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BY EMAIL AND RESS

June 25, 2020

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

Dear Ms. Long,

Re: EB-2019-0082 – Hydro One Network Inc.'s 2020-2022 Transmission Custom IR Application and Evidence – Draft Rate Order Reply Submission

Pursuant to the Ontario Energy Board's ("OEB") April 23, 2020 Decision and Order on the Application, and in response to OEB Staff and intervenor submissions on Hydro One's May 28, 2020 Draft Rate Order, please find attached Hydro One's Draft Rate Order Reply Submission.

An electronic copy of the Draft Rate Order Reply Submission has been filed using the OEB's Regulatory Electronic Submission System (RESS).

Sincerely,

Frank D'Andrea

Frank D'Andrea

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

AND IN THE MATTER OF an application for electricity transmission revenue requirements beginning January 1, 2020 until December 31, 2022.

HYDRO ONE NETWORKS INC.

DRAFT RATE ORDER REPLY SUBMISSION

OEB File No. EB-2019-0082

June 25, 2020

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1 INTRODUCTION

On May 28, 2020, Hydro One Networks Inc. ("**Hydro One**") filed a Draft Rate Order ("**DRO**") pursuant to the Ontario Energy Board's (the "**OEB**") Decision and Order on Hydro One's three-year custom incentive rate-setting application for changes to its transmission revenue requirement for 2020-2022 (the "**Decision and Order**"). Submissions on the DRO were received on June 11, 2020 from OEB Staff, as well as from the Association of Major Power Consumers in Ontario ("**AMPCO**"), London Property Management Association ("**LPMA**"), School Energy Coalition ("**SEC**") and Vulnerable Energy Consumers Coalition ("**VECC**"). This is Hydro One's reply to the submissions of OEB Staff and intervenors on the DRO, and it is organized as follows to address the points that have been raised:

i. Capital Reduction and Forecasted In-Service Additions;
ii. Tax Considerations;
iii. Deferral and Variance Accounts ("**DVA**");
iv. Transmission Scorecard; and
v. Rates.

Hydro One's DRO appropriately implements the Decision and Order while providing the OEB with an opportunity to efficiently address certain discrete implications for the Decision and Order arising from circumstances relating to the COVID-19 pandemic. In response to the submissions received, Hydro One has revised and hereby resubmits several of the draft accounting orders. Hydro One is also resubmitting the UTR schedules and foregone revenue calculations to reflect the OEB-approved revenue requirements for Niagara Reinforcement Limited Partnership and B2M Limited Partnership. Furthermore, Hydro One has identified two aspects for potential minor adjustments as discussed further under Section 3 - Tax Considerations. However, as those impacts are largely offsetting and the resulting impact on revenue requirement is immaterial, and in consideration of regulatory efficiency, it is Hydro One's view that changes to the DRO to reflect these tax impacts are not warranted. While OEB Staff and intervenors also made submissions on a number of other aspects, the focus of those submissions was to seek further clarification on a range of matters. While Hydro One has endeavoured to provide that clarification, in Hydro One's view and for the reasons set out below, they do not merit further modifications to the DRO.

2 CAPITAL REDUCTION AND FORECASTED IN-SERVICE ADDITIONS

2.1 Work Program Capital Reductions and Corresponding Rate Impacts

In the DRO, Hydro One's proposed 2020-2022 capital expenditures of $3,864.7 million were reduced to $3,397.5 million to reflect the OEB's capital expenditure reductions to System Renewal, System Service, General Plant; and an amount to reflect the removal from the capital forecast of the non-service component of other post-employment benefit ("**OPEB**") costs. As indicated in the DRO, the total in-service addition reductions across the System Renewal, System Access, System Service and General Plant categories was $310.8 million over the 2020-2022 period.

Expenditure Reduction to Transmission Stations

Of the $390 million capital reduction to the System Renewal category, Hydro One applied $340 million to the Transmission Lines sub-category and $50 million to the Transmission Stations sub-category.

OEB Staff supported Hydro One's $340 million reduction to transmission lines capital expenditures.[1] OEB Staff agreed with Hydro One that in-service additions generally lag

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[1] Of the $390 million capital reduction directed to be made to the Transmission Lines

behind capital expenditures for multi-year transmission projects. OEB Staff requested that Hydro One provide additional information as to how it made the $50 million reduction to the transmission stations sub-category.[2]

In the DRO, Hydro One identified constraints which limited Hydro One's ability to recognize the full $390 million against the Transmission Lines sub-category. A $50 million reduction was applied to the Transmission Stations sub-category using Hydro One's risk-based prioritization framework. In doing so, Hydro One considered system reliability, customer requirements and broader system planning considerations.

The reductions were primarily realized through revised pacing of complex load station transformer and component replacement projects. These projects were part of investment categories SR-05 – Load Station Transformer Replacement Project, SR-06 – Load Station Switchgear and Ancillary Equipment Replacement Project, and SR-08 – John Transformer Station Reinvestment Project. Although there is risk, equipment and operational redundancy and safeguards are in-place to allow the short-term deferral of these project investments. In addition, any reliability issues at designated load stations are less impactful than stations which form part of the bulk electricity system. Work related to the latter remains a priority which is consistent with the objectives of Hydro One's 2020-2022 system plan.

Portfolio Level of Rate Base Not Materially Changed and Category In-Service Additions

Although the OEB made determinations related to capital expenditures on a category level, it is the overall portfolio level of in-service amounts on which revenue requirement and ultimately rates are based. Intervenors and OEB staff have instead focused only on the category level and attempted to extrapolate the result to the portfolio level of in-service additions.

[2] OEB Staff DRO Submission, p.5-6

SEC notes that 2020 System Renewal in-service additions increase by $59.3 million even though Hydro One allocated a $55.1 million reduction to the 2020 System Renewal capital expenditures. SEC submits that if the 2020 increase in System Renewal in-service additions is related to the timing of previously forecast 2019 in-service additions, then Hydro One should provide detailed opening and closing annual rate base numbers related to System Renewal and a full explanation of the adjustments made.

SEC's assertion is made without full consideration of the portfolio level as a whole and the fact that increases in one category are offset by decreases in another to leave the proposed level of rate base virtually unchanged.

For example, Leamington DESN #2 (approximately $35 million) was placed in-service in 2019 because of an expedited customer connection timeline that advanced the project from 2020. This contributed to the decrease in 2020 System Access in-service additions. The scheduling of the H7L/H11L underground cable replacement project (approximately $40 million) enabled this advancement since it was deferred from 2019 to 2020, contributing to the increase in 2020 System Renewal in-service additions. In both cases, these projects were substantially complete prior to 2020, and forecast to have immaterial capital expenditures during the 2020-2022 test period.

Across other categories, including General Plant and System Service, similar timing shifts have occurred.

OEB Staff noted that the Decision and Order called for a $5.7 million reduction to the System Service category attributed to the Kapuskasing Area Reinforcement ("**KAR**") project. In the DRO, Hydro One forecasted an increase of $3.8 million over 2020-2022 in capital additions. Consequently, OEB Staff indicated that there is a $9.5 million increase in the forecasted capital additions. OEB Staff noted that Hydro One identified delays in two projects as being the main drivers of the increase: the Wataynikaneyap Line at Pickle Lake project (SS-02) ("**Wataynikaneyap Pickle Lake Project**") and the Barrie Area

Transmission Upgrade project (SS-09) ("**Barrie Upgrade Project**"). OEB Staff requested that Hydro One explain in its reply submission why delays in these projects result in an increase in capital additions.[3]

At the time of the initial filing, the Barrie Upgrade Project was assumed to be delivered in phases, with a portion of the project energized in 2020. The Wataynikaneyap Pickle Lake Project was to be in-service in Q4 2020. Hydro One highlighted the impact of these two projects as they account for the majority of the movement of work out of 2020 into 2021 and 2022.

The residual increase in System Service is largely attributable to the installation of facilities in the Lake Huron and Port Colborne areas in response to performance concerns raised by customers. These reflect projects that were expected to be in-service in 2019 and are to be completed in 2020. These projects are forecast to have immaterial capital expenditures during the 2020-22 test period given that expenditures were made in 2019 to facilitate project completion in 2020.

OEB Staff noted that the Decision and Order established a $4.3 million reduction to the Integrated System Operating Centre ("**ISOC**") and that Hydro One reflected a $0.6 million increase to General Plan in-service additions in the DRO. OEB Staff requested that Hydro One identify the key projects that drive the $4.9 million increase that led to the net change in capital additions of $0.6 million.[4]

Approximately $3.7 million of the in-service additions variance to General Plant over the 3 years is attributable to GP-07 – Hardware/Software Refresh and Maintenance associated with expenditures incurred in 2019, including the ongoing multiyear refresh of business

[3] OEB Staff DRO Submission, p.6-7
[4] OEB Staff DRO Submission, p.6-7

technology applications and operating systems, largely associated with software packages such as Windows 10.

Also, as noted the deferral of project in-service dates from 2019 to 2020 do not affect proposed 2019 closing and 2020 opening rate base at the portfolio level since changes in the system service category are offset by other capital category changes.

Hydro One has delivered upon a capital and in-service addition portfolio that is materially consistent at the envelope level with OEB-approved category levels of spending. At the time of filing, Hydro One had forecasted 2019 in-service capital of approximately $951 million; in 2019, Hydro One placed in-service approximately $960 million of capital expenditures, a 0.9% variance relative to the bridge year forecast. Therefore, contrary to SEC's submission that Hydro One could be double counting if adjustments are not made to the 2019 closing balance, the closing rate base is materially as filed and does not result in any double counting.

3 TAX CONSIDERATIONS

OEB Staff and SEC made several submissions with respect to Hydro One's regulatory income tax calculations. For the most part, these submissions have requested further information and clarification as to the manner in which the tax calculations have been performed and the revenue requirement impact thereof. No other intervenors made submissions with respect to tax. Subsections 3.1 to 3.3 below address the concerns raised by OEB Staff and SEC specifically with respect to the overall tax calculation and capitalized overhead costs, the impact of capital expenditure reductions on the tax calculation and the impact of OPEB on the tax calculation. Based on its consideration of the submissions received, Hydro One has identified two aspects for potential minor adjustments. However, as those impacts are largely offsetting and the resulting impact on revenue requirement is immaterial, and in consideration of regulatory efficiency, it is Hydro One's view that changes to the DRO to reflect these tax impacts are not warranted.

3.1 Overall Tax Calculation and Capitalized Overhead Costs

OEB Staff requested confirmation as to whether the $35.8 million difference between the 2020 total opening Undepreciated Capital Cost ("**UCC**") balance of $7,221.3 million in Exhibit 1.5.2 of the DRO and the 2020 total opening UCC balance of $7,257.1 million from Hydro One's response to interrogatory I-1-OEB-208 is due to Hydro One performing a true-up of the forecasted value to the actual opening value.[5]

Hydro One clarifies that the $35.8 million difference ($7,257.1 - $7,221.3) is not the result of a true-up of the forecasted value to the actual opening value as believed by OEB Staff. Rather, the difference arises from the manner in which the $36.3 million cumulative eligible capital ("**CEC**") balance is presented, with the remainder of the difference of $0.5 million being attributable to rounding. More particularly, in interrogatory response I-1-OEB-208 the CEC balance was presented as part of the UCC, whereas in Exhibit 1.5.2 of the DRO the CEC balance was presented separately from the UCC. Hydro One further clarifies that there is no impact on the tax calculations as the CCA rates are the same and it was only a matter of presentation difference.

Additionally, OEB Staff noted that the Capitalized Overhead Costs in Exhibit 1.5.1 of the DRO have not changed from the pre-filed evidence or Hydro One's interrogatory response in I-1-OEB-208 despite the fact that the Decision and Order reduced capital expenditures.[6] OEB Staff expressed an expectation, because of the reduction in capital expenditures, that the capitalized overhead adjustment for regulatory tax purposes would also have been reduced.

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[5] OEB Staff DRO Submission, p.10
[6] OEB Staff DRO Submission, p.11

Hydro One acknowledges that, at least conceptually, reduced capital expenditures should result in a reduction in the amount of overhead costs recovered through capital with a corresponding increase in the amount of overhead costs recovered through OM&A, along with the associated tax impact.[7] If Hydro One were to update its capitalized overheads, the reduction in capital expenditures referenced by OEB Staff would be expected to increase Hydro One's revenue requirement by approximately $1.2 million for 2020 (approximately $1.1 million in additional OM&A and approximately $0.1 million in additional taxes), with the subsequent years being even higher due to inflationary adjustments[8] for OM&A beyond 2020.

With respect to changes to overall tax, SEC stated that it could not find a calculation supporting "Other Timing Differences" of $29.5 million, $30.2 million and $31.0 million in each of 2020, 2021 and 2022 in Exhibit 1.5 of the DRO, and requested clarification as to how these amounts reconcile to the increase in regulatory income tax of $43 million over 2020-2022.[9]

To clarify, Hydro One notes that the increase in "Other Timing Differences" in Exhibit 1.5 of the DRO is in fact largely related to the OPEB OM&A amounts. Table 1 below provides a breakdown of "Other Timing Differences" by the individual components. The Other Post-Employment Benefits Expense in the first row of Table 1 includes amounts recognized as OM&A, as well as the non-service component of OPEB costs and disbursal of the OPEB Cost deferral account. Please refer to subsection 3.3 for further details on OPEB and Table 6 for a detailed breakdown of the OPEB components.

[7] Hydro One has not historically updated its revenue requirement for changes related to capitalized overheads resulting from changes to capital expenditures in OEB Decisions.
[8] Inflation less productivity
[9] SEC DRO Submission, p.4

Table 1 – Breakdown of Other Timing Differences

	Hydro One Proposed			OEB Decision Impact			OEB Approved		
	2020	2021	2021	2020	2021	2021	2020	2021	2021
Other Post Employment Benefits expense	21.1	21.5	21.1	28.5	28.8	29.1	49.6	50.3	50.2
Other Post Employment Benefits payments	(28.7)	(30.7)	(31.3)	-	-	-	(28.7)	(30.7)	(31.3)
Other	(65.0)	(71.9)	(74.8)	1.0	1.3	1.9	(64.0)	(70.5)	(72.9)
Total Other Timing Differences	(72.7)	(81.1)	(85.0)	29.5	30.2	31.0	(43.1)	(50.9)	(54.0)

3.2 Impact of Capital Expenditure Reductions on Regulatory Tax

OEB Staff was unclear as to what adjustments have been made by Hydro One to in-service additions to derive the net additions for tax purposes and whether those adjustments have changed from the pre-filed evidence.[10] For ease of reference, a table outlining the differences that was provided by OEB Staff is reproduced below as Table 2.

Table 2 – OEB Staff Comparison of In-Service Additions and Net Additions ($ millions)

	2020	2021	2022
Exhibit 1.5.2 – Net Additions	$848.8	$966.3	$1,171.1
DRO Table 5 – In-Service Additions	$938.9	$1,078.0	$1,285.2
Difference	($90.1)	($111.7)	($114.1)

In response to OEB Staff, Table 3, below, provides a summary of the adjustments that have been made to assist in reconciling the in-service additions in DRO Table 5 to the net additions for tax included in Exhibit 1.5.2 of the DRO. Please note that the 2020 net additions as submitted in Exhibit 1.5.2 are $848.4 million (slightly different than in the table presented by OEB Staff of $848.8 million) and that Table 3 was prepared on such basis.

[10] OEB Staff DRO Submission, p.10

Table 3 – DRO In-Service Additions and Net Tax Additions

	OEB Approved 2020	OEB Approved 2021	OEB Approved 2022	
DRO Table 5 - In-Service Additions	$ 938.9	$ 1,078.0	$ 1,285.3	
Non-service components of OPEBs	(8.4)	(21.8)	(23.1)	[A]
Total (Removing OPEB)	**930.5**	**1,056.2**	**1,262.2**	
Timing Difference Adjustments				
Asset removal costs	50.8	56.4	58.2	
Interest capitalized	(43.6)	(48.5)	(51.3)	
Overheads capitalized	(34.7)	(35.7)	(36.0)	
Depreciation capitalized	(13.3)	(13.5)	(13.6)	
OPEB capitalized	(12.6)	(15.1)	(16.1)	
Pension capitalized	(23.8)	(25.1)	(24.9)	
Share grants / LTIP	(7.3)	(7.5)	(7.3)	
Other **	2.4	(1.0)	0.1	
Total Adjustments	(82.1)	(89.9)	(91.0)	[A]
Exhibit 1.5.2 - Net Tax Additions	**848.4**	**966.3**	**1,171.2**	
Sum of Total Adjustments	**(90.5)**	**(111.7)**	**(114.1)**	Sum of A

** Relates to non-depreciable property and amounts expensed for accounting but capitalized for tax

SEC submitted that the OEB has not been provided with any information on how the allocation of the capital spending reductions to asset classes affects the tax shield.[11] Furthermore, SEC submitted that it was unable to recreate the $56.4 million change in Capital Cost Allowance ("**CCA**") resulting from the Decision and Order over the 2020 to 2022 period and that the 2021 amount of $42.1 million was unexplained and seemed anomalous (Exhibit 1.5).[12]

In response to SEC's submission on the changes in CCA over the 2020-2022 period, Hydro One clarifies that the tax additions, as reconciled in Table 4 below, are based on Hydro One's implementation of the Decision and Order, which was based on the proposed capital spending summary (as detailed in DRO Table 4) and the proposed in-service capital

[11] SEC DRO Submission, p.4
[12] SEC DRO Submission, p.4

additions summary (as detailed in DRO Table 5).[13] The asset classes affected by the capital spending reduction and the associated reduction in the tax shield are based on tax legislation and are not within Hydro One's control. Furthermore, Hydro One notes that the total change in CCA as submitted in Exhibit 1.5.2 is $55.4 million ($5.7 million + $42.1 million + $7.6 million) and not $56.4 million as referenced in the SEC submission; Hydro One responds on this basis.

Table 4 – Change in Tax Additions

	2020	2021	2022
Hydro One Proposed - Tax Additions[14]	918.8	1,166.2	1,152.7
OEB Approved - Tax Additions	848.4	966.3	1,171.1
Change in Tax Additions	(70.4)	(199.8)	18.4

The reconciliation of reductions in CCA to the change in tax additions is provided in Appendix 'A'.

In response to the SEC request for Hydro One to provide Exhibit 1.5.2, Calculation of CCA, in a format to show the impact of the Decision and Order,[15] Hydro One references Appendix 'A', which includes an appropriate level of detail in respect of the impact of the Decision and Order on CCA.

[13] As summarized during the proceeding, capital expenditure and in-service additional amounts presented in the Application were based on the assumption that Hydro One would be permitted to capitalize the non-service component of OPEB costs. As such, the non-service component of OPEB costs were included in the capital and in-service addition amounts. However, for purposes of calculating revenue requirement and rate base, the non-service component of OPEB costs were excluded pending a decision on this point. Exhibit F, Tab 5, Schedule 1, p. 10 of 11. See Undertaking J-6.04 for a description of the non-service component of OPEB costs for Transmission and Distribution.

[14] The tax additions on the blue page update as $927.3 million, $1,182.79 million, and $1175.9 million from 2020 to 2022 respectively. The difference in additions from the blue page update to Hydro One proposed is mainly attributable to OPEB non-service costs being expensed.

[15] SEC DRO Submission, p.4

3.3 Impact of Other Post-Employment Benefits on Regulatory Tax

OEB Staff commented that the increase in regulatory taxes is directionally in line with the OEB's determination in the Decision and Order to recognize the non-service component of OPEB costs as OM&A.[16] However, OEB Staff, as well as SEC, requested further information on the regulatory tax impact of the Decision and Order with respect to the non-service component of OPEB. To explain the basis of its requests for further clarification, OEB Staff produced a table outlining the differences between the OPEB expenses shown in Exhibit 1.5.1 of the DRO and those set out in Hydro One's interrogatory response I-1-OEB-208.[17] For ease of reference, the table is reproduced below as Table 5.

Table 5 – OEB Staff Comparison of OPEB Expense Adjustment ($ millions)

	2020	2021	2022
DRO Exhibit 1.5.1 – Calculation of Utility Income Taxes	$49.6	$50.3	$50.2
Interrogatory Response – I-1-OEB-208	$21.1	$21.5	$21.1
Difference	$28.5	$28.8	$29.1

With reference to the above table, OEB Staff requested clarification as to how the increase of $28.5 million correlates to the $21 million increase in OM&A resulting from the OEB's determination that the non-service component of Hydro One's OPEB costs may not be capitalized.[18] In addition, OEB Staff requested clarification as to why the $49.6 million of OPEB expense differs from the $37 million financial accounting OPEB expense.[19]

Similarly, SEC stated that it was not able to reconcile the $21.0 million of non-service component of OPEB expenses in Table 6 of the DRO with any adjustments related to the tax shield in Exhibit 1.5.1 of the DRO.[20]

[16] OEB Staff DRO Submission, p.12
[17] OEB Staff DRO Submission, p.12
[18] OEB Staff DRO Submission, p.13
[19] OEB Staff DRO Submission, p.13
[20] SEC DRO Submission, p.4

Hydro One clarifies that the total OPEB reflected in the calculation of income tax includes: 1) the OPEB amounts recovered as OM&A, 2) the non-service component of OPEB amounts previously capitalized, and 3) amounts related to disbursal of the 2018 audited balance of the OPEB Costs Deferral Account. Table 6, below, provides a summary of the referenced OPEB components that give rise to the total OPEB amount that is reflected in Exhibit 1.5.1 of the DRO.

Table 6 – OPEB Components ($ millions)

OPEB Details	Hydro One Proposed			OEB Decision Impact			OEB Approved		
	2020	2021	2021	2020	2021	2021	2020	2021	2021
OPEB - Interrogatory Response - I-1-OEB-208	21.1	21.5	21.1	-	-	-	21.1	21.5	21.1
OPEB - non-service component				21.0	21.4	21.7	21.0	21.4	21.7
Disbursal of OPEB Deferral account				7.5	7.5	7.5	7.5	7.5	7.5
Total OPEB expense - Exhibit 1.5.1	21.1	21.5	21.1	28.5	28.8	29.1	49.6	50.3	50.2

The $28.5 million increase in 2020 OPEB recovery consists of $21 million related to the 2020 non-service component of OPEBs and $7.5 million related to disposition of the balance in the OPEB Cost Deferral Account, as approved by the OEB.[21]

As recognized by OEB Staff in their submission, OPEB expense is a taxable timing difference,[22] so the $28.5 million incremental revenue would be subject to tax. Consequently, the revenue requirement impact relating to regulatory tax would be $10.3 million ($28.5 million x 26.5% ÷ 73.5%).

Moreover, OEB Staff requested further clarification as to the relationship between the $37 million (which represents the financial accounting OPEB expense) and the $49.6 million of

[21] Decision and Order, p.165, the disposition over the application period.
[22] In OEB Staff DRO Submission at page 12, the OEB Staff noted "Specifically, the financial accounting OPEB expense is added back to regulatory net income before taxes (to remove the impact of OPEB expense) and OPEB payments made are deducted. As a result…. the increase in OM&A would result in higher regulatory taxable income, and therefore, higher regulatory taxes."

OPEB expense shown in Exhibit 1.5.1 of the DRO which is added back to regulatory net income before taxes.[23]

Hydro One clarifies that the $12.6 million difference ($49.6 million - $37 million) is due to a combination of the $7.5 million pro-rated disbursal of the OPEB Cost Deferral Account balance as approved by the OEB and $5.1 million relating to the difference in Hydro One's proposed 2020 OPEB expense (of $21.1 million) reflected in Exhibit 1.5.1 of the DRO as compared to the $16 million as shown in the OPEB table.[24]

If corrected, the decrease of $5.1 million in OPEB expense would reduce Hydro One's regulatory income tax. Ultimately, this would lower Hydro One's revenue requirement by approximately $1.7 million in 2020 ($5.1 million x 26.5% ÷ 73.5%).

In response to SEC's comment that, "with respect to OPEBs, from a tax point of view, the tax should be the same whether OPEBs are treated as operating costs or capital expenditures" and that "shifting OPEBs to operating costs increases revenue requirement, but the tax liability remains the same",[25] Hydro One respectfully disagrees for the following reasons.

Financial accounting OPEB costs are not deductible for tax purposes until related payments are made. As correctly noted by SEC, the total available OPEB deduction does not change whether OPEB charges are recognized as operating costs (i.e., OM&A) or capital expenditures. However, revenue requirement is directly impacted by the method through which OPEB costs are recognized. If OPEB amounts are treated as capital expenditures, the revenue requirement impact will be spread out over the life of the capital assets and recovered as part of annual accounting depreciation. If OPEB amounts are treated as

[23] OEB Staff DRO Submission, p.13
[24] Decision and Order, p. 144, Table 10
[25] SEC DRO Submission, p.4

OM&A, as SEC correctly noted, this will increase the annual revenue requirement. Thus, the revenue requirement impact is accelerated when OPEB costs are recognized as OM&A, relative to the capital treatment, notwithstanding that the total deduction is the same. There is still an increase in regulatory income tax arising from the non-deductible accounting OPEB expense for tax with a corresponding reduction in regulatory income tax (i.e., benefits to be returned to the ratepayers) in the future when the payment is made for the OPEB expense.

Net Tax Impacts are Not Material

As discussed in Subsection 3.1, above, if Hydro One were to update its capitalized overheads to reflect the reduction in capital expenditures from the Decision and Order, this would be expected to increase Hydro One's revenue requirement by approximately $1.2 million for 2020, with the impact for subsequent years being even higher due to inflationary adjustments[26] for OM&A beyond 2020. However, if Hydro One were to correct its regulated income tax due to the $5.1 million overstatement of the OPEB expense described in Subsection 3.3, this would be expected to decrease Hydro One's revenue requirement for 2020 by approximately $1.7 million. In Hydro One's view, the net impact of these potential areas for adjustment is not material in the context of its overall revenue requirement. As such, for purposes of regulatory efficiency, Hydro One does not propose to reflect either adjustment in the DRO.

4 DEFERRAL AND VARIANCE ACCOUNTS

Despite receiving submissions on several aspects of the DRO relating to DVAs, no submissions were made in respect of Hydro One's calculation of the final disposition balance for its DVAs, which was calculated to be $44.0 million.

[26] Inflation less productivity

OEB Staff made a number of submissions relating to the accounting orders which Hydro One provided in the DRO and requested that further and amended accounting orders be included as part of this reply submission.[27] Hydro One's responses to OEB Staff's specific comments on the draft accounting orders are set out under subsection 4.1, below.

OEB Staff and intervenors also made specific submissions on Hydro One's proposed further modification to the Capital In-Service Variance Account ("**CISVA**") and on Hydro One's re-submitted request to establish the Transmission Foregone Revenue Deferral Account. These aspects are addressed below under subsections 4.2 and 4.3, respectively.

4.1 Accounting Orders

Customer Connection and Cost Recovery Agreement True-up ("CCRA") Variance Account and Earnings Sharing Mechanism ("ESM") Deferral Account

OEB Staff noted in their submission that the OEB approved the establishment of the CCRA True-up Variance Account and the ESM Deferral Account in the Decision and Order but that Hydro One did not file any updated draft accounting orders with the DRO. Consequently, OEB Staff requested that Hydro One file final draft accounting orders, and that for the ESM Deferral Account in particular that the final draft accounting order be updated to reflect the findings on pages 41 and 42 of the Decision and Order.[28] Hydro One notes that the draft accounting orders were previously filed in Attachment 3 and 4 of Exhibit H-1-2.

The final draft accounting orders for the CCRA True-up Variance Account and the ESM Deferral Account are provided in Exhibits 3.4 and 3.5, respectively.

[27] OEB Staff DRO Submission, p.14-18
[28] OEB Staff DRO Submission, p.13/14

Integrated System Operating Center ("ISOC") Asymmetrical Variance Account

In respect of the ISOC Asymmetrical Variance Account, OEB Staff requested clarification with respect to the adjustment which Hydro One proposed for the purpose of ensuring that any balance captured in the account would be excluded from the calculation of the Transmission CISVA.[29]

Hydro One clarifies that the CISVA and the ISOC Asymmetrical Variance Account are both asymmetrical to the benefit of ratepayers. As such, an entry is only recorded if the revenue requirement associated with actual capital assets placed in service is less than the revenue requirement associated with forecasted in-service additions as approved by the OEB. Since there is a separate asymmetrical variance account specifically for the ISOC, it would be inappropriate to include the variance between the actual and forecasted in-service dollars relating to this particular project in the CISVA. The adjustment would avoid the double counting that would result, which in Hydro One's view was not intended and would be unreasonably punitive, if an entry was required to both the CISVA and the ISOC Asymmetrical Variance Account due to under in-servicing for the ISOC. Furthermore, Hydro One submits that the language is consistent with the final OEB-approved rate order for distribution in EB-2017-0049.

OEB Staff also comment that the draft accounting order should be revised to reflect the use of Account 4110 – Transmission Services Revenue rather than Account 4050 – Revenue Adjustment.[30] While Hydro One acknowledges that Account 4110 may be more appropriate for this purpose, it would be inconsistent with Hydro One's prior practice. In particular, a similar accounting order was submitted in Hydro One's 2018-2022 Custom IR Application as part of the DRO,[31] which was subsequently approved by the OEB based on the use of Account 4050. Changing to Account 4110 would add complexity to the manner

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[29] OEB Staff DRO Submission, p.15
[30] OEB Staff DRO Submission, p.15/16
[31] EB-2017-0049 Draft Rate Order, Exhibit 10.0

in which Hydro One maps its General Ledger accounts to its regulatory accounts, and result in an inconsistency as between its transmission and distribution businesses. As such, while Hydro One respects the submission from OEB Staff on this point, it is the company's preference to maintain its use of Account 4050.

Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account

In respect of the Depreciation Expense (Asset Removal Cost) Asymmetrical Cumulative Variance Account, OEB Staff submitted that the accounting order should be updated to reflect the use of Account 4110 – Transmission Services Revenue rather than Account 4305 – Regulatory Debits.[32]

An updated accounting order for the Depreciation Expense (Asset Removal Cost) Asymmetrical Cumulative Variance Account, reflecting the requested change to Account 4110, is provided in Exhibit 3.1.

4.2 Capital In-Service Variance Account

Hydro One has proposed a further modification to the modified CISVA that was approved in the Decision and Order. The further modification is in response to uncertainties arising from the COVID-19 pandemic and would involve foregoing the 2020 CISVA calculation and instead performing the calculation on a cumulative basis in 2021, for the 2020 to 2021 period. OEB Staff supports the proposed further modification and agrees that Hydro One should not be penalized in the event that it underspends relative to its forecasted in-service additions in 2020 as a result of delayed capital investments due to the pandemic. OEB Staff also argues that, while not typical to address a proposed modification to the Decision and Order in the DRO stage, it was not possible to address it earlier and approving the request

[32] OEB Staff DRO Submission, p.16

during the DRO stage would achieve regulatory efficiency by avoiding the need for Hydro One to submit another application.[33]

VECC, SEC, LPMA and AMPCO oppose the proposed further modification to the CISVA.[34] Their reasons, and Hydro One's responses thereto, are as follows.

Separate Consultation Regarding the Impact of COVID-19

VECC, SEC, LPMA and AMPCO argue that the proposed modification to the CISVA should be denied on the basis that the appropriate forum for addressing the impact of COVID-19 is the generic consultation proceeding that the OEB has recently initiated.[35] The generic proceeding on the COVID-19 emergency is not the best forum for addressing the manner in which Hydro One's transmission CISVA operates, particularly given that this issue may be most efficiently addressed now, as part of this proceeding.

The concern from intervenors, which is not shared by OEB Staff, should therefore be dismissed. Whereas the generic proceeding was established to consider the basis on which incremental costs or revenue loss related to COVID-19 will be tracked and eventually disposed of, the proposed further modification to the CISVA does not concern incremental costs or revenue loss from COVID-19. Rather, the proposed further modification to the CISVA is about ensuring that Hydro One's CISVA works as intended and does not, as a result of the unforeseen circumstances relating to the pandemic, unfairly and unreasonably penalize Hydro One for delays in its in-service additions during this unprecedented period.

The CISVA was established in response to concerns about historical variances between forecast and actual in-service additions and on that basis is designed to protect customers

[33] OEB Staff DRO Submission, p. 17
[34] VECC DRO Submission, p. 1, SEC DRO Submission, p. 2-3, LPMA DRO Submission, p. 2, AMPCO DRO Submission, p. 2
[35] VECC DRO Submission, p. 1, SEC DRO Submission, p. 2-3, LPMA DRO Submission, p. 2, AMPCO DRO Submission, p. 2

from potential underspending on Hydro One's capital plan that may occur in the normal course. Through the proposed further modification, the CISVA will continue to serve this important purpose, but without inadvertently accounting for delayed in-service additions during 2020 which if any, are expected to be largely attributable to the pandemic. To do so would be unfair to Hydro One as it would penalize the company for behavior over which it has no control, and due to the asymmetrical nature of the account would not provide Hydro One the ability make up for 2020 delays without being penalized in 2020.

Additionally, the consultation process is addressing issues which are generic to the industry, including electricity generators, transmitters, distributors and gas distributors. The mechanics of the CISVA are unique to Hydro One's transmission business as transmission projects are generally multi-year and large scale in nature. Consequently, meeting annual in-service addition targets is highly dependent on specific projects.

Evidence of the Need for Further Modification of the CISVA and Making the Request in the DRO

VECC and LPMA argue that the proposed further modification of the CISVA should be denied on the basis that the proposal has not been tested throughout the proceeding.[36] SEC takes an even more rigid view and argues that the proposed modification to the CISVA should be denied on the basis that it is effectively a motion to review and vary and the DRO should only concern implementation of the Decision and Order into final rates.[37]

Hydro One acknowledges that this particular proposal was not contemplated during the proceeding. However, no party could have anticipated the circumstances of the pandemic in the design of the CISVA as contemplated during the hearing. Hydro One has proposed this further modification to the CISVA at its first opportunity to do so and included

[36] VECC DRO Submission, p. 1, LPMA DRO Submission, p. 2
[37] SEC DRO Submission, p. 2-3

appropriate information in its DRO sufficient to enable parties to consider and make informed submissions on the proposal. With support from OEB Staff, who recognize the regulatory efficiency of dealing with the request through the DRO process, the proposal will avoid the company having to submit a separate application for the modification. The OEB has broad discretion in the methodologies it uses to establish rates and, in Hydro One's submission, addressing the proposed further modification to the CISVA through the DRO process is, in the circumstances, an appropriate exercise of that discretion.

Distinguishing Between In-Service Delays Due to COVID-19 and Other Reasons

LPMA and AMPCO argue that the proposed further modification to the CISVA should be denied on the basis that a methodology to distinguish between COVID-19 related delays and delays due to other factors has not been established and it would be difficult to differentiate between the two types of delays.[38]

To clarify, in light of the uniqueness of the situation, the discrete nature of the modification, as well as for the purposes of regulatory and administrative efficiency, Hydro One is not proposing to differentiate between COVID-19 delays and delays caused by other factors in 2020. The calculation will be performed in 2021 to reflect any and all delays in in-service additions for 2020 and 2021 on a cumulative basis.

While this may ultimately include delays caused by circumstances related to the pandemic, it is Hydro One's expectation based on circumstances as of the date of this reply submission that being able to measure in-service additions over the combined 2020 to 2021 period will provide the company with a reasonable period in which to overcome delays to capital projects caused by the COVID-19 emergency and to develop and implement effective solutions for working within any ongoing pandemic-related constraints that may

[38] LPMA DRO Submission, p. 2; AMPCO DRO Submission, p. 2

persist over this period. Furthermore, as submitted by Hydro One in the DRO[39] and supported by OEB Staff[40], the company intends to notify the OEB as part of the 2022 annual update, whether the planned in-service additions for 2020 and 2021 have been materially impacted by the COVID-19 pandemic, and if so that it be provided with an opportunity to extend the relief to the CISVA to 2022. This would provide Hydro One with the opportunity to catch up on its 2020 and 2021 in-service additions in 2022 without booking an amount to the CISVA in 2020 or 2021. Alternatively, Hydro One indicated that the OEB could extend the modification requested to 2022 with the provision that in the event that COVID-19 impacts continued to be an issue in 2021, Hydro One could elect to attempt to catch-up in 2022 and treat the CISVA account as cumulative in respect of in-service additions in 2020, 2021 and 2022.

Impact of the Further Modification on the Company

SEC argues that the proposed further modification to the CISVA should be denied on the basis that the proposal would result in the company being over-compensated.[41] AMPCO argues that the proposed further modification removes the benefit of returning any revenue requirement impact associated with delays in in-service additions or if work costs less.[42]

Hydro One submits that the proposed modification would not over-compensate the company but, instead, will ensure that the company is not unfairly penalized. It will provide reasonable and limited flexibility to Hydro One so as to not detract from the underlying objective of the account. Hydro One reiterates that while the intent of the CISVA account is to protect customers from potential underspending on Hydro One's capital plan that may occur in the normal course, it is not intended to be punitive and should not be punitive to Hydro One for delayed capital investments and the associated in-

[39] Hydro One DRO, p.30/31
[40] OEB Staff DRO Submission, p. 17
[41] SEC DRO Submission, p. 3
[42] AMPCO DRO Submission, p. 2

service additions due to the unprecedented and unforeseeable circumstances relating to the COVID-19 pandemic, which are beyond Hydro One's control. Hydro One remains committed to driving the right behaviors and achieving its planned outcomes over this period, in a safe manner.

To maintain consistency with the Depreciation Expense (Asset Removal Cost) Asymmetrical Cumulative Variance Account, Hydro One is providing a revised draft accounting order for the CISVA updated for the mapping of proposed revenue accounts in Exhibit 3.2.

4.3 Foregone Transmission Revenue Deferral Account

Given OEB Staff's support for Hydro One's proposed implementation alternatives (discussed in subsection 6.4, below), OEB Staff also expressed support for establishing the Foregone Transmission Revenue Deferral Account, including the interest calculation consistent with other OEB-approved DVAs. In respect of the draft accounting order which Hydro One provided as part of the DRO submission, OEB Staff commented that Account 1509 – Impacts Arising from the COVID-19 Emergency should be used instead of Account 1508 – Other Regulatory Assets, Sub-account Foregone Revenue Transmission Deferral Account, as proposed by Hydro One.

While Hydro One acknowledges OEB Staff's general support for the account, Hydro One respectfully disagrees with OEB Staff's submission on the appropriate account to be used. In its submission, OEB Staff argues that Account 1509 should be used because in accordance with its April 29, 2020 accounting order that is the account that is to be used by transmitters to record lost revenues resulting from the COVID-19 emergency.[43] However, in Hydro One's view Account 1508 is more appropriate for several reasons.

[43] OEB Staff Submission, p. 18

First, the use of Account 1508 is consistent with Hydro One's Foregone Transmission Revenue Deferral Account final OEB-approved accounting order in its 2017-2018 transmission revenue requirement application (EB-2016-0160).

Second, while it is correct that the OEB's letter of April 17, 2020 directs distributors electing to defer implementation of May 1, 2020 rates to track temporarily foregone revenue in Account 1509, in the case of Hydro One Transmission, the company is providing the OEB with options to defer the implementation date for rates relative to the date that the OEB already established in its Decision and Order. Under any of the options that have been presented to the OEB, a foregone transmission revenue deferral account would be required and a foregone revenue amount would be approved as part of the current proceeding. These are circumstances that support and are consistent with the historical use of Account 1508, rather than Account 1509.

Third, the OEB has commenced a consultation on Account 1509 – Impacts Arising from the COVID-19 Emergency but has yet to provide clear guidance on the eligibility requirements for amounts to be recorded in the account, the timing for disposition, and the process or criteria for review for disposition. With respect to any amounts of foregone revenue that Hydro One may have as a result of the delayed implementation of rates under one of the alternative options it has proposed, while it would be expected that the OEB would review any balance for disposition to ensure it has been appropriately calculated, it would not be appropriate for such amounts to be subject to the uncertain outcome of the OEB's consideration in the consultation process as to such matters as the timing for disposition and process or criteria for disposition review. In Hydro One's circumstances, the foregone revenue is revenue that the OEB would be approving as part of the current proceeding. It is only the timing for recovery that would be delayed. Accordingly, Hydro One submits that it would be appropriate for Hydro One to record the foregone transmission revenue resulting from the selection of any of the implementation alternatives in Account 1508.

Furthermore, OEB Staff commented that any interest on foregone revenue should be recorded in Account 4405 - Interest and Dividend Income, rather than Account 6305 – Other Interest Expense as previously proposed. An updated accounting order for the Foregone Transmission Revenue Deferral Account, reflecting this change, is provided in Exhibit 3.3.

Intervenors – VECC, SEC, LPMA and AMPCO – express support for the establishment of the Foregone Transmission Revenue Deferral Account in the event that the OEB selects one of the proposed implementation alternatives. However, they oppose the application of interest to balances recorded in the deferral account.[44]

Hydro One believes that including carrying charges on the account is appropriate and consistent with the long-established OEB practice of applying carrying charges to DVAs, as the interest represents and reasonably accounts for the time value of the money for which recovery (or the return of funds) has been deferred. Additionally, including carrying charges is consistent with the approach the OEB has taken with distributors which elected to defer May 1, 2020 rate implementation to November 1, 2020. There, the OEB indicated that carrying charges would apply to the distribution revenue component associated with the postponed implementation of May 1, 2020 rates.[45]

In regards to VECC's statements that the interest rate associated with the carrying charge will be out of date and too high given that interest rates have declined due to the pandemic,[46] Hydro One notes that the prescribed interest rates for DVAs is set by the OEB on a quarterly basis to reflect the most up to date market conditions. At the time VECC filed its submission, it would have been referring to the OEB's Q2 prescribed interest rate for approved regulatory accounts of 2.18%. However, on June 16, 2020, the OEB issued

[44] VECC DRO Submission, p. 1, SEC DRO Submission, p. 5, LPMA DRO Submission, p. 3, AMPCO DRO Submission, p. 2
[45] Letter regarding *Initial Implementation Guidance to Incentive Rate-setting Decisions for May 1, 2020 Rates for Postponing Distributors*, April 17, 2020
[46] VECC DRO Submission, p. 1

its updated interest rate for Q3, which reduced the applicable rate to 1.38%. As such, it appears that VECC's argument on this point is moot.

5 TRANSMISSION SCORECARD

In the Decision and Order, the OEB requested the addition of a metric to measure the accomplishment of the System Renewal program at the portfolio level, to demonstrate the degree to which Hydro One is able to complete its planned program within the approved budget for this work category. In the DRO Hydro One revised the Capital Program Accomplishment (composite index) ("**CPAI**") measure to include an additional eleven components from the System Renewal category and revised the name to the Transmission Capital Accomplishment Index ("**TCAI**"). Hydro One proposed the TCAI measure, which offers additional units of accomplishment that were representative of the System Renewal category including transformers, breakers, protections, and circuit kilometers that covered over 80% of the System Renewal portfolio.

OEB Staff commented that Hydro One should explain why it was unable to design a metric to cover the entire System Renewal program as directed by the OEB and that Hydro One should provide additional clarification on how projects or programs will be divided or subdivided into units planned and units installed.[47] SEC submits that Hydro One should be required to file the revised planned units and budgets for each program that the actual accomplishments will be compared against.[48]

The portion of the portfolio not captured in the TCAI is made up of investments that are demand driven or do not have planned power system units of accomplishment which are sufficiently uniform for purposes of measurement on a scorecard. This includes demand investments that respond to unexpected asset failures. Since the type and quantity of units

[47] OEB staff DRO Submission, p. 8-9
[48] SEC DRO Submission p. 5

accomplished within these investments is related to unplanned events that vary from case to case, it is not appropriate to include these accomplishments in the metric. Investments that do not have planned power system units of accomplishment include NERC driven investments and telecom solutions, where each site may require a slightly different solution such that there is no uniform ‘unit’ of accomplishment.

In any event, the TCAI remains a valid and effective performance measure since Hydro One included in this metric the major assets associated with station centric and lines refurbishment projects being transformers, breakers, protections and circuit kilometers. These assets are the primary drivers for the System Renewal category and the expected outcomes for this investment category. The accomplishment of Hydro One in achieving the planned System Renewal program is properly reflected in placing in-service these assets and is appropriately measured by the TCAI.

This metric is but one element which can demonstrate the degree to which Hydro One is able to complete the planned capital program within the approved budget for the System Renewal category. The TCAI measure is meant to be evaluated in the context of other measures presented in Transmission scorecard and with the understanding that the measure itself is a blend of programs and projects.

SEC requested that Hydro One file the revised units and budgets for each program that the actual accomplishment will compared against.

Consistent with the OEB’s Decision and Order, the TCAI is a measure of unit accomplishment.[49] Unit accomplishments for each System Renewal investment included in the TCAI have been revised to reflect the Decision and Order and have been presented in Table 7 below. As shown in Table 7, the importance of a particular asset relative to the

[49] Hydro One’s evolved Transmission Scorecard in TSP Section 1.5 includes the ‘CapEx as % of Budget’ metric to measure capital spending accomplishments.

other assets captured by the measure is represented by relative weightings. The relative weightings are not a one-to-one link to the capital expenditure budget amounts reflected in the Decision and Order for each system renewal investment category (as shown in Table 7). This is because the forecasted amount for System Renewal project-based investments include expenditures that are for the main power system assets that are installed (and considered in the TCAI) as well as other costs related to ancillary activities and components that are in addition to the cost of the main power system assets but are required to be done as part of the project - for example, fencing or ground grid in the case of certain station work. As a result, it is not appropriate to use forecasted investment amounts of each System Renewal category for the purpose of weighing project-based power system assets relative to other project or program assets. Hydro One expects that the assumptions underpinning the TCAI measure and resulting accomplishments will be evaluated by the Board in Hydro One's next rate application.

Table 7 – Revised Planned Units and Budgets for the TCAI

Segment	Units	Weighting (a)	Units Planned (b) 2020-2022	Units Completed (c)	Completion (d) Units Completed (c) ÷ Units Planned (b)	Weighted Index (e) Completion (d) × Weighting (a)
SR-01 Air Blast Circuit Breaker Replacement Projects	# of breakers	11%	339	339	100%	11%
SR-02 Station Reinvestment Projects	# of protections	11%		1,112	100%	11%
SR-03 Bulk Station Transformer Replacement Project			1,112			
SR-04 Bulk Station Switchgear and Ancillary Equipment Replacement Project	# of transformers	15%		40	100%	15%
SR-05 Load Station Transformer Replacement Project			40			
SR-06 Load Station Switchgear and Ancillary Equipment Replacement Project						
SR-07 Protection and Automation Replacement Project						
SR-08 John Transformer Station Reinvestment Project						
SR-09 Transmission Station Transformer Spares	# of transformers	4%		20	100%	4%
			20			
SR-19/20 Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	# of km of circuit replaced	26%	634	634	100%	26%
SR-21 Wood Pole Structure Replacement	# of structures	11%		3,003	100%	11%
			3,003			
SR-22 Steel Structure Coating Program	# of structures	4%		1,315	100%	4%
			1,315			
SR-23 Tower Foundation Assess/Clean/Coat Program	# of structures	2%		2,542	100%	2%
			2,542			
SR-24 Shieldwire Replacement Program	# of km of shieldwire replaced	3%	953	953	100%	3%
SR-25 Tx Lines Insulator Replacement Program	# of structures	14%	10,898	10,898	100%	14%
SR-27 C5E/C7E Underground Cable Replacement Project	# of km of underground cable replaced	0%	-	-	0%	0%
					Transmission Capital Accomplishment Index	**100%**

6 RATES

6.1 Rates Revenue Requirement and Charge Determinants by Rate Pool

OEB Staff notes that the percentage splits of total revenue requirement by rate pool presented in the DRO reconcile with the allocation results filed in Hydro One's application, and that Hydro One has accurately allocated revenue offset items to the rate pools.[50] Intervenors did not comment on this issue.

6.2 Export Transmission Service

OEB Staff notes that it takes no issues with the amount of ETS revenues included in Hydro One's revenue requirement for setting UTRs.[51] Intervenors did not comment on the ETS revenue amount.

6.3 Uniform Transmission Rate Schedules

OEB Staff commented that the UTR schedules prepared by Hydro One used Niagara Reinforcement Limited Partnership's ("**NRLP**") interim revenue requirement but that a final revenue requirement for NRLP has since been established.[52] Consistent with this comment from OEB Staff, Hydro One submits that the final B2M Limited Partnership ("**B2M**") 2020 revenue requirement (EB-2019-0178) should also be updated in the UTR schedules, which currently reflect only the interim B2M revenue requirement. As such, Hydro One has updated the UTR schedules and foregone revenue calculations to reflect

[50] OEB Staff submission, p. 19.
[51] OEB Staff submission, p. 20.
[52] OEB Staff submissions p. 20.

NRLP's[53] and B2M's 2020 revenue requirements as approved by the OEB on June 4, 2020 and February 20, 2020, respectively. These updated schedules and calculations are enclosed with this reply submission.

6.4 Implementation Alternatives for Consideration in UTR Proceeding

To assist the OEB in its upcoming UTR implementation proceeding and in light of its observations in the Decision and Order and other recent decisions regarding the impacts of the COVID-19 emergency, Hydro One identified three alternatives for the OEB to consider as part of the UTR implementation proceeding. The foregone revenue amounts associated with the implementation alternatives have changed slightly to reflect the update to the NRLP and B2M 2020 revenue requirement, as discussed in subsection 6.3. The implementation alternatives are reproduced below for ease of reference.

> **Alternative 1**: Implement Hydro One's approved 2020 revenue requirement and charge determinants in update to UTRs on July 1, 2020 but *defer* collection of Hydro One's January to June 2020 Foregone Revenue of $28.2 million[54] to January 1, 2021 *over a period of one year*.

> **Alternative 2**: Maintain interim UTRs to the end of 2020. On January 1, 2021 implement UTRs for 2021 to reflect Hydro One's approved 2021 revenue requirement, the approved charge determinants, and collect Hydro One's January to December 2020 Foregone Revenue of $57.4 million[55] *over a period of one year*.

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[53] As per Schedule A of the OEB's NRLP Revenue Requirement and Charge Determinant Order (EB-2018-0275) issued on June 4, 2020, the approved 2020 Rates Revenue Requirement is $13,160,593, which includes both the base revenue requirement of $8,662,167 and NRLPDA of $4,498,426.

[54] This amount is the January to June foregone revenue amount shown in Exhibit 2.3.2, and would be subject to interest improvement. Intervenor submissions regarding interest improvement are addressed in conjunction with Hydro One's reply submissions regarding the foregone revenue account, above.

[55] This amount is the January to December foregone revenue amount shown in Exhibit 2.3.2, and would be subject to interest improvement. Intervenor submissions regarding interest improvement are addressed in conjunction with Hydro One's reply submissions regarding the foregone revenue account, above.

> **Alternative 3**: Maintain interim UTRs to the end of 2020. On January 1, 2021 implement UTRs for 2021 to reflect Hydro One's approved 2021 revenue requirement, the approved charge determinants, and collect Hydro One's January to December 2020 Foregone Revenue of $57.4 million[56] *over a period of two years*.

The estimated impact on UTRs and average customer bills for each of the Decision and Order and the three alternatives remain as set out in Table 11 of the DRO.

OEB Staff, SEC and AMPCO agreed with Hydro One that Alternative 3 is the preferred alternative.[57] LPMA did not agree that the OEB should adopt any of the three alternatives, but if one of the three were to be adopted, Alternative 1 was preferred by LPMA. VECC was non-committal, indicating that it was sensitive to rate impacts at the current time but also seeing merit in the LPMA position.

As indicated in the DRO, Hydro One's concern with proceeding with UTR implementation on July 1, 2020 is that directly-connected customers and directly-connected LDCs will experience the effects of a rate increase[58] during the COVID-19 emergency. While the UTR implementation date is a matter for the OEB to determine as part of the UTR implementation proceeding, Hydro One submits that the OEB should carefully consider what option would best help support Ontario electricity customers and LDCs experiencing liquidity concerns during this difficult time. Notwithstanding that the UTR implementation date is a question for determination in the UTR implementation proceeding, the OEB may find it necessary in the present proceeding to at least determine whether it intends to maintain the implementation date contemplated in the Decision and Order or adopt one of

[56] This amount is the January to December foregone revenue amount shown in Exhibit 2.3.2, and would be subject to interest improvement. Intervenor submissions regarding interest improvement are addressed in conjunction with Hydro One's reply submissions regarding the foregone revenue account, above.
[57] OEB Staff submissions p. 24; AMPCO submissions p. 1; SEC submissions p. 5 (SEC indicated that Alternative 3 was the preferred option as between Alternative 2 and Alternative 3, it explained that as its member schools are not transmission connected customers, they would not see the change in UTRs on their bills until January 1, 2021 when distributors RTSRs are adjusted).
[58] As noted in the DRO, the increase is due to the re-set of Hydro One's revenue requirement and charge determinants reflecting the OEB-approved load forecast.

the alternatives (with the specific alternative to be considered and determined in the UTR proceeding), as this initial decision point will impact the OEB's consideration as to whether a Foregone Transmission Revenue Deferral Account should be established for Hydro One in the present proceeding.

Input on Alternative Implementation Dates from other Ontario Transmitters

In its submission, OEB Staff commented that the selection of a particular implementation approach should consider the impact on other affected transmitters. To this end, OEB Staff commented that Hydro One Transmission has partnership arrangements with Hydro One Sault Ste. Marie ("**HOSSM**"), B2M and NRLP, so should be able to confirm their agreement with Alternative 3, and that Hydro One should also confirm that there would be no material impact on the other two transmitters, Five Nations Energy Inc. ("**FNEI**") and Canadian Niagara Power Inc. ("**CNPI**").

Hydro One can confirm that HOSSM, which is wholly-owned by Hydro One Inc., is in agreement with Alternative 3. With respect to B2M LP and NRLP, which as OEB Staff notes are partnerships between subsidiaries of Hydro One Inc. and unaffiliated third parties, Hydro One can confirm that these transmitters are also in agreement with Alternative 3. As part of the OEB's process to reset UTRs, HOSSM, B2M LP and NRLP will identify their foregone revenue associated with the implementation date that the OEB selects for resetting UTRs. Moreover, if the OEB selects one of the alternative UTR implementation dates, HOSSM, B2M LP and NRLP's position is that it is appropriate to include a carrying charge on the associated foregone transmission revenue account as the interest simply represents the time value of money and to include the carrying change is consistent with prior OEB practice of applying carrying charges to deferral and variance accounts established by the OEB.

With respect to FNEI and CNPI Hydro One believes that it would be more appropriate for the OEB to seek feedback directly from these transmitters, who are not related to Hydro

One, and request their input on the proposed implementation alternatives and as part of the OEB's UTR implementation proceeding.

7 SUPPORTING MATERIAL

Detailed supporting information for the DRO, revised in accordance with these reply submissions, is provided in the following Exhibits.

Tab 1

Appendix A – ISA Reductions and CCA

Tab 2

Revised DRO Exhibit 2.3.1 to 2.3.3 – 2020 Foregone Revenue calculations:

Revised DRO Exhibit 2.3.1 2020 UTR for Foregone Revenue calculations

Revised DRO Exhibit 2.3.2 2020 Monthly Foregone Revenue calculations

Revised DRO Exhibit 2.3.3 Annualized 2020 Foregone Revenue calculations

Revised DRO Exhibit 2.4 – 2020 Rates Revenue Requirement by Rate Pool (including Annualized Foregone Revenue)

Revised DRO Exhibit 2.6.1 & 2.6.2 – Proposed 2020 UTR Schedule (July 1, 2020 implementation):

Revised DRO Exhibit 2.6.1 Revenue Requirement and Disbursement Allocators

Revised DRO Exhibit 2.6.2 UTR Rate Schedule (including ETS Rate)

Tab 3

Revised DRO Exhibit 3.1 – Depreciation Expense (Asset Removal Costs)

Asymmetrical Cumulative Variance Account – Accounting Order

Revised DRO Exhibit 3.2 – Modified CISVA – Accounting Order

Revised DRO Exhibit 3.3 – Foregone Revenue – Accounting Order

Exhibit 3.4 – CCRA True-up Variance Account – Accounting Order

Exhibit 3.5 – ESM Deferral Account – Accounting Order

Tab 1

CCA Calculations from change in tax additions

The decrease in additions above translates to a reduction of CCA for each of the respective years as follows

2020

CCA Class	Opening UCC	Net Additions	UCC Pre-1/2 year	Adjusted Additions	UCC for CCA	CCA Rate	CCA	Closing UCC
CHANGE IN TAX ADDITIONS		(70.4)						
1	-	(6.5)	(6.5)	(2.5)	(9.0)	4%	(0.4)	(6.1)
2	-	0.0	-	-	-	6%	-	-
3	-	0.0	-	-	-	5%	-	-
6	-	0.0	-	-	-	10%	-	-
7	-	0.0	-	-	-	15%	-	-
8	-	(6.7)	(6.7)	(2.5)	(9.2)	20%	(1.8)	(4.8)
9	-	0.0	-	-	-	25%	-	-
10	-	(3.0)	(3.0)	(1.2)	(4.2)	30%	(1.3)	(1.8)
12.0	-	4.6	4.6	(0.6)	4.1	100%	4.1	0.6
13	-	0.0	-	-	-	0%	-	-
14.1	-	(3.6)	(3.6)	(1.4)	(5.0)	5%	(0.2)	(3.3)
17	-	(1.2)	(1.2)	(0.5)	(1.7)	8%	(0.1)	(1.1)
35	-	0.0	-	-	-	7%	-	-
42	-	0.0	-	-	-	12%	-	-
45	-	0.0	-	-	-	45%	-	-
46	-	0.0	-	-	-	30%	-	-
47	-	(54.0)	(54.0)	(20.5)	(74.5)	8%	(6.0)	(48.1)
50		0.0	0.0	0.0	0.0	55%	0.0	0.0
			-					
	-	(70.4)	(70.4)	(29.1)	(99.5)		(5.7)	(64.7)

2021

CCA Class	Opening UCC	Net Additions	UCC Pre-1/2 year	Adjusted Additions	UCC for CCA	CCA Rate	CCA	Closing UCC
CHANGE IN TAX ADDITIONS		(199.8)						
1	(6.1)	(1.7)	(7.8)	(0.70)	(8.5)	4%	(0.3)	(7.5)
2	-	-	-	-	-	6%	-	-
3	-	-	-	-	-	5%	-	-
6	-	-	-	-	-	10%	-	-
7	-	-	-	-	-	15%	-	-
8	(4.8)	(28.0)	(32.9)	(11.78)	(44.6)	20%	(8.9)	(23.9)
9	-	-	-	-	-	25%	-	-
10	(1.8)	(2.4)	(4.1)	(0.99)	(5.1)	30%	(1.5)	(2.6)
12	0.6	(10.4)	(9.8)	-	(9.8)	100%	(9.8)	-
13	-	0.3	0.3	0.14	0.5	0%	-	0.3
14.1	(3.3)	(0.1)	(3.5)	(0.04)	(3.5)	5%	(0.2)	(3.3)
17	(1.1)	0.5	(0.6)	0.20	(0.4)	8%	(0.0)	(0.6)
35	-	-	-	-	-	7%	-	-
42	-	-	-	-	-	12%	-	-
45	-	-	-	-	-	45%	-	-
46	-	-	-	-	-	30%	-	-
47	(48.1)	(158.9)	(206.9)	(66.73)	(273.7)	8%	(22.0)	(184.9)
50		0.9	0.9	0.39	1.3	55%	0.7	0.2
	(64.7)	(199.8)	(264.4)	(79.5)	(343.9)		(42.1)	(222.3)

2022

CCA Class	Opening UCC	Net Additions	UCC Pre-1/2 year	Adjusted Additions	UCC for CCA	CCA Rate	CCA	Closing UCC
CHANGE IN TAX ADDITIONS		18.4						
1	(7.5)	7.6	0.2	3.81	4.0	4%	0.2	(0.0)
2	-	-	-	-	-	6%	-	-
3	-	-	-	-	-	5%	-	-
6	-	-	-	-	-	10%	-	-
7	-	-	-	-	-	15%	-	-
8	(23.9)	(11.9)	(35.8)	(5.93)	(41.7)	20%	(8.3)	(27.4)
9	-	-	-	-	-	25%	-	-
10	(2.6)	(2.1)	(4.7)	(1.03)	(5.7)	30%	(1.7)	(3.0)
12	-	13.0	13.0	-	13.0	100%	13.0	-
13	0.3	(0.4)	(0.1)	(0.21)	(0.3)	0%	-	(0.1)
14.1	(3.3)	(0.4)	(3.6)	(0.18)	(3.8)	5%	(0.2)	(3.5)
17	(0.6)	1.0	0.4	0.50	0.9	8%	0.1	0.3
35	-	-	-	-	-	7%	-	-
42	-	-	-	-	-	12%	-	-
45	-	-	-	-	-	45%	-	-
46	-	-	-	-	-	30%	-	-
47	(184.9)	7.6	(177.3)	3.81	(173.5)	8%	(13.9)	(163.5)
50	0.2	3.9	4.1	1.94	6.0	55%	3.3	0.8
	(222.3)	18.4	(203.9)	2.7	(201.2)		(7.6)	(196.3)

Tab 2

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

2020 Interim Uniform Transmission Rates and Revenue Disbursement Allocators (Updated for H1N, NRLP and B2MLP's 2020 Revenue Requirement and Charge Determinants, excluding 2020 Foregone Revenue)

Effective January 1, 2020 to December 31, 2020

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,790,719	$914,623	$2,282,750	$7,988,092
CNPI	$2,787,078	$532,096	$1,328,027	$4,647,201
H1N SSM	$24,480,432	$4,673,695	$11,664,787	$40,818,914
H1N	$951,027,050	$181,565,841	$453,159,011	$1,585,751,902
B2MLP	$33,192,514	$0	$0	$33,192,514
NRLP	$13,160,593	$0	$0	$13,160,593
All Transmitters	$1,029,438,386	$187,686,255	$468,434,575	$1,685,559,216

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	235,252.608	228,852.936	195,027.487	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	239,504.148	232,385.678	196,285.037	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**4.30**	**0.81**	**2.39**	
FNEI Allocation Factor	**0.00465**	**0.00487**	**0.00487**	
CNPI Allocation Factor	**0.00271**	**0.00284**	**0.00284**	
H1N SSM Allocation Factor	**0.02378**	**0.02490**	**0.02490**	
H1N Allocation Factor	**0.92384**	**0.96739**	**0.96739**	
B2MLP Allocation Factor	**0.03224**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.01278**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

* The sum of 12 monthly charge determinants for the year.

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2016-0231 dated January 18, 2018.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016.

Note 3: H1N SSM 2020 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0266 dated December 17, 2019.

Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0082, issued April 23, 2020, as per Exhibit 2.2, Table 1 in Hydro One's DRO filed on May 28, 2020.

Note 5: B2M LP 2020 Revenue Requirement per OEB Decision and Order EB-2019-0178 dated February 20, 2020.

Note 6: NRLP 2020 Revenue Requirement per OEB Decision and Order EB-2018-0275 June 04, 2020.

Note 7: Calculated data in shaded cells.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

2020 Foregone Revenue Calculation

Table 1 - HONI Transmission Charge Determinant Forecast for the Year 2020 (MW)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	19,819	19,585	18,899	17,431	18,573	20,969	21,952	21,462	19,838	17,848	18,963	19,916	235,253
Line Connection	19,027	18,888	18,096	16,875	18,261	20,052	21,443	20,836	19,425	17,750	18,431	19,770	228,853
Transformation Connection	16,265	16,204	15,558	14,317	15,623	17,203	18,432	17,785	16,900	14,558	15,443	16,739	195,027

Table 2 - Monthly Charge Determinant Share of Annual Total

% Share	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	8.42%	8.32%	8.03%	7.41%	7.89%	8.91%	9.33%	9.12%	8.43%	7.59%	8.06%	8.47%	100.00%
Line Connection	8.31%	8.25%	7.91%	7.37%	7.98%	8.76%	9.37%	9.10%	8.49%	7.76%	8.05%	8.64%	100.00%
Transformation Connection	8.34%	8.31%	7.98%	7.34%	8.01%	8.82%	9.45%	9.12%	8.67%	7.46%	7.92%	8.58%	100.00%

Table 3 - 2020 UTR Charge Determinant (including all Transmitters)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	20,177	19,938	19,241	17,746	18,908	21,348	22,348	21,850	20,196	18,170	19,305	20,276	239,504
Line Connection	19,321	19,179	18,376	17,135	18,543	20,362	21,774	21,157	19,725	18,024	18,715	20,075	232,386
Transformation Connection	16,370	16,309	15,658	14,410	15,724	17,314	18,551	17,899	17,009	14,652	15,543	16,847	196,285

Table 4 - 2020 Interim UTR*

	$/kw-month	Hydro One Revenue Allocators
Network	3.92	0.92606
Line Connection	0.97	0.96747
Transformation Connection	2.33	0.96747

* As per Exhibit 2.5.1, in Hydro One's DRO filed on May 28, 2020

Table 5 - 2020 Revenue at 2020 Interim UTR and 2020 Load Forecast (Table 3 x Table 4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	73.2	72.4	69.8	64.4	68.6	77.5	81.1	79.3	73.3	66.0	70.1	73.6	869.4
Line Connection	18.1	18.0	17.2	16.1	17.4	19.1	20.4	19.9	18.5	16.9	17.6	18.8	218.1
Transformation Connection	36.9	36.8	35.3	32.5	35.4	39.0	41.8	40.3	38.3	33.0	35.0	38.0	442.5
Total	**128.3**	**127.1**	**122.4**	**113.0**	**121.5**	**135.6**	**143.4**	**139.5**	**130.2**	**115.9**	**122.7**	**130.4**	**1,530.0**

Table 6 - Proposed 2020 UTR**

	$/kw-month	Hydro One Revenue Allocators
Network	4.30	0.92384
Line Connection	0.81	0.96739
Transformation Connection	2.39	0.96739

** As per Exhibit 2.3.1

Table 7 - 2020 Revenue at Proposed 2020 UTR and 2020 Load Forecast (Table 3 x Table 6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	80.2	79.2	76.4	70.5	75.1	84.8	88.8	86.8	80.2	72.2	76.7	80.5	951.4
Line Connection	15.1	15.0	14.4	13.4	14.5	16.0	17.1	16.6	15.5	14.1	14.7	15.7	182.1
Transformation Connection	37.8	37.7	36.2	33.3	36.4	40.0	42.9	41.4	39.3	33.9	35.9	39.0	453.8
Total	**133.1**	**131.9**	**127.0**	**117.2**	**126.0**	**140.8**	**148.7**	**144.8**	**135.0**	**120.2**	**127.3**	**135.2**	**1,587.4**

Table 8 - 2020 Forgone Revenue (Table 7 Revenue at Proposed Rates - Table 5 Revenue at Current Rates)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	6.9	6.8	6.6	6.1	6.5	7.3	7.7	7.5	6.9	6.2	6.6	6.9	82.0
Line Connection	-3.0	-3.0	-2.8	-2.7	-2.9	-3.2	-3.4	-3.3	-3.1	-2.8	-2.9	-3.1	-36.0
Transformation Connection	0.9	0.9	0.9	0.8	0.9	1.0	1.1	1.0	1.0	0.8	0.9	1.0	11.4
Total	**4.9**	**4.8**	**4.6**	**4.3**	**4.5**	**5.2**	**5.4**	**5.2**	**4.8**	**4.3**	**4.6**	**4.8**	**57.4**

Foregone Revenue for January 1, 2020 to June 30, 2020: **$28,233,896**

Foregone Revenue for January 1, 2020 to December 31, 2020: **$57,365,091**

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

Derivation of Annualized 2020 Foregone Revenue

Rate Pool	Sum of 12 Monthly Charge Determinants (A)	Sum of Monthly Charge Determinants for Jul-Dec (B)	Foregone Revenue for January to June 2020* (C)	Annualized Foregone Revenue (D=A/B*C)
Network	239,504	122,146	$40,178,228	$78,781,311
Line Connection	232,386	119,470	($17,486,131)	($34,012,961)
Transformation Connection	196,285	100,501	$5,541,799	$10,823,537
			$28,233,896	**$55,591,887**

* As per Exhibit 2.3.2

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

2020 Rates Revenue Requirement for Uniform Transmission Rates To Be Implemented on July 1, 2020

	Network	Line Connection	Transformation Connection	Total
Rates Revenue Requirement (Excl. Foregone Revenue) ($M)	$951.0	$181.6	$453.2	$1,585.8
Annualized Foregone Revenue ($M)*	$78.8	($34.0)	$10.8	$55.6
Total Rates Revenue Requirement (Incl. Foregone Revenue) ($M)	**$1,029.8**	**$147.6**	**$464.0**	**$1,641.3**

*As per Exhibit 2.3.3

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

Uniform Transmission Rates and Revenue Disbursement Allocators (Including Annualized 2020 Foregone Revenue)
Effective January 1, 2020 to December 31, 2020
Implementation on July 1, 2020

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$5,011,871	$718,110	$2,258,110	$7,988,092
CNPI	$2,915,737	$417,772	$1,313,692	$4,647,201
H1N SSM	$25,610,515	$3,669,523	$11,538,877	$40,818,914
H1N	$1,029,808,361	$147,552,881	$463,982,548	$1,641,343,790
B2MLP	$33,192,514	$0	$0	$33,192,514
NRLP	$13,160,593	$0	$0	$13,160,593
All Transmitters	$1,109,699,591	$152,358,286	$479,093,227	$1,741,151,104

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	235,252.608	228,852.936	195,027.487	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	239,504.148	232,385.678	196,285.037	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**4.63**	**0.66**	**2.44**	
FNEI Allocation Factor	**0.00452**	**0.00471**	**0.00471**	
CNPI Allocation Factor	**0.00263**	**0.00274**	**0.00274**	
H1N SSM Allocation Factor	**0.02308**	**0.02408**	**0.02408**	
H1N Allocation Factor	**0.92800**	**0.96847**	**0.96847**	
B2MLP Allocation Factor	**0.02991**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.01186**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

* The sum of 12 monthly charge determinants for the year.

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2016-0231 dated January 18, 2018.
Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016.
Note 3: H1N SSM 2020 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0266 dated December 17, 2019.
Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0082, issued April 23, 2020, as per Exhibit 2.4
Note 5: B2M LP 2020 Revenue Requirement per OEB Decision and Order EB-2019-0178 dated February 20, 2020.
Note 6: NRLP 2020 Revenue Requirement per OEB Decision and Order EB-2018-0275 June 04, 2020.
Note 7: Calculated data in shaded cells.

Filed: 2020-06-25
EB-2019-0082
DRO Reply Submission
Revised Exhibit 2.6.2
Page 1 of 6

2020 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2020-xxxx

The rate schedules contained herein shall be implemented as of July 1, 2020

Issued: Month, 2020
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generationare obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation ; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery

Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**4.63**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.66**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.44**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Tab 3

TRANSMISSION ACCOUNTING ORDER – DEPRECIATION EXPENSE (ASSET REMOVAL COSTS) ASYMMETRICAL CUMULATIVE VARIANCE ACCOUNT

Hydro One Transmission proposes the establishment of a new "Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account" to record the difference between the revenue requirement associated with asset removal costs forecasts that have been included in the proposed depreciation expenses for 2020-2022 and actual asset removal costs incurred in each of the test years, net of tax. The account calculation will be cumulative by the end of 2022 – the account balance will be brought forward for disposition in a future rate application in the event that there is an over collection on a cumulative basis over the 2020 to 2022 period. This account will be asymmetrical to the benefit of ratepayers - if the actual asset removal costs are lower than the forecasted asset removal costs, Hydro One Transmission will return the difference to ratepayers.

The account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "Asset Removal Costs Asymmetrical Cumulative Variance Account" effective January 1, 2020. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

USofA #	Account Description
DR 4110	Transmission Services Revenue
CR 2405	Other Regulatory Liabilities – Sub-Account "Asset Removal Costs Asymmetrical Cumulative Variance Account"

Initial entry to record the difference between actual asset removal costs and forecasted asset removal costs.

DR 6035	Other Interest Expense
CR 2405	Other Regulatory Liabilities – Sub-Account “Asset Removal Costs Asymmetrical Cumulative Variance Account”

To record interest improvement on the principal balance of the Asset Removal Costs Asymmetrical Cumulative Variance Account.

TRANSMISSION ACCOUNTING ORDER – CAPITAL IN-SERVICE ADDITIONS VARIANCE ACCOUNT

Hydro One Transmission proposes the establishment of a modified "Capital In-Service Additions Variance Account ("CISVA")" to record the differences between the revenue requirement associated with the actual capital in-service additions for 2020 through 2022 and the revenue requirement associated with the Board-approved capital in-service additions for those years.

Hydro One Transmission will track the impact on revenue requirement of any capital in-service additions that are 98% of the Board-approved amount or less on a combined basis for test years 2020 and 2021 at the end of 2021, including any 2019 variances, in consideration of the potential impacts of the COVID-19 pandemic on current year in-service additions. In other words, Hydro One requests that 2020 and 2021 be considered cumulatively at the end of 2021, rather than performing a calculation in each year of 2020 and 2021. This will incentivize Hydro One Transmission to ensure that capital in-service additions targets are met by the end of 2021 in the event there are uncontrollable impacts arising from the COVID-19 pandemic that cause it to defer in-servicing assets from 2020 to 2021. For cumulative in-service additions that are 98% of the Board-approved level or less, the associated revenue requirement impact will be computed and reported in 2021 and 2022 in this account, net of the revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains. The approval of the 2020 rate base figure in this Application would inherently include the 2019 in-service additions forecast; therefore, Hydro One is proposing that for 2021 calculation, the account should consider 2019, 2020, and 2021 in-service additions on a cumulative basis.

At the end of the three-year term, Hydro One Transmission will seek disposition of the account balance. The variance account will be asymmetrical; should the cumulative in-service additions in years 2020-2021 recorded in 2021, and in years 2022 exceed 98% of the cumulative Board-approved amount, no entry will be made in the variance account. The account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "Capital In-Service Additions Variance Account" effective January 1, 2020. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

USofA #	Account Description
DR 4110	Transmission Services Revenue
CR 2405	Other Regulatory Liabilities – Sub-Account "Capital In-Service Additions Variance Account"

Initial entry to record the differences between the revenue requirement associated with the actual capital in-service additions and the revenue requirement associated with the Board-approved in-service capital additions.

DR 6035	Other Interest Expense
CR 2405	Other Regulatory Liabilities – Sub-Account "Capital In-Service Additions Variance Account"

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

TRANSMISSION ACCOUNTING ORDER – FOREGONE TRANSMISSION REVENUE DEFERRAL ACCOUNT

Hydro One Transmission proposes the establishment of a new "Foregone Transmission Revenue Deferral Account" to record the difference between revenue earned by Hydro One Transmission under interim Uniform Transmission Rates (UTR), and the revenues that would have been received under the approved UTR based on OEB-approved 2020 rates revenue requirement and load forecast ("Foregone Revenue"). The account will capture the Foregone Revenue from January 1, 2020 to the date when the approved rates revenue requirement and load forecast are reflected in an update to current interim UTR rates.

The account will be established as Account 1508, Other Regulatory Assets – Sub-Account "Foregone Transmission Revenue Deferral Account" effective January 1, 2020. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

USofA #	Account Description
CR 4110	Transmission Services Revenue
DR 1508	Other Regulatory Assets – Sub account "Foregone Transmission Revenue Deferral Account"

Initial entry to record Foregone Revenue.

CR 4405	Interest and Dividend Income
DR 1508	Other Regulatory Assets – Sub account “Foregone Transmission Revenue Deferral Account”

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

TRANSMISSION ACCOUNTING ORDER – CCRA TRUE-UP VARIANCE ACCOUNT

Hydro One proposes to create a new variance account to track the differences between components of revenue requirement and actual results related to load true-ups performed in accordance with Transmission System Code section 6.5.3.

The account will be established as Account 1508, Other Regulatory Asset, sub-account "CCRA True-up Variance Account" effective January 1, 2020. Hydro One will record interest on any balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this deferral account.

USofA #	Account Description
CR/DR: 4110	Transmission Services Revenue
DR/CR: 1508	Other Regulatory Assets – Sub account "CCRA True-up Variance Account"

Initial entry to record the CCRA true-up variance.

CR/DR: 6035	Other Interest Expense
DR/CR: 1508	Other Regulatory Assets – Sub account "CCRA True-up Variance Account"

To record interest improvement on principal balance of CCRA True-up Variance Account.

TRANSMISSION ACCOUNTING ORDER – ESM DEFERRAL ACCOUNT

Hydro One proposes the establishment of a new "Earnings Sharing Mechanism ("ESM") Deferral Account" to record 50% of earnings that exceed the regulatory return on equity (ROE) reflected in this Application by more than 100 basis points in any year of the three-year term through Hydro One's transmission revenue. The calculation of the actual ROE shall use the OEB-approved mid-year rate base for that period to avoid double counting with amounts proposed in the Capital In-Service Additions Variance Account. The ROE calculation shall be normalized for revenue impacting items such as entries that are recorded in the year which relate to prior years to normalize the in-year net income. The customer share of earnings will be adjusted for any tax impacts. The balance in the account will be reviewed for disposition in Hydro One's next rebasing application scheduled for the 2023 revenue requirement.

The account will be established as Account 2435, Accrued Rate-Payer Benefit effective January 1, 2020. Hydro One will record interest on any balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this deferral account.

USofA #	Account Description
DR: 4395	Rate-Payer Benefit Including Interest
CR: 2435	Accrued Rate-Payer Benefit

Initial entry to record the over-earnings realized in any year of the three-year term.

DR: 4395	Rate-Payer Benefit Including Interest
CR: 2435	Accrued Rate-Payer Benefit

To record interest improvement on principal balance of ESM deferral account.