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:

[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

[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.

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[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				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	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.

[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