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January 17, 2020

RESS, EMAIL & COURIER

Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Attention: Ms. Christine E. Long, Registrar and Board Secretary

Dear Ms. Long:

Re: Hydro One Networks Inc. ("Hydro One")
Custom Incentive Rate-setting ("Custom IR") Application for 2020-2022 Transmission Rates (OEB File No. EB-2019-0082)
Applicant Reply Argument

We are legal counsel to Hydro One in the above-referenced proceeding. Pursuant to Procedural Order No. 3, please find enclosed Hydro One's Reply Argument. Copies have been filed on RESS and served on each party in the proceeding.

Yours truly,

Charles Keizer

Enclosure

cc: Hydro One
All Parties

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ONTARIO ENERGY BOARD

EB-2019-0082

APPLICATION FOR ELECTRICITY TRANSMISSION

REVENUE REQUIREMENT BEGINNING JANUARY 1, 2020

UNTIL DECEMBER 31, 2022

REPLY ARGUMENT OF

HYDRO ONE NETWORKS INC.

JANUARY 17, 2020

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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, being Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c. 15;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. to the Ontario Energy Board seeking approval of its electricity transmission revenue requirement, to be effective from January 1, 2020 to December 31, 2022.

REPLY ARGUMENT

HYDRO ONE NETWORKS INC.

January 17, 2020

INTRODUCTION

These are Hydro One Networks Inc.'s ("Hydro One") reply submissions in its three-year Transmission Custom Incentive Rate-Setting ("CIR" or "Custom IR") application for the period commencing January 1, 2020 and ending December 31, 2022 (the "Application").

Fundamentally, Hydro One's plan is about balance. Balance between the imperatives of prudent transmission system asset stewardship, customer needs and preferences, productivity, compliance and service obligations, and efficient execution of work - all with a view to achieving these objectives while minimizing revenue requirement for the benefit of ratepayers. The Application achieves this balance primarily as a result of Hydro One's engagement with customers and Indigenous communities, its condition-based asset management practices, capital and OM&A plans, and its productivity framework.

Informed by the entirety of its ongoing engagement activities, research, and the fundamental understanding of cost as a priority consideration, Hydro One identified and considered customer needs and preferences in the formulation of its plan and its proposed spending priorities.

Unequivocally, condition is the primary driver of asset renewal needs and, thereby, it is the primary driver of the resulting investment plan. Condition-based renewal is the cornerstone of Hydro One's asset management practices and investment planning processes. As a prudent steward of the transmission system, Hydro One has an intrinsic accountability, not only to the transmission system itself, but also to its customers and the residents of Ontario, to identify and mitigate risks through ongoing assessments based on condition information and to manage the system in such a way as to avoid run-to-fail scenarios.

Hydro One, informed by its customer engagement activities, has presented a comprehensive capital plan that is underpinned by a rigorous investment planning process. Through that engagement and its investment planning process, Hydro One identified and prioritized investments to narrow the scope of the plan with a reduction of $997 million before finalizing the capital investment plan. Hydro One's verified asset condition assessments allow it to fulfill its role as a prudent steward of the transmission system while improving reliability, maintaining asset condition in accordance with customer needs and preferences and doing so at a reasonable cost.

Cognizant of the cost impacts, the proposed 2020 test year OM&A of $374.1 million is lower than both the historical Ontario Energy Board ("OEB" or "Board")-approved and actual OM&A levels over the 2015 to 2018 period. While the 2020 Sustainment OM&A level is somewhat higher than 2019, Hydro One again strikes a balance by passing on efficiency and productivity gains achieved in 2019 by not allowing the 2020 level to return to the higher 2018 level. To minimize the cost or rate impact of increased funding in specific Sustainment OM&A categories, the proposed 2020 Sustainment OM&A reflects a minimum sustainable budget to avoid the adverse effects on the system, and ultimately ratepayers, of extended deferrals of compliance obligations, preventive maintenance, transformer refurbishments, vegetation management and overhead lines maintenance programs.

Overarching Hydro One's plan is its comprehensive productivity framework, which encompasses rigorous processes to identify, develop, implement, monitor, and measure specific productivity initiatives, while maintaining or improving service quality, work outputs, and nurturing a workforce culture of productivity. Aligned with prior direction from the OEB, Hydro One has made its productivity forecasts explicit in the plan, together with the resulting net benefits to its customers. Extending the OEB's direction, Hydro One has introduced progressive productivity initiatives to stretch itself and to find new ways to perform work and to better deliver on the outcomes in the Application at a lower cost. Hydro One's productivity initiative is the most comprehensive and sophisticated framework for incenting, implementing, verifying, and tracking productivity yet to be considered by the OEB.

The elements of Hydro One's proposed Custom IR framework are appropriate in Hydro One's circumstances. The elements comply with well-established OEB policy and objectives, contain X factor components calibrated to reflect the strong cost performance of Hydro One (supported by benchmarking evidence), and contain upfront progressive productivity savings commitments resulting in lower capital factors than would otherwise be the case.

In summary, and as addressed further in the sections that follow, Hydro One's Application is grounded on a balanced and appropriate revenue requirement request which is based on a customer-oriented investment plan and is supported by identified asset condition needs. As such, Hydro One submits that the OEB should grant the approvals sought in the Application, including the total rates revenue requirement for the 2020 test year and the proposed Custom IR framework for determining Hydro One's transmission rates revenue requirement for each of 2021 and 2022.

A. GENERAL

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

As set out in Hydro One's Argument in Chief, the company has taken appropriate steps to address all relevant OEB directions from its prior transmission revenue requirement proceeding, including with respect to its capital planning and customer engagement processes, as well as by filing various internally and externally prepared reports.[1]

OEB staff submitted that "Hydro One has responded appropriately to all relevant OEB directions from previous proceedings, subject to any concerns OEB staff may express in subsequent sections of (its) submission."[2] To the extent that OEB staff has expressed any concerns in other sections of its submission, Hydro One will address those concerns under the corresponding issue.

For the most part, intervenors did not make submissions on this issue directly[3] or they found that Hydro One has addressed all prior Board directions adequately.[4] A few intervenors raised specific points under this issue, which Hydro One responds to in detail under the relevant substantive issue later in these reply submissions. The corresponding issues under which Hydro One provides its responses are identified below, along with summaries of the areas of intervenor concern.

Three intervenors argue that Hydro One has not addressed a portion of the Board's prior direction to "begin the customer engagement process sufficiently in advance of filing the application, include LDCs (to determine practical ways to seek some input from their end users),

[1] Hydro One, Argument in Chief, pp. 11-14.

[2] OEB Staff Submission, p. 8.

[3] AMPCO, APPrO, CME, SEC, SUP, PWU.

[4] VECC submitted that Hydro One responded to prior Board's directions in good faith, but dealt with customer engagement concerns in the body of their argument (VECC Submission, p. 3); LPMA submitted that Hydro One responded appropriately and adequately to all of the relevant OEB directions from previous proceedings (LPMA Submission, p. 3); CCC acknowledged that Hydro One has responded to the OEB directions and dealt with issues arising from the studies directed by the OEB in the body of their submissions (CCC Submission, pp. 5-6).

incorporate timely and meaningful input from First Nations representatives, and ensure that information presented to customers is unambiguous and easy to understand".[5] In particular:

- Anwaatin argues that Hydro One did not implement the Board's prior direction to incorporate timely and meaningful input from First Nations representatives.[6] Hydro One addresses this under Issue 12.

- VECC argues that Hydro One did not directly engage LDC end-use customers[7] and BOMA asserts that Hydro One's customer engagement did not "ensure that the customer satisfaction/engagement determinations deal with the LDC's customers' satisfaction levels and concerns"[8]. Hydro One notes that the submissions from both VECC and BOMA are off-target in that they fail to consider the actual direction provided by the Board in the prior proceeding, which was to "include LDCs (to determine practical ways to seek some input from their end users)".[9] Hydro One addresses these points under Issue 3.

Energy Probe made two submissions under Issue 1, neither of which relate to prior Board directions. These include (i) that Hydro One has let the state of Ontario's transmission assets deteriorate, which has resulted in a major drop in its reliability rankings, and (ii) that Hydro One has not done enough to reduce its above-market compensation and pension costs.[10] These assertions are addressed under Issue 9 and Issue 17, respectively.

Arguments made by Environmental Defence on transmission line losses are addressed under Issue 8.

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[5] EB-2016-016 Decision and Order (November 1, 2017). pp. 24 and 117.
[6] Anwaatin Submission, pp. 13-15.
[7] VECC Submission, pp. 3-4.
[8] BOMA Submission, p. 25.
[9] EB-2016-0160 Decision and Order (November 1, 2017), pp. 24 and 117.
[10] Energy Probe Submission, p. 6.

SEC has argued that although Hydro One responded to the Board's direction to obtain a third-party review of its investment planning process, the third party (BCG) was not independent.[11] Hydro One addresses this submission under Issue 9.

Based on the foregoing, and on Hydro One's responses to each of the concerns raised as indicated, the Board should find that Hydro One has responded appropriately to all relevant OEB directions from previous proceedings.

[11] SEC Submission, p. 5.

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

Hydro One indicated in its Argument in Chief that it used the same methodology to determine the bill impacts of the Application as it used in the EB-2016-0160 proceeding, which was approved by the OEB. In addition, Hydro One indicated that despite certain bill impact drivers being out of the company's control, the relatively small bill impacts resulting from the proposed Rates Revenue Requirement reflect Hydro One's efforts to appropriately balance system and asset needs and identified customer preferences regarding outcomes and rates.[12] Regarding the bill impact drivers that are out of the company's control, the most significant is load decline due to government conservation initiatives and lower consumption. While Hydro One is proposing only a 0.3% increase to its Rates Revenue Requirement for 2020 (relative to 2019), when combined with the 3.8% rate increase attributable to the resetting of the load forecast for 2020 the result is an average transmission rate increase of 4.1% in 2020, and over the 2020 to 2022 period the Application results in an average annual transmission rate increase of 5.5%, but 3.8% if the effects of load decline are removed.[13]

OEB staff submitted that the total bill impacts resulting from the Application, both for the average transmission connected customer and for the average distribution connected customer (0.3% in each instance), are reasonable as they are significantly below current inflation rates. While staff noted that the transmission rate increases resulting from the Application are higher (three-year average increase of 5.5%), they also note that a significant part of that increase is due to the effects of the declining load forecast.[14] VECC submitted that the bill impacts resulting from the Application are reasonable and that no mitigation is required.[15]

LPMA makes submissions in respect of the bill impacts in 2021 and 2022.[16] Although no other parties have made substantive submissions regarding this issue, Hydro One notes that a

[12] Hydro One, Argument in Chief, p. 15.
[13] Hydro One, Argument in Chief, p. 15.
[14] OEB Staff Submission, p. 9.
[15] VECC Submission, p. 3.
[16] LPMA Submission, p. 4. 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, these concerns are addressed under Issues 9 and 13.

number of the intervenors have used out-of-date references to the evidence in respect of bill and rate impacts. For example, AMPCO referrers to an increase in the Network Service Charge based on information that was subsequently updated in response to Undertaking J8.5;[17] BOMA refers to out-of-date rate impacts and an out-of-date inflation rate;[18] CME refers to non-current information on Hydro One's proposed revenue requirement and resulting rate increases;[19] and SEC uses out-of-date references to rate increases that appear to be based on Hydro One's response to Undertaking J1.1 rather than the most current information from J8.5.[20] To avoid confusion, Hydro One clarifies that, consistent with its response to Undertaking J8.5, the UTRs ($/kW-Month) resulting from Hydro One latest evidence are as follows:

	2020	**2021**	**2022**
Network	4.16	4.40	4.67
Line Connection	0.79	0.84	0.89
Transformation Connection	2.35	2.48	2.63

Moreover, Table 7 of Undertaking J8.5 presents an update to Table 3 of Exhibit I2, Tab 5, Schedule 1, which sets out the bill impacts for a typical Medium Density (R1) Residential Customer. This is reproduced as follows:

[17] AMPCO Submission, p. 4.
[18] BOMA Submission, pp. 36-37.
[19] CME Submission, p. 1.
[20] SEC Submission, p. 3.

	Typical R1 Residential Customer					
	Blue Page	**CoC Update**	**Blue Page**	**CoC Update**	**Blue Page**	**CoC Update**
	400 kWh	**400 kWh**	**750 kWh**	**750 kWh**	**1,800 kWh**	**1,800 kWh**
Total Bill as of May 1, 2018[1]	$83.40	$83.40	$121.75	$121.75	$236.81	$236.81
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$4.78	$4.78	$8.96	$8.96	$21.50	$21.50
Estimated 2019 Monthly RTSR[2]	$5.10	$5.10	$9.56	$9.56	$22.95	$22.95
2019 increase in Monthly Bill	**$0.13**	**$0.13**	**$0.24**	**$0.24**	**$0.58**	**$0.58**
2019 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$5.52	$5.30	$10.35	$9.93	$24.83	$23.83
2020 increase in Monthly Bill	**$0.42**	**$0.20**	**$0.79**	**$0.37**	**$1.89**	**$0.89**
2020 increase as a % of total bill	*0.5%*	*0.2%*	*0.6%*	*0.3%*	*0.8%*	*0.4%*
Estimated 2021 Monthly RTSR[3]	$5.84	$5.58	$10.96	$10.47	$26.29	$25.13
2021 increase in Monthly Bill	**$0.32**	**$0.29**	**$0.61**	**$0.54**	**$1.46**	**$1.30**
2021 increase as a % of total bill	*0.4%*	*0.3%*	*0.5%*	*0.4%*	*0.6%*	*0.5%*
Estimated 2022 Monthly RTSR[3]	$6.17	$5.93	$11.56	$11.12	$27.76	$26.68
2022 increase in Monthly Bill	**$0.32**	**$0.34**	**$0.61**	**$0.64**	**$1.46**	**$1.54**
2022 increase as a % of total bill	*0.4%*	*0.4%*	*0.5%*	*0.5%*	*0.6%*	*0.6%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).

[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One's 2019 rates revenue requirement as shown in Table 6 above.

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 6above, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

Finally, Hydro One wishes to address the suggestion from Energy Probe that Hydro One should, in reply, provide a comparison of its transmission rates to the transmission rates charged in other Canadian provinces using publicly available information. Energy Probe argues that the relative cost for Ontario transmission customers is material information that should have been filed and is relevant.[21] In Hydro One's submission, there are three main reasons that the Board should reject Energy Probe's request. First, the calculation of transmission rates in other provinces is very different than in Ontario, so the requested comparison could not reasonably be provided. For example, transmission rates charged by utilities in other provinces are not split into network, line connection and transformation connection "rate pools" with rates linked to coincident and non-coincident monthly peaks. Second, it is not appropriate for Energy Probe to request new evidence be filed at this stage of the proceeding. Such a request could have been made through interrogatories or otherwise during the discovery phase of the proceeding, which

[21] Energy Probe Submission, p. 7.

is now closed, or it could have been prepared and filed by Energy Probe. If filed by Hydro One as part of this reply submission, there would be no opportunity for discovery of that additional evidence and to provide such an opportunity would cause delay. Third, the requested information is not needed for the Board to determine the Application. Accordingly, the Board should not require Hydro One to provide the requested information.

Based on the foregoing, the Board should conclude that the bill impacts resulting from Hydro One's proposed revenue requirement are reasonable.

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?

As described in the Argument in Chief and detailed in the evidence, Hydro One is in frequent contact with its direct customers through a wide variety of customer engagement activities that, together, were sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending. These activities include large customer account management activities, customer conference, and oversight and working groups, in addition to the transmission customer engagement survey carried out by Innovative Research Group ("IRG") in 2017.

Hydro One engaged IRG to conduct the transmission survey in order to fill in gaps in customer preferences not addressed by other forms of ongoing customer engagement activities. The survey was tailored to Hydro One's specific planning needs. It focused on identifying the outcomes that should be considered when setting priorities across possible projects and in assessing the appropriate balance between price and other outcomes. Building on previous experience which showed these customers are difficult to reach, the survey aimed at securing the highest possible participation by including only critical questions and the most relevant background information. Through several diagnostic questions at the end of the survey, most customers indicated they were satisfied with the survey and the background information it included.

Together, these various customer engagement activities informed Hydro One of customer needs and preference, including those of LDCs' end-users, so that they could be taken into account during the investment planning process. In its submissions OEB Staff submits that Hydro One's customer engagement efforts are generally appropriate (subject to only two points of concern, which we address below) and OEB Staff "acknowledges that Hydro One has improved its transmission customer engagement compared to the last application."[22]

[22] OEB Staff Submission, p. 57.

The concerns raised by OEB Staff and intervenors focus mainly on three discrete aspects of the 2017 transmission customer engagement survey by IRG:

- First, OEB Staff and some intervenors raise a concern that a particular question in the survey did not include cost in a list of outcomes to be ranked, and so OEB Staff, SEC and others question whether Hydro One considered cost to be an important outcome for customers during the investment planning process. In fact, the evidence is clear that cost was recognized by Hydro One as an important priority for customers – this was well known by Hydro One and was taken into account in the investment planning process, along with customer feedback as to the level of investment customers thought should be made to achieve certain outcomes (i.e. the right balance of cost and achieving reliability or other outcomes – which was at the heart of the IRG survey).

- Second, OEB Staff and some intervenors questioned Hydro One's use of the reliability risk model (RRM) as a basis for including certain risk-related information in the survey question about illustrative investment scenarios. The RRM was used only for a limited purpose in that survey question – to just provide a directional indication of reliability risk associated with the illustrative scenarios, along with various other information customers were given – and it was reliable for this purpose. The RRM was not used for making investment decisions.

- Third, although no concern was raised by OEB Staff in this regard, some intervenors raised a concern that IRG did not directly survey or engage with LDCs' end use customers. However, Hydro One in fact took steps – through the IRG survey and otherwise during its customer engagement activities to obtain feedback as to the views and interests of LDCs' end use customers, and took this into account in the investment planning process. IRG was not in a position, and it would not have been practical, to directly survey the LDCs' end use customers as part of this transmission customer survey.

We address each of these points in more detail below, along with a few smaller points raised by intervenors which we address at the end.

Hydro One Understood and Took Into Account that Cost Was a Priority

The concern raised by OEB Staff and others on this topic is solely based on the fact that in one question in an early portion of the IRG survey, the survey respondents were given a list of seven outcomes and were asked to rate their importance on a scale of 0 to 10 and to rank those particular outcomes against each other. Since that particular list of outcomes in that question did not include cost, OEB Staff and others argue that the survey process was flawed and that Hydro One did not consider cost as being important to customers. That is not the case, and it ignores: (i) the clear explanation by Mr. Lyle of IRG regarding this particular survey question and its purpose; (ii) that other portions of the survey obtained feedback on cost considerations; and (iii) other customer engagement information Hydro One had in respect of cost being a priority to customers. It was well understood that cost is a priority for customers, and Hydro One took this into account in the investment planning process.

This IRG survey was focused on additional information Hydro One planners needed for purposes of preparing the investment plan (along with all of the other information the planners had). In particular, the survey focused on three main tasks which Mr. Lyle explained as follows:

> So essentially, there are three tasks the workbook is informing: What is the stack of potential investments that we should be looking for?
>
> Hydro One has a bunch of ways that they look at that, but in that first question, the need is basically a safety valve to say is there something on the minds of customers that you haven't previously considered.
>
> The second, the questions on the outcome, are focussed on how do we order the projects within the stacks to make sure that we do the things that matter the most to customers first.
>
> And then the third part, where we do the trade-off, basically says: how far down the stack of investments do we go to the point at which customers no longer feel they're receiving value for paying any more.[23]

Mr. Lyle confirmed that when he and Hydro One were developing the survey, they looked at prior research and other customer feedback information they had. Based on this other information and research, Hydro One was well aware that cost is an important overall concern of customers, particularly low volume end-use residential customers of LDCs. Since that fact

[23] Oral Hearing Transcript, Vol. 6, p. 142; Vol. 7, pp. 4-5.

was already well known, Mr. Lyle explained "that wasn't what [he was] getting at when doing [IRG's] survey, because it is known at Hydro One that most people care about price."[24]

In respect of the first task described above by Mr. Lyle, the survey asked an open-ended question as to customers' needs. Customers could provide any response they chose to express their concerns or needs in response to this question (including in respect of cost or price). Mr. Lyle then explained that the one outcomes question on which OEB Staff and intervenors focus (in which customers were asked to rank a list of seven outcomes, such as reliability, safety, etc.) is a question to assist with the second task above, i.e. how to order the potential investments in the stack "to make sure we do things that matter the most to customers first." Stated differently, Mr. Lyle indicated that "these are the outcomes that we asked [customers] to identify for the purpose of deciding *which investments are more important*."[25]

That particular question was not for purposes of determining how important cost is to customers "because again, we have other research showing that, and in that other research we get very high concern, particularly among end-users, over cost." There are also other questions in the survey relating to cost. In particular, besides the above-mentioned initial open-ended question about needs or priorities (in response to which customers could refer to cost), the third section and task of the IRG survey related directly to cost considerations. As Mr. Lyle stated: the "opportunity to talk about cost in terms of a rate impact comes later in the survey under the investment scenario section." He elaborated: "That's why that third section on what's the right balance between cost and investment is there. It's really the meat and potatoes." That section, with illustrative investment scenarios, is about what is the right balance and pace. "Cost determines how far down the stack [of potential investments] you go."[26]

In addition to the important cost-related feedback Hydro One obtained from customers from the third section of the IRG survey, Hydro One also had other customer engagement research

[24] Oral Hearing Transcript, Vol. 6, p. 182, and other cites including Vol. 6, p. 194; Vol. 7, p. 8.
[25] Oral Hearing Transcript, Vol. 7, p. 15.
[26] Oral Hearing Transcript, Vol. 6, pp. 189-191; Vol. 7, pp. 18-19.

emphasizing the importance of cost and price as a priority to customers, including to LDCs' end-use customers.[27]

The record is clear that Hydro One took this customer priority into consideration during the investment planning process and also at the time of approval of the plan by its board of directors. The evidence on this point includes the following.

Mr. Gill (Hydro One's strategic advisor to the president and, until very recently, its director of large customer accounts) testified that "costs is an issue across all customers", and "this is known at Hydro One." He confirmed that: "our approach ultimately with respect to a plan that gets filed and that is before you is informed not only by the survey, but information that is -- comes in through other means through our ongoing engagement, other surveys, so cost is definitely an issue that is at the top of mind."[28]

Mr. Gill also reiterated that all of the customer engagement Hydro One does – not just the IRG survey – as well as all of its other research, informed the final investment plan. "It is certainly informed by our knowledge of the general concern for rates in Ontario," he stated. In response to OEB Staff's questions, he further stated that: "The plan itself is informed by all of our customer engagement activities," and he indicated that Exhibit A-7-1, attachment 1, "outlines all of our customer engagement activities that ultimately inform the plan." Those various activities – which, again, go well beyond the 2017 IRG survey – are summarized in Hydro One's Argument in Chief.[29]

The oral hearing testimony also confirmed that the business plan "reflected the fact that other research [i.e. besides the IRG survey] told them customers are very concerned about [price and cost]." On a more granular level, Mr. Gill testified that discussions with customers about developing projects for less money "happen through individual discussions with individual customers through the key account management model;" and "when we are planning investments together with customers, with LDCs, that's where discussions around the total cost of a particular investment is more tangible and more real in a conversation." Mr. Gill also

[27] Exhibit B-1-1, TSP Section 1.3, pp. 28-29.
[28] Oral Hearing Transcript, Vol. 7, p. 83.
[29] Oral Hearing Transcript, Vol. 7, pp. 2, 10 and 20.

emphasized "how critical this model [i.e. the key account management model] is to informing the plan." These customers have direct access to Hydro One's planners through its operations group and Hydro One deals with customers' concerns related to costs on "an ongoing basis throughout the year."[30]

In cross-examination, Mr. Brett of BOMA directly suggested to Mr. Jesus (Hydro One's vice president of planning and engineering) that price was not something that was considered as a priority when Hydro One was putting together its transmission plan, and in response Mr. Jesus stated unequivocally: "I would disagree with that entirely." Mr. Jesus went on to explain that: "cost is an inevitable outcome of the plan;" and that, in respect of the IRG survey, cost is being taken into account when customers made their choices on the investment scenarios continuum. Customers could have chosen any level of investment, but the one most selected was option C, a $6.6 billion investment level. That feedback was one of the inputs in developing the investment plan. And in response to a question from the Chair, Mr. Jesus reiterated that cost "is absolutely an outcome that we considered in developing the transmission system plan" and it helped Hydro One "prioritize the investments."[31]

In fact, from start to finish the investment planning process emphasized being responsive to customer priorities, including cost. For example, Hydro One's Investment Planning Kick-Off Session emphasized this point, including that "expressed customer preferences should guide the development of the investment plan." Distribution customers' key preferences were discussed at this session and it was specifically noted that those "customers consistently prioritized low rates as the top priority and wanted Hydro One to do its best to limit increases."[32]

Prioritizing cost ultimately resulted in significant reductions to the final capital investment plan. From the candidate investment stage to the final plan, the capital investment plan was reduced from $7.616 billion to $6.619 billion, a $997 million reduction. Various investments were prioritized out of the plan and not included in this Application.[33]

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[30] Oral Hearing Transcript, Vol. 7, pp. 10, 20, 29-30.
[31] Oral Hearing Transcript, Vol. 3, pp. 109, 11-114; OEB-39.
[32] CCC-7, Attachment 1, 2019-2024 Investment Planning Kick-Off Session, pp. 10-11.
[33] SEC-28; JT1.2, p. 4.

In respect of approval of the final plan by Hydro One's board of directors, Mr. Gill confirmed that:

> Ultimately our investment plans get approved by our board of directors, and so they are informed certainly by what our customers' needs are through this survey, but also other work that we do through ongoing engagement, plus also the needs of end use customers as well and the prevailing -- the prevailing concern around rates in the province was there.

And he further stated that cost, the prevailing context of rates, and the need to balance that concern, was an important consideration in the Hydro One board's final decision on the plan.[34] Indeed, Hydro One's newly appointed board delayed the filing of this application so they could re-evaluate the company's transmission business plan with a particular focus on increasing productivity and minimizing rate increases to customers.[35]

In conclusion on this first concern, OEB Staff and intervenors are simply wrong to suggest that cost (or price) was somehow not considered as a priority during the investment planning process. In fact it was, as confirmed repeatedly on the evidentiary record and is highlighted above. Hydro One was aware of customers' views as to the importance of cost (and price) and it was considered throughout the planning process.

We also note that, in respect of AMPCO members' concerns about cost (emphasized in its submissions), the evidence is that their main focus has in fact been the global adjustment charges, for which Hydro One is not responsible. In response to questions by AMPCO, Mr. Gill stated:

> I can say that rates-type discussions that we have had with your members and our largest customers revolve predominantly around the price of the global adjustment, which is the largest portion of their bills.
>
> So they are concerned about -- call it the biggest issue that they have. A lot of the conversations that we have with them are with respect to their desire to shave global adjustment charges through peak avoidance.[36]

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[34] Oral Hearing Transcript, Vol. 6, pp. 143-144, and 194.
[35] See Exhibit A-3-1, p. 4.
[36] Oral Hearing Transcript, Vol. 7, pp. 79-80.

Limited Use of the Risk Reliability Model (RRM)

Staff and several intervenors (SEC, CME, AMPCO, BOMA) raised concerns with Hydro One's use of the RRM for purposes of transmission customer engagement. The thrust of their concerns pertains to the fact that the OEB found the RRM deficient as an indicator of reliability risk. Specifically, the OEB noted in its EB-2016-0160 decision:[37]

- "The model may be used to directionally compare investment scenarios, but it cannot be used to predict the benefit of any given scenario in terms of reliability."
- "The model needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability."

As part of Hydro One's last customer engagement survey for the 2017-2018 transmission rate application, a direct correlation was made between spending and percentage reliability impact, which could have benefited from a full explanation of what the RRM results are meant to convey. In contrast, this latest survey contained clear information to properly contextualize and explain "reliability risk" and the directional impact of investment decisions on reliability.[38] As part of the four illustrative scenarios shown in the customer survey, "reliability risk" was provided (accompanied by arrows) to directionally inform customers on the expected long-term reliability impact of each investment scenario.[39] Using the RRM in this manner is consistent with the limitations of the tool identified in the EB-2016-0160 decision.

Although OEB Staff and some intervenors question Hydro One's use of the RRM (based on the above comments about the RRM in the last transmission application decision), the evidence is clear that its use was very limited, in connection with an IRG survey question.

Mr. Gill of Hydro One testified that the RRM is no longer in use for planning purposes at Hydro One. In response to previous concerns that had been raised about the RRM, Hydro One recast its use of the RRM. At the time of and in connection with the 2017 IRG survey, the RRM was

[37] EB-2016-0160 Decision and Order (November 1, 2017), p. 23.
[38] Exhibit B-1-1, TSP Section 1.3, Attachment 1, pp. 111-112.
[39] Oral Hearing Transcript, Vol. 7, pp. 21-23; Exhibit B-1-1, TSP Section 1.3, Attachment 1, p. 46.

only used as a tool to seek, directionally, customers' appetite as to the level of system investment. The IRG survey included the following description relating to reliability risk and the RRM:

> Reliability risk is a forward looking or leading indicator of system reliability performance. It is calculated using a model which forecasts the risk or probability of asset failure (or needed replacement), based on the historical relationship between asset age and retirement.
>
> It is an outcome measure used to indicate the potential improvement or decline in system reliability as the result of an investment plan. This measure also serves as a directional indicator to inform the appropriate level of pacing of sustainment investments to avoid future decline in reliability. The reliability model is not used to identify specific asset needs and investments. Hydro One chooses the assets it replaces based on detailed assessments of their actual condition.[40]

The RRM was only used in a limited way in connection with the illustrative investment scenarios question in the IRG survey, which provided four illustrative scenarios along a spectrum of potential investment levels. One of the table entries gave customers a directional sense (by using an up or down arrow) as to the impact on reliability risk of each particular illustrative investment scenario. As Mr. Gill explained: "Directionally you can see that we chose to use arrows, so as not to imply absolute precision" and this was for "directionally informing customers in terms of what they could expect in terms of long-term reliability impact, recognizing that there is a latency there."[41]

It is important to note that the RRM is not used for making investment decisions, rather it served merely as a communication tool to convey directional outcomes of various scenarios. The RRM was a reliable tool for this limited purpose. Concerns expressed by the OEB about the RRM needing refinement do not affect its ability to be used to provide a directional, arrow sense of long-term reliability impact, as was done in this case.

Furthermore, and recognizing the limitations of the tool, Hydro One articulated other outcome measures associated with the illustrative scenarios used in customer engagement, including long-term reliability performance, rate impacts, and asset age profile. This suite of outcomes

[40] Oral Hearing Transcript, Vol. 6, pp. 176-177; Exhibit B-1-1, TSP Section 1.3, Attachment 1, p. 137.
[41] Oral Hearing Transcript, Vol. 7, pp. 20-22.

provided a multi-lens perspective to inform customers during the engagement. The output of the RRM was by no means the sole proof point.

Hydro One Obtained and Considered Feedback Regarding LDCs' End-Users

We note that OEB Staff raised no concern on this point; it presumably is comfortable with Hydro One's activities to obtain the views and interests of LDCs' end-users as part of its customer engagement activities. Some intervenors, though, raised a concern in this regard. However, the evidence demonstrates that Hydro One took reasonable and practical steps to obtain this type of feedback, and it was taken into account in the investment planning process along with other customer engagement feedback.

As outlined in its Argument in Chief, Hydro One took a number of steps to obtain feedback in respect of LDCs' end-users and their priorities. These steps included that, at the outset of the IRG survey, LDC respondents were specifically directed as follows: "As a distributer, please respond to the questions in this survey with your customers in mind. Your feedback should be made with consideration to your customers' needs." That was an overriding direction/request to all LDCs who participated in the survey.[42] In this way Hydro One sought to have the needs of LDCs' customers reflected in their survey responses.

A further question in the survey asked LDCs if their responses were informed by specific customer engagement activities or research they had done. Mr. Lyle of IRG explained that this question was asking LDCs if they had done relevant engagement activities or research on transmission issues that informed their views. In response, eleven of the twenty-eight LDC respondents answered that, yes, they had done such activities or research. Contrary to the suggestion in SEC's submissions, that question was *not* asking LDCs whether they complied with the overriding direction at the start of the survey to respond to the survey with their customers' needs in mind. SEC's submissions on this point are directly contrary to the evidence given by Mr. Lyle on this.[43]

[42] Oral Hearing Transcript, Vol. 6, pp. 148-149; Exhibit B-1-1, TSP Section 1.3, Attachment 1, p. 96.
[43] Oral Hearing Transcript, Vol. 6, pp. 152-154.

There is no basis in the record to suggest that LDCs failed to respond to the IRG survey with their customers' needs in mind. The LDCs, of course, were well aware of their own customer engagement surveys and research indicating the key priorities of their end-user customers. It is only reasonable to conclude that they took it and their customers' needs into account when responding to the survey, as they were specifically requested to do.

Importantly, besides the IRG survey, Hydro One also had the benefit of other customer engagement research and continuing engagement activities which provided feedback as to the views of LDCs end-users. Hydro One had other customer engagement research on end-users (indicating what end-users' priorities are), which was taken into account.[44]

As part of its ongoing customer engagement activities, and consistent with LDCs' suggested way to obtain feedback, Hydro One account executives engaged LDCs in discussions regarding the needs of end-users. As and when requested, Hydro One participated, along with LDCs, in meetings directly with LDCs' end-user customers. In his testimony, for example, Mr. Gill discussed how Hydro One coordinated through an LDC "several meetings with customers, large manufacturers within the area who wanted to speak to our executives about their concerns." Mr. Gill further stated that Hydro One is "amenable to always meeting with end-use customers, along with our LDC partner, that is – that is the convention, if you will. We don't work around LDCs and speak directly to their customers."[45] LDCs have made it clear that it wanted Hydro One to continue to work through the key account managers, not to contact their end-use customers directly.

The results of LDCs' customer surveys were considered during Hydro One's planning process. Hydro One's own distribution customer engagement results were also taken into account, including at the outset of the investment planning process as noted above.[46]

Hydro One's actions respecting LDCs' customers are consistent with the OEB's direction in the company's last transmission application, which was to "include LDCs (to determine practical

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[44] Oral Hearing Transcript, Vol. 6, p. 182; Vol. 7, p. 8.

[45] Oral Hearing Transcript, Vol. 7, pp. 30-3l.

[46] Exhibit B-1-1, TSP Section 1.3, Appendix 2 and Section 1.3.2; Oral Hearing Transcript, Vol. 6, pp. 149, 152.

ways to seek some input from their end users)."[47] This stands at some distance from the obligation to directly contact the customers of other LDCs, which is what intervenors are suggesting Hydro One was obligated to do. That was not the direction from the OEB.

In fact, it was noted in the OEB's decision on Hydro One's last transmission application that direct involvement of LDCs' end-users in Hydro One's engagement process "is obviously impractical and does not fall within Hydro One's direct accountability."[48] Mr. Gill similarly noted in his testimony that: "It's just not acceptable to approach another LDC's customers directly," and "Hydro One is not in possession of contact information, customer contact information for other utilities' customers." Given Hydro One's relationships with the LDCs, it would not have been appropriate for Hydro One to try to directly survey their customers. Hydro One cannot be faulted for not doing so.[49]

In all of the circumstances, Hydro One took reasonable and practical steps to obtain feedback in respect of LDCs' end-users, and this feedback was considered during the investment planning process.

A final point that should be kept in mind here, which Mr. Lyle emphasized in his testimony (in response to SEC's questions), is that customers' responses to the investment scenarios question (i.e. the third task of the IRG survey) were consistent with responses IRG typically sees from LDCs' end-use customers to similar questions. In surveys of those customers, notwithstanding that they rate price as a top priority, Mr. Lyle confirmed:

> And then when we say, okay, would you be willing to pay more to get this particular project built, they will typically say yes, I will pay more to build that project.
>
> And then when we say overall, when you think of the costs of all of these projects, are you willing to pay more in order to have a more sustainable grid, the answer is normally, yes.
>
> And so when you look at the outcome here with people responding to the scenarios [in this 2017 transmission survey], their responses to the scenarios are

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[47] EB-2016-0160 Decision and Order (November 1, 2017), pp. 24 and 117

[48] EB-2016-0160 Decision and Order (November 1, 2017), p. 23.

[49] Oral Hearing Transcript, Vol. 6, p. 182; Vol. 7, p. 32.

> very similar to the responses that we would get to an equivalent question in an LDC.[50]

Other Points Raised by Intervenors

The above sections address the main concerns raised by OEB Staff and intervenors. SEC, and one or two other intervenors, raised a few additional points which we address here.

The Amount of Information Given to IRG Survey Participants

SEC raises a concern in this regard and submitted that "Hydro One provided little in the way of background information as part of the survey to provide the necessary context about Hydro One's transmission system, its assets, reliability. To get the information, participants were required to access a separate document, which provided the necessary contextual information."[51]

The important question here is how the customers who participated in the survey felt about the survey, people who are among the most sophisticated customers in the industry:

- page 59 of the IRG reports shows 81 had a positive impression and just 3 had a negative impression; and
- page 60 of the IRG report shows 78 said the survey had the right amount information with only 9 saying too little and 5 saying too much.

In the customers' own view, the survey provided the right balance.

In Mr. Lyle's testimony he emphasized the highly sophisticated nature of the respondents; they were "planners and LDCs, people that run the electricity accounts for the largest industrial generators." They are very knowledgeable in respect of the industry and contextual information about the transmission system.[52]

[50] Oral Hearing Transcript, Vol. 6, pp. 157-158.
[51] SEC's Submission, p. 421.
[52] Oral Hearing Transcript, Vol. 6, pp. 166-173.

Further, to the extent respondents wanted additional contextual information, they could simply access the links provided with the survey,[53] a straightforward thing to do.

Therefore, given the nature of this survey and the nature of these sophisticated transmission customer respondents, sufficient information was provided in the IRG survey to allow them to meaningfully respond to the survey. The customers overwhelmingly confirmed they had no concerns in this regard.

The Descriptions of the Illustrative Investment Scenarios

SEC briefly raises a concern that a heading in the IRG survey relating to investment scenario C was misleading. The heading stated: “Scenario C: Maintain current level of investment”. SEC argues this heading was misleading because that scenario was based on the proposed investment plan that was before the OEB at the time, but the OEB ultimately decided to make reductions to that plan.

In fact, there was nothing misleading about the description of Scenario C in the survey. The bullet point text under the heading made it clear that this scenario “extends investment plan in rate application currently before the Ontario Energy Board to 2023” – that was entirely accurate. Also, the rest of the description of Scenario C clearly laid out the total dollar amount of investment under the scenario, namely $6.6 billion and the average annual transmission rate increase it would represent, along with various other information regarding that illustrative scenario.[54]

SEC also argues that the respondents may not have been aware that the projected rate increase information in respect of the four illustrative scenarios did not include the potential impact of changes in load. However, the survey specifically informed respondents that: “As you consider these illustrative scenarios, please bear in mind that your rates can also be impacted by changes in load forecast…” Both Messrs. Lyle and Gill also emphasized that these sophisticated respondents, including the LDCs, have information and expectations about load and its impacts which they would be bearing in mind. Mr. Lyle stated that these respondents

[53] Oral Hearing Transcript, Vol. 7, p. 92.
[54] Exhibit B-1-1, TSP Section 1.3, Attachment 1, pp. 113-117.

"probably know exactly what to expect in terms of load", and "I don't have much doubt they were thinking about the load factor and probably also their guesses about global adjustments and other things that would have impacted their bills when they were looking at total bill impacts."[55]

No other customer engagement survey submitted to the OEB has included this information, as far as Hydro One is aware. Indeed, the filing requirements do not require load impacts to be included in customer engagement. The purpose of the customer engagement exercise is to gather the needs and preferences of customers so these may be included in the transmission system plan. Unlike capital and OM&A spending that Hydro One has some level of control over, it does not have any control over externalities such as load impact (i.e. unlike spending levels, there are no customer "choices" to be made with respect to load impacts). This is why external elements such as load impact, or the change in tax legislation that drove down bill impacts, are not included in the customer engagement survey.[56]

The Timing of the Customer Engagement Activities

SEC submits that the customer engagement activities were carried out before the OEB rendered its decision in EB-2016-0160 and so they are unchanged compared to prior customer engagement activities about which the OEB had noted some concerns. This is incorrect and SEC's concern in this regard is without merit.

First of all, in respect of timing, while the IRG transmission customer engagement survey was carried out before that OEB decision was issued, the various other forms of customer engagement activities that also provided useful customer feedback and informed the investment planning continued to occur after the decision was issued and were responsive to parts of it.[57]

Second, under cross-examination by SEC as to why Hydro One did not do a further IRG survey after the release of the decision in EB-2016-0160, Mr. Gill explained that: "It really comes down to timing. At the outset the timing of the survey was tight with respect to meeting the filing requirements and ultimately the – I believe the filing date was a bit of a moving target, so it was never really apparent there was time to re-engage customers again in the same manner, rather

[55] Exhibit B-1-1, TSP Section 1.3, Attachment 1, p. 113; Oral Hearing Transcript, Vol. 6, pp. 166-169.
[56] Oral Hearing Transcript, Vol. 6, pp. 167-168.
[57] Exhibit B-1-1, TSP Section 1.3, Attachment 2, and TSP Section 1.1, pp. 29-35.

[Hydro One] rely upon our ongoing customer engagement that is described elsewhere in the evidence." He similarly noted that "while the filing date may have been a year after it was intended, it was a moving target throughout that year."[58]

Third, and importantly, the timing of the IRG survey allowed the feedback to be incorporated into the investment planning process. That timing was in fact responsive a main piece of feedback from the OEB and intervenors. In other words, various OEB and intervenor feedback was considered, and responsive steps were taken, even prior to the release of the decision in EB-2016-0160. The evidentiary record details the steps taken by Hydro One in this regard relating to its customer engagement activities, including the table on page 31 of TSP section 1.3.[59] As stated above, OEB Staff has for good reason acknowledged in its submissions that "Hydro One has improved its transmission customer engagement compared to the last application."

In conclusion on this issue, Hydro One's customer engagement activities were sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending.

[58] Oral Hearing Transcript, Vol. 6, pp. 162-163.
[59] Exhibit B-1-1, TSP Section 1.3, p. 31.

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

Hydro One explained in its Argument in Chief that the Application was filed over nine months prior to the requested effective date, that it conducted itself appropriately and met all filing deadlines, entered into settlement agreements where possible, and that, given the Application is for a rate period of only three years, it allowed sufficient time relative to the requested effective date. Hydro One also requested an interim rate order to make its current transmission revenue requirement and charges interim as of January 1, 2020 and to establish a Foregone Transmission Revenue Deferral Account to recover the differences between the revenues earned under interim rates and the revenues that would have been earned based on final rates from the January 1, 2020 effective date until the implementation date of the final rates.[60]

OEB Staff expressed the view that the proposed effective date is appropriate, as is the requested interim rate order.[61] In addition, under Issue 23, OEB staff confirm that they have no issues with the proposed Foregone Transmission Revenue Requirement Deferral Account.[62] Although VECC raises a concern with the Foregone Transmission Revenue Requirement Deferral Account, which is addressed under Issue 23, neither VECC nor any other party other than SEC has taken issue with Hydro One's proposed effective date.

Despite multiple parties making submissions in support of the proposed effective date based on their consideration of factors such as the timeframe relative to other proceedings, Hydro One acting reasonably, not causing delays and meeting all timelines,[63] SEC argues otherwise. In this regard, SEC stands alone as the only intervenor who does not agree with the proposed effective date.

SEC argues that the effective date should be the earlier of the Board's issuance of its final decision, or April 1, 2020. SEC states that Hydro One's proposed January 1, 2020 effective date would have allowed the Board just over 9 months to adjudicate Hydro One's application and that

[60] Hydro One, Argument in Chief, p. 23.
[61] OEB Staff Submission, p. 14.
[62] OEB Staff Submission, p. 134.
[63] See VECC Submission, p. 6; LPMA Submission, p. 5; CCC Submission, p. 8; and Energy Probe Submission, p. 4.

this is not enough time due to the quantum of the proposed revenue requirement and the fact that this is the first transmission rates application that has been filed as a Custom IR application.[64] To support its argument that 9 months is an insufficient amount of time, SEC advanced three arguments, each of which should be rejected for the reasons below:

First, SEC asserts that Hydro One's last major transmission application (EB-2016-0160), which had a two-year test period, took approximately 16 months from filing to issuance of the Board's decision.[65] However, SEC fails to mention that the hearing phase of EB-2016-0160 was completed on February 16, 2017, and that it was therefore only because the decision was issued seven and half months later that the exceptionally long 16-month timeline occurred. Indeed, the Board recognized this in its decision in EB-2016-0160 as it considered various examples of prior proceedings and found that "a duration of approximately 7 to 8 months between the Application date and the proposed effective date is reasonable for cases similar to the current Hydro One application".[66] The Board also found that "a duration of 7 months… [was] within the range of reasonable durations of similar cases."[67] As such, there is no reason that Hydro One ought to have filed its application earlier than it did based on the timeline of the EB-2016-0160 proceeding.

Second, SEC argues that Hydro One should have expected that it would take a year from filing to issuance of a decision because, in the OEB decision on Hydro One's recent distribution Custom IR application (EB-2017-0049), the OEB said that it was reasonable for Hydro One to have expected its 5-year Custom IR application to take at least a year. It is Hydro One's submission that SEC is wrong to suggest that the current application is as complex as Hydro One's recent distribution rates application. In the current proceeding, the incentive rate setting elements being proposed have already been tested by the OEB in Hydro One's distribution rates application. Moreover, the benchmarking evidence supporting the application, which is largely unchanged, was heavily tested by intervenors and OEB staff's expert in the recent Hydro One Sault St Marie ("Hydro One SSM") proceeding (EB-2018-0218). Moreover, because the OEB is being asked to approve funding over a test period of 3 years, the scope of review in

[64] SEC Submission, p. 75.
[65] SEC Submission, p. 75.
[66] EB-2016-0160 Decision and Order (September 28, 2017), p. 114.
[67] EB-2016-0160 Decision and Order (September 28, 2017), p. 114.

relation to the TSP is more in line with a 2-year cost of service proceeding than a typical 5-year Custom IR proceeding. As such, it is unreasonable to suggest that the current proceeding should be subject to the same timeline for effective dates as was the case in EB-2017-0049. That SEC is an outlier as the only party taking this position underscores the unreasonableness of its submissions.

Third, SEC argues that an April 1, 2020 effective date would be consistent with the Board's new metrics for cost-based applications that are greater than $500M. However, those metrics were not in effect when Hydro One filed its application. The metrics were announced by the Board in a letter dated March 12, 2019, and came into effect on April 1, 2019, after Hydro One filed its Application on March 21, 2019, and include provisions for procedural steps that are not relevant to Hydro One transmission (e.g. community meetings).[68] Hydro One submits that the new standards do not apply to the present Application. Rather, the Board's guidance in effect at the time the Application was filed was that a utility filing for an effective date of January 1, 2020 must file by April 26, 2019,[69] which was approximately one month later than Hydro One filed its Application.

In light of the foregoing, Hydro One submits that the proposed effective date of January 1, 2020 is appropriate.

[68] See the Board's March 12, 2019 letter at the following link: https://www.oeb.ca/sites/default/files/letter_performance_standards_for_processing_rate_applications_20190311.pdf

[69] See the Board's November 27, 2018 letter at the following link: http://www.rds.oeb.ca/HPECMWebDrawer/Record/627327/File/document

B. CUSTOM APPLICATION:

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

As outlined in the Argument in Chief, the elements of Hydro One's proposed CIR framework for the determination of revenue requirement are appropriate in Hydro One's circumstances and are supported by the evidentiary record. The elements of the framework:

- adhere to existing and well-established OEB policy, including meeting the objectives of the OEB's RRF and the requirements in the *Handbook for Utility Rate Applications* ("the "*Handbook*");
- contain X factor components that are calibrated, consistent with OEB policy, to reflect the strong cost performance of Hydro One; and
- contain an upfront commitment to finding progressive productivity savings, which benefit customers through lower C (capital) factors than would otherwise be the case while providing a financial incentive for continuous improvement.

OEB Staff and intervenors take no issue with Hydro One's overall proposed Custom IR framework in this application. They do take issue with certain parameters of the framework, principally the proposed X factor and the calculation of the C-factor. However, OEB Staff's and a number of intervenors' submissions on the X factor and C-factor parameters: (i) are contrary to the expert evidence on the record, including the recommendations of OEB's Staff's own expert – both sides' experts find that Hydro One is a top quartile cost performer that is outpacing the industry productivity trend; (ii) are inconsistent with OEB policy, and would result in inappropriate incentives for utilities; and (iii) contradict or ignore key factual evidence on the record which explains why the parameters of the framework are appropriate and justified in the circumstances.

OEB Staff and various intervenors have suggested changes to the framework parameters which, together with suggested cuts to capital and OM&A budgets, would be unprincipled and punitive, and are not supported by the evidence or the OEB's policies in respect of incentive regulation. Those suggested changes should be rejected.

The sections below address the various elements of the proposed framework and the issues or concerns raised by OEB Staff and intervenors.

The Inflation Factor

No party has taken issue with Hydro One's proposed inflation factor.

The proposed inflation factor is specific to the transmission industry and is based on a custom weighted two factor input price index, supported by the study of Hydro One's expert consultant, Power System Engineering, Inc. ("PSE").[70]

As noted by OEB Staff, the OEB previously approved this same input price index methodology for Hydro One SSM (EB-2018-0218) and in the 2019 revenue requirement update for Hydro One (EB-2018-0130).[71] The record here establishes that it remains appropriate for this application.

The X Factor

Hydro One's proposed X factor – which combines the base productivity factor and the stretch factor – is calibrated at 0%, based on the industry productivity and cost benchmarking studies performed by PSE and established OEB policy. OEB Staff's own expert consultant, Pacific Economics Group Research ("PEG") recommends an X factor of 0.05%. BOMA supports PEG's recommended X factor of 0.05%.[72]

Both sides' experts therefore recommend an X factor of about 0%. Despite this, OEB Staff and a number of intervenors suggest an X factor of 0.3%.[73] To arrive at this much higher X factor than PEG or PSE, OEB Staff and certain intervenors[74] effectively "cherry pick" from half of

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[70] The weightings, representative of the transmission sector, are 14% labour and 86% non-labour, which OEB Staff and other parties agree are reasonable. See Exhibit A-4-1, Attachment 1, p. 50.

[71] EB-2018-0218 Decision and Order (June 20, 2019), p. 16.

[72] BOMA Submission, p. 35.

[73] See Energy Probe Submission, p. 14; and LPMA Submission, p. 6.

[74] OEB Staff Submission, pp. 22-23: Staff concludes that PEG's TFP analysis is to be preferred, but then, instead of following PEG's recommendation of a negative 0.25 base productivity factor which flows from PEG's analysis which it purportedly agrees with, states that for the base productivity factor 0% is preferable. See also LPMA Submission, pp. 5-6.

PEG's evidence and ignore or discount the other half of PEG's evidence as well as PEG's overall recommended X factor. It should not be open to OEB Staff to argue against its own expert evidence especially when there is no opinion from any other expert supporting its position, and when OEB Staff's position ignores other important factual evidence supporting Hydro One's proposed X factor. Some intervenors also appear to misunderstand PEG's findings as they advocate for an overall 0.3% X factor as being "commensurate with PEG's findings"[75] when in fact PEG recommended a 0.05% overall X-factor. One intervenor recommends, without any supporting evidence whatsoever, an even higher X factor.[76]

Below, we show that if OEB incentive regulation is to be evidence-based and adhere to the OEB's policies, OEB Staff and intervenors' X factor submissions must be rejected.

The Base Productivity Factor

<u>Both Experts Agree that the Transmission Industry Is Experiencing Negative Productivity Growth</u>

As confirmed by the OEB in its rate setting parameters policy guidance and in past decisions, the productivity factor should consist of an "empirically derived industry productivity trend."[77] Regardless of any methodological differences between PSE's and PEG's total factor productivity (TFP) studies, both experts concluded that the transmission industry TFP has been and is expected to continue to be negative.[78]

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[75] See CME Submission, p. 8, VECC Submission, p. 8, see also EP Submission, p. 14.

[76] See CCC Submission, p. 11.

[77] Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, p. 17.

[78] Based on the time period 2005 to 2018, PSE concluded that the TFP trend is -1.61% (Reply Report, Table 2). PEG's results showed a similar decline over that period of time -- for the period 2005 to 2016 PEG found a -1.47% trend. PEG concluded, however, that over an older time period starting and ending in earlier years, from 1996 to 2016, the TFP trend is -0.25%. PEG's results are shown in Table 3 of Exhibit A Regardless of which particular trend figure is more predictive of upcoming productivity trends, it is important to bear in mind that both experts found the transmission industry TFP trend is negative.

Moreover, both experts also concluded that the reality of the negative industry TFP trend (whether PEG's -0.25% or PSE's -1.61%) should be taken into account in setting an appropriate X factor:

- PSE does so by recognizing that setting the base productivity factor at 0% results in an implicit stretch factor because it already requires Hydro One to outperform the industry, and therefore this implicit stretch must be taken into account when considering the stretch factor component of the X factor.

- PEG does so by recommending that the base productivity factor be set at -0.25%, which offsets the recommended stretch factor to arrive at an appropriate X factor.[79]

In other words, both experts agree that the industry TFP is negative and this cannot be ignored when determining the stretch factor and what an appropriate overall X factor should be. Accordingly, though the base productivity factor in the formula may be set at 0%, one cannot pretend that the actual industry TFP is zero. Yet this is exactly what OEB Staff, SEC, VECC and others attempt to do. Unlike PEG who recommends a negative 0.25 base productivity factor, or PSE, who recommends zero but recognizes an implicit stretch, OEB Staff and others unfairly seek to ignore the reality of the negative TFP trend found by both experts.

There is no basis in the record for OEB Staff and others to ignore both experts' opinions and recommendation as to the appropriate X factor, or to effectively 'cherry pick' only part of PEG's analysis. OEB Staff and intervenors are not the experts in regulatory economics, econometrics or incentive regulation plans, nor did they testify as such.

PEG and PSE TFP Trend Results Align When the Same Study Period is Considered

OEB Staff and some intervenors submit that PEG's TFP trend results are more plausible and OEB Staff "does not believe that a transmission sector TFP in the range of -1.6% is credible, even for the shortened time period." Those submissions are without merit.

PSE's -1.6% TFP result for the time period 2005 to 2018 is in fact consistent with and validated by PEG's own study results. PEG estimates the transmission industry TFP from 2005 to 2016 at

[79] Exhibit M1, p. 10.

-1.47%. Over that same time period, PSE's results are -1.45%, virtually the same as PEG. If PEG were to update its results to include 2017 and 2018 data (as PSE did), it is estimated that PEG's methodology would result in a TFP of -1.6% or below for the 2005 to 2018 period, just like PSE found.

Therefore, PEG's own study results – which are almost identical to PSE's results over the same time period – prove that PSE's results over the 2005-2018 time period are highly credible, contrary to OEB Staff's and SEC's submissions. The TFP analysis conducted by both PSE and PEG fundamentally used the same methodology that the OEB relied upon to determine the TFP trend in the distribution industry under 4GIRM. The fact that the TFP is significantly negative does not mean the methodology is not reliable.

The difference in overall TFP results between PSE and PEG is simply due to the sample period they each used for their study: PSE used 2005 to 2018; whereas PEG used 1995 to 2016. The objective in this proceeding is to determine the appropriate base productivity trend for the Custom IR period. Given the significant structural changes that have occurred in the industry over the years, the more recent period used by PSE is a better estimator of what the TFP trend is likely to be during 2020 to 2022.[80]

PEG's sample period goes back to 1995 and does not include 2017 and 2018. Its TFP result of -0.25% is heavily influenced by the older trends of the 1990s that are not representative of the current situation and realities of today's industry:

- output growth is far different now than back in the 1990s, particularly for Hydro One – near zero output growth is projected during the 2020-2022 period;
- the significant industry structural change towards ISOs/RTOs occurred in the late 1990s and early 2000s therefore a sample period after this change is a better predictor of current and expected TFP in the coming years;

[80] PSE Reply Report, p. 2.

- the challenge of aging infrastructure issue was far less of an issue back in the 1990s, and PEG itself acknowledges that the current aging infrastructure challenge is likely to continue in the 2020-2022 period; and
- there has been an increased focus on transmission grid reliability since the 1990s as well as cost pressures which have emerged in recent years and are expected to continue, such as cybersecurity.[81]

The actual TFP results for the most recent years prove that the PSE sample period and study results are a more accurate or reliable predictor. Throughout the last 10 years of PEG's sample (2007 to 2016), every year had productivity that was in fact lower than PEG's TFP study results of -0.25%. The years 2017 and 2018 continued this trend. As noted by Mr. Fenrick, "the 2017 and 2018 results show that using the more recent sample period of 2005-2016 is a far better predictor of the 2017 and 2018 TFP trends than the less applicable time period of 1996 to 2016."[82] There is no evidence to suggest that the industry trend in recent years is likely to abate during the 2020-2022 period. PEG itself has acknowledged that various increased cost pressures on transmitters, such as the challenge of aging infrastructure, increased reliability standards and emerging cybersecurity issues are likely to persist in the coming years.[83]

While some parties are critical of PSE's 14-year sample period for its study there are multiple precedents of regulators relying on shorter sample periods to determine industry trends. In 4GIRM the OEB relied upon a 10-year sample period for the distribution industry (from 2003 to 2012). In the Hydro One SSM application there was reference to a transmission industry study from the Australian Energy Regulator, which also used a 10-year sample period (2007 to 2016). In PEG's own report in the amalgamation application between Enbridge Gas and Union Gas (EB-2017-0306/EB-2017-0307) PEG stated that an appropriate productivity sample period should be at least 10 years long, should include the latest year for which data is available, but also should be reflective of the latest technology trends.[84] PSE's sample period of 2005 to 2018

[81] PSE Reply Report, pp. 18-19.

[82] PSE Reply Report, p. 6.

[83] Exhibit L1-1-12(b); Oral Hearing Transcript, Vol. 9, pp. 148-150.

[84] Enbridge Gas and Union Gas merger application, Exhibit M1, EB-2017-0306/EB-2017-0307, pp. 42 and 43.

accomplishes the above criteria and is longer than the sample period used in 4GIRM. On the other hand, PEG's sample period, although longer, includes older years not representative of the current industry reality, and does not use the two most recent years of data, 2017 and 2018.[85]

For all of the above reasons, PSE's sample period and its TFP study result are a more reliable indicator of the likely industry TFP in the 2020-2022 period.

The Stretch Factor

OEB Staff and a number of interveners argue that a stretch factor of 0.3%, and a resulting overall X factor of 0.3%, should be adopted. There are a number of reasons why doing so would not be appropriate or consistent with OEB policy having regard to Hydro One's cost performance.

Hydro One's Strong Cost Benchmarking

To begin with, we must stress – and the OEB cannot ignore – that neither of the econometrician and incentive regulation experts who testified recommend or support an overall X factor of 0.3%. As stated, the uncontradicted expert opinion and recommendation of both PSE and PEG is that an X factor of 0% (PSE's view) or 0.05% (PEG's view) is appropriate here based on the expected industry TFP, Hydro One's cost performance and OEB policy.[86]

The stretch factor should be set based on econometric cost benchmarking results and, according to established OEB policy, strong cost performers are to be rewarded with a lower stretch factor, including a 0% stretch factor where appropriate. In its Report of the Board on *Rate Setting Parameters and Benchmarking under the RRF*, the OEB stated: "Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend." The OEB further stated: "The Board is setting the lower-bound stretch

[85] PSE Reply Report, pp. 19-20.

[86] PSE's recommendation is provided in Exhibit A-4-1, Attachment 1, pp. 16-17. PEG's recommendation is provided in Exhibit M1, pp. 7-10.

factor value to zero to strengthen the efficiency incentives inherent in the rate-adjustment mechanism and in doing so reward the top performers."[87]

Hydro One is an efficient and good cost performer. PSE's benchmarking results show that Hydro One has consistently been a very strong cost performer in recent years and is expected to be 32.9% below the benchmark in the 2020-2022 period. This cost performance supports a 0% stretch factor. As Mr. Vetsis of Hydro One testified in this regard, "the number is zero because Hydro One's cost performance is well below that of a modelled utility and Hydro One is a good cost performer, and consistent with the calibration of the stretch factor established by the OEB and its policies we have assigned it accordingly."[88]

Importantly, PEG's study results – notwithstanding its methodological flaws we address below – also have Hydro One as a top quartile cost performer in 2018 that is outperforming the industry productivity trend.[89] In other words, both experts (regardless of their methodological differences) found that Hydro One is a relatively strong, top quartile performer. The stretch factor that is assigned should recognize and reward that performance. Hydro One should not receive a stretch factor as though it were an average or below average performer, as that would be inconsistent with OEB policy and would not provide appropriate incentives.

OEB Staff argues that a 0.3% stretch factor would be reasonable based on PEG's analysis and because the OEB "approved a 0.3% stretch factor for Hydro One SSM". However, the reason the OEB did so in the Hydro One SSM case does not apply here. In Hydro One SSM, the OEB concluded that there were no Hydro One SSM-specific benchmarking studies in the record (i.e. there were no benchmarking studies of that particular entity) on which it could rely to set the stretch factor. In the absence of such studies, the OEB ordered an average or middle of the road stretch factor of 0.3%.[90] In this current application, the OEB has applicable cost

[87] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, November 21, 2013, p. 19 and 20.

[88] Oral Hearing Transcript, Vol. 8, p. 19.

[89] PEG's report shows a TFP trend of -1.17% for Hydro One over the 2005-2016 period (Exhibit M1, Table 4) while measuring a TFP trend of -1.47% for the industry over that same period (Exhibit M1, Table 3). Mr. Fenrick notes Hydro One's ranking under PEG's analysis in his oral testimony (Oral Hearing Transcript, Vol. 7, p. 162).

[90] Hydro One SSM Decision**,** p. 20. Specifically, the OEB stated: "The PSE and PEG evidence for electricity transmission utilities provided in this proceeding was based primarily on 43 U.S. utilities with the only Canadian utility being Hydro One Networks. Given the absence of sufficient Canadian

benchmarking studies by PSE and PEG, both of which show that Hydro One has been a strong performer. These studies cannot be ignored.

PEG's own cost benchmarking study of Hydro One, which was completed earlier in 2019 and filed in the Hydro One SSM proceeding, showed Hydro One to be a good cost performer, well below benchmark expectations.[91] Those study results showed that Hydro One's average performance was 31.2% below the benchmark for the period 2004-2018, and showed that Hydro One was expected to be 11% below the cost benchmark for the upcoming 2020-2022 period. Neither result would support a 0.3% stretch factor for Hydro One. In fact, in that study PEG's results found that Hydro One was a top 5 cost performer out of the entire PEG sample of 50 utilities.[92] In the Hydro One SSM proceeding, PEG and OEB Staff stood behind those cost benchmarking results for Hydro One and submitted to the OEB that they were appropriate and reliable.[93]

Now in this application, only a short time later, PEG has produced significantly different cost benchmarking score for Hydro One, suggesting that Hydro One is expected to be 6.8% over the benchmark costs for the period 2020-2022. However – and it is important to keep this in mind – PEG's results still find that Hydro One is a top quartile performer in 2018 compared to all other utilities in its industry sample.[94]

PEG arrives at its new and substantially different score for Hydro One even though it is benchmarking the same company, over the same time period, and using essentially the same dataset and model variables as it did in its study earlier in 2019. Hydro One submits that PEG's

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data and utilities the size of Hydro One SSM, the OEB finds neither study appropriate to determine the stretch factor for Hydro One SSM, a small Canadian transmission utility. In the absence of applicable evidence, regardless of the reason, the OEB must rely upon its judgement and experience in incentive regulation to establish a stretch factor." In this proceeding, there is applicable evidence. The OEB Staff Submissions misleadingly ignore the basis for the OEB's determination in Hydro One SSM that 0.3% was an appropriate stretch factor in that case.

[91] The evidence in Hydro One SSM proceeding was adopted on the record for this proceeding in the OEB's letter dated June 28, 2019. PEG's corrected benchmarking results for Hydro One were provided in their response to Exhibit L1-1-6, part i (b).

[92] Oral Hearing Transcript Vol. 8, p. 39.

[93] Oral Hearing Transcript Vol. 9, p. 124-125.

[94] Oral Hearing Transcript, Vol. 7, p. 162; PSE Reply Report, p. 9.

latest score is not reliable given the two significant methodological flaws in PEG's latest study which were identified in PSE's reply report.[95]

The first significant flaw in PEG's latest study, as described by Mr. Fenrick, is that PEG's latest model "contains a clear and obvious bias against the recent years (and the forecasted years) for all utilities in the sample." This bias has a major impact on PEG's evaluation of Hydro One's Custom IR period of 2020-2022.

As Mr. Fenrick explained, a model without a systematic bias should have sample average scores that hover around 0%."We would expect 0% to be the average benchmark score for the sample because this would indicate an average performing utility is at their benchmark (or expected) total costs… PEG's model is not producing those results but, instead, is calculating the benchmark scores of the entire sample to be 15% higher in 2018." As the year approaches 2018, it gets harder and harder for any utility in PEG's model to be performing below benchmark – such that by 2018 only 13 of the 50 utilities in the sample are below the benchmark cost. This is an abnormal distribution, contrary to econometric modeling fundamentals, and contrary to the OEB's stretch factor allocation framework utilized in 4GIRM. In the words of PWU, "[t]his results in a nonsensical scenario in which the average of the peer group's costs is 15% above benchmark costs."[96]

When setting the demarcation points for the stretch factors in 4GIRM, the OEB saw "merit in starting out with an allocation across the five groups that more closely resembles a normal distribution curve" and noted that its selected demarcation points "produce a relatively normal distribution curve across the stretch factor assignment groups."[97] PEG's model does not do so. "In a properly specified, unbiased model you would expect there to be about half of the utilities to be below cost and half of the utilities to be above cost. That's not what we're finding in the PEG model." This point is well explained and illustrated by the graphs on pages 8-10 of PSE's reply report.[98]

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[95] PSE Reply Report pp. 4 and 5.

[96] PWU Submission, para. 9.

[97] EB-2010-0379, Report of the Board *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, pp. 21-22.

[98] PSE Reply Report, p. 9; Fenrick oral testimony, Oral Hearing Transcript, Vol. 7, pp. 162-164.

In its submissions, SEC's counsel is critical of what they refer to as Mr. Fenrick's "theory that benchmarking results should average zero over the entire sample." With respect, the fact that benchmarking results should average to zero is not Mr. Fenrick's "theory" but rather is a well-established econometric principle: the residuals, which are the benchmark scores, will tend to average zero over the entire sample in a properly specified model.[99] As Mr. Fenrick further explained, "by 2018 [PEG's] model is disadvantaging all of the utilities in the sample by about 15%, and that's growing over time."[100] Moreover, common sense says that a good model accurately predicts actual results on average, i.e. has residuals around zero. That PEG's model is unfairly disadvantaging Hydro One and other good performers is illustrated by the fact that in 2018 Hydro One is ranked as a top quartile utility in PEG's own rankings (13th out of 50),[101] yet would receive a higher than average benchmark score.

SEC asserts that PSE did not identify the reason for the bias in PEG's model. In fact, Mr. Fenrick did explain that PEG's model is missing a variable, and fails to take into account the structural change that occurred in the industry. It is because of this structural change that the omitted variable is needed.[102]

SEC also wrongly states that "whenever Mr. Fenrick studies the productivity or benchmarking of his Ontario utility clients, he always concludes that his clients are strong cost performers relative to their peers." One needs to look no further than PSE's work in the last Hydro One distribution application (EB-2017-0049) to see that SEC's suggestion is false. In that application, PSE's study showed that Hydro One Distribution's total costs performance was 22% above the benchmark, resulting in a recommended stretch factor of 0.45%, which the OEB adopted.[103]

The second significant flaw in PEG's model is its change in modelling procedure in respect of autocorrelation adjustment, which also has a significant impact on Hydro One's benchmark

[99] The further away the average residuals are from zero the worse the model is at estimating costs in each year. A clear pattern in the benchmark scores which deviates from zero (such as PEG's latest model) is evidence of a mis-specified and biased model – a clear pattern like this "violates Econometrics 101."

[100] Oral Hearing Transcript, Vol 7, p. 162.

[101] PSE Reply Report, p. 9.

[102] Oral Hearing Transcript, Vol. 7, p. 164.

[103] EB-2017-0049 Decision and Order (March 7, 2019), p. 29. PSE's total cost benchmarking study in Hydro One's distribution application was provided in Exhibit A-3-3, Attachment 2.

scores.[104] PEG has acknowledged that this modeling change is a large contributor to its revised benchmarking scores compared to its report in the Hydro One SSM application.[105] PEG even acknowledged that the scores changed “more than one might expect.”[106] Despite Mr. Fenrick’s concerns on this point,[107] PEG produced no academic article or research to show that its change in modeling procedure is a valid procedure to use in this case, i.e. on an unbalanced panel dataset.

Although PEG and some of the intervenors in their submissions suggest that the autocorrelation adjustment PEG made is a standard approach, that is clearly not the case because PEG has conducted many studies without using this approach. PEG did not make this autocorrelation adjustment in various other studies before the OEB, such as: (i) its benchmarking study of Hydro One transmission in the Hydro One SSM case; (ii) its benchmarking study in the last Hydro One distribution rate case (EB-2017-0049); and (iii) in its studies in the 2007 IR proceedings for Enbridge Gas and Union Gas (EB-2007-0606/0615). When cross-examined, PEG could not confirm if it had made the same adjustment in certain other past studies either.[108]

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 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.

For the above reasons, PSE’s cost benchmarking scores for Hydro One are more credible and reliable than those of PEG in this application.[109] PSE’s analysis: (i) consistently uses the same

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[104] PSE Reply Report, pp. 7, 12 and 17.

[105] Oral Hearing Transcript, Vol. 9, p. 136.

[106] Oral Hearing Transcript, Vol. 9, p. 130; EB-2019-0082, Exhibit L1-1-1(a).

[107] PSE Reply Report, pp. 15-17.

[108] Oral Hearing Transcript, Vol. 9, pp. 136-146.

[109] Hydro One notes that PEG has also admitted that it made some other errors in its latest benchmarking study application, which harmed Hydro One’s results. One such mistake is that there were certain OM&A expenses PEG subtracted from the U.S. utilities in the data set that it did not fully or correctly

modeling approach for both the distribution and transmission applications; (ii) yields un-biased benchmark scores centred around the expected value of 0%; and (iii) uses a sample period that is a better reflection of the current realities of the industry. The lack of consistency in PEG's modeling approaches between Hydro One's distribution and transmission applications, the biased pattern of results in respect of all utilities in its sample, and the significantly different benchmarking scores it now provides for Hydro One compared to its results earlier in 2019 (in its report filed in Hydro One SSM), are significant grounds to question the credibility of PEG's benchmarking score.

Nevertheless, the OEB should not be distracted by the different benchmarking scores for Hydro One. Regardless of the different scores, both experts' studies rank Hydro One in the top quartile. Based on established OEB policy, a top performer should be rewarded with a lower stretch factor.

Other Reasons Supporting a 0% Stretch Factor

There are also other reasons supporting the conclusion that a 0% stretch factor is appropriate here.

First, there is already an implicit stretch factor on Hydro One by virtue of setting the base productivity factor at 0%, when the actual expected industry TFP is negative.[110] Hydro One will already have to stretch itself and out-perform the industry, a point that should not be ignored.

Second, Hydro One's progressive productivity proposal is a new and important feature of this application which is relevant to this analysis. It represents an upfront commitment by Hydro One to find further efficiencies over the 2020-2022 period when executing the necessary planned investments in its transmission system without reducing work volumes. These progressive savings result in lower capital factors than would otherwise be the case. The evidence shows

subtract from Hydro One. That error alone caused Hydro One's predicted benchmark score in PEG's September 5, 2019 Report to be about 2.2% higher than it ought to have been for the 2020-2022 period. See Oral Hearing Transcript, Vol. 8, pp. 13, 133-135.

[110] As noted above, by PSE's calculation this implicit stretch factor is -1.61%. Even on PEG's analysis there is a stretch factor of -0.25% (assuming a base productivity factor of 0% is approved).

that they amount to an additional stretch factor from a revenue requirement perspective of about 0.15% in 2012 and 0.3% in 2022.[111]

In making its submissions as to an appropriate stretch factor, OEB Staff and a number of intervenors have ignored the progressive productivity savings feature of this application, as did PEG in arriving at its stretch factor recommendation. Ignoring the uncontradicted evidence on progressive productivity sends the wrong message to utilities from a policy and practical perspective. Utilities will have no incentive to include these types of continuous improvement or cost efficiency/stretch features in their applications and to reduce capital plan budgets accordingly, if the OEB will not recognize and give effect to them when determining what stretch factor is appropriate.

Conclusion on X Factor

For the above reasons, and on the evidentiary record here, Hydro One has established 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%.

OEB Staff and some intervenors say that they support PEG's analysis and recommendation, but they then submit that there should be an X factor of 0.3%. However, as stated, PEG's recommendation is that the X factor should be 0.05%. In actuality, OEB Staff and these intervenors suggest a higher X factor that no expert recommends or says is warranted here.[112] They have come up with that suggestion on their own without any evidentiary basis.

Timing of PSE's Reply Report

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[111] Exhibit A-4-1, Attachment 1, pp. 5-6; Oral Hearing Transcript, Vol. 8, pp. 19-20; JT2.42.

[112] On page 11 of their submission, CCC not only ignores the expert recommendations but also established OEB policies and precedents in somehow concluding that a positive base productivity trend of 0.3% would be warranted despite the evidence on record.

In its submissions, OEB Staff takes issue with the timing of the delivery of PSE's reply report and therefore submits that "it should be given little or no weight by the OEB." There is no proper basis for this submission. As a matter of basic procedural fairness and natural justice, Hydro One was entitled to deliver a reply report from PSE in the circumstances here, and it did so in a timely way after PEG had delivered its report and its interrogatory responses to which PSE was replying.[113]

Hydro One filed PSE's report in this case on March 21, 2019. On September 5, 2019 (about 5.5 months later) PEG issued its responding report. In that responding report PEG did much more than merely update its report in Hydro One SSM or respond to PSE's studies. PEG instead significantly changed its methodology (as discussed above) and raised a number of new issues and points. These new issues included (among others) the section of its report entitled "Other Plan Design Issues", in which it raised points and made new recommendations including its S-factor recommendation. Hydro One asked interrogatories of PEG on the new points it had raised, including asking it to perform certain additional calculations or analyses. In its responses, PEG refused to do certain requested calculations or analyses (including updating its analysis to include 2017 and 2018 data) and stated that PSE could do so.[114] In other words, PEG invited PSE to do more work in order to answer the interrogatories that PSE had asked of PEG.

Promptly upon receiving PEG's final interrogatory responses, which did not arrive until October 10, 2019 (and were delivered late), Hydro One informed OEB Staff and the intervenors that, given the new issues and points raised in PEG's report and its interrogatory responses, Hydro One intended to deliver a reply report from PSE to respond to them. Obviously, PSE could not have addressed these new points and issues in its initial report as they were only raised in PEG's responding report.[115]

Neither OEB Staff nor any of the intervenors took issue at the time with Hydro One indicating that it would be delivering a reply report. As mentioned, this same procedure had also been

[113] A similar process was also followed in the recent Toronto Hydro case (EB-2018-0165).

[114] For example, see PEG's responses to: Exhibit L1-1-6, part h); L1-1-7, part c); L1-1-10, part f); L1-1-15, part b); and L1-1-23, part b).

[115] See email sent by Hydro One's counsel on Thursday, October 10, 2019 5:51 PM.

followed in the recent Toronto Hydro case. PSE promptly delivered its reply report on October 15, 2019, only 5 days after receiving all of PEG's interrogatory responses. That was 16 days before Mr. Fenrick began testifying on October 31, 2019. Upon receiving PSE's reply report, OEB Staff did not indicate that it wished to ask any further interrogatories in response to it, nor took issue with the delivery of the reply report.

OEB Staff and all intervenors had an opportunity to test the reply report through cross-examination at the hearing. Only when Mr. Fenrick was testifying did OEB Staff ask for further working papers, which were then provided.

In summary, having chosen to allow PEG to significantly change its methodology and raise significant new issues in its responding report, OEB Staff cannot now complain about PSE providing a reply report responding to those issues. Basic procedural fairness and natural justice entitled it to do so, and OEB Staff could have asked further interrogatories if it felt the need to do so. It would be highly unfair for the OEB to give less weight to the reply report as that report is directly relevant and useful on the issues being considered in this application, identifies some material concerns, was delivered as quickly as possible after receiving PEG's interrogatory responses, and was tested through cross-examination at the hearing.

The Capital Factor

OEB Staff agrees that Hydro One's proposed C-factor is reasonable on a conceptual basis.[116] As stated by OEB Staff,"[t]he OEB has seen and approved the C-factor methodology as a mechanism for reflecting a utility's capital requirements in a multi-year Custom IR plan."[117] As a result, most parties do not take issue with its inclusion in the proposed Custom IR framework.[118]

OEB Staff submits, however, that an additional stretch factor (referred to as an "S-factor") of 0.15% should be imposed on the C-factor. Some of the intervenors also argue for a 0.15%[119] or

[116] OEB Staff Submission, p 25.

[117] OEB Staff Submission, p 25.

[118] BOMA is an outlier in this regard as it does not support the C-factor. In response, Hydro One notes that as noted by other parties, the C-factor is now a "tried and tested" mechanism that has been approved many times by the OEB.

[119] See CCC Submission, p. 11; Energy Probe Submission, p. 14, CME Submission, p. 16; LPMA Submission, p. 6.

higher[120] S-factor. For the reasons outlined below, Hydro One submits there is no need or proper basis in the record to impose an additional S-factor on the C-factor.

First, there is no need for a supplemental stretch factor on capital because the progressive productivity feature of Hydro One's proposal is already a bottom line reduction to the capital sought for cost recovery that amounts to a stretch factor of about 0.15% in 2021 and 0.3% in 2022. It is therefore already achieving the same result as OEB Staff's proposed S-factor in 2021 and an even greater revenue requirement reduction in 2022.

OEB Staff points to the fact that in Hydro One Distribution's last application (EB-2017-0049) the OEB imposed an additional stretch factor of 0.15% on the capital factor. In particular, the OEB gave the following reason in that case for imposing that 0.15% stretch factor:

> The OEB expects Hydro One to stretch itself more to find additional initiatives and to consider new approaches to its business. The OEB is therefore imposing an additional stretch factor for the capital factor of 0.15% to incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront.[121]

The progressive productivity reduction to the capital plan in this current application, which was not a feature in Hydro One Distribution's application, already achieves that exact purpose. It incents further productivity improvements throughout this 2020-2022 Custom IR term, and is in line with the OEB's *Handbook* expectations for continuous improvement.[122] As Mr. Vetsis of Hydro One testified: "What we're seeking recovery for is the C-factor net of progressive productivity. So we're taking the actual cost of service of the capital work and we're putting in a reduction to what we're seeking rate recovery for, to incent ourselves to achieve those amounts."[123]

If OEB Staff believes it is more important for these additional capital cost savings to be explicitly reflected in the RCI formula as an S-factor, then OEB Staff should also be submitting a commensurate *increase* to the proposed capital expenditure and ISA amounts. Otherwise, OEB Staff's proposal is tantamount to more than doubling the supplemental stretch factor imposed by

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[120] VECC Submission, p. 9, SEC Submission, p. 19.
[121] EB-2017-0049 Decision, p. 32.
[122] See *Handbook*, pp. 2, 3, 25 among others.
[123] Oral Hearing Transcript, Vol. 8, p. 74.

the OEB in the Hydro One distribution rate case (EB-2017-0049) – and doing so despite evidence that Hydro One transmission is a good cost performer. OEB Staff's proposal is unprincipled and punitive in this regard.

Second, the rationale for PEG's S-factor proposal, on which OEB Staff seeks to rely, does not apply to this application. PEG's stated rationale for imposing an S-factor is to make Custom IR equivalent to an ICM/ACM materiality threshold and deadband. However, the OEB has already (and for good reason) concluded that the rationale for the materiality threshold and deadband in those contexts do not apply to Custom IR applications in the same way. ICM and ACM applications are different, and the OEB has confirmed that the main reason for the materiality threshold and deadband in those contexts is for "discouraging numerous applications for marginal amounts that the utility would be expected to manage under the RRFE and Price Cap IR framework." That has no application here.[124]

Third, as PEG itself (and OEB Staff) have acknowledged, the S-factor concept and methodology are still very much a work in progress. Hydro One submits that the proposed S-factor methodology and calculation would in fact lead to perverse results in that they would remove any incentive for a utility to be a good cost performer. That is because, as Dr. Lowry conceded on cross-examination, PEG's proposed S-factor has an inverse relationship to the X factor stretch factor: the higher the X factor, the lower the S-factor.

As a result, under PEG's S-factor proposal, the worst cost performers (who have the highest X factor) would get rewarded with no S-factor, whereas the best cost performers (who have the lowest X factor) would get punished by having a high S-factor. The methodology works that way in order to achieve the ICM/ACM equivalent result PEG proposes. [125] As a matter of policy and having regard to the fundamental principles of incentive regulation in the RRFE, the OEB should not adopt this type of approach. The proposed S-factor should be rejected for this reason alone,

[124] Report of the OEB (EB-2014-0219): New Policy Options for the Funding of Capital Investments: Supplemental Report dated January 22, 2016**;** see also OEB Decision and Order dated March 7, 2019 in EB-2017-0049 (Hydro One's recent distribution rates case) in which the OEB concluded that an ICM is a different mechanism than the proposed capital factor"

[125] Sample calculations are shown in PEG's response in Exhibit L1-1-13, part b); Oral Hearing Transcript, Vol. 9, p. 108.

at least at this early stage of its development. It has no sound policy basis and creates the wrong incentives for utilities, contrary to the principles espoused by the OEB.

Fourth, OEB Staff is actually suggesting that the OEB impose on Hydro One an even higher, more punitive and unfair S-factor than PEG itself would propose. This is another instance of OEB Staff ignoring an important aspect of PEG's analysis and testimony, and making a submission contrary to its own expert, with no principled or evidentiary basis. OEB Staff submits that the X factor should be 0.3%, and it submits that a further S-factor of 0.15% should be imposed as well on the C-factor.

However, PEG opined that in the event the OEB were to order a 0.3% X factor – which PEG does not recommend, and which Hydro One also submits would be inappropriate – there would be no need for an additional S-factor under PEG's proposed methodology. That is because a 0.3% X factor would already be achieving an ACM equivalent result, and so Dr. Lowry confirmed that "the ACM-equivalent S-factor in that scenario would be only 0.01 percent" – "there would be no need for it."[126] PEG's methodology and rationale would only support a 0.15% S-factor if the X factor were 0.16% or lower.[127] Moreover, it is important to keep in mind that PEG did not even factor in Hydro One's progressive productivity proposal in their methodology and rationale.[128]

Some intervenors[129] assert that the C-factor is funding capital on a forecast cost of service basis. However, the evidence on the record demonstrates that this is not the case. After the various other productivity initiatives and commitments are factored in, the C-factor only funds the (already reduced) forecast cost of service reduced further by progressive productivity. This reduction in capital is shown clearly in table 2of section 3.2 of the TSP.[130]

After factoring in the progressive productivity commitment, intervenors who propose a 0.31% S-factor[131] are in fact proposing a combined capital-related supplemental stretch factor of 0.46% in

[126] Oral Hearing Transcript, Vol. 9, p. 106.
[127] Oral Hearing Transcript, Vol. 9, p 104-106; PEG's response in Exhibit L1-1-13, part b).
[128] Oral Hearing Transcript, Vol. 9, p. 113.
[129] BOMA Submission, p. 33, VECC Submission, p. 9, SEC Submissions, p. 18.
[130] The corresponding reduction to in-service additions is provide in Table 1 of Exhibit C-2-1.
[131] SEC Submission, p. 19.

2021 and 0.61% in 2022 (in *addition* to their proposed increases to the X factor). Not only would these amount to the largest supplemental stretch factors ever imposed by the OEB in a Custom IR application, they would be imposed on a utility with a strong and lengthy record of good cost performance. Such an outcome would reduce the cost containment incentives for utilities, as it would remove any reward for achieving good cost performance. This suggested outcome by SEC is also directly contrary to the opinion evidence of both PSE and PEG, is contrary to the basic tenets of incentive regulation espoused by the OEB and should therefore be rejected.

In its submissions SEC also comments that the OEB should be wary of approving capital programs of utilities where there is "declining demand" for the product. However, (i) the record contains extensive evidence on asset needs, age, and condition which drive the proposed capital spending, and (ii) while overall demand may be declining, there are areas of the province (for example, the Leamington area) which are experiencing growth and which require additional investment. As Mr. Vetsis testified:

> The reality in this case is that we have an application seeking funding to conduct work that has been identified through detailed asset management practices…
>
> You are right that overall, demand is declining. However, there are pockets of the province that are experiencing some growth, such as Leamington, and there are places such as the Toronto area which are having capacity issues. So there are places, pockets within the system, that have to be invested in.[132]

Mr. Vetsis further emphasized that a theoretical discussion about costs always equaling revenue (in the short term) does not reflect the reality of this industry, including the nature of the transmission system infrastructure and necessary investments that have to be made in it.[133] The OEB approves rate recovery based on established need, and the evidentiary record here clearly establishes the need for the capital spending.

OEB Staff submission regarding updating the C-factor annually for inflation

OEB Staff submits that Hydro One should be ordered to update the C-factor for inflation annually. Hydro One has reviewed OEB Staff's detailed submission in this regard, but as noted

[132] Oral Hearing Transcript, Vol. 8, p. 72.
[133] Oral Hearing Transcript, Vol. 8, pp. 72-73.

by OEB Staff,[134] Hydro One does not wish to generate a methodological difference between distribution and transmission Custom IR plan terms to conclusion in 2022. As a result, Hydro One appreciates that OEB Staff submits that it could be reasonable[135] to re-visit this issue in Hydro One's future distribution and transmission rates case.

Working capital in the calculation of the capital factor

LPMA and CME submit that working capital should not be included as part of the C-factor calculation because this would be consistent with the Board's decision on this matter in Hydro One's recent distribution proceeding. Hydro One notes that circumstances for its transmission business are different and may warrant different treatment. Working capital costs in transmission arise from activities related to the transmission business only, unlike distribution where working capital amounts also include costs related to the settlement of the cost of power. Moreover, working capital amounts are significantly smaller in transmission and do not materially impact the calculation of the C-factor.[136]

BOMA submissions regarding the Earnings Sharing Mechanism Deadband

While OEB Staff[137] and many intervenors[138] submit that Hydro One's proposed earnings sharing mechanism is reasonable and compliant with OEB policy, BOMA submits that the 100 basis point deadband be removed from the proposed ESM.

Hydro One submits that the removal of the 100 basis point deadband on the ESM would be inconsistent with OEB precedent and its policy. The OEB makes clear in the *Handbook* that "utilities that achieve productivity improvements above what is expected are allowed to keep certain earnings above the approved ROE."[139] The *Handbook* also expressly notes that "while an earnings sharing mechanism protects customers from excess earnings, it can diminish the

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[134] OEB Staff Submission, pp. 31-33.
[135] OEB Staff Submission, p. 33.
[136] See LPMA-2.
[137] OEB Staff Submission, p. 35.
[138] SEC Submission, p. 22; LPMA Submission, p. 5; CME Submission, p. 24; CCC p. 12.
[139] *Handbook*, p. 27.

incentives for a utility to improve their productivity, and any benefits to customers are deferred."[140]

The submissions of OEB Staff[141] and many other intervenors[142] align with the above, i.e. they note that Hydro One's proposed ESM is consistent with OEB precedent and policy and they are supportive of the proposed ESM.

In sum, Hydro One submits that the 100 basis point deadband on the ESM is reasonable and should be approved.

Submissions on Growth Factor

OEB Staff submits that a growth factor of zero should be included in Hydro One's RCI because a factor with a value of zero is "conceptually" not the same as omitting the factor. OEB Staff also states that a value of zero "is reasonable for Hydro One's 2020-2022 revenue cap plan."[143]

Both PSE and PEG, however, agree that a growth factor is not required in this case.[144] As such, Hydro One submits that OEB Staff's preference for a growth factor appears to be purely theoretical, serves no tangible or practical purpose, and should be rejected.

Conclusion on the Elements of Hydro One's Custom IR Framework

For all of the above reasons, the elements of Hydro One's proposed Custom IR framework are appropriate. Among other things, the framework elements: are calibrated according to OEB policy to reflect the specific performance of Hydro One transmission, which is very strong relative to other Custom IR applications (including the last Hydro One distribution application); and include a voluntary upfront commitment to finding additional efficiencies through progressive productivity. In fact, the progressive productivity commitments are already greater than the supplemental stretch factor that was ordered by the OEB in the Hydro One distribution

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[140] *Handbook*, p. 28.
[141] OEB Staff Submission, p. 35.
[142] SEC Submission, p. 22; LPMA Submission, p. 5; CME Submission, p. 24; CCC Submission, p. 12.
[143] OEB Staff Submission, p. 30.
[144] Exhibit A-4-1, Attachment 1, p. 13; Oral Hearing Transcript, Vol. 9, p. 161, ln. 16-17.

rate application (EB-2017-0049), despite the fact that Hydro One transmission is a better cost performer.

In respect of the differences between PSE and PEG's benchmarking evidence, the OEB need not be distracted by the methodological differences and resulting different specific scores because both experts agree on these important points:

- Both PSE and PEG derived the TFP trend for overall transmission sector and for Hydro One individually, and both found that Hydro One's TFP trend outpaced that of the industry.[145]

- Hydro One is, at least, a top quartile performer when one ranks the total cost benchmarking scores for each utility in the sample under both PSE's and PEG's analyses.[146]

Some intervenors have mentioned "common sense" in their submissions. In fact, "common sense" would indicate that a utility that consistently outperforms the industry and ranks highly among its peers cannot be considered to be an average or below average performer.

Both consultants have shown that Hydro One is more efficient than its peers and both recommend an overall X factor of about 0%, which is aligned with what the OEB assigns to top performing utilities under 4GIRM. Hydro One should not receive an X factor that would normally be assigned to a below average cost performer, as OEB Staff and some intervenors suggest. If incentive regulation is to have any meaning then the calibration of the parameters should recognize and reward efficient utilities for their performance. Hydro One's proposal aligns the calibration of the rate-setting parameters with the empirically derived cost performance, consistent with OEB policy.

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[145] In its report (Exhibit A-4-1, Attachment 1, Table 12), PSE finds that the industry TFP was -1.45% over the 2005-2016 period while Hydro One's TFP trend was -0.18% over the same period. Similarly, PEG found that industry TFP trend was -1.47% as compared to Hydro One's TFP trend of -1.17% over the same period (Exhibit M1, Tables 3 and 4). In both instances, Hydro One's TFP trend exceeded that of the industry.

[146] PSE Reply Report, p. 9, para. 1 indicates that Hydro One is top quartile under PEG's model. Similarly, Hydro One is one of 6 utilities out of a sample of 53 with total cost performance less than -25% indicated in Figure 3 of the Reply Report.

In respect of OEB Staff's and intervenors' suggestion of imposing an S-factor on the C-factor, this should be rejected for the reasons set out above, including in light of the new progressive productivity feature in this application. This feature should not be ignored, otherwise there will be no incentive for utilities to pursue these types of initiatives, which should be encouraged and rewarded by the OEB. Further, OEB Staff's overall submissions – which suggest a significant cut to capital, *and* an X factor of 0.3%, *and* a further S-factor of 0.15% – are punitive in the circumstances here and are directly contrary to its own expert's opinion. PEG itself only suggested that *one* of those measures would be appropriate, but OEB Staff somehow argues (without a principled basis or evidentiary support) that *all of* these be imposed on Hydro One.

Hydro One's proposed CIR framework should be approved, without modification, for all of the reasons set out above.

C. PRODUCTIVITY IMPROVEMENT AND PERFORMANCE MEASURES:

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

Hydro One 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. In contrast to a formulaic approach to identifying and quantifying productivity savings, as some parties advocate, the rigorous, prominent and transparent process taken by Hydro One 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.[147] Moreover, the inclusion of progressive productivity targets, which have been embedded in the plan, represents a voluntary stretch by Hydro One above and beyond what is warranted based on benchmarking results. Hydro One's productivity initiative is therefore aligned with the Board's expectations for continuous improvement and with the Board's findings in recent proceedings regarding the need for additional stretch to drive productivity improvement.[148] If the Board 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 Board's expectations for utility productivity are reasonable or practically achievable.

Contrary to the submissions of Board Staff and intervenors, Hydro One has taken appropriate steps to identify and quantify productivity improvements in its transmission operations. The total revenue requirement and resulting rate impacts from this Application have been mitigated by $370 million in productivity savings over the 3-year Application period through defined capital and OM&A initiatives ($283 million), as well as undefined progressive productivity initiatives for capital ($87 million). Regardless of whether initiatives have been fully defined to date or remain undefined, all have been incorporated into the Investment and Business Planning processes. The revenue requirement has been reduced in this Application by the full amount of these productivity commitments. As a result, Hydro One's proposed revenue requirement for 2020 is

[147] Oral Hearing Transcript, Vol. 5, p. 164.

[148] See EB-2017-0049 Decision and Order, p. 32; and EB-2018-0165 Decision and Order in Toronto Hydro's distribution rate proceeding, pp. 40-41.

approximately $24 million lower than it otherwise would have been, with further annual revenue requirement reductions of approximately $31 million in 2021 and approximately $39 million in 2022, for a total revenue requirement reduction over the 2020 to 2022 Custom IR term of nearly $100 million.[149]

These productivity savings are the result of a rigorous process that has been developed and which is being carried out by Hydro One for identifying, developing, implementing, monitoring and measuring initiatives that will reduce costs while maintaining or improving service quality and work outputs. The rigour of the process is evident from the December 2018 Productivity Review Report, dated January 31, 2019, which was provided by Hydro One in response to Undertaking J6.3.

Submissions in respect of Hydro One's efforts to identify and quantify productivity improvements were received from OEB staff and eight intervenors. One of those intervenors, LPMA, is generally supportive of Hydro One's efforts on productivity but notes that continuous improvement will be needed and that there will be new areas of productivity to explore in the future.[150] OEB staff and the remaining intervenors (AMPCO, BOMA, CCC, CME, Energy Probe, SEC and VECC) raise a number of common concerns in relation to Hydro One's productivity. Those submissions are addressed on an issue-by-issue basis, as follows.

Genuineness of Productivity Savings and Initiatives

OEB Staff and several intervenors (AMPCO, CME, Energy Probe and VECC) make a number of submissions that question whether the savings resulting from implementation of Hydro One's productivity framework, and the individual initiatives that Hydro One has identified as contributing to its productivity objectives, provide genuine productivity savings.

OEB staff question the legitimacy of the savings by asserting that Hydro One's productivity efforts do not adequately distinguish productivity gains from normal due diligence in operating its business and that the complexity of the approach does not assist in making this distinction.

[149] See JT2.28 where Hydro One provided the breakdown of capital and OM&A productivity savings including progressive productivity for each of the test years. For the purpose of the reply submission, these productivity savings were translated to an overall revenue requirement impact. JT2.42 included the revenue requirement impact associated with progressive productivity amounts only.

[150] LPMA Submission, p. 9.

In this regard, OEB staff have relied upon the OEB's decision in Hydro One's distribution rate application (EB-2017-0049) where the OEB directed Hydro One to describe the methodology by which any claimed productivity savings are determined and whether these savings represent net cost savings for the company, which would translate into reduced costs for the ratepayers.[151] While OEB staff may find the approach to be complex, Hydro One's productivity framework and proposal, and its descriptions thereof, are aligned with and responsive to the OEB's prior directions to the company.

Under the framework, Hydro One is committed to delivering net cost savings of $283 million through defined productivity initiatives. Moreover, because productivity is not intended to be frozen over the forecast period, Hydro One has also made contingency for continued productivity efforts that are to be defined during the test period by including in the forecast undefined progressive productivity of $87 million to bring about the total net savings of $370 million as set out above. The OEB has frequently criticized utilities for indicating that productivity is subsumed in the forecasts underlying their system plans. In the current application, Hydro One has made its productivity forecasts explicit by indicating how they have been included in the plan and how they are providing a clear net benefit to ratepayers. Indeed, this appears to be acknowledged by VECC, which states in its submissions that "Hydro One has tried to address the capital productivity issue as articulated by the Board in its last Decision. As we understand it there is a business process in which the Finance group are charged with ensuring there is a measurable benefit. In this way at least we believe Hydro One has addressed the Board's comments in that Decision".[152]

Hydro One provided clear descriptions of its productivity initiatives in TSP Section 1.6. Furthermore, in response to SEC Interrogatory 26, Hydro One provided a table setting out each of the actual and forecast defined productivity savings for the period 2016 to 2024 by initiative, together with the measurement and benefits of each initiative. Further detail was provided in response to Undertaking JT2.28, where specific baseline measures were provided for each initiative.

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[151] EB-2017-0049 Decision and Order, p. 57.
[152] VECC Submission, p. 11.

Referencing the OEB's determination in the distribution decision during cross-examination, OEB staff put to the witness that Hydro One's proposal was inconsistent with the OEB's decision. In submissions, OEB staff referenced a portion of Mr. Jodoin's testimony and asserted that Hydro One had only provided a very general response to the OEB's decision relating to methodology and demonstration of net savings. However, OEB staff has parsed Mr. Jodoin's testimony in a manner which ignores his specific response to the proposition. In particular, Mr. Jodoin elaborated:

> I have mentioned SEC 26 as our baseline. Actually, it would be helpful if we could turn to SEC 26. … So down at the bottom, we have identified total capital, total OM&A, and total common expenditures. You will see 7.3 million … but that represents our 2016 actuals.
>
> As you can see, there is growth in every year, both in our actuals and in our forward-looking plan.
>
> We talked a little bit yesterday and Mr. Berardi brought up fleet right-sizing and procurement. I talked in detail about the corporate cost reduction exercise that existed last year as examples of what we've been driving towards, but we didn't stop there.
>
> We realized that, you know, while these things are true relative to our OEB-approved TX 2017 and 2018 rates, we are achieving productivity and we are bringing our costs lower in our defined initiatives. But we didn't stop in that we created a progressive productivity framework where we're stretching ourselves and pushing ourselves for more.
>
> And what I will do to try and re-emphasize how exactly that works in our application, if we could call up … our capital expenditure plan, which would be Exhibit B-01-01, TSP section 3.3, specifically page 3. So what you will see here is Hydro One's forecast for capital expenditures …
>
> The first four lines, system access, system renewal, system service and general plant, this represents our current cost of delivering the work program.
>
> Holding everything else constant, this is what Hydro One needs to fund our required asset needs.
>
> At the time of filing this application, we knew that as we pushed forward through the test years we can do better. We can find new ways to do work and deliver the same outcome better. That is why you will see the progressive productivity placeholder row.

> The 17 million, 39 million, and 61 million numbers … represent a stretch for which Hydro One is reducing our own capital envelope because we are going to attempt to deliver the same outcome, deliver the same work, at a lower cost.
>
> How are we doing that? If we could turn to technical conference Undertaking JT1.9. At the time of the technical conference we were asked to provide an update of how we have been tracking with respect to our progressive productivity framework.
>
> So recall initially the progressive framework was envelope reductions. We did not know how we were going to do work better, but we knew we were going to push forward and try and achieve new initiatives that would drive our costs lower while delivering the same outcomes, and, again, that last part is very important to this.
>
> What this undertaking identifies are specific initiatives, new initiatives, relative to the date we filed this application to the technical conference, where we've begun to define the progressive framework.
>
> So Mr. Spencer talked about hydrovac excavations and temporary portable access roads at length during panel 1. And in fact, since filing this technical conference undertaking, we have in fact as of today more defined initiatives totalling … a number slightly below the 17 million commitment. And that's just two months since the technical conference.[153]

Based on the foregoing, OEB staff's assertions that the approach to defining productivity is overly complex and that the productivity initiatives need to be made more understandable in the context of translating to reduced costs are not justified.

Several intervenors question the legitimacy of Hydro One's productivity savings on the basis of their argument that a portion of the savings resulting from the productivity framework does not represent "incremental" savings. For instance, AMPCO argues that only progressive productivity initiatives represent incremental efficiencies and that the rest of the savings resulting from Hydro One's productivity framework are not, because they only reflect the impact of prior productivity initiatives that persist into the test period.[154] SEC argues that the Board should discount Hydro One's claim of the total productivity savings built into its plan because "the vast majority of those savings are not incremental and reflects the persistent impact of past initiatives that carry on into the test period".[155] CCC argues that most of the productivity being

[153] Oral Hearing Transcript, Vol. 6, pp. 11-12.
[154] AMPCO Submission, p. 24.
[155] SEC Submission, p. 23.

claimed by Hydro One "is not incremental, but reflects changes HON has made to its operations, both capital and OM&A, prior to the rate plan period . . . these changes are not incremental and should not be considered by the OEB as productivity initiatives".[156] Finally, CME argues that the actual incremental productivity amounts that Hydro One committed to, and is taking the risk of achieving, are significantly lower than the amounts calculated in its evidence and it is not appropriate to count non-incremental savings at their face value relative to their pre-initiative costs.[157] For the reasons that follow, these submissions are without merit.

During the Oral Hearing, in response to the Board Panel seeking clarification on the meaning of "incremental" in the context of Hydro One's productivity framework, Mr. Jodoin explained that if Hydro One reduces its capital cost as a result of a productivity initiative, its rate base would be lower by the amount of that initiative and in each subsequent year that the asset remains in rate base there would be incremental savings in that customers would in each year be paying less as a result of the initiative.[158]

Moreover, in response to a Board panel question as to whether Hydro One would quantify its productivity savings every time it buys a widget even if the initiative giving rise to the savings was carried out in a prior year, Mr. Berardi explained that Hydro One would quantify the savings when it buys the relevant materials because that is when the savings would be realized.[159] While Hydro One might renegotiate contract terms to achieve savings, it does not necessarily procure all of the power transformers or circuit breakers or insulators under that contract in the year the contract is renegotiated. Rather, it procures that equipment over multiple years. However, in each year that it procures materials under the renegotiated contract incremental savings would be realized by the company. Those savings are accounted for once, for each purchased unit, at the time the unit is purchased. While the benefits of a renegotiated contract or other productivity initiative may persist from one year to the next, only the incremental productivity savings realized in a given year are quantified as savings in relation to that year. Hydro One takes great care to ensure, through the rigorous procedures that support its productivity initiative, that this is so. It is therefore entirely appropriate to account for those

[156] CCC Submission, p. 13.
[157] CME Submission, pp. 21-23.
[158] Oral Hearing Transcript, Vol. 6, pp. 45-46.
[159] Oral Hearing Transcript, Vol. 6, p. 46.

savings in the year they are realized and not limit quantification of the productivity savings to the year in which the contract renegotiation or other such productivity initiative occurred.

A different approach to questioning the genuineness of Hydro One's productivity savings is taken by VECC and Energy Probe. VECC suggests that Hydro One might be inclined to "liberally forecast" the costs of capital projects, particularly those that are planned for further in the future and which are more uncertain. Consequently, VECC argues, "there is no robust way to disentangle true productivity savings from projects which are completed for less than an unrealistic (or at least unchallenging) original cost estimate".[160] Similarly, Energy Probe states that it is "skeptical about the base from which progressive productivity savings are calculated" because "it is not clear if Hydro One just padded its cost forecasts so it could add a productivity line in its tables".[161] The suggestion that Hydro One inflates its forecasts, and the related argument that this makes it difficult to distinguish true productivity savings, should be rejected.

Hydro One has provided a significant amount of detailed evidence and testimony regarding the rigorous and transparent process that it uses to identify, validate, measure and track productivity savings to ensure and demonstrate that the resulting savings are genuine. Intervenor skepticism about the legitimacy of the resulting savings, and suggestions that Hydro One is artificially inflating its forecasts are simply not supported by the record or credible. As described in TSP 1.6, reductions to forecasts are not automatically considered productivity within Hydro One's framework - productivity must be validated and tied to specific, measurable initiatives.[162] In addition, as Mr. Berardi explained during the Oral Hearing in relation to a hypothetical example from the panel, as part of the review process for a productivity initiative, Hydro One engages in very detailed discussion and analysis to assess factors such as whether the initiative gives rise to a permanent savings, results from a change in project scope (which would not be productivity) or results from the company actually doing something different and better so as to reduce cost or expedite work practices and achieving true productivity savings.[163]

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[160] VECC Submission, p. 11.
[161] Energy Probe Submission, p. 15.
[162] TSP 1.6, pp. 3-5.
[163] Oral Hearing Transcript, Vol. 6, pp. 89-90.

Baselines for Considering Productivity Savings

OEB staff and several intervenors (BOMA, Energy Probe and VECC) raise concerns about the baselines used by Hydro One for assessing its productivity savings.

OEB staff have expressed a view that, in reference to Undertaking JT 2.28, it was not clear on whether a consistent baseline was being applied. However, TSP Section 1.6 is clear that 2015 is used as the baseline for legacy initiatives and that a more recent baseline, being the last approved plan period, is used for new initiatives after considering the nature and timing of when the initiative was developed.[164] This was further clarified during the proceeding when Mr. Berardi elaborated in response to OEB staff examination relating to the fleet telematics and right-sizing initiative baseline set out in response Undertaking JT 2.28:

> The base line is based on the business plan. So it was approximately $59.7 million, and the incremental savings that we have embedded in our test years are the difference between that $60 million, rounded, to what we're actually acquiring for our capital replacements.
>
> So for instance, with the tools of telematics we're seeing increased utilization. Therefore, we're not having to invest in our fleet as we have done in the past.
>
> So our incremental savings per annum on fleet is in the order of magnitude of 30 million, and that accrues to both transmission and distribution.[165]

In the proceeding, OEB staff inquired further and Mr. Berardi responded further as follows:

> Are you taking different approaches depending on the category or the grouping of -- the initiative that you are trying to find savings in? …
>
> MR. BERARDI: It really depends on the initiative. So we just went -- we just ran through the fleet example, but if you look at procurement -- and I believe I used this example yesterday -- on the procurement what are we doing differently than we've done in the past?
>
> So we have the ability to bundle our spend. We have the ability to renegotiate contracts, true savings, renegotiated contracts, where we're seeing significant volume discounts, significant early-pay discounts and, again, significant price reductions.

[164] Exhibit B-1-1, TSP 1.6, p. 2.

[165] Oral Hearing Transcript, Vol. 6, p. 14.

> I used the example yesterday on insulators. We have very similar examples in transmission for power transformers, circuit breakers, insulators. Those are real reductions in our prices that we had from historical or from our previous contract.[166]

Clear and appropriate baselines exist for each of the defined productivity initiatives forming part of Hydro One's productivity framework.

OEB staff makes the unsubstantiated claim that Hydro One's proposed investments were increased after including progressive productivity initiatives in the capital plan to make it easier for Hydro One to claim productivity savings with a higher baseline. OEB staff rooted its position in <u>two</u> incorrect evidentiary conclusions which are wholly unsupported by the evidence, as follows.

First, OEB staff references a chart identified as Figure 6.1 of OEB staff submissions and which is also set out at TSP 1.4, Attachment 15, page 5 of 8 (the "Chart"). The Chart reflects levels of capital expenditures and OM&A for the "Transmission Power System" for the years 2017 to 2024. OEB staff then incorrectly compares those numbers with the proposed capital expenditures for System Access, System Renewal and System Service as shown in TSP Section 3.3 at pages 2 and 3 of 20 (the "TSP Tables"). OEB staff then claims that the Chart references the initial capital forecast and notes an increase in capital levels between the chart and the TSP Tables noted above. This appears to be in an effort to demonstrate an increasing baseline in the capital forecast.

However, in making these submissions OEB staff have wholly ignored the evidence provided at the hearing. The same assertion made by OEB staff in its submissions was put to Hydro One witnesses in cross examination. If OEB staff had considered the evidence, they would have understood, based on statements by Hydro One's witnesses, that:

- The Chart does not reflect the initial forecast. This is in fact set out in response to CCC-07, Attachment 1, p. 15. As a result, the OEB referenced the correct chart in cross-examination but is not referencing the correct chart in its submissions.[167]
- The Chart and the TSP Table reflect entirely different information. The Chart does not include information included in the TSP Table since the Chart reflects a functional view

[166] Oral Hearing Transcript, Vol. 6, p. 15.
[167] Oral Hearing Transcript, Vol. 3, p. 31.

of one functional area based on Hydro One's organizational structure. There are a number of functional areas that align with any particular Hydro One business unit.[168] In contrast, the TSP Table reflects total capital expenditure on a category basis view using the OEB classification.[169] As stated by Mr. Spencer: "So you can't really compare them side by side and draw conclusions from what they mean. They're just different slices of the same information, and where we are right now, we're actually at two different point in time as well".[170]

- When specifically asked about the ability to compare the number, the witness clearly stated:

> MR. SPENCER: <u>That would be incorrect and misleading, yes.</u> For example, there are some things in the functional view, like security -- if we can, sorry, just pull that up category -- so if we look at the left-hand side, you know, there's a 30 to 30-ish million dollars per year in expenditure. Some of that -- those costs associated with our cyber-security, compliance obligations, and upgrading those systems as per NERC requirements will, in fact, be embedded within our system access, system renewal, system service.
>
> Functionally at Hydro One we have a security team that manages this budget, but when it rolls up to the category level some of those costs are in fact allocated out to system access, system renewal, system service, and even general plant in some cases.[171]

Second, OEB staff's incorrect evidentiary conclusion is based on its superficial consideration of Hydro One's response to SEC-28. In SEC-28, Hydro One shows the progression of total capital expenditures by category as it evolved from the initial forecast through each stage of Hydro One's investment planning process to final corporate approval. Because of an increase in capital expenditure at the final stage of Final Review and Approval (where progressive productivity is netted off) relative to the previous stage of Enterprise Engagement, OEB staff makes the bald assertion that the increase in the final stage must have only been to move the baseline to accommodate progressive productivity. However, the evidence in the record clearly indicates otherwise and OEB staff's submissions in this regard should therefore be ignored.

SEC-28 shows the capital expenditures. However, the number of candidate investments are set out in response to SEC-27. In SEC-27, Hydro One shows that the number of candidate

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[168] Oral Hearing Transcript, Vol. 3, p. 32.
[169] Oral Hearing Transcript, Vol. 3, pp. 31-32.
[170] Oral Hearing Transcript, Vol. 3, p. 32.
[171] Oral Hearing Transcript, Vol. 3, p. 33 (emphasis added).

investments between the prioritization stage and the final stage of the Investment Planning Process increased from 532 to 563, a 6% increase. There was a corresponding increase in capital expenditures of 5.6%. However, after the netting off of progressive productivity, this increase in capital expenditures is only 1.2%. Therefore, more outcomes will be delivered. However, Hydro One will have to find the productivity savings to expend the capital necessary to complete its plan. The higher baseline does not make productivity easier because the savings taken at the outset of the plan are mostly undefined at this stage while the candidate investments are defined.

In response to the direct question on the increase in expenditures in the final stage and the netting off of progressive productivity, Hydro One's witness states:

> MR. SPENCER: A subtle clarification to your order of operations. We actually defined the necessary work, if you will, and used the best information available to define the level of expenditure for that work.
>
> And then towards the end of the planning process, that's when we made and firmed up the productivity commitments. <u>It was not we found the productivity and increased the expenditure. It was actually the other way around, where we had defined the work program and then made the forward looking commitment on the productivity to ensure we could complete the necessary volume of work.</u>[172]

Hydro One has explicitly built into its plan a productivity stretch in the form of Progressive Productivity. On this basis, the Board should ignore OEB's staff's submission that the baseline was surreptitiously moved to accommodate productivity and should also ignore the corresponding submission, which OEB staff has provided no justification for, regarding the inclusion of an explicit productivity factor in the Custom IR plan.[173] As explained under Issue 5, if OEB staff believes it is more important for these additional capital cost savings to be explicitly reflected in the RCI formula as an S-factor, then it should also be calling for a commensurate *increase* to the proposed capital expenditure and ISA amounts. Otherwise, OEB staff's proposal is tantamount to more than doubling the supplemental stretch.

BOMA argues that productivity savings should only be recognized by the Board if they are actually achieved, based on agreed measurement calculations and baselines and the scope of

[172] Oral Hearing Transcript, Vol. 1, p. 58 (emphasis added).
[173] OEB Staff Submission, pp. 40-41.

each initiative is clearly defined, and further that the appropriate baseline should be 2019 unless compelling evidence can be given for a year prior to 2019 since earlier initiatives are already reflected in earlier capital and OM&A budgets.[174] As noted, Energy Probe expresses, without further support, skepticism about the base from which progressive productivity savings are calculated.[175] VECC raises a similar concern as OEB staff regarding the difficulty of establishing a baseline for productivity savings in respect of capital projects for which the scope and cost remains undefined. Hydro One submits that these concerns have been addressed in the above reply to OEB staff. As explained, particularly with reference to JT2.28, clear and appropriate baselines exist for each of the defined productivity initiatives forming part of Hydro One's productivity framework. Moreover, BOMA's suggestion that only "actually achieved" savings should be recognized would mean that customers would only get the benefit of historical results upon rebasing, which is not compatible with Hydro One's approach of forecasting productivity and giving the benefit to customers in advance. On this basis, intervenor and OEB staff concerns regarding the baselines used in Hydro One's productivity framework are without merit and should be disregarded.

Intervenor Proposals

Based on their concerns with the legitimacy of the productivity savings and the baselines for calculating those savings, as identified by Hydro One in the Application, some of the intervenors have proposed various measures that the Board could impose. It is Hydro One's submission that none of the measures proposed by intervenors are supported by the evidence, that each would be unfairly punitive to Hydro One and, as a result, that each should be rejected.

CME argues that the Board should apply a reduction of $286 million to Hydro One's capital envelope in order to give ratepayers the benefit of Hydro One's identified productivity savings.[176] Similarly, BOMA argues that the Board should reduce Hydro One's 2020-2022 budget by $282 million ($212 million capital and $70 million OM&A) and use 2020-2022 as a trial period for the productivity savings, so as to allow the incremental amount of productivity savings from an

[174] BOMA Submission, p. 14 and 15.
[175] Energy Probe Submission, p. 15.
[176] CME Submission, p. 20.

agreed baseline, which it submits should be 2019 unless demonstrated otherwise, for each separate savings initiative in each of the years 2020-2022 to be verified.[177]

In response, Hydro One clarifies that the proposed revenue requirement has already been reduced to account for defined and undefined productivity savings. A further reduction, as proposed by CME and BOMA, would result in less work being completed and less productivity – tied to other initiatives that are part of the capital work program – being achieved. To cut the capital program which has already been reduced by forecast productivity would be adverse to ratepayers because less work would be completed and the planned outcomes of the capital plan would not be achievable. Moreover, further reducing the capital envelope by amounts that have already been removed from the capital envelope would be punitive to Hydro One. It would penalize the company for having already incorporated the expected productivity savings and taking the risk that such savings are ultimately realized. Either these intervenors are being wholly unreasonable and unfair or they do not understand Hydro One's proposal. Either way, their proposals should be rejected.

The fact that the productivity savings have already been reflected in the plan is clear from TSP 1.6, which explains that "Tier 1 Productivity" means net savings with a direct correlation to a budget and/or spending forecast reduction (i.e. 'hard savings'), which are monitored, tracked and reported on corporate scorecards,[178] that all of the $370 million of savings in the 2020-2022 test years (and $704 million over the entire 2020-2024 TSP period) reflects Tier 1 Productivity savings,[179] and that Hydro One has embedded all of these forecast productivity savings into its Business Plan such that it bears the risk of not delivering on its planned productivity improvements.[180] This was further clarified during the Oral Hearing, when Mr. Spencer stated:

> MR. SPENCER: Sure. So you are correct in your numbers, and I will focus in on the $370 million for the test period. But that is expenditure that we have already accounted for in our test year spend, be it capital or OM&A. So we are -- we have factored those productivity benefits into the application. We're not seeking recovery on those costs. I guess the corollary is had we not untaken these productivity initiatives, both defined and undefined, we would have had to seek

[177] BOMA Submission, p. 14.
[178] TSP 1.6, p. 3.
[179] TSP 1.6, p. 7.
[180] TSP 1.6 p. 8.

> an incremental 370 million dollars of expenditure. So we have made the commitment that based on legacy initiatives and some forward-looking initiatives, we are not seeking cost recovery of that 370.[181]

In addition, in response to BOMA's suggestion that 2020-2022 be used as a trial period for Hydro One's productivity savings, Hydro One submits that a trial period is not necessary and would be inappropriate given that Hydro One has provided evidence demonstrating that its productivity framework is already providing significant value to ratepayers[182] and that the savings have already been included in the proposed revenue requirement as described above.

SEC argues that the Board should reduce Hydro One's entire capital budget by the savings on the basis that customers should benefit from the savings not just with the promise of additional capital work to be done, but by having their rates reduced to incorporate the savings. Therefore, SEC argues that the Board should reduce Hydro One's capital budget by $117 million, being the amount of progressive productivity savings that Hydro One has included in the test year budget, so that customers benefit from it through their rates.[183] Similarly, AMPCO argues that the OEB should reduce Hydro One's 2020 to 2022 capital budget by $117 million of progressive productivity savings to provide a true benefit to customers.[184] While the amounts of the reductions proposed by SEC and AMPCO are based only on the progressive productivity component of Hydro One's framework and are therefore lower than the reductions proposed by CME and BOMA, the flaw in SEC's and AMPCO's proposal is the same. As indicated above, these productivity savings have already been reflected in the plan. To further reduce Hydro One's capital envelope by the amount of the progressive productivity savings that have already been built into the plan would be to double count these savings, which would be punitive to Hydro One and adversely impact the company's ability to implement its capital plan for the benefit of its customers.

SEC also argues that Hydro One should build in a progressive productivity amount, on a similar 1-3% of the total OM&A budget, for 2020 on the basis that ratepayers expect Hydro One to deliver its OM&A programs in the same way it does its capital spending – seeking out greater

[181] Oral Hearing Transcript, Vol. 4, p. 104.
[182] See JT2.28.
[183] SEC Submission, p. 46.
[184] AMPCO Submission, p. 24.

efficiencies, so those benefits should also be upfront and built into the budget.[185] In response, Hydro One submits that it is already an efficient transmitter from an OM&A perspective[186] and its use of a 0% base productivity factor in its Custom IR formula represents an implicit stretch factor for the company of 1.61%. In addition, under the Custom IR framework, OM&A is only being escalated by inflation beyond 2020 and does not account for required increases, such as from aging infrastructure and regulatory and compliance pressures, such as PCB work. Furthermore, as discussed under Issue 13, Hydro One notes that its 2020 OM&A is lower than its actual and approved OM&A levels during the historical period.[187] It is also important to recognize that, as indicated in response to JT1.3 and discussed under Issue 13, any further OM&A reductions would result in less work being completed under Hydro One's OM&A program,. Finally, an incentive for OM&A productivity already exists in the form of the ESM. Hydro One is incented by the ESM to overachieve, and customers are protected through the ESM Deferral Account, along with the lower cost base that would result at the time of the company's next rebasing. The ESM enables Hydro One to retain 50% of earnings that exceed the regulatory ROE by more than 100 basis points in any year of the Custom IR term, with the other 50% being shared with customers, thereby incenting the company to overachieve.[188] Accordingly, SEC's argument that Hydro One should build in a progressive productivity amount should be rejected.

SEC argues that the manner in which Hydro One determined the amount of progressive productivity to build into the plan is not clear, and that "the seemingly arbitrarily (sic) selection of the amount of progressive productivity, leads one to conclude that the amount is not high enough".[189] In response, Hydro One notes that the manner in which it determined the amount of progressive productivity to build into the plan is described in response to OEB-2 and CME-29. Moreover, as indicated in response to JT2.42, the company's progressive productivity commitment translates into stretch factors of approximately 0.15% for 2021 and 0.3% for 2022,

[185] SEC Submission, p. 27.

[186] As shown in Tables 3 and 4 of PEG's report (Exhibit M1), Hydro One's OM&A productivity (0.83%) significantly outpaces that of the transmission sector (-1.64%) over the 2005-2016 period.

[187] See Oral Hearing Transcript, Vol. 5, p. 98.

[188] See Exhibit A-3-1, p. 10; Exhibit A-4-1, p. 9 and Exhibit H-1-2, p. 7 and Attachment 3.

[189] SEC Submission, p. 25.

which together represent an incremental commitment that is greater than the additional 0.15% capital stretch factor that the Board imposed on Hydro One in its recent Distribution decision.[190]

SEC argues that any approved progressive productivity amounts should be applied as permanent reductions to Hydro One's rate base, regardless of its ability to achieve the planned savings.[191] SEC's submission in this respect should be rejected as it would require the OEB panel in the current proceeding to bind all future OEB panels who will be responsible for determining Hydro One's rate base in respect of future rate periods. Not only does the current panel lack the jurisdiction to bind future panels in this way, but it would be inappropriate to disallow rate base additions in the absence of a full understanding and consideration of the circumstances, needs and prudence of the decisions underlying those expenditures. SEC's proposal that the Board in the current proceeding should pre-emptively declare amounts to be ineligible for rate recovery without having considered such factors is entirely inappropriate. Moreover, the OEB has clearly recognized that it understands that circumstances can change. As stated in the *Handbook*, "the OEB sets just and reasonable rates based on a total revenue requirement that is informed by an assessment of a utility's spending proposals… It is the utility's responsibility to operate its system, and undertake the projects and programs it needs to meet performance requirements within the funding provided through rates. This provides the utility with the responsibility and **flexibility to meet its obligations** in ways which benefit customers and the utility".[192] SEC's proposal would effectively deprive Hydro One of this flexibility that the Board has indicated utilities require.

CCC argues that the Board should apply an IRM formula that has an X-factor greater that 0%.[193] This is addressed by Hydro One under Issue 5.

Need for Independent Audit, Verification and Reporting

Several intervenors make submissions in respect of the need for various forms of independent audit, verification and/or reporting in connection with Hydro One's productivity framework.

[190] EB-2017-0049 Decision and Order, p. 31.
[191] SEC Submission, pp. 26-27.
[192] *Handbook*, p. 9 (emphasis added).
[193] CCC Submission, p. 14.

BOMA argues that Hydro One should be required to report annually on the extent to which the target for savings from each initiative has been achieved and that each initiative should be described in sufficient detail to be capable of verification by a third party (though BOMA does not argue that the Board should require such third party verification in this proceeding).[194] SEC argues that the Board should require Hydro One to obtain an independent third-party audit of the framework for its 2023 rate application as a means of providing greater certainty in respect of how initiatives are tracked and measured, and how reliable and appropriate the framework is.[195] VECC argues that the success of Hydro One's productivity initiative will be demonstrated in its reporting at its next cost of service application, and that the Board in the current proceeding might wish to emphasize the need to demonstrate the savings and consider whether third party audits of a sample of the initiatives should be required.[196]

In response to BOMA's submission on the need for reporting, Hydro One notes that Mr. Jodoin indicated during the Oral Hearing the company's willingness to provide reporting in respect of its Transmission business that is consistent with its commitment to providing reporting for its Distribution business.[197] Moreover, Hydro One notes that such reporting to the OEB will not be onerous given the significant and detailed internal tracking and reporting protocols already embedded into the productivity initiative. In response to SEC's submission that the Board should require an independent third-party audit of the productivity framework in Hydro One's 2023 rate application, Hydro One submits that it would be amenable to engaging a third party with relevant expertise to perform an independent review of the company's productivity framework, the results of which would be filed as part of Hydro One's next rebasing application for 2023. Hydro One expects that the review will provide parties with greater confidence that the manner in which Hydro One tracks and measures its productivity initiatives is appropriate.

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[194] BOMA Submission, pp. 13 and 15.

[195] SEC Submission, pp. 24-25.

[196] VECC Submission, pp. 11-12.

[197] See Oral Hearing Transcript, Vol. 5, p. 164, and EB-2017-0049 Decision and Order, p. 188: "File a report, within twelve months of this Decision and Order, showing the status of the productivity initiatives, including actual savings, with a discussion of any deviation from plan. The report, is to be filed on a standalone basis and will not be adjudicated. Hydro One is expected to update the report to file with its next rebasing application".

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

OEB Staff, SEC, and AMPCO argue that Hydro One should include portfolio level risk metrics on the proposed Evolved Transmission Scorecard (the "Scorecard"). Only OEB Staff made a specific proposal for the metric in question. OEB Staff proposes that Hydro One report on: (i) number of projects in-progress and forecasting a major variance (+10%) to the OEB-approved budget; and (ii) value of projects in-progress and forecasting a major variance or completed with a major variance to the OEB-approved budget (+10%).[198]

While Hydro One is receptive to the inclusion of the portfolio level metrics in the Scorecard, Hydro One urges the OEB to consider its prior decision regarding approvals at the envelope level. In the OEB's Decision and Order on Hydro One's 2017-2018 transmission rates revenue application, the OEB explicitly noted that "…the OEB does not approve capital plans, but rather a capital envelope…"[199] and that "… [t]he reason for approving a capital envelope, as opposed to a specific set of projects, is that Hydro One has the judgment, expertise and tools to determine what can be accommodated within that envelope considering both work priority and execution capability.[200]

In effect, the OEB does not approve individual projects, but rather approves the envelope that establishes the portfolio of projects. Therefore, there would not be an OEB approved project specific budget that is alluded to by OEB Staff in its submission above. As a result, if the OEB were inclined to adopt a portfolio-based measure, it should not adopt the measure as proposed by OEB Staff with respect to "OEB approved budget". In support of its measures, OEB Staff point to Undertaking JT1.16 in which Hydro One identified a series of portfolio level measures used internally by Hydro One. There, two existing measures were described: (i) Portfolio Risk: Number of Projects Forecasting a Major Variance (+/- 10%) to Budget and (ii) Portfolio Risk: Value of Projects Forecasting a Major Variance (+/- 10%) to Budget. The "Budget" relates to the internal approved project total amounts defined at the conclusion of the project definition phase,

[198] JT1.16 and J1.3
[199] EB-2016-0160 Decision and Order, p. 39.
[200] EB-2016-0160 Decision and Order, p. 31.

and aligns with the business case approval for the project. Hydro One already has a robust review, approval, and reporting process in-place to support measuring at the internal approved budget amounts, with visibility up to the executive team and the Board of Directors on this measure. There is added consistency in the process as each project has a business case approval milestone, whereas the snapshot of the basket of projects which build up to the transmission capital envelope is made up of many multi-year projects in different phases and at differing points of the project lifecycle.

Hydro One submits that performance against the approved business case is the more appropriate measure. Furthermore, to provide the appropriate baseline, the metrics should only include projects with an approved business case for full funding release – any projects still in the project definition stages would be excluded from the calculations for the metrics. Practically, even if there were OEB-approved budgets at the project level, Hydro One would have to modify existing enterprise systems to be able to report against such budgets, which would introduce additional cost and complexity with less benefit than using the approved business case for the project.

Other than the reference to portfolio risk measures and end-use customer metrics, OEB Staff and intervenors appear to be supportive of Hydro One's proposed enhanced Scorecard and its content. Hydro One submits that there is sufficient evidence and consensus for the OEB to conclude on the Scorecard's metrics and the OEB should not accept AMPCO's submission that Hydro One, Board Staff, and intervenors should work together to develop the final Scorecard metrics.

BOMA made a variety of submissions related to the scorecard. Of note is the following:

- BOMA's submission related to customer satisfaction survey is dealt with under Issue 3 above.

- BOMA's submission that the scorecard covers only 20% of the total capex and Hydro One has internal metrics related to the other 80% is dealt with above.

- BOMA's 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. The OEB approves at the envelope level. The portfolio level metrics will provide additional insight. No other party has sought this level of disaggregation.

- BOMA is incorrect when it states that Hydro One does not explain what force majeure events based on a 2-beta methodology means and what the likely change of impact of the change will be in the future. Hydro One provides an explanation both with and without 2-beta charts throughout the evidence and explained 2-beta in detail.[201]

- BOMA is also incorrect when it states that Hydro One does not provide 2020-2022 target for SAIFI. This information was provided in Undertaking JT 2.25 where Hydro One provides in year targets for each year from 2019 to 2024.

- BOMA's commentary regarding consequences related to scorecard performance are misplaced. No utility in Ontario has a set form of consequences and Hydro One submits that to develop that regulatory framework a generic process must occur.

Hydro One believes that to be of use to the OEB and stakeholders, the reporting and recording of information should be efficient and limit regulatory burden on both the provider and users of the information. With the OEB yet to approve the Scorecard[202], Hydro One submits that there is an opportunity at this juncture to promote efficiency and reduce regulatory burden and to also allow for the flexibility that is necessary for fulsome reporting of performance and scorecard measures so that relevant and useful mechanisms will be provided to Hydro One's customers.

Previously the OEB directed Hydro One to provide a report on the execution of its capital plan (the "capital program performance report")[203] to explain Hydro One's performance outside of the OEB's Filing Requirements for Electricity Transmission Applications.[204] For distributors, the OEB already has in place a robust performance reporting framework based on two fundamental tenets of (i) transparency and (ii) providing relevant and meaningful information to customers while "ensuring that information for public consumption is informative, well written and well-

[201] Exhibit B-1-1, TSP Section 1.5, pp. 27-36; Exhibit D-2-1, p. 4.
[202] EB-2016-0160 Decision and Order, p. 38.
[203] Exhibit C-2-1-1: Capital Program Performance Report – 2017 and 2018.
[204] EB-2016-0160 Decision and Order, p. 32.

presented."[205] This framework consists of a distributor scorecard complemented by a Management Discussion & Analysis ("MD&A").

In this regard, to promote continued efficiency and reduce regulatory burden, Hydro One submits that the OEB should adopt the distribution scorecard performance reporting framework of an annual scorecard complemented by a MD&A for Hydro One transmission and abolish the capital program performance report. This would permit a framework that is established on the same proven and established governing principles of:[206]

- Expressing the value of the service and performance results from a customer-centric lens and through the eyes of customers;
- 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; and
- Providing important disclosures.

Adoption of this proven framework would serve as the foundation for the Renewed Regulatory Framework 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.

[205] Scorecard and MD&A Guide for Electricity Distributors, May 22, 2015.
[206] *Ibid*.

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?

Environmental Defence requested, and the OEB granted, the inclusion of Issue 8 as part of this application. On October 17, 2019, Hydro One and Environmental Defence settled Issue 8 (the "Line Loss Settlement").

Under the terms of settlement, Hydro One agreed to participate in the IESO's stakeholder engagement on transmission line losses and through that process, to continue to identify opportunities to cost-effectively reduce transmission losses, including by preparing an internal guideline delineating Hydro One's transmission line loss process, and by including option analyses in business cases for projects where transmission line losses are material. In addition, at its next rebasing Hydro One will submit an independent third-party review of its own processes for cost-effectively reducing transmission line losses.[207]

OEB staff, Energy Probe, and LPMA support the proposed settlement agreement. OEB staff recommend that the OEB direct Hydro One to file a formal analysis of line loss opportunities at its next rebasing.[208] Under the terms of settlement, Hydro One has already agreed to submit an independent third-party review of its processes for cost-effectively reducing transmission line losses. As such, staff's recommendation is redundant and not necessary. PWU recommends that the report include an analysis of and justification for Hydro One's proposed materiality threshold.[209] Hydro One agrees to include this in its report.

Environmental Defence "strongly supports the agreed-on next steps and looks forward to working with the IESO and Hydro One to achieve concrete results."[210] Notwithstanding the Line Loss Settlement, Environmental Defence made submissions on the following points:

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[207] The full terms of settlement were included in Hydro One's Argument in Chief, p. 39
[208] OEB Staff Submission, pp. 45-46
[209] PWU Submission, para. 18
[210] Submissions of Environmental Defence dated November 9, 2019

- That Hydro One has not entirely complied with the Board's direction in EB-2016-0160 because it has not made improvements or implemented measures to mitigate its line losses;
- That Hydro One's line loss mitigation practices are not as advanced as National Grid's;
- That Hydro One has not addressed other issues raised in EB-2016-0160, in addition to the Board's specific directive on line losses; and
- That the EPRI report commissioned by the IESO and Hydro One and submitted in this application does not establish that Hydro One follows best practice.[211]

Hydro One addresses each of these concerns below. In general, Environmental Defence's points fall outside the scope of the issue, which is focused on outcomes of the Board's directive in EB-2016-0160.

The Practical Reality of Mitigating Line Losses

Before addressing the specific issues raised by Environmental Defence, it is worth clarifying a few preliminary points on the physical constraints of the transmission system and Hydro One's role in reducing system line losses.

Managing the transmission system and reducing the associated transmission losses is a split responsibility between Hydro One and the Independent Electricity System Operator ("IESO").[212] Hydro One's ability to manage line losses is limited to its role as a Transmission Owner (asset owner) in planning, selection, maintenance and operation of its transmission equipment, subject to the inherent limitations of that equipment.[213] This means that losses attributable to the

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[211] Environmental Defence Submission, p. 3.

[212] Exhibit B-1-1, TSP Section 1.8, p. 4. As a system operator, the IESO directs the operation of the transmission system including maintaining voltage schedules, and generation dispatch to meet the load demand. As a transmitter, Hydro One is responsible for the design, selection, and installation of equipment to address the needs that have been established through the transmission planning processes.

[213] Exhibit B-1-1, TSP Section 1.8, p. 2. See also TSP Section 1.8, p. 1: "The amount of losses is dependent on the specific type of transmission line conductor, other transmission assets (i.e., transformers), the amount of power flowing in the line, and the length of the line."

physical characteristics of the transmission system are fixed and can only be changed through subsequent investment in the transmission system.

The transition of the system for purposes of reducing losses is an evolutionary process that occurs within the investment planning process, which is further constrained by economics and physical limitations. Across the industry, line loss mitigation occurs as part of other investments undertaken to address asset condition and/or reliability and not purely to reduce losses.[214]

Hydro One's loss mitigation practices are described in detail at Table 1 of TSP-01-08, page 9[215] and these practices are consistent with transmission line loss practices identified by National Grid, CEER and EPRI.[216] They are also referenced in the EPRI Report that Hydro One commissioned, with the IESO, to address the Board's direction in EB-2016-0160. However, outside these sources, these practices are not formally memorialized in writing, in part because they are ingrained in the way Hydro One plans and considers its investments. Hydro One will address this through the terms of settlement, pursuant to which it will document its processes and have them reviewed by an independent third party.

Despite these practices by Hydro One and other utilities, the practical reality is that there is typically little ability to cost effectively reduce line losses in line upgrade work where the existing conductor section is being replaced. The size of the conductor is limited by the original tower structures. Selecting a conductor size beyond the tower structure design capability triggers major tower reinforcement work and is not cost effective. Hydro One is increasingly using Aluminum Conductor Steel Reinforced Trapezoidal Wire ("ACSR/TW") conductor in these situations, which has the same diameter as the conductor being replaced, but has more aluminum content and a 10-20% lower resistance. The net effect is to reduce the losses on that

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[214] Exhibit B-1-1, TSP Section 1.8, Attachment 1, p. 9 of 58, EPRI Technical Report on Hydro One Transmission Losses dated March 2018 (the "EPRI Report").

[215] Loss mitigation practices include: Raising Nominal Voltage; Optimization of Voltage Profile; Use Lower Loss Conductors; Re-direct Power Flows; Bundle Conductor Optimization; Improve Corona Losses; Shieldwire Segmentation; Improve Insulation Losses; Installation of Low-Loss Transformers. These are described in greater detail in Table 1, TSP Section 1.8.

[216] Exhibit B-1-1, TSP Section 1.8, Attachment 2, pp. 5-8.

line by the corresponding amount.[217] In most urban areas Hydro One is already using the biggest conductor size possible.

Network reinforcements offer more opportunities for loss reduction. Building a new line in parallel with an existing line reduces the losses by 50% and building a third line in parallel with two lines reduces the losses by 33% assuming loading levels remain constant. Building these additional lines to reduce line losses is not economically justifiable unless the lines are required for providing capacity or increasing reliability. Similar to network reinforcement, a system voltage upgrade involves rebuilding transmission lines and station facilities and is not economically justifiable to reduce losses, unless the voltage upgrade is required for providing additional capacity or increasing reliability.

Hydro One Met the OEB's Directive in EB-2016-0160

Environmental Defence submits that Hydro One did not meet the OEB's directive in EB-2016-0160 because it has not made improvements, avoided line losses, or implemented measures to cost-effectively reduce losses.[218] Through its directive in EB-2016-0160, the Board directed Hydro One to report on the following initiatives as part of its next rate application:

> "Hydro One should work jointly with the IESO to explore cost effective opportunities for line loss reduction.
>
> Hydro One should also explore, as part of its investment decision process, opportunities for economically reducing line losses."

Hydro One has complied with this directive:

- With the IESO, Hydro One engaged EPRI to review transmission line loss mitigation practices of other utilities and compare those practices with Hydro One's practices[219]
- The EPRI report[220] found that:

[217] Exhibit B-1-1, TSP Section 1.8, p. 2.
[218] Environmental Defence Submission, p. 3.
[219] Exhibit B-1-1, TSP Section 1.8.3.
[220] Exhibit B-1-1 TSP Section 1.8, Attachment 1.

- Hydro One's design practices materially consistent with industry best practices for loss mitigation;
- the lifetime benefits of the mitigated losses do not offset the financial cost of performing the necessary transmission line modifications; and
- while line loss mitigation is not the primary driver for transmission investments, secondary or implicit savings may be achieved through system planning and equipment selection. On this basis, Hydro One incorporates line loss mitigation into its investment plan by identifying transmission line loss reduction for projects undertaken to provide supply adequacy or reliability.[221]

In addition, Hydro One and the IESO, as part of the bulk transmission planning and regional planning exercise, routinely work together to develop projects aimed at addressing specific reliability and system capacity needs. The recommended solutions reduce line losses.[222]

Given EPRI's findings, the physical limitations of the system as described above, and Hydro One's current practices, which are consistent with industry practice, there are limited opportunities for Hydro One to change or improve upon what it is already doing (save for formalizing its practices through written documentation, which will add transparency to Hydro One's practices). Hydro One will continue to look for ways to improve including through discussions held at the IESO's stakeholder consultation, through the report it will submit at its next rebasing, and through its normal course of business.

As it stands, and as described at Table 2 of TSP-08-01, line loss reduction benefits were identified for five projects included in Hydro One's proposed capital plan.[223] As well, Hydro One's recent section 92 application for the D6V/D7V upgrade (EB-2019-0165, Exhibit B-5-1) describes the conductor selection process undertaken to reduce losses and identifies the expected loss reduction.

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[221] Exhibit B-1-1, TSP Section 1.8.5, Table 2.

[222] Exhibit B-1-1, TSP Section 1.8.2.

[223] These include: SS-06, Merivale TS to Hawthorne TS: 230kV Conductor Upgrade; SS-09, Barrie Area Transmission Upgrade; SS-11, South Nepean Transmission Reinforcement; SS-12, Aylmer-Tillsonburg Area Transmission Reinforcement; SS-14, Southwest GTA Transmission Reinforcement.

Hydro One's Practices Follow National Grid, CEER and EPRI

Environmental Defence argues that Hydro One's practices are not consistent with National Grid's. In doing so, Environmental Defence identifies a handful of practices it says National Grid follows but Hydro One does not.[224] This is simply not the case. Although Hydro One has not formalized its processes through written documentation, it follows industry best practice. As a result of the Line Loss Settlement, Hydro One will document its practices by preparing an internal guideline delineating its transmission line loss process and by including option analysis in business cases for projects where transmission line losses are material.

Contrary to Environmental Defence's submission and as set out in the evidence in great detail, Hydro One's loss mitigation practices are substantially consistent with National Grid, CEER and EPRI.[225] In particular, Table 1 in TSP 1.8.2 compares Hydro One's practices with the best industry practice in the following four major areas:

- Transmission System Planning/Investment Planning (4 examples);
- Line Loss Mitigation Practices Considered During Transmission System Planning/Regional Planning Stage (5 examples);
- Line Loss Mitigation Practices at Equipment Selection Stage (7 examples); and
- Line Loss Mitigation Practices at Transmission and Distribution System Operation (2 examples).

In terms of performance, the Ontario transmission system has low transmission losses in comparison to other jurisdictions. In 2018 the annual Ontario transmission losses were 1.82% of annual energy consumption. In comparison, National Grid's reported losses were between 1.17% - 8.04% for different parts of their network; EPRI reported transmission losses ranging from 1.5% - 5.8% in surveyed jurisdictions; and CEER reported losses in the European transmission system between 0.89% and 2.77%.[226]

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[224] Environmental Defence Submission, pp. 5-6.
[225] Exhibit B-1-1, TSP Section 1.8.2, Table 1.
[226] Exhibit B-1-1, TSP Section 1.8.2, p. 5.

Environmental Defence argues that Hydro One should not account for loss mitigation when it arises from investments that would take place in any event. Rather, Environmental Defence suggests Hydro One should consider whether additional steps could be taken to reduce losses including things like “better routing, conductors, equipment, or project design could reduce the cost of losses by more than the incremental cost of the upgrade”.[227] In fact, like National Grid, Hydro One does consider losses when alternatives are considered for investments and the losses are consequential to the ranking of the alternative investments. Hydro One’s evaluation includes consideration of the very factors Environmental Defence enumerates including routing, conductor and equipment selection. In general, the longer route, the higher the cost and losses.[228] Losses are not an afterthought for Hydro One, however, they are not the primary driver of its investments. Rather, they are considered in instances where they are consequential to the alternative selection. Hydro One submits that this is consistent with industry practice, and is a pragmatic approach that reduces line losses where possible without inefficiently increasing costs to customers.

Hydro One notes that changing the valuation of line losses by using the wholesale electricity commodity cost (which includes global adjustment) instead of the HOEP, as suggested by Environmental Defence,[229] would not have a significant impact on loss practices, because project costs are typically 50 to 100 times greater than the loss reduction benefits. Using a higher price to evaluate the cost of line losses would not in the vast majority of cases ‘move the needle’.

Clarification of the Conclusions in the EPRI Report

Environmental Defence submits that the EPRI report does not establish that Hydro One is following “best practices”[230] for three reasons – that EPRI did not receive written documentation of Hydro One’s practices so could not properly examine them; that EPRI only reviewed North

[227] Environmental Defence Submission, p. 7.
[228] Exhibit B-1-1, TSP Section 1.8.4.
[229] Environmental Defence Submission, p. 5.
[230] Environmental Defence Submission, p. 9.

American utility practices; that EPRI drew conclusions about best practices that Hydro One could not show it adhered to.

Notwithstanding that Hydro One does not have formal documentation of line loss reduction in its investment planning practice, EPRI reviewed Hydro One's accomplishments in loss mitigation to date, performed a sensitivity analysis, and reviewed Hydro One's current practices in planning, line design and equipment areas, among other things, before concluding that Hydro One's design practices are materially consistent with industry best practices for loss mitigation.[231]

Other Line Loss Issues Identified in EB-2016-0160

Environmental Defence argues that, in addition to the OEB's directive in EB-2016-0160, Hydro One did not address other issues noted in the Board's decision in that proceeding. Environmental Defence outlines five items raised in EB-2016-0160 that it says Hydro One did not address. With respect, Hydro One was not required to address these items. In any event, each of the items enumerated by Environmental Defence (as listed below) have either been addressed by Hydro One or will be addressed through the terms of settlement.

First, Environmental Defence argues that Hydro One should document its approach to evaluating line losses as part of the investment planning process. Hydro One will address this through the terms of the Line Loss Settlement.

Second, Environmental Defence argues that Hydro One does not include an option analysis in its business cases. Hydro One will address this through the terms of the Line Loss Settlement.

Third, Environmental Defence argues that Hydro One should get more input from the IESO about planning decisions like conductor size and station configuration. Hydro One and the IESO already jointly determine the system configuration and ampacity needs based on Regional Planning studies. This will likely be addressed by and explained in the report coming out of the IESO's stakeholder consultation.

Fourth, Environmental Defence argues that the Board in the last proceeding noted that Hydro One's cost/benefit analysis methodology was unsound. In fact, Environmental Defence is

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[231] Exhibit B-1-1, TSP Section 1.8, p. 9.

merely quoting the Board's summary party positions. Environmental Defence states that Hydro One did not discuss the incremental cost of upsizing conductor as part of a replacement project.[232] In fact, Hydro One provided details for incremental costs of upsizing conductor in the D6V/D7V project (EB-2019-0165) and will be documenting this process as part of the Line Loss Settlement.

Finally, Environmental Defence notes that in EB-2016-0160, the Board said it was concerned Hydro One had not provided evidence of specific initiatives to reduce line losses. That is not correct. This evidence was included at TSP-01-08-02. In addition, Hydro One's practices were delineated in the EPRI report and as part of the Line Loss Settlement, Hydro One will prepare the internal guideline described above will include option analysis in business cases for projects where transmission line losses are material.

Next Steps

Pursuant to the terms of the Line Loss Settlement and in any event, Hydro One will continue to consider the reduction of line losses for all projects and will work collaboratively with the IESO as part of its ongoing stakeholder consultation to identify and investigate other opportunities to reduce line losses as part of the regional planning process. Hydro One will also continue to participate in industry affiliations to keep abreast of the developments in loss reduction and other new technological opportunities.

[232] Environmental Defence Submission, p. 8.

D. TRANSMISSION SYSTEM PLAN:

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 has articulated through its TSP the system and asset needs that underpin its forecast capital expenditures, as shown in Table 9-1 below for the 2020-2024 plan period.

Table 9-1: 2020-2024 Capital Expenditures[233]

	Forecast ($M)				
	2020	2021	2022	2023	2024
Capital Expenditure	1,188.0	1,312.5	1,364.2	1,364.2	1,364.2

Through a rigorous asset management and investment planning process, Hydro One has ensured that asset condition is the primary driver for identifying and evaluating asset renewal needs and the resulting investment solutions. While a fleet-level indicator like expected service life can be a useful proxy for condition and provide a valuable insight to inform long-term planning, it will never be the sole determinative factor for replacement decisions, which are always verified based on asset condition and other investment drivers (such as environmental/safety requirements, functional obsolescence, capacity constraints, customer needs, etc.). Importantly, in connection with its Asset Risk Assessment ("ARA") process, Hydro One performs a number of verification and validation steps, including site visits and other needs confirmation/screening tests to ensure that the analytical results derived from the process are reflective of reality in the field and sufficiently robust to enable final prioritization.[234] This approach is closely aligned with the OEB's expectations regarding condition-based replacements as outlined in recent rebasing proceedings.

For the purpose of evaluating the parties' submissions and Hydro One's reply, Hydro One urges the OEB to consider the role and importance of condition-based renewal as the cornerstone of

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[233] Hydro One, Argument in Chief, p. 45.
[234] Exhibit B-1-1, TSP Section 1.4, Attachment 13, p. 26.

the utility's asset management and investment planning. For instance, while certain parties try to shift the narrative away from asset condition (and the risks associated with degraded assets) to focus on reliability performance instead, it is important to keep in mind that reliability metrics are a lagging indicator of asset condition and investment decisions, and that Hydro One must prudently identify and mitigate asset risks through ongoing assessments and based on known condition information. As discussed below, the attempt by parties to selectively focus on reliability as their preferred primary driver for certain investments is a red herring. For a transmission system that is managed to avoid run-to-fail scenarios and that reflects design redundancies to mitigate the impact of contingencies, it is unrealistic and misleading to suggest that reliability would or should be allowed to first materially deteriorate so that investment needs can then be justified on that basis. Hydro One assesses and replaces assets on condition to avoid failure. The company should not be penalized for doing its job as a prudent asset manager and not allowing system reliability to unacceptably deteriorate.

OEB Staff and several intervenors argue that Hydro One's forecast 2020-2022 capital expenditures should be reduced due to perceived concerns relating to:

- hazard functions for older assets (*see* ***section (a)*** *below*),
- asset condition assessment and data availability (*see* ***section (b)*** *below*),
- "repair vs. replace" evaluation (*see* ***section (c)*** *below*),
- the independence of one third-party expert (*see* ***section (d)*** *below*),
- unit costs (*see* ***section (e)*** *below*),
- project costs (*see* ***section (f)*** *below*),
- other assertions by intervenors in relation to the overall TSP and/or planning approach (see ***section (g)*** below),
- justification for proposed conductor replacements (*see* ***section (h)*** *below*), and
- specific projects within the System Renewal (*see* ***sections (i) to (o)*** *below*), System Service (*see* ***section (p)*** *below*), and General Plant (*see* ***sections (s) to (t)*** *below*) investment categories.

Each of these concerns has been addressed in turn below. Parties have also made submissions regarding Hydro One's customer engagement process, including its use of the Reliability Risk Model, which are responded to under Issue 3 above.

Respectfully, Hydro One submits that these concerns are not sufficiently grounded in the evidence. The alleged deficiencies in the investment planning and asset management processes (and the resulting plan) are not substantiated. The bulk of these arguments are predicated on a partial and/or inaccurate interpretation of the record. In particular, Staff's submissions on Issue 9 largely focused on isolating and critiquing particular elements of Hydro One's planning approach, without challenging the specific drivers, justification and forecast that underpin detailed investment proposals (other than two non-System Renewal projects that Staff took issue with). Further, the project-specific concerns raised by intervenors largely relied on over-sweeping generalizations and/or taking particular facts out of context. Notably, no party offered any credible arguments to refute the extensive record that demonstrates the significant, multi-year investment needs facing Hydro One's transmission system.

In their respective submissions, Staff and intervenors largely fail to recognize the crucial fact that Hydro One has put forward a comprehensive capital plan that is underpinned by a rigorous investment planning process and thorough asset assessments. In terms of process, Hydro One has expanded and enhanced its ARA, going beyond the traditional risk definition (i.e., probability multiplied by consequence) and incorporating the assessment of a range of factors, including load forecast, equipment ratings, performance history, operating restrictions, security incidents, environmental risks, compliance obligations, maintenance records, equipment defects, obsolescence, and health and safety considerations.[235] The ARA establishes the potential candidate investments as well as the fact base for assessing the probability and consequence of safety, reliability and environmental risks during investment planning. The quantification of risk mitigation benefits as well as the consideration of qualitative benefits that customers value (e.g., outage coordination, proactive communication, power quality, and performance improvements) enable consistent prioritization and trade-off decisions to derive the final portfolio of investments.[236]

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[235] OEB-73.
[236] *Ibid*; also see Exhibit B-1-1, TSP Section 2.1.

As explained point by point below, the assertions of the parties are inconsistent with a full and accurate view of the relevant facts and fail to establish that Hydro One's planning approach and resulting TSP are deficient as alleged – much less to justify the reductions that several parties are advocating for. In Hydro One's submission, the OEB should reject the proposed reductions in capital expenditures and in-service additions.

OVERALL PLAN & PLANNING PROCESS

(a) Hazard Functions

Failing to recognize that hazard functions help Hydro One to gauge the conditional probability of failure (not to drive replacement decisions), OEB Staff incorrectly argues that Hydro One's replacement rate for older assets (transformers and breakers) is higher than expected based on the Electric Power Research Institute's ("EPRI") hazard function report (the "Hazard Function Report").[237] Specifically, OEB Staff relies on Region 2 shown in Figure 9.2 of their submission,[238] which shows a higher likelihood of removal for Hydro One's older transformers (at least 60 years in age) relative to the Weibull/hazard function curves derived by EPRI. In doing so, Staff asserts that the Weibull/hazard function curves were derived from EPRI's sample utility data and that this data reflects condition-based replacements for these utilities. As explained below, these assertions are inaccurate; the Weibull/hazard function curves do not provide a comparison against sample utility data, much less the purported condition-based replacements of these utilities.

OEB Staff Fundamentally Misunderstood the Purpose of Hazard Functions

Staff's submissions on this issue reflect a fundamental misunderstanding of the purpose of a hazard function and its role in Hydro One's planning context. As explained in JT1.1, a "hazard function" represents the time-to-event analysis of the functional relationship between the occurrence of a well-defined event (e.g., asset failure or, for the EPRI study, removal for any reason) and the waiting time (e.g., asset age). In the case of the EPRI Hazard Function Report,

[237] Exhibit B-1-1, TSP Section 1.4, Attachment 2.

[238] Staff Submission, Figure 9.2, p. 51; originally Exhibit B-1-1, TSP Section 1.4, Attachment 2, Figure 2-4, p. 26.

the probability of asset removal was modeled based on Hydro One's historical replacement records.[239]

The record is abundantly clear Hydro One relies on detailed condition assessment when replacing end-of-life assets,[240] and the EPRI Hazard Function Report was informative regarding fleet-level planning. As such, the asset replacements in the plan are not overstated (and in fact represent only a portion of the entire population of end-of-life assets). For example, for each transformer replacement, a detailed ARA report is prepared to substantiate the proposed replacement;[241] and for each conductor replacement, condition assessment is carried out including by using LineVue or lab testing.[242] Replacements are then carefully selected in line with investment planning criteria. Hydro One summarized its practice during the oral hearing:

> "From a population point of view, [we] absolutely use these Weibulls [*i.e., hazard function curves*]. But from a replacement point of view, we rely on condition assessment. <u>We remove units based on condition assessments only</u>."[243] (*emphasis added*)

Given Staff's misunderstanding of how Hydro One uses hazard functions, Hydro One submits that Staff's attempt to link hazard functions to actual asset replacement rates is misplaced and without merit. Nevertheless, Hydro One has addressed below the specific aspects of Staff's arguments, which also reflect an inaccurate interpretation of EPRI's analysis

<u>OEB Staff Misunderstood the Basis/Implications of the Weibull Hazard Curves</u>

Staff incorrectly asserts that the Weibull/hazard function curves were derived from "EPRI's data of a number of utilities' in-service and failures datasets" and that these curves "provide

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[239] Exhibit B-1-1, Section. 1.4, p. 9.

[240] See, for example, Oral Hearing Transcript, Vol. 2, p. 135, ln. 23-27: "What we get from EPRI all the time is a projection" whereas "<u>what we replace on our system in based on condition</u>"; TSP 1.4, p. 10, where Hydro One confirmed that "replacements are not aged based decisions, they are based on verified asset condition". Also see JT1.1, and Oral Hearing Transcript Vol. 2, p. 99, ln. 14-21.

[241] OEB-19, Attachment 1.

[242] ISD SR-19 confirms: "These projects are driven by the need to replace major transmission line components, <u>verified to be at EOL by condition assessment</u>, including Aluminum Conductor Steel Reinforced ("ACSR") conductor, obsolete copper conductor, or deteriorated structures in high risk condition" (p. 1).

[243] Oral Hearing Transcript, Vol. 2, p. 137, ln. 15-21.

reasonable probabilities of removal for the sample utilities…”.[244] The hearing testimony cited by Staff confirms that “the cumulative hazard function derived from the [Hazard Function Report]’s Weibull model is represented by the red line”.[245] However, it is not the case – and Staff does not cite evidence to substantiate – that the red lines represent sample utility data.

As indicated in the Hazard Function Report, the only relevance of “previous utilities transformer data set” was that it provided the knowledge to choose the prior distributions used as a starting point (i.e., the “prior distribution”) for EPRI’s analysis of Hydro One’s removal data.[246] EPRI then established a “new, upgraded probability distribution formally called the posterior distribution or updated distribution” using Hydro One’s removal data.[247] This posterior distribution became the basis for determining the final Weibull function parameters (shape and scale) and the corresponding removal Weibull/hazard function curve (i.e., the red lines shown in Staff submission, Figure 9.2) for Hydro One’s (not of other utilities’) transformers. As such, Staff’s interpretation that the red lines somehow represent sample utility transformer replacements is incorrect.

Given the foregoing, OEB Staff’s assertion that the Weibull/hazard function curves represent sample utilities’ supposedly condition-driven replacements is also unfounded. In any event, Hydro One has explained that the Weibull/hazard function curves derived from its transformer removal data provide a “good proxy for [Hydro One’s transformer] failure hazard rate, especially for younger transformers”.[248] This is because, as EPRI put it, “younger power transformers are rarely replaced except for failure”.[249]

As stated in JT1.1, Hydro One does not run its transformer fleet to failure as this would be imprudent and would elevate safety and system risk; rather, Hydro One replaces transformers before failure driven by end-of-life condition criteria. Moreover, Hydro One has explained that its cumulative hazard function in Region 2 of the curves would be closer aligned with the Weibull

[244] Staff Submission, p. 51.
[245] Oral Hearing Transcript, Vol. 2, p. 132, pp. 19-21.
[246] Exhibit B-1-1, TSP Section1.4, Attachment 2, p. (2-4) (p. 24 of 78).
[247] *Ibid*.
[248] JT1.1, Attachment 1, p. 2.
[249] Exhibit B-1-1, TSP Section1.4, Attachment 2, p. (2-6) (p. 26 of 78).

curve if its assets were run to failure. Staff has not provided any evidence-based argument to refute this explanation.

OEB Staff Misinterpreted the Implications of Regions 1& 2 of the Hazard Curves

Hydro One has a comprehensive and robust asset management practice, and does not run its fleet to failure. Planned replacements that prudently target verified poor condition assets before failure is one factor contributing to the steeper Hydro One removal hazard curves in Region 2. [250] In response to questions in the hearing about those steeper hazard curves, Hydro One confirmed that the older assets represented by Region 2 were replaced due to their assessed end of life and that Region 2 was of “very limited use” for purposes of EPRI’s study.[251] In other words, EPRI’s Weibull/hazard function curves were predominantly shaped and influenced by the “useable” part of the curve (Region 1), which was a closer approximation of a failure hazard rate.[252]

In Hydro One’s view, it is misleading for Staff to focus the bulk of its submissions regarding hazard functions on critiquing the purported implications of Region 2 before it briefly acknowledges the context around Hydro One’s condition-driven replacements and the limited influence of Region 2 on EPRI’s results. This important context is crucial to a full and accurate understanding of the issues and should not have been relegated to secondary considerations that are mentioned in passing and then quickly dismissed. When viewed against the proper factual backdrop, Staff’s assertions are disconnected from the reality of Hydro One’s planning and asset management context. In questioning Hydro One’s replacement rates, Staff makes no attempt to understand the actual processes and criteria underlying the utility’s condition-triggered replacements.

[250] EPRI posited that the steeper replacement curve for Hydro One may be attributed to “the onset of a failure process that is more dominant in older units”; “the result of discretionary replacements”; or “some combination of both failure process and discretionary replacements.” (Exhibit B-1-1 TSP Section 1.4 Attachment 2, p. 26)

[251] Oral Hearing Transcript, Vol. 2, p. 135, ln 19-27, and p. 136, ln. 17-21. Note that while Hydro One’s testimony included the statement that “region 2 was not used as a projection” (p. 135, ln. 21-21), this was intended to explain the limited use of Region 2 for purposes of deriving the hazard curves. It was subsequently clarified (see p. 136, ln. 17-20) that “the region 2 projection here is of very limited use”.

[252] Oral Hearing Transcript, Vol. 2, p. 136, ln. 8-16.

In trying to discredit Hydro One's approach to assess and replace end of life assets, the only argument raised by Staff is that the dataset provided to EPRI did not adequately distinguish between failures and discretionary removals.[253] To this end, Staff quotes from Hydro One's oral hearing testimony, which discussed the challenges associated with categorizing the reasons for asset removal (i.e., failure vs. assessed end of life).[254] Staff's argument is flawed for multiple reasons:

- EPRI concluded that Hydro One's failure data was sparse and would not yield a usable failure hazard curve, and thus elected to use the more abundant data regarding asset removals.[255] The limited influence of Region 2 in driving the resulting failure hazard function was due to the lack of failure data points, and not due to limitations in the tracking of reasons for removal.

- The testimony quoted by Staff was a direct response to Staff's cross-examination about the sparsity of failure data in the EPRI study. Contrary to Staff's characterization, Hydro One in no way acknowledged that its practice for deeming an asset at end of life was somehow contentious or rife with uncertainty. That testimony did not purport to speak to the specifics of condition assessments at all.

- Staff incorrectly asserts that "neither EPRI nor OEB staff can tell whether Hydro One's deemed condition-based failure is aligned with industry best practice".[256] This assertion is factually inaccurate and contradicted by clear evidence, which demonstrates that Hydro One verifies end of life asset conditions based a set of well-defined processes and criteria as part of the ARA.[257] For example, in respect of Hydro One's methodology for determining transformer condition, EPRI confirmed a close alignment with industry

[253] Staff Submission, p. 52.
[254] Oral Hearing Transcript, Vol. 2, p. 133, ln. 9-20.
[255] Exhibit B-1-1, TSP Section 1.4, Attachment 2, p. 21.
[256] Staff Submission, p. 52.
[257] Exhibit B-1-1, TSP Sections 2.

best practices.[258] With respect to circuit breakers, EPRI found that Hydro One was one of the few utilities to have a formal circuit breaker condition algorithm.[259]

After eventually acknowledging in its submissions that Region 2 was of limited value, Staff then takes issue with Region 1 of the hazard function as well, arguing that "EPRI's projection based on Region 1 data is not much more than a mathematical representation of Hydro One's historic[al] removal decisions" and only "estimates the age at which Hydro One is likely to replace the asset, rather than providing a representation of the deteriorating performance of the asset".[260] Once again, Staff misunderstands the purpose of EPRI's analysis. As noted above, EPRI derived a set of removal Weibull/hazard function curves based on Hydro One's removal data to provide a reasonable proxy for failure hazard functions (especially for younger transformers), helping Hydro One to gauge the probability of failure at the fleet level. The analysis was <u>not</u> intended to compare Hydro One's historical removal rates with industry.

For the above reasons, Hydro One submits that Staff has mischaracterized or misunderstood the nature and purpose of EPRI's Hazard Function Report, and Staff's criticisms in this regard should not be accepted by the OEB.

(b) Asset Condition Assessment and Data Quality

Several intervenors take issue with Hydro One's asset condition assessment, primarily by alleging that the company's asset analytics data are insufficient.[261] These allegations reference several key sources/studies: (i) Hydro One's *Internal Audit Report on Investment Planning Support Tools* ("Internal Audit Report"),[262] (ii) METSCO's *Review of HONI's Capabilities in Asset Analytics and Reliability Risk Modelling*,[263] and (iii) EPRI's *Results of Power Transformer Expert System (PTX) Software Analysis of Hydro One's Transformer Fleet*.[264]

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[258] Exhibit B-1-1, TSP Section 1.4, p. 8.
[259] Exhibit B-1-1, TSP Section 1.4, p. 12.
[260] Staff Submission, pp. 51-52.
[261] SEC Submission, pp. 51-32; CME Submission, pp. 32-35; and AMPCO Submission, pp. 16-17.
[262] JT1.10, Attachment 2.
[263] Exhibit B-1-1, TSP Section 1.4, Attachment 13 (see p. 39 for discussion on average data availability for transformers).
[264] Exhibit B-1-1, TSP Section 1.4, Attachment 1.

Key to this discussion is the context around Hydro One's approach to assessing and validating asset condition. Even aside from the process and data quality improvements that Hydro One has made, it is important to note that the asset analytics and associated data are used as screening and prioritization tools. An investment is not made until a condition-based asset need has been confirmed and planners have completed their comprehensive review through the ARA process. In this regard, asset managers and planners conduct a number of verification and validation steps, including site visits and other needs confirmation/screening tests to ensure that the analytical results and identified investment reflect field asset condition.[265] For example, subject matter experts work with field staff to assess each of the transformers with reported oil leaks and conduct an actual inspection of the unit to verify the severity of the leak prior to commencing work.[266] It is also standard practice for subject matter experts to evaluate the transformer unit based on testing data, operation history and maintenance records.[267] The detailed asset assessment and field validation are invaluable tools for ensuring that the identified needs reflect asset condition and relevant operating information including the concerns of field personnel, which could not otherwise be verified through asset analytics alone.[268]

Internal Audit Findings

CME cites the Internal Audit Report's findings regarding certain limitations in the quality of data from Hydro One's source systems that are used as inputs for ARA.[269] However, that Internal Audit Report dates back to 2017. As explained in interrogatory response SEC-6, Hydro One developed action plans to address each recommendation from the Internal Audit Report, and implementation has been completed for all actions plans.

Data Availability

SEC, CME and AMPCO each takes issue with the average data availability for Hydro One's transformers, referencing METSCO's findings across six evaluation categories (i.e., 99.5% data

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[265] Exhibit B-1-1, TSP Section 1.4, Attachment 13, p. 26.
[266] OEB-75.
[267] CME-13(b) and 24.
[268] Exhibit B-1-1, TSP Section 2.1, p. 16.
[269] CME Submission, p. 33.

availability for demographics, 65.2% for condition, 100% for performance, 46.7% for utilization, 100% for economics, and 59.8% for criticality). But they ignore and/or reject METSCO's assessment.

With respect to condition, METSCO found Hydro One's data availability to be "robust, considering the size of HONI's asset base, the span of its territory, and the manner of presentation of the condition score relative to many other utilities".[270] In particular, METSCO noted that Hydro One's condition data does not include age or utilization (each captured through separate demographic categories) and instead solely reflects an asset's extent of degradation as assessed by field crews and empirical tests.[271] Further, the lower percentages in some evaluation categories were considered by METSCO to be a function of the number of parameters that Hydro One is seeking to track in the ideal circumstances (as opposed to tracking only a few parameters with higher availability) and is making steps to acquire data for.[272]

Even aside from the issue of data availability, METSCO found that "Hydro One also performs a number of verification and validation steps, including site visits, and other types of needs confirmation/screening tests to ensure that the analytical insights generated thus far, are reflective of reality in the field, and sufficiently robust to be incorporated into the final prioritization assessments, passed on further down the investment planning chain."[273] In contrast to what METSCO noted as "the potential pitfalls of overwhelmingly relying on automatically generated quantitative outputs alone", METSCO found that Hydro One's asset analytics and ARA capabilities function together to generate complementary insights that validate and enhance the resulting analytical output and provide the utility and ratepayers with additional value.[274] In METSCO's conclusion, "Hydro One's asset management analytics are comparable to advanced asset management tools used by other utilities of similar size and

[270] Exhibit B-1-1, TSP Section 1.4, Attachment 13, p. 39.
[271] *Ibid.*
[272] *Ibid*, p. 40.
[273] *Ibid*, p. 23.
[274] *Ibid*, pp. 9 and 97.

sophistication", and certain analytical elements were deemed to be "at the sector best practices level".[275]

Without any factual or analytical basis (or the benefit of expert opinion), SEC and CME disagree with METSCO's expert conclusions. In doing so, SEC points to the importance of asset condition for justifying transformer investments,[276] but does not explain why it is appropriate to discount all the relevant factual and contextual considerations that support METSCO's conclusions. CME asserts, without evidence, that "METSCO's reasoning does not engage with HONI's broader data availability and quality" and METSCO was likely not "aware of the widespread instances of incorrect data that plague HONI's transformer condition data".[277] The former assertion is contradicted by evidence which confirmed that METSCO specifically considered the range of parameters tracked by Hydro One as well as the level of data availability across all evaluation categories, relative to what is typical in the industry.[278] The latter assertion about what METSCO was or was not aware of is pure conjecture and void of any evidentiary support.

Similarly, without expressly acknowledging nor refuting METSCO's conclusion and rationale, AMPCO claims "the degree of confidence that the asset condition reflects true condition may be low".[279] This again is a bald assertion that ignores, and is contradicted directly by the evidentiary record. In fact, as indicated in interrogatory response SEC-14, the Data Completeness Score at the time the TSP was developed was 88% overall and 94% for transformers.[280]

PTX Analysis

Differences between EPRI's dissolved gas in oil content and oil quality analysis ("PTX analysis") and Hydro One's are not a reason to discount the rigorous ARA that underpinned Hydro One's transformer replacements. As noted above, over the years, Hydro One has made great efforts and strides in improving its asset analytics data quality and accuracy. Even where there are

[275] *Ibid*, pp. 9 and 96.
[276] SEC Submission, p. 52.
[277] CME Submission, p. 34.
[278] Exhibit B-1-1, TSP Section 1.4, Attachment 13, pp. 39-40.
[279] AMCPO Submission, p. 34.
[280] SEC-14(a).

data gaps for a particular asset, subject matter experts would verify and report on its condition by conducting on-site inspections, examining other available data, and preparing a comprehensive asset risk assessment report[281] that looks at multiple criteria to establish an investment candidate. Decisions to repair or replace transformers are ultimately based on the results of ongoing asset risk assessment. These steps ensure that the asset data for each transformer is accurate and up to date, so that the asset risk level can be properly determined.

With respect to the EPRI report on transformer condition analysis, all three intervenors reference the finding that 80.5% of condition assessments for Hydro One's transformer fleet aligned with EPRI's PTX analysis.[282] For the remaining 19.5% of the assessments that were not well-aligned, Hydro One has explained that the causes were (i) data entry or collection errors, which are being rectified and (ii) correct data that does not reflect the true condition of transformers when considering historical trends or unit design.[283] Regarding (ii), SEC, CME and AMPCO appear to impugn Hydro One's approach of relying on subject matter experts to account for these issues and to track and monitor future test results. Their arguments presume that the expertise and judgment of Hydro One experts who are experienced in asset analytics must give way to EPRI's PTX methodology. They fail to recognize that the third-party study was only meant to provide a comparison against the particular approach used by EPRI and to provide Hydro One's planners with benchmarking information that is considered in conjunction with asset analytics.[284]

In relation to the EPRI report, SEC and AMPCO argue that Hydro One's own transformer condition assessments are unreliable because, based on EPRI's methodology, 47% of the 93 planned transformer replacements for 2020-2024 would fall in the high or very high risk category.[285] AMPCO further challenges Hydro One's condition assessment, stating that Hydro One replaced 86 transformers from 2015 to 2018 where all were past their expected service life but only 51 (or 60%) were in very high or high risk condition.[286]

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[281] An example transformer assessment report was filed under OEB-77, Attachment 1.
[282] Exhibit B-1-1, TSP Section 1.4, p. 8.
[283] OEB-47; CME-13;
[284] CME-19.
[285] SEC Submission, p. 53; AMPCO Submission, p. 17.
[286] AMPCO Submission, p. 16.

With respect to historical replacements, the data referenced by AMPCO includes both planned replacements (based on condition and other investment planning drivers) as well as unplanned replacements (due to equipment failures). In other words, it is reasonable that a portion of the units replaced historically would be those in high or very high-risk condition and the remainder replaced due to other investment drivers such as obsolescence, capacity or customer requirements. Therefore, using historical replacements to challenge Hydro One's condition-driven asset renewal is misguided.

SEC and AMPCO fail to recognize that the transformer condition scores they cite are in fact "DGA scores" (as indicated in CME-19),[287] and not overall condition ratings. Dissolved Gas Analysis ("DGA") entails the testing of dissolved gases in transformer oil to gauge the extent of insulation degradation and represents only one input used when Hydro One assesses power transformers. DGA is a targeted point-in-time measurement. Changing the oil in a degraded transformer could mean a high risk DGA score before the oil change and a low risk DGA score after the oil is changed following inspection and repair efforts – all while the transformer remains in the same deteriorated condition if repairs are not possible. As such, contrary to SEC's and AMPCO's suggestion, Hydro One cannot rely on DGA scores alone to make conclusions regarding asset condition and replacements; and DGA by itself cannot replace a detailed assessment that takes into account various indicators of equipment condition and past performance. Other factors that inform transformer condition include Furan analysis, Doble testing, preventative maintenance results, trouble calls and deficiency reports.[288] Hydro One further supplements these factors with additional parameters, including, performance (e.g., outage frequency/duration and oil leaks), utilization (i.e., asset loading capabilities), criticality (e.g., customer and environmental impacts), and economics (i.e., financial impacts to utility and socio-economic impacts to customers).[289]

In addition, it is important to note that equipment can be replaced for a myriad of reasons, such as high-risk condition, environmental or safety concerns, functional obsolescence, and customer and capacity requirements. With respect to transformers, the evidence is that Hydro One plans

[287]CEM-019, Attachment 1.
[288] OEB-19, Attachment 1, p. 5; Exhibit B-1-1, TSP Section 1.4, Attachment 13, p. 40.
[289] Exhibit B-1-1, TSP Section 1.4, Attachment 13, p. 44.

to replace 75 units over the 2020-2022 test period, all of which are due to a high/very high-risk condition rating, capacity issues, PCB contamination, or major oil leaks.[290]

For the above reasons, using the DGA score alone to anchor arguments regarding overall fleet condition and associated replacement levels, as SEC and AMPCO propose to do, is flawed. For example:

- Cedar TS T7 ("Fair" DGA score) – As indicated in SR-05, oil tests have shown that this unit is in poor condition.[291]
- Main TS T3 ("Fair" DGA score) and T4 ("Low" DGA score) – As indicated in SR-05, T3 was identified for end-of-life replacement due to leaks, overheating and signs of internal degradation. T3 requires replacement due to a customer request for increased station capacity.[292]
- Minden TS T1 ("Very Low" DGA score) and T2 ("Fair" DGA score) – As indicated in SR-05, these units require replacement due to leak points and signs of insulation degradation.[293] In 2018, a catastrophic failure involving transformer fire at Minden TS impacted over 20,000 customers.[294] Stratford TS T1 ("Fair" DGA score) – As indicated in SR-05, this unit has major oil leaks.[295]
- Detweiler TS T4 ("Fair" DGA score) and T2 ("Low" DGA score) – As indicated in SR-03, both units have experienced major oil leaks requiring significant emergency top-ups.[296]
- Bridgman TS T11, 13, 14 ("Low" DGA score) – As indicated in SR-05, these units require replacement due to major leaks (with sub-standard spill containment) and internal insulation degradation.[297]

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[290] PWU-11(d).
[291] ISD SR-05, p. 17.
[292] ISD SR-05, p. 16.
[293] ISD SR-05 p. 15.
[294] Oral Hearing Transcript, Vol. 2, p. 134, ln. 13; Exhibit B-1-1, TSP Section 3.1, p. 7; also see news article https://globalnews.ca/news/4356575/minden-hills-hydro-fire/.
[295] ISD SR-05, p. 17.
[296] ISD SR-03, p. 14.
[297] ISD SR-05, p. 18.

Further to its flawed argument that Hydro One's transformer replacements are not aligned with asset condition, SEC also claims that "similar problems likely exist with respect to many other assets".[298] Hydro One rejects this assertion and notes that SEC offers no evidence at all to support its speculation.

Delivery Point Interruptions

AMPCO argues that the percentage of delivery point interruptions from transformers has improved, stating: "between 2011 to 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."[299] The two percentages are unrelated and cannot be compared as AMPCO attempts to do. The 9% figure is taken from Appendix 1.3 of the customer engagement survey, which shows the contribution to the duration of interruptions by equipment type.[300] The 13% figure comes from Figure 2 in Section 2.2 of the TSP, which shows the count (not duration) of interruptions by equipment type. As such, AMPCO's attempt to compare these two different measurements and to draw conclusions on that basis is misplaced.

Moreover, while reliability indicators like SAIDI and SAIFI reflect interruptions that impact customers, they do not (nor are they intended to) capture all equipment outages. As explained during the oral hearing, due to Hydro One's multi-supplied delivery points, the outage of a single supply point would not result in customer impact and thus not be counted as an interruption.[301] In fact, equipment outage statistics for 2009-2018 indicate an increase in transformer failures during 2014-2018 (25 failures total) compared to 2009-2013 (16 failures total). The highest number of failure over this 10-year period was in 2018 (8 failures),[302] which was double the 10-year average of 4 failures per year and 60% higher than the 2014-2018 average of 5 failures per year. Given the prolonged time period required to replace a transformer, a renewal approach is necessary to avoid the reliability, environmental, safety and financial risks associated with deteriorated transformers.

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[298] SEC Submission, p. 53.
[299] AMPCO Submission, p. 17.
[300] Exhibit B-1-1, TSP Section 1.3, Attachment 1, Appendix 1.3, p. 8.
[301] Oral Hearing Transcript, Vol. 3, p. 6.
[302] JT1.17.

(c) "Repair vs. Replace" Evaluation

Based on an example transformer assessment report prepared by Hydro One, Staff argues that the net present value ("NPV") analysis assumes the same economic end of life for both the "Status Quo" and "Repair" scenarios and therefore Hydro One is likely to find "Replace" more economical than "Repair". Staff also submits that Hydro One did not provide evidence that refurbishment will not extend an asset's operating life.[303]

This argument ignores the nature and purpose of a NPV analysis as well as clear evidence regarding Hydro One's objective in refurbishing power transformers – i.e., to preserve their expected service life and reliability, not to extend their life.[304] As further articulated during the oral hearing, refurbishment is not anticipated to enable life extensions beyond what the units are capable of. Given that the active components of a transformer and the associated insulation systems age and degrade irreversibly (with a corresponding increase in failure risk), Hydro One's objective is to keep the units in a good operable state by respecting operational limits and limiting moisture in the oil and surrounding air.[305] To this end, Hydro One's experience shows that opening up a power transformer may lead to adverse consequences due to contamination and moisture ingress. The reality of managing power transformers is that major repairs/refurbishments do not extend a power transformer's end of life.[306]

From a finance standpoint, NPV analysis is a tool to help planners understand the economic implications of project alternatives by determining the difference between the present value of cash inflows and the present value of cash outflows over a period of time. The analysis is forward looking and requires reasonable assumptions to be made, including the relevant time period for the calculation. Although an individual asset could very well fall short or exceed the expected service life, the NPV analysis cannot, nor is it intended to, yield an accurate prediction of the actual lifespan remaining until failure. As a result, some other reasonable basis of

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[303] Staff Submission, p. 53.

[304] OEB-55; Technical Conference Transcript, Vol. 1, pp. 13-14; Oral Hearing Transcript, Vol. 2, pp. 172-177.

[305] Oral Hearing Transcript, Vol. 2, pp. 178-179.

[306] EB-2016-0160, Exhibit C1-2-2, p. 17: "These [transformer] refurbishments are done where cost effective, and allow the transformer to remain in-service <u>through its expected service life</u> while maintaining reliability."

measurement of life is required. For these reasons, as part of the NPV analysis for scenario selection, it is reasonable and necessary to use the economic end of life, which in the case of the assessment reports at issue is based on the expected service life of transformers.

It is important to note that Hydro One planners do not use the economic end of life when determining whether a transformer warrants replacement. That determination is guided by the output of the ARA process, which is condition based.

(d) Third Party Expert Independence

SEC, BOMA and CCC[307] claim that the Boston Consulting Group ("BCG") lacked independence in relation to its assessment of Hydro One's investment planning process and urge the OEB to discount BCG's expert conclusions. In doing so, they have distorted the meaning of "independence" (which has been considered by the courts and the OEB) and mischaracterized the relationship between BCG and Hydro One. It is also noteworthy that they made no submission on the substantive processes and criteria used by Hydro One for investment planning.

The leading judgment on expert independence is *White Burgess Langille Inman v. Abbott and Haliburton Co.*, 2015 SCC 23. There, the Supreme Court of Canada directly addressed what it means for an expert to be impartial, independent and unbiased. The acid test is "whether the expert's opinion would not change regardless of which party retained him or her"; and the mere fact that an expert has been retained, instructed and paid by one of the parties in an adversarial proceeding does not undermine the expert's independence.[308] The Court outlined the threshold criteria below for concluding that an expert is unable to give fair, objective and non-partisan opinion:

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[307] SEC Submission, pp. 41-45; BOMA Submission, pp. 6-7; and CCC Submission, p. 15. AMPCO supported SEC's submissions on this issue (AMPCO Submission, p. 23).

[308] *White Burgess Langille Inman v. Abbott and Haliburton Co.*, 2015 SCC 23 ("*White Burgess*"), para. 32.

- "For expert testimony to be inadmissible, more than a simple appearance of bias is necessary. The question is not whether a reasonable person would consider that the expert is not independent."[309]

- "It is always desirable that an expert should have no actual or apparent interest in the out-come of the proceedings in which he gives evidence, but such disinterest is not automatically a precondition to the admissibility of his evidence."[310]

- "[I]t is the nature and extent of the interest or connection with the litigation or a party thereto which matters, not the mere fact of the interest or connection; the existence of some interest or a relationship does not automatically render the evidence of the proposed expert inadmissible. In most cases, a mere employment relationship with the party calling the evidence will be insufficient to do so."[311] (emphasis added)

A recent decision of the Ontario Superior Court, *The Russia Federation v. Luxtona Limited*, 2019 ONSC 4503, illustrates the threshold test that must be met. The Court considered the independence of an expert who had a "long history of providing strategic advice and expert reports" to one of the parties, and who had "received substantial compensation from [one] of the parties] in relation to this and his prior engagements".[312] The Court concluded:[313]

- The test in *White Burgess* requires a finding of actual bias, not merely an appearance of bias.

- The fact that the expert is being paid or has been paid on previous occasions by similarly-situated parties, cannot be the basis for finding a lack of independence. There is no evidence the expert has any inappropriate or direct financial or personal interest in the arbitration or any stake in any of the parties' success or failure in the litigation.

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[309] *White Burgess*, para. 36.
[310] *White Burgess*, para. 42.
[311] *White Burgess*, para. 49.
[312] *The Russia Federation v. Luxtona Limited*, 2019 ONSC 4503 ("*Luxtona*"), para. 14.
[313] *Luxtona*, paras. 24-27.

- The fact that the expert may have become the "go to guy" for entities wishing to make similar claims is, again, not evidence of lack of independence. His accumulated expertise makes him a natural selection as an expert witness. <u>The expert's history of providing opinion evidence for or in relation to the same client does not undermine his independence</u>.

Based on the foregoing, the allegations being raised by intervenors fall far short of establishing a lack of independence on the part of BCG. Other than referencing BCG's consulting arrangements with Hydro One (which cannot be the basis for disqualifying experts, as per the above threshold test) and making unsubstantiated allegations of bias, the parties do not point to any evidence or any substantive aspect of the work performed that would suggest an actual bias on the part of BCG. In any event, even putting aside the legal standard, the parties have mischaracterized the relationship between BCG and Hydro One and the work that was previously undertaken by BCG, as explained below.

SEC, BOMA and CCC argue that BCG is unqualified to undertake the assessment, alleging that the engagement put the consultant in a conflicted position to assess its own work relating to BCG's past involvement with Hydro One's Good to Great program.[314] This allegation appears to be a mere resuscitation of a similar line of cross-examination pursued by SEC at the oral hearing – though now omitting from the submissions Hydro One's testimony that factually contradicted the basis of the allegation. When asked at the hearing about BCG's involvement with the Good to Great program, Hydro One's witness panel confirmed that BCG's role in that engagement was not to help develop the investment planning process, but to assess continuous improvement initiatives and opportunities across the entire enterprise.[315] In particular, "BCG had nothing to do with [the development of the improved 8-step investment planning process]" which it independently reviewed in connection with the present application.[316] Hydro One specifically refuted the suggestion that BCG was "in essence… grading their own work" and noted the fact that the engagement for Good to Great dated back to the 2015-2016 time period, much earlier

[314] SEC Submission, pp. 43-44; BOMA Submission, p. 6; CCC Submission, p. 15.
[315] Oral Hearing Transcript, Vol. 1, pp. 86-88.
[316] *Ibid*, p. 88, ln. 10-11.

than the development of the business plan and the review of the investment planning process as later directed by the OEB.[317]

As part of the mischaracterization of the relationship between BCG and Hydro One, SEC also took out of context the wording of the engagement letter for the investment planning process review.[318] SEC wants the OEB to believe that BCG approached the engagement from a biased perspective from the get-go and that BCG aimed to reach findings favorable to Hydro One's 2020-2022 transmission rate application. However, the excerpts quoted by SEC were simply factual statements regarding BCG's knowledge of Hydro One's business from prior engagements and the nature and purpose of the mandate in light of the OEB's directions. If anything, the inclusion of these facts directly in the engagement letter shows the transparency with which BCG and Hydro One approached the project as well as BCG's full awareness of OEB expectations regarding the independent review.

Hydro One emphasizes that BCG was initially retained in 2015-2016 in relation to the Good to Great program and the provision of rate case management services (not the current rate proceeding). In September 2017, the OEB issued its EB-2016-0160 decision, including directions on the enhancement and review of Hydro One's investment planning process. From a timing perspective alone, it is not correct to argue that BCG would be in a position to review its own work, considering BCG's prior engagement preceded the OEB decision that focused Hydro One's process enhancements. The fact is, as a well-known consulting firm with leading expertise in capital planning (having completed more than 2,500 engagements with utilities[319]) as well as familiarity with Hydro One's continuous improvement efforts, BCG was uniquely qualified to effectively carry out the mandate as an independent expert.

SEC further cites the amount of fees related to BCG's engagements with Hydro One in the past 5 years as evidence of a supposed lack of independence. Linking consultant fees with alleged bias is not sufficient under the courts' standard of "independence" discussed above. These baseless allegations could have serious consequences, including harms to the reputation and professional standing of organizations and individuals. Taking SEC's argument to its logical

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[317] *Ibid*, p. 89, ln. 3-5.
[318] A copy of the engagement letter dated November 13, 2017 was filed at -SEC-16, Attachment 1.
[319] Oral Hearing Transcript, Vol. 1, p. 87, ln. 19.

conclusion would also lead to untenable outcomes, i.e., based on SEC's standard, the limited pool of well-known and qualified experts in the utility industry would largely be presumed to be biased and partisan vis-à-vis their client utilities (which are often repeat clients).

It is puzzling to Hydro One as to why SEC would suggest at this stage that the authors of the BCG report should have been present at the oral hearing.[320] Notably, of all the interrogatories in this proceeding, four touched upon the BCG report, and only one of the four directly related to the substantive content and methodology of the assessment.[321] No party challenged the findings or recommendations of the report. SEC did not (nor did anyone else) request BCG's attendance at the hearing. The BCG report formed part of the direct evidence of Hydro One and as such that evidence is before the OEB on filing. All evidence can be subject to cross examination and the authors are known to be available for cross examination (which was also contemplated as part of BCG's scope of services, if required, under the retainer agreement[322]). It is not for Hydro One to urge parties to cross examine various witnesses or to provide notice that they are available for cross examination. It is the fundamental premise of the proceeding that they are available to be crossed and Hydro One should not now be prejudiced on the basis of any assumption that the witness was not at the hearing.

For the above reasons, the OEB should reject the allegations being raised with respect to BCG's independence and give due weight to the conclusions and findings presented in the independent expert report.

(e) Unit Costs

Without the support of evidence, SEC asserts that Hydro One will likely replace either fewer assets within the approved budget or overspend to replace those assets, and that Hydro One replaced assets at a higher unit cost than forecast.[323] SEC relied on a mathematical

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[320] SEC Submission, p. 45.
[321] SEC-16.
[322] SEC-16 Attachment 1 p. 2.
[323] SEC Submission, pp. 46-49.

manipulation of the evidence that it prepared, which had a number of deficiencies such that it cannot be used to determine unit costs in the manner SEC attempts to do.

Specifically, SEC relies upon the table from JT1.24, Attachment 1,[324] to claim that actual unit costs were higher than forecast. Without knowing SEC's intended use of the table, Hydro One provided the requested information. However, there were a number of significant problems with SEC's original table and the type of information requested, making it incorrect and unreliable for determining unit costs, as explained below.

- As part of the Draft Rate Order ("DRO") update in 2017, Hydro One updated its forecast capital expenditures but did not present segregated costs for integrated station centric project equipment (i.e. transformers, breakers and protections). Furthermore, the OEB decision did not require a revised forecast of units for each major asset class. Accordingly, forecast units were not updated. This important fact was noted when Hydro One first completed the table as requested by SEC.[325]

- Similarly, for the capital programs (wood poles and steel structures), SEC relied on the updated forecast capital expenditures but used the original 2018 forecast units to determine unit costs,[326] which resulted in the artificial lowering of forecast unit costs for 2018. For example, JT1.24 Attachment 1 shows that the cost of steel structures was updated from $54.4 million to $26.2 million for 2018 but the number of units was not updated and remained at 1,600. SEC used this information to arrive at a forecast unit cost that was artificially lower.[327]

- The table that SEC asked Hydro One to complete pertains to annual capital expenditures and does not reflect in-service additions. Given that capital spend may occur over multiple years (e.g., integrated station centric investments relating to transformers, breakers and protections, or conductor replacements) before a unit goes

[324] Based on SEC-36, Attachment 1, and subsequently recast by SEC as shown in Exhibit K1.2, p. 64.
[325] See SEC-36, footnote **.
[326] Exhibit C-2-1-1, Table 17, p. 35, and Table 38, p. 54.
[327] Exhibit K1.2, p. 64.

into service, forecast and actual unit costs cannot be reasonably ascertained in the manner proposed by SEC.

- SEC's comparison ignores operating realities that cause unit costs to fluctuate. As explained in the hearing, safety incidents have caused operating practices to change and unit costs to increase in the case of the steel structure renewal program. As a result of an electrical contact incident involving a worker in mid-2017, work methods were modified to ensure crew safety (requiring more outages, more climbing, and more personnel), which led to increased unit costs.[328]

- The forecast costs for station equipment (transformers, breakers and protection) in EB-2016-0160, which now anchor SEC's proposed analysis, were based on preliminary planning estimates and could not reflect certain project details (e.g., specific voltage and size of equipment) that would significantly impact unit costs (refer to section (f) Project Costs below). Hydro One has explained that these forecasts are a proxy estimate because the nature of an integrated investment makes it difficult to segregate the unit costs.[329] The actual costs provided in this proceeding reflect planning and operating realities that would have driven replacement costs higher on a unit basis, including (i) reactive replacements necessitated by equipment failures, and (ii) consolidation of assets that lowered the actual unit count (e.g., two transformers consolidated into one larger unit[330]). For example, Hydro One experienced 8 transformer failures in 2018 compared to an average of 4 in 2016-2017.[331] Consequently, as a result of such costlier unplanned replacements being in-serviced in 2018 (as well as the other reasons above), the actual unit cost was $6.92 million compared to an average of $4.7 million in 2016-2017.[332]

Fundamentally, a unitized comparison cannot be properly made when the extrapolated unit costs are only a proxy of the broader integrated project. In Hydro One's view, integrated station-

[328] Oral Hearing Transcript, Vol. 1, p. 97, ln. 24-28.

[329] SEC-036-01, footnote ***: "These capital expenditures are conducted for both the asset and station centric approach, estimated unit costs have been provided".

[330] JT1.21 a) and b).

[331] JT1.17.

[332] Exhibit K1.2, p. 65.

centric assets (transformers, breakers, and protection systems) cannot be evaluated narrowly on a unitized basis since the costs are captured from varying projects with fluctuating spend from year to year. Further, SEC's comparator unit cost is based on Hydro One's 2017-2018 forecasts from EB-2016-0160, which as noted above were preliminary estimates that do not lend themselves to the type of comparison SEC now proposes. It is simply not the case that all units are the same or even comparable. In the case of transformers, the number of 115kV, 230kV and 500kV replacements varied year over year, and the mix of units and reasons for replacement (planned or due to failures) would all affect the resulting costs. Ignoring these important contextual factors makes SEC's comparison superficial and unreliable.

In any event, even aside from these fundamental flaws, SEC's actual calculations also reflect serious deficiencies. This renders SEC's analysis partial and distorted, as explained below.

- For transformers, SEC's calculations conveniently ignore 2016 actuals, which were significantly lower than historical average on a unit cost basis. While SEC's comparison uses a 2017-2018 average unit cost of $6.26 million, the 2016-2018 average is actually $5.68 million, which falls in line with SEC's comparator 2017-2018 forecast unit cost of $5.5 million.

- For protection systems, SEC's calculations again ignore the 2016 actuals and look only at the 2017-2018 period which saw a one-year cost increase in 2018. Whereas SEC uses a 2017-2018 average unit cost of $0.166 million, the 2016-2018 average is $0.128 million, which aligns with SEC's comparator 2017-2018 forecast unit cost of $0.125 million. After the one-year increase in 2018, Hydro One's forecast for 2019-2022 reflects unit costs that compare well with historical average.

- For conductors, SEC derives unit costs of $0.521 million based on 2017-2018 actuals versus $0.333 million based on 2017-2018 forecast, thus concluding a variance of 56.5%. SEC's unitized comparison ignores the reality of how line refurbishment projects are planned and executed. These projects span multiple years and experience fluctuating annual expenditures based on project stage (e.g., newly initiated projects have smaller expenditures in early years while projects being constructed have larger expenditures).[333] By aggregating multiple projects in different stages, SEC's comparison simply points to the fact that more construction work (higher cost work) in one year leads to higher annual expenditures whereas more planning/engineering work (lower cost work) in another year leads to lower annual expenditures, which is not informative as a unit cost analysis. At the same time, it is important to note that the historical average unit costs pre-2017 were generally much higher compared to what was forecast for 2017-2018. For example, when comparing the forecast versus actual unit costs for 2016-2018 ($0.352 million versus $0.443 million), the variance falls to 25.9%. If the analysis goes back to 2014, the average unit costs based on 2014-2018 actuals is again higher (due to the higher costs in earlier years) at around $0.395 million. Notwithstanding this fact, Hydro One expects the unitized costs to trend lower and dip below historical average for the last two years (2021-2022) of the test period.

- For the steel structure portfolio, as explained above, the increase in unitized costs starting in 2017 was due to modified work methods to ensure work safety after an electrical contact incident occurred mid-2017. Having completed a full safety investigation, Hydro One is returning to more of a typical work process with some improved safety requirements,[334] such that the forecast test period costs on a unitized basis will be more in line with historical average.

For the reasons detailed above, Hydro One submits that SEC's unit cost analysis is significantly flawed and fails to establish SEC's assertions with respect to Hydro One's unit cost performance.

(f) Project Costs

SEC argues that the overall costs of Hydro One's projects are increasing over time, citing the air blast circuit breaker ("ABCB") projects in particular.[335] It also points to the costs of projects shown in J4.7 (i.e., projects over $20 million in the previous and current applications) as supposed evidence of cost escalation problems affecting Hydro One's projects. As discussed

[333] OEB-121.
[334] Oral Hearing Transcript, Vol. 1, p. 97.
[335] SEC Submission, p. 50.

below, SEC's argument disregards the reality of planning and managing complex capital investments (including the normal refinement of cost estimates over time) and mischaracterizes the implications of normal project cost variances across the portfolio by narrowing in on subsets of the portfolio of capital expenditure over the test years.

The maturation of cost estimates in the ordinary course is an indispensable part of the business of any project delivery organization. Hydro One employs a rigorous capital delivery process, comprised of three stages: planning, definition, and execution. Between a project's definition stage and execution stage, the final plan is reviewed and approved by Hydro One senior management and released with an AACE Class 3 estimate (i.e., within a -20% to +30% accuracy range) based on information provided in the engineering deliverables and execution plan.[336]. At the time of Hydro One's TSP filing, projects are in different stages of the capital delivery process, and their costs have varying levels of accuracy. Project costs evolve as Hydro One progresses with project definition and move into execution.[337]

SEC attempts to tie Hydro One to the initial cost estimates and to ignore or diminish the reality that costs estimates are expected to be refined over time. SEC's position is neither practical nor fair. When SEC cross-examined Hydro One in relation to SR-01 at the hearing, the witness panel clarified, among other things, Hydro One manages at the project level but ultimately aims to deliver outcomes and meet financial commitments at the overall portfolio level.[338] In this proceeding, Hydro One has shown a track record of effective capital portfolio delivery. To quote from Staff's submissions, "Hydro One has demonstrated its ability to successfully track and perform large capital work plans by delivering its 2017 and 2018 investment plan on an envelope basis within 1.5% of OEB-approved capital expenditures levels and 0.7% of OEB-approved in-service additions"; and "Hydro One has excelled in its capital plan execution".[339]

Further, SEC's comparison of actual spending relative to preliminary budget estimates is not appropriate and does not mean that these projects were over budget. In reality, Hydro One tracks project-level performance against the estimates included in the business case approval,

[336] Exhibit B-2-1, p. 8.
[337] Oral Hearing Transcript, Vol. 1, p. 104.
[338] Oral Hearing Transcript, Vol. 1, p. 102, ln. 25-27.
[339] Staff Submission, p. 67.

because at that point, project scope, schedule and cost are reasonably defined to provide a baseline for tracking and reporting.[340] As shown in J3.7, over the 2014-2018 period, the majority of projects were completed at or below their approved business case budget. All projects (with only one exception) that had approved business case budget greater than $50 million were completed on or below budget.[341] As referenced in reply to Issue 7, assessing performance against the approved business case is more appropriate, given the more consistent reference point from project to project and the overarching internal governance applicable to the improved project planning and definition phase culminating in the business case approval.

Even if one were to accept SEC's overly simplistic comparison, the numbers do not bear out its assertions. SEC wants the OEB to believe that a 7.1% variance in the aggregate costs of 55 projects is somehow symptomatic of serious problems in Hydro One's capital delivery.[342] However, even when SEC's calculation of a 14.4% cost increase in system renewal projects is used for the comparison, a variance of this magnitude is well within the above-noted tolerance range of estimation accuracy (i.e., -20% to +30% accuracy range). Additionally, SEC's use of "average variance" per project is misleading. When SEC states: "costs contained in this application are on average 12.64% higher than what was provided in Hydro One's last application",[343] this is simply an arithmetic mean of all percentage variances across 55 projects, without regard to performance at the portfolio or total cost level. To this end, a few projects that have smaller budgets but larger percentage variances in costs could significantly skew the arithmetic mean, which is why Hydro One believes the 7.1% variance on a total cost basis (and other capital delivery indicators at the portfolio level as outlined in the application) is a more meaningful number.

With respect to the ABCB replacements projects, they should not be over-simplified in the manner proposed by SEC and CME, which compares the costs from one point in time to another without any consideration of the nature of these projects and scope changes over time. The fact is ABCB projects are some of the most complex projects within Hydro One's capital portfolio, due to their multi-staged nature and required coordination of planned outages with

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[340] J3.7 and J5.8.
[341] J3.7, p. 2.
[342] SEC Submission, p. 51.
[343] *Ibid*.

large generators, load customers, and the IESO over multiple years. The in-service ABCBs are at least four times less reliable than the newer equivalent SF6 circuit breakers, which is the dominant factor in their prioritized replacement, and are ten times more costly to maintain.[344] In multiple projects referenced in the filing, the poor and degrading condition and performance of the infrastructure during the execution of the project caused additional cost and schedule pressures as Hydro One and other market participants had to adapt and modify the project execution plans during execution to balance the individual project needs with broader system needs.[345]

Further, SEC's argument is predicated on an inaccurate and over-simplistic characterization of the cost estimation and management of complex projects over time. The costs for the ABCB projects from the previous transmission rate application were defined under Hydro One's older capital delivery model.[346] As detailed in Exhibit B-2-1 of the TSP, Hydro One has improved various aspects of its capital delivery process since 2017, ensuring that the most significant risks tied to cost/schedule variances are more effectively considered upfront.[347] The projects that were approved via business cases at the time of the last application would not have reflected the benefits of this enhanced process, which are now starting to be realized as Hydro One moves through execution.[348] For these reasons, SEC's argument should not be accepted by the OEB as it does not apply to Hydro One's improved capital delivery model and the proposed capital investments in this application.

(g) Other Assertions Relating to the Overall Plan

Intervenors have made certain other assertions in relation to Hydro One's overall TSP and/or planning approach, including in relation to the pace of asset renewal and resulting reliability performance, the starting point for Hydro One's capital budgeting process, and the prioritization of investments. As discussed point by point below, each of these assertions is inconsistent with and/or unsubstantiated by the evidence and should be rejected by the OEB.

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[344] Exhibit A-4-1, Attachment 1, p. 10.
[345] Oral Hearing Transcript, Vol. 1, p. 105, ln. 1-11.
[346] *Ibid*, ln. 25-28.
[347] Exhibit B-2-1; Oral Hearing Transcript, Vol. 1, p. 106, ln. 1-5.
[348] Oral Hearing Transcript, Vol. 1, p. 106, ln. 6-12.

Pace of Asset Replacement and Reliability Performance

Energy Probe argues that "Hydro One's Board of Directors and Senior Management should be held responsible for not replacing aging assets at an appropriate pace to maintain System Reliability" and that "letting the Provincial transmission system deteriorate is irresponsible".[349] Hydro One submits that this assertion is incorrect and unsupported by the record in this proceeding. In fact, Energy Probe does not provide any evidentiary basis for this serious allegation.

The facts on the record show that Hydro One was able to deliver its 2017 and 2018 investment plan on an envelope basis in-line with the OEB's direction in the last transmission application.[350] Hydro One prudently manages and plans renewal investments to identify end-of-life assets for replacement before failures and reliability/customer consequences materialize. In this application, Hydro One has proposed a balanced and appropriate investment plan that is customer-oriented and is based on a comprehensive risk-based planning process to address deteriorating asset conditions in a manner that balances competing system and customer needs.[351]

As would be typical and expected of any utility, Hydro One's complex and expansive transmission system experiences fluctuation in system reliability performance from year to year. For instance, the severe weather events in 2018 led to reliability results that were worse than average.[352] Notwithstanding these normal fluctuations, and contrary to Energy Probe's suggestion that Hydro One has irresponsibly let reliability deteriorate, Hydro One's system reliability compares well with industry averages. For instance, Hydro One's transmission line unavailability has generally been under the CEA composite 5-year moving average; and its frequency of interruptions (including both sustained and momentary), duration of sustained interruptions, and delivery point unreliability have generally been below the CEA composite average.[353]

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[349] Energy Probe Submission, pp. 16, 19-20.
[350] Hydro One, Argument in Chief, p. 8.
[351] Hydro One, Argument in Chief, p. 11.
[352] EnergyProbe-10; Oral Hearing Transcript, Vol. 3, p. 9, ln. 14-20.
[353] Exhibit D-2-1, section 1.3; OEB-147(b).

Notably, Energy Probe advocates for significant reductions to Hydro One's capital plan (including a 10% or $32 million reduction to the 2020 investments in lines). Given that reliability is a lagging indicator of asset condition and renewal decisions, such major reductions to the capital plan can be expected to lead to a growing population of deteriorating assets and increasing failures and reliability impact. Energy Probe's attempt to criticize Hydro One's reliability performance while at the same time advocating for plan reductions to further jeopardize future reliability is unreasonable and not grounded in the evidence.

Lastly, Energy Probe asserts that it is not possible to know based on the evidence whether Hydro One's proposed renewal will reverse declining reliability.[354] In Hydro One's submission, asset condition assessments and condition-based risks are the key drivers for the renewal investments in its TSP. Poor asset condition will cause a myriad of risks to materialize if left unaddressed, including detrimental impact to system reliability, which is a lagging indicator of actual fleet condition and the level of replacements undertaken. As such, the identification and renewal of degraded assets based on end-of-life criteria, as Hydro proposes to do over the plan period, will directly contribute to the utility's reliability objectives, including to achieve top quartile reliability performance relative to industry peers.[355] In support of its target reliability improvements, Hydro One's plan reflects the integration of key reliability initiatives, as described in interrogatory response OEB-18(c). Notably, the company's scorecard reflects specific reliability performance targets across a number of well-defined metrics,[356] so as to strongly incent the alignment of utility performance with relevant objectives.

[354] Energy Probe Submission, p. 20.
[355] Exhibit A-3-1, p. 3; OEB-83.
[356] Exhibit B-1-1, Section 1.5, p. 5.

<u>Starting Point for 2020 Capital Budget</u>

BOMA argues that Hydro One's starting point for the 2020 capital budget was inappropriate because it was based on the utility's proposed capital plan for 2017-2018 rather than the OEB-approved plan for 2017-2018.[357]

In effect, BOMA ignores the multi-faceted input and processes that underpin Hydro One's enhanced eight-step investment planning process, during which cost impact was a key consideration. As noted under Issue 3, from the candidate investment stage to the final plan, the capital investment plan was reduced from $7.616 billion to $6.619 billion, a $997 million reduction, and various investments were prioritized out of the plan altogether and not included in this application.[358] To focus only on the starting allocation while ignoring the rigor of the substantive process undertaken by Hydro One to arrive at an optimized plan is unduly partial and unreasonable.

Further, consistent with the OEB's expectations, customer feedback was a key input in Hydro One's development of the investment plan. When presented with four investment scenarios (including Scenario C, which "extends investment plan in rate application current before the [OEB] to 2023), customers could have chosen any option, but most selected Scenario C, a $6.6 billion investment level.[359]

BOMA argues that Hydro One should have used the OEB-approved 2017-2018 plan as the starting point. However, in accordance with OEB directions, Hydro One's customer survey was conducted sufficiently in advance of TSP development so as to meaningfully engage customers and inform plan formulation. At the time of the survey, the OEB's decision in the prior transmission rate proceeding was not yet available. As such, the 2017-2018 plan that was before the OEB at the time of the survey provided a reasonable and sound basis for obtaining customer feedback regarding preferred spending and guiding Hydro One's budgeting process.

As demonstrated by evidence, the budget constraints reflect an appropriate balance between rate impacts and outcomes, consistent with customer preference for Scenario C, which reflects

[357] BOMA Submission, pp. 3-5.
[358] SEC-27 and 28; JT1.2, p. 4.
[359] Exhibit B-1-1, TSP Section 1.1, p. 32.

long-term reliability performance improvement with level rate increases in the future (as opposed to higher future rate increases for example).[360]

Prioritization of Investments

BOMA asserts that "some utilities … rank programs and projects in order of priority" and such an "exercise should not be that difficult". It further states that Hydro One "has not included in its evidence a prioritized list for each asset class and for all asset classes, nor has it explained how it has applied the six factors it uses to prioritize to various projects and programs".[361]

Respectfully, Hydro One submits that BOMA has ignored clear evidence regarding the utility's rigorous investment planning framework and efforts. Instead, BOMA attempts to pursue an over-simplistic version of what it thinks a utility's investment prioritization process should look like, which has no connection to the evidence in this proceeding or to the reality of how the TSP was derived.

As Hydro One detailed in evidence and explained in response to BOMA's questions at the hearing, Hydro One prioritizes and optimizes candidate investments based on risk-spend efficiency with trade-offs to address non-risk considerations.[362] This approach allows the utility to maximize risk mitigation benefits (i.e., in the categories of safety, reliability and environment) within the capital envelope by comparing investments across asset classes.[363] In this manner, both the total risk and the risk/spend efficiency are evaluated, and Hydro One is able to "prioritize all of the investments based on the greatest value that they're providing".[364] As one of the key findings from BCG's independent review of Hydro One's investment planning process, Hydro One's prioritization and selection process exceeds the level of performance that is expected from a typical utility, and reflects a consistent assessment of risk mitigation potential

[360] SEC-29.

[361] BOMA Submission, p. 11.

[362] Exhibit B-1-1, TSP Section 2.1; OEB-46; Oral Hearing Transcript, Vol. 3, pp. 130-131.

[363] OEB-68(a).

[364] Oral Hearing Transcript, Vol. 1, p. 170, ln. 11-15; Vol. 3, pp. 130, ln. 12-27; Technical Conference Transcript, Vol. 1, p. 82, ln. 16-20.

through risk scoring.[365] Based on the foregoing, BOMA has overlooked the relevant evidence in its submissions, and its argument should not be accepted by the OEB.

Having addressed the parties' submissions relating to the overall plan and planning approach, Hydro One will now respond to the submissions regarding specific capital investments within the System Renewal, System Service, and General Plant investment categories. Note that none of the parties raised any concerns regarding Hydro One's proposed System Access investments. Specifically, OEB Staff submits that no cuts should be made to this investment category.[366]

SYSTEM RENEWAL

(h) System Renewal: Conductor Replacements

Staff and various intervenors submit that Hydro One has not justified the overall need for its proposed conductor replacements. Their submissions include assertions relating to the following:

- condition testing rather than actual performance as the dominant investment driver,
- outage statistics and conductor replacements relative to system reliability,
- conductor condition degradation and the degree of degradation,
- longer expected service life than previously expected, and
- differentiation between wire versus splice failures.

Hydro One addresses each point in the discussions that follow. From the outset of this discussion, it is important to understand the planning context and drivers that underpin this important renewal investment. Notably, the position taken by the parties with respect to station assets (e.g., transformers) stands in stark contrast with their position regarding conductors. As discussed above, several parties challenged Hydro One's proposed transformer investments, primarily due to perceived concerns about the availability and quality of condition data. In contrast, the arguments being raised with respect to conductors appear to discount the robust condition results that Hydro One has obtained through enhanced assessment practices. This apparent and arbitrary shift in logic led to a set of incongruent arguments, which suggest that

[365] Exhibit B-1-1, TSP Section 1.4, Attachment 14, pp. 41-42.
[366] Staff Submission, p. 47.

Staff and intervenors have fundamentally misunderstood and/or mischaracterized the actual planning context and drivers that underpin the proposed investments.

Primary Investment Driver: Safety Risk based on Assessed Condition

Staff submits that Hydro One: (i) replaces conductors based on condition testing as opposed to actual performance, (ii) has not demonstrated a correlation between conductor condition and performance deterioration, and (iii) has not demonstrated a materially increased risk of physical failure during expected operating conditions during the forecast period.[367]

As detailed throughout the evidentiary record, Hydro One aims to prudently replace deteriorated assets so as to mitigate failure risks.[368] Overhead conductors are the single largest and most vulnerable component of the transmission system, and failures can cause severe safety and reliability consequences. Hydro One's clear evidence is that conductor replacements are planned based on condition, which is tied directly to safety as the main driver. Although Staff acknowledges that safety is a factor, its submission on the issue primarily focuses on reliability, which was in fact secondary to the planning of this investment.[369]

Since the EB-2016-0160 proceeding, there has been a near 40% increase in conductors (from 2,643 km to 3,680 km) that are verified to be in high or very high risk condition.[370] Contrary to Staff's claim that Hydro One has not shown a materially increased risk of physical conductor failure during the forecast period, the reality is that safety risk due to physical failure is directly tied to the condition of conductors, with the two major failure modes being the loss of tensile strength and loss of ductility.[371] Once a conductor fails ductility and tensile strength tests and is deemed mechanically unfit, it must be replaced to prevent safety risks from materializing in the event of failure.

As discussed in ISD SR-19, a broken conductor will lead to the suspended span and associated hardware components dropping to the ground, resulting in a prolonged outage and physical

[367] Staff Submission, p. 55.
[368] As explained, for example, in OEB-23(c).
[369] Oral Hearing Transcript, Vol. 3, p. 116.
[370] JT1.21.
[371] OEB-93(d).

danger to all persons and infrastructure in its proximity. A typical transmission line spans 300 m at an approximate height of 30 m. Weighing about 1.6 kg per meter, a falling conductor span is equivalent to a 480 kg metallic mass, which is capable of causing catastrophic damage. In some cases, a broken conductor can remain energized, which presents an added danger of electrocution and fire hazard.[372]

Hydro One establishes the end of life of conductors based on its empirical assessment of asset condition and confirmation of deterioration. As outlined in the TSP, Hydro One is an industry leader in assessing the condition of line assets, particular ACSR conductors, and has been using a conductor sample removal method combined with lab testing since the late 1980s.[373] Most recently, Hydro One's deployment of the LineVue tool[374] has enabled a greater number of condition assessments per year and is more cost efficient than removing conductor samples for lab testing.

As a result of making replacement decisions based on condition assessment, many good condition conductors that have aged beyond expected service life are kept in service, and conversely, prematurely deteriorated conductors can be identified and addressed before they fail.[375] Moreover, the potential severity of safety impact is assessed based on each conductor's location, e.g., a conductor near a school or parking lot would be prioritized differently than one crossing a remote forested area.[376]

Through ongoing condition assessment, 3,680 km or 13% of Hydro One's conductor fleet is known to be in high or very high-risk condition. This includes lines with deteriorated ACSR and copper conductors, many of which suffer from damage caused by lightning strikes and tensile strength loss and can no longer be repaired due to obsolete repair components.[377] Furthermore,

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[372] ISD SR-19.

[373] Exhibit B-1-1, TSP Section 2.3, p. 36.

[374] The Kinectrics LineVue tool travels along energized and non-energized conductor span to measure the remaining cross-sectional area of the steel core wires in ACSR conductors (TSP Section 2.3, p. 36).

[375] Exhibit B-1-1, TSP Section 2.3, p. 36.

[376] Oral Hearing Transcript, Vol. 2, p. 20, ln. 14-20; Vol. 3, pp. 169-170.

[377] ISD SR-19, p. 3.

EPRI projected the population of ACSR conductors expected to be in high risk condition within the next five, ten and twenty-year periods:

Table 9-2. EPRI Projection of ACSR Circuit-km Expected to be in High Risk Condition[378]

Life Event Modeled	Input Data	Projection Means (and 95% Confidence Bands) in km		
		5 Years (2023)	10 Years (2028)	20 Years (2028)
Reaching EOL Or near EOL condition	Condition assessment data	3,273 (2,552, 4,123)	6,467 (5,182, 7,867)	12,366 (10,468, 14,134)

EPRI's projection shows that over 12,000 circuit-km (or 42%) of the conductor fleet is expected to be in high risk condition over the next twenty years, further validating the need for investments in conductor replacements so as to maintain acceptable fleet condition and to minimize both serious safety risks and a sudden rise in future replacements due to failure. Contrary to what the parties suggest in their submissions, it is not prudent to wait for reliability degradation - without regard to the growing population of deteriorated conductors and the safety risks that they pose - before commencing replacements.[379]

BOMA argues that Hydro One was not able to confirm that the proposed investments would result in a change to asset condition. While BOMA makes this assertion under the heading of "Conductor Replacement", it extends the argument to all "major asset classes".[380] This assertion is factually incorrect and directly contracted by evidence. Hydro One has clearly outlined the expected reductions to the proportion of high risk and very high-risk assets in its four major asset classes, assuming no additional discoveries. As summarized below, Hydro One forecasts reductions across all asset types by the end of the 3-year test period and the end of the 5-year planning period (except a small increase for breakers by the end of the 3-year test period).

[378] ISD SR.20, p. 4.
[379] Hydro One, Argument in Chief, p. 50; and ISD SR-20, p. 4.
[380] BOMA Submission, p. 7.

Table 9-3. Percentage of Assets at High or Very High Risk

Asset Class	Current Application[381]	Forecast[382]	
		End of the 3-year test period (2022)	End of the 5-year planning period (2024)[381]
Transformers	17%	13.8%	10.9%
Breakers	9%	10.0%	7.1%
Protections	27%	20.6%	16.3%
Conductors	13%	7.6%	4.9%

Secondary Driver: Reliability Performance

SEC, CME, AMPCO, and BOMA argue that Hydro One's proposed conductor replacements are not justified because outage performance appears to be improving over time; while PWU argues that the number of failures is not a proxy for asset condition as conductors are replaced on a predictive basis (based on condition assessment).[383] Staff argues that the planned replacements are not shown to meaningfully improve system reliability.[384] As highlighted above, the primary driver of conductor replacements is to address asset condition which could manifest into a safety risk, not to directly address a reliability risk, which seems to be misunderstood by the parties throughout their submissions. Further, the concerns being raised in terms of the relationship between conductor renewal and reliability are unfounded, as explained below.

Reliability performance is a lagging indicator of asset condition and not expected to decline under a planned renewal approach. For the reasons outlined above, Hydro One cannot defer its condition-triggered conductor replacements until reliability degradation begins to materialize. Nevertheless, it is incorrect to suggest that Hydro One's proposed conductor renewal lacks justification in relation to reliability. Beyond the overriding safety driver, there is a known correlation between conductor condition and failure rates based on the difference in interruptions among deteriorated conductors versus the overall fleet. Specifically, evidence

[381] JT1.21, p. 2.
[382] PWU-10(f).
[383] PWU Submission, para. 47.
[384] Staff Submission, p. 56.

shows that between 2008 and 2018, the conductors being targeted for refurbishment experienced five times more delivery point interruptions relative to the overall fleet,[385] reflecting the relationship between poor asset condition and performance. Without a planned renewal approach to keep the population of high risk conductors from growing rapidly (as projected by EPRI for the next 20 years), it is reasonable to expect a significant increase in delivery point interruptions due to conductor failures.

Hydro One recognizes that overhead conductor forced outages show an overall improving trend (in both duration and frequency) since 2008.[386] However, Hydro One disagrees with the parties' over-simplistic use and interpretation of this data, particularly for an asset inventory as large as overhead conductors. Contrary to what the parties suggest, an overall improvement in reliability does not mean the primary investment driver (i.e., safety risk based on assessed condition) is rendered moot, and in no way invalidates the pressing need to address a sizeable and growing population of high risk conductors. Over the period 2008 to 2017, there have been significant volatility and spikes in outage frequency and duration in certain years, which impact the overall trend line and simply cannot be predicted with any degree of accuracy. It would not be prudent to wait until noticeable reliability degradations materialize before undertaking the required investments.[387]

By taking a narrow view of reliability, the parties fail to recognize certain aspects of system reliability that have been deteriorating and require mitigation. Staff argues that “the replacement of the 1,903 circuit-km ACSR conductors will potentially address 0.3% (30% of 1%) of annual customer deliver[y] point interruptions”.[388] This characterization ignores the important dimension of outage duration, which could entail a long period of customer impact and restoration efforts. As an example, undertaking response JT1.28 highlights the prolonged outage durations caused by component issues on circuit A4L (which could be similar for conductor failure), which resulted in 1,137 minutes or 19 hours of interruptions in 2016, over 94.5% of which (1,075 minutes or 18 hours of interruptions) was caused only by two events. More generally, Hydro One's transmission system average interruption duration index (“T-SAIDI”) over 2014-2018 was on

[385] OEB-120(e)(i) and 125(a).
[386] Exhibit B-1-1, TSP Section 2.2, p. 58, Figures 19 and 20.
[387] Exhibit B-1-1, TSP Section 2.2, p. 57.
[388] Staff Submission, p. 56.

average 54.9 minutes per delivery point per year and has been increasing since 2014, indicating a growing average duration of interruptions per delivery point.[389] In this regard, even if the total forced outage frequency decreases overall, it would not alleviate the need to address the fact that each interruption is getting longer.

Additionally, as noted above, Hydro One's transmission system reflect design redundancies (i.e., dual circuits supplying a customer delivery point) such that a single contingency involving the outage of one circuit would not necessarily result in a customer interruption captured by SAIDI or SAIFI metrics. In terms of equipment outages, the percentage of forced outage by equipment type shows that conductors contribute significantly to forced outages. Over the 2014-2018 period, 35.3% of equipment outages (irrespective of whether there was a customer interruption) on average per year were attributable to lines. This percentage was the highest in 2018 at 44.7%, surpassing the contribution of breakers (33.5% in 2018) and transformers (18.4% in 2018).[390]

In summary, Staff and certain intervenors appear to believe that the increase in poor condition conductors on Hydro One's system does not warrant intervention so long as there is not yet a material degradation in system reliability. Based on the foregoing, this position is misguided and, if accepted by the OEB, would put Hydro One in the quandary of having to ignore condition data and safety risks. The simplistic picture that the parties try to paint in relation to overall reliability fails to reflect the actual need and drivers for conductor renewal and masks key aspects of deteriorating reliability performance that require planned mitigation.

Increase in High Risk Condition Conductors

AMPCO and CME argue that the increase in high risk condition conductors (from 9% to 13%) is likely a result of Hydro One assessing more conductors and outages will not increase as a result of identifying more deteriorated conductors.[391] CME also argues that line asset condition is not truly degrading over time and outages will not increase as a result of identifying more deteriorated conductors.

[389] Exhibit B-1-1, TSP Section 1.5, pp. 31-32.
[390] J3.6.
[391] AMPCO Submission, p. 18; CME Submission, pp. 37-38.

AMPCO's and CME's arguments rely on flawed logic: that outages will not increase because more high-risk conductors have been identified therefore replacements are not justified. Hydro One submits that the identification of deteriorated conductors reveals the magnitude of the problem Hydro One is facing, i.e., that there are 1,037 km more high risk conductors in-service since the prior application (nearly a 40% increase),[392] while 6,061 km still need to be assessed (which is expected to reveal further high risk conductors).[393] Hydro One must prudently manage its conductor fleet risk and, contrary to what the intervenors argue, it cannot ignore verified condition assessments that demonstrate that the mechanical capability of the conductor has failed. The parties' position is akin to arguing that where a car owner recently discovers that the car's brakes have been worn out, it would not be prudent to replace the brakes because they did not fail during the time the issue was unknown.

If this logic were adopted, utilities would in effect be penalized both for having a perceived lack of adequate inspection/condition testing data and for improving asset management processes to obtain more data. Even if a high-risk conductor was previously unidentified, it poses the same operating risks and requires planned replacement. Moreover, CME's argument that outages will not increase as a result of identifying degraded conductors is speculative and ignores the serious safety risks that such conductors pose and that Hydro One must minimize to protect crew, customer, property, and public safety.

BOMA incorrectly argues that Hydro One has not provided evidence on how many conductors fall into the high risk category every year or how many fail in every year.[394] To the contrary, Hydro One provided a comparison of the number of high risk and very high risk conductors between the current and prior proceeding (nearly 40% increase),[395] the number of conductor outages in each year,[396] the number of delivery points impacted,[397] and the number of annual failures.[398] Hydro One aims to replace assets before they fail and cause outages.[399] As Hydro

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[392] Hydro One, Argument in Chief, Table 9-3, p. 47.
[393] Exhibit B-1-1, TSP Section 2.2, Table 1, p. 3.
[394] BOMA Submission, p. 8.
[395] Hydro One, Argument in Chief, Table 9-3, p. 47; and JT1.21.
[396] Exhibit B-1-1, TSP Section 2.2, Figure 19, p. 58.
[397] Exhibit 1-01-OEB-120(e) and 125.
[398] AMPCO-030 Attachment 1.
[399] OEB-23(c).

One replaces conductors based on verified poor condition, the number of failures is a lagging indicator reflecting the failure to prevent an outage.

Increase in Conductor Expected Service Life ("ESL")

SEC argues that conductors are lasting significantly longer than Hydro One had thought (i.e. increased from 70 to 90 years in alignment with EPRI's study) and that this was likely the reason Hydro One undertook less conductor replacement than forecast in EB-2016-0160.[400] CME and AMPCO also point to the increase in expected service life and the resulting decrease in the percentage of conductors past expected service life on Hydro One's transmission system.[401]

The parties appear to misunderstand the important distinction of expected service life as a fleet-wide planning indicator rather than a driver for replacement. While expected service life is a useful proxy for asset condition and associated risk of failure, Hydro One confirms conductor condition through assessment and testing. An increase in expected service life for fleet management and planning purposes does not negate the need to address those conductors that are verified to be in deteriorated condition.[402] Given the growing population of conductors that are projected to become high risk in the planning period and over the next 20 years, Hydro One must act now to mitigate and contain associated risks in a planned and paced manner.

SEC's argument that the increase in expected service life led to Hydro One undertaking less conductor replacements than forecast in EB-2016-0160 is mere speculation. Aside from the fact that expected service life does not determine conductor replacements, annual expenditures are not necessarily indicative of need. In response to interrogatory OEB-121, projects that are just starting have relatively smaller expenditures in initial years, as this is when the work is planned and engineered; whereas projects in execution have larger expenditures associated with materials and construction. Thus, delays in project timeline will shift expenditures to later years of execution but this fact alone does not diminish project need. Hydro One also notes that SEC

[400] SEC Submission, p. 54.
[401] CME Submission, p. 4-; AMPCO Submission, p. 18.
[402] Exhibit B-1-1, TSP 2.2, p. 57.

understated the total conductor replacement costs for 2017-2019, which is $226.1 million (not the $216.1 million quoted by SEC).

<u>Splice vs. Wire Failures</u>

Staff argues that Hydro One does not differentiate between conductor wire versus splice failures when categorizing "conductor system" failures, and therefore Hydro One does not know what proportion of its conductor system failures are related to each type of failures. Staff further argues that this differentiation is an important economic consideration because Hydro One has indicated that replacing all the conductor wire between two splices costs approximately 20 times more than simply replacing a poor condition splice.[403]

Staff's argument relies on a fundamental misunderstanding of conductor and splice replacements. Conductors are replaced based on condition assessment, not because the splices are broken. In other words, the condition assessment of conductors would never only examine an individual sub-component, such as connectors, splices or sleeves, and thereby trigger a replacement of the whole conductor. The conductor itself is always part of the assessment and its condition is the primary factor for determining overall condition. A deteriorated conductor span cannot be sustained by simply replacing the connector or splice.

On the other hand, if deterioration is verified to be isolated to particular conductor system component, then only that component is replaced.[404] For example, for conductors that are otherwise verified to be in good condition, only the deteriorated connectors and/or splices are replaced, without replacing the overall conductor system.

In addition to the planned replacements of conductors based on condition, where there is an accident (e.g., falling tree or lightning strike) that breaks the line, Hydro One will perform repairs, including re-splicing, to remediate the line temporarily and restore service, until the circuit can be replaced (assuming it has been deemed to be at end of life).[405]

[403] Staff Submission, p. 55.
[404] OEB-115(e).
[405] Oral Hearing Transcript, Vol. 2, p. 105.

Risk Mitigation Assessment

Staff argues that Hydro One has not shown that conductor renewal compares favorably, from a cost efficiency point of view, to other reliability driven programs.[406] Staff says that Hydro One's proposed expenditures on conductor replacements are not cost effective, as measured on a proposed metric of dollar spent per avoided customer interruption ("$/ACI").[407] BOMA makes a similar argument, suggesting that Hydro One should have used such a metric.[408]

The $/ACI metric was not put forward by Hydro One in this proceeding, rather it was disclosed in evidence from Hydro One's distribution proceeding.[409] Therefore, Staff's claim that "proposed expenditures on conductor replacements are not cost effective, as measured on [$/ACI]" is unsubstantiated as there is no evidence on record for Staff to base such a claim.

Staff's and BOMA's argument in favour of $/ACI aims to misdirect the focus of conductor replacement away from its primarily drivers of condition and safety risk towards a secondary outcome of reliability. The reality is that Hydro One is obligated to address conductors that are in poor condition and likely to cause severe consequences upon failure.

Hydro One's planning process cannot be distilled to a singular metric. Rather, it entails a comprehensive risk assessment through the lens of safety, reliability and environmental risk. In response to J-4.2, Hydro One provided a list of 563 investments (with those less than $3 million being consolidated into a single line item) and the corresponding quantification of risk mitigation benefits. Through this risk quantification, transmission line renewals projects are assessed against other projects and programs on both a total risk mitigated and risk-spend efficiency basis, resulting in a capital plan that balances competing system needs.

(i) System Renewal: Protection Systems

SEC and AMPCO submit that the expenditure for protection system replacements should be maintained according to historical actuals (2017-2018) because there has been no change in

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[406] Staff Submission, p. 56.
[407] Staff Submission, p. 56.
[408] BOMA Submission, p. 8.
[409] JT1.11-1 and 3.

the percentage of protection systems in high and very high risk since the EB-2016-0160 application and asset failure trends have improved.[410]

Hydro One submits that the percentage obscures the degrading condition of the fleet. The percentage of protection system assets in high or very high-risk condition (27%) has not changed since the EB-2016-0160 application because the protection fleet size has increased during this period (from 12,103 to 12,506) while the number of protection devices in high or very high risk has also increased (from 3,267 to 3,362). In order to manage the number (not the percentage) of high risk protection systems, an additional 95 protection systems must be replaced,[411] which contributed to the higher forecast expenditures for the test period. Other factors that contribute to the increase in costs include the need to comply with applicable NERC/NPCC standards[412] and need for additional civil infrastructure (such as cable trending and/or ducts).

AMPCO asserts that the percentage of delivery point interruptions from protection equipment has improved in recent years (purported to be 6% from 2011 to 2015, and 17% from 2008 to 2017). Hydro One notes that this comparison is invalid. Similar to the flawed comparison AMPCO proposed in relation to transformers, the two percentages do not measure the same thing and cannot be compared in the way AMPCO proposes. The 6% figure pertains to SAIDI data (i.e., duration) while the 17% shows the count of delivery point interruptions by equipment type.[413] The two numbers are unrelated.

SEC exaggerates the proposed number of replacements over 3 years as a 43% annual increase compared to a 2-year period (2017-2018) that SEC selected. Hydro One notes that when either 2016 or 2019 is included in the comparator historical period (to provide a 3-year to 3-year comparison), the proposed increase is closer to 7% or 24% respectively. Similarly, SEC

[410] SEC Submission, pp. 55-56; AMPCO Submission, pp. 17-18.

[411] There is no way to reliably predict when protection systems are likely to fail as most of the systems and their components do not show signs of wear and fatigue. They usually operate until they suffer an abrupt failure (ISD SR-07, p. 5).

[412] ISD SR-07, pp. 2-3.

[413] Exhibit B-1-1, TSP 1.3, Attachment 1, Appendix 1.3, p. 8; and TSP Section 2.2, p. 4.

exaggerates the replacement costs (annual cost increase of $14.3 million) by comparing the 2-year period (2017-2018) it selected to the 3-year test period forecast (2020-2022).

For these reasons and given the detailed investment justification (underpinned by condition data) in the evidence, Hydro One requests the OEB to reject the arguments raised by SEC and AMPCO.

(j) System Renewal: SONET Systems

Regarding Hydro One's plan to replace its end-of-life SONET system with a new packet-based technology, SEC does not dispute the need for an updated system, but submits that Hydro One's request is premature on the basis that (i) the project is "behind schedule" because the technology has yet to be selected and (ii) Hydro One will in-service costs related to the project in 2020 prior to the execution stage.[414] AMPCO makes a similar argument in its submissions.[415]

SEC's argument that the project is "behind schedule" is not supported by the evidence. In SR-11, Hydro One provided its plan regarding the SONET system replacement schedule, expecting to determine the replacement technology platform by the end of 2019. SEC relies on updates provided in October 2019 to make its assertion. Additionally, SR-11 forecasts an implementation and staging plan thereafter. In J3.8, Hydro One confirmed that the plan was on track to complete the development and estimation phase in 2020 and the execution phase in 2021. The project has progressed and matured to the point where estimation and tendering can occur based on the choice of technology that has been evaluated and pre-tested.

Furthermore, SEC's concern that costs will be put in-service prior to project execution stems from its misunderstanding of interrogatory response SEC-42, which reflects the ratio of the <u>cumulative</u> forecast capital expenditures incurred over the 2020-24 period divided by the <u>cumulative</u> forecast in-service additions over the 2020-24 period, not the in-year in-service ratio as SEC submits. Therefore, its argument that costs will be put in-service in 2020 on this basis is not valid and its submission to reduce the capital to in-service ratio for this project should be rejected.

[414] SEC Submission, pp. 56-57.
[415] AMPCO Submission, p. 19.

(k) System Renewal: Oil Circuit Breakers

CME expresses support for replacing oil circuit breakers that have unacceptable PCB levels (i.e., 69 out of 247 replacement candidates), but argues that Hydro One's proposed pacing for replacing the remaining oil circuit breakers is not justified because: (i) Hydro One's outage statistics do not show a need for a surge in oil circuit breaker replacements; (ii) EPRI found that replacing these units with single pressure gas breakers would yield only marginal benefits to Hydro One; and (iii) replacements due to PCB driver coupled with slowed replacements of non-PCB oil circuit breakers should provide sufficient spare parts for Hydro One.[416]

As detailed throughout evidence, Hydro One aims to replace deteriorated assets to mitigate failure risks.[417] Outage statistics, which are a lagging indicator of asset condition, are one factor considered when making investment decisions, Oil circuit breakers replacements are selected for a number of reasons including PCB compliance, functional obsolescence, safety risks, operating limitations (at or above nameplate rating), or likelihood to contribute to load interruption or unsupplied energy.[418] Similar to other asset replacements, oil circuit breaker projects are assessed against other projects and programs on both a total risk mitigated and risk-spend efficiency basis, resulting in a capital plan that balances competing system needs.[419]

Regarding the benefits of replacing oil circuit breakers with single pressure gas breakers, CME had mis-applied EPRI's findings to try to downplay the perceived benefits,[420] as explained below.

- While CME characterizes the proportion of respondent utilities that found single pressure gas breakers more reliable than oil circuit breakers as a "slim majority", the fact is that a proportion of 3 out of 5 (or 60%) is by no means insignificant. In any event, Hydro One is not proposing to replace end of life oil circuit breakers with similarly aged or deteriorated single pressure gas breakers. The EPRI survey cited by CME asked utilities to compare

[416] CME Submission, pp. 42-43.
[417] As explained, for example, in OEB-23(c).
[418] As detailed in ISD SR-04, pp. 3-4.
[419] J4.2.
[420] EPRI, Review of Utilities' Management of Oil Circuit Breakers – Current Industry Practices, Technical Update, April 2018 (Exhibit B-1-1, TSP Section 1.4, Attachment 9).

the reliability of these two types of breakers, not to compare an end of life oil circuit breaker with a new single pressure gas breaker. Thus, the implication CME wants to draw (i.e., Hydro One's plan will have only marginal reliability benefit) is unfounded.

- With respect to the EPRI survey results on the cost and difficulty of performing maintenance on oil versus single pressure gas pressures, CME stated "two thirds of [respondents]" found oil circuit breakers to be: (i) equally or less costly/difficult in terms of minor maintenance and (ii) equally costly/difficult in terms of major maintenance.[421] The way CME has characterized the survey results does not reflect the fact that (i) 5 out of 6 utilities found oil circuit breakers more or equally costly/difficult (i.e., 2 utilities answered "more costly/difficult" and 3 utilities answered "same") in terms of minor maintenance, and (ii) all 6 utilities found oil circuit breakers more or equally costly/difficult (i.e., 2 utilities answered "more costly/difficult" and 4 utilities answered "same") in terms of major maintenance.[422] Since Hydro One's maintenance practices are based on manufacturer manuals,[423] it is important to note that out of the 6 respondents, only 3 follow vendor-recommended maintenance. Out of those 3 utilities, 2 responded that major maintenance on oil circuit breakers is costlier compared to single pressure gas breakers.[424]

CME also argues that oil circuit breaker replacements due to PCB driver coupled with its proposed slowdown in the replacements of non-PCB breakers should provide sufficient spare parts for Hydro One. CME's proposal for strategic sparing is already deployed at Hydro One where repairs (funded by sustainment OM&A) are prudent.[425] However, the need to replace oil breakers that do not meet operating limits or pose a safety risk will not be aided by availability of spare parts as these issues relate to system conditions or irreparable/costly options. Thus, CME's proposal to "slowdown" replacements is misguided.

[421] CME Submission, p. 41.
[422] Exhibit B-1-1, TSP Section 1.4, Attachment 9, pp. 17-18.
[423] Exhibit B-1-1, TSP Section 2.3, p. 9.
[424] *Ibid.*, Tables 3-9 and 3-10.
[425] Oral Hearing Transcript, Vol. 2, p. 33, ln 13-17.

Furthermore, a sparing strategy does not resolve the long term pressure Hydro One faces from such a large fleet of oil breakers (1,600 oil breakers and by 2024 the number of breakers exceeding ESL will increase threefold[426]) that need to be managed and replaced in a programmatic manner as EPRI found other utilities have done.[427] In addition, the average age of Hydro One's oil breaker fleet is 42 years whereas EPRI found that most utilities became 'concerned' with leaving their breaker fleet in-service at age 46-50.[428] Notwithstanding these background factors, Hydro One's proposed replacement rate (49 breakers per year) is in line with the historical rate (44 per year)[429] driven by factors noted above such as PCB compliance, functional obsolescence, safety risks, operating limitations (at or above nameplate rating),and likelihood to contribute to load interruption or unsupplied energy.

(l) System Renewal: Wood Poles

With regard to wood pole replacements, AMPCO accepts Hydro One's forecast pace of renewal investments, but takes issue with the $156.1 million budget to replace 2,400 poles over the test period (compared to an actual of $119.3 million to replace 2,462 poles from 2016 to 2018).[430] AMPCO submits that there is no detailed evidence to account for this increase in budget to replace fewer poles, and that wood pole replacements should be tracked on a unit cost basis on the scorecard. PWU expressed concern that Hydro One's proposal to replace 800 wood poles per year is insufficient to satisfy the TSP objective of clearing the backlog of poles in high risk condition by the end of 2024, and that under the proposed pole replacement plan there will be 7% (i.e. 2900 poles) at high risk by the end of the 3-year period (2022).[431]

Hydro One has explained the forecast cost increase in detail. As per ISD SR-21, Hydro One enumerated the relevant factors that impact capital expenditures for this program, including structure type, pole size, location/ease of access, environmental restrictions, and work

[426] Exhibit B-1-1, TSP Section 2.2, Table 6, p. 17: 499/151 = 3.3

[427] Exhibit B-1-1, TSP Section 1.4, Attachment 9, p. 15: Over the last decade, … all of the utilities having performed programmatic replacements of these types of breakers; and Table 3-4: the principal motivation for replacement of oil circuit breakers is condition/reliability, programmatic replacement and insufficient replacement.

[428] Exhibit B-1-1, TSP Section 1.4, Attachment 6, p. 8-1.

[429] JT1.26-01.

[430] AMPCO Submission, p. 19.

[431] PWU Submission, paras. 38-39.

bundling.[432] Further, as explained in response to OEB-126, Hydro One made the decision during its 2018 business planning process to disaggregate wood pole investments and target only high criticality, publicly accessible locations (rather than continuing to bundle all end-of-life components on a line section for replacement). This approach facilitates the effective and timely identification and prioritization of high risk candidates, and resulted in a higher unit cost largely due to higher costs for mobilizing resources for one-off replacements.[433] During the oral hearing, Hydro One further clarified that bundling would still be applied to take advantage of opportunities for efficiency, like reduced mobilization efforts and outages.[434] Notwithstanding PWU's concern, similar to other asset replacements, the wood pole program is assessed against other projects and programs on both a total risk mitigated and risk-spend efficiency basis, resulting in a capital plan that balances competing system needs such that the proposed 800 poles a year reflects a prudent pace of replacement.

(m) System Renewal: Tower Foundation Assess/Clean/Coat Program

AMPCO does not support the increased pace of Tower Foundation Coating Program. According to AMPCO, "Hydro One indicated the predominant factor for the change is the way they classify [tower foundations], they're not specifying them as grillage foundations. This is contrary to ISD-23 which states that the Program focuses on steel grillage footings." AMPCO also argues that Hydro One has not presented a change in strategy, asset focus or asset condition that would drive the proposed increase in the Tower Foundation Assess/Clean/Coat Program.[435] As discussed below, AMPCO's argument is not supported by evidence and relies on certain presumptions that are factually inaccurate.

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[432] ISD SR-21, pp. 9-10.

[433] OEB-126(b); also see unit costs shown in SEC-22.

[434] "[F]rom the last filing to this filing we thought about disaggregating the portfolio, and we would then look at wood poles in critical areas. In doing so we recognized that we had on paper what seemed to be unit cost that was very much higher than what it used to be. So then we recognized that we would need to bundle where we could" (Oral Hearing Transcript, Vol. 1, p. 96-97, ln. 27-7).

[435] AMPCO Submission, pp. 19-20.

First, this program does indeed only target grillage footings and anchors which, due to their age and configuration, sustain a higher incidence of corrosion.[436] The statement in question from the oral hearing[437] is in fact incorrect in this context.

Second, contrary to AMPCO's assertion that Hydro One has not presented evidence regarding changes that would warrant the proposed increase, there is comprehensive evidence on the record. As explained in TSP Section 2.2 and ISD SR-23, all grillage foundations are or will be 50 years or older during the course of the next 5 years and will need to be assessed through the Asses, Clean and Coat program. In fact, the average age of steel grillage footings is 74 years, as compared to an expected serve life of 80 years. Of the 32,000 grillage footings on Hydro One's transmission system, 10,235 (32%) are currently beyond their expected service life, and that population will increase to 12,185 (38%) by 2024 and 14,360 (45%) by 2029.[438] Hydro One's planning of this program is determined by foundation type and consequence of asset failure. Based on condition assessment, where severe corrosion has caused significant strength reduction, the foundation will be identified as a candidate for major repair or replacement. The failure of foundation could directly result in structure failures which could cause a lengthy system operation interruption and a possible employee or public safety concern. Furthermore, damaged foundations could result in very costly repairs or even necessitate the replacement of the entire tower.[439]

As per Hydro One's strategy for steel structures and foundations, this program prioritizes grillage foundations based on line voltage, type of structures and geographic location of the lines. For example, the current plan is focusing on 500 kV guyed towers located in Northern region where most of towers are located in wetland or muskeg area. These towers were built in 1960s and there has been a high incidence of tower foundation failures.[440]

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[436] ISD SR.-23, p. 1.

[437] "[T]he predominant factor for the change is the 1,600 foundations, which, the way we classify them, we're not specifying them as grillage foundations. They are other types of foundations. So it's a little bit of an apples-to-orange comparison" (Oral Hearing Transcript, Vol. 3, p. 164, ln. 22-26).

[438] Exhibit B-1-1, TSP Section 2.2., pp. 72-73; ISD SR-23, pp. 2-3.

[439] ISD SR-23, p. 3.

[440] ISD SR-23, p. 5.

Further information regarding the detailed investment need, drivers, condition assessment, expenditures plan and alternative evaluation are provided in ISD SR-23. AMPCO's assertion that Hydro One has not provided sufficient evidence to justify the program is not consistent with the record.

(n) System Renewal: Air Blast Circuit Breakers

SEC's and CME's submission regarding the costs of ABCB projects have been responded to under subsection (f) (Project Costs) above.

In addition, BOMA argues that Hydro One has not quantified (i) the savings that will result from avoiding maintenance costs or (ii) the contribution to customer outages from ABCB failures. BOMA's assertion is incorrect. Hydro One quantified the annual OM&A savings from avoided maintenance costs at OEB-90(d) ($4.8 million). Maintenance cost avoidance is not the primary driver for this investment. ABCB replacements are necessary to address the high risk of failure arising from deteriorated condition and asset obsolescence. Installed in the 1970s, the entire fleet of ABCBs will exceed their expected service life by the end of 2023 and are already functionally obsolete. Any forced outage at critical stations (where ABCBs are installed) due to ABCB failures would greatly impact the sensitive operations of customers (i.e. hydraulic, gas and nuclear plant operators and interties).[441] As illustrated in Figure 9-1 below, the number of forced outages relating to ABCBs has increased significantly since 2012. The in-service ABCBs are at least four times less reliable than the newer SF6 circuit breakers, which is the dominant factor in their prioritized replacement, and are ten times more costly to maintain.[442] Hydro One expects reliability improvement (with all else being constant)[443] due to the retirement of the ABCB fleet.

[441] ISD SR-01, p. 1.
[442] Exhibit A-4-1, Attachment 1, p. 10.
[443] Oral Hearing Transcript, Vol. 2, p. 23, ln 2-3.

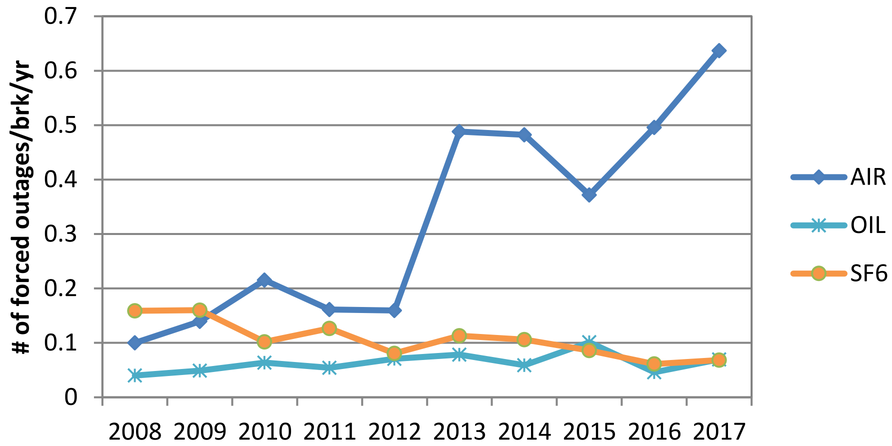

Figure 9-1: Summary of Forced Outages by Breaker Type[444]

(o) System Renewal: Shieldwire Replacement

AMPCO submits that Hydro One has not provided (i) the current quantity of end of life shieldwire or (ii) evidence to explain the need to change the asset strategy and replace double the circuit-km of shieldwire over the test period.[445]

Once again, AMPCO's submission ignores the relevant evidence. As stated in TSP Section 2.2, 6% or 2,078 km of Hydro One's shieldwire fleet is currently at end of life and requires replacement.[446] Significantly more shieldwire is now at end of life, primarily as a result of historic construction and demographic patterns, compared to the 480 km as indicated in the last application, which was the key driver for additional investment in shieldwire replacement over the test period.

[444] ISD SR-01, p.4.
[445] AMPCO Submission, p. 21.
[446] Exhibit B-1-1, TSP 2.2, p. 99.

SYSTEM SERVICE

(p) System Service: Kapuskasing Area Reinforcement

OEB staff and intervenors recommended no reductions in the System Service category except with one specific project.[447]

Staff takes issue with the costs of the Kapuskasing Area Reinforcement Project, arguing that Hydro One failed to mention the accuracy of the forecast at the time of the leave-to-construct ("LTC") application, and did not provide evidence in this proceeding to demonstrate efforts to address project scope changes as cost effectively as possible.[448] In this regard, Staff has failed to consider directly relevant evidence that contradicts the basis of its assertions.

Hydro One provided full disclosure in the LTC proceeding (application filed in Q1 2018), indicating that the station cost estimates were "preliminary costs" and that the updated costs would be provided as they become available.[449] Further, in the letter update to the OEB dated March 18, 2019, Hydro One clearly referenced the "station cost component" as documented in the LTC application as being in the "budgetary estimating phase of a project lifecycle". As indicated at the oral hearing in the current proceeding, the preliminary estimate from the LTC application would have been at an AACE Class 4 (+50%/-30%)[450] based on the natural evolution of the project estimating lifecycle and reflecting the level of engineering maturity. In any event, Hydro One submits that it is inappropriate to now relitigate issues from the LTC proceeding.

Regarding Staff's concern about cost-effectiveness, Hydro One notes that it is mandated to complete the project and that the IESO has concluded, as recently as May 2019, that the project as designed represents the least cost solution for meeting the reliability in the Kapuskasing area.[451] If Staff wants to challenge certain parts of the project costs as not being cost effective, it

[447] Staff Submission, p 47.
[448] Staff Submission, pp. 62-63.
[449] EB-2018-0098, Exhibit B-3-1, ln. 3.
[450] Oral Hearing Transcript, Vol 3., p. 43, ln. 11-22.
[451] EB-2019-0134, IESO Report dated May 8, 2019, p. 10, ln. 27-34.

should do so based on the detailed evidence that is before the OEB, rather than invoking unsubstantiated statements about a general lack of cost-effectiveness.

Staff also suggests that in the next rebasing application, for all investments requiring LTC, Hydro One should provide comparisons of project costs as between the LTC application and budgeted amount reflected in capital expenditures for the test years. Hydro One is agreeable to this proposal in principle, and, if so directed by the OEB, will provide the requested comparison as feasible at the time of the next rebasing application.

GENERAL PLANT

(q) General Plant: Integrated System Operating Centre (ISOC)

Staff, SEC, Energy Probe and VECC make various submissions with respect to the ISOC project. Their submissions are not supported by evidence and should not be accepted by the OEB. In short, as the project evolved and progressed, new risks arose due to unforeseeable market conditions. The increase from $138.5 million to $154.5 million was a direct response to the additional risks identified, and appropriate actions were taken to seek and implement cost reduction opportunities. In light of the new risks that arose, Hydro One has provided sufficient evidence in support of the reasonableness of the 12% increase. It would neither be fair nor just to require Hydro One to undertake the ISOC project with a budget that does not reflect current costs brought about by externalities outside of Hydro One's control.

Staff submits that the 12% increase in forecast costs from $138.4 million per 2018-2022 distribution CIR application to $154.5 million is: (i) above the accuracy range of ±5% associated with the former estimate, and (ii) of concern in terms of the reliability of the updated cost estimate.[452] In reply, Hydro submits that estimate updates reflecting the most recent cost to complete the ISOC are not a basis to deny recovery of those costs. OEB Staff and intervenors' position is contrary to the regulatory principle that rates should be sufficient to recover reasonably and prudently incurred costs. For the reasons discussed below, the ISOC costs are reasonable and prudent, and their recovery should be approved.

[452] Staff Submission, pp. 65-66.

Furthermore, Staff's rationale with respect to the avoidance of unanticipated costs has no basis. The increase in cost estimates was due to factors beyond Hydro One's control. It would be unreasonable to expect Hydro One to foresee a foreign government (USA) imposing a tariff that drives up steel cost by 20% or rebar cost by 30%. Additionally, there was an unexpected escalation in the demand for skilled labour in the GTA resulting in a 25% increase to the labour component. No evidence showed the increase was due to Hydro One's planning and engineering. As discussed below, the ISOC also benchmarks lower on a cost-per-square foot basis than other recent projects in the industry.

Staff's argument about the purported unreliability of Hydro One's cost forecasting is flawed. Hydro One took extensive measures to ensure the greatest possible cost certainty in its project estimate. When RFPs were issued to the market, Hydro One specifically required vendors to submit fixed price contracts, to ensure a high level of cost certainty. As a reflection of the stringency of such approach, some vendors resisted the request for this type of fixed-price contract. Additionally, Hydro One hired a third-party cost consultant, again to ensure that the cost estimates were prepared and aligned with acceptable industry practices. With time, it is not unreasonable for costs to evolve as unanticipated factors could impact budget. In keeping with acceptable industry standard, some vendors even insisted that the cost estimates be refreshed within 30-90 days due to the aforementioned realities of project estimating.

As noted in Hydro One's 2018-2022 distribution application, the ISOC project's contingency was $11 million.[453] As filed in the current proceeding, the project contingency is $6.7 million.[454] The unforeseen changes discussed above were not anticipated in the project contingency nor should they have been based on information available at the time. It is not good project management practice for "project contingency" to be considered a catchall exercise for any and all possible externalities, but rather, it should focus on reasonable, direct risks related to the project. Notwithstanding these considerations, Hydro One took yet an additional, prudent step by requesting that vendors responding to the RFP provide a list of value engineering opportunities to reduce costs which were weighed in the evaluation process.

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453 EB-2017-0049, Oral Hearing Transcript, Vol. 10, p. 32, ln. 24-26.
454 J4.05, Attachment 1, p. 5.

SEC accepts the reasons for the increased cost estimate but asserts that Hydro One should have found ways adjust the project design and reduce overall budget.[455] Hydro One rejects the SEC's assertion, and notes that facility design has been adjusted to find cost reductions from the outset of the project, including through planning needs assessment, detailed design phase and the initial RFP.[456] In addition, Hydro One undertook a final prudence check in the form of a RFP that asked vendors to identify value engineering opportunities for cost reduction. The relevant opportunities were weighed during the evaluation process and implemented as appropriate.[457]

Hydro One rejects SEC's characterization of ISOC cost benchmarking as being 11% above average. To provide a more recent comparison with industry comparators, Hydro One updated the industry comparator table in undertaking J4.4 (relative to the table at ISD GP-01, Appendix B, p.32). The updated information includes investments in facilities and data centre development projects constructed after 2015. This more current information yields a 2018 industry comparator average cost of CAD $2,215 per square foot, which is significantly higher than the estimated cost of the ISOC (CAD $1,266 per square foot). The cost of ISOC is 43% lower than industry comparators, which is a testament of the fiscal restraint and level of prudence exercised by Hydro One. Disallowing expenditures as SEC has recommended would not be reasonable and would result in a facility that fails to meet applicable requirements/standards commensurate with the criticality of the systems and functions that the ISOC is required to support.

Energy Probe claims that the ISOC is a "nice to have state of the art facility for an investor-owned utility" and should be extended over a 5-year period for a 2025 completion.[458] In reply, Hydro One submits that slowing development over a 5-year window would lead to inefficiencies and ultimately increase the overall cost of the project, which will be counterproductive to Hydro One's extensive efforts to prudently control and minimize costs. For example, technology assets are located both at the OGCC and the BUCC. These technology assets are refreshed based on

[455] SEC Submission, p. 59.

[456] Oral Hearing Transcript, Vol. 4, p. 74 ln. 25 to p. 76 ln. 3; and EB-2017-0049 Oral Hearing Transcript, Vol. 9, p. 153 ln. 19 to p. 154 ln. 10.

[457] Oral Hearing Transcript, Vol. 4, p. 74 ln. 7-22.

[458] Energy Probe Submission, p. 20.

regular IT lifecycles that will continue and be leveraged into the new ISOC.[459] Hydro One specifically considered these lifecycles in establishing the planned construction period. Slowing development of the ISOC could lead to significant technology assets being stranded. Moreover, characterizing the ISOC as a “nice to have” facility is false. Built in 1956, the current backup control centre is at end of service life and must be replaced. Hydro One has provided detailed explanation of business and regulatory requirements in the current proceeding and the previous distribution rate proceeding.[460]

VECC asks the OEB to establish the same type of asymmetric account for the transmission-allocated portion of ISOC costs as it did in the distribution proceeding. VECC also argues that the amount to be recovered in rates should be based on an allocation of the original $138.4 million estimate.[461] Hydro One disagrees with VECC’s request regarding an asymmetric variance account. The reality of managing a complex multi-year capital investment is that external factors and cost pressures beyond Hydro One’s reasonable anticipation and control may materialize. The proposed asymmetric variance account presumptively assumes that any cost increases resulting from such external factors are not reasonable or prudent. In the event market conditions lead to uncontrollable cost increases, Hydro One should not be forced to compromise the ISOC’s design requirements and capabilities. In the event the OEB decides to impose the proposed variance account, for the reasons highlighted above, the appropriate basis for determining the transmission-allocation of ISOC should be the current estimate of $154.5 million.

(r) General Plant: Grid Control Network Sustainment

AMPCO submits that 75% of the budget should be approved to account for cancellations and other risks (on the basis that Hydro One spent 75% of the planned budget over 2015-2018 and potential risks around procuring outages and project prioritization).[462]

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[459] OEB-98.
[460] For example, see J4.05, Attachment 1, p. 2; and EB-2017-0049, I-30-Staff-174.
[461] VECC Submission, p. 22.
[462] AMPCO Submission, p. 22.

In Hydro One's submission, the proposed reduction to this investment will give rise to a number of unacceptable risks. As explained in GP-02, this investment is required to:

- replace elements of the Grid Control Network (which allows Hydro One controllers at the OGCC to continuously monitor and control the grid) that are at or approaching end of vendor support, and
- facilitate the migration of the Grid Control Network to a new network topology so as to ensure compliance with IESO Market Rules regarding high performance telemetry measurements.[463]

If this work is deferred, the reliability of this critical grid control tool will be jeopardized, Hydro One may not be able to comply with IESO Market Rules, and the remote terminal units in the Grid Control Network (which are no longer supported by vendors and have high failure risk) may experience lengthy equipment restoration in the event of failure.[464]

The potential execution risks cited by AMPCO are normal risks faced by most projects, and do not by themselves warrant the cut proposed by AMPCO. In fact, Hydro One identifies and plans to mitigate execution risks to ensure on-time and on-budget delivery. With respect to AMPCO's argument about a 75% accomplishment rate over the historical period, Hydro One notes that normal fluctuations and variances in project accomplishments (which may occur for a number of reasons) are not a reasonable basis for funding disallowance. In fact, the company has a robust portfolio management process, including a formalized redirection process that supports investment plan adjustments in response to relevant considerations, including prevailing industry or corporate circumstances.[465] In this regard, Hydro One established a Redirection Committee which regularly meets to appropriately redirect funds or authorize additional spending as necessary, allowing prudent and timely adjustments to be made to the original plan.[466]

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[463] ISD GP-02, pp. 3-6.
[464] ISD GP-02, p. 8.
[465] OEB-131(a).
[466] Exhibit B-1-1, TSP Section 2.1, p. 46.

(s) General Plant: Network Management System Capital Sustainment

AMPCO submits that it is not clear what plan is in place to ensure another utility will implement and test the project in time, and thus recommends a 25% capital reduction to account for potential delays.[467] As discussed below, AMPCO's submission should not be accepted given that Hydro One has clearly articulated the need for this investment, a plan to manage implementation risks, and the unacceptable risks that would arise if the investment is not made in accordance with the plan.

To reduce project execution risk, proof of concept NMS console(s) will be designed and tested prior to full deployment, including use of the proof of concept NMS console in parallel with the current system prior to the final transition to the upgraded system. This approach provides for more testing opportunities and allows for non-conformances to be corrected prior to deployment. Furthermore, leveraging the lessons learned from the previous NMS upgrade project, completed in 2015, product maturity risk will be minimized by avoiding the installation of a product that is not yet in a production release status.[468]

In ISD GP-03, Hydro One clearly explains that the current NMS application software, server hardware and operating system are forecasted to be out of the vendor support window by 2023. All NMS end of vendor support components require an upgrade before reaching the end of vendor support. This upgrade is necessary to maintain required levels of NMS performance, reliability, availability and regulatory compliance (including compliance with NERC cyber security standards).[469]

Without this investment, the continued high availability, high performance, and security of the NMS would not be assured. Alarms may not annunciate if the NMS system is impeded operationally or rendered unavailable. Failure to clear a fault or isolate a faulted element from the system in a timely manner could result in a wide spread interruption in the Bulk Electric System due to the cascading effect of protection systems. One example of the potential impact

[467] AMPCO Submission, p. 22.
[468] ISD-GP-03, p. 8, ln. 13-20.
[469] ISD-GP-03, pp. 1-2.

of a delayed response is the 2003 Northeast Blackout, ultimately attributed to control room operation and tool issues.[470]

Furthermore, this investment has significant customer impacts as it allows for Hydro One control room staff to monitor customer connection status, coordinate customer outage requests, and restore or investigate events impacting customers.[471]

Adopting AMPCO's recommendation would mean this critical tool will be operated beyond vendor support, increasing reliability, regulatory and security risks to Ontario as well as the wider regional BES beyond acceptable levels. Based on the foregoing, AMPCO's suggested change to project timeline and cost should be rejected.

(t) General Plant: Facility Accommodation

AMPCO recommends an arbitrary 33% reduction to this investment. In doing so, AMPCO relies on generic claims regarding cost certainty, regulatory timelines and historical underspending, instead of anchoring its argument in the evidence. If this argument were adopted, then almost all projects put before the OEB could by default face similar cuts solely due to the existence of general execution risks, without regard to the particulars of how each project is actually planned and implemented.

Hydro One's evidence explained that field facilities are aging (more than 40% are 40 years old) and are largely undersized, inadequately configured and underperforming relative to current operational requirements.[472] Without the necessary capital repairs, upgrades and replacements, facilities will deteriorate to the point where operational costs will increase, business operations will be impacted and personnel safety will become impaired.[473] Citing historical underspending, AMPCO now proposes to reduce facility spending not just to average historical spending, but to

[470] ISD-GP-03, p. 2.
[471] ISD-GP-03, p. 3, ln 21-25.
[472] ISD GP-10, p. 2.
[473] ISD GP-10, p. 6.

less than actual historical spending levels while ignoring the extensive evidence of investment need.[474] This proposal is completely arbitrary and without evidentiary support.

Based on the foregoing, Hydro submits that the Board should find that the proposed forecast capital expenditures and in-service additions arising from the transmission system plan are appropriate, and that the rationale for Hydro One's planning and pacing choices (including consideration of customer preferences, planning criteria, system reliability, asset condition and benchmarking) are appropriate and have been adequately explained.

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[474] AMPCO Submission, p. 22: 2020-2022 Forecast $21.1M minus AMPCO's proposal $7M = $14.1M versus historical spending ($16.7M).

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?

As discussed in Hydro One's Argument in Chief, the company has allocated its Common Corporate capital costs to the Transmission business using a methodology recommended by Black & Veatch, which follows a cost causative approach and is consistent with the OEB-approved approach used to allocate such costs in prior Hydro One rate proceedings. Hydro One also noted that, in the OEB's EB-2017-0049 Decision and Order, the OEB stated that the allocation methodology will be examined in detail when Hydro One files a single application for distribution rates and transmission revenue requirement for the 2023-2027 period.[475]

With respect to the proposed Overhead Capitalization Rate, Hydro One noted that it capitalizes overhead costs that support capital projects, using an overhead capitalization rate that represents the relative amount of overhead costs derived using a methodology reviewed by Black & Veatch and that has been approved by the OEB in prior proceedings. Hydro One also noted that the OEB in EB-2016-0160 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 capitalization of overhead amounts, while in EB-2017-0049 the OEB indicated its expectation that it will review Hydro One's approach to capitalization in its next distribution rebasing proceeding.[476]

OEB staff, in its submissions, takes no issue with the allocation of Common Corporate capital costs and shared assets to the Transmission business. However, as discussed below, OEB staff notes a timing concern with respect to the Black & Veatch reports and proposes that the OEB should order that three particular items be subject to review in Hydro One's combined transmission and distribution rate application. Hydro One notes that OEB staff inexplicably included its submissions on the methodologies to allocate common corporate costs and other OM&A costs under this Issue 10. Hydro One addresses those submissions under Issue 14.

[475] Hydro One, Argument in Chief, pp. 71-72.
[476] Hydro One, Argument in Chief, pp. 72-73.

Energy Probe provided no discussion but expressed general support for the submissions of OEB staff on this issue. No other intervenors raised any concerns with respect to this issue.

OEB staff notes that due to the timing of issuance of the Black & Veatch reports, the February 21, 2019 Government Directive relating to executive compensation and any findings from the March 7, 2019 Hydro One Distribution decision and order would not have been addressed in the Black & Veatch reports.[477] In response, Hydro One notes that the Application reflects Bill 2 and is consistent with the approach that was accepted by the OEB in the Hydro One Distribution decision, which was assumed in the Black & Veatch reports.[478] The Directive only had a minor impact on the Application, which was addressed in the blue page update to Exhibit F, Tab 4, Schedule 1. At pp. 35-36 of that Schedule, Hydro One explains that its executive compensation framework is consistent with the Directive and that the impact of the Directive is reflected in the proposed revenue requirement. As such, OEB staff's concern is without merit.

OEB staff argues that the Board should require a detailed review of Hydro One's shared asset allocation methodology to be carried out as part of Hydro One's combined 2023 and subsequent years application, to be consistent with the OEB's treatment of the allocation methodology of common corporate costs in the prior distribution proceeding.[479] OEB staff's proposal is vague and should be disregarded by the Board. Hydro One files shared asset allocation studies with each of its transmission and distribution rate applications to support its proposed allocation of shared assets. The difference between the OEB's normal course review of that evidence and the "detailed review" contemplated by OEB staff is not apparent, nor does it appear to require Hydro One to provide information that is incremental to what it typically files. It would be up to

[477] OEB Staff Submission, p. 68.

[478] At p. 7, the report states: "Black & Veatch believes that Hydro One's current cost allocation methodology continues to be appropriate for Hydro One because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent and regulatory practice) and promotes transparency and efficiency. This finding is qualified by the acknowledgement that in order for Hydro One to comply with the requirements of The Act, it was required to make certain non-cost based direct assignments of executive costs to Shareholder responsibility. Therefore, the model departs from a cost-based approach for those instances where such direct assignments were made. Black & Veatch finds that Hydro One's application of direct assignment to reflect the requirements of The Act are appropriate for legislative compliance purposes."

[479] OEB Staff Submission, p. 71

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.

With respect to overhead capitalization, OEB staff indicated that they have no issue due to the overhead capitalized costs being driven primarily by an increased amount of assets being placed in service and not by an increase in overhead capitalized costs. However, OEB staff argues that the applicable overhead capitalization study by Black & Veatch should be examined in detail in Hydro One's combined application.[480] Hydro One notes that, in the Hydro One Distribution decision, the OEB already indicated its intention to review Hydro One's approach to overhead capitalization in the combined proceeding and has specified its expectations as to the information Hydro One should then file to facilitate that review.[481] As Hydro One already intends to comply with the Board's requirement from the Distribution decision, a further Board directive is not necessary in the current proceeding.

On pp. 71-72 of its submission, OEB staff asserts that "a utility benefits from the ability to capitalize more because they will be entitled to earn a return on rate base associated with the capitalized cost in addition to also recovering the cost in rates through annual depreciation expense." This is not a statement of fact or that is supported by Hydro One's evidence in the proceeding and, as such, should be given no weight by the Board. Rather, as explained by Hydro One during the Oral Hearing, 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.[482] However, by treating these costs as OM&A and making current ratepayers pay for the full cost of building capital assets that will be used to serve customers over a long period of time, issues of intergenerational inequity would arise with today's customers bearing the full cost and future customers being able to enjoy the benefits of the assets without bearing any of the cost. Capitalization enables the costs to be aligned with the timing of the benefits derived by ratepayers.

In connection with the above-noted assertion, OEB staff argues that the appropriateness of Hydro One's continued use of a US GAAP based capitalization policy for regulatory purposes

[480] OEB Staff Submission, p. 71.
[481] EB-2017-0049 Decision and Order, pp. 81-82.
[482] Oral Hearing Transcript, Vol. 6, p. 30, ln. 9-21.

should be addressed in the upcoming combined 2023-2027 rates proceeding, rather than through a general policy review proceeding, and that to facilitate a review of this issue Hydro One will need to provide detailed evidence 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.[483] As noted above, Hydro One's view is that US GAAP provides mechanisms that allow for a more appropriate matching of costs with the benefits that flow to customers, and that there is no compelling reason to require Hydro One to transition to MIFRS. However, 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. In carrying out that review, Hydro One would also consider whether it would be appropriate to assess the impact of transitioning to MIFRS. Hydro One is reluctant to commit to this because of its concern that IFRS 14, inclusive of a rate regulation standard, may become a permanent standard by the time of the 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.

Based on the foregoing, Hydro One submits that the Board should find that the methodologies used to allocate Common Corporate capital expenditures to the transmission business and to determine the transmission Overhead Capitalization Rate are appropriate.

[483] OEB Staff Submission, p. 73.

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?

Hydro One is requesting approval to continue capitalizing the non-service components of OPEB costs for both its Transmission and Distribution businesses. In the alternative, if the OEB does not permit continued capitalization of the non-service components of OPEB, Hydro One is requesting approval to continue the OPEB Cost Deferral Account and apply a 20-year rolling balance method for disposition. In the event the OEB denies Hydro One's request for continued capitalization and its alternative proposal, Hydro One would need to recover the relevant amounts as part of OM&A, which would have significant impacts on Hydro One's Transmission and Distribution revenue requirements.[484] A separate issue relating to OPEBs, which was addressed under Issue 11 in Hydro One's Argument in Chief, concerns a proposed alternative methodology for determining the amounts to be recorded in Hydro One's OPEB Asymmetrical Carrying Charge Account. That issue is addressed under Issue 22 of this Reply Argument.

OEB staff does not support Hydro One's request for continued capitalization of the non-service components of OPEB or the alternative proposal.[485] As such, OEB staff implicitly supports Hydro One's recovery of the non-service components of OPEB through OM&A for both the Transmission and Distribution businesses. Similar positions are taken by SEC, CME, Energy Probe and LPMA, either based on similar arguments as OEB staff or by endorsing the submissions of OEB staff without elaborating on them.[486] Detailed submissions in support of Hydro One's request for continued capitalization are made by SUP.[487] The relevant context for this issue, and Hydro One's responses to the specific arguments made by parties, are as follows.

[484] Hydro One, Argument in Chief, pp. 73-76.

[485] OEB Staff Submission, pp. 78-79.

[486] See SEC Submission, pp. 70-71, CME Submission, p. 45, Energy Probe Submission, p. 20 and LPMA Submission, p. 13.

[487] SUP Submission, pp. 6-7.

<u>Background</u>

In March 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) 2017-07, which amends the US GAAP accounting standard that applies to accounting for pension and OPEB costs. The primary purpose of the ASU was to improve the presentation of pension costs and post-retirement benefits costs in the income statements of US GAAP-reporting companies.[488] As Hydro One accounts for pension costs on a cash basis, only Hydro One's OPEB costs have been impacted by ASU 2017-07. Effective from January 1, 2018, the amendments introduced by ASU 2017-07 have limited the ability of US GAAP-reporting companies to capitalize the non-service component of OPEB costs.

Prior to ASU 2017-07, all of the components of net periodic OPEB costs were, as a whole, eligible for capitalization. As a result of ASU 2017-07, the components must be distinguished and only the current service component of OPEB cost is eligible to be capitalized. While this limitation applies to Hydro One in the first instance as a company that follows US GAAP, as explained in response to Undertaking J6.8 its application is subject to the accounting guidance established under Accounting Standards Codification (ASC) 980 – Regulated Operations. ASC 980 impacts the timing for recognition of revenues and expenses, and includes provisions which, in effect, provide that if a regulated business (i.e. Hydro One) has a regulator (i.e. the OEB) that permits it to deviate from standard US GAAP, then the regulated business is permitted to do so. As discussed in response to Undertaking J6.8, it is not unusual for the OEB to grant approvals that allow for Hydro One to depart from standard US GAAP as permitted by ASC 980. That response addressed a request from the Board panel for examples of instances where Hydro One has previously deviated from US GAAP with the approval of a regulator.

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[488] ASU 2017-07 requires entities to (1) disaggregate the current-service-cost component from the other components of net benefit cost (the "other components") and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations if such a subtotal is presented. It also requires entities to disclose the income statement lines that contain the other components if they are not presented on appropriately described separate lines. In addition, following ASU 2017-07 only the service-cost component of net benefit cost is eligible for capitalization (e.g., as part of inventory or property, plant, and equipment). This is a change from the prior practice, under which entities capitalized the aggregate net benefit cost when applicable.

Hydro One's current request for continued capitalization of OPEB should be considered in that light.

Hydro One's 2017-2018 Transmission revenue requirement approved by the OEB in EB-2016-0160 was established in advance of and therefore did not account for ASU 2017-07. As such, Hydro One applied for and received OEB approval to establish the OPEB Costs Deferral Account, effective January 1, 2018, to capture the financial impacts resulting from the change. In Hydro One's 2018-2022 distribution rates application, it requested and the OEB approved an equivalent account for the Distribution business. In both instances, the OEB indicated that the panel in the current Transmission Application could determine the matter of whether Hydro One should be permitted to continue to capitalize the non-service components of its OPEB costs, and that Hydro One should propose an approach for the disposition of the amounts recorded in the OPEB Cost Deferral Accounts.

It is within this context that Hydro One, in the current proceeding, is requesting approval to continue capitalizing the non-service components of OPEB costs for both its Transmission and Distribution businesses. In the alternative, if the OEB does not permit continued capitalization of the non-service components of OPEB, Hydro One is requesting approval to continue the OPEB Cost Deferral Accounts and apply a 20-year rolling balance method of disposition. In the event the OEB denies Hydro One's request for continued capitalization and its alternative proposal, Hydro One would need to recover the relevant amounts as part of OM&A, which would have significant impacts on each of Hydro One's Transmission and Distribution revenue requirements.

OEB staff has indicated that it does not support continued capitalization of the non-service component of OPEBs "on the basis that over the long-term, it is more expensive for ratepayers to fund these costs in rate base as opposed to OM&A due to the return on rate base that is applied to these costs when they are capitalized".[489] A similar argument is made by SEC.[490] Both OEB staff and SEC also comment that no other Ontario utility that follows US GAAP has to date requested OEB approval to continue capitalizing the non-service components of OPEBs.[491]

[489] OEB Staff Submission, p. 78.
[490] SEC Submission, p. 70.
[491] See OEB Staff Submission, p. 78 and SEC Submission, p. 71.

OEB staff suggests that the Board should look at ASU 2017-07 as a means of addressing the OEB's general concerns about the amount of capitalization permitted under US GAAP in comparison to MIFRS.[492] In addition, OEB staff argues that, in respect of Hydro One's alternative proposal, "there is no benefit to the added regulatory burden associated with accumulating such costs in a deferral account when the annual rate impact from recognizing these costs in OM&A would be so insignificant".[493]

For the following reasons, the Board should reject each of these submissions and approve Hydro One's request for continued capitalization of the non-service components of OPEBs.

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. Rather, it prohibits capitalizing the non-service components of OPEB as part of a general rule applicable to all US GAAP-reporting companies for the purposes of improving the presentation of costs in income statements, while allowing for the possibility under ASC 980 for rate-regulated utilities that use US GAAP to continue, for rate-setting purposes, to capitalize these amounts with the approval of their economic regulator. Hydro One's request for continued capitalization is therefore appropriate within the overall framework that is contemplated under the revised accounting standards.

As noted in response to Undertaking J6.8, under US GAAP for non-rate-regulated entities, costs are recorded in the period in which they are incurred. However, established principles of rate regulation dictate that costs should to the extent possible match the period in which ratepayers benefit from the costs. ASC 980 provides that the accounting treatments approved by a regulator to achieve this matching are acceptable under US GAAP. This is precisely the basis for Hydro One's request for continued capitalization. ASU 2017-07 changed the standard rules regarding capitalization of the non-service components of OPEBs, which has given rise to a mismatch between the period in which the costs must be recognized and the period in which ratepayers benefit from the costs. Hydro One is seeking permission to continue capitalizing those amounts so as to restore the alignment that previously existing between these costs and

[492] OEB Staff Submission, p. 79.
[493] OEB Staff Submission, p. 79.

the ratepayer benefits that existed prior to the rule change. Restoring that alignment also mitigates significant rate impacts for customers, identified below.

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. As there has been no change to Hydro One's underlying business and there has been no change to the nature of the underlying costs, there is no reasonable basis to support a change in the regulatory treatment of these costs. Neither OEB staff nor any party has identified any regulatory principles, or evidence, that supports such a change. Hydro One acknowledges the submission made by the Society of United Professionals (the "Society" or "SUP") in this respect. The Society cites OEB staff's submissions on the importance of consistency in rate-setting methodology across rate periods, and asks why the need for consistency is considered to be a sound argument in the context of cash pension costs but is not even a consideration for OEB staff in the context of its submissions on the continued capitalization of OPEB costs.[494] This inconsistency reveals a key flaw in OEB staff's argument that these historically capitalized costs should now be recovered as OM&A.

It is also important to recognize that there is a strong and clear precedent for an economic regulator allowing continued capitalization of the non-service components of OPEB costs for regulated utilities subsequent to the issuance of ASU 2017-07. As explained in response to Undertaking J6.4, Hydro One's request is aligned with guidance that the Federal Energy Regulatory Commission (FERC) provided in its accounting issuance letter, dated December 28, 2017, which allows FERC-regulated entities, which are subject to US GAAP and the changes in ASU 2017-07, to continue to capitalize both the service and non-service cost components of pensions and OPEBs. A copy of the FERC letter is provided in Attachment 1 to undertaking J6.4. In particular, on the question as to whether it is appropriate for regulated entities to capitalize pension and post-retirement benefits other than pensions (PBOP), FERC states that "provided that the pension and PBOP costs are based on appropriate labor costs and have a definite relation to construction . . . (regulated) entities may continue to capitalize the service cost component and non-service cost components of pension and PBOP costs as it has

[494] Society of United Professionals Submission, p. 6.

traditionally been the widely accepted practice, or they may elect to capitalize only the service cost component of pension and PBOP costs . . . Both methods are appropriate and are not precluded by the Commission's accounting requirements".[495] The FERC guidance is directly on point and no party has suggested any reason as to why the FERC guidance, which is based on sound regulatory principles, should not be followed by the Board.

The focus of OEB staff's submission on Hydro One's request for continued capitalization of the non-service component of OPEB costs, is its assertion that "over the long-term, it is more expensive for ratepayers to fund these costs in rate base as opposed to OM&A". As Hydro One stated in response to a similar point made by OEB staff under Issue 10, above, this is not a statement of fact and it is not a statement that is supported by Hydro One's evidence in the proceeding. It is merely an assertion that is made without any supporting evidence and, as such, should be given no weight by the Board. In contrast, as explained by Hydro One in testimony during the Oral Hearing, whether recovered as OM&A or as capital, the <u>same</u> amounts would be recovered in the fullness of time if the time value of money is properly considered.[496] In the passage quoted above, the indifference shown by FERC as to whether a utility continues to capitalize the service cost component and non-service cost components of pension and PBOP costs or elects to capitalize only the service cost component of pension and PBOP costs, suggests that FERC clearly recognized that ultimately the same amounts are recovered. While this may not be intuitive given that recovery as capital includes both a return of capital through depreciation expense and a return on capital through the cost of capital applied to the relevant portion of Hydro One's rate base, the fact that approximately the same amounts would be recovered in the fullness of time, as discussed above.

Another key reason for Hydro One's request for continued capitalization of the non-service components of OPEB costs, which was alluded to above, is that continued capitalization enables Hydro One to accurately reflect the true costs of its capital assets in rates. This is because, with continued capitalization, all relevant labour costs incurred in developing and building capital assets can be allocated to the corresponding assets and recovered over the

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[495] FERC, Accounting and Financial Reporting for Pensions and Post-retirement Benefits other than Pensions, Docket No. AI18-1-000, December 28, 2017, p. 4 (filed as Attachment 1 to Undertaking J6.4).

[496] Oral Hearing Transcript, Vol. 6, p. 30, lines 9-21.

useful lives of those assets. In this way, continued capitalization allows for the appropriate matching of asset costs with the benefits that flow to customers from the assets over time. Instead of paying for the full cost of long-lived assets up front in the first year the assets go in service, capitalization enables customers to pay for the cost of the assets over their useful life. The matching of costs with benefits is a fundamental objective of rate regulation.

In contrast to the matching of costs with benefits through continued capitalization, recovery of the non-service components of OPEB costs through OM&A would give rise to two key problems. First, there would be material impacts on Hydro One's revenue requirements for both its Transmission and Distribution businesses. In particular, as indicated in Table 1 of the response to Undertaking J6.4, Hydro One forecasts the non-service component of OPEB costs to be $15 million in each of 2020 and 2021 and $16 million in 2022 for the Distribution business for a total of $46 million. For the Transmission business, the costs are $21 million in 2020 and $23 million in each of 2021 and 2022 for a total of $67 million. In addition, in respect of 2018 and 2019, Hydro One would have to recover material historical amounts that have been recorded in the OPEB Cost Deferral Accounts for each of its Transmission and Distribution businesses. Those amounts would require disposition in a manner typical for regulatory accounts.

In addition to the above-noted revenue requirement impacts, recovery of these costs through OM&A would give rise to intergenerational inequities. By making current ratepayers pay for the full cost of building capital assets that will be used to serve customers over a long period of time, today's customers would be unfairly asked to bear the full brunt of these costs and future customers would be able to enjoy the benefits of the relevant assets without bearing their full cost. This is contrary to fundamental principles of rate-making that the OEB has recognized and applied in prior proceedings.[497]

Underlying the submissions from OEB staff, SEC and other likeminded intervenors, who endorse an outcome that would adversely impact today's ratepayers and which is not grounded in sound regulatory principles, is an assumption that recovery through capitalization is inherently

[497] See OEB, Partial Decision and Procedural Order No. 3, Essex Powerlines Corporation (EB-2014-0301), March 25, 2015, p. 7; OEB Decision and Order, B2M LP (EB-2015-0026), December 29, 2015, pp. 16-17.

inferior to recovery through OM&A. This assumption should be rejected. First, as explained above, it is not correct to assume that recovery through capitalization will in the long run be more costly to ratepayers. Second, the focus should be on customers and applying sound rate-making principles, rather than on the objective that is apparent from staff and intervenor submissions of preventing Hydro One from earning a return on the relevant costs. Continued capitalization would not present a windfall to or unjustly compensate Hydro One. The cost of capital, including the cost of debt and the cost of equity, are real costs that effectively reflect the time value of money. They are the costs incurred to spread out the cost of the underlying assets over the life of the assets, which it is appropriate to do to match the costs of the assets with the benefits of the assets and to smooth the rate impacts of capital investments.

As indicated in the introduction to this section, if the OEB does not approve continued capitalization of the non-service components of Hydro One's OPEB costs, Hydro One is requesting as an alternative that the OEB approve continuation of the OPEB Cost Deferral Accounts for each of the transmission and distribution businesses and that it be permitted to apply a 20-year rolling balance method for disposition. That methodology is described in greater detail in Exhibit H, Tab 1, Schedule 2, Section 3.16.2 and Attachment 10, as well as in Hydro One's Argument in Chief under Issue 11. OEB staff argues that there is no benefit to the added regulatory burden associated with accumulating such costs in the deferral account when the annual rate impact from recognizing these costs in OM&A would be so insignificant.[498] SEC and LPMA make similar arguments, and SEC adds that there is no basis for the account.[499] In response, Hydro One submits that its alternative proposal would mitigate the rate impacts that would otherwise result from having to recover the amounts through OM&A along with recovery of the amounts already recorded in the accounts for prior years as a one-time recovery instead of a 20-year rolling balance method for disposition proposed by Hydro One. It would also provide a different means of recovering the amounts over a period of time that better aligns with the useful life of the underlying assets. Hydro One also notes the submissions of the Society on this alternative:

> The Society rejects OEB staff's views that Hydro One's second option should be rejected due to increased regulatory burden and immateriality as unsupported

[498] OEB Staff Submission, p. 79.

[499] See SEC Submission, p. 71 and LPMA Submission, p. 13.

> and unsupportable. The burden is not different than any other deferral account time and the materiality is clear in comparison to other issues and deferral and variance items deemed material by the OEB in prior hearings. It should be noted that this option avoids staff's concerns with continued capitalization as the costs are not included in rate base and no return on equity is earned.[500]

As such, while continued capitalization would be the simpler and preferred approach, the regulatory burden of administering the alternative approach would not be unreasonable and, if the Board is inclined to disallow continued capitalization, the alternative proposal would address two of the key disadvantages of recovery through OM&A.

Finally, as noted, OEB staff suggests that the Board should look at ASU 2017-07 as a means of addressing the OEB's general concerns about the amount of capitalization permitted under US GAAP in comparison to MIFRS.[501] This sentiment is echoed by SEC.[502] In Hydro One's view, 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. The Board has clearly indicated that the matter of capitalization under US GAAP as compared to under MIFRS generally is a matter that the OEB will consider either through a generic policy review proceeding or in Hydro One's next distribution rebasing application, which will be the combined transmission and distribution rates proceeding for 2023 and subsequent years.[503] Either way, it is not a matter to be determined now and the Board in the current proceeding should not prejudice the future panel's consideration of the issue by finding a need to address the concern that has yet to be considered by that future panel.

Based on the foregoing, it is Hydro One's submission that the Board should find that the continued capitalization of the non-service components of OPEB costs for both Hydro One Transmission and Hydro One Distribution is appropriate.

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[500] Society Submission, p. 7.
[501] OEB Staff Submission, p. 79.
[502] SEC Submission, pp. 70-71.
[503] See EB-2016-0160 Decision and Order, p. 82, and EB-2017-0049Decision and Order, p. 82.

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

In its Argument in Chief, Hydro One explains that its approach to addressing the rights and concerns of Indigenous customers and rights-holders is informed by engagement with transmission customers, as well as efforts to engage directly with Indigenous communities. Hydro One also noted that, in response to the Board's direction in the EB-2016-0160 Decision for Hydro One to seek and incorporate timely and meaningful input from First Nations representatives into its TSP, it has thoughtfully considered and appropriately addressed the unique rights and concerns of Indigenous customers and rights-holders.[504]

OEB staff has indicated that it does not have any concerns with Hydro One's ongoing practices in addressing the rights and concerns of Indigenous customers and rights-holders.[505] Other than Anwaatin, no intervenor has made any submissions in relation to this issue. Anwaatin's submissions are focused on reliability, distributed energy resources (DERs) and Indigenous customer engagement. Hydro One responds to Anwaatin's concerns as follows.

With respect to reliability, Anwaatin argues that the Board should facilitate additional Indigenous monitoring and reporting on the conditions of the lines serving the Anwaatin communities and Hydro One's northern Ontario system generally, and that the Board may wish to expressly direct Hydro One to achieve stated reliability improvement targets for these areas. In response, Hydro One notes that it has a robust reliability reporting system that monitors and reports transmission reliability performance on an ongoing basis across the entire province. Annual assessments are carried out on poor performing transmission circuits and reliability performance "outliers" to mitigate and address future operational and reliability risks. A requirement for additional performance monitoring of one specific circuit serving the Anwaatin communities is not necessary because it is already covered through this ongoing performance monitoring and assessment process. This closed loop performance management system enables Hydro One to target system reliability improvements that add the most value for our customers and improve transmission reliability performance to top quartile performance as benchmarked with our peers.

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[504] Hydro One, Argument in Chief, pp. 80-83.
[505] OEB Staff Submission, p. 80.

With respect to DERs, Anwaatin argues that the Board should direct Hydro One to proceed with Phase 2 of the Settlement Agreement from EB-2017-0335 and encourage Hydro One to expand the use of DERs for Indigenous customers experiencing long-term reliability issues. As explained by Hydro One in response to Anwaatin IR #1, Hydro One has taken a number of steps towards implementing the Settlement Agreement, and has several steps remaining. In particular, Hydro One expected to complete the Battery Energy Storage System (BESS) Pilot Project by the end of 2019, following which it plans to monitor and evaluate performance for a period of time sufficient to determine if the expected *distribution* reliability benefits have been achieved. Subsequently, once that evaluation of costs and benefits has been completed, Hydro One will carry out Phase 2 assessments for other First Nations communities supplied by the A4L circuit, and at its next rebasing application Hydro One indicated that it would identify initiatives to address the unique reliability challenges experienced in northern communities as directed by the OEB in EB-2017-0049. To proceed with Phase 2 before Phase 1 has been sufficiently monitored and evaluated would therefore be premature. Moreover, the Settlement Agreement relates entirely to Hydro One's distribution system and not its transmission system that underlies the revenue requirement for which approval is currently being sought.[506] As such, it would not be appropriate for the Board to direct Hydro One to proceed with Phase 2 of the Settlement Agreement in the current proceeding. Furthermore, through its Decision and Order in Hydro One's distribution rate proceeding (EB-2017-0049) and the EB-2018-0288 consultation proceeding, the Board has already taken steps to facilitate the expanded use of DERs for Indigenous customers experiencing long-term reliability challenges.[507] Further measures in the current proceeding are not warranted.

With respect to Indigenous customer engagement, Anwaatin argues that Hydro One has not implemented the direction from the Board in EB-2016-0160 to incorporate timely and meaningful input from First Nations representatives because it did not ensure that the information presented was unambiguous and easy to understand and because Anwaatin's understanding is that Hydro One did not engage with Indigenous communities to collect timely and meaningful input specifically on the Application. Accordingly, Anwaatin argues that the Board should require Hydro One to include an Indigenous consultation metric on its Transmission Scorecard to

[506] See Hydro One response to Anwaatin IR #1(b).
[507] See Hydro One responses to Anwaatin IRs #1(e) and #4(c-g).

ensure the importance of Indigenous engagement and the duty to consult and potentially accommodate are reflected in the implementation of Hydro One's transmission planning.

With respect to the Board's direction in its Decision and Order in EB-2016-0160, for Hydro One to improve its customer engagement process by seeking timely and meaningful input from First Nations representatives, Hydro One notes that it has carried out a wide range of activities in an effort to engage, build relationships and seek timely and meaningful input from Indigenous representatives, as described in Exhibit A, Tab 7, Schedule 2. The feedback received from all such activities has been considered in developing the TSP, not just the input received from the formal customer engagement survey process. Notably, that formal process was carried out prior to the Board's direction in the EB-2016-0160 Decision and Order, which was issued on September 28, 2017. The survey was in market from May 11, 2017 to June 15, 2017. Despite that sequencing, Hydro One attempted to collect feedback from its LDC transmission customers through the formal survey process regarding the needs and preferences of the Indigenous communities they serve. While that effort did not prove to be particularly fruitful, Hydro One was able to rely on the feedback it received through other engagement methods to understand the needs and preferences of Indigenous customers and, moreover, it provided a learning experience that Hydro One will draw upon in designing its future Indigenous engagement processes.

Anwaatin contends that Hydro One did not ensure that the information presented during Indigenous engagement activities was unambiguous and easy to understand.[508] In support of that assertion, Anwaatin cites a section of the transcript where the source of confusion was electricity bills, not the information presented during customer engagement.[509] In any event, when Hydro One engages with Indigenous communities it does so through its Indigenous Relations group, which provides information in plain language and with meaningful context. Hydro One's Indigenous Relations Group invites other Hydro One subject matter experts as required to facilitate technical conversations and importantly, keeps the door open for ongoing dialogue. Mr. Chum also referenced the challenge of frequent changes in leadership within the

[508] Anwaatin Submission, pp. 14-15, para 27.
[509] Oral Hearing Transcript, Vol. 7, pp. 50-51.

Indigenous communities it engages with, so educating the communities comes through ongoing dialogue between Hydro One and the communities.[510]

In response to Anwaatin's suggestion that the Board should require Hydro One to include an Indigenous consultation metric on its Transmission Scorecard to ensure the importance of Indigenous engagement and the duty to consult and potentially accommodate are reflected in the implementation of Hydro One's transmission planning, Hydro One notes that Anwaatin has not suggested any particular metric. In addition, for the following two reasons Hydro One submits that a Transmission Scorecard metric is not necessary to drive improvements in respect of the company's Indigenous consultation efforts.

First, the duty to consult and potentially accommodate (which duties are borne by the Crown but may be delegated in certain instances) are legal duties. Where these duties have been delegated to Hydro One, Hydro One is legally obligated to fulfill those duties. Including a metric on its Transmission Scorecard would not change the extent to which these duties would be reflected in the implementation of Hydro One's transmission planning.

Second, the importance of Indigenous engagement is already reflected to a significant extent in Hydro One's transmission planning processes and recent developments will enhance the importance of such engagement in a range of business processes going forward. In particular, as described in Exhibit A, Tab 7, Schedule 2, Hydro One reports quarterly to its Board of Directors and its Health, Safety, Environment and Indigenous Peoples Committee on specific performance targets related to Indigenous Employment and Training, Indigenous Procurement, Indigenous Community Investment and Indigenous Community Engagement which includes Indigenous major project consultations. These metrics are designed by the Canadian Council for Aboriginal Business' Progressive Aboriginal Program (CCAB's PAR Program), which is a leading national certification program that confirms corporate performance in Indigenous relations. Certification signals to Indigenous communities and shareholders that the company is a good business partner; a great place to work and is committed to prosperity in Indigenous communities. In addition, Hydro One tracks its Indigenous community engagement efforts through a Customer Relationship Management (CRM) database called Borealis, which informs

[510] Oral Hearing Transcript, Vol. 7, p. 51.

the company's record of consultation for its work programs. CCAB commitments related to employment and training, procurement and community investment are also tracked by other lines of business in Borealis and all performance reporting is done on a quarterly basis. Accordingly, it is Hydro One's submission that there would be no value in the Board requiring Hydro One to include an Indigenous consultation metric on its Transmission Scorecard.

Based on the foregoing, the Board should find that Hydro One's TSP sufficiently addresses the unique rights and concerns of Indigenous customers and rights-holders.

E. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS:

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

The proposed 2020 test year total OM&A expenditures (summarized in Table 13-1 below) are appropriate, and the rationale for planning choices is adequately explained. Other than the 2019 OM&A forecast amount, Hydro One's proposed 2020 OM&A of $374.1 million is lower than both the historical OEB-approved OM&A levels and historical actuals. Hydro One's success in managing OM&A has been recognized in benchmarking studies that show Hydro One is an efficient transmitter from an OM&A perspective as its OM&A productivity significantly outpaced that of the transmission sector over the 2005-2016 period.[511]

In 2019, Hydro One had to implement one-time maintenance reductions, find productivity, and reduce corporate costs as a result of Hydro One's 2019 application for inflationary adjustment. While somewhat higher than 2019, 2020 OM&A is lower than historical levels as Hydro One has been able to sustain many of the 2019 reductions into 2020. The investment plan underpinned by the proposed funding will improve reliability and maintain asset condition over the planning period, while balancing the need to minimize customer rate impacts through lower than historical expenditure with the requirements of the system to provide safe and reliable transmission service.[512]

[511] As shown in Tables 3 and 4 of PEG's report (Exhibit M1), Hydro One's OM&A productivity is 0.83% versus the transmission sector at -1.64% over the 2005-2016 period.

[512] Hydro One, Argument in Chief, p. 84.

Table 13-1: Summary of Transmission OM&A Expenditures ($M)[513]

	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**

The submissions that follow address the parties' arguments on OM&A costs that are unrelated to compensation. Submissions related to compensation have been provided under Issue 17.

OEB Staff advocates for a reduction to Hydro One's 2020 forecast OM&A by $10.5 million.[514] This amount is derived based upon a 2.0% inflationary increase to Hydro One's 2019 OM&A forecast. AMPCO and CCC in effect adopt the submissions of OEB Staff. For reasons different

[513] The "plan" values at the category level reflect the funding levels proposed by Hydro One in its prior applications to the OEB and have not been adjusted to reflect the OEB's subsequent decisions. Reductions to the overall OM&A expenditure levels are itemized in the "adjustments" section, and are captured in the total plan values for each applicable year. As such, the "total transmission OM&A" plan values include the effect of the adjustments and represent the final plan or OEB-approved OM&A envelope for the year.

[514] OEB Staff Submission, p. 82; AMPCO Submission, p. 29; and CCC Submission, pp. 15-16.

than those proposed by OEB Staff, LPMA proposes a reduction of OM&A of a similar magnitude.[515] SEC has indicated that 2020 OM&A should remain close to 2019 levels.[516] The only submission SEC makes other than those on compensation[517] and productivity (which Hydro One has responded to elsewhere in these reply submissions) is that an increase in OM&A is not required to efficiently and productively operate the transmission system, even after adjusting for the one-time reductions made in 2019. As a result, the focus of the submissions below is on the arguments of OEB Staff and LPMA related to Sustainment OM&A.[518] OEB Staff and the noted intervenors accepted the other categories of OM&A costs including development, operations and customer care as reasonable.

Considering OEB Staff's submission in general, Hydro One submits that the proposed reduction to the 2020 OM&A is arbitrary and is not appropriate for a rebasing year under the Custom IR framework. OEB Staff's proposed inflation rate of 2.0% is not based on any applicable inflationary index and its proposed treatment of Hydro One's 2020 OM&A in effect ignores the OEB's rebasing principles and adopts an annual IR index. Simply, OEB Staff have put forward an arbitrary mechanistic proposal for determining 2020 OM&A without providing evidence to support the basis of their reduction.[519]

Sustainment OM&A

Hydro One's proposed Sustainment OM&A budget for the 2020 test year is required to maintain safety and reliability, sustain asset condition as well as comply with regulatory obligations over the planning period. As detailed in evidence[520], the proposed budget of $214.2M is in line with

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[515] LPMA Submission, p. 15: $8.0 million reduction to Sustainment OM&A and $2.7 million reduction to regulatory costs.

[516] SEC Submission, p. 60.

[517] VECC, CME and BOMA also advocate for reductions to the 2020 OM&A budget based on perceived concerns with compensation costs, which are discussed in relation to Issue 17 below.

[518] LPMA's submissions related to regulatory costs are dealt with in relation to common and corporate costs (Issue 14).

[519] PWU Submission, para. 59: With respect to Staff's proposed mechanistic reduction, PWU raises concerns similar to Hydro One's: "This method of deriving a proposed disallowance is not appropriate for any cost of service proceeding, and in particular this proceeding as extenuating circumstances required Hydro One's 2019 OM&A budget to be based on a mechanistic adjustment rather than its cost to serve. Board Staff does not attempt to justify this derivation".

[520] Exhibit F-1-3, p. 5.

the prior five year (2015-2019) average spending of $219.3M. Continued funding at the 2019 level, or a reduction below the 2020 forecast amount, will pose unreasonable safety and reliability risks, which will adversely affect Hydro One's ability to meet its customer needs and priorities.

Sustainment OM&A Cannot Be Deferred

OEB Staff takes the position that Hydro One is able to continue the one-year deferral of maintenance cycles in 2019 into 2020 and that the 2019 level of Sustainment OM&A expenditures should apply for 2020. In doing so, OEB Staff fails to reference any evidence in support of its position that Hydro One "is able to operate" at the forecasted 2019 levels.[521] More importantly, Staff ignores 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 has detailed in evidence (including in response to undertaking JT1.3) the reasons why 2019 expenditures levels are not acceptable for 2020. OEB Staff provided no response to those clear evidentiary facts.

2020 Sustainment OM&A Includes Additional Mandatory Compliance Work

A significant driver of the 2020 Sustainment OM&A increase of $13.6 million relative to 2019 forecast is the PCB Retirement (remediation) work to ensure compliance with federal PCB Regulations. A significant volume of additional PCB retrofill and sampling work relative to 2019 is necessary and has been planned for the test period.[522] This work represents $6.9 million or about 51% of the funding increase. Because of the need to schedule outages[523] (which requires IESO coordination) and the potential to discover newly identified PCB filled equipment that requires resolution, funding this work at 2019 levels is not feasible and will not be sufficient to complete the planned retrofill and sampling work in time to meet Environment Canada's 2025 deadline.[524] As Hydro One indicated in oral hearing testimony:

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[521] OEB Staff Submission, p. 88.
[522] VECC-36(b).
[523] F-1-5, p. 4, ln. 18-22
[524] JT1.3, p. 2.

> "When we're looking at the PCB, that's mandated. That will have to get done by 2025. There are a lot of still outstanding units that we have to finish our sampling by 2021 and we have to retro-fill by the end of 2024. We have to leave some time in case we find new discoveries. We'll have to do that."[525]

If the 2020 Sustainment OM&A remains at the 2019 level of $200.6 million, accommodating this mandatory PCB work would result in the reprioritization and reduced funding of other maintenance work categories to levels significantly below 2019 budgets. This funding approach would be ill advised as it would introduce a much greater level of risk in these below-2019 funded categories than that originally contemplated for 2019.[526]

2020 Sustainment OM&A Includes Further Essential Maintenance; 2019 Funding Level is not Prudent

Incremental funding not related to mandatory PCB remediation work is associated with further essential maintenance work that cannot be held at 2019 levels. This includes additional funding relative to 2019 for Power Equipment Preventive Maintenance ($2.4 million), Transformer Refurbishments ($1.5 million), Site Infrastructure Maintenance ($1.5 million), Vegetation Management ($2.2 million), and Overhead Lines Maintenance ($3.2 million).[527] It is important to put these cost levels in historical context. In total, the proposed Sustainment OM&A budget of $214.2 million for the 2020 Test Year is almost $10 million lower than the 2015-2018 average spending of $224.0 million,[528] notwithstanding incremental cost pressures from aging infrastructure, additional station and line assets, additional compliance obligations, and cost inflation. For each of the work categories above, notwithstanding the increase in funding relative to 2019, almost all of these categories remain funded below historical levels based on the 2015-2018 average as well as the 2015-2019 average, as outlined in undertaking response JT1.3.

It is also important to note that not all categories of Sustainment OM&A are receiving increased funding. To offset additional 2020 funding, many categories have been funded in line with or

[525] Oral Hearing Transcript, Vol. 3, p. 54.
[526] JT1.3, p. 2, ln. 9-13.
[527] JT1.3, p. 2, ln. 19-23.
[528] JT1.3, p. 1, ln. 24-26.

below 2019 levels. In particular, Engineering & Environmental Support has been reduced by $1.2 million below the 2019 level; and Protection and Control, and Telecom maintenance has been reduced by $3.3 million below the 2019 level, demonstrating that 2020 Sustainment OM&A has not been increased across all categories relative to 2019.[529]

Hydro One has set the expenditure at the minimum level required for completing the necessary work and balancing prudent asset stewardship with rate impact. 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 3 years of suspended maintenance work relative to historical levels, affecting all of the maintenance programs highlighted below:

- **Power Equipment Preventive Maintenance**[530] – Maintaining 2020 funding at the 2019 level would be equivalent to suspending all breaker and switch maintenance for 2 and 1.4 years respectively, relative to historical levels. This would result in deteriorating assets such as transformers, breakers, tap changers and switches not being maintained in time to prevent more costly repairs or becoming inoperable when needed, thereby causing larger outage zones which may impact connected customers, inhibit other maintenance or capital work, and result in inefficiencies such as delays and increased costs to deliver this planned work.[531]

- **Transformer Refurbishment**[532] – Maintaining 2020 funding at 2019 level would be equivalent to suspending all transformer refurbishment work for 2.5 years relative to historical unit accomplishments. This will put transformers at risk of accelerated deterioration that may result in failure or reduce expected service life, as the objective of transformer refurbishment activities is to ensure the asset is able to safely and reliably operate to its designed expected service life. In light of the significant expense and potential customer reliability impact arising from transformer replacements, the proposed 2020 level of refurbishment is the minimum necessary to prevent greater

[529] JT1.3, p. 5, ln. 12-14.

[530] Required to cost effectively preserve equipment functionality, reliability, availability, and meet safety, and regulatory requirements.

[531] JT1.3, pp. 3-4.

[532] Addresses verified poor condition transformers that need to be treated.

future capital replacement costs.[533] Furthermore, as noted during the hearing, transformer subcomponents such as tap changers require an increasing level of maintenance support than in the past:[534]

> "We haven't touched on the almost 550 [tap changer] units that we have. We haven't looked at the fact that we have had real failures on tap changers, we have had a Fairchild, we have had an Essa, we have had a John TS. <u>We're looking at overall on these units that are costing us a lot of time and money and at the same time we're unable to get to most of them with the OM&A allocation that we currently have.</u> We're looking at prioritizing based on condition rating, C3, CR3, CR4, which is actually the worst end. We're not looking at the number of operations these units have gone through. On a normal basis to manage them we would be looking at 300,000 operations. …. <u>We're unable to manage that. Right now we have many, many tap changers that are running way beyond that. We have not been able to do an [overhaul] on those tap changers because we're managing just the most critical. So where the transformers are concerned we're having real problems, because we have an older fleet.</u> At the same time, we're looking at 40 percent of the transformers that we have today are leakers. 10 percent of the transformers of the 40 percent are major leakers. Every year 1 percent of the fleet is added to that bunch." (emphasis added)

- **Vegetation Management** – Maintaining 2020 funding at the 2019 level would be equivalent to <u>suspending line clearing activities on 115 kV non-critical circuits for one year</u> and <u>suspending brush control for a third of a year</u> relative to historical unit accomplishments. These circuits are generally radial circuits that supply large industrial customers and/or vulnerable communities in Northern Ontario. Vegetation management on these circuits cannot be indefinitely deferred as neglecting these corridors will result in overgrowth, leading to higher future clearing costs and danger trees that could fall on the line. Further, continuing to suppress funding for the test period at the 2019 level will curtail vegetation work in urban areas that require more costly work in light of the heightened effort to coordinate with adjacent property owners and municipal governments.[535]

[533] JT1.3, pp. 3-4.
[534] Oral Hearing Transcript, Vol. 3. p. 52.
[535] JT1.3, p. 4.

- **Overhead Lines Maintenance**[536] - Maintaining 2020 funding at the 2019 level would be equivalent to suspending all preventive and assessment work for wood poles, conductor and foot patrols by 1.3, 1.9 and 3 years respectively, relative to historical unit accomplishments. This work directly relates to condition assessments, and a significant volume of assessments remains outstanding for overhead lines components.[537] Without the funding proposed by Hydro One for 2020, Hydro One would complete significantly fewer condition assessments resulting in less condition data to underpin investment decisions. This assessment work directly supports the required prioritization of Hydro One's capital investments, and the unavailability of condition information means high priority deficiencies may not be identified and included in planned replacement programs prior to failure.[538]

Expenditures Are Consistent with Historical Actuals

OEB Staff suggests that based on prior years' spending patterns, Hydro One may be over-forecasting Sustainment OM&A requirements. LPMA adopts the same argument. However, neither OEB Staff nor LPMA gave a basis for their assertion. The clear evidence is that Hydro One's 2020 forecast Sustainment OM&A[539] is lower than 2015-2018 actuals, which range from $215.1 million to $233.6 million and average $224 million over the four years. Some attempt was made in the proceeding by OEB Staff to mischaracterize the variance between higher historical plan amounts and lower historical actual amounts, as set out in the above Table 13-1, to support the claim that Hydro One overstated its funding needs.[540] However, as clearly explained in the hearing, comparisons to historical plan levels are not appropriate because they reflect amounts before any reductions were made as a result of OEB decisions.[541] Therefore,

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[536] Planned maintenance activities include inspections and condition assessment of overhead lines components to identify defects and end of life assets.

[537] Oral Hearing Transcript, Vol. 3, p. 55.

[538] JT1.3, p. 5.

[539] Exhibit F-1-3, Table 1.

[540] OEB Staff Submission, p. 83.

[541] Oral Hearing Transcript, Vol. 3, pp. 63-64.

the more appropriate basis of comparison is the actual expenditure incurred[542] and, on this basis, Hydro One's 2020 forecast is already lower than the historical level of funding.

In addition to the flawed comparison adopted by Staff and, LPMA also ties its basis for disallowance to the fact that Sustainment OM&A dips in 2019 relative to 2018 and then increases in 2020. LPMA ignores the factual evidentiary basis and need for the increase in 2020 Sustainment OM&A, and instead argues 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. Respectfully, this argument seems only to say that because the funding level is forecast to increase it should be denied and the evidentiary basis underlying the forecast/increase is irrelevant. This is not an appropriate basis for regulatory decision-making or for setting just and reasonable rates. In Hydro One's submission, the evidentiary record is clear that the 2019 expenditure levels are not sustainable. As discussed above, funding at 2019 levels would result in reduced funding of other maintenance work categories to levels significantly below 2019 budgets in order to fund mandatory PCB work. This would result in 3 years of additional suspended maintenance for essential maintenance work programs and would introduce a much greater level of risk than originally contemplated for the reduction in 2019. [543] In fact, because the 2020 forecast amount is less than 2018 actuals, the OEB's incentive rate framework worked appropriately, where costs were reduced during the incentive period (2019) and some of those costs savings (where system needs permitted) were passed onto customers at rebasing in 2020.[544] On this basis, the proposed 2020 levels are supported fully by the evidentiary record and should be approved.

Capital and OM&A Relationship Must be Considered in the Appropriate Context

OEB Staff attempts to justify its suggested disallowance of the proposed Sustainment OM&A on the basis that OM&A savings associated with new capital have not been adequately quantified and accounted for by Hydro One. This position is not justified, and the clear evidence is that

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[542] On an overall basis, between 2015-2018, Hydro One managed its OM&A spending within 99% of OEB-approved amounts (Oral Hearing Transcript, Vol. 5, p. 96, ln. 4-10).

[543] JT1.3

[544] OEB-184(c).

based on the total capital need and the amount of capital expended in the aggregate there is not an identifiable effect on OM&A expenditures.

Hydro One acknowledges 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. 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.[545] However, it is not appropriate to extrapolate the impact on a single asset onto total OM&A. 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.

Given Hydro One’s sizeable asset population and the need for renewal relative to the actual work undertaken, the result is that the changes to OM&A as a result of capital replacements are offset by the larger population of older assets that require greater levels of maintenance. As explained during the oral hearing:

> “MR. JESUS: I think we need to put this in context, in that there is a lot of assets that we have on the system, whether it is breakers, transformers, protections. There's millions of assets that we've got, and the fact that we're replacing 723 breakers is hardly going to move the needle, I would suggest to you. I think there are savings when you're specifically down to the one breaker, or the 128 that we're going to be replacing in that one year, for sure. <u>But in the grand scheme of things when we've got millions of assets, I would suggest it's a drop in the bucket</u>.
>
> MR. SIDLOFSKY: Well, okay. But we've talked about breakers, we have talked about transformers, we have talked about circuits. At what point does it move the needle? Like how many projects do I have to look at to understand when or if there's going to be some corresponding savings in OM&A? Or is the only indication that I have that your sustainment OM&A is lower in the 2020 test year?
>
> MR. JESUS: I think you have to appreciate that -- I agree with you that there are savings from installing new facilities, no different than buying a brand new car. I totally understand the premise.
>
> <u>But the reality is we have all of these assets that are aging, and if I've got a lot of old cars, they're going to require a lot more maintenance on those old cars</u>.

[545] Oral Hearing Transcript, Vol. 2, pp. 138-139.

> So yes, we're going to have some savings over here, but we need to put those savings into those old assets that are aging. We've already said over the next over the test period, those aging assets are going from 1.8 times beyond their ESL to almost three times beyond the ESL.
>
> So I agree with you. There will be savings on those assets. We call out specifically the air blast circuit breaker savings for sure. Absolutely.
>
> But in the grand scheme of things, we still need to maintain the aging assets that we have, and I would suggest to you that those costs are way and above the cost savings on the brand new assets"[546] (emphasis added)

Continued Need for Corrective and Preventive Maintenance

Notwithstanding the capital and Sustainment OM&A investments, there will be a continued need for both corrective and preventive maintenance on Hydro One's transmission system over the plan period, as discussed below.

With respect to corrective maintenance, while capital replacements may alleviate corrective maintenance costs associated with the specific asset targeted for replacement, corrective maintenance due to deteriorating condition and periodic preventive maintenance on the remaining fleet is still required according to the manufacturer's manual, industry technical reports and Hydro One's operating experience.[547] With respect to preventive maintenance, TSP Section 2.3 outlines Hydro One's maintenance schedules for its power system assets.[548] This preventive maintenance is carried out on new and old equipment, analogous to routine work being required on both new and old cars (e.g., vehicle oil change and inspection).

For many asset categories regulatory compliance dominates the Sustainment OM&A forecast and must be completed whether the asset is new or old. For example, the maintenance and its frequency for protection systems on the Bulk Electric System ("BES"), whether new or old, is governed by mandatory NERC standards.[549] The maintenance and its frequency on pneumatic (air) systems, whether new or old, are governed by mandatory TSSA regulations.[550] The

[546] Oral Hearing Transcript, Vol. 2, pp. 158-159.
[547] Exhibit B-1-1, TSP Section 2.3, p. 9.
[548] Exhibit B-1-1, TSP Section 2.3, pp. 9 (Table 2), 13-14 (Table 3), 20 (Table 4).
[549] Exhibit B-1-1, TSP Section 2.3, p. 17-19: NERC and NPCC standards.
[550] Exhibit B-1-1, TSP Section 2.3, p. 32.

maintenance and its frequency on battery systems, whether new or old, are governed by NERC regulations.[551] The annual 230 and 500 kV vegetation management inspections are governed by mandatory NERC regulations,[552] irrespective of whether the transmission line or its components are new or old. Nearly 7%[553] of Hydro One's 2020 Sustainment OM&A is allocated to PCB remediation and waste management that must be completed. This level of spending for PCB and waste management is driven by regulatory compliance and reflects a 90% increase to historical spending and is necessary whether Hydro One installs the forecast new assets.

While Hydro One's investment planning process aims to prioritize replacements according to the overall risk posed, Hydro One has provided the current status of the growing level of high risk assets, as highlighted in the table below.[554]

Table 13-2: Assets in High or Very High Risk

Asset Type	Assets in High or Very High Risk[555]		
	Prior Application	Current Application	Change
Transformers	108	122	+13%
Circuit Breakers	499	460	-8%
Protection Systems	3,267	3,363	+3%
Conductors (km)	2,643	3,680	+39%
Wood Poles	4,832	5,630	+17%

Proposed replacement levels will not completely eliminate these high risk assets[556] or the associated corrective maintenance requirements. For example, 40% of the transformer fleet has been confirmed via visual inspections to have oil leaks, with 10% being classified as major leakers. Based on Hydro One's experience, new leaks will appear in approximately 1% of the

[551] Exhibit B-1-1, TSP Section 2.3, p. 32: ERC PRC-005-02 and NPCC Directory 4 & 8 regulations.
[552] Exhibit B-1-1, TSP Section 2.3, p. 47: NERC standard FAC-003.
[553] Exhibit F-1-3, Table 1 and Table 3. $14.6M/$214.2M and 1-(14.6/7.7M)
[554] Hydro One, Argument in Chief, p. 47, Table 9-3.
[555] JT1.21.
[556] PWU-10(f).

fleet per year, most commonly as a result of gasket deterioration over time.[557] New assets will not prevent new leaks that will emerge within the older fleet nor will they reduce the associated maintenance that is expected to be required every year.

In summary, the OM&A reductions proposed by Staff and certain intervenors are not supported by clear evidence that substantiates the appropriateness of Hydro One's forecast 2020 funding level, including the operational and maintenance needs that directly underpin this forecast as well as consistency with historical expenditures. The parties' arguments regarding the purported relationship between OM&A and capital investments are similarly inconsistent with the facts on the record. For the above reasons, the OEB should reject the proposed reductions in this regard.

Common Corporate Costs and Other Costs

OEB Staff and intervenors recommended no reductions in the Common Corporate Cost and Other Costs category except with proposed Regulatory Affairs costs.

LPMA submits that the OEB should approve an overall reduction to the 2020 OM&A envelope of $2.7 million related to regulatory costs and legal costs, in addition to the $8 million reduction to the 2020 OM&A which they proposed in relation to Sustainment OM&A (which was discussed above).[558] More specifically, LPMA's calculation of the $2.7 million reduction is related to: (a) $1.725 million in regulatory costs (negative); (b) $2 million in legal costs (negative); and (c) an offset of $1 million in recovery (positive). Due to the nature of the Custom IR framework, where 2021 and 2022 OM&A is escalated from 2020 levels, LPMA is essentially proposing to cut over $8 million in regulatory and legal costs. LPMA's submission proposes to reduce Hydro One's regulatory costs by $1.725 million from lines 2,4,10 and 11 in Exhibit F-8-1, Attachment 1. These are application related costs for which Hydro One is requesting $2.112 million, so LPMA's proposal represents an 82% reduction in the funds available to process all of Hydro One's transmission applications. The overall reduction proposed by LPMA is premised on

[557] Exhibit B-1-1, TSP Section 2.2, p. 8.
[558] LPMA Submission, pp. 15-16.

incorrect assertions and ultimately would have a deleterious effect on the ability of Hydro One, the OEB and customers to properly process regulatory cases over the rate period.

LPMA's submission fails to take into account the fact that the Regulatory Affairs division does not only file revenue requirement rate applications with the OEB. The division performs a broad set of compliance functions, oversees the adherence to transmission and NERC reliability standards, issues numerous non-rate applications (e.g. leave to construct) with the OEB and other regulators, provides a number of regulatory reporting functions, and performs the pricing, rate-setting and load forecasting functions for substantially all of the Transmission system and its own diverse distribution system. Additionally, it is important to recognize that overall regulatory costs (as evident in Exhibit F-2-2, Table 11, p. 24) in 2020 are in line with historical spending and even lower than some historical years and lower than previously OEB approved amounts. Reducing Regulatory Affairs budget by 1.725 million, of 80% of the line items in question, would bring the budget significantly below any OEB approved or actual spending between 2015 to 2018.

LPMA makes its proposal on the basis that there are no major transmission rate applications in 2020. However, during the test period of this application, Hydro One will prepare, file and litigate, for the first time ever, a combined transmission and distribution application, which, represents a significant undertaking. Due to the nature of the Custom IR framework, Hydro One will be required to operate within the forecast 2020 envelope, as adjusted for inflation, over the rate setting period to support its combined rate filing along with its numerous other ongoing regulatory obligations. Removal of this funding will impair Hydro One's ability to provide the information relied upon by the OEB and customers.

Regarding LPMA's argument that $2 million of legal costs should be removed from the 2020 test year OM&A, Hydro One submits that, as stated above, legal expenses will be incurred during the rate period of this application. These costs support not only the upcoming joint rate application but all of Regulatory Affairs' other functions as well. Additionally, as indicated in response to JT 2.35 question 4, legal costs associated with rate applications are budgeted and recovered as part of an overall non-labour budget for General Counsel and Secretariat, which includes provisions for <u>all external legal costs</u>, not just regulatory proceedings. This is detailed in Exhibit F-2-2, pp. 21-23. The total legal budget, which is ultimately driving the revenue requirement ask for the legal costs component, was forecast based on historical expenditures and current business needs. LPMA's proposal of reducing the overall legal budget for the company by $2 million in each year in the rate period would impact funding for all functions performed by Hydro One's Regulatory Affairs department including preparation for its next rebasing application.

LPMA argues there will be significant cost reductions as a result of a combined rate application for transmission and distribution. Hydro One does not believe this will be the case. Hydro One will be required to file two separate system plans underpinned by separate customer engagement activities from the relevant customers of each respective business. Any supporting asset management information such as benchmarking studies would be separate for each side of the business with no substantial cost savings expected. Additional studies were ordered in the last distribution decision which will form an additional expense relative to prior filings. Distribution and transmission rate setting policies are different, which means that the OEB and intervenors will have to review two separate rate setting frameworks supported by separate benchmarking analyses, load forecasts, cost allocations, and rate designs, etc. These are just some of the elements of evidence for which there is limited overlap between Hydro One's transmission and distribution business. Considering these factors, it is unclear on what basis LPMA can claim that the costs incurred by Hydro One will be meaningfully reduced.

Based on the apparent needs of the diverse Regulatory Affairs division and the needs of the OEB and customers to effectively adjudicate Hydro One's requests, Hydro One submits that its regulatory and legal costs are appropriate.

Property Taxes and Rights Payments

As explained in its Argument in Chief, Hydro One incurs expenses related to taxes (other than income and capital taxes) arising from its obligations to pay property taxes and to make rights payments. Hydro One 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.[559]

OEB staff, in its submissions under Issue 15, accepts 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.[560] No intervenor raised any concerns with respect to Hydro One's forecasts for property taxes and rights payments.

Accordingly, the Board should find that Hydro One's forecast expenses for property taxes and rights payments, as a component of the company's OM&A costs, are appropriate.

[559] Hydro One, Argument in Chief, p. 94-95.
[560] OEB Staff Submission, p. 97.

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

As explained in Hydro One's Argument in Chief, Common Corporate Costs are comprised of costs incurred for the provision of Customer Care, Asset Management Planning, IT and other shared functions that are referred to as Common Corporate Functions and Services (or CCF&S), which provide common services to all business units. Other OM&A costs are comprised of credits associated with capitalized overheads that are determined from the Black & Veatch *Review of Overhead Capitalization Rates (Transmission) – 2019* report, environmental provisions, indirect depreciation and other costs. These amounts are allocated to the company's Transmission and Distribution businesses and each of its affiliates based on a methodology, established in the Black & Veatch *Review of Allocation of Common Corporate Costs (Transmission) – 2019* report, which is based on cost causality principles. That methodology is consistent with the methodologies approved by the Board in Hydro One's 2016-0160 and EB-2017-0049 proceedings.[561] Hydro One is requesting a 2020 Common Corporate Costs and Other OM&A cost of $30.3 million for its Transmission business.

OEB staff, which made its submissions on this issue under Issue 10, supports Hydro One's request, considers it to be reasonable and takes no issue with the amount, which it considers to be largely driven by an allocation methodology developed by Black & Veatch that has been in place since 2009.[562] Moreover, no intervenor has raised any concerns in relation to this issue. LPMA raises concerns related to Regulatory and Legal costs which ultimately are embedded in the Common Corporate Costs OM&A, but these concerns are discussed under Issue 13, above, as they relate to the quantum of the expense and not the allocation methodology. As noted by Hydro One, pursuant to the OEB's Decision and Order in EB-2017-0049 the allocation methodology will be examined in detail as part of Hydro One's application for 2023-2027 distribution rates and transmission revenue requirement.[563] As discussed under Issue 10, OEB staff acknowledge that such review of the allocation methodology will be carried out and, in addition, have proposed that the Board in the present proceeding order that a detailed review of

[561] Hydro One, Argument in Chief, pp. 96-97.
[562] OEB Staff Submission, p. 70.
[563] Hydro One, Argument in Chief, p. 97.

Hydro One's common corporate cost allocation methodology be carried out at the same time.[564] This proposal from OEB staff is vague and should be disregarded. The difference between the OEB's normal course review of the common corporate costs allocation methodology and the "detailed review" contemplated by OEB staff is not apparent, nor does it appear to require Hydro One to provide information that is incremental to what it typically files. 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.

Based on the foregoing, Hydro One submits that the Board should find that the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the Transmission business are appropriate.

[564] OEB Staff Submission, p. 71.

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 has calculated its income tax expenses, for purposes of recovery through its transmission revenue requirement, in a manner that is consistent with the OEB's Filing Requirements and supported by detailed calculations, reconciliations and supporting schedules. The proposed income tax expense includes an appropriate allocation of tax savings to ratepayers arising from Hydro One's departure from the PILS regime and incorporates the impact of the Accelerated Investment Incentive (federal Bill C-97).[565]

In its submissions, OEB staff generally accepts the amounts that Hydro One proposes to include in the revenue requirement for income taxes. However, OEB staff argues that the Board should require Hydro One to provide various additional calculations as part of the Draft Rate Order. In addition, OEB staff comments on the manner in which the revenue requirement impact of the Accelerated Investment Incentive should be tracked in Account 1592. Finally, OEB staff indicates that it does not support Hydro One's request for a variance account to track the impacts of its appeal to the Divisional Court, if successful.[566] Energy Probe expresses support for OEB staff's submissions without elaboration[567] and LPMA has raised concerns similar to those raised by OEB staff in relation to the accuracy of the forecast impact of the Accelerated Investment Incentive program and the need for detailed calculations of the overall income tax expense for each year during the Custom IR rate period.[568] The requests for additional calculations and OEB staff's comments on the Account 1592 are addressed below. OEB staff's submission on Hydro One's requested variance account for tracking the impact of a successful appeal is addressed under Issue 23. OEB staff's submissions regarding taxes other than income taxes[569] are addressed under Issue 13.

565 Hydro One, Argument in Chief, pp. 97-100.
566 OEB Staff Submission, pp. 95-96.
567 Energy Probe Submission, p. 22.
568 LPMP Submission, p. 17.
569 OEB Staff Submission, p. 97.

OEB staff argues that Hydro One should revisit its calculations related to the impact of the Accelerated Investment Incentive program in the Draft Rate Order in this proceeding to confirm the accuracy of the calculations due to the concern that Hydro One quantified the impacts quickly after enactment of Bill C-97 and more information may have become available since that would affect the calculations.[570] In Hydro One's view, it is not necessary for it to revisit the calculations because the forecasted eligible additions have not changed, and there has been no more information since that which was made available on the application of the new rules that would affect Hydro One's initial calculations for the test years. Those initial calculations of the impact of the program were carried out by applying the enhanced CCA rules to Hydro One's forecasted eligible additions for the test years.

OEB staff further argues that, in the Draft Rate Order, Hydro One should provide the detailed calculations that underpin the regulatory income tax expense amounts that it is seeking to recover in each year of the Custom IR term due to staff's concern that the calculations on the record do not reconcile to the amounts presented in Table 19 of staff's submission. OEB staff specifies that the calculations should incorporate the regulatory income tax expense impacts of all matters addressed by the OEB in its decision.[571] Consistent with its past practice, to the extent that there are any changes to income tax expense arising from the decision, 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, document the reason for the change and allow for that change to be reviewed by the Board.

In addition, OEB staff argues that Hydro One should quantify the 2018 impact of the Accelerated Investment Incentive program in the Draft Rate Order and confirm that it will record that amount in the new sub-account of Account 1592, as directed in the OEB's July 25, 2019 letter.[572] Hydro One disagrees with staff's submission in this respect. This is because, as indicated in response to OEB-208(c), the 2018 tax return did not incorporate the new Accelerated CCA rules given that the statute was enacted on June 21, 2019 while the filing deadline was June 30, 2019. However, it is important to recognize that, as further indicated in response to OEB-208(c), the total CCA deductions that are available over the life of an asset

[570] OEB Staff Submission, p. 95.
[571] OEB Staff Submission, p. 95.
[572] OEB Staff Submission, p. 96.

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, additional deductions will be available to be applied to the benefit of ratepayers in subsequent years. More importantly, it should be noted that the estimated impact of accelerated CCA on Hydro One's transmission business for 2018 is only $0.2M, which is not material in the context of Hydro One's Transmission materiality threshold. While Hydro One expected this amount to be immaterial, as indicated in response to OEB Staff Interrogatory #208, it has only recently been quantified by the company.

As noted, OEB staff comments on the manner in which the revenue requirement impact of the Accelerated Investment Incentive should be tracked in Account 1592. In particular, OEB staff states that "for the 2019 revenue requirement impact of the (Accelerated Investment Incentive) program, Hydro One provided an estimate as part of its response to interrogatories. OEB staff submits that the amount that gets tracked in the new sub-account of 1592 should be based on the actual impact, once it is known".[573] The referenced interrogatory response is OEB-208(e). First, Hydro One notes that 2019 is not part of the present Application – the test period is 2020 to 2022. Second, Hydro One does not agree with OEB staff's assertion that the amount that gets tracked should be based on the actual impact once known. As Account 1592 was intended to capture variances arising from changes in tax legislation, the amount should be calculated based on the differences in taxes due to applying the Accelerated Investment Incentive program to the capital additions that are estimated to be eligible for enhanced CCA based on the 2019 revenue requirement. Doing so would ensure Account 1592 solely captures the tax impact of the accelerated CCA on the planned in-service capital as included in the rate filing. As such, Account 1592 would not be calculated using actual capital additions, which would capture variances in CCA that are beyond the scope of the changes in tax legislation that are to be tracked. Therefore, the Board should not accept OEB staff's submission on this aspect.

Based on the foregoing, Hydro One submits that the Board should find that the amounts proposed to be included in the revenue requirement for income taxes, including consideration of the Accelerated Investment Incentive (Federal Bill C-97), are appropriate.

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[573] OEB Staff Submission, p. 96.

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

As described in its Argument in Chief, Hydro One retained Foster Associates to prepare an independent depreciation study that involved a review of Hydro One's existing depreciation rates and the provision of updated rates for the Application. Foster Associates has prepared, and the OEB has accepted, such studies and updates since 2006, including most recently for the transmission business in EB-2016-0160.[574] Hydro One confirms that OEB staff, in Table 20 of its submission, has accurately identified the amounts that Hydro One seeks to recover as its depreciation and amortization (collectively referred to as depreciation) expense over the Custom IR term. This table is reproduced below. In addition, as explained in Argument in Chief and noted by OEB staff, implementing the proposed depreciation rates results in a lower depreciation expense by approximately $14 million over the 2020-2022 rate period, relative to maintaining the existing depreciation rates.[575]

Table 16-1: Proposed 2020-2022 Depreciation and Amortization Expense[576]

($M)	2020	2021	2022	Total
Depreciation Expense	$474.5	$503.4	$528.9	$1,506.8

OEB staff in its submission accepts Hydro One's proposed depreciation expense and notes that they were determined by an independent study by a third-party consultant with significant experience in the field, and which has prepared the depreciation studies underpinning the rates arising from prior Hydro One applications using the same methodology.[577]

Five intervenors – AMPCO, BOMA, CCC, LPMA and SEC - have made submissions in respect of Hydro One's proposed depreciation expense, which Hydro One responds to below. The submissions from these intervenors arise from their concerns regarding the extent of the increase in depreciation expense beginning in the 2019 bridge year and continuing over the 2020 to 2022 period, and/or the extent of the variances between Hydro One's forecast and

[574] Hydro One, Argument in Chief, pp. 100-101.
[575] See Hydro One Argument in Chief, p. 101 and OEB Staff Submission, p. 98.
[576] Exhibit J1.1, Table 2.
[577] OEB Staff Submission, p. 98.

actual depreciation expenses that can be seen during the historical period.[578] Hydro One's proposed depreciation expense for the 2020 to 2022 test years, as well as for the 2015 to 2018 historical and 2019 bridge years, are presented in Table 1 of Exhibit F, Tab 6, Schedule 1. The total proposed depreciation expense was further updated in Exhibit J8.5, Table 2. In addition, a comparison between forecast/approved and actual depreciation for the historical years is presented in response to AMPCO Interrogatory #87. The information from these sources has been consolidated into the following table.

Table 16-2: Historical and Forecast Depreciation Expense Breakdown

	Historical												Bridge	Test		
	2015			2016			2017			2018			2019	2020	2021	2022
	Approved	Historical	Variance	Approved	Historical	Variance	Approved	Historical	Variance	Approved	Historical	Variance	Forecast	Forecast	Forecast	Forecast
Depreciation on Fixed Assets	349.2	339.0	(10.2)	364.1	350.8	(13.3)	381.3	370.6	(10.7)	402.0	387.3	(14.7)	416.7	420.9	439.7	461.6
Less Capitalized Depreciation	(6.4)	(9.0)	(2.6)	(6.7)	(12.0)	(5.3)	(12.1)	(12.6)	(0.5)	(12.8)	(13.0)	(0.2)	(13.1)	(13.3)	(13.5)	(13.6)
Asset Removal Costs	38.1	29.0	(9.1)	33.7	34.6	0.9	53.4	38.3	(15.1)	69.2	37.7	(31.5)	57.3	54.1	59.7	61.5
Losses/(Gains) on Asset Disposition	-	-	-	-	(0.1)	(0.1)	-	(2.0)	(2.0)	-	(0.5)	(0.5)	-	-	-	-
Total	**380.9**	**359.0**	**(21.9)**	**391.1**	**373.3**	**(17.8)**	**422.6**	**394.3**	**(28.3)**	**458.4**	**411.5**	**(46.9)**	**460.8**	**461.7**	**485.9**	**509.5**

There are, in essence, four submissions from intervenors on this issue, as follows.

a) Three of the intervenors argue that Hydro One's depreciation expense for the 2020 to 2022 test years should be reduced. In particular, AMPCO, CCC and LPMA suggest that the OEB adjust Hydro One's test period forecast depreciation expense based on the average historical variance, which LPMA calculates at 6.8% but AMPCO and CCC appear to have rounded up to 7%.[579] As discussed below, Hydro One submits that the Board should reject this intervenor proposal.

[578] See AMPCO Submission, pp. 27-28, BOMA Submission, p. 39, CCC Submission, pp. 5 and 17, LPMA Submission, pp. 17-21, and SEC Submission, pp. 19-22.

[579] See AMPCO Submission, p. 28, CCC Submission, p. 17 and LPMA Submission, p. 20.

b) One intervenor – BOMA – suggests that a variance account be established to reflect the impact on depreciation expense from the redirection process or other substitution of projects for the projects included in the forecast capital expenditure budget with different depreciation rates, to reflect the difference between the depreciation forecast in the application for 2020 to 2022 and the actual depreciation incurred in each of those years.[580] As discussed below, Hydro One proposes an alternative approach to the variance account proposed by BOMA.

c) One intervenor – LPMA – argues that the OEB should direct Hydro One to provide a study in its next rebasing application as to why the actual depreciation expense is consistently lower than that which it has forecast.[581] As discussed below, Hydro One proposes a variation of LPMA's suggestion.

d) Two intervenors – CCC and SEC – make submissions in respect of using the CISVA as a mechanism for addressing the issue of historical variances in depreciation expenses. More particularly, CCC suggests that, as an alternative to the 7% reduction it proposed, that the Board "could require HON to flow through its actual depreciation expense in the CISVA"[582] and SEC argues that, if the Board approves the CISVA as proposed by Hydro One then it should do so on certain conditions, one of which is that it should be used to track all capital related variances regardless of the cause, including variances in depreciation and taxes that are caused by the changes in the actual assets that Hydro One puts into service.[583] These submissions, which focus on Hydro One's proposed modifications to the CISVA, are addressed under Issue 23. However, in general Hydro One's view is that the CISVA is not an appropriate mechanism to address intervenor concerns with historical variances between forecast and actual depreciation expenses, and that doing so would not be consistent with incentive-rate setting, would not support the decoupling of rates from costs, and diminishes the Custom IR framework through the truing up of costs to actuals rather than employing the formulaic approach that Hydro

[580] BOMA Submission, p. 39. Hydro One assumes BOMA's reference to the account reflecting the impact on depreciation "rates" is intended to mean the impact on depreciation "expense".

[581] LPMA Submission, p. 20.

[582] CCC Submission, p. 17.

[583] SEC Submission, p. 22.

One has proposed. Moreover, given that Hydro One is proposing an ESM account this proposal would be redundant and would add significant and unnecessary complexity to the administration of the CISVA.

In response, Hydro One first reiterates that OEB staff has accepted the proposed depreciation expense and no parties have taken issue with Hydro One's proposed amortization costs, its updated depreciation study or the impacts on the proposed depreciation expense resulting from the updated depreciation rates identified in the study.[584] As such, the balance of the reply on this issue relates to the intervenor concerns regarding the historical variances in Hydro One's depreciation expense. To address those concerns, Hydro One submits that it is essential to look at the component parts of the depreciation expense and, in particular, to distinguish between the two main components of (a) depreciation on fixed assets, and (b) asset removal costs.

Depreciation on Fixed Assets

Depreciation on fixed assets is by far the most significant component of Hydro One's depreciation expense, representing approximately 90% of the total each year. The purpose of incurring a cost for depreciation on fixed assets is for the utility to recover its investments in plant incrementally throughout the service lives of its assets. This supports the objective of having today's customers pay for a proportionate share of the cost of the assets that are used to provide them with service, while ensuring that future customers also pay for a proportionate share of the cost of the assets that are used to provide them with service.

Determining how quickly to recover investments through depreciation can greatly impact both ratepayers and the utility. An excessive depreciation expense will result in higher rates, increased cash flow for the utility, and a reduction in the utility's return on investment as the rate base is quickly depleted. Conversely, an insufficient depreciation expense will result in lower rates, decreased cash flow for the utility, and a greater return on the utility's investment as the assets remain in rate base longer. A reasonable depreciation rate is one that appropriately balances these interests.

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[584] See for example LPMA Submission, p. 17.

Though calculating a depreciation rate is simple in concept, the realities of utility operation introduce complexities into the calculation. While accuracy is important, because of the number and range of assets used to provide service, individual unit depreciation is not practical. Moreover, estimating precise service lives and final salvage values for assets, sometimes forty or more years in the future, verges on impossible. Changing utility practices, markets, technology, and regulatory forces can further affect the ability to estimate depreciation rates. To accommodate these complexities, depreciation models have been developed which combine both analysis and the use of professional judgment from experienced depreciation actuaries, such as Hydro One's expert Foster Associates, to produce rational and supportable depreciation rate projections. A significant amount of time, care and expertise goes into developing and from time to time updating the depreciation rates.

For the historical period of 2015 to 2018, Hydro One had relatively small variances between its forecast/approved depreciation on fixed assets and its actual depreciation on fixed assets, averaging just 3.2% over this period. In Hydro One's view, this amount of historical variation is reasonable and does not support an adjustment to Hydro One's forecast depreciation on fixed assets during the test years. As explained by Mr. Chhelavda of Hydro One during the Oral Hearing, depreciation on fixed assets is a function of the mix of assets. When Hydro One plans work, it has expectations as to the particular assets that will be placed into service and when. However, during the implementation period Hydro One uses a redirection process to reprioritize some work over other work as needs and circumstances change. Where those changes result in assets having higher depreciation costs coming into service sooner and assets having lower depreciation costs coming into service later, or being scaled back or deferred, this can result in changes to Hydro One's overall cost of depreciation on fixed assets and thereby give rise to variances relative to plan.[585] This is consistent with Hydro One's understanding that a utility is provided with the flexibility and responsibility to carry out the particular projects and programs that it determines are needed to meet performance and customer needs within the overall funding envelope provided through rates, rather than being bound to execute work strictly in accordance with the plans used to inform their approved rates.[586] Because of the need for such flexibility, changes in the mix of assets put into service are to be expected, and with that there is

[585] Oral Hearing Transcript, Vol. 5, p. 86.
[586] See *Handbook*, p. 9; and EB-2016-0160 Decision and Order, p. 31.

a corresponding expectation that there will be changes in depreciation on fixed assets relative to plan.

Asset Removal Costs

Asset removal costs are the second main component of Hydro One's depreciation expense, representing approximately 10% of the total each year. Hydro One acknowledges that, with the exception of 2016, there have been material variances between its forecast/approved asset removal costs and its actual asset removal costs incurred during the 2015 to 2018 historical period. For context, asset removal costs consist of the costs associated with removing old assets, such as the costs of digging up old foundations or removing old equipment. Most of these costs are labour and equipment costs, rather than costs for materials. Asset removal costs are included as a component of Hydro One's depreciation expense because, in an income statement, components are either classified by their nature or by their function. Classifying expenses according to salaries, electricity, repairs, etc. is referred to as classifying expenses by their nature. To report expenses by function means to report them according to the activity for which the expenses were incurred. The reporting of expenses by function means the income statement will report expenses according to the following functional classifications: cost of power, operations, maintenance & administration, depreciation and amortization and financing. Functional classification of expenses requires grouping similar expenses. Accordingly, expenses such as depreciation, amortization and asset removal costs are grouped together due to their similar characteristics.

Hydro One identified the historical variances in its transmission asset removal costs during its investment planning process which underlies the present Application. As a result, Hydro One updated its transmission planning assumptions to reflect lower removal costs. Specifically, Hydro One reduced the assumed cost of asset removals from 12% to 8% for transmission lines, and from 8% to 4% for transmission stations.[587] Therefore, when forecasting asset removal costs for purposes of calculating the depreciation expense proposed in this Application, Hydro One assumed that where a transmission line is being removed and replaced, the costs of removal represent 8% of the cost of the new line rather than 12%, and where a station is being

[587] The asset removal assumptions from an initial planning perspective were reviewed and updated to align with recent historic actual rates, which were 8% and 4%.

removed and replaced that the cost of removal represents 4% of the new station cost rather than 8%. Hydro One anticipates that these changes in planning assumptions will, during the test years, significantly reduce or eliminate the variances that were observed for asset removal costs during the historical years. However, Hydro One is continuing to monitor and consider this issue, and to assess and refine its approach to asset removal costs, as appropriate.

Although Hydro One has changed the planning assumptions that it uses to determine its forecast asset removal costs, the impacts of that change are not obvious when considering the test period asset removal cost relative to historical levels. This is attributable to Hydro One's increasing work program needs, the impact of which has masked the impact of the updated planning assumptions that otherwise would have lowered the asset removal costs relative to levels previously approved by the OEB.

Hydro One plans to stay on top of this issue during the test period by actively monitoring and tracking its actual asset removal costs against the forecasts, which reflect the revised planning assumptions and are embedded in the overall depreciation expense that has been proposed. To the extent that Hydro One sees significant variances continuing, it would carry out internal analysis to determine what is driving these variances and develop corresponding solutions.

In Hydro One's view, 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 as noted above the historical variances in respect of the depreciation on fixed assets component have been relatively small and within the range of reasonableness. Applying such an adjustment would significantly undermine and effectively negate the 3rd party expert opinion and recommendations from Foster Associates on the appropriate depreciation rates that are to be applied. This is because a blanket adjustment of 6.8% or 7% to the total depreciation expense would effectively reduce Hydro One's recovery of depreciation on fixed assets to a level that is outside what Foster Associates has determined would be reasonable, based on a methodology that the Board has accepted repeatedly in prior proceedings.

Rather, in Hydro One's view, 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 an extent, ratepayers will be protected from discrepancies between forecast and actual asset removal costs, by means of the proposed ESM, which is described in Exhibit A, Tab 4, Schedule 1, pp. 9-10. However, recognizing BOMA's submission that the ESM would not completely address this given the proposed 100 basis point deadband in the ESM, Hydro One submits that the issue of its variances in the asset removal costs component of its depreciation expense would most appropriately be addressed:

- Through Hydro One's above-noted commitment to actively monitor and track its actual asset removal costs against the forecasts that reflect its revised planning assumptions, and to report on this in its next transmission rebasing application; and

- By establishing 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. The account will be brought forward to be cleared at the end of the Custom IR period in the event that there is an over collection on a cumulative basis over the 2020 to 2022 period. This account would further protect customers in the event the revised planning assumptions do not substantially resolve the discrepancy during the test period and would provide a strong incentive in such circumstances for Hydro One to have addressed this issue by the time it returns to the Board for its next transmission rebasing application. The annual impact of any over/under collections would be excluded from the annual ESM calculation in order to avoid double counting.

While Hydro One does not believe that this account is necessary given the steps it has already taken to address the issue of historical variances in asset removal costs, Hydro One understands the concern and proposes this account as a means of providing the Board and parties with additional comfort on this issue during the test period. It would be Hydro One's objective to eliminate the need for the account thereafter, assuming the cause(s) of the historical variances prove to have been sufficiently mitigated.

Based on and subject to the above, Hydro One submits that the Board should find the proposed depreciation expense to be appropriate.

F. COMPENSATION COSTS:

Issue 17: Are the compensation related costs appropriate?

As described in the Argument in Chief, Hydro One's compensation costs are appropriate. Hydro One has taken prudent steps to efficiently manage its costs and the size and use of its work force, while accomplishing significantly growing work programs and delivering on important outcomes.

OEB Staff and a number of intervenors take issue with the fact that Hydro One's overall compensation costs remain somewhat above market median and suggest that further reductions should be made. The record shows, however, that Hydro One 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. These realities include: Hydro One's largely unionized workforce and governing collective agreements with which it must comply; the need to attract and retain an appropriate workforce; and the magnitude of Hydro One's capital work program.

Hydro One has also recently made further reductions to the amount of compensation for recovery in revenue requirement since the 2017 Mercer Study was conducted. These reductions bring Hydro One's overall compensation costs even closer to market median.

We address these points in the sections below and reply to the specific concerns raised by OEB Staff and intervenors.

Hydro One Has Made Progress Towards Bringing Its Compensation to Market Median

While a number of parties have acknowledged that Hydro One has made progress in reducing its compensation levels towards market median, OEB Staff and certain intervenors argue that Hydro One is not making sufficient advances in this regard.[588] Hydro One submits that it has made and continues to make significant progress to reduce its overall compensation costs towards alignment with the market median and that the steps it has taken in this regard are

[588] OEB Staff Submission, pp. 104-105, 108; SEC Submission, paras. 5.2.8-5.2.14; CME Submission, paras. 194-203; VECC Submission, para. F2; Energy Probe Submission, pp. 25-27, CCC Submission, p. 20.

reasonable in the circumstances. The benchmarking studies show improvements by Hydro One, with various categories of employees being at, or very close to, market median levels.

In respect of management and non-represented employee compensation, Hydro One's compensation program is targeted to pay approximately at the market median, based on a multi-faceted approach founded on best practices, as outlined in the Argument in Chief. This approach allows Hydro One to balance the competing demands of attracting, retaining and incenting management and non-represented employees with maintaining compensation costs at appropriate levels and being responsive to OEB and stakeholders concerns.

In this regard, the 2017 Mercer Study confirms that Hydro One management and non-represented total compensation is in fact positioned at essentially market median – it is 1% above market median. Similarly, the Willis Towers Watson benchmarking study for management and non-represented employees shows that while the Executive and Operations compensation is below market on a Total Direct Compensation basis, the Core Service compensation structure is slightly above market to address internal compression issues, particularly at first level management roles and to preserve a reasonable internal differential relative to the Operations segment.[589] Willis Towers Watson in fact recommended a salary increase budget of 2.5% for management, whereas this application assumes only a 2% escalation in 2019 and 2020.[590]

Further, Hydro One has removed the full cost of its executive leadership team compensation from the revenue requirement.

In respect of represented staff, while Hydro One remains above market median, it has made progress in this regard and must work within the constraints of the existing bargaining process and collective agreements. Hydro One has been successful in incrementally reducing costs and/or increasing productivity through collective bargaining. For example, over the 2016-2019 period, Hydro One has managed to contain its wage increases to a level below the consumer price index ("CPI"). The average CPI increase over this period was 1.8%; whereas the average wage increases for SUP employees was 0.9%, and for Power Workers Union ("PWU")

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[589] Exhibit F-4-1, pp. 18-24; Hydro One, Argument in Chief, pp. 104-106.
[590] OEB-178 (c); Oral Hearing Transcript, Vol. 5, pp. 148-149.

employees was 1.45%. Managing base wage costs has a multiplier effect on savings in labour burdens including pension, benefits and overtime costs.[591]

In respect of all groups of employees, Hydro One has been successful in taking steps to significantly reduce its pension costs. These include steps to increase employee contributions and reduce benefits with all employee groups. In particular, Hydro One has demonstrated this commitment to reducing pension costs by:

- making incremental increases in employee pension contributions for all employee groups;
- improving the ratio of employer and employee cost sharing by moving towards the 50%-50% cost sharing ratio;
- closing the Defined Benefit Pension for new Management employees and introducing a lower cost Defined Contribution Plan; and
- changing the early undiscounted pension thresholds for PWU and legacy SUP employees starting in 2025.[592]

As a result of these steps taken by Hydro One, over the period 2013 to present, employee contributions have increased from 20% to 40% as a whole, resulting in a meaningful reduction in costs borne by customers. For the years 2018 and 2019, these steps to reduce pension costs have resulted in savings for customers of approximately $22 million annually (on average) and this level of savings is expected to continue over the 2020-2022 period.[593]

Hydro One's efforts over the recent years have resulted in a 5% improvement in overall compensation levels relative to market in the time period 2008 to 2017, as evident from the 2017 Mercer Study (a reduction from 17% to 12% above median).[594] The 2017 Mercer Study

[591] Oral Hearing Transcript, Vol. 6, pp. 57-58, 123-124; Hydro One, Argument in Chief, p. 106.
[592] Exhibit F-4-1, pp. 38-41.
[593] Exhibit F-4-1, p. 40; and J4.11; Oral Hearing Transcript, Vol. 4, p. 117.
[594] Exhibit F-4-1, Table 8.

also included additional forms of Hydro One compensation (such as share grants and lump sum payments) compared to prior studies, but Hydro One's compensation was still trending lower.[595]

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, that is a misleading or unfair suggestion. As Mr. Morris of Mercer explained, each study is predominantly a point in time comparison of Hydro One's total compensation to market median. For each study, the comparator group changes for a variety of reasons and, as a result, some changes in market study results may be occurring as comparators are changing. In light of this, one should look at the longer-term trends. As stated, 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 (as a result of certain compensation elements in that year, including one-time share grants and lump sum payments negotiated to offset significant ongoing increased employment pension contributions).[596]

Further, Mercer's updated benchmark analysis – updated and projected to October 1, 2020 based on certain assumptions it considered reasonable – is that Hydro One's overall compensation levels are projected to be only 10% above market median.[597]

In order to ensure that Hydro One has continued, and will continue going forward, to make further incremental progress in bringing its compensation costs to market median, Hydro One regularly undertakes the following initiatives:

- benchmarking the compensation levels relative to the external market to assess competitiveness – the results of these studies are used to inform future compensation decisions, labour negotiations and potential program revisions;
- 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 – for example, as an outcome of the most recent round of bargaining with the

[595] Exhibit F-4-1, p. 37, and Exhibit F-4-1, Attachment 2, p. 3.
[596] Oral Hearing Transcript, Vol. 5, pp. 10-11; OEB-173.
[597] Energy Probe-21.

SUP, a committee was formed between management and the union with a mandate to review compensation programs and propose potential improvements; and

- engaging with third party independent experts to provide guidance on industry best practices and compensation.

Also, when considering this issue of Hydro One's compensation levels relative to market median, it is important to bear in mind the realities of Hydro One's situation and of constrains within which it must operate. These realities include its largely unionized workforce and collective agreement constraints, and the need to staff appropriately to perform its growing capital work program and delivery on outcomes that are important to customers. When OEB Staff baldly asserts (with no specifics as to steps to be taken or how they can be taken) that "Hydro One's level of compensation is not moving towards the market median at an acceptable pace,"[598] OEB Staff is simply ignoring these realities, as are the intervenors who make a similar suggestion.

In this regard, it must be kept in mind that Hydro One has a legacy inherited from its predecessor, Ontario Hydro. Hydro One's labor force is 90% unionized and having collectively bargained agreements that it is unable to unilaterally alter is the context in which Hydro One operates. The prudence of Hydro One's decisions should be evaluated in that context. The legacy agreements established the 'floor' upon which future negotiations have been and will continue to be based.

While legacy collective agreements inevitably continue to strongly influence current Hydro One collective agreements, Hydro One has nonetheless done much to change the status quo. It has made reasonable, incremental progress in reducing costs and/or increasing productivity through collective bargaining, as referred to above.

What also should be kept in mind is that Hydro One has taken prudent steps to manage costs relative to its growing capital work program. While the transmission business work program is growing by approximately 26% between 2019 and 2022, Transmission related compensation costs are, by contrast, only growing by 12% over this period, or 4% per annum (in part

[598] OEB Staff Submission, p. 109.

attributable to escalations and growing workforce, including requisite FTE increases) – which is less than half of the extent of the increase in work program. Compensation costs as a percentage of total work program costs are improving from 48% in 2014 to 44% in 2022. Compensation costs as a percentage of total Transmission cost are improving from 49% to 40% in 2022.[599]

While the 2020 transmission-allocated costs represent an increase over 2019 levels, the increase is reasonable and necessary (and FTE levels are reasonable),[600] as it is mainly driven by additional resourcing requirements necessary to execute Hydro One's expanded work programs over the test period, and by negotiated wage increases in compensation for Hydro One's represented staff. These increases are offset by the reduction in vacancies for common corporate functions, and also by the further 7% reduction in staffing budget dollars that was layered in at the end of the budgeting process.[601]

Hydro One is managing by utilizing a work-based approach to staffing, whereby the resources are allocated according to work programs rather than planning the work around the number of internal resources available. To address the fluctuating and seasonal nature of work programs, Hydro One maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, temporary, PWU Hiring Hall, casual construction and contract staff. Hydro One has a very rigorous process to manage its headcount in year. As was explained during the oral hearing, "…we certainly track our headcount on a monthly basis, we provide that information to our executives, and we also have an approval to hire process. So, it is not just the fact that, you know, we have an approved FTE level and therefore everyone goes out and hires."[602] This allows Hydro One to be efficient and contain compensation costs.

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[599] Exhibit F-4-1, p. 32.

[600] In its submissions, OEB Staff raises no specific concerns in respect of transmission FTEs. OEB Staff notes Hydro One's confirmation that its work program drives the FTEs, and further that the increase in 2019 in respect of the transmission work program is primarily caused by the transfer of non-regular lines apprentices from the distribution business to transmission (OEB Submission, p. 101).

[601] Exhibit F-2-1, p. 1, Oral Hearing Transcript, Vol. 5, pp. 106-108.

[602] Oral Hearing Transcript, Vol. 5, p. 161.

Accordingly, Hydro One submits that its relatively modest increase in costs relative 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.

Recent reductions to Amount of Compensation For Recovery In Revenue Requirement

Besides the above steps and progress Hydro One has made to bring its compensation costs closer to market median, Hydro One has also reduced the amount of compensation for recovery in revenue requirement since the 2017 Mercer Study was completed. These reductions effectively bring Hydro One's overall compensation costs even closer to market median. The difference to market median reflected in the 2017 Mercer Study should be updated to reflect these further offsetting reductions, consistent with the OEB approach in its EB-2017-0049 decision.[603]

The variance between the Mercer Study market median and Hydro One compensation as well as the reductions included in this application related to OM&A are set out in the table below:

Net Mercer Median Reductions Allocated to OM&A ($M)	**2020**
Mercer Median – Tx OM&A	10.1
Pension Reduction OM&A	(5.5)
OPEB Reduction OM&A	(2.4)
Executive Comp. Reduction	(1.5)
The Directive	(0.1)
Total Net Mercer OM&A Reductions	0.5
Updated Pension Reduction OM&A	(1.7)
Total Net Mercer OM&A Reductions	(1.2)

- Mercer Median (+$10.1 million) is the OM&A component of the transmission allocated portion of $38.6 million;

[603] EB-2017-0049 Decision and Order, p. 111.

- the current revenue requirement reflects the reduced pension OM&A costs (-$5.5 million) due to the actuarial valuation as of December 31, 2017 completed by Willis Towers Watson (Exhibit F, Tab 5, Schedule 1, Attachment 1);
- the current revenue requirement reflects the reduced OPEB OM&A costs (-$2.4 million) as a result of the latest valuation which is provided in Staff-205;
- the current revenue requirement reflects the reduced executive compensation OM&A costs (-$1.5 million) identified in EB-2018-0130, Exhibit I, Tab 7, Schedule 3, p. 2 to be in compliance with Bill 2;
- as part of the blue-page update Hydro One further reduced its OM&A (-$0.1 million) by factoring the Ontario Government Directive issued on January 1, 2019 as discussed in Exhibit F, Tab 4, Schedule 1, p. 35 and also identified in Exhibit F, Tab 1, Schedule 1, p. 3; and
- as a result of the updated actuarial pension valuation as of December 31, 2018, which Hydro One provided in the updated response to JT 2.31, pension OM&A costs are further reduced by (-$1.7 million).

Some intervenors seek to have the OEB ignore these further reductions, when there is no proper basis to do so and this suggestion by intervenors is contrary to the OEB's approach in EB-2017-0049. In that decision (in Hydro One's last Distribution application), the OEB expressly rejected this same type of suggestion by intervenors. In that case, Hydro One had made certain compensation-related reductions to the revenue requirement since the time of the 2017 Mercer Study. The OEB concluded that those reductions should be taken into account in determining the final net amount by which Hydro One remained above market median.[604] The OEB stated:

> The OEB agrees that these reductions should be taken into account…given that Hydro One has already made compensated related reductions totaling $12.2 million following the Mercer study, and the OEB is making a further reduction of $0.5 million associated with the Hydro One Accountability Act… the ***net reduction*** to Hydro One's OM&A related compensation is $4.8 million. (emphasis added)

[604] EB-2017-0049 Decision and Order, p. 111.

The same approach should be taken here, meaning that the reductions in the table above – which represent actual savings to the revenue requirement – should be factored in.

In fact, based on the most recent pension valuation, the current OM&A ask in the application reflects reductions which are actually larger than the OM&A component of compensation costs that was above market median based on the 2017 Mercer Study – i.e. the OM&A amount above market median for 2020 (based on the Mercer Study) was $10.1 million, but these reductions shown in the table above amount to $11.3 million. In other words, in respect of the OM&A portion of compensation costs, Hydro One is actually seeking recovery in revenue requirement of an amount that is $1.2 million *below* market median, and Hydro One is not asking that the revenue requirement be increased by that amount.[605]

In respect of the above reductions, SEC submits that Hydro One's pension and OPEB reductions have nothing to do with the pension and OPEB amounts that are part of the Mercer calculation.[606] However, 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. The assumptions and methodology are set at the time the study is completed and are not updated post-study. The assumptions and methodology used in its assessment of pension and OPEB differ from an actuarial valuation. Hydro One's proposed pension and OPEB reductions are based on recent actuarial valuations and will directly impact ongoing costs of providing these programs making them relevant in determining the revenue requirement. As stated, these reductions represent actual savings.[607]

SEC also takes issue with Hydro One's approach to remove executive compensation from the above-market median compensation.[608] The Mercer Study includes a representative sample of benchmarked Management (MCP) jobs to assess market compensation levels and it excludes "executives". The removal of the full cost of executive compensation is another example of actual cost savings to revenue requirements. Furthermore, Bill 2 applies only to Hydro One

[605] Oral Hearing Transcript, Vol. 5, p. 152.

[606] SEC Submission, paras. 5.3.3 and 5.3.4.

[607] SEC also refers to the existence of the pension variance account, but this does not change the fact that Hydro One has lowered costs and lowered the revenue requirement.

[608] SEC Submission, paras. 5.3.5 and 5.3.6.

Limited, and there were only three executives in that company. However, Hydro One went beyond the strict legal requirements and removed compensation of its executive leadership team, which is a broader group of executives.[609]

In its submissions, OEB Staff accepts the above reductions that have been made in respect of the OM&A component of compensation costs, resulting in an amount in Hydro One's proposed revenue requirement that is below market median. Its submissions then state that: "OEB Staff accepts Hydro One's position that it does not need to add any amounts to Hydro One's requested OM&A related to compensation to bring it to the market median amount."

Even though Hydro One is recovering in revenue requirement $1.2 million below market median in respect of the OM&A component of compensation, OEB Staff nonetheless goes on to suggest that there should be a $1.7 million reduction to revenue requirement relating to the capital component of compensation costs that are above market median.[610] Hydro One disagrees with this suggestion for the following two main reasons:

- First, if the objective is to have the compensation costs reflected in revenue requirement be at market median, this should be done on an overall basis, taking into account both the OM&A and capital components of compensation costs. There is no principal basis to ignore the fact that Hydro One is below median in respect of OM&A. On an overall (or net) basis – taking into account both OM&A and capital – Hydro One is only seeking to recover in revenue requirement $0.5 million above market median (i.e. the net of being $1.7 million over on capital and $1.2 million under on OM&A).
- Second, OEB Staff's suggested approach may result in double-counting. In the event the OEB were to make any reduction to Hydro One's capital-related revenue requirement in this application, the Board should follow its approach in the most recent transmission rate decision and not make a compensation-related capital reduction. In the last transmission rate proceeding, the Board noted that it "appreciates that a portion of total compensation costs are in budget amounts included in transmission capital projects" and

[609] Oral Hearing Transcript, Vol. 6, p. 67.

[610] OEB Staff calculates that the capital component of compensation costs in revenue requirement is $1.7 million above market median, but it invites Hydro One to correct this amount in its reply submissions.

> since the Board had already decided to make a reduction to the capital budget, this would have some compensation reduction impact.[611]

Accordingly, Hydro One submits that no reductions to compensation costs in revenue requirement are warranted. Alternatively, if the OEB were inclined to make any such reductions, it should only be the overall (net) amount of $0.5 million as stated above.

SEC makes the novel 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. This suggested approach is inconsistent with the OEB's prior decisions and approach, including in the most recent Hydro One Transmission decision.[612] It is also inconsistent with the *Handbook* which provides that, if the OEB determines that a specific project or program has not been adequately justified, this may result in a reduction to the requested revenue requirement and that it is the utility's responsibility to operate its system, and undertake the projects and programs within the funding provided through rates. According to the *Handbook*, this provides the utility with the responsibility and flexibility to meet its obligations in ways which benefit customers and the utility.[613] The OEB should not deviate from this well-established approach here in the event it is inclined to make any reduction.

CME and CCC suggest that the OEB, in its decision in this case, should make an order requiring Hydro One to file a plan in its next joint application showing how its compensation costs will be at the 50th percentile market median by the end of that Custom IR term, i.e. by 2027. The OEB should decline to make such an order in this case. First, at issue in this application is the 2020-2022 plan period, not future periods. Second, the type of order being suggested would not be practical at this stage, including because 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 in recent history. Hydro One does not unilaterally determine wages for unionized employees, who represent over 90% of the workforce. Given the nature of the collective bargaining process, the plan CME and CCC

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[611] EB-2016-0160 Decision and Order, pp. 58-59.
[612] EB-2016-0160 Decision and Order, p. 62; EB-2013-0416 Decision and Order, pp. 24-25.
[613] *Handbook*, p. 9.

requests would hinder Hydro One's ability to bargain effectively and in good faith (and would involve disclosing bargaining strategy for future cycles).

In addition, as Mr. Morris has articulated, market compensation is a moving target as companies work to minimize compensation costs while reacting to labour market changes in demands and costs for key technical and operational skills. Compensation costs for the 2023-2027 should be based on robust market data gathered closer to that time. 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. Hydro One has made significant progress in managing costs and intends to continue to do so. Hydro One will present its future compensation costs evidence in the joint application and it can be assessed by the OEB and all parties in that proceeding.

In the sections below, we address some specific items in respect of Hydro One's compensation costs on which OEB Staff or intervenors have made submissions.

Proposed burden amounts are appropriate and have been fully justified

As part of its submissions, OEB Staff takes issue with Hydro One's proposed burden amounts and submits that there was unexplained differences between their calculations and Hydro One's.[614] In fact, there are no unexplained differences – proper explanations have been provided in Undertaking, J6.1.

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. Put simply, OEB Staff's calculations are incorrect. Hydro One has completed an FTE-based analysis in J6.1 Attachment 1, which is a reproduced version of OEB Staff exhibit, K6.1 and provided additional commentary based on a compound annual growth rate per FTE which is the more appropriate way to review compensation costs over the application term. Furthermore, the burdens calculation is largely a reflection of the escalation and excluding pension and OPEB remain relatively constant.

Contractors Costs Are Appropriate and Not Overstated

[614] OEB Staff Submission, pp. 110-111.

OEB Staff also submits that the amounts paid to contract staff may mask a higher level of compensation being paid out than that reflected in the requested 2020 compensation amount.[615] That is not in fact the case and OEB Staff's submissions ignore the fact that compensation costs for a contractor are not equal comparisons to a regular FTE. There are different structures of compensation and methodologies involved. Generally speaking, a contractor does not have all of the associated labour burdens, so they would be more cost effective in that regard and often are used on a projected basis.[616]

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. Further, the labour rates in the construction trades within Ontario are set at the sector level.[617]

STIP and LTIP Programs Are Appropriate and Provide Benefits to Ratepayers

Some intervenors suggest that Hydro One's STIP and LTIP programs are expensive and have limited benefit to ratepayers.[618] There is no basis for that suggestion on the evidentiary record, and it ignores key evidence provided by Hydro One during the oral hearing. Hydro One's Director, Compensation & Human Resources Analytics (Ms. Lila) explained that the main objective of the STIP and LTIP programs is to encourage and incentivize employees to deliver efficiency improvements and productivity savings in key corporate metrics. Hydro One established key corporate metrics in areas that are important to the organization, its customers and the general public as they include metrics in areas such as health and safety, work program delivery and reliability.[619]

Hydro One utilizes a rigorous process to review its incentive programs and ensure that they are appropriate and fair. Hydro One has recently updated its STIP program to reduce its individual performance multiplier level to align with the *Hydro One Accountability Act.*[620] Hydro One also benchmarks its STIP and LTIP programs to ensure that they are comparable to and aligned with

[615] OEB Staff Submission, pp. 111-112.
[616] Technical Conference Transcript, Vol. 2, pp. 37-38.
[617] Oral Hearing Transcript, Vol. 2, p. 80; Technical Conference Transcript, Vol. 1, pp. 66-67.
[618] CME Submission, paras. 224-238.
[619] Oral Hearing Transcript, Vol. 6, pp. 129-132.
[620] Oral Hearing Transcript, Vol. 5, pp. 41-42.

the market.[621] As was explained by Ms. Lila in her testimony, the metrics used for incentive compensation purposes goes through a rigorous governance process. Then at year-end, there is a multilayered procedure involving management, the human resources committee of the board, and approval of the board of directors (as well as an audit function). All of these ensures that STIP and LTIP awards are appropriate.[622]

Recovery of Legally Required Pension Contribution Costs in Rates

No party has taken issue with the proposed recovery by Hydro One of its legally required pension costs. OEB Staff specifically confirmed that it accepts the 2020 pension contribution amount, but merely asked that Hydro One provide a table that reconciles that amount with Hydro One's December 31, 2018 pension valuation as part of its reply submissions – this table is provided below.

As explained by Hydro One in the Argument in Chief and demonstrated by the evidence, Hydro One cannot take a contribution holiday during the rate period. As was clear in the evidence, it will be "virtually impossible" for Hydro One to do so.[623] Given this uncontradicted fact, and given that no party takes issue with the proposed recovery by Hydro One of its legally required pension costs, the OEB should allow recovery of these 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.

Reconciliation Table

2020 – Forecast Pension Costs
($ millions)

Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	9	15	2	27
Capital	23	16		39
	32	**32**	**2**	**66**

621 Oral Hearing Transcript, Vol. 6, pp. 130, 134-135.

622 Oral Hearing Transcript, Vol. 6, pp. 136-137.

623 Argument in Chief, pp. 108-110 and the various evidentiary cites there, including Oral Hearing Transcript, Vol. 4, pp. 141-142.

Benchmarking Studies Relied Upon by Hydro One Are Appropriate

Mercer market median is appropriate and not overstated

OEB Staff argues that the Mercer market median may be overstated because it was projected forward at a rate of CPI plus 0.6%, which is higher than inflation of approximately 2%.[624] However, the assumption that average market salary increase, for non-represented employees, will be equal to inflation is factually incorrect. The Mercer market median is not overstated.

Average market salary increases, reported annually since 2008 by Mercer and other reliable research organizations, have exceeded the inflation rate by 1.0% on average. The amount the average market increase exceeds inflation varies by year and is negatively correlated with the inflation rate over that period – the higher the inflation rate the closer the average market increase is to the inflation rate. Given the projected inflation rates for 2018 to 2022 (see OB21 Table 2) the market salary increase is expected to exceed the inflation rate by 0.6% or CPI plus 0.6%. The calculation in Energy Probe's submissions at page 26 does not reflect the actual average market salary increases reported annually since 2008. Energy Probe uses an artificially low rate not representative of true market conditions, and thus its proposed reduction in compensation of $2.3 million over 2021 to 2022 is not warranted.

The Mercer Study calculated the market median based on the study findings. All projections were based on the FTE levels in F-04-01, p. 13 (the updated version). The methodology used to project the "gap" to market median from the base year to 2021 was described in EP-21.[625]

Overtime does not affect benchmarking

Some intervenors suggest that the Mercer Study understates Hydro One's compensation levels compared to the market because it leaves out a significant component of compensation –

[624] OEB Staff Submission, pp. 108-109.
[625] Energy Probe IR 21.

overtime.[626] This suggestion is incorrect and ignores the evidence of Mercer on this point. During the oral hearing, Mr. Morris of Mercer explained that benchmarking overtime is not a common approach and none of the compensation surveys that are completed by major consulting firms in Canada include overtime as a measure. Furthermore, it is very difficult to compare overtime across employers as organizations track overtime differently and there are a lot of variables in terms of how organizations use overtime and why they use it. In light of the foregoing challenges, typical compensation studies look at actual compensation for individuals.[627]

Some intervenors also submit that Hydro One's overtime costs continued to increase without adequate explanation and without added value to ratepayers.[628] This is incorrect. Hydro One explained that overtime varies quite significantly from year to year due to a large portion being attributable to storm restoration efforts, which are hard to forecast. However, this is particularly relevant for the 2017-2018 period as Hydro One experienced significant storm activity in its service territory.[629] Furthermore, overtime results not only from storm restoration work, but also due to outage restorations and bundling of outages for the benefit of customers. Overtime is an element of work force flexibility that is needed to leverage the completion of planned work.[630]

As Mr. Berardi of Hydro One explained in this testimony:

> Just to add is if you look at some of the overtime on the planned work, we do have overtime on planned work.
>
> So for instance, when we're upgrading a line, upgrading a station, where we need to actually take the customer out of service, so we tend to do that not the regular nine to five. We tend to do that work where it best suits the customer, so we don't impact the productivity from a customer standpoint. So we would do some of that work on the weekend as well.
>
> And things like commissioning of a new transmission station, that may be done on off-peak times as well for planned work.

[626] SEC Submission, paras. 5.2.2 and 5.2.3; CME Submission, para. 213; VECC Submission, para. F2.
[627] Oral Hearing Transcript, Vol. 5, pp. 48-49.
[628] CME Submission, para. 223.
[629] Oral Hearing Transcript, Vol. 5, pp. 26-27.
[630] Oral Hearing Transcript, Vol. 5, p. 33.

Given that there are significant increases in Hydro One's capital work, it is reasonably expected there will be some higher levels of overtime.[631]

Benchmarked positions and peer groups are appropriate

Some intervenors argue that the Mercer Study produces more favourable results for Hydro One as it 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.632 However, this assertion ignores the fact that the Mercer Study benchmarking is largely focused on utility-specific trades and technical roles. The vast majority of positions in the Mercer Study are operations-focused roles that are appropriate for utilities as opposed to non-utility organizations. As such, the Mercer Study uses an appropriate utility peer group. In comparison, the WTW studies provide more holistic benchmarking and are therefore appropriate to compare to non-utility organizations. Hydro One uses a segmented approach for Management (MCP) and does benchmarking with Willis Towers Watson to ensure that it is compensating appropriately for these segments based on where it is seeking talent either from utility or non-utility organizations.

For unionized roles (i.e. Society and PWU), it is unreasonable to expect Hydro One to pay non-utility levels of compensation, given internal and pay equity considerations and the collective bargaining process. Hydro One does the benchmarking on a segmented basis to appropriately understand its market position and inform the collective bargaining process, in addition to other market research on unionized compensation.[633]

Hydro One Has Complied with the Board's Direction Regarding Presentation of Compensation Costs

OEB Staff is the only party that raised any questions or made any submission on this topic. OEB Staff essentially accepts that Hydro One has addressed in this proceeding all of the items

[631] Oral Hearing Transcript, Vol. 5, p. 34.
[632] SEC Submission, paras. 5.2.4-5.2.7.
[633] Exhibit F-4-1, p. 46.

requested by the OEB in the prior transmission proceeding.[634] OEB Staff raised a question about the relevance of any differences between compensation practice and policy between Hydro One's transmission and distribution businesses, but OEB Staff acknowledges that any such questions can be considered and addressed in Hydro One's next application as it will include both businesses. Lastly, OEB Staff submits that it "is of the view that more evidence needs to be filed in future proceedings to provide greater comparability of compensation amounts and FTEs between the different proceedings," but OEB Staff does not specify what type of additional evidence.

In the current proceeding, Hydro One has provided evidence showing strong evolution of the level of information provided by Hydro One in respect to its headcount, FTEs, compensation costs, and this information is comparable to the last distribution and transmission proceedings. Hydro One's detailed presentation of its compensation costs allows for a complete review and analysis of compensation at the transmission, distribution and consolidated levels and trending over the baseline compensation data. This enabled a detailed analysis to be completed by OEB Staff and a lengthy discussion on the subject matter between OEB Staff counsel and Hydro One's compensation witness during the oral hearing.[635]

In short, Hydro One has fully complied with the OEB's prior direction regarding presentation of compensation costs. This is further addressed in the response to undertaking J5.6.

In conclusion on this issue, for the reasons addressed above and in the Argument in Chief, Hydro One's compensation costs are appropriate. This is especially so having regard to the growing work programs, and the meaningful strides and progress Hydro One has made in efficiently managing its costs.

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[634] OEB Staff Submission, p. 115. OEB Staff questions the difference between "total number of employees" and number of FTEs, but indicates that forecasts of number of FTEs provided by Hydro One is most useful and that Hydro One "should only be required to provide FTEs going forward."

[635] Oral Hearing Transcript, Vol. 6, pp. 22-23.

G. RATE BASE AND COST OF CAPITAL:

Issue 18: Are the amounts proposed for rate base (including the working capital allowance amounts) reasonable?

Hydro One submitted in its Argument in Chief that the proposed 2020-2022 rate base amounts[636] have been correctly determined and are appropriate.[637] Hydro One 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.[638] Working capital allowance amounts are appropriate as the underlying methodology is supported by Navigant's updated study of the working capital requirements of Hydro One's transmission business.[639]

OEB staff submits that Hydro One's proposed rate base is reasonable, subject to staff's proposed adjustments as set out under Issue 9.[640] Similarly, LPMA and VECC support Hydro One's methodology used to calculate rate base, subject to their respective submissions related to the level of capital expenditures.[641] Regarding the working capital amounts, OEB staff accepts that Hydro One's proposed working capital allowance is reasonable, as do those intervenors that have made submissions on the working capital methodology.[642]

Accordingly, for the reasons highlighted above and detailed in the Application, Hydro One submits 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.

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636 Provided in detail in Exhibit C-1-1 and further updated as part of undertaking response J8.5 (see Table 2: Summary of Revenue Requirement Components).

637 Hydro One, Argument in Chief, p. 110.

638 Exhibit C-1-1, p. 1.

639 Exhibit C-5-1, Attachment 1.

640 OEB Staff Submission, p. 121.

641 See LPMA Submission, p. 21 (LPMA notes that its support of the methodology used to calculate rate base is also subject to its comments on depreciation. These are addressed above under Issue 16); VECC Argument p. 25.

642 See OEB Staff Submission, p. 121 and LPMA Submission, pp. 21-22 (LPMA supports the working capital allowance amounts and methodology as updated for any changes related to the OEB's decision on other matters in the proceeding).

Issue 19: Is the proposed cost of capital (interest on debt, return on equity) and capital structure reasonable?

Hydro One has proposed a deemed capital structure for rate-making purposes of 60% debt (56% long-term and 4% short-term) and 40% common equity, which is consistent with the approved structure from Hydro One's last transmission rebasing revenue requirement proceeding, as well as with the approved structure in the most recent Hydro One distribution rates proceeding and OEB policy. Hydro One has 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 over this period. In addition, Hydro One is proposing to use the deemed short-term debt rate of 2.75% based on the 2020 rate issued by the OEB on October 31, 2019, and a rate of return on equity of 8.52% based on the cost of capital parameters issued by the OEB on December 11, 2019.[643]

In its submission, OEB staff confirmed that the 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 should therefore be accepted by the OEB in the present Application.[644] With the exception of Energy Probe and LPMA, no intervenors have raised any concerns with respect to Hydro One's proposed cost of capital.

Energy Probe notes that Hydro One's 2020 projection of long-term debt is based on lower costs for new debt issuances in 2018 and 2019 and argues that, with the U.S. debt market moving lower, Hydro One may not have reflected that post-2020 debt levels for new issuances may be lower.[645] In response, Hydro One notes that the reduction in the rate from 4.57% to 4.33% reflects both the impact of 2019 actual issuances as of April 2019 and the lower forecast interest rates on the planned balance of 2019 debt issuances and 2020 debt issuances. However, the intention underlying Energy Probe's reference to post-2020 debt levels is unclear. Hydro One's cost of debt will be established for the 3-year Custom IR term based on debt issuances up to and including 2020. As such, Hydro One's cost of long-term debt for 2021 and 2022 is not

[643] Hydro One, Argument in Chief, pp. 111-112.
[644] OEB Staff Submission, p. 122.
[645] Energy Probe Submission, p. 28.

relevant for determining 2020 rates. To update the cost of capital parameters during the Custom IR term would be contrary to the OEB *Handbook*.

LPMA comments that Hydro One updated its long-term debt rate to reflect actual debt issuances in 2019 and the updated cost of capital parameters issued by the OEB on October 31, 2019, and notes that this reduced the long-term debt rate for 2020 from 4.57% to 4.33%. LPMA then states that, while it expects the 4.33% to be accurate, it is not aware of whether this calculation was provided to parties and it therefore requests that the OEB direct Hydro One to file the relevant information to show the long-term debt rate for 2020 in the draft rate order.[646] In response, Hydro One notes its intention to file updated schedules in its Draft Rate Order consistent with its typical approach to implementing OEB decisions with supporting schedules, including debt schedules. As such, an express OEB direction is not needed. Hydro One further submits that the stated 4.33% reflects actual debt issuances as of April 2019 and forecasted debt issuances for the balance of 2019 as presented in response to LPMA IR 19 and further updated to reflect Hydro One's long term interest rates for 2019 and 2020 consistent with the update of the other cost of capital parameters using September 2019 Consensus Forecast data. As stated in Exhibit G, Tab 1, Schedule 1 and consistent with prior practice, Hydro One intends to update the rate at the Draft Rate Order stage to reflect actual debt issuances for 2019.

Based on the foregoing, Hydro One submits that the Board should find the proposed cost of capital, including the rates of interest on debt and the rate of return on equity, as well as the proposed capital structure, to be reasonable.

[646] LPMA Submission, p. 22.

H. LOAD & REVENUE FORECAST:

Issue 20: Is the load forecast methodology (including consideration of CDM impacts) and the resulting load forecast appropriate?

In its Argument in Chief, Hydro One explains that the load forecast methodology used in the Application is consistent with the OEB-approved load forecast methodology that has been used for transmission rates since 2007 and that was most recently approved in Hydro One's 2017-2018 transmission application (EB-2016-0160). Hydro One's load forecast methodology has proven, year-over-year, to result in an accurate load forecast. The proposed load forecast was prepared in December 2018 and relies upon a consistent set of CDM assumptions over the historical and forecast period per the 2013 LTEP, as well as the latest information provided by the IESO. Resetting the load forecast for 2020 results in a drop of 3.9% relative to the load forecast built into the currently approved UTRs. The decrease in the 2020 load forecast is due to the fact that the actual peak load in 2018 was 3.5% lower than the currently approved load forecast, primarily driven by the impact of the expanded Industrial Conservation Initiative ("ICI"), as well as the further decline of 0.4% between 2018 and 2020 due to a combination of slow economic growth and higher Conservation and Demand Management ("CDM") that are forecast during this period. The proposed load forecast contemplates further reductions of 0.7% and 0.8% for 2021 and 2022, respectively.[647]

OEB staff takes the position that the one-time reduction in the load forecast of 3.5% in 2020 relative to 2018 is reasonable based on the expanded ICI program explanation.[648] However, for the reasons discussed below, Hydro One notes that there is an additional 0.4% decline in load in 2020 that needs to be taken into account in addition to the 3.5% to reflect actual load decline due to the ICI program expansion, bringing the total load decline in 2020 to 3.9% relative to the currently approved load forecast. OEB staff argue that this additional 0.4% decline in load in 2020, as well as further declines in load of 0.7% and 0.8% in 2021 and 2022, respectively, are not appropriate and should each be reduced to 0.0%.[649] Similarly, LPMA indicates that it has no issue with the load forecast methodology or the forecast for 2020, but argues that there should

[647] Hydro One, Argument in Chief, pp. 113-114.
[648] OEB Staff Submission, p. 123.
[649] OEB Staff Submission, p. 123.

be zero, rather than negative, load growth for 2021 and 2022.[650] LPMA's submission is supported by CCC.[651] BOMA, as discussed below, takes issue with the 3.5% reduction in load in resetting the load forecast for 2020, arguing that it may be impacted by special circumstances (which BOMA does not identify).[652] No other parties made any substantive submissions regarding Hydro One's proposed load forecast. For the reasons that follow, the OEB staff, LPMA and BOMA submissions are without merit.

The main drivers for the load forecast are Hydro One's load forecasting models and its CDM assumptions. Despite arguing that these reductions for 2020-2022 (or 2021-2022 in the case of LPMA) should be reduced to 0.0%, OEB staff and LPMA have raised no concerns with either of Hydro One's load forecasting models or its CDM assumptions. If the models are appropriate and the CDM assumptions are appropriate, then their arguments are baseless. It is also important to keep in mind that Hydro One's load forecast is a key driver of UTRs, which apply to all rate-regulated transmitters in Ontario. If Hydro One's load forecast is too high, the revenues collected by all transmitters will be adversely impacted. Increases to the load forecast must be properly supported by evidence, otherwise they will unfairly impact Hydro One and all other rate-regulated transmitters in Ontario by leaving them in a position where they do not have a fair opportunity to recovery their full revenue requirement through rates. As discussed below, there is no evidentiary basis for the load forecast increases being proposed by OEB staff and LPMA.

First, OEB staff states 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 has precipitously dropped to a 30 MW and 13 MW decrease in 2021 and 2022 respectively."[653] In stating that there has been a precipitous drop in 2021 and 2022, OEB staff has mischaracterized the load growth pattern. The growth in load before deducting the impacts of embedded generation and CDM between 2017 and 2020 (as noted by OEB staff based on Exhibit E, Tab 3, Schedule 1, Table 3, p. 20) includes additional load that was added to the forecast produced by the forecasting models to account for specific developments in Leamington and the surrounding area. The inclusion of this additional load led to greater load

[650] LPMA Submission, pp. 22-23.
[651] CCC Submission, p. 20.
[652] BOMA Submission, pp. 38-39.
[653] OEB Staff Submission, p. 123.

growth in the years 2019 and 2020 compared to 2021 and 2022. Moreover, as shown in response to VECC-27(c), the load growth rates from the forecasting models are -0.5% in 2020, -0.6% in 2021, and -0.5% in 2022 (i.e. consistently slightly negative in all three years). It is only after including the additional load for Leamington and the surrounding area for 2019 and 2020 that the forecast load (without CDM) changes to 1.7%, -0.1% and -0.1% in 2020, 2021 and 2022 respectively. 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.

Second, OEB staff states that "the 2020-2022 economic forecast shows growth, albeit at a slower pace compared to previous years, as identified by the expected growth rates of Gross Domestic Product, population growth, housing starts, commercial floor space and industrial production from 2019 onwards.[654] Based on this, OEB staff argues that this continuing growth is inconsistent with the precipitous drop that it perceived in Hydro One's load forecast before deducting the impacts of embedded generation and CDM in 2021 and 2022. With respect, this submission is not correct. While it is correct that the economic forecast shows growth, OEB staff ignores the evidence provided in response to PWU-3(a), which notes that there are many factors that reduce the load which can offset economic/customer growth. The main factors having a negative impact on load before deducting CDM and embedded generation include natural efficiency improvements by customers, inter-sectorial shifts in load from electricity intensive sectors (e.g., manufacturing) to less electricity intensive sectors (e.g., commercial), fuel switching from electricity to other sources of energy, Distributed Energy Resources ("DERs") and behind the customer meter generation. Consequently, only economic growth (e.g. GDP, population, housing starts, etc.) that can fully compensate for the negative impact of these factors will lead to net growth in the load forecast. In the proposed load forecast, the models imply that economic growth after 2019 is not strong enough to yield positive load growth. As shown in the figures in Exhibit E, Tab 3, Schedule 1, Attachment 1, the GDP growth rate over the years 2014-2017 has been 2.7%, which was sufficient to offset the factors driving a decline in load, which yielded a 0.1% load growth before deducting the load impact of CDM and embedded generation.[655] This indicates that GDP growth needs to

[654] OEB Staff Submission, pp. 123-124.
[655] See Exhibit E-3-1, Attachment 1, pp. 1 and 8.

be at least 2.6% (= 2.7% - 0.1%) to yield a positive load growth before deducting the load impact of CDM and embedded generation. However, over the forecast period economic growth is forecast only at about 2.0%, which is therefore not sufficient to offset the factors contributing to a decline in load.

Third, OEB staff states that "Hydro One's evidence shows that 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. In other words, CDM is forecasted to slow down in 2021 and 2022. Hydro One states that the forecasted CDM impacts are consistent with the 2013 LTEP and the latest figures from IESO" and that "the reductions of 0.4%, 0.7% and 0.8% in 2020, 2021 and 2022 respectively are not appropriate and should be reduced to 0.0% from 2020 to 2022 for the reasons discussed above".[656] In response, Hydro One notes that its load forecasting methodology, which has been previously approved by the Board, deducts the load impact of CDM and embedded generation from the gross load forecast to arrive at a net load forecast that is used to set transmission rates. Regarding the CDM pattern noted by OEB staff, the higher figures in the years 2017-2020 include the load impact of the current round of LDC CDM programs designed for the years 2015-2020. However, after 2020, the CDM impact declines as new LDC CDM programs had not yet been designed at the time LTEP 2013 was issued. Going forward, it is the IESO that will be designing the next round of CDM programs. As noted in response to VECC-34(b), the IESO concern with reducing system peak implies that the peak impact of future CDM programs could be greater than what is assumed in this Application. However, at the time the forecast for this Application was prepared, the magnitude of CDM programs beyond 2020 was not known. As such, it was reasonable for Hydro One to use the LTEP 2013 figures. The net result is that Hydro One's lower embedded generation and CDM forecast in 2020, 2021 and 2022 represent a conservative assumption that benefits load customers by contributing to lower rates.

In response to LPMA, Hydro One notes that as discussed above in greater detail in response to OEB staff's submissions, the forecast of load implied by the forecasting models is consistent across all forecast years. However, after adding to that forecast the load impact of investment plans in Leamington and the surrounding areas it becomes uneven, reflecting more growth in load before deducting the CDM and embedded generation impacts in 2019 and 2020 compared to

[656] OEB Staff Submission, p. 124.

2021 and 2022. Thus, such a front-loaded load growth is due to the pattern of investment planned in Leamington and the surrounding area. This pattern benefits customers as it leads to less growth in transmission rates earlier than later. Moreover, this pattern does not imply that there is something unreasonable about the forecast.

VECC has submitted that it has no concerns with respect to Hydro One's approach to transmission load forecasting, including Hydro One's use of econometric and end-use models, incorporation of CDM impacts in the historical data used for forecast purposes, and reduction in the forecast by the anticipated impacts of CDM in the test years.[657] However, VECC has raised a concern that Hydro One has not used the best available information. Specifically, VECC argues that Hydro One has not incorporated the actual verified CDM results from the IESO for the 2006-2017 period, which separated out energy efficiency programs from codes and standards ("C&S") savings and reported savings by customer segment.

VECC's submission, which is supported by Energy Probe,[658] is flawed because it incorrectly assumes Hydro One only needs consistent CDM data up to 2017 for preparing its load forecasting models.[659] As discussed in response to Undertaking J8.3, cited in VECC's submission, Hydro One's monthly forecasting model uses actual CDM data up to October 2018. Consequently, 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 notes that having consistent CDM data over the bridge and test years, while not strictly required to produce the load forecast, helps to evaluate the reasonability of the model results. As Hydro One has noted in its pre-filed evidence and interrogatory responses, it has always used all of the available information for the purposes of preparing its load forecast[660] and it shall continue doing so in the future.

BOMA has expressed concern with the 3.5% reduction in load in resetting the 2020 load forecast, arguing that "there may have been special circumstances in 2018 that were not necessarily repeatable and the 2018 actual load was not normalized", as well as that "Hydro One should have

[657] VECC Submission, pp. 25-27.
[658] Energy Probe Submission, p. 28.
[659] See VECC Submission, p. 26, paras H2-H6.
[660] See Exhibit E-3-1, p. 7 and VECC IR 24(d).

produced a new load forecast for 2020-2022 using the normalized 2018 demand as a base".[661] BOMA does not make any suggestions as to what special circumstances it may be referring to and points to no evidence whatsoever to support its assertions.

As Hydro One explained in Exhibit E, Tab 3, Schedule 1, at page 21, the 3.5% reduction in load relative to 2016 was largely due to the expansion of the ICI to a much wider customer base through successive reductions in the threshold minimum load for participation. In 2017, the actual load was 3.3% lower compared to the forecast for 2017, and in 2018 it was 3.5% lower. If by normalizing load for special circumstances BOMA means normalizing load for special weather conditions, this has been already performed as the comparison was on a weather-normal basis.[662] If by normalizing load BOMA is referring to non-weather special circumstances, the response is as follows. For two consecutive years, the impact of the expanded ICI reduced the load. As such, the reductions clearly had a persistent base and were not due to "special circumstances in 2018" as BOMA has speculated. In fact, the residuals of the forecasting models were examined in response to Energy Probe Interrogatory 2(d) and (e), where no extreme values reflecting "special circumstances" or structural changes were present for the years 2017 and 2018 (for the monthly model that uses actual load for up to October 2018).

Also, BOMA errs in stating that the forecast base year is 2018, when in fact it is 2017 as discussed in response to VECC Interrogatory 26(a). Hydro One's forecast methodology predicted the 2018 load with a great precision, as shown in response to VECC Interrogatory 26(b)(iii). If the 2018 load had been low due to "special circumstances", the forecast for 2018 would have been above the 2018 actual load. However, the 2018 forecast was even lower than the 2018 actual, although marginally, so Hydro One elected not to update the forecast as this would have led to marginally higher rates for customers. Therefore, it is clear that the reduction in actual load in 2017 and 2018 has not been due to special circumstances in 2018 but instead reflects actual weather-normalized load observed for those years. BOMA's submissions with respect to Hydro One's load forecast should be ignored.

[661] BOMA Submission, p. 38.
[662] See Exhibit E-3-1, pp. 9 and 20, and response to VECC IR 26.

Based on the foregoing, Hydro One submits 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 Board.

Issue 21: Are Other Revenue (including export revenue) forecasts appropriate?

Hydro One's Other Revenues consist of revenues received from sources other than transmission rates and which are applied as an offset to Hydro One's revenue requirement for the purpose of determining its rates revenue requirement, thereby reducing the amount of revenue to be collected from ratepayers through UTRs. Hydro One's Other Revenues are comprised of external revenues, wholesale meter service revenues, funding for the Low Voltage Switch Gear credit and export transmission service revenues.[663] Hydro One confirms that the 2015-2018 historical and 2019-2022 forecast of external revenues presented in Table 30 of OEB staff's submission are accurate. That table is reproduced below. In its submissions, OEB staff also acknowledges Hydro One's explanation for the significant decrease in the test year forecast from the historical actuals, which arises from forecast difficulties associated with Hydro One's role in managing the Provincial Secondary Land User Program on behalf of the Province of Ontario.[664]

Historical and Forecast External Revenues ($ Millions)

	Actual	Actual	Actual	Actual	Bridge	Test Year	Forecast Year	Forecast 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

On this issue, OEB staff submitted that the forecasted external revenues (including export revenues) are reasonably explained, and that the associated variance accounts for external revenues should be approved because any variance against the forecast is symmetrically

[663] Hydro One, Argument in Chief, pp. 114-115.
[664] OEB Staff Submission, p. 125.

treated.[665] Energy Probe agreed with OEB staff's submission in support of Hydro One's Other Revenue (including export revenue) forecasts.[666]

Two intervenors – LPMA and VECC – have raised concerns with respect to Hydro One's Other Revenue and export revenue forecasts. LPMA argues that the OEB should increase Hydro One's Other Revenue forecast by $9.4 million per year in each of 2020 through 2022 based on its analysis of Hydro One's historical forecasting of Other Revenues. In addition, LPMA argues that Hydro One's Export Transmission Service revenue forecast should be increased by $1.7 million in each of 2020 and 2021 and by $1.3 million in 2022 due to concerns with the three-year rolling average methodology that Hydro One has used to forecast export volumes. While LPMA acknowledges that variances are tracked in variance accounts in respect of each of these amounts, it argues that increasing the forecasts will provide more of the benefits of Other Revenues and export revenues to ratepayers up front rather than requiring them to wait until 2023.[667] VECC submits that, while the forecasts are acceptable for setting transmission rates on the assumption that the Board approves the continuation of these variance accounts, if the Board does not approve continuation of the accounts then the Other Revenue forecast should be increased by at least $7 million in each of 2020-2022.[668] These are addressed as follows.

In response to LPMA, Hydro One reiterates that its forecast of Other Revenues is appropriate 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, and its forecast of Export Transmission Service revenue is appropriate and methodologically sound. With respect to Other Revenues, it would not be appropriate to inflate the forecast of Other Revenues based on mere speculation from historical data. Ratepayers should not benefit from an offset to revenue requirement arising from Other Revenues except to the extent that Hydro One actually earns those Other Revenues or has a high degree of certainty that it will. As Hydro One is not currently expecting to earn more than the forecast level of Other Revenues, it would not be appropriate to give ratepayers a further up-front offset to revenue requirement as suggested by LPMA. With respect to Hydro One's forecast of Export Transmission Service revenues, Hydro

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[665] OEB Staff Submission, p. 125.
[666] Energy Probe Submission, p. 5.
[667] LPMA Submission, pp. 23-25.
[668] VECC Submission, pp. 28-29.

One notes that its forecasting methodology is the same as that which has been used and approved by the Board in previous Transmission rate applications. LPMA's suggestion of using a three-year average of 2016 to 2018 rather than a three-year rolling average of 2017 to 2019 (where 2019 is itself a forecast) would effectively result in a methodology that relies more heavily on older data. In Hydro One's view, this would not result in a more accurate forecast of export volumes. Rather, the proposed methodology is preferable and should be maintained. In response to VECC, Hydro One submits that the request to continue each of these variance accounts is fair and appropriate given the forecasting uncertainties associated with these aspects. However, it would not be appropriate for the OEB to artificially inflate these forecast amounts in the event it decides to discontinue the accounts.

Accordingly, Hydro One submits that the Board should find that Hydro One's Other Revenue (including export revenue) forecasts are appropriate.

I. DEFERRAL & VARIANCE ACCOUNTS:

Issue 22: Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Hydro One has a total of sixteen Regulatory Accounts in respect of its Transmission business. In the Application, Hydro One is seeking to dispose of the forecast balances, as at December 31, 2019, for twelve of the Regulatory Accounts, which have a total debit balance of $20.5 million. Hydro One is seeking approval to recover this amount from customers by adjusting its revenue requirement by $6.8 million per year over a three-year period commencing January 1, 2020.[669] With the exception of the OEB Cost Differential Account,[670] Hydro One is also seeking to continue each of these Regulatory Accounts. Hydro One is not seeking disposition of (but is seeking to continue) the remaining four Regulatory Accounts in respect of its Transmission business. Two of those accounts are tracking accounts. The third is the OPEB Cost Deferral Account, which 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). The fourth is the OPEB Asymmetrical Carrying Charge Account, which has a zero balance and is subject to Hydro One's request for approval of an alternative methodology for calculating the balance.[671]

Accounts for Disposition

As noted, Hydro One has indicated that it is seeking disposition of its forecast balances as at December 31, 2019, based on the December 31, 2018 balances plus forecast interest and less any amounts approved for disposition in 2019. OEB staff have indicated that they have no concerns with the proposed disposition of the December 31, 2018 deferral and variance account balances.[672] Moreover, OEB staff takes no issue with Hydro One's approach to forecasting the December 31, 2019 balances.

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[669] Hydro One notes that it erred in its Argument in Chief by stating that this amount would be refunded to customers.

[670] See Exhibit H-1-1, pp. 11-12 regarding the OEB's prior approval for the discontinuation of the OEB Cost Differential Account.

[671] Hydro One, Argument in Chief, pp. 115-117.

[672] OEB Staff Submission, p. 127.

One intervenor – VECC – has raised a concern with respect to the proposed amount and disposition of the LDC CDM and Demand Response Variance Account (the “CDM/DR Variance Account”). In particular, VECC argues that in calculating the 2017 balance of the CDM/DR Variance Account, Hydro One has included the impact of more than just the variance related to OPA-funded LDC delivered programs and Demand Response programs, which the Board approved for recording in the account. VECC states that the account also includes the impacts of Codes and Standards, the impacts of energy efficiency savings from transmission connected end-use customers, the impact of time of use rates and the impact of energy efficiency programs implemented by other parties, and that the scope of the account has never been changed by the Board. Therefore, VECC submits that the Board cannot approve the proposed balance of this account and that Hydro One should be required to re-calculate the balance consistent with the approved scope of the account and to seek recovery in a future application.

In response to VECC, Hydro One submits that the proposed approach to calculation of the CDM/DR Variance Account is appropriate. In addition, Hydro One submits that even if the Board were to agree with VECC on the scope of the account (which Hydro One does not support for the reasons set out below), this aspect could be addressed through the Draft Rate Order rather than being deferred to a future application. Each of these points are addressed as follows.

As explained by Mr. Andre during the Oral Hearing,[673] the concern that gave rise to the CDM/DR Variance Account in the settlement agreement for Hydro One’s EB-2012-0031 Transmission application was with the <u>total</u> amount of CDM included in Hydro One’s load forecast and not strictly with the OPA-funded LDC-delivered energy efficiency and demand response programs. However, due to the lack of data for some of the CDM components at that time, the settlement agreement in EB-2012-0031 required Hydro One to only track OPA-funded LDC-delivered energy efficiency and demand response programs. In 2018, the IESO issued verified 2017 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 (“C&S”). The data issued by the IESO is consistent with what Hydro One included in its approved 2017 load

[673] Oral Hearing Transcript, Vol. 8, pp. 110-111.

forecast.[674] Given the availability of verified CDM data for the energy efficiency and C&S CDM amounts used in developing the approved 2017 load forecast, Hydro One believes its calculation of the CDM/DR Variance Account, as detailed in Exhibit H-1-1 and Exhibit H-1-2, Attachment 11, is appropriate and consistent with the original intent for this account.

With respect to VECC's concern that Hydro One included "the impact of time of use rates" in its calculation of the energy efficiency component of the account, Hydro One submits that this is not correct. As noted by Dr. Alagheband during cross examination,[675] only the items related to energy efficiency are included in measuring energy efficiency. The impact of time of use rates is not such an item and therefore was not included in Hydro One's calculation of the energy efficiency component of the CDM/DR Variance Account.

In response to VECC's suggestion that the Board should deny Hydro One's request to dispose of the balance associated with this account as currently calculated, and require Hydro One to re-calculate the balance consistent with the account's approved definition and re-file for recovery in a future application, Hydro One submits that this proposal should be rejected. VECC is the only party that makes this submission. Moreover, if the Board were to agree with VECC regarding the scope of the energy efficiency component of the account, this would not fundamentally alter the request and would not justify deferring the matter to a future application for the following reasons.

First, neither VECC nor any party has identified any concerns with the scope or calculation of the Demand Response component of the account balance, which at $13.22 million represents the majority of the $22.67 CDM/DR Variance Account balance.[676]

Second, the IESO-verified results used to calculate the energy efficiency component of the account clearly breaks out the various energy efficiency programs, including specifically

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[674] As explained in Exhibit E-3-1, pp. 9-10, Hydro One adds total energy efficiency and C&S to actual peak during the historical period to produce a forecast for gross load and then deducts total energy efficiency and C&S during the forecast period from its gross forecast to arrive at the net load used for setting rates.

[675] Oral Hearing Transcript, Vol. 8, p. 117.

[676] As shown in Exhibit H-1-2, Attachment 11, the total balance of $22.67M is comprised of $13.22M for Demand response programs ($12.86M for ICI, $0.83M for Dispatched Load, ($0.47M) for DR Auction) and $9.46M for energy efficiency programs.

identifying the LDC-delivered CDM programs.[677] As such it would be a simple matter to re-calculate the energy efficiency component of the account to include only LDC-delivered programs, which Hydro One is prepared to do as part of the Draft Rate Order process in the current proceeding if the OEB were to agree with VECC on the scope of the energy efficiency component of this account.

Third, delaying recovery of the balance until the next application, currently planned for 2023, would result in additional accumulation of interest amounts associated with the regulatory balance and recovery of the balance from a generation of ratepayers that is even more remote from the generation of ratepayers who benefitted from the transmission service that resulted in the underlying costs recorded in the account. This exacerbates the intergenerational inequity in the recovery of the costs.

Hydro One notes that modifying the calculation of the energy efficiency component of the CDM/DR Variance Account to only include the LDC-Delivered programs as suggested by VECC[678] would result in an <u>increase</u> of approximately $7.5 million in the energy efficiency amount to be collected from customers, from $9.46 million to $16.95 million.[679] The primary reason for this is that the CDM from <u>non-LDC delivered programs</u> decreased from 2016 to 2017. That CDM was helping to offset the increase that LDC-delivered energy efficiency programs contributed to the amount to be collected in the account. As such, Hydro One submits that not only is its proposed methodology more consistent with the original intent of the CDM/DR Variance Account as discussed above, but it actually results in a smaller amount being collected from customers.

[677] A breakout of the verified CDM results for all energy efficiency components is provided in the spreadsheet included in the response to VECC IR 24(d), Item 7, and was also provided as an Excel worksheet as Attachment 1 thereto.

[678] This would exclude C&S, energy efficiency programs from non-LDC sources (e.g. federal government programs, gas companies etc), and transmission direct customer energy efficiency programs. Note that the impact of time-of-use on CDM amounts achieved were already previously excluded as they were not considered an energy efficiency component.

[679] See Exhibit H-1-2, Attachment 11; and *supra*, note 677, above.

<u>Accounts Not for Disposition</u>

With respect to the accounts for which Hydro One is not seeking disposition, OEB staff have indicated that they have no concerns with not disposing of the East West Tie and SECTR accounts on the basis that both are tracking accounts, which serve to provide visibility to the OEB as to the costs associated with the corresponding projects.[680] However, OEB staff does have concerns with respect to Hydro One's proposals to not dispose of the OPEB Cost Deferral Account and the OPEB Asymmetrical Carrying Charges Account, as discussed below. The Society has provided submissions in support of Hydro One's proposed treatment of the OPEB Cost Deferral Account and the OPEB Asymmetrical Carrying Charge Account.[681]

OPEB Cost Deferral Account

Hydro One has <u>not</u> proposed to dispose of the balance of the OPEB Cost Deferral Account because it is subject to the OEB's determination regarding capitalization of the non-current service component of OPEBs. OEB staff submits that, under Issue 11, it is possible that the OEB disallows Hydro One's proposal for continued capitalization of the relevant costs and that it also disallows Hydro One's proposal to continue to use the OPEB Cost Deferral Account going forward to capture the relevant costs. OEB staff notes that Hydro One has indicated that if such an outcome were to occur, then its intention would be to dispose of the 2018 audited balance within this account as part of the current proceeding. Accordingly, OEB staff argues that if Hydro One seeks disposition of the December 31, 2018 balance in this account, then it will need to amend its deferral and variance account disposition request as part of the draft rate order in the proceeding. In addition, under Issue 23 of OEB staff's submission, OEB staff argues that the Board should also order this account to be closed upon disposition of the current balance in the account.[682] Hydro One agrees that, if the OEB disallows both its proposal to continue capitalization and its alternative proposal to continue using the OPEB Cost Deferral Account, Hydro One would need to amend its request for deferral and variance account disposition as part of the draft rate order to reflect its request to dispose of the 2018 audited balance for this account and once the 2019 audited balance is disposed of at the next rebasing application

[680] OEB Staff Submission, p. 130.
[681] Society Submission, pp. 19-21.
[682] OEB Staff Submission, p. 136.

Hydro One will seek to discontinue the account. Hydro One's reply submissions on the issue of the continued capitalization of OPEBs is provided under Issue 11.

OPEB Asymmetrical Carrying Charges Account

The OPEB Asymmetrical Carrying Charges Account was established, effective from January 1, 2018, through a generic proceeding (EB-2015-0040) in connection with the OEB's *Report on the Regulatory Treatment of Pension and OPEB Costs* issued September 14, 2017 (the "OPEB Report"). In the OPEB Report, the OEB determined that it would set rates for the recovery of pension and OPEB costs using the accrual method of accounting and directed utilities to establish variance accounts to track the difference between the forecasted OPEB accrual amount in rates and actual cash payments made, with a carrying charge applied to the differential, or "reference amount".

As summarized in Hydro One's Argument in Chief, the OPEB Report established a default methodology for determining the forecast accrual amount recovered in rates, but also expressly recognized that where utilities capitalize a portion of the OPEB amounts the default approach <u>may not be appropriate</u> and utilities may propose an alternative methodology. As Hydro One capitalizes a material amount of its OPEB costs, it has proposed an enhanced methodology that better reflects the actual amounts recovered in rates.[683]

Specifically, rather than determining the reference amount using the gross costs from the actuarial valuation, Hydro One proposes to calculate the reference amount based on the sum of the following, less cash expenses:

- The full amount of OPEB costs recorded in OM&A;
- The capitalized OPEB expense which is recovered as part of the depreciation of PP&E from the effective date of the account (2018); and
- The annual recovery of the OPEB costs recorded in the OPEB Cost Deferral Account and recovered over a 20-year period. This component is currently subject to the OEB's

[683] Hydro One, Argument in Chief, pp. 77-78.

determination of the appropriate treatment of the non-service cost component of OPEB, as discussed in detail under Issue 11.

Hydro One proposes to track the difference between the sum of these three amounts and the actual cash payments in the OPEB Asymmetrical Carrying Charge Account.

OEB staff stands alone in taking issue with Hydro One's proposed enhanced methodology, as considered below, and the Society provides submissions in support of the proposal. The Society notes that the openness to an alternative was included by the OEB to ensure greater precision and fairness where a utility's capitalization policy made a straight cash vs. accrual variance inappropriate. In regards to OEB staff's proposed methodology, any utility applying their proposed method 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. OEB staff's position essentially makes the alternative unworkable and unusable by any utility in any circumstance. This was obviously not the OEB's intent in offering the alternative to the generic treatment discussed in the OPEB Report. The Society's view is that Hydro One's proposed treatment is reasonable, balanced and that it meets the intent of the exception in the OPEB Report. It allows a fairer assessment of the variance amount compared to the default methodology and is auditable. In addition, it does not carry the hint of retroactive rate making that OEB staff's proposal does. Therefore, the Society argues that Hydro One's proposal should be approved.[684]

As noted, OEB staff has indicated that it does not support Hydro One's proposed alternative methodology and submits that the Board should require Hydro One to follow the default methodology from the OPEB Report, which in staff's view is the only viable and fair option available.[685] OEB staff argues that the alternative methodology understates the forecast accrual amount that Hydro One is actually recovering in rates related to its OPEB costs, thereby effectively minimizing the return that ratepayers will receive in the form of asymmetrical carrying charges on the differential tracked within the account. More particularly:

[684] Society Submission, pp. 19-20.
[685] OEB Staff Submission, pp. 130-133.

- OEB staff argues that the understatement occurs because the alternate methodology only recognizes the depreciation associated with OPEB costs that have been capitalized to rate base from January 1, 2018 (the effective date of the account), and fails to take into account the depreciation associated with OPEB costs that have been capitalized prior to January 1, 2018.[686]

- OEB staff argues that the alternate methodology does not result in a true representation of what Hydro One will recover because it omits a potentially material component of depreciation associated with its capitalized OPEB costs.[687]

- OEB staff suggests that, if the alternative methodology is permitted, it should be based on the sum of (a) the portion of the annual OPEB costs expensed to OM&A, (b) the annual depreciation associated with the cumulative undepreciated capitalized OPEB costs in rate base, and (c) the annual amortization of costs recorded in the OPEB Cost Deferral Account subject to the OEB approving the continued use of the account under Issue 11.[688]

- Ultimately, OEB staff argues that, since Hydro One was unable to provide a calculation consistent with OEB staff's revised alternative methodology due to the OPEB amounts capitalized in prior periods not being identifiable[689], the only viable and fair option remaining is to revert to the default methodology.[690]

In response, Hydro One acknowledges that the data needed to implement OEB staff's suggested revised alternative is not available and that staff's approach could therefore not be used. However, this is not the relevant consideration for the Board and OEB staff's submissions should therefore be rejected. In Hydro One's view, prior year capitalized OPEB amounts are not relevant and should not be included in the calculation. More particularly, it would not be

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[686] OEB Staff Submission, p. 130.
[687] OEB Staff Submission, p. 131.
[688] OEB Staff Submission, p. 132.
[689] As explained in response to Undertaking JT2.5, Hydro One is unable to provide a reasonable estimate of the depreciation associated with OPEBs that have been capitalized to date, as OPEB amounts capitalized in prior periods are not identifiable at the individual capital asset level to allow for an estimate of depreciation.
[690] OEB Staff Submission, p. 132.

appropriate to take into account depreciation associated with OPEB costs that have been capitalized to rate base prior to January 1, 2018. First, the OPEB Report clearly indicates the Board'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, which was 2018.[691] Second, as demonstrated in response to JT2.5, to require Hydro One in the alternative methodology to include amounts from prior to January 1, 2018 would be unfair because it would be inconsistent with the treatment of a utility that applies the default methodology, under which pre-2018 amounts are not accounted for. Specifically, Hydro One shows by way of an example in JT2.5 that a company that expenses all of its OPEB costs as OM&A and applies the default methodology is not required to account for its over-recovered accrual basis expense prior to implementation of the account effective January 1, 2018. In its argument, OEB staff has failed to address the question of why they believe a utility that capitalizes its OPEB costs and a utility which expenses its OPEB costs should be treated differently and the basis for their view that this was the Board's intent in the OPEB Report.

In addition, it would be unfair to require Hydro One to use the default methodology in the absence of a sound basis for doing so. In establishing the default methodology, the Board expressly recognized that it is based on an assumption that the total gross accrual cost is reflected in a utility's total OM&A expense and that this might not be appropriate for utilities, such as Hydro One, which capitalize a material portion of their OPEB accrual costs. Hydro One's proposal is therefore aligned with the Board's expectations. It provides an appropriate balance between the objectives and methodology set out in the OPEB Report and what Hydro One can provide from a practical perspective. In fact, advocating against an alternative methodology proposed by Hydro One would go against the spirit of the OEB report which clearly states the following:

> The forecast accrual reference amount that will be used to calculate the entries recorded in this new account assumes that the total gross accrual cost as determined by an actuarial valuation is what is recorded in a utility's total OM&A expense. <u>If a utility capitalizes a material portion of its total pension and OPEB accrual costs, and there is sufficient incremental value to warrant the added complexity of tracking amounts that are capitalized separately from those that are expensed, any party may propose an enhanced methodology for determining the reference amount and the appropriate carrying charge to be applied, including</u>

[691] See JT2.5 and OEB Staff-222(c).

journal entries consistent with the intent of the account as outlined in this report.[692]

As discussed in the Argument in Chief, in the case of Hydro One the alternative methodology more accurately depicts the money that is effectively "lent" to the utility by customers as compared to the OEB's standard methodology, which is based on the assumption that the total gross accrual cost is recorded in OM&A. Therefore, the alternative methodology is necessary to achieve the purpose of the account without unfairly penalizing the utility by eroding its ability to earn a fair return. Moreover, given the materiality of the difference arising from the two calculations as summarized below, any additional complexities introduced by the alternative methodology are warranted.[693]

Table 22-1: Default vs Alternative Approach ($ millions)

	2018	2019	2020	2021	2022
Default approach					
Accrual vs cash (cumulative)	29	53	79	106	133
Carrying charge	0.8	1.5	2.3	3.1	3.8
Alternative approach					
Accrual vs cash (cumulative)	(0.2)	(9.4)	(19.4)	(30.3)	(40.3)
Carrying charge	-	-	-	-	-

Based on the foregoing, Hydro One submits that the Board should find that the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts, including the proposed enhanced methodology for the OPEB Asymmetrical Carrying Charge Account, are appropriate.

[692] OPEB Report, p. 20 (emphasis added).
[693] Hydro One, Argument in Chief, p. 79.

Issue 23: Are the proposed new deferral and variance accounts appropriate?

Hydro One is seeking approval to establish four new Regulatory Accounts – a Foregone Transmission Revenue Deferral Account[694], an ESM Deferral Account, a CCRA True-up Variance Account and a variance account to track the difference between Hydro One's revenue requirement underlying its approved transmission rates and its transmission revenue requirement after reflecting the outcome of a successful appeal to the Divisional Court, if applicable, which OEB staff has referred to as the Transmission Revenue Requirement Variance Tracking Account (the "TRRVTA"). In addition, the company is requesting approval to modify the In-Service Capital Additions Variance Account (the "CISVA"), for which continuance is requested.[695]

OEB staff indicate that they have no concerns with Hydro One's proposals in respect of the Foregone Transmission Revenue Deferral Account, ESM Deferral Account, or the CCRA True-up Variance Account. However, OEB staff does have concerns with the TRRVTA. Although OEB staff raises those concerns under Issue 15, Hydro One responds to those concerns as part of Issue 23, below. In addition, while OEB staff makes submissions on both Hydro One's proposal to continue certain deferral and variance accounts and its proposed modification to the CISVA under Issue 23, Hydro One responds to the submissions regarding the continuance of accounts under Issue 22 and to the submissions regarding the proposed modification of the CISVA under this Issue 23, below.

Four intervenors – CCC, Energy Probe, SEC and the PWU – make submissions on this issue. In summary, CCC supports Hydro One's proposed modifications to the CISVA, PWU supports Hydro One's request for the TRRVTA, and both SEC and Energy Probe raise concerns with Hydro One's proposed modifications to the CISVA. These are discussed below. As no party has made submissions on the Foregone Transmission Revenue Deferral Account, the ESM

[694] On December 10, 2019 the Board declared Hydro One's current transmission revenue requirement and charges to be interim as of January 1, 2020, until such time as a new transmission revenue requirement and charges are approved, and indicated that it would determine the need for the Foregone Transmission Revenue Deferral Account at the time it makes its final determination on the effective date for Hydro One's 2020 revenue requirement.

[695] Hydro One, Argument in Chief, pp. 99 and 117.

Deferral Account, or the CCRA True-up Variance Account, these are not addressed further but are summarized with evidence references in Hydro One's Argument in Chief.[696]

Transmission Revenue Requirement Variance Tracking Account (the "TRRVTA")

As discussed under Issue 15, the issue of future tax savings resulting from the Government of Ontario's decision to sell its ownership interest in Hydro One Limited in connection with the initial public offering is not a matter for this proceeding since it is the subject of an appeal to the Divisional Court. However, Hydro One has requested approval to establish 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 its transmission revenue requirement during this period after reflecting the outcome of a successful appeal, if applicable. In Hydro One's view, it is appropriate for the OEB to provide for the potential outcome of a successful appeal to facilitate the recovery of any amounts that the appeal decision may ultimately determine to be recoverable dating back to January 1, 2017.

Under Issue 15 in its submissions, OEB staff indicates that it does not support establishment of this proposed variance tracking account because the appeal is still ongoing and the outcome is unknown. In staff's view, there is no benefit to the increased regulatory burden associated with tracking amounts that may not materialize, and an account should only be established once the need for it is established depending on the outcome of the appeal proceeding.[697] LPMA similarly argues that it would be premature to establish the account as the appeal is still with the Divisional Court.[698] In response, Hydro One submits that there would be no increased regulatory burden associated with tracking amounts in the proposed variance account. As explained in response to PWU-23, if and when Hydro One receives a successful appeal decision, it would then record the relevant amounts in the account, along with applicable interest, and apply to the OEB for disposition of the recorded balance over such period and in such manner as it considers appropriate at that time. Unless and until such a decision is received, there is no regulatory burden arising from the account. Moreover, establishing the account in the current proceeding would avoid the need for Hydro One to seek approval for the

[696] Hydro One, Argument in Chief, pp. 117-118.
[697] OEB Staff Submission, p. 96.
[698] LPMA Submission, p. 27.

account 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. PWU expresses support for this account in its submissions, stating that "any delay to recovering (the revenue requirement impact) would necessitate additional carrying costs to be recovered from ratepayers and would exacerbate intertemporal collection issues, extending the time between when the costs were incurred and when the costs are recovered".[699]

Modification to the CISVA

Hydro One has proposed a modification to the CISVA to exclude verifiable productivity savings from the calculation of the balance that flows to the account so as to ensure that additional productivity savings are incented throughout the term of this Custom IR application.[700] The proposal is discussed in detail with an example in response to Undertaking J9.1.

OEB staff argues that the proposed modification introduces significant regulatory burden to the process of assessing the prudence of amounts to be disposed of from the account. In particular, OEB staff argues that it will be difficult to differentiate between what is a productivity gain as opposed to savings that result from such things as due diligence, inflated forecasts, and changes to the scope of a project as discussed by OEB staff under Issue 6 in its submission.[701] On this basis, OEB staff argues that the OEB should reject the proposed modifications to the CISVA and require the account to be continued using the same approach that was approved in the last transmission rates application. SEC argues that while the account is meant to protect ratepayers from material underspending on capital, it creates a perverse incentive for the utility and in the long-term may make customers worse off. It further states that the nature of the account is to protect ratepayers against aggregate underspending of more than 2%. Moreover, SEC asserts that the account does not consider worsening productivity or the ability to meet project and unit cost forecasts. SEC argues that while the proposed conditions and adjustments to the CISVA proposed by Hydro One (namely the 2% deadband and exclusion of verifiable productivity gains) represent an improvement, they do not sufficiently protect customers and the

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[699] PWU Submission, para 83-84.
[700] Hydro One, Argument in Chief, p. 119.
[701] OEB Staff Submission, p. 136.

continuation of the account should therefore be approved subject to certain conditions.[702] Energy Probe argues that Hydro One's proposed 2% deadband should be reduced to 1% and that there should not be any incentive for meeting in-service additions.[703] CCC is supportive of Hydro One's proposed modifications to the CISVA, but submits that Hydro One should be required in its next rebasing application to provide a detailed account of the amounts in the account, how they were recorded and to demonstrate specifically how productivity has impacted those amounts.[704]

In response to OEB staff, Hydro One submits that the proposed modifications should be approved because, as indicated in response to OEB Staff-11(a) and as reiterated in response to Undertaking J9.1, it would be consistent with the exclusion of verifiable productivity gains from the CISVA that was approved in the Hydro One Distribution decision.[705] In addition, OEB staff's approach would have the effect of creating a disincentive for Hydro One to find additional capital productivity savings over the Custom IR term by penalizing the company for achieving further productivity savings. Finally, OEB staff's approach 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. As a result, at the time of rebasing, Hydro One would rebase with a higher rate base than it otherwise would under the proposed scenario where Hydro One is not penalized for excluding verifiable productivity gains from the CISVA.

With respect to OEB staff's suggestion that it will be difficult to differentiate between what is a productivity gain as opposed to savings from other factors, Hydro One disagrees. As indicated in response to Undertaking J9.1, at the next transmission rebasing application, the onus will be on Hydro One to prove the achieved incremental productivity savings above the levels embedded in the approved revenue requirement. Furthermore, the OEB approved the same account for Hydro One Distribution in EB-2017-0049 and no concerns were raised in respect of any difficulties with such tracking. Moreover, if it would be of assistance to the Board, Hydro One would be willing to provide an update on its productivity progress following completion of

[702] SEC Submission, pp. 19-22.
[703] Energy Probe, pp. 29-30.
[704] CCC Submission, p. 12.
[705] See OEB Staff-11(a); and EB-2017-0049 Decision and Order, pp. 172-173.

the 2020 test year consistent with a similar request from the Board in the Distribution application.

Regarding SEC's submission that the nature of the CISVA only protects ratepayers from aggregate underspending, Hydro One submits that the account was established as part of EB-2014-0140 in response to parties expressing concerns with Hydro One's historical ISA levels comparted to OEB approved ISA levels. This is exactly what the account was intended to capture, and is the basis for the Board's prior approval of the account for both Hydro One Transmission and Hydro One Distribution. Additionally SEC is missing the point that Hydro One has proposed an ESM account which would capture differences in revenue requirement.

While SEC appears to incorrectly believe that Hydro One is requesting a new CISVA rather than proposing modifications to an existing CISVA that it wishes to continue, SEC argues that if the OEB approves the CISVA as generally proposed by Hydro One, then it should do so subject to the conditions that (a) the onus will be on Hydro One to demonstrate in its next Custom IR application that both the amount of excluded incremental productivity savings is determined appropriately, and that it is appropriate for the company to retain those amounts, and (b) the CISVA be altered to capture any capital related variances regardless of the cause.

In response to the second condition proposed by SEC, Hydro One notes the OEB's direction in the *Handbook*, as follows:

> The OEB sets just and reasonable rates based on a total revenue requirement that is informed by an assessment of a utility's spending proposals… It is the utility's responsibility to operate its system, and undertake the projects and programs it needs to meet performance requirements within the funding provided through rates. This provides the utility with the responsibility and **flexibility to meet its obligations** in ways which benefit customers and the utility.[706]

As such, 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. SEC's submission is entirely unreasonable and does not reflect the fact that circumstances can change over a rate term.

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[706] *Handbook*, p. 9 (emphasis added).

SEC's proposal 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.

Furthermore, SEC's submission on the CISVA is inconsistent with the concerns addressed in other areas of its submission. On the one hand, SEC incorrectly criticizes Hydro One's C-factor proposal for funding capital on a cost of service basis. On the other hand, SEC proposes changes to the CISVA which would result in truing up elements of the revenue requirement due to variability in taxes, depreciation, etc. These two views are inconsistent with one another and with incentive-rate setting generally, which seeks to decouple rates from costs through mechanistic adjustments.

With respect to the first condition proposed by SEC, regarding the onus on the company in its next Custom IR application, Hydro One submits that there is nothing for the panel in the current proceeding to do to give effect to SEC's condition. It will be up to the panel in the next application to determine whether the amounts recorded in the 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's proposal is consistent with the OEB's guidance and with the approach that was approved for Hydro One Distribution (EB-2017-0049). The proposed modifications to the CISVA appropriately balance the needs of protecting customers and providing Hydro One sufficient flexibility to adapt to changing circumstances, while incenting Hydro One to pursue continuous improvement over the rate setting term.

In response to Energy Probe, Hydro One notes that the requested deadband of 2% is consistent with the deadband that has been approved by the Board in respect of Hydro One's distribution business.[707] As explained in response to LPMA-3, a 2% deadband is appropriate for ensuring alignment between the behaviors that are incented by the account and the outcomes that ratepayers value. Absent the 2% deadband, Hydro One would be incented to spend 100% of its planned capital amounts each year and to do whatever it can to ensure planned projects are in-serviced by December 31 each year (including paying for additional overtime) rather than minimizing execution costs. The proposed 2% deadband would instead incent Hydro One to

[707] See OEB Staff-11(a) and EB-2017-0049 Decision and Order, pp. 172-173.

find ways to lower capital project costs, and support the efficient execution of projects near the end of the calendar year. Though customers are not materially impacted if a project is in-serviced in late December as compared to early January, Hydro One would be financially impacted. Energy Probe's suggested 1% deadband would reduce the strength of and thereby diminish the effectiveness of these incentives.

In response to CCC, Hydro One submits that the CISVA 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. As previously stated in response to Undertaking 9.1, Hydro One 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. The CISVA entry, or lack thereof, will be undertaken by Finance and will be part of the Company's audited financial statements.

In summary, Hydro One submits that the modified CISVA (with the 98% threshold and the exclusion of verifiable productivity gains from the calculation) strikes an appropriate balance between providing protection to ratepayers and incenting appropriate behaviours in Hydro One's capital program, while also incenting the utility to strive for continuous productivity improvements. While Hydro One has proposed the continuation of this account subject to the above-noted modifications based on its view that the modified CISVA would be in the interests of customers, if the Board is not inclined to accept the proposed modifications or continuation of the account as it was previously approved then Hydro One submits that it would be more appropriate to have no CISVA whatsoever than to apply the conditions/changes that have been proposed by SEC (which, among other things, are not consistent with incentive-rate setting, do not support the decoupling of rates from costs, and diminish the Custom IR framework through the truing up of costs to actuals rather than employing the formulaic approach that Hydro One has proposed). Moreover, SEC's proposals ignore the fact that Hydro One is proposing an ESM account which would share any of the overearning with customers above 100 basis points and would give rise to significant and unnecessary regulatory burden and result in a different treatment than applies to Hydro One's Distribution business.

Based on the foregoing, Hydro One submits that the Board should find that all four of the proposed new deferral and variance accounts, as well as the proposed modifications to the CISVA, are appropriate.

J. COST ALLOCATION:

Issue 24: Is the transmission cost allocation proposed by Hydro One appropriate?

In its Argument in Chief, Hydro One noted that it is continuing to follow the OEB-approved methodology from its last transmission rebasing application to allocate the transmission rates revenue requirement into rate pools.[708]

No concerns have been raised, either by OEB staff or intervenors, regarding Hydro One's proposed approach to transmission cost allocation.[709] However, OEB staff has raised a concern with respect to Hydro One's proposal to update the definition of billing demand for Line and Transformation Connection services to reflect changes in the embedded generation market over the years, such as the inclusion of energy storage facilities.[710] LPMA has indicated that it shares this concern.[711]

As explained in response to OEB Interrogatory 225, the definitions of "billing demand" for the line and transformation connection services and embedded generation in the current UTR Schedules have not been updated since 2005. The proposed changes in wording are intended to clarify and reflect Hydro One's interpretation of these definitions and its current practice in respect of the data provided to the IESO for transmission billing purposes. OEB staff has expressed a concern

> that Hydro One is proposing 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. OEB staff suggests that there may also be policy considerations around the question of the appropriate treatment of energy storage facilities that would warrant further industry consultation and OEB direction. In its reply submission, Hydro One should clarify whether the OEB has previously approved Hydro One's current practice regarding storage facilities. However, OEB staff cannot at this time

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[708] Hydro One, Argument in Chief, p. 120.

[709] See OEB Staff Submission, p. 138; VECC Submission, p. 31; and LPMA Submission, p. 27.

[710] OEB Staff Submission, p. 139.

[711] LPMA Submission, p. 27.

> support the proposed amendments to the Terms and Conditions of the UTR Schedules.[712]

LPMA submits that no change should be made until the OEB can consult with potentially affected customers.[713]

In response, Hydro One notes that while the term “energy storage facilities” is not specifically included in the currently approved UTR schedules, its practice regarding such facilities is appropriate. 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 and, since energy storage is not identified as a “renewable energy source” within the definition of that term set out in s. 2(1) of the *Electricity Act, 1998*, Hydro One’s treatment is consistent with the current rules. Therefore, even if the UTR Schedules are not changed, it would be Hydro One’s intention to continue treating “behind the meter” energy storage facilities as embedded non-renewable generation.[714] As such, while the proposed changes to the definitions of billing demand would provide greater transparency, Hydro One is indifferent as to whether the changes are implemented in the UTR Schedules.

Based on the foregoing, it is Hydro One’s submission that the transmission cost allocation proposed by Hydro One is appropriate.

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[712] OEB Staff Submission, p. 139.
[713] LPMA Submission, p. 27.
[714] Response to Undertaking J9.3.

K. EXPORT TRANSMISSION SERVICE RATES:

Issue 25: Is the Export Transmission Rate of $1.85 and the resulting ETS revenues appropriate?

As explained in Hydro One's Argument in Chief,[715] Hydro One is proposing to maintain the Export Transmission Service (ETS) rate at the existing level of $1.85/MWh. Hydro One updated the 2015 Elenchus cost allocation model based on updated information, which identified an ETS rate of $1.25/MWh based on the cost allocation scenario set out in the Elenchus study. The decline is attributable to decreased Hydro One OM&A costs from 2015 to 2019, and an increase in forecast export volumes.[716] However, applying this would adversely impact Ontario electricity customers by reducing the offset to Hydro One's transmission revenue requirement. Moreover, the existing rate was determined by a combination of OEB decisions and settlement agreements informed by cost allocation studies, but the ETS rate has historically not been set strictly on principles of cost causality.

In its submission, OEB staff indicated that it supports Hydro One's proposal to maintain the ETS rate at the current level of $1.85/MWh due to deficiencies in the recommended cost allocation study. In particular, OEB staff referenced Hydro One's testimony regarding the fact that the cost allocation study did not allocate shared capital costs to export customers completely even though those assets do serve export customers, and because no jurisdictional review was performed to understand how ETS rates are determined in other jurisdictions.[717] OEB staff also submitted that Hydro One should propose a cost-based ETS rate in its next rebasing application, with supporting calculations allocating shared capital costs to export customers. As discussed further below, Hydro One does not take issue with OEB staff's submission and notes that the Elenchus model allows for the requested calculations.

APPrO makes a number of submissions in connection with the proposed ETS, which are addressed below. In addition, a number of intervenors express concerns similar to those expressed by OEB staff regarding the methodology recommended by Elenchus, including the

[715] Hydro One, Argument in Chief, p. 121.
[716] Oral hearing Transcript, Vol. 8 (Revised), pp. 147-148.
[717] OEB Staff Submission, p. 141.

fact that it lacks a jurisdictional review and that it does not allocate any capital costs associated with the shared Network facilities to export customers. These concerns are addressed below.

As explained by Hydro One, the company is financially indifferent to the ETS rate but recognizes the impact it has on Ontario transmission customers.[718] As such, the primary objective in these reply submissions is to ensure the Board has accurate and complete information on which to base its decision on this issue. To that end, and contrary to APPrO's claim that Hydro One has a "systemic bias against exporters",[719] the following will focus on identifying what Hydro One considers to be legitimate points raised by intervenors.

APPrO states in its submission that the Elenchus Study, prepared by a recognized expert in cost allocation and rate design, recommended a single cost allocation methodology as being appropriate for the ETS rate and ran six other scenarios for purposes of sensitivity analysis.[720] In Hydro One's view, APPrO has mischaracterized the significance of the six additional scenarios in the study by suggesting that they were simply used for "sensitivity analysis" of the assumptions made, and that the Elenchus study "expressly rejected" the alternate cost allocation methodologies that were identified.

While the study's testing of 1 CP vs 12 CP as an allocator, or the use of a single year of historical data versus the average of 3 years, could be considered a form of sensitivity analysis, the Elenchus Scenario 5 (no dedicated assets allocated to exporters) and Scenario 6 (allocating a share of network assets to exporters) represent materially different approaches to the allocation of costs that go beyond a simple "sensitivity analysis". Similarly, while the Elenchus study provides a rationale for the cost allocation choices that it recommends, it does not go so far as to say that the other methodologies are "expressly rejected".

As indicated by Mr. Andre and Mr. Li during the oral hearing, all of the scenarios considered in the Elenchus study could be considered to produce cost-based rates,[721] and Scenario 6 (allocating a share of network assets to exporters) will generate an ETS rate that would be

[718] See I2-4-1, p. 3; Oral Hearing Transcript, Vol. 7, p. 177, line 28 to p. 178, line 3, and p. 196, line 28 to p. 197, line 2.

[719] APPrO Submission, p. 10.

[720] APPrO Submission, pp. 14-15.

[721] Oral Hearing Transcript, Vol. 7, p. 179, lines 14-16.

considerably higher than the recommended rate.[722] As such, it is Hydro One's view that the currently approved rate of $1.85/MWh falls within the range of possible cost-based rates identified by Elenchus, depending on the allocation methodology adopted.

As noted above, a number of parties including OEB staff have raised concerns with the methodology recommended by Elenchus, including the fact that it lacks a jurisdictional review and that the recommended methodology does not allocate any capital costs associated with shared Network facilities to export customers.

Hydro One notes that a jurisdictional review was previously completed by Charles River Associates ("CRA") as part of a study completed in 2012 for the IESO under proceeding EB-2012-0031.[723] The CRA study was referenced by APPrO in its submissions[724] and Hydro One draws to the Board's attention the comparison of ETS rates in Ontario's neighbouring jurisdictions, which is provided in Table 2 on page 15 of the CRA study. That comparison shows that Hydro One's then-approved ETS rate of $2.00/MWh was the *lowest* export charge of any of the neighbouring jurisdictions that export electricity to Ontario. As shown in Table 2 of the CRA study, the export charges applicable to entities exporting power to Ontario ranged from a low of $3.32/MWh (in MISO) to a high of $8.24/MWh (in Quebec).[725] While an update to the jurisdictional review may be helpful to the Board, it is unlikely that the charges in Ontario's neighbouring jurisdictions have been materially reduced, particularly after accounting for cost inflation since 2012.

With regard to the concern raised by intervenors about the sharing of Network capital costs, Hydro One notes that Scenario 6 in the Elenchus study does calculate an ETS rate that includes a sharing of Network asset costs, but recognizes that the results of that scenario were not subject to review and scrutiny by intervenors or OEB staff in the current proceeding.

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[722] Oral Hearing Transcript, Vol. 9, p. 12, lines 1-15.

[723] Filed in EB-2012-0031 as Exhibit H1-5-2, Appendix B.

[724] APPrO Submission, p. 6.

[725] Table 2 includes some neighbouring jurisdictions that have reciprocal bilateral agreements that completely eliminate the export charges between the participating jurisdictions, but Ontario is not party to any of those reciprocal agreements.

If the Board chooses to adopt the Elenchus recommended methodology, APPrO's submission suggests that the ETS rate should be calculated based on a three-year rolling average of historical export volume as opposed to the approach used by Hydro One, of using the prior year's historical volume. Hydro One disagrees with APPrO's approach, for the following reasons:

- Use of a single historical year of volume data is the methodology recommended by Elenchus for cost allocation. APPrO endorses all other aspects of the Elenchus recommended methodology, with the notable exception of this one item. Hydro One submits that it is not appropriate for APPrO to cherry pick specific elements of the Elenchus methodology to be adopted; and

- Given the recent downward trend of export volumes,[726] the 2018 historical volume represents the best forecast of the export volume for 2020 to 2022. Consistent with cost allocation principles the best forecast should be used to allocate costs for the purpose of setting rates.

APPRO also takes issue with the fact that Hydro One uses a three-year rolling average of export volumes to forecast export revenues, which is different than the historical year approach used for cost allocation purposes. Hydro One has addressed this in a Technical Conference undertaking response, where it noted that for cost allocation purposes it is important to use the best available export volume forecast, consistent with the methodology recommended by Elenchus.[727] However, when it comes to forecasting revenues, the three-year rolling average export volume is recommended for the following reasons:

- It results in a higher forecast of ETS revenue that will lower transmission rates, which is a benefit for Ontario rate payers;[728]

- If the ETS forecast <u>revenue</u> is incorrect, any difference in forecast revenue is tracked in a variance account for disposition in the future.[729] This is different than the forecast

[726] Response to VECC IR #55.
[727] JT1.36, Question 1 (a) and (b).
[728] Oral Hearing Transcript, Vol. 7, p. 195, lines 1-9.
[729] Oral Hearing Transcript, Vol. 7, p. 194, lines 16-21.

volume used to allocate costs and set the ETS rate, which gets locked in for the rate period covered by the Application with no opportunity to "correct" for any error in the forecast assumption;[730] and

- Use of a three-year rolling average volume to forecast ETS revenue is the same methodology that has been approved by the OEB in previous transmission rate applications.[731]

Hydro One acknowledges the arguments made by SEC and VECC that the methodology approved by the Board for calculating pole attachment charges concluded that the rates charged to 3rd party attachers should include asset-related costs associated with shared components of the pole.[732] Given that the Elenchus study has never been reviewed in front of the Board,[733] and therefore the cost allocation option that looked at the allocation of shared network costs to exporters has not been fully explored, Hydro One supports intervenor arguments that a cost allocation methodology that includes the allocation of Network shared costs to exporters should be provided with Hydro One's next cost-of-service application.

In summary, Hydro One believes it is appropriate to maintain the ETS rate at the current level of $1.85/MWh for the 2020 to 2022 rate period. OEB staff and all intervenors other than APPrO support Hydro One's position of at least maintaining the current ETS rate of $1.85/MWh. Since electricity market opening in 2002, the ETS rate has always been set by settlement agreement or OEB decision and not strictly based on principles of cost causality. Regardless, the current rate of $1.85/MWh is not inconsistent with the principle of cost causality given that it falls within the range of all cost-based rate scenarios considered by the Elenchus study. In addition, lowering the ETS rate from the existing level of $1.85/MWh would adversely impact all Ontario electricity consumers as ETS revenue is used to offset the revenue requirement collected through UTRs.

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[730] Oral Hearing Transcript, Vol. 9, p. 14 line 28 to p. 15 line 8.
[731] Oral Hearing Transcript, Vol. 9, p. 14, lines 2-11.
[732] See SEC Submission, p. 74 and VECC Submission, p. 33.
[733] VECC-54; and Oral Hearing Transcript, Vol. 8, p. 147, lines 17-19.

Based on the foregoing, Hydro One submits that the OEB should find the ETS rate of $1.85//MWh and the resulting ETS revenues to be reasonable.

All of which is respectfully submitted this 17th day of January 2020.

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