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

DECISION AND ORDER

EB-2019-0082

HYDRO ONE NETWORKS INC.

Application for electricity transmission revenue requirements beginning January 1, 2020 until December 31, 2022

BEFORE: Emad Elsayed
Presiding Member

Lynne Anderson
Member

Robert Dodds
Vice Chair and Member

April 23, 2020

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1 INTRODUCTION AND SUMMARY

This Decision and Order responds to the application by Hydro One Networks Inc. (Hydro One) for Ontario Energy Board (OEB) approval of its electricity transmission revenue requirements to be effective January 1, 2020 to December 31, 2022.

Hydro One is a wholly owned subsidiary of Hydro One Inc., which is a wholly owned subsidiary of the parent company Hydro One Limited. Neither Hydro One Limited nor Hydro One Inc. is regulated by the OEB. Hydro One is the OEB regulated utility. This is because Hydro One is a monopoly electricity transmission and distribution services provider.

Hydro One owns and operates the largest electricity transmission and distribution system in Ontario. The transmission system is made up of a high voltage network of transmission lines, steel towers and equipment. It conveys electricity long distances from electricity generation facilities to large power consumers, urban centres and to transformer stations. The distribution system consists of a lower voltage network of distribution lines, poles and equipment. It conveys electricity at lower voltages from the transformer stations to homes and businesses throughout the province.

Hydro One applies for transmission revenue requirements and distribution rates separately at the present time. This Decision and Order deals with an application by Hydro One for the approval of transmission revenue requirements. Hydro One stated that the total bill impacts for 2020 resulting from its application would be a 0.3% increase for both an average transmission-connected customer and an average distribution-connected customer, while for 2021 these impacts would be 0.4% for both, and, for 2022, the impacts would be 0.5% for an average transmission-connected customer and 0.4% for an average distribution-connected customer.[1]

Hydro One's transmission system serves approximately 98% of Ontario by capacity, transmitting electricity from generation sources to load customers, including transmission-connected local distribution companies (LDCs), Hydro One's own distribution system and large industrial customers directly connected to the transmission system. It is also linked to five jurisdictions adjacent to Ontario through high-voltage interconnections.

The revenue requirement that the OEB has approved in this Decision and Order is set based on the OEB's determination of the level of revenue that is required by Hydro One

[1] Undertaking J8.5, Table 6, p.6.

to cover the reasonably incurred costs of operating and maintaining the transmission system at a level of service that meets the needs of its customers. The approved revenue requirement will be used later this year to set the uniform transmission rates (UTRs) that apply across the province.

In October 2016, the OEB issued its *Handbook for Utility Rate Applications* (the Rate Handbook) which outlines the key principles and expectations the OEB will apply when reviewing rate applications under the *Renewed Regulatory Framework* (RRF).[2] One of the multi-year rate-setting options identified in the Rate Handbook is custom incentive rate-setting (Custom IR). A Custom IR application is considered a rebasing application because it includes a forecast of costs and volumes which re-establish the base revenue requirement. This was the methodology on which Hydro One's application was based.

The OEB has concluded that Hydro One's proposed three-year term for rates from 2020 to 2022 has sufficiently met the requirements of a Custom IR application, and a three-year term is approved. The use of an earnings sharing mechanism (ESM) will provide protection for customers if actual cost and load exceed forecasts. This three-year term will end at the same time as the five-year term approved for Hydro One's distribution business. The OEB expects Hydro One's next rebasing application to be combined for its transmission and distribution businesses.

Hydro One proposed that the annual rate escalation be determined by a revenue cap index (RCI) where RCI growth is driven by an inflation factor less a productivity factor of zero, no stretch factor and a capital factor. The OEB accepts Hydro One's proposed RCI approach as well as its proposed inflation factor. However, the inflation factor will be reduced by a combination of the base productivity and overall stretch factor of 0.3% in place of Hydro One's proposal. The OEB also approves the approach to the capital factor proposed by Hydro One, but imposes an additional 0.15% stretch factor to be subtracted from the calculated capital factor, as well as the removal of the working capital allowance component, which is in addition to the aforementioned 0.30% stretch factor.

The OEB finds that the proposed overall increase in the transmission revenue requirement from 2020 to 2022 is not reasonable. This Decision and Order includes specific findings on the components of the revenue requirement that lead to this

[2] Ontario Energy Board *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012. Note that prior to the issuance of the Rate Handbook, the RRF was originally referred to as the RRFE (Renewed Regulatory Framework for Electricity).

conclusion. The OEB finds that with the adjustments required by this Decision and Order, the revenues required to provide transmission service will be reasonable.

The OEB finds that Hydro One's customer engagement efforts were appropriate for this Application. The OEB agrees with Hydro One that while it would not be appropriate to engage directly with the LDC customers, i.e., the customers of their customers, it is helpful for Hydro One to continue to find practical means of working with the LDCs on how best to get the views of their end-use customers. The OEB however finds that there were a number of areas of concern and shortcomings with Hydro One's customer engagement efforts.

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

The OEB finds that the proposed capital expenditure budget of $3,864.7 million for 2020 – 2022 is not fully supported and shall be reduced to $3,464.7 million (a reduction of $400 million or 10.4%). This reduction reflects the OEB's concerns in a number of areas, including: (1) data quality concerns, (2) deficiencies in customer engagement as noted above, (3) concerns about progressive productivity savings and (4) the OEB's assessment that capital cost reductions can be made within the System Renewal, System Service and General Plant categories. The $400 million reduction consists of $390 million in the System Renewal category, $5.7 million in System Service and $4.3 million in General Plant.

The OEB approves an Operations, Maintenance and Administration (OM&A) budget for 2020 of $364.0 million which represents a $10.1 million (2.7%) reduction compared to Hydro One's application. The $10.1 million reduction is entirely related to Hydro One's staff compensation, which represents approximately half of the requested OM&A funding for 2020, and continues to be higher than market median. The OEB is also concerned that Hydro One provided insufficient evidence of OM&A reductions associated with increased capital expenditures. Apart from the OEB's finding regarding staff compensation, the OEB finds that the proposed work programs in the various OM&A categories are reasonable.

The OEB finds that its ongoing concern about Hydro One's compensation costs being higher than comparable companies has not been satisfactorily addressed. This concern has been expressed in almost every OEB decision involving both the distribution and transmission costs for Hydro One for the last ten years. The OEB finds that the correlation between total compensation and Full Time Equivalent Employees (FTEs) requires further elaboration by Hydro One. The OEB finds no compelling reason for the ratepayers to continue to be burdened with this unreasonable compensation level. Although the overall Hydro One transmission compensation costs relative to market median did slightly improve in 2011 and 2013 relative to 2008, it did worsen again in 2016 and 2017.

Hydro One has identified specific progressive productivity initiatives for its capital program, and has included additional undefined productivity initiatives in the capital budget. The OEB concludes that Hydro One can do more to achieve productivity improvements. The OEB is also concerned that no progressive productivity measures were developed for OM&A. The OEB is directing Hydro One to engage an independent third party to review and report on its productivity framework as part on its next combined (transmission and distribution) rebasing application.

The OEB finds that the unique rights and concerns of Indigenous customers and rights-holders have been adequately addressed in Hydro One's Transmission System Plan in terms of taking steps to improve overall system reliability. Specific direction regarding reliability issues in northern communities was provided by the OEB to Hydro One in prior proceedings. The OEB directs Hydro One to implement this direction in a timely fashion.

The OEB accepts Hydro One's load forecast for 2020. The OEB also accepts Hydro One's load forecast for 2021 and 2022 before deducting impacts of embedded generation and CDM. Hydro One has used the same methodology in previous forecasts that were accepted by the OEB. The OEB recognizes that the decline in demand forecast since 2017 is a main contributor to the transmission rate increases. This appears to be largely due to the Industrial Conservation Initiative (ICI), which provides a benefit to many customers using one megawatt and larger, and the OEB accepts this as reasonable.

The OEB approves an Export Transmission Service (ETS) rate of $1.85/MW for the 2020 to 2022 term. The OEB recognizes that this rate was established as part of a settlement proposal accepted by the OEB in a previous proceeding. While the rate was informed by a previous cost allocation study, it was not derived solely on a cost basis. The OEB has determined that further work is required before amending the rate.

The OEB approves an effective date of January 1, 2020 for the approved revenue requirement. The OEB has considered the nature of Hydro One's requests and the application metrics that were in place at the time that Hydro One filed its Application. The OEB agrees that Hydro One was responsive to procedural deadlines established throughout this proceeding.

Hydro One's revenue requirement is approved effective January 1, 2020. The OEB plans to update UTRs to be effective July 1, 2020. The OEB previously declared Hydro One's transmission revenue requirement interim as of January 1, 2020.[3] As part of the draft revenue requirement/charge determinant process, Hydro One is expected to provide a calculation of its foregone revenue from January 1, 2020 to June 30, 2020 to be approved by the OEB and incorporated in the UTRs.

The severity and duration of the current COVID-19 emergency, which has occurred after the close of the record in this proceeding, and its impact on electricity utilities (i.e., transmitters) and customers alike, is uncertain. At this time, the OEB does not expect that the pandemic will impact the implementation of the Decision and Order, or its ability to update UTRs to be effective July 1, 2020, but the OEB will continue to closely monitor this situation. The OEB also notes that residential customer bills will not be impacted by this Decision and Order until electricity distributors update their retail transmission service rates. The OEB anticipates that this will occur effective January 1, 2021 or May 1, 2021, depending on whether a distributor's rates are based on a January 1 or May 1 rate year.

[3] EB-2019-0082, *Decision and Order on Interim Rates and Confidentiality,* December 10, 2019

2 THE PROCESS AND ORGANIZATION OF THE DECISION

Hydro One Networks Inc. (Hydro One) filed a three-year custom incentive rate-setting (Custom IR) application with the Ontario Energy Board (OEB) on March 21, 2019 under section 78 of the *Ontario Energy Board Act, 1998*[4], seeking approval for changes to its transmission revenue requirement to be effective January 1, 2020 to December 31, 2022 (the Application). Hydro One also sought an amendment to the Ontario Uniform Transmission Rates to allow for recovery of the proposed revenue requirement.

A Notice of Hearing was published in various newspapers in April 2019. Interested participants applied to become parties to the proceeding. The OEB granted intervenor status to 19 parties:

- Anwaatin Inc. (Anwaatin)
- Association of Major Power Consumers in Ontario (AMPCO)
- Association of Power Producers of Ontario (APPrO)
- Brookfield Renewable (Brookfield)
- Building Owners and Managers Association, Greater Toronto (BOMA)
- Canadian Manufacturers & Exporters (CME)
- Consumers Council of Canada (CCC)
- Energy Probe Research Foundation (Energy Probe)
- Environmental Defence Canada Inc. (Environmental Defence)
- HQ Energy Marketing Inc. (HQEM)[5]
- Independent Electricity System Operator (IESO)
- London Property Management Association (LPMA)
- Michipicoten First Nation (MFN)
- Ontario Power Generation Inc. (OPG)
- Power Workers' Union (PWU)
- School Energy Coalition (SEC)
- Society of United Professionals (SUP)[6]
- TransAlta Corporation (TransAlta)
- Vulnerable Energy Consumers Coalition (VECC)

[4] S.O. 1998, c.15 (Schedule B)
[5] Late intervenor status approved on June 12, 2019
[6] Late intervenor status approved on August 9, 2019

Each of Anwaatin, AMPCO, BOMA, CCC, CME, Energy Probe, Environmental Defence, LPMA, MFN, SEC and VECC were found eligible to apply for cost awards pursuant to the OEB's *Practice Direction on Cost Awards*.

The OEB also received four letters of comment from individuals. The panel considered these letters and placed them on the public record for this proceeding.

Procedural Order No. 1 issued on May 30, 2019 (corrected May 31, 2019) set out the process and scheduled procedural steps. Parties engaged in discovery through written interrogatories and responses, a technical conference, the scoping of a proposed issues list and provision for the filing of expert evidence. Subsequent procedural orders and decisions were issued to parties with respect to conducting a second round of discovery on expert evidence filed by OEB staff (from the Pacific Economics Group LLC (PEG)). In addition, the OEB received requests for the redaction of certain confidential information from Hydro One and OEB staff, which the OEB granted. The OEB also adopted on the record of this proceeding certain evidence from the Hydro One Sault Ste. Marie case,[7] and issued an order that made Hydro One's current transmission revenue requirement and charges interim as of January 1, 2020.

Hydro One filed evidence updates on June 19, 2019 to replace 2018 financial forecast numbers with audited actuals. A final issues list was approved by the OEB and issued on September 23, 2019.[8]

The oral hearing commenced on October 21, 2019 and concluded on November 4, 2019. In total, there were nine hearing days. Exhibits referenced in the hearing, along with undertakings, responses to the undertakings and transcripts of the oral hearing, are all available on the public record.

Following the hearing, Hydro One filed its Argument-in-Chief on November 22, 2019. OEB staff filed its submission on December 11, 2019. The OEB also received final submissions from: AMPCO, Anwaatin, APPrO, BOMA, CCC, CME, Environmental Defence, Energy Probe, LPMA, PWU, SEC, SUP and VECC. Hydro One filed its reply submission on January 17, 2020.

This Decision and Order is structured and organized to mirror the final issues list.

[7] Decision on Issues List and Confidentiality issued on September 23, 2019, pg. 4
[8] *Ibid*

3 DECISION

3.1 GENERAL

3.1.1 OEB Directions from Previous Proceedings (Issue 1)

Issue 1. Has Hydro One responded appropriately to all relevant Ontario Energy Board (OEB) directions from previous proceedings?

Hydro One noted that in its previous transmission revenue requirement proceeding,[9] the OEB had directed it to make improvements to certain of its processes and practices, or to prepare and provide certain information in the Application. Hydro One stated that it had taken appropriate steps to address all relevant OEB directions, including addressing the OEB's concerns regarding its capital planning and customer engagement processes.

Hydro One also noted that the OEB had directed it to file various reports, including benchmarking studies comparing outcomes that are consistent with the RRF and that demonstrate continuous improvement. Hydro One stated that it had responded to these directions by filing numerous internally and externally prepared reports as part of the Application.

Hydro One submitted that based on the foregoing, it had responded appropriately to all relevant OEB directions from previous proceedings.

Parties generally agreed that Hydro One had responded to all relevant OEB directions from previous proceedings, though in some of these cases parties disagreed with the substance of some of the responses. These concerns are discussed under the specific issues to which they are related.

[9] EB-2016-0160

Findings

The OEB finds that Hydro One has responded to all relevant OEB directions from previous proceedings subject to any comments of the OEB through this Decision and Order regarding the substance of Hydro One's responses.

3.1.2 Bill Impacts (Issue 2)

Issue 2. Are the bill impacts resulting from Hydro One's proposed revenue requirement reasonable?

Hydro One stated that the bill impacts resulting from its proposed revenue requirement are reasonable. Hydro One further stated that to determine the impact of its proposed rate changes on an average transmission-connected and distribution-connected customer's bill, it had adopted the same approach as in the previous proceeding which was approved by the OEB.

Hydro One stated that the Application proposes a 0.3% increase to its rates revenue requirement[10] for 2020 (relative to 2019), which, combined with the 3.8% rate increase attributable to the resetting of the load forecast in 2020, results in an average transmission rate increase of 4.1% in 2020. Hydro One added that over the 3-year period from 2020 to 2022, the Application will result in an average annual transmission rate increase of 5.5%, or 3.8% when excluding the impact of changes in the load forecast.

Hydro One further stated that the resulting total bill impacts in 2020 are 0.3% for both an average transmission connected customer and an average distribution-connected customer. Furthermore, on this basis, the total bill increase is expected to be about 37 cents per month for a typical Hydro One Medium Density (R1) Residential Customer (750 kWh/month), and 88 cents per month for a typical Hydro One General Service (GSe) Customer (2,000 kWh/month).

[10] The rates revenue requirement is the total transmission revenue requirement less other revenues including external revenue, wholesale meter service revenue, regulatory assets, export transmission service revenue and funding for the low voltage switchgear credit (revenue offset).

Hydro One submitted that while certain bill impact drivers (e.g., declining load) are out of its control, the relatively small bill impacts resulting from the proposed rates revenue requirement reflect Hydro One's objective of, and efforts in, appropriately balancing system and asset needs and identified customer preferences regarding outcomes and rates. Hydro One argued that based on the foregoing, the bill impacts resulting from the Application are reasonable.

OEB staff agreed with Hydro One that the total bill impacts resulting from this Application for the average transmission and distribution connected customers (0.3%) are reasonable as they are significantly below current inflation rates. OEB staff noted that while the transmission rate increases are higher at a 2020 - 2022 three-year average increase of 5.5%, a significant part of this increase is due to the effects of a declining load forecast. VECC took a similar position.

Some parties argued that the bill increases were too high.

SEC submitted that neither the increased revenue requirement proposed, nor the rates that ultimately flow to customers are just and reasonable. SEC noted in this context that Hydro One's application represents an annual average transmission rate increase over the three-year period of 6.2%, which represents more than three times Hydro One's proposed inflation factor of 1.8%. As well, even if the impacts of load changes are excluded, the rate increase represents an amount more than double the inflation rate at an average increase of 4.5%.

AMPCO argued that given the current state of Ontario electricity prices, any upward pressure on rates further reduces the competitiveness of the Ontario industry as compared to neighbouring jurisdictions and even just and reasonable rates are still a problem if they are not affordable for customers. AMPCO submitted that it would like to see Hydro One do more with less.

LPMA submitted that the OEB should not place much emphasis on the bill impacts that result from Hydro One's proposed revenue requirement as transmission costs make up only a relatively small portion of a typical customer bill. LPMA noted that Hydro One has proposed an increase in average transmission rates of 4.1% in 2020, 5.8% in 2021 and 6.5% in 2022. LPMA further noted that while the 2020 increase is primarily driven by the reduction in the load forecast, the 2021 and 2022 increases are driven by increases in the rates revenue requirement. LPMA submitted that the increases in these two years are not reasonable, as at 5.2% and 5.8% respectively, they are on average triple the current inflation rate of 1.8%, while also taking place when demand on the system is falling. BOMA and CCC made similar arguments.

Hydro One stated that consistent with LPMA's recognition that the bill impacts in these years are largely driven by changes in the revenue requirement due to planned capital and OM&A spending, it would address LPMA's concerns under those issues. Hydro One also noted that a number of intervenors had used out-of-date references in the evidence in respects of bill and rate impacts and provided the up-to-date numbers.

Energy Probe submitted that Hydro One had not provided any evidence positioning its proposed transmission rates relative to those of other Canadian provinces. Energy Probe argued that this is relevant information and Hydro One's failure to provide it was a deficiency in its Application which should be rectified in its reply argument.

Hydro One submitted that the OEB should reject Energy Probe's request for three main reasons, which are:

> (1) The calculation of transmission rates in other provinces is very different from those in Ontario so the requested comparison could not reasonably be provided;
>
> (2) It is not appropriate for Energy Probe to request that new information be filed at this stage of the proceeding, and if filed by Hydro One at this time there would be no opportunity for discovery of that additional evidence without causing delay and
>
> (3) The requested information is not needed for the OEB to make a determination upon the application.

Findings

The OEB finds that, with the adjustments required by this Decision and Order, the revenue required by Hydro One to provide transmission service is reasonable, and consequential rate and bill impacts will also be reasonable. In future applications, the OEB finds that it would be helpful for Hydro One to provide a comparison of its proposed transmission revenue requirement and resulting rates to those of other jurisdictions as part of its evidence.

3.1.3 Customer Engagement Activities (Issue 3)

Issue 3. Were Hydro One's customer engagement activities sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending?

Hydro One stated that it had engaged in a broad range of customer engagement activities that had sufficiently and appropriately enabled customer needs to be identified for the formulation of its investment plan. Hydro One submitted that it had gained a clear understanding of the outcomes that customers care about as well as the level and mix of investments that customers wanted to see included in the investment plan. Hydro One stated that its investment planning process had accounted for customer feedback throughout, ensuring that the ultimate plan is responsive to customer needs and preferences and drives value for customers.

Hydro One noted that its transmission operations serve a diverse customer base comprising three customer segments located across the province: distributors, transmission-connected generators, and end users.

Hydro One further noted that serving customers in northern and rural areas presents different challenges from customers located in more populated areas due to sparse populations, remote location of assets and the prevalence of single-phase circuits. On the other hand, customers in non-rural, more populated areas, often share multi-circuit lines with other transmission customers.

Hydro One stated that due to such differences, it uses a variety of channels to engage effectively with its customer segments. Hydro One added that these customer engagement activities (both those specific and non-specific to the Transmission System Plan (TSP)) are integrated as part of Hydro One's business practices and are fundamental to how Hydro One interacts with and serves its customers. Hydro One states that these activities consist primarily of:

1. The transmission customer engagement survey
2. Customer satisfaction research and surveys
3. Large customer account management
4. The Ontario Grid Control Centre (OGCC) customer operating support group
5. Large customer conferences
6. Oversight committees and working groups
7. Engagement with Indigenous communities

1. Transmission Customer Engagement Survey

Hydro One stated that its customer engagement survey for the Application, which had been conducted by Innovative Research Group (IRG) in 2017, had enabled it to obtain important feedback regarding customer needs and preferences that directly informed its investment planning. Hydro One further stated that its engagement approach incorporated improvements based on feedback received from both the OEB and intervenors in the previous transmission proceeding. Hydro One stated the improvements made had responded to the OEB decision in the previous proceeding as follows:

> OEB Direction 1: Timing of Survey – Hydro One stated that the 2017 survey had been completed sufficiently in advance of plan development to allow Hydro One planners to meaningfully incorporate customer feedback when developing the TSP and for management to hold a series of cross functional sessions to review relevant findings, trends and customer feedback.

> OEB Direction 2: Include Feedback from LDC End-Users – Hydro One stated that it had taken steps to include feedback from LDC end-users with the 2017 survey specifically asking LDCs to respond “with your customers in mind” and “with consideration to your customers’ needs,” and to identify whether their responses were informed by their own customer engagement, or other customer research. Hydro One further stated that its account executives had engaged LDCs in discussions regarding the needs of end-users and that the results of LDC customer surveys were also considered during Hydro One’s planning process.

> OEB Direction 3: Incorporate Input from Indigenous Groups – Hydro One stated that its survey had asked relevant LDC customers whether there was anything they felt it could do to better service the specific needs of First Nations and Métis communities and it had also used its ongoing engagement with these communities to identify their needs and preferences.

> OEB Direction 4: Ensure Information Presented to Customers is Easy to Understand – Hydro One stated that the 2017 survey had been designed to ensure that its content was clear, sufficiently informative for customers to respond to, and easy for customers to comprehend. Hydro One further stated that in response to a post-survey question, 76% of respondents had indicated that the survey contained the right amount of information.

2. Customer Satisfaction Research and Surveys

Hydro One stated that it collects feedback from transmission customers through annual customer satisfaction research and uses this data to stay informed of trends that matter most to customers and to guide and improve business practices. Hydro One further stated that the OGCC also surveys satisfaction among its medium and large business customers to improve customer service policies, service delivery processes and communications within the OGCC's areas of accountability, such as outage planning and interruption restoration information.

3. Large Customer Account Management

Hydro One stated that its large customer account management group is an important channel of ongoing customer engagement as it communicates with customers on matters that include connection requests, sustainment and system development plans and projects, and concerns regarding service levels or power quality. Hydro One further noted that executives from this group regularly meet with transmission customers to discuss their needs and ensure action plans are developed as required. Hydro One stated that this open dialogue during the planning of candidate investments ensures customer needs and preferences are accounted for and addressed in a collaborative manner.

4. OGCC Customer Operating Support Group

Hydro One stated that the OGCC's customer operating support group works directly with transmission customers to efficiently plan real-time outage operations, coordinate planned outages so Hydro One or the customer can complete required work, respond quickly to unexpected outages and coordinate switching activities. Hydro One further stated that as part of its work, this group also organizes bi-annual customer meetings throughout the province to coordinate outage planning activities.

5. Large Customer Conferences

Hydro One stated that each year it organizes and hosts a large customer conference for all large transmission and distribution (2 MW and up) customers, which provides an opportunity for large customers to hear about Hydro One's plans and initiatives, ask questions, discuss their interests, and raise any concerns they may have.

6. Oversight Committees and Working Groups

Hydro One stated that it has established various oversight committees and working groups, including the Sarnia Area Reliability Oversight Committee, LDC Working Group, Toronto Hydro Oversight Committee, Nuclear Switchyard Oversight Committees with OPG and Bruce Power, Metrolinx Working Group, and Hydro Ottawa Oversight Committee. Hydro One stated that the purpose of these groups is to engage with and obtain feedback from customers on issues with a high level of customer interest which provides it with valuable early insight regarding future investment needs.

7. Engagement with Indigenous Communities

Hydro One stated that it has carried out an extensive program of engagement with Indigenous customers and rights holders, which has further informed the formulation of the TSP and is discussed in more detail under Issue 10.

Hydro One concluded that its numerous channels of customer engagement activities yielded robust and meaningful feedback, in a variety of forms, from its diverse groups of customers. Hydro One added that it had considered and addressed the identified customer needs in its investment planning process and the formulation of proposed spending in the Application such that the resulting plans are responsive to those needs and preferences.

OEB staff submitted that Hydro One's customer engagement efforts had been generally appropriate, subject to the concerns raised with respect to these efforts in the TSP section of its submission and under Issue 24 with respect to the lack of engagement with customers potentially affected by proposed amendments to the Terms and Conditions of the UTR Schedules. OEB staff also expressed some concerns with the lack of direct input from distribution customers as to their views on the proposed increases incorporated into the IRG survey.

OEB staff noted that the combined transmission and distribution application that is to be filed by Hydro One for 2023 and subsequent years may allow Hydro One a greater opportunity to get more specific feedback from its distribution customers regarding the proposed transmission rate changes, in addition to those for distribution services.

A number of intervenors expressed concerns about Hydro One's approach to customer engagement. These concerns generally fell into three major areas:

(1) The customer engagement for the Application was completed before the decision on the 2017-2018 transmission revenue requirement application[11] was issued. Although the decision expressed concerns with the customer engagement approach used, Hydro One did not update its customer engagement to reflect these concerns even though it had had time to do so;

(2) Hydro One did not engage LDC end-use customers, who will bear most of the costs of Hydro One's proposed revenue requirement, in spite of the OEB raising this as an area of concern in the decision on the 2017-2018 transmission revenue requirement application; and

(3) The IRG study did not put cost as a consideration to customers that participated in the survey.

VECC expressed the concern that given the reliance on LDC representatives to provide feedback, the absence of any questions with respect to Customer Delivery Point Performance Standards was perplexing. VECC also submitted that future customer engagement should include an "account manager" report for all the 63 LDCs connected to the transmission system.

Anwaatin submitted that further work is required on the part of Hydro One in order to sufficiently engage and consult with Indigenous communities on the application in a clear and unambiguous manner.

LPMA argued that future Hydro One customer engagement activities should be focused on its customers alone and not attempt to survey or surmise the views of its customers' customers. LPMA submitted that this was not a useful exercise, as the vast majority of non-Hydro One distribution customers are not even aware that they are paying transmission costs. LPMA argued that the main concerns of such customers are rising costs and the level of reliability, but such customers do not have the in-depth knowledge or understanding to be able to determine the allocation of these concerns between distribution and transmission.

Energy Probe submitted that the OEB should provide strong direction to Hydro One that customer surveys should be based on a proposed set of real scenarios related to

[11] EB-2016-0160

system reliability and capital investment, which it argued was not the case in the present Application.

Hydro One stated that the concerns expressed by parties as noted above were unfounded. Hydro One argued that OEB staff and intervenors were incorrect to suggest that cost (or price) was not considered as a priority during the investment planning process, as it was, which was confirmed repeatedly on the evidentiary record.

Hydro One further submitted that it had taken a number of steps to obtain feedback from LDC end-users. At the outset of the IRG survey, LDC respondents were specifically directed as follows: “As a distributor, please respond to the questions in this survey with your customers in mind. Your feedback should be made with consideration to your customers’ needs.” In its reply argument, Hydro One also listed other steps that it had taken in regard to this concern.

Hydro One argued that concerns that customer engagement had been carried out before the decision on the 2017-2018 transmission revenue requirement application[12] was issued were also invalid. Hydro One made the following assertions.

> (1) While the IRG survey had been conducted prior to the issuance of the OEB decision, various other forms of customer engagement activities that also provided useful customer feedback and informed investment planning continued to occur after the decision was issued and were responsive to parts of it.
>
> (2) The timing of the survey had been tight with respect to the filing date of the Application but had been early enough to allow the feedback to be incorporated into the investment planning process.

Observations related to customer engagement as it specifically relates to the TSP are discussed under Issue 9.

Findings

The OEB finds that Hydro One’s engagement efforts were appropriate for this Application. The OEB agrees with Hydro One that while it would not be practical to

[12] EB-2016-0160

engage directly with the LDC customers, i.e., the customers of their customers, it is helpful for Hydro One to continue to find other practical means of working with the LDCs on how best to get the views of their end-use customers.

The OEB notes the following areas of concern and shortcomings:

a) IRG did not include explicit scenarios to show the impact of Hydro One's proposed investment plan on price and reliability

b) the lack of input from end-use LDC customers regarding their views on the proposed price increases that were incorporated in the IRG survey

c) the fact that the survey results were not updated to reflect the outcome of the most recent OEB decision.

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

The OEB directs Hydro One to explicitly address these areas of concern in the combined transmission and distribution application to be submitted for 2023 and subsequent years, as part of its evidence on its customer engagement activities.

3.1.4 Proposed Effective Date (Issue 4)

Issue 4. Is the proposed effective date of January 1, 2020 appropriate?

Hydro One noted that in the Application, it had requested that the OEB's rate orders be made effective January 1, 2020. Hydro One observed that the Application had been filed on March 21, 2019, which is over nine months prior to the requested effective date. Hydro One submitted that this has provided a sufficient period to allow for the requested effective date, particularly given that the Application is for a rate period of only three years.

Hydro One further submitted that the Application was deemed complete by the OEB as originally filed and that Hydro One had conducted itself appropriately and met all filing deadlines that the OEB established throughout the proceeding. Hydro One argued that, as such, the proposed effective date of January 1, 2020 is appropriate.

OEB staff submitted that the proposed effective date of January 1, 2020 is appropriate as Hydro One had met all of the filing deadlines established by the OEB. [13]

Other parties, with the exception of SEC, were generally in agreement with OEB staff's position or took no position on this issue. SEC argued that Hydro One's proposed effective date of January 1, 2020 was unreasonable and a more appropriate effective date would be the earlier of the date of the OEB's issuance of its final decision, or April 1, 2020.

SEC noted that the proposed effective date would have allowed the OEB just over nine months to adjudicate the Application, but that the previous major transmission application had taken approximately 16 months from its filing to the issuance of the OEB's decision. SEC argued that, as such, Hydro One should have expected this application to take as long, if not longer, and filed accordingly. SEC submitted that the OEB had made a similar finding for Hydro One's most recent distribution decision, as it found that Hydro One should have expected that it would take at least a year from filing to issuance of the decision. SEC concluded that an April 1st effective date would also be consistent with the OEB's own metrics for cost based applications that are greater than $500 million of 355 days from the issuance of the completeness letter, which for the current application took place on April 4, 2019, to decision.

Hydro One submitted that SEC's argument should be rejected for three reasons:

> (1) The timeline for the previous application was exceptionally long as the decision was not issued until seven and a half months after the hearing phase had been completed.
>
> (2) SEC's comparison to the time frame of the recent distribution Custom IR application[14] is not valid as it is wrong to suggest that the current Application is as complex as that application.

[13] OEB Staff Submission, p. 14.
[14] EB-2017-0049

(3) SEC's suggestion that its proposed April 1, 2020 effective date would be consistent with the OEB's new metrics for cost based applications that are greater than $500 million is not valid as these metrics were not in effect when Hydro One filed its Application and the previous guideline would have suggested a filing date of April 26, 2019 which was approximately one month later than when Hydro One filed the Application.

Findings

The OEB approves an effective date of January 1, 2020 for the approved revenue requirement. The OEB has considered the nature of Hydro One's requests and the application metrics that were in place at the time that Hydro One filed its Application. The OEB agrees that Hydro One was responsive to procedural deadlines established throughout this proceeding.

The OEB notes that the metric for cost based rate applications for companies with a revenue requirement greater than $500 million was increased to 355 days after Hydro One filed its Application. Hydro One's requested effective date of January 1, 2020 would have been within the previous guideline. Hydro One must take the new metric, as it may be updated from time to time, into consideration in filing its joint transmission and distribution application for 2023 rates.

The OEB plans to update UTRs to be effective July 1, 2020. The OEB previously declared Hydro One's transmission revenue requirement interim as of January 1, 2020.[15] As part of the draft revenue requirement/charge determinant process, Hydro One is expected to provide a calculation of its foregone revenue from January 1, 2020 to June 30, 2020 to be approved by the OEB and incorporated in the UTRs.

[15] EB-2019-0082 *Decision and Order on Interim Rates and Confidentiality,* December 10, 2019

3.2 CUSTOM APPLICATION

3.2.1 Custom IR Framework based on a Revenue Cap Index (Issue 5)

Issue 5. Are all elements of Hydro One's proposed Custom Incentive Rate framework for the determination of revenue requirement appropriate?

Hydro One proposed a three-year Custom IR plan that consists of rebasing its revenue requirement for 2020 on a cost of service basis, followed by annual adjustments of the revenue requirement for 2021 and 2022 using a revenue cap, which includes a capital adjustment factor (Capital factor or C-factor). The OEB deals with the revenue cap rate adjustment plan for 2021 and 2022 under this issue, while the 2020 revenue requirement set on a cost of service basis is dealt with elsewhere in this Decision.

Hydro One retained Power Systems Engineering, Inc. (PSE) to do an independent study (PSE Report) on electricity transmission productivity (Total Factor Productivity or TFP) and total cost benchmarking, based on the historical (and forecasted, for total cost benchmarking) data of Hydro One and a sample of U.S. electricity transmitters. PSE's research also made a recommendation for a transmission-specific inflation factor. PSE's evidence in the original pre-filed evidence was an update of a similar report filed and considered in the Hydro One Sault Ste. Marie LP (Hydro One SSM) proceeding from late 2018 and early 2019.[16] Hydro One SSM is an affiliate of Hydro One. On October 15, 2019, Hydro One, on behalf of PSE, filed a reply report (the PSE Reply Report).

OEB staff retained Pacific Economics Group LLC (PEG) to assess Hydro One's proposed revenue cap plan and PSE's evidence. PEG conducted its own analyses, based largely on PSE's data and models, but with some additional data and variables. PEG filed its evidence on September 5, 2019 (PEG Report).

PSE and PEG responded to interrogatories on their respective reports and participated in the Technical Conference, and witnesses for PSE and PEG testified at the oral hearing.

Since PSE's evidence and Hydro One's revenue cap framework were very similar to, and largely based on, the same analyses used to support Hydro One SSM's revenue cap plan, the OEB adopted the record of PSE's and PEG's evidence from the Hydro

[16] EB-2018-0218

One SSM case on the record of this Application.[17] This largely avoided unnecessary and duplicative interrogatories and cross-examination.

Revenue Cap Formula

For 2021 and 2022, Hydro One proposed that the prior year's transmission revenue requirement be adjusted by a revenue cap formula. Mathematically,

$$RR_t = RR_{t-1} \times (1 + RCI_t) \quad (1)$$

where

RR_t would be the revenue requirement for year t

RCI_t would be the revenue cap index for year t

The revenue cap index was calculated formulaically for each year as:

$$RCI_t = I_t - X + C_t \quad (2)$$

where

I_t would be the transmission-specific inflation factor as calculated from data available through Statistics Canada

X would be the X-factor, composed of a base productivity (base X) and stretch factor, and would be fixed over the plan term (i.e., the same for the two years)

C_t would be the capital factor (C-factor) adjustment to reflect the impact of incremental capital spending per Hydro One's TSP for that year.

OEB staff noted that Hydro One's formula for the RCI above is a simplification of the general revenue cap formula:

$$RCI_t = I_t - X + g + C_t \pm Z_t \ (3)$$

[17] OEB letter, EB-2019-0082, July 4, 2019

where

> g is a growth factor
> Z_t is an adjustment for qualifying exogenous events that reflect unavoidable and material cost changes outside of the firm's ability to predict or control.

The issues of growth and Z-factor are discussed in later subsections under this issue.

OEB staff noted that the OEB has specified that a revenue cap formula is a permissible form of incentive regulation for electricity transmitters, and that the OEB had recently approved a revenue cap plan for Hydro One SSM. Hydro One's proposed revenue cap formula for its Custom IR plan differs only in including the C-factor.

OEB staff and many intervenors generally considered that Hydro One's proposed revenue cap formula is appropriate for its Custom IR plan, and is consistent with the OEB's rate- (or revenue requirement-) setting policies for electricity transmitters. However, OEB staff and several intervenors made submissions on the individual parameters of the revenue cap formula as proposed by Hydro One, and on other matters, such as the ESM and Off-ramps. PWU supported Hydro One's Application, including the proposed overall Custom IR plan, except where it made specific comments. These various submissions, and the OEB's findings on the various elements of the proposed revenue cap formula, are discussed below.

In its reply submission, Hydro One noted that no party took issue with the Custom IR plan overall, but other parties did make submissions on some of the plan parameters. Hydro One submitted that the proposals of OEB staff and intervenors were contrary to the experts' evidence and should be rejected. Hydro One submitted that its Custom IR revenue cap plan should be approved as proposed in its Application.

Findings

The OEB approves the revenue cap formula of $RCI_t = I_t - X + C_t$ to be used to set Hydro One's revenue requirement for 2021 and 2022. The OEB's policies specifically contemplate a revenue cap approach to incentive regulation for transmitters. No parties objected to this approach and the OEB approved the same formula for Hydro One's distribution operations, in the context of a price cap-based Custom IR plan.

Hydro One shall recalculate the RCI each year. The inflation factor (I) will be updated for inflation based on an approved formula. The productivity factor (X) includes base productivity and a stretch factor and will remain constant throughout the term. The capital factor (C) has been determined for each year in this proceeding, and includes a capital stretch factor. These elements of the formula and other aspects of the Custom IR plan, including the Z-factor and ESM, are discussed in the subsections that follow.

Inflation

Hydro One proposed an Input Price Index (IPI) for inflation, based on the OEB's two-factor IPI methodology first adopted for electricity distributors, but with weightings for the labour and non-labour (i.e., capital and materials) components more representative of the electricity transmission sector. Hydro One proposed weights of 14% labour and 86% non-labour, representative of the very capital-intensive transmission network and operations. The derivation of the weights was based on an analysis in PSE's evidence, reflecting the weights of Hydro One and the sample of U.S. utilities' transmission operations used in PSE's TFP and total cost benchmarking analyses.

OEB staff and several intervenors noted that the OEB has already approved this same IPI methodology for another transmitter, Hydro One's affiliate, Hydro One SSM, in that transmitter's revenue cap plan. The OEB also approved the use of this IPI in the single-year revenue requirement update for 2019 for Hydro One.[18] OEB staff submitted that the inflation index should be representative of the sector, and not of one single utility, and, along with many intervenors, did not take any issue with Hydro One's proposed inflation factor.

In its submission, OEB staff included a table documenting the calculation of the transmission IPI for 2020 based on the updated Statistics Canada data and the proposed weights, resulting in a value of 1.8%. Hydro One also used this value in its updated revenue requirement in response to an undertaking.

In reply, Hydro One noted that no party opposed the proposed inflation factor, the methodology for which had previously been approved for Hydro One SSM.

[18] EB-2018-0130, Decision and Order, April 25, 2019, p. 7

Findings

The OEB approves the two-factor inflation factor proposed by Hydro One, including weights of 14% for labour and 86% for non-labour components. The calculation will be updated each year based on Statistics Canada data. The OEB agrees it is appropriate to modify the labour and non-labour weights from those used for the distribution sector to reflect the more capital-intensive nature of Hydro One's transmission business. As noted previously, the OEB has approved this inflation factor in previous transmission revenue requirement proceedings for both Hydro One and Hydro One SSM.[19]

X-factor, including the components of base productivity and stretch factors

The X-factor is a main parameter of revenue cap and price cap formulae that acts as a (partial) offset to input price inflation. It acts as a proxy for the productivity and efficiency increases that are expected of the company during the incentive rate-setting (IRM) or Custom IR term.

In incentive rate-making, particularly as it is used in the Ontario energy sector, the X-factor is based on two components:

- A base X-factor (productivity factor) which is derived from a historical analysis of TFP. This analysis is based on the sector or a sample of firms in the sector, and not on the applicant utility alone

- A stretch factor representing the incremental productivity gains that the utility should be able to achieve during the rate-setting plan term. Benchmarking analyses of the costs of utilities is considered in establishing a stretch factor

PSE and PEG both conducted TFP and Total Cost Benchmarking analyses in their evidence, which served as the quantitative evidence for, respectively, the base productivity and the stretch factor components of the X-factor.

Hydro One proposed an X-factor of 0%, composed of a 0% base X-factor and a 0% stretch factor. PSE's evidence, as filed in this Application, is an update of the same evidence filed and considered in the Hydro One SSM proceeding. PSE noted the nature

[19] Hydro One Networks' 2019 transmission revenue requirement (EB-2018-0130), Hydro One SSM's 2019-2023 Custom IR plan (EB-2018-0218).

and extent of the updates in its evidence from that filed in the Hydro One SSM case. PSE also filed updated evidence in a Reply Report filed on October 15, 2019.[20]

PSE recommended the 0% stretch factor for two reasons:

- First, its total cost benchmarking analysis suggested that Hydro One is a superior cost performer relative to the sample of U.S. utilities' transmission operations. While its cost benchmarking performance declines over the forecasted 2020-2022 plan period, in large part due to the increased capital expenditures, it still remains a good cost performer, taking into account the characteristics of its service territory and customer base, relative to the U.S. utilities based on the estimated cost model

- Second, PSE argued that its recommended X-factor of 0% implicitly incorporates a large stretch-factor of 1.61% since the base sector TFP for the transmission sector is -1.61%, per the updated evidence in the Reply Report

Starting from its evidence filed in the Hydro One SSM case[21] and PSE's updated evidence and "working papers",[22] PEG updated its evidence and proposed an overall X-factor of 0.05%, composed of a base X of -0.25% and a stretch factor of 0.30%. PEG recommended a stretch factor of 0.30% based on its analysis that suggested that Hydro One is within the normal bounds of cost performance. The 0.30% stretch factor for "normal" performance was adopted from the OEB's stretch factor range for electricity distributors, which ranges from 0% (for superior cost performance) to 0.6% (for the poorest cost performance). As with its TFP analysis, PEG used a longer time range, from 1995 to 2016, compared to PSE, whose cost benchmarking analyses began in 2004.

PWU submitted that Hydro One's proposed X-factor of 0%, including a 0% stretch factor, should be approved as filed. Hydro One stated that its proposal of 0%, based on

[20] In its Reply Report, filed on October 15, 2019, PSE extended the historical time period for the analysis from 2004 to 2018. However, its recommendations were unchanged.

[21] EB-2018-0218, Exhibit M1 and associated interrogatory responses filed in Exhibit L1, and both adopted on the record in this proceeding.

[22] The "working papers" of both PSE and PEG consist of spreadsheets with the data for all utilities used in the TFP and cost benchmarking analyses, software and program codes and other documentation to enable replication of the results. PSE's and PEG's "working papers" were afforded confidential status by the OEB in this proceeding.

the historical TFP of -1.61% from PSE's TFP analysis, meant that there was implicitly a stretch factor of +1.61%, and that no additional stretch factor was required.

OEB staff submitted that the OEB should approve an X-factor of 0.3%, composed of a 0% base productivity and a 0.3% stretch factor. OEB staff submitted that PSE's historical TFP, estimating a -1.61% annual productivity, does not appear reasonable, as it would imply a 20% decline in productivity in the North American electricity sector over the sample period from 2004 to 2018. OEB staff noted that PEG, during Examination-in-Chief, testified that PSE's and PEG's work on TFP and total cost benchmarking done in the Hydro One SSM case, and updated in this case, are among the first such studies of electricity transmission, particularly in North America.[23] PEG testified that there have been factors, such as restructuring with Regional Transmission Operators (RTOs) in the U.S. that, in PEG's expert opinion, have reduced productivity for a number of U.S. utilities.

OEB staff submitted that PEG's analysis, based on a longer time frame, and its explanations regarding likely drivers for the materially negative TFP calculated by PSE for the shorter time period, provide a more plausible annual productivity change of -0.25%. Noting that the OEB has not set a negative X-factor, OEB staff submitted that a base productivity factor of 0% is reasonable. While accepting 0% as the base productivity factor, OEB staff submitted that an additional and positive stretch factor is appropriate in order to incent "continuous improvement" in accordance with an objective in the Rate Handbook.[24] OEB submitted that a 0.3% stretch factor was appropriate, based on PEG's analysis and recommendation. LPMA supported OEB staff's recommendations for the X-factor.

VECC noted that PSE's and PEG's analyses are updates of the evidence considered in the earlier Hydro One SSM case, and that the analyses are similar in nature and conclusions. VECC submitted that:

> We do not think the methodology employed by either consultant is particularly robust nor worth the time and money to argue as to the minutia between them. It seems quite startling to think the Board would rely on either result given the wide variation that can result depending on how one applies essentially the same econometric model. In our

[23] Oral Hearing Tr., Vol. 9, November 4, 2019, pp. 46-51
[24] Rate Handbook, p. 3

> submission, the Board might take note of the results in a general sense – that is that there is no evidence of productivity growth in the transmission business. However, the spurious specificity of either of the consultant's results should be recognized. In our submission the Board should substitute its expert judgement in order to find incentives which improve outcomes rather than accept the status quo.[25]

VECC submitted that a modest stretch factor adjustment of 0.3% should be adopted that recognizes the general results from the consultants and includes an incentive for Hydro One to become more productive.

SEC made a submission similar to that of VECC, with criticisms of the work of both PEG and PSE, and pointing out that the OEB must consider not only technical econometric matters, but also what is common sense. SEC submitted that PEG's evidence should be preferred to that of PSE because the results from PSE were not consistent with common sense. SEC submitted that the base productivity of 0% and a stretch factor of 0.3%, along with a 0.31% stretch factor on Hydro One's capital factor (discussed later), should be adopted.

BOMA supported PEG's recommendation of a -0.25% base productivity and a 0.3% stretch factor.

CCC submitted that the OEB should approve an X-factor that incents Hydro One to seek efficiencies, and recommended an X-factor of 0.6%, composed of a 0.3% base productivity and 0.3% stretch factor.

CME accepted Hydro One's proposal for a 0% base productivity factor, but submitted that a stretch factor of 0.3% was appropriate, submitting that PEG's cost benchmarking was more reasonable than PSE's.

Energy Probe submitted that Hydro One's proposed revenue cap formula did not provide sufficient incentives for capital productivity savings, and the OEB should adopt the PEG recommended stretch factor of 0.3% and a 0.15% capital stretch factor, for a net X factor of 0.45%.

[25] VECC submission, p. 8

In reply, Hydro One rebutted the points made in various submissions, and concluded that the submissions of OEB staff and several intervenors for non-zero stretch factors ignored the evidence and recommendations, and were without any evidentiary basis. Hydro One submitted that:

> …an overall X factor of 0% is appropriate having regard to: (i) the negative TFP trend and the implicit stretch factor this already imposes on Hydro One; (ii) Hydro One's strong cost benchmarking performance that should be recognized and rewarded to ensure proper incentives are maintained; (iii) the inclusion of progressive productivity which already amounts to a supplemental stretch factor of about 0.15% in 2021 and 0.3% in 2022; and (iv) the fact that both side's experts recommend an overall X factor of close to 0% – PSE recommends 0%, and PEG recommends 0.05%.[26]

Hydro One also pointed to its productivity proposals, including progressive productivity, in support of its argument against a non-zero X-factor.

Critiques of Expert Evidence

Many parties noted that PSE's and PEG's analyses were largely based on the same data, and even similar modelling approaches. With respect to TFP, PSE and PEG came to similar conclusions and recommendations, finding that the North American electricity transmission sector, as represented by U.S. transmitters and Hydro One, have shown negative productivity for over two decades. However, the magnitudes of the TFP estimates differed between the two experts. In part this was due to the different time frames (2004-2016 for PSE and then extended to 2018 with the updated evidence in the Reply Report, and 1995-2016 for PEG). PSE and PEG also differed in their opinions on the factors underpinning the observed negative productivity.

With regard to total cost benchmarking, while largely based on the same data, PSE's and PEG's models differed, and PSE and PEG presented different results and recommendations. PSE found Hydro One to be a superior cost performer (after accounting for business environmental differences compared to U.S. transmitters), while PEG found Hydro One to be "normal" relative to the sample.

[26] Hydro One, Reply Submission, p. 43. Detailed discussion was in the preceding pages 32 to 43 of its Reply Submission.

In their evidence, interrogatory responses, testimony, and in PSE's Reply Report, both experts focused on, and were critical of, various differences in their modelling approaches. As noted earlier, the TFP and total cost benchmarking analyses are among the first such studies to be considered in regulatory proceedings for the electricity transmission sector. Data availability and quality, and understanding of drivers for costs and productivity, are less mature.[27]

PSE and PEG critiqued each other's approaches. Many of these criticisms focused on technical aspects of the sophisticated econometric techniques employed for data construction and model estimation. These included the following (although this list is not exhaustive):

- Time frame, with PSE starting in 2004 while PEG started in 1995
- Estimation techniques to correct for autocorrelation and heteroscedasticity (e.g., Use of the Driscoll-Kraay method by PSE versus PEG's use of Generalized Least Squares), and the optimality of the techniques used by each consultant[28]
- Replicability of analyses, in part due to data availability or introduction of new variables (i.e., the construction standard measure used by PSE)
- Use of, or omission of, quadratic and cross-product terms for certain variables
- Alleged bias in the results, particularly for Total Cost Benchmarking, as documented by PSE in its Reply Report and testimony [29]
- Changes in PEG's estimated model from the evidence in the Hydro One SSM case to the updated models filed in PEG's evidence in this proceeding.

In addition to the above, both experts pointed out, in evidence and testimony, other analytical differences (i.e., in some variables) and computational errors of their

[27] Oral Hearing Tr., Vol. 9 (November 4, 2019), pp. 46 and 119. See also EB-2018-0218, Exhibit I/Tab 1/Schedule 63 and Exhibit L/Tab 1/Schedule 1 and Exhibit L/Tab 1/Schedule 17. PSE's and PEG's evidentiary record from the Hydro One SSM proceeding (EB-2018-0218) was adopted on the record of this case by the OEB (refer to OEB Correspondence June 28, 2019 and July 4, 2019 in this proceeding).
[28] PSE Reply Report, October 15, 2019, pp. 12-17, Oral Hearing Tr., Vol. 8 (November 1, 2019), pp. 166-173, Tr., Vol. 9 (November 4, 2019), pp. 135-146, Hydro One Reply Submission, January 17, 2020, pp. 40-41
[29] PSE Reply Report, October 15, 2019, pp. 7-17, Oral Hearing Tr., Vol. 7 (October 31, 2019), pp. 155-168

analyses.[30] However, there was no consensus on whether these differences had material impacts on the results of the experts' analyses.

PSE elaborated on these in its Reply Report and during oral testimony. PEG provided further explanations during its Examination-in-Chief and oral testimony.[31]

OEB staff questioned PSE's claim that its models were optimal through the use of the Driscoll-Kraay autocorrelation correction technique. OEB staff preferred PEG's analysis, but pointed out various issues and shortcomings of the analyses of both experts (with an emphasis on PSE's evidence), and submitted that the OEB would need to also use its experience and knowledge of TFP and cost benchmarking in other sectors to make its determinations.

Some intervenors, notably SEC, VECC and Energy Probe, were critical of the expert evidence generally, although some submitted that PEG's analyses were preferable compared to PSE's.

SEC submitted that PSE's criticism of the changes in PEG's models were unfounded, and that the changed models represented PEG improving its models. SEC and VECC, in particular, also submitted that the OEB should give much greater weight to its own experience and knowledge, relative to the analyses of PSE and PEG.

Hydro One and PWU were both critical of PEG's analyses. Hydro One submitted that PSE had demonstrated on the record, particularly through testimony and the Reply Report, that PSE's evidence was superior. Hydro One submitted that PSE's shorter time period for its TFP and cost benchmarking was more representative of the current period, and hence preferable to PEG's longer historical period. Hydro One also submitted that:

> As a matter of fairness, the same cost benchmarking modelling approach should be utilized for both the distribution and transmission sides of Hydro One's business. PEG has not done so here, nor did it provide a credible explanation for why it took different modeling approaches in that or other previous cases. PSE's

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[30] Examples include Exhibit L1/Tab 1/Schedules 1, 5 part d, 13, 21, 24, Oral Hearing Tr., Vol. 7 (October 31, 2019), pp. 161-166), Tr. Vol. 8 (November 1, 2019), pp. 27-28, on errors and differences regarding some errata in data, . Oral Hearing Tr., Vol. 9 (November 4, 2019), pp. 46-55 on PEG's concerns with structural change in the U.S. for transmitters.
[31] Oral Hearing Tr., Vol. 9 (November 4, 2019) pp. 46-63, 85-86

> reply report highlights the magnitude of these errors. If either of PEG's errors are corrected, Hydro One's benchmark scores would warrant a 0.15% stretch factor. If both errors are corrected, Hydro One's benchmark scores would warrant a 0% stretch factor. Both of these outcomes would be more appropriate for a utility ranked in the top quartile.[32]

PSE's Reply Report

OEB staff noted that PSE's Reply Report was filed on October 15, 2019, less than one week prior to the start of the oral hearing on October 21, 2019, and that the filing of this report had not been mandated in the OEB's procedural directions.

OEB staff further submitted that, given the late timing of the filing of the PSE Reply Report, which hindered proper discovery from taking place, the Reply Report should be given little or no weight by the OEB in its deliberations on the matters covered by it. Energy Probe made a similar submission.

In reply, Hydro One submitted that OEB staff's concerns were unsubstantiated, and the proposal to give little or no weight ignored procedural fairness. It stated that PSE's Reply Report was filed as quickly as possible, and that no party objected to it when first filed. Hydro One submitted that PSE's updated evidence was fully tested and should be accepted on the record.

Findings

The OEB is setting the X factor at 0.3%. This is a combination of the base productivity and overall stretch factor.

Both PSE and PEG calculated a negative TFP for the transmission sector, to varying degrees. There were criticisms of both studies by the parties, and PEG and PSE expressed concerns about each other's studies. It was acknowledged that TFP and total cost benchmarking for the electricity transmission sector are relatively recent in regulatory proceedings. For this reason, data availability and quality, and understanding of drivers for costs and productivity are less mature.

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[32] Hydro One, Reply Submission. p. 41

There was also general agreement that structural changes have occurred in the transmission industry over time. Hydro One argued that this means that the more recent period used by PSE is a better estimator of the TFP trend for 2020 to 2022. The PSE Reply Report stated that, given a large structural change in the late 1990's and early 2000's, and other factors occurring now, beginning the sample period in 2004 is far more reflective of the expected productivity experience in upcoming years than PEG's sample that begins in 1996. OEB staff argued that PSE's result of -1.6% annual TFP over the shorter time period was not credible. Furthermore, the PEG Report stated that the sample period used by PSE was "fairly short for an X factor calibration study", and during the 2005 to 2016 sample period, the productivity growth for U.S. transmission was strongly influenced by special circumstances that included policy initiatives of the U.S. government.

The OEB is therefore left with competing expert reports and differing opinions on the results of the TFP analysis. There were numerous submissions from parties on improvements that could be made to both reports. With TFP analysis and total cost benchmarking for transmission still maturing, and evidence of structural changes in the U.S. transmission industry, the OEB concludes that it cannot rely on either report as a good estimate of TFP trends for the 2020 to 2022 term.

The OEB uses a performance-based approach to regulation. The OEB's Rate Handbook emphasizes the requirement for utilities to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. Furthermore, the Rate Handbook explains the variety of incentive rate-setting options available to utilities consistent with this performance-based approach. The OEB concludes that a revenue cap adjustment that allows Hydro One to escalate its revenue requirement by the full amount of inflation is not consistent with that approach. The OEB has therefore set the X factor at 0.3% to provide a reasonable incentive for Hydro One to achieve efficiencies that will benefit customers. This is the mid-point of the X factor that the OEB applies to electricity distributors.

Hydro One has both transmission and distribution operations. In the past, the OEB has set the revenue requirement / rates for these operations separately. The TFP analysis provided in this proceeding by PSE indicated that Hydro One's total costs for its transmission operations are well below the benchmark expectations. In Hydro One's last distribution proceeding, PSE's analysis showed that Hydro One's average total cost levels for its distribution operations were well above benchmark expectations. The OEB does not have the evidence to make any conclusions about why the same company can have such different results for its operations. There are significant common costs that are allocated between the operations. As indicated by the OEB under Issue 10, the OEB expects to review these allocations in the joint rebasing application to be filed by Hydro One for 2023 revenue requirement / rates. The OEB also expects Hydro One to review the different benchmark cost performance between its transmission and distribution operations and provide explanations for this difference in the next rebasing application.

C-factor and incremental capital stretch factor (S-factor)

Hydro One's proposed Custom IR revenue cap plan includes the addition of a capital-factor (C-factor) in the formula. The purpose of the C-factor is to proxy the additional revenue requirement of forecasted capital expenditures (in-service additions) above and beyond what is factored in and recoverable from the established revenue requirement, as adjusted by inflation less productivity, each year.

OEB staff, in its submission, noted that the C-factor concept was first introduced and approved for Toronto Hydro-Electric System Limited's (Toronto Hydro's) 2015-2019 Custom IR plan.[33] A C-factor was also proposed and approved for Hydro One's 2018-2022 Custom IR plan for distribution rates.[34] The OEB also recently approved a C-factor in Toronto Hydro's new Custom IR application for 2020-2024 distribution rates.[35] This current Application is the first revenue cap application for a utility's electricity transmission revenue requirement where a C-factor has been proposed.

OEB staff and many intervenors submitted that, in this context, Hydro One's proposed C-factor is reasonable on a conceptual basis, with two qualifications:

- First, ultimately the need for and the quantum of capital spending for a C-factor must be based on a review of the utility's capital system plan (TSP for an electricity transmitter).

- Second, while the first C-factor for Toronto Hydro's 2015-2019 Custom IR plan[36] had no stretch factor, beginning with Hydro One's distribution 2018-2022 Custom

[33] EB-2014-0116
[34] EB-2017-0049
[35] EB-2018-0165
[36] EB-2014-0116

> IR plan,[37] consideration has been given to the need for an incremental stretch factor (which PEG's witness called an S-factor) as part of the C-factor in order to incent the utility to seek additional productivity gains on its forecasted capital plan and budget. PEG, OEB staff and several intervenors submitted that a non-zero S-factor is needed for the C-factor in order to provide additional incentives for the utility to seek productivity and cost efficiencies on its forecasted capital plan.

In this proceeding, Hydro One proposed no S-factor, based on PSE's analyses.

As part of the Price Cap rate-setting option, the OEB has established an incremental capital module (ICM) for incremental funding of capital, which includes a materiality threshold with a 10% dead band. Updating and expanding on its evidence from the Hydro One SSM hearing,[38] which was also adopted as part of the record in this proceeding, PEG filed evidence and discussed its work to establish a more conceptual basis for an S-factor to have similar incentive power to the ICM materiality threshold.[39].

PEG initially proposed an S-factor of 0.62%, which was subsequently updated to 0.31%.[40] However, PEG testified that there is an inverse relationship between the S-factor and the X-factor, such that, as the X-factor increases, the S-factor that equates to the ICM materiality threshold decreases.[41] Based on PEG's spreadsheet showing its S-factor derivation, Hydro One's counsel cross-examined PEG on this relationship, with the suggestion that an X-factor of 0.3% would largely eliminate the need for the S-factor (i.e., the S-factor should have a value of zero).[42]

OEB staff and several intervenors submitted that, regardless, a non-zero S-factor was needed in order to incentivize containment of capital costs, a point also made by PEG during the oral hearing.[43] OEB staff further submitted that a 0.15% S-factor on the C-

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[37] EB-2017-0049

[38] EB-2018-0165. PEG's evidence is Exhibit M1, filed March 20, 2019. PEG's response to SEC-13 (Exhibit L1/Tab 5/Schedule 13) provided PEG's theoretical derivation of the S-factor to equate to the ICM materiality threshold.

[39] Exhibit M1, filed September 5, 2019. See also Oral Hearing Tr., Vol. 9, pp. 94-102, and Exhibit L1/Tab 1/Schedules 12, 13, 16, 17, 20, Exhibit L1/Tab 4/Schedule 3

[40] Oral Hearing Transcript, Vol. 9, p. 105

[41] Oral Hearing Transcript, Vol. 9, p. 58

[42] Oral Hearing Transcript, Vol. 9, p. 106

[43] Transcript. Day 9, pp. 106-107

factor is reasonable, and in alignment with its proposal for a 0.3% X-factor. OEB staff advanced four reasons for this:

- OEB staff agreed with PEG's testimony that the relationship between the X-factor and the S-factor is not as simple as suggested by Hydro One during oral cross-examination, such that the S-factor should actually turn negative for larger values of X.[44]
- A non-zero and positive S-factor would be consistent with the OEB's expectation for productivity improvements that are no lower than what would be expected under a price (or revenue) cap IR plan, consistent with the expectation of "continuous improvement" under the RRF.[45]
- OEB staff shared the skepticism of PEG and some intervenors[46] of Hydro One's argument that its "progressive productivity" approach, introduced in this Application, already incorporates productivity savings in its capital budget and forecasted capital additions, and thus no further incentive for capital savings is needed. OEB staff submitted that a non-zero S-factor is a more certain way of ensuring that Hydro One pursues capital efficiencies and productivity and ratepayers receive a share of realized savings.
- OEB staff noted that the OEB had approved, along with a 0.45% X-factor, a 0.15% S-factor for Hydro One's 2018-2022 Custom IR plan for distribution rates, in order to provide an additional incentive for Hydro One to pursue productivity improvements and cost containment in its distribution capital expenditures.[47]

LPMA supported OEB staff's submission. CCC and Energy Probe also submitted that an S-factor value of 0.15% should be approved.

SEC made submissions on what it considers deficiencies in both PSE's and PEG's arguments, and submitted that it considered PEG's recommended 0.31% S-factor to be inadequate. SEC recommended that the OEB look at its 4th Generation IRM policies generically on the cost containment incentives of existing rate-making policies. However, in the context of this Application, SEC submitted that the OEB should approve a 0.31% S-factor as the best evidence on record. VECC also argued for a 0.31% S-factor in this proceeding, distinguishing it from the Hydro One SSM revenue cap plan.

[44] *Ibid*.
[45] Rate Handbook, pp. 2, 23-28
[46] Oral Hearing Tr., Vol. 8, pp. 19-20, 73-76, 80-82, 84-87, Vol. 9, pp. 111-113
[47] EB-2017-0049

LPMA and CME, in their submissions, argued that the working capital should not be taken into account in the C-factor, for consistency with what the OEB determined in the recent Hydro One Distribution Custom IR plan.

In reply, Hydro One submitted that the submissions of OEB staff and intervenors ignored the evidence on the record and should be dismissed. Hydro One submitted that explicit and progressive productivity savings are factored into its capital expenditures and in-service additions for each year of the plan, so that customers receive the benefits of the lower forecasted capital additions.

Hydro One submitted that OEB staff's proposal was "punitive" and asserted that OEB staff was ignoring aspects of its own expert's (PEG's) analysis. Hydro One acknowledged PEG's and OEB staff's admission that the S-factor methodology is still evolving. Hydro One submitted that the way that the S-factor formula works, whereby poorer performers would get a lower (or even zero) S-factor compared to good cost performers, is contrary to the principles of the RRF, and the S-factor should be rejected.

In Hydro One's view, adding an additional stretch factor on the C-factor would doubly recover the savings. Hydro One submitted that proposals for a 0.31% S-factor are "… in fact proposing a combined capital-related supplemental stretch factor of 0.46% in 2021 and 0.61% in 2022 (in addition to their proposed increases to the X factor)." Hydro One concluded that the record substantiated its capital needs for the plan period.

Hydro One refuted LPMA's and CME's submission to omit the working capital from the C-factor. Hydro One submitted that the working capital requirement for its transmission business was different than its distribution business, and that the differences may warrant different treatment. Hydro One also submitted that the working capital for transmission is much smaller than it is for distribution, and has an immaterial impact on the C-factor calculation.

Updating of the C-factor

OEB staff submitted that Hydro One's proposal for the annual revenue cap updating of the revenue requirement for January 1 of each of 2021 and 2022 was reasonable, but raised an issue with respect to the C-factor. OEB staff noted that Hydro One's proposal in the Application is to fix the C-factor values at what is approved by the OEB in this

Decision and Order for each year (2020-2022), and that approach is consistent with the C-factor values for its current Custom IR plan for distribution rates.[48]

OEB staff submitted that Hydro One's methodology is different from how the C-factor worked for Toronto Hydro's 2015-2019 Custom IR plan.[49] For Toronto Hydro's Custom IR plan, the C-factor was updated annually to reflect the updated inflation factor, which is also a parameter in the formula for the C-factor.[50] While the approved forecasted capital expenditures, and, hence capital additions, are fixed, the C-factor itself is updated annually as it depends on the updated inflation factor approved by the OEB for that year. This same C-factor formula has been approved in Toronto Hydro's recent Custom IR plan for 2020-2024.[51]

OEB staff submitted that the methodology approved and used for Toronto Hydro is correct. Hydro One's approach for fixing the C-factor even when the inflation changes means that the utility will potentially under- or over-recover the revenue requirement for its approved forecasted capital additions in each year due solely to changes in inflation, although the amount may not be material. OEB staff noted that updating the C-factor for inflation each year is formulaic.

OEB staff's preference was for Hydro One to be ordered to update the C-factor annually as part of the annual application, consistent with the C-factor methodology approved in Toronto Hydro's Custom IR plans. If the OEB does not wish to have a methodological difference between the distribution and transmission Custom IR plans for Hydro One, OEB staff submitted that Hydro One's proposal to fix the C-factors for each year in this Decision and Order could be reasonable. However, OEB staff submitted that, for any future distribution or transmission multi-year plans including a C-factor, the C-factor should be updated annually based on the inflation factor each year. LPMA made a similar submission.

VECC submitted that OEB staff's rationale is conceptually correct, but that the change was unnecessary due to immateriality.

[48] EB-2017-0049
[49] EB-2014-0116
[50] EB-2014-0116, Toronto Hydro Draft Rate Order, January 22, 2016, pp. 11-12
[51] EB-2018-0165, Decision and Order, December 19, 2019, pp. 36-41

In reply, Hydro One submitted that OEB staff's proposal for deferring consideration of this matter to a subsequent rate application was reasonable, as Hydro One did not wish to create an inconsistency between the distribution and transmission rate plans at this time.

Findings

The OEB approves Hydro One's approach to calculating the C-factor with the addition of an incremental capital stretch factor of 0.15% and removal of the working capital allowance component. This stretch factor is consistent with what the OEB approved for Hydro One's distribution business and is intended to incent the utility to seek additional productivity gains on its forecasted capital plan and budget.

Hydro One's proposal for an incentive rate-setting mechanism application includes a forecast of capital expenditures for each year of the three-year term. Hydro One's transmission business is capital intensive, so this is a large part of revenue requirement that will escalate well beyond the I – X component of the RCI adjustment. The OEB concludes that it is appropriate to include the incremental stretch factor given that the revenue cap framework includes an update to rate base each year based on this forecast of capital expenditures.

The OEB discusses Hydro One's progressive productivity approach under Issue 6. While this approach is an improvement in Hydro One's planning process, the results of it are yet untested. The OEB has also made specific reductions to Hydro One's capital plan, as discussed under Issue 9. The OEB is establishing the 0.15% incremental stretch factor on capital taking each of these issues into consideration.

Hydro One calculates working capital as a percentage of OM&A, and therefore the OEB agrees with LPMA and CME that the working capital allowance should be excluded from the C-factor calculation. This is consistent with the C-factor for Hydro One's distribution operations.

It is also consistent with the distribution operations not to update the C-factor for the updated inflation factor. The OEB therefore accepts Hydro One's approach for this Custom IR term.

Growth

A growth factor was not included in Hydro One's proposed revenue cap formula. The omission of the growth factor was raised in this proceeding. Hydro One, and its expert, PSE, stated that growth in the transmission sector is very close to zero.[52] When questioned by the OEB panel, PSE's witness referred to the output growth measure in PSE's TFP analysis, showing growth to be at 0.01% for the period.[53] PEG's witness also concurred that, while the growth factor should be there, he had no reason to dispute PSE's evidence of little or no growth in the electricity transmission sector.[54]

OEB staff accepted the available evidence that there is almost no growth in electricity transmission output, based on the current output measures of "ratcheted" peak demand and kilometres. of line, and submitted that including a growth factor, albeit with a value of zero, is reasonable for Hydro One's 2020-2022 revenue cap Custom IR plan.

In reply, Hydro One stated that the experts agreed that no growth factor was required, and that "OEB Staff's preference for a growth factor appears to be purely theoretical, serves no tangible or practical purpose, and should be rejected".

Findings

The OEB will not incorporate a growth factor in the revenue cap formula. The OEB accepts the testimony of the experts that there is little or no growth in the electricity transmission sector, so that any factor would not be material. The OEB notes that a growth factor was not included in the revenue cap plan that it recently approved for Hydro One SSM.[55]

Z-factor

Hydro One proposed that the OEB's established Z-factor policy and methodology be available during the Custom IR plan, consistent with the OEB's general rate-setting

[52] Oral Hearing Transcript, Vol. 8, pp. 28-31
[53] Oral Hearing Transcript, Vol. 9, pp. 31-34
[54] *Ibid.*, pp. 75-77, 160-161
[55] EB-2018-0218, Decision and Order, *op. cit.*, p. 14

approach as documented in the Rate Handbook. Hydro One is proposing no deviations from the OEB's established approach.

OEB staff and LPMA made submissions supporting Hydro One's proposal for Z-factor treatment as being consistent with the OEB's rate-setting policies.

Findings

The OEB approves a Z-factor mechanism for Hydro One during the Custom IR term for claims that meet the criteria of Materiality, Causation and Prudence as approved by the OEB for Hydro One's distribution business.[56]

The Filing Requirements For Electricity Transmission Applications - Chapter 2 - Revenue Requirement Applications (Transmission Filing Requirements) require Hydro One to propose a materiality threshold for a Z-factor. Hydro One stated that it was relying on the materiality threshold of $3 million for variance explanations from Section 2.1.1 of the Transmission Filing Requirements.

The OEB notes that the Transmission Filing Requirements state that the materiality threshold for a Z-factor claim "should exceed the OEB-defined materiality threshold set out in section 2.1.1 on a revenue requirement basis". While Hydro One's proposed materiality threshold for a Z-factor claim does not "exceed" the materiality threshold set out in section 2.1.1 of the Transmission Filing Requirements, the OEB is approving it for this Custom IR term so that it is the same as the materiality threshold for Hydro One's distribution business. The appropriate materiality threshold can be considered again as part of Hydro One's joint distribution and transmission application for 2023 rates.

Earnings Sharing Mechanism

Hydro One proposed the following ESM based on its return on equity (ROE) results:

> Hydro One proposes to share with customers 50% of any earnings that exceed the OEB allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral

[56] EB-2017-0049, Decision and Order, p. 42

> account for clearance at the time of Hydro One's next rebasing. The calculation of the actual ROE for a test year will use the OEB approved mid-year rate base for that period to avoid double counting with amounts in the proposed capital in-service variance account …[57]

OEB staff, CCC and LPMA supported Hydro One's proposed ESM as being compliant with OEB policy.

BOMA submitted that there should be no dead band for the ESM threshold, on the basis that ratepayers should also realize the benefits of any overearnings by the utility.

Hydro One submitted that BOMA's proposal is inconsistent with OEB policy and should be rejected.

Findings

The OEB approves the ESM proposed by Hydro One. This proposed ESM is consistent with what was approved for Hydro One's distribution business. The OEB concludes that sharing savings if earnings exceed 100 basis points from the approved ROE provides a reasonable balance between incenting the utility to seek efficiency and productivity improvements and protecting customers from excess earnings.

Off-ramps

Hydro One proposed to apply the OEB's existing policy with respect to off-ramps. OEB staff, supported by LPMA, submitted that Hydro One's proposal is compliant with OEB policy.

Findings

The OEB approves Hydro One's proposed off-ramp. While there is no specific policy for transmitters, an off-ramp with a trigger at ±300 basis points is consistent with the policy the OEB established for electricity distributors. The OEB will monitor Hydro One's results reported under the OEB's Electricity Reporting and Record Keeping

[57] Exhibit A/Tab 4/Schedule 1, p. 9.

Requirements and will determine if a regulatory review is warranted if the off-ramp is triggered. Any such review will be prospective, and could result in modifications, termination or the continuation of Hydro One's Custom IR framework. This is the same off-ramp as the OEB approved for Hydro One's distribution business.

3.3 PRODUCTIVITY IMPROVEMENT AND PERFORMANCE SCORECARD

3.3.1 Productivity Improvements (Issue 6)

Issue 6. Has Hydro One taken appropriate steps to identify and quantify productivity improvements in all areas of its transmission operations?

Hydro One stated that it has developed and presented a framework to incent, implement, verify and track productivity savings. Hydro One noted that the total revenue requirement and resulting rate impacts have been mitigated by $370 million in productivity savings over the 3-year application period through defined capital initiatives of $213 million, OM&A initiatives of $70 million, and additional undefined progressive productivity initiatives of $87 million for capital. Hydro One estimated that the proposed revenue requirement for 2020-2022 is approximately $100 million lower than it otherwise would have been.

OEB staff and intervenors questioned the legitimacy of the claimed savings. OEB staff submitted that Hydro One has not adequately distinguished what is a true productivity gain from what is normal due diligence in operating its business. SEC submitted that the vast majority of these savings are not incremental and reflect the persistent impact of past initiatives that carry on into the test period. Both AMPCO and SEC argued that only the $117 million of capital progressive productivity initiatives ($87 million in undefined savings plus $30 million in defined savings) represent incremental efficiencies.

In response, Hydro One discussed the process it uses to ensure that the resulting savings are genuine. Hydro One noted that productivity must be validated and tied to specific, measurable initiatives to be considered as savings within its framework. In addition, it engages in detailed discussion and analysis to review factors that might lead to unreliable savings to ensure that true productivity savings are achieved.

OEB staff and intervenors also questioned the baselines for the various productivity initiatives outlined by Hydro One. As an indication as to how the baselines had shifted, OEB staff noted that the progressive productivity savings were added at the final plan review and approval stage and at that stage, the proposed capital expenditures had increased by $394 million from the previous stage.

Hydro One referred to the number of candidate investments in response to OEB staff's submission, stating that the number of investments also increased in the final stage of the planning process, and therefore, more outcomes will be delivered.

In response to intervenor suggestions that the amount of savings should be a reduction to Hydro One's capital envelope to provide ratepayers the benefit of the identified productivity savings, Hydro One clarified that the proposed revenue requirement has already been reduced to account for defined and undefined productivity savings. Hydro One submitted that a further reduction would result in less work being completed and less productivity being achieved.

With respect to SEC's concern that Hydro One has not included any progressive productivity proposals in its 2020 OM&A budget, Hydro One listed a number of reasons why it believes that progressive productivity for OM&A is not necessary. The reasons included the observation that its 2020 OM&A budget is lower than its actual and approved OM&A levels during the historical period. Furthermore, the existence of the ESM already provides an incentive for OM&A productivity.

In response to concerns expressed by intervenors on the need for independent audit, verification and reporting in connection with Hydro One's productivity framework, Hydro One expressed its willingness to provide reporting related to its transmission business in a way that is consistent with its commitment for reporting of its distribution business. Hydro One submitted that it would be amenable to engaging a third party to perform an independent review of its productivity framework as part of its next rebasing application.

Hydro One argued that it has developed and presented what may be the most comprehensive and sophisticated framework for incenting, implementing, verifying and tracking productivity savings that the OEB has ever had an opportunity to consider. Hydro One submitted that its rigorous, prominent and transparent approach, in contrast to the formulaic approach advocated by some parties, is important for driving cultural change and incenting business units and individual employees to continually seek, identify, define and implement productivity improvements across the company. Hydro One argued that if the OEB were to disregard or discount Hydro One's productivity savings by adopting any of the intervenor proposals in this regard, it would call into question whether the OEB's expectations for utility productivity are reasonable or practically achievable.

Findings

This issue addresses the steps Hydro One has taken to identify and quantify productivity improvements. The OEB is not imposing additional productivity measures, but has taken these factors into consideration in setting an overall stretch factor of 0.3% and an incremental capital stretch factor of 0.15% (as discussed under Issue 5), and in making certain reductions to the capital budget (as discussed under Issue 9).

Hydro One stated that its productivity includes "quantifiable productivity improvements with clear accountabilities for delivering the anticipated savings and a robust governance framework to measure accomplishments". While the OEB expects that the productivity framework introduced by Hydro One will improve its planning processes, this will not be tested until Hydro One's next rebasing application. Hydro One has explained that as part of its framework, it will report productivity results monthly to its Chief Executive Officer and senior executives. The OEB expects Hydro One to provide a summary of that reporting and to report on its verifiable results as part of its next rebasing application.

Hydro One has identified specific progressive productivity initiatives for its capital program, and has included additional undefined productivity initiatives in the capital budget. Together these initiatives total $117 million over the three-year term. The capital expenditures proposed by Hydro One over this term are $3,865 million. The progressive productivity initiatives are therefore 3% of the proposed capital investment. Hydro One has also identified other capital productivity measures, for a total over the three-year term of $300 million (7.8% of the total capital plan). It is not clear the extent to which these other measures should have just been considered as part of the normal business planning process the OEB expects of any utility.

Hydro One is forecasting capital expenditures for the 2020 to 2022 term that are $880 million (29.5%) higher than the capital expenditures approved/forecast for the 2017 to 2019 term from the last rebasing proceeding.[58] Given this increase in forecast capital spending, the OEB concludes that Hydro One can do more to achieve productivity improvements, and therefore the identified productivity measures are not sufficient. The

[58] Since there was no "approved" capital budget for 2019, the 2019 "forecast" was used instead.

OEB is also concerned that no progressive productivity measures were developed for OM&A. While Hydro One's OM&A is forecast to decrease for 2020, the OEB expects utilities to practice continuous improvement.

The OEB is directing Hydro One to engage an independent third party to review and report on its productivity framework as part of its next combined (transmission and distribution) rebasing application.

3.3.2 Proposed Scorecard Metrics (Issue 7)

Issue 7. Are the metrics in the proposed scorecard appropriate and do they adequately reflect appropriate outcomes? Do the outcomes adequately reflect customer expectations?

Hydro One proposed an Evolved Electricity Transmitter Scorecard (Scorecard). Compared to its previous scorecard, six metrics have been added and four have been removed. This results in a total of 24 metrics on the Scorecard. The proposed Scorecard is shown below.

Table 1: Proposed Scorecard

								Targets					
Performance Outcomes	**Performance Categories**	**Measures**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Customer Focus	Customer Satisfaction	Satisfaction with Outage Planning Procedures (% Satisfied)	86	92	89	94	85	86	86	87	87	88	88
		Overall Customer Satisfaction (% Satisfied)	77	85	78	88	90	88	88	88	88	88	88
	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	11.8	14.3	9.7	9.5	10.1	12.0	11.7	11.5	11.3	11.0	10.8
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)	1.8	1.7	1.1	1.2	1.1	1.1	1.1	1.0	0.9	0.9	0.9
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)	0.60	0.59	0.46	0.65	0.83	0.55	0.54	0.53	0.52	0.51	0.50
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)	0.48	0.50	0.33	0.47	0.50	0.49	0.48	0.48	0.47	0.46	0.45
		T-SAIDI (Ave minutes of interruptions per Deliver Point)	36.7	43.9	80.8	42.8	70.0	35.4	34.66	33.96	33.28	32.62	31.97
		System Unavailability (%)	0.48	0.63	0.70	0.69	0.71	0.48	0.47	0.47	0.46	0.45	0.44
		Unsupplied energy (minutes)	12.2	11.8	11.4	13.2	19.5	9.8	9.59	9.40	9.21	9.02	8.84
	Asset & Project Management	Transmission System Plan Implementation Progress (%)	99	105	100	94	99	100	100	100	100	100	100
		CapEx as % of Budget	90	106	105	100	98	100	100	100	100	100	100
		OM&A Program Accomplishment (composite index)		97	99	108	108	100	100.0	100.0	100.0	100.0	100.0
		Capital Program Accomplishment (composite index)		122	59	88	116	100	100.0	100.0	100.0	100.0	100.0
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	8.4	9.0	8.6	7.9	7.7	7.3	7.8	7.9	7.7	7.3	7.0
		OM&A per Gross Fixed Asset Value (%)	2.7	2.9	2.5	2.3	2.3	1.8	1.8	1.7	1.6	1.5	1.5
		Line Clearing Cost per kilometer ($/km)	2,495	2,234	1,966	2,100	2,797	2,295	2,264	2,200	2,175	2,100	2,100
		Brush Control Cost per Hectare ($/Ha)	1,624	1,566	1,542	1,356	1,539	1,625	1,620	1,630	1,608	1,608	1,608
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments	100	100	100	100	100	100	100	100	100	100	100
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met, %	100	100	100	100	100	100	100	100	100	100	100
		End-of-Life Right-Sizing Assessment Expectation				Met	Met	Met	Met	Met	Met	Met	Met
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.69	0.13	0.20	0.13	0.12						
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.16	1.39	1.43	1.47	1.53						
		Profitability: Regulatory Return on Equity — Deemed (included in rates)	9.36	9.30	9.19	8.78	9.00						
		Profitability: Regulatory Return on Equity — Achieved	13.12	10.93	10.02	9.03	11.08						

Hydro One submitted that the addition and removal of metrics was in response to OEB direction from its previous proceeding. The added metrics are described below.

- The OEB stated that Hydro One had measures proposed for asset management that could potentially run counter to the cost control performance indicators.[59] To address the OEB's concerns, Hydro One proposed a measure which it described as comparable to the "Distribution System Plan Implementation Progress" measure currently reported on its Electricity Distributor Scorecard. This measure (Transmission System Plan (TSP) Implementation Progress) tracks actual in-service additions compared to the budget, including any OEB variances.

[59] EB-2016-0160, Decision and Order, November 1, 2017, p 39.

- The OEB determined that the work plan execution is important but should not be driven by a performance indicator solely based on ensuring that the level of spending originally considered reasonable is spent.[60] In response, Hydro One introduced the metrics OM&A Program Accomplishment (composite index) and Capital Program Accomplishment (composite index), which Hydro One stated are directly related to expenditures and associated work completion and are expected to drive it toward having a more positive and direct impact on customer outcomes.

- The OEB directed Hydro One to 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.[61] Hydro One proposed the metrics Line Clearing Cost per kilometer ($/km) and Brush Control Cost per Hectare ($/Ha). Hydro One justified these metrics on the basis that in 2017, its transmission line clearing and brush control activities accounted for approximately 80% of the overall transmission Forestry budget.

- The OEB found that 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 OEB stated that one example of the type of measure it anticipated under this element of the scorecard was a qualitative assessment of Hydro One's response performance related to the policy objectives embedded in the government's smart grid initiatives.[62] Hydro One proposed the metric of End-of-Life Right-Sizing Assessment Expectation. Hydro One justified this metric on the basis that one component of the Long-Term Energy Plan (LTEP) was to achieve efficiencies and one component of achieving efficiencies is the right-sizing of end-of-life equipment.

[60] EB-2016-0160, pg 39.
[61] EB-2016-0160, pg 40.
[62] EB-2016-0160 pg 40.

The additional metrics are summarized in the following table:

Table 2: Additional Metrics on 2020-2022 Evolved Transmission Scorecard

Performance Outcomes		
		Transmission System Plan Implementation Progress (%)
		OM&A Program Accomplishment (composite index)
		Capital Program Accomplishment (composite index)
		Line Clearing Cost per kilometer ($/km)
		Brush Control Cost per Hectare ($/Ha)
		End-of-Life Right-Sizing Assessment Expectation

Hydro One also proposed that several metrics be removed in response to concerns expressed by the OEB in Hydro One's 2017-2018 transmission decision, as described below.

- Hydro One noted that the OEB had expressed concerns in its previous transmission rates decision that measures proposed for asset management, specifically "In-Service Capital Additions as % of OEB-Approved Plan" and "CapEx as % of Budget" could potentially run counter to the cost control performance indicators.[63] This was because the proposed asset management measures did not allow for the eventuality that execution of particular elements of the original plan could run counter to the objective of serving the best interests of Hydro One's customers.

- Hydro One noted that the OEB had also stated, with respect to public policies, that it did not consider the inclusion of North American Electricity Reliability Corporation

[63] EB-2016-0160, pg 39.

(NERC) and Northeast Power Coordinating Council (NPCC) Standards to be aligned with the intent of the OEB's scorecard objective so these metrics were also proposed for removal.[64]

The removed metrics are summarized in the following table.

Table 3: Removed Metrics from 2017-2018 Transmission Scorecard

Performance Outcomes		
		In-service additions as % of OEB-approved plan
		Sustainment capital /Gross fixed asset value
		NERC & NPCC Standards Compliance – High impact issues
		NERC & NPCC Standards Compliance – Medium/low impact issues

Hydro One submitted that its Scorecard metrics (and associated Performance Reporting Governance Framework) demonstrate a proven and continuous commitment to enhancing performance management, reflect the OEB's directions, and enable it to drive and achieve relevant outcomes.

Hydro One argued that, to promote continued efficiency and reduce regulatory burden, the OEB should adopt the Hydro One Distribution scorecard performance reporting framework of an annual scorecard complemented by a Management Discussion & Analysis (MD&A) for Hydro One Transmission and abolish the capital program performance report.

Hydro One submitted that this would permit a framework that is based on the same proven and established governing principles of:

- Expressing the value of the service and performance results from a customer-centric lens

[64] EB-2016-0160, pg 39-40.

- Analyzing and providing the story behind the numbers
- Providing objective forward looking views and explaining the expected future outcomes
- Focusing on materiality and material trends and uncertainties
- Providing important disclosures

Hydro One concluded that adoption of this proven framework would serve as the foundation for the RRF outcomes-based approach and provide a tool for customers to improve their literacy and to allow them to assess for themselves the value of the service they are receiving.

OEB staff submitted that the removed metrics are appropriately and adequately explained. OEB staff submitted that Hydro One should include capital expenditure portfolio risk metrics on the proposed Scorecard. OEB staff stated that $4.5 billion or 80% of the total System Renewal budget for the 2020-2024 period is not captured in the proposed Scorecard. OEB staff further submitted that the following with respect to the portfolio risk metrics should be added to the Scorecard: (i) the number of projects forecasting or completed with a major variance (+10%) to the OEB approved budget and (ii) value of the projects forecasting or completed with a major variance (+10%) to the OEB approved budget.

OEB staff submitted that Hydro One should continue working with LDCs, including Hydro One Distribution, to determine the satisfaction level of the ultimate end use customer to be included in the next scorecard.

SEC expressed concerns similar to those of OEB staff with respect to the need for a metric tracking project variances relative to the OEB approved budget. SEC argued that with Hydro One's proposed metrics, it could hit its target of 100%, but customers would not know from the metric that Hydro One accomplished the forecast work at a cost that was higher than budgeted. SEC further submitted that for customers, both parts – the work accomplished and budget variances – are equally important and, as such, the metrics should compare weighted actual in-service accomplishments as compared to forecast, against the weighted actual costs compared to budget.

SEC stated that it is also concerned that Hydro One's Scorecard has no metrics that look at cost control for capital projects or programs. SEC noted that the composite metric does not look at the cost per unit of accomplishment (i.e., unit cost).

However, SEC argued that even if this is remedied, as SEC proposes, the metric still only looks at a number of specific programs although Hydro One's proposed capital plan is primarily made up of projects, not programs. SEC observed that only about 20% of Hydro One's proposed System Renewal budget is made up of programs. SEC submitted that Hydro One has had a problem with the increasing cost of its projects, especially those that involve replacements of multiple asset types over numerous years, and it is these program costs that are hard for the OEB and customers to track. As such, SEC argued, it is in this area that a metric is required to monitor Hydro One's performance.

SEC argued that it would not be necessary for Hydro One to develop new metrics to meet this need as Hydro One's evidence states that it has begun to internally track several portfolio level measures that look at project management and provided a list of them. SEC stated that it is these controls and asset management metrics that Hydro One should be including in its Scorecard.

AMPCO made similar recommendations to those of OEB staff and SEC regarding the need for portfolio level project management metrics and suggested that it may be helpful for Hydro One, OEB staff and intervenors to work together to develop such metrics.

AMPCO also made some specific recommendations for additional metrics including: (1) tracking wood pole replacements as a unit cost metric, (2) given the importance of frequency of interruptions, an interruption frequency metric, (3) to reverse recent increases in vehicle operating costs, the Vehicle Utilization Rate should also be a Scorecard candidate, and (4) the Resource Utilization Rate or Billable Hours Ratio with a view to reducing cost and improving performance over time.

Hydro One stated that it is receptive to include portfolio level metrics in the Scorecard but argued that the OEB should consider its prior decision where it approved the envelope that established the portfolio of projects and not individual projects. Hydro One argued that, in effect, the OEB does not approve individual projects, but rather the envelope that establishes the portfolio of projects. As such, Hydro One submitted, there would not be an OEB approved project specific budget as alluded to by OEB staff in its submission.

Hydro One argued the budget described in the metrics referenced in OEB staff's submission related to internal approved project total amounts defined at the conclusion of the project definition phase, and aligned with the business case approval for the project. Hydro One submitted that performance against the approved business case is more appropriate as a measure but the existing enterprise systems would require modifications to be able to report the metric.

BOMA argued that, at the present time, the Scorecard is deficient and needs to be made more detailed with clear targets and consequences for not achieving those targets. BOMA submitted that with respect to reliability, in addition to the targets for system average interruption duration index / system average interruption frequency index (SAIDI/SAIFI) (sustained) SAIFI (monetary), and the other items, Hydro One should explain what improvements it needs to make to return to top quartile reliability performance as compared to its Canadian peers.

BOMA further explained that it is not clear whether the proposed budget will accomplish that goal, and how much the changes in reliability targets and performance (SAIDI and SAIFI) are due to the changes the company has recently made in the manner in which it measures major event day (MED) events and force majeure. BOMA observed that Hydro One has stated that it has changed its reporting of SAIDI and SAIFI from 2019 forward so that the targets and performance measurement going forward will exclude force majeure events based on a two-beta methodology. BOMA expressed the concern that Hydro One does not explain what force majeure events based on a two-beta methodology means, and what the likely change of impact of the change will be in the following years.

BOMA expressed a number of specific concerns with the proposed Scorecard:

- The description of the Customer Satisfaction Corporate Survey does not comply with the OEB's last proceeding to ensure that the customer satisfaction/engagement determinations deal with the LDCs' customers' satisfaction levels and concerns.
- The customers' delivery point performance standard outlier metric needs a more coherent explanation.
- The Capital Program Accomplishment Composite Index applies to only selected capital expenditure categories and only covers 20% of the total capital expenditure.
- Each of the capital programs and groups of projects should be broken out separately on the Scorecard.
- Each method of calculation should be displayed in the table, or attached as an appendix.

- The company keeps a corporate scorecard on the other 80% of capital projects and programs and these progress reports should be shown as part of the Capital Program Accomplishment Indices in the Scorecard.
- Some of the Scorecard measures are too aggregated to be useful and should be disaggregated further.
- Unit cost targets should be introduced where possible.

BOMA also submitted that Hydro One should report on earned value analysis for each project in each year.

Hydro One responded by stating that BOMA's concerns with respect to the customer satisfaction survey were dealt with under the customer engagement survey section, while the concern about the Scorecard covering only 20% of the total capital expenditures has been discussed in its response to the portfolio metrics issue raised by other parties. Hydro One further stated that it had explained what force majeure events based on a 2-beta methodology mean and the suggestion that each of the capital programs and groups of projects should be broken out separately on the Scorecard is excessive and provides no incremental benefit, with no other party having suggested this level of disaggregation.

Anwaatin submitted that the OEB should require Hydro One to include a metric related to First Nations consultation in its Scorecard. The metric is required to ensure that the importance of Indigenous engagement and the duty to consult and potentially accommodate are reflected in the implementation of Hydro One's transmission planning.

VECC argued that while there is nothing inherently wrong with a reliance on SAIFI for outage metrics, it is strongly correlated with weather, which makes interpreting the results difficult. VECC argued that this issue should be addressed by having the Scorecard report outages, both frequency and duration, due to defective equipment. VECC noted that Hydro One tracks this metric at a sub level, but does not report on it on the Scorecard. VECC concluded that this would be a much better indicator of the efficacy of a capital program than SAIFI.

VECC also expressed concerns with respect to Customer Delivery Point Performance Standards (CDPPS). VECC submitted that the standards in question should be reviewed and at a minimum updated to reflect the most current data rather than the 20 year and older data it now includes. VECC suggested that the OEB might also revisit the premise that low volume delivery points should have a lower standard than larger delivery points. VECC argued that the current standard discriminates against small isolated LDCs and Indigenous communities.

Energy Probe argued that the OEB should not allow recovery of incentive pay related to reliability in rates until a threshold equal to the 2014-2018 average of 54.85 minutes is passed for system reliability. Energy Probe submitted that Hydro One should amend the Team Scorecard threshold to 54.85 minutes so only better SAIDI (Multi Circuits) would be eligible. Energy Probe concluded that this should be the threshold for SAIDI improvements with a target 22-minute reduction by 2024.

BOMA, VECC and LPMA generally advocated for consequences associated with the Scorecard metrics. LPMA noted that in most competitive industries, companies that fail to meet targets have consequences of lower profitability and that Hydro One and other regulated utilities do not have the same extent of consequences if they fail to meet targets. VECC noted that the entire premise of the RRF relies on a link between outcomes (i.e., reliability metrics) and the revenue the utility is allowed. LPMA urged the OEB to start looking at the consequences associated with scorecard metrics, both positive and negative, and give some teeth to the metrics.

Hydro One, while specifically responding to BOMA's submission, stated that no utility in Ontario has a set form of consequences and submitted that a generic process must occur to develop that type of regulatory framework.

Findings

The OEB approves Hydro One's proposed Scorecard with the addition of one more metric. Hydro One shall propose a new metric to measure the accomplishment of the System Renewal program at the portfolio level as part of the draft revenue requirement/charge determinant process in this proceeding.

The OEB finds that the metrics in the proposed Scorecard are generally appropriate. The six additional metrics measure Hydro One's ability to implement its TSP and effectively deliver its capital and OM&A programs within its approved budgets. In addition, these measures address planning needs associated with public policy.

One of the issues raised by OEB staff and other parties in this proceeding is Hydro One's ability to plan and execute the System Renewal component of its capital program. This component represents 81.3% of Hydro One's proposed capital spending in the

2020-2022 period, and as a result of this Decision and Order, will represent 79.4% of the approved capital budget.

The new Capital Program Accomplishment (composite index) metric proposed by Hydro One covers only six programs under the System Renewal budget which represent a small fraction of that budget.

The OEB finds that it would be beneficial for Hydro One to add one more metric which measures the System Renewal program accomplishment at a portfolio level for the remainder of the System Renewal program. Given all the issues raised in this proceeding about the planning and execution of the System Renewal program (transmission lines in particular), the OEB finds that this measure should be designed to demonstrate the degree to which Hydro One is able to complete its planned program within the approved budget for this work category.

One of Hydro One's key arguments about the need for capital spending, particularly the System Renewal component, is to sustain or improve system reliability. The OEB expects that Hydro One will address the issue of correlation between capital spending and reliability in its next rebasing application.

3.3.3 Transmission Line Loss Reduction Opportunities (Issue 8)

Issue 8. What is the status of Hydro One's joint work with the IESO to explore cost effective transmission line loss reduction opportunities and to report on those initiatives?

The OEB directed Hydro One in its previous transmission decision to work with the IESO to explore cost effective opportunities for line loss reduction and to report on these initiatives.[65]

Environmental Defence, an intervenor in this proceeding, expressed concerns about the extent of Hydro One's compliance with this directive. Hydro One and Environmental Defence agreed to terms of settlement in respect of this issue during the current proceeding, and included details of the steps that Hydro One will take under the terms of settlement.

[65] EB-2016-0160, Decision and Order, November 1, 2017, page 33.

These steps included participating in, and contributing to, the ongoing IESO stakeholder engagement on transmission line losses, preparing an internal guideline delineating the transmission line losses process, and including an option analysis and report on losses in business cases for projects where losses are material.

Hydro One agreed with PWU's recommendation that the report include an analysis of, and justification for Hydro One's proposed materiality threshold.

Environmental Defence, while agreeing with Hydro One about the appropriate next steps, disagreed with Hydro One's assertion that it has substantially completed all OEB directives related to transmission line losses. Environmental Defence identified a list of areas, including implementing cost effective loss reduction measures and documentation of loss evaluation, where it believes more work is needed and that this work needs to happen in a more timely fashion.

In response to Environmental Defence's submission, Hydro One first explained the physical constraints of the transmission system and its role in reducing system line losses. Hydro One stated that its ability to manage line losses as a transmission assets owner is limited. It explained that losses attributable to the physical characteristics of the transmission system are fixed and can only be changed through subsequent investment in the transmission system. It further asserted that it is industry practice that line loss mitigation occurs as part of other investments undertaken to address asset condition and/or reliability and not purely to reduce losses.

Hydro One then referred to the report prepared by Electric Power Research Institute (EPRI), which found that Hydro One's design practices are materially consistent with industry best practices for loss mitigation. Hydro One also noted five projects included in its capital plan where line loss reduction benefits were identified.

Furthermore, Hydro One referred to a comparison of its practice with industry best practice and concluded that its practices are substantially consistent with National Grid, the Council of European Energy Regulators (CEER), and EPRI. Hydro One noted that losses are not the primary driver of its investment; however, they are considered in instances where they are consequential to the alternative selection. Hydro One disagreed with Environmental Defence's suggestion of using the wholesale electricity commodity cost that includes global adjustment instead of the hourly Ontario energy price (HOEP) to value losses considering that project costs are typically 50 to 100 times greater than the loss reduction benefits.

In accordance with the terms of settlement, Hydro One expressed its willingness to continue to consider the reduction of line losses for all projects and to work collaboratively with the IESO to identify and investigate other opportunities to reduce line losses as part of the regional planning process.

Findings

Hydro One filed a letter with the OEB in which it and Environmental Defence reached a settlement on Issue 8. No parties opposed the settlement. The OEB accepts the settlement proposal and confirms that Hydro One is expected to take the following steps:

1. Hydro One will participate in, and contribute to, the ongoing IESO stakeholder engagement on transmission line losses, including offering to be a contributor to the final report which will document the IESO and Hydro One’s respective practices with regard to mitigating transmission line losses as well as identifying potential areas for overall net benefit reductions in transmission line losses.

2. As part of the IESO stakeholder engagement process, Hydro One will endeavor to identify any additional opportunities to cost-effectively reduce transmission losses including through improved processes, option analysis methodologies, documentation and reporting. This includes the opportunities for improvement identified in points 3 and 4 below.

3. Hydro One will prepare an internal Hydro One guideline delineating the transmission line loss process that Hydro One will follow and is accountable for. This will be developed in Q1 2020 and refined throughout the IESO stakeholder consultation as necessary.

4. In business cases for projects where transmission line losses are material, Hydro One will include an option analysis and report on transmission line losses. This will be implemented over the course of 2020 for any projects meeting a documented materiality threshold.

5. At the end of the IESO stakeholder consultation and issuance of the IESO report, if the IESO determines that it will not proceed to engage an independent third party to review the IESO’s and Hydro One’s processes,

> Hydro One will initiate an independent third party review of its own processes for cost-effectively reducing transmission line losses, to be filed at its next rate application. This review would aim to identify any additional opportunities to cost-effectively reduce transmission line losses, including through improved processes, option analysis methodologies, documentation, and reporting, and would invite input from stakeholders.

Hydro One stated that its loss mitigation practices are not formally documented but are ingrained in the way that it plans and considers its investments. Hydro One committed to formalizing these practices through written documentation for greater transparency. Hydro One also committed to include in its report an analysis and justification for its proposed materiality for step 4 above. As part of the report to be completed for the settlement proposal, the OEB expects to review these matters in Hydro One's next rebasing application.

3.4 TRANSMISSION SYSTEM PLAN

3.4.1 Appropriateness of Forecast Capital Expenditures and Planning Choices (Issue 9)

Issue 9. Are the proposed forecast capital expenditures and in-service additions arising from the Transmission System Plan appropriate, and is the rationale for planning and pacing choices (including consideration of customer preferences, planning criteria, system reliability, asset condition and benchmarking appropriate and adequately explained?

Hydro One stated that its proposed capital expenditures are developed from its 5-year TSP. Hydro One further stated that in response to the OEB's previous direction, it has made significant improvements to several aspects of its planning framework. The improvements include timely and comprehensive customer engagement to inform plan development, robust risk scoring and prioritization of investment candidates, embedding progressive productivity into the plan, and improving the management and reporting of capital program delivery to ensure execution feasibility and efficiency.

While acknowledging improvements that have been made in Hydro One's 2020-2024 TSP, OEB staff and intervenors expressed concerns with respect to Hydro One's TSP for the OEB's consideration.

OEB staff identified two major areas of concern:

- Hazard Functions – Studies produced by EPRI show that Hydro One's pace of replacing transformers and circuit breakers is faster than EPRI's forecast based on industry best practices.

- Repair vs. Replace Evaluation – By reviewing Hydro One's net present value (NPV) analysis (for making repair vs. replace decisions for high-value assets), OEB staff submitted that the NPV analysis will likely conclude that it is more economical to replace the asset rather than to repair it since the repair scenario includes additional costs without any benefit of incremental economic life.

In response to OEB staff's submissions on hazard functions, Hydro One stated that EPRI's analysis helped it to gauge the probability of failure at the fleet level and the analysis was not intended to compare Hydro One's historical removal rates with the industry. With respect to the repair vs. replace evaluation, Hydro One asserted that its objective in refurbishing power transformers is to preserve their expected service life and reliability, not to extend their life, and the expected service life of transformers as the measurement of life is required as part of the NPV analysis in the assessment report.

SEC submitted that it had three areas of concern with respect to Hydro One's TSP and the proposed capital expenditures:

- Unit Costs – By comparing the forecast and actual unit costs for major asset categories over 2017-2018, SEC found that with the exception of circuit breakers, Hydro One replaced its assets at a higher cost than forecast, which means that customers got less than what they paid in rates.

- Increases in Project Costs – SEC identified examples of projects for which the overall cost is increasing over time. A comparison of project costs (projects higher than $20 million) between the 2017-2018 application and the current 2020-2022 Application shows that the revised forecast (or actual) costs contained in this Application are on average 12.64% higher than what was provided in Hydro One's last application. On a total cost basis, the increase is 7.1%.

- Data Quality – SEC submitted that data quality issues still exist in Hydro One's asset condition assessment. SEC used transformers as an example, questioning

> the reasonableness of the proposed level of spending when only 65.2% of condition data and 59.8% of criticality data are available for transformers. In addition, SEC noted that EPRI found that 19.5% of Hydro One's transformer asset condition assessments were not aligned with its findings. EPRI also found that only 47% of Hydro One's proposed 93 planned transformer replacements between 2020 and 2024, that it had tested, are in high or very high risk categories.

Hydro One provided reasons explaining why actual unit costs were higher than forecast for 2017-2018 in response to SEC's submissions, including the fact that in the draft rate order process in 2017, forecast costs were not provided and forecast units were not updated for major asset classes (transformers, breakers and protections) to reflect the OEB's reductions in the capital envelope. Hydro One stated that integrated station-centric assets cannot be evaluated narrowly on a unitized basis since the costs are captured from varying projects with fluctuating spending from year to year. For capital programs (e.g., steel structure), Hydro One noted that an electrical contact incident in mid-2017 caused changes in operating practices that led to increased unit costs.

Regarding increases in project costs, Hydro One reiterated that project cost estimates are expected to be refined over time and it aims to deliver outcomes and meet financial commitments at the overall portfolio level. Hydro One responded that comparing projects on an average variance basis could be misleading because a few projects that have smaller budgets but larger variances in costs could skew the arithmetic mean. Hydro One stated that it believes the 7.1% variance on a total cost basis is a more meaningful number.

To respond to the concern about insufficient data for transformers, Hydro One referred to Metsco Energy Solutions' statements describing its data availability to be robust, considering the size of Hydro One's asset base, the span of its territory, and the manner of presentation of the condition score relative to many other utilities.[66] Hydro One explained that the misalignment between EPRI's and Hydro One's analysis on the 19.5% of transformer condition assessments was caused by data entry or collection errors, and correct data not reflecting the true condition of transformers. Hydro One stated that the transformer condition scores cited by SEC were Dissolved Gas Analysis

[66] Metsco Energy Solutions is a consultant which assisted Hydro One in benchmarking its asset condition/management process.

(DGA) scores (i.e., not overall condition ratings), such that it cannot rely on DGA scores alone to make conclusions regarding asset condition and replacements.

CME remained concerned with the data quality and completeness that goes into Hydro One's asset analytics system, which was identified in Hydro One's Internal Audit Report.[67] Hydro One asserted that the report dates back to 2017 and it has implemented action plans to address each recommendation.

VECC submitted that the TSP incorporates a considerable amount of judgement and estimation. VECC also reviewed Hydro One's past reliability outcomes by examining SAIFI. This index is presented as the number of sustained (one minute and longer) interruptions per delivery point per year. VECC noted that the average interruptions due to equipment failure appear to fluctuate around 0.17 over 2014-2017 and only increased slightly to 0.21 in 2018. When reviewing the breakdowns of equipment failure by asset category (i.e., line, breaker, transformer and other) over 2014-2018, VECC identified no dramatic trend that may suggest a significant deterioration of system reliability. VECC submitted that a reduction to the capital investment budget would, therefore, have little apparent consequence to reliability.

In its reply argument, Hydro One submitted that reliability metrics are a lagging indicator of asset condition and investment decisions and they are not a primary driver for certain investments.

Boston Consulting Group (BCG) Report

In its decision on Hydro One's 2017-2018 transmission revenue requirements application, the OEB required Hydro One to complete an independent third-party assessment of its TSP and to file this assessment with its next transmission rate application.[68] In this Application, Hydro One engaged BCG to undertake a review and produce a report on its planning process. Hydro One stated that BCG found Hydro One's enhanced process to be consistent and thorough, and that it meets or exceeds expectations for an above average utility planning process.

AMPCO, BOMA, CCC and SEC submitted that BCG was far from independent and the OEB should give little weight to its assessment of Hydro One's planning process. SEC

[67] Exhibit JT-1.10, Attachment 2, p. 7.
[68] EB-2016-0160, Decision and Order, November 1, 2017, page 18.

argued that BCG was uniquely unqualified to undertake the assessment considering its past involvement with Hydro One's Good to Great program and its engagement in providing program management support for the 2019-2023 transmission rate filing. SEC submitted that the OEB should require Hydro One to undertake a true independent third-party assessment of its planning process in its next Custom IR application. To ensure the independence of the third-party, SEC suggested that the assessor should be chosen by way of an RFP that explicitly excludes entities who have done previous work for Hydro One, or as an alternative, OEB staff should be the ones to select the consultant.

Hydro One disagreed with the intervenors' submissions and quoted threshold criteria from the Supreme Court of Canada and the Ontario Superior Court for concluding whether an expert is independent. Hydro One asserted that the amount of consultant fees paid in the past 5 years is not sufficient evidence of a lack of independence under the courts' standard of "independence" discussion. Hydro One emphasized that BCG was initially retained in 2015-2016 in relation to the Good to Great program and the provision of rate case management services was not for the current rate proceeding.

Customer Engagement

The subject of customer engagement activities in general is addressed under Issue 3. This section deals with how the customer engagement activities impacted the development of the TSP.

Hydro One stated that its TSP is a customer-focused plan that reflects investment levels in line with what the majority of its customers support. The transmission customer engagement survey identified the needs and preferences of transmission customers and the TSP incorporated the identified customer priorities: safety, reliability, and outage restoration.

OEB staff and a number of intervenors identified deficiencies in Hydro One's customer engagement activities and rejected Hydro One's assertion that outcomes from the customer engagement process sufficiently support the proposed level of capital expenditures.

Design of the Survey

Most parties had concerns regarding the design of the customer engagement survey, including the list of outcomes, the level of investment in Scenario C (one of four investment scenarios in the survey), and the absence of important information.

Hydro One stated that its transmission investment plan addresses and is responsive to customers' priorities of safety, reliability and outage restoration. OEB staff and intervenors observed that customers' top priorities were identified by asking them to rank the importance of seven outcomes that exclude cost, and cost was selected as the missing outcome by LDCs, end users, and generators. AMPCO and SEC submitted that if Hydro One had incorporated cost in its capital plan as the number one outcome for customers as supported by LDCs' surveys, one would have expected to see a much smaller capital investment proposal.

SEC pointed out that when participants reviewed the four investment scenarios in the survey, Scenario C was titled as maintaining the current level of investment, but the level of investment in Scenario C reflected capital expenditures proposed for 2017-2018 rather than what was approved, SEC also noted that the budget constraints are consistent with the customer preference for Scenario C, which was based on a 5-year capital investment plan of $6.6 billion from 2019-2023 or $1.3 billion per year. SEC noted that the proposed capital plan included in the Application is an average annual capital expenditure request of $1.29 billion.

AMPCO submitted that its members are interested in information on Hydro One's allowed and achieved return on equity and such information should be provided in future customer engagement surveys. SEC noted three types of information that were missing in the survey: load forecast for customers to understand the total bill impacts, information associated with Hydro One's current reliability and the trade-off between overall spending and changes in reliability, and background information for participants to consider when they respond to the survey.

Hydro One claimed that it understood that cost is a priority for customers by looking at prior research and other customer feedback information they had. Hydro One emphasized that it took cost into account when most customers selected Scenario C, a $6.6 billion investment level, and that feedback was one of the inputs in developing the investment plan. Regarding the level of investment in Scenario C, Hydro One noted that the scenario description explained that this scenario extends the investment plan in the Application before the OEB to 2023. Hydro One provided explanations in response to SEC's concerns regarding the missing load information, including noting that the survey respondents are sophisticated and have information and expectations about load impacts, and the filing requirements do not require load impacts to be included in customer engagement. Hydro One referred to participants' positive feedback about the survey in response to SEC's comment on the lack of background information included in the survey.

Risk Reliability Model

OEB staff and a number of intervenors remained concerned about using the risk reliability model (RRM) in the customer engagement process. Although RRM is not used to identify asset needs or justify investments, it was used to provide a directional indicator to customers and stakeholders to communicate reliability risk.

In its decision on Hydro One's 2017-2018 transmission revenue requirement application, the OEB found that it is impossible to determine from the model whether a certain reduction in reliability risk is worth a certain level of capital investment. The OEB concluded that the RRM needed 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.[69]

Hydro One responded that concerns expressed by the OEB about the RRM needing refinement do not affect its ability to be used to provide a directional sense of long-term reliability impact. It also submitted that the RRM was not the sole proof point and listed other outcome measures (e.g., long-term reliability performance, rate impacts, and asset age profile) used in the illustrative scenarios.

[69] EB-2016-0160, Decision and Order, revised October 11, 2017, page 24.

Timing of the Engagement

SEC submitted that most of the concerns regarding Hydro One's customer engagement activities, including the use of RRM and LDCs speaking for their end-use customers, were raised by stakeholders in the 2017 stakeholder meetings. The stakeholder meetings took place before the release of the OEB's decision in the last Hydro One transmission proceeding and before Hydro One undertook the customer engagement survey. SEC submitted that Hydro One proceeded with the customer engagement activities as planned without addressing stakeholders' concerns.

Hydro One indicated that various other forms of customer engagement activities occurred after the OEB's decision was issued. Hydro One explained it did not do a further IRG survey after the OEB decision because the timing of the survey was tight with respect to meeting the filing requirements and the filing date. However, Hydro One asserted that the timing of the survey still allowed the feedback to be incorporated into the investment planning process.

Capital Expenditures

Hydro One proposed capital expenditures of $3,864.7 million for the 2020-2022 test years. Table 4[70] below provides a summary of the historical and forecast capital expenditures.

[70] Exhibit J1.1, Table 6, page 6 of 10. 2017 actual data from Exhibit B-1-1, TSP Section 3.3, Table 1, page 2 of 20.

Table 4: Capital Expenditure Summary ($Millions)

Category	2017 Approved	2017 Actual	2018 Approved	2018 Actual	2019 F/Cast	2020 Test	2021 Test	2022 Test	2020-2022 Total
System Access	33.3	42.7	24.3	33.7	45.1	24.8	11.3	11.7	**47.8**
System Renewal	733.7	740.7	780.4	776.2	773.3	865.2	1,103.1	1,172.8	**3,141.1**
System Service	97.0	93.5	75.6	73.9	103.8	204.1	148.2	151.8	**504.1**
General Plant	86.0	76.9	119.7	83.6	116.3	115.4	94.4	94.7	**304.5**
Progressive Productivity		0.0		0.0	0.0	-17.0	-39.0	-61.0	**-117.0**
Directive					-0.3	-0.3	-0.3	-0.4	**-1.0**
Sub-total	**950.0**	**953.9**	**1000.0**	**967.3**	**1,038.2**	**1,192.2**	**1,317.7**	**1,369.6**	**3,879.5**
Pension Adjustment					-3.2	-4.2	-5.2	-5.4	**-14.8**
Total	**950.0**	**953.9**	**1000.0**	**967.3**	**1,035.0**	**1,188.0**	**1,312.5**	**1,364.2**	**3,864.7**

The proposed 2020-2022 capital expenditures of $3,864.7 million represent an increase of 29.5% over the OEB-approved level of $2,985.0 million for 2017-2019.[71] The proposed capital expenditures for 2020-2022 also represent an increase of $908.5 million (30.7%) over the actual spending for 2017-2019.

The proposed increase in capital spending is driven mostly by investments in the System Renewal category, for which Hydro One proposed an average year-over-year

[71] Exhibit B-1-1, TSP Section 3.3, updated 2019-06-19, Table 1 and Table 2, pp. 2-3 of 20. For the 2019 rate year, the OEB approved Hydro One's revenue requirement by applying a revenue cap index to the approved 2018 level. Therefore, no capital expenditures were specifically approved for 2019. The 2019 forecast capital spending is used as the proxy of actual/approved expenditures for the purpose of discussion in this decision. Since there was no "approved" capital budget for 2019, the 2019 "forecast" was used instead.

increase of 15.2% over the 2020-2022 period. The proposed average capital expenditures on System Renewal for 2020-2022 is $1,047.0 million per year, which represents an increase of 34.2% from the last OEB-approved level of $780.4 million for 2018.

System Renewal

System Renewal expenditures comprise the bulk of Hydro One's planned investments, representing close to 83.3% of capital expenditures over the planning period. They are mainly driven by plans to replace assets that are near or at the end of their lives. System Renewal projects include transmission line refurbishment, station reinvestments, transformer replacements, and air blast circuit breaker replacements.

Table 5 below summarizes the historical capital expenditures on System Renewal over 2015-2019 and the proposed spending for 2020.[72]

[72] Exhibit B-1-2, filed 2019-06-19, Appendix 2-AA, Capital Projects Table.

Table 5: Capital Expenditures on System Renewal ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Circuit Breakers	7.1	4.1	0.4	0.1	0.0	4.1
Transmission Lines	125.4	164	197.2	221.2	291.9	323.9
Integrated Stations	374.2	469.1	481.0	410.7	336.9	405.1
Underground Line Cables	3.5	1.7	10.7	16.5	15.0	7.1
Power Transformers	43.5	13.0	0.0	-0.7	0.1	0.0
Other Power Equipment	12.5	5.3	0.0	0.3	0.0	0.0
Protection and Automation	60.2	40.5	20.9	44.4	72.8	77.7
Ancillary System, Site Facilities and Station Environment	35.3	11.7	3.7	1.0	0.0	0.0
Transformers Demand and Spares	27.2	24.6	26.8	82.6	56.6	47.4
Total	**688.9**	**733.9**	**740.7**	**776.2**	**773.3**	**865.2**

OEB staff noted that for the 2020 rate year, approximately 46.8% of the proposed expenditures are driven by investments on integrated stations. Following that, investment on transmission lines accounts for about 37.4% of the budget.

The planned investments on integrated stations include some proposed replacements of transformers, circuit breakers, and protection systems. The planned investments on transmission lines include replacements of conductors, defective insulators, wood poles, and the coating of steel structures.

OEB staff suggested an envelope reduction of $318.5 million (10.1%) to the total 2020-2022 capital expenditures on System Renewal. The suggested reduction has resulted from the identified issues with respect to Hydro One's rate of removal, repair vs. replace evaluation, and conductor replacements.

A number of intervenors made submissions on Hydro One's proposed capital plan for replacing major asset groups, which is a large component of the proposed expenditures on asset replacements.

Table 6 below provides a summary of historical and forecast capital expenditures on major assets.[73]

Table 6: Capital Expenditures on Major Asset Classes ($Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast	2021 Forecast	2022 Forecast
Conductors	58.4	68.0	36.5	52.0	137.6	150.8	191.4	211.7
Protection Systems	33.3	57.3	42.8	60.5	64.7	67.8	54.9	76.2
Transformers	132.0	77.3	75.7	193.6	110.3	50.6	131.9	111.1
Circuit Breakers	21.7	42.4	54.7	77.9	47.5	74.3	58.9	50.3
Wood Poles	38.5	42.8	41.2	35.3	34.8	51.0	52.0	53.0
Steel Structure	5.1	2.3	42.1	37.7	9.3	11.4	21.8	22.3
Underground Cable	3.5	1.7	10.7	16.5	15.0	7.1	32.5	33.6
Total of Major Asset Classes	**292.5**	**291.7**	**303.7**	**473.5**	**419.3**	**413.0**	**543.5**	**558.2**

[73] Exhibit JT 1.24, filed 2019-08-28, Attachment 1, page 1 of 1. Table 5 reflects Hydro One's integrated station-centric plan approach while Table 6 reflects capital expenditures for major asset classes. Capital expenditures under the same title (e.g. circuit breakers) are not necessarily the same.

Intervenors made submissions on major asset groups that include conductors, protection systems, transformers, circuit breakers, and wood poles. These are each discussed in the subsections that follow.

Conductors

SEC noted that Hydro One proposed to spend $553.9 million on conductors over the 2020-2022 period, which is an increase of more than double the actual/forecast spending of $226.1 million over the 2017-2019 period. SEC also noted Hydro One's plan of replacing 1,342 kilometres of conductors over the test period, as compared to the 310 kilometres replaced between 2017 and 2019. SEC submitted that the evidence does not demonstrate the need for an increase in spending on conductors.

OEB staff submitted that Hydro One has not demonstrated a correlation between its conductor condition assessment testing and its historical conductor performance deterioration. From a cost and benefit point of view, Hydro One has not demonstrated that the planned conductor replacements will meaningfully improve system reliability. In addition, no evidence was provided showing that proposed expenditures on conductor replacements are cost effective on a dollar spent per avoided customer interruption basis, relative to other investments.

BOMA submitted that a revised assessment of the Expected Service Life (ESL) for conductors from 70 to 90 years has lessened the pressure for conductor replacement. BOMA also noted that the overhead conductor forced outage frequency and duration have both reduced over the last ten years. BOMA also submitted that Hydro One did not quantify OM&A savings on the renewal of conductors and air blast circuit breakers.

CME submitted that Hydro One's proposal to significantly increase spending on its conductor fleet is not supported by the evidence because asset condition is not degrading over time, the outage statistics are improving over time, and the number of assets reaching ESL is less than that outlined in the last transmission proceeding.

AMPCO submitted that the pace of conductor renewal should be continued at the historical level considering the decreasing trend in forced outage frequency and duration for overhead conductors over the 2008-2017 period, and the change of ESL from 70 to 90 years for Aluminum Conductor Steel Reinforced (ACSR) conductors.

Hydro One claimed that the primary driver of conductor replacement is to address asset condition which could manifest itself as a safety risk, while reliability was in fact secondary to the planning of this investment.

Protection Systems

AMPCO noted that the percentage of protection system population in very high or high risk condition remained unchanged from the last proceeding and the percentage of delivery point interruptions from protection equipment has improved in recent years. AMPCO submitted that the historical level of spending should be maintained.

SEC noted that although Hydro One reduced the level of replacements from 977 to 622 as a result of the OEB's reductions in the previous transmission rates proceeding, it was still able to maintain the overall condition of these assets, measured as a percentage of assets in high and very high risk condition. SEC also identified a certain type of protection system, Programmable Auxiliary Logic Controllers, where the number of failures of the asset has consistently declined from 29 in 2013 to 3 in 2017.

To explain the proposed increase in protection system spending, Hydro One noted that while the percentage of protection system assets in high or very high risk condition remained at 27%, the protection fleet size (from 12,103 to 12,506) as well as the number of protection devices in those risk groups (from 3,267 to 3,362) have increased from the last proceeding. Hydro One noted other factors that contribute to the increased budget in protection systems, including the need to comply with applicable NERC/NPCC[74] standards.

Transformers

AMPCO observed that among the 86 replaced transformers over 2015-2018, only 51 or 60% were in very high or high risk conditions. Of the 45 total replaced transformers in 2017 and 2018, just over half or 24 transformers were in very high risk or high risk conditions.

[74] "NERC" refers to the "North American Reliability Corporation", which sets the reliability standards that ensure the integrity of the interconnected North American Bulk Electricity Systems. NERC standards are enforced by the IESO. "NPCC" refers to the "Northeast Power Coordinating Council", which develops regional reliability standards, monitors and enforces compliance, and coordinates regional system planning, design and operations, and assessments of reliability.

AMPCO further stated that the percentage of delivery point interruptions from transformers has improved, noting that between 2011 and 2015, the percentage of equipment interruptions from transformers was 9% compared to 13% over the 2008 to 2017 period, with improvements over the 2015 to 2017 period.

Hydro One stated that the historical replacement data includes both planned and unplanned replacements and it is reasonable that a portion of the units replaced were in high or very high risk conditions, and the remainder were replaced due to other investment drivers such as obsolescence, capacity or customer requirements.

In response to AMPCO's statements that the percentage of delivery point interruptions from transformers has improved, Hydro One explained that the 9% figure shows the contribution to the duration of interruptions by equipment type while the 13% figure shows the count of interruptions by equipment type; as such, these two measurements cannot be compared.

Circuit Breakers

With respect to air blast circuit breakers (ABCB), SEC noted that when comparing the overall budget of an ABCB replacement project reported in the last application and the current Application, the total cost of this project increased from $90.7 million in the last application to $110.2 million, an increase of 21.5%. Hydro One explained that the dominant factor in this replacement is that the in-service ABCBs are at least four times less reliable than the newer equivalent SF6 circuit breakers. In addition, ABCBs are ten times more costly to maintain than SF6 circuit breakers.

Regarding oil circuit breakers, CME submitted that the proposed pacing of replacement for oil circuit breakers that are not contaminated with unacceptable levels of polychlorinated biphenyl (PCB) is not justified. CME noted that a report by EPRI found that there would likely be marginal benefits to Hydro One from replacing oil circuit breakers with single pressure gas breakers. In addition, outage statistics do not show a need for a surge in oil circuit breaker replacements.

Hydro One responded that oil circuit breaker replacements are selected for a number of reasons, including PCB compliance, safety risks, and operating limitations. Outage statistics are one factor considered when making investment decisions.

Wood Poles

AMPCO noted that Hydro One proposes to spend $156.1 million over the test period to replace 2,400 wood poles, which is $36.8 million more than the previous period (2016 to 2018) where Hydro One replaced more poles (2,462) for less money ($119.3 million).

Hydro One noted factors that have an impact on the capital expenditures for this program, including structure type, pole size, location/ease of access, environmental restrictions, and work bundling.

Other Projects/Programs

Intervenors also made submissions on a number of projects/programs that were provided in the Investment Summary Documents (ISD).

AMPCO questioned proposals for the Synchronous Optical Network (SONET) system replacement project (SR-11), the tower foundation assess/clean/coat program (SR-23), and the transmission line shieldwire replacement program (SR-24).

SEC also submitted that Hydro One has not justified the proposed level of spending on the SONET system replacement (SR-11).

Hydro One disagreed with SEC's argument that the SONET project is behind schedule because the technology has yet to be selected. Hydro One confirmed that the plan was on track to complete the development and estimation phase in 2020 and the execution phase in 2021. Hydro One submitted that SEC's concern that costs will be put in-service prior to project execution stems from its misunderstanding of an interrogatory response,[75] which reflects the ratio of the cumulative forecast capital expenditures incurred over the 2020-24 period divided by the cumulative forecast in-service additions over the 2020-24 period, not the in-year in-service ratio as SEC submitted.

Therefore, Hydro One submitted that SEC's argument that costs will be put in-service in 2020 on this basis is not valid, and SEC's submission to reduce the capital to in-service ratio for this project should be rejected.

[75] SEC 42

Regarding the tower foundation coating and the transmission line shieldwire replacement programs, AMPCO submitted that Hydro One did not explain changes in asset strategy or condition to support the proposed increase in spending. Hydro One responded to AMPCO's concerns by explaining the key drivers for the proposed investments. With respect to the tower foundation coating program, Hydro One stated that the proposed plan is determined by foundation type and consequence of asset failure. For the shieldwire replacement program, Hydro One noted an increase in shieldwire that is at End of Life (EOL).

System Service

System Service investments are required to maintain inter-area network transfer capability, ensure local area supply adequacy, mitigate system risks related to safety, security and reliability, and address customer power quality concerns. These investments account for about 13.3% of total capital expenditures over the planning period.

Table 7 below summarizes the historical capital expenditures on System Service over 2015-2019 and the proposed spending for 2020.[76]

Table 7: Capital Expenditures on System Service ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Inter Area Network Transfer Capability	86.3	80.8	36.0	48.9	54.9	121.0
Local Area Supply Adequacy	64.9	54.3	45.1	20.7	39.0	73.9
Smart Grid	3.5	3.3	0.7	0.2	0.0	0.0
TS Upgrades to Facilities Distribution Generation	-1.2	0.0	0.0	0.0	0.0	0.0
Performance Enhancement	1.3	0.4	0.0	0.0	0.3	0.3
Risk Mitigation	3.1	1.8	9.5	2.6	5.4	4.7
Power Quality	0.0	0.2	2.3	1.4	4.1	4.2
Total	**157.9**	**140.9**	**93.5**	**73.9**	**103.8**	**204.1**

The forecast capital investments in System Service for 2020 represents an increase relative to historical levels. Hydro One explained that the increases are attributed to major transmission projects that will upgrade and expand system capacity, such as the East-West Tie Connection project and Barrie Area Bulk Transmission Upgrade project.

OEB staff and intervenors took no issues with the proposed capital expenditures on System Service except with one specific project, the Kapuskasing Area Reinforcement project.

[76] Exhibit B-1-2, Appendix 2-AA, Capital Projects Table.

Kapuskasing Area Reinforcement (KAR) Project

The KAR project, which is the recommended solution from the IESO for meeting reliability in the Kapuskasing area, was approved by the OEB in a leave to construct (LTC) proceeding. By a letter dated March 18, 2019, Hydro One informed the OEB of a change in the in-service date and cost of the KAR project. The overall project cost increased from $21.07 million ($15.07 million in lines cost and $6 million in station cost) to $32.1 million ($14.8 million in lines cost and $17.3 million in station costs). The expected in-service dates are March 2020 and January 2021 for the line component and the station component, respectively.

OEB staff noted that Hydro One made no reference in the LTC application to the accuracy range of its cost estimate (using the Association for the Advancement of Cost Engineering (AACE) standards). It is in this proceeding that Hydro One stated that the original cost estimate was at AACE Class 4. OEB staff also noted that evidence as filed in this Application does not demonstrate whether Hydro One tried to address the changes in project scope in as cost effective a way as possible, in order to ensure that the updated budget would be as close to the original as possible. OEB staff suggested that the cost increase be split between Hydro One and ratepayers, and proposed a disallowance of $5.7 million.

Hydro One pointed out its disclosure of the cost estimates in the LTC application where it noted that the estimates were preliminary costs, and updated costs would be provided as they become available. Regarding cost-effectiveness, Hydro One noted that it is mandated to complete the project and the IESO has confirmed that the KAR project remains the recommended solution for meeting reliability in the Kapuskasing area.

OEB staff submitted that in the next rebasing application, for all investments requiring leave to construct approvals, Hydro One should provide comparisons of those projects between what was filed in the LTC applications and what was budgeted into capital expenditures for the test years, and provide explanations of any material variances regarding scope, cost or schedule.

Hydro One stated that it agrees with this proposal in principle and that it will provide the comparisons as feasible at the time of the next rebasing application, if directed by the OEB.

System Access

System Access investments are driven by new load and generation customer connections, and transmission asset modifications to accommodate third party requests. These investments account for about 1.0% of total capital expenditures over the planning period.

Table 8 below summarizes the historical capital expenditures on System Access over 2015-2019 and the proposed spending for 2020.[77]

Table 8: Capital Expenditures on System Access ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Transmission Lines	-0.5	1.8	-0.9	4.4	2.9	0.9
Generator Customer Connection	-1.7	0.2	0.4	0.3	1.1	2.3
Load Customer Connection	7.7	13.6	42.3	28.5	41.1	21.6
P&C Enablement for Generation Connections	2.1	1.3	0.8	0.5	0.0	0.0
Total	**7.6**	**17.0**	**42.7**	**33.7**	**45.1**	**24.8**

No parties raised any concerns regarding Hydro One’s proposed capital expenditures on System Access projects.

General Plant

General Plant assets are not part of Hydro One’s transmission system. However, General Plant expenditures are required to support the performance of Hydro One’s core business and operational functions. These investments account for about 6.8% of total capital expenditures over the planning period.

[77] Exhibit B-1-2, Appendix 2-AA, Capital Projects Table.

Table 9 below summarizes the historical capital expenditures on General Plant over 2015-2019 and the proposed spending for 2020.[78]

Table 9: Capital Expenditures on General Plant ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Facilities & Real Estate	22.7	13.9	6.7	7.0	7.2	8.1
Grid Operating and Control Facilities	14.2	7.6	6.0	3.8	37.4	35.3
Information Technology	21.6	35.9	32.8	42.0	33.7	25.7
Operating Infrastructure	1.4	4.6	4.8	5.8	10.2	21.1
Other (including CDM)	0.7	0.3	-1.1	-0.7	0.0	0.0
Site Facilities and Infrastructure	5.9	8.1	10.8	16.4	12.0	9.4
Transport and Work & Service Equipment	22.1	24.6	16.9	9.3	15.9	15.8
Total	**88.6**	**94.8**	**76.9**	**83.6**	**116.3**	**115.4**

General Plant spending remained stable over 2015 to 2018. However, spending is projected to increase through 2019 and 2020. Hydro One noted that increases are attributed to investments in grid operating and control facilities associated with the new Integrated System Operating Centre (ISOC).

OEB staff and intervenors made submissions on four projects/programs: the ISOC, the Grid Control Network Sustainment, the Network Management System Capital Sustainment, and the Facility Accommodation & Improvements Service Centres & Admin.

78 Exhibit B-1-2, Appendix 2-AA, Capital Projects Table.

Integrated System Operating Centre (ISOC)

The ISOC project began in 2015 and is expected to be in service in 2021. It will serve as Hydro One's primary operating control centre. The ISOC will house multiple lines of business through provision of dedicated control centres, an integrated data centre, and shared back office area. The capital investment on ISOC increased from $138.4 million (as filed in Hydro One's 2018-2022 distribution Custom IR application) to $154.5 million as included in this Application, [79] approximately a 12% increase in the estimated cost.

Hydro One allocates the ISOC cost between its distribution and transmission businesses, with 49.93% allocated to the transmission portion and 50.07% allocated to distribution. The transmission allocated costs of the ISOC are estimated to be $32.4 million and $12.7 million for 2020 and 2021 respectively.

OEB staff questioned the reliability of the updated cost estimate considering the fact that the 12% increase is well above the accuracy range of +/-5% of the original Class A cost estimate. Hydro One explained that the increase in cost estimates was due to unexpected externalities that were beyond its control. It noted the increase in steel cost resulted from an unforeseeable foreign tariff.

To respond to SEC's comment that Hydro One did not make any adjustments to the design to reduce costs, Hydro One noted that it took an additional step by requesting vendors responding to the RFP to provide a list of value engineering opportunities to reduce costs which were weighed in the evaluation process.

Hydro One disagreed with SEC's assertion that the ISOC cost benchmarking is 11% higher than the average cost of similar facilities. It noted that the updated information including investments in facilities and data centre development projects constructed after 2015 shows that the cost of ISOC is 43% lower than industry comparators.

In its decision on the 2018-2022 distribution Custom IR application, the OEB directed Hydro One to create an asymmetric variance account to track the actual cost of the distribution portion of the ISOC against the forecast cost. If the revenue requirement at the actual cost is lower than the revenue requirement at the forecast cost, Hydro One will return the difference to ratepayers.[80]

[79] Exhibit J4.5, page 5 of 10.
[80] EB-2017-0049, Decision and Order, March 7, 2019, page 165.

VECC submitted that the same type of asymmetric account for the transmission allocated portion of the ISOC should be established to be consistent with the distribution proceeding. The amount to be recovered in rates should be based on an allocation of the original amount of $138.4 million.

Hydro One disagreed with VECC's suggestion stating that the proposed asymmetric variance account presumptively assumes that any cost increases resulting from external factors are not reasonable or prudent. In the event that the OEB decides to impose such a variance account, Hydro One submitted that the basis for determining the transmission portion of the ISOC cost should be the current estimate of $154.5 million.

Other Projects/Programs

AMPCO identified three ISDs with execution risks that may have an impact on the proposed budget. These projects were Grid Control Network Sustainment (GP-02), Network Management System Capital Sustainment (GP-03), and Facility Accommodation & Improvements Service Centres & Admin (GP-10). AMPCO noted that Hydro One spent 75% of the planned budget on Grid Control Network Sustainment over 2015 to 2018, and risks exist around project prioritization. Regarding the Network Management System Capital Sustainment project, AMPCO expressed concern for potential delays of the project considering Hydro One's plan of learning from another utility's experience of implementing and testing the new product. Regarding the Facility Accommodation & Improvements Service Centres & Admin program, AMPCO submitted that the timeline for the plan is uncertain since it depends on the availability of suitable sites and Hydro One's ability to obtain municipal approvals, which could be a lengthy process.

Hydro One noted that potential execution risks are normal risks faced by most projects. It noted actions it undertook to reduce execution risk at the project level as well as at the overall budget level.

Summary of Submissions on Capital Expenditures

OEB staff and a number of the intervenors recommended reductions to the overall capital budget based on the review of Hydro One's historical spending and the conclusion that the TSP did not provide full justifications supporting the proposed level of capital expenditures. These recommended reductions were in the range of $300 million (7.8%) to $905 million (23.4%) of the total proposed 2020-2022 capital expenditures. Some of these amounts included part of Hydro One's identified "productivity savings" ranging from $117 million to $286 million.

PWU submitted that the proposed capital expenditures and in-service additions arising from Hydro One's TSP represent the minimum required to address Hydro One's system needs and should be approved.

LPMA submitted that the OEB should determine a reduction in capital based on in-service additions rather than capital expenditures, and suggested reductions in System Renewal in-service additions of $140 million in 2021 and $280 million in 2022.

Findings

The OEB finds that the proposed capital expenditure budget of $3,864.7 million for 2020 – 2022 is not fully supported and shall be reduced to $3,464.7 million (a reduction of $400 million or 10.4%). This reduction consists of $390.0 million in System Renewal, $5.7 million in System Service, and $4.3 million in General Plant. As a result, the approved budget for System Renewal, System Service and General Plant is $2,751.1 million, $498.4 million, and $300.2 million, respectively. The proposed capital expenditures for the System Access category is approved as submitted at $47.8 million.

The considerations applied by the OEB to arrive at this finding are summarized in the following sections.

<u>Data Quality (TSP)</u>

A comparison of all projects over $20 million that were included in both the 2017-2018 application and the current 2020-2022 Application shows that the revised forecast (or actual) costs contained in this Application are on average 12.6% higher than what was provided in Hydro One's last application. Although Hydro One expects that project cost estimates will be refined over time, the OEB would expect that the depth and breadth of experience and competence of Hydro One should lead to more precise cost estimates than those carried in the proposed capital expenditure budget.

Concern with respect to data quality issues in Hydro One's asset condition assessment were raised by OEB staff and a number of the intervenors. Although Hydro One uses external consultants to gauge probability to failure and to provide overall assessment of the TSP by EPRI and BCG, respectively, the TSP incorporates a considerable amount of judgement and estimation. This includes the existence of qualitative assessment based on engineering analysis and judgement to assign a relative risk level, and concepts of ESL and EOL used in the TSP.

Accordingly, the OEB has taken the quality of the data into consideration in its findings, below.

Customer Engagement

OEB staff and a number of intervenors identified deficiencies in Hydro One's customer engagement activities and rejected Hydro One's assertion that outcomes from the customer engagement process sufficiently support the proposed level of capital expenditures. The OEB acknowledges the concerns expressed by OEB staff and a number of intervenors and does not rely on the outcome as reported by Hydro One as compelling evidence of customer support for the proposed level of capital expenditures. The OEB's findings primarily rely on the established need and prudence of the proposed level of capital expenditures.

The OEB expects Hydro One to address these areas of concern regarding customer engagement in the combined transmission and distribution application to be submitted for 2023 and subsequent years, as described under Issue 3.

Progressive Productivity Savings

Progressive productivity savings are savings that Hydro One has embedded in its capital plan. For the 2020-2022 period, these consist of $30 million of "defined" capital savings and $87 million of "undefined" savings. The latter category is described as a placeholder to be allocated to any future initiatives that have not been identified.

The OEB acknowledges that embedding productivity savings as a bottom-line adjustment is a step in the right direction in response to previous OEB directions in other proceedings. However, the OEB also agrees with various parties that this should not be done at the expense of doing less work. It is the OEB's expectation that a well-run utility should be seeking these efficiency improvements on an ongoing basis by finding ways to complete its work program at a lower cost. Therefore, the OEB will not impose any additional efficiency improvement reductions, but expects that Hydro One will achieve the proposed embedded productivity savings while completing its planned work program.

Adequacy of Proposed Capital Expenditures

Hydro One's proposed capital expenditures of $3,864.7 million for the 2020-2022 test years are comprised of six categories, as follows:

System Access (1%)
System Renewal (81%)
System Service (13%)
General Plant (8%)
Progressive Productivity (-3%)
Pension Adjustment (<1%)

The OEB's assessment is that capital cost reductions can be made within the System Renewal, System Service and General Plant categories. These are discussed in further detail below.

System Renewal

The largest component of the proposed capital expenditure is System Renewal which is further broken down into sub-categories, listed below in order of capital cost amount.

Integrated Station
Transmission Lines (including Conductors)
Protection and Automation
Transformer Demands and Spares
Underground Line Cables
Circuit Breakers

The proposed expenditures on transmission lines of $323.9 million for 2020 represent an 83.0% increase over the average annual spending of $177.0 million over 2015 to 2018. OEB staff and a number of intervenors made submissions on Hydro One's replacement proposal for conductors, submitting that Hydro One has not demonstrated a correlation between its conductor condition assessment testing and its historical conductor performance deterioration. No evidence was provided showing that proposed expenditures on conductor replacements are cost effective on a dollar spent per avoided customer interruption basis relative to other investments. Intervenors recommended reductions in capital spending on transmission lines ranging from $96.0 million to $397.4 million.

The OEB finds that the increased pace of replacing transmission lines (more than three-fold between 2016-2018 and 2020-2022) has not been justified in view of the fact that the forced outage frequency and duration for overhead conductors has been trending down on average, and the ESL of most conductors has increased from 70 to 90 years according to the EPRI study. The OEB finds that a reduction in the System Renewal category of $390 million is warranted to be more in line with historical levels.

The OEB finds that, with the exception of transmission lines, the proposed expenditures for the other sub-categories seem reasonable.

System Service

System Service investments are required to maintain inter-area network transfer capability, ensure local area supply adequacy, mitigate system risks related to safety, security and reliability, and address customer power quality concerns. The primary components of this category are Inter Area Network Transfer Capability and Local Area Supply Adequacy.

With respect to this latter component, OEB staff made reference to the KAR project which was approved by the OEB in a recent LTC proceeding. Subsequently, Hydro One informed the OEB of a change in the in-service date and cost of the KAR project, an increase from $21 million to $32 million. The station cost component of the project had increased from the original estimate of $6 million to an updated estimate of $17.3 million. OEB staff also noted that evidence as filed in this Application does not demonstrate whether Hydro One tried to address the changes in project scope as cost effectively as possible, in order to ensure that the updated budget would be as close to the original one as possible. OEB staff suggested that the cost increase be split between Hydro One and ratepayers and suggested a disallowance of $5.7 million.

The OEB finds that there is no strong evidence to demonstrate that Hydro One took sufficient proactive measures to manage the scope and cost of the KAR project, resulting in a 50% increase in cost. The OEB finds that a disallowance of $5.7 million is appropriate and that it should form part of the overall reduction in the proposed capital expenditure for 2020-2022.

The OEB affirms the recommendation that in the next rebasing application, for all investments requiring LTC approvals, Hydro One should provide comparisons for those projects between what was approved in the LTC applications and what was budgeted into capital expenditures for the test years, and provide explanations of any material variances regarding scope, cost or schedule.

General Plant

General Plant expenditures are not part of the transmission system but are required to support the performance of Hydro One’s core business and operational functions. These investments account for about 7% of total capital expenditures.

Regarding the ISOC project, Hydro One explained that the increase in cost estimate was due to unexpected externalities that were beyond its control and noted that it took an additional step to reduce costs by requesting vendors responding to the RFP to provide a list of value engineering opportunities to reduce costs which were weighed in the evaluation process. The updated information, including investments in facilities and data center development projects constructed after 2015, shows that the cost of the ISOC is 43% lower than industry comparators. Hydro One submitted that the basis for determining the transmission portion of the ISOC cost should be the current estimate of $154.5 million.

OEB staff and an intervenor recommended, for the portion attributable to transmission, a commensurate reduction in the proposed capital expenditure envelope. OEB staff recommended a reduction of $4.5 million and the intervenor recommended $4.0 million.

The OEB agrees that Hydro One should have taken more proactive measures to stay within the ISOC approved budget and, therefore, a reduction in the 2020-2022 proposed capital budget of approximately $4.3 million is warranted in relation to this project. Furthermore, the OEB is establishing the same type of asymmetric variance account for the transmission portion of the ISOC that was established for the distribution portion. This is one project with allocations between Hydro One’s different businesses; it is therefore appropriate to have the same treatment for the allocated costs. If the revenue requirement at the actual cost is lower than the revenue requirement at the forecast cost, Hydro One will return the difference to ratepayers.

Hydro One shall file a draft accounting order as part of the draft revenue requirement/charge determinant process.

Reduction in the 2020-2022 Capital Budget (Summary)

The OEB concludes that the significant increases in the proposed capital budget compared to previous approved or actual/forecast levels have not been fully supported by the evidence in this proceeding, including the lack of meaningful customer feedback.

As mentioned earlier, the reduction in the 2020-2022 capital budget imposed by the OEB in this Decision and Order is $400 million which consists of $390.0 million in System Renewal, $5.7 million in System Service and $4.3 million in General Plant.

The OEB also notes the following facts in support of its decision to reduce the capital budget:

- Hydro One's proposed overall capital spending for 2020-2022 is significantly higher than the approved levels for 2017-2019 (by $879.7 million or 29.5%).

- Hydro One's proposed overall capital spending for 2020-2022 is significantly higher than the actual/forecast spending for 2017-2019 (by $908.5 million or 30.7%).

- Hydro One's proposed System Renewal spending for 2020-2022, which represents 81.3% of the total proposed capital budget, is significantly higher than the average actual/forecast spending for 2017-2019 (by $850.9 million or 37.1%).

The approved budget of $3,464.7 million for 2020-2022 is still significantly higher than both the approved budget for 2017-2019 (by $479.7 million or 16.1%) and the actual/forecast spending for 2017-2019 (by $508.5 million or 17.2%). This should provide Hydro One with the ability to plan and execute its capital investment plan in an efficient and effective manner.

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 budget. The OEB requires that Hydro One, as part of the draft revenue requirement/charge determinant process of this Application, provide a preliminary estimate of the breakdown of the $400 million reduction over the 2020-2022 period along with the corresponding rate impacts.

Based on concerns raised by the various parties under Issue 9, the OEB directs Hydro One to do the following as part of its next rebasing application:

- Provide a breakdown of its proposed capital spending by work category for each test year. In the current Application, this breakdown was only provided for 2020

- For all investments requiring leave to construct (LTC) approval, provide comparisons between what was filed in the LTC application for those projects and what is being budgeted in the capital expenditures for the test years, and provide explanations of any material variances regarding scope, cost or schedule

The OEB also shares some of the concerns raised about the approach used to select Boston Consulting Group to carry out the assessment of Hydro One's TSP. In similar future assessments, the OEB expects Hydro One to demonstrate that its selection is based on a more transparent, competitive process.

3.4.2 Common Corporate Capital Expenditures Allocation Methodology (Issue 10)

Issue 10. Are the methodologies used to allocate Common Corporate capital expenditures to the transmission business and to determine the transmission Overhead Capitalization Rate appropriate?

This section addresses the allocation of common corporate capital expenditures and the allocation of shared assets to Hydro One's transmission business. This section also addresses overhead capitalization rates. Although Issue 14 involves the methodologies used to allocate common corporate costs and other OM&A costs to the transmission business, this issue is also addressed below.

Hydro One filed three Black and Veatch (B&V) reports, dated January 31, 2019, in this proceeding, as follows:

1) Review of Allocation of Common Corporate Costs (Transmission) – 2019 Black & Veatch Project No. 188588.
2) Review of Shared Assets Allocation (Transmission) -2019 Black & Veatch Project No. 188588.
3) Review of Overhead Capitalization Rates (Transmission) – 2019 Black & Veatch Project No. 188588.

Hydro One indicated that the Ontario provincial government's Bill 2 (i.e., Schedule 1 of Bill 2 is the *Hydro One Accountability Act, 2018*[81] or HOAA) was addressed in the first and third of the above noted reports, and not required for the second report. However, OEB staff noted that due to the timing of issuance of the B&V reports, the February 21,

[81] *The Urgent Priorities Act, 2018*

2019 Directive (the Directive)[82] and any findings from the March 7, 2019 Hydro One distribution decision and order[83] were not addressed in the B&V reports.

Hydro One also noted that the B&V methodology is materially consistent with that of prior applications. Hydro One stated that there are no key recommendations to be implemented when comparing the three B&V studies and the prior studies from previous applications. Hydro One further stated that there have been no material differences among the actual studies, and that B&V believes that the methodology used in this Application continues to be appropriate for Hydro One.

OEB staff submitted that the B&V methodologies should continue in this proceeding, as they have been tested and accepted in prior proceedings, and there are no material differences among the studies.

Hydro One submitted that its Application reflects Bill 2 and is consistent with the approach that was accepted by the OEB in the Hydro One distribution decision. Hydro One submitted that the Directive only had a minor impact on its Application. Hydro One concluded that OEB staff’s concern regarding the timing of issuance of the B&V reports is without merit.

Allocation of Common Corporate Costs and Shared Assets Background

Hydro One is requesting a 2020 Common Corporate Costs and Other Costs OM&A of $30.3 million for its transmission business. Hydro One stated that Common Corporate OM&A costs are allocated to its distribution and transmission businesses and to each unregulated segment based on shared functions and services provided and an established cost allocation approach based on the cost causality principle.

Hydro One further stated that it uses a centralized shared services model to deliver common services to its transmission and distribution businesses, as well as to its affiliated companies. Hydro One noted that the centralized shared services model is an effective and widely used method of delivering common corporate services to multiple

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[82] At Exhibit F, Tab 4, Schedule 1, Page 35, Hydro One described the Ontario Government Directive that was issued on February 21, 2019. Hydro One stated that the government set out certain compensation-related requirements for the Chief Executive Officer, other executives and Board of Directors of Hydro One Limited and its subsidiaries, which Hydro One must follow when developing its Board and Executive compensation framework as set out in the HOAA.
[83] EB-2017-0049

subsidiaries and/or multiple business units. Hydro One noted that since 2009 it has been applying this cost allocation methodology developed by B&V.

OEB staff noted that in the March 7, 2019 Hydro One distribution decision and order, the OEB determined that the allocation methodology of common corporate costs, developed by B&V, and approved by the OEB in Hydro One's previous transmission rate proceeding, is acceptable for the plan term. OEB staff also noted the OEB's expectation that this issue is to be examined in detail when Hydro One files a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027.

OEB staff submitted that Hydro One's 2020 Common Corporate Costs and Other Costs OM&A request of $30.3 million for its transmission business is reasonable, as it is largely driven by a cost allocation methodology that has been in place since 2009, as developed by B&V.

OEB staff submitted that the OEB should order in this proceeding that a detailed review of Hydro One's shared assets allocation methodology should occur at the time of Hydro One's combined 2023-2027 rebasing application. As a result, OEB staff took no issue with the allocation of corporate costs (capital expenditures and OM&A) and shared assets allocation to the transmission business in this proceeding. SUP also stated that these costs are reasonable.

SUP agreed with OEB staff that an assessment at the next combined transmission and distribution hearing for 2023 rates of all Hydro One Networks Inc.'s shared corporate and other costs represents the best opportunity to examine common policy issues, common services costs and common asset depreciation/allocation.

LPMA submitted that it has no issues or concerns associated with the methodologies used to allocate common corporate capital expenditures to the transmission business.

Hydro One argued that OEB staff's proposal regarding a future detailed review of Hydro One's shared assets allocation methodology and common corporate cost allocation methodology is vague and should be disregarded by the OEB. Hydro One submitted that it would be up to the parties and the panel in the combined proceeding to determine how closely they want to review the evidence that is filed on this aspect.

Overhead Capitalization Rate Background

Hydro One provided the following table showing its proposed overhead capitalization rates and amounts.[84]

Table 10: Overhead Capitalization Rates and Amounts

Overhead Cost Category	Bridge (%)	Test Years (%)			Bridge ($ millions)	Test Years ($ millions)		
	2019	2020	2021	2022	2019	2020	2021	2022
Capitalized Administrative & General Costs[1]	9%	8%	8%	8%	91.3	96.6	99.3	100.1
Capitalized Planning, Customer and Operating Costs[2]	2%	2%	2%	2%	22.9	22.8	23.2	23.7
Total	11%	10%	10%	9%	114.1	119.4	122.6	123.8

[1] *Administrative & General Costs include all common corporate functions and services costs*

[2] *Operating costs include asset management, network operating and customer care management costs*

Hydro One concluded that its overhead and indirect cost capitalization methodology, as reviewed by B&V and previously approved by the OEB, is consistent with: (a) legacy Canadian and existing US GAAP; and (b) regulatory principles.

Hydro One also stated that:

- The capitalization rate is decreasing due to the methodology; as it is specifically affected by the ratio of corporate costs (slight increase) to capital spend (larger increase)
- The overhead capitalized costs in this proceeding are lower by approximately $16 million when comparing 2020 to the previously filed 2018 capitalization amount, which is mainly due to a reduction in overall corporate overheads

Hydro One noted that in its prior transmission decision,[85] the OEB indicated that it will consider whether it should initiate a policy review regarding whether it is appropriate to allow for the continued use of US GAAP for the purpose of determining the

[84] Exhibit C, Tab 8, Schedule 2, Page 2, Table 1

[85] EB-2016-0160

capitalization of overhead amounts. Hydro One further stated that in its prior distribution decision,[86] the OEB stated that it expects to review Hydro One's approach to capitalization in its next rebasing application. Hydro One stated that the OEB's expectation is that Hydro One will provide a report comparing its capitalization of common corporate costs with those of other utilities. Given the OEB's directions on this issue, Hydro One submitted that the proposed methodology for determining the transmission overhead capitalized in the current Application is appropriate and should be approved.

OEB staff submitted that it took no issue with the overhead capitalized costs as they are driven primarily by an increased amount of assets being placed in service, and not by an increase in overhead capitalized costs.

OEB staff and SUP submitted that the applicable overhead capitalization B&V study should also be examined in detail in Hydro One's combined application. OEB staff also submitted that Hydro One advised that this study was first generated for 2006 transmission rates and confirmed that B&V did not look specifically at US GAAP policy relative to rate-regulated accounting. OEB staff submitted that such a review should also be undertaken, as accounting standards have evolved since 2006.

SUP took issue with OEB staff's submission that "accounting standards from 2006 have evolved" with respect to US GAAP treatment of overheads. SUP stated that this is debatable and, with the exception of the specific other post-employment benefits (OPEBs) change under discussion in this proceeding, OEB staff's assertion that US GAAP has changed needs further exploration and should not be accepted by the OEB without confirming evidence being submitted and evaluated.

LPMA submitted that it has no issues or concerns associated with the methodologies related to the transmission overhead capitalization rate.

Hydro One submitted that as it already intends to comply with the OEB's requirement from the Hydro One distribution decision regarding overhead capitalization, a further OEB directive is not necessary in the current proceeding.

[86] EB-2017-0049

US GAAP

Hydro One follows US GAAP for regulatory purposes and therefore follows a US GAAP based capitalization policy. Under US GAAP, Hydro One has the ability to capitalize more in the form of overhead costs than it otherwise would be permitted if it had been ordered to follow the OEB's Modified International Financial Reporting Standards (MIFRS) based capitalization policy, with a corresponding reduction in OM&A. A utility can earn a return on rate base associated with that capitalized cost. Most utilities in Ontario are required to follow the MIFRS capitalization policy.

OEB staff raised concerns with Hydro One's continued use of a US GAAP based capitalization policy for regulatory purposes in both its last transmission and distribution rates proceedings. In response to the concerns raised during the previous transmission rates proceeding, the OEB indicated that it would consider whether it should initiate a policy review regarding whether it is appropriate to allow for the continued use of US GAAP for the purpose of determining the capitalization of overhead amounts. Furthermore, in the last distribution rates proceeding, the OEB stated it expects to review Hydro One's approach to capitalization in its next distribution rebasing application. To facilitate such a review, the OEB indicated its expectation that Hydro One will provide a report comparing its capitalization of common corporate costs with those of other utilities in Ontario, Canada, and North America.

In the current transmission rates proceeding, OEB staff asked interrogatories related to overhead capitalization under US GAAP to which Hydro One proposed the following:

> Given the OEB's direction on this topic, questions in respect of Hydro One's capitalization of common corporate costs should be addressed in one of the two proceedings-types noted by the OEB above, where the appropriate evidence may be prepared and submitted for consideration. [87]

The two types of proceedings are either the general policy review that the OEB referenced in the previous transmission rates proceeding, or in Hydro One's next combined 2023-2027 rebasing application, where the OEB indicated that it expects to review Hydro One's approach to capitalization.

[87] Exhibit I, Tab 1, Schedule 140.

OEB staff submitted that the issue related to the appropriateness of Hydro One's continued use of a US GAAP based capitalization policy for regulatory purposes should be addressed in the upcoming 2023-2027 combined application since Hydro One will be preparing a capitalization study that was ordered by the OEB in previous distribution rates application.

OEB staff agreed with Hydro One that in order to facilitate a proper regulatory review of this issue, Hydro One must provide detailed evidence as part of its 2023-2027 combined application that presents the revenue requirement impact of transitioning to an MIFRS capitalization policy for regulatory purposes, along with a detailed analysis of the regulatory risks and challenges associated with doing so.

SUP submitted that the wider issue of capitalization of indirect and overhead costs should be studied from a policy perspective before a decision is taken to block this one sub-category of costs from being included in rate base or otherwise deferred.

In its reply argument, Hydro One indicated that if the OEB is inclined to review this issue as part of the combined proceeding rather than through a general policy review proceeding, Hydro One would be willing to conduct a review of its capitalization policy and practices under US GAAP, including benchmarking against comparable utilities that use US GAAP, and include the results of that review in its evidence during the combined proceeding.

Hydro One further indicated that it is reluctant to commit to the review because of its concern that IFRS 14, inclusive of a rate regulation standard, may become a permanent standard by the time of the upcoming 2023-2027 combined application, in which case moving to MIFRS (which was implemented to address concerns raised due to IFRS not having a rate regulation standard) may not be prudent. Moreover, Hydro One anticipates that the rate regulation standard under IFRS 14 is likely to align closely with US GAAP, subject to differences in where items are to be presented on the balance sheet.

Findings

The OEB has combined Issue 10 and Issue 14, as both issues address common corporate costs (capital expenditures and OM&A).

The OEB finds that the methodologies used to allocate common corporate capital expenditures, common corporate costs and other OM&A costs, as well as shared assets to the Hydro One transmission business in this Application are appropriate. These methodologies, developed by B&V, are based on the principle of cost causality and have been in place since 2009. The OEB has also found that these methodologies are appropriate in prior Hydro One proceedings.

The OEB agrees with the suggestion put forward by various parties that this issue of the common corporate cost allocation methodologies and shared assets methodologies should be examined in detail when Hydro One files a combined application for its transmission and distribution businesses. This would enable the OEB to ensure that the methodologies used and their application are consistent across the Hydro One organization.

The OEB, therefore, orders that a detailed review of Hydro One's common corporate costs and shared assets allocation methodologies (capital and OM&A) be filed as part of Hydro One's combined transmission and distribution application due to be filed for 2023 revenue requirement and rates.

The OEB finds that the methodology used by Hydro One to determine the Overhead Capitalization Rates, based on a 2006 B&V study, is appropriate for the purposes of this proceeding. However, given the evolution of accounting standards since then, the OEB confirms its expectation, articulated in the last distribution proceeding decision, that Hydro One's approach to capitalization is expected to be reviewed in its next rebasing application, including the provision of a report by Hydro One comparing its capitalization of common corporate costs with those of other utilities in Ontario, Canada, and North America (both under USGAAP and IFRS). The OEB also orders that a detailed review of Hydro One's B&V study regarding overhead capitalization be filed in its next rebasing application.

Regarding the continued use of US GAAP by Hydro One for regulatory purposes, the OEB finds that this issue should also be addressed in Hydro One's next combined rebasing application as part of the capitalization study previously ordered by the OEB. This should include the revenue requirement impact and risk analysis associated with the transition from US GAAP to MIFRS.

3.4.3 Other Post-Employment Benefits (OPEB) Capitalization (Issue 11)

Issue 11. Is the proposed capitalization of other post-employment benefits (OPEB) for both Hydro One Transmission and Hydro One Distribution appropriate, and if not, what is the appropriate approach for these costs?

In March 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) No. 2017-07 which amends the US GAAP standard related to the accounting for pension and other post-employment benefit (OPEB) costs. Effective January 1, 2018, the changes introduced by the ASU limit an entity's ability to capitalize these costs to assets. For regulatory reporting purposes, the change only impacts Hydro One's OPEB costs because it recovers its pension costs on a cash basis.

The net periodic benefit cost of defined benefit pension and OPEB plans (pension and OPEB expense) is comprised of several components including current service cost, interest cost, return on plan assets, and the amortization of actuarial gains/losses and prior service costs. Prior to the issuance of ASU No. 2017-07, all components of the net periodic benefit cost were eligible to be capitalized. However, as a result of ASU No. 2017-07, only the service cost component is now eligible to be capitalized.

Hydro One's 2017-2018 transmission revenue requirement approved by the OEB did not reflect the impact of the change in this accounting standard because the standard was issued after the record of that proceeding was closed. Therefore, Hydro One applied and received OEB approval to establish a deferral account, effective January 1, 2018 until such time as the OEB makes a determination on the regulatory treatment of the impacted costs, to capture the OPEB costs previously capitalized but no longer allowed to be capitalized as per ASU 2017-07.

Similarly, in Hydro One's application for 2018-2022 distribution rates, the OEB approved the establishment of an OPEB Cost Deferral Account for the distribution business, which is equivalent to the account established for the transmission business. The deferral account for the distribution business was also given an effective date of January 1, 2018 and the OEB instructed Hydro One to file the necessary evidence regarding the distribution business OPEB Cost Deferral Account in its next transmission rebasing proceeding (being the current proceeding) so as to permit this matter to be determined for both Hydro One's transmission and distribution businesses.

In the current transmission rates proceeding, Hydro One has requested OEB approval to continue capitalizing the non-service components of OPEBs for both its transmission and distribution businesses on the basis that the continued capitalization of these costs enables Hydro One to accurately depict the true costs of its capital assets (preferred approach).

If Hydro One's request for continued capitalization of the OPEB costs impacted by ASU No 2017-07 is denied, then Hydro One has alternatively requested OEB approval to permanently continue using the OPEB Cost Deferral Account for each of the transmission and distribution businesses in order to capture the impacted OPEB costs and to dispose of the balance that accumulates in each account on a twenty-year rolling balance (as opposed to periodic clearance of the accounts in future rate applications). Hydro One argued that the proposed methodology is appropriate as the use of twenty years is consistent with the US GAAP guidance that allows recovery of OPEB related amounts over a period not exceeding twenty years. As part of this alternate proposal, Hydro One also proposed that interest improvement be recorded on the opening monthly principal balance in the account.

OEB staff noted that, to date, no other utility that follows US GAAP has requested OEB approval to continue capitalizing the costs that are now prohibited by ASU No. 2017-07, or to establish a deferral account to capture the impact.

With respect to Hydro One's preferred option, OEB staff did not support the continued capitalization of the OPEB costs. It submitted that Hydro One's option has a negative impact on ratepayers over the long-term because it will be more expensive for them to fund such costs as part of rate base (as opposed to OM&A) due to the return on rate base that is applied to these costs when they are capitalized. OEB staff also indicated that approving such an option would not be consistent with the concerns that the OEB had previously raised with respect to the large capitalization amounts that US GAAP allows compared to MIFRS.[88]

OEB staff also submitted that it did not support Hydro One's alternate approach of continuing to use the OPEB Cost Deferral account to capture these costs because the additional regulatory burden it introduces is not justified when the annual rate impact from recognizing these costs in OM&A is not significant.

LPMA and Energy Probe supported and adopted OEB staff's submission on this issue. CME indicated that it also agreed with OEB staff's submission on this matter.

[88] EB-2016-0160, p. 82.

SEC had a similar position to OEB staff related to Hydro One's preferred and alternate proposals on this issue. SEC further argued that the inclusion of the impacted OPEB costs in the deferral account, as opposed to OM&A, masks Hydro One's actual OPEB costs by not including them in its base revenue requirement.

SUP submitted that Hydro One's alternate proposal results in the exclusion of the impacted OPEB costs from rate base and therefore would address OEB staff's concerns about affordability to customers.

SUP supported the continued capitalization of the OPEB costs because it ensured that the appropriate customers were paying for the costs they cause or benefit from. It argued that this is the same logic that allowed the FASB and FERC to provide for an exception for rate-regulated entities.

It was also SUP's position that the wider issue of cost capitalization of indirect and overhead costs should be studied from a policy perspective before a decision is taken to block this one sub-category of costs.

In its reply argument, Hydro One asserted that ASU 2017-07 does not establish a complete prohibition on capitalizing the non-service components of OPEBs, nor does it suggest any substantive concerns by FASB regarding the amount of capitalization by US GAAP-reporting companies.

Hydro One further argued that the important objective of regulatory consistency is best served by providing for continued capitalization of the non-service component of OPEB costs. These costs have historically been capitalized by Hydro One together with the service cost component of OPEBs. There has been no change to Hydro One's underlying business and nature of the underlying costs and therefore there is no reasonable basis to support a change in the regulatory treatment of these costs.

Hydro One indicated that there is a strong and clear precedent for an economic regulator (FERC) allowing continued capitalization of the non-service components of OPEB costs for regulated utilities subsequent to the issuance of ASU 2017-07.

Hydro One also asserted that whether recovered as OM&A or as capital, the same amounts would be recovered in the fullness of time if the time value of money is properly considered. However, recovering the impacted OPEB costs in OM&A results in material impacts (increase) on Hydro One's annual revenue requirement, and also gives rise to intergenerational inequities.

Finally, Hydro One stated that disallowing continued capitalization of the non-service components of Hydro One's OPEB costs in an effort to reduce the gap between what may be capitalized under US GAAP and what may be capitalized under MIFRS would not be appropriate.

Findings

The OEB finds that the non-service component of Hydro One's OPEB costs shall be recognized as OM&A costs for both its transmission and distribution businesses. Continuing to capitalize the non-service component is currently prohibited by ASU No. 2017-07. In addition, this approach exacerbates the issue previously raised by the OEB about the large capital amounts allowed by US GAAP compared to MIFRS.

The OEB finds that Hydro One's proposed alternative approach of permanently continuing to use the OPEB Cost Deferral Account is problematic. The regulatory burden associated with the ongoing disposition of balances in this account is not justified given the small annual rate impact of recognizing these costs in OM&A.

Hydro One needs to adjust the test year OM&A revenue requirement during the draft revenue requirement/charge determinant process of this proceeding to reflect these findings. Also, the capital expenditure amount in this proceeding needs to be adjusted to remove the non-service cost component of OPEBs. In addition, Hydro One shall update its variance account during the draft revenue requirement/charge determinant process to reflect this finding. Hydro One Distribution may need to continue accumulating the impacted OPEB costs in the OPEB Cost Deferral Account until its next rebasing application.

3.4.4 Indigenous Customer Issues (Issue 12)

Issue 12. Does Hydro One's Transmission System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?

Hydro One explained that its approach to addressing the rights and concerns of Indigenous customers and rights-holders is informed by direct engagement with Indigenous communities.

Anwaatin was the only party to raise concerns in relation to this issue.

Anwaatin made submissions related to: the electricity reliability disparity in portions of Northern Ontario and the Anwaatin First Nation communities, the role of Distributed Energy Resources (DERs), and the status and direction of Hydro One's Indigenous engagement activities.

Hydro One provided responses to Anwaatin's submissions as follows:

- Reliability – A requirement for additional performance monitoring of one specific circuit serving the Anwaatin communities is not necessary because it is already covered through Hydro One's ongoing performance monitoring and assessment process

- DERs – Hydro One referred to projects it undertook to achieve reliability benefits for northern communities and noted that the OEB has already taken steps to facilitate the expanded use of DERs for Indigenous customers experiencing long-term reliability challenges in Hydro One's distribution rate proceeding

- Indigenous Customer Engagement – Hydro One noted that it has carried out a wide range of activities in an effort to engage, build relationship with, and seek timely and meaningful input from, Indigenous representatives.

Hydro One concluded that the OEB should find that its TSP sufficiently addresses the unique rights and concerns of Indigenous customers and rights-holders.

Findings

The OEB finds that the unique rights and concerns of Indigenous customers and rights-holders have been adequately addressed in Hydro One's TSP in terms of taking steps to improve overall system reliability. Specific direction regarding reliability issues in northern communities was provided by the OEB to Hydro One in prior proceedings.[89] The OEB directs Hydro One to implement this direction in a timely fashion.

[89] In the EB-2017-0335 "Decision and Order," August 23, 2018, the OEB accepted the "Settlement Proposal Anwaatin Inc. Motion to Review and Vary the Ontario Energy Board's Decision on Hydro One Network Inc.'s Transmission Rates in EB-2016-0160," June 15, 2018.

3.5 OPERATING MAINTENANCE & ADMINISTRATION COSTS

3.5.1 Appropriateness of Proposed 2020 OM&A and Planning Choices (Issue 13)

Issue 13. Are the proposed 2020 OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained?

General OM&A

Hydro One applied for a 2020 test year OM&A of $374.1 million, which is comprised of the amounts shown in the table below, and which also reflects an update filed October 22, 2019 relating to a new pension valuation:[90]

Table 11 : Summary of Transmission OM&A Expenditures ($ millions)

	Historical								Bridge	Test
	2015		2016		2017		2018		2019	2020
	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Forecast
Category Level										
Sustainment	233.6	238.7	215.1	241.1	218.1	241.2	229.4	238.5	200.6	214.2
Development	6.1	12.9	4.6	13.4	5.1	4.8	5.2	5.0	6.0	6.9
Operations	59.0	58.5	62.5	59.1	61.1	61.3	53.4	62.1	46.1	48.9
Customer Care	5.1	5.5	4.5	5.5	8.5	4.0	11.0	3.9	7.3	7.5
Common Corporate Costs and Other Costs[260]	73.9	70.2	60.1	71.3	41.5	49.9	54.9	47.5	29.4	30.3
Property Taxes & Rights Payments	63.9	66.3	61.3	67.0	50.7	63.6	65.3	64.3	67.2	68.1
Adjustments										
EB-2014-0140 Settlement Reduction		-20.0		-20.0						
EB-2016-0160 Decision Reduction						-15.0		-15.0		
Removal of B2M Expense		-0.9		-0.7		-0.8		-2.1		
Pension Adjustment						-11.4		-9.9		
Directive[261]									-0.1	-0.1
Pension Adjustment Dec 31, 2018 Valuation[262]										-1.7
Envelope Level										
Total Transmission OM&A	**441.6**	**431.2**	**408.1**	**436.8**	**385.0**	**397.7**	**419.2**	**394.3**	**356.5**	**374.1**

[90] Exhibit J1.1, page 5, October 22, 2019; Argument in Chief Page 85

Hydro One stated that its investment plan is designed to utilize the approved funding to improve system reliability and maintain asset condition over the planning period. Hydro One further stated that the investment plan appropriately balances the need to minimize customer rate impacts with the requirements of the system for supporting the delivery of safe and reliable transmission service. Hydro One submitted that its rationale for planning choices is appropriately and adequately explained.

Hydro One submitted that in its view, its success in managing OM&A has been recognized in benchmarking studies that show Hydro One is an efficient transmitter from an OM&A perspective. Hydro One stated that its OM&A productivity significantly outpaced that of the transmission sector over the 2005-2016 period.

Hydro One stated that its 2019 OM&A expenditures are expected to be $38 million or 9.6% lower than the 2018 plan funding envelope. Hydro One indicated that this OM&A reduction will be achieved largely through sustained productivity gains, a one-time extension of Hydro One’s planned asset maintenance cycles, and corporate cost reductions. Hydro One stated that it plans to increase its 2020 OM&A expenditures by 5% from 2019 forecast levels while still remaining 4.7% below the 2018 plan funding envelope.

OEB staff noted that with Hydro One’s revised pension valuation, the updated requested 2020 OM&A of $374.1 million is 4.9% higher than 2019 levels, while still remaining 5.1% below the 2018 plan funding envelope. OEB staff stated that when compared to the 2018 actual OM&A of $419.2 million, this 2020 requested OM&A is also lower by $45.1 million or a decrease of 10.8%.

OEB staff supported a revised 2020 OM&A of $363.6 million, which is the 2019 forecast of $356.5 million uplifted by the approximate rate of inflation of 2.0%. OEB staff submitted that a revised 2020 OM&A of $363.6 million would represent a reduction of $10.5 million, or 2.8% from the requested 2020 OM&A. OEB staff argued that the revised amount of 2020 OM&A of $363.6 million is appropriate for the following reasons:

1. Hydro One has not shown sufficient evidence of OM&A cost savings associated with newer capital. More enhanced high level analysis of this correlation should be provided going forward.

2. 2016 and 2017 OM&A actuals were lower than plan amounts, by 6.6% and 3.2% respectively, which suggests that Hydro One may be over-forecasting its 2020

OM&A. The 2016 actual versus plan was $28.7 million lower or 6.6%. The 2017 actual versus plan was $12.7 million lower or 3.2%.

3. Requested 2020 Sustainment OM&A of $214.2 million may be overstated as the assumption that a deferment of maintenance cycles that occurred in 2019 cannot be repeated again in 2020 is not well supported.

4. Requested 2020 total staff compensation for the transmission business of $680.0 million, of which 26% is allocated to OM&A and 74% to capital, appears to be too high, as discussed further under Issue 17.

5. It is not clear to OEB staff that the claimed OM&A productivity savings of $22.0 million incorporated into the 2020 test year are genuine productivity savings. This is discussed under Issue 6, which relates to productivity improvements.

While most parties agreed that Hydro One has made progress related to its OM&A spending in the last several years, many of these parties suggested making further reductions in Hydro One's proposed 2020 OM&A budget, primarily in areas related to high compensation costs, impact of increased capital spending and further productivity improvement.

SEC submitted that the proposed OM&A should be reduced by at least $14.1 million in 2020 to reflect reductions in compensation costs and the lack of any progressive productivity built into the budget.[91] SEC submitted that the OEB should approve an OM&A budget that is closer to the 2019 forecast. Specifically, SEC argued that the OEB should:

1. Reduce Hydro One's OM&A by $10.1 million, which represents the premium between the benchmark market median (P50), and the actual level of compensation

2. Require a reduction of between 1% and 3% in 2020 to incorporate incremental productivity improvements that Hydro One has either not identified, or not

[91] SEC Submission, December 17, 2019 (Revised), page 7, 60; page 60 stated that SEC proposes a reduction of Hydro One's 2020 OM&A budget by at least $14.1 million to reflect an appropriate reduction in compensation costs and the lack of any progressive productivity. The OEB was unable to reconcile all of the components of the $14.1 million to SEC's submission and therefore allocated $0.3 million to "Other" in the table of the decision that provides a summary of proposed OM&A cost reductions.

validated, at this time. SEC proposed that this would result in a reduction of at least $3.7 million in 2020, based on a 1% progressive productivity amount

AMPCO and CCC agreed with OEB staff's proposal of setting the 2020 OM&A by inflating the 2019 forecast by 2%. This would result in reducing the proposed 2020 OM&A budget by $10.5 million.

VECC submitted that the OEB should reduce the 2020 revenue requirement by $10 million in OM&A to recognize Hydro One's continued above market compensation.

VECC argued that, for the OM&A category of productivity savings, there is a question as to when a productivity initiative becomes simply "business as usual".

CME submitted that there should be a reduction for the full amount that Hydro One remains above market median for compensation (i.e., $10.1 million for OM&A and $28.5 million for capital), given the significant attention this issue has drawn over the last several applications and the limited improvement that Hydro One has demonstrated to date.

Energy Probe noted that reductions in operations, customer care, and common corporate costs are appropriate. Energy Probe stated that its only concern is whether the 2020 Sustainment OM&A budget of $214.2 million is too low and whether or not that may affect system reliability.

AMPCO outlined additional concerns regarding Hydro One's vehicle utilization rate and billable hours ratio and provided tables augmenting its argument. AMPCO submitted that these issues should be addressed in Hydro One's scorecard, with a view to reducing cost and improving performance over time.

PWU submitted that the proposed 2020 OM&A expenditures are appropriate and are well supported in the evidence. PWU was of the view that Hydro One has made material progress in controlling and reducing OM&A costs. PWU noted that this is reflected in the 2020 OM&A budget which is lower than approved and actual OM&A in any year between 2015 and 2018.

PWU noted that the largest increase in forecast 2020 OM&A relative to the 2019 forecast is in the sustainment category, which represents a $13.6 million increase, but remains lower than historic levels. PWU suggested that the increase is necessary for a variety of reasons.

PWU disagreed with OEB staff's proposed disallowance of $10.5 million in 2020 OM&A. In PWU's view, OEB staff's proposed OM&A budget is not, nor does it attempt to be, based on Hydro One's cost to serve. In PWU's view, none of the reasons provided by OEB staff justifies any disallowance.

SUP submitted that OEB staff's proposed reduction of 2020 OM&A to $363.6 million results in an unreasonably low expenditure level which is insufficient to complete required work. In particular, SUP submitted that OEB staff's assertion that Hydro One's requested 2020 transmission compensation of $680.0 million, of which 26% is allocated to 2020 transmission OM&A, appears to be too high is incorrect.

SUP stated that the average annual sustainment expenditures for 2015 until 2019 is $219.4 million. In this context, SUP submitted that a proposed expenditure of $214.2 million in 2020 is reasonable.[92]

LPMA submitted that the overall reduction in Hydro One's 2020 OM&A expenditures should be $10.7 million, representing decreases of $8.0 million in sustainment and $2.7 million in regulatory related costs. LPMA submitted that its suggested reduction in 2020 OM&A has been arrived at using a different approach than that outlined in OEB staff's submission, but amounts to a reduction of the same magnitude.

LPMA submitted that it is concerned that in the sustainment category, Hydro One has underspent the planned amount in every year shown. LPMA noted in this context that Hydro One has shifted sustainment spending from 2019 to 2020 which accomplishes two things. LPMA stated that 1) the return for the shareholder increases in 2019 as compared to spending more on sustainment in the bridge year; and 2) it bumps up the level of 2020 OM&A which is the base upon which the I – X factor is applied for 2021 and 2022. LPMA summarized its views by noting that Hydro One gets a higher return in 2019 and gets more in OM&A for three years.

LPMA submitted that a reasonable approach to deal with the 2019 dip and the 2020 increase in sustainment OM&A is to reduce the forecast by one-half of the historical under-spending over the 2015 to 2018 period. LPMA supported a reduction of $8.0 million in the 2020 forecast sustainment spending, reducing it from $214.2 million to $206.2 million.

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[92] SUP referenced 2019 Sustainment OM&A of $214.2 million instead of 2020 Sustainment OM&A

LPMA also submitted that in addition to the $8.0 million reduction related to sustainment expenditures, the OEB should approve a reduction of $2.7 million involving regulatory related costs. LPMA noted that Hydro One confirmed that the costs associated with the current application have been recorded in 2019 and there are no costs directly associated with the current Application included in the 2020 test year revenue requirement.

A summary of the recommendations made by parties who proposed overall OM&A cost reductions is provided in Table 12 below. This table excludes any changes suggested by parties relating to the 2020 pension and OPEB amounts proposed for recovery.

Table 12: Summary of 2020 Proposed OM&A Cost Reductions (millions)

	AMPCO	CCC	CME	LPMA	SEC	VECC	OEB Staff
General OM&A	$10.5	$10.5		$10.7			$10.5
Productivity Related OM&A					$3.7		
General Compensation			$10.1[93]		$10.1	$10.0	
Other					$0.3		
Total	**$10.5**	**$10.5**	**$10.1**	**$10.7**	**$14.1**	**$10.0**	**$10.5**

Hydro One submitted that OEB staff's proposed reduction to the 2020 OM&A, which was supported by other parties, is not appropriate for a rebasing year under the Custom IR framework. Hydro One argued that the proposed inflation rate of 2.0% is not based on any applicable inflationary index. In Hydro One's view, OEB staff's proposed treatment of Hydro One's 2020 OM&A in effect ignores the OEB's rebasing principles

[93] CME Submission, December 16, 2019, page 50 - stated that $38,466,291 should be allocated to capital. However, the OEB interprets CME's submission as the total amount of 2020 compensation allocated to transmission being $38,566,291 (and not $38,466,291) with $10.1 million to OM&A and the balance ($28.5 million) to capital.

and adopts an annual IR index. Hydro One concluded that OEB staff has put forward an arbitrary mechanistic proposal for determining 2020 OM&A, without providing evidence to support the basis of the reduction. Hydro One also opposed LPMA's suggested reductions to its proposed regulatory related costs.

The following sections address some of the key issues, including the various categories of proposed OM&A expenditures, in more detail.

OM&A Cost Savings Associated with Newer Capital

At the oral hearing, Hydro One provided a high level overview as to how it takes into account the impact of capital spending on its OM&A, which OEB staff also described in its submission.

OEB staff noted that Hydro One provided multiple examples of technological advances that will provide opportunities for OM&A savings. OEB staff stated that many recent technological innovations should enable Hydro One to undertake its operations and maintenance activities more cost efficiently than in past years as innovations are integrated into Hydro One's asset management processes.

OEB staff submitted that the OM&A cost savings associated with new capital have not been adequately quantified by Hydro One. OEB staff voiced concerns with Hydro One's lack of evidence demonstrating that it has fully accounted for OM&A expenditure savings that should accrue to the benefit of ratepayers. OEB staff argued that these benefits should accrue as a result of leveraging new technologies and the asset enhancements with which replacement assets come equipped as standard features.

OEB staff submitted that its proposed reduction to OM&A in 2020 of $10.5 million is partly supported by Hydro One's lack of evidence of its leveraging technology and capital expenditures to reduce OM&A, particularly given the magnitude of the requested capital increases.

OEB staff submitted that going forward, Hydro One's OM&A cost forecasts should reflect productivity gains due to technological improvements and other innovations. OEB staff argued that the productivity gains linked to the introduction of time and labour saving condition assessment and evaluation tools and techniques for, (i) general and (ii) asset-specific OM&A activities, should be measured and tracked.

OEB staff argued that more enhanced high level analysis should be provided going forward as to the OM&A cost savings associated with newer capital.

BOMA argued that Hydro One's evidence shows that there would be OM&A savings from replacing assets such as older transformers with new assets. BOMA submitted that Hydro One was unable to quantify certain OM&A reductions that result from the installation of some new capital assets. BOMA submitted that Hydro One should have these numbers and Hydro One has exaggerated the difficulty of producing them.

Hydro One argued that OEB staff's position that OM&A savings associated with new capital have not been adequately quantified and accounted for by Hydro One is not justified. Hydro One stated that it is clearly evident, based on the total capital need and the amount of capital expended in the aggregate, that there is not an identifiable effect on OM&A expenditures.

Hydro One acknowledged that reductions to OM&A costs do not materialize immediately when a particular asset is replaced with a new unit and that it may take some time for such reductions to fully materialize.[94] However, Hydro One submitted that it is not appropriate to extrapolate the impact on a single asset onto total OM&A. Hydro One argued that any impact on total OM&A must be considered in the context of the full level of capital work and the fleet of assets that it is intended to renew. Hydro One further stated that, given its sizeable asset population and the need for renewal relative to the actual work undertaken, the result is that the changes to OM&A arising from capital replacements are offset by the larger population of older assets that require greater levels of maintenance.

Sustainment OM&A

Hydro One is requesting 2020 Sustainment OM&A in the amount of $214.2 million. Hydro One noted that the Sustainment OM&A budget is comprised of the investments required for ongoing maintenance to existing transmission lines and stations facilities to ensure that their functionality, as originally designed, is maintained. Hydro One indicated that this OM&A category is also required to comply with regulatory obligations over the planning period.

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[94] Reply Submission, January 17, 2020, page 172-173; Hydro One also noted that as explained at the oral hearing, rigorous maintenance is actually required on a newly installed transformer during its infancy life stage (i.e., first one to two years after installation) to ensure satisfactory design, with maintenance requirements subsequently leveling off before increasing again closer to end of life.

Hydro One stated that the proposed budget for Sustainment OM&A in the 2020 test year is $13.6 million higher compared to the 2019 bridge year (i.e., $214.2 million in 2020 versus $200.6 million in 2019), but it is in-line with average historical levels.

OEB staff noted that actual Sustainment OM&A was less than planned OM&A for each of the 2015-2018 rate years, as discussed at the oral hearing.[95]

Hydro One submitted that the proposed Sustainment OM&A budget for the 2020 test year strikes an appropriate balance between the needs of customers, system reliability and the overall stewardship of Hydro One's assets. In Hydro One's view, the resulting investment plan represents the minimum level of investment needed to ensure this balance is achieved.

Hydro One also stated the following:

- The increase in 2020 versus 2019 is necessary to meet the legislated deadlines associated with the polychlorinated biphenyl (PCB) program, fund planned transformer overhauls, support previously deferred preventive maintenance for station assets, and address the backlog in overhead lines and component inspections and assessments.

- The 2019 bridge year forecast for Sustainment OM&A is lower than historical levels partially as a result of a one-time extension of Hydro One's planned asset maintenance cycles.[96]

Hydro One further stated that $6.9 million of the $13.6 million increase in 2020 Sustainment OM&A over 2019, or 50.7% of the increase, is comprised of mandatory PCB retirement (remediation) work to address PCB filled equipment in order to comply with federal PCB regulations.[97] Hydro One also noted that because of the need to schedule outages and the potential to discover newly identified PCB filled equipment that requires resolution, funding this work at 2019 levels is not feasible. Hydro One also

[95] Oral Hearing Transcript October 24, 2019, page 61
[96] At Exhibit F, Tab 1, Schedule 1, Page 4 Hydro One stated that this includes fewer planned demand and corrective expenditures, extension of the PCB testing and retrofill program, deferral of overhead transmission line preventive maintenance and deferral of vegetation management on select 115kV circuits.
[97] Undertaking – JT 1.3

stated that this level “will not be sufficient to complete the planned retrofill and sampling work in time to meet Environment Canada’s 2025 deadline”.

Hydro One stated that the 2019 deferment of maintenance was a one-time reduction and that such funding level is not sustainable over the long term. Hydro One further stated that excluding this work from 2020 would in essence take a one-year cut to preventive maintenance and condition assessments and extend it over a four-year period (2019 to 2022), which would lead to an unmanaged risk. Hydro One stated that if 2020 Sustainment OM&A for essential maintenance were funded at suppressed 2019 levels for three additional years over the test period, the overall impact would be up to three years of suspended maintenance work relative to historical levels, affecting many of its maintenance programs.

OEB staff submitted that if Hydro One’s asset management practices have improved, there should be a better integration of capital and OM&A trade-offs. However, OEB staff noted that the 2019 deferment only affected OM&A and not capital. OEB staff indicated that, in Hydro One’s view, the reason capital was not targeted is because the cost of capital has much less impact on meeting envelopes.

OEB staff noted that its proposed reduction in 2020 total OM&A of $10.5 million is supported by a cut that also should be made to 2020 Sustainment OM&A. OEB staff submitted that Hydro One’s deferment of maintenance cycles that occurred in 2019 could be repeated again in 2020 to some extent, which would decrease the proposed 2020 OM&A.

OEB staff questioned why the total increase of $13.6 million to 2020 sustainment versus 2019 is required, when Hydro One is able to operate at the forecasted 2019 level of $200.6 million. OEB staff submitted that based on prior years’ spending patterns, Hydro One may be over-forecasting sustainment OM&A requirements in the current Application.

OEB staff submitted that it is also unclear why there was no impact on capital amounts from the one-time extension of planned asset maintenance cycles in 2019. OEB staff was of the view that capital amounts should also be considered, along with OM&A, when planned asset maintenance cycles are deferred.

Hydro One argued that OEB staff’s submission fails to reference any evidence in support of its position that Hydro One “is able to operate” at the forecasted 2019 levels. Hydro One stated that OEB staff also ignored clear evidence that maintaining 2020

Sustainment OM&A expenditures at 2019 levels would adversely affect Hydro One's ability to appropriately execute required operation and maintenance activities.

Hydro One stated that not all categories of Sustainment OM&A are receiving increased funding. Hydro One noted that to offset additional 2020 funding, many categories within Sustainment OM&A have been funded in line with or below 2019 levels.

Hydro One submitted that although OEB staff and LPMA suggested that based on prior years' spending patterns, Hydro One may be over-forecasting Sustainment OM&A requirements, in its view, neither OEB Staff nor LPMA gave a basis for their assertions. Hydro One noted that "some attempt was made in the proceeding by OEB staff to mischaracterize the variance between higher historical plan amounts and lower historical actual amounts… to support the claim that Hydro One overstated its funding needs." However, Hydro One argued that comparisons to historical plan levels are not appropriate because they reflect amounts before any reductions were made as a result of OEB decisions.

Hydro One also argued that LPMA ties its basis for disallowance to the fact that Sustainment OM&A dips in 2019 relative to 2018 and then increases in 2020. In Hydro One's view, LPMA ignored the factual evidentiary basis and need for the increase in 2020 Sustainment OM&A. Hydro One took issue with LPMA's argument that the objective of the increase is to achieve higher OM&A during the test period through the application of the incentive rates escalator of I-X, than if the 2019 levels were retained.

Development OM&A

Hydro One is requesting 2020 Development OM&A in the amount of $6.9 million. Hydro One stated that Development OM&A expenditures consist of costs associated with developing technical standards, technical approaches and solutions, participating in industry research collaborations and subscriptions, and customer power quality.

OEB staff submitted that Hydro One's 2020 Development OM&A of $6.9 million is reasonable. No intervenor took issue with the requested 2020 Development OM&A.

Operations OM&A

Hydro One is requesting 2020 Operations OM&A in the amount of $48.9 million. Hydro One stated that its Operations OM&A expenditures reflect the costs of performing the central transmission operations function at its OGCC, or via the Back-Up Control Centre if the OGCC is rendered unavailable. Hydro One also noted that the Operations function manages the real-time operation of Hydro One's transmission system equipment including: monitoring and controlling transmission assets, coordinating and scheduling planned outages, reacting to system contingencies, provisioning for customer notifications, and reporting on the performance of the transmission system.

OEB staff submitted that the proposed 2020 Operations OM&A of $48.9 million is reasonable. No intervenor took issue with the requested 2020 Operations OM&A.

Customer Care OM&A

Hydro One is requesting 2020 Customer Care OM&A in the amount of $7.5 million. Hydro One stated that this category of OM&A expenditures pertains to the delivery of customer care functions to Hydro One's transmission customers.

OEB staff submitted that the requested 2020 Customer Care OM&A of $7.5 million is reasonable. No intervenor took issue with the requested 2020 Customer Care OM&A.

Common Corporate Costs and Other Costs

This area is addressed under Issue 10 of this Decision.

Property Taxes and Rights Payments

Hydro One stated that it incurs expenditures related to taxes (other than income and capital taxes) arising from its obligations to pay property taxes and to make rights payments.

Hydro One stated that it is seeking to recover a total of approximately $68.1 million for such taxes other than income taxes, which is comprised of approximately $61.2 million for property taxes and approximately $6.9 million for rights payments. The property taxes include taxes levied on Hydro One by municipalities, as well as amounts paid annually to First Nations as payments in lieu of taxes for transmission assets located on reserve lands. The rights payments include payments for land rights under agreements or permits, including for transmission facilities to cross or occupy rail or government properties, as well as First Nations reserve lands.

Hydro One noted that OEB staff, in its submissions under Issue 15, had accepted the $68.1 million forecast for property taxes and rights payments as being reasonable on the basis that it is consistent with actual historical trends for these amounts during the historical period.

Hydro One further noted that no intervenor had raised any concerns with respect to Hydro One's forecasts for property taxes and rights payments.

Hydro One, accordingly argued that the OEB should find that its forecast expenditures for property taxes and rights payments, as a component of the company's OM&A costs, are appropriate.

Hydro One Accountability Act, 2018 and the Directive

Hydro One addressed the HOAA and the Directive, which placed limitations on the amount of compensation paid to Hydro One executives that could be included by the OEB in approving just and reasonable rates for Hydro One Limited or any of its subsidiaries.

Hydro One indicated that the results of addressing the Directive had modest impacts on OM&A and capital, resulting in total reductions of $0.6 million and $2.1 million, respectively, over the 2019 to 2024 period. Hydro One also stated that the in-year reductions are shown as bottom line adjustments in the respective OM&A and capital exhibits.

Regarding Hydro One's compliance with the HOAA and the Directive, as well as the OEB's Hydro One distribution decision and order,[98] Hydro One confirmed that no additional adjustments are required to its requested executive compensation and board of directors costs included in its evidence.

Hydro One further stated that its Application reflects Bill 2 and is consistent with the approach that was accepted by the OEB in the Hydro One distribution decision. Hydro One noted that the Directive only had a minor impact on the Application. Hydro One

[98] EB-2017-0049

also noted that its executive compensation framework is consistent with the Directive and that the impact of the Directive is reflected in the proposed revenue requirement.

SUP submitted that executive costs have been reduced to be in compliance with Bill 2. SUP argued that Hydro One went beyond what Bill 2 specified by including all executives within the executive leadership team (ELT). SUP also submitted that Hydro One's reduced compensation in order to be compliant with the Directive further benefitted ratepayers.

OEB staff took no issue with Hydro One's approach to its requested executive compensation and board of directors costs and submitted that no further adjustments are required to the 2020 test year revenue requirement with regard to these matters.

Findings

The OEB approves an OM&A budget for 2020 of $364.0 million which represents a $10.1 million (2.7%) reduction compared to Hydro One's Application. The $10.1 million reduction is entirely related to Hydro One's staff compensation. The impact of OPEB capitalization on the 2020 OM&A is addressed under Issue 11.

The OEB agrees with several parties that Hydro One has made progress over the last few years in its planning process and its ability to seek productivity improvements which, to some degree, is demonstrated by the downward trend in its OM&A expenditures. The subject of productivity improvements is discussed in further detail under Issue 6. However, there are some areas that the OEB would like to highlight:

1. Staff compensation, which represents approximately half of the requested OM&A funding for 2020, continues to be higher than market median. This topic is addressed in more detail under Issue 17.

2. Insufficient evidence of OM&A reductions associated with increased capital expenditures. The OEB realizes that there may be a time lag between capital investments and corresponding reduced need for maintenance. The OEB also realizes that, as assets are refurbished or replaced, other assets continue to age requiring more maintenance. However, the OEB finds that Hydro One has not demonstrated or explained in this Application the correlation between increased capital expenditures and potential reductions in OM&A costs. It is the OEB's expectation that, when a business case is prepared for capital investments, an

assessment of the impact of that investment on OM&A cost is typically addressed. The OEB expects that, in future rate applications, Hydro One will provide a high level assessment of such correlation, or lack of, at the program level.

Apart from the OEB's finding regarding staff compensation, the OEB finds that the proposed work programs in the various OM&A categories are reasonable. The OEB also finds that Hydro One has demonstrated its compliance with the HOAA, the Directive and the OEB's distribution decision and order regarding the area of staff compensation.

3.5.2 Common Corporate OM&A Allocation Methodology (Issue 14)

Issue 14. Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the transmission business appropriate?

This is addressed under Issue 10. The OEB has combined Issue 10 and Issue 14, as both issues address common corporate costs (capital expenditures and OM&A).

3.5.3 Income Taxes (Issue 15)

Issue 15. Are the amounts proposed to be included in the revenue requirement for income taxes appropriate, including consideration of the Accelerated Investment Incentive (Federal Bill C-97)?

Hydro One is requesting approval to recover the following regulatory income tax expense amounts over the term of its 2020-2022 custom IR application: [99]

Table 13: Regulatory Income Tax Recovery (millions)

	2020	2021	2022	Total
Regulatory Income Tax Expense	$26.3	$27.2	$40.4	**$93.9**

The regulatory income tax expense amount forms part of the 2020 revenue requirement and is required for the 2021-2022 Custom Revenue Cap Index (CRCI) calculation.[100]

[99] Exhibit J1.1, Table 2
[100] The regulatory income tax expense amount is part of the C-factor calculation.

On June 21, 2019, Bill C-97, the *Budget Implementation Act, 2019, No. 1*, was given Royal Assent. Included in Bill C-97 are various changes to the federal income tax regime. One of the changes introduced by Bill C-97 is the Accelerated Investment Incentive (AII) program, which provides for a first-year increase in capital cost allowance (CCA) deductions on eligible capital assets acquired after November 20, 2018. An eligible capital asset that would have been subject to the half-year rule will, in essence, qualify for an enhanced CCA equal to three times the normal first-year deduction.
On July 25th, 2019, the OEB issued accounting direction regarding Bill C-97 and other changes in regulatory or legislated tax rules for CCA. In that communication, the OEB indicated that it expects utilities to reflect the aforementioned CCA rule changes in their cost-based applications for 2020 rates and beyond.[101]

Hydro One updated its test period regulatory income tax expense calculations during the current proceeding in order to reflect the revenue requirement impact of the AII program.

OEB staff submitted that since Hydro One prepared its estimate pertaining to the revenue requirement impact of the AII program so soon after Bill C-97 was enacted on June 21, 2019, it should revisit its calculations during the draft revenue requirement/charge determinant process of the current proceeding and confirm that no further updates or changes are required. OEB staff also noted that the regulatory income tax calculations currently on the record of the proceeding do not reconcile to what Hydro One is seeking to recover during the Application term and therefore submitted that Hydro One be directed to file an updated set of regulatory tax calculations during the draft revenue requirement/charge determinant process. LPMA also made a similar submission on this matter.

OEB staff further submitted that Hydro One should quantify the 2018 impact of the AII program during the draft revenue requirement/charge determinant process and record the corresponding amount in the new sub-account of Account 1592, as was directed by the OEB in its July 25, 2019 letter.

In its reply argument, Hydro One submitted that it is not necessary for it to revisit the calculations pertaining to the estimated revenue requirement impact of the AII because the forecast eligible additions have not changed, and there has been no more

[101] OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance / July 25, 2019.

information on the application of the new rules that would affect Hydro One's initial calculations for the test years.

Hydro One further submitted that consistent with its past practice, to the extent that there are any changes to income tax expense arising from the decision in this proceeding, Hydro One will reflect those changes in its draft rate order, including calculations to support the regulatory income tax expense to be included in the updated revenue requirement. Hydro One will document the reason for the change and allow for that change to be reviewed by the OEB.

In regard to capturing the 2018 impact of the AII in the new sub-account of 1592, Hydro One argued that it should not be required to do so on the basis that the expected impact is quantified to be $0.2 million, which is not material in the context of Hydro One's transmission materiality threshold. In addition, Hydro One indicated that the total CCA deductions that are available over the life of an asset are the same under the new rules, as the new rules simply increase the amount that may be claimed in the first year. As such, to the extent that accelerated CCA has not been claimed for prior years (such as 2018), additional deductions will be available to be applied to the benefit of ratepayers in subsequent years.

Findings

The OEB finds that Hydro One shall review its calculations regarding the revenue requirement impact of the AII program and confirm that no further changes are required, as part of the draft revenue requirement/charge determinant process of the current proceeding. Hydro One is also directed to file an updated set of regulatory tax calculations during the draft revenue requirement/charge determinant process.

While Hydro One stated that the expected impact of the AII is not material for 2018, the evidence indicates that there is a material impact for 2019.[102] The OEB therefore finds that Hydro One shall record the impact of the AII for both 2018 and 2019 in the new sub-account of 1592, as required by the OEB's accounting direction.

[102] Exhibit I, Tab 1, Schedule 208, p. 4, (e)

3.5.4 Depreciation Expense (Issue 16)

Issue 16. Is Hydro One's proposed depreciation expense appropriate?

As shown in the table below, Hydro One has sought to recover approximately $1.5 billion in depreciation expense over the Application term.

Table 14: Hydro One's Proposed Depreciation Expense (millions)

	2020	2021	2022	Total
Depreciation Expense	$474.5	$503.4	$528.9	**$1,506.8**

The depreciation amounts are underpinned by an independent depreciation study completed by Foster Associates (Depreciation Study). The Depreciation Study involved a review of Hydro One's existing deprecation rates and the provision of updated depreciation rates. The OEB has historically accepted the Depreciation Study and the methodology set out therein as the basis for determining depreciation expense in Hydro One's transmission rates applications.

OEB staff submitted that it accepts the annual depreciation expense on the basis that these amounts were determined by an independent study prepared by a third-party consultant with significant experience in the field which has prepared the depreciation studies that underpinned the depreciation rates of previous Hydro One rate applications. The methodology used to determine Hydro One's depreciation rates is consistent with what has been previously accepted by the OEB.

Energy Probe supported the position of OEB staff on this matter.

LPMA submitted that based on Hydro One's proven inability to accurately forecast depreciation expense, the OEB needs to reduce the forecasts of these costs that affect not only the 2020 revenue requirement to be recovered through rates but also the capital factor through the inclusion of the forecast depreciation expense in the total capital related revenue requirement.

LPMA proposed a reduction to the annual depreciation over the Application term of 6.8% based on Hydro One's historical over-estimate of depreciation costs. AMPCO and CCC proposed similar reductions.

BOMA proposed the use of a variance account to capture the difference between the depreciation forecast in the Application for 2020, 2021, and 2022, and the actual depreciation incurred in each of those years.

In its reply submission, Hydro One argued that it would not be appropriate to apply a blanket adjustment of 6.8% or 7%, as proposed by intervenors, to the entirety of Hydro One's proposed depreciation expense because the historical variances in respect of the depreciation on fixed assets component have been relatively small and within the range of reasonableness.

Hydro One further submitted that the focus should be strictly on addressing the historical variances in asset removal costs, which Hydro One has acknowledged and already taken steps to mitigate. To that end, Hydro One further proposed the establishment of an asymmetrical cumulative variance account to record any differences between the asset removal cost forecasts that have been included in the proposed depreciation expense for 2020 to 2022 based on the updated planning assumptions and the actual asset removal costs incurred in each of those years, where differences would be calculated and booked to the account net of tax impact.

Findings

The OEB accepts the annual depreciation expense proposed by Hydro One on the basis that the methodology used is consistent with what the OEB accepted in prior proceedings. Hydro One shall update the calculation of depreciation expense to reflect the OEB's findings in this Decision.

The OEB also agrees with Hydro One's proposal regarding the establishment of an asymmetrical cumulative variance account. Hydro One shall file a draft accounting order for this account as part of the draft revenue requirement/charge determinant process.

3.6 COMPENSATION COSTS

3.6.1 Compensation Costs (Issue 17)

Issue 17. Are the compensation related costs appropriate?

Overall FTEs and Compensation

Hydro One's requested transmission FTEs are as shown in the following table:[103]

Table 15: Transmission FTEs

FTE Transmission	2017	2018	2019	2020	2021	2022
Total	4,304	4,247	4,474	4,691	4,738	4,613

Hydro One's requested transmission compensation is as shown in the following table:[104]

Table 16: Transmission Compensation ($)

	2017	2018	2019	2020	2021	2022
Total Capital Transmission Comp	394,177,597	424,531,224	453,763,524	502,291,507	537,485,570	538,422,230
Total OM&A Transmission Comp	223,675,880	185,069,058	174,699,777	177,721,606	169,507,508	167,297,820
Total Transmission Compensation	**617,853,477**	**609,600,282**	**628,463,301**	**680,013,112**	**706,993,078**	**705,720,050**

Hydro One confirmed that its work program drives the FTEs and then FTEs drive the compensation costs.[105] Hydro One stated that it looks at the work program requirements and then staffs up accordingly through its various flexible work force arrangements.

Hydro One indicated that in looking at the FTEs, the entire work program needs to be considered (OM&A and capital).[106] Hydro One stated that a direct relationship cannot be made between increasing FTEs and declining OM&A because doing that would be ignoring the capital component of the FTE requirements.

Hydro One indicated that it is supporting a 26% increase in the transmission work program (OM&A and capital) over the 2019-2022 period.

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103 Exhibit I, Tab 01, Schedule 172 (OEB Staff Interrogatory #172)
104 Undertaking J4.09
105 Oral Hearing Transcript October 25, 2019, page 133
106 Oral Hearing Transcript October 28, 2019, page 124

In Hydro One's view, it has made progress in reducing and limiting compensation costs, and actively managing the efficiency and size of its workforce. However, Hydro One also indicated that in order to accomplish the work programs reflected in this Application and deliver on the important outcomes that the company is committing to, it is necessary for Hydro One to attract, motivate, engage and retain a highly skilled and high performing workforce with appropriate compensation systems.

Hydro One submitted that while the 2020 transmission-allocated costs represent an increase over 2019 levels, the increase is reasonable and necessary, including the FTE levels.

Hydro One submitted that its relatively modest increase in costs compared to the increase in work program is reasonable and reflective of improving productivity and better controls in monitoring and approving headcount, as well as reductions in corporate costs.

Hydro One provided an explanation as to why compensation is increasing at a rate faster than inflation, as follows:[107]

- The projected compensation costs contain several underlying factors based on best estimates across each factor, in each year including: forecast FTE changes, base escalation, labour burdens and the allocation between the transmission business and distribution business[108]

- As the compensation forecast includes several interconnected factors, they will not align with inflation rates in isolation

- Hydro One's base wage increases for represented employees are at or below inflation

Hydro One provided an explanation as to why compensation cost is increasing at a faster rate than FTEs.[109] Hydro One indicated that the 4.2% increase in transmission compensation costs, which represents the simple growth rate over the period 2018 to

[107] Undertaking – JT 2.10
[108] Exhibit KT 2.1 shows the projected compensation costs
[109] Undertaking – JT 2.10

2022, includes compensation costs associated with a 2.2% FTE increase (also over the period 2018 to 2022) and escalation assumptions in compensation.[110]

Hydro One referenced a table in its pre-filed evidence which shows total compensation versus total work programs.,[111] Hydro One indicated that it provided an analysis of transmission compensation relative to transmission spend and there is a decline in those ratios. Hydro One stated that the ratio started at 49% and is expected to decrease to 40% in 2022. Hydro One further stated that this decline is partly accounted for by efficiency and outsourcing of certain aspects of its capital program.

Hydro One provided a table which showed the FTE changes for both Hydro One transmission and distribution.[112] This table was included in the OEB staff submission.

Hydro One indicated the following regarding some changes in FTEs over the 2019-2022 period:

- The increase of 200 FTEs in the 2019 transmission work program, compared to 2018, is primarily caused by the transfer of non-regular lines apprentices from the distribution business to transmission.

- The reductions in FTEs related to the transmission work program shown in 2020, compared to 2019, as well as the additional reduction in 2022, represent decreases in the direct hire casual trade workforce, as a result of expected efficiencies due to progressive productivity savings.[113]

Hydro One confirmed that there are only 200 FTEs that are being transferred or reclassified from distribution to transmission in 2019. As well, Hydro One confirmed that there are no significant FTEs that are being transferred from transmission to distribution. Hydro One also noted that the 415 FTE increase in 2019 relating to distribution "is a reflection of the plan that was outlined as per the previous application to support the previous distribution application."

Hydro One further indicated that due to the timing of the distribution decision, which occurred on March 7, 2019, and the initial March 21, 2019 filing for the current

[110] Exhibit KT 2.1, cell N111 shows the 4.2% increase and cell N166 shows the 2.2% increase
[111] Oral Hearing Transcript, October 28, 2019, page 157
[112] Undertaking – JT 2.07
[113] *Ibid*

transmission Application, Hydro One did not have “sufficient opportunity to restate all of the FTEs to align with that distribution reduction.” Hydro One also stated that when it comes back and files its joint application (2023 rates), some of those pieces will be clarified. Hydro One stated that there is no “double counting” of FTEs between transmission and distribution when the lines of businesses provide their requirements to fulfil the work program that has been outlined. However, Hydro One noted that there is also “in-year accounting for movements.”[114]

Hydro One summarized that its compensation related costs are appropriate based on the following:

1. The progress made in reducing/limiting compensation costs as evidenced by improving benchmarking results.

2. The increase in transmission compensation costs is relatively low compared to the increase in the work program.

3. Its overall compensation and pension framework and strategy.

4. The progress made in reducing pension costs and in respect of collective bargaining, including having regard to the reality of the collective agreements Hydro One inherited from Ontario Hydro.

OEB staff noted that Hydro One is requesting a 2020 transmission compensation level of $680.0 million, of which 26% is allocated to OM&A and 74% to capital. OEB staff submitted that this amount may be overstated for the following reasons:

i. The increase in compensation is excessive given: (1) repeated concerns expressed by the OEB about Hydro One’s compensation levels in prior decisions, and (2) Hydro One’s statements about its improved productivity in the current Application.

ii. Much of the increase in compensation has been attributed to the needs of the growing capital program (with 74% of 2020 compensation allocated to capital). As there is a reduction recommended in the work program for capital (see Issue 9), there should also be a related compensation cut which would impact both capital and OM&A.

[114] Oral Hearing Transcript October 29, 2019, pp. 2 to 7

iii. The Mercer "market median" level of compensation may be overstated. As a result, the reduction of Hydro One's requested compensation incorporated into the 2020 revenue requirement may be understated and further reductions may be required.

iv. The amounts paid to contract staff (i.e., staff not included in FTEs) may mask an even higher level of compensation being paid out than that reflected in the requested 2020 compensation amount.

v. The total burdens, excluding pension and OPEB, may be overstated since OEB staff could not reconcile its estimated calculations of these burdens to the amounts requested in the compensation spreadsheet provided by Hydro One (Compensation Spreadsheet).

vi. The year over year increases in total transmission compensation cost per FTEs between 2019 and 2022 are higher than the inflation rate of approximately 2.0%.

Based on a simple growth rate analysis, OEB staff provided the increases in compensation and FTEs in the following table.[115] OEB staff noted that this table was not updated to reflect the new pension valuation. However, the table remained directionally consistent.

[115] OEB Staff Submission, December 11, 2019, page 103

Table 17: Movements in Hydro One Transmission and Distribution Compensation and FTEs

OEB Staff Table 11 - Movements in Hydro One Transmission and Distribution Compensation and FTEs
Exhibit KT2.1

	2022 versus 2018		2020 versus 2018	
	Total % Change	**Annual % Change**	**Total % Change**	**Annual % Change**
Total Transmission Compensation	17.00%	4.20%	12.50%	6.30%
Total Distribution Compensation	14.80%	3.70%	8.30%	4.10%
Total Transmission FTEs	8.60%	2.20%	10.50%	5.20%
Total Distribution FTEs	8.70%	2.20%	6.50%	3.30%

OEB staff was also of the view that further improvements to the presentation of compensation information are required.

Findings

The OEB finds that the correlation between total compensation and FTEs required further elaboration by Hydro One. According to Tables 15 and 16, the increase in total compensation in 2020 versus 2019 is 8.2% while the increase in FTEs is 4.9%. According to Hydro One, a significant portion of the compensation cost (74%) is attributed to capital work and the rest (26%) to OM&A. The breakdown of FTEs between capital and OM&A was not provided. There could be a number of reasons that the increase in compensation cost is higher than the increase in FTEs, including the use of overtime, etc. In order for the OEB to better assess the relationship between changes in compensation and FTEs, the OEB directs Hydro One in future rebasing applications to explicitly provide compensation costs and associated FTEs, broken down between capital and OM&A, and to explain any significant differences between percentage changes in compensation costs and FTEs from year to year.

Market Median Compensation

Background

OEB staff stated that the Mercer calculation is designed to determine what would be Hydro One's total transmission compensation costs if they were at the P50 level, or at the “market median.” The calculation shows the difference between what Hydro One is requesting in this Application and what that market median level would be. Based on the Mercer study, the gap is quantified from 2017 and projected going forward.[116]

OEB staff noted that regarding the five total compensation studies (2008, 2011, 2013, 2016, and 2017) that have been conducted by Mercer, the table below shows that while Hydro One improved in the 2008 to 2017 period by 5%, it worsened by 2% in the more recent 2013 to 2017 period. OEB staff submitted that while the results since 2016 are encouraging, it is not a sufficient period of time in order to establish a trend.

Table 18: Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median

Employee Group	2008 Survey Results	2011 Survey Results	2013 Survey Results	2016 Survey Results	2017 Survey Results	Total Change from 2008 to 2017
Management	-1%	-17%	-1%	2%	1%	2%
Society	5%	5%	9%	11%	12%	7%
PWU	21%	18%	12%	16%	12%	-9%
Overall	17%	13%	10%	14%	12%	-5%

**Management employee group positioning of -17% to market median likely impacted by legislative freeze for non-represented compensation.*

Hydro One stated that it is not possible for it to be at market median, as it does not reflect the reality of its collective bargaining process.[117] Hydro One indicated that it is over 90% unionized. Hydro One noted that collective agreements are currently in place,

[116] Oral Hearing Transcript, October 29, 2019, pp. 55-57
[117] Oral Hearing Transcript, October 29, 2019, pp.57-58

and it has made significant movements to reduce a number of compensation elements, either maintaining them at market, at the Consumer Price Index (CPI), or below. Hydro One acknowledged that it is not easy to make these kinds of changes.

Hydro One stated that it has been taking reasonable steps and made progress in recent years in reducing and containing its overall compensation costs and bringing them closer to market median, having regard to the realities in which Hydro One operates. Hydro One stated that these realities include:

- its largely unionized workforce and governing collective agreements with which it must comply
- the need to attract and retain an appropriate workforce
- the magnitude of Hydro One's capital work program

Offsetting Reductions Claimed by Hydro One Related to Market Median Amounts

Hydro One noted that it recently made further reductions to the amount of compensation for recovery in the 2020 revenue requirement since the 2017 Mercer study was conducted. These included reductions in pension, OPEB and executive compensation costs. In Hydro One's view, these reductions bring Hydro One's overall compensation costs even closer to market median.

Hydro One confirmed that the impact on the 2020 test year revenue requirement if its compensation were to be brought to market median for its transmission business is $38.6 million, with $10.1 million being the OM&A component of this amount.[118] As described further below, Hydro One is of the view that subsequent reductions of $20.1 million related to capital would need to be taken into account in determining the amount of compensation to be recovered in the 2020 revenue requirement to align with the market median.

Hydro One originally confirmed that $9.6 million of the $10.1 million OM&A component is already reflected in its 2020 test year revenue requirement.[119] This represents an offsetting amount related to pension, OPEB and executive compensation costs. Therefore, Hydro One was of the view that only $0.5 million needed to be subtracted from the requested OM&A related to compensation to align the amount of compensation

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[118] Technical Conference Transcript August 13, 2019, page 40
[119] Technical Conference Transcript August 13, 2019, page 40, 42

to be recovered in the 2020 revenue requirement with Mercer's market median level of compensation.

However, Hydro One filed new information associated with an updated pension valuation on October 17, 2019.[120] Although it appeared in a table provided by Hydro One (which was also included in OEB staff's submission) that $1.2 million needed to be added to its requested compensation, Hydro One confirmed in the oral hearing that it is not seeking recovery of this amount of $1.2 million.[121] Despite this confirmation, Hydro One subsequently stated in its reply submission that if the OEB was inclined to make any reductions to its revenue requirement, it is requesting to reduce its 2020 revenue requirement by an amount of $0.5 million above market median, which is the net of being $1.7 million over on capital and $1.2 million under on OM&A. This $1.7 million amount is described below.

Regarding the capital component, Hydro One originally provided a breakdown of the $28.5 million capital amount impacting the 2020 test year revenue requirement to bring the compensation to market median.[122] Hydro One indicated that only a $24.3 million reduction to the capital related to compensation was required. Hydro One indicated that other net reductions of $4.2 million related to pension, OPEB, and executive compensation costs were already incorporated into its requested 2020 revenue requirement.[123]

However, as noted above, Hydro One filed new information associated with an updated pension valuation. Hydro One confirmed that, based on the new information, there is an amount of $20.1 million of capital-related above-median compensation (not $24.3 million).[124] The breakdown of this amount was provided by Hydro One in a table (which was also included in OEB staff's submission). Hydro One indicated that other net reductions of $8.4 million related to pension, OPEB, and executive compensation costs were already incorporated into its requested 2020 revenue requirement.[125]

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[120] Exhibit JT-2.31, Attachment 1, October 17, 2019
[121] Oral Hearing Transcript October 28, 2019, pp.152 & 153
[122] Undertaking – JT 2.9
[123] The $4.2 million amount is the difference between the $28.5 million and $24.3 million shown in Undertaking JT 2.9.
[124] Oral Hearing Transcript October 25, 2019, page 155; Undertaking JT 2.9 revised October 17, 2019
[125] The $8.4 million amount is the difference between the $28.5 million and $20.1 million shown in Undertaking JT 2.9 revised October 17, 2019

OEB staff noted that it is not clear whether Hydro One has aligned the amount of compensation to be recovered in the 2020 revenue requirement with Mercer's market median level of compensation.[126] OEB staff further noted that the alignment of the compensation to the market median was an adjustment required by the OEB in the Hydro One distribution decision and order.[127]

OEB staff accepted Hydro One's position that it does not need to add any amounts to its requested OM&A related to compensation to bring it to the market median amount. OEB staff also submitted that the $20.1 million capital amount translates to a $1.7 million reduction to Hydro One's proposed 2020 revenue requirement.[128] OEB staff invited Hydro One to provide the actual revenue requirement impact amount in its reply submission, if different from $1.7 million. Hydro One did not provide a different amount in its reply submission.

However, given Hydro One's above noted position on the adjustments required to bring its compensation to a market median level, OEB staff submitted that Hydro One may need to further reduce the amount of compensation to be recovered in the 2020 revenue requirement for the following reasons:

1. Hydro One is not making sufficient advances in reducing its compensation to market levels, as Hydro One's position relative to market worsened by 2% in the 2013 to 2017 period, as shown in the above "Table 18: Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median."

2. The level of FTEs assumed in the market median compensation calculation may be overstated. With higher assumed FTEs, the market median compensation would be inflated.[129]

3. Hydro One indicated that its market median calculations factored in higher than typical compensation levels for management, as well as reflecting an increased

[126] OEB Staff Submission, December 11, 2019, page 105
[127] EB-2017-0049 March 7, 2019, page 3
[128] OEB Staff Submission, December 11, 2019, page 107 & 108 show the calculations of the $1.7 million
[129] Undertaking – JT 2.15 Hydro One indicated that the market median calculation is based on the differential between the average salary and the market median rate for the corresponding level, multiplied by the number of incumbents in the relevant level based on the FTE forecast found in the Compensation Spreadsheet.

compensation rate of CPI plus 0.6%, which is higher than inflation of approximately 2.0%.

SEC submitted that with respect to the capitalized portion of compensation, the OEB should not simply reduce the overall capital expenditure envelope as it has in past decisions. SEC argued that all that ends up happening is that Hydro One defers capital projects to account for the reduction in compensation funding provided to it.

SEC submitted that the OEB should, after making any other reductions to its capital plan, re-calculate the total cost of the premium based on the new approved capital plan, and then make the compensation-related reduction while holding Hydro One to achieve the approved capital plan. SEC was of the view that this would be an attempt to ensure that the cost of the premium is paid by the shareholder, not Hydro One's ratepayers through deferred capital work.

SEC argued that based on Hydro One's estimate of the difference between its proposed compensation costs and the market median, the OEB should make reductions of $10.1 million to the 2020 OM&A, and $28.5 million in annual capital costs for each of 2020 to 2022. SEC indicated that a reduction on this basis is consistent with what the OEB has said in an OPG proceeding regarding its role as the market proxy in a monopoly situation.

SEC noted that regarding the reductions required to meet the Mercer market median, Hydro One is of the view that there are several offsetting reductions that should be made consistent with the OEB's decision in the previous distribution proceeding.

SEC argued that taking a closer look at these adjustments demonstrates that they are on an entirely different basis than the amount calculated by the Mercer study. SEC noted that in some cases they are not true reductions in the sense that the amounts were already protected by a variance account. SEC submitted, with one limited exception, they should not be considered as "offsets" to any reduction the OEB may make regarding Hydro One's above median compensation levels. SEC argued that the only adjustments that are appropriate are those that ensure that there is no double counting. SEC further elaborated in its submission regarding the pension & OPEB amounts which, in SEC's view, are not true offsetting reductions.

SEC submitted that the OEB should consider modifying its approach to more appropriately address a long-standing issue with Hydro One. SEC argued that the OEB should require Hydro One to do the same amount of capital and OM&A work that it approves, notwithstanding the reductions in compensation it may make. SEC submitted that this would help ensure Hydro One's shareholders, not ratepayers, pay the market premium. SEC noted that as Hydro One forecasts specific capital assets it will replace or construct, as opposed to OM&A, it may make sense to apply this expectation to only the approved capital budget.

SEC submitted that the OEB can accomplish this by requiring Hydro One to recalculate the difference between its actual compensation levels and the Mercer market median, at the draft rate order stage, based on its revised work program. SEC argued that this would ensure there is no double counting, as some of the total above-market compensation amount is reflective of the number of FTEs that Hydro One has forecast to deliver its proposed capital and OM&A plan.

SEC also submitted that the OEB should require Hydro One to complete an updated compensation benchmarking study, using the same Mercer methodology, for its 2023-2027 consolidated transmission and distribution application.

CME argued that the offsetting adjustments claimed by Hydro One are not proper as they do not have an impact on the above market median calculation made by Mercer. CME noted that the challenges with removing the reductions from the Mercer calculations are dealt with in more detail in SEC's submissions, which CME agrees with. In addition to submitting that there should be a reduction to Hydro One's compensation costs for the full amount that it remains above market median, CME stated that additional reductions should be ordered to address the following three aspects of Hydro One's compensation:

1. Generous incentive packages for managers that are tied to profits to Hydro One

2. Increasing overtime pay which is not benchmarked

3. Shareholder grants that are a benefit to Hydro One employees at no cost to the corporation

CCC, BOMA, and VECC also advocated for reductions in compensation related to market median amounts.

VECC stated that Hydro One's compensation costs are inordinately high and that more should be done to control both the number of FTEs and compensation per FTE.

Energy Probe proposed a $2.3 million reduction in management unrepresented employee compensation over 2021 and 2022.[130] Energy Probe also noted that ratepayers should not pay for increases in compensation costs above the CPI *[sic[131]]* inflation factor in 2020-2022.

PWU noted that OEB staff proposed that the revenue requirement should be reduced by $1.7 million to reflect the impact of capital-related compensation – being $24.3 million above the Mercer median.[132,] PWU stated that there is no proposed reduction in OM&A because identified compensation impacts, including pension and OPEB reductions, have in fact reduced OM&A compensation to $1.2 million below the market median. PWU submitted that any reduction made to the revenue requirement as a result of higher than median compensation for capital-related costs should be offset by lower than median compensation costs for OM&A.

PWU also stated that the PWU and SUP represented employees received lump sum payments and share grants in the 2015 collective bargaining agreements along with low base wage growth, higher employee pension contributions, and modified pension determinants. PWU submitted that compensation control measures and studies implemented since the collective bargaining agreements should be considered in determining the appropriateness of proposed compensation costs in the test period. PWU provided calculations that show since 2015, compensation per FTE has increased at a rate materially lower than inflation.

SUP submitted that the compensation related costs put forward by Hydro One are appropriate and justified. SUP provided calculations to demonstrate that lower share grant costs would materially reduce the adjusted Mercer market median impacts in 2020. SUP submitted that Hydro One compensation costs are approaching the Mercer study market median costs in 2020 for a variety of reasons.

Hydro One noted that OEB staff and a number of intervenors took issue with the fact that Hydro One's overall compensation costs remain somewhat above market median and suggested that further reductions should be made. In Hydro One's view, there is no

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[130] Energy Probe submission, December 17, 2019, page 27 – stated that it proposes a $2.3 million reduction in management unrepresented employee compensation over 2021 and 2022.
[131] Energy Probe referenced "PCI" instead of "CPI"
[132] Page 108 of OEB staff's submission references $20.1 million and not $24.3 million

proper basis to do so, and it is contrary to the OEB's approach in the Hydro One distribution decision and order.[133]

Hydro One stated that some parties try to focus only on the benchmarking study results for 2013 compared to 2017 and suggest the Mercer study shows that Hydro One's overall position relative to market worsened by 2% in that period. However, in Hydro One's view that is a misleading or unfair suggestion, as the longer-term trends should be considered. Hydro One stated that over the 2008 to 2017 period, Hydro One's trend line goes downward toward the market median, despite the fact that there is a "blip up" in 2016. Hydro One also argued that the 2017 Mercer study also included additional forms of compensation (e.g., share grants and lump sum payments) compared to prior studies, but that Hydro One's compensation was still trending lower.

Hydro One took issue with SEC's submission that its pension and OPEB reductions "have nothing to do with the pension and OPEB amounts that are part of the Mercer calculation." Hydro One stated that SEC ignores the fact that the Mercer study uses a specific set of actuarial assumptions in a calculation to determine the "relative value" of retirement and post retirement plans. Hydro One noted that the assumptions and methodology are set at the time the study is completed and are not updated post-study.

Hydro One also took issue with SEC's suggestion that, in the event the OEB makes a reduction to compensation costs, it should go further and make an order specifying the capital and OM&A work Hydro One is still required to accomplish over the 2020-2022 period. Hydro One stated that this suggested approach is inconsistent with the OEB's prior decisions and approach, as well as the *Handbook for Utility Rate Applications.*

Hydro One concluded that no reductions to compensation costs in revenue requirement are warranted. Alternatively, Hydro One stated that if the OEB were inclined to make any such reductions, it should only be the overall (net) amount of $0.5 million, as described earlier in this section.

Transition to the Market Median

Hydro One noted that the 2017 Mercer study confirmed that its management and non-represented total compensation is positioned at only 1% above market median. Hydro One also stated that in respect of represented staff, while it remains above market

[133] EB-2017-0049 Decision and Order, p. 111

median, the utility has made progress in this regard and must work within the constraints of the existing bargaining process and collective agreements. Hydro One also described several initiatives that it has taken in the past, and is continuing going forward, to make further progress in bringing its compensation costs to market median.[134]

OEB staff and CME submitted that Hydro One should file a plan for its next application (2023 to 2027 rates), for transitioning to market median by the end of the next Custom IR term. CCC made a similar suggestion.

Hydro One disagreed with this suggestion, primarily focusing on the premise that unionized compensation costs will be subject to further cycles of negotiation between now and 2023 (and thereafter) and those cycles are typically for a negotiated period of two to five years. Hydro One noted that this would hinder its ability to bargain effectively and in good faith and would disclose the bargaining strategy for future cycles. Hydro One also argued that compensation costs for the 2023-2027 period cannot be determined at this stage, nor should the OEB make any order now in respect of that future plan period.

Other Issues with Benchmarking Studies

Overtime

SEC stated and CME noted that the Mercer study likely understates Hydro One's compensation levels compared to the market, as it excludes overtime which, in SEC's view, is a significant component of compensation. SEC further stated and CME also noted that as part of its most recent collective bargaining agreement with the PWU, Hydro One changed its overtime policy. SEC noted that each hour worked in excess of a regular work week is now paid at double the base rate, as compared to previously, where a threshold number of hours were paid at one and a half times the base pay.

[134] Reply Submission, January 17, 2020, page 196 & 197. Hydro One stated that these initiatives are:
- Benchmarking the compensation levels relative to the external market to assess competitiveness
- Continuing to engage with union counterparts on a variety of committees and initiatives to assist in identifying opportunities to improve and modernize the compensation programs
- Engaging with third party independent experts to provide guidance on industry best practices and compensation

CME noted that the amount of overtime pay provided to SUP, PWU represented employees and temporary employees, and allocated to transmission, has increased significantly since 2017 and remains high throughout the 2020-2022 period. CME provided several tables in its submission which demonstrated, in CME's view, that Hydro One is paying overtime and budgeting for overtime at a growing and significant rate.

CME submitted that the amount of overtime paid by Hydro One has continued to increase without adequate explanation and without added value to ratepayers. CME argued that Hydro One has not made efforts to review its overtime policies and practices to ensure that they align with the market or explain the dramatic increase in overtime spend.

In its reply submission, Hydro One argued that it is incorrect to suggest that the Mercer study understates Hydro One's compensation levels compared to the market because it leaves out overtime compensation. Hydro One submitted that this suggestion ignores the evidence of Mercer on this point. Hydro One highlighted that during the oral hearing, Mr. Morris of Mercer explained that benchmarking overtime is not a common approach. Hydro One noted that none of the compensation surveys that are completed by major consulting firms in Canada include overtime as a measure. Hydro One also stated that it is very difficult to compare overtime across employers as organizations track and use overtime differently. Hydro One also noted that in light of the foregoing challenges, typical compensation studies look at actual compensation for individuals.

Hydro One also stated that some intervenors submitted that its overtime costs continued to increase without adequate explanation and without added value to ratepayers. Hydro One submitted that this is incorrect. Hydro One explained that overtime varies quite significantly from year to year due to storm restoration efforts, which are hard to forecast. Hydro One concluded that overtime is an element of work force flexibility that is needed to leverage the completion of planned work.

Benchmarked Positions and Peer Groups

SEC observed that the benefit of the Mercer study is that it allows the OEB and Hydro One to monitor progress on roughly the same basis over time. However, SEC took the view that there was a flaw in the study which is that it compares all the benchmarked staff positions to only similar positions at other utility sector companies. SEC stated that while this makes sense for certain positions, many other firms that Hydro One competes with for talent are not restricted to this narrow type of business. SEC argued that utility companies are likely to be highly unionized and better paying compared to the broader market.

SEC noted that this is demonstrated by the other compensation benchmarking studies that Hydro One has undertaken. SEC noted that two studies were undertaken by Willis Towers Watson that benchmarked total cash compensation for the PWU and SUP represented employees.

VECC submitted that the Mercer market sample reads as a “who’s who” of regulated utilities, rendering the exercise entirely circular in nature. In this context, VECC noted that the premise of these studies is that Hydro One must pay Toronto Hydro level wages or lose employees in some notional competition for employees. VECC submitted that this circularity pushes up the wages of these companies. VECC and BOMA noted that Hydro One offered no evidence that there is a shortage of highly skilled competent people willing to work at the salary levels offered by Hydro One.

VECC was of the view that the OEB should seek to better understand the gap between the compensation of the utilities it regulates and the average compensation of the customers who pay their bills. VECC submitted that this is an issue that should be considered by the OEB when it considers what a reasonable compensation amount is. For example, VECC submitted that the OEB might want to consider whether it will allow the total compensation bill to exceed the average wage increase in the province.

VECC noted that the OEB could consider requiring Hydro One, in its next rebasing application, to file evidence helping it to understand the trend in Ontario wage rates. VECC submitted that such an exercise would at least provide the OEB and Hydro One with a perspective on the compensation costs that is different than the usual Mercer type of circular study.

SUP submitted that in order to provide a reasonable market median of compensation for comparative purposes, the Mercer study results must be adjusted to take into account cost of living differences between the peer group companies, including the different provincial sales tax levels. SUP submitted that Hydro One should include on a trial basis in its next compensation benchmarking study a provincial cost of living factor to normalize compensation levels across the peer group. SUP argued that if the cost of living normalization factor proves to be immaterial, it should be dropped from such compensation benchmarking studies in future.

Hydro One noted that some intervenors' viewpoints were that the Mercer study compares the benchmarked positions to only similar positions at the other utility sector companies, which are highly unionized and better paying compared to the broader market. Hydro One submitted that this assertion ignores the fact that the Mercer study benchmarking is largely focused on utility-specific trades and technical roles.

Burdens

Hydro One explained that the increase in total burdens for both its transmission and distribution businesses is mainly due to higher FTE levels and base escalation assumptions which subsequently result in increases in the various components that make up the labour burdens.[135] Hydro One indicated that it incurs additional burdens other than pensions and OPEBs.[136]

Hydro One stated that the total burden amounts included in the Compensation Spreadsheet are calculated by applying an assumed burden percentage to base pay.[137] Hydro One noted that the assumed burden is based on Hydro One's estimate of its FTE requirements to execute the TSP included in the Application. However, Hydro One noted that the pension and OPEB burden amounts included in the Compensation Spreadsheet are derived differently, as follows:

- 2014 to 2018 are based on actuals
- 2019 to 2022 are based on an actuarial valuation dated effective December 31, 2017 which is based on historical FTE numbers and does not consider the same assumptions for future FTE growth as the total burden amounts

OEB staff submitted that there are differences in Hydro One's proposed burden amounts that have not been adequately explained.

OEB staff submitted that the "unexplained differences" in a table provided in its submission show approximately how much the total transmission burdens have been uplifted. The "unexplained differences" noted by OEB staff varied from approximately

[135] Undertaking – JT 2.11
[136] Exhibit I, Tab 08, Schedule 22 (PWU Interrogatory #22); These additional burdens include the Canada Pension Plan, employment insurance, employee health tax, Workplace Safety and Insurance Board, group life insurance, and health and dental.
[137] Undertaking J6.1

$5.9 million in 2018 to $31.8 million in 2022. OEB staff noted that the amounts have been uplifted by updating the transmission pension and OPEB amounts shown in a version of the Compensation Spreadsheet to reflect the forecasted FTEs in the Application, versus the historical FTEs used in the actuarial valuation. As a result, OEB staff submitted that the burden amounts that flow into capital and OM&A amounts reflected in the analysis provided for 2019 to 2022 (including the 2020 test year revenue requirement) cannot be fully supported by items such as Hydro One's actuarial valuation.

OEB staff submitted that these unexplained differences in burdens, with the unexplained amounts representing significant increases, provide further support for OEB staff's proposed reduction in 2020 total OM&A in the absence of a clearer explanation for this differential by Hydro One than that provided in its undertaking responding to OEB staff's concerns.[138]

Hydro One submitted that the analysis on which OEB staff relied is flawed and misleading as it does not take into account increasing FTE levels necessary to support the growing transmission work program. Hydro One submitted that a compound annual growth rate per FTE is the more appropriate way to review compensation over the Application term, and a FTE-based analysis was completed in an undertaking.[139]

Contract Staff

Hydro One stated that it has two types of contractors.[140] Hydro One noted that going forward with the growth in the transmission capital portfolio, it intends to have an increased reliance on contractors to perform both the engineering and construction elements of its work program.[141] Hydro One stated that historically approximately 10% of its power system work has been contracted out, and moving forward this is going to trend up to about 30% so that it can build both scale and capacity with the flexible work force.

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[138] OEB Staff Submission, December 11, 2019, page 111; Undertaking J6.1

[139] Undertaking, J6.1

[140] Oral Hearing Transcript October 28, 2019, page 31; The two types of contractors are:

1. Professional services-type contractors which are used for its IT operations, as well as for project management type functions that are project-based
2. Contractors used for contracting out pieces of its operations (e.g. cable locates, capital programs) to scale up

[141] Oral Hearing Transcript October 21, 2019, pp. 157 & 158

Hydro One stated that in its comparisons, the costs of using internal or external workforce are very similar, the predominant reason being that the labour rates in the construction trades within Ontario are set at the provincial level, and whether a construction trades person works for Hydro One or one of the multitude of contractors, the actual labour rates are identical.[142]

OEB staff submitted that its proposed reduction in 2020 OM&A is supported by the lack of clarity provided by Hydro One with respect to its contractor costs. OEB staff stated that Hydro One could not provide detail of the amounts rolled into the 2020 revenue requirement related to contract staff. OEB staff also stated that Hydro One was not able to quantify the impact on the 2020 revenue requirement, if amounts paid to contract staff were instead paid to employees of Hydro One and rolled into the FTE count.

Hydro One disagreed with OEB staff and stated that OEB staff's submission ignores the fact that compensation costs for a contractor are not comparable to those of a regular FTE. Hydro One also noted that using third-party contractors is a cost-effective and flexible tool that Hydro One uses to build scale and help deliver on a growing capital work program.

Short Term Incentive Plan and Long Term Incentive Plan

CME and Energy Probe noted that changes in compensation for the non-represented group are within Hydro One's control, rather than limited by collective bargaining agreements. CME indicated that spending on this employee group has not been curtailed or adjusted downwards. CME argued that, in fact, Hydro One has "refreshed" the short term and long term incentive plans (STIP and LTIP) for this group since Hydro One became a public company, which has resulted in increased compensation to these managerial employees.

CME stated that the STIP in particular is directly contributing to Hydro One's above-market positioning as stated in the Mercer study. CME provided a summary of the STIP and LTIP in its submission, including CME's related concerns. CME's position is that the STIP and LTIP are expensive programs that are contributing to Hydro One's above-market positioning and which have limited benefit to ratepayers.

[142] Oral Hearing Transcript October 22, 2019, page 80

CME also noted an excerpt from the prior Hydro One transmission proceeding decision – specifically, that the OEB shared concerns raised by intervenors that “costs of incentive plans that are primarily designed to deliver value to the shareholder should not be recoverable from utility ratepayers.”

Energy Probe submitted that the OEB should not allow recovery in rates of incentive pay related to reliability until a SAIDI threshold equal to the 2014-2018 average performance 54.85 minutes is reduced with a target 22-minute reduction by 2024. Energy Probe submitted that incentive pay should only be paid to senior management when the baseline historic performance standards are exceeded.

BOMA noted that the corporate (team) scorecard is structured to ensure that the overall corporate results determine 80% of the short-term incentive bonuses for all management employees. BOMA stated that the largest determinant of the cash bonus short-term incentive pool is 30% arising from the net income to common shareholders, which is higher than, for example, customer satisfaction.

BOMA noted that the long term incentive plan, available only to senior management, director level and above, is based on only two criteria, earnings per share, and productivity increases. BOMA took issue with Hydro One's proposed 50-50 earnings sharing.

Hydro One stated that there is no basis for the suggestion that its STIP and LTIP programs are too expensive and have limited benefit to ratepayers. Hydro One submitted that this suggestion ignores its evidence.

Summary of Proposed Reductions Related to the Market Median

CME, SEC, VECC, and OEB staff proposed different levels of reductions in OM&A and capital associated with compensation levels in relation to the market median, as summarized in the following table. Other intervenors supported a reduction of the 2020 revenue requirement to bring Hydro One’s requested compensation costs to the market median, but did not specify amounts.

Table 19: Proposed Reductions to Compensation Related to Market Median (millions)

	CME	SEC	VECC	OEB Staff
Compensation Allocated to OM&A	$10.1[143]	$10.1	$10.0	
Compensation Allocated to Capital	$28.5	$28.5		$20.1
Total	**$38.6**	**$38.6**	**$10.0**	**$20.1**

A high level summary of the above table is provided below:

- CME submitted that the offsetting adjustments claimed by Hydro One are not proper as they do not have an impact on the above market median calculation made by Mercer.

- SEC argued that taking a closer look at these offsetting adjustments demonstrates that they are on an entirely different basis than the amount calculated by the Mercer study and in some cases are not true reductions.

- VECC submitted that the OEB should reduce the 2020 revenue requirement by $10 million in OM&A to recognize Hydro One's continued above market compensation.

- OEB staff submitted that a $20.1 million reduction in capital was required as this amount related to above-median compensation.

Although not advocating for a reduction in the 2020 revenue requirement, SUP provided calculations to demonstrate that lower share grant costs would materially reduce the adjusted Mercer market median impacts in 2020.

[143] CME Submission, December 16, 2019, page 50 - stated that $38,466,291 should be allocated to capital. However, the OEB interprets CME's submission as the total amount of 2020 compensation allocated to transmission being $38,566,291 (and not $38,466,291) with $10.1 million to OM&A and the balance ($28.5 million) to capital.

Findings

The OEB continues to be concerned about Hydro One's total compensation costs being higher than comparable companies. As mentioned in the OEB's decision and order for Hydro One's distribution business,[144] this concern has been expressed in almost every OEB decision involving both the distribution and transmission costs for the last ten years.

The OEB finds no compelling reason for the ratepayers to continue to be burdened with this unreasonable compensation level. Although the relationship of overall Hydro One transmission compensation costs relative to market median did slightly improve in 2011 and 2013 relative to 2008, it did worsen again in 2016 and 2017.

The OEB also finds that there is no clear evidence as to how, and by how much, Hydro One's so called "offsetting" reductions, in both OM&A and capital, would impact the results of the Mercer study since the 2017 Mercer study itself was not updated to reflect these "offsetting" reductions. Using the last 2017 Mercer study results and projected forward, the evidence shows that, in order to bring Hydro One's total compensation costs to market median, Hydro One's 2020 OM&A budget would have to be reduced by $10.1 million and its capital budget reduced by $28.5 million in each year from 2020 to 2022. The OEB agrees with some of the parties that these "offsetting" reductions may not be true reductions for benchmarking purposes, and may have been determined on an entirely different basis than the amounts calculated in the Mercer study. The OEB, therefore, finds that the impact of these reductions on the Mercer study results has not been explicitly assessed using the Mercer study methodology.

The OEB, therefore, finds that Hydro One's proposed 2020 OM&A budget shall be reduced by the full $10.1 million without taking into account any suggested "offsetting" reductions.

The OEB directs Hydro One to complete an updated benchmarking study using the same Mercer methodology for its upcoming combined rebasing application. To the extent possible, this benchmarking study should address the impact of items like overtime and utilization of contract staff on the results and should include all forms of compensation such as share grants and lump sum payments. It would also be beneficial if the study included comparison with non-utility companies which employ trades and

[144] EB-2017-0049, March 7, 2019, p. 3

technical unionized staff. The study should also compare management group incentive programs (STIP and LTIP) to similar programs in comparator companies.

Hydro One shall include a plan with its next rebasing application to bring its compensation levels in line with market median.

The OEB expects Hydro One to demonstrate, in its next rebasing application, that it has delivered its 2020 OM&A work program and that it has not accommodated the compensation reduction by reducing its planned work programs.

Pensions and Other Post-Employment Benefit Costs

Recovery Methodology

The OEB has established the use of the accrual accounting method as the default method on which to set rates for pension and other post-employment benefits (OPEB) amounts in cost-based applications.[145] For utilities that propose to set rates using a method other than accrual, the OEB's policy requires that such a proposal be supported with evidence that gives consideration to factors such as providing value to customers, fairness, intergenerational equity, and other principles and practices.

As part of the current Application, Hydro One has proposed to recover its test period OPEB costs on an accrual accounting basis and its pension costs on a cash basis. This is consistent with the recovery methodologies that were approved in Hydro One's recent distribution rates proceeding.[146] Hydro One provided evidence with respect to its proposed recovery methodologies that addressed the OEB's policy.

OEB staff submitted that the use of the accrual method by Hydro One to recover its OPEB costs is appropriate as it is consistent with the default methodology prescribed in the OEB's policy. OEB staff further noted that Hydro One has provided the evidence required by the OEB policy in support of its continued use of the cash method as the basis to recover its pension costs. OEB staff submitted that the continued use of the cash method by Hydro One to recover its pension costs is justified because it has

[145] EB-2015-0040, *Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs*, September 14, 2017
[146] EB-2017-0049

historically recovered its pension costs on a cash basis and its ratepayers have historically been better-off under the cash method.

Amounts Proposed for Recovery in the Test Period

Hydro One requested recovery of the following amounts in the test period pertaining to its pension and OPEB costs:

Table 20: Proposed Pension and OPEBs Recoveries (millions)

Test Year 2020	Pension	OPEBs	Total
OM&A	$9.3	$16	$25.3
Capital	$22.8	$18	$40.8
Deferral Account		$21	$21.0
Total	$32.1	$55	$87.1

With respect to Hydro One's OPEB costs, they are supported by a December 13, 2017 projection report that was prepared by Willis Towers Watson and provided the projected benefit cost for the period 2018 – 2023. The report was prepared in accordance with US GAAP (i.e., prepared under the accrual accounting methodology). Hydro One has reconciled the amounts presented in the Willis Towers Watson report to the total amount for OPEBs that it is seeking to recover in 2020.[147]

On October 17, 2019, Hydro One filed a pension valuation, updating the December 31, 2018 pension valuation, which underpins the pension costs it is seeking to recover for the test period.[148] OEB staff noted that the December 31, 2018 pension valuation also represented the first valuation that Hydro One had filed with the Financial Services Regulatory Authority of Ontario under new funding rules. OEB staff noted that Hydro One's actuary has confirmed that the utility is legally obligated under the Pension Benefits Act (PBA) to make pension contributions in 2019, 2020, and 2021.[149]

[147] Undertaking JT-2.3
[148] JT-2.31, Attachment 1
[149] Exhibit JT-2.31, Attachment 1, p. 15 of 59, it indicates that Hydro One is required to make pension contributions of $66.5 million, $66.0 million, and $65.3 million in 2019, 2020, and 2021 respectively.

OEB staff acknowledged that the amounts Hydro One has proposed to recover for pension and OPEB costs for 2020 are supported by valuation reports and projections that have been prepared by a licensed actuary in accordance with accepted actuarial practice in Canada and other legislation (i.e., PBA). On this basis, OEB staff accepted that the 2020 amounts for both pension and OPEB costs were reasonable.

Energy Probe submitted that 50% of the employer pension contribution premium not be recovered in rates (50% of $6.8 million/year, or $10 million over three years). Energy Probe and SEC also took issue with Hydro One's pace of addressing more equitable pension contribution sharing.

SUP stated that the increased employee pension contributions are the result of negotiated lump sum payments followed by share grants with SUP and PWU. SUP stated that Hydro One confirmed that the increase in employee pension contributions more than offset the costs of the share grants to both SUP and PWU.

Hydro One stated that over the six-year period from 2013 to present, employee contributions have increased from 20% to over 40% as a whole. Hydro One noted that it has made significant strides towards the ultimate goal of 50-50 cost sharing, and this has resulted in a meaningful reduction to costs borne by customers.

Hydro One submitted that the OEB should allow recovery of these legally required pension costs. They have historically been accepted by the OEB as prudently incurred costs for the provision of the rate regulated services Hydro One provides to its customers.

Findings

The OEB finds that the pension and OPEB amounts requested by Hydro One for 2020 are supported by sufficient evidence and will allow the recovery of these amounts. The recovery mechanism for OPEBs is addressed under Issue 11. Hydro One's use of the cash method for pensions and the accrual method for OPEBs for cost recovery is a continuation of the approach approved in Hydro One's last transmission proceeding, and is consistent with the approach approved for Hydro One's distribution business. The OEB's policy on pensions noted that for stability and predictability, maintaining a consistent method used to determine recovery over time may be one reason for not adopting the accrual method for rate setting.

3.7 RATE BASE & COST OF CAPITAL

3.7.1 Rate Base and Working Capital Allowance (Issue 18)

Issue 18. Are the amounts proposed for rate base (including the working capital allowance amounts) reasonable?

Hydro One noted that it determines transmission rate base based on the net book value of fixed assets which are forecast on a mid-year average basis, plus a working capital allowance. Net fixed assets are calculated as gross plant in service, including the forecasted in-service additions for a year, minus accumulated depreciation. Hydro One submitted that these amounts had been correctly determined and are appropriate.

Hydro One further submitted that its depreciation expense is appropriate for the reasons set out under Issue 16 and the planned in-service additions are appropriately forecast based on its proposed capital expenditures, which as explained under Issue 9, were derived through a robust investment planning process that underpins the TSP.

Hydro One argued that its working capital allowance amounts are also appropriate as the underlying methodology is supported by Navigant's updated lead-lag study, which examined the working capital requirements of Hydro One's transmission business.

Hydro One added that in accordance with the OEB's direction in the previous cost of service transmission decision,[150] it has provided a comparison with the prior study to show material changes in study results, which are attributable to an overall increase in revenue lag.

Hydro One concluded that for the reasons discussed above and in the Application, its proposed rate base amounts are appropriate and should be used to determine revenue requirement for the 2020-2022 test period.

No parties opposed Hydro One's rate base proposals, subject to adjustments related to their recommended changes to Hydro One's proposals in related areas of the Application. LPMA submitted that the OEB should direct Hydro One to update the working capital allowance to reflect its decision as part of the draft rate order.

[150] EB-2016-0160

Hydro One submitted that its proposed rate base amounts (including the working capital allowance amounts) are appropriate and should be used to determine revenue requirement for the 2020-2022 test period.

Findings

The OEB finds that the proposed rate base amounts (including the working capital allowance amounts) are appropriate and should be used to determine the revenue requirement for the 2020-2022 test period, subject to adjustments related to OEB's findings in related areas of this Application.

3.7.2 Cost of Capital and Capital Structure (Issue 19)

Issue 19. Is the proposed cost of capital (interest on debt, return on equity) and capital structure reasonable?

Hydro One stated that its deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base. Hydro One further stated that this capital structure is consistent with the approved structure in its last transmission rebasing revenue requirement proceeding, as well as the capital structure approved in the most recent distribution rates proceeding and OEB policy. Hydro One noted that the 60% debt component consists of 56% long-term debt and 4% deemed short-term debt.

Hydro One stated that it had calculated its long-term debt rate to be 4.33% for 2020 to 2022 based on the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2020. Hydro One added that the 2020 revenue requirement had been reduced due to 2019 actual debt issuances and the updated cost of capital parameters issued by the OEB in October 2019.

Hydro One stated that the deemed short-term debt rate of 2.75% was also updated by Hydro One for the 2020 to 2022 test years based on the 2020 deemed short-term debt rate issued by the OEB in October 2019.

Hydro One further stated that an ROE of 8.52% had been used for the equity component of the cost of capital and that this had also been based on the OEB's most recent cost of capital parameters.[151]

Hydro One concluded that its proposed costs of capital and capital structure are reasonable and consistent with what had been approved in previous OEB decisions and, as such, should be accepted by the OEB.

OEB staff submitted that Hydro One's proposed capital structure and cost of capital are in accordance with OEB policy and with the OEB's most recent transmission and distribution decisions for Hydro One, and accordingly should be accepted by the OEB.

No party opposed Hydro One's proposed capital structure and cost of capital. LPMA noted that during the proceeding, Hydro One had updated its long-term debt rate from 4.57% to 4.33%. LPMA stated that while it expected this calculation to be accurate it was not aware of where it had been placed on the record and submitted that the OEB should direct Hydro One to file the relevant information to show the 4.33% long-term debt rate for 2020 in the draft rate order. Energy Probe expressed a related concern, arguing that with the US debt market moving lower, it is not sure that Hydro One has reflected that post-2020 debt cost levels for new issues may be lower.

Hydro One submitted that the OEB did not need to address either of these concerns. With respect to Energy Probe's uncertainty as to whether or not Hydro One has reflected that post-2020 debt cost levels for new issues may be lower, Hydro One stated that its cost of long-term debt for 2021 and 2022 is not relevant for determining 2020 rates and argued that to update the cost of capital parameters during the Custom IR term would be contrary to the OEB *Rate Handbook.*

Hydro One stated that LPMA's concern that it expected Hydro One's update of its calculated long-term debt rate to be accurate, but was not aware of where it had been placed on the record, was also unfounded. Hydro One submitted that this was because it intended to file updated schedules in its draft rate order consistent with its typical approach to implementing OEB decisions with supporting schedules, including debt schedules and, as such, express OEB direction to this effect is not necessary. Hydro One also provided additional details as to how the 4.33% rate, which LPMA had questioned, was calculated.

[151] Ontario Energy Board "2020 Cost of Capital Parameters," October 31, 2019.

Findings

The OEB approves Hydro One's proposed capital structure and cost of capital. The OEB concludes that they have been calculated in accordance with both the OEB's policy and the most recent decisions for Hydro One's transmission and distribution businesses. This structure and the parameters will remain in place for the 2020 to 2022 term, consistent with the expectations set out in the OEB's Rate Handbook. The OEB expects Hydro One to file supporting schedules, including debt schedules, as part of the draft revenue requirement/charge determinant order process

3.8 LOAD & REVENUE FORECAST

3.8.1 Load Forecast (Issue 20)

Issue 20. Is the load forecast methodology (including consideration of CDM impacts) and the resulting load forecast appropriate?

Hydro One stated that its load forecasting methodology and the resulting load forecast are appropriate. Hydro One further stated that the load forecasting methodology it had used is consistent with the OEB-approved load forecast methodology that has been used for transmission rates since 2007 and was most recently approved in its 2017-2018 transmission application.[152] Hydro One noted that it uses a number of inputs, such as econometric (top-down) models, end-use (bottom-up) models, customer forecast surveys and hourly load shape analysis to produce the forecast required for its transmission business.

Hydro One's forecast of demand for each of its charge determinants is as follows:

[152] EB-2016-0160.

Table 21: Hydro One's 2017-2022 Load Forecast
(12- Month Average Peak in MW)

	Ontario Demand	Hydro One Rate Categories (Charge Determinants)		
		Network Connection	Line Connection	Transformation Connection
2017	19,696	19,705	19,100	16,306
2018	19,657	19,678	19,137	16,329
2019	19,595	19,614	19,078	16,258
2020	19,586	19,604	19,071	16,252
2021	19,451	19,469	18,941	16,142
2022	19,304	19,322	18,800	16,021

Hydro One is forecasting a 3.9% reduction of 2020 load forecast as compared to the OEB-approved 2018 load forecast. This reduction is composed of a 3.5% reduction to the approved 2018 load forecast due to the expanded Industrial Conservation Initiative (ICI) and a further 0.4% reduction due to forecast slower economic growth and Conservation Demand Management (CDM) initiatives. Hydro One is also forecasting a further reduction of 0.7% and 0.8% for 2021 and 2022 respectively.

OEB staff submitted that the one-time reduction of 3.5% in 2020 compared to the approved 2018 forecast is reasonable based on the expanded ICI program explanation. OEB staff also noted that between 2017 and 2020 there has been a step-wise increase in the load forecast before deducting impacts from embedded generation and CDM. This is an average 315 MW increase each year, which dropped to a 30 MW and 13 MW decrease in 2021 and 2022 respectively. OEB staff further noted that the 2020-2022 economic forecast shows growth, albeit at a slower pace compared to previous years. OEB staff submitted that this continuing growth is inconsistent with the precipitous drop in Hydro One's load forecast before deducting the impacts of embedded generation and CDM in 2021 and 2022.

OEB staff further noted that Hydro One's evidence shows the load impact of CDM has been growing at approximately 300 MW annually from 2017 to 2020 reducing to approximately 100 MW annually from 2021 to 2022.

OEB staff concluded that the reductions of 0.4%, 0.7% and 0.8% in 2020, 2021 and 2022 respectively are not appropriate and should be revised to 0.0% from 2020 to 2022 for the reasons discussed above relating to economic growth and decreasing CDM forecast.

LPMA, supported by CCC, made similar arguments to those in OEB staff’s submission, regarding the proposed reductions of 0.7% and 0.8% for 2021 and 2022. LPMA argued the difference in economic growth between the periods of 2018 through 2020 and 2021 through 2022 is not markedly different and therefore the OEB should approve a change of 0% in the Ontario demand load forecast for both 2021 and 2022.

BOMA argued that Hydro One’s request for a reduction of 3.5% to the 2018 OEB-approved load forecast is unpersuasive and should be denied. BOMA argued there may have been special circumstances in 2018 that may not be repeatable; the 2018 actual load was not normalized; and Hydro One should have produced a new load forecast for 2020-2022 using the normalized 2018 demand as a base.

Hydro One responded by noting that no parties other than OEB staff, LPMA and BOMA made any substantive submissions regarding its proposed load forecast and these submissions are without merit. Hydro One submitted that neither OEB staff nor LPMA has raised concerns with either its load forecasting models or its CDM assumptions, and if these are appropriate then the arguments of OEB staff and LPMA are baseless.

Where OEB staff’s statement about the step-wise increase in the load forecast between 2017 and 2020 followed by the drop in 2021 and 2022 is concerned, Hydro One argued that OEB staff has mischaracterized the load growth pattern. Growth in load between 2017 and 2020 was due to additional load that was added to the forecast produced by the forecasting models to account for specific developments in Leamington and the surrounding area. Hydro One stated that it was this growth that led to the greater growth in the years 2019 and 2020, as compared to 2021 and 2022. Hydro One noted that while the manual adjustment to account for load in Leamington and the surrounding area results in the uneven pattern noted by OEB staff, it also increases the load forecast relative to what was produced by the forecasting models, which helps lower transmission rates to the benefit of customers.

With respect to OEB staff’s statement that the 2020 to 2022 economic forecast shows growth, albeit at a slower pace than previous years, Hydro One argued that this ignores the evidence that there are many factors that can reduce load and offset economic/customer growth, such as natural efficiency improvements by customers, inter-sectorial shifts in load from electricity intensive sectors to less electricity intensive sectors and other factors.

Finally, Hydro One stated that the higher figures in the years 2017 to 2020 include the load impact of the current round of LDC CDM programs designed for the years 2015-2020, but after 2020, the CDM impact declines as new LDC CDM programs had not yet been designed at the time the IESO's Long Term Energy Plan (LTEP) was issued. Hydro One acknowledged that going forward, it will be the IESO that will be designing the next round of CDM programs. The IESO concern with reducing system peak implies that the peak impact of future CDM programs could be greater than what is assumed in the Application. However, Hydro One noted that at the time the forecast for the Application was prepared, the magnitude of CDM programs beyond 2020 was not known and it was reasonable for Hydro One to use the LTEP 2013 figures. Hydro One argued that the net result is that its lower embedded generation and CDM forecast for the 2020 to 2022 period represents a conservative assumption that benefits load customers by contributing to lower rates.

Hydro One had a similar response to the arguments of LPMA.

With respect to BOMA's concern that the 2018 load was not normalized and there may have been special circumstances in 2018, Hydro One first noted that BOMA did not make any suggestions as to the special circumstances it may have been referring to. With respect to BOMA's normalization concerns, Hydro One stated if by normalizing load BOMA means for special weather conditions, this has already been done through weather normalization. Hydro One further stated that if BOMA was referring to non-weather special circumstances, for two consecutive years the impact of the expanded ICI reduced the load and, as such, the reductions had a persistent base and were not due to special circumstances in 2018. Finally, Hydro One stated that BOMA had erred in stating that the forecast base year is 2018 when it was 2017. Hydro One concluded that BOMA's submissions with respect to its load forecast should be ignored.

VECC, supported by Energy Probe, submitted that Hydro One had not used the best available information for preparing its load forecast. The historic CDM values used by Hydro One were values that were provided in the IESO's 2016 Ontario Power Outlook. However, VECC noted that Hydro One had the actual verified results up to 2017 and provided (on a consistent basis) the CDM savings for 2016 to 2017. VECC argued that Hydro One should use the best available information in future applications.

Hydro One argued that VECC had incorrectly assumed it only needs consistent CDM data up to 2017 for preparing its load forecasting models. Hydro One stated that its monthly forecasting model used actual CDM data up to October 2018. As such, Hydro One needs consistent CDM data to add to all the historical years affected by CDM, including 2018, for estimating model parameters and producing an unbiased forecast. Hydro One also noted that having consistent CDM data over the bridge and test years, while not strictly required to produce the load forecast, helps to evaluate the reasonableness of the model results. Hydro One added that it has always used all of the available information for the purposes of preparing its load forecast and it shall continue doing so in the future.

Hydro One concluded that its load forecast methodology, inclusive of the manner in which it has considered CDM impacts, and the resulting load forecast are appropriate and should be accepted by the OEB.

Findings

The OEB accepts Hydro One's load forecast for 2020. The OEB also accepts Hydro One's load forecast for 2021 and 2022 before deducting impacts of embedded generation and CDM. Hydro One has used the same methodology in previous forecasts that were accepted by the OEB. The OEB recognizes that the decline in demand forecast since 2017 is the main contributor to the transmission rate increases. This appears to be largely due to the ICI, which provides a benefit to many customers one megawatt and larger, and the OEB accepts this as reasonable.

The OEB is concerned by the further decrease in demand forecast for 2021 and 2022. The forecast of total Ontario demand before deducting impacts of embedded generation and CDM remains relatively stable (decreasing by only 43 MW or 0.2% from 2020 to 2022). However, when the impacts of embedded generation and CDM are included, the forecast of total demand decreases by 282 MW (1.4%) from 2020 to 2022. This is a period of transition for policies that can affect the amount of CDM and embedded generation going forward making the use of CDM assumptions per the 2013 LTEP less relevant. The OEB concludes that it is prudent to hold the forecast for these items at the 2020 forecast level.

With the impacts of embedded generation and CDM kept at the 2020 level, the resultant forecast of the Ontario demand is as follows:

Table 22: Hydro One's 2020-2022 Ontario Demand

	Ontario Demand (MW)
2020	19,586
2021	19,557
2022	19,544

Hydro One is expected to calculate the charge determinants for the Network Connection, Line Connection and Transformation Connection based on this updated forecast of Ontario demand.

The OEB shares the concern raised by VECC about using forecast CDM values for 2016 and 2017 to adjust historical data. Hydro One is expected to continue to evolve its methodology for adjusting for CDM in its next application.

3.8.2 Other Revenue

Issue 21. Are Other Revenue (including export revenue) forecasts appropriate?

Hydro One stated that Other Revenues consist of revenues received from sources other than transmission rates, which are applied as an offset to its total revenue requirement for the purpose of determining its rates revenue requirement. This revenue offset reduces the amount of revenue to be collected from ratepayers through UTRs. Hydro One further stated that its other revenues are comprised of external revenues, wholesale meter service revenues, funding for the low voltage switchgear credit and export transmission service (ETS) revenues. Hydro One submitted that the OEB should find that its other revenue (including export revenue) forecasts are appropriate. The components of other revenue are discussed in the subsections that follow.

External Revenues

Hydro One's historical 2015-2018 external revenues and 2020 external revenue forecast are shown in the following table.[153]

[153] Hydro One's Reply Argument, p. 221.

Table 23: External Revenue (Millions)

	Actual	Actual	Actual	Actual	Bridge	Test Year	Test Year	Test Year
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Secondary Land Use	$ 34.3	$ 24.9	$ 20.1	$ 25.6	$ 17.6	$ 17.9	$ 18.2	$ 18.5
Station Maintenance	$ 9.5	$ 6.2	$ 3.9	$ 4.6	$ 4.0	$ 4.0	$ 4.0	$ 4.0
Engineering & Construction	$ 0.4	$ 0.2	$ 0.3	$ 0.1	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Other External Revenues	$ 10.1	$ 11.0	$ 11.2	$ 9.1	$ 9.4	$ 9.2	$ 10.3	$ 9.4
Total	$ 54.3	$ 42.3	$ 35.5	$ 39.4	$ 31.3	$ 31.4	$ 32.7	$ 32.2

Hydro One also stated that there are variance accounts for all the external revenue sources shown in the table above.

OEB staff, CCC, Energy Probe and VECC submitted that the amounts of external revenues are appropriate based on the assumption that the variance accounts remain open.

Hydro One submitted that the request to continue each of these variance accounts is fair and appropriate given the forecasting uncertainties associated with these accounts.

VECC further submitted that if the variance accounts are not approved by the OEB, the amount of external revenues should be increased by $7 million which is roughly the minimum variance over the last four years of actuals.

Hydro One argued that it is not appropriate for the OEB to artificially inflate these forecast amounts in the event the OEB decides to discontinue the variance accounts.

LPMA, supported by CCC, submitted that there should be an increase in the external revenue forecast of $9.4 million per year in each of 2020 through to 2022, with any variance tracked in the variance accounts. LPMA submitted that its proposed increase is reasonable based on the level of historical under-forecast by the utility that saw actual external revenues exceed the OEB approved amounts in the 2015 to 2018 period by an average of $12.7 million per year, which when adjusted for a 2015 outlier, resulted in an average of $9.4 million per year.

With respect to LPMA's submission that the external revenue forecast should be increased, Hydro One argued that ratepayers should not benefit from an offset to revenue requirement arising from external revenues except to the extent that Hydro One actually earns, or has a high degree of certainty that it will earn, external revenues. Hydro One submitted that it would not be appropriate to forecast external revenues based on speculation from historical data given the forecasting difficulties associated with Hydro One's role in managing the Provincial Secondary Land User Program on behalf of the Province of Ontario.

Wholesale Meter Service Revenues and Low Voltage Switchgear Credit

Hydro One continues to be the meter service provider (MSP) to some market participants. Hydro One proposed to continue the current annual fee of $7,900 per meter point for MSP services and the current exit fee of $5,200 per meter point. These fees were previously approved by the OEB.[154] The forecast revenue for wholesale meter service is $0.1 million for each year of the plan term.

The low voltage switchgear credit is a payment to two distributors as compensation for owning low voltage switchgear assets on transformation stations owned by Hydro One. The methodology used to calculate the credit was approved by the OEB in a previous proceeding.[155] Hydro One has not proposed any change to the methodology and stated that average low voltage switchgear service costs remain at the same percentage as total station costs. For funding of the low voltage switchgear credit, Hydro One's has forecast $14.8 million for 2020, $15.6 million for 2021 and $16.3 million for 2022. This is a reduction to other revenue.

No parties made submissions on the forecasts for wholesale meter service revenues or the funding for the low voltage switchgear credit.

[154] EB-2016-0160
[155] EB-2016-0160

Export Transmission Service Revenue

The discussion of ETS is under Issue 25.

Findings

The OEB approves total external revenues of $37.0 million for 2020, $38.0 million for 2021 and $37.8 million for 2022. This is based on an increase to the Secondary Land Use revenue. The OEB understands Hydro One's argument that this item is difficult to forecast; however, the actual revenue from this activity has been significantly higher than the forecast revenue in each year since 2017. The OEB is therefore increasing the forecast revenue for Secondary Land Use to the average of the last three years, which is $23.5 million. This results in an increase in the total external revenue of $5.6 million in 2020, $5.3 million in 2021 and $5.0 million in 2022.

Table 24: Hydro One's 2020-2022 External Revenue (Millions)

	Test Year	**Test Year**	**Test Year**
	2020	**2021**	**2022**
Secondary Land Use	$23.5	$23.5	$23.5
Station Maintenance	$ 4.0	$ 4.0	$ 4.0
Engineering & Construction	$ 0.3	$ 0.3	$ 0.3
Other External Revenues	$ 9.2	$ 10.3	$ 9.4
Total	$ 37.0	$ 38.0	$ 37.2

The OEB concludes that customers should benefit immediately from a forecast that is more consistent with the revenue that has been generated in the past from Secondary Land Use. However, as determined under Issue 22, the OEB is retaining the variance accounts associated with the external revenues. As a result, there will be a true-up to the actual revenues.

The OEB approves the other categories of external revenues. Hydro One's forecast for these revenues is consistent with historical trends.

The OEB also approves the forecast revenue for wholesale meter service revenues and the low voltage switchgear credit. These are both based on previous OEB approvals.

Under Issue 25, the OEB has approved an ETS rate of $1.85 for the term. Based on this approved rate, the approved ETS revenue is $35.9 million in 2020 and 2021 and $36.3 million in 2022.

3.9 DEFERRAL/VARIANCE ACCOUNTS

3.9.1 Disposition of Balances (Issue 22)

Issue 22. Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Hydro One is seeking approval to dispose of its December 31, 2018 audited deferral and variance account balances, adjusted for dispositions approved by the OEB during 2019, plus forecast interest on the principal balance to December 31, 2019. A summary of the account balances is provided in the following table:

Table 25:
Disposition of December 31, 2018 DVA Account Balances (Millions)

Account	Description	Principal[156]	Interest[157]	Total
2405	Excess Export Service Revenue	$4.72	$0.07	$4.79
2405	External Secondary Land Use Revenue	($9.98)	($0.45)	($10.43)
2405	External Station Maintenance, E&CS [158] and Other External Revenue	$4.43	$0.08	$4.51
1592	Tax Rate Changes		$0.00	$0.00
2405	Rights Payments	$2.31	$0.08	$2.39
2405	Pension Costs Differential	($4.17)	($0.31)	($4.48)
1508	Long-Term Transmission Future Corridor Acquisition and Development		$0.00	$0.00
1508	LDC CDM and Demand Response Variance Account	$22.68	$0.94	$23.62
2405	External Revenue – Partnership Transmission Projects Account		$0.00	$0.00
1508	Waasigan Transmission Deferral Account	$0.82	$0.05	$0.87
1508	OEB Cost Differential Account	($0.11)	($0.02)	($0.13)
2405	In-Service Capital Additions Variance Account	($0.64)	($0.01)	($0.65)
	TOTAL	**$20.06**	**$0.43**	**$20.49**

Hydro One is seeking approval to recover the above amounts from its customers by adjusting its revenue requirement by approximately $6.8 million per year over the three-year term of its Application, commencing January 1, 2020.

Hydro One has confirmed that all of the regulatory accounts presented above have been established consistent with the requirements of the OEB's Accounting Procedures Handbook and any subsequent direction provided by the OEB. Hydro One has further confirmed that the OEB's prescribed rates were used for purposes of calculating the

[156] Exhibit H, Tab 1, Schedule 5, Attachment 1(excel continuity schedule)
[157] *Ibid*
[158] Engineering and Construction Services.

carrying charges on the principal balances, and that no adjustments have been made to deferral and variance account balances that were previously approved by the OEB on a final basis.

Hydro One is not seeking disposition of the following December 31, 2018 deferral and variance account balances as part of its current Application:

Table 26:
2018 Deferral and Variance Account Balances Not Being Disposed (Millions)

Account	Description	Principal[159]	Interest[160]	Total
1508	OPEB Cost Deferral	$22.38	$0.61	$22.99
1508	East-West Tie Deferral Account (Tracking only)	$15.79	$0.00	$15.79
1508	SECTR Deferral Account (Tracking only)	$54.32	$0.00	$54.32
1522	OPEB Asymmetrical Carrying Charge Account			
	TOTAL	**$92.49**	**$0.61**	**$93.10**

Hydro One has indicated that it has not requested disposition of the East West Tie and SECTR account balances because both are currently only tracking accounts.

Hydro One further indicated that it did not seek disposition of its OPEB Cost Deferral Account as it is subject to the OEB's determination regarding Hydro One's request for continued capitalization of the non-current service component of OPEBs (see Issue 11).

Hydro One has also not sought to dispose of its OPEB Asymmetrical Carrying Charge Account in the current proceeding because its position is that the balance is zero. This account is also subject to the OEB's determination on Hydro One's request to use an alternate methodology for calculating the balance within this account.

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[159] Exhibit H, Tab 1, Schedule 5, Attachment 1(excel continuity schedule)
[160] *Ibid*

Hydro One is seeking to continue all of its existing deferral and variance accounts (inclusive of accounts proposed and not proposed for disposition). The OEB Cost Differential Account was previously closed by the OEB.

OEB staff submitted that it has no concerns with the proposed disposition of the December 31, 2018 audited deferral and variance account balances as presented in Table 25 above.

OEB staff further submitted that it had no concerns with the continuance of the deferral and variance accounts as proposed by Hydro One, subject to the OEB's finding pertaining to Issue 11. In that finding, should the OEB determine that continuation of the OPEB Cost Deferral account is not appropriate, then OEB staff submitted that the OEB should direct Hydro One to close the OPEB Cost Deferral account upon disposition of the balance currently tracked. Hydro One agreed with OEB staff's position on this matter.

OEB staff submitted that it had no concerns with not disposing of the balances in the East West Tie and SECTR accounts because both are currently only tracking accounts.

OEB staff further submitted that the OPEB Cost Deferral Account may require disposition in the current proceeding if the OEB does not permit both the continued capitalization of impacted OPEB costs and the continued use of the OPEB Cost Deferral Account as part of its findings on Issue 11. Accordingly, the OEB would need to direct Hydro One to amend its DVA disposition request as part of the draft rate order in this proceeding. Hydro One agreed with OEB staff's position on this matter.

Finally, OEB staff submitted that it did not support Hydro One's proposed alternate methodology pertaining to the OPEB Asymmetrical Carrying Charges account as it failed to take into account the depreciation that Hydro One recovers for OPEB costs that were capitalized pre-January 1, 2018, which minimizes the return that ratepayers will be entitled to receive. OEB staff proposed an alternate methodology and asked Hydro One to provide the calculation as part of the interrogatories. Since Hydro One stated that it does not have the necessary data, OEB staff submitted that Hydro One should instead follow the default methodology prescribed in the OEB's *Report on the Regulatory Treatment of Pension and OPEB Costs* (Pension Report). CME also made a similar argument on this matter.

LPMA submitted that it has no concerns or issues with the amounts proposed for disposition in the existing deferral and variance accounts. It also indicated that it adopts

OEB staff's submission in relation to the continuance of certain deferral and variance accounts. However, LPMA submitted that amounts that Hydro One intends to record to the new sub-account of Account 1592 pertaining to the 2018 and 2019 impacts of the AII from Bill C-97 should be refunded to ratepayers as part of the current Application, rather than when the next rebasing occurs. It argued that the OEB should direct Hydro One to refund one-third of the current estimated 2019 amount, or $6.1 million, through Account 1592 as part of the disposition of deferral and variance accounts in the current proceeding.

SUP submitted that the OPEB Cost Deferral Account should be left in place until the OEB renders its policy decision on the capitalization of all indirect costs, including otherwise ineligible OPEBs, preferably for 2023 rates. Unless the OEB decides to allow a capitalization or deferral exception in its decision on this proceeding, amounts that are otherwise ineligible for capitalization under US GAAP should continue to be captured in this account.

SUP submitted that Hydro One's proposed alternate methodology related to its OPEB Asymmetrical Carrying Charges account is reasonable, balanced and that it meets the intent of the exception in the OEB Report. In addition, it does not carry the hint of retroactive rate making that it believes OEB staff's proposal does. As such, it submitted that Hydro One's proposal should be approved.

VECC submitted that the OEB should deny Hydro One's request to dispose of the balance associated with the LDC CDM and Demand Response Variance Account as currently calculated. Hydro One should instead be directed to re-calculate the balance in the account consistent with the account's approved definition and re-file for recovery in a future application. VECC contended that Hydro One had included the impact of more than just the variance related to OPA-funded LDC delivered programs and Demand Response programs as approved by the OEB. VECC indicated that Hydro One's calculation also includes: i) the impact of Codes and Standards, ii) the impact of Energy Efficiency (EE) savings from transmission connected end-use customers, iii) the impact of time of use rates and v) the impact of EE programs implemented by other parties such as Natural Resources Canada, Enbridge and Union Gas.

In response to VECC's concerns related to the LDC CDM and Demand Response Variance Account, Hydro One submitted that it believes its calculation of the LDC CDM and Demand Response Variance Account is appropriate and consistent with the original intent for this account.

Hydro One noted that in 2018, the IESO issued verified historical results for all energy efficiency programs, not just LDC-delivered programs, as well as for the components of CDM driven by codes and standards. Hydro One submitted that the data issued by the IESO is consistent with what it included in its approved 2017 load forecast, and given the availability of verified CDM data for the energy efficiency and Codes and Standards CDM amounts, its calculation of the LDC CDM and Demand Response Variance Account is appropriate.

Hydro One further contended that VECC's assertion that it had included "the impact of time of use rates" in its calculation of the energy efficiency component of the account is not correct as only the items related to energy efficiency were included in measuring energy efficiency. The impact of time of use rates is not an energy efficiency item and was not included in the calculation of this component.

Finally, Hydro One submitted that modifying the calculation of the energy efficiency component of the LDC CDM and Demand Response Variance Account to only include the LDC-Delivered programs, as suggested by VECC, would result in an increase of approximately $7.5 million in the energy efficiency amount to be collected from customers, from $9.46 million to $16.95 million.

Hydro One also rejected VECC's proposal to direct Hydro One to re-calculate the balance in in the LDC CDM and Demand Response Variance Account and to re-file for recovery in a future application. Hydro One argued that even if the OEB were to agree with VECC regarding the scope of the energy efficiency component of the account, it would not justify deferring the matter to a future application because it could be addressed as part of the draft rate order process in the current proceeding.

Hydro One argued that any utility applying to use an alternate method related to the OPEB Asymmetrical Carrying Charges account, would almost certainly have the same information availability constraints that Hydro One is facing if it tried to adopt OEB staff's method of calculating the reference amount. It argued that OEB staff's position essentially makes the alternative unworkable and unusable by any utility in any circumstance.

Hydro One further argued that it would not be appropriate to take into account depreciation associated with OPEB costs that have been capitalized to rate base prior to January 1, 2018. Hydro One believed that the OEB Report clearly indicates that it is the OEB's expectation that the amounts to be recorded in the account should include capitalized amounts of OPEB costs only from the date of implementation of the account.

Hydro One also asserted that it would be unfair to order it to include amounts from prior to January 1, 2018 because it would be inconsistent with the treatment of a utility that applies the default methodology of the OEB Report, under which pre-2018 amounts are not accounted for.

Findings

The OEB approves the disposition of the balances in the deferral and variance accounts in Table 25 above, including the LDC CDM and Demand Response Variance Account. These are audited balances as at December 31, 2018, with interest projected to December 31, 2019. Hydro One should update the interest calculation to June 30, 2020 as part of the draft revenue requirement/charge determinant order process. The OEB also approves that continuation of all of the accounts in Table 26, except the OEB Cost Differential Account, which the OEB previously closed.

LDC CDM and Demand Response Variance Account

VECC disagreed with the calculation of the LDC CDM and Demand Response Variance Account because it should be based only on LDC delivered programs. Hydro One stated that if it recalculates the balance based on VECC's submission, the balance to be collected from customers would increase by approximately $7.5 million. This assertion was not tested in this proceeding and therefore the OEB cannot reach conclusions based on this.

The LDC CDM and Demand Response Variance Account was first established for Hydro One's 2013 revenue requirement.[161] For its 2017 and 2018 revenue requirement, the OEB directed Hydro One to use its best efforts to obtain the peak savings information it needs to calculate the variance for this account.[162] The OEB concludes that the previous OEB panel recognized that there may be changes to how this account was calculated. This is a variance account to record differences between savings from CDM and demand response included in the load forecast and the actual CDM and demand response savings. Hydro One argued that it used data to record the CDM savings that is consistent with what it included in its approved 2017 load forecast. The

[161] EB-2012-0031

[162] EB-2016-0160 p. 74

OEB concludes that Hydro One's approach is acceptable because the same basis was used both to record CDM savings and to adjust the load forecast for CDM.

Hydro One proposed to close the LDC CDM and Demand Response Variance Account in its last proceeding, and the OEB denied this request given there had been a significant credit in the account.[163] The OEB concludes that there will be ongoing difficulty with this account going forward as the framework for CDM transitions. The OEB therefore will close this account effective January 1, 2020 for the plan term. Hydro One can propose a new account in its next rebasing application.

East West Tie Deferral, SECTR and Waasigan Transmission Deferral Accounts

The OEB agrees with not disposing of the balances in the East West Tie and SECTR accounts because both are currently only tracking accounts. The OEB notes that the Waasigan Transmission Deferral Account is also now a tracking account, and the OEB approved a new accounting order for it in a previous proceeding.[164]

OPEB Cost Deferral Account

Given the OEB's findings under Issue 11, the OEB approves the disposition of the balance in the OPEB Cost Deferral Account. Hydro One shall update its DVA balances for disposition as part of the draft rate order.[165] The account shall remain open until the 2019 balance is disposed.

OPEB Asymmetrical Carrying Charge Account

The OEB does not agree with Hydro One's approach to calculating the OPEB Asymmetrical Carrying Charge Account. The OEB does not approve Hydro One's calculation of $0.0 for the balance in the account.

The OPEB Asymmetrical Carrying Charge Account was established by the OEB in the Pension Report to track the difference between OPEB costs recovered in rates on an accrual basis and the actual cash payments the utility makes for OPEBs (referred to as the reference amount). Carrying charges are calculated on the difference if there is a cumulative credit balance, to provide compensation to customers.

[163] EB-2016-0160, p.74.
[164] EB-2019-0151
[165] *Ibid*

The OEB's default methodology set out in the Pension Report assumes that all OPEB costs are part of OM&A, for simplicity. The Pension Report also allows a utility to propose an alternative approach if a significant portion of its OPEB costs is capitalized. Hydro One proposed an alternative that would record the amount of OPEB costs in its OM&A, and the capitalized OPEB component would be based on the OPEB costs in depreciation from 2018 onwards. The OEB concludes that while the default approach would overstate the balance in the tracking account, Hydro One's approach understates the balance. This is because there is an OPEB amount in rates for depreciation prior to 2018.

Hydro One argued that the Pension Report established the OPEB Asymmetrical Carrying Charge Account effective January 1, 2018 and the account should include capitalized amounts of OPEB costs only from the date of implementation of the account. Hydro One also argued that utilities that apply the default methodology are not required to account for pre-2018 amounts and the same should apply to Hydro One's alternate methodology. The OEB disagrees. The Pension Report highlights the intent of the account is to compensate customers for the time value of money for the difference between the higher amounts in rates for OPEB costs on the accrual basis and what these costs would have been on a cash basis. The amount of OPEB costs in rates includes both the OM&A portion and the OPEB component in total depreciation, not just the depreciation since 2018. It is the carrying costs on the difference that are calculated on a prospective basis from 2018 onwards.

Hydro One's evidence shows that prior to 2013, approximately 40% of the OPEB costs in rates were from capital. From 2013 to 2017 this percentage increased to approximately 54%. For 2020. Hydro One has forecast OPEB costs that are 29.1% OM&A, 32.7% capital and 38.2% in the OPEB Cost Deferral Account.

Hydro One provided a comparison between the OEB's default methodology for the OPEB Asymmetrical Carrying Charge Account and the one it proposed. Using the default methodology, the accumulated balance in the account would be $79 million in 2020, on which carrying charges would be calculated. Using Hydro One's methodology, the balance would be negative and no carrying charges would accrue to customers.

Hydro One's illustrative example for the OPEB Asymmetrical Carrying Charge Account shows that the reference amount calculated for 2020 would have no amount for capitalized OPEBs, despite how much of Hydro One's OPEB costs have been capitalized and included in rate base. While this example may be illustrative, it appears to show directionally what is expected to be recorded in the OPEB Cost Deferral Account. The OEB concludes that this result is not reasonable.

Given the OEB's findings under Issue 11, the amounts forecast for the OPEB Cost Deferral Account will now be part of OM&A (total now 67.3%). As a result, the default methodology from the Pension Report would now be a closer proxy to the OPEB costs in rates.

The OEB accepts that Hydro One may not have the information to adopt the alternate approach proposed by OEB staff and therefore will not order that methodology. Hydro One may either adopt the default methodology, or propose a methodology that reflects the OPEB costs in the total depreciation expense based on reasonable assumptions. The OEB will assess Hydro One's approach for both the transmission and distribution businesses in the joint application for 2023 rates.

3.9.2 New Deferral and Variance Accounts (Issue 23)

Issue 23. Are the proposed new deferral and variance accounts appropriate?

Hydro One is seeking approval to establish four new regulatory accounts as part of its current Application:

1. A CCRA True-up Variance Account to track the difference between components of revenue requirement and actual results related to load true-ups performed in accordance with section 6.5.3 of the Transmission System Code.

2. A Foregone Transmission Revenue deferral account to capture foregone revenue from January 1, 2020 to the date when the approved 2020 UTRs are reflected in the revenue earned by Hydro One transmission.

3. An asymmetrical ESM Deferral Account effective January 1, 2020 to record any over-earnings realized during any year of the three-year term of the current Custom IR Application (2020-2022). The account will record (to return to ratepayers) 50% of any earnings that exceed the regulatory return on equity approved in the current Application by more than 100 basis points in any year of the three-year term.

4. A variance account, effective January 1, 2017, to track the difference between Hydro One's regulatory income tax revenue requirement underlying its approved transmission rates and what that transmission revenue requirement would have been if its appeal before the Divisional Court related to the sharing of tax benefits from its recent Initial Public Offering (IPO) is successful.

In addition, Hydro One sought to continue its Capital In-Service Variance Account (CISVA) as previously approved, except for a modification to the calculation of the balance that will be tracked in this account. It has proposed to exclude any verifiable productivity savings from the calculation of the balance that flows to the account in order to ensure that true productivity savings are incented throughout the term of the Custom IR Application.

OEB staff submitted that it has no concerns with approving the establishment of the CCRA True-up Variance Account, ESM Deferral Account, and the Foregone Revenue Deferral Account. LPMA had the same positon as OEB staff for these accounts.

CME, CCC, and SEC submitted that they supported Hydro One's proposal for an ESM variance account.

Concerning the modification proposed to the CISVA, OEB staff submitted that Hydro One's modification should be rejected as it introduces significant regulatory burden to the process of assessing the prudence of the disposition amount in the account. OEB staff contended that it will be very difficult to differentiate between what is a productivity gain as opposed to savings that resulted from such things as proper due diligence, inflated forecasts, and changes to the scope of a project.

OEB staff also submitted that Hydro One must provide an updated draft accounting order related to the CISVA that is prepared using the same wording that was approved for this account by the OEB in Hydro One's last transmission rates cost-of-service application.

CME submitted that the OEB should reject Hydro One's proposed modification to the CISVA due to concerns with how stakeholders will be able to ensure that the productivity amounts that Hydro One proposes to remove from the calculation of the account are truly the result of productivity.

Energy Probe suggested that a CIVSA 1% dead-band is more appropriate for first generation Transmission IRM. Energy Probe also does not agree that there should be incentive for meeting in service additions.

CCC accepted the CISVA for the rate plan period including the proposed modification. However, it submitted that Hydro One should be required in its next rebasing proceeding (2023) to provide a detailed account of the amounts in the account, how they were recorded and to demonstrate specifically how productivity impacted those amounts.

SEC argued that while the CISVA is meant to protect ratepayers from material underspending on capital, it creates a perverse incentive for the utility. In the long-term the CISVA may make customers worse off as it does not ensure that the correct amount of work gets done, or that the work is done at the forecast cost.

SEC further submitted that the CISVA should be subject to conditions that require Hydro One to demonstrate at its next Custom IR application that both the amount of excluded incremental productivity savings was determined appropriately, and that it is appropriate for Hydro One to retain those amounts. Depending on the evidence that is filed, SEC believed that the future OEB panel should be allowed the discretion to order that those productivity savings be included in the CISVA balance.

SEC also argued that the CISVA should not simply track the difference in the capital related revenue requirement caused by variance in actual versus approved in-service additions in excess of 2%, but any capital related variance regardless of the cause. This would include variances in depreciation and taxes that are caused by the changes in the actual assets that Hydro One puts into service.

In response to OEB staff's submission on the CISVA account, Hydro One argued that the proposed modification to the CISVA is consistent with the exclusion of verifiable productivity gains from the CISVA that was approved in the previous Hydro One Distribution decision. In addition, it contends that not accepting the modification to the CISVA has the effect of creating a disincentive for Hydro One to find additional capital productivity savings, and would incent Hydro One to do more work in the event that it is able to find additional productivity gains instead of completing the same amount of work for less.

Finally, Hydro One asserted that it will have the onus to prove the achieved incremental productivity savings above the levels embedded in the approved revenue requirement, and that it would be willing to provide an update on its productivity progress following completion of the 2020 test year.

Regarding SEC's submission on the CISVA, Hydro One submitted that the CISVA is operating as was intended by the OEB and that it has proposed an ESM account that would capture differences in revenue requirement.

With respect to SEC's proposal to place the onus on Hydro One in its next Custom IR application, Hydro One submits that there is nothing for the current panel to do to give effect to this condition. It will be up to the panel in the next application to determine whether the amounts recorded in the CISVA account have been calculated appropriately and how such amounts should be disposed of, and it will be up to Hydro One to demonstrate at that time why its proposed balance and method for disposition is appropriate.

Hydro One further asserted that the OEB contemplates that there will be a degree of variation between the approved and actual capital owing to the flexibility that is afforded to utilities to manage within their approved funding envelope in order to meet their obligations. However, it contends that SEC's submission on the CISVA does not reflect the fact that circumstances can change over a rate term. It instead incents a dogmatic line by line commitment to the TSP and penalizes the utility for managing within the existing funding envelope in response to changing circumstances.

In response to Energy Probe's proposal to reduce the deadband of the CISVA to 1%, Hydro One argued that a 2% deadband incents Hydro One to find ways to lower capital project costs, and support the efficient execution of projects near the end of the calendar year.

In response to CCC, Hydro One submitted that the CISVA balance will be disposed of in the normal course at the time of the next rebasing application and will be subject to typical review by the OEB as it would for other deferral and variance accounts. Hydro One stated that it is committed to demonstrating to the OEB at the next rebasing application the results of the productivity program and how it has impacted the associated capital spending levels and the CISVA.

OEB staff submitted that it did not support Hydro One's proposal to establish a variance tracking account pertaining to its appeal before the Divisional Court because the appeal proceeding is still ongoing and its outcome is unknown. Therefore, the additional regulatory burden associated with tracking an amount that may never materialize is not justified. OEB staff submitted that the account should only be established once the need for it is confirmed. LPMA made a similar argument on this matter.

Both PWU and SUP supported the establishment of a variance account in the current proceeding pertaining to Hydro One's appeal before the Divisional Court. PWU submitted that this will facilitate the implementation of any resulting rate impact, and that any delay in recovering that revenue would necessitate additional carrying costs to be recovered from ratepayers and would exacerbate intertemporal collection issues.

SUP submitted that this type of legal contingency is exactly the sort of situation that is ideally suited to be tracked in an auditable tracking account in case the information is required for regulatory purposes at a later date. SUP also indicated that it expects that the administrative cost of maintaining such an account would be insignificant to Hydro One. SUP raised a concern that establishing the account at the date a decision on the appeal is rendered implies that only impacts after this date can be considered by the OEB.

In its reply argument, Hydro One submitted that there would be no increased regulatory burden associated with tracking amounts in the proposed variance account related to the outcome of its Divisional Court appeal proceeding because the relevant amounts would only be recorded to the account upon receiving a successful appeal decision, and not before that time.

Hydro One further argued that establishing this account in the current proceeding would avoid the need for Hydro One to seek approval through a standalone regulatory proceeding in the event Hydro One's appeal is successful, and would enable Hydro One to start recovering any resulting amounts more promptly thereafter.

VECC argued that since the OEB has established interim rates it does not see the need for the establishment of a Foregone Revenue Deferral Account. In VECC's view, it is simpler for the OEB to order the recovery of any deferred amounts through the establishment of the appropriate rate rider. Hydro One did not respond to this submission.

Findings

The OEB approves the establishment of a CCRA True-up Variance Account. No parties disagreed with its establishment. The Transmission System Code (TSC) requires Hydro

One to do an economic evaluation for new or modified connections based on a forecast of load. The TSC also requires Hydro One to do a true-up calculation for the actual load. Hydro One relies on information from third parties to forecast the load, therefore the OEB agrees that a variance account to true up between forecast and actual is appropriate.

The OEB will not establish the Foregone Transmission Revenue deferral account. The OEB set Hydro One's revenue requirement interim as of January 1, 2020. Under Issue 4, the OEB established an effective date of January 1, 2020 for the approved revenue requirement. The OEB expects to issue new UTRs effective July 1, 2020. As part of the new UTRs, the OEB will incorporate the difference between Hydro One's revenue requirement at the existing UTRs and the updated UTRs. Hydro One has been ordered to provide this calculation of foregone revenue as part of the draft rate order process. The OEB concludes that a deferral account is not required for the OEB to incorporate this foregone revenue in the UTRs.

The OEB approves the asymmetrical ESM Deferral Account to share with customers, on a 50:50 basis, any earnings that exceed the approved regulatory return on equity by more than 100 basis points. The OEB concludes that establishing a threshold at 100 basis points is appropriate to provide Hydro One an incentive to achieve productivity improvements over the term. The balance in the account will be reviewed in Hydro One's next rebasing application scheduled for the 2023 revenue requirement. As discussed under Issue 6, the OEB expects to review Hydro One's productivity achievements during the term in the next rebasing application, and this review can consider the extent to which the productivity improvements are sustainable into the next term to benefit customers.

The OEB will not establish a variance account to track the difference between the tax revenue requirement at existing rates and what it would be if Hydro One's appeal to the Divisional Court on the sharing of tax benefits is successful. The OEB expects that if the appeal is successful, the Divisional Court will direct any next steps. The OEB does not accept the arguments made by SUP and PWU about potential delays because Hydro One is not prohibited from keeping records to track the variance if it chooses to do so.

The OEB accepts the modifications proposed by Hydro One to the CISVA. The account was established to protect customers from potential underspending of Hydro One's capital plan. The OEB finds it reasonable to have a threshold at 98% to allow Hydro One to manage its operations without a potential penalty from underspending. The OEB also finds it acceptable during this three-year term to allow Hydro One to adjust the account for identifiable productivity improvements, in order to encourage continuous improvement. The OEB agrees with Hydro One that the OEB panel for its next rebasing application can review these adjustments to determine whether they were true productivity savings and reasonable. The OEB panel for that proceeding can also determine whether the CISVA account should continue, and if so, whether these productivity adjustments add too much complexity to the account and should be discontinued.

Under Issue 9, the OEB established an asymmetric variance account for the transmission portion of the ISOC on the same basis as was established for the distribution portion. Hydro One shall file a draft accounting order for this account as part of the draft revenue requirement/charge determinant process.

3.10 COST ALLOCATION

3.10.1 Cost Allocation (Issue 24)

Issue 24. Is the transmission cost allocation proposed by Hydro One appropriate?

Hydro One stated that it continues to follow the OEB-approved methodology from the last transmission rebasing application to allocate the transmission rates revenue requirement into three rate pools: Network, Line Connection and Transformation Connection. The rate pools are based on functional categories of assets and their associated costs.

The derivation of the revenue required to be collected through transmission rates is based on Hydro One’s proposed total revenue requirement offset by other revenues consisting of: external revenue, wholesale meter service revenue, regulatory assets, ETS revenue, and funding for low voltage switchgear credit.

Hydro One proposed not to re-run the cost allocation model for the 2021 and 2022 test years, but rather to determine the rates revenue requirement by rate pool using the methodology approved for its 2019 transmission revenue cap adjustment.

No parties submitted concerns with the proposed transmission cost allocation.

OEB staff noted that Hydro One is proposing to update the definition of billing demand for the Line and Transformation Connection services to reflect the changes in the embedded generation market over the years. Specifically, Hydro One proposed to include energy storage facilities in the definition of billing demand for embedded generation.[166] Hydro One stated that the proposed changes in wording clarify and reflect its interpretation of these definitions in the data provided to the IESO for transmission billing purposes.

Hydro One stated that it does not consider energy storage facilities as a renewable energy source and asserted that its understanding is consistent with the definition under Section 2 of the *Electricity Act, 1998* (the Electricity Act).[167] Hydro One stated in response to a query from OEB staff that it had not consulted with storage customers on this proposed wording. Hydro One noted that these wording changes are intended to clarify and reflect its interpretation of the current rules and practice and customers will not be impacted by these changes.

Hydro One noted that the current UTR schedules, and the corresponding Terms and Conditions, do not mention energy storage facilities. OEB staff noted that Hydro One's practice is to effectively impose gross load billing on transmission customers with energy storage facilities behind their meters based on a 1 MW threshold for non-renewable generation rather than the 2 MW threshold that applies to renewable generation.

OEB staff submitted that it had concerns with Hydro One's proposal to formalize its practice with regard to energy storage facilities by amending the Terms and Conditions of the UTR schedule in the absence of, at a minimum, consultation with potentially affected customers and further consideration by, and direction from the OEB. LPMA shared OEB staff's concerns and submitted that no change should be made until the OEB can consult with customers that may be affected, to determine if the changes to the Terms and Conditions of the UTR schedule are appropriate.

Hydro One submitted that its practice regarding energy storage facilities is appropriate because when a storage facility discharges and displaces a customer load, its impact to the measured demand is identical to the impact of an embedded generator. Hydro One asserted that its treatment is consistent with the current rules because energy storage is not identified as a renewable energy source within the definition of that term set out in the Electricity Act*.* Furthermore, Hydro One indicated that it would be its intention to

[166] Exhibit JT 2.34-Q18, p. 1.
[167] Exhibit J9.3, p.1.

continue treating behind the meter energy storage facilities as embedded non-renewable generation.

Findings

The OEB approves Hydro One's cost allocation methodology for the plan term. Hydro One shall use this methodology to update the revenue requirement by rate pool to be filed as part of the draft rate order process.

The OEB agrees that affected customers should be consulted prior to amending the Terms and Conditions of the UTR schedule with respect to Hydro One's proposal to continue treating behind the meter energy storage facilities as embedded non-renewable generation. Hydro One has indicated that customers will not be impacted by these changes, and the changes are intended to clarify the current rules and practice. Rather than waiting three years to incorporate this clarification in the Terms and Conditions, the OEB will consider these amendments in the proceeding for the 2021 revenue requirement, provided Hydro One can provide evidence that affected customers have been consulted. This review should be mechanistic if there are no concerns raised by affected customers.

3.11 EXPORT TRANSMISSION SERVICE RATES

3.11.1 Export Transmission Rate and Resulting Revenues (Issue 25)

Issue 25. Is the Export Transmission Rate of $1.85 and the resulting ETS revenues appropriate?

Hydro One stated that it owns and operates assets, as part of its transmission system, which are used to facilitate export transactions at the points of interconnection with Ontario's neighboring markets. The IESO collects ETS revenue from export transactions and remits them to Hydro One for the use of its assets in facilitating these transactions. ETS revenue is an offset to Hydro One's revenue requirement, and therefore it serves to reduce transmission rates for domestic customers.

Hydro One proposed to maintain the ETS rate at the existing level of $1.85/MWh. The $1.85/MWh rate originated as part of a settlement proposal from Hydro One's 2015-

2016 transmission proceeding.[168] Hydro One had filed a cost allocation study prepared by Elenchus Research Associates Inc. (Elenchus) in which Elenchus recommended an ETS rate of $1.70/MWh. The parties in that proceeding proposed that the rate be set midway between the previous approved rate of $2.00/MWh and the recommended rate of $1.70/MWh. The OEB accepted that proposal.

As part of the current proceeding, Hydro One filed an update to the 2015 Elenchus cost allocation model using updated information and calculated an ETS rate of $1.25/MWh. The decline is attributable to decreased OM&A costs from 2015 to 2019, and an increase in forecast export volumes.

Hydro One stated that it proposed to maintain the existing ETS rate of $1.85/MWh because a decreased rate would adversely impact Ontario electricity customers by reducing the offset to Hydro One's transmission revenue requirement.

OEB staff and a number of intervenors supported Hydro One's proposal and raised concerns regarding the cost allocation methodology recommended by Elenchus, including the fact that it does not allocate any capital costs associated with the shared Network facilities to export customers, and the lack of a jurisdictional review. SEC argued that electricity that is exported may traverse hundreds of kilometers on the Hydro One transmission system from the generator to the border, and exporters only pay for the part at the very end, the intertie. SEC submitted that there should be a reasonable allocation of shared costs to exporters, and if the OEB determines that the ETS rate should be adjusted using a cost-based method, it may be appropriate to require Hydro One to undertake a more thorough study that accounts for export customers' use of network capital assets.

SEC submitted that an apt comparison to the ETS rate may be the approach to attachments on distribution poles.[169] SEC noted that pole attachers are allocated the full cost of the dedicated part of the pole and also an allocated share of the common costs of the pole, even though those pole costs would have been incurred regardless of these attachments.

[168] EB-2014-0140

[169] Report of the Ontario Energy Board: Wireline Pole Attachment Charges (EB-2015-0304), March 22 2018, p.33

OEB staff noted that no jurisdictional review was done to understand how ETS rates are determined in other jurisdictions.

LPMA argued that the ETS revenue forecast should be increased to $37.6 million from Hydro One's proposed $35.9 million for each of 2020 and 2021, and proposed $36.3 million for 2022. Hydro One proposed the ETS revenue forecast be calculated using a three-year rolling average of 2017 to 2019 multiplied by the ETS rates. LPMA argued the three-year rolling average incorporates a 2019 forecast year, which uses an average of 2016 to 2018 actuals, this puts more weight on the years of 2017 to 2018. Instead of the three-year rolling average, LPMA proposed a straight three-year average of 2016 to 2018 actuals.

In response to LPMA's proposals regarding ETS revenues, Hydro One noted that the forecasting methodology for ETS revenues is the same as it was in previous OEB-approved transmission rate applications and the three-year average methodology proposed by LPMA would not result in a more accurate forecast in export volumes.

APPrO disagreed with Hydro One's approach submitting that an ETS rate of $1.21/MWh would be appropriate for 2020-2022. This rate is calculated using the Elenchus cost allocation methodology and a three-year rolling average of forecast export volume as the billing determinants for calculating ETS rate.

APPrO argued that:

- The current rate of $1.85/MWh is not a cost-based rate and therefore is not in compliance with the OEB's decision on the ETS rate in a previous proceeding (ETS Decision) that ordered Hydro One to prepare a cost allocation study and propose a cost-based rate.[170] The current rate resulted from a settlement between parties to set the rate at the mid-point between a cost-based rate of $1.70/MWh from a previous Elenchus study and the rate of $2.00/MWh approved by the OEB in the ETS Decision.
- An ETS rate of $1.21/MWh is a cost-based rate and the OEB needs to approve this rate to implement the ETS Decision.
- While the Elenchus Study tested the sensitivity of other assumptions through different scenarios, it recommended a single cost allocation methodology. No

[170] EB-2021-0031 Decision and Order June 6, 2013.

parties challenged the cost allocation methodology and Hydro One agreed that the scenario recommended by Elenchus resulted in a cost-based rate.

- Exporters are unique because they are not considered by Hydro One in planning its transmission system. Furthermore, exporters are an interruptible service so they receive a lower quality of service and lower priority compared to domestic customers. This is why the Elenchus Study recommended that there be no costs for shared assets allocated to exporters.
- The OEB explicitly rejected the approach of allocating the costs of shared assets to exporters in a previous decision for the Ontario Power Authority (OPA).[171] Furthermore, in the ETS Decision, the OEB rejected the methodologies used in other jurisdictions and directed Hydro One to propose a proper cost-based ETS rate based on a cost allocation study. Requiring another jurisdictional scan is an attempt to defer the application of cost-based principles in the manner that was contemplated in the ETS Decision.

In responses to APPrO's statement that Elenchus recommended a single cost allocation methodology and the six other scenarios were prepared for sensitivity analysis, Hydro One explained that all scenarios considered in the Elenchus study could be considered to produce cost-based rates.

Hydro One noted that where the issue of allocating shared Network facilities is concerned, Scenario 6 in the Elenchus study includes a sharing of such costs to exporters and generates an ETS rate that would be considerably higher than $1.85/MWh.

Hydro One stated that the existing rate of $1.85/MWh falls within the range of possible cost-based rates identified by Elenchus. Hydro One acknowledged that the Elenchus study has not been fully explored before the OEB and agreed to provide a cost allocation methodology that includes the allocation of shared Network costs to exporters in its next cost-of-service application.

Hydro One noted that with respect to the matter of conducting a jurisdictional review, a previous study had been completed by Charles River Associates (CRA) in 2012. This study showed that Hydro One's then-approved ETS rate of $2.00/MWh was the lowest of neighboring jurisdictions that export electricity to Ontario. Hydro One indicated that it

[171] EB-2010-0279, Decision and Order for Ontario Power Authority (OPA), p. 16-17.

is unlikely that the charges in Ontario's neighboring jurisdictions have been materially reduced since then, particularly after accounting for cost inflation since 2012.

APPrO noted that Hydro One used two different annual forecasts of 2020 export volumes, one for the purposes of rate design and the other to forecast export revenues to be applied against the 2020 revenue requirement. To arrive at the calculated $1.25/MWh ETS rate, Hydro One used the 2018 export value as the billing determinants. For the purpose of forecasting export revenue, Hydro One used a three-year rolling average to estimate the export volume. APPrO recommended using the three-year rolling average, as the billing determinants for calculating the ETS rate would be consistent with the method of forecasting export revenue.

Hydro One disagreed with APPrO's recommendation and stated that using a single historical year of volume data is the methodology recommended by Elenchus for cost allocation. Hydro One further stated that, for cost allocation purposes, the best forecast should be used to allocate costs for the purpose of setting rates, the 2018 historical volume captures the recent downward trend of export volumes.

Hydro One stated that for forecasting export revenue, the three-year rolling average method is preferred for three reasons: (1) a higher forecast of export revenue will lower Ontario transmission rates; (2) any difference in forecast revenue is tracked in a variance account for disposition in future, and (3) the three-year rolling average method has been approved by the OEB in previous transmission rates applications.

In conclusion, Hydro One reiterated its belief that it is appropriate to maintain the ETS rate at the existing level, since the ETS rate has always been set by settlement agreement or OEB decision and not strictly based on principles of cost causality. Moreover, the existing rate of $1.85/MWh falls within the range of all cost-based rate scenarios and lowering the ETS rate would adversely impact all Ontario electricity consumers through UTRs.

Findings

The OEB approves an ETS rate of $1.85/MW for the 2020 to 2022 term. The OEB recognizes that this rate was established as part of a settlement proposal accepted by the OEB in a previous proceeding. While the rate was informed by a previous cost allocation study, it was not derived solely on a cost basis. The OEB has determined that further work is required before amending the rate.

Shared network facilities have been paid for by domestic customers. The OEB has determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates. The OEB does see some similarity with the rate established for attachments to distribution poles by third parties such as telecommunications and cable companies, as noted by SEC. For pole attachments, the OEB adopted a hybrid methodology to allocate common costs. The OEB has insufficient information to conclude what the appropriate allocation of common network costs should be for exporters. This needs to take into consideration that while exporters make use of the network system, Hydro One does not plan its system for the benefit of exporters. However, at the oral hearing Hydro One testified that once scheduled, with the exception of an emergency or supply issue, exporters are treated as firm as domestic load.

The OEB disagrees with APPrO that the OEB rejected the results of a previous jurisdictional scan in favour of setting the ETS solely on the basis of a cost allocation study. It is important to understand the cost of ETS, and therefore it was reasonable for the OEB panel for the ETS Decision to conclude that a cost allocation study should be prepared. However, the OEB does not interpret the ETS Decision as saying this means that there should be no other considerations, such as the market in other jurisdictions.

Hydro One supported intervenor arguments that a cost allocation methodology that includes the allocation of shared network costs to exporters should be provided in Hydro One’s next transmission rebasing application. The OEB agrees. This study should include different scenarios to take into consideration the fact that exporters do not receive the same priority access as domestic service until they are scheduled. The OEB agrees with the OEB panel for the ETS Decision that export service should continue to be viewed as a separate class. This study should be filed with Hydro One’s next transmission rebasing application.

The OEB would also be assisted by an updated jurisdictional review that provides the rates in other jurisdictions, rationale behind those rates and market implications. By the time the ETS issue is reviewed again, the last jurisdictional review will be more than a decade old. The OEB understands that the operation of the electricity market is the responsibility of the IESO, not Hydro One. Hydro One is therefore expected to discuss the approach to a jurisdictional review with the IESO and OEB staff to determine the best approach to complete a review before Hydro One’s next transmission rebasing application.

While the allocation of some shared network costs would increase the ETS rate, the current volume of exports and lower Hydro One OM&A costs would have an offsetting effect, the extent to which is unknown. The OEB therefore concludes that it is appropriate to leave the ETS rate at the current level pending this next review.

4 CONCLUSION

The following list is a summary of directions for filing and other matters contained in this Decision and Order. Where any discrepancies exist between this list and the text of the Decision and Order, the text in the Decision and Order governs.

Hydro One shall:

- In future applications, the OEB finds that it would be helpful for Hydro One to provide a comparison of its proposed transmission revenue requirement and resulting rates to those of other jurisdictions as part of its evidence.
- Explicitly address identified areas of concern with its customer engagement efforts in the combined transmission and distribution application to be submitted for 2023 and subsequent years.
- Review the different benchmark cost performance between its transmission and distribution operations and provide explanations for this difference in the next rebasing application.
- Provide a summary of its monthly reporting of productivity results to the CEO and senior executives as well as reporting on verifiable results in the next rebasing application.
- Engage an independent third party to review and report on its productivity framework as part of the next combined (transmission and distribution) rebasing application.
- Address the issue of the correlation between its capital spending and reliability in the next rebasing application.
- Initiate an independent third party review of its own processes for cost-effectively reducing transmission line losses, to be filed at the next rate application and fulfill all of the requirements of the settlement proposal on loss reduction.
- Provide a breakdown of its proposed capital spending by work category for each test year (in this Application, this breakdown was only provided for 2020) as part of the next rebasing application.
- Demonstrate that its selection process for consultants for future TSPs, or similar matters, is based on a more transparent, competitive process than the approach used to select Boston Consulting Group in this proceeding.
- Provide comparisons for all investments requiring LTC approvals, between what was approved in the LTC applications and what was budgeted into capital expenditures for the test years, and provide explanations of any material variances regarding scope, cost or schedule in the next rebasing application.

- File a detailed review of its common corporate costs and shared assets allocation methodologies (capital and OM&A) as part of the combined transmission and distribution application due to be filed for 2023 revenue requirement and rates.
- Provide a report comparing capitalization of common corporate costs with those of other utilities in Ontario, Canada, and North America (both under USGAAP and IFRS). The OEB also orders that a detailed review of Hydro One's B&V study regarding overhead capitalization be filed in its next rebasing application. This should include the revenue requirement impact and risk analysis associated with the transition from US GAAP to MIFRS.
- Provide a high level assessment of the correlation, or lack of same, between capital investments and OM&A costs at the program level in future rate applications.
- Explicitly provide compensation costs and associated FTEs, broken down between capital and OM&A and explain any significant differences between percentage changes in compensation costs and FTEs from year to year in future rebasing applications.
- Complete an updated benchmarking study using the same Mercer methodology for the upcoming combined rebasing application as outlined in the Decision and Order.
- Include a plan with the next rebasing application to bring compensation levels in line with market median.
- Demonstrate, in the next rebasing application, that the 2020 OM&A work program has been delivered and that the compensation reduction has not been achieved by reducing planned work programs.
- Continue to evolve the methodology for adjusting for CDM in the next application given the concern about Hydro One's use of forecast CDM values for 2016 and 2017 to adjust historical data.
- Provide an ETS study using a cost allocation methodology that includes the allocation of shared network costs to exporters in the next transmission rebasing application as outlined in the Decision and Order.
- File an updated ETS jurisdictional review that provides the rates in other jurisdictions, rationale behind those rates and market implications. Hydro One is expected to discuss the approach to a jurisdictional review with the IESO and OEB staff to determine the best approach to complete a review before Hydro One's next transmission rebasing application.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Hydro One shall file the draft revenue requirement/charge determinant order and the draft UTR rate order and supporting schedules no later than May 28, 2020.

2. 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 no later than June 11, 2020.

3. 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 June 25, 2020.

All materials filed with the OEB must quote the file number, **EB-2019-0082**, be made in a searchable/unrestricted PDF format and sent electronically through the OEB's web portal at https://pes.ontarioenergyboard.ca/eservice. Filings must clearly state the sender's name, postal address and telephone number, fax number and email address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at https://www.oeb.ca/industry. If the web portal is not available parties may email their documents to boardsec@oeb.ca.

NOTE: The OEB is temporarily waiving the paper copy filing requirement until further notice. All communications should be directed to the attention of the Board Secretary and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Martin Davies, at Martin.Davies@oeb.ca, and OEB Counsel, James Sidlofsky at James.Sidlofsky@oeb.ca.

DATED at Toronto April 23, 2020

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar and Board Secretary