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BY EMAIL AND RESS

March 31, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2021-0110 - Custom IR Application (2023-2027) for Hydro One Networks Inc. Transmission and Distribution (Hydro One) - Evidence Update

Hydro One's letters to the Ontario Energy Board (OEB) dated February 4, 7 and 11, requested a postponement to the settlement conference to allow Hydro One to make necessary material amendments to its Application and evidence. Procedural Order Number 4, dated February 18, granted the postponement and placed the Application in abeyance as of February 4, 2022.

Hydro One thanks the OEB for the opportunity to update its evidence. Attached is Hydro One's Exhibit O evidence update which includes the following:

- Exhibit O-01-01 – Executive Summary
- Exhibit O-01-02 – Inflation Update
- Exhibit O-01-03 – Load Forecast Update
- Exhibit O-01-04 – Deferral Recovery Mechanism
- Exhibit O-01-05 – Update on Transmission External Revenues Variance Account
- Exhibit O-01-06 – Schedule of Updated Interrogatory and Undertaking Responses

Hydro One is in the final stage of completing its segmented audited financials for its transmission and distribution businesses. Once this process is complete, Hydro One will file **Exhibit O-02-01 – Report on 2021 Actuals**. Hydro One anticipates it will be able to file this additional piece of evidence on or before April 14, 2022.

In **Attachment 1** to this letter, Hydro One has proposed a revised schedule for the balance of the steps in this proceeding. The proposed schedule was prepared in consideration of Rule 2.01 and the objectives of expediency and efficiency and follows similar timelines to those previously established by the OEB in Procedural Order No. 1.

With the filing of this amendment, Hydro One believes all parties can engage in meaningful settlement discussions and pursue an appropriate process going forward in the event the Application is not settled.

This filing has been submitted electronically using the OEB's Regulatory Electronic Submission System (RESS).

Sincerely,

Frank D'Andrea

Frank D'Andrea
Encls.
cc. EB-2021-0110 parties

ATTACHMENT 1

Proposed Schedule

Procedural Steps	No Settlement	Partial Settlement
Hydro One Submits Evidence Update	March 31, 2022	
Interrogatories Received	April 14, 2022	
Interrogatory Responses Due	April 28, 2022	
Settlement Conference Begins	May 5, 2022	
Settlement Conference Ends	May 10, 2022	
Settlement Conference Progress Letter Filed	May 10, 2022	
Settlement Proposal Filed	May 12, 2022	May 31, 2022
OEB Staff Submission on Settlement Proposal Filed	NA	June 8, 2022
Oral Hearing Begins	May 23, 2022	June 21, 2022
Oral Hearing Ends	June 24, 2022	June 30, 2022
Argument in Chief	July 8, 2022	July 14, 2022
Staff Submissions	July 29, 2022	August 4, 2022
Intervenor Submissions	August 5, 2022	August 11, 2022
Reply Due	August 26, 2022	September 1, 2022
Decision Issued	**November 25, 2022**	**October 27, 2022**
DRO Due	December 16, 2022	November 17, 2022
Comments on DRO Received	January 20, 2023	December 8, 2022
Reply Due	February 10, 2023	January 12, 2023
Final Rate Order	**March 3, 2023**	**February 2, 2023**

EVIDENCE UPDATE – EXECUTIVE SUMMARY

1.0 EXECUTIVE SUMMARY

1.1 OVERVIEW

As a customer and community-focused company, Hydro One believes in the importance of fairness, transparency and delivering on our commitments to customers and all Ontarians. In recent months, global events have resulted in economic uncertainty and unanticipated levels of high inflation.

This Exhibit presents an update to Hydro One's evidence to reflect a customer-centric approach to update the inflation assumptions and load forecasts in the current application in a manner that preserves our ability to deliver on our commitments to customers without impacting the proposed transmission and distribution rates during the 2023 to 2027 period in a material way. Hydro One's Investment Plan was built with engagement from customers and is for the benefit of customers and Ontarians at large. Hydro One believes strongly in keeping its commitment to customers to complete the proposed investment plans against a backdrop of inflationary pressures. To achieve this, Hydro One is proposing to mitigate the economic impacts of unique global events through a mechanism that ensures customers are not burdened by inflationary pressures and changing load forecasts affecting the cost of investments that benefit current and future generations.

This Exhibit also reflects clarification of an inconsistency identified earlier in the proceeding in relation to Transmission External Revenues Variance Account. In addition, Hydro One has provided revisions to materially impacted interrogatory and undertaking responses.

1.2 INFLATION UPDATE

In response to the Ontario Energy Board's (OEB) 2018 direction that Hydro One file a joint rate application (Application) for its transmission and distribution businesses for the 2023 to 2027 period, Hydro One developed and eventually completed its Investment Plan in early 2021 and filed the Application on August 5, 2021. Hydro One's five-year Investment Plans for transmission and distribution used a 2% Ontario Consumer Price Index (CPI) assumption for all forecast years.

At the end of 2021 and during the first quarter of 2022, the economy has experienced inflation that could not have been contemplated at the time of filing or Investment Plan development. Furthermore, the nature of the inflationary trend could not be better understood until early 2022. Consistent with price pressures Hydro One had begun to experience and with the outbreak of the COVID-19 Omicron variant, the December 2021 Consensus Forecast showed average 2022 Canadian CPI moving outside the Bank of Canada's 1% to 3% inflation control range for the first time, with a 2022 inflation mean forecast of 3.3%. In late January 2022, the average Canadian CPI according to the Consensus Forecast remained outside the Bank of Canada's control range with a forecasted 2022 inflation mean at 3.4% and inflationary pressures expected to persist. In response, Hydro One began to re-assess its ability to manage the material change in inflationary pressures through the 2023-2027 rate period. Hydro One concluded that it must develop a customer-centric approach to address current inflation projections in relation to costs included in the Investment Plan for 2023-2027.

For these reasons, Hydro One made the difficult decision to request that the settlement conference be rescheduled until after the Company updated its evidence to reflect the impact of inflation on its proposed Investment Plan. Since then, inflationary pressures and volatility have been exacerbated by the Russian invasion of Ukraine, which has had significant impacts and created considerable uncertainty related to inflationary trends and commodity pricing directly affecting the costs underpinning Hydro One's plans. With evolving circumstances continuing to impact forecast inflation levels (and the trend) for 2022 and 2023, Hydro One has developed an approach to help protect its customers from the impacts of this uncertainty on their electricity transmission and distribution rates and to deliver on our public commitments by deferring the recovery of approved revenue requirements that reflect the updated inflation assumptions impacting capital and OM&A forecasts.

Recognizing its obligation to update the Application pursuant to Rule 11 of the OEB's *Rules of Practice and Procedure*, in Exhibit O-01-02 Hydro One has updated its capital expenditures and OM&A for transmission and distribution to account for the updated forecast inflation and to provide the necessary funding to permit Hydro One to make the investments needed to renew or replace poor condition assets and maintain safe and reliable transmission and distribution of electricity. Based on actual Ontario CPI of 3.5% for 2021 and forecast Ontario CPI of 4.5% and 3.3% for 2022 and 2023 provided by Scotiabank Capital (Scotia), Hydro One has increased its capital expenditures for transmission by $381.0M for a total of $7,639.4M and for distribution by $278.0M for a total of $5,574.5M over the 2023–2027 period. OM&A for 2023 has increased for 2023 by $22.1M for transmission and by $31.4M for distribution.

The resulting amendments to the 2023 revenue requirements for transmission and distribution are $26.1M and $36.7M, respectively, at the above noted inflation levels.

However, since Hydro One started the process of updating the Application in February 2022, Scotia provided updated inflation forecast in March with Ontario inflation rates rising a further 1.8% to 6.3% for 2022 and remaining at 3.3% for 2023 before returning to more normal levels beginning in 2024.

Hydro One recognizes that our customers and all Ontarians will also be experiencing once-in-a-generation inflationary pressures. As a result, Hydro One is proposing to defer the Transmission and Distribution revenue requirement increases arising from the higher assumed inflation to the next rate period. The incremental revenue requirements associated with this inflation update will be recorded in deferral accounts for recovery commencing in 2028. As a result, there will be no material changes to the proposed transmission or distribution rates for the 2023 to 2027 rate period due to the proposed changes in inflation assumptions.

Hydro One also recognizes that inflation rates are subject to change. Although the inflation update set out in this update is based upon a January 2022 Scotia forecast, the inflation forecasts have continued to evolve. To account for the forecast variability and ensure that Hydro One is implementing the most current and accurate forecast for 2022 and 2023, Hydro One has proposed in Exhibit O-01-02 Section 2.5 a process to confirm and adjust the inflation forecast used in Hydro One's Plans. As part of the Draft Rate Order process, Hydro One will update the inflation forecast for 2022 and 2023, employing either the actual 2022 rate or the forecast 2022 and 2023 inflation rates based upon an updated Scotia forecast. The updated inflation rates will enable an adjustment to the approved revenue requirements based on the parameters set out in Exhibit O-01-02 Section 2.5 to reflect those updated rates.

1.3 LOAD FORECAST UPDATE

Consistent with the approach approved in Hydro One's prior transmission and distribution rate applications, the company's load forecast methodology relies upon CDM levels forecasted by the IESO as a key input. As set out in Exhibits D-04-01 and D-05-01, Hydro One's load forecast as initially filed with the Application reflected the then-current CDM forecast from the IESO, which was provided to Hydro One in February 2021 and was consistent with the IESO's 2020 Annual Planning Outlook (APO) issued in December 2020.

In December 2021, the IESO issued its 2021 APO. The 2021 APO[1] contains materially higher forecasts for CDM in Ontario, averaging a 19% increase in CDM compared to the forecast used in the pre-filed evidence over the test period (2023-2027). As a result of the change in the IESO's CDM forecast, from its 2020 APO to its 2021 APO, the CDM assumptions used to establish Hydro One's load forecasts for both transmission and distribution have become outdated. Updating the CDM assumptions in Hydro One's load forecasts has a material impact on the load forecasts for both distribution and transmission, which must be taken into account to ensure that the billing determinants underpinning rates appropriately allow for recovery of Hydro One's approved rates revenue requirements.

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[1] IESO, *2021 Annual Planning Outlook: Ontario's Electricity System Needs: 2023-2042* (December 2021) https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

Hydro One has therefore updated its transmission and distribution load forecasts to reflect the IESO's new CDM forecasts. Specifically, Hydro One's load forecasts have been updated to reflect the IESO's December 2021 CDM figures, as well as the IESO's updated hourly pattern of CDM as set out in the 2021 APO. The updated transmission and distribution load forecasts were prepared using the same methodology outlined in Exhibits D-04-01 and D-05-01, respectively. Overall, the above-described updates to Hydro One's load forecasts result in an average 1.2% reduction over the test period in the case of the transmission load forecast and an average 1.9% reduction over the test period in the case of the distribution load forecast. These changes put upward pressure on both transmission and distribution rates to account for the reduction in charge determinants. The transmission revenue deficiency attributed to the change in transmission load forecast totals $122.8M over the 2023 to 2027 period. The distribution revenue deficiency attributed to the change in distribution load forecast totals $52.9M over the 2023 to 2027 period.

Hydro One recognizes that customers will be experiencing inflationary pressures in a wide range of areas and is proposing to maintain as-filed customer rate impacts by deferring, to the next rate period, the approved revenue requirements associated with the revenue deficiencies attributed to the changes in the transmission and distribution load forecasts to reflect the IESO's updated CDM assumptions. For each of transmission and distribution, the approved revenue requirement equal to the revenue deficiency from the load forecast update will be recorded in a newly proposed deferral account for recovery commencing in 2028. As a result, there will be no material changes to the proposed transmission or distribution rates for 2023 to 2027 due to the proposed load forecast updates.

1.4 DEFERRED RECOVERY MECHANISM

As noted above, Hydro One is proposing to defer recovery, until after the 2023 to 2027 rate period, of: (i) the transmission and distribution approved revenue requirement increases arising from the use of updated, higher inflation assumptions, and (ii) the transmission and distribution approved revenue requirement equal to the revenue deficiencies arising from the changes in billing determinants because of the transmission and distribution updated load forecasts. For each of transmission and distribution, the incremental revenue requirement associated with both of these factors will be recorded in a newly proposed deferral account (tracked in separate Sub-accounts for inflation and load forecast for greater transparency) for recovery commencing in 2028. As a result, relative to the Application as filed, there will be no material change to the proposed transmission or distribution rates for the 2023 to 2027 period due to the proposed inflation and load forecast updates. This will allow Hydro One to deliver on its commitments to customers in respect of both costs and system benefits.

1.5 UPDATE ON TRANSMISSION EXTERNAL REVENUES VARIANCE ACCOUNT

As explained at the Technical Conference and in response to Undertaking JT-4.13, Hydro One identified an inconsistency in the External Station Maintenance, E&CS and Other External Revenues amount for transmission, as provided in its responses to interrogatories (VECC 26 to 29). Upon identification of the inconsistency, Hydro One performed and has completed its analysis in respect of its calculation of Other External Revenues recorded in the "External Station Maintenance, E&CS and Other External Revenues variance account" over the 2013 to 2020 period for Hydro One Transmission. While a correcting entry was required for the historical period, the findings of this review have no impact on the 2023 to 2027 revenue requirement, as the Transmission external revenue test year forecast remains accurate.

The review identified that the External Station Maintenance, E&CS and Other External Revenues variance account balances from 2013 to 2020 were understated by $25.8M. As an outcome of this review, Hydro One has taken the appropriate steps to correct for previously unreported amounts and ensure the completeness of the actual external revenues to be used in the calculation of the Transmission External Revenues variance accounts on a go-forward basis. A life-to-date credit adjustment of $27.2M (inclusive of accrued interest) recorded to the External Station Maintenance, E&CS and Other External Revenues variance account relating to the 2013 to 2020 years was subject to audit by KPMG, as part of their audit of the Hydro One Limited financial statements.

As part of this evidence update, Hydro One proposes to return $27.5M (inclusive of further accrued interest)[2] to customers as part of the 2023 Rates Revenue Requirement over a one-year period to be implemented at the time of the DRO, by flowing through this life-to-date adjustment within the External Station Maintenance, E&CS and Other External Revenues variance account. This will ensure that ratepayers receive the immediate benefit of this credit in 2023.

1.6 CONTENT AND STRUCTURE

The evidence update includes the following:

(i) Inflation assumptions for 2021, 2022 and 2023 that were used to forecast costs for 2023 have been updated (see Exhibit O-01-02)

(ii) The load forecast has been updated to reflect the IESO's new (and higher) CDM forecasts as issued in December 2021 (see Exhibit O-01-03)

(iii) A deferral mechanism is proposed, to delay recovery of the revenue requirement associated with the inflation and load updates to 2028 (see Exhibit O-01-04)

(iv) Transmission external revenues variance account has been updated to address the issue raised at the Technical Conference (see Exhibit O-01-05)

(v) Interrogatory and undertaking responses that are materially impacted by the load and inflation updates have been amended (see Exhibit O-01-06)

Hydro One's report on 2021 Actuals will be provided on or before April 14, 2022 as Exhibit O-02-01.

The structure of the update is provided below in table 1:

[2] Hydro One quantified and recognized a regulatory liability in the amount of $27.2M, which is comprised of $25.8M principal, and $1.4M of accrued interest from 2013–2020. With projected carrying charges for 2021 and 2022, a total credit balance of $27.5M amount is proposed to be returned to customers in 2023.

Table 1 - Exhibit O Structure and Contents

Exhibits/attachments denoted by “*” have been provided in Excel format.

Exhibit	Tab	Schedule	Attachment	Contents
O	**1**	**1**		**Executive Summary**
O	**1**	**2**		**Inflation Update**
O	1	2	1	Scotiabank Capital Inflation Report dated March 31, 2022
O	1	2	2	Investment Summary Documents Updated for Inflation
O	1	2	3A*	Transmission OM&A (Appendix 2-JA, JB, JC, L)
O	1	2	3B*	Distribution OM&A (Appendix 2-JA, JB, JC, L)
O	1	2	4A*	Appendix 2-AB – Tx (Capital Expenditures Summary Table – Transmission)
O	1	2	4B*	Appendix 2-AA – Tx (Capital Projects Table – Transmission)
O	1	2	4C*	Appendix 2-AB – GP (Capital Expenditures Summary Table – General Plant)
O	1	2	4D*	Appendix 2-AA – GP (Capital Projects and Programs Table – General Plant)
O	1	2	4E*	Appendix 2-AB – Dx (Capital Expenditures Summary Table – Distribution)
O	1	2	4F*	Appendix 2-AA – Dx (Capital Projects Table – Distribution)
O	1	2	4G*	In-Service Additions – Transmission
O	1	2	4H*	In-Service Additions – Distribution
O	1	2	5A*	2023 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 1)
O	1	2	5B*	2024 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 2)
O	1	2	5C*	2025 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 3)
O	1	2	5D*	2026 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 4)
O	1	2	5E*	2027 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 5)
O	1	2	5F*	2023 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 1)
O	1	2	5G*	2024 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 2)
O	1	2	5H*	2025 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 3)
O	1	2	5I*	2026 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 4)
O	1	2	5J*	2027 Distribution Revenue Requirement Workform

				(Exhibit D-01-01 Attachment 5)
O	1	2	6A	Rate Base Schedule (Exhibit C-04-01)
O	1	2	6B	Continuity of Gross PP&E schedule (Exhibit C-04-02)
O	1	2	6C	Continuity of Accumulated Depreciation (Exhibit C-04-03)
O	1	2	7*	Return on Capital (Exhibit F-01-03)
O	1	2	8	Depreciation Schedule (Exhibit E-08-01 Attachment 2)
O	1	2	9*	CCA Schedule (Exhibit E-09-02 Attachment 2)
O	**1**	**3**		**Load Forecast Update**
O	1	3	1*	Derivation of Distribution Revenue Deficiency Attributed to Change in Load
O	**1**	**4**		**Deferred Recovery Mechanism**
O	1	4	1	Draft Accounting Order– Transmission Approved Revenue Requirement Deferral Account
O	1	4	2	Draft Accounting Order – Distribution Approved Revenue Requirement Deferral Account
O	**1**	**5**		**Update on Transmission External Revenues Variance Account**
O	1	5	1*	Transmission DVA Continuity Schedule (Exhibit G-01-05 Attachment 1)
O	**1**	**6**		**Schedule of Updated Interrogatories and Undertakings**

1.7 WITNESS LIST

The following witnesses will speak to this evidence:

Exhibit/Section	Witnesses
O-01-01 Executive Summary	As listed below, by section
1.0 Executive Summary	
1.1 Overview	BERARDI Rob, CORNACCHIA Joseph, JESUS Bruno, VETSIS Stephen
1.2 Inflation Update	BERARDI Rob, CORNACCHIA Joe, JESUS Bruno
1.3 Load Forecast Update	VETSIS Stephen
1.4 Deferred Recovery Mechanism	CORNACCHIA Joe, VETSIS Stephen
1.5 Update on Transmission External Revenues Variance Account	CORNACCHIA Joe
O-01-02 Inflation Update	As listed below, by section
1.0 Overview	BERARDI Rob, CORNACCHIA Joe, JESUS Bruno, VETSIS Stephen
2.0 Inflation	
2.1 Current Assumptions and Inflation Updates	DICKINSON Kevin, JACKSON Alexander, JESUS Bruno
2.2 Current Inflation Pressures Experienced by Hydro One	BERARDI Rob

2.3 Description of Inflationary Update to Evidence	JACKSON Alexander, JESUS Bruno
2.4 Impact of Inflation on Hydro One's Investment Plan	JACKSON Alexander, JESUS Bruno
2.5 Deferred Recovery Mechanism for Incremental Revenue Requirement Attributed to Inflation and Confirmation and Adjustment of Inflation Forecast	CORNACCHIA Joe; JODOIN Joel
3.0 Impact on OM&A	JODOIN Joel
4.0 Impact on Capital & In-Service Additions	JACKSON Alexander, JESUS Bruno
5.0 Impact on Revenue Requirement and Related Components	
5.1 2023 Revenue Requirement	JODOIN Joel
5.2 Rate Base	JODOIN Joel
5.3 Return on Capital	DICKINSON Kevin
5.4 Depreciation and Amortization Expense	CORNACCHIA Joseph
5.5 Regulatory Taxes	TRAN Nancy
6.0 Custom IR Framework	VETSIS Stephen
O-01-03 Load Forecast Update	As listed below, by section
1.0 Overview of Load Forecast Update	ALAGHEBAND Bijan, LI Clement, VETSIS Stephen
1.1 Transmission	ALAGHEBAND Bijan
1.2 Distribution	ALAGHEBAND Bijan
2.0 Revenue Deficiency Associated with Change in Load Forecasts	LI Clement, VETSIS Stephen
O-01-04 Deferred Recovery Mechanism	As listed below, by section
1.0 Overview	CORNACCHIA Joseph, VETSIS Stephen
2.0 Summary of Requested Approvals	CORNACCHIA Joseph, VETSIS Stephen
3.0 Proposed New Approved Revenue Requirement Deferral Accounts	CORNACCHIA Joseph
4.0 Incremental Revenue Requirements Attributed to Inflation Update	CORNACCHIA Joseph
5.0 Deferral of Approved Revenue Requirement Associated with Revenue Deficiencies Attributed to Revised Load Forecasts	VETSIS Stephen
6.0 Attachment, Updated Appendices and Models	CORNACCHIA Joseph
O-01-05 Update on Transmission External Revenues Variance Account	CORNACCHIA Joseph
O-01-06 Updated Interrogatories and Undertakings	As provided in each Interrogatory & Undertaking

INFLATION UPDATE

1.0 OVERVIEW

1.1 BACKGROUND

In response to the Ontario Energy Board's (OEB) 2018 direction that Hydro One file a joint rate application (Application) for its transmission and distribution businesses for the 2023 to 2027 period, Hydro One developed and eventually completed its investment plan in early 2021 and filed the Application on August 5, 2021. Hydro One's investment plans for transmission and distribution used a 2% Ontario Consumer Price Index (CPI) assumption for all forecast years.

At the end of 2021 and during the first quarter of 2022, the economy has experienced inflation levels that are drastically different than that experienced for many years and that could not have been contemplated at the time that the investment plan was developed or the Application filed. Furthermore, the non-transitory nature of inflationary trends could not have been fully understood until early 2022. Consistent with price pressures Hydro One had begun to experience and with the outbreak of the COVID-19 Omicron variant, the December 2021 Consensus Forecasts for 2022 Canadian CPI mean forecast moved outside the Bank of Canada's 1% to 3% inflation control range, with a 2022 inflation mean forecast of 3.3%. In late January 2022, the average Canadian CPI according to the Consensus Forecast remained outside the Bank of Canada's control range with forecasted 2022 Canadian CPI mean at 3.4% and inflationary pressures expected to persist. In response, Hydro One began to re-assess its ability to manage the inflationary pressures through the 2023-2027 rate period. Hydro One concluded that there was a material disconnect between the volumes of work included in the investment plan for 2023-2027 and the associated costs. In effect, forecast OM&A and capital expenditures would both start from incorrect 2023 base amounts unless 2021-2023 inflation assumptions were adjusted.

For these reasons, Hydro One made the difficult decision to request that the settlement conference be rescheduled until the Company updated its evidence to reflect the impact of inflation on its proposed investment plan. Since then, inflationary pressures and volatility have been further exacerbated by the Russian invasion of Ukraine which has had significant impacts and created considerable uncertainty related to inflationary trends and commodity pricing, and directly affects the costs underpinning Hydro One's investment plans. Evolving circumstances will continue to affect forecast inflation levels (and the trend) for 2022 and 2023, impacting Hydro One's capital and OM&A forecasts.

Recognizing its obligation to update the Application pursuant to Rule 11.02 of the OEB's *Rules of Practice and Procedure*, Hydro One has updated its capital and OM&A expenditures for transmission and distribution to account for inflation and to provide the necessary funding to permit Hydro One to execute its investment plans and make the investments needed as intended. Based on actual Ontario CPI of 3.5% for 2021 and forecast Ontario CPI of 4.5% and 3.3% for 2022 and 2023, respectively, as provided by Scotiabank Capital (Scotia) in February (Scotia January Forecast), Hydro One has increased its capital expenditures for transmission by $381.0M for a total of $7,639.4M and for distribution by $278.0M for a total of $5,574.5M over the 2023–2027 period. OM&A in 2023 has increased by $22.1M for transmission and $31.4M for distribution. These adjustments allow Hydro One to make investment in Ontario's electricity system to ensure it remains reliable, affordable and accommodates growth in demand.

The resulting 2023 revenue requirement increases for transmission and distribution are $26.1M and $36.7M, respectively, at the above noted inflation levels with impacts on 2024-2027 revenue requirements as outlined below.

Hydro One recognizes that our customers will also be experiencing inflationary pressures and is proposing to defer the revenue requirement increases arising from the higher assumed inflation to the next rate period. The incremental revenue requirements associated with this inflation update will be recorded in newly proposed transmission and distribution deferral accounts for recovery commencing in 2028. As a result, there will be no change to the proposed transmission or distribution rates for 2023 to 2027 due to the proposed inflation adjustment.

Hydro One also recognizes that inflation rates are subject to change. Although the inflation update set out in this Exhibit is based upon a January 2022 Scotia forecast, inflation forecasts have changed further since then. To account for the forecast variability and ensure that Hydro One is implementing the most current and accurate forecast for 2022 and 2023, in Section 2.5 below Hydro One proposes a process to confirm and adjust the inflation forecast used in Hydro One's Plans. As part of the Draft Rate Order (DRO) process, Hydro One will update the inflation forecast for 2022 and 2023. Depending on the timing of the DRO, this update will be based on either the actual 2022 rate or the forecast 2022 and 2023 inflation rates as determined in an updated Scotia forecast. The updated inflation rates will enable an adjustment to the approved revenue requirement based on the parameters set out in Section 2.5.

Accordingly, this Exhibit contains the following sections:

- Section 2: Inflation
    - Current assumptions and inflation updates
    - Current inflation pressures experienced by Hydro One
    - Description of the inflationary update to evidence
    - Impacts of inflation on Hydro One's investment plan
    - Deferred recovery for incremental revenue requirement and confirmation and adjustment of inflation forecast
- Section 3: OM&A impacts
- Section 4: Capital and in-service additions impacts
- Section 5: Revenue requirement impacts and related components
- Section 6: Custom IR Framework
- Section 7: Attachments, updated appendices and models

2.0 INFLATION

2.1 CURRENT ASSUMPTIONS AND INFLATION UPDATES

Capital expenditures in the 2023 to 2027 period and OM&A for 2023 included an inflationary adjustment of 2.0% applied annually over the 2021-2027 period and relative to 2020 base cost estimates.

The 2.0% per year inflationary assumption was applied to all costs in the investment plans. Actual Ontario CPI for 2021 was 3.5%, or 1.5% higher than the assumed 2.0%. As noted, forecasts for 2022 and for 2023 reflect higher inflation levels, and inflation has continued to increase in 2022.

Hydro One engaged Scotia to forecast Ontario CPI for 2022 and 2023. Scotia provided Hydro One with the January 2022 inflation forecast on February 11, 2022, which Hydro One used to update the inflationary assumptions in its evidence. The updated assumptions are 3.5% for 2021 (actual), 4.5% for 2022 and 3.3% for 2023. While these updated assumptions have been used by Hydro One for purposes of updating this Application, the current economic and geopolitical environment continues to evolve, together with the inflationary trend. Since February 2022, the time that Hydro One had begun the process of updating the Application, Scotia provided updated inflation forecasts with Ontario inflation rates rising a further 1.8% to 6.3% for 2022 and remaining at 3.3% for 2023 (Scotia March Forecast) before returning to more normal levels beginning in 2024. Scotia's report is provided in Attachment 1 (Scotia Report).

The updated inflation assumptions for purposes of this update are set out below as follows:

Table 1 - Forecast Inflation Assumptions (Ontario)

Date	2021	2022	2023
As-filed Investment Plan	2.0%*	2.0%*	2.0%*
Scotia January Forecast	3.5%**	4.5%*	3.3%*

**forecast*
*** actual*

2.2 CURRENT INFLATION PRESSURES EXPERIENCED BY HYDRO ONE

Hydro One is currently experiencing the impacts of inflation, especially as it relates to materials and services in both transmission and distribution.

There have been significant market price changes across many commodities that are inputs to Hydro One's costs. Given the nature of Hydro One's business and capital program, the price of essential commodities has a significant impact on our costs. Equipment purchased by Hydro One (i.e. power transformers, breakers and tower steel) is heavily impacted by certain raw material indices. Essential commodities such as copper, aluminum and steel have undergone price increases and supply shortages. From January 2021 to January 2022, the price of copper has increased by 27.1%, aluminum has increased by 41.6% and steel has increased by 111.6%.[1] In addition, over the first two months of 2022, key commodities have continued to see significant price increases, including fuel which has seen a price increase of 21%, and aluminum, which has increased by 16%.[2]

In addition to commodity costs, shipping costs have contributed to price inflation in many materials on which Hydro One relies. Global supply chains continue to experience a shortage of shipping containers leaving suppliers with stockpiles of materials and finished products that are

[1] Based on the following indices for copper, aluminum, and steel, respectively: Copper (New York), Aluminum N. America, and Steel Plate N. America from January 2021 to January 2022.
[2] Based on the following indices for fuel and aluminum, respectively: Gasoline: Reformulated Gasoline Blendstock N. America, and Aluminum N. America.

unable to be exported internationally. Continuous demand and limited supplies have led to significant price increases for freight-based shipping. Shipping prices are up 103% since January 2021 impacting suppliers who have also been requesting price escalations due to these increases.[3]

As a result of these market changes, Hydro One is experiencing price escalation for many materials and services, especially for those associated with steel, copper, aluminum, and transportation. Due to inflation, the pricing for power transformers increased by approximately 20% to 25% in 2021, leading to historically high prices at the start of 2022. The Company is expecting the price to remain at this level in 2022. Increases in specialized labour throughout 2021 have led to an estimated price escalation for Engineering, Procurement and Construction (EPC) contracts from 8% to 10% in 2022 within the transmission business. In the distribution business, distribution transformers are also very dependent on the steel, copper and aluminum indices, and are estimated to have increased by 20% to 25% throughout 2021.

Rising fuel costs have led to a 30% to 35% increase in the 2022 forecast for Hydro One's internal fleet. Rising fuel cost will impact most categories of materials and services purchased by Hydro One, in varying degrees. For example, many of Hydro One's suppliers' services require large volumes of fuel to perform their services (e.g., General Contractors, EPC, Transportation) and increases in fuel prices will be reflected in the costs they charge Hydro One.

While the cost categories discussed above are significant individual contributors to the inflationary cost pressures that Hydro One is experiencing, the Company has seen and expects to see further price inflation across a range of input costs. Table 2 lists direct inflationary

[3] Container Rate Index - Asia to North America – Based on "Container Rate Index - Asia to North America" Source: Container Trades Statistics Ltd.

impacts to the Company's top ten material and service categories, which represent the majority of its spending.[4]

Table 2 - 2022 Inflation Risk for the Top Ten Material and Service Categories

Category	Inflation Risk %	Key Cost Drivers
Electrical T&D Construction (EPC)	8% - 10%	Canadian Labour, Steel, Aluminum & Copper
Transformers and Components	20% - 25%	Steel, Copper & Aluminum
Facilities Maintenance and Services	General CPI	General CPI
IT Services	General CPI	General CPI
Rentals & Operated Equipment	General CPI	General CPI
Construction Materials	10% - 15%	Steel, Transportation, Lumber & Resin
Fleet Management	10% - 20%	Repair, Maintenance & Fuel
IT Software	General CPI	General CPI
Telecom	General CPI	General CPI
Construction Management Services	5%-10%	Canadian Labour, General Freight & Fuel

Hydro One manages some commodity risk exposure through provisions in long-term contracts with suppliers. While the specific terms differ by category and suppliers, the following terms are often part of the contracts:

- Price Adjustment Frequency – Quarterly, Semi-Annual, Annually where price adjustments differ by category and supplier.
- Defined Formula & Industry References – All price adjustment clauses contain details regarding the commodity, contributions to overall price, and references to open market indices to manage change.

These pre-determined price adjustment mechanisms have allowed Hydro One to mitigate short-term commodity fluctuation risks that can occur in volatile markets. However, in some cases, suppliers have been motivated to consider the economics of not fulfilling their agreed obligations relative to the costs of contractual performance. As contracts come to the end of

[4] This data represents adjustments made solely on index fluctuation. Actual costs vary per contract.

their term and new agreements are sourced, new terms and conditions will reflect current market behaviours.

Hydro One will experience a long term, sustained change in pricing, because commodity markets have maintained consistent increases through an extended period of time. Hydro One will continue to develop strategies to minimize disruption for high-risk materials and services, in addition to the assurance of supply strategies, as outlined in Exhibit E-05-02.

As evident from the analysis above, Hydro One is already experiencing inflationary pressures across the business that are higher than actual and forecast inflation levels. As noted in the Section 2.3 below, Hydro One is proposing to increase its forecast by applying actual and forecast Ontario CPI levels mechanistically to the overall impact on OM&A and capital envelope levels.

2.3 DESCRIPTION OF INFLATIONARY UPDATE TO EVIDENCE

This evidence update replaces the 2.0% annual inflation escalation assumption used in the investment plan over the 2023-2027 period, with the following:

- Actual Ontario inflation in 2021 of 3.5%
- Forecasted Ontario inflation in 2022 of 4.5% (based on Scotia January Forecast)
- Forecasted Ontario inflation in 2023 of 3.3% (based on Scotia January Forecast)

The update was conducted mechanistically by de-escalating the plan amounts by the original inflation assumption of 2.0% per year to the base year of 2020. The plan was then re-escalated using the revised inflation rates listed above for each of 2021, 2022, and 2023 for capital and OM&A, and by 2.0% for years 2024 through 2027 for capital. These steps collectively describe Hydro One’s approach to update the original inflation assumptions in the investment plan (the “Inflation Update”).

As a result of the Inflation Update, all planned OM&A costs in 2023 and capital costs for 2023 to 2027 were increased by a factor of 1.0525[5] ("Proration Factor") from as-filed amounts. This factor was derived as follows:

$$Proration\ Factor = \frac{(1+\ i_{2021}) \times (1+\ i_{2022}) \times (1+\ i_{2023})}{(1+i_{as-filed})^3}$$

Where: i_{2021} is the actual Ontario inflation in 2021 of 3.5%

i_{2022} is the Scotia forecasted Ontario inflation in 2022 of 4.5%

i_{2023} is the Scotia forecasted Ontario inflation in 2023 of 3.3%

$i_{as\text{-}filed}$ is the 2% rate used in as-filed plan

$$Proration\ Factor = \frac{(1.035)\text{x}(1.045)\text{x}(1.033)}{1.02^3} = 1.0525$$

Hydro One applied the Proration Factor of 1.0525 to all cost categories, effectively replacing the 2.0% annual inflation assumption with the revised inflation rates. This is consistent with the approach used when incorporating inflation into the as-filed investment plan.

Hydro One also reviewed the impact of the Inflation Update on its interrogatory and undertaking responses and provided an update for any material changes in Exhibit O-01-06. The changes to Hydro One's proposed amounts for its OM&A and capital envelopes are shown below in Table 3 and Table 4.

Table 3 - Increases to Hydro One's Proposed 2023 OM&A ($M)

	2023 Test Year As-Filed (A)	2023 Test Year Inflation Update (B)	Increase	Relative Increase (B/A)
Transmission	420.5	442.6	22.1	1.0525
Distribution	597.5	628.9	31.4	1.0525

[5] 2021 actual Ontario inflation of 3.47% was used for the purposes of the calculation, as compared to the rounded figure of 3.5% referenced throughout the exhibit.

Table 4 - Increases to Hydro One's Proposed Capital Expenditures for 2023-2027 ($M)

	2023	2024	2025	2026	2027
Transmission					
As-Filed (A)	1,434.0	1,463.9	1,450.4	1,461.8	1,448.2
Inflation Update (B)	1,509.3	1,540.7	1,526.6	1,538.5	1,524.3
Increase	75.3	76.8	76.1	76.7	76.0
Relative Increase (B/A)	1.0525	1.0525	1.0525	1.0525	1.0525
Distribution					
As-Filed (A)	1,005.1	1,028.0	1,120.8	1,071.7	1,070.9
Inflation Update (B)	1,057.9	1,081.9	1,179.7	1,127.9	1,127.2
Increase	52.8	54.0	58.8	56.2	56.2
Relative Increase (B/A)	1.0525	1.0525	1.0525	1.0525	1.0525

For In-Service Additions (ISA), Hydro One applied the Proration Factor to the underlying 2023-2027 capital expenditures provided in the Interrogatory Response to C-SEC-175 and added the incremental amounts to the ISA envelopes. The resulting changes in ISA are provided in Table 5 below.

Table 5 - Increases to Hydro One's Proposed ISA for 2023-2027 ($M)

	2023	2024	2025	2026	2027
Transmission					
As-Filed (A)	1,368.1	1,332.4	1,710.3	1,280.3	1,599.8
Inflation Update (B)	1,404.5	1,393.2	1,795.6	1,347.5	1,683.8
Increase	36.4	60.7	85.3	67.2	84.0
Relative Increase (B/A)	1.0266	1.0456	1.0499	1.0525	1.0525
Distribution					
As-Filed (A)	970.9	1,027.3	1,203.4	1,061.2	1,107.8
Inflation Update (B)	1,012.5	1,080.9	1,266.6	1,116.9	1,165.9
Increase	41.6	53.6	63.2	55.7	58.1
Relative Increase (B/A)	1.0428	1.0522	1.0525	1.0525	1.0525

As demonstrated in Table 5 above, the relative increase in ISA is below the 1.0525 proration factor in earlier years. This is because the ISA planned in 2023-2027 includes capital expenditures that occurred prior to 2023 and Hydro One is only applying the Inflation Update to capital expenditures in 2023-2027 (current test period).

2.4 IMPACT OF INFLATION ON HYDRO ONE'S INVESTMENT PLAN

Hydro One's investment plan reflects its ongoing commitment to ensuring safe, reliable, and sustainable transmission and distribution systems to meet the electricity needs of its customers. The investment plan has identified and paced targeted investments to meet regulatory and customer service requirements and to ensure system performance consistent with customer expectations as expressed in Hydro One's extensive customer engagement exercise.

To successfully achieve the outcomes and benefits of Hydro One's proposed plan, the forecast costs must be updated to include the impacts of inflation. If current inflation levels are not accounted for, Hydro One will not be able to complete the work included in the investment plan. Planned investment and work programs are necessary to sustain and improve transmission and distribution system performance and to achieve intended customer-focused outcomes. This would include investments to maintain and improve reliability and customer service, including those required to address poor condition infrastructure on both the transmission and distribution systems.

If the plan is not adjusted for updated inflation assumptions, a range of investments that are not deemed "mandatory" (e.g., driven by regulatory or compliance obligations) would be impacted by deferrals and reductions. The potential impact areas include System Renewal investments that are required to mitigate asset-related risks (e.g., to address a subset of deteriorated system assets based on verified condition, risk-based prioritization, and prudent planning to manage the overall proportion of poor-condition assets) as well as System Service investments that aim to improve service for some of the customers that experience reliability issues. The examples below further highlight the likely areas of impact:

Distribution System Renewal

- Distribution Station Refurbishment (D-SR-04): As described in DSP Section 3.2, approximately 20% of the overall transformer population is categorized as being in poor condition; these transformers are subject to an elevated risk of failure and are considered for replacement or corrective repair to address deficiencies before failures occur and impact service to distribution customers. Should current and expected inflation not be accounted for, Hydro One would need to adopt a more reactive approach to station transformer replacements and slow down the proposed station transformer replacement plan, which would lead to a higher risk of outages due to transformer failures, further deterioration of the condition of the transformer fleet, and additional future investment requirements.

- Pole Sustainment Program (D-SR-07): As outlined in DSP Section 3.2, approximately 79,000 distribution poles are in poor condition and at high risk of failure. During the plan period, it is expected that an additional 50,000 poles will be added to the poor condition category due to deteriorating condition. Without an inflation adjustment, there is likely to be reduced funding for the Pole Sustainment Program, resulting in fewer poles being replaced out of the subset of poor condition poles that have been prioritized as replacement candidates under this program due to their higher consequence of failure (i.e., serving large numbers of customers). This would lead to a higher risk of customer impact due to pole failures as well as further deterioration of the condition of the wood pole fleet.

Distribution System Service

- Worst Performing Feeders (D-SS-05): As described in ISD D-SS-05, Hydro One is currently planning to address approximately 500 feeders with the highest contribution to SAIDI, through the worst performing feeders program. If inflation is not adequately accounted for, Hydro One would undertake lower volumes of grid modernization – an investment customers supported. New technology allows Hydro One to more quickly detect, repair and restore power, and reducing it would lead to lower levels of reliability improvement for customers.

- System Upgrades Driven by Load Growth (D-SS-01): System capacity constraints that are caused by regional growth result in system issues characterized by power quality complaints, system inefficiencies, or thermal constraints (where system elements are being operated near, or above, their rating). Should recent inflation not be accounted for, Hydro One would need to adopt a more reactive approach to growth investments, deferring planned investments that are needed to upgrade and enhance investments to facilitate local growth. This would in turn potentially delay community growth and economic development, especially in rural areas, and negatively affect reliability and power quality for existing customers in the long run.

Transmission System Renewal

- Transmission Line Refurbishment (T-SR-13): As noted in TSP Section 2.2, regarding Hydro One's overhead conductors, investments to date have not kept pace with asset condition-driven demands. Currently, 3,874 circuit-kms or 14% of Hydro One's conductor fleet has been tested and confirmed to be in poor condition. That is an increase from 2,643 circuit-kms of poor condition conductors at the end of 2016 and 3,680 circuit-kms of poor condition conductors at the end of 2018. Without an adjustment for inflation, Hydro One would need to defer and slow down the proposed transmission line refurbishment and replacement plan, which would adversely impact the current level of safety and reliability performance, result in further deterioration of the condition of the conductor fleet, and necessitate additional future investment requirements.

- Transmission Station Renewal – Connection Stations (T-SR-03): As noted in ISD T-SR-03, approximately 26% (152 units) connection station transformers are rated poor condition, with an additional 63 units (11%) assessed to be in fair condition with some form of deterioration. Further, approximately 401 of circuit breakers (11%) at connection stations are rated poor condition, and another 1203 units (36%) in fair condition. Given that deterioration cannot be stopped or reversed, this population of fair condition assets will start migrating to the poor condition category. Should recent inflation not be accounted for, Hydro One would need to defer transmission connection station reinvestment, which would impact Hydro One's ability to maintain reliable power delivery at stations, increase performance and environmental risks, and create the need for additional investment in the future. This approach would also mean deferring investments in load serving stations in smaller communities, including those in northern and eastern Ontario.

A revised listing of the Investment Summary Documents updated for inflation has been filed in Attachment 2 of this Exhibit.

With respect to Hydro One's transmission and distribution OM&A, significant portions of the programs are mandatory, including transmission programs required to maintain NERC/NPCC compliance and correct equipment defects as well as those on the distribution system to respond to trouble calls, restore power following storms, repair damaged equipment or conduct cable locates.

As noted in Exhibit E-02-02, Hydro One previously deferred system maintenance, which has resulted in an accumulated backlog of transmission station and lines maintenance and transmission vegetation management activities that need to be addressed during the test period. Addressing the backlogged vegetation management is required to maintain system reliability and control costs associated with having to maintain an overgrown right of way. Postponement of vegetation management work increases reliability risks and results in a vegetation backlog that is more difficult and costly to clear in the future.

Station maintenance has been deferred over the 2019 to 2022 period to manage the OM&A envelope and complete the necessary PCB remediation work. Maintaining the proposed work volumes of stations preventative maintenance is critical, as this work provides crucial insights into the condition of the assets and provides a basis to identify new capital replacement candidates before they malfunction or fail. This, in turn, will reduce the risk of unplanned equipment failure impacting reliability of the transmission system.

As noted in Exhibit E-03-02, it is important for the distribution vegetation management program to be sustained as proposed to target vegetation defects in a timely manner. Delays or interruptions in vegetation management on a right of way allows vegetation defects to multiply, resulting in worsening reliability, safety risks and increased future forestry clearing work at a higher cost.

Opportunities to defer critical OM&A work is limited; such a deferral would increase reliability, safety, and environmental risks, as well as increased asset failures and deteriorated asset reliability to adversely affect the adequacy and security of the system as a whole and the communities served.

2.5 DEFERRED RECOVERY MECHANISM FOR INCREMENTAL REVENUE REQUIREMENT ATTRIBUTED TO INFLATION AND CONFIRMATION AND ADJUSTMENT OF INFLATION FORECAST

2.5.1 DEFERRED RECOVERY MECHANISM FOR INCREMENTAL REVENUE REQUIREMENT ATTRIBUTED TO INFLATION

Hydro One recognizes that customers are also experiencing inflationary pressures which are currently predicted to persist for several years before eventually returning to the Bank of Canada’s target range of 2.0% per year. To help mitigate affordability issues while dealing with extraordinary inflationary pressures, Hydro One is proposing that the OEB approve the incremental revenue requirements attributable to inflation as part of Hydro One’s total approved revenue requirements for each of Transmission and Distribution (detailed calculations for updated revenue requirements are presented in Section 5.0 below) and approve the deferred recovery of the incremental revenue requirements associated with the inflation update. To give effect to such deferred recovery, Hydro One will record the incremental revenue requirements in newly created deferral accounts for each of Transmission and Distribution. Commencing in 2028, Hydro One would recover the incremental revenue requirement (to be approved as part of the current application). This approach allows Hydro One to continue delivering the work program that it has developed to meet customer needs and expressed preferences (as discussed in Section 1.6 of the Systems Plans Framework), without exacerbating the cost pressures that customers are experiencing during the current period of extraordinary inflation. The deferred recovery mechanism is described in greater detail in Exhibit O-01-04.

2.5.2 CONFIRMATION AND ADJUSTMENT OF INFLATION FORECAST

Hydro One recognizes that inflation rates are subject to change. The inflation update set out in this Exhibit is based upon a January 2022 Scotia forecast, however, inflation forecasts have continued to evolve. To account for the forecast variability and ensure that Hydro One is implementing the most current and accurate forecast for 2022 and 2023, Hydro One proposes that the following process be used to confirm and adjust the inflation forecast used in Hydro One's investment plans.

As part of the Draft Rate Order process, Hydro One will update the inflation forecast for 2022 and 2023. For the 2022 rate, Hydro One will employ either the actual 2022 Ontario CPI rate (if available) or the forecast 2022 rate based upon an updated Scotia forecast. For the 2023 rate, an updated Scotia forecast will be used. Those updated inflation rates will be applied to Hydro One's capital and OM&A using the same mechanism as applied in this update subject to any adjustments arising from the OEB's Decision in this matter. Based on any variance in applicable actual and forecast inflation rates and the application of the adjustment parameters below, the incremental revenue requirement arising from the difference in inflation assumptions (i.e. the difference between the final inflation rate confirmed at DRO and the 2.0% per year used in the as-filed plan) will be recorded in the proposed new Transmission and Distribution Approved Revenue Requirement Deferral Accounts, to be collected from rate payers starting in 2028. The proposal for those accounts is described in Exhibit O-01-04.

If the forecast inflation rates for 2022 and 2023 at the time of DRO are less than the rates used in this evidence update (i.e. 4.5% for 2022 and 3.3% for 2023), Hydro One will use the lower inflation forecast to recalculate the incremental revenue requirements, and record the revised balances in the proposed deferral accounts.

If the forecast inflation rates for 2022 and 2023 at the time of DRO are higher than the forecasts used in this evidence update (i.e. 4.5% for 2022 and 3.3% for 2023), then the following process is proposed:

- The revenue requirement will be updated to reflect the new inflation rate, but will not exceed a prescribed inflation cap (the “Inflation Forecast Cap”).
- Hydro One proposes an Inflation Forecast Cap of 10% cumulative inflation over 2022 and 2023. For clarity, a 10% cumulative inflation means the sum of inflation in 2022 and 2023 equals 10%. For example, inflation of 7.0% in 2022 and 3.0% in 2023 results in cumulative inflation of 10%.
- If the cumulative inflation for 2022 and 2023 exceeds 10%, Hydro One will aim to manage its work program to the capped amount through investment reprioritization and redirection and will adjust the outcomes outlined in TSP Section 2.5 and DSP Section 3.5 accordingly.

3.0 IMPACT ON OM&A

Hydro One is seeking approval of an updated 2023 test year OM&A budget of $442.6M for Transmission and $628.9M for Distribution. In support of the revised OM&A expenditures, Appendix 2-JA, 2-JB, 2-JC and 2-L have been filed in Attachments 3A and 3B of this Exhibit (Exhibits E-02-01 Attachment 1A and E-03-01 Attachment 1A). The variances to the as-filed amounts by OM&A component are included below.

3.1 TRANSMISSION OM&A

The updated 2023 test year OM&A budget, reflecting revised inflation assumptions, is $442.6M for Transmission as outlined in Table 6 below.

Table 6 - Summary of Transmission Recoverable OM&A Expenses ($M)

Transmission	Historical					Bridge (As-Filed)	Test Year (As-Filed)	Inflation Update	Variance
	2018	2019	2020		2021	2022	2023	2023	2023
	Actual	Actual	Actual	OEB-Approved	Forecast	Forecast	Forecast	Forecast	Forecast
Sustainment	229.4	207.8	200.9	-	205.2	208.3	219.6	231.2	11.5
Development	5.2	4.4	6.7	-	8.3	8.9	8.6	9.0	0.5
Operations	53.4	51.0	47.9	-	48.8	48.6	49.0	51.6	2.6
Customer Care	11.0	7.2	7.0	-	6.0	6.7	6.9	7.3	0.4
Common and Other	54.9	26.7	70.5	-	51.6	50.7	65.0	68.4	3.4
Property Taxes and Rights Payments	65.3	60.8	65.4	-	69.1	70.2	71.4	75.1	3.7
Total	**419.2**	**357.9**	**398.5**	**385.0**	**389.0**	**393.4**	**420.5**	**442.6**	**22.1**

Exhibit reference: E-02-01, Table 2

3.2 DISTRIBUTION OM&A

The updated 2023 test year OM&A budget, reflecting revised inflation assumptions, is $628.9M for Distribution which include OM&A expenditures related to the Acquired Utilities as outlined in Table 7 below. As previously outlined in Exhibit E-03-01, 2023 test year OM&A amount would have to be normalized for non-service costs component of OPEBs and Acquired Utilities' OM&A in order to compare it to any amounts presented prior to 2023.

Table 7 - Summary of Distribution Recoverable OM&A Expenses ($M)

Distribution	Historical					Bridge (As-Filed)	Test Year (As-Filed)	Inflation Update	Variance
	2018	2018	2019	2020	2021	2022	2023	2023	2023
	OEB-Approved	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast
Sustainment	-	312.3	347.1	324.9	299.6	303.6	311.4	327.7	16.3
Development	-	7.5	7.1	6.0	10.0	10.2	11.0	11.6	0.6
Operations	-	37.3	36.6	33.0	39.7	41.3	40.8	42.9	2.1
Customer Care	-	111.7	97.8	111.2	108.6	107.9	118.3	124.5	6.2
Common and Other	-	84.9	66.3	79.7	68.0	67.0	110.0	115.8	5.8
Property Taxes and Rights Payments	-	5.1	4.6	5.4	5.6	5.8	6.0	6.3	0.3
Total	**544.4**	**558.8**	**559.6**	**560.2**	**531.4**	**535.8**	**597.5**	**628.9**	**31.4**

Exhibit reference: E-03-01, Table 2

4.0 IMPACT ON CAPITAL AND IN-SERVICE ADDITIONS (ISA)

4.1 TRANSMISSION CAPITAL

Hydro One has updated its transmission capital expenditure plan reflecting updated inflation assumptions as documented in Section 2.3 above. Over the 2023-2027 plan term, Hydro One forecasts average annual transmission capital expenditures of $1,527.9M per year, for a total of $7,639.4M. The updated plan is presented below in Table 8, with further details provided in Attachments 4A, 4B, 4C and 4D of this Exhibit.

Table 8 - Updated Transmission Capital Expenditures for 2023-2027 ($M)

OEB Investment Category	Forecast Period – Inflation Update					% of Portfolio
	2023	2024	2025	2026	2027	
System Access	83.6	74.6	63.0	38.4	52.8	4%
System Renewal	1,239.8	1,292.8	1,317.3	1,344.4	1,330.4	82%
System Service	95.6	107.0	90.3	98.0	94.8	6%
General Plant (Transmission)	154.5	130.5	120.2	122.0	110.5	8%
Subtotal	**1,573.5**	**1,604.9**	**1,590.8**	**1,602.7**	**1,588.5**	**100%**
Progressive Productivity[6]	-64.2	-64.2	-64.2	-64.2	-64.2	
Total Transmission Capital	**1,509.3**	**1,540.7**	**1,526.6**	**1,538.5**	**1,524.3**	

This updated 2023-2027 plan is $381.0M higher than the as-filed plan[7], with proportional increases seen across all four OEB categories to reflect the impacts of inflation. Table 9 presents the variance between the updated plan and the as-filed plan for each OEB category.

[6] Progressive productivity represents commitments made during the 2020-22 Transmission rate application for 2022 that are sustained through the test period. Incremental productivity reductions are applied to revenue requirement via productivity stretch factors, as described in SPF Section 1.4.

[7] Exhibit B-02-01, TSP Section 2.1, Table 4

Table 9 - Variance Between the Updated and As-Filed Transmission Capital Plan ($M)

OEB Category		Forecast Period				
		2023	**2024**	**2025**	**2026**	**2027**
System Access	As-Filed Evidence	79.4	70.9	59.8	36.5	50.1
	Inflation Update	83.6	74.6	63.0	38.4	52.8
	Variance	**4.2**	**3.7**	**3.1**	**1.9**	**2.6**
System Renewal	As-Filed Evidence	1178.0	1228.3	1251.6	1277.3	1264.0
	Inflation Update	1239.8	1292.8	1317.3	1344.4	1330.4
	Variance	**61.8**	**64.5**	**65.7**	**67.0**	**66.3**
System Service	As-Filed Evidence	90.9	101.6	85.8	93.1	90.1
	Inflation Update	95.6	107.0	90.3	98.0	94.8
	Variance	**4.8**	**5.3**	**4.5**	**4.9**	**4.7**
General Plant (Transmission)	As-Filed Evidence	146.8	124.0	114.2	115.9	105.0
	Inflation Update	154.5	130.5	120.2	122.0	110.5
	Variance	**7.7**	**6.5**	**6.0**	**6.1**	**5.5**
Progressive Productivity	As-Filed Evidence	-61.0	-61.0	-61.0	-61.0	-61.0
	Inflation Update	-64.2	-64.2	-64.2	-64.2	-64.2
	Variance	**-3.2**	**-3.2**	**-3.2**	**-3.2**	**-3.2**
TOTAL	As-Filed Evidence	1434.0	1463.9	1450.4	1461.8	1448.2
	Inflation Update	1509.3	1540.7	1526.6	1538.5	1524.3
	Variance	**75.3**	**76.8**	**76.1**	**76.7**	**76.0**

4.2 DISTRIBUTION CAPITAL

Hydro One has updated its distribution capital expenditure plan reflecting updated inflation assumptions. Over the 2023-2027 plan term, Hydro One forecasts average annual distribution capital expenditures of $1,114.9M per year, for a total of $5,574.5M. The updated plan is presented below in Table 10, with further details provided in Attachments 4E, 4F, 4C and 4D of this Exhibit.

Table 10 - Updated Distribution Capital Expenditures for 2023-2027 ($M)

OEB Investment Category	Forecast Period – Inflation Update					% of Portfolio
	2023	2024	2025	2026	2027	
System Access	252.2	253.3	238.9	223.8	215.0	21%
System Renewal	392.7	431.8	520.1	517.3	524.0	43%
System Service	206.8	178.6	241.6	202.1	216.7	19%
General Plant (Distribution)	206.2	218.2	179.0	184.7	171.5	17%
Total Distribution Capital	**1057.9**	**1081.9**	**1179.7**	**1127.9**	**1127.2**	**100%**

This updated 2023-2027 plan is $278.0M higher than the as-filed plan, with proportional increases seen across all four OEB categories to reflect the impacts of inflation. Table 11 presents the variance between the updated plan and the as-filed plan for each OEB category.

Table 11 - Variance Between the Updated and As-Filed Distribution Capital Plan ($M)

OEB Category		Forecast Period				
		2023	2024	2025	2026	2027
System Access	As-Filed Evidence	239.6	240.6	227.0	212.6	204.3
	Inflation Update	252.2	253.3	238.9	223.8	215.0
	Variance	**12.6**	**12.6**	**11.9**	**11.2**	**10.7**
System Renewal	As-Filed Evidence	373.1	410.3	494.2	491.5	497.8
	Inflation Update	392.7	431.8	520.1	517.3	524.0
	Variance	**19.6**	**21.5**	**25.9**	**25.8**	**26.1**
System Service	As-Filed Evidence	196.5	169.7	229.6	192.0	205.9
	Inflation Update	206.8	178.6	241.6	202.1	216.7
	Variance	**10.3**	**8.9**	**12.0**	**10.1**	**10.8**
General Plant (Distribution)	As-Filed Evidence	195.9	207.4	170.1	175.5	162.9
	Inflation Update	206.2	218.2	179.0	184.7	171.5
	Variance	**10.3**	**10.9**	**8.9**	**9.2**	**8.6**
TOTAL	As-Filed Evidence	1005.1	1028.0	1120.8	1071.7	1070.9
	Inflation Update	1057.9	1081.9	1179.7	1127.9	1127.2
	Variance	**52.8**	**54.0**	**58.8**	**56.2**	**56.2**

4.3 TRANSMISSION IN-SERVICE ADDITIONS

Hydro One has updated its transmission in-service additions plan reflecting updated inflation assumptions. Over the 2023-2027 plan term, Hydro One forecasts average annual transmission capital in service additions of $1,524.9M per year, for a total of $7,624.5M. The updated plan is presented below in Table 12, with further details provided in Attachment 4G of this Exhibit.

Table 12 - Updated Transmission Capital In-Service Additions for 2023-2027 ($M)

OEB Investment Category	Forecast Period – Inflation Update					% of Portfolio
	2023	2024	2025	2026	2027	
System Access	75.7	51.4	63.9	66.5	41.0	4%
System Renewal	1157.6	1227.7	1488.5	1149.9	1476.5	82%
System Service	60.6	21.7	172.3	75.7	104.4	5%
General Plant (Transmission)	166.8	156.6	135.1	119.6	126.1	9%
Subtotal	**1460.7**	**1457.4**	**1859.8**	**1411.7**	**1747.9**	**100%**
Progressive Productivity	-56.2	-64.2	-64.2	-64.2	-64.2	
Total Transmission ISA	**1404.5**	**1393.2**	**1795.6**	**1347.5**	**1683.8**	

This updated 2023-2027 plan is $333.6M higher than the as-filed plan,[8] with increases seen across all four OEB categories to reflect the impacts of inflation. Table 13 presents the incremental changes seen between this updated plan and the as-filed plan for each OEB category.

[8] Exhibit C-02-01, Table 1.

Table 13 - Variance Between the Updated and As-Filed Transmission In-Service Additions ($M)

OEB Category		Forecast Period				
		2023	2024	2025	2026	2027
System Access	As-Filed Evidence	73.0	48.9	60.7	63.2	38.9
	Inflation Update	75.7	51.4	63.9	66.5	41.0
	Variance	**2.7**	**2.6**	**3.2**	**3.3**	**2.0**
System Renewal	As-Filed Evidence	1128.7	1172.3	1418.6	1092.6	1402.9
	Inflation Update	1157.6	1227.7	1488.5	1149.9	1476.5
	Variance	**28.9**	**55.3**	**70.0**	**57.3**	**73.6**
System Service	As-Filed Evidence	58.9	20.6	163.7	71.9	99.2
	Inflation Update	60.6	21.7	172.3	75.7	104.4
	Variance	**1.7**	**1.1**	**8.6**	**3.8**	**5.2**
General Plant (Transmission)	As-Filed Evidence	162.1	151.6	128.4	113.7	119.8
	Inflation Update	166.8	156.6	135.1	119.6	126.1
	Variance	**4.7**	**5.0**	**6.7**	**6.0**	**6.3**
Progressive Productivity	As-Filed Evidence	-54.6	-61.0	-61.0	-61.0	-61.0
	Inflation Update	-56.2	-64.2	-64.2	-64.2	-64.2
	Variance	**-1.6**	**-3.2**	**-3.2**	**-3.2**	**-3.2**
TOTAL	As-Filed Evidence	1,368.1	1,332.4	1,710.3	1,280.3	1,599.8
	Inflation Update	1,404.5	1,393.2	1,795.6	1,347.5	1,683.8
	Variance	**36.4**	**60.7**	**85.3**	**67.2**	**84.0**

4.4 DISTRIBUTION IN-SERVICE ADDITIONS

Hydro One has updated its distribution in-service addition plan reflecting updated inflation assumptions. Over the 2023-2027 plan term, Hydro One forecasts average annual distribution capital in service additions of $1,128.6M per year, for a total of $5,642.9M. The updated plan is presented below in Table 14, with further details provided in Attachment 4H of this Exhibit.

Table 14 - Updated Distribution Capital In-Service Additions for 2023-2027 ($M)

OEB Investment Category	Forecast Period – Inflation Update					% of Portfolio
	2023	2024	2025	2026	2027	
System Access	252.1	254.5	239.4	223.7	214.8	21%
System Renewal	372.9	447.9	530.9	501.3	533.9	42%
System Service	232.1	156.3	264.4	211.4	205.4	19%
General Plant (Distribution)	155.5	222.2	231.9	180.5	211.8	18%
Total Distribution ISA	**1,012.5**	**1,080.9**	**1,266.6**	**1,116.9**	**1,165.9**	**100%**

This updated 2023-2027 plan is $272.2M higher than the as-filed plan, with increases seen across all four OEB categories to reflect the impacts of inflation. Table 15 presents the incremental changes seen between this updated plan and the as-filed plan for each OEB category.

Table 15 - Variance Between the Updated and As-Filed Distribution In-Service Additions ($M)

OEB Category		Forecast Period				
		2023	2024	2025	2026	2027
System Access	As-filed Evidence	239.6	241.8	227.5	212.5	204.1
	Inflation Update	252.1	254.5	239.4	223.7	214.8
	Variance	**12.5**	**12.7**	**11.9**	**11.2**	**10.7**
System Renewal	As-filed Evidence	355.2	425.6	504.4	476.3	507.3
	Inflation Update	372.9	447.9	530.9	501.3	533.9
	Variance	**17.7**	**22.3**	**26.5**	**25.0**	**26.6**
System Service	As-filed Evidence	226.3	148.8	251.2	200.9	195.1
	Inflation Update	232.1	156.3	264.4	211.4	205.4
	Variance	**5.8**	**7.5**	**13.2**	**10.5**	**10.2**
General Plant (Distribution)	As-filed Evidence	149.9	211.1	220.4	171.5	201.2
	Inflation Update	155.5	222.2	231.9	180.5	211.8
	Variance	**5.6**	**11.1**	**11.6**	**9.0**	**10.6**
TOTAL	As-filed Evidence	970.9	1,027.3	1,203.4	1,061.2	1,107.8
	Inflation Update	1,012.5	1,080.9	1,266.6	1,116.9	1,165.9
	Variance	**41.6**	**53.6**	**63.2**	**55.7**	**58.1**

5.0 IMPACT ON REVENUE REQUIREMENT AND RELATED COMPONENTS

Hydro One is seeking approval of updated 2023-2027 revenue requirements for each of the transmission and distribution businesses, adjusted for the inflation assumptions, as described in Section 2.3 above. The changes in revenue requirement are the result of impacts from the updated inflation assumptions on OM&A, rate base, return on capital, depreciation and amortization, and Regulatory Taxes. The impacts of updated inflation assumptions on these components of revenue requirement are described in the following sections:

- Impact on OM&A – as described in Section 3.0
- Impact on Capital Related Revenue Requirement driven by rate base change due to higher capital and the associated in-service additions described in Section 4.0 and Section 5.2:
  - Return on Capital – as described in Section 5.3
  - Depreciation and Amortization Expense – as described in Section 5.4
  - Regulatory Taxes – as described in Section 5.5

The Revenue Requirement Workforms in support of the updated 2023 to 2027 revenue requirements are filed in Attachments 5A through to 5J of this Exhibit (updates to Exhibit D-01-01, Attachments 1 through 5 for Transmission, and Attachments 6 through 10 for Distribution).

5.1 2023 REVENUE REQUIREMENT

The updated 2023 Transmission revenue requirement is $1,849.3M, which reflects a $26.1M (or 1.4%) increase relative to the as-filed Transmission Revenue Requirement. The updated 2023 Distribution revenue requirement is $1,669.1M, which reflects a $36.7M (or 2.2%) increase relative to the as-filed 2023 Distribution Revenue Requirement.

5.1.1 TRANSMISSION REVENUE REQUIREMENT

The updated 2023 Transmission Revenue Requirement summarized in Table 16 below represents an increase of 1.8% (or $33.1M) as compared to the 2022 OEB-approved revenue requirement of $1,816.2M. As stated in Exhibit D-01-01 this increase, which is significantly below the expected rate of inflation, is predominantly driven by investments in the work program necessary to achieve outcomes that are valued by customers and required to sustain safe and reliable transmission system operations, to maintain equipment performance and to fund necessary investments to address system needs and service obligations, partly offset by benefits arising from rebasing in 2023, such as a reduced cost of capital and incremental productivity gains as further described in SPF Section 1.4.

Table 16 - Transmission Revenue Requirement ($M)

Components	2020 Rebasing Year Note 1	2021 Note 2	2022 (Forecast) Note 3	2022 (Approved) Note 4	2023 Test (As-Filed) Note 5	2023 Test (Inflation Update)* Note 5	2023 Test Year Variance
OM&A	385.0	-	-	-	428.1	450.2	22.1
Depreciation and Amortization	473.4	-	-	-	528.2	531.9	3.7
Regulatory Taxes	30.1	-	-	-	40.5	39.8	-0.7
Return on Capital	741.0	-	-	-	826.3	827.4	1.1
Total Revenue Requirement	**1,629.6**	**1,704.3**	**1,807.6**	**1,816.2**	**1,823.2**	**1,849.3**	**26.1**

**Exhibit Reference: D-01-01, Table 1*

Note 1: Represents OEB-approved 2020 revenue requirement in EB-2019-0082
Note 2: Represents OEB-approved 2021 revenue requirement in 2021 Annual Update in EB-2020-0202
Note 3: 2022 Revenue Requirement = $1,704.3M(2021 Revenue Requirement)(1 + (2.00% inflation factor - 0.30% stretch factor + 2.70% capital factor)) + $28.4(DTA Recovery) = $1,807.6M. 2022 OEB-approved revenue requirement to be established as part of the 2022 Annual Update.*
Note 4: Approved 2022 Revenue Requirement in EB-2021-0185. In the 2022 Annual Update Application, the OEB approved the 2022 Revenue Requirement: $1,704.3M (2021 Revenue Requirement)(1+ (2.50% inflation factor - 0.30% stretch factor + 2.70% capital factor)) + $28.4M(DTA Recovery) = $1,816.2M*
Note 5: The OM&A and Depreciation and Amortization lines reflect the Proposed PCB Treatment for revenue requirement purposes, as further explained in Section 4 of Exhibit D-01-01

5.1.2 DISTRIBUTION REVENUE REQUIREMENT

The updated 2023 Distribution Revenue Requirement summarized in Table 17 below represents a decrease of 1.4% (or $23.0M) as compared to the 2022 OEB-approved revenue requirement of $1,692.1M. As stated in Exhibit D-01-01, this decrease is predominantly driven by benefits arising from rebasing in 2023, such as reduced cost of debt and incremental productivity gains as further described in SPF Section 1.4, partly offset by investments necessary to provide safe and reliable distribution of power and sufficient grid capacity to accommodate customer demand and align with customer preferences, increases to OM&A due to the inclusion of OPEB non-service costs and the incremental revenue requirement related to the Acquired Utilities in 2023.

The 2023 Distribution Revenue Requirement includes an incremental $31.0M of revenue requirement related to Acquired Utilities, which is not included in the 2022 OEB-approved revenue requirement. If 2023 is adjusted to exclude this amount to provide for a more comparable analysis, the decrease in 2023 revenue requirement relative to the 2022 OEB-approved amount results in a reduction of about 3.2% (or about $53.0M).

Table 17 - Distribution Revenue Requirement ($M)

Components	**2018 Rebasing Year** Note 1	**2019** Note 1	**2020** Note 2	**2021** Note 3	**2022 (Forecast)** Note 4	**2022 (Approved)** Note 5	**2023 Test (As-Filed)** Note 6	**2023 Test (Inflation Update)*** Note 6	**2023 Test Year Variance**
OM&A	544.4	-	-	-	-	-	603.0	634.4	31.4
Depreciation and Amortization	397.8	-	-	-	-	-	460.1	465.1	5.0
Regulatory Taxes	43.1	-	-	-	-	-	37.2	36.2	-1.0
Return on Capital	473.2	-	-	-	-	-	532.1	533.4	1.3
Total Revenue Requirement	**1,458.5**	**1,497.9**	**1,539.2**	**1,596.2**	**1,674.6**	**1,692.1**	**1,632.4**	**1,669.1**	**36.7**

**Exhibit Reference: D-01-01, Table 7*

Note 1: Represents OEB-approved 2018 and 2019 revenue requirement in EB-2017-0049
Note 2: Represents OEB-approved 2020 revenue requirement in 2020 Annual Update in EB-2019-0043
Note 3: Represents OEB-approved 2021 revenue requirement in 2021 Annual Update in EB-2020-0030
Note 4: 2022 Revenue Requirement = $1,596.2M(2021 Revenue Requirement)(1 + (2.20% inflation factor - 0.45% stretch factor + 1.85% capital factor)) + $21.0M(DTA Recovery) = $1,674.6M. 2022 OEB-approved revenue requirement to be established as part of the 2022 Annual Update.*
*Note 5: 2022 Approved Revenue Requirement in EB-2021-0032. In the 2022 Annual Update Application, the OEB approved the 2022 Revenue Requirement: $1,596.2M(2021 Revenue Requirement) * (1+ (3.3% inflation factor - 0.45% stretch factor + 1.85% capital factor)) + $21.0M(DTA Recovery) = $1,692.1M*
Note 6: The OM&A and Depreciation and Amortization lines reflect the Proposed PCB Treatment for revenue requirement purposes, as further explained in Section 4 of Exhibit D-01-01

5.2 RATE BASE

The Transmission and Distribution rate base amounts underlying the 2023-2027 revenue requirements include revised forecasts of net fixed assets and working capital allowance. With the inflationary update, rate base amounts reflect updated in-service additions and the associated depreciation on those additions. The 2023-2027 rate base amounts and supporting calculations are filed at Attachments 6A through to 6C of this Exhibit for Transmission and Distribution (Exhibits C-04-01, C-04-02 and C-04-03).

5.2.1 TRANSMISSION RATE BASE

The 2023-2027 Transmission rate base reflecting the revised inflation assumptions is shown in Table 18 below:

Table 18 - Transmission Rate Base, 2023-2027 ($M)

Description	Forecast Period				
	2023	2024	2025	2026	2027
Transmission Rate Base (As-Filed Evidence)	14,592.7	15,450.3	16,448.9	17,394.1	18,256.2
Transmission Rate Base (Inflation Update)*	14,611.5	15,516.6	16,585.5	17,602.6	18,534.1
Variance	18.8	66.3	136.6	208.5	277.9

**Exhibit reference: C-01-01, Table 3 (Transmission)*

5.2.2 DISTRIBUTION RATE BASE

The 2023-2027 Distribution rate base reflecting the revised inflation assumptions is shown in Table 19 below:

Table 19 - Distribution Rate Base, 2023-2027 ($M)

Description	Forecast Period				
	2023	2024	2025	2026	2027
Distribution Rate Base (As-Filed Evidence)	9,372.0	9,962.9	10,641.2	11,301.8	11,880.5
Distribution Rate Base (Inflation Update)*	9,394.7	10,031.4	10,764.2	11,477.9	12,104.7
Variance	22.6	68.5	123.0	176.0	224.2

**Exhibit reference: C-01-01, Table 8 (Distribution)*

5.3 RETURN ON CAPITAL

The updated 2023 rate base figures increased the returns on capital for Transmission and Distribution to $827.4M and $533.4M respectively, which reflect an increase of $1.1M and $1.3M in the Transmission and Distribution, respectively, from the as-filed evidence. As described in Exhibit F-01-01, Hydro One proposes that the 2023 cost of capital parameters established at the time of the Draft Rate Order be used to determine the final revenue requirements for the 2023 to 2027 test years.[9] Exhibit F-01-03 for the 2023 test year for Transmission and Distribution has been re-filed with this evidence update as Attachment 7 to this Exhibit.

5.3.1 TRANSMISSION - COST OF CAPITAL

The revised Transmission capital structure in 2023 reflecting revised inflation assumptions is shown in Table 20 below:

Table 20 - Transmission Cost of Capital Parameters (2023)

Particulars	Rate Base ($M) **As-Filed Evidence**	Revised Rate Base **Inflation Update**	Cost Rate (%)	Return on Capital ($M) **As-Filed Evidence**	Return on Capital ($M) **Inflation Update***
Long-term debt	7,873.7	7,873.7	4.04%	318.3	318.3
Short-term debt	583.7	584.5	1.56%	9.1	9.1
Deemed long-term debt	298.2	308.7	4.04%	12.1	12.5
Total debt	8,755.6	8,766.9	3.87%	339.5	340.0[1]
Common equity	5,837.1	5,844.6	8.34%	486.8	487.4
Total rate base	14,592.7	**14,611.5**	5.66%	826.3	**827.4**

**Exhibit reference: F-01-03 (page 4)*

[1]Long-term debt, Short-term debt and Deemed long-term debt exact numbers add up to Total debt

[9] Hydro One anticipates updating the revenue requirements for the 2023 to 2027 test years when the OEB releases its 2023 cost of capital parameters around fourth quarter 2022, reflecting: (a) the OEB-approved 2023 return on equity and deemed short term debt rate; and (b) long-term debt rates based on Hydro One's actual 2021 and 2022 debt issuances to-date and forecasted debt issues in 2023 with coupon rates based on the September 2022 Consensus Forecast.

5.3.2 DISTRIBUTION - COST OF CAPITAL

The revised Distribution capital structure in 2023 reflecting revised inflation assumptions is shown in Table 21 below:

Table 21 - Distribution Cost of Capital Parameters (2023)

Particulars	Rate Base ($M) **As-Filed Evidence**	Revised Rate Base **Inflation Update**	Cost Rate (%)	Return on Capital ($M) **As-Filed Evidence**	Return on Capital ($M) **Inflation Update***
Long-term debt	4,880.7	4,880.7	4.07%	198.6	198.6
Short-term debt	374.9	375.8	1.56%	5.8	5.9
Deemed long-term debt	367.7	380.3	4.07%	15.0	15.5
Total debt	5,623.2	5,636.8	3.90%	219.4	220.0
Common equity	3,748.8	3,757.9	8.34%	312.7	313.4
Total rate base	9,372.0	**9,394.7**	5.68%	532.1	**533.4**

**Exhibit reference: F-01-03 (page 3)*

5.4 DEPRECIATION AND AMORTIZATION EXPENSE

The revised depreciation and amortization expenses for the inflation update are $539.5M for Transmission and $470.6M for Distribution in the 2023 test year, which reflect increases of $3.7M and $5.0M for Transmission and Distribution, respectively, from the as-filed evidence.[10] These increases are driven by incremental asset removal costs associated with the additional capital expenditures and the incremental depreciation on fixed assets associated with incremental in-service additions. The 2023-2027 depreciation and amortization schedules for Transmission and Distribution are filed at Attachment 8 of this Exhibit (Exhibit E-08-01, Attachment 2).

5.4.1 TRANSMISSION – DEPRECIATION AND AMORTIZATION EXPENSE

The 2023-2027 depreciation and amortization expenses for Transmission, reflecting the updated inflation assumptions are shown in Table 22 below:

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[10] With the Proposed Treatment of PCB for revenue requirement purposes, the 2023 depreciation and amortization expense is $531.9M for Transmission and $465.1M for Distribution.

Table 22 - Transmission Depreciation and Amortization Expense ($M)[11]

	Forecast Period				
Distribution	**2023**	**2024**	**2025**	**2026**	**2027**
Total Depreciation and Amortization Expense (As-Filed Evidence)	535.8	565.1	600.4	625.1	647.3
Total Depreciation and Amortization Expense (Inflation Update)*	**539.5**	**570.2**	**607.6**	**634.2**	**657.9**
Variance	3.7	5.1	7.2	9.1	10.6

**Exhibit reference: E-08-01-02 (page 2 Tx)*

5.4.2 DISTRIBUTION - DEPRECIATION AND AMORTIZATION EXPENSE

The 2023-2027 depreciation and amortization expenses for Distribution, reflecting the updated inflation assumptions, are presented in Table 23 below.

Table 23 - Distribution Depreciation and Amortization Expense ($M)[12]

	Forecast Period				
Distribution	**2023**	**2024**	**2025**	**2026**	**2027**
Total Depreciation and Amortization Expense (As-Filed Evidence)	465.6	486.7	523.0	557.3	592.3
Total Depreciation Expense (Inflation Update)*	**470.6**	**493.7**	**532.7**	**569.3**	**606.9**
Variance	5.0	7.0	9.7	12.0	14.6

**Exhibit reference: E-08-01-02 (page 2 Dx)*

[11] The Depreciation and Amortization expenses include the Environmental Provision
[12] The Depreciation and Amortization expenses include the Environmental Provision

5.5 REGULATORY TAXES

The revised 2023 income tax expenses for the purposes of rate recovery (Regulatory Taxes) requested for approval are $39.8M for Transmission and $36.2M for Distribution, which reflect decreases of $0.7M and $1.0M in Regulatory Taxes for Transmission and Distribution, respectively.

Due to the changes in inflation assumptions used to forecast costs and the impact on Capital and ISAs as noted in Section 4.0, the Regulatory Taxes for Transmission and Distribution are expected to decrease. These decreases arise from the higher tax CCA deductions resulting from higher tax ISA additions.

Hydro One intends to update the Regulatory Taxes and incorporate the full Regulatory Taxes related revenue requirement impact into the Transmission and Distribution final revenue requirements at the time of the DRO.

A reconciliation of the Regulatory Taxes in the as-filed evidence to the Regulatory Taxes revised for inflation is provided below, and reflects anticipated changes in Regulatory Taxes related to inflation assumptions impacting capital and ISA.[13] The supporting calculations for the increase in CCA for 2023-2027 for Transmission and Distribution are filed at Attachment 9 of this Exhibit (Exhibit E-09-02-02).

[13] The updated Regulatory Taxes for inflation and the as-filed calculations do not take into account the amount related to the unintended exclusion of depreciation and amortization expense for Regulatory Tax purposes as further outlined in response to Interrogatory E-Staff-295. Hydro One intends to update the Regulatory Tax calculation to reflect this change at the time of the Draft Rate Order.

5.5.1 TRANSMISSION – REGULATORY TAXES

The 2023-2027 regulatory taxes for Transmission, reflecting updated inflation assumptions, are shown in Table 24 below:

Table 24 - Transmission Regulatory Taxes ($M)

	Forecast Period				
	2023	**2024**	**2025**	**2026**	**2027**
Transmission	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Total Regulatory Taxes (As-Filed Evidence)	40.5	70.9	61.4	83.1	84.3
Tax Changes due to:					
Increase in Regulatory Net Income (before tax)	-	0.3	0.6	1.3	1.8
Increase in Depreciation Expense	1.0	1.3	1.9	2.4	2.8
Increase in CCA*	(1.7)	(2.6)	(4.8)	(5.8)	(7.1)
Other	-	0.1	-	(0.1)	(0.1)
Total Regulatory Taxes (Inflation Update)	**39.8**	**70.0**	**59.1**	**80.9**	**81.7**
Variance	(0.7)	(1.0)	(2.3)	(2.1)	(2.6)

Rounded values might not add up in the table
**Exhibit reference: E-09-02-02*

5.5.2 DISTRIBUTION – REGULATORY TAXES

The 2023-2027 regulatory taxes for Distribution, reflecting updated inflation assumptions, are shown in Table 25 below:

Table 25 - Distribution Regulatory Taxes ($M)

	Forecast Period				
	2023	**2024**	**2025**	**2026**	**2027**
Distribution	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Total Regulatory Taxes (As-Filed Evidence)	37.2	54.6	42.4	59.2	68.7
Tax Changes due to:					
Increase in Regulatory Net Income (before tax)	(0.1)	0.4	0.6	1.2	1.7
Increase in Depreciation Expense	1.3	1.8	2.6	3.2	3.9
Increase in CCA*	(2.2)	(3.0)	(5.1)	(5.8)	(6.6)
Other	-	0.1	-	-	(0.1)
Total Regulatory Taxes (Inflation Update)	**36.2**	**53.9**	**40.4**	**57.8**	**67.6**
Variance	(1.0)	(0.7)	(1.9)	(1.4)	(1.1)

Rounded values might not add up in the table
**Exhibit reference: E-09-02-02*

6.0 CUSTOM IR FRAMEWORK

Below are updated tables which set out the calculation of the components of the Custom IR framework for Hydro One consistent with the calculations outlined in Exhibits A-04-02 and A-04-03. In light of the unprecedented levels of inflation currently being seen, Hydro One wishes to clarify that the Capital factor would not become negative in the case of exceptionally high inflation.

6.1 UPDATED CUSTOM IR TABLES

Table 26 - Summary of Revenue Requirement Components for Hydro One Transmission ($M)

Line		2023	2024	2025	2026	2027
1	Rate Base	14,611.5	15,516.6	16,585.5	17,602.6	18,534.1
2	Return on Debt	340.0	361.0	385.9	409.6	431.2
3	Return on Equity	487.4	517.6	553.3	587.2	618.3
4	Depreciation (note 1)	531.9	562.7	601.0	634.3	658.0
5	Income Taxes	39.8	70.0	59.1	80.9	81.7
6	**Total Capital Related Revenue Requirement**	**1,399.1**	**1,511.3**	**1,599.3**	**1,712.0**	**1,789.2**
7	Less Working Capital Related Revenue Requirement		2.4	2.4	2.5	2.5
8	**Total Capital Related Revenue Requirement (excluding working capital)**	**1,399.1**	**1,508.9**	**1,596.9**	**1,709.5**	**1,786.8**
9	Less Productivity Factor on Capital (0.00%+0.15%)		(2.3)	(2.4)	(2.6)	(2.7)
10	Less Prior Year Productivity Factor on Capital			(2.3)	(4.7)	(7.2)
11	Less Removing Working Capital from Capital Factor		(0.1)	(0.0)	(0.1)	(0.0)
12	**Total Capital Related Revenue Requirement (excluding working capital and Productivity)**	**1,399.1**	**1,509.0**	**1,594.6**	**1,704.7**	**1,779.3**
13	OM&A (note 1)	450.2	459.2	468.4	477.8	487.3
14	**Total Revenue Requirement**	**1,849.3**	**1,968.2**	**2,063.0**	**2,182.5**	**2,266.6**
15	Increase in Capital Related Revenue Requirement		109.9	85.7	110.1	74.6
16	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement		5.94%	4.35%	5.34%	3.42%
17	Less Capital Related Revenue Requirement in I-X		1.51%	1.53%	1.55%	1.56%
18	**Capital Factor**		**4.43%**	**2.82%**	**3.79%**	**1.86%**

Note 1: The OM&A and Depreciation lines reflect the Proposed PCB Treatment for revenue requirement purposes, as further explained in Section 4 of Exhibit D-01-01

Table 27 - Custom Revenue Cap Index (RCI) by Component for Hydro One Transmission

Custom Revenue Cap Index by Component (%)	**2024**	**2025**	**2026**	**2027**
Inflation Factor (I)	2.00	2.00	2.00	2.00
Productivity Factor (X)	-	-	-	-
Capital Factor (C)*	4.43	2.82	3.79	1.86
Custom Revenue Cap Index Total	**6.43**	**4.82**	**5.79**	**3.86**
Additional Productivity Factor for Capital Only	-0.15	-0.15	-0.15	-0.15

** Includes Supplemental Stretch of 0.15% on capital.*

Table 28 - Summary of Revenue Requirement Components for Hydro One Distribution ($M)

Line		2023	2024	2025	2026	2027
1	Rate Base	9,394.7	10,031.4	10,764.2	11,477.9	12,104.7
2	Return on Debt	220.0	234.9	252.0	268.8	283.4
3	Return on Equity	313.4	334.6	359.1	382.9	403.8
4	Depreciation (note 1)	465.1	488.2	531.7	569.4	606.9
5	Income Taxes	36.2	53.9	40.4	57.8	67.6
6	**Total Capital Related Revenue Requirement**	**1,034.7**	**1,111.6**	**1,183.3**	**1,278.8**	**1,361.7**
7	Less Working Capital Related Revenue Requirement		17.5	17.7	17.9	18.2
8	**Total Capital Related Revenue Requirement (excluding working capital)**	**1,034.7**	**1,094.1**	**1,165.6**	**1,260.9**	**1,343.6**
9	Less Productivity Factor on Capital (0.30%+0.15%)		(4.9)	(5.2)	(5.7)	(6.0)
10	Less Prior Year Productivity Factor on Capital			(4.9)	(10.2)	(15.8)
11	Less Removing Working Capital from Capital Factor		0.2	0.4	0.6	0.8
12	**Total Capital Related Revenue Requirement (excluding working capital and Productivity)**	**1,034.7**	**1,106.9**	**1,173.5**	**1,263.6**	**1,340.7**
13	OM&A (note 1)	634.4	646.4	658.7	671.2	684.0
14	**Total Revenue Requirement**	**1,669.1**	**1,753.3**	**1,832.2**	**1,934.8**	**2,024.6**
15	Increase in Capital Related Revenue Requirement		72.2	66.6	90.1	77.0
16	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement		4.33%	3.80%	4.92%	3.98%
17	Less Capital Related Revenue Requirement in I-X		1.18%	1.20%	1.22%	1.24%
18	**Capital Factor**		**3.15%**	**2.60%**	**3.70%**	**2.74%**

Note 1: The OM&A and Depreciation lines reflect the Proposed PCB Treatment for revenue requirement purposes, as further explained in Section 4 of Exhibit D-01-01

Table 29 - Custom Revenue Cap Index (RCI) by Component for Hydro One Distribution

Custom Revenue Cap Index by Component (%)	**2024**	**2025**	**2026**	**2027**
Inflation Factor (I)	2.20	2.20	2.20	2.20
Productivity Factor (X)	-0.30	-0.30	-0.30	-0.30
Capital Factor (C)*	3.15	2.60	3.70	2.74
Custom Revenue Cap Index Total	**5.05**	**4.50**	**5.60**	**4.64**
Additional Productivity Factor for Capital Only	-0.15	-0.15	-0.15	-0.15

** Includes Supplemental Stretch of 0.15% on capital.*

7.0 ATTACHMENTS, UPDATED APPENDICES AND MODELS

The following attachments are provided as part of this section:

- Attachment 1 – Scotiabank Capital Inflation Report dated March 31, 2022
- Attachment 2 – Investment Summary Documents Updated for Inflation
- Attachment 3A – Transmission OM&A (Appendix 2-JA, JB, JC, L)
- Attachment 3B – Distribution OM&A (Appendix 2-JA, JB, JC, L)
- Attachment 4A – Appendix 2-AB – Tx (Capital Expenditures Summary Table – Transmission)
- Attachment 4B – Appendix 2-AA – Tx (Capital Projects Table – Transmission)
- Attachment 4C – Appendix 2-AB – GP (Capital Expenditures Summary Table – General Plant)
- Attachment 4D – Appendix 2-AA – GP (Capital Projects and Programs Table – General Plant)
- Attachment 4E – Appendix 2-AB – Dx (Capital Expenditures Summary Table – Distribution)
- Attachment 4F – Appendix 2-AA – Dx (Capital Projects Table – Distribution)
- Attachment 4G – In-Service Additions – Transmission
- Attachment 4H – In-Service Additions – Distribution
- Attachment 5A – 2023 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 1)
- Attachment 5B – 2024 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 2)
- Attachment 5C – 2025 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 3)
- Attachment 5D – 2026 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 4)
- Attachment 5E – 2027 Transmission Revenue Requirement Workform (Exhibit D-01-01 Attachment 5)

- Attachment 5F – 2023 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 1)
- Attachment 5G – 2024 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 2)
- Attachment 5H – 2025 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 3)
- Attachment 5I – 2026 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 4)
- Attachment 5J – 2027 Distribution Revenue Requirement Workform (Exhibit D-01-01 Attachment 5)
- Attachment 6A – Rate Base Schedule (Exhibit C-04-01)
- Attachment 6B – Continuity of Gross PP&E Schedule (Exhibit C-04-02)
- Attachment 6C – Continuity of Accumulated Depreciation (Exhibit C-04-03)
- Attachment 7 – Return on Capital (Exhibit F-01-03)
- Attachment 8 – Depreciation Schedule (Exhibit E-08-01 Attachment 2)
- Attachment 9 – CCA schedule (Exhibit E-09-02 Attachment 2)

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Attachment 1

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Scotiabank.

GLOBAL ECONOMICS

March 31, 2022

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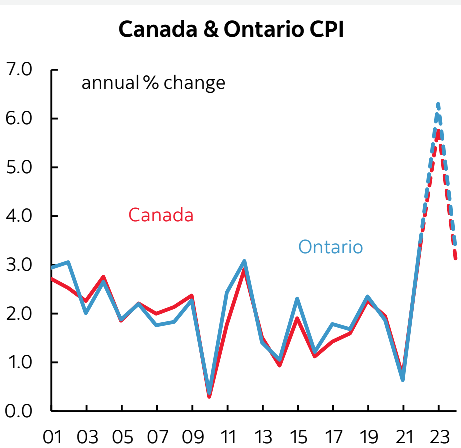
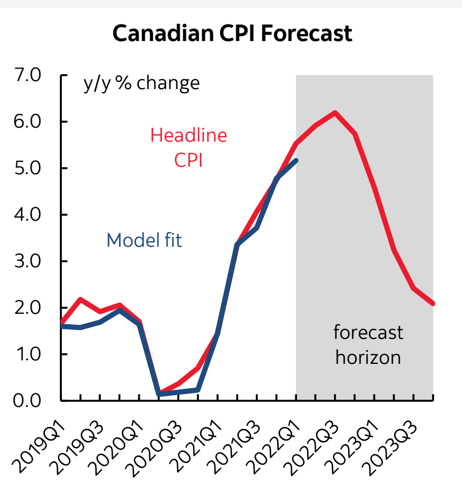
Chart 1



Sources: Scotiabank Economics, Statistics Canada.

Chart 2



Sources: Scotiabank Economics.

What Drove Inflation and Will it Persist?

Inflation has sharply risen to rates unseen since the early 1990s. To varying degrees, central banks, markets and forecasters were all caught off-guard. Why? How have forecasts adapted? Where might inflation go from here?

Our March forecasts for Ontario's inflation rates are 6.3% in 2022 and 3.3% in 2023 (up from 4.5% and 3.3% respectively in our prior January forecasts). After 2023 through 2027 we expect Ontario's inflation rate to converge toward the national target of 2%.

Scotiabank Economics has been asked by Hydro One to offer explanations to a series of questions that broadly relate to why inflation surpassed many forecasters' expectations over 2021 and where we expect inflation to go over 2022-27.

Q1. What happened to inflation in 2020-21 and how did forecasts evolve?

Q2. What is the current 2022-27 inflation forecast?

Q3. When did the signs first appear that a bigger inflation problem was brewing?

Q4. What arguments for rising inflation have been disproven?

Q5. What are the more credible arguments for what is driving inflation?

Each of these questions will be addressed in turn.

Q1. WHAT HAPPENED TO INFLATION IN 2020-21 AND HOW DID FORECASTS EVOLVE?

Canada's inflation rate averaged 3.4% in 2021 in what was a marked acceleration from 0.7% in 2020 during the first year of the pandemic. Ontario's inflation rate performed similarly in that it accelerated from 0.6% in 2020 to 3.5% in 2021. Year-end rates of inflation hit 4.8% y/y for Canada and 5.2% y/y for Ontario.

In its January 2021 Monetary Policy Report, the Bank of Canada had forecast Canadian CPI inflation of 1.6%, 1.7% and 2.1% in 2021, 2022 and 2023 respectively. Even by the BoC's October 2021 forecasts they only anticipated inflation of 3.4% in 2022 and 2.3% in 2023. The Consensus Economics average projection goes forward two years at a time across a large sample of forecasters and at January 2021 indicated that Canadian CPI inflation was expected to equal 1.7% in 2021 and 1.9% in 2022. Scotiabank Economics' January 2021 forecast release anticipated Canadian inflation to equal 1.6% in 2021 and 2.0% for 2022.

As late as December 2021 the Federal Reserve's US inflation forecast was 2.6% for 2022 versus its early-2021 forecast for inflation to equal 2% in 2022. Their March 2022 forecast update projected inflation at 4.3% this year and officials say risks remain to the upside.

The first pivot in terms of forecasting inflation began to arrive in late 2020 into early 2021 when fears were transitioning away from deflationary concerns that were prevalent at the start of the pandemic and toward a stickier and more stable environment for inflation and then upside risk late in 2021. The massive stimulus responses plus the arrival of vaccines and behavioural changes played major roles in this regard. The arrival of the war in Ukraine has added another round of supply shocks to inflation.

Q2. WHAT IS THE CURRENT 2022-27 INFLATION FORECAST?

The full suite of potential drivers of inflation during highly uncertain times is difficult to encapsulate within a single approach to forecasting. At Scotiabank Economics, we use a variety of model– and judgement-based approaches. They point in the direction of material upward revisions to our inflation expectations compared to earlier beliefs.

Our forecast is for Canadian inflation to equal 5.9% in 2022, 3.1% in 2023, 2½% in 2024 and then return toward the Bank of Canada's 2% inflation target in subsequent years.

This is a front-loaded upward revision from our forecast at the start of the year in January that anticipated inflation would reach 4.3% this year and 3.2% next year.

While the year-over-year rate is projected to gradually decelerate (chart 1), this assumes that the Bank of Canada will raise its policy interest rate as aggressively as we forecast. We expect a total of 2.0 percentage points of Bank of Canada rate hikes this year including the already delivered 0.25% increase followed by another 0.5% in 2023 with the policy rate peaking at 3%. Should policy not tighten accordingly, we would probably raise our inflation forecast for a longer period of time.

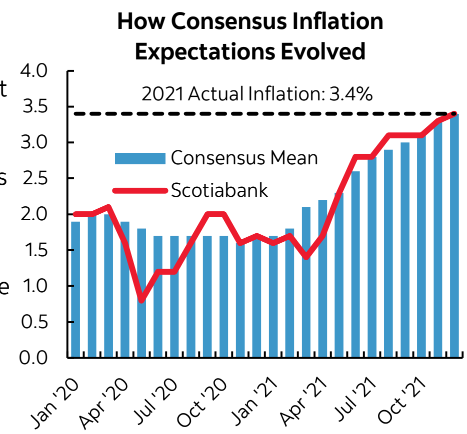
The latest Consensus Economics forecast from March anticipates Canadian inflation of 5.1% in 2022 (high 5.9%, low 4.4%) and 2.6% in 2023 (high 3.8%, low 2.0%).

There is likely to be little difference in comparing projected inflation in Ontario to Canada. Historical differences have tended to be small (chart 1 again), and when they occur tend to be driven by factors such as provincial policy differences that we don't anticipate in a significant way going forward. Our March forecasts for Ontario's inflation rates are 6.3% in 2022 and 3.3% in 2023 compared to 4.5% and 3.3% in our January forecasts. After 2023 through 2027 we expect Ontario's inflation rate to converge toward the national target of 2%.

Scotiabank Economics has a proprietary model based upon expanded work done by our econometricians.[1] It was recently updated to better account for supply side drivers. This econometric approach builds upon a traditional Phillips Curve approach that expresses the relationship between inflation and unemployment. We use a modified approach that takes into account the levels of spare capacity in the economy, as well as labour costs. The resulting model offers a reasonable statistical 'fit' to actual recent inflation (chart 2).

A variable has been added to this equation to account for supply chain disruptions which performs well in terms of improving the model's statistical performance. We have not encountered supply chain difficulties like those observed today in decades and so they represent a consideration that has until now not been well captured in traditional models for forecasting inflation. In fact, we have been dealing with serial supply-side shocks that started with the disruptions introduced by the Trump administration's trade wars, became amplified by the pandemic and are becoming further inflamed by the war in Ukraine.

Chart 3



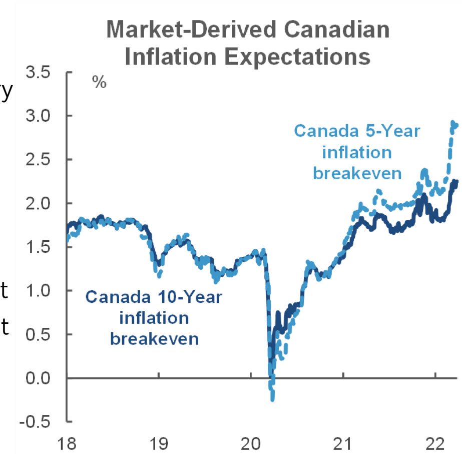
Sources: Scotiabank Economics, Consensus Economics.

Q3. WHEN DID THE SIGNS FIRST APPEAR THAT A BIGGER INFLATION PROBLEM WAS BREWING?

It is true that the evolution of consensus forecasts was somewhat slow to adapt to the rising inflationary pressures and did so in its most powerful form relatively late in 2021 (chart 3).

There are several plausible reasons for this initial failure to forecast most of the surge in inflationary pressures.

Chart 4



Sources: Scotiabank Economics, Bloomberg.

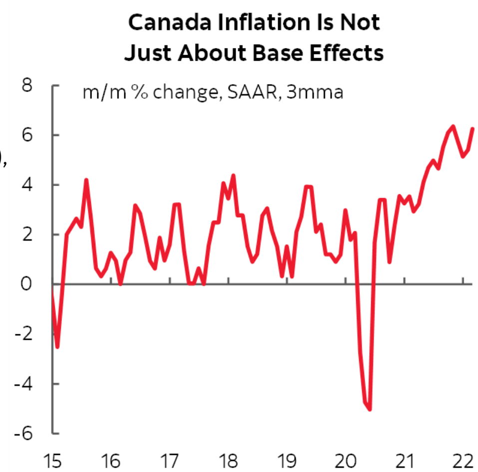
- Inflation expectations had been set low for many years prior to the pandemic and most approaches to forecasting inflation pay significant attention to the role of adaptive expectations that implied higher levels of price stickiness than we've seen. It's unclear why this suddenly became a less powerful influence as we are getting inflation rates like we haven't seen since the early 1990s. Chart 4 shows the relatively sudden upward movements in market-based measures of expectations and I'll return to other measures later.
- Because of this prior experience, had anyone forecast this kind of inflation early last year or before then, there would have been a high level of disbelief and unwillingness to incorporate such expectations into business decisions. Firms that need to form inflation expectations and base business decisions upon them might have been perceived to be acting imprudently on behalf of their stakeholders.
- Omicron's arrival played an important role in driving deeper damage to the supply-side of the economy in an inflationary sense toward

1. *Supply Chain Issues, Even if Temporary, Will Have a Persistent Impact on Inflation—The BoC Should Not Ignore Them*, Rene Lalonde, Nikita Perevalov, Scotiabank Economics, January 19th 2022.

year-end. The war in Ukraine adds to this argument in what has migrated away from serial downside risks to inflation forecasting to serial upside risks.

- Omicron also reintroduced demand-side uncertainty in that it wasn't clear how demand would hold up and hence whether this would lead to downside risk to inflation. It took time to understand that demand proved more resilient in part given higher vaccination rates but also fundamental shifts in behaviour compared to the earlier alpha and delta variants.
- There was high uncertainty around how resilient demand-side drivers of economic activity would be as multiple waves of COVID-19 variants struck. Behaviour became progressively more resilient and this was incrementally inflationary over time.
- There was high uncertainty over how rapidly the supply-side of the economy would be able to meet incremental demand in this cycle. When would job gains trip definitions of maximum employment in this cycle such that wages would begin to accelerate? How serious are semiconductor capacity shortages and how quickly can they be addressed? How quickly can new capacity be brought on line through investment?
- Further, there was uncertainty over the tolerance thresholds of central banks toward inflation. Central banks took considerably longer to pivot toward being concerned about high inflation than was appropriate. This partly reflected a desire not to act prematurely against inflation which had tended to be the past pattern of behaviour. It also reflected the fact that central banks were themselves deeply uncertain toward the durability of inflationary pressures. In fact, it was only by December 2021 that both the Federal Reserve and the Bank of Canada began to change their tunes on inflation by moving away from dismissive references toward expressing greater concern about levels and durability.
- There may also be changes underway to underlying structural and longer-term drivers of inflation that are difficult to assess in a timely fashion. Demographic change may be pivoting toward being more inflation or at least less disinflationary. Trade liberalization—the last example being China's accession to the WTO in 2001—has turned toward more restrictive trade policies (e.g. Trump's trade wars, Russian sanctions, bilateral disputes etc), pandemic effects and generally increased effort upon tightening supply chains. Technological change may be pivoting away from early disinflationary consequences toward more concentrated pricing power.

Chart 5



Sources: Scotiabank Economics, Statistics Canada.

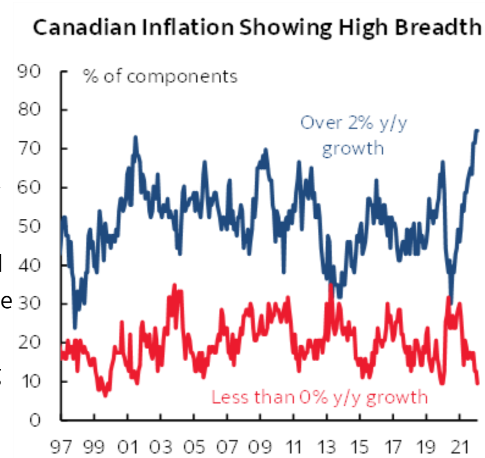
Q4. WHAT ARGUMENTS FOR RISING INFLATION HAVE BEEN DISPROVEN?

After explaining when forecasts changed and what impeded such change, the next step is to explain why the process of raising inflation forecasts remained relatively slow at low rates for many months. Then the focus will turn to arguments that are now more fully emphasized to explain inflation forecasts at this point.

a) From Just Base Effects to Rising Momentum

In the initial stages of accelerating inflation, some observers asserted that soft prices in 2020 presented such a powerful springboard off of which to post a strong subsequent gain that this so-called base effect explained the inflation surge over 2021. For example, had a cup of coffee cost $2 in 2021 it would have risen by 11% had the prior year's price been $1.80, but only ~5% if the prior year's price had been $1.90. If it were true that inflation only accelerated due to a soft starting point for prices at the beginning of the pandemic when overall prices only increased by just 0.7% in 2020, then it would be prudent to treat much of the surge as a transitory statistical fluke. However, what was observed was a long string of powerful price increases on a sustained month-over-month basis starting from about September 2020 through to the present day. The annualized rate of month-over-month and seasonally adjusted price increases has averaged 4.6% since September 2020. Rapid price increases at the margin played a major role in driving inflation higher. This effect has accelerated over time as shown in chart 5.

Chart 6



Sources: Scotiabank Economics, Statistics Canada.

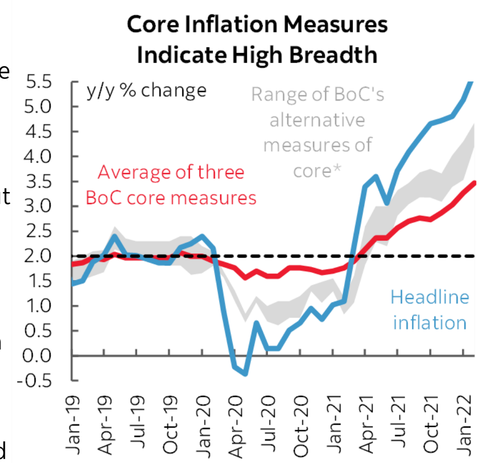
This point also relates back to the prior section's question on why consensus forecasts pivoted relatively late in 2021. A significant part of the reason had to do with the fact that the evidence on month-over-month price pressures took time to evaluate.

b) From Narrowly Based to High and Rising Breadth

At an earlier stage, some argued that such inflationary pressure was narrowly-driven by items like gasoline and therefore did not represent generalized price pressures. This is an important issue because if only one or a small handful of prices were distorting total CPI higher then this so-called relative price shock could be transitory. In fact, if it was powerful enough, then it could have squeezed household budgets in such fashion as to leave less money to spend on other items in the CPI basket and ultimately drive weaker price pressures for everything else.

This is also an incorrect depiction of what drove inflation higher in 2021. Several supporting pieces of evidence can be drawn upon to show why. Chart 6 shows that by the end of 2021, about 75% of all of the prices within the CPI basket were rising by over 2% (the BoC's inflation target) which is one way of indicating high breadth beyond just gasoline prices. Chart 7 shows the average rate of increase in consumer prices using measures that attempt to control for some of the more extreme movements in some prices, both up and down. This average of trimmed mean CPI, weighted median CPI and common component CPI measures of price changes also accelerated which indicates that inflation was not just driven by a few outlier prices. Key categories that play major roles in terms of household spending activities related to housing, food and vehicles have been driving much of the inflation we have been witnessing.

Chart 7



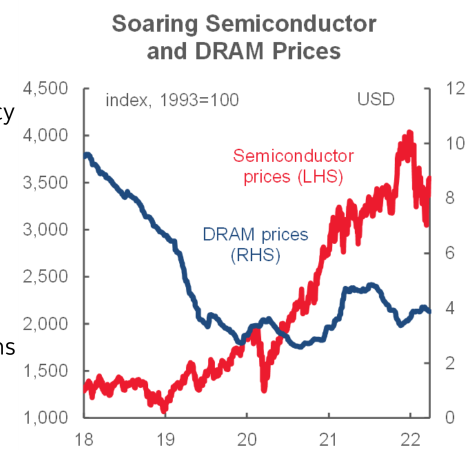
*Includes CPIX, CPIXFET, CPIW measures.
Sources: Scotiabank Economics, Statistics Canada.

c) From Just Reopening Effects to Something Grander

Since the Canadian economy has been subject to rolling bouts of pandemic restrictions, it's plausible that some of the inflationary pressure has been driven by spurts of closing and reopening effects. There is some limited evidence for this but the broader evidence points to how trend inflationary pressures have persisted through such waves of the pandemic and the associated policy responses.

When COVID-19 cases have risen, month-over-month changes in overall consumer prices tend to accelerate. That is partly due to damaged supply chains when some sectors of the economy are closed in whole or in part, when curfews have been embraced and when mobility restrictions have negatively impacted the supply of workers and production inputs. When restrictions ease, such supply side pressures tend to moderate and price pressures tend to ease. Further, when restrictions are applied, it tends to shift more demand toward goods relative to services and inflames goods price inflation.

Chart 8



Sources: Scotiabank Economics, Bloomberg.

The earlier points about high breadth and monthly persistence through waves of reopening and closing effects indicate that price pressures have a more common underlying set of drivers than transitory reopening and closing effects. The behavioural changes brought on by the pandemic may be longer-lived in nature and involve more persistent shifts in the composition of demand toward goods relative to services in inflationary fashion.

Q5. WHAT ARE THE MORE CREDIBLE EXPLANATIONS FOR WHAT IS DRIVING INFLATION?

a) Damaged Supply Chains Have Played a Role

Much emphasis has been placed upon how supply chains have been damaged by the pandemic as a root cause of higher inflation. There is considerable merit to this argument.

For instance, surging demand for semiconductors due to surging demand for vehicles and electronics has driven large gains in semiconductor prices (chart 8). After semiconductor prices initially fell at the start of the pandemic, they went on to rise by 200% by the end of 2021. Prices have since ebbed somewhat into the new year and may gradually weaken going forward but at a moderate pace that means it will take time to clear resulting order backlogs across multiple types

Chart 9

Sources: Scotiabank Economics, Statistics Canada.

of products.

The supply side has also been unable to keep up with demand side pressures on prices in a more general and broader sense beyond electronics components. Chart 9 shows how depleted retail inventories have become in Canada and with a similar picture in the United States. This lack of choice has given retailers some pricing power for the limited stock of goods they have on hand. It will take time to be able to restock shelves and repair this damage to inventory positions. There is growing evidence that companies are slowly able to adjust production in a manner that involves investing in inventories. This process is expected to gradually unfold.

b) So Has Soaring Demand

If higher inflation was just due to supply side challenges and the supply side woes may gradually improve over time, then perhaps inflation will turn suddenly lower as this process unfolds.

While recognizing the role of the supply side in driving prices higher, we cannot ignore the contributions to inflation that have come from the demand side (chart 10). Housing investment soared in response to extremely low borrowing costs and as budgets and behaviour adapted to the pandemic by lifting demand for living space. This indicator of new housing supply has been unable to keep up with demand and so sales of existing homes have been pushed to the record heights during the pandemic.

Retail sales have also been pushed to levels that are well above pre-pandemic levels in terms of the value of sales and the volumes of sales. This observation somewhat overstates the strength of consumer demand because the pandemic relatively favoured goods over services consumption and because retail sales tend to underweight services spending. Nevertheless, total consumer spending volumes across goods and services has fully recovered from the pandemic's shock by the third quarter of last year and is now surpassing pre-pandemic levels.

Thus, both constrained supply and soaring demand have played roles in driving higher inflation.

c) Closure of Spare Capacity

The combination of these two forces of supply and demand and how they can drive price pressures in the overall economy is difficult to measure. One attempt is reflected in chart 11 that shows the evolution of the economy's output gap, defined as the balance between overall supply and demand in the broad economy. When the output gap is positive it indicates that demand pressures are outstripping supply pressures. When the output gap is negative—as it tends to be in recessions and the early stages of recoveries- it tends to indicate that excess supply exists. Excess demand is denoted by positive numbers and is generally inflationary, excess supply is generally denoted by negative numbers and is disinflationary.

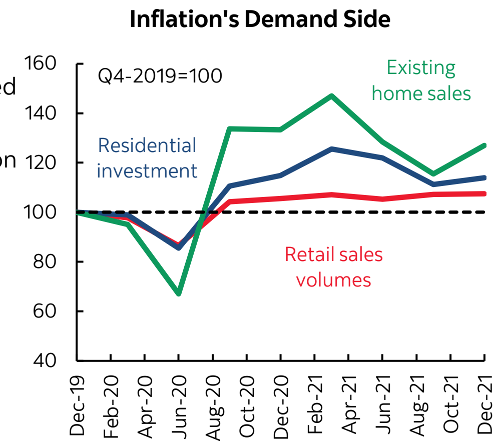
Throughout much of the pandemic, there was broad underutilized capacity in the economy. As a recovery unfolded, spare capacity diminished and removed the worst downside risks to inflation. Further closure of spare capacity contributed toward stabilizing but still low rates of inflation through much of 2021. Going forward, we think a push into excess aggregate demand that is now underway will provide the next leg of upward pressures upon inflation.

d) Accelerating Wage Inflation

Faster wage pressure in response to changing labour market conditions and rising inflation can also reinforce inflation expectations. There is evidence that this is indeed happening.

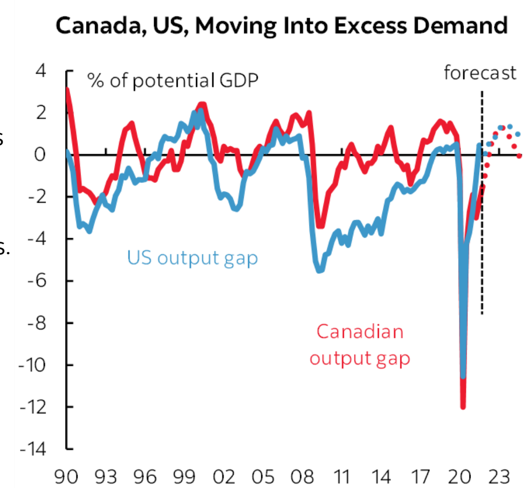
The way to observe this is to consider changes in average hourly wages in month-over-month seasonally adjusted and annualized terms much like what was done with CPI earlier in this note.

Chart 10



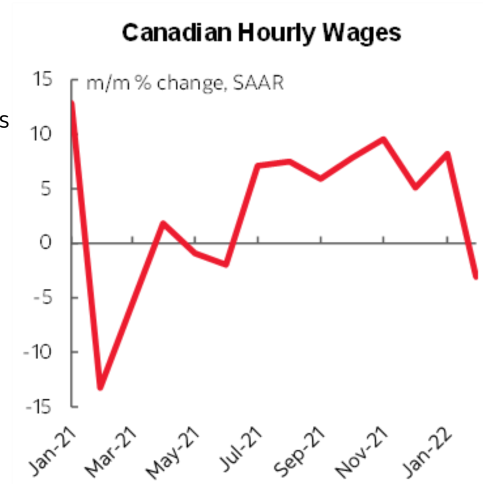
Sources: Scotiabank Economics, CREA, Statistics Canada.

Chart 11



Sources: Scotiabank Economics, Bank of Canada, CBO.

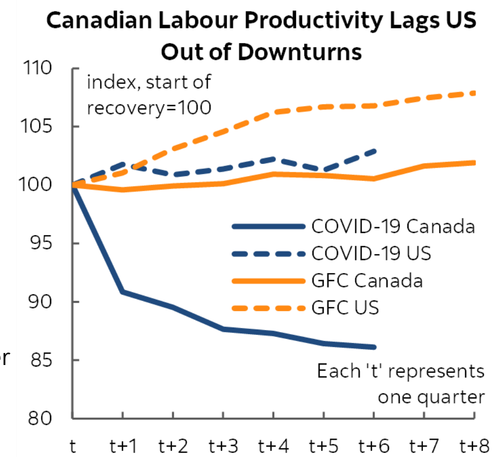
Chart 12



Sources: Scotiabank Economics, Statistics Canada.

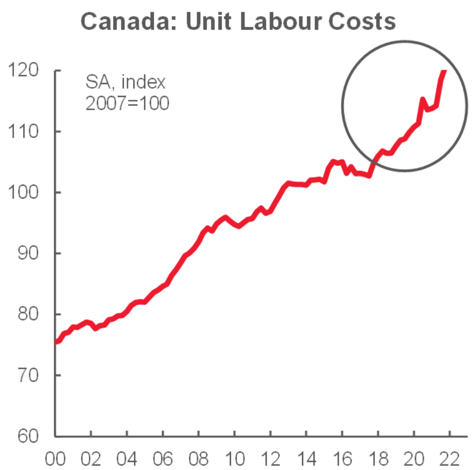
This month-over-month wage growth measure will be better at flagging rapid changes at the margin under evolving conditions than, say, slower moving measures like year-over-year growth in wages. Month-over-month wage pressures are especially better at flagging changes than what some people emphasize by pointing to changes in wages compared to two years ago and hence into an environment that pre-dates the pandemic. If wage pressures are unfolding, then the year-over-year and year-over-two-years-ago measures of wage growth may reveal such pressures long after it has begun to unfold.

Chart 13



Sources: Scotiabank Economics, Statistics Canada, Bureau of Labour Statistics.

Chart 14

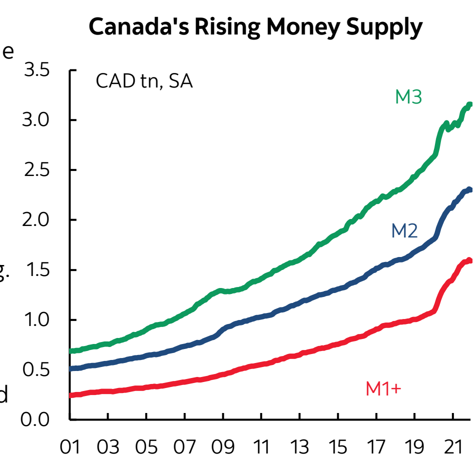


Sources: Scotiabank Economics, Bloomberg.

Chart 12 shows this preferred measure of wage growth. The trend in the month-over-month seasonally adjusted and annualized percentage change in wages has been rapidly accelerating since about last July. Over the seventh month period since then, wage growth has averaged about 6% by this measure. We expect further trend gains along a volatile path.

Percentage growth in wages is only a part of the story, however, in that inflation that is supported or fed by higher wages can also be caused by producing less at the same pay, let alone higher pay. This is where labour productivity becomes an important consideration as measured by inflation-adjusted output per hour worked by all employed Canadians. Canada's labour productivity has been sharply falling throughout the pandemic. Chart 13 shows that Canada typically underperforms the United States on labour productivity growth coming out of major negative shocks like the Global Financial Crisis and the pandemic. This time, however, is much worse in that while US productivity growth has been soft, Canadian productivity is sharply falling.

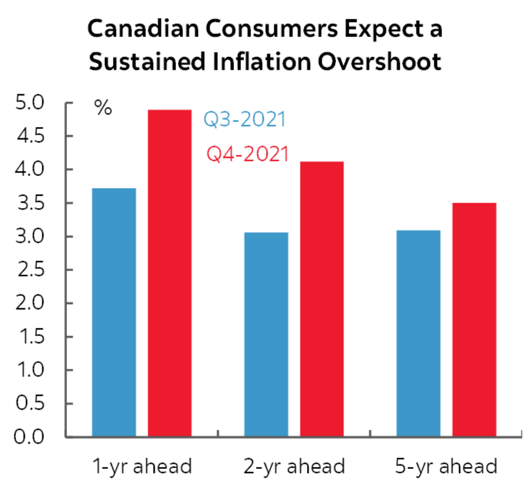
Chart 15



Sources: Scotiabank Economics, Bank of Canada.

A way to combine these labour market developments into a single measure of how wages can reinforce inflationary pressures is to adjust overall employment costs – including wages and benefits – for productivity. This is called unit labour costs, defined as the employment costs paid to produce a dollar of goods and services in the overall economy. Canada's unit labour costs began accelerating before the pandemic (chart 14). The United States started seeing unit labour costs rise at an accelerated pace during the pandemic. The combination of accelerating wage pressures in tightening labour markets and weak productivity growth is inflationary on both counts.

Chart 16



Sources: Scotiabank Economics, Bank of Canada.

e) Excessive Stimulus

With the partial benefit of hindsight, monetary and fiscal policies applied excessive amounts of stimulus as a major driver of soaring inflation. Various definitions of money supply soared as shown in chart 15. Given how fiscal policy generally responded with too little too late in response to past shocks, central banks may have counted upon a repeat performance in the pandemic. Instead, aggressive fiscal stimulus was applied and the benefits of globally coordinated stimulus were probably underestimated which probably amplified the actions of any one country. Emergency stimulus responses were justifiably put in place when the pandemic first struck at a time before vaccines were in sight and there were palpable fears of a deflationary depression.

Instead, vaccines did arrive alongside other treatments, behaviour adapted and so did other policy measures. We are not out of the pandemic, but the extreme stimulus that was put in place has proven to be excessive. In addition to cutting policy rates to zero, major central banks around the world greatly expanded their balance sheets and aggressively expanded money supply. More stimulus chasing damaged supply chains has compounded inflationary pressures.

f) Expectations

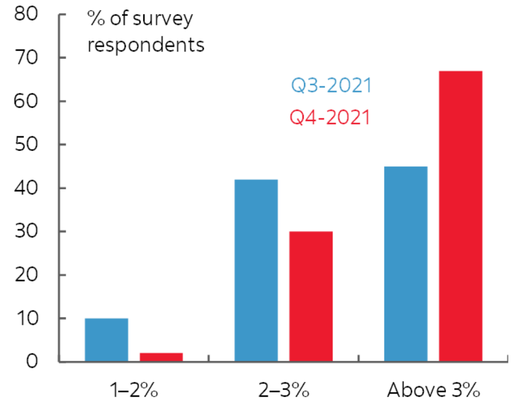
What worries central banks and markets probably more than anything else is the extent to which rising price pressures begin to be expected. If attitudes and behaviour adjust in such fashion that incorporates expectations for rapidly rising prices then high and volatile inflation can become a self-fulfilling prophecy.

There is some evidence that this is happening. Consumers have been raising their expectations for inflation over the coming year (2022), the following year, and over the full five years ahead (chart 16). The latest survey-based estimates produced by the Bank of Canada's Survey of Consumer Expectations are at or above the upper limit of the Bank of Canada's 1-3% inflation target range across all of the time horizons.

Businesses have also taken note of rising inflationary pressures. The Bank of Canada's Business Outlook Survey polls respondents across C-suites for what they think will happen to inflation over the coming two years combined (2022-23). Over two-thirds of businesses expect inflation to average over 3% over this 2022-23 period (chart 17).

Chart 17

Canadian Businesses Expect Inflation to Surpass BoC's Target



Sources: Scotiabank Economics, Bank of Canada.

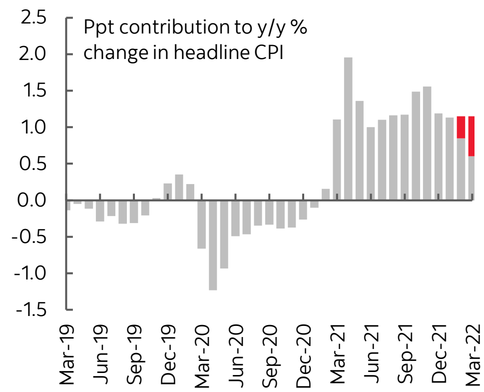
g) Commodities

Soaring commodity prices have become a more recent driver of high inflation since early December 2021 and particularly over the past month as the war in Ukraine broke out.

Higher oil prices influence Canadian inflation in a variety of ways. The direct effect on CPI is mostly limited to gasoline prices that are adding about 1.2 percentage points to Canada's present 5.1% y/y inflation rate (chart 18). This contribution would have been falling by now and bringing about lower inflation if not for the oil shock brought on by the war in Ukraine.

Chart 18

Gasoline Contribution to Canadian Inflation to Remain Elevated



Sources: Scotiabank Economics, BLS.

The fuller effect of higher oil prices on Canadian CPI inflation has to also consider the potential for pass-through into other prices, plus the ability of consumers to substitute and change behaviour and the fuller effects upon their inflation-adjusted incomes. The incomes of a net exporter of oil and other commodities like Canada benefit from higher commodities by selling its exports at a rising price relative to the prices it pays for what it imports. That is an imported positive income shock. The Bank of Canada's estimate that accounts for these full effects is that for every 10% rise in the price of a barrel of oil, CPI inflation rises by ~0.3% within one – year.

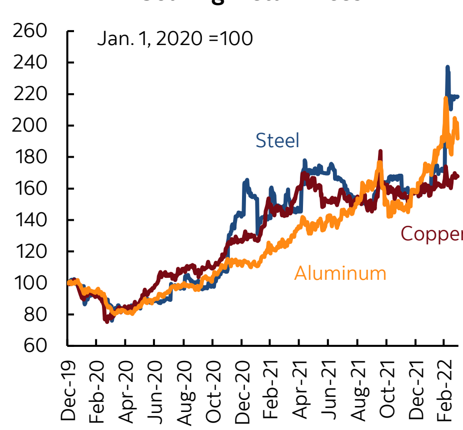
Since the rise in oil prices has been multiples of this amount since December, the impact on inflation is probably on the order of adding 1¾-2¾ percentage points.

Add to that the fact that the Canadian dollar *usually* appreciates when oil soars which is embedded in traditional estimates of pass through effects of higher oil prices into CPI inflation. Clearly that's not happening this time and so these may be rather conservative estimates with the oil plus CAD effect possibly topping three percentage points.

There is likely to be additional pass-through of higher prices for other commodities into the CPI basket going forward. Multiple food categories—especially grains—plus higher prices for fertilizers and a range of metals should also contribute to total inflation (chart 19).

Chart 19

Soaring Metal Prices



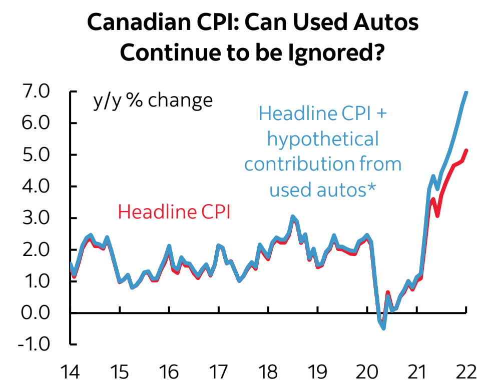
Sources: Scotiabank Economics, Bloomberg.

h) Measurement issues

Everything in this report has addressed official CPI inflation statistics. A caution is that official measurements may be altered by this summer. Statistics Canada has guided they are working toward incorporating measures of used vehicle prices that are presently excluded from CPI and this may be done by summer. This may add 1-2% to currently estimated inflation. Chart 20 offers a depiction of the possible effects.

In June, Statistics Canada will also refresh spending weights in the CPI basket to reflect 2021 spending patterns. This is not expected to result in a major change but it's possible that the incluision of used vehicle prices may occur simultaneously to refreshing the CPI basket.

Chart 20



*Contribution to CPI assumes weighting equal to US CPI used vehicle weighting.
Sources: Scotiabank Economics, Statistics Canada, Canadian Black Book, BLS.

ISD	Investment Name	Forecast Period (As Filed) $M					Forecast Period (Updated Inflation) $M					Increase from As-Filed Evidence ($M)				
		2023	2024	2025	2026	2027	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
System Access																
T-SA-01	New Customer Connection Station	13.5	13.5	-	-	-	14.2	14.2	-	-	-	0.7	0.7	-	-	-
T-SA-02	IAMGOLD - 115 kV Mine Connection	10.0	-	-	-	-	10.5	-	-	-	-	0.5	-	-	-	-
T-SA-03	Halton TS: Build a Second 230/27.6kV Station	-	1.5	4.5	1.9	0.0	-	1.6	4.8	2.0	0.1	-	0.1	0.2	0.1	0.0
T-SA-04	Connect Metrolinx Traction Substations	3.5	3.6	0.8	-	-	3.7	3.8	0.9	-	-	0.2	0.2	0.0	-	-
T-SA-05	Future Transmission Load Connection Plans	3.1	5.2	9.4	10.4	10.4	3.3	5.5	9.9	11.0	11.0	0.2	0.3	0.5	0.5	0.5
T-SA-06	Protection and Control Modifications for Distributed Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T-SA-07	Secondary Land Use Projects	37.8	2.8	2.8	0.8	0.8	39.8	3.0	3.0	0.9	0.9	2.0	0.1	0.1	0.0	0.0
T-SA-08	H29/H30: Reconductor 230kV Circuits	0.2	0.4	0.3	2.1	2.3	0.2	0.4	0.3	2.2	2.4	0.0	0.0	0.0	0.1	0.1
T-SA-09	New Transformer Station in Northern York Region	-	-	5.6	3.7	2.4	-	-	5.9	3.9	2.5	-	-	0.3	0.2	0.1
T-SA-10	Build Leamington Area Transformer Stations	7.6	40.9	33.5	14.5	32.6	8.0	43.0	35.3	15.3	34.3	0.4	2.1	1.8	0.8	1.7
System Access Projects and Programs Less Than Materiality Threshold		3.7	2.9	2.9	3.0	1.5	3.9	3.1	3.0	3.2	1.6	0.2	0.2	0.2	0.2	0.1
Total System Access		**79.4**	**70.9**	**59.8**	**36.5**	**50.1**	**83.6**	**74.6**	**63.0**	**38.4**	**52.8**	**4.2**	**3.7**	**3.1**	**1.9**	**2.6**
System Renewal																
T-SR-01	Transmission Station Renewal - Network Stations	209.4	199.6	213.6	158.4	213.1	220.4	210.1	224.8	166.7	224.3	11.0	10.5	11.2	8.3	11.2
T-SR-02	Transmission Station Renewal - Air Blast Circuit Breakers	172.3	153.8	115.8	99.3	34.4	181.3	161.8	121.9	104.5	36.2	9.0	8.1	6.1	5.2	1.8
T-SR-03	Transmission Station Renewal - Connection Stations	334.5	357.7	350.1	406.5	428.6	352.0	376.5	368.5	427.8	451.1	17.6	18.8	18.4	21.3	22.5
T-SR-04	Wood Pole Structure Replacements	56.5	57.6	58.8	60.0	61.2	59.5	60.7	61.9	63.1	64.4	3.0	3.0	3.1	3.1	3.2
T-SR-05	Steel Structure Coating Program	23.6	24.1	24.5	25.0	25.4	24.9	25.3	25.8	26.3	26.8	1.2	1.3	1.3	1.3	1.3
T-SR-06	Tower Foundation Assess/Clean/Coat Program	17.3	17.6	17.9	18.3	18.6	18.2	18.5	18.9	19.2	19.6	0.9	0.9	0.9	1.0	1.0
T-SR-07	Transmission Line Shieldwire Replacement	12.1	12.3	12.5	12.8	13.0	12.7	12.9	13.2	13.5	13.7	0.6	0.6	0.7	0.7	0.7
T-SR-08	Transmission Line Insulator Replacement	78.4	78.1	79.5	81.0	82.5	82.6	82.1	83.7	85.2	86.8	4.1	4.1	4.2	4.3	4.3
T-SR-09	Transmission Station Demand and Spares and Targeted Assets	43.9	44.7	45.2	46.2	47.0	46.2	47.0	47.5	48.6	49.4	2.3	2.3	2.4	2.4	2.5
T-SR-10	Protection Relay Replacement Program	8.8	8.9	9.0	9.1	9.2	9.2	9.3	9.4	9.5	9.6	0.5	0.5	0.5	0.5	0.5
T-SR-11	Legacy SONET System Replacement	19.5	29.4	29.2	27.6	8.3	20.5	30.9	30.8	29.0	8.7	1.0	1.5	1.5	1.4	0.4
T-SR-12	Telecom Performance Improvements	4.2	5.8	3.8	-	-	4.4	6.1	4.0	-	-	0.2	0.3	0.2	-	-
T-SR-13	Transmission Complete Line Refurbishment	60.1	125.8	190.8	235.9	220.5	63.3	132.4	200.8	248.3	232.1	3.2	6.6	10.0	12.4	11.6
T-SR-14	Mobile Radio System Replacement	5.2	6.7	5.6	2.4	-	5.5	7.0	5.9	2.5	-	0.3	0.4	0.3	0.1	-
T-SR-15	Transmission Line Emergency Restoration	10.2	10.4	10.6	10.8	11.0	10.7	10.9	11.2	11.4	11.6	0.5	0.5	0.6	0.6	0.6
T-SR-16	HV UG Cable – Replace/Refurbish Pumping Plants	-	-	0.1	0.2	5.5	-	-	0.1	0.2	5.8	-	-	0.0	0.0	0.3
T-SR-17	OPGW Infrastructure Projects	28.5	27.8	30.4	20.1	10.5	30.0	29.2	32.0	21.2	11.0	1.5	1.5	1.6	1.1	0.5
T-SR-18	C5E/C7E Underground Cable Replacement	38.3	23.7	4.6	0.1	-	40.3	24.9	4.9	0.1	-	2.0	1.2	0.2	0.0	-
System Renewal Projects and Programs Less Than Materiality Threshold		55.4	44.7	49.6	63.9	75.3	58.3	47.0	52.2	67.3	79.3	2.9	2.3	2.6	3.4	4.0
Total System Renewal		**1,178.0**	**1,228.3**	**1,251.6**	**1,277.3**	**1,264.0**	**1,239.8**	**1,292.8**	**1,317.3**	**1,344.4**	**1,330.4**	**61.8**	**64.5**	**65.7**	**67.0**	**66.3**
System Service																
T-SS-01	Nanticoke TS: Connect HVDC Lake Erie Circuits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T-SS-02	St. Lawrence TS: Phase Shifter Upgrade	6.0	-	-	-	-	6.3	-	-	-	-	0.3	-	-	-	-
T-SS-03	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	9.0	-	-	-	-	9.5	-	-	-	-	0.5	-	-	-	-
T-SS-04	Richview x Trafalgar 230kV Conductor Upgrade	12.6	16.4	12.1	2.4	-	13.3	17.2	12.7	2.5	-	0.7	0.9	0.6	0.1	-
T-SS-05	Merivale TS: Add 230/115kV Autotransformers	25.0	30.0	22.0	-	-	26.3	31.6	23.2	-	-	1.3	1.6	1.2	-	-
T-SS-06	Southwest GTA Transmission Reinforcement	6.5	7.5	3.0	-	1.0	6.8	7.9	3.2	-	1.1	0.3	0.4	0.2	-	0.1
T-SS-07	West of Chatham Reinforcement	8.3	20.4	5.2	-	-	8.8	21.4	5.5	-	-	0.4	1.1	0.3	-	-
T-SS-08	Future Transmission Regional Plans	10.7	20.0	20.4	20.4	20.4	11.3	21.1	21.5	21.5	21.5	0.6	1.1	1.1	1.1	1.1
T-SS-09	West of London Reinforcement	4.2	4.2	18.7	60.9	54.8	4.4	4.5	19.6	64.1	57.7	0.2	0.2	1.0	3.2	2.9
System Service Projects and Programs Less Than Materiality Threshold		8.5	3.1	4.4	9.4	13.8	9.0	3.3	4.7	9.9	14.5	0.4	0.2	0.2	0.5	0.7
Total System Service		**90.9**	**101.6**	**85.8**	**93.1**	**90.1**	**95.6**	**107.0**	**90.3**	**98.0**	**94.8**	**4.8**	**5.3**	**4.5**	**4.9**	**4.7**

ISD	Investment Name	Forecast Period (As Filed) $M					Forecast Period (Updated Inflation) $M					Increase from As-Filed Evidence ($M)				
		2023	2024	2025	2026	2027	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
System Access																
D-SA-01	Joint Use and Relocations	24.8	29.0	27.0	26.5	27.2	26.1	30.5	28.4	27.9	28.7	1.3	1.5	1.4	1.4	1.5
D-SA-02	New Load Connections, Upgrades, Cancellations	150.7	154.6	158.5	162.5	166.7	158.6	162.7	166.8	171.1	175.4	7.9	8.1	8.3	8.6	8.7
D-SA-03	Connecting Distributed Energy Resources	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	0.1	0.1	0.1	0.1	0.1
D-SA-04	Metering Sustainment	62.6	55.6	40.1	22.2	8.9	65.9	58.6	42.2	23.3	9.4	3.3	3.0	2.1	1.1	0.5
System Access Projects and Programs Less Than Materiality Threshold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Access		**239.6**	**240.6**	**227.0**	**212.6**	**204.3**	**252.2**	**253.3**	**238.9**	**223.8**	**215.0**	**12.6**	**12.7**	**11.9**	**11.2**	**10.7**
System Renewal																
D-SR-01	Distribution Stations Demand Capital Program	6.2	6.3	6.4	6.5	6.7	6.5	6.6	6.7	6.9	7.0	0.3	0.3	0.3	0.4	0.3
D-SR-02	Mobile Unit Substation Program	3.5	4.2	2.9	3.3	4.6	3.7	4.5	3.0	3.4	4.8	0.2	0.3	0.1	0.1	0.2
D-SR-03	Distribution Station Planned Component Replacement Program	4.6	3.3	1.1	1.2	1.2	4.8	3.5	1.2	1.2	1.2	0.2	0.2	0.1	0.0	0.0
D-SR-04	Distribution Station Refurbishment	44.8	41.5	28.5	32.3	32.1	47.2	43.7	30.0	34.0	33.7	2.4	2.2	1.5	1.7	1.7
D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	106.0	108.1	110.3	112.5	114.7	111.6	113.8	116.1	118.4	120.8	5.6	5.7	5.8	5.9	6.1
D-SR-06	Distribution Lines PCB Equipment Replacement Program	9.4	9.5	9.5	-	-	9.9	9.9	10.0	-	-	0.5	0.4	0.5	-	-
D-SR-07	Pole Sustainment Program	107.9	110.6	112.4	114.9	116.8	113.5	116.4	118.3	120.9	122.9	5.6	5.8	5.9	6.1	6.1
D-SR-08	Distribution Lines Minor Component Replacement Program	12.4	14.5	13.5	8.6	7.1	13.0	15.3	14.2	9.0	7.5	0.6	0.8	0.7	0.4	0.4
D-SR-09	Submarine Cable Replacement Program	12.2	12.5	12.7	13.0	13.2	12.8	13.1	13.4	13.6	13.9	0.6	0.6	0.7	0.6	0.7
D-SR-10	Distribution Lines Sustainment Initiatives	31.5	30.3	35.3	43.2	42.7	33.2	31.9	37.1	45.4	45.0	1.7	1.6	1.8	2.2	2.3
D-SR-11	Life Cycle Optimization & Operational Efficiency Projects	2.8	6.5	7.1	0.8	0.4	3.0	6.9	7.4	0.9	0.5	0.2	0.4	0.3	0.1	0.1
D-SR-12	Advanced Meter Infrastructure 2.0 (AMI 2.0)	30.9	62.0	153.7	154.4	157.3	32.5	65.3	161.7	162.6	165.5	1.6	3.3	8.0	8.2	8.2
System Renewal Projects and Programs Less Than Materiality Threshold		0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	0.0	0.0	0.1	0.1	0.1
Total System Renewal		**373.1**	**410.3**	**494.2**	**491.5**	**497.8**	**392.7**	**431.8**	**520.1**	**517.3**	**524.0**	**19.6**	**21.5**	**25.9**	**25.8**	**26.2**
System Service																
D-SS-01	System Upgrades Driven by Load Growth	98.2	76.3	127.5	76.1	100.2	103.3	80.3	134.2	80.1	105.4	5.1	4.0	6.7	4.0	5.2
D-SS-02	Reliability Improvements	7.3	0.1	6.5	18.6	7.5	7.6	0.1	6.8	19.6	7.9	0.3	(0.0)	0.3	1.0	0.4
D-SS-03	Demand Investments	13.2	13.4	13.7	13.9	14.2	13.9	14.1	14.4	14.6	15.0	0.7	0.7	0.7	0.7	0.8
D-SS-04	Energy Storage Solutions	34.3	35.0	35.6	36.3	36.0	36.1	36.8	37.5	38.2	37.9	1.8	1.8	1.9	1.9	1.9
D-SS-05	Worst Performing Feeders	39.6	40.9	42.2	43.0	43.8	41.7	43.0	44.4	45.2	46.1	2.1	2.1	2.2	2.2	2.3
D-SS-06	Power Quality and Stray Voltage	3.8	3.9	4.0	4.0	4.1	4.0	4.1	4.2	4.2	4.3	0.2	0.2	0.2	0.2	0.2
System Service Projects and Programs Less Than Materiality Threshold		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	(0.0)	0.1	(0.0)
Total System Service		**196.5**	**169.7**	**229.6**	**192.0**	**205.9**	**206.8**	**178.6**	**241.6**	**202.1**	**216.7**	**10.3**	**8.9**	**12.0**	**10.1**	**10.8**

ISD	Investment Name	Forecast Period (As Filed) $M					Forecast Period (Updated Inflation) $M					Increase from As-Filed Evidence ($M)				
		2023	2024	2025	2026	2027	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
Fleet																
G-GP-01	Transport and Work Equipment	67.2	68.7	69.3	70.4	72.8	70.8	72.3	73.0	74.1	76.7	3.5	3.6	3.6	3.7	3.8
G-GP-02	Helicopter Renewal	9.2	9.4	9.6	9.6	9.8	9.7	9.9	10.1	10.1	10.3	0.5	0.5	0.5	0.5	0.5
Total Fleet		**76.4**	**78.0**	**78.9**	**80.0**	**82.6**	**80.4**	**82.1**	**83.0**	**84.2**	**86.9**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**
Facilities and Real Estate																
G-GP-03	Facilities and Accommodations	78.5	79.3	51.6	48.4	40.8	82.7	83.5	54.3	51.0	42.9	4.1	4.2	2.7	2.5	2.1
G-GP-04	Transmission Facilities	12.9	12.8	10.1	9.6	9.7	13.6	13.5	10.6	10.1	10.2	0.7	0.7	0.5	0.5	0.5
Total Facilities and Real Estate		**91.4**	**92.1**	**61.7**	**58.1**	**50.5**	**96.2**	**96.9**	**64.9**	**61.1**	**53.1**	**4.8**	**4.8**	**3.2**	**3.0**	**2.6**
Information Solutions																
G-GP-05	Information Technology Services Enablement	19.5	21.9	27.2	28.9	24.9	20.5	23.0	28.7	30.4	26.2	1.0	1.1	1.4	1.5	1.3
G-GP-06	Corporate Services Enablement	24.4	18.1	18.3	16.9	16.6	25.7	19.1	19.3	17.8	17.4	1.3	1.0	1.0	0.9	0.9
G-GP-07	Customer Service Technology Enablement	4.1	18.7	18.1	35.1	33.0	4.3	19.7	19.1	36.9	34.7	0.2	1.0	1.0	1.8	1.7
G-GP-08	Work and Asset Management Enablement	37.3	42.0	36.1	22.8	16.7	39.3	44.3	38.0	24.0	17.6	2.0	2.2	1.9	1.2	0.9
G-GP-09	Operating Technology Cyber Security Equipment Replacement	5.7	3.4	2.8	6.0	7.9	6.0	3.6	3.0	6.3	8.3	0.3	0.2	0.1	0.3	0.4
G-GP-10	Physical Security Upgrades	14.0	8.0	8.0	8.0	4.0	14.7	8.4	8.4	8.4	4.2	0.7	0.4	0.4	0.4	0.2
G-GP-11	Security Monitoring	6.5	4.0	1.0	1.0	1.0	6.8	4.2	1.1	1.1	1.1	0.3	0.2	0.1	0.1	0.1
Information Solutions Projects and Programs Less Than Materiality Threshold		8.4	2.0	2.0	3.5	2.0	8.8	2.1	2.1	3.7	2.1	0.4	0.1	0.1	0.2	0.1
Total Information Solutions		**119.9**	**118.1**	**113.6**	**122.1**	**106.1**	**126.2**	**124.3**	**119.5**	**128.5**	**111.7**	**6.3**	**6.2**	**6.0**	**6.4**	**5.6**
System Operations																
G-GP-12	Common Operating Technology Infrastructure	8.0	7.0	5.0	5.5	4.0	8.4	7.4	5.3	5.8	4.2	0.4	0.4	0.3	0.3	0.2
G-GP-13	Operating Technology Facilities Sustainment	-	-	2.0	-	-	-	-	2.1	-	-	-	-	0.1	-	-
G-GP-14	Integrated Voice Communication Technology Refresh	2.3	-	-	-	-	2.4	-	-	-	-	0.1	-	-	-	-
G-GP-15	BU-OGCC Office Remediation	-	2.0	-	-	-	-	2.1	-	-	-	-	0.1	-	-	-
G-GP-16	Network Management System Investments	7.6	-	1.2	2.5	2.5	8.0	-	1.3	2.6	2.6	0.4	-	0.1	0.1	0.1
G-GP-17	Outage Response Management System Upgrade	5.5	5.5	-	-	-	5.8	5.8	-	-	-	0.3	0.3	-	-	-
G-GP-18	Distribution Management System Upgrade	4.0	4.0	-	-	-	4.2	4.2	-	-	-	0.2	0.2	-	-	-
Total System Operations		**27.4**	**18.5**	**8.2**	**8.0**	**6.5**	**28.8**	**19.5**	**8.6**	**8.4**	**6.8**	**1.4**	**1.0**	**0.4**	**0.4**	**0.3**
Other General Plant																
G-GP-19	Grid Control Network Sustainment	6.5	6.6	6.8	7.0	7.1	6.8	7.0	7.2	7.3	7.5	0.3	0.3	0.4	0.4	0.4
G-GP-20	Transmission Non-Operational Data Management System	5.5	1.1	-	-	-	5.8	1.2	-	-	-	0.3	0.1	-	-	-
G-GP-21	Remote Terminal Unit Replacement Program	7.7	7.9	8.0	8.2	8.3	8.1	8.3	8.4	8.6	8.8	0.4	0.4	0.4	0.4	0.4
G-GP-22	Hydro One Distribution Capital Contribution to Hydro One Transmission	2.0	2.2	1.1	1.0	-	2.1	2.3	1.2	1.1	-	0.1	0.1	0.1	0.1	-
Other Projects and Programs Less Than Materiality Threshold		5.8	6.8	6.1	7.0	6.8	6.1	7.2	6.4	7.4	7.1	0.3	0.4	0.3	0.4	0.4
Total Other General Plant		**27.5**	**24.6**	**22.0**	**23.2**	**22.3**	**29.0**	**25.9**	**23.1**	**24.4**	**23.4**	**1.4**	**1.3**	**1.2**	**1.2**	**1.2**
Total Net General Plant Capital ($M)		**342.7**	**331.4**	**284.3**	**291.4**	**268.0**	**360.7**	**348.8**	**299.2**	**306.7**	**282.0**	**18.0**	**17.4**	**14.9**	**15.3**	**14.1**
Allocated to Transmission		146.8	124.0	114.2	115.9	105.0	154.5	130.6	120.2	122.0	110.5	7.7	6.6	6.0	6.1	5.5
Allocated to Distribution		195.9	207.4	170.1	175.5	162.9	206.2	218.2	179.0	184.7	171.5	10.3	10.8	8.9	9.2	8.6

Appendix 2-JA
Transmission OM&A - Summary of Recoverable OM&A Expenses

($M)

	2018 Actuals	2019 Actuals	2020 Last Rebasing Year OEB Approved	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Sustainment	$ 229.4	$ 207.8		$ 200.9	$ 205.2	$ 208.3	$ 219.6	$ 231.2
Development	$ 5.2	$ 4.4		$ 6.7	$ 8.3	$ 8.9	$ 8.6	$ 9.0
Operating	$ 53.4	$ 51.0		$ 47.9	$ 48.8	$ 48.6	$ 49.0	$ 51.6
Asset Management (Planning) costs	$ 31.0	$ 26.7		$ 25.3	$ 25.2	$ 26.6	$ 27.4	$ 28.9
SubTotal	**$ 319.0**	**$ 289.9**		**$ 280.8**	**$ 287.5**	**$ 292.4**	**$ 304.7**	**$ 320.7**
%Change (year over year)		-9.1%		-3.1%	2.4%	1.7%	4.2%	9.7%
%Change (Test Year vs Last Rebasing Year - Actual)							8.5%	14.2%
Customer Service (Billing, Collecting, Bad Debt, Misc)	$ 11.0	$ 7.2		$ 7.0	$ 6.0	$ 6.7	$ 6.9	$ 7.3
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	$ 4.6	$ 4.5		$ 4.4	$ 7.2	$ 7.3	$ 7.6	$ 8.0
Common Functions and Services	$ 87.9	$ 83.7		$ 84.1	$ 83.6	$ 87.6	$ 89.3	$ 94.0
Information Technology	$ 50.4	$ 53.7		$ 51.2	$ 51.4	$ 51.2	$ 53.7	$ 56.5
Property taxes and rights payments	$ 65.3	$ 60.8		$ 65.4	$ 69.1	$ 70.2	$ 71.4	$ 75.1
SubTotal	**$ 219.2**	**$ 209.8**		**$ 212.3**	**$ 217.2**	**$ 223.0**	**$ 228.8**	**$ 240.8**
%Change (year over year)		-4.3%		1.2%	2.3%	2.7%	2.6%	8.0%
%Change (Test Year vs Last Rebasing Year - Actual)							7.8%	13.4%
Miscellaneous(Other OM&A, Recovery)	-$ 119.0	-$ 141.9		-$ 94.6	-$ 115.7	-$ 122.0	-$ 113.0	-$ 118.9
Total	**$ 419.2**	**$ 357.9**	**$ 385.0**	**$ 398.5**	**$ 389.0**	**$ 393.4**	**$ 420.5**	**$ 442.6**
%Change (year over year)		-14.6%	7.6%	11.4%	-2.4%	1.1%	6.9%	12.5%

	2018 Actuals	2019 Actuals	2020 Last Rebasing Year OEB Approved	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)
Sustainment	$ 229.4	$ 207.8		$ 200.9	$ 205.2	$ 208.3	$ 219.6	$ 231.2
Development	$ 5.2	$ 4.4		$ 6.7	$ 8.3	$ 8.9	$ 8.6	$ 9.0
Operating	$ 53.4	$ 51.0		$ 47.9	$ 48.8	$ 48.6	$ 49.0	$ 51.6
Asset Management (Planning) costs	$ 31.0	$ 26.7		$ 25.3	$ 25.2	$ 26.6	$ 27.4	$ 28.9
Customer Service (Billing, Collecting, Bad Debt, Misc)	$ 11.0	$ 7.2		$ 7.0	$ 6.0	$ 6.7	$ 6.9	$ 7.3
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	$ 4.6	$ 4.5		$ 4.4	$ 7.2	$ 7.3	$ 7.6	$ 8.0
Common Functions and Services	$ 87.9	$ 83.7		$ 84.1	$ 83.6	$ 87.6	$ 89.3	$ 94.0
Information Technology	$ 50.4	$ 53.7		$ 51.2	$ 51.4	$ 51.2	$ 53.7	$ 56.5
Property taxes and rights payments	$ 65.3	$ 60.8		$ 65.4	$ 69.1	$ 70.2	$ 71.4	$ 75.1
Miscellaneous (Other OM&A, Recovery)	-$ 119.0	-$ 141.9		-$ 94.6	-$ 115.7	-$ 122.0	-$ 113.0	-$ 118.9
Total	**$ 419.2**	**$ 357.9**	**$ 385.0**	**$ 398.5**	**$ 389.0**	**$ 393.4**	**$ 420.5**	**$ 442.6**
%Change (year over year)		-14.6%	7.6%	11.4%	-2.4%	1.1%	6.9%	12.5%

	2018 Actuals	2019 Actuals	2020 Last Rebasing Year OEB Approved	2020 Actuals	2021 Forecast	Variance 2020 Approved vs. 2020 Actuals	2022 Bridge Year	Variance 2022 Bridge vs. 2021 Forecast	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)	Variance 2023 Test vs. 2022 Bridge
Sustainment	$ 229.4	$ 207.8		$ 200.9	$ 205.2		$ 208.3	$ 3.0	$ 219.6	$ 231.2	$ 22.9
Development	$ 5.2	$ 4.4		$ 6.7	$ 8.3		$ 8.9	$ 0.7	$ 8.6	$ 9.0	$ 0.1
Operating	$ 53.4	$ 51.0		$ 47.9	$ 48.8		$ 48.6	-$ 0.2	$ 49.0	$ 51.6	$ 3.0
Asset Management (Planning) costs	$ 31.0	$ 26.7		$ 25.3	$ 25.2		$ 26.6	$ 1.4	$ 27.4	$ 28.9	$ 2.3
Customer Service (Billing, Collecting, Bad Debt, Misc)	$ 11.0	$ 7.2		$ 7.0	$ 6.0		$ 6.7	$ 0.7	$ 6.9	$ 7.3	$ 0.5
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	$ 4.6	$ 4.5		$ 4.4	$ 7.2		$ 7.3	$ 0.2	$ 7.6	$ 8.0	$ 0.6
Common Functions and Services	$ 87.9	$ 83.7		$ 84.1	$ 83.6		$ 87.6	$ 4.0	$ 89.3	$ 94.0	$ 6.4
Information Technology	$ 50.4	$ 53.7		$ 51.2	$ 51.4		$ 51.2	-$ 0.2	$ 53.7	$ 56.5	$ 5.4
Property taxes and rights payments	$ 65.3	$ 60.8		$ 65.4	$ 69.1		$ 70.2	$ 1.1	$ 71.4	$ 75.1	$ 4.9
Miscellaneous (Other OM&A, Recovery)	-$ 119.0	-$ 141.9		-$ 94.6	-$ 115.7		-$ 122.0	-$ 6.3	-$ 113.0	-$ 118.9	$ 3.1
Total OM&A Expenses	**$ 419.2**	**$ 357.9**	**$ 385.0**	**$ 398.5**	**$ 389.0**	**$ 13.47**	**$ 393.4**	**$ 4.5**	**$ 420.5**	**$ 442.6**	**$ 49.2**
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)[3]											
Total Recoverable OM&A Expenses	$ 419.2	$ 357.9	$ 385.0	$ 398.5	$ 389.0	$ 13.5	$ 393.4	$ 4.5	$ 420.5	$ 442.6	$ 49.2
Variance from previous year		-$ 61		$ 41	-$ 10		$ 4		$ 27	$ 49	
Percent change (year over year)		-14.6%		11.4%	-2.4%		1.1%		6.9%	12.5%	
Percent Change: Test year (2023) vs. Most Current Actual (2020)									5.5%	11.1%	
Simple average of % variance for all years									0.5%	1.6%	
Compound Annual Growth Rate for all years										1.1%	
Compound Growth Rate (2020 Actuals vs. 2018 Actuals)										-2.5%	

Note:

CAGR from 2020 actual to 2023 1.8%

1 Historical actuals going back to the last cost of service application are required to be entered by the applicant.
2 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.
3 For unrecoverable OM&A Expenses see Section 2.4.3.7

Appendix 2-JB
Recoverable OM&A Cost Driver Table [1,3]

($M)

OM&A	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Opening Balance [2]	$ -	$ 419.2	$ 357.9	$ 398.5	$ 389.0	$ 393.4	$ 393.4
Land Assessment and Remediation		-$ 0.3	-$ 0.4	$ 0.3	-$ 0.0	$ 0.1	$ 0.1
Environment Management		-$ 1.5	-$ 3.5	$ 6.2	$ 0.8	-$ 7.9	-$ 7.1
Power Equipment		-$ 9.3	-$ 7.7	$ 1.9	-$ 0.3	$ 8.0	$ 10.7
Ancillary System Maintenance		$ 0.8	-$ 1.1	-$ 0.5	-$ 0.1	$ 1.9	$ 2.4
Protection, Control, Monitoring, Metering and Telecommunications (including cybersecurity)		-$ 3.9	$ 1.8	-$ 0.7	$ 2.3	$ 4.2	$ 7.2
Site Infrastructure Maintenance		-$ 3.2	$ 1.1	$ 0.2	$ 0.5	$ 1.5	$ 2.7
Rights of Way		-$ 5.4	$ 0.7	-$ 0.2	-$ 0.1	$ 0.7	$ 2.4
Overhead Lines		-$ 0.6	-$ 1.1	-$ 1.6	$ 0.2	$ 2.4	$ 3.3
Underground Cables		-$ 2.0	-$ 1.2	-$ 0.4	-$ 0.2	$ 0.3	$ 0.5
Engineering & Environmental Support		$ 3.8	-$ 2.6	-$ 0.7	-$ 0.0	$ 0.3	$ 0.6
Transmission Standards Program		-$ 0.3	$ 1.6	-$ 0.2	$ 0.1	$ 0.2	$ 0.4
Research Development and Demonstration		-$ 0.4	$ 0.5	$ 1.0	$ 0.6	-$ 0.6	-$ 0.4
Customer Power Quality Program		-$ 0.2	$ 0.2	$ 0.7	$ 0.0	$ 0.0	$ 0.1
Operations Contracts		$ 0.6	-$ 0.6	$ 2.8	-$ 1.5	$ 1.8	$ 3.0
Environmental, Health and Safety		$ 0.6	-$ 1.0	$ 0.4	-$ 0.0	$ 0.0	$ 0.1
Operators		-$ 3.6	-$ 1.5	-$ 2.3	$ 1.3	-$ 1.4	-$ 0.1
Customer Service OM&A		-$ 3.8	-$ 0.1	-$ 1.0	$ 0.7	$ 0.2	$ 0.5
Corporate Management		-$ 1.5	$ 0.3	-$ 0.8	$ 0.0	$ 0.1	$ 0.2
Finance		-$ 3.4	-$ 1.6	-$ 1.3	$ 0.3	-$ 0.5	$ 0.3
Human Resources		$ 0.5	$ 1.5	-$ 2.2	$ 0.8	$ 1.4	$ 2.0
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		-$ 0.1	-$ 0.0	$ 2.7	$ 0.2	$ 0.2	$ 0.6
General Counsel		-$ 0.7	$ 0.9	-$ 0.7	$ 0.2	$ 0.1	$ 0.3
Regulatory Affairs		-$ 0.3	$ 0.6	$ 1.0	$ 1.0	-$ 1.0	-$ 0.4
Security Management		-$ 0.8	-$ 0.5	$ 1.0	$ 0.4	$ 0.1	$ 0.3
Internal Audit		-$ 0.1	-$ 0.5	$ 0.6	$ 0.2	$ 0.2	$ 0.3
Facilities and Real Estate		$ 2.0	-$ 0.4	$ 1.9	$ 1.1	$ 1.4	$ 3.4
Asset Management (Planning) costs		-$ 4.3	-$ 1.4	-$ 0.1	$ 1.4	$ 0.8	$ 2.3
Information Technology		$ 3.3	-$ 2.4	$ 0.2	-$ 0.2	$ 2.5	$ 5.4
Cost of Sales		-$ 4.7	$ 3.9	-$ 1.3	-$ 1.5	$ 0.8	$ 1.1
Other Recovery		-$ 18.2	$ 43.3	-$ 19.8	-$ 4.7	$ 8.2	$ 1.9
Property Taxes & Rights Payments		-$ 4.5	$ 4.6	$ 3.7	$ 1.1	$ 1.2	$ 4.9
Closing Balance	$ 419.2	$ 357.9	$ 398.5	$ 389.0	$ 393.4	$ 420.5	$ 442.6

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.

2 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the OEB-Approved amount. For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

Appendix 2-JC
OM&A Programs Table

($M)

Programs	2018 Actuals	2019 Actuals	2020 Board Approved	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)	Variance (Test Year vs. 2021 Forecast)	Variance (Test Year vs. 2020 Approved)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Sustainment										
Land Assessment and Remediation	1.3	1.0		0.7	0.9	0.9	0.9	1.0	0.1	
Environment Management	13.9	12.5		15.9	22.1	23.0	15.1	15.9	-6.2	
Power Equipment	60.1	50.8		43.1	45.0	44.7	52.6	55.4	10.4	
Ancillary System Maintenance	8.3	9.1		8.0	7.5	7.4	9.3	9.8	2.3	
Protection, Control, Monitoring, Metering and Telecommunications (including cybersecurity)	55.1	51.2		52.9	52.2	54.5	58.7	61.7	9.5	
Site Infrastructure Maintenance	22.7	19.5		20.7	20.9	21.3	22.8	24.0	3.2	
Rights of Way	37.3	31.9		32.6	32.4	32.3	33.0	34.7	2.3	
Overhead Lines	18.9	18.3		17.2	15.6	15.8	18.2	19.1	3.5	
Underground Cables	7.6	5.6		4.3	4.0	3.7	4.0	4.2	0.2	
Engineering & Environmental Support	4.1	7.9		5.4	4.7	4.7	5.0	5.2	0.6	
Sub-Total	229.4	207.8		200.9	205.2	208.3	219.6	231.2	25.9	
Development										
Transmission Standards Program	2.8	2.5		4.1	4.0	4.0	4.3	4.5	0.5	
Research Development and Demonstration	2.2	1.8		2.3	3.4	3.9	3.3	3.5	0.1	
Customer Power Quality Program	0.2	0.1		0.2	0.9	1.0	1.0	1.1	0.1	
Sub-Total	5.2	4.4		6.7	8.3	8.9	8.6	9.0	0.8	
Operating										
Operations Contracts	19.5	20.2		19.5	22.3	20.8	22.6	23.8	1.5	
Environmental, Health and Safety	1.4	2.0		1.1	1.5	1.4	1.4	1.5	0.0	
Operators	32.5	28.8		27.3	25.0	26.4	25.0	26.3	1.3	
Sub-Total	53.4	51.0		47.9	48.8	48.6	49.0	51.6	2.8	
Customer										
Customer Service OM&A	11.0	7.2		7.0	6.0	6.7	6.9	7.3	1.2	
Sub-Total	11.0	7.2		7.0	6.0	6.7	6.9	7.3	1.2	
Common Functions and Services										
Corporate Management	3.9	2.4		2.7	1.9	2.0	2.1	2.2	0.2	
Finance	20.8	17.5		15.8	14.5	14.8	14.4	15.1	0.6	
Human Resources	10.4	10.9		12.4	10.2	11.0	12.4	13.0	2.8	
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	4.6	4.5		4.4	7.2	7.3	7.6	8.0	0.8	
General Counsel	5.0	4.3		5.2	4.5	4.7	4.8	5.1	0.5	
Regulatory Affairs	9.2	9.0		9.6	10.6	11.6	10.6	11.1	0.6	
Security Management	2.9	2.1		1.6	2.6	3.0	3.1	3.3	0.7	
Internal Audit	3.0	2.9		2.4	3.0	3.2	3.3	3.5	0.5	
Facilities and Real Estate	32.7	34.7		34.3	36.2	37.3	38.7	40.7	4.5	
Sub-Total	92.5	88.2		88.6	90.7	94.9	96.9	101.9	11.2	
Asset Management (Planning) costs										
Sub-Total	31.0	26.7		25.3	25.2	26.6	27.4	28.9	3.7	
Information Technology										
Information Technology	50.4	53.7		51.2	51.4	51.2	53.7	56.5	5.1	
Sub-Total	50.4	53.7		51.2	51.4	51.2	53.7	56.5	5.1	
Miscellaneous										
Cost of Sales	8.4	3.7		7.7	6.4	4.9	5.7	6.0	-0.4	
Other Recovery	-127.4	-145.6		-102.3	-122.1	-126.8	-118.7	-124.9	-2.8	
Property Taxes & Rights Payments	65.3	60.8		65.4	69.1	70.2	71.4	75.1	6.0	
Sub-Total	-53.7	-81.1		-29.2	-46.6	-51.8	-41.6	-43.8	2.8	
Total	**419.2**	**357.9**	**385.0**	**398.5**	**389.0**	**393.4**	**420.5**	**442.6**	**53.6**	**57.6**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	2018 Actual	2019 Actuals	2020 Board Approved	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
OM&A Costs								
O&M	$ 326,678,725	$ 269,685,406		$ 309,923,392	$ 298,275,876	$ 298,535,907	$ 323,665,611	$ 340,652,503
Admin Expenses (CCFS)	$ 92,493,986	$ 88,190,273		$ 88,583,877	$ 90,718,464	$ 94,910,488	$ 96,864,059	$ 101,947,761
Total Recoverable OM&A from Appendix 2-JB [5]	$ 419,172,711	$ 357,875,679	$ 385,040,207	$ 398,507,268	$ 388,994,340	$ 393,446,394	$ 420,529,670	$ 442,600,264
Number of Delivery Points [2,4]	668	675		676	680	684	688	$ 688
Number of FTEs [3,4]	4,247	4,028		3,983	4,149	4,218	4,285	$ 4,285
Customers/FTEs	0.16	0.17		0.17	0.16	0.16	0.16	0.16
OM&A cost per delivery point								
O&M per delivery point	$ 489,040	$ 399,534		$ 458,467	$ 438,641	$ 436,456	$ 470,444	$ 495,134
Admin per delivery point	$ 138,464	$ 130,652		$ 131,041	$ 133,410	$ 138,758	$ 140,791	$ 148,180
Total OM&A per delivery point	$ 627,504	$ 530,186		$ 589,508	$ 572,050	$ 575,214	$ 611,235	$ 643,314
OM&A cost per FTE								
O&M per FTE	$ 76,920	$ 66,957		$ 77,809	$ 71,893	$ 70,784	$ 75,535	$ 79,499
Admin per FTE	$ 21,779	$ 21,896		$ 22,240	$ 21,866	$ 22,503	$ 22,605	$ 23,792
Total OM&A per FTE	$ 98,699	$ 88,853		$ 100,049	$ 93,759	$ 93,287	$ 98,140	$ 103,291

Total OM&A/delivery pt
3.7% change from 2020
-2.6% change from 2018
1.2% CAGR 2020 to 2023

Total OM&A/FTE
-1.9% change from 2020
-0.6% change from 2018
-0.6% CAGR 2020 to 2023

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers must be identified. Should correspond with data provided in Appendix 2-IB.
Number of delivery points are used for Hydro One Transmission, and thus number of customers is not provided consistent with 2020-22 Tx Application.

3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K.
Per Attachment E-06-01-02A, the FTE portion for transmission is based on the average FTEs by month-end

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

Appendix 2-JA
Distribution OM&A - Summary of Recoverable OM&A Expenses

($M)

	2018 Last Rebasing Year OEB Approved	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Sustainment		$ 312.3	$ 347.1	$ 324.9	$ 299.6	$ 303.6	$ 311.4	$ 327.7
Development		$ 7.5	$ 7.1	$ 6.0	$ 10.0	$ 10.2	$ 11.0	$ 11.6
Operating		$ 37.3	$ 36.6	$ 33.0	$ 39.7	$ 41.3	$ 40.8	$ 42.9
Asset Management (Planning) costs		$ 15.7	$ 13.5	$ 14.2	$ 13.6	$ 14.4	$ 14.9	$ 15.7
SubTotal		**$ 372.8**	**$ 404.3**	**$ 378.0**	**$ 362.9**	**$ 369.6**	**$ 378.0**	**$ 397.9**
%Change (year over year)			8.5%	-6.5%	-4.0%	1.8%	2.3%	7.7%
%Change (Test Year vs Last Rebasing Year - Actual)							1.40%	6.73%
Customer Service (Billing, Collecting, Bad Debt, Misc)		$ 111.7	$ 97.8	$ 111.2	$ 108.6	$ 107.9	$ 118.3	$ 124.5
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		$ 7.5	$ 7.5	$ 7.2	$ 6.9	$ 7.1	$ 7.3	$ 7.7
Common Functions and Services		$ 72.5	$ 69.4	$ 69.2	$ 76.9	$ 80.1	$ 81.8	$ 86.1
Information Technology		$ 73.8	$ 81.1	$ 78.4	$ 83.8	$ 81.5	$ 85.9	$ 90.4
Property taxes and rights payment		$ 5.1	$ 4.6	$ 5.4	$ 5.6	$ 5.8	$ 6.0	$ 6.3
SubTotal		**$ 270.6**	**$ 260.4**	**$ 271.4**	**$ 281.7**	**$ 282.4**	**$ 299.3**	**$ 315.1**
%Change (year over year)			-3.8%	4.2%	3.8%	0.2%	6.0%	11.6%
%Change (Test Year vs Last Rebasing Year - Actual)							10.6%	16.4%
Miscellaneous (Other OM&A, Recovery)		-$ 84.7	-$ 105.2	-$ 89.2	-$ 113.2	-$ 116.1	-$ 79.9	-$ 84.1
Total	**$ 544.4**	**$ 558.8**	**$ 559.6**	**$ 560.2**	**$ 531.4**	**$ 535.8**	**$ 597.5**	**$ 628.9**
%Change (year over year)			0.1%	0.1%	-5.1%	0.8%	11.5%	17.4%

	2018 Last Rebasing Year OEB Approved	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)
Sustainment		$ 312.3	$ 347.1	$ 324.9	$ 299.6	$ 303.6	$ 311.4	$ 327.7
Development		$ 7.5	$ 7.1	$ 6.0	$ 10.0	$ 10.2	$ 11.0	$ 11.6
Operating		$ 37.3	$ 36.6	$ 33.0	$ 39.7	$ 41.3	$ 40.8	$ 42.9
Asset Management (Planning) costs		$ 15.7	$ 13.5	$ 14.2	$ 13.6	$ 14.4	$ 14.9	$ 15.7
Customer Service (Billing, Collecting, Bad Debt, Misc)		$ 111.7	$ 97.8	$ 111.2	$ 108.6	$ 107.9	$ 118.3	$ 124.5
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		$ 7.5	$ 7.5	$ 7.2	$ 6.9	$ 7.1	$ 7.3	$ 7.7
Common Functions and Services		$ 72.5	$ 69.4	$ 69.2	$ 76.9	$ 80.1	$ 81.8	$ 86.1
Information Technology		$ 73.8	$ 81.1	$ 78.4	$ 83.8	$ 81.5	$ 85.9	$ 90.4
Property taxes and rights payment		$ 5.1	$ 4.6	$ 5.4	$ 5.6	$ 5.8	$ 6.0	$ 6.3
Miscellaneous (Other OM&A, Recovery)		-$ 84.7	-$ 105.2	-$ 89.2	-$ 113.2	-$ 116.1	-$ 79.9	-$ 84.1
Total		**$ 558.8**	**$ 559.6**	**$ 560.2**	**$ 531.4**	**$ 535.8**	**$ 597.5**	**$ 628.9**
%Change (year over year)			0.1%	0.1%	-5.1%	0.8%	11.5%	17.4%

	2018 Last Rebasing Year OEB Approved	2018 Actuals	Variance 2018 Approved vs. 2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	Variance 2022 Bridge vs. 2021 Forecast	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)	Variance 2023 Test vs. 2022 Bridge
Sustainment		$ 312.3		$ 347.1	$ 324.9	$ 299.6	$ 303.6	$ 4.1	$ 311.4	$ 327.7	$ 24.1
Development		$ 7.5		$ 7.1	$ 6.0	$ 10.0	$ 10.2	$ 0.2	$ 11.0	$ 11.6	$ 1.4
Operating		$ 37.3		$ 36.6	$ 33.0	$ 39.7	$ 41.3	$ 1.6	$ 40.8	$ 42.9	$ 1.6
Asset Management (Planning) costs		$ 15.7		$ 13.5	$ 14.2	$ 13.6	$ 14.4	$ 0.8	$ 14.9	$ 15.7	$ 1.3
Customer Service (Billing, Collecting, Bad Debt, Misc)		$ 111.7		$ 97.8	$ 111.2	$ 108.6	$ 107.9	-$ 0.7	$ 118.3	$ 124.5	$ 16.6
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		$ 7.5		$ 7.5	$ 7.2	$ 6.9	$ 7.1	$ 0.2	$ 7.3	$ 7.7	$ 0.6
Common Functions and Services		$ 72.5		$ 69.4	$ 69.2	$ 76.9	$ 80.1	$ 3.2	$ 81.8	$ 86.1	$ 6.0
Information Technology		$ 73.8		$ 81.1	$ 78.4	$ 83.8	$ 81.5	-$ 2.2	$ 85.9	$ 90.4	$ 8.9
Property taxes and rights payment		$ 5.1		$ 4.6	$ 5.4	$ 5.6	$ 5.8	$ 0.2	$ 6.0	$ 6.3	$ 0.5
Miscellaneous (Other OM&A, Recovery)		-$ 84.7		-$ 105.2	-$ 89.2	-$ 113.2	-$ 116.1	-$ 2.9	-$ 79.9	-$ 84.1	$ 32.0
Total OM&A Expenses	**$ 544.4**	**$ 558.8**	**$ 14.38**	**$ 559.6**	**$ 560.2**	**$ 531.4**	**$ 535.8**	**$ 4.5**	**$ 597.5**	**$ 628.9**	**$ 93.0**
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)[3]											
Total Recoverable OM&A Expenses	**$ 544.4**	**$ 558.8**	**$ 14.38**	**$ 559.6**	**$ 560.2**	**$ 531.4**	**$ 535.8**	**$ 4.5**	**$ 597.5**	**$ 628.9**	**$ 93.0**
Variance from previous year				$ 0.8	$ 0.6	-$ 28.8	$ 4.5		$ 62	$ 93	
Percent change (year over year)				0.1%	0.1%	-5.1%	0.8%		11.5%	17.4%	
Percent Change: Test year (2023) vs. Most Current Actual (2020)									6.7%	12.3%	
Simple average of % variance for all years									1.5%	2.7%	
Compound Annual Growth Rate for all years										2.4%	
Compound Growth Rate (2020 Actuals vs. 2018 Actuals)										0.1%	

Note:

$	597.5	**Total**
	20.1	Non-service OPEB
	12.2	LDC Acquired
$	**565.2**	**Normalized to 2018**
	0.2%	**CAGR**

1 Historical actuals going back to the last cost of service application are required to be entered by the applicant.
2 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.
3 For unrecoverable OM&A Expenses see Section 2.4.3.7

Appendix 2-JB
Recoverable OM&A Cost Driver Table [1,3]

($M)

OM&A	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Opening Balance [2]	$ -	$ 558.8	$ 559.6	$ 560.2	$ 531.4	$ 535.8	$ 535.8
Stations		-$ 1.7	$ 2.1	-$ 1.0	-$ 0.7	-$ 0.3	$ 0.79
Lines		$ 15.8	$ 0.9	-$ 28.7	$ 4.1	$ 6.7	$ 13.62
Meters, Telecom & Control		-$ 2.2	-$ 0.6	$ 2.6	-$ 0.0	$ 2.3	$ 3.32
Vegetation Management		$ 22.9	-$ 24.6	$ 1.8	$ 0.7	-$ 1.0	$ 6.35
Engineering & Technical Studies		-$ 0.1	-$ 0.3	$ 0.6	$ 0.0	-$ 0.1	-$ 0.0
Distribution Generation Connections		$ 0.7	-$ 0.9	-$ 0.0	-$ 0.0	$ 0.0	$ 0.09
Distribution Standards Program		-$ 0.4	$ 0.3	$ 0.7	$ 0.2	$ 0.1	$ 0.14
Research Development & Demonstration		-$ 0.6	-$ 0.3	$ 2.7	$ 0.0	$ 0.9	$ 1.20
Customer Power Quality Program		$ 0.0	-$ 0.1	$ 0.1	$ 0.0	$ 0.0	$ 0.01
Operations Support		$ 9.4	-$ 0.9	$ 1.2	$ 0.6	-$ 1.8	-$ 1.2
Operations		-$ 2.4	$ 0.1	$ 5.4	$ 2.0	$ 1.2	$ 2.58
Health, Safety & Environment		$ 0.1	-$ 0.9	$ 0.4	-$ 0.0	$ 0.0	$ 0.08
Smart Grid		-$ 7.8	-$ 1.9	-$ 0.2	-$ 1.0	$ 0.1	$ 0.13
Customer Service		-$ 13.9	$ 13.4	-$ 2.7	-$ 0.7	$ 10.4	$ 16.64
Asset Management (Planning) costs		-$ 2.2	$ 0.7	-$ 0.5	$ 0.8	$ 0.5	$ 1.28
Corporate Management		-$ 1.1	-$ 0.4	$ 0.1	$ 0.0	$ 0.1	$ 0.24
Finance		-$ 2.0	-$ 0.1	$ 2.9	$ 0.3	-$ 0.5	$ 0.34
People and Culture		-$ 0.7	$ 0.7	$ 0.2	$ 0.8	$ 1.4	$ 1.99
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		-$ 0.0	-$ 0.3	-$ 0.3	$ 0.2	$ 0.2	$ 0.61
General Counsel		$ 0.2	$ 0.8	-$ 0.3	$ 0.2	$ 0.1	$ 0.29
Regulatory Affairs		-$ 0.1	$ 0.5	-$ 0.8	$ 0.7	-$ 0.7	-$ 0.2
Security Management		-$ 0.6	-$ 0.3	$ 0.8	$ 0.4	$ 0.1	$ 0.22
Internal Audit		$ 0.3	-$ 0.5	$ 1.0	$ 0.2	$ 0.2	$ 0.34
Real Estate and Facilities		$ 0.9	-$ 0.9	$ 3.8	$ 0.7	$ 1.1	$ 2.74
Information Technology		$ 7.3	-$ 2.7	$ 5.4	-$ 2.2	$ 4.3	$ 8.86
Cost of Sales		-$ 5.1	-$ 1.1	-$ 0.1	$ 0.4	-$ 0.0	$ 0.21
Other Recovery		-$ 15.4	$ 17.1	-$ 23.9	-$ 3.3	$ 36.2	$ 31.82
Property Taxes & Rights Payments		-$ 0.5	$ 0.8	$ 0.2	$ 0.2	$ 0.2	$ 0.53
Closing Balance	$ 558.8	$ 559.6	$ 560.2	$ 531.4	$ 535.8	$ 597.5	$ 628.9

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.

2 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the OEB-Approved amount. For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

Appendix 2-JC
OM&A Programs Table

($M)

Programs	2018 Board Approved	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)	Variance (Test Year vs. 2021 Forecast)	Variance (Test Year vs. 2018 Board-Approved)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Sustainment										
Stations		21.8	20.1	22.2	21.2	20.5	20.2	21.3	0.1	
Lines		133.3	149.0	149.9	121.2	125.3	132.0	138.9	17.7	
Meters, Telecom & Control		17.7	15.5	14.9	17.5	17.5	19.8	20.8	3.3	
Vegetation Management		139.5	162.4	137.9	139.6	140.3	139.4	146.7	7.1	
Sub-Total		312.3	347.1	324.9	299.6	303.6	311.4	327.7	28.1	
Development										
Engineering & Technical Studies		1.9	1.8	1.5	2.1	2.2	2.0	2.1	0.0	
Distribution Generation Connections		1.7	2.4	1.5	1.5	1.5	1.5	1.6	0.0	
Distribution Standards Program		0.6	0.2	0.5	1.2	1.4	1.5	1.5	0.4	
Research Development & Demonstration		3.2	2.6	2.3	5.0	5.0	5.9	6.2	1.2	
Customer Power Quality Program		0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.0	
Sub-Total		7.5	7.1	6.0	10.0	10.2	11.0	11.6	1.6	
Operating										
Operations Support		3.6	13.0	12.1	13.2	13.8	12.0	12.6	-0.6	
Operations		20.7	18.4	18.4	23.8	25.9	27.0	28.4	4.6	
Health, Safety & Environment		1.8	1.9	1.0	1.3	1.3	1.3	1.4	0.0	
Smart Grid		11.2	3.4	1.5	1.3	0.4	0.5	0.5	-0.8	
Sub-Total		37.3	36.6	33.0	39.7	41.3	40.8	42.9	3.2	
Customer										
Customer Service OM&A		111.7	97.8	111.2	108.6	107.9	118.3	124.5	16.0	
Sub-Total		111.7	97.8	111.2	108.6	107.9	118.3	124.5	16.0	
Common Functions and Services										
Corporate Management		4.0	2.9	2.5	2.7	2.7	2.8	2.9	0.3	
Finance		15.0	13.0	12.9	15.8	16.2	15.7	16.5	0.6	
Human Resources		9.7	9.0	9.7	10.0	10.8	12.1	12.8	2.8	
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		7.5	7.5	7.2	6.9	7.1	7.3	7.7	0.8	
General Counsel		3.2	3.4	4.2	3.9	4.0	4.1	4.3	0.4	
Regulatory Affairs		10.8	10.7	11.2	10.3	11.0	10.3	10.9	0.5	
Security Management		2.3	1.7	1.4	2.2	2.6	2.6	2.8	0.6	
Internal Audit		2.3	2.6	2.1	3.0	3.2	3.4	3.5	0.5	
Real Estate and Facilities		25.2	26.1	25.2	29.0	29.7	30.8	32.4	3.4	
Sub-Total		80.1	76.9	76.4	83.8	87.2	89.1	93.8	10.0	
Asset Management (Planning) costs										
Sub-Total		15.7	13.5	14.2	13.6	14.4	14.9	15.7	2.0	
Information Technology										
Information Technology		73.8	81.1	78.4	83.8	81.5	85.9	90.4	6.6	
Sub-Total		73.8	81.1	78.4	83.8	81.5	85.9	90.4	6.6	
Miscellaneous										
Cost of Sales		10.4	5.3	4.1	4.0	4.4	4.4	4.6	0.6	
Other Recovery		-95.1	-110.5	-93.4	-117.3	-120.6	-84.3	-88.7	28.5	
Property Taxes & Rights Payments		5.1	4.6	5.4	5.6	5.8	6.0	6.3	0.7	
Sub-Total		-79.6	-100.6	-83.8	-107.7	-110.3	-73.9	-77.8	29.9	
Total	**544.4**	**558.8**	**559.6**	**560.2**	**531.4**	**535.8**	**597.5**	**628.9**	**97.5**	**84.5**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year 2018 - OEB Approved	Last Rebasing Year - 2018 Actual	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year (As-Filed)	2023 Test Year (Inflation Update)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
OM&A Costs								
O&M		$ 478,720,164	$ 482,612,804	$ 483,713,609	$ 447,585,352	$ 448,618,580	$ 508,325,432	$ 535,038,479
Admin Expenses (CCFS)		$ 80,052,569	$ 76,940,973	$ 76,439,659	$ 83,794,574	$ 87,213,757	$ 89,143,594	$ 93,822,432
Total Recoverable OM&A from Appendix 2-JB [5]	$ 544,391,756	$ 558,772,733	$ 559,553,777	$ 560,153,268	$ 531,379,925	$ 535,832,337	$ 597,469,026	$ 628,860,911
Number of Customers [2,4]		1,303,089	1,314,463	1,323,421	1,333,269	1,343,110	1,413,905	1,413,905
Number of FTEs [3,4]		4,182	4,486	4,481	4,787	4,803	4,830	4,830
Customers/FTEs		311.6	293.0	295.3	278.5	279.7	292.8	292.8
OM&A cost per customer								
O&M per customer		367.4	367.2	365.5	335.7	334.0	359.5	378.4
Admin per customer		61.4	58.5	57.8	62.8	64.9	63.0	66.4
Total OM&A per customer		428.8	425.7	423.3	398.6	398.9	422.6	444.8
OM&A cost per FTE								
O&M per FTE		$ 114,472	$ 107,579	$ 107,944	$ 93,502	$ 93,410	$ 105,250	$ 110,781
Admin per FTE		$ 19,142	$ 17,151	$ 17,058	$ 17,505	$ 18,159	$ 18,457	$ 19,426
Total OM&A per FTE		$ 133,614	$ 124,730	$ 125,003	$ 111,007	$ 111,570	$ 123,708	$ 130,207

-0.2% change since 2020
-1.5% change since 2018
-0.3% CAGR since 2018

-1.0% change since 2020
-7.4% change since 2018
-1.5% CAGR since 2018

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers must be identified. Should correspond with data provided in Appendix 2-IB.

3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K.
FTE numbers represent the distribution portion of total FTEs using the average FTE counts by month-end, per Attachment E-06-01-02A

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.
Number of customers for the years 2018-2022 exclude Acquired Utilities, and for 2023 include Acquired Utilities

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

Revised Appendix 2-AB
Table 2 - Transmission Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan & actual)															Forecast Period (As-Filed)					Forecast Period (Updated Inflation)****				
	2018			2019			2020			2021			2022												
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	As-Filed Forecast	Var	Plan	As-Filed Forecast	Var	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
			%			%			%			%			%										
System Access	24.3	33.7	39%		46.2	--	24.8	19.5	-21%	11.3	40.1	256%	11.7	31.5	168%	79.4	70.9	59.8	36.5	50.1	83.6	74.6	63.0	38.4	52.8
System Renewal	780.4	776.2	-1%		792.6	--	810.1	804.0	-1%	982.8	739.6	-25%	958.2	971.5	1%	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0	1,239.8	1,292.8	1,317.3	1,344.4	1,330.4
System Service*	75.6	73.9	-2%		85.6	--	198.4	196.1	-1%	148.2	223.9	51%	151.8	122.0	-20%	90.9	101.6	85.8	93.1	90.1	95.6	107.0	90.3	98.0	94.8
General Plant	119.7	83.6	-30%		92.1	--	111.1	124.7	12%	94.4	137.8	46%	94.7	102.8	9%	146.8	124.0	114.2	115.9	105.0	154.5	130.5	120.2	122.0	110.5
Progressive Productivity							- 17.0			- 39.0			- 61.0	- 48.1		- 61.0	- 61.0	- 61.0	- 61.0	- 61.0	- 64.2	- 64.2	- 64.2	- 64.2	- 64.2
Other**							- 25.5			- 28.4			- 29.1												
TOTAL EXPENDITURE	1,000.0	967.3	-3%	-	1,016.5	--	1,101.9	1,144.4	4%	1,169.2	1,141.5	-2%	1,126.4	1,179.7	5%	1,434.0	1,463.9	1,450.4	1,461.8	1,448.2	1,509.3	1,540.7	1,526.6	1,538.5	1,524.3
System O&M***	$ 394.3	$ 419.2	6%		$ 357.9	--	$ 385.0	$ 398.5	3%		$ 389.0	--		$ 393.4	--	$ 420.5					$ 442.6				

* The 2019-2022 Actuals exclude new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan).

** Includes OPEB, pension and compensation directive adjustments.

*** System O&M reflects total Operations, Maintenance and Administration expenses. 2024 - 2027 is determined based on the escalation factor identified in Exhibit A-04-02.

****The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
TSP Section 2.9
Notes on year over year Plan vs. Actual variances for Total Expenditures
TSP Section 2.9
Notes on Plan vs. Actual variance trends for individual expenditure categories
TSP Section 2.9

Appendix 2-AA
Transmission Capital Projects Table ($M)

						As-Filed					Updated Inflation**				
Projects	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**	**2023 Test**	**2024 Test**	**2025 Test**	**2026 Test**	**2027 Test**	**2023 Test**	**2024 Test**	**2025 Test**	**2026 Test**	**2027 Test**
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
System Access															
Generator Customer Connection	0.3	0.5	2.2	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load Customer Connection	28.5	40.1	18.4	38.3	25.9	41.6	68.1	57.0	35.6	49.3	43.8	71.6	60.0	37.5	51.9
Component Replacement Programs and	4.4	5.9	-1.7	0.5	5.5	37.8	2.8	2.8	0.8	0.8	39.8	3.0	3.0	0.9	0.9
P&C Enablement for Generation Connections	0.5	-0.3	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	33.7	46.2	19.5	40.1	31.5	79.4	70.9	59.8	36.5	50.1	83.6	74.6	63.0	38.4	52.8
System Renewal															
Ancillary Systems	0.7	0.1	-15.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Circuit Breakers	0.1	1.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Integrated Station Investment	410.7	426.8	499.7	359.8	512.5	733.3	722.5	699.6	698.3	728.8	771.8	760.4	736.3	734.9	767.1
IT Security	22.9	24.5	35.9	40.9	34.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Power Equipment	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Component Replacement Programs	221.2	230.5	196.0	243.8	297.2	271.2	338.5	406.0	455.1	438.4	285.5	356.3	427.3	479.0	461.4
Power Transformers	-0.7	-2.7	-2.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Protection and Automation	21.6	18.6	14.4	29.6	54.5	81.6	88.4	87.5	68.9	36.1	85.9	93.1	92.1	72.5	38.0
Site Facilities and Infrastructure	0.3	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tx Transformers Demand and Spares	82.6	78.2	68.3	51.3	45.4	50.7	51.5	52.2	53.2	54.1	53.4	54.2	54.9	56.0	56.9
Underground Lines Cable Refurbishment & Replace	16.5	14.9	7.1	14.2	27.6	41.1	27.4	6.4	1.9	6.6	43.3	28.8	6.7	2.0	6.9
Sub-Total	776.1	792.6	804.0	739.6	971.5	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0	1,239.8	1,292.8	1,317.3	1,344.4	1,330.4
System Service*															
Inter Area Network Transfer Capability	48.9	57.9	144.8	174.4	86.2	31.5	25.1	24.5	65.4	60.4	33.1	26.4	25.8	68.8	63.5
Local Area Supply Adequacy	20.7	19.7	41.6	44.9	34.1	54.9	74.0	58.8	25.8	27.7	57.7	77.9	61.9	27.1	29.2
Performance Enhancement	0.0	0.6	3.2	0.7	1.2	2.5	0.5	0.5	0.0	0.0	2.6	0.5	0.5	0.0	0.0
Power Quality	1.4	3.1	1.9	0.8	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk Mitigation	2.6	4.2	4.6	3.2	0.5	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1
Smart Grid	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	73.9	85.6	196.1	223.9	122.0	90.9	101.6	85.8	93.1	90.1	95.6	107.0	90.3	98.0	94.8
General Plant															
Fleet	9.3	15.0	13.5	14.4	14.9	25.8	26.4	26.7	27.0	27.9	27.2	27.8	28.1	28.5	29.4
Facilities & Real Estate	23.4	16.0	19.7	15.4	15.5	26.0	24.9	17.5	18.2	14.8	27.4	26.2	18.4	19.1	15.5
Information Solutions	42.0	47.1	42.2	30.1	29.1	57.4	46.5	45.0	43.7	35.9	60.5	49.0	47.4	46.0	37.8
System Operations	3.8	6.0	38.8	59.0	21.8	12.0	3.8	4.2	4.8	4.2	12.6	4.0	4.4	5.1	4.4
Operating Infrastructure	5.8	8.7	7.5	18.9	21.5	25.5	22.4	20.9	22.2	22.3	26.9	23.6	22.0	23.3	23.4
Other	-0.7	-0.7	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	83.6	92.1	124.7	137.8	102.8	146.8	124.0	114.2	115.9	105.0	154.5	130.5	120.2	122.0	110.5
Progressive Productivity					-48.1	-61.0	-61.0	-61.0	-61.0	-61.0	-64.2	-64.2	-64.2	-64.2	-64.2
Total	**967.3**	**1,016.5**	**1,144.4**	**1,141.5**	**1,179.7**	**1,434.0**	**1,463.9**	**1,450.4**	**1,461.8**	**1,448.2**	**1,509.3**	**1,540.7**	**1,526.6**	**1,538.5**	**1,524.3**
Less Renewable Generation Facility Assets															
Total	**967.3**	**1,016.5**	**1,144.4**	**1,141.5**	**1,179.7**	**1,434.0**	**1,463.9**	**1,450.4**	**1,461.8**	**1,448.2**	**1,509.3**	**1,540.7**	**1,526.6**	**1,538.5**	**1,524.3**

* The 2019-2022 Actuals exclude new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan)

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Appendix 2-AB
Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements
General Plant System Plan Filing Requirements ($M)

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan and actual/forecast)												Bridge			Forecast Period (As-Filed)					Forecast Period (Updated Inflation)*				
	2018			2019			2020			2021			2022												
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	As-Filed Forecast[1]	Var	Plan	As-Filed Forecast[2]	Var (Plan to As-Filed)	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
			%			%			%			%			%										
General Plant Allocated to Transmission	119.7	83.6	-30%	NA	92.1	NA	111.1	124.7	12%	94.4	137.8	46%	94.7	102.8	9%	146.8	124.0	114.2	115.9	105.0	154.5	130.5	120.2	122.0	110.5
General Plant Allocated to Distribution	90.7	90.7	0%	142.8	114.3	-20%	150.3	178.2	19%	95.3	173.8	82%	100.4	105.7	5%	195.9	207.4	170.1	175.5	162.9	206.2	218.2	179.0	184.7	171.5
Total General Plant	NA	174.3		NA	206.4		NA	302.9		NA	311.7		NA	208.5		342.7	331.4	284.3	291.4	268.0	360.7	348.8	299.2	306.7	282.0

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2

Notes to the Table:
1. 2021 data is based on a 12-month forecast
2. 2022 data is based on a 12-month forecast

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
For a more detailed explanation of shifts in forecast vs historical expenditures, please see GSP Section 4.9 Capital Expenditures - Trends and Variances
Notes on year over year Plan vs. Actual variances for Total Expenditures
For a more detailed explanation of shifts in forecast vs historical expenditures, please see GSP Section 4.9 Capital Expenditures - Trends and Variances, and GSP Section 4.9 Attachment 2 General Plant Capital Performance Report
Notes on Plan vs. Actual variance trends for individual expenditure categories
For a more detailed explanation of shifts in forecast vs historical expenditures, please see GSP Section 4.9 Capital Expenditures - Trends and Variances, and GSP Section 4.9 Attachment 2 General Plant Capital Performance Report

Appendix 2-AA
Capital Projects and Programs Table for General Plant ($M)

					As-Filed						Updated Inflation*				
General Plant Capital Projects and Programs	**2018**	**2019**	**2020**	**2021 Forecast**	**2022 Bridge**	**2023 Test**	**2024 Test**	**2025 Test**	**2026 Test**	**2027 Test**	**2023 Test**	**2024 Test**	**2025 Test**	**2026 Test**	**2027 Test**
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
General Plant Allocated to Hydro One Transmission															
Fleet	9.3	15.0	13.5	14.4	14.9	25.8	26.4	26.7	27.0	27.9	27.2	27.8	28.1	28.5	29.4
Facilities & Real Estate	23.4	16.0	19.7	15.4	15.5	26.0	24.9	17.5	18.2	14.8	27.4	26.2	18.4	19.1	15.5
Information Solutions	42.0	47.1	42.2	30.1	29.1	57.4	46.5	45.0	43.7	35.9	60.5	49.0	47.4	46.0	37.8
System Operations	3.8	6.0	38.8	59.0	21.8	12.0	3.8	4.2	4.8	4.2	12.6	4.0	4.4	5.1	4.4
Operating Infrastructure	5.8	8.7	7.5	18.9	21.5	25.5	22.4	20.9	22.2	22.3	26.9	23.6	22.0	23.3	23.4
System Capability Reinforcement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	-0.7	-0.7	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total GP Allocated to Transmission	**83.6**	**92.1**	**124.7**	**137.8**	**102.8**	**146.8**	**124.0**	**114.2**	**115.9**	**105.0**	**154.5**	**130.5**	**120.2**	**122.0**	**110.5**
General Plant Allocated to Hydro One Distribution															
Fleet	18.1	29.0	25.7	28.3	28.5	50.6	51.7	52.2	53.0	54.7	53.2	54.4	55.0	55.8	57.6
Facilities & Real Estate	13.7	15.6	45.0	23.7	26.5	65.4	67.2	44.2	39.9	35.7	68.8	70.7	46.5	42.0	37.6
Information Solutions	52.3	67.4	76.2	66.1	44.0	62.5	71.6	68.5	78.5	70.2	65.8	75.4	72.1	82.6	73.9
System Operations	5.3	4.7	32.8	55.7	5.7	15.4	14.7	4.0	3.2	2.3	16.2	15.5	4.3	3.3	2.4
Operating Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Capability Reinforcement	2.9	-1.0	-0.7	0.0	1.0	2.0	2.2	1.1	1.0	0.0	2.1	2.3	1.2	1.1	0.0
Other	-1.7	-1.5	-0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total GP Allocated to Distribution	**90.7**	**114.3**	**178.2**	**173.8**	**105.7**	**195.9**	**207.4**	**170.1**	**175.5**	**162.9**	**206.2**	**218.2**	**179.0**	**184.7**	**171.5**
Total General Plant	**174.3**	**206.4**	**302.9**	**311.7**	**208.5**	**342.7**	**331.4**	**284.3**	**291.4**	**268.0**	**360.7**	**348.8**	**299.2**	**306.7**	**282.0**

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2

Notes:
1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.
2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Revised Appendix 2-AB
Table 2 - Distribution Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements ($M)

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan1 & actual)															Forecast Period (As-Filed)					Forecast Period (Updated Inflation)***				
	2018			2019			2020			2021			2022												
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	As-Filed Forecast	Var	Plan	As-Filed Forecast	Var	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
			%			%			%			%			%										
System Access	175.1	175.1	0%	147.9	197.3	33%	153.4	193.6	26%	150.9	171.5	14%	143.0	180.8	26%	239.6	240.6	227.0	212.6	204.3	252.2	253.3	238.9	223.8	215.0
System Renewal	219.7	219.7	0%	202.3	189.0	-7%	222.2	228.6	3%	237.3	236.1	-1%	256.7	224.9	-12%	373.1	410.3	494.2	491.5	497.8	392.7	431.8	520.1	517.3	524.0
System Service*	79.1	79.1	0%	124.0	112.8	-9%	129.4	98.1	-24%	144.1	132.6	-8%	103.0	153.2	49%	196.5	169.7	229.6	192.0	205.9	206.8	178.6	241.6	202.1	216.7
General Plant	90.7	90.7	0%	142.8	114.3	-20%	150.3	178.2	19%	95.3	173.8	82%	100.4	105.7	5%	195.9	207.4	170.1	175.5	162.9	206.2	218.2	179.0	184.7	171.5
TOTAL EXPENDITURE	564.5	564.5	0%	617.1	613.4	-1%	655.3	698.6	7%	627.6	714.0	14%	603.2	664.6	10%	1,005.1	1,028.0	1,120.8	1,071.7	1,070.9	1,057.9	1,081.9	1,179.7	1,127.9	1,127.2
System O&M**	$ 544.4	$ 558.8	3%		$ 559.6	--		$ 560.2	--	--	$ 531.4	--	--	$ 535.8	--	$ 597.5	*	*	*	*	$ 628.9	*	*	*	*

* The 2019-2022 Actuals exclude new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan).

** System O&M reflects total Operations, Maintenance and Administration expenses. 2024 - 2027 is determined based on the escalation factor identified in Exhibit A-04-02.

***The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
For a more detailed explanation of shifts in forecast vs historical expenditures, please see DSP Section 3.9
Notes on year over year Plan vs. Actual variances for Total Expenditures
See DSP Section 3.9 Appendix B "Capital Program Performance Report 2019, 2020"
Notes on Plan vs. Actual variance trends for individual expenditure categories
See DSP Section 3.9 Appendix B "Capital Program Performance Report 2019, 2020"

Appendix 2-AA
Distribution Capital Projects Table ($M)

					As-Filed						Updated Inflation*				
Projects	**2018**	**2019**	**2020**	**2021 Forecast**	**2022 Bridge**	**2023 Test**	**2024 Test**	**2025 Test**	**2026 Test**	**2027 Test**	**2023 Test**	**2024 Test**	**2025 Test**	**2026 Test**	**2027 Test**
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
System Access															
D-SA-01 Joint Use and Relocations	20.4	28.8	26.2	21.4	19.1	24.8	29.0	27.0	26.5	27.2	26.1	30.5	28.4	27.9	28.7
D-SA-02 New Load Connections, Upgrades, Cancellations	121.2	141.7	146.4	130.6	141.7	150.7	154.6	158.5	162.5	166.7	158.6	162.7	166.8	171.1	175.4
D-SA-03 Customer Demand Distributed Energy Resources	6.7	6.6	2.2	1.9	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5
D-SA-04 Metering Sustainment	26.8	20.1	18.8	17.6	18.5	62.6	55.6	40.1	22.2	8.9	65.9	58.6	42.2	23.3	9.4
D-SA-Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	**175.1**	**197.3**	**193.6**	**171.5**	**180.8**	**239.6**	**240.6**	**227.0**	**212.6**	**204.3**	**252.2**	**253.3**	**238.9**	**223.8**	**215.0**
System Renewal															
D-SR-01 Distribution Stations Demand Capital Program	6.6	5.6	9.8	4.9	5.0	6.2	6.3	6.4	6.5	6.7	6.5	6.6	6.7	6.9	7.0
D-SR-02 Mobile Unit Substation Program	1.3	6.9	4.0	4.2	4.3	3.5	4.2	2.9	3.3	4.6	3.7	4.5	3.0	3.4	4.8
D-SR-03 Distribution Station Planned Component Replacement Program	5.0	7.7	8.8	6.9	7.1	4.6	3.3	1.1	1.2	1.2	4.8	3.5	1.2	1.2	1.2
D-SR-04 Distribution Station Refurbishment	11.7	16.5	7.4	6.9	3.2	44.8	41.5	28.5	32.3	32.1	47.2	43.7	30.0	34.0	33.7
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response	112.7	74.6	118.4	92.3	93.8	106.0	108.1	110.3	112.5	114.7	111.6	113.8	116.1	118.4	120.8
D-SR-06 Distribution Lines PCB Equipment Replacement Program	6.3	8.1	4.8	9.5	9.5	9.4	9.5	9.5	0.0	0.0	9.9	9.9	10.0	0.0	0.0
D-SR-07 Pole Sustainment Program	52.0	44.3	43.6	73.4	60.1	107.9	110.6	112.4	114.9	116.8	113.5	116.4	118.3	120.9	122.9
D-SR-08 Distribution Lines Minor Component Replacement Program	1.4	4.9	6.3	12.4	12.3	12.4	14.5	13.5	8.6	7.1	13.0	15.3	14.2	9.0	7.5
D-SR-09 Submarine Cable Replacement Program	3.2	6.3	6.7	10.9	11.1	12.2	12.5	12.7	13.0	13.2	12.8	13.1	13.4	13.6	13.9
D-SR-10 Distribution Lines Sustainment Initiatives	7.8	8.1	11.7	10.7	13.7	31.5	30.3	35.3	43.2	42.7	33.2	31.9	37.1	45.4	45.0
D-SR-11 Life Cycle Optimization & Operational Efficiency Projects	9.1	3.9	6.2	2.5	0.2	2.8	6.5	7.1	0.8	0.4	3.0	6.9	7.4	0.9	0.5
D-SR-12 Advanced Meter Infrastructure 2.0 (AMI 2.0)	0.0	0.0	0.0	0.7	3.9	30.9	62.0	153.7	154.4	157.3	32.5	65.3	161.7	162.6	165.5
D-SR-Other	2.6	2.0	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Sub-Total	**219.7**	**189.0**	**228.6**	**236.1**	**224.9**	**373.1**	**410.3**	**494.2**	**491.5**	**497.8**	**392.7**	**431.8**	**520.1**	**517.3**	**524.0**
System Service															
D-SS-01 System Upgrades Driven by Load Growth	26.5	45.2	50.7	97.1	108.5	98.2	76.3	127.5	76.1	100.2	103.3	80.3	134.2	80.1	105.4
D-SS-02 Reliability Improvements	1.7	4.1	4.6	3.8	3.7	7.3	0.1	6.5	18.6	7.5	7.6	0.1	6.8	19.6	7.9
D-SS-03 Demand System Modifications	7.9	11.8	14.0	7.5	10.9	13.2	13.4	13.7	13.9	14.2	13.9	14.1	14.4	14.6	15.0
D-SS-04 Energy Storage Solutions	0.1	1.6	5.0	3.7	4.2	34.3	35.0	35.6	36.3	36.0	36.1	36.8	37.5	38.2	37.9
D-SS-05 Worst Performing Feeders	8.3	21.9	20.7	17.0	22.0	39.6	40.9	42.2	43.0	43.8	41.7	43.0	44.4	45.2	46.1
D-SS-06 Power Quality and Stray Voltage	1.0	1.3	1.2	3.3	3.4	3.8	3.9	4.0	4.0	4.1	4.0	4.1	4.2	4.2	4.3
D-SS-Other	33.6	26.9	2.0	0.1	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sub-Total	**79.1**	**112.8**	**98.1**	**132.6**	**153.2**	**196.5**	**169.7**	**229.6**	**192.0**	**205.9**	**206.8**	**178.6**	**241.6**	**202.1**	**216.7**
General Plant Allocated to Distribution															
Fleet	18.1	29.0	25.7	28.3	28.5	50.6	51.7	52.2	53.0	54.7	53.2	54.4	55.0	55.8	57.6
Facilities & Real Estate	13.7	15.6	45.0	23.7	26.5	65.4	67.2	44.2	39.9	35.7	68.8	70.7	46.5	42.0	37.6
Information Solutions	52.3	67.4	76.2	66.1	44.0	62.5	71.6	68.5	78.5	70.2	65.8	75.4	72.1	82.6	73.9
System Operations	5.3	4.7	32.8	55.7	5.7	15.4	14.7	4.0	3.2	2.3	16.2	15.5	4.3	3.3	2.4
System Capability Reinforcement	2.9	-1.0	-0.7	0.0	1.0	2.0	2.2	1.1	1.0	0.0	2.1	2.3	1.2	1.1	0.0
Other	-1.7	-1.5	-0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0					
Sub-Total	**90.7**	**114.3**	**178.2**	**173.8**	**105.7**	**195.9**	**207.4**	**170.1**	**175.5**	**162.9**	**206.2**	**218.2**	**179.0**	**184.7**	**171.5**
Total	**564.5**	**613.4**	**698.6**	**714.0**	**664.6**	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**	**1,057.9**	**1,081.9**	**1,179.7**	**1,127.9**	**1,127.2**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*															
Total	**564.5**	**613.4**	**698.6**	**714.0**	**664.6**	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**	**1,057.9**	**1,081.9**	**1,179.7**	**1,127.9**	**1,127.2**

* The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Appendix 2-AB – Transmission In-Service Additions

OEB Category	2018		2019		2020		2021		2022		2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
	OEB Approved	Actuals	OEB Approved	Actuals	OEB Approved	Actuals	OEB Approved	Forecast (As-Filed)	OEB Approved	Bridge (As-Filed)	Forecast Period (As-Filed)					Forecast Period (Updated Inflation)*				
1. System Access	68.2	12.1	NA	72.6	8.6	7.2	13.8	15.1	52.3	43.6	73.0	48.9	60.7	63.2	38.9	75.7	51.4	63.9	66.5	41.0
2. System Renewal	761.4	852.3	NA	744.8	821.3	824.5	735.9	653.7	1,031.0	895.3	1,128.7	1,172.3	1,418.6	1,092.6	1,402.9	1,157.6	1,227.7	1,488.5	1,149.9	1,476.5
3. System Service	244.8	218.0	NA	45.5	54.2	32.6	235.7	180.7	182.0	386.6	58.9	20.6	163.7	71.9	99.2	60.6	21.7	172.3	75.7	104.4
4. General Plant	104.0	77.9	NA	96.6	75.1	79.9	134.5	156.3	82.5	80.1	162.1	151.6	128.4	113.7	119.8	166.8	156.6	135.1	119.6	126.1
Subtotal before Adjustments	1,178.4	1,160.4	NA	959.5	959.2	944.3	1,119.8	1,005.9	1,347.8	1,405.7	1,422.7	1,393.4	1,771.3	1,341.3	1,660.8	1,460.7	1,457.4	1,859.8	1,411.7	1,747.9
Progressive Productivity	-	-	NA	-	(15.8)	-	(36.3)	-	(56.7)	(24.1)	(54.6)	(61.0)	(61.0)	(61.0)	(61.0)	(56.2)	(64.2)	(64.2)	(64.2)	(64.2)
Other	-	-	NA	-	(12.9)	-	(27.3)	-	(28.8)	-	-	-	-	-	-	-	-	-	-	-
Grand Total	1,178.4	1,160.4	NA	959.5	930.5	944.3	1,056.2	1,005.9	1,262.2	1,381.6	1,368.1	1,332.4	1,710.3	1,280.3	1,599.8	1,404.5	1,393.2	1,795.6	1,347.5	1,683.8

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

Appendix 2-AB – Distribution In-Service Additions

OEB Category	2018		2019		2020		2021		2022		2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
	OEB Approved	Actuals	OEB Approved	Actuals	OEB Approved	Actuals	OEB Approved	Forecast	OEB Approved	Bridge	Forecast Period (As-Filed)					Forecast Period (Updated Inflation)*				
1. System Access	196.9	196.9	147.7	189.9	144.7	197.5	160.8	182.7	143.1	181.2	239.6	241.8	227.5	212.5	204.1	252.1	254.5	239.4	223.7	214.8
2. System Renewal	229.6	229.6	223.3	201.9	225.3	217.8	241.9	248.7	251.2	225.5	355.2	425.6	504.4	476.3	507.3	372.9	447.9	530.9	501.3	533.9
3. System Service	113.9	113.9	81.6	89.2	170.9	97.3	138.8	70.8	112.4	137.7	226.3	148.8	251.2	200.9	195.1	232.1	156.3	264.4	211.4	205.4
Subtotal Categories 1, 2, and 3	**540.4**	**540.4**	**452.6**	**481.1**	**540.9**	**512.6**	**541.4**	**502.2**	**506.7**	**544.4**	**821.0**	**816.2**	**983.1**	**889.7**	**906.5**	**857.0**	**858.8**	**1,034.7**	**936.4**	**954.1**
4. General Plant Allocated to Distribution	87.4	87.4	103.9	104.1	135.9	155.5	164.1	197.9	103.4	112.0	149.9	211.1	220.4	171.5	201.2	155.5	222.2	231.9	180.5	211.8
Grand Total	**627.8**	**627.8**	**556.5**	**585.1**	**676.8**	**668.1**	**705.5**	**700.1**	**610.1**	**656.4**	**970.9**	**1,027.3**	**1,203.4**	**1,061.2**	**1,107.8**	**1,012.5**	**1,080.9**	**1,266.6**	**1,116.9**	**1,165.9**

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input [1]

		Initial Application		Adjustments	Application Update		Adjustments	Per Board Decision	
		($ millions)	(2)		($ millions)	(6)		($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$22,913		$18	$22,931			$22,931	
	Accumulated Depreciation (average)	($8,352)	(5)	($0.2)	($8,352)			($8,352)	
	Allowance for Working Capital:								
	Controllable Expenses	$428		$22.1	$450			$450	
	Cost of Power								
	Working Capital Rate (%)	7.5%	(9)		7.3%	(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Transmission Revenue at Current Rates								
	Transmission Revenue at Proposed Rates	$1,763		($1.4)	$1,762				
	Other Revenue:								
	Specific Service Charges								
	Non-rate revenues	$40		$ -	$40				
	Export Revenue Credits	$37		$ -	$37				
	LVSG + Regulatory Balances	($18)		$27.5	$10				
	Total Revenue Offsets	$60	(7)	$27.5	$87				
	Operating Expenses:								
	OM+A Expenses	$428.1		$22.1	$450			$450	
	Depreciation/Amortization	$528.2		$3.7	$532			$532	
	Property taxes								
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($373.2)	(3)		($375.9)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$29.8			$29.2				
	Income taxes (grossed up)								
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	11.50%			11.50%				
	Income Tax Credits	($0.3)			($0.3)				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.04%			4.04%				
	Short-term debt Cost Rate (%)	1.56%			1.56%				
	Common Equity Cost Rate (%)	8.34%			8.34%				
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement. DVAs have been included within total offsets, as regulatory balances have been approved to be recovered through UTRs

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$22,912.6	$18	$22,930.8	$ -	$22,931
2	Accumulated Depreciation (average)	(2)	($8,351.9)	($0)	($8,352.1)	$ -	($8,352)
3	Net Fixed Assets (average)	(2)	$14,560.7	$18	14,578.7	$ -	$14,579
4	Allowance for Working Capital	(1)	$32.0	$1	32.9	($33)	$ -
5	**Total Rate Base**		$14,592.7	$19	14,611.5	($33)	$14,579

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$428.1	$22	450.2	$ -	$450
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$428.1	$22	$450	$ -	$450
9	Working Capital Rate %	(1)	7.47%	-0.17%	7.30%	-7.30%	0.00%
10	Working Capital Allowance		$32.0	$1	$32.9	($33)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
	Operating Revenues:						
1	Transmission Revenue (at Proposed Rates)		$1,763.3	($1)	$1,762	$ -	$1,762
2	Other Revenue	(1)	$59.9	$27	$87	$ -	$87
3	Total Operating Revenues		$1,823.2	$26	$1,849.3	$ -	$1,849
	Operating Expenses:						
4	OM+A Expenses		$428	$22.1	$450.2	$ -	$450
5	Depreciation/Amortization		$528	$3.7	$531.9	$ -	$532
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$956	$26	$982.1	$ -	$982
10	Deemed Interest Expense		$340	$0.4	$340.0	($1)	$339
11	Total Expenses (lines 9 to 10)		$1,296	$26	$1,322.1	($1)	$1,321
12	**Utility income before income taxes**		$527	($0)	$527.2	$1	$528
13	Income taxes (grossed-up)		$40	($1)	$39.8	$ -	$40
14	**Utility net income**		$487	$1	$487.4	$1	$488

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$40	$ -	$40		$40
	Other Distribution Revenue	$37	$ -	$37		$37
	Other Income and Deductions	($18)	$27	$10		$10
	Total Revenue Offsets	$59.9	$27	$87.4	$ -	$87

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Taxes/PILs

Line No.	Particulars	Application ($ millions)	Application Update ($ millions)	Per Board Decision ($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$527.3	$527.2	$486
2	Adjustments required to arrive at taxable utility income	($373.2)	($375.9)	($376)
3	Taxable income	$154.1	$151.3	$110
	Calculation of Utility income Taxes			
4	Income taxes	$29.8	$29.2	$29
6	Total taxes	$29.8	$29.2	$29
7	Gross-up of Income Taxes	$10.7	$10.5	$11
8	Grossed-up Income Taxes	$40.5	$39.8	$40
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$40.5	$39.8	$40
10	Other tax Credits	($0.3)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$8,172	4.04%	$330.4
2	Short-term Debt	4.00%	$584	1.56%	$9.1
3	**Total Debt**	60.00%	$8,756	3.88%	$339.5
	Equity				
4	Common Equity	40.00%	$5,837	8.34%	$486.8
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$5,837	8.34%	$486.8
7	**Total**	100.00%	$14,593	5.66%	$826.3
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$8,182	4.04%	330.8
2	Short-term Debt	4.00%	$584	1.56%	9.1
3	**Total Debt**	60.00%	$8,767	3.88%	339.97
	Equity				
4	Common Equity	40.00%	5,844.6	8.34%	487.4
5	Preferred Shares	0.00%	$ -	0.00%	-
6	**Total Equity**	40.00%	$5,845	8.34%	487.4
7	**Total**	100.00%	14,611.5	5.66%	827.4
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$8,164	4.04%	$330
9	Short-term Debt	4.00%	$583	1.56%	$9
10	**Total Debt**	60.00%	$8,747	3.88%	$339
	Equity				
11	Common Equity	40.00%	$5,831	8.34%	$486
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$5,831	8.34%	$486
14	**Total**	100.00%	$14,579	5.66%	$826

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$2,343		$2,340
2	Transmission Revenue	$ -	$1,763	$ -	($581)	$ -	($578)
3	Other Operating Revenue Offsets - net	$60	$60	$87	87.4	$87	$87
4	**Total Revenue**	$60	$1,823.2	$87	1,849.3	$87	$1,849
5	Operating Expenses	$956	$956	$982	982	$982	$982
6	Deemed Interest Expense	$340	$340	$340	340	$339	$339
8	**Total Cost and Expenses**	$1,296	$1,296	$1,322	1,322	$1,321	$1,321
9	**Utility Income Before Income Taxes**	($1,236)	$527.3	($1,235)	527	($1,234)	$528.0
10	Tax Adjustments to Accounting Income per 2013 PILs model	($373)	($373)	($376)	($376)	($376)	($376)
11	**Taxable Income**	($1,609)	$154.1	($1,611)	151	($1,610)	$152
12	Income Tax Rate	26.50%	26.50%	26.50%	0	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$40.8	$ -	40	$ -	$40.3
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	($1,236)	$486.8	($1,234)	487	($1,234)	$488
16	**Utility Rate Base**	$14,593	$14,593	$14,612	14,612	$14,579	$14,579
17	Deemed Equity Portion of Rate Base	$5,837	$5,837	$5,845	5,845	$5,831	$5,831
18	Income/(Equity Portion of Rate Base)	-21.17%	8.34%	-21.12%	8.34%	-21.15%	8.37%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-29.51%	0.00%	-29.46%	0.00%	-29.49%	0.03%
21	Indicated Rate of Return	-6.14%	5.66%	-6.12%	5.66%	-6.13%	5.68%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	5.66%	5.66%	5.66%	5.66%
23	Deficiency/Sufficiency in Rate of Return	-11.80%	0.00%	-11.78%	0.00%	-11.80%	0.01%
24	Target Return on Equity	$487	$487	$487	$487	$486	$486
25	Revenue Deficiency/(Sufficiency)		($0)	$1,722	($0)	$1,720	$2
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$2,343 (1)		$2,340 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

For Transmission, revenue deficiency and sufficiency have been removed, as it does not yield the same level of comparability with Distribution

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$428.1		$450.2		$450	
2	Amortization/Depreciation	$528.2		$531.9		$532	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$40.5		$39.8		$40	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$339.5		$340.0		$339	
	Return on Deemed Equity	$486.8		$487.4		$486	
8	**Service Revenue Requirement (before Revenues)**	$1,823.2		$1,849.3		$1,847	
9	Revenue Offsets	$59.9		$87.4		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,763.3		$1,761.9		$1,847	
11	Transmission revenue	$1,763.3		$1,761.9		$1,762	
12	Other revenue	$59.9		$87.4		$87	
13	**Total revenue**	$1,823.2		$1,849.3		$1,849	
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	($0.0)	(1)	$0.0	(1)	$2	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,823	$1,849	$0	$1,847	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$2,343		$2,340	
Base Revenue Requirement (to be recovered from Rates)	$1,763	$1,762	($0)	$1,847	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,763	$1,762	($0)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%
	Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.		**Service Revenue Requirement (from Sheet 9)**	**$ 1,823.20**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
			1	2	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	*Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 826	5.66%	$ 14,593	$ 428	$ 32	$ 528	$ 40	$ 428	$ 1,823	$ 60	$ 1,763	$ -
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Data Input [1]

		Initial Application [2]	Adjustments	Application Update [6]	Adjustments	Per Board Decision
		($ millions)		($ millions)		($ millions)
1	**Rate Base**					
	Gross Fixed Assets (average)	$24,197	$67	$24,263		$24,263
	Accumulated Depreciation (average)	($8,780) [5]	($1)	($8,782)		($8,782)
	Allowance for Working Capital:					
	Controllable Expenses	$437	$23	$459		$459
	Cost of Power					
	Working Capital Rate (%)	7.75% [9]		7.55% [9]		[9]
2	**Utility Income**					
	Operating Revenues:					
	Transmission Revenue at Current Rates					
	Transmission Revenue at Proposed Rates	$1,883	$30	$1,913		
	Other Revenue:					
	Specific Service Charges					
	Non-rate revenues	$36	$ -	$36		
	Export Revenue Credits	$37	$ -	$37		
	LVSG + Regulatory Balances	($19)	($0)	($19)		
	Total Revenue Offsets	$55 [7]	($0)	$54.73		
	Operating Expenses:					
	OM+A Expenses	$437	$23	$459		$459
	Depreciation/Amortization	$558	$5	$563		$563
	Property taxes					
	Productivity adjustments	($2)	($0.01)	($2)		($2)
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($317) [3]		($322)		
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$52.12		$51.4		
	Income taxes (grossed up)					
	Federal tax (%)	15.00%		15.00%		
	Provincial tax (%)	11.50%		11.50%		
	Income Tax Credits	($0.3)		($0.3)		
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%		56.0%		
	Short-term debt Capitalization Ratio (%)	4.0% [8]		4.0% [8]		[8]
	Common Equity Capitalization Ratio (%)	40.0%		40.0%		
	Prefered Shares Capitalization Ratio (%)					
		100.0%		100.0%		
	Cost of Capital					
	Long-term debt Cost Rate (%)	4.04%		4.04%		
	Short-term debt Cost Rate (%)	1.56%		1.56%		
	Common Equity Cost Rate (%)	8.34%		8.34%		
	Prefered Shares Cost Rate (%)					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement. DVAs have been included within total offsets, as regulatory balances have been approved to be recovered through UTRs

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$24,196.7	$67	$24,263	$ -	$24,263
2	Accumulated Depreciation (average)	(2)	($8,780.2)	($1)	($8,782)	$ -	($8,782)
3	Net Fixed Assets (average)	(2)	$15,416.5	$65	$15,482	$ -	$15,482
4	Allowance for Working Capital	(1)	$33.8	$1	$35	($35)	$ -
5	**Total Rate Base**		$15,450.3	$66	$15,517	($35)	$15,482

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$436.7	$23	$459.2	$ -	$459
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$436.7	$23	$459	$ -	$459
9	Working Capital Rate %	(1)	7.75%	-0.19%	7.55%	-7.55%	0.00%
10	Working Capital Allowance		$33.8	$1	$34.7	($35)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Utility Income

Line No.	Particulars	Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
	Operating Revenues:					
1	Transmission Revenue (at Proposed Rates)	$1,883.1	$30	$1,913.5	$ -	$1,913
2	Other Revenue (1)	$54.7	($0)	$54.7	$ -	$55
3	Total Operating Revenues	$1,937.8	$30	$1,968.2	$ -	$1,968
	Operating Expenses:					
4	OM+A Expenses	$436.7	$23	$459.2	$ -	$459
5	Depreciation/Amortization	$557.6	$5	$562.7	$ -	$563
6	Property taxes	$ -	$ -		$ -	
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	($2.3)	($0)	($2.3)	$ -	($2)
9	Subtotal (lines 4 to 8)	$992.0	$28	$1,019.6	$ -	$1,020
10	Deemed Interest Expense	$359.5	$2	$361.0	($1)	$360
11	Total Expenses (lines 9 to 10)	$1,351.5	$29	$1,380.6	($1)	$1,380
12	**Utility income before income taxes**	$586.3	$1	$587.6	$1	$588
13	Income taxes (grossed-up)	$70.9	($1)	$70.0	$ -	$70
14	**Utility net income**	$515.4	$2	$517.6	$1	$518

Notes

Other Revenues / Revenue Offsets

(1)

	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
Specific Service Charges	$ -		$ -		$ -
Late Payment Charges	$36	$ -	$36		$36
Other Distribution Revenue	$37	$ -	$37		$37
Other Income and Deductions	($19)	($0)	($19)		($19)
Total Revenue Offsets	$54.7	($0)	$55	$ -	$55

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Taxes/PILs

Line No.	Particulars	Application ($ millions)	Application Update ($ millions)	Per Board Decision ($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$586.3	$587.6	$516
2	Adjustments required to arrive at taxable utility income	($317.5)	($322.3)	($322)
3	Taxable income	$268.9	$265.3	$194
	Calculation of Utility income Taxes			
4	Income taxes	$52.1	$51.4	$51
6	Total taxes	$52.1	$51.4	$51
7	Gross-up of Income Taxes	$18.8	$18.5	$19
8	Grossed-up Income Taxes	$70.9	$70.0	$70
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$70.9	$70.0	$70
10	Other tax Credits	($0.3)	($0.3)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$8,652	4.04%	$349.8
2	Short-term Debt	4.00%	$618	1.56%	$9.6
3	**Total Debt**	60.00%	$9,270	3.88%	$359.5
	Equity				
4	Common Equity	40.00%	$6,180	8.34%	$515.4
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$6,180	8.34%	$515.4
7	**Total**	100.00%	$15,450	5.66%	$874.9
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$8,689	4.04%	$351.3
2	Short-term Debt	4.00%	$621	1.56%	$9.7
3	**Total Debt**	60.00%	$9,310	3.88%	$361.0
	Equity				
4	Common Equity	40.00%	$6,207	8.34%	$517.6
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$6,207	8.34%	$517.6
7	**Total**	100.00%	$15,517	5.66%	$878.7
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$8,670	4.04%	$351
9	Short-term Debt	4.00%	$619	1.56%	$10
10	**Total Debt**	60.00%	$9,289	3.88%	$360
	Equity				
11	Common Equity	40.00%	$6,193	8.34%	$516
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$6,193	8.34%	$516
14	**Total**	100.00%	$15,482	5.66%	$877

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$2,508		$2,505
2	Transmission Revenue	$ -	$1,883	$ -	($594)	$ -	($592)
3	Other Operating Revenue Offsets - net	$55	$55	$55	$55	$55	$55
4	**Total Revenue**	$55	$1,937.8	$55	$1,968	$55	$1,968
5	Operating Expenses	$992	$992	$1,020	$1,020	$1,020	$1,020
6	Deemed Interest Expense	$359	$359	$361	$361	$360	$360
8	**Total Cost and Expenses**	$1,351	$1,351	$1,381	$1,381	$1,380	$1,380
9	**Utility Income Before Income Taxes**	($1,297)	$586.3	($1,326)	$588	($1,325)	$588.4
10	Tax Adjustments to Accounting Income per 2013 PILs model	($317)	($317)	($322)	($322)	($322)	($322)
11	**Taxable Income**	($1,614)	$268.9	($1,648)	$265	($1,647)	$266
12	Income Tax Rate	26.50%	26.50%	26.50%	$0	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$71.2	$ -	$70	$ -	$70.5
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	($1,296)	$515.4	($1,326)	$518	($1,325)	$518
16	**Utility Rate Base**	$15,450	$15,450	$15,517	$15,517	$15,482	$15,482
17	Deemed Equity Portion of Rate Base	$6,180	$6,180	$6,207	$6,207	$6,193	$6,193
18	Income/(Equity Portion of Rate Base)	-20.98%	8.34%	-21.36%	$0	-21.39%	8.37%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	$0	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-29.32%	0.00%	-29.70%	($0)	-29.73%	0.03%
21	Indicated Rate of Return	-6.06%	5.66%	-6.22%	$0	-6.23%	5.68%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	5.66%	$0	5.66%	5.66%
23	Deficiency/Sufficiency in Rate of Return	-11.73%	0.00%	-11.88%	($0)	-11.89%	0.01%
24	Target Return on Equity	$515	$515	$518	$518	$516	$516
25	Revenue Deficiency/(Sufficiency)		$0	$1,843	($0.00)	$1,841	$2
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$2,508 (1)		$2,505 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$436.7		$459.2		$459	
2	Amortization/Depreciation	$557.6		$562.7		$563	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$70.9		$70.0		$70	
6	Other Expenses	($2.3)		($2.3)		($2)	
7	Return						
	Deemed Interest Expense	$359.5		$361.0		$360	
	Return on Deemed Equity	$515.4		$517.6		$516	
8	**Service Revenue Requirement (before Revenues)**	$1,937.8		$1,968.2		$1,966	
9	Revenue Offsets	$54.7		$54.7		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,883.1		$1,913.5		$1,966	
11	Transmission revenue	$1,883.1		$1,913.5		$1,913	
12	Other revenue	$54.7		$54.7		$55	
13	**Total revenue**	$1,937.8		$1,968.2		$1,968	
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	$0.0	(1)	$0.0	(1)	$2	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,938	$1,968	**$0**	$1,966	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$2,508		$2,505	
Base Revenue Requirement (to be recovered from Rates)	$1,883	$1,913	**$0**	$1,966	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,883	$1,913	**$0**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1]	%
	From Sheet 10. Load Forecast			(7A)	
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,937.82**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year	Price Cap IR Period 1	Price Cap IR Period 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	*Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
	From sheet 10. Load Forecast					From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$ 875	5.66%	$ 15,450	$ 437	$ 34	$ 558	$ 71	$ 437	$ 1,938	$ 55	$ 1,883	$ -
1													

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Data Input (1)

		Initial Application (2)	Adjustments	Application Update (6)	Adjustments	Per Board Decision
		($ millions)		($ millions)		($ millions)
1	**Rate Base**					
	Gross Fixed Assets (average)	$25,650	$140	$ 25,789.7		$25,790
	Accumulated Depreciation (average)	($9,235) (5)	($4)	($9,239)		($9,239)
	Allowance for Working Capital:					
	Controllable Expenses	$445	$22.96	$ 468.4		$468
	Cost of Power					
	Working Capital Rate (%)	7.57% (9)		7.37% (9)		(9)
2	**Utility Income**					
	Operating Revenues:					
	Transmission Revenue at Current Rates					
	Transmission Revenue at Proposed Rates	$1,973	$36	$2,009		
	Other Revenue:					
	Specific Service Charges					
	Non-rate revenues	$36	$0	$36		
	Export Revenue Credits	$37	$0	$37		
	LVSG + Regulatory Balances	($19)	($0)	($19)		
	Total Revenue Offsets	$54 (7)	($0)	$54		
	Operating Expenses:					
	OM+A Expenses	$445	$22.96	$468		$468
	Depreciation/Amortization	$594	$7	$601		$601
	Property taxes					
	Productivity adjustments	($5)	($0.03)	($5)		($5)
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($377) (3)		($388)		
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$45.15		$43.43		
	Income taxes (grossed up)					
	Federal tax (%)	15.00%		15.00%		
	Provincial tax (%)	11.50%		11.50%		
	Income Tax Credits	($0.3)		($0.3)		
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%		56.0%		
	Short-term debt Capitalization Ratio (%)	4.0% (8)		4.0% (8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%		40.0%		
	Prefered Shares Capitalization Ratio (%)					
		100.0%		100.0%		
	Cost of Capital					
	Long-term debt Cost Rate (%)	4.04%		4.04%		
	Short-term debt Cost Rate (%)	1.56%		1.56%		
	Common Equity Cost Rate (%)	8.34%		8.34%		
	Prefered Shares Cost Rate (%)					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$25,649.9	$140	$25,789.7	$ -	$25,790
2	Accumulated Depreciation (average)	(2)	($9,234.8)	($4)	($9,238.8)	$ -	($9,239)
3	Net Fixed Assets (average)	(2)	$16,415.1	$136	$16,551.0	$ -	$16,551
4	Allowance for Working Capital	(1)	$33.7	$ -	$34.5	($35)	$ -
5	**Total Rate Base**		$16,448.9	$136	$16,585.5	($35)	$16,551

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$445.4	$23	$468.4	$ -	$468
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$445.4	$23	$468.4	$ -	$468
9	Working Capital Rate %	(1)	7.57%		7.37%	-7.37%	0.00%
10	Working Capital Allowance		$33.7		$34.5	($35)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Utility Income

Line No.	Particulars		Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
	Operating Revenues:						
1	Transmission Revenue (at Proposed Rates)		$1,973.1	$36	$2,008.6	$ -	$2,009
2	Other Revenue	(1)	$54.4	($0)	$54.4	$ -	$54
3	Total Operating Revenues		$2,027.5	$36	$2,063.0	$ -	$2,063
	Operating Expenses:						
4	OM+A Expenses		$445	$23	$468	$ -	$468
5	Depreciation/Amortization		$594	$7	$601	$ -	$601
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($5)	($0)	($5)	$ -	($5)
9	Subtotal (lines 4 to 8)		$1,035	$30	$1,065	$ -	$1,065
10	Deemed Interest Expense		$383	$3	$386	($1)	$385
11	Total Expenses (lines 9 to 10)		$1,417	$33	$1,451	($1)	$1,450
12	**Utility income before income taxes**		$610	$2	$612	$1	$613
13	Income taxes (grossed-up)		$61	($2)	$59	$ -	$59
14	**Utility net income**		$549	$5	$553	$1	$554

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$36	$ -	$36		$36
	Other Distribution Revenue	$37	$ -	$37		$37
	Other Income and Deductions	($19.3)	($0)	($19.4)		($19)
	Total Revenue Offsets	$54.4	($0)	$54.4	$ -	$54

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
		($ millions)	($ millions)	($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$610.2	$612.4	$552
2	Adjustments required to arrive at taxable utility income	($377.1)	($388.2)	($388)
3	Taxable income	$233.1	$224.2	$164
	Calculation of Utility income Taxes			
4	Income taxes	$45.1	$43.4	$43
6	Total taxes	$45.1	$43.4	$43
7	Gross-up of Income Taxes	$16.3	$15.7	$16
8	Grossed-up Income Taxes	$61.4	$59.1	$59
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$61.4	$59.1	$59
10	Other tax Credits	($0.3)	($0.3)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$9,211	4.04%	$372.5
2	Short-term Debt	4.00%	$658	1.56%	$10.3
3	**Total Debt**	60.00%	$9,869	3.88%	$382.7
	Equity				
4	Common Equity	40.00%	$6,580	8.34%	$548.7
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$6,580	8.34%	$548.7
7	**Total**	100.00%	$16,449	5.66%	$931.5
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$9,288	4.04%	$375.5
2	Short-term Debt	4.00%	$663	1.56%	$10.3
3	**Total Debt**	60.00%	$9,951	3.88%	$385.9
	Equity				
4	Common Equity	40.00%	$6,634	8.34%	$553.3
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$6,634	8.34%	$553.3
7	**Total**	100.00%	$16,585	5.66%	$939.2
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$9,269	4.04%	$375
9	Short-term Debt	4.00%	$662	1.56%	$10
10	**Total Debt**	60.00%	$9,931	3.88%	$385
	Equity				
11	Common Equity	40.00%	$6,620	8.34%	$552
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$6,620	8.34%	$552
14	**Total**	100.00%	$16,551	5.66%	$937

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$2,652		$2,649
2	Transmission Revenue	$ -	$1,973	$ -	($643)	$ -	($641)
3	Other Operating Revenue Offsets - net	$54	$54	$54	$54	$54	$54
4	**Total Revenue**	$54	$2,027.5	$54	$2,063.0	$54	$2,063
5	Operating Expenses	$1,035	$1,035	$1,065	$1,065	$1,065	$1,065
6	Deemed Interest Expense	$383	$383	$386	$386	$385	$385
8	**Total Cost and Expenses**	$1,417	$1,417	$1,451	$1,451	$1,450	$1,450
9	**Utility Income Before Income Taxes**	($1,363)	$610.2	($1,396)	$612.4	($1,395)	$613.2
10	Tax Adjustments to Accounting Income per 2013 PILs model	($377)	($377)	($388)	($388)	($388)	($388)
11	**Taxable Income**	($1,740)	$233.1	($1,784)	$224.2	($1,784)	$225
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$61.8	$ -	$59.4	$ -	$59.6
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	($1,363)	$548.8	($1,396)	$553.3	($1,395)	$554
16	**Utility Rate Base**	$16,449	$16,449	$16,585	$16,585	$16,551	$16,551
17	Deemed Equity Portion of Rate Base	$6,580	$6,580	$6,634	$6,634	$6,620	$6,620
18	Income/(Equity Portion of Rate Base)	-20.71%	8.34%	-21.04%	8.34%	-21.07%	8.37%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-29.05%	0.00%	-29.38%	0.00%	-29.41%	0.03%
21	Indicated Rate of Return	-5.96%	5.66%	-6.09%	5.66%	-6.10%	5.67%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	5.66%	5.66%	5.66%	5.66%
23	Deficiency/Sufficiency in Rate of Return	-11.62%	0.00%	-11.75%	0.00%	-11.77%	0.01%
24	Target Return on Equity	$549	$549	$553	$553	$552	$552
25	Revenue Deficiency/(Sufficiency)		$0	$1,949	($0.00)	$1,947	$2
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$2,652 (1)		$2,649 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$445.4		$468.4		$468	
2	Amortization/Depreciation	$593.8		$601.0		$601	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$61.4		$59.1		$59	
6	Other Expenses	($4.6)		($4.7)		($5)	
7	Return						
	Deemed Interest Expense	$382.7		$385.9		$385	
	Return on Deemed Equity	$548.7		$553.3		$552	
8	**Service Revenue Requirement (before Revenues)**	$2,027.5		$2,063.0		$2,061	
9	Revenue Offsets	$54.4		$54.4		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,973.1		$2,008.6		$2,061	
11	Transmission revenue	$1,973.1		$2,008.6		$2,009	
12	Other revenue	$54.4		$54.4		$54	
13	**Total revenue**	$2,027.5		$2,063.0		$2,063	
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	$0.0	(1)	$0.0	(1)	$2	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$2,028	$2,063	**$0**	$2,061	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$2,652		$2,649	
Base Revenue Requirement (to be recovered from Rates)	$1,973	$2,009	**$0**	$2,061	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,973	$2,009	**$0**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

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Revenue Requirement Workform (RRWF) for 2025 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 2,027.51**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
			1	2	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	*Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 931	5.66%	$ 16,449	$ 445	$ 34	$ 594	$ 61	$ 445	$ 2,028	$ 54	$ 1,973	$ -
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	Transmission
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Data Input [1]

		Initial Application [2]	Adjustments	Application Update [6]	Adjustments	Per Board Decision
		($ millions)		($ millions)		($ millions)
1	**Rate Base**					
	Gross Fixed Assets (average)	$27,078	$216	$27,294		$27,294
	Accumulated Depreciation (average)	($9,719) [5]	($8)	($9,728)		($9,728)
	Allowance for Working Capital:					
	Controllable Expenses	$454	$23	$478		$478
	Cost of Power			$0		
	Working Capital Rate (%)	7.70% [9]		7.50% [9]		[9]
2	**Utility Income**					
	Operating Revenues:					
	Transmission Revenue at Current Rates					
	Transmission Revenue at Proposed Rates	$2,087	$42	$2,129		
	Other Revenue:					
	Specific Service Charges					
	Non-rate revenues	$36	$0	$36		
	Export Revenue Credits	$37	$0	$37		
	LVSG + Regulatory Balances	($20)	$0	($20)		
	Total Revenue Offsets	$53.1 [7]	$0	$53.1		
	Operating Expenses:					
	OM+A Expenses	$454	$23	$478		$478
	Depreciation/Amortization	$625	$9	$634		$634
	Property taxes					
	Productivity adjustments	($7)	($0.05)	($7)		($7)
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($349) [3]		($362)		
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$61.0		$59.5		
	Income taxes (grossed up)					
	Federal tax (%)	15.00%		15.00%		
	Provincial tax (%)	11.50%		11.50%		
	Income Tax Credits	($0.3)		($0.3)		
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%		56.0%		
	Short-term debt Capitalization Ratio (%)	4.0% [8]		4.0% [8]		[8]
	Common Equity Capitalization Ratio (%)	40.0%		40.0%		
	Prefered Shares Capitalization Ratio (%)					
		100.0%		100.0%		
	Cost of Capital					
	Long-term debt Cost Rate (%)	4.04%		4.04%		
	Short-term debt Cost Rate (%)	1.56%		1.56%		
	Common Equity Cost Rate (%)	8.34%		8.34%		
	Prefered Shares Cost Rate (%)					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$27,078.4	$216	$27,294.4	$ -	$27,294
2	Accumulated Depreciation (average)	(2)	($9,719.2)	($8)	($9,727.6)	$ -	($9,728)
3	Net Fixed Assets (average)	(2)	$17,359.1	$208	$17,566.8	$ -	$17,567
4	Allowance for Working Capital	(1)	$35.0	$ -	$35.8	($36)	$ -
5	**Total Rate Base**		$17,394.1	$208	$17,602.6	($36)	$17,567

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$454.3	$23	$477.8	$ -	$478
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$454.3	$23	$477.8	$ -	$478
9	Working Capital Rate %	(1)	7.70%		7.50%	-7.50%	0.00%
10	Working Capital Allowance		$35.0		$35.8	($36)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
	Operating Revenues:						
1	Transmission Revenue (at Proposed Rates)		$2,087.2	$42	$2,129.3	$ -	$2,129
2	Other Revenue	(1)	$53.1	$ -	$53.1	$ -	$53
3	Total Operating Revenues		$2,140.3	$42	$2,182.5	$ -	$2,182
	Operating Expenses:						
4	OM+A Expenses		$454	$23	$478	$ -	$478
5	Depreciation/Amortization		$625	$9	$634	$ -	$634
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($7)	($0)	($7)	$ -	($7)
9	Subtotal (lines 4 to 8)		$1,072	$33	$1,105	$ -	$1,105
10	Deemed Interest Expense		$405	$5	$410	($1)	$409
11	Total Expenses (lines 9 to 10)		$1,477	$37	$1,514	($1)	$1,513
12	**Utility income before income taxes**		$663	$5	$668	$1	$669
13	Income taxes (grossed-up)		$83	($2)	$81	$ -	$81
14	**Utility net income**		$580	$7	$587	$1	$588

Notes

Other Revenues / Revenue Offsets

(1)

	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
Specific Service Charges	$ -		$ -		$ -
Late Payment Charges	$36	$ -	$36		$36
Other Distribution Revenue	$37	$ -	$37		$37
Other Income and Deductions	($20.3)	$ -	($20)		($20)
Total Revenue Offsets	$53.1	$ -	$53	$ -	$53

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Taxes/PILs

Line No.	Particulars	Application ($ millions)	Application Update ($ millions)	Per Board Decision ($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$663.3	$668.2	$586
2	Adjustments required to arrive at taxable utility income	($348.7)	($361.5)	($362)
3	Taxable income	$314.7	$306.6	$225
	Calculation of Utility income Taxes			
4	Income taxes	$61.0	$59.5	$59
6	Total taxes	$61.0	$59.5	$59
7	Gross-up of Income Taxes	$22.0	$21.4	$21
8	Grossed-up Income Taxes	$83.1	$80.9	$81
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$83.1	$80.9	$81
10	Other tax Credits	($0.3)	($0.329)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$9,741	4.04%	$393.9
2	Short-term Debt	4.00%	$696	1.56%	$10.9
3	**Total Debt**	60.00%	$10,436	3.88%	$404.7
	Equity				
4	Common Equity	40.00%	$6,958	8.34%	$580.3
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$6,958	8.34%	$580.3
7	**Total**	100.00%	$17,394	5.66%	$985.0
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$9,857	4.04%	$398.6
2	Short-term Debt	4.00%	$704	1.56%	$11.0
3	**Total Debt**	60.00%	$10,562	3.88%	$409.6
	Equity				
4	Common Equity	40.00%	$7,041	8.34%	$587.2
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$7,041	8.34%	$587.2
7	**Total**	100.00%	$17,602.6	5.66%	$996.8
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$9,837	4.04%	$398
9	Short-term Debt	4.00%	$703	1.56%	$11
10	**Total Debt**	60.00%	$10,540	3.88%	$409
	Equity				
11	Common Equity	40.00%	$7,027	8.34%	$586
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$7,027	8.34%	$586
14	**Total**	100.00%	$17,567	5.66%	$995

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$2,787		$2,784
2	Transmission Revenue	$ -	$2,087	$ -	($657)	$ -	($654)
3	Other Operating Revenue Offsets - net	$53	$53	$53	$53	$53	$53
4	**Total Revenue**	$53	$2,140.3	$53	$2,182.5	$53	$2,182
5	Operating Expenses	$1,072	$1,072	$1,105	$1,105	$1,105	$1,105
6	Deemed Interest Expense	$405	$405	$410	$410	$409	$409
8	**Total Cost and Expenses**	$1,477	$1,477	$1,514	$1,514	$1,513	$1,513
9	**Utility Income Before Income Taxes**	($1,424)	$663.3	($1,461)	$668.2	($1,460)	$669.0
10	Tax Adjustments to Accounting Income per 2013 PILs model	($349)	($349)	($362)	($362)	($362)	($362)
11	**Taxable Income**	($1,773)	$314.7	($1,823)	$306.6	($1,822)	$307
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$83.4	$ -	$81.3	$ -	$81.5
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	($1,424)	$580.3	($1,461)	$587.2	($1,460)	$588
16	**Utility Rate Base**	$17,394	$17,394	$17,603	$17,603	$17,567	$17,567
17	Deemed Equity Portion of Rate Base	$6,958	$6,958	$7,041	$7,041	$7,027	$7,027
18	Income/(Equity Portion of Rate Base)	-20.46%	8.34%	-20.75%	8.34%	-20.78%	8.37%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-28.80%	0.00%	-29.09%	0.00%	-29.12%	0.03%
21	Indicated Rate of Return	-5.86%	5.66%	-5.97%	5.66%	-5.98%	5.67%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	5.66%	5.66%	5.66%	5.66%
23	Deficiency/Sufficiency in Rate of Return	-11.52%	0.00%	-11.64%	0.00%	-11.65%	0.01%
24	Target Return on Equity	$580	$580	$587	$587	$586	$586
25	Revenue Deficiency/(Sufficiency)		($0)	$2,048	($0)	$2,046	$2
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$2,787 (1)		$2,784 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$454.3		$477.8		$478	
2	Amortization/Depreciation	$625.1		$634.3		$634	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$83.1		$80.9		$81	
6	Other Expenses	($7.2)		($7.3)		($7)	
7	Return						
	Deemed Interest Expense	$404.7		$409.6		$409	
	Return on Deemed Equity	$580.3		$587.2		$586	
8	**Service Revenue Requirement (before Revenues)**	$2,140.3		$2,182.5		$2,180	
9	Revenue Offsets	$53.1		$53.1		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$2,087.2		$2,129.3		$2,180	
11	Transmission revenue	$2,087.2		$2,129.3		$2,129	
12	Other revenue	$53.1		$53.1		$53	
13	**Total revenue**	$2,140.3		$2,182.5		$2,182	
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	($0.0)	(1)	$0.0	(1)	$2	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$2,140	$2,182	**$0**	$2,180	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$2,787		$2,784	
Base Revenue Requirement (to be recovered from Rates)	$2,087	$2,129	**$0**	$2,180	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$2,087	$2,129	**$0**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 2,140.28**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** (11)

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
			1	2	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates				Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate	Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 985	5.66%	$ 17,394	$ 454	$ 35	$ 625	$ 83	$ 454	$ 2,140	$ 53	$ 2,087	$ -
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Data Input [1]

		Initial Application	[2]	Adjustments	Application Update	[6]	Adjustments	Per Board Decision	
		($ millions)			($ millions)			($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$28,459		$292	$28,751			$28,751	
	Accumulated Depreciation (average)	($10,238)	[5]	($14)	($10,253)			($10,253)	
	Allowance for Working Capital:								
	Controllable Expenses	$463		$24	$487			$487	
	Cost of Power				$0				
	Working Capital Rate (%)	7.62%	[9]		7.41%	[9]			[9]
2	**Utility Income**								
	Operating Revenues:								
	Transmission Revenue at Current Rates								
	Transmission Revenue at Proposed Rates	$2,166		$48	$2,213				
	Other Revenue:								
	Specific Service Charges								
	Non-rate revenues	$37		$0	$37				
	Export Revenue Credits	$37		$0	$37				
	LVSG + Regulatory Balances	($21)		($0)	($21)				
	Total Revenue Offsets	$54	[7]	($0)	$54				
	Operating Expenses:								
	OM+A Expenses	$463		$24	$487			$487	
	Depreciation/Amortization	$647		$11	$658			$658	
	Property taxes								
	Productivity adjustments	($10)		($0.09)	($10)			($10)	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($374)	[3]		($390)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$61.99			$60.1				
	Income taxes (grossed up)								
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	11.50%			11.50%				
	Income Tax Credits	($0.3)			($0.3)				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	[8]		4.0%	[8]			[8]
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.04%			4.04%				
	Short-term debt Cost Rate (%)	1.56%			1.56%				
	Common Equity Cost Rate (%)	8.34%			8.34%				
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$28,459.2	$292	$28,750.8	$ -	$28,751
2	Accumulated Depreciation (average)	(2)	($10,238.3)	($14)	($10,252.7)	$ -	($10,253)
3	Net Fixed Assets (average)	(2)	$18,220.9	$277	$18,498.0	$ -	$18,498
4	Allowance for Working Capital	(1)	$35.3	$ -	$36.1	($36)	$ -
5	**Total Rate Base**		$18,256.2	$277	$18,534.1	($36)	$18,498

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$463.4	$24	$487	$ -	$487
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$463.4	$24	$487	$ -	$487
9	Working Capital Rate %	(1)	7.62%		7.41%	-7.41%	0.00%
10	Working Capital Allowance		$35.3		$36.1	($36)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
	Operating Revenues:						
1	Transmission Revenue (at Proposed Rates)		$2,165.5	$48	$2,213.1	$ -	$2,213
2	Other Revenue	(1)	$53.6	($0)	$53.5	$ -	$54
3	Total Operating Revenues		$2,219.1	$48	$2,266.6	$ -	$2,267
	Operating Expenses:						
4	OM+A Expenses		$463	$24	$487.3	$ -	$487
5	Depreciation/Amortization		$647	$11	$658.0	$ -	$658
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($10)	($0)	($9.9)	$ -	($10)
9	Subtotal (lines 4 to 8)		$1,101	$34	$1,135.4	$ -	$1,135
10	Deemed Interest Expense		$425	$6	$431.2	($1)	$430
11	Total Expenses (lines 9 to 10)		$1,526	$41	$1,566.6	($1)	$1,566
12	**Utility income before income taxes**		$693	$7	$700.0	$1	$701
13	Income taxes (grossed-up)		$84	($3)	$81.7	$ -	$82
14	**Utility net income**		$609	$9	$618.3	$1	$619

Notes

Other Revenues / Revenue Offsets

(1)

Specific Service Charges	$ -		$ -		$ -
Late Payment Charges	$37	$ -	$37		$37
Other Distribution Revenue	$37	$ -	$37		$37
Other Income and Deductions	($20.9)	($0)	($21)		($21)
Total Revenue Offsets	$53.6	($0)	$53.5	$ -	$54

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Taxes/PILs

Line No.	Particulars	Application ($ millions)	Application Update ($ millions)	Per Board Decision ($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$693.4	$700.0	$617
2	Adjustments required to arrive at taxable utility income	($373.8)	($390.3)	($390)
3	Taxable income	$319.6	$309.7	$227
	Calculation of Utility income Taxes			
4	Income taxes	$62.0	$60.1	$60
6	Total taxes	$62.0	$60.1	$60
7	Gross-up of Income Taxes	$22.4	$21.7	$22
8	Grossed-up Income Taxes	$84.3	$81.7	$82
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$84.3	$81.7	$82
10	Other tax Credits	($0.3)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$10,223	4.04%	$413.4
2	Short-term Debt	4.00%	$730	1.56%	$11.4
3	**Total Debt**	60.00%	$10,954	3.88%	$424.8
	Equity				
4	Common Equity	40.00%	$7,302	8.34%	$609.0
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$7,302	8.34%	$609.0
7	**Total**	100.00%	$18,256	5.66%	$1,033.8
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$10,379	4.04%	$419.7
2	Short-term Debt	4.00%	$741	1.56%	$11.6
3	**Total Debt**	60.00%	$11,120	3.88%	$431.2
	Equity				
4	Common Equity	40.00%	$7,414	8.34%	$618.3
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$7,414	8.34%	$618.3
7	**Total**	100.00%	$18,534	5.66%	$1,049.5
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$10,359	4.04%	$419
9	Short-term Debt	4.00%	$740	1.56%	$12
10	**Total Debt**	60.00%	$11,099	3.88%	$430
	Equity				
11	Common Equity	40.00%	$7,399	8.34%	$617
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$7,399	8.34%	$617
14	**Total**	100.00%	$18,498	5.66%	$1,047

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application		Application Update		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$2,899		$2,897
2	Transmission Revenue	$ -	$2,166	$ -	($686)	$ -	($683)
3	Other Operating Revenue Offsets - net	$54	$54	$54	$54	$54	$54
4	**Total Revenue**	$54	$2,219.1	$54	$2,266.6	$54	$2,267
5	Operating Expenses	$1,101	$1,101	$1,135	$1,135	$1,135	$1,135
6	Deemed Interest Expense	$425	$425	$431	$431	$430	$430
8	**Total Cost and Expenses**	$1,526	$1,526	$1,567	$1,567	$1,566	$1,566
9	**Utility Income Before Income Taxes**	($1,472)	$693.4	($1,513)	$700.0	($1,512)	$700.9
10	Tax Adjustments to Accounting Income per 2013 PILs model	($374)	($374)	($390)	($390)	($390)	($390)
11	**Taxable Income**	($1,846)	$319.6	($1,903)	$309.7	($1,903)	$311
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$84.7	$ -	$82.1	$ -	$82.3
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	($1,472)	$609.1	($1,513)	$618.3	($1,512)	$619
16	**Utility Rate Base**	$18,256	$18,256	$18,534	$18,534	$18,498	$18,498
17	Deemed Equity Portion of Rate Base	$7,302	$7,302	$7,414	$7,414	$7,399	$7,399
18	Income/(Equity Portion of Rate Base)	-20.15%	8.34%	-20.40%	8.34%	-20.43%	8.37%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-28.49%	0.00%	-28.74%	0.00%	-28.77%	0.03%
21	Indicated Rate of Return	-5.74%	5.66%	-5.84%	5.66%	-5.85%	5.67%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	5.66%	5.66%	5.66%	5.66%
23	Deficiency/Sufficiency in Rate of Return	-11.40%	0.00%	-11.50%	0.00%	-11.51%	0.01%
24	Target Return on Equity	$609	$609	$618	$618	$617	$617
25	Revenue Deficiency/(Sufficiency)		$0	$2,131	($0)	$2,129	$2
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$2,899 (1)		$2,897 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$463.4		$487.3		$487	
2	Amortization/Depreciation	$647.3		$658.0		$658	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$84.3		$81.7		$82	
6	Other Expenses	($9.8)		($9.9)		($10)	
7	Return						
	Deemed Interest Expense	$424.8		$431.2		$430	
	Return on Deemed Equity	$609.0		$618.3		$617	
8	**Service Revenue Requirement (before Revenues)**	$2,219.0		$2,266.6		$2,265	
9	Revenue Offsets	$53.6		$53.5		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$2,165.5		$2,213.1		$2,265	
11	Transmission revenue	$2,165.5		$2,213.1		$2,213	
12	Other revenue	$53.6		$53.5		$54	
13	**Total revenue**	$2,219.1		$2,266.6		$2,267	
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	$0.0	(1)	$0.0	(1)	$2	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$2,219	$2,267	**$0**	$2,265	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$2,899		$2,897	
Base Revenue Requirement (to be recovered from Rates)	$2,165	$2,213	**$0**	$2,265	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$2,166	$2,213	**$0**	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [(1)] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[(1)] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 2,219.05**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio: Test Year	Price Cap IR Period 1	Price Cap IR Period 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	Initial Application

Customer and Load Forecast | Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design) | Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1) | Distribution Rates | Revenue Reconciliation

	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate	Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 1,034	5.66%	$ 18,256	$ 463	$ 35	$ 647	$ 84	$ 463	$ 2,219	$ 54	$ 2,165	$ -
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	Distribution
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input (1)

		Initial Application	(2)	Adjustments	Application Update	(6)	Adjustments	Per Board Decision	
		($ millions)			($ millions)			($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$14,813		$20.80	$ 14,834.1			$14,834	
	Accumulated Depreciation (average)	($5,691)	(5)	($0.43)	($5,691)			($5,691)	
	Allowance for Working Capital:								
	Controllable Expenses	$603		$31.4	$ 634.4			$634	
	Cost of Power	$3,423			$ 3,422.8			$3,423	
	Working Capital Rate (%)	6.20%	(9)		6.20%	(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$1,666			$1,666				
	Distribution Revenue at Proposed Rates	$1,586	(10)		$1,623				
	Other Revenue:								
	Specific Service Charges								
	Late Payment Charges								
	Other Distribution Revenue	$46		($0)	$46.4				
	Other Income and Deductions								
	Total Revenue Offsets	$46	(7)	($0)	$46				
	Operating Expenses:								
	OM+A Expenses	$603		$31.4	$ 634			$634	
	Depreciation/Amortization	$460		$5.0	465			$465	
	Property taxes								
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($208)	(3)		($211.38)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$27.33			$26.60				
	Income taxes (grossed up)								
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	11.50%			11.50%				
	Income Tax Credits	(0.4)			(0.4)				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.07%			4.07%				
	Short-term debt Cost Rate (%)	1.56%			1.56%				
	Common Equity Cost Rate (%)	8.34%			8.34%				
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

(10) Distribution revenue at proposed rates is net of revenue offsets, in order to achieve comparability against distribution revenues at current rates, where the last approved rates are net of offsets

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$14,813.3	$21	$14,834.1	$ -	$14,834
2	Accumulated Depreciation (average)	(2)	($5,690.8)	($0)	($5,691.2)	$ -	($5,691)
3	Net Fixed Assets (average)	(2)	$9,122.5	$20	$9,142.9	$ -	$9,143
4	Allowance for Working Capital	(1)	$249.5	$2	$251.7	($252)	$ -
5	**Total Rate Base**		$9,372.0	$23	$9,394.7	($252)	$9,143

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$603.0	$31	$634.4	$ -	$634
7	Cost of Power		$3,422.8	$ -	$3,422.8	$ -	$3,423
8	Working Capital Base		$4,025.8	$31	$4,057.2	$ -	$4,057
9	Working Capital Rate %	(1)	6.20%	0.01%	6.20%	-6.20%	0.00%
10	Working Capital Allowance		$249.5	$2	$251.7	($252)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Utility Income

Line No.	Particulars	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
		($ millions)		($ millions)		($ millions)
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$1,586.0	$37	$1,622.6	$ -	$1,623
2	Other Revenue (1)	$46.4	($0)	$46.4	$ -	$46
3	Total Operating Revenues	$1,632.4	$37	$1,669.1	$ -	$1,669
	Operating Expenses:					
4	OM+A Expenses	$603	$31	$634.4	$ -	$634
5	Depreciation/Amortization	$460	$5	$465.1	$ -	$465
6	Property taxes	$ -	$ -		$ -	
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$1,063	$36	$1,099.5	$ -	$1,099
10	Deemed Interest Expense	$219	$1	$220.0	($6)	$214
11	Total Expenses (lines 9 to 10)	$1,283	$37	$1,319.5	($6)	$1,314
12	**Utility income before income taxes**	$349.9	($0)	$349.6	$6	$355
13	Income taxes (grossed-up)	$37	($1)	$36.2	$ -	$36
14	**Utility net income**	$312.7	$1	$313.4	$6	$319

Notes

Other Revenues / Revenue Offsets

(1)

	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
Specific Service Charges	$ -		$ -		$ -
Late Payment Charges	$ -		$ -		$ -
Other Distribution Revenue	$46	($0)	$46		$46
Other Income and Deductions	$ -		$ -		$ -
Total Revenue Offsets	$46.4	($0)	$46	$ -	$46

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Taxes/PILs

Line No.	Particulars	Application ($ millions)	Application Update ($ millions)	Per Board Decision ($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$349.9	$349.6	$305
2	Adjustments required to arrive at taxable utility income	($207.9)	($211.4)	($211)
3	Taxable income	$142.0	$138.2	$94
	Calculation of Utility income Taxes			
4	Income taxes	$27.3	$26.6	$27
6	Total taxes	$27.3	$26.6	$27
7	Gross-up of Income Taxes	$9.9	$9.6	$10
8	Grossed-up Income Taxes	$37.2	$36.2	$36
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$37.2	$36.2	$36
10	Other tax Credits	($0.4)	($0.4)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$5,248	4.07%	$213.6
2	Short-term Debt	4.00%	$375	1.56%	$5.8
3	**Total Debt**	60.00%	$5,623	3.90%	$219.5
	Equity				
4	Common Equity	40.00%	$3,749	8.34%	$312.7
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,749	8.34%	$312.7
7	**Total**	100.00%	$9,372	5.68%	$532.1
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$5,261	4.07%	$214.1
2	Short-term Debt	4.00%	$376	1.56%	$5.9
3	**Total Debt**	60.00%	$5,637	3.90%	$220.0
	Equity				
4	Common Equity	40.00%	$3,758	8.34%	$313.406
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,758	8.34%	$313.4
7	**Total**	100.00%	$9,395	5.68%	$533.4
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$5,120	4.07%	$208
9	Short-term Debt	4.00%	$366	1.56%	$6
10	**Total Debt**	60.00%	$5,486	3.90%	$214
	Equity				
11	Common Equity	40.00%	$3,657	8.34%	$305
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$3,657	8.34%	$305
14	**Total**	100.00%	$9,143	5.68%	$519

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		($80)		($43)		($60)
2	Distribution Revenue	$1,666	$1,666	$1,666	$1,666	$1,666	$1,683
3	Other Operating Revenue Offsets - net	$46	$46	$46	$46	$46	$46
4	**Total Revenue**	$1,712	$1,632.4	$1,712	$1,669.1	$1,712	$1,669
5	Operating Expenses	$1,063	$1,063	$1,099	$1,099	$1,099	$1,099
6	Deemed Interest Expense	$219	$219	$220	$220	$214	$214
8	**Total Cost and Expenses**	$1,283	$1,283	$1,319	$1,319	$1,314	$1,314
9	**Utility Income Before Income Taxes**	$430	$349.9	$393	$350	$399	$355.5
10	Tax Adjustments to Accounting Income per 2013 PILs model	($208)	($208)	($211)	($211)	($211)	($211)
11	**Taxable Income**	$222	$142.0	$181	$138	$187	$144
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$59	$37.6	$48	$36.6	$50	$38.2
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	$371	$312.7	$345	$313.4	$349	$319
16	**Utility Rate Base**	$9,372	$9,372	$9,395	$9,395	$9,143	$9,143
17	Deemed Equity Portion of Rate Base	$3,749	$3,749	$3,758	$3,758	$3,657	$3,657
18	Income/(Equity Portion of Rate Base)	9.90%	8.34%	9.18%	8.34%	9.55%	8.73%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	1.56%	0.00%	0.84%	0.00%	1.21%	0.39%
21	Indicated Rate of Return	6.30%	5.68%	6.01%	5.68%	6.16%	5.83%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	5.68%	5.68%	5.68%	5.68%
23	Deficiency/Sufficiency in Rate of Return	0.63%	0.00%	0.34%	0.00%	0.49%	0.16%
24	Target Return on Equity	$313	$313	$313	$313	$305	$305
25	Revenue Deficiency/(Sufficiency)	($59)	$0	($32)	($0)	($44)	$14
26	**Gross Revenue Deficiency/(Sufficiency)**	($80) (1)		($43) (1)		($60) (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$603.0		$634.4		$634	
2	Amortization/Depreciation	$460.1		$465.1		$465	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$37.2		$36.2		$36	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$219.5		$220.0		$214	
	Return on Deemed Equity	$312.7		$313.4		$305	
8	**Service Revenue Requirement (before Revenues)**	$1,632.4		$1,669.1		$1,655	
9	Revenue Offsets	$46.4		$46.4		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,586.0		$1,622.6		$1,655	
11	Distribution revenue	$1,586.0		$1,622.6		$1,623	
12	Other revenue	$46.4		$46.4		$46	
13	**Total revenue**	$1,632.4		$1,669.1		$1,669	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0.0	(1)	$0	(1)	$14	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,632	$1,669	**$0**	$1,655	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	($80)	($43)	**($0)**	($60)	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,586	$1,623	**$0**	$1,655	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	($80)	($43)	**($0)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,632.38**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** *(11)*

	Name of Customer Class	Proposed Revenue-to-Cost Ratio: Test Year	Price Cap IR Period: 1	Price Cap IR Period: 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates				Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate Rate	Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 532	5.68%	$ 9,372	$ 4,026	$ 249	$ 460	$ 37	$ 603	$ 1,632	$ 46	$ 1,586	-$ 80
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Distribution*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Data Input [1]

		Initial Application [2]	Adjustments	Application Update [6]	Adjustments	Per Board Decision
		($ millions)		($ millions)		($ millions)
1	**Rate Base**					
	Gross Fixed Assets (average)	$15,634.2	$68	$ 15,703		$15,703
	Accumulated Depreciation (average)	($5,923.7)	($2)	($5,926)		($5,926)
	Allowance for Working Capital:					
	Controllable Expenses	$614	$32	$ 646		$646
	Cost of Power	$3,423		$ 3,423		$3,423
	Working Capital Rate (%)	6.25%		6.26% [9]		[9]
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$1,594		$1,594		
	Distribution Revenue at Proposed Rates	$1,665		$1,707		
	Other Revenue:					
	Specific Service Charges					
	Late Payment Charges					
	Other Distribution Revenue	$46		$46		
	Other Income and Deductions					
	Total Revenue Offsets	$46		$46		
	Operating Expenses:					
	OM+A Expenses	$614	$32	$ 646		$646
	Depreciation/Amortization	$481	$7	$ 488		$488
	Property taxes					
	Productivity adjustments	($5)	($0.05)	($5)		($5)
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($179)		($184)		
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$40.1		$39.6		
	Income taxes (grossed up)					
	Federal tax (%)	15.00%		15.00%		
	Provincial tax (%)	11.50%		11.50%		
	Income Tax Credits	($0.4)		($0.4)		
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%		56.0%		
	Short-term debt Capitalization Ratio (%)	4.0%		4.0% [8]		[8]
	Common Equity Capitalization Ratio (%)	40.0%		40.0%		
	Prefered Shares Capitalization Ratio (%)					
				100.0%		
	Cost of Capital					
	Long-term debt Cost Rate (%)	4.07%		4.07%		
	Short-term debt Cost Rate (%)	1.56%		1.56%		
	Common Equity Cost Rate (%)	8.34%		8.34%		
	Prefered Shares Cost Rate (%)					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
1	Gross Fixed Assets (average)	(2)	$15,634.2	$68	$15,703	$ -	$15,703
2	Accumulated Depreciation (average)	(2)	($5,923.7)	($2)	($5,926)	$ -	($5,926)
3	Net Fixed Assets (average)	(2)	$9,710.5	$66	$9,777	$ -	$9,777
4	Allowance for Working Capital	(1)	$252.4		$255	($255)	$ -
5	**Total Rate Base**		$9,962.9	$66	$10,031	($255)	$9,777

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$614	$32	$646	$ -	$646
7	Cost of Power		$3,423	$ -	$3,423	$ -	$3,423
8	Working Capital Base		$4,037	$32	$4,069	$ -	$4,069
9	Working Capital Rate %	(1)	6.25%		6.26%	-6.26%	0.00%
10	Working Capital Allowance		$252.4		$254.8	($255)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Utility Income

Line No.	Particulars		Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,664.8	$42	$1,706.9	$ -	$1,707
2	Other Revenue	(1)	$46.5	$ -	$46.5	$ -	$46
3	Total Operating Revenues		$1,711.3	$42	$1,753.3	$ -	$1,753
	Operating Expenses:						
4	OM+A Expenses		$614.5	$32	$646.423	$ -	$646
5	Depreciation/Amortization		$481.3	$7	$488.223	$ -	$488
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($4.7)	($0)	($4.727)	$ -	($5)
9	Subtotal (lines 4 to 8)		$1,091.1	$39	$1,129.919	$ -	$1,130
10	Deemed Interest Expense		$233.3	$2	$234.890	($6)	$229
11	Total Expenses (lines 9 to 10)		$1,324.3	$40	$1,364.810	($6)	$1,359
12	**Utility income before income taxes**		$386.9	$2	$388.525	$6	$394
13	Income taxes (grossed-up)		$54.6	($1)	$53.876	$ -	$54
14	**Utility net income**		$332.4	$2	$334.649	$6	$341

Notes

Other Revenues / Revenue Offsets

		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -	$ -	$ -		$ -
	Late Payment Charges	$ -	$ -	$ -		$ -
	Other Distribution Revenue	$46	$ -	$46		$46
	Other Income and Deductions	$ -	$ -	$ -		$ -
	Total Revenue Offsets	$46	$ -	$46	$ -	$46

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
		($ millions)	($ millions)	($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$386.9	$388.5	$326
2	Adjustments required to arrive at taxable utility income	($179.3)	($183.6)	($184)
3	Taxable income	$207.6	$205.0	$143
	Calculation of Utility income Taxes			
4	Income taxes	$40.1	$40	$40
6	Total taxes	$40.1	$40	$40
7	Gross-up of Income Taxes	$14.5	$14	$14
8	Grossed-up Income Taxes	$54.6	$54	$54
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$54.6	$54	$54
10	Other tax Credits	($0.4)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
					($ millions)
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$5,579.2	4.07%	$227.1
2	Short-term Debt	4.00%	$398.5	1.56%	$6.2
3	**Total Debt**	60.00%	$5,977.7	3.90%	$233.3
	Equity				
4	Common Equity	40.00%	$3,985.2	8.34%	$332.4
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,985.2	8.34%	$332.4
7	**Total**	100.00%	$9,962.9	5.68%	$565.6
		Application Update			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$5,618	4.07%	$228.6
2	Short-term Debt	4.00%	$401	1.56%	$6.3
3	**Total Debt**	60.00%	$6,019	3.90%	$234.9
	Equity				
4	Common Equity	40.00%	$4,013	8.34%	$334.6
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,013	8.34%	$334.6
7	**Total**	100.00%	$10,031	5.68%	$569.5
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$5,475	4.07%	$223
9	Short-term Debt	4.00%	$391	1.56%	$6
10	**Total Debt**	60.00%	$5,866	3.90%	$229
	Equity				
11	Common Equity	40.00%	$3,911	8.34%	$326
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$3,911	8.34%	$326
14	**Total**	100.00%	$9,777	5.68%	$555

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$71		$113		$95
2	Distribution Revenue	$1,594	$1,594	$1,594	$1,594	$1,594	$1,611
3	Other Operating Revenue Offsets - net	$46	$46	$46	$46	$46	$46
4	**Total Revenue**	$1,640	$1,711.3	$1,640	$1,753	$1,640	$1,753.3
5	Operating Expenses	$1,091	$1,091	$1,130	$1,130	$1,130	$1,130
6	Deemed Interest Expense	$233	$233	$235	$235	$229	$229
8	**Total Cost and Expenses**	$1,324	$1,324	$1,365	$1,365	$1,359	$1,359
9	**Utility Income Before Income Taxes**	$316	$386.9	$276	$389	$281	$394
10	Tax Adjustments to Accounting Income per 2013 PILs model	($179)	($179)	($184)	($184)	($184)	($184)
11	**Taxable Income**	$137	$207.6	$92	$205	$98	$211
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$36	$55.0	$24	$54	$26	$56
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	$280	$332	$252	$335	$256	$341
16	**Utility Rate Base**	$9,963	$9,963	$10,031	$10,031	$9,777	$9,777
17	Deemed Equity Portion of Rate Base	$3,985	$3,985	$4,013	$4,013	$3,911	$3,911
18	Income/(Equity Portion of Rate Base)	7.03%	8.34%	6.27%	8.34%	6.55%	8.71%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-1.31%	0.00%	-2.07%	0.00%	-1.79%	0.37%
21	Indicated Rate of Return	5.15%	5.68%	4.85%	5.68%	4.96%	5.83%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	5.68%	5.68%	5.68%	5.68%
23	Deficiency/Sufficiency in Rate of Return	-0.52%	0.00%	-0.83%	0.00%	-0.72%	0.15%
24	Target Return on Equity	$332	$332	$335	$335	$326	$326
25	Revenue Deficiency/(Sufficiency)	$52	$0	$83	$0	$70	$14
26	**Gross Revenue Deficiency/(Sufficiency)**	$71 (1)		$113 (1)		$95 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
		($ millions)		($ millions)		($ millions)	
1	OM&A Expenses	$614.5		646.4		$646	
2	Amortization/Depreciation	$481.3		488.2		$488	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$54.6		53.9		$54	
6	Other Expenses	($4.7)		($4.7)		($5)	
7	Return						
	Deemed Interest Expense	$233.3		234.9		$229	
	Return on Deemed Equity	$332.4		334.6		$326	
8	**Service Revenue Requirement (before Revenues)**	$1,711.3		1,753.3		$1,739	
9	Revenue Offsets	$46.5		46.5		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,664.8		1,706.9		$1,739	
11	Distribution revenue	$1,664.8		1,706.9		$1,707	
12	Other revenue	$46.5		46.5		$46	
13	**Total revenue**	$1,711.3		1,753.3		$1,753	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0.0	(1)	$0	(1)	$14	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,711.3	$1,753	**$0**	$1,739	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$71	$113	**$1**	$95	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,664.8	$1,707	**$0**	$1,739	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$71	$113	**$1**	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	**Initial Application**			**Application Update**			**Per Board Decision**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class (3) From Sheet 10. Load Forecast	Costs Allocated from Previous Study (1)	%	Allocated Class Revenue Requirement (1) (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,711.29**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [(11)]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	2019	2020	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 566	5.68%	$ 9,963	$ 4,037	$ 252	$ 481	$ 55	$ 614	$ 1,711	$ 46	$ 1,665	$ 71
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Distribution*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Data Input [1]

		Initial Application [2]	Adjustments	Application Update [6]	Adjustments	Per Board Decision
1	**Rate Base**					
	Gross Fixed Assets (average)	$16,558	$127	$ 16,685		$16,685
	Accumulated Depreciation (average)	($6,171)	($6)	($6,178)		($6,178)
	Allowance for Working Capital:					
	Controllable Expenses	$626	$33	$ 659		$659
	Cost of Power	$3,419		$ 3,419		$3,419
	Working Capital Rate (%)	6.30%		6.31% [9]		[9]
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$1,673		$1,673		
	Distribution Revenue at Proposed Rates	$1,739		$1,786		
	Other Revenue:					
	Specific Service Charges					
	Late Payment Charges					
	Other Distribution Revenue	$47		$47		
	Other Income and Deductions					
	Total Revenue Offsets	$46.5		$47		
	Operating Expenses:					
	OM+A Expenses	$626	$33	$ 659		$659
	Depreciation/Amortization	$522	$10	$ 532		$532
	Property taxes					
	Productivity adjustments	($10)	($0.1)	($10)		($10)
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($236)		($245)		
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$31.1		$29.7		
	Income taxes (grossed up)					
	Federal tax (%)	15.00%		15.00%		
	Provincial tax (%)	11.50%		11.50%		
	Income Tax Credits	($0.4)		($0.4)		
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%		56.0%		
	Short-term debt Capitalization Ratio (%)	4.0%		4.0% [8]		[8]
	Common Equity Capitalization Ratio (%)	40.0%		40.0%		
	Prefered Shares Capitalization Ratio (%)					
				100.0%		
	Cost of Capital					
	Long-term debt Cost Rate (%)	4.07%		4.07%		
	Short-term debt Cost Rate (%)	1.56%		1.56%		
	Common Equity Cost Rate (%)	8.34%		8.34%		
	Prefered Shares Cost Rate (%)					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$16,557.7	$127	$16,684.5	$ -	$16,685
2	Accumulated Depreciation (average)	(2)	($6,171.4)	($6)	($6,177.7)	$ -	($6,178)
3	Net Fixed Assets (average)	(2)	$10,386.3	$120	$10,506.8	$ -	$10,507
4	Allowance for Working Capital	(1)	$254.9		$257.4	($257)	$ -
5	**Total Rate Base**		$10,641.2	$120	$10,764.2	($257)	$10,507

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$626	$33	$659	$ -	$659
7	Cost of Power		$3,419	$ -	$3,419	$ -	$3,419
8	Working Capital Base		$4,046	$33	$4,078	$ -	$4,078
9	Working Capital Rate %	(1)	6.30%		6.31%	-6.31%	0.00%
10	Working Capital Allowance		$254.9		$257.4	($257)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,738.5	$47	$1,785.7	$ -	$1,786
2	Other Revenue	(1)	$46.5	$ -	$46.5	$ -	$47
3	Total Operating Revenues		$1,785.1	$47	$1,832.2	$ -	$1,832
	Operating Expenses:						
4	OM+A Expenses		$626.1	$33	$658.7	$ -	$659
5	Depreciation/Amortization		$522.0	$10	$531.7	$ -	$532
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($9.6)	($0)	($9.7)	$ -	($10)
9	Subtotal (lines 4 to 8)		$1,138.5	$42	$1,180.7	$ -	$1,181
10	Deemed Interest Expense		$249.2	$3	$252.0	($6)	$246
11	Total Expenses (lines 9 to 10)		$1,387.7	$45	$1,432.7	($6)	$1,427
12	**Utility income before income taxes**		$397.4	$2	$399.5	$6	$406
13	Income taxes (grossed-up)		$42.4	($2)	$40.4	$ -	$40
14	**Utility net income**		$355.0	$4	$359.1	$6	$365

Notes

Other Revenues / Revenue Offsets

(1)

	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
Specific Service Charges	$ -	$ -	$ -		$ -
Late Payment Charges	$ -	$ -	$ -		$ -
Other Distribution Revenue	$47	$ -	$47		$47
Other Income and Deductions	$ -	$ -	$ -		$ -
Total Revenue Offsets	$46.5	$ -	$47	$ -	$47

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$397.4	$399.5	$351
2	Adjustments required to arrive at taxable utility income	($235.8)	($245.3)	($245)
3	Taxable income	$161.6	$154.2	$105
	Calculation of Utility income Taxes			
4	Income taxes	$31.1	$29.7	$30
6	Total taxes	$31.1	$29.7	$30
7	Gross-up of Income Taxes	$11.2	$10.7	$11
8	Grossed-up Income Taxes	$42.4	$40.4	$40
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$42.4	$40.4	$40
10	Other tax Credits	($0.4)	($0.4)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$5,959.1	4.07%	$242.5
2	Short-term Debt	4.00%	$425.6	1.56%	$6.6
3	**Total Debt**	60.00%	$6,384.7	3.90%	$249.2
	Equity				
4	Common Equity	40.00%	$4,256.5	8.34%	$355.0
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,256.5	8.34%	$355.0
7	**Total**	100.00%	$10,641.2	5.68%	$604.16
		Application Update			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$6,027.9	4.07%	$245.3
2	Short-term Debt	4.00%	$430.6	1.56%	$6.7
3	**Total Debt**	60.00%	$6,458.5	3.902517%	252.0
	Equity				
4	Common Equity	40.00%	$4,305.7	8.34%	$359.1
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,305.7	8.34%	359.1
7	**Total**	100.00%	$10,764.2	5.68%	$611.14
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$5,884	4.07%	$239
9	Short-term Debt	4.00%	$420	1.56%	$7
10	**Total Debt**	60.00%	$6,304	3.90%	$246
	Equity				
11	Common Equity	40.00%	$4,203	8.34%	$351
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$4,203	8.34%	$351
14	**Total**	100.00%	$10,507	5.68%	$597

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$65		$113		$95
2	Distribution Revenue	$1,673	$1,673	$1,673	$1,673	$1,673	$1,691
3	Other Operating Revenue Offsets - net	$47	$47	$47	$47	$47	$47
4	**Total Revenue**	$1,720	$1,785.1	$1,720	$1,832	$1,720	$1,832.2
5	Operating Expenses	$1,139	$1,139	$1,181	$1,181	$1,181	$1,181
6	Deemed Interest Expense	$249	$249	$252	$252	$246	$246
8	**Total Cost and Expenses**	$1,388	$1,388	$1,433	$1,433	$1,427	$1,427
9	**Utility Income Before Income Taxes**	$332	$397.4	$287	$400	$293	$406
10	Tax Adjustments to Accounting Income per 2013 PILs model	($236)	($236)	($245)	($245)	($245)	($245)
11	**Taxable Income**	$96	$161.6	$42	$154	$48	$160
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$25	$42.8	$11	$41	$13	$42
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	$307	$355	$276	$359	$281	$365
16	**Utility Rate Base**	$10,641	$10,641	$10,764	$10,764	$10,507	$10,507
17	Deemed Equity Portion of Rate Base	$4,256	$4,256	$4,306	$4,306	$4,203	$4,203
18	Income/(Equity Portion of Rate Base)	7.21%	8.34%	6.42%	8.34%	6.68%	8.69%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-1.13%	0.00%	-1.92%	0.00%	-1.66%	0.35%
21	Indicated Rate of Return	5.23%	5.68%	4.91%	5.68%	5.01%	5.82%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	5.68%	5.68%	5.68%	5.68%
23	Deficiency/Sufficiency in Rate of Return	-0.45%	0.00%	-0.77%	0.00%	-0.66%	0.14%
24	Target Return on Equity	$355	$355	$359	$359	$351	$351
25	Revenue Deficiency/(Sufficiency)	$48	$0	$83	$0	$70	$15
26	**Gross Revenue Deficiency/(Sufficiency)**	$65 [(1)]		$113 [(1)]		$95 [(1)]	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Requirement

Line No.	Particulars	Application	Application Update	Per Board Decision
1	OM&A Expenses	$626.1	$658.7	$659
2	Amortization/Depreciation	$522.0	$531.7	$532
3	Property Taxes	$ -		
5	Income Taxes (Grossed up)	$42.4	$40.4	$40
6	Other Expenses	($9.6)	($9.7)	($10)
7	Return			
	Deemed Interest Expense	$249.2	$252.0	$246
	Return on Deemed Equity	$355.0	$359.1	$351
8	**Service Revenue Requirement (before Revenues)**	$1,785.1	$1,832.2	$1,818
9	Revenue Offsets	$46.5	$46.5	$ -
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,738.5	$1,785.7	$1,818
11	Distribution revenue	$1,738.5	$1,785.7	$1,786
12	Other revenue	$46.5	$46.5	$47
13	**Total revenue**	$1,785.1	$1,832.2	$1,832
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0.0 (1)	$0 (1)	$15 (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,785.1	$1,832	**$0**	$1,818	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$65	$113	**$1**	$95	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,738.5	$1,786	**$0**	$1,818	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$65	$113	**$1**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%
	Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.		**Service Revenue Requirement (from Sheet 9)**	**$ 1,785.08**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	2019	2020	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	*Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
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Total Transformer Ownership Allowance	$ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 604	5.68%	$ 10,641	$ 4,046	$ 255	$ 522	$ 42	$ 626	$ 1,785	$ 47	$ 1,739	$ 65
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Distribution*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Data Input [1]

		Initial Application	(2)	Adjustments	Application Update	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$17,495		$186	$ 17,681			$17,681	
	Accumulated Depreciation (average)	($6,451)		($13)	($6,464)			($6,464)	
	Allowance for Working Capital:								
	Controllable Expenses	$638		$33	$ 671			$671	
	Cost of Power	$3,419			$ 3,419			$3,419	
	Working Capital Rate (%)	6.36%			6.37%	(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$1,747			$1,747				
	Distribution Revenue at Proposed Rates	$1,835			$1,889				
	Other Revenue:								
	Specific Service Charges								
	Late Payment Charges								
	Other Distribution Revenue	$46			$46				
	Other Income and Deductions								
	Total Revenue Offsets	$46			$46				
	Operating Expenses:								
	OM+A Expenses	$638		$33	$ 671			$671	
	Depreciation/Amortization	$557		$12	$ 569			$569	
	Property taxes								
	Productivity adjustments	($15)		($0.2)	($15)			($15)	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($211)			($221)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$43.5			$42.5				
	Income taxes (grossed up)								
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	11.50%			11.50%				
	Income Tax Credits	($0.4)			($0.4)				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%			4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)								
					100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.07%			4.07%				
	Short-term debt Cost Rate (%)	1.56%			1.56%				
	Common Equity Cost Rate (%)	8.34%			8.34%				
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$17,495.0	$186	$17,681.2	$ -	$17,681
2	Accumulated Depreciation (average)	(2)	($6,451.2)	($13)	($6,464.0)	$ -	($6,464)
3	Net Fixed Assets (average)	(2)	$11,043.8	$173	$11,217.2	$ -	$11,217
4	Allowance for Working Capital	(1)	$258.0		$260.7	($261)	$ -
5	**Total Rate Base**		$11,301.8		$11,477.9	($261)	$11,217

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$638	$33	$671	$ -	$671
7	Cost of Power		$3,419	$ -	$3,419	$ -	$3,419
8	Working Capital Base		$4,057	$33	$4,090	$ -	$4,090
9	Working Capital Rate %	(1)	6.36%		6.37%	-6.37%	0.00%
10	Working Capital Allowance		$258.0	$3	$260.7	($261)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

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Revenue Requirement Workform (RRWF) for 2026 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,835.1	$54	$1,889	$ -	$1,889
2	Other Revenue	(1)	$46.0	$ -	$45.997	$ -	$46
3	Total Operating Revenues		$1,881.1	$54	$1,935	$ -	$1,935
	Operating Expenses:						
4	OM+A Expenses		$638.0	$33	$671	$ -	$671
5	Depreciation/Amortization		$557.3	$12	$569	$ -	$569
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($15.0)	($0)	($15)	$ -	($15)
9	Subtotal (lines 4 to 8)		$1,180.3	$45	$1,225	$ -	$1,225
10	Deemed Interest Expense		$264.6	$4	$268.8	($6)	$263
11	Total Expenses (lines 9 to 10)		$1,444.9	$49	$1,494	($6)	$1,488
12	**Utility income before income taxes**		$436.2	$4	$441	$6	$447
13	Income taxes (grossed-up)		$59.2	($1)	$58	$ -	$58
14	**Utility net income**		$377.0	$6	$383	$6	$389

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -	$ -	$ -		$ -
	Late Payment Charges	$ -	$ -	$ -		$ -
	Other Distribution Revenue	$46	$ -	$46		$46
	Other Income and Deductions	$ -	$ -	$ -		$ -
	Total Revenue Offsets	$46.0	$ -	$46.0	$ -	$46.0

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Revenue Requirement Workform (RRWF) for 2026 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$436.2	$440.7	$374
2	Adjustments required to arrive at taxable utility income	($211.2)	($221.0)	($221)
3	Taxable income	$225.0	$219.6	$153
	Calculation of Utility income Taxes			
4	Income taxes	$43.5	$42	$42
6	Total taxes	$43.5	$42	$42
7	Gross-up of Income Taxes	$15.7	$15	$15
8	Grossed-up Income Taxes	$59.2	$58	$58
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$59.2	$58	$58
10	Other tax Credits	($0.4)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$6,329.0	4.07%	$257.6
2	Short-term Debt	4.00%	$452.1	1.56%	$7.0
3	**Total Debt**	60.00%	$6,781.1	3.90%	$264.6
	Equity				
4	Common Equity	40.00%	$4,520.7	8.34%	$377.0
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,520.7	8.34%	$377.0
7	**Total**	100.00%	$11,301.8	5.68%	$641.7
		Application Update			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$6,428	4.07%	$261.604
2	Short-term Debt	4.00%	$459	1.56%	$7.2
3	**Total Debt**	60.00%	$6,887	3.90%	$268.76
	Equity				
4	Common Equity	40.00%	$4,591	8.34%	$382.901
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,591	8.34%	$382.901
7	**Total**	100.00%	$11,478	5.68%	$651.7
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$6,282	4.07%	$256
9	Short-term Debt	4.00%	$449	1.56%	$7
10	**Total Debt**	60.00%	$6,730	3.90%	$263
	Equity				
11	Common Equity	40.00%	$4,487	8.34%	$374
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$4,487	8.34%	$374
14	**Total**	100.00%	$11,217	5.68%	$637

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Revenue Deficiency/Sufficiency

		Initial Application		Application Update		Per Board Decision	
Line No.	Particulars	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$89		$142		$124
2	Distribution Revenue	$1,747	$1,747	$1,747	$1,747	$1,747	$1,764
3	Other Operating Revenue Offsets - net	$46	$46	$46	$46	$46	$46
4	**Total Revenue**	$1,793	$1,881.1	$1,793	$1,935	$1,793	$1,934.8
5	Operating Expenses	$1,180	$1,180	$1,225	$1,225	$1,225	$1,225
6	Deemed Interest Expense	$265	$265	$269	$269	$263	$263
8	**Total Cost and Expenses**	$1,445	$1,445	$1,494	$1,494	$1,488	$1,488
9	**Utility Income Before Income Taxes**	$348	$436.2	$298	$441	$304	$447
10	Tax Adjustments to Accounting Income per 2013 PILs model	($211)	($211)	($221)	($221)	($221)	($221)
11	**Taxable Income**	$136	$225.0	$77	$220	$83	$226
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$36	$59.6	$20	$58	$22	$60
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	$312	$377	$278	$383	$283	$389
16	**Utility Rate Base**	$11,302	$11,302	$11,478	$11,478	$11,217	$11,217
17	Deemed Equity Portion of Rate Base	$4,521	$4,521	$4,591	$4,591	$4,487	$4,487
18	Income/(Equity Portion of Rate Base)	6.90%	8.34%	6.06%	8.34%	6.30%	8.67%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-1.44%	0.00%	-2.28%	0.00%	-2.04%	0.33%
21	Indicated Rate of Return	5.10%	5.68%	4.77%	5.68%	4.86%	5.81%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	5.68%	5.68%	5.68%	5.68%
23	Deficiency/Sufficiency in Rate of Return	-0.58%	0.00%	-0.91%	0.00%	-0.82%	0.13%
24	Target Return on Equity	$377	$377	$383	$383	$374	$374
25	Revenue Deficiency/(Sufficiency)	$65	$0	$105	$0	$91	$15
26	**Gross Revenue Deficiency/(Sufficiency)**	$89 (1)		$142 (1)		$124 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2)

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Revenue Requirement Workform (RRWF) for 2026 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$638.0		$671.2		$671	
2	Amortization/Depreciation	$557.3		$569.4		$569	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$59.2		$57.8		$58	
6	Other Expenses	($15.0)		($15.2)		($15)	
7	Return						
	Deemed Interest Expense	$264.6		$268.8		$263	
	Return on Deemed Equity	$377.0		$382.9		$374	
8	**Service Revenue Requirement (before Revenues)**	$1,881.1		$1,934.8		$1,920	
9	Revenue Offsets	$46.0		$46.0		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,835.1		$1,888.8		$1,920	
11	Distribution revenue	$1,835.1		$1,888.8		$1,889	
12	Other revenue	$46.0		$46.0		$46	
13	**Total revenue**	$1,881.1		$1,934.8		$1,935	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0.0	(1)	$ -	(1)	$15	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,881.1	$1,935	**$0**	$1,920	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$89	$142	**$1**	$124	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,835.1	$1,889	**$0**	$1,920	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$89	$142	**$1**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

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Revenue Requirement Workform (RRWF) for 2026 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,881.14**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [(11)]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	2019	2020	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	Initial Application

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
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#			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance	$ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

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Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 642	5.68%	$ 11,302	$ 4,057	$ 258	$ 557	$ 59	$ 638	$ 1,881	$ 46	$ 1,835	$ 89
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Distribution*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Data Input [1]

		Initial Application	[2]	Adjustments	Application Update	[6]	Adjustments	Per Board Decision
1	**Rate Base**							
	Gross Fixed Assets (average)	$18,396		$243	$ 18,639			$18,639
	Accumulated Depreciation (average)	($6,777)		($22)	($6,799)			($6,799)
	Allowance for Working Capital:							
	Controllable Expenses	$650		$34	$ 684			$684
	Cost of Power	$3,418			$ 3,418			$3,418
	Working Capital Rate (%)	6.42%			6.43%	[9]		[9]
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$1,843			$1,843			
	Distribution Revenue at Proposed Rates	$1,919			$1,979			
	Other Revenue:							
	Specific Service Charges							
	Late Payment Charges							
	Other Distribution Revenue	$46			$46			
	Other Income and Deductions							
	Total Revenue Offsets	$46			$46			
	Operating Expenses:							
	OM+A Expenses	$650		$34	$ 684			$684
	Depreciation/Amortization	$592		$15	$ 607			$607
	Property taxes							
	Productivity adjustments	($21)		($0.3)	($21)			($21)
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($204)			($215)			
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$50.5			$49.7			
	Income taxes (grossed up)							
	Federal tax (%)	15.00%			15.00%			
	Provincial tax (%)	11.50%			11.50%			
	Income Tax Credits	($0.4)			($0.4)			
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			
	Short-term debt Capitalization Ratio (%)	4.0%			4.0%	[8]		[8]
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			
	Prefered Shares Capitalization Ratio (%)							
					100.0%			
	Cost of Capital							
	Long-term debt Cost Rate (%)	4.07%			4.07%			
	Short-term debt Cost Rate (%)	1.56%			1.56%			
	Common Equity Cost Rate (%)	8.34%			8.34%			
	Prefered Shares Cost Rate (%)							

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$18,396.2	$243	$18,639.4	$ -	$18,639
2	Accumulated Depreciation (average)	(2)	($6,776.8)	($22)	($6,798.5)	$ -	($6,799)
3	Net Fixed Assets (average)	(2)	$11,619.5	$221	$11,840.9	$ -	$11,841
4	Allowance for Working Capital	(1)	$261.0	$ -	$263.8	($264)	$ -
5	**Total Rate Base**		$11,880.5	$221	$12,104.7	($264)	$11,841

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$650	$34	$684	$ -	$684
7	Cost of Power		$3,418	$ -	$3,418	$ -	$3,418
8	Working Capital Base		$4,068	$34	$4,102	$ -	$4,102
9	Working Capital Rate %	(1)	6.42%		6.43%	-6.43%	0.00%
10	Working Capital Allowance		$261.0		$263.8	($264)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,918.9		$1,978.5	$ -	$1,979
2	Other Revenue	(1)	$46.1	$ -	$46.1	$ -	$46
3	Total Operating Revenues		$1,965.0	$ -	$2,024.6	$ -	$2,025
	Operating Expenses:						
4	OM+A Expenses		$650.2	$34	$684.0	$ -	$684
5	Depreciation/Amortization		$592.3	$15	$606.9	$ -	$607
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($20.7)	($0)	($21.1)	$ -	($21)
9	Subtotal (lines 4 to 8)		$1,221.7	$48	$1,269.8	$ -	$1,270
10	Deemed Interest Expense		$278.2		$283.4	($6)	$277
11	Total Expenses (lines 9 to 10)		$1,499.9		$1,553.2	($6)	$1,547
12	**Utility income before income taxes**		$465.0	$ -	$471.4	$6	$478
13	Income taxes (grossed-up)		$68.7	($1)	$67.6	$ -	$68
14	**Utility net income**		$396.3	$1	$403.8	$6	$410

Notes

Other Revenues / Revenue Offsets

(1)

	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
Specific Service Charges	$ -	$ -	$ -		$ -
Late Payment Charges	$ -	$ -	$ -		$ -
Other Distribution Revenue	$46	$ -	$46		$46
Other Income and Deductions	$ -	$ -	$ -		$ -
Total Revenue Offsets	$46.1	$ -	$46	$ -	$46

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$465.0	$471.4	$395
2	Adjustments required to arrive at taxable utility income	($204.1)	($214.7)	($215)
3	Taxable income	$260.9	$256.7	$180
	Calculation of Utility income Taxes			
4	Income taxes	$50.5	$49.7	$50
6	Total taxes	$50.5	$49.7	$50
7	Gross-up of Income Taxes	$18.2	$17.9	$18
8	Grossed-up Income Taxes	$68.7	$67.6	$68
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$68.7	$67.6	$68
10	Other tax Credits	($0.4)	($0.4)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$6,653.1	4.07%	$270.8
2	Short-term Debt	4.00%	$475.2	1.56%	$7.4
3	**Total Debt**	60.00%	$7,128.3	3.90%	$278.2
	Equity				
4	Common Equity	40.00%	$4,752.2	8.34%	$396.3
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,752.2	8.34%	$396.3
7	**Total**	100.00%	$11,880.5	5.68%	$674.5

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application Update			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$6,779	4.07%	$275.9
2	Short-term Debt	4.00%	$484	1.56%	$7.5
3	**Total Debt**	60.00%	$7,263	3.90%	$283.4
	Equity				
4	Common Equity	40.00%	$4,842	8.34%	$403.812
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,842	8.34%	$403.8
7	**Total**	100.00%	$12,104.7	5.68%	$687.2

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$6,631	4.07%	$270
9	Short-term Debt	4.00%	$474	1.56%	$7
10	**Total Debt**	60.00%	$7,105	3.90%	$277
	Equity				
11	Common Equity	40.00%	$4,736	8.34%	$395
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$4,736	8.34%	$395
14	**Total**	100.00%	$11,841	5.68%	$672

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$75		$135		$117
2	Distribution Revenue	$1,843	$1,843	$1,843	$1,843	$1,843	$1,862
3	Other Operating Revenue Offsets - net	$46	$46	$46	$46	$46	$46
4	**Total Revenue**	$1,889	$1,965.0	$1,889	$2,025	$1,889	$2,024.6
5	Operating Expenses	$1,222	$1,222	$1,270	$1,269.798	$1,270	$1,270
6	Deemed Interest Expense	$278	$278	$283	$283	$277	$277
8	**Total Cost and Expenses**	$1,500	$1,500	$1,553	$1,553	$1,547	$1,547
9	**Utility Income Before Income Taxes**	$390	$465.0	$336	$471	$342	$478
10	Tax Adjustments to Accounting Income per 2013 PILs model	($204)	($204)	($215)	($215)	($215)	($215)
11	**Taxable Income**	$185	$260.9	$122	$257	$128	$263
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$49	$69.1	$32	$68	$34	$70
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	($0)	($0)
15	**Utility Net Income**	$341	$396	$304	$404	$309	$410
16	**Utility Rate Base**	$11,880	$11,880	$12,105	$12,105	$11,841	$11,841
17	Deemed Equity Portion of Rate Base	$4,752	$4,752	$4,842	$4,842	$4,736	$4,736
18	Income/(Equity Portion of Rate Base)	7.17%	8.34%	6.29%	8.34%	6.52%	8.66%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-1.17%	0.00%	-2.05%	0.00%	-1.82%	0.32%
21	Indicated Rate of Return	5.21%	5.68%	4.86%	5.68%	4.95%	5.80%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	5.68%	5.68%	5.68%	5.68%
23	Deficiency/Sufficiency in Rate of Return	-0.47%	0.00%	-0.82%	0.00%	-0.73%	0.13%
24	Target Return on Equity	$396	$396	$404	$404	$395	$395
25	Revenue Deficiency/(Sufficiency)	$55	($0)	$99	$0	$86	$15
26	**Gross Revenue Deficiency/(Sufficiency)**	$75 [1]		$135 [1]		$117 [1]	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Revenue Requirement

Line No.	Particulars	Application	Application Update	Per Board Decision
1	OM&A Expenses	$650.2	$684.0	$684
2	Amortization/Depreciation	$592.3	$606.9	$607
3	Property Taxes	$ -		
5	Income Taxes (Grossed up)	$68.7	$67.6	$68
6	Other Expenses	($20.7)	($21.1)	($21)
7	Return			
	Deemed Interest Expense	$278.2	$283.4	$277
	Return on Deemed Equity	$396.3	$403.8	$395
8	**Service Revenue Requirement (before Revenues)**	$1,965.0	$2,024.6	$2,010
9	Revenue Offsets	$46.1	$46.1	$ -
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,918.9	$1,978.5	$2,010
11	Distribution revenue	$1,918.9	$1,978.5	$1,979
12	Other revenue	$46.1	$46.1	$46
13	**Total revenue**	$1,965.0	$2,024.6	$2,025
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0.0) (1)	$ - (1)	$15 (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,965	$2,025	**$0**	$2,010	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$75	$135	**$1**	$117	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,919	$1,979	**$0**	$2,010	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$75	$135	**$1**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** (1) Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1]	%
	From Sheet 10. Load Forecast			(7A)	
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,964.96**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** *(11)*

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year	Price Cap IR Period 1	Price Cap IR Period 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: ***Initial Application***

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates				Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate Rate	Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 675	5.68%	$ 11,880	$ 4,068	$ 261	$ 592	$ 69	$ 650	$ 1,965	$ 46	$ 1,919	$ 75
1														

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Utility Rate Base
Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

Particulars		**2022**		**2023**		**2024**		**2025**		**2026**		**2027**
Electric Utility Plant												
Gross plant at cost	$	22,262.1	$	23,599.5		24,927.4	$	26,652.0	$	27,936.7	$	29,564.8
Less: accumulated depreciation	$	(8,145.1)		(8,559.2)		(9,003.9)		(9,473.6)		(9,981.5)		(10,523.9)
Net plant for rate base	$	14,117.0		15,040.3		15,923.5		17,178.4		17,955.2		19,040.9
Average net plant for rate base	$			14,578.6		15,481.9		16,551.0		17,566.8		18,498.0
Average net utility plant	$		$	14,578.6	$	15,481.9	$	16,551.0	$	17,566.8	$	18,498.0
Working Capital												
Cash working capital	$			18.7		20.3		19.8		20.8		20.8
Materials and Supplies Inventory	$			14.1		14.4		14.7		15.0		15.3
Total working capital	$			32.8		34.7		34.5		35.8		36.1
Total rate base	$		$	14,611.5		15,516.6		16,585.5		17,602.6		18,534.1

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Statement of Utility Rate Base
Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

Particulars		**2022**		**2023**		**2024**		**2025**		**2026**		**2027**
Electric Utility Plant												
Gross plant at cost	$	14,290.5	$	15,330.0	$	16,231.2	$	17,296.9	$	18,226.8	$	19,215.6
Less: non-regulatory		(75.0)		(77.0)		(78.9)		(80.1)		(81.2)		(82.4)
Gross plant at cost for rate base		14,215.5		15,253.0		16,152.3		17,216.8		18,145.6		19,133.3
Less: accumulated depreciation	$	(5,579.3)		(5,839.8)		(6,087.1)		(6,351.2)		(6,667.7)		(7,028.3)
Less: non-regulatory		31.6		35.5		39.4		43.4		47.4		51.5
Accumulated depreciation for rate base		(5,547.7)		(5,804.3)		(6,047.7)		(6,307.8)		(6,620.3)		(6,976.8)
Net plant for rate base	$	8,667.8		9,448.7		10,104.6		10,909.0		11,525.3		12,156.5
Average net plant for rate base	$			9,142.9		9,776.6		10,506.8		11,217.2		11,840.9
Average net utility plant	$		$	9,142.9	$	9,776.6	$	10,506.8	$	11,217.2	$	11,840.9
Working Capital												
Cash working capital	$			245.7		248.7		251.2		254.3		257.3
Materials and Supplies Inventory	$			6.0		6.1		6.2		6.4		6.5
Total working capital	$			251.7		254.8		257.4		260.7		263.8
Total rate base	$		$	9,394.7	$	10,031.4	$	10,764.2	$	11,477.9	$	12,104.7

2023-2027 figures are presented on a combined basis including Acquired Utilities. 2023 average rate base includes opening adjustment for Acquired Utilities.

Witness: Joel Jodoin

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historical								
1	2018	17,076.7	1135.6	(10.9)	(15.9)	(0.5)	18,185.0	17,630.8
2	2019	18,185.0	959.5	(59.7)	(6.9)	15.8	19,093.7	18,639.3
3	2020	19,093.7	944.3	(59.9)	(15.5)	6.8	19,969.4	19,531.5
4	2021-Forecast	19,969.4	1006.0	(51.1)		9.0	20,933.2	20,451.3
Bridge								
5	2022	20,933.2	1381.6	(53.8)		1.0	22,262.1	21,597.7
Test								
6	2023	22,262.1	1404.5	(68.1)		1.0	23,599.5	22,930.8
7	2024	23,599.5	1393.2	(66.4)		1.0	24,927.4	24,263.5
8	2025	24,927.4	1795.6	(72.0)		1.1	26,652.0	25,789.7
9	2026	26,652.0	1347.5	(63.9)		1.1	27,936.7	27,294.4
10	2027	27,936.7	1683.8	(56.8)		1.1	29,564.8	28,750.8

Witness: CORNACCHIA Joseph

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

Line No.	Year	Opening Balance (a)	Additions (b)	Retirements (c)	Sales (d)	Transfers In/Out (e)	Closing Balance (f)	Average (g)
Historical								
1	2018	11,624.1	627.8	(181.8)	(36.1)	(5.1)	12,028.9	11,826.5
2	2019	12,028.9	585.1	(60.2)	(13.6)	9.2	12,549.5	12,289.2
3	2020	12,549.5	668.1	(56.8)	(16.7)	6.9	13,150.9	12,850.2
4	2021-Forecast	13,150.9	700.1	(116.2)	0.0	6.8	13,741.6	13,446.3
Bridge								
5	2022	13,741.6	656.4	(108.3)	-	0.8	14,290.5	14,016.1
Test								
6	2023	14,490.3	1,012.5	(173.7)	-	0.9	15,330.0	14,910.1
7	2024	15,330.0	1,080.9	(180.6)	-	0.9	16,231.2	15,780.6
8	2025	16,231.2	1,266.6	(201.8)	-	0.9	17,296.9	16,764.0
9	2026	17,296.9	1,116.9	(187.9)	-	0.9	18,226.8	17,761.8
10	2027	18,226.8	1,165.9	(178.1)	-	0.9	19,215.6	18,721.2

2018-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock).
2023-2027 figures are presented on a combined basis including Acquired Utilities.

2023 Opening Balance reflects the integration of Acquired Utilities.

Witness: CORNACCHIA Joseph

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out and Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historical								
1	2018	6,301.7	387.3	(10.9)	(14.6)	(1.4)	6,662.1	6,481.9
2	2019	6,662.1	406.6	(59.7)	(6.2)	0.5	7,003.2	6,832.7
3	2020	7,003.2	410.9	(59.9)	(7.4)	1.7	7,348.6	7,175.9
4	2021-Forecast	7,348.6	440.2	(51.1)			7,737.6	7,543.1
Bridge								
5	2022	7,737.6	461.2	(53.8)			8,145.1	7,941.3
Test								
6	2023	8,145.1	482.3	(68.1)			8,559.2	8,352.1
7	2024	8,559.2	511.0	(66.4)			9,003.9	8,781.6
8	2025	9,003.9	541.7	(72.0)			9,473.6	9,238.8
9	2026	9,473.6	571.8	(63.9)			9,981.5	9,727.6
10	2027	9,981.5	599.2	(56.8)			10,523.9	10,252.7

Witness: CORNACCHIA Joseph

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out and Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historical								
1	2018	4,352.5	346.1	(181.8)	(30.9)	(0.0)	4,486.0	4,419.3
2	2019	4,486.0	351.7	(60.2)	(12.3)	(0.4)	4,764.8	4,625.4
3	2020	4,764.8	355.4	(56.8)	(14.6)	0.0	5,048.8	4,906.8
4	2021-Forecast	5,048.8	370.2	(116.2)	0.0	0.0	5,302.8	5,175.8
Bridge								
5	2022	5,302.8	384.9	(108.3)	0.0	0.0	5,579.3	5,441.0
Test								
6	2023	5,609.8	403.8	(173.7)	0.0	0.0	5,839.8	5,724.8
7	2024	5,839.8	427.9	(180.6)	0.0	0.0	6,087.1	5,963.4
8	2025	6,087.1	465.9	(201.8)	0.0	0.0	6,351.2	6,219.1
9	2026	6,351.2	504.4	(187.9)	0.0	0.0	6,667.7	6,509.4
10	2027	6,667.7	538.7	(178.1)	0.0	0.0	7,028.3	6,848.0

2018-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock).
2023-2027 figures are presented on a combined basis including Acquired Utilities.

2023 Opening Balance reflects the integration of Acquired Utilities.

Witness: CORNACCHIA Joseph

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Debt and Equity Summary
Historical Years (2018, 2019, 2020) and Bridge Years (2021, 2022)
As at December 31
($M)

Updated Line No.	Particulars	Amount Outstanding 2018 Actual	Amount Outstanding 2019 Actual	Amount Outstanding 2020 Actual	Amount Outstanding 2021 Bridge	Amount Outstanding 2022 Bridge
		(a)	(b)	(c)	(d)	(e)
1	Long-term debt *	3,600.7	4,215.7	4,610.6	4,487.9	4,636.9
2	Short-term debt	712.3	332.3	44.4	340.7	352.5
3	Preference shares	-	-	-	-	-
4	Common equity	2,716.0	2,635.0	2,770.0	3,406.8	3,525.1

* Includes debt payable within one year; excludes the 2.25 year debt issue used as short term debt, variable rate debt, unamortized debt premiums/discount, hedging gains/losses and marks to market

HYDRO ONE NETWORKS INC.
TRANSMISSION
Debt and Equity Summary
Historical Years (2018, 2019, 2020) and Bridge Years (2021, 2022)
As at December 31
($M)

Updated Line No.	Particulars	Amount Outstanding 2018 Actual	Amount Outstanding 2019 Actual	Amount Outstanding 2020 Actual	Amount Outstanding 2021 Bridge	Amount Outstanding 2022 Bridge
		(a)	(b)	(c)	(d)	(e)
1	Long-term debt *	5,358.3	6,243.3	7,101.3	7,236.2	7,635.9
2	Short-term debt	1,634.7	1,149.7	681.7	517.1	545.6
3	Preference shares	-	-	-	-	-
4	Common equity	4,729.0	4,866.0	5,170.0	5,170.9	5,456.4

* Includes debt payable within one year; excludes the 2.25 year debt issue used as short term debt, variable rate debt, unamortized debt premiums/discount, hedging gains/losses and marks to market

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Summary of Cost of Capital
Test Year 2023
Utility Capital Structure
Year Ending December 31
($M)

		2023			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	4,880.7	52.0%	4.07%	198.6
2	Short-term debt	375.8	4.0%	1.56%	5.9
3	Deemed long-term debt	380.3	4.0%	4.07%	15.5
4	Total debt	5,636.8	60.0%	3.90%	220.0
5	Common equity	3,757.9	40.0%	8.34%	313.4
6	Total rate base	9,394.7	100.0%	5.68%	533.4

HYDRO ONE NETWORKS INC.
TRANSMISSION
Summary of Cost of Capital
Test Year 2023
Utility Capital Structure
Year Ending December 31
($M)

		2023			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	7,873.7	53.9%	4.04%	318.3
2	Short-term debt	584.5	4.0%	1.56%	9.1
3	Deemed long-term debt	308.7	2.1%	4.04%	12.5
4	Total debt	8,766.9	60.0%	3.87%	340.0
5	Common equity	5,844.6	40.0%	8.34%	487.4
6	Total rate base	14,611.5	100.0%	5.66%	827.4

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Summary of Cost of Capital
Last OEB-approved year (2018)
Utility Capital Structure
Year Ending December 31
($M)

		2018			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	3768.1	49.34%	4.47%	168.5
2	Short-term debt	305.5	4.00%	2.29%	7.0
3	Deemed long-term debt	508.5	6.66%	4.47%	22.7
4	Total debt	4582.1	60.00%	4.33%	198.3
5	Common equity	3054.8	40.00%	9.00%	274.9
6	Total rate base	7,636.9	100.00%	6.20%	473.2

HYDRO ONE NETWORKS INC.
TRANSMISSION
Summary of Cost of Capital
Last OEB-approved year (2020)
Utility Capital Structure
Year Ending December 31
($M)

		2020			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	6409.4	51.86%	4.42%	283.6
2	Short-term debt	494.4	4.00%	2.75%	13.6
3	Deemed long-term debt	512.0	4.14%	4.42%	22.7
4	Total debt	7415.8	60.00%	4.31%	319.8
5	Common equity	4943.8	40.00%	8.52%	421.2
6	Total rate base	12,359.6	100.00%	6.00%	741.0

HYDRO ONE NETWORKS INC.
TRANSMISSION
Depreciation & Amortization Expenses
Historical Years (2018, 2019, 2020 and 2021-Forecast)
Year Ending December 31
($M)

Line No.	Particulars	2018 Deprn Rate	2018 Provision ($M)	2019 Deprn Rate	2019 Provision	2020 Deprn Rate	2020 Provision	2021 Deprn Rate	2021 Provision ($M)
		(a)	(b)	(e)	(f)	(g)	(h)	(a)	(b)
	Depreciation Expenses								
1	Major Fixed Assets	2.06%	362.3	2.07%	382.0	2.01%	386.7	2.02%	409.3
2	Minor Fixed Assets	11.32%	25.0	7.43%	24.6	7.90%	24.2	7.84%	30.9
3	Depreciation on Fixed Assets		387.3		406.6		410.9		440.2
4	Less Capitalized Depreciation		(13.0)		(13.1)		(14.4)		(14.5)
5	Asset Removal Costs		37.7		45.9		39.6		63.1
6	Losses/(Gains) on Asset Disposition		(0.5)		(0.5)		(2.4)		0.0
7	Total Depreciation Expenses		411.5		438.9		433.7		488.8
	Amortization Expenses								
8	Environmental Costs		6.7		5.5		7.7		15.5
9	Other Regulatory Amortization		0.0		0.0		0.0		-
10	Other Amortization		0.0		0.0		0.0		-
11	Total Amortization Expenses		6.7		5.5		7.7		15.5
12	Total Depreciation & Amortization Expenses		418.2		444.4		441.4		504.3
13	Exclude Other Reg Amort		0.0		-		-		-
14	Depreciation & Amortization for recovery		418.2		444.4		441.4		504.3

HYDRO ONE NETWORKS INC.
TRANSMISSION
Depreciation & Amortization Expenses
Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

		2022		2023		2024		2025		2026		2027	
Line No.	**Particulars**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(i)	(j)	(i)	(j)
	Depreciation Expenses												
1	Major Fixed Assets	2.02%	432.0	2.00%	453.3	2.00%	480.6	2.01%	511.3	2.00%	540.8	1.99%	566.0
2	Minor Fixed Assets	7.33%	29.2	7.42%	29.0	7.47%	30.4	7.22%	30.4	7.07%	31.1	7.10%	33.1
3	Depreciation on Fixed Assets		461.2		482.3		511.0		541.7		571.8		599.2
4	Less Capitalized Depreciation		(14.5)		(14.8)		(14.9)		(15.1)		(15.2)		(15.3)
5	Asset Removal Costs		56.4		64.4		66.6		74.4		77.6		74.2
6	Total Depreciation Expenses		503.1		531.9		562.7		601.0		634.2		657.9
	Amortization Expenses												
7	Environmental Costs		16.3		7.6		7.5		6.6		0.0		0.0
8	Other Regulatory Amortization												
9	Other Amortization												
10	Total Amortization Expenses		16.3		7.6		7.5		6.6		0.0		0.0
11	Total Depreciation & Amortization Expenses		519.4		539.5		570.2		607.6		634.2		657.9
12	Exclude Other Reg Amort												
13	Depreciation & Amortization for recovery		519.4		539.5		570.2		607.6		634.2		657.9

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Depreciation & Amortization Expenses
Historical Years (2018, 2019, 2020 and 2021-Forecast)
Year Ending December 31
($M)

		2018		2019		2020		2021	
Line No.	**Particulars**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision**	**Deprn Rate**	**Provision**	**Deprn Rate**	**Provision ($M)**
		(a)	(b)	(e)	(f)	(g)	(h)	(a)	(b)
	Depreciation Expenses								
1	Major Fixed Assets	2.80%	303.5	2.76%	312.1	2.68%	316.6	2.59%	335.6
2	Minor Fixed Assets	7.17%	41.4	7.43%	39.6	7.90%	38.8	7.29%	34.5
3	Depreciation on Fixed Assets		344.9		351.7		355.4		370.1
4	Less Capitalized Depreciation		(18.0)		(18.3)		(17.7)		(17.9)
5	Asset Removal Costs		50.6		53.8		59.3		54.8
6	Losses/(Gains) on Asset Disposition		(1.3)		(1.2)		(0.5)		
7	Total Depreciation Expenses		376.2		386.0		396.5		407.0
	Amortization Expenses								
8	Environmental Costs		14.4		15.5		14.3		13.4
9	Other Regulatory Amortization		0.0		0.0		0.0		0.0
10	Other Amortization		0.0		0.0		0.0		
11	Total Amortization Expenses		14.4		15.5		14.3		13.4
12	Total Depreciation & Amortization Expenses		390.6		401.5		410.8		420.4
13	Exclude Other Reg Amort		3.9		4.3		4.4		4.1
14	Depreciation & Amortization for recovery		386.7		397.2		406.4		416.3

2018-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock). 2023-2027 figures are presented on a combined basis including Acquired Utilities.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Depreciation & Amortization Expenses
Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

		2022		2023		2024		2025		2026		2027	
Line No.	**Particulars**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision ($M)**
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(i)	(j)	(i)	(j)
	Depreciation Expenses												
1	Major Fixed Assets	2.59%	350.6	2.58%	366.6	2.56%	384.9	2.62%	418.6	2.68%	453.1	2.71%	483.2
2	Minor Fixed Assets	7.09%	34.3	7.47%	37.2	7.99%	43.0	8.15%	47.3	8.22%	51.3	8.20%	55.6
3	Depreciation on Fixed Assets		384.9		403.8		427.9		465.9		504.3		538.7
4	Less Capitalized Depreciation		(17.9)		(18.2)		(18.3)		(18.5)		(18.7)		(18.9)
5	Asset Removal Costs		56.4		83.4		82.6		88.3		87.7		91.2
6	Total Depreciation Expenses		423.4		468.9		492.2		535.7		573.3		611.0
	Amortization Expenses												
7	Environmental Costs		12.9		5.5		5.4		1.0		0.0		0.0
8	Other Regulatory Amortization												
9	Other Amortization												
10	Total Amortization Expenses		12.9		5.5		5.4		1.0		0.0		0.0
11	Total Depreciation & Amortization Expenses		436.3		474.4		497.6		536.7		573.3		611.0
12	Exclude Other Reg Amort		4.3		3.8		3.9		4.0		4.0		4.1
13	Depreciation & Amortization for recovery		432.0		470.6		493.7		532.7		569.3		606.9

2018-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock). 2023-2027 figures are presented on a combined basis including Acquired Utilities.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost Allowance (CCA) - 2023-2027 Updated for Inflation Assumptions
Historical Actual (2021-Forecast), Bridge (2022) & Test Years (2023 - 2027)
Year Ending December 31
($M)

2021 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,850.0	29.3	1,879.3	(14.7)	27.0	1,891.6	4%	75.7	1,803.6
2	393.1	-	393.1	-	-	393.1	6%	23.6	369.5
3	195.9	-	195.9	-	-	195.9	5%	9.8	186.1
6	53.1	-	53.1	-	-	53.1	10%	5.3	47.8
7	1.6	-	1.6	-	-	1.6	15%	0.2	1.4
8	140.7	106.8	247.6	(53.4)	98.3	292.4	20%	58.5	189.1
9	1.6	-	1.6	-	-	1.6	25%	0.4	1.2
10	24.8	9.9	34.7	(4.9)	9.1	38.8	30%	11.6	23.0
12	2.4	24.8	27.2	(12.4)	11.4	26.2	100%	26.2	1.0
13	6.7	-	6.7	-	-	6.7	N/A	1.3	5.4
14.1 (ECE)	27.7	-	27.7	-	-	27.7	7%	1.9	25.7
14.1 (Post-2017)	15.2	8.3	23.5	(4.2)	7.6	27.0	5%	1.3	22.1
17	108.3	1.9	110.2	(1.0)	1.8	111.0	8%	8.9	101.4
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.1
42	50.4	-	50.4	-	-	50.4	12%	6.0	44.3
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	8.0	-	8.0	-	-	8.0	30%	2.4	5.6
47	4,441.0	720.9	5,161.8	(360.4)	663.2	5,464.6	8%	437.2	4,724.7
50	25.1	8.9	34.0	(4.5)	8.2	37.8	55%	20.8	13.3
Total CCA	**7,345.8**	**910.8**	**8,256.6**	**(455.4)**	**826.6**	**8,627.7**		**691.2**	**7,565.3**
							Less CCA not in rates	(8.9)	
							Total CCA for RR	**682.4**	

2022 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,803.6	24.5	1,828.1	(12.2)	24.5	1,840.4	4%	73.6	1,754.5
2	369.5	-	369.5	-	-	369.5	6%	22.2	347.4
3	186.1	-	186.1	-	-	186.1	5%	9.3	176.8
6	47.8	-	47.8	-	-	47.8	10%	4.8	43.0
7	1.4	-	1.4	-	-	1.4	15%	0.2	1.2
8	189.1	46.3	235.3	(23.1)	46.3	258.4	20%	51.7	183.6
9	1.2	-	1.2	-	-	1.2	25%	0.3	0.9
10	23.0	8.1	31.1	(4.0)	8.1	35.2	30%	10.5	20.6
12	1.0	24.1	25.1	(12.1)	12.1	25.1	100%	25.1	-
13	5.4	-	5.4	-	-	5.4	N/A	1.3	4.1
14.1 (ECE)	25.7	-	25.7	-	-	25.7	7%	1.8	23.9
14.1 (Post-2017)	22.1	14.3	36.5	(7.2)	14.3	43.6	5%	2.2	34.3
17	101.4	4.4	105.8	(2.2)	4.4	108.0	8%	8.6	97.2
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.1
42	44.3	-	44.3	-	-	44.3	12%	5.3	39.0
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	5.6	-	5.6	-	-	5.6	30%	1.7	3.9
47	4,724.7	1,134.1	5,858.8	(567.0)	1,134.1	6,425.8	8%	514.1	5,344.7
50	13.3	5.8	19.0	(2.9)	5.8	21.9	55%	12.1	7.0
Total CCA	**7,565.3**	**1,261.6**	**8,826.9**	**(630.8)**	**1,249.5**	**9,445.7**		**744.8**	**8,082.1**
							Less CCA not in rates	(8.1)	
							Total CCA for RR	**736.7**	

2023 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,754.5	22.6	1,777.1	(11.3)	22.6	1,788.4	4%	71.5	1,705.6
2	347.4	-	347.4	-	-	347.4	6%	20.8	326.5
3	176.8	-	176.8	-	-	176.8	5%	8.8	167.9
6	43.0	-	43.0	-	-	43.0	10%	4.3	38.7
7	1.2	-	1.2	-	-	1.2	15%	0.2	1.0
8	183.6	115.2	298.9	(57.6)	115.2	356.5	20%	71.3	227.6
9	0.9	-	0.9	-	-	0.9	25%	0.2	0.7
10	20.6	17.6	38.2	(8.8)	17.6	47.0	30%	14.1	24.1
12	-	25.0	25.0	(12.5)	12.5	25.0	100%	25.0	-
13	4.1	-	4.1	-	-	4.1	N/A	1.3	2.8
14.1 (ECE)	23.9		23.9			23.9	7%	1.7	22.3
14.1 (Post-2017)	34.3	6.1	40.4	(3.1)	6.1	43.5	5%	2.2	38.3
17	97.2	2.8	99.9	(1.4)	2.8	101.3	8%	8.1	91.8
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.1
42	39.0	-	39.0	-	-	39.0	12%	4.7	34.3
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	3.9		3.9			3.9	30%	1.2	2.8
47	5,344.7	1,082.1	6,426.8	(541.1)	1,082.1	6,967.9	8%	557.4	5,869.4
50	7.0	6.2	13.1	(3.1)	6.2	16.2	55%	8.9	4.2
Total CCA	**8,082.1**	**1,277.6**	**9,359.7**	**(638.8)**	**1,265.1**	**9,986.0**		**801.8**	**8,557.9**
							Less CCA not in rates	(7.4)	
							Revised CCA updated for inflation	794.4	
							CCA in prefiled (E-09-02)	788.0	
							Additional CCA	6.3	
							Increase in CCA (Tax Effected)	**1.7**	

2024 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,705.6	47.3	1,752.9	(23.6)	23.6	1,752.9	4%	70.1	1,682.7
2	326.5	-	326.5	-	-	326.5	6%	19.6	306.9
3	167.9	-	167.9	-	-	167.9	5%	8.4	159.5
6	38.7	-	38.7	-	-	38.7	10%	3.9	34.9
7	1.0	-	1.0	-	-	1.0	15%	0.1	0.8
8	227.6	95.1	322.7	(47.5)	47.5	322.7	20%	64.5	258.1
9	0.7	-	0.7	-	-	0.7	25%	0.2	0.5
10	24.1	18.1	42.2	(9.1)	9.1	42.2	30%	12.7	29.5
12	-	19.6	19.6	(9.8)	9.8	19.6	100%	19.6	-
13	2.8	-	2.8	-	-	2.8	N/A	1.3	1.5
14.1 (ECE)	22.3	-	22.3	-	-	22.3	7%	1.6	20.7
14.1 (Post-2017)	38.3	8.3	46.5	(4.1)	4.1	46.5	5%	2.3	44.2
17	91.8	1.0	92.8	(0.5)	0.5	92.8	8%	7.4	85.4
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.1
42	34.3	-	34.3	-	-	34.3	12%	4.1	30.2
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	2.8	-	2.8	-	-	2.8	30%	0.8	1.9
47	5,869.4	1,067.4	6,936.8	(533.7)	533.7	6,936.8	8%	554.9	6,381.8
50	4.2	3.7	7.9	(1.8)	1.8	7.9	55%	4.4	3.6
Total CCA	**8,557.9**	**1,260.4**	**9,818.4**	**(630.2)**	**630.2**	**9,818.4**		**775.9**	**9,042.4**
							Less CCA not in rates	(6.8)	
							Revised CCA updated for inflation	769.1	
							CCA in prefiled (E-09-02)	759.3	
							Additional CCA	9.8	
							Increase in CCA (Tax Effected)	**2.6**	

2025 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,682.7	27.6	1,710.4	(13.8)	13.8	1,710.4	4%	68.4	1,642.0
2	306.9	-	306.9	-	-	306.9	6%	18.4	288.5
3	159.5	-	159.5	-	-	159.5	5%	8.0	151.6
6	34.9	-	34.9	-	-	34.9	10%	3.5	31.4
7	0.8	-	0.8	-	-	0.8	15%	0.1	0.7
8	258.1	102.9	361.0	(51.4)	51.4	361.0	20%	72.2	288.8
9	0.5	-	0.5	-	-	0.5	25%	0.1	0.4
10	29.5	19.0	48.6	(9.5)	9.5	48.6	30%	14.6	34.0
12	-	47.0	47.0	(23.5)	23.5	47.0	100%	47.0	-
13	1.5	-	1.5	-	-	1.5	N/A	1.5	(0.0)
14.1 (ECE)	20.7	-	20.7	-	-	20.7	7%	1.4	19.2
14.1 (Post-2017)	44.2	10.7	54.9	(5.3)	5.3	54.9	5%	2.7	52.1
17	85.4	3.4	88.7	(1.7)	1.7	88.7	8%	7.1	81.6
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.0
42	30.2	-	30.2	-	-	30.2	12%	3.6	26.6
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	1.9	-	1.9	-	-	1.9	30%	0.6	1.3
47	6,381.8	1,453.0	7,834.8	(726.5)	726.5	7,834.8	8%	626.8	7,208.0
50	3.6	3.9	7.4	(1.9)	1.9	7.4	55%	4.1	3.3
Total CCA	**9,042.4**	**1,667.5**	**10,709.9**	**(833.7)**	**833.7**	**10,709.9**		**880.2**	**9,829.7**
							Less CCA not in rates	(6.2)	
							Revised CCA updated for inflation	874.0	
							CCA in prefiled (E-09-02)	855.9	
							Additional CCA	18.1	
							Increase in CCA (Tax Effected)	**4.8**	

2026 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,642.0	30.2	1,672.1	(15.1)	15.1	1,672.1	4%	66.9	1,605.2
2	288.5	-	288.5	-	-	288.5	6%	17.3	271.2
3	151.6	-	151.6	-	-	151.6	5%	7.6	144.0
6	31.4	-	31.4	-	-	31.4	10%	3.1	28.2
7	0.7	-	0.7	-	-	0.7	15%	0.1	0.6
8	288.8	102.4	391.1	(51.2)	51.2	391.1	20%	78.2	312.9
9	0.4	-	0.4	-	-	0.4	25%	0.1	0.3
10	34.0	18.7	52.7	(9.4)	9.4	52.7	30%	15.8	36.9
12	-	23.9	23.9	(12.0)	12.0	23.9	100%	23.9	-
13	(0.0)	-	(0.0)	-	-	(0.0)	N/A	0.1	(0.1)
14.1 (ECE)	19.2	-	19.2	-	-	19.2	7%	1.3	17.9
14.1 (Post-2017)	52.1	10.1	62.2	(5.0)	5.0	62.2	5%	3.1	59.1
17	81.6	1.9	83.6	(1.0)	1.0	83.6	8%	6.7	76.9
35	0.0	-	0.0	-	-	0.0	7%	0.0	0.0
42	26.6	-	26.6	-	-	26.6	12%	3.2	23.4
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	1.3	-	1.3	-	-	1.3	30%	0.4	0.9
47	7,208.0	1,033.5	8,241.5	(516.8)	516.8	8,241.5	8%	659.3	7,582.2
50	3.3	4.6	8.0	(2.3)	2.3	8.0	55%	4.4	3.6
Total CCA	**9,829.7**	**1,225.4**	**11,055.0**	**(612.7)**	**612.7**	**11,055.0**		**891.7**	**10,163.4**
							Less CCA not in rates	(5.7)	
							Revised CCA updated for inflation	885.9	
							CCA in prefiled (E-09-02)	864.1	
							Additional CCA	21.8	
							Increase in CCA (Tax Effected)	**5.8**	

2027 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,605.2	26.2	1,631.5	(13.1)	13.1	1,631.5	4%	65.3	1,566.2
2	271.2	-	271.2	-	-	271.2	6%	16.3	254.9
3	144.0	-	144.0	-	-	144.0	5%	7.2	136.8
6	28.2	-	28.2	-	-	28.2	10%	2.8	25.4
7	0.6	-	0.6	-	-	0.6	15%	0.1	0.5
8	312.9	55.5	368.4	(27.8)	27.8	368.4	20%	73.7	294.7
9	0.3	-	0.3	-	-	0.3	25%	0.1	0.2
10	36.9	19.8	56.7	(9.9)	9.9	56.7	30%	17.0	39.7
12	-	20.2	20.2	(10.1)	10.1	20.2	100%	20.2	-
13	(0.1)	-	(0.1)	-	-	(0.1)	N/A	1.0	(1.1)
14.1 (ECE)	17.9	-	17.9	-	-	17.9	5%	0.9	17.0
14.1 (Post-2017)	59.1	12.6	71.6	(6.3)	6.3	71.6	5%	3.6	68.1
17	76.9	1.6	78.4	(0.8)	0.8	78.4	8%	6.3	72.2
35	0.0	-	0.0	-	-	0.0	7%	0.0	0.0
42	23.4	-	23.4	-	-	23.4	12%	2.8	20.6
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	0.9	-	0.9	-	-	0.9	30%	0.3	0.7
47	7,582.2	1,406.9	8,989.2	(703.5)	703.5	8,989.2	8%	719.1	8,270.0
50	3.6	5.6	9.2	(2.8)	2.8	9.2	55%	5.0	4.1
Total CCA	**10,163.4**	**1,548.3**	**11,711.7**	**(774.2)**	**774.2**	**11,711.7**		**941.6**	**10,770.1**
							Less CCA not in rates	(5.3)	
							Revised CCA updated for inflation	936.4	
							CCA in prefiled (E-09-02)	909.4	
							Additional CCA	26.9	
							Increase in CCA (Tax Effected)	**7.1**	

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost Allowance (CCA) - 2023-2027 Updated for Inflation Assumptions
Historical Actual (2021-Forecast), Bridge (2022) & Test Years (2023 - 2027)
Year Ending December 31
($M)

2021 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,326.6	32.5	1,359.1	(16.2)	32.1	1,375.0	4%	55.0	1,304.1
2	177.4	-	177.4	-	-	177.4	6%	10.6	166.7
3	10.2	-	10.2	-	-	10.2	5%	0.5	9.7
6	17.5	-	17.5	-	-	17.5	10%	1.7	15.7
7	1.8	-	1.8	-	-	1.8	15%	0.3	1.5
8	82.8	75.9	158.6	(37.9)	75.1	195.8	20%	39.2	119.5
9	1.8	-	1.8	-	-	1.8	25%	0.4	1.3
10	57.8	21.0	78.8	(10.5)	20.8	89.2	30%	26.7	52.1
12	1.3	55.1	56.4	(27.5)	27.3	56.1	100%	56.1	0.3
13	15.9	2.9	18.8	(1.4)	-	17.4	N/A	2.2	16.6
14	1.4	-	1.4	-	-	1.4	N/A	0.1	1.3
14.1 (ECE)	17.0	0.2	17.2	(0.1)	0.2	17.2	7%	1.2	15.9
14.1 (Post-2017)	0.3	3.2	3.5	(1.6)	3.2	5.1	5%	0.3	3.3
17	32.0	-	32.0	-	-	32.0	8%	2.6	29.4
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	7.0	-	7.0	-	-	7.0	30%	2.1	4.9
47	3,521.5	467.0	3,988.5	(233.5)	462.5	4,217.5	8%	337.4	3,651.1
50	2.7	2.4	5.1	(1.2)	2.4	6.3	55%	3.5	1.6
Total CCA	**5,275.0**	**660.2**	**5,935.2**	**(330.1)**	**623.7**	**6,228.7**		**539.9**	**5,395.3**
							Less CCA not in rates	(6.4)	
							Less CCA (acquired LDC)	(11.0)	
							Total CCA for RR	**522.5**	

2022 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,304.0	24.7	1,328.7	(12.3)	24.7	1,341.0	4%	53.6	1,275.0
2	166.7	-	166.7	-	-	166.7	6%	10.0	156.7
3	9.7	-	9.7	-	-	9.7	5%	0.5	9.2
6	15.7	-	15.7	-	-	15.7	10%	1.6	14.2
7	1.5	-	1.5	-	-	1.5	15%	0.2	1.3
8	119.5	20.9	140.4	(10.5)	20.9	150.9	20%	30.2	110.2
9	1.3	-	1.3	-	-	1.3	25%	0.3	1.0
10	52.1	16.9	69.0	(8.5)	16.9	77.5	30%	23.2	45.8
12	0.3	38.1	38.3	(19.0)	19.0	38.3	100%	38.3	-
13	16.6	5.8	22.5	(2.9)	-	19.6	N/A	2.7	19.7
14	1.3	-	1.3	-	-	1.3	N/A	0.1	1.2
14.1 (ECE)	16.4	0.1	16.5	(0.0)	0.1	16.5	7%	1.2	15.3
14.1 (Post-2017)	3.3	4.3	7.6	(2.2)	4.3	9.7	5%	0.5	7.1
17	29.4	-	29.4	-	-	29.4	8%	2.4	27.1
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	4.9	-	4.9	-	-	4.9	30%	1.5	3.4
47	3,651.1	491.5	4,142.7	(245.8)	491.5	4,388.4	8%	351.1	3,791.6
50	1.6	1.7	3.4	(0.9)	1.7	4.3	55%	2.3	1.0
Total CCA	**5,395.8**	**604.1**	**5,999.8**	**(302.0)**	**579.2**	**6,277.0**		**519.8**	**5,480.1**
							Less CCA not in rates	(6.2)	
							Less CCA (acquired LDC)	(11.1)	
							Total CCA for RR	**502.5**	

2023 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,275.0	29.0	1,304.0	(14.5)	29.0	1,318.5	4%	52.7	1,251.3
2	156.7	-	156.7	-	-	156.7	6%	9.4	147.3
3	9.2	-	9.2	-	-	9.2	5%	0.5	8.7
6	14.2	-	14.2	-	-	14.2	10%	1.4	12.8
7	1.3	-	1.3	-	-	1.3	15%	0.2	1.1
8	110.2	59.5	169.7	(29.8)	59.5	199.5	20%	39.9	129.8
9	1.0	-	1.0	-	-	1.0	25%	0.3	0.8
10	45.8	36.7	82.5	(18.3)	36.7	100.8	30%	30.2	52.2
12	-	44.2	44.2	(22.1)	22.1	44.2	100%	44.2	-
13	19.7	6.5	26.3	(3.3)	-	23.0	N/A	3.3	22.9
14	1.2	-	1.2	-	-	1.2	N/A	0.1	1.1
14.1 (ECE)	15.3	0.1	15.4	(0.0)	0.1	15.5	7%	1.1	14.3
14.1 (Post-2017)	7.1	6.0	13.1	(3.0)	6.0	16.1	5%	0.8	12.3
17	27.1	-	27.1	-	-	27.1	8%	2.2	24.9
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	3.4	-	3.4	-	-	3.4	30%	1.0	2.4
47	3,791.6	742.7	4,534.3	(371.3)	742.7	4,905.6	8%	392.5	4,141.8
50	1.0	1.8	2.8	(0.9)	1.8	3.7	55%	2.1	0.8
Total CCA	**5,480.1**	**926.5**	**6,406.5**	**(463.2)**	**897.9**	**6,841.2**		**581.9**	**5,824.7**
							Less CCA not in rates	(5.8)	
							Total CCA for RR	576.1	
							CCA in prefiled (E-09-02)	567.6	
							Additional CCA	8.5	
							Increase in CCA (Tax Effected)	**2.2**	

2024 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,251.3	67.3	1,318.6	(33.6)	33.6	1,318.6	4%	52.7	1,265.8
2	147.3	-	147.3	-	-	147.3	6%	8.8	138.5
3	8.7	-	8.7	-	-	8.7	5%	0.4	8.3
6	12.8	-	12.8	-	-	12.8	10%	1.3	11.5
7	1.1	-	1.1	-	-	1.1	15%	0.2	0.9
8	129.8	80.3	210.2	(40.2)	40.2	210.2	20%	42.0	168.1
9	0.8	-	0.8	-	-	0.8	25%	0.2	0.6
10	52.2	37.9	90.1	(18.9)	18.9	90.1	30%	27.0	63.1
12	-	41.0	41.0	(20.5)	20.5	41.0	100%	41.0	-
13	22.9	17.7	40.6	(8.8)	-	31.8	N/A	5.0	35.7
14	1.1	-	1.1	-	-	1.1	N/A	0.1	1.0
14.1 (ECE)	14.3	0.1	14.4	(0.0)	0.0	14.4	7%	1.0	13.4
14.1 (Post-2017)	12.3	10.4	22.7	(5.2)	5.2	22.7	5%	1.1	21.5
17	24.9	-	24.9	-	-	24.9	8%	2.0	22.9
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	2.4	-	2.4	-	-	2.4	30%	0.7	1.7
47	4,141.8	733.8	4,875.7	(366.9)	366.9	4,875.7	8%	390.2	4,485.5
50	0.8	1.6	2.4	(0.8)	0.8	2.4	55%	1.3	1.1
Total CCA	**5,824.7**	**990.1**	**6,814.7**	**(495.0)**	**486.2**	**6,805.9**		**575.2**	**6,239.6**

Less CCA not in rates	(5.4)
Total CCA for RR	569.8
CCA in prefiled (E-09-02)	558.6
Additional CCA	11.2
Increase in CCA (Tax Effected)	**3.0**

2025 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,265.8	47.8	1,313.6	(23.9)	23.9	1,313.6	4%	52.5	1,261.1
2	138.5	-	138.5	-	-	138.5	6%	8.3	130.2
3	8.3	-	8.3	-	-	8.3	5%	0.4	7.9
6	11.5	-	11.5	-	-	11.5	10%	1.1	10.3
7	0.9	-	0.9	-	-	0.9	15%	0.1	0.8
8	168.1	101.5	269.6	(50.8)	50.8	269.6	20%	53.9	215.7
9	0.6	-	0.6	-	-	0.6	25%	0.1	0.4
10	63.1	38.9	101.9	(19.4)	19.4	101.9	30%	30.6	71.3
12	-	91.6	91.6	(45.8)	45.8	91.6	100%	91.6	-
13	35.7	12.8	48.5	(6.4)	-	42.1	N/A	6.4	42.0
14	1.0	-	1.0	-	-	1.0	N/A	0.1	0.8
14.1 (ECE)	13.4	0.1	13.5	(0.0)	0.0	13.5	7%	0.9	12.6
14.1 (Post-2017)	21.5	8.9	30.4	(4.4)	4.4	30.4	5%	1.5	28.9
17	22.9	-	22.9	-	-	22.9	8%	1.8	21.1
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	1.7	-	1.7	-	-	1.7	30%	0.5	1.2
47	4,485.5	872.8	5,358.4	(436.4)	436.4	5,358.4	8%	428.9	4,929.5
50	1.1	4.4	5.5	(2.2)	2.2	5.5	55%	3.0	2.5
Total CCA	**6,239.6**	**1,178.7**	**7,418.3**	**(589.4)**	**583.0**	**7,412.0**		**682.0**	**6,736.3**
							Less CCA not in rates	(5.1)	
							Total CCA for RR	676.9	
							CCA in prefiled (E-09-02)	657.8	
							Additional CCA	19.1	
							Increase in CCA (Tax Effected)	**5.1**	

2026 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,261.1	29.7	1,290.8	(14.8)	14.8	1,290.8	4%	51.6	1,239.2
2	130.2	-	130.2	-	-	130.2	6%	7.8	122.4
3	7.9	-	7.9	-	-	7.9	5%	0.4	7.5
6	10.3	-	10.3	-	-	10.3	10%	1.0	9.3
7	0.8	-	0.8	-	-	0.8	15%	0.1	0.7
8	215.7	91.7	307.4	(45.8)	45.8	307.4	20%	61.5	245.9
9	0.4	-	0.4	-	-	0.4	25%	0.1	0.3
10	71.3	39.0	110.3	(19.5)	19.5	110.3	30%	33.1	77.2
12	-	69.9	69.9	(34.9)	34.9	69.9	100%	69.9	-
13	42.0	6.3	48.4	(3.2)	-	45.2	N/A	5.4	43.0
14	0.8	-	0.8	-	-	0.8	N/A	0.1	0.7
14.1 (ECE)	12.6	0.1	12.6	(0.0)	0.0	12.6	7%	0.9	11.8
14.1 (Post-2017)	28.9	6.0	34.9	(3.0)	3.0	34.9	5%	1.7	33.2
17	21.1	-	21.1	-	-	21.1	8%	1.7	19.4
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	1.2	-	1.2	-	-	1.2	30%	0.4	0.8
47	4,929.5	781.7	5,711.2	(390.8)	390.8	5,711.2	8%	457.1	5,254.1
50	2.5	3.4	5.9	(1.7)	1.7	5.9	55%	3.2	2.6
Total CCA	**6,736.3**	**1,027.8**	**7,764.1**	**(513.9)**	**510.7**	**7,760.9**		**696.1**	**7,068.0**
							Less CCA not in rates	(4.9)	
							Total CCA for RR	691.2	
							CCA in prefiled (E-09-02)	669.4	
							Additional CCA	21.8	
							Increase in CCA (Tax Effected)	**5.8**	

2027 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,239.2	53.9	1,293.1	(27.0)	27.0	1,293.1	4%	51.7	1,241.4
2	122.4	-	122.4	-	-	122.4	6%	7.3	115.0
3	7.5	-	7.5	-	-	7.5	5%	0.4	7.1
6	9.3	-	9.3	-	-	9.3	10%	0.9	8.4
7	0.7	-	0.7	-	-	0.7	15%	0.1	0.6
8	245.9	88.1	334.0	(44.0)	44.0	334.0	20%	66.8	267.2
9	0.3	-	0.3	-	-	0.3	25%	0.1	0.2
10	77.2	40.5	117.8	(20.3)	20.3	117.8	30%	35.3	82.4
12	-	63.1	63.1	(31.6)	31.6	63.1	100%	63.1	-
13	43.0	13.9	56.9	(6.9)	-	49.9	N/A	6.6	50.2
14	0.7	-	0.7	-	-	0.7	N/A	0.1	0.6
14.1 (ECE)	11.8	0.1	11.8	(0.0)	0.0	11.8	5%	0.6	11.3
14.1 (Post-2017)	33.2	9.4	42.5	(4.7)	4.7	42.5	5%	2.1	40.4
17	19.4	-	19.4	-	-	19.4	8%	1.6	17.9
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	0.8	-	0.8	-	-	0.8	30%	0.2	0.6
47	5,254.1	805.7	6,059.8	(402.9)	402.9	6,059.8	8%	484.8	5,575.0
50	2.6	3.1	5.8	(1.6)	1.6	5.8	55%	3.2	2.6
Total CCA	**7,068.0**	**1,077.9**	**8,145.9**	**(538.9)**	**532.0**	**8,139.0**		**725.0**	**7,420.9**
							Less CCA not in rates	(4.5)	
							Total CCA for RR	720.6	
							CCA in prefiled (E-09-02)	695.8	
							Additional CCA	24.7	
							Increase in CCA (Tax Effected)	**6.6**	

LOAD FORECAST UPDATE

1.0 OVERVIEW OF LOAD FORECAST UPDATE

As set out in Exhibits D-04-01 and D-05-01, Conservation and Demand Management (CDM) programs have a direct impact on electricity system demand. Consistent with the approach approved in Hydro One's prior transmission and distribution rate applications before the OEB, Hydro One's load forecast methodology relies upon CDM levels forecasted by the IESO as a key input. Hydro One's as-filed evidence explained that its load forecast reflected the then most current CDM forecast from the IESO, which was provided to Hydro One in February 2021 and was consistent with the IESO's 2020 Annual Planning Outlook (APO) issued in December 2020.[1]

In December 2021, the IESO issued its 2021 APO. The 2021 APO[2] contains materially higher forecasts for CDM in Ontario, averaging a 19% increase in CDM compared to the forecast used in the as-filed evidence over the test period (2023-2027). As a result of the change in the IESO's CDM forecast, from its 2020 APO to its 2021 APO, the CDM assumptions used to establish Hydro One's load forecasts for both transmission and distribution became outdated. Moreover, updating the CDM assumptions in Hydro One's load forecasts has a material impact on the load forecasts for both distribution and transmission, which must be taken into account to ensure that the billing determinants underpinning rates appropriately allow for recovery of Hydro One's approved rates revenue requirements.

Pursuant to Rule 11.02 of the OEB's *Rules of Practice and Procedure,* Hydro One is obligated to amend its evidence to reflect new information that constitutes a material change to the evidence already before the OEB in the Application. Hydro One has therefore updated its transmission and distribution load forecasts to reflect the IESO's new CDM forecasts. Specifically, Hydro One's load forecasts have been updated to reflect the IESO's December 2021 CDM figures, as well as the

[1] Exhibit D-04-01, p. 4.
[2] Annual Planning Outlook, Ontario's electricity system needs: 2023-2042, December 2021.

IESO's updated hourly pattern of CDM as set out in the December 2021 APO.[3] The new hourly pattern accounts for differences between leap year and non-leap year, affecting the 12-month average CDM for peak. The updated transmission and distribution load forecasts were prepared using the same methodology outlined in Exhibits D-04-01 and D-05-01, respectively.

Overall, the update to Hydro One's load forecasts results in an average reduction of 1.2% to the transmission forecast and an average reduction of 1.9% to the distribution load forecast over the 2023 to 2027 period. These changes put upward pressure on both transmission and distribution rates. This is because the rates need to be adjusted upwards to account for the revenue deficiency caused by the reduction in charge determinants in order for Hydro One to be able to recover its revenue requirement. The transmission revenue deficiency attributed to the change in transmission load forecast totals $122.8M over the 2023 to 2027 period. The distribution revenue deficiency attributed to the change in distribution load forecast totals $52.9M over the 2023 to 2027 period.

Hydro One recognizes that our customers will be experiencing inflationary pressures and is proposing to maintain as-filed customer rate impacts by deferring, to the next rate period, the approved revenue requirements associated with the revenue deficiencies attributed to the changes in the transmission and distribution load forecasts to reflect the IESO's updated CDM assumptions. For each of transmission and distribution, the approved revenue requirement equal to the revenue deficiency from the load forecast update will be recorded in a newly proposed deferral account (tracked in a separate sub-account from amounts related to the inflation update) for recovery commencing in 2028. As a result, there will be no material changes to the proposed transmission or distribution rate impacts for 2023 to 2027 due to the proposed load forecast updates.

[3] Hydro One has also made a minor modification to the manual adjustments to its load forecast as detailed in the updated response to JT-VECC-TCQ-4 which was filed concurrently with and as part of this evidence update.

1.1 TRANSMISSION

The IESO's new forecast CDM savings from energy were converted to peak using the same methodology discussed in the as-filed evidence. The updated CDM forecast from the 2021 APO was reflected in Hydro One's Transmission load forecast, which resulted in a lower net forecast for transmission charge determinants compared to the forecast used in the as-filed evidence as presented in Table 1 below.

Table 1 - Hydro One's 2023-2027 Load Forecast
(12-Month Average Peak in MW)

Year	Ontario Demand		Hydro One Rate Categories (Charge Determinants)					
			Network		Line Connection		Transformation Connection	
	As Filed	Updated	As Filed	Updated	As Filed	Updated	As Filed	Updated
2023	19,451	19,416	19,252	19,218	18,689	18,655	15,898	15,869
2024	19,527	19,414	19,327	19,215	18,761	18,653	15,959	15,868
2025	19,547	19,303	19,347	19,106	18,780	18,548	15,975	15,778
2026	19,584	19,191	19,384	18,995	18,816	18,441	16,006	15,687
2027	19,607	19,238	19,406	19,042	18,837	18,486	16,024	15,725

Exhibit reference: Exhibit D-04-01, Table 1

The updated peak and 12-month average peak CDM figures are presented in Table 2. A two-step process was used to update the CDM figures. First, the 12-month average peak was updated for all years using the latest load profile from the IESO, which distinguishes between leap years and non-leap years. Peak values are not affected by this step. Second, for the years 2019 to 2027, both peak and 12-month average peak values were scaled by the latest forecast of energy savings from CDM in the 2021 APO over the forecast of energy savings from CDM used in the as-filed evidence. This leaves the load factor intact, as the ratio of average hourly energy savings to maximum hourly energy savings in each year.

Table 2 - Load Impact of CDM on Ontario Demand (MW)

Year	Cumulative CDM Impact on Peak Demand *	Cumulative CDM Impact on 12-month Average Peak Demand **
2006	289	209
2007	778	561
2008	893	644
2009	997	720
2010	1,167	842
2011	1,318	971
2012	1,470	1,091
2013	1,621	1,221
2014	1,820	1,360
2015	1,942	1,433
2016	2,167	1,646
2017	2,099	1,587
2018	2,391	1,853
2019	2,639	2,055
2020	2,648	2,073
2021	2,772	2,229
2022	2,912	2,397
2023	3,033	2,534
2024	3,085	2,587
2025	3,234	2,758
2026	3,423	2,946
2027	3,434	2,994

* The figures represent the load impact of CDM on summer peaks.
** The figures represent the load impact of CDM on monthly peaks, averaged over 12 months in the year.

Exhibit reference: D-04-01, Table 2

Table 3 below presents the forecast prepared for this evidence update before and after deducting the load impacts attributed to embedded generation and CDM for the period 2019 to 2027. The charge determinant forecast is based on the methodology approved by the OEB in its Decisions for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2016-0160 and EB-2019-0082.

Table 3 - Load Forecast Before and After Embedded Generation and CDM
(12-Month Average Peak in MW)

Year	Ontario Demand	Charge Determinant: Network Connection	Line Connection	Transformation Connection
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2019	22,244	22,130	21,339	18,209
2020	21,927	21,703	20,901	17,779
2021	22,171	21,945	21,118	17,964
2022	22,393	22,164	21,347	18,159
2023	22,623	22,391	21,566	18,345
2024	22,674	22,442	21,615	18,387
2025	22,734	22,501	21,672	18,435
2026	22,809	22,576	21,744	18,497
2027	22,906	22,671	21,836	18,575
Load Impact of Embedded Generation				
2019	613	610	476	406
2020	634	628	476	405
2021	671	664	493	419
2022	673	666	495	421
2023	673	666	495	421
2024	673	666	495	421
2025	673	666	495	421
2026	673	666	495	421
2027	673	666	495	421
Load Impact of CDM				
2019	2,055	2,045	1,983	1,692
2020	2,073	2,052	1,989	1,692
2021	2,229	2,206	2,123	1,806
2022	2,397	2,373	2,285	1,944
2023	2,534	2,508	2,415	2,055
2024	2,587	2,561	2,466	2,098
2025	2,758	2,730	2,629	2,236
2026	2,946	2,916	2,808	2,389
2027	2,994	2,964	2,855	2,428
Load Forecast after Deducting Embedded Generation and CDM				
2019	19,575	19,475	18,880	16,111
2020	19,219	19,023	18,435	15,682
2021	19,272	19,075	18,502	15,739
2022	19,323	19,126	18,567	15,794
2023	19,416	19,218	18,655	15,869
2024	19,414	19,215	18,653	15,868
2025	19,303	19,106	18,548	15,778
2026	19,191	18,995	18,441	15,687
2027	19,238	19,042	18,486	15,725

Note: All figures are weather-normal.

Exhibit reference: Exhibit D-04-01, Table 3

Table 4 below presents the upper and lower bands associated with one standard deviation for the charge determinant forecast.

Table 4 - One Standard Deviation Uncertainty Bands for Hydro One Transmission's Charge Determinants (12-Month Average Peak in MW)

Year	Lower Band	Forecast	Upper Band
Network			
2020 (Actual)	19,023	19,023	19,023
2021	18,770	19,075	19,383
2022	18,662	19,126	19,593
2023	18,704	19,218	19,730
2024	18,606	19,215	19,823
2025	18,370	19,106	19,839
2026	18,207	18,995	19,780
2027	18,099	19,042	19,981
Line Connection			
2020 (Actual)	18,435	18,435	18,435
2021	18,206	18,502	18,800
2022	18,116	18,567	19,020
2023	18,156	18,655	19,153
2024	18,061	18,653	19,243
2025	17,833	18,548	19,260
2026	17,676	18,441	19,203
2027	17,570	18,486	19,398
Transformation Connection			
2020 (Actual)	15,682	15,682	15,682
2021	15,487	15,739	15,993
2022	15,411	15,794	16,180
2023	15,445	15,869	16,292
2024	15,364	15,868	16,369
2025	15,170	15,778	16,383
2026	15,036	15,687	16,335
2027	14,946	15,725	16,501

Exhibit reference: Exhibit D-04-01, Table 4

Table 5 below provides year-over-year comparison of load weather-normalized over historical, bridge year (2019) and test years.

Table 5 - Comparison of Historical, Bridge-Year, and Test-Years Load Weather-Normalized (12-month average peak in MW)

			Charge Determinants					
Year	Ontario Peak	% Change	Network	% Change	Line Connection	% Change	Transformation Connection	% Change
2008	21,574	0.5	21,067	0.7	20,156	0.6	17,413	0.5
2009	21,340	-1.1	20,868	-0.9	19,796	-1.8	17,333	-0.5
2010	20,684	-3.1	20,330	-2.6	19,348	-2.3	16,839	-2.9
2011	20,547	-0.7	20,245	-0.4	19,417	0.4	16,769	-0.4
2012	20,348	-1.0	20,086	-0.8	19,298	-0.6	16,645	-0.7
2013	20,360	0.1	20,220	0.7	19,322	0.1	16,606	-0.2
2014	20,554	1.0	20,601	1.9	19,626	1.6	16,819	1.3
2015	20,203	-1.7	20,236	-1.8	19,576	-0.3	16,731	-0.5
2016	20,274	0.4	20,245	0.0	19,540	-0.2	16,715	-0.1
2017	19,696	-2.8	19,705	-2.7	19,100	-2.3	16,306	-2.4
2018	19,657	-0.2	19,678	-0.1	19,137	0.2	16,329	0.1
2019	19,575	-0.4	19,475	-1.0	18,880	-1.3	16,111	-1.3
2020	19,219	-1.8	19,023	-2.3	18,435	-2.4	15,682	-2.7
2021	19,272	0.3	19,075	0.3	18,502	0.4	15,739	0.4
2022	19,323	0.3	19,126	0.3	18,567	0.4	15,794	0.4
2023	19,416	0.5	19,218	0.5	18,655	0.5	15,869	0.5
2024	19,414	0.0	19,215	0.0	18,653	0.0	15,868	0.0
2025	19,303	-0.6	19,106	-0.6	18,548	-0.6	15,778	-0.6
2026	19,191	-0.6	18,995	-0.6	18,441	-0.6	15,687	-0.6
2027	19,238	0.2	19,042	0.2	18,486	0.2	15,725	0.2

Exhibit reference: Exhibit D-04-01, Appendix G

1.2 DISTRIBUTION

Hydro One derives its distribution energy savings from the transmission energy savings provided by the IESO. Consequently, the distribution energy savings in this update have increased along with the increase in the transmission energy savings in the 2021 APO. Using the same methodology as described in Exhibit D-05-01, and taking into account the higher forecasted CDM from the 2021 APO, has resulted in a reduction to Hydro One's Distribution load forecast. Below, Hydro One provides a number of updated tables which reflect the updated CDM forecast. Hydro One's updated distribution load is shown in Table 6. The customer count forecast was not affected by the change in CDM.

Table 6 - Hydro One Distribution Load and Number of Customers

Year	GWh Delivered Forecast		Distribution
	As Filed	Updated	Customer Count
2021	34,785	34,653	1,333,269
2022	34,907	34,677	1,343,110
2023 *	35,854	35,522	1,413,905
2024 *	35,974	35,497	1,424,106
2025 *	36,090	35,400	1,434,135
2026 *	36,202	35,273	1,443,532
2027 *	36,312	35,379	1,452,813

* The figures include the impact of integrating Acquired Utilities into Hydro One Distribution.

Exhibit reference: D-05-01, Table 3

The updated CDM impact assumed in Hydro One's distribution system load forecast is presented in Table 7 below. The CDM figures for all years are consistent with the IESO's 2021 APO.

Table 7 - CDM Impact on Hydro One Distribution Load (GWh)

Year	Retail Customers	ST Customers		Total
		Direct	LDC	
2019	2,464	273	1,193	3,929
2020	2,513	286	1,187	3,986
2021	2,735	305	1,292	4,332
2022	2,950	330	1,394	4,675
2023*	3,348	379	1,493	5,220
2024*	3,497	396	1,560	5,453
2025*	3,668	415	1,636	5,719
2026*	3,842	436	1,713	5,991
2027*	3,993	457	1,781	6,231

Note. All figures are weather-normal.
* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

Exhibit reference: Exhibit D-05-01, Table 4

Table 8 below presents the load forecast before and after deducting the impact of CDM.

Table 8 - Hydro One Distribution Load Forecast Before and After Deducting CDM Impact (GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2019	21,670	17,260	38,930
2020	21,661	16,997	38,658
2021	21,842	17,143	38,985
2022	22,047	17,304	39,351
2023 *	23,377	17,364	40,741
2024 *	23,487	17,463	40,950
2025*	23,575	17,544	41,119
2026*	23,649	17,615	41,264
2027*	23,838	17,772	41,610
Load Impact of CDM			
2019	2,464	1,466	3,929
2020	2,513	1,473	3,986
2021	2,735	1,597	4,332
2022	2,950	1,724	4,675
2023 *	3,348	1,872	5,220
2024 *	3,497	1,956	5,453
2025*	3,668	2,051	5,719
2026*	3,842	2,149	5,991
2027*	3,993	2,238	6,231
Load Forecast After Deducting Impact of CDM			
2019	19,207	15,794	35,001
2020	19,149	15,524	34,673
2021	19,107	15,546	34,653
2022	19,097	15,580	34,677
2023 *	20,029	15,492	35,522
2024 *	19,990	15,507	35,497
2025*	19,907	15,493	35,400
2026*	19,807	15,466	35,273
2027*	19,845	15,534	35,379

Note. All figures are weather-normal.
* Includes Acquired Utilities.

Exhibit reference: Exhibit D-05-01, Table 5

Since the forecast is weather-normal, the actual load could be below or above the forecast depending on the weather conditions and/or a different economic growth pattern. Table 9 below presents the upper and lower bands of one standard deviation for the Hydro One Distribution system load forecast. Based on historical data, there is a two-in-three chance that the actual load over the forecast years (2021-2027) will fall within the upper and lower bands. The bands are derived using a Monte Carlo simulation technique relating variations in load to variations in Ontario GDP and weather.

Table 9 - One Standard Deviation Uncertainty Bands for Hydro One Distribution Load (GWh)

Year	Lower Bound	Forecast	Upper Bound
2020	34,673	34,673	34,673
2021	33,971	34,653	35,325
2022	33,809	34,677	35,551
2023	34,498	35,522	36,548
2024	34,223	35,497	36,766
2025	33,897	35,400	36,929
2026	33,466	35,273	37,112
2027	33,200	35,379	37,597

Exhibit reference: Exhibit D-05-01, Table 6

Year-over-year changes on load during the historical and forecast period are presented in Table 10, below.

Table 10 - Hydro One Distribution Load History and Forecast in GWh

Year	Actual/Forecast GWh	% Change	Normalized Weather GWh	% Change
2015	36,686	-2.9	36,419	-1.8
2016	35,856	-2.3	36,139	-0.8
2017	35,101	-2.1	35,426	-2.0
2018	35,846	2.1	34,023	-4.0
2019	36,738	2.5	35,001	2.9
2020	37,029	0.8	34,673	-0.9
2021	34,653	-6.4	34,653	-0.1
2022	34,677	0.1	34,677	0.1
2023*	35,522	2.4	35,522	2.4
2024*	35,497	-0.1	35,497	-0.1
2025*	35,400	-0.3	35,400	-0.3
2026*	35,273	-0.4	35,273	-0.4
2027*	35,379	0.3	35,379	0.3

* Includes Acquired Utilities.

Exhibit reference: Exhibit D-05-01, Table E.4

Detailed tables for actual and weather-normalized total load, energy and peak by rate class are provided in Tables 11 to 14, below. Consistent with the methodology outlined in the as-filed evidence, the peak forecast for each rate class is derived from the corresponding sales forecast using a load factor. Results by rate class in Tables 11 to 14 reflect changes due to customer classification[4] and continuation of these changes over the years 2021 to 2027, as discussed in Exhibit L-01-02 of the Application.

[4] See Exhibit G-01-02-01 of Hydro One's distribution application, EB-2013-0416.

Table 11 - Actual Sales and Forecast in GWh

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generator	16	17	26	29	29	28	29	29	30	31	31	32	33
General Service - Demand Billed	2,394	2,343	2,482	2,542	2,447	2,364	2,186	2,182	2,164	2,156	2,143	2,128	2,129
General Service - Energy Billed	2,189	2,132	2,239	2,322	2,329	2,222	2,039	2,021	1,978	1,957	1,932	1,905	1,892
Residential - Medium Density	4,930	4,851	4,596	4,927	4,954	5,101	4,746	4,771	5,041	5,057	5,060	5,060	5,096
Residential - Low Density	4,767	4,614	4,418	4,783	4,832	4,902	4,514	4,497	4,788	4,763	4,726	4,687	4,681
Seasonal	671	641	594	711	647	698	638	631	0	0	0	0	0
Sub-transmission *	15,806	15,468	15,143	15,915	15,728	15,618	15,035	15,067	14,983	14,998	14,984	14,957	15,023
Urban General Service - Demand Billed	1,064	1,036	1,020	1,059	1,007	934	879	878	876	874	869	864	866
Urban General Service - Energy Billed	600	589	597	616	602	567	532	530	543	540	536	532	532
Urban Residential	1,983	1,947	1,833	1,994	1,946	2,100	1,956	1,970	2,008	2,019	2,026	2,030	2,050
Street Light *	122	122	100	89	84	79	78	78	83	82	81	80	80
Sentinel Light *	21	21	14	14	13	12	12	11	11	11	11	10	10
Unmetered Scattered Load *	24	24	29	29	30	31	31	31	32	33	33	33	33
Acquired Residential	301	300	297	342	328	348	330	338	336	334	332	330	327
Acquired General Service - Energy Billed	110	109	111	120	117	119	115	118	117	116	115	114	113
Acquired General Service - Demand Billed	235	237	267	271	242	238	229	233	231	229	227	225	223
Acquired Urban Residential	102	100	100	112	117	123	116	117	118	119	119	120	121
Acquired Urban General Service - Energy Billed	43	43	41	45	49	43	40	41	41	41	42	42	43
Acquired Urban General Service - Demand Billed	136	138	161	197	196	186	178	183	118	119	119	119	119
Sum: Includes Acquired Utilities for 2023-2027 only	34,586	33,804	33,093	35,028	34,647	34,656	32,674	32,697	33,500	33,478	33,387	33,269	33,370

* Includes Acquired Utilities corresponding figures in 2023 and 2027 only.

Exhibit reference: D-05-01, Table E.5

Table 12 - Weather Corrected Sales and Forecast in GWh

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generator	16	17	26	29	29	28	29	29	30	31	31	32	33
General Service - Demand Billed	2,373	2,368	2,515	2,407	2,260	2,194	2,186	2,182	2,164	2,156	2,143	2,128	2,129
General Service - Energy Billed	2,169	2,155	2,269	2,198	2,152	2,063	2,039	2,021	1,978	1,957	1,932	1,905	1,892
Residential - Medium Density	4,901	4,907	4,645	4,766	4,746	4,725	4,746	4,771	5,041	5,057	5,060	5,060	5,096
Residential - Low Density	4,738	4,668	4,464	4,627	4,629	4,541	4,514	4,497	4,788	4,763	4,726	4,687	4,681
Seasonal	667	648	600	687	620	647	638	631	0	0	0	0	0
Sub-transmission *	15,683	15,526	15,243	15,275	15,137	15,013	15,035	15,067	14,983	14,998	14,984	14,957	15,023
Urban General Service - Demand Billed	1,054	1,047	1,034	1,001	905	881	879	878	876	874	869	864	866
Urban General Service - Energy Billed	595	595	605	582	541	534	532	530	543	540	536	532	532
Urban Residential	1,971	1,969	1,852	1,948	1,867	1,943	1,956	1,970	2,008	2,019	2,026	2,030	2,050
Street Light *	122	122	100	89	84	79	78	78	83	82	81	80	80
Sentinel Light *	21	21	14	14	13	12	12	11	11	11	11	10	10
Unmetered Scattered Load *	24	24	29	29	30	31	31	31	32	33	33	33	33
Acquired Residential	299	300	300	333	315	322	330	338	336	334	332	330	327
Acquired General Service - Energy Billed	109	109	112	113	107	112	115	118	117	116	115	114	113
Acquired General Service - Demand Billed	233	237	270	256	220	223	229	233	231	229	227	225	223
Acquired Urban Residential	101	100	101	110	113	114	116	117	118	119	119	120	121
Acquired Urban General Service - Energy Billed	42	43	42	43	44	40	40	41	41	41	42	42	43
Acquired Urban General Service - Demand Billed	135	138	164	186	176	174	178	183	118	119	119	119	119
Sum: Includes Acquired Utilities for 2023-2027 only	34,334	34,068	33,397	33,650	33,013	32,691	32,674	32,697	33,500	33,478	33,387	33,269	33,370

* Includes Acquired Utilities corresponding figures in 2023 to 2027 only.

Exhibit reference: D-05-01, Table E.6

Tables 13 and 14 below represent the billing peak by demand-billed rate class. The billing peak forecast is derived from sales so that the ratio of energy to peak remains the same as in the as-filed evidence.[5]

Table 13 - Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2015	165,405	8,536,187	3,076,837	35,473,518	662,107	393,100	47,251,947
2016	171,973	8,118,010	2,846,792	33,699,203	665,454	397,953	44,835,978
2017	188,672	7,848,256	2,745,769	30,285,554	663,744	403,987	41,068,251
2018	196,614	7,528,602	2,640,406	28,829,784	627,455	577,262	39,195,406
2019	198,346	7,639,374	2,666,577	26,468,846	672,176	546,176	36,973,143
2020	192,801	7,248,717	2,457,504	31,360,107	666,224	525,155	41,259,129
2021	198,263	7,007,183	2,301,759	30,672,549	638,623	502,596	40,179,754
2022	203,923	6,992,726	2,294,267	30,739,442	651,472	514,709	40,230,359
2023	208,699	6,937,130	2,284,824	30,627,361	646,691	334,039	41,038,745
2024	213,944	6,911,301	2,273,615	30,657,357	640,641	334,225	41,031,084
2025	218,627	6,868,979	2,257,070	30,628,773	635,376	334,687	40,943,511
2026	223,062	6,821,354	2,238,837	30,574,766	629,258	334,742	40,822,018
2027	229,085	6,824,946	2,237,252	30,709,901	622,315	334,386	40,957,884

* The total and ST include corresponding Acquired Utilities figures and for only 2023 to 2027.

Exhibit reference: D-05-01, Table E.7a

Table 14 - Weather Corrected Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2015	165,405	8,484,670	3,058,267	35,259,430	658,111	390,728	46,967,772
2016	171,973	8,116,669	2,846,321	33,693,637	665,344	397,887	44,828,600
2017	191,621	7,970,925	2,788,685	30,758,917	674,118	410,301	41,710,148
2018	196,614	7,531,163	2,641,235	28,839,440	627,668	577,443	39,208,452
2019	198,346	7,432,859	2,600,591	30,918,505	654,005	532,660	41,150,301
2020	192,801	7,033,288	2,313,812	30,629,379	623,758	489,352	40,169,280
2021	198,263	7,007,183	2,301,759	30,672,549	638,623	502,596	40,179,754
2022	203,923	6,992,726	2,294,267	30,739,442	651,472	514,709	40,230,359
2023	208,699	6,937,130	2,284,824	30,627,361	646,691	334,039	41,038,745
2024	213,944	6,911,301	2,273,615	30,657,357	640,641	334,225	41,031,084
2025	218,627	6,868,979	2,257,070	30,628,773	635,376	334,687	40,943,511
2026	223,062	6,821,354	2,238,837	30,574,766	629,258	334,742	40,822,018
2027	229,085	6,824,946	2,237,252	30,709,901	622,315	334,386	40,957,884

* The total and ST include corresponding Acquired Utilities figures and for only 2023 to 2027.

Exhibit reference: D-05-01, Table E.7b

[5] This ratio is set out in interrogatory response D-VECC-054.

The updated CDM figures by rate class are presented in Table 15, below.

Table 15 - Hydro One Distribution CDM Impacts (GWh) by Rate Class

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
General Service - Demand Billed	295	345	399	433	438	450	493	533	570	598	629	661	687
General Service - Energy Billed	374	438	500	552	595	609	656	705	747	777	811	845	875
Residential - Medium Density	239	283	319	346	366	373	407	441	501	525	553	581	606
Residential - Low Density	231	269	307	336	357	358	387	416	476	495	516	538	557
Seasonal	32	37	41	50	48	51	55	58	0	0	0	0	0
Sub-transmission *	992	1,141	1,223	1,478	1,417	1,425	1,545	1,667	1,810	1,891	1,984	2,078	2,164
Urban General Service - Demand Billed	131	152	164	180	180	178	198	214	231	242	255	268	279
Urban General Service - Energy Billed	102	121	133	147	154	155	171	185	205	214	225	236	246
Urban Residential	96	114	127	140	144	153	168	182	200	210	221	233	244
Acquired Residential	25	27	30	33	35	35	39	42	45	47	49	51	53
Acquired General Service - Energy Billed	14	15	16	18	20	21	23	25	26	28	29	30	32
Acquired General Service - Demand Billed	30	32	37	40	41	42	45	49	52	55	57	60	62
Acquired Urban Residential	15	16	18	20	21	21	23	25	27	28	29	31	32
Acquired Urban General Service - Energy Billed	6	7	6	6	7	7	7	8	12	13	13	14	15
Acquired Urban General Service - Demand Billed	20	21	25	28	29	30	33	36	35	36	38	40	41
Sum: Includes Acquired Utilities for 2023-2027 only	2,492	2,901	3,214	3,662	3,699	3,752	4,078	4,401	4,936	5,158	5,409	5,666	5,894

* Includes Acquired Utilities corresponding figures in 2023 and 2027 only.

**Note: All savings are at end-use level.*
Exhibit reference: D-05-01, Table E.8

2.0 REVENUE DEFICIENCY ASSOCIATED WITH CHANGE IN LOAD FORECASTS

As discussed in Section 1.0, the update to Hydro One's load forecasts results in an average reduction of 1.2% to the forecast transmission charge determinants and an average reduction of 1.9% to the forecast distribution charge determinants over the 2023 to 2027 period. This change puts upward pressure on both transmission and distribution rates as they need to go up to account for the reduction in charge determinants in order for Hydro One to be able to recover its revenue requirement.

As noted in Section 1.0 above and discussed further in Exhibit O-01-04, in order to maintain as-filed rate impacts for its customers Hydro One proposes to defer rate recovery of a portion of its approved transmission and distribution revenue requirements equivalent to the revenue deficiency that arises from the change in transmission and distribution forecast charge determinants. For each of transmission and distribution, the incremental approved revenue requirement associated with the revenue deficiency from the load forecast update will be recorded in a newly proposed deferral account as set out in Exhibit O-01-04. The derivation of the revenue deficiencies associated with the changes in charge determinants for transmission and distribution are described in Sections 2.1 and 2.2, below. The deferred recovery mechanism is described in greater detail in Exhibit O-01-04.

2.1 TRANSMISSION

The transmission revenue deficiency, associated with the change in transmission charge determinants, is calculated by taking the percent change in total charge determinants, between the as-filed and the updated transmission load forecast outlined in this exhibit, and multiplying it by the as-filed rates revenue requirement in each of the forecast years. The resulting 2023 to 2027 transmission revenue deficiencies attributed to the change in load are set out in Table 16, below.

Table 16 - Transmission Revenue Deficiency Attributed to Change in Charge Determinants($M)

Forecast Period	Total Annual Charge Determinants (As Filed)*	Total Annual Charge Determinants (Updated)*	Change in Charge Determinants	Rates Revenue Requirement (As Filed)**	Transmission Revenue Deficiency Attributed to Change in Charge Determinants
	(A)	(B)	(C) = (A-B)/(B)	(D)	(E) = (C)*(D)
2023	646,068	644,906	0.18%	$1,806.8	**$3.3**
2024	648,572	644,836	0.58%	$1,883.1	**$10.9**
2025	649,228	641,174	1.26%	$1,973.1	**$24.8**
2026	650,461	637,461	2.04%	$2,087.2	**$42.6**
2027	651,213	639,032	1.91%	$2,165.5	**$41.3**
				TOTAL	**$122.8**

** See Table 1 for as-filed and updated 12-Month Average Charge Determinants.*
*** See Exhibit H-10-01 Table 2*

2.2 DISTRIBUTION

The distribution revenue deficiency, associated with the change in distribution charge determinants, is calculated as the difference in revenues that would be collected by the as-filed and the updated distribution charge determinants shown in Tables 12 and 14 of this exhibit. Revenues are calculated by multiplying the as-filed distribution rates by the charge determinants for each rates class. A detailed derivation of the revenue deficiency arising from the update to the distribution charge determinants for 2023-2027 is provided in Exhibit O-01-03-01.

Table 17 - Distribution Revenue Deficiency Attributed to Change in Charge Determinants ($M)

	2023	2024	2025	2026	2027	Total
Distribution Rates Revenues with As Filed Charge Determinants*	$1,585.7	$1,664.8	$1,738.5	$1,835.2	$1,918.8	
Distribution Rates Revenues with Updated Charge Determinants	$1,579.4	$1,657.5	$1,728.2	$1,821.1	$1,903.8	
Revenue Deficiency Attributed to Change in Charge Determinants	**$6.3**	**$7.3**	**$10.3**	**$14.0**	**$15.0**	**$52.9**

** Consistent with the as-filed rates revenue requirement for 2023-2027 (calculated using rounded distribution rates).*

DERIVATION OF DISTRIBUTION REVENUE DEFICIENCY ATTRIBUTED TO CHANGE IN LOAD

This exhibit has been filed separately in MS Excel.

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DEFERRED RECOVERY MECHANISM

1.0 OVERVIEW

In order to maintain as-filed rates for its customers, Hydro One is proposing to defer rate recovery of a portion of its transmission and distribution revenue requirements ultimately approved by the OEB (as part of the current proceeding) to a future period to account for the increase in revenue requirement resulting from the inflation update described in Exhibit O-01-02 and the deficiency resulting from the update to the transmission and distribution load forecasts described in Exhibit O-01-03. Therefore, relative to the Application as originally filed, customers will not be impacted by these two changes over the test period. As such, the proposed rates and bill impacts in Exhibits H and L as previously filed remain reflective of the impacts that customers will see with the update for inflation and load forecasts.

As noted in Section 2.5.1 of Exhibit O-01-02, Hydro One recognizes that customers are also experiencing inflationary pressures. To help mitigate affordability issues while dealing with extraordinary inflationary pressures, Hydro One is proposing that the OEB approve both (i) the incremental revenue requirements attributable to the inflation updates as part of Hydro One's total approved revenue requirements for each of Transmission and Distribution, and (ii) the deferred recovery of those incremental revenue requirements associated with the inflation update.

Similarly, as noted in Section 2.0 of Exhibit O-01-03 and also in recognition of cost pressures facing customers, Hydro One is proposing for each of transmission and distribution that the OEB approve both (i) the load forecasts inclusive of the updated CDM assumptions based on the latest IESO forecasts, and (ii) the deferred recovery of a portion of the approved revenue requirement equivalent to the revenue deficiency that arises from the change in transmission or distribution forecast charge determinants, as applicable. This is because the updates to CDM assumptions result in reductions to Hydro One's load forecasts, which puts upward pressure on transmission and distribution rates since rates need to increase to offset the reduction in charge determinants so that Hydro One can recover its revenue requirement even after the deferral of revenue requirement arising from the inflation update.

This Exhibit describes Hydro One's proposed mechanism and process to enable the deferred recovery of the increment to approved revenue requirements associated with the inflation update and the further adjustment to approved revenue requirements to account for the revenue deficiency arising from the updated load forecasts for each of transmission and distribution. This exhibit includes:

- The steps and approvals required for the deferred recovery mechanism (Section 2.0)
- The proposed new deferral accounts in which the amounts deferred for recovery, for transmission and distribution, will be recorded (Section 3.0)
- The approach to calculating the incremental revenue requirements associated with the inflation update (Section 4.0)
- The approach to calculating the incremental revenue requirements associated with the revenue deficiencies from the revised load forecasts (Section 5.0)
- Attachments, updated appendices and models (Section 6.0)

2.0 STEPS AND APPROVALS REQUIRED FOR DEFERRED RECOVERY

2.1 STEPS FOR DEFERRED RECOVERY

The following steps outline the process that Hydro One proposes that the OEB approve to implement the deferred recovery mechanism.

Step 1: As described in Section 2.3 of Exhibit O-01-02, Hydro One has applied the updated inflation forecast to the Transmission and Distribution capital and OM&A expenditures. The updated base revenue requirements (or total revenue requirement) for each of Transmission and Distribution form the basis of the OEB's review and approval in its Decision and Order in this proceeding, subject to confirmation and adjustment as set out in Section 2.5.2 of Exhibit O-01-02 at the time of the Draft Rate Order (DRO), as described in Step 3.

Step 2: Based on a comparison between the updated and approved base revenue requirements (as confirmed and adjusted, if necessary, at the time of the DRO review) and the revenue requirements based on as-filed 2% inflation assumptions for Transmission and Distribution, the incremental revenue requirements associated with the inflation update, as presented in Table 1 and Table 2 (based on the current inflation assumptions, to be updated at DRO), will be recorded in the proposed Inflation Updates Sub-accounts of the Transmission Approved Revenue Requirement Deferral Account and the Distribution Approved Revenue Requirement Deferral Account, as applicable, for recovery commencing in 2028. For greater certainty, the confirmation and adjustment for inflation at the time of the DRO review will be subject to a proposed inflation cap that is further described in Section 2.5.2 of Exhibit O-01-02.

Step 3: As described in Section 2.0 of Exhibit O-01-03, Hydro One proposes to defer recovery of a portion of the revenue requirement equivalent to the revenue deficiency that arises from the change in transmission and distribution forecast charge determinants. The final approved rates revenue requirements to be confirmed at the time of the DRO will be inclusive of the impact from all applicable deferral and variance accounts, and any other updates as determined to be necessary in the ordinary course of the DRO process. The revenue requirement shortfalls due to the load updates will be captured on an annual basis in the Load Shortfalls Sub-accounts of the Transmission Approved Revenue Requirement Deferral Account and the Distribution Approved Revenue Requirement Deferral Account for recovery commencing in 2028.

2.2 SUMMARY OF REQUESTED APPROVALS

In completing the above process, Hydro One requests that the OEB, in its Decision and Order, approve the following in relation to this Evidence Update:

a. The updated base revenue requirements, together with the incremental revenue requirements, from 2023 to 2027 for Transmission and Distribution due to the inflation update;
b. The updated load forecast and billing determinants for Transmission and Distribution;

c. The updated base revenue requirements, together with the incremental revenue requirements, from 2023 to 2027 for Transmission and Distribution due to the confirmation and adjustment for inflation at the time of the DRO;

d. The adjustments to the approved rates revenue requirements from 2023 to 2027 for Transmission and Distribution due to the revenue deficiencies arising from the load updates to be flowed through at the time of DRO; and

e. Establishment of the proposed Transmission Approved Revenue Requirement Deferral Account and Distribution Approved Revenue Requirement Deferral Account, based on the Draft Accounting Orders included in Attachments 1 and 2.

In conjunction with the foregoing, at the time of the DRO, Hydro One would do the following:

a. Confirm and adjust, if necessary, the inflation forecasts as outlined in section 2.5.2 of Exhibit O-01-02;

b. Flow through all other adjustments as required in the ordinary course of the DRO process; and

c. Flow through the impacts of the load updates to re-calculate final rates.

3.0 APPROVED REVENUE REQUIREMENT DEFFERAL ACCOUNTS

To record the incremental approved transmission and distribution revenue requirements resulting from the inflation update, and to defer recovery of parts of the approved rates revenue requirements attributed to the changes in forecast billing determinants for transmission and distribution, Hydro One proposes to establish two new “Approved Revenue Requirement Deferral Accounts”, each with distinct Sub-accounts to track deferred amounts relating to the inflation update and the load forecast updates, as follows.

Hydro One Transmission requests approval to establish Account 1508 - Other Regulatory Assets, Sub-Account “Transmission Approved Revenue Requirement Deferral Account” to record incremental approved transmission revenue requirement for the 2023-2027 rate application term. This account would have two Sub-accounts:

1) Sub-Account, Inflation Updates – Used to record the incremental approved revenue requirement, including the full Regulatory Taxes, in an amount equal to the difference between the as-filed base revenue requirement and approved base revenue requirement arising from the inflation update for the 2023-2027 rate application term.

2) Sub-Account, Load Shortfalls – Used to record a portion of the approved rates revenue requirement, including the full Regulatory Taxes, equal to the revenue deficiency attributed to the change in forecast billing determinants for the 2023-2027 rate application term.

Hydro One Distribution requests approval to establish Account 1508 - Other Regulatory Assets, Sub-Account "Distribution Approved Revenue Requirement Deferral Account" to record incremental approved distribution revenue requirement for the 2023-2027 rate application term. This account would have two Sub-accounts:

1) Sub-Account, Inflation Updates – Used to record the incremental approved revenue requirement, including the full Regulatory Taxes, in an amount equal to the difference between the as-filed base revenue requirement and the approved base revenue requirement arising from the inflation update for the 2023-2027 rate application term.

2) Sub-Account, Load Shortfalls – Used to record a portion of the approved rates revenue requirement, including the full Regulatory Taxes, in an amount equal to the revenue deficiency attributed to the change in forecast billing determinants for the 2023-2027 rate application term.

Further details regarding the proposed accounts are set out in the Draft Accounting Orders for the Transmission Approved Revenue Requirement Deferral Account and the Distribution Approved Revenue Requirement Deferral Account, which are provided in Attachment 1 and Attachment 2, respectively.

Hydro One proposes that, commencing in 2028, it would recover the approved revenue requirements recorded in each of the sub-accounts of the two accounts (to be approved as part of the current application), along with applicable carrying costs.

In respect of the deferred recovery of approved revenue requirements attributable to the inflation update, this approach allows Hydro One to continue delivering the work program necessary to meet customer needs and expressed preferences (as discussed in Section 1.6 of the Systems Plans Framework), while avoiding exacerbating cost pressures on customers during the current period of extraordinary inflation. In respect of the deferred recovery of approved rates revenue requirements attributable to the updated CDM assumptions in the load forecasts, this approach allows Hydro One to recover its approved revenue requirements on a deferred basis, while further alleviating the cost pressures on its customers.

The establishment of each deferral account meets the OEB's requirements for causation, prudence and materiality.

Regarding causation, the amounts to be recorded in each of the accounts will clearly be outside of the base upon which the transmission and distribution rates proposed in the current Application are derived for the 2023-2027 period. This is because the amounts to be recorded will consist of amounts from the approved revenue requirements, for which recovery is proposed to be deferred by excluding such amounts from the calculation of rates during the 2023 to 2027 rate period.

Regarding prudence, the amounts to be recorded in the Inflation Sub-accounts for Transmission and Distribution meet this eligibility criterion because recovery of the incremental approved revenue requirements associated with the inflation updates are required in order for Hydro One to accomplish the outcomes and achieve the intended benefits of its proposed investment plans as originally proposed, based on customer needs and preferences, under the prior inflation assumptions. The amounts to be recorded in the proposed Load Shortfalls Sub-accounts for

Transmission and Distribution meet this eligibility criterion because recovery of the revenue deficiencies due to changes in load is required in order to ensure that Hydro One is able to recover the full revenue requirements as approved by the OEB in the current proceeding for Transmission and Distribution.

Regarding materiality, in accordance with the OEB's Transmission Filing Requirements,[1] Hydro One Transmission's materiality threshold is $3M and in accordance with the OEB's Distribution Filing Requirements,[2] Hydro One Distribution's materiality threshold is $1M. The amounts to be recorded in the deferral accounts will clearly be material as they are well in excess of the $3M and $1M materiality thresholds.

4.0 INCREMENTAL REVENUE REQUIREMENTS ATTRIBUTED TO INFLATION UPDATE

Table 1 for Transmission and Table 2 for Distribution, below, summarize the incremental revenue requirements that Hydro One is proposing to record for each of the 2023 to 2027 test years in the Inflation Updates Sub-accounts, within each of the Transmission Approved Revenue Requirement Deferral Account and the Distribution Approved Revenue Requirement Deferral Account, as applicable. Section 5.0 of Exhibit O-01-02 provides further explanations regarding the differences in revenue requirement as a result of inflation by each of the components, including the Revenue Requirement Workforms in support of the updated 2023 to 2027 revenue requirements.

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[1] Chapter 2 of the OEB's Filing Requirements for Electricity Transmission Applications (February 11, 2016), Section 2.1.1

[2] Chapters 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (June 24, 2021), Section 2.0.8

Table 1 - Transmission Deferred Revenue Requirement from Inflation Update, 2023-2027 ($M)

Description	Forecast Period				
	2023	2024	2025	2026	2027
Transmission Revenue Requirement (As-Filed Evidence)	1,823.2	1,937.8	2,027.5	2,140.3	2,219.0
Transmission Revenue Requirement (Inflation Update)	1,849.3	1,968.2	2,063.0	2,182.5	2,266.6
Variance (Incremental Revenue Requirement Due to Inflation)	**26.1**	**30.4**	**35.5**	**42.2**	**47.6**

Table 2 - Distribution Deferred Revenue Requirement from Inflation Update, 2023-2027 ($M)

Description	Forecast Period				
	2023	2024	2025	2026	2027
Distribution Revenue Requirement (As-Filed Evidence)	1,632.4	1,711.3	1,785.1	1,881.1	1,965.0
Distribution Revenue Requirement (Inflation Update)	1,669.1	1,753.3	1,832.2	1,934.8	2,024.6
Variance (Incremental Revenue Requirement Due to Inflation)	**36.7**	**42.0**	**47.2**	**53.7**	**59.7**

As further outlined in Section 2.5.2 of Exhibit O-01-02, Hydro One proposes that at the time of the DRO it will update the revenue requirements for which it seeks approval, for each of Transmission and Distribution, based on the actual or most recent inflation forecast for 2022 and 2023, which would then be applied to the final approved Capital and OM&A plans. At that time, the incremental revenue requirement arising from the difference in inflation assumptions (i.e. the final inflation rate confirmed at the DRO process and the 2.0% original inflation rate used in the plan per year) will be recorded in the Inflation Updates Sub-accounts, within the Transmission Approved Revenue Requirement Deferral Account or the Distribution Approved Revenue Requirement Deferral Account, as applicable.

Additionally, in accordance with the normal process for the DRO, Hydro One intends to update the Transmission and Distribution revenue requirements to flow through the impacts of the OEB-approved inflation factors for Transmission and Distribution, the cost of capital (as described in Exhibit F-01-01), the full regulatory tax related revenue requirement impact, and any other aspects of the OEB's Decision, as appropriate.

5.0 DEFERRED REVENUE REQUIREMENTS ASSOCIATED WITH REVENUE DEFICIENCIES ATTRIBUTED TO REVISED LOAD FORECASTS

Table 3 for Transmission and Table 4 for Distribution, below, summarize the deferred revenue requirements that Hydro One is proposing to record for each of the 2023 to 2027 test years in the Load Shortfalls Sub-accounts, within each of the Transmission Approved Revenue Requirement Deferral Account and the Distribution Approved Revenue Requirement Deferral Account, as applicable. Section 2.0 of Exhibit O-01-03 describes how these amounts were derived.

Table 3 - Transmission Deferred Revenue Attributed to Change in Load ($M)

Description	Forecast Period				
	2023	2024	2025	2026	2027
Transmission Deferred Revenue Attributed to Change in Load	3.3	10.9	24.8	42.6	41.3

Table 4 - Distribution Deferred Revenue Attributed to Change in Load ($M)

Description	Forecast Period				
	2023	2024	2025	2026	2027
Distribution Deferred Revenue Attributed to Change in Load	6.3	7.3	10.3	14.0	15.0

The final deferred revenue attributed to the changes in load, to be approved by the OEB for each of Transmission and Distribution at the time of the DRO, will be calculated based on the final rates revenue requirements and load forecasts approved at the time of the DRO.

6.0 ATTACHMENTS, UPDATED APPENDICES AND MODELS

The following attachments are provided as part of this section:

- Attachment 1 – Draft Accounting Order (Transmission Approved Revenue Requirement Deferral Account)
- Attachment 2 – Draft Accounting Order (Distribution Approved Revenue Requirement Deferral Account)

HYDRO ONE TRANSMISSION DRAFT ACCOUNTING ORDER
ACCOUNT 1508 – OTHER REGULATORY ASSETS, SUB-ACCOUNT "TRANSMISSION APPROVED REVENUE REQUIREMENT DEFERRAL ACCOUNT"

Hydro One Transmission proposes the establishment of a new Account 1508 - Other Regulatory Assets, Sub-Account "Transmission Approved Revenue Requirement Deferral Account" to record incremental approved revenue requirement, including the full Regulatory Taxes, not collected during the 2023-2027 rate application term.

The Transmission Approved Revenue Requirement Deferral Account shall have two sub-accounts:

1) Sub-Account, Inflation Updates
    a. This account shall record the incremental approved revenue requirement, including the full Regulatory Taxes, in an amount equal to the difference between the as-filed base revenue requirement and approved base revenue requirement arising from the inflation update for the 2023-2027 rate application term.

2) Sub-Account, Load Shortfalls
    a. This account shall record the portion of approved rates revenue requirement, including the full Regulatory Taxes, equal to the revenue deficiency attributed to the change in forecast billing determinants for the 2023-2027 rate application term.

The accounts will be established as follows:

1) Account 1508, Other Regulatory Assets – "Transmission Approved Revenue Requirement Deferral Account", Sub-Account "Inflation Updates" effective January 1, 2023.

2) Account 1508, Other Regulatory Assets – "Transmission Approved Revenue Requirement Deferral Account", Sub-Account "Load Shortfalls" effective January 1, 2023.

Hydro One Transmission will record interest on the balance in the sub-accounts using the simple interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the accounts until the balances are fully disposed.
The following outlines the proposed accounting entries for these deferral accounts.

<u>Account 1508, Other Regulatory Assets – "Transmission Approved Revenue Requirement Deferral Account", Sub-Account "Inflation Updates"</u>

USofA #	Account Description
DR. 1508	Other Regulatory Assets – “Transmission Approved Revenue Requirement Deferral Account”, Sub-Account “Inflation Updates”
CR. 4110	Transmission Services Revenues[1]

Initial entry to record the incremental approved revenue requirement, including taxes, in an amount equal to the difference between the as-filed base revenue requirement and approved base revenue requirement arising from the inflation update for the 2023-2027 rate application term.

USofA #	Account Description
DR. 1508	Other Regulatory Assets – “Transmission Approved Revenue Requirement Deferral Account”, Sub-Account “Inflation Updates”
CR. 6035	Other Interest Expense

To record interest improvement on the principal balance of the Transmission Approved Revenue Requirement Deferral Account, Sub-Account “Inflation Updates”

Account 1508, Other Regulatory Assets – “Transmission Approved Revenue Requirement Deferral Account”, Sub-Account “Load Shortfalls”

USofA #	Account Description
DR. 1508	Other Regulatory Assets – “Transmission Approved Revenue Requirement Deferral Account”, Sub-Account “Load Shortfalls”
CR. 4110	Transmission Services Revenues [2]

Initial entry to record the portion of approved rates revenue requirement, including taxes, equal to the revenue deficiency attributed to the change in forecast billing determinants for the 2023-2027 rate application term.

USofA #	Account Description
DR. 1508	Other Regulatory Assets – “Transmission Approved Revenue Requirement Deferral Account”, Sub-Account “Load Shortfalls”
CR. 6035	Other Interest Expense

To record interest improvement on the principal balance of the Transmission Approved Revenue Requirement Deferral Account, Sub-Account “Load Shortfalls”

[1] The offset to the proposed deferral account remains under review. If an update is required, Hydro One will prepare an updated draft accounting order at the Draft Rate Order stage.
[2] The offset to the proposed deferral account remains under review. If an update is required, Hydro One will prepare an updated draft accounting order at the Draft Rate Order stage.

HYDRO ONE DISTRIBUTION DRAFT ACCOUNTING ORDER
ACCOUNT 1508 – OTHER REGULATORY ASSETS, SUB-ACCOUNT "DISTRIBUTION APPROVED REVENUE REQUIREMENT DEFERRAL ACCOUNT"

Hydro One Distribution proposes the establishment of a new Account 1508 - Other Regulatory Assets, Sub-Account "Distribution Approved Revenue Requirement Deferral Account" to record incremental approved revenue requirement, including the full Regulatory Taxes, not collected during the 2023-2027 rate application term.

The Distribution Approved Revenue Requirement Deferral Account shall have two sub-accounts:

1) Sub-Account, Inflation Updates
   a. This account shall record the incremental approved revenue requirement, including the full Regulatory Taxes, in an amount equal to the difference between the as-filed base revenue requirement and approved base revenue requirement arising from the inflation update for the 2023-2027 rate application term.

2) Sub-Account, Load Shortfalls
   a. This account shall record the portion of approved rates revenue requirement, including the full Regulatory Taxes, equal to the revenue deficiency attributed to the change in forecast billing determinants for the 2023-2027 rate application term.

The accounts will be established as follows:

1) Account 1508, Other Regulatory Assets – "Distribution Approved Revenue Requirement Deferral Account", Sub-Account "Inflation Updates" effective January 1, 2023.

2) Account 1508, Other Regulatory Assets – "Distribution Approved Revenue Requirement Deferral Account", Sub-Account "Load Shortfalls" effective January 1, 2023.

Hydro One Distribution will record interest on the balance in the sub-accounts using the simple interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the accounts until the balances are fully disposed.

The following outlines the proposed accounting entries for these deferral accounts.

<u>Account 1508, Other Regulatory Assets – "Distribution Approved Revenue Requirement Deferral Account", Sub-Account "Inflation Updates"</u>

USofA #	Account Description
DR. 1508	Other Regulatory Assets – “Distribution Approved Revenue Requirement Deferral Account”, Sub-Account “Inflation Updates”
CR. 4080	Distribution Services Revenues[1]

Initial entry to record the incremental approved revenue requirement, including taxes, in an amount equal to the difference between the as-filed base revenue requirement and approved base revenue requirement arising from the inflation update for the 2023-2027 rate application term.

USofA #	Account Description
DR. 1508	Other Regulatory Assets – “Distribution Approved Revenue Requirement Deferral Account”, Sub-Account “Inflation Updates”
CR. 6035	Other Interest Expense

To record interest improvement on the principal balance of the Distribution Approved Revenue Requirement Deferral Account, Sub-Account “Inflation Updates”

Account 1508, Other Regulatory Assets – “Distribution Approved Revenue Requirement Deferral Account”, Sub-Account “Load Shortfalls”

USofA #	Account Description
DR. 1508	Other Regulatory Assets – “Distribution Approved Revenue Requirement Deferral Account”, Sub-Account “Load Shortfalls”
CR. 4080	Distribution Services Revenues [2]

Initial entry to record the portion of approved rates revenue requirement, including taxes, equal to the revenue deficiency attributed to the change in forecast billing determinants for the 2023-2027 rate application term.

USofA #	Account Description
DR. 1508	Other Regulatory Assets – “Distribution Approved Revenue Requirement Deferral Account”, Sub-Account “Load Shortfalls”
CR. 6035	Other Interest Expense

To record interest improvement on the principal balance of the Distribution Approved Revenue Requirement Deferral Account, Sub-Account “Load Shortfalls”

[1] The offset to the proposed deferral account remains under review. If an update is required, Hydro One will prepare an updated draft accounting order at the Draft Rate Order stage.
[2] The offset to the proposed deferral account remains under review. If an update is required, Hydro One will prepare an updated draft accounting order at the Draft Rate Order stage.

UPDATE ON TRANSMISSION EXTERNAL REVENUES VARIANCE ACCOUNT

1.0 UPDATE ON TRANSMISSION EXTERNAL REVENUES VARIANCE ACCOUNT

As explained at the Technical Conference[1] and in response to Undertaking JT-4.13, Hydro One identified an inconsistency in the External Station Maintenance, E&CS and Other External Revenues amount provided in its responses to interrogatories (VECC 26 to 29). Upon identification of the inconsistency, Hydro One performed and has completed its analysis in respect of its calculation of Other External Revenues recorded in the "External Station Maintenance, E&CS and Other External Revenues variance account" over the 2013 to 2020 period for Hydro One Transmission. While a correcting entry was required for the historic period noted above, the findings of this review have no impact on the 2023 to 2027 revenue requirement, as the Transmission external revenue test year forecast remains accurate.

As noted above, Hydro One performed an internal review and identified that the External Station Maintenance, E&CS and Other External Revenues variance account balances from 2013 to 2020 were understated by $25.8M as noted in Table 1. The understatement is primarily due to the inadvertent exclusion of actual revenues related to internal work performed by Hydro One Transmission for its affiliates, including Hydro One Distribution and Acronym (formerly Hydro One Telecom). As an outcome of this internal review, Hydro One has taken the appropriate steps to correct for previously unreported amounts and ensure the completeness of the actual external revenues to be used in the calculation of the Transmission External Revenues variance accounts on a go-forward basis.

[1] Day 4 Technical Conference, December 16, 2021, p. 129, line 4

Table 1 - Historical Correcting Entry

Year	Total Adjustment (in $M)
Total Principal (2013-2020)	**(25.8)**
Accrued Interest 2013-2020	(1.4)
Total Recognized in 2021 (Principal and Interest)	(27.2)
Total Included in Rates Revenue Requirement (with projected carrying charges to Dec. 31, 2022)	**(27.5)**

The life-to-date credit adjustment of $27.2M recorded to the External Station Maintenance, E&CS and Other External Revenues variance account relating to the 2013 to 2020 years was subject to audit by KPMG, as part of their audit of the Hydro One Limited financial statements. Hydro One confirms that the 2021 calculation for the Transmission external revenues variance account, which has also been audited, has been performed correctly and recorded in 2021.

As part of this evidence update, Hydro One proposes to return $27.5M to customers as part of the 2023 Rates Revenue Requirement over a one-year period to be implemented at the time of the Draft Rate Order stage (DRO), by flowing through this life-to-date adjustment[2] within the External Station Maintenance, E&CS and Other External Revenues variance account. This will ensure that ratepayers receive the immediate benefit of this credit in 2023.

The total Transmission regulatory account balances requested for disposition in this Application have been updated to reflect an overall credit balance of $21.9M and will be reflected in the updated Uniform Transmission Rates at the time of the DRO.[3] A revised Transmission DVA Continuity Schedule has been filed at Exhibit G-01-05 Attachment 1 with this life-to-date adjustment included.

[2] Hydro One quantified and recognized a regulatory liability in the amount of $27.2M, which is comprised of $25.8M principal, and $1.4M of accrued interest from 2013–2020. With projected carrying charges for 2021 and 2022, a total credit balance of $27.5M amount is proposed to be returned to customers in 2023.
[3] Previously, a debit balance of $5.6M was proposed for disposition. Note that the other regulatory accounts requested for disposition remain over a five-year period as originally proposed.

To align with the approach determined in Hydro One's internal review, actual 2018 to 2020 Transmission External Revenues in the Other External Revenues category have been updated in Table 2 below to include internal work revenues within the Other External Revenues category. There were also minor corrections made to the Secondary Land Use and Stations Maintenance categories as an outcome of reviewing the groupings/classifications and completeness of the revenues.

Hydro One confirms that the findings from its review have no impact on the 2023 to 2027 revenue requirement, as the Transmission external revenue test year forecasts remain accurate.

Table 2 - Updated Transmission External Revenues ($M)*

	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Secondary Land Use	25.6	26.9	28.4	46.5	28.8	28.0	24.3	24.6	24.9	25.1
Station Maintenance	4.6	4.0	4.2	3.4	3.4	3.4	3.4	3.4	3.2	3.2
Engineering & Construction	0.1	0.1	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other External Revenues	10.0	9.5	11.4	8.7	7.2	8.4	8.2	8.1	7.8	8.6
Total	**40.3**	**40.5**	**44.2**	**59.0**	**39.8**	**40.1**	**36.2**	**36.5**	**36.2**	**37.3**

**Exhibit Reference: D-02-01, Table 1*

Based on the above corrections, there are revisions to certain historical actual figures noted in the interrogatory responses to VECC-026, VECC-027, VECC-028 and VECC-029, but the forecasts remain unchanged. Please refer to the above noted interrogatory responses appended with this update for details.

2.0 ATTACHMENTS, UPDATED APPENDICES AND MODELS

The following attachment is provided as part of this section:

- Attachment 1 – Transmission DVA Continuity Schedule (Exhibit G-01-05 Attachment 1)

UPDATE ON TRANSMISSION EXTERNAL REVENUES VARIANCE ACCOUNT

This exhibit has been filed separately in MS Excel.

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SCHEDULE OF UPDATED INTERROGATORIES AND UNDERTAKINGS

As part of this evidence update, Hydro One has updated key responses to interrogatories (IRRs) and undertakings (UTs) that have been affected by:

- the update to inflation assumptions as described in Exhibit O-01-02;
- the update to load forecast, as described in Exhibit O-01-03;
- the update to Transmission Revenues variance account as described in Exhibit O-01-05;
- and the disclosure of the 2021 productivity report at year end.

The updated IRRs and UTs are summarized in Table 1 below. Note that the scope of applicable inflation updates is limited to those IRRs and UTs where there is a material variance[1] over the 2023-2027 forecast period; where materiality is defined as per the OEB's Transmission and Distribution Filing Requirements. A detailed description of the inflationary update to the evidence is found in Section 2.3 of Exhibit O-01-02.

[1] Where the variance is the delta between the 'Inflation Update' amount and 'As-filed' amount.

Table 1 - Revised Schedule of IRRs and UTs

Revised IRRs/UTs	Inflation Update	Tx External Revenues Variance Account	Load Forecast Update	Productivity Monthly Report
I-01-A-Staff-005	X			
I-01-B2-Staff-066	X			
I-01-B2-Staff-085	X			
I-01-B2-Staff-095	X			
I-01-B3-Staff-138	X			
I-01-E-Staff-242	X			
I-03-B1-AMPCO-006	X			
I-03-B2-AMPCO-025	X			
I-03-B2-AMPCO-025-01	X			
I-03-B2-AMPCO-030	X			
I-03-B2-AMPCO-030-01	X			
I-03-B3-AMPCO-078	X			
I-03-B3-AMPCO-078-01	X			
I-03-B3-AMPCO-094	X			
I-06-E-CCC-025	X			
I-06-E-CCC-034	X			
I-06-G-CCC-040	X			
I-08-B2-Energy Probe-019	X			
I-08-B3-Energy Probe-031	X			
I-08-B3-Energy Probe-033	X			
I-08-B3-Energy Probe-038	X			
I-08-B3-Energy Probe-039	X			
I-08-B3-Energy Probe-043	X			
I-08-B4-Energy Probe-045	X			
I-08-B4-Energy Probe-047	X			
I-08-E-Energy Probe-065	X			
I-09-B2-ED-011	X			
I-09-B3-ED-024	X			
I-14-C-LPMA-011	X			
I-22-B1-SEC-046	X			
I-22-B2-SEC-078	X			
I-22-B2-SEC-081	X			
I-22-B2-SEC-089	X			
I-22-B2-SEC-092	X			
I-22-B2-SEC-092-01	X			
I-22-B2-SEC-094	X			
I-22-B2-SEC-094-01	X			
I-22-B2-SEC-095	X			
I-22-B2-SEC-095-01	X			
I-22-B2-SEC-107	X			
I-22-B2-SEC-107-01	X			

Revised IRRs/UTs	Inflation Update	Tx External Revenues Variance Account	Load Forecast Update	Productivity Monthly Report
I-22-B3-SEC-136	X			
I-22-B3-SEC-139	X			
I-22-B3-SEC-139-01	X			
I-22-B3-SEC-141	X			
I-22-B3-SEC-141-01	X			
I-22-B3-SEC-148	X			
I-22-B3-SEC-150	X			
I-22-B3-SEC-154	X			
I-22-B4-SEC-165	X			
I-22-B4-SEC-167	X			
I-22-B4-SEC-167-01	X			
I-22-C-SEC-175	X			
I-22-C-SEC-175-01	X			
I-24-B3-VECC-012	X			
I-24-D-VECC-026		X		
I-24-D-VECC-027		X		
I-24-D-VECC-028		X		
I-24-D-VECC-029		X		
I-24-D-VECC-036			X	
I-24-D-VECC-038			X	
I-24-D-VECC-040			X	
I-24-D-VECC-041			X	
I-24-D-VECC-043			X	
I-24-D-VECC-051			X	
I-24-D-VECC-052			X	
I-24-D-VECC-055			X	
I-24-D-VECC-056			X	
I-24-D-VECC-057			X	
I-24-E-VECC-069	X			
I-25-D-OSEA-003			X	
UNDERTAKING JT-3.02	X			
UNDERTAKING JT-3.20	X			
UNDERTAKING JT-4.07	X			
UNDERTAKING JT-4.29				X
UNDERTAKING JT-5.17	X			
UNDERTAKING JT-VECC-TCQ-04			X	
UNDERTAKING JT-VECC-TCQ-06			X	

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2021 ACTUALS UPDATE

This exhibit to be filed forthwith.

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A - OEB STAFF INTERROGATORY - 005

Reference:

Exhibit A-4-2
Exhibit A-4-3
Exhibit B-2-1
Exhibit B-3-1
Exhibit B-4-1

Preamble:

Hydro One has documented its planned capital projects for each year of the plan from 2023 to 2027 in each of its Transmission System Plan (TSP), Distribution System Plan (DSP) and General System Plan (GSP). General plant capex and capital additions in each year are allocated between Transmission and Distribution per Hydro One's proposed methodology.

OEB staff are interested in examining Hydro One's assumptions regarding inflation as factored into the capital budgets in the TSP, DSP and GSP, and hence reflected in the costs factored into Transmission and Distribution capital additions to rate base as shown in Table 1 of Exhibit A/Tab 4/Schedule 2 (Transmission) and Table 1 of Exhibit A/Tab 4/Schedule 3 (Distribution) relative to the assumed Transmission (Distribution) inflation index (Input Price Index).

Interrogatory:

a) Please confirm that, for both Transmission and Distribution, the rate base consists of mid-year or average in-service Net Fixed Assets, a working capital allowance plus an allocated portion of General Plant mid-year or average in-service Net Fixed Assets.

b) Please provide the assumed inflation factor in aggregate capital expenditures for each of:
   i. the TSP
   ii. the DSP
   iii. the GSP

   If different inflation assumptions are made for each year, please provide this information for each year of the plan.

c) Please provide a weighted average inflation factor for capital additions to the Transmission rate base shown in line 1 of Table 1 of Exhibit A/Tab 4/Schedule 2. This would be a weighted average of the TSP capex inflation provided in b) i. and the GSP capex inflation provided in b)

iii. above, with the weights being gross book value of Transmission capital additions for the year from the TSP and the gross book value of General Plant capital additions allocated to the Transmission rate base for that year. If the information is more easily available, Transmission capital expenditures and General Plant capital expenditures allocated to Transmission could be used as weights.

d) Please provide a weighted average inflation factor for capital additions to the Distribution rate base shown in line 1 of Table 1 of Exhibit A/Tab 4/Schedule 3. This would be a weighted average of the DSP capex inflation provided in b) ii. and the GSP capex inflation provided in b) iii. above, with the weights being gross book value of Distribution capital additions for the year from the DSP and the gross book value of General Plant capital additions allocated to the Distribution rate base for that year. If the information is more easily available, Distribution capital expenditures and General Plant capital expenditures allocated to Distribution could be used as weights.

Response:

a) Rate base is further explained in Exhibit C-01-01. Rate base includes a forecast of net fixed assets (including the allocated portion of Common General Plant Assets), calculated on a mid-year basis, plus a working capital allowance. Net fixed assets are calculated as gross plant in service minus accumulated depreciation and minus contributed capital. Working capital includes an allowance for cash working capital as well as materials and supplies inventory.

b) The assumed inflation escalation across the system plans is provided in the table below based on CPI projections at the time of the update, which is further described in Exhibit O-01-02. These assumptions are consistent across all system plans.

	2021	2022	2023	2024	2025	2026	2027
Inflation	3.5%	4.5%	3.3%	2.0%	2.0%	2.0%	2.0%

c) Please refer to part b) above.

d) Please refer to part b) above.

B2 - OEB STAFF INTERROGATORY - 066

Reference:

Exhibit B-2-1, TSP Section 2.9, Page 11

Preamble:

Based on Table 7 at the above reference, the average actual/forecast system renewal expenditure for 2018 – 2022 inclusive is $816.78 million. The planned average system renewal expenditure, for 2023-2027 inclusive is $1,239.84 million. This is a 51.8% increase in the five-year average.

Interrogatory:

a) Please explain why the proposed 51.8% increase in the five-year average system renewal expenditure is reasonable.

Response:

a) As detailed in the TSP, the System Renewal plan for 2023 to 2027 is underpinned by, and necessary to address, the verified condition of deteriorated and at-risk lines and stations assets (detailed in Section 2.2). Hydro One's System Renewal plan must be assessed at the investment and asset level and not period over period comparisons. Since the last transmission application, the population of poor condition assets has continued to exist or increased across major asset classes. As the asset fleet continues to deteriorate, based on verified condition assessments, Hydro One has undertaken prudent transmission system planning that reflects a rate of planned replacements that maintains the system's performance and reliability. Otherwise, increased failures of deteriorated equipment will lead to higher customer impacts from delivery point interruptions, escalated operational constraints/risk from the loss of supply paths, safety hazards for the public and employees, and/or potentially costly and protracted reactive repairs and replacements.

With asset condition serving as a primary basis for identifying investment needs, the overall year-over-year pacing of investments is also informed by other aspects of asset risk assessment including: criticality, performance, and obsolescence; feedback from a comprehensive two-phase customer engagement process; mandatory compliance and customer service obligations; as well as other relevant considerations and studies such as asset and system needs identified through regional planning and Hydro One's ability to execute the proposed System Renewal plan.

It is noteworthy that the proposed TSP does not address all known poor condition assets (and the associated risk) over the 5-year test period, nor does it seek to address new discoveries of poor condition assets from ongoing condition assessments over the test period. Through Hydro One's asset management and investment planning process, System Renewal investments have been selected and prioritized to target the work that most efficiently mitigates the most risk and yields the highest value for customers.

Notwithstanding that a period over period comparison is not appropriate as discussed above, the 2018 to 2022 period posed by the interrogatory is not the appropriate baseline to assess Hydro One's 2023-2027 System Renewal capital plan. As discussed below, the 2020-2022 period provides a more appropriate reference point, as it reflects the most recent OEB-approved System Renewal plan underpinned by asset and system needs/conditions that in large part continue to be relevant in this Application.

Hydro One's 2018 and 2019 System Renewal capital plan reflected planning considerations from 2016 (EB-2016-0160) that differed from the system needs that Hydro One considered in the 2020-2022 period or for the proposed 2023-2027 plan. Notably, certain critical investments in the 2020-2022 TSP (and continuing in the current plan) had not yet risen to a critical level of planning priority or matured into full execution in 2018 and 2019. This included investments to replace Air Blast Circuit Breakers and poor condition conductors, which were materially higher in the 2020-2022 plan than in the 2018 and 2019 plans and are continuing into the 2023-2027 period. Further, stations investments proposed and initiated as part of the 2020-2022 TSP are now in execution and remain ongoing during the 2023-2027 period, in addition to new renewal work that must be undertaken in 2023-2027 to address identified system and asset needs. Moreover, due to materially higher than expected System Access and System Service investments that are required in 2021 and 2022, Hydro One had to defer $200M in System Renewal investment to the 2023-2027 period (see C-VECC-018). These System Access and System Service investments were not a factor in the 2018 and 2019 time period.

Consequently, the 2020-2022 OEB-approved System Renewal expenditures (EB-2019-0082) provide a more appropriate reference point. The 2020-2022 OEB-approved System Renewal expenditures (along with 2023-2027 forecast for the current Application) are shown in the table below.

($Millions)	EB-2019-0082 (OEB Approved)[1]				EB-2021-0110 (Forecast Period)					
	2020	2021	2022	**Avg.**	2023*	2024*	2025*	2026*	2027*	**Avg.***
System Renewal	810.1	982.8	958.2	**917.0**	1,239.8	1,292.8	1,317.3	1,344.4	1,330.4	**1,304.9**

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

The proposed average annual System Renewal expenditure for 2023-2027 is 42.3% higher over the average annual approved System Renewal funding for 2020-2022. When normalizing the test period for inflation (indexing back to 2020), this percent difference is approximately 25%.[2]

[1] TSP Section 2.9, Table 3

[2] To determine the 25% difference, the 2020-2022 approved amounts have been normalized based on the original inflation assumptions, while the 2023-2027 amounts have been normalized based on the updated inflation assumptions. See Interrogatory I-1-Staff-005 part b) for further information.

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B2 - OEB STAFF INTERROGATORY - 085

Reference:

Exhibit B-2-1, TSP Section 2.11, T-SR-02, Page 1

Preamble:

As indicated in the Summary:

> This investment involves the replacement of all Air Blast Circuit Breakers (ABCBs) at Hydro One's transmission stations due to asset's poor condition, obsolescence, and poor performance. The primary trigger for the investment is significant reliability risk and high operation and maintenance costs. The investment is expected to increase reliability performance, reduce operation and maintenance costs, and decrease unplanned outages within major bulk transmission stations.

Interrogatory:

a) Please explain and quantify how Hydro One determined that spending $575 million dollars over the next five (5) years replacing ABCBs represents the optimal balance of capital spending pace vs. performance risk mitigation vs. OM&A costs to keep the targeted ABCB's in service.

b) Please quantify the risk associated with spending only half of this amount over the five (5) years and show how this increased risk exposure was calculated.

Response:

a) The pacing and prioritization ABCB investments over the 2023-2027 period was established through the asset management and investment planning processes, further detailed in TSP Section 2.7. The principal drivers of the investments are unacceptable reliability performance posing risks to continuous operation of bulk electricity system, high operation and maintenance costs and unavailability of spare parts and technical support due to asset obsolescence. The lack of available spare parts due to the obsolescence of the technology further constrains Hydro One's ability to maintain these assets to ensure that the appropriate level of reliability is maintained.

As further discussed in T-SR-02, Hydro One has ABCBs installed at critical transmission network stations that connect major nuclear and hydraulic generation plants and deliver power to major load centers in Ontario. These transmission network stations also enable international power flow to the states of New York and Michigan. There are seven generators connected through Hydro One's network stations with ABCBs with the total output of 13,707 MW of nuclear and hydro power generation. Any forced outages at these critical transmission stations due to ABCB failures may adversely impact and/or constrain generation resources, and lessen the reliability of bulk power flows to load centers. In the case of nuclear generating plants, a forced outage can cause supply interruptions to the station service transformers and/or the loss of production. For example, any unplanned outage as result of failed ABCBs at:

- Cherrywood TS, may affect both Darlington and Pickering Nuclear Generation output;
- Bruce TS, may affect Bruce Nuclear output;
- Beck TS, may affect OPG's Niagara Hydro Generation Plants and their respective output;
- Middleport TS, may affects Niagara, Burlington, Detweiler, Nanticoke large load areas;
- Lennox TS, may affects the Lennox Generation station plus the new Napanee GS output

Furthermore, in response to the IESO planning outlook, ABCB investments are required to secure nuclear sites and bulk transfers as generation resources retire or shift geographically. As explained in TSP Section 2.8, throughout the 2020s, many existing generation contracts will expire, nuclear refurbishments will be underway, and Pickering Nuclear Generating Station will be retired. As a result, there will be a need for capacity, and reinforcing transmission in key areas of the province will be essential to maintaining reliability. Based on the foregoing factors and through the integrated investment planning process, Hydro One determined that spending $606M[1] over the next five years replacing ABCBs represents the optimal balance of capital spending pace vs. performance risk mitigation vs. OM&A costs to keep the targeted ABCB's in service.

b) Part (a) above describes the criticality of and the need for ABCBs investments. Given the impact that the failed ABCBs may cause, it is not prudent to execute only half of the investments and leave the rest in-service. Furthermore, T-SR-02 is comprised of eleven ABCB investments of which eight investments are in execution phase and three are expected to be

[1] The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

in execution by 2023 and 2024. Completing only half of the proposed investments would lead to project cost write-offs and further design, project planning and engineering costs at a future time period.

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B2 - OEB STAFF INTERROGATORY - 095

Reference:

Exhibit B-2-1, TSP Section 2.11, T-SS-08

Interrogatory:

a) Please provide historic costs and show how these were used to calculate the annual expenditures for the Future Transmission Regional Plans investment.

b) Please explain how work that is not yet specifically identified could trigger $10.7 million of expenditure in 2023, in as short a timeframe as less than two years from now.

Response:

a) Hydro One is proposing the Future Transmission Regional Plans investment to ensure that adequate funds are available to accommodate future unforeseen transmission projects, that may be triggered during the regional planning process for which need, and scope have not been defined.

The main factor considered in developing the future costs is the historic spending envelope. The expectation is that Regional Plan investments will continue to be required as in the past and the forecast is adjusted to be in line with historic expenditures. Figure 1 below shows the historic actuals and forecast expenditures for the regional plans. By the end of the test period, the regional planning expenditures will be down to only $5-8 million per year without this allowance for future investments, which is not a reasonable forecast given the anticipated future needs of the regional supply system as noted in response to part (b) below.

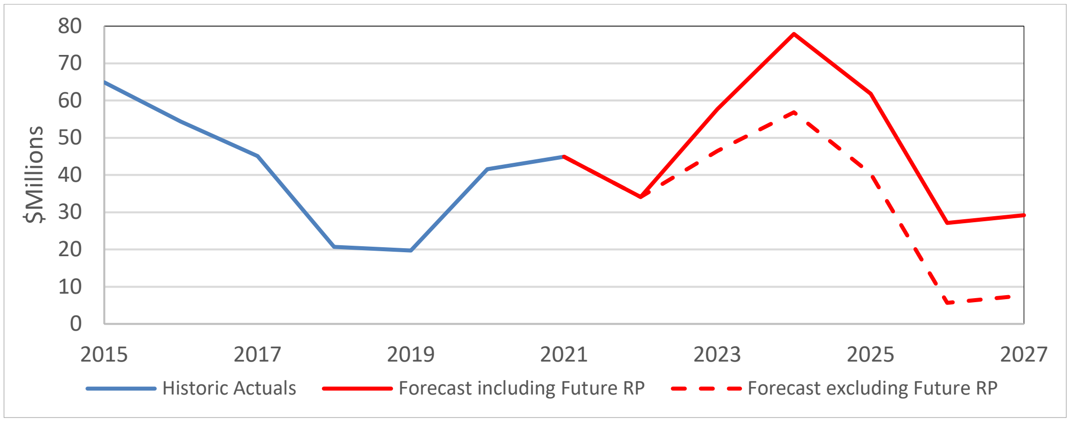

Figure 1: Local Area Supply Historic Actuals and Forecast Expenditures[1]

b) As mentioned in response to part (a) above, the expectation is that Regional Plan expenditure will continue to be required to support the adequacy of the regional supply system. These include the GTA, Ottawa, Hamilton, Leamington, and the Northern Ontario, among other areas where we see accelerated needs over the next few years due to rapid development. Triggers like electrification and climate change policy can shift needs very quickly. The $11.3[1] million expenditure in 2023, and the amounts in the years 2024 to 2027, are based on these anticipated needs.

[1] The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

B3 - OEB STAFF INTERROGATORY - 138

Reference:

DSP Section 3.11, D-SA-04
Exhibit B-3-1, DSP Section 3.9, Attachment 1

Preamble:

As stated in Lines 14 to 17 of page 5 and Lines 1 to 12 of page 6:

> The Metering Sustainment program funds the following needs over the test period:
>
> - Replacing failed AMI 1.0 meters (approximately 316,000 meters);
> - Ensuring there are sufficient meters to address sampling and reverification regulatory requirements (approximately 12,700 meters);
> - Upgrading non-standard meter installations to Hydro one Distribution’s current wholesale and retail revenue meter standards because of acquisition due to a boundary change or the acquisition of an LDC;
> - Upgrading WRMI to a retail revenue meter when customers choose to become a retail customer of Hydro One Distribution;
> - Replacing WRMI Instrument transformers with a high degree of failure risk
> - Replacing aging and obsolete meter lab equipment to ensure compliance with Measurement Canada requirements to maintain accreditation as a licensed meter service provider for testing, verification, and sampling of meters;
> - Upgrading aging 600V self-contained meters with 120V transformer rated meters, since vendors are no longer supporting this form factor. Replacing these 600V meters with an inherently safer 120V unit increases employee and customer safety, and allows Hydro One Distribution to meet expired seal obligations.

Based on information found at the second reference, the five-year average (2018-2022) cost for the metering sustainment program (D-SA-04) is $20.4 million.

Interrogatory:

a) Please provide a table for each item listed above, modeled after Table 2 – Total Investment Cost (per the template below):

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Costs						
Less Removals						
Capital and Minor Fixed Assets						
Less Capital Contributions						
Net Investment Cost						

b) Expenditures in 2023 of $62.6 million represent a $44.1 million (238%) increase compared to $18.5 million in 2022, and $42.2 million (207%) from previous 5-year (2018-2022) average of $20.4 million. For the items in part a) responsible for this increase, please provide a business case for the increased expenditures including options considered, requirements mandated through legislation, and cost control measures implemented.

Response:

a) Please find attached tables modeled after Table 2 D-SA-04 for each item in D-SA-04 lines 14 to 17 of page 5 and Lines 1 to 12 of page 6.

Original Version per Table 2 D-SA-04

1. Corrective Maintenance Meters ($M)	2023	2024	2025	2026	2027	Total
Gross Investment Costs	22.8	20.0	13.1	6.9	2.3	**65.2**
Less Removals*	1.9	2.1	2.3	3.9	3.8	**14.1**
Capital and Minor Fixed Assets	**20.9**	**17.9**	**10.8**	**3.0**	**(1.5)**	**51.1**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**20.9**	**17.9**	**10.8**	**3.0**	**(1.5)**	**51.1**
Includes replacing AMI 1.0 failed meters						

Corrected Version

1. Corrective Maintenance Meters ($M)	2023**	2024**	2025**	2026**	2027**	Total
Gross Investment Costs	24.0	21.1	13.8	7.3	2.5	**68.7**
Less Removals*	1.7	1.5	1.0	0.5	0.2	**4.8**
Capital and Minor Fixed Assets	**22.4**	**19.6**	**12.8**	**6.8**	**2.3**	**63.9**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**22.4**	**19.6**	**12.8**	**6.8**	**2.3**	**63.9**

**An error was identified in the calculation of removal costs resulting in an overstatement of the removal costs by $9.6M. The updated removal costs have been included in the above table (corrected version). Note, in Exhibit B-3-1 Section 3.11 D-SR-12, Table 7, the removal costs were also not properly reflected which results in a total net understatement of removal costs for both Exhibit B-3-1, DSP Section 3.11, D-SA-04 & D-SR-12 of approximately $0.8M from 2023 to 2027. For D-SR-12 Table 7 updated removal costs, please refer to IR I-01-B3-Energy Probe-38.*

*** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

1 **Original version per Table 2 D-SA-04**

2. Corrective Maintenance Network ($M)	2023	2024	2025	2026	2027	Total
Gross Investment Costs	2.5	2.5	2.5	2.1	1.4	**11.0**
Less Removals*	0.3	0.3	0.4	0.6	0.6	**2.2**
Capital and Minor Fixed Assets	**2.1**	**2.2**	**2.1**	**1.5**	**0.8**	**8.7**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**2.1**	**2.2**	**2.1**	**1.5**	**0.8**	**8.7**

2

Corrected Version

2. Corrective Maintenance Network ($M)	2023**	2024**	2025**	2026**	2027**	Total
Gross Investment Costs	2.6	2.7	2.6	2.2	1.5	**11.5**
Less Removals*	0.2	0.2	0.2	0.2	0.1	**0.8**
Capital and Minor Fixed Assets	**2.4**	**2.5**	**2.4**	**2.0**	**1.4**	**10.7**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**2.4**	**2.5**	**2.4**	**2.0**	**1.4**	**10.7**

**An error was identified in the calculation of removal costs resulting in an overstatement of the removal costs by $1.5M. The updated removal costs have been included in the above table (corrected version). Note, in Exhibit B-3-1 Section 3.11 D-SR-12, Table 7, the removal costs were also not properly reflected which results in a total net understatement of removal costs for both Exhibit B-3-1, DSP Section 3.11, D-SA-04 & D-SR-12 of approximately $0.8M from 2023 to 2027. For D-SR-12 Table 7 updated removal costs, please refer to IR I-01-B3-Energy Probe-38.*

*** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

3. Meter Inventory ($M)	2023*	2024*	2025*	2026*	2027*	Total
Gross Investment Costs	32.1	29.1	21.0	13.0	6.3	**101.5**
Less Removals	0.0	0.0	0.0	0.0	0.0	**0.0**
Capital and Minor Fixed Assets	**32.1**	**29.1**	**21.0**	**13.0**	**6.3**	**101.5**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**32.1**	**29.1**	**21.0**	**13.0**	**6.3**	**101.5**

Includes inventory costs for replacing AMI 1.0 failed meters, network & sampling/reverification

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

4. Meter conversions & efficiency improvements ($M)	**2023***	**2024***	**2025***	**2026***	**2027***	**Total**
Gross Investment Costs	6.0	6.0	6.0	4.0	3.1	**25.0**
Less Removals	0.2	0.2	0.2	0.1	0.1	**0.7**
Capital and Minor Fixed Assets	**5.8**	**5.8**	**5.8**	**3.9**	**3.0**	**24.3**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**5.8**	**5.8**	**5.8**	**3.9**	**3.0**	**24.3**

Includes upgrading non-standard meter installations (including 600V), upgrading deregistered wholesale to retail meter

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

5. Accredited Meter Lab ($M)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
Gross Investment Costs	1.1	1.0	1.0	1.0	0.1	**4.2**
Less Removals	0.0	0.0	0.0	0.0	0.0	**0.1**
Capital and Minor Fixed Assets	**1.1**	**1.0**	**1.0**	**1.0**	**0.1**	**4.2**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**1.1**	**1.0**	**1.0**	**1.0**	**0.1**	**4.2**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

6. Wholesale Meter replacement & upgrades ($M)	**2023***	**2024***	**2025***	**2026***	**2027***	**Total**
Gross Investment Costs	2.6	1.6	0.7	0.8	0.8	**6.5**
Less Removals	0.0	0.0	0.0	0.0	0.0	**0.0**
Capital and Minor Fixed Assets	**2.6**	**1.6**	**0.7**	**0.8**	**0.8**	**6.5**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**2.6**	**1.6**	**0.7**	**0.8**	**0.8**	**6.5**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Original version per Table 2 D-SA-04

TOTAL METERING SUSTAINMENT COSTS ($M)	2023	2024	2025	2026	2027	Total
Gross Investment Costs	65.1	58.3	42.9	26.8	13.5	**206.6**
Less Removals	2.4	2.7	2.8	4.7	4.5	**17.1**
Capital and Minor Fixed Assets	**62.6**	**55.6**	**40.1**	**22.2**	**8.9**	**189.5**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**62.6**	**55.6**	**40.1**	**22.2**	**8.9**	**189.5**

Corrected Version

TOTAL METERING SUSTAINMENT COSTS ($M)	2023**	2024**	2025**	2026**	2027**	Total
Gross Investment Costs	68.5	61.4	45.2	28.2	14.2	**217.4**
Less Removals*	2.0	1.8	1.3	0.8	0.4	**6.4**
Capital and Minor Fixed Assets	**66.4**	**59.5**	**43.8**	**27.4**	**13.8**	**211.1**
Less Capital Contributions	-	-	-	-	-	**-**
Net Investment Cost	**66.4**	**59.5**	**43.8**	**27.4**	**13.8**	**211.1**

**An error was identified in the calculation of removal costs resulting in an overstatement of the removal costs by $11.1M. The updated removal costs have been included in the above table (corrected version). Note, in Exhibit B-3-1 Section 3.11 D-SR-12, Table 7, the removal costs were also not properly reflected which results in a total net understatement of removal costs for both Exhibit B-3-1, DSP Section 3.11, D-SA-04 & D-SR-12 of approximately $0.8M from 2023 to 2027. For D-SR-12 Table 7 updated removal costs, please refer to IR I-01-B3-Energy Probe-38. ** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

b) Investments in 2023 relative to 2022 that contributed to the increase are largely non-discretionary and required to maintain compliance with Wholesale Revenue Metering (WRMI) and retail metering regulatory requirements (see Exhibit B-3-1 section 3.9 pp. 13-14). More specifically, investments that contributed to this increase are: 1) the replacement of projected failed AMI 1.0 retail revenue meters that are reaching end of life (85%); 2) the need to replace 600 V meters that are no longer being supported by the vendor to ensure billing reliability compliance (11%); the proactive replacement of Instrument Transformer meter models that are experiencing high failure rates (2%); and replacing obsolete laboratory equipment to maintain accreditation as a licensed meter service provider for testing, validation, and sampling of meters (2%).

The most significant contributor to the increase, as noted above, is the replacement of failing AMI 1.0 meters that are reaching end-of-life. The activity of replacing failed AMI 1.0 meters is a non-discretionary investment to ensure compliance with multiple regulatory requirements (see D-SA-04 Table 1) and importantly maintains customer satisfaction. In general, vendor attestations (see Exhibit B-3-1, Section 3.3, Attachment 4), condition of assets (see DSP Section 3.3, Subsection 3.2.4), meter failure historic trending (see DSP Section 3.2, Subsection 3.2.4 Figure 74 and 75), and benchmarking data (see DSP Section 3.3, Attachment 6) all align to show an approximately 15-year service life for AMI 1.0 meters, resulting in meters beginning to reach end of life in 2022. Notwithstanding the above, in order to further corroborate this finding, and to provide the best possible information on which to base forecasts of future failures, Hydro One engaged Hydro Quebec to independently design and perform Accelerated Life Testing (ALT) on Hydro One meters and report on results. ALT is the process of testing samples from a meter population and subjecting them to stressors that simulate the service life by reducing time-to-failure without introducing any new failure mechanisms. By analyzing the meter's response to such tests, predictions can be made regarding meter service life. The study's complete findings are documented in "Accelerated Life Testing of Focus ALF meters with GEN 1 and GEN 3 Communications Boards, September 2020" (see B-3-1, Section 3.3, Attachment 5). The projected accumulated GEN 1 meter failures by year based on the appropriate ALT study Acceleration Factors and Time to Failure (TTF) results at the 50% confidence is provided in D-SR-12 Figure 2 and has been reproduced below for convenience.

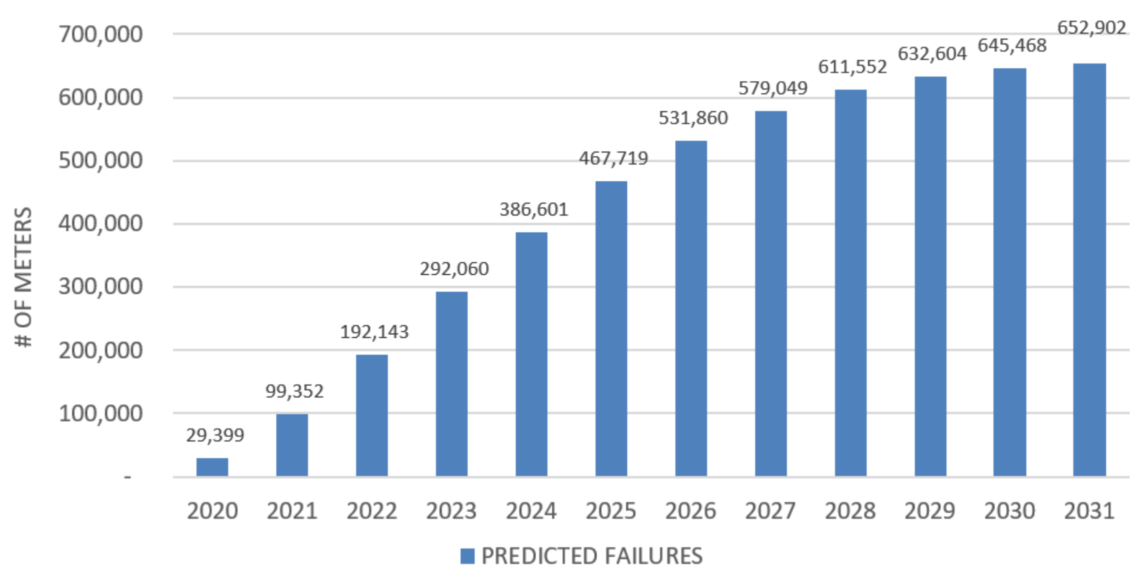

Figure 2: Projected Accumulated GEN 1 Meter Failures Based On ALT Results at the 50% Confidence Level

Hydro One adopted the 50% confidence level (as recommended by Hydro Quebec) as the most prudent approach for planning purposes. Of note, while actual AMI meter failures are likely never to exactly match ALT study-based projections, 2020 actual meter failures of 22,596 meters (see Exhibit B-3-1, Section 3.2, Table 74) fell well within the bounds between the 5% and 95% confidence levels and are closest to the projected 29,399 meter failures at the 50% confidence level. While the ALT study provides the foremost independent analysis of meter failure modes and meter time-to-failure (TFF) projections on which to base plans, variation in the actual vs. projected number of increasing annual meter failures is expected.

E - OEB STAFF INTERROGATORY - 242

Reference:

Exhibit E-4-2, Page 32, Table 13

Preamble:

At the above reference, Table 13 provides a summary of allocated facilities and real estate costs for the 2018 to 2023 period.

Interrogatory:

a) Please provide a breakdown of the increase in the total amount of these costs allocated to Transmission from the 2020 actual level of $34.3 million to the 2023 Test Year level of $38.7 million.

b) Please provide a breakdown of the increase in the total amount of these costs allocated to Distribution from the 2020 actual level of $25.2 million to the 2023 Test Year level of $30.8 million.

c) Given the occurrence of the COVID-19 pandemic, has Hydro One’s current and future anticipated buildings and work space accommodation needs changed? If so, please identify and explain the changes in such needs.

Response:

a) The breakdown for increase from 2020 actual level of $59.6M (for Transmission and Distribution on a combined basis) to the 2023 test year of $73.1M (for Transmission and Distribution on a combined basis, based on an update for inflation assumptions) is largely attributable to increase in Facilities costs as outlined below. These Facilities costs are allocated evenly between Transmission and Distribution:
   - The lease renewal of Trinity Head Office ($2.4M), addition of Woodstock Admin Office ($1.1M) lease, addition of Orillia Office and Peterborough Ashburnham Office ($1.2M) leases;
   - Addition of new Woodstock OC ($0.7M), Dunnville OC ($0.4M), Orleans OC ($0.4M) and Integrated System Operating Control (ISOC) facility ($2.1M) being operational;
   - Building Condition Assessments on select facilities ($0.7M); and
   - Proactive Radon testing assessment program at Hydro One facilities ($0.1M).

b) Please see part a) above for details as the same rationale holds.

c) Please refer to Interrogatory Response B4-Staff-152, part c).

B1 - ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORY - 006

Reference:

Exhibit B-1-1, SPF Section 1.7, Page 15

Interrogatory:

The current state assessment establishes the necessary fact base to assess the probability and consequence of safety, reliability and environmental risks at the scoring stage of the Investment Planning process described in section 1.7.4.1 below. Risks related to asset con dition, performance and utilization inform the probability score, and risks relating to asset criticality directly inform the consequence score.

a) Please complete the following table to show the allocation of the transmission budget to the three risk taxonomies:

Risk Taxonomies	EB-2019-0082 Transmission Capital $	EB-2019-0082 Transmission Capital %	EB-2021-0110 Transmission Capital $	EB-2021-0110 Transmission Capital %
Safety				
Reliability				
Environmental				
Total				

b) Please complete the table to show the allocation of the distribution budget to the three risk taxonomies:

Risk Taxonomies	EB-2017-0049 Distribution Capital $	EB-2017-0049 Distribution Capital %	EB-2021-0110 Distribution Capital $	EB-2021-0110 Distribution Capital %
Safety				
Reliability				
Environmental Risks				
Total				

Response:

a) The table below shows the proportion of transmission capital that mitigates each of the three risks. Please note that some investments may address multiple risks and as a result the values shown will exceed the total capital envelope.

The percentages provided below show the proportion of the total dollars allocated to a specific taxonomy. Please note some investments may impact multiple taxonomies, as a result the sum of the percentages may exceed 100%.

Risk Taxonomies	EB-2019-0082 Transmission Capital $ (2020-24)	EB-2019-0082 Transmission Capital %	EB-2021-0110 Transmission Capital $ (2023-27) Inflation Update*	EB-2021-0110 Transmission Capital %
Safety	2,233	34%	2,488	32%
Reliability	4,719	71%	6,257	82%
Environmental	2,108	32%	2,197	29%
Total Capital	6,621		7,639	

b) The table below shows the proportion of distribution capital that mitigates each of the three risks. Please note that some investments may address multiple risks and as a result the values shown will exceed the total capital envelope.

The percentages provided below show the proportion of the total dollars allocated to a specific taxonomy. Please note some investments may impact multiple taxonomies, as a result the sum of the percentages may exceed 100%.

As noted in Exhibit I-22-B1-SEC-056, enhancements were made to the investment planning process following EB-2017-0049, and as a result the requested information/breakdown cannot be provided for EB-2017-0049 on a comparable basis.

Risk Taxonomies	EB-2017-0049 Distribution Capital $	EB-2017-0049 Distribution Capital %	EB-2021-0110 Distribution Capital $ (2023-27) Inflation Update*	EB-2021-0110 Distribution Capital %
Safety	Not comparable		55	1%
Reliability			2,631	47%
Environmental			725	13%
Total			5,575	

* The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

B2 - ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORY - 025

Reference:

Exhibit B-2-1, TSP Section 2.8, Page 9, Table 3
Exhibit B-2-1, TSP Section 2.8, Page 17, Table 5
Exhibit B-2-1, TSP Section 2.8, Page 17, Table 7

Interrogatory:

Please provide an excel version of Tables 3, 5 and 7 combined.

Response:

Please see updated Attachment 1.

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ISD	Investment Title	2023*	2024*	2025*	2026*	2027*
T-SA-01	New Customer Connection Station	14.2	14.2	-	-	-
T-SA-02	IAMGOLD – 115 kV Mine Connection	10.5	-	-	-	-
T-SA-03	Halton TS: Build a Second 230/27.6kV Station[1]	-	1.6	4.8	2.0	0.1
T-SA-04	Connect Metrolinx Traction Substations	3.7	3.8	0.9	-	-
T-SA-05	Future Transmission Load Connection Plans	3.3	5.5	9.9	11.0	11.0
T-SA-06	Protection and Control Modifications for Distributed Generation	-	-	-	-	-
T-SA-07	Secondary Land Use Projects	39.8	3.0	3.0	0.9	0.9
T-SA-08	H29/H30: Reconductor 230kV Circuits [1,2]	0.2	0.4	0.3	2.2	2.4
T-SA-09	New Transformer Station in Northern York Region [1]	-	-	5.9	3.9	2.5
T-SA-10	Build Leamington Area Transformer Stations [1,2]	8.0	43.0	35.3	15.3	34.3
	Other Transmission System Access	3.9	3.1	3.0	3.2	1.6
Total System Access		**83.6**	**74.6**	**63.0**	**38.4**	**52.8**

[1] *Investments identified in the Regional Planning Process*

[2] *Investments that require Leave to Construct Approval*

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

ISD	Investment Title	2023*	2024*	2025*	2026*	2027*
T-SR-01	Transmission Station Renewal - Network Stations	220.4	210.1	224.8	166.7	224.3
T-SR-02	Transmission Station Renewal - Air Blast Circuit Breakers	181.3	161.8	121.9	104.5	36.2
T-SR-03	Transmission Station Renewal - Connection Stations	352.0	376.5	368.5	427.8	451.1
T-SR-04	Wood Pole Structure Replacements	59.5	60.7	61.9	63.1	64.4
T-SR-05	Steel Structure Coating Program	24.9	25.3	25.8	26.3	26.8
T-SR-06	Tower Foundation Assess/Clean/Coat Program	18.2	18.5	18.9	19.2	19.6
T-SR-07	Transmission Line Shieldwire Replacement	12.7	12.9	13.2	13.5	13.7
T-SR-08	Transmission Line Insulator Replacement	82.6	82.1	83.7	85.2	86.8
T-SR-09	Transmission Station Demand and Spares and Targeted Assets	46.2	47.0	47.5	48.6	49.4
T-SR-10	Protection Relay Replacement Program	9.2	9.3	9.4	9.5	9.6
T-SR-11	Legacy SONET System Replacement	20.5	30.9	30.8	29.0	8.7
T-SR-12	Telecom Performance Improvements	4.4	6.1	4.0	-	-
T-SR-13	Transmission Complete Line Refurbishment	63.3	132.4	200.8	248.3	232.1
T-SR-14	Mobile Radio System Replacement	5.5	7.0	5.9	2.5	0
T-SR-15	Transmission Line Emergency Restoration	10.7	10.9	11.2	11.4	11.6
T-SR-16	HV UG Cable – Replace/Refurbish Pumping Plants	-	-	0.1	0.2	5.8
T-SR-17	OPGW Infrastructure Projects	30.0	29.2	32.0	21.2	11.0
T-SR-18	C5E/C7E Underground Cable Replacement	40.3	24.9	4.9	0.1	-
	Other Transmission System Renewal Work	58.3	47.0	52.2	67.3	79.3
Total System Renewal		**1,239.8**	**1,292.8**	**1,317.3**	**1,344.4**	**1,330.4**

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

ISD	Investment Title	2023*	2024*	2025*	2026*	2027*
T-SS-01	Nanticoke TS: Connect HVDC Lake Erie Circuits[3]	-	-	-	-	-
T-SS-02	St. Lawrence TS: Phase Shifter Upgrade	6.3	-	-	-	-
T-SS-03	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade[2,3]	9.5	-	-	-	-
T-SS-04	Richview x Trafalgar 230kV Conductor Upgrade[2]	13.3	17.2	12.7	2.5	-
T-SS-05	Merivale TS: Add 230/115kV Autotransformers[1]	26.3	31.6	23.2	-	-
T-SS-06	Southwest GTA Transmission Reinforcement [1,2]	6.8	7.9	3.2	-	1.1
T-SS-07	West of Chatham Reinforcement[2]	8.8	21.4	5.5	-	-
T-SS-08	Future Transmission Regional Plans	11.3	21.1	21.5	21.5	21.5
T-SS-09	West of London Reinforcement[2]	4.4	4.5	19.6	64.1	57.7
Other System Service Investments		9.0	3.3	4.7	9.9	14.5
Total System Service		**95.6**	**107.0**	**90.3**	**98.0**	**94.8**

[1] *Investment identified in the Regional Planning Process*

[2] *Investment that requires Leave to Construct Approval*

[3] *Investment identified in the 2017 Long-Term Energy Plan*

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

B2 - ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORY - 030

Reference:

EB-2019-0082, Exhibit I-12-AMPCO-037-01

Interrogatory:

Please add the following columns to the table: 2020 actuals, 2021 actuals and update the forecast for 2022 to 2024 and provide an excel version of the table.

Response:

Please see Attachment 1 for the table from EB-2019-0082 Exhibit I-12-AMPCO-037-01 updated to include 2020 actuals and the 2021 to 2024 forecast included in this Application.

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List of Material Capital Investments (EB-2019-0082 Exhibit B-1-1 TSP Section 3.3.6.1)

Table 5 - System Access - Material Capital Investments Proposed

		EB-2019-0082 (As Filed)					EB-2021-0110				
		Plan	Plan	Plan	Plan	Plan	Actual	Forecast	Forecast	Forecast	Forecast
ISD	Investment Name	2020	2021	2022	2023	2024	2020	2021	2022	2023*	2024*
SA-01	Connect New IAMGOLD Mine	24.9	0.0	0.0	0.0	0.0	4.0	15.0	19.4	24.5	0.0
SA-02	Horner TS: Build a Second 230/27.6kV Station	29.9	0.0	0.0	0.0	0.0	31.3	13.0	0.5	0.0	0.0
SA-03	Halton TS: Build a Second 230/27.6kV Station	8.0	17.7	6.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
SA-04	Connect Metrolinx Traction Substations	6.5	7.9	7.1	1.0	0.0	0.4	0.3	0.3	10.5	12.9
SA-05	Future Transmission Load Connection Plans	0.0	5.0	24.9	24.9	0.0	0.0	0.0	0.0	5.5	25.2
SA-06	Protection and Control Modifications for Distributed Generation	3.8	3.1	2.7	2.8	2.8	7.7	5.0	5.0	4.2	4.2
SA-07	Secondary Land Use Transmission Asset Modifications	55.1	15.0	13.9	15.6	3.9	15.6	21.8	19.1	10.3	5.2
System Access Projects & Programs Less Than $3M		**27.6**	**9.4**	**8.5**	**7.8**	**9.2**	**31.2**	**58.7**	**34.0**	**110.9**	**109.3**
Total Gross System Access Capital ($M)		**155.7**	**58.1**	**63.0**	**52.0**	**15.8**	**90.2**	**113.8**	**78.3**	**165.9**	**162.4**
Less Capital Contributions ($M)		*-130.9*	*-46.7*	*-51.3*	*-39.3*	*-11.7*	*-70.6*	*-73.6*	*-46.9*	*-82.3*	*-87.8*
Total Net System Access Capital ($M)		**24.8**	**11.3**	**11.7**	**12.7**	**4.1**	**19.5**	**40.1**	**31.5**	**83.6**	**74.6**

Table 6 - System Renewal - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024	2020	2021	2022	2023*	2024*
SR-01	Air Blast Circuit Breaker Replacement Projects	107.5	128.4	133.5	129.2	98.7	177.8	138.6	130.4	158.2	131.1
SR-02	Station Reinvestment Projects	107.0	125.4	120.6	87.9	53.9	121.7	94.7	110.6	106.1	80.6
SR-03	Bulk Station Transformer Replacement Projects	33.2	51.8	72.5	131.5	113.8	15.1	20.2	63.1	112.9	102.1
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	17.5	32.4	41.4	34.6	49.3	12.2	12.1	47.2	76.9	60.2
SR-05	Load Station Transformer Replacement Projects	91.2	132.3	129.4	178.5	200.0	83.9	101.1	140.7	164.6	171.4
SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	19.2	30.8	47.5	58.4	77.0	17.8	12.9	22.6	41.1	50.6
SR-07	Protection and Automation Replacement Projects	6.7	8.6	12.7	12.2	21.7	7.1	7.0	8.9	2.3	1.6
SR-08	John Transformer Station Reinvestment Project	3.5	17.9	25.6	24.0	20.9	0.0	0.0	0.0	0.3	0.4
SR-09	Transmission Station Demand and Spares and Targeted Assets	44.2	36.4	37.0	37.7	38.3	61.3	40.2	41.0	46.2	47.0
SR-10	Transformer Protection Replacement	3.8	0.0	0.0	0.0	0.0	0.3	0.6	0.6	0.0	0.0
SR-11	Legacy SONET System Replacement	4.1	26.0	27.6	28.1	28.1	0.4	0.6	4.6	20.5	30.9
SR-12	Telecom Performance Improvements	0.0	0.9	5.5	3.7	0.0	0.0	0.0	0.0	1.0	6.1
SR-13	ADSS Fibre Optic Cable Replacements	7.0	7.1	1.0	0.0	0.0	0.5	5.0	3.3	3.4	0.0
SR-14	Mobile Radio System Replacement	2.9	6.2	6.1	4.0	0.0	0.0	0.3	3.0	5.5	7.0
SR-15	Telecom Fibre IRU Agreement Renewals	0.0	2.8	8.5	2.6	1.5	0.0	2.8	8.5	2.8	1.5
SR-16	NERC CIP-014 Physical Security Implementation	18.0	18.0	18.0	0.0	0.0	24.2	20.6	15.1	0.0	0.0
SR-17	NERC CIP Transient Cyber Asset Project	3.5	0.0	0.0	0.0	0.0	1.1	7.5	7.6	0.0	0.0
SR-18	PSIT Cyber Equipment Replacement	1.0	5.0	7.7	7.0	3.4	2.9	6.4	8.3	0.0	0.0
SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	81.8	122.1	94.5	51.0	75.9	43.5	54.7	96.0	48.9	49.9
SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	62.2	63.4	111.7	117.8	137.7	0.1	5.9	0.0	6.7	64.9
SR-21	Wood Pole Structure Replacements	51.0	52.0	53.0	54.1	55.2	47.0	48.8	52.7	59.5	60.7
SR-22	Steel Structure Coating Program	11.4	21.8	22.3	22.7	23.2	8.1	21.4	22.6	24.9	25.3
SR-23	Tower Foundation Assess/Clean/Coat Program	11.8	22.3	22.8	23.3	23.7	8.4	8.5	11.3	11.1	11.3
SR-24	Transmission Line Shieldwire Replacement	12.3	12.6	12.8	13.1	13.4	4.5	12.2	12.9	12.7	12.9
SR-25	Transmission Line Insulator Replacement	68.3	69.7	66.3	67.6	68.9	57.1	67.5	68.6	82.6	82.1
SR-26	Transmission Line Emergency Restoration	9.6	9.8	10.0	10.2	10.4	12.0	9.7	9.9	10.7	10.9
SR-27	C5E/C7E Underground Cable Replacement	2.1	29.8	30.9	32.2	29.2	2.8	11.8	25.1	40.3	24.9
SR-28	OPGW Infrastructure Projects	5.3	7.5	2.2	6.2	9.7	0.1	1.7	11.2	17.0	11.3
SR-29	Physical Security ISL Application Replacement	5.0	1.1	0.0	0.0	0.0	4.3	1.5	0.0	0.0	0.0
System Renewal Projects & Programs Less Than $3M		**77.8**	**67.3**	**60.1**	**44.1**	**41.1**	**98.3**	**29.8**	**59.2**	**190.2**	**249.9**
Total Gross System Renewal Capital ($M)		**869.1**	**1109.2**	**1181.1**	**1181.5**	**1194.9**	**812.4**	**744.2**	**984.9**	**1246.1**	**1294.9**
Less Capital Contributions ($M)		*-3.8*	*-6.1*	*-8.3*	*-4.1*	*-1.1*	*-8.4*	*-4.5*	*-13.4*	*-6.3*	*-2.1*
Total Net System Renewal Capital ($M)		**865.2**	**1103.1**	**1172.8**	**1177.4**	**1193.8**	**804.0**	**739.6**	**971.5**	**1239.8**	**1292.8**

List of Material Capital Investments (EB-2019-0082 Exhibit B-1-1 TSP Section 3.3.6.1)

Table 7 - System Service - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024	2020	2021	2022	2023*	2024*
SS-01	Lennox TS: Install 500kV Shunt Reactors	32.3	0.0	0.0	0.0	0.0	21.8	19.0	0.0	0.0	0.0
SS-02	Wataynikaneyap Line to Pickle Lake Connection	24.9	1.5	0.0	0.0	0.0	5.1	22.9	4.0	0.0	0.0
SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits	3.0	10.0	4.0	0.0	0.0	0.0	0.0	3.1	10.7	4.3
SS-04	East-West Tie Connection	46.3	38.8	22.6	0.0	0.0	68.1	21.5	20.0	1.1	0.0
SS-05	St. Lawrence TS: Phase Shifter Upgrade	9.0	18.0	9.0	0.0	0.0	0.9	17.0	37.8	12.6	0.0
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	5.0	10.0	8.4	0.0	0.0	0.3	1.0	9.0	9.5	0.0
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	0.0	2.0	3.0	69.4	119.1	0.0	0.0	0.0	0.0	0.0
SS-08	Northwest Bulk Transmission Line	8.0	12.9	8.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SS-09	Barrie Area Transmission Upgrade	38.1	28.2	8.5	0.0	0.0	13.2	31.2	34.6	0.0	0.0
SS-10	Kapuskasing Area Transmission Reinforcement	6.7	3.8	0.0	0.0	0.0	16.6	3.0	2.3	0.0	0.0
SS-11	South Nepean Transmission Reinforcement	27.5	10.5	0.0	0.0	0.0	29.4	17.6	3.3	0.0	0.0
SS-12	Alymer-Tillsonburg Area Transmission Reinforcement	10.0	13.1	6.1	0.0	0.0	0.7	2.7	0.7	0.0	0.0
SS-13	Leamington Area Transmission Reinforcement	4.9	9.7	59.1	63.8	63.8	44.4	99.7	27.3	0.2	0.0
SS-14	Southwest GTA Transmission Reinforcement	10.3	7.8	6.9	3.9	2.0	0.6	0.5	4.1	6.8	7.9
SS-15	Future Transmission Regional Plans	0.0	0.0	10.5	19.6	0.0	0.0	0.0	0.0	11.3	21.1
SS-16	Customer Power Quality Program	3.3	3.4	3.4	3.4	3.5	1.2	0.0	0.0	0.0	0.0
System Service Projects & Programs Less Than $3M		**9.1**	**8.2**	**9.9**	**14.0**	**15.9**	**19.6**	**11.3**	**16.4**	**60.4**	**78.1**
Total Gross System Service Capital ($M)		**238.3**	**177.9**	**160.3**	**174.3**	**204.2**	**221.9**	**247.4**	**162.5**	**112.7**	**111.4**
Less Capital Contributions ($M)		*-34.2*	*-29.7*	*-8.5*	*0.0*	*0.0*	*-25.8*	*-23.5*	*-40.5*	*-17.1*	*-4.4*
Total Net System Service Capital ($M)		**204.1**	**148.2**	**151.8**	**174.3**	**204.2**	**196.1**	**223.9**	**122.0**	**95.6**	**107.0**

Table 8 - General Plant - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024	2020	2021	2022	2023*	2024*
GP-01	Integrated System Operations Centre - New Facility Development	32.4	12.7	0.0	0.0	0.0	28.1	42.2	0.0	0.0	0.0
GP-02	Grid Control Network Sustainment	8.0	6.1	6.3	6.5	6.6	3.6	4.4	4.4	6.8	7.0
GP-03	Network Management System Capital Sustainment	0.0	7.8	22.4	8.2	0.0	5.0	10.4	16.6	8.0	0.0
GP-04	Integrated Voice Communications and Telephony System Refresh	0.0	1.9	3.2	1.1	0.0	0.0	1.0	3.2	1.0	0.0
GP-05	Transmission Non-Operational Data Management System	5.2	5.3	5.4	5.5	1.1	0.0	5.3	5.4	5.8	1.2
GP-06	Operating Common IT Infrastructure	0.8	2.0	3.7	3.3	2.2	0.0	2.0	2.0	3.6	3.1
GP-07	Hardware/Software Refresh and Maintenance	2.0	2.0	1.9	1.9	5.8	4.0	2.2	1.7	1.3	2.5
GP-08	Corporate Services Transformation - HR / Payroll	5.0	1.5	0.0	0.0	0.0	4.3	5.2	6.2	0.0	0.0
GP-09	Corporate Services Transformation - Finance	1.0	3.0	5.0	6.5	5.0	0.1	2.6	0.5	10.6	14.1
GP-10	Facility Accommodation & Improvements Service Centres & Admin	8.1	4.9	8.2	16.4	4.3	5.3	5.5	5.2	12.3	12.5
GP-11	Transmission Facilities & Site Improvements	9.4	9.5	9.6	9.7	9.9	11.4	9.5	9.6	10.2	10.4
GP-12	Transport & Work Equipment	13.2	13.2	13.3	13.3	13.3	8.8	12.3	9.7	21.9	22.4
General Plant Projects & Programs Less Than $3M		**30.2**	**24.3**	**15.8**	**11.1**	**10.7**	**54.2**	**35.2**	**38.2**	**73.0**	**57.3**
Total Gross System Service Capital ($M)		**115.4**	**94.4**	**94.7**	**83.6**	**58.9**	**124.7**	**137.8**	**102.8**	**154.5**	**130.5**
Total Net General Plant Capital ($M)		**115.4**	**94.4**	**94.7**	**83.6**	**58.9**	**124.7**	**137.8**	**102.8**	**154.5**	**130.5**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

B3 - ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORY - 078

Reference:

Exhibit B-3-1, DSP Section 3.9, Attachment 1

Interrogatory:

a) Please add 2018 to 2020 Plan amounts to Appendix 2-AA and provide an excel version.

b) Please provide Appendix 2-AA from part (a) on the basis of Inservice Additions and provide an excel version.

c) Please provide the annual amount of System Service work: (1) deferred; (2) cancelled; and (3) advanced for each of the years 2016 to 2021.

Response:

a) Please see interrogatory response to B3-SEC-141.

b) Please see Excel Attachment ‘I-03-B3-AMPCO-078-01' of this interrogatory response, which has been updated to reflect the impact of inflation as described in Exhibit O-1-2.

c) For 2016, System Service Plan = $103.3M, Actual = $77.4M, representing deferrals of $25.9M in capital. These deferrals were as a result of reprioritization, to accommodate unforeseen increases in other areas of capital spending. For 2017, Plan = $110.1M, Actual = $66.6M, representing deferrals of $43.5M. These deferrals were a result of reprioritization to accommodate increased spending in General Plant driven by IT investments as well as unplanned TX capital contributions. Due to the timing of the Decision for the previous filing, there is no annual variance for the year 2018. For the years 2019 and 2020, please see the Capital Performance report included in this filing, B-03-01 Section 3.9 Attachment 2, for details on variations from planned expenditures. For 2021, please see Exhibit B-03-01 Section 3.9 for an explanation of the forecast $11.5M in System Service deferrals.

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Appendix 2-AA: On the basis of ISA
Capital Projects Table ($M)

											Forecast Period (As-Filed)					Forecast Period (Updated for Inflation)*				
Projects	2018 Plan (DRO)	2018	2019 Plan (DRO)	2019	2020 Plan (DRO)	2020	2021 Plan (DRO)	2021 Bridge	2022 Plan (DRO)	2022 Bridge	2023 Test	2024 Test	2025 Test	2026 Test	2027 Test	2023 Test	2024 Test	2025 Test	2026 Test	2027 Test
Reporting Basis		USGAAP		USGAAP		USGAAP		USGAAP		USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
System Access																				
D-SA-01 Joint Use and Relocations	23.4	23.4	17.1	26.9	17.7	24.6	17.7	23.8	17.9	19.3	24.4	28.7	27.1	26.5	27.2	25.6	30.2	28.5	27.9	28.6
D-SA-02 New Load Connections, Upgrades, Cancellations	124.5	124.5	101.8	134.8	106.0	147.3	104.7	137.0	105.6	141.6	150.7	154.5	158.4	162.4	166.5	158.6	162.6	166.8	171.0	175.3
D-SA-03 Customer Demand Distributed Energy Resources	15.7	15.7	8.0	8.2	2.7	3.8	2.2	5.0	1.6	1.7	2.4	2.4	1.4	1.4	1.4	2.6	2.6	1.5	1.5	1.5
D-SA-04 Metering Sustainment	32.0	32.0	20.8	20.0	18.4	21.7	36.2	16.9	18.0	18.6	62.1	56.1	40.5	22.2	8.9	65.3	59.1	42.6	23.3	9.4
D-SA-Other	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total System Access	**196.9**	**196.9**	**147.7**	**189.9**	**144.7**	**197.5**	**160.8**	**182.7**	**143.1**	**181.2**	**239.6**	**241.8**	**227.5**	**212.5**	**204.1**	**252.1**	**254.5**	**239.4**	**223.7**	**214.8**
System Renewal																				
D-SR-01 Distribution Stations Demand Capital Program	3.9	3.9	5.3	4.8	4.7	5.2	4.8	5.9	4.9	4.9	6.2	6.7	7.3	6.0	6.1	6.5	7.1	7.7	6.3	6.4
D-SR-02 Mobile Unit Substation Program	0.0	0.0	3.3	7.2	4.6	5.3	4.3	3.5	4.8	3.2	4.0	3.8	3.8	3.0	3.7	4.2	4.0	4.0	3.2	3.9
D-SR-03 Distribution Station Planned Component Replacement Program	4.4	4.4	7.4	7.9	6.4	8.0	6.7	9.9	6.8	7.0	6.5	3.3	1.1	1.1	1.2	6.8	3.5	1.2	1.2	1.2
D-SR-04 Distribution Station Refurbishment	15.0	15.0	33.1	26.7	21.3	7.6	23.9	15.4	28.0	7.4	26.4	56.3	34.0	26.8	38.0	27.7	59.2	35.8	28.2	40.0
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response	112.0	112.0	75.6	74.5	80.2	117.6	78.7	92.2	79.5	93.8	107.1	109.2	111.4	113.6	115.9	112.4	114.9	117.2	119.6	122.0
D-SR-06 Distribution Lines PCB Equipment Replacement Program	6.3	6.3	9.9	8.1	11.0	4.8	12.4	9.5	12.5	9.5	9.4	9.5	9.5	0.0	0.0	9.9	9.9	10.0	0.0	0.0
D-SR-07 Pole Sustainment Program	51.8	51.8	53.2	44.2	59.7	43.5	58.8	73.3	58.3	60.1	107.9	110.0	112.2	114.4	116.7	113.2	115.8	118.1	120.4	122.8
D-SR-08 Distribution Lines Minor Component Replacement Program	4.1	4.1	7.0	4.9	4.1	6.3	7.2	9.9	7.6	12.5	12.5	12.4	12.2	8.3	6.5	13.1	13.1	12.8	8.7	6.9
D-SR-09 Submarine Cable Replacement Program	3.6	3.6	9.1	6.2	9.7	6.6	9.8	10.2	9.9	11.1	12.1	12.4	12.7	12.9	13.2	12.7	13.1	13.3	13.6	13.9
D-SR-10 Distribution Lines Sustainment Initiatives	7.6	7.6	11.1	9.4	12.8	9.8	26.4	13.0	30.4	11.2	30.3	33.1	37.2	31.9	47.6	31.8	34.8	39.2	33.6	50.1
D-SR-11 Life Cycle Optimization & Operational Efficiency Projects	18.2	18.2	6.2	5.1	4.9	2.4	3.1	4.4	6.2	0.0	1.0	6.0	8.5	3.0	0.2	1.0	6.4	8.9	3.1	0.2
D-SR-12 Advanced Meter Infrastructure 2.0 (AMI 2.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	3.9	30.9	62.0	153.7	154.4	157.3	32.5	65.3	161.7	162.6	165.6
D-SR-Other	2.7	2.7	2.2	2.8	6.1	0.9	5.8	0.6	2.3	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Sub-Total System Renewal	**229.6**	**229.6**	**223.3**	**201.9**	**225.3**	**217.8**	**241.9**	**248.7**	**251.2**	**225.5**	**355.2**	**425.6**	**504.4**	**476.3**	**507.3**	**372.9**	**447.9**	**530.9**	**501.3**	**533.9**
System Service																				
D-SS-01 System Upgrades Driven by Load Growth	34.4	34.4	15.8	24.7	125.0	58.1	94.3	20.4	74.0	95.4	147.8	52.6	150.4	90.9	83.9	151.6	55.3	158.3	95.7	88.3
D-SS-02 Reliability Improvements	2.1	2.1	7.8	4.2	5.3	5.0	5.9	2.8	0.0	5.5	5.5	3.2	5.5	13.4	13.2	5.7	3.4	5.8	14.1	13.9
D-SS-03 Demand System Modifications	12.5	12.5	8.8	11.4	8.8	12.9	8.6	8.1	10.6	8.9	12.1	13.0	13.3	13.5	13.8	12.4	13.7	14.0	14.2	14.5
D-SS-04 Energy Storage Solutions	0.0	0.0	8.1	0.0	0.0	0.0	0.0	8.5	0.0	3.4	16.3	34.6	35.2	35.9	36.2	16.7	36.3	37.1	37.8	38.1
D-SS-05 Worst Performing Feeders	4.7	4.7	18.5	18.6	15.8	17.2	15.2	26.9	12.8	21.0	40.6	41.4	42.7	43.0	43.8	41.7	43.5	44.9	45.2	46.1
D-SS-06 Power Quality and Stray Voltage	1.0	1.0	0.8	1.3	0.9	1.2	0.9	3.3	0.9	3.4	3.8	3.9	4.0	4.0	4.1	3.9	4.1	4.2	4.2	4.3
D-SS-Other	59.2	59.2	21.8	28.9	15.2	2.8	13.9	0.8	14.2	0.1	0.13	0.13	0.13	0.14	0.14	0.1	0.1	0.1	0.1	0.1
Sub-Total System Service	**113.9**	**113.9**	**81.6**	**89.2**	**170.9**	**97.3**	**138.8**	**70.8**	**112.4**	**137.7**	**226.3**	**148.8**	**251.2**	**200.9**	**195.1**	**232.1**	**156.3**	**264.4**	**211.4**	**205.4**
General Plant Allocated to Distribution																				
Fleet	18.1	18.1	27.8	29.0	29.4	25.7	28.3	28.3	28.2	28.5	50.6	51.7	52.2	53.0	54.7	52.5	54.4	55.0	55.8	**57.6**
Facilities & Real Estate	13.0	13.0	11.4	12.0	34.5	41.4	15.1	14.4	50.6	29.5	31.1	82.4	58.8	29.1	63.5	32.3	86.7	61.9	30.6	**66.8**
Information Solutions	45.0	45.0	56.7	63.2	67.8	80.1	36.7	65.7	22.3	50.5	54.6	51.7	105.3	85.1	78.5	56.9	54.4	110.8	89.6	**82.6**
System Operations	7.3	7.3	6.6	2.2	4.2	6.3	84.1	89.5	2.3	3.5	10.5	23.1	4.0	3.3	3.5	10.9	24.3	4.3	3.4	**3.7**
System Capability Reinforcement	4.1	4.1	1.5	0.3	0.0	-0.7	0.0	0.0	0.0	0.0	3.0	2.2	0.0	1.1	1.0	3.2	2.3	0.0	1.2	**1.1**
Other	0.0	0.0	0.0	-2.7	0.0	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	**0.0**
Sub-Total General Plant	**87.4**	**87.4**	**103.9**	**104.1**	**135.9**	**155.5**	**164.1**	**197.9**	**103.4**	**112.0**	**149.9**	**211.1**	**220.4**	**171.5**	**201.2**	**155.5**	**222.2**	**231.9**	**180.5**	**211.8**
Subtotal (SA, SR, SS)	**540.4**	**540.4**	**452.6**	**481.1**	**540.9**	**512.6**	**541.4**	**502.2**	**506.7**	**544.4**	**821.0**	**816.2**	**983.1**	**889.7**	**906.5**	**857.0**	**858.8**	**1,034.7**	**936.4**	**954.1**
GRAND TOTAL	**627.8**	**627.8**	**556.5**	**585.1**	**676.8**	**668.1**	**705.5**	**700.1**	**610.1**	**656.4**	**970.9**	**1,027.3**	**1,203.4**	**1,061.2**	**1,107.8**	**1,012.5**	**1,080.9**	**1,266.6**	**1,116.9**	**1,165.9**

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

B3 - ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORY - 094

Reference:

DSP Section 3.11, D-SR-07, Page 11

Interrogatory:

Please complete the following table on the basis of Gross Investment Cost:

D-SR-07	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Test and Treat										
Pole Refurbishment										
Pole Replacement										
Removals										
Total										

Response:

D-SR-07

($M)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023***	**2024***	**2025***	**2026***	**2027***
Test and Treat	0.0	0.0	1.3	7.5	7.7	8.4	8.6	8.7	8.9	9.2
Pole Refurbishment	0.0	0.0	0.0	4.0	8.2	6.2	6.3	6.4	6.5	6.6
Pole Replacement	59.0	50.3	48.2	71.9	52.5	114.4	117.5	119.2	122.0	123.9
Removals	-7.0	-6.0	-5.9	-10.0	-8.2	-15.5	-15.9	-16.1	-16.5	-16.7
Total	**52.0**	**44.3**	**43.6**	**73.4**	**60.1**	**113.5**	**116.4**	**118.3**	**120.9**	**122.9**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

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E - CONSUMERS COUNCIL OF CANADA INTERROGATORY - 025

Reference:

Exhibit E-2-1, Page 4, Table 2

Interrogatory:

Please provide Transmission OM&A in the same format as Table 2 – Summary of Recoverable OM&A Expenses for the period 2015-2023. Please include the most updated forecast for 2021.

Response:

Please see updated table below for 2021 Q3 actuals by the following Transmission OM&A cost categories and also 2015 to 2017 figures. Please also see A-SEC-002 for further details. 2023 Test year OM&A has also been updated to reflect the inflation adjustment.

Table 1 - Summary of Recoverable OM&A Expenses ($M) from Exhibit E-02-01

	Historical									Bridge	Test
	2015	2016	2017	2018	2019	2020	2020	2021	2021	2022	2023**
Transmission	Actual	Actual	Actual	Actual	Actual	OEB Approved	Actual	Q3 YTD Actuals	Forecast*	Forecast	Inflation Update
Sustainment	233.6	215.1	218.1	229.4	207.8		200.9	158.7	205.2	208.3	231.2
Development	6.1	4.6	5.1	5.2	4.4		6.7	5.4	8.3	8.9	9.0
Operations	59.0	62.5	61.1	53.4	51.0		47.9	35.3	48.8	48.6	51.6
Customer Care	5.1	4.5	8.5	11.0	7.2		7.0	4.3	6.0	6.7	7.3
Common and Other	73.9	60.1	41.5	54.9	26.7		70.5	46.9	51.6	50.7	68.4
Property Taxes and Rights Payments	63.9	61.3	50.7	65.3	60.8		65.4	47.1	69.1	70.2	75.1
Total	**441.6**	**408.1**	**385.0**	**419.2**	**357.9**	**385.0**	**398.5**	**297.6**	**389.0**	**393.4**	**442.6**

***This reflects the 2021 forecasted amounts included in the 'as filed' evidence dated August 5, 2021. For 2021 actual amounts, please refer to Exhibit O-2-1, Attachment 6*
*** The 2023 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2*

Witness: JODOIN Joel

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E - CONSUMERS COUNCIL OF CANADA INTERROGATORY - 034

Reference:

Exhibit E-6-1, Page 18

Interrogatory:

With respect to FTEs HON has planned increases to regular FTE for 2021 and 2022 attributable to the addition of approximately 250 employees into the Shared Services and Information Services LOBs to repatriation of Inergi employees. Please provide the overall cost of the addition of these employees for 2023 and identify the offsetting reduction associated with a reduction in the Inergi contract can be found.

Response:

Table 1 below presents Hydro One's costs for information technology, supply chain, payroll, and finance and accounting services previously outsourced to Inergi. History of the Inergi Agreement and details of the sourcing strategy to transition concluding services are described in Exhibit E-05-01, Sections 4 and 5, respectively.

The total cost impact as a result of repatriating Inergi employees into Hydro One is more than offset by the reduction in fees paid to third parties, net of transition and other costs to insource work activities. The decision to repatriate Inergi employees was essential to achieving reduced rates in the Capgemini Agreement for non-sustainment work program delivery.

Table 1 - Summary of Total Costs for Information Technology, Supply Chain, Finance and Accounting, and Payroll Services Previously Outsourced to Inergi ($M)

	Historic			Bridge		Test
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Description	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast (Inflation Adjusted)***
Total Payments to Inergi LP	114.3	114.9	119.7	37.0	-	-
Total Payments to Third-Parties	-	-	-	44.0	48.1	50.6
Repatriation of Inergi Employees	-	-	-	22.7	40.6	43.2
Transition and Transformation	-	-	-	6.2	1.7	-
Tools and Other	-	-	-	-	5.6	5.9
Total	**114.3**	**114.9**	**119.7**	**109.9**	**96.0**	**99.7**

**The 2023 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Witness: BERARDI Rob, MARCOTTE Kevin

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G - CONSUMERS COUNCIL OF CANADA INTERROGATORY - 040

Reference:

Exhibit G-1-2, Page 33

Interrogatory:

HONI is requesting a new symmetrical variance account to record the revenue requirement impact, including tax, of overspending and underspending relative to HONI's distribution capital investment plan which underlies the proposed revenue requirement for the 2023-2027 period where overspending or underspending is for work related to third-party initiate relocation, DER connection or service upgrades which HONI is required to undertake.

a) Please provide a complete 2023-2027 forecast of the costs that will be subject to this variance account;

b) Please provide a complete list all categories of costs that will be captured by this account even if they have not been included in the 2023-2027 forecast;

c) Please provide a list of all costs from the period 2018-2021 that would have been captured by this account had it been in place for that period;

d) How does this account differ from Z-factor treatment?

e) Is HON seeking approval to record costs in this account only for costs that exceed the $1 million annual materiality threshold?

Response:

a) The following table provides a forecast for in-service additions for the components of the ISDs that are anticipated to be impacted by this account:

		In-Service Additions*				
		2023	**2024**	**2025**	**2026**	**2027**
D-SA-01	**Joint Use and Relocations**	25.6	30.2	28.5	27.9	28.6
D-SA-02	**New Load Connections, Upgrades, Cancellations – (Service Upgrades portion only)**	31.6	32.4	33.3	34.1	34.9
D-SA-03	**Customer Demand Distributed Energy Resources**	2.6	2.6	1.5	1.5	1.5

* *The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

b) Please see Interrogatory Response G-Staff-304 part e) and refer to Exhibit G-01-02, Section 7.2 page 33 for a list of anticipated costs.

c) Please see Interrogatory Response G-Staff-304 part b).

d) Please see Hydro One’s Interrogatory Response G-Staff-304 part g).

e) No. If the account is approved, Hydro One will record all eligible costs in this account irrespective of the dollar amount. Hydro One is not aware of a $1M materiality threshold or any materiality threshold pertaining to the amounts that may be recorded in an approved regulatory account.

B2 - ENERGY PROBE INTERROGATORY - 019

Reference:

Exhibit B-2-1, TSP Section 2.11, T-SA-05, Page 4, Table 2

Interrogatory:

Please explain how the forecast of amounts shown in Table 2 was developed using numerical examples.

Response:

Hydro One is proposing the Future Transmission Load Connection investment to ensure that adequate funds are available to accommodate future unforeseen request from load customers to connect to Hydro One's transmission system for which need, and scope have not been defined.

Figure 1 below shows the historic actuals and forecast expenditures for load connections. The forecast for load connections (excluding ISD T-SA-05 Future Connections) over the test years, primarily represents only the new load connections for the Leamington area. However, the expectation is that load connections investments will continue to be required as in the past across the Province, and not solely for just one region. Hydro One considers this historical trend in the forecasting of these future connection costs to reflect the anticipation of needs over the next few years due to rapid development. Triggers like electrification and climate change policy can shift needs very quickly.

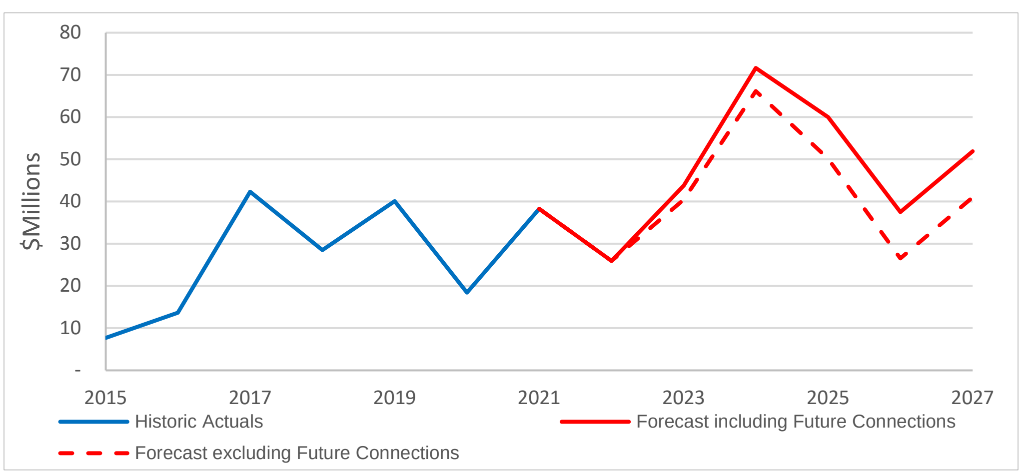

Figure 1. Load Connections Historical Actuals and Forecast Expenditures[1]

[1] The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

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B3 - ENERGY PROBE INTERROGATORY - 031

Reference:

DSP Section 3.11, D-SA-04, Page 1-8, Figure 2, Table 2

Interrogatory:

a) Please explain how the forecast of the cost of the sampling and verification of the meter inventory shown in Figure 2 was prepared showing all calculations and assumptions particularly the large fluctuations from year to year.

b) Please explain how the forecast of the total investment cost shown in Table 2 was prepared showing all calculations and assumptions.

Response:

a) The forecasted cost for sampling and verification meter inventory shown in Figure 2 is a function of meter volumes required for sampling and reverification, meter hardware costs, material surcharges, and overhead. Meter sampling and reverification volumes are based on meter age characteristics and derived based on Measurement Canada regulations for meter sampling (S-S-06 effective date 2021-07-28) and meter reverification (S-E-02 effective date 2021-07-28). Fluctuations in costs year-to year are primarily a result of fluctuating meter volumes to be sampled or reverified derived from the regulations.

See forecast of the cost of the sampling and verification of the meter inventory below.

Meter Inventory	2023**	2024**	2025**	2026**	2027**	Total
Total Meters	2,706	3,169	1,953	3,274	1,557	12,659
Average $/meter*	$223	$228	$232	$237	$242	-
Total ($M/year)	**$0.60**	**$0.72**	**$0.45**	**$0.78**	**$0.38**	**$2.93**

**Average $/meter = average meter cost + overhead + material surcharge*
*** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

b) The forecast of total investment cost for the Metering Sustainment program funds the investments set out in D-SA-04 Section B. Please see the calculations and assumptions detailing out Table 2.

Original version per Table 2 D-SA-04

Corrective Maintenance Meters	2023	2024	2025	2026	2027	Total	Assumptions / Comments
Units	114,383	98,206	62,495	31,617	9,659	**316,360**	AMI 1.0 meter failure volumes based on 50% confidence interval from ALT study
Average unit cost ($)	200	204	210	218	242	-	Labour rate is based on blended 2020 actual cost Average unit cost includes overhead, escalation and Capital accounting treatment
TOTAL GROSS COSTS ($M)	**22.8**	**20.0**	**13.1**	**6.9**	**2.3**	**65.2**	
Less Removals ($M)	1.9	2.1	2.3	3.9	3.8	**14.1**	Error was identified in the calculation of removal costs which resulted in an overstatement of removal costs $9.6M. The updated removal costs are reflected in corrected version table below
NET INVESTMENT COSTS ($M)	**20.9**	**17.9**	**10.8**	**3.0**	**(1.5)**	**51.1**	

Corrected Version

Corrective Maintenance Meters	2023*	2024*	2025*	2026*	2027*	Total	Assumptions / Comments
Units	114,383	98,206	62,495	31,617	9,659	**316,360**	AMI 1.0 meter failure volumes based on 50% confidence interval from ALT study
Average unit cost ($)*	210	215	221	230	255	-	Labour rate is based on blended 2020 actual cost Average unit cost includes overhead, escalation & Capital accounting treatment
TOTAL GROSS COSTS ($M)	**24.0**	**21.1**	**13.8**	**7.3**	**2.5**	**68.7**	
Less Removals ($M)*	1.7	1.5	1.0	0.5	0.2	**4.8**	Updated removal costs. Note, in Exhibit B-3-1 Section 3.11 D-SR-12, Table 7, the removal costs were also not properly reflected which results in a total net understatement of removal costs for both Exhibit B-3-1, DSP Section 3.11, D-SA-04 & D-SR-12 of approximately $0.8M from 2023 to 2027. For D-SR-12 Table 7 updated removal costs, please refer to IR I-01-B3-Energy Probe-38
NET INVESTMENT COSTS ($M)	**22.4**	**19.6**	**12.8**	**6.8**	**2.3**	**63.9**	

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Original version per Table 2 D-SA-04

Corrective Maintenance Network	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**	**Assumptions / Comments**
Units	2,725	2,733	2,634	2,129	1,449	**11,671**	Network failure volumes based on historical failure rates
Average unit cost ($)	908	926	945	964	983	-	Labour rate is based on blended 2020 actual cost Average unit cost includes overhead and escalation
TOTAL GROSS COSTS ($M)	**2.5**	**2.5**	**2.5**	**2.1**	**1.4**	**11.0**	
Less Removals ($M)	0.3	0.3	0.4	0.6	0.6	**2.2**	Error was identified in the calculation of removal costs which resulted in an overstatement of removal costs $1.5M. The updated removal costs are reflected in corrected version table below
NET INVESTMENT COSTS ($M)	**2.1**	**2.2**	**2.1**	**1.5**	**0.8**	**8.7**	

Corrected version

Corrective Maintenance Network	**2023***	**2024***	**2025***	**2026***	**2027***	**Total**	**Assumptions / Comments**
Units	2,725	2,733	2,634	2,129	1,449	**11,671**	Network failure volumes based on historical failure rates
Average unit cost ($)*	956	975	994	1,014	1,034	-	Labour rate is based on blended 2020 actual cost Average unit cost includes overhead and escalation
TOTAL GROSS COSTS ($M)	**2.6**	**2.7**	**2.6**	**2.2**	**1.5**	**11.5**	
Less Removals ($M)*	0.2	0.2	0.2	0.2	0.1	**0.8**	Updated removal costs. Note, in Exhibit B-3-1 Section 3.11 D-SR-12, Table 7, the removal costs were also not properly reflected which results in a total net understatement of removal costs for both Exhibit B-3-1, DSP Section 3.11, D-SA-04 & D-SR-12 of approximately $0.8M from 2023 to 2027. For D-SR-12 Table 7 updated removal costs, please refer to IR I-01-B3-Energy Probe-38
NET INVESTMENT COSTS ($M)	**2.4**	**2.5**	**2.4**	**2.0**	**1.4**	**10.7**	

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Meter Inventory	2023*	2024*	2025*	2026*	2027*	Total	Assumptions / Comments
Units	116,509	100,337	64,522	33,274	10,787	**325,429**	Includes meters, network, Primary mounted unit and Instrument transformers
Average unit cost ($)*	276	290	326	391	583	-	Average AMI 1.0 meter cost based on the latest Outline Agreements and/or purchasing prices at the beginning of 2021. All other inventory unit costs based on historical costs Average unit cost includes overhead, material surcharge and escalation
TOTAL GROSS COSTS ($M)	**32.1**	**29.1**	**21.0**	**13.0**	**6.3**	**101.5**	
Less Removals ($M)*	0.0	0.0	0.0	0.0	0.0	**0.0**	
NET INVESTMENT COSTS ($M)	**32.1**	**29.1**	**21.0**	**13.0**	**6.3**	**101.5**	

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Meter Conversion & Efficiencies	2023*	2024*	2025*	2026*	2027*	Total	Assumptions / Comments
Units	313	313	313	140	52	**1,131**	Based on number of installations
Average unit cost ($)*	19,036	19,036	19,065	28,833	58,834	-	Average unit cost includes labour (blended 2020 actuals) and materials
TOTAL GROSS COSTS ($M)	**6.0**	**6.0**	**6.0**	**4.0**	**3.1**	**25.0**	
Less Removals ($M)*	0.2	0.2	0.2	0.1	0.1	**0.7**	
NET INVESTMENT COSTS ($M)	**5.8**	**5.8**	**5.8**	**3.9**	**3.0**	**24.3**	

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Accredited Meter Lab	2023*	2024*	2025*	2026*	2027*	Total	Assumptions / Comments
Units						-	
Average unit cost ($)							
TOTAL GROSS COSTS ($M)*	**1.1**	**1.0**	**1.0**	**1.0**	**0.1**	**4.2**	Based on replacing obsolete lab equipment to maintain accreditation
Less Removals ($M)*	0.0	0.0	0.0	0.0	0.0	**0.1**	
NET INVESTMENT COSTS ($M)	**1.1**	**1.0**	**1.0**	**1.0**	**0.1**	**4.2**	

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Wholesale Meter replacements & upgrades	**2023***	**2024***	**2025***	**2026***	**2027***	**Total**	**Assumptions / Comments**
Units	17	13	10	10	10	**60**	Based on a mix of partial and full upgrades
Average unit cost ($)*	155,830	120,631	73,358	75,253	77,147		Average unit cost includes labour (blended 2020 actuals) and materials
TOTAL GROSS COSTS ($M)	**2.6**	**1.6**	**0.7**	**0.8**	**0.8**	**6.5**	
Less Removals ($M)	-	-	-	-	-	**-**	
NET INVESTMENT COSTS ($M)	**2.6**	**1.6**	**0.7**	**0.8**	**0.8**	**6.5**	

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

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B3 - ENERGY PROBE INTERROGATORY - 033

Reference:

Exhibit B-3-1, DSP Section 3.11, D-SR-05, Page 6-7, Table 2

Preamble:

The forecast expenditures for this demand program are projected from historical costs and trends. Storm response expenditures are based on an inflation-adjusted average of annual expenditures since 2005, with "outlier" years of unusually high expenditures (i.e. due to more severe storms) removed from the forecast – namely, 2006, 2013, and 2018. The expenditures for other categories of activities are guided by an inflation adjusted three year historical average.

Interrogatory:

Please provide the calculations that were used to derive the amounts shown in Table 2.

Response:

Table 2 is the output of the investment planning process as described in DSP Section 3.7.

The inputs into the investment planning process, excluding Norfolk, Woodstock, and Haldimand were the 2017-2019 inflation adjusted average expenditure with the following exceptions:

- "Emergency submarine and underground cable replacements" adjusted with additional $0.9M to account for increasing demand.

- "Post-trouble response" adjusted with $2.4M reduction to move out Power Quality related investments from this category.

Gross $ in millions 2020 dollar reference	2017	2018	2019	Average	Adjustment	Total Gross
Emergency pole and equipment replacements	$22.4	$22.4	$31.5	$25.4		$25.4
Emergency submarine and underground cable replacements	$6.5	$7.0	$9.1	$7.5	$0.9	$8.4
Post-trouble response	$18.0	$20.3	$23.0	$20.5	($2.4)	$18.1
Damage claims	$8.0	$9.3	$10.6	$9.3		$9.3

- “Storm damage response” was calculated as the 2005-2019 inflation adjusted average expenditure, excluding years 2006, 2013, 2018 as these had unusually high expenditures due to more severe storms.

Gross $ in millions (2020 dollar reference)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total Gross**
Storm damage response	$51.5	$120.3	$40.6	$70.1	$47.8	$37.9	$83.9	$52.1	$117.4	$49.9	$63.6	$56.4	$66.2	$101.3	$41.2	$55.1

When reviewing the calculations for this activity, it was realized that 2005 was mistakenly left out from the calculation. When included, the result of the average is $0.33M less per year than what is presented in evidence. The change results in an update to table 2 as follows:

Table 2 - Total Investment Cost

($M)	**2023***	**2024***	**2025***	**2026***	**2027***	**Total**
Gross Investment Cost	$133.7	$136.4	$139.1	$141.9	$144.8	$696.0
Less Removals	$16.0	$16.4	$16.7	$17.0	$17.4	$83.5
Capital and Minor Fixed Assets	**$117.7**	**$120.0**	**$122.4**	**$124.9**	**$127.4**	**$612.5**
Less Capital Contributions	$6.5	$6.6	$6.7	$6.9	$7.0	$33.7
Net Investment Cost	**$111.2**	**$113.4**	**$115.7**	**$118.0**	**$120.4**	**$578.8**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

The inputs into the investment planning process for Norfolk, Woodstock, and Haldimand was the 2018-2020 three year historical average expenditure across all activities which was $3.6M.

The total corrected D-SR-05 Gross Investment Cost is $119.9M in 2020 dollar reference which translates to the Gross Investment Cost as shown in the revised Table 2 above, when adjusted for inflation.

B3 - ENERGY PROBE INTERROGATORY - 038

Reference:

DSP Section 3.11, D-SR-12, Pages 33-38

Interrogatory:

a) Are all costs of the three alternatives assumed to be capital costs or are some of the costs expected to be OM&A? Please explain your answer.

b) Was the decision to select Alternative 3, Mass Replace the AMI System with a Competitively Procured AMI 2.0 System with Modern Functionality, based on a quantitative analysis such as discounted cash flow or a quantitative risk analysis, or was it based on a qualitative analysis that did not use any numerical methods? If a quantitative analysis was used, please file the analysis. If the answer is no, please explain why not.

Response:

a) Exhibit B-3-1 Section 3.11 D-SR-12 provides the investment summary for the replacement of Hydro One's current Advanced Metering Infrastructure (AMI 1.0) with a new AMI 2.0 system. There was an omission in the creation D-SR-12-Table 7 where removal costs and a previous year investment were not accurately reflected. The table should have contained an additional $30.3M in removal expense and an additional $0.7M in prev. year investment.

The original Table 7 and a corrected version of Table 7 are provided below:

Table 7 - Total Investment Cost (evidence per D-SR-12)

($M)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	3.9	30.9	62.0	153.7	154.4	158.3	128.0	691.2
Less Removals	0.0	0.0	0.0	0.0	0.0	1.0	0.0	1.0
Capital and Minor Fixed Assets	**3.9**	**30.9**	**62.0**	**153.7**	**154.4**	**157.3**	**128.0**	**690.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.9**	**30.9**	**62.0**	**153.7**	**154.4**	**157.3**	**128.0**	**690.2**

Table 7 - Total Investment Cost (Corrected Version)

($M)	Prev. Years	2023*	2024*	2025*	2026*	2027*	Forecast 2028+	Total
Gross Investment Cost	4.6	32.5	65.3	161.7	162.6	166.6	128.0	691.9
Less Removals	0.0	0.0	1.4	3.6	3.7	4.8	17.4	30.3
Capital and Minor Fixed Assets	**4.6**	**32.5**	**63.9**	**158.1**	**158.9**	**161.8**	**110.6**	**661.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**4.6**	**32.5**	**63.9**	**158.1**	**158.9**	**161.8**	**110.6**	**661.6**

Note: Exhibit B-3-1 Section 3.11 D-SA-04 Table 2 had removal costs overstated (see IR response to B3-Staff-138). The total net impacts based on errors from Exhibit B-3-1 Section 3.11 D-SA-04 Table 2 and Exhibit B-3-1 Section 3.11 D-SR-12 Table 7 is a total understated net removal cost of $0.8M between 2023 and 2027.
**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Except for the $30.3M removal expenses, all the costs in Table 7 (Corrected Version) above are capital investments to extend the service life of the metering system.

b) The decision to select Alternative 3, Mass Replace the AMI 1.0 System with Competitively Procured AMI 2.0 System with Modern Functionality, was based on a qualitative analysis which is provided in Exhibit B-3-1, Section 3.11, D-SR-12, Subsection F. In summary:

- Alternative 1, the status quo option of continuing to reactively replace failed AMI 1.0 with AMI 1.0 meters was assessed to be not viable, not economically prudent, posed significant regulatory and customer service risk, and restricted Hydro One's ability to plan for, and address, foreseeable customer needs over the system's long service life (see response to AMPCO IR 107).

- Alternative 2, mass replacing the AMI 1.0 system with an AMI 1.0 system with the same functionality, would involve placing obsolete equipment into service at the time it was installed. Given that a new AMI system is a 20-year investment, any new AMI system must not only address current needs but must also consider and address future needs. This is particularly relevant to AMI given it is not economic nor practical to retrofit meters in-situ in the future. This is because costs would be incurred to visit, remove, retrofit, reseal, and re-install 1.4M meters as well as upgrading thousands of network devices. Also, each installation would require multiple additional visits, resulting in millions of dollars of unplanned costs over the whole program compared to the limited site visits in a mass replacement contemplated for AMI 2.0. An AMI 2.0 system with up-to-date functionality not only addresses core functionality to ensure regulatory compliance, but also provides customers with benefits from advancements in AMI technology since 2007 (e.g., improved network coverage, additional features, enhanced security, etc.), savings (e.g., reduced manual meter reading, reduced network management costs, etc.) and responds to evolving customer expectations, technological innovation, and a changing policy landscape (e.g., carbon reduction initiatives in response to climate change). For further details, please refer B3-DRC-010.

- Alternative 3, the selected alternative, involved the release of the AMI 2.0 RFP in 2020, following Hydro One’s established guidelines and processes ensuring quality, fairness, and due diligence in engaging third-party suppliers. Of note, Hydro One entered a joint procurement process with Alectra Utilities which in the event both parties independently select the same vendor, price benefits occur through joint purchase volumes. This process is expected to be completed in 2022.

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B3 - ENERGY PROBE INTERROGATORY - 039

Reference:

DSP Section 3.11, D-SS-01, Page 15

Interrogatory:

a) Are all costs of the two alternatives assumed to be capital costs or are some of the costs expected to be OM&A? Please explain your answer.

b) Was the decision to select Alternative 2, System Upgrades to Meet Load Growth, based on a quantitative analysis such as discounted cash flow or a quantitative risk analysis, or was it based on a qualitative analysis that did not use any numerical methods? If a quantitative analysis was used, please file the analysis. If the answer is no, please explain why not.

Response:

a) All costs of the two alternatives are capital costs. The “Do Nothing” alternative will eventually lead to asset failure, which would be resolved by other capital programs D-SR-01 “Distribution Stations Demand Capital Program” or D-SR-05 “Distribution Lines Trouble Call”.

b) The alternative selected was based on a quantitative risk assessment using the methodology detailed in B-03-01 Section 3.7, Pg.9, Line 4, and the taxonomy tables found in B-01-01 Section 1.7, pg.19-20. The table below summarizes the total risk mitigated for each project, as well as the Risk Spend Efficiency (RSE).

   In the table below, there are four additional projects listed that were not shown in the ISD filed. These projects had been incorrectly listed under D-SR-04 “other projects <$1M” and are now being correctly listed under D-SS-01.

Project Name	Project ID	Risk Mitigated	Risk Spend Efficiency
City of Owen Sound Tie-Line Reinforcement	SS-01.01	48021	18241
Bradford North DS	SS-01.02	127475	25821
Colpoys Bay DS F2 Feeder Upgrade	SS-01.03	50606	40796
Lively DS F2 Upgrade - Black Lake Rd	SS-01.04	57817	35281
Mar DS	SS-01.05	145936	30143
Town of Shelburne voltage conversion	SS-01.06	99803	27623
New Old School DS and feeders	SS-01.07	501692	62125
King City DS - New Station & Feeders	SS-01.08	34426	10075
Caledonia TS New Feeders	SS-01.09	1804204	280270
Brockville 44kV Load Growth	SS-01.10	842588	78872
Dresden Area Load Relief	SS-01.11	364876	32871
Ancaster Area Load Relief	SS-01.12	101288	12099
Dover Center Load Relief	SS-01.13	131340	24086
Hawthorne TS M1 Load Growth	SS-01.14	133799	27011
Almonte TS M28 Load Growth	SS-01.15	103478	30559
Elginburg DS F2 and Station Load Growth	SS-01.16	56928	36926
Harrowsmith DS F3 F5 Load Growth	SS-01.17	49175	13287
Pembroke TS Load Growth	SS-01.18	90627	8609
Calabogie DS F1 Load Growth	SS-01.19	40230	17268
Manotick DS Add F3 Feeder Load Growth	SS-01.20	56928	21282
Stewartville TS Load Growth	SS-01.21	251771	186437
Kemptville 8kV Load Growth	SS-01.22	55929	31956
Chesterville TS Load Growth	SS-01.23	302922	249669
Listowel Load Relief - Load Growth	SS-01.24	71101	18950
Ferndale DS F2 Feeder Upgrade - Load Growth	SS-01.25	50587	20382
Saugeen Shores DS and Port Elgin Load Growth	SS-01.26	184966	32101
Commanda DS Load Growth	SS-01.27	15578	11212
Kirkland Lake Voltage Conversion - Stage 2	SS-01.28	148468	57559
Kirkland Lake Voltage Conversion - Part 3	SS-01.29	178954	57463
Manitoulin TS - Add Third Feeder - Load Growth	SS-01.30	70494	13257
Wikwemikong Supply - Station & Line Work	SS-01.31	71065	10279
Crilly DS Upgrade	SS-01.32	55746	7183
Elmhurst Beach DS	SS-01.33	51546	9486
Kleinburg TS M26 Extension	SS-01.34	34426	14462
Mount Albert DS	SS-01.35	143227	78229

Midhurst Wilson DS F2 Extend to Doran Rd Load Grow	SS-01.36	58040	23825
Midhurst Wilson DS Feeder Development to Carson Rd	SS-01.37	52033	52033
Carlisle DS Offloading	SS-01.38	44700	14114
Solina DS Upgrade and Feeder Expansion	SS-01.39	130118	25699
Bondhead Area Load Relief	SS-01.40	27107	5808
South Middle Road TS DESN1 Feeder Development	SS-01.41	716253	5061
Norfolk TS new feeder build	SS-01.42	87520	9470
Edgeware TS new feeder build	SS-01.43	35825	17457
Bloomsburg HVDS new feeder build	SS-01.44	119910	24015
South Middle Road TS DESN2 Feeder Development	SS-01.45	637479	9106
Rockland West Load Growth	SS-01.46	48674	17605
Brockville 8kV Load Growth	SS-01.47	62008	18684
Frontenac TS Load Growth	SS-01.48	35410	8364
Napanee TS M3 Load Growth	SS-01.49	251771	96961
Curve Inn DS New Feeder	SS-01.50	739955	179514
Belle River Load Growth	SS-01.51	19716	3509
Manning Road and Hwy 2 Load Growth	SS-01.52	19640	4314
Holland DS F1 to Doane DS F2 Feeder Tie	SS-01.53	45953	21099
Corbetton Area Load Growth	SS-01.54	12383	7284
Kleinburg TS M28 Expansion - Load Growth	SS-01.55	96966	11278
Tillsonburg TS M1 Load Relief	SS-01.56	2545989	220802
Strathroy Carroll St. Loop	SS-01.57	55929	34333
Strathroy TS Load Relief	SS-01.58	108949	43742
Wolverton HVDS Feeder Load Relief	SS-01.59	123683	71190
Meaford TS M2 Conductor Refurbishment Load Growth	SS-01.60	88551	58573
Owen SoundTS M26 Conductor Refurb Load Growth	SS-01.61	103234	41481
Meaford TS M2 Padmounts Lora Bay Oxmead DS F3	SS-01.62	223795	74145
Palmerston TS – M2 Load relief - New feeder	SS-01.63	118514	19854
Plainfield DS F3 Enhancement	SS-01.64	15125	5729
Dartford DS F3 Enhancement	SS-01.65	12009	4081
Jarvis TS New Feeder Build	SS-01.66	860806	141095
Shabaqua DS F1 upgrade	SS-01.67	127492	25279
Sunnidale Corners DS Load Growth	SS-01.68	12383	6131
Marionville DS Load Growth	SS-01.69	89515	16077
Kemptville East 8kV Load Growth	SS-01.70	44066	11297
Brockville 44kV Load Growth Part 2	SS-01.71	764170	117972
Newport PDS Load Relief	SS-01.72	143227	27126
Lambton TS M7 M8 Feeder Build	SS-01.73	399655	44406

Burleigh DS F2 1ph to 3ph Conversion - Part 2	SS-01.74	86134	57423
Leamington Area DESN5 Feeder Development	SS-01.75	722990	14864
Leamington Area DESN6 Feeder Development	SS-01.76	612128	12096
Forest Jura DS Fan Monitoring	SS-01.77	45554	31395
Dunnville DS F1 Load Relief	SS-01.78	159846	113366
Brockville Centennial DS Transformer	SS-01.79	35795	17898
Mount Forest DS #2	SS-01.80	6799	6756
Carleton Place Francis DS Padmounts	SS-01.81	44044	29019
Trenton Oak Contingency	SS-01.82	4343	4062

As a result of the aforementioned changes between SR-04 and SS-01, following are the revised investment tables for each respective ISD:

SR-04: Table 2 - Total Investment Cost

($M)	2023*	2024*	2025*	2026*	2027*	Total
Gross Investment Cost	51.0	48.5	32.3	36.7	36.3	204.8
Less Removals	5.3	6.4	3.9	3.3	3.6	22.4
Capital and Minor Fixed Assets	**45.8**	**42.1**	**28.4**	**33.5**	**32.7**	**182.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**45.8**	**42.1**	**28.4**	**33.5**	**32.7**	**182.4**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

SS-01: Table 2 - Total Investment Cost

($M)	2023*	2024*	2025*	2026*	2027*	Total
Gross Investment Cost	114.6	88.6	146.8	89.5	118.5	558
Less Removals	9.9	6.7	11.1	8.8	12.0	48.6
Capital and Minor Fixed Assets	**104.7**	**81.9**	**135.8**	**80.6**	**106.5**	**509.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**104.7**	**81.9**	**135.8**	**80.6**	**106.5**	**509.4**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

B3 - ENERGY PROBE INTERROGATORY - 043

Reference:

Exhibit B-3-1, DSP Section 3.11, D-SS-05, Pages 10-11, Table 2

Interrogatory:

a) Please explain how the forecast of the Gross Investment Cost was developed showing all calculations.

b) Are all costs of the three alternatives assumed to be capital costs or are some of the costs expected to be OM&A? Please explain your answer.

c) Was the decision to select Alternative 3, Continue with the WPF Investment to Improve Reliability for 600,000 Customers, based on a quantitative analysis such as discounted cash flow or a quantitative risk analysis, or was it based on a qualitative analysis that did not use any numerical methods? If a quantitative analysis was used, please file the analysis. If the answer is no, please explain why not.

Response:

a) The average gross cost to deploy remote controllable switching equipment and communicating faulted circuit indicators was estimated per device. The expected number of devices needed per feeder was determined based on historical deployments under this program. The number of devices was then multiplied by expected cost per device.

The table below shows the calculation over the plan period:

	2023*	2024*	2025*	2026*	2027*
Feeders with Switches	44	45	46	46	46
# of Feeders with CFCIs	60	60	60	60	60
Total Feeders	104	105	106	106	106
Number of CFCIs	1070	1070	1070	1070	1070
Expected Cost per CFCI ($k) ($3.1k/device in 2023)*	3.1	3.2	3.2	3.3	3.3
Expected cost for CFCIs ($M)*	**3.4**	**3.5**	**3.5**	**3.6**	**3.6**
Number of Switches	243	247	252	253	254
Expected Cost per Switch ($k) ($158/Device in 2023)*	158.1	160.2	162.5	165.2	167.4
Expected Cost for Switches ($M)*	**38.4**	**39.6**	**40.9**	**41.8**	**42.5**
Total Program Cost ($M)*	**41.7**	**43.0**	**44.4**	**45.3**	**46.1**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

b) There is no cost associated with Alternative 1 (Do nothing alternative). The associated cost with Alternative 2 and 3 are all capital cost as it involves the installation of new equipment.

c) The alternative selected was based on a quantitative risk assessment using the methodology detailed in B-03-01 Section 3.7, Pg.9, Line 4, and the taxonomy tables found in B-01-01 Section 1.7, pg.19-20. The table below summarizes the results of total lifecycle risk mitigated as well as the Risk Spend Efficiency for each of the two major categories under this investment: installation of remote operable devices, and installation of communicating fault current indicators (CFCI). Furthermore, Customer Engagement results supported Hydro One's Accelerated Plan Pace, to provide reliability improvements for 600,000 customers.

The table below shows risk mitigated and Risk Spend Efficiency (RSE) for Remote Operable devices:

Plan Year	Risk Mitigated	Risk Spend Efficiency
2023	2,449,691	67,236
2024	624,685	16,818
2025	568,682	15,017
2026	502,441	12,688
2027	439,653	10,893

The table below shows risk mitigated and Risk Spend Efficiency (RSE) for Communicating Fault Current Indicators:

Plan Year	Risk Mitigated	Risk Spend Efficiency
2023	161,293	50,247
2024	144,598	44,355
2025	128,773	39,022
2026	113,773	33,962
2027	34,842	10,248

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B4 - ENERGY PROBE INTERROGATORY - 045

Reference:

Exhibit B-4-1, GSP Section 4.1, Page 8, Table 2, Figure 1 and Figure 2

Interrogatory:

a) Please Provide the Historic (5 year) together with the Bridge and 2023-2027 forecast, General Plant expenditures in the same format as Table 2 and Figure 1

b) Please provide the CAGR (%) for each year and the 10 year period.

c) Why are GP expenditures in 2022 forecast to be so low?

d) Under the prior IRM plans for Transmission and Distribution, please provide the annual and average percentages of General Plant Expenditures as a percentage of Total CAPEX.

e) Please provide the percentage for the current IRM plans.

f) Provide the following Metrics 2017- 2027:
   i. GP expenditures/MWh load
   ii. GP expenditures/customer
   iii. Based on the above, discuss how GP expenditures have/have not kept pace total CAPEX, load, and number of customers.

Response:

a) and b)

The Historic, Bridge and Forecast Period years are provided in Table 1 and Figure 1 below. In addition, Table 1 includes the CAGR for each year, relative to the 2018 base year. As shown in Table 1, the CAGR for the ten-year period is 5%.

Table 1 - Net Capital Expenditures for General Plant, including CAGR

General Plant Area	Historical Actual/Forecast ($M)				Bridge Forecast ($M)	Forecast Period ($M)**				
	2018	2019	2020	2021*	2022	2023	2024	2025	2026	2027
Fleet	27.4	44.0	39.2	42.7	43.4	80.4	82.1	83.0	84.2	86.9
Facilities & Real Estate	37.1	31.6	64.7	39.1	42.0	96.2	96.9	64.9	61.1	53.1
Information Solutions	94.4	114.6	118.4	96.2	73.0	126.2	124.3	119.5	128.5	111.7
System Operations	9.1	10.7	71.6	114.8	27.5	28.8	19.5	8.6	8.4	6.8
Other	6.3	5.5	8.9	18.9	22.6	29.0	25.9	23.1	24.4	23.4
Total General Plant	**174.3**	**206.4**	**302.9**	**311.7**	**208.5**	**360.7**	**348.8**	**299.2**	**306.7**	**282.0**
General Plant - Transmission Allocation	83.6	92.1	124.7	137.8	102.8	154.5	130.5	120.2	122.0	110.5
General Plant - Distribution Allocation	90.7	114.3	178.2	173.8	105.7	206.2	218.2	179.0	184.7	171.5
CAGR (%)	**0%**	**18%**	**32%**	**21%**	**5%**	**16%**	**12%**	**8%**	**7%**	**5%**

**This reflects the 2021 forecasted amounts included in the 'as filed' evidence dated August 5, 2021. For 2021 actual amounts, please refer to Exhibit O-2-1, Attachment 4.*

***The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

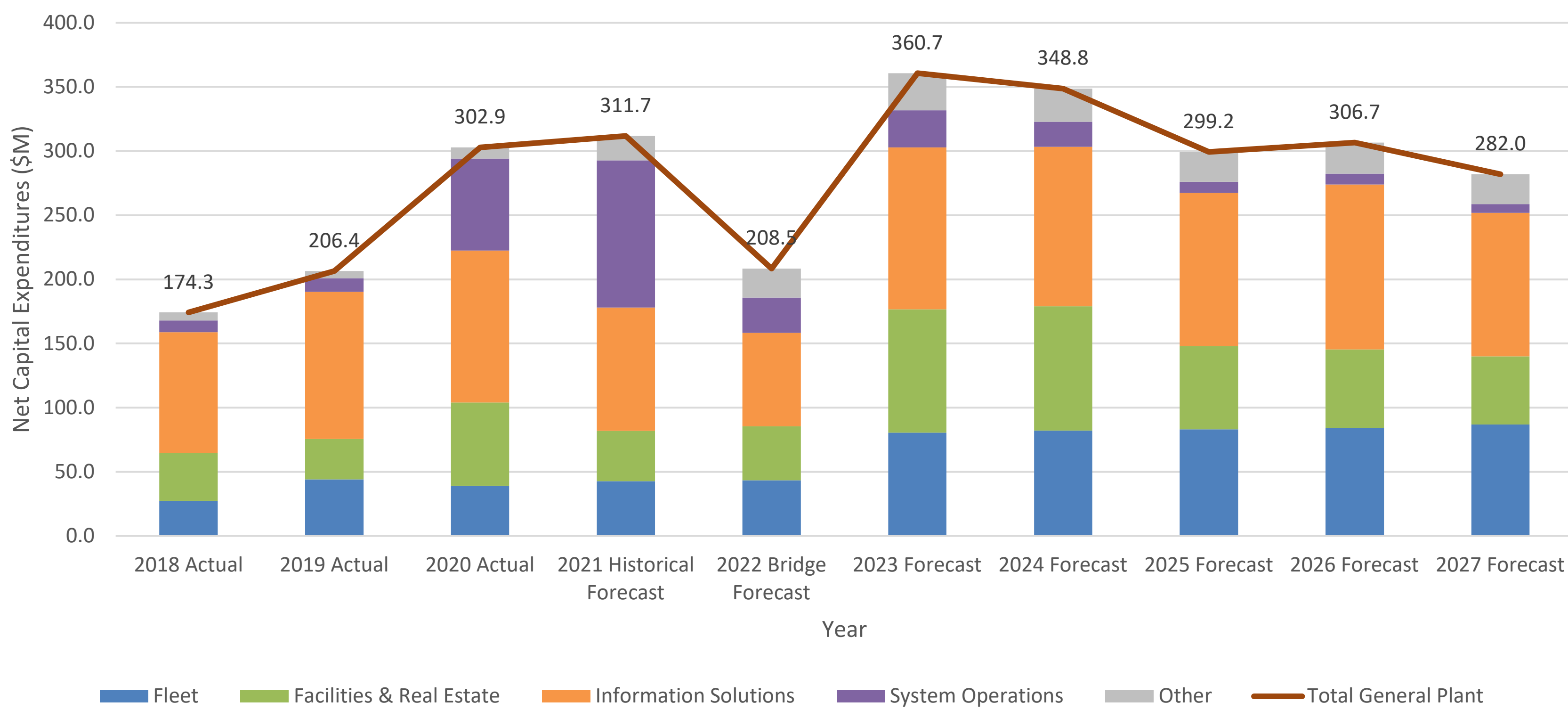

Figure 1: Net capital expenditures for General Plan by function from 2018-2027

c) Please refer to the interrogatory response in B4-Staff-158 question (a).

d) The annual and average percentages of General Plant Expenditures as a percentage of Total CAPEX are provided below in Table 2 for 2018-2022.

Table 2 - Annual and Average Percentages of General Plant Expenditures as a Percentage of Total CAPEX for 2018-2022

General Plant %	Actual			Forecast		5-Year Average
	2018	2019	2020	2021	2022	
General Plant % of Total Transmission CAPEX	9%	9%	11%	12%	8%	10%
General Plant % of Total Distribution CAPEX	16%	19%	26%	24%	16%	20%

e) The annual and average percentages of General Plant Expenditures as a percentage of Total CAPEX are provided below in Table 3 for 2023-2027.

Table 3 - Annual and Average Percentages of General Plant Expenditures as a Percentage of Total CAPEX for 2023-2027

	2023	2024	2025	2026	2027	5-Year Average
General Plant % of Total Transmission CAPEX	10%	8%	8%	8%	7%	8%
General Plant % of Total Distribution CAPEX	19%	20%	15%	16%	15%	17%

f) The requested metrics for (i) and (ii) are provided in Tables 4 and 5 for Transmission and Distribution, respectively.

Table 4 - Transmission Allocated General Plant Expenditures per MW and Delivery Point

Metric	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(i) GP Expenditures per MW Load[1] ($/MW)	3,531	3,596	4,227	5,102	6,455	4,803	7,194	6,055	5,569	5,640	5,106
(ii) GP Expenditures per Delivery Point ($/DP)[2]	115,330	125,114	136,469	184,486							

[1] 2017 to 2020 assumes the MW Load to be equal to the annual peak MW. For 2021-2027, the annual peak is not available, so the 12-month average peak forecast is used for the load.
[2] Delivery points are not forecasted for Transmission.

Table 5 - Distribution Allocated General Plant Expenditures per MWh and Customer

Metric	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(i) GP Expenditures per MWh Load ($/MWh)	3	3	3	6	5	3	6	6	5	5	5
(ii) GP expenditures per distribution customer ($/customer)	75	67	83	129	125	75	146	153	125	128	118

iii. Expenditures in General Plant are paced to help ensure that safe, reliable and functional General Plant assets are available to enable the Transmission and Distribution businesses to execute their work programs and achieve their strategic objectives. As such, these expenditures are not correlated with the number of delivery points, customers or load. For additional details on the pacing of General Plant expenditures, please refer to B4-Staff-158.

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B4 - ENERGY PROBE INTERROGATORY - 047

Reference:

Exhibit B-4-1, GSP Section 4.3, Page 6

Interrogatory:

a) When did Hydro One last undertake a Fleet life cycle study? Please provide a copy of the Study?

b) How are vehicles assigned to Transmission and Distribution? Please provide the split for 2021

c) Based on the Utilimarc Study, please provide the Capital Investment Plans related to the Historic and Proposed Scenarios (delineate by type of vehicle)

d) Please provide the 2021 -2027 Operating Costs related to the two scenarios (fuel and maintenance)

e) Please provide the labour hours for each scenario and annual labour cost.

Response:

a) As stated in Exhibit B-4-1 Section 4.3, this is the first time Hydro One has undertaken a study of this kind.

b) Vehicles are assigned based on line of business (LOB) work programs and execution needs and staffing requirements. For 2021, on-road vehicles were assigned 53% to Distribution LOBs, 36% to Transmission LOBs and 11% to other shared LOBs.

c) Table 1 below shows the capital investment plan by vehicle type under the Historic Funding Scenario. The capital investment plan for the Proposed Scenario can be found in GSP Section 4.11, ISD G-GP-01, Table 1, page 8. [1]

[1] Small Off-Road and Service Equipment were not included in the Utilimarc Fleet Lifecycle Study.

Table 1 - Capital Investment Plan by Vehicle Type under the Historic Funding Scenario

Vehicle Type	2023 ($M)	2024 ($M)	2025 ($M)	2026 ($M)	2027 ($M)
Heavy PTO	12.0	12.2	12.4	12.7	12.9
Light & Heavy Non-PTO	7.5	7.7	7.9	8.0	8.2
Miscellaneous	4.9	3.7	5.2	5.3	4.8
Off Roads	4.1	5.6	4.3	4.4	4.9

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

d) See Exhibit B-4-1 Section 4.3, Attachment 2, Section 3.2 (Projections), pages 12-13 for the maintenance related to the two scenarios. Equipment fuel performance is assumed to have a minimal difference between old and new units, thus fuel costs are expected to be in line between the two scenarios.

e) Table 2 provides the labour hours for each scenario.[2]

Table 2 - Labour Hours for each Funding Scenario

Year	2023	2024	2025	2026	2027
Full Funding	354,785	344,052	334,045	324,383	315,896
Proposed Funding	359,953	353,667	347,848	341,966	336,052
Historical Funding	375,880	383,991	391,955	399,617	406,851

Tables 3 and 4 provide the labour costs for each scenario by Internal Labour and External Labour, respectively.

[2] The model assumes consistent usage of equipment regardless of vehicle age. This is due to the implicit assumption that an older vehicle can do the same work as a young vehicle. However, this does not usually occur in practice. Equipment usually sees its peak utilization in years 2 and 3, which can be expected to drop to about 60% of peak utilization by the end of its life. This means that the above-noted labour hours projections should *not* be compared to historic labour hours or interpreted as staffing levels recommendations.

1

Table 3 - Internal Labour Cost for each Funding Scenario ($M)

Year	2023	2024	2025	2026	2027
Full Funding	24.8	24.5	24.3	24.1	23.9
Proposed Funding	25.2	25.3	25.4	25.4	25.5
Historical Funding	26.3	27.4	28.5	29.7	30.8

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

2

Table 4 - External Labour Cost for each Funding Scenario ($M)

Year	2023	2024	2025	2026	2027
Full Funding	18.0	17.8	17.6	17.5	17.4
Proposed Funding	18.2	18.3	18.3	18.4	18.4
Historical Funding	19.1	19.9	20.6	21.5	22.3

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

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E - ENERGY PROBE INTERROGATORY - 065

Reference:

Exhibit E-4-4, Page 2, Table 1

Interrogatory:

a) Please provide the Total annual percentage increases.

b) Please provide a line showing the Total Cost each year escalated by inflation for each year from 2018 (rebasing distribution).

c) Are the allocations to Transmission and Distribution consistent with the B&V recommendations? Please compare the allocation percentages.

Response:

a) Please see the revision to the referenced Table 1 below under part b) with the added row for "Year over Year Change".

b) Please see the revision to the referenced Table 1 below with the added row for "2018 Costs with Inflation". A 2% annual inflation was assumed for Transmission and Other allocated costs, and a 2.2% annual inflation was assumed for Distribution allocated costs between 2018 and 2020. For 2021, 2022 and 2023, an annual inflation of 3.5%, 4.5% and 3.3% was assumed, respectively.

Table 1 - Summary of Total Information Solutions OM&A ($M)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast*	Forecast	Inflation Update**
IT Sustainment	73.9	92.1	85.7	86.8	86.2	93.6
Business Telecom	18.2	18.5	18.5	17.8	17.8	18.9
IT Development	15.2	8.8	9.6	16.4	12.7	15.1
Security	3.9	4.8	4.6	6.8	7.5	8.9
IT Management and Project Control	14.3	11.9	12.8	9.6	10.9	12.6
Total	**125.5**	**136.2**	**131.2**	**137.4**	**134.9**	**149.3**
Year over Year Change		**8.5%**	**-3.7%**	**4.7%**	**-1.8%**	**10.7%**
Allocated to Transmission	50.4	53.7	51.2	51.4	51.2	56.5
Allocated to Distribution	73.8	81.1	78.4	83.8	81.5	90.4
Allocated to Other[1]	1.4	1.4	1.6	2.2	2.2	2.4
2018 Actuals with Inflation Rates Noted Above	**125.5**	**128.3**	**131.0**	**135.5**	**141.5**	**146.2**

**This reflects the 2021 forecasted amounts included in the 'as filed' evidence dated August 5, 2021. For 2021 actual amounts, please refer to Exhibit O-2-1, Attachment 6.*

***The 2023 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

c) As described in exhibit E-04-08, the Black & Veatch allocation methodology applies to common corporate costs. The allocation recommendations contained in Attachment 1 to that exhibit impact only common corporate costs, which make up a portion of Information Solutions OM&A costs within exhibit E-04-04 Table 1, specifically captured under the "IT Management and Project Control" item. The common corporate costs and their allocations are consistent with the Black & Veatch allocation methodology.

Table 2 – Common Corporate Costs Associated with Information Solutions

Common Corporate Costs Associated with Information Solutions	2018	2019	2020	2021	2022	2023
Allocated to Transmission	55%	55%	54%	46%	46%	46%
Allocated to Distribution	45%	45%	46%	54%	54%	54%

[1] As discussed in Exhibit E-04-08, Section 3.0, the amounts allocated to "Other" in Table 1 above reflect costs allocated to Hydro One Network's affiliates.

B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 011

Reference:

Exhibit B-2-1, TSP Section 2.11, T-SA-01 to T-SA-10

Interrogatory:

a) Please complete the following table for T-SA-01 to T-SA-10:

	Total Cost	Total CIAC	Total forecast incremental revenue
T-SA-01			
…			
T-SA-10			

b) Does Hydro One's application include projects that are 100% customer funded? If not, please estimate the cost of these projects over 2023-2027.

c) Please provide a table showing the system access costs for each year from 2018 (historic) to 2027 (forecast) broken down by those funded by the customers being connected and those recovered from all ratepayers through the revenue requirement.

Response:

a) The completed table is provided below. The Contribution-in-Aid-of-Construction (CIAC) is defined simply as Capital Contribution. The Capital Contribution is determined by subtracting the incremental revenue from the customer's load from the total project cost.

ISD	Investment Title	Total Project Cost ($ Millions)	Customer Capital Contribution ($ Millions)	Total Forecast Incremental Rate Revenue ($ Millions)
T-SA-01	New Customer Connection Station	100.0	73.0	27.0
T-SA-02	IAMGOLD – 115 kV Mine Connection	65.1[1]	33.3	25.8
T-SA-03	Halton TS: Build a Second 230/27.6kV Station	34.9	26.9	8.0
T-SA-04	Connect Metrolinx Traction Substations	25.3	17.4	8.0
T-SA-05	Future Transmission Load Connection Plans[2]	109.1	70.6	38.5
T-SA-06	Protection and Control Modifications for Distributed Generation[2]	18.0	18.0	0.0
T-SA-07	Secondary Land Use Projects	112.2	56.2	56.0
T-SA-08	H29/H30: Reconductor 230kV Circuits	8.0	2.7	5.3
T-SA-09	New Transformer Station in Northern York Region	35.0	23.3	11.7
T-SA-10	Build Leamington Area Transformer Stations	135.9	0.0	135.9

[1] *includes $6.1M in removal costs as outlined in ISD T-SA-02*
[2] *reflects total project costs over the five-year test period as outlined in the referenced ISD*

b) Yes, Hydro One's application includes 100% customer funded projects.

c) Please see table below for the System Access historical and future forecast costs, broken down by those funded by the connecting customers through capital contributions and those recovered through incremental rate revenue as a result of the load connected.

($ Millions)	Historical				Bridge	Test Years*				
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Total Expenditures	95.3	88.7	90.8	113.8	78.3	165.9	162.4	122.8	85.0	88.2
Customer Capital Contributions	61.7	42.7	71.4	73.6	46.9	82.3	87.8	59.8	46.6	35.4
Incremental Rate Revenue	33.7	46.1	19.4	40.1	31.5	83.6	74.6	63.0	38.4	52.8

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 024

Reference:

Exhibit B

Exhibit G-1-2, Page 35

Preamble:

Hydro One states as follows:

> *Additionally, objectives related to decarbonisation and electrification may result in increased adoption of electric vehicle or fuel switching, which are likely to drive changes to forecasts for service upgrades.*

Interrogatory:

a) What investments is Hydro One making over 2023-2027 to accommodate an expansion of electric vehicles? Please describe these and provide the dollar total.

b) What investments is Hydro One making over 2023-2027 to accommodate fuel switching over that period? Please describe these and provide the dollar total.

Please confer with staff for the Canada Greener Homes Grant to obtain estimates of: (i) the number of customers in Ontario that will use the grant to switch from fossil fuel heating to an electric heat pump and (ii) the number of customers that will use the grant to switch from electric resistance heating to an electric heat pump. Please provide a response on an annual basis if possible.

Response:

Hydro One notes that the preamble to this interrogatory is taken from the description of Hydro One’s proposed Externally Driven Distribution Projects Variance Account. For context, the full paragraph excerpt is as follows:

> *In addition, the [Externally Driven Distribution Projects Variance Account] will capture variances resulting from new externally driven work requirements that may arise during the 2023-2027 period, but which were not contemplated in the investment plan. As an example Hydro One Distribution could be required to respond to enable increasing DER connections, new DER procurement programs or assume a new or expanded role in the deployment of coordinated infrastructure solutions to facilitate electrification, transportation or other policy objectives. Additionally, objectives related to decarbonisation and electrification may result*

in increased adoption of electric vehicle or fuel switching, which are likely to drive changes to forecasts for service upgrades.

a) In respect of planned investments being made by Hydro One over 2023-2027 to accommodate an expansion of electric vehicles, the projected investment in electric vehicles for 2023-2027 is $**89.6M**.[1] Additional investments will be made by Facilities and Real Estate to install new EV charging infrastructure thereby supporting the roll out of electric vehicles at various Hydro One sites. Based on the need for infrastructure over the past years, the expected annual estimated costs for electric vehicle charger installations is $0.7M across 10 sites for the current planning period of 2023-2027.

As the EV load projection for consumers is embedded within Hydro One's load forecasts, there is no specific investment for consumer EV load at this time. However, Hydro One is proactively assessing the overall impact of increasing EV penetration and the best approach to minimize future upgrade costs to rate payers.

b) Fuel switching is embedded within Hydro One's load forecasts; there is no specific investment for fuel switching at this time.

c) Hydro One has reached out the Greener Homes Division at Natural Resources Canada to request this information, however we did not receive any data from them yet. Conservation savings from the Canada Greener Homes Grant program are included in IESO's total CDM savings assumption which is used for the purposes of this filing. Program specific information is not available.

[1] The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2

C - LONDON PROPERTY MANAGEMENT ASSOCIATION - 011

Reference:
Exhibit C-2-2, Table 1

Interrogatory:
Please update Table 1 to reflect the most recent actual information available for 2021. Please also explain any changes that result from the 2021 update in 2022 and/or subsequent years.

Response:
Hydro One continues to track toward the 2021 forecast as filed. Any variance at year-end will be accommodated through an adjustment in 2022 to maintain consistency with the OEB-approved plan total.

1 **Table 1 – In-Service Capital Additions 2018-2027 ($M) (Exhibit C-2-2, p.2)**

OEB Category	2018		2019		2020		2021			2022		2023	2024	2025	2026	2027
	OEB Approved	Actuals	OEB Approved	Actuals	OEB Approved	Actuals	OEB Approved	2021 YTD (Q3)	Forecast	OEB Approved	Bridge	Forecasting Period*				
1. System Access	196.9	196.9	147.7	189.9	144.7	197.5	160.8	157.4	182.7	143.1	181.2	252.1	254.5	239.4	223.7	214.8
2. System Renewal	229.6	229.6	223.3	201.9	225.3	217.8	241.9	159.8	248.7	251.2	225.5	372.9	447.9	530.9	501.3	533.9
3. System Service	113.9	113.9	81.6	89.2	170.9	97.3	138.8	49.1	70.8	112.4	137.7	232.1	156.3	264.4	211.4	205.4
Subtotal Categories 1, 2, and 3	**540.4**	**540.4**	**452.6**	**481.1**	**540.9**	**512.6**	**541.4**	**366.2**	**502.2**	**506.7**	**544.4**	**857.0**	**858.8**	**1034.7**	**936.4**	**954.1**
4. General Plant Allocated to Distribution	87.4	87.4	103.9	104.1	135.9	155.5	164.1	96.2	197.9	103.4	112.0	155.5	222.2	231.9	180.5	211.8
Grand Total	**627.8**	**627.8**	**556.5**	**585.1**	**676.8**	**668.1**	**705.5**	**462.4**	**700.1**	**610.1**	**656.4**	**1012.5**	**1080.9**	**1266.6**	**1116.9**	**1165.9**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

B1 - SCHOOL ENERGY COALITION INTERROGATORY - 046

Reference:

Exhibit B-1-1, SPF Section 1.2, Page 15

Interrogatory:

Please provide a table that includes for each year between 2018 and 2027, the total amount of Hydro One's actual and forecast transmission capital expenditures for projects that are included in a Regional Infrastructure Plan (RIP), broken down by category (i.e. system access, renewal, service, etc.). Please provide a similar table on an in-service addition basis.

Response:

Please see below tables for Hydro One's actual and forecast totals for transmission projects included in a Regional Infrastructure Plan (RIP) by OEB Category.

Table 1 - Transmission Capital Expenditures for projects included in a RIP by OEB category

($ Millions)	Actual			Forecast						
OEB Category	**2018**	**2019**	**2020**	**2021**	**2022**	**2023***	**2024***	**2025***	**2026***	**2027***
System Access	25.6	42.0	17.4	32.9	6.8	9.2	35.1	17.0	8.1	5.1
System Renewal	201.0	236.6	269.8	268.8	430.0	558.6	505.6	488.2	433.5	400.1
System Service	14.9	17.9	75.3	166.0	70.8	45.4	39.5	26.3	0.0	0.0

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

Table 2 - Transmission In-Service Additions for projects included in a RIP by OEB category

($ Millions)	Actual			Forecast						
OEB Category	**2018**	**2019**	**2020**	**2021**	**2022**	**2023***	**2024***	**2025***	**2026***	**2027***
System Access	7.8	62.9	4.9	11.3	43.2	2.8	0.0	46.6	0.0	26.3
System Renewal	197.9	199.0	257.1	222.0	320.0	567.5	482.8	615.4	411.3	481.6
System Service	2.6	22.2	6.8	34.0	286.6	12.0	0.0	108.5	0.0	0.0

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

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B2 - SCHOOL ENERGY COALITION INTERROGATORY - 078

Reference:

Exhibit B-2-1, TSP Section 2.4, Page 9

Interrogatory:

Please provide a revised version of Table 3 that includes 2018 to 2022 actual/forecast information.

Response:

Please see Table 3 below, revised to include System Renewal actual/forecast expenditures for the 2018 to 2022 period. The Line Connection and Network expenditures were mislabelled in TSP Section 2.4, and this has been corrected below.

Pool	OEB Investment Category	2018	2019	2020	2021	2022	2023*	2024*	2025*	2026*	2027*
Line Connection	System Renewal	114.7	105.6	104.9	118.3	125.9	144.2	165.7	180.7	199.2	196.5
Network	System Renewal	349.4	370.2	340.9	310.9	451.8	578.0	603.7	616.1	632.1	634.4
Transformation	System Renewal	230.7	235.7	277.9	221.2	278.5	410.3	406.2	402.0	411.6	429.8
Common	System Renewal	81.4	81.0	80.3	89.3	115.3	107.4	117.2	118.4	101.4	69.6
Grand Total		**776.2**	**792.6**	**804.0**	**739.6**	**971.5**	**1239.8**	**1292.8**	**1317.3**	**1344.4**	**1330.4**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

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B2 - SCHOOL ENERGY COALITION INTERROGATORY - 081

Reference:

Exhibit B-2-1, TSP Section 2.4, Attachment 2, Page 5

Interrogatory:

Hydro One states that for "Group and Individual Performance outliers, Hydro One will cover the remedial costs of restoring and sustaining the inherent reliability performance of the existing assets to what was designed originally.":

a) For each year since 2018, how many times has Hydro One undertaken such activities and what was the total annual cost?

b) How much is budgeted for such activities in each year in 2023 and 2027 and under which capital program are the costs contained within?

Response:

a) Hydro One undertakes remedial actions in two steps, i) as part of System Renewal capital investments to address poor condition and deteriorating infrastructure that would restore and/or sustain the inherent reliability performance of the delivery point to what it was designed to and ii) identify any incremental remediation in the absence of planned System Renewal investments based on three years of rate revenue.

Twenty-seven System Renewal investments were carried out over the 2018-2020 period with annual costs shown in the table below. Asset condition is the primary driver for these investments and their completion is expected to improve the reliability performance of the identified outliers.

$ Millions (Net Capital, Actual)	2018	2019	2020
System Renewal	32.8	48.8	71.5

b) The forecast 2023-2027 capital expenditures for System Renewal investments that also provide remediation to Delivery Point outliers is shown in the table below.

$ Millions (Net Capital, Forecast)	2023*	2024*	2025*	2026*	2027*
System Renewal	136.3	144.9	114.8	26.9	17.6

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

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B2 - SCHOOL ENERGY COALITION INTERROGATORY - 089

Reference:
Exhibit B-2-1, TSP Section 2.7

Interrogatory:
Please provide a table that shows both the total, and for each category of capital expenditures (i.e. system renewal, system service, etc.), the budget at each stage of the transmission investment planning process.

Response:
Please see the below table:

OEB Category	2023-2027 Transmission Capital Expenditure ($ Millions)						
	Candidate Investment Development	Prioritization and Optimization	Customer Engagement Phase 2	Enterprise Engagement	Final Plan	Final Plan - Filed	Final Plan – Inflation Update*
1. System Access	217	154	243	295	297	297	312
2. System Renewal	9,058	6,358	6,299	6,212	6,199	6,199	6,525
3. System Service	1,000	683	775	466	461	461	486
4. General Plant	900	468	490	604	606	606	638
5. Progressive Productivity	-	-	0	(305)	(305)	(305)	(321)
Total	**11,175**	**7,663**	**7,807**	**7,273**	**7,258**	**7,258**	**7,639**

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.*

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B2 - SCHOOL ENERGY COALITION INTERROGATORY - 092

Reference:

Exhibit B-2-1, TSP Section 2.8, Attachment 1

Interrogatory:

Please provide a version of 2-AB on an in-service additions basis. Please also provide the table in Excel format.

Response:

Please see updated Attachment 1.

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Appendix 2-AB

Table 2 - In-Service Addition Summary from Chapter 5 Consolidated

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned) ****				
	2018			2019			2020			2021			2022			2023	2024	2025	2026	2027
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast *****	Var	Plan	Forecast[2]	Var					
			%			%			%			%			%					
System Access	68.2	12.1	-82%		72.6	--	8.6	7.2	-16%	13.8	15.1	10%	52.3	43.6	-17%	75.7	51.4	63.9	66.5	41.0
System Renewal	761.4	852.3	12%		744.8	--	821.3	824.5	0%	735.9	653.7	-11%	1,031.0	895.3	-13%	1,157.6	1,227.7	1,488.5	1,149.9	1,476.5
System Service*	244.8	218.0	-11%		45.5	--	54.2	32.6	-40%	235.7	180.7	-23%	182.0	386.6	112%	60.6	21.7	172.3	75.7	104.4
General Plant	104.0	77.9	-25%		96.6	--	75.1	79.9	6%	134.5	156.3	16%	82.5	80.1	-3%	166.8	156.6	135.1	119.6	126.1
Progressive Productivity							- 15.8	-		- 36.3	-		- 56.7	- 24.1		- 56.2	- 64.2	- 64.2	- 64.2	- 64.2
Other**							- 12.9	-		- 27.3	-		- 28.8	-						
TOTAL IN-SERVICE ADDITIONS	1,178.4	1,160.4	-2%	-	959.5	--	930.5	944.3	1%	1,056.2	1,005.9	-5%	1,262.2	1,381.6	9%	1,404.5	1,393.2	1,795.6	1,347.5	1,683.8
System O&M***	$ 394.3	$ 419.2	6%		$ 357.9	--	$ 385.0	$ 398.5	3%		$ 389.0	--		$ 393.4	--	$ 442.6				

* The 2019-2022 Actuals exclude new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan).

** Includes OPEB, pension and compensation directive adjustments.

*** System O&M reflects total Operations, Maintenance and Administration expenses. 2024 - 2027 is determined based on the escalation factor identified in Exhibit A-04-02.

**** The 2023-2027 forecast rreflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

***** This reflects the 'as-filed' forecast, please refer to Exhibit O-02-01, Attachment 5 for 2021 Actuals.

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

B2 - SCHOOL ENERGY COALITION INTERROGATORY - 094

Reference:

Exhibit B-2-1, TSP Section 2.9, Attachment 1

Interrogatory:

Please provide a version of 2-AA with additional columns that show the approved expenditures (as calculated for the purposes of the DRO) in each year between, 2018 to 2022. Please also provide the table in Excel format.

Response:

Please see updated Attachment 1.

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Appendix 2-AA
Capital Projects Table ($M)

Projects	2018 Actual	2018 Plan	2019 Actual	2019 Plan	2020 Actual	2020 Plan	2021 ** Forecast	2021 Plan	2022 Forecast	2022 Plan	2023* Test	2024* Test	2025* Test	2026* Test	2027* Test
Reporting Basis	USGAAP		USGAAP		USGAAP		USGAAP		USGAAP		USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
System Access															
Generator Customer Connection	0.3	1.2	0.5		2.2	0.8	1.3	1.5	-	-	-	-	-	-	-
Load Customer Connection	28.5	18.1	40.1		18.4	23.4	38.3	9.2	25.9	11.2	43.8	71.6	60.0	37.5	51.9
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	4.4	5.0	5.9		(1.7)	0.4	0.5	0.5	5.5	0.5	39.8	3.0	3.0	0.9	0.9
P&C Enablement for Generation Connections	0.5	(0.0)	(0.3)		0.6	0.1	-	-	-	-	-	-	-	-	-
Other	-	-	-		0.0	-	-	-	-	-	-	-	-	-	-
Sub-Total	33.7	24.3	46.2	-	19.5	24.8	40.1	11.3	31.5	11.7	83.6	74.6	63.0	38.4	52.8
System Renewal															
Ancillary Systems	0.7	0.5	0.1		(15.7)	-	-	-	-	-	-	-	-	-	-
Circuit Breakers	0.1	3.0	1.3		0.5	0.2	-	-	-	-	-	-	-	-	-
Integrated Station Investment	410.7	397.4	426.8		499.7	465.6	359.8	555.3	512.5	494.6	771.8	760.4	736.3	734.9	767.1
IT Security	22.9	31.3	24.5		35.9	36.0	40.9	39.0	34.4	34.2	-	-	-	-	-
Other Power Equipment	0.3	0.2	0.2		0.0	-	-	-	-	-	-	-	-	-	-
Overhead Lines Refurbishment Projects, Component Replacement Programs	221.2	222.8	230.5		196.0	209.8	243.8	282.7	297.2	287.4	285.5	356.3	427.3	479.0	461.4
Power Transformers	(0.7)	0.5	(2.7)		(2.5)	-	0.1	-	-	-	-	-	-	-	-
Protection and Automation	21.6	26.7	18.6		14.4	25.7	29.6	29.7	54.5	51.7	85.9	93.1	92.1	72.5	38.0
Site Facilities and Infrastructure	0.3	0.6	0.2		0.3	-	-	-	-	-	-	-	-	-	-
Tx Transformers Demand and Spares	82.6	67.2	78.2		68.3	63.5	51.3	52.9	45.4	45.8	53.4	54.2	54.9	56.0	56.9
Underground Lines Cable Refurbishment & Replacement	16.5	30.1	14.9		7.1	9.4	14.2	23.1	27.6	44.5	43.3	28.8	6.7	2.0	6.9
Sub-Total	776.1	780.4	792.6	-	804.0	810.1	739.6	982.8	971.5	958.2	1,239.8	1,292.8	1,317.3	1,344.4	1,330.4
System Service															
Inter Area Network Transfer Capability	48.9	39.0	57.9		144.8	152.7	174.4	77.0	86.2	127.5	33.1	26.4	25.8	68.8	63.5
Local Area Supply Adequacy	20.7	27.8	19.7		41.6	-	44.9	-	34.1	-	57.7	77.9	61.9	27.1	29.2
Performance Enhancement	0.0	0.3	0.6		3.2	38.7	0.7	66.2	1.2	20.7	2.6	0.5	0.5	-	-
Power Quality	1.4	4.1	3.1		1.9	2.6	0.8	0.5	0.1	0.5	-	-	-	-	-
Risk Mitigation	2.6	4.5	4.2		4.6	1.8	3.2	0.9	0.5	0.9	2.1	2.1	2.1	2.1	2.1
Smart Grid	0.2	-	0.1		0.0	2.6	-	3.6	-	2.3	-	-	-	-	-
Sub-Total	73.9	75.6	85.6	-	196.1	198.4	223.9	148.2	122.0	151.8	95.6	107.0	90.3	98.0	94.8
General Plant															
Fleet	9.3	31.3	15.0		13.5	17.5	14.4	14.5	14.9	17.7	27.2	27.8	28.1	28.5	29.4
Facilities & Real Estate	23.4	16.6	16.0		19.7	15.8	15.4	15.1	15.5	15.1	27.4	26.2	18.4	19.1	15.5
Information Technology	42.0	28.9	47.1		42.2	25.7	30.1	18.3	29.1	16.1	60.5	49.0	47.4	46.0	37.8
System Operations	3.8	13.8	6.0		38.8	11.2	59.0	11.9	21.8	12.0	12.6	4.0	4.4	5.1	4.4
Operating Infrastructure	5.8	29.1	8.7		7.5	40.9	18.9	34.7	21.5	33.7	26.9	23.6	22.0	23.3	23.4
Other	(0.7)	-	(0.7)		3.0	-	-	-	-	-	-	-	-	-	-
Sub-Total	83.6	119.7	92.1	-	124.7	111.1	137.8	94.4	102.8	94.7	154.5	130.5	120.2	122.0	110.5
Progressive Productivity		-				(17.0)		(39.0)	(48.1)	(61.0)	(64.2)	(64.2)	(64.2)	(64.2)	(64.2)
Other**		-				(25.5)		(28.4)		(29.1)					
Total	**967.3**	**1,000.0**	**1,016.5**	**-**	**1,144.4**	**1,101.9**	**1,141.5**	**1,169.2**	**1,179.7**	**1,126.4**	**1509.3**	**1540.7**	**1526.6**	**1538.5**	**1524.3**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***															
Total	**967.3**	**1,000.0**	**1,016.5**	**-**	**1,144.4**	**1,101.9**	**1,141.5**	**1,169.2**	**1,179.7**	**1,126.4**	**1509.3**	**1540.7**	**1526.6**	**1538.5**	**1524.3**

* The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

** This reflects the 'as filed' forecast, please refer to Exhibit O-02-01, Attachment 2 for 2021 Actuals

B2 - SCHOOL ENERGY COALITION INTERROGATORY - 095

Reference:

Exhibit B-2-1, TSP Section 2.9, Attachment 1

Interrogatory:

Please provide a version of 2-AA that shows the information on an in-service additions basis. Please also provide the table in Excel format.

Response:

Please see updated Attachment 1.

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Appendix 2-AA

Capital Projects Table ($M) [In-Service Additions Basis]

Projects	2018	2019	2020	2021***	2022	2023**	2024**	2025**	2026**	2027**
	Actual	Actual	Actual	Forecast	Forecast	Test	Test	Test	Test	Test
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
System Access										
Generator Customer Connection	(0.8)	0.3	0.4	1.9	-	-	-	-	-	0.0
Load Customer Connection	8.6	65.6	4.6	14.4	43.1	31.9	48.6	60.9	65.1	40.1
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	3.7	7.0	0.5	(1.6)	0.5	43.8	2.8	3.0	1.4	0.9
P&C Enablement for Generation Connections	0.5	(0.3)	1.8	0.4		-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
Sub-Total	12.1	72.6	7.2	15.1	43.6	75.7	51.4	63.9	66.5	41.0
System Renewal										
Ancillary Systems	5.3	0.3	(15.7)	0.5	-	-	-	-	-	-
Circuit Breakers	-	2.5	1.1	0.5	-	-	-	-	-	-
Integrated Station Investment	519.3	392.2	496.1	290.1	484.1	792.0	738.7	790.8	531.1	857.4
IT Security	8.8	27.7	18.5	48.6	39.5	-	-	-	-	-
Other Power Equipment	0.2	0.1	-	0.7	-	-	-	-	-	-
Overhead Lines Refurbishment Projects, Component Replacement Programs	192.1	222.2	205.2	227.0	306.2	245.0	346.6	425.8	456.7	525.7
Power Transformers	1.7	0.2	-	2.6	-	-	-	-	-	-
Protection and Automation	42.6	22.9	9.1	24.5	18.0	67.4	86.0	102.2	105.8	36.2
Site Facilities and Infrastructure	0.2	0.1	1.1	0.1	-	-	-	-	-	-
Tx Transformers Demand and Spares	79.7	74.5	67.9	58.0	45.1	50.6	53.7	54.4	55.6	56.7
Underground Lines Cable Refurbishment & Replacement	2.4	2.1	41.3	1.1	2.4	2.6	2.7	115.3	0.6	0.6
Sub-Total	852.3	744.8	824.5	653.7	895.3	1,157.6	1,227.7	1,488.5	1,149.9	1,476.5
System Service*										
Inter Area Network Transfer Capability	205.3	18.9	4.7	140.9	299.8	47.7	1.1	37.8	-	80.8
Local Area Supply Adequacy	10.1	15.9	16.4	34.8	85.8	8.1	18.5	129.8	73.6	21.5
Performance Enhancement	-	-	3.9	-	-	3.2	-	2.5	-	-
Power Quality	1.8	2.2	3.1	1.3	0.4	0.0	-	-	-	-
Risk Mitigation	0.7	8.5	4.5	3.7	0.6	1.6	2.1	2.1	2.1	2.1
Smart Grid	0.2	0.1	-	-	-	-	-	-	-	-
Sub-Total	218.0	45.5	32.6	180.7	386.6	60.6	21.7	172.3	75.7	104.4
General Plant										
Fleet	9.3	15.0	13.5	14.4	14.9	26.6	27.2	28.1	28.5	29.4
Facilities & Real Estate	22.6	18.3	17.4	15.4	14.4	13.8	40.3	14.7	23.0	17.2
Information Technology	35.1	57.8	36.9	26.8	35.7	66.1	41.2	70.9	48.2	43.3
System Operations	7.0	2.3	6.3	85.3	2.0	48.7	3.1	4.4	2.5	8.0
Operating Infrastructure	3.9	5.4	3.7	14.3	13.1	11.6	44.7	17.1	17.5	28.3
Other			2.1			-	-	-	-	-
Sub-Total	77.9	98.8	79.9	156.3	80.1	166.8	156.6	135.1	119.6	126.1
Progressive Productivity					(24.1)	(57.4)	(64.2)	(64.2)	(64.2)	(64.2)
Total	**1,160.4**	**961.6**	**944.3**	**1,005.9**	**1,381.6**	**1,404.5**	**1,393.2**	**1,795.6**	**1,347.5**	**1,683.8**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***										
Total	**1,160.4**	**961.6**	**944.3**	**1,005.9**	**1,381.6**	**1,404.5**	**1,393.2**	**1,795.6**	**1,347.5**	**1,683.8**

* The 2019-2022 Actuals exclude new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan).

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

*** This reflects the 'as filed' forecast, please refer to Exhibit O-02-01, Attachment 5 for 2021 Actuals

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

B2 - SCHOOL ENERGY COALITION INTERROGATORY - 107

Reference:

Exhibit B-2-1, TSP Section 2.11

Interrogatory:

Please provide a table that lists each ISD with the forecast spending for 2023 to 2027, and on the same basis, actual/forecast spending, for each year between 2018 and 2027 (i.e. similar to what filed in response to EB02019-0082, I-12-38(a)).

Please also provide the response in Excel format.

Response:

Please see updated Attachment 1 for a table that lists each ISD in this Application with forecast spending in the test years, and for each ISD provides the actual/forecast spending over the 2018 to 2027 period.

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$ Millions

		Actuals			As-Filed Bridge / Forecast		Test Years				
JRAP ISD Reference	**JRAP ISD Reference Name**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023***	**2024***	**2025***	**2026***	**2027***
T-SA-01	New Customer Connection Station	-	-	-	0.8	7.2	14.2	14.2	-	-	-
T-SA-02	IAMGOLD - 115 kV Mine Connection	0.0	(0.0)	1.4	4.0	10.4	10.5	-	-	-	-
T-SA-03	Halton TS: Build a Second 230/27.6kV Station	-	-	-	-	(0.0)	-	1.6	4.8	2.0	0.1
T-SA-04	Connect Metrolinx Traction Substations	0.0	(0.0)	-	-	-	3.7	3.8	0.9	-	-
T-SA-05	Future Transmission Load Connection Plans	-	-	-	-	-	3.3	5.5	9.9	11.0	11.0
T-SA-06	Protection and Control Modifications for Distributed Energy Resources	0.0	(0.0)	0.1	-	-	-	-	-	-	-
T-SA-07	Secondary Land Use Projects	3.7	5.0	(1.6)	0.5	5.5	39.8	3.0	3.0	0.9	0.9
T-SA-08	H29/H30: Reconductor 230kV Circuits	-	-	-	-	-	0.2	0.4	0.3	2.2	2.4
T-SA-09	New Transformer Station in Northern York Region	-	-	-	-	-	-	-	5.9	3.9	2.5
T-SA-10	Build Leamington Area Transformer Stations	-	-	-	-	1.0	8.0	43.0	35.3	15.3	34.3

		Actuals			As-Filed Bridge / Forecast		Test Years				
JRAP ISD Reference	**JRAP ISD Reference Name**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023***	**2024***	**2025***	**2026***	**2027***
T-SR-01	Transmission Station Renewal - Network Stations	1.4	3.4	8.5	25.0	121.9	220.4	210.1	224.8	166.7	224.3
T-SR-02	Transmission Station Renewal - Air Blast Circuit Breakers	51.6	98.5	162.3	134.6	134.4	181.3	161.8	121.9	104.5	36.2
T-SR-03	Transmission Station Renewal - Connection Stations	8.5	12.0	33.1	95.3	206.5	352.0	376.5	368.5	427.8	451.1
T-SR-04	Wood Pole Structure Replacements	35.3	39.7	47.0	48.8	52.7	59.5	60.7	61.9	63.1	64.4
T-SR-05	Steel Structure Coating Program	37.7	11.1	8.1	21.4	22.6	24.9	25.3	25.8	26.3	26.8
T-SR-06	Tower Foundation Assess/Clean/Coat & LIfe Extension Program	5.8	13.5	10.4	14.6	17.9	18.2	18.5	18.9	19.2	19.6
T-SR-07	Transmission Line Shieldwire Replacement	9.3	8.4	4.5	12.2	12.9	12.7	12.9	13.2	13.5	13.7
T-SR-08	Transmission Line Insulator Replacement	65.5	78.5	57.1	67.5	68.6	82.6	82.1	83.7	85.2	86.8
T-SR-09	Transmission Station Demand and Spares and Targeted Assets	49.6	66.6	60.8	40.2	41.0	46.2	47.0	47.5	48.6	49.4
T-SR-10	Protection Relay Replacement Program	-	-	0.3	4.7	4.7	9.2	9.3	9.4	9.5	9.6
T-SR-11	Legacy SONET System Replacement	3.3	1.5	0.4	0.6	4.6	20.5	30.9	30.8	29.0	8.7
T-SR-12	Telecom Performance Improvements	-	0.1	0.1	1.3	3.3	4.4	6.1	4.0	-	-
T-SR-13	Transmission Line Complete Refurbishment	5.3	2.0	1.3	12.8	45.3	63.3	132.4	200.8	248.3	232.1
T-SR-14	Mobile Radio System Replacement	-	-	-	0.3	3.0	5.5	7.0	5.9	2.5	-
T-SR-15	Transmission Line Emergency Restoration	9.7	9.9	12.0	9.7	9.9	10.7	10.9	11.2	11.4	11.6
T-SR-16	HV UG Cable – Replace/Refurbish Pumping Plants	-	-	-	-	-	-	-	0.1	0.2	5.8
T-SR-17	OPGW Infrastructure Projects	0.3	0.3	0.2	2.2	15.1	30.0	29.2	32.0	21.2	11.0
T-SR-18	C5E/C7E Underground Cable Replacement	0.5	1.0	2.8	11.8	25.1	40.3	24.9	4.9	0.1	-

		Actuals			As-Filed Bridge / Forecast		Test Years				
JRAP ISD Reference	**JRAP ISD Reference Name**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023***	**2024***	**2025***	**2026***	**2027***
T-SS-01	Nanticoke TS: Connect HVDC Lake Erie Circuits	0.0	0.0	0.0	-	-	-	-	-	-	-
T-SS-02	St. Lawrence TS: Phase Shifters Replacement	0.0	0.2	0.2	8.5	18.9	6.3	-	-	-	-
T-SS-03	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	0.0	0.2	0.3	1.0	9.0	9.5	-	-	-	-
T-SS-04	Richview x Trafalgar 230kV Conductor Upgrade	-	0.0	0.4	0.5	5.1	13.3	17.2	12.7	2.5	-
T-SS-05	Merivale TS Add 230/115kV Autotransformers	-	-	-	0.5	2.5	26.3	31.6	23.2	-	-
T-SS-06	Southwest GTA Transmission Reinforcement	0.3	0.3	0.6	0.5	4.1	6.8	7.9	3.2	-	1.1
T-SS-07	West of Chatham Reinforcement	-	-	-	-	2.0	8.8	21.4	5.5	-	-
T-SS-08	Future Transmission Regional Plans	-	-	-	-	-	11.3	21.1	21.5	21.5	21.5
T-SS-09	West of London Reinforcement	-	-	-	-	1.0	4.4	4.5	19.6	64.1	57.7

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

B3 - SCHOOL ENERGY COALITION INTERROGATORY - 136

Reference:

Exhibit B-3-1, DSP Section 3.7

Interrogatory:

Please provide a table that shows both the total, and for each category of capital expenditures (i.e. system renewal, system service, etc.), the budget at each stage of the distribution investment planning process.

Response:

The distribution planning process undertaken in support of this application over the period 2023-2027 is shown below.

OEB Category	2023-27 - Distribution ($M)						
	Candidate Investment Development	**Prioritization and Optimization**	**Customer Engagement Phase 2**	**Enterprise Engagement**	**Final Plan**	**Final Plan - Filed**	**Final Plan – Inflation Update***
1. System Access	1,514	1,165	1,164	1,124	1,124	1,124	1,183
2. System Renewal	3,214	1,811	2,044	2,114	2,267	2,267	2,386
3. System Service	1,560	1,123	977	978	994	994	1,046
4. General Plant	1,471	494	681	913	912	912	960
Total	**7,760**	**4,593**	**4,866**	**5,129**	**5,297**	**5,297**	**5,575**

* *The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Throughout the phases of the planning process described in Section 3.7, planning assumptions continue to evolve in response to the factors described in Section 3.6, including feedback from customer engagement, regional planning, regulatory compliance and system modernization.

Witness: JESUS Bruno

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B3 - SCHOOL ENERGY COALITION INTERROGATORY - 139

Reference:

Exhibit B-3-1, DSP Section 3.8, Attachment 1

Interrogatory:

Please provide Appendix 2-AB on an in-service addition basis. Please also provide in Excel format.

Response:

Please refer to the updated Excel Attachment ‘I-22-B3-SEC-139-01' of this interrogatory response.

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Appendix 2-AB - ISA
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements
Distribution System Plan Filing Requirements ($M)

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (As-Filed)					Forecast Period (Updated for Inflation)*				
	2018			2019			2020			2021			2022			2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Fcst	Var	Plan	Fcst[2]	Var										
			%			%			%			%			%										
System Access	196.9	196.9	0%	147.7	189.9	29%	144.7	197.5	36%	160.8	182.7	14%	143.1	181.2	27%	239.6	241.8	227.5	212.5	204.1	252.1	254.5	239.4	223.7	214.8
System Renewal	229.6	229.6	0%	223.3	201.9	-10%	225.3	217.8	-3%	241.9	248.7	3%	251.2	225.5	-10%	355.2	425.6	504.4	476.3	507.3	372.9	447.9	530.9	501.3	533.9
System Service	113.9	113.9	0%	81.6	89.2	9%	170.9	97.3	-43%	138.8	70.8	-49%	112.4	137.7	23%	226.3	148.8	251.2	200.9	195.1	232.1	156.3	264.4	211.4	205.4
General Plant	87.4	87.4	0%	103.9	104.1	0%	135.9	155.5	14%	164.1	197.9	21%	103.4	112.0	8%	149.9	211.1	220.4	171.5	201.2	155.5	222.2	231.9	180.5	211.8
TOTAL EXPENDITURE	627.8	627.8	0%	556.5	585.1	5%	676.8	668.1	-1%	705.5	700.1	-1%	610.1	656.4	8%	970.9	1,027.3	1,203.4	1,061.2	1,107.8	1,012.5	1,080.9	1,266.6	1,116.9	1,165.9
System OM&A			--														*	*	*	*		*	*	*	*

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.

B3 - SCHOOL ENERGY COALITION INTERROGATORY - 141

Reference:

Exhibit B-3-1, DSP Section 3.8, Attachment 1

Interrogatory:

Please provide a version of 2-AA with additional columns that show the approved expenditures (as calculated for the purposes of the DRO) in each year between, 2018 to 2022. Please also provide the table in Excel format.

Response:

Please refer to the updated Excel Attachment 'I-22-B3-SEC-141-01' of this interrogatory response.

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Appendix 2-AA w/ OEB Approved 2018-2022
Capital Projects Table ($M)

											Forecast Period (As-Filed)					Forecast Period (Updated for Inflation)				
Investment	2018 Plan (DRO)	2018	2019 Plan (DRO)	2019	2020 Plan (DRO)	2020	2021 Plan (DRO)	2021 Bridge	2022 Plan (DRO)	2022 Bridge	2023 Test	2024 Test	2025 Test	2026 Test	2027 Test	2023* Test	2024* Test	2025* Test	2026* Test	2027* Test
System Access																				
D-SA-01 Joint Use and Relocations	20.4	20.4	16.6	28.8	17.7	26.2	17.7	21.4	17.9	19.1	24.8	29.0	27.0	26.5	27.2	26.1	30.5	28.4	27.9	28.7
D-SA-02 New Load Connections, Upgrades, Cancellations	121.2	121.2	108.9	141.7	105.6	146.4	104.6	130.6	105.8	141.7	150.7	154.6	158.5	162.5	166.7	158.6	162.7	166.8	171.1	175.4
D-SA-03 Customer Demand Distributed Energy Resources	6.7	6.7	3.8	6.6	2.6	2.2	1.7	1.9	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5
D-SA-04 Metering Sustainment	26.8	26.8	18.6	20.1	27.6	18.8	26.9	17.6	18.0	18.5	62.6	55.6	40.1	22.2	8.9	65.9	58.6	42.2	23.3	9.4
D-SA-Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total System Access	**175.1**	**175.1**	**147.9**	**197.3**	**153.4**	**193.6**	**150.9**	**171.5**	**143.0**	**180.8**	**239.6**	**240.6**	**227.0**	**212.6**	**204.3**	**252.2**	**253.3**	**238.9**	**223.8**	**215.0**
System Renewal																				
D-SR-01 Distribution Stations Demand Capital Program	6.6	6.6	4.6	5.6	4.8	9.8	4.8	4.9	5.0	5.0	6.2	6.3	6.4	6.5	6.7	6.5	6.6	6.7	6.9	7.0
D-SR-02 Mobile Unit Substation Program	1.3	1.3	4.9	6.9	4.0	4.0	4.8	4.2	4.8	4.3	3.5	4.2	2.9	3.3	4.6	3.7	4.5	3.0	3.4	4.8
D-SR-03 Distribution Station Planned Component Replacement Program	5.0	5.0	6.2	7.7	6.7	8.8	6.8	6.9	6.9	7.1	4.6	3.3	1.1	1.2	1.2	4.8	3.5	1.2	1.2	1.2
D-SR-04 Distribution Station Refurbishment	11.7	11.7	18.7	16.5	14.2	7.4	21.3	6.9	27.6	3.2	44.8	41.5	28.5	32.3	32.1	47.2	43.7	30.0	34.0	33.8
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response	112.7	112.7	75.3	74.6	80.2	118.4	78.7	92.3	79.5	93.8	106.0	108.1	110.3	112.5	114.7	111.6	113.8	116.1	118.4	120.8
D-SR-06 Distribution Lines PCB Equipment Replacement Program	6.3	6.3	9.9	8.1	11.0	4.8	12.4	9.5	12.5	9.5	9.4	9.5	9.5	0.0	0.0	9.9	9.9	10.0	0.0	0.0
D-SR-07 Pole Sustainment Program	52.0	52.0	53.2	44.3	59.7	43.6	58.8	73.4	58.3	60.1	107.9	110.6	112.4	114.9	116.8	113.5	116.4	118.3	121.0	122.9
D-SR-08 Distribution Lines Minor Component Replacement Program	1.4	1.4	7.4	4.9	4.1	6.3	7.2	12.4	7.6	12.3	12.4	14.5	13.5	8.6	7.1	13.0	15.3	14.2	9.0	7.5
D-SR-09 Submarine Cable Replacement Program	3.2	3.2	9.1	6.3	9.7	6.7	9.8	10.9	9.9	11.1	12.2	12.5	12.7	13.0	13.2	12.8	13.1	13.4	13.6	13.9
D-SR-10 Distribution Lines Sustainment Initiatives	7.8	7.8	6.8	8.1	16.6	11.7	22.0	10.7	33.8	13.7	31.5	30.3	35.3	43.2	42.7	33.2	31.9	37.1	45.4	45.0
D-SR-11 Life Cycle Optimization & Operational Efficiency Projects	9.1	9.1	4.0	3.9	5.0	6.2	5.1	2.5	6.8	0.2	2.8	6.5	7.1	0.8	0.4	3.0	6.9	7.4	0.9	0.5
D-SR-12 Advanced Meter Infrastructure 2.0 (AMI 2.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	3.9	30.9	62.0	153.7	154.4	157.3	32.5	65.3	161.7	162.6	165.5
D-SR-Other	2.6	2.6	2.2	2.0	6.3	0.9	5.8	0.8	4.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Total System Renewal	**219.7**	**219.7**	**202.3**	**189.0**	**222.2**	**228.6**	**237.3**	**236.1**	**256.7**	**224.9**	**373.1**	**410.3**	**494.2**	**491.5**	**497.8**	**392.7**	**431.8**	**520.1**	**517.3**	**524.0**
System Service																				
D-SS-01 System Upgrades Driven by Load Growth	26.5	26.5	64.5	45.2	85.5	50.7	98.4	97.1	65.1	108.5	98.2	76.3	127.5	76.1	100.2	103.3	80.3	134.2	80.1	105.4
D-SS-02 Reliability Improvements	1.7	1.7	6.9	4.1	3.5	4.6	5.7	3.8	0.0	3.7	7.3	0.1	6.5	18.6	7.5	7.6	0.1	6.8	19.6	7.9
D-SS-03 Demand System Modifications	7.9	7.9	9.8	11.8	7.3	14.0	10.6	7.5	10.6	10.9	13.2	13.4	13.7	13.9	14.2	13.9	14.1	14.4	14.6	15.0
D-SS-04 Energy Storage Solutions	0.1	0.1	8.0	1.6	0.0	5.0	0.0	3.7	0.0	4.2	34.3	35.0	35.6	36.3	36.0	36.1	36.8	37.5	38.2	37.9
D-SS-05 Worst Performing Feeders	8.3	8.3	15.0	21.9	15.8	20.7	15.2	17.0	12.8	22.0	39.6	40.9	42.2	43.0	43.8	41.7	43.0	44.4	45.2	46.1
D-SS-06 Power Quality and Stray Voltage	1.0	1.0	0.8	1.3	0.9	1.2	0.9	3.3	0.9	3.4	3.8	3.9	4.0	4.0	4.1	4.0	4.1	4.2	4.2	4.3
D-SS-Other	33.6	33.6	19.1	26.9	16.5	2.0	13.3	0.1	13.7	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total System Service	**79.1**	**79.1**	**124.0**	**112.8**	**129.4**	**98.1**	**144.1**	**132.6**	**103.0**	**153.2**	**196.5**	**169.7**	**229.6**	**192.0**	**205.9**	**206.8**	**178.6**	**241.6**	**202.1**	**216.7**
General Plant Allocated to Distribution																				
Fleet	18.1	18.1	27.8	29.0	29.4	25.7	28.3	28.3	28.2	28.5	50.6	51.7	52.2	53.0	54.7	53.2	54.4	55.0	55.8	57.6
Facilities & Real Estate	13.7	13.7	17.6	15.6	39.4	45.0	22.5	23.7	45.2	26.5	65.4	67.2	44.2	39.9	35.7	68.8	70.7	46.5	42.0	37.6
Information Solutions	52.3	52.3	61.6	67.4	47.2	76.2	24.6	66.1	21.6	44.0	62.5	71.6	68.5	78.5	70.2	65.8	75.4	72.1	82.6	73.9
System Operations	5.3	5.3	35.6	4.7	34.3	32.8	19.9	55.7	5.4	5.7	15.4	14.7	4.0	3.2	2.3	16.2	15.5	4.3	3.3	2.4
System Capability Reinforcement	2.9	2.9	0.2	-1.0	0.0	-0.7	0.0	0.0	0.0	1.0	2.0	2.2	1.1	1.0	0.0	2.1	2.3	1.2	1.1	0.0
Other	-1.7	-1.7	0.0	-1.5	0.0	-0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total General Plant	**90.7**	**90.7**	**142.8**	**114.3**	**150.3**	**178.2**	**95.3**	**173.8**	**100.4**	**105.7**	**195.9**	**207.4**	**170.1**	**175.5**	**162.9**	**206.2**	**218.2**	**179.0**	**184.7**	**171.5**
Subtotal (SA, SR, SS)	**473.9**	**473.9**	**474.2**	**499.1**	**505.0**	**520.4**	**532.3**	**540.2**	**502.7**	**558.9**	**809.2**	**820.6**	**950.7**	**896.1**	**908.0**	**851.7**	**863.7**	**1,000.6**	**943.2**	**955.7**
Total	**564.5**	**564.5**	**617.1**	**613.4**	**655.3**	**698.6**	**627.6**	**714.0**	**603.2**	**664.6**	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**	**1,057.9**	**1,081.9**	**1,179.7**	**1,127.9**	**1,127.2**

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

B3 - SCHOOL ENERGY COALITION INTERROGATORY - 148

Reference:

Exhibit B-3-1, DSP Section 3.11, D-SA-02

Interrogatory:

With respect to new Load Connections, Upgrade and Cancellations program:

a) [p.3] Please expand Table 1 to include actual/forecast amounts for 2018 to 2022.

b) [p.9] Please provide tables that shows in same format as Table 3, the cost of i) new connections, ii) service upgrades, and iii) service cancellations, for each year between 2018 and 2027.

Response:

a)

Table 1 - New Connection, Service Upgrade and Service Cancellation Volumes by Year

Description	2018	2019	2020	2021-Q3 YTD Actual	2022	2023	2024	2025	2026	2027
New Connections	17,385	15,355	17,786	14,363	17,178	18,130	18,230	18,330	18,430	18,540
Service Upgrades	4,174	4,154	4,604	3,540	4,330	4,500	4,530	4,550	4,580	4,600
Service Cancellations	3,376	3,168	2,733	2,160	4,992	5,130	5,130	5,130	5,130	5,130

b)

Table 2 - New Connection Costs by Year

$M	2018	2019	2020	2021 Q3 YTD Actual	2022	2023	2024	2025	2026	2027
Gross Investment Costs	118.3	141.0	146.4	117.7	141.4	157.9	161.9	166	170.1	174.4
Less Removals	1.1	1.4	1.4	1.0	1.4	1.6	1.6	1.7	1.7	1.8
Capital and Minor Fixed Assets	117.2	139.7	145.0	116.8	140.0	156.3	160.2	164.3	168.4	172.7
Less Capital Contributions	19.2	24.8	29.7	17.9	26.3	29.4	30.1	30.8	31.6	32.3
Net Investment Costs	97.9	114.9	115.3	98.8	113.7	126.9	130.2	133.5	136.8	140.3

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Table 3 - Service Upgrade Costs by Year

$M	2018	2019	2020	2021 Q3 YTD Actual	2022	2023	2024	2025	2026	2027
Gross Investment Costs	34.9	46.0	52.6	38.0	43.4	48.6	49.9	51.2	52.4	53.7
Less Removals	4.1	5.4	6.3	4.5	5.2	5.8	6.0	6.1	6.3	6.4
Capital and Minor Fixed Assets	30.8	40.6	46.4	33.6	38.2	42.8	43.9	45.0	46.1	47.3
Less Capital Contributions	7.6	13.8	15.6	8.8	10.2	11.2	11.4	11.7	11.9	12.2
Net Investment Costs	23.3	26.8	30.7	24.8	28.0	31.7	32.5	33.4	34.2	35.0

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

1 **Table 4 - Service Cancellation Costs by Year**

$M	2018	2019	2020	2021 Q3 YTD Actual	2022	2023	2024	2025	2026	2027
Gross Investment Costs	2.5	2.9	1.5	1.9	4.1	4.5	4.5	4.6	4.7	4.8
Less Removals	2.5	2.9	1.1	1.8	4.1	4.5	4.5	4.6	4.7	4.8
Capital and Minor Fixed Assets	0.0	0.0	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Costs	**0.0**	**0.0**	**0.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

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B3 - SCHOOL ENERGY COALITION INTERROGATORY - 150

Reference:

Exhibit B-3-1, DSP Section 3.11, D-SR-05

Interrogatory:

With respect to Distribution Lines Trouble Call and Storm Damage Response program, Hydro One states: “The forecast expenditures for this demand program are projected from historical costs and trends. Storm response expenditures are based on an inflation-adjusted average of annual expenditures since 2005, with “outlier” years of unusually high expenditures (i.e. due to more severe storms) removed from the forecast – namely, 2006, 2013, and 2018. The expenditures for other categories of activities are guided by an inflation adjusted three-year historical average.

a) Please provide a breakdown of the program by each categories of activities/spending in this program for each between 2018 and 2027.

b) For the demand program category, please provide the total expenditures between 2005 to 2027.

c) Please explain what type of work in this category would require a capital contribution.

d) For each year between 2018 and 2021, and for each category of spending/activities provided in part (a), please detail the number and type of assets replaced.

Response:

a)

($M)	2018	2019	2020	2021	2022	2023**	2024**	2025**	2026**	2027**
Emergency pole and equipment replacements	18.9	27.3	25.0	21.1	21.4	25.8	26.3	26.8	27.4	27.9
Emergency submarine and underground cable replacements	6.1	7.9	8.0	7.6	7.7	8.6	8.7	8.9	9.2	9.3
Storm damage response	86.0	35.7	70.9	45.8	46.6	55.9	57.0	58.2	59.4	60.5
Post-trouble response*	0.0	0.0	12.7	15.0	15.2	18.2	18.5	18.9	19.3	19.7
Damage claims	1.6	3.8	1.7	2.8	2.8	3.2	3.2	3.3	3.3	3.4

**In 2018/2019 Post-trouble response is included in SS-Other.*
*** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

b) Note, this date range is only applicable to Storm damage response. See part a) for 2018-2027.

(in $ millions)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Storm damage response	$34.5	$82.9	$28.2	$50.4	$34.6	$27.8	$63.7	$40.2	$93.2	$39.9	$52.2	$47.1	$56.4

c) Capital contribution is required for Damage Claims.

d) Hydro One does not internally report on specific number of assets replaced. Reporting is focused on the objectives of the capital program. The table below outlines the portion of the program and the unit reported:

Categories of Activities	Reporting Unit	2018	2019	2020	2021 Q3
Emergency pole and equipment replacements	Poles/Equipment Replaced	2734	3951	3846	2704
Emergency submarine and underground cable replacements	Submarine/UG Cable Replaced (m)	20750	37872	23529	15290
Storm damage response	Number of Customers Restored	N/A*	N/A*	1101234	286237
Post-trouble response	Number of instances 2018/2019, Poles/Equipment Replaced 2020+	1140	1195	453**	385
Damage claims	Number of instances	984	1038	1202	879

**Number of customers restored began being tracked as an objective for storm response starting in 2020.*
***Post-trouble response moved from reporting number of instances to poles/equipment replaced starting in 2020. This is a transition year for the change and does not represent a full year.*

B3 - SCHOOL ENERGY COALITION INTERROGATORY - 154

Reference:

Exhibit B-3-1, DSP Section 3.11, D-SR-12

Interrogatory:

With respect to Advanced Meter Infrastructure 2.0 Program:

a) Please explain the difference in functionality and capabilities between the meters proposed be deployed as part of this program and those previously deployed.

b) [p.20] Please provide an update on the status of the Phase 1 Pre-Deployment RFP.

c) [p.20] Please provide a copy of the material provided to Hydro One's Board of Directors in seeking approval to entire into contract with the selected vendor

d) [p.22] What is the expected life of the meters Hydro One is planning to use as part of the program.

e) [p.24] Do the new meters require a new different network system and hardware or has the hardware also reached its end of life? Please provide details.

f) [p.30] Please provide the full calculations underlying Figure 12.

Response:

a) The overview of Hydro One's current Advanced Metering Infrastructure (AMI) system capabilities (AMI 1.0) can be found Exhibit B-3-1, Section 3.11, D-SR-12, Section A.

The following is an overview of AMI 1.0 function and capabilities:

a. Over-the-air meter readings
b. Record hourly interval readings for Time-of-Use and Two-Tier customer billing
c. Real-time power outage messaging
d. Remote disconnect/reconnect (1% deployment)
e. Basic voltage monitoring (voltage register once per hour)

The following is an overview of AMI 2.0 function and capabilities:

a. Over-the-air meter readings
b. Record 15-minute interval readings for Time-of-Use and Two-Tier customer billing
c. Real-time power outage messaging
d. Remote disconnect/reconnect (all eligible meters deployed)
e. Advanced voltage monitoring (voltage sag, voltage swell, voltage register)
f. Improved network coverage as result of operating at 900 MHz frequency and dynamic bandwidth control
g. Wi-Sun Alliance standards-based hardware and software enabling interoperability
h. Distributed Intelligence (further described below)

One of the most significant advancements in AMI technology in the last 15 years is the introduction Distributed Intelligence (DI) also known as “grid-edge” computing. See Response to OEB staff IR 105 a).

b) As set out in D-SR-012 C.3 Work Scope, Hydro One is progressing through the Pre-Deployment RFP phase 2021 Q3/Q4 program activities and has received a delegation of authority from the Board of Directors authorizing entering into a contract with the selected hardware and software vendor for the new AMI 2.0 solution. The AMI 2.0 Program Management Office has also begun to be established with the recent appointment of a Program Director.

c) The materials provided to the Board of Directors in seeking approval for the delegation of authority in b) above are attached:
- Attachment 1: Advanced Metering Infrastructure 2.0 Appx1_Board Cover Memo
- Attachment 2: Advanced Metering Infrastructure 2.0 Appx 2_ Strategic Overview

d) Hydro One is seeking to purchase meters designed for a 20-year service life.

e) See Response to OEB-Staff-104 a).

f) The details underlying Figure 12 is as follows:

**Total Program Costs by Year:
5-Year Plan**

Period	**Pre-Test**		**Test Period***					**Post-Test**	
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
AMI 2.0 Mass Deployment	$0.7	$1.6	$20.0	$58.5	$137.3	$137.4	$138.5	$91.3	$585.2
AMI 2.0 - HES and Network Management System	$0.1	$0.2	$3.4	$-	$2.6	$2.6	$2.2	$-	$11.0
AMI 2.0 – IT Integration	$-	$2.0	$6.4	$-	$2.2	$-	$-	$1.7	$12.2
ESCALATION	$-	$0.1	$2.8	$6.8	$19.6	$22.5	$25.9	$13.7	$62.1
Meter Inventory Sustainment	$8.4	$8.9	$29.3	$26.0	$18.5	$11.2	$5.3	$1.9	$109.4
Field Metering Services Capital	$5.5	$5.8	$21.7	$18.7	$11.9	$6.0	$1.8	$-	$71.4
Field Network Labor Capital	$1.6	$1.7	$2.4	$2.4	$2.3	$1.9	$1.3	$0.7	$14.2
ESCALATION	$-	$0.3	$5.0	$5.5	$4.5	$3.1	$1.5	$0.4	$11.2
Field Metering - Meter OMA	$2.5	$2.7	$3.3	$3.2	$2.8	$1.9	$0.8	$0.9	$18.1
Field Metering - Sampling - OMA	$1.0	$0.7	$0.8	$1.1	$1.3	$2.7	$1.8	$-	$9.4
DX Leased Circuits	$2.9	$3.0	$3.1	$2.9	$2.3	$1.8	$1.1	$0.4	$17.5
TOTAL	$22.6	$26.9	$98.2	$124.9	$205.3	$191.0	$180.3	$110.9	$921.8

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Total Program Costs by Year: 7-Year Plan										
Period	**Pre-Test**		**Test Period***					**Post-Test**		
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
AMI 2.0 Mass Deployment	$0.7	$1.6	$19.4	$58.0	$118.9	$124.0	$124.9	$75.8	$59.6	$38.1	$621.0
AMI 2.0 - HES and Network Management System	$0.1	$0.2	$3.4	$-	$2.6	$2.6	$-	$2.3	$-	$-	$11.2
AMI 2.0 – IT Integration	$-	$2.0	$3.6	$-	$2.2	$-	$-	$1.7	$1.7	$-	$11.1
ESCALATION	$-	$0.1	$2.5	$6.7	$17.1	$20.4	$23.0	$11.8	$10.4	$6.5	$72.0
Meter Inventory Sustainment	$8.4	$8.9	$29.3	$26.0	$19.1	$12.1	$6.5	$3.3	$1.5	$0.7	$115.7
Field Metering Services Capital	$5.5	$5.8	$21.7	$18.7	$12.4	$6.8	$2.7	$1.0	$0.2	$-	$74.9
Field Network Labor Capital	$1.6	$1.7	$2.4	$2.4	$2.3	$1.9	$1.4	$0.8	$0.4	$0.1	$15.0
ESCALATION	$-	$0.3	$5.0	$5.5	$4.7	$3.3	$1.9	$0.8	$0.3	$0.1	$12.6
Field Metering - Meter OMA	$2.5	$2.7	$3.3	$3.2	$2.8	$1.9	$0.8	$0.9	$0.9	$-	$19.0
Field Metering - Sampling - OMA	$1.0	$0.7	$0.8	$1.1	$1.3	$2.7	$1.8	$-	$-	$-	$9.4
DX Leased Circuits	$2.9	$3.0	$3.1	$2.9	$2.3	$1.8	$1.1	$0.4	$0.4	$-	$17.9
TOTAL	$22.6	$26.9	$94.5	$124.4	$185.8	$177.5	$164.3	$98.8	$75.4	$45.5	$979.8

** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

B4 - SCHOOL ENERGY COALITION INTERROGATORY - 165

Reference:

Exhibit B-4-1, GSP Section 4.9, Page 10

Interrogatory:

Please provide a revised version of Table 3 that includes 'security investments' in the historic/bridge year data on the same basis as now (i.e. proposed to be included as a General Plan expenditure beginning in 2023).

Response:

The revised version including security investments in the historic/bridge year data is provided below in Table 1.

Table 1 - Ten-year capital plan snapshot for General Plant investments and security investments that were classified as System Renewal in 2018-2022.

General Plant Function	Historical Actual/Forecast ($M)				Bridge Forecast ($M)	Forecast Period (Planned $M)**				
	2018	2019	2020	2021*	2022	2023	2024	2025	2026	2027
Fleet	27.4	44.0	39.2	42.7	43.4	80.4	82.1	83.0	84.2	86.9
Facilities and Real Estate	37.1	31.6	64.7	39.1	42.0	96.2	96.9	64.9	61.1	53.1
Information Solutions	117.2	139.1	154.4	137.1	107.4	126.2	124.3	119.5	128.5	111.7
System Operations	9.1	10.7	71.6	114.8	27.5	28.8	19.5	8.6	8.4	6.8
Other	6.3	5.5	8.9	18.9	22.6	29.0	25.9	23.1	24.4	23.4
Total General Plant	**197.1**	**230.9**	**338.9**	**352.6**	**242.8**	**360.7**	**348.8**	**299.2**	**306.7**	**282.0**
Transmission Allocation	106.4	116.6	160.7	178.8	137.2	154.5	130.5	120.2	122.0	110.5
Distribution Allocation	90.7	114.3	178.2	173.8	105.7	206.2	218.2	179.0	184.7	171.5

**This reflects the 2021 forecasted amounts included in the 'as filed' evidence dated August 5, 2021. For 2021 actual amounts, please refer to Exhibit O-2-1, Attachment 4.*
***The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

B4 - SCHOOL ENERGY COALITION INTERROGATORY - 167

Reference:
Exhibit B-4-1, GSP Section 4.9, Attachment 1

Interrogatory:
Please provide Appendix 2-AA on an in-service additions basis. Please also provide the response in Excel format.

Response:
Please refer to Attachment 1 for the Appendix 2-AA Projects and Programs Table for General Plant on an in-service additions basis. Please see Excel Attachment 'I-22-B4-SEC-167-01' for the response in Excel format.

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Appendix 2-AA - In-Service Additions
Projects and Programs Table for General Plant ($M)

General Plant Capital Projects and Programs	2018	2019	2020	2021 Forecast	2022 Bridge	Forecasting Period (Updated Inflation)*				
						2023 Test	2024 Test	2025 Test	2026 Test	2027 Test
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
General Plant Allocated to Hydro One Transmission										
Fleet	9.3	15.0	13.5	14.4	14.9	26.6	27.2	28.1	28.5	29.4
Facilities & Real Estate	22.6	18.3	17.4	15.4	14.4	13.8	40.3	14.7	23.0	17.2
Information Solutions	35.1	57.8	36.9	26.8	35.7	66.1	41.2	70.9	48.2	43.3
System Operations	7.0	2.3	6.3	85.3	2.0	48.7	3.1	4.4	2.5	8.0
Operating Infrastructure	3.9	5.4	3.7	14.3	13.1	11.6	44.7	17.1	17.5	28.3
System Capability Reinforcement						0.0	0.0	0.0	0.0	0.0
Other		-2.1	2.1			0.0	0.0	0.0	0.0	0.0
Total GP Allocated to Transmission	**77.9**	**96.6**	**79.9**	**156.3**	**80.1**	**166.8**	**156.6**	**135.1**	**119.6**	**126.1**
General Plant Allocated to Hydro One Distribution										
Fleet	18.1	29.0	25.7	28.3	28.5	52.5	54.4	55.0	55.8	57.6
Facilities & Real Estate	13.0	12.0	41.4	14.4	29.5	32.3	86.7	61.9	30.6	66.8
Information Solutions	45.0	63.2	80.1	65.7	50.5	56.6	54.4	110.8	89.6	82.6
System Operations	7.3	2.2	6.3	89.5	3.5	10.9	24.3	4.3	3.4	3.7
Operating Infrastructure						0.0	0.0	0.0	0.0	0.0
System Capability Reinforcement	4.1	0.3	-0.7	0.0		3.2	2.3	0.0	1.2	1.1
Other		-2.7	2.7			0.0	0.0	0.0	0.0	0.0
Total GP Allocated to Distribution	**87.4**	**104.1**	**155.5**	**197.9**	**112.0**	**155.5**	**222.2**	**231.9**	**180.5**	**211.8**
Total General Plant	**165.4**	**200.7**	**235.4**	**354.2**	**192.1**	**322.3**	**378.7**	**367.0**	**300.2**	**337.9**

*The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

C - SCHOOL ENERGY COALITION INTERROGATORY - 175

Reference:

No reference provided

Interrogatory:

Please complete the attached Excel table.

Response:

Please refer to the updated Excel Attachment ‘I-22-C-SEC-175-01' of this interrogatory response.

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C-SEC-175a

Transmission

Total Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
Total Capital Expendiures	1,509	1,541	1,527	1,539	1,524
In-Service in 2023	730				
In-Service in 2024	511	707			
In-Service in 2025	195	694	821		
In-Service in 2026	52	96	552	647	
In-Service in 2027	22	43	150	738	732
In-Service in 2028 or later	-	-	3	154	793

System Access Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
System Access Capital Expenditures	84	75	63	38	53
In-Service in 2023	54				
In-Service in 2024	20	32			
In-Service in 2025	9	40	14		
In-Service in 2026	0	1	37	28	
In-Service in 2027	0	2	12	10	17
In-Service in 2028 or later	-	-	-	-	36

System Renewal Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
System Renewal Capital Expenditures	1,240	1,293	1,317	1,344	1,330
In-Service in 2023	580				
In-Service in 2024	483	627			
In-Service in 2025	128	556	719		
In-Service in 2026	33	72	495	550	
In-Service in 2027	16	39	103	681	638
In-Service in 2028 or later	-	-	-	114	692

System Service Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
System Service Capital Expenditures	96	107	90	98	95
In-Service in 2023	33				
In-Service in 2024	9	13			
In-Service in 2025	42	80	50		
In-Service in 2026	8	14	20	34	
In-Service in 2027	3	0	19	53	28
In-Service in 2028 or later	-	-	1	11	66

General Plant Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
General Plant Capital Expenditures	155	131	120	122	111
In-Service in 2023	95				
In-Service in 2024	32	68			
In-Service in 2025	15	51	69		
In-Service in 2026	11	10	32	67	
In-Service in 2027	2	2	17	25	80
In-Service in 2028 or later	-	-	2	29	30

Progressive Productivity ($M)	2023*	2024*	2025*	2026*	2027*
Progressive Productivity	(64)	(64)	(64)	(64)	(64)
In-Service in 2023	(32)				
In-Service in 2024	(32)	(32)			
In-Service in 2025	-	(32)	(32)		
In-Service in 2026	-	-	(32)	(32)	
In-Service in 2027	-	-	-	(32)	(32)
In-Service in 2028 or later	-	-	-	-	(32)

Please complete the shaded areas

* The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

C-SEC-175b

Distribution					
Total Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
Total Capital Expendiures	1,058	1,082	1,180	1,128	1,126
In-Service in 2023	834				
In-Service in 2024	150	925			
In-Service in 2025	65	131	1,071		
In-Service in 2026	6	22	103	986	
In-Service in 2027	3	4	6	112	1,041
In-Service in 2028 or later	-	-	-	29	86

System Access Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
System Access Capital Expenditures	252	253	239	224	215
In-Service in 2023	250				
In-Service in 2024	2	253			
In-Service in 2025	-	1	239		
In-Service in 2026	-	-	0	224	
In-Service in 2027	-	-	-	0	215
In-Service in 2028 or later	-	-	-	-	0

System Renewal Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
System Renewal Capital Expenditures	393	432	520	517	524
In-Service in 2023	355				
In-Service in 2024	27	421			
In-Service in 2025	11	6	514		
In-Service in 2026	-	5	6	490	
In-Service in 2027	-	-	-	17	517
In-Service in 2028 or later	-	-	-	10	6

System Service Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
System Service Capital Expenditures	207	179	242	202	217
In-Service in 2023	117				
In-Service in 2024	50	101			
In-Service in 2025	39	61	164		
In-Service in 2026	1	15	73	122	
In-Service in 2027	-	2	4	61	138
In-Service in 2028 or later	-	-	-	19	79

General Plant Capex/ISA Conversion ($M)	2023*	2024*	2025*	2026*	2027*
General Plant Capital Expenditures	206	218	179	185	172
In-Service in 2023	113				
In-Service in 2024	72	151			
In-Service in 2025	14	64	154		
In-Service in 2026	5	2	24	151	
In-Service in 2027	3	2	2	34	171
In-Service in 2028 or later	-	-	-	1	0

Please complete the shaded areas

* The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-01-02.

B3 - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 012

Reference:

Exhibit B-3-1, DSP Section 3.11, SR-12

Interrogatory:

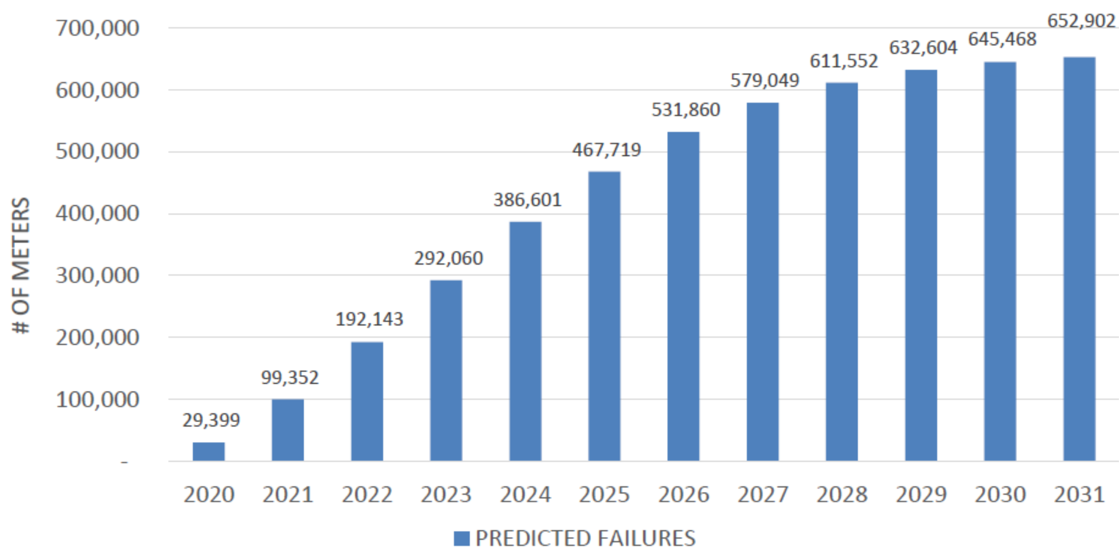


Figure 2: Projected Accumulated GEN 1 Meter Failures Based On ALT Results at the 50% Confidence Level

a) Given the magnitude of the project why did Hydro One not choose to use the regulatory constructs of the ACM or ICM for the AMI program?

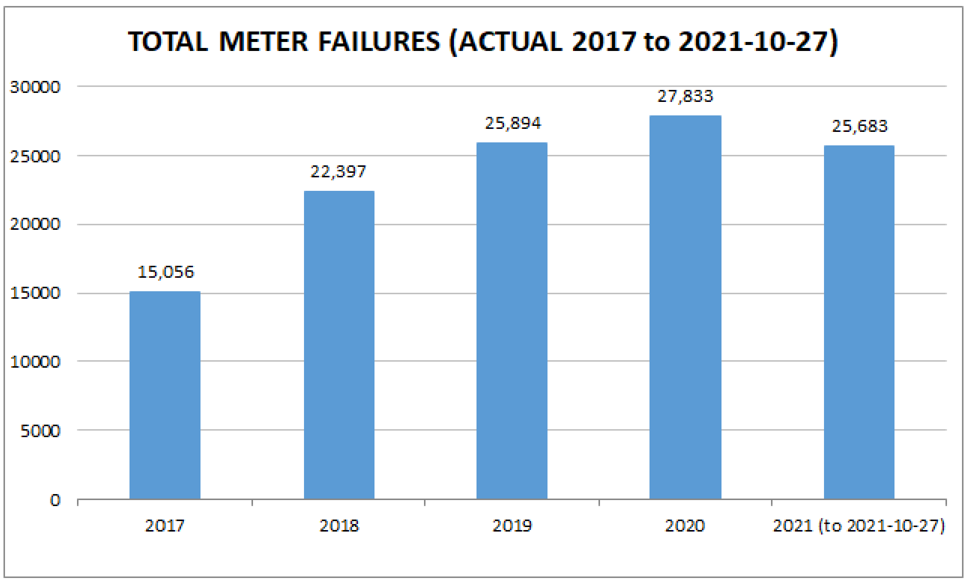
b) Please provide the actual meter failures in 2020 and 2021 (to-date).

c) Please provide a list of the IT systems with operational interdependency to the AMI system. For each of these IT systems please note if and when an upgrade to that system will be required in conjunction with AMI 2.0; the timing of that update and its estimated cost.

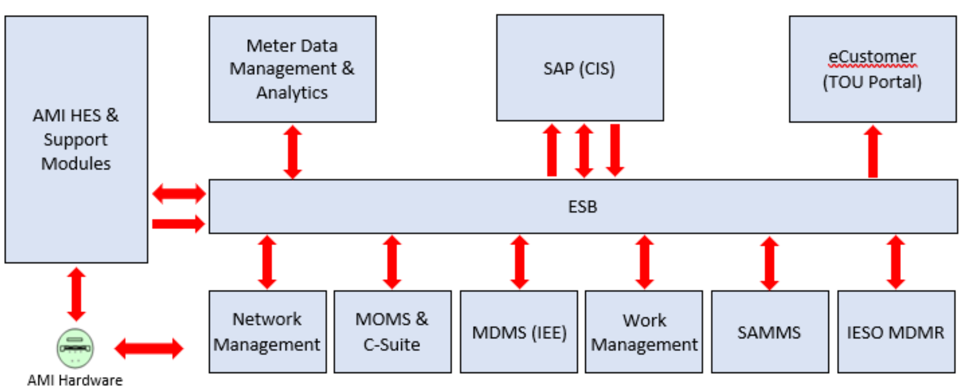
Response:

a) Hydro One's application is a Custom IR. The ICM and ACM mechanisms for funding capital projects are not available to utilities pursuing a Custom IR application.

b) The total number of meter failures issued up to October 27, 2021 is provided in the Figure below.



c) IT systems with operational interdependencies to the AMI system are set out in the figure below:



No major upgrades, apart from the replacement of the AMI 2.0 Head End System (HES), have been identified to interdependent AMI 2.0 systems. The estimated costs associated with standard enhancements of integrating the AMI 2.0 HES to related systems are provided in the table below. The structured approach to designing, building, integrating, and testing the AMI 2.0 HES (see D-SR-12 Section C.3, Table 4) is planned for the period Q3 2022 through Q2 2023.

Original (IR response to B3-VECC-012)

	Pre-Test		Test Period					Post-Test	
Year	2021	2022	2023	2024	2025	2026	2027	2028	Total
IT Integration	$0	$2.0M	$6.4M	$0	$0	$2.2M	$0	$1.7M	$12.2M

Corrected (IR response to B3-VECC-012*)**

	Pre-Test		Test Period					Post-Test	
Year	2021	2022	2023	2024	2025	2026	2027	2028	Total
IT Integration*	$0	$2.0M	$6.4M	$0	$2.2M	$0	$0	$1.7M	$12.2M
Inflation**	$0	$0	$0.6M	$0	$0.3M	$0	$0	$0.2M	$1.2M
Total	$0	$2.0	$7.0M	$0	$2.5M	$0	$0	$1.9M	$13.4M

**The original response to VECC-012 transposed 2025 and 2026 costs and this error is addressed in the corrected table.*
***The corrected table also provides a line item for inflation escalation.*
****The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

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D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 026

Reference:

Exhibit D-2-1, Page 2

Preamble:

The Application states: "*The costing of external work is determined on the basis of cost causality, consistent with the costing of internal work, using the standard labour rates, equipment rates, material surcharge, and overhead rates. An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit to transmission ratepayers*".

Interrogatory:

a) Please provide a schedule that for each of the years 2018-2023 sets out the "margin" (i.e., the revenues in excess costs) included in each category of External Revenues in Table 1.

Response:

a) Please see below table which sets out the "margin" (i.e., the revenues in excess of costs) for each category of External Revenues for the years 2018 to 2023.

	Historical				Bridge	Forecast
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Secondary Land Use	Note 1					
Station Maintenance *	1.7	1.5	2.1	0.5	0.5	0.5
Engineering & Construction	0.0	0.0	0.0	0.0	0.0	0.0
Other External Revenues	Note 1					

Note 1: As outlined in Exhibit E-4-1, Hydro One does not directly track costs for all its unregulated service revenues, in particular for secondary land use and other external revenues. These costs are embedded in the company's Common Corporate costs. The costing of external work is calculated the same way as for internal work and further described in Exhibit C-9-1 to C-9-4.

** The 2020 historical actual figure in the table was revised due to the Tx external revenue correcting entry described in Exhibit O-01-05*

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D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 027

Reference:

Exhibit D-2-1, Pages 3-4

Interrogatory:

a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast Secondary Land Use External Revenue (per Table 2) for each year with the amounts approved for inclusion in rates over the same period.

b) At page 4 the Application states: "Hydro One has received or expects to receive $4M in 2020, $23M in 2021, and $9M in 2022 and 2023." Please confirm the amount actually received in 2020 and update the annual amounts expected for 2021-2022 as required.

c) The payments from Imperial Oil are characterized as the result of a "one time easement arrangement". For each of the years 2018-2022 what are the total revenues included in Table 2 for such arrangements and what are the forecast amounts included for each of the years 2023-2027?

Response:

a) The following table outlines the 2018 to 2022 actual/forecast secondary land use external revenues (as per Table 2 of Exhibit D-2-1) compared to the OEB approved amounts.

Secondary Land Use Revenue ($ Millions)	Historical				Bridge
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast
Actual */ Forecast[1]	25.6	26.9	28.4	46.5	28.8
OEB Approved	15.6	15.6	23.5	23.5	23.5

Note: the 2019 Transmission Revenue Requirement Application (EB-2018-0130) was an inflationary update application from 2018.
** The 2019 and 2020 historical actual figures in the table were revised due to the Tx external revenue correcting entry described in Exhibit O-01-05*

b) The amount of $4 million was received in 2020, $23 million is forecast in 2021, and $9 million is forecast between 2022 and 2023.

[1] Exhibit D-2-1, Table 2

c) The total combined forecast for the Imperial Oil payments on the Waterdown to Finch Pipeline project is approximately $36 million between years 2020 and 2023. Hydro One received $4 million in 2020, is forecast to receive $23 million in 2021, and is forecast to receive an additional $9 million between 2022 and 2023, as outlined in response to part (b) above. There are no other revenues forecast for the 2024 to 2027 period for this project.

D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 028

Reference:

Exhibit D-2-1, Page 5

Interrogatory:

a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast Station Maintenance External Revenues (per Table 3) for each year with the amounts approved for inclusion in rates over the same period.

b) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast Engineering and Construction External Revenues (per Table 4) for each year with the amounts approved for inclusion in rates over the same period.

Response:

a) The following table outlines the 2018 to 2022 actual/forecast station maintenance external revenues (as per Table 3 of Exhibit D-2-1), compared to the OEB approved amounts.

Station Maintenance ($ Millions)	Historical				Bridge
	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Forecast	Forecast
Actual */ Forecast[1]	4.6	4.0	4.2	3.4	3.4
OEB Approved	5.3	5.3	4.0	4.0	4.0

Note the 2019 Transmission Revenue Requirement Application (EB-2018-0130) was an inflationary update application from 2018.

** The 2020 historical actual figure in the table was revised due to the Tx external revenue correcting entry described in Exhibit O-01-05*

b) The following table outlines the 2018 to 2022 actual/forecast engineering and construction external revenues (as per Table 4 of Exhibit D-2-1) compared to the OEB approved amounts.

[1] Exhibit D-2-1, Table 3

Engineering & Construction ($ Millions)	**Historical**				**Bridge**
	2018	**2019**	**2020**	**2021**	**2022**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**
Actual / Forecast[2]	0.1	0.1	0.2	0.4	0.4
OEB Approved	-	-	0.3	0.3	0.3

Note the 2019 Transmission Revenue Requirement Application (EB-2018-0130) was an inflationary update application from 2018.

[2] Exhibit D-2-1, Table 4

D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 029

Reference:

Exhibit D-2-1, Page-6

EB-2019-0082, Exhibit 10, Schedule 20, part b)

Interrogatory:

a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast Other External Revenues (per Table 5) for each year with the amounts approved for inclusion in rates over the same period.

b) Please explain why Other External Revenues decrease annually from 2023-2026 and then increase in 2027.

c) Do the forecast Other External Revenues include revenues as a result of the vegetation management cycle planned to be completed for Bruce to Milton Limited Partnership every 6 years? If yes, how much and in what years? If not, why not?

d) Do the actual/forecast Other External Revenues include revenues from the leasing of idle transmission lines? If not, why not? If yes, please provide a schedule of the annual actual/forecast revenues for 2018-2027.

e) Do the actual/forecast Other External Revenues include revenues from the by-pass charges? If not, why not? If yes, please provide a schedule of the annual actual/forecast revenues for 2018-2027.

Response:

a) The following table outlines the 2018 to 2022 actual/forecast other external revenues (as per Table 5 of Exhibit D-2-1) compared to the OEB approved amounts.

Other External Revenues ($ Millions)	Historical				Bridge
	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Forecast	Forecast
Actual */ Forecast[1]	10.0	9.5	11.4	8.7	7.2
OEB Approved	7.6	7.6	9.2	10.3	9.4

Note the 2019 Transmission Revenue Requirement Application (EB-2018-0130) was an inflationary update application from 2018.

** The 2018 to 2020 historical actual figures in the table were revised due to the Tx external revenue correcting entry described in Exhibit O-01-05*

b) Other External Revenues includes revenues from work completed by Hydro One Transmission on behalf of the Hydro One's affiliate companies. In particular, the Bruce to Milton LP vegetation management maintenance work which is cyclical in nature during the plan years is driving the fluctuations in this category.

c) Yes, Other External Revenues includes forecast revenues as a result of the vegetation management cycle planned to be completed for Bruce to Milton Limited Partnership as follows:

($ Millions)	2023	2024	2025	2026	2027
Bruce to Milton LP Vegetation Management Maintenance	0.86	0.34	0.30	0.06	0.74

d) Yes, Other External Revenues include revenues from the leasing of idle transmission lines, please see table below for the annual actual/forecast revenues for 2018 to 2027:

($ Millions)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Revenues from Leasing of Idle Transmission Lines	4.0	3.1	2.2	2.5	2.5	2.5	2.5	2.5	2.5	2.5

e) The actual/forecast does not include revenues from temporary by-pass charges due to the cessation of it with Toronto Hydro in 2018.

[1] Exhibit D-2-1, Table 5

D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 036

Reference:

Exhibit D-4-1, Pages 4-5
EB-2019-0082, Exhibit I-10-24
EB-2019-0082, Exhibit JT2.34, Question 11c

Preamble:

The Application states (page 5): "Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2027."

Interrogatory:

a) With respect to Table 2, for what years are the Cumulative CDM Impact on Peak Demand values actual vs. forecast?

b) Please provide breakdown of the Cumulative CDM Impact on Peak Demand as between Energy Efficiency Programs and Codes & Standards for each of the years 2006-2027.

c) Please confirm that the values for the years 2006-2018 are taken from the 2013 LTEP (as the values in Table 2 match those in the 2013 LTEP per EB-2019-0082, Exhibit I, Tab 10, Schedule 24)?

d) Are the values in Table 2 measured at point of delivery (end-use) or point of generation? The footnote suggests that it is point of delivery. However, in the response to Exhibit JT2.34, Q 11 c) the generation level values match those in Table 2.

e) It is noted that the Application refers to the values for the historical years as being "assumed" values (page 5, line 1)? What is the basis for assuming that the actual values for the years 2013-2018 are the same as the forecast values in the 2013 LTEP (e.g., is Hydro One Networks aware of any "after the fact" analysis that would verify this assumption)?

f) Between 2013 and 2018 did the IESO (or the former OPA) provide any updates/revisions to the actual or forecast MW CDM savings for the years prior to 2019 (e.g., in its Annual Planning Outlooks) that differed from the CDM savings for 2013-2018 in the 2013 LTEP? If yes, why weren't these values used instead?

g) Between 2013 and 2018 did the IESO (or the former OPA) provide any updates/revisions to either the actual or forecast MWH CDM savings for the year prior to 2019 (e.g., in its Annual Planning Outlooks) that differed from the CDM MWh savings in the 2013 LTEP? If yes, why weren't the CDM MW savings for 2013-2018 adjusted to reflect this change, assuming a change in MWh savings would result in a change in MW savings?

Response:

a) The 2006-2019 CDM peak savings is the "estimated" actual from the IESO. Due to data availability issues from IESO, the historical CDM impact can only be "estimated" but not "verified".

b) Hydro One does not have the breakdown of EE and C&S for the peak impact for 2019-2027.

Year	Energy Efficiency (EE)	Code and Standards (C&S)	Total Cumulative CDM Impact on Peak Demand *
2006	289	0	289
2007	760	18	778
2008	853	40	893
2009	930	67	997
2010	1,060	107	1,167
2011	1,034	284	1,318
2012	1,141	329	1,470
2013	1,248	373	1,621
2014	1,435	386	1,821
2015	1,528	413	1,941
2016	1,662	505	2,167
2017	1,575	525	2,100
2018	1,752	639	2,391
2019			2,639
2020			2,648
2021			2,772
2022			2,912
2023			3,033
2024			3,085
2025			3,234
2026			3,423
2027			3,434

* The figures represent the load impact of CDM on summer peak.

c) Confirmed.

d) The values in Table 2 noted above are measured at generation level.

e) Hydro One is not aware of any official "after the fact" analysis on 2013-2018 peak savings for all EE and C&S programs from the IESO.

f) No, there is no updated CDM peak (MW) savings for 2013-2018 from the IESO.

g) Yes, the APO 2020 provided the updated CDM energy MWH savings, however the difference between 2015-2018 energy savings (TWh) used in Hydro One's load forecast in the pre-filed evidence and the APO 2020 is insignificant as shown in the table below.

	2015	2016	2017	2018	2019
OPO2020	13.97	15.03	17.24	19.34	19.48
Energy savings used in load forecasting	13.93	15.55	17.27	19.31	19.41

In the updated evidence, CDM energy savings are the same as in APO 2021.

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D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 038

Reference:

Exhibit D-4-1, Pages 4-5
EB-2019-0082, Exhibit I-10-24

Preamble:

The Application states (page 4): "Hydro One has used the 2013 LTEP assumptions and taken into account the IESO's latest province-wide conservation forecast to establish the CDM impacts in the load forecast. Hydro One adopted two CDM categories that are consistent with the IESO's (then the OPA) 2013 LTEP information: energy efficiency programs and codes and standards. Details of the latest information that was provided in February 2021 by the IESO, which are consistent with the IESO's latest Annual Planning Outlook APO), and the methodology used by Hydro One to derive the CDM impacts for the three charge determinants, have been documented in sections 3.1 and 4.0 of this exhibit."

Interrogatory:

a) Did the 2013 LTEP forecast CDM MW savings for any of the years after 2022. If yes, please provide the forecast savings from energy efficiency programs and code & standards (separately). Please also provide a copy of the source reference.

b) It is noted that the CDM savings set out in Table 2 for the years after 2018 differ from those in the 2013 LTEP. Please describe how the savings from i) energy efficiency programs and ii) codes and standards were determined for each of the years 2019-2027 and provide copies of any relevant sources/references used.

c) If not included in the response to part (b), please demonstrate that the forecast values in Table 2 are consistent with the IESO's CDM demand savings targets for the Interim (CDM) Framework and the 2021-2024 CDM Framework.

d) What was the nature of the "latest information that was provided in February 2021 by the IESO"? Please provide copies of any correspondence or reports received.

e) What information from the latest IESO APO is the forecast consistent with and which IESO APO is the Application referring to?

Response:

a) Yes. The requested information is provided below:

Peak Demand Reduction Associated with Energy Savings Targets

Peak Demand Saving (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EE (historical and future programs)	1248	1435	1528	1662	1575	1752	2022	2321	2357	2470	2636	2865	2985	3125	3224	3378	3444	3556	3720	3880
Codes and Standards (existing and forecast)	373	386	413	505	525	639	777	876	984	1039	1056	1128	1176	1244	1398	1537	1647	1768	1879	1988
Total	1621	1820	1942	2167	2099	2391	2799	3197	3341	3509	3693	3993	4160	4369	4622	4915	5091	5324	5599	5868

b) In the pre-filed evidence, the 2019-2027 Peak savings are derived based on the information from the IESO in Feb 2021 and 2013 LTEP data.

Step 1: The EE peak savings for 2019-2027 is provided by the IESO in Feb 2021.

Peak Demand Reduction Associated with Energy Savings Targets

Peak Demand Saving (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EE (historical and future programs)	1248	1435	1528	1662	1575	1752	2022	2321	2357	2470	2636	2865	2985	3125	3224	3378	3444	3556	3720	3880
Codes and Standards (existing and forecast)	373	386	413	505	525	639	777	876	984	1039	1056	1128	1176	1244	1398	1537	1647	1768	1879	1988
Total	1621	1820	1942	2167	2099	2391	2799	3197	3341	3509	3693	3993	4160	4369	4622	4915	5091	5324	5599	5868

The following table is the EE summer peak saving from the IESO in February 2021. The C&S savings are not included.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Summer peak savings (IESO_Feb 2021)	2,511	2,493	2,544	2,609	2,683	2,667	2,581	2,469	2,273	(1)
Incremental savings							(86)	(112)	(196)	

Step 2: To construct a consistent data set required for Load forecasting purposes, Hydro One added C&S savings for 2025-2027 based on the 2013 LTEP. The incremental C&S savings in 2027 vs 2024 is 270 MW based on the 2013 LTEP. The judgement was used for the adjustment of C&S to make sure the incremental peak savings is similar to that for the 2021-2024 CDM framework period (175MW).

	2019	2020	2021	2022	2023	2024	2025	2026	2027	
EE (historical and future programs)	2022	2321	2357	2470	2636	2865	2985	3125	3224	
Codes and Standards (existing and forecast)	777	876	984	1039	1056	1128	1176	1244	1398	(2)
Total	2799	3197	3341	3509	3693	3993	4160	4369	4622	
C&S Incremental savings							48	68	154	(3)=incremental of (2)

Step 3: We added half of the C&S incremental savings to derive the savings for 2025-2027.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Summer peak savings (IESO_Feb 2021)	2,511	2,493	2,544	2,609	2,683	2,667	2,581	2,469	2,273	(1)
Ajudstment (50% of Incremental C&S)							24	34	77	(4)-50%
Peak savings used in the load forecast	2,511	2,493	2,544	2,609	2,683	2,667	2,691	2,725	2,802	(5)-(1)+(

In the updated evidence, the peak values are derived in the following manner.

Step 1. IESO latest load profiles in the 2021 APO, which distinguish between leap-years and non-leap-years, were used to update the 12-month average CDM for peak used in the pre-filed evidence D-4-1, Table 2 for all the years. The peak CDM figures in that table remain intact at this step.

Step 2. For the years 2019-2027, both the peak and 12-month average peak from step 1 was multiplied by the ratio of CDM energy savings in the APO 2021 over the CDM energy savings used in the pre-filed evidence. The resulting load factor, defined as the ratio of average hourly CDM saving over the maximum 1-hour peak saving over the same year, remains above 1 as in the pre-filed evidence indicating that the peak estimate is conservative and to the benefit of customers.

c) In the pre-filed evidence, the forecast values in Table 2 include savings from all historical and future EE programs. The saving targets for the 2019-2020 Interim CDM Framework and the 2021-2024 Framework are part of the total EE savings shown. In the updated evidence, savings are consistent with savings in APO 2021 as detailed in response to part B) above.

d) Please see the Excel table provided as I-24-D-VECC-038-01 to this Exhibit.

e) The pre-filed evidence is referring to the 2020 APO. The forecast in the updated evidence is consistent with APO 2021.

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D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 040

Reference:

Exhibit D-4-1, Pages 6 and 11
Exhibit D-4-1, Appendix A

Preamble:

The Application states: “The load impacts of CDM and embedded generation are added back to the historical data set during the modelling process.”

Interrogatory:

a) What historical months/years were used to estimate the Monthly Econometric Model?

b) What are the annual values for the load impact of CDM added back to the historical data set?

c) What was the basis for the annual CDM (energy) impacts added back to the historical data set? In responding, please indicate whether the historical amounts added back are consistent with the verified CDM results reported by the IESO.

d) What types of embedded generation were added back to the historical data and does the definition match that used for Embedded Generation in the Application (page 6)?

e) What were the annual load impacts for embedded generation that were added back in each of the historical years?

f) What is the Monthly Econometric Model’s predicted annual energy use (before any deductions for CDM or Embedded Generation) for the last year for which 12 months of historical data was available? (Note: Predicted values would the model’s prediction for those years where the actual results were known)? How does this value compare with the actual annual energy use in the same year?

g) What is the Monthly Econometric Model’s predicted annual energy use for each of the subsequent years (before any deductions for CDM or Embedded Generation)?

h) Are the forecast values from the Monthly Econometric Model based on energy use measured at point of generation or at the point delivery to the customer?

Response:

a) From Jan 1970 to Jan 2021.

b) The annual values are presented in the following table.

Year	GWh
2006	1,600
2007	3,500
2008	4,000
2009	4,900
2010	5,400
2011	6,700
2012	7,900
2013	8,900
2014	11,300
2015	12,800
2016	15,030
2017	17,240
2018	19,340
2019	20,400
2020	20,900
2021	22,727

c) The annual values were arrived at after consultation with IESO for use in forecasting load. The basis for the data is summarized in part c) of VECC-57.

d) The embedded generation matches that described in the Application (page 6) and includes: Solar, Wind, Water, Bio, Cogeneration. For more details, see Hydro One's response to Energy Probe-57, part b)

e) The annual embedded generation numbers are presented in the following table.

Year	GWh
2007	802
2008	1,087
2009	1,797
2010	3,034
2011	3,652
2012	4,131
2013	4,651
2014	5,315
2015	6,035
2016	6,635
2017	7,028
2018	7,270
2019	7,361
2020	7,612
2021	8,046

f) The requested information is not available from State-Space software. However, an R-squared of 0.994 and D.W. Statistic of 1.8 indicate that the predicted values were close to actual values.

g) The Monthly Econometric Model's predicted values, gross of CDM and Embedded generation, are presented in the following table.

Year	GWh
2021	160,897
2022	160,271
2023	160,743

h) They are based on energy use at the point of generation.

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D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 041

Reference:

Exhibit D-4-1, Pages 3-11
Exhibit D-4-1, Appendix B

Preamble:

For each of the sectors, Appendix B (pages 27, 30, 32, 36 and 37) states that the impact of CDM has been included.

Interrogatory:

a) What historical years were used to estimate the Annual Econometric Model?

b) What are the annual values for the load impact of CDM added back to the historical data set? For each year, please provide a breakdown as between Residential, Commercial, Industrial, Agricultural and Transportation.

c) What was the basis for the annual CDM (energy) impacts added back to the historical data set? In responding, please indicate whether the historical amounts added back are consistent with the verified CDM results reported by the IESO.

d) There is no reference to the impact of embedded generation being added back to the energy use for the Commercial and Industrial sectors. How was the impact of embedded (behind the meter) generation accounted for in the modelling of Commercial and Industrial Use?

e) Given the Annual Econometric Model is sectoral (i.e., Residential, Commercial, etc.), how does the modelling account for the impact of embedded generation that is sold directly to local distributors?

f) What is the Annual Econometric Model's predicted annual energy use (before any deductions for CDM or Embedded Generation) for the last year for historical data was available? How does this compare with the actual annual energy use in the same year?

g) What is the Annual Econometric Model's predicted annual energy use for each of the subsequent years (before any deductions for CDM or Embedded Generation)?

h) Please confirm that the historical and forecast energy use values per the Annual Econometric Model are measured at the point of use by customers.

Response:

a) The answer for each sector follows:

Residential and Industrial: 1962-2019
Agriculture and Transportation: 1981-2019
Commercial: 1963-2019

b) The CDM impact by sector at end-use level is presented in the following table.

Year	Residential	Commercial	Agriculture	Transportation	Industrial
2006	1,048	351	3	1	59
2007	1,558	1,027	26	9	580
2008	1,781	1,267	29	10	570
2009	2,021	1,758	38	11	652
2010	1,997	2,282	38	11	608
2011	2,450	2,943	39	12	702
2012	2,860	3,383	53	10	951
2013	3,176	3,786	65	13	1,139
2014	4,002	4,893	83	18	1,390
2015	4,120	5,718	114	24	1,791
2016	4,833	6,708	131	28	2,118
2017	5,435	7,543	163	37	2,691
2018	5,967	8,282	196	44	3,336
2019	6,263	8,693	240	50	3,561

c) The annual values presented in part b) were arrived at after consultation with IESO for use in forecasting load. The basis for the data is summarized in part c) of VECC-57.

d) The energy figures by sector are at end-use level. Consequently, the figures are not affected by embedded generation. In other words, they measure usage no matter who is the supplier. The same applies to industrial and commercial users.

e) Please see the response to part d).

f) The predicted values for the year 2019 are presented in the following table.

Sector	Actual	Predicted
Commercial	61976	61546
Residential	46645	46643
Industrial	49165	50288
Agriculture	2870	2822
Transportaion	595	606

g) The predicted values, gross of CDM, over the subsequent years are presented in the following table.

Year	Residential	Commercial	Agriculture	Transportation	Industrial
2020	46,310	62,398	2,867	604	51,109
2021	45,904	62,609	2,882	614	53,702
2022	45,431	63,033	2,954	624	54,159
2023	45,058	63,645	2,808	632	53,504
2024	44,779	64,333	2,796	637	52,413
2025	44,556	65,109	2,801	641	51,285
2026	44,375	65,957	2,785	645	50,220
2027	44,219	66,844	2,761	648	49,165

h) Confirmed.

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D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 043

Reference:

Exhibit D-4-1, Page 6 and 16-18
Exhibit D-4-1, Appendix G
EB-2016-0160, Exhibit I-12-25

Preamble:

The Application states (page 6): "The forecast base year is corrected for abnormal weather conditions as explained in Section 4.1 and the forecast growth rates are applied to the normalized base year value".

The Application states (page 16): "Table 3 presents the forecast prepared for this application before and after deducting the load impacts attributed to embedded generation and CDM for the period 2019 to 2027".

The Application states (page 16): "Appendix D to this Exhibit provides the historical actual and weather-corrected charge determinant data for years 2008 to 2020"

Interrogatory:

a) The graph on page 6 and the second quote referenced above from page 16 suggest that the base year for the forecast was 2020. However, the first quote referenced above from page 16 suggests that it was 2018 (i.e., 2019 is part of the forecast period). Please clarify what the base year was to which the forecast growth rates were applied. As part of the response please confirm that the values for the base year to which the growth rates were applied are actual weather normalized values.

b) With respect to both Table 3 and Appendix G, please indicate for which years are the values provided actual results vs. forecast.

c) Please provide a schedule that sets out the forecast growth rates from each of the three models and the forecast growth rates that were used for to determine the forecast values for each year after the base year.

d) Please confirm that the methodology for forecast the Charge Determinants is the same as that described in EB-2016-0160: "the Ontario peak growth rates, prior to Embedded Generation and CDM deductions, were applied to the 2015 charge determinants. Then the corresponding Embedded Generation and CDM impacts were deducted to arrive at charge determinants net of those impacts." If not confirmed what is the approach used in the current Application?

e) Please provide a schedule that sets out the base year values for the Ontario Demand and each of the three Charge Determinant and their forecast (to 2027) annual values based on each of the three forecasting models and Hydro One's proposed forecast.

Response:

a) Values for 2019 and 2020 are actual. They have been presented alongside the forecast for reference, as in previous rate applications. Hydro One confirms that the base year for the forecast is 2020 and that growth rates are applied to weather normalized values as indicated on page 6 of D-4-1.

b) In Table 3 and Appendix G, data up to 2020 are actual and other subsequent figures are forecast.

c) The forecast growth rates presented in the following table are gross of the load impact of CDM and Embedded Generation when applicable.

Year	Monthly Econometric	Annual Econometric	End-Use	Average	Used
2021	0.42	1.48	0.32	0.74	1.11
2022	-0.39	0.30	0.16	0.02	1.00
2023	0.29	-0.33	-0.11	-0.05	1.03
2024		-0.41	-0.02	-0.22	0.23
2025		-0.34	-0.04	-0.19	0.26
2026		-0.25	-0.09	-0.17	0.33
2027		-0.21	-0.08	-0.15	0.42

The growth rates used in the proposed forecast are higher compared to the average forecast growth rate implied by the forecasting model in view of other considerations including developments in Leamington and surrounding areas and to account for potential additional load growth due to other factors (e.g., EVs) that could materialize. These adjustments reflect a high-side risk on the forecast to the benefit of customers.

d) Confirmed.

e) Please see below the requested forecasts.

Table 1. Load Forecast, Net of the Impact of CDM and Embedded Generation, Based on Monthly Econometric Model

12-Month Average peak in MW	2020	2021	2022	2023
Ontario Peak	19219	19119	18863	18791
H1 Charge Determinant Forecast				
Network	19023	18924	18670	18599
Line Connection	18435	18356	18128	18059
Transformation Connection	15682	15615	15421	15362

Table 2. Load Forecast, Net of the Impact of CDM and Embedded Generation, Based on Annual Econometric Model

12-Month Average peak in MW	2020	2021	2022	2023	2024	2025	2026	2027
Ontario Peak	19219	19353	19248	19037	18892	18645	18402	18307
H1 Charge Determinant Forecast								
Network	19023	19155	19052	18842	18698	18454	18214	18119
Line Connection	18435	18579	18496	18294	18155	17920	17688	17598
Transformation Connection	15682	15804	15733	15562	15444	15244	15047	14970

Table 3. Load Forecast, Net of the Impact of CDM and Embedded Generation, Based on End-Use Model

12-Month Average peak in MW	2020	2021	2022	2023	2024	2025	2026	2027
Ontario Peak	19219	19097	18963	18802	18745	18566	18358	18292
H1 Charge Determinant Forecast								
Network	19023	18902	18769	18610	18553	18377	18170	18105
Line Connection	18435	18335	18223	18070	18016	17845	17647	17583
Transformation Connection	15682	15597	15502	15371	15325	15180	15011	14957

Table 4. Load Forecast, Net of the Impact of CDM and Embedded Generation, Based on Used Growth Rates

12-Month Average peak in MW	2020	2021	2022	2023	2024	2025	2026	2027
Ontario Peak	19219	19272	19323	19416	19414	19303	19191	19238
H1 Charge Determinant Forecast								
Network	19023	19075	19126	19218	19215	19106	18995	19042
Line Connection	18435	18502	18567	18655	18653	18548	18441	18486
Transformation Connection	15682	15739	15794	15869	15868	15778	15687	15725

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D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 051

Reference:

Exhibit D-5-1, Pages 11 and 28-30

Preamble:

The Application (page 18) state: “End-use models are used to analyze the distribution system load by customer rate class”.

Interrogatory:

a) What is the base year used in the End-Use Model and is it the same for all sectors?

b) Do the combined Residential, Commercial, Industrial and Agricultural sectors (per the End-Use Model) represent the same customer classes as the Retail Load used as the dependent variable in the Monthly Econometric Model? If not, please explain the difference.

c) Please explain how the End-Use Model accounted for the fact that Norfolk, Haldimand and Woodstock are ST customers for 2021 and 2022 by then into Hydro One Distribution for 2023 onwards. If the load forecast for the retail customers in these utilities was for 2023 onwards was done separately, please explain the basis for the forecast.

d) Do the forecast results for the End-Use Model reflect the same definition of Retail as used in Table 5 (D/5/1, page 18)? It not, what is the difference?

e) Please provide a schedule that, of each of the three models (Monthly Econometric, Annual Econometric and End-Use, sets out the actual 2020 weather normalized energy (before deducting CDM) and reconcile the differences with the2020 value set out in Table 5 (page 18) for Retail Customers.

Response:

a) 2020.

b) In the End-Use model, all ST non-LDC customers are included in Hydro One load.

c) The End-Use model considers Hydro One retail load excluding Acquired LDCs. For details on the separate forecasts for acquired utilities, please see response to D-VECC-49, part e).

d) No, and the difference is that End-Use retail load includes ST non-LDC load.

e) The 2020 weather normalized energy (before deducting CDM) for monthly and annual econometric models is 23,855 GWh, of which 2,193 GWh accounts for general service customer that had moved to ST. To have consistent series, the latter amount was added to retail load. Deducting back 2,193 GWh from 23,855 GWh, we obtain the 21,661 GWh shown in updated Table 5 noted above. Figures may not add up due to rounding.

2020 Gross Value	23,855
Deduct GS moved to ST	-2,193
Gross Retail Load	21,661

f) The 2020 End-Use model starts with 2020 actual and forecast includes incremental CDM relative to the 2020 base year value. The 2020 weather normalized energy for the End-Use model including ST non-LDC (i.e., ST Direct) is 24,444. Deducting from the latter figure ST non-LDC load of 5,295 GWh, we obtain 19,149 GWh. Finally, adding the 2020 CDM effect of 2,513 to the latter figure we obtain 21,661 GWH, which is the retail gross load as shown in updated Table 5 noted above. Figures may not add up due to rounding.

2020 Net Value	24,444
Deduct ST non-LDC	-5,295
Add CDM	2,513
Gross Retail Load	21,661

D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 052

Reference:

Exhibit D-5-1, Pages 16-18

Interrogatory:

a) Please provide a schedule that sets out;
   i. The actual weather normalized Retail Load for 2016 (before deducting impact of CDM)
   ii. The predicted Retail load for 2020 and the forecast Retail load for 2021-2027 based on the Monthly Econometric Model (before deducting CDM).
   iii. The predicted Retail load for 2020 and the forecast Retail load for 2021-2027 based on the Annual Econometric Model (before deducting CDM).
   iv. The predicted Retail load for 2020 and the forecast Retail load for 2021-2027 based on the End Use Model (before deducting CDM).
   v. The actual Retail load for 2020 and the forecast Retail load for 2021-27 per the Application (before deducting impact of CDM).

b) With respect to the response to part (a), was the same forecast used for the 2023-2027 retail load associated with the Acquired Utilities for all three models. If not please provide the 2023-2027 forecast for the retail load associated with the Acquired Utilities included in each Model's results and in the 2023-2027 forecast Retail load per the Application (Table 5).

c) Please provide the detail calculations setting out how the proposed Retail load forecast (before deducting CDM) for each of the years 2021 to 2027 was determined using the results of these three models.

d) Have the forecast customer volumes for the ST class and the General Service (demand) classes been adjusted to account for GS customers that will now qualify as ST customer based on Hydro One Distribution's proposal to change the ST class eligibility requirements (per L/1/2, page 3)?
   a) If yes, specifically what adjustments were made?

Response:

a)

i. It is 21,845 GWh.

ii. The requested information is provided in the following table. The 2020 value was available as shown in the following table. The model predicted value for 2020 is not available due to State-Space nature of the forecasting model.

Year	Monthly Econometric	Annual Econometric	End-Use	Average	Forecast Used in the Application
2020	21,661	21,661	21,661	21,661	21,661
2021	21,348	21,040	21,626	21,338	21,842
2022	21,593	20,767	21,575	21,311	22,047
2023*	23,106	21,847	22,932	22,624	23,377
2024*		21,941	23,027	22,720	23,487
2025*		22,110	22,900	22,745	23,575
2026*		22,332	22,980	22,898	23,649
2027*		22,522	23,015	23,014	23,838

* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

iii. The predicted 2020 is 21,812 GWh, and actual 21,661; these values exclude retail load moved to ST as explained in response to part e) and are weather normalized. For forecast, after deducting retail load moved to ST, please see response to part ii)

iv. The model predicted value for 2020 is not available due to the nature of the End-Use forecasting model. Please see response to part ii) for the 2020 actual and forecast values for 2021-2027.

v. Please see response to part a) ii).

b) Yes.

c) The forecasts from the three models cited above were examined and, to mitigate uncertainty involved in the future state of the economy in a “rapidly evolving situation” and speed of EV and electrification and other developments, a forecast higher than each of these 3 forecasts was arrived at for this Application to the benefit of customers, as shown in response to part ii). This can also be observed in the growth rates of forecasts discussed in part ii), as presented below.

Year	Monthly Econometric	Annual Econometric	End-Use	Avearge	Forecast Used in the Application
2021	-1.4	-2.9	-0.2	-1.5	0.8
2022	1.1	-1.3	-0.2	-0.1	0.9
2023*	7.0	5.2	6.3	6.2	6.0
2024*		0.4	0.4	0.4	0.5
2025*		0.8	-0.6	0.1	0.4
2026*		1.0	0.3	0.7	0.3
2027*		0.9	0.2	0.5	0.8

* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

d) Yes, the adjustments are presented in the following table.

Adjustment	2023	2024	2025	2026	2027
Moved from GSd to ST	58.2	57.4	56.6	55.7	55.3
Moved from Ugd to ST	13.6	13.5	13.4	13.2	13.1

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D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 055

Reference:

Exhibit D-5-1, Pages 6 and 13-14

Preamble:

The Application (page 13) states: “ST customers include embedded distribution utilities, or large industrial and commercial customers. Both econometric and customer analysis based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.”

The Application also states (page 14): “The econometric approach was used to forecast the load for embedded utilities and industrial analysis was used to forecast the load for the embedded industrial customers. In both cases, results from the customer survey were taken into account in developing the forecast.”

Interrogatory:

a) Please outline the econometric analysis used to forecast the embedded distribution utility load. As part of the response please indicate how the analysis addressed the fact that the Acquired Utilities are only ST customers for 2021 and 2022.

b) Please provide a schedule that sets out:
   i. The actual (weather corrected) embedded distribution utility load for 2020 and the forecast values for 2021-2027 per the Application (before deducting CDM).
   ii. The predicted embedded distribution utility load (before deducting CDM) for 2020-2027 based on the econometric analysis.
   iii. How the customer survey results were taken into account in developing the forecast.

Response:

a) Please see Exhibit D-5-1, Appendix B for the model used to forecast Embedded Utilities load. The embedded portion of Acquired Utilities during the historical period is included in the actual and so is the forecast implied by that model. For the years 2023 to 2027, forecast of Acquired Utilities, which are arrived at separately, are deducted from the Embedded utility load forecast. It should be noted that Woodstock had never been a Hydro One Embedded Utility, and only a portion of Norfolk and Haldimand load was embedded.

b)

i. The requested information is presented in the following table.

Year	GWh
2020	11,962
2021	12,079
2022	12,198
2023 *	11,986
2024 *	12,088
2025*	12,168
2026*	12,221
2027*	12,265

ii. Please see response to Part b) i).

iii. Customer survey had limited responses and was supportive of the econometric results. For example, the results were used to see if the customer expects a new plant development or closure.

D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 056

Reference:

Exhibit D-5-1, Pages 6 and 13-14

Preamble:

The Application (page 13) states: “ST customers include embedded distribution utilities, or large industrial and commercial customers. Both econometric and customer analysis based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.”

The Application also states (page 14): “The econometric approach was used to forecast the load for embedded utilities and industrial analysis was used to forecast the load for the embedded industrial customers. In both cases, results from the customer survey were taken into account in developing the forecast.”

Interrogatory:

a) Please outline the industrial analysis used to forecast the Direct (i.e., large industrial and commercial) load.

b) Please provide a schedule that sets out:
   i. The actual (weather corrected) Direct customer load for 2020 and the forecast for 2021-2027 per the Application (before deducting CDM).
   ii. The predicted Direct customer load (before deducting CDM) for 2020-2027 based on the industrial analysis.
   iii. How the customer survey results were taken into account in developing the forecast.

Response:

a) The industrial analysis was based on several considerations including knowledge through tracking industrial news by sector, information provided by planners/customers, historical trend taking into account the impact of the pandemic on different industries.

b)

i. The requested information is presented in the following Table.

Year	GWh
2020	5,035
2021	5,064
2022	5,106
2023 *	5,378
2024 *	5,375
2025*	5,376
2026*	5,394
2027*	5,507

ii. There was not a separate forecast based on industrial analysis alone.

iii. As noted in response to Part a), various factors were involved in preparing the forecast for Direct load, including a limited number of survey results. For example, the results were used to see if the customer expects a new plant development or closure.

D - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 057

Reference:

Exhibit D-5-1, Pages 7 and 18

Interrogatory:

a) Please explain how CDM is defined for purposes of Tables 4 and 5 (e.g., does it just include the impact or OPA/IESO and distributor-funded efficiency programs?).

b) Tables 4 and 5 only show the impact of CDM on Retail and ST Customers for 2019 and after. Please provide a schedule as to the annual impact of CDM on each of Retail Load and ST Load (broken down between Direct and LDC) for each historical years used to estimate the Monthly Econometric Model and/or the Annual Econometric Model. If CDM includes more than just the impact of energy efficiency programs, please provide a further breakdown by CDM component.

c) Please provide the source documents (or their web-links) from which the historic values provided in part (b) were derived and any supporting calculations regarding their derivation.

d) Are the historical CDM values used by Hydro One consistent with those published by the IESO in its most recent Annual Planning Outlook (APO) and previous publications?
   i. If not, why not?
   ii. If yes, please provide schedule that sets out the actual CDM savings reported by the IESO in its most recent APO and previous publications for the historic period used by Hydro One in its econometric models and demonstrate how the values used by Hydro One are consistent.

Response:

a) The CDM impact on Hydro One distribution load can be grouped in the following categories, which are also used by the IESO:
   - Non-target CDM programs (2005-2010) initiated by both Hydro One and the OPA
   - Target CDM programs (2011-2014 and 2015-2020) initiated by the IESO (former OPA)
   - CDM programs funded by other organizations, such as federal, provincial, and/or municipal governments, natural gas companies, and other non-government organizations
   - CDM impacts from code and standards

b) The requested information is presented in GWh in the following table. Hydro One does not have EE and C&S savings broken down by the categories requested in this interrogatory. Please refer to the response to part c). Hydro One does not have the breakdown for 2006-2021.

Year	Retail	Direct	LDC
2006	195	20	112
2007	430	45	245
2008	491	51	280
2009	606	63	346
2010	670	70	382
2011	845	88	482
2012	985	108	582
2013	1,092	128	629
2014	1,414	159	795
2015	1,619	169	856
2016	1,899	205	975
2017	2,149	227	1,037
2018	2,357	252	1,277
2019	2,464	273	1,193

c) The CDM savings for HONI distribution is based on the total energy savings for Ontario. In the updated evidence the 2021 APO is used as the source of total energy savings for Ontario. The following table lists the data sources for the 2006-2027 savings.

	EE+CS	**Data source**
2006	OPO 2018 Slide 19	D-VECC-057 Attachment 1
2007		
2008		
2009		
2010		
2011		
2012		
2013		
2014		
2015		
2016	APO 2021, Demand Forecast Module Data (Excel) Figure 15, 16, 17, 18. 19 and 20	https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/Demand-Forecast-Module-Data.ashx
2017		
2018		
2019		
2020		
2021		
2022		
2023		

2024		
2025		
2026		
2027		

d)

i. Not applicable.

ii. Yes, the historical CDM energy savings used by Hydro One are as follows:

Year	Annual Energy Conservation Savings (TWh)	Data Source
2006	1.60	OPO 2018 Slide 19
2007	3.50	
2008	4.00	
2009	4.90	
2010	5.40	
2011	6.70	
2012	7.90	
2013	8.90	
2014	11.30	
2015	12.80	
2016	15.03	APO 2021 Figure 15
2017	17.24	
2018	19.34	
2019	20.40	
2020	20.90	
2021	22.73	Estimated based on the linear growth equation (2023 vs 2020)
2022	24.55	
2023	26.38	APO 2021 Figures 16-20
2024	27.54	
2025	28.88	
2026	30.28	
2027	31.49	

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E - VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORY - 069

Reference:

Exhibit E-4-1

Interrogatory:

Table 1 - Summary of Total Common and Other OM&A Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Common Corporate Functions & Services (CCF&S)	203.4	192.6	183.9	206.5	207.8	214.6
Planning	46.8	40.2	39.5	39.0	41.1	42.5
Information Solutions	125.5	136.2	131.2	137.4	134.9	141.8
Cost of Sales - External Work	18.8	9.0	11.8	10.4	9.3	10.1
Other OM&A	-222.5	-256.1	-195.6	-239.4	-247.4	-203.0
Total[2]	**172.1**	**121.9**	**170.7**	**153.9**	**145.8**	**206.1**
Year over Year Change		**-29.2%**	**40.0%**	**-9.8%**	**-5.3%**	**41.4%**

a) Please map the categories in Table 1 above to the associated categories for TX and DX Appendix 2-JC - OM&A Programs tables.

Response:

a) The referenced table in the preamble of this interrogatory reflects total OM&A, inclusive of common costs allocated to other non-regulated segments/affiliates and therefore does not directly map to the Transmission and Distribution Appendix 2-JC – OM&A Program tables. However, within the same exhibit (E-4-1), common and other OM&A costs allocated to Transmission and Distribution are broken down in Tables 2 and 3, respectively, and can be mapped accordingly.

Table 2 - Summary of Total Common and Other OM&A Costs Allocated to Transmission ($M)

	Test	**Tx (E-02-01-01A) – Appendix 2-JC**
Description	**2023***	
	Inflation Update	
Common Corporate Functions & Services (CCF&S)	101.9	Common Functions and Services
Planning	28.9	Asset Management (Planning) costs
Information Solutions	56.5	Information Technology
Cost of Sales - External Work	6.0	Cost of Sales
Other OM&A	-124.9	Other Recovery
Total	**68.4**	

** The 2023 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Table 3 - Summary of Total Common and Other OM&A Costs Allocated to Distribution ($M)

	Test	**Dx (E-03-01-01A) – Appendix 2-JC**
Description	**2023***	
	Inflation Update	
Common Corporate Functions & Services (CCF&S)	93.8	Common Functions and Services
Planning	15.7	Asset Management (Planning) Costs
Information Solutions	90.4	Information Technology
Cost of Sales - External Work	4.6	Cost of Sales
Other OM&A	-88.7	Other Recovery
Total	**115.8**	

** The 2023 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

D - ONTARIO SUSTAINABLE ENERGY ASSOCIATION INTERROGATORY - 003

Reference:
Exhibit D-4-1

Preamble:
Hydro One's transmission and distribution load forecasts include the impact of CDM activities. OSEA is interested in understanding Hydro One's assumptions about CDM.

Interrogatory:
a) For Table 2 (Exhibit D-4-1, pg. 5), Load Impact of CDM on Ontario Demand (MW), please provide the CDM impact on peak demand for winter peaks.

Response:
a) The requested information is provided below:

Year	Cumulative CDM Impact on Winter Peak Demand (MW)
2006	184
2007	494
2008	567
2009	633
2010	740
2011	860
2012	974
2013	1,099
2014	1,216
2015	1,276
2016	1,492
2017	1,438
2018	1,705
2019	1,900
2020	1,924
2021	2,107
2022	2,305
2023	2,445
2024	2,490
2025	2,658
2026	2,850
2027	2,917

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UNDERTAKING JT-3.02

Reference:
I-08-B4-EP-050

Undertaking:
Referring to B4-Energy Probe-50, to do a compare of historical having only combustion engines versus the current plan.

Response:

Table 1 - Capital for 2023 with and without Electrification ($M)

Equipment Type	With Electrification	Without Electrification
	2023	2023
Light & Heavy Non-PTO	22.9	21.3
Heavy PTO	27.0	26.5
Off-Road	6.3	6.3
Miscellaneous	5.5	5.5
Small Off-Road	2.1	2.1
Service Equipment	6.7	6.7
Total	70.7	68.4

**The 2023 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Table 2 - Operating Costs for 2023 with and without Electrification ($M)

Description	With Electrification	Without Electrification
	2023	2023
Operations & Repairs	86.6	86.9
Fuel Costs	27.4	27.5
Depreciation	48.2	48.0
Subtotal	162.2	162.4
Rentals	2.1	2.1
Totals	164.3	164.5

**The 2023 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

The Transport & Work Equipment (TWE) program involves the replacement of end-of-life fleet vehicles with like-for-like replacements and the overall program costs. If no EV are purchased the capital would be reduced by an estimated $2M in 2023. The reduced capital exposure would impact the operating costs with an increase of an estimated $0.1M for fuel, $0.2M in maintenance costs; $0.05M of carbon credit and a reduction in depreciation of approximately $0.2M.

UNDERTAKING JT-3.20

Reference:

I-09-B3-ED-024

Undertaking:

To provide the details and breakdown per annum for Hydro One's projected investment in EVs for 2023 to 2027 of $85.1 million.

Response:

Table 1 - Investment in EVs for 2023 to 2027 ($M)

Equipment Type	2023	2024	2025	2026	2027	Total
EV Light & Heavy Non-PTO	7.4	6.3	12.9	18.0	22.6	67.3
EV Heavy PTO	2.7	3.7	4.7	5.6	5.6	22.3
Total EV Investment	**10.1**	**10.0**	**17.7**	**23.6**	**28.2**	**89.6**
Non-EV Light & Heavy Non-PTO	15.7	16.5	9.5	4.8	0.2	46.7
Non-EV Heavy PTO	24.3	26.1	22.1	21.6	24.6	118.7
Off-Road	6.3	7.1	7.4	7.7	5.8	34.2
Miscellaneous	5.5	3.5	7.2	7.1	8.2	31.4
Total TWE Investment	**61.9**	**63.1**	**63.8**	**64.7**	**67.0**	**320.6**
% of EV Investment	**16%**	**16%**	**28%**	**36%**	**42%**	**28%**
Small Off-Road	2.1	2.2	2.2	2.3	2.3	11.2
Service Equipment	6.7	6.8	6.9	7.2	7.3	34.9
Total GP-01 Investment (Including Service Equipment and Small Off-Road)	**70.7**	**72.3**	**72.9**	**74.1**	**76.6**	**366.8**

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

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UNDERTAKING JT-4.07

Reference:

I-22-B3-SEC-154

Undertaking:

In response to a question from VECC regarding ISA values from B3-SEC-154, Attachment 1, and whether or not VECC could use the ISA values there to match up with the capital values presented B3-SEC-002, Attachment 4, Appendix 2-AA, to clarify the capital and ISA values.

Response:

In summary, capital and ISA values for the Advanced Metering Infrastructure 2.0 (AMI2.0) investment were provided in the following evidence:

1. DSP Section 3.9, Attachment 1 (Appendix 2-AA), Capital Projects Table – August 5, 2021

2. B3-SEC-154, Attachment 1 – Submission to the Board of Directors – November 9, 2021

3. A-SEC-002, Attachment 4 (Appendix 2-AA), Capital Projects Table – November 29, 2021

4. B3-Energy Probe-038, Table 7 Total Investment Cost – November 29, 2021

The correct capital expenditures for the AMI2.0 are those presented in B3-Energy Probe-038 (item 4. above) as these values include corrections for removal costs, as discussed in the interrogatory response. Table 7 from the response is reproduced below:

Table 7 - Total Investment Cost (Corrected Version)

($M)	Prev. Years	2023*	2024*	2025*	2026*	2027*	Forecast 2028+	Total
Gross Investment Cost	4.6	32.5	65.3	161.7	162.6	166.6	128.0	691.9
Less Removals	0.0	0.0	1.4	3.6	3.7	4.8	17.4	30.3
Capital and Minor Fixed Assets	**4.6**	**32.5**	**63.9**	**158.1**	**158.9**	**161.8**	**110.6**	**661.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**4.6**	**32.5**	**63.9**	**158.1**	**158.9**	**161.8**	**110.6**	**661.6**

Note: Exhibit B-3-1 Section 3.11 D-SA-04 Table 2 had removal costs overstated (see IR response to B3-Staff-138). The total net impacts based on errors from Exhibit B-3-1 Section 3.11 D-SA-04 Table 2 and Exhibit B-3-1 Section 3.11 D-SR-12 Table 7 is a total understated net removal cost of $0.8M between 2023 and 2027.
** The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Witness: PAISH David

The errors associated with items 1. to 3. above are as follows:

1. DSP Section 3.9, Attachment 1 (item 1.) and A-SEC-002, Attachment 4 (item 3.):
    a. Did not include $11.9M of removal expenses and incorrectly accounted for removal costs associated with the D-SA-04 Metering Sustainment investment.

2. B3-SEC-154, Attachment 1 – Submission to the Board of Directors:
    a. Differences in the Gross Capital Costs due to rounding errors, the inclusion of OM&A costs in prior years, and an interest charge error in 2023.

These errors are not material and do not have a material impact on the calculation of the revenue requirement, which was presented in the prefiled evidence filed on August 5, 2021.

As part of the Draft Rate Order process, Hydro One will make the necessary corrections to the evidence.

UNDERTAKING JT-4.29

Reference:

I-22-B1-SEC-053

Undertaking:

To consider a request to file the November report confidentially, if HONI is in a position to provide the information on any basis; if not, to advise and explain why.

Response:

Hydro One is not in a position to provide the November 2021 Productivity Report as it has been advised that this would constitute a selective disclosure of non-public material information. As Hydro One Networks Inc. (which includes the businesses of Hydro One Transmission and Distribution) is an indirect subsidiary of a Hydro One Limited and a subsidiary of Hydro One Inc., which are public companies subject to securities laws, Hydro One Networks Inc. is precluded from selectively sharing material non-public information.

Furthermore, Hydro One has provided both 2021 forecast as well as September 2021.

Updated Undertaking

On January 19, 2022 as part of settlement discussions held in conjunction with a motion on interrogatory and undertaking responses and refusals, the parties have concluded and agreed to resolve the matter in respect of undertaking request JT-4.29 as follows:

i. Hydro One with the support of SEC, seeks a consent order from the OEB requiring production of the November 2021 productivity report on a confidential basis, and on that basis Hydro One would be able to produce the report.[1] As a result of the request, the OEB granted the confidential treatment of the undertaking response.[2]

ii. On February 25th, following the fourth-quarter results being released, Hydro One will file the information on the public record and would also file the December 2021 version of the report for the year end.[3]

[1]EB-2021-0110 Motions Hearing, January 19, 2022, pages 10-11, lines 26-3
[2]EB-2021-0110 Motions Hearing, January 19, 2022, pages 20-21, lines 24-5
[3]EB-2021-0110 Motions Hearing, January 19, 2022, page 11, lines 14-18

Updated Response:

December:

Productivity $mm LoB	Description	December YTD Actual	December YTD Budget	Year-End Prior	Year-End Current	Year-End Budget	Status
Distribution Lines	Outsourcing Cable Locates decreases the unit price per locate, Dx Poles efficiently replaced or refurbished, and workforce efficiencies from M2M and Design Optimization & Transformation (DOT)	24.1	29.0	23.1	24.1	29.0	
Forestry	Distribution Line Patrol initiative reduces the need for Forestry to conduct their own patrols of the same lines. Fewer tree casued outages, due to OCP cycle, reduces the number of trouble calls	15.5	14.6	15.8	15.5	14.6	
Tx and Stations	Key initiatives include controls to reduce OT, Continuous Improvement Modeling and Wrench Time Studies to improve labour efficiency, Reducing Hydro Vac Excavations in Stations, Temporary Access Roads and Reconditioning Oil in house.	38.8	43.9	36.6	38.8	43.9	
System Operations	Load Transfer Studies initiative that reduces the unit cost to complete a Load Transfer Study using the Distribution Management System.	1.3	0.9	1.3	1.3	0.9	
Planning	Improved planning of transformers reduces the cost of infrastructure for equivalent service. Maintenance cycle times drives savings as well as a reduction in organizational costs	7.6	21.7	9.6	7.6	21.7	
Engineering	EDM Platform improves the way we track, manage and store drawings, increasing productivity and compliance.	1.1	1.6	1.2	1.1	1.6	
Operations Total		**88.4**	**111.8**	**87.5**	**88.4**	**111.8**	
Customer Service	Savings driven by Call Center and Settlements teams' Insourcing and switching customers to eBilling.	21.9	17.6	20.3	21.9	17.6	
Fleet	Right-sizing the number and type of Fleet vehicles required to deliver the work program and tracking of their use efficiency through Telematics.	45.8	34.3	47.0	45.8	34.3	
Supply Chain	Strategic Sourcing initiatives driving down material and service costs. Also includes savings from Early Pay Discounts and Volume rebates.	79.2	62.5	76.8	79.2	62.5	
Real Estate	Leveraging appraisal reports and property assessments to drive Secondary Land Use Revenue competitive lease rates and reduced property taxes from successful appeals	32.4	5.8	32.3	32.4	5.8	
Corporate	Reduction of in-year Corporate Costs to the historical baseline.	48.4	48.1	46.7	48.4	48.1	
Information Technology	Savings primarily from the Inergi ITO Contract Reduction measured through a lower fixed price	27.8	25.1	28.6	27.8	25.1	
Corporate Total		**255.5**	**193.5**	**251.7**	**255.5**	**193.5**	
Hydro One Total		**343.9**	**305.3**	**339.2**	**343.9**	**305.3**	

November:

Productivity $mm LoB	Description	November YTD Actual	November YTD Budget	Year-End Forecast Prior	Year-End Forecast Current	Year-End Forecast Budget	Status
Distribution Lines	Outsourcing Cable Locates decreases the unit price per locate, Dx Poles efficiently replaced or refurbished, and workforce efficiencies from M2M and Design Optimization & Transformation (DOT)	22.9	26.9	23.2	23.1	29.0	
Forestry	Distribution Line Patrol initiative reduces the need for Forestry to conduct their own patrols of the same lines. Fewer tree casued outages, due to OCP cycle, reduces the number of trouble calls	15.0	14.0	16.7	15.8	14.6	
Tx and Stations	Key initiatives include controls to reduce OT, Continuous Improvement Modeling and Wrench Time Studies to improve labour efficiency, Reducing Hydro Vac Excavations in Stations, Temporary Access Roads and Reconditioning Oil in house.	34.9	39.7	33.0	36.6	43.9	
System Operations	Load Transfer Studies initiative that reduces the unit cost to complete a Load Transfer Study using the Distribution Management System.	1.2	0.8	1.3	1.3	0.9	
Planning	Improved planning of transformers reduces the cost of infrastructure for equivalent service. Maintenance cycle times drives savings as well as a reduction in organizational costs	7.7	11.9	10.7	9.6	21.7	
Engineering	EDM Platform improves the way we track, manage and store drawings, increasing productivity and compliance.	1.0	1.4	1.2	1.2	1.6	
Operations Total		**82.7**	**94.7**	**86.1**	**87.5**	**111.8**	
Customer Service	Savings driven by Call Center and Settlements teams' Insourcing and switching customers to eBilling.	19.3	16.2	19.9	20.3	17.6	
Fleet	Right-sizing the number and type of Fleet vehicles required to deliver the work program and tracking of their use efficiency through Telematics.	35.7	31.5	47.2	47.0	34.3	
Supply Chain	Strategic Sourcing initiatives driving down material and service costs. Also includes savings from Early Pay Discounts and Volume rebates.	73.1	55.7	77.3	76.8	62.5	
Real Estate	Leveraging appraisal reports and property assessments to drive Secondary Land Use Revenue competitive lease rates and reduced property taxes from successful appeals	29.5	5.3	31.6	32.3	5.8	
Corporate	Reduction of in-year Corporate Costs to the historical baseline.	48.4	40.6	46.1	46.7	48.1	
Information Technology	Savings primarily from the Inergi ITO Contract Reduction measured through a lower fixed price	26.2	23.0	28.0	28.6	25.1	
Corporate Total		**232.1**	**172.3**	**250.1**	**251.7**	**193.5**	
Hydro One Total		**314.9**	**267.0**	**336.2**	**339.2**	**305.3**	

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UNDERTAKING JT-5.17

Reference:

I-22-A-SEC-45

Undertaking:

To consider and advise, if reasonably possible within the timeframe for responding to undertakings, re: the new accounting standard that has been applied, if the OEB did not allow capitalization, if they ask to deviate from a U.S. GAAP standard, what would be the revenue-requirement impact.

Response:

If Hydro One is not permitted to capitalize its cloud computing costs, revenue requirement in 2023 will increase by approximately $50M between Transmission and Distribution, with approximately $21M in Transmission and $29M in Distribution. This impact is mainly attributable to the increase in OM&A as capitalized cloud computing costs would have to be recovered as OM&A. The annual revenue requirement impact would decline over the application period as rate base would be reduced as a result of no longer capitalizing assets and placing them in-service.

A correction is required to A-Staff-018 for parts a) and c), shown below, as the analysis performed to quantify impacts from cloud implementation was inadvertently completed against an outdated 2023-2027 investment plan.

<u>Correction to A-Staff-018 part a):</u>

The total amount of capitalized implementation costs in the 2023 test year (total capital in-serviced in 2023) as a result of the adoption of ASU 2018-15 is anticipated to be approximately $29.0M. Prior response indicated that $11.8M of capitalized implementation costs has been included.

<u>Correction to A-Staff-018 part c):</u>

The revised forecasted amounts that have been capitalized each year from 2023 to 2027 are shown below. Note that for clarity, both the capital annual spend as well as annual in-service additions are listed separately in Table 1 and Table 2.

Table 1 - Annual Capital Forecasted for Cloud Implementation

$M	2023	2024	2025	2026	2027
Tx Capital	21.0	19.4	18.4	13.5	9.3
Dx Capital	28.6	37.7	40.0	38.3	33.5
Total	**49.6**	**57.0**	**58.4**	**51.8**	**42.8**

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Table 2 - Annual In Service Additions Forecasted for Cloud Implementation

$M	2023	2024	2025	2026	2027
Tx ISA	12.3	10.4	38.1	17.3	11.5
Dx ISA	16.8	14.9	74.3	45.0	38.1
Total	**29.0**	**25.3**	**112.5**	**62.3**	**49.6**

**The 2023-2027 forecast reflects updated inflation assumptions calculated using the methodology described in Section 2.3 of Exhibit O-1-2.*

Table 3 - Annual In Service Additions Forecasted for Cloud Implementation (previously presented in A-Staff-018)

$M	2023	2024	2025	2026	2027
Tx ISA	5.9	9.4	17.8	15.3	32.9
Dx ISA	5.9	16.8	20.8	31.5	62.5
Total	**11.8**	**26.2**	**38.6**	**46.8**	**95.4**

UNDERTAKING JT-VECC-TCQ-04

Reference:

Exhibit I, Tab 24, Schedule D-VECC 43 c)

Preamble:

VECC 43 c) sets out the annual energy growth rates produced by each models and the annual energy growth rates used by Hydro One in in developing the Transmission load forecast.

Undertaking:

a) Are the 2021 growth rates for each of the three models based on comparing the model's forecast for 2021 with the actual (weather normal) use in 2020?

b) The response to VECC 43 c) indicates that the growth rates are "gross of the load impact of CDM and Embedded Generation when applicable". Does this mean that:

   i. For the Monthly Model the growth rates are gross of CDM and Embedded Generation, but
   ii. For the Annual Model and the End Use Model the growth rates are gross of CDM but not Embedded Generation?

   If not, what does it mean?

c) The response to VECC 43 c) states:

   > "The growth rates used in the proposed forecast are higher compared to the average forecast growth rate implied by the forecasting model in view of other considerations including developments in Leamington and surrounding areas and to account for potential additional load growth due to other factors (e.g., EVs) that could materialize."

   i. What impact from the Leamington developments was factored into the 12 month average system peak forecast for 2021 to 2027?
   ii. What incremental impact was attributed to electric vehicles for the years after 2020?
   iii. What other considerations led to adopting a higher load forecast?

Response:

d) They reflect the year-over-year growth rate of gross load for each forecasting model tuned to 2020 weather-normalised gross load.

e)

i. Yes.

ii. No; annual Econometric and End-Use model are based on usage at customer level (no matter who is the generator) and, as such, are already gross of embedded generation. Thus, embedded generation is not added to actual since it would lead to double-counting embedded generation. Consequently, these forecasts are gross of both embedded generation and CDM as in monthly model.

f) i-iii. The requested information is provided in the following table. The figures are provided as average monthly peak values in MW.

Year	EV	Other *	Leamington
2021	39	10	33
2022	61	16	222
2023	83	21	435
2024	109	28	501
2025	139	86	515
2026	172	156	525
2027	213	243	525

* Includes impact of electrification and other considerations.

The last column of the above table reflects the load impact of new customer connections, largely greenhouses, in Leamington and surrounding areas. The adjustments for EVs and Other factors (e.g., electrification and long-term considerations) were added based on the confidence intervals for the potential impact of those factors on peak load. Hydro One's assumptions for EVs remain consistent with IESO's APO. As noted on page 45, lines 21-26 of the December 14th, 2021, transcript for the technical conference in this proceeding, the adjustments were made to mitigate the high-side risk related to EV and electrification. These adjustments are to the benefit of customers as they result in a load forecast that is higher than what would be implied by the forecasting models alone. In the updated load forecast provided with the Inflation Update, the load that was added to the forecast in the "Other" column above has been adjusted downwards relative to the pre-filed evidence in view of a declining optimism regarding the future state of the economy (as compared to optimistic recovery in short run assumed in the pre-filed evidence). Factors contributing to this change include the following:

1. As detailed in response to LPMA interrogatories 15 and 17, high inflation and significant supply constraints would lead to an increase in interest rates, leading to slower economic growth than expected in the pre-filed evidence. The increase in the Bank Rate set by the Bank of Canada started in early March and is widely expected to continue. Not surprisingly, consumer confidence - which is a leading economic indicator - continuously declined from 55.4 points in July 2021 to 51.4 in February 2022 as shown in: https://tradingeconomics.com/canada/consumer-confidence.

2. A more recent event that would slow down the economic growth is the war in Ukraine, which is expected to further increase inflation and have a negative impact on the global economy as noted by IMF (https://www.imf.org/en/News/Articles/2022/03/05/pr2261-imf-staff-statement-on-the-economic-impact-of-war-in-ukraine). For example, the price of aluminum is forecast to increase by an additional 10% and the price of steel by an additional 30% due to the war and related sanctions, which increases production cost and, thereby, consumer prices. The price of grain products is also expected to rise, affecting consumer prices directly (source: IHS Global Insight). Such world-wide additional inflation and supply constraints would further reduce economic growth and, thereby, load growth in Ontario.

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UNDERTAKING JT-VECC-TCQ-06

Reference:

Exhibit I, Tab 24, Schedule D-VECC 57 c)

Preamble:

VECC 40 b) sets out the annual historic CDM energy savings added back for purposes of the Monthly Energy model.

VECC 40 c) refers to VECC 57 c) for the source of values and VECC 57 c) indicates that, for the period 2006-2018, the source of these values is the 2018 OPO. VECC 57 c), Attachment 1 (Figure 19) provides the actual values as copied below:

Long Term Conservation Forecast													
TWh	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.8	3.1	4.2	5.2	6.3	7.0
Existing program savings and persistence (2006-2018)	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	9.7	9.4	10.0	11.3
Savings from future energy efficiency initiatives (2019 onward)													
	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	13.9	14.6	16.3	18.4

Undertaking:

a) VECC 57 c) indicates that the source of the Ontario CDM energy savings for 2019-2021 is from the IESO and refers to VECC 92 Attachment 1 as the source. However, the Attachment to VECC 92 deals solely with the MW savings attributable to ICI for 2016 to 2019 and has no energy savings data.

   i. Please provide the source of the CDM energy savings values used for 2019-2021.
   ii. As part of the response, please demonstrate that the energy savings for 2019-2020 are consistent with the 1.4 TWh of savings the IESO's Interim CDM Framework targeted for that period.

Response:

i. The sources of the CDM energy savings values used for 2019-2021 in the pre-filed evidence are provided in the table below. Hydro One uses these two different sources to estimate the CDM energy savings because the EE and C&S savings for 2020-2021 are not available in the 2020 APO.

	2019	2020	2021	Data source
EE saving	11.81	11.87	12.86	Information from the IESO 202102 (VECC38 Attachement 1)
C&S	7.6	7.8	8	OPO2018
Total Savings (TWh)	19.41	19.67	20.86	

In this evidence update, CDM energy savings for the years 2019-2021 are the same as in APO 2021.

ii. The EE savings from the IESO included 2006-2018 historical programs, as well as 2019-2020 Framework programs. In the 2020 APO and most recently released 2021 APO, the IESO does not separately present the energy savings for 2019-2020 Framework programs. The table below shows the EE and C&S energy savings in the 2020 and 2021 APO.

APO	Savings TWh	2016	2017	2018	2019	2020	2021
APO2020	Energy Efficiency - Programs	9.86	10.96	12.27	12.11		
	Codes and Standards	5.17	6.28	7.07	7.37		
	Total	15.03	17.24	19.34	19.48	Not provided	
APO2021	Programs (Energy Efficiency Programs)	9.86	10.96	12.27	13.03	13.53	Not provided
	Regulations (Codes & Standards)	5.17	6.28	7.07	7.37	7.37	
	Total	15.03	17.24	19.34	20.4	20.9	