.

The OEB expects Hydro One to file the 2017 and 2018 supporting information that it commonly files in its transmission rate orders, including a revenue requirement summary with supporting detail, bill impacts, revenue requirement by rate pool, summary of charge determinants, 2017 uniform transmission rates (effective January 1, 2017 for implementation on October 1, 2017) and revenue disbursement factors, the wholesale meter service and exit fee schedule, the low voltage switch gear credit calculation, and deferral and variance account information as appropriate. In addition, the company must file the information required in section 15.1.5 of this Decision.

The OEB acknowledges that some information on these schedules, such as the approved 2017 revenue requirements of the other transmitters, have not yet been approved by the OEB. However, Hydro One is directed to use the most up-to-date information currently available to populate the schedules.

For 2017, the OEB intends to set the uniform transmission rates under a specific UTR case number, EB-2017-0280, which will include the OEB's decisions on the applicable approved revenue requirements and load forecasts of each transmitter in the Ontario transmission rate pool. Therefore, Hydro One is requested to file its draft revenue requirement/charge determinant order under both the EB-2017-0160 and EB-2017-0280 case numbers.

Deferral Account for Foregone Transmission Revenue

As the OEB has determined that the effective date of the 2017 revenue requirement for Hydro One transmission is to be January 1, 2017, provision must be made for recording the foregone revenue for the 9 months period from the January 1, 2017 effective date to the October 1, 2017 implementation date.

Therefore, the OEB will mandate the creation of a deferral account record the foregone transmission revenues over that period to capture the differences between revenue earned by Hydro One under the interim 2017 UTR (set at the 2016 UTR level and subject to adjustment following the OEB’s determination of 2017 revenue requirement applications by rate-regulated transmitters), and the revenues that would have been received under the approved final 2017 UTR. If this difference is a credit amount, then it will be refunded to ratepayers in an appropriate manner. The text of the accounting order is to be broad enough to cover this contingence.

In its draft revenue requirement/charge determinant order, Hydro One should include a draft accounting order patterned after the draft foregone revenue accounting order filed by B2M LP in its June 14, 2017 filing in proceeding EB-2016-0349.

19.0 CONCLUSION

The following list is a summary of directions for filing and other matters contained in this Decision. Where any discrepancies exist between this list and the text of the Decision, the text in the Decision governs.

Hydro One must:

- Continue to make improvements to its planning process addressing the issues that have been identified in this proceeding as well those identified in Hydro One's internal audit, and to report on the progress made in this area in its next transmission rates application (p. 18)

- Complete an independent third-party assessment of its TSP and to file this assessment with its next rate application (p. 18)

- Begin the customer engagement process sufficiently in advance of filing the application, include LDCs (to determine practical ways to seek some input from their end users), incorporate timely and meaningful input from First Nations representatives, and ensure that information presented to customers is unambiguous and easy to understand (p. 24)

- Provide a report detailing its overall performance in the execution of the capital program relative to plan showing the performance at the program level in terms of overall expenditures and in-service additions compared to the approved plan. In addition, for major projects or programs with total budgeted cost greater than $3 million which are planned to be completed during the test years, the report should show the status of each project and an explanation of any variances regarding scope, cost or schedule (p. 30)

- Work jointly with the IESO to explore cost effective opportunities for line loss reduction, explore opportunities for economically reducing line losses and report on these initiatives as part of its next rate application (p. 32)

- Report on its implementation of the recommendations from the benchmarking study in future proceedings and consider the shortcomings identified in this proceeding in undertaking future benchmarking studies (p. 34)

- Establish firm short and long term targets for productivity improvements and associated reduction in revenue requirements as a means to drive continuous improvement and improve its internal and external benchmarking standings. Put more emphasis on including performance metrics in the scorecard that provide objective year-over-year unit cost measures of productivity, safety, reliability and quality of service improvements. Consider the merits of implementing measures that reflect outcomes of its overall business such as gross fixed assets/unit of load serving capacity to more fully illustrate its overall cost of service provision. Provide an analysis of the merits of this and similar measures with its next scorecard submission. (p. 38)

- Provide a detailed explanation in future applications of any material change in the lead-lag study results from previous similar studies (p. 40)

- File complete total compensation information in the distribution rates proceeding as soon as possible incorporating items a) through g) listed in section 7.2.4 of this Decision (pp. 54-55)

- Provide, in future applications, a high level description of the main contributors to any material variance between approved and actual total OM&A expenditures in previous applications and the impact of those variances on its longer-term ability to operate and maintain its assets (p. 61)

- Report in its next transmission rates case on how the NSC determinant might be modified to respond to the concerns raised by CME in its argument (p. 67)

- Modify the language of the proposed in-service variance account for 2017 and 2018 to include the impact in 2017 and 2018 of negative variances between the 2016 forecast in-service additions of $911.7 million and the actual 2016 amounts. (p. 73)

- Establish a variance account that will operate prospectively from January 1, 2018 and is compliant with the provisions of the Pension and OPEBs Report to track the differences between the accrual costs for OPEBs and the cash payments that would be payable under the auspices of the cash method of accounting for such costs. (p. 74)

- Continue to work diligently with affected First Nations to resolve outstanding permit issues in a timely manner with the objective of providing appropriate compensation while respecting First Nations rights. (p. 75)

20.0 ORDER

THE OEB ORDERS THAT:

1.0 Hydro One shall file the draft revenue requirement/charge determinant order and the draft UTR rate order and supporting schedules (including a draft accounting order for foregone revenue) no later than October 10, 2017.

2.0 Hydro One shall also file, no later than October 10, 2017:

a) a revision to Exhibit J11.3 that separates the amounts in the “FMV in excess of Tax Basis” shown in Exhibit J11.3 between its “recapture” and “gain” components and includes a reconciliation of the deferred tax liability and deferred tax asset amounts for Networks recorded in the financial statements filed in evidence in this proceeding for the periods immediately before and after the completion of the IPO, including, in particular, a reconciliation to the deferred tax liability of $1,794 million in the unconsolidated financial statement for Networks at October 31, 2015 for “Capital cost allowance in excess of depreciation and amortization”.

b) Grossed up regulatory taxes recoverable from ratepayers in 2017 and 2018 in amounts derived by multiplying taxes calculated for each of those years, under an assumed 100% allocation to shareholders of future tax savings benefits, by the 71% recapture ratio for transmission.

3.0 Intervenors, OEB staff and other Ontario transmitters may submit comments on Hydro One's draft revenue requirement/charge determinant order and the draft UTR rate order and supporting schedules (including a draft accounting order for foregone revenue) order no later than October 14, 2017.

4.0 Hydro One shall file with the OEB, and forward to intervenors, responses to any comments on its draft revenue requirement/charge determinant order and the draft UTR rate order and supporting schedules no later than October 18, 2017.

DATED at Toronto, September 28, 2017

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX 1

THE PROCEEDING, PARTICIPANTS AND WITNESSES

THE PROCEEDING

On May 31, 2016, Hydro One filed an application with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, Schedule B for approval of its 2017 and 2018 transmission revenue requirements to be used to determine the 2017 and 2018 Uniform Transmission Rates (UTR) effective January 1 of each year.

The OEB issued a Notice of Application on July 7, 2016. In response to the Notice, the OEB received 15 requests for intervenor status. The OEB approved these interventions.

The OEB also received 9 Letters of Comment from ratepayers across Ontario, generally expressing the viewpoint that no increase should be granted and that Hydro One should control costs by becoming more efficient and controlling salaries.

An interrogatory process was held in the month of August and Hydro One senior management made a presentation of its application to the OEB, OEB staff and intervenors on September 8, 2016. A transcribed Technical Conference was held September 22 and 23, 2016 to clarify matters arising from the interrogatories.

Hydro One updated its pre-filed evidence in this case on July 20, 2016 and again on December 2, 2016.

The OEB approved an issues list for this case on October 12, 2016.

Decision on Interim Rates

On the first day of the oral hearing on November 24, 2016, in response to a request from Hydro One, the OEB acknowledged that its decision may not be issued until after the proposed effective date of January 1, 2017 and declared the current approved Uniform Transmission rates interim as of January 1, 2017 pending the OEB's final decision on the application.

The Hearing

The oral hearing began on November 24, 2016 and continued for 13 days, concluding on December 16, 2016. Hydro One submitted its Argument-in-Chief on January 13,

2017. Intervenor submissions were complete by February 6, 2017 and Hydro One's Reply Argument was filed on February 16, 2017.

PARTICIPANTS

A list of participants and their representatives who were active either at the oral hearing or at another stage of the proceeding is shown below. A complete list of intervenors is available at the OEB's offices.

OEB counsel and staff (OEB staff)	Jennifer Lea, Michael Millar, Harold Thiessen, Chris Codd, Mark Rozic, Chris Oakley
Hydro One Networks Inc. (Hydro One)	Gordon Nettleton, Kim McNab
Society of Energy Professionals (SEP)	Bohdan Dumka, Vicki Power
Consumers Council of Canada (CCC)	Julie Girvan
Canadian Manufacturers and Exporters (CME)	Emma Blanchard, Vince DeRose
Association of Major Power Consumers of Ontario (AMPCO)	Shelley Grice
Energy Probe Research Foundation (EP)	Roger Higgin, Brady Yauch
School Energy Coalition (SEC)	Mark Rubenstein, Jay Shepherd
Vulnerable Energy Consumers' Coalition (VECC)	Michael Janigan
Power Workers' Union (PWU)	Richard Stephenson Bayu Kidane
Environmental Defence (ED)	Kent Elson
Anwaatin Inc. (Anwaatin)	Elisabeth DeMarco Cary Ferguson

WITNESSES

Twenty-five witnesses testified at the oral hearing.

Witnesses called by Hydro One (all Hydro One employees):

Michael Vels, Chief Financial Officer
Oded Hubert, Vice President – Regulatory Affairs
Mike Penstone, Vice President – Planning
Glendy Cheung, Senior Manager – Taxation
Graham Henderson, Director – Account Management
Scott McLachlan, Director – Planning Optimization/Analytics
Kevin Mancherjee, Manager – Investment Planning
Bing Young, Director – System Planning
CK Ng, Director – Transmission Asset Management
Andy Stenning, Vice President – Stations and Operating
Gary Schneider, Vice President – Shared Services
Brad Bowness, Vice President – Construction Services
Joel Jodoin, Senior Financial Advisor
Samir Chhelavda, Director – Corporate Accounting and Reporting
Keith McDonell, Director – HR Operations
Judy McKellar, Senior Vice President – People and Culture/Health, Safety and Environment
Henry Andre, Director – Pricing and Compliance
Bijan Alagheband, Manager – Economics and Load Forecasting

Non Hydro One Employees:

IPSOS Panel
Sandra Guiry, Vice President and Manager (IPSOS Reid)
Brad Griffin, Senior Vice President, Head of Qualitative Canada (IPSOS Reid)

Navigant Panel
Ben Grunfeld, Director (Navigant)
Ken Buckstaff, Managing Director (First Quartile)

Compensation Panel
Georges Soaré, Partner & EVP (Hugessen Consulting)
Ryan Resch, Executive Compensation Practice Leader (Willis Towers Watson)

Witnesses called by intervenors:
For the Environmental Defence: Travis Lusney, Director, Power Advisory LLP
For Anwaatin Inc.: Don Richardson, Shared Values Solutions

TAB 4

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Ontario

BY E-MAIL

October 11, 2017

Mr. Frank D'Andrea
Vice President, Chief Regulatory Officer,
Chief Risk Officer
Hydro One Networks Inc.
7th Floor South Tower
483 Bay Street
Toronto, ON M5G 2P5

Dear Mr. D'Andrea:

Re: Hydro One Networks Inc, 2017-2018 Transmission Revenue Requirement & Charge Determinants Application Board File Number EB-2016-0160 Clarification to Decision and Order

The OEB issued its Hydro One Transmission 2017 and 2018 Revenue Requirement and Charge Determinant Decision and Order (EB-2016-0160) on September 28, 2017. On October 10, 2017, Hydro One filed its draft Revenue Requirement and Charge Determinant Order as required by the OEB. In that filing, Hydro One advised that a statement regarding the compensation of the new Chair of Hydro One, found on page 47 of the Decision and Order, did not reflect the evidence in the proceeding, in particular Undertaking J12.5 filed on December 16, 2016. The OEB agrees that the statement in the Decision and Order referred to by Hydro One requires clarification.

The last full paragraph on page 48 of the Decision and Order currently reads:

> The budgeted annual compensation cost of the new Chair is about $1.7 million and $1.8 million in 2017 and 2018, respectively, with about 53% of those amounts being allocable to transmission. The 2014 cost of the Chair that was replaced was about $300,000.

Pursuant to section 41.02 of the OEB's Rules of Practice and Procedure, the OEB will clarify that paragraph on page 48 of the Decision and Order to read:

> The budgeted annual compensation cost of the new Chair is about $1.7 million and $1.8 million in 2017 and 2018, respectively, with about 53% of those amounts being allocable to transmission. *Of those amounts, $1.4 million is attributable to the Ombudsman's Office.* The 2014 cost of the Chair that was replaced was about $300,000.

A revised version of the EB-2016-0160 Decision and Order has been issued.

Sincerely,

Original Signed By

Kirsten Walli
Board Secretary

c All Parties, EB-2016-0160

TAB 5

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2016-0160**	**Hydro One Networks Inc. Transmission**
VOLUME:	**1**	
DATE:	**November 24, 2016**	
BEFORE:	**Ken Quesnelle**	**Presiding Member**
	Emad Elsayed	**Member**
	Peter C.P. Thompson, Q.C.	**Member**

EB-2016-0160

THE ONTARIO ENERGY BOARD

HYDRO ONE NETWORKS INC. TRANSMISSION

Application for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Thursday, November 24, 2016,
commencing at 9:36 a.m.

VOLUME 1

BEFORE:

KEN QUESNELLE	Presiding Member
EMAD ELSAYED	Member
PETER C.P. THOMPSON, Q.C.	Member

A P P E A R A N C E S

MICHAEL MILLAR	Board Counsel
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MICHAEL JANIGAN	Vulnerable Energy Consumers' Coalition (VECC)

investments to apply zinc protective coatings to aged steel towers in corrosive environments to extend their asset life in a cost-efficient manner and mitigate future rate impacts.

Our approach in making integrated station investments achieves planning efficiencies in the following fashions. It enables stations to be reconfigured when they are being refurbished to reduce the amount of major power equipment within the refurbished environment. This will reduce capital costs and long-term operation and maintenance expenditures.

Secondly, integrated station investments enables us to reduce the number of planned outages necessary to accomplish the work. This reduces the risk of customer interruptions and contributes to increased customer satisfaction.

MR. NETTLETON: Now, Mr. Penstone, I mentioned to the Panel that you will be appearing also on the investment planning panel as well. And just can you confirm that more detailed matters about the investment plans will be matters that you are prepared to address as part of that separate panel?

MR. PENSTONE: Yes, I can confirm that.

MR. NETTLETON: Thank you.

Ms. Cheung, turning to you now and with respect to income tax changes resulting from privatization. Now, this was a topic that the Board highlighted in Procedural Order 3, and I am wondering if you could please summarize the main factors that have given rise to the changes in income tax resulting from privatization.

MS. CHEUNG: Yes, I can summarize those changes.

There are three main factors. First, the Province previously owned 100 per cent of the outstanding shares of Hydro One. When the Province decided to sell more than 10 per cent of its interest in Hydro One, it changed the Hydro One's federal non-taxable status and the application of provincial PILs regime. Hydro One will now be subject to tax under the federal tax regime.

Second, the change from the non-taxable to taxable status was not a change in tax law; it was application of those laws. Under the regulation to the Electricity Act, Hydro One became liable to pay a departure tax. That amount of this cost was 2.6 billion.

The tax obligation was a direct result of the Province's decision to sell its interest in Hydro One. It did not relate in any way of -- related to the regulated services which Hydro One provides to its customers. For this reason, no portion of the departure tax is being recovered or included in Hydro One's revenue requirement.

Third, when a corporation ceases to be exempt from tax, a deemed disposition is triggered under the provisions of the Federal Income Tax Act. Hydro One is deemed to dispose and reacquire its asset at fair market value. This deemed disposition triggered a tax obligation on a difference between the fair market value and the tax costs of the assets.

From a tax perspective, this also means that Hydro One's assets was revalued at fair market value. It will now become the new tax costs of its asset for which capital cost allowance is calculated and deducted.

MR. NETTLETON: Now, Ms. Cheung, did the disposition of the Province's shares result in Hydro One actually making a payment for the departure tax obligation?

MS. CHEUNG: Yes, it did. Payment of this amount was made to the Ontario Electricity Financial Corporation, the OEFC. Importantly, when payments are made to the OEFC they are directed to a specific purpose, namely, the retirement of provincial long-term debt.

Prior to the transaction, when Hydro One was under the PILs regime, PILs payments were made to the OEFC. Subsequent to the IPO, Hydro One is no longer subject to PILs of corporate income tax, so the departure tax may be viewed as a lump sum of the future PILs that the OEFC would have received if the IPO did not occur.

MR. NETTLETON: Now, Mr. Vels, with regards to financing the departure tax obligation, can you discuss what options Hydro One had to finance that $2.6 billion obligation?

MR. VELS: Sure. At the outset, it's important that we understand that the departure tax was only one of the costs that Hydro One incurred at the time of the IPO. For example, we also incurred costs associated with the payment of a special dividend, and these costs were financed by incurrence of additional debt.

With respect to the departure tax, there were only three potential options: firstly, a recovery in rates; secondly, raise debt to finance the payment; or, third, arrange for a shareholder contribution.

Option one was rejected because of cost causation principles. Again, the cost was caused by the IPO. It's really unrelated to regulatory services provided by the company and, as such, would have been inappropriate to request recovery of this amount in customer revenues.

Option 2 was also rejected because, by doing so, it would have significantly affected the valuation of the company. As you recall, this was being done at a time when the market was valuing the shares to be sold in the market. Incurrence of a significant amount of debt required to finance the departure tax payment would have caused a significantly lower recovery for the shareholder when those shares were sold in the market because of the higher leverage levels.

Option 3 was selected because the shareholder could take steps to protect the valuation of Hydro One shares and thus avoid the adverse valuation result. However, this still meant that the shareholder incurred a cost, because it had to raise the necessary funds and make a contribution equal to the departure tax payment, and, in return, it received additional shares in the company.

MR. NETTLETON: Now, panel, were the proceeds of the departure tax used to fund the shareholder's investment? Ms. Cheung?

MS. CHEUNG: No. The payment of the departure tax was used to pay down debt by the OEFC.

MR. NETTLETON: Mr. Vels, the evidence is that Hydro One incurred a $2 billion cost. Is it also the case that the shareholder has incurred a cost?

MR. VELS: Yes. The shareholder incurred a cost because it was required to maintain its valuation in the shares by contributing an amount into the company equivalent to cover the expense of the departure tax.

As a result, it no longer had access the that cash, and it was unable to use it for different purposes. They will be able to, and we expect they will, recover part of that cost in the future as they sell the shares at a higher valuation than would otherwise have been the case if they had not recapitalized the company.

MR. NETTLETON: Now let's turn to capital cost allowance, Ms. Cheung. Will the change in CCA reduce Hydro One's future tax obligations?

MS. CHEUNG: Yes. The CCA is an allowable tax deduction that reduces taxable income, which results in lower income tax obligations. The increase in this deduction arises because Hydro One was no longer a tax-exempt entity under the Federal Income Tax Act, and, as such, its assets were deemed to be acquired at fair market value.

The increased deduction is a benefit to Hydro One. However, this benefit follows from the costs incurred, which resulted from the shareholder's decision to sell a portion of its ownership to the public market. It is this decision that caused Hydro One to no longer have a non-taxable status under the Federal Income Tax Act, so these concepts, the IPO, the cost to finance, and payment of the departure tax were all linked costs and relate to the benefits of the increase in CCA deduction.

MR. NETTLETON: Okay. Ms. Cheung, why is the increase in CCA not reflected in the revenue requirement that's been applied for in this application?

MS. CHEUNG: The principle that Hydro One has applied is that all costs and all benefits arising from the IPO are to the company's account. Hydro One is not seeking the recovery from the ratepayer of any costs associated with the IPO, so the departure tax is not being recovered in rates. Similarly, the fair market value bump does not affect the accounts and balances upon which rates are set. Rates remain calculated using historical net book value. Since ratepayers are not incurring costs of the IPO, the benefits of those transactions, like the deferred tax asset, are also not being included in the Hydro One's rates.

The principles that we are following here are Hydro One's transmission remains regulated on a standalone basis and that benefit should follow costs.

MR. NETTLETON: Now, in the Board Staff's Interrogatory 134, Hydro One was referred to the RP-2004-0188 decision, which is entitled:

"The Report of the Board on the 2006 Electricity

Distribution Rate Handbook”

And, Mr. Vels, do you believe the circumstances in that case are similar to the ones now before the Board?

MR. VELS: No. We believe there are significant factual differences. In the case of Hydro One, the shareholder has incurred a real cost, as we discussed earlier. In the RP 2004-0188 decision, the Board disregarded the regulatory principle that benefits follow costs.

In 2001, the Ministry of Finance required the revaluation of assets to fair market value. The tax bump in that circumstance is due to the introduction of the PILs regime. The shareholder had not incurred a cost, and, thus, the benefits did not accrue to the shareholder. The Board decided in that case to allocate those windfall benefits to the ratepayers.

The obligation to pay the amount is due to the application of existing tax laws and tax regimes. The deemed disposition laws applied when there was a change in the taxpayer's taxable status.

So Hydro One has incurred a real cost and paid $2.6 billion to the OEFC. In contrast, in RP 2004-0188, there was no similar cost payment.

MR. NETTLETON: Thank you, panel.

Mr. Chairman, those are my questions for direct evidence. This panel is available for cross-examination now.

MR. QUESNELLE: Thank you, Mr. Nettleton. I have one

TAB 6

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2016-0160**	**Hydro One Networks Inc. Transmission**

VOLUME:	**2**	
DATE:	**November 25, 2016**	
BEFORE:	**Ken Quesnelle**	**Presiding Member**
	Emad Elsayed	**Member**
	Peter C.P. Thompson, Q.C.	**Member**

EB-2016-0160

THE ONTARIO ENERGY BOARD

HYDRO ONE NETWORKS INC. TRANSMISSION

Application for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Thursday, November 25, 2016,
commencing at 9:34 a.m.

VOLUME 2

BEFORE:

KEN QUESNELLE	Presiding Member
EMAD ELSAYED	Member
PETER C.P. THOMPSON, Q.C.	Member

A P P E A R A N C E S

MICHAEL MILLAR	Board Counsel
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BOHDAN DUMKA	Society of Energy Professionals (SEP)
MICHAEL JANIGAN	Vulnerable Energy Consumers' Coalition (VECC)

well, the utility operations, regulated operations, is what produced a value significantly greater than the current tax value?

MR. VELS: Yes. The profits that the shareholder retains from the regulated entities drives the value of the shares of the company.

MR. THOMPSON: So that's a cause of -- one of the causative elements of a component of this 2.6 billion?

MR. VELS: Because it drives the value of the assets that the shareholder owns, yes.

MR. THOMPSON: And so then we come to the obligation to pay that departure tax. Now, does the obligation rest with Hydro One Inc. -- does it, I guess, emanate from the transmission piece and the distribution piece that are owned by Hydro One Networks Inc., which is in turn held by Hydro One Inc.?

MS. CHEUNG: The departure liability or the cost that was paid was paid by each legal entity. So Hydro One Networks Inc. itself paid 2.3 billion and the remaining was paid by the remaining, the other subs.

MR. THOMPSON: Well, is that accurate, or is it Hydro One Limited paid those amounts on behalf of its subsidiaries? It's the holding company at the top that paid the money, as I understand the facts. Am I missing something?

MS. CHEUNG: From what I understand, it went through the chain of the companies. There was a recapitalization between -- from up top to below, and then paid out the

departure tax. Each legal entity had the pay their share.
MR. THOMPSON: I see. So they sent the money down to pay it to the government?
MS. CHEUNG: Yes.
MR. THOMPSON: Okay. And so that money had to be paid before there could be any privatization. That was a precursor to being able to sell shares to the public, was it? Am I right?
MS. CHEUNG: That was paid before the privatization.
MR. THOMPSON: And so, in the privatization transaction, as Mr. Millar mentioned, the shareholder of Hydro One, which is the government, right, advanced $2.6 billion to Hydro One Limited. Have I got that straight?
MR. VELS: Yes.
MS. CHEUNG: That's correct.
MR. THOMPSON: And took in return 2.6 billion shares of Hydro One Limited?
MS. CHEUNG: That's correct.
MR. THOMPSON: And then those 2.6 billion shares -- so that was in addition to the 100,000. Am I right?
MR. VELS: Yes.
MR. THOMPSON: And then those 2.6 billion shares were -- and I am looking here again at page 3-H of Mr. Brett's compendium -- there was what I think is called a reverse split, and so the 2.6 billion shares which were acquired at $1 per common share, were then put into reverse split so that. at the end of the day, there would be 595 million common shares; is that right?

TAB 7

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2016-0160**	**Hydro One Networks Inc. Transmission**

VOLUME:	**11**	
DATE:	**December 12, 2016**	
BEFORE:	**Ken Quesnelle**	**Presiding Member**
	Emad Elsayed	**Member**
	Peter C.P. Thompson, Q.C.	**Member**

EB-2016-0160

THE ONTARIO ENERGY BOARD

HYDRO ONE NETWORKS INC. TRANSMISSION

Application for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Monday, December 12, 2016,
commencing at 9:10 a.m.

VOLUME 11

BEFORE:

KEN QUESNELLE	Presiding Member
EMAD ELSAYED	Member
PETER C.P. THOMPSON, Q.C.	Member

APPEARANCES

MICHAEL MILLAR	Board Counsel
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-- we're obviously in your hands -- is Mr. Shepherd was going to go first. Mr. Shepherd has questions, as you know, on the deferred tax asset.

I was then going to go second. My questions are entirely on the chronology IPO November draft business plan figures. And I believe then others were going to follow from thereon with the two of us -- Mr. Shepherd setting deferred tax asset issue.

Mr. Rubenstein does have a few questions on the chronology that he was going to follow with Mr. Shepherd, so that SEC stays whole.

But I think that directionally was what we were going to suggest, if that is fine with you.

MR. QUESNELLE: I think that will work. Let's go on that basis then. So, Mr. Shepherd, if you start off then.

HYDRO ONE NETWORKS INC. - STRATEGY PANEL, RESUMED

Michael Vels,

Mike Penstone,

Glendy Cheung; Previously Affirmed

CROSS-EXAMINATION BY MR. SHEPHERD:

MR. SHEPHERD: Thank you, Mr. Chairman. My name is Jay Shepherd; I am co-counsel with Mr. Rubenstein for the School Energy Coalition.

I do have a compendium, which I would ask be put in evidence.

MR. NETTLETON: Sorry, Mr. Shepherd. Does this panel need to be re-sworn?

MR. SHEPHERD: No.

MR. NETTLETON: Okay, thank you.

MR. MILLAR: This will be Exhibit K11.1.

EXHIBIT NO. K11.1: CROSS-EXAMINATION COMPENDIUM OF SEC FOR THE STRATEGY PANEL

MR. SHEPHERD: This was provided to everybody yesterday, and everything in it is on the record. I have four sort of general points I want to deal with. The first relates to the accounting for the revaluation, the deemed disposition.

I am right -- I guess these questions are for you, Ms. Cheung, yes? Probably.

MR. VELS: Just two things. Firstly, if you wouldn't mind, Mr. Shepherd, just speaking up. We have having a little trouble hearing you.

MR. SHEPHERD: I am trying. My voice isn't --

MR. VELS: All right. And then, I guess secondly, if you could just let me know what the question is, and we will work out on our end who is best to answer it.

MR. SHEPHERD: Thank you. So when the province sold 10 percent of Hydro One's shares, you had a deemed disposition of all your assets, depreciable and non-depreciable. And that deemed disposition was actually two, right? One under the Electricity Act and another under the federal Income Tax Act, right?

MS. CHEUNG: The deemed disposition occurred under the federal act and as part of the Electricity Act. It is one deemed disposition.

MR. SHEPHERD: Isn't there a deemed disposition under the Electricity Act to calculate the departure tax, and then a deemed disposition under the federal Income Tax Act when you entered that system?

MS. CHEUNG: The Electricity Act refers to the deemed disposition in the federal act.

MR. SHEPHERD: Okay. And that deemed disposition all happens at once, right? It's one transaction?

MS. CHEUNG: Yes.

MR. SHEPHERD: All right. So under the Electricity Act, the deemed disposition creates income and taxes payable to the province, and some of it is recaptured and some of it is taxed as capital gains, right?

MS. CHEUNG: That's correct.

MR. SHEPHERD: We have seen that in J1.3; there is a calculation which we will come to. Under the federal Income Tax Act, there is no tax. It's simply your starting base for taxation under the federal act, right?

MS. CHEUNG: Can you just repeat the question?

MR. SHEPHERD: Yes. Under the federal act, there is no tax to be paid federally. What you have is a starting point, because you're entering the system, and so you enter at fair market value, right? That's the point of the deemed disposition?

MS. CHEUNG: So when Hydro One, more than 10 percent was sold, or Ontario has sold more than 10 percent of the shares of Hydro One as a whole, it ceased to be -- it ceased -- it had departed the PILs regime. At that time, all the assets were sold or deemed disposed at fair market value. And then all the assets will be reacquired at fair market value under the federal regime.

MR. SHEPHERD: There you go.

MS. CHEUNG: Departure tax will be paid under PILs.

MR. SHEPHERD: All right. And so at the time of that deemed disposition, there's actually two sets of accounting entries, right? There is one set that creates the tax liability, and you are going to owe some PILs, some departure tax. And there is another set that creates the deferred tax asset, right?

MS. CHEUNG: That's correct.

MR. SHEPHERD: Okay. In theory, those two amounts are the same, right?

MS. CHEUNG: They are different because there's two different valuations were used to calculate those amounts. One was an estimate, and one was more of an actuals at the time the departure occurred.

MR. SHEPHERD: I am going to come to the differences between the two amounts.

MS. CHEUNG: Okay.

MR. SHEPHERD: But in theory, the idea is that they are the same and they offset each other, right?

MS. CHEUNG: They might not be the same because the departure tax calculates capital gains and the deferred tax asset is based on the difference between fair market value and tax cost.

MR. SHEPHERD: Now, the tax liability is an immediate requirement to pay. But the deferred tax asset is the value of the future tax benefit over time, right?

MR. VELS: That's correct.

MR. SHEPHERD: It's not net present value. It's actually the calculation of what those taxes would be in the future, right?

MS. CHEUNG: It's not net present value.

MR. SHEPHERD: Right. So I looked at your annual report to find those amounts -- because they are big amounts, right? You would expect them to be in your 2015 statements -- and they are not anywhere in the income tax statement -- in the income statement.

And so the conclusion I reach -- and tell me whether this is right -- is that the ability to pay the tax, which is like a payable, is charged to other comprehensive income, and the deferred tax asset is credited to other comprehensive income; they offset in OCI. Is that right? That's the accounting entry.

MR. VELS: If you'd like the full accounting entry, we'd be happy to provide that by way of undertaking.

MR. SHEPHERD: That's fine. But I guess I am wondering whether my simple description is materially inaccurate.

MR. VELS: I think we will reserve on that, and we will provide -- if this is what you are asking -- all of the accounting entries related to the booking of these assets and liabilities. It is a complicated transaction, as you are correctly pointing out, and I would rather not answer your questions piecemeal.

MR. SHEPHERD: Mr. Chairman, I am trying to keep this as simple as possible, and I think most of the details of the accounting transactions are not really helpful to the Board. But if the bulk of the entries are an offset in OCI, which I believe they are, I think that if Mr. Vels knows that he should tell you.

MR. NETTLETON: Mr. Chairman, your comments that predicated this panel's appearance was that you wanted the best record, that this was an important issue for the Board. I am actually quite surprised that we are even having this discussion where the witness is offering up the opportunity to provide more information to approve and make sure you have the best record, and my friend is saying he doesn't want it.

So I think that, in fairness, sir, that Mr. Vels's request of providing this information on the record in this proceeding should be given, and it be taken by way of undertaking.

MR. QUESNELLE: Well, I think what would be most helpful to this Panel, and looking at the record afterwards, would be the undertaking, but also an understanding as to how the further questions can be posed so that we can carry on with Mr. Shepherd's cross-examination. So I think the details of it, Mr. Vels, we would appreciate it in that undertaking, we'll take one, but that there be an allowance for Mr. Shepherd to carry on on a premise at a high level, if that's acceptable.

MR. VELS: Yes, it is. I just want to reiterate that the entries and the accounting for this are very complicated, and I don't consider myself on the spur of the moment sufficiently qualified to give you a comprehensive answer on all of the accounting entries that were created as a result of this transaction.

So absolutely, if there a premise or if there are questions that I can answer with the confidence that I am providing you a full answer, I will absolutely do that. If I can't, I will need to provide the information later.

MR. SHEPHERD: My understanding from reading your financial statements is that the bulk of the entry is tax liability, OCI, on one side, and deferred tax asset and OCI on the other side. Those are the two balancing entries. I mean, I know there is a lot of other details, I get that, but the basic transaction is that; isn't that right?

MR. VELS: I think maybe if you'd like, I would maybe point you to Exhibit I-09-002-01, and perhaps we can point out for you and show you where the entries are related to some of the IPO transactions.

MR. QUESNELLE: While that's coming up, I take it we still would like to have the production of the undertaking, if we can give that a number.

MR. MILLAR: Yes, the undertaking is J11.1.

MR. QUESNELLE: Thank you.

UNDERTAKING NO. J11.1: TO UPDATE BOARD STAFF IR 9.7

MR. SHEPHERD: Mr. Chairman, does Mr. Vels know whether the answer to my question is yes or no? Because if he knows, maybe he could tell us first, and then we can go through the details.

MR. VELS: The answer is no.

MR. SHEPHERD: No, they don't go through OCI?

MR. VELS: The answer is I do not know the answer to your question.

MR. SHEPHERD: Sorry, I thought you were the chief financial officer.

MR. VELS: I am the chief financial officer of the corporation. As I explained to you -- and if you would perhaps go to this exhibit --

MR. SHEPHERD: It's not up on the screen yet.

MR. VELS: -- I'd show you at least the attempt that we made in the IPO to simplify these transactions and explain what the relevant entries were in the books of the company. It is a very complicated set of accounting entries. As I have said before, I am not prepared to answer yes or no to your questions without having the ability to go back and check and ensure that all of the transactions that I am representing are correctly expressed by me in an answer. I think that's a reasonable request.

MR. SHEPHERD: I don't see anything in -- nothing is on screen yet that helps me. Can you tell me what you are referring to?

MR. VELS: It's on page F1-30.

MR. SHEPHERD: Go ahead.

MR. VELS: Okay, thank you. So just to ensure I know where I am here. So page F1-30, sorry. About halfway up. You will see under "deferred income-tax liabilities" --

MR. SHEPHERD: It's not on our screens anymore.
MR. VELS: I am sorry.
MR. SHEPHERD: There we go.
MR. VELS: Could you let me know when it's on your screen?
MR. SHEPHERD: Yeah, it's on the screen.
MR. VELS: Okay, thank you. So this is a pro forma consolidated set of financial statements that outline what the impact on the company's accounts would have been. It's a reasonable proxy for all of the entries that were booked by the company at a top level, and clearly they are subsidiary accounting entries that were required to accomplish those.
But at least on a consolidated level, these are all the entries that the company would have made in its books of account, this one on a pro forma basis, but it does give you a fairly good understanding and an outline of the transactions that occurred.
So for example, we have a deferred income-tax liability halfway of up $1.380 million, beginning balance. As you can see, that amount was extinguished by netting part of the deferred tax asset against it.
If you move across to the previous page, F1-29, there is a deferred income-tax asset balance, and the remainder of the $2.6 billion was raised as an asset on the balance sheet for a net balance once all of the entries were completed for 1451, which is a number we have discussed previously in this hearing. That created -- was the

creation of the asset on the balance sheet.

At the provincial level differently --

MR. SHEPHERD: Sorry, can I just stop you for a second?

MR. VELS: Yes.

MR. SHEPHERD: So when you created that asset what was the corresponding debit?

MR. VELS: So we would have to move to the income statement -- sorry, you mean on the balance sheet? If you look down at the retained earnings line, down the bottom on page F1-30, there is several adjustments to retained earnings. The one of $2.6 billion is an adjustment to retained earnings. The explanation for that is outlined in note 2A, and I will read it:

> "In connection with the offering, Hydro One's exemption from tax under the Income Tax Act (Canada) and the Taxation Act 2007 (Ontario) will cease the apply. Under the Income Tax Act (Canada) and the Taxation Act 2007 (Ontario), Hydro One will be deemed to have disposed of its assets immediately before it loses its tax-exempt status for proceeds equal to the fair market value of those assets at that time. Hydro One will be liable to make a payment in lieu of tax under the Electricity Act 1998 in respect of the income and capital gains calculated by reference to the Income Tax Act (Canada) that arises as a result of this deemed disposition. The Minister

of Finance, Hydro One -- sorry, the amount payable is generated for departure tax. In the context of the public offering and with the consent of the Minister of Finance, Hydro One will be authorized to pay to the OEFC an amount that reasonably approximates the amount of the departure tax that will be payable by Hydro One in respect of the deemed disposition of its assets."

That is an explanation of the booking and the entries that were made through retained earnings and the assets and liabilities related to the departure tax, which is the cost the company paid and the related asset that it raised on its balance sheet, known as the fair -- as the bump or the deferred tax asset.

MR. SHEPHERD: So the deferred tax asset is really an asset and removal of the liability, and it goes in the equity line; right? The corresponding entry is the equity line? In this case retained earnings, rather than OCI; is that right?

MR. VELS: I have outlined the transactions that were made. The other entries related to the departure tax would be separate. Again, I would prefer to provide you with a full accounting of that before I answer all those questions in full.

MR. SHEPHERD: Let me just cut to the chase here.

MR. VELS: I would appreciate that, because I would just like to understand what it is that you are asking specifically.

MR. SHEPHERD: At the point of time where the deemed disposition occurs, you haven't yet paid the tax, right? You've just had the deemed disposition; you can't pay it immediately at the same time.

So you have a payable and you have an asset. Those two are the same, roughly, and your assets have gone up and your liability has gone up by the same amount, right? Roughly?

MR. VELS: No, they haven't, because the calculation of the two amounts is different. It doesn't have to be the same, and they are not the same.

MR. SHEPHERD: They are different by a couple hundred million dollars, right?

MR. VELS: Let's say, subject to check, that you are correct that they are different.

MR. SHEPHERD: Okay, so -- they are different by a couple of hundred million dollars, right?

MR. VELS: Subject to check, they are different by a couple of hundred million dollars.

MR. SHEPHERD: Thank you. So subject to that difference, you have got an asset and a liability. You haven't changed your net equity. You have made some entries to the equity, but the actual amount of your shareholder's equity, total shareholders equity, has only changed by the difference between the asset and the liability. Is that right?

Sorry, these actually set-up questions. This should be a fairly simple question to answer, I thought.

MR. VELS: And again, I don't think I am comfortable to answer those questions in detail, without reviewing all of the accounting and all of the transactions related to this.

I am sorry, Mr. Shepherd, but you are asking questions verbally that are very detailed, very complex, and I don't feel without preparation, that I am in a good position the answer them.

I do apologize for that. But that is unfortunately the fact of the matter.

MR. SHEPHERD: Fine. So I want to go to the second area, and that is at this point, once you have the deemed disposition, you have a tax liability and you have an asset.

The tax liability is a current liability. You have to pay that right away. But the asset is a deferred asset, so you are not going to get it right away. So you have a problem; you need the $2.6 billion, right? You have the find it somewhere?

MR. VELS: So at the time of the transaction, there a liability that arises, which is the departure tax. It is exactly 2.6 billion. The company is prepared to pay that; it's a cost to the company and it's required to pay it.

At the same time, you are correct, there is a deemed disposition under the income tax Canada act, which revalues the assets for tax purposes. That asset, which is a result of the IPO and the shareholder transactions that occurred, is an asset that is available to the company relative to the cost that it incurred, which allows it to deduct, on a non-regulated basis, CCA over a period of time in the future and allows it to recover the cost via cash taxes of the cost that it incurred to pay the departure tax. That is correct.

MR. SHEPHERD: So in order to get the 2.6 billion dollars -- that wasn't my question. My question was --

MR. VELS: I am sorry.

MR. SHEPHERD: -- you needed 2.6 billion dollars; you had to pay it, you didn't have the cash, right? So the province came and said we'll inject 2.6 billion dollars of equity into Hydro One so you can pay the tax, right?

MR. VELS: So the company made a number of -- I'm sorry, I am going to have to give you full answers. The company made a number of transactions at the time. There was about an $800 million dividend to the government and we had to pay the departure tax.

You are correct that there are two things we did at that time. First of all, we recapitalized the company and increased our debt levels. Secondly, we, through a subscription of shares or issuance of shares to the government, received $2.6 billion from the government via an equity issue, that is correct.

MR. SHEPHERD: All right. So I guess there's two ways to look at it. Your evidence, as I understand it, is that the company needed money to pay a tax and the province provided it. You could have asked for it from the ratepayers, you could have borrowed, but the smartest way to do it was to get an equity injection from the province to pay the tax.

That's the essence of your evidence in this proceeding, isn't that right?

MR. VELS: No, it's not. We have significantly more evidence in this proceeding; that is not the essence of it.

What you have asked me a question on is how did we finance the payment of the departure tax. The payment of the departure tax was financed by an equity issue to the province.

In terms of essence of our evidence, I don't think I can agree that that's true.

MR. SHEPHERD: So the other way to look at it, and Mr. Millar was driving at it on day two, is that the province simply waived the tax so you didn't have to pay it. You can see how people would look at it that way, right?

MR. VELS: Could you just rephrase that?

MR. SHEPHERD: When you were cross-examined by Mr. Millar on day two of this proceeding, the proposition he was putting to you was that essentially the province waived the tax. You owed them the money; they said no, you don't have to pay it, it's okay, and you did it by circulating cheques.

You can see how people would see it that way, right?

MR. VELS: No, not really. But could we go back to the transcript, so we could see what was asked and what was answered?

MR. SHEPHERD: My estimate, Mr. Chair --

MR. VELS: Mr. Shepherd, I don't recall people talking about waiving the tax. Potentially, Mr. Millar did ask if the province waived the tax, or waived the obligation or the liability. I don't recall that and if he did, I would just like to see the context in which it was asked and what the answer was.

MR. SHEPHERD: Mr. Millar says -- this is page 28 of our compendium. Mr. Millar says:

> "So what happened was that the money to pay the departure tax was provided by Hydro One to the shareholder, and then I understand it's paid to OEFC. That's who gets the 2.6 billion."

MR. VELS: Sorry, what page is that? Twenty-eight?

MR. SHEPHERD: Twenty-eight.

MR. VELS: So this transcript explains, as I understand it, that the departure tax was paid by Hydro One to the shareholder and to the OEFC. Yes, that's what it says.

MR. SHEPHERD: So he asked you there, and previously and subsequently that -- in a series of questions, he asked you, this money just went around the circle, right. There was actually no net transaction, right?

Or I am asking you. Forget Mr. Millar. I am asking you.

MR. VELS: With respect, sir, you did say that Mr. Millar asked that, and I just don't believe he did. So you are asking me?

MR. SHEPHERD: I will ask it.

MR. VELS: Okay, thank you. Could you rephrase the question?

MR. SHEPHERD: The money just went around in a circle, didn't it?

MR. VELS: I don't believe so. So I am not -- and at the risk of saying this, I am not an expert in provincial accounting. But this is my understanding of what occurred.

So the company paid the departure tax to the province. The province paid the cash to the OEFC. However, the way the province accounts for this -- and it is important that the province is different -- the gain or the increase in the value of the company related to the departure tax is booked by the province as a gain.

That gain, and I refer you if you'd -- in terms of why and how I know this --

MR. SHEPHERD: Can I just clarify?

MR. VELS: Sorry, if you wouldn't mind --

MR. SHEPHERD: I may have misunderstood what you said.

MR. VELS: If you wouldn't mind just not interrupting. I am just explaining what I understand happened at the province.

MR. SHEPHERD: And I didn't hear what you said, and I am asking for you to repeat.

MR. VELS: Which part are you asking me to repeat? Sorry.

MR. SHEPHERD: I thought I heard you say the gain is booked as a gain by the province. The gain on the payment of the departure tax? I don't understand.

MR. VELS: So first of all, the departure tax is paid by Hydro One to the province. The province takes that cash, my understanding, and was required to pay it to the OEFC.

At the same time, the way the province accounts for this -- and it's outlined in more detail and probably in a more simple way than I can explain it -- in the 2015/16 public accounts for Ontario, in the financial accountability office's report entitled "An assessment of the financial impact of the potential sale of Hydro One on the province", and also in the 2015 and 2016 Ontario budget.

So there's a $22.6 billion, roughly, gain that the province realizes as a result of the set up of the departure tax -- sorry, the set up of the deferred tax asset. That gain was transferred by the province into the Trillium trust. The expectation at the time of the province is that by doing that, it gave the province the authority and the ability to invest that money into infrastructure.

The province, from a cash perspective -- and the province is now by necessity required to recover that through incremental tax deductions, and the cash that it will recover from its investment in Hydro One.

MR. SHEPHERD: All right.

MR. VELS: The cost of that is the departure tax. The province could have retained the cash and effectively had that money available in its treasury. Because it was required to recapitalize the company, instead of having that money available to it, which it would normally have had, because the departure tax is income and is cash received by the province, it needed in order to retain the value of the company that was there prior to the transaction and restore the value of the company post the departure tax payment, it needed to recapitalize the company, and did so by way of shares.

So the cost to the province of retaining the value of the company both pre and post the IPO was effectively the recapitalization of the money and the money it was required to put into the company to ensure that we were able to continue to operate without impairment to the company.

Those costs effectively are now included in the valuation of the province's shares. The province can now recover that cost either by selling its shares to another shareholder who will now receive a share which has that cost embedded in it, or, if it continues to hold the shares, it will be required -- or the company will be required to realize that deferred tax asset which, as you correctly pointed out, will be recovered over time, and the cash that will be returned to the company will offset the cost that the province had to incur to recapitalize the company in order to keep it whole.

I really do apologize for the long question (sic), but I think it's important, as you've asked what the provincial government's accounting was and whether it was a circular cash trail. I don't believe it was. The money goes to different places. The accounting by the province is different, and the decision by the province to recapitalize the company is in fact the cost to the province of the transaction.

MR. SHEPHERD: Are you finished?

MR. VELS: Yes, I have.

MR. SHEPHERD: Thank you. So let's just unpack that.

There was a payment of the departure tax to the province, you say, who then paid it to the Trillium trust; is that right?

MR. VELS: No, I didn't say that. I said --

MR. SHEPHERD: Okay --

MR. VELS: -- it was paid to the OEFC.

MR. SHEPHERD: Sorry?

MR. VELS: I said it was paid to the OEFC.

MR. SHEPHERD: Okay. Well, what's the Trillium trust then? Where does that come in? I thought you said the departure tax went to the Trillium trust.

MR. VELS: No, I said the gain that the province realizes on the setup of the deferred tax asset, that gain is credited to the Trillium trust, and it is that that provides the government in its budget with the ability to use the Trillium trust to invest in infrastructure.

MR. SHEPHERD: So do we have evidence on that in this proceeding? Because I don't recall seeing the reference to the Trillium trust in any of the evidence.

MR. NETTLETON: Well, Mr. Chairman, the fact is, is that, as I have said before, there has been only one interrogatory asked on this whole topic area until this oral proceeding. So if Mr. Shepherd wants to see the report that Mr. Vels referred to that shows that accounting entry, I am sure that Mr. Vels would oblige.

MR. QUESNELLE: Thank you. I was just --

MR. SHEPHERD: It was a simple question: Is it in the record of the proceeding or not?

MR. QUESNELLE: If it is --

MR. SHEPHERD: It's yes-no question.

MR. NETTLETON: The answer is no, but it can be.

MR. SHEPHERD: All right.

MR. QUESNELLE: Thank you.

MR. NETTLETON: Would you like it, sir?

MR. SHEPHERD: Not yet, maybe later. Unless the Panel would like to see it.

MR. QUESNELLE: I think we would like it on the record, Mr. Shepherd, thank you.

MR. SHEPHERD: Thank you.

MR. VELS: Can I just be clear? There were three documents? Okay.

MR. QUESNELLE: Understood, thank you.

MR. MILLAR: So Mr. Chair, that is J11.2.

MR. QUESNELLE: Thank you.

UNDERTAKING NO. J11.2: TO PROVIDE DOCUMENTATION REGARDING TRANSACTIONS INVOLVING THE TRILLIUM TRUST.

MR. SHEPHERD: So it's correct, isn't it, that you paid the departure tax to OEFC, they took the money, and they paid down the province's debt; right?

MR. VELS: So we paid the money to the province, the province paid it to OEFC --

MR. SHEPHERD: Sorry, sorry, let me stop you. Did you pay it to the province or OEFC? Because your evidence is you paid it to OEFC.

MR. VELS: Oh, I'm sorry, yes, we paid it to OEFC.

MR. SHEPHERD: Thank you. And OEFC then is required to use it to pay down the debt, right? That's also your evidence.

MR. VELS: That is our understanding.

MR. SHEPHERD: Okay. So that's one side of the transaction. Then the province has to write a cheque for $2.6 billion. Where did they get that money?

MR. VELS: I don't know.

MR. SHEPHERD: Well, they are running a deficit. Presumably they got it by borrowing it, right?

MR. VELS: I don't know how the province financed that, and I really don't think I should speculate on how they would have financed the payment to us.

MR. SHEPHERD: Fine. Fine. You see -- and Mr. Vels, were you at the closing of this transaction when all this money moved around?

MR. VELS: Our lawyers were present at the closing of the transaction, and they were responsible for all of the schedules and the relevant legal documentation that underlies all of the transactions that occurred in this IPO.

MR. SHEPHERD: Were you at the transaction? Were you at the closing? Again, it's a yes-no question. I don't actually care whether your lawyers were there.

MR. VELS: So I am not a lawyer, and so my understanding, there is a fairly complicated series of closings where I am a signatory to some of the closing documents and some that I am not.

If your question is which closing documents did I sign and which ones didn't I, I could find out and provide that by way of an undertaking.

MR. SHEPHERD: I didn't ask that question. When I --

MR. VELS: Well, unfortunately I can't say yes or no without qualifying it in terms of which part of the closing, what part was I responsible for in terms of signing and which I wasn't. The transaction is very complicated.

MR. SHEPHERD: Here is what I am trying to understand.

MR. VELS: Okay.

MR. SHEPHERD: When you do corporate deals often you have to move money around that -- and it ends up back in the same place, and so what often happens is that you get what's called a daylight loan. Do you know what a daylight loan is?

MR. VELS: A bridge loan? Is that what you are referring to?

MR. SHEPHERD: Well, it's referred to in corporate transactions as a daylight loan, but a bridge loan, a loan that's less than one day. You are familiar with that, right?

MR. VELS: I am familiar with bridge financing, yes.

MR. SHEPHERD: All right. And so you get that -- you get a bank to give you $2.6 billion, the province, for example, or Hydro One even gets a bank to give you $2.6 billion, you hand it to the province. The province then hands you a cheque for $2.6 billion. You give it back to the bank. It takes like five minutes.

Is that what happened here?

MR. VELS: I would have to check on that and provide those details.

MR. SHEPHERD: You don't recall whether the $2.6 billion was an exchange of cheques?

MR. VELS: I can tell you that the money was transferred by wire transfer. In terms of the exact timing and scheduling of all of the cash transfers, no, I can't give you that detail off the top of my head. I do not have it available to me, and -- that documentation available to me right now, and I can't provide that answer.

MR. SHEPHERD: Let me move on. This is not really productive.

MR. QUESNELLE: Do you require that answer, though, Mr. Shepherd?

MR. SHEPHERD: I will get to it another way, Mr. Chairman, I hope. Or perhaps somebody else will.

The -- I want you to look at page 21 of our materials, Mr. Vels. This is page 33 of the transcript for Day 1. It's your direct evidence. And it says that the shareholder put in the $2.6 billion to maintain the valuation of the shares. Is that right? Do I understand that correctly?

MR. VELS: That's what it says, yes.

MR. SHEPHERD: And if you look at page 2 of our materials, this is your response to Undertaking J1.3. You say that the province's equity did not increase the book value or equity value of HOL, it reinstated the value of HOL to what it was immediately prior to the payment of the departure tax. Do you see that?

MR. VELS: Yes, thank you.

MR. SHEPHERD: All right. So now, that's not entirely correct; is it? Can you take a look at page -- actually, what it was is not to maintain the existing valuation, it's actually to increase the valuation of Hydro One; isn't that right? By $2.6 billion.

MR. VELS: So my understanding is that the value of the company would have and was reduced by the value of the departure tax that was paid, because it is a cost to the company, reduces the retained earnings of the company.

MR. SHEPHERD: But it also offset -- was offset by the deferred tax asset; right?

MR. VELS: I'm sorry --

MR. SHEPHERD: So the net was zero.

MR. VELS: Sorry, I see where you are going. So the cash that we required by an equity issuance was necessary to ensure that the value of the company did not deteriorate because of the impact on our balance sheet and the impact of the departure tax on our credit ratings, for example.

MR. SHEPHERD: But when you say here that the book value and the equity value didn't change, that's not right, is it?

MR. VELS: Could you just point me to that, please?

MR. SHEPHERD: On page 2, I showed you, page 2, "did not increase the book value or equity value of HOL."

MR. NETTLETON: What line are you at, sir?

MR. SHEPHERD: Line 25. So that's not right, is it?

MR. VELS: Well, it says that the recapitalization of the company following the payment of the departure tax did not increase the book value or equity value for HOL. It reinstated the value of HOL to what it was immediately prior to the payment of the departure tax.

MR. SHEPHERD: And that's not true, is it? I am going to take you to your statement.

MR. VELS: It would depend again on the timing of the entries, and the relative book values of the company relative to the time of the departure tax and the set up of the deferred tax asset.

MR. SHEPHERD: No. Take a look at page 14 of our materials. This is your 2015 balance sheet, isn't it? You recognize this, right? Do you see that?

MR. VELS: I am on page 14, yes.

MR. SHEPHERD: Okay. So did your equity stay the same, or did it go up?

MR. VELS: Did my equity stay the same, or did it go up from when?

MR. SHEPHERD: At the end of 2014, it went up to 9.8 --

MR. VELS: Sorry?

MR. SHEPHERD: At the 2014, it was 7.5. It went up to 9.8, even after you paid a dividend equal to and all of your earnings.

MR. VELS: So these are two different time periods. 2014 was prior -- so the equity balance between 2014 and 2015 has increased, that's correct.

MR. SHEPHERD: And it increased because of the $2.6 billion the government put in, isn't that right? Again, it's yes-no question.

MR. VELS: The value of the equity was increased when we -- when the government subscribed for shares, that's correct.

MR. SHEPHERD: And -- all right. So if the equity investment increased the value -- now, you've been saying it maintained the value. But it actually increased the value, right, of the company?

MR. VELS: Yes, it was required to increase the value.

MR. SHEPHERD: All right. Now the tax you paid, you didn't include that in your tax expense, did you, in your financial statements?

MS. CHEUNG: In the income statement of the annual report on page 15 of your package --

MR. SHEPHERD: Yes.

MS. CHEUNG: -- the 2.6 billion departure tax would have been booked in the current income tax line of that

2.9 million.
MR. SHEPHERD: Sorry, this is not your income statement now, is it? That's a note.
MS. CHEUNG: Oh that's a note, sorry.
MR. SHEPHERD: So can you show us on page 12, your income statement, where it shows.
MS. CHEUNG: So on page 12, income tax line for 2015 was 105 million. That's net of current and deferred taxes.
MR. SHEPHERD: And but the reason why it doesn't show that you had an expense there is because you don't include things that are not rate regulated in your income statement, do you?
MS. CHEUNG: Non-rate-regulated items would be included in this expense line for future taxes.
MR. SHEPHERD: Okay. Then why do you -- if you look at page 9 of our materials, you say, well, we are concerned about FFO. You know what FFO is, right? Funds from operations.
MR. VELS: Yes, I know what it is.
MR. SHEPHERD: Okay. You say, well, our FFO was really bad in 2015 because we had the pay all this tax. But that's not really our real FFO, so we are going to adjust for it; isn't that right?
MR. VELS: Well, that is incorrect. Our -- and I hesitate to use the word "real", but our FFO was negative 1.479. We showed the impact on that FFO of the deferred -- sorry, of the departure tax payment in order that shareholders could see a comparable number between 2014 and

2015, as 2014 did not include a departure tax payment of that magnitude.

MR. SHEPHERD: The equity injection from the province, $2.6 billion, the province had shares prior to that time, right?

MR. VELS: That's right.

MR. SHEPHERD: They owned a hundred percent of the company.

MR. VELS: Yes.

MR. SHEPHERD: And they then gave you $2.6 billion for more shares. But they still just had a hundred percent, right?

MR. VELS: That's right.

MR. SHEPHERD: But the value of the company went up by the same $2.6 billion, right? That's what happened in that transaction.

MR. VELS: Well, we issued equity, so the value of the equity increased, that's correct.

MR. SHEPHERD: So they got 2.6 billion dollars worth of shares for their money.

MR. VELS: That's right.

MR. SHEPHERD: So if the value of the hundred percent of the company they had before was, let's say, $15 billion and they gave you 2.6 billion, after the transaction their 100 percent was worth 17.6; is that right?

MS. CHEUNG: Well, soon after they pay the departure tax of 2.6 billion, so the company would have been down by another 2.6.

MR. SHEPHERD: Well, no, it wouldn't be, would it? Because we just looked at the equity at the end of the year -- this is after the departure tax is paid, right? The departure tax was paid before the end of 2015?

MS. CHEUNG: Pardon me?

MR. SHEPHERD: The departure tax was paid by December 31st, '2015, is that right?

MS. CHEUNG: It was paid soon after Hydro One departed the PILs regime, so a matter of days.

MR. SHEPHERD: Okay, it was a yes-no question. The departure tax was paid before December 31st, 2015, is that right?

MR. VELS: That's correct.

MR. SHEPHERD: Thank you. So if your equity went up by that 2.6 billion dollars at the end of the year, that means that paying that departure tax didn't reduce their value, did it?

MR. VELS: Sorry, the equity didn't go up at the end of the year. The equity was issued to the province prior to the completion of the IPO, at the time the departure tax was paid.

MR. SHEPHERD: Your portraying to this Board that the province paid the departure -- paid the equity, and you paid the departure tax, and everybody was in the same position as before. But that isn't true, is it?

MR. VELS: No, so I -- what we are portraying is that there was a transaction that was created by the shareholder, that resulted in both payment of a departure tax, as you correctly pointed out, the necessity to raise and show a deferred tax asset on the balance sheet, and then we needed to finance the cash required to pay the departure tax, and issued shares to the province to fund that. That's what we are representing.

MR. SHEPHERD: Could we go back to page 2 of our materials, before we leave the equity. When you did the IPO, the market value of the company was -- it says here was based on the equity return. And I think you have said somewhere else that you actually used discounted future cash flow, right?

MR. VELS: We used DCF, or discounted cash flow, to value the company, that's correct.

MR. SHEPHERD: All right, Mr. Chairman, I am assuming that we are not going to have a break because we have already had lots of them.

MR. QUESNELLE: I'll ask the court reporter. Are you okay?

MR. SHEPHERD: I am trying to get through this as fast as possible, but as you can see, it's taking longer than I thought. I will try to do my best; I will change how I am wording my questions.

So now going forward, you have a tax calculation which is at page 7 of our materials, it's J2.10. Do you have that? And I couldn't figure out these numbers until I realized this is just transmission; right? This doesn't include -- this is not including the whole impact of the departure tax and the deferred tax asset, it's only the transmission impact; right?

MS. CHEUNG: Are we looking at the corporate minimum tax or the departure tax "calc"? I think you said page 2.

MR. SHEPHERD: I am talking about, going forward, what your taxes will be, so this shows what your taxes will be going forward; right? On page 7.

MS. CHEUNG: Yes.

MR. SHEPHERD: Right. And I also thought it appears like you are saying, well, our taxes would be 35.9 million, but instead they are going to be 12.2 million, but that's not right; is it?

MS. CHEUNG: So this schedule calculates the Ontario income tax and the corporate -- Ontario corporate minimum tax and compares the two.

MR. SHEPHERD: I understand. But there is also the federal tax; right?

MS. CHEUNG: Yes.

MR. SHEPHERD: So the total that you would pay, if it weren't for the deferred tax asset, in 2017 would be 81.3 million, right? That's the number in your application.

MS. CHEUNG: Can you refer back to the exhibit for that number?

MR. SHEPHERD: I am sorry, I don't have it in front of me. The number has been thrown around like 20 times in the last week, and it's in your evidence. Will you accept subject to check that your application is asking for $81.3 million --

MR. VELS: Well, I think if it's in the evidence why don't we just go to it.

MR. SHEPHERD: Because I don't know where it is.

MR. VELS: Oh, okay.

MR. NETTLETON: Mr. Shepherd, part of the issue is that there have been updates to the evidence, and one of the updates has been this number.

MR. SHEPHERD: Okay.

MR. NETTLETON: So if you give us a minute, if you don't have the reference to the number that you are using in your cross-examination --

MR. SHEPHERD: I do not.

MR. NETTLETON: -- then we can help you if you give us a minute, but I don't think it's necessary to be so pejorative to the witness, okay?

MR. SHEPHERD: I am sorry, I am not getting straight answers, and it's very difficult cross-examination.

MR. VELS: It is in Exhibit C1, tab 4, Schedule 4, page 1. It's referred to in our question 9.

MR. NETTLETON: And I am just wanting to make sure, sir, that that's the updated number, because there have been updates to it.

MR. VELS: We have three schedules roughly that all change the number, so it is a difficult schedule, and I would just like to make sure that for the evidence we are referring to the correct schedule.

MR. SHEPHERD: So you would rather use 81.9? The difference doesn't matter. For the point we are talking about --

MR. NETTLETON: I think the record does matter, sir.

MR. SHEPHERD: We are admonished by the Board periodically for not going after things that are not material. The difference between 81.9 and 80.3 is not material.

MR. QUESNELLE: I suppose that what is important, Mr. Shepherd, is that we have it in the right context, and I haven't followed the reason for the update, but if the updated number is 81.9, let's use that in the context it was provided.

MR. SHEPHERD: Is that the right number, 81.9?

MS. CHEUNG: That's the last update.

MR. SHEPHERD: Okay. So what you are proposing to collect from the ratepayers is $81.9 million plus the gross-up for that; right?

MR. VELS: What do you mean by "gross-up"?

MR. SHEPHERD: Well, you have to collect a gross amount in order to have money for taxes, right, because the money you collect is also taxed.

MR. VELS: Well, the way our revenue requirement is calculated is we recover the actual amount of taxes paid on the regulated assets based on our tax calculations. I believe that's the way the revenue requirement is calculated, subject to correction.

MR. SHEPHERD: Really? I have never seen a utility that did that.

So when you get the $81.9 million in rates, you have to pay tax on it; right?

MS. CHEUNG: So in our model we do a circular "calc". It does go through this calculation. It goes through many iterations to determine the revenue requirement for tax.

MR. SHEPHERD: So it is grossed-up.

MS. CHEUNG: I don't have the calculation.

MR. SHEPHERD: I don't need it. So is that 81.9 the grossed-up number or the net number?

MR. VELS: This is the tax that we would recover from customers.

MR. SHEPHERD: So you are proposing to collect some number that is at least $81.9 million from ratepayers, but in 2017 you're actually expecting to pay $12.2 million in tax; right? That's what page 7 says; isn't that right?

MS. CHEUNG: The calculation that was prepared for corporate minimum tax was an illustration for -- as a legal entity for Hydro One Networks we will be paying minimum tax. But based on the calculation for taxable income from regulatory purposes we have taxable income, and that tax, Ontario tax, for that taxable income for regulatory purposes is in excess of the Ontario minimum tax.

MR. SHEPHERD: You lost me. You are collecting from the ratepayers 81.9 million, right?

MS. CHEUNG: Yes.

MR. SHEPHERD: You are not sure whether that's the grossed-up number or not. I think Mr. Vels says it's not the grossed-up number, but I think you've said it is.

MS. CHEUNG: It runs through an iteration of calculation. I am not -- our other group prepares the calculation, so --

MR. SHEPHERD: Right. So you are going to collect, let's say, 81.9 million. You are actually not going to pay 81.9 million in tax for 2017; are you? You are actually going to pay 12.2 million.

MR. VELS: No. So again, I just want to be clear. And I think this will help. The number's illustrative in terms of what we will actually pay will be based on a calculation of taxable income at the Hydro One Networks Inc. level at the end of the year.

But for the purposes -- if you wouldn't mind me presuming, for the purpose of where you are going here, I think your point is that the amount of taxes that we would be including in rates is greater than the amount that we would pay. I think that's --

MR. SHEPHERD: And the amount you are going to pay is a small fraction of -- you expect it's going to be a small fraction, because you have enough shelter to cover everything off except minimum tax; right?

MR. VELS: Yes, that's correct, because we pay the minimum tax, as you pointed out, and we will utilize the deductions arising from the deferred tax asset, which is a non-regulated deduction that's made at the HONI level, and that reduces the consolidated legal entity's taxes, and as a result we do pay less taxes at the legal entity level because we are making use of the tax shield that arises from the deferred tax asset that arose as a result of the

IPO transaction and is unrelated to the regulated assets upon which we usually deduct CCA and which is the basis for our revenue requirement both before and after the IPO.

MR. SHEPHERD: When you refer to "on a legal entity basis", the legal entity is the company that is regulated by this Board; right?

MR. VELS: That's correct.

MR. SHEPHERD: So it's a legal entity, but it's also regulated by this Board; right?

MS. CHEUNG: Well, the legal entity composed of three segments: the transmission, distribution, and our non-regulated segment.

MR. SHEPHERD: Okay. And you have allocated this tax deduction to the non-regulated, even though it actually arises out of the assets that are used in the regulated segment; right?

MR. VELS: No, it doesn't. It arises from the deemed disposition and the revaluation for tax purposes, not for regulatory purposes, of the assets that we utilize to provide the service to ratepayers. So it is different.

MR. SHEPHERD: So you are going to have extra deductions on the regulated assets --

MR. VELS: On the revaluation of the regulated asset; that's correct.

MR. SHEPHERD: Well, it's the same assets; right? Is it different assets?

MR. VELS: No, they're the same assets.

MR. SHEPHERD: Same assets, right? So you are going to have more deductions than you've used in your calculation before this Board, you are going to have more deductions, but the ratepayers will not get the benefit of that; right?

MR. VELS: The ratepayers will not get the benefit of the element that is not related to the usual CCA deduction. Equally, we -- they will not be charged the cost, the $2.6 billion cost, that was expended by the company in departure taxes that arose -- that was one of the results of the transaction that gave rise to the creation of the deferred tax asset.

MR. SHEPHERD: Well, you weren't charged it either, right, because the province just gave the money right back to you.

MR. VELS: No, we had to pay the departure tax.

MR. SHEPHERD: And they gave it back to you.

MR. VELS: There is a difference between an expense and a cost to the company, and a recapitalization of the company required to pay the cash. They are different.

MR. SHEPHERD: Now, you have talked about this tax break being around for five years, but it's actually going to be quite a bit longer than that; right?

MR. VELS: We believe that the effect of the cash tax savings will last for at least five years. It may well be longer; it depends on the level of taxable income in those five years.

MR. SHEPHERD: Well, the way I calculate it based on these -- on your estimate of taxable income and your statements, et cetera, it looks like you are going to save somewhere around $120 to $130 million in taxes for both regulated components for at least twenty years. Is that reasonable? Am I in the ballpark?

MR. VELS: No.

MS. CHEUNG: I don't understand your calculation.

MR. VELS: I don't believe so. So the deductions that arise from the deferred tax asset will last for some time, and effectively over the lives of the underlying assets.

In terms of the value of the cash taxes of those deductions, I can't tell you that it's twenty years. I believe it is longer than five, which I think was your original question. At the time that we made the estimate, we believed it was at least five. But we would have to calculate that if you were interested in understanding how long and by how much.

MR. SHEPHERD: When your auditors passed on the deferred tax asset on your balance sheet, you did a calculation for them of the deferred tax asset?

MR. VELS: A calculation of the deferred tax asset?

MR. SHEPHERD: Yes. There was a worksheet, right?

MS. CHEUNG: Yes, we calculated something, and our auditors reviewed that.

MR. SHEPHERD: Okay. And that calculation has to demonstrate two things. It has to demonstrate how much is the value of the asset based on current tax rates, right? Is that true?

MS. CHEUNG: Can you repeat that?

MR. SHEPHERD: The first thing it has to show, that calculation has to show, is the value of the asset based on current tax rates, right?

You take the deductions, you multiply them by the current tax rates, and you get a number, right?

MS. CHEUNG: The deferred tax asset was calculated based on the value of the assets and the tax cost, and then times the tax rate, essentially.

MR. SHEPHERD: You lost me there.

MS. CHEUNG: Yes, I was kind of lost, too, from how you describing. So maybe you can clarify.

MR. SHEPHERD: You have a bump, right; you a bump in the value of the assets, right? The deferred tax asset is the value of that bump -- that is the dollar, the extra deductions you are going to get because of the bump -- multiplied by the tax rate today. Is that right?

MS. CHEUNG: It would be based on future tax rate, which is the same as the statutory rate right now.

MR. SHEPHERD: Yes, okay. So that's the first part. You have to show them that.

But the second thing you have to show under US GAAP, tell me if this is right -- you are under US GAAP, right?

MR. VELS: That's right.

MS. CHEUNG: Yes.

MR. SHEPHERD: So the second thing you have to show is that that value will be realized during a period where you are able to realize it. That is, that it won't expire, that it won't disappear over time, because you can't treat it as an asset unless you are going to be able to recover it, right?

MR. VELS: Well, there needs to be an expectation that the asset will be realized through future tax deductions, that's correct.

MR. SHEPHERD: So your calculation of the deferred tax asset shows both those things, right?

MR. VELS: Umm --

MR. SHEPHERD: I think you've seen the spreadsheet, right?

MR. VELS: Sorry, which one you talking about?

MR. SHEPHERD: The spreadsheet she just referred to.

MS. CHEUNG: Well, obviously we had something in order to calculate in the undertakings, IRs, to determine what was the deferred tax asset for DX and TX -- I mean distribution and transmission. So we do have some calculations.

MR. SHEPHERD: All right. I wonder if you could undertake to provide those.

MR. VELS: Can I just be clear on what we are undertaking to provide?

MR. SHEPHERD: You are undertaking to provide the calculation of the deferred tax asset, either -- the better one would be the one Ms. Cheung just referred to, which is the one that splits up transmission and distribution for the purposes of this proceeding. But I'd also like to see the one that was approved by your auditors.

MR. VELS: So we will undertake to provide the calculation of the deferred tax asset.

MR. SHEPHERD: Well, that's not what I asked.

MR. VELS: Okay.

MR. SHEPHERD: First of all, there is a document that was prepared and reviewed by your auditors. I would like to see that.

Secondly, there was a more detailed calculation just referred to, to split it between distribution and transmission for the purposes of this proceeding. I'd like to see that.

Those are existing documents, right? I am not asking you to make a new document. I'd prefer not to see a new document. I'd prefer the see the documents that have already been prepared.

MR. VELS: I'm just concerned about your first request. Is it you are asking for a document that was reviewed and approved by our auditor? I'd just really like it to be specific in terms of what the calculation is that you are asking for -- and I apologize if I am misunderstanding.

I just want to be absolutely crystal as to what the calculation is that you are looking for.

MR. SHEPHERD: Ms. Cheung said a document was prepared that calculated the deferred tax asset, and it was provided to the auditors who reviewed it. Is that right?

MS. CHEUNG: That would be part of our tax provision working papers.

MR. SHEPHERD: Okay. So I would like that working paper.

MR. VELS: Can we discuss this separately, at least, and get back and understand if we can provide it.

MR. SHEPHERD: Why would you not be able to provide it?

MR. VELS: It's a very detailed set of working papers and the spreadsheets, and understanding that you would like a simple answer, I am not sure if we need to actually summarize and prepare it to a point of quality that it could be entered into evidence, or if it is a series of very complex and detailed spreadsheets that show other information that we may choose not to provide to this hearing.

I don't know the answer. I have not reviewed the document myself. I am just nervous about agreeing to provide an existing document that may not provide your answer.

MR. SMITH: Ms. Cheung has seen the document, right?

MS. CHEUNG: Well, it's a very detailed document. I don't know what you are trying to achieve by looking at each different classes in our calculations.

MR. SHEPHERD: Well, I will tell you what, can I suggest this? If you think it's too complicated for us to understand, then please provide the document with a summary.

MR. NETTLETON: Well, Mr. Chairman, my understanding from the list of questions that Mr. Thompson provided over the weekend was this is touching on the same area of "give us the background calculations to the deferred tax asset." And my response, that's now on the record, is that it's going to take time to do that.

So what I want to understand with respect to Mr. Shepherd's request of getting the specific documents and detailed working papers that were provided to Hydro One's auditors, why he would think that is essential for purposes of his cross-examination, or for purposes of his position, as opposed to having a document that provides detail regarding the calculation.

It strikes me that the latter is what is of interest, or should be of interest to the Board. The fact it was provided to Hydro One's auditor or not does not seem to be the relevant issue here. It's understanding the calculation.

MR. QUESNELLE: Mr. Shepherd?

MR. SHEPHERD: Mr. Chairman, everything that I have seen on the record in this proceeding relating to the deferred tax asset appears to us to have a sort of spin attached to it -- and I don't mean that in a pejorative way. It's trying to present the best foot forward from the company.

I understand why they do that, but that's why the Board allows us to ask for original documents. Original documents can't have that spin; they have to just be straightforward, tell the truth. And it may be that it's so complicated that our brains will explode, but if -- and if that's the case, then fine, give us a summary.

But don't say that there's a document that exists that gives us information that relates to this proceeding, but the Board can't see it. That's not right.

Mr. Nettleton asked what am I going to use it for. The whole purpose of this is so that I can then estimate, because they are not going to tell me -- that I can then estimate how much they're going to ask the ratepayers to pay every year for how many years that they are not paying in taxes.

MR. NETTLETON: Mr. Chairman, my friend has made the suggestion, the implied suggestion at least, that the evidence that Hydro One is going to be providing is something less than the truth, and I take great exception to that.

The fact is that all of the evidence that has been provided in this record, and all of the evidence and testimony that Hydro One is providing, is under oath. It's been adopted, and we are very mindful of the oath that these witnesses and this company has been given.

So I take great exception to that suggestion.

I think that what Mr. Shepherd is after and should be after for the purposes of this proceeding is understanding the calculation. The calculation can be provided. I see no reason why we have to go the added step of saying, Let's get your auditors involved.

MR. QUESNELLE: No, I don't think that that's what's being asked for, Mr. Nettleton, it was the original document. Your witness did provide the evidence that there is a document that was used in this context, and I mentioned again my earlier comment that context matters in a lot of this, and to the extent that this was provided to the external auditor for review, that document, if it contains more information than we need for this particular purpose and it can be dealt with through the summary, through an explanation, I think Mr. Shepherd has the -- wants it for his cross -- or his argument in the context that it was provided, I think that's fair, and that's not unusual. It's certainly not unusual to have that original document.

MR. NETTLETON: It's a question of timing, sir. It is unusual for this information -- it is unusual, sir, that this type of information is coming up at the late hour that it is.

MR. QUESNELLE: Well, I think -- I will address this now -- late relative to what? Because I think this Panel is prepared to stay on this issue until we are satisfied that we have enough to render a decision, so the current schedule and the current argument schedule is -- we place that in abeyance right now until we are satisfied that we have a sufficient record to move forward.

So to the extent that -- Mr. Shepherd, I believe there was perhaps two documents that you suggested. The one was the original working documents, working papers, that would have gone to the external auditors for review on an aggregate sense.

MR. SHEPHERD: Yes.

MR. QUESNELLE: And then a further calculation that had been done for the purpose of this proceeding that would separate between transmission and distribution.

MR. SHEPHERD: That's correct.

MR. QUESNELLE: Okay, can we have that undertaking?

MR. MILLAR: It's J11.3.

UNDERTAKING NO. J11.3: TO PROVIDE THE ORIGINAL WORKING DOCUMENTS, WORKING PAPERS, THAT WOULD HAVE GONE TO THE EXTERNAL AUDITORS FOR REVIEW ON AN AGGREGATE SENSE; AND THEN THE FURTHER CALCULATIONS THAT HAD BEEN DONE FOR THE PURPOSE OF THIS PROCEEDING THAT WOULD SEPARATE BETWEEN TRANSMISSION AND DISTRIBUTION.

MR. SHEPHERD: So on this -- and Mr. Chairman, time check -- and I know that this is now the longest I have ever gone over in my whole career here. I think I can do the rest in ten minutes, touching wood somewhere.

MR. QUESNELLE: Please proceed, thank you.

MR. SHEPHERD: You did a -- have you done the calculation of what the rate impact is of collecting this money and this excess over time? Have you done that calculation?

MR. VELS: No, we have not.

MR. SHEPHERD: Why not?

MR. VELS: I believe we answered this in an interrogatory, and again, I am not sure I can pull it up, because I don't remember the number. But --

MR. SHEPHERD: I didn't see it. If you answered it, I didn't see it.

MR. VELS: Could you just give me a second?

MR. SHEPHERD: Sure.

MR. VELS: I am not trying to mess up your time, I promise.

MR. SHEPHERD: Wasn't there only one interrogatory on deferred tax asset?

MR. VELS: So it's Exhibit 1, tab 1, schedule 134, and it's on page 3.

MR. SHEPHERD: Okay.

MR. VELS: And we were asked if we would provide that calculation. Our answer was that it hasn't -- that analysis has not been performed, as it would be inconsistent with the standalone benefits followed cost principle and the Board's handbook.

We would need to understand and work through how the cost would be recovered in rates at the same time, which I expect would be a difficult calculation. We would need some level of guidance from the Board as to how we would reflect the recovery of the cost of this transaction in rates going forward.

MR. SHEPHERD: I am not asking for that. I am asking what the impact on rates is of the difference between what you are asking in taxes and what you are going to actually pay in taxes until the deferred tax asset is used up.

MR. VELS: So we don't have that calculation.

MR. SHEPHERD: Okay. Would you accept that it's in the range of six-and-a-half percent? Does that sound about right?

MR. VELS: No, I can't accept that. I think you would have to tell me what your calculations are.

MR. SHEPHERD: All right. I will include it in my argument.

MR. VELS: Thank you.

MR. SHEPHERD: You did a valuation of the company, and you used discounted future cash flow; right?

MR. VELS: That's right.

MR. SHEPHERD: When you did the future cash flow, did you use expected net income -- or expected cash from operations less actual tax payable or deemed tax payable for regulatory purposes?

MS. CHEUNG: We had an external provider who did the valuation. So we are not in the position to give you, like, how that calculation was done.

MR. SHEPHERD: You don't know whether the benefit of the tax break was included in your valuation; is that what you are saying?

MR. VELS: I would like to check it.

MR. SHEPHERD: All right, well, why don't we simplify it. Why don't you just file the valuations.

MS. CHEUNG: Pardon me?

MR. SHEPHERD: If you can't give us the answer on the stand, just give us the valuation, and we will look for ourselves, okay?

MR. VELS: Actually, I can provide you an undertaking to give you a specific answer to that question.

MR. SHEPHERD: I would rather have the -- if I am going get it by undertaking anyway, I would rather have the valuation. That's what I am asking for. Can I have the valuation, please?

MS. CHEUNG: Which valuation?

MR. SHEPHERD: The valuation that uses discounted future cash flow to value the company.

MR. VELS: That is a calculation that was prepared by the province as a part of the IPO. It is prepared by an outside expert. It includes a significant amount of information that this company would consider to be confidential and material.

We are prepared, as I have outlined, to answer specific questions as to what the basis was. More than happy to check on it, come back after the break and give you the answer. I am just not prepared to provide an incorrect answer to you in the moment --

MR. SHEPHERD: Mr. Chairman, what I am asking for is the actual valuation that used the discounted cash flow. This will allow us to redo the calculation without the tax break to see what the impact is over time and to see what the impact was at the time of the issuance of the shares to the public.

MR. NETTLETON: Well, Mr. Chairman, we are trying to find a solution to Mr. Shepherd's question that provides some balance here. The fair market value calculation, the end result of that calculation, has been reported publicly. It is in the public domain with respect to the prospectus.

What Mr. Shepherd has asked is what the specific aspect of that calculation that concerns the level of the CCA that was included in future periods for the purposes of that calculation. What Mr. Vels has said is that all other aspects of that calculation he thinks contains confidential information and is a matter that has been party to or involved other parties, including the province.

I see no reason, sir, why the full valuation, calculation, or formula, or work product, or working papers associated with that calculation have any material value to Mr. Shepherd's request of the specific level of CCA that has been included in the calculation. So I --

MR. QUESNELLE: Mr. Nettleton, when you say "material value", is it -- it's my understanding that the lion's share of the valuation is based on the assets of the regulated companies; is it not?

MR. NETTLETON: Perhaps Mr. Vels can clarify, because I don't know the answer to that question specifically. I haven't seen a calculation.

MR. QUESNELLE: Mr. Vels --

MR. VELS: Valuation was required by the province to calculate departure tax, and then we used it to -- as a basis for agreeing the tax values with the CRA.

It's a combination of cash flows from both regulated and unregulated, so it's -- not obviously -- but it would include the cash flows that do stem from the regulated businesses as well.

MR. SHEPHERD: I have no objection, Mr. Chairman, if they want to file it in confidence. I would understand why it would be in confidence. But, you know, let's be realists. There were pension funds and people like that who bought shares in this IPO. They certainly saw this document, so lots of people have seen it, and what my friend is saying is, oh, but the regulator can't see it.

MR. VELS: Can I just be clear? That is a highly confidential document, and was not ever and will not be provided to any shareholder of this company, apart from actually, just to be clear, from the province at the time of the IPO, as the province required that as basis for the departure tax calculation. It's a valuation of the company. We would not provide that information to anybody outside the company on a normal-course basis.

MR. QUESNELLE: Mr. Vels, is there any way which you would propose that this Board have the opportunity to have on the record here the underpinning of the valuations tied to the regulated companies and the asset thereof?

The question that's at play here obviously is one as to whether or not there's -- well, the company's evidence is that the benefits follow the cost on this, and we are talking about the benefit being identified as the bump-up in the valuation.

It's somewhat circular in that it comes right back to that, and if this Board is having to make a determination as to whether or not it accepts the proposition, then how do we measure, for lack of a better term, the inputs to that valuation and how they are associated with the assets?

MR. VELS: So we can absolutely do that. In fact, that was the track that I was going down with Mr. Shepherd.

We can definitely provide the basis of the valuation, the discount rates that we used, the basis of certain assumptions that will be helpful to him in providing the basis for his calculations. We would be prepared to do that.

What we cannot provide is our future cash flows, our estimates of profitability, without some significant discussion. But I don't think that's what he is looking for.

MR. SHEPHERD: I am actually looking for the future cash flows and how they were calculated. That's exactly what I am looking for, because that's how you value the impact -- that's how you show the impact of the tax break on the valuation. That's exactly what I am looking for. Look, the --

MR. VELS: Sorry. I thought your first question was a specific question to the valuation on what the estimate or the assumption was behind the cash taxes that were included in the valuation. What I said was I would endeavour to find that out in short order, and provide you the answer.

So if you have other questions like discount rates, we would be prepared to find that out, too, and provide that to you. I didn't hear you ask for our future cash flows and that is not something I would actually undertake to provide.

MR. SMITH: Actually, Mr. Chairman, I specifically said I want to be able to calculate and put in my argument the impact over time of this tax break, and you do that by taking the DCF calculation, with it and without it, and you can see year after year what the progression is going to be and for how many years. That's the calculation I would like to do.

MR. QUESNELLE: That's the premise of the cash flows from what?

MR. SHEPHERD: From the regulated businesses. I don't care about the unregulated businesses.

MR. QUESNELLE: Is there a way to separate that out, Mr. Vels, and maintain the confidentiality of the unregulated business?

MR. VELS: I really would need to check on this and come back to you. The valuation doesn't specifically belong to the company. We asked for a valuation from an outside expert, and I would have to work through the legalities of what I can and can't provide.

We have certain information that clearly we have inside the company relative to the assumptions and the inputs that went into that valuation. I can provide those.

Whether or not I am in a position to actually provide the valuation itself, which is the property of our external expert, would require their approval and we would have to work through that with them.

So I am trying to be helpful and understand what it is that Mr. Shepherd is trying to do in terms of cash flows. He could, you know, presumably assume cash flows into the future as long as he understands the basis upon which we calculated our cash taxes, discount rates, et cetera. I assume he can reconstruct the calculation that he would use in argument.

I understand that's a little presumptuous, but we would have difficulty understanding and explaining to you at this point in time whether I could undertake to provide the valuation.

MR. SHEPHERD: Mr. Chairman, can I ask a question?

MR. QUESNELLE: Please.

MR. SHEPHERD: Do you have a copy of the valuation?

MR. VELS: No.

MR. SHEPHERD: Does Hydro One have a copy of the valuation?

MR. VELS: Yes.

MR. SHEPHERD: Mr. Chairman, I think the rule is fairly clear. If you have an expert do any valuation, or do any document, and you have it in your possession, you cannot say, oh, that's not ours and not provide it to the Board.

You are a regulated entity. Regulated entities are required to make sure when they have something they can give it to their regulator.

MR. QUESNELLE: Mr. Nettleton?

MR. NETTLETON: Mr. Chairman, my understanding of Mr. Shepherd's argument is that he wants to show in final argument the impact of a change, a change between what alleged difference would be in the CCA amount.

What I heard Mr. Vels say is that in order to make that argument, you don't need the actual amounts that have been included in the discounted cash flow calculation. You can make assumptions all you want, as long as you have the underlying assumptions that are used for purposes of the discounted cash flow calculation, like discount rate used and made available.

But the actual cash flows that the company has relied on for purposes of a far different issue, like the valuation of the company for purposes of the sale of shares by the owner of those shares, not Hydro One, but the owner of those shares, seems to me to be something that isn't relevant to this issue.

The issue that Mr. Shepherd is seeking is to make an argument about the impact that the CCA value would have for purposes of suggesting that ratepayers are going to somehow suffer. But I don't think the need to make that argument requires the actual cash flow streams.

MR. SHEPHERD: Mr. Chairman, I have a suggestion. Actually, Mr. Rubenstein has a suggestion which I will take credit for, and that is I wonder if the company could provide a reasonably realistic forecast of cash flows with and without this tax break to show the difference. It doesn't need to be exact; it doesn't need to use your real cash flows, just something that is not nutty.

MR. QUESNELLE: Well, would the cash flows that -- do we have any cash flows in evidence based on the requirements as they stand today in the calculation of this revenue requirement?

MR. NETTLETON: I mean, think that's forecast on the record here is the five-year forecast period, and I am thinking about that for purpose of -- it's two years, I am sorry. It's the cap ex that's five years.

But again, I am not sure -- like it's good for Mr. Rubenstein to realize that it doesn't have to be actuals, it could be some reasonable replication. My argument, sir, is I don't even know why it has to be reasonable. It can just be assumed away because that's not what's giving rise to the metric that Mr. Shepherd is seeking, and that's the rate of change that he suggests is 6 percent, or something in that neighbourhood.

So I think if we focus on the variable as opposed to all the noise around the variable, that's the most salient and relevant issue.

MR. QUESNELLE: I think there is a nervousness of making assumptions, and having those assumptions being put in any kind of context which is inappropriate. I think that to the extent we can be precise in what is for, and then it can't be misconstrued as being something that the company views as its future lot in life from a cash-flow perspective.

Mr. Shepherd, do you have a suggestion or further refinement on this so we can move forward?

MR. SHEPHERD: What I am trying to do is -- I think it's going to be relevant to the Board if the basically tax-free period of the company is five years or 25 years.

And I think it may be closer to 25 years, and the DCF will show us that. It will show us that calculation and show where the tax breaks end.

It will also show what the rate impact is along that period and in that way, you can assess, well, does this really make sense. I mean, there's principle issues as well; I get that. But there's also issues of reasonableness and you may want that information in order to assess the reasonableness.

MR. NETTLETON: Mr. Chairman, why don't we let the witness do what he has offered and provide something to the parties so that we have some context around what it looks like, and then make a decision about why what Mr. Vels has provided is sufficient or why it is isn't sufficient.

But at least let's get something down so that we have some context.

MR. QUESNELLE: The Panel has heard arguments from both sides on this, so just give me one moment.

The Panel has obviously demonstrated its interest in this as well. We have been very -- well, it has become quite clear as to the importance we place on this issue, and I would ask Mr. Shepherd and Mr. Nettleton to take that into consideration and, perhaps off-line, work something out and attempt to come to a mutual understanding of what exactly would work, and provide the Board with more light on this issue. And we will render a decision later. If you can come to a satisfactory and mutually beneficial outcome on this, that's great, we will accept it, and if not, we will render our decision subsequent.

MR. SHEPHERD: Okay. Mr. Chairman, we will do that at lunch.

MR. QUESNELLE: Yes, please.

MR. SHEPHERD: Okay. I have just one more area. I am not going to give a time estimate. And this is -- we started this -- we talked about, Ms. Cheung, we talked about the fact that there is a difference in the value of the tax liability and the tax asset; right?

MS. CHEUNG: Yes.

MR. SHEPHERD: And as I see it, there is two differences, and tell me whether this is right. One is that the tax liability was calculated earlier and agreed with the province, and then you did revaluation later for the entry into the federal system. And that wasn't the same; right?

MS. CHEUNG: So the first valuation for the province was to determine the departure tax approximate so we could start the IPO process.

MR. SHEPHERD: Yes.

MS. CHEUNG: For -- for the next set of valuation was more, like, a trued-up value of what was available for that date.

MR. SHEPHERD: Did you use the same valuation, the same deemed disposition value, for the entry into the feds and the payment of the departure tax?

MS. CHEUNG: We used the same assumptions, just matter that we had a different time period. One was an estimate and one was based on more of the actual -- the date the departure occurred.

MR. SHEPHERD: Did you pay -- the actual departure tax that you paid, was it the -- on this same valuation that you used for federal purposes or a different valuation?

MS. CHEUNG: It was a different valuation, but the same assumptions were used.

MR. SHEPHERD: All right. So I am going to ask you to tell us what those differences were in terms of the tax impacts, but before I get to that, there is a second area in which there is a difference which you alluded to, I think, and that is, if you take a look at page 4 of our materials, this is your calculation of the departure tax. This is the calculation of the actual departure tax; right?

MS. CHEUNG: This is a high-level summary.

MR. SHEPHERD: Is the number 2264 correct? The number -- departure tax 2264; is that correct or not?

MS. CHEUNG: That's correct.

MR. SHEPHERD: Okay. And what you actually did is you paid 2408, but then you got a dividend refund?

MS. CHEUNG: That was part of the calculation.

MR. SHEPHERD: And the dividend refund exists because the capital gain is investment income, and when you pay it out to the province, which you did, or some of it, you got a refund of part of the tax; right?

MS. CHEUNG: That's right.

MR. SHEPHERD: Do you have more dividend refunds accrued on that? Like, you had a capital gain, a taxable capital gain, of 1132. So was 144 the total dividend refund, or was it only part of it?

MS. CHEUNG: I would have to check the calculations, because this is just for Hydro One Networks, and there is other entities as well.

MR. SHEPHERD: All right. So what I am trying to figure out is -- and by the way, can I ask one other question about this? You see in the line "fixed assets"?

MS. CHEUNG: Yes.

MR. SHEPHERD: So you have the tax base. That's the costs for tax purposes before the deemed disposition; right?

MS. CHEUNG: That's right.

MR. SHEPHERD: And some of it is adjusted cost base and some of it is undepreciated capital cost.

MS. CHEUNG: I would have to check.

MR. SHEPHERD: And some of it is committed on eligible capital as well; right?

MS. CHEUNG: The eligible capital expenditures is on the goodwill line.

MR. SHEPHERD: Okay. So the fixed assets are only ACB and UCC; right?

MS. CHEUNG: That's right.

MR. SHEPHERD: Okay. And then the fair market value figure is -- that's the new valuation, and the difference is the taxable component; right?

MS. CHEUNG: That's right, but there is --

MR. SHEPHERD: Okay. That's the --

MS. CHEUNG: -- two components, yeah.

MR. SHEPHERD: Okay. So I didn't understand why the recapture plus the capital gain didn't total the difference. Can you explain that?

MS. CHEUNG: This is a high-level summary, so I don't have the details here. This is high-level summary. It's not meant to be -- to show the detailed calculation to match exactly the difference.

MR. SHEPHERD: It's $500 million out. It wasn't meant to be within $500 million?

MS. CHEUNG: I am sorry, I can't answer that question, because this was just a high-level summary. I would have to go back to the detailed calculation.

MR. SHEPHERD: When you were sworn, you swore that this is your responsibility; right? You swore that this was true; right?

MS. CHEUNG: That's right.

MR. SHEPHERD: So then why doesn't it balance?

MS. CHEUNG: It's not meant to balance here. This is just to give you an idea how which components were recaptured and what components were capital gain.

MR. SHEPHERD: Is there something else besides those two?

MS. CHEUNG: No, there isn't.

MR. SHEPHERD: All right. And so --

MR. QUESNELLE: Mr. Shepherd, you just asked a series of questions that Ms. Cheung said she would have to check and get back to you. Are we taking that as an undertaking?

MR. SHEPHERD: Yes, I think we should.

MR. QUESNELLE: And I don't know --

MR. SHEPHERD: What I'd like to -- I am going to talk about the differences between the asset --

MR. VELS: Sorry, Mr. Shepherd, I was just checking with her to make sure that in fact we don't have your answer. If you wouldn't -- just give me a minute.

Thanks for that. We just confirmed that there is some detail required to provide the answer.

MR. SHEPHERD: All right. So can you reconcile the first line in this table of fixed assets, please, by undertaking?

MR. VELS: Yes.

MR. MILLAR: It's J11.4.

UNDERTAKING NO. J11.4: TO RECONCILE THE FIRST LINE IN THE TABLE OF FIXED ASSETS.

MR. SHEPHERD: And then my --

MR. NETTLETON: So Mr. Shepherd, maybe you could just -- just to the witnesses, you may want to check the math -- we are doing the math as we speak, and you may want to look at the fixed-asset line, and you may want to take a look at the goodwill line, because it looks like there is a netting there.

MR. VELS: I think it has been netted, that's what we discussed, but we would just like to be sure that that is the case.

MR. SHEPHERD: Yeah, I don't think there is a netting there, but you can answer that by way of undertaking.

MR. VELS: Yeah, we will do that.

MR. SHEPHERD: So what I am trying to figure out then is, you have the liability and you have the asset. For regulatory -- for the regulatory component -- I don't care about the other components, just the regulatory component -- can you give us a side-by-side detail of the calculation, not all the -- not every single CCA class, just higher level than that, but not just one number, that shows the calculation of the liability and the calculation of the asset, identifies the differences, and explains what they are? Are they valuation differences, are they because you have a capital gain that became UCC and therefore you get a full deduction? What are the reasons for the differences? Can you show us that calculation side by side?

MS. CHEUNG: We do not have that calculation.

MR. SHEPHERD: I am asking you to do it.

MS. CHEUNG: That would take significant time.

MR. VELS: I guess it's physically possible to do it.

MR. QUESNELLE: Are we talking days, Ms. Cheung?

MR. SHEPHERD: We are talking an hour, Mr. Chairman.

MS. CHEUNG: Pardon me?

MR. SHEPHERD: We are talking an hour.

MS. CHEUNG: An hour?

MR. QUESNELLE: Let's get past the difference of opinion by finding out if we have a difference...

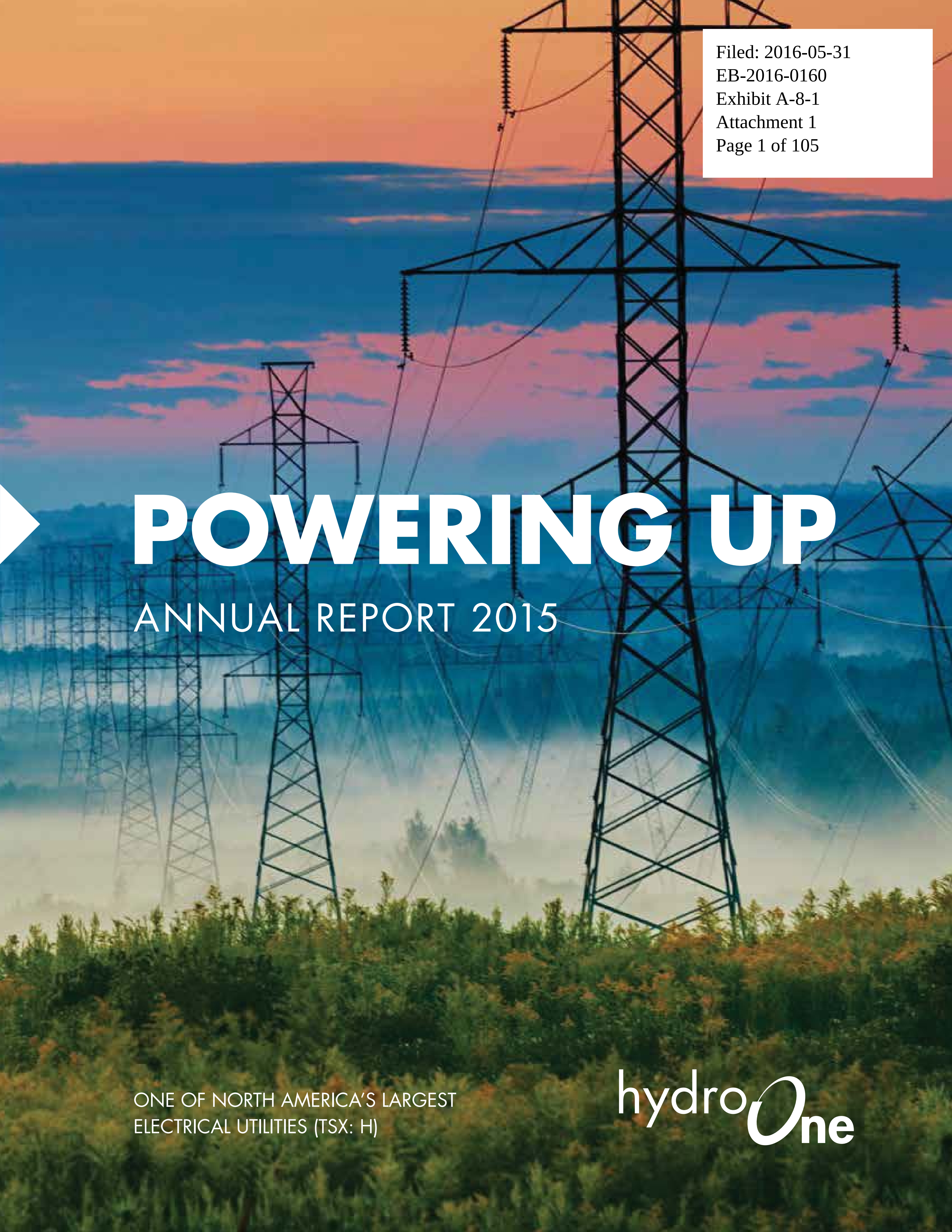
MS. CHEUNG: I don't have an answer right now.

MR. QUESNELLE: Okay.

MR. SHEPHERD: Mr. Chairman, I have no more questions.

TAB 8

Filed: 2016-05-31
EB-2016-0160
Exhibit A-8-1
Attachment 1



POWERING UP

ANNUAL REPORT 2015

ONE OF NORTH AMERICA'S LARGEST
ELECTRICAL UTILITIES (TSX: H)

hydro One

7. Income Taxes

Income taxes / provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Income taxes / provision for PILs at statutory rate	217	222
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(37)	(72)
Pension contributions in excess of pension expense	(25)	(24)
Overheads capitalized for accounting but deducted for tax purposes	(15)	(15)
Interest capitalized for accounting but deducted for tax purposes	(13)	(13)
Environmental expenditures	(5)	(5)
Non-refundable investment tax credits	(2)	(3)
Post-retirement and post-employment benefit expense in excess of cash payments	(1)	3
Prior year's adjustments	(1)	(4)
Other	(2)	(1)
Net temporary differences	(101)	(134)
Net tax benefit resulting from transition from PILs Regime to Federal Tax Regime	(19)	–
Hydro One Brampton spin-off	7	–
Net permanent differences	1	1
Total income taxes / provision for PILs	105	89

The major components of income tax expense are as follows:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Current income taxes / provision for PILs	2,949	79
Deferred income taxes / provision for (recovery of) PILs	(2,844)	10
Total income taxes / provision for PILs	105	89
Effective income tax rate	12.84%	10.63%

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime). At December 31, 2015, $12 million (2014 – $39 million) due from the OEFC was included in due from related parties and $1 million (2014 – $nil) due from the CRA was included in prepaid expenses and other assets on the Consolidated Balance Sheet.

In connection with the IPO, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Under the PILs Regime, Hydro One was deemed to have disposed of its assets immediately before it lost its tax exempt status under the Federal Tax Regime, resulting in Hydro One making payments in lieu of tax (Departure Tax) totalling $2.6 billion. To enable Hydro One to make the Departure Tax payment, the Province subscribed for common shares of Hydro One for $2.6 billion (See Note 18 – Share Capital). Hydro One used the proceeds of this share subscription to pay the Departure Tax.

At December 31, 2015, the total income taxes / provision for PILs includes deferred income taxes / recovery of PILs of $2,844 million (2014 – deferred provision of $10 million), including $2,810 million (2014 – $nil) resulting from transition from the PILs Regime to the Federal Tax Regime, that is not included in the rate-setting process, using the liability method of accounting. Deferred income taxes / PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

materials installed in some of its facilities, as well as $1 million (2014 – $1 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal.

18. Share Capital

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2015, the Company had 595,000,000 common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2015, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2015, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2015, Series 1 preferred dividends of $3 million or $0.18 per share were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to $25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20 of every fifth year thereafter, or $25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

Prior to October 31, 2015, the Company had 12,920,000 issued and outstanding 5.5% cumulative preferred shares held by the Province, with a redemption value of $25 per share or $323 million total value. These preferred shares were entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which was payable on a quarterly basis. These preferred shares had conditions for their redemption that were outside the control of the Company because the Province could exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. At December 31, 2014, these preferred shares were classified on the Consolidated Balance Sheet as temporary equity because the redemption feature was outside the control of the Company. On October 31, 2015, these preferred shares were purchased and cancelled by Hydro One Inc. See "Reorganization" below for further details.

TAB 9

INCOME TAX / PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

1. INTRODUCTION

This Exhibit explains how Hydro One calculates its income tax expenses for the purposes of rate recovery. Exhibit C2, Tab 4, Schedules 1 and 2 contain detailed calculations for rate recovery purposes of income tax liabilities, supporting reconciliations, as needed, as well as copies of Hydro One's October 31, 2015 and November 4 2015 tax returns and supporting financial statements and an explanation of how tax credits were determined. The information provided in this Application is consistent with section 2.8.11 of the Filing Requirements. Material exceptions have been identified and explained.

2. DEPARTURE FROM PILS REGIME

Under the *Electricity Act, 1998* (Ontario), as a Crown-owned company exempted under section 149(1) of the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (Federal Tax Regime) from paying corporate income taxes, Hydro One was obligated to make payments in lieu of corporate income taxes ("PILs") to the Ontario Electricity Financial Corporation.

Effective as of October 31, 2015, in connection with a public offering of its shares, Hydro One was no longer subject to this exemption and exited the PILs regime. Under the *Income Tax Act*, Hydro One was deemed to have disposed of its assets at fair market value at that time and immediately re-acquired them at the same value. Hydro One Networks Inc. was obligated to pay a one-time PILs departure tax of approximately $2.3 billion based on an estimated gain under the *Electricity Act, 1998***.**

TAB 10

CALCULATION OF UTILITY INCOME TAXES HISTORIC YEARS 2013-2015

HYDRO ONE NETWORKS INC.
Transmission

Calculation of Utility Income Taxes
Historic Years
Calculation of Utility Income Taxes Historical Years (2013, 2014, 2015)
Year Ending December 31
($ Millions)

Line No.	Particulars		2013		2014		2015*
	Calculation of Federal and ON Taxable Income						
1	Net Income Before Tax (NIBT)	$	596.9	$	621.9	$	467.2
2	**Required Adjustments to accounting NIBT**						
3	**Recurring items included in Revenue Requirement (RR):**						
4	Other Post Employment Benefit expense greater than payments		1.2		(4.5)		(1.2)
5	Depreciation and amortization		326.3		341.9		366.1
6	Capital Cost Allowance		(487.7)		(482.8)		(481.0)
7	Cumulative Eligible Capital		(9.2)		(3.7)		(3.5)
8	Removal costs		(3.7)		(3.7)		(2.8)
9	Environmental costs paid		(6.1)		(5.9)		(7.1)
10	Non-deductible items (50% Meals & entertainment / interest)		5.0		3.6		3.1
11	R & D Fed ITC/ Apprenticeship (prior yr addback)		1.8		1.1		0.6
12	Capitalized overhead costs deducted		(29.8)		(33.6)		(32.2)
13	Capital additions deducted for accounting		12.5		8.4		21.2
14	Capitalized Pension cost deductions		(50.1)		(46.2)		(45.7)
15		$	(239.8)	$	(225.4)	$	(182.5)
16	**Deferral accounts not part of RR:**						
17							
18	Restricted Depreciation		1.9		1.2		1.4
19	CDM a/c Variance		0.0		24.7		27.8
20	Tx Export credit/Deferred export Rev		9.3		(17.0)		19.5
21	Deferred Pension		(5.9)		9.8		(2.7)
22	Deferral a/c's etc.		0.7		(1.9)		-
23	Tax Changes deferral a/c s		-		(2.6)		-
24	Station Revenue and Secondary Use		9.6		(13.9)		12.7
25		$	15.6	$	0.3	$	58.7
26	**Reversal of accounting adjustments not part of RR:**						
27	Contingent liability movement		1.7		(0.6)		(2.3)
28	Capitalized interest deductible for tax		(32.3)		(32.6)		(35.8)
29	Capitalized SRED deducted for tax		0.0		(2.3)		0.0
30		$	(30.6)	$	(35.5)	$	(38.1)

TAB 11

Canada Revenue Agency | Agence du revenu du Canada

T2 Corporation Income Tax Return

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) 001 87086 5821 RC0001

Corporation's name
002 Hydro One Networks Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 483 Bay Street, 8th Floor
012 South Tower

City	Province, territory, or state
015 Toronto	016 ON
Country (other than Canada)	Postal code/Zip code
017	018 M5G 2P5

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o Giovanna Baragetti
022 483 Bay Street, 7th floor
023 South Tower

City	Province, territory, or state
025 Toronto	026 ON
Country (other than Canada)	Postal code/Zip code
027	028 M5G 2P5

Location of books and records (if different from head office address)
Has the location of books and records changed since the last time we were notified? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 483 Bay Street, 7th floor
032 South Tower

City	Province,territory, or state
035 Toronto	036 ON
Country (other than Canada)	Postal code/Zip code
037	038 M5G 2P5

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . 043 ______ YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2015-01-01 (YYYY MM DD)	061 2015-10-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [X] 2 No [ ]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . 079 ______

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ______

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

095 | 096 | 898

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2015-10-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Adjustments and transfers** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		3,637,279,150	4,953,667	21,617,173	3663849990			4	0	0		
2.	2		826,941,005			826,941,005			6	0	0		
3.	3		255,046,347	8,148,798	2,208,827	265,403,972			5	0	0		
4.	6		89,587,984	4,879,638		94,467,622			10	0	0		
5.	7		25,238			25,238			15	0	0		
6.	8		185,255,080	66,206,407	740,634	252,202,121			20	0	0		
7.	9		5,983,227			5,983,227			25	0	0		
8.	10		160,119,989	52,424,104	203,192	212,747,285			30	0	0		
9.	12		15,430,673	9,747,419		25,178,092			100	0	0		
10.	13	Leases	345,369		439,840	785,209			NA	0	0		
11.	17		81,627,929	6,160,851		87,788,780			8	0	0		
12.	35		105,340			105,340			7	0	0		
13.	42		73,028,699	8,655,300		81,683,999			12	0	0		
14.	45	Computers - old cl.10 post Mar 2	311,052		1,606	312,658			45	0	0		
15.	46	cl.8 post Mar 22/04	15,815,674	898,446		16,714,120			30	0	0		
16.	47	Electricity Assets > 22-02-2005	5,039,012,496	580,652,147	29,605,508	5649270151			8	0	0		
17.	50	Computers	92,681,205	36,338,524	27,889	129,047,618			55	0	0		
18.	13	Barrie Office (WBS 700004578)	315,600			315,600			NA	0	0		
19.	13	Atrium on Bay (WBS 300040666	71,201			71,201			NA	0	0		
20.	13	Newmarket Garage (WBS 30004	118,535			118,535			NA	0	0		
21.	13	255 Matheson Mississauga (WBS	1,173,450			1,173,450			NA	0	0		
22.	13	95 Mural Street (WBS 70001035	1,408			1,408			NA	0	0		
23.	13	Nipigon (WBS 700011829)	138,242			138,242			NA	0	0		
24.	13	Kemptville (WBS 700009832)	6,042			6,042			NA	0	0		

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Adjustments and transfers**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate % ****	9 Recapture of capital cost allowance***** (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ******	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)
	200		201	203	205	207	211		212	213	215	217	220
25.	13	Sudbury (WBS 700010356)	268,506			268,506			NA	0	0		
26.	13	Lionhead (WBS 700015140)	34,480			34,480			NA	0	0		
27.	13	483 Bay St (WBS 300042991C)	3,683,515		194	3,683,709			NA	0	0		
28.	13	Newmarket SC (WBS 700016578	9,787		699	10,486			NA	0	0		
29.	13	Orillia Forestry Work Centre (WB	299,720	19,603	18,732	338,055			NA	0	0		
30.	13	483 Bay St WBS 700015844/843	10,657,553	26,562	484,434	11,168,549			NA	0	0		
31.	13	Arnprior Forestory Work Centre (	297,884		18,617	316,501			NA	0	0		
32.	13	Orleans OC		2,307,628		2,307,628			NA	0	0		
		Totals	10,495,672,380	781,419,094	55,367,345	11,332,458,819							

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments.*

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (14)

Proceeds of disposition do not reflect FMV because the PILs arising from the deemed disposition of assets triggered by the exit from the PILs regime has already been paid under a separate process that has been the subject of a formal agreement with Ontario pursuant to subsection 16.1(5) of Regulation 207/99 of the Electricity Act, 1998 (Ontario).

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2015-10-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") ..... 200 74,626,267 A

Add: Cost of eligible capital property acquired during the taxation year 222 1,227,832

Other adjustments 226

Subtotal (line 222 plus line 226) 1,227,832 x 3 / 4 = 920,874 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 ..... 228 x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 920,874 ▶ 920,874 D

Amount transferred on amalgamation or wind-up of subsidiary ..... 224 154,310 E

Subtotal (add amounts A, D, and E) 230 75,701,451 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year ..... 242 100,935,268 G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) ..... 244 H

Other adjustments ..... 246 I

(add amounts G,H, and I) 100,935,268 x 3 / 4 = 248 75,701,451 J

Cumulative eligible capital balance (amount F minus amount J) ..... K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business 249

amount K

less amount from line 249

Current year deduction ..... x 7.00 % = 250 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) ▶ L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") ..... 300 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Proceeds of disposition do not reflect FMV because the PILs arising from the deemed disposition of assets triggered by the exit from the PILs regime has already been paid under a separate process that has been the subject of a formal agreement with Ontario pursuant to subsection 16.1(5) of Regulation 207/99 of the Electricity Act, 1998 (Ontario).

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")		►		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409	►		9	
Line 6 minus line 9 (if negative, enter "0")				►	O
Line N minus line O (if negative, enter "0")					P
Line 5				x 1 / 2 =	Q
Line P minus line Q (if negative, enter "0")					R
Amount R				x 2 / 3 =	S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

TAB 12

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities.

These securities have not been, and will not be, registered under the United States Securities Act of 1933, as amended (the "1933 Act"), or any state securities laws, and accordingly will not be offered, sold or delivered, directly or indirectly within the United States of America, its possessions and other areas subject to its jurisdiction, except in limited circumstances. See "Plan of Distribution".

SUPPLEMENTED PREP PROSPECTUS

Initial Public Offering
by way of Secondary Offering

October 29, 2015

HYDRO ONE LIMITED

$1,662,550,000

81,100,000 Common Shares

This prospectus qualifies the distribution of 81,100,000 common shares of Hydro One Limited ("**common shares**") being offered by the Province of Ontario (the "**Province**" or the "**Selling Shareholder**") at a price of $20.50 per common share. **Hydro One Limited will not receive any proceeds from this offering**. See "Principal and Selling Shareholder".

Immediately following the closing of this offering, and the other transactions contemplated by this prospectus, the Province will hold approximately 85% of Hydro One Limited's total issued and outstanding common shares (approximately 84% if the Over-Allotment Option is exercised in full). As a result, the Province will have a significant influence over Hydro One Limited and its affairs. See "Governance and Relationship with Principal Shareholder" and "Risk Factors".

Prior to the closing of this offering, Hydro One Limited will acquire all of the issued and outstanding shares of Hydro One Inc. Hydro One is the largest electricity transmission and distribution company in Ontario. Hydro One owns and operates substantially all of Ontario's electricity transmission network, and is the largest electricity distributor in Ontario by number of customers.

On August 31, 2015, at the direction of the Province, as sole shareholder of Hydro One Inc., Hydro One Inc. declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton Networks Inc. The dividend was paid to the Province, at its direction, by transferring all of the issued and outstanding shares of Hydro One Brampton Networks Inc. to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning this dividend and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc.

There is currently no market through which Hydro One Limited's common shares may be sold, and purchasers may not be able to resell common shares purchased under this prospectus. This may affect the pricing of the common shares in the secondary market, the transparency and availability of trading prices, the liquidity of the common shares, and the extent of issuer regulation. See "Risk Factors". The Toronto Stock Exchange (the "**TSX**") has conditionally approved the listing of the common shares distributed under this prospectus on the TSX under the symbol "H". Listing will be subject to Hydro One Limited fulfilling all of the requirements of the TSX on or before January 25, 2016. See "Plan of Distribution".

Price: $20.50 per Common Share

	Price to the Public(1)	Underwriters' Fee(2)	Net Proceeds to the Selling Shareholder(3)
Per common share	$ 20.50	$0.205/$0.615	$ 20.172
Total offering(4)	$1,662,550,000	$ 26,600,800	$1,635,949,200

Notes:

(1) The offering price for the common shares will be determined by negotiations between the Province and the Underwriters (as defined below).

(continued on next page)

Future Investments in Hydro One by First Nations and Métis Communities

In response to the Chiefs of Ontario's expression of First Nations' interest to own a portion of the Company, the Province has indicated that it is in discussions regarding potential equity participation by the First Nations. The Company understands that these discussions focus on facilitating equity participation for such communities through future offerings by the Province. These discussions are ongoing and are not expected to affect the number of shares available for purchase in this offering. In addition, the Métis Nation of Ontario has expressed an interest in dialogue with the Province in relation to this offering. The Province has indicated that it is also prepared to engage in a dialogue with the Métis in relation to broadened ownership of the Company.

DEPARTURE TAX

By virtue of being wholly owned by the Province, Hydro One is exempt from tax under the Tax Act and the *Taxation Act, 2007* (Ontario). However, under the Electricity Act, Hydro One is required to make payments in lieu of tax to the Ontario Electricity Financial Corporation. The payments in lieu of tax are, in general, based on the amount of tax that Hydro One would otherwise be liable to pay under the Tax Act and the *Taxation Act, 2007* (Ontario) if it was not exempt from taxes under those statutes.

In connection with this offering, Hydro One's exemption from tax under the Tax Act and the *Taxation Act, 2007* (Ontario) will cease to apply. Under the Tax Act and the *Taxation Act, 2007* (Ontario), Hydro One will be deemed to have disposed of its assets immediately before it loses its tax exempt status for proceeds equal to the fair market value of those assets at that time. Hydro One will be liable to make a payment in lieu of tax under the Electricity Act in respect of the income and capital gains, calculated by reference to the Tax Act, that arise as a result of this deemed disposition. The amount payable is generally referred to as "departure tax".

In the context of a public offering of shares, and with the consent of the Minister of Finance, Hydro One will be authorized to pay to the Ontario Electricity Financial Corporation an amount that, in the Minister's opinion, reasonably approximates the amount of the departure tax that would be payable by Hydro One in respect of the deemed disposition of its assets. Hydro One has received a letter from the Minister of Finance confirming that the total amount of the departure tax payable by Hydro One is $2.6 billion. Prior to the completion of this offering, the Province, as shareholder, will subscribe for additional common shares of Hydro One Limited for an aggregate subscription price of $2.6 billion, which amount Hydro One will use to pay the applicable departure tax.

As a result of leaving the PILs regime and entering the corporate tax regime, Hydro One will recognize a deferred tax asset that is currently estimated in the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus to be $1,245 million due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. This estimated deferred tax asset was based on an estimated fair market value of Hydro One's net assets of approximately $13,522 million, which was the same estimated fair market value used for the purposes of determining the departure tax amount of $2.6 billion referred to above. This estimated fair market value of Hydro One's net assets was determined by Hydro One principally using a discounted cash flow approach for certain assets and an asset-based approach for other assets, and was used in calculating the amount of the departure tax payable that was agreed between Hydro One and the Province in early September 2015. The actual fair market value of Hydro One's net assets will be determined following pricing of this offering. The departure tax payable by Hydro One has been fixed at $2.6 billion, and will not be adjusted based on the fair market value of Hydro One's net assets as finally determined. See "Summary Consolidated Financial Information" and "Selected Consolidated Financial Information". Management believes the deferred tax asset will result in annual net cash savings over the next five years due to the reduction of cash taxes payable by Hydro One. See note 2C(vi) of the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus for a presentation of the net cash savings that would have resulted for the periods shown if the transaction triggering the revaluation of the tax basis of Hydro One's fixed assets had occurred on January 1, 2014. Management believes that these net cash savings will not result in a corresponding reduction in its revenue requirement in future rate applications to the Ontario Energy Board. However, no determination has been made by the Ontario Energy Board and there can be no assurance that there will not be such a reduction. See "Risk Factors – Risks Relating to Hydro One's Business – Regulatory Risks and Risks Relating to Hydro One's Revenues".

Hydro One Inc. expects to pay the Ontario Electricity Financial Corporation approximately $200 million in additional payments in lieu of tax in connection with this offering. This is in addition to the departure tax payable of $2.6 billion. See note 2C(iii) of the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars, except number of shares)	**2014**	**2013**
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	2	31
Accounts payable	173	135
Accrued liabilities *(Notes 15, 16)*	611	654
Due to related parties *(Note 20)*	227	230
Accrued interest	100	100
Regulatory liabilities *(Note 11)*	47	85
Derivative instruments *(Note 13)*	3	–
Long-term debt payable within one year (includes $252 measured at fair value; 2013 – $506) *(Notes 12, 13)*	552	756
	1,715	1,991
Long-term debt (includes $nil measured at fair value; 2013 – $256) *(Notes 12, 13)*	8,373	8,301
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	1,533	1,488
Deferred income tax liabilities *(Note 7)*	1,313	1,129
Pension benefit liability *(Note 15)*	1,236	845
Environmental liabilities *(Note 16)*	221	239
Regulatory liabilities *(Note 11)*	168	163
Net unamortized debt premiums	18	20
Asset retirement obligations *(Note 17)*	9	14
Long-term accounts payable and other liabilities	17	20
	4,515	3,918
Total liabilities	**14,603**	**14,210**
Contingencies and commitments (Notes 22, 23)		
Subsequent Event (Note 25)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 18, 19)*	323	323
Noncontrolling interest subject to redemption *(Note 4)*	21	–
Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 18, 19)*	3,314	3,314
Retained earnings	4,249	3,787
Accumulated other comprehensive loss	(9)	(9)
Noncontrolling interest *(Note 4)*	49	–
Total equity	**7,603**	**7,092**
	22,550	**21,625**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Sandra Pupatello
Chair

George L. Cooke

7. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Income before provision for PILs	836	912
Canadian federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	222	242
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(72)	(72)
Pension contributions in excess of pension expense	(24)	(23)
Overheads capitalized for accounting but deducted for tax purposes	(15)	(14)
Interest capitalized for accounting but deducted for tax purposes	(13)	(13)
Environmental expenditures	(5)	(4)
Prior year's adjustments	(4)	(8)
Non-refundable investment tax credits	(3)	(4)
Post-retirement and post-employment benefit expense in excess of cash payments	3	4
Other	(1)	(1)
Net temporary differences	(134)	(135)
Net permanent differences	1	2
Total provision for PILs	89	109

The major components of income tax expense are as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Current provision for PILs	79	111
Deferred provision (recovery) for PILs	10	(2)
Total provision for PILs	89	109
Effective income tax rate	10.63%	11.98%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, $39 million due from the OEFC was included in due from related parties on the Consolidated Balance Sheet (2013 – $29 million).

At December 31, 2014, the total provision for PILs includes deferred provision for PILs of $10 million (2013 – deferred recovery of $2 million) that is not included in the rate-setting process, using the liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

TAB 13

UNDERTAKING – J11.3

Undertaking

Provide the original working documents, working papers that would have gone to the external auditors for review on an aggregate sense; and then the further calculations that had been done for the purpose of this proceeding that would separate between transmission and distribution.

Response

Refer to Attachment 1 for a summary of the deferred tax asset of $2,595 million for Hydro One Networks Inc. ("HONI") for the Transmission, Distribution and Norfolk regulated business of HONI. The deferred tax asset arising from revaluation of the assets in Transmission and Distribution (including Norfolk) regulated business is $1,475 million and $1,120 million, respectively.

Refer to Attachment 2 for the working paper schedules that were provided to the external auditors for the review of the deferred tax asset/recovery of HONI.

HYDRO ONE NETWORKS INC.
SUMMARY OF DEFERRED TAX ASSET BY SEGMENT
OCTOBER 31, 2015
($ Millions)

	FMV	Tax Basis	FMV in excess of Tax Basis	Tax Rate	Total
Transmission					
Fixed Assets	9,965	6,482	3,483	26.5%	923
Goodwill*	2,692	51	1,968	26.5%	522
Construction in Progress	116	-	116	26.5%	31
Deferred Tax Asset	**12,773**	**6,533**	**5,567**		**1,475**
Distribution					
Fixed Assets	7,121	4,845	2,277	26.5%	603
Goodwill*	2,455	26	1,815	26.5%	481
Construction in Progress	80	-	80	26.5%	21
Deferred Tax Asset	**9,656**	**4,871**	**4,171**		**1,105**
Norfolk					
Fixed Assets	55	-	55	26.5%	15
Goodwill*	-	-	-	26.5%	-
Construction in Progress	-	-	-	26.5%	-
Deferred Tax Asset	**55**	**-**	**55**		**15**
Hydro One Networks Inc.					
Fixed Assets	17,142	11,327	5,815	26.5%	1,541
Goodwill*	5,147	77	3,783	26.5%	1,003
Construction in Progress	196	-	196	26.5%	52
Deferred Tax Asset	**22,484**	**11,404**	**9,794**		**2,595**

* Only 75% of the goodwill is included in cumulative eligible capital pool. As such, the FMV in excess of Tax Basis is calculated as 75% of the FMV less the Tax Basis.

In million of $

Estimated Taxes		**SCENARIO A** 14B FV Actual Oct UCC Revised October 30th
Estimated Future tax benefit - HONI	Fixed Asset	(1,540.9)
Estimated Future tax benefit - HONI	ECE	(1,002.9)
Estimated Future tax benefit - CIP		(51.6)

Schedule 1B
Hydro One Inc.
Estimate valuation of selected legal entities
DRAFT - FOR DISCUSSION PURPOSES ONLY
Valuation summary - Property, plant and equipment
As at October 31, 2015

CAD

Hydro One Networks Inc. 1200					Current
Allocation Category		**UCC Class**	**FV**	**UCC Class**	**FV**
1200 - 210 - 0	210 - Land	0	928,365,041	0	1,359,160,362
1200 - 210 - 01	210	1	3,085,049,985	1	5,290,463,996
1200 - 210 - 02	210	2	2,171,802,860	2	3,256,786,260
1200 - 210 - 03	210	3	277,387,773	3	315,024,006
1200 - 210 - 06	210	6	70,261,949	6	86,788,484
1200 - 210 - 08	210	8	68,692,658	8	182,006,347
1200 - 210 - 10	210	10	110,850	10	318,659,892
1200 - 210 - 10(f)	210	10(f)	45,534,630	10(f)	46,394,765
1200 - 210 - 12	210	12	10,355,924	12	15,247,786
1200 - 210 - 13	210	13	6,302	13	12,399,267
1200 - 210 - 17	210	17	84,199,832	17	101,185,216
1200 - 210 - 42	210	42	130,311,966	42	130,388,583
1200 - 210 - 45	210	45	16,752,200	45	24,066,540
1200 - 210 - 46	210	46	2,733,086	46	9,556,920
1200 - 210 - 47	210	47	3,439,979,554	47	6,622,404,724
1200 - 210 - 50	210	50	196,106,499	50	273,045,252
1200 - 210 - 52	210	52	15,518,400	52	15,898,502
1200 - 210 - 98	210	98	16,163,239	98	17,738,050
1200 - 210 - 99	210	99	503,433,501	99	535,105,641
1200 - 210 - BM/Suspense	210 - Suspense	BM/Suspense 210	140,587,082	BM/Suspense 210	140,587,082
1200 - 210 - CIP	210	CIP 210	971,350,687	CIP 210	971,350,687
1200 - 215 - 01	215	1	-	BM/Suspense 220	270,118,072
1200 - 215 - 10(f)	215	10(f)	-	CIP 220	346,188,140
1200 - 215 - 47	215	47	1,056	Eligible Capital Expenditure (ECE)	-
1200 - 220 - 0	220 - Land	0	405,427,770	BM/Suspense 222	-
1200 - 220 - 01	220	1	2,185,671,082	CIP 222	-
1200 - 220 - 02	220	2	1,084,983,400	9	19,289,475
1200 - 220 - 03	220	3	37,369,887	134	-
1200 - 220 - 06	220	6	15,306,117	BM/Suspense 300	(407,120,776)
1200 - 220 - 08	220	8	60,273,905	CIP 300	-
1200 - 220 - 10	220	10	12,480,350	FUTURE USE 210	32,617,384
1200 - 220 - 10(f)	220	10(f)	854,180	FUTURE USE 220	50,880,159
1200 - 220 - 12	220	12	3,723,791		
1200 - 220 - 13	220	13	1,249,635		
1200 - 220 - 17	220	17	14,750,518		
1200 - 220 - 42	220	42	76,617		
1200 - 220 - 45	220	45	598,900		
1200 - 220 - 46	220	46	416,461		
1200 - 220 - 47	220	47	3,149,293,423		
1200 - 220 - 50	220	50	18,279,218		
1200 - 220 - 52	220	52	355,400		
1200 - 220 - 98	220	98	1,574,810		
1200 - 220 - 99	220	99	31,672,140		
1200 - 220 - BM/Suspense	220 - Suspense	BM/Suspense 220	270,118,072		
1200 - 220 - CIP	220	CIP 220	346,188,140		
1200 - 220 - ECE	220	Eligible Capital Expenditure (ECE)			
1200 - 300 - 0	300 - Land	0	25,367,551		
1200 - 300 - 01	300	1	19,742,928		
1200 - 300 - 03	300	3	266,346		
1200 - 300 - 06	300	6	1,220,419		
1200 - 300 - 08	300	8	53,039,783		
1200 - 300 - 09	300	9	19,289,475		
1200 - 300 - 10	300	10	306,068,692		
1200 - 300 - 10(f)	300	10(f)	5,955		
1200 - 300 - 12	300	12	1,168,070		
1200 - 300 - 134	300	13	11,143,330		
1200 - 300 - 17	300	17	2,234,867		
1200 - 300 - 45	300	45	6,715,440		
1200 - 300 - 46	300	46	6,407,373		
1200 - 300 - 47	300	47	492,820		
1200 - 300 - 50	300	50	58,659,536		
1200 - 300 - 52	300	52	24,702		
1200 - 300 - BM/Suspense	300 - Suspense	BM/Suspense 300	(407,120,776)		
1200 - 300 - CIP	300	CIP 300	-		
1200 - FUTURE USE - 210	300 - Future use	FUTURE USE 210	32,617,384		
1200 - FUTURE USE - 220	300 - Future use	FUTURE USE 220	50,880,159		
1200- 210 - ECE		Eligible Capital Expenditure (ECE)			
Capital contributions	210	47	32,637,871		
Total fair value without land			**18,589,988,533**		**18,589,988,533**
Total fair value of fixed assets			**20,036,230,816**		**20,036,230,816**
Rounded Fair Value			**20,036,200,000**		**20,036,200,000**

UCC Class	HONI	(in Millions)	Intangibles	TOTAL
1	5,290,463,996	5,290		5,290
2	3,256,786,260	3,257		3,257
3	315,024,006	315		315
6	86,788,484	87		87
8	182,006,347	182		182
9	19,289,475	19		19
10	365,054,657	365		365
12	15,247,786	15	363	378
13	12,399,267	12		12
17	101,185,216	101		101
42	130,388,583	130		130
45	24,066,540	24		24
46	9,556,920	10		10
47	6,625,989,102	6,626		6,626
50	273,045,252	273		273
52	15,898,502	16		16
98	17,738,050	18		18
99	535,105,641	535		535
-	1,359,160,362	1,359		1,359
Fixed Assets in Service	18,635,194,446	18,635	363	18,998
Future Use	83,497,543	83	-	83
CIP	1,317,538,827	1,318	-	1,318
TOTAL	**20,036,230,816**	**20,036**	**363**	**20,399**

	TX	DX	NPDI	Total
TOTAL FMV OF FIXED ASSETS PER DELOITTE VALUATION	12,323,398,020	7,712,832,795		20,036,230,816
Add- Class 12 per Deloitte Valuation	107,677,767	255,279,976		362,957,743
	12,431,075,787	7,968,112,771	-	20,399,188,558
Less-				
Class 98	(16,163,239)	(1,574,810)		(17,738,050)
Class 99	(503,433,501)	(31,672,140)		(535,105,641)
Land	(928,365,041)	(405,427,770)		(1,333,792,811)
Land- BU300	(14,459,504)	(10,908,047)		(25,367,551)
Future use	(32,617,384)	(50,880,159)		(83,497,543)
CIP	(971,350,687)	(346,188,140)		(1,317,538,827)
				-
	9,964,686,431	7,121,461,704	-	17,086,148,136
Add- NPDI	-	-	55,415,575	55,415,575
	9,964,686,431	7,121,461,704	55,415,575	17,141,563,711
UCC per Oct. 31, 2015 provision	6,481,759,114	4,844,957,122	-	11,326,716,236
Excess FMV over UCC	3,482,927,317	2,276,504,582	55,415,575	5,814,847,475
Tax rate	26.50%	26.50%	26.50%	26.50%
Estimated future tax benefit - Fixed Assets	**922,975,739**	**603,273,714**	14,685,127	1,540,934,581

HYDRO ONE NETWORKS
ESTIMATED DEPARTURE TAX
31-Oct-15

STEP 4 - DETERMINATION OF GOODWILL FMV IN HONI

FMV of shares of HONI	**FROM "1- HOI Departure Tax Tab"**	13,331
FMV of shares of NPDI		59
		13,389
Add		
Liabilities reported on HONI B/S other than regulatory and environmental and some deferred costs		13,033
Intercompany Demand Facility		1,377
Norfolk Liabilities		37
FMV to be allocated to HONI gross assets		27,836

FIXED ASSET - HONI	
Fixed Asset	20,399
Less CIP	(1,318)
Less Future Use	(83)
Fixed Assets	18,998

Allocation of FMV to identifiable assets	**HONI** FMV	**NPDI** FMV	FMV	Tax Base
Fixed Asset	18,998	56	19,054	11,660
Construction in progress	1,318	1	1,319	1,123
Future Use Assets	83		83	83
Cash		3	3	3
Regulatory Assets	1,733	9	1,742	1,742
Accounts Receivable (External)	992		992	992
Deferred Tax Asset			-	-
Materials and supplies	20		20	20
Other current assets	12		12	12
Deferred Debt Issuacne Costs	-		-	-
Goodwill - Per Deloitte F/S	4,585	27	4,612	76
				-
SUBTOTAL - Assets allocated value other than goodwill	27,741	95	27,836	15,710
			-	Inclusion Rate
				Applicable Tax Rate

Note A - This represents amounts capitalized for accounting, but deducted for tax. Under an agreement with the Ministry of Finance, 1/3 of the capitalized amounts deducted for tax are reduced for the UCC pool every year. Therefore, the tax basis on CIP will be lower than acconutin for the capitalized amounts that have not moved to UCC.

STEP 4.1 - DETERMINATION OF CAPITAL GAIN AND RECAPTURE IN HON

Determination of Fair Market Value of Fixed Assets in HONI at December 31, 2015:
The Net Book Value is assumed to Approximate Fair Market Value (pending valuation). The Net Book Value at December has been estimated by taking the actual NBV at the end of June

Determination of UCC of Fixed Assets in HONI at December 31, 2015:
The UCC is based upon the tax provision for Hydro One Networks as at December 31, 2014.
The UCC is then adjusted for additions from January to June 30, 2015

Determination of Capital Cost Fixed Assets in HONI at December 31, 2015:
Capital Cost for 2014 was computed by taking the ending UCC as of December 31, 2014 and adding back all the CCA since inception.
The Capital Cost was computed for June 30, 2015 by adding back the adds from January to June 2015

	(Norfolk and HONI) (A)	(Norfolk and HONI) (B)	(Norfolk and HONI) (C)	(A) - (B) (only if positive)	Lower of (A) and (B) Less (C)	
CCA Class	**Estimated FMV (OCTOBER 31)**	**Cap Costs**	**UCC**	**Capital Gain**	**Recapture**	**ECE Recapture**
1	5,291.1	6,631	3,659	-	1,632	
2	3,259.2	2,191	827	1,068	1,364	
3	315.0	468	265	-	50	
6	86.8	167	94	-	(8)	
8	182.3	523	255	-	(72)	
9	19.3	19	6	0	14	
10	365.7	1,040	211	-	155	
12	378.2	987	25	-	353	
13	12.4	29	21	-	(8)	
17	101.2	116	88	-	13	
42	130.4	232	82	-	49	
45	24.1	49	0	-	24	
46	9.6	45	17	-	(7)	
47	6,677.3	7,679	5,648	-	1,029	
50	273.1	440	129	-	144	
52	15.9	97	-	-	16	
Total UCC	17,142	20,712	11,327	1,068	4,747	-
ECE	535.4		76			2,573
	-					
Landscaping	17.7	18	-	18	-	-
Land	1,359.2	333	333	1,026	-	-
Grand Total	19,054	21,063	11,736	**2,112**	**4,747**	**2,573**
	(Reconciles to above)					

Note 1					TX	DX
Goodwill	4094	4,612	Per Tab 1		2,162	2,450
NBV of easements		535	Per Above		530	4.98
Estimated Proceeds		5,147			2,692	2,455
Pro-rated		75.0%			75%	75%
		3,860			2,019	1,841
CEC Balance		75.5			51	26
Gain		3,785		-1002.91235	1,968	1,815
Previous Depreciation		(151)			(102)	(52)
Amount Taxable		3,634			1,866	1,763
Inclusion Rate		67%			67%	67%
ECE GAIN		**2,423**			1,244	1,175
ADD PREVIOUS ECE DEDUCTION		**151**			102	52
TOTAL		**2,573**			1,346	1,227

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	HONI -per deloitte	NPDI	TOTAL HONI
	Estimated FMV (OCTOBER 31)	**Estimated FMV (OCTOBER 31)**	**Estimated FMV (OCTOBER 31)**
1	5,290	0.6	5,291.1
2	3,257	2.4	3,259.2
3	315		315.0
6	87	0.0	86.8
8	182	0.3	182.3
9	19		19.3
10	365	0.7	365.7
12	378	0.0	378.2
13	12		12.4
17	101	-	101.2
42	130	-	130.4
45	24	-	24.1
46	10	-	9.6
47	6,626	51.3	6,677.3
50	273	0.0	273.1
52	16		15.9
	17,086.1	55.4	17,141.6
ECE	535	0.3	535.4
		-	-
Landscaping	18	-	17.7
Land	1,359	-	1,359.2
	18,998.2	**55.7**	**19,053.9**
			-

HONI UCC deduction

ACCOUNTING
42307

Mapping
Schedule 1

2015

Division Factor 3.00

CURRENT YEAR **(PASTE VALUES IN BLUE TEXT)**	**Specific Notes**	**Ref**	**TOTAL Transmission**	**TOTAL Distribution**	**TOTAL NETWORKS**	**Current Year Transmission**	**Current Year Distribution**	**Current Year TOTAL**	**Subsequent Year 1**	**Subsequent Year 2**	**Cumulative Three Years**	**Reconciliation**
Interest adjustment to UCC		Note 5	(30,585,856.59)	(11,813,069.46)	(42,398,926.05)	(10,195,285.53)	(3,937,689.82)	(14,132,975.35)	(14,132,975.35)	(14,132,975.35)	(42,398,926.05)	0.00
Depreciation reduction to UCC		Note 8	(7,321,478.13)	(14,364,693.05)	(21,686,171.18)	(2,440,492.71)	(4,788,231.02)	(7,228,723.73)	(7,228,723.73)	(7,228,723.73)	(21,686,171.18)	0.00
OPEB reduction to UCC		Note 1	(24,348,512.30)	(32,275,935.09)	(56,624,447.39)	(8,116,170.77)	(10,758,645.03)	(18,874,815.80)	(18,874,815.80)	(18,874,815.80)	(56,624,447.39)	0.00
Potential Pension reduction to UCC		Note 26	(39,121,594.00)	(42,491,619.00)	(81,613,213.00)	(13,040,531.33)	(14,163,873.00)	(27,204,404.33)	(27,204,404.33)	(27,204,404.33)	(81,613,213.00)	0.00
Removal Cost added to income via depn		Note 8	24,856,842.56	47,470,812.03	72,327,654.59	8,285,614.19	15,823,604.01	24,109,218.20	24,109,218.20	24,109,218.20	72,327,654.59	0.00
less amount "deducted" on Sch 1		Note 8	(3,794,880.74)	(2,383,950.73)	(6,178,831.47)	(1,264,960.25)	(794,650.24)	(2,059,610.49)	(2,059,610.49)	(2,059,610.49)	(6,178,831.47)	0.00
Capitalized overhead reduction to UCC		Note 25	(27,444,414.02)	(19,925,861.09)	(47,370,275.11)	(9,148,138.01)	(6,641,953.70)	(15,790,091.70)	(15,790,091.70)	(15,790,091.70)	(47,370,275.11)	0.00
	CY adjustment to UCC					**(35,919,964.41)**	**(25,261,438.80)**	**(61,181,403.20)**				
PRIOR YEAR IMPACTS												
Prior year 1	2014					(44,174,137.16)	(29,151,780.59)	(73,325,917.74)	(73,325,917.74)			
Prior year 2	2013					(45,494,623.13)	(25,757,622.08)	(71,252,245.21)				
TOTAL adjustments made to UCC adds			**(107,759,893.22)**	**(75,784,316.39)**	**(183,544,209.61)**	**(125,588,724.70)**	**(80,170,841)**	**(205,759,566)**	**(134,507,321)**	**(61,181,403)**	**(183,544,210)**	

TX	**(116,014,066)**
DX	**(79,674,658)**
Ending Pool Value	**(195,688,724)**

TAB 14

UNDERTAKING – J11.13

Undertaking

To respond to Exhibit K11.2 question 4:

> Provide the allocation of the tax cost before and after revaluation of Hydro One Networks Inc. ("HONI") and the departure tax calculations between Transmission and Distribution.

Response

As illustrated in Attachment 1, the total departure tax paid in respect of Transmission and Distribution was $2,264 million. This amount consists of the following:

	Amount (in millions)
Transmission	$ 1,280
Distribution	984
	2,264
Norfolk Power Distribution Inc.	5
Rounding	2
Total departure tax paid by HONI	$ 2,271

Per Exhibit J1.3, the total departure tax reported for HONI was $2,264 million. The amount reported on this Exhibit did not include the departure tax incurred in respect of Norfolk Power Distribution Inc. Norfolk Power Distribution Inc. was wound-up into HONI on September 1, 2015.

We have provided the tax cost of the assets before and after the revaluation and the departure tax computation for Transmission and Distribution in Attachment 1.

Witness: Glendy Cheung

HYDRO ONE NETWORKS INC.
2015 TAX COST AND DEPARTURE TAX CALCULATIONS FOR TRANSMISSION AND DISTRIBUTION
OCTOBER 31, 2015

TRANSMISSION	**FMV ****	**Tax Base ***	**Recapture**	**Cap Gain**	**ECE Income**	**Total**
Fixed Assets	10,796	6,659	2,647	1,490	-	
Construction In Progress	1,100	985	-	116	-	
Future Use Assets	107	107	-	-	-	
Regulatory Assets	1,123	1,123	-	-	-	
Accounts Receivable	140	140	-	-	-	
Materials and Supplies	13	13	-	-	-	
Other current assets	10	10	-	-	-	
Goodwill/ECE	2,342	51	-	-	1,170	
Liabilities	(8,342)	(8,342)				
	7,289	745	2,647	1,606	1,170	
		Inclusion Rate	100%	50%	100%	
			2,647	803	1,170	
		Tax Rate	26.5%	46.17%	26.5%	
		Departure Tax	701	371	310	1,382
					Less: dividend refund	(102)
					Departure Tax	1,280
					Rounded	**1,300**

DISTRIBUTION	**FMV ****	**Tax Base ***	**Recapture**	**Cap Gain**	**ECE Income**	**Total**
Fixed Assets	7,586	4,817	2,186	583	-	
Construction In Progress	357	282	-	75	-	
Future Use Assets	41	41	-	-	-	
Regulatory Assets	639	639	-	-	-	
Accounts Receivable	926	926	-	-	-	
Materials and Supplies	7	7	-	-	-	
Other current assets	9	9	-	-	-	
Goodwill/ECE	2,222	26	-	-	1,111	
Liabilities	(6,377)	(6,377)				
	5,411	372	2,186	658	1,111	
		Inclusion Rate	100%	50%	100%	
			2,186	329	1,111	
		Tax Rate	26.5%	46.17%	26.5%	
		Departure Tax	579	152	294	1,026
					Less: dividend refund	(42)
					Departure Tax	984
					Rounded	**1,000**

TOTAL	**FMV ****	**Tax Base ***	**Recapture**	**Cap Gain**	**ECE Income**	**Total**
Fixed Assets	18,382	11,476	4,833	2,074	-	
Construction In Progress	1,457	1,266	-	191	-	
Future Use Assets	148	148	-	-	-	
Regulatory Assets	1,762	1,762	-	-	-	
Accounts Receivable	1,066	1,066	-	-	-	
Materials and Supplies	19	19	-	-	-	
Other current assets	19	19	-	-	-	
Goodwill/ECE	4,564	77	-	-	2,281	
Liabilities	(14,718)	(14,718)	-	-	-	
	12,700	1,117	4,833	2,264	2,281	
		Inclusion Rate	100%	50%	100%	
			4,833	1,132	2,281	
		Tax Rate	26.5%	46.17%	26.5%	
		Departure Tax	1,281	523	604	2,408
					Less: dividend refund	(144)
					Departure Tax	2,264
					Rounded	**2,300**

* The tax base is the tax cost of the asset prior to the revaluation.
** Tax base of the asset after the revaluation.

TAB 15

From: CHEUNG Francis
To: CHEUNG Glendy
Subject: FW: $2.271B Departure Tax from HONI to OEFC
Date: Monday, December 19, 2016 9:13:24 AM

FYI

Francis

From: Joe Pedota [mailto:Joe.Pedota@ofina.on.ca]
Sent: Wednesday, November 04, 2015 2:02 PM
To: CHEUNG Francis; CASHP; SETTLEMENT
Cc: Francisco Chinchon; Alfonso Soriano; Risa Thau; Nurudin Kaba; CASHP; Ken Kandeepan; SULEMAN Ali; PAOLUCCI William; BARAGETTI Giovanna
Subject: RE: $2.271B Departure Tax from HONI to OEFC

Hi Francis,

2.271B confirmed received.

Thanks,

Joe

Joe Pedota
Ontario Financing Authority
Coordinator – Settlements, Payments and Fiscal Agency
Finance & Treasury Division
1 Dundas Street West, Suite 1400
Toronto, ON M7A 1Y7

(416) 325-3851 (Tel)
(416) 204-7933 (Fax)
(647) 282-8442 (Mobile)

From: Francis.Cheung@HydroOne.com [mailto:Francis.Cheung@HydroOne.com]
Sent: Wednesday, November 04, 2015 1:32 PM
To: Joe Pedota <Joe.Pedota@ofina.on.ca>; CASHP <CASHP@ofina.on.ca>; SETTLEMENT <SETTLEMENT@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Alfonso Soriano <Alfonso.Soriano@ofina.on.ca>; Risa Thau <Risa.Thau@ofina.on.ca>; Nurudin Kaba <Nurudin.Kaba@ofina.on.ca>; CASHP <CASHP@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; a.suleman@HydroOne.com; w.paolucci@HydroOne.com;

Giovanna.Baragetti@HydroOne.com
Subject: RE: $2.271B Departure Tax from HONI to OEFC

We have wired $2.271B (in 5 wires) to OEFC for HONI's Departure Tax payment. Please see reference below and confirm receipt. Thanks!

_	11/04/2015	151104B3888000WIRE	500,000,080.00 DR
_	11/04/2015	151104B3875600WIRE	500,000,080.00 DR
_	11/04/2015	151104B3892500WIRE	271,000,080.00 DR
_	11/04/2015	151104B3882500WIRE	500,000,080.00 DR
_	11/04/2015	151104B3887100WIRE	500,000,080.00 DR

151104B3888000	CIBCCATTXXX	13.19	LVTS #5FCM9JKXG
151104B3875600	CIBCCATTXXX	13.20	LVTS #5FCM9N0E0
151104B3892500	CIBCCATTXXX	13.21	LVTS #5FCMA0Q94
151104B3882500	CIBCCATTXXX	13.22	LVTS #5FCMAOB21
151104B3887100	CIBCCATTXXX	13.27	LVTS #5FCMCATN9

Francis Cheung
Manager, Treasury Operations
Treasury and Risk, TCT07
Hydro One Networks Inc.
Tel: (416) 345-6141
Email: Francis.Cheung@HydroOne.com

HYDRO ONE INC
Statement of Account
Sunday, November 01, 2015 - Monday, November 30, 2015

Account Name:	Account:	Branch:	Currency:
HO Networks Inc. General [redacted]	[redacted]	[redacted]	CAD

B/D	Description	Debit	Credit	Date	Balance
	Balance Forward			11/02/2015	$0.00
	TFR 1020 5332560	$2,560,227.66		11/02/2015	
	TFR 1020 5332579	$10,400,763.47		11/02/2015	
	TFR 1020 5422713	$521,134.12		11/02/2015	
	TFR 1020 0401442		$13,482,125.25	11/02/2015	$0.00
	TFR 1020 5332560	$2,206,777.71		11/03/2015	
	TFR 1020 5332579	$593,589.79		11/03/2015	
	TFR 1020 5422713	$508,955.68		11/03/2015	
	TFR 1020 0401442		$3,309,323.18	11/03/2015	$0.00
	CREDIT MEMO		$500,000,000.00	11/04/2015	
	CREDIT MEMO		$500,000,000.00	11/04/2015	
	CREDIT MEMO		$500,000,000.00	11/04/2015	
	CREDIT MEMO		$500,000,000.00	11/04/2015	
	CREDIT MEMO		$271,000,000.00	11/04/2015	
	151104B3888000WIRE	$500,000,080.00		11/04/2015	
	151104B3875600WIRE	$500,000,080.00		11/04/2015	
	151104B3892500WIRE	$271,000,080.00		11/04/2015	
	151104B3882500WIRE	$500,000,080.00		11/04/2015	
	151104B3887100WIRE	$500,000,080.00		11/04/2015	

TAB 16

HYDRO ONE NETWORKS INC.

FINANCIAL STATEMENTS
(unaudited)

OCTOBER 31, 2015

7. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

(millions of Canadian dollars)	Period from January 1 to October 31, 2015	Year ended December 31, 2014
Provision for PILs at statutory rate	176	214
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(29)	(63)
Pension contributions in excess of pension expense	(20)	(24)
Overheads capitalized for accounting but deducted for tax purposes	(12)	(15)
Interest capitalized for accounting but deducted for tax purposes	(11)	(13)
Prior year's adjustment	(2)	(2)
Environmental expenditures	(5)	(5)
Non-refundable ITCs	(2)	(3)
Post-retirement and post-employment benefit expense in excess of cash payments	–	2
Other	–	(4)
Net temporary differences	(81)	(127)
Net tax expense resulting from transition fromm PILs Regime to Federal Tax Regime	2,271	–
Net permanent differences	–	2
Total provision for PILs	2,367	89
Current provision for PILs	2,365	73
Deferred provision for PILs	2	16
Total provision for PILs	2,367	89
Effective income tax rate	359.94%	11.04%

The current provision for PILs is remitted to, or received from, the OEFC. At October 31, 2015, $2.3 billion was due to the OEFC (December 31, 2014 – $33 million receivable).

The total provision for PILs includes deferred provision for PILs of $2 million (December 31, 2014 – $16 million) that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Departure Tax

Hydro One Networks' exemption from tax under the Federal Tax Regime ceased to apply on October 31, 2015. As a result, under the *Electricity Act*, 1998 (Ontario) (PILs Regime), Hydro One Networks was deemed to have disposed of its assets immediately before it lost its tax exempt status under the Federal Tax Regime, for proceeds equal to the fair market value of those assets at that time. Consequently, Hydro One Networks is liable to make a payment in lieu of tax (Departure Tax) under the PILs Regime in respect of the income and capital gains that arose as a result of this deemed disposition.

Hydro One Networks will pay to the OEFC an amount that reasonably approximates the amount of the Departure Tax that would be payable by Hydro One Networks in respect of the deemed disposition of its assets and that is not subject to appeal or re-assessment. The amount of Departure Tax recognized by Hydro One Networks is $2,271 million. See Note 25 – Subsequent Events for payment of the Departure Tax.

Hydro One Networks Preferred Shares

On November 2, 2015, a special resolution of Hydro One (as sole shareholder of Hydro One Networks) was made to amend the articles of Hydro One Networks to delete the share ownership restrictions and to amend the Hydro One Networks Preferred Share terms to provide for basic redeemable preferred shares.

Hydro One Networks Common Shares

On November 3, 2015, Hydro One Networks declared a stock dividend on its common shares, which due to the number of shares issued and the resulting effect on the price per share was treated as a stock split. On November 5, 2015, Hydro One Networks effected a reverse split and issued as consideration one common share to Hydro One. There was no impact to the capital structure of Hydro One Networks as a net result of the stock dividend and the reverse split.

Payment of Departure Tax

To enable Hydro One Networks to make the Departure Tax payment, on November 4, 2015, Hydro One subscribed for 53,067,036 additional common shares of Hydro One Networks for $2,271 million. Hydro One Networks used the proceeds of this share subscription to pay the Departure Tax of $2,271 million.

Equity Compensation Plans

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited to certain eligible members of the Power Workers' Union annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. The number of common shares granted annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by the price of the common shares of Hydro One Limited in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited to certain eligible members of The Society of Energy Professionals annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. The number of common shares granted annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by the price of the common shares of Hydro One Limited in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares.

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One Limited established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company will match 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. No contributions were made under the ESOP during 2015.

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted a Long-term Incentive Plan (LTIP). Under the LTIP, long-term incentives will be granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units, performance share units, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance. No long-term incentives were awarded during 2015.

TAB 17

ONTARIO ENERGY BOARD

IN THE MATTER OF a cost of service application made by Hydro One Networks Inc. Transmission with the Ontario Energy Board on May 31, 2016 under section 78 of the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2017 and January 1, 2018;

OEB PROCEEDING EB-2016-0160

APPLICATION BY HYDRO ONE NETWORKS INC.
FOR APPROVAL OF TRANSMISSION REVENUE REQUIREMENT

ARGUMENT IN CHIEF
OF
HYDRO ONE NETWORKS INC.

January 12, 2017

Tax.[243] The shareholder incurred a cost to preserve the market value of the company.[244] The shareholder's ultimate disposition of its ownership interests was not the source of funds used to finance the necessary recapitalization. That is because the cost to recapitalize the company occurred before the time at which the shareholder ultimately sold shares to the public under the terms of the initial public offering. The only relationship between the recapitalization costs and proceeds from the initial public offering was the shareholder's desire to ensure that the Company's valuation at the time of the IPO was not harmed by the Company incurring the Departure Tax liability.

(f) Applying Rate Making Principles to the Present Circumstances

The evidence before the Board demonstrates that costs incurred by Hydro One for the Departure Tax do not pertain to the provision of regulated transmission service. The provision of regulated transmission services is not what caused Hydro One to incur the Departure Tax costs. The deferred tax asset similarly has not resulted from the provision of regulated transmission services. But for the IPO and the related incurrence of the Departure Tax, there would be no deferred tax asset. Given this, Hydro One submits it would be unreasonable to allocate any of the Departure Tax costs or the deferred tax asset benefits to the regulated transmission services and the rates charged for such services as determined through calculation of the rates revenue requirement.

The evidence before the Board demonstrates that Hydro One has incurred a real cost. Ratepayers have not borne these expenses. Consistent with the EB-2009-0408 Decision, there is good reason to consistently find that cost causation and stand-alone principles should be applied in the same manner. It is appropriate to have ratepayers remain unaffected by the

[243] Exhibit J1.3.
[244] Exhibit J1.3.